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October 14, 2003
PY-CEI/NRR-2737L

United States Nuclear Regulatory Commission
Document Control Desk
Washington, D.C. 20555

Perry Nuclear Power Plant
Docket No. 50-440
LER 2003-002-00

Ladies and Gentlemen:

Enclosed is Licensee Event Report (LER) 2003-002, Reactor Scram as a Result of a Loss Of Off-Site Power. This event is being reported in accordance with 10CFR50.73. There are no regulatory commitments contained in this letter. Any actions discussed in this document that represent intended or planned actions, are described for the NRC's information, and are not regulatory commitments.

If you have questions or require additional information, please contact Mr. Vernon K. Higaki, Manager – Regulatory Affairs, at (440) 280-5294.

Very truly yours

Enclosure: LER 2003-002

cc: NRC Project Manager
NRC Resident Inspector
NRC Region III

IE22

NRC FORM 366 (7-2001) U.S. NUCLEAR REGULATORY COMMISSION	APPROVED BY OMB NO. 3150-0104 EXPIRES 7-31-2004
LICENSEE EVENT REPORT (LER) (See reverse for required number of digits/characters for each block)	Estimated burden per response to comply with this mandatory information collection request: 50 hrs. Reported lessons learned are incorporated into the licensing process and fed back to industry. Send comments regarding burden estimate to the Records Management Branch (T-6 E6), U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001, or by internet e-mail to bjs1@nrc.gov, and to the Desk Officer, Office of Information and Regulatory Affairs, NEOB-10202 (3150-0104), Office of Management and Budget, Washington, DC 20503. If a means used to impose 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 Scram as a Result of a Loss of Off-site Power

5. EVENT DATE			6. LER NUMBER			7. REPORT DATE			8. OTHER FACILITIES INVOLVED	
MO	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REV NO	MO	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
8	14	2003	2003	002	0	10	14	2003	FACILITY NAME	DOCKET NUMBER

9. OPERATING MODE	Mode 1	11. THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check all that apply)							
			20.2201(b)		20.2203(a)(3)(ii)		50.73(a)(2)(ii)(B)		50.73(a)(2)(ix)(A)
10. POWER LEVEL	100%		20.2201(d)		20.2203(a)(4)	X	50.73(a)(2)(iii)		50.73(a)(2)(x)
			20.2203(a)(1)		50.36(c)(1)(i)(A)	X	50.73(a)(2)(iv)(A)		73.71(a)(4)
			20.2203(a)(2)(i)		50.36(c)(1)(ii)(A)		50.73(a)(2)(v)(A)		73.71(a)(5)
			20.2203(a)(2)(ii)		50.36(c)(2)		50.73(a)(2)(v)(B)	X	OTHER Special Report, ORM 7.6.2.1, ECCS Injection
			20.2203(a)(2)(iii)		50.46(a)(3)(ii)		50.73(a)(2)(v)(C)		
			20.2203(a)(2)(iv)		50.73(a)(2)(i)(A)	X	50.73(a)(2)(v)(D)		
			20.2203(a)(2)(v)	X	50.73(a)(2)(i)(B)	X	50.73(a)(2)(vii)		
			20.2203(a)(2)(vi)		50.73(a)(2)(i)(C)		50.73(a)(2)(viii)(A)		
			20.2203(a)(3)(i)		50.73(a)(2)(ii)(A)		50.73(a)(2)(viii)(B)		

12. LICENSEE CONTACT FOR THIS LER	
NAME	TELEPHONE NUMBER (Include Area Code)
Kenneth F. Russell (Compliance Engineer)	(440) 280-5580

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

14. SUPPLEMENTAL REPORT EXPECTED				15. EXPECTED SUBMISSION DATE	MONTH	DAY	YEAR
X	YES (If yes, complete EXPECTED SUBMISSION DATE).		NO		12	15	2003

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

On August 14, 2003, at 1610 hours, with the Perry Nuclear Power Plant operating in Mode 1, at approximately 100 percent reactor power, a generator trip due to under-frequency occurred resulting in a turbine control valve fast closure scram. The under-frequency was the result of a loss of off-site power. The cause of the grid disturbance that resulted in the loss of off-site power is still under investigation by FirstEnergy. The loss of off-site power required entry into the emergency plan for an Unusual Event. Entry into the emergency plan is reportable per 10CFR50.72(a)(1)(i). Additional reporting requirements are documented in the event report.

