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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: The ROP working group is currently working to prepare a response.	1/25 Introduced 2/28 NRC to discuss with resident 4/25 Discussed 5/22 On hold 6/12 Discussed. Related FAQ 30.8 9/26 Discussed 10/31 Discussed	LaSalle
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	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

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		(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: The ROP working group is currently working to prepare a response.		
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? Response: The ROP working group is currently working to prepare a response.	5/22 Introduced 6/12 Discussed 9/26 Discussed. 10/31 Discussed	Generic
32.3a	IE02	Question: An unplanned scram occurred October 7, 2001, during startup following an extended forced outage. The unit was in Mode 1 at approximately 8% reactor power with a main feed pump and low-flow feedwater preheating in service. The operators were preparing to roll the main turbine when a reactor tripped occurred. The cause of the trip was a loss of voltage to the control rod drive mechanisms and was not related to the heat removal path. Main feedwater isolated on the trip, as designed, with the steam generators being supplied by the auxiliary feedwater (AFW) pumps. At 5 minutes after the trip, the reactor coolant system (RCS) temperature was 540 degrees and trending down. The operators verified that the steam dumps, steam generator power operated relief valves, start-up steam supplies and blowdown were isolated. Additionally, AFW flow was isolated to all Steam Generators as allowed by the trip response procedure. At 9 minutes after the trip, with RCS temperature still trending down, the main steam isolation valves (MSIV) were closed in accordance with the reactor trip response procedure curtailing the cooldown. The RCS cooldown was attributed to steam that was still being supplied to low-flow feedwater preheating and #4 steam generator AFW flow control valve not automatically moving to its flow retention position as expected with high AFW flow. The low-flow feedwater preheating is a known steam load during low power operations and the AFW flow control issue was identified by the control room balance of plant operator. The trip response procedure directs the operators to check for and take actions to control AFW flow and eliminate the feedwater heater steam	1/23 Revised. Split into two FAQs 3/20 Discussed 5/1 Discussed 5/22 Tentative Approval 6/18 Discussion deferred to July 7/24 Discussed	DC Cook

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		supply. When this trip occurred the unit was just starting up following a 40 day forced outage. The reactor was at approximately 8% power and there was very little decay heat present following the trip. With very little decay heat available, the primary contribution to RCS heating is from Reactor Coolant Pumps (RCPs). Evaluation of these heat loads, when compared to the cooling provided by AFW, shows that there is approximately 3.5 times as much cooling flow provided than is required to remove decay heat under these conditions plus pump heat. This resulted in rapid cooling of the RCS and ultimately required closure of the MSIVs. Other conditions such as low flow feedwater preheating and the additional AFW flow due to the AFW flow control valve failing to move to its flow retention setting contributed to this cooldown, but were not the primary cause. Even without these contributors to the cooldown, closure of MSIVs would have been required due to the low decay heat present following the trip. It should also be noted that the conditions that are identified as contributing to the cooldown are not conditions which prevent the secondary plant from being available for use as a cooldown path. The AFW flow control valve not going to the flow retention setting increases the AFW flow to the S/G, and in turn causes an increase in cooldown. This condition is corrected by the trip response procedure since the procedure directs the operator to control AFW flow as a method to stabilize the RCS temperature. With low-flow feedwater preheating in service, main steam is aligned to feedwater heaters 5 and 6 and is remotely regulated from the control room. Low-flow feedwater preheating is used until turbine bleed steam is sufficient to provide the steam supply then the system is isolated. There are no automatic controls or responses associated with the regulating valves, so when a trip occurs, operators must close the regulating valves to secure the steam source. Until the steam regulating valves are closed, this is a steam load contributing to a cooldown. The low-flow preheating steam supplies are identified in the trip response procedure since they are a CNP specific design issue. The actions taken to control RCS cooldown were in accordance with the plant procedure in response to the trip. The primary reason that the MSIVs were required to be closed was due to the low level of decay heat present following a 40 day forced outage. The closure of the MSIVs was to control the cooldown as directed by plant procedure and not to mitigate an off-normal condition or for the safety of personnel or equipment. With the low decay heat present following the 40 day forced outage, there would not have been a need to reopen the MSIVs prior to recommencing the startup. Should the reactor trip described above be counted in the Unplanned Scrams with Loss of Normal Heat Removal Performance Indicator?		
		Response: Yes. The licensee's reactor trip response procedure has an "action/expected response" that reactor coolant system temperature following a trip would be stable at or trending to the no-load Tavg value. If that expected response is not obtained, operators are directed to stop dumping steam and verify that steam generator blowdown is isolated. If cooldown continues, operators are directed to control total feedwater flow. If cooldown continues, operators are directed to close all steam generator stop valves (MSIVs) and other steam valves. During the unit trip described, the #4 steam generator auxiliary feedwater flow control valve did not reposition to the flow retention setting as expected (an off normal condition). In addition, although control room operators manually closed the low-flow feedwater preheat control valves that were in service, leakage past these valves (a pre-existing degraded condition identified in the Operator Workaround database) also contributed to the cooldown. Operator logs attributed the reactor system cooldown to the #4 AFW flow control valve failure as well as to steam being supplied to low-flow feedwater preheating. As stated above, the trip response procedure directs operators to control feedwater flow in order to control the cooldown. Operator inability to control the cooldown through control of feedwater flow as directed is considered an off normal condition. Since the cooldown continued due to an off normal condition, operators closed the MSIVs, and therefore this trip is considered a scram with loss of normal heat removal.		
34.6	IE02	Question:	3/20 Introduced	STP

