50-410
3/7/2000

Distribution Sheet

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From: Esperanza Lomosbog

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Subject:
Nine Mile Point 2,Two Standby Liquid Control Valves Not Tested As Required By Technical Specification 4.0.5.Licensee Event Report

APR 04 2000

A04

Body:
ADAMS DISTRIBUTION NOTIFICATION.

Electronic Recipients can RIGHT CLICK and OPEN the first Attachment to View the Document in ADAMS. The Document may also be viewed by searching for Accession Number ML003696160.

IE22 - 50.73/50.9 Licensee Event Report (LER), Incident Rpt, etc.

Docket: 05000410

Niagara Mohawk

March 7, 2000
NMP2L 1940

United States Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555

RE: Docket No. 50-410
LER 99-19, Supplement 1

Gentlemen:

In accordance with 10CFR50.73(a)(2)(i)(B), we are submitting LER 99-19 Supplement 1, "Two Standby Liquid Control Valves Not Tested As Required By Technical Specification 4.0.5."

Corrective Action 2 was to revise a safety classification determination and to initiate a licensing document change request by January 31, 2000. The purpose of this supplement is to inform you that Niagara Mohawk Power Corporation completed this corrective action on February 24, 2000.

Very truly yours,

Michael F. Peckham
Plant Manager - NMP2

MFP/CES/tmk
Attachment

xc: Mr. H. J. Miller, Regional Administrator, Region I
Mr. G. K. Hunegs, NRC Senior Resident Inspector
Records Management

NRC FORM 366 U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104
EXPIRES:

LICENSEE EVENT REPORT (LER)

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Nine Mile Point Unit 2	05000410	01 OF 05

TITLE (4)
Two Standby Liquid Control Valves Not Tested As Required By Technical Specification 4.0.5

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 NAMES	DOCKET NUMBER(S)
10	26	99	99	019	01	03	07	00	N/A	
									N/A	

OPERATING MODE (9): 1

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

POWER LEVEL (10)				
100%	☐ 20.2201(b)	☐ 20.2203(a)(2)(v)	☒ 50.73(a)(2)(i)	☐ 50.73(a)(2)(viii)
	☐ 20.2203(a)(1)	☐ 20.2203(a)(3)(i)	☐ 50.73(a)(2)(ii)	☐ 50.73(a)(2)(x)
	☐ 20.2203(a)(2)(i)	☐ 20.2203(a)(3)(ii)	☐ 50.73(a)(2)(iii)	☐ 73.71
	☐ 20.2203(a)(2)(ii)	☐ 20.2203(a)(4)	☐ 50.73(a)(2)(iv)	☒ OTHER 50.73(a)(2)(i)(B)
	☐ 20.2203(a)(2)(iii)	☐ 50.36(c)(1)	☐ 50.73(a)(2)(v)	*(Specify in Abstract below and in Text, NRC Form 366A)*
	☐ 20.2203(a)(2)(iv)	☐ 50.36(c)(2)	☐ 50.73(a)(2)(vii)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
Stephen Geier, Manager Engineering	(315) 349-7887

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

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO EPIX	CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO EPIX

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 fifteen single space typewritten lines)* (16)

On October 26, 1999, while at 100 percent power, Niagara Mohawk Power Corporation identified that two standby liquid control system valves were not being reverse flow tested as required by American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code Section XI. Therefore, Technical Specification Surveillance Requirement 4.0.5 was not met. This condition was discovered as a result of the corrective actions described in Licensee Event Report 99-11 (Valves Not Correctly Tested as Required By Technical Specification 4.0.5).

The cause was a misapplication of the design basis and design standards. Contributing to the cause was inadequate reviews for the safety classification determinations and the safety evaluation that removed the valves from the Inservice Testing Program.

Valves 2SLS*V12 and 2SLS*V14 were added to the Second Ten-Year Interval Inservice Testing Program and satisfactorily reverse flow tested. The design documents will be revised and a licensing document change request will be initiated to incorporate changes to the Updated Safety Analysis Report. Additionally, the population of valves that are only tested in one direction will be reviewed to ensure adequate testing is being performed.

