UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

April 25, 2000

MEMORANDUM TO: Michael R. Johnson, Section Chief
Inspection Program Branch
Division of Inspection Program Management

FROM: August K. Spector
Inspection Program Branch
Division of Inspection Program Management

August K. Spector

SUBJECT: REACTOR OVERSIGHT PROCESS INITIAL IMPLEMENTATION PUBLIC MEETING - APRIL 13, 2000

The NRC conducted a public meeting on April 13, 2000, to discuss progress of initial implementation of the Reactor Oversight Process. The meeting was held at the Nuclear Regulatory Commission, One White Flint North, Rockville, MD. A list of participants, a copy of the agenda and handouts distributed are attached.

Attachments: As stated

1. Participants and Agenda
2. 1998-1999 Scram Data Summary
3. Frequently Asked Questions
4. NRC Inspection Manual: Temporary Instruction 2515/144
   Performance Indicator Data Collecting and Reporting Process Review

Public Meeting

April 13, 2000

Participants

Dennis Hassler, PSEG
Patricia Loftus, ComED
Kevin Borton, PECO
David Robinson, Nebraska Public Power
Wade Warren, Southern Company
Alan Madison, NRC
Tom Houghton, NEI
Steve Floyd, NRI
Michael Johnson, NRC
Cornelius Holden, NRC
August Spector, NRC
Don Hickman, NRC
Serita Sanders, NRC
William Dean, NRC

Public Meeting

April 13, 2000

Agenda

1. Discuss up-date of Frequently Asked Questions

2. Discuss up-date of initiating event performance indicator

3. Discuss Allowed Outage Time 9AOT) issues and changes

4. Discuss unavailability performance indicator definition

5. Up-date of Cross-Cutting Issues Task Force activities

6. Discuss Fire Protection SDP issues

7. Discuss RHR Thresholds up-date of industry issue

Attachment 1

DRAFT 4/12/00

File Copy

1998 – 1999 Scram Data Summary

There were a total of 178 scrams (111 automatic and 67 manual) at power during the period 1998 to 1999. Manual scrams accounted for 37.6% of all scrams.

The causes of the scrams can be grouped as follows:

Primary Side Problems (58)

- Rod control system problems – 17
- Primary loop (RCPs, recirc pumps, CCW,etc.) – 8
- Reactor protective system logic trips – 22
- Steam generator/reactor water level instrumentation – 11

Balance of Plant Problems (120)

- Circulating water – 4
- Condenser – 15
- Main generator/offsite power/ electrical distribution – 30
- Main steam/turbine – 37
- Feedwater -- 34

Attachment 2

Proposed Initiating Events PI

Unplanned Plant Shutdowns

This indicator monitors the number of times that the plant must be rapidly shutdown in response to problems with either the primary or secondary systems. It measures the rate of unplanned shutdowns and provides an indication of initiating event frequency. The shutdown is considered rapid if power operations are ceased and the reactor is subcritical within 30 minutes of the identification of the problem.

Primary problems include (but are not limited to):

- Problems with the rod control system
- Problems with reactor coolant pump seals, recirculation pumps, component cooling water or integrity of the reactor coolant pressure boundary
- Reactor protection system logic trips
- Problems with primary plant instrumentation

Secondary problems include (but are not limited to):

- Reductions in circulating water
- Condenser problems
- Problems with main generator, offsite power or internal electrical distribution systems
- Problems with main steam system or turbine
- Problems with feedwater system

DRAFT 4/12/00

Initiating Event Performance Indicator Task Force

Background

The current initiating event performance indicators (unplanned scrams and scrams with loss of normal heat removal) could have the potential for unintended consequences by inhibiting an operator from initiating a manual scram to avoid exceeding a performance threshold. Given the importance of this issue, focused efforts should be undertaken to explore other performance indicators which do not have the potential for unintended consequences and which would be an adequate substitute in the NRC's Revised Reactor Oversight Process.

Mission

To explore the feasibility of an alternate initiating event indicator that could substitute for unplanned scrams and scrams with loss of normal heat removal, thereby eliminating the potential for unintended consequences.

Scope

1. Review historical scram data focusing on causes of scrams and available industry data on initiating events (e.g. NUREG/CR-5750) to identify potential replacement indicators.

