UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
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ARLINGTON, TEXAS 76011-4005

May 4, 2004

Mr. J. V. Parrish
Chief Executive Officer
Energy Northwest
P.O. Box 968; MD 1023
Richland, Washington 99352-0968

SUBJECT: COLUMBIA GENERATING STATION - NRC INTEGRATED INSPECTION REPORT 05000397/2004002

Dear Mr. Parrish:

On March 24, 2004, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Columbia Generating Station. The enclosed inspection report documents the inspection findings which were discussed on March 29, 2004, with you and other members of your staff.

The inspections examined 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. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

Based on the results of this inspection, the NRC identified four issues that were evaluated under the risk significance determination process as having very low safety significance (Green). These findings were also determined to be violations of NRC requirements. However, because they were of very low safety significance and because they were entered into your corrective action program, the NRC is treating these issues as noncited violations consistent with Section VI.A of the NRC Enforcement Policy. If you contest these noncited violations, you should provide a response with the basis for your denial, within 30 days of the date of this inspection report, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator, Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011-4005; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident inspector at the Columbia Generating Station.

In accordance with 10 CFR 2.390 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

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Sincerely,

/RA/

William B. Jones, Chief
Project Branch E
Division of Reactor Projects

Docket: 50-397
License: NPF-21

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NRC Inspection Report
05000397/2004002

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ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket:	50-397
License:	NPF-21
Report:	05000397/2004002
Licensee:	Energy Northwest
Facility:	Columbia Generating Station
Location:	Richland, Washington
Dates:	January 1 through March 24, 2004
Inspectors:	G. D. Replogle, Senior Resident Inspector, Project Branch E, DRP Z. K. Dunham, Senior Resident Inspector, Project Branch E, DRP R. P. Mullikin, Senior Reactor Inspector, DRS B. W. Tindell, Reactor Inspector, DRS D. L. Stearns, Project Engineer, Project Branch E, DRP
Approved By:	W. B. Jones, Chief, Project Branch E, Division of Reactor Projects
ATTACHMENT:	Supplemental Information

SUMMARY OF FINDINGS

IR05000397/2004002; 1/1/2004 - 3/24/2004; Columbia Generating Station. Equipment Alignments, Operability Evaluations, Surveillance Testing, and Other.

The report covered a 12-week period of inspection by the resident inspectors, and a regional senior reactor inspector, reactor inspector and project engineer. Four Green noncited violations were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter 0609, "Significance Determination Process." Findings for which the significance determination process does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

- Green. The inspectors identified a noncited violation of Technical Specification 5.4.1.a (inadequate procedure) for testing of the safety-related inverters. Specifically, Procedure 10.25.1, "Inspection and Cleaning Division 1, E-IN-3A and E-IN-3B, and Division 2, E-IN-2A and E-IN-2B, Inverters," prescribed placing a spare inverter in-service for load testing with a second inverter that was already in-service. This condition was not analyzed and was found to render the associated 125 VDC safety related battery inoperable. The inspectors also identified a problem identification issue related to this finding.

  This issue affects the mitigating systems cornerstone objective to ensure the availability of onsite emergency DC power. This issue is more than minor because it could have an actual impact on the ability of one train of emergency batteries to mitigate a loss of AC power to the safety-related inverters. Using the Phase 1 significance determination process the inspectors determined that the issue was of very low safety-significance because the issue: (1) was not a design or qualification deficiency; (2) did not result in the loss of a safety system; (3) did not represent an actual loss of a safety function of a single train for greater than its Technical Specification allowed outage time; (4) did not represent an actual loss of safety function of one or more nontechnical specification trains of equipment designated as risk significant per 10 CFR 50.65 for greater than 24 hours; and (5) was not potentially risk significant due to a seismic, fire, flooding, or severe weather initiating event (Section 1R15).

- Green. The inspectors identified a noncited violation of Technical Specification 5.4.1.a (inadequate procedure) for inappropriate preconditioning of a standby liquid control system valve. Procedure OSP-SLC/IST-Q701, "Standby Liquid Control Pumps Operability Test," failed to prescribe testing Valve SLC-V-1B in the as-found condition.

  This issue affects the mitigating systems cornerstone objective to ensure the reliability of the standby liquid control system to mitigate an initiating event to prevent undesirable consequences. This issue is more than minor because it could have an actual impact on identifying degraded valve performance and therefore impact the ability of the standby liquid control system to mitigate an anticipated transient without scram. Using the Phase 1 significance determination process the inspectors determined that the issue was of very low safety-significance because the issue: (1) was not a design or qualification deficiency; (2) did not result in the loss of a safety system; (3) did not represent an actual loss of a safety function of a single train for greater than its technical specification allowed outage time; (4) did not represent an actual loss of safety function of one or more nontechnical specification trains of equipment designated as risk significant per 10 CFR 50.65 for greater than 24 hours; and (5) was not potentially risk significant due to a seismic, fire, flooding, or severe weather initiating event (Section 1R22).

- Green. The inspectors identified a noncited violation of Technical Specification 5.4.1.d (inadequate procedure) because Procedure ABN-CR-EVAC, "Control Room Evacuation and Remote Cooldown," failed to provide adequate post-fire direction to: (1) assure suppression pool temperatures did not increase above residual heat removal pump temperature limits following depressurization; and (2) assure adequate core cooling with one safety relief valve stuck open.

