March 5, 1999

MEMORANDUM TO: File

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

SUBJECT: SUMMARY OF THE FEBRUARY 10, 1999 MEETING WITH THE NUCLEAR POWER INSTITUTE TO DISCUSS THE CONTINUED DEVELOPMENT OF PERFORMANCE ASSESSMENT PROCESS AND INSPECTION PROGRAM IMPROVEMENTS

On February 10, 1999, a public meeting was held between the NRC and the NEI to continue exchanging information and views in further developing the concepts sent to the Commission for improving the process for overseeing the safety performance of nuclear power reactors. The meeting agenda, a list of those who attended the meeting, a copy of written information exchanged at the meeting, and summary minutes are attached.

Attachments: As stated

Contact: August K. Spector
301-415-2140

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Public Meeting Minutes

Date: February 10, 1999

Time: 9:00 a.m. to 3:30 p.m.

Topic: NRC/NEI MEETING TO DISCUSS THE CONTINUED DEVELOPMENT OF PERFORMANCE ASSESSMENT PROCESS AND INSPECTION PROGRAM IMPROVEMENTS

Attendees: See Attached Listing

Items Distribute: See attachments

Overview:

For NEI and the NRC to discuss and review the NRC's development of performance assessment process and inspection program improvements. Participants shared progress by the NRC's Transition Task Force (TTF) on the new Regulatory Oversight initiative and to gained input from NEI and the public.

Issues discussed:

Training initiatives:

NRC discussed proposed dates for conducting three workshops/training sessions.
Two of these will be open to the public prior to the initiation of the pilot study. Public sessions to be designed to provide information related to Performance Indicators, reporting activities, etc. Workshops are planned to be held in Region III, Region II, and possibly Washington, DC subject to space availability. NEI will provide instructional assistance at these sessions. One workshop, closed to the public, will be designed to train internal NRC employees on the new procedures.

Communication initiatives:

NRC distributed an updated listing (see attached) of current planned meetings, conferences, training sessions, and other communication activities. NEI provided a calendar of nuclear industry meetings/conferences planned for the next several years. NEI provided a listing of questions from its members related to the proposed plant assessment process derived from its recent conference. (See attached)

Contact: August Spector, NRC
301-415-2140

Inspection Program initiatives:

The NRC TTF Inspection Task Lead introduced members of the Inspection Task Group which will be meeting during the next few weeks on developing inspection program activities.

Performance Indicator initiatives:

Cornerstone areas were discussed with NRC indicating current efforts to clarify cornerstone areas. NEI indicated that they are developing a document which will describe EP, Security and Radiation Protection Cornerstones. This document will be considered for inclusion in the NRC response. NEI briefed participants on its recent Workshop and distributed to NRC workshop participant notebook which includes viewgraphs of each presentation. NRC distributed its draft Process for Characterizing Risk Significance of Inspection Findings (see attached) and discussed its framework.

Pilot Project:

NEI reported that all proposed pilot plants with the exception of Prairie Island have been notified and that NEI would confirm participation to NRC. It was agreed that NRC would notify each State Program Office of those plants selected for participation in the pilot program. NRC distributed and reviewed its draft Objectives of the Regulatory Oversight Process Improvement Pilot Program report (see attached) and the current draft of the PI Pilot Program Reporting Manual.

Feasibility Study:

NRC distributed and reviewed the draft Inspection Non-conformance Evaluation Matrix in relation to the emergency preparedness cornerstone (see attached). Discussion between NRC and participants related to the correlation of enforcement policy and regional application during pilot study.

Next meeting:

Agreed to hold next public meeting on February 24, 1999 from 9:00 a.m. to 3:30 p.m.

Meeting adjourned at 3:30 p.m.

ATTENDANTS
Public Meeting
February 10, 1999

NEI

Ellen Ginsberg
Tom Houghton
Stephen D. Floyd

NUCLEAR REGULATORY COMMISSION

David Gamberoni, NRR, DISP
Peter Eselgroth, Region I
Lee Miller, TTC
Pete Wilson, NRR
Jim Lieberman, OE
Alan Madison, NRR, DISP
Tim Frye, NRR, DISP
Steven Stein, NRR, DISP
Michael Runyan, Region IV
Jim Heller, Region III
McKenzie Thomas, Region III
Dave Nelson, OE
Barry Westreich, OE
William Dean, NRR, DISP
Frank Gillespie, NRR, DISP
Michael R. Johnson, NRR, DISP
August Spector, NRR, DISP
Jeffrey Jacobson, NRR, DISP
Donald Hickman, NRR, DISP
Morris Branch, NRR, DISP
Garreth Parry, NRR
Renee Pedersen, OE
R.W. Borchardt, OE
Desiree R. Calhoun, OE
Terry Reis, OE
Douglas Coe, NRR, DISP

OTHERS

Joe Burton, NPPD/CNS
Michael Callahan, Self
Rosemary Reeves, NUS-IS
Sidney Crawford, Self
Robert W. Boyce, PECO
James McCarthy, Virginia Power
Kevin Nietmann, Baltimore Gas & Electric Company
Jeffrey Reinhart, INPO

OTHERS, Continued

Deann Raleigh, Bechtel Power
Rosemary Reeves, NUS-IS
Ralph Shell, TVA
Edward J. Vigluicci, TVA
John Lamberski, Troutman Sanders
Greg Gibson, Southern California Edison
Don Irwin, Hunton & Williams
Bill Baer, Morgan, Lewis & Backius
Doug True, Erin Engineering

Draft: Regulatory Oversight Process Communication Plan

January 1999
1/14 Brief Regional DRP Directors
1/14 Meet with NEI to discuss Pilot Plan
1/20 Commission briefing on Process Recommendations
1/20 Enforcement Coordinators Briefing
1/22 Press Release to announce 30 day comment period
1/26 Brief ACRS on Final Recommendations
1/27 NEI/Public Meeting
1/28 Brief Industry Regulatory Compliance and Technology Group
1/28 Visit Salem

February 1999

2/3 R-I Town Meeting Conference Call
2/2 NEI Meeting with Industry; Site VPs/Licensing Managers - East
2/3 NEI Meeting with Industry; Site VPs/Licensing Managers - West
2/10 NEI/Public Meeting: coordinated with OE
2/11 NEI Task Force Briefing of NSIAC
2/17 R-II Resident Meeting
2/18 R-IV Resident Counterpart Meeting
2/23 Public Comment Period ends
2/24 NEI/Public Meeting
TBA - Regional Meetings (coincide with PPRs to describe new process)

March 1999

3/3-5 Regulatory Information Conference (introduce concepts)
3/11 NEI/Public Meeting
3/24 NEI/Public Meeting
3/26 Draft IP and IMC 0610 & PIM Guidance for Pilot use issued for comment (made available to the public)

April 1999
4/7 NEI/Public Meeting
4/6-8 Briefing for American Power Conference (Frank Gillespie presenter)
4/12-16 PI Workshop (R-3) public
4/22 NEI/Public Meeting
4/26-30 Inspector Workshop (R-2) NRC

May 1999

5/4-6 R-1 Resident Mtg. (Tentative)
Joint NRC/NEI meeting to resolve issues prior to Pilot (TBA)
5/10-14 Pilot Workshop - Public R-1/HQ = (TBA)

June 1999

6-10 ANS Conference presentation (tentative)
6/15 Issue Press Release on Enforcement Revisions

July 1999

7/12 Present at MIT Course (Gillespie)
7/15-30 Conduct Regional Meetings with States on details of new process

September 1999

Brief commission TAs on Progress (TBD)

October 1999

10/11-25 (TBD) conduct joint NRC/Industry 2 day Workshop (NRC/NEI)
Issue a Press Release regarding the Workshop

December 1999

Brief Commission TA's

January 2000

1/15 Press Release issued announcing full process implementation and SALP deletion

May 2000

Commission Briefing on Assessment results
Press Release issued

Note:
1. Change Coalition, Change Champion and other internal communication vehicles to be on going
2. Public Information to be posted on NRC Web-page

OBJECTIVES OF THE REGULATORY OVERSIGHT PROCESS IMPROVEMENT PILOT PROGRAM

1. Limited scale exercise of processes to evaluate whether they can function efficiently including:

    - Performance indicator data collection and reporting by the industry
    - Risk-informed baseline inspection program implementation by the NRC
    - Evaluation of PI and inspection results and determination of appropriate actions through the assessment process
    - Enforcement process implementation

2. Identify problems with processes and implementing procedures and make appropriate changes prior to full implementation in January 2000:

    - Final PI collection and reporting guidance to the industry by October 1999
    - Inspection procedures, IMC 0610, IMC2515, etc., issued by December 1999
    - Final enforcement policy revisions by December 1999
    - Assessment process management directive issued by February 2000

3. To the extent possible, evaluate the effectiveness of the processes to determine whether:

    - PIs and their thresholds provide an objective measure of plant performance and can accurately reflect changing trends in licensee performance
    - The baseline inspection program adequately supplements PIs so that the combination of PIs and inspection provide reasonable assurance that the cornerstone objectives are being met
    - The baseline inspection program is effective at independently verifying the accuracy of the PIs
    - Enforcement actions are taken more consistently

- The assessment process and action matrix are sufficient to aid in making consistent action decisions for plants with varying levels of performance

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REACTOR OVERSIGHT PILOT PROGRAM

1. Pilot coordinator - Tim Frye
2. PI lead - Don Hickman
3. Inspection program lead - Steve Stein
4. Assessment lead - Dave Gamberoni
5. Enforcement lead - Dave Nelson
6. Information systems lead - Tom Boyce

Prerequisites:

1. Develop inspection finding significance screening process	February 1999
2. Perform process feasibility study	February 1999
3. Establish Transition Task Force (TTF)	February 1999
4. Select pilot plants	February 1999
5. Develop success criteria for all parts of pilot	February 1999
6. Develop PI procedure (Management Directive, administrative letter)	March 1999
7. Develop baseline inspection procedures, PI verification inspection procedure [also, IMC 0610, IMC 2515 revisions]	March 1999
8. Develop assessment procedure (Management Directive)	April 1999
9. Develop enforcement procedure (guidance document)	April 1999
10. Develop information management systems for pilot (PIM, RITS, www)	April 1999
11. Train licensees	April 1999
12. Train BCs, SRIs, RIs, and PEs	April 1999
13. Joint NRC/Industry workshop	May 1999
14. Issue PI procedure, baseline inspection procedures, enforcement procedure	May 1999

Major pilot activities:

1. Licensee PI data collection and submittal	May 1999
2. Commence pilot program	June 1, 1999
3. **PI verification inspection**	**July 1999**
4. **Periodic NRC/Industry meetings to review pilot results**	**Jul, Sep, Dec 1999**
5. NRC baseline inspection trial and documentation in inspection reports	Jul, Sep, Nov 1999
6. Assessment - quarterly review	September 1999
7. Assessment - mid-cycle review	December 1999
8. Enforcement	as required

Analysis:

1. PI results	ongoing, December 1999
2. Baseline inspection procedure evaluations	ongoing, December 1999
3. Assessment process efficacy	December 1999
4. Enforcement process efficacy	December 1999

5. Evaluate success criteria	ongoing, December 1999

Final products:

1. PI procedure	**October 1999**
2. Baseline inspection procedures (& PI verification procedure)	**December 1999**
3. Assessment procedure	**February 2000**
4. Enforcement procedure	**December 1999**
5. Information systems	**December 1999**

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PILOT PROGRAM GROUND RULES

- The pilot plants would receive the new baseline inspection program in lieu of the current core program.

