Posting Date 01/10/2001 **ID** 245 **Archive Date** 7/1/2001

Topic

Question How does uncertain data resulting from missing information or lack of credible information (i.e., willful acts) impact current and past PI data reporting?

Response The past or current data must be revised when the correct information is determined, regardless of the cause.

Posting Date 10/01/2000 **ID** 217 **Archive Date** 7/1/2001

Topic

Question FAQ 170 discusses correcting past unavailability hours for Emergency AC System surveillance testing which were found to be incorrectly reported to WANO. The FAQ response states that historical data does not have to be revised, except to ensure that the data is accurate back to the first quarter of 2000. Can this response be applied to any correction of performance indicator data that occurred in the historical (prior to first quarter of 2000) data time period?

Response Data in the historical submittal (through the end of 1999) does not require correction. However, data may be revised by the licensee if desired and as described and allowed by NEI 99-02.

Posting Date 05/31/2001 **ID** 275 **Archive Date** 1/1/2002

Topic

Question A plant is reducing power for a planned refueling outage, and is planning to insert a manual scram at 25 percent power in accordance with the plant shutdown procedure. At 28 percent power, as a result of a report from the field, operators believe they are about to have an equipment failure that would lead to an automatic scram. The operators immediately insert a manual scram. Afterwards, the operators determine that the actual field condition was minor, and the suspected equipment failure would not have occurred. Therefore, there would not have been an automatic scram. Should the manual scram be counted as an unplanned scram?

Response Yes, the manual scram should be counted because the scram was inserted above the 25% level specified in the plant shutdown procedure.

Posting Date 04/01/2000 **ID** 159 **Archive Date** 7/1/2001

Topic

Question With the Unit in Operational Condition 2 (Startup) a shutdown was ordered due to an insufficient number of operable Intermediate Range Monitors (IRM). The reactor was critical at 0% power. "B" and "D" IRM detectors failed, and a plant shutdown was ordered. The manual scram was inserted in accordance with the normal shutdown procedure. Should this count as an unplanned reactor scram?

Response No. If part of a normal shutdown, (plant was following normal shut down procedure) the scram would not count.

Posting Date 11/11/1999 **ID** 5 **Archive Date** 7/1/2001

Topic Unplanned Scrams

Question The Clarifying Notes for the Unplanned Scrams per 7000hrs PI state that scrams that are included are: scrams "that resulted from unplanned transients...." and a "scram that is initiated to avoid exceeding a technical specification action statement time limit;" and, scrams that are not included are "scrams that are part of a normal planned operation or evolution" and, scrams "that occur as part of the normal sequence of a planned shutdown..." If a licensee enters an LCO requiring the plant to be in Mode 2 within 7 hours, applies a standing operational procedure for assuring the LCO is met, and a manual scram is executed in accordance with that procedure, is this event counted as an unplanned scram?

Response If the plant shutdown to comply with the Technical Specification LCO, was conducted in accordance with the normal plant shutdown procedure, which includes a manual scram to complete the shutdown, the scram would not be counted as an unplanned scram. However, the power reduction would be counted as an unplanned transient (assuming the shutdown resulted in a power change greater than 20%).However, if the actions to meet the Technical Specification LCO required a manual scram outside of the normal plant shutdown procedure, then the scram would be counted as an unplanned scram.

Posting Date 02/08/2001 **ID** 255 **Archive Date** 7/1/2001

Topic

Question Appendix D - Diablo Canyon Units 1 and 2<p>At Diablo Canyon (DC), intrusion of marine debris (kelp and other marine vegetation) at the circulating water intake structures can occur and, under extreme storm conditions result in high differential pressure across the circulating water traveling screens, loss of circulating water pumps and loss of condenser. Over the past several years, DC has taken significant steps, including changes in operating strategy as well as equipment enhancements, to reduce the vulnerability of the plant to this phenomenon. DC has also taken efforts to minimize kelp, however environmental restrictions on kelp removal and the infeasibility of removing (and maintaining removal of) extensive marine growth for several miles around the plant prevent them from eliminating the source if the storm-driven debris. To minimize the challenge to the plant under storm conditions which could likely result in loss of both circulating water pumps, DC procedurally reduces power to 25% power or less. From this power level, the plant can be safely shut down by control rod motion and use of atmospheric dump valves without the need for a reactor trip. <p>Is this anticipatory plant shutdown in response to an external event, where DC has taken all reasonable actions within environmental constraints to minimize debris quantity and impact, able to be excluded from being counted under IE01 and IE02?

Response In consideration of the intent of the performance indicators and the extensive actions taken by PG&E to reduce the plant challenge associated with shutdowns in response to severe storm-initiated debris loading, the following interpretation will be applied to Diablo Canyon. A controlled shutdown from reduced power (less than 25%), which is performed in conjunction with securing of the circulating water pumps to protect the associated traveling screens from damage due to excessive debris loading under severe storm conditions, will not be considered a "scram." If, however, the actions taken in response to excessive debris loading result in the initiation of a reactor trip (manual or automatic), the event would require counting under both the Unplanned Scrams (IE01) and Scrams with a Loss of Normal Heat Removal (IE02) indicators.

Posting Date 09/12/2001 **ID** 287 **Archive Date** 1/1/2002

Topic

Question Should the following reactor trip described in the scenario below be reported as a “Scram with Loss of Normal Heat Removal?” Following a reactor trip, No. 11 Moisture Separator/Reheater second-stage steam source isolation valve (1-MS-4025) did not close. The open valve increased the cooldown rate of the Reactor Coolant System. Control Room Operators closed the main steam isolation valves and used the atmospheric dump valves to control Reactor Coolant System temperature. Within three hours, 1-MS-4025 was shut manually. Control Room Operators opened the main steam isolation valves, and Reactor Coolant System temperature control using turbine bypass valves was resumed.

Response Yes. The normal heat removal path could not be restored from the control room without diagnosis or repair to restore the normal heat removal path. In this case, manual action was necessary outside the control room to manually isolate a valve to restore the normal heat removal path.

Posting Date 09/12/2001 **ID** 286 **Archive Date** 1/1/2002

Topic

Question Should the following reactor trip described in the scenario below be reported as a “Scram with Loss of Normal Heat Removal?” A loud noise was heard in the Control Room from the Unit 2 Turbine Building. Operators noted a steam leak, but could not determine the source of the steam because of the volume of steam in the area. It was suspected that the leak was coming from the No. 21 or 22 Moisture Separator Reheater (MSR). The steam prevented operators from accessing the MSR manual isolation valves. Due to the difficulty in determining the exact source of the leak, the potential for personnel safety concerns, and the potential for equipment damage due to the volume of steam being emitted into the Turbine Building, operators manually tripped the Unit. After the manual trip, a large volume of steam was still being emitted, and the shift manager had the main steam isolation valves (MSIVs) shut. Once the MSIVs where shut, the operators identified a ruptured 2? inch diameter vent line from No. 21 MSR second stage to No. 25A Feedwater Heater. The operators shut the second stage steam supplies and isolated the leak. Once the leak was isolated, the MSIVs were opened and normal heat removal was restored. The majority of the steam that was emitted following the trip was due to all the fluid in the MSR and feedwater heater escaping from the pipe.

Response Yes. Investigation and diagnosis were required to determine that the main steam isolation valves could be reopened.

Posting Date 08/16/2001 **ID** 282 **Archive Date** 1/1/2002

Topic

Question Some plants are designed to have a residual transfer of the non-safety electrical buses from the generator to an off-site power source when the turbine trip is caused by a generator protective feature. The residual transfer automatically trips large electrical loads to prevent damaging plant equipment during reenergization of the switchgear. These large loads include the reactor feedwater pumps, reactor recirculation pumps, and condensate booster pumps. After the residual transfer is completed the operators can manually restart the pumps from the control room. The turbine trip will result in a reactor scram. Should the trip of the reactor feedwater pumps be counted as a scram with a loss of normal heat removal?

Response No. In this instance, the electrical transfer scheme performed as designed following a scram and the residual transfer. In addition the pumps can be started from the control room. Therefore, this would not count as a scram with a loss of normal heat removal.

Posting Date 04/04/2001 **ID** 264 **Archive Date** 1/1/2002

Topic

Question Should the reactor trip described in the scenario below be included as a "Scram with Loss of Normal

Heat Removal?"<p>A very heavy rainfall caused the turbine building gutters to overflow and water entered the interior of the turbine building. Water subsequently leaked onto the main feedwater pump B area and affected the pump speed control circuitry. Feedwater pump B speed increased and feedwater pump A speed decreased to compensate. Shortly thereafter feedwater pump B speed decreased and feedwater pump A increased. The control room operators placed the feedwater pump turbine master speed controller in manual in an attempt to recover from the transient. This action stabilized pump speed.<p>The transient caused the digital feedwater control system to place the feedwater regulating valves in manual control. Levels in steam generators B, C, and D began to rise.<p>A hi-hi steam generator level (P-14) occurred in steam generator B. The P-14 signal tripped both main feedwater pumps, generated a feedwater isolation signal, and tripped the main turbine. The reactor tripped upon turbine trip. Main feedwater pumps tripped on the P-14 signal as part of the plant design. Feedwater pump B had malfunctioned; however, feedwater pump A remained available. Auxiliary feedwater system automatic starts occurred for motor driven pumps A and B as well as the turbine driven auxiliary feedwater pump (all of these responses were as designed).

Response No, because the MFW system was readily restorable to perform its post trip cooldown function.

Posting Date 02/08/2001 **ID** 249 **Archive Date** 7/1/2001

Topic

Question This FAQ is a replacement for FAQ 142. FAQ 142 has been withdrawn.<p>Under the Scram with Loss of Normal Heat Removal performance indicator in NEI 99-02 Draft D, the Definition of Terms states that a loss of normal heat removal path has occurred whenever any of the following conditions occur:·loss of main feedwater,·loss of main condenser vacuum,·closure of main steam isolation valves·or loss of turbine bypass capability. The purpose of the indicator is to count scrams that require the use of mitigating systems, however, instances that meet the above criteria in a literal sense could occur without the necessity of using mitigating systems. To illustrate, would the following two examples constitute scrams with loss of normal heat removal? <p>1. A short term loss of main feedwater injection capability due to pump trip on high reactor water level post-scram is a BWR event. Under these conditions, there is ample time to restart the main feed pumps before addition of water to the vessel via HPCI or RCIC is required. <p>2. A second example would be a case where the turbine bypass valves (also commonly called steam dump valves) themselves are unavailable, but sufficient steam flow path to the main condenser exists via alternate paths (such as steam line drains, feed pump turbine exhausts, etc.) such that no mitigating systems are called upon.

Response 1. No. The determining factor in this indicator is whether or not the normal heat removal path is available to the operators, not whether the operators choose to use that or some other path. The indicator excludes events in which the normal heat removal path through the main condenser is easily recoverable without the need for diagnosis or repair.<p>2. Yes. The normal flow path is not being used in this example.

Posting Date 02/08/2001 **ID** 248 **Archive Date** 7/1/2001

Topic

Question In the Scrams With a Loss of Normal Heat Removal performance indicator, the definition of "loss of normal heat removal path" includes loss of main feedwater. Our plant is designed to isolate main feedwater after a trip by closing the main feedwater control valves. The auxiliary feedwater pumps then are designed to start on low steam generator level (which is expected following operation above low power conditions), providing our normal heat removal. A clarifying note in the Guideline clearly states that "Design features to limit the reactor cooldown rate, such as closing the main feedwater valves on a reactor scram, are not counted in this indicator." Also, the response to FAQ 65 states that "The PI is monitoring the use of alternate means of decay heat removal following a scram." Our plant received a spurious invalid feedwater isolation signal due to technician error, causing turbine trip, reactor trip, main feedwater pump trip and closure of feedwater regulation valves. The auxiliary feedwater pumps started on the loss of the main feedwater pumps, prior to reaching a low SG level condition. Operators could have restored main feedwater from the control room in this case with a few simple actions. This action is proceduralized. This is not believed to be a Scram with a Loss of Normal Heat Removal. Is this the correct interpretation?

Response Yes. This is an appropriate interpretation, because the MFW pumps are considered to be easily recoverable without the need for diagnosis or repair.

Posting Date 02/08/2001 ***ID*** 142 ***Archive Date*** 7/1/2001

Topic

Question FAQ 142 has been withdrawn and replaced by FAQ 249.

Response

Posting Date 01/10/2001 ***ID*** 238 ***Archive Date*** 7/1/2001

Topic

Question Crystal River Unit 3 (CR-3) is configured with two once-through steam generators (OTSGs). Two Main Steam Isolation Valves (MSIVs) are installed in each of the two main steam lines.<p>On August 27, 1998, CR-3 was in MODE 1 operating at 100 percent RATED THERMAL POWER. While troubleshooting a half trip signal on the Emergency Feedwater Initiation and Control (EFIC) System Channel A Main Steam Line Isolation (MSLI), both MSIVs to OTSG A closed. This action isolated steam relief to the condenser through the turbine bypass valves from the A OTSG and isolated the steam supply to Main Feedwater Pump (MFP) A. As requiredby administrative procedures, the reactor operator initiated a manual trip upon closure of the MSIVs.<p>After the manual trip, the OTSG A level lowered enough to initiate Emergency Feedwater (EFW). EFW controlled level in both OTSGs as designed, although MFP B remained in service and available at all times. OTSG B provided RCSheat removal to the condenser with EFW maintaining OTSG level.<p>Does this count?

Response No. It must be a complete loss of normal heat removal to count in this indicator.

Posting Date 10/01/2000 ***ID*** 220 ***Archive Date*** 7/1/2001

Topic

Question Following a plant trip, operators closed the MSIVs due to a stuck open steam dump valve. RCS temperature was maintained using atmospheric dump valves. Does this count as a scram with loss of normal heat removal?

Response Yes. The MSIVs could not be recovered because of the stuck open steam dump valve.

Posting Date 10/01/2000 ***ID*** 204 ***Archive Date*** 7/1/2001

Topic Replacement for FAQ 196

Question (This FAQ is a replacement for FAQ 196. FAQ 196 has been withdrawn)
During a startup following a refueling outage (reactor at 24% power w/minimal decay heat), one feed water regulating valve failed open causing a loss of feed water control. In response, one of the two feed water pumps was manually tripped to minimize overfeeding of the steam generators. SG levels continued to rise, so the reactor was manually scrammed. Within one minute of scram, with normal heat removal still available through both main feedwater bypasses, the failed open feed water regulating valve was isolated by closing it's feed water block valve as part of Standard Post Trip Actions. Operators quickly diagnosed this as an uncomplicated reactor trip and completed the remaining steps of Standard Post Trip Actions. Eleven minutes after the scram with steam generator levels continuing to slowly rise, the remaining feed water pump was stopped to terminate overfeeding of the steam generators and avoid excess RCS cooldown. Nineteen minutes after the scram, the Reactor Trip Recovery procedure was entered. Thirty nine minutes after the scram, with steam generator levels down to normal levels, AFW was established at 81 gpm for normal startup feed water alignment. Three minutes later, the Plant Startup procedure was initiated.

<p>Mitigating systems such as Aux feed and Atmospheric Dump valves were not required nor used to establish scram recovery conditions. Rather, steam generator inventory provided by normal feed water and the normal steam path to main condenser via the normal steam bypass control system accounted for 100% capability for post scram RCS heat removal (i.e., no loss ofcapability for performing the heat removal function). Would this event count as a scram with loss of normal heat removal?

Response No. The indicator counts events in which the normal heat removal path through the main condenser is not available and is not easily recoverable from the control room without the need for diagnosis or repair. In this event, the main feedwater system could have easily been returned to service at any time if needed.

Posting Date 10/01/2000 ***ID*** 196 ***Archive Date*** 7/1/2001

Topic

Question FAQ 196 has been withdrawn and replaced by FAQ 204.

Response

Posting Date 05/24/2000 ***ID*** 180 ***Archive Date*** 7/1/2001

Topic

Question We have two normal methods for removing decay heat. One method uses the main steam system through the condenser steam dumps into the main condenser. This system is normally aligned during power operations to automatically regulate Reactor Coolant temperature, and will control temperature following a reactor scram without operator action. The second system uses atmospheric steam dumps, which are also normally in automatic to control steam generator pressure. This second method will regulate reactor coolant temperature by controlling steam generator pressure with no operator action. As a backup to both of these, we have installed code safety valves on each steam generator.NEI 99-02 states, for scrams with a loss of normal heat removal, that the purpose of the indicator is to monitor "that subset of unplanned and planned automatic and manual scrams that necessitate the use of mitigating systems and are therefore more risk-significant than uncomplicated scrams." Since both of the methods described above are capable of automatically removing decay heat following a scram, should we count only those scrams in which we lose both the condenser steam dumps and the atmospheric steam dumps and their associated feed methods?

Response For consistency throughout the industry, the indicator counts the number of scrams in which the normal heat removal path through the main condenser is lost prior to establishing reactor conditions that allow use of the plant's normal long term heat removal systems. A loss of normal heat removal path through the main condenser, necessitating the use of atmospheric steam dumps or code safety valves would be counted. The Clarifying Notes do however allow the exception of intentional operator actions to control reactor cooldown rate.

Posting Date 01/07/2000 ***ID*** 65 ***Archive Date*** 7/1/2001

Topic Scrams with a Loss of Normal Heat Removal

Question Does the Scrams with a Loss of Normal Heat Removal PI include main condenser perturbations that result in scrams. For example, if a scram occurs due to a partial or total loss of main feedwater and then, as expected, main feedwater is isolated as part of the plant design following the scram, does this count as a Scram with a Loss of Normal Heat Removal. Similarly, do scrams that occur due to a partial loss of condenser vacuum affect this PI.

Response The PI is monitoring the use of alternate means of decay heat removal following a scram. Therefore, the described feedwater scenario would not be included in the PI. Similarly, a partial loss of condenser vacuum that results in a scram yet provides adequate decay heat removal following the scram would not be included in the PI.

Posting Date 11/11/1999 **ID** 4 **Archive Date** 7/1/2001

Topic Scrams with a Loss of Normal Heat Removal

Question The NEI 99-02 instructions for Scrams With Loss of Normal Heat Removal (LONHR) equate LONHR with "loss of main feedwater." At some plants the feedwater pumps trip on high reactor water level, which normally occurs on most scrams. To prevent the feedwater pumps from tripping on a scram, the operator has to quickly take manual control of level. Since the operators often have more important concerns during a scram (e.g., trying to figure out what happened, verifying all the rods are in, etc.) they have been instructed (correctly) to let the pumps trip. When this occurs steam continues to flow to the condenser and make up to the reactor is accomplished using other means (e.g., CRD pumps). Does this count as a hit against the LONHR indicator?

Response In this instance, because the system actions and operator response for this plant are normal expected actions following a scram, this would not count against the LONHR indicator.

Posting Date 07/12/2001 **ID** 277 **Archive Date** 1/1/2002

Topic

Question In February 2000, a leak was identified in main generator hydrogen cooler No. 34. At that time the leak rate was considered low enough for continued plant operation in accordance with Main Generator Gas System Operating Procedure (SOP-TG-001). Development of an Action Plan and outage schedule was initiated, daily trending of the hydrogen leakage rate was initiated, and plans for repair formulated. By the end of February 2000, an outage schedule was developed, Work Requests planned, material identified and orders placed. The schedule and work package was set aside for use if it became necessary to effect repairs prior to Refueling Outage 11 (scheduled for April 2001). In October 2000, the hydrogen leak rate increased (exceeded approximately 500 cu ft per day) and in accordance with the procedure additional monitoring via a special log was initiated. The approved Action Plan recommended that hydrogen coolers No. 33 and 34 be replaced with available spares. The leak continued to increase and after a maintenance shutdown October 25, the leakage increased to 843 cu ft per day by November 1. By the beginning of December the leak had increased to approximately 1200 cu ft per day and on December 18, the hydrogen leak rate increased to 2054 cu-ft per day. After assessing the condition, plant management decided to shut down the plant and perform the repairs as detailed in the outage schedule based on holiday resource scheduling. On December 19, the plant was shut down prior to reaching the procedural limitation of 4000 cu-ft per day which would have required an operability determination. This limitation is also less than the leakage specification specified by the vendor for continued operation. The 4000 cu-ft per day was considered a threshold for re-evaluation of the condition as required by the procedure. Repairs made and the unit returned to service close to the original outage schedule. This forced outage was evaluated for determining if it was applicable under the classification rules for an unplanned outage. In accordance with the guidelines of NEI-99-02, if the outage was planned more than 72 hours in advance, the outage could be classified as planned. Since the off-normal condition (leak) was identified in February and planning developed, although not all details completed, the shutdown met the criteria of identifying and planning 72 hours prior to the shutdown, and it was classified as a "planned" shutdown. The additional clarification in NEI-99-02, under FAQ No. 6 reinforced that determination. The shutdown was planned and per the examples in NEI-99-02, the time period between discovery of the off-normal condition exceeded 72 hours allowing assessment of plant conditions, preparation and review in anticipation of an orderly power reduction and shutdown. Does this event qualify as a unplanned shutdown?

Response No, the degraded condition was identified in February 2000, and an Action Plan was developed to address the condition, including a outage schedule, Work Request, material identification and procurement. Therefore, the degraded condition was identified and planning had been performed more than 72 hours prior to the initiation of plant shutdown. 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. The December leak rate did not exceed procedural limits requiring assessment of operability and plant shutdown and did not require a rapid response.

Posting Date 05/31/2001 **ID** 274 **Archive Date** 1/1/2002

Topic

Question Appendix D: Diablo Canyon<p>The response to PI FAQ #158 states "Anticipatory 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."<p>Due to its location on the Pacific coast, Diablo Canyon is subject to kelp/debris intrusion at the circulating water intake structure under extreme storm conditions. If the rate of debris intrusion is sufficiently high, the traveling screens at the intake of the main condenser circulating water pumps (CWPs) become overwhelmed. This results in high differential pressure across the screens and necessitates a shutdown of the affected CWP(s) to prevent damage to the screens.To minimize the challenge to the plant should a shutdown of the CWP(s) be necessary in order to protect the circulating water screens, the following operating strategy has been adopted:·<p>-- If a storm of sufficient intensity is predicted, reactor power is procedurally curtailed to 50% in anticipation of the potential need to shut down one of the two operating CWPs. Although the plant could remain at 100% power, this anticipatory action is taken to avoid a reactor trip in the event that intake conditions necessitate securing a CWP. One CWP is fully capable of supporting plant operation at 50% power.·<p>-- If one CWP must be secured based on adverse traveling screen/condenser differential pressure, the procedure directs operators to immediately reduce power to less than 25% in anticipation of the potential need to secure the remaining CWP. Although plant operation at 50% power could continue indefinitely with one CWP, this anticipatory action is taken to avoid a reactor trip in the event that intake conditions necessitate securing the remaining CWP. Reactor shutdown below 25% power is within the capability of the control rods, being driven in at the maximum rate, in conjunction with operation of the atmospheric dump valves. <p>-- Should traveling screen differential pressure remain high and cavitation of the remaining CWP is imminent/occurring, the CWP is shutdown and a controlled reactor shutdown is initiated. Based on anticipatory actions taken as described above, it is expected that a reactor trip would be avoided under these circumstances.<p>How should each of the above power reductions (i.e., 100% to 50%, 50% to 25%, and 25% to reactor shutdown) count under the Unplanned Power Changes PI?

Response Anticipatory power reductions, from 100% to 50% and from 50% to less than 25%, that result from high swells and ocean debris are proceduralized and cannot be predicted 72 hours in advance. Neither of these anticipatory power reductions would count under the Unplanned Power Changes PI. However, a power shutdown from less than 25% that is initiated on loss of the main condenser (i.e., shutdown of the only running CWP) would count as an unplanned power change since such a reduction is forced and can therefore not be considered anticipatory.

Posting Date 05/31/2001 **ID** 270 **Archive Date** 1/1/2002

Topic

Question If a plant chooses to correct a deficiency less than 72 hours following discovery (a steam leak or other condition) and reduces plant power to limit radiation exposure (ALARA) and this reduction in power (>20%) is <u>not</u> required by the license bases would this reduction be counted?

Response If the ALARA program determines that a power reduction of >20% is appropriate to conduct the maintenance/ repair, and the downpower is conducted in less than 72 hours from discovery, the downpower would count.

Posting Date 01/10/2001 **ID** 244 **Archive Date** 7/1/2001

Topic

Question FAQ 6 describes a situation where degraded equipment conditions are monitored and plans are made for repairs. The monitoring continues beyond 72 hours from the problem identification until an administratively established limit is achieved. FAQ 6 indicates this would not be counted in the unplanned power change indicator.<p>Similarly we have a situation of known potential degradation, however, it involves multiple equipment components. Specifically cooling tower components that may require power reductions of >20% power to repair the degraded condition(s). There is a monitoring program established that identifies off-normal conditions as well as establishing administrative limits for the components at which time a plant shutdown should be initiated. If the time period between discovery of an off-normal condition (identification of specific degraded component) and the power reduction exceeds 72 hours until the administratively established limit is reached, does this count as an unplanned power change

Response No. Provided the time period between the discovery of an off-normal condition of the specific component (that would require a power reduction upon reaching the administrative limits) and the power reduction exceeds 72 hours for each degradation occurrence.

Posting Date 01/10/2001 **ID** 237 **Archive Date** 7/1/2001

Topic

Question You have a slow leak on a feedwater pump and a work request is initiated and placed on the 12 week schedule, then after 72 hours passes the leakage increases, but the work package is still applicable. You immediately decrease power to fix the pump. Is this considered an unplanned power change since you had a work package written and there was greater than 72 hours?

Response The event would count as an Unplanned Power Change. Power changes caused by or in response to off-normal events during the course of a pre-planned activity, count as unplanned power changes when a determination is made that the off-normal events necessitated a course of action that was outside contingency planning in place for the pre-planned activities. In these instances, the off-normal events cause, in effect, an exiting of the preplanned course of action and any power changes that occur following the exit of the plan are counted toward the performance indicator. Minor modifications to a planned activity in response to events are not considered unplanned power changes and are not counted toward the performance indicator.

Posting Date 10/31/2000 ***ID*** 231 ***Archive Date*** 7/1/2001

Topic

Question This FAQ raises a question regarding the proper interpretation of the wording of this PI. NEI 99-02 states the purpose of this PI as: “This indicator monitors the number of unplanned power changes (excluding scrams) that could have, under other plant conditions, challenged safety functions.” Our plant planned a sequence of power changes and equipment manipulations to deal with a secondary chemistry problem. The plan was ready >72 hours in advance, and a written schedule existed. During execution of the plan, an additional equipment problem was discovered, but plant management chose to continue with the planned sequence of power changes, and to address the emergent equipment issue later in the planned outage. Had it occurred by itself, the equipment problem may have required a power change in excess of 20%. However, the problem did not cause departure from the already planned and scheduled activities, and did not cause urgent response from Operations staff to mitigate the equipment problem. There were no reactor safety implications. Consistent with the intent of the PI, we believe this event should not be counted against this PI. <p>However, part of the PI definition on page 18 of NEI 99-02 states that “Unplanned changes in reactor power are changes in reactor power that are initiated in 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% full power to resolve.” This wording could be viewed in two ways:<p>* This was a newly emergent off-normal condition that, by procedure, would have “required” the plant to reduce power if the condition were not fixed, it should be counted whether or not the power reduction was already planned and scheduled.<p>Or<p>* The emergent condition was not what initially caused the planned reduction in power, but was simply a secondary reason to proceed with the existing plan, the condition did not “result in” a change in power level greater than 20%.<p>Should the sequence of power changes be counted as an unplanned power change?

Response No. This sequence of power changes would not count.

Posting Date 10/31/2000 ***ID*** 228 ***Archive Date*** 7/1/2001

Topic

Question The licensee reduced power on both units to support grid stability in response to a fault on off?site transmission line 15616. Each of the licensee’s two operating units are supplied from two 345 kilovolt (kV) lines. Line 15616, which supplies Unit 1 , was lost as a result of a static line failure. The power reduction was requested by the system load dispatcher in accordance with System Planning Operating Guide (SPOG) 1-3-F-1, “Station Operating Guidelines,” Revision 1, to allow disabling the Unit 1 turbine generator trip scheme while line 15616 was out of service. With line 15616 out of service, a fault on the second line supplying Unit 1 (line 15501 from) would cause a Unit 1 turbine trip. The turbine trip would then cause a reactor trip (if reactor power is greater than the P?8 interlock setpoint of 32.1%). The turbine trip is intended to prevent overloading remaining grid circuits, causing the grid to become unstable. It is not a Reactor Protection System function. Reducing power and disabling the Unit 1 turbine trip scheme would prevent Unit 1 from tripping if line 15501 was faulted or lost. There were no on?site problems associated with the loss of the transmission line. The first paragraph of SPOG 1?3?F?1 states that “it is not necessary to take any corrective measures for stability for the outage of any single line provided that the protection system is normal. However, it may be desirable to disable the unit trip scheme(s) during single line outages.” The power reductions requested by the load dispatcher (just over 20%) met the procedurally recommended output limitations for the station with line 15616 out of service with the stability trip scheme disabled.<p>Does this situation count?

Response No. In the situation described, the power reduction would not count. The exception from counting unplanned power changes when directed by the load dispatcher is intended to exclude power changes directed by the load dispatcher under normal operating conditions due to load demand and economic reasons, and for grid stability or nuclear plant safety concerns arising from external events outside the control of the nuclear unit. However, power reductions due to equipment failures that are under the control of the nuclear unit are included in this indicator.

