Nuclear Operating Company
South Texas Project Electric Generating Station P.O. Box 289 Wadsworth, Texas 77483

May 23, 2013
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10 CFR 50.73
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U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555-0001

South Texas Project
Unit 2
Docket No. STN 50-499
Revision 1 of Licensee Event Report 2-2013-002
Reactor Trip Due to Main Transformer Lockout Relay Trip

Pursuant to 10 CFR 50.73, STP Nuclear Operating Company (STPNOC) submits the attached revision to the South Texas Project (STP) Unit 2 Licensee Event Report (LER) 2-2013-002 to address the reactor trip that occurred on January 8, 2013.

This event is reportable pursuant to 10CFR50.73(a)(2)(iv)(A), any event or condition that resulted in manual or automatic actuation of any of the systems listed in paragraph (a)(2)(iv)(B) of this section, and 10 CFR 50.73(a)(2)(vii), any event where a single cause or condition caused at least one independent train or channel to become inoperable in multiple systems or two independent trains or channels to become inoperable in a single system designed to: (A) Shut down the reactor and maintain it in a safe shutdown condition; (B) Remove residual heat; (C) Control the release of radioactive material; or (D) Mitigate the consequences of an accident.

This event did not have an adverse effect on the health and safety of the public.

The attached LER revision adds a description of a human performance error made by a control room operator during the event response. The original LER was marked Revision 1 in error. Attached is the correct Revision 1 of LER 2-2013-002.

There are no commitments contained in this LER. Corrective actions will be implemented in accordance with the STP Corrective Action Program.

If there are any questions on this submittal, please contact either Ben Whitmer at (361) 972-7449 or me at (361) 972-7566.

G. T. Powell
Site Vice President

BLW

Attachment: LER 2-2013-002, Rev. 1

IE22
NRR

cc:
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NRC FORM 366 (10-2010) U.S. NUCLEAR REGULATORY COMMISSION	APPROVED BY OMB: NO. 3150-0104 EXPIRES: 10/31/2013
LICENSEE EVENT REPORT (LER) (See reverse for required number of digits/characters for each block)	Estimated burden per response to comply with this mandatory collection request: 80 hours. Reported lessons learned are incorporated into the licensing process and fed back to industry. Send comments regarding burden estimate to the FOIA/Privacy Section (T-5 F53). U.S. Nuclear Regulatory Commission, Washington. DC 20555-0001, or by internet e-mail to Infocollects.resource@nrc.gov, and to the Desk Officer, Office of Information and Regulatory Affairs. NEOB-10202. (3150-1104), Office of Management and Budget. Washington. DC 20503. If a means used to impose an information collection does not display a currently valid OMB control number, the NRC may not conduct or sponsor, and a person is not required to respond to the information collection.

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4. TITLE Reactor Trip Due to Main Transformer Lockout Relay Trip

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
01	08	2013	2013	002	01	06	03	2013	N/A	N/A

9. OPERATING MODE 1

10. POWER LEVEL 100%

11. THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10CFR§: *(Check all that apply)*

☐ 20.2201(b)	☐ 20.2203(a)(3)(i)	☐ 50.73(a)(2)(i)(C)	☒ 50.73(a)(2)(vii)
☐ 20.2201(d)	☐ 20.2203(a)(3)(ii)	☐ 50.73(a)(2)(ii)(A)	☐ 50.73(a)(2)(viii)(A)
☐ 20.2203(a)(1)	☐ 20.2203(a)(4)	☐ 50.73(a)(2)(ii)(B)	☐ 50.73(a)(2)(viii)(B)
☐ 20.2203(a)(2)(i)	☐ 50.36(c)(1)(i)(A)	☐ 50.73(a)(2)(iii)	☐ 50.73(a)(2)(ix)(A)
☐ 20.2203(a)(2)(ii)	☐ 50.36(c)(1)(ii)(A)	☒ 50.73(a)(2)(iv)(A)	☐ 50.73(a)(2)(x)
☐ 20.2203(a)(2)(iii)	☐ 50.36(c)(2)	☐ 50.73(a)(2)(v)(A)	☐ 73.71(a)(4)
☐ 20.2203(a)(2)(iv)	☐ 50.46(a)(3)(ii)	☐ 50.73(a)(2)(v)(B)	☐ 73.71(a)(5)
☐ 20.2203(a)(2)(v)	☐ 50.73(a)(2)(i)(A)	☐ 50.73(a)(2)(v)(C)	☐ OTHER
☐ 20.2203(a)(2)(vi)	☐ 50.73(a)(2)(i)(B)	☐ 50.73(a)(2)(v)(D)	Specify in Abstract below or in NRC Form 366A

