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	LaSalle

Attachment 9

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?	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
		Response: No. As stated in NEI 99-02 Rev 2, page 16, lines 15-16 (and FAQ 249), the determining factor for this indicator is whether or not the normal heat removal path is available to the operators, not whether the operators choose to use that or some other path. The indicator excludes events in which the normal heat removal path through the main condenser is easily recoverable without the need for diagnosis or repair. In this event, since the turbine driven feed pumps remained available throughout the event and procedures were in place for their recovery from the control room, the normal heat removal path through the main condenser was easily recoverable without the need for diagnosis or repair.		

Temp No.	PI	Question/Response	Status	Plant/ Co.
28.5	MS01	Question: Treatment of Planned Overhaul Maintenance in the Clarifying Notes section of the Mitigating Systems Cornerstone, Safety System Unavailability, states that plants that perform on-line planned overhaul maintenance (i.e., within approved Technical Specification allowed Outage Time) do not have to include planned overhaul hours in the unavailable hours for this performance indicator under the conditions noted. This section further states that the planned overhaul maintenance may be applied once per train per operating cycle. EDG(s) at Prairie Island are on an 18 month overhaul frequency per T.S.4.6.A.3.a, while the plant operating cycles are typically a month or two longer. Thus, the EDG 18 month overhaul will occur twice in some cycles. If major overhauls, performed in accordance with the plant's technical specification frequency, result in more than one major overhaul being performed within the same operating cycle, can both of these overhauls be excluded from counting as planned unavailable hours? Response Yes, as long as the overhaul maintenance is completed within an established preventive maintenance program and the overhaul is completed within the specified technical specification frequency, the unavailable hours do not need to be counted.	2/28 Introduced 4/25 Discussed 6/12 Discussed	Prairie Island
28.6	OR01	Question: While in a high radiation area (HRA) removing scaffold, workers inadvertently dislodged lead shielding around a hot spot flush rig and created conditions that required posting a locked HRA (dose rates in excess of 1 rem per hour). Several minutes later when they moved to a location closer to the hot spot, the three scaffold workers received dose rate alarms. Upon receiving the alarms, they immediately left the area and the alarms cleared. After reading their dosimeters and verifying that they had not received any unexpected dose, they discussed the alarms with their supervisor and concluded that the momentary alarm was not unexpected since general area dose rates in the HRA could have caused the alarms. When the three workers attempted to log out of the RCA at the access control point, Health Physics (HP) discovered that all three individuals received a "Dose Rate" alarm on their electronic dosimeters. Independent from the ensuing exposure investigation, and approximately within the same time period (within minutes), a HP technician found radiation levels in excess of 1 rem per hour when performing a routine survey to support removal of the hot spot flush rig. The HP technician established proper controls and posting for the area and discovered that local shielding around the flush rig had been disturbed. Does this count against the technical specification high radiation area occurrence PI? Response: *Yes, because the circumstances represent the creation of a technical specification high radiation area (> 1,000 mrem/hour) without the proper corrective actions (i.e., posting and controls) being taken. The dosimeter alarms that occurred represented an opportunity for timely corrective action to be taken by Health Physics, i.e., to re-evaluate the radiological conditions in the area and establish proper controls and posting. The opportunity was "missed" when the workers did not promptly notify Health Physics about the dosimeter alarms. If Health Physics had been promptly notified and responded properly in a timely manner, this would not count against the PI.*	2/28/02 Introduced 3/21 Discussed 4/25 Tentative Approval. Answer discussion being drafted	St. Lucie
28.10	MS01 -04	Question The guidance in the unavailability portion of NEI 99-02 states that operator actions to recover from an equipment malfunction or an operating error can be credited if the function can be promptly restored from the control room by a qualified operator taking an uncomplicated action (a single action or a few simple actions) without diagnosis or repair (i.e. the restoration actions are virtually certain to be successful during accident conditions). In this context, what does the word "diagnosis" mean?	2/28 Introduced 3/21 To be rewritten 4/25 Discussed 6/12 Discussed	PSEG