2. Draft recommended performance indicator(s) consistent with level of detail in NEI 99-02

3. Assess impact on inspection modules (ability of new indicator to replace current indicators)

4. Obtain NRC concurrence with concept

5. Collect historical data

6. Establish candidate thresholds

7. Assuming NRC approval, establish pilot study of 8-10 plants to test the indicators

8. Analyze pilot results and make necessary changes

9. Obtain NRC concurrence with indicator

10. Train and implement

Schedule

Commence	April 2000
Target implementation	January 2001

Draft 04/12/00 5:30 PM
FAQ Log 6

No.	PI	Question	Proposed Answer	Plant/ company
1	PP01	Variable Normalization Factor During steady state operations our site has one access portal open for personnel to enter the protected area. During an outage we open a second access portal. The change in protected area barrier configuration affects the number of zones that are used. The result is we have a 1.9 normalization factor during steady state, and 1.95 during an outage. What value of normalization factor should we report for quarters that include an outage?	A prorated normalization factor that addresses periods when the seconds access portal is open should be reported	Detroit Ed
2	PP01	NEI 99-02 under the Preventive maintenance section indicates that during preventive maintenance or testing, cameras that do not function properly and can by compensated for by means other than posting an officer, no compensatory man-hours are counted. Does this exclusion only apply to camera events discovered during the above mentioned times or can this exclusion be applied to any time a camera can be compensated for by means other than posting an officer?	The PI counts compensatory man-hours. Any compensatory actions other than posting a security officer (e.g., use of alternate equipment) are not counted.	Palo Verde
3	EP01	During an evaluated scenario, the conditions for a General Emergency (GE) were met based on Plant conditions with three barriers breached. The Emergency Director (ED) failed to recognize the classification conditions had been met within 15 minutes. After the 15 minutes, a release occurred and a dose projection was performed which exceeded levels for a GE. The ED recognized this and a GE was declared based on Radiological Conditions and all required notifications and PARs were completed. Would the first opportunity based on Plant conditions be considered a missed opportunity? Would a second opportunity be allowed based on Radiological conditions? If a second opportunity is not allowed can any credit be taken for successfully completing notification and PAR opportunities based on the second opportunity?	The scenario identified only one general emergency (plant conditions), PAR development, classification, notification, and PAR notification. This represents four opportunities. The second general emergency (radiological conditions) opportunity does not count since it was not identified as an opportunity prior to the drill. However the notification, development of the PAR, and PAR notification are given credit. Therefore three of the four opportunities identified were successful.	WNP2
4	PP01	Is the tamper detection system considered part of the IDS? For example, if the tamper detection system is being monitored for compensatory measures, but the IDS is properly functioning, do	Not if IDS is functioning as intended.	Check with NRC security

Attachment 3

No.	PI	Question	Proposed Answer	Plant/ company
		licensees need to count these compensatory hours?		
5	PP01	**Appendix D: North Anna Site** At North Anna Power Station we have only one part time CCTV camera that is used as part of the PA perimeter threat assessment during refueling outages. With one part time CCTV camera, that has been reliable, we have not had any compensatory hours to report for this portion of the PI. This results in what might seem to be an artificially high performance index for this PI since the CCTV camera portion of the indicator is equally weighted with the IDS portion. Is it appropriate to continue to report CCTV camera compensatory hours for a site with a low number of and infrequently used CCTV cameras?	Continue to report in accordance with the current guidance in NEI 99-02. That is, report compensatory hours for the part time CCTV camera as they occur. Put a note for this PI in the comments section submitted to the NRC similar to the following: "Performance data reflects zero, (or X), hours of CCTV camera operation during this reporting period."	VP
6	PP01	**Appendix D: Surry Site** At Surry Power Station we have only one full time CCTV camera that is used as part of the PA perimeter threat assessment. With only one CCTV camera, that has been reliable, we have not had any compensatory hours to report for this portion of the PI. This results in what might seem to be an artificially high performance index for this PI since the CCTV camera portion of the indicator is equally weighted with the IDS portion. Is it appropriate to continue to report CCTV camera compensatory hours for a site with such a low number of CCTV cameras?	Continue to report in accordance with the current guidance in NEI 99-02. That is, report compensatory hours for the single CCTV camera as they occur. Put a note for this PI in the comments section submitted to the NRC similar to the following: "Performance data reflects one CCTV camera."	VP
7	MS01	Our site has two units, each of which has two trains of EAC with separate buses, for a total of four buses. There are four diesels on the site, and each diesel can be aligned to either unit, but are train specific. We are only required to have one diesel per train, for a total of 2 for the site, but PSA suggests that aligning each of the four diesels to its own bus is the preferred option. When one diesel is out for maintenance, we can align the other diesel in that train to both buses in the train, one bus in each unit. Technical Specifications do not limit the amount of time the plant can be in this configuration. We are counting unavailability for NRC indicators as follows: If an EAC bus does not have a diesel aligned to it in standby, then hours are counted for unavailability against that train. If a diesel is aligned	The purpose of this indicator is to monitor the readiness of important safety systems to perform their safety function in response to off-normal events or accidents. Plant specific requirements must be reviewed to determine the answer to your question (i.e., what are the safety functions of your diesels?)	WEPCO

No.	PI	Question	Proposed Answer	Plant/ company
		in test to a bus, that is also counted as unavailability for that train because we cannot immediately restore the diesel nor does the diesel automatically start and supply the bus on a loss of power. If a diesel is aligned in test to both units, then it is counted as unavailability for both units. However, when a diesel is out of service for maintenance, it is not counted as unavailability if the alternate same-train diesel is aligned in standby to both buses in that train. We consider the extra diesel in each train as a maintenance train according to the rules in the NRC/NEI 99-02 guidance. Are we correct in the interpretation of these rules? Also, the diesels are currently not considered alternate AC power supplies for SBO, but they could be if we chose per our SBO submittal. If we did choose to declare our normal alternate AC power supply unable to provide the function and chose to use an EDG for this purpose, would we have to count for this indicator the time the EDG is unavailable to support SBO? Or, stated more generally, do we need to consider for this indicator all CLB functions of the EDGs (such as SBO or App R), or only those cited in our Technical Specifications?		
8		withdrawn		
9	MS04	Can a Spent Fuel Cooling train be considered an installed spare of Shutdown Cooling under certain conditions? If yes, should unavailable hours be counted during a planned removal from service of the entire Shutdown Cooling System, if it has been demonstrated that a single SFC train will meet the requirements for an installed spare of the shutdown cooling function, and two SFC trains are currently operable? NEI 99-02, states that an "installed spare" is "a component (or set of components) that is used as a replacement for other equipment to allow for the removal of equipment from service for preventive or corrective maintenance without incurring a limited condition for operation (where applicable) or violating the single failure criteria. To be an "installed spare," a component must not be required in the	FAQ 17 applies. (Does this need to be a FAQ?) Also, note that Rev 0 does not require forced flow.	Duane Arnold

