Cornerstone

PI

Posting Date 12/04/2003 ***ID*** 356

Question NEI 99-02, revision 2 refers to the "NEI performance indicator Website (PIWeb)" on page 3 (line 6), page 5 (line 21), and page B-1 (line 5). Specifically, these sections describe the role of PIWeb in the collection of data and the development of quarterly NRC data files and change files. With the implementation of Consolidated Data Entry (CDE), is it acceptable to use CDE to accomplish these functions?

Response Yes. CDE has been demonstrated to accurately collect the ROP data and generate the associated quarterly NRC data files and change files

Cornerstone Initiating Events

PI IE01 Unplanned Scrams

Posting Date 09/25/2003 **ID** 354

Question Several units scrammed as a result of the major grid disturbance and blackout this summer. Are they required to count this external event caused scram in the IE01 performance indicator?

Response Yes, there is no exemption from counting these scrams under IE01, Unplanned scrams. Note, however, that they are not counted under IE02, Scrams with loss of normal heat removal, because there is a specific exemption from counting loss of offsite power.

Cornerstone Initiating Events

PI IE01, IE03 Initiating Events

Posting Date 12/13/2001 **ID** 296

Question As a result of a stator cooling water leak, power was reduced to remove the main turbine from service. When the main turbine was tripped, a loss of condenser vacuum occurred which necessitated a plant scram. The loss of vacuum was caused by inadequate torque on a moisture separator/reheater manway, which resulted in significant air in-leakage when the pressure in the tank relaxed as a result of taking the turbine off line. The NRC resident inspector office has indicated the appropriate NEI 99-02 guidance that should be followed is a paragraph (starting on line 8 of page 17, NEI 99-02, Revision 1) discussing when an unplanned off-normal condition occurs during a planned power change. The paragraph discusses when the unplanned condition should be counted as an unplanned power change because it is outside or beyond the scope of the planned power change. The NRC interpretation is that both an unplanned power reduction and an unplanned scram should be counted for such an event. Our position is that another paragraph of NEI 99-02 applies (starting on line 6 of page 18), which says that off-normal conditions that begin with one or more power reductions and end with an unplanned reactor trip are counted in the unplanned reactor scram indicator only. Should this event be counted only as an unplanned scram because the power reduction and the scram were related, or should it be counted as both an unplanned power reduction and an unplanned scram?

Response There should be a count for both indicators because the cause of each occurrence was different. The unplanned power change was initiated in response to the stator cooling water leak and the scram was initiated due to loss of vacuum.

Posting Date 10/23/2003 **ID** 355

Question This question seeks clarification of the description of events that are not to be counted as a Scram with Loss of Normal Heat Removal (Scram w/LONHR), specifically page 16, lines 36-37, of NEI 99-02.
<p>At our plant, an automatic scram occurred due to a turbine trip from a load reject along with a simultaneous loss of offsite power to the Power Conversion System (PCS) with a total loss of power to PCS after the turbine/generator output breaker opened. Power to two of three Emergency Safety Feature (ESF) transformers were lost. All three of the emergency diesel generator divisions started and aligned to the three busses previously fed from the two lost transformers. The third ESF transformer is powered by an independent 115 Kv line and was not lost during the event.
<p>The NRC Senior Resident agrees this was not a design basis loss of offsite power event to the Emergency Core Cooling System (ECCS). However, the NRC Senior Resident interprets the referenced exemption is not applicable in this case.
The NEI 99-02 guidance noted above exempts the "loss of offsite power" but does not explicitly address a situation where a partial loss of offsite power occurred that resulted in a complete loss of offsite power to the power conversion system.

<p><u>Event Description:</u>
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.
<p>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.
<p>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 <u>not</u> 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.
<p>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.

<p>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.

Posting Date 05/22/2003 **ID** 347

Question An unplanned scram occurred on July 22, 2002, during full power operations. The trip was initiated by a turbine trip caused by low vacuum in the 2C Condenser. The low vacuum was considered a partial loss of vacuum, and therefore was not counted as a loss of heat removal. At 3 minutes after the trip, the operators performed a main steam isolation due to the lowering RCS pressure that approached the Safety Injection set point and lowering Tavg due to AFW. This drop in RCS pressure is a design feature of Westinghouse plants with a large Tavg program. A rapid outsurge from the Pressurizer occurs when

the RCS hot leg rapidly cools down from over 600 degrees to 547 degrees.
<p>The alignment of the auxiliary steam loads to the Unit 2 main steam system was the condition originally identified that resulted in the excessive cooldown. However, further review of this transient using the plant simulator provides additional insight into the plant response following a trip from full power. A review of plant trip response was performed to determine if the plant responded as expected and as per design. The plant RCS temperature and pressure response in July 2002 is similar to historical trips.
<p>Simulator scenarios were run to examine plant response to a normal reactor trip. Specifically, the Pressurizer pressure response and the response of Tavg to AFW throttling were observed. The pressure response was observed to ensure the simulator modeled what the Operators were seeing in the plant. Scenarios were run from full power, equilibrium, MOL conditions with Aux Steam aligned to Unit 2. Pressurizer Pressure lowered to about 1930 psi within one minute following the reactor trip. This closely matches the pressure response noted on the July 22, 2002 trip of Unit 2. As stated above, this drop in RCS pressure is a design feature of Westinghouse plants with a large Tavg program. The SI actuation setpoint for Unit 2 is 1900 psi. The SI setpoint was never reached during simulator testing. This is consistent with Pressurizer design which states that the Pressurizer is sized such that the Emergency Core Cooling Signal will not be activated during reactor trip and turbine trip (UFSAR Sect. 4.2.2.2).
<p>The lowest pressure reached was observed to occur within the first minute following the trip and was recovering soon after the minimum value was reached. The minimum value of pressure reached was observed to be independent of any RCS cooldown that occurred following the initial hot leg temperature reduction resulting from the reactor trip. During the time Tavg was lowering and <547 degrees, Pressurizer pressure was rising toward the program value of 2235 psi. The scenario was run using current Cook Plant EOPs and the Operator throttling AFW flow in Step 1 of ES-0.1 about 8 minutes after the Trip. It took 2 to 3 minutes to stabilize AFW flow at about 300Klbm/hr total. Tavg continued to lower for another 2 minutes, and was <543 degrees before it stopped lowering and began to recover. This means that at least 4 to 5 minutes passed from the time the crew began taking action to stop the RCS cooldown and Tavg actually stabilized and began to recover. This is similar to the responses seen in the plant following a reactor trip.
<p>Operators initially perform Immediate Actions in Procedure E-O to verify proper plant response. Operators observe key plant parameters during the Immediate Actions to determine whether an automatic SI setpoint has been reached or is being approached. If an automatic SI setpoint has been reached or is being rapidly approached, the Operators may take the action to manually actuate SI. As discussed above, RCS pressure rapidly decreases following a plant trip, approaching the SI setpoint of 1900 psi. Simulator response has shown that RCS pressure can go as low as 1930 psi. Operators are trained to take manual action to prevent inadvertent SI actuation. On July 22, 2002 Operators saw both RCS pressure and temperature rapidly decreasing and conservatively took action to close MSIVs to curtail RCS cooldown and prevent RCS pressure from lowering to the SI setpoint.
<p>The actions taken to control RCS cooldown were in accordance with plant procedures in response to the trip. The closure of the MSIVs was to control the cooldown as directed by plant procedure and not to mitigate an off-normal condition or for the safety of personnel or equipment.
<p>Should the reactor trip described above be counted in the Unplanned Scrams with Loss of Normal Heat Removal Performance Indicator?

Response Yes. Closure of MSIVs to mitigate an off-normal condition (i.e., stopping reactor coolant system pressure from reaching an automatic safety injection setpoint) is counted in the performance indicator as an Unplanned Scram with Loss of Normal Heat Removal.

Posting Date 05/22/2002 **ID** 310

Question On June 5, 2000, a S/G perturbation occurred because of rain-damaged main feed water pump turbine speed control circuitry. Due to rainwater in its speed control panel, the 2B main feedwater pump sped up uncontrollably, then slowed down. Consequently, the 2A pump automatically compensated by lowering and raising its speed in attempts to maintain steam generator levels within program. This cycle continued until the pumps' master controller was placed in "manual," allowing operators to take control of the pump speeds. Moments later, the main turbine and reactor tripped on Hi-Hi Steam Generator level (P-14) and a feedwater isolation signal resulted in both turbine-driven feed pumps tripping. The auxiliary feedwater system responded as designed and the plant was stabilized within minutes.<p>At the time of the event, because both pumps were cycling, the licensee did not know if both main feed pumps' speed control circuitry were affected/damaged by rainwater. Approximately two hours later a work order was generated for the 2A pump, which contained the instructions: "before doing anything at all, engineering requests that 'as found' readings be taken on all power supplies before anything is reset...remove any moisture from the cabinet. Make any needed repairs to return pump to service." It was determined shortly after the event that the 2A pump's circuitry had not been affected by the rainwater. None of the troubleshooting associated with the 2A pump would have prevented it from operating in manual had the operators attempted to start it. Ultimately, only the 2B pump was placed under clearance to allow repairs to its control circuitry, which had been clearly damaged.<p>To determine whether this event constituted a Scram with LONHR, the licensee asked the operators who were on shift (in hindsight) would they have attempted to start the 2A pump in manual if the need had arisen. Operators responded that they would. The inspector reviewed the licensee's emergency operating procedures, specifically the functional restoration procedure for the loss of secondary heat sink, FR-H.1, and determined that operators are directed to attempt to start one of the main feed pumps (through a series of steps) if a problem occurs with the auxiliary feedwater systemShould this count as a Scram with Loss of Normal Heat Removal?

Response No. This situation occurred June 5, 2000 while Revision 0 of NEI 99-02 was in effect. This would not count as a scram with loss of normal heat removal because at least one main feedwater pump was available..

Posting Date 03/21/2002 **ID** 303

Question Appendix D - Ginna<p>NEI 99-02 Rev 1, states in part on page 14, lines 11 - 14: "Intentional operator actions to control the reactor water level or cool down rate, such as securing main feedwater or closing the MSIVs, are not counted in this indicator, as long as the normal heat removal path can be easily recovered from the control room without the need for diagnosis or repair to restore the normal heat removal path."<p>Revision 1 added the wording "…as long as the normal heat removal path can be easily recovered from the control room without the need for diagnosis or repair to restore the normal hear removal path." to this statement.<p>If the MSIVs are closed to control cooldown rate following a scram or normal shutdown at our station, the MSIVs are not reopened. In Mode 3, Operators typically close the MSIVs as part of procedurally directed shutdown activities to assist in controlling the cooldown rate and pressurizer level, and to perform IST and Technical Specification required testing. Once the Operators intentionally close the MSIVs, they, by procedure, do not reopen them. In fact, for normal plant shutdowns on 3/1/99 and 9/18/00, operators closed the MSIVs as early as 2 hours upon entering Mode 3. For two reactor trips, one on 4/23/99 from intermediate range issues and one on 4/27/99 from an OTDT issue, the MSIVs were closed for control purposes within ~10 minutes of the reactor trip as allowed by plant procedures. The secondary system was available in both of these instances. <p>The MSIV bypass valves at our station cannot be operated from the Main Control Board or anywhere else in the Control Room. Original design of our station's MSIVs requires an Aux Operator to open a bypass valve located at the MSIVs prior to reopening the MSIVs, thus requiring operator action outside the control room. This action is an operational task that is considered to be uncomplicated and is virtually certain to be successful during the conditions in which it is performed. However, it would require diagnosis, as it is not the normal procedural method for the Operators to control cooldown rate once the MSIVs are closed. Does the closure of the MSIVs, while in Mode 3 or lower, to control cooldown rate, pressurizer level, or to perform testing following a scram constitute a scram with loss of normal heat removal?

Response No. Because the normal plant response to a scram without complications requires the MSIVs to be closed to control the cooldown rate, and the operators are instructed and trained to do this after every scram, such a scram would not count as a scram with loss of normal heat removal.

Posting Date 01/25/2002 **ID** 299

Question While performing routine Unit 2 maintenance, personnel in the control room placed one channel of main steam line pressure instrumentation in test. Next, they notified a field technician to isolate the associated pressure transmitter. The field technician isolated the wrong transmitter and immediately notified the control room. This condition satisfied the 2/3 logic for lo lo steam line pressure and initiated a main steam isolation signal. The main steam isolation valves (MSIVs) on all four loops closed. The steam line code relief valves and the pressurizer power operated relief valves opened. The reactor tripped on overtemperature delta temperature. The condenser dump valves opened and began blowing down the steam chest. The main feedwater pumps went to rollback hold. In rollback hold, the main feedwater pumps can be aligned from the control room to the auxiliary steam supply system which receives its steam from the opposite unit. At the time, Unit 1 was operating at 100 percent power. The auxiliary feedwater system started upon receipt of a steam generator lo lo level signal. <p>Operators immediately entered the reactor trip procedure. The main steam isolation signal was reset. Approximately 35 minutes after reactor trip, the main steam bypass valves were opened. This provided a heat removal path and began to equalize the pressure differential across the MSIVs. At the time, main steam line pressure upstream of the MSIVs was approximately 1100 psig while pressure in the steam chest (downstream of the MSIVs) was approximately 70 psig. By design, a differential pressure of less than 50 psid must be established across the MSIVs prior to opening them. Approximately 50 minutes after opening the MSIV bypass valves, pressure had been equalized. All four MSIVs were opened approximately two hours after the reactor trip. This restored the normal heat removal path through the MSIVs and back to the main condenser. The normal heat removal path could have been recovered sooner. However, Operations did not see any need to restore the path sooner since the plant was stable and heat was being removed by main feedwater and the steam line code relief valves.<p>Following the reactor trip, operators entered the applicable reactor trip procedure and initiated all recovery actions from the control room. There was no need for diagnosis or repair. All safety systems functioned as required. Main feedwater was available and reestablished per the reactor trip procedure. Condenser vacuum was maintained at all times. The normal heat removal path through the MSIVs was not recovered for approximately two hours after the reactor trip; however, this path could have been recovered sooner if desired. Does this count as a scram with loss of normal heat removal?

Response Yes. The normal heat removal path was lost and an alternate path was required for heat removal.

Posting Date 06/16/2004 **ID** 366

Question <p>During a scheduled refueling outage, the rotor was replaced on the 'C' low pressure turbine. During initial startup on October 27, 2003, with the plant stable at 17.7% reactor power, high vibrations were detected on the bearings associated with the replaced rotor. The turbine was tripped and shutdown, a troubleshooting team formed and a repair plan developed. In order to collect vibration data required to identify the optimum location for the placement of balancing weights, the repair plan called for the starting and phasing of the main turbine. With reactor power at 22.2%, the main generator breaker was closed at 18:32. After the collection of vibration data, the turbine was tripped at 20:37 and reactor power reduced to 1.1%. When the performance indicator data for the 4th quarter of 2003 was submitted, this reduction in power of 21.1% was not included in the Unplanned Power Changes per 7,000 Critical Hours Performance Indicator.</p>

<p>The NEI 99-02 criteria for reporting power changes of greater than 20% is for discovered off-normal conditions that require a power change of greater than 20% to resolve. Frequently, high vibrations and/or rubbing occur during startup following rotor replacement. As an expected condition rather than an off-normal condition, the associated reduction in power should not count as an unplanned power change.</p>

<p>Is the power change described above considered an unplanned power change for performance indicator reporting?</p>

Response Yes, the power change is considered an unplanned power change for performance indicator reporting. Although not discussed in the proposed FAQ, during the May 27, 2004, ROP public meeting, the licensee stated that the plan was to gather vibration data at 30% reactor power. However, during the power ascension the turbine was tripped at 22.2% reactor power due to vibrations and power was reduced to 1.1%. The repair plan did not include procedural guidance to trip the turbine or reduce power due to turbine vibrations.

Posting Date 05/27/2004 **ID** 365

Question <p>Frazil icing is a condition that is known to occur in northern climates, under certain environmental conditions involving clear nights, open water, and low air temperatures. Under these conditions the surface of the water will experience a super-cooling effect. The super-cooling allows the formation of small crystals of ice, frazil ice. Strong winds also play a part in the formation of frazil ice in lakes. The strong winds mix the super-cooled water and the entrained frazil crystals, which have little buoyancy, to the depths of the lake. The submerged frazil crystals can then form slushy irregular masses below the surface. The crystals will also adhere to any submerged surface regardless of shape that is less than 32°F. </p>
<p>In order to prevent the adherence of frazil ice crystals to the intake structure bars and ensure maintenance of the ultimate heat sink, the bars of the intake structure are continuously heated. Surveillance tests conducted before and after the event confirmed the operability of the intake structure deicing heaters. While heating assists in preventing formation of frazil ice crystals directly on the bars of the intake structure, the irregular slushy masses discussed above can be drawn to the intake structure in quantities that reduce flow to the intake canal. If the flow to the intake canal is restricted in this manner, then the circulating (lake) water flow must be reduced, to allow frazil ice formations to clear. This water flow reduction necessitates a reduction of reactor power. </p>
<p>The plant had previously put procedural controls in place to monitor the potential for frazil ice formation during periods of high susceptibility. A surveillance test requires evaluating the potential for frazil ice formation during the winter months, when intake temperature is less than 33°F. In support of the surveillance test, the Chemistry Department developed a test procedure for assessing the potential for frazil ice formation. An abnormal operating procedure was developed to mitigate the consequences of an event should frazil icing reduce the flow through the intake structure. During the overnight hours between February 14, and February 15, 2004 the environmental conditions were conducive to the formation of frazil ice. Chemistry notified Operations that the potential for frazil icing was very high. Operators were briefed on this condition, the very high potential for frazil ice formation, and the need to closely monitor intake level.</p>

<p>When indications showed a lowering intake canal level with no other abnormalities indicated, operations reduced power from 100% to approximately 30% per procedure so that circulating water pumps could be secured, thereby reducing flow through the intake structure heated bars, to slow the formation or accumulation of frazil ice and allow melting of the ice already formed.</p>
<p>NEI 99-02, in discussing downpowers that are initiated in response to environmental conditions states “The circumstances of each situation are different and should be identified to the NRC in a FAQ so that a determination can be made concerning whether the power change should be counted.” </p>
<p>Does the transient meet the conditions for the environmental exception to reporting Unplanned Power changes of greater than 20% RTP?</p>

Response Yes, the downpower was caused by environmental conditions, beyond the control of the licensee, which could not be predicted greater than 72 hours in advance. Procedures were in place to address this expected condition.

Posting Date 03/25/2004 **ID** 360

Question <p>NEI 99-02 states that anticipatory power reductions intended to reduce the impact of external events such as hurricanes or range fires threatening offsite power lines are excluded.</p>

<p>On September 20, 2003, both units were manually shutdown due to switchyard arcing from salt buildup on insulators in the switchyard. The salt buildup was due to unusual meteorological conditions (hurricane force winds, with minimal rain). These conditions led to an abnormal buildup of salt from the river to be deposited on the insulators. The shutdowns were not conducted in response to any existing or immediate equipment problems. The shutdowns were initiated to address the impact of an external event, that manifested itself in an unexpected manner and to alleviate nuclear plant safety concerns arising from an external event outside the control of the plant.</p>

<p>Should these shutdowns be counted as unplanned power reductions?</p>

Response <p>No. The shutdowns were initiated to address the impact of an unexpected external event that threatened equipment in the switchyard and as such do not need to be included as an unplanned power change. However, it is expected that the licensee would update procedures training, etc., to reflect the expected response in the event of similar meteorological conditions (i.e., high winds with minimal rain).</p>

<p>If these conditions are experienced in the future, they should be considered an expected problem, and any power change greater than 20% should be counted unless the actions to take in response to the condition are proceduralized, cannot be predicted greater than 72 hours in advance, and are not reactive to the sudden discovery of an off-normal condition.</p>

Posting Date 05/01/2003 **ID** 343

Question In December 2001 the plant identified degradation of the "A" Reactor Feed Pump (RFP) seal. Engineering evaluated the degradation (JENG-01-0701) and provided monitoring guidance that addressed several potential degradation scenarios and specific actions for each. On August 20, 2002 the monitoring guidance was incorporated into an Operations Shift Standing Order (OSSO 01-0007). On October 2, 2002 one of the monitoring criteria was exceeded and the operations staff took the actions specified in OSSO 01-007. The Operating Crew reduced power and took the "A" RFP out of service. When the monitoring criterion was exceeded the plant was at approximately 97% CTP and power was reduced to approximately 48% CTP to support removing the RFP from service. The downpower was performed in accordance with normal plant Operating Procedure OP-65. The following sequence of events has been extracted from the shift log for 10/02/02.