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

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		Industry Proposed Response: Essential to understanding that a PAR opportunity exists, is the need to realize that it is a regulatory requirement for a licensee to develop and communicate a PAR when EPA PAG doses may be exceeded beyond the 10-mile plume exposure pathway EPZ. Accordingly, if a scenario objective identifies that dose assessments support the need for PAR development beyond the 10 mile plume exposure EPZ, then the licensee shall develop and communicate such PAR. It is expected that this PAR development and communication has been contemplated by the scenario with an expectation for success and criteria provided. With all that in place, this constitutes a PI opportunity as defined in NEI 99-02. It should be noted that the licensee has the latitude to identify PI opportunities prior to the exercise and may choose to not include a PAR beyond the plume EPZ as a PI opportunity due to its ad hoc nature. Also, separate from the identification of the PAR development, is a PI opportunity associated with the timeliness of the communication of the PAR. Again, the licensee has the latitude to identify the timeliness of the communication as a PI opportunity or not. However, whether a PI opportunity is identified or not, it does not relinquish the evaluation by the NRC and the licensee of the PAR development and its timely ~~communication~~. Further, the NRC will ~~evaluate~~ the subsequent ability of the licensee to identify ~~and~~ critique ~~unacceptable~~ exercise performance with regard to PAR development and communication. *See send of this document for NRC Proposed Response.*		
	2		*deleted*	
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	
		Response: No. The evaluation of the DEP opportunities is a crew evaluation for the entire Emergency Response Organization. Key ERO members may receive credit for the drill if their participation is a meaningful opportunity to gain proficiency in their ~~assigned position~~ *ERO function.*		

Temp No.	PI	Question/Response	Status	Plant/ Co.
30.2	MS01	Appendix D Question: NEI 99-02, Revision 1, in the Clarifying Notes for the Mitigating Systems Cornerstone, allows a licensee to not count planned unavailable hours under certain conditions when testing a monitored system. At our two-unit PWR station, three EDGs provide emergency AC power. There is one dedicated diesel for each unit and one swing diesel available for either unit. During the monthly surveillance testing required by Technical Specifications, there is an approximate four-hour period when the EDG is run for the operational portion of the test and is inoperable but available. In 2001, surveillance-testing procedures were revised to take credit for restoration actions that would enable not counting the hours as unavailable. The restoration actions for the two dedicated diesels during the approximate four-hour period consist of implementing a "contingency actions" attachment to the test procedure. This process verifies system alignment and places the EDG on its emergency bus. The steps allow the dedicated control room operator to change the emergency generator auto-exercise selector from exercise to auto, verify or place the emergency supply switch in auto, depress the emergency generator fast start reset button and adjust the engine speed and voltage as necessary. The process steps are, individually and collectively, simple and done by a dedicated operator. The last step requires the governor speed droop control to be adjusted to zero. However, the speed droop adjustment is not required for the EDG to satisfy its safety function. This step is performed to relieve the dedicated operator and does not challenge operation or control of the EDG. Question (1); can credit be taken during the restoration actions that require only one dedicated control room operator (no other assigned duties) resulting in not counting the unavailable hours during this portion of the testing of the dedicated EDGs? The restoration actions for the swing diesel also consist of implementing a "contingency actions" attachment to the test procedure with a few minor differences. Three additional steps determine which emergency bus the swing EDG needs to be aligned to before placing the swing EDG on that emergency bus. The rest of the actions are identical to the dedicated EDG explanation described above. Question (2); can credit be taken for these restoration actions that require only one dedicated control room operator (no other assigned duties) resulting in not counting the unavailable hours during this portion of the testing of the swing EDG? Response: No credit can be taken for restoration actions in these cases.	5/22 Introduced 6/12 Discussed 8/22 Tentative Approval. Answer being redrafted by NRC.	Surry
30.3	EP01	Question: Should the follow up PAR change notifications be counted as four inaccurate notifications for the situation described below? A drill was conducted which included opportunities for Classification, Notification and PARs. The initial Notification for the General Emergency and the associated PAR contained the accurate Time Event Declared of the classification. On follow up PAR change notifications (4), the Time Event Declared block was completed with the time of the PAR data instead of the time the GE was declared. The initial GE Event notification contained the proper time. There were four PAR changes made. The PAR, MET and other required information was accurate. Each PAR developed was accurate. The time the PAR was developed was accurate on the form. Once a General Emergency was accurately declared, and the INITIAL notification was made in a timely and accurate manner, changing of the time in the Time Event Declared block on the follow up notifications had no influence on the event initiation, nor did it result in untimely or inaccurate PARs being issued to the states and counties. Changing of the time in follow up PAR change notifications did not impact their response since the states and counties were provided the accurate time of event declaration in the initial notification. No additional events were declared since the plant was already at the GE classification. This issue was critiqued and actions were taken to ensure the time desired for the Time Event Declared block on the form was communicated to those responsible for completing the form	5/22 Introduced 6/12 Discussed 9/26 Tentative Approval	OPPD