12. LICENSEE CONTACT FOR THIS LER

FACILITY NAME	TELEPHONE NUMBER *(Include Area Code)*
Ben Whitmer, Licensing Engineering Specialist	361-972-7449

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

CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX	CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX
E	EL	XFMR	McGraw-Edison (M175)	YES	N/A	N/A	N/A	N/A	N/A

14. SUPPLEMENTAL RESPONSE EXPECTED		15. EXPECTED SUBMISSION DATE	MONTH	DAY	YEAR
☐ YES (If yes, complete 15. EXPECTED SUBMISSION DATE)	☑ NO		N/A	N/A	N/A

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

On January 8, 2013, at 16:40 CST, with South Texas Project Unit 2 at 100% power, a fault in the 'C' phase of the Unit 2 2A Main Transformer (MT2A) occurred resulting in a Unit 2 automatic trip and partial loss of offsite power. Pressure from the fault ruptured the transformer tank and the oil ignited. The onsite fire brigade responded, and the fire suppression system worked as designed. The fire was extinguished at 16:56. There were no injuries and no radiological impacts to the public or station personnel.

An Unusual Event was declared at 16:55 CST for initiating condition HU-2, "Fire or explosion in protected area or switchyard which affects normal plant operations". Local, county, and state offices were notified as required, and the Unusual Event was terminated at 19:47 CST, after the partial loss of offsite power was restored.

Failure analysis concluded the most likely cause was an internal ground fault or an internal turn-to-turn fault inside the "C" phase high voltage windings due to untimely degradation of the paper insulation from the cumulative effects of pass-through faults, elevated temperatures, elevated moisture, and grid disturbances over a period of years. The damage to the transformer challenged a determination of the direct root cause of the fault. If warranted, the root cause report and LER will be revised after failure evaluation forensics are complete.

Corrective actions include replacement of MT2A with an on-hand spare, installation of wireless monitoring and notification features for the online dissolved gas monitors, approval for future replacement of all four main transformers with new units to support reliable operation through the end of the currently projected plant life, and implementation of a Large Equipment Asset Management process.

NARRATIVE

I. DESCRIPTION OF EVENT

A. Reportable Event Classification

This event is reportable pursuant to 10CFR50.73(a)(2)(iv)(A), any event or condition that resulted in manual or automatic actuation of any of the systems listed in paragraph (a)(2)(iv)(B) of this section, and 10 CFR 50.73(a)(2)(vii), any event where a single cause or condition caused at least one independent train or channel to become inoperable in multiple systems or two independent trains or channels to become inoperable in a single system designed to: (A) Shut down the reactor and maintain it in a safe shutdown condition; (B) Remove residual heat; (C) Control the release of radioactive material; or (D) Mitigate the consequences of an accident.

B. Plant Operating Conditions Prior to Event

South Texas Project Unit 2 was in Mode 1 at 100% power.

C. Status of Structures, Systems, and Components that were Inoperable at the Start of the Event and That Contributed to the Event

No other structures, systems, or components were inoperable at the start of the event that contributed to the event.

D. Narrative Summary of the Event

On January 8, 2013 at 1359 hours, Unit 2 reached full power following a brief plant shutdown. At 16:40 CST Unit 2 Main Transformer 2A (MT2A) [EL][XFMR], faulted without warning, causing a main generator [TB][GEN] lock out and automatic reactor trip [JE]. Control room operators entered procedure 0POP05-EO-EO00, “Reactor Trip or Safety Injection,” and stabilized the plant in mode 3 with the reactor core being cooled by natural circulation.

