U.S. NUCLEAR REGULATORY COMMISSION

REGION V

Report No: 50-397/91-23

Docket No: 50-397

Licensee: Washington Public Power Supply System
P. O. Box 968
Richland, WA 99352

Facility Name: Washington Nuclear Project No. 2 (WNP-2)

Inspection at: WNP-2 Site, near Richland, Washington

Inspection Conducted: June 24 - August 6, 1991

Inspectors: R. C. Sorensen, Senior Resident Inspector
D. L. Proulx, Resident Inspector
P. M. Qualls, Reactor Inspector (Paragraph 13)
D. F. Kirsch, Chief, Reactor Safety Branch (Paragraph 14)

Approved by: P. H. Johnson (signature) 8/18/91

P. H. Johnson, Chief — Date Signed
Reactor Projects Section 3

Summary:

Inspection on June 24 - August 6, 1991 (Inspection Report No. 50-397/91-23)

Areas Inspected: Routine inspection by the resident inspectors of control room operations, licensee action on previous inspection findings, requalification training, operational safety verification, surveillance program, maintenance program, licensee event reports, special inspection topics, procedure adherence, design changes and modifications, engineering program improvements, and review of periodic reports. During this inspection, Inspection Procedures 37700, 41701, 61726, 62703, 71707, 90712, 90713, 92700, 92702 and 93702 were utilized.

Safety Issues Management System (SIMS) Items: None.

Results:

General Conclusions and Specific Findings

Apparently insufficient control of electrical configuration led to a complete loss of 500KV and 230 KV power into the WNP-2 facility on July 8, 1991 (Paragraph 4).

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Significant Safety Matters: None.

Summary of Violations and Deviations: No violations or deviations were identified.

Open Items Summary: One open item and three LERs were closed; one new item was opened.

DETAILS

1. Persons Contacted

J. Baker, Plant Manager
*L. Harrold, Assistant Plant Manager
C. Edwards, Quality Control Manager
*R. Graybeal, Health Physics and Chemistry Manager
J. Harmon, Maintenance Manager
*A. Hosler, Licensing Manager
*S. Davison, Quality Assurance Manager
R. Koenigs, Generation Engineering Manager
*S. McKay, Operations Manager
*J. Peters, Administrative Manager
G. Gelhaus, Assistant Technical Manager
*W. Shaeffer, Assistant Operations Manager
R. Webring, Plant Technical Manager
*D. Feldman, Assistant Maintenance Manager

The inspectors also interviewed various control room operators; shift supervisors and shift managers; and maintenance, engineering, quality assurance, and management personnel.

*Attended the Exit Meeting on August 6, 1991.

2. Plant Status

At the start of the inspection period, the plant was in cold shutdown due to ongoing revision of emergency operating procedures (EOPs) and training of licensed operators on the revisions. The plant remained in cold shutdown for the duration of the inspection period.

3. Previously Identified NRC Inspection Items (92701, 92702)

The inspectors reviewed records, interviewed personnel, and inspected plant conditions relative to licensee actions on previously identified inspection findings, as follows:

a. (Closed) Violation (397/90-31-03): Failure to Meet Surveillance Requirements for Flow Control Valves in Jet Pump Operability Surveillance

Technical Specifications require the jet pump operability surveillance to be conducted with both flow control valves in the same position. However, the licensee's implementing procedure, PPM 7.4.4.1.2, Jet Pump Operability, required flow rates in each loop to be matched. Since the flow characteristics of each recirculation loop were different, the flow control valves were in different positions.

The licensee revised PPM 7.4.4.1.2 to match flow control valve positions as required by Technical Specifications. A Technical Specification Amendment Request was also issued to allow this surveillance testing with recirculation loop flows matched vice flow control valve position.

This item is closed.