No.	PI	Question	Proposed Answer	Plant/ company
		design basis safety analysis for the system to perform its safety function." Using the above definition, it would appear a Spent Fuel Cooling System train could be considered an installed spare of the shutdown cooling function under certain conditions: no design basis safety analysis requirement, a connection between the spent fuel pool and reactor vessel, and analysis indicating that under the current conditions the train is adequate to offset the combined vessel and fuel pool decay heat load. FAQ 17 appears to support the interpretation that SFC can be an installed spare of shutdown cooling under certain conditions. NEI 99-02 goes on to say that "those portions of the Shutdown Cooling System associated with one heat exchanger flow path can be taken out of service without incurring planned or unplanned unavailable hours provided the other heat exchanger flow path is available (including at least one pump) and an alternate, NRC approved means of removing core decay heat is available." In the case cited above, each SFC train has taken the place of a Shutdown Cooling System train, as an installed spare. Each SFC train can maintain the core decay heat load within the temperature limits set by the plant's design basis. Therefore, there continues to be a heat exchanger flow path, and an alternate, closed-cycle, forced means of removing core decay heat. Thus, it would appear no unavailable hours need be incurred.		
10	MS01 - MS04	NEI 99-02 does not adequately address how to evaluate unplanned unavailable hours for situations where support systems are not immediately required but are required for long term operation. For example: One of our plants has a situation where a breaker for some DG support systems, specifically, fuel transfer to the DG day tank (4 hour capacity), and room cooling (during the winter) was found to	The Support System Unavailability section of 99-02 states that "the technical specification criteria for determining operability may not apply when determining train unavailability. In these cases, analysis or sound engineering judgement may be used to determine the effect	Southern Co.

No.	PI	Question	Proposed Answer	Plant/ company
		be inoperable. For this situation, the DG would have started and performed it's intended function for a length of time (probably 4 hours). Also, control room alarms and/or local log recording would have noted the deficient condition, and administrative controls would have provided for restoration of the system without losing the Diesel Generator safety function. Engineering analysis can determine how long the DG would operate compared to the expected response by the plant for restoration of the support systems. However, NEI 99-02 does not address alarms and operator actions for this type of situation. For this type of situation, may credit be taken for analysis involving alarms and actions?	of support system unavailability on the monitored system." For the above example, if the licensees analysis can ascertain the restoration actions are virtually certain to be successful (i. e. probability nearly equal to 1) during accident conditions and the Diesel Generator's safety function would not have been lost, then there would be no safety system unavailable hours. Generally, each situation would need to be handled on a case by case basis and discussed with the resident inspector.	
11	IE03	Concerning Unplanned Power Changes per 7,000 Critical Hours, does the 72 hour period apply to situations where power reductions are required to conduct expected rod pattern adjustments? A specific example involves a reactor start-up and power ascension following a scram. It is expected that the subsequent startup will probably require a rod pattern adjustment after achieving 100% power. To conduct the adjustment after achieving 100% power would require a power reduction potentially greater than 20%. If this situation occurs in less than a 72 hour period (time frame from the scram to the > 20% power reduction following return to power operation) does this count as an unplanned power change?	This indicator monitors changes in reactor power that are initiated following the discovery of an off-normal condition. The example described would not be counted in the unplanned power changes indicator provided the condition is expected.	Southern Co.
12	MS01 - MS04	Does planned preventive maintenance (PM) or corrective maintenance (CM) on support systems have to be taken as Planned Unavailable Hours for the supported system? Page 22, lines 9 – 33 infers that <u>any</u> PM or CM must be credited as Planned Unavailable hours. One example is a site where there are four EDGs. Each EDG has two approximate 50% fuel oil tanks. The fuel oil tanks are a support system for the EDG. At times, a fuel oil tank is removed from service and drained for cleaning. In this case, the Technical Specification requires the corresponding EDG to be declared Inoperable. However, with one fuel oil tank remaining available, the	For the above-cited examples, the hours do not have to be counted as unavailable hours for the EDG. Additionally, planned maintenance on support systems does not have to be counted as unavailable hours on the supported system providing the supported system will function as designed during an emergency without the need for any prompt operator action.	Hope Creek

No.	PI	Question	Proposed Answer	Plant/ company
		EDG will start and has enough fuel to run for over 3 days with no operator action required (Note: the mission time is 7 days). In addition, plans are in place in emergency scenarios for the delivery of fuel oil. Another example for the same configuration, each fuel oil storage tank has a separate fuel oil transfer pump. At one time, both fuel oil transfer pumps were inoperable to support troubleshooting activities. The EDG day tanks were available and would support EDG start and contain sufficient fuel to run for a few hours. During the troubleshooting activities, work was performed in accordance with a procedure, an operator was stationed locally for restoration, and the restoration steps were non-complicated. For both examples, the EDG will perform its safety function for an ample time following a loss of offsite power with no immediate operator action; does this time have to be counted as unavailable hours for the EDG?		
13	MS01 - MS04	NEI 99-02 Rev 0 states on Page 31, Lines 4 – 6 states: "In some instances, unavailability of a monitored system that is caused by unavailability of a support system used for cooling need not be reported if cooling water from another source can be substituted. Limitations on the source of the cooling water are as follows:" Further on page 31, lines 18 - 21 states: "for emergency generators, cooling water provided by a pump powered by another class lE (safety grade) power source can be substituted, provided a pump is available that will maintain electrical redundancy requirements such that a single failure cannot cause a loss of both emergency generators."	A water source that is required as backup in case of equipment failure to allow the system to meet redundancy requirements or the single failure criterion is not considered to be cooling water from another source. With respect to the third question, for availability use NEI99-02. For operability determination, apply your tech specs and appropriate industry/NRC guidance.	PSEG

