UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
SAM NUNN ATLANTA FEDERAL CENTER
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ATLANTA, GEORGIA 30303-8931

April 20, 2001

Duke Energy Corporation
ATTN: Mr. W. R. McCollum
Vice President and
Oconee Nuclear Station
7800 Rochester Highway
Seneca, SC 29672

SUBJECT: OCONEE NUCLEAR STATION -NRC INSPECTION REPORT 50-269/01-08, 50-270/01-08, AND 50-287/01-08

Dear Mr. McCollum:

On March 23, 2001, the NRC completed an inspection at your Oconee Nuclear Station. The enclosed report documents the inspection findings which were discussed on March 22, 2001, with you and other members of your staff. Subsequently on April 19, 2001, the inspection findings were discussed again with Mr. L. Nicholson of your staff.

The inspection was an examination of activities conducted under your licenses as they relate to the identification and resolution of problems and compliance with the Commission's rules and regulations and with the conditions of your licenses. Within these areas, the inspection involved a selected examination of procedures and representative records, observations of activities, and interviews with personnel.

On the basis of the sample selected for review, it was concluded that the majority of problems were properly identified, evaluated, and resolved in an effective manner within your established problem identification and resolution programs. However, for a number of problems identified by your staff, all pertinent issues associated with the problems were not fully recognized nor evaluated. Additionally, the inspectors noted the corrective actions for several problems were not adequate or were not implemented in a timely manner. During the inspection two apparent violations were identified for inadequate or incomplete corrective actions for previously identified conditions adverse to quality concerning the implementation of tornado mitigation strategies and non-safety related piping in the control room. These issues have not yet been characterized by the Significance Determination Process and have therefore not yet been dispositioned. Accordingly, please be advised that the number and characterization of the apparent violations described in the enclosed inspection report may change as a result of further NRC review. No response regarding the apparent violations is required at this time.

The inspection also identified four issues of very low safety significance (Green and No Color). These findings were determined to be violations of NRC requirements. However, because of their very low safety significance and because the issues have been entered into your corrective action program, the NRC is treating these issues as non-cited violations, in accordance with Section VI.A.1 of the NRC's Enforcement Policy.

If you contest these non-cited violations you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the United States Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with copies to the Regional Administrator, Region II; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Oconee Nuclear Station.

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).

Sincerely,

/RA/

Robert Haag, Chief
Reactor Projects Branch 1
Division of Reactor Projects

Docket Nos.: 50-269, 50-270, 50-287
License Nos.: DPR-38, DPR-47, DPR-55

Enclosure: NRC Inspection Report Nos. 50-269/01-08, 50-270/01-08, 50-287/01-08
w/Attached NRC's Revised Reactor Oversight Process

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U. S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos.:	50-269, 50-270, 50-287
License Nos.:	DPR-38, DPR-47, DPR-55
Report Nos.:	50-269/01-08, 50-270/01-08, 50-287/01-08
Licensee:	Duke Energy Corporation
Facility:	Oconee Nuclear Station, Units 1, 2, and 3
Location:	7800 Rochester Highway Seneca, SC 29672
Dates:	March 5-9, 2001 and March 19-23, 2001
Inspectors:	S. Shaeffer, Senior Resident Inspector - McGuire (Lead Inspector) R. Schin, Senior Reactor Inspector S. Freeman, Resident Inspector - Oconee
Approved by:	R. Haag, Chief Reactor Projects Branch 1 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS
Oconee Nuclear Station, Units 1, 2, and 3

IR 05000269-01-08, IR 05000270-01-08, and IR 05000287-01-08, on 03/5-9/2001 and 3/19-23/2001, Duke Energy Corporation, Oconee Nuclear Station, Units 1,2 &3, annual baseline inspection of the identification and resolution of problems.

The inspection was conducted by two resident inspectors and one regional reactor inspector. The inspection identified three Green findings and one No Color finding. These findings were considered to be non-cited violations (NCV). The significance of most of the findings is indicated by their color (Green, White, Yellow, Red) using the Significance Determination Process (SDP) found in Inspection Manual Chapter 0609. Findings to which the SDP does not apply are indicated by “no color” or by the severity level of the applicable violation. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described at its Reactor Oversight Process website at http://www.nrc.gov/NRR/OVERSIGHT/index.html.

In addition, the inspection identified two apparent violations that will require additional review and analysis to determine their safety significance.

Identification and Resolution of Problems

Overall, the licensee’s corrective action program was effective at identifying, evaluating, and correcting problems. The threshold for entering problems into the corrective action program was sufficiently low. Reviews of operating experience information were comprehensive. In general, the licensee properly prioritized items in its corrective action program database, which ensured that timely resolution and appropriate causal factor analyses were employed commensurate with safety significance.

Several exceptions were noted in the area of problem identification where the licensee could have been more effective in the identification of all pertinent issues of problems which would have supported more comprehensive corrective actions. The inspection also identified several examples where the prioritization and evaluation of issues was not commensurate with its safety significance. Thresholds for performing root cause determinations were conservative for the samples reviewed and the root cause determinations reviewed were considered comprehensive.

In the area of effectiveness of corrective actions, some issues were identified where the corrective action program was either not timely or ineffective in adequately addressing the identified problems. Other than minor discrepancies, no problems were identified concerning the documentation of corrective action program issues.

In general, previous non-compliance issues documented as non-cited violations were properly tracked and resolved via the corrective action program. In one case, however, resolution was not fully effective in addressing all relative aspects of the non-cited violation; resulting in further enforcement action for not implementing thorough corrective actions.

The results of the last comprehensive corrective action program audit conducted by the licensee and other related audits identified in the report were properly entered and dispositioned in the corrective action program.

Based on discussions with plant personnel and the apparently low threshold for items entered in the corrective action program database, the inspectors concluded that workers at the site generally felt free to raise safety concerns to their management.

Cornerstone: Initiating Events

- Significance To Be Determined. An apparent violation of 10 CFR 50, Appendix B, Criterion XVI, Corrective Action, was identified for failure correctly identify and evaluate a condition adverse to quality involving a potential control room flooding issue. On June 19, 2000, the licensee had identified a concern that non-safety related pipes were in the control rooms and could potentially leak onto safety related equipment. The inspectors identified that the licensee had not questioned seismic qualification of the pipes to evaluate the potential for the pipes to break during a seismic event, disable safety related equipment, and cause operators to abandon the control rooms. As a seismically-induced pipe break above the control panels could potentially cause an initiating event and affect the ability to safely shut down the plant, this issue is being treated as an apparent violation, pending further NRC review of the safety significance (Section 4OA2.b.(2).3).

Cornerstone: Mitigating Systems

- Green. A non-cited violation of 10 CFR 50, Appendix B, Criterion XVI, Corrective Action, was identified for failure to enter a condition adverse to quality into the corrective action program and failure to perform an operability evaluation such that the full scope of required corrective action was not addressed. Specifically, the use of the station auxiliary service water (ASW) pump would result in substantially exceeding the vendor limits on steam generator tube-to-shell differential temperature. This condition, which would result in increased stresses on the tubes, was identified by licensee engineers in about September 2000. However, the licensee had not entered the condition into the corrective action program and had not performed an operability evaluation.

  This violation was of more than minor significance because it had a credible impact on safety, in that the licensee’s lack of an operability evaluation contributed to their inappropriate delay in revising the emergency operating procedures for aligning the station ASW pump to mitigate a tornado event. Since the licensee concluded on March 21, 2001, that the station ASW pump was operable (i.e., could perform its design basis function), this issue was determined to have very low safety significance (Section 4OA2.a.(2).2).

- No Color. A non-cited violation of 10 CFR 50, Appendix B, Criterion XVI, Corrective Action, was identified for failure to correct the cause of an improper operability determination on the 3B Reactor Building Cooling Unit. This had originally been identified by the NRC in non-cited violation 50-287/00-02-02. The licensee evaluated this earlier non-cited violation within their corrective action program, but incorrectly concluded the operability determination had been appropriate and took no related corrective actions. The inspectors discussed this discrepancy with the licensee, who subsequently performed a re-evaluation and implemented appropriate corrective actions.

  Having a credible impact on safety, this violation was considered more than minor because it involved a previously identified violation of NRC requirements and because prompt determination of operability is important to preserving the validity of the plant safety analysis. However, because it did not directly affect plant equipment or a cornerstone, this issue was determined to have very low safety significance and was not processed through the Significance Determination Process (Section 4OA2.b.(2).2).

- Significance To Be Determined. An apparent violation of 10 CFR 50, Appendix B, Criterion XVI, Corrective Action, was identified for failure to promptly correct a condition adverse to quality. The condition concerns an inability to align the station auxiliary service water pump to supply lake water to the steam generators within the 40 minutes required for mitigation of a design basis tornado. This condition, which the licensee identified on January 27, 2000, was not corrected as of March 22, 2001. As this untimely corrective action resulted in a known inability to mitigate a design basis tornado for over one year, it is being treated as an apparent violation, pending further NRC review of the safety significance (Section 4OA2.c.(2).2).