4. Loss of All 500 Kilovolt (KV) Power into WNP-2 (93702)

On July 8 at about 1:13 a.m., WNP-2 lost all 500 KV electrical power into the plant. Electrical power was being supplied to the plant at the time by a 500 KV backfeed through the main transformers. 500 KV electrical power is supplied to WNP-2 from Bonneville Power Administration's (BPA's) Ashe substation, just outside the plant switchyard. The Ashe substation is a ring bus configuration, with four offsite sources of 500 KV electrical power supplying it. A fault developed on one of the four sources, the Marion line, about twelve miles from the plant. Normally, this would have caused two circuit breakers in the ring bus to trip, clearing the fault from the rest of the ring bus and leaving intact the other three sources of 500 KV power. However, a relay selector switch at the Ashe substation had been left in the wrong position (following maintenance in June), and was selected to allow tripping of only one of the two breakers which connect the Marion line to the ring bus. Since the ground fault on the Marion line was therefore not effectively isolated, the other three sources of 500 KV power continued to feed the ground fault. The circuit breakers associated with the other three sources tripped, leaving WNP-2 with no sources of 500 KV electrical power.

Normally, a fast transfer would have occurred at this point, transferring house loads at WNP-2 from the normal transformers (supplied by backfeed from 500 KV offsite power) to the startup transformer (supplied from 230 KV offsite power). For this to occur, an interlock requires that both 500 KV circuit breakers which connect WNP-2 to the Ashe substation must be tripped. However, only one of these had tripped, by design, because the breaker logic recognized that WNP-2 was not operating and thus was not feeding the fault. Since the fast transfer to TR-S did not occur, house loads were momentarily deenergized while the vital busses, SM-7 and SM-8, transferred to their power supply from the backup transformer, TR-B. Both Emergency Diesel Generators (EDGs) started (a reportable ESF actuation) due to a momentary undervoltage condition on SM-7 and SM-8, but were not called upon to supply the vital buses since TR-B had already done so, as designed. Also, the operating shutdown cooling pump tripped on undervoltage, and several Nuclear Steam Supply Shutoff System (NSSSS) isolations occurred. Shutdown cooling was restored a short time later, and the EDGs were secured.

The inspector and Region V management expressed concern to plant management regarding the ease with which the 500 KV power supplies into the Ashe substation were lost. Only one selector switch was out of position, coupled with a routine ground fault on one of four transmission lines. Had a fault occurred on TR-B, or had it been out of service as allowed by Technical Specifications in Mode 4, a loss of all offsite power would have occurred. This is of particular concern since the licensee relies on BPA to control operations at the Ashe substation. The plant manager responded that a nonconformance report (NCR) had been

issued concerning this event, automatically invoking a root cause analysis, and that corrective actions were being elicited from BPA. The inspector reviewed the preliminary root cause analysis near the end of the inspection period and noted that the corrective actions agreed to by BPA were substantive and thorough and seemed to indicate that they had taken the event seriously. The Plant Operations Committee (POC) issued an action item to track these corrective actions and ensure that they are completed.

No violations or deviations were identified.

5. Requalification Training Observation (41701)

The inspectors witnessed portions of requalification training for licensed operators, both in the classroom and on the simulator. The inspectors observed that the instructors appeared to be knowledgeable, that the students were generally alert, and that there was good interaction between the class and the instructors. Simulator scenarios ranged in difficulty from no required entry into EOPs to multiple events. Communication techniques used during the scenarios had improved since last observed.

In addition, the inspectors observed portions of the validation of the improved EOPs. Meaningful comments were provided by the licensed operators, many of which were subsequently incorporated, and new flow charts developed.

No violations or deviations were identified.

6. Operational Safety Verification (71707)

a. Plant Tours

The following plant areas were toured by the inspectors during the course of the inspection:

- Reactor Building
- Control Room
- Diesel Generator Building
- Radwaste Building
- Service Water Buildings
- Technical Support Center
- Turbine Generator Building
- Yard Area and Perimeter

b. The following items were observed during the tours:

(1) Operating Logs and Records. Records were reviewed against Technical Specification and administrative control procedure requirements.

(2) Monitoring Instrumentation. Process instruments were observed for correlation between channels and for conformance with Technical Specification requirements.

