Attachment 9

FAQ Log (Part 2) 4/28/05

TempNo.	PI	Topic	Status	Plant/ Co.
52.1	IE03	Initiation of contingency planning	3/17 Introduced *4/28 Discussed*	Nine Mile Point
52.2	EP03	Crediting of siren testing conducted at facilities that are not normally attended	3/17 Introduced *4/28 Discussed* *4/28 Revised* *4/28 Tentative Approval*	Kewaunee
52.3	IE02	Loss of main feedwater flow, condenser vacuum, or turbine bypass capability caused by partial loss of offsite power	3/17 Introduced 3/17 Discussed *4/28 Discussed* *4/28 Withdrawn*	River Bend
52.4	IE02	Loss of main feedwater flow, condenser vacuum, or turbine bypass capability caused by partial loss of offsite power	3/17 Introduced 3/17 Discussed *4/28 Discussed* *4/28 Withdrawn*	River Bend
53.1	*MS02*	*Equipment unavailability due to design deficiency*	*4/28 Introduced* *4/28 Discussed*	*Palo Verde*
53.2	*EP01*	*Controller intervention*	*4/28 Introduced*	*Vogtle*

FAQ 52.1

Submitted 2/14 by Terry F. Syrell
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Nine Mile Point Nuclear Station
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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 52.2

FAQ TEMPLATE

Plant: _Kewaunee Nuclear Power Plant___________
Date of Event: __none____________________
Submittal Date: __March 4, 2005___________________
Licensee Contact: ________________________ Tel/email: ________________
NRC Contact: ________________________ Tel/email: ________________

Performance Indicator: Alert and Notification System (ANS)

Site-Specific FAQ (Appendix D)? No

FAQ requested to become effective when approved.

Question Section

On January 13, 2005 the NRC transmitted the results of an inspection conducted at Davis-Besse Nuclear Power Station related to a discrepant ANS Reliability Performance Indicator. The inspection report concluded that some siren tests could not be counted because they were performed from a licensee test point that was not normally attended.

NEI 99-02 Guidance needing interpretation Page 95 Lines 19-28 – Specifically lines 27 and 28 listed below and Line 25 and 26 in the NEI Document

"Siren systems may be designed with equipment redundancy or feedback capability. It may be possible for sirens to be activated from multiple control stations. Feedback systems may indicate siren activation status, allowing additional activation efforts for some sirens. If the use of redundant control stations is in approved procedures and is part of the actual system activation process, then activation from either control station should be considered a success. A failure of both systems would only be considered one failure, whereas the success of either system would be considered a success. *If the redundant control station is not normally attended, requires setup or initialization, it may not be considered as part of the regularly scheduled test.* Specifically, if the station is only made ready for the purpose of siren tests it should not be considered as part of the regularly scheduled test."

Event or circumstances requiring guidance interpretation:

BACKGROUND: The Kewaunee siren testing procedure, states that Kewaunee County or Kewaunee Count Sheriff's Department will initiate all actual or systems tests that are needed. The procedure also states that the tests are alternated between the two entities. The Sheriff Dispatch is manned continuously and the Kewaunee County Emergency Operations Center (EOC) is manned during most normal business hours and declared emergencies. As previously stated, both locations are expected to be able to activate the sirens. Hence the process for testing the sirens from both locations since either may be required to activate the sirens. This FAQ has generic implications because many county Emergency Operations Centers (EOCs) are not co-located with the dispatch centers and therefore, not normally attended .

The guidance in NEI 99-02 pertaining to the counting of tests from redundant control stations that are not normally attended could be interpreted to apply to any facility conducting a siren test and not just a specific licensee facility. The Kewaunee County EOC is not maintained for the purposes of siren testing but for the purposes of planned emergency response. This would result in excluding tests conducted at the Kewaunee County EOC and other EOCs not co-located with dispatch centers. In most situations, the EOC is the most probable location for an actual activation of the system in emergency conditions. When an emergency situation escalates the EOC is staffed and performs as the Emergency Center. If situations continued to deteriorate the ANS system would generally be activated from the EOC. Prohibiting testing from this facility could potentially reduce the reliability of the system most likely to be actually used.

Potentially Relevant Existing FAQ: 358

The following in an excerpt from FAQ 358, (emphasis in italics):

Q: Can the licensee modify the ANS testing methodology when calculating the site value for this indicator?

