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September 12, 2001

MEMORANDUM TO: Mark Satorius, Chief
Performance Assessment Section
Inspection Program Branch
Division of inspection Program Management
Office of Nuclear Reactor Regulation

FROM: August K. Spector, Communication Task Lead August K. Spector
Inspection Program Branch
Division of Inspection Program Management
Office of Nuclear Reactor Regulation

SUBJECT: REACTOR OVERSIGHT PROCESS SUMMARY OF PUBLIC MEETING HELD ON September 12, 2001

On September 12, 2001 a public meeting was held at the NRC Headquarters, Two White Flint North, Rockville, MD to discuss and review the initial implementation of the revised reactor oversight process. An agenda, attendance list, and information exchanged at the meeting are attached.

Attachments:

1. List of Participants
2. Agenda
3. Power Change Indicator Comparison Charts
4. Draft IE03 Comparison 4/1/00 to 3/31/01 "Best Effort" (9/10/01) Charts
5. Revision of the EP SDP
6. Occupational Radiation Safety SDP Appendix C
7. Frequently Asked Question Log # 15, 16, 18, 20, 21, 22, 23, 24, 25

cc: John W. Thompson, NRR/IIPB

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cc: John W. Thompson, NRR/IIPB

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OFC:	DIPM/IIPB AKS				
NAME:	ASpector				
DATE:	9/12/01				

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NRC Public Meeting
Reactor Oversight Process
List of Participants
Sept. 12, 2001

D. Hickman, NRC.
M. Satorius, NRC
S. Ferrel, TVA
P. Loftus, COMED
L. Whitney, NRC
T. Houghton, NEI
R. Ritzman, PSEG
A. Spector, NRR
J. Thompson, NRC
T. Pickens, NMC
S. Ketelsen, PG&E
W. Warren, SN
R. Pascarelli, NRC
R. Sullivan, NRC

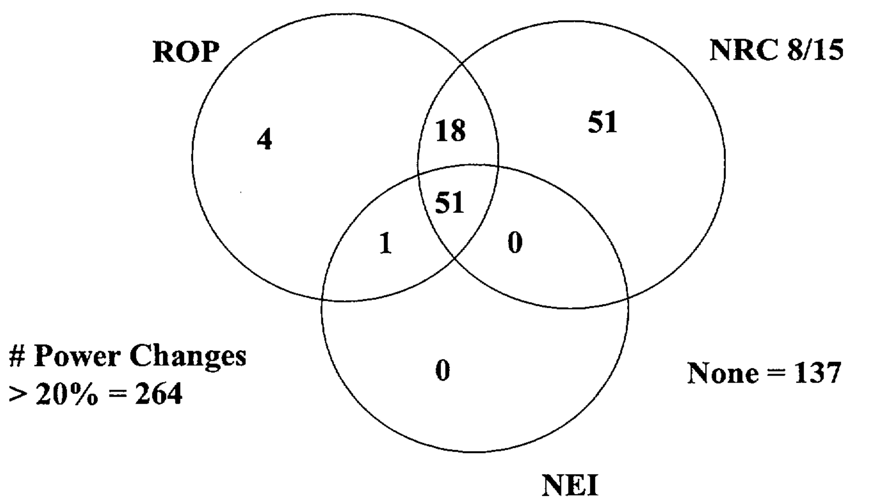
Attachment 1

AGENDA
ROUTINE ROP PUBLIC MEETING
9/12/01

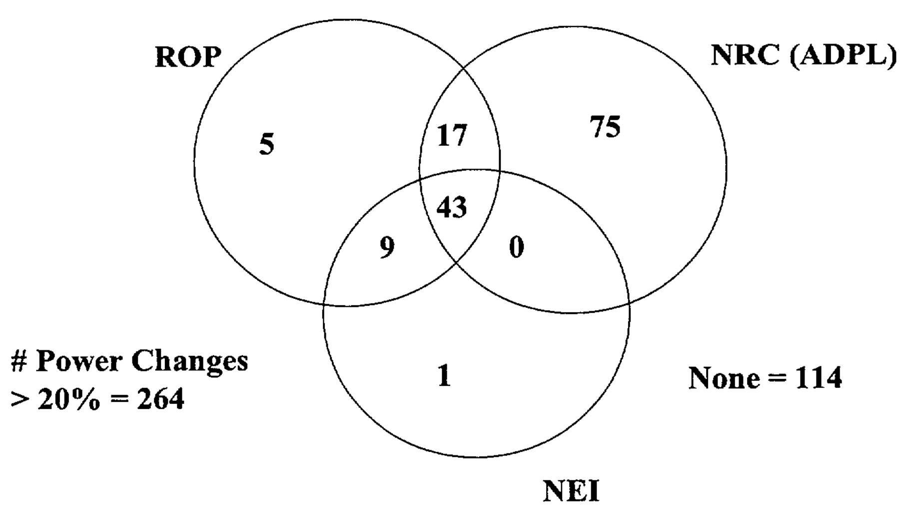
8:00 a.m.	Welcome & confirm agenda	John Thompson
8:10 a.m.	Discussion of RIS communicating a six month pilot test replacement for unplanned power changes performance indicator	Don Hickman
8:30 a.m.	Review and approval of FAQs	John Thompson & Don Hickman
9:30 a.m.	Discussion of process for up dating WEB Performance indicator data	Ron Frahm
10:00 a.m.	Discussion of status of issues before the Unavailability Performance Indicator Working Group	Don Hickman
	Discussion of the following SSU policy issues: 1. Status of the fault exposure T/2 hours issue 2. Status of the Inconsistency between PI color and inspection finding significance 3. Status of the EDG demand failures will be assessed By the SDP process 4. Status of development of a standard definition of SSU	
10:30 a.m.	Discussion on revising the guidance to NEI 99-02, PI reporting criteria, agreement on policy issues, RIS issued, pilot test begins, pilot ends, evaluation of pilot, results to Commission, issue RIS.	Don Hickman
11:15a.m.	Discussion of initiating event performance indicators	Leon Whitney Don Hickman
12:00-1:00 p.m.	Lunch	
1:00 p.m.	Discussion of significance determination process issues	Peter Koltay
	a. EP SDP	Randy Sullivan
	b. ALARA SDP changes and schedule	Peter Koltay
	c. Physical Protection SDP	Terry Reis
1:45 p.m.	Discussion of next revision of IMC 305	Bob Pascarelli
3:30 p.m.	Discussion of risk-informed thresholds related to industry trends	Mark Satarious
4:00 p.m.	Adjourn	

Attachment 2

IE 03 Power Change Indicator Comparison
4/1/00 - 3/31/01 (45 units)
NRC 8/15 Version



IE 03 Power Change Indicator Comparison
4/1/00 - 3/31/01 (45 units)
NRC Avg. Daily Pwr Level Version



Attachment 3

DRAFT IE03 Comparison 4/1/00 to 3/31/01 "Best Effort" (9/10/2001)

Plant	Counts as:				
	ROP	NEI	NRC	NRC8/15	Cause/Explanation
Braidwood2	1	1	1	1	Unit 2 turbine-generator was rampled off-line to repair a hydraulic oil leak. Reactor power change was aproximately 80%. The 8/15 proposal would include this because it does not meet any of the exceptions identified in the draft document.
Brunswick 1	1	1	1	1	Rx power reduced to < 60% due to trip of the 1A RFP turbine on low suction pressure. NEI 99-02: Unplanned power change > 20%. NEI Proposed: Power reduction occurs automatically or immediately with no operator action. NRC Proposed: Average daily power change > 20%.
Brunswick 1	1	1	1	1	Rx power reduced to ~ 60% - 1A RFP turbine tripped due to problems with the main oil pump. NEI 99-02: Unplanned power change > 20%. NEI Proposed: Power reduction occurs automatically or immediately with no operator action. NRC Proposed: Average daily power change > 20% (6/19/00).
Brunswick 2	1	1	1	1	2B Recirc pump tripped due to problems with the MG set exciter collector ring. NEI 99-02: Power change initiated < 72 hours following the discovery of an off-normal event. NEI Proposed: Power reduction occurs automatically or immediately with no operator action. NRC Proposed: Average daily power change > 20%.
ComPeak1	1	1	2	1	Rx Power: 30% Gen Power: 30% approx 287 MWe. (242 MWe NET) 70% power reduction. High sodium in waterbox power to 30% to investigate. Leak isolated ramped to 722 MWe (677 MWe NET) 60% Rx power for repairs. Returned to 100% 7/26/00 ------------------------------ NEI 99-02: Counted due to it being a Unplanned Power Change > 20%.---------------------------- NEI Proposed: Counted due to it being a unanticipated Rx power reduction.----------------------- NRC Proposed: Counted due to exceeding net Average Daily Power change > 20% *The *NRC Proposed PI is not specific to events and as a result this event caused the ADP to change by >33% on the first day and by an additional 22% on the second day (total 55%). The wording of the PI does not exclude this counting as 2 for "the number of reductions in average daily power (ADP) level > 20% of full power". NRC 8/15: Counted due to it being and power reduction greater that 20%. This*
ComPeak1	1	1	1	1	Rx Power: 65% Gen Power: 65% approx 748 MWe (703 MWe NET). 34% power reduction. Heater Drain Pump 1-02 Expansion Joint leak. Returned to 100% power on 9/25/2000.--------- NEI 99-02: Counted due to it being a Unplanned Power Change > 20%.---------------------------- NEI Proposed: Counted due to it being a unanticipated Rx power reduction.----------------------- NRC Proposed: Counted - Exceeded net Average Daily Power change > 20% (ADP 28.4%)---NRC 8/15: Counted due to it being and power reduction greater that 20%.
ComPeak2	1	1	1	1	Rx Power: 65% Gen Power: 65% approx 762 MWe (717 MWe NET). 34% power reduction. Heater Drain Pump 2-01 Expansion Joint leak. Returned to 100% power on 11/15/2000.-------- NEI 99-02: Counted due to it being a Unplanned Power Change > 20%.---------------------------- NEI Proposed: Counted due to it being a unanticipated Rx power reduction.----------------------- NRC Proposed: Counted - exceeded net Average Daily Power change > 20%- (ADP 31.1%)--- NRC 8/15: Counted due to forced downpower > 20%.
Cooper	1	1	1	1	Discovered a hot wiring connection through thermography on the "A" Recirc MG-Set. Reduced power to enter Single Loop Operation and repair. Meets NRC PI criteria.
Cooper	1	1	1	1	Human error during performance of a surveillance resulted in a critical bus load shed and tripping of a recirc pump. This would count under both proposed criteria as well as the current criteria.

Attachment 4

DRAFT IE03 Comparison 4/1/00 to 3/31/01 "Best Effort" (9/10/2001)

Cooper	1	1	0	1	During performance of a surveillance, it was discovered that two sump pumps required for secondary containment were outside the surveillance acceptance criteria. This required them to be declared inoperable and thus initiated a technical specification entry into LCO 3.0.3. The power reduction was initiated and exceeded 20%. This met the criteria for the current NRC PI and the proposed NEI PI. It did not meet the proposed NRC criteria as the daily average power level did not drop below 80%.
Dresden 2	1	1	1	1	Unplanned Inadvertent trip of "B" RR M/G set 820 MWE to 210 MWE loss of 5596 MWH 28% ADPL reduction
Dresden 2	1	1	1	1	Rx Power: 25% Gen Power: 20% approx 150 MWe.75% power reduction. Reactor Recirculation pump tripped manually due to brush arcing.----------------------------------NEI 99-02: Counted due to it being unplanned >20% power change. --------------------------------------- NEI Proposed: Counted due to it being an unplanned >20% power change. ---------------- NRC Proposed: Counted due to being >20% ADPL decrease (75% decrease)
Dresden 3	1	1	0	1	Unplanned 820mwe to 600mwe to repair stm seal relief, loss of 1150mwh 6% ADPL recduction
Farley 1	1	1	1	1	Power reduction to 60% due to cooling tower structural failure. The average daily power level change was 20.6% therefore this counts in the NRC proposed PI. This also is considered a count in the NEI proposed PI since a ramp was commenced 9 minutes after receiving information locally of the damaged cooling tower. The ramp was completed in 48 minutes which is faster than a normal ramp.
FitzPatrick	1	1	1	1	Decreased power from 94 % to approximately 60%. A short circuit within RWCU hold pump resulted in a voltage perturbation on L-13 bus, causing 02A-K46A relay to drop out causing an "A" RWR pump run back to 44%. **Current ROP**: Counted due to being an Unplanned Power change > 20%. **NEI Proposed**: Counted due to being an unanticipated Rx. Power reduction. **NRC Proposed**: Counted – exceeded net Average Daily Power change > 20% (25.2% ADP)
FitzPatrick	1	1	1	1	Decreased power from 100% to approximately 50% due to an outboard seal failure on the "B" Rx. Feedwater pump. **Current** **ROP**: Counted due to being an Unplanned Power change >20%. **NEI** **Proposed**: Counted due to being an unanticipated Rx. Power changed > 20%. **NRC Proposed**: Counted – exceeded net ADP change > 20% (ADP 30.8%)
FitzPatrick	1	1	1	1	Decreased power from 100% to approximate 50% due to an oil leak from the "B" Rx. Feedwater pump bearing oil seal. **Current** **ROP**: Counted due to being an Unplanned Power change > 20%. **NEI** **Proposed**: Counted due to being an unanticipated Rx. Power change > 20%. **NRC Proposed**: Counted – exceeded net ADP change > 20% (ADP 44.2%).
FitzPatrick	1	1	1	1	Decreased power from 50% to 0% due to EHC fluid leak on Turbine Stop Valve #1. **Current ROP**: Counted due to being an Unplanned Power change > 20%. **NEI Proposed**: Counted due to being an unanticipated Rx. Power change > 20%. **NRC Proposed**: Counted – exceeded net ADP change > 20% (ADP 100%).
FitzPatrick	1	1	1	1	Decreased power from 100% to approximately 12% due to a Main Turbine EHC fluid leak. **Current ROP**: Counted due to being an Unplanned Power change > 20%. **NEI Proposed**: Counted due to being an unanticipated Rx. Power change > 20%. **NRC Proposed**: Counted – exceeded net ADP change > 20% (ADP 45.3%).

FitzPatrick	1	1	0	1	Decreased power from 95% to approximately 30% due to loss of "A" Rx. Feedwater pump due to power interruption to 10100 bus. **Current ROP**: Counted due to being an Unplanned Power change >20%. **NEI Proposed**: Counted due to being an unanticipated Rx. Power change > 20%. **NRC Proposed**: Not counted – did not exceed net ADP change > 20% (13.1%).
FitzPatrick	1	1	0	1	Decreased power from 100% to approximately 70% to complete repairs on outboard MSIV limit switch. **Current ROP**: Counted due to being an Unplanned Power change > 20%. **NEI Proposed**: Counted due to being an unanticipated Rx. Power reduction. **NRC Proposed**: Not counted due to not exceeding ned ADP . 20% (ADP 3.4%)
Hatch 1	1	1	0	1	Reduced load due to #4 turbine control valve closed and #1 and #2 turbine bypass valves opened. This equipment failure required prompt operator action. This does not count in the NRC proposed PI since the average daily power level reduction was not >20% from the 22nd to the 23rd. However, see the next power reduction.
Hatch 2	1	1	0	1	Power reduction due to the loss of an electrical bus (due to personnel error) resulted in a recirculation pump runback. Average daily power level change was less than 20% from the previous day, therefore it would not count in the NRC proposed PI.
LaSalle2	1	1	1	1	EHC malfunction 21 % power drop
LaSalle2	1	1	1	1	TCV failed closed 23 % power drop
LaSalle2	1	1	1	1	Feedwater pump repairs 22 % power drop
LaSalle2	1	1	1	1	Transient after Unit 1 scram
LIM1	1	1	0	1	Reactor feed pump sleeve crack, ADP not below 80%,
LIM1	1	1	0	1	1C reactor feed pump turbine lube oil reservoir low level, immediate action required, ADP not below 80%
LIM2	1	1	1	1	#4 Main Turbine Control Vlv Failed Closed due to Failed Servo, the load drop was unplanned and caused ADP to be 43%. The load drop was not required by Tech Specs to be taken but to be certain to avoid an auto scram, administratively we took a load drop so this is counted towards NEI because we took immediate action to avoid a scram
LIM2	1	1	1	1	Recirc pump trip . Unplanned load drop, ADP 75%, automatic operator action required.
LIM2	1	1	0	1	Reactor recirc pump runback, automatic action required, ADP not below 80%
Millstone 2	1	1	1	1	A forced downpower to 55% power due to a failure of the "A" Steam Generator Feed Pump trip test relay to reset.Current ROP: Counted, unplanned change greater than 20% power NEI Proposal: Counted, operator action to preclude an automatic reactor shutdown.NRC Proposal: Counted, greater than 20% ADPL reduction NRC8/15: Counted power change greater than 20% power
N Anna 2	1	1	1	1	Reactor shutdown due to RCS leakage from the "C" reactor coolant loop bypass valve leaking past the valve stem packing material.------------------- Current ROP: Counted, unplanned power change less than 72 hours from discovery of RCS leak.---NEI Proposal: Counted, power reduction in response to TS action statement.--NRC Proposal: Counted, greater than 20% ADPL reduction.----------------NRC 8/15: Counted. Greater than 20% power reduction.
OC	1	1	1	1	Power reduction to indentify and suppress fuel leaks
PB2	1	1	1	1	Unplanned - Decreased power due to the trip of the 2A recirc pump. Event occurred because of the incorrect installation of a capacitor. Action with <72 hours notice, and was required to avoid an automatic trip. Average daily power change >20% (39% decrease). **Included in 8/15 count because greater than 20%, not a regularly scheduled event.**

PB2	1	1	1	1	Unplanned - Decreased power following the test failure of drywell vacuum relief valve. Action taken <72 hours after failure of test, and was required. Average daily power change >20% (80% decrease). **Included in 8/15 count because greater than 20%, not a regularly scheduled event.**
PB3	1	1	1	1	Decreased power due to a low lube oil level alarm in the 3B recirc pump motor. Action was taken <72 hours after the condition was discovered, and was required. Average daily power change >20% (65% reduction). **Included in 8/15 count because greater than 20%, not a regularly scheduled event.**
PB3	1	1	1	1	Decreased power due to a low lube oil level alarm in the 3B recirc pump motor. Action was taken <72 hours after the condition was discovered, and was required. Average daily power change >20% (65% reduction). **Included in 8/15 count because greater than 20%, not a regularly scheduled event. Can not invoke exclusion #6, due to load drop in June.**
PV 1	1	1	1	1	Rx Cutback due to turbine generator excitation system diode failure - Rx power reduced to 10% Average daily power on 5/20/00 was 30,100 / 24 = 1254 Average daily power on 5/21/00 was 15,300 / 24 = 638 Power reduction = 616 "Maximum Dependable Capacity" for Unit 1 as used to determine capacity factor = 1243 .20 X 1243 = 249 Current ROP: Count as 1 unplanned power reduction NEI Proposal: Count as 1 non- elective power reduction NRC Proposal: Count as 1 power reduction >20% (616 is greater than 249) NRC 8/15: Count as 1 power reduction > 20%
PV 2	1	1	1	1	MSIV closed due to a faulty solenoid valve on 5/8/00 - downpowered to 65% Average daily power on 5/07/00 was 30,500 / 24 = 1271 Average daily power on 5/08/00 was 29,000 / 24 = 1208 Average daily power on 5/09/00 was 15,900 / 24 = 663 5/8/00 Power reduction = 63 5/9/00 Power reduction = 545 "Maximum Dependable Capacity" for Unit 2 as used to determine capacity factor = 1243 .20 X 1243 = 249 Current ROP: Count as 1 unplanned power reduction NEI Proposal: Count as1 non-elective power reduction NRC Proposal: Count as 1 power reduction >20% (63 is less than 249 ; 545 is greater than 249) NRC 8/15: Count as 1 power reduction > 20%
PV 2	1	1	1	1	Rx Cutback during WSCC VAR test followed by Rx trip on DNBR Average daily power on 11/17/00 was 30,700 / 24 = 1279 Average daily power on 11/18/00 was 14,000 / 24 = 583 Power reduction = 696 "Maximum Dependable Capacity" for Unit 2 as used to determine capacity factor = 1243 .20 X 1243 = 249 Current ROP: Count as 1 unplanned power reduction NEI Proposal: Count as 1 non-elective power reduction NRC Proposal: Count as 1 power reduction >20% (696 is greater than 249) NRC 8/15: Count as 1 power reduction > 20%

PV 3	1	1	2	1	Unplanned shutdown to repair leak in steam generator downcomer sample line Average daily power on 9/26/00 was 30,400 / 24 = 1267 Average daily power on 9/27/00 was 23,600 / 24 = 983 Average daily power on 9/28/00 was 0 / 24 = 0 9/27/00 Power reduction = 284 9/28/00 Power reduction = 983 "Maximum Dependable Capacity" for Unit 3 as used to determine capacity factor = 1247 .20 X 1247 = 249 Current ROP: Count as 1 unplanned power reduction NEI Proposal: Count as 1 non-elective power reduction NRC Proposal: Count as 2 power reductions >20% (284 is greater than 249 ; 983 is greater than 249) NRC 8/15: Count as 1 power reduction > 20% . The unplanned shutdown commenced on 9/27/00 and was completed on 9/28/00. Power was reduced 22.4% on the 27th and 77.6% on the 28th. The count for NRC 8/15 is 1 because, even though the shutdown took place over the course of two days, there was only one unplanned shutdown performed to address one plant problem.
Quad 1	1	1	1	1	31%RCTP = 69% power reduction;Unplanned due to recirc pump trip NEI 99-02; counted due unplanned NEI Proposal; counted due unanticipated NRC Proposal; counted due load reduction > 20% of full power (53% based on ADPL = 367)
Quad 1	1	1	1	1	27%RCTP = 73% power reduction;Unplanned due to recirc pump trip NEI 99-02; counted due unplanned NEI Proposal; counted due unanticipated NRC Proposal; counted due load reduction > 20% of full power (32% based on ADPL = 528)
Quad 2	1	1	1	1	47%RCTP = 53% power reduction;Condenser vacuum transient NEI 99-02; counted due unplanned NEI Proposal; counted due unanticipated NRC Proposal; counted due load reduction > 20% of full power (22% based on ADPL = 610)
Quad 2	1	1	1	1	33%RCTP = 67% power reduction; Unplanned SBM switch replacement NEI 99-02; counted due unplanned NEI Proposal; counted due unanticipated NRC Proposal; counted due load reduction > 20% of full power (48% based on ADPL = 375)
Quad 2	1	1	1	1	30%RCTP = 70% power reduction;Unplanned for troubleshooting #3 TCV NEI 99-02; counted due unplanned NEI Proposal; counted due unanticipated NRC Proposal; counted due load reduction > 20% of full power (22% based on ADPL = 611)
Salem 1	1	1	1	1	Traveling screen failure. This was counted in all three PI's. Power reduction commenced approximately 2 hours after the condition was discovered and resulted in an average daily power change of greater than 20%. Although the plant was not in danger of a plant trip, under other environmental conditions, this condition could have resulted in a plant trip; therefore, this is being counted toward the NEI proposal.

