<table>
<tr><th>Temp No.</th><th>PI</th><th>Question/Response</th><th>Status</th><th>Plant/ Co.</th></tr>
<tr><td>26.12</td><td></td><td>

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

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

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

<table>
<tr><th></th><th>Green/White</th><th>White/Yellow</th><th>Yellow/Red</th></tr>
<tr><td>dCDF limits</td><td>>=1E-06</td><td>>=1.4E-05</td><td>>=1E-04</td></tr>
<tr><td>Underground Path Unavailability</td><td>2.0%</td><td>4.0%</td><td>10.0%</td></tr>
<tr><td>Overhead Path Unavailability</td><td>16 9%</td><td>100.0%</td><td>N/A</td></tr>
</table>

The Green/White threshold value is consistent with the Maintenance Rule limit for unavailability of the Underground Path. Also, historical unavailability of the Underground Path would place ONS mid-way in the green band, which is consistent with average industry performance for the MS01 indicator. The White/Yellow threshold of 4 0% provides an appropriate white band as compared to the threshold of 5.0% indicated in NEI 99-02 for a system with two trains of Emergency AC equipment. The Yellow/Red threshold of 10% is conservative and is consistent with NEI 99-02 for a system with two trains of Emergency AC equipment. Monitoring the underground path only, are 2.0%, 4.0% and 10.0%, acceptable threshold values for the ONS Emergency Power performance indicator?
<hr>
Response:
Yes.
</td><td>11/15 Discussed
12/13 On hold
2/28 NRC reviewing
4/25 Tentative Approval
5/22 On Hold</td><td>Oconee</td></tr>
</table>

Attachment 13

Temp No.	PI	Question/Response	Status	Plant/ Co.
27.3	IE02	Question: Should a reactor scram due to high reactor water level, where the feedwater pumps tripped due to the high reactor water level, count as a scram with a loss of normal heat removal Background Information: On April 6, 2001 LaSalle Unit 2 (BWR), during maintenance on a motor driven feedwater pump regulating valve, experienced a reactor automatic reactor scram on high reactor water level. During the recovery, both turbine driven reactor feedwater pumps (TDRFPs) tripped due to high reactor water level The motor driven reactor feedwater pump was not available due to the maintenance being performed. The reactor operators choose to restore reactor water level through the use of the Reactor Core Isolation Cooling (RCIC) System, due to the fine flow control capability of this system, rather than restore the TDRFPs. Feedwater could have been restored by resetting a TDRFP as soon as the control board high reactor water level alarm cleared. Procedure LGA-001 "RPV Control" (Reactor Pressure Vessel control) requires the unit operator to "Control RPV water level between 11 in. and 59.5 in. using any of the systems listed below: Condensate/feedwater, RCIC, HPCS, LPCS, LPCI, RHR." The following control room response actions, from standard operating procedure LOP-FW-04, "Startup of the TDRFP" are required to reset a TDRFP. No actions are required outside of the control room (and no diagnostic steps are required). Verify the following: TDRFP M/A XFER (Manual/Automatic Controller) station is reset to Minimum No TDRFP trip signals are present Depress TDRFP Turbine RESET pushbutton and observe the following Turbine RESET light Illuminates TDRFP High Pressure and Low Pressure Stop Valves OPEN PUSH M/A increase pushbutton on the Manual/Automatic Controller station Should this be considered a scram with the loss of normal heat removal? Proposed Answer: No, the scram would not count as a scram with a loss of normal heat removal. The actions required to restore TDRFPs are not considered to be a diagnosis. The operators are fully trained (classroom and simulator training) to recognize that the TDRFPs trip on high reactor water level and are trained to take the appropriate steps to restore the feedwater pumps as soon as the high reactor level alarm clears. This evolution is a basic operator knowledge item and not a diagnostic for purposes of this indicator. Therefore, this event would not be considered a scram with a loss of normal heat removal, because, the indicator excludes events in which the heat removal path through the main condenser is easily recoverable without the need for diagnosis or repair.	1/25 Introduced 2/28 NRC to discuss with resident 4/25 Discussed 5/22 On hold 6/12 Discussed Related FAQ 30 8	LaSalle

Temp No.	PI	Question/Response	Status	Plant/ Co.
28.2	MS 01	Question: In August 2001, Our plant had just completed the monthly EDG load-run surveillance and had passed the plant's load and duration test specification. The EDG was being secured from the test in accordance with the surveillance. Generator real load (kW) was initially reduced, when it was discovered that generator reactive load (KVAR) would not respond to remote or local control inputs. Operations then tripped the generator output breaker and secured the EDG and declared it out of service. Initial trouble shooting of the voltage regulator was performed and the engine was run the next day with similar response to load control. At this point the engine was removed from service for repair of the generator. The root cause evaluation determined that the generator had two shorted coils.. The cause of the shorted coils was degradation of winding laminations over time due to poor winding processes at a repair vendor's facility for work performed in 1993. This degradation ultimately resulted in contact between a generator winding and uninsulated wedge block bolting internal to the generator while the engine was being secured following successfully satisfying the monthly surveillance. In applying fault exposure hours to this scenario we believe that by meeting the plant's load and duration test specification during the surveillance, NEI 99-02, Revision 1, page 38 line 30 criterion for successful start and load-run was met. Because the failure occurred during the unload and shutdown portion of the surveillance (the failure's time of occurrence is known), fault exposure is not applicable. The time that the engine was out of service for the initial voltage regulator trouble shooting, the second attempt to run the engine and hours associated with the generator repair are counted as unplanned unavailable hours. Have we correctly interpreted NEI 99-02 guidance that fault exposure hours would not be reported in this situation? Suggested Response: Correct. Fault exposure hours are the time that a train spends in an undetected, failed condition. In this situation, the failure's time of occurrence is known. The failure occurred while the engine was being secured during the unload and shutdown portion of the surveillance after the engine passed its load run test and passed the plant's load and duration test specification. This is a discovered condition which must be assessed in the ROP inspection process. (Unavailable hours should be counted from the time of discovery forward.) Alternate Response: While the diesel had officially passed the surveillance test, the plant was still getting information from the surveillance test during the diesel shutdown. T/2 fault exposure should be taken from the last successful test of the diesel, i e., the last monthly test before this occurrence.	2/28 Introduced 3/21 Discussed 4/25 Licensee to provide additional information 5/22 Discussed 6/12 Discussed.	Point Beach

Temp No.	PI	Question/Response	Status	Plant/ Co.
28.3	IE02	Question: This event was initiated because a feedwater summer card failed low. The failure caused the feedwater circuitry to sense a lower level than actual. This invalid low level signal caused the Reactor Recirculation pumps to shift to slow speed while also causing the feedwater system to feed the Reactor Pressure Vessel (RPV) until a high level scram (Reactor Vessel Water Level – High, Level 8) was initiated. Within the first three minutes of the transient, the plant had gone from Level 8, which initiated the scram, to Level 2 (Reactor Vessel Water Level – Low Low, Level 2), initiating High Pressure Core Spray (HPCS) and Reactor Core Isolation Cooling (RCIC) injection, and again back to Level 8. The operators had observed the downshift of the Recirculation pumps nearly coincident with the scram, and it was not immediately apparent what had caused the trip due to the rapid sequence of events. As designed, when the reactor water level reached Level 8, the operating turbine driven feed pumps tripped. The pump control logic prohibits restart of the feed pumps (both the turbine driven pumps and motor driven feed pump (MFP)) until the Level 8 signal is reset. (On a trip of one or both turbine feed pumps, the MFP would automatically start, except when the trip is due to Level 8.) All three feedwater pumps (both turbine driven pumps and the MFP) were physically available to be started from the control room, once the Level 8 trip was reset. Procedures are in place for the operators to start the MFP or the turbine driven feedwater pumps in this situation. Because the cause of the scram was not immediately apparent to the operators, there was initially some misunderstanding regarding the status of the MFP. (Because the card failure resulted in a sensed low level, the combination of the recirculation pump downshift, the reactor scram, and the initiation of HPCS and RCIC at Level 2 provided several indications to suspect low water level caused the scram.) As a result of the initial indications of a plant problem (the downshift of the recirculation pumps), some operators believed the MFP should have started on the trip of the turbine driven pumps. This was documented in several personnel statements and a narrative log entry. Contributing to this initial misunderstanding was a MFP control power available light bulb that did not illuminate until it was touched. In fact, the MFP had functioned as it was supposed to, and aside from the indication on the control panel, there were no impediments to restarting any of the feedwater pumps from the control room. No attempt was made to manually start the MFP prior to resetting the Level 8 feedwater trip signal. Regardless of the issue with the MFP, however, both turbine driven feed pumps were available once the high reactor water level cleared, and could have been started from the control room without diagnosis or repair. Procedures are in place to accomplish this restart, and operators are trained in the evolution. Since RCIC was already in operation, operators elected to use it as the source of inventory, as provided for in the plant emergency instructions, until plant conditions stabilized. Should this event be counted as a Scram with a Loss of Normal Heat Removal? Response: No. As stated in NEI 99-02 Rev 2, page 16, lines 15-16 (and FAQ 249), the determining factor for 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. In this event, since the turbine driven feed pumps remained available throughout the event and procedures were in place for their recovery from the control room, the normal heat removal path through the main condenser was easily recoverable without the need for diagnosis or repair	3/21 Discussed 4/25 Discussed 5/22 Modified to reflect discussion of 4/25, On Hold 6/12 Discussed. Related FAQ 30.8	Perry