Posting Date 10/31/2000 **ID** 227 **Archive Date** 7/1/2001

Topic

Question Regarding the Unplanned power change PI, I have the following questions:<p>1. Is the 20% full power intended to be 20% of 100% power, or 20% of the maximum allowed power for a particular unit, say 97% [(.2)(.97)= 19%]<p>2. If an unplanned transient occurs which is greater than 20%, the operators stabilize the plant briefly and then cause a transient greater than 20% in the opposite direction, does that count as 2 hits against the PI?<p>3. For calculating the change in power, should secondary power data be used, nuclear instruments or which ever is more accurate?

Response 1. It is intended to be 20% of 100%.
<p>2. In general, yes, however the specific scenario needs to be evaluated.
<p>3. Licensees should use the power indication that is used to control the plant at the time of the transient.

Posting Date 05/02/2000 **ID** 166 **Archive Date** 7/1/2001

Topic

Question Concerning Unplanned Power Changes per 7,000 Critical Hours, does the 72 hour period apply to situations where power reductions are required to conduct expected rod pattern adjustments? A specific example involves a reactor start-up and power ascension following a scram. It is expected that the subsequent startup will probably require a rod pattern adjustment after achieving 100% power. To conduct the adjustment after achieving 100% power would require a power reduction potentially greater than 20%. If this situation occurs in less than a 72 hour period (time frame from the scram to the > 20% power reduction following return to power operation) does this count as an unplanned power change?

Response This indicator monitors changes in reactor power that are initiated following the discovery of an off-normal condition. The example described would not be counted in the unplanned power changes indicator provided the condition is expected.

Posting Date 04/01/2000 **ID** 158 **Archive Date** 7/1/2001

Topic

Question Power changes (reductions) in excess of 20%, while not routinely initiated, are not uncommon during summer hot weather conditions when conducting the standard condenser backwashing evolution for our once though, salt water cooled plant. While it is known that backwashing will be performed multiple times a week during warm weather months (and less frequently during colder months), the specific timing of any individual backwash is not predictable 72 hours in advance as the accumulation of marine debris and the growth rate of biological contaminants drives the actual initiation of each evolution. The main condenser system was specifically designed to allow periodic cleaning by backwash 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 backwash evolution. Similarly load reductions during very hot weather are sometimes necessary if condenser discharge temperatures approach our NPDES Permit limit. Actual initiation of a power change is not predictable 72 hours in advance as actions are not taken until temperatures actually reach predefined levels. Would power changes in excess of 20% driven by either of these causes be counted for this indicator?

Response No. If they were anticipated and planned evolutions and not reactive to the sudden discovery of off normal conditions they would not count. The circumstances of each situation are different and should be identified to the NRC so that a determination can be made concerning whether a power change is counted.

Posting Date 04/01/2000 **ID** 157 **Archive Date** 7/1/2001

Topic

Question Power was reduced on three consecutive days for condenser cleaning, in accordance with established contingency plans for zebra mussel fouling of the main condenser. Should these power reductions count as unplanned power changes, since the 72-hour planning window discussed in NEI 99-02 was not met for each individual reduction?

Response See response for FAQ 158.

Posting Date 04/01/2000 **ID** 156 **Archive Date** 7/1/2001

Topic

Question For a situation where an unplanned runback (greater than 20%) is properly terminated by a trip (since the runback was unable to reduce power rapidly enough), should the event be counted as both an Unplanned Power Change and an Unplanned Scram?

Response No.

Posting Date 11/11/1999 **ID** 6 **Archive Date** 7/1/2001

Topic Unplanned Power Changes

Question Relative to power reductions greater than 20%, the difference between planned versus unplanned maintenance seems to be the 72 hour timeframe. In that context, we may have a situation whereby a main steam relief valve tailpipe temperature sensor is indicating a leak. The temperature is monitored and plans are made for repairs. Because the valve is located inside primary containment (inerted with nitrogen for fire protection reasons) a range of contingencies is prepared, including the replacement of the relief valve. The monitoring continues (days/weeks beyond 72 hours from problem identification) until an administratively established limit for tailpipe temperature is achieved -- at which time a plant shutdown is initiated (power reduction greater than 20%). Would this reduction be counted as an unplanned power reduction greater than 20%?

<p>A similar situation could exist for reactor coolant leakage monitoring. We have two types of leakage -- equipment leakage (identified) and floor leakage (unidentified) inside primary containment. The leakage is monitored twice per shift. At some point, indications suggest that a recirculation pump (inside containment) seal is degrading. The indications are flow to the seal and an increase in floor leakage (unidentified). Past experience and the indications conclude the floor leakage is due to recirculation pump seal degradation. Plans are made to replace or repair the seal if administratively established limits are met or exceeded (not Tech Spec). This would require a plant shutdown. The indications are monitored. The indications continue (days/weeks beyond 72 hours from problem identification) until the administrative limit is achieved. A plant shutdown (power reduction greater than 20%). Would this be counted as an unplanned power reduction greater than 20%?

Response The cases described would not be counted in the unplanned power changes indicator. In both of the cases described, the time period between discovery of an off-normal condition (i.e., main steam relief valve leakage and possible recirculation pump seal degradation) exceeded 72 hours. This allowed for assessment of plant conditions, preparation and review in anticipation of an orderly power reduction and shutdown.

Posting Date 11/11/1999 **ID** 3 **Archive Date** 7/1/2001

Topic Unplanned Power Changes

Question Does the 20% power change rule apply to an uncontrolled excursion or are any uncontrolled excursions counted? Our specific example is:

<p>Unit 1 experienced an uncontrolled power excursion from 100% to 100.3% due to a high level feed water heater dump valve failure.

Response The performance indicator counts any unplanned changes in reactor power greater than 20% of full power. In your example, the excursion does not exceed 20% and would thus not be counted under this performance indicator.

Posting Date 11/11/1999 **ID** 2 **Archive Date** 7/1/2001

Topic Overshoot of Planned Power Reduction

Question If a licensee plans to reduce from 100% to 85% (15% reduction) but due to equipment malfunction (boron dilution) overshoots and reduces to 70%. Since 15% was already planned, is the overall transient considered (100-70 = 30% and counted as a "hit"), or is it only for transients beyond that planned (85-70 = 15% and not counted as a "hit")?

Response The Unplanned Power Changes Performance Indicator addresses changes in reactor power that are not an expected part of a planned evolution or test. In the proposed example, the unplanned portion of the power evolution resulted in a 15% change in power and would not count toward the performance indicator.

Posting Date 11/11/1999 **ID** 1 **Archive Date** 7/1/2001

Topic Preplanned Contingency Power Changes

Question If a reduction from 100% to 70% is planned, and an additional 25% must occur if the situation is worse than expected, can a licensee preplan (at the time of preplanning the 30% reduction) a "second contingency step planning" for the additional 25%.

Response The 72 hour planning period is used as a mark to indicate that necessary planning has occurred to address the proposed power change. This planning may include contingency power changes that would not be counted toward the performance indicator.

Posting Date 09/12/2001 **ID** 285 **Archive Date** 1/1/2002

Topic

Question NEI 99-02 Revision 1, Page 1, INTRODUCTION, line 22 states: "Performance indicators are used to assess licensee performance in each cornerstone." Consider the situation where a certified vendor supplied a safety related sub-component for a standby diesel generator. This sub-component was refurbished, tested and certified by the Vendor with missing parts. The missing parts eventually manifested themselves as a sub-component failure that lead to a main component operability test failure. The Vendor issued a Part 21 Notification for the condition after notified by the Licensee of the test failure. (The licensee conducted a successful post maintenance surveillance and two subsequent successful monthly surveillances before the test failure. Thus there was fault exposure and unplanned maintenance unavailability incurred.)<p>If a licensee is required to take a component out of service for evaluation and corrective actions related to a Part 21 Notification or if a Part 21 Notification is issued in response to a licensee identified condition (i.e. Report # 10CFR21-0081), should the licensee have to count the fault exposure and unplanned unavailability hours incurred?

Response Yes. The PI measures unavailability of the equipment, not responsibility for unavailability.

Posting Date 08/16/2001 **ID** 283 **Archive Date** 1/1/2002

Topic

Question (This FAQ is a replacement for FAQ 276. FAQ 276 has been withdrawn) <p>Appendix D: Susquehanna<p>Analysis has shown that when RHR is operated in the Suppression Pool Cooling (SPC) Mode, the potential for a waterhammer in the RHR piping exists for design basis accident conditions of LOCA with simultaneous LOOP. SPC is used during normal plant operation to control suppression pool temperature within Tech Spec requirements, and for quarterly Tech Spec surveillance testing. We do not enter an LCO when SPC mode is used for routine suppression pool temperature control or surveillance testing because, as stated in the FSAR, the system's response to design basis LOCA/LOOP events while in SPC configuration determined that a usage factor of 10% is acceptable. The probability of the event of concern is 6.4 E-10.If the specified design basis accident scenario occurs while the RHR system is in SPC mode, there is a potential for collateral equipment damage that could subsequently affect the ability of the system to perform the safety function. If the time RHR is run in SPC mode must be counted as unavailability, then our station RHR system indicator will be forever white due to the number of hours of normal SPC run time (approximately 300 hours per year). This would tend to mask any other problems, which would not be visible until the indicator turned yellow at 5.0%. Should our station count unavailability for the time when RHR is operated in SPC mode for temperature control or surveillance testing?

Response No, as long as the plant is being operated in accordance with technical specifications and the updated FSAR.

Posting Date 05/31/2001 **ID** 272 **Archive Date** 1/1/2002

Topic

Question NEI 99-02, Revision 0, page 48, line 1 (Clarifying Notes) states:<p>"When determining fault exposure hours for the failure of an EDG to load-run following a successful start, the last successful operation or test is the previous successful load-run (not just a successful start). To be considered a successful load-run operation or test, an EDG load-run attempt must have followed a successful start and satisfied one of the following criteria:<p> a load run of any duration that resulted from a real (e.g., not a test) manual or automatic start signal<p> a load-run test that successfully satisfied the plant's load and duration test specifications<p> other operation (e.g., special tests) in which the emergency diesel generator was run for at least one hour with at least 50% of design load<p>When an EDG fails to satisfy the 12/18/24- month 24-hour duration surveillance test, the faulted hours are computed based on the last known satisfactory load test of the diesel generator as defined in the three bullets above."<p>The following sentence states:<p>"For example, if the EDG is shutdown during a surveillance test because of a failure that would prevent the EDG from satisfying the surveillance criteria, the fault exposure unavailable hours would be computed based upon the time of the last surveillance test that would have exposed the discovered fault."<p>If a 24-hour duration surveillance test revealed a failure due to a cause that pre-existed during the entire 12/18/24 month operating cycle, then it is not clear whether fault exposure should be calculated based on the guidance in the three listed criteria, or the three listed criteria are totally disregarded if the failure was not revealed until the 24-hour duration surveillance test. This is particularly unclear for a condition that could have been revealed during any test (e.g., any monthly 1-hour load-run surveillance), but actually happened during the 24-hour duration surveillance test.

Response The key to interpreting this section of the guideline is determining the cause of the surveillance failure. If the cause is known (and the time of failure cannot be ascertained) the fault exposure time would be calculated as half the time since the last test which could have revealed the failure. This could be any of the load run tests described in the section, provided it was capable of identifying the failure.

Posting Date 03/02/2001 **ID** 258 **Archive Date** 1/1/2002

Topic

Question Turkey Point's Unit 3 Emergency Diesel Generators EDGs) are air-cooled, using very large radiators (eight assemblies, each weighing 300-400 pounds) which form one end of the EDG building. After 12 years of operation the radiators began to exhibit signs of leakage, and the plant decided to replace them. Replacing all eight radiator assemblies is a labor-intensiveactivity, that requires that sections of the missile shield grating be removed, heat deflecting cowling be cut away, and support structures be built above and around the existing radiators to facilitate the fitup process. This activity could not have been completed within the standard 72 hour allowed outage time (AOT). Last year Turkey Point requested, and received, a license amendment for an extended AOT, specifically for the replacement of these radiators. NEI 99-02 allows for the exclusion of planned overhaul maintenance hours from the EAC performance indicator, but does not define overhaul maintenance. Does an activity as extensive as replacing the majority of the cooling system, for which an extended AOT was granted, qualify as overhaul maintenance?

Response In this specific case, yes, for three reasons: (1) that activity involves disassembly and reassembly of major portions of the EDG system en toto, tantamount to an overhaul; (2) the activity is infrequent, i.e., the same as the vendor's recommendation for overhaul of the engine alone (every 12 years); and (3) the NRC specifically granted an AOT extension for thisactivity supported by a quantitative analysis

Posting Date 03/02/2001 **ID** 257 **Archive Date** 1/1/2002

Topic

Question The Emergency AC Power System monitored function for the indicator is, "The ability of the emergency generators to provide AC power to the class 1E buses upon a loss of off-site power." However, on page 26 of NEI 99-02, Rev 0 under testing where simple operator action is allowed for restoration, it states "The intent of this paragraph 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." <p>For purposes of this indicator are we to assume a simultaneous loss of off-site power and also accident conditions? This may make a difference on the diesel generator response, operator restoration actions and ultimately whether or not we count unavailability during our surveillance test runs.

Response Yes, you should assume a simultaneous loss of off-site power and also accident conditions if they are specified in your design and licensing bases.

Posting Date 10/01/2000 **ID** 218 **Archive Date** 7/1/2001

Topic

Question The station UFSAR states that operator actions are required to restore the EDG room ventilation system following: 1) a fire protection system actuation 2) a HELB occurring outside of the EDG rooms. The restoration actions (manually open several sets of dampers) are directed by an operating procedure. During certain fire protection system surveillances, the EDG room ventilation system dampers are closed to the same configuration as when a HELB or fire protection system actuation occurs. No other actions are taken that would otherwise affect EDG start and load capability. The steps necessary to return the ventilation subsystem to available are specified in an operating procedure and the guidance is accessible for the personnel performing the steps. Operations personnel are briefed on the status of the DG and its room ventilation subsystem as part of the prejob briefing for the performance of the surveillance. The individual specifically involved with restoring the ventilation is briefed on the time restraints and dedicated to the testing. Since the UFSAR credits the operator actions required to restore the system to its normal operating configuration following a fire protection actuation or HELB, the actions taken to restore ventilation during testing would be similar to those credited in the UFSAR. Can the EDG be considered available during the period the room vent fan is unavailable due to the fire protection surveillances?

Response No. The situation described is more complex than the few simple operator actions that current guidance allows to be excluded. Note: This response is consistent with FAQ 150 and should be applied to data covering 2Q2000 and forward.

Posting Date 07/12/2000 **ID** 201 **Archive Date** 7/1/2001

Topic

Question (This FAQ is a replacement for FAQ 169. FAQ 169 has been withdrawn)
<p>Are Technical Specification required monthly Emergency Diesel Generator surveillance tests counted as unavailability for this PI? Actions to restore the EDGs during surveillance testing could be considered complex. However, it seems unreasonable to count these required surveillance tests as unavailability, considering the fact that the EDG is powering the Engineered Safeguards bus in parallel with the grid for the majority of the test.

Response Yes, Technical Specification required monthly Emergency Diesel Generator surveillance tests are counted as unavailability for the SSU PI unless the test configuration is automatically overridden by a valid starting signal, or the function can be promptly restored either by an operator in the control room or by a dedicated operator stationed locally for that purpose. See NEI 99-02 Revision 0, page 26, lines 31 through 40.

Posting Date 07/12/2000 **ID** 194 **Archive Date** 7/1/2001

Topic

Question Our site has two units, each of which has two trains of EAC with separate buses, for a total of four buses. There are four diesels on the site, and each diesel can be aligned to either unit, but are train specific. We are only required to have one diesel per train, for a total of 2 for the site, but PSA suggests that aligning each of the four diesels to its own bus is the preferred option. When one diesel is out for maintenance, we can align the other diesel in that train to both buses in the train, one bus in each unit. Technical Specifications do not limit the amount of time the plant can be in this configuration. SBO and Appendix R requirements do not impose any additional requirements on the number of diesels required per train nor do they add any additional requirements on the availability of a specific diesel unit.

<p>We are counting unavailability for NRC indicators as follows: If an EAC bus does not have a diesel aligned to it in standby, then hours are counted for unavailability against that train. If a diesel is aligned in test to a bus, that is also counted as unavailability for that train because we cannot immediately restore the diesel nor does the diesel automatically start and supply the bus on a loss of power. If a diesel is aligned in test to both units, then it is counted as unavailability for both units. However, when a diesel is out of service for maintenance, it is not counted as unavailability if the alternate same-train diesel is aligned in standby to both buses in that train. We consider the extra diesel in each train as a maintenance train according to the rules in the NRC/NEI 99-02 guidance. Are we correct in the interpretation of these rules?

Response Based on the information provided, your interpretation of how to count diesel unavailable hours is correct. This configuration would be reported as a two-train system.

Posting Date 07/12/2000 **ID** 169 **Archive Date** 7/1/2001

Topic

Question FAQ 169 has been withdrawn and replaced by FAQ 201.

Response .

Posting Date 05/02/2000 **ID** 171 **Archive Date** 7/1/2001

Topic

Question Do hours associated with EDG improvements (e.g., cooling improvement modifications) have to be counted as unavailable hours if done for EDG improvement and in accordance with the Tech Spec AOT(our AOT is 14 days and is partly risk informed).

Response Yes.

Posting Date 05/02/2000 **ID** 170 **Archive Date** 7/1/2001

Topic

Question We have not been counting technical specification required Emergency AC System surveillance testing as unavailability for the WANO performance indicators. The testing configuration is not automatically overridden by a valid starting signal and the function cannot be immediately restored, either by an operator in the control room or by a dedicated operator stationed locally for that purpose.Does historical data submitted Jan 21, 2000 for Emergency AC System safety system unavailability PI have to be corrected to take into account the additional unavailability?

Response No, the historical data does not have to be revised. However, data submitted for first quarter 2000 must comply with NEI 99-02.

Posting Date 04/01/2000 **ID** 151 **Archive Date** 7/1/2001

Topic

Question Section 2.2, Mitigating Systems Cornerstone, Safety System Unavailability, Clarifying Notes, Hours Train Required states the Emergency AC power system value is estimated by the number of hours in the reporting period because emergency generators are normally expected to be available for service during both plant operations and shutdown. Considering only one train of Emergency AC power systems may be required in certain operational modes (e.g. when defueled), should actual required hours be determine for each train in place of using the default period hours? In certain operational modes it appears inconsistent to use period hours for hours required, yet not report the unavailable hours if a train is removed from service and Technical Specifications are still satisfied.

Response For the situation described it is acceptable to report the default value that is period hours.

Posting Date 04/01/2000 **ID** 150 **Archive Date** 7/1/2001

Topic

Question Prior to performing surveillance testing, a Diesel Generator may be placed in an unavailable condition to allow for moisture checks. This may require opening all cylinder petcocks (test valves) and engaging the engine barring device. WANO guidance allows for not reporting unavailable hours provided the testing configuration can be quickly overridden within a few minutes by the control room or having operators stationed locally for that specific purpose. Does this condition require reporting unavailable hours to the NRC?

Response Yes. The situation described is more complex than the few simple operator actions that current guidance allows to be excluded.

Posting Date 07/12/2001 **ID** 278 **Archive Date** 1/1/2002

Topic

Question Appendix D: Prairie Island<p>At Prairie Island, the three safeguards Cooling Water (service water) pumps were declared inoperable for lack of qualified source of lineshaft bearing water. This required entry into Technical Specifications 3.0.c (motherhood). The plant requested and received a Notice of Enforcement Discretion (NOED) that allowed continued operation of both units until installation of a temporary modification to provide a qualified bearing water supply to two of the three pumps was complete (14 days). Compensatory measures were implemented to ensure continued availability of water to the lineshaft bearings.<p>The Cooling Water System is required to mitigate design basis transients and accidents, maintain safe shutdown after external events (e.g. seismic event), and maintain safe shutdown after a fire (Appendix R).The only events for which the Cooling Water System function could have been compromised are the loss of off-site power (LOOP) and a design basis earthquake (DBE). These two events are limiting because they both involve the loss of off-site power. If off-site power continues to power the non-safeguards buses, then the Cooling Water System function is not lost. <p>Our Risk Assessment determined that the initiating event frequency for a DBE during the 14 day NOED period was so low that it was not a concern. Therefore, this discussion will focus on the LOOP event. The bearing water supply was not fully qualified for LOOP because the power to the automatic backwash for strainers in the system was not safeguards. The concern was that system strainers would plug eventually. However, for this initiating event, function is not lost immediately – it takes time for the strainers to plug. The time it takes is a function of river water quality. Based on an estimate of worst-case river water quality, there are 4 to 7 hours before function would be lost (strainers plug). In fact, testing around the period of the event, showed river water quality was such that the strainers did not plug after 48 hours. Given the time available there is high probability that operators could complete recovery actions before function was lost. A specific probabilistic risk assessment of the local operator actions determined that the probability of failure was less than 1%.<p>The NOED was requested to preclude a two unit shutdown. As part of the request for the NOED, compensatory measures to assure that the Cooling Water System function is maintained were proposed. In summary, the compensatory measures were to:<p>* use a hose (pressure-rated) to connect a safety related source of Cooling Water to the lineshaft bearing supply piping for a Cooling Water Pump<p>* post a dedicated operator locally in the screenhouse near the Cooling Water Pumps<p>* pre-stage equipment and tools in the screenhouse<p>* place identification tags at the connection locations<p>* train the dedicated operator(s) on the procedure for connecting the hose.

<p>The need to implement the compensatory measures would have been identified to the Control Room operator by a loss of bearing flow alarm. As stated earlier, this condition is not expected to occur until a filter becomes plugged 4 to 7 hours after the loss of off site power. The Control Room operator would notify the dedicated operator to perform the procedure. The walkdown of the procedure determined that bearing flow could be established in less than 10 minutes. The pump is capable of operating for approximately one hour without bearing flow. When bearing flow is established, the Control Room alarm will clear, thereby giving the Control Room operator confirmation that the procedure has been performed. The procedure also required an independent verification of the bearing flow restoration within one hour of receiving the loss of bearing water flow alarm.<p>The Cooling Water System is a support system and it’s unavailability affects: High Pressure Safety Injection, Auxiliary Feedwater, Residual Heat Removal, and Unit 1 Emergency AC (Unit 2 Emergency AC is cooled independent of Cooling Water). Using NEI 99-02 criteria, Prairie Island included the time that the Cooling Water Pumps were declared inoperable, approximately 300 hours, as unplanned unavailability in our PI data report. This resulted in two White Indicators (one on each unit), two other systems (one per unit) on the Green/White threshold, and two systems (again, one per unit) close to the Green/White threshold. However, the cause for these Performance Indicators changing from Green to White is a direct result of the lack of qualified bearing water to the Cooling Water pumps. The lack of qualified bearing water was evaluated through the SDP and resulted in a White finding. A root cause evaluation was performed and corrective actions identified. Since the change in the performance Indicators from Green to White was a direct result of the unqualified bearing water, no additional corrective action is planned.<p>This event does not fit into the guidance given in NEI 99-02. In Rev. 0, page 26, the

Clarifying Notes address testing and Control Room operator actions. In Rev. 1, page 28, the Clarifying Notes only allow operator actions taken in the Control Room. We have also reviewed Catawba's FAQ 254. However, their situation addressed maintenance activity results not operator action.<p>Initially, unavailable hours were recorded from the time of discovery until completion of a Temporary Modification that provided a qualified bearing water supply. This resulted in counting approximately 300 unavailable hours per pump. Since the compensatory actions would have maintained the Cooling Water System function, should the unavailable hours be counted only from the time of discovery until the compensatory measures were in place?

Response Yes, the unavailable hours should be counted only from the time of discovery until the time that the compensatory measures were in place and remained in place. The actions required to restore the Cooling Water System function were simple and had a high probability of success. This is based upon the following factors:<p>* A probabilistic risk assessment of the local operator actions calculated less than a 1% probability of failure.<p>* There is control room alarm to alert the Control Room operator of the need for the compensatory measures.<p>* There are at least two means of communication between the Control Room and the local operator.<p>* Recovery action for each pump was simple - connect a hose to two fittings and position two valves.<p>* Time to complete the recovery action was estimated to be about 10 minutes, based on walk-throughs. Failure to successfully complete the recovery action was not expected to preclude the ability to make additional attempts at recovery.<p>* A dedicated operator was stationed in the area to complete the recovery action.<p>* The operator had a procedure and training for accomplishing the recovery action.<p>* All necessary equipment for recovery action was pre-staged and the fittings and valves were readily accessible.<p>* Indication of successful recovery actions was available locally and in the Control Room.<p>Note: This FAQ is specific to the plant and the circumstances, which included NRC approval of compensatory measures and an SDP review. Other licensees should not unilaterally apply this FAQ result, but should submit a plant specific FAQ.

Posting Date 05/31/2001 **ID** 271 **Archive Date** 1/1/2002

Topic

Question Page 4 of NEI 99-02 states: "The guidance provided in Revision 0 to NEI 99-02 is to be applied on a forward fit basis...", however there is also a provision to reset fault exposure hours (page 29) that requires 4 quarters have elapsed since discovery. If reset of fault exposure is applied to historical data submitted under the "best effort" collection method (i.e. grandfathered data previously collected under INPO 98-005 guidelines), does this constitute a backfit of the NEI 99-02 guidance? Additionally, if the reset of fault exposure hours does constitute a backfit, would the station then be required to revise all of the historical data to conform with all 99-02 requirements?

Response If the conditions have been met to reset fault exposure hours, in accordance with NEI 99-02, for fault exposure hours experienced during the historical data period, the hours can be reset without having to revise the remaining historical data to conform with all 99-02 requirements. However, because the green/white threshold was not crossed, the fault exposure hours cannot be removed.

Posting Date 05/02/2001 **ID** 265 **Archive Date** 1/1/2002

Topic

Question NEI 99-02 states "Restoration actions must be contained in a written procedure, must be uncomplicated (a single action or a few simple actions), and must not require diagnosis or repair. Credit for a dedicated local operator can be taken only if (s)he is positioned at the proper location throughout the duration of the test for the purpose of restoration of the train should a valid demand occur". Station Results and Test personnel are qualified to perform valve lineups and are in the control room and/or stationed locally during testing. Do the R&T personnel with the written test procedure meet the guidance of NEI 99-02 for being able to restore equipment to service when needed and thus not counting the testing time as planned unavailable hours?

Response Yes, provided the plant personnel are qualified and designated to perform the restoration function and are not performing any restoration steps for which they are not qualified. The Station considers the restoration steps of the test procedures to be the "written procedure" for the required "restoration actions". The qualified R&T personnel (rather than a dedicated operator) with the test procedures allow the Station to take credit for restoration actions that are virtually certain to be successful during accident conditions while performing tests and thus this time should not count towards Planned Unavailable Hours.

Posting Date 04/04/2001 **ID** 261 **Archive Date** 1/1/2002

Topic

Question Concerning removal of fault unavailable hours NEI 99-02 states: "Fault exposure hours associated with a single item may be removed after 4 quarters have elapsed from discovery""<p>In the case we are considering, the hours were discovered in the third calendar quarter. When do the four elapsed quarters begin? At the start of the fourth calendar quarter? and end at the conclusion of next year's third quarter?<p>If the period of calculation of the indicator value was only four calendar quarters beginning the quarter after they occurred, and the fault unavailable hours are reported in the quarter in which they occurred, what's the point in removing them after they are no longer a factor in the calculation of the indicator?<p>"Fault exposure hours are removed by submitting a change report that provides a revision to the reported hours for the affected quarter(s). The change report should include a comment to document this action."

Response The fault exposure hours should be reported for third quarter data and may be removed with the submittal of the next year's third quarter data provided the criteria for removing fault exposure hours are met.<p>All safety system unavailability performance indicators calculate train unavailability for 12 quarters. Therefore, the situation you describe would not exist.

Posting Date 02/08/2001 **ID** 254 **Archive Date** 7/1/2001

Topic

Question Appendix D – Catawba<p>A recently issued FAQ for the NRC Performance Indicators Program revised the positions taken for unavailability associated with planned overhaul hours. FAQ 178 was withdrawn from NEI 99-02 and replaced with FAQ 219. The new FAQ, effective for fourth quarter reporting, adds two clarifying questions and answers to the previous FAQ 178. These two additional items are:<p>Q. What is considered to be a major component for overhaul purposes? <p>A. A major component is a prime mover - a diesel engine or, for fluid systems, the pump or its motor or turbine driver or heat exchangers.<p><p>Q. Does the limitation on exemption of planned unavailable hours due to overhaul maintenance of "once per train per operating cycle" extend to support systems for a monitored system?<p>A. For this indicator, only planned overhaul maintenance of the four monitored systems (not to include support systems) may be considered for the exemption of planned unavailable hours.<p>At Catawba Nuclear Station, periodic testing indicated that crud and rust accumulation in the Nuclear Service Water System (NSWS) headers and piping was reducing water flow. To restore the water flow and the prevent further deterioration of the headers and piping, a refurbishment project was planned to clean the system, replace part of the piping, and rearrange certain piping access to the headers to avoid water stagnation. Since the NSWS is a shared system between both Catawba units, it was decided that the optimum time to perform this work would be while Unit 1 was in a refueling outage and Unit 2 was at power. This project included both "A" and "B" redundant trains of the system and was sequenced independently during the recent Catawba Nuclear Station Unit 1 End of Cycle 12 (1EOC12) refueling outage. Approximately 8,000 feet of piping was cleaned that included 4,260 feet of 42 inch, 760 feet of 30 inch, 330 feet of 24 inch, 660 feet of 18 inch, 1,935 feet of 10 inch, and 100 feet of 8 inch. Due to the extensive nature of the work performed, each train of NSWS was unavailable for approximately ten days.<p>Applicable technical specifications were revised through the standard NRC approval process (reference Amendment No. 189 to FOL NPF-35 and Amendment No. 182 to FOL NPF-52 approved October 4, 2000) to allow this project to be performed. These amendments allowed specific systems, including mitigating systems monitored under the NRC performance indicator program, to be inoperable beyond the normal technical specification allowable outage times (AOT) of 72 hours for up to a total of 288 hours on a one-time basis. A significant part of the justification for the license amendment request was a discussion of the risk assessment of the proposed change and the NRC concluded in the SER that the results and insights of the risk analysis supported the proposed temporary AOT extensions.<p>The NSWS itself is not a monitored system under the performance indicators; however, 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 contained in the Mitigating Systems Cornerstone and include: Emergency AC Power System Unavailability, High Pressure Safety Injection System Unavailability, Auxiliary Feedwater System Unavailability, and Residual Heat Removal System Unavailability. If the hours that this overhaul of the NSWS made its supported systems unavailable cannot be excluded from reporting under the performance indicators, it will result in Catawba Unit 2 reporting two white indicators for the 4Q2000 data. These two white indicators for Emergency AC Power System Unavailability and Residual Heat Removal System Unavailability would result in a degraded cornerstone situation as defined in the NRC Action Matrix. Additionally, since these indicators are twelve quarter averages, carrying these hours for the next three years would result in decreased margin to the white/yellow threshold and greatly increase the consequences of additional unavailable hours that might occur during that period of time.<p>Based on input from NRC and NEI individuals who participated in discussions related to FAQ 219, Duke Energy understands that there was a desire to eliminate exclusion of monitored systems unavailable hours caused by minor "overhaul" type activities on supporting systems. However, it seems unreasonable to require reporting of unavailable hours for situations such as this when the overhaul activities are extensive enough to have required NRC review and approval of a change in technical specifications to allow the increased AOT.<p>Should this situation be counted?

