UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
SAM NUNN ATLANTA FEDERAL CENTER
61 FORSYTH STREET SW SUITE 23T85
ATLANTA, GEORGIA 30303-8931

July 31, 2000

EA 00-069

Virginia Electric and Power Company
ATTN: Mr. David A. Christian
Senior Vice President and
Chief Nuclear Officer
Innsbrook Technical Center - 2SW
5000 Dominion Boulevard
Glen Allen, VA 23060-6711

SUBJECT: NORTH ANNA POWER STATION - NRC INTEGRATED INSPECTION REPORT NOS. 50-338/00-03, 50-339/00-03

Dear Mr. Christian:

On July 1, 2000, the NRC completed an inspection at your North Anna Power Station Units 1 and 2. The enclosed report presents the results of that inspection which were discussed with Mr. J. Hayes and other members of your staff on July 18, 2000.

The inspection was an examination of activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. Within these areas, the inspection consisted of a selective examination of procedures and representative records, observations of activities, and interviews with personnel.

Based on the results of this inspection, four issues of very low safety significance (Green) were identified. All of these issues were determined to involve violations of NRC requirements. However, the violations were not cited due to their low safety significance and that they had been entered into your corrective action program. 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 North Anna Power 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 C. Haag, Chief
Reactor Projects Branch 5
Division of Reactor Projects

Docket Nos.: 50-338, 50-339
License Nos.: NPF-4, NPF-7

Enclosure: NRC Integrated Inspection Report Nos. 50-338/00-03, 50-339/00-03

cc w/encl:
William Renz, Acting Manager
Nuclear Licensing and
Operations Support
Virginia Electric and Power Company
Electronic Mail Distribution

D. A. Heacock
Site Vice President
North Anna Power Station
Virginia Electric and Power Company
Electronic Mail Distribution

E. S. Grecheck
Site Vice President
Surry Power Station
Virginia Electric and Power Company
Electronic Mail Distribution

Executive Vice President
Old Dominion Electric Cooperative
Electronic Mail Distribution

County Administrator
Louisa County
P. O. Box 160
Louisa, VA 23093

Donald P. Irwin, Esq.
Hunton and Williams
Electronic Mail Distribution

Attorney General
Supreme Court Building
900 East Main Street
Richmond, VA 23219

Electronic Distribution w/encl:
B. Summers, OE
S. Monarque, NRR
W. Dean, NRR
PUBLIC

OFFICE	RII	RII	RII	RII	RII	RII	RII
SIGNATURE	lg	mm	lh	kb for fw	gb for sv	ws	tm
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U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos.: 50-338, 50-339
License Nos.: NPF-4, NPF-7

Report Nos.: 50-338/00-03, 50-339/00-03

Licensee: Virginia Electric and Power Company (VEPCO)

Facility: North Anna Power Station, Units 1 & 2

Location: 1022 Haley Drive
Mineral, Virginia 23117

Dates: April 2 through July 1, 2000

Inspectors: M. Morgan, Senior Resident Inspector
J. Canady, Resident Inspector
L. Hayes, Physical Security Specialist, RII (Sections 3PP1, 3PP2 and 4OA1.4)
F. Wright, Senior Radiation Specialist, RII (Section 2OS2)
S. Vias, Reactor Inspector, RII (Section 1RO7)
W. Sartor, Emergency Preparedness Specialist, RII (Sections 1EP2, 1EP3, 1EP4, 1EP5, 4OA1.1, 4OA1.2 and 4OA1.3)
T. Morrissey, Project Engineer, RII (Section 4OA3.6)

Approved by: R. Haag, Chief, Reactor Projects Branch 5
Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000338-00-03, IR 05000339-00-03, on 4/02-07/1/2000; Virginia Electric and Power Co.; North Anna Power Station Units 1 & 2. Personnel Performance During Nonroutine Plant Evolutions, Event Followup, TI 2515/144.

The inspection was conducted by resident inspectors, a regional senior radiation specialist, a regional reactor inspector, a regional physical security specialist, a regional emergency preparedness specialist and a regional project engineer. This inspection identified four green issues which were non-cited violations. The significance of issues is indicated by their color (green, white, yellow, red) and was determined by the Significance Determination Process.

Cornerstone: Initiating Event

- GREEN. A non-cited violation was identified for plant personnel failing to follow plant approved maintenance activity procedures. This is a violation of Unit 2 Technical Specification (TS) 6.8.1.a. The procedure violation resulted in a reactor coolant pump trip and a manual reactor trip on Unit 2 and a recognition that the 1H emergency diesel generator was inoperable when the diesel failed to start.

  The issue had very low safety significance for Unit 2 due to the safety systems performing as designed. On Unit 1, the issue was also of low safety significance due to the following mitigating factors: (1) the short time that the 1H emergency bus was unavailable; (2) the availability of safety related equipment powered by the 1J emergency bus; and, (3) the availability of the station blackout diesel generator. (Section 1R14.2)

Cornerstone: Mitigation Systems

- GREEN. A non-cited violation was identified for the failure to have an adequate procedure in effect to provide alternative shutdown capability (i.e., to achieve and maintain a safe shutdown condition) in the event of a main control room fire. This is a violation of Technical Specification 6.8.1.a.

  The issue was of very low safety significance due to the very low fire initiating event frequency associated with the condition. (Section 4OA3.6)

- GREEN. A non-cited violation was identified for failure to have an operable emergency diesel generator (EDG) during Unit 1 fuel handling activities (TS 3.8.1.2.b), and to have a loop of service water unavailable for longer than allowed (TS 3.7.4.1) when Unit 2 was in Mode 1. The violations resulted from 1H EDG unknowingly being inoperable due to oil in the 1H EDG cylinder and the 1J EDG being removed for maintenance.

  The issue was of very low safety significance because during the time frame both Unit 1 EDGs were inoperable, two independent offsite power supply circuits were operable and capable of supplying power to safety related equipment and the station blackout diesel was available to provide power if necessary. (Section 4OA3.2)

Cornerstone: Barrier Integrity

- GREEN. A non-cited violation was identified for inadequate surveillance testing procedures associated with the performance testing of the safeguards area exhaust dampers and air accumulators. The time duration specified in the procedures for

determining air leakage from the system's accumulators was not sufficient for determining whether the exhaust dampers would remain open for 30 days following a design basis loss of coolant accident. This is a violation of Technical Specification 6.8.1.c. After the exhaust dampers were tested with the revised surveillance procedures, they were determined to not meet the 30 day requirement.

