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SAFETY ASSESSMENT REPORT

OF

8/13/91 SITE AREA EMERGENCY EVENT-NINE MILE POINT UNIT 2

PREPARED BY: REVIEW/CONCURRED BY:

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FINAL APPROVAL: ____________________________
EXECUTIVE VP NUCLEAR

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DEFINITION OF ACRONYMS

ADS - Automatic Depressurization System
APRM - Average Power Range Monitor
ARI - Alternate Rod Insertion
ASME - American Society of Mechanical Engineers
ATWS - Anticipated Transient Without Scram

BOP - Balance of Plant
BWROG - Boiling Water Reactor Owners Group

CAN - Community Alert Network
CCP - Reactor Building Closed Loop Cooling
CPR - Critical Power Ratio
CST - Condensate Storage Tank

DBA - Design Basis Accident
DEC - Department of Environmental Conservation
DRMS - Digital Radiation Monitoring System

ECCS - Emergency Core Cooling System
ENS - Emergency Notification System
EOC RPT - End of Cycle Recirculation Pump Trip
EOF - Emergency Operations Facility
EOP - Emergency Operating Procedure
EPG - Emergency Procedure Guidelines
EPP - Emergency Plan Implementing Procedure
EQEDC - Equipment Qualification Environmental Design Criteria
ERF - Radwaste Computer
ERF's - Emergency Response Facilities
ERO - Emergency Response Organization

GEMS - Gaseous Effluent Monitoring System
GETARS - General Electric Transient and Accident Recorder System

HPCS - High Pressure Core Spray System
HRA - Human Reliability Analysis

IPE - Individual Plant Evaluation

JAF - James A. FitzPatrick Nuclear Station

LCO - Limiting Condition for Operation
LOCA - Loss of Coolant Accident
LPCI - Low Pressure Coolant Injection
LPRM - Local Power Range Monitor

MSIV - Main Steam Isolation Valve

NMPC - Niagara Mohawk Power Corporation
NMP2 - Nine Mile Point Unit 2
NRC - Nuclear Regulatory Commission

OSC - Operations Support Center

PAM - Post Accident Monitoring

RCIC - Reactor Core Isolation Cooling
RCS - Recirculation System
RHR - Residual Heat Removal
RMCS - Reactor Manual Control System
RPS - Reactor Protection System
RPV - Reactor Pressure Vessel
RRCS - Redundant Reactivity Control System
RSCM - RHR Shutdown Cooling Mode
RSCS - Rod Sequence Control System
RSS - Remote Shutdown System
RWCU - Reactor Water Cleanup System
RWM - Rod Worth Minimizer

SAE - Site Area Emergency
SDV - Scram Discharge Volume
SED - Site Emergency Director
SER - Safety Evaluation Report
SLCS - Standby Liquid Control System
SPDS - Safety Parameter Display System
SRV - Safety Relief Valve
SSS - Station Shift Supervisor

TCV - Turbine Control Valve
TS - Technical Specifications
TSC - Technical Support Center
TSV - Turbine Stop Valve

UPS - Uninterruptable Power Supply
USAR - Updated Safety Analysis Report

EXECUTIVE SUMMARY

SCOPE

This Safety Assessment Report provides a safety review of the Site Emergency Event of 8/13/91 at Nine Mile Point Unit 2 to evaluate the response of plant equipment and human factor issues. This Safety Assessment Report does not evaluate:

1) Root cause of the failure of Phase B Main Transformer 2MTX-XM1B;

2) Root cause of the failure of Normal Uninterruptable Power Supplies;

3) Emergency Plan Response

These items are evaluated in separate reports.

The assessment described within this report was the result of a detailed review of the following: plant safety systems response, non-safety systems on the plant's response, and of operational activities during the event.

OBJECTIVE

This safety assessment report provides description and assessment of the physical plant and operator response during the Site Area Emergency at Nine Mile Point Unit 2. The background of this event, analysis of the conditions (prior to, during and after), and conclusions drawn provides an accurate review of the event and recommendations to ensure that a similar circumstance cannot occur.

ASSESSMENT ABSTRACT

EVENT

On August 13, 1991 at 0548 hours, Nine Mile Point Unit 2 (NMP2) experienced a failure of the phase B main transformer and a subsequent failure of the normal uninterruptable power supplies (2VBB-UPS1A-D, G); this incident resulted in a reactor scram and a loss of non-safety related control room indication. These conditions mandated entry into a site area emergency classification as specified by Emergency Action Procedure S-EAP-2.

ASSESSMENT CONCLUSIONS

As a result of the evaluation presented in subsequent portions of this safety assessment report, the following conclusions can be made:

(1) The plant event did not adversely affect the safe shutdown process as described in USAR Section 7.4.

(2) The occurrence of any plant transient, as described in Chapter 15 of the USAR, concurrent with this event, would be bounded by the Cycle 2 reload analyses.

(3) The occurrence of a DBA-LOCA, as described in Chapter 6 of the USAR, concurrent with this event, would be bounded by the Cycle 2 reload analyses.

(4) During the event, the various water levels experienced in the RPV:

    (a) did not result in flooding of the Main Steam Liner
    (b) did not result in initiation of any ECCS, and
    (c) did not uncover the fuel.