Temp No.	PI	Question/Response	Status	Plant/ Co.
28.5	MS01	Question: Treatment of Planned Overhaul Maintenance in the Clarifying Notes section of the Mitigating Systems Cornerstone, Safety System Unavailability, states that plants that perform on-line planned overhaul maintenance (i.e., within approved Technical Specification allowed Outage Time) do not have to include planned overhaul hours in the unavailable hours for this performance indicator under the conditions noted. This section further states that the planned overhaul maintenance may be applied once per train per operating cycle. EDG(s) at Prairie Island are on an 18 month overhaul frequency per T.S.4.6 A.3.a, while the plant operating cycles are typically a month or two longer. Thus, the EDG 18 month overhaul will occur twice in some cycles. If major overhauls, performed in accordance with the plant's technical specification frequency, result in more than one major overhaul being performed within the same operating cycle, can both of these overhauls be excluded from counting as planned unavailable hours? Response Yes, as long as the overhaul maintenance is completed within an established preventive maintenance program and the overhaul is completed within the specified technical specification frequency, the unavailable hours do not need to be counted.	2/28 Introduced 4/25 Discussed 6/12 Discussed	Prairie Island
28.6	OR01	Question: While in a high radiation area (HRA) removing scaffold, workers inadvertently dislodged lead shielding around a hot spot flush rig and created conditions that required posting a locked HRA (dose rates in excess of 1 rem per hour). Several minutes later when they moved to a location closer to the hot spot, the three scaffold workers received dose rate alarms. Upon receiving the alarms, they immediately left the area and the alarms cleared. After reading their dosimeters and verifying that they had not received any unexpected dose, they discussed the alarms with their supervisor and concluded that the momentary alarm was not unexpected since general area dose rates in the HRA could have caused the alarms. When the three workers attempted to log out of the RCA at the access control point, Health Physics (HP) discovered that all three individuals received a "Dose Rate" alarm on their electronic dosimeters. Independent from the ensuing exposure investigation, and approximately within the same time period (within minutes), a HP technician found radiation levels in excess of 1 rem per hour when performing a routine survey to support removal of the hot spot flush rig. The HP technician established proper controls and posting for the area and discovered that local shielding around the flush rig had been disturbed. Does this count against the technical specification high radiation area occurrence PI? Response: Yes. (answer being drafted)	2/28/02 Introduced 3/21 Discussed 4/25 Tentative Approval. Answer discussion being drafted	St. Lucie
28 10	MS01 -04	Question The guidance in the unavailability portion of NEI 99-02 states that 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). In this context, what does the word "diagnosis" mean?	2/28 Introduced 3/21 To be rewritten 4/25 Discussed6/12 Discussed	PSEG

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Response: Diagnosis is the investigation or analysis of the cause or nature of a condition. In the context of the unavailability PI, diagnosis refers to activities that are required to determine what actions need to be taken to mitigate the condition. It includes activities such as troubleshooting and research into design documentation. Responding to alarms and following written procedures where success is a virtual certainty is not considered to be diagnosis. If the licensee and the resident inspectors do not agree if the activity in question is considered to be diagnosis, an FAQ should be submitted. Alternate Response: Diagnosis: An investigation or analysis of the cause of a condition, situation or problem. For purposes of the performance indicators, the following guidelines apply: 1. A control room operator's use of information available to her/him in the control room does not constitute diagnosis if the first attempt (a single action or a few simple actions) to correct the condition, situation or problem from the control room is successful. Identification of the condition and determination of the appropriate corrective actions together should require collecting only a few data points. If more extensive data collection is required, because of conflicting data for example, this would be considered diagnosis 2. If the control room operator's first attempt to correct the condition, situation, or problem is unsuccessful, any further actions would be considered diagnosis. 3. The fact that a procedure provides a list of alternative actions to be taken in an attempt to correct the condition, situation or problem does not necessarily mean that the procedure is diagnostic in nature. However, if in following such a procedure the operator's first attempt is not successful, further actions would constitute diagnosis. Likewise, if extensive data collection is required to determine which one of the alternative actions should be taken, this would constitute diagnosis. The intent of this paragraph is to allow credit for operator recovery actions when the condition, situation or problem can be quickly identified from indications in the control room and the necessary corrective actions can be promptly (or easily, as applicable) performed in the control room. *Activities such as troubleshooting and extensive research into design documentation are considered to be diagnostic. If the licensee and the resident inspectors do not agree if the activity in question is considered to be diagnosis, an FAQ should be submitted.*		

Temp No.	PI	Question/Response	Status	Plant/ Co.
29.4	MS01-04	Appendix D Question This question seeks an exemption from counting planned overhaul maintenance hours for a support system outage at the Grand Gulf Nuclear Station (GGNS). At GGNS, the Safety System Water (SSW) system provides Ultimate Heat Sink supply for the ECCS systems, through three divisions: ▪ SSW A supplies Division 1 Emergency Diesel, Residual Heat Removal (RHR) A and Low Pressure Core Spray. ▪ SSW B supplies RHR B, RHR C and Division 2 Emergency Diesel. ▪ SSW C supplies High Pressure Core Spray (HPCS) and Division 3 Emergency Diesel. The Emergency Diesels, RHR and HPCS are all Mitigating Systems and are monitored systems as defined in NEI 99-02. SSW is a support system as defined in NEI 99-02 and is monitored to the extent that it affects the monitored Mitigating Systems. In 1994, periodic testing of the SSW pumps identified that shaft column fasteners had washers that had deteriorated to the point that the deep draft pump column had grown in length, allowing the impeller to rub on the bottom of the pump casing. The root cause determined that the washers had deteriorated due to galvanic corrosion set up by incompatible material between the pump shaft and the fasteners which was compounded by the poor water quality in the system. These fasteners were replaced on line in 1995 with like-for-like replacement of old materials while new pumps were designed and fabricated. The 5-Year Business Planning process established 2002 for SSW A and B pump replacements and 2003 for the SSW C replacement. Work planning and business considerations determined that SSW A and SSW B pumps would be replaced in January and February 2002. Work planning also determined that the pumps could to be replaced on line within the Tech Spec LCO time (72 hours). Work duration was estimated to be 40 hours for each pump. A quantitative risk analysis was performed. Due to the complexity and uniqueness of the work, the SSW outages were planned separately from the system outages they support. That is, no parallel Emergency Diesel or RHR outage work was to be scheduled with the SSW outages. The analysis showed that the planned configuration was acceptable from a Regulatory Guide 1.177 and 1.174 standpoint. For example, the incremental conditional core damage probability, ICCDP, is less than 1E-7, and the delta CDF (core damage frequency) is less than 2E-7/yr for this maintenance SSW A and B pumps were changed in the first quarter 2002. Approximately 63 unavailable hours were incurred in the work. As a result of pump change-out, the reliability of the SSW system will be improved as the upgrade in pump material will reduce the amount of fastener deterioration to a negligible level. The new pumps are expected to last the life of the plant and should reduce any future out of service time and inspection requirements due to the improved materials compatibility. Based upon the above description, should the planned overhaul maintenance hours for the SSW system pump A and B replacements be counted in determining the PI values for Emergency Diesels, RHR and HPCS?	3/21 Introduced 4/25 Discussed 6/12 Tentative Approval	GGNS
		Response This activity qualifies as a unique plant specific situation as described in NEI 99-02 section for the Treatment of Planned Overhaul Maintenance. For this plant specific situation, the planned overhaul hours for the SSW system pump A and B replacements may be excluded from the computation of monitored system unavailabilities		

Temp No.	PI	Question/Response	Status	Plant/ Co.
29.5	EP01	Question: During an EP drill/exercise scenario, a licensee will implement their procedure(s) and develop appropriate protective action recommendations (PARs) when valid dose assessment reports indicate EPA protective action guidelines (PAGs) are exceeded. A question arises when a scenario identifies that the PAGs will be exceeded beyond the 10 mile emergency planning zone (EPZ) boundary. Should the licensee count the development of the PAR(s) [or the lack thereof] beyond the 10 mile EPZ as an EP Drill/Exercise Performance (DEP) PI opportunity, due to their "ad hoc" nature? Response: *See response at end of this document.*	3/21 Introduced 4/25 On Hold 6/12 Response being rewritten	NRC
29.8	IE 03	*Question:* *At approximately 2243 hours on September 24, 2001 the number 2 Station Power Transformer in the Salem Switchyard experienced an electrical fault on one of its associated surge arresters. The failure of this surge arrester resulted in the loss of both the number 2 and 4 main station power transformers and station power transformers 12, 14, 22 and 23. As a result, ~~of the loss of these transformers~~ each Salem Unit lost three (Unit 1 lost 11B, 12B, 13B) of the six condenser circulating pumps. Additionally, Salem Unit 1 lost power to its circulating water traveling screens, as well as the sensing instrumentation for the differential pressure across the traveling screens. Upon loss of power to the sensor, the screen delta p indication in the Control Room shows screen delta p as being in the acceptable range, regardless of actual screen delta p. With only three of six circulating water pumps operating per unit, both Salem units reduced electrical load to maintain main condenser vacuum. Following the completion of the power reduction, Salem Unit 1 personnel restored electrical power to the Unit 1 circulating water bus and the circulating water traveling screens. This occurred approximately 1 hour after the electrical fault. Because of the loss of power to the traveling screens, detritus buildup (detritus levels were between 1400 and 1500 Kg/10E6 cubic meters) caused a high differential pressure on ~~one of~~ the remaining screens. Shortly after the power was restored to the traveling screens, one (13A) of the three remaining circulating water pumps tripped due to high differential pressure across its associated traveling screen. Because of the loss of power to the sensing instrumentation, this condition was not detected prior to restoring the power. As a result of this additional loss of a circulating water pump and the resultant decrease in condenser vacuum, Salem Unit 1 licensed control room operators initiated a manual trip in accordance with the guidance provided in the abnormal operating procedure at 2351, on September 24. This event was similar to previous loss of station power transformer events that occurred in June and July of 2001. In all three of the events, each unit lost three circulators, and one of the two units lost all six traveling screens (in June and July Unit 2 lost the traveling screens), their controls, indications, and the screen wash pumps. In addition, all three events resulted in a power reduction for both units. In both the June and July events, it took longer (1.75 to 6.25 hours) to restore power to the circulators than it did in the September event. The June and July events did not result in the loss of an additional circulator after power was restored because the detritus levels were lower (in the 400's). Therefore, a plant scram was avoided.* *Salem Unit 2 circulating water traveling screens were unaffected by the loss of the 2 SPT, therefore the power reduction was sufficient to maintain main condenser vacuum. Does this event meet the criterion in NEI 99-02 that states "Off-normal conditions that begin with one or more power reductions and end with an unplanned reactor trip are counted in the unplanned reactor scram indicator only." Or are the causes of the downpower and the scram sufficiently different that an unplanned power change and an unplanned scram must both be counted.* Response: This should be treated as one continuous event. The loss of the station power transformer resulted both in the loss of three of the circulating water pumps and in the loss of power to the traveling screens, which led to the loss of the additional circulating water pump. Therefore, the cause of both the power reduction and the scram was the electrical fault. Only the scram should be counted in the performance indicators.	4/25 Introduced 5/22 Discussed 6/12 Being rewritten	Salem