The issue was of very low safety significance since the auxiliary building central ventilation system (although not seismic class 1 nor class 1E powered) can serve as a backup to the safeguards exhaust ventilation system by manual realignment through the charcoal filters. In addition, the emergency core cooling pumps located in the safeguards building can operate in excess of 24 hours without ventilation cooling. This would allow sufficient time for the radioactive dose to decrease enough for plant personnel to install a temporary air supply or restore instrument air. (Section 4OA3.3)

Report Details

Unit 1 began the inspection period shut down for a scheduled refueling outage. The unit returned to service on April 7, 2000, and full power was reached on April 12. On May 7, the unit tripped due to a failure of the Unit 1 generator output breakers. Repairs to the breakers were performed and the unit restarted on May 10. Full power was restored on May 13 and the unit operated at or near 100 % power for the remainder of the inspection period.

Unit 2 began the inspection period at 100% power. On April 3, 2000, the unit tripped due to a failure of a 2C station service transformer cable. Unit power was restored to 7% power on April 4. Later that day, the unit was manually tripped due to a loss of the C reactor coolant pump. Repairs to the service station transformer cable were completed and the unit was restarted on April 5. Full power was restored on April 6 and the unit remained at or near 100% power for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R04 Equipment Alignment

a. Inspection Scope

For the systems identified below, the inspectors reviewed the listed plant documents to determine correct system lineup, and observed equipment to verify that the system was correctly aligned:

- Unit 2 2J Emergency Diesel Generator Systems (procedures: 2-OP-6.2A, Revision 8, Valve Checkoff - Cooling Water; 2-OP-6.4A, Revision 6, Valve Checkoff - Lube Oil);
- Unit 2 2H Emergency Diesel Generator Systems (procedures: 2-OP-6.1A, Revision 6, Valve Checkoff - Cooling Water; 2-OP-6.3A, Revision 6, Valve Checkoff - Lube Oil);
- Unit 1 & 2 Service Water Pumping Systems (procedure 0-OP-49.1A, Revision 28, Valve Checkoff - Service Water);
- Unit 1 & 2 Component Cooling (CC) Heat Exchangers (procedures: 1-OP-51.1A, Revision 17, Valve Checkoff - CC; 2-OP-51.1A, Revision 13, Valve Checkoff - CC);
- Unit 2 B Charging Pump System (procedure 2-OP-8.1A, Revision 19, Valve Checkoff - Chemical and Volume Control; B Charging Pump Cubicle Section); and,
- Unit 2 C Charging Pump System (procedure 2-OP-8.1A, Revision 19, Valve Checkoff - Chemical and Volume Control; C Charging Pump Cubicle Section).

b. Issues and Findings

There were no findings identified.

1R05 Fire Protection

a. Inspection Scope

The inspectors conducted tours of the following areas to assess the adequacy of the fire protection program implementation. The inspectors checked for the control of transient combustibles and the condition of the fire detection and the fire suppression systems to verify the conditions were in accordance with Virginia Power Administrative Procedure (VPAP)-2401, Revision 13, Fire Protection Program.

- Unit 1 Mechanical Equipment Room
- Unit 1 and 2 Turbine Building (fire zones 10, 11, 12, and 14)
- Unit 2 2H Emergency Diesel Generator Room
- Unit 1 Turbine-Generator G12 Output Breaker Area
- Unit 1 and 2 Service Water Pump Building
- Unit 1 and 2 Charging Pump Cubicles

b. Issues and Findings

There were no findings identified.

1R07 Heat Sink Performance

a. Inspection Scope

The inspectors reviewed procedures and documentation and held discussions with system engineers to ensure that heat exchanger deficiencies which could mask or degrade performance were identified. The following components were inspected: component cooling heat exchangers, recirculation spray heat exchangers, charging pump gear box lube oil coolers, control room chillers, and diesel generator lube oil coolers. Site procedures for testing, inspection and cleaning of the equipment were reviewed. Inspection/cleaning records for various heat exchangers dated from 1997 to the present were reviewed for methods and criteria used, and results obtained. Maintenance Rule documentation for scoped equipment was reviewed for any recurring problems. The site plant issues (PI) database was reviewed to assure that issues pertaining to systems containing scoped components were being identified. Discussions were also held with design and system engineers related to the above components about the criteria and methodology used to determine heat sink heat transfer performance and results obtained. Performance testing activities on the Unit 1 Control Room Chiller (1-HV-E-4B) were observed utilizing Periodic Test Procedure 1-PT-77.13.B, "Control Room Chiller Equipment Performance Test (1-HV-E-4B)," Revision 8.

During the course of the inspection, the inspectors' review included the following documents and procedures:

- 0-MCM-0801-01, Cleaning, Removal, and Plugging of Component Heat Exchanger Tubes, Revision 7;
- 0-MPM-0803-01, Periodic Disassembly, Inspection and Repair of the Control Room Air Conditioning Chillers, (1 / 2-HV-E-4A, B and C), Revision 10;
- 0-PT-75.15, Generic Letter 93-13, Service Water System Testing Requirements Coordination, Revision 3;
- Component Cooling Heat Exchanger 1-CC-E-1A Performance Test, Revision 5;
- Component Cooling Heat Exchanger 1-CC-E-1B Performance Test, Revision 6;
- Component Cooling Heat Exchanger 2-CC-E-1A Performance Test, Revision 5;
- Component Cooling Heat Exchanger 2-CC-E-1B Performance Test, Revision 5;
- 1-PT-62.2.1, RSHX SW Inleakage, Revision 11;
- 2-PT-62.2.1, RSHX SW Inleakage, Revision 9; and,
- Control Room Chiller Equipment Performance Tests (1-HV-E-4B, Revision 8; 1-HV-E-4C, Revision 7; 2-HV-E-4A, Revision 6; 2-HV-E-4B, Revision 5; and 2-HV-E-4C, Revision 6).

b. Issues and Findings

There were no findings identified.