- Green. A non-cited violation of 10 CFR 50, Appendix B, Criterion XI, was identified for failure to conduct appropriate post-maintenance testing on Unit 2 reactor trip breaker CB-1 before returning it to service on March 6, 2001. Having failed to close after a shunt trip test, maintenance personnel performed corrective action on the breaker (i.e., partially racking it out and in) without any written authorization or instructions, and made no record in the completed surveillance procedure of the breaker failing to close or of the breaker being partially racked out. By performing corrective actions without written authorization or documentation of the breaker failure, maintenance personnel circumvented the work control process; thereby precluding the possible recognition for the need of a subsequent retest. In response to a subsequent Problem Investigation Process report, licensee engineers incorrectly concluded that the breaker was operable without further testing.

  This violation was more than minor because of the credible impact on safety by returning the reactor trip breaker to service without an adequate post-maintenance test to demonstrate its capability to trip when called upon. Because the breaker operated correctly during a subsequent retest prompted by this inspection, this issue was determined to have very low safety significance (Section 4OA2.c.(2).3).

- Green. A non-cited violation was identified for ineffective corrective actions taken following cold leg venting problems on Unit 2 in May, 1998. The corrective actions on Unit 2 did not correct the same problems on Unit 1. Cold leg venting problems on Unit 1 in February 2000 resulted in a decrease of approximately 32 inches in reactor coolant inventory during shutdown conditions with fuel in the reactor vessel.

  This violation was more than minor because corrective actions were not effective in preventing substantial reactor coolant system level decreases during shutdown conditions. The level decrease could also mask other events involving loss of reactor coolant system inventories from a variety of reasons. This event was determined to have very low safety significance because the licensee had compensatory measures in place for draining to mid-loop and because cold leg design would have limited the decrease to no lower than the top of the cold legs (Section 4OA2.c.(2).4).

Report Details

4. OTHER ACTIVITIES

4OA2 Identification and Resolution of Problems

a. Effectiveness of Problem Identification

(1) Inspection Scope

The inspectors reviewed Problem Investigation Process reports (PIPs), which served as the licensee's formal means of documenting equipment and human performance problems, concerns, issues, and events. The inspectors also reviewed other corrective action program (CAP) documents including completed corrective actions documented in PIPs and operating experience program (OEP) documents to verify that industry-identified problems potentially or actually affecting Oconee were appropriately entered into and resolved by the formal CAP process. Items included in the OEP effectiveness review were NRC Information Notices (IN), industry or vendor-generated reports of defects and noncompliance under 10 CFR Part 21, and vendor information letters. A detailed listing of PIPs, work requests/work orders (WR/WO), and OEP documents that were reviewed during this inspection is included at the end of the report.

The inspectors also reviewed operating logs, test deficiencies, maintenance rule functional failure list, system health reports, the non-conforming items list, and the Technical Specification (TS) Limiting Condition for Operation entry list to determine if deficiencies were being properly entered into the corrective action program. The inspectors also toured selected areas of the plant to determine if deficiencies existed that had not been entered into the corrective action program. The inspectors attended numerous Plant Status, Shift Turnover, and PIP screening meetings that assessed the significance and determined the level of evaluation required for recent plant issues. The inspectors also attended one Major Equipment Problem Resolution (MEPR) and two Corrective Action Review Team (CART) meetings to determine whether longer term plant issues were being properly reviewed and whether the appropriate level of management attention for significant and potentially significant plant issues was being recommended. During all of the above inspection activities, the inspectors also assessed whether licensee management was providing an independent review of significant plant issues, as well as providing oversight to the plant on potential cross cutting industry issues and adverse trends.

The inspectors discussed issues identified during the PIP reviews with various system engineers, maintenance personnel, procedure writers, design bases review group personnel, and other plant personnel to determine if the corrective action system was effective for identifying and tracking Conditions Adverse to Quality (CAQs).

(2) Findings

.1 General

In general, the licensee's threshold for entering problems into the corrective action program was satisfactory. The inspectors identified very few plant equipment problems or industry-related issues that had not been entered in the CAP. Based on the total number of PIPs generated at the Oconee site each year, the observed low threshold for documenting issues, and discussions with plant personnel, the inspectors concluded that the licensee's corrective action program was being effectively implemented for the identification and resolution of problems. This conclusion was based on a review of over 100 selected licensee initiated PIPs. As indicated, a few problems were identified and are documented in the following sub-sections.

.2 <u>Failure to Enter Issue of Steam Generator Tube Stresses Resulting From Use of the Station Auxiliary Service Water (ASW) Pump into the CAP and Perform Required Operability Reviews</u>

A Green finding that was dispositioned as a non-cited violation (NCV) was identified for failure to enter a condition adverse to quality into the CAP and failure to perform an operability evaluation such that the full scope of required corrective action was not addressed. Specifically, the use of the station ASW pump would result in substantially exceeding the vendor limits on steam generator tube-to-shell differential temperature. This condition, which would result in increased stresses on the tubes, was identified by licensee engineers in about September 2000. However, the licensee had not entered the condition into the CAP and had not performed an operability evaluation.

While reviewing the licensee's corrective actions for PIP O-00-00363, which addressed the inability to align the station ASW pump within 40 minutes (see Section 4OA2.c.(2).2), the inspectors identified the licensee had not documented the differential temperature concern in a PIP. The inspectors reviewed the vendor design limit on steam generator tube-to-shell differential temperature and noted that it was 60°F. The inspectors further noted that the licensee's expected tube-to-shell differential temperature of 103°F, which would occur when using the station ASW pump, substantially exceeded the design limit of 60°F. The inspectors concluded that exceeding the steam generator design limit constituted a non-conformance and a CAQ that should have been entered into the licensee's CAP.

Licensee engineers stated that one reason they were delaying corrective action for inability to align the station ASW pump in 40 minutes, was to resolve a concern with that would occur when the station ASW pump was used to supply lake water to the steam generators. Yet the inspectors noted that the higher than analyzed steam generator tube-to-shell differential temperatures had not been evaluated from an operability standpoint to determine if the station ASW pump should remain as an option for feeding the steam generators. The inspectors concluded that adequate corrective action is dependent on knowing the extent of the non-conformance and for this situation not assessing the station ASW pump's ability to perform its function without damaging the steam generators adversely impacted associated corrective actions.

In response to inspector concerns, the licensee initiated PIP O-01-00940 on March 20, 2001, and began an operability evaluation of the condition. The licensee completed the operability evaluation on March 21 and concluded that the station ASW pump was operable (i.e., could perform its design basis function). In support of that conclusion, the licensee determined that there was a reasonable expectation that operation of the station ASW pump would not fail the steam generator tubes. To resolve the nonconformance with vendor tube-to-shell differential temperature limits, the licensee was in the process of requesting a vendor analysis that they expected would confirm that the operation of the station ASW pump would not fail the steam generator tubes.

This issue was of more than minor significance because it had a credible impact on safety, in that the licensee's lack of an operability evaluation contributed to their inappropriate delay in revising the emergency operating procedures for aligning the station ASW pump to mitigate a tornado event (see Section 4OA2.c(2).2). Because the operabilty evaluation which was later performed concluded there was a reasonable expectation that operation of the station ASW pump would not fail the steam generator tubes, the delay in revising the procedures lacked merit. Since the licensee had been working to resolve this issue and because they concluded on March 21, 2001, that the station ASW pump was operable, this issue was determined to have very low safety significance (Green).

The inspectors concluded that licensee engineers were proactive in their identification of this design issue that had existed since the plant was licensed in 1973. However, the failure to initiate a PIP and to evaluate operability when the concern was identified in September 2000, was contrary to requirements of 10 CFR 50, Appendix B, Criterion XVI, Corrective Action, and the licensee's implementing procedure, Nuclear Site Directive (NSD) 208, Problem Investigation Process. This violation is being treated as a NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy and is identified as NCV 50-269,270,287/01-08-01: Failure to Enter Issue of Steam Generator Tube Stresses Resulting From Use of the Station ASW Pump into the Corrective Action Program and Perform Operability Evaluation. The licensee identified the failure to initiate a PIP and perform an operability evaluation in a timely manner in PIP O-01-00940.

The inspectors assessed that prompt resolution of the tube-to-shell differential temperature problem was important. In this event (i.e., use of station ASW pump to supply the steam generators following tornado damage to the turbine building), if the increased stresses could cause the steam generator tubes to fail, the result could be failure of all three fuel barriers. Tube failure would represent a failure of the reactor coolant system. With no high pressure injection available, loss of reactor coolant out the failed tubes would likely result in failure of the reactor fuel cladding. Additionally, the lack of main steam isolation valves and lack of tornado protection for the main steam lines could result in tornado damage which would effectively bypass the containment. Pending further NRC review of the licensee's resolution, this issue will be identified as Unresolved Item (URI) 50-269,270,287/01-08-02: Steam Generator Tube Stresses Resulting From Use of the Station ASW Pump.

.3 <u>Operator Access to Steam Generator Atmospheric Dump Valves to Mitigate a Tornado</u>

An URI was opened for further NRC review of the design and location of the atomospheric dump valves with respect to tornado mitigation.

While reviewing PIP O-00-00363, which addressed the inability to align the station ASW pump within 40 minutes (see Section 4OA2.c.(2).2), the inspectors also reviewed the abnormal operating procedure that was discussed in the PIP. The inspectors noted that AP/1/A/1700/006, Natural Disaster, Revision 7, contained procedural steps for operators to align the station ASW pump to supply lake water to steam generators to mitigate a tornado event. The steps included opening manually operated steam generator atmospheric dump valves to depressurize the steam generators to below the 70 psig discharge pressure of the station ASW pump.