I. DESCRIPTION OF EVENT

On October 26, 1999, while at 100 percent power, Niagara Mohawk Power Corporation (NMPC) identified that two standby liquid control system check valves were not being reverse flow tested. The Updated Safety Analysis Report states that in the event a relief valve failed open, check valves are provided to prevent bypass flow from one train through an open relief valve on the other train. Therefore, the valves must be able to close to prevent this bypass flow. The valves are in the Inservice Testing Program, but were not reverse flow tested because reverse flow prevention was not considered an active safety function. Therefore, Technical Specification Surveillance Requirement 4.0.5 was not met.

The standby liquid control system consists of one boron storage tank, two independent trains (each train has a suction line, a pump, a relief valve, and a check valve), and downstream of these components, the two trains combine in a common delivery line to the reactor pressure vessel. Check Valves 2SLS*V12 and 2SLS*V14 are located on the pump discharge lines downstream of the pump and relief valve. The relief valve outlet is directed back to its pump suction line. In the event that the relief valve opened and failed to reclose, Check Valves 2SLS*V12 and 2SLS*V14 would prevent bypass flow from one train back through an open relief valve in the other train.

A review of the First Ten-Year Inservice Testing Program documentation revealed that the valves were reverse flow tested. The valves' classification for the reverse flow direction were changed from active to passive in the Inservice Testing Program based on Safety Classification Determination 91-047 and Safety Evaluation 95-047. Safety Classification Determination 91-047 stated that the standby liquid control system is an independent backup to the control rod drive system, and that the standby liquid control system was not therefore required to meet the single failure criterion. The safety classification determination did not address failure of a relief valve coupled with the failure of the untested check valve to close, which would result in both standby liquid control trains being inoperable. Safety Evaluation 95-047, approved in 1997, was intended to resolve inconsistencies between the Updated Safety Analysis Report and the Inservice Testing Program. The safety evaluation relied on the safety classification determination and the change was approved. In December 1997, the Inservice Testing Program was revised to eliminate reverse flow testing of the check valves.

This condition was identified as a result of corrective actions described in Licensee Event Report 99-11 (Valves Not Correctly Tested as Required by Technical Specification 4.0 5). These two valves were included in the population of approximately 300 valves in the Inservice Testing Program that were classified as passive or had testing requirements reduced and were being reviewed for proper testing requirements.

II. CAUSE OF EVENT

The cause of the incomplete testing of the two valves was a misapplication of the design basis and design standards. Contributing to the cause was inadequate reviews for the safety classification determination and the safety evaluation that approved the change to the Inservice Testing Program.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)					PAGE (3)
		YEAR		SEQUENTIAL NUMBER		REVISION NUMBER	
Nine Mile Point Unit 2	05000410	99	-	19	-	01	03 OF 05

TEXT (If more space is required, use additional NRC Form 366A's) (17)

III. ANALYSIS OF EVENT

This event is reportable in accordance with 10CFR50.73(a)(2)(i)(B), "Any operation or condition prohibited by the plant's Technical Specifications." Due to their active function, Valves 2SLS*V12 and 2SLS*V14 are required to be reverse flow tested in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable addenda. These valves were not reverse flow tested. Therefore, NMPC did not meet Technical Specifications Surveillance Requirement 4.0.5.

The standby liquid control system is required only to shutdown the reactor and keep the reactor from going critical as the reactor cools. The system is needed only in the improbable event that sufficient control rods cannot be inserted in the reactor to accomplish shutdown and cooldown in the normal manner. To assure the availability of the standby liquid control system, two trains of components are provided in parallel. In each division train, a check valve is provided downstream of a relief valve in the pump discharge line to prevent bypass flow in the event that a relief valve opened and failed to reclose.

The valves were satisfactorily reverse flow tested, which demonstrated that the valves were able to perform their safety function.

NMPC performed a probabilistic risk analysis for this condition and determined that it is non-risk significant because subsequent testing of the valves was satisfactory.

Based on the information provided above, the failure to perform inservice testing on the two valves used in the standby liquid control system did not adversely affect the health and safety of the general public or plant personnel.

IV. CORRECTIVE ACTIONS

1. NMPC declared the standby liquid control system inoperable until the testing requirements for Valves 2SLS*V12 and 2SLS*V14 were added to the Inservice Testing Program and the valves were satisfactorily reverse flow tested.

