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 9/26 Discussed 10/31 Discussed	LaSalle

Attachment 3

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. 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 10/31 Tentative Approval	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?	2/28 Introduced 4/25 Discussed 6/12 Discussed 10/31 Tentative Approval	Prairie Island
		Response It depends on the quantitative risk assessment that was performed to justify the exclusion. If the assessment specifically addressed the use of the Technical Specification AOT twice per operating cycle, then both overhauls may be excluded from the PI. If, however, the licensee's assessment assumed that only one AOT would be used per operating cycle, or if the licensee submitted a request to the NRC for an extended AOT and did not specify the number of times the AOT would be used per cycle, then the exemption may be used only once. However, the licensee has the option to perform a risk analysis that assumes the use of two AOTs per cycle. If that analysis meets the requirements of NEI 99-02 Rev. 2, page 28 line 15, through page 29 line 2, then the licensee may exclude the overhaul hours for the two overhauls .		
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 objective identifies that the PAGs will be exceeded beyond the 10 mile emergency planning zone (EPZ) boundary. Should the licensee count the development of the PAR(s) [or the lack thereof] beyond the 10 mile EPZ as an EP Drill/Exercise Performance (DEP) PI opportunity, due to their "ad hoc" nature?	3/21 Introduced 4/25 On Hold 6/12 Response being rewritten 9/26 Discussed revised response 10/31 Tentative Approval. Response being rewritten.	NRC
		Response: *If a licensee has identified in its scenario objectives that PAGs will be exceeded beyond the 10 mile plume exposure pathway emergency planning zone (EPZ) boundary, it is expected that the required PAR development and notification has been contemplated by the scenario with an expectation for success and criteria for evaluation provided. This would constitute a PI opportunity as defined in NEI 99-02. In addition, there is a DEP PI opportunity associated with the timeliness of the notification of the PAR to offsite agencies. Essential to understanding that these DEP PI opportunities exist is the need to realize that it is a regulatory requirement for a licensee to develop and communicate a PAR when EPA PAG doses may be exceeded beyond the 10 mile plume exposure pathway EPZ. However, as discussed in NEI 99-02, the licensee always has the latitude to identify which DEP PI opportunities will be included in the PI statistics prior to the exercise. Thus, a licensee may choose to not include a PAR beyond the 10 mile EPZ as a DEP PI statistic due to its ad hoc nature*		
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 9/26 Discussed 10/31 Tentative Approval	
		Response: No. The evaluation of the DEP opportunities is a crew evaluation for the entire Emergency Response Organization. Key ERO members may receive credit for the drill if their participation is a meaningful opportunity to gain proficiency in their ERO function		

Temp No.	PI	Question/Response	Status	Plant/ Co.
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? Response: As described, 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.	5/22 Introduced 6/12 Discussed 8/22 Discussed 9/26 Hold for generic response. 10/31 Tentative Approval	St. Lucie
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?	5/22 Introduced 6/12 Discussed 9/26 Discussed 10/31 Tentative Approval	IP 2

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Response: If failure of the source range detector high flux trip circuitry is reportable per 10CFR50.73 (a) (2) (v), then this counts as a Safety System Functional Failure. Such a determination is outside the scope of NEI 99-02, the issue must be referred to the appropriate branch of the NRC.		
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: 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.	5/22 Introduced 6/12 Discussed 9/26 Discussed. 10/31 Discussed	Generic
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? 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.	7/2 Introduced 8/22 Discussed 10/31 Tentative Approval	Hatch

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		Response: Both transients in the example should be counted. There were two errors: (1) opening the wrong breaker and (2) reclosing the breaker without establishing the correct plant conditions for restarting the pump If the pump had been restored per approved procedures only the first transient would be counted.		
31.4	PP03	Question The clarifying note for the Fitness-For-Duty / Personnel Reliability Program PI states that the indicator does not include any reportable events that result from the program operating as intended There is also an example provided that indicates that a random test drug failure would not count since the program itself was successful. 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 10/31 Discussed Need more information	Beaver Valley
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? Response: Yes, unavailability should not be reported when auxiliary air is not available to the AFW FCVs These valves will still have normal control air and for the limited duration when valve manipulation is required following a secondary system pipe rupture the PSA model, procedures, and training support the use of manual isolation of the AFW motor train valves.	8/22 Introduced	Sequoyah

Temp No.	PI	Question/Response	Status	Plant/ Co.
31.7	EP03	Question: During a recent Nuclear Regulatory Commission (NRC) inspection of the Alert and Notification System (ANS) Reliability Performance Indicator (PI) at Calvert Cliffs Nuclear Power Plant (CCNPP), the inspector identified an issue concerning how CCNPP reports weekly silent test results for the ANS PI. While reviewing the ANS PI data, the inspector observed that weekly silent testing consisted of transmitting three consecutive initiation signals during the scheduled silent activation test. The inspector also observed that when reporting the PI data, CCNPP reports the three initiation signals as one test and reports the test as a success if at least one out of three initiation signals is received. When none of the three initiation signals is received, the test is considered an unsuccessful silent activation The inspector determined that by not counting and reporting each of the three initiation signals as separate siren tests, CCNPP could be unintentionally masking failures and may not be meeting the intent of the ANS PI. This issue was documented in NRC Inspection Report 50-317/02-010, 50-318/02-010, dated August 12, 2002, as an Unresolved Item Beginning in June 2001, the Calvert County procedure for activating the siren system during an actual emergency was revised to require the transmission of three sets of initiating tones to activate the sirens for one cycle. Coincident with this revision, the weekly silent test procedure was revised to mimic the full siren activation process during an actual emergency. The current CCNPP ANS is designed with no direct feedback mechanism or polling operation for siren activation. At Calvert Cliffs, we utilize three sets of initiating tones to simulate newer system designs that provide feedback and poll a receiver until it responds. This methodology minimizes the effect of momentary channel interference, provides greater assurance that each siren will perform its function, and allows us to monitor individual siren performance. The change in activation and testing methodology was not submitted to FEMA for approval prior to use. When activating sirens during an actual emergency and during weekly silent testing the following procedure is used The 911 dispatcher checks to make sure the radio channel is clear. The 911 dispatcher makes an announcement that the Calvert Cliffs Public ANS is being sounded (or tested for silent testing) The 911 dispatcher selects the CCNPP Sirens icon A 911 supervisor verifies that the correct icon is selected. The 911 dispatcher selects the transmit icon to send the first set of tones. The 911 dispatcher then waits 10 seconds and when the channel is clear, repeats the announcement, selects the icon, waits for supervisor verification, and sends the second set of tones The 911 dispatcher then waits 10 seconds and when channel is clear, repeats the announcement, selects the icon, waits for supervisor verification, and sends the third set of tones. When the third set of tones have cleared, the 911 dispatcher makes an announcement that the siren activation is completed It takes approximately one minute or less to transmit the three sets of initiating tones for a siren activation during the actual emergency and weekly silent test. We have reviewed siren testing data since the beginning of 2002 to identify whether sirens that received less than three initiation signals were capable of receiving the initiation signals during the next week's silent siren tests. This review indicated that out of 60 instances where a siren received less than three initiation signals, there was only one instance where a siren did not receive any of the three initiation signals during the next week's silent siren test. This does not include the times when a transmitter failure occurred causing multiple siren failures. The review of the data confirms that, for the most part, sirens receiving less than three initiation signals due to possible intermittent transmitter or receiver failures were capable of receiving at least one of the three initiation signals during the next week's silent siren tests. Given the testing methodology described above, is CCNPP reporting the results of weekly silent tests correctly?	9/26 Introduced 10/31 Discussed	Calvert Cliffs