The inspectors observed that the manual atmospheric dump valves were located on the upper level of the turbine building and were not protected from the effects of a tornado. Also, the area around the valves, where operators would have to access to operate the valves, was not protected from tornado debris. In fact, the valves were located next to the emergency feedwater (EFW) system upper surge tank, which was assumed to be damaged by the design basis tornado. In this event, the loss of the upper surge tank would effectively disable the EFW system, which was why the station ASW pump was needed. The inspectors noted that the only safety function of the station ASW pump that was identified in the Updated Final Safety Analysis Report (UFSAR) was to mitigate a tornado that disabled the EFW system.

The inspectors questioned why the licensee assumed operators would have access to the manual atmospheric dump valves during the design basis tornado event. Licensee engineers stated that the location of the atmospheric dump valves was well known, but was not identified in a PIP because it was not considered to be a condition adverse to quality. The licensee presumed that the condition had been previously reviewed and approved by the NRC; however, they did not provide any documentation to support this assumption. The inspectors reviewed the 1973 FSAR for Oconee, that provided a basis for NRC approval of the plant design, and noted that it stated the following about tornado mitigation: “A sufficient supply of cooling water for safe shutdown is assured by an auxiliary service water pump located in the auxiliary building and taking a suction from the Unit 2 CCW intake piping.” The inspectors also noted that the Oconee Probabilistic Risk Assessment (PRA) assumed that operators would have no difficulties in accessing the steam generator atmospheric dump valves to mitigate a tornado. The inspectors questioned whether this assumption was realistic. Pending further review of whether the NRC approved the design and location of the atmospheric dump valves for tornado mitigation, this issue is identified as URI 50-269,270,287/01-08-03: Operator Access To Steam Generator Atmospheric Dump Valves To Mitigate A Tornado.

.4 <u>Continuing Adverse Human Performance Trends</u>

A negative observation was identified regarding a continuing adverse trend in human performance errors.

The licensee has continued to monitor human performance trends on a quarterly basis. The results for the fourth quarter of 2000 showed a sizable amount of procedure adherence, communication, procedure accuracy, and work practice problems. The licensee had previously initiated PIPs to document an adverse site wide trend in communications (PIP O-00-00767) and procedure adequacy (PIP O-00-00764). Management has postponed a root cause evaluation on PIP O-00-00767, deciding to initiate a self-assessment instead. PIP O-00-00764 has resulted in several corrective actions for the engineering group to improve the technical accuracy of engineering documents. The inspectors noted that the operations human performance review group referenced PIP O-00-00764 as documenting an adverse trend in document adherence problems. However, this PIP dealt with procedure accuracy, not adherence, and only dealt with engineering documents, not operations or maintenance.

During this inspection, the inspectors reviewed a number of PIPs related to recent events and noted that human performance errors continued to occur, both in procedure accuracy and in adherence to procedures. Evidence of this has been NRC identified (i.e., NCVs: 50-270/99-08-01; 50-270,287/99-09-01; 50-287/99-09-03; 50-287/00-05-05;

50-287/00-06-04; 50-269,270,287/00-06-02; and 50-269,270,287/00-07-03) and licensee identified (i.e., PIPs: O-00-02827, O-00-03630; and Licensee Event Report 50-287/00-03-00).

The inspectors concluded that although the overall significance of the problems resulting from human performance errors has decreased, a sizable number continued to occur after the licensee had previously identified an adverse trend. These errors may be occurring in higher numbers in areas not within the specific area of focus that the previously identified adverse trends identified (i.e., not in the area of procedural adherence). Based on a review of the licensee's response to the adverse trend, further management oversight may be warranted to ensure focus on the most appropriate root causes for the current human performance errors.

b. Prioritization and Evaluation of Issues

(1) Inspection Scope

The inspectors reviewed PIPs that were assigned various Action Categories to determine whether issues were properly prioritized in accordance with NSD 208, Revision 22, Problem Investigation Process. The Action Categories (1 through 4) were defined in NSD 208 and were numbered based on decreasing significance. Action Category 1 PIPs were "significant" CAQs that required formal root cause evaluations, while Action Category 4 PIPs were low level CAQs or conditions not adverse to quality, neither of which required any type of causal evaluation. The majority of the reviewed PIPs were screened as Action Category 3, with the remainder falling into Action Categories 1, 2, and 4. Action Category 2 PIPs were defined as CAQs for which management could use its discretion in deciding whether to perform a formal root cause evaluation. Action Category 3 PIPs were problems for which an "apparent cause" analysis was sufficient in fixing the immediate problem.

The inspectors also reviewed plant issue reports and deficiency reports for systems identified in the site specific SDP worksheets to determine if risk significant conditions existed that increased plant risk. For those that did, the inspectors reviewed whether the plant reports were appropriately prioritized for correction based on the risk. The inspectors also reviewed condition reports to determine if they were properly classified based on the licensee's definition of "significant" from NSD 208.

The inspectors reviewed a sample of potentially significant and routine corrective action documents to determine whether the licensee found the appropriate causes and identified corrective action to prevent recurrence (including common cause and generic concerns), and completed the corrective actions.

(2) Findings

.1 General

In general, the licensee's threshold for prioritization and evaluation of problems in the corrective action program was considered to be satisfactory. In addition, the inspectors noted that the technical adequacy and depth of the evaluations, as documented in the corrective action program, were generally acceptable. However, several PIP issues were categorized at a level which may have impacted the responsive and thoroughness of the assigned corrective actions. Root cause evaluations and corrective actions were generally effective to prevent recurrence. Where issues recurred, the Plant Issue Review Team meetings actively evaluated them for potential repetitive or common mode issues within the CAP and assigned the appropriate level of root cause evaluation needed.

Based on the total number of PIPs with root cause evaluations that were reviewed during this inspection, the inspectors concluded that the licensee's corrective action program was being effectively implemented for the prioritization and evaluation of problems. However, several issues were identified and are documented in the following sections.

.2 Failure to Correct Conditions Leading to NRC Identified Violation

A No Color finding that was dispositioned as a NCV was identified due to the licensee's failure to take adequate corrective actions in response to a previously identified violation of TS 3.6.5 regarding operablility of reactor building cooling unit (RBCU) 3B.

On April 28, 2000, the NRC identified NCV 50-287/00-02-02 due to the use of an incorrect discovery time when declaring the 3B RBCU inoperable. In that NCV, the inspectors determined that enough information was available for the licensee to declare the RBCU inoperable from the time of initial indication of high motor bearing temperature rather than later upon discovery of a broken strut on the motor. In PIP O-00-01558, the licensee evaluated whether or not the 3B RBCU should have been declared inoperable sooner. The PIP evaluation determined that the licensee's original decision to declare the RBCU inoperable when they discovered the broken strut was appropriate. This evaluation was based on a 24-hour run in low (accident) speed where bearing temperatures did not exceed alarm setpoints and the licensee's determination that bearing temperatures are not always an indication of degraded RBCU motor bearings. Accordingly, PIP O-00-01558 contained no corrective actions.

After completion of the evaluation in PIP O-00-01558, the licensee independently initiated PIP O-00-02427 to perform an assessment of the operability determination process to ensure that conservative operability determinations were being performed in a timely manner. As part of that assessment, the licensee examined the operability determination of the 3B RBCU and concluded that it was appropriate. This conclusion was based largely on an engineering assumption that low air flow due to damper problems caused the elevated temperatures during the 24-hour run on the 3B RBCU. As the dampers do not perform a specified safety function (i.e., will be bypassed on high containment temperature), this would have provided a reasonable assurance of operability for continued operation. However, the assumption was based on information that was never fully evaluated. The licensee was unable to show any data that confirmed their assumption.

Generic Letter (GL) 91-18 states that whenever operability is called into question, the licensee must make a prompt determination of operability. If not declared inoperable initially the licensee must have a reasonable expectation that the system will be operable. Furthermore, the licensee's process should immediately declare equipment inoperable if mounting evidence suggests that the final analysis will conclude that the equipment can not perform its specified safety function. The inspectors reviewed NCV 50-287/00-02-02 and the evaluations to PIPs O-00-01558 and O-00-02427 and determined that enough information was available at the time so that a “reasonable assurance of operability” did not exist and that the licensee should have declared the 3B RBCU inoperable earlier than was done. At the time the 24-hour run was performed, the 3B RBCU had experienced multiple alarms (vibration and temperature), bearing temperatures remained elevated, and the licensee had not considered the effects that accident conditions in the containment would have on the bearings. It was later determined that operation under accident conditions could have resulted in temperatures exceeding the manufacturer’s rating for the bearing lubricant. The inspectors attributed the cause to be an inadequate analysis of the information available.

After further discussion, the licensee concluded that the evaluations of PIPs O-00-01558 and O-00-02427 were not appropriate and subsequently re-evaluated each PIP. The new evaluation accounted for the need to have a “reasonable assurance of operability”, when performing operability evaluations while affected equipment remained in service. The licensee also added corrective actions to train operations and engineering personnel on the conservative use of “reasonable assurance of operability.”

Because it involved a previously identified violation of NRC requirements and because prompt determination of operability is important to preserving the validity of the safety analysis, the inspectors considered the failure to take corrective action for the improper operability determination on the 3B RBCU to be more than minor and a violation of 10 CFR 50 Appendix B, Criterion XVI. Because it did not directly affect plant equipment or a cornerstone, this issue was determined to have very low safety significance and was not processed through the SDP (No Color). This violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy and is identified as NCV 50-287/01-08-04: Failure to Take Adequate Corrective Action in Response to a Violation of NRC Requirements. This violation is in the licensee’s corrective action program as a revision to PIP O-01-01558.