No.	PI	Question	Proposed Answer	Plant/ company
		What is meant by water from another source? Does this refer to a redundant source or a diverse cooling water source? A specific example is for the EDG cooling water: 1. Is another source meant to be from a source like demineralized water or firewater? or, 2. Is a redundant Service Water or Station Auxiliaries Cooling (SACs) pump considered to be another source? 3. What is the relationship of Technical Specification Operability and availability? If the EDG is Operable, then by definition the EDG can perform its safety function.		
14	BI01	NEI 99-02 Rev 0 states on Page 76, Lines 15 - 18 states: "This indicator monitors the steady state integrity of the fuel-cladding barrier. Transient spikes in RCS Specific Activity following power changes, shutdowns and scrams may not provide a reliable indication of cladding integrity and should not be included in the monthly maximum for this indicator. " Steady state is not defined.	If steady state is not defined, use the definition in INPO96-003 where steady state is defined as continuous operation for at least three days at a power level that does not vary more than ± 5 percent.	PSEG
15	MS01 - MS04	Under "Support System Unavailability" of NEI-99-02 the statement is made that: "for monitored fluid systems with components cooled by a support system, where both the monitored and support system pumps are powered by a class 1E (i.e. safety grade or equivalent) electric power source, cooling water supplied by a pump powered by a normal (non-class 1E--i.e., non-safety-grade) electric power source may be substituted for cooling water supplied by a class 1E electric power source, provided that redundancy requirements to accommodate single failure criteria for electric power and cooling water are met. Specifically, unavailable hours must be reported when both trains of a monitored system are being cooled by water supplied by a single cooling water pump or by cooling water pumps powered by a single class 1E power (safety-grade) source". We are defining our system boundary for the reported system to include the breaker/ switchgear providing power to the reported system's pumps/valves, etc. The main switchgear/breakers are installed in the safety switchgear panels that are cooled by a common area cooling system. This cooling system is safety grade, as cooling is required following a design basis accident from a safety grade source. The cooling system has two fan coil units, using safety	The purpose of this indicator is to monitor the readiness of important safety systems to perform their safety function in response to off-normal events or accidents. Plant specific requirements must be reviewed to determine the answer to your question.	Waterford3

No.	PI	Question	Proposed Answer	Plant/ company
		chilled water in each coil, a train A (&powered by train A 1E power) and a train B unit (powered by safety grade train B 1E power). Therefore cooling for the portions of the reported systems installed in the safety Switchgear panel is provided by redundant, class 1E powered, safety grade unit coolers (train A and B). The coolers discharge to a common plenum, which in turn cools the separate switchgear rooms. Each cooler (train A and B) has 100% capacity for cooling all (train A, B, and AB) switchgear. At our site there are currently no technical specification associated with these coolers, although we have imposed a 72 hour limitation for removing one cooler (in either train) from service in our technical requirements manual (TRM), as well as a one hour shutdown action statement if both coolers (trains) are inoperable. However, since no technical specifications exist, we do not cascade inoperability or unavailability of the unit coolers into the switchgear themselves, one reason being since the cooling duct system is common to all switchgear it is impractical to cascade. In light of the above quoted statement in the NEI document, are we required to report unavailability hours in one or more trains of the reported systems, cascaded from removal of one train of the switchgear cooling system from service (i.e. removal of one of the two, redundant, fan coil units from service), and if so how would the unavailable hours be assigned?		
16	MS02	NEI 99-02 contains the guidance for Safety System Unavailability - Planned Unavailable Hours. A system is to be considered unavailable during testing unless specified criteria are met. Monthly HPCI oil samples are taken to monitor the performance of the Turbine and the HPCI Steam Isolation Valve. While taking the oil samples on the HPCI turbine, the Aux. Oil Pump is running and the flow controller is taken to manual and set to minimum flow to prevent an over-speed condition if an initiation signal occurs while the Aux. Oil Pump is running. This monthly oil sample takes about 15 to 30 minutes per month. During this time, the system is declared inoperable and the appropriate Technical Specification actions are entered. If a HPCI initiation signal were received, HPCI will automatically start. The control room operator will manually, with the HPCI flow controller, raise HPCI turbine speed and establish injection flow at 5600 gpm as directed by procedure. This manual action is unlike the automatic response. A fully automatic response would control the transient turbine acceleration and ramp open the	The unavailable hours would count because the system response specifically relies on operator action which is not "virtually certain to be successful" (NEI99-02 page 26 line 38). The operator actions have the potential to overspeed the turbine. Discussion issue: However, the total unavailable time that is incurred by this monthly sample is less than 0.07% unavailability for the 12 quarters. The NRC considers this to be negligible and does not have to be counted for this example.	PSEG