Surry 2	1	1	1	1	Unit Shutdown from 100 % power in response to Technical Specification action statement to Replace Snubber 2-RC-HSS-116. ------------------------- Current ROP: Counted as unplanned change in power greater than 20 %-NEI Proposal: Counted as unanticipated power reduction in response to TS Action Statement---NRC Proposal: Counted as ADPL reduction greater than 20%.---------------NRC 8/15: Counted, power reduction greater than 20%
TMI	1	1	1	1	Unplanned power reduction to 65% power due to Feedwater Pump trip during surveillance testing .--NEI 99-02 : Counted due to it being an unplanned power reduction of > 20%------------------------ NEI Proposed: Counted due to it being an unplanned power reduction >20%. ----------------------NRC Proposed: Counted due to it being an unplanned power reduction >20%. (35% ADP) _____NRC 8/15/01 Proposal : Counted based on not meeting exclusion criteria (unplanned/unexpected and > 20% power reduction)
BF 3	1	0	1	1	Downpower to work on 3A recirc pump MG set
Farley 1	1	0	0	1	A leaking cooling tower header gasket was reported and 57 minutes later a ramp was commenced. I did not consider this "prompt" for the NEI proposal. The unit was ramped to 62% power in 1 hour and 53 minutes from the start of the ramp. It appears the decision to ramp was based on a conservative decision due to the concern of a potential failure similar to the July 5, 2000 structural failure. This is a faster ramp rate than normal operating procedures, however, exceeding the normal ramp rate is not a criteria in the NEI proposal. The average daily power level change from the previous day was 9.3%. Therefore, this does not meet the criteria of the proposed NRC PI.
Farley 1	1	0	0	1	A leaking rubber seal on a cooling tower header was identified at approximately 1800. At 2000 a power reduction was commenced and stopped at 2140 at 62 % power. This is a faster ramp rate than normal operating procedures in that the ramp rate exceeded 15 % per hour. This is not considered prompt under the NEI proposal. Also, the change in average daily power level due to this event was approximately 11%. Therefore, this does not meet the criteria of the proposed NRC PI.
Farley 1	1	0	0	1	After ramping to 100 % following the above power reduction, a leak was noted on another cooling tower. This leak was identified at approximately 2030. A power reduction was commenced at 2146 to approximately 60 % power at 2308. This was not considered prompt under the NEI proposal. The change in average daily power level due to this event was approximately 7.2 %. Therefore, this does not meet the criteria of the proposed NRC PI. However, over the three day period of these two power reductions the total change in average daily power level was 21.0%. However, this change of 21 % does not meet the criteria of the proposed NRC PI.
FitzPatrick	1	0	1	1	Decreased power from 100% to approximately 60% due to Condenser fouling as a result of marine and biological debris contamination. **Current ROP**: Counted but an FAQ has been submitted to the NRC with justification as to why this downpower should be considered an event created from marine and biological debris contamination. **NEI Proposed**: Not counted due to being a result of a seasonal environmental condition (biological and marine contamination). **NRC Proposed**: Counted but is contingent on results of the FAQ submittal.
Ft. Calhoun	1	0	1	1	Rx Power: 0% Gen Power: 0% approx 502 MWe.(483 MWe NET) 100% power reduction. Plant shutdown to replace degraded reactor coolant pump seals on pump A.

Ft. Calhoun	1	0	1	1	Rx Power: 0% Gen Power: 0% approx 502 MWe.(483 MWe NET) 30% power reduction. Reduced power due to feedwater chemistry problem.
Hatch 1	1	0	1	1	Unit shutdown to repair condensate demineralizer valve internals. Condensate low pressure occurred during ramp up following outage. Unit was shutdown to disassemble and inspect valve internals. No prompt operator actions resulted in >20% power change. Therefore this does not count in the NEI proposed PI. Average change in daily power level was greater than 20%.
Hatch 2	1	0	0	1	Power reduction to repair leak on feedwater heater level control valve. The leak had occurred the previous day. Therefore, it counts under the current ROP PI, but not under the NEI proposed PI. Average daily power level change was less than 20% from the previous day, therefore it would not count in the NRC proposed PI.
LIM1	1	0	1	0	Load drop for condenser waterbox tube repairs, unplanned and ADP was 78%, the load drop was anticipated (in other words not a prompt or automatic action and not a Tech Spec requirement)
OC	1	0	1	1	Main Generator taken offline to perform maintenance on the main transformer (M1A). Less than 72 hours planning, but was perfomed as a controlled maintenance activity.
OC	1	0	1	1	Power reduction to repair Cooling Water system leak. Less than 72 hours planning, but was performed as a controlled maintenance activity.
OC	1	0	1	1	Power reductino to replace turbine vacuum trip device. Less than 72 hours planning, but was performed as a controlled maintenance activity.
PB2	1	0	1	1	Unplanned - Decreased power in order to isolate the "B" feedwater heater string. Action was taken <72 hours after identification of the problem. Action was not immediately required to avoid an automatic trip or turbine reactor shutdown (leaking tubes in the 2B feedwater heater). Average daily power change >20% (33% decrease). **Included in 8/15 count because greater than 20%, not a regularly scheduled event.**
PB2	1	0	1	1	Unplanned - Decreased power to repair leaks in the A2 condenser waterbox. Action was not required to avoid a turbine trip or reactor shutdown, but was taken <72 hours after discovery of the condition. Average daily power change >20% (33% decrease). **Included in 8/15 count because greater than 20%, not a regularly scheduled event**.
PB2	1	0	1	1	Unplanned - Decreased power following intrusion of neutrally bouyant log into 2C circ water travelling screen. Action taken <72 hours after discovery of condition, but was not required. Average daily power change >20% (21% decrease). **Included in 8/15 count because greater than 20%, not a regularly scheduled event.**
Salem 1	1	0	1	1	Voltage Regulator Replacement followed by heater drain valve maintenance. This counts under the current rules because although the voltage regulator replacement was planned and scheduled more than 72 hours in advance, the heater drain valve maintenance was not. It would count under the NRC proposal because the average daily power changed by greater than 20% from the previous day. It would not count under the NEI proposal because it was voluntary maintenance.
Salem 1	1	0	1	1	EHC O-ring leakage. This counts under the current rules because the power reduction began 17 hours after discovery of the issue. It would count under the NRC proposal because the average daily power changed by greater than 20% from the previous day. It would not count under the NEI proposal because there was no impact on operability at the time that the power reduction commenced.
LIM2	1	0	1	1	Planned and unplanned maintenance on reactor feed pump and MSIV solenoid, ADP 79%, load drop was anticipated (in other words not a prompt or automatic action and not a Tech Spec requirement)
BF 3	0	0	1	1	Work on Heater Drain system flow element - THE RIGHT THING TO DO

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BF2	0	0	1	1	Planned manual downpower w/shutdown to repair drywell leakage **within** of TS allowable
Braidwood2	0	0	1	1	Unit 2 was ramped down > 20% to allow repairs to 2FW090A which had a packing leak in containment. Planning had been in progress for longer than a month prior to the downpower when repairs were made. This was preplanned > 72 hours in advance. The 8/15 proposal would include this because it does not meet any of the exceptions identified in the draft document.
Brunswick 2	0	0	1	1	Rx power reduced to 25% to add oil to the Recirc pump motor. NEI 99-02: Planned power reduction. NEI Proposed: Not unanticipated. NRC Proposed: Average daily power change > 20% (5/6/00).
Cooper	0	0	1	1	Inidications of a fuel pin leak are observed. Reduced power to find and suppress the leaking pin. This meets the new NRC criteria but did not meet the previous criteria since this was a planned power reduction that occurred greater than 72 hours after the first indication of a leak.
Cooper	0	0	1	1	Planned downpower to investigate and troubleshoot a problem with one of the Main Turbine Govenor valve position limit switches. The problem had been identified two weeks prior to the downpower so it does not meet either the current criteria or the proposed NEI criteria. It does meet the new NRC criteria.
Dresden 2	0	0	1	1	Planned 820MWE drop to 700mwe for 3D3 heater leak loss of 4183mwh 21% ADPL reduction
Dresden 2	0	0	0	1	Planned drop for steam leak in feedwater heater 817mwe drop to 650mwe, loss of 3432mwh 17% ADPL reduction
Dresden 2	0	0	1	1	Rx Power: 30% Gen Power: 23% approx 200 MWe. 70% power reduction. Planned to repair condensor tube leaks.---------------------------------NEI 99-02: Not counted due to it being a planned evolution. -------------------------------------- NEI Proposed: Not counted due to it being a anticipated Rx power reduction. --------------- NRC Proposed: Counted due to being >20% ADPL decrease (70% decrease)
Dresden 3	0	0	1	1	Unit taken off line for generator ring repair 820mwe to 0mwe, loss of 38000mwh
Dresden 3	0	0	0	1	Planned 820 to 540mwe for FWRV, loss of 3360mwh 17% ADPL reduction
Dresden 3	0	0	1	1	Rx Power: 37% Gen Power: approx 300 MWe. 63% power reduction. Planned power drop to repair a feedwater heater. ----------------------------------- NEI 99-02: Not counted due to it being a planned evolution.--- NEI Proposed: Not counted due to it being a anticipated Rx power reduction.------------------ NRC Proposed: Counted since ADPL was >20% (63% decrease)
Farley 1	0	0	1	1	Planned power reduction to remove a cooling tower from service for repairs. The change in average daily power level was 25.3 %. Therefore, this event would be included in the proposed NRC PI. Since this was planned it did not count in the current PI nor the proposed NEI PI.
Farley 1	0	0	0	1	Ramp from 94 % to 55 % power due to noise indicated on the steam generator metal impact monitoring system. Since this was planned it did not count in the current PI nor the proposed NEI PI. The change in average daily power level was 3.4%.
Farley 1	0	0	0	1	Planned power reduction to remove a cooling tower from service for repairs.The change in the average daily power level was 5.5 %. Since this was planned it did not count in the current PI nor the proposed NEI PI.
Farley 1	0	0	1	1	Power reduction from 100% to 67% to repair feed water pump lube oil temperature control problems. The change in the average daily power level was 36 %. Therefore, this event would be included in the proposed NRC PI. Since this was planned it did not count in the current PI nor the proposed NEI PI.
Farley 2	0	0	1	1	Planned power reduction to remove a cooling tower from service for repairs. The change in the average daily power level was 26%. Therefore, this counts in the proposed NRC PI. Since this was planned it did not count in the current PI nor the proposed NEI PI.

Farley 2	0	0	0	1	Planned power reduction to remove a cooling tower from service for repairs. The change in the average daily power level was 10%. Since this was planned it did not count in the current PI nor the proposed NEI PI.
FitzPatrick	0	0	0	1	Decreased power from 100% to approximately 60% to perform repairs on Off-gas Recombiner Inlet valve. **Current ROP**: Not counted due to being a planned evolution. **NEI Proposed**: Not counted due to being a anticipated Rx power reduction. **NRC Proposed**: Not counted due to not exceeding net ADP >20% (ADP 19%)
FitzPatrick	0	0	1	1	Decreased power from 100% to approximately 50% for scheduled maintenance activities. **Current ROP**: Not counted due to being a planned evolution. **NEI Proposed**: Not counted due to being a anticipated Rx. Power reduction. **NRC Proposed**: Counted - downpower was not scheduled prior to startup from a refuel outage and exceeded net ADP > 20% (ADP 46.8%).
FitzPatrick	0	0	1	1	Power was decreased from 90% to 0% in support of a planned maintenance outage. **Current ROP**: Not counted due to being a planned evolution. **NEI Proposed**: Not counted due to being a anticipated Rx. Power reduction. **NRC Proposed**: Counted – downpower was not scheduled prior to startup from a refuel outage and exceeded net ADP > 20%.
Hatch 1	0	0	1	1	Additional planned power reduction to repair steam leak on MSR manway resulted in average daily power reduction being greater than 20% from Nov 24 to 25th. This is not counted as part of the current ROP PI or NEI proposed PI because it was part of the planned power change.
Hatch 1	0	0	1	1	Additional power reduction from the 26th to repair steam leak on MSR manway, replace EHC system servo strainers and EHC system filters. This does not count in the current ROP PI since it was planned. Change in average daily power level was greater than 20%.
Hatch 2	0	0	1	1	Replace diode function generator card in the EHC system control loop and repair steam leaks on feedwater heaters. This did not count under the current ROP PI or NEI proposed PI since the work was planned greater than 72 hours in advance. However, the average daily power level change was greater than 20%.
Hatch 2	0	0	0	1	Further power reduction for inspection and maintenance activities in condenser bay and too conduct turbine valve testing during power ascension. Note change in average daily power from pervious day was 19.83%.
Hatch 2	0	0	1	1	Additional power reduction for planned maintenance activities which included feedwater valve maintenance, repair leak on feedwater heater level control valve, change EHC system filters, replace servo-strainers on turbine control valves and repair MSIV limit switch. These activities had been preplanned therefore they would not count in the NEI proposed PI or the current ROP PI. However, the average daily power level change was greater than 20%.
Hatch 2	0	0	1	1	Additional power reduction for turbine valve testing and planned maintenance activities which included feedwater valve maintenance, change EHC system filters, replace servo-strainers on turbine control valves. These activities had been preplanned therefore they would not count in the NEI proposed PI or the current ROP PI. However, the average daily power level change was greater than 20%.
Hope Creek	0	0	1	1	Main transformer maintenance. This does not count under the current PI because it is pre-planned (greater than 72 hours in advance). It does not count under the NEI proposal because it was a planned evolution. It does count under the NRC proposal because it resulted in an average daily power change of greater than 20%.
LaSalle 1	0	0	0	1	Planned > 72 hours for TS surveillance/concurrent maintenance longer than TS surveillance
LaSalle 1	0	0	1	1	Planned > 72 hours - Repair work on TCV solenoid valve 82 % power drop

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LaSalle 1	0	0	1	1	Planned > 72 hours repair work on 12 A Feedwater heater 50 % power drop
LaSalle2	0	0	1	1	Planned > 72 hours repair EHC Accumulator 50 % power drop
LaSalle2	0	0	1	1	Planned > 72 hours repair #2 CIV servo valve 50 % power drop
LaSalle2	0	0	1	1	Planned > 72 hours Feedwater pump swap from TDRFP to MDRFP to allow Repairs to TDRFP25 % power drop
LaSalle2	0	0	1	1	Planned > 72 hours Feedwater pump swap from MDRFP to TDRFP after repairs, 25 % power drop
LaSalle2	0	0	0	1	Planned > 72 hours for TS surveillance/concurrent maintenance longer than TS surveillance
LaSalle2	0	0	1	1	Planned > 72 hours Repair work on 2A TDRFP 22 % power drop
LIM1	0	0	1	0	Rod Pattern adjustment and reactor feed pump repair, Planned, ADP 79%. (Other maintenance was performed, but the original LD was planned, doesn't count for NEI per the third example given)
LIM1	0	0	1	0	Planned LD for scram time testing, condensate pump repair, rod pattern adjustment, and MSIV testing. ADP 67%.
N Anna 2	0	0	1	1	Ramped down to 27% power to isolate 2-RC-49 ("B" loop hot leg sample isolation valve) due to suspected leakage from 2-SS-TV-208B ("B" loop hot leg sample trip valve).---Current ROP: Not counted. Transient initiated greater than 72 hours after discovery of leaking valve.---NEI Proposal: Not counted, doesn't meet any of the three criteria.----------NRC Proposal: Counted. Greater than 20% ADPL reduction.---------------NRC 8/15: Counted. Greater than 20% power reduction.
OC	0	0	1	1	Power reduction to repair the 1-2 tank reheater. Planned maintenance 72 hours prior to power reduction.
PB2	0	0	1	1	Power reduced to remove "B" feedwater heater string from service, due to suspected leaks. Action >72 hours after discovery of condition, not required. Power reduced to 68%. **Included in 8/15 count because greater than 20%, not a regularly scheduled event.**
PB3	0	0	1	1	Planned - Power reduction for planned evolution - lube oil system repairs on 3B recirc pump motor. Power reduced to 18%. **Included in 8/15 count because greater than 20%, not a regularly scheduled event. Can not invoke exclusion #6, due to load drop in October.**
Prairie Island1	0	0	1	1	On 9/16/2000, power was reduced to perform turbine valve testing and to clean condenser tubes (approx. 57% power reduction). The unit returned to full power on 9/18/2000. NEI 99-02: Not counted due to it being planned testing and maintenance. NEI Proposed: Not counted due to it being anticipated (reduced power to perform planned testing and condenser tube cleaning). NRC Proposed: Counted due to ADPL change of > 20% was exceeded (change in ADPL of 64.6%). NRC 8/15/01 Draft: Counted for NRC 8/15/01 Draft because condenser tube cleaning extending extended down power condition time beyond exception allowed for Tech Spec required valve testing.
Prairie Island1	0	0	1	1	On 12/1/2000, the unit was taken off-line to perform repairs to the Reactor Coolant Pump seals (100% power reduction). The Unit was returned to service on 12/13/2000 and reached full power on 12/14/2000. NEI 99-02: Not counted due to it being planned outage for maintenance. NEI Proposed: Not counted due to it being anticipated (unit taken off-line to perform maintenance). NRC Proposed: Counted due to ADPL change of > 20% was exceeded (ADPL went from 549 to a negative value when shutdown, which calculated to be a change in ADPL of 102.4%). NRC 8/15/01 Draft: Counted due to > 20% power change to perform maintenance.

PV 3	0	0	1	1	Planned shutdown to repair RCP high vibration Average daily power on 2/16/01 was 30,200 / 24 = 1258 Average daily power on 2/17/01 was 200 / 24 = 8 2/17/01 Power reduction = 1250 "Maximum Dependable Capacity" for Unit 3 as used to determine capacity factor = 1247 .20 X 1247 = 249 Current ROP: No count - planned power reduction NEI Proposal: No count - elective power reduction NRC Proposal: Count as 1 power reduction >20% (1250 is greater than 249) NRC 8/15: Count as 1 power reduction > 20%
Quad 1	0	0	0	1	52% RCTP = 48% power reduction; Planned to support corrective actions from prior recirc trip. NEI 99-02; not counted due planned NEI Proposal; not counted due anticipated NRC Proposal; not counted due <20% power [645 ADPL; 17% load reduction based on ADPL and RNWMe] * Note: on the next day (11/16/00, the ADPL of 619 = 20.1% which would then be counted under the NRC Proposal although, technically, there wasn't a reduction on the 16th so would it get counted or not?. Load reduction began on 11/15/00 at 2000hrs and load was returned to full power at 0845 on 11/16/00. Had the load drop been longer over the 2 days, would the NRC Proposal require in the same event being reported twice?
Quad 1	0	0	0	1	42% RCTP = 58% power reduction; Planned to support corrective actions from prior recirc trip. NEI 99-02; not counted due planned NEI Proposal; not counted due anticipated NRC Proposal; not counted due <20% power [634 ADPL; 18% load reduction based on ADPL and RNWMe] ** On the next day, 11/18/00, the ADPL is reduced to 269 which is a 65% reduction from rated but since the reduction was actually on the 17th, would the 18th be counted?
Quad 2	0	0	1	1	0% RCTP = 100% power reduction; TCV #3 Repairs. NEI 99-02; not counted due planned NEI Proposal; not counted due anticipated NRC Proposal; counted due >20% power [267 ADPL; 66% load reduction based on ADPL and RNWMe]
Salem 1	0	0	1	1	This power reduction was for maintenance on the generator backup voltage regulator. It counts under the NRC proposal because it resulted in an average daily power change of greater than 20%. It does not count toward the current indicator or the NEI proposal because it was preplanned (greater than 72 hours in advance).
Salem 1	0	0	0	1	Inspect and fill Reactor Coolant Pump Oil. This does not count under the current PI because it was planned greater than 72 hours in advance. It does not count toward the NRC proposal because it did not result in an average daily power change of greater than 20% (change was 98mw <10%). It does not count toward the NEI proposal because it is voluntary maintenance.
Sequoyah2	0	0	1	1	Planned power reduction for corrective maintenance on Mn Feed pumps.

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TMI	0	0	1	1	Decreased power to 50% to fix minor condenser leak. Evolution conducted > 72 hrs after identification of problem. Downpower was electively initiated and not required to avoid turbine trip or reactor shutdown. Average daily power decrease was >20% --------------------------------NEI 99-02: Not counted due to it being a planned evolution. ---NEI Proposed: Not counted due to it being an anticipated power reduction. -------------------NRC Proposed: Counted due to it being a reduction <20% power level that does not meet any of the exceptions. (50% ADP)_____NRC 8/15/01 Proposal : Counted based on not meeting exclusion criteria (not a normally scheduled plant procedure)
PB2	1	1	1	0	Unplanned - Decreased power in order to troubleshoot feedwater heater water hammer and pressurization events. Action was not immediately required to avoid an automatic trip or reactor shutdown, but was taken <72 hours after the condition was identified. Average daily power change >20% (56% decrease). **Not included in 8/15 count - exclusion #6. This load drop addressed continuing problems with the feedwater heaters on Unit 2.**
Hatch 2	1	0	0	0	Subsequent unexpected power increase (bus re-energized and controlled returned pump to normal speed) of greater than 20% power when power restored to the electrical bus and recirculation pump speed increased. Power change was unplanned. NEI proposed PI does not consider unexpected power increases. Average daily power level change was less than 20% from the previous day, therefore it would not count in the NRC proposed PI.
LIM1	1	0	1	0	Rod Pattern adjustment after a scram, the load drop was anticipated (in other words not a prompt or automatic action and not a Tech Spec requirement), NRC proposal because ADP 79%
Millstone 2	1	0	1	0	During Combine Intermediate Valve testing a secondary plant transient occurred due to feedwater heater drain level control problems. Operators reduced power to 80% and restored feedwater heater to normal configuration.Current ROP: Counted, however was not greater than 20% power reduction and is being reevaluated for reporting.NEI Proposal: Not counted, not greater than 20% power reduction NRC Proposal: Counted, ADPL reduction slightly greater than 20%.-*Note: Counted or not counted for this power reduction appears to be a function of measuring gross output (reactor power) versus net output (ADPL) NRC815: less than 20% power change
BF2	0	0	1	0	downpower to 75% for control rod pattern adjustments and SCRAM testing
BF2	0	0	1	0	Repair 2A Condensate pump, SCRAM testing, Rod adjustments, RPS testing and misc scheduled maintenance
BF2	0	0	1	0	SCRAM Testing
BF2	0	0	0	0	Commenced Refueling Outage
Braidwood1	0	0	0	0	Unit 1 load was reduced from 65% in preparation for A1R08.
Braidwood2	0	0	0	0	Unit 2 load was reduced from 100% to 0% for refueling outage A2R08. This was a planned shutdown. The 8/15 proposal includes downpowers for refuels as an exception.
Brunswick 1	0	0	1	0	Rx power reduced to 55% for Rod Improvement, valve and scram time testing. NEI 99-02: Planned power change. NEI Proposed: An anticipated power reduction. NRC Proposed: Average daily power change > 20% (6/24/00).
Brunswick 1	0	0	0	0	Rx power reduced to 55% for special backwashing of A-N and A-S debris filters. NEI 99-02: Planned power change initiated > 72 hours following discovery of an off-normal event. NEI Proposed: See clarifying notes under "*Unanticipated power reductions that are not counted*". NRC Proposed: Average daily power change > 20%, however, reductions in response to expected problems, such as accumulation of marine debris or biological contaminants in certain seasons are not counted. NRC 8/15: This is classified as a proceduralized unit power reduction in response to the accumulation of marine debris, and therefore excluded.