Response For this plant specific situation, the planned overhaul hours for the nuclear service water support system may be excluded from the computation of monitored system unavailabilities. <p> 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 02/08/2001 **ID** 252 **Archive Date** 7/1/2001

Topic

Question How should "t over 2" Fault Exposure time be counted for an installed spare?

Response If a failure is discovered in equipment that is or has been credited as an installed spare, the appropriate way to estimate fault exposure hours is to count from the date of failure back to one half the time since the last successful operation and include only those hours during that period when the equipment was required to be available.

Posting Date 02/08/2001 **ID** 247 **Archive Date** 7/1/2001

Topic

Question NEI 99-02 Revision 0 defines criteria for determining availability during surveillance testing. This definition can be found on page 26. It allows operator action to be credited for the declaration of availability. NEI 99-02 also defines criteria for determining fault exposure. This definition can be found on pages 28 & 29. Line 5, page 29 references operator action. It states, "Malfunctions or operating errors that do not prevent a train from being restored to normal operation within 10 minutes, from the control room, and that do not require corrective maintenance, or a significant problem diagnosis, are not counted as failures." In addition, page 29, line 13, states, "A train is available if it is capable of performing its safety function."<p>If the fault can be corrected quickly (much less than 10 minutes) by a single operator action that is contained in a written procedure, is uncomplicated, and does not require diagnosis or repair, but the operator action cannot be shown to satisfy auto-start time design assumptions (e.g., HPCI injection within 45 seconds), should fault exposure hours be assigned to a failure?

Response Operator actions to recover from an equipment malfunction or an operating error can be credited if the function can be promptly restored from the control room by a qualified operator taking an uncomplicated action (a single action or a few simple actions) without diagnosis or repair (i.e., the restoration actions are virtually certain to be successful during accident conditions). (Note that under stressful, chaotic conditions, otherwise simple multiple actions may not be accomplished with the virtual certainty called for by the guidance. For example, some manual operations of systems designed to operate automatically, such as manual control of the HPCI turbine to establish and control injection flow, are not virtually certain to be successful.) NEI 99-02 will be revised to reflect this FAQ response.

Posting Date 01/10/2001 ***ID*** 241 ***Archive Date*** 7/1/2001

Topic

Question NEI 99-02 Revision 0, states the following regarding Planned Unavailable Hours:<p>"Testing, unless the test configuration is automatically overridden by a valid staring signal or the function can be promptly restored either by an operator in the control room or a dedicated operator stationed locally for that purpose. Restoration actions must be contained in a written procedure, must be uncomplicated (a simple action or a few simple actions) and must not require diagnosis or repair. Credit for a dedicated operator can be taken only if (s)he is positioned at the proper location throughout the duration of the test for the purpose of restoration of the train should a valid demand occur. The intent of this paragraph is to allow licensees to take credit for restoration action that are virtually certain to be successful (i.e. probability nearly equal to 1) during accident conditions."<p>The question is whether normal surveillance test restoration steps (normally used to re-align the system after the surveillance testing is complete) are adequate to satisfy the requirements for a "written procedure."<p>Example: The Low Pressure Injection (LPI) surveillance procedure (SP) has the LPI pump discharge aligned to the "recirculation line" and flowing to the Borated Water Storage Tank. Closing one motor operated valve (MOV), if an accident were to take place, would isolate this flow path. The MOV would be closed from the control room. The restoration actions for the SP have closure of this valve as part of the normal plant restoration. In this case, CR-3 engineering personnel believe that the restoration instructions in the surveillance procedure are adequate to meet the intent of a "written procedure" identified in the above paragraph from NEI 99-02.

Response Yes, normal surveillance test restoration steps are adequate to satisfy the requirements for a “written procedure.” A separate restoration procedure need not be prepared.

Posting Date 01/10/2001 ***ID*** 239 ***Archive Date*** 7/1/2001

Topic

Question This FAQ is a replacement for FAQ 190. FAQ 190 has been withdrawn.<p>The guidance in NEI 99-02 states that fault exposure hours may be removed after certain criteria are met. One criterion is that supplemental inspection activities by the NRC have been completed and all open items have been closed out. If a licensee has fault exposure hours that meet all other stated criteria (>336 hours, corrective actions completed, and four quarters have elapsed) but the indicator is still green, does the baseline inspection count in place of the supplemental inspection? Also, please clarify the intent of the phrase “after 4 quarters have elapsed from discovery.”

Response 1. No. Fault exposure hours may be removed only if the indicator is outside the green band so that supplemental inspection is necessary (and all other stated criteria are met). The intent of this provision was to allow the removal a large number of fault exposure hours due to a single event or condition so that a licensee would not be outside the green band for an extended time period. There are two reasons for this: (1) after the stated criteria are met, the PI is no longer considered to be indicative of current performance; and (2) unavailable hours accumulated later would put the licensee further into the white band but would not trigger any further NRC action, since the white band is 1.5 to 2 times as wide as the green band. For these reasons, the hours may be removed to reset the indicator so that further fault exposure hours could trigger further NRC response. <p>2. The intent of the phrase “after 4 quarters have elapsed from discovery” was that the indicator would be non-green for 4 quarters minimum, regardless of when the corrective actions were completed and the supplemental inspection closed out. The quarter in which the fault exposure hours is identified would be the first non-white quarter, and 12 months (four quarters) later, assuming all required conditions are met, the hours could be removed from the calculation for that quarter.

Posting Date 01/10/2001 **ID** 190 **Archive Date** 7/1/2001

Topic

Question FAQ 190 has been withdrawn and replaced by FAQ 239.

Response

Posting Date 10/31/2000 **ID** 224 **Archive Date** 7/1/2001

Topic

Question Our Standby Service Water System (SSW) is designated as a Support System for each of the four mitigating systems. The system has two trains and each train has two 50% capacity pumps. At the mitigating system interface, the SSW support system either has both trains of SSW supplied to the cooling load or one SSW train exclusively supplying the cooling load. A train with one pump in service will supply the required SSW loads except the RHR train. The RHR train is normally valved out of service and is manually lined up to support a design basis accident condition some time after the automatic initiation sequence is completed. We consider all mitigating systems within a train, except RHR in that train, available with one SSW pump out of service. However, RHR, with the SSW from the other train available, is considered available. Have we calculated the availability correctly?

Response Yes. The mitigating systems that can be supplied by a single SSW train with one SSW pump in service are available.

Posting Date 10/01/2000 **ID** 219 **Archive Date** 7/1/2001

Topic

Question (This FAQ is a replacement for FAQ 178. FAQ 178 has been withdrawn)
<p>FAQ on Planned Overhaul Hours
<p>The concept of not counting major on-line overhaul hours against the SSU performance indicator is sound. It allays a prevalent concern that a licensee could end up with a white indicator, and potentially a degraded cornerstone, primarily due to performing on-line maintenance that is considered in PSA analyses and bounded by the Tech. Spec. AOT, and has been determined to be a good business practice [to reduce outage length, etc.]. To ensure consistency of reporting and inspector oversight, the following issues should be addressed:

<p>1. What defines overhaul versus non-overhaul maintenance?
<p>2. What is considered to be a major component for overhaul purposes?
<p>3. Is application of planned overhaul hours limited to systems for which a risk informed AOT extension has been approved?
<p>4. Is there a limit to the number of planned overhaul outages a licensee can report on a given system / train?
<p>5. Can an overhaul be performed in two segments in separate AOTs during an operating cycle?
<p>6. If an overhaul maintenance interval is scheduled to take 120 hours, but the actual unavailable interval is greater [say 140 hours] but still bounded by T.S. AOT, can the entire interval be designated as planned overhaul hours, or is only the scheduled interval appropriate?
<p>7. Can additional non-overhaul maintenance be performed during a planned overhaul maintenance interval?
<p>8. Can Major rebuild tasks necessitated by an unexpected component failure be counted as overhaul maintenance? [Example: RHR pump wipes a motor bearing during surveillance run. It is decided to pull PM activities ahead to replace the motor with a spare.]

<p>9. Does the limitation on exemption of planned unavailable hours due to overhaul maintenance of “once per train per operating cycle” extend to support systems for a monitored system?

Response 1. NOTE: This answer applies to how unavailable hours are counted for PI purposes. It does not establish or recommend any changes in regulatory requirements or licensee maintenance actions. This FAQ is a clarification and applies to data submittals covering 4Q2000 data and beyond.Overhaul maintenance comprises those activities that are undertaken voluntarily and performed in accordance with an established preventive maintenance program to improve equipment reliability and availability. Overhauls include disassembly of major components and may include replacement of parts as necessary, cleaning, adjustment, lubrication as necessary, and reassembly.
<p>2. A major component is a prime mover - a diesel engine or, for fluid systems, the pump or its motor or turbine driver or heat exchangers.
<p>3. No. Any AOT sufficient to accommodate the overhaul hours may be considered. However, to qualify for the exemption of unavailable hours, licensees must have in place a quantitative risk assessment. This assessment must demonstrate that the planned configuration meets either the requirements for a risk-informed TS change described in Regulatory Guide 1.177, or the requirements for normal work controls described in NUMARC 93-01, Section 11.3.7.2. In addition, all other requirements described in the response to this FAQ must be met. Otherwise the unavailable hours must be counted. The Safety System Unavailability indicator excludes maintenance-out-of-service hours on a train that is not required to be operable per technical specifications (TS). This normally occurs during reactor shutdowns. Online maintenance hours for systems that do not have installed spare trains would normally be included in the indicator. However, some licensees have been granted extensions of certain TS allowed outage times (AOTs) to perform online maintenance activities that have, in the past, been performed while shut down. Acceptance guidelines for such TS changes are given in Sections 2.2.4 and 2.2.5 of Regulatory Guide 1.174 and Section 2.4 of Regulatory Guide 1.177. These guidelines include demonstration that the change has only a small quantitative impact on plant risk (less than 5x10-7 incremental conditional core damage probability). It is appropriate and equitable, for licensees who have demonstrated that the increased risk to the plant is small, to exclude unavailable hours for those activities for which the extended AOTs were granted. However, in keeping with the NRC’s increased emphasis on risk-informed regulation, it is not appropriate to exclude unavailable hours for licensees who have not demonstrated that the increase in risk is small. In addition, 10 CFR 50.65(a)(4), which goes into effect on November 28, 2000, requires licensees to assess and manage the increase in risk that may result from proposed maintenance activities. Guidance on a quantitative approach to assess the risk impact of maintenance activities is contained in the latest revision of Section 11.3.7.2 (dated February 22, 2000) of NUMARC 93-01, Revision 2. That section allows the use of normal work controls for plant configurations in which the incremental core damage probability is less than 10-6. Licensees must demonstrate that their proposed action complies with either the requirements for a risk-informed TS change or the requirements for normal work controls described in NUMARC 93-01.
<p>4. Yes. Once per train per operating cycle.
<p>5. Yes, provided that no more than two segments be used and the total time to perform the overhaul does not exceed one AOT period.
<p>6. If the unavailability is caused by activities designated as planned overhaul maintenance, the hours should not be counted in the unavailability indicator. If the additional unavailability is caused by a failure that would prevent the fulfillment of a safety function, the additional hours would be non-overhaul hours and/or potential fault exposure hours, and would count toward the indicator. (Also, see footnote 3 page 26 Rev 0.)
<p>7. Yes, as long as the outage duration is bounded by overhaul activities, other activities may be performed. If the overhaul activities are complete, and the outage continues due to non-overhaul activities, the additional hours would be non-overhaul hours and would count toward the indicator.
<p>8. No.
<p>9. For this indicator, only planned overhaul maintenance of the four monitored systems (not to include support systems) may be considered for the exemption of planned unavailable hours.

Posting Date 10/01/2000 **ID** 178 **Archive Date** 7/1/2001

Topic

Question FAQ 178 has been withdrawn and replaced by FAQ 219.

Response

Posting Date 07/12/2000 **ID** 199 **Archive Date** 7/1/2001

Topic

Question SSES has 5 diesel generators, 4 are required to support operation of both units and the fifth is an installed spare capable of substituting for any one of the other 4. We perform diesel generator overhauls with the units on line by swapping in the spare for the overhauled diesel to maintain the required number of 4. No unavailable time is charged during the overhaul. However, following the overhaul we perform post maintenance testing and are in a 72-hour LCO until the overhauled diesel is declared operable. We have previously counted this post maintenance testing time as unavailable.

<p>In light of the new FAQ's approved on 5/24...particularly as FAQ 178 on Planned Overhaul hours would apply to our unique design...is it the intent of this PI to include the post maintenance testing time following a planned overhaul as unavailable hours?

Response Not if the diesel passes the test and the requirements of the paragraph that starts on line 31 of page 26 of NEI 99-02 are met. If the diesel fails the test, the entire test time would be counted as unavailable time, or any portions of the test that do not meet the requirements of the cited paragraph would be counted as unavailable time.

Posting Date 06/14/2000 **ID** 192 **Archive Date** 7/1/2001

Topic

Question Does the response to FAQ #88 mean that engineering judgement is equivalent to and can be used in lieu of component failure analysis, circuit analysis, or event investigation?

Response The intent of the use of the term "with certainty" is to ensure that an appropriate analysis and review to determine the time of failure is completed, documented in your corrective action program, and reviewed by management. The use of component failure analysis, circuit analysis, or event investigations are acceptable. Engineering judgement may be used in conjuction with analytical techniques to determine the time of failure.

Posting Date 06/14/2000 **ID** 191 **Archive Date** 7/1/2001

Topic

Question Our station has several areas containing a variety of safety system components from multiple safety systems and both trains (motor operated valves, instrumentation, pumps, etc.). Examples are the auxiliary building general area, pipe chases, penetration rooms, etc. These general areas are cooled by what we refer to as "area coolers" and there is an A train and a B train cooler for each area, both fed from opposite divisions of class 1E power and separate trains of cooling water. Additionally, these fans have 100% capacity (each) to maintain the required temperature for the area; i.e., these could be viewed as installed spares. As far as support systems to the fan, with one train of area cooling out of service, it would require a loss of 2 off-site power supplies coincident with the specific train of diesel generator power and cooling to render the remaining train of area cooling unavailable.

<p>Based on the guidelines given in NEI 99-02, R0, section 2.2, "Support System Unavailability", we interpret this to mean that if we remove one train of area cooling, it would not constitute any safety system unavailability.

<p>Is this a correct interpretation?

Response Yes. In this case, as described above, the removal of one train of area cooling would not constitute safety system unavailability if the other fan maintains environmental conditions. See NEI 99-02, page 33, lines 25 through 28.

Posting Date 06/14/2000 **ID** 187 **Archive Date** 7/1/2001

Topic

Question Under "Support System Unavailability" of NEI-99-02 the statement is made that: "for monitored fluid systems with components cooled by a support system, where both the monitored and support system pumps are powered by a class 1E (i.e. safety grade or equivalent) electric power source, cooling water supplied by a pump powered by a normal (non-class 1E--i.e., non-safety-grade) electric power source may be substituted for cooling water supplied by a class 1E electric power source, provided that redundancy requirements to accommodate single failure criteria for electric power and cooling water are met. Specifically, unavailable hours must be reported when both trains of a monitored system are being cooled by water supplied by a single cooling water pump or by cooling water pumps powered by a single class 1E power (safety-grade) source". We are defining our system boundary for the reported system to include the breaker/ switchgear providing power to the reported system's pumps/valves, etc. The main switchgear/breakers are installed in the safety switchgear panels that are cooled by a common area cooling system. This cooling system is safety grade, as cooling is required following a design basis accident from a safety grade source. The cooling system has two fan coil units, using safety chilled water in each coil, a train A (&powered by train A 1E power) and a train B unit (powered by safety grade train B 1E power). Therefore cooling for the portions of the reported systems installed in the safety Switchgear panel is provided by redundant, class 1E powered, safety grade unit coolers (train A and B).

<p>The coolers discharge to a common plenum, which in turn cools the separate switchgear rooms. Each cooler (train A and B) has 100% capacity for cooling all (train A, B, and AB) switchgear. At our site there are currently no technical specification associated with these coolers, although we have imposed a 72 hour limitation for removing one cooler (in either train) from service in our technical requirements manual (TRM), as well as a one hour shutdown action statement if both coolers (trains) are inoperable. However, since no technical specifications exist, we do not cascade inoperability or unavailability of the unit coolers into the switchgear themselves, one reason being since the cooling duct system is common to all switchgear it is impractical to cascade. In light of the above quoted statement in the NEI document, are we required to report unavailability hours in one or more trains of the reported systems, cascaded from removal of one train of the switchgear cooling system from service (i.e. removal of one of the two, redundant, fan coil units from service).

Response No. In this case, as described above, the removal of one train of area cooling would not constitute safety system unavailability if the other fan maintains environmental conditions. See NEI 99-02, page 33, lines 25 through 28.

Posting Date 05/24/2000 **ID** 181 **Archive Date** 7/1/2001

Topic

Question Can Improved Technical Specification criteria be used to reevaluate system unavailability incurred in prior years under the previous technical specifications?<p>If the actual plant conditions at that time met the requirements of the current Improved Technical Specifications, can credit for functionality be taken for that past period?

Response No. The conditions and requirements in place at the time should be used to determine system unavailability.

Posting Date 05/24/2000 **ID** 179 **Archive Date** 7/1/2001

Topic

Question NEI 99-02 allows historical data submitted data to be revised to reflect current guidance if desired.

Draft D of NEI 99-02 allowed the submittal of WANO data as reported to WANO. Can major overhaul maintenance unavailable hours be removed from the historical data submitted without additional modifications to the WANO data? Or do other aspects of Revision 0 that are different from WANO reporting have to be considered concurrent with removal of the major overhaul maintenance unavailable hours? For example, in the EAC PI, if it was desired to remove from previously submitted data the overhaul maintenance unavailable hours per revision 0 would I also need to research and modify (if necessary) the historical data to account for limitations of operator action usage that are expected in NRC PI reporting, yet different from WANO reporting?

Response Revision 0 of NEI 99-02 may be used on a PI by PI basis for data submitted prior to 2Q2000 provided that a best effort is made to apply all the guidance in Revision 0 that applies to the PI. For the example stated in the question, the overhaul hours may be removed provided other guidance in NEI 99-02 Revision 0 related to fault exposure, credit for operator actions, etc. is also applied on a best effort basis.

Posting Date 05/02/2000 ***ID*** 175 ***Archive Date*** 7/1/2001

Topic

Question NEI 99-02 describes the requirements for including testing as planned unavailable hours for safety system unavailability. In this, credit is allowed for a dedicated local operator only if they are positioned at the proper location throughout the duration of the test for the purpose of restoration of the train should a valid demand occur. If the operator dedicated to conducting the test is in the proper location, and has no other duties other than to conduct the test and to restore from the test in the event of a valid demand, then does that operator meet the requirements of this paragraph, or does an additional operator need to be stationed for the sole purpose of restoration. Note that the operator conducting the test has no other duties when a valid demand is received than to restore the system, and the written guidance for restoration is embedded in the test procedure and in his possession during the testing.

Response The operator performing the test meets the requirements, provided the additional conditions for exclusion of testing hours, identified on page 26 of NEI 99-02, are met.

Posting Date 05/02/2000 ***ID*** 168 ***Archive Date*** 7/1/2001

Topic

Question Assume a recirculation spray pump tested poorly and had only previously been tested 2 years ago. Per the NEI 99-02 FAQ I believe I am to go back and revise the fault exposure hours for these quarters. Should I zero out any other unavailability for those months, since the accumulation of unavailability could be greater than the hours required?

Response Remove the double count by removing the planned and unplanned hours which overlap with the fault exposure hours. Put an explanation in the comment field. If you later remove the fault exposure hours, restore the hours which had been removed.

Posting Date 05/02/2000 ***ID*** 167 ***Archive Date*** 7/1/2001

Topic

Question Does planned preventive maintenance (PM) or corrective maintenance (CM) on support systems have to be taken as Planned Unavailable Hours for the supported system? Page 22, lines 9 - 33 infers that any PM or CM must be credited as Planned Unavailable hours.

<p>One example is a site where there are four EDGs. Each EDG has two approximate 50% fuel oil tanks. The fuel oil tanks are a support system for the EDG. At times, a fuel oil tank is removed from service and drained for cleaning. In this case, the Technical Specification requires the corresponding EDG to be declared Inoperable. However, with one fuel oil tank remaining available, the EDG will start and has enough fuel to run for over 3 days with no operator action required (Note: the mission time is 7 days). In addition, plans are in place in emergency scenarios for the delivery of fuel oil.

<p>Another example for the same configuration, each fuel oil storage tank has a separate fuel oil transfer pump. At one time, both fuel oil transfer pumps were inoperable to support troubleshooting activities. The EDG day tanks were available and would support EDG start and contain sufficient fuel to run for a few hours. During the troubleshooting activities, work was performed in accordance with a procedure, an operator was stationed locally for restoration, and the restoration steps were non-complicated.

<p>For both examples, the EDG will perform its safety function for an ample time following a loss of offsite power with no immediate operator action; does this time have to be counted as unavailable hours for the EDG?

Response Yes. No credit may be taken for operator actions for planned or unplanned unavailable hours other than testing as discussed on page 26 of NEI 99-02.

Posting Date 05/02/2000 ***ID*** 165 ***Archive Date*** 7/1/2001

Topic

Question NEI 99-02 does not adequately address how to evaluate unplanned unavailable hours for situations where support systems are not immediately required but are required for long term operation. For example: One of our plants has a situation where a breaker for some DG support systems, specifically, fuel transfer to the DG day tank (4 hour capacity), and room cooling (during the winter) was found to be inoperable. For this situation, the DG would have started and performed it's intended function for a length of time (probably 4 hours). Also, control room alarms and/or local log recording would have noted the deficient condition, and administrative controls would have provided for restoration of the system without losing the Diesel Generator safety function. Engineering analysis can determine how long the DG would operate compared to the expected response by the plant for restoration of the support systems. However, NEI 99-02 does not address alarms and operator actions for this type of situation. For this type of situation, may credit be taken for analysis involving alarms and actions?

Response No. No credit may be taken for operator actions for planned or unplanned unavailable hours other than testing as discussed on page 26 of NEI 99-02.

Posting Date 04/01/2000 ***ID*** 154 ***Archive Date*** 7/1/2001

Topic

Question When accounting for Fault Exposure Hours during a current quarter it is discovered that the Fault Exposure Hours (T/2) would also have been accrued in the previous quarter (overlapped with previous quarter). Does the previously submitted quarterly data need to be revised to reflect the Fault Exposure Hours that were assumed to occur in the previous quarter?

Response The fault exposure unavailable hours associated with a component failure may include unavailable hours covering several reporting periods (e.g., several quarters). In this case, the fault exposure unavailable hours should be assigned to the appropriate reporting periods. For example, if a failure is discovered on the 10th day of a quarter and the estimated number of unavailable hours is 300 hours, then 240 hours should be counted for the current quarter and 60 unavailable hours should be counted for the previous quarter. Note: This will require an update of the previous quarter's data.

Posting Date 04/01/2000 ***ID*** 152 ***Archive Date*** 7/1/2001

Topic

Question Support systems (service water, component cooling, electrical) at our plant for HPSI and RHR each contain 100% redundant equipment. On a periodic basis, these systems and equipment are realigned to swap components, flow paths or alignments as part of normal operation. The evolutions are frequently performed, by procedure with the operator in close contact with the control room and dedicated to the evolutions. The evolutions can be stopped, backed out and the systems restored to the original configuration at any point of the procedure. The ability of safety systems HPSI and RHR to actuate and start is not impaired by these evolutions. Restoration actions are virtually certain to be successful. Does the time to perform these evolutions on a support system need to be counted as unavailability for HPSI and RHR?

Response No. As described in the question, the ability of safety systems HPSI and RHR to actuate and start is not impaired by these evolutions. There are no unavailable hours.

Posting Date 04/01/2000 **ID** 147 **Archive Date** 7/1/2001

Topic

Question NEI 99-02 states that Planned Unavailable Hours include testing, unless the configuration is automatically overridden by a valid starting signal or the function can be promptly restored, either by an operator in the control room or by a dedicated operator stationed locally for that purpose. If credit is taken for an operator in the control room, must it be a "dedicated" control room operator or can prompt operator actions be conducted by the same operator who would then perform the configuration restoration?

Response Yes, a dedicated operator is required. The intent is that the configuration be restored promptly by an operator independent of other control room operator immediate actions that may also be required. Therefore, an individual must be "dedicated." Normal control room staffing may satisfy this purpose depending on work assignments during the configuration. However, in all cases the staffing consideration must be made in advance and purposely include the dedicated immediate response for the testing configuration.

Posting Date 02/15/2000 **ID** 88 **Archive Date** 7/1/2001

Topic Certainty

Question If a failure occurs and the time of discovery is known and the time of failure can be estimated with an appropriate level of investigation, analysis and engineering judgment, should the fault exposure unavailability hours be determined using this information or does "Only the time of the failure's discovery is known with certainty," imply that the time of failure must be known with certainty (and can not be determined through analysis, reviews, or engineering estimates)?

Response The intent of the use of the term "with certainty" is to ensure an appropriate analysis and review is completed to determine the time of failure. The use of component failure analysis, circuit analysis,engineering judgement, or event investigations are acceptable provided these approaches are documented in your corrective action program and reviewed bymanagement.

Posting Date 02/15/2000 **ID** 86 **Archive Date** 7/1/2001

Topic Off-normal events or accidents

Question In NEI 99-02, it states, "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." NEI 99-02 also states, "Hours required are the number of hours a monitored safety system is required to be available to satisfactorily perform its intended safety function." Does the phrase "perform their safety functions in response to off-normal events or accidents" refer only to credited accidents in the UFSAR, or is it intended to include events such as an Appendix R event?

Response Yes. "Off-normal events or accidents" are as specified in your design and licensing bases, therefore, UFSAR and Appendix R events should be considered.

Posting Date 02/15/2000 **ID** 74 **Archive Date** 7/1/2001

Topic Hours Train Required

Question NEI 99-02, Section 2.2, Mitigating Systems Cornerstone, Safety System Unavailability, Clarifying Notes, under Hours Train Required:

<p>For all other systems (e.g Aux Feed and HPSI), this value is estimated by the number of critical hours during the reporting period, because these systems are usually required to be in service only while the reactor is critical and for short periods during startup or shutdown. As I read this statement, we are to estimate by counting critical hours and are not required to count time in lower modes, even if that equipment is required to be operable per Tech Specs in the lower modes, correct?

Response The default value in the denominator can be used to simplify data collection. However, the numerator must include all unavailable hours that the train is required, regardless of the default value.

Posting Date 02/15/2000 **ID** 73 **Archive Date** 7/1/2001

Topic Planned Unavailable Hours

Question NEI 99-02, Section 2.2, Mitigating Systems Cornerstone, Safety System Unavailability, Clarifying Notes, under Planned Unavailable Hours:

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

<p>A clarification question is: Can we credit an operator in the main control room if the operator is not positioned directly over the piece of equipment, but is in close vicinity to it and can respond to start the equipment?

<p>Another clarification question is: As stated above, restoration actions must be uncomplicated --If a field operator with communication to the Main Control Room is available to restore a piece of equipment that has been tagged Out of Service (OOS), can we credit the action of lifting the OOS as "uncomplicated", or is it to be regarded as more complex since it will involve more than a single action?

Response The answer to the first question is yes.The second question is very situation specific, but most likely the answer would be no, because clearing tags for OOS equipment would be complicated and not meet the restoration criteria.

Posting Date 02/15/2000 **ID** 70 **Archive Date** 7/1/2001

Topic Planned Activities

Question Is there guidance as to how many hours in advance the activities must be planned to be considered "Planned Unavailable hours"? If not, do we establish our own time limit?

Response The footnote was removed because it did not apply to this indicator. The guidance for this indicator defines “planned unavailable hours” and “unplanned unavailable hours.” The intent is that if equipment is “electively” removed from service it is considered planned maintenance, independent of the number of hours it was planned ahead.