No.	PI	Question	Proposed Answer	Plant/ company
		steam stop valve and control the response of the governor control valve such that 5600 gpm is achieved in 35 seconds or better. The restoration actions are simple, can be completed by a control room operator, are contained in a procedure, and the HPCI function can be restored. The question is if credit for operator restoration can be taken in this case based on the system starting on an automatic signal, restoration actions are part of a normal response to the system start and contained in a procedure, and the operators are trained on this action? Can HPCI be considered available in this case? In general, must the SSC response be identical to a fully automatic initiation and how does this compare to "or the function can be immediately restored."		
18	MS04	**Appendix D: Millstone Unit 2** Unavailability Monitoring For RHR on Combustion Engineering (CE) Plants. Currently, on Millstone Unit 2, the RHR function is monitored as Shutdown Cooling (SDC) for Modes 4, 5 & 6 and Containment Spray (CS) for modes 1, 2 & 3. In this capacity, the RHR function is monitored as one system with two trains because of the shared SDC heat exchangers. It is Millstone Engineering's assessment that this configuration meets the definition found in INPO Document 98-05 chapter 6, page 6-68 (2nd para) which describes figure G-2 on page 6-73. When this information is compared to NEI document 99-02 which describes PWR RHR Systems and the two functions monitored. The problem is, the SDC system only performs one of these functions (remove decay heat during normal shutdown) on a CE plant. The first function mentioned above is performed by two systems: HPSI takes a suction from the sump and injects into the core, but does not flow through the SDC heat exchanger and CS takes a suction from the sump and flows through the SDC heat exchanger but does not inject into the core. Both of the functions mentioned in the NEI definition would be applicable to some Westinghouse plants. It is assumed the two desired functions to be monitored (from all available information)	Reporting of unavailability hours for multi-function system should be counted only during the time the particular affected function is required by technical specifications. The two functions are added together to derive the total hours of RHR unavailability to be reported. Overlap times when both functions/systems are required can be adjusted to eliminate double counting the same incident.	Millstone U2 Check

No.	PI	Question	Proposed Answer	Plant/ company
		are the ability to remove decay heat from the core during a normal shutdown to refuel or perform maintenance and to remove decay heat from the core following a LOCA i.e., long term cooling. If this position is correct, then a CE plant would monitor SDC and HPSI systems only. Please provide clarification of the functions and systems to be monitored.		
19	MS04	**Appendix D: CE Designs** Certain CE ECCS designs are significantly different from the standard Westinghouse PWR designs. One of these CE designs runs all ECCS pumps during the injection phase (Containment Spray (CS), High Pressure Safety Injection (HPSI), and Low Pressure Safety Injection (LPSI)), and on Recirculation Actuation Signal (RAS), the LPSI pumps are automatically shutdown, and the suction of the HPSI and CS pumps is shifted to the containment sump. The HPSI pumps then provide the recirculation phase core injection, and the CS pumps by drawing inventory out of the sump, cooling it in heat exchangers, and spraying the cooled water into containment support containment cooling. How should CE designs report RHR	In NEI 99-02 the RHR indicator has two monitored function. The first is repeated below. "The ability of the RHR system to take a suction from the containment sump, cool the fluid, and inject at low pressure into the RCS." The CE plant design described above uses HPSI to "take a suction from the sump", CS to "cool the fluid", and HPSI to "inject at low pressure into the RCS". Due to these design differences, CE plants with this design should monitor unavailability in the following manner. The HPSI pumps and there suction valves are already monitored under the HPSI function, and no monitoring under the RHR PI is necessary or required. The two containment spray pumps and associated coolers should be counted as two trains of RHR providing the post accident recirculation cooling, function 1. The SDC system should be counted as two additional trains of RHR providing decay heat removal, function 2.	

No.	PI	Question	Proposed Answer	Plant/ company
			Four trains should be monitored, when required by Technical Specifications, as follows: Train 1 (recirculation mode) Consisting of the "A" containment spray pump associated MOVS, and the required spray pump heat exchanger and MOVS. Train 2 (recirculation mode) Consisting of the "B" containment spray pump associated MOVS, and the required spray pump heat exchanger, and MOVS. Train 3 (shutdown cooling mode) Consisting of the "A" SDC pump, associated MOVS and heat exchanger. Train 4 (shutdown cooling mode) Consisting of the "B" SDC pump, associated MOVS and heat exchanger.	
20	MS01	Withdrawn		
21		Withdrawn		
22	MS01 02,03, 04	Revision 0 of 99-02 added the provision that, for the mitigating systems unavailability, "on-line planned overhaul maintenance" does not have to be counted as unavailable hours for the performance indicator. This new term needs to be defined. Our practice is to do on-line maintenance during the system outage windows as allowed by our Tech Spec out of service time. During these outages we perform corrective maintenance, preventive and predictive maintenance, surveillance testing, etc. The question needing to be answered is: How much of the unavailability time used during these planned on-line outages counts as "on-line planned overhaul maintenance time?	See No 23 question 5	Clinton

No.	PI	Question	Proposed Answer	Plant/ company
23	MS01 ,02,03 ,04	FAQs on Planned Overhaul Hours The concept of not counting major on-line overhaul hours against the SSU performance indicator is sound. It allays a prevalent concern that a licensee could end up with a white indicator, and potentially a degraded cornerstone, primarily due to performing on-line maintenance that is considered in PSA analyses and bounded by the Tech. Spec. AOT, and has been determined to be a good business practice [to reduce outage length, etc.]. To ensure consistency of reporting and inspector oversight, the following issues should be addressed: 1. Is application of planned overhaul hours limited to systems for which a risk informed AOT extension has been approved? 2. Is there a limit to the number of planned overhaul outages a licensee can report on a given system / train? 3. If an overhaul maintenance interval is scheduled to take 120 hours, but the actual unavailable interval is greater [say 140 hours] but still bounded by T.S. AOT, can the entire interval be designated as planned overhaul hours, or is only the scheduled interval appropriate?	1.No, application is for any AOT sufficient to Accommodate the overhaul hours. 2. The intent is to allow licensees to perform on line Overhaul maintenance that is bounded by the Tech. Spec. AOT. Typically, such overhaul activities are performed infrequently in accordance with an established preventive maintenance program. For a specific Safety System / Train, it is expected that only one or two planned maintenance intervals during an operating cycle would be designated as overhaul maintenance. 3. If the unavailability is caused by activities designated as planned overhaul maintenance, the hours should not be counted in the unavailability indicator. If the additional unavailability is caused by a failure that would prevent a safety function, the additional hours would be non-overhaul hours and would count toward the indicator. (Also, see footnote 3 page 26 Rev 0.)	Fermi

