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10 CFR 50.46(a)(3)(ii)
10 CFR 50.59(d)(2)
10 CFR 72.48(d)(2)

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555

Subject: **COLUMBIA GENERATING STATION, DOCKET NO. 50-397
INDEPENDENT SPENT FUEL STORAGE INSTALLATION,
DOCKET NO. 72-35
2007 ANNUAL OPERATING REPORT**

Dear Sir or Madam:

Enclosed is the annual operating report for Columbia Generating Station for calendar year 2007. This report is submitted pursuant to 10 CFR 50.46, 10 CFR 50.59, 10 CFR 72.48, Regulatory Guide 1.16, Guidelines for Managing NRC Commitment Changes (NEI 99-04), and Licensee Controlled Specification 1.7.8. There are no commitments being made to the NRC by this letter, however, one existing commitment has been changed.

If you have any questions or desire additional information pertaining to this report, please contact Mr. MC Humphreys at (509) 377-4025.

Respectfully,

DK Atkinson, Vice President
Nuclear Generation & Chief Nuclear Officer

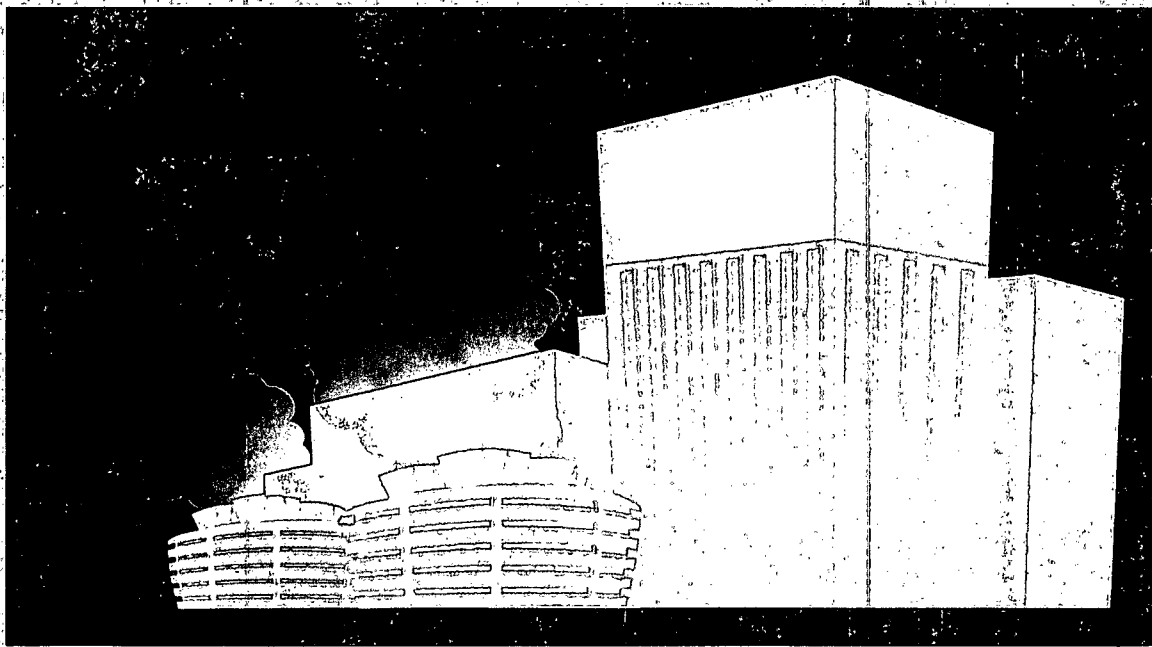
Enclosure: Columbia Generating Station 2007 Annual Operating Report

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Columbia Generating Station

2007 ANNUAL OPERATING REPORT



COLUMBIA GENERATING STATION

2007 ANNUAL OPERATING REPORT

DOCKET NO. 50-397

DOCKET NO. 72-35

FACILITY OPERATING LICENSE NO. NPF-21

Energy Northwest
P.O. Box 968
Richland, Washington 99352

**Columbia Generating Station
2007 Annual Operating Report**

Table of Contents

<u>Section</u>	<u>Page</u>
1.0 Reporting Requirements-----	1
2.0 Summary of Plant Operations-----	2
3.0 Outages and Forced Reductions in Power-----	3
4.0 Sealed Source Contamination-----	5
5.0 Fuel Performance-----	6
6.0 10 CFR 50.46 Changes or Errors in ECCS LOCA Analysis Models-----	6
7.0 10 CFR 50.59 Changes, Tests, and Experiments-----	7
8.0 10 CFR 72.48 Changes, Tests, and Experiments-----	14
9.0 Regulatory Commitment Changes (NEI Process)-----	14

