



Constellation Energy

• Nine Mile Point Nuclear Station

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May 17, 2004
NMP2L 2117

U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555

SUBJECT: Nine Mile Point Unit 2
 Docket No. 50-410
 License No. NPF-69

Review and Comment: Nine Mile Point Unit 2 Preliminary Accident
Sequence Precursor Analysis of the August 14, 2003 Operational Event

Gentlemen:

By letter dated March 18, 2004, the NRC forwarded for review and comment a preliminary Accident Sequence Precursor (ASP) Analysis for Nine Mile Point Unit 2 (NMP2) of the August 14, 2003, operational event involving loss of offsite power associated with the regional transmission grid blackout of the same date. The March 18 letter provided a risk assessment of the event based upon current NRC models and solicited licensee comment on the technical adequacy of the preliminary analysis, including the depiction of plant equipment and equipment capabilities. Written guidance was provided for peer review and comment, including specific supporting documentation requirements.

The requested review has been completed for NMP2. Results based upon the current NMP2 Probabilistic Risk Assessment (PRA) model are in general agreement with those of the preliminary ASP analysis, but show a lower conditional core damage probability. Details and supporting documentation are provided by attachment to this letter.

If you have any questions, please contact Mr. Ted Kulczycky, Principal Engineer, Reliability Engineering, at 315-349-1949.

Very truly yours,

William C. Holston
Manager, Engineering Services

WCH/JRH/jm
Attachment

cc: Mr. H. J. Miller, NRC Regional Administrator, Region I
 Mr. G. K. Hunegs, NRC Senior Resident Inspector
 Mr. P. S. Tam, Senior Project Manager, NRR (2 copies)

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NINE MILE POINT 2

**Review of NRC Preliminary Precursor Analysis (PPA)
of August 14, 2003
NMP2 Grid Disturbance Event**

**Review of NRC Preliminary Precursor Analysis (PPA) of
August 14, 2003 NMP2 Grid Disturbance Event**

In a letter dated 3/18/2004¹ the Nuclear Regulatory Commission (NRC) provided a preliminary analysis of the risk significance of the August 14, 2004 offsite grid related event at Nine Mile Point Unit 2 (NMP2). The NRC letter solicited comment on the preliminary analysis and this "White Paper" provides the comments from the NMP Probabilistic Risk Assessment (PRA) Team.

We agree with the overall conclusion of the PPA. Namely, that the event represented a significant plant challenge and should be included in the Accident Sequence Precursor Program (ASP) database. However, we note significant conservatisms in the analysis and believe that the reported conditional core damage probability (CCDP) of $4.7E-4$ is more appropriately less than $1E-4$.

The conservatisms that we recommend should be reviewed and adjusted are as follows:

EDG Failure Data:

The NRC PPA report indicates that NMP2 Emergency Diesel Generator (EDG) failure rate is higher than industry average and references NUREG/CR-5500 Volume 5². The NMP2 PRA Team has reviewed this NUREG and found inconsistencies with the data reported. Table DATA-1, below, shows a summary of the NUREG data along with associated PRA team information.

Table DATA-1: NMP2 PRA Team Evaluation of NUREG/CR-5500 EDG Failure Data			
Date (NUREG)	NUREG Failure Mode	PRA Team Comment	Failure Assigned to PRA database?
7/21/88	FTS	Division 2 FTS noted on 7/28/88	Y
12/21/88	FTR	Division 2 FTS, low lube oil trip prior to loading	Y but FTS
2/15/89	FTS	Division 2 Overspeed trip	Y
9/20/89	FTS	Division 1 FTS noted on 3/12/89	Y
12/2/89	FTS	Division 2 FTS, Governor	Y
1/29/90	FTR	Division 1 FTR	Y
9/30/90	FTS	Invalid failure – Post Maintenance Test (PMT)	N
5/21/91	FTR	Line 5 failure; License Event Report (LER) 41091012 and its associated Deviation Event Report (DER) do not indicate any EDG failures. Frequency was noted low but within limits. A subsequent DER investigated and noted failed troubleshooting test but not judged PRA failure.	N
5/21/91	RFP	Line 5 failure; LER 41091012, EDG Log, DER 1991-276, DER 1991-398 do not indicate any restoration failures. If a misalignment caused unavailability, it would be included as maintenance unavailability failure mode.	N
9/15/91	RFP	EDG log does not indicate any demands on 9/15/91. Also, no LERs were identified by the PRA team. NUREG references Special Report 41091, which could not be identified by the PRA Team. If a misalignment caused unavailability, it would be included as maintenance unavailability failure mode.	N
3/23/92	MOOS	Shutdown Loss of Offsite Power (LOSP), Division 1 EDG in maintenance. No demand failures. NMP2 PRA model includes maintenance unavailability as separate failure mode.	N
4/6/92	FTS	Output breaker failure	Y
4/29/92	FTR	Division 1 fuel leak, test aborted. EDG log declared invalid test, PRA considered event an EDG failure	Y
4/30/92	FTR	PMT of 4/29/92 failure, not considered an additional failure by PRA	N
8/13/92	RFR	Division 1 FTS noted on 8/14/92	Y
8/17/93	MOOS	Switchgear trip caused by radio-frequency interference during pre-planned EDG maintenance. Not considered a demand failure. NMP2 PRA model includes maintenance unavailability as separate failure mode.	N