2. Safety Classification Determination 91-047 was revised, and a licensing document change request was initiated to incorporate the changes into the active valve table during the next update of the Updated Safety Analysis Report. These actions were completed on February 24, 2000.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)					PAGE (3)
		YEAR		SEQUENTIAL NUMBER		REVISION NUMBER	
Nine Mile Point Unit 2	05000410	99	-	19	-	01	04 OF 05

TEXT (If more space is required, use additional NRC Form 366A's) (17)

IV. CORRECTIVE ACTIONS (Cont'd)

3. In addition to the review of approximately 300 valves that were classified as passive or had their testing requirements reduced, NMPC will review the safety classification determinations and ASME XI Inservice Test Program and basis documents requirements associated with valves that are only tested in one direction to ensure that the safety classification determinations and testing requirements are correct by March 31, 2000.

4. The majority of the corrective actions described in Licensee Event Reports 99-09, 99-11, 99-14, Supplement 1 determine the extent of condition, address inadequacies in past management's expectations and communication of these expectations, and address the failure of plant personnel to adhere to management's expectations for reviewing and researching design and licensing documents. These corrective actions address the causes in these areas.

V. ADDITIONAL INFORMATION

A. Failed components: none.

B. Previous similar events:

Licensee Event Reports 99-14 Supplement 1 (Missed Technical Specification ASME Section XI Surveillance Testing), 99-09 (Nonconformance with Technical Specification Regarding ASME Section XI Class 2 Check Valve Reverse Flow Testing), and 99-08 (Inadequate Surveillance of Reactor Core Isolation Cooling Check Valve) describe NMPC's failure to properly test safety-related check valves. These licensee event reports were identified as the result of the investigation stemming from Licensee Event Report 97-07 (Violation of Technical Specifications Regarding ASME Code Section XI Class 2 Weld Inspection Requirements Due to Improper Use of an Exemption). Licensee Event Report 99-11 (Valves Not Correctly Tested as Required by Technical Specification 4.0.5) identifies 26 valves in multiple systems that were improperly reclassified as passive valves and were not being properly tested. Licensee Event Report 99-18 (Valves in the Steam Condensing Mode Were Not Tested as Required by Technical Specification 4.0.5) also, identified four valves in the steam condensing mode were not being properly tested. The corrective actions from Licensee Event Report 99-11 would have identified these additional valves.

NRC FORM 366A	U.S. NUCLEAR REGULATORY COMMISSION	APPROVED OMB NO. 3150-0104 EXPIRES:
LICENSEE EVENT REPORT (LER) TEXT CONTINUATION		ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION. REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)					PAGE (3)
		YEAR		SEQUENTIAL NUMBER		REVISION NUMBER	
Nine Mile Point Unit 2	05000410	99	-	19	-	01	05 OF 05

TEXT (If more space is required, use additional NRC Form 366A's) (17)

C. Identification of components referred to in this Licensee Event Report:

Components	IEEE 803A Function	IEEE 805 System ID
Standby Liquid Control System	N/A	BR
Check Valve	V	BR
Relief Valve	RV	BR
Pump	P	BR
Reactor	RCT	AC

50-410
3/7/2000

Distribution Sheet

Priority: Normal

From: Esperanza Lomosbog

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ID: 003696165:1

Subject:
Nine Mile Point 2,Reactor Trip Due to Feedwater Master Controller Failure,Licensee Eve nt Report

APR 0 4 2000

A04

Body:
ADAMS DISTRIBUTION NOTIFICATION.

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IE22 - 50.73/50.9 Licensee Event Report (LER), Incident Rpt, etc.

Docket: 05000410

Niagara Mohawk

March 7, 2000
NMP2L 1941

United States Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555

RE: Docket No. 50-410
LER 99-10, Supplement 1

Gentlemen:

In accordance with 10 CFR 50.73(a)(2)(iv) and 10 CFR 50.73(a)(2)(v), we are submitting Licensee Event Report 99-10, Supplement 1, "Unit 2 Reactor Trip due to a Feedwater Master Controller Failure."

This report removes the corrective action to install an electronic dampening circuit modification for the reactor core isolation cooling flow transmitter. Niagara Mohawk Power Corporation re-evaluated this corrective action and concluded it is not relevant to the causes identified in this licensee event report. Furthermore, this corrective action, if completed, would not have corrected or prevented the reactor core isolation cooling system trip that occurred on March 3, 2000. Therefore, this corrective action has been deleted from the licensee event report.