- Pilot plants would be assessed under the new assessment process in lieu of the current PPR process (no August PPR for pilot plants). Assessment for pilot plants will occur under the mid-cycle review, scheduled for November.

- PI data collection for the pilot program will start in May 1999, with the first PI report due June 15, 1999. In addition to the pilot plants, the NEI task group plants will be asked to also participate in the PI reporting portion of the pilot. The participating plants will be asked to collect and report two years worth of historical PI data to supplement the data collected during the pilot.

- Pilot plants will be handled under the new enforcement policy, in lieu of the current enforcement policy.

- Subsequent to the completion of the pilot program, pilot plants would continue under the new oversight processes if full implementation is delayed for the short term (less than 3 months). If it is expected that full implementation will be delayed for greater than three months, than staff will evaluate restoring pilot plants to the current regulatory oversight processes.

- The risk-informed baseline inspection program would be piloted as follows:
  - Inspection planning would be tested at all pilot plants
  - Adjustments to the inspection schedule would be tested at all plants
  - All new inspection procedures will be tested, but not necessarily at all plants. For example the biannual problem identification and resolution inspection procedure might be tested at only 3 pilot plants.
  - The PI verification portion of the inspection program will be tested at all plants, but not all PIs would need to be verified at each plant.
  - As many inspectable areas as possible will be tested based on their intended frequency and the availability of associated activities. Some inspectable areas will not be used because they will not be applicable to the pilot sites; such as the refueling and outage related activities and several of the occupational exposure inspectable areas.

- Regional inspection planning meetings, with program office oversight and assistance, will be held for each pilot plant in May 1999. At this time, previously scheduled regional initiative inspections will be re-evaluated to determine the continued need for the inspection under the new oversight framework.

- The need for additional regional initiative inspection during the pilot program will be determined based on PIs and baseline inspection findings.

- A mid-cycle review and inspection planning meeting will be held for each pilot plant, and a six-month inspection look-ahead letter will be issued for the pilot plants by end of November 1999. These assessment and inspection planning activities will be based on the 5 months of pilot data collected by the end of October 1999.

- Pilot plants will be discussed as part of the April 2000 SMM. Performance review and discussion at the screening meetings will be on PIs and baseline inspection results, and actions specified by the action matrix. The action matrix will be used to the extent practicable to determine those pilot plants that need to be discussed further at the SMM.

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SUCCESS CRITERIA
REGULATORY OVERSIGHT PROCESS IMPROVEMENT
PILOT PROGRAM

The following success criteria will be used to evaluate the results of the regulatory oversight process improvement pilot program. These criteria will determine whether the overall objectives of the pilot program have been met, and whether the new oversight processes: 1) ensure that plants continue to be operated safely, 2) increase the public confidence in regulatory oversight, 3) improve the efficiency and effectiveness of regulatory oversight by focusing agency and licensee resources on those issues with the most safety significance, and 4) reduce unnecessary regulatory burden on licensees as the processes become more efficient and effective.

Performance indicator data collection and reporting by the industry

- Can PI data be accurately reported by the industry, in accordance with reporting guidelines? Yes, if by the end of the pilot program, each PI is reported accurately for at least 8 out of the 9 pilot plants.

- Can PI data results be submitted by the industry in a timely manner? Yes, if by the end of the pilot program, all plants submit PI data within 1 business day of the due date.

Risk-informed baseline inspection program implementation by the NRC

- **Can the inspection planning process be efficiently performed to support the assessment cycle? Yes, if the planning process supports issuing an inspection look-ahead letter within fours weeks from the end of an assessment cycle.**

- Are the inspection procedures clearly written so that the inspectors can consistently conduct the inspections as intended? Yes, if by the end of the pilot program, resources expended to perform each inspection procedure are within 25% of each other for at least 8 out of the 9 pilot plants .

- **Are less NRC inspection resources required to perform the new risk-informed baseline inspection program. Yes, if the direct inspection resources expended to perform the baseline program are about 15% less than that expended for the core inspection program.**

- **Can the inspection finding evaluation guidance be used by inspectors and regional management to efficiently categorize inspection findings in a timely manner? Yes if by the end of the pilot program, inspection reports and updated plant issues matrices (PIMs) can be issued within 30 days of the end of an inspection period.**

- Can inspection findings be properly assigned a safety significance rating in accordance with established guidance? Yes, if by the end of the pilot program, at least 95% of the inspection findings were properly categorized and no risk significant inspection findings were screened out. Success will be determined by an independent review by the pilot program evaluation panel.

- Are the scope and frequencies of the baseline inspection procedures adequate to address their intended cornerstone attributes? Success will be determined by an independent pilot program evaluation panel.

- Does the implementation of the entire baseline inspection program (planning, inspection, evaluation of findings, documentation) require no more resources than currently required? Yes, if by the end of the pilot program, baseline inspection program planning, inspection, evaluation of findings, and documentation of inspection results requires no additional resources than are currently allotted for these activities.

<u>Periodic assessment of PI and inspection results to determine appropriate NRC actions</u>

- Can the assessment process be performed within the scheduled time? Yes, if for all pilot plants, an assessment of the PIs and inspection findings can be completed, and an assessment letter can be prepared and issued, within four weeks of the last PI data submittal.

- Can the action matrix be used to take appropriate NRC actions in response to indications of licencee performance? Yes, if there is no more than one **instance (with a goal of zero) where the independent pilot program evaluation panel concluded that action required for a pilot plant is different than the range of actions specified by the action matrix.**

- Do the PIs and inspection findings provide an adequate indication of licensee performance? Does the process provide a reasonable assurance that the cornerstone objectives are being met and safe plant operation is maintained? Success will be determined by an independent pilot program evaluation panel.

- **Are the mid-cycle assessments performed, with inspection look-ahead letters issued, for the pilot plants in a manner that is consistent across the regions and that meets the objectives of the assessment program guidance? Success will be determined by an independent pilot program evaluation panel.**

<u>Enforcement process implementation</u>

- **Can the revised enforcement process be efficiently implemented by regional and HQ staff. Yes, if for at least 90% of the cases only one enforcement panel is needed to determine the significance and disposition of a violation.**

- **Are inspection findings appropriately dispositioned in accordance with the new enforcement policy. Yes, if 95% of the issues are handled in accordance with enforcement policy requirements, as determined by an independent pilot program evaluation panel.**

- **Are enforcement actions taken for individual findings consistent with the inspection finding evaluation guidance? Yes, if 95% of the enforcement actions taken are determined to be consistent with the inspection finding evaluation guidance, as determined by an independent pilot program evaluation panel.**

Information Management Systems

- Are the assessment inputs and results readily available to the public? Yes, if by the end of the pilot program, the NRC information systems support receiving industry data, and PIs and inspection findings are publically available on the Internet within 30 days of the data submittal.

- Are the time reporting and budget systems ready to support the process changes. Yes, if by the end of the pilot program, these information systems support the reporting of time expended for regulatory oversight, and that discrepancies with the reporting of hours are less than 5%.

- **Are the NRC information support systems, such as the Reactor Program System (RPS) and its associated modules, ready to support full implementation of the new oversight processes? Yes, as determined by evaluation by the pilot plant evaluation panel.**

Overall

- **Have inspectors and managers been provided adequate training to successfully implement the new oversight processes? Yes, as determined by a customer satisfaction survey evaluated by the pilot plant evaluation panel.**

- Are the new regulatory oversight processes overall more efficient and effective? Yes, if by the end of the pilot program, overall agency resources required to implement the inspection, assessment, and enforcement programs about 15% less than current required.

- Do the new oversight processes remove unnecessary regulatory burden, as appropriate, for the pilot plants. Yes, as determined at the end of the pilot program, based on the results of a pilot plant licensee survey.

PILOT PLANT SELECTION

The following criteria was used to identify potential sites for the pilot plant program:

- To the maximum extent possible, licensees were chosen that had either volunteered to be a pilot plant, or had participated in the NEI regulatory oversight process improvement task group. The number of different licensees chosen to participate was also maximized.

- Plants were chosen to represent a broad spectrum of performance levels, but did not include plants that were in extended shutdowns due to performance issues.

- A mix of both pressurized water reactors (PWRs) and boiling water reactors (BWRs) was chosen.

- A mix of plant vendors and ages was chosen.

  To the extent possible, two plants with different performance levels within each region were chosen.

- NRC regional office concerns such as experience of NRC staff associated with pilot plants and transition issues (such as expected departure of key NRC personnel during the pilot study) were considered.

- Licensee concerns such as their involvement with other significant NRC activities (license renewal, steam generator replacement, etc.) was considered.