Temp No.	PI	Question/Response	Status	Plant/ Co.
29.9	IE03	NEI 99-02, Rev 2, states that anticipated power changes greater than 20% in response to expected problems (such as accumulation of marine debris and biological contaminants in certain seasons) which are proceduralized but cannot be predicted greater than 72 hours in advance may not need to be counted if they are not reactive to the sudden discovery of off-normal conditions. The circumstances of each situation are different and should be identified to the NRC in a FAQ so that a determination can be made concerning whether the power change should be counted. At Salem, this type of problem is caused by high river grass concentrations biofouling the heat exchanges, coolers, and condensers. Salem Generating Station has a number of methods to determine the possibility of high biofouling, in order to prevent an unplanned shutdown. These methods include regular sampling to determine river grass concentration, visual confirmation of excess river debris, an excessive Service Water Traveling Screen carryover, and high dP across heat exchangers and/or pumps. In the event of high river grass triggered by these methods, procedural instructions (SC.OP-AB.ZZ-0003(Q), Component Biofouling) are in place to initiate preventative actions to reduce biofouling. Over the past few months, the level of detritus has frequently risen above the Action Level I state, described in SC.OP-AB.ZZ-0003(Q), Component Biofouling, resulting in increased preventative actions. Unfortunately, high river grass concentrations and the biofouling of necessary equipment cannot be predicted. On February 26, and again on February 28, Salem 1 reduced power to clean the 13A Condenser Water box due to the accumulation of marine debris and biological contaminants on the 13A Circulating Water Pump Traveling Screen. The 13B Circulating Water Pump had been out of service for maintenance in preparation for the upcoming grassing season. A downpower is procedurally required in situations like this when there are no operating Circulating Water Pumps (13A and 13B) in a Condenser Shell. Concentrations this year began to increase in early October, decrease in early December, and increase again in mid-February. In normal years, the high season was only spring, which was caused by ice thawing in the marshes. That type of river grass is commonly local marsh grass. The type of river grass seen this year, sertularia argentea "Garland Hydroid" and garveia franciscana "Rope Grass", are common to the Chesapeake Bay but have not previously been this abundant in the Delaware Bay. According to Dr. Dale Calder, author of Hydroids and Hydromedusae of Southern Chesapeake Bay, the type of hydroids the Delaware Bay is experiencing are common in high salinity water (ca. 13-30 o/oo) and is active from late September to early June. The observance of high salinity in the Delaware River this year may be attributed to the drought conditions observed over the past few months. The following table indicates the river grass sample concentration, expressed in Kg/million cubic meters, for the time period in the question. The rapidly increasing levels contributed to the biofouling, which required the downpower. 2/18/2002 328 2/21/2002 624 2/22/2002 488 2/24/2002 399 2/26/2002 1149 2/28/2002 1809 3/2/2002 2326 3/4/2002 5133 Do these two examples need to be reported as Unplanned Power Changes?	4/25/02 Introduced 5/22 Discussed 6/12 Being rewritten	Salem

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Response: No. These two examples represent power changes in response to expected accumulation of marine debris that cannot be predicted in advance. The response is proceduralized, and the operators followed their procedures. The environmental conditions cannot be predicted, but were appropriately monitored and the operator response was in accordance with expectations.		
29.10	IE 03	Question: NEI 99-02, Rev 2, states that anticipated power changes greater than 20% in response to expected problems (such as accumulation of marine debris and biological contaminants in certain seasons) which are proceduralized but cannot be predicted greater than 72 hours in advance may not need to be counted if they are not reactive to the sudden discovery of off-normal conditions. The circumstances of each situation are different and should be identified to the NRC in a FAQ so that a determination can be made concerning whether the power change should be counted. NEI 99-02, Rev 2, does not discuss whether the power changes associated with these FAQs should be counted while awaiting disposition. Is it satisfactory to state in the comment field that a FAQ has been submitted, and not to include the power changes in the PI calculation?	4/25 Introduced 6/12 Discussed To be rewritten	Salem
		Response: Yes. The comment field should be annotated to state that a FAQ has been submitted. *The licensee and the NRC should work expeditiously and cooperatively, sharing concerns, questions, and data, in order that the issue can be resolved quickly. However, if the issue is not resolved by the time the quarterly report is due, and the licensee has a reasonable expectation that this exclusion applies, it is not necessary to include these power changes in the submitted data. Conversely, if the licensee does not have a reasonable expectation that this exclusion applies, the unplanned power change(s) should be counted. In either case,* ~~If the licensee believes that this exclusion applies, it is not necessary to include them in the PI calculation. T~~the report can be amended, if required, at a later date.		
30.1	EP02	Question: NEI 99-02 states in the clarifying notes for the ERO PI, "When the functions of key ERO members include classification, notification, or PAR development opportunities, the success rate of these opportunities must contribute to Drill/Exercise Performance (DEP) statistics for participation of those key ERO members to contribute to ERO Drill Participation." Must the key ERO members individually perform an opportunity of classification, notification, or PAR development in order to receive ERO Drill Participation credit?	5/22 Introduced 6/12 Discussed	
		Response: No. The evaluation of the DEP opportunities is a crew evaluation for the entire Emergency Response Organization. Key ERO members may receive credit for the drill if their participation is a meaningful opportunity to gain proficiency in their assigned position		

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30.2	MS01	Appendix D Question: NEI 99-02, Revision 1, in the Clarifying Notes for the Mitigating Systems Cornerstone, allows a licensee to not count planned unavailable hours under certain conditions when testing a monitored system. At our two-unit PWR station, three EDGs provide emergency AC power. There is one dedicated diesel for each unit and one swing diesel available for either unit. During the monthly surveillance testing required by Technical Specifications, there is an approximate four-hour period when the EDG is run for the operational portion of the test and is inoperable but available. In 2001, surveillance-testing procedures were revised to take credit for restoration actions that would enable not counting the hours as unavailable. The restoration actions for the two dedicated diesels during the approximate four-hour period consist of implementing a "contingency actions" attachment to the test procedure. This process verifies system alignment and places the EDG on its emergency bus. The steps allow the dedicated control room operator to change the emergency generator auto-exercise selector from exercise to auto, verify or place the emergency supply switch in auto, depress the emergency generator fast start reset button and adjust the engine speed and voltage as necessary. The process steps are, ~~individually and collectively, simple and~~ done by a dedicated operator. The last step requires the governor speed droop control to be adjusted to zero. However, the speed droop adjustment is not required for the EDG to satisfy its safety function. This step is performed to relieve the dedicated operator and does not challenge operation or control of the EDG. Question (1); can credit be taken during the restoration actions that require only one dedicated control room operator (no other assigned duties) resulting in not counting the unavailable hours during this portion of the testing of the dedicated EDGs? The restoration actions for the swing diesel also consist of implementing a "contingency actions" attachment to the test procedure with a few ~~minor~~ differences. Three additional steps determine which emergency bus the swing EDG needs to be aligned to before placing the swing EDG on that emergency bus. The rest of the actions are identical to the dedicated EDG explanation described above. Question (2); can credit be taken for these restoration actions that require only one dedicated control room operator (no other assigned duties) resulting in not counting the unavailable hours during this portion of the testing of the swing EDG?	5/22 Introduced 6/12 Discussed	Surry

except for the speed droop adjustment.

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Licensee Response: Yes, credit can be taken for restoration actions in both cases above and unavailable hours are not counted. Although NEI 99-02, revision 2, does not specifically apply to these questions, the exceptions to allow credit for operator compensatory actions with monitored systems, listed in Appendix D, are addressed to provide a rationale for the answer. (Item numbers below correspond to items in Appendix D.) 1. Not applicable. 2. High 3. A loss of off-site power is recognizable from alarms and installed instrumentation at the EDG control panel in the control room. 4. A dedicated operator is assigned during EDG testing who will conduct the compensatory actions if needed. All licensed operators were trained on the compensatory actions that are part of the operators continuing training. Operators in training were able to perform the contingencies and complete recovery actions within 3-5 minutes. 5. Communications is not applicable since an operator in the control room conducts the compensatory actions. 6. Compensatory equipment is normally installed station equipment. 7. Compensatory actions are specified in an attachment to the test procedure and are always available during the test. 8. All licensed operators were trained on the compensatory actions that are part of the operators continuing training. Compensatory actions are discussed as part of the pre-job brief each time testing is performed 9. The probability of successful completion of compensatory actions is nearly one. • Action steps are simple, individually and collectively. Operators in training were able to perform the contingencies and complete recovery actions within 3-5 minutes. • A dedicated operator conducts the actions • No diagnosis or repair is required to complete the procedure • PRA calculations were conducted to determine the probability of successful completion of compensatory actions For the dedicated EDGs, the probability of success is 99.75%. For the swing EDG, the probability of success is 99.5%. • The dedicated operator is easily able to maintain EDG frequency/voltage within required specifications by making manual adjustments during the time loads are sequenced onto the EDG. Once loads are sequenced on, adjustments would only be necessary when loads are removed per Emergency Operating Procedures.	tentative approval	