Brunswick 1	0	0	0	0	Rx power reduced to 55% for Rod Improvement. NEI 99-02: Planned power change. NEI Proposed: Not an unanticipated power reduction. NRC Proposed: Average daily power change < 20%.
Brunswick 1	0	0	0	0	Derated to 620 MWe due to loss of Weatherspoon transmission line. NEI 99-02: Power change requested by the system load dispatchers are excluded. NEI Proposed: Not an unanticipated power reduction/ prompt operator action required to preclude an automatic reactor shutdown or turbine trip. NRC Proposed: Average daily power change < 20% and reductions directed by the load dispatcher for grid stability concerns arising from external events outside the control of the nuclear unit are excluded.
Brunswick 1	0	0	1	0	Rx power reduced to 55% for Rod Improvement, valve and scram time testing. NEI 99-02: Planned power change. NEI Proposed: An anticipated power reduction. NRC Proposed: Average daily power change > 20%.
Brunswick 2	0	0	0	0	Rx power reduced to 55% for Rod improvement and scram time testing. NEI 99-02: Planned power change. NEI Proposed: Not unanticipated. NRC Proposed: Average daily power change < 20%.
Brunswick 2	0	0	0	0	Rx power reduced to 56% to perform special backwashing of the 2B-N debris filter. NEI 99-02: Planned power change initiated > 72 hours following the discovery of an off-normal event. NEI Proposed: Not an unanticipated power reduction. NRC Proposed: Average daily power change < 20% and reductions in response to expected problems, such as accumulation of marine debris or biological contaminants in certain seasons are not counted. NRC 8/15: This is classified as a proceduralized unit power reduction in response to the accumulation of marine debris, and therefore excluded.
Brunswick 2	0	0	0	0	Rx power reduced to 70% for Rod Improvement. NEI 99-02: Planned power change. NEI Proposed: Not unanticipated. NRC Proposed: Average daily power change < 20%.
Brunswick 2	0	0	1	0	Rx power reduced to 55% for valve and scram time testing. NEI 99-02: Planned > 72 hours before power reduction. NEI Proposed: An anticipated power reduction. NRC Proposed: Average daily power change > 20%.
Brunswick 2	0	0	0	0	All Rods Out (final rod improvement for cycle 15). NEI 99-02: Planned power change. NEI Proposed: Not an unanticipated power reduction. NRC Proposed: Average daily power change < 20%.
Brunswick 2	0	0	0	0	Rx power reduced to ~ 60% for Rod Improvement. NEI 99-02: Planned power change. NEI Proposed: An anticipated power reduction. NRC Proposed: Average daily power change < 20%.
ComPeak1	0	0	0	0	Rx Power: 76% Gen Power: 76% approx 875 MWe.(830 MWe NET) 24% power reduction. Planned Routine OPT-217 Turbine stop and control valve testing.-----------------------------------NEI 99-02: Not counted due to it being a planned evolution. -- NEI Proposed: Not counted due to it being a anticipated Rx power reduction. ---------------------- NRC Proposed: Not counted due to not exceeding net ADP change > 20% (ADP 7.3%) ---------- NRC 8/15: Not counted due to exemption No. 4. Routine test or Surviellance.
ComPeak1	0	0	0	0	Rx Power: 76% Gen Power: 76% approx 875 MWe. (830 MWe NET) 24% power reduction. Planned Routine OPT-217 Turbine stop and control valve testing. ------------------------------------ NEI 99-02: Not counted due to it being a planned evolution.-- NEI Proposed: Not counted due to it being a anticipated Rx power reduction.------------------- NRC Proposed: Not counted due to not exceeding net ADP change > 20% (ADP 8.5%) ------ NRC 8/15: Not counted due to exemption No. 4. Routine test or Surviellance.

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ComPeak1	0	0	1	0	Rx Power: 76% Gen Power: 76% approx 875 MWe. 24% power reduction.------------------------ Planned Routine OPT-217 Turbine stop and control valve testing, and planned feedwater heater 1A steam leak repair.--- NEI 99-02: Not counted due to it being a planned evolution.--------------------------------------- NEI Proposed: Not counted due to it being planned work that plant management elected to completed during a routine downpower for testing.-- NRC Proposed: Counted - testing and repairs exceeded net ADP change > 20% (ADP 26.2%) NRC 8/15: Not counted due to exemption No. 4. Routine test or Surviellance.
ComPeak1	0	0	0	0	Rx Power: 83% Gen Power: 83% approx 957 MWe (914 MWe NET). Feedwater Heater 1B tube leak. Returned to 100% power on 1/28/2001. Approximate 17% power reduction. NEI 99-02: Not counted due to reactor power change not greater than 20%. NEI Proposed: Not counted due to reactor power change not greater than 20%.NRC Proposed: Counted due to potentially exceeding net ADP change > 20% **The NRC Proposed PI is not specific to what value is considered NET full power. Comanche Peak Unit 1 is designed rated at 1150 MWe. Using this criteria the change in ADP is 20.5%. If we use the 100% power level before the event or a 30 day average for full power (1111 MWe NET), the reduction was 17.8%. This would not have met the criteria for an event. The actual performance during the hottest summer months when high lake temperatures make the MWe NET performance about 1090 MWe NET, demonstrates the potential fluctuations in value for NET FULL POWER.* NRC 8/15: Not counted due to downpower being less than 20% power reduction.
ComPeak1	0	0	0	0	Rx Power: 76% Gen Power: 76% approx 875 MWe. 24% power reduction.------------------------ While down for the unplanned derate for the feedwater heater 1B tube leak repairs, the decision was made to take advantage of the downpower and perform the OPT-217 Turbine stop and control valve testing in the derate window. NEI 99-02: Not counted due to it being a planned evolution. NEI Proposed: Not counted due to it being a anticipated Rx power reduction.NRC Proposed: Possibly counted with the above event due to exceeding net ADP change > 20%. Power change did not exceed 20% until the performance of the OPT-217. NRC 8/15: Not Counted due to planned downpower for repairs was less than 20% power and the downpower greater than 20% was only for the testing (Exemption No. 4). However, if the unit was downpowered to do the testing and then a problem was identified would it be a count. Would it be a count if it did not extend the time for the testing?
ComPeak1	0	0	1	0	Rx Power: 79% Gen Power: 79% approx 906 MWe. (861 MWe NET). Approx 21% reduction. EHC Pressure switch failure. Returned to 93% Full Power 3/18/2001 (Unit in End of Cycle Coastdown for start of 1RF08) .------NEI 99-02: Not counted due to it being a less than 20% reduction in Rx Power.----NEI Proposed: Not counted due to it not exceeding 20% of full power. ----NRC Proposed: Possibly counted event due to exceeding design net ADP change > 20%. However, the unit full power (Reactor and Turbine) was only 93% due to the coastdown. The reduction from 93% to 79% would only be 14% reduction. The NRC proposed does not clearly address how this would be counted. -----NRC 8/15: Not Counted due to downpower not exceeding 20% (only 14%) However, the definition for "Full Power" does not state if means design or thermal or maximum achievable (summer lake temperatures). It might help to inlcude in the definition "maximum achievable".

ComPeak1	0	0	0	0	Rx Power: 0% Gen Power: 0% approx 0 MWe. 100% power reduction. -------------------------- Ramp down to begin 1RF08. This would not be counted due to being a planned evolution. NEI 99-02: Not counted due to it being a planned evolution. -- NEI Proposed: Not counted due to it being a anticipated Rx power reduction. ------------------ NRC Proposed: Not counted due to it being a scheduled pre-outage activity.--------------------- NRC 8/15: Not Counted due to Exemption No. 1.Planned Outage.
ComPeak2	0	0	0	0	Rx Power: 76% Gen Power: 76% approx 875 MWe.(830 MWe NET) 24% power reduction. Planned Routine OPT-217 Turbine stop and control valve testing.--------NEI 99-02: Not counted due to it being a planned evolution. ---------NEI Proposed: Not counted due to it being a anticipated Rx power reduction. --------NRC Proposed: Not counted due to not exceeding net ADP change > 20% (ADP 5.7%) NRC 8/15: Not counted due to exemption No. 4. Routine test or Surviellance.
ComPeak2	0	0	0	0	Rx Power: 76% Gen Power: 76% approx 875 MWe.(830 MWe NET) 24% power reduction. Planned Routine OPT-217 Turbine stop and control valve testing.----------------------------------NEI 99-02: Not counted due to it being a planned evolution. -- NEI Proposed: Not counted due to it being a anticipated Rx power reduction. --------------- NRC Proposed: Not counted due to not exceeding net ADP change > 20% (ADP 4.5%)--- NRC 8/15: Not counted due to exemption No. 4. Routine test or Surviellance.
ComPeak2	0	0	0	0	Rx Power: 0% Gen Power: 0% approx 0 MWe. 100% power reduction. -------------------------- Ramp down to begin 2RF05. Returned from outage 11/05 sync and 11/10 100% NEI 99-02: Not counted due to it being a planned evolution. -- NEI Proposed: Not counted due to it being a anticipated Rx power reduction. ------------------ NRC Proposed: Not counted due to it being a scheduled pre-outage activity.-(ADP 61.9%)---NRC 8/15: Not counted due to exemption No. 1. Planned Refueling Outage.
ComPeak2	0	0	0	0	Rx Power: 76% Gen Power: 76% approx 875 MWe.(830 MWe NET) 24% power reduction. Planned Routine OPT-217 Turbine stop and control valve testing.----------------------------------NEI 99-02: Not counted due to it being a planned evolution. -- NEI Proposed: Not counted due to it being a anticipated Rx power reduction. --------------- NRC Proposed: Not counted due to not exceeding net ADP change > 20% (ADP 4.9%) NRC 8/15: Not counted due to exemption No. 4. Routine test or Surviellance.
ComPeak2	0	0	0	0	Rx Power: 85% Gen Power: 74% approx 851 MWe. 15% reactor power reduction, 26% generator power reduction---------- EHC pressure switch failure. --NEI 99-02: Not counted due N16 Rx power not exceeding >20%.(see below)------------------ NEI Proposed: Not counted due to n16 Rx power not exceeding >20% (see below) --------- NRC Proposed: Not counted due to not exceeding net ADP change > 20% (ADP 16.0%) ---NRC 8/15: Not counted due not exceeding 20% power reduction.
ComPeak2	0	0	0	0	Rx Power: 76% Gen Power: 76% approx 875 MWe. 24% power reduction.------------------------ While down for the unplanned derate for EHC pressure switch failure repairs (See Above), the decision was made to take advantage of the downpower and perform the OPT-217 Turbine stop and control valve testing in the derate window. This adjustment staggered the unit testing . ---- NEI 99-02: Not counted due to it being a planned evolution.---------------------- NEI Proposed: Not counted due to it being a anticipated Rx power reduction.-------------------- NRC Proposed: Not counted due to not exceeding net ADP change > 20% (ADP 16.0%) ---- NRC 8/15: Not counted due to exemption No. 4. Routine test or Surviellance.

Cooper	0	0	1	0	Normal downpower for a control rod pattern adjustment. This did not count under the current criteria as it was scheduled greater than 72 hours in advnace and does not represent a degraded condition. This would count under the new NRC criteria based on a daily power average.
Cooper	0	0	1	0	Normal downpower for a control rod sequence exchange. This did not count under the current criteria as it was scheduled greater than 72 hours in advnace and does not represent a degraded condition. This would count under the new NRC criteria based on a daily power average.
Cooper	0	0	1	0	Normal downpower for a control rod pattern adjustment. This did not count under the current criteria as it was scheduled greater than 72 hours in advnace and does not represent a degraded condition. This would count under the new NRC criteria based on a daily power average.
Cooper	0	0	1	0	Normal downpower for required surveillances. This did not count under the current criteria as it was scheduled greater than 72 hours in advnace and does not represent a degraded condition. This would count under the new NRC criteria based on a daily power average.
Dresden 2	0	0	0	0	Planned Control Rod Swap 820mwe to 648mwe, loss of 715mwh 4% ADPL reduction 8/15 CRD Swap (5)
Dresden 2	0	0	0	0	Planned CRD testing 820 to 648mwe. Loss of 1503mwh 8% ADPL recduction 8/15 CRD Testing (5)
Dresden 2	0	0	0	0	Rx Power: 0% Gen Power: 0% approx 0 MWe.100% power reduction. Reactor Recirculation pump trip that led to a subsequent manual scram when they other recirculation pump tripped.----------------------------------NEI 99-02: Not counted due to it being part of an event that culminated with a scram. -- NEI Proposed: Not counted due to being counted in the unplanned scram indicator. --------------- NRC Proposed: Not counted due it being counted in the unplanned scram indicator. 8/15 Counted in unplanned scram indicator (8)
Dresden 3	0	0	0	0	Load Drop per Load Dispatchers request 750mwe to 520mwe, loss of 1745mwh 9% ADPL reduction 8/15 LD request (2)
Dresden 3	0	0	0	0	Planned 820 to 580mwe for rod swap. Loss of 1767mwh 9% ADPL reduction 8/15 Rod swap (5)
Dresden 3	0	0	0	0	Rx Power: 70% Gen Power: approx 550MWe. 30% power reduction. Planned power change for control rod pattern swap.-----------------------------------NEI 99-02: Not counted due to it being a planned evolution. -------------------------------------- NEI Proposed: Not counted due to it being a anticipated Rx power reduction. --------------- NRC Proposed: Not counted since ADLP was <20% (5.0% decrease). 8/15 rod swap (5)
Dresden 3	0	0	0	0	Rx Power: 0% Gen Power: 0% approx 0 MWe. 100% power reduction. Reactor scram caused by reactor low level-------------------------------- NEI 99-02: does not count due being counted as a reactor scram .----------------------------- NEI Proposed: Doesn't count since counted as an unplanned reactor scram.------------------------ NRC Proposed: Doesn't count since counted as an unplanned reactor scram. 8/15 counted in unplanned scram (8)
Farley 2	0	0	0	0	Planned power reduction for mid-cycle steam generator chemical flushing. The change in average daily power level was 87 %. However, since this was a planned mid-cycle activity this activity does not count in the NRC proposed PI as well as the current and NEI proposed PIs.
FitzPatrick	0	0	0	0	Decreased power from 100% to approximately 70% to complete control rod adjustments. **Current ROP**: Not counted due to being a planned evolution. **NEI Proposed**: Not counted due to being a anticipated Rx. Power reduction. **NRC Proposed**: Not counted due to not exceeding net ADP > 20% (ADP 5.4%)

FitzPatrick	0	0	0	0	Decreased power from 100% to approximately 60% due to Condenser fouling as a result of marine and biological debris contamination. **Current ROP**: Not counted due to being a result of conditions created from marine and biological debris contamination. **NEI Proposed**: Not counted due to being a result of a seasonal environmental condition (biological and marine contamination). **NRC Proposed**: Not counted due to being a result of conditions created from marine and biological debris contamination.
FitzPatrick	0	0	0	0	Decreased power from 100% to approximately 60% due to Condenser fouling as a result of marine and biological debris contamination. **Current ROP**: Not counted due to being a result of conditions created from marine and biological debris contamination. **NEI Proposed**: Not counted due to being a result of a seasonal environmental condition (biological and marine contamination). **NRC Proposed**: Not counted due to being a result of conditions created from marine and biological debris contamination.
FitzPatrick	0	0	0	0	Decreased power from 100% to approximately 60% due to Condenser fouling as a result of marine and biological debris contamination. **Current ROP**: Not counted due to being a result of conditions created from marine and biological debris contamination. **NEI Proposed**: Not counted due to being a result of a seasonal environmental condition (biological and marine contamination). **NRC Proposed**: Not counted due to being a result of conditions created from marine and biological debris contamination.
Ft. Calhoun	0	0	0	0	Rx Power: 70% Gen Power: 70% approx 502 MWe.(483 MWe NET) 19.14% power reduction. Reduced power to reduce coolant activity before the refueling outage.
Ft. Calhoun	0	0	1	0	Rx Power: 30% Gen Power: 30% approx 502 MWe.(483 MWe NET) 40% power reduction. Reduced power to reduce coolant activity before the refueling outage. (ALARA Concerns)
Hatch 1	0	0	0	0	Planned control rod sequence exchange, scram time testing and turbine control valve testing. The average daily power level change was not greater than 20%.
Hatch 1	0	0	0	0	Planned control rod sequence exchange, scram time testing and turbine control valve testing. The average daily power level change was not greater than 20%.
Hatch 1	0	0	0	0	Automatic reactor scram due to turbine stop valve fast closure. Does not count in any of the PIs due to being a scram.
Hatch 1	0	0	0	0	During shutdown for refueling outage manual reactor scram at 55% power due to low suction pressure. Does not count in any of the PIs due to being a scram.
Hatch 1	0	0	0	0	Planned load reduction for control rod pattern adjustment
Hatch 1	0	0	1	0	Additional power reductions to replace servo-strainer on turbine control valve. These additional power reductions do not count under the current ROP PI and the proposed NEI PI. The additional power change was part of the planned power step change to repair the turbine control valve after stablizing the unit earlier. However, this power reduction in combination with the power reduction on Nov 23 did result in the average daily power reduction being greater than >20% from Nov 23 to the 24th. The unit power was subsequently raised and stablized until the following power reduction was commenced as part of a planned power reduction.
Hatch 1	0	0	0	0	Planned control rod sequence exchange and scram time testing. Average daily power change was less than 20%.

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Hatch 1	0	0	0	0	Automatic reactor scram due to turbine trip. Does not count in any of the PIs due to being a scram.
Hatch 2	0	0	0	0	Control rod sequence exchange. The average daily power level change was not greater than 20%.
Hatch 2	0	0	0	0	Control rod sequence exchange and scram time testing. The average daily power level change was not greater than 20%.
Hatch 2	0	0	0	0	Control rod sequence exchange, scram time testing and turbine control valve testing. Also replaced EHC servo-strainers and EHC system filters. The average daily power level change was not greater than 20%.
Hatch 2	0	0	0	0	Control rod sequence exchange and scram time testing. The average daily power level change was not greater than 20%.
Hatch 2	0	0	0	0	Control rod sequence exchange and scram time testing. The average daily power level change was not greater than 20%.
Hope Creek	0	0	0	0	Shutdown for RF09
Hope Creek	0	0	0	0	Rod adjustments. This does not count under the current PI because it is pre-planned (greater than 72 hours in advance). It does not count under the NEI proposal because it was a planned evolution. It does not count under the NRC proposal because it did not result in an average daily power change of greater than 20%.
Hope Creek	0	0	1	0	Control valve testing and rod adjustments. This does not count under the current PI because it is pre-planned (greater than 72 hours in advance). It does not count under the NEI proposal because it was a planned evolution. It does count under the NRC proposal because it resulted in an average daily power change of greater than 20%.
Hope Creek	0	0	1	0	Rod adjustments. This does not count under the current PI because it is pre-planned (greater than 72 hours in advance). It does not count under the NEI proposal because it was a planned evolution. It does count under the NRC proposal because it resulted in an average daily power change of greater than 20%.
Hope Creek	0	0	0	0	Rod adjustments. This does not count under the current PI because it is pre-planned (greater than 72 hours in advance). It does not count under the NEI proposal because it was a planned evolution. It does not count under the NRC proposal because it did not result in an average daily power change of greater than 20% (approximately 17%).
Hope Creek	0	0	0	0	Control valve and scram time testing. This does not count under the current PI because it is pre-planned (greater than 72 hours in advance). It does not count under the NEI proposal because it was a planned evolution. It does not count under the NRC proposal because it did not result in an average daily power change of greater than 20%.
Hope Creek	0	0	0	0	This power reduction was anticipatory due to solar magnetic disturbances and does not count in any of the three indicators.
LaSalle 1	0	0	0	0	Planned > 72 hours for Tech Spec. surveillance/ Tech. Spec Surveillance
LaSalle 1	0	0	0	0	Planned > 72 hours for Tech Spec. surveillance/ Tech. Spec Surveillance
LaSalle 1	0	0	0	0	Planned > 72 hours for Tech Spec. surveillance/ Tech. Spec Surveillance
LaSalle 1	0	0	0	0	Planned > 72 hours for Tech Spec. surveillance/ Tech. Spec Surveillance
LaSalle 1	0	0	0	0	Planned > 72 hours for Tech Spec. surveillance/ Tech. Spec Surveillance
LaSalle 1	0	0	0	0	Planned > 72 hours for Tech Spec. surveillance/ Tech. Spec Surveillance
LaSalle 1	0	0	0	0	Planned > 72 hours for Tech Spec. surveillance/ Tech. Spec Surveillance
LaSalle2	0	0	0	0	Planned > 72 hours for Tech Spec. surveillance/ Tech. Spec Surveillance
LaSalle2	0	0	0	0	Planned > 72 hours for Tech Spec. surveillance/ Tech. Spec Surveillance
LaSalle2	0	0	0	0	Planned > 72 hours for Tech Spec. surveillance/ Tech. Spec Surveillance
LaSalle2	0	0	0	0	Planned > 72 hours for Tech Spec. surveillance/ Tech. Spec Surveillance

LaSalle2	0	0	0	0	Planned > 72 hours for Tech Spec. surveillance/ Tech. Spec Surveillance
LIM2	0	0	1	0	Planned Rod pattern adjustment, scram time testing, condenser tube trial cleaning, ADP 75%
Millstone 2	0	0	0	0	Reactor shutdown for scheduled refueling outage
Millstone 2	0	0	0	0	Reactor Trip from 65% power caused by a component failure related to the turbine-generator Power Load Unbalance test pushbutton Current ROP: Not counted, reactor trips excluded.NEI Proposal: Not counted, this is counted in the unplanned reactor shutdown indicator.NRC Proposal: Not counted, this is counted in the unplanned scram indicator.NRC 8/15 not counted
N Anna 1	0	0	0	0	Automatic reactor trip due to generator output breaker failure. Current ROP: Not counted, automatic reactor trips excluded-NEI Proposal: Not counted since it is counted in unplanned reactor shutdown indicator-NRC Proposal: Not counted as it is included in the unplanned scram indicator NRC 8/15: Not counted, included in the unplanned scram indicator.
N Anna 1	0	0	0	0	There was no event on this date. The reactor was fully shutdown.-----------NRC Proposal: This meets the criteria because ADPL goes from 309 Mwe on 5/7 to 0 Mwe on 5/8.
N Anna 2	0	0	1	0	There was no event on this date. The reactor was fully shutdown.-----------NRC Proposal: This meets the criteria because ADPL goes from 558 Mwe on 1/19 to 0 Mwe on 1/20.
N Anna 2	0	0	0	0	Ramped down from 72% power for scheduled refueling outage.
N Anna 2	0	0	0	0	There was no transient on this date. There was a greater than 20 % ADPL change.--NRC Proposal: Not counted, unit shutdown for a scheduled refueling outage
PB2	0	0	1	0	Planned - Power reduced for planned evolution - control rod pattern adjustment. Power reduced to 75%. **Not included in 8/15 count - exclusion #5.**
PB2	0	0	1	0	Planned - Power reduced for planned evolution - control rod pattern adjustment. Power reduced to 67%. **Not included in 8/15 count - exclusion #5.**
PB2	0	0	1	0	Planned - Power reduced for planned evolution - control rod pattern adjustment. Power reduced to 60%. **Not included in 8/15 count - exclusion #5.**
PB2	0	0	1	0	Planned - Power reduced for planned evolution - control rod pattern adjustment. Power reduced to 69%. **Not included in 8/15 count - exclusion #5.**
PB2	0	0	1	0	Planned - Power reduced for planned evolution - control rod pattern adjustment. Power reduced to 75%. **Not included in 8/15 count - exclusion #5.**
PB2	0	0	1	0	Planned - Power reduced for planned evolution - control rod pattern adjustment. Power reduced to 57%. **Not included in 8/15 count - exclusion #5.**
PB3	0	0	0	0	Planned - Power reduced for planned evolution - control rod pattern adjustment. Power reduced to 67%. **Not included in 8/15 count - exclusion #5.**
PB3	0	0	1	0	Planned - Power reduced for planned evolution - control rod pattern adjustment. Power reduced to 59%. **Not included in 8/15 count - exclusion #5.**
PB3	0	0	1	0	Planned - Power reduced for planned evolution - control rod pattern adjustment, other planned maintenance activities accomplished at same time. Power reduced to 21%. **Not included in 8/15 count - exclusion #5.**
PB3	0	0	1	0	Planned - Power reduced for planned evolution - control rod pattern adjustment. Power reduced to 74%. **Not included in 8/15 count - exclusion #5.**