No.	PI	Question	Proposed Answer	Plant/ company
		4. Can additional non-overhaul maintenance be performed during a planned overhaul maintenance interval?	4. Yes, as long as the outage duration is bounded by overhaul activities, other maintenance activities may be performed. However, modifications or corrective maintenance that affects availability would count. If the overhaul activities are complete, and the outage continues due to non-overhaul activities, the additional hours would be non-overhaul hours and would count toward the indicator	
		5. What defines overhaul versus non-overhaul maintenance?	5. Overhaul maintenance is maintenance, performed on line within the Technical Specification Allowable outage time, to implement equipment overhaul tasks. Overhaul tasks are those that require major disassembly of components and are performed infrequently in accordance with an established preventive maintenance program.	
		6. Can Major rebuild tasks necessitated by an unexpected component failure be counted as overhaul maintenance? [Example: RHR pump wipes a motor bearing during surveillance run. It is decided to pull PM activities ahead to replace the motor with a spare.]	6. No.	
24	MS01 02, 03, 04	Assume a recirculation spray pump tested poorly and had only previously been tested 2 years ago. Per the NEI 99-02 FAQ I believe I am to go back and revise the fault exposure hours for these quarters. Should I zero out any other unavailability for those months, since the accumulation of unavailability could be greater than the hours required?	Remove the double count by removing the planned and unplanned hours which overlap with the fault exposure hours. Put an explanation in the comment field. If you later remove the fault exposure hours, restore the hours which had been removed.	Beaver Valley
25		APPENDIX D PALO VERDE NEI 99-02, revision 0 states "Some plants have a startup feedwater pump that requires manual actuation. Startup	Based on the information provided, these particular SSCs should be considered a third train of auxiliary feedwater for NEI 99-02	APS

No.	PI	Question	Proposed Answer	Plant/ company
		feedwater pumps are not included in the scope of the AFW system for this indicator." Our plants have startup feedwater pumps that require manual actuation. They are not safety related, but they are credited in the safety analysis report as providing additional reliability/availability to the AFW system and are required by Technical Specifications to be operable in modes 1, 2 and 3. They are also included in the plant PRA and are classified as high risk significant. Should these pumps be treated as third train of auxiliary feedwater for NEI 99-02 monitoring purposes or does the startup feedwater pump exemption apply?	monitoring purposes.	
26		Are Technical Specification required monthly Emergency Diesel Generator surveillance tests counted as unavailability for this PI? Actions to restore the EDGs during surveillance testing could be considered complex. However, it seems unreasonable to count these required surveillance tests as unavailability, considering the fact that the EDG is powering the Engineered Safeguards bus in parallel with the grid for the majority of the test.	Yes.	FPC
27		We have not been counting technical specification required Emergency AC System surveillance testing as unavailability for the WANO performance indicators. The testing configuration is not automatically overridden by a valid starting signal and the function cannot be immediately restored, either by an operator in the control room or by a dedicated operator stationed locally for that purpose. Does historical data submitted Jan 21, 2000 for Emergency AC System safety system unavailability PI have to be corrected to take into account the additional unavailability? NEI 99-02, Revision D, is not clear in this respect.	No, the historical data does not have to be revised unless there were known reporting errors to WANO. If you were reporting in accordance with WANO direction you do not have to revise your historical input. However, data submitted for first quarter 2000 must comply with NEI 99-02.	FPC
28		withdrawn		
29		The Decay Heat Removal Technical Specifications state that at or below 280 degrees, 2 of the 4 following coolant loops shall be operable:	No. Since the Steam Generators are classified by the technical specifications as "NRC approved alternatives" for decay heat removal, unavailability hours would not be counted as	ANO

No.	PI	Question	Proposed Answer	Plant/ company
		(1) Reactor Coolant Loop (A) and its associated Steam Generator and at least one associated reactor coolant pump (2) Reactor Coolant Loop (B) and its associated Steam Generator and at least one associated reactor coolant pump (3) Decay Heat Removal Loop (A) (4) Decay Heat Removal Loop (B) The Low Pressure Injection Technical Specification is not applicable below 300 psig. With the RCS pressure below 300 psig and RCS temperature below 280 degrees, and with both Steam Generators available for decay heat removal, technical specifications allow decay heat pumps to be taken out of service. During the time that decay heat pumps are out of service and the plant is relying on steam generators for decay heat removal, would any unavailability time be counted?	long as any 2 of the 4 coolant loops are operable as stated in the technical specification. NEI 99-02 FAQ #149 response states that unavailability hours should be counted only during the time that a particular affected function is required by technical specifications. NEI 99-02 FAQ #155 allows NRC approved alternate shutdown cooling trains to replace RHR systems without incurring unavailability.	
30		Do hours associated with EDG improvements (e.g., cooling improvement modifications) have to be counted as unavailable hours if done for EDG improvement and in accordance with the Tech Spec AOT(our AOT is 14 days and in partly risk informed). Can you provide any more specific information? When will we be likely to see something from the NRC or NEI?	Yes.	Pilgrim

NRC INSPECTION MANUAL

IIPB

Temporary Instruction 2515/144

PERFORMANCE INDICATOR DATA COLLECTING AND REPORTING PROCESS REVIEW

CORNERSTONES: INITIATING EVENTS
MITIGATION SYSTEMS
EMERGENCY PREPAREDNESS
OCCUPATIONAL RADIATION SAFETY
PHYSICAL PROTECTION

APPLICABILITY: This temporary instruction (TI) applies to all holders of operating licenses for nuclear power reactors, except (1) nuclear power reactors that have permanently ceased operations and have certified that fuel has been permanently removed from the reactor vessel, and (2) D.C. Cook Units 1 and 2 and Browns Ferry Unit 1 nuclear power reactors that have been shutdown for an extended period of time.