Loss of off-site power to the safety-related emergency power supply busses for greater than 15 minutes resulted in the declaration of an Unusual Event, which was reported to the NRC via the Emergency Notification System (ENS) at 1635 hours. Subsequently, it was recognized that power was not available at the Emergency Operations Facility and the Backup Emergency Operations Facility. This condition was reported to the NRC via the ENS at 2225 hours. The Unusual Event was terminated at 1952 hours on August 15, 2003, following restoration of off-site power. Following restoration of power to the emergency busses with the emergency diesel generators, low pressure alarms were received on low pressure core spray (LPCS) and on residual heat removal (RHR) A loop. Following initial investigation, both LPCS and RHR A were declared inoperable at 1847 hours. The associated water-leg pump was determined to be air bound and was vented. Both LPCS and RHR A were vented prior to returning to service.

This report also satisfies Operational Requirements Manual section 7.6.2.1, which requires a special report submittal following an Emergency Core Cooling System actuation and injection into the reactor coolant system.

LICENSEE EVENT REPORT (LER)

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NARRATIVE *(If more space is required, use additional copies of NRC Form 366A)* **(17)**

I. INTRODUCTION

On August 14, 2003, at 1346 hours, the Perry Nuclear Power Plant (PNPP) was operating in Mode 1 at approximately 100 percent reactor power when the PNPP control room operators contacted the FirstEnergy Systems Control Center (SCC) to report voltage spikes being observed on the PNPP control room console voltage meters. The SCC subsequently requested that Perry increase its main transformer [XFMR] voltage to maximum. A control room operator, assigned to monitor the generator [EL], observed an upward, saw-tooth trend on the MVAR recorder starting at about 1530 hours. At about 1536 hours voltage fluctuations were seen on the PNPP main transformer and the generator out of step supervisory relay tripped. The SCC was notified of these conditions. The PNPP control room operator lowered the generator voltage regulator setpoint to maintain generator field voltage less than the trip setpoint (528 volts). At 1541 hours plant operators entered the off-normal instruction for degraded grid and both off-site AC sources were declared inoperable as a result of grid voltage fluctuations. At about 1610 hours the operator monitoring the generator observed a number of spikes on the generator field voltmeter followed by the meter indication going full upscale. The MVAR and Megawatt (MW) meter also went full upscale. Reactor water cleanup pumps [CE] tripped and the offgas system [WF] isolated. At 1610 hours, a main generator trip occurred which caused a turbine trip resulting in an automatic reactor scram due to a turbine control valve fast closure signal. Loss of off-site power to the essential switchgear busses is reportable per 10CFR50.72(b)(3)(v)(D) and 50.73(a)(2)(v)(D), an event or condition that could have prevented fulfillment of a safety function, 10CFR50.73(a)(2)(iii), an external condition that posed an actual threat to the safety of the nuclear power plant as well as 10CFR50.73(a)(2)(vii), common-cause inoperability of independent trains.

The Nuclear Regulatory Commission was notified via the Emergency Notification System (ENS) at 1635 hours on August 14, 2003, (ENF No. 40063), in accordance with 10CFR50.72(a)(1)(i), declaration of any emergency class (Unusual Event). At 1705 hours, a follow-up notification was made for 10CFR50.72(b)(2)(iv)(A), ECCS discharge to the RCS, 10CFR50.72(b)(2)(iv)(B), as an event that resulted in an actuation of the reactor protection system when the reactor is critical, 10CFR50.72(b)(3)(iv)(A), specified system actuation for multiple system containment isolation valves and main steam isolation valves. At 2225 hours, an additional follow-up notification was made for 10CFR50.72(b)(3)(xiii), any event that results in a major loss of off-site response capability, when it was recognized that there was no power available to the Emergency Operations Facility (EOF) and the Backup EOF (BEOF).

