Attachment 5

FAQ Log 10/19/05

TempNo.	PI	Topic	Status	Plant/ Co.
54.1	MS1-4	Exemption of overhaul hours	5/19 Introduced 7/21 Discussed 8/18 Discussed	Catawba
55.1	MS01	Planned unavailable hours	7/21 Introduced 8/18 Awaiting licensee revision 10/19 Revised by Licensee to reflect comments	TMI1
55.2	MS02	Fault exposure hours	7/21 Introduced 8/18 Discussed 9/22/05 Discussed 9/22/05 To be entered into Appeal process.	Millstone 3
56.2	IE02	Scram following Turbine Trip	9/22/05 Introduced 10/19 Revised by Licensee to reflect comments	Seabrook
56.3	MS04	Appendix D – Overhaul Exemption	9/22/05 Introduced	Crystal River 3
56.4	MS01	Appendix D – Exemption of BF1 EDG Restoration Activities	9/22/05 Introduced 10/19/05 Revised by licensee to include requested information.	Browns Ferry Units 2 and 3

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

RESPONSE SECTION

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~~October 17, 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)? Yes

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 C~~c~~ontrol R~~r~~oom. ~~A combination of automatic actions, two manual actions in the control room~~

No immediate manual actions are required to restore the EDG to Operable status. As a result of the modification, the voltage regulator for the diesel under test returns automatically and instantaneously to an Auto/Unit (isochronous, or isolated operation) mode of operation to power safety loads as required. These automatic actions initiated by all emergency signals establish uniform voltage response for emergency mode operation. A longer term proceduralized action for an operator is to make an adjustment to the governor droop adjustment at the local diesel skid.

The dedicated operator in the control room, involved with the test, and local dedicated operator at the diesel are not required to remain at the diesel or Control Room diesel controls for a design start of the equipment from an emergency signal.

The only operator action required is to adjust the EDG governor by turning the Droop knob to zero. The action is proceduralized and this is a long-term action (i.e., hours into the event) that is not required to be sequenced with any other action. Specifically, this action is to 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.

It is understood that during the scheduled diesel test, the local EDG operator is dedicated to the test but may may have other duties associated with a loss of offsite power (or whatever else could have been the initiating event of the emergency signal) and is not required to perform any actions to the diesel before being assigned other critical duties.

The long-term action to locally adjust governor droop at the skid would be included in the surveillance test procedure, station emergency procedures, and operator training on recognition and restoration. Engineering analysis and testing 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. Through the use of procedures and training, completion of that step has a certainty of success due to its simplicity and routing nature. This is an adjustment that is procedurally performed during monthly surveillance testing of the site EDG's.

~~, 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.~~1. ~~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:

TMI has discussed this FAQ with the NRC resident inspector. The NRC resident inspector has not stated any disagreement with this position.

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 at fully loaded surveillance test conditions in this case. Note that unavailability will still need to be counted during the time periods of partial load and setup operations for the monthly surveillance runs. This is based on the following:

1. ~~Although conducted at two locations, the number of steps to~~ There are no immediate operator actions 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 lon-term operator actions ~~are~~is proceduralized and the operators are routinely trained on the action~~s~~ ~~e steps~~. This meets the intent of the "few simple actions" threshold of NEI 99-02, Section 2.2.

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. This is because the analysis shows that this action is a long-term action that does not have to be performed immediately after the initiating emergency signal. Analysis shows that this time will be greater than 1 hour.

6. No troubleshooting is necessary. The single operator reaction to a plant parameter (i.e., the engine droop~~frequency~~ adjustment) is performed after the situation/plant event 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 action~~s are virtually~~ is certain to be successful.

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

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 SIH 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.

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

FAQ 56.1

FAQ 56.1 Withdrawn at 10/22/2005 Public Meeting

FAQ 56.2

Plant: Seabrook

Date of Event: May 1, 2005

Submittal Date: August 18, 2005, Revision Submitted September 29, 2005

Licensee Contact: ~~Mike O'Keefe~~Jim Peschel (603) 773-~~7745~~7194, ~~michael_o'keefe@fpl.com~~james_peschel@fpl.com

NRC Contact: Glenn Dentel (603) 474-3580, gtd@nrc.gov

Performance Indicator: IE02, Unplanned Scrams with Loss of Normal Heat Removal

Site Specific FAQ (Appendix D)? No

FAQ requested to become effective when approved.