Prairie Island1	0	0	0	0	On 5/28/2000, power was reduced to perform turbine valve testing (approx. 52% power reduction). The unit returned to full power on the 5/28/2000. NEI 99-02: Not counted due to it being planned testing. NEI Proposed: Not counted due to it being anticipated (reduced power to perform planned testing). NRC Proposed: Not counted due to ADPL change > 20% was NOT exceeded (change in ADPL of 15.2%) NRC 8/15/01 Draft: Not counted. Power reduction to perform Tech Spec required turbine valve testing.
Prairie Island1	0	0	0	0	The unit was in coastdown operation for the upcoming refueling outage. The unit was at about 79.5% power on 1/19/2001, when it was taken off-line to begin the refueling outage (79.5% power reduction). The outage ended when the Unit was placed on-line on 2/25/2001. The Unit reached full power on 2/28/2001. NEI 99-02: Not counted due to it being planned activity (refueling outage). NEI Proposed: Not counted due to it being anticipated (reduced power to take unit off-line for refueling outage). NRC Proposed: Not Counted due to activity being a scheduled refueling outage. NRC 8/15/01 Draft: End of cycle coast down and shutdown for refueling outage not counted.
Prairie Island2	0	0	0	0	On April 28th, power reduction began to remove the unit from service to start the refueling outage. While reducing power, at about 22% power, the reactor tripped due to feedwater heater level. The total power reduction was 100%. The outage ended when the unit was placed on-line on 6/7/2001. The Unit reached full power on 6/10/2001. NEI 99-02: Not counted due to it being planned activity (refueling outage). Scrams are not counted for this indicator. NEI Proposed: Not counted due to it being anticipated (reduced power to perform planned testing). Scram is not counted because it's included in the unplanned reactor shutdown indicator. NRC Proposed: Not Counted due to activity being a scheduled refueling outage. Scram is not counted because it's included in the unplanned scram indicator. NRC 8/15/01 Draft: Not counted due to this being a planned refueling outage. Scram which occurred during shutdown not counted since it's counted in unplanned scram indicator.
Prairie Island2	0	0	0	0	On Sept. 23rd, the unit reduced power to perform turbine valve testing (approx. 51% power reduction). The unit returned to full power operation on the Sept. 24th. NEI 99-02: Not counted due to it being planned testing. NEI Proposed: Not counted due to it being anticipated (reduced power to perform planned testing). NRC Proposed: Not counted due to ADPL change > 20% was NOT exceeded (change in ADPL of 17.98%) NRC 8/15/01 Draft: Not counted. Power reduction to perform Tech Spec required turbine valve testing.

Prairie Island2	0	0	0	0	On Dec 22nd, the unit reduced power to perform turbine valve testing (approx. 48% power reduction). The unit returned to full power operation on the Dec. 23rd. NEI 99-02: Not counted due to it being planned testing. NEI Proposed: Not counted due to it being anticipated (reduced power to perform planned testing). NRC Proposed: Not counted due to ADPL change > 20% was NOT exceeded (change in ADPL of 5.54%) NRC 8/15/01 Draft: Not counted. Power reduction to perform Tech Spec required turbine valve testing.
Prairie Island2	0	0	0	0	On March 28th, the unit reduced power to perform turbine valve testing (approx. 52% power reduction). The unit returned to full power operation on the March 29th. NEI 99-02: Not counted due to it being planned testing. NEI Proposed: Not counted due to it being anticipated (reduced power to perform planned testing). NRC Proposed: Not counted due to ADPL change > 20% was NOT exceeded (change in ADPL of 7.13%) NRC 8/15/01 Draft: Not counted. Power reduction to perform Tech Spec required turbine valve testing.
Quad 1	0	0	0	0	79%RCTP = 21% power reduction; Planned load reduction for CRD return to service & PMTs, and turbine testing. NEI 99-02; not counted due planned NEI Proposal; not counted due anticipated NRC Proposal; not counted due load reduction < 20% of full power based on rated NET electrical power (ADPL = 16730MWE/day / 24hrs = 697.08MWE/hr / 775 RNMWe = 90% = 10% power reduction).
Quad 1	0	0	0	0	57% RCTP = 43% power reduction; Planned reduction for rod pattern adjustment NEI 99-02; not counted due planned NEI Proposal; not counted due anticipated NRC Proposal; not counted due <20% power [692 ADPL; 11% load reduction based on ADPL and RNWMe]
Quad 1	0	0	0	0	66% RCTP = 34% power reduction; Planned for rod pattern adjustment NEI 99-02; not counted due planned NEI Proposal; not counted due anticipated NRC Proposal; not counted due <20% power [749 ADPL; 3% load reduction based on ADPL and RNWMe]
Quad 1	0	0	0	0	68% RCTP= 32% power reduction; Planned for rod pattern adjustment NEI 99-02; not counted due planned NEI Proposal; not counted due anticipated NRC Proposal; not counted due <20% power [731 ADPL; 6% load reduction based on ADPL and RNWMe]
Quad 1	0	0	0	0	75% RCTP= 25% power reduction; Planned for scram timing & rod pattern adjustment NEI 99-02; not counted due planned NEI Proposal; not counted due anticipated NRC Proposal; not counted due <20% power [729 ADPL; 6% load reduction based on ADPL and RNWMe]

Quad 1	0	0	0	0	67% RCTP= 33% power reduction; Planned for rod pattern adjustment NEI 99-02; not counted due planned NEI Proposal; not counted due anticipated NRC Proposal; not counted due <20% power [733 ADPL; 6% load reduction based on ADPL and RNWMe]
Quad 1	0	0	0	0	65% RCTP= 35% power reduction; Planned for rod pattern adjustment NEI 99-02; not counted due planned NEI Proposal; not counted due anticipated NRC Proposal; not counted due <20% power [731 ADPL; 6% load reduction based on ADPL and RNWMe]
Quad 1	0	0	0	0	0% RCTP= 100% power reduction; Planned shutdown for refuel outage Q1R16 NEI 99-02; not counted due planned NEI Proposal; not counted due anticipated NRC Proposal; not counted due planned refueling outage
Quad 1	0	0	0	0	48% RCTP= 52% power reduction; Planned for startup testing and rod pattern adjustment NEI 99-02; not counted due planned NEI Proposal; not counted due anticipated NRC Proposal; not counted due scheduled as post refuel startup testing. The reduction is however >20% power [607 ADPL; 22% load reduction based on ADPL and RNWMe].
Quad 1	0	0	1	0	No power reduction, just the ramp back up to full power from the drop on the night of the 15th. However, the ADPL = 600 which corresponds to a 23% delta with respect to rated net power. Does this count?
Quad 1	0	0	0	0	75% RCTP = 25% power reduction; Planned rod pattern adjustment as part of scram recovery. NEI 99-02; not counted due planned NEI Proposal; not counted due anticipated NRC Proposal; not counted due <20% power [760 ADPL; 2% load reduction based on ADPL and RNWMe]
Quad 1	0	0	0	0	60% RCTP = 40% power reduction; Planned scram timing & rod pattern adjustment. NEI 99-02; not counted due planned NEI Proposal; not counted due anticipated NRC Proposal; not counted due <20% power [780 ADPL; 0% load reduction based on ADPL and RNWMe]. Note that on the next day, 02/25/01, where the recovery takes place, the ADPL = 686 corresponding to a delta from rated net generation of 11%.
Quad 2	0	0	0	0	57% RCTP = 43% power reduction; Scram Timing, rod pattern adjustment, 1C1 FW Heater work. NEI 99-02; not counted due planned NEI Proposal; not counted due anticipated NRC Proposal; not counted due <20% power [688 ADPL; 13% load reduction based on ADPL and RNWMe]
Quad 2	0	0	1	0	30% RCTP = 70% power reduction; Planned scram timing, rod pattern adjustment, & TCV #3 repairs. NEI 99-02; not counted due planned NEI Proposal; not counted due anticipated NRC Proposal; counted due >20% power [465 ADPL; 41% load reduction based on ADPL and RNWMe]

Quad 2	0	0	0	0	0% RCTP = 100% power reduction; Shutdown for Q2M16. NEI 99-02; not counted due planned NEI Proposal; not counted due anticipated NRC Proposal; not counted due <20% power [690 ADPL; 12% load reduction based on ADPL and RNWMe] Note - for the next several days with the unit offline, the ADPL = -192/24hrs = -8 or 108% reduction from rated net electrical power. Would this be reported each day?
Salem 1	0	0	0	0	Manual trip - counted in scram PI
Salem 1	0	0	0	0	This power reduction was anticipatory due to a severe storm with the potential to impact a transmission line and does not count in any of the three indicators.
Salem 1	0	0	0	0	This power reduction was anticipatory due to solar magnetic disturbances and does not count in any of the three indicators.
Salem 1	0	0	0	0	Plant trip - counted in scram PI
Salem 1	0	0	0	0	Plant trip - counted in scram PI
Salem 2	0	0	1	0	Turbine control valve testing and feedwater heater maintenance. This counts toward the NRC proposal because it resulted in an average daily power change of greater than 20%. It does not count toward the current PI because it was planned greater than 72 hours in advance. It does not count toward the NEI proposal because it is limited to planned maintenance and surveillance testing. It does not count toward the 8/15 NRC proposal because the Corrective Maintenance was conducted concurrently with the valve testing.
Salem 2	0	0	1	0	Turbine control valve testing. This counts toward the NRC proposal because it resulted in an average daily power change of greater than 20%. It does not count toward the current PI because it was planned greater than 72 hours in advance. It does not count toward the NEI proposal because it is limited to planned maintenance and surveillance testing. It does not count toward the 8/15 NRC proposal because the Corrective Maintenance was conducted concurrently with the valve testing.
Salem 2	0	0	0	0	This power reduction does not count for any of the proposals because it was due to a load dispatcher request associated with abnormal grid situation and solar magnetic disturbances.
Salem 2	0	0	0	0	This power reduction does not count for any of the proposals because it was for the beginning of 2R11.
Salem 2	0	0	1	0	Turbine control valve testing and scheduled equipment repairs. This counts toward the NRC proposal because it resulted in an average daily power change of greater than 20%. It does not count toward the current PI because it was planned greater than 72 hours in advance. It does not count toward the NEI proposal because it is limited to planned maintenance and surveillance testing. It does not count toward the 8/15 NRC proposal because the Corrective Maintenance was conducted concurrently with the valve testing.
Salem 2	0	0	0	0	Turbine control valve testing. This does not count toward the NRC proposal because it did not result in an average daily power change of greater than 20%. It does not count toward the current PI because it was planned greater than 72 hours in advance. It does not count toward the NEI proposal because it is limited to planned maintenance and surveillance testing. It does not count toward the 8/15 NRC proposal because the Corrective Maintenance was conducted concurrently with the valve testing.
Sequoyah 1	0	0	0	0	none
Surry 1	0	0	0	0	Reactor shutdown for scheduled refueling outage.

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Surry 1	0	0	0	0	Unit 1 Reactor Trip due to Unit 2 Outage Work being performed on wrong unit.-- Current ROP: Not counted, automatic reactor trips excluded------------------NEI Proposal: Not counted since it is counted in unplanned reactor shutdown indicator---NRC Proposal: Not counted as it is included in the unplanned scram indicator.--NRC 8/15: Not counted, included in the unplanned scram indicator.
Surry 2	0	0	0	0	Reactor shutdown for scheduled refueling outage.
Vogtle1	0	0	0	0	Manual Scram when main steam isolation valve closed. This does not count in the current PI nor either of the proposed PIs since this was a scram.
Vogtle1	0	0	0	0	Automatic scram during solid state protection system and reactor trip breaker testing. This does not count in the current PI nor either of the proposed PIs since this was a scram.
WattsBar 1	0	0	0	0	Coastdown for refueling; no single days reduction exceeded 20% power
	74	52	135	~~123~~ 120	

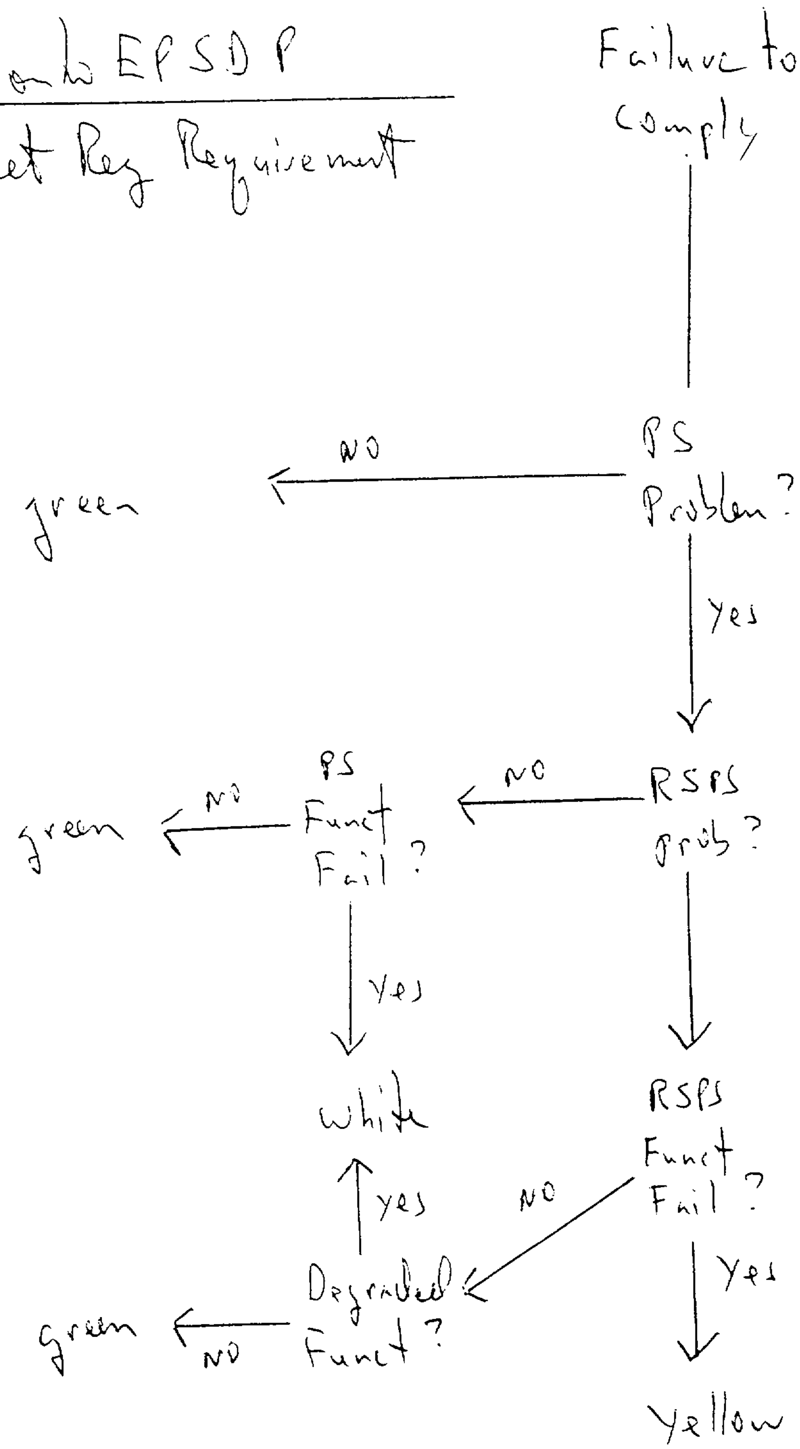
Revision of the EP SDP

- Incorporate comments
- Clarify guidance and word-smith
- Change use of "failure to meet" and "failure to implement," to be more consistent with common usage of the words. This was accomplished by introducing the concept of a "functional failure" of a PS.
- Increase flexibility for functional failure of RSPS. Current SDP only allows for yellow or green findings. Proposed SDP allows assessment of RSPS degradation to be white finding.
- Examples within SDP are essentially test cases, but additional test cases would be welcomed.
- Comments are welcome over the next 30 days. Proposed SDP will be sent to other NRC stakeholders informally and eventually, formally as part of the approval process.
- Additional tweaking will continue, to improve clarity and incorporate additional comments, but significant changes are presented in the draft.

Attachment 5

Proposal Revision to EPSDP

Failure to Meet Reg Requirement Branch



Appendix B

Emergency Preparedness
Significance Determination Process

1.0 INTRODUCTION

The framework of the Emergency Preparedness (EP) Cornerstone is described in SECY-99-007 and SECY-99-007a. The Cornerstone Objective and Performance Expectation are the bases for the inspection program and performance indicators. They are repeated here for convenience.

The Emergency Preparedness Cornerstone Objective is to: "Ensure that the licensee is capable of implementing adequate measures to protect the public health and safety in the event of a radiological emergency."

The Objective is supported by a Performance Expectation: "Demonstrate that reasonable assurance exists that the licensee can effectively implement its emergency plan to adequately protect the public health and safety in the event of a radiological emergency."

Licensee performance in this cornerstone is assessed by considering the relationship of performance indicators (PIs) with regard to thresholds and the significance of inspection findings. The significance determination process (SDP) provides a method to place inspection findings in context for risk significance in a manner that allows them to be combined with PI results. This information is used to determine the level of NRC engagement in accordance with (IAW) the Reactor Oversight and Assessment Process Action Matrix.

The EP SDP consists of flow chart logic to disposition inspection findings into one of the following categories: "green - licensee response band," "white - increased regulatory response band," "yellow - required regulatory response band," or "red - unacceptable performance band." Manual Chapter 0610* contains criteria for determining which inspection issues should be placed in context through SDP.

The EP SDP is structured such that any finding that enters the SDP will be at least green. The significance of a finding reflects the significance of the loss of program function. During the development of EP Cornerstone, the most risk significant elements were identified as distinct from other important program elements. These development efforts were performed by a group of EP subject matter experts, including industry stakeholders, with input from members of the public. The EP SDP methodology recognizes failures in the identified risk significant elements as more significant than failures in other program elements. 10 CFR Part 50 codifies a set of EP planning standards in 10 CFR 50.47(b) and supporting requirements in Appendix E to Part

50. The more risk significant elements of EP align with a subset of the planning standards and requirements. The SDP logic identifies the loss of program function required by planning standards as more significant than noncompliance with regulatory requirements. Functional failure of the more risk significant planning standards results in greater significance than the loss of function of the other planning standards (e.g., a yellow finding as opposed to a white finding.) The stratification of EP requirements is as follows:

- the most risk significant planning standards (RSPS); 10 CFR 50.47(b)(4), (5), (9) and (10) and portions of Appendix E (as defined in the individual RSPS sections.)
- the remaining planning standards (PS); 10 CFR 50.47(b)(1), (2), (3), (6), (7), (8), (11), (12), (13), (14), (15), and (16) and portions of Appendix E, and
- other EP related regulations, remaining portions of Appendix E, applicable orders and the commitments of the Emergency Plan (Plan).

While the EP SDP assigns risk significance to findings it should be understood that even a green finding (very low risk significance) does not mean that the performance associated with the finding is acceptable. The finding may represent a violation of 10 CFR. The green significance determination means that the safety significance of the finding is very low and correction of the item is considered to be within the "licensee response band."

2.0 GENERAL GUIDANCE FOR SDP USE

The following general guidance is provided to assist in using the EP SDP.

a. "RSPS" means 10 CFR 50.47(b)(4), (5), (9) and (10) and portions of Appendix E as defined under each RSPS.

b. "PS" means the planning standards of 10 CFR 50.47(b), including the RSPS and portions of Appendix E to 10 CFR 50 as defined under each PS.

c. "Regulatory requirements" means any EP related requirement, including the PS and Appendix E, e.g., failure to follow Plan commitments is non-compliance with 50.54(q).

d. "Failure to comply" means that a program is not in compliance with a regulatory requirement. This term is meant to include noncompliance items that are more than minor through the failure of a RSPS function.

e. "Loss of PS function" or "PS functional failure" means that program elements are not adequate, in compliance or otherwise functional to such an extent that the function of the PS is not met. This is a subset of a "failure to comply." It may be that the Plan commitments are not met, that the Plan is inadequate, that implementing procedures are inadequate or that program design is inadequate, but the result is that even if the program were implemented as designed, it would not meet the intended function of the PS.

f. Loss of PS function is determined by program compliance with the regulation. However, the regulatory wording of the PS is not always exact and at times the determination of a loss of PS function may not be obvious. The determination may be informed by program compliance with the guidance of NUREG-0654. NUREG-0654 provides guidance for licensees to use in developing a program to meet the PS. The Plan was assessed (for most plants in the early 1980s) for adequacy against NUREG-0654 and other guidance, orders and regulations, and approved by NRC. The Plan is the licensee's commitment for meeting the PS. The Plan may have been approved with processes that differ from the guidance of NUREG-0654, but which appeared to meet the regulatory requirements.