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		Should the following event be counted as a scram with loss of normal heat removal? STP Unit Two was manually tripped on Dec. 15, 2002 as required by the off normal procedure for high vibration of the main turbine. Approximately 17 minutes after the Unit was manually tripped main condenser vacuum was broken at the discretion of the Shift Supervisor to assist in slowing the turbine. Plant conditions were stabilized using Auxiliary Feedwater and Steam Generator Power Operated Relief Valves. Main Feedwater remained available via the electric motor driven Startup Feedwater pump. Main steam headers remained available to provide cooling via the steam dump valves. At any time vacuum could have been reestablished without diagnoses or repair using established operating procedures until after completion of the scram response procedures. Scrams with a Loss of Normal Heat Removal performance indicator is defined as *"The number of unplanned scrams while critical, both manual and automatic, during the previous 12 quarters that were either caused by or involved a loss of the normal heat removal path prior to establishing reactor conditions that allow use of the plant's normal long term heat removal systems."* This indicator states that a loss of normal heat removal has occurred whenever any of the following conditions occur: loss of main feedwater, loss of main condenser vacuum, closure of the main steam isolation valves or loss of turbine bypass capability. The determining factor for this indicator is whether or not the normal heat removal path is available, not whether the operators choose to use that path or some other path. The STP plant is designed to isolate main feedwater after a trip by closing the main feedwater control valves. The auxiliary feedwater pumps are then designed to start on low steam generator levels. This is expected following normal operation above low power levels and in turn provides the normal heat removal. This design functioned as expected on December 15, 2002 when the reactor was manually tripped due to high turbine vibration. Normal plant operating procedures 0POP03-ZG-0006 (Plant Shutdown from 100% to Hot Standby) and 0POP03-ZG-0001 (Plant Heatup) state if Auxiliary Feedwater is being used to feed the steam generators than the preferred method of steaming is through the steam generator power operated relief valves. This can be found in steps 7.4 and 7.5 of 0POP03-ZG-0001 and steps 6.6.5 and 6.6.10 of 0POP03-ZG-0006. The note prior to 6.6.10 states "*the preferred method for controlling SG steaming rates while feeding with AFW is with the SG PORVs*". The normal heat removal path as defined in NEI 99-02 Revision 2 was in service and functioning properly for seventeen minutes after the manual reactor trip and would have continued to function had not the shift supervisor voluntarily broke condenser vacuum and closed the MSIV's. Interviews with the shift supervisor showed that the decision to break vacuum was two part. 1) Based on experience and reports from the field it was known that vacuum would need to be broken to support the maintenance state required for the main turbine and at a minimum to support timely inspection. 2)This would assist in slowing the turbine. The decision to break vacuum was not based solely on mitigating an off-normal condition or for the safety of personnel or equipment. Because Auxiliary Feedwater system had actuated and was in service as expected, the decision was made to use Auxiliary Feedwater and steam through the SG PORVs. As stated earlier, this is the preferred method of heat removal if the decision to use Auxiliary Feedwater is employed as supported by the normal operating procedures while the plant is in Mode 3. Main feedwater remained available via the electric motor driven Startup Feedwater pump and the main steam headers remained available to provide cooling via the steam dump valves if required. Discussion with the shift supervisor showed he was confident that at any time vacuum could have been readily recovered from the control room without the need for diagnoses or repair using established operating procedures if the need arose. An outside action would be required in drawing vacuum in that a Condenser Air Removal pump would require starting locally in the TGB. This is a simplistic, proceduralized and commonly performed evolution. Personnel are fully confident this would have been performed without incident if required. Closing the MSIVs and breaking vacuum as quickly as possible is not uncommon at STP. For a normal planned shutdown MSIVs are closed and vacuum broken within four to six hours typically to support required maintenance in the secondary. If maintenance in the secondary is known to be critical path than vacuum has been broken as early as three hours and fifteen minutes following opening of the main generator breaker. The only reason that vacuum is not	3/20 Discussed 6/18 Discussed; Question to be revised to reflect discussion 7/24 Discussed	

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		broken sooner is because in most cases it is needed to support chemistry testing. By limiting the flow path as described in NEI 99-02 for normal heat removal there is undue burden being placed on the utility. Only recognizing this one specific flow path reduces operational flexibility and penalizes utilities for imparting conservative decision making. Conditions are established immediately following a reactor trip (100% to Mode 3) that can be sustained indefinitely using Auxiliary Feedwater and steaming through the steam generator PORVs. This fact is again supported in the stations Plant Shutdown from 100% to Hot standby and Plant Heatup normal operating procedures. The cause of a trip, the intended forced outage work scope, or outage duration varies and inevitably will factor into which method of normal long term heat removal is best for the station to employ shortly following a trip.		
		Response: The ROP working group is currently working to prepare a response. Licensee Proposed Response: NO. Since vacuum was secured at the discretion of the Shift Supervisor and could have been restored using existing normally performed operating procedures, the function meets the intention of being available but not used.		
36.1	IE02	Question: With the unit in RUN mode at 100% power, the control room received indication that a Reactor Pressure Vessel relief valve was open. After taking the steps directed by procedure to attempt to reseat the valve without success, operators scrammed the reactor in response to increasing suppression pool temperature. Following the scram, and in response to procedural direction to limit the reactor cooldown rate to less than 100 degrees per hour, the operators closed the Main Steam Isolation Valves (MSIVs). The operators are trained that closure of the MSIV's to limit cool down rate is expected in order to minimize steam loss through normal downstream balance-of-plant loads (steam jet air ejectors, offgas preheaters, gland seal steam). At the time that the MSIVs were closed, the reactor was at approximately 500 psig. One half hour later, condenser vacuum was too low to open the turbine bypass valves and reactor pressure was approximately 325 psig. Approximately eight hours after the RPV relief valve opened, the RPV relief valve closed with reactor pressure at approximately 50 psig. This information is provided to illustrate the time frame during which the reactor was pressurized and condenser vacuum was low. Although the MSIVs were not reopened during this event, they could have been opened at any time. Procedural guidance is provided for reopening the MSIVs. Had the MSIVs been reopened within approximately 30 minutes of their closure, condenser vacuum was sufficient to allow opening of the turbine bypass valves. If it had been desired to reopen the MSIVs later than that, the condenser would have been brought back on line by following the normal startup procedure for the condenser. As part of the normal startup procedure for the condenser, the control room operator draws vacuum in the condenser by dispatching an operator to the mechanical vacuum pump. The operator starts the mechanical vacuum pump by opening a couple of manual valves and operating a local switch. All other actions, including opening the MSIVs and the turbine bypass valves, are taken by the control room operator in the control room. It normally takes between 45 minutes and one hour to establish vacuum using the mechanical vacuum pump. The reactor feed pumps and feedwater system remained in operation or available for operation throughout the event. The condenser remained intact and available and the MSIVs were available to be opened from the control room throughout the event. The normal heat removal path was always and readily available (i.e., use of the normal heat removal path required only a decision to use it and the following of normal station procedures) during this event. Does this scram constitute a scram with a loss of normal heat removal?	9/25 Introduced and discussed	Quad Cities
		Response:		