  This issue affects the mitigating systems cornerstone objective to ensure the availability of the low pressure coolant injection system to mitigate an initiating event to prevent undesirable consequences. This issue is greater than minor because it impacted the mitigating systems cornerstone and affected the ability of the low pressure coolant injection system to provide adequate core cooling to prevent core damage in the event of an external factor, fire. This issue is of very low safety significance because: (1) general operator knowledge that suppression pool temperatures must be monitored and shutdown cooling must be used as a means to ensure the pool retains the ability to feed the low pressure injection system; and (2) the need to initiate shutdown cooling after depressurization is probably not an immediate pressing issue (Section 4OA5).

Cornerstone: Mitigating Systems and Barrier Integrity

- Green. The inspectors identified a violation of License Condition 2.C (14) for the failure to take appropriate corrective measures to address a condition adverse to quality affecting the low pressure coolant injection system. During a control room fire, the system was vulnerable to a water hammer since at least 1997 due to a leaking check valve in Train B of the residual heat removal system. Energy Northwest took more than five years to identify the condition and failed to specify appropriate corrective measures to promptly fix the condition.

  This issue affects the mitigating systems and barrier integrity cornerstone objective to ensure the availability of the low pressure coolant injection system to mitigate an initiating event to prevent undesirable consequences. This issue is greater than minor because it impacted the mitigating systems cornerstone and affected the ability of the low pressure coolant injection system to provide adequate core cooling to prevent core damage and to provide adequate decay heat removal from containment to prevent containment failure in the event of an external factor, fire. This issue is of very low safety significance because the low probability that a water hammer event results in a pipe failure or loss of system function. This issue was documented in Energy Northwest's corrective action program as Problem Evaluation Request 203-0997 (Section 4OA5).

B. Licensee Identified Violations

None

Report Details

Summary of Plant Status:

The inspection period began with Columbia Generating Station at 100 percent power. Except for scheduled reductions in power to accommodate testing and an unscheduled power reduction on January 24 through 28, 2004, to address a condenser tube leak, the plant was maintained at essentially 100 percent power for the entire inspection period

1. REACTOR SAFETY
   Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope

On January 5 and 6, 2004, the inspectors completed one sample to assess Energy Northwest's readiness and response to frigid weather which was forecast for the area. The inspectors walked down the standby service water system, observed an equipment operator perform compensatory actions in response to an ice cap which had formed on the standby service water spray ponds, and reviewed the standby service water system design to cope with abnormally cold weather conditions. Additionally, the inspectors performed general walkdowns of safety related equipment to ensure that mitigating systems were not adversely affected by the cold weather conditions.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignments (71111.04)

a. Inspection Scope

The inspectors completed three partial system walkdowns and one complete walkdown of safety-related systems during the inspection period. The inspectors reviewed system drawings, the Final Safety Analysis Report, Technical Specifications, and operating procedures to establish the proper equipment alignment to ensure system operability. The inspectors then walked down the system to verify that critical valve and electrical breaker positions were aligned correctly, and that support equipment such as cooling water, ventilation, and lube oil systems were in the proper configuration.

.1 Partial System Walkdowns (Quarterly)

- Division I Emergency Diesel Generator: On February 12, 2004, the inspectors walked down the mechanical and electrical alignments of the Division I emergency diesel generator while the Division II unit was out of service for planned maintenance. The inspectors reviewed the alignment of critical system components using Procedure SOP-DG1-STBY, "Emergency Diesel Generator (Div I) Standby Lineup," Revision 3, as criteria for this inspection.

- Reactor Core Isolation Cooling (RCIC) System: On March 2, 2004, the inspectors walked down the mechanical and electrical alignments of the reactor core isolation cooling system while the high pressure core spray (HPCS) system was inoperable for planned maintenance. The inspectors reviewed the alignment of critical system components using Drawing M-519, "Flow Diagram (RCIC) Reactor Core Isolation Cooling," Revision 86, and Procedure SOP-RCIC-STBY, "Placing RCIC in Standby Lineup," Revision 0.

- HPCS System: On March 15, 2004, the inspectors walked down the mechanical and electrical alignments of the HPCS while the RCIC system was inoperable for scheduled maintenance. The inspectors reviewed the alignment of critical system components using Procedure OSP-HPCS-M102, "HPCS Valve Lineup," Revision 0 and Procedure SOP-HPCS-STBY, "Placing HPCS in Standby Status," Revision 0.

.2 Complete System Walkdown (Semiannual)

From January 27 through February 4, 2004, the inspectors performed one complete system walkdown of the HPCS system to verify operational status and material condition of the system and its components. The inspectors also reviewed outstanding maintenance work orders and assessed operability and conformance with licensing requirements and commitments. The inspectors evaluated Energy Northwest's corrective measures to address related conditions adverse to quality. The inspectors reviewed the following additional documents during the inspection:

- Final Safety Analysis Report
- Technical Specifications
- Procedure OSP-HPCS/IST-Q701 "HPCS System Operability Test" Revision 18
- Drawing M-520 "Reactor Building HPCS and LPCS flow diagram" Revision 90

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Quarterly Walkdowns

a. Inspection Scope

The inspectors performed walkdowns of six fire protection areas to verify operational status and material condition of fire detection and mitigation systems, passive fire barriers and fire suppression equipment. The inspectors reviewed Energy Northwest's implementation of controls for combustible materials and ignition sources in selected fire protection zones. The inspectors compared observed plant conditions against descriptions and commitments described in the Final Safety Analysis Report, Section 9.5.1, “Fire Protection System,” and Appendix F, “Fire Protection Evaluation.” The fire areas inspected were:

- Fire Area RC-4; Division 1 Electrical Switchgear; February 23
- Fire Area RC-8; Switchgear Room No. 2; February 23
- Fire Area R-1; 606 foot elevation of Reactor Building; February 24
- Fire Area DG-1; High Pressure Core Spray Diesel Generator Room; February 25
- Fire Area R-21; South Valve and Pipe Space Room, 522 foot elevation of Reactor Building; February 26
- Fire Area D-10; Diesel Generator Building Deluge Valve Room; March 20, 2004

b. Findings

No findings of significance were identified.

