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Anthony J Vitale
Site Vice President

NL-18-043

June 18, 2018

U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Mail Stop O-P1-17
Washington, D.C. 20555-0001

SUBJECT: Licensee Event Report # 2018-002-00, "Manual Reactor Trip Due to Trip of Both Main Boiler Feedwater Pumps"
Indian Point Unit No. 2
Docket No. 50-247
DPR-26

Dear Sir or Madam:

Pursuant to 10 CFR 50.73(a)(1), Entergy Nuclear Operations Inc. (ENO) hereby provides Licensee Event Report (LER) 2018-002-00. The enclosed LER identifies an event where the reactor was manually tripped following an automatic trip of both Main Boiler Feedwater Pumps (MBFPs). This event is reportable under 10 CFR 50.73(a)(2)(iv)(A). As a result of the MBFP trip, the Auxiliary Feedwater System was actuated, which is also reportable under 10 CFR 50.73(a)(2)(iv)(A). The condition was recorded in the Entergy Corrective Action Program as Condition Report CR-IP2-2018-02806.

There are no new commitments identified in this letter. Should you have any questions regarding this submittal, please contact Mr. Robert Walpole, Manager, Regulatory Assurance at (914) 254-6710.

Sincerely,

AJV/cdm

IE22
NRR

cc: Mr. David Lew, Acting Regional Administrator, NRC Region I
NRC Resident Inspector's Office
Ms. Bridget Frymire, New York State Public Service Commission

U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB: NO. 3150-0104 EXPIRES: 03/31/2020

LICENSEE EVENT REPORT (LER)

(See Page 2 for required number of digits/characters for each block)

(See NUREG-1022, R.3 for instruction and guidance for completing this form http://www.nrc.gov/reading-rm/doc-collections/nuregs/staff/sr1022/r3/)

1. Facility Name	2. Docket Number	3. Page
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4. Title
Manual Reactor Trip Due to Trip of Both Main Boiler Feedwater Pumps

5. Event Date			6. LER Number			7. Report Date			8. Other Facilities Involved	
Month	Day	Year	Year	Sequential Number	Rev No.	Month	Day	Year	Facility Name	Docket Number 05000
04	19	2018	2018	- 002	- 00	06	18	2018	Facility Name	Docket Number 05000

9. Operating Mode	11. This Report is Submitted Pursuant to the Requirements of 10 CFR §: *(Check all that apply)*			
1	☐ 20.2201(b)	☐ 20.2203(a)(3)(i)	☐ 50.73(a)(2)(ii)(A)	☐ 50.73(a)(2)(viii)(A)
	☐ 20.2201(d)	☐ 20.2203(a)(3)(ii)	☐ 50.73(a)(2)(ii)(B)	☐ 50.73(a)(2)(viii)(B)
	☐ 20.2203(a)(1)	☐ 20.2203(a)(4)	☐ 50.73(a)(2)(iii)	☐ 50.73(a)(2)(ix)(A)
	☐ 20.2203(a)(2)(i)	☐ 50.36(c)(1)(i)(A)	☒ 50.73(a)(2)(iv)(A)	☐ 50.73(a)(2)(x)
10. Power Level	☐ 20.2203(a)(2)(ii)	☐ 50.36(c)(1)(ii)(A)	☐ 50.73(a)(2)(v)(A)	☐ 73.71(a)(4)
8	☐ 20.2203(a)(2)(iii)	☐ 50.36(c)(2)	☐ 50.73(a)(2)(v)(B)	☐ 73.71(a)(5)
	☐ 20.2203(a)(2)(iv)	☐ 50.46(a)(3)(ii)	☐ 50.73(a)(2)(v)(C)	☐ 73.77(a)(1)
	☐ 20.2203(a)(2)(v)	☐ 50.73(a)(2)(i)(A)	☐ 50.73(a)(2)(v)(D)	☐ 73.77(a)(2)(ii)
	☐ 20.2203(a)(2)(vi)	☐ 50.73(a)(2)(i)(B)	☐ 50.73(a)(2)(vii)	☐ 73.77(a)(2)(iii)
		☐ 50.73(a)(2)(i)(C)	☐ Other (Specify in Abstract below or in NRC Form 366A	