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		No. The normal heat removal path was not lost even though the MSIVs were manually closed to control cooldown rate. There was no leak downstream of the MSIVs, and reopening the MSIVs would not have introduced further complications to the event. The normal heat removal path was purposefully and temporarily isolated to address the cooldown rate, only. Reopening the normal heat removal path was always available at the discretion of the control room operator and would not have involved any diagnosis or repair. Further supporting information: The clarifying notes for this indicator state: "*Loss of normal heat removal path* means the loss of the normal heat removal path as defined above. The determining factor for this indicator is whether or not the normal heat removal path is *available*, not whether the operators choose to use that path or some other path." In this case, the operator did not choose to use the path through the MSIVs, even though the normal heat removal path was available. The clarifying notes for this indicator also state: "*Operator actions or design features to control the reactor cooldown rate or water level*, such as closing the main feedwater valves or closing all MSIVs, are not reported in this indicator as long as the normal heat removal path can be readily recovered from the control room without the need for diagnosis or repair." In this case, the closing of the MSIVs was performed solely to control reactor cooldown rate. It was not performed to isolate a steam leak. There was no diagnosis or repair involved in this event. The MSIVs could have been reopened following normal plant procedures		
36.2	IE02	Question: Should an "Unplanned Scram with a Loss of Normal Heat Removal" be reported for the Peach Bottom Unit 2 (July 22, 2003) reactor scram followed by a high area temperature Group I isolation? <u>Description of Event:</u> At approximately 1345 on 07/22/03, a Main Generator 386B and 386F relay trip resulted in a load reject signal to the main turbine and the main turbine control valves went closed. The Unit 2 reactor received an automatic Reactor Protection System (RPS) scram signal as a result of the main turbine control valves closing. Following the scram signal, all control rods fully inserted and, as expected, Primary Containment Isolation System (PCIS) Group II and III isolations occurred due to low Reactor Pressure Vessel (RPV) level. The Group III isolation includes automatic shutdown of Reactor Building Ventilation. RPV level control was re-established with the Reactor Feed System and the scram signal was reset at approximately 1355 hours. At approximately 1356 hours, the crew received a High Area Temperature alarm for the Main Steam Line area. The elevated temperature was a result of the previously described trip of the Reactor Building ventilation system. At approximately 1358, a PCIS Group I isolation signal occurred due to Steam Tunnel High Temperature resulting in the automatic closure of all Main Steam Isolation Valves (MSIV).Following the MSIV closure, the crew transitioned RPV pressure and level control to the High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) systems. Following the reset of the PCIS Group II and III isolations at approximately 1408, Reactor Building ventilation was restored. At approximately 1525, the PCIS Group I isolation was reset and the MSIVs were opened. Normal cooldown of the reactor was commenced and both reactor recirculation pumps were restarted. Even though the Group I isolation could have been reset following the Group II/III reset at 1408, the crew decided to pursue other priorities before reopening the MSIVs including: stabilizing RPV level and pressure using HPCI and RCIC; maximizing torus cooling; evaluating RCIC controller oscillations; evaluating a failure of MO-2-02A-53A "A" Recirculation Pump Discharge Valve; and, minimizing CRD flow to facilitate restarting the Reactor Recirculation pumps. **Problem Assessment:** It is recognized that loss of Reactor Building ventilation results in rising temperatures in the Outboard MSIV Room. The rate of this temperature rise and the maximum temperature attained are exacerbated by summertime temperature conditions. When the high temperature isolation occurred, the crew immediately recognized and understood the cause to be the loss of Reactor Building ventilation. The crew then prioritized their activities and utilized existing General	9/25 Introduced and discussed	Peach Bottom

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		Plant (GP) and System Operating (SO) procedures to re-open the MSIVs. Reopening of the MSIVs was: • easily facilitated by restarting Reactor Building ventilation, • completed from the control room using normal operating procedures • without the need of diagnosis or repair Therefore, the MSIV closure does not meet the definition of "Loss of normal heat removal path" provided in NEI 99-02, Rev. 2, page 15, line 37, and it is appropriate not to include this event in the associated performance indicator – Unplanned Scrams with Loss of Normal Heat Removal. <u>Discussion of specific aspects of the event:</u> Was the recognition of the condition from the Control Room? ▪ Yes. Rising temperature in the Outboard MSIV Room is indicated by annunciator in the main control room. Local radiation levels are also available in the control room. During the July 22, 2003 scram, control room operators also recognized that the increase in temperature was not due to a steam leak in the Outboard MSIV Room because the local radiation monitor did not indicate an increase in radiation levels. Initiation of the Group I isolation on a Steam Tunnel High Temperature is indicated by two annunciators in the control room. Does it require diagnosis or was it an alarm? ▪ The event is annunciated in the control room as described previously. Is it a design issue? ▪ Yes. The current Unit 2 design has the Group I isolation temperature elements closer to the Outboard MSIV Room ventilation exhaust as compared to Unit 3. As a result, the baseline temperatures, which input into the Group I isolation signal, are higher on Unit 2 than Unit 3. Are actions virtually certain to be successful? ▪ The actions to reset a Group I isolation are straight forward and the procedural guidance is provided to operate the associated equipment. No diagnosis or troubleshooting is required. Are operator actions proceduralized? ▪ The actions to reset the Group I isolation are delineated in General Plant procedure GP-8.A "PCIS Isolation-Group I." The actions to reopen the MSIVs are contained in System Operating procedures SO 1A.7.A-2 "Main Steam System Recovery Following a Group I Isolation" and Check Off List SO 1A.7.A-2 "Main Steam Lineup After a Group I Isolation." These procedures are performed from the control room. How does Training address operator actions? ▪ The actions necessary for responding to a Group I isolation and subsequent recovery of the Main Steam system are covered in licensed operator training. Are stressful or chaotic conditions during or following an accident expected to be present? • As was demonstrated in the event of July 22, 2003, sufficient time existed to stabilize RPV level and pressure control and methodically progress through the associated procedures to reopen the MSIVs without stressful or chaotic conditions		
		Response: The Peach Bottom Unit 2 July 22, 2003 reactor scram followed by a high area temperature Group I isolation should not be included in the Performance Indicator - "Unplanned Scram with a Loss of Normal Heat Removal." This specific MSIV closure does not meet the definition of "Loss of normal heat removal path" provided in NEI 99-02, Rev. 2, page 15, line 37, in that the main steam system was "easily recovered from the control room without the need for diagnosis or repair. Therefore, it would not be appropriate to include this event in the associated performance indicator – Unplanned Scrams with Loss of Normal Heat Removal.		