<p>0530 determined increase in input to floor drain sumps due to leakage from "A" RFP seal area (This was documented in a late log entry at 0626)

<p>0600 Logged report of 20 - 60 GPM seal leak on "A" RFP

<p>0600 Performed Shift Turnover

<p>0612 Reset scoop tube of "B" RWR MG set in preparation for downpower

<p>0614 Entered OP-65, Commenced downpower

<p>0619 Lowered power to 85% using RWR "A" and "B"

<p>0623 Lowered power to 75% using RWR "A" and "B"

<p>0630 Lowered power to 69% using RWR "A" and "B"

<p>0642 Inserted first CRAM Group lowered power to 52% IAW OP-65)

<p>0705 Removed "A" RFP from service by tripping the pump IAW OP-2A

<p>Under definition of Terms NEI 99-02 Rev. 2 states <i>"Unplanned changes in reactor power</i> 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 than 20% of full power to resolve."
<p>Under Clarifying Notes NEI 99-02 Rev. 2 states the following:
<p><i>"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 conditions, and prepare, review, and approve the necessary work orders, procedures, and necessary safety reviews to effect repair. The key element to be used in determining whether a power change should be counted as part of this indicator is the 72 hour period and not the extent of the planning that is performed between the discovery of the condition and the initiation of the power change."
<p>"This indicator captures changes in reactor power that are initiated following discovery of an off-normal condition. If a condition is identified that is slowly degrading and the licensee prepares plans to reduce power when the condition reaches a predefined limit, and 72 hours have elapsed since the condition was first identified, the power change does not count. If the situation suddenly degrades beyond the predefined limits and requires rapid response this situation would count."</i>
<p>This guidance statement contains three specific elements to be considered when determining if the power change counts as an Unplanned Power Change of greater that 20% rated CTP.
<p><dl><dt>First, had 72 hours elapsed between the identification of the condition and the reduction in power of greater than 20% of rated CTP?
<p><dd>The degrading condition was identified in December 2001 and was monitored for more than 10 months using criteria for action documented in an engineering memorandum and later in an Operations Department standing order.
<p><dt>Second, did "the situation suddenly degrade beyond the predefined limits"?
<p><dd>The monitoring plan in the engineering memorandum and standing order criteria included the condition observed on 10/02/002. The plan stated "IF flashing occurs at the seals, THEN take the pump off service immediately."
<p>The observed condition on 10/02/02 was a significant change in seal leakage, however, it was consistent with a specific criterion in the monitoring plan and the operators executed the actions described in the plan.

<p><dt>Third, did the condition "require rapid response"?
<p><dd>When the condition exceeded the monitoring criteria the operating crew logged the increase, completed shift turnover, entered a normal operating procedure and reduced power in a measured and deliberate response to the observed condition.
</dl>
<p>Comment: The guidance states that this indicator captures changes in reactor power that are initiated following the discovery of an off-normal condition and as noted above provides criteria for determining when a downpower should be counted. The monitoring plan was in place for 10 months and while there was a significant change in leakage rate there was no rapid response. A rapid response would be one that required the operating crew to take immediate action to manipulate the plant in

response to an unexpected event or transient. However, in this case the operating crew observed the increase in leakage, referred to the monitoring plan, assessed the situation against the plan, and determined the appropriate course of action. The operating crew then turned the shift over to the next crew, the oncoming crew briefed on the evolution, and executed a controlled downpower using normal operating procedures. In the view of the plant this deliberate and controlled response in accordance with a documented monitoring plan does not represent a rapid response by the operating crew.

<p>While no past FAQs directly address this particular scenario several do address elements of the scenario.

<p>FAQ 6 presented two hypothetical cases one of which concerned RCS unidentified leakage that could be attributed to a degrading recirculation pump seal. The FAQ asked if plans are made to repair or replace the seal if administratively established limits are exceeded and the seal leakage exceeds the administratively set limit days/weeks later would this be counted as an unplanned power change? The response stated, "The cases described would not be counted in the unplanned power changes indicator." In discussing the time between discovery and exceeding an administratively set limit the response stated, "This allowed for assessment of plant conditions, preparation and review in anticipation of an orderly plant shutdown."
<p>Comment: The circumstances in the case being submitted for consideration are similar in that the condition was identified, the potential for further degradation was assessed, monitoring criteria and actions were prepared, the condition was monitored for months and when it exceeded an action level an orderly power reduction was made.

<p>FAQ 277 addresses a condition where a hydrogen leak is identified in February 2000 and monitored until December 2000 when leakage increased to a level that the licensee shut down the plant to affect repairs. The FAQ asked in this counted as an unplanned power change. The response stated "No, the degraded condition was identified in February 2000 and an Action Plan was developed to address the condition, including an outage schedule, work request, material identification, and procurement." The response goes on to say "The increased leak rate in December 2000 was not a different condition, only a continuing degradation of the off-normal condition discovered in February 2000."
<p>Comment: Similar, to FAQ 277 the condition in the case being submitted for consideration was identified months before the need to reduce power occurred. In the time between condition identification and power reduction an action plan was put in place, work control documents were planned, and materials necessary to replace the degrading seal were identified and procured.

<p>FAQ 311 addresses another hydrogen leak scenario that included monitoring and more than one contingency for repair. In summary the question asked, if a degraded condition is identified more than 72 hours prior to the initiation of a plant shutdown, then the shutdown is considered a planned shutdown. The condition, necessitating the shutdown of the unit in this case was initially identified 30 days prior to the actual shutdown. The possibility of the need to shutdown for repairs was recognized just days later and limits were established to trigger that action. In addition repair efforts, including shutdown contingency plans, were ongoing throughout that thirty-day period. Does this situation qualify as a "planned" shutdown as suggested by NEI-99-02 FAQ 277? The response stated, "Yes, this was a planned shutdown and did not require a 'rapid response.' (NEI 99-02 page 20 lines 1-3) Therefore, it does not count as an unplanned power change."
<p>Comment: As discussed previously the degraded condition in case being submitted for consideration was identified 10 months in advance of the power reduction, plans were developed, thresholds were established and when those thresholds were exceeded power was reduced using normal operating procedures as required by the monitoring plan.
In view of the guidance provided in NEI-99-02 Rev. 2 and the guidance provided by the FAQs should the 10/02/02 downpower count as an unplanned power change?

Response Although the condition was identified greater than 72 hours before the power reduction and a monitoring plan was in place, the condition suddenly degraded beyond the predefined limit, and as specified in the monitoring plan, required rapid action. Therefore, the power change counts toward the indicator.

Posting Date 01/23/2003 **ID** 334

Question The indicator counts changes in reactor power, greater than 20%, before 72 hours have elapsed following the discovery of an off-normal condition. The unit 2 experienced a power change greater than 20% in 2002 that was not included in the indicator. Discussion of the event follows. In February 2002, Unit 2 was returning to service after a scheduled refueling outage. During plant heat-up, a steam generator stop valve was drifting off the open detents while at normal operating pressure and temperature. This was a documented, long-standing condition for these types of valves during reactor start-ups, and identified in the corrective action program at 1600 hours on February 25, 2002. Preliminary evaluation of the condition concluded, based upon previous experience with these valves, that when power was increased, the valve would remain on the detents with lower steam pressure. The decision was made to continue with reactor start-up and the unit was placed online. It was recognized by plant personnel that should the condition not correct itself as anticipated, a downpower would be required to effect repairs to the valve. Additionally, during this period, the valve was monitored by plant personnel and a problem solving team was formed to establish contingency plans should the condition not correct itself. On February 28, with reactor power at 28%, the stop valve was still drifting off the open detents. The decision was made to remove the generator from service and reduce reactor power to 2% to adjust the valve packing assembly. That decision was based on further evaluation by the problem solving team of the possible causes for the valve drifting off the open detents. At 2033 hours on February 28, Unit 2 commenced the power reduction to 2 % reactor power. When the unit was returned to service after the packing adjustment, the valve remained on the open detents. The event was not counted as an unplanned power change since 76.5 hours had elapsed from the discovery (as documented in the corrective action program) of the valve drifting off the open detents to the commencement of the power reduction. The resident inspection staff questions the off-normal condition that caused the power change. Since no plans were made to remove the unit from service for repairs but to continue the start-up with the expectation that the condition would correct itself at higher power levels based on previous experience, the decision to downpower the unit to adjust the packing assembly when the condition did not correct itself constituted a different off-normal condition. Should the power change described above be counted in the Unplanned Power Changes per 7,000 Critical Hours Performance Indicator?

Response No, this indicator captures changes in reactor power that are identified following the discovery of an off-normal condition. Although the identified condition had occurred previously in plant history, and had corrected itself after power ascension, the management team recognized that this may not always occur. As discussed above, during this period the valve was monitored by plant personnel and a problem solving team was formed to evaluate options and establish contingency plans should the condition not correct itself. Once it was identified that the condition would not correct itself, a power reduction was completed to affect repairs. The power reduction was commenced greater than 72 hours after the condition was identified. This is consistent with the guidance of NEI 99-02, Rev. 2.

Posting Date 12/12/2002 **ID** 329

Question NEI 99-02 states that unplanned power changes include runbacks and power oscillations greater than 20% of full power. Under what circumstances does a power oscillation that results in an unplanned power decrease of greater than 20% followed by an unplanned power increase of 20% count as one PI event versus two PI events? For example: During a maintenance activity an operator mistakenly opens the wrong breaker which supplies power to the recirculation pump controller. Recirculation flow decreases resulting in a power decrease of greater than 20% of full power. The operator, hearing an audible alarm, suspects the alarm may have been caused by the activity and closes the breaker resulting in a power increase of greater than 20% full power.

Response Both transients in the example should be counted. There were two errors: (1) opening the wrong breaker and (2) reclosing the breaker without establishing the correct plant conditions for restarting the pump. If the pump had been restored per approved procedures only the first transient would be counted.

Posting Date 09/26/2002 **ID** 320

Question NEI 99-02, Rev 2, states that 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 a FAQ so that a determination can be made concerning whether the power change should be counted.

<p>NEI 99-02, Rev 2, does not discuss whether the power changes associated with these FAQs should be counted while awaiting disposition. Is it satisfactory to state in the comment field that a FAQ has been submitted, and not to include the power changes in the PI calculation?

Response Yes. The comment field should be annotated to state that a FAQ has been submitted. The licensee and the NRC should work expeditiously and cooperatively, sharing concerns, questions, and data, in order that the issue can be resolved quickly. However, if the issue is not resolved by the time the quarterly report is due, and the licensee is confident that this exclusion applies, it is not necessary to include these power changes in the submitted data. Conversely, if the licensee is not confident that this exclusion applies, the unplanned power change(s) should be counted. In either case, the report can be amended, if required, at a later date.

Posting Date 09/26/2002 **ID** 319

Question At approximately 2243 hours on September 24, 2001 the number 2 Station Power Transformer in the Switchyard experienced an electrical fault on one of its associated surge arresters. The failure of this surge arrester resulted in the loss of both the number 2 and 4 main station power transformers and station power transformers 12, 14, 22 and 23. As a result, each unit lost three (Unit 1 lost 11B, 12B, 13B) of the six condenser circulating pumps. Additionally, unit 1 lost power to its circulating water traveling screens, as well as the sensing instrumentation for the differential pressure across the traveling screens. Upon loss of power to the sensor, the screen delta p indication in the Control Room shows screen delta p as being in the acceptable range, regardless of actual screen delta p. With only three of six circulating water pumps operating per unit, both units reduced electrical load to maintain main condenser vacuum. Following the completion of the power reduction, unit 1 personnel restored electrical power to the Unit 1 circulating water bus and the circulating water traveling screens. This occurred approximately 1 hour after the electrical fault. Because of the loss of power to the traveling screens, detritus buildup (detritus levels were between 1400 and 1500 Kg/10E6 cubic meters) caused a high differential pressure on the remaining screens. Shortly after the power was restored to the traveling screens, one (13A) of the three remaining circulating water pumps tripped due to high differential pressure across its associated traveling screen. Because of the loss of power to the sensing instrumentation, this condition was not detected prior to restoring the power. As a result of this additional loss of a circulating water pump and the resultant decrease in condenser vacuum, Unit 1 licensed control room operators initiated a manual trip in accordance with the guidance provided in the abnormal operating procedure at 2351, on September 24. This event was similar to previous loss of station power transformer events that occurred in June and July of 2001. In all three of the events, each unit lost three circulators, and one of the two units lost all six traveling screens (in June and July Unit 2 lost the traveling screens), their controls, indications, and the screen wash pumps. In addition, all three events resulted in a power reduction for both units. In both the June and July events, it took longer (1.75 to 6.25 hours) to restore power to the circulators than it did in the September event. The June and July events did not result in the loss of an additional circulator after power was restored because the detritus levels were lower (in the 400's). Therefore, a plant scram was avoided.
<p>Unit 2 circulating water traveling screens were unaffected by the loss of the 2 SPT, therefore the power reduction was sufficient to maintain main condenser vacuum. Does this event meet the criterion in NEI 99-02 that states "Off-normal conditions that begin with one or more power reductions and end with an unplanned reactor trip are counted in the unplanned reactor scram indicator only." Or are the causes of the downpower and the scram sufficiently different that an unplanned power change and an unplanned scram must both be counted.

Response The causes of the downpower and the scram are different. The loss of the station power transformer caused the downpower. The operators' failure to anticipate the effects of power restoration led to the loss of the fourth circulator and the scram. Therefore both an unplanned power change and an unplanned scram should be counted.

Posting Date 05/22/2002 **ID** 311

Question Question:Plant surveillance procedure 3-OSP-090.2, <I>Main Electrical Generator Hydrogen Leakage Calculation</I> is performed on a weekly basis. Data is gathered on the weekend by operations. Calculations and tracking are performed by the System Engineer each Monday morning. During the past 17 months, hydrogen leakage on the Unit 3 main generator ranged about 800 to 1300 cu ft/day. This leakage was due primarily to a known bad hydrogen seal on the north end of the generator. This hydrogen was being safely discharged through the seal oil vapor extractor vent. Repair of this leak was planned for the upcoming refueling outage.<p>Hydrogen consumption by the Unit 3 main generator during the weekend of 07/07/01 increased significantly. The calculated consumption per 3-OSP-090.2 was 1665 cubic feet per day. This is in excess of the typical Westinghouse generator leakage and a sizeable increase of the trend for Unit 3. On 07/11/01 the system engineer initiated Condition Report (CR01-1364), and a concerted effort began to identify the source of the leak.<p>During the week of 07/11/01, the Engineering Systems Manager and the System Engineer briefed the Plant Manger on the leakage. During this meeting the possibility of a unit shutdown to effect repairs was recognized and discussed. Since no administrative limit on hydrogen leakage had been previously established, the Plant Manager established criteria for unit shutdown. The criteria was:<p>(1) Leakage not attributed to the seal becoming greater than 2000 cu ft/day (approx. 3000 cu ft/day total) AND there was evidence of hydrogen pooling in any area around the generator in excess of 50% LEL,<p>(2) an unisolable leak that could not be repaired on-line <p>(3) a leak that was rapidly degrading. <p>The decision was made to pursue on-line repairs, as long as conditions permitted and to shutdown if on-line repairs could not be performed.<p>From 07/11/01 through 07/28/01 extensive system checking was performed by Engineering and Maintenance personnel. All valves and devices were inspected sniffed and snooped. Additionally, accessible piping was checked hand over hand. The known leak via the seal oil system was re-quantified and ruled out as the source of the new leakage. During this period, several minor leaks were identified and isolated or repaired. <p>The Main Generator leakage data gathered on 07/28/01 showed leakage on Unit 3 had increased to 2091 cu ft/day. Air movers were installed to draw off hydrogen gases from areas around the generator. The generator skirt access plates, doors, etc. on the turbine deck were removed/opened to sample that space and prevent hydrogen pooling (the turbine building is an “open air” design). No evidence of hydrogen pooling was found. System inspections continued and a cap was installed down stream of valve 3-100-23-1 to isolate a minor leak there. Scaffolding was ordered built to access the belly of the generator so that the penetrations could be inspected. <p>On Saturday, 08/04/01 the hydrogen leakage data showed a leak rate of 3015 cu ft/day. The hydrogen dryer was isolated. No evidence of hydrogen pooling was found.
<p>On Monday 08/06/01 the hydrogen leakage data showed a leak rate of 2840 cu ft/day, only a slight decrease. The Plant Manager ordered daily calculations and contingency plans for shutdown repairs if the leak was found to be unisolable. Scaffolding was in place under the south end of the generator and an extensive inspection of the generator system was performed, but no additional leaks were found. The presence of hydrogen was measured in that vicinity at 8% LEL, but no source could be pinpointed.<p>On Tuesday 08/07/01, operations began methodical monitoring of the leak rate by taking data readings every 6 hours. Additional scaffolding was erected beneath the center section of the generator to allow leakage checks of the hydrogen system piping penetrations. Thermographic images were taken of the area under the generator, but no evidence of leaks were found.<p>On Wednesday 08/08/01, the leak rate was calculated to be 3001 cu ft/day, the scaffolding extension for the full length of the generator was completed. New high sensitivity hydrogen detection equipment was received and put to work. Engineering and Maintenance continued testing for leaks and evidence of pooling. The Isophase ducts were sampled but no hydrogen found. Each generator penetration was snooped and sniffed. The length of each pressurized hydrogen line, paying particular attention to welds and valves, was sniffed and snooped. Some additional minor leaks were found. <p>Engineering personnel then found a large leak on the generator lead box. Cracking was evident between the bottom flange and vertical member weld on the southwest corner. Investigation by plant personnel determined that a fillet weld at the base of the collar of the main lead box assembly was cracked. The crack appeared to be several inches in length and seemed to go around the lower southwest corner of the box. To ensure safety, additional air movers were installed to dissipate the hydrogen gas. <p>Engineering personnel were directed by plant management to develop two specific repair methods: <p>(A) a temporary repair method to be worked on-line and <p>(B) (as a parallel effort) a repair method to be performed off-line. <p>Plan A, the on-line repair method, proposed using strong backs and sealing material, mechanically

wedged or clamped against the crack and then filled with Fermanite. Plan B, the off-line repair method, proposed a weld overlay. Additional scaffolding was erected to safely reach the lead box to support either activity.<p>On Thursday 08/09/01, the leak rate was calculated to be 4421 cu ft/day. Upon closer examination of the crack, engineering determined that Plan A, the on-line repair method, was not viable. Plan B, which used welding, was judged the only effective repair method. Plan B required the generator to be purged of hydrogen and depressurized maintaining a CO2 cover gas. <p>On Friday 08/10/01 at about 2:30PM, Unit 3 was brought to mode 2 in an orderly fashion and the generator purged with CO2. The unit was brought down to mode 2 at a rate of about 10% per hour, using the normal operating procedure, 3-GOP-103, "Power Operation to Hot Standby. " The "Fast Load Reduction Procedure, " 3-ONOP-100, was never entered. The weld was repaired using the weld overlay procedure outlined in CR01-1364 Interim Disposition #1.<p>The main generator hydrogen system is described in Section 10.1 of the UFSAR. The UFSAR does not reference any allowable leak rates and there are no Technical Specifications with regard to hydrogen leakage. There are no adverse effects on the Turkey Point FSAR and Technical Specifications. The concern for hydrogen leakage is in regard to the potential for adverse personnel and industrial safety. Measures (forced ventilation) were taken to maintain safety; therefore, shutdown for repairs was a conservative and prudent action. The decision to shutdown was not based on operability or safety concerns, but rather on establishing the necessary conditions to facilitate repairs. <p>In accordance with NEI-99-02, if a degraded condition is identified more than 72 hours prior to the initiation of a plant shutdown, then the shutdown is considered a planned shutdown. The condition, necessitating the shutdown of Unit 3, was initially identified on July 11, 2001 (30 days prior to the actual shutdown). Moreover, the possibility of the need to shutdown for repairs was recognized just days later and limits were established to trigger that action (a plan established). In addition, repair efforts, including shutdown contingency plans, were ongoing throughout that thirty-day period. Does this situation qualify as a “planned” shutdown as suggested by NEI-99-02 FAQ 277?

Response Yes, this was a planned shutdown and did not require a “rapid response.” (NEI 99-02 page 20 lines 1-3). Therefore it does not count as an unplanned power change.

Posting Date 04/25/2002 **ID** 306

Question This FAQ is submitted based on the statement in NEI 99-02 Rev 1, page 17, lines 28 - 33:<p>"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 that 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 a FAQ so that a determination can be made concerning whether the power change should be counted."<p>The water conditions of Lake Ontario have improved over the years. One of these improvements has been the increased clarity of the water. This increased clarity allows the sun light to penetrate much deeper in all areas of the lake, thus encouraging aquatic growth, such as lake grass. The spring and summer of 2001 have been storm-free on most of Lake Ontario causing little disturbance and turnover of the lake water.<p>On July 26, 2001, a significant change in the weather and lake environment caused the station engineers monitoring the condenser efficiency to check the condenser parameters. Due to the influx of lake grass, the delta-T across potions of the main condenser had increased, but remained within environmental release limits. Due to micro-fouling (zebra mussels, silt) in the past, the station is sensitive to lake conditions, however, prior to this event, the station had not experienced condenser fouling due to lake grass. In addition, the need to check condenser efficiency with no adverse indication is not proceduralized.<p>The delta-T across the affected condenser side improved over the next couple of days as the weather and the lake conditions returned to more normal and the lake grass washed itself from the condenser. However, a down power was needed to clean the main condenser. A decision was made to clean the main condenser when the electric grid loading allowed for it. Discussion with load control dispatchers determined that July 28, 2001, would be the most opportune and economic time to reduce load. The main condenser was cleaned that Saturday morning. At no time between discovery and condenser cleaning did any condenser parameter require a load adjustment other than to improve efficiency as a result of the lake grass influx. Is this greater than 20% power change considered an unplanned power change?

Response No The influx of lake grass had not caused condenser fouling in the past and was therefore an unanticipated event. The licensee is expected to take reasonable steps to prevent intrusions of lake grass from causing power reductions in the future

Posting Date 03/21/2002 **ID** 305

Question Conditions arise that would require unit shutdown, however an NOED is granted that allows continued operation before power is reduced greater than 20%. Should the event be reported as an unplanned change in reactor power under the Unplanned Power Changes per 7,000 Critical Hours performance indicator?

Response No, the condition should not be counted as an unplanned power change because no actual change in power occurred on the units involved. A comment should be made that the NRC had granted an NOED during the quarter, which, if not granted, may have resulted in an unplanned power change.