No, it requires more than a few simple actions

Temp No.	PI	Question/Response	Status	Plant/ Co.
30.3	EP01	Question: Should the follow up PAR change notifications be counted as four inaccurate notifications for the situation described below? ~~On January 22, 2002, A~~a drill was conducted which included opportunities for Classification, Notification and PARs. The initial Notification for the General Emergency and the associated PAR contained the accurate Time Event Declared of the classification. On follow up PAR change notifications (4), the Time Event Declared block was completed with the time of the PAR data instead of the time the GE was declared. The initial GE Event notification contained the proper time. ~~The time was changed due to confusion of the Protective Measures Manager as to the meaning of this block. This was identified in the critique following the drill.~~ There were four PAR changes made. The PAR, MET and other required information was accurate. Each PAR developed was accurate. The time the PAR was developed was accurate on the form. Once a General Emergency was accurately declared, and the INITIAL notification was made in a timely and accurate manner, changing of the time in the Time Event Declared block on the follow up notifications had no influence on the event initiation, nor did it result in untimely or inaccurate PARs being issued to the states and counties. ~~The states and counties were provided the accurate information needed to take the appropriate actions for protection of the public.~~ Changing of the time in follow up PAR change notifications did not impact their response since the states and counties were provided the accurate time of event declaration in the initial notification. No additional events were declared since the plant was already at the GE classification. This issue was critiqued and actions were taken to ensure the time desired for the Time Event Declared block on the form was communicated to those responsible for completing the form. ~~Although the performance was not up to our expectations, considering the entire notification inaccurate on four separate occasions does not reflect the overall performance of the ERO team in the area of classification, notification and PARs. The team is fully capable of providing accurate classifications and PARs as well as timely and accurate notifications.~~	5/22 Introduced 6/12 Discussed	OPPD
		Response: *No.* ~~Since the INITIAL notification was made in a timely and accurate manner, changing of the time in the Time Event Declared block on the follow up notifications had no influence on the event initiation, nor did it impact the response of the states and counties. The states and counties were provided the accurate time of event declaration in the initial notification. Therefore, they can be counted as SUCCESSFUL as long as the other elements required for accuracy were correctly communicated to the states in a timely manner~~ *Based on the example above, the 4 of 5 notifications should be counted as successful. Since it was the same error in 4 follow-up notifications, it should only be counted once since it was in the same exercise. Note: if the same crew made the same mistake in a subsequent exercise, it would be counted as a separate missed opportunity.*		
30.4	MS01	Question: The St. Lucie Station programmatically maintains and manages risk associated with overhaul maintenance performed within Technical Specification Allowed Outage Times (AOTs). The program implements Regulatory Guide 1.177 and/or NUMARC 93-01 requirements for risk management during the maintenance activities. All work to be accomplished during a planned overhaul is scheduled in advance and includes maintenance activities that are required to improve equipment reliability and availability. St. Lucie considers overhaul maintenance as those overhaul activities associated with the major component as well as pre-planned corrective and preventive maintenance on critical subcomponents. For example, the EDG preventive maintenance program requires hydrostatic testing of the lube oil cooler every 12 years and the subsequent repair or replacement of the cooler as necessary. The purpose of the hydrostatic test is to pre-emptively reveal defects to preclude a run-time failure by applying far more pressure to the lube oil cooler than would be experienced during normal operation. This test was a scheduled item during a planned EDG overhaul, and the lube oil cooler did not pass the hydrostatic test. The lube oil cooler replacement was not included as a scheduled contingency item, nor was a replacement cooler on-site. However, replacement coolers of this type were known to be readily obtainable. The original overhaul duration was extended by the time needed for procurement and installation of a replacement lube oil cooler. Do the additional hours count as planned overhaul maintenance hours?	5/22 Introduced 6/12 Discussed	St. Lucie

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Response: As described, the condition above is considered planned overhaul maintenance hours. In accordance with NEI 99-02, 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. The EDG lube oil hydrostatic test meets this requirement. Additional guidance states that overhauls include disassembly and reassembly of major components and may include replacement of parts as necessary, cleaning, adjustment, and lubrication as necessary. NEI 99-02 provides a list of typical major components such as diesel engine or generator, pumps, pump motor or turbine driver, or heat exchangers. However, these guidelines do not preclude critical subcomponent planned maintenance, testing, or inspection activities from meeting the requirement for overhaul maintenance as long as these activities are preplanned and performed as part of the approved preventive maintenance program for the major component. The lube oil cooler hydrostatic test was a line item within the EDG overhaul schedule, and it was performed as directed by the preventive maintenance program. The failed hydrostatic test does not represent a new failure due to the anticipatory nature of the surveillance. Replacement of the lube oil cooler did not represent a major rebuild task, and the replacement part was readily available. Furthermore, planned overhaul maintenance does not mean that all contingency items for replacement parts need to be explicitly scheduled items during the overhaul. Therefore, the additional hours spent on lube oil cooler procurement and replacement are considered planned overhaul hours for the purposes of the safety system unavailability PI.		
30.5	MS01	Question: The overhaul of the EDG fuel priming pump was planned corrective maintenance and was scheduled as part of the overall overhaul activities for the EDG. Post maintenance testing revealed that parts installed in the fuel oil priming pump during the overhaul did not result in optimal performance. Although the pump operation would not have prevented the fuel oil priming pump from fulfilling its required safety function, the decision was made to rework the pump to recover pump performance. The rework resulted in extending the overhaul past its originally scheduled time. Does the maintenance rework count as planned overhaul maintenance?	5/22 Introduced 6/12 Discussed	St. Lucie
		Response: As describe, the condition above is considered planned overhaul unavailability hours. The planned corrective maintenance for the EDG fuel oil priming pump was an activity undertaken voluntarily and performed in accordance with the established preventive maintenance program to improve equipment reliability and availability. NEI 99-02 states that additional time needed to repair equipment problems discovered during the planned overhaul count as non-overhaul hours only if the problem would have prevented the fulfillment of a safety function. The concern that was identified on the fuel oil priming pump during the post maintenance test would not have prevented the fulfillment of a safety function. Therefore, the additional hours spent on fuel priming pump rework are considered planned overhaul hours for the purposes of the safety system unavailability PI.		

Temp No.	PI	Question/Response	Status	Plant/ Co.
30.6	MS05	Question: Review of the Safety System Functional Failure Performance Indicator (PI) by the NRC Resident Inspector questioned whether Indian Point 2 LER 2000-006 should have been counted as a functional failure. Regardless of whether this LER constitutes a functional failure or not, there would be no PI threshold change LER 2000-006 was submitted to the NRC on September 5, 2000. The LER is entitled "Source Range Detector High Flux Trip Circuitry Outside of Plant Design Basis Due To Revised Local Cabinet Temperature Uncertainty." This LER was coded as 10 CFR 50.73(a)(2)(ii). The LER determined the cause of the plant being outside the design basis was the temperature errors associated with the maximum control room design temperature were not explicitly accounted for when the setpoint was changed in 1973. There were no safety consequences associated with this LER since: • The IP-2 Tech Specs do NOT include any reactor trip set point limits for the NIS source range detectors, • The source range high flux trip is NOT credited in any UFSAR Chapter 14 accident analysis, and • The intermediate and power range flux trips would be available to provide for termination of a power excursion during a reactor startup or low power operation. The review of this LER did not determine this was a safety system functional failure since the source range high flux trip is not relied on in the UFSAR. Additional information: • NEI 99-02, Revision 1 refers to 10 CFR 50.73(a)(2)(v). It does state that paragraphs (a)(2)(i), (a)(2)(ii), and (a)(2)(vii) should also be reviewed for applicability for this PI (these were reviewed and the determination was only section (a)(2)(ii) was applicable), • NEI 99-02, Revision 1 also refers to NUREG-1022 for additional guidance that is applicable to reporting under 10 CFR 50.73(a)(2)(v), • NUREG-1022, Revision 2, section 3.2.7, at page 54 defines "safety function" as those four functions listed in the reporting criteria…as described or relied on in the UFSAR and • NUREG-1022 also adds at page 54, "or required by the regulations." Regulations are being interpreted to include technical specifications. Is it the intent of NEI 99-02 to solely report safety system functional failures as described or relied on in the UFSAR or is it the intent to additionally incorporate the guidance in NUREG-1022, section 3.2.7 that the failure of any component addressed in the plant's Technical Specification constitutes a safety system functional failure whether credited or not in the UFSAR chapter 14 analyses? Response: Since only SSCs credited in the UFSAR are intended or expected by the NRC PI program to meet the four reporting criteria (A)-(D) listed at page 67 of NEI 99-02 and page 52 of NUREG-1022, the phrase, 'or required by the regulations,' at page 54 of NUREG-1022 is an unintended application of NUREG-1022 to the NRC PI and should be disregarded for purposes of the NRC PI, safety system functional failures.	5/22 Introduced 6/12 Discussed	IP 2

Temp No.	PI	Question/Response	Status	Plant/ Co.
30.7	MS02 ,03,04	Question: As part of plant tour by an on-shift senior reactor operator, two covers were found to be missing for a piece of "guard" pipe used as a barrier over the main steam supply line to a Turbine Driven Auxiliary Feedwater pump. This "guard" pipe was designed to be used as a secondary barrier to prevent the spread of steam in the event of a steam supply line break to ensure environmental qualification of other plant equipment in the area The covers provide access for inspection of the inner pipe and supports and are only needed for the postulated design basis rupture of that specific section of steam pipe. The deficiency was easily corrected by replacement of the covers The time of occurrence is associated with original plant construction and accordingly the deficiency has existed for a number of years. Engineering reviews are still being performed and the impact on equipment qualification is still indeterminate. Can the fault exposure period for a construction/modification deficiency, as described above, that existed for a long period of time and that could not be identified by normal surveillance tests be addressed in the same fashion as a design deficiency hours described in NEI 99-02, Revision 2, Page 33, Lines 8 through 23? Response: Yes. While not specifically the result of a design deficiency, this construction caused equipment failure was not capable of being discovered during normal surveillance tests and has a long fault exposure periods thus meeting the same criteria as an excluded design deficiency. Its significance, like that of design deficiency, is more amenable to evaluation through the NRC's inspection process and thus should also be excluded from the unavailability indicators.	5/22 Introduced 6/12 Tentative Approval	Watts Bar
30 8	IE02	Question: Many plant designs trip the main feedwater pumps on high reactor water level (BWRs), and high steam generator water level or certain other automatic trips (PWRs). Under what conditions would a trip of the main feedwater pumps be considered/not considered a scram with loss of normal heat removal?	5/22 Introduced 6/12 Discussed	Generic

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Response: For loss of all main feedwater due to high water level, or other design trips, the following guidance applies: 1. If all of the main feedwater pumps are not recoverable due to a problem in the feedwater system that requires repair actions, the condition is a scram with loss of normal heat removal. 2. If all main feedwater pumps are not available, and repair actions are required to restore at least one normal main feedwater pump, the condition is a scram with loss of normal heat removal. 3. If the main feedwater pumps are not needed but procedures call for the pumps to be started if needed and it is determined that at least one pump would have restored feedwater flow, the condition is NOT a scram with loss of normal heat removal. 4. If the main feedwater pumps are needed and no main feedwater pumps are able to restore flow, then the condition is a scram with loss of normal heat removal. 5. If the main feedwater pumps are needed and at least one main feedwater pump would have been able to restore flow, it is NOT a scram with loss of normal heat removal. 6. If the main feedwater pumps are secured following a scram in accordance with emergency operating procedures to reduce the steam load on the reactor, it is NOT a scram with loss of normal heat removal. For the conditions NOT to be a scram with loss of normal feedwater, at least one main feedwater pump must be capable of being recovered without the need for repair and diagnosis. The main feedwater pumps must be able to be restarted from the control room with normal monitoring/startup actions by an auxiliary operator dispatched locally.		
31.1	MS 01	Question: Florida Power Corporation's (FPC) Crystal River Unit 3 (CR-3) seeks to apply the NEI 99-02, Revision 2, Safety System Unavailability (SSU) T/2 Fault Exposure Hour treatment for T/2 Fault Exposure Hours incurred prior to January 1, 2002. Specifically, FPC seeks approval to remove 345 T/2 Fault Exposure Hours incurred in a single increment against Emergency Diesel Generator EGDG-1B from the calculation of Emergency AC SSU PI. These hours **DID NOT** result in the associated SSU Performance Indicator (PI) exceeding the green-white threshold. In accordance with the guidance of NEI 99-02, Revision 2, these hours would be reported in the "Comment" section of the PI data file. Continuing to carry these Emergency AC SSU T/2 Fault Exposure Hours until the Fault Exposure Hour reset criteria are met is inconsistent with the current philosophy for treatment of T/2 Fault Exposure Hours. This situation will result in the SSU PIs for various plants being non-comparable depending on when any T/2 Fault Exposure Hours were discovered. This could easily occur at a multi-unit site. Further, if a plant discovered different events which contributed T/2 Fault Exposure Hours attributable to a period before January 1, 2002, and another after, the PI would be internally inconsistent. Response: This situation does not meet the requirements for resetting fault exposure hours, in that the green white threshold was not exceeded.	6/12 Tentative Approval	Crystal River 3