(3) Shift Manning. Control room and shift manning were observed for conformance with 10 CFR 50.54.(k), Technical Specifications, and administrative procedures. The attentiveness of the operators was observed in the execution of their duties and the control room was observed to be free of distractions such as non-work related radios and reading materials.

(4) Equipment Lineups. Valves and electrical breakers were verified to be in the position or condition required by Technical Specifications and administrative procedures for the applicable plant mode. This verification included routine control board indication reviews and conduct of partial system lineups. Technical Specification limiting conditions for operation were verified by direct observation.

(5) Equipment Tagging. Selected equipment, for which tagging requests had been initiated, was observed to verify that tags were in place and that the equipment was in the condition specified.

(6) General Plant Equipment Conditions. Plant equipment was observed for indications of system leakage, improper lubrication, or other conditions that could prevent the system from fulfilling its functional requirements. Annunciators were observed to ascertain their status and operability.

(7) Fire Protection. Firefighting equipment and controls were observed for conformance with administrative procedures.

(8) Plant Chemistry. Chemical analyses and trend results were reviewed for conformance with Technical Specifications and administrative control procedures.

(9) Radiation Protection Controls. The inspectors periodically observed radiological protection practices to determine whether the licensee's program was being implemented in conformance with facility policies and procedures and in compliance with regulatory requirements. The inspectors also observed compliance with Radiation Work Permits, proper wearing of protective equipment and personnel monitoring devices, and personnel frisking practices. Radiation monitoring equipment was frequently monitored to verify operability and adherence to calibration frequency.

(10) Plant Housekeeping. Plant conditions and material/equipment storage were observed to determine the general state of cleanliness and housekeeping. Housekeeping in the radiologically controlled area was evaluated with respect to controlling the spread of surface and airborne contamination.

The licensee began painting the control room front panels an alternate color during the inspection period. The inspector noted that the painters had the responsibility to remove and replace the label plates and mimics on the panels. The

inspector was concerned that there was no Quality Assurance or Quality Control involvement to ensure that these label plates and mimics were replaced in the proper location. This was brought to the attention of the Plant Manager, who responded that a licensed operator would perform a formal 100% verification of the main control room panels, subsequent to painting of the panels. At the end of the inspection period, the inspector saw objective evidence that this direction had been given to the operations staff and was being carried out.

(11) Security. The inspectors periodically observed security practices to ascertain that the licensee's implementation of the security plan was in accordance with site procedures, that search equipment at the access control points was operational, that vital area portals were kept locked and alarmed, and that personnel allowed access to the protected area were badged and monitored and the monitoring equipment was functional.

c. Engineered Safety Feature Walkdown

Selected engineered safety features (and systems important to safety) were walked down by the inspectors to confirm that the systems were aligned in accordance with plant procedures. During the walkdown of the systems, items such as hangers, supports, electrical power supplies, cabinets, and cables were inspected to determine that they were operable and in a condition to perform their required functions. Proper lubrication and cooling of major components were observed for adequacy. The inspectors also verified that certain system valves were in the required position, based upon both local and remote position indication, as applicable.

Accessible portions of the following systems were walked down on the indicated dates.

System	Dates
Diesel Generator Systems, Divisions 1, 2, and 3.	July 25, 30, 31
Hydrogen Recombiners	July 31
Low Pressure Coolant Injection (LPCI), Trains "A", "B", and "C"	August 2
Low Pressure Core Spray (LPCS)	August 1
High Pressure Core Spray (HPCS)	July 31
Reactor Core Isolation Cooling (RCIC)	August 1
Residual Heat Removal (RHR), Trains "A" and "B"	August 2

Scram Discharge Volume System	July 31
Standby Liquid Control (SLC) System	July 31
Standby Service Water System	August 2
125 VDC Electrical Distribution, Divisions 1 and 2	August 1
250V DC Electrical Distribution	August 1

No violations or deviations were identified.