   However, there is an element of judgement involved in this determination. There are many guidance elements in NUREG-0654. A program may be in non-compliance with some and yet be able to meet the PS function. In this case, there may be a noncompliance with the Plan, or an inappropriate change to the Plan may have occurred that removed commitments to NUREG-0654. The PS function remains, but a failure to comply exists that will result in a finding.

g. "Failure to implement" means that a failure to comply with regulatory requirements occurred during an <u>actual event</u>.

h. Failure to implement a PS means that there was a functional failure in the implementation of the PS. Generally, failure to implement a PS is the result of personnel errors. The associated program elements are adequate and if implemented properly would have fulfilled the PS function. However, failure to implement may reveal that the program has a loss of PS function. This may be determined by a review against the criteria for loss of PS function.

i. Failure to implement during a drill or exercise is a performance problem that should be corrected, but is not a "failure to implement" as the term is used in this SDP.

j. A "drill or exercise critique problem" means that the critique did not identify participant performance problems that would have been a failure to comply had the event been an actual emergency. The term "critique" includes all formal, documented aspects of drill assessment.

k. There are three branches of the EP SDP. Actual Event Implementation Problem, Drill or Exercise Critique Problem and Failure to Comply. Findings should be assessed through all paths that are applicable and the most significant finding issued. Parallel findings may be noted in the inspection report, but only the most significant finding should be issued. For example, an implementation problem during an actual event may also reveal a failure of PS function. If the failure of PS function is the more significant finding, it would dictate the color of the issued finding.

l. Failure to correct weaknesses and deficiencies should be analyzed against compliance with PS 50.47(b)(14). If the weakness challenges the function of a RSPS, it may represent a PS functional failure. The guidance for PS 50.47(b)(14) is provided in a separate section of this attachment.

m. The Enforcement Policy (NUREG-1600) indicates that a failure to make reports required by NRC regulations is an item of noncompliance that cannot be assessed through the SDP process. However, under the EP Cornerstone, the failure to classify and notify are integral to the EP SDP and guidance is provided, e.g., a failure to activate ERDS or staff the ENS line is a failure to comply with the requirements of 50.72 and should be considered a failure to implement under the EP SDP.

n. The NRC Policy Statement on Safety Goals for the Operations of Nuclear Power Plants, states that EP is a defense in depth measure. This indicates that the likelihood of a reactor accident should not be used to determine the safety significance of an EP element. Rather, the safety significance of a failure to comply with EP requirements should be viewed as assuming the EP program is being implemented in response to an emergency. This view may be used to answer the MC 610* "Threshold for Documentation Questions."

3.0 ACTUAL EVENT IMPLEMENTATION PROBLEM

<u>Background</u>

This branch of the SDP is used when a failure to comply occurred during an actual event.

An actual event implementation problem is generally the result of personnel error. The program elements are adequate and would have complied with requirements if they had been implemented.

Failure to implement a PS means the PS function was not implemented in a timely manner during the event. Failure to implement some Plan elements may occur and yet the PS function be achieved.

The definition of "timely" and "accurate" for the Drill and Exercise Performance PI are not universally appropriate for determining whether a RSPS was implemented during an actual event. Timeliness should be judged in context with the competing pressures placed on the staff to respond to the event and ensure public health and safety through mitigation actions. The performance expectations is that classifications will be made as soon as possible after conditions/data are available to allow classification. This will usually be within 15 minutes. Similarly, notifications are expected to be made within 15 minutes of classification. In general, classifications and notifications that are performed within 15 minutes are adequate. Those that take longer should be examined and a judgement as to adequacy rendered. There may be good reason for the delay and it may have minimal impact on the Cornerstone Objective. It is not the intent to issue findings for classifications or notifications that are a few minutes late when licensee was performing safety related activities meant to protect the public health and safety. However, errors in recognition, delays not based on competing safety related activities or delays that deny offsite authorities the opportunity to protect the public health and safety may be assessed as not implementing the RSPS. Each event and response must be judged on a case-by-case basis.

Similarly, the definition of "accurate" in the Drill and Exercise Performance PI contributes data that indicates the efficacy of program elements such as training, drills, procedure quality, corrective actions, etc. An error in the notification form may have no impact on off site agency efforts, but would have been considered a failure under the PI definition. The effect of errors should be judged against the PS function to determine if the failure rises to the level of a failure to implement a PS.

Failure to comply with requirements during a drill is a performance problem that should be corrected, but is not a failure to implement as the term is used in this SDP.

Criteria

a. Failure to comply with a requirement has occurred during an actual event. This is generally determined by reviewing compliance with a regulation or Plan commitment.

b. Failure to implement a PS function has occurred during an actual event. This is generally determined by reviewing licensee performance against the PS function.

Considerations

Review the PS function. If the poor performance had little impact on function, it may not be appropriate to consider the performance as a failure to implement a PS or perhaps even a failure to comply.

4.0 DRILL OR EXERCISE CRITIQUE PROBLEM

Background

This branch of the SDP is used for inspector issues identified through the baseline program inspection of licensee drills and exercises. Inspection procedure No. 71114 instructs inspectors to observe drills and exercises and identify weaknesses (i.e., a demonstrated level of performance that could have precluded effective implementation of the emergency plan in an actual emergency.) Performance that would not comply with requirements had it occurred during an actual event is a subset of weaknesses and represents a more significant performance problem.

The SDP stratifies critique failures at two levels; those involving the failure to identify RSPS weaknesses are potentially white and the failure to identify other weaknesses are potentially green.

Licensees critique drills and exercises in many different ways and inspectors should be flexible in accepting mechanisms for problem identification. The critical feature of any critique is that weaknesses are captured and entered into a corrective action system with appropriate priority. If the inspector can assure her/him self that the weakness will be entered into a corrective action system, the critique should be considered successful.

The disposition of critique findings varies between sites. The licensee must evaluate numerous evaluator observations and prioritize resources for correction. Indeed, some evaluator suggestions may be counter productive in the judgement of responsible EP management. Care should be taken to understand the logic for suggestion disposition before the disposition is identified as a critique problem. However, disregard for well founded evaluator identified weaknesses should be considered as a critique problem. In particular, if the weakness would be a failure to comply if the event had been actual. the NRC expectation would be for it to be captured by the critique.

The Plan and procedures contain the approved commitments for implementation of NRC regulations and may be used to judge effective, timely and accurate implementation. If the Plan or procedures themselves are inadequate, it is not a drill/exercise critique issue and the branch of the SDP for a failure to comply with a regulatory requirement may be helpful. Licensee mistakes and mis-steps that only detract from implementation should not be considered weaknesses. Mistakes are likely to happen in the course of an exercise and when these are corrected by the ERO it may reveal an organizational strength rather than a weakness, but this judgement is left to the inspector.

RSPS problems should be given the highest priority in the critique process. The baseline inspection program is based on predicated on the availability of accurate PI data to properly reflect licensee performance. The Drill and Exercise Performance PI (DEP) is based on licensee determination of timely and accurate classification, notification and PAR development. If the licensee critique fails to identify an inaccurate or untimely classification, notification or PAR development effort, it should be judged as a failure to identify a RSPS problem. NEI 99-02 defines timely and accurate for classification, notification and PAR development. A critique that fails to identify problems within the definitions, should be considered as failure to identify RSPS problems. A failure to identify some facet of these processes that is outside the definitions would not be considered as failure to identify RSPS problems. The NRC expectation is for the licensee critique to emphasize evaluation of performance in the RSPS areas.

The RSPS include 10 CFR 50.47(b)(9). This RSPS is covered by the DEP PI in an indirect manner (i.e., classification and PARs may be based on dose projections.) Judgement may be exercised in viewing the significance of performance problems concerning this RSPS, i.e., some mis-steps may not rise to the level of a weakness. However, the NRC expectation is for the licensee critique to emphasize evaluation in the RSPS areas and weaknesses should be identified and corrected.

Criteria

A licensee critique of a drill or exercise has failed to identify a weakness observed by NRC inspectors.

Considerations

The weakness that was missed by the critique must be a demonstrated level of performance that could have precluded effective implementation of the emergency plan in an actual emergency. Some mis-steps in performance may not rise to the level of a weakness and/or were corrected by the subsequent actions of the ERO.

5.0 LOSS OF PS FUNCTION

Loss of PS function or PS Functional Failure means that program elements are not in compliance with the PS of 10 CFR 50.47(b) because the function of the PS is not available for emergency response. It may be that the Plan commitments are not met, that the Plan commitments are inadequate, that implementing procedures are inadequate, that program design is inadequate, that personnel are not capable of implementation, etc. The PS function is taken from the PS as found in 50.47(b). Compliance with all NRC requirements is necessary. However, for the purposes of determining the significance of licensee failure to comply with regulatory requirements, the PS function is identified. Criteria for determinating loss of PS function is provided. Loss of PS function is more significant than noncompliance with individual requirements associated with the PS. Appendix E to 10 CFR 50 contains requirements that generally align with the PS. Compliance with these requirements is a measure of the PS functionality. Another measure of PS functionality is compliance with the planning criteria of NUREG-0654, taking into consideration any deviations from NUREG-0654 that were approved by NRC.

However, the failure to comply with one or a few of these requirements and/or criteria does not, in itself, meant that PS function is lost. The criteria must be assessed and judgement applied to determine if the PS function has been lost.

Loss of function of RSPS results in a yellow finding. There may be cases where the PS function is not lost, but is degraded. These cases warrant a finding, but do not represent a degraded cornerstone, i.e., a yellow finding. Guidance is provided for these contingencies under each RSPS.

The failure to correct weaknesses and deficiencies may be a functional failure of PS 50.47(b)(14). The guidance for this area is extensive and is placed in Section 6.0 rather than with the guidance for 50.47(b)(14).

5.1 10 CFR 50.47(b)(1)

The PS functions are:

- Responsibility for emergency response is assigned and
- the response organization has the staff to respond on a continuing basis.

Requirements are found in Appendix E, §IV. A. 1., 2., 3., 4., 5., 6., 7., and 8.

Criteria are found in NUREG-0654 § II. A.

Examples of loss of PS function include:

- The organization assigned responsibilities in the Plan no longer has the authority, staff or resources to respond and to augment initial response on a continuous basis.

5.2 10 CFR 50.47(b)(2)

The PS functions are:

- On-shift emergency response responsibilities are assigned,
- adequate initial response staff is maintained and
- the capability for timely augmentation of initial response staff is maintained

Requirements are found in Appendix E, §IV. A. 2. a., b., and c. and 3 and Appendix E, §IV. C.

Criteria are found in NUREG-0654 § II. B.

Examples of loss of PS function include:

- On-shift staffing routinely (or procedurally) is allowed to degrade to levels less than those committed in the Plan.
- Staffing changes have resulted in an organization that can not respond to emergencies IAW the commitments of the Plan.
- Staffing augmentation processes are not capable of ensuring augmentation of the initial response staff IAW facility activation commitments, i.e., one or more Plan required ERO functions IAW Plan commitments to NUREG-0654 Table B-1.
- Changes (not approved by NRC) to the Plan have resulted in a staff that no longer meets applicable guidance (or is not consistent with previous NRC approval) for emergency response staffing.

5.3 10 CFR 50.47(b)(3)

The PS functions are:

- Arrangements for requesting and using offsite assistance have been made, and
- State and local staff can be accommodated at the EOF and

- organizations capable of supporting the response effort have been identified.

Requirements are found in Appendix E § IV. A. 6. and 7.

Criteria are found in NUREG-0654 § II. C.

Examples of loss of PS function include:

- Plan elements have degraded to the point that commitments for offsite assistance can no longer be met or lists of possible support organizations are no longer maintained or available.
- The EOF has been changed in such a manner that it can no longer accommodate offsite authorities, IAW the Plan.

5.4 <u>10 CFR 50.47(b)(4)</u>

The PS function is:

- A standard scheme of emergency classification and action levels be in use.

Requirements are found in Appendix E § IV. B. and C.

Criteria are found in NUREG-0654 § D.

It should be noted that NRC has endorsed NESP/NUMARC-007 which provides an alternate "standard scheme of emergency classification." Additionally, NRC has allowed certain modifications to the classification scheme as outlined in EPPOS-2.

Examples of loss of PS function include:

- The EAL scheme has been changed so that it is no longer a standard scheme, i.e., EAL changes have downgraded the Emergency Class of an initiating condition (or conditions) such that more than two Alerts, more than one Site Area Emergency or any General Emergency that should be declared under approved guidance would not be declared under the changed scheme.

Examples of degradation of PS function include:

- Changes to the EAL scheme that do not rise to the level of a PS functional failure, but are a serious degradation of the PS function are: EAL changes have downgraded the Emergency Class of an initiating condition (or conditions) such that more than one Alert and any Site Area Emergency that should be declared under approved guidance would not be declared under the changed scheme.

- Changes to the EAL scheme that deviate from approved guidance but do not rise to either of the above levels may still be a decrease in effectiveness and in noncompliance with 10 CFR 50.54(q).

5.5 10 CFR 50.47(b)(5)

The PS functions are:

- Procedures for notification are established and in use.
- the procedure for notification must be capable of notifying within 15 minutes (this is a requirement from Appendix E that is a function of the RSPS.)
- the means for public alert and notification are established and available. (However, since the ANS PI covers availability, with >90% reliability as the yellow threshold, findings for availability are not appropriate.)
- the public alert and notification system shall be capable of providing an alert signal throughout the 10 mile EPZ, within 15 minutes (REP-10 and ASLB Case Law.)
- the public alert and notification system shall be capable of ensuring direct coverage of essentially 100% of the population within 5 miles of the site (REP-10 and ASLB Case Law.)
- special arrangements will be made to ensure 100% of the public in the EPZ is notified within 45 minutes (REP-10 and ASLB Case Law)

Requirements are found in Appendix E §IV. D. 1. and 3. Much of these requirements are integral to the RSPS function and have been incorporated above.

Criteria are found in NUREG-0654 § E

Criteria are found in FEMA-REP-10. Some of these criteria are integral to the RSPS function and have been incorporated above.

Case law includes: ASAB-935, Seabrook Offsite EP Issues; ASLBP No. 82-472-03, Shearon Harris; ASAB-852, Appeal of Shearon Harris. It may be noted that ASAB rulings are precedent setting nationally. ASLBP ruling are not, but the guidance therein can inform deliberations.

Examples of loss of PS function include:

- Procedures will not enable personnel to perform offsite notifications within 15 minutes.
- Communications systems will not enable personnel to implement offsite notifications within 15 minutes.
- Personnel are not capable of implementing procedures or using systems for the notification offsite authorities.
- Public alert and notification systems are not designed or have degraded (and not been detected by the surveillance program) to the point that less than 98% of the public can be notified.
- Public alert and notification systems are not designed or have degraded (and not been detected by the surveillance program) to the point that less than 98% of the public can be notified within 15 minutes within 5 miles and within 45 minutes beyond 5 miles. (but within the EPZ.)

Examples of degradation of PS function include:

TBD Need examples of white findings and green findings

5.6 <u>10 CFR 50.47(b)(6)</u>

The PS functions are:

- That systems are established for prompt communications among Principal emergency response organizations,
- backup power supplies exist and are operational for at least one onsite and one offsite communication system (from Appendix E,) and
- systems are established for prompt communications to emergency response personnel.

Requirements are found in Appendix E § IV E. 9.

Criteria are found in NUREG-0654 § II. F.

Examples of loss of PS function include:

- Equipment is so degraded as to preclude communications among the TSC, EOF, and/or Control Room necessary to implement the Plan for longer than about a day. In the event of major disruptive events (e.g., hurricane, fire, explosion, loss of power, etc.,) compensating measures are acceptable while repair activities proceed with high priority.

- Backup power supplies for at least one onsite and one offsite communication systems, as required by Appendix E, are not functional for more than 30 days, in the absence of compensating measures.
- Equipment is so degraded as to preclude communications with field monitoring teams, the OSC or damage control teams for longer than about a week. In the event of major disruptive events (e.g., hurricane, fire, explosion, loss of power, etc.,) compensating measures are acceptable while repair activities proceed with high priority.

5.7 10 CFR 50.47(b)(7)

The PS functions are:

- EP information is made available to the public within the EPZ and
- arrangements are made for dissemination of public information during emergencies.

Requirements are found in Appendix E, §IV. D. 2.

Criteria are found in NUREG-0654 § II. G.

Examples of loss of PS function include:

- EP related public information has not been disseminated for a period 25% longer than that committed to in the Plan.
- The news facility is not functional for a period of longer than a week. In the event of major external disruptive events (e.g., hurricane, fire, explosion, loss of power, etc.,) compensating measures are acceptable while repair activities proceed with high priority.
- Processes for dissemination of information during emergencies can not be implemented, e.g., staff necessary to operate the emergency news center is not knowledgeable in the skills necessary to operate the center, augmentation (call out) processes will not ensure activation of center staff in a timely manner, and/or methods for information approval will not allow timely and accurate information releases.

5.8 10 CFR 50.47(b)(8)

The PS functions are:

- adequate facilities are maintained to support emergency response and

- adequate equipment is maintained to support emergency response.

Requirements are found in Appendix E. §IV. E. 1. 2. 3. 4. 8. and G.

Criteria are found in NUREG-0654 § II. H.

Examples of loss of PS function include:

- The TSC or EOF is not functional for a period of longer than about a day. In the event of major disruptive events (e.g., hurricane, fire, explosion, loss of power, etc.,) compensating measures are acceptable while repair activities proceed with high priority.
- The backup EOF is not functional for a period of longer than about 30 days. In the event of major disruptive events (e.g., hurricane, fire, explosion, loss of power, etc.,) compensating measures are acceptable while repair activities proceed with high priority.
- Equipment necessary to implement the Plan is not available or not functional to an extent that would prevent implementation of the Plan. e.g., lack of field monitoring team instrumentation, lack of damage control equipment, etc. The availability of additional equipment, on site, in a reasonably timely manner is considered as compensating.

5.9 <u>10 CFR 50.47(b)(9)</u>

The RSPS function is:

- Methods, systems and equipment for assessment of radioactive releases are in use.

Requirements are found in Appendix E. §IV. B. and E. 9.

Criteria are found in NUREG-0654 § II. I.

Examples of loss of PS function include:

- Personnel can not effectively implement methods to estimate source term and/or project offsite dose due to a radioactive release.
- methods are inadequate to estimate source term and/or project offsite dose due to a radioactive release, and
- equipment for dose projection is not functional to the extent that no capability exists for immediate dose projection.

Examples of a degradation of the PS function include:

- Off normal hours, on shift personnel responsible for dose assessment are not available more than 5% of the time.
- The field monitoring function is unavailable for more than about 3 days. In the event of major disruptive events (e.g., hurricane, fire, explosion, loss of power, etc.,) compensating measures are acceptable while repair activities proceed with high priority.
- Personnel responsible for dose assessment can not recognize erroneous high results beyond physical possibility, as demonstrated in a comprehensive drills, i.e., the degradation is not to be based on the performance of one drill team.

5.10 10 CFR 50.47(b)(10)

This PS has two aspects that are of differing risk significance. The establishment and implementation of PARs is integral to protection of public health and safety and is considered to be a RSPS. However, the PS also addresses emergency workers. While the protection of emergency workers is very important, it is not as important as the protection of public health and safety. Worker protection is considered to be a PS.

The RSPS function is:

- A range of public protective action recommendations (PARs) is available for implementation during emergencies.

There are no requirements in Appendix E.

Criteria are found in NUREG-0654 § II. J. 1., 7., 8., and 10.

Examples of loss of RSPS function include:

- Personnel responsible for the development of PARs are not able to implement the guidance and
- Licensee procedures do not provide PARs that are in accordance with Plan commitments or federal guidance.

Examples of a degradation of the RSPS function include:

- Licensee PAR guidance is not complete in that PARs do not cover a small population (<1% of EPZ) near site, e.g., in a park in the exclusion area or owner controlled area.
- Licensee PAR guidance is not complete in that PARs do not cover a population (>1% of EPZ,) within the EPZ.

- Protective action guidelines for the ingestion exposure pathway are not in accordance with Plan commitments or federal guidance.

The PS function is:

- A range of public protective actions is available for emergency workers during emergencies.

There are no requirements in Appendix E.

Criteria are found in NUREG-0654 § II. J. 2., 3., 4., 5. and 6.

Examples of loss of PS function include:

- Processes are not in place or not adequate for the protection of workers.
- Processes to account for workers will not ensure that accountability can be accomplished IAW Plan timeliness commitments and can be maintained during an emergency.
- Knowledgeable personnel are not available to implement protective actions for workers.

5.11 <u>10 CFR 50.47(b)(11)</u>

The PS function is:

- The means for controlling radiological exposures for emergency workers are established.

Requirements are found in Appendix E. §IV. E.. 1.

Criteria are found in NUREG-0654 § II. K.

Examples of loss of PS function include:

- Knowledgeable personnel are not available to control worker exposures during an emergency.
- Radiological control equipment or instrumentation, necessary to control exposures is not available to such an extent that emergency work in high radiation areas could not be conducted IAW regulatory requirements during emergencies.
- Processes for controlling exposures during emergencies will not ensure that exposures are maintained IAW Plan commitments.

5.12 <u>10 CFR 50.47(b)(12)</u>

The PS function is:

- Arrangements are made for medical services for contaminated injured individuals.

Requirements are found in Appendix E. §IV. E. 5.. 6. and 7.

Criteria are found in NUREG-0654 § II. L.

Examples of loss of PS function include:

- The assigned hospital is no longer available or qualified to receive contaminated injured personnel.
- The assigned hospital no longer has the appropriate equipment for the care of contaminated injured personnel.

5.13 10 CFR 50.47(b)(13)

The PS function is:

- Recovery plans are developed.

There are no requirements in Appendix E.

Criteria are found in NUREG-0654 § II. M.

Examples of loss of PS function include:

- The elements within the Plan addressing recovery have been removed or revised to eliminate commitments for adequate recovery capability.

5.14 10 CFR 50.47(b)(14)

The PS function is:

- A drill and exercise program is established,
- Drills and exercises are assessed via a formal critique process and
- identified weaknesses and deficiencies are corrected.

Requirements are found in Appendix E. §IV. F. 1. And 2.

Criteria are found in NUREG-0654 § II. N.

Examples of loss of PS function include:

- More than one drill or exercise during the inspection cycle have not been conducted IAW the Plan.
- The drill and exercise critique process does not identify significant performance problems. such as a RSPS problem.
- Formal critiques are not conducted for more than one drill or exercise during the inspection cycle.

Appendix E provides an important requirement important in section IV. F. g. This requires that weaknesses and deficiencies be corrected. The correction of weaknesses and deficiencies is of fundamental importance to the Cornerstone Objective. Guidance for this element of the PS is provided below in Section 6.0.

5.15 <u>10 CFR 50.47(b)(15)</u>

The PS function is:

- Training is provided to emergency responders.

Requirements are found in Appendix E. §IV. F. 1.

Criteria are found in NUREG-0654 § II. O.

Examples of loss of PS function include:

- Personnel have not received committed training to such an extent that coverage by emergency response personnel is not available for a key ERO function (as defined by NEI 99-02.)

5.16 <u>10 CFR 50.47(b)(16)</u>

The PS function is:

- Responsibility for Plan development is established.

There are no requirements in Appendix E.

Criteria are found in NUREG-0654 § II. P.

Examples of loss of PS function include:

- The organization assigned Plan maintenance does not have the expertise or resources to maintain the Plan.

6.0 CORRECTION OF WEAKNESSES AND DEFICIENCIES

6.1 INTRODUCTION

NRC Reactor Oversight Process EP Cornerstone is based on the licensee response band created by the PI program and the licensee problem identification and resolution (PI&R) program. As related to EP, PI&R is largely the licensee's drill and exercise critique program and the corrective action program. The EP Baseline Inspection Program provides oversight of licensee efforts to critique drills and exercises and correct weaknesses. 10 CFR 50.47(b)(14) and Appendix E § IV. F. 2. g. require drills and exercises be formally assessed and that identified weaknesses be corrected.