1.0 Reporting Requirements

The reports in this document are provided pursuant to: 1) the requirements of Licensee Controlled Specification (LCS) 1.7.8, "Sealed Source Contamination;" 2) the requirements of 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light-Water Nuclear Power Reactors;" 3) the requirements of 10 CFR 50.59, "Changes, Tests, and Experiments;" 4) the requirements of 10 CFR 72.48, "Changes, Tests, and Experiments;" 5) the guidance contained in Regulatory Guide 1.16, "Reporting of Operating Information-Appendix A. Technical Specifications," Revision 4, August 1975; and 6) the guidance contained in NEI 99-04, "Guidelines for Managing NRC Commitment Changes," Revision 0, July 1999.

Licensee Controlled Specification 1.7.8 requires a report be submitted to the Commission, on an annual basis, if sealed source or fission detector leakage tests reveal the presence of greater than or equal to 0.005 microcuries of removable contamination.

Regulation 10 CFR 50.46(a)(3)(ii) requires, in part, that for each (non-significant) change to or for each error discovered in an acceptable Emergency Core Cooling System (ECCS) performance evaluation model or in the application of such a model that affects the temperature calculation, the applicant or licensee report the nature of the change or error and the estimated effect on the limiting ECCS analysis to the Commission at least annually as specified in 10 CFR 50.4.

Regulation 10 CFR 50.59(d)(2) requires that licensees submit, as specified in 10 CFR 50.4, a report containing a brief description of any changes, tests, and experiments, including a summary of the evaluation of each. This report must be submitted at intervals not to exceed 24 months.

Regulation 10 CFR 72.48(d)(2) requires that licensees submit, as specified in 10 CFR 72.4, a report containing a brief description of any changes, tests, and experiments, including a summary of the evaluation of each. This report must be submitted at intervals not to exceed 24 months.

Regulatory Guide 1.16 states that routine operating reports covering the operation of the unit during the previous calendar year should be submitted prior to March 1 of each year. Each annual operating report should include:

- A narrative summary of operating experience during the report period relating to safe operation of the facility, including safety-related maintenance not covered elsewhere.

- For each outage or forced reduction in power of over 20 percent of design power level where the reduction extends for more than four hours:
 - (a) The proximate cause and the system and major component involved (if the outage or forced reduction in power involved equipment malfunction).
 - (b) A brief discussion of (or reference to reports of) any reportable occurrences pertaining to the outage or power reduction.
 - (c) Corrective action taken to reduce the probability of recurrence, if appropriate.
 - (d) Operating time lost as a result of the outage or power reduction.
 - (e) A description of major safety-related corrective maintenance performed during the outage or power reduction, including the system and component involved and identification of the critical path activity dictating the length of the outage or power reduction.
 - (f) A report of any single release of radioactivity or single radiation exposure specifically associated with the outage, which accounts for more than ten percent of the allowable annual values.
- A tabulation on an annual basis of the number of station, utility and other personnel (including contractors) receiving exposures greater than 100 mrem/year and their associated man-rem exposure according to work and job functions. (Columbia Generating Station [Columbia] License Amendment 190 eliminated the requirement to report this information.)
- Indications of failed fuel resulting from irradiated fuel examinations, including eddy current tests, ultrasonic tests, or visual examinations completed during the report period.

“Guidelines for Managing NRC Commitment Changes,” NEI 99-04, is an NRC-endorsed method for licensees to follow when managing or changing NRC commitments. For commitment changes that meet certain criteria, the guidance specifies that the NRC staff be notified of the changes either annually or along with Final Safety Analyses Report (FSAR) updates required by 10 CFR 50.71(e).

2.0 Summary of Plant Operations

The summary of plant operations is provided in accordance with Regulatory Guide 1.16, Revision 4, Section C.1.b.(1).