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Response: Yes. The use of multiple initiating tones to activate the sirens is contained in an approved procedure and is part of the actual system activation process during an emergency at the plant This practice mimics state-of-the-art siren systems, which are designed with feedback on siren activation and send more than one signal or set of tones during activation to mitigate the effects of radio channel interference. Additionally, the testing procedure is uncomplicated and is capable of being performed in a small amount of time (one minute or less). The procedure does not include any activities outside the regularly scheduled test, such as troubleshooting, post-maintenance testing, or activation signals sent after the initial activation test procedure has ended (see archived FAQ No. 232).		
31.8	IE03	Question The indicator counts changes in reactor power, greater than 20%, before 72 hours have elapsed following the discovery of an off-normal condition. When evaluating an off-normal condition, does a change in the cause of or the repair plans for the off-normal condition result in a new condition that must exist for more than 72 hours to be considered as a planned down power? Our plant experienced two power changes greater than 20% in 2002 that were not included in the indicator. The decision to not count these power changes was based on the elapsed time between discovery and the change in power without consideration for the cause of the condition. . Event #1 In February 2002, Unit 2 was returning to service after a scheduled refueling outage. During plant heat-up, a steam generator stop valve was drifting off the open detents while at normal operating pressure and temperature. This was a documented, long-standing condition for these types of valves during reactor start-ups, and identified in the corrective action program at 1600 hours on February 25, 2002. Experience with these valves showed that when power was increased, the valve would remain on the detents with lower steam pressure. Reactor start-up continued and the unit was placed online. On February 28, with reactor power at 28%, the stop valve was still drifting off the open detents The decision was made to remove the generator off-line and reduce reactor power to 2% to adjust the packing assembly. That decision was based on the evaluation of the causes for the valve drifting off the open detents. At 2033 hours on February 28, Unit 2 commenced the power reduction to 2 % reactor power. When the unit was returned to service after the packing adjustment, the valve remained on the open detents. The event was not counted as an unplanned power change since 76.5 hours had elapsed from the discovery (as documented in the corrective action program) of the valve drifting off the open detents to the commencement of the power reduction. No consideration was given to why the valve was drifting off the detents. The resident inspection staff questions the off-normal condition that caused the power change. Since no plans were made to remove the unit from service for repairs but to continue the start-up, the decision to remove the unit to adjust the packing assembly constituted a different off-normal condition.	9/26 Introduced 10/31 Discussed	DC Cook
		Response: This indicator captures changes in reactor power that are identified following the discovery of an off-normal condition. If a power reduction is performed and the actual cause of the condition or repair plans differs from the apparent cause or proposed plans, the power reduction does not count if greater than 72 hours elapsed from the initial discovery of the condition. If, however, the condition degraded to where a rapid response is required, the power reduction would count.		

Temp No.	PI	Question/Response	Status	Plant/ Co.
31.9	IE03	Question The indicator counts changes in reactor power, greater than 20%, before 72 hours have elapsed following the discovery of an off-normal condition. When evaluating an off-normal condition, does a change in the cause of or the repair plans for the off-normal condition result in a new condition that must exist for more than 72 hours to be considered as a planned down power? Our plant experienced two power changes greater than 20% in 2002 that were not included in the indicator. The decision to not count these power changes was based on the elapsed time between discovery and the change in power without consideration for the cause of the condition. Event #2 On April 23, 2002, an action request was generated documenting a 30-drop per minute leak from a low pressure turbine reheat steam stop valve. A work request and condition report was generated from the action request. On May 10, 2002, Maintenance removed insulation from the bottom of the valve to ascertain the location of the leak. It could not be determined if the leak was coming from the flange or a previous Furmanite repair. Maintenance requested a job order to remove the insulation and investigate for a possible Furmanite repair. On May 12, the work request was reassigned to the Work Assessment Group to build scaffolding, remove insulation, and plan a Furmanite repair. On May 22, the priority of the job was increased due to the worsening condition of the leak. In the morning of May 24, the job was scoped out by the Furmanite technician and it was determined that the valve flange was most likely leaking and the repair shouldn't be difficult. Later in the evening, the lagging was removed from the valve revealing a larger than expected leak. A recommendation was made to remove Unit 2 from service to make the repairs. After discussions with management, the decision was made to remove the moisture separator reheaters from service so that the steam would be visible for the Furmanite repair on May 25. In the afternoon of May 25, the Furmanite technician discovered that the leak was not from the flange gasket but was instead from a circumferential crack, 210 degrees around the valve flange. A meeting was held and at 1530 hours, the decision was made to remove Unit 2 from service to facilitate repairs A shutdown, using normal operating procedures, commenced at 1600 hours with the unit shutdown completing at 1951hours that evening The shutdown was normal and controlled. The turbine building was evacuated to minimize the chance for injury. The evacuation was not based on the steam leak, as this was low pressure (approximately 70 pounds) steam, but on the concern for the structural integrity of the valve. The event was not counted as an unplanned power change since 32 days had elapsed from the discovery (as documented in the corrective action program) of the steam leak to the commencement of the power reduction No consideration was given to the cause of the steam leak. The event was not counted because of the time that had elapsed from discovery to the shutdown and the shutdown was a normal and controlled shutdown using normal operating procedures. The resident inspection staff questions the off-normal condition that caused the power change. Since no plans were made to remove the unit from service for the Furmanite repairs, the decision to shutdown the unit, based on the knowledge of a circumferential crack, constituted a different off-normal condition.	9/26 Introduced 10/31 Discussed	DC Cook
		Response: This indicator captures changes in reactor power that are identified following the discovery of an off-normal condition. If a power reduction is performed and the actual cause of the condition or repair plans differs from the apparent cause or proposed plans, the power reduction does not count if greater than 72 hours elapsed from the initial discovery of the condition. If, however, the condition degraded to where a rapid response is required, the power reduction would count.		

