Review and Evaluation Of The MSPI Pilot Program

MSPI Public Meeting Presentation

March 24, 2004

Inspection Program Branch
Division of Inspection Program Management
Office of Nuclear Reactor Regulation

Attachment 3

Background

- Problems with the Safety System Unavailability (SSU) PIs warranted the need to search for a replacement performance indicator (PI).

- In 2001, a Reactor Oversight Program (ROP) Working Group Subcommittee formed to develop a replacement PI (Mitigating Systems Performance Index, MSPI) that would meet stated goals and objectives.

- A one year MSPI pilot program was initiated in 2002 at 9 sites (20 units); completed in the fall of 2003.

- Internal/external stakeholders provided comments on whether the MSPI should be fully implemented.

- There have been 33 public meetings and two public workshops on MSPI since February, 2001.

- Since December, 2003, industry and staff have agreed that there is enough information to make a decision on MSPI.

Objectives of the MSPI Pilot

- To develop a PI that would be a better PI than the SSU PI

- To understand and minimize the differences between the MSPI, probabilistic risk analyses (PRAs), Standardized plant analysis risk (SPAR), significance determination process (SDP), and the Maintenance Rule.

- To perform benchmarking analyses and comparison studies to verify the mechanics of the MSPI.

- To understand compatibility issues with the ROP and to identify unintended consequences, if any.

MSPI Pilot Assessment and Conclusions

- MSPI, SSU and SDP comparisons were difficult because each tool had different definitions and measured different outputs.

- Staff needed to upgrade SPARs for pilot plants in order to perform an adequate comparison study between SPAR and MSPI.

- SPAR/MSPI comparison studies conducted during the pilot revealed some differences with PRA that could affect MSPI results. Most changes resulted in revising SPAR models. There were a few significant issues identified where the licensee should have made a change, but no effort was made to resolve the difference.

- Staff determined that significant inspection resources needed to perform the temporary instruction (TI) for each pilot plant.

- Significant Regional concerns – SRA/resident inspectors time.

Inspection/Assessment/Enforcement

- The most important defining characteristic of the SDP is that it elevates potentially risk-significant issues associated with performance deficiencies early in the ROP process.

- As currently constructed, MSPI is designed to detect statistically significant adverse trends over a three year period without regard to the presence of a performance deficiency such that it may not meet the stated characteristic of the ROP.

- The ROP Inspection Program is designed to focus on the risk significance of performance deficiencies and to evaluate/understand their root causes and corrective action. Implementing MSPI would not direct the inspection program to focus on evaluating performance deficiencies associated with simple single failures under certain conditions/failures.

- Enforcement policy tied to individual event significance, not integrated accrued risk.

Impact of MSPI on ROP PI Program

- Significant inspection resources required for initial MSPI implementation and long term inspection and oversight.

- Although use of pre-defined (staff-reviewed) success criteria will help to reduce the number of disputes and frequently asked questions (FAQs), the expectation for MSPI is that its complexity, differences over system boundary definitions, use of PRA assumptions and plant data used in calculating Fussel-Vesely coefficients, and lacking a suitable PRA standard, will generate FAQs.

- Significant differences between SPAR and PRA that go unresolved could reduce public confidence and generate frequently asked questions (FAQs).

- Periodic PRA updates will require additional staff hours to evaluate.

Inspection Resource Impacts

- Substantial NRC resources will be required for initial MSPI implementation
  - Regional inspector training (minimal 3-5 days of training, permanent training course to be developed)
  - Public workshops (three separate workshops planned)
  - Temporary instruction for inspectors to assess adequacy of implementation of MSPI (estimated at approximately 200 hours per dual unit site, extrapolated from pilot TI experience and accounting for use of a risk-informed checklist developed from pilot experience)
  - Contract expenditures related to SPAR enhancements for non-pilot plants (approx. 2-3 million for remaining non-pilot plants)
  - Resolving MSPI-related FAQs during initial implementation (8-12 hours/month/hq), and 4-6 hours/month/region)

MSPI Conclusion

- Benefits gained from a risk-informed MSPI are offset by:
  - Inspector verification of MSPI competes with time available to inspect safety issues.
  - High costs to implement.
  - High costs to provide for long term oversight (onsite verification and FAQs).
  - Incompatible with ROP goals for prompt risk assessment of performance deficiencies.
  - Efficiency increases may not be realized due to need to evaluate LERF and external events by SDP.
  - Complexity, lack of transparency and access to data and PRA-specific information by the public may reduce public confidence.
  - Significant enforcement program impact.

- Not clear if MSPI would have a significant impact on ROP assessment (action matrix) results.

- Significant resource impact on regions (SRAs and inspectors) – regions have been heavily involved in development and assessment of MSPI.

- Several RIS 02-14 MSPI Success Criteria and agency goals were not met.

- <u>**Decision:**</u> **Terminate development and implementation of MSPI.**

Attachment 4

DRAFT (Industry)

STEAM GENERATOR SIGNIFICANCE DETERMINATION PROCESS

Minor Violations/Issues

Minor violations are below the significance of Severity Level IV violations, and violations associated with green SDP findings, and are not the subject of enforcement action. The failure to implement a requirement that has insignificant safety and regulatory consequences should normally be categorized as a minor violation. While licensees must correct minor violations, minor violations do not normally warrant documentation in inspection reports or inspection records and do not warrant enforcement action.

NRC Inspection Manual Chapter 0612 provides guidance for determining whether issues identified under the reactor oversight process are minor. Where a licensee does not take corrective action or willfully commits a minor violation, the circumstances will result in categorization at least at Severity Level IV or associated with a least a green SDP finding, and consideration of an NOV requiring a formal written response from the licensee.

Examples of different categories of violations that may be considered minor include, but are not limited to:

a. Record keeping issues - issues that do not preclude the licensee from being able to take appropriate action on safety-significant matters or properly assessing, auditing, or otherwise evaluating its safety-significant activities.

b. Licensee administrative requirement/limit issues - cases where licensees exceed administrative limits, limits that licensees impose upon themselves that are more conservative than regulatory limits.

c. Insignificant dimensional, time, calculation, or drawing discrepancies - characterized by minor discrepant values referred to in either the licensee's Final Safety Analysis Report (FSAR) or design documents.

d. Insignificant procedural errors - procedural errors or inadequate procedures that have no impact on safety equipment or personnel safety.

e. Work in progress findings - for the purposes of enforcement, "work in progress" is defined as any violation occurring and identified in the course of performing work or maintenance on equipment that is out of service or declared inoperable per the technical specifications and has no safety consequences, and the violation is identified and corrected prior to returning the equipment to service and/or declaring the equipment operable. Errors that occur on non-designated pieces of equipment, such as inadvertently or mistakenly operating a different train of the equipment, or errors that cause another requirement (e.g., technical specifications) to be violated, are not considered minor by this definition.

f. Minor changes to requirements - a failure to meet 10 CFR 50.59 requirements that involves a change to the FSAR description or procedure, or involves a test or experiment not described in the FSAR, where there was not a reasonable likelihood that the change would ever require NRC approval per 10 CFR 50.59. A failure to meet 10 CFR 50.71(e) by not updating the FSAR, where the failure would not have a material impact on safety or licensed activities. The focus of the minor violation is not on the actual change, test, or experiment, but on the potential safety role of the system, equipment, etc. that is being changed, tested, or experimented on.

In all cases, minor violations should have negligible actual safety consequences, little to no potential to impact safety, little to no impact on the regulatory process, and no willfulness. The following examples apply the above guidance and demonstrate a thought process that can be used in making the determination of whether a violation is minor.

<u>Examples of Minor Violations/Issues Relating to Steam Generator Inspections</u>

1. <u>Record Keeping Issues</u>

   a. In the Steam Generator Report, the licensee reported eddy current test results. The NRC later discovered that some of the information was entered erroneously.

      The violation: Under 10 CFR 50.9, the licensee is required to provide complete and accurate information in all material respects.

      Minor because: This is a failure to include accurate information that has no safety consequences.

      Not minor if: The omission was shown to be deliberate.

   b. An inspector found that a licensee was missing a steam generator tube eddy current record.

      The violation: Eddy current records are required by plant procedures (i.e., through License Condition, Technical Safety Requirements, or Technical Specifications).

      Minor because: The record is missing, but the eddy current testing was actually performed.

      Not minor if: The tube was not tested.

2. <u>Licensee Administrative Requirement/Limit Issues</u>

   An inspector found that a licensee failed to plug a steam generator tube at the licensee's administrative limit.

The violation: Failure to identify and plug a tube as required by plant procedures (i.e., through License Condition, Technical Safety Requirements, or Technical Specifications).

Minor because: The licensee conservatively set their internal plugging criteria below the required NEI performance criteria, the tube integrity was satisfactory and would meet all performance criteria (e.g., >3dP) over the entire fuel cycle.

Not minor if: The tube would not have meet the NEI performance criteria over the entire fuel cycle or exceed the NEI tube plugging performance criteria.

