Indian Point 3
Nuclear Power Plant
P.O. Box 215
Buchanan, New York 10511

914-736-8000

New York Power Authority

July 28, 1995
IPN-95-082

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

SUBJECT: Indian Point 3 Nuclear Power Plant
Docket No. 50-286
License No. DPR-64
Licensee Event Report # 95-012-00
"Manual Reactor Trip in Response to Decreasing Steam Generator Levels and Low Feedwater Flow Due to Degraded Feedwater Controller"

Dear Sir:

The attached Licensee Event Report (LER) 95-012-00 is hereby submitted as required by 10 CFR 50.73. This event is the type defined in 10 CFR 50.73 (a)(2)(iv).

Also attached are the commitments made by the Authority in this letter.

Very truly yours,

L. M. Hill
Site Executive Officer
Indian Point 3 Nuclear Power Plant

LMH/vjw

Attachments

cc: See next page

IE22
1/1

cc: Mr. Thomas T. Martin
Regional Administrator
Region I
U.S. Nuclear Regulatory Commission
475 Allendale Road
King of Prussia, Pennsylvania 19406-1415

INPO Record Center
700 Galleria Parkway
Atlanta, Georgia 30339-5957

U.S. Nuclear Regulatory Commission
Resident Inspectors' Office
Indian Point 3 Nuclear Power Plant

List of Commitments

Number	Commitment	Due
IPN-95-082-01	Determine (Work Request No. 95-03672-00) the appropriate setpoint for the 31 and 32 MBFPT control oil system orifice screen differential pressure alarm switches.	October 30, 1995.
IPN-95-082-02	Revise ARP-7 to reflect the MBFPT control oil orifice screen differential pressure alarm switch setpoint determined by WR 95-03672-00.	November 30, 1995.
IPN-95-082-03	Investigate (DER 95-1736) how the orifice screen differential pressure alarm setpoint was changed without an adequate engineering evaluation.	October 30, 1995.
IPN-95-082-04	An evaluation will be performed on incorporating into the I&C preventive maintenance program the calibration of the control oil orifice screen differential pressure alarm switches.	October 30, 1995.
IPN-95-082-05	Review and revise, as required, procedure OD-14 to require an assessment of what compensatory actions will be performed if layup is not performed or is determined to be inadequate, and to provide the requirements for exiting layup. Evaluate the NYPA equipment layup standard ES-4 for any impact from the changes to OD-14.	November 30, 1995.
IPN-95-082-06	Share the lessons learned with the operators on the pressurizer pressure controller's system response time that should be expected and incorporate this expected response into requalification training.	October 30, 1995.

NRC FORM 366 (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)

(See reverse for required number of digits/characters for each block)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Indian Point Unit 3	05000286	1 OF 6

TITLE (4) Manual Reactor Trip in Response to Decreasing Steam Generator Levels and Low Feedwater Flow Due to Degraded Feedwater Controller

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
06	29	95	95	-- 012 --	00	07	28	95		05000
									FACILITY NAME	DOCKET NUMBER 05000

OPERATING MODE (9)	N
POWER LEVEL (10)	012

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more) (11)

	20.402(b)		20.405(c)	✓ 50.73(a)(2)(iv)	73.71(b)
	20.405(a)(1)(i)		50.36(c)(1)	50.73(a)(2)(v)	73.71(c)
	20.405(a)(1)(ii)		50.36(c)(2)	50.73(a)(2)(vii)	OTHER
	20.405(a)(1)(iii)		50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	(Specify in Abstract below and in Text, NRC Form 366A)
	20.405(a)(1)(iv)		50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
	20.405(a)(1)(v)		50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
Charles Caputo, Senior Technical Advisor	(914)736-8814

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)			EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
	YES (If yes, complete EXPECTED SUBMISSION DATE).	✓ NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines) (16)

On June 29, 1995, with reactor power at 12%, turbine load at approximately 50 MW, and feedwater pump control in automatic, the reactor operator observed that levels in the steam generators were decreasing as a result of decreasing feedwater flow. The operator changed the feedwater controller to manual and attempted to increase feedwater pump output with the feedwater pump controller but it failed to respond. A manual reactor trip was initiated in anticipation of receiving an automatic trip. The reactor trip and auxiliary feedwater systems functioned as required. The cause was rust-clogged orifice screen filters of the feedwater pump turbine control oil system due to inadequate guidelines in the equipment layup procedure. The control system oil was flushed, screen filters cleaned and replaced, and the oil sampled and analyzed. Orifice screen filter differential pressure alarm switches were calibrated to vendor recommendations.