7. Surveillance Testing (61726)

   a. Surveillance tests required to be performed by the Technical Specifications (TS) were reviewed on a sampling basis to verify that: (1) a technically adequate procedure existed for performance of the surveillance tests; (2) the surveillance tests had been performed at the frequency specified in the TS and in accordance with the TS surveillance requirements; and (3) test results satisfied acceptance criteria or were properly dispositioned.

   b. Portions of the following surveillance test was observed by the inspectors on the date shown:

Procedure	Description	Dates Performed
7.4.6.6.1.3.D	Hydrogen Recombiner 1B Flow Indicator Channel Check	July 1

No violations or deviations were identified.

8. Plant Maintenance (62703)

During the inspection period, the inspectors observed and reviewed documentation associated with maintenance and problem investigation activities to verify compliance with regulatory requirements and with administrative and maintenance procedures, required QA/QC involvement, proper use of clearance tags, proper equipment alignment and use of jumpers, personnel qualifications, and proper retesting. The inspector verified that reportability for these activities was correct.

The inspector witnessed portions of the following maintenance activities:

Description	Dates Performed
Correct Stroke on Containment Atmosphere Control (CAC)-FCV-6B per AR 4565	July 8, 9, 10
Correct Stroke on CAC-TCV-4A per AR 4567	July 8, 9, 10

Correct Stroke on CAC-TCV-4B per AR 4568 — July 8, 9, 10

While routinely touring the reactor building, the inspector identified a loose bolt on the motor cover for valve RRC-V-16B. RRC-V-16B is a safety-related containment isolation valve that is environmentally qualified (EQ). The inspector researched representative records to determine what work had been done on the valve recently, as this might have been the cause for the loose bolt, which may have jeopardized the valve's EQ. It was determined that four different Maintenance Work Requests (MWRs) had been issued for work on this valve during the recent refueling outage. One of the MWRs, AR-3142, stated in its instructions for valve restoration, "all cabinets, cubicles, junction boxes, etc. are closed and fasteners tightened." At the time of this discovery it was not certain which of these four MWRs was completed last. However, it appeared from the signature dates that AR-3142 was the last MWR in which work was performed. Thus, the above instruction was not properly followed in that a fastener was found loose on the motor cover. This is an apparent violation of Technical Specifications, Section 6.8.1, which references the required maintenance procedures of Regulatory Guide 1.33.

According to applicable design documents for the valve, this cover bolt is not required to be torqued and need not be in place for the valve to maintain its environmental qualification. Therefore, due to the limited safety significance, and because the criteria specified in Section V.G. of the NRC Enforcement Policy (10 CFR 2, Appendix C) were satisfied, this violation is not being cited (Non-cited violation (NCV) 397/91-23-01). The inspector emphasized to licensee management at the exit meeting that the NRC expects approved, written instructions to be followed and all fasteners on safety-related valves to be tightened.

9. Design Changes and Modifications (37700)

The inspector reviewed a representative sample of design change packages to ascertain the licensee's compliance with the requirements 10 CFR 50.59. In addition, the inspector reviewed the licensee's program for implementation of 10 CFR 50.59. The inspector also evaluated the degree of involvement of licensee QA organizations in maintaining the requisite quality of the design modification process.

The inspector reviewed the following Plant Modification Records (PMRs) that were implemented during the R6 refueling outage:

PMR Number	Description
87-0106-0	Modification of SGT-TS-1A1 Reset Band
88-0450-0	Service Water Corrosion Protection
89-0103-0	Install Manual Valve/Flanges on Service Water Crosstie Pipe
90-0081-0	Appendix R Design Modification

90-0291-0	HPCS-V-36/HPCS-V-74 Stiffening
90-0335-0	RCIC-V-8 Stroke Length Motor Changes
91-0040-0	DG-GEN-DG1 External Lube Oil Reservoir
91-0157-0	Relocate SEIS-TPA-2 and SEIS-RSR-1/1
91-0159-0	DG1 Generator Bearing Modification
91-0189-0	Short Couple HPCS-V-62 and 70

In addition, the inspector reviewed licensee procedure PPM 1.3.43, "10 CFR 50.59 Review and Safety Evaluation Process," to ascertain whether the licensee's design change program was in compliance with 10 CFR 50.59.