The year began with Columbia operating at 100% power. On April 8th, 2007, during replacement of a failed transformer (E-TR-IN/2) on the Division 2 120 VAC power supply inverter, technicians lifted the neutral wire at E-TR-IN/2, causing a loss of ground reference at main control room power panel (E-PP-8AA). Due to the ensuing power fluctuations operators declared the panel inoperable, entering Technical Specifications Action Statement (TSAS) 3.8.7.A. Prior to exceeding the 8 hour completion time, management decided to initiate a controlled reactor shutdown on April 9. Plant staff completed the repairs and the unit was taken to 99% power on April 15. On May 12, the station began the scheduled refueling and maintenance outage (R-18). The outage ended 44 days later when the operators synchronized the generator to the grid early June 25. On June 28th, with the plant at 70% power, Operations personnel were transferring lube oil filters on a condensate booster pump (COND-P-2B) when the pump tripped and the reactor scrambled on low water level. The COND-P-2B trip on low oil level was caused by the filter transfer and the incorrect filter duplex configuration. Plant staff corrected the configuration and power was restored to 100% on July 5. On the afternoon of August 2, operators reduced reactor power to 15% and removed the main generator from service to facilitate repairs on the links for one of the main transformers (E-TR-M1). Repairs were completed and power was returned to 100% on August 6. On August 21, operators reduced power to about 60% in response to a failed check valve in the Digital Electro-Hydraulic (DEH) dump valve assembly that closed a main steam intercept valve. After the check valve was replaced, operators restored power to 100% on August 22. On November 24, the operators reduced power to about 80% due to the loss of one of the two reactor feedwater heaters (RFW-HX-6B). The next day, operators reduced power to 70% to support recovery of the heater. Operators recovered the heater and restored power to 100% on November 25.

Planned power reductions were made routinely during the year for equipment maintenance, surveillance testing, control rod manipulations, and economic dispatch.

3.0 Outages and Forced Reductions in Power

The information about the outages or forced reductions in power is provided in accordance with Regulatory Guide 1.16, Section C-1.b.(2).

April 9, 2007 (approximately 140 generator off-line hours)

On April 8, during replacement of failed transformer E-TR-IN/2, technicians lifted the neutral wire at E-TR-IN/2, causing a loss of ground reference for power panel E-PP-8AA. Due to the ensuing power fluctuations, operators declared the panel inoperable, entering TSAS 3.8.7.A. [LER-2007-003] Prior to exceeding the 8 hour completion time, management decided to initiate a controlled reactor shutdown on April 9. Repairs were completed and operators synchronized the main generator to the grid early on April 14. The plant reached 99% power on April 15.

Columbia Generating Station 2007 Annual Operating Report

The root cause of lifting the neutral wire was a less than optimal design which established vulnerability and an error-prone condition. Contributing causes were less-than-adequate drawing configuration requiring extensive interpretation vs. identification and application, less-than-adequate training provided to personnel responding to emergent equipment issues, and a less-than-adequate procedure. Corrective actions included adding information to applicable drawings, modifying the model work order, establishing appropriate training on neutral grounds, and revising the procedure.

May 12 - June 25, 2007 (approximately 1056 generator off-line hours)

Energy Northwest began the 18th refuel outage (R-18) as planned on May 12. Activities completed included replacement of the following components; both reactor feedwater heat exchangers (RFX-HX-6A and 6B), a reactor water recirculation (RRC) pump (RRC-P-1A) motor, mechanical seals on both RRC pumps (RRC-P-1A and 1B), the high pressure core spray (HPCS) pump and motor, 24 control rod drive mechanisms, 30 low power range monitors (LPRM), and 6 main steam safety relief valves (SRV). Repairs were made to RFW-P-1B, extensive transformer yard corrective and preventive maintenance was performed, and the digital electro-hydraulic (DEH) control system upgrade project was completed.

The main generator was synchronized to the grid again at 00:13 on June 25, officially ending the R-18 outage.

During R-18, one individual received a planned single exposure in excess of 10% of the allowable annual occupational dose limit of 10 CFR 20. That individual was performing hose hookups and disconnects for chemical decontamination of the reactor water cleanup (RWCU) system. The individual received a whole body dose of 546 mrem (as measured by an electronic dosimeter) during a single radiological controlled area (RCA) entry. The individual's TLD reading (the dose of record), for the entire outage duration, was 661 mrem.

June 28, 2007 (approximately 94 generator off-line hours)

On June 28th, the plant was operating at 70% power due to a problem with COND-P-2A. While operations personnel were transferring lube oil filters on COND-P-2B, the pump tripped and the reactor scrammed on low water level. **[LER-2007-004]** Operators synchronized the generator to the grid early on July 2. Power reached 100% on July 5.

Root causes of the COND-P-2B trip were less-than-adequate configuration control for the COND-P-2B lube oil filter valves, and less-than-adequate risk assessment performed by the operating crew. Corrective actions include revisions to applicable procedures, implementation of an operational decision tree applicable to emergent low-level issues, and correction of the filter valve configuration.