.3 Failure to Correctly Identify and Evaluate a Control Room Flooding Issue

An apparent violation (AV) of 10 CFR 50, Appendix B, Criterion XVI, Corrective Action, was identified for failure to correctly identify and evaluate a CAQ involving a potential control room flooding issue.

On June 19, 2000, the licensee had identified in PIP O-00-02273 a concern that non-safety related pipes were in the control rooms and could potentially leak onto safety-related equipment. The PIP also stated that operators should have instructions on how to isolate the potential pipe leaks. However, the licensee had not questioned seismic qualification of the pipes and the potential for the pipes to break during a seismic event, cause flooding in the control room, disable safety-related equipment, and cause operators to abandon the control rooms.

The inspectors reviewed PIP O-99-01268, Auxiliary Building Internal Flood Design Basis Needs Clarification, and noted that it included a discussion of non-safety related pipes running above the control rooms. The PIP stated that the affect on control room instrumentation and controls, as well as the methods to isolate leakage needed to be addressed. PIP O-00-02273, Non-Safety Grade Piping Routed Through the Control Rooms Needs to be Evaluated for Leakage Potential and the Affect on Plant Controls, also addressed this issue and stated that the issue had been identified on

June 19, 2000. The two PIPs referenced PIP O-98-03017, UFSAR References Incorrect Information Regarding Design Basis for Flooding of Auxiliary Building, for an operability analysis. PIP O-98-03017 stated that "Oconee Nuclear Station is operable, but with a non-conforming condition" because the standby shutdown facility (SSF) can be relied upon to mitigate any auxiliary building flooding events.

The inspectors expressed concern about this operability analysis because TS require that each safety system individually must be operable. The inspectors also noted that PIPs O-99-01268 and O-00-02273 did not include a concern about seismic qualification of the non-safety related pipes above the control room. The PIPs addressed only the concern that the pipes could leak, and did not recognize the potential that a seismic event could cause the pipes to break and cause flooding. The inspectors toured the Unit 1 and 2 control room and observed that five pipes were routed across the control room ceiling, directly above safety related control panels. The panels below the pipes included controls for the Keowee hydro-electric power units, containment ventilation coolers, component cooling water, nuclear service water, and spent fuel pool cooling.

In response to inspector questions, the licensee entered the concern regarding the lack of seismic qualification of the pipes above the control rooms into PIP O-00-02273 and initiated an operability evaluation for that concern. The licensee completed the operability evaluation on March 27, 2001, and concluded that the control rooms were operable, but non-conforming, because of the presence of non-seismically designed pipes. The non-seismically designed pipes in the control rooms included: low pressure service water, plant drinking water, plant heating, and sanitary sewer. The evaluation concluded that a break in the non-seismic pipes could result in water spraying on control panels and operator evacuation of a control room. The evaluation further concluded that the control rooms were operable because the plant was designed to be able to be safely shut down following a loss of the control rooms by using the SSF.

The failure to address the current seismic operability and qualification of the pipes in a PIP and to perform a proper operability evaluation when the condition of pipes above the control rooms was identified on June 19, 2000, was contrary to requirements of 10 CFR 50, Appendix B, Criterion XVI, Corrective Action, and the licensee's implementing procedure, NSD 208, Problem Investigation Process. This violation of 10 CFR 50, Appendix B, Criterion XVI, is more than minor because a seismically-induced pipe break above the control panels could potentially cause an initiating event and affect the ability to safely shut down the plant. It is being treated as an AV, pending further NRC review of the safety significance, and is identified as AV 50-269,270,287/01-08-05: Failure to Correctly Identify and Evaluate a CAQ Involving a Potential Control Room Flooding Issue. The issue is entered into the licensee's corrective action program in PIP O-00-02273.

.4 Potential for Low CAP Categorization and Priority Examples Contributing to Corrective Action Problems

A negative observation was identified concerning the following examples where PIP categorization and assigned corrective action levels did not appear to be consistent with the relative safety significance of the issues. The subjective criteria used to make this observation was provided in NSD 208, Problem Investigation Process.

– The licensee identified a problem with inability to align the station ASW pump within 40 minutes on January 27, 2000, and documented the issue in PIP O-00-00363 (see paragraph 4OA2.c.(2).2). This issue had safety importance in that it resulted in the inability to mitigate a design basis tornado. However, the licensee had assigned a low priority to the PIP. They had assigned an action category 4 (the lowest category on a scale of 1 to 4) and a corrective action priority of O2. O2 indicated that the corrective action was to be accomplished during an outage with a routine priority. The low priority and outage corrective action assigned to this PIP may have contributed to the untimely corrective action that is discussed in paragraph 4OA2.c.(2).2 of this report.

– PIP O-99-00902 identified questions concerning whether manual active valves have been sized or tested to meet their design basis required functions. The reviews were to assess whether manual active valves greater than 2 inches used in response to plant events could be manipulated during the actual environmental conditions seen during the events. This review was part of an extent of condition review for a previously identified problem with operators' ability to stoke a required valve as described in PIP O-99-00348. PIP O-99-00902 was identified on March 9, 1999, and assigned an action category of 3 and a corrective action priority of I3c. The action priority of I3c corresponds to those long-term enhancements which are greater than 2 years. The inspectors inquired on March 19, 2001, as to the status of the corrective actions. The licensee indicated that no specific reviews had been completed for any of the manual active valves identified for the review. The inappropriately low action priority may have contributed to the lack of progress in corrective actions for this PIP.

– PIPs O-00-00738 and O-00-00639 concerned inadvertent reactor coolant system level reductions (see Section 4OA2.c.(2).5) and were listed as Action Category 4; therefore they did not receive a cause evaluation. The inspectors reviewed NSD 208 and noted that under Appendix C of that procedure, an unanticipated loss of water from the RCS during shutdown conditions was recommended to be classified as an Action Category 2 PIP and plant transients not categorized as 1 or 2 were Action Category 3. NSD 208 required that both Category 2 and 3 PIPs receive a cause evaluation. The inspectors determined that low action category and resulting lack of formal cause evaluation may have contributed to the inadequate corrective action issue identified in Section 4OA2.c.(2).5.

c. <u>Effectiveness of Corrective Actions</u>

(1) <u>Inspection Scope</u>

The inspectors reviewed PIPs to assess the licensee's actions to determine causal factors, to develop and implement appropriate actions to correct the adverse condition, and, if significant, prevent recurrence. These PIPs were primarily related to cornerstones in the Reactor Safety strategic performance area of the NRC inspection program. However, PIPs were also reviewed in the areas of Radiation Safety and Safeguards to maintain some distribution across all NRC inspection program cornerstones. PIPs associated with past NCVs were reviewed to verify that the associated problems were corrected.

The inspectors reviewed industry operating experience (OE) issues that were evaluated in the past two years to determine if this information had been appropriately assessed for applicability to the station and whether applicable issues were incorporated into the station CAP. Items reviewed for the OEP included vendor information letters (VILs), NRC Information Notices (INs), and NRC Generic Letters (GLs) .

The inspectors also performed sample reviews of long-term open CAP issues, the licensee's rational for deleted PIPs, issues documented in NRC inspection reports as NCVs, and the plant issues matrix. A focus review was conducted on the status of the licensee's Emergency Operating Procedure (EOP) Corrective Action Program. The inspectors reviewed opened and closed corrective actions for NCVs to determine whether the licensee had corrected previous examples of non-compliance with NRC regulations and on corrective actions from OE reviews. For further insight into potential problems, CAP entries were discussed with the resident inspectors who routinely evaluated these activities as part of the NRC baseline inspection program.

In addition, the inspectors interviewed plant personnel directly involved with the CAP, as well as those cognizant of specific technical issues, to verify and understand corrective actions associated with those items reviewed.

(2) Findings

.1 General

In general, PIP reports associated with NCVs adequately addressed the associated problems. The majority of the sampled corrective actions identified and implemented by the licensee were effective in addressing the root causes of the problems. However, as indicated below, several examples were identified where the corrective actions warranted improvement.

Sample reviews of industry OE issues concluded that the licensee's process for screening and evaluating both internal and external OE were well established and adequately addressed the issues at the Oconee site. Documentation of the OE evaluations were for the most part complete, with only minor documentation problems noted concerning the referencing of the site response to the OE database.

.2 Inability to Align the Station ASW Pump Within 40 Minutes

Brief Overview

An AV of 10 CFR 50, Appendix B, Criterion XVI, Corrective Action, was identified for failure to promptly correct a CAQ. The condition concerns an inability to align the station ASW pump to supply lake water to the steam generators within the 40 minutes required for mitigation of a design basis tornado. PIP O-00-00363 identified that operators took over 60 minutes to align the pump during a simulator exercise on January 27, 2000. The simulator exercise had been performed in a controlled manner to specifically validate the ability of operators to accomplish the procedural actions within the required times. At the time of this inspection in March 2001, the licensee had not implemented corrective actions to assure that operators could align the station ASW pump within 40 minutes.

