Nebraska Public Power District
GENERAL OFFICE
P.O. BOX 499, COLUMBUS, NEBRASKA 68601-0499
TELEPHONE (402) 564-8561

NLS8500045

February 28, 1985

Office of Nuclear Reactor Regulation
Operating Reactors Branch No. 2
Division of Licensing
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Attention: Mr. Domenic B. Vassallo, Chief

Dear Mr. Vassallo:

Subject: Submittal of Additional SPDS Information
Cooper Nuclear Station
NRC Docket No. 50-298, DPR-46

Reference: 1) Letter from J. M. Pilant to D. B. Vassallo dated October 5, 1984, "Schedule for Submittal of Additional SPDS Information - Cooper Nuclear Station"

In accordance with Reference 1, the following additional SPDS information is submitted:

Attachment	Item
1	Finalized list of SPDS parameters as well as a discussion of the rationale for any deletions and/or additions to the parameter set proposed in Table 7-1 of the SPDS Safety Analysis.
2	Commitment to provide a highly-reliable power supply system for the SPDS and a description of the power supply system in terms of its impact on total SPDS reliability (flow charts or diagrams may be helpful).
3	Certification report being prepared by CPI that discusses the acceptance criteria, testing procedures used to certify proper isolation, and the results of that testing.
4	Large format color photographs or reproductions and all PMIS display pages that are defined as SPDS displays and all unique display/control hardware interfaces.
5	A written description for SPDS displays that are not self-evident.

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Mr. Domenic B. Vassallo
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A summary of the reliability report being prepared by SAIC was also scheduled by Reference 1 to be submitted by February 28, 1985. However, this report is not available at the present time but will be submitted at a later date. Additionally, material in Attachment 1 reference the draft of Revision 2 to Document 503-8500000-78. Recently, the final Revision 2 copy of 503-8500000-78 has been issued and is submitted in Attachment 5 in place of the draft.

Due to potential problems with interfacing the SPDS with other components of Supplement 1 of NUREG-0737; i.e., CRDR, Regulatory Guide 1.97, etc., changes to previously-submitted schedules may occur. The District will keep the staff informed of any changes in schedule should they appear likely to take place.

Five copies are forwarded for the staff's use. However, just one copy of Attachment 4, the large format color photographs, is being sent. Should you have any questions or require additional information, please contact me.

Sincerely,

Jeffrey D. Weaver for

Jay M. Pilant
Technical Staff Manager
Nuclear Power Group

JMP/grs:emz28/8
Attachments

Attachment 1

Finalized list of SPDS parameters as well as a discussion of the rationale for any deletions and/or additions to the parameter set proposed in Table 7-1 of the SPDS Safety Analysis.

DATA POINTS FOR GENERATING
COOPER NUCLEAR STATION SPDS DISPLAYS

1. SPDS DATA REQUIREMENTS

The field input data points required for generating the CNS SPDS displays are listed in Table 1. Some of these data points are used directly by the SPDS, but most are used in calculations to derive composed points which are displayed on the SPDS. A summary of the field input and composed data points used in generating the SPDS displays is presented in Table 3-1 of document 503-85000000-78, Rev. 2* (attached). This table includes the following types of data points:

- Field input points
    - Analog
    - Digital
- PMIS composed points
    - Pseudo analog
        - healthy maximum
        - healthy average
        - logarithm
    - Transform
        - rate-of-change
    - Boolean
        - healthy OR
        - healthy AND
- SPDS composed points
    - External (real) points

*Detailed Descriptions of the Displays for the Cooper Nuclear Station Safety Parameter Display System (SPDS), 503-8500000-78, Revision 2 (Draft) January 4, 1985.

Also included in Table 3-1 is a listing of how the data points are used by the SPDS. Data points are used as follows:

- To drive a bar, trend, one axis of an x-y plot, or a digital current value that appears in a display. The associated display is identified in Table 3-1.

- To calculate another data point (the other data point is listed in Table 3-1).