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36.8	IE02	Question: On August 14, 2003 Ginna Station scrammed due to the wide spread grid disturbance in the Northeast United States. Subsequent to the scram, Main Feedwater Isolation occurred as designed on low Tavg coincident with a reactor trip. However, due to voltage swings from the grid disturbance, instrument variations caused the Advanced Digital Feedwater Control System (ADFCS) to transfer to manual control. This transfer overrode the isolation signal causing the Main Feedwater Regulation Valves (MFRVs) to go to, and remain at, the normal or nominal automatic demand position at the time of the transfer, resulting in an unnecessary feedwater addition. The feedwater addition was terminated when the MFRVs closed on the high-high steam generator level (85%) signal. Operators conservatively closed the MSIVs in accordance with the procedure to mitigate a high water level condition in the Steam Generators. Decay heat was subsequently removed using the Atmospheric Relief Valves (ARVs). Should the scram be counted under the PI "Unplanned Scrams with Loss of Normal Heat Removal?" Response: No. Under clarifying notes, page 16, lines 18 - 22, NEI 99-02 states: "Actions or design features to control the reactor cool down rate or water level, such as closing the main feedwater valves or closing all MSIVs, are not reported in this indicator as long as the normal heat removal path can be readily recovered from the control room without the need for diagnosis or repair. However, operator actions to mitigate an off-normal condition or for the safety of personnel or equipment (e.g., closing MSIVs to isolate a steam leak) are reported." In this case, a feedwater isolation signal had automatically closed the main feed regulating valves, effectively mitigating the high level condition. Manually closing the MSIVs was a conservative procedure driven action, which in this case was not by itself necessary to protect personnel or equipment. The main feed regulating valves were capable of being easily opened from the control room, and the MSIVs were capable of being opened from the control room (after local action to bypass and equalize pressure, see FAQ 303). In addition, the cause of the high steam generator level was due to voltage fluctuations on the offsite power grid which resulted in the operators closing the MSIVs. Clarifying notes for this performance indicator exempt scrams resulting in loss of all main feedwater flow , condenser vacuum, or turbine bypass capability caused by loss of offsite power. In this case, offsite power was not lost. However, the disturbances in grid voltage affected the ADFCS system which started a chain of events which ultimately resulted in the closure of the MSIVs.	1/22 Introduced 3/25 Discussed 6/16 Discussed	Ginna
36.9	IE02	Question: During startup activities following a refueling outage in which new monoblock turbine rotors were installed in the LP turbines, reactor power was approximately 10% of rated thermal power, and the main turbine was being started up. Feedwater was being supplied to the steam generators by the turbine driven main feedwater pumps, and the main condensers were in service. During main turbine startup, the turbine began to experience high bearing vibrations before reaching its normal operating speed of 1800 rpm, and was manually tripped. The bearing vibrations increased as the turbine slowed down following the trip. To protect the main turbine, the alarm response procedure for high-high turbine vibration required the operators to manually SCRAM the reactor, isolate steam to the main condensers by closing the main steam isolation valves and to open the condenser vacuum breaker thereby isolating the normal heat removal path to the main condensers. This caused the turbine driven main feedwater pumps to trip. Following the reactor SCRAM, the operators manually started the auxiliary feedwater pumps to supply feedwater to the steam generators. Based on industry operating experience, operators expected main turbine vibrations during this initial startup. Nuclear Engineering provided Operations with recommendations on how to deal with the expected turbine vibration issues that included actions up to and including breaking condenser vacuum. Operations prepared the crews for this turbine startup with several primary actions. First, training on the new rotors, including industry operating experience and technical actions being taken to minimize the possibility of turbine rubs was conducted in the pre-outage Licensed	1/22 Introduced 3/25 Discussed. Question to be rewritten and response provided 4/22 Question and response provided 6/16 Discussed 7/22 Discussed 8/18 Discussed	Millstone 2