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		Response: No. Based on the example above, the 4 of 5 notifications should be counted as successful. Since it was the same error in 4 follow-up notifications, it should only be counted once since it was in the same exercise. Note: if the same crew made the same mistake in a subsequent exercise, it would be counted as a separate missed opportunity.		
30.4	MS01	Question: The St. Lucie Station programmatically maintains and manages risk associated with overhaul maintenance performed within Technical Specification Allowed Outage Times (AOTs). The program implements Regulatory Guide 1.177 and/or NUMARC 93-01 requirements for risk management during the maintenance activities. All work to be accomplished during a planned overhaul is scheduled in advance and includes maintenance activities that are required to improve equipment reliability and availability. St. Lucie considers overhaul maintenance as those overhaul activities associated with the major component as well as pre-planned corrective and preventive maintenance on critical subcomponents. For example, the EDG preventive maintenance program requires hydrostatic testing of the lube oil cooler every 12 years and the subsequent repair or replacement of the cooler as necessary. The purpose of the hydrostatic test is to pre-emptively reveal defects to preclude a run-time failure by applying far more pressure to the lube oil cooler than would be experienced during normal operation. This test was a scheduled item during a planned EDG overhaul, and the lube oil cooler did not pass the hydrostatic test. The lube oil cooler replacement was not included as a scheduled contingency item, nor was a replacement cooler on-site. However, replacement coolers of this type were known to be readily obtainable. The original overhaul duration was extended by the time needed for procurement and installation of a replacement lube oil cooler. Do the additional hours count as planned overhaul maintenance hours?	5/22 Introduced 6/12 Discussed 8/22 Discussed 9/26 Tentative Approval	St. Lucie
		Response: No.. When problems are discovered that are due to a licensee performance deficiency, and resolution of that problem results in additional hours beyond those scheduled for the overhaul, the additional hours must be counted. In this case, the licensee's RT examination of the lube oil cooler to determine its susceptibility to failure during the planned hydrostatic test was faulty. That examination led them to erroneously conclude that their cooler was of a more robust design than it actually was and that it was not susceptible to failure. This deficiency resulted in an unplanned extension to the planned overhaul.		
30.5	MS01	Question: The overhaul of the EDG fuel priming pump was planned corrective maintenance and was scheduled as part of the overall overhaul activities for the EDG. Post maintenance testing revealed that parts installed in the fuel oil priming pump during the overhaul did not result in optimal performance. Although the pump operation would not have prevented the fuel oil priming pump from fulfilling its required safety function, the decision was made to rework the pump to recover pump performance. The rework resulted in extending the overhaul past its originally scheduled time. Does the maintenance rework count as planned overhaul maintenance?	5/22 Introduced 6/12 Discussed 8/22 Discussed 9/26 Hold for generic response. *Need to discuss intent of planned overhaul and PMT.*	St. Lucie
		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.		

