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

August 2, 2005

J. V. Parrish (Mail Drop 1023)
Chief Executive Officer
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P.O. Box 968
Richland, WA 99352-0968

SUBJECT: COLUMBIA GENERATING STATION - NRC INTEGRATED INSPECTION REPORT 05000397/2005003

Dear Mr. Parrish:

On June 23, 2005, 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 June 21 with Mr. Dale Atkinson and other members of your staff. Documented findings were also discussed on July 12 and 26 with Mr. Tom Lynch 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.

This report documents two NRC identified and one self-revealing finding. One of these findings was determined to involve a violation of NRC requirements. However, because of the very low safety significance and because it is entered into your corrective action program, the NRC is treating this finding as a noncited violation (NCV) consistent with Section VI.A.1 of the NRC Enforcement Policy. If you contest these findings, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, 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 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.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Thomas R. Farnholtz, Chief
Project Branch A
Division of Reactor Projects

Docket: 50-397
License: NPF-21

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NRC Inspection Report
05000397/2005003

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ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket:	50-397
License:	NPF-21
Report:	05000397/2005003
Licensee:	Energy Northwest
Facility:	Columbia Generating Station
Location:	Richland, Washington
Dates:	March 24 through June 23, 2005
Inspectors:	Z. Dunham, Senior Resident Inspector, Project Branch A, DRP R. Cohen, Resident Inspector, Project Branch A, DRP W. Sifre, Reactor Inspector, Engineering Branch L. Carson, Senior Health Physicist, Plant Support Branch D. Stearns, Health Physicist, Plant Support Branch L. Ricketson, Senior Health Physicist, Plant Support Branch
Approved By:	T. R. Farnholtz, Chief, Project Branch A, Division of Reactor Projects
ATTACHMENT:	Supplemental Information

CONTENTS

SUMMARY OF FINDINGS

IR05000397/2005003; 3/25/2005 - 6/23/2005; Columbia Generating Station. Operator Workarounds, Access Control to Radiological Significant Areas, and Event Followup.

The report covered a 13-week period of inspection by resident inspectors, health physicist inspectors, and a reactor inspector. One Green noncited violation, two Green findings, and one unresolved item was identified. The significance of most findings is indicated by their color (Green, White, Yellow, or 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: Initiating Events

- Green. A self-revealing finding associated with maintenance technicians' failure to follow a system operating procedure occurred when the reactor feedwater pump 1B low suction pressure switch contact was inadvertently jumpered during a maintenance activity. This resulted in the loss of reactor feedwater pump 1B and an automatic reactor scram on low reactor vessel water level when feedwater flow was lost. The main steam isolation valves subsequently closed on low-low reactor water level which resulted in the additional loss of reactor feedwater pump 1A. This finding had crosscutting aspects in the area of human performance in that the technicians failed to ensure the configuration of the circuit and subsequently failed to meet the requirement of a procedure step during the maintenance activity.

  The finding was of more than minor risk significance because it was a human performance issue which impacted the initiating events cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions. A Phase 2 evaluation was performed in accordance with Manual Chapter 0609, "Significance Determination Process," based on the finding contributing to both the likelihood of a reactor trip and that mitigation functions would not be available. The phase 2 review was performed using the Columbia Generating Station site specific worksheets. A senior reactor analyst reviewed the Phase 2 results and adjusted the results to account for the ability of the operators to bypass and open the main steam isolation valves and recover the reactor feedwater pumps following the scram and the low power at which the event occurred. The finding was determined to be of very low safety significance. Immediate corrective actions included senior management review and approval of all maintenance related activities for the remainder of the forced outage and following restart of the plant up to 90 percent power (Section 4OA3.4).

Cornerstone: Barrier Integrity

- Green. On April 29, 2005, an NRC identified finding was identified associated with an inadequate compensatory measure. The compensatory action, established in response to an inoperable primary containment isolation valve, prevented emergency ventilating the drywell during post accident conditions. This finding had crosscutting aspects of problem evaluation in that Energy Northwest did not identify that the compensatory action prevented implementation of the affected procedure. This finding was not subject to enforcement actions because it involved an equipment function which was not safety related.

  The finding was more than minor because if left uncorrected the finding would become a more significant safety concern since primary containment integrity would be challenged due to the inability to emergency ventilate the drywell. Additionally, the finding was a configuration control issue which affected the barrier integrity cornerstone attribute to provide reasonable assurance that physical design barriers (containment) protect the public from radio nuclide releases caused by accidents or events. Using the Significance Determination Process, Phase 1 worksheet, the inspectors determined that the finding was of very low risk significance because the finding did not represent an actual open pathway in the physical integrity of the reactor containment. Corrective actions included evaluating alternate compensatory measures to address the inoperable containment isolation valve (Section 1R16).

Cornerstone: Occupational Radiation Safety

- Green. On May 25, 2005, the inspector identified a noncited violation of 10 CFR 20.1904 because the licensee failed to label a canister containing radioactive material. The canister in the equipment storage area of the refueling pool contained used filters from a pool filtering system. The canister was secured to the handrail with a rope and could be moved by hand. Dose rates were measured and found to be 17 rem per hour on contact with the canister. Neither the canister nor the rope were labeled to identify the contents and radiological hazards.

  This finding is greater than minor because it is associated with an Occupational Radiation Safety cornerstone attribute (human performance) and affected the cornerstone objective in that the failure to warn individuals of radiological hazards diminished the licensee ability to ensure adequate protection of the worker health and safety from exposure to radiation. Using the Occupational Radiation Safety Significance Determination Process, the inspector determined that the finding was of very low safety significance because it did not involve: (1) ALARA planning and controls, (2) an overexposure, (3) a substantial potential for overexposure, or (4) an impaired ability to assess dose. This finding also had crosscutting aspects associated with human performance. The failure of licensee personnel to follow the established program of controls for items stored in the refueling pool directly contributed to the finding. The licensee documented this event in Condition Report 2-05-04272 (Section 2OS1).

B. Licensee Identified Violations

Violations of very low safety significance which were identified by Energy Northwest have been reviewed by the inspectors. Corrective actions taken or planned by Energy Northwest have been entered into their corrective action program. These violations and corrective action tracking numbers are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status:

The inspection period began with Columbia Generating Station at 100 percent power. On May 7, 2005, the plant was shutdown to begin refueling outage R-17. The reactor plant was brought critical on June 9 and was synchronized with the grid to end the refueling outage on June 11. The plant achieved 100 percent power on June 14. The plant subsequently was shutdown following an automatic reactor scram on June 15 and entered forced outage F-05-01 due to an inadvertent closure of the main turbine throttle valves when a circuit control card failed. The reactor plant was brought critical on June 22 and was synchronized with the grid to end the forced outage on June 22. The plant was subsequently shutdown following an automatic reactor scram on June 23 from approximately 24 percent power and entered forced outage F-05-02 due to lowering reactor water level when the running reactor feedwater pump governor valve inadvertently closed during a maintenance activity. The plant was shutdown, in Mode 4, in forced outage F-05-02 at the end of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R04 Equipment Alignments (71111.04)

a. Inspection Scope

The inspectors: (1) walked down portions of the three below listed risk important systems and reviewed plant procedures and documents to verify that critical portions of the selected systems were correctly aligned; and (2) compared deficiencies identified during the walk down to the licensee's corrective action program to ensure problems were being identified and corrected.

The inspectors completed three samples.

- Residual Heat Removal - Division 1, in shutdown cooling operation; May 21, 2005
- Standby Service Water - Division 2, following maintenance outage; June 14, 2005
- Containment Instrument Air - while in service; June 8, 2005

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Quarterly Inspection

a. Inspection Scope

The inspectors walked down the six below listed plant areas to assess the material condition of active and passive fire protection features and their operational lineup and readiness. The inspectors: (1) verified when applicable that transient combustibles and hot work activities were controlled in accordance with plant procedures; (2) observed the condition of fire detection devices to verify they remained functional; (3) observed fire suppression systems to verify they remained functional; (4) verified that fire extinguishers and hose stations were provided at their designated locations and that they were in a satisfactory condition; (5) verified that passive fire protection features (electrical raceway barriers, fire doors, fire dampers, steel fire proofing, penetration seals, and oil collection systems) were in a satisfactory material condition; (6) verified when applicable that adequate compensatory measures were established for degraded or inoperable fire protection features; and (7) reviewed the corrective action program to determine if the licensee identified and corrected fire protection problems.

The inspectors completed six samples.

- Fire Area R-2; Primary Containment; May 10 and 13, 2005
- Fire Area RC-19; Radwaste Control Building - Corridor C205; May 26, 2005
- Fire Area R-6; Reactor Core Isolation Cooling Pump Room; May 31, 2005
- Fire Area SW-1; Standby Service Water Pump House 1A; June 16, 2005
- Fire Area RC-2; Cable Spreading Room; June 18, 2005
- Fire Area SW-2; Standby Service Water Pump House 1B; June 18, 2005

b. Findings

No findings of significance were identified.