<u>Background</u>

In PIP O-00-00363, dated January 27, 2000, the licensee stated that the problem (inability to align the station ASW pump within 40 minutes) did not affect operability of the pump. The reason stated was that the problem was related to procedures and/or training for tornado mitigation and that, per NSD-203, Operability, procedure and training deficiencies were not considered to be operability issues. The licensee also originally stated that the risk related to this problem was low, in that, the failure to perform this action would result in less than a 2 percent increase in the estimated core damage frequency for Oconee. Also, tornado frequency during the months of January and February was very low. The PIP stated that to assure operators' ability to start the station ASW pump within 40 minutes, the licensee planned to revise three procedures: EP/1,2,3/1800/01, Emergency Operation Procedure; AP/1,2,3/1700/011, Loss of Power; and AP/1,2,3/1700/006, Natural Disaster.

The design basis tornado event that was simulated on January 27, 2000, involved loss of offsite power to all three units, loss of all 4KV power to Unit 1, loss of main and emergency feedwater to all three units, failure of the SSF, and loss of the Keowee overhead path of electrical power. The simulation included the Keowee underground path subsequently energizing the standby busses to power equipment in Units 2 and 3. Licensee personnel stated that during this scenario, Unit 1 operators initially followed the EOPs for reactor trip and loss of all AC power, as required. They worked through the procedures attempting to operate several pieces of equipment damaged by the event before eventually getting to the Natural Disaster Abnormal Procedure (AP) steps for aligning the station ASW pump. Then, aligning the station ASW pump took some time. It involved manually opening steam generator atmospheric dump valves in the upper level of the turbine building, depressurizing the steam generators in coordination with the control room, repositioning several manual valves to align and start the station ASW pump in the lower level of the auxiliary building, and manually operating steam generator flow control valves in two penetration rooms in the upper level of the auxiliary building.

Aligning the station ASW pump was addressed in the Natural Disaster AP. Licensee engineers stated that in order to have operators start aligning the station ASW pump earlier in the event, the EOP and Loss of Power AP needed to be revised to integrate the operation of the station ASW pump into them. Draft revised procedures had been written and had been validated in September 2000. The simulator validation had demonstrated that the draft revised procedures would assure the ability to align the station ASW pump within the required 40 minutes during a design basis tornado event. However, the draft revised procedures had not been implemented as of March 22, 2001.

The licensee's reasons for not promptly revising and implementing procedures to assure the ability of operators to align the station ASW pump within 40 minutes included:

1) The risk of a tornado in January and February 2000 was low.

2) Failure to perform this action would result in less than a 2 percent increase in the estimated core damage frequency for Oconee.

3) Oconee was in the midst of a major EOP rewrite in January 2000 and did not want to further burden EOP writers or operators with more procedure changes.

At the time of this inspection, the licensee was performing another major EOP rewrite to put EOPs into a two-column format.

4) The same procedures were also being revised to address identified problems with taking a suction from the spent fuel pool with an HPI pump to mitigate a tornado. Addressing the two problems in one procedure revision would result in less burden to operators.

5) Around September 2000, licensee engineers identified a technical problem with the use of the station ASW pump. Use of the pump to supply lake water to a steam generator would result in exceeding the vendor operational limits on maximum steam generator tube-to-shell differential temperatures. Licensee engineers decided that resolution of the problem would involve a new vendor analysis of the effects of the potential tube-to-shell differential temperatures. They decided to wait until this problem was resolved before issuing revised procedures for aligning the station ASW pump.

6) This licensee's planned procedure revision included a rapid cool down of the reactor coolant system with station ASW flow to the steam generators in order to quickly reduce the steam generator tube-to-shell differential temperatures. However, licensee engineers wanted to verify that operators could stop this cool down in time to prevent inadvertent nitrogen injection into the reactor coolant system from the core flood tanks.

Assessment

The inspectors noted that the station ASW pump is not addressed in TS, but is addressed in Selected Licensee Commitments (SLCs), which are in Chapter 16 of the UFSAR. SLC 16.9.9, ASW System and Main Steam Atmospheric Dump Valves, required that the ASW pump and main steam atmospheric dump valves be operable with the plant in modes 1, 2, or 3. SLC 16.9.9 further required that if the ASW system was inoperable, the licensee must restore it to operable within 30 days or submit a report to the NRC within 30 additional days. The licensee had not corrected the procedural deficiencies within 30 days and had not submitted a report to the NRC because of their interpretation in NSD-203 that procedure and training deficiencies did not affect operability.

The inspectors noted that the licensee had re-analyzed the need for aligning station ASW within 40 minutes, and had confirmed that the ASW was needed within 40 minutes to prevent core damage. This new analysis was documented in calculation OSC-2262, Tornado Protection Analysis, Revision 4, dated December 21, 2000.

The inspectors assessed each of the licensee's reasons as stated above for not promptly establishing the ability to align station ASW within 40 minutes:

1) The delay for the lack of tornado environmental conditions was only applicable through February 2000. However, over a year had passed and the issue remained unresolved.

2) The inspectors estimated, and licensee engineers confirmed, that a 2 percent increase in core damage frequency for Oconee would represent a magnitude of

about 1.8E-6. At the request of the inspectors, the licensee estimated the increase in core damage frequency resulting from the inability to align station ASW within 40 minutes and found it to be 6E-6. The inspectors noted that either estimate was more than the value of 1E-6 (i.e., a risk significance that could result in a White or greater finding).

3) The EOP upgrade dealt largely with procedural enhancements and should not have delayed the correction of an important procedural deficiency. Both the SLC statements and the increase in core damage frequency of 6E-6 indicated that this procedural deficiency should have been promptly corrected.

4) It was not appropriate to delay the correction of this important procedural deficiency to coordinate with other less important planned procedure changes. The inspectors noted that the licensee had relied on the ability to use the station ASW pump to limit the safety significance of the deficient HPI procedures for tornado mitigation that was characterized as a White Finding (SDP/EA-00-137) in NRC Inspection Reports 50-269,270,287/00-11 and 00-07.

5) It was not appropriate to delay the correction of this important procedural deficiency to coordinate with resolution of the steam generator tube-to-shell differential temperature issue, particularly once they concluded that the station ASW pump was operable because its operation was not reasonably expected to fail the steam generator tubes. The licensee should have promptly corrected the procedural deficiencies because their analysis showed that failure to align the station ASW pump within 40 minutes would lead to core damage. Correcting the procedures would not have made the steam generator tube-to-shell differential temperature problem worse. Starting the ASW pump earlier would actually reduce the differential temperature because the reactor coolant temperature would not be as high. In the possibility that operation of the station ASW pump would fail some steam generator tubes, failure of the tubes within 40 minutes may be preferred, in that, there was still a possibility of preventing core damage. The inspectors concluded that the worst condition would be to start the station ASW pump in 60 minutes, when core damage is expected, and to fail the steam generator tubes at that time.

6) It was not appropriate to delay the correction of this important procedural deficiency to coordinate with resolution of other problems that had not yet been introduced. The existing procedures did not include a rapid cool down of the steam generators and did not raise the concern of injecting nitrogen into the reactor coolant system.

Enforcement

10 CFR 50, Appendix B, Criterion XVI, Corrective Action, requires that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected. This requirement is implemented through the licensee's Quality Assurance Program by NSD 208, Problem Investigation Process. Contrary to the requirements of Criterion XVI, the licensee failed to promptly correct a condition adverse to quality in that the inability to align the station ASW pump within 40 minutes to mitigate a tornado, which was identified on January 27, 2000, was not corrected as of March 22, 2001. The untimely corrective action resulted in an inability to mitigate a design basis tornado for

over one year. This violation of 10 CFR 50, Appendix B, Criterion XVI, is being treated as an AV, pending further NRC review of the safety significance. It is identified as AV 50-269,270,287/01-08-06: Failure to Promptly Correct the Inability to Align Station ASW Within 40 Minutes. This AV is in the licensee's corrective action program as a revision to PIP O-00-0363.

.3 Inadequate Post-Maintenance Testing of Reactor Trip Breaker

A Green finding that was dispositioned as a NCV of 10 CFR 50, Appendix B, Criterion XI, was identified for failure to conduct appropriate post-maintenance testing on a reactor trip breaker.

During attendance of a PIP screening meeting, the inspectors reviewed PIP O-01-00763, which described a condition identified by the licensee on March 6, 2001. The PIP questioned the operability of Unit 2 reactor trip breaker CB-1 because the breaker had been returned to service without being retested after being partially racked out. Maintenance personnel had been performing the monthly surveillance test on the reactor trip breaker, which required independently testing the undervoltage trip and the shunt trip. The breaker had correctly tripped when tested, but then failed to close after the shunt trip test. In an attempt to correct the problem, maintenance personnel partially racked out the breaker and racked it back in; thereby "wiping" the secondary contacts in the process to improve the electrical connections. However, maintenance personnel performed this corrective action without any written authorization or instructions, and made no record in the completed surveillance procedure of the breaker failing to close or of the breaker being partially racked out. The breaker was subsequently closed from the control room and returned to service.

