UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-8064

September 22, 2000

Gregory M. Rueger, Senior Vice
President, Generation and Chief Nuclear Officer
Pacific Gas and Electric Company
Diablo Canyon Power Plant
P.O. Box 3
Avila Beach, CA 93424

SUBJECT: DIABLO CANYON SUPPLEMENTAL INSPECTION REPORT NO. 50-275/00-13; 50-323/00-13

Dear Mr. Rueger:

On August 24, 2000, the NRC completed a supplemental inspection at your Diablo Canyon Power Plant, Units 1 and 2. The enclosed report presents the results of that inspection. The results were discussed with your staff in an exit meeting on August 24, 2000.

The inspectors examined activities conducted under your license as they relate to safety and to compliance with the Commission's rules and regulations and with the conditions of your license. Within these areas, the inspectors examined a selection of procedures and representative records, observed activities, and conducted interviews with personnel.

The inspectors conducted this supplemental inspection to evaluate your root cause analyses and corrective actions associated with three scrams that had a loss of normal heat removal. These three scrams resulted in a white performance indicator in the Reactor Safety strategic performance area for Unit 2. The inspectors determined that the licensee had performed comprehensive root cause evaluations and implemented appropriate corrective actions for each scram.

In addition to the supplemental inspection, the inspectors evaluated comments in a transcript of a public meeting. Specifically, following a meeting on May 19, 2000, with you and your staff to discuss the safety conscious work environment at Diablo Canyon, NRC had conducted a meeting with members of the public. NRC committed to review the transcript of the meeting and review any comments that might have an impact on safety. Most of the comments had previously been reviewed and resolved; however, statements not reviewed were evaluated and documented in Section 4 of this report.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/NRC/ADAMS/index.html (the Public Electronic Reading Room).

Should you have any questions concerning this inspection, we will be pleased to discuss them with you.

Sincerely,

/RA/

Linda Joy Smith, Chief
Project Branch E
Division of Reactor Projects

Docket Nos.: 50-275
50-323

License Nos.: DPR-80
DPR-82

Enclosure:
NRC Inspection Report No.
50-275/00-13
50-323/00-13

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Only inspection reports to the following:
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NRR Event Tracking System **(IPAS)**
DC Site Secretary **(JWG)**
Dale Thatcher **(DFT)**

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ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket No.:	50-275 50-323
License No.:	DPR-80 DPR-82
Report No.:	50-275/00-13 50-323/00-13
Licensee:	Pacific Gas and Electric Company
Facility:	Diablo Canyon Nuclear Power Plant
Location:	7 ½ miles NW of Avila Beach Avila Beach, California
Dates:	August 21-24, 2000
Inspector:	Gregory A. Pick, Senior Project Engineer
Accompanied By:	Grant F. Larkin, Reactor Engineer
Approved By:	Linda Joy Smith, Chief, Project Branch E

ATTACHMENTS:

Attachment 1: Supplemental Information

Attachment 2: NRC's Revised Reactor Oversight Process

SUMMARY OF FINDINGS

IR 05000275-00-13, IR 05000323-00-13; on 08/21-24/2000; Pacific Gas & Electric Co.; Diablo Canyon Nuclear Power Plant, Units 1 & 2; Supplemental Inspection. No findings identified.

Cornerstone: Mitigating Systems

The inspectors performed a supplemental inspection to examine a change from green to white in the Scrams With Loss of Normal Heat Removal performance indicator. This change in performance resulted from Unit 2 experiencing three scrams with loss of normal heat removal over the previous 12 quarters. Following each event, NRC had evaluated operator response, plant and equipment response, and immediate corrective actions. During this supplemental inspection, performed in accordance with Procedure 95001, the inspectors evaluated the adequacy of the root cause evaluation and long-term corrective actions for each individual event. The inspectors also evaluated the effectiveness of the licensee review into the collective events. The inspectors determined that the licensee had performed comprehensive root cause evaluations and corrective actions for each individual scram and the events collectively.