.2 Annual Inspection

a. Inspection Scope

The inspectors observed a fire brigade drill on April 27, 2005, to evaluate the readiness of licensee personnel to prevent and fight fires, including the following aspects: (1) use of protective clothing, (2) use of breathing apparatuses, (3) placement and use of fire hoses, (4) entry into the fire area, (5) use of fire fighting equipment, (6) brigade leader command and control, (7) communications between the fire brigade and control room, (8) searches for fire victims and fire propagation, (9) smoke removal, (10) use of pre-fire plans, and (11) adherence to the drill scenario. The licensee simulated a fire in the 471' Hallway Storage Area.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (71111.08)

Procedure 71111.08 requires a minimum sample size of 1 for a boiling water reactor facility (Section 02.01). The inspector fulfilled the requirements of Inspection Procedure 71111.08, "Inservice Inspection Activities."

2.01 Performance of Nondestructive Examination Activities

a. Inspection Scope

The procedure requires the review of 2 to 3 types of nondestructive examination activities. The inspector observed and reviewed 24 volumetric examinations and 16 visual examinations. The volumetric examinations included 22 ultrasonic examinations of the reactor vessel head nuts, and two radiographic examinations of class two welds. The inspector also observed portions of the automated ultrasonic examination of the reactor pressure vessel assembly welds and full penetration welds of nozzles in the reactor vessel. Fifteen of the surface examinations were visual (VT1) examinations of reactor vessel head nuts and washers. The inspector also reviewed portions of the in-vessel visual inspection of the reactor pressure vessel internals.

For each of the reviewed and observed examinations, the inspector verified that the correct nondestructive examination procedure was used, examinations and conditions were as specified in the procedures, and test instrumentation or equipment was properly calibrated and within the allowable calibration period. The inspector also reviewed the documentation and verified that accepted indications were reviewed and dispositioned in accordance with the appropriate American Society of Mechanical Engineers (ASME) Code specified acceptance standards. The nondestructive examination certifications of personnel observed performing examinations or identified during review of completed examination packages was reviewed by the inspector.

The inspection procedure requires review of one or two examinations from the previous outage with recordable indications that were accepted for continued service to ensure that the disposition was done in accordance with the ASME Code. There were no apparent recordable indications from other inspection activities found.

The procedure requires verification for one to three welds that the welding process and welding examinations were performed in accordance with the ASME Code, if welding on the pressure boundary for Class 1 or 2 systems has been completed by the licensee. The inspector reviewed two Class 2 welds and verified that the weld process and post-weld examinations were performed in accordance with the ASME Code.

a. Findings

No findings of significance were identified.

2.05 Identification and Resolution of Problems

b. Inspection Scope

The inspector reviewed twelve inservice inspection-related condition reports issued during the current and past refueling outage. The review served to verify that the licensee's corrective action process was being correctly utilized to identify conditions adverse to quality and that those conditions were being adequately evaluated, corrected and trended. The inspector confirmed that the licensee's threshold for initiating condition reports was low, thereby capturing most deficiencies identified in the inservice inspection program. The inspector also verified that corrective actions were being appropriately addressed.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

a. Inspection Scope

On April 18, 2005, the inspectors observed testing and training of senior reactor operators and reactor operators to identify deficiencies and discrepancies in the training, to assess operator performance, and to assess the evaluator's critique. The training scenario involved a reactor closed cooling system leak in containment followed by a loss of coolant accident and failure of the high pressure core spray system and startup transformer.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors reviewed the below listed maintenance activities to: (1) verify the appropriate handling of structure, system, and component (SSC) performance or condition problems; (2) verify the appropriate handling of degraded SSC functional performance; (3) evaluate the role of work practices and common cause problems; and

(4) evaluate the handling of SSC issues reviewed under the requirements of the maintenance rule, 10 CFR 50 Appendix B, and the Technical Specifications.

The inspectors completed one sample.

- Standby Service Water (SW) pump 1A (SW-P-1A) shaft failure; June 23, 2005

b. Findings

Introduction. An Unresolved Item (URI) was identified pending the NRC's determination of the regulatory aspects and evaluation of the safety significance of the performance issues associated with performance degradation of SW-P-1A.

Description. On June 14, 2005, following a start of the SW-P-1A, control room operators noted that SW flow to the Division 1 residual heat removal heat exchanger was low out of specification. A subsequent surveillance test on SW-P-1A determined that; 1) performance had degraded, and 2) the pump was operating at the intersection of the alert and action ranges of its performance curve. Energy Northwest declared SW-P-1A inoperable.

Energy Northwest replaced SW-P-1A with a spare pump already on site. During disassembly of SW-P-1A, Energy Northwest determined that the cause of the degraded pump performance was due to intergranular shaft corrosion cracking (IGSCC) of the pump shaft end flanges on two of the shaft sections. The corrosion cracking resulted in the coupling between one of the shaft sections to fail. As a result, the overall shaft length increased causing the pump impeller to rest on the pump suction casing when the pump was stopped. During subsequent pump starts, the pump impeller would rub on the casing causing the impeller leading edge to erode and deform which resulted in degraded pump performance. Energy Northwest documented the pump degradation in PER 205-0417.

Energy Northwest conducted a metallurgical examination of the damaged pump shaft. It was determined that in addition to the identified shaft end flange cracking, axial cracking had occurred on the impeller pump shaft segment and two diagonal cracks had occurred on the top column shaft. The examination also determined that the shaft material, TP410 martensitic stainless steel, had become susceptible to tempering embrittlement (the shaft material had been tempered at 970 degrees Fahrenheit which was conducive to tempering embrittlement). Tempering embrittlement can reduce the corrosion resistance of TP410 martensitic stainless steel to pitting attack which increases the materials susceptibility to IGSCC.

Energy Northwest determined that SW-P-1B was also susceptible to the same failure mechanism which was identified in SW-P-1A, but that SW-P-1B had not exhibited any degraded performance. Energy Northwest plans to inspect SW-P-1B following the procurement of repair parts which would be needed to facilitate disassembly and inspection of the pump. Corrective actions included additional monitoring of SW-P-1B to verify pump performance until the pump can be inspected.

The inspectors reviewed applicable operating experience and identified that Energy Northwest had evaluated two NRC Information Notices, IN 93-68 and IN 94-45, which provided information regarding shaft coupling failures associated with Byron Jackson pumps and with corrosion of shaft coupling assemblies of long shaft vertical pumps. Energy Northwest's SW pumps are long shaft vertical pumps manufactured by Byron Jackson. The inspectors noted the following performance issues:

- Information Notice 93-68, dated September 1, 1993, described a problem caused by temper embrittlement of couplings used in Byron Jackson pumps using a type 410 stainless steel shaft couplings. Pump shafts containing temper embrittled couplings could fail during operation if the pump has worn bearings, if the shaft is misaligned, or shaft motion is impeded by silt or debris ingestion. Energy Northwest documented their evaluation of IN 93-68 in OER 84079S and PTL H104148 and determined that both SW pumps couplings were to be inspected per vendor recommendation during scheduled pump overhauls in refueling outages R10 (SW-P-1B) and R11 (SW-P-1A). The inspectors noted that although the corrective action was documented in the review of IN 93-68, the corrective action was not formally tracked as a required action in OER 84709S. Energy Northwest Procedure PPM 1.10.4, "External Operational Experience Review," Revision 10, which was in effect at the time of the evaluation, required that when a corrective action is required as a result of an OE review that the "Action Required" section of the OE Issue Form be completed indicating the action to be implemented. Subsequently, the pump overhauls did not occur and the couplings were not inspected. The inspectors considered Energy Northwest failure to properly characterize and track the identified corrective action as a missed opportunity to identify potential shaft coupling degradation prior to the failure on June 14, 2005.

- Information Notice 94-45, dated June 17, 1994, described a problem where differing coupling materials could experience galvanic corrosion resulting in a failure of the shaft coupling and subsequent failure of long shaft vertical pumps. Energy Northwest documented their evaluation of IN 94-45 in OER 82008Y and PTL H102543. The evaluation concluded that since the shaft coupling materials for the SW pumps were all type 410 stainless steel, galvanic corrosion was not a concern and closed the evaluation with no action taken. However, the inspectors noted that in addition to IN 94-45 specifically addressing galvanic corrosion of shaft couplings, it also generally addressed a concern that current testing methodologies of vertical line shaft pump hydraulic and mechanical performance may not identify, before damage occurs, interference between the pump impellers and bowls caused by a change in shaft length. The inspectors considered Energy Northwest's evaluation of IN 94-45 to be narrowly focused and a missed opportunity to establish a periodic evaluation to ensure the operability of the shaft couplings of the SW pumps.

