UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-4005

February 13, 2006

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

SUBJECT: COLUMBIA GENERATING STATION - NRC INTEGRATED INSPECTION REPORT 05000397/2005005

Dear Mr. Parrish:

On December 31, 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 January 5, 2006, with Mr. D. Atkinson 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 self-revealing findings. These findings were determined to involve violations of NRC requirements. However, because of the very low safety significance and because they are entered into your corrective action program, the NRC is treating these findings as noncited violations (NCVs) 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/

Claude E. Johnson, Chief
Project Branch A
Division of Reactor Projects

Docket: 50-397
License: NPF-21

Enclosure: NRC Inspection Report 05000397/2005005
w/attachments

cc w/enclosure:
W. Scott Oxenford (Mail Drop PE04)
Vice President, Technical Services
Energy Northwest
P.O. Box 968
Richland, WA 99352-0968

Albert E. Mouncer (Mail Drop PE01)
Vice President, Corporate Services/
General Counsel/CFO
Energy Northwest
P.O. Box 968
Richland, WA 99352-0968

Chairman
Energy Facility Site Evaluation Council
P.O. Box 43172
Olympia, WA 98504-3172

Douglas W. Coleman (Mail Drop PE20)
Manager, Regulatory Programs
Energy Northwest
P.O. Box 968
Richland, WA 99352-0968

Gregory V. Cullen (Mail Drop PE20)
Supervisor, Licensing
Energy Northwest
P.O. Box 968
Richland, WA 99352-0968

Chairman
Benton County Board of Commissioners
P.O. Box 190
Prosser, WA 99350-0190

Dale K. Atkinson (Mail Drop PE08)
Vice President, Nuclear Generation
Energy Northwest
P.O. Box 968
Richland, WA 99352-0968

Cheryl M. Whitcomb (Mail Drop PE03)
Vice President, Organizational
Performance & Staffing/CKO
Energy Northwest
P.O. Box 968
Richland, WA 99352-0968

William A. Horin, Esq.
Winston & Strawn
1700 K Street, NW
Washington, DC 20006-3817

Matt Steuerwalt
Executive Policy Division
Office of the Governor
P.O. Box 43113
Olympia, WA 98504-3113

Lynn Albin, Radiation Physicist
Washington State Department of Health
P.O. Box 7827
Olympia, WA 98504-7827

Electronic distribution by RIV:
Regional Administrator **(BSM1)**
DRP Director **(ATH)**
DRS Director **(DDC)**
DRS Deputy Director **(RJC1)**
Senior Resident Inspector **(ZKD)**
Branch Chief, DRP/A **(CEJ1)**
Senior Project Engineer, DRP/E **(TRF)**
Team Leader, DRP/TSS **(RLN1)**
RITS Coordinator **(KEG)**
RSLO, **(WAM)**
Only inspection reports to the following:
DRS STA **(DAP)**
J. Dixon-Herrity, OEDO RIV Coordinator **(JLD)**
ROPreports
Columbia Site Secretary **(LEF1)**

SUNSI Review Completed: CEJ ADAMS: √ Yes ☐ No Initials: CEJ

√ Publicly Available ☐ Non-Publicly Available ☐ Sensitive √ Non-Sensitive

R:_REACTORS_COL\2005\COL2005-05RP-ZKD.wpd

SRI:DRP/A	RI:DRP/A	SPE:DRP/A	C:DRS/OB	C:DRS/PSB
ZKDunham	RBCohen	TRFarnholtz	ATGody	MPShannon
E-CEJ	E-CEJ	/RA/	/RA/	/RA/
2/8/06	2/8/06	2/8/06	2/6/06	2/1/06

EPI:DRS/OB	HPI:DRS/PSB	C:DRS/PEB	C:DRS/EB	BC:DRP/A
PJElkmann	DLStearns	LJSmith	JAClark	CEJohnson
/RA/	/RA/	/RA/	/RA/	/RA/
1/31/06	2/1/06	2/6/06	2/6/06	2/13/06

OFFICIAL RECORD COPY T=Telephone E=E-mail F=Fax

ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket:	50-397
License:	NPF-21
Report:	05000397/2005005
Licensee:	Energy Northwest
Facility:	Columbia Generating Station
Location:	Richland, Washington
Dates:	September 24 through December 31, 2005
Inspectors:	Z. Dunham, Senior Resident Inspector, Project Branch A, DRP R. Cohen, Resident Inspector, Project Branch A, DRP J. Keeton, Reactor Inspector, NRC Contractor P. Elkman, Emergency Preparedness Inspector, Operations Branch T. McKernon, Senior Operations Engineer D. Stearns, Health Physicist, Plant Support Branch
Approved By:	C. E. Johnson, Chief, Project Branch A, Division of Reactor Projects
ATTACHMENT:	Supplemental Information

TABLE OF CONTENTS

PAGE

SUMMARY OF FINDINGS

IR05000397/2005005; 9/24/2005 - 12/31/2005; Columbia Generating Station; ALARA Planning and Controls, and Other Activities.

The report covered a 13-week period of inspection by resident inspectors, emergency preparedness inspectors, a health physicist, a senior operations engineer, and a reactor inspector. Two noncited green findings 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. A Green self-revealing noncited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," was identified because Energy Northwest failed to maintain the design capability of the reactor core isolation cooling system consistent with Final Safety Analysis Report specified design functions. Following the implementation of a design change in 2001, the reactor core isolation cooling system was not capable under all required plant conditions of initiating automatically upon reaching a predetermined low level in the reactor vessel or restarting automatically with no operator action. Specifically, during conditions where the reactor core isolation cooling system suction header pressure was reduced to that provided by the condensate storage tanks, the reactor core isolation cooling pump would inadvertently trip due to low suction pressure as a result of a momentary hydraulic perturbation in the system which occurred as the system was starting up. The design change made the reactor core isolation cooling system more susceptible to inadvertently tripping.

  This finding was more than minor in accordance with Manual Chapter 0612, Appendix B, in that it was a plant modification design issue which affected the mitigating systems cornerstone attribute of equipment performance and reliability which could impact the ability of the reactor core isolation cooling system to respond to an initiating event. Using Manual Chapter 0609, “Significance Determination Process,” Phase 1 worksheet, the inspectors determined that a Phase 2 evaluation was warranted since an actual loss of system safety function occurred. A subsequent Phase 2 and Phase 3 evaluation were performed. A senior reactor analyst conducted the Phase 3 evaluation using a Standardized Plant Analysis Risk model simulation of the failure of the reactor core isolation cooling pump to automatically start and inject into the reactor coolant system. The analyst concluded that the core damage frequency associated with the event was 4.3×10^{-8} and that any increase in core risk due to external events was insignificant given the low core damage frequency (< 1×10^{-6}). The inspectors concluded that the finding was of very low risk significance.

Cornerstone: Occupational Radiation Safety

- Green. A self-revealing noncited violation was identified for the licensee's failure to have adequate procedures in accordance with Technical Specification 5.4.1.a to prevent the internal contamination of three workers during replacement of a blank flange on the equipment drain system.

  This finding was more than minor in that the replacement of a contaminated flange without the use of an adequate radiation work permit was associated with the occupational radiation safety's attribute of procedures for exposure control and affected the cornerstone objective to ensure the adequate protection of the worker's health and safety from exposure to radiation from radioactive material. The cause of the finding is related to the crosscutting aspects of human performance. Using the occupational radiation safety significance determination process, the finding was determined to be of very low risk significance because it did not represent an ALARA or work controls issue, did not involve an overexposure, did not constitute a substantial potential for an overexposure, and did not compromise the ability to assess dose.

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 November 5 through 6, 2005, 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)

.1 Readiness For Seasonal Susceptibilities

a. Inspection Scope

The inspectors completed a review of the licensee's readiness of seasonal susceptibilities involving extreme cold and freezing temperatures. The inspectors: (1) reviewed plant procedures, the Updated Safety Analysis Report, and Technical Specifications to ensure that operator actions defined in adverse weather procedures maintained the readiness of essential systems; (2) walked down portions of safety related systems to ensure that adverse weather protection features and system lineup were sufficient to support operability, including the ability to perform safe shutdown functions; (3) evaluated operator staffing levels to ensure the licensee could maintain the readiness of essential systems required by plant procedures; and (4) reviewed the corrective action program to determine if the licensee identified and corrected problems related to adverse weather conditions.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

.2 Readiness For Impending Adverse Weather Conditions

a. Inspection Scope

On November 23, 2005, the inspectors completed a review of the licensee's readiness of the two systems listed below for impending adverse weather involving cold and freezing weather. The inspectors: (1) reviewed plant procedures, the Updated Safety Analysis Report, and Technical Specifications to ensure that operator actions defined in adverse weather procedures maintained the readiness of essential systems; (2) walked down portions of the systems to ensure that adverse weather protection features were sufficient to support operability, including the ability to perform safe shutdown functions; (3) reviewed maintenance records to determine that applicable surveillance requirements were current before anticipated freezing conditions developed; and (4) reviewed plant modifications, procedure revisions, and operator work arounds to determine if recent facility changes challenged plant operation.