Temp No.	PI	Question/Response	Status	Plant/ Co.
31.3	IE03	Question; NEI 99-02 states that unplanned power changes include runbacks and power oscillations greater than 20% of full power. Under what circumstances does a power oscillation that results in an unplanned power decrease of greater than 20% followed by an unplanned power increase of 20% count as one PI event versus two PI events? Response: A power oscillation resulting from equipment failure without operator influence is considered one event in the PI. A power oscillation resulting from a maintenance activity or operating error where the initiating condition is immediately restored to it's pre-event condition is considered one event in the PI. However, if a power reduction occurs from any failure or activity and the plant stabilizes such that personnel discuss a restoration method, and during the restoration, power subsequently increases unexpectedly by greater than 20% of full power, then the event is considered two events in the PI. For example: During a maintenance activity an operator mistakenly opens the wrong breaker which supplies power to the recirculation pump controller. Recirculation flow decreases resulting in a power decrease of greater than 20% of full power. The operator, hearing an audible alarm, suspects the alarm may have been caused by the activity and closes the breaker resulting in a power increase of greater than 20% full power. This is considered one event in the PI.	7/2 Introduced	Southern Nuclear
31.4	PP03	<u>Question</u> The clarifying note for the Fitness-For-Duty / Personnel Reliability Program PI states that the indicator does not include any reportable events that result from the program operating as intended. There is also an example provided that indicates that a random test drug failure would not count since the program itself was successful. The following example is somewhat more complex and would help to further clarify treatment of situations associated with random testing: Example - A licensee supervisor is selected for a random drug test but refuses and resigns prior to providing a specimen All actions taken upon discovery are in accordance with Part 26 and the program functions as intended. The subject supervisor, prior to the event, was expected to be effectively practicing the behavioral observation techniques (for which supervisors are required to be trained per 10 CFR 26.22) in his role as a supervisor. Would this example count as a PI data element? Response: No. The program functioned as intended and the requirements of Part 26 were met.	7/2 Introduced	Beaver Valley

Temp No.	PI	Question/Response	Status	Plant/ Co.
31.5	MS04	*Question Appendix D* *Sequoyah Nuclear Plant (SQN) has two units. Each Unit has three trains of AFW, two motor driven trains (A train and B train), and one turbine driven train (Terry Turbine train, A or B train power). All three trains have Level Control Valves (LCVs) that are the steam generator injection valves. The LCVs are normally closed, air operated valves that auto open when AFW receives a start signal. The valves fail open when air is removed from them. SQN uses Control Air as the normal air supply to the LCVs. Control Air is not a seismically qualified, 1E system. Auxiliary Air is the LCV's standby, safety related air supply. A train Auxiliary Air feeds two Terry Turbine train LCVs and the two motor driven A train LCVs. B train Auxiliary Air feeds the other two Terry Turbine train LCVs and the two motor driven B train LCVs. Auxiliary Air automatically starts whenever the Control Air pressure drops below its setpoint. The Terry Turbine train LCVs also have accumulator tanks and high pressure air cylinders to control them during a loss of all power. The Terry Turbine train LCVs can be controlled from the main control room for one hour after the loss of all air using the accumulator tanks.* *For all scenarios except a major secondary system pipe rupture, the fail open LCVs are conservative, as they allow AFW to deliver the required flow. During a major secondary system pipe rupture, AFW is required to be isolated from the faulted steam generator. In the absence of both Control Air and Auxiliary Air, manual action at the LCVs will have to be taken to isolate the corresponding motor driven AFW train from the faulted steam generator. This action is proceduralized in Emergency Procedures and Abnormal Operating Procedures. The PSA also models the AFW system as available while Auxiliary Air is taken out of service.* *Since the PSA models the AFW system as available while Auxilary Air is unavailable (gives credit for the manual isolation of motor driven AFW trains) and the manual actions are proceduralized and trained on, is it correct to be consider the affected train(s) of AFW as still available during the periods when Auxiliary Air is taken out of service?*	*8/22 Introduced*	*Sequoyah*

Response to 29.5:

Essential to understanding that a PAR opportunity exists, is the need to realize that it is a regulatory requirement for a licensee to develop and communicate a PAR when EPA PAG doses may be exceeded beyond the 10-mile plume exposure pathway EPZ. The following discussion clarifies the regulatory requirement. This requirement is addressed in 10 CFR Part 50 as follows:

Section 50.54(q) of 10 CFR Part 50 states that a licensee authorized to possess and operate a nuclear power reactor shall follow and maintain in effect emergency plans which meet the standards in 10 CFR 50.47(b) and the requirements in Appendix E to 10 CFR Part 50.

Section 10 CFR 50.47(b)(10) states:

> A range of protective actions has been developed for the plume exposure pathway EPZ for emergency workers and the public. In developing this range of actions, consideration has been given to evacuation, sheltering, and, as a supplement to these, the prophylactic use of potassium iodide (KI), as appropriate. Guidelines for the choice of protective actions during an emergency, consistent with Federal guidance, are developed and in place, and protective actions for the ingestion exposure pathway EPZ appropriate to the locale have been developed.

Section IV.B, Assessment Actions, in Appendix E to 10 CFR Part 50 states:

> *The means to be used for determining the magnitude of and for continually assessing the impact of the release of radioactive materials shall be described, including emergency action levels that are to be used as criteria for determining the need for notification and participation of local and State agencies, the Commission, and other Federal agencies, and the emergency action levels that are to be used for determining when and what type of protective measures should be considered within and outside the site boundary to protect health and safety.*

In the statement of considerations for the final emergency preparedness rule published in the Federal Register (45 FR 55406) on Tuesday, August 19, 1980, the Commission explained that response bases for the emergency planning zones (EPZs) are intended to facilitate the development of capabilities sufficient to respond outside the EPZ should such a response be needed:

> *The Commission notes that the regulatory basis for adoption of the Emergency Planning Zone (EPZ) concept is the Commission's decision to have a conservative emergency planning policy in addition to the conservatism inherent in the defense-in-depth philosophy. This policy was endorsed by the Commission in a policy statement published on October 23, 1979 (44 FR 61123). At that time the Commission stated that two Emergency Planning Zones (EPZs) should be established around each light-water nuclear power plant. The EPZ for airborne exposure has a radius of about 10 miles; the EPZ for contaminated food and water has a radius of about 50 miles. Predetermined protective action plans are needed for the EPZs. The exact size and shape of each EPZ will be decided by emergency planning officials after they consider the specific conditions at each site. These distances are considered large enough to provide a response base that would support activity outside the planning zone should this ever be needed. (emphasis added)*

Thus, the Commission intended the response base for the EPZ to be a planning tool to facilitate advance planning and development of offsite emergency response capabilities; the Commission never intended the licensee's emergency response to be limited to the EPZ if an offsite emergency actually occurred.

Based upon the above, the staff position has been, and will continue to be, that the requirement for a licensee to provide predetermined protective actions plans for the 10-mile plume exposure pathway EPZ provides the response base for licensee activities beyond the EPZ should it ever be needed. Therefore, even though predetermined protective actions plans are not required for activities beyond the EPZ, licensees are required to develop and communicate protective actions when EPA PAGs may be exceeded beyond the 10-mile plume exposure pathway EPZ. Accordingly, if a scenario identifies that dose assessments support the need for PAR development beyond the 10 mile plume exposure EPZ, then the licensee shall develop and communicate such PAR. It is expected that this PAR development and communication has been contemplated by the scenario with an expectation for success and criteria provided. With all that in place, this constitutes a PI opportunity as defined in NEI 99-02. It should be noted that the licensee has the latitude to identify PI opportunities prior to the exercise and may choose to not include a PAR beyond the plume EPZ as a PI opportunity due to its ad hoc nature. Also, separate from the identification of the PAR development, is a PI opportunity associated with the timeliness of the communication of the PAR. Again, the licensee has the latitude to identify the timeliness of the communication as a PI opportunity or not. However, whether a PI opportunity is identified or not, it does not relinquish the evaluation by the NRC and the licensee of the PAR development and its timely communication. Further, the NRC will evaluate the subsequent ability of the licensee to identify and critique unacceptable exercise performance with regard to PAR development and communication.

~~2.2 MITIGATING SYSTEMS CORNERSTONE~~

~~The objective of this cornerstone is to monitor the availability, reliability, and capability of systems that mitigate the effects of initiating events to prevent core damage. Licensees reduce the likelihood of reactor accidents by maintaining the availability and reliability of mitigating systems. Mitigating systems include those systems associated with safety injection, decay heat removal, and their support systems, such as emergency ac power. This cornerstone includes mitigating systems that respond to both operating and shutdown events.~~

~~Some aspects of mitigating system performance cannot be adequately reflected or are specifically excluded from the performance indicators in this cornerstone. These aspects include performance of structures, systems, and components (SSCs) specifically excluded from the performance indicators, the effect of common cause failure, and the performance of certain plant specific systems. These aspects of licensee performance will be addressed through the NRC inspection program.~~
~~There are two sets of indicators in this cornerstone:~~

- ~~Mitigating System Performance Index~~
- ~~Safety System Functional Failures~~

MITIGATING SYSTEM PERFORMANCE INDEX

Purpose

The purpose of the mitigating system performance index is to monitor the ~~risk impact of changes in~~ performance of selected systems based on their ability to perform risk-significant functions as defined here-in.~~,~~ It is comprised of two elements - system unavailability and system unreliability. For single demand failures and accumulated unavailability, the index is used to determine the significance of performance issues. Due to the limitations of the index, the following conditions will rely upon the inspection process for evaluating performance issues:

1. Multiple concurrent failures of components ~~within a monitored system~~
2. Common cause failures
3. Conditions not capable of being discovered during normal surveillance tests
4. Failures of non-active components

Indicator Definition

Mitigating System Performance Index (MSPI) is the sum of changes in a simplified core damage frequency evaluation resulting from changes in unavailability and unreliability relative to baseline values.