An URI (URI 50-397/05-03-01, Service Water Pump A Performance Degradation) was opened for the NRC review of the performance issues associated with identified degradation of SW-P-1A. The resolution of the URI will also include an NRC staff review of Energy Northwest's evaluation of: 1) the ability of SW-P-1A to complete is design mission time given the as-found condition of the pump; and 2) the as-found condition of SW-P-1B following the planned pump inspection at the next available opportunity.

Analysis. The issues associated with the SW-P-1A performance degradation are under review by the NRC staff. A determination of the safety significance associated with any performance deficiencies will be addressed in the resolution of the URI.

Enforcement. The issues associated with the SW-P-1A performance degradation are under review by the NRC staff. A determination of the enforcement aspects associated with any performance deficiencies will be addressed in the resolution of the URI.

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

a. Inspection Scope

The inspectors reviewed the five below listed assessment activities to verify: (1) performance of risk assessments when required by 10 CFR 50.65 (a)(4) and licensee procedures prior to changes in plant configuration for maintenance activities and plant operations; (2) the accuracy, adequacy, and completeness of the information considered in the risk assessment; (3) that the licensee recognizes, and/or enters as applicable, the appropriate licensee-established risk category according to the risk assessment results and licensee procedures, and (4) the licensee identified and corrected problems related to maintenance risk assessments.

The inspectors completed five samples.

- Residual heat removal (Division 1) motor operator valve maintenance coincident with containment vacuum breaker CVB-V-1LM and primary containment isolation valve Containment Purge and Exhaust (CEP) CEP-V-2A out of service; April 19, 2005

- Fuel shuffle coincident with residual heat removal (Division 1) system out of service; May 13, 2005

- Residual heat removal valves RHR-V-8 and RHR-V-9 maintenance outage; May 26, 2005

- Reactor pressure vessel operating pressure leak test coincident with diesel generator (Division 1), standby service water pump (Division 1), and residual heat removal (Division 1) out of service for maintenance; June 3, 2005

- Standby service water pump (Division 1) out of service for pump replacement during forced outage FO-05-01 (plant in high risk configuration for shutdown cooling); June 16, 2005

b. Findings

No findings of significance were identified.

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

k. Inspection Scope

The inspectors: (1) reviewed operator logs, plant computer data, and/or strip charts for the below listed evolutions to evaluate operator performance in coping with non-routine events and transients; (2) verified that the operator actions and response was in accordance with the response required by plant procedures and training; (3) and verified that the licensee has identified and implemented appropriate corrective actions associated with personnel performance problems that occurred during the non-routine evolutions sampled.

The inspectors completed five samples.

- Main generator output oscillations; April 7, 2005

- Feedwater heater 3A recovery; April 12, 2005

- Reactor unit shutdown for refueling outage; May 6 and 7, 2005

- Reactor scram due to main turbine throttle valves inadvertently closing; June 15, 2005

- Reactor Scram due to loss of feedwater pump resulting in lowering reactor water level and reactor core isolation cooling system performance problems; June 23, 2005

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors: (1) reviewed plant status documents such as operator shift logs, emergent work documentation, deferred modifications, and standing orders to determine if an operability evaluation was warranted for degraded components; (2) referred to the Updated Safety Analysis Report and design basis documents to review the technical adequacy of licensee operability evaluations; (3) evaluated compensatory measures associated with operability evaluations; (4) determined degraded component impact on any Technical Specifications; (5) used the Significance Determination Process to evaluate the risk significance of degraded or inoperable equipment; and (6) verified that the licensee has identified and implemented appropriate corrective actions associated with degraded components.

The inspectors completed four samples.

- PER 205-0248; High Pressure Core Spray 42 relay settings; May 31, 2005
- PER 205-0305; A 3" Cond/RHR A cross tie spool piece is disconnected and not seismically supported because COND-HGR-922 was removed; June 6, 2005
- CR 2-05-04589; RHR-P-2A Discharge Pressure Low; June 2, 2005
- CR 2-05-04380; RHR pump B fuse block cracked; May 29, 2005

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (71111.16)

.1 Selected Operator Workarounds

a. Inspection Scope

On April 29, 2005, the inspectors reviewed the operations' department "Columbia Operational Challenges List" tracking log to determine what issues had been identified as operator workarounds by Energy Northwest and completed one sample for a potential operator workaround associated with an inoperable containment isolation valve. The inspectors evaluated the potential operator workaround to: (1) determine if the functional capability of the system or human reliability in responding to an initiating event is affected; (2) evaluate the effect of the operator workaround on the operator's ability to implement abnormal or emergency operating procedures; and (3) verify that the licensee has identified and implemented appropriate corrective actions.

The inspectors completed one sample.

b. Findings

Introduction. A Green NRC identified finding associated with an inadequate compensatory measure was identified. The compensatory measure, established in response to an inoperable primary containment isolation valve, prevented implementing a procedure which directed emergency ventilating the drywell during post accident conditions. This finding had crosscutting aspects of problem identification in that Energy Northwest did not identify that the compensatory action prevented implementation of the affected procedure. This finding was not subject to enforcement actions because it involved a procedure and equipment function which was not safety related.

Description. The inspectors reviewed the "Columbia Operational Challenges List" and noted that Challenge # 05-082, "CEP-V-2A slow and erratic when opening valve," documented a danger tag clearance order which was greater than 90 days old. Containment Purge and Exhaust Valve CEP-V-2A is a 30" air operated butterfly valve which provides a flow path for venting the drywell to the standby gas treatment system during normal operations and is also opened in procedure PPM 5.5.15, "Emergency Drywell Venting," Revision 4. Procedure PPM 5.5.15 is required to be implemented in Emergency Operating Procedure (EOP) 5.2.1, "Primary Containment Control," Step P-14, for venting the primary containment. Valve CEP-V-2A has a safety function to close for primary containment isolation purposes but no safety function to open.

Valve CEP-V-2A had exhibited degraded stroke timing in the open direction on several occasions as documented in CR 2-04-03446, CR 2-04-05726, CR 2-04-05835, and CR 2-04-07036. Valve CEP-V-2A was declared inoperable on December 28, 2004, due to the noted increased stroke time and due to noted poor performance (metal to metal sounds and abrupt movement of the valve noted during stroking). Energy Northwest closed and de-energized CEP-V-1A and CEP-V-1B, the valves located immediately downstream of CEP-V-2A to ensure that the associated primary containment penetration was isolated consistent with Technical Specification 3.6.1.3 requirements. The inspectors noted that to de-energize CEP-V-1A and CEP-V-1B that Energy Northwest removed fuses from the valve's control circuitry to ensure that operating air could not be applied to the valve operators to prevent opening the valves. The fuses were located in an instrument rack on the 548' elevation of the reactor building. The inspectors questioned the control room staff if the fuses could be installed in a post-accident environment to allow re-opening of valves CEP-V-1A and CEP-V-1B to facilitate venting the primary containment in accordance with EOP 5.2.1 and PPM 5.5.15. Energy Northwest determined that post-accident radiation levels on the 548' elevation of the reactor building would prevent an operator from entering the area to install the fuses needed to re-energize valves CEP-V-1A and CEP-V-1B. Without the ability to install the fuses and energize CEP-V-1A, the operators would not be able to emergency ventilate and depressurize the drywell during post-accident conditions when primary containment integrity was adversely challenged.

The inspectors also noted a problem identification aspect in that Energy Northwest documented in CR 2-04-07036 that CEP-V-2A was used in plant EOP's to allow venting of the drywell and that compensatory actions were needed as required by TS to close the valve during an accident. The compensatory actions were to consist of a dedicated operator to close CEP-V-2A after valves CEP-V-1A and CEP-V-1B were re-energized and opened during drywell venting operations. However, the compensatory action was not evaluated to determine what environmental conditions and radiation hazards would be present post-accident to allow re-energization of CEP-V-1A and CEP-V-1B. The inspectors concluded that the failure to evaluate and identify the inadequacy of the proposed compensatory actions to be a problem identification crosscutting aspect to the finding.

Analysis. The inability to implement PPM 5.5.15 during post-accident conditions in accordance with EOP 5.2.1 was a performance deficiency. The finding was more than minor because if left uncorrected the finding would become a more significant safety concern since primary containment integrity would be challenged due to the inability to emergency ventilate the drywell. Additionally, the finding was a configuration control issue which affected the barrier integrity cornerstone attribute to provide reasonable assurance that physical design barriers (containment) protect the public from radionuclide releases caused by accidents or events. Using the Significance Determination Process, Phase 1 worksheet, the inspectors determined that the finding was of very low risk significance (Green) because the finding did not represent an actual open pathway in the physical integrity of the reactor containment.

Enforcement. No violation of regulatory requirements occurred because the affected equipment did not have a safety-related function to open. Energy Northwest documented the problem in CR 2-05-02869 (FIN 50-397/05-03-02, Compensatory Action Prevented Implementation of Drywell Emergency Ventilation Procedure).