Posting Date 02/15/2000 **ID** 19 **Archive Date** 7/1/2001

Topic Planned vs. Unplanned

Question If a maintenance activity goes beyond the originally scheduled time frame due to delays in work or additional work items are found during the course of a planned system maintenance outage, are the additional unavailable hours considered planned?

Response Yes, unless you detect a new failed component that prevented the train from performing its intended safety function.

Posting Date 02/15/2000 ***ID*** 14 ***Archive Date*** 7/1/2001

Topic Restoration Actions

Question In the guidance for planned unavailable hours it says 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. Is it acceptable to have a procedure action call for restoration of the transmitter if directed by the control room (when normal transmitter restoration is a skill of craft evolution), or would detailed procedure steps be required (i.e., lift test leads, land wire, etc.). Also, is it intended that for an activity to be uncomplicated, it must involve a single action, or is the definition of uncomplicated dependent on the specific circumstances (e.g., the amount of time available for restoration, the difficulty of the actions regardless of number, etc.).

Response As stated in the guideline, credit is allowed for restoration actions that are virtually certain to be successful (i.e., probability nearly equal to 1) during accident conditions. Under stressful, chaotic conditions, otherwise simple, multiple actions may not be accomplished with the virtual certainty called for by the guidance (e.g., lift test leads, land wires).

Posting Date 01/07/2000 ***ID*** 87 ***Archive Date*** 7/1/2001

Topic Unavailability and Fault Exposure Hours

Question Should unavailability and fault exposure hours be counted for items that do not affect the automatic start and load of the Emergency Diesel Generators (EDG), but do affect the ability to manually start them?

Response This is a plant specific question which must be answered based on safety function of the manual start feature. Make a best faith effort (which could include discussion with your resident) to determine the answer and document your decision.

Posting Date 01/07/2000 ***ID*** 71 ***Archive Date*** 7/1/2001

Topic RHR Unavailable Hours

Question In regards to the NRC PWR Residual Heat Removal (RHR) Performance Indicator, at our plant the Low Pressure Safety Injection (LPSI) pumps do not contribute to the post accident recirculation function (they receive an auto shutdown signal on a Recirculation signal). Given that, if a LPSI pump or header is taken OOS for maintenance while the unit is at power, should unavailable hours be counted against the train since its only function (normal S/D cooling) is not needed in this mode and there is an extended period of time before the plant would be in condition to begin normal S/D cooling?

Response If your tech specs do not require your LPSI pumps while at power, then the hours do not count as unavailable for the PI. Make a best faith effort to provide the data and state your assumptions in the comment field.

Posting Date 11/11/1999 ***ID*** 21 ***Archive Date*** 7/1/2001

Topic Fault Exposure Hours

Question If a load run failure occurs during the time that the EDG is not required to be operable by Tech Specs, is this counted as fault exposure if corrective measures are implemented prior to conditions requiring that same EDG to be made operable? This happens in shutdown conditions whereby one EDG at a time could be electively removed from service.

Response Fault exposure hours do not need to be counted when an EDG is not required to be operable.

<p>When a failure occurs on equipment that is not required to be operable, if the most recent

successful test and recovery/correction of the failure are all made inside the window where the equipment is not required available, no faulted hours are recorded.

<p>If the most recent successful test occurred when the EDG was required to be operable and discovery/correction of the failure are made during a period when the EDG is not required to be operable, faulted hours are recorded on equipment for that portion of the time that the EDG was required to be operable. No fault exposure hours are recorded for times when the EDG is not required.

Posting Date 11/11/1999 **ID** 20 **Archive Date** 7/1/2001

Topic Clarification of "recirculation"

Question Do you have to count unavailability time for when test return lines used for surveillance testing are out of service? NEI 99-02 states, This capability is monitored for the injection and recirculation phases of the high pressure system response to an accident condition. Does the term "recirculation" refer to the HPCI system taking water from its suppression pool suction, injecting that water into the vessel, and having that water leak from the vessel through the break back to the suppression pool (as opposed to taking the water from the CST and injecting it)? Or is it intended to refer to the system alignment where the test-return valve is open and HPCI is taking water from the CST or suppression pool and putting the water back to the CST or suppression pool without injecting it into the vessel?

Response The test-return line is not required for availability of the HPCI/RCIC system. The test return line can be out of service without counting HPCI/RCIC as unavailable.

<p>The term "recirculation" in this context refers to the recirculation of the water from the suppression pool, into the vessel through the injection line, and back to the suppression pool through the leak.

Posting Date 11/11/1999 **ID** 18 **Archive Date** 7/1/2001

Topic Design Deficiency

Question The Nuclear Service Water (NSW) assured suction supply to Auxiliary Feedwater (AFW) was recently determined to be sufficiently occluded with MIC build-up to be unable to fulfill its function under certain accident scenarios. During a postulated seismic event concurrent with a loss of offsite power (LOOP), the normal seismic condensate suction sources would be assumed to be unavailable. Because of the pressure drop associated with the MIC occlusion, it would be possible to induce a negative pressure at the AFW suction, potentially drawing air into the suction from the postulated secondary side line break.

<p>The MIC build-up has since been cleared, and flow testing of the NSW supply is now performed. The NSW piping had not been flow tested as part of the plant’s GL 89-13 program until after discovery of this condition, so the fault exposure time of this condition is indeterminate. Under the NEI 99-02 guidelines, how should the fault exposure hours for this condition be addressed?

Response First, an assessment needs to be performed to determine the impact of the MIC build-up on capability of the AFW system to perform its safety functions under all design basis conditions. If the MIC buildup is severe enough to prevent fulfillment of the AFW safety function under design basis accident conditions, then the following guidance would apply.

<p>The absence of periodic inspection or testing of portions of a system that is relied upon during design basis accident conditions, would be considered a design deficiency. For design deficiencies that occurred in a previous reporting period, fault exposure hours are not reported. However, unplanned unavailable hours are counted from the time of discovery. The indicator report is annotated to identify the presence of the design deficiency, and the inspection process will assess the significance of the deficiency.

Posting Date 11/11/1999 **ID** 17 **Archive Date** 7/1/2001

Topic Alternate Methods of Decay Heat Removal

Question Can both RHR Shutdown Cooling subsystems be removed from service without incurring Planned or Unplanned Unavailable Hours provided an alternate method of decay heat removal is verified to be available for each RHR Shutdown Cooling subsystem required to be Operable for the Mitigating Systems / Safety Systems Performance Indicator?

Response Approved alternate methods for decay heat removal during shutdown cooling may be considered Installed Spares provided the components are not required in the design basis safety analysis for the system to perform its safety function. NEI 99-02 provides additional guidance on Installed Spares and Redundant Maintenance Trains. Unavailability hours for installed spares are to be counted if the installed spare becomes unavailable while serving as a replacement and the hours the installed spare is relied upon will also be included in the calculation's required hours.

Posting Date 11/11/1999 ***ID*** 15 ***Archive Date*** 7/1/2001

Topic Unique Plant Configurations

Question The Safety System Unavailability Performance Indicator requests data be provided for the following functions: 1) high pressure injection systems, 2) heat removal systems, 3) residual heat removal systems, and 4) emergency AC power systems. The monitored functions for the RHR system are:

<p>Removal of heat from the suppression, and

<p>Removal of decay heat from the reactor core during a normal unit shutdown (e.g. for refueling or servicing).

<p>Our plant does not have an RHR system. The identified functions are performed by the Low-Pressure Coolant Injection/Containment Cooling Service Water system and the Shutdown Cooling system, What should be reported for this indicator?

Response It is acknowledged that unique plant configurations can affect performance indicator reporting. The circumstances of each occurrence should be identified as early as possible to the NRC so that a determination can be made as to whether alternate data reporting can be used in place of the data called for in the guidance.

Posting Date 11/11/1999 ***ID*** 13 ***Archive Date*** 7/1/2001

Topic Use of Qualified Plant Personnel

Question Is it intended that the operator used in the definition of planned unavailability be a licensed operator or can the restoration actions be accomplished by other qualified plant personnel (e.g., I&C technician)

Response Qualified plant personnel, provided there is a means of communication with the Control Room, can perform the restoration actions.

Posting Date 11/11/1999 ***ID*** 12 ***Archive Date*** 7/1/2001

Topic Operable yet Unavailable

Question Was it intended or anticipated when developing the guidance that SSCs could be considered operable, yet unavailable? Our plant has performed an Operability Determination that justifies maintaining the SI system operable when an SI flow transmitter is out of service for calibration (Restoration is uncomplicated and can be completed well before the transmitter function is needed). However, under NEI 99-02 guidance the out of service time would be counted under planned unavailability.

Response It is possible for an SSC to be considered operable yet unavailable per guidance in NEI 99-02. 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. System unavailability due to testing is included in this indicator except when the testing configuration is automatically overridden or the function can be immediately restored. NEI 99-02 provides further guidance. The specifics of your situation should be assessed against this guidance to determine if the calibration time is counted.

Posting Date 11/11/1999 **ID** 11 **Archive Date** 7/1/2001

Topic Reporting Fault Exposure Hours

Question How do you report Fault Exposure unavailability hours when ongoing failure analysis or root cause analysis may identify a specific time of occurrence for the failure? Do you report the unavailability time and fault exposure hours immediately upon discovery or can you report unavailability immediately and defer reporting potential fault exposure hours until completion of the failure analysis.

Response If the time of failure is not known with certainty, then the fault exposure hours should be reported as one half the time since the last successful test or operation that proved the system was capable of performing its safety function. The unavailability hours can be amended in a future report if further analysis identifies the time of failure or determines that the affected train would have been capable of performing its safety function during an operational event.

Posting Date 05/31/2001 ***ID*** 273 ***Archive Date*** 1/1/2002

Topic

Question Appendix D: Ginna<p>Page 62 of NEI 99-02, Rev 0, states in part:<p>"...the isolation valve(s) between the RHR system and the HPSI pump suction is the boundary of the HPSI system."<p>Ginna Station's system design has three MOV's meeting this definition: 857A and 857C (two valves in series from the A RHR train) and 857B from the B RHR train. Each RHR train is a 100% train. MOVs 857 A and 857C are in parallel with 857B. If Ginna Station was to have a fault exposure to one of these three valves, it would not prevent any of the three HPSI pumps from performing its function of taking a suction from the containment emergency sump. Rather, a fault exposure to one of these three valves would prevent its associated RHR train from supplying a suction from the containment emergency sump to any of the three HPSI pumps. Thus, the boundary between the RHR and HPSI systems needs to be adjusted for Ginna Station.

Response The down-stream side of the isolation valve(s) between the RHR system and the HPSI pump suction is the boundary of the HPSI system for Ginna Station. The isolation valve(s) themselves will be in the RHR system and be associated with their respective RHR train.

Posting Date 10/31/2000 ***ID*** 225 ***Archive Date*** 7/1/2001

Topic

Question On page 49 of NEI 99-02, the monitored function of the BWR HPCI system is described as "The ability of the monitored system to take suction from the condensate storage tank or [emphasis added] from the suppression pool and inject at rated pressure and flow into the reactor vessel." However, the CST only provides about 30 minutes of water and the safety analysis assumes HPCI availability for about 8 hrs. If the suction path from the CST is available but the path from the suppression pool is not, are unavailable hours counted for HPCI?

Response Yes. The intent of the indicator is to monitor the ability of a system to perform its safety function. In this case, the safety function requires the availability of the suction path from the suppression pool. (Editorial Note: The guidance in NEI 99-02 will be changed to eliminate the words "from the condensate storage tank or," leaving only "from the suppression pool.".)

Posting Date 10/31/2000 ***ID*** 223 ***Archive Date*** 7/1/2001

Topic

Question In NEI 99-02, under the Support System Unavailability header, it is identified that in some instances, unavailability of a monitored system that is caused by unavailability of a support system used for cooling need not be reported if cooling water from another source can be substituted. The rules further state that if both the monitored and support system pumps are powered by a class 1E electric power source, then a pump powered by a non- class 1E source may be substituted provided the redundancy requirements to accommodate single failure requirements for electric power and cooling water are met. <p>At our site, the HPCS pump room is cooled by a safety related unit cooler, HVR-UC5. This unit cooler has non-safety related/non-Class 1E powered Normal Service Water (NSW) supplied to it and a safety related/Class 1E Standby Service Water (SSW) supplied to it as a backup cooling source. The SSW system has four 50% capacity pumps, two per train. Both trains of SSW merge into a common header at the unit cooler. If we remove one train of SSW from service can NSW be credited as a substitute thus keeping HVR-UC5 and the HPCS pump available?

Response In this case, no substitution is required, since the HPCS system is still available. Removal of one 100% train of SSW from the unit cooler has no effect on the availability of HPCS since one 100% train of SSW is still available to service the HVR-UC5 unit cooler. The single failure criteria should only be applied to cases where there is substitution of the support system and in cases where the mitigating systems have installed spares or redundant trains.

Posting Date 06/14/2000 **ID** 188 **Archive Date** 7/1/2001

Topic

Question Appendix D, Indian Point 3
<p>Regarding the HPSI indicator, we have the following question. Our plant has a unique flow path for high head recirculation. If this flow path was found isolated by a manual valve, would fault exposure hours necessarily be counted, even if the main flow path was available?

<p>Our plant has three trains of HPSI with three intermediate pressure pumps fed by separate safety related power supplies. Our three trains share common suction supplies. For the recirculation phase of an accident, two HPSI pumps are required in the short term if the event was a small break LOCA. For a large break LOCA, the HPSI pumps are not required until we transfer to hot leg recirculation, which is required to occur between 14 and 23.4 hours after the LOCA. During high head recirculation (hot or cold leg), the HPSI suction is supplied by the output of low head pumps. We have two internal SI Recirculation pumps located in the containment that provide the primary choice for low head recirculation and for supplying the suction of the HPSI pumps. The external RHR pumps provide a backup to the internal SI Recirculation pumps for both functions. Both sets of pumps deliver flow through the RHR HXs that can then be routed to a common header for the suction of the HPSI pumps.

<p>In the case of a passive failure requiring the isolation of the flow path to the common HPSI suction piping, we have a unique design in that a separate flow path is installed to deliver a suction supply to just one of our three SI pumps (specifically, the 32 SI pump). This flowpath bypasses the RHR HXs and would deliver sump fluid directly from the RHR pump discharge to the suction of the 32 SI pump. The internal recirculation pumps can not support this flowpath, but they can still be run for containment heat removal via recirculation spray if required. This alternate low to high head flowpath does not fit into the typical "train" design common in the industry because it is not used in the event of any active failure, and it relies on powering pumps and valves from all 3 of our EDGs. Our system is also unique in that loss of the alternate flow path is not a failure that equates to the NEI guidance. It appears that the mispositioning of a valve in the designs of the NEI guidance would cause the loss of one of two trains used for high head injection considering either and active or passive failure.

<p>The mispositioning of the valve was reported in LER 2000-001. The LER reported a bounding risk assessment since the IPE does not model the passive failure flow path to the HHSI pumps header. The risk assessment determined that the core damage frequency (CDF) would be approximately 3E-8 per year with a conditional CDF of approximately 7.5E-9 for a period of three months (approximate time of valve misposition). This is not risk significant.

Response The fault exposure hours do not have to be counted. Except as specifically stated in the indicator definition and reporting guidance, no attempt is made to monitor or give credit in the indicator results for the presence of other systems (or sets of components) that add diversity to the mitigation or prevention of accidents. The passive failure mitigation features described as supporting the high head recirculation function, while serving a system diversity function, are not included as part of the high head safety injection system components monitored for this indicator.

Posting Date 05/02/2000 **ID** 176 **Archive Date** 7/1/2001

Topic

Question NEI 99-02 contains the guidance for Safety System Unavailability - Planned Unavailable Hours. A system is to be considered unavailable during testing unless specified criteria are met.

<p>Monthly HPCI oil samples are taken to monitor the performance of the Turbine and the HPCI Steam Isolation Valve. While taking the oil samples on the HPCI turbine, the Aux. Oil Pump is running and the flow controller is taken to manual and set to minimum flow to prevent an over-speed condition if an initiation signal occurs while the Aux. Oil Pump is running. This monthly oil sample takes about 15 to 30 minutes per month. During this time, the system is declared inoperable and the appropriate Technical Specification actions are entered. If a HPCI initiation signal were received, HPCI will

automatically start. The control room operator will manually, with the HPCI flow controller, raise HPCI turbine speed and establish injection flow at 5600 gpm as directed by procedure. This manual action is unlike the automatic response. A fully automatic response would control the transient turbine acceleration and ramp open the steam stop valve and control the response of the governor control valve such that 5600 gpm is achieved in 35 seconds or better.

<p>The restoration actions are simple, can be completed by a control room operator, are contained in a procedure, and the HPCI function can be restored. The question is if credit for operator restoration can be taken in this case based on the system starting on an automatic signal, restoration actions are part of a normal response to the system start and contained in a procedure, and the operators are trained on this action? Can HPCI be considered available in this case? In general, must the SSC response be identical to a fully automatic initiation and how does this compare to "or the function can be immediately restored."

Response The unavailable hours would count because the system response specifically relies on operator action which is not "virtually certain to be successful" (NEI99-02 page 26 line 38). The operator actions have the potential to overspeed the turbine.

Posting Date 09/12/2001 **ID** 284 **Archive Date** 1/1/2002

Topic

Question Appendix D: San Onofre<p>At our ocean plant we periodically recirculate the water in our intake structure causing the temperature to rise in order to control marine growth. Marine mollusks, if allowed to grow larger than ¾" in size, can clog the condenser and component cooling water heat exchangers. This process is carried out over a six hour period in which the temperature is raised slowly in order to encourage fish to move toward the fish elevator so they can be removed from the intake. Temperature is then reduced and tunnels reversed to start the actual heat treat. Actual time with warm water in the intake is less than half of the evolution. A dedicated operator is stationed for the evolution, and by procedure at any point, can back out and restore normal intake temperatures by pushing a single button to reposition a single circulating water gate. The gate is large and may take several minutes to reposition and clear the intake of the warm water, but a single button with a dedicated operator, in close communication with the control room initiates the gate closure. During this evolution, one train of service water, a support system for HPSI and RHR, is aligned to the opposite unit intake and remains fully Operable in accordance with the Technical Specifications. The second train is aligned to participate in the heat treat, and while functional, has water beyond the temperature required to perform its design function. This design function of the support system is restored with normal intake temperatures by the dedicated operator realigning the gate with a single button if needed. Gate operation is tested before the start of the evolution and restoration actions are virtually certain. Does the time required to perform these evolutions on a support system need to be counted as unavailability for HPSI and RHR?

Response No. The period of heat treatment will not be considered as "unavailable" for the HPSI and RHR systems because of the utility's actions to limit the environmental impact of heat treatments. As described in the question, the ability of safety systems HPSI and RHR to actuate and start is not impaired by these evolutions There are no unavailable hours.

Posting Date 07/12/2001 **ID** 280 **Archive Date** 1/1/2002

Topic

Question NEI 99-02, Rev. 0 states in the Definition and Scope section for PWR High Pressure Safety Injection Systems that: "Because the residual heat removal system has been added to the PWR scope, the isolation valve(s) between the RHR system and the HPSI pump suction is the boundary of the HPSI system. The RHR pumps used for piggyback operation are no longer in HPSI scope." It is further stated later in the same section that the function monitored for HPSI is: "the ability of a HPSI train to take a suction from the primary water source (typically, a borated water tank), or from the containment emergency sump, and inject into the reactor coolant system at rated flow and pressure." These two statements appear to conflict. For our plant design the RHR / HPSI piggyback mode is the only path available for HPSI to get water from the containment sump and inject it into the RCS. Therefore, we have been counting unavailability of the RHR system upstream of the isolation valves between the RHR system and the HPSI pump suction as unavailability for RHR and HPSI. This would include component unavailability for containment sump isolation valves, RHR heat exchangers and the isolation valves between the RHR and HPSI systems.<p>Should the RHR and HPSI systems be treated independently such that RHR system unavailability should not count against HPSI even though the RHR system is required for the HPSI system to fulfill the function of taking a suction from the containment sump? If so, should unavailability of the isolation valves between the RHR and HPSI pumps' suction be only counted against HPSI?

Response Because RHR and HPSI are monitored as separate systems with each having its own performance indicator, there is no need to cascade RHR system unavailability into HPSI. RHR system unavailability includes the system upstream of the RHR system to HPSI system isolation valves. Unavailability of the isolation valves between the RHR system and the HPSI pump suction are only counted against the HPSI system.

Posting Date 08/16/2001 **ID** 281 **Archive Date** 1/1/2002

Topic

Question Appendix D: Davis Besse <p>Davis-Besse has an independent motor-driven feedwater pump (MDFP) that is separate from the two trains of 100% capacity turbine-driven auxiliary feedwater pumps. The piping for the MDFP (when in the auxiliary feedwater mode) is separate from the auxiliary feedwater system up to the steam generator containment isolation valves. The MDFP is not part of the original plant design, as it was added in 1985 following our loss-of-feedwater event to provide "a diverse means of supplying auxiliary feedwater to the steam generators, thus improving the reliability and availability of the auxiliary feedwater system" (quote from the DB Updated Safety Analysis Report). <p>The resolution to FAQ 182 was that Palo Verde should count the unavailability hours for their startup feedwater pump. However, since the DB MDFP is manually initiated, DB has not been reporting unavailability hours for the MDFP due to the exception stated on page 69 of NEI 99-02 Revision 0.<p>The DB MDFP is non-safety related, non-seismic, and is not Class 1E powered or automatically connected to the emergency diesel generators. <p>The DB MDFP is required by the Technical Specifications to be operable in modes 1 - 3. However, the Tech Specs do not require the MDFP to be aligned in the auxiliary feedwater mode when below 40 percent power. (The MDFP is used in the main feedwater mode as a startup feedwater pump when less than 40% power).<p>The DB auxiliary feedwater system is designed to automatically feed only an intact steam generator in the event of a steam or feedwater line break. Manual action must be taken to isolate the MDFP from a faulted steam generator.<p>The MDFP is included in the plant PRA, and is classified as high risk-significant for Davis-Besse<p>Per the DB Tech Specs, the MDFP and both trains of turbine-driven auxiliary feedwater pumps are required in Modes 1-3. The MDFP does not fit the NEI definition of either an "installed spare" or a "redundant extra train" perNEI 99-02, Rev. 0, pages 30 - 31.<p>Should the Davis-Besse MDFP be reported as a third train of Auxiliary Feedwater, even though it is manually initiated?<p> (Note: this FAQ is similar to Appendix D questions for Palo Verde and Crystal River regarding the auxiliary feedwater system)

Response Based on the information provided, this pump should be considered a third train of auxiliary feedwater for NEI 99-02 monitoring purposes. See the Palo Verde Appendix D question.

Posting Date 05/31/2001 **ID** 268 **Archive Date** 1/1/2002

Topic

Question Appendix D: Ginna<p>NEI 99-02 states (p 26) that Planned Unavailable Hours include "...testing, unless the test configuration is automatically overridden by a valid starting signal, or the function can be promptly restored either by an operator in the control room or by a dedicated operator stationed locally for that purpose." Also,(p 40) The control room operator must be "...an operator independent of other control room operator immediate actions that may also be required. Therefore, an individual must be 'dedicated.'" Ginna Station's Standby Aux Feedwater Pumps do not have an auto-start signal; they are required to be manually started by an operator within 10 minutes. Should this be counted as unavailable time

Response No. The PI should not count them since this is an NRC approved design.

Posting Date 04/04/2001 **ID** 260 **Archive Date** 1/1/2002

Topic

Question The Nuclear Service Water (NSW) system provides assured suction supply to the Auxiliary Feedwater (AFW) system under certain accident scenarios. During a postulated seismic event concurrent with a loss of offsite power (LOOP), the normal non-safety related, non-seismic condensate suction sources are assumed to be unavailable. <p>Flow testing is performed under the plant's Generic Letter 89-13 program to assure adequate flow. The alignment used in this testing renders this flowpath unavailable to fulfill its assured supply function. However, the normal condensate source remains available.<p>Recently a reactor trip occurred during the performance of this testing. The testing was terminated, but due to resource limitations during event recovery, the normal operating alignment was not restored. Therefore, the assured AFW supply remained unavailable for an extended period.

However, during the event, the AFW system started automatically on a valid autostart signal (2/4 lo-lo SG level in 1/4 SGs, loss of both main feedwater pumps) and continued to operate for a period of two days to maintain steam generator levels drawing suction from the normal condensate supply.<p>Previously, whenever the assured supply has been unavailable, whether for testing or other alignments, the entire AFW system has been deemed unavailable based on a hypothetical design basis event scenario. However, the real world event described above results in the dichotomy of calling a system unavailable because its assured supply is unavailable while it was in fact fulfilling its design basis function. Under the NEI 99-02 guidelines, how should unavailability be addressed in conditions where the assured supply is unavailable with the normal supply available?

Response The purpose of the safety system unavailability indictor is to monitor the readiness of important safety systems to perform their safety functions in response to off-normal events or accidents. Since the assumed suction supply to the AFW system is credited for off-normal events or accidents, the unavailable time should be counted unless the system could have been promptly restored by a dedicated operator stationed for that purpose during the testing

Posting Date 09/21/2000 **ID** 206 **Archive Date** 7/1/2001

Topic

Question Appendix D, Crystal River Unit 3 (CR-3) regarding FAQ 182 resolution. <p>PART B<p>CR-3 has an independent motor driven pump and independent piping system for the Auxiliary Feedwater (AFW) System that is separate from the EF System. The AFW pump (FWP-7) and associated components are designed to provide an additional non-safety grade source of secondary cooling water to the steam generators should a loss of all main and EF occur. This reduces reliance on the High Pressure Injection/Power Operated Relief Valve (HPI/PORV) mode of long term cooling. This AFW source was added to CR-3 in 1988 in response to NRC concerns on the issue of EF reliability (Generic Issue 124).<p>Per the FSAR, "The AFW source is non-safety grade and is not Class 1E powered or electrically connected to the emergency diesel generators. As such, it is not relied upon during design basis events and is intended for use on an "as available" basis only. AFW performs no safety function and there is no impact on nuclear safety if it fails to operate…..It is not environmentally qualified nor Appendix R protected……Although the AFW source is non-safety grade it is creditedby the NRC as a compensating feature in enhancing the reliability of secondary decay heat removal. Auxiliary feedwater may be used, as defense-in depth, during emergency situation when steam generator pressure has been reduced to the point where EFP-2 is no longer available or to avoid EFP-2 cyclic operation."<p>FWP-7 is powered by an independent, non-safety related, diesel. FWP-7 is a manually started pump and the associated control valves are manually controlled from the Main Control Room.<p>FWP-7 is not safety related. <p>FWP-7 is not required by ITS to be OPERABLE in any MODE.<p>FWP-7 cannot replace either EFP-2 or EFP-3 to meet two train EFW ITS requirements. CR-3 design and usage of FWP-7 does not fit the NEI definition of either an "installed spare" or a "redundant extra train" as given on pages 30 and 31 of NEI 99-02, Rev. 0. <p>FWP-7 is credited in the FSAR for providing defense-in depth and as an additional source non-safety grade source of secondary cooling water to steam generators.<p>Should this be reported as a third train of AFW?

Response No, since the pump has no operability requirements in the Technical Specifications.

Posting Date 09/21/2000 **ID** 205 **Archive Date** 7/1/2001

Topic

Question Appendix D, Crystal River Unit 3 (CR-3) regarding FAQ 182 resolution. <p>PART A<p>CR-3 has two EF System pumps and associated piping systems that are credited for Design Basis Accidents of Loss of Main Feedwater, Main Feedwater Line Break, Main Steam Line Break, and Small Break LOCA. A design criterion for the EF System is that a maximum time limit of 60 seconds from initiation signal to full flow shall not be exceeded forautomatic initiation. Pumps EFP-2 (steam turbine driven) and EFP-3 (independent diesel driven) are auto-start pumps and are tested for the 60-second time criteria. EFP-3 was installed in 1999 to replace a third pump, the electric motor driven (EFP-1) pump, due to emergency diesel generator electrical loading concerns in certain accident scenarios.<p>Per FSAR Section 10.5.2, "MAR [modification approval record] 98-03-01-02 installed a diesel driven Emergency Feedwater Pump (EFP-3) to functionally replace the motor driven Emergency Feedwater Pump (EFP-1) as the "A" EF Train."<p>The motor driven pump does not receive an automatic start signal. The motor driven pump is interlocked with the diesel driven pump so that if the diesel driven pump is operating, EFP-1 will be tripped or its start inhibited. The motor driven pump is maintained for defense-in-depth. EFP-1 can be used to transfer water from the condenser hotwell into the steam generators during a seismic event, if long term cooling is necessary. EFP-1 can be used as a backup to EFP-2 to supply EFW to the steam generators for fires in the Main Control Room, Cable Spreading Room, and Control Complex HVAC Room.<p>CR-3 is reporting RROP safety system unavailability performance indicator data on the basis of two EF pumps and trains. CR-3 is not reporting on EFP-1. CR-3 design and usage of EFP-1 does not fit the NEI definition of either an "installed spare" or a "redundant extra train" as given on pages 30 and 31 of NEI 99-02, Rev. 0. <p>EFP-1 is safety-related and tested. However, EFP-1 is not required to be OPERABLE in any MODE in accordance with the Improved Technical Specifications (ITS). EFP-1 cannot replace EFP-3 to meet two train EFW ITS requirements. EFP-1 is included in the PRA but is not a "risk significant" component. EFP-1 is credited in the FSAR as noted above for providing defense-in depth and maintained for potential use in certain seismic and Appendix R conditions.<p>Should this be reported as a third train of AFW?

Response No, since the pump has no operability requirements in the Technical Specifications.