(5) During the event:

    (a) no ECCS systems were initiated
    (b) all Class 1E safety related buses remained continuously energized from both 115KV offsite power feeder
    (c) All three Divisional diesel generators did not and were not required to start.

(6) During this event, an actual fire, if it had occurred, would have been detected and extinguished in a timely manner, therefore, preserving the safe shutdown capability of the plant.

(7) The protective relaying schemes actuated and performed their intended function as designed.

(8) Operator response and the use of emergency operating procedures resulted in the stabilization of all plant parameters and were, therefore, effective and appropriate.

(9) At no during the event did drywell pressure rise sufficiently to initiate Primary Containment Isolation.

In conclusion, based upon the analysis contained in this report and the previously identified conclusions, at no time during this event was public health and safety affected.

ASSESSMENT CONCLUSIONS

As a result of the evaluation presented in subsequent portions of this safety assessment report, the following conclusions can be made:

(1) The plant event did not adversely affect the safe shutdown process as described in USAR Section 7.4.

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(3) The occurrence of a DBA-LOCA, as described in Chapter 6 of the USAR, concurrent with this event, would be bounded by the Cycle 2 reload analyses.

(4) During the event, the various water levels experienced in the RPV:

  (a) did not result in flooding of the Main Steam Lines
  (b) did not result in initiation of any ECCS, and
  (c) did not uncover the fuel.

(5) During the event:

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In conclusion, based upon the analysis contained in this report and the previously identified conclusions, at no time during this event was public health and safety affected.

BACKGROUND AND DESCRIPTION OF EVENT

On August 13, 1991 at 0548 hours, Nine Mile Point Unit 2 (NMP2) experienced a failure of the phase B main transformer and subsequent failure of the normal UPS's; this incident resulted in a reactor scram and a loss of control room annunciators. These conditions mandated a declaration of a Site Area Emergency classification as specified by Emergency Action Procedure S-EAP-2.

Prior to the event the NMP2 was in operational condition 1 (RUN) at 100 % thermal power. Residual Heat Removal Low Pressure Coolant Injection - Loops B and C were removed from service for maintenance prior to the events however they were returned to service during the event. Several Limiting Conditions for Operations (LCO's) were entered prior to the event for various process effluent monitors. Aside from the LCO's and the RHR LPCI Loop B&C outage, plant operations for all purposes was normal.

For the sequence of events for this incident refer to the SCRAM summary 91-01, N2-RAP-6 (Attachment A).

SUMMARY OF CAUSES

The initiating event was the failure of 2MTX-XM1B Phase B Main Output Transformer. Subsequently the Normal UPSs 2VBB-UPS1A, 1B, 1C, 1D, and 1G failed.

ANALYSIS

Preamble

As a result of the August 13, 1991 electrical transient, subsequent plant response, and Site Area Emergency at Nine Mile Point Unit 2 the station's response organizations responded and appropriately took the plant to cold shutdown. Operability of the Nine Mile Point Unit 1 and J. A. Fitzpatrick plants were not affected, however, J. A. FitzPatrick declared and Alert. NRC Augmented Inspection Teams and subsequently Incident Investigation Teams arrived at the site to assess the potential generic safety significance of the multiple electrical component failures and the challenges this presented to operator understanding and response to the imposed transient. This action was taken by the NRC independent of the analysis and assessment performed by Niagara Mohawk Power Corporation (NMPC).

This section of the report discusses the results of NMPC's assessment of physical plant and human factors issues. Additionally, this section discusses the potential impacts of the electrical transient and subsequent plant responses on nuclear safety.

EVALUATION OF PLANT EVENT AGAINST NMP2 LICENSING BASIS FOR PLANT SAFE SHUTDOWN PROCESS

The purpose of this evaluation is to demonstrate that the failure of the Phase B main output transformer and the tripping of the normal UPSs (2VBB-UPS1A-D, G) did not adversely affect the safe shutdown process described in the Updated Safety Analysis Report (USAR). The evaluation process compares the USAR discussion of the safe shutdown process with the evolution of the plant event. Each safe shutdown system is individually discussed and the response to the plant event is evaluated.

Introduction

USAR Section 7.4 indicates that instrumentation and controls of the following systems can be used for safe shutdown:

(1) Reactor Core Isolation Cooling System (RCIC),
(2) Standby Liquid Control System (SLCS),
(3) RHR Shutdown Cooling Mode (RSCM), and
(4) Remote Shutdown System (RSS).

The sources that supply power to the above safe shutdown systems originate from onsite AC/DC safety-related buses which remained available throughout event. Therefore, the tripping of the normal UPSs (1A-D,1G) and the failure of the Phase B main output transformer at no time adversely affected the safety-related safe shutdown capability of NMP2. The design basis at Nine Mile Point Unit 2 does not rely upon the operability of non-safety related systems to accomplish a safe shutdown and therefore not evaluated.