August 2, 2007 (approximately 68 generator off-line hours)

On August 2, operators reduced reactor power to 15% in order to remove the main generator from service. The generator was taken off the grid so that technicians could repair failing connection interfaces on the disconnect links for one of the main step-up transformers (E-TR-M1). Repairs were completed and the plant was returned to 100% power on August 6.

The root causes of the condition were the lack of inspection-for-replacement criteria for the main transformer link plates and less-than-adequate joint preparation in the work instructions. Corrective actions include a procedure revision to include inspection-for-replacement criteria and joint preparation instructions.

August 21, 2007 (approximately 24 hours at reduced power)

On the night of August 20, operators responded to a DEH trouble alarm and found a main steam low pressure turbine intercept valve had closed, due to a leaking check valve in the DEH dump valve assembly. Operators immediately began reducing power to 62%. The check valve was replaced and the DEH and main steam valves were returned to normal operations. The return to 100% power was delayed to resolve problems with speed control on an RFW pump. Operators restored the plant to 100% power on August 22.

The cause of the failed check valve was the 1993 system cleaning using a cleaning fluid containing amines, which have been shown to initiate stress corrosion cracking in copper alloys. Corrective actions include replacement of all of the check valves on the dump valve assemblies for the intercept, reheat, throttle, and governor valves during the next forced outage, if practical, or the 19th refueling outage (R-19). Also, a sample of copper alloy components on the turbine valve actuators will be replaced during R-19 to determine extent of damage to other copper components.

November 24, 2007 (approximately 32 hours at reduced power)

On November 24, operators reduced power to about 80% in response to the RFW-HX-6B trip on high level. On November 25, the operators reduced power to 70% to support recovery of the heat exchanger. After operators returned RFW-HX-6B to service, they restored reactor power to 100% at 18:35.

The heat exchanger tripped due to a false high level signal. Further investigation revealed a failed level switch. Preventive maintenance activities will be enhanced for the switch and others in similar configurations and environments. A plan will be developed by engineering for the removal of the single point vulnerability caused by the lack of diversity or redundancy in the logic of the level switches for RFW-HX-6A and 6B.

4.0 Sealed Source Contamination

There were no incidents of sealed source contamination during 2007 that required reporting in accordance with LCS 1.7.8.

5.0 Fuel Performance

The fuel integrity information is provided in compliance with Regulatory Guide 1.16, Section C.1.b.(4), and FSAR Section 4.2.4.3, "Post-Irradiation Surveillance."

No fuel failures were identified during calendar year 2007 (Cycles 18 and 19). This conclusion was based on readings of offgas radioactivity from the pre-treatment process radiation monitoring system.

The sum-of-six-readings have stayed considerably below 300 microCi/sec, one of the INPO thresholds for fuel failures. The values for the Xe-133 activity and the Xe-133/Xe-135 and Xe-138/Xe-133 activity ratios have been within the range for an intact core.

Since Columbia did not experience any fuel defects or gross cladding anomalies during Cycle 18, fuel inspections were not required during R-18 by FSAR commitments. However, inspections were performed during the R18 outage on four assemblies that resided in the core for one to two cycles. These inspections are in response to the Energy Northwest implementation, in recent years, of several new water chemistry programs. The programs include noble metals addition, iron and zinc injection, and hydrogen water chemistry injection. Visual inspection results indicated normal fuel performance for both once and twice burned fuel. In addition to fuel visual inspections, fuel channel bow measurements on 62 twice-burned ATRIUM-10 assemblies were performed to confirm channel performance in the Columbia core in response to the potential concern on channel bow observed in other BWRs with Zr-2 channels that were exposed to control blades early in life. The channel performance was normal and there was no indication of shadow corrosion induced bow.

6.0 10 CFR 50.46 Changes or Errors in ECCS LOCA Analysis Models

The non-significant changes and errors in ECCS cooling performance models are provided in compliance with 10 CFR 50.46.

The Westinghouse methodology was used to license SVEA-96 fuel in the Columbia core. An error was discovered in the Westinghouse ECCS loss of coolant accident (LOCA) analysis model which involved modeling of the core inlet side-entry orifice. Evaluation by Westinghouse indicated there was no impact on peak clad temperature (PCT) from this error. Therefore no revisions were made to the Columbia LOCA Analysis Report during 2007.

The AREVA methodology was used to license ATRIUM-10 fuel in the Columbia core. No errors were discovered in the AREVA ECCS LOCA analysis model and no revisions were made to the Columbia LOCA Analysis Report during 2007.