- Standby service water
- Emergency diesel generator HVAC

The inspectors completed two samples.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignments (71111.04)

.1 Partial Walkdown

a. Inspection Scope

The inspectors: (1) walked down portions of the two 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.

- High Pressure Core Spray Diesel Generator; October 20, 2005
- Reactor Feedwater; November 24, 2005

The inspectors completed two samples.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Quarterly Inspection

a. Inspection Scope

The inspectors walked down the plant areas listed below 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.

- Fire Area RC-10; Main Control Room; October 17, 2005
- Fire Area RC-3; Cable Chase; October 11, 2005
- Fire Area RC-5; Battery Room Number 1; October 11, 2005
- Fire Area RC-8; Division #2 Switchgear Room; November 21, 2005
- Fire Area RC-9; Remote Shutdown Room; November 21, 2005
- Fire Area RC-12; Control Room Air Conditioning Unit; November 22, 2005

The inspectors completed six samples.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

.1 Internal Flood Protection

a. Inspection Scope

The inspectors where applicable: (1) reviewed the Updated Safety Analysis Report, the flooding analysis, and plant procedures to assess susceptibilities involving internal flooding; (2) reviewed the corrective action program to determine if the licensee identified and corrected flooding problems; and (3) walked down the area listed below to verify the adequacy of floor and wall penetration seals and common drain lines.

- Room 208 Pipe Chase on the 471 foot level; October 31, 2005

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

.1 Quarterly Inspection of a Licensed Operator Requalification Exam

a. Inspection Scope

On November 8, 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 the crew's ability to respond to a remote air intake radiation monitor (WOA-RIS-31A failure), a seismic event with a major rupture of the reactor closed cooling pumps suction piping, a loss of coolant accident requiring containment sprays, main turbine bypass valves fail to open, and a loss of high pressure feedwater.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

.2 Review of Annual Operating Examination Testing Cycle

a. Inspection Scope

Following the completion of the annual operating examination testing cycle, which ended the week of December 15, 2005, the inspectors reviewed the overall pass/fail results of the annual individual job performance measure operating tests, and simulator operating tests administered by the licensee during the operator licensing requalification cycle. Seven separate crews participated in simulator operating tests, and job performance measure operating tests, totaling 54 licensed operators. All of the crews, but one, tested passed the simulator portion of the annual operating test. The licensed operators were successfully remediated prior to returning to shift. All of the licensed operators passed the job performance measure portion of the examination. These results were compared to the thresholds established in Manual Chapter 609, Appendix I, "Operator Requalification Human Performance Significance Determination Process."

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 maintenance activities listed below 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 Part 50 Appendix B, and the Technical Specifications.

- Emergency Trip of Division 2 Emergency Diesel Generator; September 26, 2005
- High Pressure Core Spray Diesel Generator failed to stop normally and failed to shutdown by emergency tripping; November 2, 2005

- Main Steam Valve MS-V-22A, closed faster than expected during Main Steam Isolation Valve Closure Scram Functional Surveillance; November 23, 2005

The inspectors completed three samples.

b. Findings

No findings of significance were identified.

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

.1 Risk Assessment and Management of Risk

a. Inspection Scope

The inspectors reviewed the risk assessment activities listed below 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.

- Replace 250 VDC Battery cells #226 and #157 while performing scheduled instrumentation and control surveillances; November 21, 2005
- Down Power and work on Main Condenser; November 5 and 6, 2005
- Division II residual heat removal keep-fill pump work and service water Pump B planned surveillances; November 15, 2005
- Service Water Pump 1B pump replacement and Diesel Generator #2 planned outage; December 12-15, 2005

The inspectors completed four samples.

b. Findings

No findings of significance were identified.

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

a. 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 response was in accordance with the response required by plant procedures and training; (3) verified that the licensee has identified and implemented appropriate corrective actions associated with personnel performance problems that occurred during the non-routine evolutions sampled.

- Deep-down power to locate main condenser tube leak; November 7, 2005

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors: (1) reviewed plants 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.

- CR 2-05-09003; DG-GEN-DG2 engine speed setting outside of normal expected band; November 18, 2005
- CR-2-05-08982; Incorrect control power fuses installed for RHR-P-3; November 17, 2005
- CR-2-05-08510; Single Cell charger placed on 250 VDC Battery without regard for proper engineering review for the single cell charger; November 2, 2005
- CR-2-05-09179; Rain water leaking into Division I, Division II and Division III Diesel Rooms; November 25, 2005

The inspectors completed four samples.

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (71111.16)

.1 Cumulative Review of the Effects of Operator Workarounds

a. Inspection Scope

On December 12, 2005, 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 postmaintenance test activities of risk significant systems or components listed below for review. 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 postmaintenance testing.

- WO 01102358; RHR-V-27B Recovery; September 26, 2005
- WO 01105461; HPCS-V-12 Investigate Overload Trip of MOV; September 27, 2005
- WO 01094756; SW-V-105D and SW-V-107D Repair Leaks; October 5, 2005
- WO 01109759; EB-2-1 Cell 157 Replacement; November 22, 2005

The inspectors completed four samples.

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 surveillance activities listed below 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.

- OSP-LPCS/IST-Q702; LPCS System Operability Test; Revision 15; October 6, 2005

- ISP-CRD-Q902; RPS - Channels B and D ½ scram SDV CFT; Revision 7; October 11, 2005

- OSP-RHR-Q703; RHR Loop B Operability Test; Revision 0; October 17, 2005

The inspectors completed three samples which included a review of an in-service pump test.

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 temporary modification listed below was 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 modification was 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.

- TMR 05-019; Support risk management reduction for the Probability Risk Assessment during a station blackout by increasing the availability time of the batteries as a compensatory measure during Diesel Generator 2 outage; November 28, 2005.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP2 Alert Notification System Testing (71114.02)

a. Inspection Scope

The inspector discussed with licensee staff the status of offsite siren and tone alert radio systems to determine the adequacy of licensee methods for testing the alert and notification system in accordance with 10 CFR Part 50, Appendix E. The licensee's alert and notification system testing program was compared with criteria in NUREG-0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," Revision 1, Federal Emergency Management Agency (FEMA) Report REP-10, "Guide for the Evaluation of Alert and Notification Systems for Nuclear Power Plants," and the licensee's current FEMA-approved alert and notification system design report.

The inspector completed one sample.

b. Findings

No findings of significance were identified.

1EP3 Emergency Response Organization Augmentation Testing (71114.03)

a. Inspection Scope

The inspector reviewed the following documents related to the emergency response organization augmentation system to determine the licensee's ability to staff emergency response facilities in accordance with the licensee emergency plan and the requirements of 10 CFR Part 50, Appendix E.

EPI-19; Communications Tests; Revision 5

PPM 13.10.1; Control Room Operations and Shift Manager Duties; Revision 29

PPM 13.4.1; Emergency Notification; Revision 32

Evaluation Reports for 7 pager and drive-in drills conducted between February 2004 and September 2005

The inspector completed one sample.

b. Findings

No findings of significance were identified.

1EP4 Emergency Action Level and Emergency Plan Changes (71114.04)

.1 Review of Revision 14

a. Inspection Scope

The inspector performed an in-office review of Revision 14 to the Columbia Generating Station emergency plan implementing Procedure13.1.1.A, "Classifying the Emergency - Technical Bases," received September 8, 2005. This revision:

- Clarified the definition of a failure of the reactor protection system to initiate a reactor scram
- Reworded the description of vital areas in the Turbine Building in 13 emergency action levels
- Added descriptions of the vital areas of the Radwaste/Control Building to 13 emergency action levels
- Deleted the description of a hostile force from 1 emergency action level
- Corrected minor errors in references

The revision was compared to its previous revision, to the criteria of NUREG-0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," Revision 1, to NEI 99-01, "Methodology for Development of Emergency Action Levels," Revision 2, and to the requirements of 10 CFR 50.47(b) and 50.54(q) to determine if the licensee adequately implemented 10 CFR 50.54(q).

The inspector completed one sample.

b. Findings

No findings of significance were identified.

.2 Review of Revision 15

a. Inspection Scope

The inspector performed an in-office review of Revision 15 to the Columbia Generating Station Emergency Plan Implementing Procedure 13.1.1A, “Classifying the Emergency - Technical Bases,” received October 3, 2005. This revision:

- Restored the definition of civil disturbance in emergency action level 9.1.S.1
- Defines impeding access to safe shutdown buildings

The revision was compared to its previous revision, to the criteria of NUREG-0654, “Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants,” Revision 1, to NEI 99-01, “Methodology for Development of Emergency Action Levels,” Revision 2, and to the requirements of 10 CFR 50.47(b) and 50.54(q) to determine if the licensee adequately implemented 10 CFR 50.54(q).

The inspector completed one sample.

b. Findings

No findings of significance were identified.

1EP5 Correction of Emergency Preparedness Weaknesses and Deficiencies (71114.05)

a. Inspection Scope

The inspector reviewed the following documents related to the licensee’s corrective action program to determine the licensee’s ability to identify and correct problems in accordance with 10 CFR 50.47(b)(14) and 10 CFR Part 50 Appendix E.