.2 Annual Drill

a. Inspection Scope

The inspectors observed and evaluated a fire protection drill on February 9, 2004. The inspectors considered whether the drill scenario properly demonstrated the use of fire fighting equipment and that the subsequent drill critique was self-critical. The following documents were reviewed as part of this inspection:

- Drill Scenario
- Attribute Checklists

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

a. Inspection Scope

On February 18, 2004, the inspectors observed one licensed operator requalification training activity as operators participated in a scenario on the plant simulator. The inspectors evaluated crew performance in terms of formality of communication, prioritization of actions, annunciator response and implementation of procedures. The inspectors also evaluated simulator fidelity by comparing simulator configurations with the plant control room.

b. Findings

No findings of significance were identified.

1R12 Maintenance Rule Implementation (71111.12)

a. Inspection Scope

The inspectors performed two in-office reviews of maintenance rule related issues and/or safety related systems to evaluate Energy Northwest's assessment of availability and reliability of risk-significant structures, systems and components.

- On March 15, 2004, the inspectors reviewed Energy Northwest's tracking of unavailability hours and functional failure assessments of the standby liquid control system to verify that the system was properly characterized as a(2) within 10 CFR 50.65. The inspectors also performed an independent review of operators' logs, corrective action documents, and Energy Northwest's limiting condition for operability (LCO) database to ensure that Energy Northwest was accurately tracking system equipment availability and reliability.

- During March, 2004, the inspectors reviewed Energy Northwest's maintenance rule evaluation of Problem Evaluation Report 203-2578, plant trip due to grounding of current transformer wire, dated July 2, 2003.

The inspectors utilized the following documents for this inspections:

- Columbia Generating Station Maintenance Rule Program Biannual Period Status Report, July - December, 2003

- TI 4.22, Maintenance Rule Program, June 19, 2001

- Columbia Generating Station Maintenance Rule Scoping Matrix, October 30, 2003

- NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," Revision 2

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13)

a. Inspection Scope

The inspectors selected six samples of planned and emergent maintenance tasks for evaluation. The evaluation consisted of reviewing Energy Northwest's assessment of plant risk for the activity, risk management and review of compensatory measures, where appropriate, and reviewing plant status to ensure that other equipment deficiencies did not adversely impact the planned risk assessment. The inspectors sample included:

- Division II emergency diesel generator out of service for planned maintenance concurrently with a failed division II hydrogen monitor, January 29, 2004
- Residual heat removal system, Train C, out of service for planned maintenance, February 9, 2004
- Emergent condenser work, requiring a plant down-power, January 24 and 25, 2004
- Division I residual heat removal/low pressure core spray systems keepfill pump work, planned maintenance, February 10, 2004
- Planned maintenance on the high pressure core spray system, March 2, 2004
- Emergency reactor core isolation cooling system maintenance due to injection valve failure, February 21, 2004

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Nonroutine Plant Evolutions and Events (71111.14)

a. Inspection Scope

From January 23 to 27, 2004, operators reduced plant power in response to a condenser tube leak and in preparation for plant repairs. The inspectors reviewed the operators' response to this nonroutine operation.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed four operability evaluations to evaluate Energy Northwest's assessment of operability for degraded or nonconforming equipment performance. The inspectors reviewed the Final Safety Analysis Report , Technical Specifications, applicable system drawings and design specifications, and associated corrective action documents to determine if Energy Northwest had appropriately evaluated operability.

- Problem Evaluation Report 204-0628; E-IN-3A was running, for testing, in parallel with E-IN-3B which could cause an overload condition on the Division 1 125 VDC system; March 10, 2004

- Problem Evaluation Request 204-0246, loose fastener on high pressure core spray diesel cooling water heat exchanger, January 20, 2004

- Condition Report 2-04-00460, failure of high pressure core spray system breaker charging springs, March 4, 2004

- Problem Evaluation Request 202-2466 "HPCS-LS-3A&3B are Unable to Achieve Design Performance Requirements," dated August 26, 2002, reviewed on February 4, 2004

b. Findings

Introduction. The inspectors identified a Green noncited violation of Technical Specification 5.4.1.a for an inadequate maintenance procedure which caused unintended inoperability of the station's 125 VDC safety related batteries on two occasions.

Description. On March 10, 2004, Energy Northwest performed Electrical Maintenance Procedure 10.25.1, "Inspection and Cleaning Division 1, E-IN-3A and E-IN-3B, and Division 2, E-IN-2A and E-IN-2B, Inverters," Revision 18. This procedure provided instructions for cleaning, inspecting, and preventive maintenance testing of the critical instrument power inverters. These inverters, during a station loss of AC power systems, would convert 125 VDC power from the station's Division 1 and Division 2 125 VDC safety related batteries to supply 120/240 VAC power to critical instruments and controls in the main control room. Normally, only one inverter per train was in service with the other inverter available as an installed spare.