Very truly yours,

Michael F. Peckham
Plant Manager - NMP2

MFP/CES/tmk
Attachment

xc: Mr. H. J. Miller, Regional Administrator, Region I
Mr. G. K. Hunegs, NRC Senior Resident Inspector
Records Management

IE22

NRC FORM 366	U.S. NUCLEAR REGULATORY COMMISSION	APPROVED OMB NO. 3150-0104 EXPIRES:
LICENSEE EVENT REPORT (LER)		ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Nine Mile Point Unit 2	05000410	01 OF 07

TITLE (4)

Unit 2 Reactor Trip due to a Feedwater Master Controller Failure

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
06	24	99	99	010	01	03	07	00	N/A	
									N/A	

OPERATING MODE (9)	1	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: *(Check one or more of the following)* (11)			
POWER LEVEL (10) 100%		☐ 20.2201(b)	☐ 20.2203(a)(2)(v)	☐ 50.73(a)(2)(i)	☐ 50.73(a)(2)(viii)
		☐ 20.2203(a)(1)	☐ 20.2203(a)(3)(i)	☐ 50.73(a)(2)(ii)	☐ 50.73(a)(2)(x)
		☐ 20.2203(a)(2)(i)	☐ 20.2203(a)(3)(ii)	☐ 50.73(a)(2)(iii)	☐ 73.71
		☐ 20.2203(a)(2)(ii)	☐ 20.2203(a)(4)	☒ 50.73(a)(2)(iv)	☐ OTHER *(Specify in Abstract below and in Text, NRC Form 366A)*
		☐ 20.2203(a)(2)(iii)	☐ 50.36(c)(1)	☒ 50.73(a)(2)(v)	
		☐ 20.2203(a)(2)(iv)	☐ 50.36(c)(2)	☐ 50.73(a)(2)(vii)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
Don Bosnic - Operations Manager	(315) 349-7952

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO EPIX	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO EPIX
X	SJ	ECBD	B045	Yes	X	EL	RLY	A500	Yes

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 fifteen single space typewritten lines)* (16)

On June 24, 1999, at 3:41 p.m., Nine Mile Point Unit 2 automatically tripped from 100 percent power. The cause of the transient was a low reactor water level due to a failure of the feedwater master controller. Additionally, there was an unexpected partial loss of offsite power (Line 5) and the reactor core isolation cooling system failed to perform correctly in the automatic mode of operation.

The cause of the reactor trip was failure of a manual-tracking card in the feedwater master controller due to aging. The cause of the loss of Line 5 was failure of one of the main generator output breaker individual fault relays. The primary cause of the reactor core isolation cooling system flow oscillations was air found in the flow transmitter, with a contributing cause of a miscalibrated flow controller.

Corrective actions included: stabilizing the plant, replacing the feedwater manual-tracking card, replacing the main generator output breaker individual fault relay, calibrating the flow controller, and venting the reactor core isolation cooling system transmitter.

I. DESCRIPTION OF EVENT

On June 24, 1999, at 3:41 p.m., Nine Mile Point Unit 2 automatically tripped from 100 percent power. The cause of the transient was a low reactor water level due to a failure of the feedwater master controller.

Maintenance technicians were preparing to flush the feedwater flow instrument lines in accordance with a work order package. To support the work order package, operators prepared to shift the feedwater level control system from three element to single element control by shifting the master controller to manual. Immediately after this step was performed, the controller output dropped to zero and the feedwater level control valves started to close. The licensed operator noted that the level control valves were closing and attempted to manually open the valves. After verifying the valves did not open, feedwater flow was low, and reactor water level was decreasing, the operator returned the feedwater master controller to automatic. The valves began reopening to slow the reactor water level decrease. Seconds later, a reactor trip signal at Level III (159.3 inches) was received. Reactor water level started to increase until an offsite power source (Line 5) was de-energized resulting in tripping the feedwater and condensate booster pumps supplied from this electrical source. The subsequent condensate transient caused the remaining condensate booster and feedwater pumps to trip on low suction pressure.

The reactor trip resulted in a main turbine trip on reverse power as designed. The turbine trip caused a fast transfer of both 13.8 kV buses to offsite power sources. The fast transfer was completed with one 13.8 kV bus transferring to Line 5 and the other transferring to Line 6. Shortly, after the fast transfer of the 13.8 kV buses was completed, Line 5 breakers tripped unexpectedly. Division I and III lost electrical power and, as designed, both diesel generators automatically started and energized their respective buses. Prior to the event, part of the electrical system was in an off-normal condition to support planned circuit breaker maintenance. The off-normal electrical line-up resulted in the loss of power to all of the turbine electrohydraulic control system pumps and the offgas system. With the loss of electrohydraulic control system pumps and the offgas system, the condenser was eventually unavailable.