Posting Date 03/21/2002 **ID** 304

Question Appendix D Quad Cities<p>1) At Quad Cities, load reductions in excess of 20% during hot weather are sometimes necessary if the limits of the NPDES Permit limit would be exceeded. Actual initiation of a power change is not predictable 72 hrs in advance, as actions are not taken until temperatures actually reach predefined levels. Would these power changes be counted?<p>2) Power reductions are sometimes necessary during summer hot weather and/or lowered river level conditions when conducting standard condenser flow reversal evolutions. The load reduction timing is not predictable 72 hrs in advance as the accumulation of Mississippi River debris/silt drives the actual initiation of each evolution. The main condenser system design allows for cleaning by flow reversal, which is procedurally controlled to assure sufficient vacuum is maintained. It is sometimes necessary, due to high inlet temperatures, to reduce power more than 20% to meet procedural requirements during the flow reversal evolution. These conditions are similar to those previously described in FAQ 158. Would these power changes be counted for this indicator?

Response 1) No.<p>2) No. Power changes in excess of 20% for the purposes of condenser flow reversal are not counted as an unplanned power change.

Posting Date 01/25/2002 **ID** 300

Question On 4/19/01 at 1917 hours, a DC bus ground was traced to the breaker for a heater drain pump at BVPS Unit 2. This was verified via a troubleshooting plan at 1152 hours on 4/21/01. The Unit 2 NSS had contacted Conversion Economics and stated that BVPS-2 desired a window to perform a power reduction to approximately 40% in order to perform a breaker swap-out on the "A" Heater Drain Pump due to a DC ground. The window could be Saturday (4/21/01) or Sunday (4/22/01) or the following weekend, and that BVPS-2 could "load follow" in place of another FE plant since the system demand was projected to be low over these weekends. At 1323 hours on 4/21/01, it was decided by Conversion Economics that BVPS-2 would begin to load follow at 2200 hours on 4/21/01 to an output of approximately 40%. Return to full power was set to begin at 0700 hours on 4/22/01.<p>Based on the above, this reduction was considered to be "load following", and therefore, the reduction was NOT counted against this PI value in April 2001. A load reduction within the 72 hours following identification of the specific equipment problem was not required, nor specifically requested by the plant. The date and time of the load reduction was left to the discretion of the load dispatcher. The NRC Resident Inspector questioned whether this event should have been counted in the PI for unplanned power changes.<p>QUESTION: The plant has an equipment malfunction and initiates a call to the system load dispatcher requesting a window to perform a power reduction to facilitate repairs. The plant informs the load dispatcher that the window does not need to be within 72 hours of the equipment problem. However, the load dispatcher subsequently responds with a load reduction window that occurs within 72 hours of the equipment problem. Does this qualify the load reduction as being "directed by the load dispatcher" and therefore not reportable under this PI?

Response No. The power change was not under "normal operating conditions due to load demand and economic reasons," nor was it "for grid stability or nuclear plant safety concerns arising from external events outside the control of the nuclear unit." It was "due to equipment failures that are under the control of the nuclear unit." Because the power was reduced in less than 72 hours, the downpower counts. (See NEI

99-02 Rev 1 page 17 lines 37 to 41. Rev 2 page 20 lines 37 to 41)

Posting Date 12/13/2001 **ID** 295

Question Appendix D - Point Beach Units 1 and 2<p>On June 27th, Point Beach Unit 2 was manually scrammed, in accordance with Abnormal Operating Procedure AOP 13A, "Circulating Water System Malfunction," and power was reduced on Point Beach Unit 1 by greater than 20% (from 100% to 79%) due to reduced water level in the pump bay attributable to an influx of small forage fish (alewives). The large influx of fish created a high differential water level across the traveling screens and ultimately failure of shear pins for the screen drive system, leading to a rapid drop in bay level. The plant knows when the alewife spawning and hatching seasons occur and the effects of Lake Michigan temperature fluctuations on the route of alewife schools. It was aware of the presence of large schools at other Lake Michigan plants this spring and discussed those events and the potential of them occurring at Point Beach at the morning staff meetings. During the thirty years of plant operation, there have been a few instances where a large number of fish entered the plant circ water system. High alewife populations coupled with seasonal variations, lake conditions and wind conditions created the situation that resulted in the down power on June 27th. Point Beach staff believe that these are uncontrollable environmental conditions. Plant procedures are in place which direct actions when the water level in the pump bay decreases. However, it is not possible to predict the exact time of an influx of schooling fish nor the massive population of fish that arrived in the pump bay. Page 17 of NEI 99-02 Revision 1 states, "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." Would this situation count as an unplanned power change?

Response No. The influx of alewives was expected as evidenced by the discussion of events at other plants on Lake Michigan but was not predictable greater than 72 hours in advance due to the variables involved. Large schools of alewives are a result of environmental and aquatic conditions that occur in certain seasons. The response to the drop in bay level is proceduralized.

Posting Date 12/13/2001 **ID** 294

Question This spring the above water portion of the circulating water intake structure was removed. This action was required by two federal agencies due to the issue of the intake structure attracting, inadvertently trapping and leading to the demise of double crested cormorants (a protected migratory bird species). Anticipating the possibility of fouling, contingency work orders were created on April 3 before the intake demolition started for cleaning of the main condenser water boxes and condensate coolers. These activities anticipated the necessity for reductions in power by greater than 20% and prescribed plant operating criteria that would necessitate initiation of these cleaning activities in response to accumulation of marine debris. However, the exact dates when these power reductions and cleaning activities would occur could not be predicted greater than 72 hours in advance. <p>Power was reduced by greater than 20% for cleaning attributable to the accumulation of marine debris due to the ongoing intake structure activities on May 19th and May 25th for Unit 2 and Unit 1, respectively. In both cases, the rapid deterioration in the monitored plant parameters dictated power reductions and cleaning in less than 72 hours from the onset of the conditions. <p>In addition, a Tech Spec surveillance required main turbine stop and governor valve with turbine trip test, requiring a reduction in power to about 65%, had been scheduled approximately 12 months in advance to occur at a later date. Since Unit 2 required a load reduction to 50% due to marine fouling for water box cleaning, the Tech Spec surveillance was moved up to also take place during that power reduction.<p>Would any of these power changes in excess of 20% be counted for this indicator?

Response No. As discussed on p. 17 of NEI 99-02 Revision 1, if the power reductions were anticipated in response to expected problems (such as accumulation of marine debris and biological contaminants in certain season), a part of a contingency plan and not reactive to the sudden discovery of off normal conditions, they would not count. The planned maintenance power reduction to 65% would still be considered planned since it was planned greater than 72 hours in advance of its occurrence.

Posting Date 07/22/2004 **ID** 367

Question <p>This FAQ seeks clarification of the guidance in NEI 99-02 regarding fault exposure. Specifically, NEI 99-02, page 30, lines 3-6 describe fault exposure (T) in terms of failure and the failure's known time of occurrence and known time of discovery. Lines 13-20 provide "T/2" fault exposure guidance where the time of failure is uncertain and only the time of discovery is known. This clarification will be used to determine whether a situation is "T" or "T/2." </p>

<p>Emergency diesel generator "A" (EDG A) failed a monthly surveillance on September 29, 2003. A fuel oil line connection on the diesel failed during the surveillance; the surveillance was halted and the diesel declared inoperable. Based upon guidance in NEI 99-02 and FAQ 318, the plant reported in the 3Q03 performance indicator submittal T/2 fault exposure hours based upon the time from the last successful surveillance (September 2, 2003) until EDG A failed on September 29, 2003. This is due largely to the guidance that notes <i>"…Fault exposure hours for this case must be estimated. The value used to estimate the fault exposure hours for this case is: one half the time since the last successful test or operation that proved the system was capable of performing its safety function."</i> Is this interpretation of the guidance correct?<p>
<p><u>Additional Details:</u>
A root cause determined that plant maintenance introduced a latent condition on May 16, 2003 during maintenance on the diesel that lead to EDG A failure during the September 29 surveillance. The root cause established the failure mechanism was fatigue. A time of failure after the introduction of the latent maintenance condition cannot be predicted with certainty because of the complexity of the fatigue phenomenon e.g., fatigue failure is a non-linear function of time; it is also cumulative. The fatigue failure was further complicated by multiple starts and stops of the diesel during monthly surveillances. (From the time the tubing was installed in May 2003, EDG A ran for almost 29 hours over a period of about 4 months and 5 successful surveillances.)</p>

Response For this specific situation, use of T/2 is acceptable. Engineering judgment in conjunction with analytical techniques was unable to determine the time when the train would have been unavailable with enough certainty for use in the performance indicator.

Posting Date 04/22/2004 **ID** 363

Question <p>Appendix D
NEI 99-02 Rev 2 recognizes that some provisions are intentionally restrictive to ensure that the NRC is informed of plant conditions. On page D-2 lines 19 through 31 guidance is given to allow exceptions to allow credit for operator compensatory actions to mitigate the effects of unavailability of monitored systems.</p>

<p>During a surveillance test on December 9, 2003, South Texas Project Unit 2 SDG-22 experienced a catastrophic failure and STP Nuclear Operating Company (STPNOC) could not complete the repairs in the current 14 day AOT. As a result SPTNOC submitted a series of Technical Specification amendment request to allow a one-time-only increase of the Allowed Outage Time to a total of 113 days. These amendments were approved by the NRC and resulted in the continued operation of STP from December 9, 2003 until March 31, 2004. This one-time-only extended allowed outage time will result in 2,712 hours of unavailability on SDG 22 and a Performance Indicator value of 4.5% (White) for Emergency AC Power. If the Technical Specification one-time change had not been granted, STP would have incurred less than 336 hours of unavailability on SDG 22 and would have remained in the Green band (1.6%). For Emergency AC Power, the NEI 99-02R2 NRC Performance Indicator Green/White threshold is set at 2.5%, while the White/Yellow threshold is set at 10%.</p>

<p>STP Unit 2 received an allowable outage time (AOT) extension in an approved license amendment request, predicated upon a combination of alternative systems and operator compensatory actions for the unavailable system. The NRC evaluated, and documented the acceptability of these alternative methods; the NRC's SER confirms that the licensee did indeed provide an acceptable interim compliance configuration in accordance with their new license amendment. See "Event Details and

Supporting Information" below for more information.</p>

<p>License amendments do redefine a plant's licensing basis. If alternative methods are proposed, submitted, reviewed, approved, and inspected, then the NRC has publicly endorsed the alternative methods as providing acceptable compliance. As long as the licensee maintains the newly licensed configuration and compensatory measures, the unavailable hours should not accrue unless the newly licensed configuration was no longer maintained. NEI 99-02 Rev 2 allows for an exemption of unavailability hours based on operator compensatory actions.</p>

<p>Since the unavailability incurred by SDG 22 was approved by a license amendment to the STP Unit 2 Technical Specifications that provided compensatory measures and an approved credited backup power supply to Train "B", and since counting all hours incurred would significantly mask future degrading performance, should the unavailable hours be counted only from the time of discovery until the compensatory measures were in place?</p>

Response <p>Yes, the unavailable hours should be counted only from the time the diesel became inoperable until the time that the compensatory measures and non-class diesel generators were in place and remained in place. This is based upon the following factors: </p>

The condition was approved by a change to the plant Technical Specifications.
The Technical Specification change credited a backup non-class power supply for SDG 22 in addition to the other two Standby Diesel Generators at the Unit.
There are control room alarms to alert the Control Room operator of the need for the compensatory measures.
Dedicated operators are stationed in the area to complete the recovery action.
The operators have procedures and training has been accomplished for the recovery action.
There are at least four means of communication between the Control Room and the local operators.
All necessary equipment for recovery action is pre-staged and has been tested.
Indication of successful recovery actions is available locally and in the Control Room.
The non-class diesel generators are inspected weekly and operated monthly on a load bank to verify their availability.
The probability of successful completion of compensatory actions were evaluated by sensitivity studies as part of the amendment request and accepted by the NRC SER.

Posting Date 03/20/2003 **ID** 335

Question The overhaul of the EDG fuel priming pump was planned corrective maintenance and was scheduled as part of the overall overhaul activities for the EDG. Post maintenance testing revealed that parts installed in the fuel oil priming pump during the overhaul did not result in optimal performance. Although the pump operation would not have prevented the fuel oil priming pump from fulfilling its required safety function, the decision was made to rework the pump to recover pump performance. The rework resulted in extending the overhaul past its originally scheduled time. Does the maintenance rework count as planned overhaul maintenance?

Response The corrective maintenance activity extended the overhaul beyond the planned overhaul hours. Those additional hours count toward the indicator. NEI 99-02 will be changed at the next revision to make this clear.

Posting Date 12/12/2002 **ID** 325

Question Treatment of Planned Overhaul Maintenance in the Clarifying Notes section of the Mitigating Systems Cornerstone, Safety System Unavailability, states that plants that perform on-line planned overhaul maintenance (i.e., within approved Technical Specification allowed Outage Time) do not have to include planned overhaul hours in the unavailable hours for this performance indicator under the conditions noted. This section further states that the planned overhaul maintenance may be applied once per train per operating cycle. EDG(s) at our plant are on an 18 month overhaul frequency per T.S.4.6.A.3.a, while the plant operating cycles are typically a month or two longer. Thus, the EDG 18 month overhaul will occur twice in some cycles. If major overhauls, performed in accordance with the plant's technical specification frequency, result in more than one major overhaul being performed within the same operating cycle, can both of these overhauls be excluded from counting as planned unavailable hours?

Response It depends on the quantitative risk assessment that was performed to justify the exclusion. If the assessment specifically addressed the use of the Technical Specification AOT twice per operating cycle, then both overhauls may be excluded from the PI. If, however, the licensee's assessment assumed that only one AOT would be used per operating cycle, or if the licensee submitted a request to the NRC for an extended AOT and did not specify the number of times the AOT would be used per cycle, then the exemption may be used only once. However, the licensee has the option to perform a risk analysis that assumes the use of two AOTs per cycle. If that analysis meets the requirements of NEI 99-02 Rev. 2, page 28 line 15, through page 29 line 2, then the licensee may exclude the overhaul hours for the two overhauls.

Posting Date 10/31/2002 **ID** 324

Question The station programmatically maintains and manages risk associated with overhaul maintenance performed within Technical Specification Allowed Outage Times (AOTs). The program implements Regulatory Guide 1.177 and/or NUMARC 93-01 requirements for risk management during the maintenance activities. All work to be accomplished during a planned overhaul is scheduled in advance and includes maintenance activities that are required to improve equipment reliability and availability. The station considers overhaul maintenance as those overhaul activities associated with the major component as well as pre-planned corrective and preventive maintenance on critical subcomponents. For example, the EDG preventive maintenance program requires hydrostatic testing of the lube oil cooler every 12 years and the subsequent repair or replacement of the cooler as necessary. The purpose of the hydrostatic test is to preemptively reveal defects to preclude a run-time failure by applying far more pressure to the lube oil cooler than would be experienced during normal operation. This test was a scheduled item during a planned EDG overhaul, and the lube oil cooler did not pass the hydrostatic test. The lube oil cooler replacement was not included as a scheduled contingency item, nor was a replacement cooler on-site. However, replacement coolers of this type were known to be readily obtainable. The original overhaul duration was extended by the time needed for procurement and installation of a replacement lube oil cooler. Do the additional hours count as planned overhaul maintenance hours?

Response No. The hours must be included in the indicator. When problems are discovered that are due to a licensee performance deficiency, and resolution of that problem results in additional hours beyond those scheduled for the overhaul, the additional hours must be counted. In this case, the licensee's RT examination of the lube oil cooler to determine its susceptibility to failure during the planned hydrostatic test was faulty. That examination led them to erroneously conclude that their cooler was of a more robust design than it actually was and that it was not susceptible to failure. This deficiency resulted in an unplanned extension to the planned overhaul.

Posting Date 10/31/2002 **ID** 322

Question Appendix D – Surry
<p>NEI 99-02, Revision 1, in the Clarifying Notes for the Mitigating Systems Cornerstone, allows a licensee to not count planned unavailable hours under certain conditions when testing a monitored system.
<p>At our two-unit PWR station, three EDGs provide emergency AC power. There is one dedicated diesel for each unit and one swing diesel available for either unit. During the monthly surveillance testing required by Technical Specifications, there is an approximate four-hour period when the EDG is run for the operational portion of the test and is inoperable but available. In 2001, surveillance-testing procedures were revised to take credit for restoration actions that would enable not counting the hours as unavailable.
<p>The restoration actions for the two dedicated diesels during the approximate four-hour period consist of implementing a “contingency actions” attachment to the test procedure. This process verifies system

alignment and places the EDG on its emergency bus. The steps allow the dedicated control room operator to change the emergency generator auto-exercise selector from exercise to auto, verify or place the emergency supply switch in auto, depress the emergency generator fast start reset button and adjust the engine speed and voltage as necessary. The process steps are, individually and collectively, simple and done by a dedicated operator. The last step requires the governor speed droop control to be adjusted to zero. However, the speed droop adjustment is not required for the EDG to satisfy its safety function. This step is performed to relieve the dedicated operator and does not challenge operation or control of the EDG.
<p>Question (1); can credit be taken during the restoration actions that require only one dedicated control room operator (no other assigned duties) resulting in not counting the unavailable hours during this portion of the testing of the dedicated EDGs? The restoration actions for the swing diesel also consist of implementing a “contingency actions” attachment to the test procedure with a few minor differences. Three additional steps determine which emergency bus the swing EDG needs to be aligned to before placing the swing EDG on that emergency bus. The rest of the actions are identical to the dedicated EDG explanation described above.
<p>Question (2); can credit be taken for these restoration actions that require only one dedicated control room operator (no other assigned duties) resulting in not counting the unavailable hours during this portion of the testing of the swing EDG?

Response Question 1: No. A review of the restoration actions specified in the licensee’s surveillance procedure was performed to determine if the restoration actions were uncomplicated (a single or a few simple actions) and not requiring diagnosis or repair as discussed in NEI 99-02, revision 2. Although some of the individual restoration actions met the above criteria, the procedure involved eight or more actions, two of which did not meet the above criteria. Specifically, the two actions involve the diagnosis and reaction to particular plant parameters. For an approximate three minute period, while loads are sequenced onto the emergency bus, engine speed must be adjusted to maintain bus frequency and bus voltage must be adjusted to maintain voltage within specified limits. Therefore, unavailable hours should be counted during the testing of the dedicated EDGs.
<p>Question 2: No. The answer to question 1 also applies to the swing EDG. The restoration actions for the swing EDG are further complicated by the potential need to remove the EDG from one unit’s emergency bus and subsequently place the swing EDG onto the other unit’s emergency bus. These additional restoration actions, coupled with the restoration actions required for the dedicated EDGs, exceed those actions constituting a single or a few simple actions. Therefore unavailable hours should be counted during the testing of the swing EDG.

Posting Date 09/26/2002 **ID** 318

Question In August 2001, Our plant had just completed the monthly EDG load-run surveillance and had <u>passed the plant’s load and duration test specification</u>. The EDG was being secured from the test in accordance with the surveillance. Generator real load (kW) was initially reduced, when it was discovered that generator reactive load (KVAR) would not respond to remote or local control inputs. Operations then tripped the generator output breaker and secured the EDG and declared it out of service. Initial trouble shooting of the voltage regulator was performed and the engine was run the next day with similar response to load control. At this point the engine was removed from service for repair of the generator. The root cause evaluation determined that the generator had two shorted coils. The cause of the shorted coils was degradation of winding laminations over time due to poor winding processes at a repair vendor’s facility for work performed in 1993. This degradation ultimately resulted in contact between a generator winding and uninsulated wedge block bolting internal to the generator while the engine was being secured <u>following</u> successfully satisfying the monthly surveillance.

<p>In applying fault exposure hours to this scenario we believe that by meeting the plant’s load and duration test specification, during the surveillance, NEI 99-02, Revision 1, page 38 line 30 criterion for successful start and load-run was met. Because the failure occurred during the unload and shutdown portion of the surveillance (the failure’s time of occurrence is known), fault exposure is not applicable. The time that the engine was out of service for the initial voltage regulator trouble shooting, the second attempt to run the engine and hours associated with the generator repair are counted as unplanned unavailable hours.

<p>Have we correctly interpreted NEI 99-02 guidance that fault exposure hours would <u>not</u> be reported in this situation?

Response No. While the diesel had officially passed the surveillance test, the plant was still getting information from the surveillance test during the diesel shutdown. T/2 fault exposure should be taken from the last successful test of the diesel, i.e., the last monthly test before this occurrence.

Posting Date 08/22/2002 **ID** 317

Question Florida Power Corporation's (FPC) Crystal River Unit 3 (CR-3) seeks to apply the NEI 99-02, Revision 2, Safety System Unavailability (SSU) T/2 Fault Exposure Hour treatment for T/2 Fault Exposure Hours incurred prior to January 1, 2002.

<p>Specifically, FPC seeks approval to remove 345 T/2 Fault Exposure Hours incurred in a single increment against Emergency Diesel Generator EGDG-1B from the calculation of Emergency AC SSU PI. These hours DID NOT result in the associated SSU Performance Indicator (PI) exceeding the green-white threshold. In accordance with the guidance of NEI 99-02, Revision 2, these hours would be reported in the “Comment” section of the PI data file.