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Potential Pilot Plants

Region	Plant	Licensee	Last SALP	PWR/ BWR	Vendor/Age
1	Hope Creek	Public Service Electric &Gas (PSE&G)	2221	BWR	General Electric(GE) Type 4/ 13 years
1	Salem 1&2	PSE&G	1221	PWR	4 Loop Westinghouse (W)/ 20 years
1	Fitzpatrick	Power Authority of the State of New York	2222	BWR	GE Type 4/ 24 years
2	Harris	Carolina Power & Light Company	1121	PWR	3 Loop W/ 12 years
2	Sequoyah 1&2	Tennessee Valley Authority	2221	PWR	4 Loop W 18 years
3	Prairie Island 1&2	Northern States Power Company	2121	PWR	2 Loop W 25 years
3	Quad Cities 1&2	Commonwealth Edison Company	2332	BWR	GE Type 3 26 years
4	Ft. Calhoun	Omaha Public Power District	2212	PWR	Combustion Engineering (CE)/ 26 years
4	Cooper	Nebraska Public Power District	2231	BWR	GE Type 4/ 25 years
SUMMARY	9 Plants	8 Licensees	1121 to 2332	5 PWRs 4 BWRs	4 W plants 1 CE plant 4 GE plants

Note: Licensees for shaded plants are not on NEI task group

Process for Characterizing Risk Significance of Inspection Findings

Objectives

1) To characterize the risk-significance of an inspection finding consistent with the regulatory response thresholds used for Performance Indicators in the NRC licensee performance assessment process (and for the enforcement process?), and

2) To provide a risk-informed framework for discussing and communicating the potential significance of inspection findings

Entry Conditions

This process is designed to assess inspection findings within the cornerstones for initiating events, mitigation systems, and barrier integrity under the Reactor Safety Strategic Performance Area. There are certain types of possible inspection findings, both within and outside of this Strategic Performance Area, that cannot be assessed using this process. These findings either 1) must be evaluated using non-risk-based methods or 2) will require risk analysis methods beyond the scope of this relatively simple process. First among these are findings under the emergency preparedness cornerstone, and radiation safety and safeguards areas. The significance of these findings will be assessed by the process described in (XXXXXXX). Additionally, if the finding involves any of the following, it may be a candidate for "exceptional" treatment outside of this process: a significant programmatic weakness not yet manifested by actual degraded performance, multiple performance issues that individually would be considered minor but collectively point to an uncorrected underlying cause, the safety of ex-core reactor fuel (e.g., spent fuel), seismic qualification issues, core safety during shutdown conditions. Finally, any actual event (e.g., a reactor trip) that is complicated by equipment malfunction or operator error will be assessed by NRC risk analysts outside of the process described here.

Defining Characteristic

The most important characteristic of this process is intended to be that it elevates potentially risk-significant issues early in the process, and screens out those findings that have minimal or no risk-significance. It is further intended that field inspectors and their management be able to efficiently use the basic accident scenario concepts in this process to categorize individual inspection findings by potential risk significance. It presumes the user has a basic understanding of risk analysis methods.

Introduction

The proposed overall licensee assessment process (as defined outside of this document) evaluates licensee performance using a combination of performance indicators (PI) and inspections. Thresholds have been established for the PIs which, if exceeded, may prompt additional NRC action to evaluate licensee performance and to help understand and arrest a potential decline in performance. The finding assessment process described below evaluates the significance of individual inspection findings so that the overall licensee performance assessment process can compare and evaluate these findings on a similar significance scale as the PI information.

Inspection findings related to reactor safety cornerstones (initiating events, mitigating systems, and barrier integrity) will be assessed differently than the remaining cornerstones (emergency planning, occupational exposure, public exposure, and physical security). For the reactor safety cornerstones, each finding is evaluated using a risk-informed framework that relates the finding to specific structures, systems, or components (SSCs), identifies the core damage scenarios to which the failure of the SSCs contribute, estimates how likely the initiating event for such scenarios might be, and finally determines what capability would remain to prevent core damage assuming the initiating events for the identified scenarios actually occurred. The emergency planning and the non-reactor cornerstones do not lend themselves directly to the risk-informed framework described by this finding assessment process. Therefore, each finding under these cornerstones will be characterized according to separately developed significance criteria.

<u>Process Discussion</u>

The inspection finding assessment process is a graduated approach using a three phase process to differentiate inspection findings based on their potential risk significance. Findings that pass through a screening phase will generally proceed to be evaluated by the next phase.

Phase 1 -	**Definition and Initial Screening of Findings** - Precise characterization of the finding and an initial screening-out of low significance findings
Phase 2 -	**Risk Significance Approximation and Basis** - Initial approximation of the risk-significance of the finding and development of the basis for this determination, for those findings that pass through the Phase 1 screening
Phase 3 -	**Risk Significance Finalization and Justification** - As-needed refinement of the risk-significance of Phase 2 findings by an NRC risk analyst

Phases 1 and 2 are intended to be primarily accomplished by field inspectors and their management. Until a user becomes practiced in its use, it is expected that an NRC risk analyst may be needed to assist with some of the assumptions used for the Phase 2 assessment. However, after inspection personnel become more familiar with the process, risk analyst involvement is expected to become more limited. The Phase 3 review is not mandatory and is only intended to confirm or modify the results of significant ("white" or above) or controversial findings from the Phase 2 assessment. Phase 3 analysis methods will utilize current PRA techniques and rely on the expertise of knowledgeable risk analysts.

Step 1 - Definition and Initial Screening of Findings

Step 1.1 - Definition of the Inspection Finding

It is crucial that inspection findings be well-defined in order to consistently execute the logic required by this process. The process can be entered with inspection findings that involve one or more degraded conditions influencing equipment or operator reliability, or initiating event frequency. The definition of the finding should be strictly based on the known existing facts and should NOT include hypothetical failures such as the one single failure assumed for licensing basis design requirements. Further, any explicitly stated assumptions regarding the effect of the finding on the safety functions should initially be conservative (i.e., force a potentially higher risk-significance), because the final result will always be viewed from the context of those assumptions. Subsequent information or analysis may reduce the significance of the finding, with appropriate explicit rational. A well-defined finding must make all assumptions explicit, because these assumptions can be modified using this process to examine their influence on the results. Because of the range of possible findings, inclusive rules for defining all possible findings cannot be developed. However, the general rule is that the definition of the finding must address its safety function impact and any assumptions regarding other plant conditions. Some examples are:

1) A finding involving failure or degradation of equipment could be stated as follows: "Equipment/System/Component X does not perform its safety function of ..." . For example, a motor operated valve (MOV) in a PWR auxiliary feedwater system that is found with hardened gearbox grease (i.e., degraded) and an MOV with a broken wire (i.e., non-functional) would both be characterized conservatively as "MOV does not perform its safety function of opening to provide flow to the steam generators."

2) A finding involving a deficiency in the design of the plant could be stated as follows: "Equipment/System/Component X would not perform its safety function of .... under conditions ...". For example, a remote shutdown panel that might be rendered inhabitable during a cable spreading room fire that causes a loss of offsite power, due to inadequate HVAC dispersion of the resulting smoke, would be characterized as "plant cooldown not possible from control room or remote shutdown panel during a loss of offsite power caused by cable spreading room fire, due to inhabitability from resulting smoke and loss of power to remote shutdown panel HVAC."

3) A finding involving degradation in operator performance could be stated as follows: "Operator action X would (or would not) be performed under the conditions of ....". For example, an observation that operators mis-manipulated offsite power source breakers could be characterized conservatively as "operator error increases the likelihood of a loss-of-offsite-power initiating event and reduces the likelihood of recovery of offsite power sources."

Step 1.2 - Initial Screening of the Inspection Finding

For the purpose of efficiency, the guidelines below screen out those findings that have minimal or no impact on risk early in this process. The screening guidelines are linked to the cornerstones as follows: if there is arguably no significant impact on meeting the reactor safety cornerstone objectives, the finding can be identified as having minimal or no impact on risk, and thus is equivalent to a green PI. The process described in this document focuses on the impact to core damage frequency, and thus only the reactor safety initiating event and mitigating systems cornerstones are addressed. Findings related to barriers and non-reactor safety cornerstones will be addressed separately.

The decision logic is outlined below.

The finding should be analyzed by the Phase 2 assessment process

IF 1.2.1 - the finding and associated assumptions could simultaneously affect any two or more of the following:

increase the estimated frequency of initiating events,

degrade mitigating system reliability,

degrade containment or RCS barrier performance,

OTHERWISE, continue.

The finding may be screened OUT (considered "green" without performing the Phase 2 assessment)

IF 1.2.2 - the finding and associated assumptions do NOT increase the estimated frequency of initiating events,

AND

1.2.3 - the finding and associated assumptions do NOT degrade mitigating system reliability,

AND

1.2.4 - the finding and associated assumptions do NOT degrade containment or RCS barrier performance.

OTHERWISE, continue.

Findings that ONLY affect mitigating systems or barriers may still be screened OUT:

IF 1.2.5 - the finding and associated assumptions do NOT represent a loss of safety function of a single train of a multi-train system,

OR

1.2.6 - the finding and associated assumptions represent a loss of safety function of a single train of a multi-train system for LESS THAN the Allowed Outage Time prescribed by the LCO for Technical Specification equipment, or 24 hours for other equipment,

OR

1.2.7 - the finding and associated assumptions represent design or qualification errors or structural degradations that indicate less than expected performance or margin, but do not result in the system or barrier being unable to perform its safety function (e.g., meets NRC Generic Letter 91-18 criteria to remain operable).

Findings that ONLY affect initiating event frequency may still be screened OUT:

IF 1.2.8 - the finding and associated assumptions have NO other impact than to increase the likelihood of an uncomplicated reactor trip.

Any inspection finding that is NOT screened out by the above decision logic should be assessed using the Phase 2 process described below.

draft

Phase 2 - Risk Significance Approximation and Basis

Step 2.1 - Define the Applicable Scenarios

Once an inspection finding passes through the Phase 1 screening it is evaluated in a more detailed manner using the Phase 2 process described here. Licensee-identified issues, when reviewed by NRC inspectors, are also candidates for inclusion in this three phase process. The first step in Phase 2 is to ask the question "Under what core damage accident scenarios would the identified issue increase the risk to safe plant operation?"

Determining which scenarios make an inspection finding risk-important may be intuitive based on the knowledge and experience of individual inspectors. However, plant-specific PRA studies, safety analysis reports, technical specification bases, and/or emergency operating procedures (as examples) should be reviewed as needed to ensure that the most likely events and circumstances are considered. Specifically, the inspector must determine which core damage scenario(s) are adversely impacted by each specific finding.

During this phase of the process, inspectors may determine that several different scenarios are affected by a particular inspection finding. This can occur in one of two ways.

> First, the finding may be related to an increase in the likelihood of an initiating event, which may require consideration of several dominating (i.e., most likely) scenarios resulting from this initiating event.
>
> Second, a finding may be related to a system required to respond to several initiating events. For example, the discovery of a degraded instrument air system could affect plant response to a both a loss of offsite power and a LOCA. Each of these two initiating events must be considered separately, so that the next step of the Phase 2 evaluation process can determine which scenario is potentially most significant.