1R11 Licensed Operator Requalification

a. Inspection Scope

The inspectors observed licensed operator performance during simulator training conducted on May 5, 2000, (Scenario Number 27) to determine whether the operators:

- were familiar with and could successfully implement the procedures associated with recognizing and recovering from an automatic safety injection failure and a recirculation swap-over failure;
- recognized the high-risk actions in those procedures; and,
- were familiar with related industry operating experiences.

b. Issues and Findings

There were no findings identified.

1R12 Maintenance Rule Implementation

.1 Equipment Issues

a. Inspection Scope

For the equipment issues described in the PIs and deviation reports (DRs) listed below, the inspectors reviewed the licensee's implementation of the Maintenance Rule (10 CFR 50.65) with respect to the characterization of failures, the appropriateness of the

associated a(1) or a(2) classification, and the appropriateness of either the associated a(2) performance criteria or the associated a(1) goals and corrective actions:

- N-2000-1057, B Main Condenser Steam Dump Valves failure;
- N-2000-1328, Unit 1 Generator Output Breaker, G-12 failure;
- N-1999-0445, DC Breakers to 1-I, 1-II, 1-III, and 1-IV Invertors Overheating; and,
- N-1998-1365, Unit 1 CRDM Fan and Damper failures.

b. Issues and Findings

There were no findings identified.

.2 System Implementation Reviews

a. Inspection Scope

The inspectors evaluated the effectiveness of the licensee's maintenance rule program for the Unit 1 feedwater discharge check valves, the emergency diesel generator batteries, and pressurizer powered operated relief valves (PORVs) 1-RC-PVC-1455C and 1456. The inspectors checked for proper system scoping, monitoring and categorization as required by the licensee's maintenance rule program (VPAP-0815, Revision 10, Maintenance Program).

b. Issues and Findings

There were no findings identified.

1R13 Maintenance Work Prioritization & Control

a. Inspection Scope

The inspectors reviewed the licensee's assessments of the risk impacts of removing from service those components associated with emergent work items. The inspectors determined whether the risk assessments were made in accordance with Section 6.7 of VPAP-2001, Revision 7, "Station Planning and Scheduling." The inspectors reviewed the following emergent items to verify that the licensee had taken the necessary steps to demonstrate that they were adequately planned and controlled to avoid initiating events, and to verify that the licensee ensured the functional capability of systems:

- PI N-2000-0003, 2-III Inverter SCR Diode Overheating;
- PI N-2000-1060, C Reserve Station Transformer Inspection / Restoration;
- PI N-2000-1079, Unit 2 C Station Service Transformer Cable Repairs;
- PI N-2000-1199, High Vibration on the Unit 1 A Feedwater Pump Motor Bearings;

- PI N-2000-1404, Lake Anna 1B Spillway Skimmer Gate Failures;
- PI N-2000-1633, Unit 2 A Charging Pump Motor Seal Repair; and,
- PI N-2000-1685, Unit 2 A Charging Pump Seal Repairs.

b. Issues and Findings

There were no findings identified.

1R14 Personnel Performance During Nonroutine Plant Evolutions

.1 Evolutions

a. Inspection Scope

The inspectors reviewed the licensee's post-event and post-trip reports and Licensee Event Reports (LERs) listed below to determine whether operator response to the event was in accordance with licensee procedures and training:

- N2-04-03-00 - April 3, Unit 2 Automatic Reactor Trip (LER 50-339/00001-00);
- N-2000-1061- April 4, 1H Emergency Diesel Generator (EDG) Start Failure (LER 50-338, 339/00002-00); and,
- N1-05-07-00 - May 7, Unit 1 Automatic Reactor Trip (LER 50-338/00004-00).

b. Issues and Findings

There were no findings identified.

.2 (Closed) LER 50-339/00002-00: manual reactor trip due to loss of a reactor coolant pump (RCP). On April 4, personnel errors caused the F transfer bus, Unit 1 and 2 C station service busses (SSBs) and the 1H (Unit 1) and 2J (Unit 2) emergency busses to be de-energized. This resulted in a trip of the C RCP. Since North Anna is not licensed to operate with less than 3 RCPs running, the operators manually tripped the Unit 2 reactor. Prior to the trip the unit was operating at about 7% power after the restart from the automatic trip on April 3.

All Unit 2 engineered safety feature (ESF) equipment responded as designed, including the 2J EDG which automatically started and re-energized the 2J emergency bus. Operators stabilized the unit using emergency procedure E-0, “Reactor Trip or Safety Injection.” After restoring offsite power to the 2J emergency bus and restarting the C RCP, the unit was restarted on April 5.

On Unit 1 the C RCP and the A residual heat removal (RHR) pump tripped. The 1H EDG failed to automatically start (see Section 4OA3.2); therefore, the 1H emergency bus was de-energized. At the time the unit was shutdown in Mode 5 for a refueling outage. The A RHR train, which is powered from the 1H emergency bus, was providing shutdown cooling. Within approximately two minutes, operators placed the B RHR train

in service for shutdown cooling. The 1H emergency bus remained de-energized for approximately 30 minutes until the F transfer bus and the Unit 1 C SSB were re-energized from offsite power. With the 1H EDG unavailable, two independent offsite power supply circuits were operable and capable of supplying power to safety related equipment and the station blackout diesel was also operable. The C RCP was restarted in approximately 50 minutes.

The licensee determined that event occurred when the incorrect potential transformer (PT) compartment drawer was opened. A licensed and one nonlicensed operator and a plant electrician were to reinstall fuses in the PT compartment for the C SSB. The workers were instructed to report to the switchgear room and wait for a senior reactor operator (SRO) and an electrical supervisor to arrive to perform a detailed pre-job brief. Prior to their arrival, the workers performed an informal search for the equipment tags/fuses associated with the C SSB. During their search they opened a PT compartment drawer other than the one associated with the C SSB. Opening a PT compartment drawer disconnects the PT fuses which causes the associated bus to be de-energized.

By opening the PT compartment drawer, personnel violated the following procedures:

- MPAP-0025, “Quality Maintenance Team Process,” Revision 9, Step 6.4.1 for performing actions prior to a planned pre-job brief;

- OPAP-0006, “Shift Operating Practices,” Revision 2, Step 6.10 for not receiving Shift Supervisor approval prior to performing actions on the equipment; and,

- VPAP-1401, “Conduct of Operation,” Revision 9, Step 5.3.6 for not using self-checking in performance of their duties.