A: Yes. Page 95, lines 19-23 of NEI 99-02 will be modified as follows:
Changes to the activation and/or testing methodology shall be noted in the licensee's quarterly PI report in the comment section. Siren systems may be designed with equipment redundancy, multiple signals, or feedback capability. It may be possible for sirens to be activated from multiple control stations or signals. If the use of redundant control stations or multiple signals is in approved procedures *and is part of the actual system activation process, then activation from either control station or any signal should be considered a success.*

Question:

May siren testing conducted at ~~facilities~~ *redundant control stations,* such as county EOCs, that are ~~not normally attended~~ *staffed during an emergency by an individual capable of activating the sirens* be credited in the ANS PI?

<u>Proposed Response:</u>

Answer: Yes. *If the redundant control station is in a facility that is staffed during an emergency by an individual capable of activating the sirens, then it is considered to be normally attended.* ~~The restriction on crediting redundant control stations was intended to apply to control stations that are not normally attended in an emergency for purposes of activation.~~

~~FAQ~~

~~**Licensee/Plant:** RIVER BEND STATION~~

~~**Date of Event:** October 1st, 2004~~

~~**FAQ Submittal Date:** February 3, 2005~~

~~Licensee Contact:~~	~~Robert L. Biggs~~
~~Tel/email:~~	~~225-381-3731/rbiggs@entergy.com~~
~~NRC Contact:~~	~~Peter Alter, RBS Senior Resident Inspector~~
~~Tel/email:~~	~~225-381-4566~~

~~**Performance Indicator:** IE02 – Unplanned SCRAMS with Loss of Normal Heat Removal~~

~~**Type of FAQ Requested:** Generic~~

~~**Effective Date:** FAQ requested to become effective on issuance~~

~~**NEI 99-02 Guidance Needing Interpretation**~~

~~Current performance indicator guidance provides the following key measures by which a licensee can interpret a scram that must be evaluated as a potential input to the *Unplanned Scrams With a Loss of normal Heat Removal* performance indicator.~~

- ~~NEI 99-02 Revision 2 defines a *Loss of the normal heat removal path* (Power Conversion System/PCS) as: when any of the following conditions have occurred and cannot be easily recovered from the control room without the need for diagnosis or repair to restore the normal heat removal path:~~
  - ~~*complete* loss of all main feedwater flow~~
  - ~~insufficient main condenser vacuum to remove decay heat~~
  - ~~*complete* closure of at least one MSIV in each main steam line~~
  - ~~failure of turbine bypass capacity that results in insufficient bypass capability remaining to maintain reactor temperature and pressure~~
- ~~The guidance further provides that *operator actions or design features to control the reactor cooldown rate or water level*, such as closing the main feedwater valves or closing all MSIVs, are not reported in this indicator as long as the normal heat removal path can be readily recovered from the control room without the need for diagnosis or repair. However, operator actions to mitigate~~

~~an off-normal condition or for the safety of personnel or equipment (e.g., closing MSIVs to isolate a steam leak) are reported.~~

~~NOTE: The key message here is the need to be able to rapidly recover PCS from the control room without the need for diagnosis or repair. No credit is considered for mitigation actions outside of these guidelines by NEI 99-02 Revision 2.~~

- ~~NEI 99-02 Revision 2 also states that the following examples do not count:~~
  - ~~*loss of all main feedwater flow, condenser vacuum, or turbine bypass capability caused by loss of offsite power;*~~
  - ~~partial losses of condenser vacuum or turbine bypass capability after an unplanned scram in which sufficient capability remains to remove decay heat;~~

~~Note: Additional examples excluded due to non-applicability to this issue.~~

~~The River Bend Station Partial Loss of Offsite Power event of October 1st, 2004 that ultimately resulted in a reactor scram and a loss of normal heat removal would not count in the performance indicator process except as an unplanned scram. This is because of the following:~~

1. ~~The flash-over/failure of insulators on an incoming feed line/ main generator line at the station resulted in electrical fault protection actuations. These actuations resulted in protective tripping of the unit main generator that initiated a scram.~~

2. ~~Feed water pumps were lost due to partial loss of offsite power ('A' directly and 'B' and 'C' due to loss of condensate supply due to power loss).~~

3. ~~Condenser vacuum was lowering because of a loss of condenser circulating water. Two of the three main condenser circulating water pumps (CWS) in service before the event shut down due to loss of power. The output of the remaining pump was short-cycled through the discharge of the idle pumps due to the loss of power to their discharge valves.~~

~~This position is consistent with the response to FAQ #355. The response is provided below:~~