This Licensee Event Report is being submitted in accordance with:

- 10CFR50.73(a)(2)(i)(B), an operation or condition prohibited by Technical Specifications,
- 10CFR50.73(a)(2)(iii), any natural phenomenon or other external condition that posed an actual threat to the safety of the nuclear power plant,
- 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) (includes the reactor protection system, general containment isolation signals affecting containment isolation valves in more than one system or multiple main steam isolation valves, emergency core cooling systems, reactor core isolation cooling system, emergency ac electrical power systems including emergency diesel generators and emergency service water systems that do not normally run and that serve as ultimate heat sinks),
- 10CFR50.73(a)(2)(v)(D), any event or condition that could have prevented the fulfillment of the safety function of structures or systems, (loss of both off-site electrical power sources),
- 10CFR50.73(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.

NARRATIVE *(If more space is required, use additional copies of NRC Form 366A)* (17)

This report also satisfies Operational Requirements Manual (ORM) section 7.6.2.1, which requires a special report to be submitted following an Emergency Core Cooling System (ECCS) actuation and injection into the reactor coolant system. The special report shall include a description of the circumstances of the actuation and the total accumulated actuation cycles to date. Additionally, the current value of the usage factor for each affected safety injection nozzle shall be provided when its value exceeds 0.70. The High Pressure Core Spray (HPCS) [BG] system was used for level control and injected into the Reactor Pressure Vessel [RPV] on 16 occasions during this event. The injections occurred over about 10 hours and over a RPV pressure range of 1000 psig to about 110 psig, with not all injections being design cycles. There had been 14 HPCS injections over the life of the plant prior to this event, which results in a total of 30 HPCS injections to date. Forty design cycles would result in a nozzle usage factor of 0.164. Since the HPCS injection nozzle usage factor is less than 0.70, an exact value has not been calculated for inclusion in this report. The Low Pressure Core Spray (LPCS) [BM] system was manually operated for RPV level control for about 25 hours after the HPCS system. The RPV pressure was less than 200 psig when LPCS was first used. Use of LPCS for level control is not considered an ECCS injection since the design injections are for a pressure of 520 psig down to 450 psig. However, operation of the system was reviewed for its impact on the injection nozzle. The nozzle usage factor for LPCS is less than 0.70.

II. EVENT DESCRIPTION

On August 14, 2003, at 1610 hours, with the plant operating at approximately 100 percent reactor power, a main generator trip occurred which caused a turbine trip resulting in an automatic reactor scram due to a turbine control valve fast closure signal. The reactor scram is reportable per 10CFR50.72(b)(2)(iv) B), reactor protection system actuation while critical, and 50.73(a)(2)(iv), actuation of specified systems. All control rods fully inserted as required.

In addition to the scram, the following system isolations occurred: balance of plant (BOP), reactor water cleanup system (RWCU), residual heat removal (RHR) [BO], reactor sample, main steam line drains and main steam isolation valves (MSIV)[SB]. Automatic start of the division 1, 2, and 3 diesel generators [EK] as well as emergency service water [BI] and emergency closed cooling [CC] occurred as a result of the loss of power. The system isolations and automatic starts are reportable per 10CFR50.72(b)(3)(iv) and 50.73(a)(2)(iv) as valid actuations of specified systems. An initiation of HPCS and the reactor core isolation cooling system (RCIC)[BN], and an automatic trip of the reactor recirculation system pumps [AD] occurred due to a RPV low water level signal (Level 2, 130 inches above the top of active fuel). The HPCS injection is reportable per 10CFR50.72(b)(2)(iv)(A) for ECCS discharge into the reactor coolant system and 50.73(a)(2)(iv) for specified system actuation. Safety Relief Valves (SRVs) [RV] opened due to a high reactor pressure signal at 1103 psig (1 valve) and 1113 psig (8 of 9 valves). The highest pressure that occurred was 1112 psig which was within the tolerance of the SRV setpoint. Low-Low set operation provided automatic pressure control following the initial pressure reduction until operators established control to lower the pressure band.