Procedure 10.25.1 directed that Inverter E-IN-3A, the spare inverter which was being tested, be aligned to receive power from it's respective battery while a test load bank was connected to the AC output of the inverter. The inverter was then loaded to 100 percent load capacity. During the conduct of the load check on the inverter, the control room received an alarm indicating that the associated Battery Charger E-C1-1B had reached it's load limit of 230 amperes and that voltage had dropped below the alarm setpoint of 127 VDC. The load test was immediately stopped and charger current and voltage was recovered. Energy Northwest evaluated the charger overload condition and determined that the test could be performed again as long as the inverter load was slowly raised and monitored to ensure that charger limits would not be exceeded. The inspectors reviewed the circumstances surrounding the alarming condition of the battery charger and was concerned that neither operability of the battery charger nor the associated battery had been appropriately considered. Prior to restart of the test, the inspectors communicated this concern to the control room staff to determine if an analysis demonstrating battery operability with both inverters operating in parallel had been performed. No analysis could be provided by the operators. The inspectors concluded that Energy Northwest had not adequately assessed the operability impact of the inverter testing on the associated battery, E-B1-1 and the in-service charger, E-C1-1B. The operators stopped any further inverter testing until an operability assessment could be performed.

Energy Northwest documented the issue in their corrective action program in PER 204-0628. Energy Northwest determined that during the time that Inverters E-IN-3A and E-IN-3B were operated in parallel, that both Battery E-B1-1 and Charger E-C1-1B were inoperable. The total time of inoperability was determined to be approximately 30 minutes. Energy Northwest also determined that a similar occurrence took place during testing performed previously on March 9, 2004, on Inverter E-IN-2A. Energy Northwest determined that during that test that Battery E-B1-2 and Charger E-C1-2B were inoperable for approximately 35 minutes. The Technical Specification allowed outage times for each of the station's safety related batteries being inoperable was 2 hours.

The inspectors noted that Revision 15 to Procedure 10.25.1, dated May 25, 2001, added steps to test the spare inverter at a full load condition while operating in parallel with the in-service inverter. The inspectors reviewed the associated "Screening for Licensing Basis Changes" form to determine the basis for the revision to the procedure and identified that Energy Northwest had determined that a 10 CFR 50.59 safety evaluation for the procedure revision was not warranted. Instead, Energy Northwest referenced Safety Evaluation SE-00-0025, which was associated with the design change to install the spare inverters. The inspector reviewed Safety Evaluation SE-00-0025 and the Final Safety Analysis Report and could not identify an analysis nor design information which supported operating the in-service and spare inverters in parallel. The inspectors concluded that Energy Northwest's evaluation of Revision 15 to Procedure 10.25.1 was incorrect and that a 10 CFR 50.59 safety evaluation should have been performed because the proposed procedure revision involved a change to the facility as described in the facility Final Safety Analysis Report which had not been previously evaluated by an applicable 10 CFR 50.59 screening or safety evaluation.

The inspectors also considered Energy Northwest's failure to identify the impact of the inverter load test on battery operability a problem identification issue. Energy Northwest focused on justification for recommencement of the load test following the receipt of the low battery charger output voltage and increased amperage instead of questioning the impact of the inverter load test on battery operability. This problem identification issue is referenced in Section 4OA2.

Analysis. The inoperability of Battery E-B1-1 on March 10, 2004, and Battery E-B1-2 on March 9, 2004, during the performance of Procedure 10.25.1 was considered a performance deficiency because Energy Northwest did not adequately evaluate the impact of Revision 15 to Procedure 10.25.1. Additionally, the inspectors determined that prescribed steps in Procedure 10.25.1 to test the spare inverter at full load while in parallel with the in-service inverter was a procedural quality concern which affected the mitigating systems cornerstone objective to ensure the availability of onsite emergency DC power. This issue is more than minor because it could have an actual impact on the ability of one train of emergency batteries to mitigate a loss of AC power to the safety-related inverters. The issue was of very low safety significance (Green) because the issue: (1) was not a design or qualification deficiency; (2) did not result in the loss of a safety system; (3) did not represent an actual loss of a safety function of a single train for greater than its technical specification allowed outage time; (4) did not represent an actual loss of safety function of one or more nontechnical specification trains of equipment designated as risk significant per 10 CFR 50.65 for greater than 24 hours; and (5) was not potentially risk significant due to a seismic, fire, flooding, or severe weather initiating event.

Enforcement. Technical Specification 5.4.1.a required, in part, that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operation)," Appendix A, Section 9.a, required, in part, that maintenance that can affect the performance of safety-related equipment should be properly pre-planned and performed in accordance with written procedures appropriate to the circumstances. Contrary to this requirement, Maintenance Procedure 10.25.1 was inadequate in that for test purposes it prescribed placing in-service a fully loaded spare inverter in parallel with an already in-service inverter. This was a condition not previously analyzed in the facility's Final Safety Analysis Report. Subsequently, Battery E-B1-2 was rendered inoperable on March 9, 2004, for approximately 35 minutes and Battery E-B1-1 was rendered inoperable on March 10, 2004, for approximately 30 minutes. This violation is being treated as a noncited violation, consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 50-397/04-02-01, Inadequate Maintenance Procedure Renders Safety-Related 125 VDC Battery Inoperable. Energy Northwest documented this issue in their corrective action program in PER 204-0628. As a short term corrective action, Energy Northwest suspended future inverter testing pending resolution of PER 204-0628.

1R16 Operator Workarounds (71111.16)

a. Inspection Scope

The inspectors performed one inspection of operator workarounds on March 5, 2004. The inspectors evaluated the potential affects of the workarounds on the operator's ability to implement abnormal or emergency operating procedures and the cumulative effects of workarounds on the reliability and availability of plant systems.

b. Findings

No findings of significance were identified.

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors observed or completed an in-office review of three postmaintenance tests. The inspectors reviewed the scope of the maintenance activity through document review and interviews with plant personnel to determine what safety function if any was affected by the maintenance activity. The inspectors then reviewed the applicable postmaintenance test procedure and results to verify that the procedure adequately tested the affected components and that acceptance criteria were appropriate and were met.

