U.S. NUCLEAR REGULATORY COMMISSION

Region I

License No.: DPR-59

Report No.: 96-08

Docket No.: 50-333

Licensee: New York Power Authority
Post Office Box 41
Scriba, New York 13093

Facility Name: James A. FitzPatrick Nuclear Power Plant

Dates: November 17, 1996 through January 4, 1997

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EXECUTIVE SUMMARY

James A. FitzPatrick Nuclear Power Plant
NRC Inspection Report 50-333/96-08

Operations

- The reactor startup following the refueling outage was performed in a safe and prudent manner. The post refueling outage startup training was well presented and comprehensive.

- Operators demonstrated conservative decision making by directing a manual scram to be inserted when an electro-hydraulic control (EHC) system leak was identified on a turbine bypass valve. In addition, operators demonstrated excellent control of the plant transient.

- Auxiliary operators performed watchstanding duties in an acceptable manner. Good radiological control practices were observed and operators demonstrated attentiveness by identifying and documenting minor equipment deficiencies. Minor logkeeping discrepancies as well as some equipment storage discrepancies were noted and were addressed by operations management.

- An unresolved item **(URI 50-333/95021-01)** involving extended operation of all four residual heat removal system pumps in the suppression pool cooling mode was closed. Failure to perform a safety evaluation prior to performing this evolution resulted in a violation of 10 CFR 50.59. **(VIO 50-333/96008-01)**

Maintenance

- The approach to maintenance activities on the bypass valves was not rigorous and contributed to bypass valve hydraulic actuator seal failures and in one case resulted in a manual reactor scram to be required. The licensee's equipment failure evaluation was thorough and corrective actions well developed to address maintenance practices for the bypass valves.

- Personnel error by technicians during surveillance testing on reactor water level instrumentation resulted in automatic reactor protection and primary containment isolation actuation. Since the plant was shutdown at the time of the event, there was no effect on plant operation. The inspector noted that this event contained similarities with the September 16, 1996, scram described in NRC inspection report 50-333/96-06 in that technicians proceeded with work without fully recognizing the potential to cause a plant transient. The condition [a valve packing leak] was not reported to supervision; thus the decision to proceed with the packing adjustment was not challenged.

- Configuration control for reinstallation of tubing for the HPCI governor hydraulic control system was lost during maintenance when tags used to label components

became illegible. Although efforts were made to regain configuration control for the tubing, the licensee failed to ensure that installation was proper. The problem was identified during HPCI post work testing.

Engineering

- Primary containment leakage rate testing was well conducted by the operations staff. The program was properly implemented and the as-left testing data met the requirements for plant start-up following the refueling outage.

- The equipment failure evaluation for the local leak rate testing (LLRT) failures was comprehensive with appropriate corrective actions completed or planned for completion. The licensee's decision to replace several poor performing valves was warranted based on the testing history. The LLRT results over the past several refueling cycles have shown continuous improvement in the number of as found failures. However, since the as-found total leakage rate based on Type B and C LLRT results was greater than the technical specification (TS) limits, a violation of NRC requirements occurred. This violation will not be cited in accordance with Section VII.B.1 of the NRC Enforcement Manual as the violation was non-recurring, promptly corrected and of low safety significance **(50-333/96008-02)**.

Plant Support

- There were several radiological control barriers and radiation worker practices which were not adhered to by two workers which resulted in one worker becoming contaminated. These requirements which were not met included the failure to obtain a radiation control brief, not adhering to the radiation work permit, wearing inadequate anti-contamination clothing, disregarding radiological posting requirements and improper use of the portal monitor. The results were that an individual became contaminated and the potential existed for the spread of contamination. The issue is unresolved item **(URI 50-333/96008-03)**.

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ATTACHMENT

Report Details

Summary of Plant Status

The unit began this inspection period in cold shutdown with the refueling outage in progress. The control rod drive change out was completed on November 19 the core was reloaded on November 27 and reactor vessel pressure testing was completed on December 3. On December 6, the licensee implemented technical specification amendment No. 239. This amendment increased the steady state reactor core power level limit from 2436 to 2536 megawatts (thermal). The licensee had to complete several actions as conditions for the approval of this power uprate license amendment. These actions included monitoring the recirculation pump motor vibrations during initial power ascension, performance of a startup test program and incorporation of any potential effects of operation at an increased power level into operator training.