3. Nonsignificant Dimensional, Time, Calculation, or Drawing Discrepancies

An inspector's review of steam generator testing results from a previous outage concluded that a licensee did not identify steam generator tube flaws.

The violation: The licensee is required to identify all significant steam generator tube flaws exceeding the NEI performance criteria.

Minor because: The licensee used the state of the art technology in performing the steam generator inspection. It is expected that technology will improve and licensees are encouraged to adopt new technology as it becomes available; but licensees will not be cited for failing to identify flaws that could not be reasonably detected using then-current Industry-accepted testing methodologies.

Not minor if: The licensee failed to properly use their existing testing equipment and/or misread their testing results, such that they failed to identify and plug a tube that exceeded the NEI tube plugging performance criteria.

4. Insignificant Procedural Errors

An inspector observed that a licensee failed to follow the required procedure steps as written during a steam generator tube inspection.

The violation: Failure to follow plant procedures (i.e., through License Condition, Technical Safety Requirements, or Technical Specifications).

Minor because: While the licensee personnel failed to follow procedures, the testing accuracy and results were not compromised.

Attachment 5

Examples of "Minor" SG Tube Integrity Findings

1. An inspection reveals a flaw that does not violate any tube integrity requirements, but review of the data from the previous inspection, together with the data from the current inspection, indicate that there was a flaw with a depth >40% of the wall thickness at the time of the previous inspection. (Presumes both inspections were not deficient in other respects.)

2. During operation, a tube leak exceeds the operational leakage limit in the technical specifications, but physical examination of the flaw determines that it was not of a type or was not in a location that makes it potentially capable of causing tube rupture or sufficient leakage to alter the outcome of accident sequences.

3. A tube that was scheduled for inspection was missed (not inspected). (Presumes subsequent inspection indicates that it continues to meet integrity criteria.)

TempNo.	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: The ROP working group is currently working to prepare a response.	1/25 Introduced 2/28 NRC to discuss with resident 4/25 Discussed 5/22 On hold 6/12 Discussed. Related FAQ 30.8 9/26 Discussed 10/31 Discussed	LaSalle
28.3	IE02	Question: This event was initiated because a feedwater summer card failed low. The failure caused the feedwater circuitry to sense a lower level than actual. This invalid low level signal caused the Reactor Recirculation pumps to shift to slow speed while also causing the feedwater system to feed the Reactor Pressure Vessel (RPV) until a high level scram (Reactor Vessel Water Level – High, Level 8) was initiated. Within the first three minutes of the transient, the plant had gone from Level 8, which initiated the scram, to Level 2 (Reactor Vessel Water Level – Low Low, Level 2), initiating High Pressure Core Spray (HPCS) and Reactor Core Isolation Cooling (RCIC) injection, and again back to Level 8. The operators had observed the downshift of the Recirculation pumps nearly coincident with the scram, and it was not immediately apparent what had caused the trip due to the rapid sequence of events. As designed, when the reactor water level reached Level 8, the operating turbine driven feed pumps tripped. The pump control logic prohibits restart of the feed pumps (both the turbine driven pumps and motor driven feed pump (MFP))	3/21 Discussed 4/25 Discussed 5/22 Modified to reflect discussion of 4/25, On Hold 6/12 Discussed. Related FAQ 30.8	Perry

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		until the Level 8 signal is reset. (On a trip of one or both turbine feed pumps, the MFP would automatically start, except when the trip is due to Level 8.) All three feedwater pumps (both turbine driven pumps and the MFP) were physically available to be started from the control room, once the Level 8 trip was reset. Procedures are in place for the operators to start the MFP or the turbine driven feedwater pumps in this situation. Because the cause of the scram was not immediately apparent to the operators, there was initially some misunderstanding regarding the status of the MFP. (Because the card failure resulted in a sensed low level, the combination of the recirculation pump downshift, the reactor scram, and the initiation of HPCS and RCIC at Level 2 provided several indications to suspect low water level caused the scram.) As a result of the initial indications of a plant problem (the downshift of the recirculation pumps), some operators believed the MFP should have started on the trip of the turbine driven pumps. This was documented in several personnel statements and a narrative log entry. Contributing to this initial misunderstanding was a MFP control power available light bulb that did not illuminate until it was touched. In fact, the MFP had functioned as it was supposed to, and aside from the indication on the control panel, there were no impediments to restarting any of the feedwater pumps from the control room. No attempt was made to manually start the MFP prior to resetting the Level 8 feedwater trip signal. Regardless of the issue with the MFP, however, both turbine driven feed pumps were available once the high reactor water level cleared, and could have been started from the control room without diagnosis or repair. Procedures are in place to accomplish this restart, and operators are trained in the evolution. Since RCIC was already in operation, operators elected to use it as the source of inventory, as provided for in the plant emergency instructions, until plant conditions stabilized. Should this event be counted as a Scram with a Loss of Normal Heat Removal?		
		Response: The ROP working group is currently working to prepare a response.		
30.8	IE02	Question: Many plant designs trip the main feedwater pumps on high reactor water level (BWRs), and high steam generator water level or certain other automatic trips (PWRs). Under what conditions would a trip of the main feedwater pumps be considered/not considered a scram with loss of normal heat removal?	5/22 Introduced 6/12 Discussed 9/26 Discussed. 10/31 Discussed	Generic
		Response: The ROP working group is currently working to prepare a response.		
32.3a	IE02	Question: An unplanned scram occurred October 7, 2001, during startup following an extended forced outage. The unit was in Mode 1 at approximately 8% reactor power with a main feed pump and low-flow feedwater preheating in service. The operators were preparing to roll the main turbine when a reactor tripped occurred. The cause of the trip was a loss of voltage to the control rod drive mechanisms and was not related to the heat removal path. Main feedwater isolated on the trip, as designed, with the steam generators being supplied by the auxiliary feedwater (AFW) pumps. At 5 minutes after the trip, the reactor coolant system (RCS) temperature was 540 degrees and trending down. The operators verified that the steam dumps, steam generator power operated relief valves, start-up steam supplies and blowdown were isolated. Additionally, AFW flow was isolated to all Steam Generators as allowed by the trip response procedure. At 9 minutes after the trip, with RCS temperature still trending down, the main steam isolation valves (MSIV) were closed in accordance with the reactor trip response procedure curtailing the cooldown. The RCS cooldown was attributed to steam that was still being supplied to low-flow feedwater preheating and #4 steam generator AFW flow control valve not automatically moving to its flow retention position as expected with high AFW flow. The low-flow feedwater preheating is a known steam load during low power operations and the AFW flow control issue was identified by the control room balance of plant operator. The trip response procedure directs the operators to check for and take actions to control AFW flow and eliminate the feedwater heater steam supply.	1/23 Revised. Split into two FAQs 3/20 Discussed 5/1 Discussed 5/22 Tentative Approval 6/18 Discussion deferred to July 7/24 Discussed	DC Cook

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		When this trip occurred the unit was just starting up following a 40 day forced outage. The reactor was at approximately 8% power and there was very little decay heat present following the trip. With very little decay heat available, the primary contribution to RCS heating is from Reactor Coolant Pumps (RCPs). Evaluation of these heat loads, when compared to the cooling provided by AFW, shows that there is approximately 3.5 times as much cooling flow provided than is required to remove decay heat under these conditions plus pump heat. This resulted in rapid cooling of the RCS and ultimately required closure of the MSIVs. Other conditions such as low flow feedwater preheating and the additional AFW flow due to the AFW flow control valve failing to move to its flow retention setting contributed to this cooldown, but were not the primary cause. Even without these contributors to the cooldown, closure of MSIVs would have been required due to the low decay heat present following the trip. It should also be noted that the conditions that are identified as contributing to the cooldown are not conditions which prevent the secondary plant from being available for use as a cooldown path. The AFW flow control valve not going to the flow retention setting increases the AFW flow to the S/G, and in turn causes an increase in cooldown. This condition is corrected by the trip response procedure since the procedure directs the operator to control AFW flow as a method to stabilize the RCS temperature. With low-flow feedwater preheating in service, main steam is aligned to feedwater heaters 5 and 6 and is remotely regulated from the control room. Low-flow feedwater preheating is used until turbine bleed steam is sufficient to provide the steam supply then the system is isolated. There are no automatic controls or responses associated with the regulating valves, so when a trip occurs, operators must close the regulating valves to secure the steam source. Until the steam regulating valves are closed, this is a steam load contributing to a cooldown. The low-flow preheating steam supplies are identified in the trip response procedure since they are a CNP specific design issue. The actions taken to control RCS cooldown were in accordance with the plant procedure in response to the trip. The primary reason that the MSIVs were required to be closed was due to the low level of decay heat present following a 40 day forced outage. The closure of the MSIVs was to control the cooldown as directed by plant procedure and not to mitigate an off-normal condition or for the safety of personnel or equipment. With the low decay heat present following the 40 day forced outage, there would not have been a need to reopen the MSIVs prior to recommencing the startup. Should the reactor trip described above be counted in the Unplanned Scrams with Loss of Normal Heat Removal Performance Indicator?		
		Response: Yes. The licensee's reactor trip response procedure has an "action/expected response" that reactor coolant system temperature following a trip would be stable at or trending to the no-load Tavg value. If that expected response is not obtained, operators are directed to stop dumping steam and verify that steam generator blowdown is isolated. If cooldown continues, operators are directed to control total feedwater flow. If cooldown continues, operators are directed to close all steam generator stop valves (MSIVs) and other steam valves. During the unit trip described, the #4 steam generator auxiliary feedwater flow control valve did not reposition to the flow retention setting as expected (an off normal condition). In addition, although control room operators manually closed the low-flow feedwater preheat control valves that were in service, leakage past these valves (a pre-existing degraded condition identified in the Operator Workaround database) also contributed to the cooldown. Operator logs attributed the reactor system cooldown to the #4 AFW flow control valve failure as well as to steam being supplied to low-flow feedwater preheating. As stated above, the trip response procedure directs operators to control feedwater flow in order to control the cooldown. Operator inability to control the cooldown through control of feedwater flow as directed is considered an off normal condition. Since the cooldown continued due to an off normal condition, operators closed the MSIVs, and therefore this trip is considered a scram with loss of normal heat removal.		
34.6	IE02	Question: Should the following event be counted as a scram with loss of normal heat removal? STP Unit Two was manually tripped on Dec. 15, 2002 as required by the off normal procedure for high vibration of the	3/20 Introduced 3/20 Discussed 6/18 Discussed;	STP