Question:
The guidance in question is contained on page 13, lines 3 and 4, and 36 through 42 on *page 14, lines 15 and 16* of~~in pages 13 and 14 of~~ NEI 99-02, Revision 3.

During initial startup activities of the main turbine, following a refueling outage in which the HP turbine rotor was replaced, with reactor power at approximately 17% of rated thermal power the turbine automatically tripped at approximately 1045 rpm when turbine vibration exceeded the trip setpoint of 12 mils. Following the turbine trip, vibration levels continued to increase to between 22 and 24 mils. As a result, the operators manually tripped the reactor in accordance with a station abnormal operating procedure (AOP) in preparation for breaking condenser vacuum to slow the turbine. The emergency feedwater system actuated on low steam generator levels following the reactor trip. Normal feedwater remained available via the starup feed pump and the main steam isolation valves (MSIVs) remained open during the event. Condenser vacuum was broken at 11:09 until the high vibration condition cleared and was then subsequently restored to provide a secondary heat sink. The high vibration trip signal reset after approximately 20 minutes with turbine speed below 350 rpm. The heat removal process that dumps steam to the main condenser was not in service for approximately one hour (restoration of condenser vacuum was started at 11:40). The unavailability of the condenser for this brief period following the reactor trip was inconsequential. Because of the low decay heat with the new core, the emergency feedwater system alone provided more than the required heat removal capability. There was no temperature increase sufficient to demand operation of the atmospheric or condenser steam dump valves. Emergency feedwater flow needed to be throttled to prevent overcooling the plant. In addition, for this event, restoration of condenser vacuum is uncomplicated and would not require any diagnosis or repair. The actions necessary to establish vacuum include locally closing the manually operated vacuum breaker AR-V122 *(condenser vacuum breaker valve)- and remotely (control room)* aligning the vacuum pump discharge and starting the vacuum pumps. The vacuum breaker closure can be accomplished in approximately one minute once an operator is at the valve.

Normal feedwater can be restored by resetting the Feedwater Isolation signal and reopening the associated valves, all actions that are accomplished from the Control Room. In addition, the Startup Feedwater Pump was available to add additional flow to the steam generators if the operator chose to do so. However, as stated above, the emergency feedwater flow was throttled to avoid overcooling.

The turbine startup was being controlled by the Post Maintenance Turbine Startup procedure, a limited use procedure used for controlling turbine startup following major maintenance. A precaution in the procedure states that higher than normal vibration levels are expected at turbine critical speeds of 800 to 1200 rpm. If, during turbine startup, the vibration levels exceed specified limits, the procedure directs the operators to implement the Turbine Generator High Vibration abnormal operating procedure (AOP). A reactor trip is a planned evolution when such a turbine trip occurs if it is required to break vacuum to slow the turbine. The Station operating philosophy is that abnormal operating procedures are used in the Control Room instead of test procedures so as not to unduly challenge the operators or remove them from their normal operating roles. The operators are trained on these procedures, are comfortable using them and know what responses are required. Following a turbine trip, the procedure directs the operators to evaluate breaking condenser vacuum if vibration is greater than 14 mils for greater than 10 seconds and independent of critical speeds; i.e., not at a critical speed. The crews were prepared for the evolution and made aware of the critical parameters during the pre job briefing. The briefing was attended by a nuclear systems operator who would have been dispatched to perform the manual actions required to restore vacuum by operating AR-V122.

The licensee and the NRC Senior Resident inspector do not disagree on the facts and circumstances of the event; however, the licensee and the inspector disagree whether~~that~~ the event should counts against the performance indicator.

Does this reactor trip count against the performance indicator for Unplanned Scrams with Loss of Normal Heat Removal?

~~Proposed~~ Answer:
No, this trip does not count against the performance indicator for unplanned scrams with loss of normal heat removal as the manual scram was not complicated by the conscious decision to break vacuum. As stated in the test procedure, higher than normal vibration levels may be ~~are~~ expected when returning a turbine to service after extensive maintenance and operators are directed to implement the abnormal operating procedure if turbine vibrations exceed specified limits. A reactor trip is ~~a planned~~the next sequential -evolution when ~~such a~~ turbine vibrations do not decrease following the turbine trip~~ occurs~~. Condenser vacuum was broken to expedite slowing the turbine. Station operating philosophy is to use abnormal operating procedures rather than embedding the AOPs in a post-maintenance or special test procedure, so as not to unduly challenge the operators. Operators are trained in making the transition from normal operating procedures to the AOPs, thereby ensuring effective and safe operations. In addition, the crews are prepared for the evolution and made aware of the critical parameters during the pre job briefing. The briefing was attended by a nuclear systems operator who would have been dispatched to perform the manual actions