During the reactor trip, reactor water level reached a minimum of 115 inches (129.4 inches above the top of active fuel) and a maximum of 205 inches. Primary Containment Isolation Groups 4 (residual heat removal radwaste discharge and sampling valves) and 5 (residual heat removal shutdown cooling valves and other system valves) isolated due to reactor water level falling below the isolation setpoint of 159.3 (Level III). The Primary Containment Isolation Groups 4 and 5 valves were in their normal, closed position; therefore, the valves did not change position.

The operators initiated the reactor core isolation cooling system to maintain reactor vessel level following the loss of the feedwater and condensate booster pumps, and noted flow oscillations while the flow controller was in automatic. The operators placed the flow controller in manual and the oscillations stopped. Operators then used the reactor core isolation cooling system to restore and maintain reactor water level. Oscillations

I. DESCRIPTION OF EVENT (Cont'd)

were observed during each of three occasions in automatic and stopped with the flow controller in manual.

The maximum reactor pressure recorded during the transient was 1019 psig. The operators closed the outboard main steam isolation valves to minimize the cooldown rate and to isolate the condenser, which was losing vacuum as a result of the loss of electrical power to the offgas system. The main steam system safety relief valves were manually cycled to control reactor pressure by directing steam to the suppression pool.

II. CAUSE OF EVENT

The cause of the reactor trip was determined to be a failure of the feedwater master controller. Specifically, the manual-tracking card failed to provide an output signal when the feedwater master controller was switched from automatic to manual mode of operation. The manual-tracking card functions to track the feedwater level control valve in the automatic mode of operation and to maintain valve position in the manual mode of operation. The manual-tracking card failed due to aging.

Line 5 was de-energized because the backup protection scheme for the main generator output breakers tripped open all 345 kV breakers adjacent to Breaker R-230. This de-energized the 345 kV bus that powered Line 5. The cause of the backup protection scheme initiating was the failure of one individual fault relay on the main generator output breakers.

The cause of the reactor core isolation cooling system failure to operate in automatic control was determined to be air found in the flow transmitter sensing lines. The air had accumulated in the flow transmitter from the process stream. A contributing cause was a miscalibrated flow controller. The derivative setting on the flow controller was improperly set.

III. ANALYSIS OF EVENT

This event is considered reportable under 10 CFR 50.73(a)(2)(iv) and 10 CFR 50.73(a)(2)(v). 10 CFR 50.73(a)(2)(iv) requires a report when any event or condition resulted in manual or automatic actuation of any engineered safety features, including the reactor protection system. 10 CFR 50.73(a)(2)(v) requires a report when any event could have prevented the fulfillment of the safety function of a system to remove residual heat.

III. ANALYSIS OF EVENT (Cont'd)

The reactor trip was the design response to a low reactor water level. All control rods fully inserted in response to the reactor trip signal. The operators manually initiated the reactor core isolation cooling system. Although automatic control of the reactor core isolation cooling system did not function properly, operators were able to use the manual control to maintain reactor water level. The high pressure core spray system was operable at the time of the event and is designed to initiate on a Level II signal (108.8 inches). The automatic depressurization system and the low pressure emergency core cooling systems were operable throughout this event.

The conditional core damage probability for this event has been analyzed using Nine Mile Point Unit 2 probabilistic risk assessment model. The analysis included de-energizing Line 5 and the unavailability of the feedwater system and the condenser. The analysis does recognize the potential for recovery of the three systems. The analysis considered the reactor core isolation cooling system available because the system functioned to maintain reactor water level. Based on the analysis, the conditional core damage probability is 3.0E-06.

The plant response was in accordance with the Updated Safety Analysis Report transient analysis for a loss of feedwater flow, with the exception of reactor core isolation cooling system flow oscillations in the automatic mode of operation.

Based on the above analysis, there were no adverse safety consequences as a result of this event. The reactor trip posed no threat to the health and safety of the general public or plant personnel.

IV. CORRECTIVE ACTIONS

1. Operators performed scram recovery actions, and placed the plant in a stable condition.

2. Maintenance personnel replaced the feedwater manual-tracking card with a new card.

3. Based on discussions with the vendor and the industry, Technical Support personnel will develop recommendations on improving the reliability of the feedwater manual-tracking card by August 31, 1999.