Following the initial scram level transient, injection with HPCS was procedurally over-ridden off and RCIC was automatically terminated at level 8 (219 inches) at about 1616 hours. RCIC was then used, as required, to makeup for RPV level decrease primarily as a result of SRV manual operation. SRVs were being operated for RPV pressure control. On August 14, 2003, at about 1925 hours, level control was shifted to HPCS. Continued use of RCIC would have resulted in an automatic isolation of RCIC due to high steam tunnel temperature. The increasing steam tunnel temperature was caused by not having ventilation. The ventilation was de-energized due to the loss of off-site power. HPCS was used for level control until the LPCS fill and vent was completed and it was placed in service at 0230 hours on August 15. The pressure at that time was being maintained at 100 to 250 psig. RHR A was used for suppression pool cooling from 1425 hours until 1433 hours on August 15, 2003 following fill and venting of that system. Shutdown cooling operation using RHR A was commenced at 1934 hours on August 15, 2003. The plant achieved cold shutdown, Mode 4, at 0120 hours on August 16, 2003.

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Loss of power to the main steam line leak detection system caused the isolation of the main steam line isolation valves. Following the power loss, the feedwater pumps tripped, reactor recirculation pumps tripped, isolation signals were received for residual heat removal, balance of plant, reactor water cleanup and sample system. The emergency diesel generators [EK] received an automatic start signal. Within 10 seconds, the division 1 and 2 diesel generators began to supply power to their respective busses. The SRVs opened in pressure relief mode to control RPV pressure. About 2 seconds later the division 3 diesel generator began supplying power to its electrical bus. HPCS and RCIC started on RPV level 2 (130 inches above top of active fuel) and injected into the RPV to restore level. RPV level and pressure were restored and stabilized. Additional operator actions included operation of the RHR B loop in suppression pool cooling mode to remove the heat added by the SRV operation. The maximum pressure during the event was 1112 psig. The maximum neutron flux level reached was 102% as a result of the pressure transient. The minimum water level reached was 103.9 inches above the top of active fuel on wide range level instruments. The maximum suppression pool temperature was 129 ° Fahrenheit.

Loss of off-site power to the safety-related emergency power supply busses for greater than 15 minutes required entry into an Unusual Event, the lowest level of the plant's emergency plan. The Unusual Event was entered at 1610 hours. The State of Ohio and Lake, Ashtabula and Geauga counties were notified of the Unusual Event at 1625 hours and the NRC was notified at 1635 hours. Subsequently, it was recognized that power was not available at the EOF and the BEOF. Although the activation of the EOF and BEOF was not required for this event, this condition was reported to the NRC via the Emergency Notification line at 2225 hours. The Unusual Event was terminated at 1952 hours on August 15, 2003, following restoration of off-site power to the safety-related emergency power supply busses and stabilization of the off-site power supply.

The following equipment deficiencies were noted during the transient and shutdown following the scram:

The LPCS/RHR A water-leg pump was found running but not supplying adequate keep-fill pressure after receipt of low pressure alarms. As a result, the LPCS and the RHR A pumps were placed in secured status at 1847 hours and were made inoperable until verification was performed that they were adequately filled. Additionally, RHR B was inoperable for injection at 1636 hours when it was placed in suppression pool cooling. This combination resulted in 3 ECCS injection pumps being unavailable. Three injection pumps inoperable requires entry into Technical Specification 3.0.3 which requires the plant to be in cold shutdown within the following 37 hours. Operation in this condition continued until 2002 hours on August 15, 2003, when the RHR A system was declared operable, a period of about 25 hours and 15 minutes. LPCS was subsequently declared operable at 0318 hours on August 16, 2003. Entry into Technical Specification 3.0.3 for greater than 1 hour is reportable per 10CFR50.73(a)(2)(i)(B), as a condition prohibited by Technical Specifications.