- SWP-CAP-1, “Corrective Action Program,” Revision 9

- Four Final After-Action Event Reports

- Two Quality Assurance Audits

- Summaries of 127 Condition Reports assigned to the Emergency Preparedness department during calendar years 2004 and 2005

- Details of 23 selected Condition Reports

- Nine Drill and Exercise Evaluation Reports

The inspector completed one sample during this inspection.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

For the drill listed below which contributed to the Drill/Exercise Performance (DEP) and Emergency Response Organization (ERO) Performance Indicator, the inspectors: (1) observed the training evolution to identify any weaknesses and deficiencies in classification, notification, and Protective Action Requirements (PAR) development activities; (2) compared the identified weaknesses and deficiencies against licensee identified findings to determine whether the licensee is properly identifying failures; and (3) determined whether licensee performance is in accordance with the guidance of the NEI 99-02 document's acceptance criteria.

- Plant wide emergency drill which included a fire in a residual heat removal pump room, a startup transformer lock-out, reactor water cleanup steam leak outside primary containment and a significant radioactive release to the environment; October 25, 2005

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS2 ALARA Planning and Controls (71121.02)

a. Inspection Scope

The inspectors assessed licensee performance with respect to maintaining individual and collective radiation exposures 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 inspectors interviewed licensee personnel and reviewed radiological surveys and biological assay reports.

b. Findings

Introduction. A Green self-revealing noncited violation was identified for failure to have adequate procedures and instructions in accordance with Technical Specification 5.4.1.a to prevent the internal contamination of three workers during replacement of a blank flange on the Equipment Drain System (EDR).

Description. On November 10, 2005, at approximately 1:00 p.m., maintenance technicians replaced a blank flange on the EDR pipe with a new flange that contained a flush port. The work was conducted in the northeast corner of Reactor Building 501 foot elevation and was performed to support EDR line cleaning to lower dose rates in the vicinity. A pre-job brief was conducted prior to commencement of work due to concerns with the risk associated with increased radiological dose and the potential for the spread of contamination during the work activity. The pre-job brief also discussed the possibility that some water may be present in the piping during the work and that precautions should be taken to address the potentially contaminated water.

Following the removal of the old flange, the workers placed the flange into the bottom of a glove bag which had been installed to minimize the potential for spread of contamination during the activity. Once the flange was removed, the technicians noted that contrary to the pre-job brief concerns for the possibility for water in the pipe/flange, that the pipe and flange internals were dry. The technicians also noted dry surface contamination on the interior of the pipe and cleaned the accessible internal areas of the pipe to minimize the radiation dose rate. There was no significant reduction in dose rate and the cleaning was discontinued.

Following the installation of the new flange, the technicians removed the glove bag containing the old flange. While removing the glove bag, a health physics technician squeezed the neck of the bag in order to twist the neck closed. The technician relocated the bag for later disposal.

After completion of the work, one mechanic found contamination on his hand while performing a self-frisk. Subsequently, Energy Northwest identified other workers who were contaminated. The following personnel contamination was identified:

a. A health physics technician was contaminated to 30,000 dpm/probe area (pa) on the neck.

b. One worker was contaminated on the face, finger, and chest to 6000 dpm/pa maximum.

c. One worker was contaminated on the shirt, chin, and hard hat to 15,000 dpm/pa maximum.

d. One worker was contaminated on the chin at 1000 dpm/pa.

e. Another health physics technician was contaminated on the hard hat, shoes, and left shoulder to 25,000 dpm/pa maximum.

Subsequent whole body counts demonstrated that three individuals were internally contaminated. Calculated internal doses for the individuals were as follows: 4 mrem CEDE, 1 mrem CEDE and 9 mrem CEDE. Energy Northwest determined that when the health physics technician squeezed the neck of the glove bag that a release of contamination to the surrounding area occurred and was the source of the personnel contaminations.

A post critique analysis of the event by Energy Northwest determined that the radiological work procedure used for the flange replacement failed to incorporate several precautions and instructions which should have been implemented. These missed precautions included the potential for dry and airborne contamination and the proper installation, handling, and removal of radiological glove bags.

Analysis. This issue was a performance deficiency, in that, the Radiological Work Procedure (RWP 30001598) was inadequate in that Energy Northwest failed to incorporate adequate precautions and instructions in the RWP to minimize the potential for personnel contamination. Also, there were no procedures or instructions on the installation, testing, and removal of the glove bag which is an infrequently performed evolution. With the levels of contamination in the system, precautions should have been specified in the Work Order and the RWP. This finding was more than minor in that the replacement of a highly contaminated flange without the use of an adequate radiation work permit was associated with the occupational radiation safety's cornerstone attribute of procedures for exposure control and affected the cornerstone objective to ensure the adequate protection of the worker's health and safety from exposure to radiation from radioactive material. The cause of the finding is related to crosscutting aspects of human performance. Using the occupational radiation safety significance determination process (SDP), the finding was determined to be of very low risk significance (Green) because the finding was not an ALARA issue, did not involve an overexposure, did not constitute a substantial potential for an overexposure, and did not compromise the ability to assess dose.

Enforcement. Technical Specification 5.4.1.a requires 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, Appendix A, Section 7.e(1), requires radiation protection procedures, including a procedure for access control to radiation areas including a radiation work permit system for limiting personnel exposure. Contrary to this requirement, on November 10, 2005, RWP 30001598 was inadequate for limiting personnel exposure in that it did not provide adequate instructions to prevent workers from receiving internal contamination of radioactive material. In addition, the radiation work permit did not provide instructions for installation, use, and removal of the glove bag. Because the failure to provide an adequate radiation work permit was of very low safety significance and was entered into the corrective action program (Condition Reports 2-05-08798, -09113, -09114 and -09115), this violation is treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000397/2005005-01, Failure to provide adequate radiation work permit to prevent an unintended uptake of radioactive material).

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

a. Inspection Scope

The inspector sampled licensee submittals for the performance indicators listed below for the period July 1, 2004, through September 30, 2005. The definitions and guidance of NEI 99-02, "Regulatory Assessment Indicator Guideline," Revisions 2 and 3, were used to verify the licensee's basis for reporting each data element in order to verify the accuracy of performance indicator data reported during the assessment period. Licensee performance indicator data were also reviewed against the requirements of Procedure 1.10.10, "Consolidated Data Entry Process Description," Revision 5, and Emergency Planning Instruction EPI-18, "Emergency Preparedness NRC Performance Indicators," Revision 8.

Emergency Preparedness Cornerstone:

- Drill and Exercise Performance
- Emergency Response Organization Participation
- Alert and Notification System Reliability

The inspector reviewed a 100 percent sample of drill and exercise scenarios and licensed operator simulator training sessions, notification forms, and attendance and critique records associated with training sessions, drills, and exercises conducted during the verification period. The inspector reviewed emergency responder rosters and drill participation records. The inspector reviewed alert and notification system testing procedures, maintenance records, and a 100 percent sample of siren test records. The inspector also interviewed licensee personnel responsible for collecting and evaluating performance indicator data.

The inspector completed three samples during this inspection.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Semiannual Trend Review

a. Inspection Scope

The inspectors reviewed Energy Northwest's corrective action program (CAP) and associated documents to identify equipment trends that could indicate the existence of a more significant safety issue. The inspector's review included the six month period of July through December 2005, although some examples expanded beyond those dates when the scope of the trend warranted. The inspectors reviewed the repetitive and/or rework maintenance lists, system health reports, quality assurance audit/surveillance reports and maintenance rule assessments. The inspectors reviewed selected corrective actions associated with any Energy Northwest identified trends to ensure that corrective actions were appropriately identified and documented.

b. Findings and Observations

No findings of significance were identified. The inspectors evaluated trending methodology and observed that Energy Northwest had performed a detailed review. Energy Northwest routinely reviewed cause codes and key words to identify potential trends in their CAP data base. The inspectors compared Energy Northwest's identified trends with the results of the inspectors' evaluation and did not identify any discrepancies or potential trends that Energy Northwest had failed to identify. However, the inspectors noted that Energy Northwest had documented a trend associated with fuse replacement control (see section 4OA2.3 for a detailed discussion). The inspectors also identified in parallel with Energy Northwest a trend of missed opportunities associated with the failure to appropriately use operating experience which resulted in plant events, equipment deficiencies, and programmatic issues.

Missed Opportunities To Use Operating Experience

The inspectors identified an adverse trend in missed opportunities to use operating experience which if properly evaluated may have prevented several events from occurring. The inspectors noted the following corrective action documents from 2005 in which operating experience was identified or noted to have contributed to events at the station:

- PER 205-0428; A reactor scram occurred due to low RPV water level +13 inches from RFW-P-1B governor valve closure when electricians performed a continuity check on the RFP suction trip pressure switch while restoring the pressure switch to service; The station failed to incorporate 2002 BWR Owners Group Scram Reduction Committee Recommendations regarding single point vulnerabilities of the reactor feedwater system and in particular consideration of an installed time delay on the feedpump suction low header pressure trip.

- PER 205-0417; SW-P-1A displays abnormally low system pressure and flow due to degraded SW pump shafts; The station failed to incorporate operating experience from IN 93-68 and IN 94-45 which if properly evaluated and/or implemented may have identified the degraded pump shafts earlier.