Temp No.	PI	Question/Response	Status	Plant/ Co.
32.2	MS02 MS04	Appendix D Question: Component cooling water (CCW) system at our plant is a clean treated water cooling system that supports the High pressure safety injection (HPSI) pumps and Residual heat removal (RHR) system Our commitment to Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment" includes routine tube side (intake cooling water) cleanings. This FAQ seeks an exemption from counting planned overhaul maintenance hours for a support system outage (CCW heat exchanger maintenance). The CCW system transfers heat from the HPSI pump seal and bearing coolers and the RHR system to the ultimate heat sink. Sulzer Pumps Inc. Document E12.5.0730, "Qualification Report for HPSI Pump Bearings and Mechanical Seals without Cooling Water" has concluded the HPSI pumps can be operated without the use of CCW. The RHR system, therefore, is the only mitigating system as defined in NEI 99-02 requiring CCW as a support system Our response to Generic Letter 89-13, "Service Water Problems Affecting Safety-Related Equipment" included routine maintenance and cleaning of the CCW heat exchangers Work duration typically lasts for 45 to 50 hours while the Unit is in a 72 hour Technical Specification LCO. These activities function to remove micro and macro fouling thereby maintaining the heat transfer capability and reliability of the heat exchanger. These activities are undertaken voluntarily and performed in accordance with an established preventive maintenance program to improve equipment reliability and availability and as such are considered planned overhaul maintenance as defined in NEI 99-02. Other activities may be performed with the planned overhaul maintenance provided the system outage duration is bounded by the overhaul activities NEI 99-02 goes on to state the following: "This overhaul exemption does not normally apply to support systems except under unique plant-specific situations on a case-by-case basis The circumstances of each situation are different and should be identified to the NRC so that a determination can be made Factors to be taken into consideration for an exemption for support systems include (a) the results of a quantitative risk assessment, (b) the expected improvement in plant performance as a result of the overhaul activity, and (c) the net change in risk as a result of the overhaul activity." In accordance with the NEI guidance the following results can be expected Based on the plant on-line risk monitor (OLRM), the incremental change in core damage probability (ICCDP) and incremental change in large early release probability (ICLERP) over a 72 hour duration due to unavailability of a RHR train is less than 3E-08 and 1E-09 respectively. The ICCDP and ICLERP is considered small based on guidance in RG 1.177. The total change in core damage frequency (delta CDF) and change in large early release frequency (delta LERF) assuming each train of RHR is out-of-service for a 72 hour CCW heat exchanger maintenance window is, therefore, less than 6E-08/yr. and 2E-09/yr, respectively. Using a 72 hour duration for the risk assessment (the maximum allowed time based on the Technical Specification LCO) adds conservatism to this assessment. Historically this CCW maintenance has been completed within approximately 50 hours. The assessment results conclude that the delta CDF and delta LERF is in region III of RG 1.174 Figures 3 and 4 and is thus considered very small. Routine cleaning maintains the heat transfer capability from the RHR system to the ultimate heat sink by removing biofouling, silt, and other marine organisms from the heat exchangers. Shells lodged in the CCW heat exchanger tubes that have historically caused accelerated flow and erosion of the tube wall are also removed. The eddy current testing (ECT) and plugging activities have helped to identify and remove degraded tubes from service, thereby reducing the probability of CCW system inventory loss. These efforts have combined to increase the component and system reliability and availability. It is judged that the reliability increase from cleaning the CCW heat exchangers and identification of degraded tubes before failure offsets the small increase in risk resulting from the additional RHR system unavailability.	9/26 Introduced 10/31 Discussed	St. Lucie
		Response: As described, the routine maintenance and cleaning of CCW heat exchangers is considered planned overhaul maintenance unavailability hours of an RHR support system. These activities are accomplished within the AOT to improve equipment reliability and availability. The factors taken into consideration above yield favorable results, therefore, the CCW heat exchanger planned overhaul maintenance hours should not be cascaded to the RHR system		