12. Licensee Contact for this LER

Licensee Contact	Telephone Number (Include Area Code)
Christopher Bohren, Manager, Operations Support	(914) 254-2971

13. Complete One Line for each Component Failure Described in this Report

Cause	System	Component	Manufacturer	Reportable To ICES	Cause	System	Component	Manufacturer	Reportable To ICES
D	TG	SHV	W351	Y					

14. Supplemental Report Expected	15. Expected Submission Date	Month	Day	Year
☐ Yes (If yes, complete 15. Expected Submission Date) ☒ No				

Abstract (Limit to 1400 spaces, i.e., approximately 14 single-spaced typewritten lines)

On April 19, 2018, at 2100 hours, during initial plant startup following the Spring 2018 refueling outage (2R23), Indian Point Unit 2 commenced performance of the main turbine generator startup procedure to conduct turbine overspeed testing. At 2107 hours, the control room received main feedwater supervisory and panel alarms, and the main turbine control valves were observed to have opened rapidly. The unexpected rapid opening of the turbine control valves caused steam flow to increase, which in turn, caused all four steam generator water levels to swell. The high steam generator levels initiated an automatic main feedwater isolation and main turbine trip, with both Main Boiler Feedwater Pumps (MBFPs) tripping on closure of their discharge valves as part of the main feedwater isolation actuation. At 2108 hours, with reactor power at 8 percent and no MBFPs running, a manual reactor trip was inserted by the control board operators in accordance with the abnormal operating procedure for loss of main feedwater. All control rods fully inserted and all required safety systems functioned properly. The plant was stabilized in hot standby with decay heat being removed by the main condenser. The Auxiliary Feedwater System (AFWS) automatically started as expected on the tripping of the MBFPs to maintain steam generator inventory. The direct cause of the event was main turbine control oil stop valve LO-Z being out of its required position (closed instead of open). The root cause was main turbine generator startup procedure (2-SOP-26.4) provided a weak barrier to maintain the proper configuration of the main turbine control oil system. Corrective actions primarily involved the resolution of configuration control and management vulnerabilities.

This event had no effect on the public health and safety. The event was reported to the Nuclear Regulatory Commission on April 19, 2018 under 10 CFR 50.72(b)(2)(iv)(B) and 50.72(b)(3)(iv)(A).

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NARRATIVE

Note: The Energy Industry Identification System Codes are identified within the brackets { }.

DESCRIPTION OF EVENT

On April 19, 2018, at approximately 2100 hours, during initial plant startup following the Spring 2018 refueling outage (2R23), Indian Point Unit 2 (IP2) commenced performance of main turbine generator {TA, TB} startup procedure 2-SOP-26.4 to conduct turbine overspeed testing. When the main turbine is offline, two Load Limit controllers {TG, PC} function to modulate the main turbine control valves {SB, FCV}. The Load Limit controller with the lower control oil pressure controls modulation of the turbine control valves. The Load Limit 2 controller (Load Limit 2) was selected to raise turbine speed. Unknown to the operators, turbine control oil stop valve LO-Z {TG, SHV} was incorrectly positioned to the closed position. With LO-Z closed, Load Limit 2 was isolated from the common control oil line, which removed its ability to modulate the turbine control valves. The Load Limit 2 control oil pressure was at minimum as expected (control board indication read 0.3 pounds per square inch gauge (psig)). However, with Load Limit 2 isolated and effectively out of service, the Load Limit 1 controller (Load Limit 1) was in control of the turbine control valves. This was an undetected abnormal condition that caused the turbine control valves to respond uncharacteristically when the control room operators raised Load Limit 1 control oil pressure in accordance with 2-SOP-26.4 to ensure Load Limit 2 was in control.

At approximately 2107 hours, the control room received main feedwater {SJ} supervisory and panel alarms {IB}, including the steam generator level control deviation {XA}, heater drain high/low level {LA}, and moisture separator drain tank high level {LA} alarms. Also at this time, the main turbine control valves were observed to have opened rapidly. With the main turbine stop valves {SB, SHV} opened previously per procedure 2-SOP-26.4, the unexpected rapid opening of the main turbine control valves caused steam flow to the high pressure turbine to increase from 0 pounds mass per hour (lbm/hr) to 1.0E6 lbm/hr in 17 seconds. This step increase in steam flow caused all four steam generator {AB, SG} water levels to swell (increase) from approximately 38 percent to 73 percent narrow range level. The high steam generator levels initiated an automatic main feedwater isolation and main turbine trip. Both Main Boiler Feedwater Pumps (MBFPs) {SJ, P} tripped on closure of their discharge valves {SJ, 20} as part of the main feedwater isolation actuation. Operations entered abnormal operating procedure (AOP) 2-AOP-FW-1 for loss of main feedwater.