In response to the PIP written by operations personnel, which questioned the need for post-maintenance testing, licensee engineers concluded that the breaker was operable without further testing because the ability of the breaker to close demonstrated that the trip function would work. The inspectors reviewed the TS surveillance requirement, the breaker electrical control diagram, photos of the breaker internals, and the completed work order and surveillance procedure; discussed them with licensee engineers; and concluded that the engineers had reached an incorrect conclusion. The inspectors noted that closing of the breaker did not verify that the secondary contacts for the shunt trip circuit had the needed electrical connection. Also, there were no indicating lights to confirm that the shunt trip circuit was energized. The inspectors noted that partially racking out the breaker could possibly improve the electrical connections of the secondary contacts; but could also possibly degrade the electrical connection of the secondary contacts, including those for the shunt trip circuit. Consequently, the action of partially racking out the breaker removed the assurance the monthly surveillance test provided that the breaker would trip open via the shunt trip circuit; therefore, the breaker should have been retested before being returned to service. In response to the inspectors concerns, the license satisfactorily completed a monthly surveillance test on breaker CB-1 before the end of this inspection.

The inspectors concluded that maintenance personnel, by performing corrective actions without written authorization or documentation of the breaker failure, circumvented the work control process; thereby precluding the possible recognition for the need of a subsequent retest. Similarly, the inadequate operability assessment by engineering was another missed opportunity to identify the need for a subsequent retest. This issue was more than minor because of the credible impact on safety by returning the reactor trip breaker to service without an adequate post-maintenance test to demonstrate its capability to trip when called upon. Because the breaker operated correctly during the subsequent retest, this issue was determined to have very low safety significance (Green).

Criterion XI of 10 CFR 50, Appendix B requires in part that all testing required to demonstrate that components will perform satisfactorily in service is identified and performed. The failure to perform post-maintenance testing on reactor trip breaker CB-1 is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy and is identified as NCV 50-270/01-08-07: Failure to Conduct Appropriate Post-Maintenance Testing on Unit 2 Reactor Trip Breaker CB-1. The licensee entered this issue into their corrective action program via PIP O-01-0957.

.4 <u>Significant Decrease in Reactor Coolant Level During Shutdown</u>

A Green finding that was dispositioned as a NCV of 10 CFR 50, Appendix B, Criterion XVI, Corrective Action, was identified for failure to take adequate corrective action for a condition adverse to quality. Corrective actions taken following cold leg venting problems on Unit 2 during shutdown in May 1998, did not correct repetitive issues of an increased magnitude on Unit 1. Specifically, similar cold leg venting problems on Unit 1 in February 2000, resulted in a notable decrease in reactor coolant inventory during shutdown conditions with fuel in the reactor vessel.

On February 26, 2000, with Unit 1 in Mode 5 for a RCS leak repair, RCS level decreased from the normal operating band of 76 - 80 inches (reactor flange) to 34 inches. The operators had previously filled the RCS following the repair and had been monitoring the volume of water added. Prior to the time of the event, they concluded that 7000 gallons were still needed to maintain the RCS full to 80 inches. Because of this volume deficiency, the operators anticipated that air was still trapped in the cold legs and could result in a level decrease. Therefore, they had maintained in effect the requirements for draining below 50 inches. Upon noticing the level decrease, the operators immediately began adding water and refilled the RCS to 79 inches. This event was caused by air in the J-portion of the cold leg that was trapped by tight seals on the uncoupled reactor coolant pumps (RCPs). When maintenance personnel lifted the 1B1 RCP shaft for coupling, air in that cold leg vented and allowed water from the reactor vessel to fill the cold leg and steam generator, which resulted in the level decrease. The licensee documented this event in the corrective action program as PIP O-00-00738.

The inspectors noted that PIP O-00-00738 contained no cause evaluation and no corrective actions. When questioned, the licensee stated that the event was anticipated, they had determined how much air volume was in the cold legs, and if it all vented at once level would reach approximately 35 inches on 1LT-5. The inspectors later learned that a similar, but smaller (two inches) level decrease on Unit 1 had occurred on February 21, 2000. The PIP for that event (PIP O-00-00639) also contained no problem evaluation, but did contain corrective actions (developed after the February 26, 2000, event) to coordinate RCP coupling activities with RCS fill to eliminate or reduce trapped air in the cold legs. The inspectors did a search and found a previous event on Unit 2 in May 1998 that was documented in PIP O-98-02450. This PIP evaluated the cause as trapped air in the cold leg and provided corrective actions to vent the cold legs when filling. The inspectors reviewed procedures and found that instructions to vent the cold legs were included for all three units; however, the instructions for Units 2 & 3 were different from those for Unit 1 because of the different types of RCPs. Because the Unit 1 cold legs were not vented sufficiently to preclude the event of February 26, 2000, the inspectors considered the venting instructions for Unit 1 to be ineffective for correcting the problem identified in PIP O-98-02450. None of the PIPs referenced any of the others.

Because of the size of the decrease (32 inches), the inspectors considered this a loss of control event that could be a precursor to events that result in an actual loss of decay heat removal (DHR). Although the operators were aware that air may have been trapped in the RCS and that a decrease in level may occur, the level decrease was not planned and the operators could not have been certain at the time that trapped air was the cause. Other circumstances, such as a fluid leak in the DHR system or an intersystem leak, could have caused the same level decrease and assuming that trapped air was the reason would have masked the real event. The inspectors evaluated this event using the Shutdown Operations SDP. Because it was considered a loss of control event, a quantitative phase 3 analysis was performed by a risk analyst. This event was determined to have very low safety significance (green) because the licensee had compensatory measures in place for draining below 50 inches and because cold leg design would have limited the decrease to no lower than the top of the cold legs.

The inspectors concluded that the ineffective cold leg venting instructions for Unit 1 failed to correct a condition adverse to quality from a similar event on Unit 2 in 1998. This constituted a violation of 10 CFR 50 Appendix B, Criterion XVI. This violation is being treated as a NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy and is identified as NCV 50-269/01-08-09: Inadequate Corrective Actions For Air in RCS Cold Legs Resulting in an Inadvertent RCS Level Decrease. This violation is in the licensee’s corrective action program as PIP O-01-01140.

.5 Effectiveness of EOP Corrective Action Program

A negative observation was identified concerning the progress of the licensee’s EOP Corrective Action Program. The inspectors concluded that the licensee’s program was progressing slowly in validating time critical actions. This was based on accomplishments made since the last NRC review of the program.

The licensee’s progress on the EOP Corrective Action Program was last reviewed by the NRC in April 2000, and was documented in NRC Special Inspection Report 50-269,270,287/00-04. During this inspection, the inspectors noted that the licensee had maintained their list of time critical operator actions that were needed to mitigate potential events. The list briefly described each action, the event that was being mitigated, the time within which the action must be completed, and identified the actions that were evaluated by the PRA as having high and medium risk importance.

The inspectors noted that the list included 68 time critical actions, of which the licensee had successfully validated 31 to date. Validations involved simulating performance of the actions on the simulator and in the plant to assure that operators could perform the actions correctly and within the required times. The licensee had completed validation of all of the actions with the highest risk significance that had to be performed within the first 30 minutes of an event. However, the inspectors noted that the licensee had not validated some medium risk significant actions that had to be completed within 30 minutes. The licensee also had not validated some high risk and some medium risk actions that had longer allowable completion times.

One of the medium risk actions that had not been successfully validated was alignment of the station ASW pump within 40 minutes to mitigate a tornado (see Section 4OA2.c.(2).2). Examples of other important actions that had not been validated, included: align hotwell recirculation flow to emergency feedwater system upper surge tank within 20 minutes to mitigate a loss of main feedwater; add water to the elevated water storage tank using a fire truck following a turbine building flood; open control rod drive breakers in the cable room within about 1 minute to mitigate an anticipated transient without scram (ATWS) event; throttle high pressure injection within 10 minutes to prevent pressurized thermal shock; control auxiliary building flooding within 10 minutes to prevent loss of safety related equipment; and trip reactor coolant pumps within about 1 minute if all seal cooling is lost.

The inspectors questioned why the action to immediately trip reactor coolant pumps if all seal cooling was lost had not been validated, since that action had been in the emergency operating procedures for years and should not have been difficult to validate. Licensee personnel stated that this action had not been validated because it had just been added to the list. It had not originally been on the list because the allowable time for completing the action had not been determined. While the list currently indicated a required completion time of 1 minute, licensee personnel stated that they believed that, with the new reactor coolant pump seals that had been installed on Unit 1 at the end of 2000, the new required completion time might be as long as 14 minutes, but had not yet been determined. The inspectors also noted that the action to stop control room flooding (see Section 4OA2.b.(2).3) was not yet included on the list. The inspectors concluded that the licensee's EOP Corrective Action Program was still identifying time critical operator actions and was progressing slowly in validating them as well.

d. Effectiveness of Self-Assessments and Audits

(1) Inspection Scope

The inspectors reviewed a variety of licensee audits and self-assessments of problem identification and resolution to determine whether they were consistent with NRC findings. As part of these reviews, the inspectors reviewed the licensee's most recent comprehensive self-assessment of the CAP to verify if findings and recommended areas for improvement were being entered into the licensee's CAP, and that appropriate corrective actions were taken to resolve identified CAQs or program deficiencies. As applicable, self-assessment findings were compared to recent NRC findings. The self-assessment was conducted of the Nuclear Assessment and Issues Division, Nuclear Performance Assessment Section from the Duke Energy General Office from September 13-30, 1999, and was identified as SA-99-35 (ALL)(RA), Level 3 Assessment of the Corrective Action Program. The findings from this assessment were documented in PIP G-99-00352.