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

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

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

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		• without the need of diagnosis or repair Therefore, the MSIV closure does not meet the definition of "Loss of normal heat removal path" provided in NEI 99-02, Rev. 2, page 15, line 37, and it is appropriate not to include this event in the associated performance indicator – Unplanned Scrams with Loss of Normal Heat Removal. Discussion of specific aspects of the event: Was the recognition of the condition from the Control Room? ▪ Yes. Rising temperature in the Outboard MSIV Room is indicated by annunciator in the main control room. Local radiation levels are also available in the control room. During the July 22, 2003 scram, control room operators also recognized that the increase in temperature was not due to a steam leak in the Outboard MSIV Room because the local radiation monitor did not indicate an increase in radiation levels. Initiation of the Group I isolation on a Steam Tunnel High Temperature is indicated by two annunciators in the control room. Does it require diagnosis or was it an alarm? ▪ The event is annunciated in the control room as described previously. Is it a design issue? ▪ Yes. The current Unit 2 design has the Group I isolation temperature elements closer to the Outboard MSIV Room ventilation exhaust as compared to Unit 3. As a result, the baseline temperatures, which input into the Group I isolation signal, are higher on Unit 2 than Unit 3. Are actions virtually certain to be successful? ▪ The actions to reset a Group I isolation are straight forward and the procedural guidance is provided to operate the associated equipment. No diagnosis or troubleshooting is required. Are operator actions proceduralized? ▪ The actions to reset the Group I isolation are delineated in General Plant procedure GP-8.A "PCIS Isolation-Group I." The actions to reopen the MSIVs are contained in System Operating procedures SO 1A.7.A-2 "Main Steam System Recovery Following a Group I Isolation" and Check Off List SO 1A.7.A-2 "Main Steam Lineup After a Group I Isolation." These procedures are performed from the control room. How does Training address operator actions? ▪ The actions necessary for responding to a Group I isolation and subsequent recovery of the Main Steam system are covered in licensed operator training. Are stressful or chaotic conditions during or following an accident expected to be present? • As was demonstrated in the event of July 22, 2003, sufficient time existed to stabilize RPV level and pressure control and methodically progress through the associated procedures to reopen the MSIVs without stressful or chaotic conditions Response: The Peach Bottom Unit 2 July 22, 2003 reactor scram followed by a high area temperature Group I isolation should not be included in the Performance Indicator - "Unplanned Scram with a Loss of Normal Heat Removal." This specific MSIV closure does not meet the definition of "Loss of normal heat removal path" provided in NEI 99-02, Rev. 2, page 15, line 37, in that the main steam system was "easily recovered from the control room without the need for diagnosis or repair. Therefore, it would not be appropriate to include this event in the associated performance indicator – Unplanned Scrams with Loss of Normal Heat Removal.		
36.5	OR1	Question: Two individuals enter an area of containment, previously surveyed and posted as a radiation area. They comply with all applicable RWPs and procedures. Additionally, they are continuously, remotely monitored by teledosimetry (Electronic Personnel Dosimeter, EPD). During the entry, their EPDs alarm on dose rate, which had been preset to alarm at 150 mrem/hr. The individuals detect the alarm and immediately exit the area to notify HP. Concurrently, HP technicians	1/22 Introduced	Vogtle

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		manning the Central Alarm Station detect the alarm condition and dispatch a nearby roving HP technician to the area to confirm the alarm and verify worker protection. The area is immediately surveyed by HP and found to contain dose rates of approximately 2 rem/hr at 12 inches; the area is reposted as a Locked High Radiation Area (LHRA). Investigation of the event reveals that the area entered contains a length of piping and a valve through which the reactor cavity is filled and drained. Shortly before this entry, the reactor cavity had been filled via this pipe. The specific area's dose rate had been confirmed by past experience to be unaffected by cavity filling and therefore was not flagged for resurvey following the fill evolution. It is hypothesized that a hot particle dislodged from an upstream location during filling and migrated into the vicinity of the work location prior to the worker's entry. The same area had been occupied numerous times after the last survey, before filling, with no problems. Should this be counted as a performance indicator event? Furthermore, should any event be counted against this PI in which an entry into an area occurs where the dose rate increased (to greater than 1 rem/hr) in a reasonably unanticipated manner?		
		Response: This is not a PI occurrence for either instance questioned above, particularly for a case where the area has been specifically considered for a possible dose rate increase. However, instances where the potential dose rate change is not considered and should have been, would be a PI event. Additionally, the unanticipated dose criteria would still apply.		
36.6	IE03	Question: NEI 99-02 states that anticipatory power reductions intended to reduce the impact of external events such as hurricanes or range fires threatening offsite power lines are excluded. On September 20, 2003, Salem 1 and 2 were manually shutdown due to switchyard arcing from salt buildup on insulators in the switchyard. The salt buildup was due to unusual meteorological conditions (hurricane force winds, with minimal rain). These conditions led to an abnormal buildup of salt from the Delaware River to be deposited on the insulators. The shutdowns were not conducted in response to any existing or immediate equipment problems. The shutdowns were initiated to address the impact of an external event, that manifested itself in an unexpected manner and to alleviate nuclear plant safety concerns arising from an external event outside the control of the plant. Should these shutdowns be counted as unplanned power reductions?	~~1/22 Introduced 2/19 Tentative Approval~~ final	Salem
		Response: No. The shutdowns were initiated to address the impact of an unexpected external event that threatened equipment in the switchyard and as such do not need to be included as an unplanned power change. However, it is expected that the licensee would update procedures training, etc., to reflect the expected response in the event of similar meteorological conditions (i.e., high winds with minimal rain). If these conditions are experienced in the future, they should be considered an expected problem, and any power change greater than 20% should be counted unless the actions to take in response to the condition are proceduralized, cannot be predicted greater than 72 hours in advance, and are not reactive to the sudden discovery of an off-normal condition.		
36.7	MS01-04	Question (Appendix D): Proposed Overhaul Exemption for Unavailability Hours Incurred On Unit 2 Safety Systems Due To Planned Overhaul of Unit 1 Nuclear Service Water System (NSWS) Pump Catawba Nuclear Station (CNS) refurbished the 1B Nuclear Service Water System (NSWS) pump during a recent refueling outage. Unit 1 was defueled and Unit 2 at power operation during this activity. Technical Specifications provided for an allowable outage time sufficient to accommodate the overhaul hours associated with the pump replacement. Catawba has a shared NSWS between both units such that the 'B' train pumps for both units (1B and 2B NSWS pumps) share a common intake pit and discharge header. Removing and reinstalling 1B NSWS pump for	1/22 Introduced 2/19 Discussed. See revised response. tentative	Catawba