~~*"The clarifying notes for this performance indicator exempt scrams resulting in loss of all main feedwater flow, condenser vacuum, or turbine bypass capability caused by loss of offsite power. There is no distinction made or implied regarding a complete or partial loss of offsite power. In this case, while the loss of offsite power was not a complete loss, the loss did **affect** the feedwater, condensate and condenser systems."*~~

~~Event description~~

~~On October 1, 2004, at 7:17 a.m., a flash-over occurred in the 230kV station transformer yard across a post insulator. This caused the loss of Reserve Station Service (RSS) No. 1, which interrupted power to the Division 1 standby bus. The Division 1 diesel generator started automatically, and restored power to the bus. This event also interrupted power to the "A" reactor protection system (RPS) bus. Operators responded to this event by restoring power to the "A" RPS bus and resetting the half scram.~~

~~At 7:30 a.m., a second flash-over occurred across a 230kV post insulator on the main generator line, resulting in a main generator trip and main turbine trip.~~

~~The main generator trip combined with the loss of RSS no. 1 resulted in the trip of two main condensate pumps and one main feedwater pump. The remaining two feedwater pumps tripped on low suction pressure following the loss of the condensate pumps. Ten main steam safety relief valves (SRVs) actuated automatically during the pressure transient resulting from the main turbine trip. SRVs were subsequently cycled manually to control reactor pressure and to aid in achieving cold shutdown.~~

~~Two of the three main condenser circulating water pumps (CWS) in service before the event shut down due to loss of power. The output of the remaining pump was short-cycled through the discharge of the idle pumps due to the loss of power to their discharge valves, diverting flow from the main condenser. It was not possible to maintain main condenser vacuum, and the operators manually closed the outboard main steam isolation valves, and then cycled SRVs as needed to control reactor pressure.~~

~~Proposed FAQ Answer:~~

~~The scram described here does not count as a scram with loss of normal hear removal. There is no distinction made or implied regarding a complete or partial loss of offsite power. In this case, while the loss of offsite power was not a complete loss, the loss did affect the feedwater, condensate and condenser systems (vacuum).~~

~~Do the licensee and NRC resident/Region agree on facts and circumstances?~~ ~~Yes~~

~~Potentially relevant existing FAQ numbers:~~ ~~282, 249, 248, 65, 354, 355~~[1]

~~FAQ #355~~

~~Question~~ ~~Our plant automatically scrammed at 0948 CDST on 4/24/2003 due to a turbine trip from a load reject. Breakers opened in both the local switchyard and in remote switchyards that removed all paths of generation onto the grid and offsite power to the power conversion system. At the time of the scram, there was a severe thunderstorm in the vicinity. High winds caused a closure of an open disconnect into a grounded breaker under on-going maintenance. This lockout condition led to protective relaying actuating to isolate the fault, and caused the load reject.~~

~~During the event, Division 1, 2 and 3 Diesel Generators (DGs) started and energized their respective safety busses. All safety systems functioned as designed and responded properly. During this transient, no deviations were noted in any safety functions. Offsite power was automatically restored to the East 500 KV bus, once the main turbine output breaker opened and the fault was cleared. The West 500 KV bus, which was undergoing maintenance at the time of the event, remained deenergized. While all three DGs started and supplied their buses, this did constitute a design bases Loss Of Offsite Power (LOOP) and an emergency declaration of an unusual event because one of the three sources of off site power (a 115KV line to Engineered Safety Feature (ESF) Transformer 12 (ESF12) remained energized and was available throughout the event. Any of the three ECCS buses could have been transferred to this source of power at any time during the event. Based on the above considerations, it is concluded that this event would be best modeled as a T2, or Loss of PCS (Power Conversion System), initiator. A T2 initiator results in the loss of the power conversion systems (feedwater, condenser, and condensate) and the modeling of this event does allow for recovery of the power conversion systems.~~

~~Under the current Revision 2 of NEI 99-02, does this Scram count as a Scram with Loss of Heat Removal?~~

~~Response~~ ~~No. The clarifying notes for this performance indicator exempt scrams resulting in loss of all main feedwater flow, condenser vacuum, or turbine bypass capability caused by loss of offsite power. There is no distinction made or implied regarding a complete or partial loss of offsite power. In this case, while the loss of offsite power was not a complete loss, the loss did affect the feedwater, condensate and condenser systems.~~

~~Proposed Resolution of NEI 99-02 Guidance, attach separate mark-up revision of NEI 99-02 wording (Attach additional sheets if required):~~

~~Revise NEI 99-02R2, Page 16, line 41 as follows:~~

[1] FAQ No. 355 is the most relevant to this particular circumstance although the others substantiate existing guidance that is being referenced in this FAQ.