The scenario resulting in the highest significance will be used to establish the initial relative risk-significance of the finding. If a Phase 2 assessment of multiple applicable scenarios results in all "green" significance, the user should seek assistance via Phase 3 of this process, since the Phase 2 process cannot effectively "sum" the significance of multiple low significance scenarios. Additionally, a particular inspection finding may affect multiple cornerstones by both increasing the probability of an initiating event and degrading the capability or reliability of a mitigating system. Again, each applicable scenario must be considered to determine which is the most significant, although scenarios in which both the affected initiating event and system failure contribute would be expected to produce the greatest risk significance.

In identifying possible core damage accident scenarios, consideration must also be given to the role of support systems as well as front line systems. For example, if a particular initiating event can be mitigated by more than one system providing the same safety function, but all such systems are dependent on a single train of a support system (e.g., service water or emergency ac power), the limiting scenario may involve the failure of the single train of the support system rather than the individual front line system trains.

Step 2.2 - Likelihood estimation of scenario initiating events

In step 2.1, the set of core damage accident scenarios or containment failures were determined that could be made more likely by the identified inspection finding (degraded condition). This should result in the identification of one or more initiating events each followed by various sequences of equipment failures or operator errors. To determine the most limiting scenario, perform the following analysis for each set of scenarios with a common initiating event.

If the finding does not relate to an increased likelihood of an initiating event, the initiating events for which the affected SSC(s) are required are allocated to a frequency range in accordance with guidance provided in Table 1 below. Table 1 is entered from the left column using the initiating event frequency and from the bottom using the estimated time that the degraded condition occurred, to arrive at a likelihood rating (A - H) for the combination of the initiating event and the existence of the degraded condition.

If the finding relates to an increased likelihood of a specific initiating event, then the likelihood of that initiating event is increased according to the significance of the degradation. For example, if the inspection finding is that loose parts are found inside a steam generator, then the frequency of SGTR for that plant may increase to the next higher frequency category , and Table 1 is entered accordingly.

Finally, remember that the definition of the finding and the selection of core damage accident scenarios should be strictly based on the known existing facts and should NOT include hypothetical failures, such as the one single failure assumed for licensing basis design requirements.

Approx. Freq.	Example Event Type	Estimated Likelihood Rating		
>1 per 1 - 10 yr	Reactor Trip Loss of main FW Loss of condensor	A	B	C
1 per 10 - 10^2 yr	LOOP SGTR Stuck open SRV(BWR) MSLB (outside cntmt) Loss of 1 SR AC bus Loss of Instr/Cntrl Air Fire	B	C	D
1 per 10^2 - 10^3 yr	Small LOCA (PWR) Stuck open PORV/SV MFLB Flood	C	D	E
1 per 10^3 - 10^4 yr	Med LOCA (PWR) Small LOCA (BWR) MSLB (inside cntmt) Loss of all service water	D	E	F
1 per 10^4 - 10^5 yr	Lg/Med LOCA (BWR)	E	F	G
<1 per 10^5 yr	Large LOCA (PWR) ISLOCA Vessel Rupture Severe Earthquake	F	G	H
		> 30 days	30-3days	<3 days
		Exposure Time for Degraded Condition		

Table 1 - Estimated Likelihood Rating for Initiating Event Occurrence During Degraded Period

Use of Table 1 should result in one or more initiating events of interest with an associated likelihood rating ("A" through "H") for each.

Step 2.3 - Estimation of remaining mitigation capability

The scenarios of interest have now been identified, and the likelihood of the frequency with which the initiating events associated with these scenarios has been estimated. Each scenario represents an initiating event followed by a series of system, component, or human failures. For the evaluation of the impact of each scenario on risk, the conditional probability of failure of redundant or diverse success paths will need to be assessed for each scenario. If an inspection finding involves a system or component in a failed state (e.g., pump rotor found seized), then the conditional probability would be assessed by combining the independent or common cause failures of the remaining trains or systems that constitute the remaining success paths at the time of the discovery. In order to perform this assessment, the inspector must determine how many alternate success paths were available for each core damage scenario.

Success paths may be redundant trains of components identical to the one discovered in a failed state, or they may be diverse systems that provides the same function. Thus in reading Table 2, Risk Significance Estimation Matrix, the following interpretation should be made:

> 1 train refers either to a remaining train that was redundant to the one assumed failed (it is assumed that if a CCF had occurred it would have been part of the finding), or it could be a diverse one-train system (e.g., RCIC).
>
> A redundant system refers to a multi-train system that is used to perform the same safety function as that for the failed system or component (even though it may achieve it in a different way). An example would be depressurization and low pressure injection as a diverse means of inventory control to high pressure injection (BWR).

If an inspection finding involved a potentially recoverable system failure, such as an automatic start feature found failed but indication exists and simple operator action would be able to start the equipment, then such operator action can be credited as one success path. In addition, recovery actions that establish alternate electrical or water supplies through the use of non-safety equipment can also be credited, provided operator training, written procedures, and necessary equipment is appropriately staged and available. Inspector judgements with support from the SRAs (when crediting non-safety equipment) in estimating remaining mitigation capability will continue to be needed, with the basis for such judgements appropriately documented. When all scenarios have been assigned and associated likelihood and remaining mitigation capability estimated, the Table 2 matrix described in the next section can be used to estimate the potential significance of the degraded condition.

Step 2.4 - Estimating the Risk Significance of Inspection Findings

The last step of the Phase 2 assessment process is to estimate the finding's relative risk significance. This risk estimation is performed by employing an evaluation matrix (see below) which utilizes the information gained from Steps 2.1 through 2.3 above. Simply stated, the matrix compares scenario likelihood derived in Step 2.2 with remaining mitigation capability determined in Step 2.3, and establishes an estimated risk significance for the particular finding. One of only four possible results can be obtained: Green, White, Yellow, or Red.

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Risk Significance Estimation Matrix

	Remaining Mitigation Capability (From Step 2.3)					
Scenario Likelihood (From Step 2.2)	≥3 trains or 2 redundant systems	1 redundant system + 1 train	2 trains	1 redundant system	1 train	0
A	Green	White	Yellow	Red	Red	Red
B	Green	Green	White	Yellow	Red	Red
C	Green	Green	Green	White	Yellow	Red
D	Green	Green	Green	Green	White	Red
E	Green	Green	Green	Green	Green	Yellow
F	Green	Green	Green	Green	Green	White
G	Green	Green	Green	Green	Green	Green
H	Green	Green	Green	Green	Green	Green

Example uses of the Phase 1 and 2 process are included in Appendix 1 of this document.

Step 3 - Risk Significance Finalization and Justification

If determined necessary, this phase is intended to confirm or modify the earlier screening results from Phase 1 and 2. Phase 3 analysis will utilize current PRA techniques and rely on the expertise of knowledgeable risk analysts. The Phase 3 assessment is not described in this document.

Work Remaining

Continue to perform sensitivity tests of the issue screen and decision matric process depicted in this paper, by evaluating known examples.

The definitions of "remaining capability" needs continued refinement.

Define the threshold required to document this process for specific inspection findings.

Identify how to address inspection findings that could increase risk due to significant programmatic weakness not yet manifested by actual degraded performance, multiple performance issues that individually would be considered minor but collectively point to an uncorrected underlying cause, the safety of ex-core reactor fuel (e.g., spent fuel), seismic qualification issues, core safety during shutdown conditions.

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Appendix 1

INSPECTION FINDING RISK ASSESSMENT PROCESS SENSITIVITY TEST

Background

The sensitivity of the inspection finding risk assessment screening process described in section ---- was measured by evaluating examples of reactor cornerstone items that represent a typical input to the process. Additionally, several previous ASP events were pushed backwards through the process to ensure that the screening criteria were set at the appropriate level. It is also expected that because of the simplicity of the model, the process has the potential to overestimate the risk significance of some events possibly requiring a more refined evaluation before a final assessment can be determined.

TYPE OF ISSUES REVIEWED

Issue - a (Design Issue) Appendix "R" Safe Shutdown Panel Inoperable

This scenario involved a failure to meet 10 CFR part 50 Appendix "R" requirements III.L.2.e and III.L.3. These sections of Appendix "R" require that support functions be capable of providing the process cooling necessary to permit the operation of equipment used for safe-shutdown functions, and that alternative shutdown capability accommodate post-fire conditions when off-site power is or is not available. The case study reviewed, postulated that a fire in the control room or in the cable spreading room could cause a loss of HVAC due to a fire induced loss of offsite power (LOOP). This would result in a loss of HVAC to the electrical equipment room and the adjacent hot shutdown control panel room.

When this item was screened by the risk assessment model, several assumptions were made. First it was assumed that a fire in the cable spreading room could grow sufficiently to require evacuation of the main control room and cause a LOOP resulting in a loss of HVAC, which in turn results in the single safe shutdown panel room being inoperable. An additional assumption was that the loss of habitability of the alternative safe shutdown panel room resulted in the inability to shutdown and maintain the plant safely shutdown under the postulated conditions. When the staff asked the screening questions listed in step 1.2 the item was considered risk important because of a loss of redundancy in the mitigating capability and the item passed through the screen thereby requiring additional review for risk significance.

Determining risk importance of the Appendix "R" issue using the risk significance estimation matrix involved entering the matrix to determine the approximate frequency and estimated likelihood based on duration of the condition. The IPEEE and Licensee's Risk Analysis was used at this step. In the case reviewed, the likelihood was rated as a "E" event(ie 1E-04 - 1E-05). Once the likelihood was categorized, a review of remaining mitigation capability was performed. Since the scenario resulted in the loss of the one and only safe shutdown panel room and administrative operator intervention was not assumed, mitigation was not allowed by the matrix. This item would therefor be categorized as a yellow item.

Issue - b (LER) Charging/High Head Safety Injection Pump Configuration Outside Plant Design Basis with All Three Pumps Technically Inoperable

This issue involved the licensee's discovery that all three charging/high-head safety injection pumps (CCP) were in a configuration that was outside plant design basis. Specifically, the system design included three CCP, trains A and B with the "C" pump being a swing pump that could be powered from either emergency electrical bus. The design included a breaker interlock and trip feature to prevent potential electrical bus overloading while being powered by an EDG. The system configuration resulted in the "C" pump being unable to automatically start because its hand switch was in pull-to-lock. The breaker interlock and trip feature would have tripped the "A" pump if a LOOP occurred and the "B" pump was assumed to be the single failure. This condition existed for approximately ten days.

When the staff asked the screening questions listed in step 1.2, the item was considered risk important because of a loss of redundancy and the item passed through the screen thereby requiring additional review for risk significance.