DESCRIPTION OF EVENT

On June 29, 1995, at approximately 1900 hours, the unit was synchronized to the grid for the first time following a 28 month improvement outage. Rod control was in manual and the 32 Main Boiler Feedwater Pump (MBFP) (SJ) was in service via the low flow bypass lines. The 31 MBFP had not been returned to service.

After placing the 32 MBFP in automatic at approximately 1943 hours the operator observed an apparent stable response. However, after checking other plant parameters the operator noticed feedwater pump speed and flow decreasing. The operator placed the feedwater controller in manual and attempted to increase feedwater pump speed, but the pump did not respond and feedwater flow continued to decrease with a corresponding decrease in steam generator levels.

At approximately 1950 hours, with reactor power at 12%, turbine load at approximately 50 MW, and steam generator levels at approximately 15% to 18%, the reactor operator initiated a manual reactor trip as a result of decreasing steam generator levels and failure of the feedwater pump turbine controller (JK) to respond to operator actions to increase feedwater flow. The manual reactor trip was initiated via the control room panel trip push button.

Both reactor trip breakers opened and all rods fully inserted. The reactor trip and auxiliary feedwater systems functioned as required. Operations initiated a Deviation Event Report No. 95-1551 and a four hour non-emergency report to the NRC.

During post trip recovery, a low pressurizer pressure signal was generated (normal for post trip conditions), but the pressurizer backup heaters did not energize as anticipated. The reactor operator manually turned on the backup heaters to increase pressure. The pressurizer spray valves did not open when pressurizer pressure was restored. The reactor operator placed the pressurizer pressure master controller in manual to open the spray valves.

Operations performed a post trip review (No. 95-01) and initiated an investigation of the problem with the MBFP turbine speed controller and the pressurizer pressure master controller. The pressurizer pressure master controller was determined to be functioning properly. The pressurizer backup heaters are controlled off the controlling channel and the low pressure alarm comes off the bistable train. The controller is based on actual pressure whereas the low pressure alarm is based on a low pressure setpoint. The investigation concluded the operators responded to the alarm condition (low pressurizer pressure) before the controlling channel had a chance to take effect. Review of computer trend data showed the pressurizer spray valve was responding to high pressure but the valve had not moved sufficiently to actuate the valve position limit switch and illuminate the indicating light.

An investigation of the MBFP turbine (MBFPT) speed control problem revealed that the oil orifice screen filters of the control oil system for the Lovejoy turbine controller (L253) were clogged with rust scale. Rust had formed in the predominately carbon steel piping downstream of the high pressure oil filters of the control oil system during the extended plant shutdown. The system was not put in layup to prevent rusting nor was the system flushed to ensure contaminates were removed. Oil sampling is not performed on the high pressure control oil which contains the carbon steel piping. The high pressure control oil system does not have oil sample taps at appropriate locations to provide samples representative of the oil in the carbon steel piping. Prior to the event, Chemistry had sampled and assessed the oil and found it to be acceptable.

When the system was returned to service the rust scale inside the oil piping sloughed off and clogged the MBFPT control system oil screen filters. Clogging the MBFPT control oil filters prevented proper speed control of the MBFP turbine resulting in decreasing feedwater flow and corresponding steam generator levels. Following the event, maintenance prepared a Work Request package (WR 95-03511-00) to flush the control oil system. The control system oil was flushed, screen filters cleaned and damaged screens replaced.

Operations received a high differential pressure alarm on the control room SDF panel for MBFP speed control trouble while testing the oil system's operation. An I&C technician inspected the setpoints for the hydraulic inlet orifice screens differential pressure alarm switches (63) (63-FPA and 63-FPB) and discovered values that were between the Alarm Response Procedure (ARP-7) value and the vendor manual recommended value. The 32 MBFP alarm switch as-found values were 17.26 psi and 8.5 psi. The 31 MBFP alarm switch as-found values were 12.5 psi and 16.5 psi.