~~"There is no distinction made or implied regarding a complete or partial loss of offsite power. While a loss of offsite power may not be a complete loss, the loss did affect the feedwater, condensate and condenser systems."~~[2]

[2] ~~This recommended change would essentially incorporate the response to relevant FAQ No. 355 that has already been approved.~~

~~FAQ~~

~~**Licensee/Plant**: RIVER BEND STATION~~

~~**Date of Event**: August 15th, 2004~~

~~**FAQ Submittal Date**: February 3, 2005~~

~~Licensee Contact: Robert L. Biggs~~
~~Tel/email: 225-381-3731/rbiggs@entergy.com~~
~~NRC Contact: Peter Alter, RBS Senior Resident Inspector~~
~~Tel/email: 225-381-4566~~

~~**Performance Indicator:** IE02 Unplanned SCRAMS with Loss of Normal Heat Removal~~

~~**Type of FAQ Requested**: Generic~~

~~**Effective Date**: FAQ requested to become effective on issuance~~

~~**NEI 99-02 Guidance Needing Interpretation**~~

~~Current performance indicator guidance provides the following key measures by which a licensee can interpret a scram that must be evaluated as a potential input to the *Scrams With a Loss of normal Heat Removal* performance indicator.~~

- ~~NEI 99-02 Revision 2 defines a *Loss of the normal heat removal path* as: when any of the following conditions have occurred and cannot be easily recovered from the control room without the need for diagnosis or repair to restore the normal heat removal path:~~
    - ~~*complete* loss of all main feedwater flow~~
    - ~~insufficient main condenser vacuum to remove decay heat~~
    - ~~*complete* closure of at least one MSIV in each main steam line~~
    - ~~failure of turbine bypass capacity that results in insufficient bypass capability remaining to maintain reactor temperature and pressure~~
- ~~The guidance further provides that *operator actions or design features to control the reactor cooldown rate or water level*, such as closing the main feedwater valves or closing all MSIVs, are not reported in this indicator as long as the normal heat removal path can be readily recovered from the control room without the need for diagnosis or repair. However, operator actions to mitigate an off-normal condition~~

~~or for the safety of personnel or equipment (e.g.[3], closing MSIVs to isolate a steam leak) are reported.~~

- ~~NEI 99-02 Revision 2 also states that the following examples do not count:~~

  - ~~*loss of all main feedwater flow, condenser vacuum, or turbine bypass capability caused by loss of offsite power;*~~

  - ~~partial losses of condenser vacuum or turbine bypass capability after an unplanned scram in which sufficient capability remains to remove decay heat;~~

~~Note: Additional examples excluded due to non-applicability to this issue.~~

~~The River Bend Station Partial Loss of Offsite Power event of August 15th, 2004 that ultimately resulted in a reactor scram and a loss of normal heat removal would not count in the performance indicator process except as an unplanned scram. This is because of the following:~~

1. ~~The scram ultimately resulted from a partial loss of offsite power~~

2. ~~Condensate and feedwater were affected by the partial loss of offsite power.~~

3. ~~Condenser vacuum was lowering because of a loss of power to one of the mechanical vacuum pumps and a coincidental failure of the other pump to start.~~

4. ~~MSIVs were operated consistent with good operational practice and procedure e.g., to maintain cooldown/anticipate loss of vacuum.~~

~~Event description~~

~~At 4:05 a.m. on August 15, 2004, with the plant operating at 100 percent power, an automatic reactor scram occurred as a result of a main generator trip and subsequent main turbine trip. The 230kv oil circuit breakers at the River Bend switchyard (known as Fancy Point) responded to a fault signal on the 230kv transmission system remote from the switchyard. The fault was initiated by the failure of a guy wire, leading to a structural failure of a 230kv transmission tower.~~

~~Slow operation of a total of four 230kv breakers at Fancy Point resulted in operation of breaker backup protection and led to the loss of one of the two main generator output breakers and loss of power to the Division 2 standby switchgear, as well as parts of the balance-of-plant electrical system. The Division 2 diesel generator started as designed and restored power to its switchgear. In addition, the ground fault protection system for the main generator step-up transformers actuated due to the delay in the fault clearing time. This resulted in the trip of the remaining generator output breaker.~~