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		refurbishment rendered 2B NSWS pump unavailable. Removal of the 1B NSWS pump required making the 2B NSWS pump inoperable for 2.6 hours in order to disconnect a submerged support and inspect the nuclear service water pond intake. Once the 1B NSWS pump was removed from the pit, the 2B NSWS pump was restored to operable status and Unit 2 safety systems were restored to fully operable status. After the 1B NSWS pump refurbishment was complete, the 2B NSWS pump was again rendered inoperable for reinstallation of the 1B NSWS pump. The reinstallation was originally scheduled for 20 hours but took longer due to complications. Catawba is seeking to exclude the unavailability that was incurred from the actual 2.6 hours required to remove the pump and the 20 hours originally scheduled for reinstallation (22.6 hours total). Although the NSWS is not a monitored system under NEI 99-02 guidance, its unavailability does affect various systems and components, many of which are considered major components by the definition contained in FAQ 219 (diesel engines, heat exchangers, and pumps). The specific performance indicators affected by unavailability of the NSWS are Emergency AC, High Pressure Safety Injection, Residual Heat Removal, and Auxiliary Feedwater. If the requested hours for this overhaul of the 1B NSWS pump cannot be excluded it would result in 22.6 hours unavailability on 'B' train of each of the four monitored systems. 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." The following information is provided iaw the NEI guidance. QUANTITATIVE RISK ASSESSMENT Duke Power has used a risk-informed approach to determine the risk significance of taking the 'B' loop of NSWS out of service for up to 22.6 hours within 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. The NSWS outage did not create any new core damage sequences not currently evaluated by the existing PRA model. The resulting Incremental Conditional Core Damage Probability (ICCDP) was 1.2E-06, a low-to-moderate increase in the CDF, and was acceptable based on consideration of the non-quantifiable factors involved in the contingency measures that were implemented during the overhaul. Based on the expected increase in overall system reliability of the NSWS, an overall increase in the safety of both Catawba units is expected. Contingency measures during the overhaul included Component Cooling Water System cross train alignment which allowed the "A" train to supply cooling to the High Pressure Injection and Auxiliary Feedwater pump motor coolers during the "B" train work. The RN pipe inspection evolution also included the following protective measures: • "A" train EDGs were protected throughout the evolution. • The Unit 2 transformer yard was protected throughout the evolution. • The "A" train equipment supported by RN was protected. • No maintenance or testing on operable offsite power sources. • All testing and maintenance on the operable train rescheduled to other time periods. • No work or testing that could affect the SSF or SSF Diesel Generator. • No work or testing that could affect the Turbine-Driven AFW Pump on Unit 2. EXPECTED IMPROVEMENT IN PLANT PERFORMANCE The NSWS pumps are refurbished on a specified interval to assure continued, reliable operation. The NSWS pump		

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		refurbishment is expected to increase overall system reliability. NET CHANGE IN RISK AS A RESULT OF THE OVERHAUL ACTIVITY Increased NSWS train unavailability as a result of this overhaul did involve an increase in the probability or consequences of an accident previously evaluated during the time frame the NSWS header was out of service for pump refurbishment. Considering the small time frame of the 'B' 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 that were utilized during the overhaul, net change in risk as a result of the overhaul activity is reduced.		
		Response: For this case, the refurbishment of the nuclear service water system pumps on a specified interval , an exemption of the overhaul hours does not apply. Page 29 of NEI 99-02 , Revision 2 states that "(the) overhaul exemption does not normally apply to support systems except under unique plant-specific situations and on a case-by-case basis" and that "(t)he circumstances of each situation are different and should be identified to the NRC so that a determination can be made." FAQs 254, 315 and 337 resulted in exemptions for support system overhauls based on unique plant situations. For the Catawba service water piping replacements, information was provided that detailed the extensive nature of the work resulting in a significant amount of time that the support system would be unavailable, the need for Technical Specification changes, the affect on the monitored systems performance indicators (and impact due to the NRC Action Matrix),and the enhanced system performance expected for long term operations. For the Grand Gulf safety system water pump replacements, the work was performed to upgrade the pump material and the new pumps were expected to last the life of the plant. Several factors, including the information provided by the licensee (discussed above) and the items listed in NEI 99-02 (page 29 , lines 22 through 25), were taken into consideration. It is noted that since each case is unique, the list of factors to consider (in NEI 99-02) is not all inclusive. The decision to not allow the exclusion of support system overhaul hours is based on several factors including that the work is a "minor" overhaul type activity that is performed periodically to maintain reliable operation of the system and the hours cascaded into the four monitored systems have little impact on the margin to a threshold. As stated in FAQ 254, "...(the licensee understood) that there was a desire to eliminate exclusion of monitored systems unavailability hours caused by minor ' overhaul' type activities on supporting systems.		
36.8	IE02	Question: On August 14, 2003 Ginna Station scrammed due to the wide spread grid disturbance in the Northeast United States. Subsequent to the scram, Main Feedwater Isolation occurred as designed on low Tavg coincident with a reactor trip. However, due to voltage swings from the grid disturbance, instrument variations caused the Advanced Digital Feedwater Control System (ADFCS) to transfer to manual control. This transfer overrode the isolation signal causing the Main Feedwater Regulation Valves (MFRVs) to go to, and remain at, the normal or nominal automatic demand position at the time of the transfer, resulting in an unnecessary feedwater addition. The feedwater addition was terminated when the MFRVs closed on the high-high steam generator level (85%) signal. Operators conservatively closed the MSIVs in accordance with the procedure to mitigate a high water level condition in the Steam Generators. Decay heat was subsequently removed using the Atmospheric Relief Valves (ARVs). Should the scram be counted under the PI "Unplanned Scrams with Loss of Normal Heat Removal?"	1/22 Introduced	Ginna
		Response: No. Under clarifying notes, page 16, lines 18 - 22, NEI 99-02 states: "Actions or design features to control the reactor cool down rate or water level, such as closing the main feedwater valves or closing all MSIVs, are not reported in this indicator as long as the normal heat removal path can be readily recovered from the control room without the need for diagnosis or repair. However, operator actions to mitigate an off-normal condition or for the safety of personnel or equipment (e.g., closing MSIVs to isolate a steam leak) are reported." In this case, a feedwater isolation signal had		

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		automatically closed the main feed regulating valves, effectively mitigating the high level condition. Manually closing the MSIVs was a conservative procedure driven action, which in this case was not by itself necessary to protect personnel or equipment. The main feed regulating valves were capable of being easily opened from the control room, and the MSIVs were capable of being opened from the control room (after local action to bypass and equalize pressure, see FAQ 303). In addition, the cause of the high steam generator level was due to voltage fluctuations on the offsite power grid which resulted in the operators closing the MSIVs. Clarifying notes for this performance indicator exempt scrams resulting in loss of all main feedwater flow , condenser vacuum, or turbine bypass capability caused by loss of offsite power. In this case, offsite power was not lost. However, the disturbances in grid voltage affected the ADFCS system which started a chain of events which ultimately resulted in the closure of the MSIVs.		
36.9	IE02	Question: During startup activities following a refueling outage on Millstone Unit 2 new monoblock turbine rotors were installed in the LP turbines, reactor power was approximately 10% of rated thermal power, feedwater was being supplied to the steam generators by the turbine driven main feedwater pumps, the main condensers were in service, and the main turbine was being started up in preparation for plant startup. During main turbine startup, the turbine began to experience high bearing vibrations before reaching its normal operating speed of 1800 rpm, and was manually tripped. The bearing vibrations began to increase ~~as the turbine slowed down following~~ the trip. To protect the main turbine, the alarm response procedure for high-high turbine vibration required the operators to manually SCRAM the reactor, isolate steam to the main condensers by closing the main steam isolation valves and to open the condenser vacuum breaker thereby isolating the normal heat removal path to the main condensers. This caused the turbine driven main feedwater pumps to trip. Following the reactor SCRAM, the operators manually started the auxiliary feedwater pumps to supply feedwater to the steam generators. The atmospheric dump valves operated automatically to control reactor coolant system temperature, by removing core decay heat and reactor coolant pump heat. The core decay heat load was very low during this event due to the length of the refueling outage and the fact that approximately one-third of the fuel assemblies in the core had been replaced. Does a SCRAM in which the normal heat removal path is manually isolated in accordance with plant procedures for protection of non-safety plant equipment count against this indicator? Response:	1/22 Introduced	Millstone 2
37.1	OR1	Question: Two job-coverage Radiation Protection technicians were performing a job turnover at the entrance to a Steam Generator Bay. At the time the Steam Generator Bay was posted and locked as a Locked High Radiation Area. During the turn over process the RP Technicians entered into the posted region of the Locked High Radiation Area. When they entered a few feet past the doorway the door was left open and the radiological posting was left down. However, the Radiation Protection technicians provided direct surveillance capable of preventing unauthorized entry in the high radiation area. The RP Technicians were cognizant of the need to control access to the area and did so throughout the turnover. Is this event considered performance indicator occurrence? Response: This is not considered a performance indicator occurrence because the Radiation Protection technicians maintained positive control over access to the area.	2/19 Introduced 3/25 Revised	Ft. Calhoun
37.2	MS01	Question:	3/25/04 Introduced	STP