2515/144-01 OBJECTIVE

To review a licensee's performance indicator (PI) data collecting and reporting process to determine whether the licensees are appropriately implementing the NRC/Industry guidance.

2515/144-02 BACKGROUND

The revised reactor oversight process uses PI information, along with the results from its reactor inspection program, to provide the basis for NRC staff to assess plant performance and establish the appropriate regulatory response. PIs provide objective indicators of licensee safety performance in each cornerstone of safety on a periodic basis. The PI information is a basic element of the revised reactor oversight process (RROP).

The performance indicator portion of the RROP was designed to use data submitted by licensees. The effectiveness of the performance indicator portion of the RROP is contingent upon licensees providing PI data for their respective reactor facilities in accordance with the guidance contained in Nuclear Energy Institute (NEI) 99-02

Attachment 4

Revision 0, "Regulatory Assessment Performance Indicator Guideline."

Several problems were identified during the pilot program with accurately reporting the PIs in accordance with the industry guideline document, NEI 99-02. Most of these errors were minor in nature and were largely attributed to the difficulty in collecting and reporting historical data and problems with ambiguous definitions and clarifying instructions. There were, however, some situations where errors in reporting were substantial and continued for some time due to misinterpretation of guidance. For example, power changes that should have been included in the Unplanned Power Changes PI were not reported and fault exposure hours were not accounted for in the Safety System Unavailability PI due to misinterpretations of the guidance. As a result, many changes were made to the industry guideline document to improve the clarity of the guidance. However, a key lesson learned from the pilot program is that an effort to assure the NRC and the licensees have a common understanding of how to apply the guidance in NEI 99-02 is important.

The NRC issued two Regulatory Issue Summaries (RIS) to document the understanding between the industry, as represented by the Nuclear Energy Institute (NEI), and the NRC that all non-pilot plant licensees would voluntarily submit to the NRC in January 2000 a historical PI data submittal and that all licensees would voluntarily submit PI data on a quarterly basis beginning April 21, 2000. Each licensee voluntarily submitted their historical PI data on January 21, 2000. The January submittal included data for each indicator covering two years (1st quarter 1998 - 4th quarter 1999) or data sufficient to calculate a 4th quarter 1999 indicator value, whichever is greater. All licensees are expected to begin submitting quarterly PI data, with the first submittal due April 21, 2000.

It is recognized that in instituting this new and voluntary initiative, that reporting errors will occur. This was a lesson learned during the pilot program. The Office of Enforcement (OE) has established a policy of blanket enforcement discretion for issues related to non-willful, inaccurate PI reporting through January 31, 2001. The enforcement guidance to support the initial implementation of the RROP is provided in Enforcement Guidance Memorandum (EGM) 00-001, "Application of the Enforcement Policy in Conjunction with the Revised Reactor Oversight Process."

2515/144-03 INSPECTION REQUIREMENTS

PI Process Review

Review the licensee's PI data collecting and reporting process and determine whether the data collecting and reporting methods for current PI data are consistent with the guidance contained in NEI 99-02, Revision 0, "Regulatory Assessment Performance Indicator Guideline." To verify each licensee's PI data collecting and reporting process, review indicator definitions, data reporting elements, calculational methods, definitions of terms, and clarifying notes used by the licensees for consistency with industry guidance document NEI-99-02, for the following indicators:

1. Initiating Events - Unplanned Power Changes per 7000 Critical Hours.

2. Mitigating Systems - Any of the safety System Unavailability (SSU) Performance Indicators and Safety System Functional Failures.

3. Emergency Preparedness - Emergency Response Organization Drill Participation (ERO)

4. Occupational Radiation Safety - Occupational Exposure Control Effectiveness

5. Physical Protection - Protected Area Security Equipment Performance Index

2515/144-04 GUIDANCE

PI Process Review

The intent of this inspection effort is to review and determine whether the licensee's have a clear understanding of the indicator definitions, data reporting elements, calculational methods, definitions of terms, and clarifying notes and a process that will produce accurate performance indicators in accordance with the guidance in NEI-99-02, Revision 0. The PIs identified for review in Section 03 were based on consideration of factors such as the recently revised indicator thresholds, revised NEI-99-02 guidance and an effort to obtain a good representation of important performance areas. The inspector may review indicator data submittal for the first quarter of CY 2000 and beyond to support the PI process review.

It is not the intent of this TI to verify the accuracy of the licensee's performance indicator data. The periodic verification of PI data accuracy is performed via inspection procedure 71151, "Performance Indicator Verification." However, the inspector may perform this PI process review in coordination with the PI verification inspection if adequate data exists at the time the TI is accomplished.

At quarterly intervals, each licensee will submit to the NRC the performance indicator data by the 21st calender day of the month following the end of the reporting quarter. The format and examples of the data are provided in NEI 99-02. The guidance provided in NEI 99-02, Revision 0, should be used in the preparation and submittal of performance indicator data for second quarter CY 2000 and beyond. Guidance contained in NEI 99-02, Draft Revision D, will typically be utilized for first quarter CY 2000 data. PI data submitted prior to the issuance of NEI 99-002, Revision 0, may be revised and resubmitted to reflect current guidance if desired by the licensee. However, revisions of previously submitted data that are the result of changes to guidance alone are not required.