- To drive a status indicator
  - Safety Function Indicator (SFI)
  - Equipment Status Indicator (ESI)
  - EOP Limit Status Indicator (EOPSI)
  - Downscale Indicator (DNSCI)
  - Not-Valid Indicator (NVI)
  - System Alarm Area (SAA) Indicator

The SPDS displays and operation of all of the display features are described in detail in document 503-8500000-78, Rev. 2

2. COMPARISON OF ACTUAL AND PREDICTED SPDS DATA REQUIREMENTS

The SPDS Safety Analysis* presented in Table 7-1 (attached) a list of plant variables expected to be monitored by the CNS SPDS. Variables listed in Table 7-1 of 503-8500000-76 which are not included in Table 1 or Table 3-1 of 503-8500000-78 are summarized in Table 2. The bases for deleting these variables are noted in Table 2. The primary reasons for deleting most of these variables are: (a) data was not required (i.e., IRM data), (b) adequate substitute data was available, (c) data was not available on PMIS, or (d) a secondary containment display was not implemented on the CNS SPDS, largely because of (c), above.

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*Safety Parameter Display System Safety Analysis, 503-8500000-76, Revision 0, March 1, 1984.

Variables that are used by the SPDS, but were not listed in Table 7-1 of 503-8500000-76 are identified in Table 1. These additional variables are used to provide: (a) the ability to perform needed calculations, or (b) an expanded status indication capability for key equipment.

Table 1. Field Input Points for Generating Cooper SPDS Displays.

Point ID	Point Type*	Variable Name	Listed in SAR**	New Point
B000	A	APRM A flux level	X	
B001	A	B	X	
B002	A	C	X	
B003	A	D	X	
B004	A	E	X	
B005	A	F	X	
A527	D	APRM upscale alarm (any)		X
A528	D	APRM inoperative alarm (any)		X
A535	D	APRM Ch A bypassed		X
A536	D	Ch B		X
A537	D	Ch C		X
A538	D	Ch D		X
A539	D	Ch E		X
A540	D	Ch F		X
N040	A	SRM log count rate Ch A	X	
N041	A	B	X	
N042	A	C	X	
N043	A	D	X	
A519	D	SRM detector not startup position (any)	X	
A520	D	SRM upscale alarm (any)		X
A521	D	SRM inoperative alarm (any)		X
A533	D	SRM bypassed (any)		X
N520	D	All control rods in	X	
D530	D	Reactor scram Ch A	X	
D531	D	B	X	
B021	A	RPV water level - narrow range (0 to 60") A	X	
N011	A	B	X	
N012	A	C	X	
G032	A	RPV water level wide range (-150" to 60") A	X	
G033	A	B	X	
N009	A	RPV water level - fuel zone range (-100" to 200") A***	X	
N010	A	B***	X	
N013	A	Reactor pressure (0-1500 psi) A	X	
N014	A	B	X	
D554	D	Group 1 isolation A signal	X	
D555	D	B	X	
N781	D	Group 2 isolation signal - inboard	X	
N782	D	- outboard	X	
N783	D	Group 3 isolation signal - inboard	X	

Table 1. Field Input Points for Generating Cooper SPDS Displays (Continued).

Point ID	Point Type*	Variable Name	Listed in SAR**	New Point
N784	D	Group 3 isolation signal - outboard	X	
N785	D	Group 4 isolation A signal	X	
N786	D	B	X	
N787	D	Group 5 isolation A signal	X	
N788	D	B	X	
N789	D	Group 6 isolation A signal	X	
N790	D	B	X	
N791	D	Group 7 isolation signal - inboard	X	
N792	D	- outboard	X	
N797	D	Main steam iso valve A inboard		X
N801	D	A outboard		X
N798	D	Main steam iso valve B inboard		X
N802	D	B outboard		X
N799	D	Main steam iso valve C inboard		X
N803	D	C outboard		X
N800	D	Main steam iso valve D inboard		X
N804	D	D outboard		X
D556	D	Main stm relief valve A press sw	X	
T142	A	A temp	X	
D557	D	B press sw	X	
T143	A	B temp	X	
D558	D	C press sw	X	
T144	A	C temp	X	
D559	D	D press sw	X	
T145	A	D temp	X	
D560	D	E press sw	X	
T146	A	E temp	X	
D561	D	F press sw	X	
T147	A	F temp	X	
D562	D	G press sw	X	
T148	A	G temp	X	
D563	D	H press sw	X	
T149	A	H temp	X	
M186	A	MS safety valve A temp	X	
T139	A	A temp	X	
M187	A	B temp	X	
T140	A	B temp	X	
M188	A	C temp	X	
T141	A	C temp	X	
N002	A	HPCI flow	X	
N003	A	RCIC flow	X	
N000	A	Core spray pump A flow	X	
N001	A	B	X	
M578	D	Core spray A status		X

Table 1. Field Input Points for Generating Cooper SPDS Displays (Continued).