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		Operator Requalification Training. Second, the Alarm Response Procedures (A-34 and B-34) for turbine vibrations were modified to include procedures to rapidly slow the main turbine to protect it from damage. Under the worst turbine vibration conditions, the procedure required operators to trip the reactor, close MSIVs and break main condenser vacuum. Third, operating crews were provided training in the form of a PowerPoint presentation for required reading which included a description of the turbine modifications, a discussion of the revised Alarm Response Procedures and industry operating experience. Does this SCRAM count against the performance indicator for scrams with loss of normal heat removal?		
		Response: No, this scram does not count against the performance indicator for scrams with loss of normal heat removal. The conditions that resulted in the closure of the MSIVs after the reactor trip were expected for the main turbine startup following rotor replacement. Operator actions for this situation had been incorporated into normal plant procedures.		
37.9	EP02	Question: NEI 99-02 Rev 2 ERO Participation PI defines the numerator and denominator of the calculation as based on Key ERO Members. The key position list (on page 89 and 90) was originally created from NUREG 0696 key functions that involved actions associated with the risk significant planning standards (classification, notification, PARs, and assessment), with the addition of the Key OSC Operations Manager included from a mitigation perspective. When a single individual is assigned in more than one 'key position' that individual must be counted for each key position (page 91 lines 4-7 of NEI 99-02). ` Guidance is not provided in the case where more than one key position is performed by a single member of the ERO in a single drill/exercise. For example, the communicator is defined in NEI 99-02 as the key position that fills out the notification form, seeks approval and usually communicates the information to off site agencies (these duties may vary from site to site based on site procedures). Assigning a single member to multiple Key Positions and then only counting the performance for one Key Position could mask the ability or proficiency of the remaining Key Positions. The concern is that an ERO member having multiple Key Positions may never have a performance enhancing experience for all of them, yet credit for participation will be given when any one of the multiple Key Positions is performed. When the communicator key position is performed by an ERO member who is also assigned another key position (e.g., the Shift Manager (Emergency Director)), should participation be counted for two key positions or for one key position?	4/22 Introduced 5/27 Discussed. To be revised to reflect discussion. 7/22 EP peer experts to review this issue 8/18 To be discussed at 9/1 EP public meeting 9/16 Tentative Approval *10/13 Final*	generic

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		Response: Participation by a single member of the ERO performing multiple key positions should be counted for each key position performed. For the situation described, two key positions should be counted. ERO participation should be counted for each key position, even when multiple key positions are assigned to the same ERO member. In the case where a utility has assigned two or more key positions to a single ERO member, each key position must be counted in the denominator for each ERO member and credit given in the numerator when the ERO member performs each key position “Assigned” as used in this FAQ applies to those ERO personnel filling key positions listed on the licensee duty roster on the last day of the reporting period (quarter). Note, however, the exception on page 92 line 1-2 of NEI 99-02, that states, “All individuals qualified to fill the Control Room Shift Manager/Emergency Director position that actually might fill the position should be included in this indicator.” This FAQ will become effective 1/1/05 and applies to data submitted for the first quarter 2005 and going forward.		
38.2	MS01, MS04	Question: If the emergency AC power system or the residual heat removal system is not required to be available for service (e.g., the plant is in "no mode" or Technical Specifications do not require the system to be operable), is it appropriate to include this time in the "hours train required" portion of the safety system performance indicator calculation? NEI 99-02, Revision 2, starting on line 25 of page 33, discusses the term "hours train required" as used in safety system unavailability performance indicators. For the emergency AC power system and residual heat removal system, the guidance allows the "hours train required" to be estimated by the number of hours in the reporting period because the emergency generators are normally expected to be available for service during both plant operations and shutdown, and because the residual heat removal system is required to be available for decay heat removal at all times. ~~The response to FAQ 183 states: "During periods and conditions where Technical Specifications allow both shutdown cooling trains to be removed from service the shutdown cooling system is, in effect, not required and required hours and unavailable hours would not be counted."~~ Response: *NEI 99-02 permits the hours train required to be estimated by the number of hours in reporting period. It incorrectly states that the residual heat removal system is required to be available for decay heat removal “at all times.” NEI 99-02 will be corrected in Rev. 3 to state that it is normally required to be in service at all times. The amount of time emergency AC power systems and residual heat removal systems are not required to be available is typically very small (small portions of outages) and would have minimal impact on the PI result. For example, to increase the RHR result from 1.5% (the threshold) to 1.6% would require 68 days in no mode condition. To increase the EAC result from 2.5% (the threshold) to 2.6% would require 42 days. There is no reason to increase reporting and inspection burden for such a minimal effect.*	5/27 Introduced 7/22 Discussed 8/18 Discussed 9/16 Discussed *10/13 Tentative Approval*	
38.3	MS01	Appendix D FAQ: Mitigating Systems – Safety System Unavailability, Emergency AC Power During a monthly surveillance test of Emergency Diesel Generator 3 (EDG3), an alarm was received in the control room for an abnormal condition. The jacket water cooling supply to EDG3 had experienced a small leak (i.e., less than 1 gpm) at a coupling connection that resulted in a low level condition and subsequent control room alarm. The Low Jacket Water Pressure Alarm, which annunciates locally and in the control room, indicated low pump suction pressure. This was due to low level in the diesel generator jacket water expansion tank. An Auxiliary Operator (AO) stationed at EDG3 responded to the alarm by opening the manual supply valve to provide makeup water to the	6/16 Introduced 7/22 Discussed 8/18 Discussed *10/13 Tentative Approval. Response to be rewritten*	Brunswick