.2 Cumulative Review of the Effects of Operator Workarounds

a. Inspection Scope

The inspectors reviewed the cumulative effects of operator workarounds to determine: (1) the reliability, availability, and potential for misoperation of a system; (2) if multiple mitigating systems could be affected; (3) the ability of operators to respond in a correct and timely manner to plant transients and accidents; and (4) if the licensee has identified and implemented appropriate corrective actions associated with operator workarounds.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors selected the four below listed post-maintenance test activities of risk significant systems or components. For each item, the inspectors: (1) reviewed the applicable licensing basis and/or design-basis documents to determine the safety functions; (2) evaluated the safety functions that may have been affected by the maintenance activity; and (3) reviewed the test procedure to ensure it adequately tested the safety function that may have been affected. The inspectors either witnessed or reviewed test data to verify that acceptance criteria were met, plant impacts were evaluated, test equipment was calibrated, procedures were followed, jumpers were properly controlled, the test data results were complete and accurate, the test equipment was removed, the system was properly re-aligned, and deficiencies during testing were documented. The inspectors also reviewed the corrective action program to determine if the licensee identified and corrected problems related to post-maintenance testing.

The inspectors completed four samples.

- WO 01095465; HPCS air deflector replacement and motor repair; March 25 and 26, 2005
- WO 01059796; LPCS-V-33 and LPCS-V-34 Replacement; May 19, 2005
- WO 01064758; RHR-HX-2A SW side clean and inspect; May 20, 2005
- WO 01067000; SW-P-1A Pump Replacement; June 21, 2005

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities (71111.20)

.1 Refueling Outage R-17 (May 7 to June 11, 2005)

a. Inspection Scope

The inspectors reviewed the following risk significant refueling items or outage activities to verify defense in depth commensurate with the outage risk control plan and compliance with the Technical Specifications: (1) the risk control plan; (2) tagging/clearance activities; (3) reactor coolant system instrumentation; (4) electrical power; (5) decay heat removal; (6) spent fuel pool cooling; (6) inventory control; (7) reactivity control; (8) containment closure; (9) reduced inventory and refueling cavity floodup and draindown evolutions; (10) refueling activities; (11) heatup and cooldown activities; and (12) licensee identification and implementation of appropriate corrective actions associated with refueling and outage activities.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

.2 Forced Outage FO-05-01 (June 15 to 22, 2005)

a. Inspection Scope

The inspectors reviewed the following risk significant outage activities to verify defense in depth commensurate with the outage risk control plan and compliance with the technical specifications: (1) the outage risk control plan; (2) reactor coolant system instrumentation; (3) electrical power; (4) decay heat removal; (5) heatup and cooldown activities; and (6) licensee identification and implementation of appropriate corrective actions associated with refueling and outage activities.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors reviewed the Updated Final Safety Analysis Report, procedure requirements, and Technical Specifications to ensure that the six below listed surveillance activities demonstrated that the SSC's tested were capable of performing their intended safety functions. The inspectors either witnessed or reviewed test data to verify that the following significant surveillance test attributes were adequate: (1) preconditioning; (2) evaluation of testing impact on the plant; (3) acceptance criteria; (4) test equipment; (5) procedures; (6) jumper/lifted lead controls; (7) test data; (8) testing frequency and method demonstrated Technical Specification operability; (9) test equipment removal; (10) restoration of plant systems; (11) fulfillment of ASME Code requirements; (12) updating of performance indicator data; (13) engineering evaluations, root causes, and bases for returning tested SSC's not meeting the test acceptance criteria were correct; (14) reference setting data; and (15) annunciators and alarms setpoints. The inspectors also verified that the licensee identified and implemented any needed corrective actions associated with the surveillance testing.

The inspectors completed six samples. Included in the samples was one in-service test associated with the performance testing of the main steam relief valves and automatic depressurization relief valves. Also included in the samples was one containment isolation valve local leak rate test of containment exhaust purge valve CEP-V-2A.

- TSP-DG1/LOP-B501; Standby Diesel Generator DG1 Loss of Power Test; Revision 6; May 18, 2005

- OSP-RPV-R801; Reactor Pressure Vessel Leakage Test; Revision 15; June 3, 2005

- TSP-CONT-R801; Containment Isolation Valve and Penetration Leak Test Program (for valve CEP-V-2A); Revision 11; June 8, 2005

- TSP-DG-E501; Simultaneous Start of all three Diesel Generators; Revision 2; May 3, 2005

- BCT-2000; Battery E-B1-1 24 Month Load Test; May 12, 2005

- TSP-MSRV/IST-B501; Safety / Relief Valve and ADS Operability; Revision 3; June 10, 2005

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed the Updated Final Safety Analysis Report, plant drawings, procedure requirements, and Technical Specifications to ensure that the two below listed temporary modifications were properly implemented. The inspectors: (1) verified that the modification did not have an affect on system operability/availability; (2) verified that the installation was consistent with the modification documents; (3) ensured that the post-installation test results were satisfactory and that the impact of the temporary modification on permanently installed SSC's were supported by the test; (4) verified that the modifications were identified on control room drawings and that appropriate identification tags were placed on the affected drawings; and (5) verified that appropriate safety evaluations were completed. The inspectors verified that licensee identified and implemented any needed corrective actions associated with temporary modifications.

The inspectors completed two samples.

- TMR 05-010; 3" Condensate Line at RHR-V-7 is not supported and is a Seismic Issue; April 6, 2005

- TMR 05-011; Add scaffolding to support the condensate line and attached RHR line and restrain the line from impacting required or safety related equipment; April 29, 2005

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety (OS)

2OS1 Access Control To Radiological Significant Areas (71121.01)

C. Inspection Scope

This area was inspected to assess the licensee's performance in implementing physical and administrative controls for airborne radioactivity areas, radiation areas, high radiation areas (HRAs), and worker adherence to these controls. The inspector used the requirements in 10 CFR Part 20, the technical specifications, and the licensee's procedures required by technical specifications as criteria for determining compliance. During the inspection, the inspector interviewed the radiation protection manager, radiation protection supervisors, and radiation workers. The inspector performed independent radiation dose rate measurements and reviewed the following items:

- Performance indicator events and associated documentation packages reported by the licensee in the Occupational Radiation Safety Cornerstone
- Controls (surveys, posting, and barricades) of 3 radiation, high radiation, or airborne radioactivity areas
- Radiation work permit procedure, and engineering controls, and air sampler locations
- Conformity of electronic personal dosimeter alarm set points with survey indications and plant policy; workers' knowledge of required actions when their electronic personnel dosimeter noticeably malfunctions or alarms
- Physical and programmatic controls for highly activated or contaminated materials (non-fuel) stored within spent fuel and other storage pools
- Self-assessments, audits, licensee event reports, and special reports related to the access control program since the last inspection
- Corrective action documents related to access controls
- Radiation work permit briefings and worker instructions
- Adequacy of radiological controls such as, required surveys, radiation protection job coverage, and contamination controls during job performance

- Dosimetry placement in high radiation work areas with significant dose rate gradients

- Changes in licensee procedural controls of high dose rate - high radiation areas and very high radiation areas

- Controls for special areas that have the potential to become very high radiation areas during certain plant operations

- Posting and locking of entrances to all accessible high dose rate - high radiation areas and very high radiation areas

- Radiation worker and radiation protection technician performance with respect to radiation protection work requirements

Either because the conditions did not exist or an event had not occurred, no opportunities were available to review the following items:

- Licensee actions in cases of repetitive deficiencies or significant individual deficiencies

- Barrier integrity and performance of engineering controls in airborne radioactivity areas

- Adequacy of the licensee's internal dose assessment for any actual internal exposure greater than 50 millirem CEDE

The inspectors completed 21 of the required 21 samples.

b. Findings

Introduction. The inspectors identified a noncited violation of 10 CFR 20.1904 because the licensee failed to label a filter canister located in the equipment storage section of the refueling pool. The violation had very low safety significance.

Description. During a review of items stored in the refueling pool on May 25, 2005, the inspectors found an unlabeled canister containing used filters from a pool filtering system. The canister was sitting on the bottom of the equipment storage area and was secured to the handrail with a rope. The canister was not labeled to identify the contents of the canister and the radiological hazards, nor were the contents identified by a readily available written record, such as a tag on the rope. The inspectors were able to lift the canister off the bottom of the pool by pulling on the rope. Dose rates on contact with the canister were measured with an underwater probe and found to be approximately 17 rem per hour.