- PER 205-0175; HPCS-M-P/1 upper air deflector shield is cracked approximately 180 degrees; The station failed to incorporate recommendations from GE SIL 484 to overhaul and inspect ECCS pump motors at a 10 year frequency which may have identified the cracked deflector earlier.

- PER 205-0128; CGS is not following the recommendations of GE SIL 484 for replacement of motor oil drain plug o-ring replacement.

The inspectors noted that Energy Northwest independently documented this adverse trend in PER 205-0417 on November 17, 2005. In addition to the events identified by the inspectors, ENW also identified the following additional issues that had elements of failing to incorporate operating experience:

- PER 205-0560; On August 25, 2005, the operations and engineering training programs were placed on probation by the National Academy for Nuclear Training.

- PER 205-0502; During review of fuse control log discovered SLC-P-1A had wrong type control fuse installed.

.2 Annual Sample - Substantive Crosscutting Issue in Human Performance

a. Inspection Scope

In the annual assessment letter, dated March 2, 2005, and a midcycle assessment letter, dated August 30, 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 associated with procedure adherence, contributed to a number of Green findings in different cornerstones. The inspectors performed a review of documented Condition Reports and Problem Event Resolutions during the periods of January 1 through December 31, 2005, focusing on significant human performance related errors caused by operations department and maintenance department personnel to determine the adequacy of corrective actions that Energy Northwest had taken to address the substantive crosscutting issue.

b. Findings and Observations

No significant findings were identified. The inspectors concluded that although there had been a few isolated significant events related to human performance and procedure usage that resulted in one significant plant event (Plant scram on June 23, 2005, see IR 0500397/2005003) and one equipment configuration control issue (incorrect lead terminated on the startup transformer, see IR 05000397/2005004) the overall number of significant human performance errors caused by operations and maintenance personnel over the year had declined as determined by the decrease in overall numbers of corrective action documents associated with procedure use and adherence as compared to the previous assessment cycle. The inspectors concluded that this overall improvement indicated that Energy Northwest's corrective actions had made a positive impact on station performance in this area.

.3 Annual Sample - Fuse Replacement Control at the Station

a. Inspection Scope

The inspectors reviewed PER 205-0502 for a followup of identified and completed corrective actions. Energy Northwest initiated PER 205-0502, on July 6, 2005, to document a configuration control issue associated with an incorrect fuse that had been installed in the motor control circuitry for standby liquid control pump 1A. Subsequently, Energy Northwest identified several additional fuse control issues which were of less significance than the fuse control issue associated with the standby liquid control pump. These additional issues, although not operability issues, represented a lack of understanding by plant staff of the station's requirements for fuse control during maintenance activities. Energy Northwest documented this issue as an adverse trend. The inspectors evaluated Energy Northwest's root cause of the issue and assessed the adequacy of corrective actions to correct the root cause.

b. Findings and Observations

No significant findings or observations were identified.

.4 Annual Sample - Emergency Preparedness

a. Inspection Scope

The inspectors selected 27 condition reports for detailed review. The reports were reviewed to ensure that the full extent of the issues were identified, an appropriate evaluation was performed, and appropriate corrective actions were specified and prioritized. The inspectors evaluated the condition reports against the requirements of Procedures SWP-CAP-1, "Corrective Action Program," Revision 9, and SWP-CAP-2, "Cause Determination," Revision 3.

b. Findings

No findings of significance were identified.

4OA5 Other Activities

.1 Institute of Nuclear Power Operations (INPO) Audit and Evaluation Review

On November 3, 2005, the inspector completed a review of the final INPO audit and evaluation report for Columbia Generating Station. The INPO team was on site during January 2005.

.2 (Closed) URI 05000397/2005004-01: Adequacy of Design of the Reactor Core Isolation Cooling System and Keepfill Pump

a. Inspection Scope

The inspectors completed an evaluation of the risk significance and assessment of applicable regulatory requirements associated with a failure of the RCIC system to start when operators attempted to start the system following a scram on June 23, 2005.

b. Findings

Introduction. A Green self-revealing NCV of 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” was identified because Energy Northwest failed to maintain the design capability of the RCIC system in accordance with the FSAR.

Description. As discussed in IR 05000397/2005004, Section 1R17, the inspectors determined that during the implementation of Basic Design Change (BDC) 394 that Energy Northwest failed to maintain the design of the RCIC system in accordance with the FSAR stated design function. Specifically, FSAR, Section 5.4.6, ,”Reactor Core Isolation Cooling System,” Amendment 56, described that the RCIC system was designed to initiate automatically upon reaching a predetermined low level in the reactor vessel and to restart automatically with no operator action after a reactor vessel level 8 shutdown of RCIC-P-1. Contrary to this design requirement, following the implementation of BDC 394 on June 18, 2001, the RCIC system was not capable under all required plant conditions of initiating automatically upon reaching a predetermined low level in the reactor vessel or restarting automatically with no operator action.

Analysis. The performance deficiency associated with this finding was Energy Northwest’s failure to maintain the RCIC system design function with the implementation of BDC 394. This self-revealing finding was determined to be more than minor in accordance with Manual Chapter 0612, Appendix B, in that it was a plant modification design issue which affected the mitigating systems cornerstone attribute of equipment performance and reliability which could impact the ability of the RCIC system to respond to an initiating event. Using Manual Chapter 0609, “Significance Determination Process,” Phase 1 worksheet, the inspectors determined that since an actual loss of system safety function occurred that a Phase 2 evaluation was warranted. As a result, the inspectors performed a Phase 2 analysis using Appendix A, “Technical Basis for At Power Significance Determination Process,” of Manual Chapter 0609, “Significance Determination Process,” and the Phase 2 worksheets from “Risk-Informed Inspection Notebook for Columbia Generating Station. The inspectors assumed that the duration of the susceptible condition of RCIC was greater than 30 days since BDC 394 was implemented in 2001. The inspectors also assumed no mitigating capability credit for the RCIC system, but that operator recovery credit was warranted since instructions for manually starting RCIC were proceduralized and the operators received periodic training on manual starting of RCIC. The preliminary results of the Phase 2 evaluation were referred to a regional senior reactor analyst for an evaluation of the final safety significance. The senior reactor analyst conducted a Phase 3 evaluation using a Standardized Plant Analysis Risk (SPAR) model simulation of the failure of the RCIC pump to start and inject into the Reactor coolant system. The analyst concluded that the ΔCDF associated with the event was 4.3×10^{-8} and that any increase in core risk due to external events was insignificant given the low ΔCDF ($< 1 \times 10^{-6}$). (See attachment in this inspection report for a full description of the risk analysis of the issue). The inspectors concluded that the finding was of very low risk significance (Green).

Enforcement. 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” required in part that design control measures shall provide for verifying or checking the adequacy of design. Contrary to this requirement, since the implementation of BDC 394 on June 18, 2001, Energy Northwest failed to ensure that the interaction of the RCIC keepfill pump with the RCIC system suction header did not inadvertently cause a failure of RCIC-P-1 to start automatically under all required operating conditions as specified in FSAR, Section 5.4.6. Because this finding was of very low safety significance and entered into the licensee's corrective action program as PER 205-0429, this violation is being treated as an NCV, consistent with Section VI.A of the Enforcement Policy (NCV 05000397/2005005-02, Failure to Maintain Design of RCIC in Accordance with FSAR Design Requirements). Energy Northwest took immediate corrective actions to correct the design deficiency by implementing a design change to delay the actuation of the RCIC suction header low pressure suction trip to ensure that any momentary hydraulic perturbations would not cause an inadvertent trip of RCIC-P-1 but still provide protection of the pump in the event of a loss of net positive suction head pressure.

.3 <u>(Opened) URI 05000397/2005005-03: Acceptability of Applying WD-40 Lubricant to Service Water Pump Shaft Coupling Components</u>

a. <u>Inspection Scope</u>

The inspectors performed a review of Condition Report CR 2-05-09690, Problem Evaluation Request 205-0722, and an Energy Northwest evaluation of the use of WD-40 on the Service Water System, dated December 21, 2006 to identify the circumstances associated with applying WD-40 as lubricant to standby service water pumps during assembly and replacement and its impact on the Service Water system.

b. <u>Findings</u>

<u>Introduction</u>. An unresolved item was identified pending completion of the licensee's evaluation and the NRC's review of this evaluation associated with applying WD-40 as a lubricant to Standby Service Water Pumps SW-P-1A and SW-P-1B during assembly and replacement of these pumps.

<u>Description</u>. On December 14, 2005, Energy Northwest documented in CR 2-05-09690 that WD-40 was applied to the SW-P-1B stainless steel shaft sleeves and pump shafts to lubricate the components to aid in assembly during a replacement of service water pump SW-P-1B. WD-40 contains chlorine which is a known initiator and contributor to intergranular stress corrosion cracking, a long term degradation concern in stainless steel components given sufficient concentrations. SW-P-1B was replaced because of pump shaft degradation which occurred as a result of intergranular stress corrosion cracking. The condition report documented the concern that the application of WD-40 on the pump stainless steel shaft components may not have been appropriate. Additionally, the condition report provided that it was reasonable to assume that the WD-40 would be flushed out with water after the pump shafts were wetted and the pump had been operated, therefore no WD-40 would remain in contact with any stainless steel surfaces. The condition report stated that WD-40 was also applied to SW-P-1A which had been replaced in June 2005. At the end of this inspection Energy Northwest had plans to inspect both affected pumps in 2013 per the originally established inspection frequency. During a conference call held on December 21, 2005 the NRC expressed concerns regarding the licensee's proposed plan to inspect and remove WD-40 from the shaft couplings in 8 years. The licensee informed the NRC staff that they would re-evaluate this concern. An URI was opened pending further

evaluation by the licensee and NRC's review of the evaluation results. URI 05000397/2005005-03, Application of WD-40 to Service Water Pump Shaft Components.