The regulations require and the EP Cornerstone is designed to foster drill and exercise programs that provide opportunities for emergency response organization members to develop and maintain skills. It is the nature of a drill program that performance errors will be made and equipment, facility and procedure problems will surface. The identification and correction of these weaknesses is a positive and vital aspect of the program. The Drill and Exercise Performance PI, which measures licensee proficiency in the most risk significant EP activities, provides a 90% success threshold for the licensee response band. This infers that a certain level of error in (drill and exercise) performance is recognized as acceptable and that correction of these errors is within the licensee response band.

The regulations require that weaknesses identified during training and drills be corrected. Weaknesses may be identified through processes that are not drill or training related, such as assessment of performance during actual events, reviews required by 50.54(t), audits, etc. It is the NRC expectation that weaknesses identified through these processes will also be corrected, even if failure to do so is not in noncompliance with NRC requirements. The SDP reflects this expectation.

6.2 TIMELINESS

<u>Background</u>

Guidance is provided on the timeliness aspect of correction of weaknesses. The following guidance can not be judged as absolute. The licensee should be left to determine the safety significance of the weakness and set priorities IAW commitments and approved corrective action programs. The appropriateness of those priorities will have to be judged in the context of the problem, but the guidance provided may be used as a limit for inspector involvement in timeliness aspects, e.g., if the weakness is corrected in a shorter time than that suggested in the guidance, the inspector probably does not need to review the basis for timeliness of corrective actions.

Root cause analyses, common cause analyses and the like may take 30-60 days to complete. While immediate corrective actions, such as briefings or lessons learned summaries may be implemented rapidly, they may not represent actual correction of the weakness. The expectation is that the licensee will resolve problems in a manner appropriate to the risk significance. That will often be in less time than suggested below, but there are times when a licensee should take more time. When the time is longer, the inspector should review the scheduling rationale for reasonableness and potential to impact the public health and safety. Should a corrective action item be scheduled in a manner that is not reasonable or potentially impacts the public health and safety (in that the Plan can not be implemented) a finding may be appropriate against PS 50.47(b)(14).

- Resolution of a loss of RSPS function or a failure to implement a RSPS during an actual event is reasonable within 60 days of identification.

- Resolution of a loss of PS function or a failure to implement a PS during an actual event is reasonable within 90 days of identification.

- Resolution of a failure to comply with or a failure to implement during an actual event, a regulatory requirement is reasonable within 180 days of identification.

EP related corrective action systems may track enhancement suggestions that result from the drill program. These suggestions often add value to the program, but are not required nor do they address weaknesses. There is no timeliness expectation for resolution of such enhancement suggestions.

Criteria

The timeliness of the resolution of a weakness is not appropriate for its risk significance. If the weakness is a RSPS problem the failure to resolve should be considered a failure to meet PS 50.47(b)(14) [i.e., a white finding], otherwise it should be considered a failure to comply with regulatory requirements [i.e., a green finding]. If the weakness did not result from a drill, exercise or training evolution, the finding may be issued without a regulatory noncompliance citation.

Considerations

It is not appropriate to consider enhancement items.

6.3 FAILURE TO CORRECT WEAKNESSES

Determination of a failure to correct a weakness requires a detailed review of the issue. It is not intended that a single repeat of a problem automatically be judged as a failure. Conversely, success in a drill/exercise, perhaps by a recently drilled team, should not be considered as success. When an apparent failure to resolve a weakness is observed, a review of specific corrective actions should be conducted. Similar occurrences in response to actual events, drills, exercises and training evolutions should be reviewed. The status of relevant PIs should be considered. Corrective action, self assessment and inspection records should be reviewed for an inspection cycle (biennial exercise to biennial exercise, nominally two years,) with emphasis on similar problems. Completion of corrective actions should be verified, in detail. Assessment of the effectiveness of the corrective actions should be based on the full record.

6.3.1 Failure to correct equipment, facility or procedure weaknesses

Background

A premise of the EP Cornerstone is that site PIs in the licensee response band indicate a program that is identifying equipment, facility and procedure problems and resolving them at an acceptable rate. The basis for this is that:

- DEP could not be in the green band without a reasonable level of operating equipment, functional centers, and effective procedures and
- the ERO PI ensures a substantial portion of the emergency response organization will use equipment, facilities and procedures. The Cornerstone assumption is that ERO members will identify problems they experience and the EP program will correct them.

The Baseline Inspection program focuses on the correction of weaknesses, rather than on the identification of weaknesses during infrequent inspections. Nuclear plant EP programs are mature and have successfully (generally) completed numerous inspection cycles. This being the case, equipment, facilities and procedures are prioritized below many other aspects of the program (in inspection procedure 71114, for example.) However, inspection of corrective actions may reveal repetitive problems, trends or the lack of resolution.

Criteria

Equipment, facility or procedure problems exist, have been previously identified and are not corrected to such an extent that the program elements they support can not be implemented. If the weakness involves a RSPS problem, the failure to correct may be considered a failure to meet PS 50.47(b)(14) and assessed as a white finding. Others findings under this criteria should be assessed as green.

However, if problem is significant, it may bring into question whether the PS is functional.

Considerations

A certain level of equipment failure is to be expected. Phones fail, equipment malfunctions and procedures are misfiled. A licensee EP program operating in the licensee response band should be allowed to correct these kinds of problems. Findings should only be issued in this area when the lack of correction would prevent implementation of the Plan.

6.3.2 Failure to resolve drill and exercise performance problems

Background

10 CFR 50.47(b)(14) requires that *Periodic exercises are conducted to evaluate major portions of emergency response capabilities, periodic drills are conducted to develop and maintain key skills and deficiencies identified as a result of exercises and drills are (will be) corrected*. Appendix E, section IV, F, g, states *All training, including exercises, shall provide for formal critiques in order to identify weak or deficient areas that need correction. Any weaknesses or deficiencies that are identified shall be corrected*.

A failure to identify weaknesses in drill performance is treated elsewhere (Drill or Exercise Critique Problem). This section addresses a failure to resolve performance weaknesses.

The PI system collects performance data from a broad cross section of drills. There is no intention to limit the licensee's ability to conduct drills (and exercises) in which ERO members may fail in the process of developing and maintaining key skills. Any such limitation would detract from licensee ability to meet the

Cornerstone Objective. Correction of drill/exercise weaknesses are within the licensee response band.

The DEP PI allows a 10% failure rate threshold for the licensee response band in the most risk significant areas of the Cornerstone. If the PI were to cross the threshold, the licensee would have to provide planned actions to address the performance problem and a white input would documented.

In an attempt to resolve the conflicting tensions discussed above, it is thought that a 20% failure rate for drill/exercises performance, would approximate the bounds of the licensee response band. This is means that detailed inspection of correction of weaknesses is not necessary unless performance problems are above a 20% failure rate over an inspection cycle.

It is understood that the performance failure rate in non-RSPS areas is not readily available. However, data from drill critiques may be used to develop these statistics. The absence of a identified weaknesses may be construed as indicating success.

Where performance in an area exhibits greater than a 20% failure, rate, the inspector should review the corrective actions to determine adequacy. If corrective actions are not adequate and the weakness involves a RSPS, a loss of PS function should be considered and a white finding issued. Others findings would be green.

If corrective actions are aggressive, appear to be complete but are still not effective, a judgement may be made to allow more time for performance improvement. In this case, future drills are expected to show performance improvement.

Criteria

Licensee corrective actions for drill/exercise performance problems as indicated by failure rate worse than about 20%.

Failure to correct weaknesses that affect a RSPS should be assessed as a functional failure of PS 50.47(b)(14), i.e., a white finding. Other failures to correct weaknesses will be assessed as green.

Enhancement or improvement items are not intended for consideration under the EP SDP.

Considerations

If corrective actions are aggressive, appear to be complete but are still not effective, a judgement may be made to allow more time for performance improvement. In this case, future drills are expected to show performance improvement.

6.3.3 Failure to resolve actual response problems

Background

Implementation problems during actual events will result in findings IAW sheet 2 of the SDP. A functional PS failure of 10 CFR 50.47(b)(14) may be appropriate if the same (or similar) problems were evident from previously identified drill performance issues or previous actual events.

If the actual event performance problem involved RSPS performance DEP PI data may be useful. The green band indicates proficiency in classification, notification and PAR development and that correction of performance problems is generally effective. However, a review of specific corrective actions, critiques and response to off normal conditions should be performed. It may be appropriate to review DEP failure trends. If the failures are skewed toward the actual event problem, it may indicate a failure to correct weaknesses. Data is skewed if the ratio of failures to opportunities for classification, notification or PAR development, (taken individually,) is ~33% higher than the average ratio. For example, 100 opportunities with 10 failures may contain 40 opportunities for classification, 50 for notification and 10 for PAR development. One might expect that the failures would also be about 40% classification, 50% notification, etc.

If DEP data is skewed (e.g. 8 notification failures vs. 5 in the above example,)and that same area is actual event performance problem, it may indicate a failure to correct weaknesses. However, this statistical analysis is not an absolute criteria. It indicates an area worthy of additional inspector review. The inspector should review the corrective actions in detail to determine adequacy.

The similarity of the of the occurrences should be reviewed critically. Differences in circumstances may negate the initial appearance of similarity.

The completeness of corrective actions should be viewed critically. The most effective corrective action would include root cause analysis. Less complete corrective actions, such as lessons learned briefings and practice in drills, are often implemented and may be appropriate. Weaker solutions include required reading, procedural changes and generic classroom training. In the case of repetitive problems in actual events these later actions may be considered suspect.

Finally, the licensee should be held to high standards for the correction of actual event performance problems. Especially WRT the RSPS areas of classification, notification, PAR development and assessment. Repetition of avoidable problems during actual events, should be reviewed for a failure to correct weaknesses. If it appears that licensee corrective actions were not complete and effective or that an existing weakness led to the subsequent error, a finding of a loss of PS function should be issued.

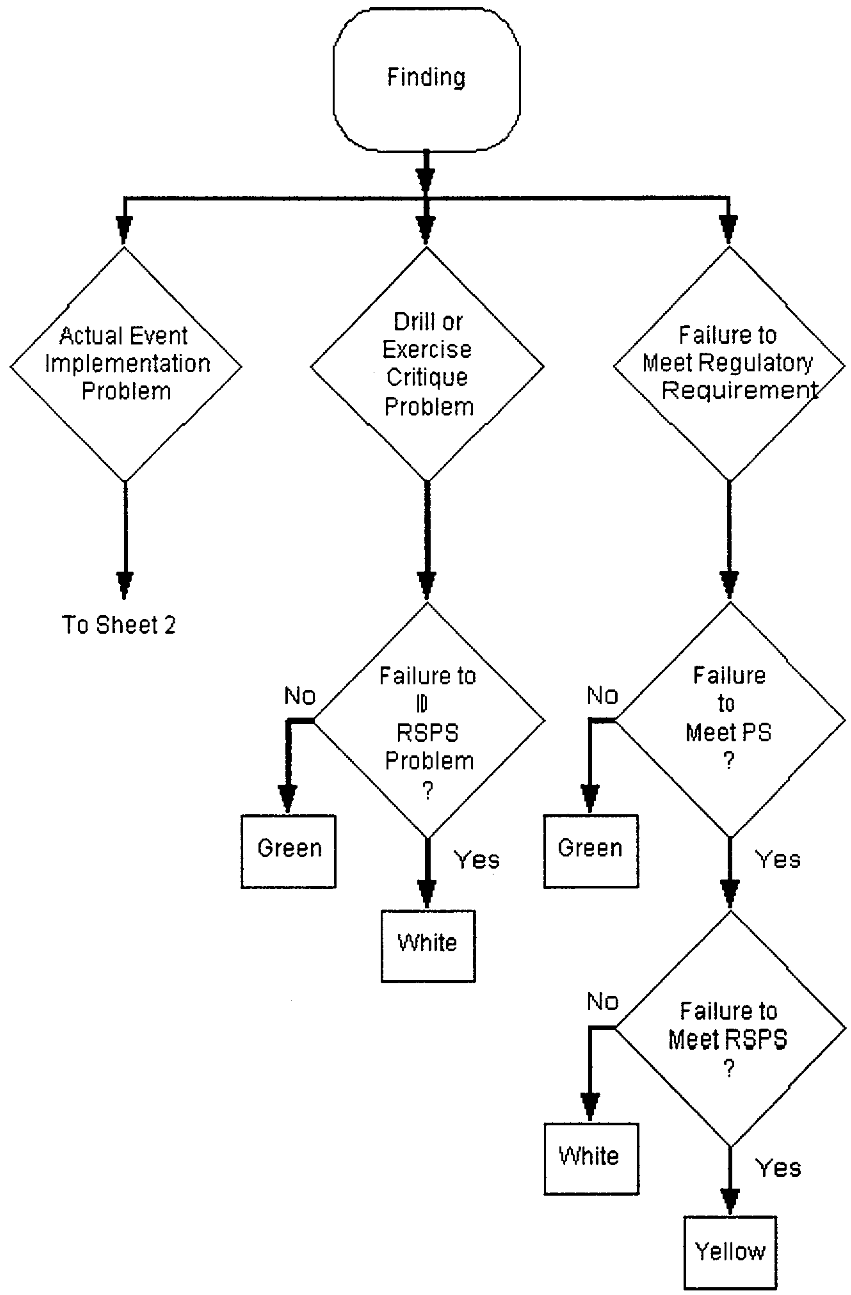
Criteria

A weakness was not resolved, was repeated during an actual event and review of corrective actions show them to be inadequate.

If the weakness involves a RSPS, the failure to correct should be considered as a PS functional failure and a white finding issued. Other failures to correct should be issued as green findings.

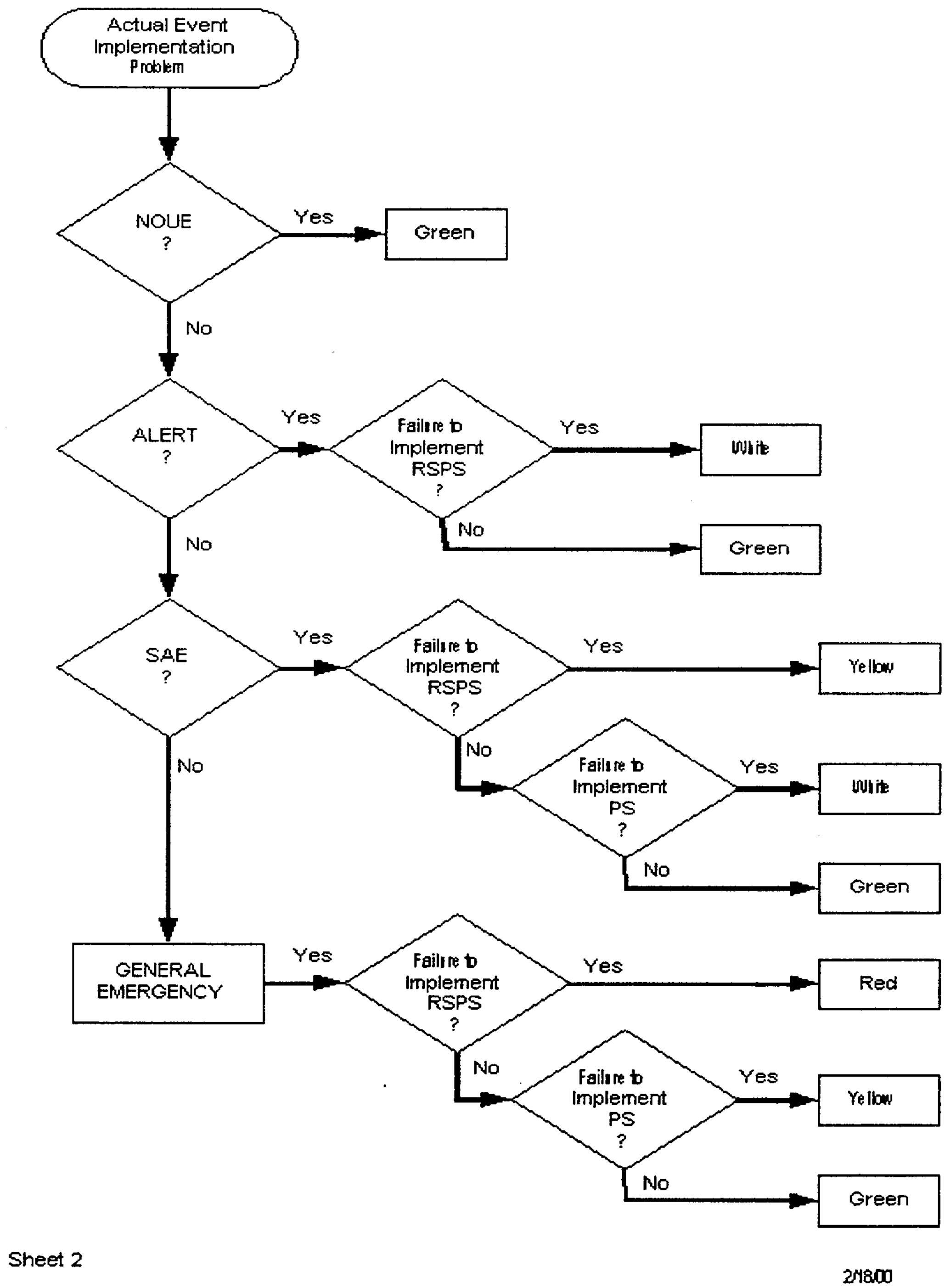
Considerations

The apparent similarity of repeat problems should be reviewed critically.



Sheet 1

2/18/00


Actual Event Implementation Problem
NOUE ?
Yes
Green
No
ALERT ?
Yes
Failure to Implement RSPS ?
Yes
White
No
Green
No
SAE ?
Yes
Failure to Implement RSPS ?
Yes
Yellow
No
Failure to Implement PS ?
Yes
White
No
Green
No
GENERAL EMERGENCY
Yes
Failure to Implement RSPS ?
Yes
Red
No
Failure to Implement PS ?
Yes
Yellow
No
Green
Sheet 2
2/18/00

Appendix C

OCCUPATIONAL RADIATION SAFETY
SIGNIFICANCE DETERMINATION PROCESS

General

The objective of this cornerstone is to ensure worker health and safety from exposure to radiation from licensed or unlicenced radioactive materials during routine operations of civilian nuclear reactors. The health and safety of workers is assured by maintaining their doses within the limits in 10 CFR 20 and as low as is reasonably achievable (ALARA).

Section 1101 of 10 CFR Part 20 requires that each licensee develop, document, and implement a radiation protection program sufficient to ensure compliance with Part 20 and for keeping occupational radiation doses ALARA. Performance in this cornerstone is assessed by considering licensee reported performance indicators (PI) in combination with inspection findings. A baseline inspection is maintained to verify the accuracy and completeness of the PI data (i.e., work control in radiologically significant areas), supplement the PI data in areas where the PI alone is not sufficient to measure performance (i.e., problem identification and resolution), and complement the PI data with inspection findings of performance for areas not covered by the PI (i.e., ALARA planning and controls, radiation monitoring instrumentation, and personnel dosimetry).

The Significance Determination Process (SDP) is the mechanism in which the significance of individual events (follow-up of an operational occurrence, substantiated allegation, or other inspection finding) can be normalized and combined with the PI results to arrive at an overall cornerstone performance assessment. Logic flow charts are provided below to outline the process. A finding that gets through the process (flow chart) without tripping a decision "gate", or one whose significance is determined to be low, ends up as GREEN. This does not mean that the performance on this individual finding is good, or even acceptable. The issue may be a non-conformance or a violation of a regulatory requirement. It does mean that the safety significance of the event is not large enough to warrant further NRC intervention. Licensees are still required to come into conformance with the regulations and their regulatory commitments. However, the licensees are given the latitude to self correct these non-conformances.

ALARA

Section 1101.(b) of 10 CFR Part 20 states that licensees "shall use, to the extent practical, procedures and engineering controls based upon sound radiation protection principles to achieve occupational doses that are as low as is reasonably achievable (ALARA)." The Statements of Consideration (SOC) published with this regulation (Federal Register, Volume 56, dated May 21, 1991, at 23367) expressed the Commission's continued emphasize on the importance of the ALARA concept to an adequate radiation protection program. However, the SOC clarifies that "compliance

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with this requirement will be judged on whether the licensee has incorporated measures to track and, if necessary, to reduce exposures and not whether exposures and doses represent an absolute minimum or whether the licensee has used all possible methods to reduce exposures." While admitting that this is subjective criteria, the SOC goes on to state the expectation that the "level of effort expended [with regard to ALARA measures] should reflect the magnitude of the potential exposures..."

Reactor licensees currently have mature ALARA programs to plan significant work, estimate the resulting collective dose, and make the determination as to what dose reducing radiological and engineering controls are reasonably achievable. Consistent with the above regulatory basis, the NRC inspections verify the reasonableness of the licensee's ALARA program. Inspection findings are based on comparing the actual dose outcome of work activities with the planned, intended dose for the work activity that is reasonably expected. In addition, the SDP employs dose criteria to represent "magnitudes of exposure" that reflect differences in the level of effort that is reasonably expected to be applied by the licensee with regard to ALARA measures. These dose criteria have been selected, based on regulatory experience and typical industry practices, solely to judge the relative significance of ALARA concerns as they relate to the regulatory requirement for an ALARA program. The dose criteria should not be construed to imply a staff position or regulatory guidance beyond their application within the context of the SDP and the reactor oversight process.

For the purpose of this cornerstone, unplanned, unintended occupational collective dose is the total sum of the occupational radiation doses (collective dose) received by individuals for a work activity in excess of that collective dose planned or intended (e.g., that dose the licensee determined was ALARA) for that work activity. A work activity is one or more closely related tasks that the licensee has identified as a unit of work for the purpose of ALARA planning and work controls. Examples of planned and intended collective dose include; realistic dose estimates (or projections) established in the ALARA planning; or
the dose expected by the licensee (i.e., historically achievable) for the reasonable exposure control measures specified in ALARA planning. These do not include "stretch goals" set by a licensee to challenge their organization to strive for excellence in ALARA performance.

Situations where the unplanned, unintended collective dose for a work activity does not exceed 50% of the planned, intended dose, should normally be considered as minor issues and screened out from SDP consideration (see appendix B to MC 0610* for a discussion of the screening process). This criterion reflects a reasonable expectation of the accuracy of ALARA planning. In addition, failures that exceed this 50% criterion for work activities where the actual total collective dose is less than 5 person-rem should also generally be considered as minor. However, situations where the licensee has arbitrarily divided the radiological work into very small "work activities" for the purpose of avoiding inspection findings (i.e., tolerate weaknesses in the program that result in several or wide-spread failures to plan and control exposures), should be considered more than minor.

The 5 person-rem criterion represents a level of actual dose associated with a work activity at which it is reasonably expected that the licensee will, at a minimum, apply measures to review and plan work, track dose and, if practical, to reduce exposures.