Key for Table DATA-1 (NUREG Failure Mode Designators)

FTS – Fail to Start

FTR – Fail to Run

RFP – Restoration Failure, Offsite Power

RFR – Restoration Failure, EDG

MOOS – Out Of Service for Maintenance

Table DATA-2 provides a summary of Raw EDG related data for the Division 1 and 2 EDGs and Table DATA-3 provides similar information for the Division 3 EDG. Table DATA-4 provides EDG values if Raw data were used compared to the Bayesian updated values included in the updated PRA.

The NRC PPA uses older data for EDG failure probability. Also, as can be seen from Tables DATA-2 and DATA-3, NMP2 EDG performance has improved substantially over time. Therefore, it is recommended that the NRC consider using lower values for EDG failure rate. It is also recommended that NRC delete the statement that NMP2 EDG failure rate is "... higher than industry average..." or at least modify the statement to clarify that the data used is over 11 years old and not reflective of current reliability.

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Table DATA-2: NMP2 EDG PRA Data Summary (Division 1 and 2)							
Period	Start Failures	Start Demands	1 st Hour Run Failures	1 st hour Run Time (HRS)	Post 1 st Hour Run Failures	Post 1 st Hour Run Time (Hrs)	Comment
5/15/88 – 12/31/91	5	265	1	258	0	264	Individual Plant Examination (IPE) period
1/1/92 – 12/31/93	2	63	0	50	1	208	5/88 to 12/31/93 period used for NUREG/CR-5500, Vol 5
1/1/94 – 12/31/97	2	128	1	103	0	425	First PRA Update
1/1/98 – 12/31/2001	0	96	0	96	0	56	Second PRA Update (EDG Allowed Outage Time (AOT) Evaluation)
Total	9	552	2	507	1	953	

Table DATA-3: NMP2 EDG PRA Data Summary (Division 3)							
Period	Start Failures	Start Demands	1 st Hour Run Failures	1 st hour Run Time (HRS)	Post 1 st Hour Run Failures	Post 1 st Hour Run Time (Hrs)	Comment
5/15/88 – 12/31/91	5	149	0	144	0	96	IPE period
1/1/92 – 12/31/93	0	24	0	23	0	39	5/88 to 12/31/93 period used for NUREG/CR-5500, Vol 5
1/1/94 – 12/31/97	0	48	0	47	0	79	First PRA Update
1/1/98 – 12/31/2001	0	48	0	48	N/A	N/A	Second PRA Update (EDG AOT Evaluation)
Total	5	269	0	262	0	214	

Table DATA-4: NMP2 EDG Failure Mode Summary		
	Raw Data Totals	Bayesian Update
D1/2 Fail to Start – Per Demand	1.63E-2	1.36E-2*
D1/2 Fail to Run (1 st Hour) - Per Hr	3.94E-3	5.59E-3*
D1/2 Fail to run (After 1 st Hour) - Per Hr	1.05E-3	2.35E-3*
D1/2 Unavailability – (8/94 – 7/97 M-Rule Data)	3.3E-3* (Div 1) 6.4E-3* (Div 2)	N/A
D3 Fail to Start – Per Demand	1.86E-2	1.3E-2*
D3 Fail to Run (1 st Hours) - Per Hr	1.9E-4 ⁺	4.43E-3*
D3 Fail to run (After 1 st hour) - Per Hr	2.34E-3 ⁺	1.48E-3*
D3 Unavailability – (8/94 – 7/97 M-Rule Data)	3.08E-3*	N/A
* Used in Current PRA model		
+ Assuming 0.5 Failures		