At approximately 2108 hours, with reactor power at 8 percent and no MBFPs running, a manual reactor trip was inserted by the control board operators in accordance with 2-AOP-FW-1. Emergency operating procedure (EOP) 2-E-0 was entered for the reactor trip to assess plant conditions and identify the appropriate recovery actions. All control rods {AA} were verified fully inserted and all required safety systems functioned properly. The plant was stabilized in hot standby with decay heat being removed by the main condenser {SG}. Pressurizer and steam generator pressures and levels, and Reactor Coolant System (RCS) {AB} temperature were being maintained within their normal bands. There was no radiation release. The emergency diesel generators {EK, DG} did not start, as offsite power remained available and stable. The Auxiliary Feedwater System (AFWS) {BA} motor-driven auxiliary boiler feedwater pumps {BA, P} automatically started as expected on the tripping of the MBFPs. Indian Point Unit 3 (IP3) was unaffected and remained at 100 percent reactor power.

As required, on April 19, 2018, at 2341 hours, the reactor trip event was reported to the Nuclear Regulatory Commission (NRC) in a 4-hour non-emergency notification under 10 CFR 50.72(b)(2)(iv)(B) for an actuation of the Reactor Protection System (RPS) {JC} when the reactor is critical, and included an 8-hour notification for valid actuations of the RPS and AFWS under 10 CFR 50.72(b)(3)(iv)(A) (Event Log No. 53348). The event was recorded in the Indian Point Energy Center (IPEC) Corrective Action Program (CAP) as CR-IP2-2018-02806.

The main turbine control oil system {TG} utilizes three controllers {TG, PC} to control high pressure steam flow to the turbine by modulating the main turbine control valves. Two Load Limit controllers are used to modulate the control valves when the turbine is offline and not at rated speed. The Load Limit controllers share a common oil line, which sends a hydraulic signal based on control oil pressure to modulate the control valves. Normally, the control valves stroke with a common control oil pressure of approximately 18 pounds per square inch (psi) (valves full closed) to 45 psi (valves full open). With the use of internal check valves, the Load Limit controller with the lower pressure signal maintains overall control of the position of the control valves. The third controller is the main turbine governor {TA, 65}, which functions as a controller {TG, TC} when the turbine is close to normal operating speed (greater than approximately 1650 revolutions per minute (rpm)). The governor uses a turbine shaft mounted impeller to adjust the common control oil pressure based on turbine speed. As such, the governor impeller oil pressure provides the modulating control signals to the turbine control valves during normal operation.

A modification of the main turbine control oil system was performed when Consolidated Edison Company owned IP2. The modification installed new oil piping and valves into the system to allow testing of the main turbine governor with the turbine offline and not at rated speed. The new piping configuration allows oil from Load Limit 2 to flow into the governor impeller oil supply line to simulate a governor impeller pressure. This allows the governor to modulate the turbine control valves during outages for testing purposes. The modification included the addition of stop ball valve LO-Z to the common control oil line upstream of the internal check valve for Load Limit 2. The modification also added stop ball valve LO-Y {TG, SHV} and associated piping to connect the Load Limit 2 common control oil supply line to the governor impeller oil supply line to the governor. For governor testing, valve LO-Z would be closed to isolate Load Limit 2 from the common control oil circuit to prevent interference with the oil pressure supplied to the governor. Valve LO-Y would be opened during the testing to allow the Load Limit 2 control oil supply to flow to the governor.