- Work Order 01054427; Replacement of Relay RHR-RLY-K55; March 9, 2004
- Work Order 01059405; Replacement of Relay RCIC-RLY-K47; March 18, 2004
- Work Order 01074231; RCIC-MO-13 Lost Power; March 22, 2004

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors observed the performance and/or reviewed the results of the three surveillance tests listed below. The inspectors reviewed Technical Specification, Final Safety Analysis Report, and applicable licensee procedures to determine if the surveillance tests demonstrated that the tested components were capable of performing their intended design functions. Additionally, the inspectors evaluated significant test attributes such as potential preconditioning, clear acceptance criteria, accuracy and range of test equipment, procedure adherence, and completion and acceptability of test data.

- Procedure OSP-SLC/IST-Q701; Standby Liquid Control Pumps Operability Test; February 19, 2004

- Procedure OSP-ELEC-M702; Diesel Generator 2 - Monthly Operability Test; March 11, 2004
- Feedwater copper surveillance results and controls, as specified by licensee document titled "Impact of Feedwater Copper Level Greater than 0.2 ppb on Fuel Performance at Columbia," no date or revision.

b. Findings

.1 Unacceptable Preconditioning of a Standby Liquid Control Isolation Valve

Introduction. The inspectors identified a Green noncited violation of Technical Specification 5.4.1.a for an inadequate surveillance test procedure which failed to prescribe In-Service Test (IST) stroke time testing of Valve SLC-V-1B in the as-found condition.

Description. On February 19, 2004, Energy Northwest performed an IST test of the Standby Liquid Control (SLC) system. Step 7.1 of Procedure OSP-SLC/IST-Q701, required that each trains' SLC pump suction isolation valves, SLC-V-1A and SLC-V-1B, be stroke timed opened and then closed to satisfy IST testing requirements. The test required a local operator to use a test control switch for the timing of each valve. The inspectors noted that per system design that the test control switch actuated both valves simultaneously and that Procedure OSP-SLC/IST-Q701 always required Valve SLC-V-1A to be timed prior to Valve SLC-V-1B. The inspectors determined that the actuation of Valve SLC-V-1B (during Valve SLC-V-1A's timing test) prior to its own timing test to be preconditioning. The inspectors referenced NRC Inspection Manual Part 9900: Technical Guidance, "Maintenance - Preconditioning of Structures, Systems, and Components Before Determining Operability," to determine the acceptability of the preconditioning. The inspectors determined that since the preconditioning of Valve SLC-V-1B could mask the as-found condition of the valve and that the preconditioning was not required for the protection of personnel or equipment, nor needed to meet manufacturer's recommendations, that the preconditioning was unacceptable. The inspectors discussed this concern with Energy Northwest during the week of February 23 and then again on March 10. Energy Northwest subsequently tested Valve SLC-V-1B in the as-found condition with acceptable results. Energy Northwest documented the concern in condition report CR 2-04-00618.

Analysis. Energy Northwest's failure to stroke time Valve SLC-V-1B in the as-found condition was considered a performance deficiency since NUREG-1482, "Guidelines for In-Service Testing at Nuclear Power Plants," and NRC Information Notice 97-16, "Preconditioning of Plant Structures, Systems, and Components Before ASME Code Inservice Testing or Technical Specification Surveillance Testing," provided guidance on what circumstances provided for acceptable versus unacceptable preconditioning. Additionally, the inspectors determined that the failure of Procedure OSP-SLC/IST-Q701 (a procedural quality issue) to prescribe stroke timing of Valve SLC-V-1B to be of greater than minor risk significance because by not testing the valve in the as-found condition, Energy Northwest may not identify potential degraded valve performance. This was determined to affect the reactor safety mitigating systems cornerstone objective to ensure the reliability and capability of systems that respond to an initiating event. The issue was of very low safety significance (Green) because the issue: (1) was not a design or qualification deficiency; (2) did not result in the loss of a safety system; (3) did not represent an actual loss of a safety function of a single train for greater than its Technical Specification allowed outage time; (4) did not represent an actual loss of safety function of one or more nontechnical specification trains of equipment designated as risk significant per 10 CFR 50.65 for greater than 24 hours; and (5) was not potentially risk significant due to a seismic, fire, flooding, or severe weather initiating event.

Enforcement. Technical Specification 5.4.1.a required, in part, that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operation)," Appendix A, Section 8, required, in part, that specific procedures for surveillance tests should include liquid poison system tests (Standby Liquid Control). Contrary to this requirement, Procedure OSP-SLC/IST-Q701 was inadequate in that it did not prescribe stroke timing of Valve SLC-V-1B in the as-found condition. This violation is being treated as a noncited violation, consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 05000397/2004-02-02, Unacceptable Preconditioning of Valve SLC-V-1B Prior to IST Surveillance Testing. Energy Northwest documented the concern in their corrective action program in CR 2-04-00618. As a short term corrective action, Energy Northwest successfully stroke timed Valve SLC-V-1B in the as-found condition on March 11, 2004.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

The inspectors observed two emergency planning drills this period. The first drill was conducted on January 14, 2004. The inspection of this particular drill was performed to complete the NRC 2003 inspection plan for 2003 as required by Inspection Procedure 71114.06, "Drill Evaluation". The second drill was conducted on March 16, 2004. The inspectors observed each of the drills from the control room simulator, emergency operating facility, and from the technical support center. The inspectors also reviewed emergency plan implementing procedures and the site emergency plan to determine the adequacy of Energy Northwest's emergency action level declarations and response to the simulated emergencies. Additionally, the inspectors reviewed the completed emergency action level declarations and protective action recommendations. Lastly, the inspectors reviewed Energy Northwest's evaluation of the drills to ensure that any noted performance deficiencies associated with classification, notification, and protective action recommendation development were accurately characterized.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

a. Inspection Scope

The inspectors assessed the accuracy of three performance indicators this inspection period. The inspectors compared the data with operator logs, equipment out of service logs and corrective action documents for the last four quarters. The inspectors verified that Energy Northwest calculated performance indicators in accordance with NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 2. Performance indicators included:

- Reactor coolant specific activity
- Reactor coolant leak rate
- Unplanned reactor scrams

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

Cross-References to PI&R Findings Documented Elsewhere

- Section 1R15 described that Energy Northwest had inadvertently rendered the Division 1 125 VDC safety related battery inoperable during load testing of an associated spare inverter. Battery inoperability was not recognized by Energy Northwest even though annunciators were received during the inverter load test which indicated that battery operability had been challenged. This was considered a problem identification issue.