Posting Date 05/24/2000 **ID** 182 **Archive Date** 7/1/2001

Topic

Question APPENDIX D PALO VERDE
<p>NEI 99-02, revision 0 states "Some plants have a startup feedwater pump that requires manual actuation. Startup feedwater pumps are not included in the scope of the AFW system for this indicator." Our plants have startup feedwater pumps that require manual actuation. They are not safety related, but they are credited in the safety analysis report as providing additional reliability/availability to the AFW system and are required by Technical Specifications to be operable in modes 1, 2 and 3. They are also included in the plant PRA and are classified as high risk significant. Should these pumps be treated as third train of auxiliary feedwater for NEI 99-02 monitoring purposes or does the startup feedwater pump exemption apply?

Response Based on the information provided, these particular SSCs should be considered a third train of auxiliary feedwater for NEI 99-02 monitoring purposes

Posting Date 08/16/2001 **ID** 276 **Archive Date** 1/1/2002

Topic

Question FAQ 276 has been withdrawn and replaced by FAQ 283.

Response

Posting Date 05/02/2001 **ID** 267 **Archive Date** 1/1/2002

Topic

Question Appendix D: Calvert Cliffs Units 1 and 2<p>Calvert Cliffs monitors the Safety System Unavailability Performance Indicator for PWR RHR using the guidance in NEI 99-02 provided for Combustion Engineering (CE) designed plants. When a unit is in Mode 6 and with water level in the Refueling Pool, at 23 feet or more above the top of the irradiated fuel assemblies seated in the reactor vessel, the Technical Specifications only require one Shutdown Cooling (SDC) loop to be operable and in operation. Unlike most of the other CE designed plants, at Calvert Cliffs, the two SDC loops on each unit have a common suction piping line. As a result, to permit required local leak rate testing and other maintenance activities on this common suction line, both trains of SDC would be taken out-of-service. Recognizing this plant specific design feature, the Technical Specifications specifically allow this required testing and maintenance to be performed without entering the action statements while the plant is in this particular condition. While the SDC trains are unavailable, decay heat is removed by natural convection to the volume of water in the Refueling Pool. Calvert Cliffs Technical Specifications Bases indicates that "a minimum refueling water level of 23 feet above the irradiated fuel assemblies seated in the reactor vessel provides an adequate available heat sink." In this situation, should unavailable hours be counted against the SDC loop given the plant design at Calvert Cliffs?

Response It is appropriate to not count unavailable hours for the above-described situation at Calvert Cliffs. Removing the SDC suction headers from service for the circumstances specifically allowed by the applicable Technical Specification is a reflection of plant design rather than an indication of adequate component or train maintenance practices. Unavailable hours would be counted while operating in accordance with this applicable Technical Specification if a situation occurred that required entering the action statement.

Posting Date 04/04/2001 **ID** 263 **Archive Date** 7/1/2001

Topic

Question Appendix D - South Texas Units 1 and 2<p> NEI 99-02 Revision 0 requires the Residual Heat Removal (RHR) system to satisfy two separate functions:<p>* The ability to take a suction from the containment sump, cool the fluid, and inject at low pressure into the RCS<p>* The ability of the RHR system to remove decay heat from the reactor during a normal unit shutdown for refueling or maintenance<p>These functions are completed by the Emergency Core Cooling System on most Westinghouse PWR designs. South Texas Project has a unique design for these functions completed by two separate systems with a shared common heat exchanger. How should unavailability be counted for South Texas Project?.

Response Due to the unique design South Texas project, unavailability will be determined as follows:<p>* In plant Modes 1, 2, 3, and 4 South Texas Project will count the unavailability of the Low Head Safety Injection Pump and the flowpath through it's associated RHR Heat Exchanger as the hours to count for the RHR performance indicator. This equipment and flowpath satisfies the requirement to "take a suction from the containment sump, cool the fluid, and inject at low pressure into the RCS". The RHR pump does not contribute to the performance of this safety function since it can not take suction on the containment sump.<p>*In plant Modes 4, 5, and 6 South Texas Project will count the unavailability hours of the RHR Pump and the flowpath through it's associated RHR Heat Exchanger as the hours to count for the RHR performance indicator. This equipment and flowpath satisfies the requirement to "remove decay heat from the reactor during a normal unit shutdown for refueling or maintenance". The RHR loop is required to be isolated from the Reactor Coolant System in Modes 1, 2, and 3 due to the system design. This requirement prevents the system from performing its intended cooling function until plant pressure and temperature are lowered to a value consistent with the system design.<p>Overlap times when both functions/systems are required will be adjusted to eliminate double counting the same time periods.<p>This position is consistent with the direction published in Frequently Asked Question #149.

Posting Date 01/10/2001 **ID** 236 **Archive Date** 7/1/2001

Topic

Question Appendix D Indian Point 2, Indian Point 3<p>The ECCS designs for Indian Point 2 and Indian Point 3 include two safety injection recirculation pumps, the recirculation sump inside containment, piping and associated valves located inside containment, and two RHR/LHSI pumps, piping, containment sump (dedicated to RHR pumps), two RHR heat exchangers and associated valves. These two subsystems are identified in the Technical Specifications and FSAR. The RHR/LHSI system is automatically started on an SI, takes suction from the RWST as do the high head SI pumps (3), provides water in the injection phase of an accident, and is secured during the transfer to the recirculation phase of the accident. The recirculation pumps remain in standby in the injection phase and are started by operator action during switchover for the recirculation phase. The recirculation pumps (2) take suction from their dedicated sump and have the capability to feed the low head injection lines, the containment spray headers, and the suction of the high head SI pumps for high head injection. The RHR head exchangers can provide cooling for both the RHR and recirculation flowpaths. The recirculation pumps are inside containment and can not be tested during operation <p>The RHR pumps perform the normal decay heat removal function during shutdown operations, and can also be aligned for post accident recirculation. However, the two redundant recirculation pumps represent the primary providers of the low head recirculation function. If a single active failure were to occur, then one recirculation pump would remain available and provides sufficient capacity to meet the core and containment cooling requirements. Only in the event of a passive failure or multiple active failures would it be necessary to align the RHR pumps for recirculation. Use of the RHR pumps for recirculation requires opening two motor operated valves aligned in series to allow suction from the containment sump. <p>How should the recirculation subsystem unavailability be reported under the mitigating system PI for RHR.

Response The Safety System Unavailability Performance Indicator for RHR monitors two functions:<p>1. The ability of the RHR system to draw suction from the containment sump, cool the fluid, inject at low pressure to the RCS, and<p>2. The ability of the RHR System to remove decay heat from the reactor during normal shutdown for refueling and maintenance.<p>At Indian Point Units 2 & 3, the two SI Recirculation Pumps and associated valves and components should be counted as two trains of RHR providing post accident recirculation cooling, function 1. The two RHR pumps and associated valves and components should be counted as two trains of RHR providing decay heat removal, function 2. The RHR Heat Exchangers and associated components and valves which serve both RHR and recirculation functions should be shared by an RHR and an SI Recirculation Pump train, functions 1 and 2. <p>The two RHR pumps are also capable of providing backup to function 1. Except as specifically stated in the indicator definition and reporting guidance, no attempt is made to monitor or give credit in the indicator results for the presence of other systems (or sets of components) that add diversity to the mitigation or prevention of accidents. The RHR pump suction flowpath from the Containment Sump provides passive failure mitigation features which, while supporting a system diversity function, are not included as part of the RHR system components monitored for this indicator.<p>Four (4) trains should be monitored as follows:<p>Train 1 (shutdown cooling mode)<p>"A" train consisting of the "A" RHR pump, "A" RHR heat exchanger, and associated valves.<p>Train 2 (shutdown cooling mode) <p>"B" train consisting of the "B" RHR pump, "B" RHR heat exchanger, and associated valves.<p>Train 3 (recirculation mode) <p>"A" train consisting of the "A" SI Recirculation pump, "A" RHR heat exchanger, and associated valves.<p>Train 4 (recirculation mode) <p>"B" train consisting of the "B" SI Recirculation pump, "B" RHR heat exchanger, and associated valves.<p>The required hours for trains 1 & 2 differ from trains 3 & 4, and will be determined using existing guidelines. Reporting of RHR data should follow this guidance beginning with the first quarter 2001 data submittal.

Posting Date 10/31/2000 **ID** 222 **Archive Date** 7/1/2001

Topic

Question Are there times when RHR Shutdown Cooling can be removed from service without incurring unavailable hours, if allowed by Technical Specifications (i.e., reactor level and temperature requirements met).

Response Yes. Unavailable hours are counted only for periods when a train is required to be available for service. However, Technical Specifications that require one subsystem remain operable and in operation above a specified temperature would be counted if one subsystem were not available or an alternate method (normally specified in the Technical Specification Action Statement) were not available.

Posting Date 10/31/2000 **ID** 221 **Archive Date** 7/1/2001

Topic

Question Function 2 of the RHR Performance Indicator monitors the ability to remove decay heat during a normal heat unit shutdown. The 2 SDSC HX's at Calvert Cliffs are supplied RCS fluid by 2 SDC pumps via a common suction and common discharge header (not single failure proof). The SDC HX's are cooled by the Component Cooling (CC) Water system. The CC system is a closed system that exchanges heat to the Salt Water system via two parallel heat exchangers (CCHX). Component Cooling is always operated cross tied before and after the CCHX's. When one of the two SW trains is removed from service only one CCHX is available. Two saltwater pumps, with independent power, are available as well as 2 component cooling water pumps with independent power. In Mode 5, RCS Loops filled, Technical Specification LCO (old: TS 3.4.1.3; ITS: 3.4.7) requires 2 SDC loops (one operable and one in operation assuming no S/G's available). We consider that one SDC loop is unavailable (SDC HX's and SDC pumps) if one Salt Water train is removed from service. Is this a proper interpretation of NEI 99-02 guidelines?

Response Yes. Assuming the Salt Water System is a necessary support system, and the Salt Water System can provide the cooling for Component Cooling sufficient to remove heat for one loop of SDC. However, when one train of the Salt Water System is removed from service, you no longer meet the “Support System Unavailability” guidance of NEI 99-02 for not reporting unavailable hours. In this situation you are required to report unavailable hours for one train of the monitored system (i.e., SDC.), since one loop of SDC is available and in operation and the other loop cannot be made available without removing heat removal capability from the operating loop of SDC. If, however, the remaining Salt Water System train is capable of satisfying the heat removal requirements of both trains of SDC, no SDC unavailability would be reported.

Posting Date 05/24/2000 **ID** 183 **Archive Date** 7/1/2001

Topic

Question Our decay heat removal Technical Specifications state that at or below 280 degrees, 2 of the 4 following coolant loops shall be operable:<p>Reactor Coolant Loop (A) and its associated Steam Generator and at least one associated reactor coolant pump <p>Reactor Coolant Loop (B) and its associated Steam Generator and at least one associated reactor coolant pump <p>Decay Heat Removal Loop (A)<p>Decay Heat Removal Loop (B)<p>The Low Pressure Injection Technical Specification is not applicable below 300 psig.<p>With the RCS pressure below 300 psig and RCS temperature below 280 degrees, and with both Steam Generators available for decay heat removal, our technical specifications allow decay heat pumps to be taken out of service. During the time that decay heat removal pumps are out of service and the plant is relying on steam generators for decay heat removal, would any unavailability time be counted?

Response No. During periods and conditions where Technical Specifications allow both shutdown cooling trains to be removed from service the shutdown cooling system is, in effect, not required and required hours and unavailable hours would not be counted.

Cornerstone Mitigating Systems

PI MS04 Residual Heat Removal System Unavailability

Posting Date 05/02/2000 **ID** 172 **Archive Date** 7/1/2001

Topic

Question For CE designed NSSS systems, the functions reported under the RHR SSU performance indicator are accomplished by multiple systems. How should CE plants collect and report data for this indicator?

Response ANO-2, Calvert Cliffs, Fort Calhoun, Millstone 2, Pallisades, Palo Verde,San Onofre, St. Lucie, and Waterford 3

<p>Issue: The Safety System Unavailability Performance Indicator for PWR RHR monitors:·

<p>The ability of the RHR system to take a suction from the containment sump, cool the fluid, and inject at low pressure into the RCS, and·
<p>The ability of the RHR system to remove decay heat from the reactor during normal shutdown for refueling and maintenance.

<p>CE ECCS designs differ from the RHR description and typical figures in NEI 99-02. CE designs run all ECCS pumps during the injection phase (Containment Spray (CS), High Pressure Safety Injection (HPSI), and Low Pressure Safety Injection (LPSI)), and on Recirculation Actuation Signal (RAS), the LPSI pumps are automatically shutdown, and the suction of the HPSI and CS pumps is shifted to the containment sump. The HPSI pumps then provide the recirculation phase core injection, and the CS pumps by drawing inventory out of the sump, cooling it in heat exchangers, and spraying the cooled water into containment, support the core injection inventory cooling. How should CE designs report the RHR SSU Performance Indicator?

<p>Resolution: For the first function: "The ability of the RHR system to take a suction from the containment sump, cool the fluid, and inject at low pressure into the RCS."
<p>The CE plant design uses HPSI to "take a suction from the sump", CS to "cool the fluid", and HPSI to "inject at low pressure into the RCS". Due to these design differences, CE plants with this design should monitor this function in the following manner. The HPSI pumps and their suction valves are already monitored under the HPSI function, and no monitoring under the RHR PI is necessary or required. The two containment spray pumps and associated coolers should be counted as two trains of RHR providing the post accident recirculation cooling.

<p>For the second function: "The ability of the RHR system to remove decay heat from the reactor during normal shutdown for refueling and maintenance."
<p>The CE plant design uses LPSI pumps to pump the water from the RCS, through the SDC heat exchangers, and back to the RCS. Due to this CE design difference, the SDC system should be counted as two trains of RHR providing the decay heat removal function.

<p>Therefore, for the CE designed plants four trains should be monitored, when the particular affected function is required by Technical Specifications, as follows:

<p>Train 1 (recirculation mode) Consisting of the "A" containment spray pump, the required spray pump heat exchanger and associated flow path valves.
<p>Train 2 (recirculation mode) Consisting of the "B" containment spray pump, the required spray pump heat exchanger and associated flow path valves.
<p>Train 3 (shutdown cooling mode) Consisting of the "A" SDC pump, associated flow path valves and heat exchanger.
<p>Train 4 (shutdown cooling mode) Consisting of the "B" SDC pump, associated flow path valves and heat exchanger.

<p>Note that required hours and unavailable hours will be determined by technical specification requirements, not "default hours."

<p>Reporting of RHR data should follow this guidance beginning with the second quarter 2000 data

submittal. Historical data was originally reported as two trains. A change report must be submitted to provide historical data for four trains. This can be accomplished in either of two ways:

<p>1. Maintain Train 1 and Train 2 historical data as is. For Train 3 and 4, repeat Train 1 and Train 2 data.
<p>2. Recalculate and revise all historical data using this guidance.

<p>Provide comments with the change report to identify the manner in which the historical data has been revised.

Posting Date 05/02/2000 **ID** 164 **Archive Date** 7/1/2001

Topic

Question Can a Spent Fuel Cooling train be considered an installed spare of Shutdown Cooling under certain conditions? If yes, should unavailable hours be counted during a planned removal from service of the entire Shutdown Cooling System, if it has been demonstrated that a single SFC train will meet the requirements for an installed spare of the shutdown cooling function, and two SFC trains are currently operable?

<p>NEI 99-02, states that an "installed spare" is "a component (or set of components) that is used as a replacement for other equipment to allow for the removal of equipment from service for preventive or corrective maintenance without incurring a limited condition for operation (where applicable) or violating the single failure criteria. To be an "installed spare," a component must not be required in the design basis safety analysis for the system to perform its safety function."

<p>Using the above definition, it would appear a Spent Fuel Cooling System train could be considered an installed spare of the shutdown cooling function under certain conditions: no design basis safety analysis requirement, a connection between the spent fuel pool and reactor vessel, and analysis indicating that under the current conditions the train is adequate to offset the combined vessel and fuel pool decay heat load.

<p>FAQ 17 appears to support the interpretation that SFC can be an installed spare of shutdown cooling under certain conditions.

<p>NEI 99-02 goes on to say that "those portions of the Shutdown Cooling System associated with one heat exchanger flow path can be taken out of service without incurring planned or unplanned unavailable hours provided the other heat exchanger flow path is available (including at least one pump) and an alternate, NRC approved means of removing core decay heat is available."

<p>In the case cited above, each SFC train has taken the place of a Shutdown Cooling System train, as an installed spare. Each SFC train can maintain the core decay heat load within the temperature limits set by the plant's design basis. Therefore, there continues to be a heat exchanger flow path, and an alternate, closed-cycle, forced means of removing core decay heat. Thus, it would appear no unavailable hours need be incurred.

Response The Spent Fuel Cooling train is not an installed spare. However, if the Spent Fuel Cooling system is an NRC approved alternate means of removing decay heat, the hours do not have to count. (Refer to p.32 lines 13-18)

Posting Date 04/01/2000 **ID** 155 **Archive Date** 7/1/2001

Topic

Question If a plant has two, 100% capacity, NRC approved, alternate shutdown cooling trains in operation during a refueling outage, may the plant take credit for these two trains and take both trains of the residual heat removal system out of service at the same time without incurring unavailability?

Response Yes, provided that both alternate means of heat removal are capable of performing the heat removal function when placed in service simultaneously.

Posting Date 04/01/2000 **ID** 153 **Archive Date** 7/1/2001

Topic

Question The 99-02 mitigating system guidance and FAQ's indicate that unless we can "promptly" recover the system, we must count it as unavailable. Is this correct as applied to the RHR Unavailability PI? Our position for the RHR suppression pool cooling/shutdown cooling PI for INPO reporting has been that up to a 5 hour recoverability time is appropriate in contrast to the 99-02 criteria of "promptly". We understand it's appropriateness for HPCI, RCIC and the diesels since they are expected to automatically and "immediately" respond to a plant event. Use of this 99-02 criteria will have implications for our work management practices. Use of this criterion makes no sense for a system that does not have to respond automatically to an event.

Response Yes. However, the unavailable hours are not counted provided an NRC approved alternative method of removing decay heat is available.

Posting Date 04/01/2000 **ID** 149 **Archive Date** 7/1/2001

Topic

Question NEI document 99-02 requires monitoring PWR RHR Systems for the following functions: ·the ability of the RHR system to take a suction from the containment sump, cool the fluid, and inject at low pressure into the RCS, and ·the ability of the RHR system to remove decay heat from the reactor during a normal shutdown for refueling or maintenance. On Millstone Unit 3, there is a separate system that performs each of the functions. The shutdown cooling/decay heat removal function is monitored by RHS and post accident recirculation function is monitored by RSS. For Millstone Unit 3 removing RHS (which is required for function 2), during Mode 1 does not affect the ability to meet the post accident recirculation function and therefore does not result in any unavailability for post accident recirculation (function 1). NEI 99-02 states that the required hours for residual heat removal is estimated by number of hours in the reporting period since the residual heat removal system is required to be available at all times. Please clarify the mode requirements for the two separate functions and specifically address the following question: Is the system which provides the shutdown cooling function (function 2) required to be monitored for unavailability in all modes even if removing it has no impact on the post-accident recirculation function?

Response Reporting of unavailability hours for multi-system should be counted only during the time the particular affected function is required by technical specifications. The two systems are added together to derive the total hours of RHR unavailability to be reported. Overlap times when both functions/systems are required can be adjusted to eliminate double counting the same incident.

Posting Date 04/01/2000 **ID** 148 **Archive Date** 7/1/2001

Topic

Question NEI 99-02, section 2.2, under "Systems Required to be in Service at All Times", states with fuel still in the reactor vessel, when decay heat is so low that forced flow for cooling purposes, even on an intermittent basis, is no longer required (ambient losses are enough to offset the decay heat load), component planned or unplanned unavailable hours are not reportable. According to our Tech Specs Bases 3.9.7, "...At reactor coolant temperatures < 150°F, natural circulation alone is adequate to provide the required decay heat removal capability while maintaining adequate margin to the reactor coolant temperature (212°F) at which a mode change would occur." However, without stating a given starting temperature the parenthetical clarification may be thermodynamically meaningless. The Tech Spec bases provide that starting temperature, i.e., "less than 150°F". Beginning from any initial temperature < 150°F, reactor coolant temperature may initially increase but only to some equilibrium (which will be less than 212°F). After equilibrium, ambient losses will offset decay heat load.

Therefore, planning a common SDC suction window outage (complete loss of RHR) when ambient heat loss's were enough to offset decay heat (reactor loaded, fuel pool gates open, fuel pool cooling in service to keep temps below 150F) has been a past practice. Is this what is meant by the parenthetical condition "ambient losses are enough to offset the decay heat load?"

Response No. If the spent fuel pool cooling system is required to maintain reactor coolant temperatures less than 150 degrees F then ambient losses are not sufficient to offset the decay heat load. Therefore, unavailable hours for the RHR system would be counted.

Posting Date 04/01/2000 **ID** 146 **Archive Date** 7/1/2001

Topic

Question In most plants, the RHR system performs the containment heat removal function (ECCS) and the shutdown cooling (SDC) function using common equipment. There are subsets of RHR equipment which are specific to only one of the functions such as the SDC suction valves from the RCS. Technical specifications generally do not require operability of the SDC function during power operation and activities affecting equipment specific only to SDC function are not tracked as LCOs. Should we monitor SDC specific equipment and report unavailability hours for the SDC function during periods when SDC is not required by technical specifications or monitor only what is required by Tech Specs that are mode specific?

Response Reporting of unavailability hours for a multi-function system should be counted only during the time the particular affected function is required by technical specifications. For RHR, unavailability hours for containment heat removal are counted only when containment cooling is required by tech specs and SDC hours are counted only when the SDC function is required by tech specs. The two are added together to derive the total hours of RHR unavailability to be reported. Overlap times when both functions are required can be adjusted to eliminate double counting the same incident.

Posting Date 04/01/2000 **ID** 145 **Archive Date** 7/1/2001

Topic

Question During refueling outages usually after reload, we conduct 4160 VAC electrical safeguards train bus outages with fuel in the core, but with the Refueling Cavity flooded (greater than 20 feet). As a result, 1 train of RHR cannot be used. Our plant shutdown safety assessment counts the refueling cavity flooded to > 20 feet and the upper internals removed as equivalent to one RHR train. Must we count the 2nd train of RHR as being unavailable when the refueling cavity is flooded?

Response If the PWR method described is an NRC approved alternate method (e.g., alternate method allowed by Technical Specifications) of removing core decay heat, then the RHR unavailability time for the first train would not be counted. If the second train is not required by Technical Specifications, then its unavailable hours would not count.

Posting Date 04/01/2000 **ID** 144 **Archive Date** 7/1/2001

Topic

Question The guidance on SSFFs regarding reporting of multiple failures could be clearer. Is the intent that if there are multiple failures documented in one LER that each one (failure) be counted by the one report date? So that one report date may be tied to numerous failures?

Response Each individual SSFF counts.

Posting Date 04/01/2000 **ID** 143 **Archive Date** 7/1/2001

Topic

Question In our plant, RCIC is not a safety system and functionally, it provides high pressure makeup which can also be provided by HPCI. For these reasons, RCIC functional failures (as determined for the maintenance rule) are not reportable under 10CFR50.73 (a)(2)(v). Given the above, would RCIC functional failures ever be reported for NEI 99-02?

Response No. The intention of NEI 99-02 is to report only those failures meeting the 10CFR50.73(a)(2)(v) reporting criteria as applied to a specific plant.

Posting Date 11/11/1999 **ID** 10 **Archive Date** 7/1/2001

Topic Safety System Functional Failures

Question For those cases where a Tech Spec required action places a system in an inoperable status, is it necessary/required to call this a SSFF? It seems like it should not be counted as a SSFF because the systems can perform their safety function.

Response If the system, upon receipt of a demand signal, would have functioned, then it would not count as a SSFF. The reportability guidelines of NUREG-1022 Revision 1, Event Reporting Guidelines, 10 CFR 50.72 and 50.73, should be used. If the situation is reportable per 10CFR50.73 (a)(2)(v) it should be counted as a SSFF.

Posting Date 11/11/1999 **ID** 9 **Archive Date** 7/1/2001

Topic Safety System Functional Failures

Question Should Appendix R issues be covered by this indicator (SSFF) or is it already covered/better covered by the fire protection inspection procedure.

Response This indicator monitors events or conditions that alone prevented, or could have prevented, the fulfillment of the safety function of structures or systems that are needed to a) shut down the reactor and maintain it in a safe shutdown condition, b) remove residual heat, c) control the release of radioactive material, or d) mitigate the consequences of an accident. Appendix R issues have the potential to affect the safety functions of structures and systems and should be evaluated accordingly. The reportability guidelines of NUREG-1022 Revision 1, should be used. If the situation is reportable per 10CFR50.73 (a)(2)(v) it should be counted as a SSFF.

Posting Date 11/11/1999 **ID** 8 **Archive Date** NRC

Topic Safety System Functional Failures

Question Does the functional area of Containment Integrity include systems and equipment associated with secondary containment? Specifically, is standby Gas Treatment an included system? If secondary containment is included, do we also include systems like Hi/Lo Volume purge (BWR-6) or Fuel Bldg. Filtration systems for designs that have a separate system for fuel building (a functional equivalent to secondary containment). Would support systems like annulus pressure control be included?

Response Yes, Standby Gas Treatment is included. The reportability guidelines of NUREG-1022 Revision 1, Event Reporting Guidelines, 10 CFR 50.72 and 50.73, should be used. If the situation is reportable per 10CFR50.73 (a)(2)(v) it should be counted as a SSFF. The other systems identified in the question have the potential to be reported under 10 CFR 50.73 (a)(2)(v) and should be evaluated accordingly.

Posting Date 09/12/2001 **ID** 288 **Archive Date** 1/1/2002

Topic

Question Our Chemistry Dept was questioned as to whether or not RCS strip isotopic data was included in the PI reporting for RCS Specific Activity. [We had not been reporting results from that method since it wasn't exactly like the method we typically use to satisfy our Tech Specs.] BVPS uses the RCS Isotopic Iodine Analysis method which is specific for isotopic Iodine in RCS (and is more accurate) for meeting our Tech Spec requirement. (We use all results even if the number of samples exceeds the TS requirement.) We also perform an RCS Strip Isotopic Analysis which is for gaseous and all other liquid isotopes in the RCS. This Strip method however, will provide isotopic Iodine in the results (although less accurate.) This method sometimes provides a higher value than the highest Iodine Isotopic analysis I-131 data for the month. However, this method is also considered to be an acceptable method for meeting the Tech Spec requirement, and is used if problems are encountered with the Isotopic Iodine method. Should ONLY the RCS Isotopic Iodine Analysis method (most accurate) for RCS samples be used for the results and determination of maximum RCS Specific Activity to be reported? or Should ALL isotopic samples of RCS, including those using less accurate analytical methods (e.g. Stripped liquid method) be considered for determination of maximum RCS Specific Activity?

Response Use the results of the method that was used at the time to satisfy the technical specifications.

Posting Date 05/02/2001 **ID** 266 **Archive Date** 1/1/2002

Topic

Question Appendix D: Cook Units 1 and 2<p>The definition for the Reactor Coolant System (RCS) Leakage performance indicator is "The maximum RCS Identified Leakage in gallons per minute each month per the technical specification limit and expressed as a percentage of the technical specification limit."<p>Cook Nuclear Plant Unit 1 and 2 report Identified Leakage since the Technical Specifications have a limit for Identified Leakage with no limit for Total Leakage. Plant procedures for RCS leakage calculation requires RCS leakage into collection tanks to be counted as Unidentified Leakage due to non-RCS sources directed to the collection tanks. All calculatedleakage is considered Unidentified until the leakage reaches an administrative limit at which point an evaluation is performed to identify the leakage and calculate the leak rate. Consequently, Identified Leakage is unchanged until the administrative limit is reached. This does not allow for trending allowed RCS Leakage. The procedural requirements will remain in place until plant modifications can be made to remove the non-RCS sources from the drain collection tanks. What alternative method should be used to trend allowed RCS leakage for the Barrier Integrity Cornerstone?

Response Report the maximum RCS Total Leakage calculated in gallons per minute each month per the plant procedures instead of the calculated Identified Leakage. This value will be compared to and expressed as a percentage of the combined Technical Specification Limits for Identified and Unidentified Leakage. This reporting is considered acceptable to provide consistency in reporting for plants with the described plant configuration.

Posting Date 04/04/2001 **ID** 262 **Archive Date** 1/1/2002

Topic

Question NRC Performance Indicator BI-01 monitors the integrity of the fuel cladding. We are required to report the maximum monthly RCS activity in micro-Curies per gram dose equivalent Iodine-131 and express it as a percentage of the technical specification limit. <p>FAQ 226 asks if licensees with limits more restrictive than the technical specification limit should use the more restrictive limit or the TS limit. The FAQ answer states that the licensee should use the most restrictive regulatory limit unless it is "insufficient to assure plant safety." If administrative controls are imposed "... to ensure that TS limits are met and to ensure the public health and safety, that limit should be used for this PI." <p>Vermont Yankee has a Basis for Maintaining Operation (BMO) that is in effect that limits the Reactor Coolant System to 0.05 uCi/gm I-131 dose equivalent. This BMO, 98-36, entitled "Effect of Main steam Tunnel and Turbine Building HELBs on the HVAC Rooms," is concerned with Control Room habitability and the regulatory dose limits to the operators. It states that there is no concern with increased radiological dose to the public from the VY HELB off-site dose analyses in FSAR Section 14.6. <p>FAQ 226 mentions the concern for both assuring plant safety and public health and safety as the intent for the more restrictive administrative controls that may be in effect. NRC Administrative Letter 98-10, which is mentioned in the answer to this FAQ, states in the Discussion that the concern is the safe operation of the facility. <p>Our question is this: "Is Vermont Yankee required to use the lower administrative limit imposed by the BMO (0.05 uCi/gm I-131 dose equivalent) even though public health and safety is not compromised if this limit is exceeded?"