Temp No.	PI	Question/Response	Status	Plant/ Co.
30.6	MS05	Question: Review of the Safety System Functional Failure Performance Indicator (PI) by the NRC Resident Inspector questioned whether Indian Point 2 LER 2000-006 should have been counted as a functional failure. Regardless of whether this LER constitutes a functional failure or not, there would be no PI threshold change. LER 2000-006 was submitted to the NRC on September 5, 2000. The LER is entitled “Source Range Detector High Flux Trip Circuitry Outside of Plant Design Basis Due To Revised Local Cabinet Temperature Uncertainty.” This LER was coded as 10 CFR 50.73(a)(2)(ii). The LER determined the cause of the plant being outside the design basis was the temperature errors associated with the maximum control room design temperature were not explicitly accounted for when the setpoint was changed in 1973. There were no safety consequences associated with this LER since: • The IP-2 Tech Specs do NOT include any reactor trip set point limits for the NIS source range detectors, • The source range high flux trip is NOT credited in any UFSAR Chapter 14 accident analysis, and • The intermediate and power range flux trips would be available to provide for termination of a power excursion during a reactor startup or low power operation. The review of this LER did not determine this was a safety system functional failure since the source range high flux trip is not relied on in the UFSAR. Additional information: • NEI 99-02, Revision 1 refers to 10 CFR 50.73(a)(2)(v). It does state that paragraphs (a)(2)(i), (a)(2)(ii), and (a)(2)(vii) should also be reviewed for applicability for this PI (these were reviewed and the determination was only section (a)(2)(ii) was applicable), • NEI 99-02, Revision 1 also refers to NUREG-1022 for additional guidance that is applicable to reporting under 10 CFR 50.73(a)(2)(v), • NUREG-1022, Revision 2, section 3.2.7, at page 54 defines “safety function” as those four functions listed in the reporting criteria…as described or relied on in the UFSAR and • NUREG-1022 also adds at page 54, “or required by the regulations.” Regulations are being interpreted to include technical specifications Is it the intent of NEI 99-02 to solely report safety system functional failures as described or relied on in the UFSAR or is it the intent to additionally incorporate the guidance in NUREG-1022, section 3.2.7 that the failure of any component addressed in the plant’s Technical Specification constitutes a safety system functional failure whether credited or not in the UFSAR chapter 14 analyses? Licensee Response. Since only SSCs credited in the UFSAR are intended or expected by the NRC PI program to meet the four reporting criteria (A)-(D) listed at page 67 of NEI 99-02 and page 52 of NUREG-1022, the phrase, ‘or required by the regulations,’ at page 54 of NUREG-1022 is an unintended application of NUREG-1022 to the NRC PI and should be disregarded for purposes of the NRC PI, safety system functional failures. Recommended Response: It is inappropriate for the FAQ process to interpret regulatory guidance in NUREG 1022. This question must be addressed by the NUREG 1022 process owner.	5/22 Introduced 6/12 Discussed 9/26 Discussed	IP 2
30.8	IE02	Question. Many plant designs trip the main feedwater pumps on high reactor water level (BWRs), and high steam generator water level or certain other automatic trips (PWRs). Under what conditions would a trip of the main feedwater pumps be considered/not considered a scram with loss of normal heat removal?	5/22 Introduced 6/12 Discussed 9/26 Discussed.	Generic

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		Response: For loss of all main feedwater due to high water level, or other design trips, the following guidance applies: 1. If all of the main feedwater pumps are not recoverable due to a problem in the feedwater system that requires repair actions, the condition is a scram with loss of normal heat removal. 2. If all main feedwater pumps are not available, and repair actions are required to restore at least one normal main feedwater pump, the condition is a scram with loss of normal heat removal. 3. If the main feedwater pumps are not needed but procedures call for the pumps to be started if needed and it is determined that at least one pump would have restored feedwater flow, the condition is NOT a scram with loss of normal heat removal. 4. If the main feedwater pumps are needed and no main feedwater pumps are able to restore flow, then the condition is a scram with loss of normal heat removal. 5. If the main feedwater pumps are needed and at least one main feedwater pump would have been able to restore flow, it is NOT a scram with loss of normal heat removal. 6. If the main feedwater pumps are secured following a scram in accordance with emergency operating procedures to reduce the steam load on the reactor, it is NOT a scram with loss of normal heat removal. For the conditions NOT to be a scram with loss of normal feedwater, at least one main feedwater pump must be capable of being recovered without the need for repair and diagnosis. The main feedwater pumps must be able to be restarted from the control room with normal monitoring/startup actions by an auxiliary operator dispatched locally.		
31.3	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	Hatch
		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.		