required to restore vacuum. The actions to be taken, including the requirements for a reactor trip, due to high vibrations during turbine startup are incorporated in abnormal operating procedures. In addition, restoration of condenser vacuum was uncomplicated and did not require any diagnosis or repair nor was there any temperature increase sufficient to demand operation of the atmospheric or condenser steam dump valves. The condenser was readily available as the manual actions necessary to establish vacuum and can be accomplished in approximately one minute once an operator is at the condenser vacuum breaker valve.

FAQ 56.3

Plant: Crystal River Unit 3 (CR-3)
Date of Event: Overhaul work scheduled for the week of 09/26/05
Submittal Date: September 1, 2005
Licensee Contact: Dennis W. Herrin (Licensing Engineer)
Tel/email: 352.563.4633/dennis.herrin@pgnmail.com
Licensee Contact: Kevin Campbell (System Engineer)
Tel/email: 352.795.6486 (ext. 3566)/Kevin.Campbell@pgnmail.com
NRC Contact:
Tel/email:

Performance Indicator: Residual Heat Removal Safety System Unavailability

Site Specific FAQ (Appendix D)? ■ Yes □ No

FAQ requested to become effective prior to the end of 4Q2005 (December 31, 2005).

Question Section

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

From NEI 99-02, Revision 3, Page 27, Lines 28 through 33:

This 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.

Event or circumstances requiring guidance interpretation:

The Crystal River Unit 3 (CR-3) Decay Heat Seawater System contains two Decay Heat Seawater Pumps (RWP-3A and RWP-3B). RWP-3A takes suction from the "A" Raw Water Pit; RWP-3B takes suction from the "B" Raw Water Pit. The pits are supplied with water from the Gulf of Mexico. The system provides cooling water to the tube side of the two heat exchangers removing heat from the Decay Heat Closed Cycle Cooling Water (DC) System and subsequently rejects it to the ultimate heat sink (the Gulf of Mexico) through the discharge canal.

A recently performed operability assessment of Decay Heat Seawater pump RWP-3B demonstrated that although the pump remains operable, it exhibits a degraded flush flow condition. A refurbishment activity to restore the flush water flow to full qualification is being planned to occur at power operation during the best available schedule opportunity. No concern exists that RWP-3B will not continue to perform its intended function for the period leading up to the CR-3 refueling outage scheduled to commence on October 29, 2005. Overhaul of RWP-3B on-line will eliminate the need to perform the overhaul activity during the refueling outage and reduce the risk of relying on an operable, but degraded, component to support mid-loop operations during the outage.

Improved Technical Specification (ITS) 3.7.10, "Decay Heat Seawater System," requires that two Decay Heat Seawater System trains shall be OPERABLE. If one train is inoperable, Condition "A" allows operation to continue for 72 hours. It is estimated that the rebuild activity of RWP-3B will take approximately 5 days. Thus, to perform the refurbishment activity online, a one-time allowed outage time (AOT) extension of the ITS 3.7.10 Completion Time to 10 days is needed. Other systems affected by the extended AOT needed to refurbish RWP-3B require their AOT to also be extended to 10 days. However, no maintenance is being performed on those systems.

CR-3 submitted License Amendment Request (LAR) #289, Revision 0, to the NRC on January 13, 2005. LAR #289, Revision 0, requested a one-time change to the CR-3 Facility Operating License in accordance with 10 CFR 50.90 to increase the Improved Technical Specification (ITS) allowed outage time (AOT) (one time from 72 hours to 10 days) in order to perform on-line overhaul maintenance to Emergency Nuclear Services Seawater Pump RWP-3B. LAR #289 proposed a one-time change to Improved Technical Specifications (ITS) 3.5.2, Emergency Core Cooling Systems (ECCS) - Operating, 3.6.6, Reactor Building Spray and Containment Cooling Systems, 3.7.8, Decay Heat Closed Cycle Cooling Water System (DC) and 3.7.10, Decay Heat Seawater System.