4. Maintenance personnel replaced the faulty relay on the main generator output breaker.

5. Nine Mile Point Unit 2 will perform a failure analysis of the failed relay and develop additional corrective actions based on the results of this evaluation, if necessary, by November 1, 1999.

IV. CORRECTIVE ACTIONS (Cont'd)

6. Maintenance personnel bench calibrated the reactor core isolation cooling system flow controller, checked the flow transmitter for noise and grounds, vented transmitter sensing lines, and verified dynamic tuning of the flow controller.

7. Procedure N2-OSP-ICS-R002, "RCIC [Reactor Core Isolation Cooling] System flow Test," was revised to include criteria for early prediction of flow/pressure oscillations and to incorporate the use of the plant computer system parameters for trending data against a baseline. The revised procedure was performed during plant startup.

8. Procedure N2-OSP-ICS-Q@002, "RCIC [Reactor Core Isolation Cooling] Pump and Valve Operability Test and System Integrity Test and ASME [American Society of Mechanical Engineers] XI Functional Test," was revised to include a step to detect precursors to flow oscillations and to include a step to have maintenance perform system tuning if required. The pump and flow controller portions of the revised procedure were performed during plant startup.

9. Maintenance personnel are reviewing, verifying, and improving procedures to ensure proper performance and documentation of all required reactor core isolation cooling system tuning and calibration activities by August 31, 1999.

10. Trending of transmitter sensing line venting results is being used to determine the frequency required to ensure the reactor core isolation cooling system flow transmitter is free of air.

V. ADDITIONAL INFORMATION

A. Failed components:

- The feedwater manual-tracking card failed on June 24, 1999, which was the cause of the transient.

- An individual fault relay on the main generator output breaker failed on June 24, 1999, which was the cause of de-energizing Line 5.

V. ADDITIONAL INFORMATION (Cont'd)

B. Previous similar events:

Nine Mile Point Unit 2 has had a number of instances where engineered safety feature actuations occurred (License Event Reports 97-04, 96-04, 98-05, 98-06, 98-13, and 99-05). The root causes of these licensee event reports were different than the root cause for this event. Therefore, the corrective actions from these licensee event reports would not have prevented this engineered safety feature actuation from occurring.

Licensee Event Reports 95-10 and 98-06 document partial losses of offsite power. Both of these instances, the breaker backup protection scheme functioned as designed. The root causes of these licensee event reports were different than the root cause for this event. Therefore, the corrective actions from these two licensee event reports would not have prevented this partial loss of offsite power.

Licensee Event Report 99-05 documented a failure of the reactor core isolation cooling system. The root cause was determined to be that the overspeed trip mechanism on the trip throttle valve was incorrectly aligned. Again the root cause was different; therefore, the corrective actions from Licensee Event Report 99-05 would not have prevented this reactor core isolation cooling system failure.

C. Identification of components referred to in this licensee event report:

Components	IEEE 803A Function	IEEE 805 System ID
Reactor Core Isolation Cooling System	N/A	BN
Reactor Core Isolation Cooling Flow Controller	FC	BN
Reactor Core Isolation Cooling Flow Transmitter	FT	BN
Residual Heat Removal Shutdown Cooling Valve	ISV	BO
Residual Heat Removal Isolation Valve	ISV	BO
Electrical Bus	BU	EA and EB

TEXT (If more space is required, use additional NRC Form 366A's) (17)

V. ADDITIONAL INFORMATION (Cont'd)

C. Identification of components referred to in this licensee event report (Cont'd):

Electrical Breakers	BKR	FK
Electric Relay	RLY	EL
Main Turbine	TRB	TA
Turbine Electrohydraulic Control Pump	P	JJ
Safety Relief Valves	RV	SB
Main Steam Isolation Valves	ISV	SB
Reactor Feedwater Pumps	P	SJ
Reactor Feedwater Master Controller	LC	SJ
Reactor Feedwater Manual-Tracking Card	ECBD	SJ
Reactor Feedwater Level Control Valve	LCV	SJ
Condensate Booster Pumps	P	SD
Condenser	COND	SG
Offgas System	N/A	WF
High Pressure Core Spray	N/A	BG
Diesel Generator	DG	EK
Suppression Pool	N/A	NH