Analysis. The issue associated with applying WD-40 as lubricant to the standby service water pumps to aid in assembly during replacement and its impact on the service water system is pending completion of the licensee’ s evaluation and NRC review of the evaluation results. A determination of the safety significance of any performance deficiencies will be addressed in the resolution of the URI.

Enforcement. Pending further evaluation by the licensee and NRC's review of the evaluation results, this item remains unresolved.

4OA6 Meetings, Including Exit

On September 29, 2005, the inspector (P. Elkmann) conducted a telephonic exit meeting to present the inspection results to Mr. C. Moore, Supervisor, Emergency Preparedness, who acknowledged the findings. The inspector confirmed that proprietary information was not provided or examined during the inspection.

On October 5, 2005, the inspector (P. Elkmann) conducted a telephonic exit meeting to present the inspection results to Mr. C. Moore, Supervisor, Emergency Preparedness, who acknowledged the findings. The inspector confirmed that proprietary information was not provided or examined during the inspection.

On November 3, 2005, the inspector (P. Elkman) presented the inspection results to Mr. W. Oxenford, Vice President, Technical Services, 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 December 15, 2005, senior Energy Northwest management met with NRC Region IV regional management to discuss actions that Energy Northwest has taken to address a previously identified substantive crosscutting issue in human performance. Discussions regarding equipment reliability also occurred.

On January 4, 2006, C. Johnson, NRC RIV Branch Chief, communicated to Doug Coleman, Manager, Performance Assessment and Regulatory Programs, the conclusions of inspection report 05000397/2005010. This inspection report documented the implementation and results of IP 95001, “Inspection For One Or Two White Inputs In A Strategic Performance Area,” which was performed in response to a white performance indicator in High Pressure Injection System Unavailability.

On January 5, 2006, the resident inspectors presented the inspection results to Mr. D. Atkinson, Vice President - Nuclear Generation, and other members of his staff who acknowledged the findings. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

On January 23, 2006 the inspectors discussed the results of the inspection with Mr. Randy Guthrie, Operations Training Supervisor of the licensee's management. The licensee acknowledged the findings presented. The inspector asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Energy Northwest

D. Atkinson	Vice President, Nuclear Generation
S. Belcher	Manager, Operations
I. Borland	Manager, Radiation Protection
D. Coleman	Manager, Performance Assessment and Regulatory Programs
G. Cullen	Licensing Supervisor, Regulatory Programs
D. Dinger	Planning Supervisor, Radiation Protection
A. Khanpour	General Manager, Engineering
W. LaFramboise	Manager, Technical Engineering
T. Lynch	Plant General Manager
W. Oxenford	Vice President, Technical Services
J. Parrish	Chief Executive Officer
C. Moore	Supervisor, Emergency Preparedeness
F. Schill	Engineer, Licensing
C. Whitcomb	Vice President, Organizational Performance and Staffing

NRC Personnel

Z. Dunham	Senior Resident Inspector
R. Cohen	Resident Inspector

ITEMS OPENED AND CLOSED

Items Opened, Closed, and Discussed During this Inspection

Opened

05000397/2005005-03	URI	Application of WD-40 to Service Water Pump Shaft Components (Section 4OA5.3)

Opened and Closed

05000397/2005005-01	NCV	Failure to Provide Adequate Instructions to Prevent an Unintended Uptake of Radioactive Material (Section 2OS2)
05000397/2005005-02	NCV	Failure to Maintain Design of RCIC in accordance with FSAR Design Requirements (Section 4OA5.2)

Closed

05000397/2005004-01	URI	Adequacy of Design of the Reactor Core Isolation Cooling System and Keepfill Pump (Section 4OA5.2)

Discussed

None.

PARTIAL LIST OF DOCUMENTS REVIEWED

Section 1R01: Adverse Weather Protection

PPM 1.3.9; Cold Weather Operations; Revision 7

PPM SOP-COLD WEATHER-OPS; Revision 1

PPM SOP-SW-COLD WEATHER; Standby Service Water Cold Weather Operations; Revision 2

Procedure 2.10.4; Diesel Generator and Cable Cooling HVAC [heating ventilation and air conditioning], Revision 25

Procedure 2.4.5; Standby Service Water System; Revision 43

PPM SOP-SW-STBY; Placing Standby Service Water in Standby Status; Revision 1

Flow Diagram M524-1; Standby Service Water System Reactor, Radwaste, D.G. Bldg's; Revision 106

WO 01101448; COLD WEATHER OPS; 12/20/05

Section 1R04: Equipment Alignment

SOP-DG3-STBY; Emergency Diesel Generator (DIV III) Standby Lineup; Revision 4

Procedure 2.2.4; Condensate and Feedwater System; Revision 18

Drawing 504; Condensate and Feedwater Flow Diagram; Revision 90

Flow Diagram M504-1; Condensate and Feedwater; Revision 95

Flow Diagram M512-4; Diesel Oil and Miscellaneous Systems; Revision 8

CR-2-05-09388; There appears to be a defect in the second stage casing of the rebuilt Standby Service Water pump; 12/05/2005

Section 1R05: Fire Protection

CR-2-05-08192; Position needed regarding emergency lighting IAW App. R(II)(J) (8-hour battery powered) for the shift managers office.
Final Safety Analysis Report

Section 1R06: Flood Protection Measures

PPM 2.11.5; Floor Drain System; Revision 29

Calculation Modification Requests

ME 02-02-02

Section 1R11: License Operator Requalification

PPM LR001303; Columbia Generating Station Simulator Examination; Revision 3

Section 1R12: Maintenance Effectiveness

CR-2-05-08482; MS-V-22A closed faster than expected during MSIV Closure Scram Functional Surveillance; November 23, 2005

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

PPM 1.3.76; Integrated Risk Management; Revision 4

CR-2-05-07898; HPCS-GEN-DG3 failed to stop normally and failed to shutdown by Emergency Tripping; October 12, 2005

Section 1R15: Operability Evaluations

CR 2-05-09003; DG-GEN-DG2 engine speed setting outside of normal expected band; November 18, 2005

CR-2-05-08982; Incorrect control power fuses installed for RHR-P-3;
November 17, 2005

CR-2-05-08510; Single Cell charger placed on 250 VDC Battery without regard for proper engineering review for the single cell charger; November 2, 2005

CR-2-05-09179; Rain water leaking into Division I, Division II, and Division III Diesel Rooms; November 25, 2005

CR-2-05-07407; DG2 had to be emergency tripped during performance of OSP-ELEC-S702, November 2, 2005

Section 1R16: Operator Work-Arounds

Columbia Operational Challenges List

Section 1R19: Post--Maintenance Testing

PPM 10.2.53; Seismic Requirements for Scaffolding, ladders, Man-lifts, Tool Gang Boxes, Hoists, and Metal Storage Cabinets; Revision 23

PPM 10.25.181; Single Cell Charging of Batteries; Revision 3
50.59 SCREEN-05-0218; Connect a non-safety related rail charger (single cell charger) to a safety related station battery to provide an equalize charge to selected cell(s) of that battery

Institute of Electrical and Electronics Engineers (IEEE) Standard 450-1995, IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead Storage Batteries for Stationary Applications

Flow Diagram M534; Radioactive Waste System Condensate Demineralization; Revision 64

WO 01102358; RHR-V-27B Recovery; September 26, 2005

WO 01105461; HPCS-V-12 Investigate Overload Trip of MOV; September 27, 2005

WO 01094756; SW-V-105D and SW-V-107D Repair Leaks; October 5, 2005

WO 01109759; EB-2-1 Cell 157 Replacement; November 22, 2005

WO 01108885; COND-V-206D; VALVE LEAKS BY PREVENTING PRECOAT OPERATIONS; November 8, 2005

CR-2-05-09534; The procedure for single cell charging of station batteries does not include limitations noted in Salems procedure for single cell charging; December 9, 2005

CR-2-05-08194; Design engineering position needed to identify if any formalized design requirements are applicable to the battery rail charger; October 24, 2005

CR-2-05-08510; Rail (single cell) charger was placed on E-B2-1 without the concerns of CR 2-05-08194 being addressed; November 2, 2005

CR-2-05-09681; NRC resident question concerning certain temporary installation. Are cases adequately addressed in design control procedures; December 14, 2005CR-2-05-00354; If all the clearance orders assigned to the parent WO are not hung, the WO cannot be moved to working status; 05/13/2005

CR-2-05-02473; The WO-0108803101 (CEP-AO-V/2A repair) was not included in the Sentinel analysis (PPM 1.5.14) during pre-planning; September 24, 2005