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		NEI 99-02 Rev 2 recognizes that some provisions are intentionally restrictive to ensure that the NRC is informed of plant conditions. On page D-2 lines 19 through 31 guidance is given to allow exceptions to allow credit for operator compensatory actions to mitigate the effects of unavailability of monitored systems. During a surveillance test on December 9, 2003, South Texas Project Unit 2 SDG-22 experienced a catastrophic failure and STP Nuclear Operating Company (STPNOC) could not complete the repairs in the current 14 day AOT. As a result SPTNOC submitted a series of Technical Specification amendment request to allow a one-time-only increase of the Allowed Outage Time to a total of 113 days. These amendments were approved by the NRC and resulted in the continued operation of STP from December 9, 2003 until March 31, 2004. This one-time-only extended allowed outage time will result in 2,712 hours of unavailability on SDG 22 and a Performance Indicator value of 4.5% (White) for Emergency AC Power. If the Technical Specification one-time change had not been granted, STP would have incurred less than 336 hours of unavailability on SDG 22 and would have remained in the Green band (1.6%). For Emergency AC Power, the NEI 99-02R2 NRC Performance Indicator Green/White threshold is set at 2.5%, while the White/Yellow threshold is set at 10%. STP Unit 2 received an allowable outage time (AOT) extension in an approved license amendment request, predicated upon a combination of alternative systems and operator compensatory actions for the unavailable system. The NRC evaluated, and documented the acceptability of these alternative methods; the NRC's SER confirms that the licensee did indeed provide an acceptable interim compliance configuration in accordance with their new license amendment. See "Event Details and Supporting Information" below for more information. License amendments do redefine a plant's licensing basis. If alternative methods are proposed, submitted, reviewed, approved, and inspected, then the NRC has publicly endorsed the alternative methods as providing acceptable compliance. As long as the licensee maintains the newly licensed configuration and compensatory measures, the unavailable hours should not accrue unless the newly licensed configuration was no longer maintained. NEI 99-02 Rev 2 allows for an exemption of unavailability hours based on operator compensatory actions. Since the unavailability incurred by SDG 22 was approved by a license amendment to the STP Unit 2 Technical Specifications that provided compensatory measures and an approved credited backup power supply to Train "B", and since counting all hours incurred would significantly mask future degrading performance, should the unavailable hours be counted only from the time of discovery until the compensatory measures were in place?	tentative	
		Response: Yes, the unavailable hours should be counted only from the time the diesel became inoperable until the time that the compensatory measures and non-class diesel generators were in place and remained in place. This is based upon the following factors: • The condition was approved by a change to the plant Technical Specifications. • The Technical Specification change credited a backup non-class power supply for SDG 22 in addition to the other two Standby Diesel Generators at the Unit. • There are control room alarms to alert the Control Room operator of the need for the compensatory measures. • Dedicated operators are stationed in the area to complete the recovery action. • The operators have procedures and training has been accomplished for the recovery action. • There are at least four means of communication between the Control Room and the local operators. • All necessary equipment for recovery action is pre-staged and has been tested.		

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		• Indication of successful recovery actions is available locally and in the Control Room. • The non-class diesel generators are inspected weekly and operated monthly on a load bank to verify their availability. • The probability of successful completion of compensatory actions were evaluated by sensitivity studies as part of the amendment request and accepted by the NRC SER.		
37.3	OR1	Question: It was determined that a physical barrier being used to control access to a high radiation area (greater than 1000 mrem per hour) could easily be circumvented. However, to circumvent the controls that were in place would require an intentional act. An example of this might include one of the following: 1. Fencing used as a barrier at the boundary of the high radiation area was not firmly secured (i.e., loosely secured, or just taped to a wall) such that an individual could, by hand, create an opening large enough to pass through. 2. The barrier was constructed of a material that could easily be breached with a pocket knife (i.e., thin plastic sheeting or webbing). 3. An individual could pass their hand through the barrier and open the locked door to the area from the inside. 4. The barrier is a short fence (<6 foot high), or hand rail, such that an individual could step over, climb over, or crawl under, with little-to-moderate effort. 5. A locked gate is provided at the top of a ladder to control access to a high radiation area on a lower level of the plant. However, by stepping around (or over) the gate, an individual can still access to the rungs of the ladder. Since the controls in place, as described above, were adequate to prevent an inadvertent entry (i.e., accidental or unintentional entry by an individual not paying sufficient attention), and the definition of terms on page 98 in NEI 99-02 Rev. 2, refers to "measures that provide assurance that inadvertent entry into the technical specification high radiation areas by unauthorized personnel," is this a (or are these) reportable PI occurrence(s)? How about if this were a very high radiation area (>500 rads per hour)?	3/25 Introduced	NRC
		Response: Yes it is (they are) a PI occurrence(s). As indicated in the PI example on page 99 of NEI 99-02, Rev. 2, the locked entrance to and the barriers at the boundaries of, a high radiation area (>1000 mrem per hour) must secure the area against unauthorized access. The unauthorized access can be intended, as well as unintended, by the individual. However, it is not reasonable to expect barriers to absolutely prevent circumvention by a determined individual. As discussed in the NRC Position C.1.5 of Regulatory Guide 8.38, access pathways through or around the barriers and doors (or gates) used to prevent access to a high radiation area, do not have to be considered if an individual would have to take exceptional measures to access the high radiation area by them (i.e., where there is a high risk of serious personal injury, by jumping down an unreasonably high drop (see NRC Part 20 Q&A # 487), or by some other equally foolish act; climbing, unaided by a ladder or equivalent, over a wall, or fence, that is at least six feet high; or using special tools to breach the barrier). The examples, as described in the question, do not require an exceptional effort, or exceptional measures, to circumvent the barrier. Therefore, each is a loss of control of access to a technical specification high radiation, and would be a PI occurrence. The physical controls around very high radiation areas must assure that an individual is not able to gain inadvertent or unauthorized access, they need to provide a higher level of deterrence to circumvention than those used for high radiation areas (i.e., fencing around very high radiation areas should extend to the overhead and preclude anyone from climbing over (Position C.1.5 in Regulatory Guide 8.38)). Since the physical barrier in question is not adequate to		

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		control access to a locked high radiation area, it follows that it would not be adequate to control access to a very high radiation area either. Therefore, it would be a PI occurrence.		
37.4	IE03	Question: During a scheduled refueling outage, the rotor was replaced on the 'C' low pressure turbine. During initial startup on October 27, 2003, with the plant stable at 17.7% reactor power, high vibrations were detected on the bearings associated with the replaced rotor. The turbine was tripped and shutdown, a troubleshooting team formed and a repair plan developed. In order to collect vibration data required to identify the optimum location for the placement of balancing weights, the repair plan called for the starting and phasing of the main turbine. With reactor power at 22.2%, the main generator breaker was closed at 18:32. After the collection of vibration data, the turbine was tripped at 20:37 and reactor power reduced to 1.1%. When the performance indicator data for the 4th quarter of 2003 was submitted, this reduction in power of 21.1% was not included in the Unplanned Power Changes per 7,000 Critical Hours Performance Indicator. The NEI 99-02 criteria for reporting power changes of greater than 20% is for discovered off-normal conditions that require a power change of greater than 20% to resolve. Frequently, high vibrations and/or rubbing occur during startup following rotor replacement. As an expected condition rather than an off-normal condition, the associated reduction in power should not count as an unplanned power change. Is the power change described above considered an unplanned power change for performance indicator reporting? Response: No. Because the power change occurred in a refueling outage during troubleshooting activities associated with turbine rotor replacement, it should not be counted as an unplanned power change against the Unplanned Power Changes per 7,000 Critical Hours performance indicator.	3/25/04 Introduced	Seabrook
37.5	OR1	Question: A worker entered a > 1R/hr Technical Specification High Radiation Area (> 1R/hr) with all requirements of the job (training, briefings, dosimetry, ALARA Plan and RWP requirements, electronic dosimetry, etc.). The worker, however, did not have the 700 mrem dose available as specified by the RWP. The worker's actual dose did not exceed the electronic dosimeter set point and the minimum administrative control guideline. The dose availability of the worker is defined as the difference between the site-specific administrative control guideline of 2000 mrem (significantly below Federal Limits) and the worker's current accumulated dose for the year. An ALARA Plan and RWP controlled the work activity. The individual used teledosimetry with predetermined alarm setpoints for the job, which transmitted dose and dose rate information during the entry. Video surveillance was utilized by radiation protection technicians and in compliance with 10CFR20.1601(b) during the entry into the >1R/hr area. The area was conspicuously posted, barricaded and utilized a red flashing light. Specific authorization was given by the remote monitoring station technician to enter into the area. The worker had the training and respiratory protection qualifications required by the RWP, multiple TLDs had been issued, the required RWP was obtained and signed, and briefings were attended. The electronic entry time was entered after the worker had exited the area. There was no over exposure or unintended dose exposure for this worker. The work was completed within the maximum projected dose for the activity. Technical Specification requirements for control of entry into the high radiation area were met and worker dose was controlled since the worker was authorized and had obtained the RWP for the job. The RWP stated that 700 mrem dose availability was required prior to entry. This administrative control is an additional defense-in-depth, licensee-initiated control to protect against exceeding the licensee's administrative control guideline. The licensee's administrative control guideline is conservatively established at 2 rem to provide a substantial margin to prevent personnel from exceeding the Federal dose limit of 5 rem and to help ensure equitable distribution of	3/25 Introduced	TMI