The inspector concluded that the majority of these PMRs appeared to reflect good engineering practices along with well documented calculations and rationale for making the modifications. However, the following inspection findings related to the licensee's 50.59 screening process and to PMR 91-0570-0 in particular (relocation of SEIS-TPA-2 and SEIS-RSR-1/1):

a. This PMR implemented a design change to move two seismic monitors to locations in which HPCS system vibration would not mask a seismic event. SEIS-TPA-2 was located on the HPCS injection line inside primary containment, and was relocated to the vertical run of pipe at the 507 foot level in the reactor building, outside primary containment. This appeared to represent a change to the WNP-2 FSAR, section 3.7.4.2, which states, "Three triaxial peak-accelerographs are provided .... Another unit is located on the HPCS injection line piping inside containment ...." While the Safety Review performed for this PMR concluded that a Safety Evaluation was not required, the Design Safety Analysis which was conducted appeared to acceptably constitute a "safety evaluation" as required by 10 CFR 50.59 for determining that an unreviewed safety question did not exist, even though the criteria of 50.59(a)(2) were not specifically addressed.

b. The licensee's governing procedure, which implemented the industry guidance provided by NSAC-125, called for the performance of a Safety Review to determine whether the facility change being considered represented a change to the FSAR. If so, then the procedure directed that a Safety Evaluation be conducted as required by 10 CFR 50.59(a)(2) to discern whether the proposed change involved an unreviewed safety question. The procedure provided for the Safety Review to be accomplished by answering five yes/no questions. One of these asked whether the proposed change represented a change in the intent of the FSAR description; however, the questions did not address whether the proposed change affected the specific facility description in the FSAR, consistent with 50.59(a)(1). Since it appeared that the licensee also uses this Safety Review screening process to determine which facility changes must be reported pursuant to 10 CFR 50.59(b)(2), it was not clear that this design change would have been reported to the NRC as required. Consequently, the inspector will follow up with the licensee to determine how they ensure that all changes made to the facility as described in the FSAR have been and are included in the annual report (Followup Item 397/91-23-02).

c. The licensee issued a deviation to surveillance procedure 7.4.2.7.2.1.3, to reflect changes made to the seismic instrumentation by PMR-0570-0. Although this deviation changed the location coordinates for SEIS-TPA-2, the revised paragraph still contained the statement, "This instrument is inside containment, located on top of a brace." The inspector apprised the licensee of this apparent discrepancy, and the licensee stated that although this statement is technically true (SEIS-TPA-2 is still located inside secondary containment) an operator would probably construe the statement to imply that this seismic instrument was in the drywell. The licensee stated that this procedure would be revised to clearly indicate that SEIS-TPA-2 is outside of primary containment.

No violations or deviations were identified.

10. Inoperable Seismic Monitoring Instrumentation

On May 17, 1991 a Problem Evaluation Request (PER) was submitted to the Management Review Committee (MRC) describing a violation of the Technical Specifications. Technical Specification 3.3.7.2 requires seismic monitoring instruments to be operable at all times. When one or more seismic instruments is inoperable for a period greater than 30 days, a special report is required to be submitted to the NRC documenting the inoperability and the steps to be taken to rectify it. As a result of reactor vessel disassembly for refueling activities, one seismic monitoring instrument which is attached to the reactor vessel space frame has been rendered inoperable for a period of greater than 30 days every refueling outage since initial plant startup. The licensee discovered during the current outage that special reports required by the Technical Specifications to document these previous periods of inoperability had not been submitted.

The inspector noted that the licensee had discovered this Technical Specification violation on their own and had taken steps to correct it. However, it appeared that submittal of an LER was appropriate to document this condition. At the exit meeting, licensee management agreed to submit an LER.

11. Licensee Event Report (LER) Followup (90712, 92700)

a. The following LERs associated with operating events were reviewed by the inspector. Based on the information provided in the report it was concluded that reporting requirements had been met, root causes had been identified, and corrective actions were appropriate. The below LERs are considered closed.