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Table DATA-5 Summary of Div 1&2 EDG Failures in PRA Database				
Date	Event	Failure Mode		
		FTS	FTR 1 st hr	FTR >1 st hr
7/28/88	Div 2 EDG fails during monthly test	1		
2/15/89	Div 2 EDG fails during test	1		
3/12/89	Div 1 EDG fails during monthly test	1		
12/2/89	Div 2 EDG fails during monthly test	1		
1/29/90	Div 1 EDG fails during monthly test		1	
11/26/90	Div 1 EDG fails during monthly test	1		
4/6/92	Div 1 EDG output breaker fails to close during monthly test. Invalid in EDG Log but maintained by PRA.	1		
4/29/92	Div 1 EDG fuel leak during 24 hr run. Invalid in EDG Log but maintained by PRA.			1
8/14/92	Div 1 EDG fails during monthly test.	1		
1/26/95	Div 1 EDG fails during monthly test.		1	
5/16/95	Div 2 EDG breaker 2ENS*SWG103-14 Failed to Close.	1		
9/11/95	Div 1 EDG Output Breaker Failed to Close.	1		
Totals		9	2	1

EDG Recovery:

No basis for the assumption that EDGs cannot be recovered is provided in the PPA. The NMP2 PRA model includes credit for EDG recovery based on NUREG-1032. It is recommended that the PPA consider crediting EDG recovery.

Offsite Power/Offsite Power Recovery:

The assumption that offsite power failed and was not recoverable for over 6 hours is overly conservative. The PPA assumes that offsite power was unavailable until reported stable by load dispatchers but this assumption unduly penalizes the plant for appropriate conservative operational decision-making.

The safety related Alternating Current (AC) switchgear experienced under-voltage conditions and EDGs started, as designed. However, one division of non-safety (i.e., balance of plant (BOP)) AC Power remained available from offsite sources and the other division was readily recovered after operators took manual control of a transformer tap changer. While some BOP equipment tripped and some was manually secured, condenser vacuum was maintained throughout the event, supported by offsite power. Operators used Reactor Core Isolation Cooling (RCIC) in lieu of condensate-feedwater for Reactor Pressure Vessel (RPV) level control. The PRA Team considers this to be an issue of conservative operational decision-making that was appropriate based on conditions encountered but not a declaration of BOP inadequacy. If RCIC was unavailable, operators could have, and would have, been able to use condensate-feedwater to maintain RPV level control.

With EDGs operating as designed and grid conditions uncertain, operators elected not to attempt to restore offsite AC power to the emergency switchgear. However, should the EDGs have failed, operators would have been instructed by procedures to attempt offsite power recovery. The state of offsite power would have readily allowed offsite power recovery much earlier than actually demonstrated.

Plant data indicates that voltage from offsite sources remained above required levels between 16:45 and 17:00, 34 to 49 minutes following event initiation. There was a brief period of minor over-voltage at approximately 18:00 and it has been concluded that this would not have significantly affected equipment operation. Between 17:30 and 17:45 frequency recovered to within the required range. At 17:00 frequency was 57.97 Hz which is slightly below the required 58.49 Hz. If EDGs had not functioned, offsite power would have been completely available at approximately 1h 45m after event initiation.

As a simplification, it is appropriate to model the event as a loss of offsite power (LOSP) initiator but offsite power recovery factors should be left as in the base model (i.e., not set to failure) to reflect actual grid conditions encountered during this particular event. Also, extended EDG run time should not be applied to the model due to the assumption regarding offsite power availability.