~~*Train*~~ *Unavailability* is the ratio of the hours the train was unavailable to perform its risk-significant functions due to planned and unplanned maintenance or test on active and non-active components during the previous 12 quarters while critical to the number of critical hours during the previous 12 quarters. (Fault exposure hours are not included; unavailable hours are counted only for the time required to recover the train's risk-significant functions.)

~~Train u~~Unreliability is the probability that the ~~train~~ system would not perform its risk-significant functions when called upon during the previous 12 quarters.

Baseline values are the values for unavailability and unreliability against which current changes in unavailability and unreliability are measured. See Appendix F for further details.

The MSPI is calculated separately for each of the following five systems for each reactor type.

BWRs

- emergency AC power system
- high pressure injection systems (high pressure coolant injection, high pressure core spray, or feedwater coolant injection)
- heat removal systems (reactor core isolation cooling)
- residual heat removal system (or their equivalent function as described in the Additional Guidance for Specific Systems section.)
- cooling water support system (includes risk significant direct cooling functions provided by service water and component cooling water or their cooling water equivalents for the above four monitored systems)

PWRs

- emergency AC power system
- high pressure safety injection system
- auxiliary feedwater system
- residual heat removal system (or their equivalent function as described in the Additional Guidance for Specific Systems section.)
- cooling water support system (includes risk significant direct cooling functions provided by service water and component cooling water or their cooling water equivalents for the above four monitored systems)

Data Reporting Elements

The following data elements are reported for each system

- Unavailability Index (UAI) due to unavailability for each monitored system
- Unreliability Index (URI) due to unreliability for each monitored system

During the pilot, the additional data elements necessary to calculate UAI and URI will be reported monthly for each system on an Excel spreadsheet. See Appendix F.

Calculation

The MSPI for each system is the sum of the UAI due to unavailability for the system plus URI due to unreliability for the system during the previous twelve quarters.

MSPI = UAI + URI.

See Appendix F for the calculational methodology for UAI due to system unavailability and URI due to system unreliability.

Definition of Terms

A train consists of a group of components that together provide the risk significant functions of the system as explained in the additional guidance for specific mitigating systems. Fulfilling the risk-significant function of the system may require one or more trains of a system to operate simultaneously. The number of trains in a system is generally determined as follows:

- for systems that provide cooling of fluids, the number of trains is determined by the number of parallel heat exchangers, or the number of parallel pumps, or the minimum number of parallel flow paths, whichever is fewer.

- for emergency AC power systems the number of trains is the number of class 1E emergency (diesel, gas turbine, or hydroelectric) generators at the station that are installed to power shutdown loads in the event of a loss of off-site power. (This does not include the diesel generator dedicated to the BWR HPCS system, which is included in the scope of the HPCS system.)

Risk Significant Functions: those at power functions of risk-significant SSCs as modeled in the plant-specific PRA. Risk metrics for identifying risk-significant functions are:

Risk Achievement Worth > 2.0, or
Risk Reduction Worth >0.005, or
PRA cutsets that account for 90% of core damage frequency~~90% of core damage frequency accounted for.~~

Risk-Significant Mission Times: The mission time modeled in the PRA for satisfying the risk-significant function of reaching a stable plant condition where normal shutdown cooling is sufficient. Note that PRA models typically analyze an event for 24 hours, which may exceed the time needed for the risk-significant function captured in the MSPI. However, other intervals as justified by analyses and modeled in the PRA may be used.

Success criteria are the plant specific values of parameters the train/system is required to achieve to perform its risk-significant function. Default values of those parameters are the plant's design bases values unless other values are modeled in the PRA.

Clarifying Notes

Documentation

Each licensee will have the system boundaries, active components, risk-significant functions and success criteria readily available for NRC inspection on site. Additionally, plant-specific information used in Appendix F should also be readily available for inspection.

Success Criteria

~~The success criteria are based on train/system mission times, not on component mission times.~~ Individual component capability must be evaluated against train/system level success criteria (e.g., a valve stroke time may exceed an ASME requirement, but if the valve still strokes in time to meet the PRA success criteria for the train/system, the component has not failed for the purposes of this indicator because the risk-significant train/system function is still satisfied). Important plant specific performance factors that can be used to identify the required capability of the train/system to meet the risk-significant functions include, but are not limited to:

- Actuation
  - Time
  - Auto/manual
  - Multiple or sequential
- Success requirements
  - Numbers of components or trains
  - Flows
  - Pressures
  - Heat exchange rates
  - Temperatures
  - Tank water level
- Other mission requirements
  - Run time
  - State/configuration changes during mission
- Accident environment from internal events
  - Pressure, temperature, humidity
- Operational factors
  - Procedures
  - Human actions
  - Training
  - Available externalities (e.g., power supplies, special equipment, etc.)

System/Component Interface Boundaries

For active components that are supported by other components from both monitored and unmonitored systems, the following general rules apply:

- For control and motive power, only the last relay, breaker or contactor necessary to power or control the component is included in the active component boundary. For example, if an ESFAS signal actuates a MOV, only the relay that receives the ESFAS signal in the control circuitry for the MOV is in the MOV boundary. No other portions of the ESFAS are included.

- For water connections from systems that provide cooling water to an active component, only the final active connecting valve is included in the boundary. For example, for service water that provides cooling to support an AFW pump, only the final active valve in the service water system that supplies the cooling water to the AFW system is included in the AFW system scope. This same valve is not included in the cooling water support system scope.

Water Sources and Inventory

Water tanks are not considered to be active components. As such, they do not contribute to URI. However, periods of insufficient water inventory contribute to UAI if they result in loss of the risk-significant train function for the required mission time. Water inventory can include operator recovery actions for water make-up provided the actions can be taken in time to meet the mission times and are modeled in the PRA. If ~~alternate~~ additional water sources are required ~~to provide make-up~~ to satisfy train mission times, only the connecting active valve from the ~~alternate system~~additional water source is considered as an active component for calculating URI. If there are valves in the primary water source that must change state to permit use of the additional water source, these valves are considered active and should be included in URI for the system.

Monitored Systems

Systems have been generically selected for this indicator based on their importance in preventing reactor core damage. The systems include the principal systems needed for maintaining reactor coolant inventory following a loss of coolant accident, for decay heat removal following a reactor trip or loss of main feedwater, and for providing emergency AC power following a loss of plant off-site power. One risk-significant support function (cooling water support system) is also monitored. The cooling water support system monitors the risk significant cooling functions provided by service water and component cooling water, or their direct cooling water equivalents, for the four front-line monitored systems. No support systems are to be cascaded onto the monitored systems, e.g., HVAC room coolers, DC power, instrument air, etc.

Diverse Systems

Except as specifically stated in the indicator definition and reporting guidance, no credit is given for the achievement of a risk-significant function by an unmonitored system in determining unavailability or unreliability of the monitored systems.

Common Components

Some components in a system may be common to more than one train or system, in which case the unavailability/unreliability of a common component is included in all affected trains or systems. un

Short Duration Unavailability

Trains are generally considered to be available during periodic system or equipment realignments to swap components or flow paths as part of normal operations. Evolutions or surveillance tests that result in less than 15 minutes of unavailable hours per train at a time need not be counted as unavailable hours. Licensees should compile a list of surveillances/evolutions that meet this criterion and have it available for inspector review. In addition, equipment misalignment or mispositioning which is corrected in less than 15 minutes need not be counted as unavailable hours. The intent is to minimize unnecessary burden of data collection, documentation, and verification because these short durations have insignificant risk impact.

If a licensee is required to take a component out of service for evaluation and corrective actions for greater than 15 minutes (for example, related to a Part 21 Notification), the unavailable hours must be included.

~~Treatment of Degraded Conditions~~

~~If a degraded condition results in the failure to meet an established success criterion, unavailable hours must be included for the time required to recover the train's risk-significant function(s). If an active component, as defined in Appendix F, is degraded such that it cannot meet its risk-significant function, a demand and a demand failure are also counted. If subsequent analysis identifies additional margin for the success criterion, future unavailable hours for degraded conditions may be determined based on the new criterion. However, unavailability must be based on the success criteria of record at the time the degraded condition is discovered. If the degraded condition is not addressed by any of the pre-defined success criteria, an engineering evaluation to determine the impact of the degraded condition on the risk-significant function(s) should be completed and documented. The use of component failure analysis, circuit analysis, or event investigations is acceptable. Engineering judgment may be used in conjunction with analytical techniques to determine the impact of the degraded condition on the risk-significant function. The engineering evaluation should be completed as soon as practicable. If it cannot be completed in time to support submission of the PI report for the current quarter, the comment field shall note that an evaluation is pending. The evaluation must be completed in time to accurately account for unavailability/unreliability in the next quarterly report. Exceptions to this guidance are expected to be rare and will be treated on a case-by-case basis. Licensees should identify these situations to the resident inspector.~~

~~Failures on Demand~~

~~Failures of active components (see Appendix F) on demand, either actual or test, while critical, are included in unreliability. Failures on demand while non-critical must be evaluated to determine if the failure would have resulted in the train not being able to perform its risk-significant at-power functions, and must therefore be included in unreliability. Unavailable hours~~

~~are included only for the time required to recover the train's risk-significant functions and only when the reactor is critical.~~

~~Discovered Conditions that are capable of being discovered by normal surveillance tests~~

~~Normal surveillance tests are those tests that are performed at a frequency of a refueling cycle or more frequently. Discovered conditions that render an active component incapable of performing its risk-significant functions are included in unreliability as a demand and a failure (unless corrected in less than 15 minutes). Unavailable hours are counted only for the time required to recover the train's risk-significant functions and only when the reactor is critical. The ROP inspection process would be used to determine the significance of discovered conditions that rendered a train incapable of performing its risk-significant function, but were not active component conditions (for example, a shut manual suction valve).~~

~~Demand failures or discovered conditions that are not capable of being discovered during normal surveillance tests~~

~~These failures or conditions are usually of longer exposure time. Since these failure modes have not been tested on a regular basis, it is inappropriate to include them in the performance index statistics. These failures or conditions are subject to evaluation through the inspection process. Examples of this type are failures due to pressure locking/thermal binding of isolation valves, blockages in lines not regularly tested, or inadequate component sizing/settings under accident conditions (not under normal test conditions). While not included in the calculation of the index, they should be reported in the comment field of the PI data submittal.~~

Treatment of Demand /Run Failures and Degraded Conditions

1. Treatment of Demand and Run Failures

   Failures of active components (see Appendix F) on demand or failures to run, either actual or test, while critical, are included in unreliability. Failures on demand or failures to run while non-critical must be evaluated to determine if the failure would have resulted in the train not being able to perform its risk-significant at power functions, and must therefore be included in unreliability. Unavailable hours are included only for the time required to recover the train's risk-significant functions and only when the reactor is critical.