The investigation following the April 19, 2018 reactor trip resulted in the discovery of valve LO-Z being out of position. The valve was closed (instead of open) during the performance of main turbine generator startup procedure 2-SOP-26.4. With valve LO-Z in the closed position, Load Limit 2 was isolated from the common control oil line. This removed the ability of Load Limit 2 to modulate the main turbine control valves, and also affected the hydraulics of the common control oil circuit by reducing the volume of oil and effectively removing the Load Limit 2 oil drain and internal check valve from the circuit. This, in turn, changed the main turbine control valve zero (opening) and span (stroke range) settings, which would cause the valves to stroke in an uncharacteristic manner. Thus, when the control room operators raised Load Limit 1 control oil pressure in accordance with 2-SOP-26.4, the control valves opened unexpectedly, causing a rapid increase in steam flow to the high pressure turbine, and this resulted in water level swell (increase) in all four steam generators. The high steam generator levels initiated an automatic main feedwater isolation and main turbine trip that caused both MBFPs to trip, and necessitated the insertion of a manual reactor trip by the control board operators. The time period during which valve LO-Z was out of its required position was determined to be between 1218 hours on April 16, 2018 and 2107 hours on April 19, 2018 (turbine trip). However, no Work Orders, procedures, or other activities performed or occurring during this period were found that directed operation of valve LO-Z, nor was the valve on any protective tagouts (PTOs), and there was no evidence of tampering. Consequently, the investigation into how the valve LO-Z became mispositioned was inconclusive.

An extent of condition (EOC) analysis was performed to determine where the same or similar conditions may exist. For this event, the EOC was limited to control oil system valves for the IP2 and IP3 main turbine generators and MBFPs where a valve misposition, valve leak, or incorrectly installed valve could lead to either an automatic or manual reactor trip. The EOC analysis concluded that there was a low EOC risk level for control oil system valves installed incorrectly or developing a leak large enough to require an automatic or manual reactor trip, and no corrective actions were required. The EOC analysis for control oil system valves being left out of position concluded that there was a medium EOC risk level due to the higher frequency that these valves are manipulated, which creates more opportunities and a higher probability for mispositioning the valves. The EOC corrective actions to address the medium risk of control oil system valves being left out of position are: (1) revise shutdown risk assessment procedure

IP-SMM-OU-104 to include a risk and work scope informed recommendation in the pre-outage risk assessment for which check off lists (COLs) should be performed at the end of an outage and (2) revise mode change checklists (Mode 3 to Mode 2) 2-PT-V053E and 3-PT-V053E to require partial performance of the MBFP and main turbine control oil system COLs.

CAUSE OF EVENT

The direct cause of the event was main turbine control oil stop valve LO-Z being out of its required position (closed instead of open). Valve LO-Z being closed led to the observed uncharacteristic turbine control valve operation and unexpected rapid increase in steam flow that caused all four steam generator water levels to swell. The high steam generator levels initiated an automatic main feedwater isolation and main turbine trip, which in turn, caused both MBFPs to trip, and culminated in the insertion of a manual reactor trip in accordance with 2-AOP-FW-1.

The root cause of the event was main turbine generator startup procedure (2-SOP-26.4) provided a weak barrier to maintain the proper configuration of the main turbine control oil system. Procedure 2-SOP-26.4 was determined to be weak because the procedure steps for startup of the main turbine generator do not reference the required positions for turbine control oil stop valves LO-Z and LO-Y. In addition, having the main turbine lube oil system aligned per the COL (2-COL-26.1) was not listed as a prerequisite in 2-SOP-26.4. This caused valve LO-Z to be out of its required position by allowing the turbine generator startup to be performed without ensuring valves LO-Z and LO-Y were properly aligned for startup.

Contributing causes:

1. Weakness in the implementation of the site configuration control process. The weakness in configuration control allowed main turbine control oil stop valve LO-Z to be left out of its required position. Although the investigation was inconclusive, the valve was likely repositioned without proper documentation or configuration tracking. A stronger site configuration control process could have mitigated the risk of valve LO-Z being left out of position.
2. Weakness in the process used to determine which COLs are performed at the end of an outage. The main turbine lube oil system COL was not performed at the end of the IP2 Spring 2018 refueling outage (2R23), nor was it required to be performed. Not performing the COL contributed to the event because its performance could have mitigated the risk of valve LO-Z being left out of position at the time of startup.

CORRECTIVE ACTIONS

The following corrective actions have been or will be performed under the Entergy CAP to address the causes of this event.