<p>Continuing to carry these Emergency AC SSU T/2 Fault Exposure Hours until the Fault Exposure Hour reset criteria are met is inconsistent with the current philosophy for treatment of T/2 Fault Exposure Hours. This situation will result in the SSU PIs for various plants being non-comparable depending on when any T/2 Fault Exposure Hours were discovered. This could easily occur at a multi-unit site. Further, if a plant discovered different events which contributed T/2 Fault Exposure Hours attributable to a period before January 1, 2002, and another after, the PI would be internally inconsistent.

Response This situation does not meet the requirements for resetting fault exposure hours, in that the green white threshold was not exceeded.

Posting Date 08/22/2002 **ID** 314

Question Appendix D – Oconee
<p>The Oconee Nuclear Station has a unique source of emergency AC power. In lieu of Emergency Diesel Generators, Oconee emergency power is provided by one of two identical Keowee Hydro units located within the Oconee Owner Controlled Area. These extremely reliable units are each capable of supplying ample power for the plant loads for all three Oconee units. Additionally, they are also used for commercial generation using an overhead line to the Oconee switchyard.

<p>Train separation at Oconee is initially established at the three (3) 4160 volt load buses in each unit. These buses are all fed from one of two main feeder buses in each unit, that are both in turn supplied from a single underground power cable from a Keowee unit. This underground path is preferred and is preferentially selected on a loss of offsite power and an Engineered Safeguards signal. If the Keowee unit aligned to the underground path trips, the ONS loads will be automatically transferred to the remaining adjacent Keowee unit. As an additional source of power, the main feeder buses can also be fed from the Keowee overhead power line via the Oconee switchyard.

<p>The PRA calculations indicate the Underground Path is significantly more important than the Overhead Path, which is susceptible to external events and therefore can be discounted. From the PRA results, it is recommended that safety system unavailability reporting for the MS01 performance indicator be based on the Underground path. PRA calculations support the following thresholds based upon the delta CDF for unavailability of the Underground Path.

<p>The Green/White threshold value is consistent with the Maintenance Rule limit for unavailability of the Underground Path. Also, historical unavailability of the Underground Path would place ONS mid-way in the green band, which is consistent with average industry performance for the MS01 indicator. The White/Yellow threshold of 4.0% provides an appropriate white band as compared to the threshold of 5.0% indicated in NEI 99-02 for a system with two trains of Emergency AC equipment. The Yellow/Red

threshold of 10% is conservative and is consistent with NEI 99-02 for a system with two trains of Emergency AC equipment. Monitoring the underground path only, are 2.0%, 4.0% and 10.0%, acceptable threshold values for the ONS Emergency Power performance indicator?

Response Yes.

Posting Date 04/22/2004 **ID** 361

Question <p>Appendix D
Proposed Overhaul Exemption for Unavailability Hours Incurred On Unit 2 Safety Systems Due To Planned Overhaul of Unit 1 Nuclear Service Water System (NSWS) Pump</p>

<p>Catawba Nuclear Station (CNS) refurbished the 1B Nuclear Service Water System (NSWS) pump during a recent refueling outage. Unit 1 was defueled and Unit 2 at power operation during this activity. Technical Specifications provided for an allowable outage time sufficient to accommodate the overhaul hours associated with the pump replacement. Catawba has a shared NSWS between both units such that the 'B' train pumps for both units (1B and 2B NSWS pumps) share a common intake pit and discharge header. Removing and reinstalling 1B NSWS pump for refurbishment rendered 2B NSWS pump unavailable.</p>

<p>Removal of the 1B NSWS pump required making the 2B NSWS pump inoperable for 2.6 hours in order to disconnect a submerged support and inspect the nuclear service water pond intake. Once the 1B NSWS pump was removed from the pit, the 2B NSWS pump was restored to operable status and Unit 2 safety systems were restored to fully operable status. After the 1B NSWS pump refurbishment was complete, the 2B NSWS pump was again rendered inoperable for reinstallation of the 1B NSWS pump. The reinstallation was originally scheduled for 20 hours but took longer due to complications. Catawba is seeking to exclude the unavailability that was incurred from the actual 2.6 hours required to remove the pump and the 20 hours originally scheduled for reinstallation (22.6 hours total).</p>

<p>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. If the requested hours for this overhaul of the 1B NSWS pump cannot be excluded it would result in 22.6 hours unavailability on 'B' train of each of the four monitored systems.</p>

<p>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 iaw the NEI guidance.</p>

<p>QUANTITATIVE RISK ASSESSMENT
Duke Power has used a risk-informed approach to determine the risk significance of taking the 'B' loop of NSWS out of service for up to 22.6 hours within its current technical specification limit of 72 hours. The acceptance guidelines given in the EPRI PSA Applications Guide were used to determine the significance of the short-term risk increase from the outage. The NSWS outage did not create any new core damage sequences not currently evaluated by the existing PRA model. The resulting Incremental Conditional Core Damage Probability (ICCDP) was 1.2E-06, a low-to-moderate increase in the CDF, and was acceptable based on consideration of the non-quantifiable factors involved in the contingency measures that were implemented during the overhaul. Based on the expected increase in overall system reliability of the NSWS, an overall increase in the safety of both Catawba units is expected.</p>

<p>Contingency measures during the overhaul included Component Cooling Water System cross train alignment which allowed the "A" train to supply cooling to the High Pressure Injection and Auxiliary Feedwater pump motor coolers during the "B" train work. The RN pipe inspection evolution also included the following protective measures:</p>

"A" train EDGs were protected throughout the evolution.

The Unit 2 transformer yard was protected throughout the evolution.
The “A” train equipment supported by RN was protected.
No maintenance or testing on operable offsite power sources.
All testing and maintenance on the operable train rescheduled to other time periods.
No work or testing that could affect the SSF or SSF Diesel Generator.
No work or testing that could affect the Turbine-Driven AFW Pump on Unit 2.

<p>EXPECTED IMPROVEMENT IN PLANT PERFORMANCE
The NSWS pumps are refurbished on a specified interval to assure continued, reliable operation. The NSWS pump refurbishment is expected to increase overall system reliability. </p>

<p>NET CHANGE IN RISK AS A RESULT OF THE OVERHAUL ACTIVITY
Increased NSWS train unavailability as a result of this overhaul did involve an increase in the probability or consequences of an accident previously evaluated during the time frame the NSWS header was out of service for pump refurbishment. Considering the small time frame of the 'B' NSWS train outage with the expected increase in reliability, expected decrease in future NSWS unavailability as a result of the overhaul, and the contingency measures that were utilized during the overhaul, net change in risk as a result of the overhaul activity is reduced.</p>

Response <p>For this case, the refurbishment of the nuclear service water system pumps on a specified interval , an exemption of the overhaul hours does not apply. Page 29 of NEI 99-02 , Revision 2 states that "(the) overhaul exemption does not normally apply to support systems except under unique plant-specific situations and on a case-by-case basis" and that "(t)he circumstances of each situation are different and should be identified to the NRC so that a determination can be made.” FAQs 254, 315 and 337 resulted in exemptions for support system overhauls based on unique plant situations. For the Catawba service water piping replacements, information was provided that detailed the extensive nature of the work resulting in a significant amount of time that the support system would be unavailable, the need for Technical Specification changes, the affect on the monitored systems performance indicators (and impact due to the NRC Action Matrix),and the enhanced system performance expected for long term operations. For the Grand Gulf safety system water pump replacements, the work was performed to upgrade the pump material and the new pumps were expected to last the life of the plant. Several factors, including the information provided by the licensee (discussed above) and the items listed in NEI 99-02 (page 29 , lines 22 through 25), were taken into consideration. It is noted that since each case is unique, the list of factors to consider (in NEI 99-02) is not all inclusive.</p>

<p>The decision to not allow the exclusion of support system overhaul hours is based on several factors including that the work is a “minor" overhaul type activity that is performed periodically to maintain reliable operation of the system and the hours cascaded into the four monitored systems have little impact on the margin to a threshold. As stated in FAQ 254, "...(the licensee understood) that there was a desire to eliminate exclusion of monitored systems unavailability hours caused by minor ' overhaul' type activities on supporting systems.</p>

Posting Date 03/20/2003 **ID** 337

Question Appendix D - Catawba
<p>Catawba Nuclear Station plans to replace the Nuclear Service Water System (NSWS) ‘A’ train header piping in January, 2003. This planned piping replacement is scheduled to occur when Unit 1 and 2 are at power operation and take approximately 141 hours to complete. A proposed tech spec amendment was submitted on 9/12/02 requesting a temporary change to certain tech specs that would allow the 'A' NSWS header for each unit to be taken out of service for seven days (168 hours) for pipe replacement. Duke requested NRC approval of the proposed amendment by 12/1/02; therefore, a tech spec with allowable outage time sufficient to accommodate the overhaul hours will be approved prior to support systems being taken out of service. Although the NSWS is not an NEI 99-02 system, 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 PIs affected by unavailability of the NSWS are Emergency AC, High Pressure Safety Injection, Residual Heat Removal, and Auxiliary Feedwater. If the hours that this overhaul of the NSWS made its supported systems unavailable cannot be excluded, it would result in reporting approximately 141 hours unavailability on 'A' train of each of the four monitored systems. This FAQ seeks approval to exclude the unavailability that will be incurred during this planned overhaul maintenance of the NSWS. 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."

<p>QUANTITATIVE RISK ASSESSMENT
<p>Duke Power has used a risk-informed approach to determine the risk significance of taking the 'A' loop of NSWS out of service for up to four days beyond its current technical specification limit of 72 hours. The acceptance guidelines given in the EPRI PSA Applications Guide were used to determine the significance of the short-term risk increase from the outage extension. The requested NSWS outage extension does not create any new core damage sequences not currently evaluated by the existing PRA model. The frequency of some previously analyzed sequences do, however, increase due to the longer maintenance unavailability of the 'A' NSWS loop. An evaluation of the Large Early Release Frequency (LERF) implications of the proposed 'A' loop NSWS outage extension concluded that they are insignificant. An evaluation was performed utilizing PRA for extending the NSWS technical specification time limit from 72 hours to 168 hours. The core damage frequency (CDF) contribution from the proposed outage extension is judged to be acceptable for a one-time, or rare, evolution. The resulting increase in the annualized core damage risk is 2.6E-06, a low-to-moderate increase in the CDF for consideration of temporary changes to the licensing basis and is acceptable based on consideration of the non-quantifiable factors involved in the contingency measures to be implemented during the overhaul. Therefore, because this is a temporary and not a permanent change, the time averaged risk increase is acceptable. Based on the expected increase in overall system reliability of the NSWS and the expected decrease in NSWS unavailability in the future as a result of the overhaul, an overall increase in the safety of both Catawba units is expected.

<p>EXPECTED IMPROVEMENT IN PLANT PERFORMANCE
<p>The structural integrity of this section of NSWS piping is not in question at this time. The concern is that over time the pipe will degrade and eventually leak. The pipe replacement will enhance system integrity for long term operation and allow for detailed inspection and testing of the section of pipe removed. The removal of this section of pipe will allow for detailed analysis of how the degradation is occurring and provide information for managing the aging of this system. The proposed NSWS pipe replacement modification is expected to increase overall system reliability, thereby minimizing future system unavailability.

<p>NET CHANGE IN RISK AS A RESULT OF THE OVERHAUL ACTIVITY
<p>Increased NSWS train unavailability as a result of this overhaul does involve a one time increase in the probability or consequences of an accident previously evaluated during the time frame the NSWS

header is out of service for pipe replacement. Considering the small time frame of the 'A' NSWS train outage with the expected increase in reliability, expected decrease in future NSWS unavailability as a result of the overhaul, and the contingency measures to be utilized during the overhaul, net change in risk as a result of the overhaul activity is reduced.

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

Posting Date 08/22/2002 **ID** 316

Question As part of plant tour by an on-shift senior reactor operator, two covers were found to be missing for a piece of “guard” pipe used as a barrier over the main steam supply line to a Turbine Driven Auxiliary Feedwater pump. This “guard” pipe was designed to be used as a secondary barrier to prevent the spread of steam in the event of a steam supply line break to ensure environmental qualification of other plant equipment in the area. The covers provide access for inspection of the inner pipe and supports and are only needed for the postulated design basis rupture of that specific section of steam pipe.

<p>The deficiency was easily corrected by replacement of the covers. The time of occurrence is associated with original plant construction and accordingly the deficiency has existed for a number of years.

<p>Engineering reviews are still being performed and the impact on equipment qualification is still indeterminate.
Can the fault exposure period for a construction/modification deficiency, as described above, that existed for a long period of time and that could not be identified by normal surveillance tests be addressed in the same fashion as a design deficiency hours described in NEI 99-02, Revision 2, Page 33, Lines 8 through 23?

Response Yes. While not specifically the result of a design deficiency, this construction caused equipment failure was not capable of being discovered during normal surveillance tests and has a long fault exposure periods thus meeting the same criteria as an excluded design deficiency. Its significance, like that of design deficiency, is more amenable to evaluation through the NRC’s inspection process and thus should also be excluded from the unavailability indicators.

Posting Date 08/22/2002 **ID** 315

Question Appendix D - Grand Gulf
<p>This question seeks an exemption from counting planned overhaul maintenance hours for a support system outage at the Grand Gulf Nuclear Station (GGNS).

<p>At GGNS, the Safety System Water (SSW) system provides Ultimate Heat Sink supply for the ECCS systems, through three divisions:

<P>* SSW A supplies Division 1 Emergency Diesel, Residual Heat Removal (RHR) A and Low Pressure Core Spray.
<p>* SSW B supplies RHR B, RHR C and Division 2 Emergency Diesel.
<p>* SSW C supplies High Pressure Core Spray (HPCS) and Division 3 Emergency Diesel.

<p>The Emergency Diesels, RHR and HPCS are all Mitigating Systems and are monitored systems as defined in NEI 99-02. SSW is a support system as defined in NEI 99-02 and is monitored to the extent that it affects the monitored Mitigating Systems.

<p>In 1994, periodic testing of the SSW pumps identified that shaft column fasteners had washers that had deteriorated to the point that the deep draft pump column had grown in length, allowing the impeller to rub on the bottom of the pump casing. The root cause determined that the washers had deteriorated

due to galvanic corrosion set up by incompatible material between the pump shaft and the fasteners which was compounded by the poor water quality in the system. These fasteners were replaced on line in 1995 with like-for-like replacement of old materials while new pumps were designed and fabricated.

<p>The 5-Year Business Planning process established 2002 for SSW A and B pump replacements and 2003 for the SSW C replacement. Work planning and business considerations determined that SSW A and SSW B pumps would be replaced in January and February 2002. Work planning also determined that the pumps could to be replaced on line within the Tech Spec LCO time (72 hours). Work duration was estimated to be 40 hours for each pump.

<p>A quantitative risk analysis was performed. Due to the complexity and uniqueness of the work, the SSW outages were planned separately from the system outages they support. That is, no parallel Emergency Diesel or RHR outage work was to be scheduled with the SSW outages. The analysis showed that the planned configuration was acceptable from a Regulatory Guide 1.177 and 1.174 standpoint. For example, the incremental conditional core damage probability, ICCDP, is less than 1E-7, and the delta CDF (core damage frequency) is less than 2E-7/yr for this maintenance

<p>SSW A and B pumps were changed in the first quarter 2002. Approximately 63 unavailable hours were incurred in the work. As a result of pump change-out, the reliability of the SSW system will be improved as the upgrade in pump material will reduce the amount of fastener deterioration to a negligible level. The new pumps are expected to last the life of the plant and should reduce any future out of service time and inspection requirements due to the improved materials compatibility.

<p>Based upon the above description, should the planned overhaul maintenance hours for the SSW system pump A and B replacements be counted in determining the PI values for Emergency Diesels, RHR and HPCS?

Response This activity qualifies as a unique plant specific situation as described in NEI 99-02 section for the Treatment of Planned Overhaul Maintenance. For this plant specific situation, the planned overhaul hours for the SSW system pump A and B replacements may be excluded from the computation of monitored system unavailabilities.

Posting Date 06/12/2002 **ID** 312

Question NEI 99-02, "Regulatory Assessment Performance Indicator Guidelines," under section 2.2 Mitigating Systems Cornerstone, provides the following guidance:<p>- The purpose of the safety system unavailability indicator is to monitor the readiness of important safety systems to perform their safety functions in response to off-normal events or accidents.<p>- Off-normal events or accidents are events specified in a plant’s design and licensing bases. These events are specified in a plants safety analysis report, however other event/analysis should be considered (e.g., Appendix R analysis) <p>- Hours required are the number of hours a monitored safety system is required to be available to satisfactorily perform its intended safety function.<p>- A train consists of a group of components that together provide the monitored functions of the system and as explained in the enclosures for specific reactor types. Fulfilling the design bases of the system may require one of more trains of a system to operate simultaneously. <p>- The specific reactor type enclosures provide figures that show typical system configurations indicating the components for which train unavailability is monitored. A statement is made that plant specific design differences may require other components to be included.<p>Plant specific design for the auxiliary feedwater, component cooling water, and essential service water systems provide Appendix R alternate shutdown capability to achieve safe shutdown from the unaffected unit through system cross ties. Our Technical Specifications (TSs) incorporate this Appendix R alternate shutdown capability. The focus of the TSs is on the availability of equipment to support the opposite unit when the opposite unit is operating. <p>Should the availability of Appendix R alternate shutdown capability be monitored and reported for safety system unavailability indicators?

Response No. Appendix R alternate shutdown capability is not monitored under these performance indicators.

Posting Date 05/22/2002 **ID** 307

Question For a single-train support system with redundant active components, does unavailability of one of the redundant active components require one of the trains of the monitored system to be considered unavailable?<p>Station Specifics: The component cooling (CC) water system provides a support function for the Residual Heat Removal (RHR) system. The RHR system provides both normal shutdown decay heat removal and decay heat removal during the containment sump recirculation phase of a design basis LOCA.<p>The CC system consists of a single loop with two 100% (redundant) pumps installed in parallel. Each pump is powered from a separate diesel backed bus. Under all license basis conditions (i.e. Chapter 14 analyses), a single pump is capable of providing 100% of the flow necessary to meet the design bases of the plant. <p>Similarly, multiple CC to Service Water (SW) heat exchangers are arranged in parallel, any one of which is fully capable of removing the accident design bases heat loads.<p>The station license considers the possibility of a temporary total loss of CC function due to a single passive failure during the long-term sump recirculation phase of an accident, and finds this acceptable since decay heat removal from containment is available via containment fan coil units. Does unavailability of a single pump and/or heat exchanger in the CC system constitute unavailability of a train of RHR, even though there is no intersystem train dependency?

Response No. Due to the redundant active components provided by the CC system design, the decay heat removal function of RHR is assured even when a single failure of a CC component has occurred. There is no intersystem train dependency with this design.

Posting Date 02/28/2002 **ID** 302

Question Appendix D – Hope Creek<p>A 1 inch relief valve with an incorrect lift setpoint (120 psig instead of 150 psig) was installed in the Safety Auxiliaries Cooling System (SACS) (SACS performs the component cooling water function). With both pumps (A and C) in the train running, the relief valve lifted, resulting in loss of approximately 12-13 gpm of inventory. Normally, this amount of water loss could easily be made up by the demineralized water makeup system, which is capable of making up at the rate of 50 gpm.<p>During a loss of offsite power, the demineralized water makeup system is not available. When the SACS tank reaches the low-low level, the failure is indicated by the SACS LOOP TROUBLE alarm and a digital point, which displays and alarms on the plant computer, indicates that SACS EXPANSION TANK LEVEL is the issue. The low-low level alarm is an indication of system leakage; this information is provided in the procedure. As a result, no diagnosis is required; Control Room personnel are only required to provide a source of makeup water to ensure continued availability of SACS. The alarm response procedure refers the operator to the procedure for SACS Malfunction, which includes the instructions to perform emergency makeup from service water (verify a valve position and open three other valves from the control room), if required. Due to the amount of time (4.5 hours using the NRC assumptions, 5.9 hours using the utilities) between receipt of the alarm and the time that the expansion tank would become unavailable; it is likely that some diagnosis into the cause of the problem would occur; however, the use of emergency makeup from service water is available and does not require diagnosis. Should the time that the relief valve with the incorrect setpoint was installed be counted as fault exposure time for the supported systems?

Response No. NEI 99-02 states that analysis or sound engineering judgment may be used to determine the effect of support system unavailability on the monitored system. The following items should be considered when analysis or judgment is used to assess the effect of support system unavailability on the monitored system: were the risk/safety significant functions lost, is the condition recognizable, are recovery actions virtually certain to be successful, and is the analysis commensurate with the risk/safety significance of the issue.<p>The function would have remained available during all postulated accidents that did not include a Loss of Offsite Power. During a Loss of Offsite Power, the normal makeup water function would have been lost. This condition would have resulted in a low-low SACS tank level, which is alarmed in the Control Room as a SACS LOOP TROUBLE alarm, along with a digital point, which displays and alarms on the plant computer, indicating that SACS EXPANSION TANK LEVEL is the issue. At this point, the Operators would have time to respond to the alarm to prevent the loss of function. If the loss of function could not be prevented, the Operators could open 3 valves from the Control Room. Opening these 3 valves would restore SACS function by providing Service Water. This evolution is simple, does not require diagnosis, is proceduralized and trained on, and can be accomplished from the Control Room. In addition, other success paths were available. Some of these success paths included the need to perform diagnosis. However, in this case, there was sufficient time to perform this diagnosis and take the appropriate actions. It is virtually certain that at least one of the available success paths could have been performed in time to maintain the availability of SACS.<p>Therefore, because no risk/safety significant functions were lost, the condition would have been recognizable, the recovery actions are virtually certain to be successful, and an operability determination commensurate with the risk/safety significance of the issue was developed, no unavailability needs to be counted as a result of this incident.