Temp No.	PI	Question/Response	Status	Plant/ Co.
32.3	IE02	Question: Donald C. Cook Nuclear Plant Unit 2 has had 2 Unplanned Scrams in the past 4 quarters that required the operators to perform a main steam isolation due to an excessive cooldown rate. The conditions causing the excessive cooldown rate are being identified as preventing the use of the normal cooldown path by the NRC resident inspector. The first 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 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 blow down were isolated. At 9 minutes after the trip, the main steam isolation valves were closed in accordance with the reactor trip response procedure curtailing the cooldown The RCS cooldown was attributed to #4 steam generator AFW flow control valve not closing automatically as expected with high AFW flow and steam that was still being supplied to low-flow feedwater preheating. The AFW flow control issue was identified by the control room balance of plant operator and the low-flow feedwater preheating is a known steam load during low power operations. The trip response procedure directs the operators to check for and take actions to control AFW flow and eliminate the feedwater heater steam supply. The second Unplanned Scram occurred on July 22, 2002 during full power operations The trip was initiated through a turbine trip caused by low vacuum in the 2C Condenser. The low vacuum was considered a partial loss of vacuum, therefore was not counted a loss of heat removal. At 3 minutes after the trip, the operators performed a main steam isolation due to RCS cooldown to 540 degrees in accordance with the trip response procedure. In addition, the cooldown caused the pressurizer to shrink, resulting in lowering RCS pressure that approached the safety injection set point. The cause of the excessive cooldown was the plant alignment of the Unit 1 and Unit 2 auxiliary steam loads to the Unit 2 main steam header (a normal plant configuration). No automatic valve action is available to switch the loads from one unit to the next and requires an operator to manually switch the steam source. For both cases, the normal cooldown path was available for use and could be restored from the control room by the operations crew. It is contended that the conditions described above causes the normal cooldown path to be unavailable. This contention is based on the premise that opening the main steam isolation valves would re-initiate the cooldown and potentially cause an RCS shrink that could initiate a safety injection. Should the reactor trips described above be counted in the Unplanned Scrams with Loss of Normal Heat Removal Performance Indicator?	10/31 Introduced and discussed	DC Cook
		Response: In accordance with NEI 99-02, the scrams were not counted in the indicator since the actions taken were "Intentional operator actions to control the reactor water level or cooldown rate," and could be recovered from the control room.		

Temp No.	PI	Question/Response	Status	Plant/ Co.
32.4	MS04	NEI 99-02 identifies the Residual Heat Removal (RHR) System as a system that is required to be in service at all times. In certain situations, monitoring the RHR System in accordance with the NEI 99-02 guidance for Millstone 2 results in the required hours for the RHR system that are less than the total hours for a given calendar quarter This is a result of the containment spray system not being required by the technical specifications in mode 3 with RCS pressures < 1750 psia. NEI 99-02 requires the following two functions be monitored for Residual Heat Removal (RHR) performance indicator. (1) the ability to take a suction from containment sump, cool the fluid, and inject at low pressure into the RCS, and (2) the ability to remove decay heat from the reactor during normal unit shutdown for refueling or maintenance For the Millstone 2 and several other Combustion Engineering (CE) designed NSSS, Appendix D of NEI 99-02 provides clarification regarding how this performance indicator should be monitored. To monitor the first function, Appendix D recommends that the two containment spray pumps and associated coolers should be counted as two trains of RHR providing the post accident recirculation cooling. To monitor the second function, Appendix D recommends that the SDC system be counted as two trains of RHR. The first function is required by the plant technical specifications in modes 1 and 2 as well as in mode 3 with RCS pressures greater than 1750 psia This second function is required by the technical specifications in modes 4, 5 and 6. As such, at Millstone 2, the RHR function is not being monitored while the plant is in mode 3 with RCS pressures less than 1750 psia. Therefore, if the plant is operated in mode 3 with RCS pressures less than 1750 psia for any given calendar quarter, the required hours for the RHR function will be less than the total hours in that quarter. There are no specific restrictions as to how long the plant can be operated in Mode 3 with RCS pressure less than 1750 psia. Depending upon the nature of plant maintenance or repairs, the hours a plant is in this mode could be considerable. From an accident analysis standpoint, following a main steam line break or loss of coolant accident inside containment, the RCS decay heat removal safety function is accomplished by a combination of the containment spray system and the Containment Area Recirculation (CAR) coolers, which are required by the technical specifications in modes 1, 2, & 3. The CAR system consists of two independent trains of two coolers each. The CAR coolers transfer energy from the containment atmosphere to a closed cooling water system to the ultimate heat sink. The containment heat removal capability of one CAR train is considered equivalent to one CS train. Following a main steam line break or loss of coolant accident inside containment in mode 3 with RCS pressures less than 1750 psia, the CAR coolers are the only technical specification required system that satisfies the RCS decay heat removal safety function. Currently the CAR function is not included as part of the RHR performance indicator. Its inclusion would result in the system required hours being equivalent to the total hours for a calendar quarter. For the purposes of reporting the RHR performance indicator, should we continue to maintain the current 99-02 methodology which could result in required system hours less than the total calendar hours for a given quarter, or should we be monitoring the availability of the CAR System as part of the RHR performance indicator? If we add the CAR coolers to the RHR performance indicator, how should they be handled in the technical specification modes where both the containment spray and CAR coolers are required (modes 1, 2 and 3 with RCS pressures greater than 1750 psia) versus the technical specification mode where only the CAR coolers are required (mode 3 with RCS pressures less than 1750)?	10/31 Tentative Approval	Millstone 2
		Response: Yes, continue to maintain the current 99-02 methodology with the understanding that frequent plant shutdowns or associated mode 3 repairs could result in an accounting mis-match between RHR system required hours and the total calendar hours for a given quarter.		