CR-3 submitted LAR #289, Revision 1, to the NRC on June 9, 2005. LAR #289, Revision 1, was necessary to update the probabilistic safety assessment that supports the acceptability of the changes proposed in LAR #289. The specific plant condition is a change in the normal position of the Power Operated Relief Valve (PORV) Block Valve (RCV-11) to be closed. This has been required in order to isolate a Reactor Coolant System (RCS) to Reactor Building atmosphere leak (approximately 2.5 gallons per minute) which was discovered on March 3, 2005, following the quarterly stroke test of RCV-11. In accordance with the evaluation performed for Administrative Instruction AI-506, "Operational Decision Making," CR-3 will be operating with the RCV-10/11 flow path closed during normal operations until Refueling Outage 14 scheduled for Fall 2005. RCV-11 will be opened during certain Emergency Operating Procedure/Abnormal Procedure (EOP/AP) events to allow usage of the PORV during these events.

Calculation P-05-0001, Revision 1, "PSA Risk Assessment of RWP-3B Extended AOT," has been revised to evaluate the risk impacts of operating with the PORV (RCV-10) and Block Valve (RCV-11) in this configuration during the proposed extended AOT for refurbishing RWP-3B.

The NRC issued License Amendment No. 221 to the CR-3 Operating License on September 15, 2005. The amendment revises the Improved Technical Specifications (ITS) to revise the completion time for CR-3 ITS 3.5.2, 3.6.6 3.7.8 3.7.10, Condition A, Required Action A.1 from 72 hours to 10 days. The extension may only be invoked once and remains applicable until RWP-3B has been refurbished.

A. <u>Results of a Quantitative Risk Assessment</u>

The PSA risk associated with the activity to repair RWP-3B is reasonable to support a one time on-line AOT extension request for 10 days based on Incremental Conditional Core Damage Probability (ICCDP) and Incremental Conditional Large Early Release Probability (ICLERP). The evaluation assumes no other equipment beyond the evaluated systems will be removed from service if the risk is adversely impacted based on maintenance rule 10 CFR 50.65(a)(4) risk assessments, that will be performed before

and during the activity by procedure. Additional compensatory actions are provided which can further reduce the risk when practical. Their use should be based on the specific plant configuration during the use of the extended AOT.

Based on the risk assessment of the extended AOT, the increase in risk warrants that compensatory actions should be implemented which can reduce the risk by lowing the likelihood of initiating events such as LOOP or fire, and by increasing the likelihood of successful mitigation by optimizing the plant configuration, ensuring availability of the operational equipment, and enhancing operator awareness. The Table below lists specific items which should be considered.

Potential Compensatory Actions

ITEM	DISCUSSION	CREDITED IN CDF
Limit maintenance beyond RWP-3B.	Normal 10 CFR 50.65(a)(4) assessments will be used. Maintenance activities which will increase risk beyond acceptable limits will be rescheduled.	The assessment assumes zero maintenance unavailability on other risk significant equipment.
Consider alternate makeup pump (MUP) configurations.	Depending plant configuration, the diversity of available support options can be increased.	This action can have significant effect, but should be evaluated in combination with all actions considered.
Walkdowns/validation of the operable ("A") train equipment as practical.	Provides additional qualitative assurance that the available equipment will perform as required.	No probabilistic credit is given in the evaluation for these activities.
Pre-job discussions on the impact not having RWP-3B during an event and potential recovery options such as cross-tying MUP suction.	Piping configurations allow the use of DHP-1A to provide a suction source to MUP-1C; however, this is not proceduralized for this application.	The PRA does not credit this action in very many scenarios; however, if the probability of this action is reduced there is still a small benefit.
Establish fire watches in the zones based on PSA and Appendix R considerations, to limit fire initiators and combustibles. In some cases enhanced manual suppression may be used.	Limit activities associated with initiation of a fire (welding, grinding, etc., operating standby equipment) or storage of transient combustibles.	A sensitivity type of analysis was performed fwhich shows the risk of fires in to be a significant contributor. Credit was added to compensate for monitoring transient combustibles and avoiding the use of standby or normally unused equipment.

The risk metric for this activity is estimated with a delta Core Damage Frequency (CDF) of 4.0E-07/yr based on internal events. This is below the RG 1.174 limit of 1E-06 and is considered to be a very small risk. The corresponding delta Large Early Release Frequency (LERF) is below 1E-09/yr and is also considered very low based on the RG 1.174 limit of 1E-07. The risk due to fire was estimated using a sensitivity assessment to get a bounding delta CDF of due to fires of 2.72E-06/yr. Specific compensatory actions are planned to manage and reduce this risk.