These failures to follow procedures were violations of Technical Specification 6.8.1.a which requires procedures recommended in Regulatory Guide 1.33, Revision 2, to be implemented.

On Unit 2 the event had very low safety significance due to the safety systems performing as designed. On Unit 1, the significance of the event was mitigated by: (1) the short time that the 1H emergency bus was unavailable; (2) the availability of safety related equipment powered by the 1J emergency bus; and, (3) the availability of the station blackout diesel generator. Based upon these considerations and in accordance with the Significance Determination Process (SDP), the inspectors and NRC risk analysts determined that the event was of very low safety significance, i.e., green.

The failure to follow procedures is a violation of NRC requirements. However, this issue is considered as an non-cited violation (NCV) (50-339/00003-01) consistent with Section VI.A.1 of the NRC Enforcement Policy. This violation is in the licensee’s corrective action program as PI N2-2000-002-00.

1R15 <u>Operability Evaluations</u>

a. <u>Inspection Scope</u>

The inspectors evaluated the technical adequacy of the operability evaluations to ensure that operability was properly justified and the subject component or system remained available such that no unrecognized increase in risk occurred. The operability evaluations were described in the PIs and Engineering Responses (ERs) listed below:

- N-2000-1615, Unit 2 A Charging Pump Bearing Failure (ER 00-1615-R1, evaluation of sealant used in the bearing housing);
- N-2000-1061, Unit 1 1H EDG Start Failure (ER 00-1061-E2, evaluation to determine operability of EDG subsequent to corrective action completion);
- N-2000-1472, Unit 2 Heating and Ventilation Damper Leaks (ER 00-1472-R1, evaluation of the use of backdraft dampers in the safeguards ventilation system);
- N-2000-1419, Unit 2 2H EDG Fan Gearbox Oil Pump Inlet Port Crack (Licensee Engineering Log Entry Dated 5/8/00 and ER 00-1419-R1); and
- N-2000-1633, Unit 2 A Charging Pump Motor Seal Failure (ER 00-1633-E2, evaluation of the use of Tite seal for use in repairs).

b. Issues and Findings

There were no findings identified.

1R16 Operator Work - Arounds (OWAs)

a. Inspection Scope

During this inspection period, the inspectors reviewed the licensee's list of OWAs to determine whether any identified workarounds affected either the functional capability of the related system or human reliability in responding to an initiating event. In addition, the inspectors attended a licensee meeting in which licensee management reviewed each identified workaround. The following OWAs were assessed:

- 99-OWA-C02 C, Fire Protection Detector Replacement, Unit 1 A Main Transformer and,
- 98-OWA-B25 A, Enhancements to Minimize Impact of Feedwater Heater Relief Valve Lifts During Reactor Trips.

b. Issues and Findings

There were no findings identified.

1R17 Permanent Plant Modifications

a. Inspection Scope

The inspectors reviewed steps taken and related modifications for OWA no. 94-OWA-B01A. This is an on-going replacement of Unit 1 P250 computer inputs with Plant Computer System (PCS) inputs. The review was to determine whether overall P250

system operability/availability was affected, that configuration control was maintained, and that the associated safety evaluation adequately justified the change.

b. Issues and Findings

There were no findings identified.

1R19 Post Maintenance Testing

a. Inspection Scope

For the repaired or replaced components listed below, the inspectors reviewed the listed post maintenance test procedures to determine that the procedures and test activities were adequate to verify operability and functional capability of the system following maintenance and if such activities were in accordance with Section 6.13, Post Maintenance Testing of VPAP-0801, Maintenance Program, Revision 8:

- Filter cleaning, (0-MCM-0606-01, Revision 6, Removal and Installation of Reactor Coolant Letdown Filter);

- Coolant Changout, (2-PT-82.9H, Revision 17, 2H Emergency Diesel Generator Slow Start Test, (Local Operator start test));

- Repair recirculation heat exchanger SW isolation valves, (2-PT-62.2.1, Revision 9, Recirculation Heat Exchanger Service Water In Leakage);

- Coolant Changout, (1-PT-82J, Revision 21, 1J Emergency Diesel Slow Start Test); and,

- Charging pump 1A seal repair, (2-PT-14.1, Revision 35, Unit 2 Charging Pump 1A Periodic Test).

b. Issues and Findings

There were no findings identified.

1R20 Refueling and Outage Activities

a. Inspection Scope

On April 7 the inspectors observed the Unit 1 restart following the spring refueling outage. The inspectors verified that the operators who performed the Unit 1 startup had received training on expected activities prior to performing the actual unit restart. The inspectors also verified that the plant startup was performed in accordance with operating procedures and Unit 1 TS requirements. The inspectors evaluated reactivity management, main turbine-generator startup activities, supervisory oversight during the approach to criticality, and overall operator attentiveness.

b. Issues and Findings

There were no findings identified.

1R22 Surveillance Testing

a. Inspection Scope

For the surveillance tests listed below, the inspectors examined the test procedure and either witnessed the testing and/or reviewed test records to determine whether the scope of testing adequately demonstrated that the affected equipment was functional and operable:

- 2-PT-75.2A.1, Revision 10, Unit 2 Service Water Pump 1A Head Curve Verification;
- 2-PT-82H, Revision 24, 2H Emergency Diesel Generator Slow Start Test;
- 2-PT-71.2Q, Revision 20, Unit 2 Feedwater Pump 3A Pump and Valve Test;
- 2-PT-30.3.2.1, Revision 30, Power Range Protection Channel N41 Channel Functional Test;
- 1-PT-44.7, Revision 15, PORV Block Valve Channel Checks; and,
- 2-PT-77.11A, Revision 14, Control Room Chiller 4A Pump and Valve Test.

b. Issues and Findings

There were no findings identified.

1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed Temporary Modification N2-99-1126, installation of a temporary resistance temperature detector in control room mechanical chiller, 2-CD-MR-1, to determine whether system operability/availability was affected, that configuration control was maintained, and that the associated safety evaluation adequately justified implementation.

b. Issues and Findings

There were no findings identified.

Cornerstone: Emergency Preparedness

1EP2 Alert and Notification System (ANS) Testing

a. Inspection Scope

The inspector evaluated the ANS system design and the testing program. The testing program was reviewed to determine that it was meeting availability requirements and the timeliness of correcting system siren problems when identified.

b. Issues and Findings

There were no findings identified.