Analysis. The failure to label the container is a performance deficiency. This finding is greater than minor because it is associated with an Occupational Radiation Safety cornerstone attribute (human performance) and affected the cornerstone objective in that the failure to warn individuals of radiological hazards diminished the licensee ability to ensure adequate protection of the worker health and safety from exposure to radiation. Using the Occupational Radiation Safety Significance Determination Process, the inspectors determined that the finding was of very low safety significance because it did not involve: (1) ALARA planning and controls, (2) an overexposure, (3) a substantial potential for overexposure, or (4) an impaired ability to assess dose. This finding also had crosscutting aspects associated with human performance. The failure of licensee personnel to follow the established program of controls for items stored in the refueling pool directly contributed to the finding.

Enforcement. 10 CFR 20.1904 requires that each container of licensed material bear a durable, clearly visible label bearing the radiation symbol and the words, "Caution Radioactive Material or Danger Radioactive Material." 10 CFR 20.1905(e) provides an exception to the labeling requirements of 10 CFR 20.1904 for containers in locations such as water-filled canals, storage vaults, or hot cells. It states that the containers are not required to be labeled if they are accessible only to individuals authorized to handle or use them, or to work in the vicinity of the containers, if the contents are identified by a readily available written record. The licensee violated the requirements of 10 CFR 20.1904 when it did not label the canister containing spent filters, and it did not meet the exception to 10 CFR 20.1904 by implementing the controls of 10 CFR 20.1905(e). The licensee placed the finding in its corrective action program as Condition Report 2-05-04272. Because the finding was placed into the corrective action program and had very low safety significance, it is being treated as a non-cited violation, consistent with Section VI.A of the NRC Enforcement Policy (NCV 05-397/05-03-03, Failure to Label a Container of Radioactive Material).

2OS2 ALARA Planning and Controls (71121.02)

a. Inspection Scope

The inspector assessed licensee performance with respect to maintaining individual and collective radiation exposures as low as is reasonably achievable (ALARA). The inspector used the requirements in 10 CFR Part 20 and the licensee's procedures required by Technical Specifications as criteria for determining compliance. The inspector interviewed licensee personnel and reviewed:

- Three work activities of highest exposure significance completed during the last outage
- Use of engineering controls to achieve dose reductions and dose reduction benefits afforded by shielding
- Workers use of the low dose waiting areas

- Exposures of individuals from selected work groups
- Records detailing the historical trends and current status of tracked plant source terms and contingency plans for expected changes in the source term due to changes in plant fuel performance issues or changes in plant primary chemistry
- Source-term control strategy or justifications for not pursuing such exposure reduction initiatives
- Specific sources identified by the licensee for exposure reduction actions and priorities established for these actions, and results achieved against the last refueling cycle
- Declared pregnant workers during the current assessment period, monitoring controls, and the exposure results
- Resolution through the corrective action process of problems identified through post-job reviews and post-outage ALARA report critiques
- Corrective action documents related to the ALARA program and followup activities such as initial problem identification, characterization, and tracking
- Effectiveness of self-assessment activities with respect to identifying and addressing repetitive deficiencies or significant individual deficiencies

The inspector completed 5 of the required 15 samples and 6 of the optional samples.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification

.1 Occupational Radiation Safety Cornerstone

a. Inspection Scope

The inspectors reviewed the following performance indicator:

- Occupational Exposure Control Effectiveness PI

Licensee records reviewed included corrective action documentation that identified occurrences of high high radiation areas (as defined in the licensee’s Technical Specifications), very high radiation areas (as defined in 10 CFR 20.1003), and unplanned personnel exposures (as defined in NEI 99-02). Additional records reviewed included

ALARA records and whole body counts of selected individual exposures. The inspectors interviewed licensee personnel that were accountable for collecting and evaluating the PI data. In addition, the inspectors toured plant areas to verify that high radiation, high high radiation, and very high radiation areas were properly controlled.

b. Findings

No findings of significance were identified.

.2 Public Radiation Safety Cornerstone

a. Inspection Scope

The inspectors reviewed the following performance indicator:

- Radiological Effluent Technical Specification/Offsite Dose Calculation Manual Radiological Effluent Occurrences

Licensee records reviewed included corrective action documentation that identified occurrences for liquid or gaseous effluent releases that exceeded PI thresholds and those reported to the NRC. The inspectors interviewed licensee personnel that were accountable for collecting and evaluating the PI data.

b. Findings

No findings of significance were identified.

4OA2 Problem Identification and Resolution

.1 Daily Corrective Action Document Review

a. Inspection Scope

The inspectors performed a review of all documented condition reports and problem evaluation reports to help identify repetitive equipment failures or specific human performance issues for followup inspection using other baseline inspection procedures. The review was accomplished by evaluating Energy Northwest's electronic condition report and problem evaluation report databases, attending periodic plant status meetings, and observing periodic condition report group review meetings.

b. Findings and Observations

No findings or observations were identified.

.2 Cross-References to Problem Identification and Resolution Findings Documented Elsewhere

A finding with a problem identification crosscutting aspect was identified when Energy Northwest failed to properly evaluate and identify an inadequate compensatory measure associated with an inoperable primary containment isolation valve (Section 1R16).

.3 Review of Identified Substantive Crosscutting Issue in Human Performance

In the annual assessment letter, dated March 2, 2005, from the NRC to Energy Northwest, the NRC documented a substantive crosscutting issue in human performance. Human performance issues with a common performance characteristic of personnel performance, contributed to a number of Green findings in different cornerstones. The findings principally involved instances of failing to follow procedures or a lack of understanding of the procedural requirements and the impact on plant operations. Energy Northwest documented this NRC identified substantive crosscutting issue in their corrective action program in PER 205-0132. Documented corrective actions completed or planned included: 1) revising the site procedure usage policy to eliminate previously allowed latitude for procedure adherence; 2) developing and implementing change management and decision making tools; 3) establishing expectations for weekly observations of the operating crew by operations' managers; 4) developing and implementing written policies for management expectations with regard to use of human error prevention tools; and 5) clarifying operations peer checking expectations. The inspectors considered the corrective actions to be appropriate for improving human performance with respect to procedure usage and adherence. The NRC will reassess this substantive crosscutting issue in the semi-annual assessment meeting scheduled for August, 2005, to determine if the corrective actions had been effective in precluding recurrence of human performance errors associated with procedure usage and understanding.

.4 Semi-Annual Trend Review

a. Inspection Scope

On June 23, 2005, the inspectors completed a semi-annual review of Energy Northwest's internal documents, quality assurance audit reports, and performance indicators to identify trends that might indicate the existence of a significant safety issue. The inspectors' review focused on repetitive equipment issues, but also considered other non-equipment related trends, including human performance related issues, to determine if other significant adverse trends existed. The inspectors also reviewed the additional following documents:

- System health reports
- Corrective action documents
- Temporary modifications
- Operator challenges list
- Control room logs

b. Findings and Observations

No findings of significance were identified. However, the inspectors did note one continuing trend in human performance which Energy Northwest had previously identified. Specifically, Energy Northwest documented an adverse trend associated with personnel performing work utilizing incorrect radiation work permit ALARA tasks in PER 204-0328, dated January 27, 2004. Although corrective actions were taken and implemented to prevent recurrence of the issue, the inspectors noted the following events listed below which indicated a potential continuing adverse trend. The inspectors also determined that there was an increase in the number of documented events after PER 204-0328 had been written. However, the inspectors recognized that the increase could have been due to a lowering in the station's threshold for documenting plant issues and events.

- CR 2-05-04616; Williams boiler maker closed condenser manway on incorrect RWP
- CR 2-05-04515; Contract employee entered reactor building on wrong RWP
- CR 2-05-04049; Personnel supporting clean and inspection of Cond-HX-9 WO 0108249601 signed in on the general RWP 30001394 instead of 30001510
- CR 2-05-03236; Individuals were permitted to enter the drywell, which was posted as a HHRA, on a high radiation area RWP
- CR 2-05-03155; Worker received an accumulated dose alarm on his electronic dosimeter
- CR 2-05-03075; Worker entered a high radiation area on the wrong RWP
- CR 2-05-00509; Wrong ALARA tasks were used for two different work activities
- CR 2-05-00495; Individuals signed in under the wrong ALARA task
- CR 2-04-04358; The wrong ALARA task was used to disassemble MS-V-22D
- CR 2-04-03811; Individual signed in on wrong ALARA task for RWCU-P-1B tagout
- CR 2-04-03284; Operators did not sign in on the specific ALARA task during tagout of HCU's on 6/13/04 due to incorrect guidance from an HP technician
- CR 2-04-02351; Workers signed in on the wrong ALARA task when entering the RCA to perform work
- CR 2-04-00394; Individual signed in on the wrong ALARA task

The inspectors also noted that Energy Northwest also assigned an additional corrective action in PER 204-0328 to perform an effectiveness review of the implemented corrective actions after refueling outage R-17. This effectiveness review had not been completed at the end of the inspection period.

.5 Section 2OS1 evaluated the effectiveness of the licensee's problem identification and resolution processes regarding access controls to radiologically significant areas and radiation worker practices. The inspectors reviewed corrective action documents for root cause/apparent cause analysis against the licensee's problem identification and resolution process. No findings of significance were identified.