LER NUMBER	DESCRIPTION
90-16	Technical Specification Violation Due to RCIC Steam Supply Line Isolation Valve Stroke Time Too Long
91-15	High Pressure Core Spray Suction Valve Switch-over on High Suppression Pool Level, Due to Personnel Error

b. (Closed) LER 91-05 - Oxygen Concentration in Suppression Chamber Not Verified per Technical Specification Requirements

The licensee had discovered that there was no methodology in place to periodically verify that wetwell oxygen concentration is within the limits required by Technical Specifications. This shortcoming had been determined as a result of a previous event wherein wetwell oxygen concentration was found to be 3.9%, greater than its Technical Specification limit of 3.5%. The high oxygen concentration was apparently the result of a surveillance test involving the initiation of wetwell spray. This caused a slight depressurization of the wetwell, opening the reactor building to wetwell vacuum breakers, and drawing air into the wetwell. Because this surveillance is conducted quarterly, and because there was no mechanism in place to verify wetwell oxygen concentration (either periodically or following such surveillance activities), it appeared to the inspector that the plant could have operated for periods of time with wetwell oxygen concentration higher than the limit. Consequently the inspector requested that the licensee evaluate the potential post-LOCA consequences, from a primary containment safety standpoint, of operating with wetwell oxygen concentration above the limit.

The WNP-2 FSAR indicated that the accident analysis for a LOCA assumed an initial oxygen concentration in the wetwell at the Technical Specification limit of 3.5%. Cognizant engineers in Generation Engineering indicated that this initial value for oxygen concentration was selected to show that a hydrogen/oxygen mixture in containment could be kept from reaching a flammable mixture by inerting containment, as long as the hydrogen recombiners are started within about six hours of the event. However, the inspector reviewed a family of curves derived by Burns & Roe showing that, as long as the hydrogen recombiners are started within about six hours, a flammable mixture would be precluded from occurring for <u>any</u> initial oxygen concentration in the wetwell up to and including pure air. Further, the inspector reviewed the emergency operating procedure (EOP) for hydrogen control in containment and confirmed that operators are directed to check for hydrogen concentration very early in an event and to start the hydrogen recombiners at a hydrogen concentration of 0.5%; i.e., well before a flammable mixture is approached. The inspector also confirmed that the operators have been trained on this procedure.

The inspector concluded that containment integrity would be maintained following a LOCA, regardless of the initial oxygen concentration in the wetwell. This LER is therefore closed.

No violations or deviations were identified.

12. Review of Periodic and Special Reports (90713)

Periodic and special reports submitted by the licensee pursuant to Technical Specifications 6.9.1 and 6.9.2 were reviewed by the inspectors.

This review included the following considerations: the report contained the information required to be reported by NRC requirements and the reported information appeared valid. Within the scope of the above, the following report was reviewed by the inspector.

o Monthly Operating Report for May, 1991.

No violations or deviations were identified.

13. Torque Switch Wiring Concerns (92700)

On July 25, 1991 the licensee identified certain fire protection design problems which could affect the ability of the licensee to safely place the plant in cold shutdown in the event of a control room fire. The licensee reported this to the NRC as required by 10 CFR 50.72(6)(2)(i). The licensee determined that the torque and limit switch power cutout relays for some of the "B" train Residual Heat Removal (RHR) valves are located physically inside of the control room. The 10 CFR 50.72 report listed 15 affected valves. Among them are RHR-V-4B, the "B" RHR pump suction valve, and RHR-V-42B, the "B" RHR injection valve.