Response No. The intent is when administrative limits are required to ensure 10 CFR Part 100 limits are not exceeded.

Posting Date 02/08/2001 **ID** 251 **Archive Date** 7/1/2001

Topic

Question In the clarifying notes section of the Reactor Coolant System Leakage indicator, required data is identified as, <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."<p>Within our Technical Specifications identified leakage is calculated on a set frequency using a surveillance procedure. The procedure measures various drain and relief tank levels over time and requires the test to be run for at least 120 minutes to produce acceptable results. The test is required to be performed at steady state conditions to guarantee accuracy.<p>During off-normal conditions, for example leakage past a drain valve of a pump, control room operators may estimate leakage by monitoring drain/relief tank level over time and produce a leakage value within a few minutes. This estimation does not meet the Technical Specification surveillance prerequisites, the acceptance criteria, does not maintain the same measurement accuracy, and does not meet the surveillance requirements. The only similarity is that a tank level over time is being measured.<p>Are leakage estimations as described above to be included as part of the data elements for the RCS identified Leakage indicator?

Response No. The TS surveillance procedure was not followed.

Posting Date 10/31/2000 **ID** 226 **Archive Date** 7/1/2001

Topic

Question (This FAQ is a replacement for FAQ 193. FAQ 193 has been withdrawn.)
<p>The definition of the RCS Specific Activity PI is the maximum RCS activity as a percentage of the technical specification limit. Should licensees with limits more restrictive than the technical specifications use the more restrictive limit or the TS limit?

Response Licensees should use the most restrictive regulatory limit (e.g., technical specifications[TS] or license condition). However, if the most restrictive regulatory limit is insufficient to assure plant safety, then NRC Administrative Letter 98-10 applies, which states that imposition of administrative controls is an acceptable short-term corrective action. When an administrative control is in place as a temporary measure to ensure that TS limits are met and to ensure public health and safety, that administrative limit should be used for this PI.

Posting Date 10/31/2000 **ID** 193 **Archive Date** 7/1/2001

Topic

Question FAQ 193 has been withdrawn and replaced by FAQ 226.

Response

Posting Date 05/24/2000 **ID** 177 **Archive Date** 7/1/2001

Topic

Question In the discussion of RCS Activity, NEI 99-02 states:<p>"This indicator monitors the steady state integrity of the fuel-cladding barrier. Transient spikes in RCS Specific Activity following power changes, shutdowns and scrams may not provide a reliable indication of cladding integrity and should not be included in the monthly maximum for this indicator. "<p>Steady state is not defined.

Response If steady state is not defined by the licensee, use the definition in INPO96-003 where steady state is defined as continuous operation for at least three days at a power level that does not vary more than ± 5 percent.

Posting Date 03/01/2000 ***ID*** 72 ***Archive Date*** 7/1/2001

Topic Application of Technical Specification Limit

Question Two of the performance indicators for the barrier integrity cornerstone use "technical specification limit" in the calculation. They are RCS specific activity and leakage. There are two situations where a plant could be operating with a more restrictive limit for RCS specific activity and/or RCS leakage than the "technical specification limit". One situation is where the Facility Operating License (FOL) contains a condition that specifies a more restrictive limit. The second situation is where the licensee has administratively implemented a more restrictive limit to maintain operability as described in Generic Letter 91-18. The guidance as currently worded would always use whatever the technical specification limit is and ignore any more restrictive limits. Is that the intent and is that appropriate?

Response The circumstances of each situation are different and should be identified to the NRC so that a determination can be made as to whether alternate data reporting can be used in place of the data called for in the guidance.

Posting Date 02/15/2000 ***ID*** 84 ***Archive Date*** 7/1/2001

Topic Reporting significant digits

Question How many significant digits should be carried for the dose equivalent I-131 maximum value? Although NEI 99-02, has guidance concerning the number of decimal places in the final reported number (percentage of TS limits), it isn't clear how many significant digits to retain in the raw data.

Response In general, the data element input forms allow data to be entered to a level of significance that is one significant figure greater than the resulting performance indicator. In some cases the input forms restrict the level of significance even further due to recognized limitations in reporting accuracy (e.g., compensatory hours are limited to two significant figures even though the PI calculation would allow input to four significant figures). In all cases, however, the accuracy of the raw data should be considered.

Posting Date 11/11/1999 ***ID*** 25 ***Archive Date*** 7/1/2001

Topic Activity Spikes

Question PWRs can expect RCS Specific Activity spikes following routine shutdowns. Are these spikes to be counted as the monthly maximum?

Response The indicator definition refers to the Technical Specifications' maximum monthly activity limit. The basis for this indicator is to monitor steady state power operations. Therefore, do not count short periods of non-steady-state or non-power operation because they may not equate to the current condition of the fuel cladding.

Posting Date 11/11/1999 ***ID*** 24 ***Archive Date*** 7/1/2001

Topic Use of Analyzed Samples

Question Are RCS sample results determined during shutdowns, using the technical specification methodology, required to be reported even if the plant is in a mode that does not require the sample. Administratively, the plant may be in a plant condition that requires the sample and analysis, although it is not required by Technical Specifications.

Response No.

Posting Date 11/11/1999 **ID** 23 **Archive Date** 7/1/2001

Topic Use of Analyzed Samples

Question Technical Specifications (TS) provide a frequency of reactor coolant sampling and analysis. If sampling and analysis is conducted on a more frequent basis, do you only report the analysis conducted at the TS frequency, or do you consider all the analyzed samples.

Response All analyzed samples obtained during steady state power operation should be considered in reporting the monthly maximum.

Posting Date 11/11/1999 **ID** 22 **Archive Date** 7/1/2001

Topic Technical Specification Requirements

Question The Reactor Coolant System Specific Activity performance indicator is based upon a measurement of RCS activity in micro-Curies per gram dose equivalent Iodine-131. Our plants measurement and associated technical specification are based upon micro-curies per gram total Iodine. What do we report for this performance indicator.

Response RCS activity for this indicator is expressed as a percentage of the technical specification limit. The maximum monthly RCS activity and your technical specification limit should be reported on a common basis. In your case RCS activity and the technical specification limit should be reported in micro-Curies per gram total Iodine.

Posting Date 04/01/2000 **ID** 135 **Archive Date** 7/1/2001

Topic

Question Our Tech Spec requires test/evaluation of primary system leakage 5 times per week. The Tech Spec limits (LCOs) are 1 gpm unidentified and 10 gpm Total. The Reactor Operators perform a daily calculation of RCS leakage based on mass flow differences, which is equivalent to Total leakage from the RCS. The unidentified RCS leak rate is also determined daily based on the daily total but using a weekly calculated Identified leak rate and subtracting it from the daily total leak rate. Based on the NEI 99-02 guideline, we would use the weekly-calculated identified leak rate? Is this correct? This leak rate is sometimes calculated more frequently due to increases in leakage during the week. Many times the identified leak rate is zero. We can look at a months worth of calculations (usually 4) and see which one is the highest and report that. Is that the intent of the PI?

Response Report the highest monthly value computed in accordance with the calculational methodology requirements of the Technical Specifications.

Posting Date 01/07/2000 **ID** 79 **Archive Date** 7/1/2001

Topic Use of Total Leakage Value

Question We have implemented ITS and have TS definitions for Reactor Coolant leakage. We have a defined limit for "Total Leakage" (25 gpm) and "Un-identified Leakage" (5 gpm). We do not have a specified limit for "Identified Leakage". You can infer directly from our TS limits an identified leakage limit of no more than 20 gpm (25 gpm total minus 5 gpm the amount of leakage we call "unidentified leakage"). Using this approach, the Tech Spec limit for the PI could vary between 25 and 20 gpm depending on the amount of "un-identified leakage" we have. Why can't we use the 20-25 gpm as the limit for the PI as can others who do not have a total leakage TS limit?

<p>The best indicator of barrier performance seems to be "Un-identified Leakage" rather than identified leakage. Unidentified is the amount of leakage falling outside designed collection systems. Trending the percentage of "Un-identified Leakage" presents a more clear picture of how well a plant is maintaining their Reactor Coolant system. It is also very well defined. It also seems to meet the SECY objective to be an indication of the "probability of more catastrophic failure potential" as specified in para C.4.5. Why is this PI concerned with identified and not Unidentified leakage?

Response NEI 99-02 states that total leakage will be used for those plants that do not have a Technical Specification limit on Identified Leakage. This is considered acceptable to provide consistency in reporting for those plants.Not all plants track total leakage. Identified leakage was chosen as capturing most of the allowed leakage.

Posting Date 01/10/2001 **ID** 243 **Archive Date** 7/1/2001

Topic

Question Part A – Indication of the event was available to the operators<p>A licensee may discover after the fact (greater that 15 minutes) that an event or condition had existed which met the emergency plan criteria but that no emergency had been declared and the basis for the emergency class no longer exist at the time of discovery. Indication of the event was available to the operators.<p>a) Should the condition described be considered as a missed classification opportunity?<p>b) Should the condition described be considered as a missed notification opportunity?<p>Part B – Indication of the event was not available to the operators<p>A licensee may discover after the fact (greater that 15 minutes) that an event or condition had existed which met the emergency plan criteria but that no emergency had been declared and the basis for the emergency class no longer exist at the time of discovery. Indication of the event was not available to the operators. In determination of whether indications were indeed not available to the operators, the timeliness of necessary calculations, verification efforts, etc. as required by EALs or physical reality, must be considered.<p>c) Should the condition described be considered as a missed classification opportunity?<p>d) Should the condition described be considered as a missed notification opportunity?

Response Part A – Indication of the event was available to the operators<p>a) Yes, this classification was not timely.<p>b) No. NUREG 1022 described the notification requirements for this consideration.<p>Part B – Indication of the event was not available to the operators<p>c) No, indication of the emergency was not available to operators until the basis for the emergency no longer existed.<p>d) No. NUREG 1022 describes the notification requirements for this consideration.

Posting Date 01/10/2001 **ID** 242 **Archive Date** 7/1/2001

Topic

Question Can initial notification be considered accurate if some of the elements on that notification form are in error?

Response Yes. NEI 99-02 indicates on page 91, line 27 that accuracy is defined by the approved Emergency Plan and implementing procedures. However, it is realized that functionally, some of the items on an initial notification form may not be significant in that mistakes in that information will not affect the offsite response. The elements which should be assessed for accuracy on the initial notification include:<p>Class of emergency<p>EAL # <p>Description of emergency (Note: the description of the event causing the classification may be brief and should not include all plant conditions. At some sites, the EAL # fulfills the need for a description.)<p>Wind direction and speed<p>Whether offsite protective measures are necessary <p>Potentially affected population and areas <p>Whether a release is taking place (Note: “release” means a radiological release attributable to the emergency event.)<p>Date and time of declaration of emergency<p>Whether the event is a drill or actual event<p>Plant and/or unit, as applicable<p>It is understood that initial notification forms are negotiated with offsite authorities. If the approved form does not include these elements, they need not be added. Alternately, if the form includes elements in addition to these, those elements need not be assessed for accuracy when determining the DEP PI. It is, however, expected that errors in such additional elements would be critiqued and addressed through the corrective action system

Posting Date 01/01/2001 **ID** 235 **Archive Date** 7/1/2001

Topic

Question Assume that an event has occurred that has resulted in an Emergency Classification. Subsequently, a utility review of the event reveals that the classification was made conservatively and that, in fact, no emergency classification criterion was exceeded. <p>Should the event be considered as an opportunity?

Response Yes, the event should be considered as an opportunity. The classification opportunity should not be considered as a success because it was not declared accurately according to the review conducted by the utility.

Posting Date 01/01/2001 **ID** 234 **Archive Date** 7/1/2001

Topic

Question NEI 99-02, Rev 0, page 100, lines 11-15, discusses the role of communicators who provide offsite notifications. A site has identified the TSC and EOF senior managers as communicators for the purposes of tracking drill participation. The basis for this is that these senior manager are "responsible" for off site notifications because they approve them before they are communicated to off site agencies.<p>Is this an appropriate interpretation of 99-02?

Response No. The expectation of 99-02 is that the participation of the communicators in drills will be tracked through the ERO Drill Participation PI. The communicator is the key ERO position that collects data for the notification form, fills out the form, seeks approval and usually communicates the information to off site agencies. Performance of these duties is assessed for accuracy and timeliness and contributes to the DEP PI. The senior managers in the above example do not perform these duties and should not be considered communicators even though they approve the form and may supervise the work of the communicator. <p>However, there are cases where the senior manager actually collects the data for the form, fills it out, approves it and then communicates it or hands it off to a phone talker. Where this is the case, the senior manager is also the communicator and the phone talker need not be tracked.

Posting Date 08/30/2000 **ID** 202 **Archive Date** 7/1/2001

Topic

Question Regarding taking credit for notification performance opportunities, NEI 99-02, page 91 defines opportunities for notifications as those made to the state and/or local government authorities. The guidance further defines timely as those offsite notifications that are initiated must be verbal in nature. On page 92 under clarifying notes (second paragraph), NEI 99-02 states that notifications may be included in the PI if they are performed to the point of filling out the appropriate forms and demonstrating sufficient knowledge to perform the actual notification. This particular note applies to operating shift simulator evaluations, not emergency drills.

<p>Can credit be taken for the notification performance opportunity when notifications are simulated during emergency drills (i.e., not operator simulator evaluations), with no actual verbal contact, as long as the procedures are completed up to the time the notification is made?

Response Yes. 99-02 allows for the simulation of notification of offsite agencies in the case of simulator based drills. There is no reason not to allow the same simulation for other EP drills. However, since the guidance in NEI 99-02 seems specific to simulator drills, it has been interpreted as not allowing such simulation for other drills. (Editorial Note: The guidance will be clarified in a future revision of the document.)

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

Posting Date 07/12/2000 **ID** 198 **Archive Date** 7/1/2001

Topic

Question For expansion of the Protective Action Recommendation (PAR), does the 15 minute assessment period start as soon as any dose projection is received indicating that the PAR might need to be expanded, or when there is sufficient field data to confirm that the PAR needs to be expanded?

Response A conservative approach should be utilized in recognizing the need for PAR expansion. PARs are developed within 15 minutes of data availability. Plant conditions, meteorological data and/or radiation monitor readings should provide sufficient information to determine the need to change PARs. While field monitoring data can be useful, it is not appropriate to wait for that data to become available if other data demonstrate the need to expand the PAR.

Posting Date 07/12/2000 ***ID*** 197 ***Archive Date*** 7/1/2001

Topic

Question For sites with multiple agencies to notify, are notifications considered to be initiated when the first agency is contacted or when the last agency is contacted?

<p>The site makes notification to 6 offsite agencies, usually simultaneously using a dedicated telephone line. About 95% of the time, we are able to get all 6 agencies on the line at one time. However, there have been a few cases when we haven't achieved this goal. With six different agencies to contact, there are many things that could go wrong that would prevent getting all of the agencies at one time. There is a thorough backup process in place to deal with these problems and still ensure timely notifications. Furthermore, the dedicated line is tested monthly to ensure its reliability. This question arises for the situation when it doesn't. In such a case, we do sequential calls.

<p>When calling sequentially, it will clearly take longer for a site that has 6 agencies to initiate contact with the 6th agency than it will take for a site that has only 1 agency. The criteria should be clarified to indicate that notifications should be considered timely if verbal contact is made to the first agency within 15 minutes of event declaration.

Response The notification is considered to be initiated when the first agency is contacted. As noted on page 91 of NEI 99-02 in the definition of timely, the offsite notifications are to be initiated (verbal contact) within 15 minutes of classification or PAR development. It should be noted that in many drill situations, the verbal contact may be with a controller rather than the actual offsite agency, or the contact with offsite agencies may be simulated in a manner that otherwise reasonably simulates the interaction.

Posting Date 07/12/2000 ***ID*** 195 ***Archive Date*** 7/1/2001

Topic

Question This question pertains to a General Emergency Classification in which the notification of the GE Classification and the notification of the initial PAR for the General Emergency condition are integral. Should this condition count as one or two notification opportunities?

Response Two. As is discussed in Question ID 29 on page 93 of NEI 99-02, notification of the PAR and notification of the GE Classification are separate opportunities, individually subject to the timeliness and accuracy criteria.

Posting Date 05/02/2000 ***ID*** 173 ***Archive Date*** 7/1/2001

Topic

Question During an evaluated scenario, the conditions for a General Emergency (GE) were met based on Plant conditions with three barriers breached. The Emergency Director (ED) failed to recognize the classification conditions had been met within 15 minutes. After the 15 minutes, a release occurred and a dose projection was performed which exceeded levels for a GE. The ED recognized this and a GE was declared based on Radiological Conditions and all required notifications and PARs were completed.

<p>(1) Would the first opportunity based on Plant conditions be considered a missed opportunity?
<p>(2) Would a second opportunity be allowed based on Radiological conditions?
<p>(3) If a second opportunity is not allowed can any credit be taken for successfully completing notification and PAR opportunities based on the second opportunity?

Response (1) Yes
<p>(2) No, because it was not the expected timely and accurate classification opportunity as described in the scenario. In some cases, the scenario controllers may prompt the ED to classify with the same

result, a failed opportunity to classify.
<p>(3) Yes, credit should be taken for the success or failure of the notification, PAR development and the PAR notification. The subsequent opportunities must not be removed from performance indicator statistics due to poor performance. Additionally, any subsequent PAR changes and the associated notification would also be assessed for timely and accurate completion.

<p> Assuming the notifications and the PAR development were timely and accurate, the result is that three out of four opportunities would be reported as successful in performance indicator statistics.

Posting Date 04/01/2000 **ID** 125 **Archive Date** 7/1/2001

Topic Fifteen minute periods

Question For the purpose of establishing success criteria for the EP DEP PI, how many 15-minute periods could there be for the example situation of a plant initially reaching a General Emergency?

Response The licensee should classify an emergency once the data is available. The licensee should take a prudent approach and not delay classification due to uncertainty. Once the data is available the licensee should classify the event (NUE, Alert, Site Area, or General Emergency) and PAR within 15 minutes. Expectations are that you assess and classify the situation within 15 minutes. If you were done in 5 you should not wait the remaining 10 minutes. The call to the offsite emergency response organizations should be initiated during the next 15-minute time frame. Any changes to classification or PARs should reflect the same 15 minute sequence.Hence there are two 15 minute time frame goals:(1) to determine the classification and PAR, and(2) to initiate notifications to the offsite emergency response agency.

Posting Date 11/11/1999 **ID** 43 **Archive Date** 7/1/2001

Topic PI

Question May credit for ERO be taken from drills that do not contribute to DEP?

Response If the position performs one of the risk significant EP functions, classification, notification or PAR development, then the drill/exercise used for ERO statistics must contribute to DEP statistics. However, some positions are not responsible for these risk significant functions and participation in a drill that does not contribute statistics to DEP could be credited as participation. For example the OSC Operations Management position could drill without contribution to DEP, as could Health Physics positions not responsible for PARs. The appropriateness including drills involving HP positions responsible for PARs is site specific. Many sites develop PARs through a management review process of the dose projections provided by HP. That being the case, drills involving just the dose projection may not be appropriate for DEP statistics, but may be appropriate for ERO Drill participation statistics.

Posting Date 11/11/1999 **ID** 41 **Archive Date** 7/1/2001

Topic Evaluation

Question How should performance be evaluated when drill participants properly declare an emergency classification that the scenario did not anticipate?

Response The opportunity may be counted as a success, However, a corrective action should be written against the scenario (or the scenario development process). Another aspect of the same issue is that if a classification is missed that was not anticipated by the scenario, it too should be counted, but as a missed opportunity.

Posting Date 11/11/1999 **ID** 40 **Archive Date** 7/1/2001

Topic Reporting

Question What if PI data is not readily available at the end of a quarterly reporting cycle, e.g., a six week operator training cycle begins before the end of quarter, but is not completed until after the quarterly reporting date.

Response The data may be reported in the next quarter, but this practice must be implemented consistently. Inspection will verify that the data is not preferentially reported to manipulate PIs.

Posting Date 11/11/1999 **ID** 39 **Archive Date** 7/1/2001

Topic Revision

Question If the utility holds the ERO to the standard of identifying multiple EALs for the same classification, could multiple opportunities for classification of a particular emergency classification be allowed?

Response This idea has merit and if a proposal were received the Staff would consider it. However, several aspects should be considered in such a proposal including consistent implementation (all opportunities are assessed); consistent evaluation; how does the ERO member document/verbalize the additional EAL; what time frame is acceptable; and will the effort detract from other expected actions.

Posting Date 11/11/1999 **ID** 38 **Archive Date** 7/1/2001

Topic Weighting

Question Why are the opportunities for NOUEs and Alerts being treated numerically the same as the ones associated with the more risk significant SAEs and GEs?

Response Although the working group initially considered using weighting factors to emphasize opportunities associated with SAEs and GEs, industry (NEI) guidance suggested that this would unnecessarily complicate the indicator calculation and not be consistent with calculation of the other PIs. PI experts within NRC concurred with this assessment.

Posting Date 11/11/1999 **ID** 37 **Archive Date** 7/1/2001

Topic Evaluation

Question During drill performance, the ERO may not always classify an event exactly the way that the scenario specifies. This could be due to conservative decision making, Emergency Director judgment call, or a simulator driven scenario that has the potential for multiple 'forks'. How does the program deal with these correct classification determinations that may not follow the path the evaluators were expecting?

Response The NRC realizes that such situations can arise and that the acceptability of the classification may be subjective. In such cases, evaluators should document the rationale supporting their decision for eventual NRC inspection. However, as specified in NEI 99-02, in evaluating the acceptability of the classification, the evaluators have to determine if the classification was appropriate to the event as specified by the approved emergency plan and implementing procedures.

Posting Date 11/11/1999 **ID** 36 **Archive Date** 7/1/2001

Topic Opportunities

Question Is there not the possibility that PARs could be issued at the SAE level?

Response If PARs at the SAE are in the site Emergency Plan they could be counted as opportunities. However, this would only be appropriate where assessment and decision making is involved in development of the PAR. Automatic PARs with little or no assessment required would not be an appropriate contributor to the PI. PARs limited to livestock or crops and no PAR necessary decisions are also not appropriate.

Posting Date 11/11/1999 **ID** 35 **Archive Date** 7/1/2001

Topic Evaluation

Question Does success in classification, notification and PARs depend on the individual or team response - could an individual failure to properly classify, notify or develop PARs be corrected by the team and still be counted as a success for this indicator?

Response The measures for successful opportunities under this indicator are accuracy and timeliness. As long as the classification, notification or PARs are timely and accurate, success is established. If the initial error of the individual is identified and corrected so that the timeliness criterion is met, the opportunity is successful.

Posting Date 11/11/1999 **ID** 34 **Archive Date** 7/1/2001

Topic Evaluation

Question If the ERO fails to identify a GE, does this count as 4 failures: one for the classification, one for the notification of the GE, one for the notification of the PARs and one for the PARs?

Response It will only count as one failure: failure to classify the GE. This is because notification of the GE, development and notification of the PARs are actions that have to be performed as a consequence of the GE classification and that it can't be inferred a posteriori that these actions would have failed.

Posting Date 11/11/1999 **ID** 33 **Archive Date** 7/1/2001

Topic Drills/Exercises

Question How does this performance indicator evaluate the difficulty of the drill/exercise?

Response In general, PI's are a summary indication of the status of a program element. They are not used to evaluate the details of performance, rather they indicate the need to evaluate the details of performance. This PI was not designed to quantify the difficulty of scenarios. However, NRC inspectors will observe drills and the biennial exercise. If scenarios are inadequate to test the emergency plan, regulatory action may be taken in accordance with Appendix E to 10 CFR 50, Section IVF.f.

Posting Date 11/11/1999 **ID** 32 **Archive Date** 7/1/2001

Topic Drills/Exercises

Question Why is there not a specified number of facility type drills? a utility could do 60 simulator drills and no EOF drills

Response This concern is addressed through the Emergency Response Organization Drill Participation (ERO) PI, which would show decreasing performance should a licensee go down this path.

Posting Date 11/11/1999 **ID** 31 **Archive Date** 7/1/2001

Topic Evaluation

Question Would the evaluators for drills or exercises have to be trained in order to assess opportunities correctly?

Response Qualifications or required training for drill/exercise evaluators was not specified because this has not been a problem. There is a good history of competent exercise evaluation by licensees. However, it would be expected that evaluators be knowledgeable of the performance area they evaluate and with the guidance of NEI 99-02 regarding the EP cornerstone.

Posting Date 11/11/1999 **ID** 30 **Archive Date** 7/1/2001

Topic Opportunities

Question Could it be implied that for each classification opportunity, there may be several associated notification opportunities due to the need to notify several different State/local authorities?

Response For each classification opportunity, there is only one associated notification opportunity even if several different State/local authorities need to be notified.

Posting Date 11/11/1999 **ID** 29 **Archive Date** 7/1/2001

Topic Opportunities

Question How do you count opportunities for PARs and notifications associated with PARs?

Response The development of an initial PAR and any changes to the PAR (usually no more than one or two follow-up changes due to wind shift or dose assessment) are to be counted. The notification associated with the PAR is counted separately: e. g., an event triggering a GE classification would represent a total of 4 opportunities: 1 for classification of the GE, 1 for notification of the GE to the State and/or local government authorities, 1 for development of a PAR and 1 for notification of the PAR. NEI 99-02 defines the term Opportunity.

Posting Date 11/11/1999 **ID** 28 **Archive Date** 7/1/2001

Topic Opportunities

Question For an actual event there may be many non-emergency events that require evaluation against the EALs. If this evaluation does not result in a classification, does the actual event count as an opportunity?

Response No it doesn't count as an opportunity. Opportunities begin when a classification is made.

Posting Date 11/11/1999 **ID** 27 **Archive Date** 7/1/2001

Topic Opportunities

Question Does a tabletop drill count for opportunities?

Response The definition of table-top drill is not clear. However, the licensee has the latitude to include opportunities in the PI as long as the drill (in whatever form) simulates the appropriate level of inter-facility interaction as described in NEI 99-02. Once identified, opportunities cannot be removed from the indicator due to poor performance.

Posting Date 11/11/1999 **ID** 26 **Archive Date** 7/1/2001

Topic Opportunities

Question How many opportunities per year for evaluating the performance of the Control Room crews are typically available?

Response This will vary depending on the design and structure of the operator training program and the size of the staff. For example, at a single unit plant with 5 operating crews, there are usually about 8 simulator training cycles. Ostensibly, any of these cycles could include opportunities. For estimation purposes, it was assumed that two cycles per year contain a classification and notification opportunity, which results in a total of 20 per year. Additional opportunities could be presented in other parts of the drill/exercise program.

Posting Date 10/31/2000 **ID** 233 **Archive Date** 7/1/2001

Topic

Question A licensee used same scenario for each of the three response teams. The drills contributed to DEP and ERO statistics. Repetitive use of the scenario has the potential to skew the PI success rate if scenario confidentiality is not maintained. There was no indication that drill participants were intentionally informing other teams about the scenario, but discussions of the drill could inadvertently reveal facts about the scenario. <p>Is it permissible to repeat the use of scenarios in drills that contribute to DEP and/or ERO statistics?

Response Yes, the licensee need not develop new scenarios for each drill or each team. However, it is expected that the licensee will maintain a reasonable level of confidentiality so as to ensure the drill is a proficiency-enhancing evolution. A reasonable level of confidentiality means that some scenario information could be inadvertently revealed and the drill remains a valid proficiency-enhancing evolution. It is expected that the licensee will remove from the drill performance statistics any opportunities considered to be compromised.<p>There are many processes for the maintenance of scenario confidentiality that are generally successful. Examples may include the following:<p>* Confidentiality statements on the signed attendance sheets,<p>* Spoken admonitions by drill controllers.<p><p>Examples of practices that may challenge scenario confidentiality include:<p>* Drill controllers or evaluators or mentors, who have scenario knowledge becoming participants in subsequent uses of the same scenarios,<p>* Use of scenario reviewers as participants.

Posting Date 04/01/2000 ***ID*** 126 ***Archive Date*** 7/1/2001

Topic Shift Communicator Function

Question Is it appropriate to track the Shift Supervisor's drill participation to meet the "shift communicator function" described in NEI 99-02?

Response Yes, if the Shift Supervisor fills the Shift Communicator function.

Posting Date 02/15/2000 ***ID*** 85 ***Archive Date*** 7/1/2001

Topic Shift Manager

Question In NEI 99-02, under Definition of Terms (Pg. 81), Control Room Shift Manager (Emergency Director) is identified as a key ERO member. We currently only include those Shift Managers who have been permanently assigned to an operating crew. Operations Department personnel who may be qualified as Shift Manager and may fill this role in relief (vacations, training, etc.) or periodically to maintain qualifications are not currently considered under this indicator.

<p>Should all individuals qualified to fill the Shift Manager position be considered under this indicator, regardless of whether they are assigned to a specific crew on a continuing basis?

Response Yes. All individuals qualified to fill the Shift Manager position who actually might fill the position should be included in this indicator.

Posting Date 11/11/1999 ***ID*** 54 ***Archive Date*** 7/1/2001

Topic Operators

Question Many plants have staff personnel who hold SRO licenses. These individuals only stand watch in the control room as necessary to retain an active license. Is it necessary to track these individuals under the ERO PI?