Temp No.	PI	Question/Response	Status	Plant/ Co.
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?	7/2 Introduced	Beaver Valley
		Response: No. The program functioned as intended and the requirements of Part 26 were met.		
31.5	MS04	Question Appendix D Sequoyah Nuclear Plant (SQN) has two units. Each Unit has three trains of AFW, two motor driven trains (A train and B train), and one turbine driven train (Terry Turbine train, A or B train power). All three trains have Level Control Valves (LCVs) that are the steam generator injection valves. The LCVs are normally closed, air operated valves that auto open when AFW receives a start signal. The valves fail open when air is removed from them. SQN uses Control Air as the normal air supply to the LCVs. Control Air is not a seismically qualified, 1E system. Auxiliary Air is the LCV's standby, safety related air supply. A train Auxiliary Air feeds two Terry Turbine train LCVs and the two motor driven A train LCVs. B train Auxiliary Air feeds the other two Terry Turbine train LCVs and the two motor driven B train LCVs. Auxiliary Air automatically starts whenever the Control Air pressure drops below its setpoint The Terry Turbine train LCVs also have accumulator tanks and high pressure air cylinders to control them during a loss of all power. The Terry Turbine train LCVs can be controlled from the main control room for one hour after the loss of all air using the accumulator tanks. For all scenarios except a major secondary system pipe rupture, the fail open LCVs are conservative, as they allow AFW to deliver the required flow. During a major secondary system pipe rupture, AFW is required to be isolated from the faulted steam generator. In the absence of both Control Air and Auxiliary Air, manual action at the LCVs will have to be taken to isolate the corresponding motor driven AFW train from the faulted steam generator. This action is proceduralized in Emergency Procedures and Abnormal Operating Procedures. The PSA also models the AFW system as available while Auxiliary Air is taken out of service. Since the PSA models the AFW system as available while Auxilary Air is unavailable (gives credit for the manual isolation of motor driven AFW trains) and the manual actions are proceduralized and trained on, is it correct to be consider the affected train(s) of AFW as still available during the periods when Auxiliary Air is taken out of service?	8/22 Introduced	Sequoyah
		Response. 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.		

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	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	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. 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.	9/26 Introduced	DC Cook

Temp No.	PI	Question/Response	Status	Plant/ Co.
32.1	MS02	Question: The PVNGS High Pressure Injection System has two trains with two cold leg injection flowpaths and one hot leg injection flowpath per train. High Pressure Safety Injection is automatically initiated by a Safety Injection Actuation Signal (SIAS) and following a SIAS, full HPSI flow is directed to the RCS cold legs However, for long term cooling, HPSI flow is manually re-aligned for simultaneous hot and cold leg injection. This requires manual balancing of HPSI hot and cold leg flow by throttling the HPSI hot leg injection valves for proper balance. Balancing the hot and cold leg injection flows during long term cooling provides flushing to prevent the development of boric acid crystals in the core cooling passages and ensures ultimate sub-cooling of the core independent of the break location. Emergency Operating Procedures (EOPs) direct this manual balancing of hot and cold leg injection flows be accomplished using hot leg injection flow indicators available in the control room. There is only one flow instrument in each hot and cold leg injection flowpath available for post accident monitoring of HPSI hot and cold Leg Injection flow. Although PVNGS Emergency Operating Procedures direct that flow balance be achieved using the hot leg flow instrument (and do not describe using only cold leg indication for this purpose), flow balance could be achieved using only cold leg flow instruments if the hot leg indicator for the train were unavailable. Palo Verde Technical Specifications permit one hot and one cold leg flowmeter to be inoperable for up to 30 days and two hot leg and two cold leg flowmeters to be inoperable for up to 7 days. NEI 99-02 defines the monitored function for HPSI to be "the ability to take a suction from the primary water source or containment sump and inject into the reactor coolant system at rated flow and pressure". This function is accomplished automatically following a SIAS through cold leg injection alone, but for longer term cooling, could be construed to include hot leg injection and flow balance capability. Should the failure or unavailability of a of a hot leg flow indicator (or any other component used only to achieve flow balance between cold and hot leg injection) be included as unavailability of the affected HPSI train?	9/26 Introduced deleted	Palo Verde
		Response: No, the ability to achieve the appropriate balance between cold and hot leg injection should not be included as part of the monitored HPSI function. The failure or unavailability of a hot leg flow indicator (or other component used only to achieve flow balance between cold and hot leg injection) should not be included as unavailability for the affected HPSI train since. • The automatic functions of the train are not affected • The ability to take a suction from the primary water source or containment sump and inject into the reactor coolant system at rated flow and pressure through the cold leg injection flowpaths would not be affected. • Balancing hot and cold leg flow is a manual activity and regulatory oversight of a plants ability to successfully accomplish these types of activities is more appropriately addressed using the Significance Determination Process rather than the Mitigating System ROP Performance Indicator.		

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	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?* *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.*	10/31 Introduced	*DC Cook*

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 Introduced	Millstone 2
		Response: *Based on the required availability of the CAR System in mode 3, the Millstone 2 preference would be to continue to maintain the current 99-02 methodology with the understanding that frequent plant shutdowns or associated mode 3 repairs would 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*	*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*	*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?*	*10/31*	*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.*		

~~NRC proposed Response to 29.5:~~

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

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

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

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

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

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

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

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

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

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

29.5 NRC version for 10/31

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

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

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

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

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

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

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

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

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