Temp No.	PI	Question/Response	Status	Plant/ Co.
32.5	OR01	Question· The scope of a job changed such that completion of the job would involve additional collective dose with regard to the original estimate. From the time that the work activities deviated from the original plan to the time that ALARA staff documented a revision to the plan and a new collective dose estimate, an individual received more than 100 mrem TEDE from external dose while continuing to work on this job During this timeframe, the worker was performing activities outside of the original work plan. The time period from deviation from the original plan to documentation of the revised plan and dose estimate for the job is approximately one day. The licensee defines an "unintended exposure event" for TEDE in their procedures as a situation in which a worker receives 100 mrem or more above the electronic dosimeter dose alarm set point for a given RCA entry. On this job, all of the workers maintained their individual dose below the electronic dosimeter dose alarm for every RCA entry performed. Is this situation an "unintended exposure event"? Response: No, the described circumstances appear to represent an ALARA issue, not a performance deficiency with regard to the scope of the Occupational Exposure Control Effectiveness PI. The purpose of the PI is to address the Occupational Radiation Safety Cornerstone objective of "keep[ing] occupational dose to individual workers below the limits specified in 10 CFR Part 20 Subpart C." During development of the Performance Indicators, it was decided not to pursue a PI for the ALARA-based objective in the Occupational Radiation Safety Cornerstone. That objective is met through the ALARA inspection module. Further, with regard to "Unintended Exposure', the PI states that it is "incumbent on the licensee to specify the method(s) being used to administratively control dose." In this case, the licensee has apparently selected the use of electronic dosimeter alarm set points as the method for administratively controlling external dose, in which case the applicable criterion for the PI would be if the external dose exceeded the alarm set point by 100 mrem or more.	10/31 Tentative Approval	Columbia
32.6	OR01	Question: During a review of electronic dosimeter (ED) /TLD discrepancies of eddy current workers, it was noted that for two of the workers, the electronic dosimeter under-reported the dose compared to the recorded official dose by TLD. An investigation revealed the following· • .Multiple TLDs were placed on each worker for work on the platform. Locations included the head, chest, upper left and upper right arms. • .A single electronic dosimeter was placed on either the right or left upper arm, depending on which arm the worker was most likely to use when manipulating the robot inside the man way. • .A "jump ticket", containing the authorized dose was used for each entry. • .The radiation protection technicians used telemetry connected to the ED to control exposures Video and voice communications were also part of the remote monitoring system. • .Estimated dose for each entry was recorded, based on the electronic dosimeter. The same TLDs were used for multiple entries. As a result, a direct comparison of TLDs to electronic dosimeter readings on a per entry basis could not be performed. • .Estimated (ED) doses for the two workers, with the highest official doses, were low by 39% and 44% • .One of the workers with an authorized dose of 300 mrem for an entry received an estimated (ED) dose of 275 mrem. Using a ratio of TLD to ED dose of either his total exposures or the other worker's total exposures for the job, a corrected dose in the range of 450 to 460 mrem could be calculated for the single entry. • .Estimated (ED) dose for 12 of 15 workers was low, when compared to the TLD at location of highest recorded exposure. Does this constitute an unintended exposure occurrence in the Occupational Radiation Safety Cornerstone as described in NEI 99-02?	10/31 Tentative Approval	Diablo Canyon

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Response: No, assuming that a proper pre-job survey and evaluation was performed Although, in retrospect, it was determined that the estimating device was not placed in the location of highest exposure, it was placed in the area anticipated to receive the highest exposure and used appropriately to keep exposure below the authorized dose per entry. Record dose was properly assigned using the results of the TLD placed at the location of highest exposure.		
32.7	OR01	Question: A radiation worker entered the containment during power operation. At that time, the containment was a posted locked high radiation area with dose rates > 1,000 mrem per hour. Prior to entering the containment, the worker in error logged onto the wrong radiation work permit (RWP), which did not allow access to a locked high radiation area In fact, the individual had been approved for entry into the containment, conformed with the controls specified in the correct RWP, and met all other requirements for entry, including being aware of the radiological conditions in the area being accessed, proper electronic dosimeter alarm set points, continuous coverage by Health Physics, etc. There was no "unintended exposure" The single error was related to logging onto the wrong RWP. Does this type of error count against the PI for Technical Specification High Radiation Area (>1,000 mrem per hour) occurrences?	10/31Tentative Approval	Seabrook
		Response: No, as described, this would not count against the PI. The performance basis of the PI was met because the worker was properly informed about radiological conditions and the proper radiological controls were implemented. The worker's error in logging in on the wrong RWP is an administrative issue that is not considered a deficiency with regard to the performance basis of the PI.		

Temp No.	PI	Question/Response	Status	Plant/ Co.
33.1	OR01	*Question:* *Plant Technical Specifications state the following for areas with radiation levels > or = 1000 mrem/hr, referred to as Tech Spec Locked High Radiation Areas (TSLHRAs):* *"...areas with radiation levels > or = 1000 mrem/hr shall be provided with locked or continuously guarded doors to prevent unauthorized entry, and the keys shall be maintained under the administrative control of Operations or health physics supervision. Doors shall remain locked except during periods of access by personnel under an approved RWP that shall specify the dose rate levels in the immediate work areas and the maximum allowable stay times for individuals in those areas... "* *Our plant is configured with a chain link cage and cage door around the outer Containment door. The cage door is secured by a chain and padlock (keys controlled by health physics supervision). Additionally, an electronic lock and card reader (ACAD) secures the door. Power to the ACAD lock is controlled by Security from a central remote location When powered, the ACAD will open the electronic lock upon reading the badge of an individual with authorized access. When power is removed, the ACAD electronic lock cannot be opened from outside the cage and therefore acts as a locked door. The door will open from inside the cage via use of a crash bar, a feature which prevents the de-energized ACAD from locking people inside.* *Plant procedures state that the Shift Supervisor (Operations) authorizes each entry into Containment and assigns responsibility to the work group supervisor or entering individuals (entering Containment) to sign on and off an entry data sheet and the controlling RWP. The necessity for an access control point is determined by the Shift Supervisor and may be judged unnecessary.* *The typical entry without a continuous access control point (as in a nonoutage situation) requires notification to HP to remove the chain and padlock, and notification to Security, to dispatch a security officer to the cage door after which power to the ACAD is turned on. Entry into Containment is made in accordance with the RWP. If the entry duration is not brief, and no access control point is established, then the security officer may notify the central station to remove ACAD power and he departs resuming other activities* *The de-energized ACAD maintains the cage door locked. Personnel inside Containment may still exit in an emergency, unassisted, using the crash bar. Add-on or subsequent entries continue to be controlled by the Shift Supervisor and RWP in accordance with plant procedures.* *Recently, the practice of controlling access to the Containment through the use of the de-energized ACAD electronic lock has been questioned. It has been suggested that this situation may constitute a "Technical Specification High Radiation Area Occurrence" against the Performance Indicator in that it was a "nonconformance with technical specifications .. applicable to technical specification high radiation areas (>1 rem per hour) that results in loss of radiological control over access...within the respective high-radiation area (>1 rem per hour)."* *Is this a performance indicator occurrence?* ***<u>Additional Information</u>*** *Plant HP customarily places a flashing light at the containment door while entries are in progress as a signal to all personnel that a Containment entry is in progress. This practice is performed in addition to the provisions of Tech Spec 5.7.3. In the situation noted above in the FAQ, a confounding factor occurred in that the flashing light had not been turned on Although the failure to activate the flashing light is not in accordance with plant procedures, use of the flashing light is not intended to be in lieu of conformance with the Technical Specification 5.7.3, and therefore is not considered material to the issue of performance indicator.*	*12/12 Introduced*	*Vogtle*