Posting Date 01/25/2002 **ID** 301

Question (This FAQ is a replacement for FAQ 293. FAQ 293 has been withdrawn)<p> Appendix D - Quad Cities Station<p>On May 1, 2001, approximately 12 hours after initiation of the 24-hour surveillance test of the Unit 2 Emergency Diesel Generator (EDG), an alarm was received in the control room for low level in the diesel generator fuel oil day tank. The test was stopped and the situation was investigated. The investigation found that a solenoid valve in the fuel oil transfer line from the fuel oil transfer pump to the day tank had failed to open when required. The solenoid valve assembly was removed and the valve was overhauled. The solenoid valve assembly was reinstalled and the test was run again. <p>Approximately 12 hours into the second test, the alarm was received in the control room again for low level in the diesel generator fuel oil day tank. The test was continued, and the situation was investigated. Again, it was found that the solenoid valve in the fuel oil transfer line had failed to open. The operator, stationed locally at the EDG, opened a drain valve in the fuel oil transfer line and the solenoid valve then opened. The test was completed without further incident. The solenoid valve was subsequently replaced with a new solenoid valve rated for a larger wattage. The test was performed one final time without any problems.<p>The manual actions required to provide fuel oil to the EDG day tank in the event of failure of the fuel oil transfer system have the following attributes. They are noted in the UFSAR, they are included in station procedures, they are included in the training program, they are accomplished utilizing pre-staged equipment, there is no troubleshooting or diagnosis required, the initiating condition is annunciated in the control room, and they have been time validated against the time available. Additionally, although the safety function of the EDG system is risk-significant, the failure of one EDG is not.<p>Should unavailability time be reported for the failure of the Emergency Diesel Generator (EDG) fuel oil transfer system (FOT) solenoid valve?

Response No. Unavailable hours need not be reported for this situation. The actions are called out in the UFSAR, they are proceduralized, operators are trained regularly on the procedure, the necessary equipment is staged, no trouble shooting or diagnosis is necessary, there is a control room alarm to alert the operators to the need for action, and the actions have been demonstrated to be able to be accomplished within the necessary time constraints. Therefore, operator recovery actions are considered to be virtually certain of success. <p>When making this determination, the following factors, as appropriate, were considered:<p>1. NRC approval through an NOED, Technical Specification change, or other means<p>2. risk-significance of the support function(s)<p>3. Capability to recognize the support system unavailability<p>4. availability of personnel to perform the recovery actions<p>5. means o f communication between the control room and the local operators<p>6. frequency with which the recovery actions are performed<p>7. probability of successful completion of recovery actions<p>8. soundness of engineering analysis

Posting Date 01/25/2002 **ID** 293

Question FAQ 293 has been withdrawn and replaced by FAQ 301. The question and response text of FAQ 301 remains the same as the text previously held by 293. FAQ 301 reflects a change in applicability of the FAQ. The FAQ now applies to Quad Cities station solely.

Response

Posting Date 12/13/2001 **ID** 297

Question <u>NEI 99-02 Reference:</u> NEI 99-02 Rev. 1 on page 33 lines 25 through 28 states "Unavailable hours are also reported for the unavailability of support systems that maintain required environmental conditions in rooms in which monitored safety system components are located, if the absence of those conditions is determined to have rendered a train unavailable for service at a time it was required to be available."<p><u>Background information:</u> Reference NRC Unresolved Item (URI) 50-454/455-00-14-01 for Byron Station from NRC Inspection Report 50-454/455-00-14, "Review of the licensee's reporting of unavailability time for the emergency alternating current power system," which in part addressed the following. During review of performance indicator data for the emergency AC power system, the inspectors identified that the licensee had not included unavailability time for the 2B diesel generator (DG) on May 18, 2000, when the 2B DG ventilation fan was out-of-service (OOS) for maintenance to calibrate a differential pressure switch. The inspectors noted that the ventilation system was not able to perform its support function for the DG with the fan OOS and that DG room ventilation was necessary for sustained DG operation to ensure operability. Although the DG was declared inoperable and the appropriate Technical Specification limiting condition for operation was entered during this maintenance activity, the licensee did not consider the DG to be unavailable. <p><u>Discussion:</u> Is the following interpretation of NEI 99-02 (revision 0 and revision 1) correct?<p>The phrase "...if the absence of those conditions is determined to have rendered a train unavailable..." implies that there must be an absence of those environmental conditions. The absence of those conditions would lead to a determination that the train would be considered unavailable. Byron Technical Requirements Manual (TRM) section 3.7.d (previously addressed as Byron Technical Specification 3/4.7.12) specifies the required environmental conditions required whenever the equipment in a room is required to be operable by specifying ambient temperature limits. The basis for these limits is that the area temperature limitations ensure that safety-related equipment will not be subjected to temperatures in excess of their environmental qualification temperatures. Exposure to excessive temperatures may degrade equipment and can cause a loss of its operability. Removing a room cooler or supporting ventilation system from service does not necessarily result in exceeding area temperature limits. As long as the required environmental conditions continue to be maintained there has not been an "absence of those conditions" and the monitored equipment would be considered available.

Response No, the interpretation is not correct. An evaluation must be performed to demonstrate that the monitored system is capable of performing its intended safety function under all conditions.

Posting Date 12/13/2001 **ID** 292

Question When reporting safety system unavailable time there are periodic evolutions that, although they may not be simple actions to restore a safety system, result in the safety system being unavailable for no more than several minutes. Is this level of tracking unavailable time required?

Response No. Evolutions or surveillance tests that result in less than 15 minutes of unavailability per train at a time should not be counted in unavailability data. The intent is to minimize unnecessary burden of data collection, documentation, and verification. Licensees should compile a list of surveillances/evolutions that meet this criterion and have it available for inspector review.

Posting Date 11/15/2001 **ID** 291

Question Appendix D - Cook Nuclear Station<p>Safety System Unavailability (SSU) indicators for Cook Units 1 and 2 are not calculated due to insufficient reported data. The SSU indicators and performance thresholds require 12 quarters of operational data to calculate unavailability and determine safety system performance. Cook Unit 1 returned to service December 18, 2000, after a 39-month forced outage and Unit 2 on June 25, 2000, after a 33-month forced outage. SSU indicator data has been reported for both units since the second quarter of the year 2000. Historical data was not reported since unavailability was not monitored during the extended outages. Cook Nuclear Plant (CNP) wants the SSU indicators to reflect actual safety system performance and have the indicators calculated with submitted data vice waiting until April 2003 for 12 quarters of data to be collected. What actions can be taken to have calculated SSU indicators and appropriately account for the effects of a T/2 fault exposure?

Response Submit a change report "zero-summing" the time prior to the 2Q2000 to provide for an indicator calculation. If a T/2 fault exposure occurs prior to obtaining 12 quarters of operational data, then the time would be reported in the comment field but not calculated for the SSU indicator. The inspection and SDP process would then evaluate the T/2 fault exposure.

Posting Date 11/15/2001 **ID** 289

Question A temporary cover was installed over the air intake damper to the emergency diesel generator ventilation system outside air intake damper.<p>1 Since manual action is required to remove the cover and permit the emergency diesel generator room ventilation system to perform its intended function, should unavailable hours be counted during the time the temporary cover was installed? <p>2. Do the criteria for determining unavailability, as described in NEI 99-02, Revision 1, page 24, lines 24-33, apply to this situation?

Response 1. Yes, the unavailable hours should be counted because the operator recovery actions were not determined to be virtually certain to be successful under accident conditions.
<p>2. No. The guidance in NEI 99-02 Revision 1, page 24, lines 24 through 33 only apply to test configurations and this was not a test configuration.

Posting Date 10/31/2001 **ID** 290

Question Should surveillance testing of the safety system auto actuation system (e.g. Solid State Protection System testing, Engineered Safety Feature testing, Logic System Functional Testing) be considered as unavailable time for all the affected safety systems? During certain surveillance testing an entire train of safety systems may have the automatic feature inhibited.

Response Yes. Restoration action involves diagnosis using Emergency Operating Procedures to restore design basis functions.

Posting Date 05/01/2003 **ID** 340

Question Appendix D: St. Lucie
<p>Component cooling water (CCW) system at our plant is a clean treated water cooling system that supports the High pressure safety injection (HPSI) pumps and Residual heat removal (RHR) system. Our commitment to Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment" includes routine tube side (intake cooling water) cleanings. This FAQ seeks an exemption from counting planned overhaul maintenance hours for a support system outage (CCW heat exchanger maintenance). The CCW system transfers heat from the HPSI pump seal and bearing coolers and the RHR system to the ultimate heat sink. Sulzer Pumps Inc. Document E12.5.0730, "Qualification Report for HPSI Pump Bearings and Mechanical Seals without Cooling Water" has concluded the HPSI pumps can be operated without the use of CCW. The RHR system, therefore, is the only mitigating system as defined in NEI 99-02 requiring CCW as a support system. Our response to Generic Letter 89-13, "Service Water Problems Affecting Safety-Related Equipment" included routine maintenance and cleaning of the CCW heat exchangers. Work duration typically lasts for 45 to 50 hours while the Unit is in a 72 hour Technical Specification LCO. These activities function to remove micro and macro fouling thereby maintaining the heat transfer capability and reliability of the heat exchanger. These activities are undertaken voluntarily and performed in accordance with an established preventive maintenance program to improve equipment reliability and availability and as such are considered planned overhaul maintenance as defined in NEI 99-02. Other activities may be performed with the planned overhaul maintenance provided the system outage duration is bounded by the overhaul activities. NEI 99-02 goes on to state the following: "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 © the net change in risk as a result of the overhaul activity." In accordance with the NEI guidance the following results can be expected:
<p>Based on the plant on-line risk monitor (OLRM), the incremental change in core damage probability (ICCDP) and incremental change in large early release probability (ICLERP) over a 72 hour duration due to unavailability of a RHR train is less than 3E-08 and 1E-09 respectively. The ICCDP and ICLERP are considered small based on guidance in RG 1.177. The total change in core damage frequency (delta CDF) and change in large early release frequency (delta LERF) assuming each train of RHR is out-of-service for a 72 hour CCW heat exchanger maintenance window is, therefore, less than 6E-08/yr. and 2E-09/yr, respectively. Using a 72 hour duration for the risk assessment (the maximum allowed time based on the Technical Specification LCO) adds conservatism to this assessment. Historically this CCW maintenance has been completed within approximately 50 hours. The assessment results conclude that the delta CDF and delta LERF is in region III of RG 1.174 Figures 3 and 4 and is thus considered very small. Routine cleaning maintains the heat transfer capability from the RHR system to the ultimate heat sink by removing biofouling, silt, and other marine organisms from the heat exchangers. Shells lodged in the CCW heat exchanger tubes that have historically caused accelerated flow and erosion of the tube wall are also removed. The eddy current testing (ECT) and plugging activities have helped to identify and remove degraded tubes from service, thereby reducing the probability of CCW system inventory loss. These efforts have combined to increase the component and system reliability and availability. It is judged that the reliability increase from cleaning the CCW heat exchangers and identification of degraded tubes before failure offsets the small increase in risk resulting from the additional RHR system unavailability.

Response The tasks listed in NEI 99-02 (starting on page 28, line 20, of Revision 2) were included as examples of items that may be accomplished during an overhaul, however, taken individually these activities may not warrant consideration as an overhaul. Although "cleaning" is listed as a task that may be included in an "overhaul," cleaning alone does not constitute overhaul hours. When the planned maintenance of the heat exchanger includes additional activities, such as eddy current testing, the maintenance of the heat exchanger may be considered planned overhaul maintenance unavailability hours of an RHR support system and these hours would not need to be cascaded to the RHR system. The exemption from counting planned overhaul maintenance hours may only be applied once per train per operating cycle.

Posting Date 02/19/2004 **ID** 359

Question NEI 99-02 states that Planned Unavailable Hours include testing, unless the “function can be promptly restored … by an operator in the control room”. The guideline further states that “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”. “The intent … is to allow licensees to take credit for restoration actions that are virtually certain to be successful (i.e., probability nearly equal to 1) during accident conditions”.
In the following scenario, a motor driven auxiliary feed pump with an auto start feature is placed in “pull-to-lock” for performance of a calibration procedure on the recirculation valve flow transmitter. Only the positioning of the pump’s control switch affected its availability.
A licensed reactor operator in the control room was briefed on the manual pump restoration task. The pre-evolution briefing to restore this pump to automatic status was completed by the Senior Reactor Operator. The “balance of plant” reactor operator was designated as the owner of this task. All crew members were briefed of the need to return the pump to automatic control. This action is uncomplicated in that it is a single action (i.e. remove the pump from pull-to-lock) and does not require diagnosis.
Restoration actions are contained within three different procedures. The Precautions and Limitations section of the calibration procedure for the recirculation valve flow transmitter is being revised to state that “the Control Room Operator shall be briefed and assigned responsibility for restoring the pump (i.e. removing from pull-to-lock) to automatic control if the pump is needed to perform it’s safety function”. directs the performer to inform the control room operator to align the control switch for the auxiliary feed pump in accordance with its “normal system arrangement” per the current plant conditions. The conduct of operations procedure, which governs operator performance at all times, specifies “anytime valid plant conditions indicate a need for…Safety System actuation, and the actuation fails to automatically occur, the operator is required to manually initiate the protective action”. That is, if there is a need for the auxiliary feedwater pump to start, the operator is to manually ensure a pump start is satisfied by taking the switch out of pull to lock. Simulator training is used to re-enforce this expectation. Finally, this pump is only required to operate during an event requiring use of the Emergency Operating Procedures and instructions are contained within this network to direct the operator to verify and/or initiate pump operation.
In this example, can the manual operator action be credited in place of the automatic pump start function for continued pump availability?

Response Yes. The actions described satisfy the criteria of NEI 99-02, Rev. 2 for considering the Auxiliary Feed Pump available.

Posting Date 06/18/2003 **ID** 348

Question Should the fault exposure time associated with a design deficiency that was revealed as a result of surveillance testing, but due to factors that are not a part of normal testing be included in the calculation for determining unavailability?
<p>Background: During post maintenance testing of an auxiliary feed water pump, the flow through the pump recirculation line was noted to be lower than allowed by the test procedure (but within pump manufacturer requirements). Note - no actual failure occurred and it was initially determined that the pump would have met its mission time. An investigation revealed that a flow orifice in the recirculation line was partially plugged with corrosion products, most likely introduced when the pump and associated piping were drained for maintenance. The normal suction path for Aux. Feedwater when conducting surveillance testing is the condensate storage tank (CST). The alternate water supply is safety-related service water (lake).
<p>A determination was later made that the orifices would likely plug from suspended material in the service water supply and render the trains incapable of performing their safety function during an operational event.
<p>NEI 99-02 page 33 lines 8-23 indicates that equipment failures due to design deficiencies should be evaluated for inclusion if the failure is capable of being discovered during surveillance testing but should be evaluated under the NRC’s Significance Determination Process if the failure was not capable of being discovered during normal surveillance test. The lack of the word <u>normal</u> in the first statement implies both conditions apply to this situation if a literal interpretation is used

Response No. Failures that are not capable of being discovered during normal surveillance tests are excluded from the unavailability indicators. During performance of the normal surveillance tests described above, CST water is used, and as such, performing the surveillance could not identify that the orifice would clog when lake water was used.

Posting Date 07/02/2002 **ID** 313

Question On March 25, 2000, excessive sealant was applied to the 11AFW pump turbine outboard bearing housing. Some sealant eventually broke off inside the housing, migrated to the bearing and resulted in a bearing failure on May 16, 2001, during an overspeed test. SDP Phase 3 assessment determined the failure had substantial safety significance (Yellow) based on the equipment function of removing decay heat and the length of time the excessive sealant was applied. On December 13, 2001, the NRC completed a supplemental inspection that reviewed evaluations and corrective actions. The supplemental inspection closed the violation associated with the AFW pump bearing failure. In accordance with NEI 99-02, Rev 1, the fault exposure time associated with the 11 AFW turbine bearing failure was estimated as one half the time since the last successful test that proved the system was capable of performing its safety function and T/2 fault exposure of 81.3 hours was reported in 1Q2001 and 1092.48 hours was reported in 2Q2001. The reported T/2 fault exposure resulted in an increase of the Safety System Unavailability, Heat Removal System (i.e., AFW) performance indicator value to 1.9% in 2Q2001.As of 1Q2002, the AFW performance indicator has not crossed the green-white threshold of >2.0% unavailability. The unit is currently in an extended refueling/steam generator replacement outage. The AFW performance indicator value will cross the green-white threshold in 2Q2002 as a consequence of the extended outage because critical hours are not accumulating during shutdown. The guidance in NEI 99-02, Rev 2, was modified to exclude T/2 fault exposure hours from the calculation of the safety system unavailability and to report the hours in the comment section of the NRC PI data file. NEI 99-02, Rev 2, was not in effect when the T/2 fault exposure hours associated with the pump failure was reported. NEI 99-02, Rev 1, was in effect and required T/2 fault exposure hours to be reported in the data section of the NRC PI data file. NEI 99-02, Rev 2, specifies that T/2 fault exposure hours may be reset, provided the following criteria are met: 1. Four quarters have elapsed since the green-white threshold was crossed, 2. The fault exposure hours in any single increment of unavailability are greater than or equal to 336 hours, 3. Corrective actions associated with the increment of unavailability to preclude recurrence of the condition have been completed by the licensee, and 4. Supplemental inspection activities by the NRC have been completed and any resulting open items related to the condition causing the fault exposure have been closed out in an inspection report. We are seeking an exception to fault exposure reset criterion Number 1 above, regarding crossing the green-white threshold. The T/2 fault exposure reported for 11 AFW in 1Q and 2Q 2001 did not result in immediately crossing the green-white threshold. The performance of the AFW system since the fault exposure was reported has kept the indicator from exceeding the green-white threshold for 3 quarters. However, an extended Unit 1 outage will result in the indicator crossing the green-white threshold. Meanwhile, the event that caused the indicator to increase close to the green-white threshold has been corrected. In this case, crossing the Unit 1 AFW PI green-white threshold will not provide an accurate indication regarding the performance of the Unit 1 AFW system over the past four quarters. A white AFW PI will, however, bring about greater attention to an old performance problem that has already been corrected. An exception would allow fault exposure hours associated with the 11 AFW pump turbine bearing failure to be reset without crossing the green-white threshold and without four quarters elapsing since the green-white threshold was crossed. Without this exception, the AFW performance indicator will cross the green-white threshold in 2Q2002.

Response While this FAQ requests an exemption from NEI 99-02 Rev 2, all four requirements to reset fault exposure hours will have been met as of the end of the second quarter of 2002.

<p>Requirement 1 - Four quarters have elapsed since the green-white threshold was crossed. While the PI threshold was not exceeded, the inspection finding (for the same issue) green white threshold was crossed with a Yellow finding, which will have been posted for four quarters, commencing 3Q01 through 2Q02.

<p>Requirement 2 - Fault exposure hours in any single increment of unavailability are greater than or

equal to 336 hours.

<p>Requirement 3 - Corrective actions associated with the increment of unavailability to preclude recurrence of the condition have been completed.

<p>Requirement 4 - Supplemental inspection activities by the NRC have been completed and any resulting open items related to the condition causing the fault exposure have been closed out in an inspection report.

<p>Based on this information, the fault exposure hours can be reset for the third quarter 2002 report, to be submitted by October 21, 2002.

Posting Date 05/01/2003 **ID** 339

Question Appendix D: Sequoyah
<p>Sequoyah Nuclear Plant (SQN) has two units. Each Unit has three trains of AFW, two motor driven trains (A train and B train), and one turbine driven train (Terry Turbine train, A or B train power). All three trains have Level Control Valves (LCVs) that are the steam generator injection valves. The LCVs are normally closed, air operated valves that auto open when AFW receives a start signal. The valves fail open when air is removed from them. SQN uses Control Air as the normal air supply to the LCVs. Control Air is not a seismically qualified, 1E system. Auxiliary Air is the LCV's standby, safety related air supply. A train Auxiliary Air feeds two Terry Turbine train LCVs and the two motor driven A train LCVs. B train Auxiliary Air feeds the other two Terry Turbine train LCVs and the two motor driven B train LCVs. Auxiliary Air automatically starts whenever the Control Air pressure drops below its setpoint. The Terry Turbine train LCVs also have accumulator tanks and high pressure air cylinders to control them during a loss of all power. The Terry Turbine train LCVs can be controlled from the main control room for one hour after the loss of all air using the accumulator tanks.

<p>For all scenarios except a major secondary system pipe rupture, the fail open LCVs are conservative, as they allow AFW to deliver the required flow. During a major secondary system pipe rupture, AFW is required to be isolated from the faulted steam generator. In the absence of both Control Air and Auxiliary Air, manual action at the LCVs will have to be taken to isolate the corresponding motor driven AFW train from the faulted steam generator. This action is proceduralized in Emergency Procedures and Abnormal Operating Procedures. The PSA also models the AFW system as available while Auxiliary Air is taken out of service.

<p>Since the PSA models the AFW system as available while Auxilary Air is unavailable (gives credit for the manual isolation of motor driven AFW trains) and the manual actions are proceduralized and trained on, is it correct to be consider the affected train(s) of AFW as still available during the periods when Auxiliary Air is taken out of service?

Response Yes, unavailability need not be reported when auxiliary air is not available to the AFW FCVs, as long as at least one train of support system air remains available.