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		dose among workers with similar jobs. The administrative control is in addition to the Technical Specification requirements for an RWP and therefore not material to the Technical Specification requirements for control of occupational dose. As it is stated in NEI 99-02, "this PI does not include nonconformance with licensee-initiated controls that are beyond what is required by technical specifications and the comparable provisions in 10CFR Part 20." The check of dose availability is a licensee-initiated administrative control that is beyond what is required by technical specifications, comparable provisions in 10CFR20, or Regulatory Guide 8.38. Does failure of the worker to meet the internal administrative control guideline for dose available as specified by the RWP for the job activity count as a PI occurrence?		
		Response: No, this event constitutes a procedural failure to meet a licensee-initiated administrative control; however, this event would not be a PI occurrence. Such an event would be reviewed under the appropriate NRC inspection criteria.		
37.6	BI02	Question: River Bend Station (RBS) seeks clarification of BI-02 information contained in NEI 99-02 guidance, specifically page 80, lines 36 and 37 *"Only calculations of RCS leakage that are computed in accordance with the calculational methodology requirements of the Technical Specifications are counted in this indicator."* NEI 99-02, Revision 2 states that the purpose for the Reactor Coolant System (RCS) Leakage Indicator is to monitor the integrity of the reactor coolant system pressure boundary. To do this, the indicator uses the identified leakage as a percentage of the technical specification allowable identified leakage. Moreover, the definition provided is "the maximum RCS identified leakage in gallons per minute each month per technical specifications and expressed as a percentage of the technical specification limit." The RBS Technical Specification (TS) states "Verify RCS unidentified LEAKAGE, total LEAKAGE, and unidentified LEAKAGE increase are within limits (12 hour frequency)." RBS accomplishes this surveillance requirement using an approved station procedure that requires the leakage values from the 0100 and 1300 calculation be used as the leakage "of record" for the purpose of satisfying the TS surveillance requirement. These two data points are then used in the population of data subject to selection for performance indicator calculation each quarter (highest monthly value is used). The RBS approved TS method for determining RCS leakage uses programmable controller generated points for total RCS leakage. The RBS' programmable controller calculates the average total leakage for the previous 24 hours and prints a report giving the leakage rate into each sump it monitors, showing the last four calculations to indicate a trend and printing the total unidentified LEAKAGE, total identified LEAKAGE, their sum, and the 24 hour average. The programmable controller will print this report any time an alarm value is exceeded. The printout can be ordered manually or can be automatic on a 1 or 8 hour basis. While the equipment is capable of generating leakage values at any frequency, the equipment generates hourly values that are summarized in a daily report. The RBS' TS Bases states "In conjunction with alarms and other administrative controls, a 12 hour Frequency for this Surveillance is appropriate for identifying changes in LEAKAGE and for tracking required trends." The Licensee provides that NEI 99-02 requires only the calculations performed to accomplish the approved TS surveillance using the station procedure be counted in the RCS leakage indicator. In this case, the surveillance procedure captures and records the 0100 and 1300 RCS leakage values to satisfy the TS surveillance requirements. The	3/25 Introduced	River Bend

TempNo.	PI	Question/Response	Status	Plant/ Co.
		NRC Resident has taken the position that all hourly values from the daily report should be used for the RCS leakage performance indicator determination, even though they are not required by the station surveillance procedure. The Resident maintains that all hourly values use the same method as the 0100 and 1300 values and should be included in the leakage determination. Is the Licensee interpretation of NEI 99-02 correct?		
		Response: Yes. It was never the intent of the guidance to require all leakage determinations to be used for this performance indicator. Only those calculations that are performed to meet the requirements of the technical specification surveillance should be considered.		

37.2 Event Details and Supporting Information

During a surveillance test on December 9, 2003, South Texas Project Unit 2 SDG-22 experienced a catastrophic failure and STP Nuclear Operating Company (STPNOC) could not complete the repairs in the current 14 day AOT. As a result SPTNOC submitted a series of Technical Specification amendment request to allow a one-time-only increase of the Allowed Outage Time to a total of 113 days. These amendments were approved by the NRC and resulted in the continued operation of STP from December 9, 2003 until March 31, 2004. This one-time-only extended allowed outage time will result in 2,712 hours of unavailability on SDG 22 and a Performance Indicator value of 4.5% (White) for Emergency AC Power.

If the Technical Specification one-time change had not been granted, STP would have incurred less than 336 hours of unavailability on SDG 22 and would have remained in the Green band (1.6 %). The White/Yellow threshold is 10% for Emergency AC Power and would require STP to incur another ~ 3,000 hours of unavailability for SDGs on Unit 2 over the normal maintenance history. This condition will mask any new issues that develop on the STP Unit 2 Emergency AC Power performance.

On December 12, 2003, NRC Region IV chartered a special inspection to review the root cause determination, the adequacy of the extent-of-condition evaluation, common mode failure contribution, corrective actions, and other items listed in the charter. The inspection validated the investigation performed by STP and did not identify any performance issues or findings contributing to the event.

NEI 99-02 Rev 2 recognizes that special conditions may arise that were not considered when the guidance was developed and provides for plant specific FAQs to address these instances. On page D-1 of NEI 99-02 Rev 2 guidance is give on what factors should be considered. The guidance is repeated below for ease of review.

There are some provisions in NEI 99-02 that are intentionally restrictive to ensure that the NRC is informed of the condition of the plant. Such provisions include (1) no exemption of overhaul hours for support systems, (2) limited credit for operator actions to recover unavailable support systems, and (3) limited credit for actions taken to mitigate the effects of unavailability of monitored systems. A risk-informed process would apply a consistent standard of judgment to each situation to determine the appropriate unavailable hours. This provision for plant-specific exceptions will risk-inform the performance indicators using the NRC/Industry public meeting forum to apply that consistent standard of judgment.

In evaluating each request for a plant-specific exception, this forum will take into consideration factors related to the particular issue. Examples of the factors to be considered for various types of exceptions are listed below:

... For exceptions to allow credit for operator compensatory actions to mitigate the effects of unavailability of monitored systems, the following issues may be addressed, along with any other pertinent information:

1. NRC approval through an NOED. Technical Specification change, or other means
2. risk-significance of the monitored function(s)
3. capability to recognize the need for compensatory actions
4. availability of trained personnel to perform the compensatory actions
5. means of communications between the control room and the local operators
6. availability of compensatory equipment
7. availability of a procedure for compensatory actions
8. frequency with which the compensatory actions are performed
9. probability of successful completion of compensatory actions within the required time

The Technical Specification Amendment requests submitted by SPTNOC and issued by the NRC as Amendments 148 and 149 to the Unit 2 Operating License discussed the items listed for consideration in the guidance. The SERs for these amendments accepted these actions as appropriate for the condition. The SER states in part:

On October 31, 1996, the NRC staff issued License Amendment Nos. 85 and 72 to the Facility Operating Licenses for STP, Units 1 and 2. License Amendment Nos. 85 and 72 extended the AOT for a single SDG to 14 days.... The NRC staff concludes that the October 31, 1996, safety evaluation and associated deterministic conclusions are applicable to the proposed 1 13 day AOT for SDG 22 since the deterministic evaluation is a function of the equipment configuration and the accident scenarios of interest, neither having changed (except for certain additional back-up electrical configurations.) The NRC staff, however, has reevaluated the STP Unit 2 electrical design to assure that power to all critical safety equipment is maintained even in the event that off-site power is lost during the 92-day AOT extension for SDG 22.

... The licensee is also implementing compensatory measures during the extended AOT, in addition to those that are called for under STP's existing Configuration Risk Management Program (CRMP). Following are the additional compensatory measures taken by STP:

- Notification of the transmission/distribution service providers (TDSP) of the condition and of the maintenance restrictions required for the STP switchyard.
- Hang extended AOT (EAOT) protected train signs.
- Planned maintenance on required systems, subsystems, trains, components, and devices that depend on the other trains of equipment during the EAOT SHALL NOT be performed.
- No planned maintenance that could result in an inoperable OPEN containment penetration.
- Containment purges shall be for pressure control only and for short duration.
- No planned maintenance on the Unit 2 Technical Support Center SDG.
- No planned maintenance on Load Center 2W.
- No planned maintenance on Motor Control Center 2G8.
- No planned maintenance on the Positive Displacement Charging Pump (PDP).
- No planned maintenance on the Emergency Transformer or the 138 kV Blessing to STP and Lane City to Bay City lines.
- No maintenance activities in the switchyard that could directly cause a LOOP event unless required to ensure the continued reliability and availability of the offsite power sources.
- No planned maintenance on the turbine-driven auxiliary feedwater pump.
- Attempt to verify that the station is not under hurricane, tornado, or flood watches or warnings. (Note: the licensee has indicated that no severe weather is currently forecast.)
- Attempt to verify with the TDSP that no adverse weather conditions exist in the areas of the offsite power supplies that challenge the stability of grid.
- Ensure the work schedule contains no planned maintenance on Switchgear 2L or 2K.