The ICCDP for the planned activity is 1.18E-06 and considers the plant configuration with RCV-11 closed. This risk is acceptable based on industry guidance with proper risk management practices. Planned compensatory actions are expected to reduce this risk. Also, the actual work activity is only scheduled to use half of the requested time, which will reduce these values proportionately. The ICCDP is greater than that generally accepted for permanent AOT changes per RG 1.177; however, it is well within

acceptable limits for performing online maintenance within the scope of maintenance rule guidance and is reasonable for a one time AOT extension.

A sensitivity case was run to assess the impact of increasing the loss of offsite power frequency. Tripling the frequency did not significantly increase the risk. Additionally, there is some increased risk to performing this activity while shutdown in Mode 5, which will further reduce the total delta risk of performing this activity at power.

Based on the IPEEE, fire can be a significant contributor to risk, however as shown, the risk can be estimated to be in the small risk region as defined by RG 1.174. In order to minimize the potential impact, compensatory actions can be used to reduce the probability of a fire occurring and enhance fire detection and suppression in the more vulnerable areas.

B. Expected Improvement in Plant Performance as a Result of the Overhaul Activity:

RWP-3B is currently OPERABLE. The lack of flush water flow to the upper pump bearings has been evaluated in accordance with Generic Letter 91-18, and the degraded condition was found acceptable. Compensatory actions such as augmented surveillance testing to ensure no further degradation have been implemented, and no pump performance issues or further degradation have been found.

During the upcoming refueling outage, the "A" Safeguards Bus will be removed from service for normal maintenance activities. These activities will result in the "B" Safeguards Bus and associated equipment (including RWP-3B) being the only method to available to remove core decay heat. CR3 plant management has conservatively requested the pump be rebuilt prior to the outage in order to reduce shutdown risk by having a fully qualified pump available to provide the decay heat removal function.

C. Net Change in Risk as a Result of the Overhaul Activity.

The net change in risk during plant operation is described in Section A. The enhancement to the plant during the shutdown (refuel) condition cannot be quantified, as CR3 does not have a shutdown PSA, but the qualitative risk will be less due to the non-degraded pump providing the necessary cooling to the Decay Heat System during a condition where decay heat cooling will be required.

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

On 09/07/02, the CR-3 Senior Resident Inspector provided verbal confirmation that he had discussed this FAQ with Region II personnel. He also confirmed that no disagreement existed with the facts and circumstances associated with CR-3's approach in seeking an exemption from counting support system on-line overhaul activities on RWP-3B against the Residual Heat Removal Safety System Unavailability NRC ROP performance indicator.

Potentially relevant existing FAQ numbers:

FAQ 219 (See NEI 99-02, Revision 3, Appendix D, Pages D-12 and D-13.)

Plant: Browns Ferry Nuclear Plant
Date of Event: Future activity planned for October and November of 2005.
Submittal Date: September 2005
Licensee Contact: Fred Mashburn Tel/email: (423)751-8817/fcmashburn@tva.gov
Paul Heck Tel/email: (256)729-3624/psheck@tva.gov
NRC Contact: Thierry Ross Tel/email: (256)729-2573/tmr@nrc.gov

Performance Indicator: Safety System Unavailability – Emergency AC Power Systems

Site-Specific FAQ (Appendix D)?: Yes

FAQ requested to become effective when approved or for 4th Qtr 2005 submittal

Question Section

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

Appendix D Page D-1 lines 16-23:

"The NEI 99-02 guidance was written to accommodate situations anticipated to arise at a typical nuclear power plant. However, uncommon plant designs or unique conditions may exist that have not been anticipated. In these cases, licensees should first apply the guidance as written to determine the impact on the indicators. Then, if the licensee believes that there are unique circumstances sufficient to warrant an exception to the guidance as written, the licensee should submit a Frequently Asked Question to NEI for consideration at a public meeting with the NRC. If the FAQ is approved, the issue will be included in Appendix D of this document as a plant-specific issue."

Event or circumstances requiring guidance interpretation:

Browns Ferry Unit 1 is being recovered from an extended shutdown. Recovery efforts include replacement of cables to the Division I and Division II Emergency AC (EAC) power. The cables are being replaced in order to provide qualified cables (including requisite documentation) to meet current Environmental Qualification, Post Accident Monitoring, Voltage Drop/Ampacity/Short Circuit requirements, Appendix R, Electrical Separation and to address breakage as identified by electrical calculations.