Posting Date 12/12/2002 **ID** 330

Question Appendix D - Millstone 2
<p>NEI 99-02 identifies the Residual Heat Removal (RHR) System as a system that is required to be in service at all times. In certain situations, monitoring the RHR System in accordance with the NEI 99-02 guidance for Millstone 2 results in the required hours for the RHR system that are less than the total hours for a given calendar quarter. This is a result of the containment spray system not being required by the technical specifications in mode 3 with RCS pressures less than 1750 psia.
<p>NEI 99-02 requires the following two functions be monitored for Residual Heat Removal (RHR) performance indicator: (1) the ability to take a suction from containment sump, cool the fluid, and inject at low pressure into the RCS, and (2) the ability to remove decay heat from the reactor during normal unit shutdown for refueling or maintenance.
<p>For the Millstone 2 and several other Combustion Engineering (CE) designed NSSS, Appendix D of NEI 99-02 provides clarification regarding how this performance indicator should be monitored. To monitor the first function, Appendix D recommends that the two containment spray pumps and associated coolers should be counted as two trains of RHR providing the post accident recirculation cooling. To monitor the second function, Appendix D recommends that the SDC system be counted as two trains of RHR. The first function is required by the plant technical specifications in modes 1 and 2 as well as in mode 3 with RCS pressures greater than 1750 psia. This second function is required by the technical specifications in modes 4, 5 and 6. As such, at Millstone 2, the RHR function is not being monitored while the plant is in mode 3 with RCS pressures less than 1750 psia. Therefore, if the plant is operated in mode 3 with RCS pressures less than 1750 psia for any given calendar quarter, the required hours for the RHR function will be less than the total hours in that quarter. There are no specific restrictions as to how long the plant can be operated in Mode 3 with RCS pressure less than 1750 psia. Depending upon the nature of plant maintenance or repairs, the hours a plant is in this mode could be

considerable.
<p>From an accident analysis standpoint, following a main steam line break or loss of coolant accident inside containment, the RCS decay heat removal safety function is accomplished by a combination of the containment spray system and the Containment Area Recirculation (CAR) coolers, which are required by the technical specifications in modes 1, 2, & 3. The CAR system consists of two independent trains of two coolers each. The CAR coolers transfer energy from the containment atmosphere to a closed cooling water system to the ultimate heat sink. The containment heat removal capability of one CAR train is considered equivalent to one CS train. Following a main steam line break or loss of coolant accident inside containment in mode 3 with RCS pressures less than 1750 psia, the CAR coolers are the only technical specification required system that satisfies the RCS decay heat removal safety function. Currently the CAR function is not included as part of the RHR performance indicator. Its inclusion would result in the system required hours being equivalent to the total hours for a calendar quarter.
<p>For the purposes of reporting the RHR performance indicator, should we continue to maintain the current 99-02 methodology which could result in required system hours less than the total calendar hours for a given quarter, or should we be monitoring the availability of the CAR System as part of the RHR performance indicator? If we add the CAR coolers to the RHR performance indicator, how should they be handled in the technical specification modes where both the containment spray and CAR coolers are required (modes 1, 2 and 3 with RCS pressures greater than 1750 psia) versus the technical specification mode where only the CAR coolers are required (mode 3 with RCS pressures less than 1750)?

Response Yes, continue to maintain the current 99-02 methodology with the understanding that frequent plant shutdowns or associated mode 3 repairs could result in an accounting mis-match between RHR system required hours and the total calendar hours for a given quarter.

Posting Date 01/25/2002 **ID** 298

Question Appendix D - CE Plants (ANO-2, Calvert Cliffs, Fort Calhoun, Millstone 2, Pallisades, Palo Verde,San Onofre, St. Lucie, and Waterford 3)<p>FAQ 172 was approved May 2, 2000, for use by CE plants and is now in Appendix D. This FAQ allowed licensees to choose between either of the following two options for reporting historical data:<p>1. Maintain train 1 and 2 historical data as is. For trains 3 and 4, repeat train 1 and train 2 data.<p>2. Recalculate and revise all historical data using this guidance.<p>However, the Containment Spray (CS) system(train 1 and 2) is required to be operable in modes 1,2, and 3, while the Shutdown Cooling (SDC) system is only required to be operable in Modes 4,5 and 6. Therefore the potential exists for the RHR SSU PI to be artificially low because of the higher than actual number of required hours reported for the denominator. As a result, as CE plants began to report the correct number of unavailable and required hours for the SDC trains at the start of Initial Implementation, some of them have shown a declining trend in performance due in part to the decreasing denominator.<p>Is it acceptable to add a third option, as described below, and allow CE plants to choose to use either option 1, 2 or 3?<p>3. Maintain trains 1 and 2 historical data as is and make a best effort to collect and report the historical unavailable and required hours for trains 3 and 4, or, if historical data are not available, to make an estimate of those hours?

Response Licensees may use Option 3. If any estimates of unavailable or required hours are used, they must be supported by a description of and a rationale for the estimating method, and any changes to the data must be explained in the comment field of the PI report.<p>Licensees who used Option 2 need not change their reported historical data.<p>Licensees who used Option 1 need not change their reported historical data unless the ratio of unavailable hours to required hours for the actual data submitted for trains 3 and 4 since the start of initial implementation (either 1Q00 or 2Q00, as applicable) exceeds 0.010. If and when this occurs, licensees should use either Option 2 or Option 3 to generate enough historical data to calculate a 12-quarter average.

Posting Date 12/12/2002 **ID** 328

Question Review of the Safety System Functional Failure Performance Indicator (PI) by the NRC Resident Inspector questioned whether our LER 2000-006 should have been counted as a functional failure. Regardless of whether this LER constitutes a functional failure or not, there would be no PI threshold change.
<p>LER 2000-006 was submitted to the NRC on September 5, 2000. The LER is entitled "Source Range Detector High Flux Trip Circuitry Outside of Plant Design Basis Due To Revised Local Cabinet Temperature Uncertainty." This LER was coded as 10 CFR 50.73(a)(2)(ii). The LER determined the cause of the plant being outside the design basis was the temperature errors associated with the maximum control room design temperature were not explicitly accounted for when the setpoint was changed in 1973. There were no safety consequences associated with this LER since:
The Tech Specs do NOT include any reactor trip set point limits for the NIS source range detectors,
The source range high flux trip is NOT credited in any UFSAR Chapter 14 accident analysis, and
The intermediate and power range flux trips would be available to provide for termination of a power excursion during a reactor startup or low power operation.
<p>The review of this LER did not determine this was a safety system functional failure since the source range high flux trip is not relied on in the UFSAR. Additional information:
NEI 99-02, Revision 1 refers to 10 CFR 50.73(a)(2)(v). It does state that paragraphs (a)(2)(i), (a)(2)(ii), and (a)(2)(vii) should also be reviewed for applicability for this PI (these were reviewed and the determination was only section (a)(2)(ii) was applicable),
NEI 99-02, Revision 1 also refers to NUREG-1022 for additional guidance that is applicable to reporting under 10 CFR 50.73(a)(2)(v),
NUREG-1022, Revision 2, section 3.2.7, at page 54 defines "safety function" as those four functions listed in the reporting criteria…as described or relied on in the UFSAR and
NUREG-1022 also adds at page 54, "or required by the regulations." Regulations are being interpreted to include technical specifications.
<p>Is it the intent of NEI 99-02 to solely report safety system functional failures as described or relied on in the UFSAR or is it the intent to additionally incorporate the guidance in NUREG-1022, section 3.2.7 that the failure of any component addressed in the plant's Technical Specification constitutes a safety system functional failure whether credited or not in the UFSAR chapter 14 analyses?

Response If failure of the source range detector high flux trip circuitry is reportable per 10CFR50.73 (a) (2) (v), then this counts as a Safety System Functional Failure. Such a determination is outside the scope of NEI 99-02; the issue must be referred to the appropriate branch of the NRC.

Posting Date 09/16/2004 **ID** 370

Question <p>River Bend Station (RBS) seeks clarification of BI-02 information contained in NEI 99-02 guidance, specifically page 80, lines 36 and 37 "Only calculations of RCS leakage that are computed in accordance with the calculational methodology requirements of the Technical Specifications are counted in this indicator."</p>

<p>NEI 99-02, Revision 2 states that the purpose for the Reactor Coolant System (RCS) Leakage Indicator is to monitor the integrity of the reactor coolant system pressure boundary. To do this, the indicator uses the identified leakage as a percentage of the technical specification allowable identified leakage. Moreover, the definition provided is "the maximum RCS identified leakage in gallons per minute each month per technical specifications and expressed as a percentage of the technical specification limit."</p>

<p>The RBS Technical Specification (TS) states "Verify RCS unidentified LEAKAGE, total LEAKAGE, and unidentified LEAKAGE increase are within limits (12 hour frequency)." RBS accomplishes this surveillance requirement using an approved station procedure that requires the leakage values from the 0100 and 1300 calculation be used as the leakage "of record" for the purpose of satisfying the TS surveillance requirement. These two data points are then used in the population of data subject to selection for performance indicator calculation each quarter (highest monthly value is used).</p>

<p>The RBS approved TS method for determining RCS leakage uses programmable controller generated points for total RCS leakage. The RBS' programmable controller calculates the average total leakage for the previous 24 hours and prints a report giving the leakage rate into each sump it monitors, showing the last four calculations to indicate a trend and printing the total unidentified LEAKAGE, total identified LEAKAGE, their sum, and the 24 hour average. The programmable controller will print this report any time an alarm value is exceeded. The printout can be ordered manually or can be automatic on a 1 or 8 hour basis. While the equipment is capable of generating leakage values at any frequency, the equipment generates hourly values that are summarized in a daily report.</p>

<p>The RBS' TS Bases states "In conjunction with alarms and other administrative controls, a 12 hour Frequency for this Surveillance is appropriate for identifying changes in LEAKAGE and for tracking required trends."</p>

<p>The Licensee provides that NEI 99-02 requires only the calculations performed to accomplish the approved TS surveillance using the station procedure be counted in the RCS leakage indicator. In this case, the surveillance procedure captures and records the 0100 and 1300 RCS leakage values to satisfy the TS surveillance requirements. The NRC Resident has taken the position that all hourly values from the daily report should be used for the RCS leakage performance indicator determination, even though they are not required by the station surveillance procedure. The Resident maintains that all hourly values use the same method as the 0100 and 1300 values and should be included in the leakage determination.</p>

<p>Is the Licensee interpretation of NEI 99-02 correct?</p>

Response <p>Appendix D</p>

<p>All calculations of RCS leakage that are computed in accordance with the calculational methodology requirements of the Technical Specifications are counted in this indicator. Since the River Bend Station leakage calculation is an average of the previous 24 hourly leakage rates which are calculated in accordance with the technical specification methodology, it is acceptable for River Bend Station to include only those calculations that are performed to meet the technical specifications surveillance requirement when determining the highest monthly values for reporting. The ROP Working Group is forming a task force to review this performance indicator based on industry practices.</p>

Posting Date 06/18/2003 **ID** 349

Question Plant TS require RCS leakage be determined periodically during steady-state operation but in no case at an interval of greater than 120 hours. In some start-up cases, when the maximum surveillance interval is approached a non-steady state RCS leakage calculation must be taken which can provide an inaccurate indication of RCS leakage (confirmed by subsequent calculations). Additionally, RCS leakage is required to support ISTs of check valves associated with loop injection upon entry into Mode 4 from Mode 5. Both of these conditions result in invalid RCS leakage calculations during non-steady state conditions that can skew the data. When the monthly RCS leakage calculations are reviewed for the maximum monthly result, should invalid calculations made during non-steady state operation be ignored?

Response No. Any RCS leakage determination made in accordance with plant technical specifications are included in the performance indicator calculation.

Posting Date 05/22/2002 **ID** 308

Question During maintenance, water from the charging pump suction header was aligned to a relief valve which relieves to a boric acid tank. This relief valve unexpectedly lifted below the setpoint tolerance. The relief valve was passing about eighteen gpm to the boric acid tank based on calculations using volume control tank level trend. The source and collection point of the leakage was unidentified until the time that realignment secured the leak. A Notice of Unusual Event was declared due to reactor coolant system (RCS) unidentified leakage greater than or equal to 10 gpm. The duration of this event was approximately thirty-five minutes.<p>The leak occurred from a piping system outside containment that communicates directly with the RCS (e.g., letdown to the volume control tank). The leak was from a source that would not be automatically isolated during a safety injection signal. The leakage was collected in a tank outside containment that is not considered in the baseline as identified leakage when performing the Technical Specification RCS Leakage surveillance procedure. Note that the WOG STS definition of Identified Leakage is "Leakage that is captured and conducted to collection systems or a sump or collecting tank." Is this leakage to be included in the RCS identified leakage PI?

Response No. The TS methodology provided by the RCS Leakage Calculation Procedure is to be used. The source and collection point of the leakage in this example were unknown during the time period of leakage, and the actual collection point was not a monitored tank or sump per the RCS Leakage Calculation Procedure. Therefore, this is not considered RCS identified leakage to be included in PI data. RCS leakage not captured under the PI should be evaluated in the inspection program.

Posting Date 01/22/2004 **ID** 357

Question In April 2003, Operations decided to change from marking “Drill” to marking “Actual” on the notification forms used in LOR simulator sessions to enhance realism. Emergency Preparedness was unaware of the policy change at the time since only Annual License Exam simulator sessions contribute to DEP.

A LOR trainee questioned the use of “actual” in mid May 2003 and this question was forwarded to Emergency Preparedness for resolution. EP reevaluated the policy of using “Actual” based on the recent FAQ 338. We decided to change our practice back to marking the notification forms as “Drill” during LOR Training as of June 2003. The expectation of how to mark notification forms during LOR simulator training was reviewed with the personnel but notification opportunities in the September NRC Exams were subsequently inconsistently marked as either “drill” or “actual” consistent with the trainee understanding of the accuracy expectation of no blank forms. There were 13 notification opportunities with 7 marked “Actual” and 6 marked “Drill”. The inconsistent form completion was discovered during EP’s review of PI data from the LOR classes for the last three weeks of September in preparing the 3rd Quarter 2003 PI results.

Reasonable assurance exists that the same error would not have occurred for an actual emergency since it is implicitly clear that “Actual” is to be marked during an actual event. The inconsistent form completion is addressed in the Corrective Action Program.

FAQ 338 provided a plant with the one time site specific allowance to count the forms as accurate with either drill or actual as long as one or the other was checked. The bases for this decision was that the lack of providing clear expectations to the LOR simulator crews on marking drill or actual event on the notification form is indicative of a programmatic weakness and not a performance weakness.

Due to the short duration from the resolution of FAQ 338 and the September NRC exam and the infrequency of the performance of simulator training EP drills, is it acceptable to apply the similar resolution to our plant also on a one time basis? This would allow the notifications to be considered as accurate as long as either actual or drill was selected (completing all the appropriate blocks on the notification form).

Response Yes. For this occurrence only (and only on a one-time basis), the plant may treat the notifications as accurate as long as either “actual” or “drill” was selected (completing all the appropriate blocks on the notification form).
For all PI submittals for all plants for the second quarter of 2004 and beyond, all notification forms must be marked consistently, either “drill” or “actual” in accordance with the requirements of the licensee’s emergency preparedness program.

Posting Date 08/21/2003 **ID** 353

Question NEI 99-02 defines an opportunity for Classification as each expected classification or upgrade in classification. In a recent actual event a utility cleared the criteria for the Alert Classification and reclassified the condition as a Notification of Unusual Event based on then existing plant conditions and proceeded to make the notification of the Classification change. The utility’s approved Emergency Plan permits downgrading Classifications based on changing plant conditions. NEI 99-02 is unclear as to whether the Classification based on the downgrade should count as an opportunity.
<p>Should a Classification based on a downgrade from a previously existing higher classification and the subsequent notification of the downgrade to offsite agencies count as opportunities for the purpose of the DEP Performance Indicator.

Response No: It was not the intent of the NEI 99-02 to count downgrades as opportunities for the DEP performance indicator.
<p>When a higher classification is reached in a drill, exercise or real event it is probable that multiple EALs at equal or lower levels have also been exceeded. When the reason for the highest level Classification is cleared many of these conditions may still exist. It is impractical to evaluate from a timeliness or accuracy standpoint the starting point for the purposes of Performance Indicator assessment. Subsequently, the notification of the downgrade opportunity should then also be handled as an update rather than a formal opportunity for a Performance Indicator

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Posting Date 08/21/2003 **ID** 352

Question If a scenario predicts that a default protective action recommendation will be used and therefore not counted as an opportunity, can the associated notification be counted as an opportunity?

Response Yes, if a scenario results in the development of PARs (whether default or not) the PAR notification should be counted as an opportunity.

Posting Date 08/21/2003 **ID** 351

Question STP performs "team training" during licensed operator requalification (LOR) by scheduling on-shift E-Plan drills during concurrent LOR, Plant Operator Requalification (POR) and Health Physics Continuing Training. This allows us to exercise the on-shift ERO as a unit instead of individually in training sessions. We count classification and PAR development opportunities and notification opportunities and evaluate performance during these opportunities.
During these sessions, occasionally the Shift Supervisor , who is the only one allowed to act as Emergency Director in an actual event, requests that the Unit Supervisor perform as the Emergency Director as part of his training for upgrade to full Shift Supervisor qualification. This is recognized and planed for prior to the start for the session. The Unit Supervisor is a licensed SRO and has completed the initial training requirements foe Emergency Director, but can not actually act in that position outside this training environment. This is recognized and planed for prior to the start for the session. Based on NRC regional inspector interpretation and direction we do not count the classification and PAR opportunities since the Unit Supervisor is not counted as key responder in the ERO. We do count the notification opportunities and award ERO participation credit to the non-licensed operators since they are the Key Responders and would actually perform the notifications in an actual event.

<p>Is it allowed to count the classification as an opportunity even though it is performed by the Unit Supervisor who is not defined as a key responder?

Response No. ERO and DEP were developed to be congruent. If the classification is performed by a key ERO member then it must be counted as an opportunity. Conversely, if the classification is performed by an individual who is not a key ERO member, then the classification cannot be considered an opportunity. <p>NOTE: If the unit supervisor has an active license and could be placed in the Emergency Director position, then consideration of adding the unit supervisor to the KEY ERO list might need to be considered.

Posting Date 08/21/2003 **ID** 350

Question STP performs "team training" during licensed operator requalification (LOR) by scheduling on-shift E-Plan drills during concurrent LOR, Plant Operator Requalification (POR) and Health Physics Continuing Training. This allows us to exercise the on-shift ERO as a unit instead of individually in training sessions. We count classification and PAR development opportunities and notification opportunities and evaluate performance during these opportunities.
During these sessions, occasionally the Shift Supervisor , who is the only one allowed to act as Emergency Director in an actual event, requests that the Unit Supervisor perform as the Emergency Director as part of his training for upgrade to full Shift Supervisor qualification. The Unit Supervisor is a licensed SRO and has completed the initial training requirements foe Emergency Director, but can not actually act in that position outside this training environment. This is recognized and planed for prior to the start for the session. Based on NRC regional inspector interpretation and direction we do not count the classification and PAR opportunities since the Unit Supervisor is not counted as key responder in the ERO. We do count the notification opportunities and award ERO participation credit to the non-licensed operators since they are the Key Responders and would actually perform the notifications in an actual event.
The simulator scenario scope lists the classification and notification as opportunities in the drill. Both activities are evaluated for proper performance.

<p>Is it allowed to count the notification as an opportunity and award ERO participation credit for the non-licensed plant operator performing the key responder role for notification?

Response Yes. If the communicator performing the entire notification during performance enhancing scenario is a key ERO member, then the notification should be considered as an opportunity and participation credit awarded to the key ERO member.

Posting Date 03/20/2003 **ID** 338

Question During a recent Nuclear Regulatory Commission (NRC) review of the historical data for the Drill/Exercise Performance (DEP) Performance Indicator (PI), the inspector identified an issue with regard to the evaluation of the accuracy of the initial notification form. During licensed operator requalification (LOR) simulator training, crews were inconsistent in marking the form as a drill or actual event. Further, the inspector noted that the DEP PI notification opportunities were evaluated as successful regardless of whether drill or actual event was marked, or in a couple of instances, not marked at all.
<p>For the purposes of evaluating Drill/Exercise Performance (DEP) PI notification opportunities, NEI 99-02 Revision 2 pg 85 states that the definition of accurate requires that the initial notification form is completed appropriate to the event and includes whether the event is a drill or actual event.
Prior to the Reactor Oversight Process (ROP) and the use of DEP PIs, LOR simulator crews were directed to mark "actual" on the notification forms to enhance the realism of the training environment, and mark "drill" during full-scale exercises. Inconsistencies began when there was a lack of clear expectations on how the crews were to mark the initial notification forms during LOR simulator training exercises that were to be included in the DEP PI data. The emergency preparedness staff did not provide direction on what the expectations were for accurately completing the form because they felt it would constitute a disruption of the operator training program.
<p>Following the identification of the issue by the NRC inspector, the emergency preparedness staff established criteria for evaluating the accuracy of the notification form with regard to marking drill or actual event when determining a successful DEP PI opportunity. The simulator crews were directed to mark "drill" on the notification form during LOR simulator training exercises. However, the historical DEP PI data was not revised to reflect the inconsistency.
<p>1.) Should the historical DEP PI data be revised to indicate that the previous opportunities were inaccurate?
<p>2.) Is it acceptable for a site's EP program requirements to specify marking "actual event" on the initial notification form during LOR simulator training exercises and to count those DEP PI opportunities as accurate notifications?