On December 7, at 10:28 p.m., a reactor startup was commenced and the reactor was critical on December 8 at 12:36 a.m. On December 15, operators identified an electro-hydraulic control (EHC) system leak from the turbine bypass valve (BPV) actuator seal and manually scrammed the reactor from 36% reactor power. Following repairs to the BPV, the reactor was restarted and was critical on December 18. At the end of the inspection period, the reactor was at 96% power and power uprate testing was in progress.

I. Operations

O1 Conduct of Operations[1]

O1.1 Reactor Startup

a. Inspection Scope

The inspectors observed portions of the reactor startup conducted on December 7, 1996. Inspector attention was focused on reactivity control, operator procedure use and communications.

b. Observations and Findings

The startup was characterized by clear operator communications and procedure use, attentive management oversight, and effective control by shift supervision. Shift turnover meetings were performed in a controlled manner and crew briefings were good. Senior operations management personnel were designated to provide continuous oversight. Training was conducted for operations personnel to cover operating parameter changes which had been made as a result of the power uprate.

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[1]Topical headings such as O1, M8, etc., are used in accordance with the NRC standardized reactor inspection report outline. Individual reports are not expected to address all outline topics.

c. Conclusions

The reactor startup following the refueling outage was performed in a safe and prudent manner.

O1.2 Manual Reactor Scram

a. Inspection Scope

On December 15, at 1:00 a.m., operators inserted a manual reactor scram following the identification of an electro-hydraulic control (EHC) fluid leak from the number four turbine bypass valve. The inspectors reviewed the post transient evaluation including logs and operator actions. The plant operating review committee (PORC) which was conducted to review the event was also observed. In addition, the inspectors verified that the action commitment tracking system (ACTS) items which were generated from the event were appropriately addressed.

b. Observations and Findings

On December 15, an operator was performing turbine building rounds and identified one to two gallon per minute (GPM) electro-hydraulic control (EHC) system leak from the turbine bypass valve (BPV) actuator seal. Based on the system engineer's recommendation and the potential for the leak to increase substantially and possibly lose EHC pressure control, shift management determined that insertion of a manual scram was a prudent course of action. Control room operators were briefed and stationed at assigned panels and a manual scram was inserted from 36% reactor power. All required actions occurred and plant response to the transient was normal. Operators stabilized reactor pressure and level and commenced a normal reactor cooldown. The EHC leak was stopped by securing the operating EHC pump.

c. Conclusions

Operators demonstrated conservative decision making by directing a manual scram to be inserted when an EHC leak was identified. In addition, operators demonstrated excellent control of the plant transient.

O2 Operational Status of Facilities and Equipment

O2.1 Engineered Safety Feature System Walkdowns

The inspectors performed a walk down of accessible portions of the following systems and performed general area tours:

- residual heat removal service water system
- emergency diesel generator
- primary containment
- alternate decay heat removal system

Equipment operability and material condition were good. Housekeeping conditions were acceptable. Some outage related equipment was not stored prior to plant operation. For example, some small tools and tubing were found unattended and several ladders in both the reactor and turbine buildings were not secured. The licensee addressed these issues.

O4 Operator Knowledge and Performance

O4.1 Observations of Auxiliary Operator Watchstanding

a. Scope

The inspectors observed auxiliary operators (AOs) during reactor and turbine building watchstanding. The inspectors assessed the performance of the AOs, and the material and housekeeping conditions of the plant. Additionally, the inspectors reviewed applicable site procedures, and held discussions with operations department personnel, including AOs, shift managers, and the operations department manager.

b. Observations and Findings

The inspectors observed AOs on the December 11, 1996, day shift rounds of the reactor building, and the December 12 day shift rounds of the turbine building. The rounds were completed in accordance with Operations Department Standing Order (ODSO) 17, "Auxiliary Operator Plant Tours and Operating Logs," Revision 59. The AOs demonstrated good radiological controls practices in the performance of their duties. The inspector identified some minor logkeeping discrepancies which were appropriately addressed by operations management. The inspector noted that AOs identified some minor equipment deficiencies and appropriately documented the deficiencies using the Problem Identification (PID) process. The operators wiped up small amounts of oil under several components including the condensate booster pumps, the reactor recirculation system (RCS) pump motor generator (MG) sets and the hydrogen seal oil pumps.

c. Conclusions

The AOs performed watchstanding duties in an acceptable manner. Good radiological control practices were observed and operators demonstrated attentiveness by identifying and documenting minor equipment deficiencies. Minor logkeeping discrepancies were noted and were addressed by operations management.