Reactor licensees generally conduct formal ALARA planning and controls at levels below this (typically, one person-rem). The 5 person-rem dose criterion should not be taken to represent a level of collective dose that is "risk-significant." However, failure to plan or control work activities at this level is a possible indication of a more significant weakness in the ALARA program, and could reasonably be viewed as a precursor to a more significant failure. Thus, a failure to "establish, maintain, or implement procedures or engineering controls, intended to achieve occupational doses that are ALARA, and that resulted in unplanned, unintended occupational collective dose for a work activity" with an actual dose in excess of 5 person-rem will be evaluated as a finding, subject to whether the actual dose also exceeded the planned, intended dose by more than 50%.

The first decision gate, in the ALARA branch of the SDP, evaluates the significance of the inspection finding in terms of the licensee's overall ALARA performance (e.g., the three-year rolling average collective dose). Inspection findings associated with an ALARA program that has an average collective dose below the criteria are assessed at no greater than GREEN. The criteria in the SDP represents the median industry three-year rolling average collective doses (as reported at the initiation of the revised ROP). Several factors can impact a particular licensee's standing with respect to the collective dose criteria. In some cases (i.e., overall plant design, or significant plant modifications such as steam generator replacement) these factors may be independent of the ALARA program performance. However, the three-year rolling average collective dose is a high level indication of the radiological challenges the program faces. The SDP is intended to direct NRC inspection resources to those programs with the largest challenges. This criteria should not be interpreted as a de-facto definition of ALARA for occupational radiation exposures. Nor, as stated above, should a GREEN finding be interpreted as acceptable. It does mean that the significance of the finding is determined not to warrant further NRC oversight.

The 25 person-rem criterion in the SDP represents a level of actual dose associated with a work activity at which it is reasonably expected that there will be review and oversight by licensee management to confirm the adequacy of ALARA measures that are being applied. Accordingly, a "failure to establish, maintain, or implement procedures or engineering controls..." at this level of dose is deemed to be of relatively greater significance with regard to the regulatory basis of the SDP. Therefore, an ALARA concern that involves a work activity with actual dose greater than 25 rem will be evaluated as a WHITE finding within the SDP.

If the actual collective job dose associated with the finding was not greater than 25 person-rem, and if there were two or fewer such occurrences in the assessment period, then the ALARA finding is GREEN. If there have been three or more such occurrences in the assessment period, then the finding is WHITE. This second path to a WHITE finding also reflects a situation where licensee management oversight is expected. The failure of management to intervene and prevent continued program failures is of relatively greater significance.

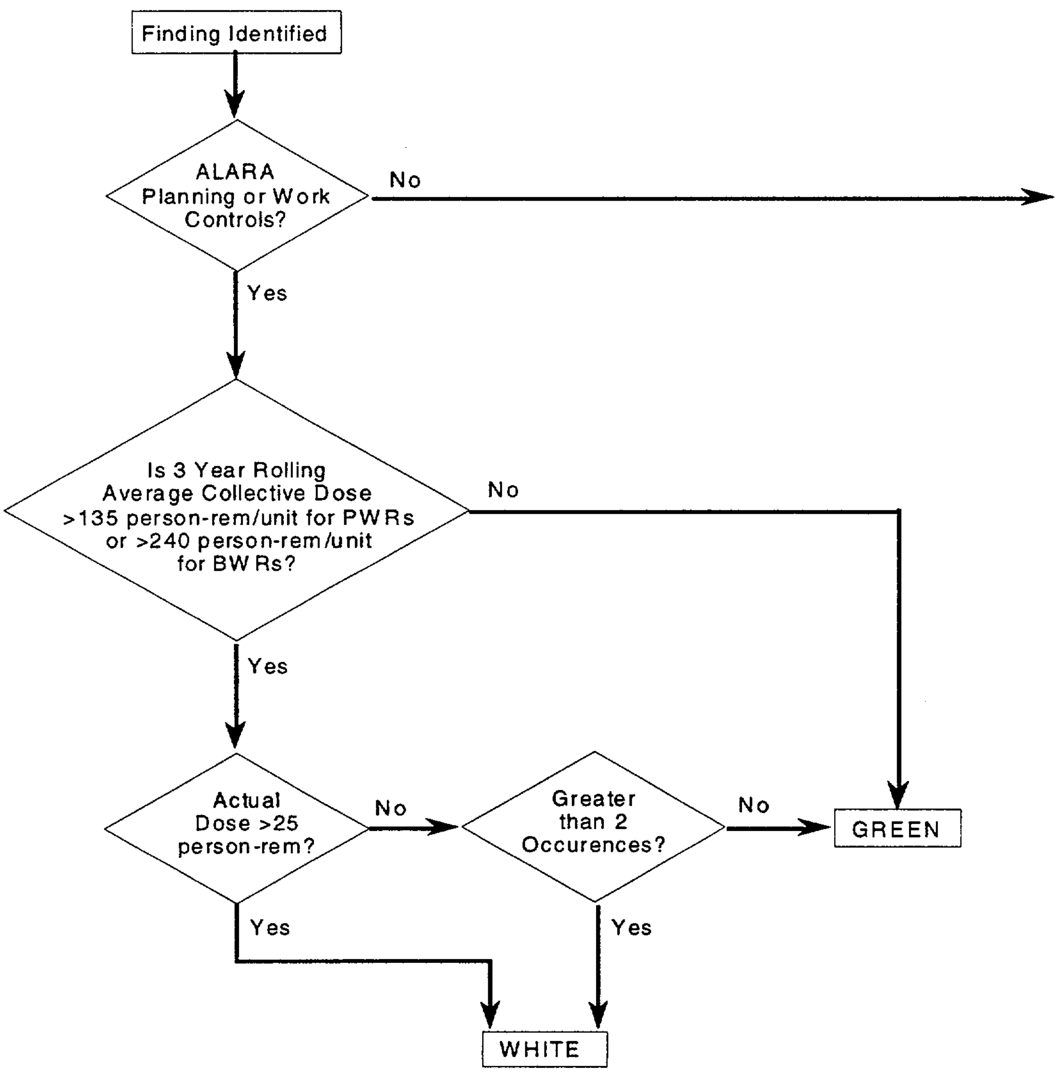
<u>Exposure Control</u>

With the exception of shallow dose limits from discrete radioactive particles (DRP), the failure to control radiation exposures to an individual resulting in a dose in excess of the 10 CFR 20 dose limits is at least a YELLOW finding. An exposure attributable to a DRP which exceeds the Enforcement Discretion of 75 μCi-hrs (as discussed in subsection 8.4.2 of the current Enforcement Manual (NUREG/BR-0195)) is assessed as a WHITE finding. Occurrences that result in dose(s) in excess of five (5) times the 10 CFR 20 dose limits are designated as RED findings.

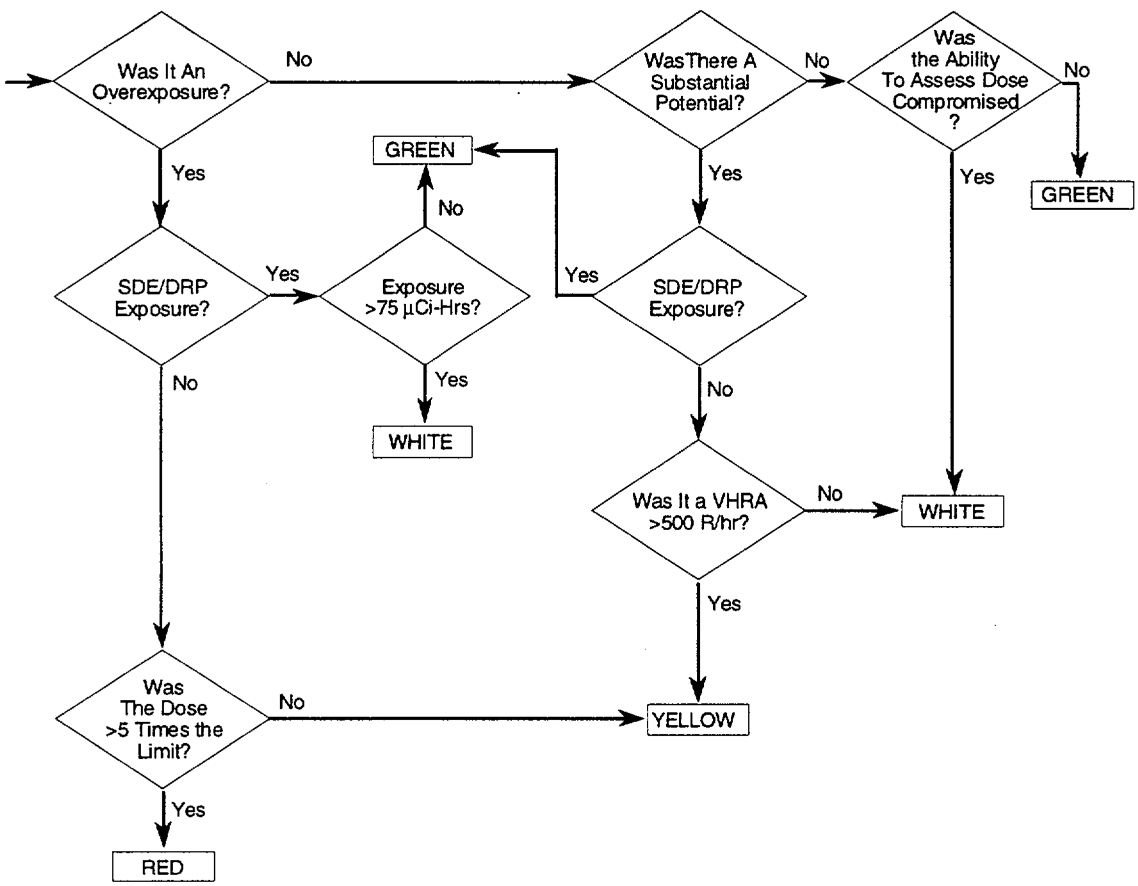
Breakdowns in the Radiation Protection Program, or unintended exposures, that do not exceed a dose limit can still be considered significant if they constitute a "Substantial Potential for Overexposure". A substantial potential, consistent with the current Enforcement Manual (NUREG/BR-0195, subsection 8.4.1), is an occurrence in which a minor alteration of the circumstances would have resulted in a violation of Part 20 limits and it was only fortuitous that the altered circumstances did not occur. In the SDP the finding involving a substantial potential for overexposure can result in a WHITE or YELLOW finding depending on the dose rates (e.g., risk of a serious outcome) associated with the failure. In a Very High Radiation Area of 500 rads/hr, it can take as little as 3 minutes for a worker to receive 25 rem. Note that the Enforcement Process (and possible civil penalty) will not engage unless the event involved an "actual consequence" (in this case an actual overexposure). The Assessment Process, rather than the Enforcement Process, will determine further licensee and NRC action for events that do not result in "actual consequences."

The last decision gate in the Exposure Control Findings portion of the Occupational Radiation Safety SDP is intended to sort out significant issues and findings related to plant equipment and facilities. The Assessment Program is a risk informed process, and radiation dose is the measure of health risk associated with licensee activities. Therefore, this gate focuses on those issues that could or do compromise the licensee's ability to assess dose. Since this gate culls out WHITE findings, it is intended that only significant, programmatic, failures of radiation monitoring and personnel dosimetry trip this gate. Examples of findings intended to be addressed by this gate include; 1) the licensee's failure to use a NVLAP certified dosimeter processor, 2) a generic and uncorrected failure of the electronic dosimeters (EDs) to respond to, or record, radiation dose, and 3) improper calibration of instruments or monitors (thereby significantly biasing their response) which are used as a basis for establishing protective controls. An individual failure to survey or monitor should be considered a failure of a radiation safety barrier and should be evaluated for its potential for unintended dose or substantial potential for overexposure, as discussed above.

Occupational Radiation Safety SDP



Occupational Radiation Safety SDP



SUMMARY OF CHANGES
TO THE
OCCUPATIONAL RADIATION SAFETY
CORNERSTONE

On March 26 through 28, 2001, the NRC conducted a public workshop to solicit stakeholder input on the lessons learned from the first year of implementation of the revised Reactor Oversight Program. A separate breakout session was conducted during this workshop to discuss issues identified in the Radiation Safety Cornerstones where several issues and points of clarification were identified. The vast majority of the issues identified were in the Occupational Radiation Safety Cornerstone associated with several inspection findings (at Callaway, Quad Cities, and Susquehanna) that were assessed as WHITE during the previous year. Subsequent to the workshop, the NRC staff conducted a series of public meetings with NEI staff and other stakeholders to resolve and clarify these issues. The following is a list proposed changes in the Occupational Radiation Safety Cornerstone resulting from these meetings.

1. The Group 2 Question 1 in MC 0610* is replaced with one based on "unplanned, unintended collective dose." Also, a footnote was added to clarify that not all ALARA findings are violations of Part 20.

2. The three-year rolling average collective dose criteria are moved into the SDP in MC 0609, such that plants with three-year rolling average collective dose below the criteria will get no more than a GREEN ALARA finding.

3. The > 50% and 5 person-rem criteria are addressed in the MC 0609 text to provide guidance in determining if an ALARA issue is "more than minor" (e.g., MC 0610* Group 1 Questions)

4. The term "work activity" replaces "job" to minimize confusion.

5. Definitions of "unplanned, unintended collective dose" and "work activity" are provided in the text to MC 0609.

6. MC 0609 text is revised to strengthen the regulatory basis for the SDP. The basis for judging the significance (i.e., GREEN or WHITE) of an ALARA finding is included.

7. The time period for "greater than 2 occurrences" has been revised from 18 months to within an assessment period (e.g., 12 months).

8. The SDP flow chart was revised to reflect the DRP exposure Enforcement Discretion and the footnotes were dropped.

9. The MC 0609 text was revised to clarify the handling of DRP exposures.

10. The flow chart was redrafted to clarify that it is a single Occupational Exposure SDP.

In addition, the NRC agreed that a Licensee's standing, with respect to the three-year rolling average, will be used to set the level of effort in a revised "variable baseline" ALARA inspection procedure (IP 71121.02).

The changes listed above are more for adding clarity to the process rather than to effect substantial change in its application. The staff benchmarked the proposed revision to the SDP by reviewing the details of the most significant findings to date and comparing the resulting assessment outcomes with the results that were deemed appropriate during the individual cases. In all cases where WHITE findings were assessed (the three WHITE ALARA findings at Callaway, the one WHITE ALARA finding at Quad Cities, and the one WHITE finding involving the substantial potential to exceed the TEDE dose limits at Susquehanna) this revised SDP arrives at the same significance determination. This is so for the ALARA findings since the definition of a "work activity" in the revised MC 0610* is identical to the operational definition of "job" that was used in both the Callaway and Quad Cities cases. The dose estimates used as a base for determining the licensee's ALARA planning and controls, would also lead to the same conclusion in terms of the "planned, intended collective dose" as used in the revised MC 0610*.

The staff did find one area in which currently documented findings will be impacted by this proposed revision. In at least two inspection reports (Grand Gulf, and D.C. Cook) a "finding without color" was identified in the ALARA area. In each case, the respective region concluded that the issue was more than minor since the ALARA planning failures noted could result in unnecessary worker dose (i.e., they passed the Group 1 question in the MC 0610* screening process). However, also in each case, the associated work activities were not greater than 5 person-rem or resulted in doses more than 50% greater than what was planned. Therefore, these issues did not pass the Group 2 screening question for ALARA. The region then applied the Group 3 questions, consistent with the MC0610* screening process, and since they had concluded the issues were more than minor, they passed and were documented accordingly. This proposed revision to MC 0610* clarifies the guidance on what should be considered a minor ALARA issue. By moving the criteria (formerly in Group 2) to Group 1, issues such as these under the proposed revision would be screened out as minor. Therefore, they would not generally be documented in the inspection report.

FAQ Log 15				
Temp No.	**PI**	**Question/Response**	**Status**	**Plant/ Co.**
15.12	MS01 MS02 MS03 MS04	**Question:** 1. Should support system unavailability be counted in the monitored safety system unavailability PI if analysis or engineering judgement has determined that the support system can be restored to available status such that the monitored system remains available to perform its intended safety function? 2. Do the criteria for determining availability described in NEI 99-02, Revision 0, page 26 lines 31-40 apply to this situation?	Introduced 10/31 12/5/00 – NEI, Licensee proposed response added. 3/2/01 – Discussed. FAQ to be discussed as part of SSU focus group.	ComEd
		Licensee Proposed Response: 1. No. During both testing and non-testing situations, the criteria described in NEI 99-02, Revision 0, page 33, lines 7-9 should apply, "In these cases, analysis or sound engineering judgment may be used to determine the effect of support system unavailability on the monitored system." If the analysis or engineering judgment determines that the unavailability of the support system does not impair the ability of the monitored system to perform its intended safety function, then the support system unavailability should not be counted in the monitored system PI. For example, if engineering analysis determines that the unavailability of a ventilation support system for the emergency diesel generator does not adversely impact the availability of the emergency diesel generator to perform its intended function, the unavailability of the support system would not be counted in the emergency diesel generator PI. The engineering analysis must evaluate such things as; the length of time between an event and the time the ventilation system is required to be available to support the safety function of the emergency diesel generator, the complexity the actions required by plant operators to restore the availability of the ventilation system, and the probability of success for the restoration actions. Restoration actions should be contained in a written procedure and must not require diagnosis or repair. The engineering analysis must provide a high degree of assurance that the unavailability of the ventilation support system does not impact the ability of the emergency diesel generator to perform its safety function. This treatment is consistent with maintenance rule and PRA. 2. No. In NEI 99-02, Revision 0, page 26, lines 31-40, criteria for exclusion of planned unavailability for testing activities of monitored systems are described. The criteria established in this section describe required actions or barriers which must be in place during *testing* so that unavailability of the monitored system is not counted in the monitored system PI.		

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FAQ Log 16				
Temp No.	**PI**	**Question/Response**	**Status**	**Plant/ Co.**
16.11	MS02 MS04	**Question:** **Appendix D** At our ocean plant we periodically recirculate the water in our intake structure causing the temperature to rise in order to control marine growth. Marine mollusks, if allowed to grow larger than ¾" in size, can clog the condenser and component cooling water heat exchangers. This process is carried out over a six hour period in which the temperature is raised slowly in order to encourage fish to move toward the fish elevator so they can be removed from the intake. Temperature is then reduced and tunnels reversed to start the actual heat treat. Actual time with warm water in the intake is less than half of the evolution. A dedicated operator is stationed for the evolution, and by procedure at any point, can back out and restore normal intake temperatures by pushing a single button to reposition a single circulating water gate. The gate is large and may take several minutes to reposition and clear the intake of the warm water, but a single button with a dedicated operator, in close communication with the control room initiates the gate closure. During this evolution, one train of service water, a support system for HPSI and RHR, is aligned to the opposite unit intake and remains fully Operable in accordance with the Technical Specifications. The second train is aligned to participate in the heat treat, and while functional, has water beyond the temperature required to perform its design function. This design function of the support system is restored with normal intake temperatures by the dedicated operator realigning the gate with a single button if needed. Gate operation is tested before the start of the evolution and restoration actions are virtually certain. Does the time required to perform these evolutions on a support system need to be counted as unavailability for HPSI and RHR? **Response:** No. The period of heat treatment will not be considered as "unavailable" for the HPSI and RHR systems because of the utility's actions to limit the environmental impact of heat treatments. As described in the question, the ability of safety systems HPSI and RHR to actuate and start is not impaired by these evolutions There are no unavailable hours.	Introduced 12/6 12/6 Discussed. HOLD needs more clarity in the question 2/5/01 – need to know design basis 7/12 Tentative Approval	San Onofre

Temp No.	PI	Question/Response	Status	Plant/ Co.
18.1	MS01 MS02 MS03 MS04	**Question:** Should surveillance testing of the safety system auto actuation system (e.g. Solid State Protection System testing, Engineered Safety Feature testing, Logic System Functional Testing) be considered as unavailable time for all the affected safety systems? During certain surveillance testing an entire train of safety systems may have the automatic feature inhibited. **Response:**	Introduced 2/8 3/2/01 – Discussed. To be discussed by SSU focus group and NEI task force.	Southern
18.2	MS01 MS02 MS03 MS04	**Question:** When reporting safety system unavailable time there are periodic (such as weekly) evolutions that although they may not be simple actions to restore a safety system, they result in the safety system being unavailable for no more than several minutes. Is this level of tracking unavailable time required?	Introduced 2/8 3/2/01 – Discussed. To be discussed by SSU focus group and NEI task force.	Southern

Temp No.	PI	Question/Response	Status	Plant/ Co.
20.3	MS04	**Appendix D Question:** FAQ for Mitigating System MS04 concerning CE Designed NSSS systems, "Alternative historical data correction method to convert 2 trains to 4 trains." Calvert Cliffs, Fort Calhoun, Millstone 2, Pallisades, Palo Verde, San Onofre, St. Lucie, and Waterford 3 In FAQ # 172, approved on May 2, 2000 for use by CE plants (now in Appendix D), two methods for changing historical data from an initial 2 train report to a revised 4 train report were outlined. Specifically, the change report methodology was to perform one of the following changes to historical data: **1. Maintain Train 1 and Train 2 historical data as is. For Train 3 and 4, repeat Train 1 and Train 2 data.** **2. Recalculate and revise all historical data using this guidance.** For CE plants incorporating method 1, a non-performance related degradation in the PI calculation for Trains 3 and 4 (and the overall PI) was subsequently observed. This degradation occurred due to a decrease in the required hours in the denominator as the historical data was replaced by typically zero (0) or low required hours reported in the revised data (post Jan, 2000) in combination with artificially high unavailability hours in the numerator (due to the doubling of non-shutdown cooling related unavailability hours from the historical data). As a result, PI values would generally degrade over time regardless of performance until the historical data drops from the PI calculation. In some cases, plants projected a fall below the GREEN/WHITE threshold in 2002, even if perfect performance was used in the projection. **Licensee Proposed Response:** To address the calculation anomaly in the determination of the RHR PI, a third alternative is suggested for the estimation of Train 3 and Train 4 data: **3) Maintain Train 1 and Train 2 historical data as is. For Train 3 and Train 4, make a best effort to collect and report the number of unavailable hours and required hours for the historical data period. If data is not available an estimate may be provided.** If changes to historical data are made, then provide comments with the change report to identify the manner in which the historical data has been revised.	4/4 – Discussed. Need CE owners to provide additional input. 5/2 Discussed 5/31 Tentative Approval 7/12 NRC to discuss with residents 8/15 Tentative Approval	CE Plants
21.4	MS01 -04	**Question:** By the NEI guidance, fault exposure hours can only be removed for "a single item" when the fault exposure hours associated with the item are greater than or equal to 336 hours. How are multiple failures of the same component handled when some of the failures have fault exposure hours less than 336 hours, yet the total of all the failures attributed to the same failed component are greater than 336 hours.?	5/2 Discussed . Response to be revised 5/31 Discussed 8/15 On Hold	Southern Co.