TempNo.	PI	Question/Response	Status	Plant/ Co.
		expansion tank. EDG3 continued to function normally and the surveillance test was completed satisfactorily. Review of data determined that improper tightening of the coupling was performed after the monthly EDG run on December 8, which led to an unacceptable leak if the EDG was required to run. The coupling was properly repaired and tested, and declared to be available and operable on January 6. The condition existed for approximately 28 days. Although the recovery action was conducted outside of the main control room, it was a simple evolution directed by a procedure step, with a high probability of success. This operator response is similar to the response described in Appendix D FAQ 301. In addition, this operator action would be successful during a postulated loss of offsite power event, except for a 23 hour period when the demineralized water supply level was too low to support gravity feed. The engineering analysis determined that a level of 21' 5" of demineralized water supply level was necessary to support gravity feed to the expansion tank. Another 9" (4,740 gallons) was added to this level to allow for the leak and nominal usage and makeup over the 24 hour mission time. Using this analysis, any time the demineralized water level fell below 22" 2", the EDG was considered to be unavailable. A human reliability analysis calculated the probability of an AO failing to add water to the expansion tank from receipt of the low pressure alarm to be 4.7 E-3. In other words, there would be a greater than 99.5% probability of successful task completion within twenty minutes of receiving the annunciator. Vendor analysis determined that, with the existing leak rate, the EDG would remain undamaged for twenty minutes. The human reliability analysis considered that the low jacket water pressure would be annunciated in the control room, the annunciator procedure provided specific direction for filling the expansion tank, the action is reinforced through operator training, and sufficient time would be available to perform the simple action. In its calculation of the probability of operator recovery, the analysis also considered that another indicator, a low-level expansion tank alarm was out-of-service during this time period. However, although the low expansion tank alarm was out of service, it results in low pump suction pressure which did annunciate. NEI 99-02 Appendix D lists several issues that may be addressed for exceptions to allow credit for operator compensatory actions to mitigate the effects of unavailability of monitored systems. 1. The capability to recognize the need for compensatory actions – Low pump suction pressure annunciates in the control room. 2. The availability of trained personnel to perform the compensatory action – This is an uncomplicated action, but operators are trained on it. An auxiliary operator simply has to open one manual valve as directed by the annunciator procedure. 3. The means of communications between the control room and the local operator – Communications can be accomplished either via the plant PA system or a portable radio. 4. The availability of compensatory equipment – No compensatory equipment is necessary. 5. The availability of a procedure for compensatory actions – There is an annunciator procedure in the diesel generator room that would direct the auxiliary operator to open the manual valve. 6. The frequency with which the compensatory actions are performed – This action is performed infrequently, but it was demonstrated to be successful during the surveillance test. 7. The probability of successful completion of compensatory actions within the required time – The human reliability analysis determined that there was a 99.5% probability of successful completion of compensatory action within the required time. In summary, over a 28-day period, jacket water cooling for EDG3 was degraded, but functional for approximately 27 days, and was totally unavailable for 23 hours. This is based on a review of Operator logs, plant trending computer points, and flow calculations. During the 27-day degraded period, a simple manual action directed by procedure and		

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		performed by an operator would have been used to ensure that jacket water was available. Should fault exposure hours be reported for the 27 days when the Emergency Diesel Generator 3 jacket water was considered to be degraded but functional?		
		Response: *Yes, in this case fault exposure hours should be reported*		
38.4	EP03	Question: Pilgrim has 112 sirens which are normally scheduled to be tested for performance indicator purposes once each calendar month (e.g., once during the month of September). This was reflected in procedure as a requirement to test all of the sirens "monthly". The person scheduling the testing of the sirens incorrectly interpreted the procedure's "monthly" frequency consistent with other "monthly" tests as allowing a 25% grace period for scheduling flexibility. As a result, 29 of the siren tests normally scheduled to be performed in September were scheduled to be performed during the beginning of October. On October 1 the status of the siren testing was discussed with other members of the plant staff who understood that the intent of the "monthly" requirement was once per calendar month and that no grace period applied. Immediate actions were taken including performing the remaining 29 tests on an accelerated basis (all satisfactory tested by October 3) and entering the item in the corrective action program. All of the 29 sirens passed the testing performed during the first 3 days of October. The testing was not delayed due to the unavailability or suspected unavailability of the sirens. The reason for the late testing of the equipment was purely an administrative error and not siren functionality related. For plants where siren tests are initiated by the utility, if a scheduled test(s) was not performed due to an administrative issue but the untested siren(s) was not out-of-service for maintenance or repair and was believed to be capable of operation if activated, should the missed tests be considered non-opportunities or failures for performance indicator reporting purposes?	6/16 Introduced 8/18 To be discussed at 9/1 EP public meeting 9/16 Tentative Approval *10/13 Final*	Pilgrim
		Response: Regularly scheduled tests missed for reasons other than siren unavailability (e.g., out of service for planned maintenance or repair) should be considered non-opportunities. The failure to perform a regularly scheduled test should be entered in the plant's corrective action program and annotated in the comment field on the quarterly data submittal. The failure to perform regularly scheduled tests may be reviewed as part of the baseline inspection process.		
38.9	OR01	Question: On March 4, 2004, workers initiated a series of diving activities related to the inspection and repair of the Steam Dryer in the Dryer Separator Pit. On March 5, 2004, a contract diver proceeded to the Unit 1 Reactor Building 117' Elevation in preparation for the next diving evolution on the Steam Dryer. Based on underwater dose gradients from the steam dryer, 5 Electronic Dosimeters (EDs), 10 thermoluminescent dosimeters (TLDs) and a telemetry transmitter were placed on the diver by a Radiation Protection Technician (RPT) to monitor personnel exposure. ED/TLD combinations were placed on the chest, right arm, left arm, right leg, and left leg. TLDs were use to monitor the extremities. Communication between the EDs and the telemetry system was verified after placement on the diver. The RPT conducted the pre-dive radiological briefing and the diver entered the Contaminated Area. Telemetry problems were experienced prior to the diver entering the Dryer Separator Pit. The underwater antenna was changed out and telemetry problems appeared to be corrected. The diver was in the Dryer Separator Pit approximately 40 minutes when additional telemetry problems occurred. The diver was instructed to exit the water and the transmitter replaced. The telemetry problems were corrected and the diver re-entered the Dryer Separator Pit. After entering the water, the left arm ED stopped communicating with the telemetry system. The telemetry computer was rebooted while the diver was in the Dryer Separator Pit, but the left arm ED failed to transmit. The RP Supervisor evaluated the situation and decided to allow the dive to continue since four of the five EDs were	7/22 Introduced 8/18 Additional information required Referred to HP group *10/13 Licensee providing additional information to HP group*	Brunswick

<table>
<tr><th>TempNo.</th><th>PI</th><th>Question/Response</th><th>Status</th><th>Plant/ Co.</th></tr>
<tr><td></td><td></td><td>transmitting properly. The left arm ED did not transmit for the remainder of the dive. However, it did remain functional and continued to accumulate dose. Upon completion of the work, the diver exited the Dryer Separator Pit and it was discovered that his left arm ED was in alarm. Specific ED results for the diver are given below:
<table>
<tr><th>ED Location</th><th>ED Result (mrem)</th></tr>
<tr><td>Chest</td><td>147</td></tr>
<tr><td>Right Arm</td><td>319</td></tr>
<tr><td>Left Arm</td><td>588</td></tr>
<tr><td>Right Leg</td><td>30</td></tr>
<tr><td>Left Leg</td><td>31</td></tr>
</table>
Per the RWP, the Administrative Dose Limit for the dive was 500 mrem.
The diver's TLDs were processed and the results are given below
<table>
<tr><th>TLD Location</th><th>TLD Result (mrem)</th></tr>
<tr><td>Chest</td><td>135</td></tr>
<tr><td>Right Arm</td><td>403</td></tr>
<tr><td>Left Arm</td><td>673</td></tr>
<tr><td>Right Leg</td><td>30</td></tr>
<tr><td>Left Leg</td><td>34</td></tr>
<tr><td>Head</td><td>216</td></tr>
</table>
Does the situation described above constitute an unintended exposure occurrence in the Occupational Radiation Safety Cornerstone as described in NEI 99-02?