The licensee determined that one scram occurred because condensate/feedwater flow problems were exacerbated by a control circuit problem (poor design and dirty slide wire) in Valve TCV-23, generator hydrogen cold gas temperature control, combined with throttling Valve CND-2-165, steam jet air ejector outlet isolation. The licensee did not identify a definite root cause for the event initiator. Operators initiated the other two scrams because debris in the circulating water system intake had increased the differential pressure across the traveling screens above the setpoint that required them to be secured prior to being damaged. The licensee determined that the onset of ocean storms, combined with the end of the growing season (peak amounts of marine growth), established conditions that exceeded the ability of the traveling screens to remove the marine growth and remain within acceptable operating parameters. The licensee established plans to upgrade the traveling screens, formalized their process for predicting conditions affecting the ability of the intake components to remove marine growth, and initiated efforts to raise the turbine trip/reactor trip setpoint to optimize withstanding this condition yet conducting an orderly shutdown of the plants.

Because the licensee addressed this issue in an acceptable manner, the white performance associated with the Scrams With Loss of Normal Heat Removal for Unit 2 will only be considered in assessing plant performance for a total of four quarters. This is in accordance with the guidance in IMC 0305, "Operating Reactor Assessment Program."

Report Details

1 Reactor Safety

Mitigating Systems

01 Inspection Scope

This supplemental inspection was performed by the NRC to evaluate a change in the Unit 2 performance indicator for Scram With Loss of Normal Heat Removal. The performance indicator crossed the white threshold in the first quarter of 2000 because Unit 2 had experienced three scrams within the previous 12 quarters. Two of the events resulted from marine debris clogging the circulating water system traveling screens, which would result in a loss of the main condenser.

The third event occurred when operators initiated the other manual scram because of a transient in the condensate/feedwater system in July 1997. These events had previously been reviewed in NRC Inspection Reports 50-275;323/98-21, 50-275;323/99-17 and 50-275;323/97-03. The inspector relied on these reports and new inspection was limited to a review of the adequacy of the root cause analysis and long-term corrective actions as documented in the associated licensee event reports, nonconformance reports, and actions requests.

02 Evaluation of Inspection Requirements

02.01 Problem Identification

a. Determine that the evaluation identifies who (i.e., licensee, self-revealing, or NRC) and under what conditions the issue was identified.

   The inspectors determined that each of these manual scrams resulted from self-revealing events. In each instance, operators took appropriate actions to manually initiate a reactor scram based upon control panel indications, prior to an automatic scram.

b. Determine that the evaluation documents how long the issue existed and prior opportunities for identification.

   The inspectors verified that the licensee event reports and the corresponding nonconformance reports provided a sequence of events. For the events related to loss of the circulating water system traveling screens, the inspectors found that, although previous similar events had occurred, the licensee implemented corrective actions following each event. The corrective actions included improving operator guidance for placing the units in a condition such that marine growth dislodged during storms that might affect operability of the circulating water traveling screens would not result in an unplanned scram. Also the inspectors determined that the licensee had continued to make improvements in the ability of the circulating water traveling screens to remove debris.

c. Determine that the evaluation documents the plant-specific risk consequences (as applicable) and compliance concerns associated with the issue.

The inspectors determined that the probabilistic safety assessment group had estimated the core damage frequency and the conditional core damage probability. The contribution to core damage frequency and the conditional core damage probability for a reactor scram with loss of normal heat removal were both on the order of E-7. Each licensee event report identified these reactor scrams with loss of normal heat removal as Condition II events, as described in the Final Safety Analysis Report Update.

02.02 Root Cause and Extent of Condition Evaluation

a. Determine that the problem was evaluated using a systematic method(s) to identify root cause(s) and contributing cause(s).

The inspectors verified that the licensee completed a formal root cause evaluation for each of the events in a systematic manner. The licensee had performed event and causal analyses and generated a flow chart evaluating the various causes.

Although the licensee did not identify an initiator for the feedwater transient, the licensee concluded that the control system for Valve TCV-23 (poor design and dirty slide wire) exacerbated the plant response by causing the valve to throttle more than normal, thereby decreasing flow to feedwater pump suction. In addition, operators had throttled Valve CND-2-165 more than normal, which contributed to the flow instability in the condensate system.

Following the December 1998 manual reactor trip, the licensee identified the primary cause as marine plant growth that overloaded the debris removal capability of the circulating water traveling screens. Several contributing causes included the unavailability of the second of two debris grinders, operators focused on controlling condenser differential pressure and not on curtailing power quickly, a lack of specific operational guidance in the intake management procedure for curtailing the units, and a lack of direction from plant management on the actions for reducing power during stormy weather.