During the inspection on March 20, 2001, the licensee completed the first of a new CAP assessment which replaces the previous comprehensive audit approach. The new assessments will now be preformed on a quarterly basis for all three Duke Energy sites to allow for more focused inspections on the subjects of problem identification and screening, root cause and apparent cause evaluations, effectiveness of corrective actions, and trending analysis. The inspectors verified that on an annual basis, the reviews should encompass all of the key areas that the previous comprehensive audits had reviewed. The inspectors reviewed the first Assessment Report (SA-01-03), which assessed the problem identification and screening aspects of the corrective action program at all three sites.

(2) Findings

.1 General

Audit and self-assessment findings were consistent with the NRC conclusions. The inspectors determined that the findings noted in the previous sections of this report were similar to those identified in the most recent focus assessment and the comprehensive 1999 licensee self-assessment of the CAP. The review indicated that the licensee self-assessments were thorough and effective in identifying deficiencies in the corrective action program and other programmatic areas. These deficiencies were routinely entered into the CAP, with areas for improvement being identified for all three Duke facilities.

.2 Technical Audits of Single Failure Vulnerabilities

The inspectors reviewed the results of the licensee's recently completed technical audits of single failure vulnerabilities of several systems that were relied upon to mitigate design basis events. The systems audited included: emergency feedwater, high pressure injection, low pressure injection, reactor building spray, service water, control room ventilation, and penetration room ventilation. The audits were well organized and documented. They were also effective, in that they identified a total of about 50 single failure vulnerabilities. The inspectors verified that the identified vulnerabilities were appropriately entered into the CAP.

.3 Self-Initiated Technical Audit (SITA) of the Standby Shutdown Facility (SSF)

The inspectors reviewed the results of the licensee's recently completed SITA of the SSF. The audit report was dated November 21, 2000. The audit appeared to be effective, identifying pertinent findings that were appropriately described in 30 new PIPs. It also included many recommendations, was well organized, and was clearly written.

e. Assessment of Safety Conscious Work Environment

(1) Inspection Scope

The inspectors discussed the issue of maintaining a safety conscious work environment while performing followup activities related to PIP reviews to determine whether any conditions exist that would cause employees to be reluctant to raise safety concerns. This included personnel from all departments that perform regulated activities and input from the NRC resident inspectors. Interviews with licensee management involved with the Duke Energy Concerns Resolution Program were also conducted.

(2) Findings

Employees did not appear reluctant to raise nuclear safety issues and the inspectors concluded a safety conscious work environment existed at Oconee.

4OA6 Management Meetings

Exit Meeting Summary

The inspectors presented the inspection results to Mr. W. McCollum, Site Vice President, as well as other members of licensee management and staff, near the conclusion of the inspection on March 22, 2001. Subsequently, on April 19, 2001, the inspection results were presented again to Mr. L. Nicholson, Regulatory Compliance Manager. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any of the material examined during the inspection should be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

L. Azzarello, Engineering Manager, Design Basis
E. Burchfield, Engineering Supervisor II, Design Basis
D. Brewer, Engineering Supervisor II, Severe Accident Analysis Group
D. Coyle, Operations Supervisor
M. Nazar, Station Manager
W. Foster, Safety Assurance Manager
L. Keller, Corporate Audits and Assessment Manager
W. McCollum, Site Vice President, Oconee Nuclear Station
L. Nicholson, Regulatory Compliance Manager

NRC

L. Plisco	Director, Division of Reactor Projects (DRP), Region II
W. Rogers	Senior Reactor Analyst, RII
N. Merriweather	Senior Reactor Inspector, RII
P. Fillion	Reactor Inspector, RII

ITEMS OPENED AND CLOSED

Opened

50-269,270,287/01-08-02	URI	Steam Generator Tube Stresses Resulting From Use of the Station ASW Pump (Section 4OA2.a.(2).2)
50-269,270,287/01-08-03	URI	Operator Access to Steam Generator Atmospheric Dump Valves to Mitigate a Tornado (Section 4OA2.a.(2).3)

50-269,270,287/01-08-05	AV	Failure to Correctly Identify and Evaluate a CAQ Involving a Potential Control Room Flooding Issue (Section 4OA2.b.(2).3)
50-269,270,287/01-08-06	AV	Failure to Promptly Correct the Inability to Align Station ASW Within 40 Minutes (Section 4OA2.c.(2).2)

Opened and Closed During this Inspection

50-269,270,287/01-08-01	NCV	Failure to Enter Issue of Steam Generator Tube Stresses Resulting From Use of the Station ASW Pump into the Corrective Action Program and Perform Required Operability Evaluation (Section 4OA2.a.(2).2)
50-287/01-08-04	NCV	Failure to Take Adequate Corrective Action in Response to a Violation of NRC Requirements (Section 4OA2.b.(2).2)
50-270/01-08-07	NCV	Failure to Conduct Appropriate Post-Maintenance Testing on Unit 2 Reactor Trip Breaker CB-1 (Section 4OA2.c.(2).3)
50-269/01-08-08	NCV	Inadequate Corrective Actions For Air in RCS Cold Legs Resulting in an Inadvertent RCS Level Decrease (Section 4OA2.c.(2).4)

LIST OF ACRONYMS

AP	-	Abnormal Procedure
ASW	-	Auxiliary Service Water
ATWS	-	Anticipated Transient Without Scram
AV	-	Apparent Violation
CAP	-	Correction Action Program
CAQ	-	Condition Adverse to Quality
CART	-	Corrective Action Review Team
CCW	-	Circulating Cooling Water
DHR	-	Decayed Heat Removal
EFW	-	Emergency Feedwater
EOP	-	Emergency Operating Procedure
FSAR	-	Final Safety Analysis Report
GL	-	Generic Letter
HPI	-	High Pressure Injection
IN	-	Information Notice
MEPR	-	Major Equipment Problem Resolution
NCV	-	Non-Cited Violation
NSD	-	Nuclear Site Directive
OE	-	Operating Experience
OEP	-	Operating Experience Program
PIP	-	Problem Investigation Report
PRA	-	Probabilistic Risk Assessment
RBCU	-	Reactor Building Cooling Unit
RCS	-	Reactor Coolant System

SITA	-	Self-Initiated Technical Audit
SSF	-	Standby Shutdown Facility
SDP	-	Significance Determination Process
SLC	-	Selected Licensee Commitment
SSF	-	Standby Shutdown Facility
TS	-	Technical Specifications
UFSAR	-	Updated Final Safety Analysis Report
URI	-	Unresolved Item
VIL	-	Vendor Information Letter
WR/WO	-	Work Request/Work Order

LIST OF DOCUMENTS REVIEWED

PIPS/Work Orders (WO)

O-93-01064	3C RBCU had high currents and tripped
O-98-02450	RCS level indication slowly decreasing
O-99-00707	Water hammer on steam generator hot blowdown lineup
O-99-01268	Auxiliary Building internal flood design basis needs clarification
O-99-02427	2C RBCU outboard bearing high temperature alarm received
O-99-03909	The EFW system is not designed to meet single failure criteria
O-99-04474	Operations not informed of tech spec related control battery parameter problems
O-99-04525	Suction source to Unit 1&2 spent fuel cooling pumps secured due to valve misposition
O-99-05041	3B RBCU motor and fan replacement
O-00-00363	Procedural issues with tornado mitigation
O-00-00403	Operations was not aware of the need to enter a TS condition while working on WO 98188783-01
O-00-00474	TS condition not entered as required
O-00-00502	Relay cabinets as Maintenance Rule A1
O-00-00512	Failure of breaker SK1 to close
O-00-00611	Pressure boundary RCS leak on 1B2 cold leg drain
O-00-00623	Powering SSF from Unit 2 during SSF design event may not be viable option for SSF diesel failure

O-00-00639	1LT-5 level changes due to changes in RCS pressure
O-00-00643	Cold leg ultrasonic level detector failed low during RCS drain
O-00-00688	Unit 2 SSF RC makeup pump discharge pressure gauge failure
O-00-00738	RCS inventory reduction below the level control band
O-00-00764	Adverse trend on procedure technical inaccuracy
O-00-00767	Adverse trend in human errors associated with communications
O-00-00874	Unit 1 SSF RC makeup pump tripped during testing
O-00-00915	Appendix R cooldown calculation
O-00-00933	All three Oconee units entered TS 3.0.3 due to failure of both the A and B chillers
O-00-00946	Company vehicle number 10580 found in the protected area in an unsecured condition
O-00-00969	Potential non-conservatism in criticality calculations for spent fuel pool
O-00-01036	During a procedure review and walk down of the SSF submersible pump, it was determined that an electrical modification to power supply at SSF building could greatly reduce the amount of time required to perform task
O-00-01193	Implementation of QA-5 program is not occurring in time frame identified; apparent confusion over program and requirements on part of maintenance and work control personnel; questions about effectiveness of communication of program and actual preparedness of station for implementation
O-00-01222	2Unit 1 RC system identified as A1 per requirements of EDM-210, Maintenance Rule
O-00-01317	Improved TS 3.5.3 bases may impose restrictions not required by actual specification
O-00-01351	Near miss on top of polar crane (personnel almost injured)
O-00-01428	NI greater than 4% below core thermal power
O-00-01436	RBCU motor stator temperatures affected by generator output voltage
O-00-01456	Inadequate LPSW pump NPSH during a LOOP/single failure scenario
O-00-01499	Potential H2 leakage in the auxiliary building