RCIC

RCIC was operable at the initial portion of the event to support core cooling and maintenance of sufficient reactor water inventory. However, as the event progressed, RCIC was declared inoperable due to the lack of full close indication in the Control Room for 2ICS*AOV156 (primary containment isolation valve). However, the RCIC was no longer needed at the time it was declared inoperable for RPV level/pressure control due to RPV pressure being within the range of operation of RHR in the shutdown cooling mode. In addition, High Pressure Core Spray (HPCS), LPCI-A Loop, LPCS, and all 7 ADS/SRVs were operable. Also, the lack of full closure indication for 2ICS*AOV156 would not have prevented the operation

of RCIC since RCIC inoperability resulted from intentionally deactivating the redundant primary containment isolation valve, 2ICS*MOV126, in the closed position. Therefore, the inoperability of RCIC did not adversely affect the safe shutdown of NMP2.

SLCS

The control rod position indication in the Control Room was inoperable due to the tripping of the normal UPSs. As a result, the operators could not determine that all control rods had been fully inserted during the manually initiated SCRAM. Therefore, the operators entered N2-EOP-C5 "Level/Power Control" due to the lack of control rod indication. However, the APRM back panel meters in the control room were operable and indicated downscale. In addition, in accordance with EOPs, the ADS auto-initiation logic was inhibited. This action is consistent with the NMP2 plant specific ATWS analysis, as documented in General Electric Report NEDE-22013, entitled "Design Analysis and SAR Inputs for ATWS Performance and Standby Liquid Control System, Nine Mile Point Unit 2 Plant" as referenced in section 15.8.4 of the USAR. After re-energization of normal UPS loads, it was determined that a substantial majority of the control rods were inserted which was consistent with the APRM back panel meters' downscale indication. Upon further action (resetting the SCRAM), operators determined that all control rods were fully inserted and that an ATWS event had not occurred. Therefore, if an actual ATWS event had occurred during this plant transient, the failure of the main output transformer and the normal UPSs would not have adversely affected the ability of the plant in conjunction with operator action to respond to an ATWS event as analyzed in the USAR. This conclusion is supported by the following factors:

(1) Both trains of Standby Liquid Control (SLCS), as described in USAR section 7.4.1.2, were fully operable prior to and during the event;
(2) The redundant reactivity control system (RRCS), which includes other ATWS mitigation features, was also operable (reference USAR Section 7.6.1.8 for a discussion of RRCS);
(3) Operator actions, based upon an assumed ATWS event, was consistent with both EOP directions and the NMP2 plant specific ATWS analysis.

RSCM

Shortly after RCIC was started, operators placed 2RHS*P1A in the suppression pool cooling mode of operation to remove heat buildup in the suppression pool due to RCIC operation and SRV actuations. This action is consistent with the USAR, Section 7.4.1.4, page 7.4-6.

Operators continued reactor pressure vessel (RPV) cooldown utilizing RCIC condensate system to continue cooldown and RPV level control until eventually until RPV pressure was reduced sufficiently to allow placing an RHR pump in the shutdown cooling mode of operation. Cooldown continued utilizing 2RHS*P1A in the shutdown cooling mode of operation in order to achieve a cold shutdown condition. This is consistent with the USAR, Section 7.4.1A, page 7.4-6. A cold shutdown condition for the plant is one of the pre-requisites to exiting the site emergency.

During reactor cooldown there existed a redundant safety grade method of supporting reactor cooldown if the shutdown cooling mode of operation of RHR became inoperable. The alternate shutdown cooling path uses a sufficient number of ADS SRVs, powered open from safety related buses, to establish a liquid flow path from the RPV to the suppression pool. RHR pumps are then used to direct flow back to the RPV via a LPCI line from the suppression pool through the RHR heat exchanger. This method of alternate shutdown cooling is described in USAR Section 5.4.7.1.1, page 5.4-34. The SRV's as discussed in USAR Section 1.12, are qualified to support SRV operation at NMP2 in the alternate shutdown cooling mode.

In addition, EOPs also allow the use of the steam condensing mode of RHR and the main steam line drain lines to provide alternate shutdown cooling if necessary.

Therefore, based upon the previous discussion, it can be concluded that the plant event did not adversely affect the shutdown cooling mode of RHR and the alternate shutdown cooling method as described in the USAR.

RSS

All instrumentation and controls for the remote shutdown system per TS LCO 3.3.7.4 were fully operable. The equipment operated by these controls as indicated on TS Table 3.3.7.4-2 was also fully operable.

CONCLUSION

Based upon the previous evaluation, it can be concluded that the plant event in no way adversely affected the safe shutdown process as described in the USAR.

EVALUATION OF USAR TRANSIENTS AND ACCIDENTS

The purpose of this evaluation is to demonstrate that if a Chapter 15 USAR transient or a USAR Chapter 6 Design basis accident - loss of coolant accident (DBA-LOCA) were to occur during this plant event, that the plant response would be bounded by the discussion of these transients and accidents in the USAR.

The following is a tabulation of transients analyzed in Chapter 15 of the USAR. The tabulation (USAR Table 15.0-5) identifies the USAR analyzed transient in Chapter 15, the applicable USAR subsection, and the non-safety grade system(s) and/or component(s) that were assumed to operate during a given transient.