1EP3 Emergency Response Organization Augmentation

a. Inspection Scope

The inspector reviewed the design of the emergency response organization augmentation system and the maintenance of the licensee's capability to staff emergency response facilities within stated timeliness goals.

b. Issues and Findings

There were no findings identified.

1EP4 Emergency Action Level (EAL) and Emergency Plan Changes

a. Inspection Scope

The inspector reviewed changes to the Emergency Plan and the EALs to determine whether any of the changes decreased the effectiveness of the Emergency Plan. The current North Anna Power Station Emergency Plan, Revision 22, had been reviewed during a 1999 calendar year inspection. The EAL revision in document EPIP-1.01, Revision 30, was reviewed. The review was performed against 10 CFR 50.54(q) and no apparent decrease in effectiveness was identified.

b. Issues and Findings

There were no findings identified.

1EP5 Correction of Emergency Preparedness Weaknesses and Deficiencies

a. Inspection Scope

The inspector evaluated the efficacy of licensee programs that addressed weaknesses and deficiencies in emergency preparedness. Items reviewed included exercise and drill critique reports, PI resolution reports, program effectiveness self assessments, and Nuclear Oversight Audit Report 00-03.

b. Issues and Findings

There were no findings identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS2 As Low As Is Reasonably Achievable (ALARA) Planning and Controls

a. Inspection Scope:

The inspectors reviewed collective radiation exposures and goals and ALARA planning documentation for the radiological controls implemented in the Unit 1 refueling outage (RFO). The inspectors interviewed the ALARA Coordinator and reviewed licensee procedures and records listed below associated with source term reduction and radiation work controls to minimize collective doses:

- FSAR, Chapter 12, Radiation Protection;
- VPAP- 2101, Radiation Protection Program, Revision14;
- VPAP- 2102, Station As Low as Reasonably Achievable (ALARA) Program, Revision 7;
- VPAP- 2105, Temporary Shielding Program, Revision 3;
- NAPS CH-93.120, Chemistry Controls: Refueling Outage, Revision 13;
- NAPS 0-PT-200.2, High Radiation Sampling System Chemistry Monitoring Instrumentation Calibration Verification, Revision 4;
- NAPS CH-94.300, High Radiation Sampling System Control, Revision 1;
- Health Physics - 1020.011, Radiological Protection Action Plan During Diving Activities, Revision 1;
- Health Physics - 1071.020, Controlling Contamination Material, Revision 2;
- Health Physics - 1081.010, Radiation Work Permits, Revision 9;
- Health Physics - 1032.061, High Radiation Key Control, Revision 7;
- North Anna Power Station (NAPS) 1999 Unit Two Refueling and 10 year ISI Outage ALARA Report, dated 12/06/99;
- NAPS Outage ALARA Guide for Unit One Refueling Outage March, 2000, (no revision or date on document);
- NAPS 1999 Annual ALARA Report, dated 02/01/00;
- Nuclear Oversight Chemistry and Radiological Protection Audit Report, 99-07, dated August 17, 1999;
- Nuclear Oversight Chemistry and Radiological Protection Audit Checklist, 99-07, dated August 18, 1999;
- Nuclear Oversight Radiological Environmental Monitoring/Offsite Dose Calculation Manual / Process Control Program Audit Report, 99-13, dated January 18, 2000;
- Nuclear Oversight Radiological Environmental Monitoring/Offsite Dose Calculation Manual / Process Control Program Audit Checklist, 99-13, dated January 20, 2000; and
- NAPS 2000 Unit 1 Controlled Shutdown Considerations, dated February 22, 2000.

b. Issues and Findings:

Licensee collective occupational radiation dose goal for the Unit 1 RFO was less than 86 person-rem. The licensee met the goal, completing the RFO with approximately 51.5 person-rem. The licensee's annual occupational collective dose goal for year 2000 was approximately 96 person-rem. The collective occupational radiation dose, accumulated in the first 3 months of year 2000, was also on target for the licensee to meet the annual exposure goal. There were no findings identified.

3. SAFEGUARDS

Cornerstone: Physical Protection

3PP1 Access Authorization

a. Inspection Scope

The inspectors reviewed VPAP-0105, “Fitness For Duty Program,” Revision 14, Fitness For Duty (FFD) reports for calendar year 1999, and licensee audit (00-01, dated April 3, 2000). Additionally, the inspectors interviewed representatives of licensee management and escort personnel concerning their understanding of the behavior observation portion of the personnel screening and FFD program. In interviewing personnel, the inspectors reviewed the effectiveness of their training and abilities to recognize aberrant behavioral traits.

b. Issues and Findings

There were no findings identified.

3PP2 Access Control

a. Inspection Scope

The inspectors observed access control activities on June 26 and 28, 2000, and equipment testing conducted on June 28, 2000. In observing the access control activities, the inspectors assessed whether officers could detect contraband prior to it being introduced into the protected area. Additionally, the inspectors assessed whether the officers were conducting access control equipment testing in accordance with regulatory requirements through observation, review of procedures, and log entries. Preventative and post maintenance procedures were reviewed and observed as performed. During the course of the inspection, the inspector reviewed the following security plan implementing procedures (SPIPs):

- SPIP- 006, Authorized Personnel Access Control, Revision 4;
- SPIP- 007, Visitor Authorization and Sign-In, Revision 5;
- SPIP- 008, Vehicle / Material Access Control, Revision 5;
- SPIP- 011, Lock, Key, Core and Key Card Control, Revision 5;
- SPIP- 015, Inspections and Tests, Revision 8; and,
- SPIP- 016, Personnel Searches, Revision 6.

b. Issues and Findings

There were no findings identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification

.1 Emergency Response Organization (ERO) Drill/Exercise Performance

a. Inspection Scope

On April 20, 2000, the inspector assessed the accuracy of the performance indicator for ERO drill and exercise performance (DEP) through review of documentation for the first quarter 2000. Records reviewed were the scenarios and drill files for specific dates of training. In addition, the inspectors reviewed and discussed the licensee's methodology for calculating the DEP performance indicator.

b. Issues and Findings

There were no findings identified.

.2 ERO Drill Participation

a. Inspection Scope

On April 20, 2000, the inspector assessed the accuracy of the performance indicator for ERO drill participation through review of source records for selected individuals.

b. Issues and Findings

There were no findings identified.

