APPENDIX B

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 50-267/89-20 Operating License: DPR-34

Docket: 50-267

Licensee: Public Service Company of Colorado (PSC)
P.O. Box 840
Denver, Colorado 80201-0840

Facility Name: Fort St. Vrain Nuclear Generating Station (FSV)

Inspection At: FSV, Platteville, Colorado

Inspection Conducted: September 1-30, 1989

Inspectors: R. E. Farrell, Senior Resident Inspector
P. W. Michaud, Resident Inspector

Approved: T. F. Westerman 10-20-89
T. F. Westerman, Chief, Project Section B Date
Division of Reactor Projects

Inspection Summary

Inspection Conducted September 1-30, 1989 (Report 50-267/89-20)

Areas Inspected: Routine, unannounced inspection of onsite followup of licensee event reports, licensee action on previously identified inspection findings, followup on violations, and deviations, operational safety verification, and onsite followup of events.

Results: Within the areas inspected, one violation was identified. Steam from the auxiliary boiler leaked into the service air system and the instrument air system. This occurred due to a lack of procedural adherence and the failure of certain components (paragraph 7.a).

A review of design calculations for the main steam ring headers showed no margin or worst case assumptions were factored into the temperature inputs. This may have resulted in an inadequate design and early failure of the main steam ring headers (paragraph 7.b).

DETAILS

1. Persons Contacted

D. Alps, Supervisor, Security
*M. Block, Systems Engineering Manager
L. Brey, Manager, Nuclear Licensing and Resources
R. Craun, Nuclear Site Engineering Manager
A. Crawford, Vice President, Nuclear Operations
*K. Einig, Nuclear Training Supervisor
*D. Evans, Operations Manager
*M. Ferris, QA Operations Manager
*C. Fuller, Manager, Nuclear Production
*D. Goss, Nuclear Regulatory Affairs Manager
J. Gramling, Supervisor, Nuclear Licensing Operations
M. Holmes, Nuclear Licensing Manager
*J. Reesy, Nuclear Support Engineering Manager
*D. Rodgers, Nuclear Computer Systems Manager
*L. Scott, QA Services Manager
*N. Snyder, Maintenance Manager
*P. Tomlinson, Manager, Quality Assurance
*J. Williams, Sr., Nuclear Licensing Engineer

The inspectors also contacted other licensee and contractor personnel during the inspection.

*Denotes those attending the exit interview conducted October 5, 1989.

2. Plant Status

The plant is permanently shut down. The licensee is evaluating defueling and decommissioning options.

3. Onsite Followup of Licensee Event Reports (LERs) (92700)

The inspectors reviewed selected LERs to determine whether corrective actions as stated in the LERs are appropriate to correct the cause of the event and to verify these corrective actions have been implemented.

LER 84-14 reported a failure of both diesel generator tie breakers to close during performance of a semiannual loss of offsite power test. The test configuration set up a situation where any failure of the "B" Diesel Generator would result in the failure of both generator sets to automatically load onto their respective 480 V buses. A sticking contact on the intake manifold differential pressure instrument was determined to be the cause of the failure of the "B" Diesel Generator. These contacts were replaced, and all relays and contacts on the "B" Diesel Generator were tested. The loss of offsite power test was subsequently performed satisfactorily. The inspector's review of these actions and others taken in response to this event found them sufficient to close this LER.

LERs 86-20 and 86-26 each reported different inadequacies in the FSAR firewater cooldown analysis. Extensive reanalysis was performed by the licensee which resulted in a power limitation of 82 percent of full power. The NRC reviewed and accepted the analysis as documented in a letter, dated July 2, 1987, which authorized operations of FSV at 82 percent of full power. These LERs are closed.

LER 87-31 reported a high hot reheat steam temperature scram due to operator inattention. The event was reviewed with the operators involved and all operations personnel, stressing the consequences of inattention to plant parameters, importance of thorough shift turnovers, and the effects of xenon transients. Alarms were added to the data logger to alert the operators if main steam or hot reheat steam temperature exceeds 1015°F. The inspector reviewed these actions and found them acceptable. No recurrence of this type of event has been observed, and this LER is closed.

4. Licensee Action on Previously Identified Inspection Findings (92701)

(Closed) Open Item 267/8714-001: Procedure Changes to Clarify NCR Use in Design Change - Licensee Procedure Q-15, Issue 6, "Control of Nonconforming Items," was ambiguous on "use as is" and "repair" dispositions. Issue 8 of this procedure is very clear as to when engineering change notices are required to implement "repair" and "use as is" dispositions. This item is closed.