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[3] ~~exempli gratia~~

~~The main generator trip signal initiated a turbine trip signal, which then initiated the reactor scram. The turbine trip caused an expected reactor pressure transient that caused the actuation of all sixteen main steam safety relief valves.~~

~~Two reactor feedwater pumps shutdown at the time of the scram due to loss of their power supplies. The remaining "A" main feedwater pump tripped automatically at approximately 4:35 a.m. when reactor water level reached the high alarm setpoint. The reactor core isolation cooling (RCIC) system was initiated manually following the loss of the third main reactor feedwater pump.~~

~~The inboard main steam isolation valves were closed manually in anticipation of a loss of main condenser vacuum. Main condenser mechanical vacuum pump "B" was unavailable due to the loss of power, and the "A" mechanical vacuum pump failed to start due to a faulty relay in its feeder breaker. The loss of both mechanical vacuum pumps (one due to failure and the other due to the loss of power) resulted in a lowering condenser vacuum. Main steam safety relief valves were subsequently cycled manually to assist in controlling reactor pressure. The outboard main steam isolation valves were closed to maintain the reactor cooldown rate within limits.~~

~~The "A" feedwater pump could not be immediately restarted due to a loss of instrumentation power which disabled permissive interlocks required for the pump start sequence. Power was subsequently restored to the affected instrument buses and to the motor-operated valves in the feedwater regulating system.~~

~~The Fancy Point switchyard provides the connection to the offsite grid for the main generator, as well as the two independent sources of offsite power to the plant's safety-related buses. The switchyard contains the two 230kv buses, referred to as the North and South buses. The switchyard provides the connections to the 230kv transmission lines entering and leaving the switchyard, as well as the River Bend generator. There are four 230kv lines exiting the station connecting to the transmission grid, two lines which provide offsite power to River Bend and a main generator output line. The circuit breaker arrangement allows the two River Bend offsite power lines, the main generator line, and three of the four lines exiting the switchyard to be connected to either the North or South bus. The remaining line exiting the station can be connected only to the North bus.~~

~~The initiating event for the fault in the Fancy Point switchyard was the failure of a guy wire on a 230kV transmission tower on one of the four transmission lines south of the site. The guy wire failure allowed the pole to collapse and lean over causing a phase-to-ground fault. The faulted line connects only to the Fancy Point north bus. The associated circuit breaker at Fancy Point received a trip signal to clear the fault, but its operation was slow, resulting in actuation of the back-up breaker protection. All other circuit breakers on the North bus were tripped by the back-up protection system, but two of these also operated slowly. The fault was eventually isolated, but the River Bend main generator step-up transformer ground fault protective relay~~

~~had already actuated due to the extended fault duration. The actuation of this relay resulted in the main generator trip, which in turn caused the main turbine trip and a reactor scram.~~

~~The structural failure of the 230kv tower also caused a second, short duration fault on a second line, adjacent to the faulted line, when the static line attached to the top of the failed structure broke and momentarily contacted or otherwise violated minimum clearance for the "C" phase. The breaker for this line also operated slowly. This resulted in operation of the remaining breaker for the reserve station service no. 2 and loss of power to the Division 2 safety related bus.~~

~~Proposed FAQ Answer:~~

~~The scram described here does not count as a scram with loss of normal hear removal. There is no distinction made or implied regarding a complete or partial loss of offsite power. In this case, while the loss of offsite power was not a complete loss, the loss did affect the feedwater, condensate and condenser systems (vacuum).~~

~~Do the licensee and NRC resident/Region agree on facts and circumstances?~~ ~~Yes~~

~~Potentially relevant existing FAQ numbers:~~ ~~282, 249, 248, 65, 354, **355**[4]~~

~~FAQ #355~~

~~Question~~ ~~Our plant automatically scrammed at 0948 CDST on 4/24/2003 due to a turbine trip from a load reject. Breakers opened in both the local switchyard and in remote switchyards that removed all paths of generation onto the grid and offsite power to the power conversion system. At the time of the scram, there was a severe thunderstorm in the vicinity. High winds caused a closure of an open disconnect into a grounded breaker under on-going maintenance. This lockout condition led to protective relaying actuating to isolate the fault, and caused the load reject.~~