.3 ANS Reliability

a. Inspection Scope

On April 20, 2000, the inspector assessed the accuracy of the performance indicator for ANS reliability during the previous four quarters (second quarter 1999 - first quarter 2000) through review of the licensee's records of annual full-cycle tests and the polling test conducted the first and third weeks of each month in the 10-mile radius surrounding the North Anna Power Station. The records reviewed showed a siren availability for year-to-date of 99.97%.

b. Issues and Findings

There were no findings identified.

.4 Physical security performance indicator

a. Inspection Scope

The inspector reviewed Virginia Power's programs for gathering and submitting data for the FFD, Personnel Screening, and Protected Area Security Equipment Performance Indicators. The review included Virginia Power's tracking and trending reports and

security event reports for the Performance Indicator data submitted from the first quarter 1998 to the first quarter of 2000.

b. Issues and Findings

There were no findings identified.

40A3 Event Follow-up

.1 Event Review

a. Inspection Scope

For the following event, the inspectors reviewed the associated facility operating logs, trip report, and LER to evaluate performance of mitigating systems and operator response:

- N2-04-04-00, April 4, Unit 2 Manual Reactor Trip, (LER 50-339/00002-00, see Section 1R14.2).

b. Issues and Findings

There were no findings identified.

.2 (Closed) LER 50-338, 339/00002-00: conditions prohibited by technical specifications and outside design basis with EDGs inoperable. On April 4, personnel errors caused the F transfer bus, Unit 1 and 2 C station service busses (SSBs) and the 1H (Unit 1) and 2J (Unit 2) emergency busses to be de-energized. The 1H EDG failed to start and re-energize the 1H emergency bus (see Section 1R14.2). The licensee determined that the 1H EDG number 3 cylinder was hydraulically locked due to lube oil between the pistons. After the oil was drained, the 1H EDG was inspected for possible damage and successfully started and operated before it was returned to service on April 5.

The licensee's review established the following sequence. On March 21 the 1H EDG was removed from service to support 1H emergency bus maintenance. During this work portions of the lube oil keep warm system were de-energized which allowed the lube oil to cool from its normal operating temperature of 120°F to approximately 92°F. When the keep warm system was returned to service, the keep warm system pump was able to push the low temperature, high viscosity lube oil into the upper crankcase. The lube oil then flowed down into the cylinders. Due to the position of the number three cylinder pistons, the exhaust ports were covered blocking the lube oil from draining back to the lube oil sump. This occurrence is consistent with the EDG manufacturer's recommendations that oil temperatures be maintained above 110°F to prevent flooding of the upper crankcase while the EDG is in standby. On March 22 following the 1H emergency bus maintenance, the licensee performed checks on the 1H EDG to verify that all switches and parameters were in their normal positions and ranges. Based upon this and that no direct maintenance was performed on the 1H EDG, the licensee did not start the EDG before declaring it operable. Thus, the 1H EDG was hydraulically locked, i.e., inoperable, from March 22 until April 4 when it failed to start.

Other contributing factors to the event were the quality of procedures and a change to work scheduling. Procedures were subsequently revised to provide additional guidance to address low lube oil temperatures.

The 1J EDG was out of service for maintenance from March 22 through March 26. Thus, the 1H and the 1J EDG were both inoperable for approximately 96 hours. As a result, the following TSs were not met:

- TS 3.8.1.2.b requires that one EDG must be operable during movement of irradiated fuel assemblies or loads over irradiated fuel assemblies when no fuel assemblies are in the reactor vessel. However, between March 23 and March 26, 2000, irradiated fuel assemblies were moved in the spent fuel pool without a Unit 1 operable EDG.

- TS 3.7.4.1 requires that two service water (SW) loops shall be operable with each loop consisting of two operable SW pumps (SWPs) with their associated normal and emergency power supplies. With two SWPs inoperable, restore one SWP to operable status within 72 hours or place both units in Hot Standby within the next six hours and in Cold Shutdown within the following 30 hours. One SW loop was operable with the Unit 2 SWPs operable. However, the other SW loop had no Unit 1 SWPs operable for greater than 72 hours and Unit 2 was not placed in Hot Standby. This condition was outside the design basis of the plant.

During the time frame both Unit 1 EDGs were inoperable, two independent offsite power supply circuits were operable and capable of supplying power to safety related equipment. In addition, the station blackout diesel was available to provide power if necessary. Based upon these considerations and using the SDP, the inspectors and Region II risk analysts determined that the event was of very low safety significance, i.e., a green issue.

This issue involved violations of Technical Specifications 3.8.1.2.b and 3.7.4.1. However, this issue is considered as an NCV (50-338, 339/00003-02) consistent with Section VI.A.1 of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as PI N2-2000-002-00.

.3 <u>(Closed) LER 50-338, 339/00003-00</u>: multiple safeguards ventilation damper test failures due to system leakage. The licensee's ventilation system integrated review team identified a concern that the safeguards exhaust ventilation system (SAVS) may not fulfill its safety function following a design basis loss of coolant accident (LOCA). The safety functions of the system are to remove heat from the safeguards building due to the running of emergency core cooling (ECCS) pump motors and to filter the air through charcoal filters prior to atmospheric release. The licensee determined that the 10 minute performance tests did not provide assurance that the SAVS discharge dampers would remain open and aligned to the charcoal filters for 30 days following the design basis LOCA. The performance tests required holding the discharge dampers open for 10 minutes using air from the system accumulators with the instrument air isolated. The licensee revised the test procedures to require holding the SAVS discharge dampers open for ten hours and to determine whether the capacity of the accumulators with the existing leakage will hold the dampers open for 30 days.

The performance tests for each units A and B SAVS trains using the ten hour testing criteria were determined to be unsatisfactory. One Unit 1 discharge damper would have closed in approximately 9.8 days and the other in 20 hours. For Unit 2, the discharge dampers would have closed in approximately 9.6 hours and 26.7 hours. After making repairs to leaks discovered during the tests, one of the two Unit 1 dampers was determined to meet the 30 day requirement. The other Unit 1 damper would have closed in approximately 16.6 days. The Unit 2 dampers were predicted to close in approximately 9 and 10 days.