Response 1.) No, for this case only. The lack of providing clear expectations to the LOR simulator crews on marking drill or actual event on the notification form is indicative of a programmatic weakness and not a performance weakness. Therefore, revising the historical data would not provide an indicator of actual performance with regard to the accuracy of the notification form. However, those historical notification opportunities that did not have either drill or actual event marked (i.e., left blank) should be revised to a failed opportunity since it indicates a lack of performance. Additionally, any future similar instances should be submitted as an FAQ for evaluation.
<p>2.) Yes, assuming all other portions of the notification form are accurate (IAW NEI 99-02, revision 2, page 85), and meet site specific EP program requirements. A successful PI opportunity is determined evaluating performance against expectations. However, not marking either drill or actual event (regardless of expectations) shall be a failed opportunity.

Posting Date 12/12/2002 **ID** 326

Question During an EP drill/exercise scenario, a licensee will implement their procedure(s) and develop appropriate protective action recommendations (PARs) when valid dose assessment reports indicate EPA protective action guidelines (PAGs) are exceeded. A question arises when a scenario objective identifies that the PAGs will be exceeded beyond the 10 mile emergency planning zone (EPZ) boundary. Should the licensee count the development of the PAR(s) [or the lack thereof] beyond the 10 mile EPZ as an EP Drill/Exercise Performance (DEP) PI opportunity, due to their "ad hoc" nature?

Response If a licensee has identified in its scenario objectives that PAGs will be exceeded beyond the 10 mile plume exposure pathway emergency planning zone (EPZ) boundary, it is expected that the required PAR development and notification has been contemplated by the scenario with an expectation for success and criteria for evaluation provided. This would constitute a PI opportunity as defined in NEI 99-02. In addition, there is a DEP PI opportunity associated with the timeliness of the notification of the PAR to offsite agencies. Essential to understanding that these DEP PI opportunities exist is the need to realize that it is a regulatory requirement for a licensee to develop and communicate a PAR when EPA PAG doses may be exceeded beyond the 10 mile plume exposure pathway EPZ. However, as discussed in NEI 99-02, the licensee always has the latitude to identify which DEP PI opportunities will be included in the PI statistics prior to the exercise. Thus, a licensee may choose to not include a PAR beyond the 10 mile EPZ as a DEP PI statistic due to its ad hoc nature.

Posting Date 10/31/2002 **ID** 323

Question Should the follow up PAR change notifications be counted as four inaccurate notifications for the situation described below?
A drill was conducted which included opportunities for Classification, Notification and PARs. The initial Notification for the General Emergency and the associated PAR contained the accurate Time Event Declared of the classification. On follow up PAR change notifications (4), the Time Event Declared block was completed with the time of the PAR data instead of the time the GE was declared. The initial GE Event notification contained the proper time. There were four PAR changes made. The PAR, MET and other required information was accurate. Each PAR developed was accurate. The time the PAR was developed was accurate on the form.
<p>Once a General Emergency was accurately declared, and the INITIAL notification was made in a timely and accurate manner, changing of the time in the Time Event Declared block on the follow up notifications had no influence on the event initiation, nor did it result in untimely or inaccurate PARs being issued to the states and counties. Changing of the time in follow up PAR change notifications did not impact their response since the states and counties were provided the accurate time of event declaration in the initial notification. No additional events were declared since the plant was already at the GE classification. This issue was critiqued and actions were taken to ensure the time desired for the Time Event Declared block on the form was communicated to those responsible for completing the form.

Response No. Based on the example above, the 4 of 5 notifications should be counted as successful. Since it was the same error in 4 follow-up notifications, it should only be counted once since it was in the same exercise. Note: if the same crew made the same mistake in a subsequent exercise, it would be counted as a separate missed opportunity.

Posting Date 05/22/2002 **ID** 309

Question At one point in the 2001 Off-Year Exercise, a wrong sub-area was identified as part of the affected PAR determination. This PAR determination, including the incorrectly identified affected sub-area, was approved for inclusion in the State notification. The State notification was made to the simulated State responder as approved and in a timely manner. Subsequently, the error in the PAR was discovered and a corrected PAR was developed, approved, and communicated to the simulated State responder, beyond the original 15 minutes.<p>This event was initially counted as three successes out of four opportunities (a successful emergency classification, a successful emergency notification, an unsuccessful PAR determination, and a successful PAR notification). Through discussions with the Senior Resident NRC Inspector, the question was raised concerning whether the paragraph on page 81, lines 6-8, of NEI 99-02, Revision 1 (page 89, lines 4-5 of Revision 2), applies to errors made during PAR determination. The paragraph is clear concerning classification errors, in that one classification error does not cascade to the notifications and PAR. However, a similar paragraph addressing errors made in PARs determination was not found in NEI 99-02. Additionally, the definition of <I>Accurate</I> states that the notification form should be completed "appropriate to the event," rather than appropriate to the understanding of the event at that time.<p>Because the issue had not been resolved at the time of the fourth quarter 2001 NRC PI submittal, this event was reported as two successes out of four opportunities (a successful emergency classification, a successful emergency notification, an unsuccessful PAR determination, and an unsuccessful PAR notification). This FAQ was developed and submitted to clarify whether the PAR notification is considered successful if the PAR information, including the incorrectly identified affected areas, is communicated as approved.<p>For a failure to properly identify the affected areas for a PAR development, is the notification considered successful if the information, including the incorrectly identified affected areas, is communicated as approved?

Cornerstone Emergency Preparedness

PI EP01 Drill/Exercise Performace

Response Yes, for a failure to properly identify the affected areas for a PAR development, the notification is considered successful if the information, including the incorrectly identified affected areas, is communicated as approved. The paragraph describing an incorrect classification as "only one failure" was intended as an example. The situation with PARs is analogous to that described in NEI 99-02 as applied to classification of an event. The Performance Indicator result should be an incorrect opportunity for development of the PAR and a successful opportunity for notification of the PAR (in addition to the successful emergency classification and emergency notification). Hence, in the situation given, this will be considered three successes out of four opportunities.

Posting Date 10/13/2004 **ID** 371

Question <p>NEI 99-02 Rev 2 ERO Participation PI defines the numerator and denominator of the calculation as based on Key ERO Members. The key position list (on page 89 and 90) was originally created from NUREG 0696 key functions that involved actions associated with the risk significant planning standards (classification, notification, PARs, and assessment), with the addition of the Key OSC Operations Manager included from a mitigation perspective.</p>

<p>When a single individual is assigned in more than one 'key position' that individual must be counted for each key position (page 91 lines 4-7 of NEI 99-02).</p>

<p>Guidance is not provided in the case where more than one key position is performed by a single member of the ERO in a single drill/exercise. For example, the communicator is defined in NEI 99-02 as the key position that fills out the notification form, seeks approval and usually communicates the information to off site agencies (these duties may vary from site to site based on site procedures). </p>

<p>Assigning a single member to multiple Key Positions and then only counting the performance for one Key Position could mask the ability or proficiency of the remaining Key Positions. The concern is that an ERO member having multiple Key Positions may never have a performance enhancing experience for all of them, yet credit for participation will be given when any one of the multiple Key Positions is performed. </p>

<p>When the communicator key position is performed by an ERO member who is also assigned another key position (e.g., the Shift Manager (Emergency Director)), should participation be counted for two key positions or for one key position?</p>

Response <p>Participation by a single member of the ERO performing multiple key positions should be counted for each key position performed. For the situation described, two key positions should be counted.</p>

<p>ERO participation should be counted for each key position, even when multiple key positions are assigned to the same ERO member. In the case where a utility has assigned two or more key positions to a single ERO member, each key position must be counted in the denominator for each ERO member and credit given in the numerator when the ERO member performs each key position</p>

<p>“Assigned” as used in this FAQ applies to those ERO personnel filling key positions listed on the licensee duty roster on the last day of the reporting period (quarter). Note, however, the exception on page 92 line 1-2 of NEI 99-02, that states, “All individuals qualified to fill the Control Room Shift Manager/Emergency Director position that actually might fill the position should be included in this indicator.”</p>

<p>This FAQ will become effective 1/1/05 and applies to data submitted for the first quarter 2005 and going forward.</p>

Posting Date 12/12/2002 **ID** 327

Question NEI 99-02 states in the clarifying notes for the ERO PI, "When the functions of key ERO members include classification, notification, or PAR development opportunities, the success rate of these opportunities must contribute to Drill/Exercise Performance (DEP) statistics for participation of those key ERO members to contribute to ERO Drill Participation." Must the key ERO members individually perform an opportunity of classification, notification, or PAR development in order to receive ERO Drill Participation credit?

Response No. The evaluation of the DEP opportunities is a crew evaluation for the entire Emergency Response Organization. Key ERO members may receive credit for the drill if their participation is a meaningful opportunity to gain proficiency in their ERO function.

Posting Date 10/13/2004 **ID** 372

Question <p>Pilgrim has 112 sirens which are normally scheduled to be tested for performance indicator purposes once each calendar month (e.g., once during the month of September). This was reflected in procedure as a requirement to test all of the sirens “monthly”. The person scheduling the testing of the sirens incorrectly interpreted the procedure’s “monthly” frequency consistent with other “monthly” tests as allowing a 25% grace period for scheduling flexibility. As a result, 29 of the siren tests normally scheduled to be performed in September were scheduled to be performed during the beginning of October. </p>
<p>On October 1 the status of the siren testing was discussed with other members of the plant staff who understood that the intent of the “monthly” requirement was once per calendar month and that no grace period applied. Immediate actions were taken including performing the remaining 29 tests on an accelerated basis (all satisfactory tested by October 3) and entering the item in the corrective action program.</p>
<p>All of the 29 sirens passed the testing performed during the first 3 days of October. The testing was not delayed due to the unavailability or suspected unavailability of the sirens. The reason for the late testing of the equipment was purely an administrative error and not siren functionality related.</p>
<p>For plants where siren tests are initiated by the utility, if a scheduled test(s) was not performed due to an administrative issue but the untested siren(s) was not out-of-service for maintenance or repair and was believed to be capable of operation if activated, should the missed tests be considered non-opportunities or failures for performance indicator reporting purposes?</p>

Response <p>Regularly scheduled tests missed for reasons other than siren unavailability (e.g., out of service for planned maintenance or repair) should be considered non-opportunities. The failure to perform a regularly scheduled test should be entered in the plant’s corrective action program and annotated in the comment field on the quarterly data submittal. The failure to perform regularly scheduled tests may be reviewed as part of the baseline inspection process.<p>

Posting Date 02/19/2004 **ID** 358

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

Response Yes. Page 95 line 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.
Note: If prior to this FAQ response, a plant changed their testing methodology, it is not necessary to recalculate their past PI data from the time of the change. However, those plants still need to update the affected PI data report by noting the change in the comment section.

Posting Date 09/16/2004 **ID** 369

Question <p>A worker entered a Technical Specification High Radiation Area (> 1R/hr) with all requirements of the job (training, briefings, dosimetry, ALARA Plan and RWP requirements, electronic dosimetry, etc.). The worker did not perform the RWP process auto-sign-in on the RWP, which would have electronically checked the worker's 700 mrem administrative RWP buffer. Not performing this auto-sign-in process did not violate the primary means of controlling access and did not invalidate the RWP for the job. The RWP stated that 700 mrem dose availability was required prior to entry. This administrative dose buffer is an additional defense-in-depth, licensee-initiated control to protect against exceeding the licensee's system of dose control and is not utilized to control dose. The worker's actual dose did not exceed the electronic dosimeter set point and the minimum administrative control guideline. The dose availability of the worker is defined as the difference between the site-specific administrative control level of 2000 mrem (significantly below Federal Limits) and the worker's current accumulated dose for the year.</p>

<p>An ALARA Plan and RWP controlled the work activity. The individual used teledosimetry with predetermined alarm setpoints for the job, which transmitted dose and dose rate information during the entry. Video surveillance was utilized by radiation protection technicians and in compliance with 10CFR20.1601(b) during the entry into the >1R/hr area. Specific authorization was given by the remote monitoring station technician to enter into the area. The worker had the training and respiratory protection qualifications required by the RWP, multiple TLDs had been issued, the required RWP was obtained and signed, and briefings were attended. The RWP entry was accomplished within pre-determined stay-time limitations, as discussed in the worker briefing. The electronic entry time was entered after the worker had exited the area. There was no over exposure or unintended dose for this worker. The work was completed within the maximum projected dose for the activity. Technical Specification requirements for control of entry into the high radiation area were met and worker dose was controlled since the worker was authorized and had obtained the RWP for the job.</p>

<p>The primary means of control of occupational dose exposure include pre-determined stay-time limitations and alarming dosimetry set below expected job levels. The administrative control level is an additional exposure control mechanism. The licensee's administrative control level is conservatively established at 2 rem, or 40% of the Federal dose limit, to provide a substantial margin to prevent personnel from exceeding the Federal dose limit of 5 rem and to help ensure equitable distribution of dose among workers with similar jobs. The individual's annual dose was well below 2 rem and the administrative control level had not been raised above 2 rem prior to the worker obtaining a TLD. If needed, additional and higher levels of managerial review and authorization are required for higher dose control levels. Increasing levels of management review and approvals are required to exceed the administrative control level of 2000 mrem (i.e., to 3000 mrem requires written approval by the Radiation Protection Manager and the work group supervisor, to 4000 mrem requires written approval by the Radiation Protection Manager, work group supervisor, and Plant Manager, to 5000 mrem requires written approval by the Site Vice President). The administrative dose buffer is in addition to the Technical Specification requirements for an RWP and therefore not material to the Technical Specification requirements for control of occupational dose.</p>

<p>As it is stated in NEI 99-02, "this PI does not include nonconformance with licensee-initiated controls that are beyond what is required by technical specifications and the comparable provisions in 10CFR Part 20." The check of dose availability is a licensee-initiated administrative control that is beyond what is required by technical specifications, comparable provisions in 10CFR20, or Regulatory Guide 8.38. Does failure of the worker to meet the internal administrative control guideline for dose available as specified by the RWP for the job activity count as a PI occurrence?</p>

Response Yes this event would be a reportable PI occurrence. The above clearly describes a nonconformance with an RWP procedural requirement that resulted in a loss of control of access to the Tech. Spec. High Radiation Area. Had the RWP procedure been adhered to, this individual would not have been allowed to enter without further approval.

Posting Date 09/16/2004 **ID** 368

Question The definition of the Occupational Exposure Control Effectiveness performance indicator refers to “measures that provide assurance that inadvertent entry into the technical specification high radiation areas by unauthorized personnel will be prevented” (page 98, NEI 99-02, Revision 2). In the context of applying the performance indicator definition in evaluating physical barriers to control access to technical specification high radiation areas, what is meant by “inadvertent entry”?

Response In reference to application of the performance indicator definition in evaluating physical barriers, the term “inadvertent entry” means that the physical barrier can not be easily circumvented (i.e., an individual who incorrectly assumes, for whatever reason, that he or she is authorized to enter the area, is unlikely to disregard, and circumvent, the barrier). The barriers used to control access to technical specification high radiation areas should provide reasonable assurance that they secure the area against unauthorized access.

Posting Date 04/22/2004 **ID** 364

Question <p>Two individuals enter an area of containment, previously surveyed and posted as a radiation area. They comply with all applicable RWPs and procedures. Additionally, they are continuously, remotely monitored by teledosimetry (Electronic Personnel Dosimeter, EPD). During the entry, their EPDs alarm on dose rate, which had been preset to alarm at 150 mrem/hr. The individuals detect the alarm and immediately exit the area to notify HP. Concurrently, HP technicians manning the Central Alarm Station detect the alarm condition and dispatch a nearby roving HP technician to the area to confirm the alarm and verify worker protection. The area is immediately surveyed by HP and found to contain dose rates of approximately 2 rem/hr at 12 inches; the area is reposted as a Locked High Radiation Area (LHRA). Investigation of the event reveals that the area entered contains a length of piping and a valve through which the reactor cavity is filled and drained. Shortly before this entry, the reactor cavity had been filled via this pipe. The specific area’s dose rate had been confirmed by past experience to be unaffected by cavity filling and therefore was not flagged for resurvey following the fill evolution. It is hypothesized that a hot particle dislodged from an upstream location during filling and migrated into the vicinity of the work location prior to the worker’s entry. The same area had been occupied numerous times after the last survey, before filling, with no problems. Should this be counted as a performance indicator event?</p>

<p>Furthermore, should any event be counted against this PI in which an entry into an area occurs where the dose rate increased (to greater than 1 rem/hr) in a reasonably unanticipated manner?</p>

Response This is a reportable Performance Indicator (PI) occurrence. The statement in this question that the "...dose rates had been confirmed by past experience..." is incorrect. As described in this example, the dose rates in this area were assumed, not confirmed by a (pre work or routine) survey. This is the heart of the performance deficiency. Placing direct (and, or remote) reading dosimeters on workers is not a substitute for adequate surveys as required by Part 20. This example is not a case where the non-conformance was reasonably unanticipated. This is an example of a lack of vigilance by the radiation protection program. The reactor refueling cavity drain and fill system clearly had the potential for high dose rates, and an adequate pre work survey would have uncovered the radiological condition.

Posting Date 04/22/2004 **ID** 362

Question <p>Two job-coverage Radiation Protection technicians were performing a job turnover at the entrance to a Steam Generator Bay. At the time the Steam Generator Bay was posted and locked as a Locked High Radiation Area. During the turn over process the RP Technicians entered into the posted region of the Locked High Radiation Area. When they entered a few feet past the doorway the door was left open and the radiological posting was left down. However, the Radiation Protection technicians provided direct surveillance capable of preventing unauthorized entry in the high radiation area. The RP Technicians were cognizant of the need to control access to the area and did so throughout the turnover. </p>

<p>Is this event considered performance indicator occurrence?</p>

Response This is not considered a performance indicator occurrence because the Radiation Protection technicians maintained positive control over access to the area.

Posting Date 05/01/2003 ***ID*** 346

Question During reactor head inspection activities with the reactor head supported on the head stand, temporary shielding blocked access to the actual locked high radiation area (LHRA) under the reactor head. Removal of the temporary shielding would require significant effort such as removal of scaffold hardware. The shielding and scaffold prevented inadvertent entry into the LHRA. However, the posting and barricade (including a flashing red light) for the inaccessible LHRA under the reactor head was conservatively posted where the radiation levels were less than 1 rem per hour. Several radiation workers were observed breaking the plane of the posted LHRA with portion of their whole body (upper arms and head) as they reached for equipment stored on top of the reactor head platform. The reactor head platform and surrounding areas were monitored remotely by Health Physics Technicians who were in contact with technicians located near the posted areas. A Quality Inspector observing the workers instructed them to move away from the posted area. At the same time, the remote coverage technician notified to local technician to remove the workers from the posted area. Does this count as an occurrence against the technical specification LHRA Performance Indicator?

Response Questions 342, 344, and this question are specific variations of the same generic question. <p>The generic question is applicable to situations where the Locked High Radiation Area(s) has been conservatively posted (i.e., at the containment door). The question is "If an individual, who has not fully met the requirements for access to a Locked High Radiation Area (i.e., no HP escort, dosimeter not turned on, etc.), crosses the posted boundary, is this a PI occurrence if additional physical controls were in place (i.e., cocooning, locked doors, or flashing lights that meet the T.S. controls) such that they could not access any dose rates greater than 1000 mrem/hr without violating those additional controls?"

<p>This situation would not constitute a loss of radiological control over access to or work activities within the respective high radiation areas. Therefore, per the definition in NEI 99-02, this violation would not be a reportable PI occurrence.

Posting Date 05/01/2003 ***ID*** 345

Question During a planned crud burst and cleanup at the start of a refueling outage, higher than anticipated dose rates were experienced outside a demineralizer vestibule. General area dose rates (measured at 30 cm) were approximately 3 rem/hr, which exceeds the criteria for a technical specification locked high radiation area (greater than 1 rem/hr). This area was found during post-crud burst surveys. The area was unposted for approximately nine hours. No electronic dosimeter alarms or unanticipated dosimetry anomalies were noted during this time period. No unanticipated dose to personnel was received due to the condition. This was the first refueling outage following steam generator replacement and as a result, a larger crud burst was experienced than in previous outages. This was an anticipated condition, and a plan to control work activities during the period of elevated dose rates was developed. Specific work restrictions in the vicinity of the demineralizer vestibule were not initially established as a part of this plan due to crediting the presence of a labyrinth entrance to the demineralizer vestibule, when no such labyrinth entrance was present, when evaluating anticipated plant conditions following the crud burst. Without the presence of the labyrinth entrance, the demineralizer vestibule would likely have been controlled as a locked high radiation area in anticipation of increased activity during the crud burst. During the crud burst, higher dose rates than anticipated were noted in some areas of the plant. As a result, more extensive surveys were performed in all letdown affected plant areas. It was during these surveys, which were in addition to those required by the shutdown plan, that the technical specification high radiation area was identified by Radiation Protection personnel. Upon discovery, the area was immediately posted and controlled as a locked high radiation area. The guidance provided in FAQ 100 appears to be applicable to this situation. This FAQ was written to address the question that if during performance of routine radiation surveys a Radiation Protection Technician identifies a Technical Specification high radiation area which results from a plant system configuration change made earlier in the shift, does this count against the Occupational Exposure Performance Indicator? The response to this FAQ states that the answer to this question depends on whether the actions taken were timely and appropriate, and whether the change in radiological conditions was anticipated, etc. In general, identifying changes in radiological conditions is an expected outcome of performing systematic and routine radiation surveys. Thus, such occurrences would not typically be counted against the PI. In this specific case, although the general area dose rates in the vicinity of the demineralizer vestibule were higher than anticipated, in part due to incorrectly crediting the presence of a labyrinth entrance to the demineralizer vestibule, it was recognized prior to the evolution that the crud burst would result in higher than normal radiological conditions in the plant. When higher than expected dose rates were noted in some areas of the plant, timely and appropriate actions were taken to identify these conditions in all areas potentially affected, and proper controls were established when conditions warranted. Should this occurrence count against the technical specification high radiation area PI?