CR-2-05-06449; Shift Manager failed to protect plant equipment per OI-49; September 24, 2005

PER 205-0579; HPCS-V-12 failed postmaintenance and operability testing; September 16, 2005

Section 1R22: Surveillance Testing

OSP-LPCS/IST-Q702; LPCS System Operability Test; Revision 15

ISP-CRD-Q902; RPS - Channels B and D ½ Scram SDV CFT; Revision 7

OSP-RHR-Q703; RHR Loop B Operability Test; Revision 0

Section 1R23; Temporary Plant Modificaitons

TMR 05-19

Section 1EP2: Alert Notification System

Description of the Early Warning System for the Washington Public Power Supply Nuclear Plants 1, 2, and 4; December 1981

Washington Nuclear Project No. 2 Site Specific Offsite Radiological Emergency Preparedness Alert and Notification System Quality Assurance Verification; May 1994

TSI 6.2.32; Bi-Weekly Emergency Response River Siren Polling Test; Revision 9

EPI-26; Tone Alert Radio Test and Survey; Revision 0

Section 1EP4: Emergency Action Level and Emergency Plan Changes

Columbia Generating Station Emergency Plan Implementing Procedure 13.1.1A; Classifying the Emergency - Technical Bases; Revision 14
Columbia Generating Station Emergency Plan Implementing Procedure 13.1.1A; Classifying the Emergency - Technical Bases; Revision 15

Section 1EP5: Correction of Emergency Preparedness Weaknesses and Deficiencies

Site Wide Procedure; SWP-CAP-1, Corrective Action Program; Revision 9

Section 1EP6; Drill Evaluation

2005 Team D Drill Report; October 25, 2005

Section 2OS2; ALARA Planning and Controls

Incident Review Board for CR 2-05-08798

RWP 30001598

CR-2-05-09113; Procedure SWP-RPP-01 contains incomplete wording for a 10 CFR Part 20 requirement; November 22, 2005

CR-2-05-09114; Inconsistent wording in RP procedures regarding the performance of ALARA evaluations for the use of respirators; November 22, 2005

CR-2-05-08798; Loss of contamination control associated with EDR line flange changeout; November 10, 2005

Section 4OA2: Identification and Resolution of Problems

PPM EES-5; General Fuse Selection Criteria and the Electrical Protection of 460 VAC and 125-250 VDC Motors; Revision 5

Site Wide Procedure; SWP-CAP-02; Cause Determination; Revision 3

Site Wide Procedure; SWP-CAP-01, Corrective Action Program; Revision 9

PPM 1.3.47; Fuse Replacement Control; Revision 9

PPM DES-2-5; Preparation and Approval of Equipment Modification Specifications; Revision 0

CR-2-05-02164; Control Power Fuse Installed in wrong Type; April 11, 2005

CR-2-05-06255; WMA-FN-53B & HPCS-P-2 under-size primary fuse for installed control transformer; August 3, 2005

CR-2-05-06339; A comprehensive review of the fuse log discovered the control power fuse for RFW-42-7A3C is a time delay rather than a fast acting fuse; August 6, 2005

CR-2-05-00726; Two different manufacturers fuses were found in E-MC-7AB/2E which supply SEC-PP-SS25; February 8, 2005

CR-2-05-04598; During restoration of CRD system discovered CRD-V-116/1443 out of position; June 2, 2005

CR-2-05-05835; During 01095686 task 01, the RPS test box was connected to wrong relay points; July 16, 2005

CR-2-05-09478; HPCS-M-P/1(HPCS-P-1) high vibration (above ALERT HI value) was not reported to the control room; December 7, 2005

CR-2-05-02421; RCIC-PS-21 was not declared INOPERABLE when surveillance ISP-RCIC-M901 became tech. spec. late; April 19, 2005

CR-2-05-06757; While performing OSP-CRD-W701 (Weekly Control Rod Exercise) control rod 34-07 was inadvertently inserted from position 46 to position 44; August 26, 2005

CR-2-05-06154; During review of fuse control log discovered SLC-P-1A had wrong type control fuse installed; July 29, 2005

CR-2-05-06336; The primary fuses for COND-42-1D4B were found to be 100 amp fuses. This disconnect should be fused at 80 amps per E528-50; August 6, 2005

CR-2-05-01099; Found wrong size (amperage) fuse installed in CW-42-6P1A Control Power Transformer; February 28, 2005

CR-2-05-04979; During OSP-RCIC/IST-B501 a restoration step was inadvertently missed at the end of section 7.4 (Step 7.4.13); June 9, 2005

CR-2-05-05911; Welds associated with HPCS-V-6/7 were pressure tested at keep fill pressure of 100 psig in lieu of full HPCS system pressure; July 20, 2005

CR-2-05-05466; Current Transformer (CT) X3 for startup transformer E-TR-S has damaged wire and is not wired per the drawings; June 25, 2005

CR-2-05-06241; Fuse log review found the wrong fuse installed in the control power circuit; July 30, 2005

CR-2-05-03956; During performance of PPM 2.7.25, Section 5.31, Under Vessel Platform Temporary Power Installation, 30 amp fuses were found at E-MC-8C/2AR; May 20, 2005

CR-2-05-06242; Fuse log review found the wrong type fuse was installed for the control power circuit for RHR-V-3A; May 20, 2005

CR-2-05-06338; A comprenhensive fuse log review found the control power fuse for RHR-42-8BA5B is a time delay FNM3 fuse vs the designed fast acting fuse; May 20, 2005

CR-2-05-00724; Two different manufacturers fuses were found in E-MC-7E/5DL which supply WOA-EHC-9; May 20, 2005

CR-2-05-06337; A comprehensive review of the fuse log reveals that the control fuse for HPCS-42-4A3C is a TRM3 a time delay fuse vs a fast acting fuse; July 30, 2005CR-2-05-06599; Incorrect fuse type and rating installed in motor starter control circuit; July 30, 2005

CR-2-05-01221; Two different manufacturers fuses were found in E-MC-6Q/1A which supplies CW-FN-11; July 30, 2005

CR-2-05-05349; At 13:46 a reactor scram occurred due to low RPV water level +13 inches; June 23, 2005

CR-2-05-06013; Received Suppression Pool High level alarms during the performance of OSP-FPC/IST-Q701 Section 7.5; July 23, 2005

CR-2-05-02122; A human performance error caused a high level trip of Low Pressure Heaters 1A & 2A; April 10, 2005

CR-2-05-03253; Operations started the flood-up of the cavity and the 606 work was not ready to flood up; May 10, 2005

CR-2-05-01754; Locking tabs on upper air deflector were not bent againt the cap screws to secure them in place, March 25, 2005

CR-2-05-01141; The NRC in their annual assessment letter has identified a substantive crosscutting issue in the area of human performance; March 2, 2005

CR-2-05-06187; Half scram on RPS-B Groups 1 and 4 due to dropped flashlight; August 2, 2005

CR-2-05-00484; Equipment operator was directed to locally start FP-P-2B. FP-P-2A was inadvertently started in error; January 26, 2005

CR-2-05-05491; Inadvertent 1/2 scram during reactor heatup; June 30, 2005

CR-2-05-01878; There is an apparent and continuing trend of poor engineering performance associated with electrical equipment; March 31, 2005

PER 205-0199; MC-4A bucket assemblies do not have one of three seismic restraints fully engaged in at least two cubicles; March 29, 2005

PER 205-0690; Columbia sometimes misses, dismisses, or forgets Industry Operating Experience that might help prevent adverse events; November 28, 2005

PER 205-0502; During review of fuse control log discovered SLC-P-1A had wrong type control fuse installed; July 29, 2005

PER 205-0386; Personal tag error by maintenance; May 30, 2005

PER 205-0502; During review of fuse control log discovered SLC-P-1A had wrong type control fuse installed; August 2, 2005

PER 205-0128; CGS not following the recommendations of GE SIL 484 for replacement of motor oil drain plug O-ring replacement; March 1, 2005

PER 205-0175; (SPER)HPCS-M-P/1 upper air deflector shield is cracked approximately 180 degrees; March 17, 2005

PER 205-0472; During 01095686 task 01, the RPS test box was connected to wrong relay points; July 16, 2005

PER 205-0428; At 13:46 a reactor scram occurred due to low RPV water level +13 inches; June 24, 2005

ATTACHMENT 2

COLUMBIA GENERATING STATION
Inadequate 50.59 Evaluation for the RCIC Keepfill Pump Starting Logic Modification
SDP Phase 3 Analysis

I. Performance Deficiency:

In 2001, the licensee failed to request NRC approval prior to implementing Basic Design Change (BDC) 394, which was associated with a design modification on the reactor core isolation cooling (RCIC) system. The design modification changed the starting logic of the RCIC keepfill pump which resulted in an increased unreliability of the RCIC pump to start and inject into the reactor coolant system.

II. Safety Significance:

The analyst determined that the performance deficiency represented a finding of very low risk significance. This was based on a Phase 3 evaluation using NRC Inspection Manual Chapter 0609, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations."

III. Description of Condition:

The RCIC keepfill pump discharges into the suction header of the RCIC pump to pressurize the RCIC pump suction and discharge headers in order to minimize waterhammer events. The suction header is normally pressurized and equal to the discharge header pressure (normally about 80 psig) with the RCIC pump secured because of check valves located upstream in the suction header.