O5 Operator Training and Qualification

O5.1 Post refueling outage (RFO) startup training

a. Inspection Scope

Post refueling outage (RFO) startup training was conducted 'o cover the power uprate technical specification amendment. The inspector observed portions of power uprate training and discussed the content of training with the Operations manager.

b. Observations and Findings

Training included power uprate training, operating experience, changes in plant system parameters, operations management expectations and an overview of special uprate test procedures including sequence of testing. The inspector noted good participation from operators that were attending the training.

c. Conclusions

The post refueling outage startup training was well presented and comprehensive.

O8 Miscellaneous Operations Issues

O8.1 (Closed) LER 50-333/96007 Engineered Safety Feature Activation Due to False High Radiation Isolation Signal. On May 22, 1996, the reactor building ventilation exhaust radiation monitor spiked. Automatic actions including reactor building ventilation system isolation, standby gas treatment system initiation, and closure of primary containment atmosphere sample system isolation valves occurred as required. The redundant ventilation radiation monitor showed no change in radiation levels.

Subsequent trouble ɔoting determined that the Geiger-Muller type radiation detector had failed nich generated the signal spike. The detector was replaced and the system re ned to operation.

Operator response to the ESF actuation was appropriate.

O8.2 (Closed) Unresolved Item 50-333/95021-01: Operation of all residual heat removal (RHR) pumps in the suppression pool cooling mode for extended periods of time. On November 7, 1995, the licensee operated all four RHR pumps for ten hours in the suppression pool cooling mode. The operation wa; conducted in response to NRC Bulletin 95-02, "Unexpected Clogging of a Resicual Heat Removal Pump Strainer While Operating in Suppression Pool Cooling Mode," using normal operating procedures. The licensee did not perform a safety evaluation pursuant to 10 CFR 50.59, "Changes, tests, and experiments," prior to performing the evolution. Subsequently, the licensee determined that a safety evaluation had not been

required, but, nonetheless, completed a formal evaluation to ensure that no safety issues had been overlooked.

Due to the potential for water hammer should a design-basis accident occur while both RHR trains are aligned for suppression pool cooling, NRC Region I referred the issue to the NRC Office of Nuclear Reactor Regulation (NRR) for evaluation. In a memorandum dated October 30, 1996 (attached to this report), the NRC concluded that infrequent operation of both RHR trains in the suppression pool cooling mode, such as on November 7, 1995, was not an unreviewed safety question. However, frequent, long-term operation of the RHR system either in the suppression pool cooling or test modes would constitute an unreviewed safety question (per 10 CFR 50.59) due to the increased likelihood of a malfunction due to a water hammer event. The inspector concluded that the licensee's failure to perform a safety evaluation prior to operating both trains of the RHR system in the suppression pool cooling mode on November 7, 1995, was a violation of 10 CFR 50.59. **(VIO 50-333/96008-01)**

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope

The inspectors observed all or portions of the following work activities:

- WR 96-06652-01 Inspect condenser thermowells for cracks and determine the extent of identified crack
- WR 96-06703-04 Post modification testing of off-gas system check valve for the steam packing exhauster drip pot drain line
- WR 95-08324 Perform inspection of scram discharge header isolation valve disk in accordance with maintenance procedure

b. Observations and Findings

The inspectors found the work performed under these activities to be professional and thorough. All work observed was performed with the work package present and in active use. Technicians were experienced and knowledgeable of their assigned task. The inspectors frequently observed supervisors and system engineers monitoring job progress, and quality control personnel were present when required. When applicable, appropriate radiation control measures were in place.

M1.2 General Comments on Surveillance Activities

a. Inspection Scope

The inspectors observed selected surveillance tests to determine whether approved procedures were in use, details were adequate, test instrumentation was properly calibrated and used, technical specifications were satisfied, testing was performed by knowledgeable personnel, and test results satisfied acceptance criteria or were properly dispositioned.

The inspectors observed portions of the following surveillance activities:

•ST 20K	control rod withdrawal checks
•ST 39Q	drywell inspection
•ST 4N	high pressure coolant injection (HPCI)
•ST 24Q	reactor core isolation cooling (RCIC) turbine slow roll and overspeed test
•ST 4K	HPCI turbine slow roll and overspeed test
•TST 55	feedwater level control power uprate startup test
•TST 56	feedwater level control power uprate startup test

b. Observations and Findings

The licensee conducted the above surveillance activities appropriately and in accordance with procedural and administrative requirements. Good coordination and communication were observed during performance of the surveillance.