Point ID	Point Type*	Variable Name	Listed in SAR**	New Point
M580	D	Core spray B status		X
N004	A	RHR loop A flow	X	
N005	A	B	X	
N861	D	RHR pump 1A status		X
N862	D	1B status		X
N863	D	1C status		X
N864	D	1D status		X
N806	D	RHR suction isolation valve, inbd		X
N807	D	RHR suction isolation valve, outbd		X
N017	A	Containment (drywell) pressure (-5 to +5 psig) A	X	
N018	A	B	X	
F084	A	Drywell pressure (0-80 psia) A	X	
F085	A	B	X	
M161	A	Drywell temperature PT-10	X	
M162	A	PT-11	X	
M163	A	PT-12	X	
N276	A	Drywell zone 2B area temp B	X	
N277	A	D	X	
T122	A	Drywell hydrogen level	X	
N061	A	Drywell/torus 0-5% oxygen level	X	
N062	A	Drywell/torus 0-10% oxygen level	X	
N065	A	Drywell/torus 0-25% oxygen level	X	
N627	D	Drywell oxygen sample No. 1	X	
N628	D	Drywell oxygen sample No. 2	X	
N629	D	Drywell oxygen sample No. 3	X	
N630	D	Torus oxygen sample	X	
N631	D	Drywell/torus oxygen range No. 1 (0-5%)	X	
N632	D	Drywell/torus oxygen range No. 2 (0-10%)	X	
N633	D	Drywell/torus oxygen range No. 3 (0-25%)	X	
N059	A	Drywell flr sump pump 1F1/2 flow	X	
N060	A	pump 1G1/2 flow	X	
N063	A	High range drywell airlock area rad monitor	X	
N023	A	Suppression pool water temp 1A	X	
N024	A	1B	X	
N025	A	1C	X	

Table 1. Field Input Points for Generating Cooper SPDS Displays (Continued).

Point ID	Point Type*	Variable Name	Listed in SAR**	New Point
N026	A	Suppression pool water temp 1D	X	
N027	A	1E	X	
N028	A	1F	X	
N029	A	1G	X	
N030	A	1H	X	
N031	A	2A	X	
N032	A	2B	X	
N033	A	2C	X	
N034	A	2D	X	
N035	A	2E	X	
N036	A	2F	X	
N037	A	2G	X	
N038	A	2H	X	
N019	A	Suppression pool level (0-30') A	X	
N020	A	B	X	
N021	A	Containment water level (0-100') A	X	
N022	A	B	X	
N079	A	ERP normal range rad monitor	X	
N073	A	AOG & RW effluent normal range rad mon	X	
N074	A	Rx bldg effluent rad monitor		
N069	A	Turbine bldg effluent normal range rad mon	X	
N082	A	SJAE radiation monitor A	X	
N083	A	B	X	
N084	A	SJAE A air flow		X
N085	A	B air flow		X

Notes: * A = analog, D = digital

** SPDS Safety Analysis Report, document 503-85J0000-76

***Data points not yet available on PMIS, but SPDS has display features and software to present this data when it becomes available

Table 2. Summary of Variables Listed in the SPDS Safety Analysis* that Were not Implemented in the Final CNS SPDS Configuration.

Variable	Reasons for Deletion
IRM log power	APRM and SRM data provides near-continuous indication of reactor power level. The complexity of deriving valid IRM data is not warranted based on the availability of the APRM and SRM data on the SPDS. IRM data is not required
IRM range	See above
IRM position	See above
RPV water level, refueling range	Data not available on PMIS. Possible future addition as noted in SPDS Safety Analysis
Suppression chamber (torus) pressure	Data not available on PMIS. Drywell pressure data used instead
Suppression chamber hydrogen concentration	Data not available on PMIS. Possible future addition as noted in SPDS Safety Analysis
Secondary contain-differential press	Analog data not available on PMIS. No secondary containment display implemented on CNS SPDS because of lack of suitable data on PMIS for assessing overall secondary containment status
Secondary containment area temp alarm status	Analog data not available on PMIS. Possible future addition as noted in SPDS Safety Analysis
Secondary containment HVAC exhaust radiation level alarm status	Analog data not available on PMIS. Possible future addition as noted in SPDS Safety Analysis. All effluent release rates are displayed on the Level 2 radioactive release displays
Secondary containment area radiation level	No secondary containment display implemented on CNS SPDS because of lack of suitable data on PMIS for assessing secondary containment status
Secondary containment floor drain and torus area water level	Analog data not available on PMIS. Possible future addition as noted in SPDS Safety Analysis