The NRC is confirming by license condition that the licensee will not change these compensatory measures except in accordance with an evaluation of the criteria in 10 CFR 50.59(c) (2).

These compensatory measures were in place prior to the expiration of the original 14-day AOT for SDG 22 on December 23, 2003. In addition to the compensatory measures listed in the license amendment, STPNOC committed to install non-class diesel generators capable of connecting to the Unit 2 safety related loads in the event of a loss of off-site power. These diesel generator units were installed and available for use with supporting equipment, personnel, training, and procedures at 1300 on January 10, 2004. The SER states in part:

The licensee committed in its December 27, 2003, letter, as supplemented, to install four vendor-supplied diesel generator sets that would be available for use by January 15, 2004, to provide temporary power to STP, if needed. The non-safety-related diesel generators (NDGs) will be capable of supplying power to an essential cooling water pump, an auxiliary feedwater pump, and required electrical auxiliary building ventilation to provide a backup power source for achieving safe shutdown. Each NDG will be capable of operating for 24 hours without refueling. Only three of the four NDGs are required to supply these loads. The NDGs will be connected to the STP non-safety emergency 13.8 kV electrical system. The NDG capability will only be utilized when the failure of emergency power sources in Unit 2 has occurred such that the remaining emergency power is judged to be inadequate for mitigation of the event. The NDGs are started and switched to the non-safety emergency 13.8 kV electrical system locally. Operating procedures will be developed to line up and control the loading of the NDGs. The operating procedures will include appropriate precautions to prevent crosstie between the STP units. The temporary equipment is not physically or electrically adjacent to any Class 1 E or safety-related equipment. Therefore, the temporary equipment does not directly or indirectly affect the design function of safety-related equipment credited in the safety analyses. The NDGs will be tested after installation and periodically thereafter. Vendor post-installation testing will include:

1) Verification that alarm functions, normal operating parameters, phase rotation, and the phasing between the NDGs is synchronous.
2) Load testing utilizing a load bank to ensure that the load demand on the NDG is distributed appropriately.
3) Verification that phasing between the NDGs and the emergency transformer is synchronous.
4) Verification that the starting batteries will perform their function.

The NDGs will be inspected weekly and operated monthly on a load bank to verify their availability.

The License Amendments also discussed the risk impact of the SDG 22 unavailability. The NRC SERs state in part:

3.3.6 Conclusions Regarding Probabilistic Evaluation

The NRC staff has concluded that the proposed 92-day one-time extension of the AOT for SDG 22 is acceptable from a PRA perspective. This conclusion is based, in part, on:

- reliability of offsite power
- operability of SDG 21 and SDG 23
- NDGs operable by January 15, 2004, credited to provide back-up power to Unit 2 train "B"
- low likelihood of SDG common-mode failure
- low likelihood of failure of credited power sources

In addition, the licensee will take compensatory measures limiting activities that could result in a plant configuration with the potential for a transient or to adversely impact the availability of onsite or offsite power supplies. The licensee will establish a plant configuration management program, and continue to monitor plant configurations to avoid high risk configurations. Therefore, the NRC staff finds that the licensee's PRA of the 92-day AOT extension for SDG 22 is acceptable.

The NRC summarized the approval of the License amendments as follows:

3.4 Conclusions Regarding Change to TS 3.8.1

The NRC staff has evaluated the licensee's proposed change to TS 3.8.1 and concludes that the licensee's proposed 1 13-day AOT for SDG 22 meets the NRC staff's deterministic and probabilistic standards for such AOT extensions. Accordingly, it is acceptable to change TS 3.8.1 , ACTION Statements a, c, and f (which provide required restoration times for inoperable SDGs), by applying the following note:

(12) For the Unit 2 Train B standby diesel generator (SDG 22) failure of December 9, 2003, restore the inoperable standby diesel generator to OPERABLE status within 113 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

As demonstrated by the above discussion, STP has provided and the NRC has approved extensive compensatory actions as well as a credited backup power supply to compensate for the unavailability of SDG 22. These compensatory actions qualify for an exemption of the unavailability hours for SDG 22 from the time the diesel became inoperable until the time that the compensatory measures and non-class diesel generators were in place and remained in place.

			2/19 Introduced	Ft. Calhoun
37.3	OR1	Question: It was determined that a physical barrier being used to control access to a high radiation area (greater than 1000 mrem per hour) could easily be circumvented. However, to circumvent the controls that were in place would require an intentional act. An example of this might include one of the following; 1. Fencing used as a barrier at the boundary of the high radiation area was not firmly secured (i.e., loosely secured, or just taped to a wall) such that an individual could, by hand, create an opening large enough to pass through. 2. The barrier was constructed of a material that could easily be breached with a pocket knife (i.e., thin plastic sheeting or webbing). 3. An individual could pass their hand through the barrier and open the locked door to the area from the inside. 4. The barrier is a short fence (<6 foot high), or hand rail, such that an individual could step over, climb over, or crawl under, with little-to-moderate effort. 5. A locked gate is provided at the top of a ladder to control access to a high radiation area on a lower level of the plant. However, by stepping around (or over) the gate, an individual can still access to the rungs of the ladder. Since the controls in place, as described above, were adequate to prevent an inadvertent entry (i.e., accidental or unintentional entry by an individual not paying sufficient attention), and the definition of terms on page 98 in NEI 99-02 Rev. 2, refers to "measures that provide assurance that inadvertent entry into the technical specification high radiation areas by unauthorized personnel," is this a (or are these) reportable PI occurrence(s)? Response: The first example on page 99 of NEI 99-02, Rev.2, clearly states that the failure to secure a high radiation area (>1000 mrem per hour) against unauthorized access is a reportable PI occurrence. Since the physical barriers provided for each of these areas can be easily circumvented (i.e., did not secure the area), they would each be a PI occurrence. The term "inadvertent entry" on page 98 of NEI 99-02, is used in the sense that the violation of the regulatory requirement (e.g., resulting from the unauthorized entry) was unintended, as opposed to whether the act itself was accidental or unintended. As used here, an unintentional violation could be a non-flagrant, intended, act resulting from a misunderstanding as to the existence the requirement, the meaning of the requirement, or that the action conformed to the requirement. If the unauthorized entry was an intended violation of the regulatory requirement, this would be a willful violation subject to normal NRC Enforcement Policy. A willful violation is outside the scope of this Performance Indicator.	3/25 Introduced	NRC

~~xx~~.2	OR1	Question: Two individuals enter an area of containment, previously surveyed and posted as a radiation area. They comply with all applicable RWPs and procedures. Additionally, they are continuously, remotely monitored by teledosimetry (Electronic Personnel Dosimeter, EPD). During the entry, their EPDs alarm on dose rate, which had been preset to alarm at 150 mrem/hr. The individuals detect the alarm and immediately exit the area to notify HP. Concurrently, HP technicians manning the Central Alarm Station detect the alarm condition and dispatch a nearby roving HP technician to the area to confirm the alarm and verify worker protection. The area is immediately surveyed by HP and found to contain dose rates of approximately 2 rem/hr at 12 inches; the area is reposted as a Locked High Radiation Area (LHRA). Investigation of the event reveals that the area entered contains a length of piping and a valve through which the reactor cavity is filled and drained. Shortly before this entry, the reactor cavity had been filled via this pipe. The specific area's dose rate had been confirmed by past experience to be unaffected by cavity filling and therefore was not flagged for resurvey following the fill evolution. It is hypothesized that a hot particle dislodged from an upstream location during filling and migrated into the vicinity of the work location prior to the worker's entry. The same area had been occupied numerous times after the last survey, before filling, with no problems. Should this be counted as a performance indicator event? Furthermore, should any event be counted against this PI in which an entry into an area occurs where the dose rate increased (to greater than 1 rem/hr) in a reasonably unanticipated manner?	3/23 Introduced	NRC
		Response: This <u>is</u> a reportable Performance Indicator (PI) occurrence. The statement in this question that the "...dose rates had been confirmed by past experience..." is incorrect. As described in this example, the dose rates in this area were assumed, not confirmed by a (pre-work or routine) survey. This is the heart of the performance deficiency. Placing direct (and, or remote) reading dosimeters on workers is not a substitute for adequate surveys as required by Part 20. This example is not a case where the non-conformance was reasonably unanticipated. This is an example of a lack of vigilance by the radiation protection program. The reactor refueling cavity drain and fill system clearly had the potential for high dose rates, and an adequate pre-work survey would have uncovered the radiological condition.		