Determining the risk importance of the CCP system degradation using the risk significance estimation matrix involved entering the matrix to determine the approximate frequency and estimated likelihood based on a 10 day duration of the condition. In the case reviewed, the likelihood was rated as an "E" based on duration, LOOP, combined with a Small LOCA or Steam Line Break event. Once the likelihood was categorized, a review of remaining mitigation capability was performed. Credit for the "B" train CCP would mitigate the event to a "G" which is green. Additionally, if analysis demonstrated that sufficient time would allow operator intervention to start another pump based on EOP actions, risk of the event would be further reduced.

Issue - c (Dual Unit Issue) Two of Three Emergency Diesel Generators Technically Inoperable

This issue involved the discovery that with Unit 1 at 100% power and the Unit 2 in cold shutdown two of the three EDGs were found to be technically inoperable. Plant design has EDG#1 dedicated to Unit 1 and EDG#2 dedicated to Unit 2 with EDG#3 being a swing diesel that will supply power to one or the other troubled units. EDG#2 had been removed from service for maintenance three days before it was discovered that one of the two fuel oil transfer pumps for EDG#3 was erroneously tagged shut when EDG#2 was taken out of service. EDG#3 was considered inoperable because a single failure could have resulted in the loss of the ability to supply fuel oil to the limited capacity day tank and therefore, sustain EDG operations was not assured.

When the staff asked the screening questions listed in step 1.2, the item was considered of low risk consequence because there was no loss of redundancy other than the allowed outage of EDG#2. EGD#3 was in fact operable, and therefore, the item did not pass through the screen. Therefore, no further review was performed. This event would be considered green as to risk significance.

Issue d. -

Suggested Regulatory Information Conference Questions

1. What do you expect to learn from the pilot plant studies?

2. Previous NRC assessment approaches have resulted in plants being placed on the "Watchlist" with little or no warning. How will the revised process provide earlier warning of a plant that needs increased attention?

3. The cornerstones appear to weighted equally in the process, yet, some cornerstones are more important than others in terms of public health and safety. How will the assessment roll-up account for this?

4. What will this process mean for my future as an NRC employee? Is this process just a reaction to fiscal pressures from Congress?

5. When will licensee self assessments be credited as a further substitute or reduction to the baseline inspection program?

6. What do you see as the future role of the NRC Regional Offices under this revised approach?

7. How will Chairman Jackson's departure in June affect this process?

8. How has all the effort the industry and NRC put into the maintenance rule being factored into this process?

9. At the September workshops there was a lot of discussion about the "rebuttable presumption" concept where it would take considerable inspection findings to overturn the PIs. How will NRC management ensure that inspection does not default to a lead role in the process based on a lot of insignificant inspection findings?

10. This process is reported to be risk-informed. Are utility PRAs sufficient to implement this process?

11. Manual scrams are not counted in the WANO indicator based on concerns for inhibiting operator actions. Why does the proposed indicator include manual scrams?

12. The green-white thresholds are set at a level that is significantly above regulatory requirements. What is INPOs role in the new process if the NRC is monitoring performance well above standards?

13. This process appears to place a lot of responsibility on the Resident Inspectors. When and how much training will the Resident Inspectors get to be able to implement this process?

14. How will enforcement be revised to be consistent with the risk-informed thresholds set for PIs and inspection findings?

15. The SECY acknowledges elimination of N+1 residents for multi-unit sites with high performance. What about single unit sites? Can the single unit sites also expect some inspection reduction based on performance? Could the second resident inspector be assigned some other duties (e.g., assist PM in licensing reviews)?

16. How will the assessment process accommodate a momentary red or yellow input that is restored quickly?

17. How will the overall performance results be communicated – colors? Numbers? Or just words?

18. Will the assessment report be based on the latest quarters worth of PIs and inspection findings or will it reflect earlier performance over the evaluation period?

19. What if a plant has one white PI or inspection finding each quarter, but all in different cornerstones? How would the assessment be characterized and reported?

NRC Proposed Plant Assessment Process
Questions and Comments

#	Loc:	Section	OH#	P/I	Question or Comment
1	A	P/I		Scrams	Why count manual scrams?
2	A	P/I			How do P/I results on one unit affect dual unit sites?
3	A	P/I		RS Scrams	Is retrofit of data required?
4	A, D	P/I		Transients	Weekend criteria are confusing. Clarification required.
5	A	P/I		SSPI	Does this reflect the Maintenance Rule in regard to numbers Of systems?
6	A	P/I		SSPI	Will the process consider EPIX reporting requirements?
7	A	P/I			Links to other processes need to be identified and documented.
8	A	P/I		SSPI	There are discontinuities between the WANO and NRC performance indicators.
9	A	P/I		SSPI	A consistent definition of unavailability is needed.
10	A	P/I		SSPI	The EDG P/I is not consistent with the extended out of service times in some Licensees Technical Specifications.
11	A	P/I		SSF	There is disagreement with the current method of classifying SSFs. An example of this is the amount of time considered when a failure is classified.
12	A	P/I			Is data reported monthly or quarterly?
13	A	P/I		RCS leak	Why is the green / white at 50% TS when containment leakage is at 100% TS?
14	A, D	P/I			What is the time frame required to be considered when a failure is identified?
15	A	P/I		ERO DEP	What is an evaluated drill? Do we have to count all training?
16	A	P/I		ERO DEP	Do all the measurable areas count towards the 75%?
17	A	P/I		Security	Compensatory measures are capable of meeting the intended function of the security equipment.
18	A	P/I		Security	Does the security equipment performance P/I deviate from the mission of protecting the health and safety of the general public?
19	A	P/I		Security	The SECY 99-007 has inconsistencies related to the security equipment P/I.
20	A	P/I		Security	He definition of protected area security equipment includes all components. The use of the word all in this context raises the concern that insignificant components may be considered.
21	A	P/I			We need to avoid the inclusion of P/Is just because they can be easily met.
22	A	P/I		Security	Do we need to consider the potential effect of making public information concerning the health of security systems at Nuclear power generating stations?
23	A	P/I	59	Security	The personnel screening process P/I may create some perverse consequences due to different thresholds at various plants.
24	A	P/I	65		Is there an effort to reduce reporting requirements?
25	A	P/I	11	RS Scrams	RS Scrams appear to be too prescriptive. Was the use of ASP considered?
26	A	P/I	66		Find out the frequency of the FEMA report related to reporting the status of ERO Alert and notification systems.
27	A	Inspect	12		Will the RIMs be public documents?
28	A	Inspect	12		Will the RIMs be ready in time for the pilot plants?
29	A	Inspect	17		Would the significance of findings concept be applied to all conditions? Example; would it be applied to planned maintenance configurations?
30	A	Inspect	19		If a plant requires other inspections beyond the RIBLI, where will the inspectors come from?
31	A	Inspect	19		During the pilots it will be very important to validate the number of inspection hours required to perform the RIBLI.
32	A	Inspect	19		The determination of the impact of inspection on the ability of the cornerstone to meet its objectives appears to be the remaining subjective piece of the process.
33	A	Inspect	19		Is the inspection significance assessment process expected to be part of the pilot

.					process?
34	A, D	Inspect	19		What happened to the cross cutting issues?
35	A	Assess			How does the NRC plan on performing all assessments simultaneously?
36	A, D	Assess			Will the 6-week inspection reports continue?
37	A	Assess			Will the PIM data still be sent to the licensee?
38	A, D	Assess			Is the PIM under development?
39	A, D	Assess	10		Will the annual assessment have a number, or color, or letter rating?
40	A	Assess	10		Why are there subtle differences in language between licensee action in columns II and III?
41	A, D	Assess	10		Is there going to be clear definitions regarding the difference between corrective action and self-assessment? What is the role of self-assessment in this process?
42	A	Assess	13		How often will the assessment be reported?
44	A, D	Assess	13		How will the corrective action program be assessed? Will it be risk based?
45	A	Assess	13		Will there be there be credit for self-identification?
46	A	Assess	13		Will there be a difference between how the process is implemented during extended outages verses normal plant operations?
47	A	Assess	13		Does the Initiating events cornerstone attribute chart represent a report card matrix for the cornerstone?
48	A	Assess	13		Will INPO change any of their processes to reflect this process?
49	A, D	Enf.	10		The criteria that propose to issue a NOV in instances where there is a failure to place an item in the corrective action system appears to be very subjective.
50	A	Enf.	10		How will the NRC disposition the results of corrective action system assessments?
51	A	Trans.	11		Will the pilot process be conducted with N or N+1 inspectors?
52	A, D	Trans.	14		There is a lot of work remaining to develop the P/I manual. The manual design needs to ensure consistency.
53	A	Trans.	18		Is the NRC still interested in certification of PRAs?
54	A	Trans.	18		The NRC has not embraced the PRA certification process.
55	A	Trans.	18		Has the NRC requested a standard process for corrective actions?
56	A	P/I		Scrams	This measurement should be moved to transients.
57	A	P/I		Security	Do pre-employment failures count?
58	A, D	P/I	6		Will there be future development of the thresholds based on plant specific PRAs?
59	D	Over	10		Are there different levels of significance of the cornerstones?
60	D	Inspect			How does the finding significance assessment work? Will it be tied to safety significance?
61	D	P/I	3		Are there separate conceptual risk models for the non-reactor areas?
62	D	P/I	4		What is the extent of the green band and will the thresholds shift as industry performance continues to improve?
63	D	P/I	7	Scrams	How would failure to insert the rods IAW procedure be reflected in the process?
64	D	P/I	8	Scrams	Scrams should be counted as transients this will remove the controversy concerning manual verse automatic.
65	D	P/I	8	Scrams	Why don't we count scrams directed by procedure?
66	D	P/I	13	RS Scrams	This indicator appears to be a potential multiple counting process when coupled with the P/Is for scrams and transients.
67	D	P/I	13	RS Scrams	Is there data available on actual industry performance in this area?
68	D	P/I	13	RS Scrams	The industry should expect NRC additional inspection if one of these events