M1.3 Conclusions on Conduct of Maintenance

Overall, maintenance and surveillance activities were well conducted, with good adherence to both administrative and maintenance procedures.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Turbine Bypass Valve Actuator Seal Leak

a. Inspection Scope

On December 15, the number four turbine bypass valve actuator seal was observed to be leaking at a rate of one to two gallons per minute. Operators inserted a manual reactor scram to address the hydraulic oil leak.[see section O1.2] The inspectors reviewed the equipment failure evaluation, reviewed material history and discussed the seal failure with the maintenance engineer.

b. Observations and Findings

The piston, piston rod and rod seal for the number four turbine bypass valve had recently been replaced during the refueling outage. The seal package consists of a

lip seal which is the primary pressure retaining device, a backup seal which supports the primary seal and a wiper seal which prevents external contamination from the seal area. It appears that the primary seal was damaged during installation. The damage to the primary seal provided a leakage path for the high pressure fluid (approximately 1600 psig) to leak past the seal. This caused pressurization of the wiper seal which is not designed to retain pressure.

On November 24, the number one bypass valve hydraulic actuator piston seal failed and approximately 50 gallons of EHC fluid leaked from the system. The EHC system had been restored to operation following preventive and corrective maintenance activities. The piston seal had been replaced earlier in the outage.

The licensee performed equipment failure evaluations for the seal failures which included a review of their maintenance practices. In the case of the number one seal failure, the piston stem had some coating degradation which caused the seal to wear during operation. The number one seal had exhibited excessive oscillation during the plant shutdown for the refueling outage and the licensee elected to replace the seal but did not inspect the piston stem. In the case of the number four seal, a small burr on the piston damaged the seal during installation. There is a starting sleeve to facilitate seal replacement which was not used because the licensee was not aware of the availability of the tool.

The licensee developed corrective actions to improve maintenance practices associated with seal replacement.

c. Conclusions

The approach to maintenance activities on the bypass valves was not rigorous and contributed to bypass valve hydraulic actuator seal failures and, in one case, resulted in the need to insert a manual reactor scram. The licensee's equipment failure evaluation was thorough and corrective actions well developed to address maintenance practices for the bypass valves.

M4 Maintenance Staff Knowledge and Performance

M4.1 Reactor Protection System Actuation Error Caused By Personnel Error

a. Inspection Scope

The inspector reviewed Licensee Event Report (LER) 96-013, Reactor Protection and Primary Containment Isolation System Actuation on False Low Reactor Water Level Due to Personnel Error, and various procedures associated with the event and discussed the issue with licensee personnel.

b. Observations and Findings

On November 16, 1996, an automatic reactor protection and primary containment isolation system actuation occurred on a false low reactor water level signal.

During surveillance testing of reactor water level instrumentation, technicians noted and attempted to correct an instrument isolation valve stem packing leak which caused a pressure transient in the level sensing lines and resulted in the instruments sensing a false low reactor water level. Systems which were in service automatically isolated and there was no negative effect on the plant.

The licensee determined that the technician attempted to tighten the valve stem packing nut while holding the valve handwheel. When the packing nut was turned, a reactor scram signal and primary containment isolation signal occurred. It appears that when the packing nut was turned, the technician slightly opened the isolation valve which resulted in a pressure decrease in the reactor water level variable leg sensing lines.

The licensee determined that the event was caused by personnel error. The procedure, IMP-G17, "Whitey Valve Packing Adjustments", which had been developed to adjust packing was not used nor was supervision informed of the packing leak. Use of the procedure would have resulted in a different system configuration which would essentially isolate the valve being worked on from the system.

c. Conclusions

Personnel error by technicians during surveillance testing on reactor water level instrumentation resulted in automatic reactor protection and primary containment isolation actuation. Since the plant was shutdown at the time of the event, there was no effect on plant operation. The inspector noted that this event contained similarities with the September 16, 1996 scram described in NRC inspection report 50-333/96-06 in that technicians proceeded with work without fully recognizing the potential to cause a plant transient. The condition [a valve packing leak] was not reported to supervision and the decision to proceed with the packing adjustment was not challenged.

Based on this review, LER 50-333/96-013 is closed.