.6 Section 2OS2 evaluated the effectiveness of the licensee's problem identification and resolution processes regarding exposure tracking, higher than planned exposure levels, and radiation worker practices. The inspector reviewed the corrective action documents listed in the attachment against the licensee's problem identification and resolution program requirements. No findings of significance were identified.

4OA3 Event Followup (71153)

.1 Damage to Safe Shutdown Building roll-up door due to unintentional impact from vehicle

a. Inspection Scope

On April 5, 2005, Energy Northwest declared an unusual event per Emergency Action Level 9.3.U.1 due to an unintentional vehicle impact into the Radwaste Building (Safe-Shutdown Building) roll-up door during the normal course of plant activities. While exiting the building a plant laborer driving a 2 ton flat bed truck with an empty C-van container strapped to its bed, struck the roll-up door. The door was opened by another employee who believed it was raised high enough to allow the top of the C-van container to clear the bottom of the roll-up door. In addition, the truck driver assumed that there was enough clearance between the door and the truck to proceed through the door. The truck subsequently struck the roll-up door as the truck was exiting the area. As a result of the impact, damage to the door prevented it from closing normally. A subsequent evaluation by Energy Northwest determined that given the minimal amount of damage to the roll-up door and the type and quantity of stored radioactive material in the immediate vicinity of the roll-up door that an unintentional release of radioactive material to the environment was not credible. Energy Northwest subsequently terminated the event approximately 43 minutes later. The inspector conducted an independent assessment of the event which included an evaluation of the extent of damage to the roll-up door, the possibilities of damage to structures within the Radwaste Building, and the potential for the spread of contamination to the environment. Energy Northwest Emergency Plan Implementing Procedure 13.1.1, “Classifying the Emergency,” Revision 33, was reviewed for the applicability for declaring an unusual event. This event was entered into Energy Northwest’s corrective action program as PER 205-0226.

b. Findings

No findings of significance were identified.

.2 June 15, 2005 Automatic Reactor Scram

a. Inspection Scope

On June 15, 2005, the inspectors observed and evaluated Energy Northwest’s response to an automatic reactor scram while the reactor was operating at 100 percent power. This scram was initiated when all Main Turbine Throttle valves went closed. The inspectors responded to the control room and verified the status of plant conditions by observing key plant parameters, annunciator status, and observing the current status of safety related mitigating equipment to ensure that the reactor plant was stable. The inspectors also observed reactor operator actions in response to the reactor scram and senior reactor operators evaluation of plant conditions and oversight of the reactor operators to ensure that operators were adhering to plant procedures. The inspectors also reviewed Energy Northwest's evaluation of the apparent cause of the scram.

b. Findings

No Findings of significance were identified.

.3 (Closed) Licensee Event Report (LER) 05000397/2004-002-00: Reactor core isolation cooling declared inoperable due to relay failure.

The inspectors reviewed LER 2004-002-00 to determine if there were any identified violations or aspects of human performance associated with the LER. This event did not constitute a violation of NRC requirements. Energy Northwest entered this condition into the corrective action program as Problem Evaluation Request 204-0570.

.4 June 23, 2005, Automatic Reactor Scram

a. Inspection Scope

On June 23, 2005, the inspectors observed and evaluated Energy Northwest's response to an automatic reactor scram due to low reactor water level while the reactor was operating at 23 percent power. The low reactor water level occurred due to a loss of the running reactor feedwater pump 1B during a maintenance activity. Complicating the scram recovery was the closure of the main steam isolation valves on low-low reactor water level. This caused the additional loss of reactor feedwater pump 1A. An additional complication occurred when the reactor core isolation cooling pump tripped when it was secured following an initial recovery of reactor water level. Operators were able to subsequently start and run the reactor core isolation cooling pump in manual. The inspector responded to the control room and verified the status of plant conditions by observing key plant parameters, annunciator status, and observing the current status of safety related mitigating equipment to ensure that the reactor plant was stable. The inspectors also observed reactor operator actions in response to the reactor scram and senior reactor operators evaluation of plant conditions and oversight of the reactor operators to ensure that operators were adhering to plant procedures.

b. Findings

Introduction. A Green self-revealing finding was identified for Energy Northwest's failure to follow a system operating procedure which resulted in a loss of a reactor feedwater pump and a subsequent reactor scram. No violations of NRC requirements were identified.

Description. On June 23, 2005, Energy Northwest bypassed the low suction pressure trips of both reactor feedwater pumps, RFW-P-1A and RFW-P-1B, to support feedwater heat exchanger maintenance. This was done in response to a reactor scram which had occurred on August 17, 2004, when an operator incorrectly restored a feedwater heat exchanger following maintenance which resulted in a momentary low pressure condition in the feedwater system and a trip of both reactor feedwater pumps (See IR 50-397/04-04, Section 4OA3.3). The low suction pressure trips were bypassed in accordance with Procedure PPM 2.2.7, "Extraction Steam and Heater Vents/Drains ", Revision 37, Step 5.15.2, which directed lifting and taping the lead associated with each reactor feedwater pumps suction pressure instrument low pressure switch contact, COND-PS-28A and COND-PS-28B on terminal board TB-1-17. However, there were two conductors terminated at TB-1-17, one wire leading to the pump trip circuit and the other wire to the pressure switch. Procedure PPM 2.2.7 did not specify which of the two leads on TB-1-17 were to be lifted. Subsequently, the lead to the pump trip circuit was lifted for RFW-P-1A due to industrial safety concerns associated with lifting the other conductor, while the lead to the pressure switch was lifted for RFW-P-1B.

Following the completion of the heat exchanger maintenance, maintenance technicians were to verify that the low pressure switch contact was open to ensure that an inadvertent low pressure trip signal would not be generated when the lifted leads were re-terminated for each pump. During this evolution RFW-P-1B was operating and supplying feedwater to the reactor vessel while RFW-P-1A, though operating, was running at minimum speed in a standby mode and was not supplying feedwater to the reactor vessel.

Energy Northwest verified the correct contact position by performing a continuity check with a multi-meter, re-terminated the lead and removed the low suction trip bypass for RFW-P-1A without incident. However, instead of verifying the low pressure switch contact was open during the removal of the low suction trip bypass for RFW-P-1B, the low pressure switch contact was inadvertently jumpered resulting in the RFW-P-1B governor valve to close causing a loss of feedwater to the reactor vessel. Although the technicians checked the position of the contact for each pump in the same manner, the different configuration of the lifted leads resulted in the loss of RFW-P-1B. Procedure PPM 2.2.7, step 5.15.5.b.4, directed the technician to verify that COND-PS-28B switch contact was open. Contrary to this step, the technicians failed to verify the configuration of the lifted lead for RFW-P-1B and jumpered across COND-PS-28B with the multi-meter instead of verifying the position of the pressure switch contact.

The inspectors noted that Energy Northwest's evaluation of the event during an incident review board identified the following performance issues: (1) the night shift bypassed the low suction trips and understood the different configuration between the two pumps and turned over that information to the day shift who later removed the bypasses. However the day shift did not fully understand or appreciate the different configuration between the lifted leads on the pumps and the impact that checking the contact positions would have on plant operations; and (2) although PPM 2.2.7 was adequate to perform the task, it was not prescriptive enough to ensure that configuration control was maintained. Energy Northwest documented the issue in PER 205-0428 and was in the process of performing a root cause evaluation at the end of the inspection period.

<u>Analysis</u>. The failure to verify the configuration of the lifted lead on the low suction trip bypass circuit for RFW-P-1B and verify that COND-PS-28B switch contact was open in accordance with PPM 2.2.7, step 5.15.5.b.4, was a performance deficiency which was reasonably within Energy Northwest's ability to foresee and prevent from occurring. The finding was of more than minor risk significance because it was a human performance issue which impacted the initiating events cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions. The safety significance of the finding was evaluated using NRC Manual Chapter 0609, Significance Determination Process, Phase 1 Worksheet, and was determined that a Phase 2 evaluation was required because the finding contributed both to the likelihood of a

reactor trip and the likelihood that mitigation equipment or function would not be available. The inspectors used the Columbia Generating Station site specific worksheets and Manual Chapter 0609 to perform a Phase 2 evaluation with the assistance of an NRC Senior Reactor Analyst.