The Alarm Response Procedure ARP-7 states the speed control trouble alarm could be caused by a high orifice screen differential pressure of greater than 32 psig. The vendor's manual has a recommendation to adjust the switch for a differential pressure of 4.5 psig. The vendor was consulted and recommended a setpoint value of 10 psi. The setpoints were calibrated to approximately 10 psi and a Term Procedure Change (TPC 95-1077) was issued for Alarm Response Procedure ARP-7. A high differential pressure alarm would have alerted operators to the degraded condition. I&C initiated a Work Request (WR 95-03672-00) to investigate the proper setpoint. A DER 95-1736 was initiated to investigate how the setpoint was changed without an adequate engineering evaluation.

Licensing's investigation for the LER revealed that there were problems with the feedwater control system during the previous fuel cycle. Work packages to correct the problems were developed and repair of the system was performed during the improvement outage. Prior to the improvement outage, NYPA recognized that the existing layup program was inadequate and was in the process of issuing a new layup program standard. The new layup program standard (ES-4) was issued (April 11, 1994) and the plant procedure (OD-14) revised, but well after entering the outage. Operations did not ensure compensatory action or a system flush was provided. Following the event, Chemistry performed a review of other balance of plant hydraulic control systems for similar problems. The main turbine control oil system was flushed prior to being returned to service.

CAUSE OF EVENT

The cause of the event was an inadequate layup program. Failure to have adequate procedural guidance resulted in inadequate equipment layup and no compensatory actions resulting in rust of the system's carbon steel piping that clogged control oil screen filters. Clogging the MBFPT control oil screen filters prevented proper speed control of the MBFP turbine resulting in decreasing feedwater flow and a corresponding decreasing steam generator levels.

Contributing factors were inadequate balance of plant setpoint control and non-representative oil sampling. The setpoint program does not include the control oil screen differential pressure alarm switches. The out-of-calibration alarm switches did not alarm when required and therefore, failed to alert operators of a degraded condition. Oil sampling is only provided for the reservoir oil and no consideration was given for sampling the oil in the high pressure piping. The layup program does not require a sample of a flush of the high pressure control oil system after layup or maintenance prior to system operation.

CORRECTIVE ACTION

The following corrective actions have been or will be performed to address the deficiencies identified during the investigation of this event and to prevent recurrence:

- Flushed and cleaned the MBFPT control oil system.
- Replaced the MBFPT control oil system oil filters.
- The MBFPT control oil source (low pressure) was sampled and analyzed for acceptable quality.
- The MBFPT control oil system differential pressure alarm switches setpoint were calibrated to the vendor's recommended value of 10 psi.
- Work Request No. 95-03672-00 was initiated to determine the appropriate setpoint for the 31 and 32 MBFPT control oil system orifice screen differential pressure alarm switches. The evaluation will be complete by October 30, 1995.
- Alarm Response Procedure ARP-7, "Panel SDF - Turbine Recorder," was revised to the vendor's recommended setpoint by TPC-95-1077 and will be revised as required to reflect the proper control oil system setpoint determined by WR 95-03762-00. Revision will be complete by November 30, 1995.
- An evaluation will be performed on incorporating into the I&C preventive maintenance program the calibration of the control oil orifice screen differential pressure alarm switches. The evaluation will be complete by October 30, 1995.

- Investigate (DER 95-1736) how the setpoint was changed without an adequate engineering evaluation. This action will be complete by October 30, 1995.

- Review and revise, as required, equipment layup procedure OD-14 to require an assessment of what compensatory actions will be performed if layup is not performed or is determined to be inadequate, and to provide the requirements for exiting layup. Evaluate the NYPA equipment layup standard ES-4 for any impact from the changes to OD-14. Evaluation and revision will be complete by November 30, 1995.

- Share the lessons learned with the operators on the pressurizer pressure controller's system response time that should be expected and incorporate this expected response into requalification training. These actions will be complete by October 30, 1995.

ANALYSIS OF EVENT

This event is reportable under 10 CFR 50.73 (a)(2)(iv). The licensee shall report any event or condition that resulted in a manual or automatic actuation of any Engineered Safety Feature (ESF), including the Reactor Protection System (RPS). Decreasing steam generator levels because of decreasing feedwater flow and no response from the feedwater pump controller required a manual reactor trip in anticipation of an automatic trip.

Similar events were reported in Licensee Event Reports 91-003, 91-004, 91-005, 92-013, 92-015.

SAFETY SIGNIFICANCE

This event did not affect the health and safety of the public.

The plant is designed and analyzed for a loss of feedwater event. The reactor would have tripped on low steam generator level. The auxiliary feedwater system was available and did start and provide feedwater as required.