M4.2 High Pressure Coolant Injection Incorrect Tubing Installation

a. Inspection Scope

On December 9, 1996, the high pressure coolant injection (HPCI) turbine would not roll during ST 4K, HPCI Turbine Slow Roll and Overspeed Test, conducted at 150 PSIG reactor pressure. The surveillance test was conducted, in part, as post work testing. The licensee identified that tubing connecting ports on the governor hydraulic control system was installed incorrectly. The inspector reviewed the maintenance procedure, the deviation and event report (DER) response and discussed the event with the system engineer. In addition, the inspector observed the performance enhancement review committee (PERC) meeting during which the personnel error was discussed.

b. Observations and Findings

During maintenance performed on the HPCI turbine, all piping was identified in accordance with MP 23.14, Turbine Maintenance. However, the method used to identify components was to use duct tape and a magic marker. The identification subsequently became illegible. The tubing was reassembled using the procedure and the tubing was walked down by the system engineer to verify correct installation. Due to the configuration, the walkdown verification failed to identify that the tubing was installed incorrectly. The problem was subsequently identified during post work testing.

As part of their corrective actions, the licensee initiated ACTS items to provide better labels for the tubing and connection ports and provided additional maintenance procedure enhancements.

c. Conclusions

Configuration control for reinstallation of tubing for the HPCI governor hydraulic control system was lost during maintenance when tags used to label components became illegible. Although efforts were made to regain configuration control for the tubing, the licensee failed to ensure that installation was proper. The problem was identified during HPCI post work testing.

III. Engineering

E1 Conduct of Engineering

E1.1 Primary Containment Leakage Rate Testing Program

a. Inspection Scope

The licensee submitted and received approval for Technical Specification Amendment No. 234 last cycle which allowed the licensee to implement 10 CFR Part 50, Appendix J, Option B, "Performance Based Containment Leakage Testing", during the refueling outage. The licensee's program is based on Nuclear Energy Industry NEI 94-01, "Industry Guidelines For Implementing Performance Based Option of 10 CFR Part 50, Appendix J, Revision 0, dated July 26, 1995. This document is endorsed by the NRC, with certain industry wide exceptions, in USNRC Regulatory Guide 1.163. The technical methods utilized by the licensee for performing Type A, B, and C test are contained in ANSI/ANS-56.8-1994, Containment System Leakage Testing Requirements. The actual implementation of the program is conducted in accordance with the licensee's surveillance testing program. The inspector observed testing, reviewed the program plan and the results of the local leak rate testing conducted during the refueling outage.

b. Observations and Findings

The inspector observed the LLRT performed on penetration X7A in accordance with ST-39B-X7A, Type C Leak Test Main Steam Line A MSIVs. The test was conducted by a group of auxiliary operators and supervised by a senior reactor operator. During the outage, testing was conducted on both shifts with oversight and coordination of the testing being directed from the work control center. The inspector noted that the operators were knowledgeable and experienced with the test equipment, procedures were in use and good communications were noted between operators in the field.

The inspector reviewed the Primary Containment Leakage Rate Testing Program against the requirements and noted the following:

* The licensee's Primary Containment Leakage Rate Testing Program was consistent with 10 CFR 50 Appendix J, Regulatory Guide 1.163 and NEI-94-01 Revision 0.

* Regulatory Guide 1.163, Performance-Based Leak Rate Test Program, requires that if the test interval for the Type A test is being extended for 10 years, then at least two refueling outages have to include a visual examination of accessible portions of the containment. The licensee completed two consecutive Type A test successfully and is extending the interval; however a visual examination was not performed as a part of the recent outage. The licensee has developed and assigned an ACTS item to write a procedure to perform this for the next outage. The next Type A test is due March 7, 2005.

* The program allows for reduced testing on good performing valves and increased test frequency for the poor performers. The inspector reviewed ST-39B, Type B and C LLRT of Containment Penetrations, and the licensee's Appendix J Option B Test Program Baseline Evaluation and concluded that all the penetrations which required LLRT were performed during the last outage or where within current testing periodicity.

* The inspector reviewed the test data and calculations for the as left minimum and maximum pathway penetration leakage rate and concluded the calculations were correct. The requirement is for both values to be less than 63.182 standard liters per minute (SLM). The minimum pathway was determined to be 16.6764 SLM and the maximum was 31.9627 SLM.

* The inspector reviewed the test data and calculations for the total as found minimum pathway leakage rate and concluded that the calculations were correct. The total as found minimum pathway was determined to be 311 SLM, exceeding the limit of 63.182 SLM. This

was reported to the NRC in accordance with 10 CFR 50.73 in Licensee Event Report LER-96-012 and is discussed in section E.1.2.

c. Conclusions

The inspector concluded that the testing was well conducted by the operations staff and the as-left testing data met the requirements for plant start-up following the refueling outage. The inspector determined that the Primary Containment Leakage Rate Testing Program was in accordance with the regulatory requirements and being properly implemented.