An Initiating Event Likelihood credit of 1 was assumed in the evaluation because a reactor scram occurred and was considered inevitable as a result of the finding. In the benchmark validation of the Phase 2 notebook, a credit of 1 was applied for transients, which typically occur at a rate of approximately one per year. For this finding, although the baseline credit would be 3 (for an exposure of less than 3 days), and the usage rule would reduce the credit to a 2 for the finding, a credit of 1 was considered more appropriate because it corresponded to the benchmark correlation of one transient per year. Full credit for remaining mitigating capability was assigned for all safety functions with the exception of the power conversion system which was not given any credit. This was because both reactor feedwater pumps were considered unavailable once the main steam isolation valves closed during the event on low-low reactor water level. A senior reactor analyst reviewed the Phase 2 results and made an adjustment to allow for an operator recovery credit of 1 for the power conversion system. This accounted for the fact that the power conversion system could be and was recovered by re-opening the MSIVs and that the event occurred at a low power level shortly after starting up from a forced outage with relatively low decay heat as compared to full power operations. The recovery credit of 1 was based on use of the SPAR-H Human Reliability Analysis Method, wherein all performance shaping factors were considered nominal, which rendered a non-recovery probability of 1.1E-2.

Sequence 1 of the Transients (Reactor Trip) worksheet was determined to be the most limiting affected sequence and was assigned a result of 7. Using Table 5, "Counting Rule Worksheet," it was determined that the finding was of very low risk significance. The occurrence of a 7 in one Phase 2 sequence required that external events and large early release frequency be considered. The senior reactor analyst determined that external events would not appreciably affect the risk of the finding because of the short time interval between startup and the reactor feed pump trip. Using Appendix H to IMC 0609, the analyst determined that large early release would not change the risk characterization of the finding because the maximum multiplier for this event would be 0.3 for high pressure sequences in a Mark II containment. This finding had crosscutting aspects in the area of human performance in that the technicians failed to ensure the configuration of the circuit and subsequently failed to meet the requirement of a procedure step during the maintenance activity.

Enforcement. Although the maintenance technicians' failure to properly check the condition of COND-PS-28B contact in accordance with PPM 2.2.7 resulted in an initiating event and was a performance deficiency, the finding was not subject to enforcement action. Operation and maintenance of the reactor feedwater system was not a safety related activity and no violations of regulatory requirements were identified (FIN 50-397/05-03-04, Loss of RFW-P-1B Due to Lack of Configuration Control and Subsequent Failure to Follow Procedure). Immediate corrective actions included senior management review and approval of all maintenance related activities for the remainder of the forced outage and following restart of the plant up to 90 percent power.

4AO4 Crosscutting Aspects of Findings

Section 1R16 described an issue with problem identification and resolution crosscutting aspects which involved an inadequate compensatory measure.

Section 2OS1 described an issue with human performance crosscutting aspects which involved the failure to label a canister containing radioactive material, as required by 10 CFR 20.1904.

Section 4OA3 described an issue with human performance crosscutting aspects which involved a maintenance technicians' failure to follow a system operating procedure resulting in a plant scram.

4OA5 Other Activities

.1 Operational Readiness of Offsite Power (Temporary Instruction (TI) 2515/163)

The inspectors collected data pursuant to TI 2515/163, "Operational Readiness of Offsite Power." The inspectors reviewed the licensee's procedures related to General Design Criteria 17, "Electric Power Systems;" 10 CFR 50.63, "Loss of All Alternating Current Power;" 10 CFR 50.65(a)(4), "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants;" and the Technical Specifications for the offsite power system. The data was provided to the Office of Nuclear Reactor Regulation for further review. Documents reviewed for this TI are listed in the attachment.

.2 (Closed) URI 50-397/04-05-03; Thread Sealant Incompatibility with Valve Internals

In Inspection Report 50-397/04-05, Section 1R15, the inspectors documented an issue in which the high pressure core spray diesel generator failed to rotate when starting air was applied to the air start motors. During a review of the issue, the inspectors questioned the application of Neolube-100, a thread sealant, on the threads of the diesel air start motor valve caps. The URI was opened pending further review of the vendor recommendations regarding the acceptability of using Neolube-100 in the application. The inspectors reviewed subsequent vendor supplied information and documentation which indicated that Neolube-100 was acceptable for use on the diesel air start motor valve caps assuming that the sealant was applied in accordance with the manufacturer's recommended directions. The inspectors interviewed station personnel to ensure that the thread sealant was applied in accordance with those directions. No additional problems have been identified with the high pressure core spray diesel generator's ability to roll over with starting air. No findings or violations of regulatory requirements were identified. This URI is closed.

.3 TI 2515/161 - Transportation of Reactor Control Rod Drives in Type A Packages

a. Inspection Scope

This area was inspected to verify that the licensee's radioactive material transportation program complies with specific requirements of 10 CFR Parts 20, 71, and Department of Transportation regulations contained in 49 CFR Part 173. The inspector interviewed licensee personnel and determined the licensee had undergone refueling/defueling activities between January 1, 2002, and present, but it had not shipped irradiated control rod drives in Department of Transportation Specification 7A Type A packages.

b. Findings

No findings of significance were identified.

4OA6 Meetings, Including Exit

Resident Inspector Routine Exit Summary

On April 28, 2005, the inspector (L. Carson) presented the inspection results to Mr. T. Lynch, Plant General Manager, and other members of his staff who acknowledged the findings. The inspector confirmed that proprietary information was not provided or examined during the inspection.

On May 17, 2005, the inspector (D. Stearns) discussed the inspection findings with Mr. D. Bennett, Chemistry Supervisor. The inspector verified that no proprietary information was provided during the inspection.

On May 26, 2005, the inspector (L. Ricketson) presented the inspection results to Mr. V. Parrish, Chief Executive Officer, and other members of his staff who acknowledged the findings. The inspector confirmed that proprietary information was not reviewed during the inspection.

On May 19, 2005, the inspector (W. Sifre) presented the inspection results to Ms. C. Whitcomb, Vice President, Organization Performance and Staffing, and other members of Energy Northwest management who acknowledged the inspection findings. The inspectors asked Energy Northwest whether any materials examined during the inspection should be considered proprietary. Several documents were identified as proprietary information. The inspectors informed the licensee that these documents would be destroyed upon completion of their review.

On June 21, 2005, the resident inspectors presented the inspection results to Mr. D. Atkinson, Vice President - Nuclear Generation, and other members of his staff who acknowledged the inspection findings. On July 12 and 26, 2005, the resident inspectors presented additional inspection results to Mr. T. Lynch, Plant General Manager, and other members of his staff who acknowledged the inspection findings. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

4OA7 Energy Northwest Identified Violations

The following violation of very low risk significance (Green) was identified by Energy Northwest and are violations of NRC Requirements which meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as a noncited violation.

Technical Specification 5.7.1 requires that each entryway to a high radiation area be barricaded and conspicuously posted. However, as documented in Condition

Report 2-05-03798, on May 18, 2005, the licensee staged six control rod drive (CRD) mechanisms on a cart outside of the control rod drive rebuild room. One of the six CRD mechanisms had a shield placed on one end. The shield had a contact dose rate of approximately 1600 millirem/hour and a dose rate of approximately 200 millirem/hour at 30 centimeters, causing a high radiation area. The cart was left outside of the rebuild room during shift turnover and the area around the cart was not barricaded or posted as a high radiation area. It was estimated that the cart was left in the area for 3 to 5 hours before the licensee discovered that it should have been controlled as a high radiation area. The finding was of very low safety significance because it did not involve; (1) ALARA planning and controls, (2) an overexposure, (3) a substantial potential for overexposure, or (4) an impaired ability to assess dose.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Energy Northwest

P. Ankrum	Engineer, Licensing
D. Atkinson	Vice President, Nuclear Generation
S. Belcher	Manager, Operations
D. Bennett	Supervisor, Chemistry
I. Borland	Manager, Radiation Protection
B. Boyum	Assistant General Manager, Engineering
P. Cambell	Technical Specialist, Radiation Protection
D. Coleman	Manager, Performance Assessment and Regulatory Programs
G. Cullen	Licensing Supervisor, Regulatory Programs
D. Dinger	Planning Supervisor, Radiation Protection
T. Erwin	Engineer, Materials Processes and Qualifications
A. Khanpour	General Manager, Engineering
W. LaFramboise	Manager, Technical Engineering
M. Laudisio	Supervisor, Radiation Protection
T. Lynch	Plant General Manager
W. Oxenford	Vice President, Technical Services
J. Parrish	Chief Executive Officer
D. Ramey	Inservice Inspection Engineer
D. Welch	Nondestructive Examination Lead
C. Whitcomb	Vice President, Organization Performance and Staffing
R. White	Training Manager

NRC Personnel

R. Cohen	Resident Inspector
Z. Dunham	Senior Resident Inspector

ITEMS OPENED AND CLOSED

Items Opened, Closed, and Discussed During this Inspection

Opened

50-397/05-03-01	URI	Service Water Pump A Performance Degradation (Section 1R12)

Opened and Closed

50-397/05-03-02	FIN	Compensatory Action Prevented Implementation of Drywell Emergency Ventilation Procedure (Section 1R16.1)
50-397/05-03-03	NCV	Failure to Label a Container of Radioactive Material (Section 2OS1)
50-397/05-03-04	FIN	Loss of RFW-P-1B Due to Lack of Configuration Control and Subsequent Failure to Follow Procedure (Section 4OA3.4)