Subsequent investigation identified on 9/11/03, that the LPCS/RHR A water-leg pump air binding was the result of a pressurized air bubble that had been trapped within the associated division 1 feedwater leakage control system (FWLCS) piping. The air bubble volume was calculated to be a maximum of 2 cubic feet at normal water-leg pump discharge pressure, approximately 44 psig. When the water-leg pump lost power, the discharge pressure decreased allowing the air bubble to expand, to as much as 8 cubic feet at atmospheric pressure, and enter the water-leg pump discharge header, the water-leg pump case, its suction piping and recirculation piping. When the pump was re-energized the water-leg pump was unable to clear the air from the pump and required venting.

The combustible gas drywell purge inboard containment isolation valve failed to close. The outboard valve in the containment penetration closed as required to provide the required safety function, which was to isolate the penetration.

The Division 1 diesel generator tripped on reverse power while being removed from service. The diesel was placed in standby and was considered to be operable until 1300 hours on August 21, 2003, when it was identified that the voltage regulator was set above the required Technical Specification limit. This condition will be reported in a separate licensee event report (LER 2003-003).

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Reactor water samples were not obtained within 4 hours as required by the Operating Requirements Manual and the Off-site Dose Calculation Manual (non-Technical Specification).

The reactor water cleanup pumps (RWCU) tripped about 90 seconds prior to the loss of off-site power.

The offgas treatment system isolated as a result of the loss of power to the offgas post-treatment radiation monitor about 3 seconds prior to the scram.

III. CAUSE OF EVENT

The cause of the generator trip was under-frequency due to grid instabilities that resulted in the loss of off-site power (LOOP). The generator trip caused the actuation of the generator lockout relay and caused the turbine to trip resulting in a turbine control valve fast closure signal. The turbine control valve fast closure signal caused an automatic reactor protection system actuation (reactor scram). As a result of the loss of off-site power, power was lost to the safety-related emergency power supply busses.

The cause of the air binding in the water-leg pump was determined to be inadequate design of the division 1 water-leg pump piping system that resulted in a collection point for air in the FWLCS system. Past venting procedures failed to remove entrapped air from two high point locations in the division 1 LPCS system and LPCS/RHR A water-leg pump piping. Subsequent venting, on a periodic basis, has resulted in minimal accumulation of air in the affected piping and assures a similar condition will not recur. The time required to accumulate sufficient air in the pipe to cause air binding of the water-leg pump when de-energized is currently being evaluated. This information is required to evaluate the impact of this condition on past operability of the LPCS, RHR A and division 1 FWLCS systems. This evaluation will be provided in a supplement to this LER.

The combustible gas drywell purge inboard containment isolation valve failed to close. Troubleshooting of the condition failed to identify a cause; the circuitry functioned as designed during testing. Review of the design and re-enactment of the event did not identify any failed or degraded components. The most likely cause was the failure of the K36 or K39 relay to reposition. The K36 relay is an interposing relay that provides isolation between the non-safety drywell radiation monitor and the safety-related valve control circuit. The K39 relay is in the override open circuit. It prevents the valve closing circuit from being energized when the valve is manually overridden open.

The loss of the EOF and the BEOF was the result of the widespread power outage. Although these facilities were not required to be activated, additional backup facilities were identified. This information was communicated to the NRC at 2345 hours. Potential facilities that were identified included the Perry Technical Support Center, the Lake County EOC, the Blaise-Naimeth minimum-security jail and the Job and Family Services Center. Power was available at each of these locations.