7.0 10 CFR 50.59 Changes, Tests, and Experiments

This section contains the summary of the evaluations for activities implemented during 2007 that were assessed pursuant to 10 CFR 50.59 requirements.

Energy Northwest evaluated the changes summarized below and determined prior NRC approval was not required.

Plant Design Change (PDC) 4661 (Evaluation 5059-06-0002)

The low suction trip set point of the RFW pumps was raised within the process design limit to optimize the protection of the pumps. The design function of the RFW system is to provide a reliable source of high purity feedwater to the reactor during both normal operations and anticipated transient conditions. Raising the RFW pump set point, staggering the set points, and installing the bypass switch were actions designed to improve the reliability of the RFW system. The set point change prevents the pump from operating below its required net positive suction head (NPSH). Staggering the set points prevents the simultaneous loss of both feedwater pumps and decreases the likelihood of losing both pumps during a low pressure transient. The inclusion of a low power (<25%) bypass switch prevents a loss of feedwater trip when suction pressure is less than the trip set points but is greater than the required operating pressure.

Evaluation Summary

This evaluation has shown that no increase in frequency of occurrence or consequences of an accident or malfunction of a structure, system, or component (SSC) important to safety previously evaluated in the FSAR will occur. This design change maintains the FSAR design function and does not create an accident of a different type or a malfunction of an SSC important to safety with a different result than previously evaluated in the FSAR.

This activity does not require prior NRC approval.

Plant Design Change EC 4934 (Evaluation 5059-06-0003)

Energy Northwest replaced the old analog DEH and turbine trip system with a digital PLC-based system that will perform all the functions of the existing system but with improved reliability and fault tolerance. The new system incorporated the control, protective, monitoring, and testing functions of the existing system, without maintaining the mechanical overspeed trip. The new system provides modes of automatic control for startup, normal operation and shutdown conditions, as well as a manual mode to position the valves.

Evaluation Summary

No FSAR described accident analyses are adversely impacted by these DEH modifications. The transients are either a non-limiting event or the results are conservative and bounding.

The probability of a turbine missile remains within the regulatory plant-specific threshold Combined Overall Probability (P4) of 1×10^{-7} established in FSAR Section 3.5.1.3. The installation of the new DEH system does not result in an increase in the probability of this event. The diversity of the modified system meets the guidance for diversity for digital systems provided in EPRI TR-102348.

Hence, the proposed activity does not result in more than a minimal increase in the frequency of occurrence of an accident previously evaluated in the FSAR.

The new system retains all of the control functions of the existing system. There are no new control functions that directly interface with important to safety SSCs. The function of the replacement DEH system will not change the operating or design parameters of any other plant system.

The new DEH system has been designed as a highly reliable system. This design is achieved through implementation of a combination of using highly reliable components and application of triple modular redundant (TMR) fault tolerant design.

Engineering performed a Failure Modes and Effects Analysis (FMEA) for the new hardware and software to verify that a single failure of the new system is unlikely to result in a plant shutdown or plant transient.

Based on the comparable probabilities for destructive overspeed, improved reliability through redundancy, fault tolerance, and a fail-safe design, the deactivation of the mechanical overspeed trip and the reliance on the electrical overspeed trip will provide adequate overspeed trip reliability.

Therefore, the proposed activity does not result in an increase in the likelihood of occurrence of a malfunction of an SSC important to safety previously evaluated in the FSAR.

Any change in response of the new DEH control system that affects the results of accident analyses (input parameter change) is evaluated using existing approved methodologies for accident initiation and control response to FSAR described events. No alternative methodology or changes to an element of methodology is required by the change in control system functions or responses.

This activity does not require prior NRC approval.

FSAR Change LDCN-FSAR-06-064 (Evaluation 5059-06-0004)

A new accident scenario was added to the FSAR. The new scenario assumes offsite power is available after a LOCA, while cooling to one residual heat removal (RHR) heat exchanger is lost. The scenario posits the continued running of all ECCS pumps in the absence of cooling from the heat exchanger. The scenario relies on operator action to secure ECCS pumps associated with the non-functional RHR heat exchanger.

The calculated post-LOCA peak suppression pool temperature is 204.5°F. The new accident scenario can be addressed by operator action, and remains within design margins for suppression pool temperature and ECCS pump NPSH.

Finally, procedures were revised to provide appropriate cautions to the operators for the operation of ECCS pumps in this new scenario.