- Restored main turbine control oil stop valve LO-Z to its proper position and performed the main turbine lube oil system COL (2-COL-26.1) before the subsequent successful plant startup.
- Revised procedure 2-SOP-26.4 to verify valves LO-Y and LO-Z are in the desired position prior to latching the main turbine.
- Revise procedure IP-SMM-OU-104 to include a risk and work scope informed recommendation in the pre-outage risk assessment for which COLs should be performed at the end of the outage.
- Review procedure revisions from 2001 to 2007 for System Operating Procedures (SOPs) related to main turbine and MBFP control oil systems and determine if applicable changes were captured for both IP2 and IP3. If changes were not captured then revise procedures as necessary.
- Add main turbine control oil stop valves LO-Z and LO-Y to the Asset Suite (AS) equipment database for IP2 and IP3, and label the valves in the field to match the equipment database designation.

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- Determine the valves to be included in the partial scope performance of the MBFP and main turbine control oil system mode change (Mode 3 to Mode 2) checklists and revise 2-PT-V53E and 3-PT-V53E to require partial performance of the MBFP and main turbine control oil system COLs.
- Evaluate main turbine vendor work packages to determine if adequate work instructions are provided, and initiate corrective actions to address vague work packages.

EVENT ANALYSIS

The event is reportable under 10 CFR 50.73(a)(2)(iv)(A). The licensee shall report any event or condition that resulted in manual or automatic actuation of any of the systems listed under 10 CFR 50.73(a)(2)(iv)(B). Systems to which the requirements of 10 CFR 50.73(a)(2)(iv)(A) apply for this event include the RPS, including reactor trip, and AFWS actuation. This event meets the reporting criteria because a manual reactor trip was initiated on April 19, 2018 at 2108 hours, and the AFWS was automatically actuated in response to the tripping of the MBFPs as part of the main feedwater isolation actuation. An investigation into the cause of the event and a post transient evaluation were initiated and completed. The root cause evaluation for this event was presented to the Performance Improvement Review Group and the post transient evaluation was presented to the Onsite Safety Review Committee. Both evaluations were approved.

PAST SIMILAR EVENTS

A review was performed of the past three years for IP2 and IP3 Licensee Event Reports (LERs) that reported a reactor trip resulting from a component being out of its required position. The review identified a past similar event that was reported in IP2 LER 2016-009 for an automatic reactor trip event which occurred on July 6, 2016. The reactor trip resulted from an Instrument and Control (I&C) technician operating the Channel B RPS bypass key out of sequence and without procedural guidance. The root cause of this event was that fundamental standards and expectations, such as procedure use and adherence, were not being maintained. While the 2016 event was caused by an individual deviating from a procedure, the event reported in this LER was the result of procedures that provided inadequate configuration controls.

SAFETY SIGNIFICANCE

This event had no effect on the health and safety of the public. There were no actual safety consequences for the event because it was an uncomplicated manual reactor trip. The automatic main feedwater isolation and turbine trip on high steam generator levels functioned as designed to terminate the steam flow and feedwater flow transients, and allowed steam generator water levels to be restored to normal. The tripping of the MBFPs was an expected response since the MBFPs are steam-driven, and not designed to operate following a reactor trip. The AFWS motor-driven auxiliary boiler feedwater pumps automatically started to supply high pressure feedwater to the steam generators to maintain water inventory. The AFWS is designed to support the removal of decay heat energy from the RCS by secondary-side steam release when the Main Feedwater System {SJ} is not operable. This condition is bounded by the analyzed event described in IP2 Updated Final Safety Analysis Report (UFSAR) Section 14.1.9, Loss of Normal Feedwater. The AFWS has adequate redundancy to provide the minimum required flow assuming a single failure. The UFSAR analysis demonstrates that the AFWS is capable of removing the stored and residual heat plus reactor coolant pump {AB, P} waste heat following a loss of normal feedwater event, thereby preventing over-pressurization of the RCS and preserving reactor coolant inventory. For this event, all control rods inserted as required upon initiation of the reactor trip. Following the reactor trip, the plant was stabilized in hot standby with decay heat being removed by the main condenser. Pressurizer and steam generator pressures and levels, and RCS temperature were being maintained within their normal bands.