~~During the event, Division 1, 2 and 3 Diesel Generators (DGs) started and energized their respective safety busses. All safety systems functioned as designed and responded properly. During this transient, no deviations were noted in any safety functions. Offsite power was automatically restored to the East 500 KV bus, once the main turbine output breaker opened and the fault was cleared. The West 500 KV bus, which was undergoing maintenance at the time of the event, remained deenergized. While all three DGs started and supplied their buses, this did constitute a design bases Loss Of Offsite Power (LOOP) and an emergency declaration of an unusual event because one of the three sources of off site power (a 115KV line to Engineered Safety Feature (ESF) Transformer 12 (ESF12) remained energized and was available throughout the event. Any of the three ECCS buses could have been transferred to this source of power at any time during the event. Based on the above considerations, it is concluded that this event would be best~~

[4] ~~FAQ No. 355 is the most relevant to this particular circumstance although the others substantiate existing guidance that is being referenced in this FAQ.~~

~~modeled as a T2, or Loss of PCS (Power Conversion System), initiator. A T2 initiator results in the loss of the power conversion systems (feedwater, condenser, and condensate) and the modeling of this event does allow for recovery of the power conversion systems.~~

~~Under the current Revision 2 of NEI 99-02, does this Scram count as a Scram with Loss of Heat Removal?~~

~~***Response*** No. The clarifying notes for this performance indicator exempt scrams resulting in loss of all main feedwater flow, condenser vacuum, or turbine bypass capability caused by loss of offsite power. There is no distinction made or implied regarding a complete or partial loss of offsite power. In this case, while the loss of offsite power was not a complete loss, the loss did affect the feedwater, condensate and condenser systems.~~

~~**Proposed Resolution of NEI 99-02 Guidance, attach separate mark-up revision of NEI 99-02 wording (Attach additional sheets if required):**~~

~~Revise NEI 99-02R2, Page 16, line 41 as follows:~~

~~*"There is no distinction made or implied regarding a complete or partial loss of offsite power. While a loss of offsite power may not be a complete loss, the loss did affect the feedwater, condensate and condenser systems."*~~[5]

[5] ~~This proposed insertion would essentially incorporate a previously approved position FAQ No. 355.~~

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

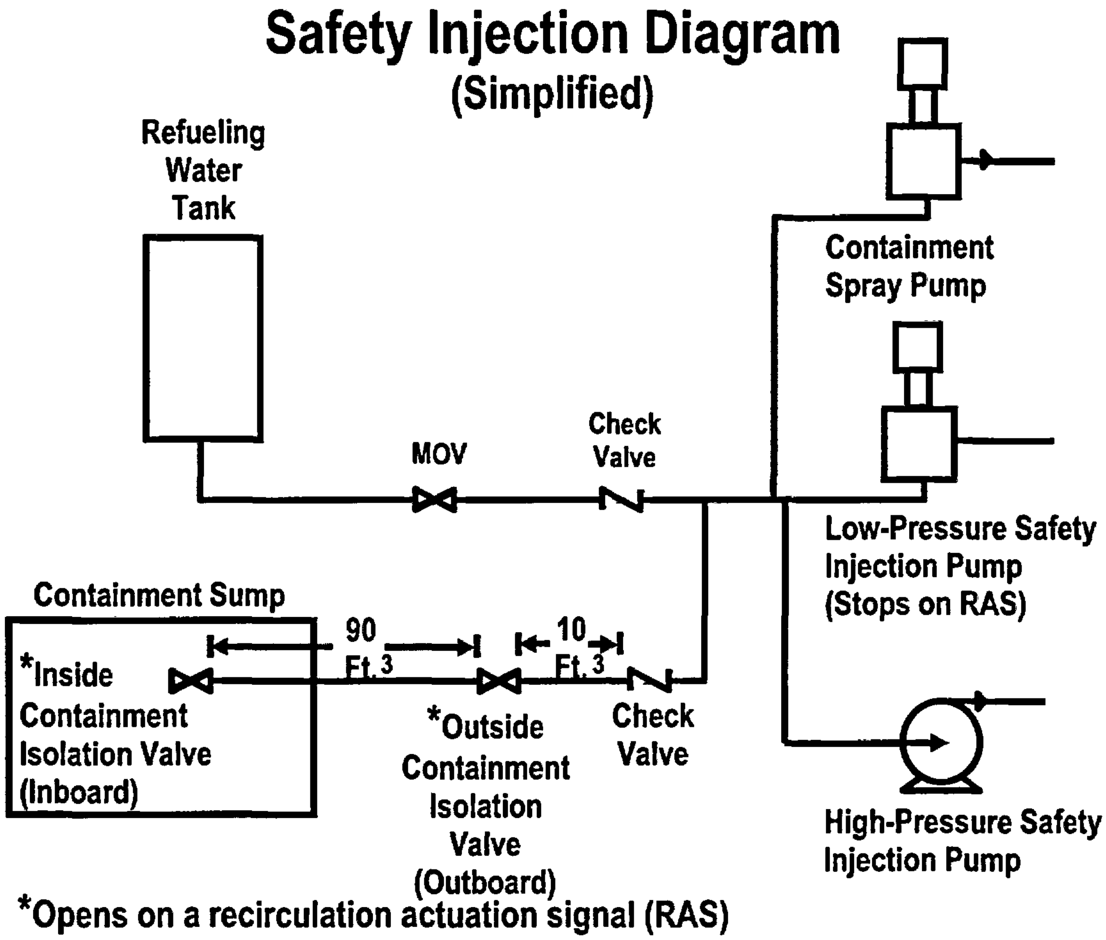
Equipment Unavailability due to Design Deficiency