Evaluation Summary

General Electric (GE) identified (10 CFR Part 21 Communication) a new post-accident scenario that is outside the Columbia design basis and licensing basis. The subsequent evaluation identified a resulting non-conformance with analyses for suppression pool water temperature during LOCA. In the absence of operator intervention, this scenario would cause a higher suppression pool temperature than originally calculated, higher than the peak temperature of 204.5°F.

The scenario added to the FSAR entails the operation of ECCS pumps after the failure of an RHR heat exchanger to cool. This differs from the analyzed scenarios in the licensing basis. The scenario adds heat to the suppression pool. The added heat raises the pool temperature and, in turn, lowers the available NPSH for the ECCS pumps.

The scenario is similar to LOCA Case C, documented in FSAR section 6.2.1.1.3.3.1.6, "Long-Term Accident Responses." That case resulted in the highest post-LOCA containment pressure and temperature documented in the FSAR. Case C is based upon the following assumptions.

1. Division 1 is not functional. RHR-A (pump and heat exchanger) and LPCS are not operating.
2. Division 2 (RHR-B and RHR-C) and Division 3 (HPCS) are operable and functioning.
3. For the first 600 seconds of the accident, there is no RHR cooling.
4. After 600 seconds, the operator performs two actions:
 - Closes RHR-V-48B, the bypass valve for RHR-HX-1B, causing 100% of the RHR flow to pass through the heat exchanger.
 - Secures RHR-P-2C, a low pressure coolant injection pump (LPCI).

The assumption of operator action after 10 minutes of the accident was considered and accepted by the NRC in the original safety evaluation report (SER), NUREG 0892. The acceptance was based upon the condition that early initiation of suppression pool cooling be emphasized in the plant emergency procedures.

The new scenario differs in that Division 1 is assumed functional and the loss of a single RHR heat exchanger is postulated. The Division 1 low pressure ECCS pumps, (RHR-P-1A and LPCS-P-1) continue to operate until secured by the operator. While the pumps operate, the pump work is assumed to be transferred to the suppression pool as heat. This heat would be added to Case C's heat, which consists of:

- post-accident core decay heat,
- pump work of HPCS-P-1 and RHR-P-2B, and
- pump work of RHR-P-2C, for 600 seconds.

After 600 seconds, energy is removed from the suppression pool by standby service water (SW) via RHR-HX-1B. The removed heat is transported to the SW spray ponds, the ultimate heat sink (UHS). For the scenario depicted in this change, the operator is assumed to secure the Division 1 ECCS pumps, along with the extra LPCI pump, as postulated in Case C. Case C remains bounding due to the following determinations.

1. There is currently sufficient information and guidance for the operator to identify the new scenario, and implement appropriate remediation. Existing guidance will be augmented by further updates to procedures and related training to document this scenario.
2. There is ample design margin in the Case C containment analysis. This margin is sufficient to ensure adequate pump NPSH in the absence of operator action for over two hours. The margin is in the form of
 - RHR cooling that occurs during the first 600 seconds of the accident and
 - performance of the ECCS strainers.

The proposed FSAR change and posited operator actions do not introduce the possibility of a change in the frequency of an accident. The change describes an operator response to a post-LOCA scenario. The scenario - loss of cooling by an RHR heat exchanger - is partially described in FSAR Table 9.2-8, "Standby Service Water System Failure Analysis." The operator response - securing of ECCS pumps that are not needed for core cooling - is not an initiator of any accident previously evaluated in the FSAR.

The proposed FSAR scenario entails no change to the methodology of the containment analysis or assumptions. In that analysis, operator action is assumed at 10 minutes to secure an unneeded ECCS pump, RHR-P-2C. As discussed in FSAR Section 6.3.2.2.6, "Emergency Core Cooling System Suction Strainers", there are sufficient margins in the NPSH and suppression pool analyses to ensure that the lack of operator action for 20 minutes will not challenge the required NPSH for the ECCS pumps at the pump nozzles or allow

cavitation anywhere in the suction lines. Further engineering evaluation verified there was sufficient margin such that lack of operator action for over two hours would not adversely affect ECCS NPSH. The results depicted in the FSAR for LOCA Case C are unchanged.

The new scenario does not result in the increase in the frequency of occurrence of accidents that are defined in the FSAR. The new scenario will not initiate any FSAR-described event. Operator actions to address the new event are consistent with current FSAR descriptions.

There is minimal increase in the likelihood that the new accident scenario will increase the occurrence of a malfunction of an SSC important to safety previously evaluated in the FSAR. Operator actions to address the new event are consistent with current FSAR descriptions and the guidance provided in procedures and training. The ample margin in the containment analysis can accommodate excursions from presumed action times for operators. Supplemental guidance will be provided by procedure revisions and training.