The inability to obtain a reactor water sample from the normal sample location was due to the loss of electrical power. The initial attempt to obtain a sample from the Post Accident Sample System (PASS) was also unsuccessful. The PASS system is the current contingency system for post accident samples that was committed to when PASS was removed from Technical Specifications. The PASS system valves were cycled several times resulting in a successful sample. The apparent cause of the inability to initially obtain a sample was a temporary flow obstruction that was eventually freed by cycling the valves during numerous attempts to line up sample flow.

The RWCU pumps tripped due to low suction flow as a result of loss of power to the suction valve interlock circuit. The suction valve interlock circuit is powered from non-safety 120 volt AC bus, K-1-N. It was likely that the voltage dropped low enough to cause the system to trip. All equipment operated correctly for the fluctuating power condition.

The offgas isolation was determined to have been caused by voltage fluctuations affecting the offgas post treatment

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radiation monitor. The radiation monitor provides isolation signals to the off-gas system on both hi radiation and a downscale signal. This condition had no impact since the main steam isolation valves received an isolation signal and closed about 4 seconds later.

IV. SAFETY ANALYSIS

This event, a LOOP, was compared to the loss of all grid connection event that is evaluated in the updated safety analysis report (USAR), section 15.2.6. Note that a LOOP, although a safety significant event, is less severe than the station blackout (SBO) event that is evaluated in USAR Appendix 15H. The loss of all grid connection event is categorized as an incident of moderate frequency, potential to occur about every 20 years. The sequence of actual events followed those as listed in the USAR. An exception was that SRVs opened later as a result of a slower pressure increase (about 9 seconds after MSIV isolation). The conditional core damage probability (CCDP) calculated for the loss of all grid event was 1.25E-04.

The LPCS/RHR A water-leg pump air binding event of August 14, 2003, resulted in the RHR A and the LPCS pumps being declared inoperable. Had a design bases event LOOP, concurrent with a loss of coolant accident (LOCA) occurred, the air binding would have still been localized to the water-leg pump piping and would have had no impact on the LPCS or RHR A pumps. The LPCS and RHR A pumps would have automatically started upon receipt of the LOCA initiation signal prior to injection system depressurization. (The impact is currently being confirmed in PNPPs corrective action program and will be communicated in a supplemental report.) Additionally, the LPCS and RHR A pumps are just 2 of several sources of makeup that can be used during a LOOP event. This condition had no significant impact on the event (LOOP). Due to the difference in piping configuration, the division 2 (RHR B and C), HPCS and RCIC water-leg pumps are not affected.

V, CORRECTIVE ACTIONS

The grid instability that caused the generator trip and resulted in the reactor scram is still being reviewed by FirstEnergy. Lessons learned by the industry that apply to PNPP will be reviewed for incorporation. The operation of the turbine, generator and main transformer were assessed. No damage to this equipment was identified to have occurred as a result of this event.

The LPCS/RHR A water-leg pump and the feedwater leakage control piping was vented and returned to normal operation. Initial interim measures were to vent the piping weekly until the appropriate interval could be determined. The piping is currently being vented at two-week intervals. Procedures were revised to add appropriate vent points. Design initiatives will be explored to modify the FWLCS piping to avoid or reduce the potential for air collection within the division 1 FWLCS piping.

The combustible gas drywell purge inboard containment isolation valve relays, K36 and K39, were cycled and the circuitry functioned as designed. The condition was entered in the corrective action program and the relays were conservatively scheduled for replacement.

Additional backup facilities were identified during the event that could have been used as an EOF during the event.

The inability to obtain a timely reactor water sample was entered into the corrective action process for trending purposes. No additional actions are required.

VI. PREVIOUS SIMILAR EVENTS

No previous loss of off-site power event or pump air binding event was identified to have occurred at the PNPP.

Energy Industry Identification System (EIIS) codes are identified in the text in the format [xx].