Response:
NEI 99-02 identifies the dose value used as a screening criterion to identify an unintended exposure occurrence as 100 mrem. The administrative dose guideline was established in the RWP as 500 mrem. Since the ED was functional and read 588 mrem, the screening criterion in 99-02 was not exceeded.</td><td></td><td></td></tr>
<tr><td>39.1</td><td>IE03</td><td>Question:
On June 23, 2004, condenser waterbox level and temperature readings on the Unit 1 and 2 main condensers indicated partial blockage of the waterbox intake debris filters. The cause was an influx of gracilaria, which is a marine grass found in the river water that is the circulating water intake supply to the plant. Subsequent backwashes of the debris filters were successful at restoring waterbox level and temperature readings to the normal band, except for the 2B-South waterbox, which is one of four waterboxes of the Unit 2 main condenser. An extended backwash was unsuccessful in restoring its readings back to normal.
Debris is removed prior to entering the circulating water intake bay by traveling screens with spray nozzles. The 2B-South debris filter is directly downstream from the 2D traveling screen. Investigation of this event found that the spray nozzles for the 2D traveling screen had more fouling than the other spray nozzles. The 2D traveling screen was able to adequately remove normal debris loading, but was not as effective as the other spray nozzles in removing the debris during the large influx of gracilaria.
A decision was made on June 24, 2004 to reduce power to about 53% and isolate the 2B-South waterbox to clean its debris filter. The decision to reduce power within 24 hours was based on several factors, such as reduced condenser efficiency, the potential for additional debris filter clogging, and a reduction in reactor water chemistry due to elevated condensate demineralizer resin temperatures. It was also based on input from work management, operations, and the load dispatcher. The 2B-South waterbox was successfully cleaned during the downpower and reactor power was restored to normal operating conditions.
<u>This was an anticipated power change in response to expected conditions.</u> Operating experience has shown that the</td><td>8/18 Introduced
9/16 On hold for more information</td><td>Brunswick</td></tr>
</table>

TempNo.	PI	Question/Response	Status	Plant/ Co.
		plant is susceptible to large influxes of gracilaria when the salinity level in the river water is elevated. For example, gracilaria problems were correlated with high salinity levels in 2002, which led to high vulnerability conditions. In addition, during another influx of gracilaria, a downpower was required in August, 2001 to clean the 1A-South debris filter. In response to experience over the past 5 years with gracilaria and other intake canal debris, modifications are being implemented at the river water intake diversion structure, which is the first barrier for intake debris, to improve the debris removal capability. In response to the influx of gracilaria, the plant implemented compensatory actions for a "High Vulnerability" condition in the intake canal. These actions include manning the diversion structure round-the-clock for manual debris removal, increasing screen wash pressure, and staging fire hoses at the traveling screens, if needed, to assist in removing debris. During the June 23 event, all four waterboxes on Unit 1 and three of four waterboxes on Unit 2 were managed within normal operating levels. <u>The power change was proceduralized.</u> The plant operating procedure for circulating water directs a power reduction to isolate a waterbox and clean the debris filter if an abnormally high differential pressure exists after debris filter flushing has been completed. <u>The influx of gracilaria was not predictable greater than 72 hours in advance.</u> Although the biology staff has found that high salinity levels in the river water make the conditions for a gracilaria release favorable, it is not possible to predict when an excessive influx will occur. The compensatory actions taken for a high vulnerability condition have usually been effective in preventing debris filter clogging. Should this event be counted as an unplanned power change?		
		Response: No, the event should not be counted as an unplanned power change. The increased accumulation of gracilaria in the river water was anticipated due to operating experience with high salinity levels in the river water, but the timing of the gracilaria release into the intake canal could not be predicted with certainty. In addition, the response to the condenser level and temperature conditions is proceduralized.		
39.2	EP03	Question: If a licensee makes a change in ANS testing methodology, when can that change be used in the ANS PI calculation?	8/18 Introduced. To be discussed at 9/1 EP public meeting 9/16 Tentative Approval *10/13 Tentative approval.*	NRC
		Response: The change in test methodology shall be reported as part of the ANS Reliability Performance Indicator effective the start of the next quarterly reporting period. A licensee may change ANS test methodology at any time consistent with regulatory guidance. For the purposes of the Performance Indicator, only the testing methodology in effect on the first day of the quarter shall be used for that reporting period. Neither successes nor failures beyond the testing methodology at the beginning of the quarter will be counted in the PI. *However, performance during actual siren activations that utilize the nuclear power plant's ANS activation system shall be included in the PI data.* NEI 99-02 requires that the periodic tests be used in developing the Performance Indicator. Pg 94, lines 12-13, states that: "Periodic tests are the regularly scheduled tests..." Therefore, a reporting period (quarter) starts with a sequence of regularly scheduled tests for that quarter. If a licensee determines that testing methodology should be changed, the plan/procedure directing the periodic tests should be revised and screened in accordance with the licensee's change. If the change in ANS test methodology is considered to be a significant change per FEMA requirements, the change is required to have FEMA approval prior to implementation. *This FAQ will take effect 1/1/05 and apply to siren testing after 1/1/05.*		