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Response: *No. As stated in NEI 99-02 the performance indicator associated with radiological control over access to TSLHRAs refers to measures that provide assurance that inadvertent entry into the TSHRA by unauthorized personnel will be prevented. As described above, each entry into the Containment must be authorized by the Shift Supervisor and conducted under the RWP. During periods when no access is being made, the chain link cage door around the outer Containment door is secured by a chain and padlock (keys controlled by health physics supervision). During periods when access to the Containment is being made, either a security officer is present to prevent unauthorized access or the ACAD lock is de-energized In all cases, inadvertent entry to the Containment cannot be made and access must be authorized by the Shift Supervisor (Operations) and conducted under the RWP.*		

Temp No.	PI	Question/Response	Status	Plant/ Co.
33.2	MS01 -04	*Question (Appendix D)* *Catawba Nuclear Station plans to replace the Nuclear Service Water System (NSWS) 'A' train header piping in January, 2003. This planned piping replacement is scheduled to occur when Unit 1 and 2 are at power operation and take approximately 141 hours to complete. A proposed tech spec amendment was submitted on 9/12/02 requesting a temporary change to certain tech specs that would allow the 'A' NSWS header for each unit to be taken out of service for seven days (168 hours) for pipe replacement. Duke requested NRC approval of the proposed amendment by 12/1/02; therefore, a tech spec with allowable outage time sufficient to accommodate the overhaul hours will be approved prior to support systems being taken out of service. Although the NSWS is not an NEI 99-02 system, its unavailability does affect various systems and components, many of which are considered major components by the definition contained in FAQ 219 (diesel engines, heat exchangers, and pumps) The specific PIs affected by unavailability of the NSWS are Emergency AC, High Pressure Safety Injection, Residual Heat Removal, and Auxiliary Feedwater. If the hours that this overhaul of the NSWS made its supported systems unavailable cannot be excluded, it would result in reporting approximately 141 hours unavailability on 'A' train of each of the three monitored systems. This FAQ seeks approval to exclude the unavailability that will be incurred during this planned overhaul maintenance of the NSWS. NEI 99-02 states that "overhaul exemption does not normally apply to support systems except under unique plant-specific situations on a case-by-case basis. The circumstances of each situation are different and should be identified to the NRC so that a determination can be made. Factors to be taken into consideration for an exemption for support systems include (a) the results of a quantitative risk assessment, (b) the expected improvement in plant performance as a result of the overhaul activity, and (c) the net change in risk as a result of the overhaul activity." QUANTITATIVE RISK ASSESSMENT Duke Power has used a risk-informed approach to determine the risk significance of taking the 'A' loop of NSWS out of service for up to four days beyond its current technical specification limit of 72 hours The acceptance guidelines given in the EPRI PSA Applications Guide were used to determine the significance of the short-term risk increase from the outage extension. The requested NSWS outage extension does not create any new core damage sequences not currently evaluated by the existing PRA model. The frequency of some previously analyzed sequences do, however, increase due to the longer maintenance unavailability of the 'A' NSWS loop An evaluation of the Large Early Release Frequency (LERF) implications of the proposed 'A' loop NSWS outage extension concluded that they are insignificant. An evaluation was performed utilizing PRA for extending the NSWS technical specification time limit from 72 hours to 168 hours. The core damage frequency (CDF) contribution from the proposed outage extension is judged to be acceptable for a one-time, or rare, evolution. The resulting increase in the annualized core damage risk is 2.6E-06, a low-to-moderate increase in the CDF for consideration of temporary changes to the licensing basis and is acceptable based on consideration of the non-quantifiable factors involved in the contingency measures to be implemented during the overhaul. Therefore, because this is a temporary and not a permanent change, the time averaged risk increase is acceptable. Based on the expected increase in overall system reliability of the NSWS and the expected decrease in NSWS unavailability in the future as a result of the overhaul, an overall increase in the safety of both Catawba units is expected EXPECTED IMPROVEMENT IN PLANT PERFORMANCE The structural integrity of this section of NSWS piping is not in question at this time. The concern is that over time the pipe will degrade and eventually leak. The pipe replacement will enhance system integrity for long term operation and allow for detailed inspection and testing of the section of pipe removed. The removal of this section of pipe will allow for detailed analysis of how the degradation is occurring and provide information for managing the aging of this system. The proposed NSWS pipe replacement modification is expected to increase overall system reliability, thereby minimizing future system unavailability.NET CHANGE IN RISK AS A RESULT OF THE OVERHAUL ACTIVITY Increased NSWS train unavailability as a result of this overhaul does involve a one time increase in the probability or consequences of an accident previously evaluated during the time frame the NSWS header is out of service for pipe replacement. Considering the small time frame of the 'A' NSWS train outage with the expected increase in reliability, expected decrease in future NSWS unavailability as a result of the overhaul, and the contingency measures to be utilized during the overhaul, net change in risk as a result of the overhaul activity is reduced*	*12/12 Introduced*	*Catawba*