*Safety Parameter Display System Safety Analysis, 503-8500000-76, Revision 0, March 1, 1984.

Table 3-1. Data Points for Generating Cooper SPDS Displays.

Point ID*	Point Type**	Variable Name	Use***
B000	A	APRM A flux level	Calculate SPDSBOX1
B001	A	B	Calculate SPDSBOX1
B002	A	C	Calculate SPDSBOX1
B003	A	D	Calculate SPDSBOX1
B004	A	E	Calculate SPDSBOX1
B005	A	F	Calculate SPDSBOX1
SPDS0006	HMAX	Healthy maximum APRM A,C,E	Calculate SPDS0008
SPDS0007	HMAX	Healthy maximum APRM B,D,F	Calculate SPDS0008
SPDS0008	HAVE	Average APRM (avg of SPDS0006, 0007)	L1.0, L2.1 Calculate SPDS0009
SPDS0009	TRAN	Average APRM rate-of-change (ROC SPDS0008)	L1.0, L2.1
SPDS0080	EXTR	All APRM below downscale trip	L2.1 ESI, Calculate SPDS0039
A527	D	APRM upscale alarm (any)	L2.1 ESI
A528	D	APRM inoperative alarm (any)	L2.1 ESI
A535	D	APRM Ch A bypassed	Calculate SPDS0001
A536	D	Ch B	Calculate SPDS0001
A537	D	Ch C	Calculate SPDS0001
A538	D	Ch D	Calculate SPDS0001
A539	D	Ch E	Calculate SPDS0001
A540	D	Ch F	Calculate SPDS0001
SPDS0001	HOR	Any APRM bypassed (OR of A535 to A540)	L2.1 ESI
N040	A	SRM log count rate Ch A	Calculate SPDS0014
N041	A	B	Calculate SPDS0014
N042	A	C	Calculate SPDS0014
N043	A	D	Calculate SPDS0014
SPDS0014	HAVE	Average SRM (healthy avg. N040, N041, N042, N043)	L2.1, calculate SPDS0013, SPDS0015
SPDS0013	LOG	Log of average SRM (LOG SPDS0014)	L2.1
SPDS0087	TRAN	Average SRM rate-of-change (ROC SPDS0014)	Calculate SPDS0015
SPDS0015	EXTR	SRM reactor period	L2.1
A519	D	SRM detector not startup position (any)	L2.1 ESI
A520	D	SRM upscale alarm (any)	L2.1 ESI
A521	D	SRM inoperative alarm (any)	L2.1 ESI
A533	D	SRM bypassed (any)	L2.1 ESI

Table 3-1. Data Points for Generating Cooper SPDS Displays (continued).

Point ID*	Point Type**	Variable Name	Use***
N520	D	All control rods in	L1.0 & L2.1 ESI
D530	D	Reactor scram Ch A	Calculate SPDS0083
D531	D	B	Calculate SPDS0083
SPDS0083	HAND	Reactor scram A/B (D530 AND D531)	Calculate SPDS0039
SPDS0039	EXTR	Reactor scram status	L1.0 & L2.1 ESI
IGL_MODE	GC	Plant mode	Mode designation
B021	A	Reactor water level - narrow range (0 to 60") A	L2.2, Calculate SPDSBOX2
N011	A	B	L2.2, Calculate SPDSBOX2
N012	A	C	L2.2, Calculate SPDSBOX2
SPDS0016	TRAN	RPV water level NR A rate-of-change (ROC B021)	L2.2
SPDS0017	TRAN	NR B rate-of-change (ROC N011)	L2.2
SPDS0018	TRAN	NR C rate-of-change (ROC N012)	L2.2
SPDS0019	HAVE	Average narrow range RPV level (healthy avg, B021, N011, N012)	L1.0, L2.2, Calculate SPDS0020
SPDS0020	TRAN	Average narrow range RPV level rate-of-change (ROC SPDS0019)	L1.0, L2.2
G032	A	RPV water level wide range (-150" to 60") A	L2.2, Calculate SPDSBOX2
G033	A	B	L2.2, Calculate SPDSBOX2
SPDS0021	TRAN	RPV water level WR A rate-of-change (ROC G032)	L2.2
SPDS0022	TRAN	WR B rate-of-change (ROC G033)	L2.2
SPDS0023	HAVE	Average wide range RPV level (healthy avg, G032, G033)	L2.2, L3.15, Calc SPDS0024 & SPDS0029
SPDS0024	TRAN	Average wide range RPV level rate-of-change (ROC SPDS0023)	L2.2, L3.15
N009	A	Reactor water level - fuel zone range (-100" to 200") A	L2.2
N010	A	Reactor water level - fuel zone range (-100" to 200") B	L2.2
SPDS0025	TRAN	RPV water level FZ A rate-of-change (ROC N009)	L2.2