NON-SAFETY GRADE SYSTEMS/COMPONENTS ASSUMED IN USAR TRANSIENT ANALYSIS

FSAR Section	Transient	Non-Safety Grade System or Component
MODERATE FREQUENCY EVENTS		
15.1.2	Feedwater Controller Failure with Maximum Demand	Level 8 Turbine and Feedwater Pump Trip, turbine Bypass, Relief Valves[1]
15.1.3	Pressure Regulator Failure, Open	Relief Valves
15.2.2	Load Rejection	Turbine Bypass, Relief Valves
15.2.3	Turbine Trip	Turbine Bypass, Relief Valves
15.2.4	Closure of all MSIVs	Relief Valves
15.2.5	Loss of Condenser Vacuum	Turbine Bypass, Relief Valves
15.2.6	Loss of AC Power	Turbine Bypass, Relief Valves
15.2.7	Loss of All Feedwater Flow	Recirculation Runback Relief Valves
15.3.1	Trip of One or Both Recirculation Pumps	Level 8 Turbine and feedwater Pump Trip, Turbine Bypass, Relief Valves
15.3.2	Recirculation Flow Control Failure with Decreasing Flow	Level 8 Turbine and Feedwater Pump Trip, Turbine Bypass, Relief Valves
15.4.1	Rod Withdrawal Error at Low Power	Rod Sequence Control System (RSCS)
15.4.2	Rod Withdrawal Error at Power	Rod Block Monitor
INFREQUENT EVENTS		
15.2.2	Load Rejection w/o Bypass	Relief Valves
15.2.3	Turbine Trip w/o Bypass	Relief Valves

FSAR Section	Transient	Non-Safety Grade System or Component
LIMITING EVENTS		
15.3.3	Recirculation Pump Seizure	Level 8 Turbine and Feedwater Pump Trip, Turbine Bypass, Relief Valves
15.3.4	Recirculation Pump Shaft Break	Level 8 Turbine and Feedwater Pump Trip, Turbine Bypass, Relief Valves

[1]"Relief Valves" refers to non-safety grade instrumentation in the relief mode of the SRVs

NOTE: Level 8 Trip itself provides a safety-grade initiation signal and is then isolated from the nonsafety-related controls circuitry to initiate turbine and feedwater pump trip.

The two parameters of concern when analyzing transients in Chapter 15 are delta critical power ratio (CPR) (fuel integrity), and peak RPV pressure (reactor coolant pressure boundary integrity).

Among the non-safety grade systems listed in the above tabulation, the failure of the Level 8 (L8 - reactor high water level) Trip and the failure of the turbine bypass are the events that would affect delta CPR. Loss of the main transformer causes a Load Rejection and the resulting scram trip of the plant. If the bypass fails, the event is equal to the limiting transient in the current analysis with a resulting delta CPR of 0.20. If a coincident or subsequent control failure (e.g. Feedwater control) is assumed, it has no effect on the fuel thermal margin since that is controlled by the Load Rejection event. The Feedwater Controller Failure, should it also occur, will only require a L8 trip (or manual shutoff) to control the water level in the RPV. In all events pressure is controlled by the turbine bypass (if available) or the safety relief valves.

The limiting events as defined in USAR Table 15.0-1, which are the Recirculation Pump Seizure and Recirculation Pump Shaft Break, are not typically analyzed for reload cycles in accordance with GESTAR II, since they are considered as accidents, and are bounded by the DBA LOCA analyses.

The peak vessel pressures for the analysis of transients not taking credit for non-safety grade systems and components are bounded by the peak pressure limit of the over pressure protection analysis described in USAR Section 5.2.

Based upon the previous evaluation, it can be concluded that the failure of the 1B main output transformer and tripping of the normal UPSs (1A-D, 1G), a transient like the analyzed Generator Load Rejection will occur. Failure of the turbine bypass is already analyzed (although it did work in the event experienced at NMP2). If additional control failure is assumed (e.g. Feedwater controller failure maximum demand), the transient would not result in fuel integrity failure or in RPV pressure exceeding ASME Code criteria. Therefore, the occurrence of any plant transient, as depicted in USAR Chapter 15, concurrent with this plant event would be bounded by the Cycle 2 Reload Analyses.

The above analysis is extremely conservative since a feedwater controller failure to maximum demand cannot occur concurrent with a UPS shutdown, since loss of UPS loads de-energizes feedwater control logic and also causes the reactor level control valves 2FWS-LV10s to lock up. In addition, the UPS shutdown also results in the minimum flow valves for feedwater, condensate booster, and condensate pumps to fail open which trips the feedwater pumps on low suction pressure.

The USAR Chapter 6 DBA LOCA analysis is based upon the proper functioning of safety related equipment. The Phase B main output transformer and the normal UPSs (1A-D, 1G), which became inoperable during the event, do not power any safety related equipment. Therefore, a DBA LOCA concurrent with this plant event would be bounded by the Cycle 2 Reload Analyses USAR analyses or depicted in Chapter 6.