4OA3 Event Followup (71153)

.1 Safety Related Reactor Vessel Level Switch Deficiencies

a. Inspection Scope

On March 23, 2004, during an inspection of Reactor Pressure Vessel Level Switch MS-LIS-37A, Energy Northwest identified that the level switch did not contain a locking washer and spacers which could affect seismic qualification of the instrument. Energy Northwest subsequently declared Switch MS-LIS-37A inoperable. This level switch provided input to reactor core isolation cooling start circuitry on Level 2 (-50 inches reactor water level) and to the 'A' train residual heat removal and low pressure core spray systems on Level 1 (-129 inches reactor water level). Energy Northwest conducted the inspection in response to a General Electric 10 CFR 21 notification, dated May 10, 2002, which communicated concerns that Barton differential pressure indicating switches, Models 288A and 289A, manufactured before 1986, may contain undersized washers installed on the switch plate locking mechanism. Instruments with these undersized washers may not be seismically qualified. The inspectors reviewed technical specifications and the Final Safety Analysis Report to verify that Energy Northwest had taken appropriate compensatory measures to address the inoperable level switch. Additionally, the inspectors reviewed Energy Northwest's plan to minimize plant risk while the switch was inoperable and verified implementation of that plan. The inspectors also reviewed Energy Northwest's repair plans to ensure that additional risk to the plant would not occur during the repair of the instrument. The instrument was repaired on March 24, 2004, and returned to an operable condition. Energy Northwest subsequently determined that the identified deficiency, although nonconforming, did not render the instrument inoperable.

b. Findings

No findings of significance were identified.

4OA5 Other

.1 (Closed) Unresolved Item (URI) 50-397/03-02-03: Two examples of a noncited violation of Technical Specification 5.4.1.d for an inadequate fire protection alternate shutdown procedure.

Introduction. The inspectors identified a Green noncited violation of Technical Specification 5.4.1.d (inadequate procedure) because Procedure ABN-CR-EVAC, "Control Room Evacuation and Remote Cooldown," Revision 4, failed to provide adequate direction to: (1) assure that containment temperatures did not increase above residual heat removal pump temperature limits following depressurization; and (2) assure adequate core cooling with one safety relief valve stuck open.

Description. The inspectors identified two examples of an inadequate procedure due to significant discrepancies between procedural requirements contained in Procedure ABN-CR-EVAC and Energy Northwest's safe shutdown analysis for a control room fire, "GE-NE-L12-00824-01," dated September 1994.

The first example was that Procedure ABN-CR-EVAC provided inadequate direction to ensure that suppression pool temperature did not exceed low pressure coolant injection system design limits during a control room fire event. Exceeding the design temperature limits could challenge low pressure coolant injection system operability. Energy Northwest's safe shutdown analysis assumed that operators would establish "normal shutdown cooling" immediately after manual depressurization. This time-sensitive action helps to ensure that suppression pool water temperature does not increase above the low pressure coolant injection pump temperature limit (204 degrees Fahrenheit). However, the procedure failed to specify time limits for placing shutdown cooling in service. Further, during procedure walkdowns, operators stated that they would not likely place the shutdown cooling in service immediately following depressurization but would wait for a potentially extended period before taking the action.

The second example was that Procedure ABN-CR-EVAC failed to provide adequate instructions to ensure adequate core cooling, assuming a scenario with one safety relief valve stuck open. Energy Northwest's fire protection analysis relied on operator action within 10 minutes to depressurize the reactor, following a reactor scram, to ensure adequate core cooling with the low pressure coolant injection system. In contrast, operators, when walking down the procedure, usually took at least 23 minutes to get to the depressurization step.

Analysis. The inspectors determined that both inadequate procedure examples had more than minor significance because each impacted the mitigating systems cornerstone and affected the cornerstone objective - to ensure the availability, reliability, and capability of the system that responds to the event to prevent undesirable consequences. The inspectors used Appendix F of Manual Chapter 0609 and determined that the inability to perform the alternate shutdown procedure required a Significance Determination Process Phase 2 and Phase 3 analysis. Based on a Phase 3 analysis, the regional senior reactor analyst determined that the finding was of very low safety significance (Green). Some of the factors used to make this determination included: (1) general operator knowledge that suppression pool temperatures must be monitored and use shutdown cooling as a means to ensure the pool retains the ability to feed the low pressure injection system, and (2) the need to initiate shutdown cooling after depressurization is probably not an immediate pressing issue.