Response No. In this specific case, although the general area dose rates in the vicinity of the demineralizer vestibule were higher than anticipated, it was recognized prior to the evolution that the crud burst would result in higher than normal radiological conditions in the plant. When higher than expected dose rates were noted in some areas of the plant, timely and appropriate actions were taken to identify these conditions in all areas potentially affected, and proper controls were established when conditions warranted, including the demineralizer vestibule. The radiological conditions were identified and appropriate controls were established as a direct result of the additional surveys conducted for that purpose.

Posting Date 05/01/2003 **ID** 344

Question An individual is briefed on the radiological conditions in his work area and travel path with dose rates of 10 mr/hr- 40 mr/hr, that is located in a BWR drywell controlled and posted as a high radiation area greater than 1.0 rem/hr. The individual enters the drywell with his electronic dosimeter (ED) turned off but does not enter any area that is actually greater than 1 rem/hr nor will any of his work activities take him into any area where the actual dose rates are greater than 1 rem/hr. The worker checks his ED within 15 minutes of the entry and finds the ED turned off. He immediately exits the area and contacts Radiation Protection (RP). Does this constitute a PI occurrence?

<p>The unit is shutdown for a refuel outage. The drywell is open and is controlled and posted at the main personnel entrance on Elevation 135' as "Locked High Radiation Area". An RP control point, manned 24 hours per day, is situated directly across from the entrance. The RP control point ensures access to the drywell is properly controlled from a radiological perspective. General area dose rates in the drywell range from 10-400 mr/hr. There are five locations in the drywell that have dose rates at 30 cm exceeding 1000 mr/hr. Four of the five areas are marked in the drywell with a flashing light, posting and rope boundary to control worker access to these areas based on scheduled work activities. The fifth spot is located on the 116' elevation that requires personnel to descend a ladder to gain access to it. The spot has two lead blankets around its sides and is posted in accordance with the procedural guidance for control of radiation shielding specified in NRC Regulatory Guide 8.38. With the lead shielding in place, this spot is essentially inaccessible due to the physical geometry of the pipe source and an immediately adjacent wall. There is no scheduled work in the area and it is not a normal travel path to other areas. There are several individuals on a crew working on the 135' elevation in the drywell approximately 10-15 feet inside the personnel entrance at about 110 degrees in a 10 mr/hr-40 mr/hr general area staging lead blankets for installation. The crew had an ALARA briefing and HP brief prior to physically signing the Radiation Work Permit. Prior to this entry the crew was briefed on the current radiological conditions in their work area by the RP control point. The briefing discussed general area dose rates of 10 mr/hr- 40 mr/hr, the exact work location and that the travel path was not going to expose workers to any areas greater than 1 rem/hr. There is one location on 135' elevation at about 280 degrees that is greater than 1000 mr/hr. This spot is marked with a flashing light, posting and rope boundary preventing unauthorized access. The crew had worked at the drywell earlier in the day. For the first entry the crew had obtained an RP briefing, turned on their electronic dosimeters and proceeded to work. The crew broke for lunch and turned off their electronic dosimeters when leaving the RCA. When returning from break one member of the crew entered the drywell without turning his electronic dosimeter on. After about 15 minutes in the area the individual checked his electronic dosimeter and saw that it was turned off and he immediately exited the area. Investigation by the radiation protection technician verified work area dose rates of 10 mR/hr- 40 mR/hr, co-workers electronic dosimetry indicated individuals received a maximum of 8 mR and were in a maximum dose rate field of 27 mR/hr.

Response Questions 342, 346 and this question are specific variations of the same generic question.
<p>The generic question is applicable to situations where the Locked High Radiation Area(s) has been conservatively posted (i.e., at the containment door). The question is "If an individual, who has not fully

met the requirements for access to a Locked High Radiation Area (i.e., no HP escort, dosimeter not turned on, etc.), crosses the posted boundary, is this a PI occurrence if additional physical controls were in place (i.e., cocooning, locked doors, or flashing lights that meet the T.S. controls) such that they could not access any dose rates greater than 1000 mrem/hr without violating those additional controls?"

<p>This situation would not constitute a loss of radiological control over access to or work activities within the respective high radiation areas. Therefore, per the definition in NEI 99-02, this violation would not be a reportable PI occurrence.

Posting Date 05/01/2003 **ID** 342

Question For an at-power containment entry, the containment building outer airlock door is posted as a very high radiation area, with the control point established at the outer airlock door. A procedural violation of a very high radiation area posting occurred, when an operator was stationed in the airlock with the outer airlock door closed and the inner airlock door open. The HP technician outside the outer airlock door was unable to gain access to the airlock under these conditions. This was treated as a violation of a very high radiation area posting due to the HP technician's inability to positively control the activities of the operator in the airlock. However, at no time were any personnel able to gain unauthorized or inadvertent access to areas in which radiation levels could be encountered at the 10CFR20.1602 limits. All areas in containment, potentially exceeding the 10 CFR 20.1602 limits, have additional access controls in place to prevent unauthorized or inadvertent entry (i.e. Reactor Sump is a Very High Radiation Area which is locked and controlled with a separate key, access to the reactor cavity is prevented by removal of the access ladder, movable incore detectors are on a clearance to prevent operation during containment entries, etc.) The question is: Does an access control violation of a very high radiation area posting constitute a "Very High Radiation Area Occurrence" for purposes of reporting the associated NRC Performance Indicator, when there is no possibility of exposure to fields as defined by 10 CFR 20.1602?

Response Questions 344, 346 and this question are specific variations of the same generic question. The generic question is applicable to situations where the Locked High Radiation Area(s) has been conservatively posted (i.e., at the containment door). The question is "If an individual, who has not fully met the requirements for access to a Locked High Radiation Area (i.e., no HP escort, dosimeter not turned on, etc.), crosses the posted boundary, is this a PI occurrence if additional physical controls were in place (i.e., cocooning, locked doors, or flashing lights that meet the T.S. controls) such that they could not access any dose rates greater than 1000 mrem/hr without violating those additional controls?"

<p>This situation would not constitute a loss of radiological control over access to or work activities within the respective high radiation areas. Therefore, per the definition in NEI 99-02, this violation would not be a reportable PI occurrence.

Posting Date 05/01/2003 **ID** 341

Question Plant Technical Specifications state the following for areas with radiation levels > or = 1000 mrem/hr, referred to as Tech Spec Locked High Radiation Areas (TSLHRAs):
<p><i>...areas with radiation levels > or = 1000 mrem/hr shall be provided with locked or continuously guarded doors to prevent unauthorized entry, and the keys shall be maintained under the administrative control of Operations or health physics supervision. Doors shall remain locked except during periods of access by personnel under an approved RWP that shall specify the dose rate levels in the immediate work areas and the maximum allowable stay times for individuals in those areas...</i>
<p>Our plant is configured with a chain link cage and cage door around the outer Containment door. The cage door is secured by a chain and padlock (keys controlled by health physics supervision). Additionally, an electronic lock and card reader (ACAD) secures the door. Power to the ACAD lock is controlled by Security from a central remote location. When powered, the ACAD will open the electronic lock upon reading the badge of an individual with authorized access. When power is removed, the ACAD electronic lock cannot be opened from outside the cage and therefore acts as a locked door. The door will open from inside the cage via use of a crash bar, a feature which prevents the de-energized ACAD from locking people inside.
<p>Plant procedures state that the Shift Supervisor (Operations) authorizes each entry into Containment

and assigns responsibility to the work group supervisor or entering individuals (entering Containment) to sign on and off an entry data sheet and the controlling RWP. The necessity for an access control point is determined by the Shift Supervisor and may be judged unnecessary.
<p>The typical entry without a continuous access control point (as in a nonoutage situation) requires notification to HP to remove the chain and padlock, and notification to Security, to dispatch a security officer to the cage door after which power to the ACAD is turned on. Entry into Containment is made in accordance with the RWP. If the entry duration is not brief, and no access control point is established, then the security officer may notify the central station to remove ACAD power and he departs resuming other activities.
<p>The de-energized ACAD maintains the cage door locked. Personnel inside Containment may still exit in an emergency, unassisted, using the crash bar. Add-on or subsequent entries continue to be controlled by the Shift Supervisor and RWP in accordance with plant procedures.
<p>Recently, the practice of controlling access to the Containment through the use of the de-energized ACAD electronic lock has been questioned. It has been suggested that this situation may constitute a "Technical Specification High Radiation Area Occurrence" against the Performance Indicator in that it was a "nonconformance with technical specifications "applicable to technical specification high radiation areas (>1 rem per hour) that results in loss of radiological control over access...within the respective high-radiation area (>1 rem per hour)."
<p>Is this a performance indicator occurrence?
<p><u>Additional Information</u>
<p>Plant HP customarily places a flashing light at the containment door while entries are in progress as a signal to all personnel that a Containment entry is in progress. This practice is performed in addition to the provisions of Tech Spec 5.7.3. In the situation noted above in the FAQ, a confounding factor occurred in that the flashing light had not been turned on. Although the failure to activate the flashing light is not in accordance with plant procedures, use of the flashing light is not intended to be in lieu of conformance with the Technical Specification 5.7.3, and therefore is not considered material to the issue of performance indicator.

Response As described, the flashing light was intended to warn that a containment entry was in progress. It wasn't provided as a control of the Locked High Radiation Area, per T. S. 5.7.3. Therefore, the failure to energize the light does not result in a performance indicator (PI) hit. The question of whether this situation violated the Technical Specifications (TS) depends on whether the means of locking the area (e.g., de-energizing the ACAD) is consistent with the TS (e.g., keys to the area are administrative controlled by the Shift Supervisor, Radiation Protection Manager (RPM), or their designated alternates). In this case, the "keys" to the area are Security personnel re-energizing the ACAD lock. Therefore, if procedures, or administrative controls (i.e., Standing Orders), are in place that would only allow re-energizing (unlocking) the ACAD for entries that have been authorized (by the Shift Supervisor, RPM, or their designees), the controls meet the intent of the TS and this is not a PI hit. However, if plant procedures, or administrative controls, are not sufficient to prevent unauthorized access (i.e., Security personnel are not required to verify that the individual(s) have the appropriate authorization to enter the high radiation area prior to re-energizing the ACAD), then this would be a violation of the TS and would be a PI hit.

Posting Date 12/12/2002 **ID** 333

Question A radiation worker entered the containment during power operation. At that time, the containment was a posted locked high radiation area with dose rates > 1,000 mrem per hour. Prior to entering the containment, the worker in error logged onto the wrong radiation work permit (RWP), which did not allow access to a locked high radiation area. In fact, the individual had been approved for entry into the containment, conformed with the controls specified in the correct RWP, and met all other requirements for entry, including being aware of the radiological conditions in the area being accessed, proper electronic dosimeter alarm set points, continuous coverage by Health Physics, etc. There was no "unintended exposure." The single error was related to logging onto the wrong RWP. Does this type of error count against the PI for Technical Specification High Radiation Area (>1,000 mrem per hour) occurrences?

Response No, as described, this would not count against the PI. The performance basis of the PI was met because the worker was properly informed about radiological conditions and the proper radiological controls were implemented. The worker's error in logging in on the wrong RWP is an administrative issue that is not considered a deficiency with regard to the performance basis of the PI.

Posting Date 12/12/2002 **ID** 332

Question During a review of electronic dosimeter (ED) /TLD discrepancies of eddy current workers, it was noted that for two of the workers, the electronic dosimeter under-reported the dose compared to the recorded official dose by TLD. An investigation revealed the following:
Multiple TLDs were placed on each worker for work on the platform. Locations included the head, chest, upper left and upper right arms.
A single electronic dosimeter was placed on either the right or left upper arm, depending on which arm the worker was most likely to use when manipulating the robot inside the man way.
A "jump ticket", containing the authorized dose was used for each entry.
The radiation protection technicians used telemetry connected to the ED to control exposures. Video and voice communications were also part of the remote monitoring system.
Estimated dose for each entry was recorded, based on the electronic dosimeter. The same TLDs were used for multiple entries. As a result, a direct comparison of TLDs to electronic dosimeter readings on a per entry basis could not be performed.
Estimated (ED) doses for the two workers, with the highest official doses, were low by 39% and 44%.
One of the workers with an authorized dose of 300 mrem for an entry received an estimated (ED) dose of 275 mrem. Using a ratio of TLD to ED dose of either his total exposures or the other worker's total exposures for the job, a corrected dose in the range of 450 to 460 mrem could be calculated for the single entry.
Estimated (ED) dose for 12 of 15 workers was low, when compared to the TLD at location of highest recorded exposure.
<p>Does this constitute an unintended exposure occurrence in the Occupational Radiation Safety Cornerstone as described in NEI 99-02?

Response No, assuming that a proper pre-job survey and evaluation was performed. Although, in retrospect, it was determined that the estimating device was not placed in the location of highest exposure, it was placed in the area anticipated to receive the highest exposure and used appropriately to keep exposure below the authorized dose per entry. Record dose was properly assigned using the results of the TLD placed at the location of highest exposure.

Posting Date 12/12/2002 **ID** 331

Question The scope of a job changed such that completion of the job would involve additional collective dose with regard to the original estimate. From the time that the work activities deviated from the original plan to the time that ALARA staff documented a revision to the plan and a new collective dose estimate, an individual received more than 100 mrem TEDE from external dose while continuing to work on this job. During this timeframe, the worker was performing activities outside of the original work plan. The time period from deviation from the original plan to documentation of the revised plan and dose estimate for the job is approximately one day. The licensee defines an "unintended exposure event" for TEDE in their procedures as a situation in which a worker receives 100 mrem or more above the electronic dosimeter dose alarm set point for a given RCA entry. On this job, all of the workers maintained their individual dose below the electronic dosimeter dose alarm for every RCA entry performed. Is this situation an "unintended exposure event"?

Response No, the described circumstances appear to represent an ALARA issue, not a performance deficiency with regard to the scope of the Occupational Exposure Control Effectiveness PI. The purpose of the PI is to address the Occupational Radiation Safety Cornerstone objective of "keep[ing] occupational dose to individual workers below the limits specified in 10 CFR Part 20 Subpart C." During development of the Performance Indicators, it was decided not to pursue a PI for the ALARA-based objective in the Occupational Radiation Safety Cornerstone. That objective is met through the ALARA inspection module. Further, with regard to "Unintended Exposure", the PI states that it is "incumbent on the licensee to specify the method(s) being used to administratively control dose." In this case, the licensee has apparently selected the use of electronic dosimeter alarm set points as the method for administratively controlling external dose, in which case the applicable criterion for the PI would be if the external dose exceeded the alarm set point by 100 mrem or more.

Posting Date 10/31/2002 **ID** 321

Question While in a high radiation area (HRA) removing scaffold, workers inadvertently dislodged lead shielding around a hot spot flush rig and created conditions that required posting a locked HRA (dose rates in excess of 1 rem per hour). Several minutes later when they moved to a location closer to the hot spot, the three scaffold workers received dose rate alarms. Upon receiving the alarms, they immediately left the area and the alarms cleared. After reading their dosimeters and verifying that they had not received any unexpected dose, they discussed the alarms with their supervisor and concluded that the momentary alarm was not unexpected since general area dose rates in the HRA could have caused the alarms. When the three workers attempted to log out of the RCA at the access control point, Health Physics (HP) discovered that all three individuals received a "Dose Rate" alarm on their electronic dosimeters. Independent from the ensuing exposure investigation, and approximately within the same time period (within minutes), a HP technician found radiation levels in excess of 1 rem per hour when performing a routine survey to support removal of the hot spot flush rig. The HP technician established proper controls and posting for the area and discovered that local shielding around the flush rig had been disturbed. Does this count against the technical specification high radiation area occurrence PI?

Response Yes, because the circumstances represent the creation of a technical specification high radiation area (> 1,000 mrem/hour) without the proper corrective actions (i.e., posting and controls) being taken. The dosimeter alarms that occurred represented an opportunity for timely corrective action to be taken by Health Physics, i.e., to re-evaluate the radiological conditions in the area and establish proper controls and posting. The opportunity was “missed” when the workers did not promptly notify Health Physics about the dosimeter alarms. If Health Physics had been promptly notified and responded properly in a timely manner, this would not count against the PI.

Posting Date 01/07/2000 **ID** 108

Question Is the determination of the amount of dose received as the result of an unintended exposure occurrence based solely on the dose tracking method being used (e.g., EPD or stay-time tracking), or can other data be used? For example, upon exiting a radiological area, an individual’s EPD indicates that the unintended exposure is 125 mrem. A subsequent evaluation of thermo-luminescent dosimeter data indicates that the unintended exposure is 75 mrem. Which result should be used in determining if the occurrence should be counted under the PI?

Response The best-available data relevant to the PI should be used to determine whether any of the PI dose-screening criteria have been exceeded.As described in the example, the determination should include an evaluation of which data more accurately represents the dose received –which is the result that should be applied to the PI dose-screening criteria. For example, if there is reason to believe that the EPD data is invalid, e.g., due to over-response to the type of radiation involved, radio-frequency interference, or equipment malfunction, then other data including the TLD results may be used.However, the evaluation should not lose sight of the intent of the PI. The PI is intended to identify occurrences of “degradation or failure of one or more radiation safety barriers resulting in …” a “readily-identifiable” level of unintended exposure for the purpose of trending overall performance in the area of occupational radiation safety. The dose-screening criteria serve as a tool for determining what level of dose is “readily identifiable,” based on industry experience, and do not represent levels of dose that are “risk-significant.” In fact the criteria are at or below levels of occupational dose that are required by regulation to be monitored or routinely reported to the NRC as occupational dose records.Therefore, the evaluation of resultant dose from an occurrence should not overshadow the objective of trending and correcting program discrepancies as intended by the use of the performance indicators.

Posting Date 01/07/2000 **ID** 101

Question An individual enters an area (not posted and controlled as a high radiation area) and his EPD alarms on high dose rate. The individual promptly exits the area and notifies health physics. . Follow-up surveys by the health physics staff indicated that radiation dose rates in the area were in excess of 1 rem per hour. Proper controls and posting were established for the area. Does this count against the PI?

Response Yes. As described, this occurrence should be counted against the PI. It appears that the high radiation area (>1 rem per hour) existed prior to access being made to the area, and that proper posting and controls were not in place to prevent unauthorized entry, as required by technical specifications.

Posting Date 01/07/2000 **ID** 100

Question During performance of routine radiation surveys a health physics technician determined that the radiation levels in an area were in excess of 1 rem per hour. Proper controls and posting were established for the area. The increase in radiation levels was due to a change in plant system configuration made earlier in the shift. Does this count against the PI?

Response The answer to this question depends upon the specific circumstances, for example, whether the survey and actions taken were timely and appropriate, whether the potential for the change in radiological conditions was anticipated, etc. In general, identifying changes in radiological conditions is an expected outcome of performing systematic and routine radiation surveys. Thus, such occurrences would not typically be counted against the PI. However, if surveys are not performed or controls are not established in an appropriate and timely manner, then such occurrences may be “countable” against the PI.It is not practical to define specific criteria for “timely and appropriate” for generic application. Such occurrences should be evaluated taking into account the circumstances that led to the change in radiological conditions and the scope and purpose of the survey that identified the change in conditions.

Posting Date 01/07/2000 **ID** 98

Question While individuals were working in an area, the local area radiation monitor alarmed. The workers promptly exited the area and notified health physics. Follow-up surveys by the health physics staff indicated that radiation dose rates in the area had increased to a level in excess of 1 rem per hour. Proper controls and posting were then established for the area. Does this count against the PI?

Response No. As described, this occurrence would not appear to be “countable” against the PI. The purpose of the area radiation monitors is to alert personnel to increases in radiation levels. It appears that the personnel responded appropriately to the alarm by exiting the area and notifying health physics, and that proper follow-up actions were then taken with regard to implementing controls as required by the technical specifications. However, the circumstances that led to the increase in dose rates and the resultant dose to the individuals should be evaluated per the criteria for the Unintended Dose element of the PI.

Posting Date 03/20/2003 **ID** 336

Question The clarifying note for the Fitness-For-Duty / Personnel Reliability Program PI states that the indicator does not include any reportable events that result from the program operating as intended. There is also an example provided that indicates that a random test drug failure would not count since the program itself was successful.

<p>The following example is somewhat more complex and would help to further clarify treatment of situations associated with random testing:
<p>Example - A licensee supervisor is selected for a random drug test but refuses and resigns prior to providing a specimen. All actions taken upon discovery are in accordance with Part 26 and the program functions as intended. (The subject event had been reported to the NRC Operations Center within 24-hours of occurrence in accordance with 10 CFR 26.73. The subject event was included in the 6-month report of performance data required by 10 CFR 26.71. NEI's Personnel Access Data System (PADS) had been immediately updated such that the subject individual's record adequately reflects this event.) The subject supervisor, prior to the event, was expected to be effectively practicing the behavioral observation techniques (for which supervisors are required to be trained per 10 CFR 26.22) in his role as a supervisor. Would this example count as a PI data element?

Response No. The program functioned as intended and the requirements of Part 26 were met