EVALUATION OF IMPACT OF EVENT ON FIRE PROTECTION PROGRAM

This event is not associated with any fire or loss of off-site power. Therefore, it did not create any 10CFR50 Appendix-R concern. Although the control room lost fire annunciation, the fire protection system remained operable from the control room and from the local fire panels throughout this event. In addition, a fire patrol was initiated, during this event, when control room fire detection annunciation was lost. The fire patrol was instituted to monitor the status of local fire protection and detection panels whose annunciation was operable throughout the event. A timely response by plant personnel to an actual fire would have occurred as a result of the surveillance by fire patrols of local fire panels. Therefore, based upon the previous evaluation, it can be concluded that an actual fire, concurrent with this plant event, would have been detected and extinguished in a timely manner.

EVALUATION OF IMPACT OF THE REACTOR WATER CHEMISTRY EXCURSION

LATER (Pat O'Brien)

ASSESSMENT OF EQUIPMENT ISSUES

Evaluation of Failure of MSIV 6D to Indicate Fully Closed

Upon reaching cold shutdown and closing the Main Steam Isolation Valves (MSIV's), MSIV6D (2MSS*AOV6D) was found to be indicating in mid position. An evaluation of this condition determined that the MSIV's were unaffected by the event because the power feeding the control circuitry for these valves is supplied from 2VBB-UPS3A and 3B which were unaffected by the event. The fact that MSIV6D was found indicating at mid position, although of concern from an equipment standpoint, poses no safety concern because the redundant valve, MSIV7D, (2MSS*AOV7D) isolated and indicated properly thereby assuring primary containment integrity in accordance with the plant licensing and design bases. The cause of the failure of MSIV6D to indicate full closure will be investigated, corrected, and the MSIV will be operable prior to restart of the unit.

Evaluation of Reactor Vessel Water Level Excursions

The discussions contained in the reports "Assessment of Operator Response and Training Effectiveness" (Reference 1) and "Scram Summary 91-01" (Attachment A) describe the level variations experienced during the event. In summary as stated in the SCRAM Summary 91-01 N2-RAP-6, the lowest level attained, approximately 124", is above the level 2 setpoint of 108.8" and the highest level attained, by calculation, was 243" which is approximately 9" below the main steam lines. Therefore, it can be concluded that the various water levels experienced in the RPV during the event:

(1) did not result in flooding of the main steam lines,
(2) did not result in initiation of any ECCS, and
(3) did not uncover the fuel.

In conclusion, the level variations were within design boundaries and were acceptable.

Evaluation of Loss of DIV II H_2/O_2 Concentration Recorder

Subsequent to the event, the Division II H_2/O_2 monitor sample pump was found tripped causing the Division II H_2/O_2 Concentration recorder to indicate a high H_2 concentration. This equipment is safety related and receives its power supply from the safety related electrical distribution (1E) buses. This cause of this failure expected to be unrelated to the event and is being evaluated. The 1E buses were continuously energized from both 115KV offsite power supplies throughout the event.

The loss of the sample pump created a situation of concern regarding the conflicting H_2/O_2 concentration indications. Further evaluation of this condition shows clearly that the pump status was indicated on panel P875 in the control room and readily indicated that the Division II sample pump was not running thereby invalidating indications produced in that division. Actual H_2/O_2 indication was available, throughout the event and subsequent cooldown period, on the redundant (Division I) safety-related instrumentations/indication in the control room on panel P601. Additionally, indication was restored to Division II once the sample pump was reset.

Only one safety related recorder for H_2/O_2 monitoring is provided, by plant design, monitoring which records only Division II H_2/O_2 levels. Since Division II H_2/O_2 monitoring capability was inoperable, the historical data of H_2/O_2 concentration, recorded during the event, was invalid. However, the loss of the recording function of this instrument channel poses no safety concern because:

(1) The ability to status and manually record H_2/O_2 concentration existed with the functioning instrument channel;
(2) Means were readily available to operators in the control room to determine which divisional H_2/O_2 indication was inoperable (by observation of the pump running indication light on panels P873 and P875 in the control room).

Evaluation of Loss of Drywell Cooling

During the event the drywell cooling fans tripped when the normal UPS's were lost. Non-safety related UPS's supplied power to an auxiliary relay circuit for the fans. As described in the USAR (Section 9.4.2.5.1), interlocks prevent the fans from starting, or trip the units automatically when any of the associated reactor building closed loop cooling water (CCP) containment isolation valves are closed. The logic circuits interlocking the CCP valve positions with the drywell cooling fan's interlocks are also powered off of non-safety related UPS power. Upon loss of UPS power the fans will automatically receive a trip signal placing them in their fail safe mode. However, loss of the drywell cooling system does not inhibit adequate mixing in the event of a LOCA; adequate atmospheric mixing is accomplished through the utilization of the primary containment spray system, recombiner system, and natural processes (reference USAR Section 6.2.5.2.1).

[illegible]

The SCRAM summary 91-01, N2-RAP-6 states that during the event drywell temperature reached a high of 165°F and low of 120°F. This compares to a normal operating range of 70°F minimum and 150°F maximum for the drywell as indicated in the USAR Table 9.4-1, page 2. This temperature maximum (150°F) provides an environment which ensures the optimum performance of equipment within the drywell.