TempNo.	PI	Question/Response	Status	Plant/ Co.
40.1	*EP03*	*Question:* *Catawba Nuclear Station has 89 sirens in their 10-mile EPZ; 68 of these are located in York County. Duke Power's siren testing program includes a full cycle test for performance indicator purposes once each calendar quarter.* *On Tuesday, September 7, 2004, York County sounded the sirens in their county's portion of the EPZ to alert the public of the need to take protective actions for a Tornado Warning. Catawba is uncertain whether to include the results of the actual activation in their ANS PI statistics. The definition in NEI 99-02 does not address actual siren activations. In contrast, the Drill/Exercise Performance (DEP) Indicator requires that actual events be included in the PI. Should the performance during the actual siren activation be included in the Alert and Notification System (ANS) Performance Indicator Data?* *Response:* *Yes. Performance during actual siren activations that utilize the nuclear power plant's ANS activation system shall be included in the PI data. The purpose of the ANS Performance Indicator is to monitor the reliability of the offsite ANS, a critical link for alerting and notifying the public of the need to take protective actions. In this case, the system was performing its intended function of alerting the public of the need to take protective actions. This FAQ will take effect 1/1/05 and apply to siren testing after 1/1/05.*	*10/13 Introduced and Tentative Approval. Response text to be revised.*	*Catawba*
40.2	*MS02*	*Question:* *As discussed in NEI 99-02 (Revision 2), licensees reduce the likelihood of reactor accidents by maintaining the availability and reliability of mitigating systems – systems that mitigate the effects of initiating events to prevent core damage. The Harris Nuclear Plant (HNP) is actively pursuing measures to reduce mitigating system unavailability, such as those discussed below pertaining to High Head Safety Injection (HHSI) unavailability.* *At the Harris plant, the Essential Services Chilled Water (ESCW) system is a support system (room cooling) for the HHSI system. The HHSI system consists of three centrifugal, high-head pumps, each housed in its own room. HNP Engineering recently analyzed the effect of a loss of ESCW on HHSI availability by performing a room heatup calculation. This analysis showed that a train of HHSI can be maintained available even without the normal room cooling support system (ESCW) for a period greater than the PRA model success criteria (24 hours) through the use of a substitute cooling source powered by a non class 1E electric power source as allowed for in NEI 99-02, Page 37, Lines 27-35.* *It is important to note that: 1) a HHSI train utilizing the substitute cooling source will be considered Inoperable, 2) only one HHSI train at a time will utilize a substitute cooling source, and 3) the length of time that HHSI is required following a design basis accident is not specified in the FSAR.* *Since HHSI will remain available throughout the 24 hour period specified in the PRA model success criteria with a substitute cooling source, the Harris plant considers it available when calculating the NRC's Safety System Unavailability performance indicator.* *HNP and the resident inspector are not in agreement with respect to how to interpret the definition of unavailability (Page 23, Line 29). Specifically, in this instance, can a safety system train be considered available if it successfully meets its PRA model success criteria or must it satisfy its design basis requirements (long term cooling) to be considered available?* *Response:* *A safety system train may be considered available if it successfully meets its PRA model success criteria. Since HHSI will remain available throughout the 24 hour period specified in the PRA model success criteria with a substitute cooling source, it can be considered available when calculating the NRC's Safety System Unavailability performance indicator.*	*10/13 Introduced*	*Harris*

TempNo.	PI	Question/Response	Status	Plant/ Co.
40.3	*MS04*	*Question:* *The Safety System Unavailability Performance Indicator for BWR Residual Heat Removal (RHR) Systems monitors:* • *the ability of the RHR system to remove heat from the suppression pool so that pool temperatures do not exceed plant design limits, and,* • *the ability of the RHR system to remove decay heat from the reactor core during a normal unit shutdown (e.g., for refueling or servicing).* *Perry Technical Specifications require an alternate means of decay heat removal (DHR) to be available when removing an RHR system from service. Technical Specifications do not restrict the options for an alternate decay heat removal system to specific systems or methods. The Bases of Technical Specifications for LCO 3.4.10, RHR Shutdown Cooling System - Shutdown, Required Action A.1 state, "The required cooling capacity of the alternate method should be ensured by verifying (by calculation or demonstration) its capability to maintain or reduce temperature. Alternate methods that can be used include (but are not limited to) the Reactor Water Cleanup System."* *During the repair of Emergency Service Water (ESW) Pump B, an Off-Normal Instruction with an attachment for "RPV Feed And Bleed With ESW Not Available" was credited as an alternate decay heat removal method for the inoperable RHR system. The referenced procedure takes reactor water from the RHR system shutdown cooling flowpath and directs it to the main generator condenser which acts as the heat sink. The condensate and feedwater systems return the cooled water to the reactor. Reactor temperature is limited to* 150^{o} *F for this alternate DHR method. The heat removal capability of this method was demonstrated by calculation before being credited. Does the Perry reactor feed and bleed methodology described above constitute an "NRC approved alternate method of decay heat removal" as referenced in NEI 99-02 above?*	*10/13 Introduced*	*Perry*
		Response: *NEI 99-02, "Systems Required to be in Service at All Times" states, "For RHR systems, when the reactor is shutdown with fuel in the vessel, those systems or portions of systems that provide shutdown cooling can be removed from service without incurring planned or unplanned unavailable hours under the following conditions:* • *RHR trains may be removed from service provided an* ***NRC approved alternate method*** *of decay heat removal is verified to be available for each RHR train removed from service. The intent is that at all times there will be two methods of decay heat removal available, at least one of which is a forced means of heat removal". (**Emphasis added**.)* *The response to FAQ ID-145 for PI MS04 Residual Heat Removal System Unavailability (Posted 04/01/2000) parenthetically defines an NRC approved method as "an alternate method allowed by Technical Specifications." Since the Bases of Technical Specification only require that the system be capable of maintaining or reducing temperature and since they do not limit the options to the Reactor Water Cleanup System, the feed and bleed methodology is acceptable as an alternate method of decay heat removal. Thus, the reactor feed and bleed alternate decay heat removal method described above is an NRC approved alternate method.*		