E1.2 (Closed) LER 96-012, Primary Containment Leakage Exceeding Technical Specifications

a. Inspection Scope

On November 11, 1996, the licensee determined that the as found running total primary containment leakage rate was in excess of the TS limit of 105.3 SLM and reported the event in accordance with 10 CFR 50.72. The licensee determined the as-found running total leakage rate to be 122 SLM. At the conclusion of the as-found minimum pathway local leak rate testing conducted during the refueling outage, the licensee determined the total as found minimum pathway to be 311 SLM, exceeding the limit of 63.182 SLM. The inspector reviewed the LER as part of the primary containment leakage rate program review.

b. Observations and Findings

The licensee processed an equipment failure evaluation (EFE) for each of the LLRT failures which discusses the causes and corrective actions for each of the failures. Five of the eight main steam isolation valves (MSIVs) failed to pass testing. The EFE concluded that this was attributed to normal wear occurring during the closing stroke of the valve. The licensee utilized a separate vendor supplied valve team with special tooling to repair the valves. All valves passed the subsequent retests. The mean time between failures of the MSIVs is about 5 years. The MSIVs are required to be tested every two years. The corrective actions appear to be adequate with respect to the MSIV failures.

Three valve failures were Anchor Darling double disk gate valves, which the licensee determined to be a poor design for steam applications. All three valves were reworked and subsequently passed the retesting. The EFE resulted in the generation of problem identification entries (PIDs) to track the replacement of two of the valves. The inspector noted that the mean time between failures for these valves was approximately a cycle. In discussion with the licensee's engineering staff, the inspector learned that the valves were replaced several cycles ago and albeit the valves have a long history of LLRT failures, the more recent failures are attributed to the design of the replacement valves. The inspector concluded that the corrective actions for these valves were adequate.

One feedwater system non-return valve, 34 NRV-111B also has a history of LLRT failures while its matching valve, 34 NRB-111A has a very good LLRT history. The licensee attributed this to a disc to seat misalignment during manufacture of the valve. The valve was repaired and subsequently retested satisfactorily. The long term corrective action for this valve included a PID to replace the valve or have a field service repair team correct the misalignment problem. The inspector concluded that the corrective actions were adequate. The remainder of the failures were attributed to normal wear, system particle accumulation, and corrosion products.

c. Conclusions

The inspector concluded that the EFEs for the LLRT failures were comprehensive with appropriate corrective actions completed or planned for completion. The licensee's decision to replace several poor performing valves was warranted based on the testing history. The LLRT results over the past several refueling cycles have shown improvement in the number of as found failures. However, since the as-found running total leakage rate, based on Type Band C LLRT results was greater than the TS limit, a violation of NRC requirements occurred. This violation will not be cited in accordance with Section VII.B.1 of the NRC Enforcement Manual as the violation was non-recurring, promptly corrected and of low safety significance **(50-333/9608-02)**. Licensee event report LER-96-012, is closed.

IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 Personnel Contamination Identified at the Security Building Radiation Monitor

a. Inspection Scope

On December 7, a non-licensed operator leaving to go home was identified as contaminated at the security building radiation monitor. The inspector reviewed the licensee's followup corrective actions including surveys, portal monitor testing, and discussed the event with licensee management. Additionally, radiological control procedures pertinent to the event were reviewed.

b. Observations and Findings

On December 7, a non-licensed operator leaving to go home was identified as contaminated at the security building radiation monitor. A health physics technician escorted the individual back to the radiation protection office and performed a whole body count and decontaminated the worker's face and hands. The workers clothing, including shoes, socks, trousers and outer coat were contaminated up to 12,000 cpm and removed. Following decontamination activities, the worker was allowed to go home. The worker's egress route was surveyed and no contamination was found. Additional subsequent surveys identified some

paperwork located in the control room that the operator had been in contact with had some detectable contamination, but was less than release limits.
The licensee's review showed that, during the week of December 1, various repairs were being performed on condensate demineralizer valves located in a contaminated area in the turbine building. On December 7, the operators involved were tasked with clearing a protective tagging request (PTR) associated with the system. The first operator did not obtain the required radiation protection briefing prior to entering the contaminated area. A second operator entered the area without a brief because he believed that the shift meeting brief covered the activity and the first operator had informed him that the required anti-contamination clothing was booties and gloves. NRC and NYPA review of the event is continuing; this is unresolved item **(URI 50-333/96008-03)** pending additional review.

c. Conclusions

A radiation worker had performed some tasks in a contaminated area and had improperly exited the radiologically controlled area. In addition, the radiation workers involved did not take proper radiological precautions while performing work.