Table 3-1. Data Points for Generating Cooper SPDS Displays (continued).

Point ID*	Point Type**	Variable Name		Use***
SPDS0026	TRAN	FZ B rate-of-change (ROC N010)		L2.2
SPDS0027	HAVE	Average FZ range RPV level (healthy avg, N009, N010)		L2.2, Calculate SPDS0028 & SPDS0029
SPDS0028	TRAN	Average FZ range RPV level rate-of-change (ROC SPDS0027)		L2.2
SPDS0029	EXTR	RPV mimic water level (healthy avg, onscale G032, G033, N009 & N010 after conversion to common reference zero)		L2.2
N013	A	Reactor pressure (0-1500 psi)	A	Calculate SPDS0030 & SPDSBOX3
N014	A		B	Calculate SPDS0030 & SPDSBOX3
SPDS0030	HAVE	Average RPV pressure (healthy avg, N013, N014)		L1.0, L2.2, L2.3, L2.4, L3.1, L3.3, L3.11 & L3.15 Calculate SPDS0031
SPDS0031	TRAN	Avg RPV pressure rate-of-change (ROC SPDS0030)		L1.0, L2.3 & L3.15
D554	D	Group 1 isolation A signal		Calculate SPDS0032
D555	D	B		Calculate SPDS0032
SPDS0032	HOR	Group 1 (D554 OR D555)		L2.3 & L2.4 ESI, Calculate SPDSBOX3
N781	D	Group 2 isolation signal - inboard		Calculate SPDS0033
N782	D	- outboard		Calculate SPDS0033
SPDS0033	HOR	Group 2 (N781 OR N782)		L2.3 & L2.4 ESI
N783	D	Group 3 isolation signal - inboard		Calculate SPDS0034
N784	D	- outboard		Calculate SPDS0034
SPDS0034	HOR	Group 3 (N783 OR N784)		L2.3 & L2.4 ESI
N785	D	Group 4 isolation A signal		Calculate SPDS0035
N786	D	B		Calculate SPDS0035
SPDS0035	HOR	Group 4 (N785 OR N786)		L2.3 & L2.4 ESI
N787	D	Group 5 isolation A signal		Calculate SPDS0036
N788	D	B		Calculate SPDS0036
SPDS0036	HOR	Group 5 (N787 OR N788)		L2.3 & L2.4 ESI
N789	D	Group 6 isolation A signal		Calculate SPDS0037
N790	D	B		Calculate SPDS0037
SPDS0037	HOR	Group 6 (N789 OR N790)		L2.3 & L2.4 ESI

Table 3-1. Data Points for Generating Cooper SPDS Displays (continued).