The Division I and Division II EAC for Units 1 and 2 each contain 2 Emergency Diesel Generators and 2 4160v Shutdown Boards with each Emergency Diesel Generator and Shutdown Board supplying approximately 50% of the emergency power required for each Division EAC. The Emergency Diesel Generators and Shutdown Board are paired as A & B in Division I and C & D in Division II.

To replace these cables, Emergency Diesel Generators A, B, and D and 4160v Shutdown Boards A, B and D will be removed from service one train at a time. The work is planned such that when

A Emergency Diesel Generator and 4160v Shutdown Board A are out of service, the B, C, and D Emergency Diesel Generators and B, C, and D 4160v Shutdown Boards will remain available. Also when the B or D train is out of service the other three trains will remain available. The work to replace the cables on any one of the trains can be done within the Tech Spec AOT of 14 days for the Emergency Diesel Generator.

A quantitative risk assessment has been performed on the configuration as required by NEI 99-02 in order to qualify for the exemption of unavailable hours. This risk assessment was done in 1997 in conjunction with the license amendment which extended the AOT from 7 to 14 days.

Browns Ferry personnel have taken great efforts to minimize any impacts of Unit 1 recovery on the operating units (Units 2 and 3). This is the second instance in which Browns Ferry has requested an exemption of unavailable hours (see discussion on FAQ 381 below) accrued as a result of Unit 1 recovery activities. As a result of this FAQ, Browns Ferry personnel have reviewed upcoming activities and, at this time, do not anticipate any other planned activities for which another exemption would be required. However, the recovery of Unit 1 is a large and complex project. It is possible that future activities might occur with unanticipated effects that would necessitate another request for exemption.

It should be noted that this exemption request (and FAQ 381) is not an "overhaul exemption" as discussed in the Clarifying Notes subsection of Section 2.2 of NEI 99-02, but a Plant Specific exception as described in Appendix D. The justification of this FAQ (and the previous FAQ) is that the unavailable hours resulting from restart of an idled unit is a plant-specific situation that was not anticipated during the formulation of the guidance document and that the hours, if counted, would not provide an accurate picture of the performance of the systems as intended by the performance indicator.

NEI 99-02 limits planned overhaul maintenance exemptions to once per train per operating cycle. There is no similar limit to exemptions for Appendix D issues. It is TVA's intent to minimize these requests and as stated before, our current review has not identified any foreseeable circumstances requiring another request of this type, although it cannot be completely ruled out due to the scope and complexity of the project.

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

The BFN Senior Resident Inspector agrees that a one-time site-specific exemption should be granted to U2 and U3 for this U1 restart activity. However, the SRI's opinion is that there should be a limit to the number of hours exempted. That is, the number of hours exempted should be limited to a licensee estimate of the expected duration for the activity. Hours accrued above that estimate should count.

Potentially relevant existing FAQ numbers

FAQ 381 (approved on March 17, 2005) addressed a similar exception required for restart of Browns Ferry 1. FAQ 381 requested the exemption of unavailability hours for the Residual Heat Removal System for hours that the system would be impacted by Unit 1 recovery efforts. The FAQ and the exclusion of unavailability hours were approved because it was a one-time-only

activity that resulted in a unique condition that had not been anticipated during the development of the PI guidance document.

<u>Response Section</u>

Proposed Resolution of FAQ

Unavailability need not be counted against the U2 and U3 during the U1 EDG restoration activities since this is a one-time unavailability event that can be contributed solely to a planned BFN U1 restart activity that was not anticipated during the development of the PI guidance document and is not a true indication of system performance. Browns Ferry has prepared a conservative, yet realistic schedule and workplan (including PMT and contingency for addressing problems encountered during the PMT) for the activity. Unavailable hours encountered beyond the schedule will be counted toward the PI.

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

None required. This is a one-time, site-specific exemption request.

4160 shutdown boards A - D serve both Unit 1 and Unit 2 loads

Normal alignment is as shown; either shutdown bus can supply any U1/U2 shutdown board

The work being done in support of Unit 1 restart will temporarily affect a single DG or shutdown board while the others remain fully operable

Under certain conditions, a Unit 1/Unit 2 shutdown board can be manually cross-tied to its Unit 3 counterpart. There normally is no connection at all, and there is never any automatic cross-connection between U1/U2 and U3 loads