					occurs.
69	D	P/I	14	Trans.	How will this P/I handle response to weather related events that require plant power reduction? An example of this would be a seaweed intrusion.
70	D	P/I	14	Trans.	This P/I appears to potentially create a negative impact on the commercial decision making responsibility of station management.
71	D	P/I	14	Trans	What is the difference between a load follow transient and a transient required by maintenance related activity?
72	D	P/I	20	SSPI	The RHR portion of the SSPI appears to be inconsistent between reactor types and also with the INPO indicators.
73	D	P/I	22	SSFs	We need a list of the 26 systems monitored by this indicator.
74	D	P/I	30	RCS leak	Is the P/I based on total leakage, and what is the green to white threshold based on?
75	D	P/I	33	Cont.	If we meet the TS requirements why do we need this indicator?
76	D	P/I	33	Cont.	Why don't we look at the active containment mitigation systems?
77	D	P/I	37	ERO	Is this negative reinforcement for implementation of less stringent critiques?
78	D	P/I	37	ERO	The SECY document refers to timely and accurate notification, this requires more definition.
79	D	P/I	37	ERO	If you watch your indicators in this area you can be successful in improving your performance.
80	D	P/I	39	ERO	This indicator does not appear to drive us in the right direction. What are we trying to accomplish? The P/I needs more definition.
81	D	P/I	45	RAD	The occupational exposure control P/I criteria needs more definition in regard to what constitutes the various elements of the indicator.
82	D	P/I	51	RAD	The offsite release P/I is the single most problematic area, based on plant design. Can we move to a percentage-based indicator?
83	D	P/I	55	Sec.	In the security equipment performance areas are weather-related events considered?
84	D	P/I			Are the near term P/Is still being worked?
85	D	P/I		RCS leak	This indicator may create unintended consequences because it cuts in half the perceived permissible RCS leakrate.
86	D	Inspect.	11		How is the RIM risk based?
87	D	Inspect.	13		What is the relationship between RIM 1 and RIM 2?
88	D	Inspect.	14		What is going to happen to the inspection module set?
89	D	Inspect.	15		What is the difference in direct inspection hours for the specific inspection areas?
90	D	Inspect.			Will the inspection process changes affect the current operator training inspection program?
91	D	Enf.			Do civil penalties have any impact?
92	D	Enf.	10		Is there a thought to eliminate the failure to abate the cause of the violation?
93	D	Trans.			Why only run the pilots for 6 months?

NUCLEAR ENERGY INSTITUTE
INDUSTRY CALENDAR

1999

January 5-8, 1999
EEI CEO Committee Meetings
EEI Board of Directors Meeting
EEI CEO Conference
Scottsdale Princess Hotel
Scottsdale, AZ
Tony Anthony (202) 508-5454

January 7, 1999
NEI Governmental Affairs Advisory Committee
(In conjunction with EEI CEO Conf)
Scottsdale Princess Hotel, Salon C
Scottsdale, Arizona

January 19-20, 1999
INPO Board of Directors
INPO Council meetings
Atlanta, GA

January 21, 1999
NEI Executive Committee
Waldorf Astoria
New York, NY
(Jan 22 Financial Analyst Briefing)

January 24-27th, 1999
Health Physics Society Symposium '99
Albuquerque, New Mexico. USA
Contact: Mr. J.M. Hylko F: (505) 837-6870
email:jhylko@msn.com
website: www.tli.org/rgctitle.htm

January 25-27, 1999
InfoCast Conference
"Opportunities in the Competitive
Nuclear Power Industry"
Washington, DC
Contact: Claire Schoor (818)902-5405x36

January 24-27, 1999
Health Physics Society Symposium '99
Albuquerque, New Mexico
Contact: J.M. Hylko
Fax: 505-837-6870
email: jhylko@msn.com

January 27, 1999
NEI Nuclear Fuel Supply Forum
Omni Shoreham
Washington, DC

February 7-10 1999
PIME '99: 11th International Workshops on Nuclear
Public Information in Practice
Avignon, France.
European Nuclear Society. Contact: Iris Riesen.
Tel: 41-31-320-61-11
E-mail:iris.riesen@to.aey.ch

February 8-9th, 1999
CNA Nuclear Industry Winter Seminar
Ottawa, Ontario.
Ms. Sylvie Caron - CNA/CNS Office
144 Front Street West, Suite 475
Toronto, Ontario. M5J 2L7, Canada
Tel: (416) 977-6152 x 18
Fax: (416) 979-8356
email:carons@cna.ca

February 10, 1999
NEI Strategic Issues Advisory Committee
The Wyndham
Washington, DC

February 18, 1999
NEI Communications Advisory Committee
NEI Office
Washington, DC

February 21-24, 1999
NEI Energy Info Centers
Sheraton West Palm Beach
West Palm Beach, FL

March 4-5, 1999
NRC Regulatory Information Conference
The Capital Hilton

March 16-17, 1999
INPO Annual Meeting
INPO Board of Directors Meeting
Committee Meetings
Atlanta, GA

March 24-25, 1999
EEI CEO Committee Meetings
EEI Board of Directors
EEI CEO/Governmental Affairs Conference
Willard Hotel
Washington, DC
Tony Anthony (202) 508-5454

March 25, 1999
NEI Governmental Affairs Advisory Committee
(In conjunction with EEI CEO/Govt. Affairs Conf)
Willard Hotel
Washington, DC

March 30, 1999
NEI Executive Committee
12-3 pm NEI Offices
Washington, DC

April 6-8, 1999
American Power Conference
Marriott Downtown Chicago
Sponsored by the Illinois
Institute of Technology in Chicago
Bob Porter: Phone (312) 567-3196;
Email: apc@iit.edu

April 11-14, 1999
NEI Fuel Cycle
Austin Renaissance
Austin, TX

April 12-14, 1999
JAIF Annual Conference

April 13-14, 1999
EPRI Board of Directors & Committee
Four Seasons Hotel
Washington, DC

April 15, 1999
NEI Strategic Issues Steering Group
NEI Offices
Washington, DC

April 18, 1999
International Conference on
Nuclear Engineering (ICONE-7)
Tokyo

April 20-22, 1999
Electric Power 99
Sponsored by: POWER
Baltimore Convention Center
Baltimore, MD
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April 26-29, 1999
3rd International Exhibition on Nuclear
Power Industry
Sanghai Mart, China
Tel 852-2827-6766
email: general@coastal.com.hk

May 2-5, 1999
NEI Fire Protection Info Forum
Cleveland Rennaissance
Cleveland, OH

May 11-12, 1999
INPO Board of Directors Meeting
Advisory Council Meeting
Atlanta, GA

May 17-19, 1999
International Symposium on Mox Fuel Cycle
Technologies for Medium and Long Term
Deployment: Experience, Advance, Trends
IAEA contact: P (+43) - 1 - 2600 (0) plus extension
F (+43) - 1 - 2600 7
EMail: Official.Mail@iaea.org
web: www.iaea.org

May 19-21, 1999
NEI Nuclear Energy Assembly
Monarch Hotel
Washington, D.C.
Lisa Steward (202) 739-8006

May 19, 1999
NEI Executive Committee
In conjunction with the Nuclear Energy Assembly
Monarch Hotel
Washington, DC
Lisa Steward (202) 739-8006

May 19, 1999
NEI Communications Advisory Committee
In conjunction with the Nuclear Energy Assembly
Monarch Hotel
Washington, DC
Lisa Steward (202) 739-8006

May 19, 1999
NEI Strategic Issues Advisory Committee
In conjunction with the Nuclear Energy Assembly
Monarch Hotel
Washington, DC

May 20, 1999
NEI Governmental Affairs Advisory Committee
(In conjunction with Nuclear Energy Assembly)
Monarch Hotel
Washington, DC

May 21, 1999
NEI Board of Directors
In conjunction with the Nuclear Energy Assembly
Monarch Hotel
Washington, DC

May 30th - June 2, 1999
CNA / CNS Annual Conference
Montreal, Quebec.
Ms. Sylvie Caron, CNA/CNS Office
144 Front Street West, Suite 475
Toronto, Ontario. M5J 2L7, Canada
Tel: (416) 977-6152 x 18
F: (416) 979-8356
email:carons@cna.ca

June 6-10, 1999
ANS Annual Meeting
Boston, MA

June 7-8, 1999
NEI Emergency Planning Forum
Don CeSar Hotel
Saint Petersburg Beach, FL

June 13-15, 1999
EEI CEO Committee Meetings
EEI Board of Directors Meeting
Convention/Expo Ctr
Long Beach, CA
Tony Anthony (202) 508-5454

June 14-18, 1999
International Conference on the Strenghtening of Strenthening of Nuclear Safety in Eastern Europe
IAEA contact: P (+43) - 1 - 2600 (0)
F (+43) - 1 - 2600 7
EMail: Official.Mail@iaea.org
web: www.iaea.org

June 20-23, 1999
NEI - Health Physics
Indian River Plantation
Stuart, FL

July 14, 1999
INPO Board of Directors Meeting
Atlanta, GA
July 20, 1999
NEI Executive Committee
NEI Offices
Washington, DC

July 28, 1999
Nuclear Fuel Supply Forum
Willard Hotel
Washington, DC

August 10-11, 1999
EPRI Board of Directors & Committees
Coronado Island Marriott Resort
Coronado, CA

August 28, 1999
NEI Strategic Issues Steering Group
NEI Offices
Washington, DC

August 30 - Sept 3, 1999
International Symposium on Technologies for the Management of radioactive Waste from Nuclear Power Plants and Back-end Nuclear Fuel Cycles Activities
IAEA contact: P (+43) - 1 - 2600 (0)
F (+43) - 1 - 2600 7
email: Official.Mail@iaea.org
web: www.iaea.org

September 7-9, 1999
EEI Chief Executive Conference
Broadmoor
Colorado Springs, CO

September 8-10, 1999
Uranium Institute 24th Annual Symposium
London, UK
Contact: 44-171-225-0303
Fax: 44-171-225-1308

September 14-15, 1999
INPO Board Meeting
Advisory Council Meeting
INPO Nominating Committee
Atlanta, GA

September 19-21, 1999
WANO Biennial General meeting
Empress Hotel and Victoria Conference Center
Victoria, BC, Canada

September 26-29, 1999
NEI Info 99/Crisis Comm Workshop
San Antonio, TX

September 30, 1999
NEI Governmental Affairs
9:30-11:30 am
NEI Offices
Washington, DC

September 30, 1999
NEI Executive Committee
12:00-3:00pm
NEI Offices
Washington, DC

October 3-6, 1999
NEI International Uranium Fuel Seminar
The Sagamore on Lake George
Bolton Landing, New York

October 17-20, 1999
EEI Financial Conference
Disney Dolphin
Lake Buena Vista, FL
Tony Anthony (202) 508-5454

October 21, 1999
NEI Strategic Issues Advisory Committee
Washington, DC

October 17-22, 1999
NEI Fundamentals of Nuclear Communication - Training Seminar
Bethesda Hyatt
Bethesda, MD

October 18-21, 1999
NEI Decommissioning Forum
Marriot at Sable Oaks
Portland, ME

October 18-21, 1999
NEI Fire Protection Workshop
Don CeSar Hotel
Saint Petersburg Beach, FL