Following the October 1999 dual unit reactor trip, the licensee assessed whether the actions taken were appropriate. The inspectors confirmed that personnel had followed plant procedures and appropriately reduced power to prevent an unscheduled shutdown. The inspectors agreed with the licensee assessment of the event, which concluded that, although the ocean swell height and period were not that significant, a larger than normal amount of marine growth exceeded the ability of the intake to process.

The licensee initiated Action Request A0507000 to evaluate the change from green to white for the Scrams With Loss of Normal Heat Removal performance indicator for Unit 2. The licensee evaluated each of the events to ensure appropriate actions had been identified and implemented. Further, the licensee assessed the need for additional corrective actions to improve performance in this indicator area.

b. Determine that the root cause evaluation was conducted to a level of detail commensurate with the significance of the problem.

The inspectors determined that each event had a detailed analysis and that personnel had performed the root cause to a level of detail commensurate with the significance of the problem.

c. Determine that the root cause evaluation included a consideration of prior occurrences of the problem and knowledge of prior operating experience.

The inspectors reviewed the previous, similar reactor scrams that the licensee described in the licensee event reports. The inspectors verified that corrective actions for the previous feedwater transients had different root causes and, therefore, would not have prevented the feedwater flow transient attributed to Valve TCV-23. As a result of marine growth during storm season exceeding the capability of the circulating water system intake, the licensee had listed manual reactor scrams dating back to 1994. The inspectors verified that the licensee continued to implement hardware upgrades (e.g., rakes on the traveling screens, strengthening the traveling screens, and increasing the traveling screen speed). Further, the licensee continued to improve the guidance provided to the operators for expected actions to take for problems with the intake.

d. Determine that the root cause evaluation included consideration of potential common cause(s) and extent of condition of the problem.

The inspectors verified that the licensee considered common cause and extent of condition by implementing the corrective actions on both units.

02.03 Corrective Actions

a. Determine that appropriate corrective action(s) are specified for each root/contributing cause or that there is an evaluation that no actions are necessary.

For the feedwater transient, the inspectors determined that the licensee established appropriate corrective actions to address each of the identified potential causes. The licensee fully opened Valve CND-2-165 and adjusted the controllers to slow the valve response to system transients. As a long-term corrective action for the “dirty” slide wire, the licensee planned a design change to modify the control system. The licensee had modified the control circuit for Valve TCV-23 in Unit 2 and will complete the modification on Unit 1 in October 2000.

Following the manual scram in December 1998, the inspectors concluded that the licensee implemented appropriate corrective actions, which included:

- Enhanced Procedure OP-28, “Intake Management,” to include lessons learned
- Enhanced expectations for performing tailboards
- Provide operator training on equipment damage mitigation coping strategies

- Evaluate circulating water system indications in the control room

- Develop a policy for determining operator actions following abnormal events

- Ensure the annunciator, abnormal, and intake management procedures provide consistent direction.

For the October 1999 manual scram, the inspectors determined that the licensee had implemented the corrective actions established following the December 1998 event. However, the operators were unable to decrease power quickly enough to prevent the need for a manual reactor scram because of the impending loss of condenser vacuum.

As documented in the evaluation of these three scrams and Action Request A0507000, the licensee continued to identify additional actions in an attempt to ensure operators could shut down the plants in a controlled manner.

- Increased management attention.

  A biofouling control team evaluates ocean swells during storm season (September to March) for their impact on the plant and provides a formalized analysis to the shift manager. The evaluation considers ocean swells (i.e., wave period and height) and marine growth (i.e., low, medium, or high) to identify the potential impact on the units. The licensee determined that the initial storms of the season have the greatest impact because of the large amount of marine growth that will be dislodged from the ocean bottom. The inspectors determined that the volume of water in ocean swells is predictable and is calculated. However, the amount of marine growth is estimated based on prior experience. Operations management will review the information provided by the biofouling control team in order to identify recommendations to the shift manager.

- Prior to each storm season, operators receive “just in time” classroom review of procedures and operational strategies and simulator scenarios for high swell warnings.