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Proposed Response: Concerning groups of fault exposure hours that sum to greater than 336 hours, but are individually less than 336: Fault exposure hours may be removed on a case-by-case basis, provided the following criteria are met: • The applicable failures are associated with the same specific component and have the same root cause • Portions of the fault exposure hours are associated with management's conservative decision to increase the surveillance testing frequency in an attempt to verify effective corrective action and a failure occurred during the increased surveillance frequency • All other NEI 99-02 criteria for removing fault exposure hours have been met • The NRC supplemental inspection considered the failures associated with the condition • The removal received concurrence with the NRC via the FAQ process • A comment is placed in the comment field of the data submitted indicating more than one failure was considered in resetting the fault exposure hours		
21.9	MS01	**Question:** NEI 99-02 Revision 0, Page 1, INTRODUCTION, line 22 states: "Performance indicators are used to assess licensee performance in each cornerstone." Consider the situation where a certified vendor supplied a safety related sub-component for a standby diesel generator. This sub-component was refurbished, tested and certified by the Vendor with missing parts. The missing parts eventually manifested themselves as a sub-component failure that lead to a main component operability test failure. The Vendor issued a Part 21 Notification for the condition after notified by the Licensee of the test failure. (The licensee conducted a successful post maintenance surveillance and two subsequent successful monthly surveillances before the test failure. Thus there was fault exposure and unplanned maintenance unavailability incurred.) If a licensee is required to take a component out of service for evaluation and corrective actions related to a Part 21 Notification or if a Part 21 Notification is issued in response to a licensee identified condition (i.e. Report # 10CFR21-0081), should the licensee have to count the fault exposure and unplanned unavailability hours incurred? **Response:** Yes. The PI measures unavailability of the equipment, not responsibility for unavailability.	5/2 Introduced 5/31 Discussed 7/12 Discussed. Response explanation being prepared 8/15 Tentative Approval	FitzPatrick
22.1	IE02	**Question** Should the following reactor trip described in the scenario below be reported as a "Scram with Loss of Normal Heat Removal?" A loud noise was heard in the Control Room from the Unit 2 Turbine Building. Operators noted a steam leak, but could not determine the source of the steam because of the volume of steam in the area. It was suspected that the leak was coming from the No. 21 or 22 Moisture Separator Reheater (MSR). The steam prevented operators from accessing the MSR manual isolation valves. Due to the difficulty in determining the exact source of the leak, the potential for personnel safety concerns, and the potential for equipment damage due to the volume of steam being emitted into the Turbine Building, operators manually tripped the Unit. After the manual trip, a large volume of steam was still being emitted, and the shift manager had the main steam isolation valves (MSIVs) shut. Once the MSIVs where shut, the operators identified a ruptured 2-inch diameter vent line from No. 21 MSR second stage to No. 25A Feedwater Heater. The operators shut the second stage steam supplies and isolated the leak. Once the leak was isolated, the MSIVs were opened and normal heat removal was restored. The majority of the steam that was emitted following the trip was due to all the fluid in the MSR and feedwater heater escaping from the pipe. **Response** Yes. Investigation and diagnosis were required to determine that the main steam isolation valves could be reopened.	5/31 Discussed 7/12 Discussed. Response explanation being prepared 8/15 Tentative Approval	Calvert Cliffs

Temp No.	PI	Question/Response	Status	Plant/ Co.
22.2	IE02	**Question** Should the following reactor trip described in the scenario below be reported as a "Scram with Loss of Normal Heat Removal?" Following a reactor trip No. 11 Moisture Separator/Reheater second-stage steam source isolation valve (1-MS-4025) did not close. The open valve increased the cooldown rate of the Reactor Coolant System. Control Room Operators closed the main steam isolation valves and used the atmospheric dump valves to control Reactor Coolant System temperature. Within three hours, 1-MS-4025 was shut manually. Control Room Operators opened the main steam isolation valves, and Reactor Coolant System temperature control using turbine bypass valves was resumed. **Response** Yes. The normal heat removal path could not be restored from the control room without diagnosis or repair to restore the normal heat removal path. In this case, manual action was necessary outside the control room to manually isolate a valve to restore the normal heat removal path.	5/31 Discussed 7/12 Discussed. Response explanation being prepared 8/15 Tentative Approval	Calvert Cliffs
23.1	MS01-04	**Question** Can credit be taken for manual operator actions performed outside the control room to recover a failed support system function when the manual actions, while not a single action, are proceduralized and do not require diagnosis or repair?	7/12 To be addressed by Unavailability Task Force	Exelon
23.2	MS01-04	**Question** When assessing the failure of a system or component to perform its safety function, can mission time be defined with reference to the station's probabilistic risk assessment (PRA)?	7/12 To be addressed by Unavailability Task Force	Exelon
24.1	IE03	**Question** This spring the above water portion of the circulating water intake structure was removed. This action was required by two federal agencies due to the issue of the intake structure attracting, inadvertently trapping and leading to the demise of double crested cormorants (a protected migratory bird species). Anticipating the possibility of fouling, contingency work orders were created on April 3 before the intake demolition started for cleaning of the main condenser water boxes and condensate coolers. These activities anticipated the necessity for reductions in power by greater than 20% and prescribed plant operating criteria that would necessitate initiation of these cleaning activities in response to accumulation of marine debris. However, the exact dates when these power reductions and cleaning activities would occur could not be predicted greater than 72 hours in advance. Power was reduced by greater than 20% for cleaning attributable to the accumulation of marine debris due to the ongoing intake structure activities on May 19th and May 25th for Unit 2 and Unit 1, respectively. In both cases, the rapid deterioration in the monitored plant parameters dictated power reductions and cleaning in less than 72 hours from the onset of the conditions. In addition, a Tech Spec surveillance required main turbine stop and governor valve with turbine trip test, requiring a reduction in power to about 65%, had been scheduled approximately 12 months in advance to occur at a later date. Since Unit 2 required a load reduction to 50% due to marine fouling for water box cleaning, the Tech Spec surveillance was moved up to also take place during that power reduction. Would any of these power changes in excess of 20% be counted for this indicator?	8/15 Tentative Approval	WEPCO

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Licensee Response No. As discussed on p. 17 of NEI 99-02 Revision 1, if the power reductions were anticipated in response to expected problems (such as accumulation of marine debris and biological contaminants in certain season), a part of a contingency plan and not reactive to the sudden discovery of off normal conditions, they would not count. The planned maintenance power reduction to 65% would still be considered planned since it was planned greater than 72 hours in advance of its occurrence.		
24.2	BI01	**Question:** Our Chemistry Dept was questioned as to whether or not RCS strip isotopic data was included in the PI reporting for RCS Specific Activity. [We had not been reporting results from that method since it wasn't exactly like the method we typically use to satisfy our Tech Specs.] BVPS uses the RCS Isotopic Iodine Analysis method which is specific for isotopic Iodine in RCS (and is more accurate) for meeting our Tech Spec requirement. (We use all results even if the number of samples exceeds the TS requirement.) We also perform an RCS Strip Isotopic Analysis which is for gaseous and all other liquid isotopes in the RCS. This Strip method however, will provide isotopic Iodine in the results (although less accurate.) This method sometimes provides a higher value than the highest Iodine Isotopic analysis I-131 data for the month. However, this method is also considered to be an acceptable method for meeting the Tech Spec requirement, and is used if problems are encountered with the Isotopic Iodine method. Should ONLY the RCS Isotopic Iodine Analysis method (most accurate) for RCS samples be used for the results and determination of maximum RCS Specific Activity to be reported? or Should ALL isotopic samples of RCS, including those using less accurate analytical methods (e.g. Stripped liquid method) be considered for determination of maximum RCS Specific Activity? **Response:** Neither. Use the results of the method that was used at the time to satisfy the technical specifications.	8/15 Tentative Approval	Beaver Valley
24.3	MS-01 to 04	**Appendix D Question** Safety System Unavailability (SSU) indicators for Cook Units 1 and 2 are not calculated due to insufficient reported data. The SSU indicators and performance thresholds require 12 quarters of operational data to calculate unavailability and determine safety system performance. Cook Unit 1 returned to service December 18, 2000, after a 39-month forced outage and Unit 2 on June 25, 2000, after a 33-month forced outage. SSU indicator data has been reported for both units since the second quarter of the year 2000. Historical data was not reported since unavailability was not monitored during the extended outages. Cook Nuclear Plant (CNP) wants the SSU indicators to reflect actual safety system performance and have the indicators calculated with submitted data vice waiting until April 2003 for 12 quarters of data to be collected. What actions can be taken to have calculated SSU indicators and appropriately account for the effects of a T/2 fault exposure? **Licensee Response:** 1. Submit a change report "zero-summing" the time prior to the 2Q2000 to provide for an indicator calculation. If a T/2 fault exposure occurs prior to obtaining 12 quarters of operational data, then the time would be reported but not calculated for the SSU indicator. The inspection and SDP process would then evaluate the T/2 fault exposure. Licensee wants 2. Submit a change report replicating submitted data to complete 12 quarters of data. This would give 12 quarters of operational data for safety system performance evaluation. 3. Submit a change report "zero-summing" the time prior to the 2Q2000 to provide for an indicator calculation. If a T/2 fault exposure occurs prior to obtaining 12 quarters of operational data, then re-construct the "zero-summed" unavailability data, where available, to provide 12 quarters of data. The T/2 fault exposure would then be evaluated as provided for in the Action Matrix.	8/15 Introduced	Cook Nuclear Plant

Temp No.	PI	Question/Response	Status	Plant/ Co.
24.4	IE-03	**Question:** On June 27th, the conditions again rapidly deteriorated due to an influx of small forage fish. Power was reduced on Unit 1 by greater than 20% (from 100% to 79%) due to reduced water level in the pump bay attributable to the accumulation of the fish. Unit 1 power level remained reduced at approximately 80% while personnel performed Unit 2 traveling screen repair, condensate cooler cleaning on Unit 1 and removal of fish to regain water level. Would this situation count as an unplanned power change? **Response:**	8/15 Introduced	WEPCO
25.1 clarify reason for initial closure MSIVs NEI owes info	IE-02	Question: NEI 99-02 Rev 1, states in part on page 15, lines 13 - 16: "Intentional operator actions to control the reactor water level or cool down rate, such as securing main feedwater or closing the MSIVs, are not counted in this indicator, as long as the normal heat removal path can be easily recovered from the control room without the need for diagnosis or repair to restore the normal heat removal path." Revision 1 added the wording "...as long as the normal heat removal path can be easily recovered from the control room without the need for diagnosis or repair to restore the normal hear removal path." to this statement. If the MSIVs are closed to control cool down rate at Ginna Station, the MSIVs are not reopened. Procedure O-2.2 (Plant Shutdown From Hot Shutdown To Cold Conditions) in step 5.1.6 (Control Tavg with Steam Dump or SG ARVs <Atmospheric Relief Valves>) has a note stating "If it becomes necessary to close the MSIVs to control cool down or low vacuum, then use SG ARVs." Once the operators intentionally close the MSIVs to control cool down, the steam generator ARVs become the "normal heat removal path" for Ginna Station. Thus the "normal heat removal path" (as defined in NEI 99-02, page 13, lines 29 - 32) is, by Ginna Station Operations procedure, intentionally never recovered. Original design of Ginna Station's MSIVs requires an Aux Operator to open a bypass valve located at the MSIVs prior to reopening the MSIVs, thus requiring operator action outside the control room. This action is an operational task that is considered to be uncomplicated and is virtually certain to be successful during the conditions in which it is performed. However, it would require diagnosis, as it is not the normal procedural method for operations to control cool down rate. Response: If the MSIVs are closed to control cool down rate at Ginna Station, the steam generator ARVs become the normal heat removal path for the remainder of this shutdown evolution.	9/12 Introduced hold more info	Ginna

Temp No.	PI	Question/Response	Status	Plant/ Co.
4.4	IE-03	**Question:** ~~On June 27th, the conditions again rapidly deteriorated due to an influx of small forage fish. Power was reduced on Unit 1 by greater than 20% (from 100% to 79%) due to reduced water level in the pump bay attributable to the accumulation of the fish. Unit 1 power level remained reduced at approximately 80% while personnel performed Unit 2 traveling screen repair, condensate cooler cleaning on Unit 1 and removal of fish to regain water level. Would this situation count as an unplanned power change?~~ On June 27th, Point Beach Unit 2 was manually scrammed, in accordance with Abnormal Operating Procedure AOP 13A, "Circulating Water System Malfunction," and power was reduced on Point Beach Unit 1 by greater than 20% (from 100% to 79%) due to reduced water level in the pump bay attributable to an influx of small forage fish (alewives). The large influx of fish created a high differential water level across the travelling screens and ultimately failure of shear pins for the screen drive system, leading to a rapid drop in bay level. The plant knows when the alewife spawning and hatching seasons occur and the effects of Lake Michigan temperature fluctuations on the route of alewife schools. It was aware of the presence of large schools at other Lake Michigan plants this spring and discussed those events and the potential of them occurring at Point Beach at the morning staff meetings. During the thirty years of plant operation, there have been a few instances where a large number of fish entered the plant circ water system. High alewife populations coupled with seasonal variations, lake conditions and wind conditions created the situation that resulted in the down power on June 27th. Point Beach staff believe that these are uncontrollable environmental conditions. Plant procedures are in place which direct actions when the water level in the pump bay decreases. However, it is not possible to predict the exact time of an influx of schooling fish nor the massive population of fish that arrived in the pump bay. Page 17 of NEI 99-02 Revision 1 states, "Anticipated power changes greater than 20% in response to expected problems (such as accumulation of marine debris and biological contaminants in certain seasons) which are proceduralized but cannot be predicted greater than 72 hours in advance may not need to be counted if they are not reactive to the sudden discovery of off-normal conditions." Would this situation count as an unplanned power change? Response: No. The influx of alewives was expected as evidenced by the discussion of events at other plants on Lake Michigan but was not predictable greater than 72 hours in advance due to the variables involved. Large schools of alewives are a result of environmental and aquatic conditions that occur in certain seasons. The response to the drop in bay level is proceduralized.	8/15 Introduced	WEPCO

need more info / may have to take out /

Temp No.	PI	Question/Response	Status	Plant/ Co.
25.2	IE-03	This FAQ is submitted based on the statement in NEI 99-02 Rev 1, page 17, lines 28 - 33: "Anticipated power changes greater than 20% in response to expected problems (such as accumulation of marine debris and biological contaminants in certain seasons) which are proceduralized but cannot be predicted greater that 72 hours in advance may not need to be counted if they are not reactive to the sudden discovery of off-normal conditions. The circumstances of each situation are different and should be identified to the NRC in a FAQ so that a determination can be made concerning whether the power change should be counted." The water conditions of Lake Ontario have improved over the years. One of these improvements has been the increased clarity of the water. This increased clarity allows the sun light to penetrate much deeper in all areas of the lake, thus encouraging aquatic growth. The spring and summer of 2001 have been storm-free on most of Lake Ontario causing little disturbance and turnover of the lake water. Ginna Station is situated on the southern shore of Lake Ontario. On the morning of July 26, 2001, the wind was coming out of the north north-east at 35 miles per hour and the lake surface had large, breaking waves due in part to a rapidly moving weather pattern that had crossed the area. This significant change in the weather and lake environment caused the engineers monitoring the condenser efficiency to check the condenser parameters. The delta-T across one side of the main condenser had increased, but remained within the New York State Department of Environmental Conservation (NYSDEC) State Pollutant Discharge Elimination System (SPDES) Circulating Cooling Water Intake-Discharge Temperature limits. The delta-T across the affected condenser side actually improved over the next days as the weather and the lake conditions returned to more normal and the lake grass washed itself from the condenser. While still operable at 100 percent power, good engineering judgment and business practices indicated that Ginna Station should down power and clean the main condenser when the electric grid loading allowed for it. Discussion with Energy Control determined that Saturday morning, July 28, 2001, would be the most opportune and economic time to reduce load on Ginna Station. The main condenser was cleaned that Saturday morning. At no time between discovery and condenser cleaning did any condenser parameter require a load adjustment. This down power was not counted in the PI based on the Clarifying Notes on page 17 of NEI 99-02. Response: This down power meets the spirit and intent of the Clarifying Notes in NEI 99-02 and does not need to be counted as an unplanned power change.	9/12 Introduced	Ginna

Temp No.	PI	Question/Response	Status	Plant/ Co.
25.3 2 causes / 2 hits / not one.	IE01 IE03	Question: As a result of a stator cooling water leak, power was reduced to remove the main turbine from service. When the main turbine was tripped, a loss of condenser vacuum occurred which necessitated a plant scram. The loss of vacuum was caused by inadequate torque on a moisture separator/reheater manway, which resulted in significant air in-leakage when the pressure in the tank relaxed as a result of taking the turbine off line. The NRC resident inspector office has indicated the appropriate NEI 99-02 guidance that should be followed is a paragraph (starting on line 8 of page 17, NEI 99-02, Revision 1) discussing when an unplanned off-normal condition occurs during a planned power change. The paragraph discusses when the unplanned condition should be counted as an unplanned power change because it is outside or beyond the scope of the planned power change. The NRC interpretation is that both an unplanned power reduction and an unplanned scram should be counted for such an event. Our position is that another paragraph of NEI 99-02 applies (starting on line 6 of page 18), which says that off-normal conditions that begin with one or more power reductions and end with an unplanned reactor trip are counted in the unplanned reactor scram indicator only. Should this event be counted only as an unplanned scram because the power reduction and the scram were related, or should it be counted as both an unplanned power reduction and an unplanned scram?	9/12 Introduced	Perry
		Licensee Response: The appropriate guidance for this situation is that only an unplanned scram should be counted. Because the off-normal condition began with an unplanned power reduction and ended with an unplanned reactor trip, the guidance states that the event should only be counted under the unplanned scram indicator. This would be consistent with the evaluation of an off-normal event that occurred during a planned power reduction and was bounded by the scope and duration of that planned power reduction. In such a case, even if the off-normal event would have resulted in a power change of >20% if it had occurred by itself, no unplanned power change would be counted because the event was bounded by the scope and duration of the planned event. An unplanned scram that was preceded by an unplanned power reduction, even if the causes are not directly related, also "bounds" the unplanned power reduction because the scram already recognizes the unplanned nature of the event and represents the unplanned power reduction that would have resulted if only the scram had occurred.		

Temp No.	PI	Question/Response	Status	Plant/ Co.
25.4	IE02	Question: While performing routine Unit 2 maintenance, personnel in the control room placed one channel of main steam line pressure instrumentation in test. Next, they notified a field technician to isolate the associated pressure transmitter. The field technician isolated the wrong transmitter and immediately notified the control room. This condition satisfied the 2/3 logic for lo lo steam line pressure and initiated a main steam isolation signal. The main steam isolation valves (MSIVs) on all four loops closed. The steam line code relief valves and the pressurizer power operated relief valves opened. The reactor tripped on overtemperature delta temperature. The condenser dump valves opened and began blowing down the steam chest. The main feedwater pumps went to rollback hold. In rollback hold, the main feedwater pumps can be aligned from the control room to the auxiliary steam supply system which receives its steam from the opposite unit. At the time, Unit 1 was operating at 100 percent power. The auxiliary feedwater system started upon receipt of a steam generator lo lo level signal. Operators immediately entered the reactor trip procedure. The main steam isolation signal was reset. Approximately 35 minutes after reactor trip, the main steam bypass valves were opened. This provided a heat removal path and began to equalize the pressure differential across the MSIVs. At the time, main steam line pressure upstream of the MSIVs was approximately 1100 psig while pressure in the steam chest (downstream of the MSIVs) was approximately 70 psig. By design, a differential pressure of less than 50 psid must be established across the MSIVs prior to opening them. Approximately 50 minutes after opening the MSIV bypass valves, pressure had been equalized. All four MSIVs were opened approximately two hours after the reactor trip. This restored the normal heat removal path through the MSIVs and back to the main condenser. The normal heat removal path could have been recovered sooner. However, Operations did not see any need to restore the path sooner since the plant was stable and heat was being removed by main feedwater and the steam line code relief valves. Following the reactor trip, operators entered the applicable reactor trip procedure and initiated all recovery actions from the control room. There was no need for diagnosis or repair. All safety systems functioned as required. Main feedwater was available and reestablished per the reactor trip procedure. Condenser vacuum was maintained at all times. The normal heat removal path through the MSIVs was not recovered for approximately two hours after the reactor trip; however, this path could have been recovered sooner if desired. Does this count as a scram with loss of normal heat removal? Licensee Response: No. Based on the facts above, we conclude that this transient did not meet the intent of the Scrams With Loss of Normal Heat Removal category.	9/12 Introduced	McGuire
25.5	MS01 - MS04	Question: NEI 99-02 says that for design deficiencies that occurred in a previous reporting period, fault exposure hours are not reported. The indicator report is annotated to identify the presence of an old design error, and the assessment process will assess the significance of the discovery. Given the following situation: An error occurred where design and configuration drawings were not updated to reflect a physical change in the plant during initial plant startup. Subsequently, an incorrect component was installed due an incorrect bill of material. Investigation determined that the incorrect component installation did not involve personnel error. Can fault exposure hours be excluded for this type of design deficiency? Response: Yes, as long as the design deficiency occurred in a previous reporting period and the incorrect installation was not as a result of a human performance issue in the current reporting period. No. The intent of this exclusion is solely to exclude fault exposure for historical issues that have existed in the plant since initial plant startup.	9/12 Introduced	PSEG Hold week

revised to 9 yes

Temp No.	PI	Question/Response	Status	Plant/ Co.
25.6	MS01 - MS04	Question: A 1 inch relief valve with an incorrect lift setpoint (120 psig instead of 150 psig) was installed in the Safety Auxiliaries Cooling System (SACS) (SACS performs the component cooling water function). With both pumps (A and C) in the train running, the relief valve lifted, resulting in loss of approximately 12-13 gpm of inventory. Normally, this amount of water loss could easily be made up by the demineralized water makeup system, which is capable of making up at the rate of 50 gpm. During a loss of offsite power, the demineralized water makeup system is not available. When the SACS tank reaches the low-low level, the failure is indicated by the SACS LOOP TROUBLE alarm and a digital point, which displays and alarms on the plant computer, indicates that SACS EXPANSION TANK LEVEL is the issue. The low-low level alarm is an indication of system leakage; this information is provided in the procedure. As a result, no diagnosis is required; Control Room personnel are only required to provide a source of makeup water to ensure continued availability of SACS. The alarm response procedure refers the operator to the procedure for SACS Malfunction, which includes the instructions to perform emergency makeup from service water (verify a valve position and open three other valves from the control room), if required. Due to the amount of time (4.5 hours using the NRC assumptions, 5.9 hours using the utilities) between receipt of the alarm and the time that the expansion tank would become unavailable; it is likely that some diagnosis into the cause of the problem would occur; however, the use of emergency makeup from service water is available and does not require diagnosis. Should the time that the relief valve with the incorrect setpoint was installed be counted as fault exposure time for the supported systems?	5/12 Introduced	PSEG
		Response: No. NEI 99-02 states that operator actions to recover from an equipment malfunction or an operating error can be credited if the function can be promptly restored from the control room by a qualified operator taking an uncomplicated action (a single action or a few simple actions) without diagnosis or repair (i.e. the restoration actions are virtually certain to be successful under accident conditions). In this case, the SACS function to provide cooling water would not have been lost due to the control room taking a few simple proceduralized actions that do not require diagnosis. The fact that the control room operators perform diagnosis or align another source of water prior to the loss of function does not negate the fact that the function could be ensured or promptly restored with a few simple actions.		