Attachment 7

March 16, 2004

Stephen D. Floyd
Vice President, Regulatory Affairs
Nuclear Generation Division
Nuclear Energy Institute
1776 I Street, NW
Suite 400
Washington, DC 20006-3708

Dear Mr. Floyd:

I am responding to your October 31, 2003, letter regarding performance indicator (PI) IE-02, Unplanned Scrams with Loss of Normal Heat Removal. Your views on the scrams with loss of normal heat removal PI are appreciated and the staff has given serious consideration to your recommendation that this PI be eliminated. In addition to sharing similar concerns about this PI, we are concerned about the status of activities related to the PI program as a whole, including the resolution of issues raised by licensees through the frequently asked questions (FAQ) process. We consider the timely resolution of FAQ's to be a very important aspect of the PI program. As discussed at the public Nuclear Regulatory Commission (NRC)/Nuclear Energy Institute (NEI) senior management meeting on December 18, 2003, we consider the time and resources recently required to address PI issues to be neither efficient nor effective.

The four points raised in your letter are discussed in an attachment to this letter. The staff concludes that it would be premature to eliminate the scrams with loss of normal heat removal PI at this time. However, based upon the importance of an indicator which monitors complex scrams and the need to improve its usefulness, we conclude that a fresh look at the PI and the implementation issues associated with it is appropriate.

Over the last several years, the staff and industry have attempted to better define what constitutes a loss of the normal heat removal path. While it is true in hindsight that the PI could have been better defined in the beginning and that the definition of what constitutes a scram with loss of normal heat removal has changed several times since then, some of the issues discussed in your letter have been resolved through the FAQ process. During the last two years, the staff has proposed a number of alternatives in an attempt to reach agreement with the industry on a clear and appropriate definition for this PI. We believe we can find an acceptable definition for this PI that more appropriately addresses plant transients beyond a routine scram and ask for NEI's support in meeting this goal.

Regarding the FAQ process, when the ROP was initially implemented, the FAQ panel members were focused on broad implementation issues that needed resolution in order for the concept to succeed. Over time, that focus has shifted to plant specific issues. NEI's support is also requested in returning the panel's focus to the broad implementation of the PI program.

In summary, the staff believes that a PI that identifies plant transients beyond routine scrams that have risk-significance in some important accident sequences has merit, and is presently worth retaining. The scrams with loss of normal heat removal PI provides a performance insight that is not obtainable from the unplanned scrams PI or the significance determination process. We will be in contact with NEI shortly to discuss the next steps in finding an acceptable definition for the scrams with loss of normal heat removal PI.

Sincerely,

/RA/

Bruce A. Boger, Director
Division of Inspection Program Management
Office of Nuclear Reactor Regulation

Attachment: As stated

In summary, the staff believes that a PI that identifies plant transients beyond routine scrams that have risk-significance in some important accident sequences has merit, and is presently worth retaining. The scrams with loss of normal heat removal PI provides a performance insight that is not obtainable from the unplanned scrams PI or the significance determination process. We will be in contact with NEI shortly to discuss the next steps in finding an acceptable definition for the scrams with loss of normal heat removal PI.

Sincerely,

Bruce A. Boger, Director
Division of Inspection Program Management
Office of Nuclear Reactor Regulation

Attachment: As stated

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J. Dyer	A. Thadani	H. Miller, RI	FAST

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Unplanned Scrams with Loss of Normal Heat Removal
Performance Indicator (PI)

Discussion of Four Key Points from
Letter dated October 31, 2003

The Nuclear Energy Institute's (NEI's) letter dated October 31, 2003, lists four key points that NEI believes supports elimination of Performance Indicator (PI) IE-02, Unplanned Scrams with Loss of Normal Heat Removal. The following provides the key points discussed in NEI's letter, and the NRC response.

Issue #1: The PI is duplicative of the existing performance indicator IE-01, Unplanned Scrams per 7000 Critical Hours.

NRC Response: Scrams with loss of normal heat removal constitute a class of events, important to plant safety in certain accident sequences, that have sufficient data to be useful as a performance indicator. In the event of a transient, maintaining the availability of the normal heat removal path can preclude the plant from relying on safety systems to remove decay heat, or can lessen the probability of a more severe event developing in the event of a failure of these safety systems. The value from this PI is the ability to identify an adverse trend (over a 12 calendar quarter period) in plant equipment that plays an important role in safely shutting down a nuclear power plant. The unplanned scrams PI does not accomplish this.

Issue #2: The NRC inspection practice of assessing every reactor scram, including scrams with loss of normal heat removal, and considering any associated findings in the significance determination process. The NEI letter concludes in part that the scrams with loss of normal heat removal PI adds no value because of these activities.

NRC Response: Under the reactor oversight process (ROP), the performance indicators are combined with inspection findings to determine in which response column of the Action Matrix a reactor unit is placed. The response column helps define the scope and depth of supplemental inspection activities at a site. In this manner, the scrams with loss of normal heat removal PI, combined with other PI's and inspection findings, potentially has a much greater impact on NRC inspection activities than may occur from the inspection of every scram. For example, the transition of the scrams with loss of normal heat removal PI from green to white could result in a reactor unit moving into the Degraded Cornerstone column from the Regulatory Response column or from the Degraded Cornerstone column into the Multiple/Repetitive Degraded Cornerstone column (assuming other greater than green inspection findings/performance indicators exist). The supplemental inspections performed in the Degraded Cornerstone and Multiple/Repetitive Degraded Cornerstone columns are typically much broader in scope than the follow-up to a reactor scram. Repeated losses of the normal heat removal path during plant scrams, trended over 12 calendar quarters, is a valid input to consider when deciding whether to expend supplemental inspection resources to determine if more wide spread performance deficiencies exist.

Attachment

Issue #3: There is no evidence or analysis to suggest that this is a leading indicator or a precursor of degraded performance.

NRC Response: The majority of the ROP PI's are not leading indicators or precursors of degraded performance. Not withstanding that, as discussed above, a PI that includes the more complicated scrams, including a loss of normal heat removal path, is considered by the NRC to be a valid input to the Action Matrix.

Issue #4: This PI has been an inordinate resource burden for the industry and the NRC staff in dealing with its intent and complexity. This PI has contributed to extended and inconclusive debate within the FAQ panel, which is comprised of both industry representatives and NRC staff, and has resulted in delayed submission of PI inputs from licensees.

NRC Response: In order for the PI's and inspection findings to properly risk-inform the NRC inspection process, the PI inputs must occur in a timely manner. As the NRC staff and NEI have previously discussed and agreed, the process for evaluating and resolving FAQ's will be modified to allow for adequate discussion by the FAQ panel and timely FAQ resolution. Going forward, FAQ's will be introduced during a monthly ROP meeting and discussed, if necessary, for two subsequent meetings. If after that time a consensus does not exist between the licensee representatives and the NRC staff, the NRC staff will determine the resolution. NEI will then incorporate the NRC resolution into the FAQ database by the next ROP meeting and into the next revision of NEI 99-02, if necessary. The final staff resolution will be made by the NRC Chief, Inspection Program Branch, and any industry appeal, if desired, will be directed to and addressed by the NRC Director, Division of Inspection Program Management.

Attachment 8

SAFETY SYSTEM FUNCTION FAILURE RECONCILIATION PROJECT

Background/Scope:

A special Industry project was performed to reconcile and understand the differences between NRC and Industry data (January 1999 through December 2003) regarding the Reactor Oversight Program Performance Indicator (PI) – Mitigating Systems (MS-05) "Safety System Functional Failure (SSFF)".

The MS-05 PI, SSFF, is defined in Nuclear Energy Institute document NEI 99-02, "Performance Indicator Program", as being the number of Licensee Event Reports (LERs) submitted each quarter in accordance with 10 CFR 50.73(a)(2)(v). This regulation requires licensees to report "... (v) Any event or condition that could have prevented the fulfillment of the safety function of structures or systems that are needed to: (A) Shut down the reactor and maintain it in a safe shutdown condition; (B) Remove residual heat; (C) Control the release of radioactive material; or (D) Mitigate the consequences of an accident... (vi) Events covered in paragraph (a)(2)(v) of this section may include one or more procedural errors, equipment failures, and/or discovery of design, analysis, fabrication, construction, and/or procedural inadequacies. However, individual component failures need not be reported pursuant to paragraph (a)(2)(v) of this section if redundant equipment in the same system was operable and available to perform the required safety function."

An NRC contractor routinely evaluates LERs. The contractor, among a number of reviews, independently considers whether the LER might have constituted a 50.73(a)(2)(v).

The listing of <u>437 SSFFs reported by licensees</u> under NEI 99-02, compiled in the master database currently maintained by the Institute of Nuclear Power Operations (INPO), differs from the listing of <u>554 SSFFs the NRC contractor</u> has developed.

The purposes of this project are to:

1. Develop a single spreadsheet presenting, for each licensee, the total licensee reported (INPO) SSFFs and the corresponding total NRC contractor evaluated SSFFs for the period January 1999 through December 2003.

2. Where the two numbers (Licensee and NRC contractor) do not agree, perform an independent evaluation/reconciliation of appropriate LERs to identify and understand the discrepancies, if any.

3. Prepare a report that documents the results of the reconciliation project, and identify any "lessons learned" for Industry and/or the NRC contractor.