Prior to the design modification, the keepfill pump ran continuously and maintained the RCIC pump suction header and discharge line pressurized. In 2001, the starting logic of the RCIC keepfill pump was modified so that the pump would start when pressure decreased to 68 psig, as sensed from a pressure sensor on the discharge of the RCIC pump downstream of a discharge check valve.

When the RCIC pump is operated, it draws down the suction header pressure to condensate storage tank head (normally about 25 psig) as it pumps water to the reactor coolant system and the discharge header pressurizes to reactor coolant system pressure. After the RCIC pump is secured, either by operator action or automatically on a reactor pressure vessel water Level 8 signal, the RCIC keepfill pump does not start and repressurize the RCIC suction header because the starting logic is controlled by the discharge header pressure which is now at a pressure much higher than the 68 psig setpoint. This leaves the suction header at condensate storage tank nominal pressure for the next RCIC pump start.

A reduced suction header pressure leaves the RCIC pump vulnerable to a momentary drop in suction header pressure as the pump subsequently starts. This may result in a low pressure suction trip of Valve RCIC-V-1, the RCIC pump steam admission valve, which prevents the RCIC pump from completing the start sequence. This occurred following the June 23, 2005, scram at Columbia Generating Station when the RCIC pump failed to successfully start in an automatic control mode on the second and third RCIC pump start attempts. The pump was started on the fourth attempt when the operators started the pump with the flow controller in manual in accordance with plant procedures.

Therefore, since 2001, when the design modification was implemented on the RCIC keepfill pump to change the keepfill pump starting logic, the RCIC pump had been susceptible to this failure mode following any initial RCIC pump start.

IV. Initial Characterization of Risk:

In accordance with NRC Inspection Manual Chapter 0612, Section 05.03, “Screen for Greater than Minor,” the inspectors determined that the finding was more than minor. This finding was associated with the equipment performance attribute of the Mitigating Systems cornerstone and was determined to affect the objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the finding resulted in an increased unreliability of the RCIC pump to start and inject into the reactor coolant system.

The inspectors evaluated the issue using the, “Significance Determination Process (SDP) Phase 1 Screening Worksheet for the Initiating Events, Mitigating Systems, and Barriers Cornerstones,” provided in NRC Inspection Manual Chapter 0609, Appendix A, Attachment 1, "User Guidance for Determining the Significance of Reactor Inspection Findings for At-Power Situations." The screening indicated that a Phase 2 estimation was required because the finding represented a loss of safety system function.

V. Phase 2 Estimation:

In accordance with NRC Inspection Manual Chapter 0609, Appendix A, Attachment 1, "User Guidance for Determining the Significance of Reactor Inspection Findings for At-Power Situations," the inspectors estimated the risk of the subject finding using the Risk-Informed Inspection Notebook for Columbia Generating Station, Revision 1. The inspectors made the following assumptions:

1) The design modification to the RCIC keepfill pump starting logic was made in 2001. This represents an exposure time of greater than one year. Therefore, an exposure window of greater than 30 days was used.

2) The RCIC pump was not capable of performing its risk-significant function from the date of the design change.

3) Table 2 of the Risk-Informed Inspection Notebook identified that the TRANS, TPCS, SLOCA, SORV, LOOP, LEAC, LODC2, LOTSW, and

LCAS initiating event scenarios needed to be evaluated when a performance deficiency affects the RCIC system.

4) The Columbia RCIC system consists of a single turbine-driven pump to provide 100% of its risk-significant function. Therefore, the Risk-Informed Inspection Notebook requires that the pump be functional to give mitigating system credit to the RCIC system.

5) Given Assumption 4, the inspectors adjusted the remaining RCIC mitigation capability credit from 1 (1 automatic steam-driven train) to 0.

6) Sufficient time was available, environmental conditions allowed access, and the required equipment was ready and available for the operators to start the RCIC pump with the flow controller in manual.

7) Given Assumption 6, credit was given for operator recovery because the actions for starting the RCIC pump with the flow controller in manual were proceduralized and the operators received periodic training on performing this procedure.

The dominant sequences from the notebook were as follows:

Initiating Event	Sequence	Mitigating Functions	Results
Transient with loss of PCS	4	HPCS - RCIC - DEP	7
Stuck Open Relief Valve	4	HPCS - RCIC - DEP	7
Loss of Offsite Power	8	EAC - RLOOP30M - HPCS - RCIC	7

Using the Counting Rule Worksheet, this finding was estimated to be of low to moderate safety significance (WHITE). However, an important assumption made during the Phase 2 estimation was overly conservative. Specifically, the assumption that the RCIC pump could not perform its risk-significant function from the date of the design change was overly conservative because the RCIC pump was capable of initially starting and injecting into the reactor coolant system for part of the exposure period. Therefore, a Phase 3 evaluation was required.

VI. Phase 3 Evaluation:

Internal Initiating Events:

The results from the notebook estimation were compared with an evaluation developed using a Standardized Plant Analysis Risk (SPAR) model simulation of the failure of the RCIC pump to start and inject into the reactor coolant system. The SPAR runs were based on the following analyst assumptions:

1) The design modification to the RCIC keepfill pump starting logic was made in 2001. Therefore, an exposure time of one year (the reactor oversight process assessment period) was used.

2) The RCIC pump would not have failed from low suction pressure as it did on June 23, 2005 had the performance deficiency not existed.

3) The SPAR model, Revision 3.30, was used to assess the significance of this event. The failure of the RCIC pump from low suction pressure was not modeled in this revision. The RCIC system fault tree was modified to account for the following assumptions. The modified model, including the component test and maintenance basic events, represents an appropriate tool for evaluation of the subject finding.

4) The RCIC pump would not have failed upon every demand as assumed during the Phase 2 estimation.

5) The RCIC pump would have failed upon demand after any surveillance test or startup when the suction pressure was less than 36 psig. From the licensee's review of system operational history, this condition was estimated to exist approximately 35 hours during the past year.

6) Given a failed pump start because of low suction pressure, the RCIC pump would start successfully if operators started the pump with the flow controller in manual.

7) Recovery from the failure mode described in Assumptions 5 and 6 was considered to be likely. The conditional probability of operators failing to properly diagnose the failure to start upon initial demand and then start the pump with the flow controller in manual was determined to be 0.12.

   The analyst used the SPAR-H method to calculate this probability. All performance shaping factors not discussed below were assumed to be at nominal value. The nominal diagnosis failure probability of 0.01 and the nominal action failure probability of 0.001 were multiplied by the following performance shaping factors:

- Procedures for Diagnosis: 5

  The analyst determined that procedures existed for starting the RCIC pump with the flow controller in manual, but were of poor quality for diagnosing the problem. The procedures do not direct the operators to start the pump with the flow controller in manual. Instead, the method for starting the pump, i.e., either a quick start or a soft start, is left to the judgment of the operators.

- Time Available for Action: 10

  The analyst determined that the available time for action was approximately the time required. The minimum time required for the pump to fail to start, the operator to diagnose the need to start the pump with the flow controller in manual, and the time required to start the pump is approximately 30 minutes. The time available before the onset of core damage was estimated to be 30 minutes.

- Stress: 2

  Stress under the conditions postulated would be high. A major accident would be ongoing, and operators would understand that the consequences of their actions would represent a threat to plant safety.

8) Given a successful pump start, the RCIC pump would have failed upon demand during the second and any subsequent start attempts.

9) Recovery from the failure mode described in Assumption 8 was considered to be highly likely. The conditional probability of operators failing to properly diagnose the failure to start upon subsequent demands and then start the pump with the flow controller in manual was determined to be 0.012.

   The analyst used the SPAR-H method to calculate this probability. All performance shaping factors not discussed below were assumed to be at nominal value. The normal diagnosis failure probability of 0.01 and the nominal action failure probability of 0.001 were multiplied by the following performance shaping factors:

   - Procedures for Diagnosis: 5

     The analyst determined that procedures existed for starting the RCIC pump with the flow controller in manual, but were of poor quality for diagnosing the problem. The procedures do not direct the operators to start the pump with the flow controller in manual. Instead, the method for starting the pump, i.e., either a quick start or a soft start, is left to the judgment of the operators.

- Time Available for Diagnosis: 0.1

  The analyst determined that there would be extra time to diagnose that the pump had not started and determine that the pump would start with the flow controller in manual. There are indications in the control room that the pump did not start and the RCIC pump is not immediately needed again since it already injected into the reactor coolant system before being secured.

- Time Available for Action: 1

  The analyst determined that the available time for action was nominal. The minimum time required for the pump to fail to start, the operator to diagnose the need to start the pump with the flow controller in manual, and the time required to start the pump is approximately 30 minutes. In this failure mode, the pump would have initially started and slowly flooded the core until it was secured. As such, the initial water level would have been higher and the decay heat lower than the failure mode described in Assumptions 5 and 6. Thus, the time available before the onset of core damage was estimated to be 2 hours.

- Stress: 2

  Stress under the conditions postulated would be high. A major accident would be ongoing, and operators would understand that the consequences of their actions would represent a threat to plant safety.