The fault caused a partial loss of offsite power: two of three Engineered Safety Features (ESF) electrical buses [JE][EA][EB][BU] lost power and the associated Standby Diesel Generators (SDG) [EL][DG] 21 and 23 subsequently started and loaded as designed.

At 16:40 CST, a fire was reported at MT2A. Sudden pressure from the fault had ruptured the transformer tank, and the oil ignited. The fire brigade was dispatched to fight the fire. The fire protection deluge system [KF] functioned as designed. At 16:49 CST the fire brigade leader reported the fire was under control. At 16:56 CST the fire was extinguished.

At 16:55 CST, the Unit 2 Shift Manager, in his capacity as Emergency Director, declared an Unusual Event based on emergency response plan initiating condition HU2, “Fire or Explosion in the Protected Area or Switchyard which Affects Normal Operation,” and emergency action level 2, “Explosion in or adjacent to any of the following areas which damages equipment necessary for normal plant operation...”

Between 17:37 and 18:43 CST, Operators electrically realigned the plant via auxiliary and standby electrical buses [EA] in order to restore offsite power. These actions then allowed the operators to secure Standby Diesel Generators 21 and 23.

The Emergency Director (Shift Manager) terminated the Unusual Event at 19:47 CST.

Response to this event did not reveal any significant deficiency in plant Operating Procedures, the Emergency Plan, or Fire Brigade protocols.

During the reactor trip response at approximately 16:45 on January 8, 2013, a control room operator inappropriately switched the Pressurizer Master Pressure Controller [AB] [PIK] from auto to manual mode and adjusted the controller without communicating his action to the control room supervisor. Earlier in the event, the operator had noted a drop in reactor coolant system pressure and misunderstood the relationship of the relief valve auto-response function to current plant conditions (i.e. the operator thought RCS pressure was low and if the PORV were to lift it would cause RCS pressure to lower further). The action configured the system such that Pressurizer Power Operated Relief Valve (PORV) PCV-0655A [PCV] would not lift when RCS pressure reached or approached the lift set point. With Pressurizer PORV PCV-0655A in manual, Pressurizer PORV PCV-0656A cycled twice at approximately 16:59 and 17:01 (lifting at approximately 2340 psig and reclosing at approximately 2320 psig). Cycling of a pressurizer PORV was expected during this transient due to the loss of normal pressurizer spray flow resulting from the partial loss of power event that secured the reactor coolant pumps. The inappropriate action by the reactor operator did not extend or complicate the control room staff response to the event.

There were no significant human performance errors that might have jeopardized nuclear safety.

Required ESF equipment responded as designed and restored electrical power to safety grade electrical buses immediately upon receiving an initiation signal. There were no personnel injuries or loss of radioactive material control.

E. Method of Discovery

The transformer fault and reactor trip, were self-revealing.

II. Event-driven Information

A. Safety Systems that Responded

All required safety systems responded as expected including the following actuations:

1. Reactor Coolant Pump Undervoltage Reactor Trip
2. Reactor Protection System P-16, Turbine Trip
3. Feedwater Isolation Actuation
4. CRE HVAC Emergency Recirculation (C Train LOOP)
5. Reactor Containment Fan Coolers (C Train LOOP)
6. Auxiliary Feedwater Actuation (All AFW pumps actuated)
7. Primary Pressure Control (Pressurizer Spray and Heaters actuated as required)
8. Emergency Diesel Generators 21 and 23 started and loaded as designed

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B. Duration of Safety System Inoperability

N/A

C. Safety Consequences and Implications of the Event

There was no impact to radiological safety, safety of the public, or safety of station personnel during this event.

After the plant trip, all systems required to maintain the Unit in a safe shutdown condition were available. The plant maintained the ability to remove residual heat and there were no challenges to systems that are used to monitor and control the release of radioactive material. Systems were available to mitigate the consequence of an accident.

Plant personnel safety was potentially challenged initially by the fire and explosion. Prompt actuation of the fire suppression system and the follow-up actions by Fire Brigade personnel extinguished the fire. Thermo graphic inspection detected hot spots and cooling spray was applied to prevent re-flash. In addition, on-shift crew actions to vent the hydrogen from the Main Generator alleviated the risk of a hydrogen fire. Station processes provided sufficient barriers to ensure personnel safety.