Point ID*	Point Type**	Variable Name	Use***
N791	D	Group 7 isolation signal - inboard	Calculate SPDS0038
N792	D	- outboard	Calculate SPDS0038
SPDS0038	HOR	Group 7 (N791 OR N792)	L2.3 & L2.4 ESI
N797	D	Main steam iso valve A inboard	Calculate SPDS0002
N801	D	A outboard	Calculate SPDS0002
SPDS0002	HAND	MSIV A (N797 AND N801)	Calculate SPDS0010
N798	D	Main steam iso valve B inboard	Calculate SPDS0003
N802	D	B outboard	Calculate SPDS0003
SPDS0003	HAND	MSIV B (N798 AND N802)	Calculate SPDS0010
N799	D	Main steam iso valve C inboard	Calculate SPDS0004
N803	D	C outboard	Calculate SPDS0004
SPDS0004	HAND	MSIV C (N799 AND N803)	Calculate SPDS0010
N800	D	Main steam iso valve D inboard	Calculate SPDS0005
N804	D	D outboard	Calculate SPDS0005
SPDS0005	HAND	MSIV D (N800 AND N804)	Calculate SPDS0010
SPDS0010	EXTR	MSIV status	L2.2 & L2.3 ESI, Calculate SPDSBOX3
D556	D	Main stm relief valve A press sw	Calculate SPDS0089
T142	A	A temp	Calculate SPDS0089
SPDS0089	EXTR	A "position"	L2.4, Calc SPDS0050
D557	D	B press sw	Calculate SPDS0093
T143	A	B temp	Calculate SPDS0093
SPDS0093	EXTR	B "position"	L2.4, Calc SPDS0050
D558	D	C press sw	Calculate SPDS0094
T144	A	C temp	Calculate SPDS0094
SPDS0094	EXTR	C "position"	L2.4, Calc SPDS0050
D559	D	D press sw	Calculate SPDS0095
T145	A	D temp	Calculate SPDS0095
SPDS0095	EXTR	D "position"	L2.4, Calc SPDS0050
D560	D	E press sw	Calculate SPDS0096
T146	A	E temp	Calculate SPDS0096
SPDS0096	EXTR	E "position"	L2.4, Calc SPDS0050
D561	D	F press sw	Calculate SPDS0097
T147	A	F temp	Calculate SPDS0097
SPDS0097	EXTR	F "position"	L2.4, Calc SPDS0050
D562	D	G press sw	Calculate SPDS0098
T148	A	G temp	Calculate SPDS0098
SPDS0098	EXTR	G "position"	L2.4, Calc SPDS0050
D563	D	H press sw	Calculate SPDS0099
T149	A	H temp	Calculate SPDS0099
SPDS0099	EXTR	H "position"	L2.4, Calc SPDS0050

Table 3-1. Data Points for Generating Cooper SPDS Displays (continued).

Point ID*	Point Type**	Variable Name	Use***
M186	A	MS safety valve A temp	Calculate SPDS0040
T139	A	A temp	Calculate SPDS0040
SPDS0040	EXTR	A "position"	L2.4, Calc SPDS0050
M187	A	B temp	Calculate SPDS0041
T140	A	B temp	Calculate SPDS0041
SPDS0041	EXTR	B "position"	L2.4, Calc SPDS0050
M188	A	C temp	Calculate SPDS0042
T141	A	C temp	Calculate SPDS0042
SPDS0042	EXTR	C "position"	L2.4, Calc SPDS0050
SPDS0050	EXTR	Number of SRVs open (RV A to H + SV A to C)	L2.2 & L2.3 ESI, Calculate SPDSBOX3
N002	A	HPCI flow	Calculate SPDS0085
SPDS0085	EXTR	HPCI status	L2.4 & L3.15 ESI
N003	A	RCIC flow	Calculate SPDS0086
SPDS0086	EXTR	RCIC status	L2.4 & L3.15 ESI
N000	A	Core spray pump A flow	L3.9
N001	A	B	L3.9
M578	D	Core spray A status	L3.9 & L3.15 ESI
M580	D	B	L3.9 & L3.15 ESI
N004	A	RHR loop A flow	L3.8
N005	A	B	L3.8
N861	D	RHR pump 1A status	L3.8 & 3.15 ESI
N862	D	1B status	L3.8 & 3.15 ESI
N863	D	1C status	L3.8 & 3.15 ESI
N864	D	1D status	L3.8 & 3.15 ESI
N806	D	RHR suction isolation valve, inbd	Calculate SPDSBOX3
N807	D	RHR suction isolation valve, outbd	Calculate SPDSBOX3
N017	A	Containment (drywell) pressure (-5 to +5 psig) A	Calculate SPDS0043 SPDSBOX2, SPDSBOX3
N018	A	B	Calculate SPDS0043 SPDSBOX2, SPDSBOX3
SPDS0043	HAVE	Avg narrow range drywell pressure (healthy avg N017, N018)	L1.0, calc SPDS0044
SPDS0044	TRAN	Avg NR drywell pressure rate-of-change (ROC SPDS0043)	L1.0

Table 3-1. Data Points for Generating Cooper SPDS Displays (continued).