The failure of the exhaust dampers due to air leakage was documented in the corrective action program as PI N-2000-1472. The immediate corrective action for the damper failures included the development of Justification for Continued Operation (JCO) 2000-01 and the implementation of a temporary modification and procedure 0-GOP-21.1, “Safeguards Ventilation Discharge Damper Temporary Air Supply,” Revision 0, which provided an air cylinder as a backup to the installed accumulator. The inspectors reviewed these immediate corrective actions and found them to be adequate. The long term corrective action to replace the existing air operated dampers with backdraft dampers was entered into the corrective action program as PI N-2000-1273.

TS 6.8.1.c requires written procedures to be established, implemented, and maintained for surveillance and test activities of safety related equipment such as the SAVS. Contrary to this requirement, the procedures listed below were inadequate, in that, the time duration for the performance testing of the SAVS exhaust dampers and air accumulators were not of sufficient duration for determining whether the exhaust dampers would remain open for 30 days following the design basis LOCA:

- Performance Test of Safeguards Area Exhaust Damper 1-HV-AOD-1301A and Air Accumulator 1-IA-TK-5A, Revision 0;
- Performance Test of Safeguards Area Exhaust Damper 1-HV-AOD-1301B and Air Accumulator 1-IA-TK-5B, Revision 1;
- Performance Test of Safeguards Area Exhaust Damper 2-HV-AOD-1301A and Air Accumulator 2-IA-TK-5A, Revision 1; and
- Performance Test of Safeguards Area Exhaust Damper 2-HV-AOD-1301B and Air Accumulator 2-IA-TK-5B, Revision 1.

The failure to meet the requirements of the TS is identified as a violation of NRC requirements. However, this issue is considered as an NCV (50-338, 339/00003-03) consistent with Section VI.A.1 of the NRC Enforcement Policy. The licensee entered this issue in the corrective action system as PI N-2000-3043.

The issue of the SAVS not being able to fulfill its safety function following a design basis LOCA was assessed using the Significance Determination Process and was determined to be of very low safety significance (i.e., green). Factored into this determination was that the auxiliary building central ventilation system can serve as a backup to the SAVS by manual realignment through the charcoal filters. However, the auxiliary building central ventilation system does not meet the licensing basis requirements of being seismic class 1 with class 1E power. Additionally the licensee determined that the ECCS pumps located in the safeguards building would continue to operate in excess of

24 hours without ventilation cooling. The basis was an informal calculation that included the environmental qualification of the pumps, heat input from the pump motors, and heat losses due to piping and concrete conduction. This would allow sufficient time for the radioactive dose to decrease enough for plant personnel to install a temporary air supply or restore instrument air. The inspectors reviewed this calculation and determined that it was reasonable.

.4 (Closed) LER 50-339/00001-00: automatic reactor trip due to loss of the station service transformer (SST). On April 3 with Unit 2 operating at 100% power, an automatic reactor trip occurred when the 2C SST lockout relay actuated. This resulted in a turbine trip/reactor trip.

Actuation of the 2C SST lockout relay was due to a ground fault in a secondary feeder cable from the 2C SST to the 2C station service bus. Operators properly responded to the trip and all ESF equipment functioned as designed. The licensee conducted a post-trip review meeting in order to identify the cause of the trip, to identify any abnormal indications which may have occurred during the trip, and to assess unit readiness for return to operation. The inspectors noted that this event posed no significant safety implications and the unit's reactor protection and ESF systems functioned as designed following the trip.

The licensee determined that the root cause of the trip was due to actuation of the 2C SST lockout relay due to a fault on a 4160 volt low side cable that shorted to the supporting cable tray. The 4160 volt low side cable failure was due to a degradation of the cable sheathing because of cable aging and repeated excessive heating at a sharp bend/crimp in the cable run. The failed cable was repaired and the 2C SST was returned to service on April 5. Other 2C SST cables are scheduled for future licensee inspections and possible replacements.

.5 (Closed) LER 50-338/00004-00: automatic reactor trip due to malfunction of generator output breaker. On May 7, Unit 1 tripped from 100% power due to a generator lockout-turbine trip. The generator lockout-turbine trip occurred due to a malfunction on the A phase of the G12 generator output breaker. The main generator was isolated from the grid by the tripping of the G104 and G105 breakers in the switch yard. The G12 breaker had failed to open on a ground fault. Control room personnel responded to the trip in accordance with the emergency procedure for a reactor trip. All ESF equipment responded as designed.

The inspectors responded to the site and observed that the plant was stable in a hot standby condition. The inspectors also toured the area of the G12 output breaker. The inspectors noted that this event posed no significant safety implications based on proper personnel performance and equipment response.

The licensee's corrective action included isolating the G12 output breaker from the circuit and subsequently replacing the breakers. The reactor trip was placed in the licensee's corrective action program as PI N-2000-1328. The root cause evaluation had not been completed by the end of the inspection period.

.6 (Closed) LER 50-338, 339/99003-00: potential loss of high head safety injection (HHSI) pumps due to postulated main control room (MCR) fire. On March 31, 1999, a licensee fire protection integrated review determined that a postulated MCR fire could result in

the loss of all Unit 1 and Unit 2 HHSI pumps. The pumps could be damaged by the depletion of both volume control tanks (VCTs) and the subsequent introduction of gas to the pumps' suction. The loss of all HHSI pumps would place the station outside its Appendix R design basis in that the loss of all HHSI pumps could result in the inability to achieve and maintain a safe shutdown condition. The circuitry for the automatic realignment of the pumps' suction from the VCT to the refueling water storage tank (RWST) was not protected from the effects of a fire and therefore, was not credited in the Appendix R Report analysis. Realignment of Unit 1 and 2 HHSI pumps suction to the applicable RWST must be performed manually. Fire contingency action (FCA) procedure 0-FCA-1.00, "Limiting MCR Fire," Revision 16, was in place to direct this realignment. However, the licensee determined that the procedure did not provide specific direction to ensure the alignment to the RWSTs was performed in time to preclude the depletion of both VCTs and a subsequent loss of all HHSI pumps. The licensee did not consider this postulated scenario during previous Appendix R reviews due to its complexity. The licensee issued DR N-99-0795 to document that the facility was outside its Appendix R design basis. The inadequate FCA procedure had existed since initial implementation of the licensee's Appendix R fire protection program. The licensee stated that procedure 0-FCA-1.00 was revised on April 1, 1999, to perform steps (i.e., manual positioning of valves, control switches and breakers) outside the MCR in time to prevent loss of HHSI on each unit. If time allows prior to evacuating the MCR, the operators protect the non-running HHSI pumps by placing them in "pull-to-lock" and realigning the pumps' suction to the RWST. However, the licensee does not take credit for these MCR actions to mitigate the consequences of a MCR fire.