2. Treatment of Degraded Conditions

   a) Capable of Being Discovered By Normal Surveillance Tests

      Normal surveillance tests are those tests that are performed at a frequency of a refueling cycle or more frequently.

      Degraded conditions, where no actual demand existed, that render an active component incapable of performing its risk-significant functions are included in unreliability as a demand and a failure. The appropriate failure mode must be accounted for. For example, for valves, a demand and a demand failure would be assumed and included in URI. For pumps and diesels, if the degraded condition would have prevented a successful start demand, a demand and a failure is included in URI, but there would be no run time hours or run failures. If it was determined that the pump/diesel would start but not run for the risk-significant mission time, the evaluated failure time would be included in run hours and a run failure would be assumed. A start demand and start failure would not be included. Unavailable hours are included for the time required to recover the risk-significant function(s).

Degraded conditions of non-active components that render a train incapable of performing its risk-significant functions are only included in unavailability for the time required to recover the risk-significant function(s).

Loss of risk significant function(s) is assumed to have occurred if the established success criteria has not been met. If subsequent analysis identifies additional margin for the success criterion, future impacts on URI or UAI for degraded conditions may be determined based on the new criterion. However, URI and UAI must be based on the success criteria of record at the time the degraded condition is discovered. If the degraded condition is not addressed by any of the pre-defined success criteria, an engineering evaluation to determine the impact of the degraded condition on the risk-significant function(s) should be completed and documented. The use of component failure analysis, circuit analysis, or event investigations is acceptable. Engineering judgment may be used in conjunction with analytical techniques to determine the impact of the degraded condition on the risk-significant function. The engineering evaluation should be completed as soon as practicable. If it cannot be completed in time to support submission of the PI report for the current quarter, the comment field shall note that an evaluation is pending. The evaluation must be completed in time to accurately account for unavailability/unreliability in the next quarterly report. Exceptions to this guidance are expected to be rare and will be treated on a case-by-case basis. Licensees should identify these situations to the resident inspector.

b) Not Capable of Being Discovered by Normal Surveillance Tests

These failures or conditions are usually of longer exposure time. Since these failure modes have not been tested on a regular basis, it is inappropriate to include them in the performance index statistics. These failures or conditions are subject to evaluation through the inspection process. Examples of this type are failures due to pressure locking/thermal binding of isolation valves, blockages in lines not regularly tested, or inadequate component sizing/settings under accident conditions (not under normal test conditions). While not included in the calculation of the index, they should be reported in the comment field of the PI data submittal.

Credit for Operator Recovery Actions to Restore the Risk-Significant Function

1. *During testing or operational alignment*:

Unavailability of a risk-significant function during testing or operational alignment need not be included if the test configuration is automatically overridden by a valid starting signal, or the function can be promptly restored ~~in time to meet the PRA risk success criteria~~ either by an operator in the control room or by a designated operator[1] stationed locally for that purpose. Restoration actions must be contained in a written procedure[2], must be uncomplicated (*a single action or a few simple actions*), must be capable of being restored in time to satisfy PRA success criteria and must not require diagnosis or repair. Credit for a designated 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. 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.

The individual performing the restoration function can be the person conducting the test and must be in communication with the control room. Credit can also be taken for an operator in the main control room provided (s)he is in close proximity to restore the equipment when needed. Normal staffing for the test may satisfy the requirement for a dedicated operator, depending on work assignments. In all cases, the staffing must be considered in advance and an operator identified to perform the restoration actions independent of other control room actions that may be required.

Under stressful, chaotic conditions, otherwise simple multiple actions may not be accomplished with the virtual certainty called for by the guidance (e.g., lifting test leads and landing wires; or clearing tags). In addition, some manual operations of systems designed to operate automatically, such as manually controlling HPCI turbine to establish and control injection flow, are not virtually certain to be successful. These situations should be resolved on a case-by-case basis through the FAQ process.

2. *During Maintenance*

Unavailability of a risk-significant function during maintenance need not be included if the risk-significant function can be promptly restored ~~in time to meet the PRA success criteria~~ either by an operator in the control room or by a designated operator[3] stationed locally for that purpose. Restoration actions must be contained in a written procedure[4], must be uncomplicated (*a single action or a few simple actions*), must be capable of being restored in time to satisfy PRA success criteria and must not require diagnosis or repair. Credit for a designated local operator can be taken only if (s)he is positioned at a proper location throughout the duration of the maintenance activity for the purpose of restoration of the train

[1] Operator in this circumstance refers to any plant personnel qualified and designated to perform the restoration function.

[2] Including restoration steps in an approved test procedure.

[3] Operator in this circumstance refers to any plant personnel qualified and designated to perform the restoration function.

[4] Including restoration steps in an approved test procedure.

should a valid demand occur. The intent of this paragraph is to allow licensees to take credit for restoration of risk-significant functions that are virtually certain to be successful (i.e., probability nearly equal to 1). The individual performing the restoration function can be the person performing the maintenance and must be in communication with the control room. Credit can also be taken for an operator in the main control room provided (s)he is in close proximity to restore the equipment when needed. Under stressful chaotic conditions otherwise simple multiple actions may not be accomplished with the virtual certainty called for by the guidance (e.g., lifting test leads and landing wires, or clearing tags). These situations should be resolved on a case-by-case basis through the FAQ process.

3. Satisfying Risk-Significant Mission Times
   Risk significant operator actions to satisfy pre-determined train/system risk-significant mission times can only be credited if they are modeled in the PRA.

Swing trains and components shared between units

Swing trains/components are trains/components that can be aligned to any unit. To be credited as such, their swing capability should be modeled in the PRA to provide an appropriate Fussel-Vessely value.

Unit Cross Tie Capability

Components that cross tie monitored systems between units should be considered active components if they are modeled in the PRA and meet the active component criteria in Appendix F. Such active components are counted in each unit's performance indicators.

Maintenance Trains and Installed Spares

Some power plants have systems with extra trains to allow preventive maintenance to be carried out with the unit at power without impacting the risk-significant function of the system. That is, one of the remaining trains may fail, but the system can still perform its risk significant function. To be a maintenance train, a train must not be needed to perform the system's risk significant function.

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 impacting the risk-significant function of the system. To be an "installed spare," a component must not be needed for the system to perform the risk significant function.

For unreliability, spare active components are included if they are modeled in the PRA. Unavailability of the spare component/train is only counted in the index if the spare is substituted for a primary train/component. Unavailability is not monitored for a component/train when that component/train has been replaced by an installed spare or maintenance train.

Use of Plant-Specific PRA and SPAR Models

The MSPI is an approximation using some information from a plant's actual PRA and is intended as an indicator of system performance. Plant-specific PRAs and SPAR models cannot be used to question the outcome of the PIs computed in accordance with this guideline.

Maintenance Rule Performance Monitoring

It is the intent that NUMARC 93-01 be revised to require consistent unavailability and unreliability data gathering as required by this guideline.

ADDITIONAL GUIDANCE FOR SPECIFIC SYSTEMS

This guidance provides typical system scopes. Individual plants should ~~apply~~ include those systems employed at their plant that are necessary to satisfy the specific risk-significant functions described below and reflected in their PRAs.

Emergency AC Power Systems

Scope

The function monitored for the emergency AC power system is the ability of the emergency generators to provide AC power to the class 1E buses upon a loss of off-site power while the reactor is critical, including post-accident conditions. The emergency AC power system is typically comprised of two or more independent emergency generators that provide AC power to class 1E buses following a loss of off-site power. The emergency generator dedicated to providing AC power to the high pressure core spray system in BWRs is not within the scope of emergency AC power.

The electrical circuit breaker(s) that connect(s) an emergency generator to the class lE buses that are normally served by that emergency generator are considered to be part of the emergency generator train.

Emergency generators that are not safety grade, or that serve a backup role only (e.g., an alternate AC power source), are not included in the performance reporting.

Train Determination

The number of emergency AC power system trains for a unit is equal to the number of class 1E emergency generators that are available to power safe-shutdown loads in the event of a loss of off-site power for that unit. There are three typical configurations for EDGs at a multi-unit station:

1. EDGs dedicated to only one unit.
2. One or more EDGs are available to "swing" to either unit
3. All EDGs can supply all units

For configuration 1, the number of trains for a unit is equal to the number of EDGs dedicated to the unit. For configuration 2, the number of trains for a unit is equal to the number of dedicated EDGs for that unit plus the number of "swing" EDGs available to that unit (i.e., The "swing" EDGs are included in the train count for each unit). For configuration 3, the number of trains is equal to the number of EDGs.

Clarifying Notes

The emergency diesel generators are not considered to be available during the following portions of periodic surveillance tests unless recovery from the test configuration during accident conditions is virtually certain, as described in "Credit for operator recovery actions during testing," can be satisfied; or the duration of the condition is less than fifteen minutes per train at one time:

- Load-run testing
- Barring

An EDG is not considered to have failed due to any of the following events:

- spurious operation of a trip that would be bypassed in a loss of offsite power event
- malfunction of equipment that is not required to operate during a loss of offsite power event (e.g., circuitry used to synchronize the EDG with off-site power sources)
- failure to start because a redundant portion of the starting system was intentionally disabled for test purposes, if followed by a successful start with the starting system in its normal alignment

Air compressors are not part of the EDG boundary. However, air receivers that provide starting air for the diesel are included in the EDG boundary.

If an EDG has a dedicated battery independent of the station's normal DC distribution system, the dedicated battery is included in the EDG system boundary.

If the EDG day tank is not sufficient to meet the EDG mission time, the fuel transfer function should be modeled in the PRA. However, the fuel transfer pumps are not considered to be an active component in the EDG system because they are considered to be a support system.

BWR High Pressure Injection Systems

(High Pressure Coolant Injection, High Pressure Core Spray, and Feedwater Coolant Injection)

Scope

These systems function at high pressure to maintain reactor coolant inventory and to remove decay heat following a small-break Loss of Coolant Accident (LOCA) event or a loss of main feedwater event.