This event was an unplanned scram with complications per NEI 99-02, revision 6, "Regulatory Assessment Performance Indicator Guideline", October 2009, because, after the scram, Main Feedwater [SJ] was unavailable or not recoverable using approved plant procedure, and the scram response procedure could not be completed without entering another EOP (Emergency Operating Procedure). Loss of forced cooling in the Reactor Coolant System (RCS) [AB] required operators to establish and maintain natural circulation of the RCS to ensure adequate core cooling. Forced circulation of the RCS was restored at 22:59 on January 8, 2013. Since the main condenser was not available due to loss of Circulating Water [NN][P] pumps, Main Steam [S] isolation was required and the normal automatic control of RCS temperature after a Reactor trip was lost requiring manual Steam Generator Power Operated Relief Valve [SB][PCV] operations to manage RCS temperature.

Probabilistic Risk Assessment (PRA):

- The conditional core damage probability (CCDP) for the loss of main transformer trip is 1.09e-7.
- The conditional large early release probability for the loss of main transformer trip is 5.67e-9.

These conditional probabilities are the appropriate risk metrics for the risk associated with a trip. That is, there is no frequency only a probability given the event occurred.

The event did not prevent Security from performing required functions and did not impair the ability of Security personnel to implement the physical security plan.

The partial loss of offsite power did not inhibit the control room from implementing emergency response plan actions to mitigate the event.

III. Cause of the Event

The most likely cause of the MT2A failure that resulted in the transformer lockout trip of the Unit 2 reactor is that either an internal ground fault or an internal turn-to-turn fault occurred inside of the "C" phase high voltage windings. The most likely cause of the fault is that the paper insulation inside of the transformer degraded faster than expected due to cumulative damage over time from a combination of pass-through faults, elevated temperatures, elevated moisture, and grid disturbances. Another potential cause that remains as "likely" on the Fault Tree is the failure of bad connections internal to the windings, but this is considered less likely due to the age of the transformer and because analysis of gases in oil samples did not indicate that a loose connection had existed for any long period of time. A more definitive cause may be determined after failure evaluation forensics are performed on the damaged transformer windings.

IV. Corrective Actions

Develop and implement a "Large Equipment Asset Management" process based on INPO AP-913, "Equipment Reliability Process Description," revision 3, March 2011, and EPRI status report 1021188, "Integrated Life Cycle Management", technical update of December 2010, and other nuclear plant asset management plans. The intent of this action is to develop proactive methodology to manage major plant assets.

Obtain approval for Main Transformer replacement. Make a recommendation to the Reliability and Asset Management committee that, when implemented, will support reliable operation through the end of the currently projected plant life. The intent is to propose and get approval for installation of new main transformers and procurement of a new spare to support reliable operation of both units through the end of the currently projected plant life.

Install a plant modification to support automatic notifications and wireless monitoring of installed gas monitor results for all main and aux transformers; following installation of the modification, set up and activate automatic notifications for installed gas monitor results

V. Previous Similar Events

The only previous failure of an identical component at STP occurred on 7/13/89 when MT2A failed and resulted in a Unit 2 reactor trip (reference LER 2-89-017). The 1989 event involved failure of the lower high voltage (HV) bushing that is internal to the transformer tank, so it was different from the recent failure of MT2A that occurred inside the HV windings. Following are the conclusions drawn from the 1989 event:

- The station problem report (SPR) describing the event states that the number three (3) high voltage bushing had failed but does not list the reason the bushing was the initial failure, instead of the transformer. An attachment to the SPR from McGraw-Edison states that an inspection revealed that the bushing had exploded inside of the transformer.
- The transformer tank was ruptured at the top-center tank joint adjacent to the H3 bushing.
- No fire occurred, only an explosion.
- The SPR states that "no true root cause of the bushing failure was found." McGraw-Edison

speculated that free water in the bushing insulating oil could have been responsible but no attempt was made to justify this as a possible cause or to explain how the water could have gotten inside of the bushing.

- The SPR concluded that no corrective actions were needed (no procedure changes, no test revisions, no additional testing is to be performed, no additional maintenance activities needed, and no generic implications were noted).

VI. Additional Information

None.