The proposed changes to the FSAR and postulated operator response to the LOCA scenario do not introduce the possibility of a change in the consequences of an accident because neither the new scenario nor the required response is an initiator of any accidents. Delays in operator response will not introduce new failure modes. The new scenario does not challenge any aspect of post-LOCA response or any fission product barrier.

The new scenario - loss of an RHR heat exchanger with operation of all ECCS pumps - does not introduce the possibility of a change in the consequences of a malfunction because the scenario cannot initiate any malfunctions and no new failure modes are introduced.

Engineering evaluation demonstrates that ample margins exist for the presumed delays in the operator action to secure ECCS pumps. A two-hour delay in operator action does not introduce the possibility of a new accident because suppression pool temperatures will remain within analyzed limits, and will not initiate any new accident nor introduce any new failure mode. Accordingly, the proposed FSAR change and posited operator actions do not create an accident of a different type than any previously evaluated in the FSAR.

The LOCA scenario introduced by the FSAR change does not introduce the possibility of an SSC malfunction with a different result. Expected operator actions - or delayed actions - do not introduce a new failure mode. The failure modes implicit in the new FSAR description are bounded by those described in the FSAR. The instrumentation that is available to the operators provides ample information to act upon and remediate the failures. The guidance of existing procedures will be augmented to fully describe the new scenario, and will reinforce operator understanding and response to the failures. Existing information and guidance provides the operator with the information required to

respond to the loss of function in one RHR heat exchanger. There is ample margin in the containment analysis to provide the operator with time to assess and respond to the new scenario. Existing procedural guidance will be augmented with additional information that addresses the new FSAR scenario. Accordingly, the new FSAR scenario does not create the possibility of a malfunction of an SSC important to safety with a different result from those currently described in the FSAR.

The scenario described in the proposed FSAR change does not represent a challenge to any fission product barrier.

1. The wetwell has a design temperature of 270°F. The original licensing basis for peak suppression pool temperature is 212°F. The new FSAR scenario does not result in either of these temperatures being exceeded.

2. Emergency core cooling is available, and adequate core cooling will be provided. There is no adverse impact on cladding temperatures.

3. The new FSAR scenario does not affect drywell conditions or the ability to perform the design functions.

The proposed change does not result in a departure from a method of evaluation described in the FSAR used in establishing the design bases or in the safety analyses. Assumptions implicit in the new scenario and supporting engineering evaluation are consistent with current FSAR descriptions. The current post-LOCA containment analysis is unchanged.

This activity does not require prior NRC approval.

FSAR Change LDCN-FSAR-07-002 (Evaluation 5059-07-0002)

This change to the FSAR describes an alternative cooling system for the reactor pressure vessel (RPV) and spent fuel pool (SFP). The cooling uses the Division 2 RHR system and fuel pool cooling (FPC) system in alternative lineups with the RPV cavity flooded to the pool skimmer level and the SFP gates removed.

Natural circulation provides reactor core flow. Under the appropriate conditions, this alternative cooling lineup will allow the removal of both trains of RHR shutdown-cooling (SDC) from service for maintenance activities during a refueling outage, such as decontamination of both loops of RRC system or maintenance of the RHR SDC suction valves, RHR-V-8 and RHR-V-9.

The change includes the following:

1. Changing procedures to realign from normal RHR SDC to FPC assist and to the head spray line and both trains of the normal FPC lineup to discharge to the RPV cavity, with the options to secure or not secure any system operation during realignment. The RHR-B SDC lineup remains available during transition to and during initial acceptance testing, while the Division 1, (RHR-A) SDC is assumed unavailable.
2. Increasing the total flow through the four skimmers and two skimmer surge tanks from 3000 gpm during RHR FPC assist-only up to 4900 gpm

during concurrent operation of RHR FPC assist, RHR discharge through the head spray line, and both trains of FPC discharge to the RPV cavity.

3. Providing a new procedure to establish acceptance criteria for full reliance on alternative cooling. These criteria must be satisfied before both trains of normal RHR SDC become unavailable.

4. Installing jet pump plugs on all twenty jet pump nozzles to allow for chemical decontamination of the RRC piping and to preclude communication of the chemical decontamination solution with the RPV coolant inventory.

5. Installing a flow diffuser tee (with or without a ball valve) on the RPV cavity head spray line flange. The ball valve will be used if needed to allow completion of local leak rate testing (LLRT) of head spray isolation valves.