The function monitored for the indicator is the ability of the monitored system to take suction from the suppression pool (and from the condensate storage tank, if credited in the plant's accident analysis) and inject -into the reactor vessel.

Plants should monitor either the high-pressure coolant injection (HPCI), the high-pressure core spray (HPCS), or the feedwater coolant injection (FWCI) system, whichever is installed. The turbine and -governor (or motor-driven FWCI pumps), and associated piping and valves for turbine steam supply and exhaust are within the scope of these systems. Valves in the feedwater line are not considered within the scope of these systems. The emergency generator dedicated to providing AC power to the high-pressure core spray system is included in the scope of the HPCS. The HPCS system typically includes a "water leg" pump to prevent water hammer in the HPCS piping to the reactor vessel. The "water leg" pump and valves in the "water leg" pump flow path are ancillary components and are not included in the scope of the HPCS system. Unavailability is not included while critical ~~but~~ if the system is below steam pressure specified in technical specifications at which the system can be operated.

Train Determination

The HPCI and HPCS systems are considered single-train systems. The booster pump and other small pumps are ancillary components not used in determining the number of trains. The effect of these pumps on system performance is included in the system indicator to the extent their failure detracts from the ability of the system to perform its risk-significant function. For the FWCI system, the number of trains is determined by the number of feedwater pumps. The number of condensate and feedwater booster pumps are not used to determine the number of trains.

BWR Heat Removal Systems
(Reactor Core Isolation Cooling or check:Isolation Condenser)

Scope

This system functions at high pressure to remove decay heat following a loss of main feedwater event. The RCIC system also functions to maintain reactor coolant inventory following a very small LOCA event.

The function monitored for the indicator is the ability of the RCIC system to cool the reactor vessel core and provide makeup water by taking a suction from either the condensate storage tank or the suppression pool and injecting at rated pressure and flow into the reactor vessel.

The Reactor Core Isolation Cooling (RCIC) system turbine, governor, and associated piping and valves for steam supply and exhaust are within the scope of the RCIC system. Valves in the feedwater line are not considered within the scope of the RCIC system. The Isolation Condenser and inlet valves are within the scope of Isolation Condenser system. Unavailability is not included while critical ~~but~~ if the system is below steam pressure specified in technical specifications at which the system can be operated.

Train Determination

The RCIC system is considered a single-train system. The condensate and vacuum pumps are ancillary components not used in determining the number of trains. The effect of these pumps on RCIC performance is included in the system indicator to the extent that a component failure results in an inability of the system to perform its risk significant function

BWR Residual Heat Removal Systems

Scope

The functions monitored for the BWR residual heat removal (RHR) system ~~is~~ are the ability of the RHR system to remove heat from the suppression pool, provide low pressure coolant injection, and provide post-accident decay heat removal.~~shutdown cooling.~~. The pumps, heat exchangers, and associated piping and valves for those functions are included in the scope of the RHR system.

Train Determination

The number of trains in the RHR system is determined by the number of parallel RHR heat exchangers.

PWR High Pressure Safety Injection Systems

Scope

These systems are used primarily to maintain reactor coolant inventory at high pressures following a loss of reactor coolant. HPSI system operation following a small-break LOCA involves transferring an initial supply of water from the refueling water storage tank (RWST) to cold leg piping of the reactor coolant system. Once the RWST inventory is depleted, recirculation of water from the reactor building emergency sump is required. 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.

The scope includes the pumps and associated piping and valves from both the refueling water storage tank and from the containment sump to the pumps, and from the pumps into the reactor coolant system piping. For plants where the high-pressure injection pump takes suction from the residual heat removal pumps, the residual heat removal pump discharge header isolation valve to the HPSI pump suction is included in the scope of HPSI system. Some components may be included in the scope of more than one train. For example, cold-leg injection lines may be fed from a common header that is supplied by both HPSI trains. In these cases, the effects of testing or component failures in an injection line should be reported in both trains.

Train Determination

In general, the number of HPSI system trains is defined by the number of high head injection paths that provide cold-leg and/or hot-leg injection capability, as applicable.

For Babcock and Wilcox (B&W) reactors, the design features centrifugal pumps used for high pressure injection (about 2,500 psig) and no hot-leg injection path. Recirculation from the containment sump requires operation of pumps in the residual heat removal system. They are typically a two-train system, with an installed spare pump (depending on plant-specific design) that can be aligned to either train.

For two-loop Westinghouse plants, the pumps operate at a lower pressure (about 1600 psig) and there may be a hot-leg injection path in addition to a cold-leg injection path (both are included as a part of the train).

For Combustion Engineering (CE) plants, the design features three centrifugal pumps that operate at intermediate pressure (about 1300 psig) and provide flow to two cold-leg injection paths or two hot-leg injection paths. In most designs, the HPSI pumps take suction directly from the containment sump for recirculation. In these cases, the sump suction valves are included within the scope of the HPSI system. This is a two-train system (two trains of combined cold-leg and hot-leg injection capability). One of the three pumps is typically an installed spare that can be aligned to either train or only to one of the trains (depending on plant-specific design).

For Westinghouse three-loop plants, the design features three centrifugal pumps that operate at high pressure (about 2500 psig), a cold-leg injection path through the BIT (with two trains of redundant valves), an alternate cold-leg injection path, and two hot-leg injection paths. One of the pumps is considered an installed spare. Recirculation is provided by taking suction from the RHR pump discharges. A train consists of a pump, the pump suction valves and boron injection tank (BIT) injection line valves electrically associated with the pump, and the associated hot-leg injection path. The alternate cold-leg injection path is required for recirculation, and should be included in the train with which its isolation valve is electrically associated. This represents a two-train HPSI system.

For Four-loop Westinghouse plants, the design features two centrifugal pumps that operate at high pressure (about 2500 psig), two centrifugal pumps that operate at an intermediate pressure (about 1600 psig), a BIT injection path (with two trains of injection valves), a cold-leg safety injection path, and two hot-leg injection paths. Recirculation is provided by taking suction from the RHR pump discharges. Each of two high pressure trains is comprised of a high pressure centrifugal pump, the pump suction valves and BIT valves that are electrically associated with the pump. Each of two intermediate pressure trains is comprised of the safety injection pump, the suction valves and the hot-leg injection valves electrically associated with the pump. The cold-leg safety injection path can be fed with either safety injection pump, thus it should be associated with both intermediate pressure trains. This HPSI system is considered a four-train system for monitoring purposes.

PWR Auxiliary Feedwater Systems

Scope

The AFW system provides decay heat removal via the steam generators to cool down and depressurize the reactor coolant system following a reactor trip. The AFW system is assumed to be required for an extended period of operation during which the initial supply of water from the condensate storage tank is depleted and water from an alternative water source (e.g., the service water system) is required. Therefore components in the flow paths from both of these water sources are included; however, the alternative water source (e.g., service water system) is not included.

The function monitored for the indicator is the ability of the AFW system to take a suction from the primary water source (typically, the condensate storage tank) or, if required, from an emergency source (typically, a lake or river via the service water system) and inject into at least one steam generator at rated flow and pressure.

The scope of the auxiliary feedwater (AFW) or emergency feedwater (EFW) systems includes the pumps and the components in the flow paths from the condensate storage tank and, if required, the valve(s) that connect the alternative water source to the auxiliary feedwater system. Startup feedwater pumps are not included in the scope of this indicator.

Train Determination

The number of trains is determined primarily by the number of parallel pumps. For example, a system with three pumps is defined as a three-train system, whether it feeds two, three, or four injection lines, and regardless of the flow capacity of the pumps. Some components may be included in the scope of more than one train. For example, one set of flow regulating valves and isolation valves in a three-pump, two-steam generator system are included in the motor-driven pump train with which they are electrically associated, but they are also included (along with the redundant set of valves) in the turbine-driven pump train. In these instances, the effects of testing or failure of the valves should be reported in both affected trains. Similarly, when two trains provide flow to a common header, the effect of isolation or flow regulating valve failures in paths connected to the header should be considered in both trains.

PWR Residual Heat Removal System

Scope

The functions monitored for the PWR residual heat removal (RHR) system are those that are required to be available when the reactor is critical. These typically include the low-pressure injection function (if risk-significant) and the post-accident recirculation mode used to cool and recirculate water from the containment sump following depletion of RWST inventory to ~~satisfy~~ provide ~~the~~ post-accident ~~mission times~~decay heat removal. ~~These times are defined as reaching a stable plant condition where normal shutdown cooling is sufficient. Typical mission times are 24 hours. However, other intervals as justified by analyses and modeled in the PRA may be used.~~ The pumps, heat exchangers, and associated piping and valves for those functions are included in the scope of the RHR system. Containment spray function should be included if it is identified in the PRA as a risk-significant post accident decay heat removal function. Containment spray systems that only provide containment pressure control are not included.

Train Determination

The number of trains in the RHR system is determined by the number of parallel RHR heat exchangers. Some components are used to provide more than one function of RHR. If a component cannot perform as designed, rendering its associated train incapable of meeting one of the risk-significant functions, then the train is considered to be failed. Unavailable hours would be reported as a result of the component failure.

Cooling Water Support System

Scope

The function of the cooling water support system is to provide for direct cooling of the components in the other monitored systems. It does not include indirect cooling provided by room coolers or other HVAC features.

Systems that provide this function typically include service water and component cooling water or their cooling water equivalents. Pumps, valves, heat exchangers and line segments that are necessary to provide cooling to the other monitored systems are included in the system scope up to, but not including, the last valve that connects the cooling water support system to the other monitored systems. This last valve is included in the other monitored system boundary.

Valves in the cooling water support system that must close to ensure sufficient cooling to the other monitored system components to meet risk significant functions are included in the system boundary.

Train Determination

The number of trains in the Cooling Water Support System will vary considerably from plant to plant. The way these functions are modeled in the plant-specific PRA will determine a logical approach for train determination. For example, if the PRA modeled separate pump and line segments, then the number of pumps and line segments would be the number of trains.

Clarifying Notes

Service water pump strainers and traveling screens are not considered to be active components and are therefore not part of URI. However, clogging of strainers and screens due to expected or routinely predictable environmental conditions that render the train unavailable to perform its risk significant cooling function (which includes the risk-significant mission times)are included in UAI.

Unpredictable extreme environmental conditions that render the train unavailable to perform its risk significant cooling function should be addressed through the FAQ process to determine if resulting unavailability should be included in UAI.