<u>Analysis</u>:

As stated in Assumption 3, the analyst modified the RCIC fault tree to account for the failure mechanism introduced by the performance deficiency. The failure of the RCIC pump because of low suction pressure was further divided into two partitions.

The first partition corresponded to the 35 hours when the suction pressure was less than 36 psig and the RCIC pump would have failed immediately upon demand. Two new basic events were created for this partition, RCI-KEEPFILL-SV and RCI-XHE-XL-RSTRT-COLD. Basic event RCI-KEEPFILL-SV was initially set to the house event FALSE to indicate that, without the performance deficiency, the RCIC pump would not have failed because of low suction pressure. Basic event RCI-XHE-XL-RSTRT-COLD represents the probability that operators fail to recover the RCIC pump from the low suction pressure trip. As described in Assumption 7, this recovery event was assigned a probability of 0.12. The first partition was completed by coupling these two basic events with an AND gate.

The second partition corresponded to the remainder of the year when the RCIC pump may have started initially, but would have failed upon the second and any subsequent demand. Three basic events were created for this partition, RCI-TDP-FS-RSTRT-HOT, RCI-XHE-XL-RSTRT-HOT, and RCI-RESTART-HOT. Basic event RCI-TDP-FS-RSTRT-HOT was initially set to the house event FALSE to indicate that, without the performance deficiency, the RCIC pump would not have failed because of low suction pressure. Basic event RCI-XHE-XL-RSTRT-HOT represents the probability that operators fail to recover the RCIC pump from the low suction pressure trip after it had already run once. As described in Assumption 9, this recovery event was assigned a failure probability of 0.012. Basic event RCI-RESTART-HOT represents the fraction of times that a restart of RCIC is required. It was assigned the nominal value of 0.085 from the basic event RCI-RESTART. The second partition was completed by coupling these three basic events with an AND gate.

The SPAR model was rebaselined with these two partitions. The analyst then used the modified SPAR model to calculate the change in core damage frequency (ΔCDF) over the exposure period. The analyst divided the exposure period into two mutually exclusive segments corresponding to the two partitions. The analyst then created change sets to calculate the change in core damage frequency separately for each segment.

The first change set changed the basic event RCI-KEEPFILL-SV to the house event TRUE to indicate that the RCIC pump would have failed upon demand when the suction pressure was less than 36 psig. As indicated in Assumption 5, this condition existed for 35 hours in the past year. The ΔCDF over this segment was:

$$\Delta CDF_1 = (CDF_1 - CDF_{Base}) * EXP_1$$

$$= (3.6 \times 10^{-6} \text{ per year}) * (35 \text{ hours} \div 8760 \text{ hours/year})$$

$$= 1.5 \times 10^{-8}$$

The second change set changed the basic event RCI-TDP-FS-RSTRT-HOT to the house event TRUE to indicate that the RCIC pump would have failed to start after any successful initial start. As indicated in Assumption 5, this condition existed the remainder of the year. The ΔCDF over this segment was:

$$\Delta CDF_2 = (CDF_2 - CDF_{Base}) * EXP_2$$

$$= (2.8 \times 10^{-8} \text{ per year}) * (8725 \text{ hours} \div 8760 \text{ hours/year})$$

$$= 2.8 \times 10^{-8}$$

The analyst then calculated the total change in core damage frequency from the performance deficiency. Because the segments are mutually exclusive, the change in core damage frequency from each segment can be added together to calculate the total change in core damage frequency. So:

$$\Delta CDF = \Delta CDF_1 + \Delta CDF_2$$

$$= 4.3 \times 10^{-8}$$

The dominant sequences from the Phase 3 evaluation are listed below. The analyst noted that these sequences are similar to the dominant sequences from the Phase 2 estimation, indicating agreement between the methods.

The analyst noted that some qualitative and quantitative differences existed between the Phase 2 and Phase 3 results. Qualitatively, the Phase 3 evaluation indicates that the failure of low pressure injection is an important contributor to the core damage frequency. The Phase 2 estimation does not indicate the importance of low pressure injection, but does indicate that a stuck-open relief valve is an important contributor to core damage frequency.

The quantitative differences are largely due to the different assumptions used in the two analyses. As noted above, the assumption that the RCIC pump could not perform its risk-significant function from the date of the design change was an overly conservative assumption of the Phase 2 estimation. This resulted in an increased core damage frequency estimate from the Phase 2 estimation than determined in the more refined Phase 3 evaluation.

Initiating Event	Sequence	Mitigating Functions	Results
Loss of Offsite Power	25-23	EPS - B1 - RCI - AC30M	1.3×10^{-8}
	21	HCS - RCI - LPI	3.9×10^{-9}
	22	HCS - RCI - DEP	2.1×10^{-9}
	25-09	EPS - HCS - RCI - AC30M	1.9×10^{-9}
Loss of Condenser Heat Sink	41	HCS - RCI - LPI - CDS - VA	6.2×10^{-9}
	40	HCS - RCI - DEP	1.0×10^{-9}
Loss of Main Feedwater	5	HCS - RCI - LPI - VA	5.9×10^{-9}
	6	HCS - RCI - DEP	3.2×10^{-9}
Transient	8	MFW - HCS - RCI - DEP	1.6×10^{-9}

External Events:

The plant-specific SDP worksheets do not currently include initiating events related to fire, flooding, severe weather, seismic, or other external initiating events. In accordance with Manual Chapter 0609, Appendix A, Attachment 1, Step 2.5, "Screen for the Potential Risk Contribution Due to External Initiating Events," experience with using the Site Specific Risk-Informed Inspection Notebooks has indicated that accounting for external initiators could result in increasing the risk significance attributed to an inspection finding by as much as one order of magnitude. The analyst determined that an evaluation of external risk would not be required because the result of the Phase 3 analysis indicated that the risk was less than 1×10^{-7}. Therefore, an increase in the risk by an order of magnitude would not result in the significance of the finding crossing the 1×10^{-6} threshold.

Large Early Release Frequency:

In accordance with Manual Chapter 0609, Appendix A, Attachment 1, Step 2.6, "Screen for the Potential Risk Contribution Due to Large Early Release Frequency (LERF)," the analyst determined that the finding was not significant from a large early release frequency perspective and no further evaluation was necessary because the Phase 3 result provided a risk significance estimation of less than 1×10^{-7}.

VI. Licensee's Result:

The licensee performed a preliminary assessment of the condition and concluded that the ΔCDF was 3.13×10^{-7}. The analyst compared the assumptions and noted that there were two primary reasons for the difference in the licensee's result and the analyst's result.

First, the licensee considered the RCIC system to be unavailable during the time period when the suction pressure was less than 36 psig. The licensee did not provide any credit for operators recovering the pump. The licensee calculated a ΔCDF of 5.4×10^{-8} for this period. The analyst performed a new calculation using this assumption and calculated a $\Delta CDF_{1,Modified}$ of 1.2×10^{-7} for this period.

Second, the licensee used NUREG-4550 and calculated the human error probability of operator recovery for the remainder of the year to be 0.022, resulting in a ΔCDF of 2.6×10^{-7} for this period. The analyst used the SPAR-H method and calculated the nonrecovery probability to be 0.012. Using the licensee's value, the analyst calculated a $\Delta CDF_{2,Modified}$ of 5.0×10^{-8} for this period.

Combining these modified values results in a modified ΔCDF of:

$$\Delta CDF_{Modified} = \Delta CDF_{1,Modified} + \Delta CDF_{2,Modified}$$

$$= 1.7 \times 10^{-7}$$

In order to best compare the models and results, the analyst compared the licensee's results with the modified results described above. The following table documents the comparison.

Analyses Comparison			
Result	Licensee's Result	Analyst's Result	Difference
Best Estimate ΔCDF	3.1×10^{-7}	4.3×10^{-8}	86%
Modified ΔCDF_1	5.4×10^{-8}	1.2×10^{-7}	122 %
Modified ΔCDF_2	2.6×10^{-7}	5.0×10^{-8}	81%
Modified ΔCDF	3.1×10^{-7}	1.7×10^{-7}	45%
Note: For the licensee's results, a modified ΔCDF correspond to the licensee's best estimate ΔCDF			

The analyst noted that this modified value was within a factor of two of the licensee's result, indicating good agreement between the two models. Additionally, both results indicated that the finding was of very low risk significance. The remaining difference is expected to be in the modeling differences between the licensee's PRA and the SPAR model. As such, the difference between results can be largely attributed to the different assumptions used in the two analyses.

VII. Conclusion:

The performance deficiency resulted in a finding that was of very low risk significance (Green).

VIII. References:

Draft NRC Inspection Report Input for 50-397/2005004

Draft Phase 2 Estimation provided by lead inspector

NRC Inspection Manual Chapter 0609, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations"

NRC Inspection Manual Chapter 0612, "Power Reactor Inspection Reports"

Risk-Informed Inspection Notebook for Columbia Generating Station, Revision 1

System Operating Procedure SOP-RCIC-INJECTION, "RCIC RPV Injection," Revision 2

IX. Participation:

Lead Inspector:	Zachary Dunham
Analyst:	Steven Alferink
Lead Reviewer:	David Loveless
Peer Review:	Russ Bywater