O-00-01509	Critique of the 2000 SSF annual outage, entered to document and create corrective actions
O-00-01558	Adequacy/timeliness of operability evaluation for 3B RBCU in December 1999
O-00-01642	SSF DBDs require parameters to be controlled in ranges that cannot be read on gauges
O-00-01795	LTOP computer points inoperable
O-00-01906	In Mode 4, one of two trains required to ensure sufficient LPI flow
O-00-02021`	Unit 3 turbine vibration is high on bearings #6, 8, and 11
O-00-02252	Flange/piping leak downstream of 2HD-60 near the 6 inch to 18 inch transition
O-00-02271	Valves 1,2,3HP-14 classified as maintenance A1 components
O-00-02273	Non-safety grade piping routed through the station control rooms needs to be evaluated for leakage potential and the effect on plant controls
O-00-02322	Unit 3 power reductions after 3B1 waterbox outlet valve closed
O-00-02396	Unit 1 SSF reactor coolant makeup pump suction gauge off-scale high
O-00-02471	Keowee service water sample shows high Asian clam count
O-00-02491	Acceptance criteria not met for 2MS-24
O-00-02515	3A LPI cooler had reduced thermal performance (adverse trend identification)
O-00-02529	Found alternate SSF submersible pump pathway blocked
O-00-02645	Concern with Maintenance Rule performance criteria being unacceptable
O-00-02687	Raw sewage overflow to yard drain
O-00-02798	Magneta rag dropped into Unit #1&2 SFP and drawn into spent furl pumps suction line
O-00-02923	Oram-Sentinel risk assessment giving a red condition
O-00-02928	Stator coolant temperature transmitters in Maintenance Rule A(1)
O-00-03079	Corrosion on the 2C HPI pump base plate
O-00-03112	Wrong correction factors used for specific gravity on power battery

O-00-03393	The 1B HPI pump would not rotate by hand during final pump and motor alignment checks
O-00-03532	A recently completed calculation, OSC-7552, titled "Penetration Room Ventilation (PRV) System Single Failure Analysis" identified five potential vulnerabilities with this system
O-00-03607	RPS trip setpoints below allowable limits
O-00-03683	Interdependencies of SSF systems need further analysis
O-00-03725	Peak RCS pressures used as input to the calculation that verifies 1HP-404 will not lift between 10 & 14 minutes after the start of an accident that requires operation of the U1 SSF RC makeup system are less than the actual maximum pressure that could be present
O-00-03788	2B2 RCP seal injection flow increase
O-00-04055	Inadequate SSF diesel generator air start system leak rate test procedure
O-00-04071	Trending is not clearly documented for the service and performance tests of SSF batteries
O-00-04078	Inadequate resolution and corrective actions of SSF DG air start system air dryer concern
O-01-00079	Unit 1 pressurizer heaters bank 1 not operating, pressurizer heater group G ground fault.
O-01-00083	A recently created calculation, OSC-7548, titled "High Pressure Injection System Single Failure Analysis," showed that for all valve, pump, or flow indication single failures, the system is adequately designed. However, in some scenarios, the procedural guidance to align the HPI system to mitigate the failure may need to be enhanced
O-01-00157	Core flood tank line break with operator action to trip reactor coolant pumps
O-01-00432	LPI single failure analysis identified a vulnerability associated with LP-104 failing in the closed position after failure of certain power supplies; this could affect long term containment environment
O-01-00763	CB-1 and CB-2 DC breakers failed to reset after shunt trip
WO 96081238	Splice cables to disable EFW and RPS feedwater PS (Temp Modification ONTM-1298)

Inspection Reports

50-269,270,287/99-08

50-269,270,287/99-09

50-269,270,287/00-01

50-269,270,287/00-02

50-269,270,287/00-05

50-269,270,287/00-07

Drawings

OFD-100A-1.3	Flow Diagram of Reactor Coolant System, Revision 9
OFD-100A-2.3	Flow Diagram of Reactor Coolant System, Revision 10
OFD-101A-1.1	Flow Diagram of High Pressure Injection System, Revision 33

NCVs (PIPs)

NCV 00-05-10 (O-97-03567)	Inappropriate acceptance criteria established for relief valve testing
NCV 99-09-02 (O-98-02788)	In-service testing program discrepancy with seal injection check valves
NCV 99-09-02 (O-00-00337)	Possible problem with documentation retention
NCV 00-05-04 (O-00-01484)	Problems associated with power range NI calibration requirements; appropriate changes to procedures did not occur when Improved TSs were implemented and when UFSAR accident analysis changes were made
NCV 00-06-07 (O-00-01486)	South low pressure invertor pump room had three inches of water
(O-00-01590)	NRC Inspection Report 99-13, dated March 9, 2000, included 7 apparent violations involving the licensing bases requirements for EFW; this PIP is to track the evaluation and associated corrective actions from the Enforcement Conference on April 25, 2000 (Multiple NCVs)
NCV 00-06-07 (O-00-02099)	Unit 1 low pressure invertor room sump pumps should be powered from a non unit specific power supply

NCV 00-05-08 (O-00-02461)	TS 3.6.5 creates vulnerability to inventory loss in Mode 4
NCV 00-06-01 (O-00-03351)	Heavy fumes in Unit 2 East Penetration Room due to painting for Material Upgrade program

Operating Experience Program Documents

OE 10139 PIP O-00-00506	Failure of Fisher model 3582 positioners
OE 10941	Reactor coolant filter repeatedly clogged after a demineralizer was returned to service following a refueling outage
OE 10566	Inadvertent start of containment spray pump due to personnel error
PIP O-00-00585	Interpretation of the Snubber SLC remedial action requirements and the operability of supported systems by snubbers
OEDB 99-024123, PIP O-00-0179	Mispositioned valve caused inadvertent draindown of the reactor coolant system as shutdown cooling is placed in service (INPO SEN-211)
OEDB 00-024200	Potential fire hazard in the use of polyalphaolefin in testing of air filters
OEDB 00-024216	SER 1-00 Significant reactor coolant system leak resulting from heat removal piping failure

Audits and Assessments (PIPs)

O-00-00457	Engineering self-assessment on corrective action timeliness and quality
O-00-00764 O-00-00767	Assessment of human errors associated with verbal communication
O-00-01023	SA-00-05 (ALL)(RA)(RP) Assessment of radiation protection area
O-00-01240	Assessment of three site maintenance/work control functional area evaluation SA-00-003 (ON)(RA)
O-01-00167	Evaluation of emergency preparedness
O-01-0590	Evaluation of ONS engineering compliance with NSD-209

Procedures

NSD 208	Problem Investigation Process (PIP), Revision 22
OP/1/A/1103/011	Draining and Nitrogen Purging RCS, Revision 41
OP/1/A/1103/011	Draining and Nitrogen Purging RCS, Revision 42

OP/1/A/1103/011	Draining and Nitrogen Purging RCS, Revision 43
OP/1/A/1103/011	Draining and Nitrogen Purging RCS, Revision 44
OP/2/A/1103/011	Draining and Nitrogen Purging RCS, Revision 38
OP/1/A/1102/004	Operation at Power, Revision 89
OP/2/A/1102/004	Operation at Power, Revision 63
OP/3/A/1102/004	Operation at Power, Revision 60
MP/0/B/1310/054	RCP Seal/Shaft Lift For RCS Fill, Revision 0
IP/0/A/0385/001A	SSF Battery Weekly Surveillance, Revision 21
IP/0/A/0385/001D	SSF Battery Quarterly Surveillance, Revision 16
IP/0/A/3000/001	Instrument and Control Battery Weekly Surveillance, Revision 24
IP/0/A/3000/001A	Power Battery Weekly Surveillance, Revision 0
IP/0/A/3000/001D	230 KV Switchyard Battery Weekly Surveillance, Revision 29
IP/0/A/3000/001F	Keowee Hydro Battery Weekly Surveillance, Revision 0
IP/0/A/3000/011	Instrument and Control Battery Quarterly Surveillance, Revision 18
IP/0/A/3000/011A	Power Battery Quarterly Surveillance, Revision 0
IP/0/A/3000/011D	230 KV Switchyard Battery Quarterly Surveillance, Revision 21
IP/0/A/3000/011F	Keowee Hydro Battery Quarterly Surveillance, Revision 0

NRC'S REVISED REACTOR OVERSIGHT PROCESS

The federal Nuclear Regulatory Commission (NRC) 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 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

- Initiating Events
- Mitigating Systems
- Barrier Integrity
- Emergency Preparedness

Radiation Safety

- Occupational
- Public

Safeguards

- Physical Protection

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 little effect on safety. WHITE findings indicate issues with some increased importance to safety, which may require additional NRC inspections. YELLOW findings are more serious issues with an even higher potential to effect safety and would require the NRC to take additional actions. RED findings represent an unacceptable loss of safety margin and would result in the NRC taking significant actions that could include ordering the plant shut down.

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 incremental degradation in safety: GREEN, WHITE, YELLOW, and RED. The color for an indicator corresponds to levels of performance that may result in increased NRC oversight (WHITE), performance that results in definitive, required action by the NRC (YELLOW), and performance that is unacceptable but still provides adequate protection to public health and safety (RED). GREEN indicators represent performance at a level requiring no additional NRC oversight beyond the baseline inspections.

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. As a licensee's safety performance degrades, the NRC will take more and increasingly significant action, as described in the matrix. 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.

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

Attachment