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Response: *For this plant specific situation, planned overhaul hours for the nuclear service water support system may be excluded from the computation of monitored system unavailabilities Such exemptions may be granted on a case-by-case basis. Factors considered for this approval include (1) the results of a quantitative risk assessment of the overhaul activity, (2) the expected improvement in plant performance as a result of the overhaul, and (3) the net change in risk as a result of the overhaul.*		
33.3	*IE03*	*Question:* *NEI 99-02 states "Anticipated power changes greater then 20% in response to expected problems (such as accumulation of marine debris and biological contaminants in certain seasons) which are proceduralized but cannot be predicted greater that 72 hours in advance may not need to be counted if they are not reactive to the sudden discovery 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." On August 4th and 5th, 2002, both the "A" and "B" Residual Heat Removal Service Water (RHRSW) subsystems were declared inoperable due to high strainer differential pressure which exceeded the 12 psid strainer operability due to high strainer operability limit during the performance of the monthly surveillance test. The perceived loss of both sub-systems ultimately resulted in plant shutdown on August 6th. The cause of the high strainer differential pressure was biological fouling at the intake structure and in the RHRSW and Emergency Service Water (ESW) wet pits. This type of biological fouling was not unexpected. A similar, but less extensive, occurrence of bio-fouling in September 2001 caused a transient differential pressure excursion across a single RHRSW strainer but did not result in a plant shutdown. During that event, the RHRSW strainer in the other train was unaffected, and subsequent disassembly revealed only minor fouling in the affected strainer. Corrective actions to deter future were implemented but this type of phenomenon it is difficult to assure that it will not recur. The sudden increase in the level of bio-fouling was not predictable 72 hours in advance The cause of the bio-fouling events in 2001 and August 2002 was identified by expert consultants as a little known animal organism, bryozoa, which grows in colonies and is a filter feeder similar to corals The environmental factors that contribute to sudden population growth are not well understood and the efficacy of biological controls is not well established Response to high strainer differential pressure during normal plant operations is procedurally controlled High strainer differential pressure is alarmed in the control room. Upon receipt of the alarm the operators enter appropriate annunciator response procedure. The conditions that would cause a repeat occurrence remain uncontrollable and unpredictable. Does this event need to be counted as an unplanned power change?* *Response:* *No The presence of biological growth in the pump pits was known and had been detected during previous pit cleaners. A sudden population growth leading to high differential pressure across the strainers could not be predicted within 72 hours. The response for dealing with high RHRSW strainer differential pressure is proceduralized*	*12/12 Introduced*	*Duane Arnold*

Temp No.	PI	Question/Response	Status	Plant/ Co.
33.4	EP01	*Question:* *NRC inspectors reviewing historical Drill/Exercise Performance data found several instances where the control room crew circled "actual" versus "drill" on the Emergency Action Level Notification forms during simulator training scenarios. The Emergency Planning personnel compiling the performance indicator (PI) data did not consider this specific piece of the form as a required element for counting opportunities as successful. Simulator scenario training strives for a high degree of realism. Operating crews are requested to perform their actions with as much fidelity as practical (within the bounds of the training environment). As such, simulator scenarios are conducted differently in some respects from emergency planning drills. For example, operators do not preface simulator announcements with "This is a drill " Also, simulator scenarios generally limit themselves to the classification of emergencies and demonstrating sufficient knowledge to perform a notification. The conflict between role-playing and reality led to inconsistencies when circling "actual" or "drill" on the Emergency Activation Level Notification forms* *NEI 99-02, Rev. 2, page 85, line 5 and line 14 include the following statements for defining "accurate" for the purposes of calculating the drill/exercise performance (DEP) indicator:" Initial notification form completed appropriate to the event to include (see clarifying notes): ... Whether the event is a drill or actual event" NEI 99-02, Rev. 2 clarifying notes, page 86, lines 5 through 9 state: "Performance statistics from operating shift simulator training evaluations may be included in this indicator only when the scope requires classification. Classification, PAR notifications and PARs may be included in this indicator if they are performed to the point of filling out the appropriate forms and demonstrating sufficient knowledge to perform the actual notification However, there is no intent to disrupt ongoing operator qualification programs." Should Emergency Action Level Notification forms from simulator training scenarios that are circled "actual" rather than "drill" count as errors on the DEP PI? If so, does this error on the form count as a missed opportunity when calculating the actual PI?* *Response:* *No. For simulator training scenarios when no offsite notifications are made, nor are there any facsimiles of the notification form sent offsite, the portion of the notification form that asks whether it is a drill or actual event is not relevant to whether or not the notification was a successful opportunity for the purpose of the PI data*	*12/12 Introduced*	*Palisades Duane Arnold*
33.5	MS04	*Question:* *During Mode 5 and 6 surveillance testing, a LPSI / SDC pump manual discharge isolation valve is closed and pump suction is aligned to the Safety Injection and Refueling Water tank. Palisades did not record pump unavailability during the LPSI / SDC pump surveillance test. Per Palisades Technical Specifications Basis the following guidance on pump Operability is given: "A SDC train may be considered OPERABLE (but not necessarily in operation) during re-alignment to, and when it is re-aligned for, LPSI service testing, if it is capable of being (locally or remotely) realigned to the SDC Mode of operation and is not otherwise inoperable. Since SDC is a manually initiated system, it need not be considered inoperable solely because some additional manual valve realignments must be made in addition to the normal initiation actions. Because of the dual functions of the components that compromise the LPSI and shutdown cooling systems, the LPSI alignment may be preferred." SDC is a manually aligned system with a design basis of approximately 20 minutes to initiate. Recovery from the test alignment is proceduralized and involves shutting down the pump in test, realigning three motor-operated valves from the control room and a 2 in. and 10 in. valve locally by auxiliary operators present in the room during the performance of the test, before the pump is manually restarted Should unavailability hours be recorded during Modes 5 and 6 when testing Shutdown Cooling Pumps (dual purpose Safety Injection Pumps) if the site technical specifications allow the pumps to remain operable during re-alignment to, and when it is re-aligned for, testing?*	*12/12 Introduced*	*Palisades*

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Response: *No The Palisades Technical Specifications Basis allows the pumps to remain operable during re-alignment to, and when it is re-aligned for, Low Pressure Safety Injection service or for testing. Based on NEI 99-02, Plant Specific Design issues, page D-6 of Appendix D, the required hours and unavailable hours will be determined by technical specification requirements, not default hours." In addition, considering that SDC is a manually initiated system by design and the length of time before the function was required, the actions to restore the function are simple and virtually certain to be successful.*		

DC Cook FAQ 32.3

Two Unit 2 reactor trips have been identified by the NRC Senior Resident Inspector (SRI) as potential Scrams With Loss of Normal Heat Removal (LONHR) in the Reactor Oversight Process. The events in question were not counted by Cook Nuclear Plant (CNP) in the LONHR performance indicator (PI) based on the plant's interpretation of the guidance provided in NEI 99-02, Regulatory Assessment Performance Indicator Guideline.