- Raising the turbine trip/reactor trip setpoint (P-9) from 15 to 30 percent to optimize the response of the units to the debris in the circulating water system intake and allow operators to effect an orderly shutdown of the units. The inspectors noted that the plant was licensed for a turbine trip/reactor trip setpoint of 50 percent.

- Equipment modifications.

  The licensee developed a modification to increase the power of traveling screen drive motors, which will enable them to function even when heavily loaded with marine growth. Further, the licensee is investigating the feasibility of installing moving bar rack rakes.

b. Determine that the corrective actions have been prioritized with consideration of the risk significance and regulatory compliance.

The licensee immediately placed the unit in a safe condition by manually initiating a reactor scram in each instance because of the impending loss of a normal decay heat removal path. Following each reactor scram, the licensee appropriately restored all equipment and ensured the plant could restart safely. The inspectors concluded that the licensee had appropriately considered risk and regulatory compliance when they established the priorities for the long-term corrective actions for each of the events.

c. Determine that a schedule has been established for implementing and completing the corrective actions.

The licensee scheduled implementation of the corrective actions according to the risk significance of the equipment or problem. The inspectors found the plans for accomplishing the remainder of the open corrective actions satisfactory.

d. Determine that quantitative or qualitative measures of success have been developed for determining the effectiveness of corrective actions to prevent recurrence.

The inspectors noted that the licensee formalized the process for predicting the potential impact of marine growth on the circulating water traveling screens during storm season. The inspectors found that this tool provided operators with additional information for taking appropriate actions needed to prevent an unplanned reactor scram with loss of normal heat removal. Although no guarantee exists that the plant would be shut down in time to prevent an unplanned reactor scram, the inspectors concluded that the licensee made a reasonable, appropriate attempt to identify potential impacts on the plant during storm season. Success will be demonstrated by operators reducing reactor power below the turbine trip/reactor trip setpoint and performing a controlled shutdown. In addition, the licensee continuously monitors the Scram With Loss of Normal Heat Removal performance indicator and reports the performance results quarterly. The licensee initiates a corrective action document anytime a performance indicator crosses a threshold.

4 OTHER ACTIVITIES

4OA4 Cross-cutting Issues

a. Scope

On May 19, 2000, NRC and the licensee had conducted a meeting to discuss the results of a focused safety culture survey performed at Diablo Canyon. Following the meeting, members of the public were allowed to make comments or ask questions. The meeting, as well as the question and answer period, was transcribed. NRC committed to review the meeting transcript for statements that could affect plant safety or other items that the

NRC had responsibility for regulating. Upon review of the transcript, NRC found that many of the statements had previously been evaluated and resolved; however, the statements quoted below had not been previously evaluated.

The inspectors reviewed each concern below to determine whether: (1) the concern existed; (2) the concern impacted plant safety or the plant culture (both the general plant culture and the safety conscious work environment); and (3) there was compliance with regulatory requirements. The inspectors interviewed operations management, some shift managers, and some nonlicensed operators. The inspectors reviewed shift logs, shutdown/cooldown control procedures, and equipment operating procedures.

b. Findings

1. "They give you four reasons -- or four things that they're working on at Diablo Canyon to resolve the problems in shift operations department shift managers on December 17th, 1999, after the OSHA determination became public and after he had been terminated. I've spoken to both of my supervisors, and neither one of the shift managers attended that meeting. There's only five at the plant. It says 'plant management held a meeting with shift managers.' It does not say the plant manager, it doesn't say senior management personnel. All of my management said, 'Gary, I wasn't there. I don't have any idea what happened.' "

   The inspectors confirmed from discussions with various individuals and review of shift logs that this meeting did take place and that the lowest level of Operations Management present were the shift managers. The shift foreman and other onshift senior reactor operators were not invited and, therefore, would not have known the content of the meeting.

2. "The second meeting, the middle of the second page, says, 'On January 7th, 2000, the plant manager held a meeting with the operations supervision to discuss actions that would promote trust in the organization.' The plant manager held a meeting with operations supervision. Once again, I asked all of my supervision. I said, 'Did you go to the meeting?' They said, 'Gary, I didn't hear anything about it. Don't have any feedback to give you.' "

   The inspectors confirmed that this meeting did occur. The Plant Manager, Operations Services Manager, Operations Director, and Operations Superintendent attended the meeting. From discussions with these individuals, the inspectors concluded that discussions on how to foster trust and improve morale were discussed. Lower level operations supervision, such as the shift managers and shift foremen, were not included in the meeting.