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.

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

<u>Response Section</u>

Proposed Resolution of FAQ

FAQ 39.1

No. The increased accumulation of gracilaria in the river water was anticipated because of the high salinity levels in the river, but the timing of the graciliaria release into the intake canal could not be predicted greater than 72 hours in advance. In addition, the actions to be taken in response to the high salinity levels in the river water were proceduralized.

FAQ 40.2

The answer to your question is as follows: A safety system train may be considered available if it is capable of meeting its *design basis* success criteria. In addition, support systems for the train must be capable of meeting their design basis criteria. In this case, the support system is the Essential Services Chilled Water (ESCW) system. The guidance provides an alternative if the normal support system is not available, as follows: "In some instances, unavailability of a monitored system that is caused by unavailability of a support system used for cooling need not be reported *if cooling water from another source can be substituted*" (NEI 99-02, Revision 2, page 37, lines 23-25). The use of a fan rather than a cooling water source in place of the normal cooling water source does not meet the limitations. In addition, credit is not given for portable equipment installed temporarily to maintain availability of monitored equipment.

FAQ 40.3

No. NRC approval means a specific method or methods described in the technical specifications.

FAQ 40.4

Yes. The actions to recover from the equipment malfunction are uncomplicated, proceduralized, and accomplished from the control room by a qualified operator without the need for diagnosis or repair.

FAQ 50.2

No. For the purpose of excluding planned overhaul hours, valves are not considered major components.

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FAQ 50.2

No. For the purpose of excluding planned overhaul hours, valves are not considered major components.

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 the plant ~~was~~ "stable"; ~~in order to make a decision on the EAL~~. The controller than asked ~~if a~~ is "transient was in progress." The shift manager said "yes" 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.

tentative approval.

ID	Cornerstone	PI	Question	Response	Date Entered
382	Initiating Events	IE01	On November 22, 2003, Salem 2 initiated a reactor startup at 2210 following refueling. The reactor was declared critical at 0106 on November 23, 2003. At 0226, low power physics testing began. Based on a review of information from the plant computer, the reactor was subcritical prior to this event. With low power physics testing continuing, a *control rod dropped into the reactor core, causing the subcritical reactor to become* more subcritical. At 0507, the Operating crew entered the abnormal procedure for a dropped control rod. Based on the reactor being in a subcritical condition, the abnormal procedure directs all rods to be inserted. The procedure does not require all rods to be inserted if the reactor remains critical. At 0519, following a crew brief, the reactor was manually tripped per procedure as directed by the Control Room Supervisor. NRC POSITION The NRC resident office has indicated that an unplanned scram should be counted for this event. The inspectors believe that the appropriate guidance in NEI 99-02, Revision 2, which should be followed begins on line 39 of page 12. This guidance states that the types of scrams that should be included are: "Scrams that resulted from unplanned transients, equipment failures, spurious signals, human error, or those directed by abnormal, emergency, or annunciator response procedures." BASIS FOR NRC POSITION The inspectors considered that for the conduct of physics testing, the reactor was maintained critical or if subcritical, very near critical. In fact the main control room logs did not distinguish otherwise and only included a log entry stating that the reactor was critical. The inspectors also considered that many transients may actually render the reactor subcritical before the resultant scram is inserted. It is the intent of this PI to count all unplanned transients that begin while the reactor is critical and result in an unplanned reactor scram. The November 23, 2003, manual reactor trip was immediately preceded by plant conditions that maintained the reactor very near critical or critical. PSEG POSITION This was not reported as an Unplanned Scram in November 2003 because the scram occurred while the reactor was subcritical. A review of the post-trip review and notification documentation indicate that both the Operations Superintendent and the Control Room Supervisor were aware of the fact that the reactor was subcritical prior to the trip and that there was a procedural requirement to insert all rods if the reactor was subcritical as a result of the dropped rod. Tripping the reactor is a conservative method to insert the rods. BASIS FOR PSEG POSITION PSEG utilized the following guidance from Section 2.1, Initiating Events Cornerstone,	No. This event does not need to be counted as an Unplanned Scram. This PI counts the number of scrams while critical. During this event, operators tripped the reactor after determining the reactor was subcritical.	04/28/2005

of NEI 99-02 to determine that the subcritical scram should not be counted:

- Page 11, Lines 24 – 26, Indicator Definition is the number of unplanned scrams during the previous four quarters, both manual and automatic, while critical per 7000 hours.
- Page 11, Lines 28 – 31, Data Reporting Elements, instruct licensees to report the number of unplanned automatic and manual scrams while critical in the previous quarter
- Page 12, Lines 1 – 4, Calculation, demonstrates that the value for this PI is derived by multiplying the total unplanned scrams while critical in the previous 4 quarters by 7000 hours and dividing the result by the total number of hours critical in the previous 4 quarters
- Page 12, Lines 16 – 17, defines criticality as existing when a licensed operator declares the reactor critical. The scram in question occurred after the reactor was verified to be subcritical.
- Page 12, Lines 17 –19, states that there may be instances where a transient initiates from a subcritical condition and is terminated by a scram after the reactor is critical and that these conditions count as a scram. The guidance specifically requires that the reactor must be critical at the time of the scram. The relevant condition is to determine if the reactor is critical at the time of the scram and, if so, is reportable under this PI.
- Page 12, Line 30 states that dropped rods are not considered reactor scrams.
- Page 13, Lines 4 and 9 state that an example of a scram that is not included *in this PI is Reactor Protection System actuation signals that occur while the* reactor is subcritical.

Should this event be counted as an Unplanned Scram?

383	Initiating Events	IE03	NEI 99-02 specifically requests an FAQ for this condition: Anticipated power changes greater than 20% in response to expected problems (such as accumulation of marine debris and biological contaminants in certain seasons) which are proceduralized but cannot be predicted greater than 72 hours in advance may not need to be counted if they are not reactive to the sudden discovery of off-normal conditions. The circumstances of each situation are different and should be identified to the NRC in an FAQ so that a determination can be made concerning whether the power change should be counted. **Event Description:** On August 31, 2004, Unit 2 experienced a trip of the 2D Circulating Water Intake Pump (CWIP). This caused a reduction in condenser vacuum,	This event does not need to be counted as an unplanned power change because the high vulnerability condition in the intake canal was being monitored, the response to the high vulnerability intake canal condition was proceduralized, and the rapid accumulation of debris was not predictable greater than 72 hours in advance.	04/28/2005

which was mitigated by a 21% power reduction. The CWIP tripped due to a high differential pressure on the traveling screen, (i.e., a moving screen upstream of the pump intake that removes debris and marine growth.) Increased accumulation of debris and marine growth on the traveling screens is an expected condition during extreme lunar tides, as was the case on August 31. Although the timing and potential vulnerability of the lunar low tide was known, it was not possible to predict if, or when, an excessive influx of marine growth or debris would occur.

The plant was in a "high vulnerability" condition, meaning that conditions in the intake canal were more likely to challenge the traveling screens and CWIPs. The marine growth is a particular nuisance in the summer months during periods of lower tides. The increased canal bottom temperature during these periods causes organic debris to decay at a higher rate and tends to produce more suspended solids in the intake water. Plant operating experience includes several instances when traveling screens have experienced high differential pressures and CWIP trips. For example, LER 2-1999-006, "Automatic Reactor Shutdown Due to Condenser Low Vacuum Main Turbine Trip" documents a similar event. Mitigating actions have been taken, such as canal dredging; however, these changes must be compatible with state environmental water quality regulations. Therefore, changes to reduce traveling screen clogging, such as increasing the mesh sizing on traveling screens, are limited in their effectiveness.

On August 30, 2004, Unit 1 traveling screens received high differential pressure alarms. As a result, both units' traveling screens were placed in the "hand fast" position. The procedure for intake canal blockages includes steps for high vulnerability conditions, such as ensuring the traveling screens are operating in "hand fast" speed and reducing reactor power for a sustained high differential pressure. Both units' screens remained in this alignment throughout the event; however, the increase in the 2D screen differential pressure was too rapid to counteract with mitigating actions to prevent the pump trip.

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.