The purpose of the LONHR PI is to monitor more risk significant scrams that necessitate the use of mitigating systems. The indicator counts the number of scrams during the previous 12 quarters that also involved a loss of the normal heat removal path through the main condenser prior to establishing reactor conditions that allow use of the plant's normal long term heat removal systems. Guidance for data collection is provided by NEI 99-02 as amended by current approved FAQs. Revision 2 to NEI 99-02 contains the following clarifying note:

> *Operator actions or design features to control the reactor cooldown rate or water level,* such as closing the main feedwater valves or closing all MSIVs, are not reported in this indicator as long as the normal heat removal path can be readily recovered from the control room without the need for diagnosis or repair. However, operator actions to mitigate an off-normal condition or for the safety of personnel or equipment (e.g., closing MSIVs to isolate a steam leak) are reported.

A review of current approved FAQs indicates only one FAQ that would provide any further guidance for the CNP events. The FAQ is an Appendix D FAQ submitted by the Ginna Nuclear Station. An Appendix D FAQ provides resolutions to PI reporting issues that are specific to individual plant designs. This FAQ was approved March 2002 and provides the following guidance:

> **Question:**
> NEI 99-02 Rev 1, states in part on page 14, lines 11 - 14: "Intentional operator actions to control the reactor water level or cool down rate, such as securing main feedwater or closing the MSIVs, are not counted in this indicator, as long as the normal heat removal path can be easily recovered from the control room without the need for diagnosis or repair to restore the normal heat removal path."
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> Revision 1 added the wording "...as long as the normal heat removal path can be easily recovered from the control room without the need for diagnosis or repair to restore the normal hear removal path." to this statement.
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> If the MSIVs are closed to control cooldown rate following a scram or normal shutdown at our station, the MSIVs are not reopened. In Mode 3, Operators typically close the MSIVs as part of procedurally directed shutdown activities to assist in controlling the cooldown rate and pressurizer level, and to perform IST and Technical Specification required testing. Once the

Operators intentionally close the MSIVs, they, by procedure, do not reopen them. In fact, for normal plant shutdowns on 3/1/99 and 9/18/00, operators closed the MSIVs as early as 2 hours upon entering Mode 3. For two reactor trips, one on 4/23/99 from intermediate range issues and one on 4/27/99 from an OTDT issue, the MSIVs were closed for control purposes within ~10 minutes of the reactor trip as allowed by plant procedures. The secondary system was available in both of these instances.

The MSIV bypass valves at our station cannot be operated from the Main Control Board or anywhere else in the Control Room. Original design of our station's MSIVs requires an Aux Operator to open a bypass valve located at the MSIVs prior to reopening the MSIVs, thus requiring operator action outside the control room. This action is an operational task that is considered to be uncomplicated and is virtually certain to be successful during the conditions in which it is performed. However, it would require diagnosis, as it is not the normal procedural method for the Operators to control cooldown rate once the MSIVs are closed. Does the closure of the MSIVs, while in Mode 3 or lower, to control cooldown rate, pressurizer level, or to perform testing following a scram constitute a scram with loss of normal heat removal?

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

The answer to this FAQ matches our understanding of the implementation methodology to be applied when determining if a LONHR has occurred. In both of the instances under discussion, CNP never lost the ability to use the normal heat removal path of the condenser as the MSIVs were isolated as a result of procedure-driven cooldown limitations.

A description of the individual events that are under question follows with a discussion of the applicability to the NEI 99-02 guidance.

1. The first 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 blow down were isolated. At 9 minutes after the trip, 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 closing automatically 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 supply. A major contributor not identified in the trip response review for cooldown was the negligible decay heat remaining following a 40 day forced outage.

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 our 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 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. The AFW flow condition and low-flow preheating steam did not render the normal heat removal path unavailable since the conditions were readily recovered from the control room without the need for diagnosis or repair. It is the conclusion of CNP that the October 7, 2001, trip does not meet the criteria for a LONHR PI scram and is correctly accounted for in the ROP.

2. The second unplanned scram occurred on July 22, 2002, during full power operations. The trip was initiated through a turbine trip caused by low vacuum in the 2C Condenser. The low vacuum was considered a partial loss of vacuum, therefore was not counted a loss of heat removal. At 3 minutes after the trip, the operators performed a main steam isolation due to the lowering RCS pressure that approached the Safety Injection set point. This drop in RCS pressure is a design feature of Westinghouse plants with a large Tavg program. A rapid outsurge from the Pressurizer occurs when the RCS hot leg rapidly cools down from over 600 degrees to 547 degrees. In addition, the plant alignment of the Unit 1 and Unit 2 auxiliary steam loads to the Unit 2 main steam header (a normal plant configuration) enhanced the cooldown. No automatic valve action is available to switch the auxiliary steam loads from one unit to the next and requires an operator to manually switch the steam source.

The alignment of the auxiliary steam loads to the Unit 2 main steam system is the condition identified that caused the excessive cooldown. A review of plant trip response was performed to determine if the plant responded as expected and as per design. The plant RCS temperature and pressure response in July 2002 appears to be similar to historical trips.

The actions taken to control RCS cooldown were in accordance with the plant procedure in response to the trip. The closure of the MSIVs was to control the cooldown as directed by plant procedure and not to mitigate an off-normal condition or for the safety of personnel or equipment. The challenge to the SI setpoint is a plant design issue that has been evaluated separately. It is the conclusion of the team that the July 22, 2002, trip does not meet the criteria for a LONHR PI scram and is correctly accounted for in the ROP.

In conclusion, CNP responded as designed. The operators responded in accordance with procedures. No off-normal event occurred that precluded the use of the normal heat sink, and, in accordance with the FAQ, the local operation of the MSIV bypass valves does not warrant counting these events as a scram with LONHR. It is the intent of CNP to evaluate design changes and procedure enhancements to limit the post-trip normal cooldowns and preclude Main Steam isolation. These include:

- Revising the plant Emergency Operating Procedures (EOP) to allow earlier throttling of Auxiliary Feedwater flow. The current EOP's do not deviate from the Emergency Response Guidelines (ERG) in this area, hence are conservative.
- Processing a license amendment to revise the Safety Injection setpoint to a lower value thereby providing more margin during the plant's designed post-trip pressure drop.
- Re-validate simulator fidelity for the post-trip response and prioritize operator training in support of the EOP and SI setpoint revision.
- Preferential alignment of the auxiliary steam system to Unit 1. The preferential alignment takes advantage of the Unit 1's lower temperature control program.