There were several radiological controls barriers and radiation worker practices which were not adhered to by the workers involved. These requirements included the failure to obtain a radiation control brief, not adhering to the radiation work permit, wearing inadequate anti-contamination clothing, disregarding radiological posting requirements and improper use of the portal monitor. The results were that an individual became contaminated and the potential existed for the spread of contamination.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of the licensee management at the conclusion of the inspection on January 14, 1997. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

X2 Review of UFSAR Commitments

A recent discovery of a licensee operating their facility in a manner contrary to the Updated Final Safety Analysis Report (UFSAR) description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR description. While performing the inspections discussed in this report, the inspector reviewed the applicable portions of the UFSAR that related to the areas inspected. The inspector verified that the UFSAR wording was consistent with the observed plant practices, procedure and/or parameters.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

M. Colomb, Plant Manager
R. Locy, Operations Manager
D. Ruddy, Director, Design Engineering
J. Maurer, General Manager, Support Services

NRC

C. Cowgill, Chief, Projects Branch 2

INSPECTION PROCEDURES USED

37550	Engineering
37551	Onsite Engineering
62703	Maintenance Observations
61726	Surveillance Observations
71707	Plant Operations
71750	Plant Support
92903	Followup - Engineering

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-333/96008-01	VIO	failure to perform a 50.59 safety evaluation
50-333/96008-02	NCV	primary containment leakage exceeding technical specifications
50-333/96008-03	URI	improper radiation worker practices by a non-licensed operator

Closed

50-333/96008-02	NCV	primary containment leakage exceeding technical specifications
50-333/96007	LER	Engineered Safety Feature Activation Due to False High Radiation Isolation Signal.
50-333/96012	LER	Primary Containment Leakage in Excess of TS Limits
50-333/96013	LER	Reactor Protection and Primary Containment Isolation System Actuation on False Low Reactor Water Level Due to Personnel Error
50-333/95021-01	URI	residual heat removal pump operation

Discussed

None

LIST OF ACRONYMS USED

ALARA	As Low As Reasonably Achievable
ASME	American Society of Mechanical Engineers
BWR	Boiling Water Reactor
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
DAW	Dry Active Waste
DP	differential pressure
dpm	disintegrations per minute
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
ESF	Engineered Safety Feature
FME	Foreign Material Exclusion
FR	Federal Register
FWLCS	Feedwater Level Control System
HCU	Hydraulic Control Unit
HPCI	High Pressure Coolant Injection
IFI	Inspection Followup Item
IPE	Individual Plant Evaluation
IR	Inspection Report
ISEG	Independent Safety Engineering Group
ISI	Inservice Inspection
IST	Inservice Testing
LER	Licensee Event Report
LSA	Low Specific Activity
MSIV	Main Steam Isolation Valves
NCV	Non-Cited Violation
NDE	Non-Destructive Examination
NRC	Nuclear Regulatory Commission
OSHA	Occupational Safety and Health Administration
PEP	Performance Enhancement Program
ppm	parts per million
PSA	Probabilistic Safety Assessment
psig	pounds per square inch gage
QA	Quality Assurance
QC	Quality Control
RCA	Radiological Controlled Area
RCIC	Reactor Core Isolation Cooling
RHR	Residual Heat Removal
RP	Radiation Protection
RP&C	Radiological Protection and Chemistry
RWCU	Reactor Water Clean-Up
RWP	Radiation Work Permit
SCO	Surface Contaminated Objects
SRV	Safety Relief Valve
TS	Technical Specification
UE	Unusual Event
UFSAR	Updated Final Safety Analysis Report
VIO	Violation

ATTACHMENT 1

UNITED STATES
NUCLEAR REGULATORY COMMISSION
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MEMORANDUM TO: Curtis Cowgill
Division of Reactor Projects, Region I

FROM: S. Singh Bajwa, Acting Director *Alexander W Dromerick for.*
Project Directorate I-1
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

SUBJECT: TIA REGARDING DESIGN BASIS FUNCTIONALITY OF FITZPATRICK RHR SYSTEM WHEN OPERATED IN THE SUPPRESSION POOL COOLING MODE (TAC NO. M94319)

By letter dated December 12, 1995, the Region raised concerns regarding water hammer issues and extended operation of the residual heat removal (RHR) system in the Suppression Pool Cooling (SPC) mode. The memorandum in particular stated a position that the regional staff considers that operation of the RHR system in secondary modes of operation for extended periods of time without consideration of the inherent susceptibility to water hammer is unacceptable.