October 19-22, 1999
International Conference on Irradiation to Ensure Safety and Quality of Food
Marrakesh, Morocco
IAEA contact: P (+43) - 1 - 2600 (0)
F (+43) - 1 - 2600 7
email: Official.Mail@iaea.org
web: www.iaea.org

October 28, 1999
NEI Communications Advisory Committee
NEI Office
Washington, DC

November 3-5, 1999
INPO Board of Directors/CEO Meeting
Atlanta, GA

November 10-12, 1999
INPO CEO Conference
INPO Board of Directors
Atlanta, GA

November 14 - 18th, 1999
ANS Winter Meeting
Long Beach, California
Contact: ANS Office
555 N. Kensington Avenue
La Grange Park, Ills. 60526
Tel: (708) 579-8258

November 16, 1999
NEI Executive Committee
NEI Office
Washington, DC

December 8, 1999
NEI Strategic Issues Steering Group
Washington, DC

2000

January 4-5, 2000
INPO Advisory Council Meeting
INPO Personnel Development & Comp Mtg
INPO Board of Directors Meeting
Atlanta, GA

January 12-14, 2000
EEI CEO Conference
EEI Board of Directors meeting
EEI CEO Committee Meetings
Ritz Carlton, Rancho Mirage, CA

Tony Anthony (202) 508-5454

January 19, 2000
NEI Nuclear Fuel Supply Forum
The Peabody Memphis
Memphis, TN

February 29, 2000
INPO Audit Committee Meeting
INPO Investment Review Committee Meeting
Atlanta, GA

March 1, 2000
INPO Annual Meeting
INPO Board of Directors Meeting
WANO-AC Governing Board Meeting
Atlanta, GA

April 2-5, 2000
NEI Fuel Cycle 2000
The Peabody Memphis
Memphis, TN

May 8-9, 2000
NRC Regulatory Information Conference

May 9-10, 2000
INPO Advisory Council Meeting
INPO Board of Directors Meeting
Atlanta, GA

June 18-21, 2000
EEI Convention
Palais des Contres
Montreal, Canada

July 12, 2000
INPO Board of Directors
Atlanta, GA

September 5-7, 2000
EEI CEO Committee meetings
EEI Board of Directors Meeting
Renaissance Chicago Hotel
Chicago, IL
Tony Anthony (202) 508-5454

September 12-13, 2000
INPO Advisory Council Meeting
INPO Nominating Committee
INPO Board of Directors Meeting
WANO-AC Governing Board Meeting
Atlanta, GA

September 24-27, 2000
NEI International Uranium Fuel Seminar
Resort at Squaw Creek
Olympic Valley, CA

October 29 -Nov 1, 1999
EEI Financial Conference
San Francisco Hilton
San Francisco, CA
Tony Anthony (202) 508-5454

October 31, 2000
INPO Board of Directors Meeting
Atlanta, GA

November 2-3, 2000
INPO CEO Conference
Atlanta, GA

2001

January 12-14, 2001
EEI Chief Executive Conference
Westin La Paloma
Tucson, AZ

April 1-4, 2001
NEI Fuel Cycle
Grand Hyatt San Francisco
San Francisco, CA

June 3-6, 2001
EEI Convention/Expos
Hyatt Regency
New Orleans, LA

2002

January 9-11, 2002
EEI Chief Executive Conference
Scottsdale Princess Hotel
Scottdale, AZ

2003

January 8-10, 2003
EEI Chief Executive Conference
Ritz Carlton
Naples, FL

DESCRIPTION OF ACRONYMS

ACORD	American Committee on Radwaste Disposal
AECL	Atomic Energy of Canada Limited
AEIC	Association of Edison Illuminating Companies
ANS	American Nuclear Society
APPA	American Public Power Association
CIP	Congressional Information Program
CNS	Canadian Nuclear Society
EEI	Edison Electric Institute
EIC	Electric Information Council
ENS	European Nuclear Society
EPRI	Electric Power Research Institute
GNS	German Nuclear Society
IAEA	International Atomic Energy Association
INPO	Institute of Nuclear Power Operations
NEI	Nuclear Energy Institute
NARUC	Nuclear Association of Regulatory Utility Commissioners
NERC	North American Electric Reliability Council
NRC	U.S. Nuclear Regulatory Commission
NRECA	National Rural Electric Cooperative Association
NUFCOR	Nuclear Fuels Corporation of South Africa
SEE	Southeastern Electric Exchange
SNE	Spanish Nuclear Society
WANO	World Association of Nuclear Operators

PERFORMANCE INDICATOR PILOT PROGRAM REPORTING MANUAL

February 1999

Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission

Performance Indicator Pilot Program Reporting Manual

1. Introduction

The purpose of this manual is to provide guidance to reactor licensees for reporting the data necessary to support the NRC's performance assessment pilot program. This program has been developed through a cooperative effort among the NRC, the Nuclear Energy Institute, the public, and other stakeholders during a series of public meetings. Performance indicators have been selected to monitor licensee performance in certain areas. Thresholds have been established for these indicators to provide clear boundaries between fully acceptable, declining, and unacceptable levels of performance. (For a detailed description of how the thresholds were established, see the appropriate appendix to Attachment 2 of SECY-99-007, "Recommendations for Reactor Oversight Process Improvements.) The purpose of the pilot program is to determine whether the performance idnicators and their associated thresholds are appropriate for their intended use.

2. General Reporting Guidance

Licensees participating in the pilot program will continue to submit reports in accordance with 10 CFR 50.72 and 50.73. Any such reports involving a cornerstone performance indicator should clearly identify the name of the indicator and the cornerstone to which it applies. Some events, such as safety system failures, may require engineering analysis to determine if they are reportable. In these cases, it is best to make a timely, conservative decision regarding reportability, followed by a more thorough analysis. If it can be established that an event that has been reported is not required to be reported, licensees should retract the report by the same method used to send in the original report; that is, if the report was phoned in to the NRC, it should be retracted by a phone call rather than by a letter.

During the pilot program, participating licensees should compile the cornerstone performance indicator data described in this manual on a monthly basis and submit the data electronically within 10 days of the end of each month in the format described in Appendix A. Each monthly report should include the plant name and the date of the report. For each indicator that was reported in accordance with 10 CFR 50.72 and/or 50.73, include the applicable 50.72 event number and/or the LER number. Those indicators for which data are only available periodically (e.g., containment leakage or emergency response organization drill/exercise performance) need be reported only for those months when new data become available.

3. Cornerstone Performance Indicator Data Reporting Guidance

This section describes the cornerstone performance indicators and the data that should be reported monthly for each of them.

(Performance Indicator Pilot Program Reporting Manual)

missing backside-

0.80, which is the current industry average. This ensures that periods when the reactor was shut down are excluded from the calculation.

- Critical means that the effective multiplication factor (k_{eff}) of the reactor at the time of the scram was essentially equal to one.

Data Elements: The following data are required to calculate this indicator:

- the number of automatic scrams while critical in the last 12 months
- the number of manual scrams while critical in the last 12 months
- the number of hours of critical operation in the last 12 months

Calculation: The unit and industry average values for this indicator are determined as follows:

- unit value = $\dfrac{\text{(total manual and automatic scrams while critical) x 7,000}}{\text{(number of critical hours)}}$

- industry average = $\dfrac{\text{(total of industry automatic and manual scrams) x 7,000}}{\text{(total of industry critical hours) x (number of operating plants)}}$

Thresholds: The following thresholds have been established for this indicator:

- Increased Regulatory Response (green-white) threshold -- 3
- Required Regulatory Response (white-yellow) threshold -- 6
- Unacceptable Performance (yellow-red) threshold -- 25

Data Qualification Requirements: Because rate indicators can produce misleadingly high values when the denominator is small, this performance indicator will not be calculated when there are fewer than 2,400 critical hours in the last 12 months. Instead, performance will be assessed through supplemental inspection.

Data Reporting Requirements: The following data should be reported by licensees monthly:

- the number of automatic scrams in the last month
- the number of manual scrams in the last month
- the number of critical hours in the last month
- the indicator value for the last 12 months (if there are fewer than 2,400 critical hours in the last 12 months, report the indicator as N/A)

- Fluctuations are transitory changes in reactor power that occur in response to changes in reactor or plant conditions. Unplanned fluctuations are those that are not an expected part of a planned evolution or test.

- The transient rate is calculated per 7,000 critical hours because that value is representative of the critical hours of operation in a year for most plants, i.e., an availability factor of 0.80, which is the current industry average. This ensures that periods of reactor shutdown are excluded from the calculation.

Data Elements: The following data are required to calculate this indicator:

- the number of transients in the last 12 months

- the number of hours of critical operation in the last 12 months

Calculation: The unit and industry average values for this indicator are determined as follows:

- unit value $= \dfrac{\text{(number of transients) x 7,000}}{\text{(number of critical hours)}}$

- industry average $= \dfrac{\text{(total of industry transients) x 7,000}}{\text{(total of industry critical hours) x (number of operating plants)}}$

Threshold: The following threshold has been established for this indicator. No Required Regulatory Response or Unacceptable Performance thresholds have been established because this indicator is not related to risk.

- Increased Regulatory Response (green-white) threshold -- 8

Data Qualification Requirements: Because rate indicators can produce misleadingly high values when the denominator is small, this performance indicator will not be calculated when there are fewer than 2,400 critical hours in the last 12 months. Instead, performance will be assessed through supplemental inspection.

Data Reporting Requirements: The following data should be reported by licensees monthly:

- the number of transients in the last month

- the number of critical hours in the last month

- the indicator value for the last 12 months (if there are fewer than 2,400 critical hours in the last 12 months, report the indicator as N/A)

Radiation Monitoring Instrumentation	Residual Heat Removal Systems
Reactor Coolant System	Safety Valves
Reactor Core Isolation Cooling System	Spent Fuel Systems
Reactor Trip System and Instrumentation	Standby Liquid Control System
Recirc. Pump Trip Actuation Instrument.	Ultimate Heat Sink

Attributes of Licensee Performance: The following attributes of licensee performance are monitored by this indicator:

- the availability and reliability of the monitored SSCs
- the adequacy of maintenance and test procedures for those SSCs
- the performance of plant personnel in maintaining the capability of the SSCs to fulfill their safety functions

Definition: The number of actual or potential failures of the safety function of the monitored SSCs during the past year.