5. Followup on Items of Noncompliance and Deviations (92702)

(Closed) Violation 267/8803-01: Failure to Follow Procedures - This violation included one example of performing activities not specifically allowed by a surveillance procedure and one example of opening the wrong valves while following a system operating procedure. Surveillance Procedure SR-RE-17-W, "Circulator Speed Modifier Weekly Check," used for calibrating the helium circulator speed indications, was modified to allow the technician to change speed sensor cables while performing the calibrations. Additionally, independent verification of proper cable termination was required in the revised procedure. The licensee also added color coding of the 48 speed cables. The colors identify the associated circulator cables and differentiates between water turbine and steam turbine cables.

The System Operating Procedure (SOP), SOP-46, "Reactor Plant Cooling Water System," was revised, adding a caution to the operator that manipulating the wrong valve would cause an unplanned release. The plant signage program greatly improved the marking of the valves in the cooling water system, further reducing the likelihood of error.

(Closed) Violation 267/8807-03: Failure to Follow Procedure - Workmen failed to heed a guideline in the instructions for straightening a bent control rod. The guideline required them to wear gloves when touching the new control rod. The licensee retrained the workmen and also cautioned them that failure to follow procedures would result in disciplinary action.

(Closed) Violation 267/8825-01: Inoperable Fire Doors - The inspector found two fire doors open with no fire watch established. The licensee has reinstructed contract workers about fire doors and added fire doors to the auxiliary tender daily round sheets.

(Closed) Deviation 267/8812-02: Failure to Maintain Helium Purge Flow to Control Rod Drives - The licensee recalibrated the purge flow indicators, increased the flow setting, and added a check of helium purge flow to the operator's daily checks.

6. Operational Safety Verification (71707)

a. General

The inspectors made daily tours of the control room during normal working hours and at least once per week during backshift hours. Control room staffing was verified to be at the proper level for the plant conditions at all times. Control room operators were observed to be attentive and aware of plant status and reasons why annunciators were lit. The inspectors observed the operators using and adhering to approved procedures in the performance of their duties. A sampling of these procedures by the inspectors verified current revisions and legible copies. During control room tours, the inspectors verified that the required number of nuclear instrumentation and plant protective system channels were operable. The operability of emergency AC and DC electrical power, meteorological, and fire protection systems was also verified by the inspectors. The reactor operators and shift supervisor logs were reviewed daily along with the TS compliance log, clearance log, operations deviation report (ODR) log, temporary configuration report (TCR) log, and operations order book. Shift turnovers were observed at least once per week by the inspectors. Information flow was consistently good, with the shift supervisors soliciting comments or concerns from the reactor operators, equipment operators, auxiliary tenders, and health physics technicians. The licensee's station manager, operations manager, and superintendent of operations were observed to make routine tours of the control room.

The inspectors made tours of all accessible areas of the plant to assess the overall conditions and verify the adequacy of plant equipment, radiological controls, and security. During these tours, particular attention was paid to the licensee's fire protection program, including fire extinguishers, firefighting equipment, fire barriers, control of flammable materials, and other fire hazards.

Plant equipment is being progressively deenergized and taken out of service. The inspectors verified bulk core temperature and method of decay heat removal on a routine basis. Availability of two trains of shutdown cooling was verified. The prestressed concrete reactor vessel steel liner was verified to be within LCO 4.2.15 temperature limits. Minimum cooling water temperatures were being maintained with the auxiliary boiler.

b. Radiological Controls

The inspectors observed health physics technicians performing surveys and checking air samplers and area radiation monitors. Contamination levels and exposure rates were posted at entrances to radiologically controlled areas and in other appropriate areas and were verified to be up to date by the inspectors. Health physics technicians were present to provide assistance when workers were required to enter radiologically controlled areas.

The inspectors observed workers following the instructions on radiation work permits concerning protective clothing and dosimetry. Also observed were workers using proper procedures for contamination control, including proper removal of protective clothing and whole body frisking upon exiting a radiologically controlled area.

c. Security

The inspectors randomly verified that the number of armed security officers required by the security plan were present. A lead security officer was on duty to direct security activities on each shift. The inspectors verified that search equipment, including an x-ray machine. explosive detector, and metal detector were operational or a 100 percent hands-on search was conducted.

The protected area barrier was surveyed by the inspectors to ensure it was not compromised by erosion or other objects. The inspectors observed that vital area barriers were well maintained and not compromised. The inspectors also observed that persons granted access to the site were badged and visitors were properly escorted.

7. Onsite Followup of Events (93702)

a. Instrument Air Malfunction

On September 6, 1989, the licensee discovered that steam from the outside auxiliary boiler had leaked into the service air system and then into the "A" Instrument Air System. This resulted from an incorrect valve lineup and the failure of two separate components.

Both steam and service air are provided to atomize fuel to the auxiliary boilers. Air is utilized for boiler startup onto a cold or depressurized steam system. When sufficient steam pressure exists, steam is utilized and service air is isolated. This is accomplished manually by opening the atomizing steam isolation valve and shutting the service air isolation valve. A check valve in the service air supply prevents steam from entering the service air system during the short time both isolation valves are open during this changeover.