Sequence 46-02:

The PPA summarizes a set of dominant accident cutsets wherein a LOSP initiator occurs followed by Division 1 EDG failure, Division 2 EDG failure, Division 3/High Pressure Core Spray (HPCS) success, and failure to recover AC power in 8 hours. Given this sequence, operators have procedural direction to cross-tie the HPCS EDG to the Division 1 or 2 switchgear. This alignment allows the HPCS EDG to maintain Safety-Related Direct Current (DC) power over the long term as well as providing for Low Pressure Coolant Injection (LPCI)/Residual Heat Removal (RHR) with low pressure ECCS. This capability is modeled in the NMP2 PRA as redundant to AC power recovery and should be credited in the PPA as well. The alignment is fairly time-consuming and the NMP2 PRA does not credit the action before 2 hours after the initiating event occurs.

Sequence 46-49:

The PPA summarizes a set of dominant accident cutsets wherein a LOSP initiator occurs followed by Div 1 EDG failure, Div 2 EDG failure, Div 3 EDG Failure, and failure of RCIC to start. For this event, condensate-feedwater would have been available and redundant to RCIC. Condensate-feedwater is supplied by the non-safety AC system which remained available from offsite power. With loss of 115 kV to the emergency switchgear and no EDGs operating, service water pumps would be idle. This would eliminate the heat sink for Turbine Building Closed Loop Cooling (TBCLC), which is required for pump cooling. Therefore, condensate-feedwater could not be credited with RPV level control over the long term but it would support success throughout the first phases of Station Blackout (SBO) response. It is recommended that the PPA analysis model this case using an "AND" gate for feedwater and early RCIC operation such that these sequences would be recoverable up to 2 to 4 hours. When combined with fire pump or Control Rod Drive (CRD) operation, see below, AC recovery for up to 8 hours may also be justifiable in the PPA model. Note that CRD has a similar support requirement to feedwater in that reactor building closed loop cooling (RBCLC) is required for long term component cooling.

Sequence 46-41:

The PPA summarizes a set of dominant accident cutsets wherein a LOSP initiator occurs followed by Div 1 EDG failure, Div 2 EDG failure, Div 3 EDG failure, and failure of the diesel fire pump (DFP). The SBO event tree included in the analysis appears to require fire water for long-term RPV injection following RCIC success. Fire water is required for the 8 hour AC recovery case but not the 4 hour case. However, RCIC can support RPV control for at least 8 hours independent of Diesel Fuel Pump (DFP) operation. The NMP2 PRA requires the DFP only if RCIC operates for 2 hours and then fails prior to 8 hours. If RCIC operates successfully for 8 hours, the 8 hour AC recovery case is applied independent of DFP status. It is recommended that the PPA model success criteria be reconsidered.

Also, independent of the 4 hours versus 8 hour success criteria, in the 8/2003 event, the electric fire pump was available from powerboard 2NNS-SWG012. Also, CRD was available from powerboards 2NNS-SWG014 and 2NNS-SWG015. For the evaluation of this event, these sources should be considered redundant to the DFP.

8-Hour Offsite Power Recovery:

In the PPA analysis, the value for failure to recover AC power in 8 hours was increased from 1E-3 to 1E-2. This appears to be due to the time window available between when load dispatchers declared the grid stable and the expiration of the 8 hour time window. Even if it were assumed that operators would have waited for the load dispatchers before trying to recover offsite power given EDG failures, it is highly doubtful that they would also wait for the load dispatchers before staging their actions. In this regard, the reduction from 1E-3 to 1E-2 is overly conservative. Operator focus regarding offsite power recovery would have been keen throughout the event. Given failure of EDGs, elapse of 6 hours, and staffing of the emergency response facilities, it is difficult to believe the PPA's 2 hour recovery window (i.e., from hour 6 to hour 8) is reflective of the non-response probability related to the conditions encountered in this event. It is therefore recommended that NRC reconsider the penalty applied to the 8-hour AC power recovery basic event.

References:

- 1) Boska, J.P., "Nine Mile Point Nuclear Station, Unit No. 2 Re: Review Of Preliminary Accident Sequence Precursor Analysis Of August 14, 2003, Operational Event," Letter to Spina, J.A, March 18, 2004.
- 2) Grant, G.M., et. al., "Reliability Study: Emergency Diesel Generator Power System, 1987-1993," NUREG/CR-5500, Volume 5, September, 1999.
- 3) Goodney, D., "Engineering Reply for August 14, 2003 grid Blackout Event NMP Offsite Power Recovery Analysis," Constellation Energy Group White Paper, 5/11/04.