Enforcement. The failure to provide an appropriate procedure for alternate shutdown is a violation of Technical Specification 5.4.1.d. This requirement specifies, in part, that Energy Northwest establish procedures for fire protection program implementation. License Condition 2.C(14) of the facility operating license states that Energy Northwest shall implement and maintain in effect all provisions of licensee's fire protection program as described in Section 9.5.1 and Appendix F of the Final Safety Analysis Report. Section F.4.3 of Appendix F, as updated, states that alternative shutdown systems used in the event of a main control room fire must meet the requirements of 10 CFR Part 50, Appendix R, Section III.L. Section III.L.3 states, in part, that procedures shall be in effect to implement alternative and dedicated shutdown capability. However, Energy Northwest failed to ensure that Procedure ABN-CR-EVAC was adequate to implement alternative and dedicated shutdown capability. Since this failure to maintain an appropriate procedure for alternate shutdown was determined to have very low safety significance and was entered into Energy Northwest's corrective action program as Problem Evaluation Request 203-0956, this violation is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-397/04-02-03, Failure to Have Adequate Procedures in Effect for Alternative Shutdown.

.2 (Closed) Unresolved Item (URI) 50-397/03-02-04: Failure to take adequate corrective action for a condition affecting safe shutdown.

Introduction. The inspectors identified a Green noncited violation of License Condition 2.C(14) for failure to take appropriate corrective measures to address a condition adverse to fire protection affecting the low pressure coolant injection system, Train B . During a control room fire, the system was vulnerable to a water hammer, which could render the train inoperable, since at least 1997.

Description. For a control room fire, Energy Northwest credits and protects portions (but not all) of the Division II residual heat removal system and the automatic depressurization system. Credited operator actions, prior to evacuating the control room, include a manual reactor trip and the closure of all main steam isolation valves. Energy Northwest is required to maintain the capability to achieve safe shutdown (cold shutdown) from the remote shutdown panel utilizing only protected systems and components.

The inspectors identified that Energy Northwest failed to take prompt corrective measures to address a long-standing low pressure coolant injection Train B water hammer vulnerability, which could jeopardize system operability. Following control room evacuation, in response to a control room fire, Procedure ABN-CR-EVAC, "Control Room Evacuation and Remote Cooldown," Revision 4, instructed operators to check the status of the Division II residual heat removal system keepfill Pump RHR-P-3 hourly when the primary system Pump RHR-P-2B is not running. However, Energy Northwest did not protect, or credit, the keepfill pump and, if the keepfill pump failed, the system could not maintain system fill for an hour due to a leaky Pump RHR-P-2B discharge check valve (RHR-V-31B). Consequently, the system could suffer a water hammer if Pump RHR-P-2B started after a loss of fill.

The inspectors reviewed pressure decay test results to check for historical Valve RHR-V-31B leak-tight integrity. The inspectors found that the valve had last demonstrated acceptable performance in 1994 and had leaked excessively since at least 1997 (no data was available between 1994 and 1997). In 1997, the valve could only maintain system fill for about 40 seconds. Between November 2000, and October 2002, Energy Northwest conducted seven leakage tests to estimate how long the valve could maintain pressure without losing system fill. The test results varied from test to test, with no particular trend. Calculated loss of fill time ranged from 6 minutes to a few hours. For four of the seven tests the valve could not maintain system fill for greater than the 1 hour procedural specification and in two instances the calculated loss of fill was less than 20 minutes.

Energy Northwest had written Problem Evaluation Request 202-2984 on October 24, 2002, to capture the deficiency (more than five years after initial indication), but Energy Northwest took ineffective corrective measures to address the problem. Energy Northwest didn’t plan to repair the valve until the spring 2005 outage and specified only one compensatory measure, which was a fire watch. However, the corrective action did not include advising operators that a control room fire could result in the loss of the keepfill pump and subsequent potential water hammer. The inspectors considered a fire tour inadequate because it had no impact on preventing a system water hammer when attempting to mitigate a control room fire. In addition, the remote shutdown panel did not have residual heat removal system pressure indication to alert operators to a leaking check valve.

Analysis. The inspectors determined that the issue was more than minor because it impacted the mitigating systems and barrier integrity cornerstones and affected the cornerstone objectives to ensure the availability, reliability, and capability of the system that responds to the event to prevent undesirable consequences. In this instance, the problem affected the ability of Train B low pressure coolant injection to provide adequate core cooling to prevent core damage and to provide adequate decay heat removal from containment to prevent containment failure. The inspectors used Appendix F of Manual Chapter 0609 and determined that the inability to perform the alternate shutdown procedure required a Significance Determination Process Phase 2 and Phase 3 analysis. Based on a Phase 3 analysis, the regional senior reactor analyst determined that the finding was of very low safety significance (Green). One factor used to make this determination was the low probability of a water hammer event resulting in a pipe failure or loss of system function.

Enforcement. The failure to take prompt corrective measures to address a condition adverse to fire protection (leaking low pressure core spray pump discharge Check Valve RHR-V-31B) is a violation of Columbia Generating Station License Condition 2.C(14), which requires Energy Northwest to implement and maintain in effect all provisions of the approved fire protection program as described in Appendix F of the final safety analysis report. The final safety analysis report, Appendix F, Section C.8 states, in part, that “Plant procedures require that conditions adverse to fire protection, such as . . . deficiencies, . . . defective components . . . are promptly identified, reported and corrected.”

Procedure SWP-FPP-01, “Nuclear Fire Protection Program,” Revision 3, Section 3.5.8, states that “Nonconforming fire protection items shall be identified, reported, dispositioned, and corrected in accordance with SWP-CAP-01.”

Procedure SWP-CAP-01, “Problem Evaluation Requests,” Revision 6, Section 2.1 states that, “The problem evaluation request process assures the following: . . . conditions adverse to quality (fire protection) are promptly identified and corrected.”