Upon completion of the LLRT, the ball valve would be opened using either a pneumatic or manual gear operator. The diffuser tee will redirect the discharge flow horizontally in two directions to minimize turbulence for underwater inspection activities. In addition, the tee will minimize the potential for foreign material intrusion into the head spray line.

Evaluation Summary

The heat removal capability of the alternative cooling paths will be verified before making both trains of RHR SDC unavailable. The reliability of the RHR and FPC systems used in alternative cooling is negligibly different (i.e., RHR uses some FPC piping in alternative cooling that is not class 1 piping, yet is capable of withstanding applicable load combinations of safe shutdown earthquake [SSE] and operating basis earthquake [OBE]) from when these same systems are normally aligned to perform their design function of decay heat removal.

Alternative cooling is not an initiator to any accident nor does it introduce a new failure mode. Therefore, the consequences of previously analyzed accidents bound this activity. For the same reasons, this activity does not create the possibility for a new type of accident or malfunction not previously analyzed.

Therefore, the consequences of this activity remain bounded. The fission product barrier most affected by this activity is the fuel cladding. This activity is performed during refueling with the cavity flooded. The water covering the fuel in the SFP and the RPV will be at atmospheric pressure plus the head of water over the top of the fuel. The fuel cladding limits will not be exceeded as long as the fuel is covered by water under these conditions and the fuel is subcritical.

Administrative controls are in place to prevent an accident whereby the alternative cooling activity can cause a loss of water inventory in the SFP or RPV or affect reactivity.

This activity does not require prior NRC approval.

Condition Report CR 2-07-95255, Accept-As-Is Disposition (Evaluation 5059-07-0003)

The CR documented the loss of a brush in the RPV during cleaning and visual inspection of RPV internals. The brush consists of a five-inch length of polyester bristles held by a two-strand, coiled-wire stem or handle. Each wire strand is 304 stainless steel, and is approximately 1/8" diameter. The overall length of the stem is approximately 7". The brush was not retrieved, and is considered a loose part.

Evaluation Summary

Engineering determined the missing brush will not cause new accidents or have any effect on the initiation or consequences of previously evaluated accidents. One issue was identified, the potential for a tube leak in an RHR heat exchanger. The tube leak was previously evaluated in the FSAR, and has no consequential effect on the heat exchanger function. The evaluation concludes that the loose part will not cause damage to the fuel nor impede any important-to-safety functions of the affected systems and components.

This activity does not require prior NRC approval.

8.0 10 CFR 72.48 Changes, Tests, and Experiments

There were no activities implemented during 2007 that required reporting pursuant to 10 CFR 72.48 requirements.

9.0 Regulatory Commitment Changes (NEI 99-04 Process)

This section reports a change to a regulatory commitment consistent with the information pertaining to Regulatory Commitment Changes (RCC) and is included pursuant to the NEI 99-04 criteria for reporting.

Compliance with NUREG 0612 (RCC-107070-00)

The original commitment description states that prior to transporting an SRV to or from the installed location and passing over the 14" LPCI B injection line, operators will verify or initiate the RHR-A loop of SDC. The commitment is based on a discussion regarding the possibility of damage to the LPCI return line from a dropped SRV. In compliance with NUREG 0612, the original commitment states:

The [RHR-B] line is protected by steel grating (1.5" deep 3/16" bars spaced 1 1/8" apart) supported on a 4' rectangle of 8" and 14" deep I beams. The RHR line is a 7' radius bend at this location making a direct blow impossible even if the grating were penetrated. This coupled with the existence of an alternate shutdown cooling system (RHR Loop A) which does not pass under the relief valve monorail provide ample assurance that shutdown cooling capability will not be compromised by a potential drop of a heavy load.

The last sentence has been revised to say:

This coupled with the existence of an alternate shutdown cooling system which does not pass under the relief valve monorail provide ample assurance that shutdown cooling capability will not be compromised by a potential drop of a heavy load.

Energy Northwest has developed an alternative RHR (shutdown cooling) system that uses safety related components. This system uses RHR-B and FPC components located outside of containment to transfer water from the SFP through the RHR-B heat exchanger and into both the SFP and RPV cavity. Outboard containment isolation valve RHR-V-42B is closed, isolating this cooling system from the LPCI-B line inside containment. Concurrent with this, the FPC system is operating to transfer water from the SFP through the FPC heat exchangers and into the RPV cavity. This configuration is proven to provide acceptable shutdown cooling performance.