The effect of the increased temperature on safety related equipment was evaluated against the Equipment Qualification Environmental Design Criteria (EQEDC). Specifically, the EQEDC was used to identify the environmental conditions for equipment ordered for Nine Mile Point Unit Two. Abnormal events were considered within the EQEDC including a loss of drywell cooling. Drywell cooling failure was assumed to occur 166 times during the 40 year plant life either as a result of power loss or loss of cooling water. The theoretical temperature peak for these events was over 170°F for at least 3 hours. Abnormal events including loss of drywell cooling were considered in the determination of equipment's qualified life. Accordingly, a two hour transient with a 165°F temperature peak has been provided for in the original design/qualified life of equipment installed within the drywell.

The drywell temperature at no time approached the structure design temperature of 293°F (Ref. USAR Table 6.2.3) and thus loss of drywell cooling during the event had no safety impact on the primary containment structure or on the safety related equipment contained within.

Evaluation of Momentary Loss of Normal Reactor Building Lighting

Normal lighting for reactor building general areas, work areas, and electrical equipment areas is provided with low wattage high pressure sodium vapor lights. When a power supply to a continuously energized sodium vapor light is interrupted, it has a cooldown period before a restrike of the lighting can occur. The cooldown period depends upon the rating of the light bulbs.

The normal lighting in the reactor building is powered from the plant normal power distribution system using the normal station transformer. The normal station transformer receives it's power from the output of the main generator at NMP2. The design is such, that upon a loss of power from the main generator, a fast transfer, as described in USAR Section 8.3.1.1.2, will occur to the offsite power sources via the two reserve station service transformers.

During the event, the plant normal distribution system experienced a transient due to the fault on the Phase B main transformer. During the event, the reactor building normal lighting was interrupted for approximately 30 seconds. This momentary loss of lighting is due to the inherent design of low voltage high pressure sodium vapor lighting which requires a cooldown period prior to a restrike whenever power in interrupted. A successful fast transfer occurred, as confirmed by the Scriba Oscillograph; whereby, the power supply for the normal reactor building light was transferred from the normal station transformer (2STX-XNS1) to the two reserve station transformers (2RTX-XSR1A and 2RTX-XSR1B).

Therefore, based upon the previous discussion, it can be concluded that the momentary loss of normal lighting in the reactor building and its subsequent restoration (as it occurred during the event) was consistent with the description as presented in USAR Sections 8.3.1.1.2 and 9.5.3.1.

Evaluation of Loss of Plant Communications

Portions of the plant communications systems powered by the plant normal uninterruptable power supply (UPS) system were lost during the event. The dial telephone system, public address system, and leaky wire radio communications all powered by the normal UPS (reference USAR Section 9.5.2.1) were lost during the event. The external phones on the New York Telephone System were operable. The maintenance and calibration communication system and sound powered communication systems were available during the event as well as portable radios without leaky wire assistance.

The loss of site communications required the control room operators to request the NMP1 Control Room to make the emergency announcements for NMP2. Offsite phones directly connected with the New York Telephone system were functional and no impact for offsite notifications occurred. The loss of communications systems delayed reports and directions to and from the control room. While restoration of power may have taken place more quickly with normal communications systems in service, operators noted that they still were able to carry out required actions. The portable radio communications system did not appear to be effective without the leaky wire antenna system.

As indicated in the USAR (Reference Section 9.5.2.4) and recognized in the NRC's SER (Section 9.5.2.1) during a design basis seismic event the communications systems would not be available and portable radios would be used to communicate throughout the plant. Testing of the portable radio system to verify its effectiveness was required as part of the NRC's SER.

The loss of communications systems has been evaluated as part of the plant design and function properly based on the loss of the normal UPS system. However, the portable radio system did not appear to be effective without the UPS powered leaky wire antenna.

The failures of the normal UPS system did impact the effectiveness of the control room operators to function as the Pocal point for emergency notifications within the plant, direct recovery actions and receive damage reports in response to the plant event. Additionally, Unit 1 operators were required to make emergency announcements utilizing the Unit 1 gaitronics system thus increasing their level of involvement in the Unit 2 event. While the operators were able to utilize other means of communications during the event it is recommended that the communications systems power sources, including UPS reliability, be evaluated. The FSAR commitments and compliance to the NRC's SER should be further evaluated relative to the ability of the portable radio system to perform its function as defined in the USAR.

Evaluation of Electrical Distribution System Performance (Reference 2)

The protective relaying schemes actuated and performed their intended function as designed; the transformer and unit differential relays actuated to isolate the fault; the unit protection schemes tripped the turbine; 13.8KV normal switchgear buses made a fast transfer to the reserve station service transformers. The emergency switchgear buses remained energized continuously throughout the event from both 115KV offsite power supplies, however, the flags appeared on the degraded voltage relays. The offsite power breakers did not trip nor did the emergency diesel generators start since the transient undervoltage condition cleared before the time delay setting was satisfied. Safety related electrical distribution systems are physically separated and electrically isolated from the normal (non-safety) systems downstream of the reserve Station Service transformers. Therefore, any fault on the non-safety related systems cannot adversely affect the safety related electrical distribution system.