Response Yes, because they could perform as the Shift Manager in an actual event. However, an informal survey of EP programs indicated that these personnel routinely participate in drills, either as key ERO members, or as evaluators. This being the case, the burden for licensees should be minimal.

Posting Date 11/11/1999 ***ID*** 53 ***Archive Date*** 7/1/2001

Topic Duty Roster

Question Can a single person fill multiple key functions?

Response Yes, if that is in accordance with the approved emergency plan.

Posting Date 11/11/1999 ***ID*** 52 ***Archive Date*** 7/1/2001

Topic Duty Roster

Question If a person is not yet qualified to fill a certain key ERO position but participated in a drill in that position for qualification purposes, would that participation count?

Response This could be left to the licensee’s judgment and verified by inspection. Where the participation in the drill/exercise is a proficiency?enhancing experience it could be counted. This would mean that the individual is familiar with the position and able to perform it but perhaps the lack of qualification is merely due to the timing of required classroom training. However, he should not formally be on the duty roster until fully qualified. When that occurs, the drill/exercise participation date could be used in reporting ERO.

Posting Date 11/11/1999 ***ID*** 51 ***Archive Date*** 7/1/2001

Topic Evaluation

Question What would happen if an ERO member fails to correctly perform its duties, for example invoked a wrong classification - does this count as participation?

Response Yes, the participation would count and the missed opportunity for proper classification would be reflected in the DEP indicator. It might be expected that the individual will receive feed back on performance to ensure proficiency, but as long as the DEP PI is in the licensee response band, this problem is left to the licensee to correct.

Posting Date 11/11/1999 **ID** 50 **Archive Date** 7/1/2001

Topic Duty Roster

Question When a key ERO member is added to the organization or changes from one key ERO position to a different key ERO position between drills, is there a grace period for having him or her participate in drills?

Response No, there is no grace period. However, if the individual's new position is similar to the old one, the last drill/exercise participation may count. If the new position is unrelated to the old position then the previous participation would not count.

Posting Date 11/11/1999 **ID** 49 **Archive Date** 7/1/2001

Topic Duty Roster

Question Is there a minimum number of ERO members.

Response The NRC's requirements for minimum staffing at nuclear power plants are given in NUREG 0654 Table B-1. The site Emergency Plan commits to a method to meet these requirements and that is the minimum ERO. The PI measures the participation of a segment of the ERO (key ERO members as defined in NEI 9902) in drills/exercises (or other appropriate proficiency enhancing experiences).

Posting Date 11/11/1999 **ID** 48 **Archive Date** 7/1/2001

Topic Drill Frequency

Question Is participating in a performance-training environment once every two years the new minimum expectation?

Response There is no NRC requirement associated with the frequency of ERO personnel participation in drills or exercises. However, the threshold for this PI is that 80% of the key ERO members participate on a 2 year frequency for a plant to be considered as operating in the licensee response band (green).

Posting Date 11/11/1999 **ID** 47 **Archive Date** 7/1/2001

Topic Duty Roster

Question Could a licensee have key ERO members cycle through a position for an exercise or drill and allow them to be counted for this indicator?

Response The licensee can have key ERO members cycle through a position for an exercise or drill and allow them to be counted for this indicator as long as the licensee can justify that their participation is a proficiency-enhancing experience.

Posting Date 11/11/1999 **ID** 46 **Archive Date** 7/1/2001

Topic Duty Roster

Question How does the program handle the case where the number of key ERO members is different at the end of the evaluation period than at the beginning of it?

Response This indicator is calculated based on the number of key ERO members at the end of the quarter.

Posting Date 11/11/1999 ***ID*** 45 ***Archive Date*** 7/1/2001

Topic Duty Roster

Question How does the program handle the case where someone shifts ERO position during the drill or exercise?

Response The person's participation may be counted for each position as long as the participation constitutes a proficiency-enhancing experience. The licensee will make this determination. The NRC will verify the adequacy of the licensee's determination as part of its performance indicator verification inspection.

Posting Date 11/11/1999 ***ID*** 44 ***Archive Date*** 7/1/2001

Topic Duty Roster

Question How does the program address a person who is qualified in more than one position and listed on the ERO roster for all positions that he or she is qualified to fill?

Response The licensee has to evaluate if the different positions being filled by the individual require different knowledge and skills to perform. If they do then it is expected that the person be counted in the denominator for each position and in the numerator only for drill/exercise participation that addresses each position. Where the skill set is similar, a single drill or exercise might be counted as participation in both positions. Examples of similar skill sets may include: Emergency Managers and their assistants or technical support staff; Communicators in different facilities; Health Physics personnel in different facilities. However, important differences in duties must be considered, e.g., TSC HP positions may involve onsite radiation safety where as EOF HP positions would not, and the EOF HP positions may involve dose projection duties where as the TSC HP positions may not.

<p>Another option would be to evaluate the need to maintain this person qualified to fill multiple positions if the depth of positions being filled is more than four, then dual qualification of the individual may not be necessary, depending on the design of the duty roster and call out system.

Posting Date 01/10/2001 ***ID*** 246 ***Archive Date*** 7/1/2001

Topic

Question If a siren is out of service during a planned overhaul or upgrade project does this need to count as both a siren test and a siren failure?

Response Discussion:The ANS PI measures the percentage of ANS sirens that are capable of performing their safety function, as measured by periodic siren testing in the previous four quarters. NEI 99-02 states, "If a siren is out of service for maintenance or is inoperable at the time a regularly scheduled test is conducted, then it counts as both a siren test and a siren failure."<p>ANS systems are aging and many sites are considering and/or performing siren overhaul or system upgrade projects. The ANS PI threshold may impact project planning in an unintended manner. It is not the intent to create a disincentive for performing ANS overhaul or upgrade projects. <p>When sirens are out of service for such projects, it is expected that the utility arrange for back-up public alerting in the appropriate siren coverage areas. This support is typically provided by local offsite agencies and often involves route alerting. The acceptable time frame for allowing a siren to remain out of service for system upgrade or preventive maintenance should be coordinated with the cognizant offsite agencies. Based on the impact to local agencies and the ANS functionality, outage time frames should be minimized and specified in ANS Upgrade/Overhaul Project Documents. When the time frame is identified in advance as part of an upgrade or overhaul project, and back-up public alerting coverage agreed to by offsite agencies, regularly scheduled tests during the siren outage may be excluded from the ANS PI statistics. Deviations from the advance outage schedule would constitute unplanned siren reliability and siren-test failures outside of the preplanned outage window would be included in the PI. This modification of the PI is not intended for preventative or corrective maintenance, i.e., siren-test failures due to preventative or corrective maintenance must be included in the ANS PI. <p>Response:No, if the ANS overhaul or upgrade project meets certain requirements as delineated in the discussion section of this FAQ. However, the exclusion is not intended for preventative or corrective maintenance.

Posting Date 10/31/2000 ***ID*** 232 ***Archive Date*** 7/1/2001

Topic

Question Siren systems may be designed with equipment redundancy or feedback capability. It may be possible for sirens to be activated from multiple control stations. Feedback systems may indicate siren activation status, allowing additional activation efforts for some sirens. <p>1) A siren system has two normally attended control stations from which the system may be activated. If a siren test from one station is unsuccessful can a test performed from the second station be considered as a part of the regularly scheduled test?<p>2) A siren test technician sent multiple activation signals to a siren that initially appeared not to respond. The siren responded. Can the multiple signals be considered as the regularly scheduled test and hence a success?

Response 1) Yes, if the use of redundant control stations is in approved procedures and is part of the actual system activation process. A failure of both systems would only be considered one failure, where as the success of either system would be considered a success. <p>If the redundant control station is not normally attended, requires set up or initialization, it may not be considered as part of the regularly scheduled test. Specifically, if the station is only made ready for the purpose of siren tests it should not be considered as part of the regularly scheduled test.<p>2) Yes, if the use of multiple signals is in approved procedures and part of the actual system activation process. However, the use of multiple activation signals to achieve successful siren tests may not include any activities outside the regularly scheduled test, such as troubleshooting, post maintenance testing or activation signals sent after the initial activation process has ended.

Posting Date 10/31/2000 ***ID*** 229 ***Archive Date*** 7/1/2001

Topic

Question During a scheduled siren test, a siren (or sirens) fail or cannot be verified to have responded to the initial test. A subsequent test is done to troubleshoot the problem. <p>1) Should the troubleshooting test(s) be counted as siren test opportunities? <p>2) Should failures during troubleshooting be considered failures?<p>3) Should post maintenance testing or system retests after maintenance be counted as opportunities?<p>4) If subsequent testing shows the siren to be operable (verified by telemetry or simultaneous local verification) without any corrective action having been performed, can the initial test be considered a success?

Response 1) No. These tests are not regularly scheduled tests because they are only conducted if there are siren failures. <p>2) No. These tests are not regularly scheduled tests because they are only conducted if there are siren failures. <p>3) No. These tests are not regularly scheduled tests because they are only conducted if there are siren failures. <p>4) Yes, but only if it is reasonably verified that the failure was in the testing equipment and not the siren control equipment, i.e., the siren would have sounded when called upon, even though the testing equipment would not have indicated the sounding. In the process of verifying that the failure is only with testing equipment, problems such as radio signal transmission weakness or intermittent signal interference should be eliminated as the cause. Maintenance records should be complete enough to support such determinations and validation during NRC inspection.

Posting Date 07/12/2000 ***ID*** 200 ***Archive Date*** 7/1/2001

Topic

Question Appendix D – Grand Gulf
<p>Of the 43 sirens associated with our Alert Notification System, two of the sirens are located in flood plain areas. During periods of high river water, the areas associated with these sirens are inaccessible to personnel and are uninhabitable. During periods of high water, the electrical power to the entire area and the sirens is turned off. The frequency and duration of this occurrence varies based upon river conditions but has occurred every year for the past five years and lasts an average of two months on each occasion.

<p>Assuming the sirens located in the flood plain areas are operable prior to the flooded and uninhabitable conditions, would these sirens be required to be included in the performance indicator during flooded conditions?

Response If sirens are not available for operation due to high flood water conditions and the area is deemed inaccessible and uninhabitable by State and/or Local agencies, the siren(s) in question will not be counted in the numerator or denominator of the Performance Indicator for that testing period.

Posting Date 05/02/2000 ***ID*** 174 ***Archive Date*** 7/1/2001

Topic

Question For plants where scheduled monthly siren tests are initiated by local or state governments, if a scheduled test is not performed either (intentionally or accidentally), is this considered a failure?

Response No. For purposes of the NRC PI, missed tests should be considered non-opportunities.

Posting Date 04/01/2000 ***ID*** 124 ***Archive Date*** 7/1/2001

Topic Shared sites

Question The EP cornerstone, PI Alert and Notification System Reliability reports tests performed of off-site sirens to determine the systems reliability. Indian Point 3 is on the same site as Indian Point 2 but owned and operated by the New York Power Authority. IP3 uses the offsite sirens to meet its EP requirements. However, the sirens are owned, operated, and tested by Con Edison, owners of Indian Point 2. IP3 has an administrative agreement on use of the sirens by IP2 for IP3. Con Edison (IP2) notifies NYPA (IP3) by letter on the results of their siren testing and the status of their equipment. Question; does Indian Point 3 have to report data for this PI (EP03) since NYPA does not perform the testing nor control the sirens, and only reports what Indian Point 2 reports ? (i.e., duplicate what IP2 reports)

Response Yes. The responsibility to notify the public is held mutually by each licensee located on the same site with the same EPZ. Therefore, each licensee should provide alert and notification performance data event if it is repetitive due to a mutually shared site.

Posting Date 04/01/2000 ***ID*** 123 ***Archive Date*** 7/1/2001

Topic Sirens testing

Question Some of the sirens included in the alert and notification performance indicator have the capability to be sounded from a remote location using a siren encoder. A quarterly 'growl' test is conducted at each siren site. Encoder testing is performed separately. Does the malfunction of a remote siren encoder constitute a failure if the siren is functional by local actuation?

Response Testing mechanisms used to comply with FEMA reporting methodology should be used to report performance indicator statistics. Failures occurring during this testing would count toward the performance indicator.

Posting Date 04/01/2000 ***ID*** 122 ***Archive Date*** 7/1/2001

Topic Counting of out-of-service sirens

Question In defining the “total number of siren-tests in the previous 4 quarters” should those sirens not tested because they were either out of service or undergoing maintenance at the time of the test be included in the denominator of total number of siren-tests? Should this number simply be the total number of sirens times the number of tests or the actual number of sirens tested? In our case, all sirens are always tested (except those that cannot be physically tested due to outage or maintenance) as part of each test.

Response The total number of sirens should be reported in the denominator.

Posting Date 11/11/1999 ***ID*** 56 ***Archive Date*** 7/1/2001

Topic Sirens

Question If some sirens were unavailable due to storm damage, would the missed siren-tests prior to the sirens being returned to service be considered failures?

Response Yes, the missed siren-tests would be considered failures. However, if the licensee can repair the damaged sirens prior to the test, then the siren tests would be considered successful.

Posting Date 11/11/1999 ***ID*** 55 ***Archive Date*** 7/1/2001

Topic Equipment

Question This indicator only monitors siren reliability. Why aren’t other EP equipment and facilities monitored?

Response Ensuring public health and safety is the goal of the NRC oversight program. Analysis of the EP function shows that the ANS is a risk-significant system in ensuring licensee ability to protect the public health and safety. There is other important equipment and facilities, but ensuring the readiness of these is in the licensee response band. ERO measures the participation of key emergency response organization members in drills/exercises and assumes, in part, that such participation is a good method to identify equipment and facility problems. DEP measures timely and accurate classifications, notifications and PARs, which can only be performed if communication and assessment equipment are functioning. It is expected that licensee corrective action programs will address equipment readiness problems that are identified during drills. These programs are a focus of the NRC inspection program.

Posting Date 01/10/2001 ***ID*** 240 ***Archive Date*** 7/1/2001

Topic

Question A Technical Specification High Radiation Area Performance Indicator occurrence is defined as a nonconformance with technical specifications and comparable requirements in 10CFR20 applicable to high radiation areas (>1 rem per hour) that results in the loss of radiological control. What are the comparable requirements in 10CFR20 applicable to these high radiation areas?

Response The comparable requirements in 10CFR20 applicable to high radiation areas (>1 rem per hour) are found in 10CFR20.1601 "Control of access to high radiation areas". Paragraphs (a), (b), (c), and (d) apply.

Posting Date 08/30/2000 ***ID*** 203 ***Archive Date*** 7/1/2001

Topic

Question Because of a breakdown in communications between the rad waste and health physics groups, a post-job survey was not performed following completion of a resin sluicing evolution. Several hours later, health physics became aware of the breakdown in communication and performed a survey of the area that found dose rates greater than 1500 mrem per hour at 30 cm from the spent resin liner. The licensee's Technical Specifications require areas with dose rates greater than 1000 mrem per hour to be controlled as a locked high radiation area. However, follow-up action to the survey was not properly prioritized within the health physics group and the area remained unguarded and unlocked until the next day before it was controlled in accordance with the Technical Specifications. Do these events constitute "concurrent nonconformances" as used in the Performance Indicator definition, and therefore, one PI occurrence?

Response No. The definitions for both the Technical Specification High Radiation Area Occurrence and the Very High Radiation Area Occurrence refer to "A nonconformance (or concurrent nonconformances) with technical specifications … and comparable requirements in 10 CFR 20 applicable to technical specification high radiation areas (>1 rem per hour) that results in the loss of radiological control over access or work activities.". As used in these definitions, concurrent means "at the same time and resulting from the same cause." During the initial events in this example, the failure to perform a timely radiation survey was the cause of the failure to post the area, control access to the area and provide dosimetry as required by Technical Specifications. They are therefore concurrent nonconformances and constitute a single PI count. However, after the survey was performed, the failure to establish proper controls over access to the area in a timely manner was caused by a separate breakdown that could not be considered concurrent with the initial failure to perform the survey. This is an example of a sequential failure that warrants a second PI count.

Posting Date 04/01/2000 ***ID*** 132 ***Archive Date*** 7/1/2001

Topic

Question For multiple unit sites, if a PI-reportable condition occurs on one unit, e.g., a Technical Specification high radiation area occurrence inside the Unit 1 containment building, is it necessary to report the occurrence in the indicator for all units?

Response Yes. The PI is a site-wide indicator. The current reporting mechanism requires that occupational radiation safety occurrences be input identically for each unit. However, the occurrence is only counted once toward the site-wide threshold value (i.e., it is not double or triple counted for multiple unit sites).

Posting Date 04/01/2000 ***ID*** 131 ***Archive Date*** 7/1/2001

Topic

Question This question refers to radiography work performed at a plant under another licensee's 10 CFR Part 34 license. If there is an occurrence associated with the radiography work involving loss of control of a high or very high radiation area or unintended dose, does this count under the occupational radiation safety PI?

Response No. Radiography work conducted at a plant under another licensee's 10 CFR Part 34 license is outside the scope of the PI. Responsibility for barriers, dose control, etc., resides with the Part 34 licensee. The reactor regulatory oversight PIs apply to Part 50 licensee activities.

Posting Date 04/01/2000 ***ID*** 130 ***Archive Date*** 7/1/2001

Topic

Question For high radiation areas (> 1 rem) where a flashing light is used as a TS required control, is it considered an occurrence under the Occupational Exposure high radiation area reporting element as a failure of administrative control if it is discovered that the flashing light has failed some time after the control was implemented? Failure of the light could be due to loss of its power source (dead battery or external power loss), mechanical failure (light bulb), etc.

Response No. The PI is intended to capture radiation safety program failures, not isolated equipment failures. This answer presumes that the occurrence was isolated and was corrected in a timely manner.

Posting Date 02/15/2000 ***ID*** 95 ***Archive Date*** 7/1/2001

Topic Occupational Exposure

Question During a routine check, the keybox (containing high radiation area keys) in the health physics office was found unlocked, which is contrary to plant procedures. A follow-up investigation determined that all keys were accounted for and no keys had been issued or used in an unauthorized manner. Does this count against the PI.

Response No. Although this situation apparently represents a nonconformance with plant procedures, it does not appear to be a situation that would be counted against the PI. The question is whether the keys were administratively controlled per the technical specifications. From the description of the circumstances, administrative control over the keys was maintained.

Posting Date 01/07/2000 ***ID*** 112 ***Archive Date*** 7/1/2001

Topic Occupational Exposure

Question Three individuals entered a radiological area to perform preventative maintenance work on a valve. Each of the workers was provided an EPD, worn on the chest, with an alarm setting of 100 mrem –which also served as the administrative dose guideline for the entry. The EPD setting, and the location of the EPD on the chest, was based on a survey that indicated that the highest source of exposure was the valve itself. Upon exiting the area the individual doses, as indicated by the EPD, ranged from 75-90 mrem. However, a follow-up survey of the area revealed that a pump, located behind where the individuals were working on the valve, represented a higher source of exposure than the valve. This was apparently missed during the pre-job survey of the work area. Therefore, the EPD, located on the chest, were not properly placed to monitor dose at the point of highest exposure. An evaluation of stay-times and orientation of the individuals in the work area determined that the actual exposures were three times what was indicated by the EPD. Does this count under the PI? If so, since three individuals were involved, would this be 1 or 3 counts under the PI?

Response Yes. This should be counted under the PI. As described, there clearly was a degradation or failure of one or more radiation safety barriers. From the example, the unintended exposure for the three individuals ranged from 125 to 170 mrem, which each exceeded the 100 mrem dose-screening criterion. Although three individuals were involved, there was only one "occurrence" involving degradation or failure of one or more radiation safety barriers. Therefore, this would only be counted once under the PI.

Posting Date 01/07/2000 ***ID*** 111 ***Archive Date*** 7/1/2001

Topic Occupational Exposure

Question A team of workers, including a health physics technician, made a containment entry at power to investigate possible primary system leakage. Each team member was provided an EPD set to alarm at 200 mrem, which was the administrative dose guideline established for the entry. The walkdown in containment took longer than expected, and eventually several of the EPDs began to alarm, having reached the alarm setpoint of 200 mrem. After discussion with the rest of the team, the health physics technician (as permitted by plant procedures) authorized an extension of the administrative dose guideline to 300 mrem to complete the walkdown. This action was taken to minimize the overall dose that would be incurred if the team were to exit the containment, regroup, and then make a second entry to complete the walkdown. When the team completed the walkdown and exited the containment, two of the team had received a dose of 325 mrem. Does this occurrence count against the PI?

Response No. This occurrence should not be counted against the PI because the resulting dose was only 25 mrem greater than the revised guideline of 300 mrem. The use and specification of administrative dose guidelines is the responsibility of the licensee. As described in the example, the revision to the administrative dose guideline was conducted in accordance with the plant procedures or program. Therefore, the revised guideline would be applicable to the PI.

Posting Date 01/07/2000 ***ID*** 110 ***Archive Date*** 7/1/2001

Topic Occupational Exposure

Question The administrative dose guideline for an individual working in a high radiation area was established via an EPD alarm setpoint at 100 mrem. When exiting the area, the individual noted that the EPD alarm was sounding and the indicated dose was 250 mrem. Due to excessive noise, the individual had not heard the alarm while in the high radiation area. Should this be counted under the PI.

Response Yes. The impact of excessive noise on the effectiveness of the EPD alarm as a dose control measure was not properly evaluated, e.g., as part of the area survey or review of the work scope. This represents a “degradation or failure” of a radiation safety barrier.

Posting Date 01/07/2000 ***ID*** 109 ***Archive Date*** 7/1/2001

Topic Occupational Exposure

Question Upon exiting from working in the fuel transfer canal, an individual monitored himself with a frisker and detected facial contamination. Follow-up investigation determined that the individual received an intake that resulted in a committed effective dose equivalent (CEDE) of 110 mrem. The pre-job evaluation did not anticipate a potential for an intake and no administrative guideline for internal dose was specified for the work. Should this be counted under the PI for unintended exposure?

Response Yes. This should be counted against the PI. Since internal dose apparently was not anticipated as part of the job planning and controls, then the 110 mrem CEDE should be applied under the PI, which exceeds the 100 mrem TEDE criterion. For similar situations involving shallow dose equivalent, lens dose equivalent, and committed dose equivalent, where such dose has not been anticipated as part of the job planning and controls, the dose received should be applied to the respective criteria.

Posting Date 01/07/2000 ***ID*** 107 ***Archive Date*** 7/1/2001

Topic Occupational Exposure

Question With regard to unintended exposure from external sources, is the EPD alarm setpoint the required reference point that should be used for determining if the 100 mrem TEDE criterion has been exceeded?

Response No. The EPD alarm setpoint is not the only reference point (i.e., administrative dose guideline) that can be used for the unintended exposure PI. The PI Manual provides guidance that “administrative dose guidelines may be established within radiation work permits or other documents, via the use of alarm setpoints for personnel monitoring devices, or other means, as specified by the licensee.” However, it is up to the licensee to specify what method or methods are being applied with regard to the unintended exposure PI.

Posting Date 01/07/2000 **ID** 106 **Archive Date** 7/1/2001

Topic Occupational Exposure

Question Does the PI for technical specification high radiation areas (>1 rem per hour) and very high radiation areas apply to spent fuel pools?

Response In general, spent fuel pools are not considered high radiation areas because of the inaccessibility of radioactive materials that are stored in the pool, provided that: "1) control measures are implemented to ensure that activated materials are not inadvertently raised above or brought near the surface of the pool water, 2) all drain line attachments, system interconnections, and valve lineups are properly reviewed to prevent accidental drainage of the water, and 3) controls for preventing accidental drops in water levels that may create high and very high radiation areas are incorporated into plant procedures" ((Regulatory Guide 8.38). However, when a diver enters the pool to perform underwater activities, or upon movement of highly radioactive materials stored in the pool, proper controls must be implemented. Health Physics Position No. 016 also provides guidance on the applicability of access controls for spent fuel pools.

Posting Date 01/07/2000 **ID** 105 **Archive Date** 7/1/2001

Topic Occupational Exposure

Question Plant procedures include a provision that approval of both the operations shift supervisor and the health physics supervisor is required for issuance of keys to very high radiation areas. This provision is in addition to that for issuance of high radiation area keys, which only requires the approval of the health physics supervisor. If a very high radiation area key is issued without the approval of the operations shift supervisor, i.e., contrary to the plant procedure, does this count against the PI.

Response Yes. This should be counted against the PI. The criteria for very high radiation area occurrences are based on "nonconformance with 10 CFR Part 20 and licensee procedural requirements that result in the loss of radiological control over access to or work within a very high radiation area." Part 20.1602 requires that licensees "shall institute additional measures to ensure that an individual is not able to gain unauthorized or inadvertent access" to very high radiation areas. Such additional measures are typically implemented through plant procedures or engineered controls because there is no technical specification specifically for very high radiation areas. Therefore, occurrences that involve a failure to implement such additional measures should be counted against the PI. Regulatory Guide 8.38 describes several additional measures that are acceptable to the staff.

Posting Date 01/07/2000 **ID** 104 **Archive Date** 7/1/2001

Topic Occupational Exposure

Question An individual accessed a high radiation area (>1 rem per hour) and was provided with a radiation survey instrument (i.e., a radiation monitoring device that continuously indicates the radiation dose rate in the area). Access was made under an approved radiation work permit (RWP) which specified a maximum allowable staytime that was complied with. Subsequent to the access, it was determined that the radiation survey instrument provided to the individual had not been source-checked "daily or prior to use" as specified in plant procedures. The radiation survey instrument was then tested and determined to be fully operable and within calibration. Should this be counted against the PI?

Response No. If the applicable provisions of technical specifications (or licensee commitments for alternate control for high radiation areas if the technical specifications do not include provisions for high radiation areas) do not explicitly require the source check, then this should not be counted against the PI. Although this situation appears to represent a nonconformance with plant procedures, the performance basis for the PI appears to have been met in that the radiation survey instrument was, in fact, operable and in calibration.

Posting Date 01/07/2000 **ID** 103 **Archive Date** 7/1/2001

Topic Occupational Exposure

Question An independent verification was not made to ensure that the door of a high radiation area (>1 rem per hour) was secured after exiting the area. The independent verification is required by plant procedures as a defense-in-depth measure. It is not explicitly required by technical specifications. A follow-up investigation determined that the door was, in fact, secured. Should this be counted against the PI?

Response No. This type of occurrence should not be counted against the PI. The reference criteria for the PI for technical specification high radiation areas (>1 rem per hour) are the technical specifications (or licensee commitments for alternate controls for high radiation areas if the technical specifications do not include provisions for high radiation areas) and applicable provisions of 10 CFR Part 20. Licensees may opt to implement additional controls, i.e., beyond what is required by technical specifications and 10 CFR Part 20, but such controls are outside the scope of the PI.

Posting Date 01/07/2000 **ID** 102 **Archive Date** 7/1/2001

Topic Occupational Exposure

Question A health physics technician exited a contaminated high radiation area (>1 rem per hour), secured the access door, removed his protective clothing, and left the high radiation area key at the stepoff pad. The technician went to a nearby frisker to check himself for contamination, and then returned to the stepoff pad to retrieve the key. Should this be counted against the PI with regard to administrative control of the key?

Response No. This should not be counted under the PI. It does not represent a loss of administrative control over the key.

Posting Date 01/07/2000 **ID** 99 **Archive Date** 7/1/2001

Topic Occupational Exposure

Question A wire cage had been constructed around an area of the plant containing a resin transfer line that, during resin transfer operations, is subject to transient radiation levels in excess of 1 rem per hour. The wire cage was constructed in a manner to preclude personnel access to areas where the dose rates exceed 1 rem per hour, sometimes referred to as a “cocoon.” The caged area is located within a room that is posted and controlled as a high radiation area. Does the PI for technical specification high radiation areas (>1 rem per hour) apply to this situation.

Response No. Health Physics Position No. 242 provides guidance that 10 CFR Part 20 requirements for high radiation areas do not apply to such areas that are not accessible, e.g., “cocooned” areas. So long as the dose rates 30 cm beyond the caged area do not exceed 1 rem per hour, the PI does not apply.

Posting Date 01/07/2000 **ID** 97 **Archive Date** 7/1/2001

Topic Occupational Exposure

Question An individual entered a high radiation area (>1 rem per hour) with an electronic personnel dosimeter (EPD) that was not turned on. Does this count against the PI?

Response Yes. The technical specifications typically provide several options for monitoring of individuals accessing high radiation areas, including the option of being provided “a radiation monitoring device that continuously integrates the radiation dose in the area and alarms when a preset integrated dose is received" (e.g., a functioning EPD). If that was the applicable option in this situation, and none of the other options were in effect, then the occurrence should be counted under the PI.

Posting Date 01/07/2000 **ID** 96 **Archive Date** 7/1/2001

Topic Occupational Exposure

Question A door to a high radiation area (>1 rem per hour) was found unlocked and unguarded. In a similar occurrence, the gate to a high radiation area (>1 rem per hour) controlled with flashing lights was found unlatched and unguarded. A follow-up investigation in both cases indicated that no unauthorized entry had been made into the area. Do these occurrences count against the PI?

Response Yes. Such occurrences should be counted under the PI as nonconformance with technical specifications. Typical wording in technical specifications states that such areas "shall be provided with locked or continuously guarded doors to prevent unauthorized entry," and that areas with flashing lights shall be "barricaded." Whether anyone accessed the area is not material to meeting the technical specification requirement.

Posting Date 01/07/2000 **ID** 94 **Archive Date** 7/1/2001

Topic Occupational Exposure

Question A key to the door of a high radiation area (>1 rem per hour) was issued to an individual. The individual used the key to provide access to the high radiation area by plant personnel. It was subsequently discovered that the individual was not qualified to be issued high radiation area keys. Does this count against the PI?