- Actual failures are those that occur upon a valid demand during operation or test. They do not include those that occur during post-maintenance testing before the SSC is declared operable and returned to service.
- Potential failures include those that could have occurred upon a valid demand for the SSC to perform its safety function assuming the necessary conditions were in place to cause the potential SSC failure to occur. For example, a safety system failure would be counted if a component was found to be environmentally unqualified so that, should a high energy line break occur in the worst-case location, the component could fail, which would render the system incapable of performing its safety function.
- The safety function of an SSC includes any function(s) for which credit was taken in any accident analysis.

Data Elements: The following data are required to calculate this indicator:

- the number of safety system failures in the last 12 months

Calculation: The unit and industry average values for this indicator are calculated as follows:

- unit value = the number of safety system failures
- industry average $= \dfrac{\text{(total of industry safety system failures)}}{\text{(number of operating plants)}}$

- Events involving the loss of one mode of operation of an SSC are considered to be safety system failures if the loss of that mode affects the system's ability to complete the safety function. For example, an event in which the ability to manually start the high-pressure coolant injection system is lost would be a failure even if the system could be started automatically. The loss of manual speed control of the same system, however, would not be a failure as long as the required flow rate could still attained.

- When multiple occurrences of an SSC failure occur, the determination of the number of failures to be counted will depend upon whether the SSC was declared to be operable between occurrences. If the licensee knew that a problem existed, tried to correct it, and considered the system to be operable, but the system was subsequently found to have been inoperable the entire time, multiple failures will be counted. But if the plant knew that a potential problem existed and declared the system inoperable, subsequent failures of the SSC for the same problem would not be counted as long as the system was not declared operable in the interim. Similarly, in situations where the licensee did not realize that a problem existed (and thus could not have intentionally declared the system inoperable or corrected the problem), only one failure is counted.

- A failure leading to an evaluation in which additional failures are found is only counted as on failure; new problems found during the evaluation are not counted, even if the causes or failure modes are different. The intent is to not count additional events when problems are discovered while resolving the original problem.

- Train failures are not counted as safety system failures as long as a completely redundant train of the same system is capable of performing the safety function. (Note that one consequence of this rule is that failures of single train systems are counted as safety system failures.)

- When a potential failure by an identified mechanism (i.e., not a random single failure) could incapacitate an SSC (all trains of the system), a safety system failure is counted. That is, if it is discovered that "redundant" trains rely on a single component or are unintentionally or incorrectly cross-connected, and a mechanism is found that could incapacitate all trains, a safety system failure is counted.

- When a single train fails while the other train is inoperable for maintenance, resulting in both trains being simultaneously inoperable, a safety system failure is counted. Similarly, when a problem affecting one train is identified, and it is determined that the other train was inoperable for any reason (including surveillance testing) during the time the problem existed, a safety system failure is counted.

- In the absence of an identified potential failure mechanism, it is not necessary to consider a single random failure. Licensees are not required to satisfy the single failure criterion for purposes of determination of a safety system failure. That is, events involving only a single train of a multi-train system are not counted as safety system failures as long as the other train always remained operable.

- Conditions in which missile shields are determined to be inadequate (for example, the turbine building walls may not be able to withstand a tornado generated missile) are not necessarily safety system failures. Such conditions should be analyzed for reporting as a failure.

3.3 Barrier Integrity Cornerstone

Reactor Coolant System (RCS) Activity

Purpose: This indicator monitors the integrity of the fuel cladding, the first of the three barriers to the release of fission products. It measures the radioactivity in the fuel as an indication of functionality of the cladding.

Attributes of Licensee performance: The following attributes of licensee performance are monitored by this indicator:

- the adequacy of the design control of fuel pins and assemblies and the nuclear core through physics testing

- the performance of plant personnel in minimizing challenges to the integrity of the fuel cladding

- the adequacy of procedures that direct activities that have the potential to affect fuel cladding integrity

- the adequacy of configuration control programs for handling, storing, and positioning nuclear fuel, for maintaining proper control rod patterns, and for maintaining proper RCS water chemistry

- the performance (integrity) of the fuel cladding

Definition: The maximum RCS activity each month as calculated per technical specifications.

Data Elements: The following data are required to calculate this indicator:

- All RCS activity calculations for the last month

Calculation: The unit and industry average values for this indicator are calculated as follows:

- unit value = the maximum value of calculated activity

- industry average $= \dfrac{\text{(total of industry unit values)}}{\text{(number of operating plants)}}$

- Required Regulatory Response (white-yellow) threshold -- 100 percent of the technical specification limit

Data Reporting Requirements: The following data should be reported by licensees monthly:

- the maximum value of the calculated RCS leakage in the last month

Containment Leakage

Purpose: This indicator monitors the integrity of the containment, the third of the three barriers to the release of fission products. It measures containment leakage as a percentage of the technical specification allowable leakage to provide an indication of containment integrity.

Attributes of Licensee performance: The following attributes of licensee performance are monitored by this indicator:

- the originally designed containment structural integrity and operational capability
- the performance (integrity) of the containment barrier

Definition: The estimated "as found" integrated leak rate for the containment as a fraction of the design basis leak rate (L_a).

- The "as found" leak rate is the result of the latest integrated leak rate test modified by the results of subsequent local leak rate tests.
- Type C tests should be performed at the beginning of each refueling outage to reflect the leak rate that existed during the previous cycle.

Data Elements: The following data are required to calculate this indicator:

- the result of the latest integrated leak rate test
- the results of subsequent local leak rate tests
- the design basis leak rate, L_a

Calculation: The unit and industry average values for this indicator are calculated as follows:

- unit value = $\dfrac{(\text{"as found" leakage})}{L_a}$

  where the "as found" leakage is the result of the latest integrated leak rate test modified by the results of subsequent local leak rate tests

DRAFT 2/10/99

INSPECTION NON-CONFORMANCE EVALUATION MATRIX

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

Key Attributes	OBSERVATION	FINDING	SIGNIFICANT FINDING
	NRC-Identified non-conformance that has little or no immediate impact on EP capability.	NRC or licensee identified non-conformance that, if left uncorrected, compromises EP capability.	NRC or licensee identified non-conformance that, if left uncorrected, would significantly challenge EP capability.

INSPECTION NON-CONFORMANCE EVALUATION MATRIX

ERO Readiness	• individuals fail augmentation test • duty roster qualification lapses • problem ID and resolution program failure	• failure to meet or implement a planning standard (other than the risk significant planning standards) e.g., 50.47 (b) 1,2,3,6,7,8,11,12,13,14,15, & 16 Examples: failure to conduct required drills CR, TSC or EOF can not be activated IAW Plan due to augmentation test failures or lack of qualified personnel failure to staff CR, TSC or EOF during an actual event • failure to conduct 50.54(t) audit • systematic failure of problem ID and resolution program	• failure to meet or implement a risk significant planning standard e.g., 50.47 (b) 4,5,9, & 10 Examples: ERO is unable to (e.g., as during an actual emergency) classify emergency conditions, perform notifications, perform assessment actions or implement PAR procedures. • ongoing failure of problem ID and resolution program

INSPECTION NON-CONFORMANCE EVALUATION MATRIX

Facilities and Equipment	• missed surveillance • equipment not IAW Plan • communications channels not IAW Plan • ANS surveillance missed • problem ID and resolution program failure	• failure to meet or implement a planning standard (other than the risk significant planning standards) e.g., 50.47 (b) 1,2,3,6,7,8,11,12,13,14,15, & 16 Examples systematic surveillance program lapses equipment or communications channel lapses render CR, TSC or EOF unable to perform functions IAW E Plan ANS testing program does not meet guidance • systematic failure of problem ID and resolution program	• failure to meet or implement a risk significant planning standard e.g., 50.47 (b) 4,5,9, & 10 Examples: degradation of equipment is such that the licensee can not perform assessment activities degradation of equipment is such that the notification functions can not be performed • ongoing failure of problem ID and resolution program

INSPECTION NON-CONFORMANCE EVALUATION MATRIX

Procedure Quality	• EPIP or supporting procedure error • EPIP change not routed to NRC IAW 10 CFR Part 50 Appendix E • superseded revision of EPIP found in ERF • problem ID and resolution program failure	• failure to meet or implement a planning standard (other than the risk significant planning standards) e.g., 50.47 (b) 1,2,3,6,7,8,11,12,13,14,15, & 16 Examples EPIP errors result in failure to activate facility EPIP errors result in failure to augment ERO EPIP errors result in failure in prompt communications among ERFs • EAL or Plan changes not IAW 50.54 (q) • systematic failure of problem ID and resolution program	• failure to meet or implement a risk significant planning standard e.g., 50.47 (b) 4,5,9, & 10 Examples EPIP errors result in failure to notify EPIP errors result in loss of the ability to properly classify emergency conditions • ongoing failure of problem ID and resolution program

INSPECTION NON-CONFORMANCE EVALUATION MATRIX

ERO Performance	• inspector follow up items • failure of the licensee critique to identify poor exercise performance such as: failure to implement a planning standard (other than the risk significant planning standards) prompting exercise participants drill control or scenario problems • problem ID and resolution program failure Please note: areas of poor exercise performance, including failure to implement planning standards, that are identified and corrected by the licensee are below the threshold of an observation. This would include weaknesses.	• failure to meet or implement a planning standard (other than the risk significant planning standards) e.g., 50.47 (b) 1,2,3,6,7,8,11,12,13,14,15, & 16 Examples: failure to conduct required drills Failure in an actual event to activate facilities IAW the E Plan • failure of the licensee critique to identify poor exercise performance such as: failure to implement a risk significant planning standard e.g., 50.47 (b) 4,5,9, & 10 • systematic failure of problem ID and resolution program	• failure to meet or implement a risk significant planning standard e.g., 50.47 (b) 4,5,9, & 10. Examples failure in actual event to perform appropriate and timely classification, notification, assessment or PAR activities Degradation of ERO performance is such that the licensee can not perform classification, notification, assessment or PAR activities • ongoing failure of problem ID and resolution program

INSPECTION NON-CONFORMANCE EVALUATION MATRIX

Offsite EP	• exercise deficiencies	• exercise deficiencies not resolved within 120 days or FEMA specified period	• FEMA withdraws finding of reasonable assurance Please note: this specific significant finding is considered so risk significant that by itself it indicates that a program is in the yellow zone.

Thresholds

Significant Findings

- One significant finding in a biennial (or should this be a two year rolling total?) inspection period - white zone
- Three significant findings in a biennial inspection period - yellow zone

Findings:

- Four findings in a biennial inspection period - white zone
- Eight findings in a biennial inspection period - yellow zone