3. "Based on this discussion with the plant manager and operations supervision, operations management will continue to work on various issues of concerned operators . . . [but those concerns] are not a priority to shift operators."

   The inspectors found that Operations management had collected comments (approximately 200) from the miniculture survey, consolidated the comments into

34 individual areas of concern, and requested that operations personnel prioritize the 34 areas of concern. The inspectors found that Operations management then generated a list of the top issues affecting the general culture and work environment at Diablo Canyon. The licensee indicated that the goal is to reestablish and improve trust in operations management. The following items are considered the priority issues as identified by operations personnel:

- Trust in management
- Communications
- Supervisory and leadership training
- Fair, consistent rules and methods for management performance evaluation
- Communicate a clear plan for Operations personnel advancement
- Improve the initial license and operator training classes
- Fair, consistent process for human error resolution
- Implement the senior control operator job improvement initiatives
- Initiate an initial license class by year end (2000)

The inspectors confirmed that the working conditions were a concern of the nonlicensed operators. Further, the inspectors confirmed that both management and the operations staff knew of the top concerns of the operators.

4. “During a weekend ramp down on both units...Procedures were not used...but if we had broken anything, we’d have to address the fact we didn’t use the procedures.”

   The inspectors determined that the ramp down of interest occurred on January 30, 2000. The inspectors reviewed logs in an attempt to identify procedures that were not used. The inspectors identified an unanticipated start of a condensate booster pump while operators secured the operating condensate booster pump. The inspectors determined that the controlling procedures used during this ramp down had the required sign-offs initialed. The inspectors noted that equipment operating procedures for the condensate system did not provide specific guidance for securing a condensate booster pump and did not have any required sign-offs. While more experienced operators would have placed the standby pump in manual or off instead of automatic prior to securing the operating pump. The inspectors found no evidence that procedures were not used.

c. <u>Conclusions</u>

While performance of this inspection clarified the record with respect to which level of operations supervision participated in various discussions of the safety culture, the licensee submittal was sufficiently complete and accurate to meet the requirements of 10 CFR 50.9. In addition, the inspectors did not identify any evidence that procedures were not used.

4OA6 Meetings

Exit Meeting Summary

On August 24, 2000, the inspectors conducted a meeting with Mr. Dave Oatley, Vice President Operations, and other members of plant management to present the inspection results. Plant management acknowledged the findings presented. Plant management also informed the inspector that no proprietary material was examined during the inspection.

ATTACHMENT 1

PARTIAL LIST OF PERSONS CONTACTED

Licensee

J. Anastasio, System Engineer, Engineering Services
G. Anderson, Day Shift Supervisor, Operations
J. Becker, Manager, Operations Services
C. Belmont, Director, Nuclear Quality Services
K. Johnston, Senior Engineer, Operations
S. Ketelsen, Supervisor, Nuclear Safety and Licensing
D. Miklush, Manager, Engineering Services
D. Oatley, Vice President and Plant Manager
N. O'Hagan, Nuclear Operator, Operations
P. Roller, Superintendent, Operations
D. Vosburg, Director, Engineering Services
L. Womack, Vice President, Power Generation and Nuclear Technical Services

NRC

G. Larkin, Reactor Engineer, Division of Reactor Projects
D. Proulx, Senior Resident Inspector, Division of Reactor Projects
L. Smith, Chief, Project Branch E, Division of Reactor Projects

LIST OF DOCUMENTS REVIEWED

Procedures:

OP O-28	“Intake Management”	Revision 6
OP AP-7	“Degraded Condenser”	Revision 23
OP AP-25	“Rapid Load Reduction”	Revision 4
OP L-4	"Normal Operations at Power - Unit 1"	Revision 45
OP L-4	"Normal Operations at Power - Unit 2"	Revision 32
OP L-5	"Plant Cooldown From Minimum Load to Cold Shutdown - Unit 1"	Revision 49
OP L-5	"Plant Cooldown From Minimum Load to Cold Shutdown - Unit 2"	Revision 34
OP C-7A:II	"Condensate & Booster Pumps - Clearing"	Revision 4
OP C-7A	"Condensate & Booster Pump"	Revision 4