Response Yes. The question is whether this situation constituted a nonconformance with the technical specifications for administrative control of high radiation area keys. For example, typical wording in technical specifications is that "the keys shall be maintained under the administrative control of the Shift Foreman on duty or health physics supervision.

Posting Date 01/07/2000 **ID** 93 **Archive Date** 7/1/2001

Topic Occupational Exposure

Question During a routine check of high radiation area doors and gates, a door popped open when tested. Follow-up investigation determined that the latching mechanism had failed due to a mechanical defect. A similar issue regards the discovery of loose mounting bolts on a high radiation area gate. The looseness of the mounting bolts could have allowed enough movement for someone to force the gate open. No one had actually made an unauthorized entry into the high radiation area in either case. Are such situations counted against the PI?

Response No. This type of situation would not be counted against the PI if it was identified and corrected in a timely manner, appeared to be an isolated occurrence, and had not led to an unauthorized entry into a high radiation area (>1 rem per hour). In essence, these situations represent the discovery of a deficient condition and do not reflect a nonconformance with applicable technical specifications or 10 CFR Part 20 requirements.

Posting Date 01/07/2000 **ID** 92 **Archive Date** 7/1/2001

Topic Occupational Exposure

Question Some radiological areas are posted or controlled as "locked high radiation areas" for precautionary or administrative purposes, even though the dose rates are not actually in excess of 1 rem per hour. Does the Technical Specification High Radiation Area (>1 rem) element of the Occupational Exposure Control Effectiveness PI apply to such areas?

Response No. The Technical Specification High Radiation Area (>1 rem) element of the PI applies to areas that are "accessible to individuals, in which radiation levels from radiation sources external to the body are in excess of 1 rem (10 mSv) per hour at 30 centimeters from the radiation source or 30 centimeters from any surface that the radiation penetrates."

Posting Date 01/07/2000 **ID** 91 **Archive Date** 7/1/2001

Topic

Cornerstone Occupational Radiation Safety

PI OR01 Occupational Exposure Control Effectiveness

Question We are currently reviewing our corrective action program documents to identify radiological occurrences that should be counted under the PI for Occupational Exposure Control Effectiveness. In conducting this review, we are trying to evaluate some occurrences that were not analyzed (at the time of occurrence) using the PI criteria, i.e., we are applying the PI criteria retrospectively. What “new” criteria are established in the PI for Occupational Exposure Control Effectiveness? How should such criteria be applied retrospectively?

Response Response is in preparation or review.

Posting Date 01/07/2000 **ID** 90 **Archive Date** 7/1/2001

Topic Best Available Data

Question The PI for RETS/ODCM radiological effluent occurrences includes the number of occurrences each quarter involving assessed dose in excess of the indicator values. However, some data utilized in assessing dose for radiological effluents may not be available at the time of making quarterly PI reports. For example, the analytical results for composite samples are typically not finalized within the PI reporting period following the end of the quarter. How should this be handled with regard to making the quarterly PI reports?

Response It is understood that not all effluent sample results are required to be finalized at the time of submitting the quarterly PI reports. Therefore, the reports should be based upon the best-available data. If subsequently available data indicates that the number of occurrences for this PI is different that that reported, then the report should be revised, along with an explanation regarding the basis for the revision. From a practical perspective, it is very unlikely that the data that is typically not available at the time of PI reporting would have the effect of causing a change in the reported number of occurrences. The circumstances associated with an occurrence as defined in this PI would be expected to include numerous indications, not limited to composite sample analysis, that there was an occurrence, for example elevated RCS activity, transient events, and effluent radiation monitor indications.

Posting Date 07/12/2001 ***ID*** 279 ***Archive Date*** 1/1/2002

Topic

Question Scheduled Equipment Upgrade<p>During a recent NRC Security Inspection (IP 71130.03), NRC Contractors were able to defeat the Intrusion Detection System (IDS) in several areas, by using assisted jumps. An engineering evaluation was issued and formal Modification/ upgrade action was initiated that directed the installation of additional razor wire to prohibit attempts to circumvent the IDS system without being detected. Is a physical modification to a protected area boundary, that is designed to prohibit the defeat of a Intrusion Detection System (IDS) component considered to be a system/ component modification or upgrade as stated in the Clarifying Notes to NEI 99-02 under Scheduled Equipment Upgrade (and as augmented by FAQ 259)?

Response Yes. A modification such as that described above would be considered a system/component modification or upgrade because the razor wire barrier is acting as an ancillary system. The hours would stop being counted when the modification/upgrade was formally initiated as defined in the Scheduled Equipment Upgrade paragraph of NEI 99-02 Rev 1.

Posting Date 05/31/2001 ***ID*** 269 ***Archive Date*** 1/1/2002

Topic

Question For sites that do not use CCTV for primary assessment of the perimeter IDS, how is the Indicator Value for the Protected Area Security Equipment Performance Index calculated?

Response Continue calculating the indicator in accordance with NEI 99-02.

Posting Date 04/01/2001 ***ID*** 256 ***Archive Date*** 7/1/2001

Topic

Question For Security Intrusion Detection Systems (IDS), if the number of IDS false alarms exceeds “x” number per hour, the licensee considers the IDS segment failed and implements compensatory measures for the IDS segment. <p>There are two questions: <p>1) If an IDS segment is declared failed (but left in service) and security personnel’s inspection identifies no reason to contact the maintenance organization for resolution and operability testing of the IDS segment by security personnel is successful (without performing corrective maintenance) should compensatory hours be counted for the time period that the IDS was considered as failed?<p>2) If an IDS segment is declared failed (but left in service) and security personnel contact the maintenance organization for resolution, the maintenance evaluation does not disclose any malfunction, and operability testing of the IDS segment by security personnel is successful, should compensatory hours be counted for the time period that the IDS was considered as failed?

Response 1) If the false alarms exceed the station security program limit, then the compensatory hours are counted regardless of which personnel evaluate the condition; provided it is in accordance with the station security program. In the absence of guidance in the security program, qualified individuals can disposition the condition.<p>2) Yes. See answer to 1.

Posting Date 03/02/2001 ***ID*** 259 ***Archive Date*** 7/1/2001

Topic

Question (This FAQ is a replacement for FAQ 250. FAQ 250 has been withdrawn)<p>If a new Intrusion Detection System (IDS) or Closed Circuit Television (CCTV) design change package has been prepared by Engineering and funding for the new upgrade has been approved by management but the physical installation will not occur immediately, when does the NEI 99-02 "Scheduled equipment upgrade" exemption occur to stop counting the compensatory hours?

Response In the situation where system degradation results in a condition that cannot be corrected under the normal maintenance program (e.g., engineering evaluation specified the need for a system/component modification or upgrade), and the system requires compensatory posting, the compensatory hours stop being counted toward the PI for those conditions addressed within the scope of the modification after such an evaluation has been made and the station has formally initiated a commitment in writing with descriptive information about the upgrade plan including scope of the project, anticipated schedule, and expected expenditures. This formally initiated upgrade is the result of established work practices to design fund, procure, install and test the project. A note should be made in the comment section of the PI submittal that the compensatory hours are being excluded under this provision. Compensatory hour counting resumes when the upgrade is complete and operating as intended by site requirements for sign-off. Reasonableness should be applied with respect to a justifiable length of time the compensatory hours are excluded from the PI.

Posting Date 03/02/2001 **ID** 250 **Archive Date** 7/1/2001

Topic

Question FAQ 250 has been withdrawn and replaced by FAQ 259.

Response

Posting Date 02/08/2001 **ID** 253 **Archive Date** 7/1/2001

Topic

Question NEI 99-02 Rev. 0, page 127, "Definition of Terms" defines "CCTV" as "The closed circuit television cameras that support the IDS." and "CCTV Normalization Factor." as "the total number of perimeter cameras divided by 30." At our plant, and possibly other larger plants, other cameras referred to as "pan-tilt-zoom" or "PTZ" cameras "support" the IDS, thus could be construed to meet the definition of "CCTV." <p>The PTZ cameras can be positioned to monitor most perimeter zones (e.g., when perimeter cameras are unavailable), but are not physically on the perimeter. It is unclear if the PTZ cameras meet the definition of perimeter camera for inclusion in the CCTV Normalization Factor. The stated purpose of the CCTV normalization factor to compensate for larger than nominal plant sizes. Can PTZ cameras be credited in the CCTV normalization factor?

Response If conditions cause a PTZ to be used for primary assessment, then it would count towards the calculation of the normalization factor. PTZ cameras that are used to provide additional information to the perimeter cameras used for primary assessment or as backup to perimeter cameras should they be out of service would not be counted in the calculation of the normalization factor.

Posting Date 10/31/2000 **ID** 230 **Archive Date** 7/1/2001

Topic

Question If perimeter intrusion equipment, CCTV monitoring equipment or systems supporting their functionality are damaged or destroyed by environmental conditions and remains unable to perform their intended function after the condition subsides (e.g., a lightning strike, wind, ice, flood) do you need to count any hours towards the performance indicator?

Response No. If after the environmental condition clears, the zone remains unavailable, despite reasonable recovery efforts, the hours do not have to be counted.

Posting Date 06/14/2000 **ID** 189 **Archive Date** 7/1/2001

Topic

Question When rounding to the “nearest tenth” of an hour for counted “comp. hours”, at what point of the data collection/computation process is the rounding applied – after an incident or at the end of each month?

Response For this performance indicator, rounding may be performed as desired provided the reported hours are expressed to the nearest tenth of an hour. For all other performance indicators, rounding of collected data is not necessary. Data should be reported to the available accuracy. Appropriate rounding is performed during the computation of the performance indicator.

Posting Date 05/24/2000 **ID** 185 **Archive Date** 7/1/2001

Topic

Question Appendix D: Surry Site
<p>At Surry Power Station we have only one full time CCTV camera that is used as part of the PA perimeter threat assessment. With only one CCTV camera, that has been reliable, we have not had any compensatory hours to report for this portion of the PI. This results in what might seem to be an artificially high performance index for this PI since the CCTV camera portion of the indicator is equally weighted with the IDS portion. Is it appropriate to continue to report CCTV camera compensatory hours for a site with such a low number of CCTV cameras?

Response Continue to report in accordance with the current guidance in NEI 99-02. That is, report compensatory hours for the single CCTV camera as they occur. Put a note for this PI in the comment section submitted to the NRC similar to the following: "Performance data reflects one CCTV camera."

Posting Date 05/24/2000 **ID** 184 **Archive Date** 7/1/2001

Topic

Question Appendix D: North Anna Site<p>At North Anna Power Station we have only one part time CCTV camera that is used as part of the PA perimeter threat assessment during refueling outages. With one part time CCTV camera, that has been reliable, we have not had any compensatory hours to report for this portion of the PI. This results in what might seem to be an artificially high performance index for this PI since the CCTV camera portion of the indicator is equally weighted with the IDS portion. Is it appropriate to continue to report CCTV camera compensatory hours for a site with a low number of and infrequently used CCTV cameras?

Response Continue to report in accordance with the current guidance in NEI 99-02. That is, report compensatory hours for the part time CCTV camera as they occur. Put a note for this PI in the comments section submitted to the NRC similar to the following: "Performance data reflects zero, (or X), hours of CCTV camera operation during this reporting period."

Posting Date 05/02/2000 **ID** 163 **Archive Date** 7/1/2001

Topic

Question Is the tamper detection system considered part of the IDS? For example, if the tamper detection system is being monitored for compensatory measures, but the IDS is properly functioning, do licensees need to count these compensatory hours?

Response Not if IDS is functioning as intended.

Posting Date 05/02/2000 **ID** 162 **Archive Date** 7/1/2001

Topic

Question NEI 99-02 under the Preventive maintenance section indicates that during preventive maintenance or testing, cameras that do not function properly and can be compensated for by means other than posting an officer, no compensatory man-hours are counted. Does this exclusion only apply to camera events discovered during the above mentioned times or can this exclusion be applied to any time a camera can be compensated for by means other than posting an officer?

Response The PI counts compensatory man-hours. Any compensatory actions other than posting a security officer (e.g., use of alternate equipment) are not counted. Note: If a security officer is normally posted for a zone (as a normal post, not compensating), and he is now told to comp a zone because cameras are not working, these hours would count.)

Posting Date 05/02/2000 **ID** 161 **Archive Date** 7/1/2001

Topic

Question Variable Normalization Factor
<p>During steady state operations our site has one access portal open for personnel to enter the protected area. During an outage we open a second access portal. The change in protected area barrier configuration affects the number of zones that are used. The result is we have a 1.9 normalization factor during steady state, and 1.95 during an outage. What value of normalization factor should we report for quarters that include an outage?

Response A prorated normalization factor that addresses periods when the second access portal is open should be reported. Add a note in the comment field describing the situation

Posting Date 04/01/2000 **ID** 160 **Archive Date** 7/1/2001

Topic

Question If a security officer is posted to comp. for two zones for 1 hour, do you count 1 or 2 compensatory hours?

Response If one security officer is posted to watch two zones for one hour, one (1) hour applies to the PI.

Posting Date 04/01/2000 **ID** 141 **Archive Date** 7/1/2001

Topic

Question NEI 99-02 guidance for the Protected Area Security Equipment Performance Indicator states that when extreme environmental conditions occur that render the IDS or CCTV temporarily inoperable, the compensatory hours are not counted. In summer months, the duration of environmental conditions is typically tied to the period of time associated with storm passage. In winter months, storm passage does not as clearly represent the duration, because significant accumulations of snow and ice can remain and be an impediment to system function far beyond the passage of the storm despite removal efforts. If the IDS and CCTV are not designed to operate under such conditions, should compensatory hours count?

Response Unavailabilities due to environmental conditions beyond the design specification of the system are not counted. If after the environmental condition clears, the zone remains unavailable, despite reasonable recovery efforts, the hours do not have to be counted.

Posting Date 04/01/2000 **ID** 140 **Archive Date** 7/1/2001

Topic

Question Is the performance indicator for IDS strictly looking at the protected area boundary or are vital doors included?

Response The Purpose paragraph establishes that the PI is for the plant perimeter.

Posting Date 04/01/2000 **ID** 139 **Archive Date** 7/1/2001

Topic

Question For the Security Equipment indicator, there is a paragraph entitled "Scheduled equipment upgrade". This paragraph requires that if a system cannot be corrected under normal maintenance program, compensatory hours stop being counted after a modification or upgrade has been initiated. For the case where there are a few particularly troubling zones that result in formal initiation of an entire system upgrade for all zones, should we stop counting compensatory hours for all zones until the upgrade is in place?

Response No, only subsequent failures that would have been prevented by the planned upgrade are excluded from the count. This exclusion applies regardless of whether the failures are in a zone that precipitated the upgrade action or not, as long as they are in a zone that will be affected by the upgrade, and the upgrade would have prevented the failure.

Posting Date 04/01/2000 **ID** 138 **Archive Date** 7/1/2001

Topic

Question Do e-fields taken out of service to support plant operations (not failures) and where guards are posted, count as Security Equipment Performance indicator compensatory hours.

Response No.

Posting Date 04/01/2000 **ID** 137 **Archive Date** 7/1/2001

Topic

Question Should compensatory hours for the security computer and multiplexers be counted on the PI data being submitted.

Response Compensatory hours for this PI cover hours expended in posting a security officer as required compensation for IDS and/or CCTV unavailability because of a degradation or defect. If problems with the security computer or multiplexer result in compensatory postings because the IDS/CCTV is no longer capable of performing its intended safeguards function, the hours would count.

Posting Date 04/01/2000 **ID** 136 **Archive Date** 7/1/2001

Topic

Question A CCTV camera is functioning properly, but lighting in an area is poor such that the camera cannot detect intrusion and compensatory actions are taken, do these hours count as part of the indicator?

Response The camera requires lighting to perform its function, therefore the system is not operating as intended and the compensatory hours are counted.

Posting Date 02/15/2000 **ID** 77 **Archive Date** 7/1/2001

Topic Compensatory Hours

Question A previous FAQ (FAQ 60) discusses one Intrusion Detection System (IDS) segment that must be covered by two or more compensatory posts (two or more watch persons) and if you count one hour or the hours expended by the watchpersons (i.e. two or more per hour). The response states that total compensatory man-hours should be counted and that this performance indicator measures total man-hours of compensatory action vs. total hours of compensatory action.

<p>At our Station, we have a situation where security persons are already in place at continuously manned remote location security booths around the perimeter of the site. In the event of a need to provide compensatory coverage for the loss IDS equipment, security persons already in these booths can fulfill this function. More than one person can be assigned to provide the coverage, since more than one person may be readily available. The question now becomes, do we need to count all of the persons that have been assigned to fulfill the compensatory function when some of the persons may have been assigned when it was not necessary to do so, but was done as a matter of convenience.

Response Only the required compensatory man-hours should be counted. If more than one person is required to provide coverage due to the lost equipment, then the hours of each should be counted toward this indicator.

Posting Date 01/07/2000 **ID** 83 **Archive Date** 7/1/2001

Topic Extreme Environmental Conditions

Question How must we address extreme environmental conditions. A steady rain is not a "severe storm". "Sun glare" is not an extreme condition. Excessive summer heat reflecting off of a hot roof that renders the IDS inoperable for brief periods, although not an extreme environmental condition, inhibits proper operation for several consecutive days at about the same time. What if a heavy rain leaves a puddle of water that makes the IDS inoperable for several hours. Conservatively reporting environmental effects on protection equipment could cause an indicator to be unacceptable. If the clarifying note addressed "adverse environmental conditions", all weather related degradations would not be counted.

Response The clarifying note is intended to allow exemption of compensatory hours that are required due to environmental conditions that exist beyond the design specifications of the system. The question to ask is, “Is the system performing in accordance with its design specifications?” If the system is not designed to function during certain instances of sun glare, the hours do not have to count.

Posting Date 01/07/2000 **ID** 82 **Archive Date** 7/1/2001

Topic Preventive Maintenance

Question In the security equipment PI, the terms corrective maintenance and Preventive maintenance are used. However, there is another subset of maintenance - predictive maintenance - and it is not clear whether to consider it preventative (exempt) or corrective (non-exempt).

<p>Predictive maintenance occurs on equipment that is currently performing its intended safety function satisfactorily (i.e., can pass surveillances and is OPERABLE), but has exhibited symptoms of declining performance (i.e., increased false alarms may indicate the need for insulator cleaning in advance of the routine PM cleaning or before eventual failure due to salt buildup; or a weak line signal may indicate the desirability of computer board replacement in advance of waiting for board failure).

Response Predictive maintenance is treated as preventive maintenance. Since the equipment has not failed (remains capable of performing its intended detection (safety) function), any maintenance performed in advance of its actual failure is preventive. It is not the NRC's intent to create a disincentive to performing maintenance to ensure the security systems perform at their peak reliability and capability

Posting Date 01/07/2000 **ID** 81 **Archive Date** 7/1/2001

Topic Compensatory Hours

Question When determining the need to compensatory post an Intrusion Detection System when it can not perform its intended safety function, there are three types of failures: (1) inability to detect intrusion; (2) inability to detect IDS sabotage (i.e., tamper alarms); and (3) inability to note equipment problems (i.e., supervisory alarm). Clearly, items 1 and 2 are failures and compensatory hours should be counted; however, what about failures of the supervisory sub-system?

Response IDS equipment issues that do not require compensatory hours would not be counted.

Posting Date 01/07/2000 **ID** 80 **Archive Date** 7/1/2001

Topic Compensatory Hours

Question A licensee performs a routine surveillance on a security Intrusion Detection System (IDS) or Closed Circuit TV (CCTV). During the surveillance, the equipment is determined to be inoperable (not capable of performing its intended safety function). When does the inoperability start.

Response The metric is based on the comp hours and starts when the IDS or CCTV is actually posted. There is no "fault exposure hours" or other consideration beyond the actual physical compensatory posting.

Posting Date 01/07/2000 **ID** 68 **Archive Date** 7/1/2001

Topic Compensatory Hours

Question If a compensatory measure such as positioning a Pan-Tilt-Zoom camera in an area that compensates for a out of service fixed zone camera, does that count against the Protected Area Security Equipment PI even though no additional man-hours are required for the compensatory measure.

Response This indicator utilizes compensatory man-hours to provide an indication of CCTV and IDS unavailability. Other compensatory measures would not be counted as part of this indicator.

Posting Date 11/11/1999 ***ID*** 61 ***Archive Date*** 7/1/2001

Topic Comp Hours for Multiple Equipment Failures

Question Compensatory hours are not double counted when compensatory measures are assigned to multiple points (i.e. a single officer spending 4 hours watching both a camera and a zone). However, where are the comp hours assigned, to the camera or the zone.

<p>What If 1 MSF (Member of the Security Force) spent a total of 12.5 hours (one standard shift) on compensatory measures for malfunctioning equipment (0530 - 1800). Of the 12.5 hours =

<p>0530 - 1400 MSF compensated for zone 4 (IDS) totaling 8.5 hrs
<p>0700 - 1200 MSF compensated for camera 4 (CCTV) totaling 5 hrs
<p>0900 - 1800 MSF compensated for camera 5 (CCTV) totaling 9 hrs

<p>How should we divide the hours up?

Response Compensatory hours expended to address multiple equipment problems are assigned based upon the piece of equipment that first required compensatory hours. When this first piece of equipment is returned to service and no longer requires compensatory measures, the second piece of equipment carries the hours, etc. In the offered example, IDS-Zone 4 would be assigned 8.5 hours and CCTV-camera 5 would be assigned 4 hours.

Posting Date 11/11/1999 ***ID*** 60 ***Archive Date*** 7/1/2001

Topic Multiple Comp Postings for Single Equipment Failur

Question If two IDS segments can be covered by a single comp post (one watchperson) then the guidance says to only count one hour (don't double count the single post). What if one IDS segment must be covered by 2 or more comp posts (two or more watchpersons), do you count one hour or the hours expended by the watchpersons (i.e., 2 or more per hour).

Response Total compensatory man-hours should be counted. This performance indicator measures total man-hours of compensatory action vs. total hours of compensatory action.

Posting Date 11/11/1999 ***ID*** 59 ***Archive Date*** 7/1/2001

Topic Comp Posting for Non-Failure of Equipment

Question For Security Intrusion Detection Systems (IDS), if the number of IDS segment false alarms exceeds 5 per hour, licensees declare the IDS segment inoperable (due to excessive false alarms. Note, these are not nuisance nor environmental alarms.), comp post the segment, repair/test the segment, return the segment to operable and remove the comp post. The question is, if an IDS segment is removed from service and comp posted, but the resultant maintenance does NOT disclose any malfunction and the system is returned to service with essentially no corrective maintenance (some minor tweaking of system sensitivity might be done since it is out of service, but for this discussion the sensitivity was not initially mis-set), do you count the comp posting hours against the metric.

Response If there is no equipment malfunction and the system would still have alarmed during intrusion (still capable of performing its intended function), then the compensatory man hours that were established as part of a precautionary maintenance activity would not be counted.

Posting Date 11/11/1999 ***ID*** 57 ***Archive Date*** 7/1/2001

Topic Reporting of Compensatory Hours for Multi-Unit Sit

Question For a multi unit site how are the CCTV and IDS Compensatory Hours to be reported? Are they reported under only 1 unit, all units, divided between the units, or separately as a site-wide program?

Response Information supporting performance indicators is reported on a per unit basis. For performance indicators that reflect site conditions, this requires that the information be repeated for each unit on the site.

Posting Date 04/01/2000 ***ID*** 134 ***Archive Date*** 7/1/2001

Topic

Question Should we include such things as "entry into a vital Area without proper authorization", or just the reporting requirements that would be reported if 10 CFR 73.56 or 10 CFR 73.57 were not met as outlined in Generic Letter 91-003 and NUREG 1304?"

Response GL 91-03 and NUREG 1304 are not germane. The only Reportable event is that defined in the PI - "a failure in the licensee's program that requires prompt regulatory notification." If you did not make a one-hour report concerning a significant failure to meet regulation it is not included for PI purposes.

Posting Date 04/01/2000 ***ID*** 133 ***Archive Date*** 7/1/2001

Topic

Question Personnel Screening Program Performance indicator: As written in NEI 99-002 it appears that this indicator only applies to reportable conditions in 10 CFR 73.56 & 57, but it needs to be absolutely clear.

Response The PI applies to § 73.56 and 73.57 and not to all of Part 73.

Posting Date 04/01/2000 **ID** 128 **Archive Date** 7/1/2001

Topic

Question For the Personnel Screening and Fitness for Duty indicator - it is not stated that the date to be used for reporting or what quarter to report an event in is the LER date. Is this an accurate assumption? This would be the same as the SSFF date requirement.

Response The criterion for reporting of performance indicators is based on the time the failure or deficiency is identified, with the exception of the Safety System Functional Failure indicator, which is based on the Report Date of the LER.

Posting Date 04/01/2000 **ID** 127 **Archive Date** 7/1/2001

Topic

Question Clarifying Notes for both the Unescorted Access Authorization Program and FFD performance indicators imply that if an event is reported appropriately in accordance with either the reporting criteria of Part 26 or Part 73.55 then the program is working as designed and there is no event counted in the PI data. What then is the meaning/purpose of the sentence on page C-6 of the guidance document of the cornerstone document: "...data is currently available and there are regulatory requirements to report significant events"...?

Response The sentence before the quoted piece used the term "program degradations." The intention is to keep the reported information in two groups:· Specific reports required by regulation (e.g., operator tested positive for drugs) which means the program is working as intended and not to be included in the PI, and· Significant programmatic failures of the implemented regulatory requirements that would amount to one-hour type reports - these are the only reports included in the PIs for access authorization or fitness-for-duty.

Posting Date 04/01/2000 **ID** 129 **Archive Date** 7/1/2001

Topic

Question The clarifying note for the Fitness-For-Duty / Personnel Reliability Program Performance Indicator states that the indicator does not include any reportable events that result from the program operating as intended. What is not clear is whether all 10 CFR Part 26 reportable events count as data reporting elements or not. For example, if a contract supervisor is selected for a random drug test, tests positive, and we take the proper action, does this count as a data reporting element or not? One could say that the random drug test failure is a failure to implement the requirements of 10 CFR Part 26. Alternatively, one could say that the program functioned as intended and we complied with the requirements of 10 CFR Part 26.

Response No. The example would not count since the program was successful. Only count program failures.

Posting Date 11/11/1999 **ID** 58 **Archive Date** 7/1/2001

Topic Reporting of FFD Data for Multi-Site Program

Question When reporting data for FFD/personnel screening for a multi-site company for which personnel are tested for both sites, how is the data reported?

Response The Personnel Screening Program Performance Indicator provides a measure of the effectiveness of programmatic efforts to implement regulatory requirements outlined in 10 CFR Part 73. Where a programmatic failure affected (or had the potential to affect) multiple sites, the instance is reported for each affected unit.

Posting Date 06/14/2000 **ID** 120 **Archive Date** 7/1/2001
Topic Performance Indicators
Question FAQ 120 Withdrawn
Response

Posting Date 06/14/2000 **ID** 119 **Archive Date** 7/1/2001
Topic Performance Indicators
Question FAQ 119 Withdrawn
Response

Posting Date 06/14/2000 **ID** 118 **Archive Date** 7/1/2001
Topic Performance Indicators
Question FAQ 118 Withdrawn
Response

Posting Date 06/14/2000 **ID** 117 **Archive Date** 7/1/2001
Topic Performance Indicators
Question FAQ 117 Withdrawn
Response

Posting Date 06/14/2000 **ID** 116 **Archive Date** 7/1/2001
Topic Performance Indicators
Question FAQ 116 Withdrawn
Response

Posting Date 06/14/2000 **ID** 115 **Archive Date** 7/1/2001
Topic Performance Indicators
Question FAQ 115 Withdrawn
Response

Posting Date 06/14/2000 **ID** 114 **Archive Date** 7/1/2001
Topic Performance Indicators
Question FAQ 114 Withdrawn
Response

Posting Date 06/14/2000 **ID** 113 **Archive Date** 7/1/2001
Topic Performance Indicators
Question FAQ 113 Withdrawn
Response

Posting Date 04/01/2000 **ID** 121 **Archive Date** 7/1/2001

Topic Quarterly Report Submittals

Question When should quarterly performance indicator reports be submitted when the normal submittal date falls on a Saturday, Sunday, or Holiday?

Response The performance indicator data reports are submitted to the NRC under 10 CFR 50.4 requirements. Per 10 CFR 50.4, if a submittal due date falls on Saturday, Sunday, or Federal holiday, the next Federal working day becomes the official due date.

Posting Date 01/07/2000 **ID** 67 **Archive Date** 7/1/2001

Topic Consistency between PRAs and NEI 99-02

Question Individual Plant Examinations (IPEs) were established using a certain set of PRA assumptions. These included assumptions regarding the availability of equipment that perform Safety functions. The criteria used for availability decisions have varying degrees of conservatism from plant-to-plant. In some cases, these criteria may be less stringent than criteria currently used in NEI 99-02 Rev D for determining the availability of equipment within the scope of Mitigating Systems. However, these less stringent criteria give a more accurate representation of risk if they accurately determine the actual status of equipment availability to perform its function.It's possible that these less stringent criteria are still being used on a day-to-day basis (e.g., to establish risk profiles for on-line maintenance). Has this potential conflict been recognized (using different decision criteria for availability of the same equipment, depending upon what process is making the decision)? Is there an expectation to reconcile this? What effect does this have upon a plant's PRA if risk assumptions are no longer valid using 99-02 criteria? Is there an expectation that availability decisions for equipment outside the scope of the performance indicators be consistent with 99-02 criteria?

Response It is recognized that there are differences in definitions between the NRC PIs, WANO indicators, maintenance rule, and IPEs. Industry and NRC will be working in year 2000 to try to reconcile indicator definitions. NEI 99-02 applies to NRC PIs and not to operability decisions or your PRA.