Contrary to the above, Energy Northwest failed to promptly identify and correct a condition adverse to fire protection. Since 1997, Valve RHR-V-31B has leaked excessively so that, during a control room fire, the one credited injection source, low pressure coolant injection Train B, was, and still is, at increased risk of water-hammer related damage and failure. Energy Northwest failed to identify the problem for 5 years and, once identified in October 2002, specified inadequate and untimely corrective measures. Since this failure to take prompt corrective action was determined to have very low safety significance and was entered into the corrective action program as Problem Evaluation Request 203-0997, this violation is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-397/04-02-04, Inadequate Corrective Action for a Condition Affecting Safe Shutdown.

4OA6 Management Meetings

Exit Meetings

On March 29, 2004, the resident inspectors presented the inspection results to Mr. J. V. Parrish, Chief Executive Officer, and other members of his staff who acknowledged the findings. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

ATTACHMENT: SUPPLEMENTAL INFORMATION

ATTACHMENT

Supplemental Information

PARTIAL LIST OF PERSONS CONTACTED

Licensee

J. Parrish, Chief Executive Officer
D. Atkinson, Vice President, Technical Services
D. Coleman, Manager, Performance Assessment and Regulatory Programs
D. Feldman, Manager, Operations
W. Oxenford, Plant General Manager
C. Perino, Manager, Licensing
I. Boreland, Manager, Radiation Services
R. Webring, Vice President, Nuclear Generation

ITEMS OPENED AND CLOSED

Items Opened, Closed, and Discussed During this Inspection

Opened

None

Opened and Closed

50-397/04-02-01	NCV	Inadequate Maintenance Procedure Renders Safety-Related 125 VDC Battery Inoperable (Section 1R15)
50-397/04-02-02	NCV	Unacceptable Preconditioning of Valve SLC-V-1B Prior to IST Surveillance Testing (Section 1R22)
50-397/04-02-03	NCV	Failure to Have Adequate Procedures in Effect for Alternative Shutdown (Section 4OA5)
50-397/04-02-04	NCV	Inadequate Corrective Action for a Condition Affecting Safe Shutdown (Section 4OA5)

Closed

50-397/03-02-03	URI	Failure to Have Adequate Procedures in Effect for Alternative Shutdown (Section 4OA5)

50-397/03-02-04	URI	Inadequate Corrective Action for a Condition Affecting Safe Shutdown (Section 4OA5)

PARTIAL LIST OF DOCUMENTS REVIEWED

Procedures

SOP-SW-Cold Weather; Standby Service Water Cold Weather Operations; Revision 1

OSP-HPCS-M102; HPCS Valve Lineup; Revision 0

SOP-HPCS-STBY; Placing HPCS in Standby Status; Revision 0

PPM 10.25.1; Inspection and Cleaning Division 1, E-IN-3A and E-IN-3B, and Division 2, E-IN-2A and E-IN-2B, Inverters; Revision 18

OSP-RHR/IST-Q704; RHR Loop C Operability Test; Revision 12

PPM 10.25.7; Testing and Setting of Time Delay Relays; September 27, 2001

PPM 13.1.1; Classifying the Emergency; Revision 32

PPM 13.2.2; Determining Protective Action Recommendations; Revision 14

OSP-ELEC-M702; Diesel Generator 2 - Monthly Operability Test; Revision 19

OSP-HPCS/IST-Q701; HPCS System Operability Test; Revision 18

Calculations

EC 2625; Calculation for Sizing of HPCS Emergency Water Volume; Revision 2 of Calculation 5.19.13

EC 1102; Modification to Calculation 5.19.14 Using 32.3 feet Net Positive Suction Head; Revision of Calculation 5.19.14

Drawings

EWD-6E-049; Electrical Wiring Diagram Reactor Core Isolation Cooling System MOV RCIC-V-13; Revision 17

M520; Reactor Building HPCS and LPCS Flow Diagram; Revision 90

Other

WO 01059405; RCIC-RLY-K47 Relay Replacement

WO 01074231; RCIC-MO-13 Lost Power

WO 01054427; Calibrate replacement relay for RHR-RLY-K55; November 11, 2003

CMR 967; Determine Freezing Characteristics of the Service Water Return Lines, Which are not Insulated Next to the Pumphouse Walls; April 16, 2001

Drill, Exercise, and Actual Events Opportunity Evaluation; Team B Drill EP00251; January 14, 2004

2004 Team B Drill Report; January 14, 2004

Drill, Exercise, and Actual Events Opportunity Evaluation; Team C Drill EP00251; March 16, 2004

2004 Team C Drill Report; March 16, 2004

50.59 SCREEN-02-0296; Screen for HPCS Suction Aligned to Suppression Pool; October 28, 2002

<u>Problem Evaluation Requests / Condition Reports</u>

PER 203-4493 "HPCS DG DCW-V-15 Seat Leakage Increased"

PER 202-1418 "Low Level Alarm Received from DCW Expansion Tank".

PER 204-0628; E-IN-3A was running, for testing, in parallel with E-IN-3B which could cause an overload condition on the Div 1 125 VDC system; March 10, 2004

PER 204-0570; (SPER) RCIC-V-13 lost power indication; February 21, 2004

PER 202-2466; Reportability Evaluation for HPCS-LS-3A&3B are Unable to Achieve Design Performance Requirements; August, 26, 2002

PER 202-0500; Unexpected HPCS-P-1 Suction Switch Over from CST to Wetwell; February 16, 2002

PER 202-2499; HPCS Suction Alignment to the Suppression Pool has not received a 50.59 Screening or Review; August 23, 2002

PER 202-2421; HPCS-LS-3A and 3B are not listed or Discussed in Technical Specifications; August 21, 2002

PER 299-2460; HPCS V-5 discharge check valve for HPCS is slowly pressurizing HPCS piping; November 4, 1999