Action Requests:

A0507000	White NRC PI - U2 scrams with loss of normal heat removal
A0507153	Provide upgraded traveling screen drives
A0507784	Provide detailed design for intake bar racks
A0509894	Change P-9 to 30 percent power

Nonconformance Reports

N0002033	Unit 2 Manual Reactor Trip Because of Condensate Flow/main Feedwater Pump Trip
N0002078	Manual Reactor Trip Because of Kelp Attack December 1, 1998
N0002107	Unit 1 & Unit 2 Manual Reactor Trips Because of Kelp Attack

Other Documents:

LER 323/97-003-01	Manual Reactor Trip on Loss of Normal Feedwater Because of Unknown Condensate/Feedwater Transient
LER 323/98-005-00	Manual Reactor Trip Because of Heavy Debris Loading of Circulating Water System Traveling Screens During a Pacific Ocean Storm
LER 275; 323/99-009-00	Manual Reactor Trip Because of Heavy Debris Loading of Traveling Screens During a Pacific Ocean Storm

Inspection Report 275; 323/97-10, Section O1.2

Inspection Report 275; 323/98-21

Inspection Report 275; 323/99-17, Section O1.5

Training Improvement Proposal 000010814, “Provide Operations Training for Equipment Damage Mitigation”

Operator Requalification Lesson R993S3 (simulator), “Kelp Attack/Loss of Circ Water/Rx Trip”

Operations Continuing Training Lesson R993C13 (classroom), “Operating Order O-28: “Intake Management”

ATTACHMENT 2

NRC's REVISED REACTOR OVERSIGHT PROCESS

The federal Nuclear Regulatory Commission (NRC) recently revamped its inspection, assessment, and enforcement programs for commercial nuclear power plants. The new process takes into account improvements in the performance of the nuclear industry over the past 25 years and improved approaches of inspecting and assessing safety performance at NRC licensed plants.

The new process monitors licensee performance in three broad areas (called strategic performance areas): reactor safety (avoiding accidents and reducing the consequences of accidents if they occur), radiation safety (protecting plant employees and the public during routine operations), and safeguards (protecting the plant against sabotage or other security threats). The process focuses on licensee performance within each of seven cornerstones of safety in the three areas:

Reactor Safety	**Radiation Safety**	**Safeguards**
• Initiating Events	• Occupational	• Physical Protection
• Mitigating Systems	• Public	
• Barrier Integrity		
• Emergency Preparedness		

To monitor these seven cornerstones of safety, the NRC uses two processes that generate information about the safety significance of plant operations: inspections and performance indicators. Inspection findings will be evaluated according to their potential significance for safety, using the significance determination process, and assigned colors of GREEN, WHITE, YELLOW, or RED. GREEN findings are indicative of issues that, while they may not be desirable, represent very low safety significance. WHITE findings indicate issues that are of low to moderate safety significance. YELLOW findings are issues that are of substantial safety significance. RED findings represent issues that are of high safety significance with a significant reduction in safety margin.

Performance indicator data will be compared to established criteria for measuring licensee performance in terms of potential safety. Based on prescribed thresholds, the indicators will be classified by color representing varying levels of performance and incremental degradation in safety: GREEN, WHITE, YELLOW, or RED. GREEN indicators represent performance at a level requiring no additional NRC oversight beyond the baseline inspections. WHITE corresponds to performance that may result in increased NRC oversight. YELLOW represents performance that minimally reduces safety margin and requires even more NRC oversight. RED indicates performance that represents a significant reduction in safety margin but still provides adequate protection to public health and safety.

The assessment process integrates performance indicators and inspection so the agency can reach objective conclusions regarding overall plant performance. The agency will use an Action Matrix to determine in a systematic, predictable manner which regulatory actions should be taken based on a licensee's performance. The NRC's actions in response to the significance (as represented by the color) of issues will be the same for performance indicators as for inspection findings. As a licensee's safety performance degrades, the NRC will take more and increasingly significant action, which can include shutting down a plant, as described in the Action Matrix.

More information can be found at: http://www.nrc.gov/NRR/OVERSIGHT/index.html.