Power supply from plant normal uninterruptable power supplies, 2VBB-UPS1A, 1B, 1C, 1D, and 1G tripped during this event. This caused the feedwater, condensate booster and condensate pump minimum flow valves to fully open (as designed) which resulted in the feedwater pumps tripping on low suction pressure. No safety concern existed since RCIC and HPCS were available to provide water to the reactor.

Illumination to certain areas of the plant were partially lost due to loss of normal UPS power; specifically, Essential and Egress lighting was lost. However, the majority of the areas operators had to access, during the event, were adequately illuminated from plant Normal, Emergency, and 8 hour battery pack lighting. Only illumination in the stairwells was not available. Lack of illumination imposed only a personnel safety concern since operators had hand held lights during the event for these areas; this is allowed per the NMP2 Update Safety Analysis Report (USAR) section 9.5.3.3. Lighting needs during this event were adequate and did not adversely impact operator response. The Normal, Emergency, Essential, Egress, and 8 hour battery pack lighting provisions for the plant are described in Section 9.5.3 of the USAR.

Group 9 isolation valves closed during this event. This isolation is the safe mode of operation limiting potential releases of contaminants from the primary containment. The isolation **apparently (**check this**)** was initiated by monitor 2GTS-RE105 when UPS power to the DRMS computer was lost.

The Reactor Manual Control System (RMCS), as described in USAR Sections 7.7.1, is an instrumentation and control system whose function is not essential for the safety of the plant. The RMCS as described in USAR Section 7.7.1.1.1, was lost during this event because its power source, the normal nonsafety related UPS, was lost. The RMCS provides the operator with means to manipulate control rods so that reactor power level and core power distribution can be controlled. This system is a power generation system and is not classified as safety related. The RMCS does not include any of the circuitry or devices used to automatically or manually scram the reactor. The RMCS control and position indication circuitry is not required for any plant safety function nor is it required to operate during any associated DBA or transient occurrence. The reactor manual control circuitry is required to operate only during normal power generation operations. The inoperability of the RMCS during this event is consistent with the discussion in USAR Sections 7.7.1 and 7.7.1.1.1 and is therefore, acceptable.

The main plant annunciators and computer systems were lost with the loss of the normal UPSs. The annunciators and computer systems are important to aid the control room operators during all periods of operation and during both normal and emergency shutdowns. However, these systems are designated as non-safety related. They are not required to perform any safety function to shutdown the plant.

ASSESSMENT OF HUMAN FACTORS ISSUES

OPERATOR RESPONSE

An assessment regarding the ability of operators to perform required actions during the UPS power loss was completed. This was conducted by review of operator written statements, shift debriefing and operator interviews. The loss of lighting was determined not to impact operator actions. The only prolonged loss was that of essential lighting which impacted stairway lighting. (Reactor Building lighting went out initially but came back on within 30 seconds.) However, operators carried flashlights, therefore, the operators felt that the loss of stairwell lighting did not impact plant operations.

Communications systems were also lost while the UPS power supply was deenergized; specifically, the GAItronics and radio systems were impacted. Loss of these systems caused reports and directions to and from the Control Room to be delayed. Operators stated that had communications been available restoration of power may have taken place more quickly but also noted that they still were able to carry out required actions.

Instrumentation availability was reviewed to determine if EOP use was impacted. Interviews with operators and panel walkdowns have verified that all parameters required to be monitored in order to implement the EOPs were available. This includes EOP entry condition parameters as well as those required to make various decisions throughout the procedures.

A review of applicable technical specification (TS) requirements has been made for the time period this event was in progress. It has revealed that all T.S. limiting conditions for operation (LCO) requirements were adhered to with <u>exceptions</u> described as follows:

- TS 4.6.4.b.1 This TS surveillance requirement specifies cycling the drywell - suppression chamber vacuum breakers through one complete cycle of full travel within two hours following a safety relief valve (SRV) actuation. However, it was not determined that SRVs had actuated until approximately four hours following event initiation. At that point the required surveillance was successfully completed in the following two hours. Therefore, delaying this surveillance had little or no safety impact.

- TS 3.3.1 action b. This TS action requirement specifies placing at least one RPS trip system in a tripped condition within one hour. Using N2-EOP-6, Attachment 14 operators had defeated all RPS interlocks (except for manual) as directed by the EOPs for a period of approximately one and one half hours. This was required in order to permit resetting the scram signal to allow the scram discharge volume (SDV) to drain down and subsequently perform additional scrams to effect control rod insertion. This action is directed by NMP2 EOPs consistent with the BWR Owners Group (BWROG) emergency procedure guidelines (EPG) Revision 4 and is recognized in the Safety Evaluation (SER) for NMP2 EOPs (SER 90-145 Revision 4, Attachment 4, Event 15.8). Additionally EPG Appendix B specifically states the following "... This is not to imply that operation beyond the Technical Specifications is recommended in any emergency. Rather, such operation is required and is now permitted under certain degraded conditions in order to safely mitigate the consequences of those degraded conditions...."

Since defeating RPS interlocks was believed to have been required (the operators were unable to determine multiple control rod positions) in order to insert control rods, and the basis for the procedures and safety evaluation recognize the potential for this condition the action taken by the operators and direction by the procedures was appropriate and conservative.