As a result of the NRC fire protection triennial baseline inspection (documented in NRC Inspection Report Nos. 50-338, 339/00-07), the licensee documented two issues associated with procedure 0-FCA-1.00. The procedure did not de-energize the motor operated suction and discharge valves associated with both unit's C HHSI pumps to preclude hot short position changes. Additionally, the licensee could not locate documentation to demonstrate that the original Appendix R project verified that operator actions would be completed in the required time frame to achieve and maintain a safe shutdown condition. These items have been entered into the licensee's corrective action program as PI's N-2000-1606 and N-2000-1607.

Factors that would mitigate the consequence of a MCR fire include: continuous manning of the MCR, wall-mounted fire extinguishers, and continuous monitoring by smoke/fire detectors. Additionally, the site maintains a minimum fire brigade at all times. Although credit is not taken for the automatic realignment of either unit's HHSI pumps suction from the VCT to the RWST in the Appendix R Report analysis, the likelihood of this capability in both units being damaged by a single fire is small and is discussed in the paragraph below. The circuitry for the automatic realignment is contained in panels that are approximately 25 feet apart. Either unit without fire damage would be able to supply HHSI to the other unit via the charging cross-connect, if necessary. The inspectors verified that the licensee has procedures in place to supply HHSI via the charging cross-connect capability.

The risk associated with the loss of all HHSI pumps is consistent with the licensee response band in that the increase in core damage frequency is estimated at less than 1E-6. A fire in the main control room growing beyond the incipient stage and propagating from panel 1-1 to 1-2, traveling approximately 25 feet and, then passing from panel 2-1 into 2-2 would be necessary to create the condition. Based upon

information in the licensee's Individual Plant Examination of External Events, a fire of this nature would occur with a frequency of 3E-7/year. Using this frequency, the SDP analysis determined that the increase in core damage frequency would be less than 1E-6 and therefore is a green finding. The fire initiating event frequency was derived from:

> (1.9E-2 fires/year in the control room) ✱ (0.0025 probability that the control room fire was in cabinet 1-1 and it propagates into cabinet 1-2) ✱ (0.077 probability fire propagates to cabinet 2-1) ✱ (0.077 probability fire propagates to cabinet 2-2) = 3E-7.

TS 6.8.1.a and Regulatory Guide 1.33, Appendix A, Item 6.p, require written procedures to be established, implemented, and maintained for plant operations during emergencies such as a forced evacuation of the control room due to a control room fire. The failure to have an adequate procedure to achieve and maintain a safe shutdown condition in the event of a MCR fire is a violation of TS 6.8.1.a. This violation is being treated as an NCV consistent with Section VI.A.1. of the NRC Enforcement Policy, and is identified as NCV 50-338, 339/00003-04. This violation is in the licensee's corrective action program as DR N-99-0795.

40A5 Other - Performance Indicator Data Collecting and Reporting Process Review (Temporary Instruction (TI) 2515/144)

a. Inspection Scope

Inspectors conducted a review of the licensee's performance indicator data collecting and reporting process to determine whether the licensee is appropriately implementing the NRC/industry guidance, Nuclear Energy Institute (NEI) 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 0.

b. Issues and Findings

The inspectors reviewed the licensee's process for performance indicator data collection and determined that the system adequately collects data and accurately reports the performance indicators.

4OA6 Management Meetings

Exit Meeting Summary

The inspectors presented the inspection results to Mr. J. Hayes and other members of licensee staff at an exit meeting on July 18, 2000. 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

D. Christian, Senior Vice President and Chief Nuclear Officer
B. Foster, Superintendent Station Engineering
C. Funderburk, Manager, Station Operations and Maintenance
J. Hayes, Manager, Station Nuclear Safety and Licensing
D. Heacock, Site Vice President
P. Kemp, Director, Nuclear Oversight
L. Lane, Superintendent, Operations
T. Maddy, Superintendent, Station Security
W. Matthews, Vice President, Nuclear Operations
W. Renz, Director, Emergency Preparedness
H. Royal, Superintendent, Nuclear Training
D. Schappell, Superintendent, Site Services
R. Shears, Superintendent, Maintenance
A. Stafford, Superintendent, Radiological Protection

ITEMS OPENED AND CLOSED

Opened and Closed During this Inspection

50-339/00003-01	NCV	loss of a reactor coolant pump/manual reactor trip due to failures to follow plant-approved maintenance activity procedures (Section 1R14.2)
50-339/00003-02	NCV	loss of full service water system capability and unavailability of a Unit 1 emergency diesel generator during performance of fuel handling activities (Section 4OA3.2)
50-338, 339/00003-03	NCV	inadequate procedure for testing safeguard ventilation system exhaust dampers (Section 4OA3.3)
50-338, 339/00003-04	NCV	failure to have an adequate procedure to provide alternative shutdown capability (Section 4OA3.6)

Closed

50-339/00002-00	LER	manual reactor trip due to loss of a reactor coolant pump (Section 1R14.2)
50-338, 339/00002-00	LER	conditions prohibited by technical specifications and outside design basis with EDGs inoperable (Section 4OA3.2)
50-338, 339/00003-00	LER	multiple safeguards ventilation damper test failures due to system leakage (Section 4OA3.3)

50-339/00001-00	LER	automatic reactor trip due to loss of the station service transformer (Section 4OA3.4)
50-338/00004-00	LER	automatic reactor trip due to malfunction of generator output breaker (Section 4OA3.5)
50-338, 339/99003-00	LER	potential loss of high head safety injection pumps due to postulated main control room fire (Section 4OA3.6)
2515/144	TI	Performance Indicator Data Collecting and Reporting Process Review (Section 4OA5.1)

Attachment 1

NRC's REVISED REACTOR OVERSIGHT PROCESS

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

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

Reactor Safety

- 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 very low safety significance. WHITE findings indicate issues that are of low to moderate safety significance. YELLOW findings are issues that are of substantial safety significance. RED findings represent issues that are of high safety significance with a significant reduction in safety margin.

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

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

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