Closed

50-397/04-05-03	URI	Thread Sealant Incompatibility with Valve Internals (Section 4OA5.2)
50-397/2004-02	LER	Reactor core isolation cooling declared inoperable due to relay failure (Section 4OA3.3)

Discussed

None

PARTIAL LIST OF DOCUMENTS REVIEWED

Procedures and Instructions

WCI-1; Unit Coordinator BPA Duties; Revision 1

WCI-3; Unit Coordinator Duties; Revision 0

ABN-ELEC-LOOP; Loss of All Of-Site Power; Revision 5

PPM 1.3.76; Integrated Risk Management; Revision 2

4.800.C4; 800.C4 Annunciator Panel Alarms; Revision 15

OSP-SW-M102; Standby Service Water Loop B Valve Position Verification; Revision 14

OSP-SW/IST-Q702; Standby Service Water Loop B Operability; Revision 11

OSP-ELEC-W101; Offsite Station Power Alignment Check; Revision 5

PPM 5.6.1; Station Blackout; Revision 12

OI-14; Columbia Generating Station Operational Challenges Program; Revision 1

PPM 1.5.11; Maintenance Rule Program; Revision 6-05-00414

PPM 2.8.2; CIA System Operating Procedures; Revision 21

ABN-RHR-SDC-ALT; Residual Heat Removal Alternate Shutdown Cooling; Revision 3

NFPA 10; Standard for Portable Fire Extinguishers; 2003 Edition

PPM 3.2.1; General Operating Procedures - Shutdown; Revision 51

PPM 5.5.15; Emergency Drywell Venting; Revision 4

PPM 1.5.14; Risk Assessment and Management for Maintenance/Surveillance Activities; Revision 14

PPM 3.2.1; General Operating Procedures - Conduct of Outages; Revision 8

PPM 3.3.1; General Operating Procedures - Reactor Scram; Revision 43

TSP -SDM-R101; Surveillance Procedures - Shutdown Margin Determination and/or Demonstration; Revision 4

PPM 10.24.21; PM/Cal Test - GE Model 180 Indicators

PPM 11.2.13.1; Radiation and Contamination Surveys; Revision 13

PPM 11.2.14.9; Control and Labeling of Radioactive Material; Revision 11

PPM 11.2.7.3; High, High High, and Very High Radiation Area Controls; Revision 24

TSP-DG-E501; Simultaneous Start of all three Diesel Generators; Revision 2

PPM 1.3.30; Repair, Replacement, and Alterations of ASME Items; Revision 16

GEN-RPP-01; ALARA Program Description; Revision 4

GEN-RPP-02; ALARA Planning and Radiation Work Permits; Revision 10

GEN-RPP-06; Dosimetry Program Description; Revision 2

GEN-RPP-13; ALARA Committee; Revision 4

GEN-RPP-14; Control of Temporary Shielding; Revision 4

QCI-3-1; Liquid Penetrant Examination Instructions; Revision 10

QCI-3-3; Liquid Penetrant Examination - Columbia Generating Station - ISI; Revision 6

QCI-4-1; Magnetic Particle Examination; Revision 8

QCI-4-3; Magnetic Particle Examination - Columbia Generating Station - ISI; Revision 7

QCI-7-1; Visual Examination; Revision 8

QCI-7-3; Visual Examination - Component Supports; Revision 5

QCI-7-4; Visual Examination of Containment; Revision 1

OSP-LPCS/IST-Q702; LPCS System Operability Test; Revision 14

QCI-7-5; Invessel Visual Inspection of the RPV Internals (IVVI); Revision 3

GE-UT-105; Procedure for Manual Ultrasonic Examination of Piping Welds and Safe Ends Outside the Scope of PDI-UT-1 and PDI-UT-2; Version 6

GE-UT-209; Procedure for Automated Ultrasonic Examination of Dissimilar Metal Welds, and Nozzle to Safe End Welds; Version 17

GE-UT-240; Procedure for Automated Phased Array Ultrasonic Flaw Detection and Length

Sizing in Austenitic and Ferritic Piping Welds with Tomoscan III; Version 1

GE-UT-300; Procedure for Manual Examination of Reactor Vessel Assembly Welds in Accordance with PDI; Version 9

GE-UT-704; Procedure for the Examination of Reactor Pressure Vessel Welds with GERIS 2000 OD in Accordance with Appendix VIII; Version 7

GE-UT-705; Procedure for the Examination of Reactor Pressure Nozzle Inner Radius and Nozzle to Vessel Welds with the GERIS 2000 OD in Accordance with Appendix VIII; Version 4

PPM 1.16.8A; Outage Risk Management; Revision 4

PPM 1.3.57; Barrier Permit; Revision 20

TSP-CONT-R801; Containment Isolation Valve and Penetration Leak Test Program; Revision 11

SOP-Cavity-Drain; Reactor Cavity and Dryer Separator Pit Draining; Revision 1

TSP-DG1/LOP-B501; Standby Diesel Generator DG1 Loss of Power Test; Revision 6

TSP-DG1/LOCA-B501; Standby Diesel Generator DG1 LOCA Test; Revision 9

PPM 3.4.1; Minimizing the Potential of Draining the Reactor Vessel or Cavity; Revision 9

SOP-Cavity-Fill; Reactor Cavity and Dryer Separator Pit Fill; Revision 2

4.800.C4; 800.C4 Annunciator Panel Alarms; Revision 15

ABN-ELEC-LOOP; Loss of All Off-Site Electrical Power

Calculations

CMR-93-0588 CMR-95-0497 CMR-93-0491 ME-02-05-06

Drawings

Flow Diagram M556; Containment Instrument Air System; Revision 48

Flow Diagram M521-1; Residual Heat Removal Loop A; Revision 98

Radiographic Examinations

2-1907 2-1908

Ultrasonic Examinations

RPV Nut 7A RPV Nut 28A RPV Nut 47A RPV Nut 63A RPV Nut 14A RPV Nut 35A

RPV Nut 49A RPV Nut 70A RPV Nut 21A RPV Nut 42A RPV Nut 55A

Visual Examinations

BM-R-1-62A	BM-R-4-62A	BM-L-2-64B	BM-L-5-65A	BM-R-2-62A	BM-R-5-62A
BM-L-3-64B	BM-R-3-62A	BM-L-1-64B	BM-L-4-65A		

Clearance Orders

O-SS-PCV-2B	O-RRC-ASD1A/1	O-RHR-SYS-A-r17-001
O-RHR-P-2A/LLRT-002		

Other

R-17 Outage Shutdown Safety Plan

Columbia Operational Challenges List

WO 01059769

WO 01089434

WO 01095524

WO 01059796

WO 01067634

WO 01064758

FSAR; Appendix F; Amendment 53

Personnel Contamination Event Report 05-0084

Exposure Report for doses greater than or equal to 100 millirem

ISI Program Plan Interval-2; Revision 17

PER/Condition Reports

PER 205-0305	CR 2-05-02980	PER 204-1246	CR 2-05-02869
CR 2-05-04183	CR 2-04-03446	CR 2-04-05746	CR 2-05-05835
CR 2-04-06461	PER 204-1269	CR 2-04-07036	CR 2-05-02015
CR 2-04-02182	PER 205-0248	CR 2-05-04589	PER 205-0248
PER 205-0305	PER 2-05-0362	CR 2-04-05343	CR 2-05-01201
CR 2-05-01990	CR 2-05-02633	CR 2-05-02908	CR 2-05-02988
CR 2-05-03307	CR 2-05-00084	CR 2-04-00025	CR 2-05-00341

CR 2-05-03679	CR 2-05-00085	CR 2-04-00162	CR 2-05-03374
CR 2-05-03689	CR 2-04-02011	CR 2-05-00309	CR 2-05-03379
CR 2-05-03803	CR 2-04-04644	CR 2-04-04728	CR 2-04-04957
CR 2-04-05029	CR 2-04-05343	CR 2-04-06705	CR 2-05-00194
CR 2-05-01149	CR 2-05-01953	CR 2-05-02540	CR 2-05-02565
CR 2-05-02570	CR 2-05-02633	PER-203-2926	

Radiation Work Permits

30001556; Revision 3
30001491; Revision 4
30001285; Revision 0
30001256; Revision 3
30001255; Revision 2
30001269; Revision 0
30001286; Revision 2
30001298; Revision 1

Audits and Self-Assessments

Quality's Integrated Performance Assessment Report (July 1 through October 31, 2003)

SA-2004-0028 Annual Review of Radiation Protection Program (August 2004)

SA-2004-0030 Assessment of Drywell Source Term Reduction (December 2004)

Continuous Monitoring Report-SR 04-10 (November 2004)

Continuous Monitoring Report-SR 05-01 (January 2005)

ALARA Work Packages

30001167 30001326 30001347 30001531