The licensee determined that, given a fire in the control room, during the 10 minute time interval for evacuating the control room and reestablishing plant control at the remote shutdown panel, a fire could cause a hot short in the valve control wiring associated with the torque or limit switch power cutout relays. This could cause the valves to spuriously actuate without torque switch and limit switch protection. This actuation could cause valve damage before local control of the valves is established by manipulation of disconnect switches at the remote shutdown panel. Valve damage could result in inability to operate the valves when local control is established, and thus an inability to safely shutdown the plant. Licensee management committed to modify the wiring to prevent the possibility of this occurrence, or to discuss any other proposed approach with Region V management, prior to plant restart from the 1991 refueling outage. At the conclusion of the inspection period, the licensee had not completed the root cause analysis, the design change package, or the Licensee Event Report (LER). The item will be tracked and further inspected after the licensee issues the related LER.

14. Initiatives to Improve Engineering and Technical Work Quality

The inspector discussed the status of the Engineering Improvement Plan (EIP) with licensee management. The plan had been substantially completed and remaining items were being tracked to completion.

The licensee had initiated other improvements to the engineering process. The Design Review Board had been restructured and provided with a written charter. The Board was composed of senior members of various disciplines and will meet approximately monthly. The Board's activity will be to select completed design products, review and report on the product adequacy, and periodically evaluate engineering problems, such as Field Change Requests, Plant Problem Reports, and Quality Finding Reports. This is a new initiative, and the Board was in the beginning phase; as such, the Board had not yet performed any assessments of Generation Engineering effectiveness.

Generation Engineering's initiative to have modification designs reviewed by a Modification Review Committee had improved during the past year. The Committee activity had resulted in improved participation of other organizations (such as Operations and Health Physics) in the modification process, with the result that fewer designs were being referred back to Engineering for rework. The average number of Field Change Requests (FCRs) for design had remained consistent from April 1988 to March 1991. However, the licensee had not developed a high degree of sophistication in trending FCRs; for example, FCRs were not being trended by cause code, such as design error, configuration error, etc. Accordingly, engineering management was not fully aware of the reasons most contributing to generation of FCRs.

The Licensing and Assurance organization was examined regarding their contribution to the improvement of engineering work quality. The licensee had conducted a Safety System Functional Inspection (SSFI) on the Low Pressure Core Spray System, AC Electrical Distribution System, and the Standby Service Water System. These SSFI reports were reviewed and found to be credible and substantial examinations of the systems. A number of findings identified during the SSFIs were being tracked to resolution. The licensee had also examined the status of the finding tracking system, and had no major findings.

The Nuclear Safety Assurance Group (NSAG) had performed a technical assessment of the Design Requirement Document program. In response to a number of findings, the Engineering Manager had initiated a Quality Action Team to provide management with recommendations for resolution of the findings and improvement of the program quality.

The Nuclear Safety Assurance Group also conducts an annual independent design review of selected modifications performed during refueling outages. During the 1991 outage, one electrical and one mechanical modification were reviewed. The scope and content of the review were substantial. The inspector reviewed the results of the 1990 outage modification inspection and found the effort to be of high quality and producing substantial findings. The findings were tracked to resolution.

The Engineering organizations had a number of initiatives in progress and in various stages of completion. Among the more interesting of these initiatives were: (1) 50.59 safety evaluation improvement program; (2) design change process improvement program; (3) configuration management program; (4) quarterly system walkdown program; (5) engineering work backlog reduction program; and (6) reliability centered maintenance program.

The Engineering Manager had formed a number of Quality Action Teams to focus on identifying improvements in the quality and efficiency of key elements of the work process: (1) design change process; (2) design requirements documentation; (3) configuration management; (4) procurement process; and (5) chemical compatibility and procurement.

The inspector considered the licensee's initiatives and activities to demonstrate a proactive attitude directed toward substantial self-assessment and improvement. The licensee was encouraged to continue these initiatives. No violations or deviations were identified.

15. <u>Exit Meeting</u>

The inspectors met with licensee management representatives periodically during the report period to discuss inspection status, and an exit meeting was conducted with the indicated personnel (refer to paragraph 1) on August 6, 1991. The scope of the inspection and the inspectors' findings, as noted in this report, were discussed with and acknowledged by the licensee representatives.

The licensee did not identify as proprietary any of the information reviewed by or discussed with the inspector during the inspection.