NRR is in agreement with the Region's position. We consider that frequent long-term operation of RHR in the SPC mode constitutes an unreviewed safety question (USQ). For example, when operating in the SPC mode, the RHR system is more likely to undergo a water hammer event should there be a loss of station power. Hence, the probability of a water hammer event is increased in direct proportion to the amount of time the system is operated in the SPC. Furthermore, the likelihood of a malfunction of the RHR system is increased when subjected to a water hammer event. Therefore, an increase in the likelihood of a water hammer increases the likelihood of a malfunction of a system important to safety. This meets the criterion for an USQ per 10 CFR 50.59(a)(2)(i).

We also believe that long-term operation of the RHR in the SPC mode constitutes a <u>modification</u> to the facility which should be (and should have been) subject to a 10 CFR 50.59 evaluation. We will recommend to the Generic Communications Branch to send a generic letter to all the BWR licensees stating our position.

The staff has previously evaluated the water hammer issue on a generic basis. In Table 3-1 of NUREG-0927, BWR system water hammer causes are listed and

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the frequency of operation of RHR in the SPC mode. Licensees typically have administrative controls in place to limit the use of RHR system in the SPC mode and, thereby, reduce the potential for water hammer of the RHR system. We believe that similar controls should be in place at FitzPatrick.

Finally, the Region provided four specific questions regarding SPC operation at FitzPatrick, they are addressed in the attachment.

Attachment: As stated

<u>Response to Region I TIA regarding</u>
<u>Suppression Pool Cooling Mode of</u>
<u>Operation at FitzPatrick</u>

Q 1. Was the operation of both RHR loops for 10 hours on November 10, 1995, at Fitzpatrick an unreviewed safety question (USQ)?

No. We do not believe that an isolated instance of both RHR loops in SPC such as the operation on November 10, 1995, constitutes an USQ. We believe that such infrequent operation is included in the system design basis as described in the FSAR which includes both periodic short-term operation as well as long-term post accident operation.

Q 2. Should RHR be considered inoperable for purposes of ECCS when run in the SPC mode?

No. RHR is considered operable for purposes of ECCS when run in the SPC mode or in the test mode. The RHR system is designed for automatic alignment to the LPCI mode if the system is in the SPC mode or in the test mode. The cumulative running time must be considered in light of maintenance specifications and pump maintenance and pump testing programs. As long as the pump is maintained in accordance with these programs, the RHR pumps are considered operable for purpose of ECCS.

Q 3. Is extended use of RHR in the SPC mode (viz., one pump more than 2 hours, both loops simultaneously, or cumulative run time in excess of 100 hours annually) beyond the licensing basis?

Yes. We believe that extended use (increased frequency and long duration) of RHR system in the SPC mode is beyond the licensing basis. Frequent use of the RHR system in the SPC mode changes the original design basis analysis (LOCA) assumptions. For example, in the original design of the RHR system, the closing speeds of the valves in the system cooling/test lines were specified as standard speed (12 inches/minute) and not fast closing valves such as the LPCI injection valves. Since the cooling/test return valves take longer to close than the LPCI injection valves take to open, there is a potential for the core injection flow to be diverted to the suppression pool. The ECCS performance analysis does not include the longer closing time of the test line vales since they are assumed to be normally closed. As the amount of time (the time the test valves are kept open) increases, the assumption is invalidated resulting in an unanalyzed condition.

Q 4. Should EOPs be reevaluated with respect to the meaning "----operate all available torus cooling?" Should torus cooling be optimized along a divisional basis until the need to maximize torus cooling is demonstrated? Should a caution statement concerning the potential water-hammering a voided system be considered?

The FitzPatrick EOP for torus cooling states the following: "Operate all available torus cooling, use only RHR pumps which do not have to be run continuously in the LPCI mode for core cooling." This is in agreement with the EPG, Rev.4 SER which states: "The EPGs are based upon maintaining core cooling and primary containment integrity. In all but a few cases the EPG

emphasize core cooling. But in a few specific situations, when a decision between a possible loss of adequate core cooling and a loss of primary containment integrity must be made, the EPGs preferentially choose to maintain primary containment integrity in order to protect against the uncontrolled release of radioactivity to the general public from a degraded core condition." The LPCI mode of operation supersedes all other modes of RHR except for scenarios where the containment integrity is in danger. This philosophy should be taught to the operators during the training process. Therefore, unless, it is found that the licensee's training program is deficient with regard to emphasizing the primacy of the LPCI mode of operation, or if the EOP fail to caution the operator in this regard, there is no need to modify the EOP for torus cooling optimization along a divisional basis.