While not the focus of this TI, if a PI data reporting error is discovered, an amended mid-quarter report is not required to be submitted by the licensees as long as the error would not have resulted in crossing a threshold licensee response. However, the corrected data should be submitted in the next quarterly report along with a brief description of the change(s) as described in NEI-99-02.

If the licensee does not agree on NRC's interpretation of an issue, the inspector should do the following:

1. Review the NEI-99-02 guidance on clarifying notes and frequently asked questions (FAQs) and determine whether the issue has already been addressed of if this review resolves the issue.

2. If interpretation difference still exists, this issue should be brought to the attention of the respective Division of Reactor Projects Branch Chief for resolution.

3. If the interpretation issue is not resolved before the end of the inspection, it should be identified as an Unresolved Item in the report and raised to the program office for interpretation and possible consideration for the NRC/NEI working group resolution process. The inspector should complete the attached Feedback Form and forward it to the Inspection Program Branch (IIPB), Office of Nuclear Reactor regulation (NRR) for review.

If the program office cannot resolve the above issue in a timely manner, then the issue will be entered in the FAQ process and will be resolved during an NRC/NEI public meeting.

If the inspector and the licensee agree on an interpretation for which NEI-99-02 guidance is not clear, then the inspector should also complete the attached Feedback Form and forward it to the Inspection Program Branch, NRR for review and possible consideration for the NRC/NEI working group.

If the inspector determines that the licensee's application of NEI 99-02 to its PI data collecting and reporting process resulted in a number of interpretation issues such that there are concerns that the licensee will collect of report PI data incorrectly, this should be brought to the attention of licensee and regional management.

2515/144-05 REPORTING REQUIREMENTS

Document inspection results in a routine inspection report in the " other activities" section of the inspection report. The report should describe the adequacy of data collecting and reporting process as well as any current process weaknesses that could affect accurate reporting of the PIs. Upon completion of the TI, a copy of each inspection report and an overall summary of the TI inspection results from each region should be sent to the Chief, Inspection Program Branch, NRR.

2515/144-06 COMPLETION SCHEDULE

This TI inspection will commence on April 30, 2000. This TI should be completed by October 30, 2000.

2515/144-07 EXPIRATION

This TI will expire one year from the date of issuance.

2515/144-08 CONTACT

Any questions regarding the performance of this TI should be addressed to R. Mathew (301) 415-2965, D. Hickman (301) 415-8541 or S. Sanders (301) 415-2956.

2515/144-09 STATISTICAL DATA REPORTING

All direct inspection effort expended on this TI is to be charged to 2515/144 for RITS reporting with an IPE code of SI.

2515/144-10 ORIGINATING ORGANIZATION INFORMATION

10.01 Organizational Responsibility. This TI was initiated by IIPB/DIPM/NRR.

10.02 Resource Estimate. The estimated direct inspection effort to perform this TI is estimated to be 24 hours.

10.03 Other. No parallel inspection procedures can be satisfied by the performance of this TI.

10.04 Training. There are no additional training requirement necessary to complete this TI because the necessary training was provided to the inspectors during the Technical Training Center sponsored course, G-200, "Reactor Inspection and Oversight Program," and various workshops. Inspectors shall familiarize themselves with the guidance contained in NEI-99-02, Revision 0.

END

Attachment

PERFORMANCE INDICATOR INTERPRETATION FEEDBACK FORM

Instructions: Fill out the form and send it to NRR/IIPB through regional DRP branch chief via E-mail to"piissues". A hard copy of the form should also be provided to Chief, Performance Assessment Section, IIPB.

1. Cornerstone:	2. PI:	3. Plant Name
A. Licensee Disagreement On NRC 's Interpretation of an Issue		
1. Description of Interpretation Issue:		
2. Licensee's Interpretation:		
3.Region's Interpretation:		
B. Licensee and NRC Agreement On Interpretation of an Issue, But the NEI-99-02 Guidance Needs Clarification or Revision		
1. Description of Interpretation Issue:		
2. Suggested Revision/Clarification to NEI-99-02 Guidance:		
3. Comment:		

Commenter Information	Name/Email:	Region/Division:	
Regional Branch Chief Review	Name/Email:	Approved:	Date:

Date Rcv'd	IIPB Action			IIPB Contact
	Immediate	Pending	Complete	

IIPB FINAL RESOLUTION	Approved By/Date

END

April 25, 2000

MEMORANDUM TO: Michael R. Johnson, Section Chief
Inspection Program Branch
Division of Inspection Program Management

FROM: August K. Spector /RA/
Inspection Program Branch
Division of Inspection Program Management

SUBJECT: REACTOR OVERSIGHT PROCESS INITIAL IMPLEMENTATION PUBLIC MEETING - APRIL 13, 2000

The NRC conducted a public meeting on April 13, 2000, to discuss progress of initial implementation of the Reactor Oversight Process. The meeting was held at the Nuclear Regulatory Commission, One White Flint North, Rockville, MD. A list of participants, a copy of the agenda and handouts distributed are attached.

Attachments: As stated

1. Participants and Agenda
2. 1998-1999 Scram Data Summary
3. Frequently Asked Questions
4. NRC Inspection Manual: Temporary Instruction 2515/144
   Performance Indicator Data Collecting and Reporting Process Review

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