A review of the NMP2 EOP (Rev. 4) Safety Evaluation (90-145) for analysis of USAR events 15.2.3 (Turbine Trip) and 15.8 (ATWS) has been completed. The only difference between actual operator performance and that described in the safety evaluation was that operators entered the EOPs based upon low RPV water level vs high RPV pressure assumed in the safety evaluation. However, this had no impact on procedure use or plant conditions.

DESCRIPTION AND ASSESSMENT, OF THE ENVIRONMENTAL IMPACT, OF THE AUGUST 13 TRANSFORMER OIL SPILL

On Aug. 13, 1991, the Supervisor of Environmental Protection, was notified of the oil spill on transformer 2MTX-XM1B. The New York State Department of Environmental Conservation (DEC) was notified at 12:05 p.m. A courtesy notification was made to the National Response Center at 12:52 p.m. on 8/13/91.

The storm sewers, oil separator and visual observation of the lake shoreline (where the storm sewer enters the lake) revealed no oil had leaked to these areas. A small amount of oil had sprayed outside of the transformer containment pit. The stones and small portion of dirt have been removed and are waiting to be properly disposed of in accordance with the DEC. The oil that remains within the transformer containment pit will be evaluated for

removal. Therefore, it can be concluded that no offsite environmental impact occurred as a result of the transformer oil spill.

RECOMMENDATIONS

In prior sections of this report, the plant response to this event was evaluated with regard to the safety significance of the event sequence. The conclusions reached have confirmed that no safety issues exist, however, issues remain regarding improving operability of the plant under transient conditions.

Reliability of the normal plant UPS system is of necessary to minimize the plant anomalies experienced upon a loss of one or more UPS's. The normal UPS's are intended to operate with either a normal AC supply, station battery supply or maintenance AC supply. These different power supplies provide three independent sources of power which would provide the level of reliability necessary for this very important power system. Upon completion of the UPS root cause evaluation and upon implementation of action, the necessary level of reliability will be restored to the uninterruptable power supply system.

Based on the evaluation performed as part of this safety assessment the following recommendations are provided:

1. <u>In-Plant Oscillograph</u>

   An evaluation of the in-plant oscillograph installation is required in order to improve the availability of data following electrical distribution system transients. Availability of an in-plant oscillograph will improve the ability to evaluate the origin of faults and the plant's response to such faults.

2. <u>Stairwell Lighting</u>

   During this event, the loss of stairwell and egress lighting was evaluated not to be a safety concern, however, the concern for personnel safety still exists. A modification for Unit 2 currently exists which will address the power supply system for the stairwell lighting which will correct this problem. Consideration to elevating the priority of this modification should be given.

3. Drywell Cooling Fan Circuit

The current drywell cooling fan operation relies upon an auxiliary relay circuit which is currently powered from the normal UPS power supply. This circuit should be modified to receive its power from the same power supply which powers the control circuit for the drywell unit cooler fans.

4. Communications - Gaitronics/Telephones/Portable Radio System

During the course of this event, the gaitronics system was inoperable in the control room. In addition, portions of the in-plant dial telephone system and the portable radio leaky wire system was also impacted during this event by the loss of the normal UPS power supply system. An evaluation of the power supply system for these communications systems which evaluates the possibility to improve operation and increase reliability.

5. Annunciator Power Supply System

The annunciator system lost power from the normal UPS power supply system during this event. An evaluation of the power supply to the annunciator should be performed to determine the feasibility of providing added reliability and/or diversity to its power supply system.

6. BOP Instrument Power Supplies

Power supplies were lost to the balance of plant instrumentation cabinets causing a loss of non-safety related instrumentation. An evaluation of the feasibility of improving the power supply system to add reliability through redundancy or diversity in the supplies should be considered and evaluated for implementation.

7. Cooling Tower Bypass Gate Failure Mode

During the course of the event, the cooling tower bypass valves opened and bypassed the tower, causing a loss of the cooling capability provided by the cooling tower. An evaluation of the cooling water system should be performed to determine whether this failure mode is the most appropriate under all transient and normal conditions for the system design.

8. <u>Minimum Flow Valve Failure Mode</u>

Because of the loss of the UPS power supply to the instrumentation cabinets, the minimum flow control valves for the feedwater pumps, condensate booster pumps, and condensate pumps defaulted to their fail open position. This causes a major portion of the water from the condensate and feedwater systems to recirculate to the condenser. An evaluation of this failure mode should be performed to assure that this failure mode is the most appropriate failure under all operating transients.

9. <u>Alternate Methods for Rod Position Indication</u>

During the course of this event, rod position indication in the control room was lost due to the loss of the normal UPS power supplies. An assessment should be undertaken to determine alternate methods for rod position indication under transients of this type and/or an evaluation of the existing power supply system to the rod position indication system should be undertaken.

ATTACHMENTS/REFERENCES:

Attachment A - Scram Summary - prepared by E. Tomlinson, NMP2 Reactor Physics

Reference 1- Assessment of Operator Response and Training Effectiveness - prepared by J. Helker, NMP2 Operations

Reference 2 - NMP2 Electrical Distribution System - prepared by A. Julka, NMP2 Design Engineering