Section 4.2 of SOP-84-02, "Outside Auxiliary Boiler," provides instructions for a manual startup of the boiler. Step 4.2.1.40 provides instructions to change to atomizing steam when steam pressure is greater than 100 psig by:

"d) Slowly open V-84885, Atomizing Steam to Atomizing Header.
e) Slowly close V-84881, Service Air to Atomizing Header."

This is the only time SOP-84-02 allows both the service air and atomizing steam isolation valves to be open simultaneously. These valves, V-84881 and V-84885, were found open after steam was discovered in the service air system. Check Valve V-84882, which is located downstream of Service Air Isolation Valve V-84881, also apparently failed, which then allowed steam to flow into the service air system. The licensee was informed that the failure to follow SOP-84-02 by virtue of having Valves V-84881 and V-84885 open simultaneously is a violation of NRC requirements (267/8920-01).

The steam, flowing from the outside auxiliary boiler atomizing steam line through apparently leaking Check Valve V-84882 and into the service air system, caused pressure in the service air system to reach 120 psig (normal operating pressure is 100 psig). Safety valves, set at 125 psig, did not lift. This elevated pressure apparently caused flow through FCV-8217, Service Air Backup to the "A" Instrument Air Header Isolation Valve. This valve provides the last backup action on a loss of instrument air pressure. With the higher pressure steam displacing the air from the service air lines, first condensed water and then steam flowed into the "A" Instrument Air Header through apparently leaking Isolation Valve FCV-8217.

The result of this steam and moisture in the "A" Instrument Air System were observed by the control room operators as malfunctioning instruments on the helium circulator auxiliaries. Manual control was taken on a number of instruments, and the "B" Helium Circulator was shut down in response to these instrument malfunctions.

The source of steam into the service air system was secured at approximately 2 a.m. on September 6, 1989. It is not clear how long the valve lineup had existed to allow this, but it is estimated between 3-6 hours.

The licensee subsequently formulated a plan to blow down each instrument supplied from the "A" Instrument Air Header, from highest to lowest elevation. This was performed over a 2-day period, with a number of instruments on Levels 1 and 2 of the reactor building found having water in the air line. Each of these instruments were blown down, calibrated, and returned to service. No problems with moisture in the "A" Instrument Air Header have been observed since.

b. Main Steam Ring Headers

Extensive cracking, apparently caused by tertiary creep, was found in the main steam ring headers as documented in NRC Inspection Report 50-267/89-16. The inspectors followed up this event with a review of the design calculations for the main steam ring headers.

Calculation GADR-9, Section 6.12, "Stress Report For Fort St. Vrain Steam Generator - External Steam Piping," was issued October 1, 1970, and includes the main steam ring header stress analysis. The thermal loading conditions developed for these analyses included full load steady state, steam leak, and zero load as well as others. The calculational methods were appropriate and were performed in accordance with ASME Boiler & Pressure Vessel Code, Section III, 1965 Edition as amended by all addenda through Winter 1966. The design temperature used in the analyses was 1005°F. Temperature profiles for the design conditions (i.e., steam leak accident) were developed based on this initial temperature. A main steam temperature of 1005°F corresponds to the nominal full power operating temperature.

Apparently, no margin was factored into the main steam temperature inputs to the design calculations. Factors such as the accuracy and location of the measuring instruments, possible flow distribution variations, and allowable operating temperature differences between individual steam generator modules compared to average main steam temperature were not evaluated in the design inputs. Thus, a worse case analysis which envelopes the actual operating conditions was not performed. The result is that the main steam ringheaders (and possibly other components which were not reviewed) were apparently operated at higher temperatures than the design temperatures. At the calculated stress levels, the expected rupture life is approximately 40 times less at 1100°F than 1000°F for Incoloy Alloy 800. A lack of conservation in the design calculations under these circumstances provides greatly distorted results. The inspector concluded that the failure to conservatively determine a worst case design temperature for the main steam ringheaders probably led to the extensive cracking which was found.

The inspector also reviewed Appendix A.13 of the FSV FSAR which describes tests and evaluations performed to demonstrate the adequacy of the steam generator design. Extensive analysis and testing was performed on the steam generator tubes. No specific mention is made of the ringheaders, though both the tubes and ringheaders are made of Incoloy Alloy 800. The conclusions reached concerning creep-fatigue of the steam generator tubes were that, if the plant operated frequently at various intermediate load levels, then crack initiation due to creep-fatigue could occur after approximately 10 years of service. Crack growth analysis showed that a tube leak might then occur after about 25 years of service. The plant began power operation in 1976, and has operated at intermediate power levels (that is, non-base loaded) its entire life.

8. Exit Meeting (30703)

An exit meeting was conducted on October 5, 1989, and attended by those identified in paragraph 1. At this meeting, the inspectors reviewed the scope and findings of the inspection. The licensee did not identify any proprietary information to the inspector.