Point ID*	Point Type**	Variable Name	Use***
F084	A	Drywell pressure (0-80 psia) A	Calculate SPDS0045
F085	A	B	Calculate SPDS0045
SPDS0045	HAVE	Avg mid-range drywell pressure (healthy avg F084, F085)	L2.3, L2.4, L3.4, L3.5, L3.6, L3.7, L3.8 & L3.9, Calculate SPDS0046
SPDS0046	TRAN	Avg mid-range drywell pressure rate-of-change (ROC SPDS0045)	L2.4
M161	A	Drywell temperature PT-10	Calculate SPDS0051
M162	A	PT-11	Calculate SPDS0051
M163	A	PT-12	Calculate SPDS0051
N276	A	Drywell zone 2B area temp B	Calculate SPDS0051
N277	A	D	Calculate SPDS0051
SPDS0051	HMAX	Calculated drywell temp (healthy max, M161, M162, M163, N276, N277)	L2.4, L3.11, Calc SPDS0052 & SPDSBOX4
SPDS0052	TRAN	Avg drywell temp rate-of-change (ROC SPDS0051)	L2.4
T122	A	Drywell hydrogen level	L3.6
N061	A	Drywell/torus 0-5% oxygen level	Calculate SPDS0069, SPDS0090, SPDS0091, & SPDS0092
N062	A	Drywell/torus 0-10% oxygen level	Calculate SPDS0069, SPDS0090, SPDS0091 & SPDS0092
N065	A	Drywell/torus 0-25% oxygen level	Calculate SPDS0069, SPDS0090, SPDS0091 & SPDS0092
N627	D	Drywell oxygen sample No. 1	Calculate SPDS0090
N628	D	Drywell oxygen sample No. 2	Calculate SPDS0091, & SPDS0092
N629	D	Drywell oxygen sample No. 3	Calculate SPDS0092
N630	D	Torus oxygen sample	Calculate SPDS0069
N631	D	Drywell/torus oxygen range No. 1 (0-5%)	Calculate SPDS0069, SPDS0090, SPDS0091 & SPDS0092
N632	D	Drywell/torus oxygen range No. 2 (0-10%)	Calculate SPDS0069, SPDS0090, SPDS0091, & SPDS0092

Table 3-1. Data Points for Generating Cooper SPDS Displays (continued).

Point ID*	Point Type**	Variable Name	Use***
N633	D	Drywell/torus oxygen range No. 3 (0-25%)	Calculate SPDS0069, SPDS0090, SPDS0091, & SPDS0092
SPDS0090	EXTR	Calculated drywell oxygen, point 1	Calculate SPDS0053
SPDS0091	EXTR	Calculated drywell oxygen, point 2	Calculate SPDS0053
SPDS0092	EXTR	Calculated drywell oxygen, point 3	Calculate SPDS0053
SPDS0053	HMAX	Healthy maximum drywell oxygen	L3.6
SPDS0069	EXTR	Calculated torus oxygen	L3.7
N059	A	Drywell flr sump pump 1F1/2 flow	Calculate SPDS0054
N060	A	pump 1G1/2 flow	Calculate SPDS0055
SPDS0054	EXTR	Drywell sump pump status	L2.3 ESI
N063	A	High range drywell airlock area rad monitor	L2.3, Calc SPDS0049, SPDS0082 & SPDSBOX3
SPDS0082	LOG	Log of drywell area rad (LOG N063)	L2.3
SPDS0049	TRAN	High range drywell airlock area rad monitor rate-of-change (ROC N063)	L2.3
N023	A	Suppression pool water temp 1A	Calculate SPDS0055
N024	A	1B	Calculate SPDS0056
N025	A	1C	Calculate SPDS0057
N026	A	1D	Calculate SPDS0058
N027	A	1E	Calculate SPDS0059
N028	A	1F	Calculate SPDS0060
N029	A	1G	Calculate SPDS0061
N030	A	1H	Calculate SPDS0062
N031	A	2A	Calculate SPDS0055
N032	A	2B	Calculate SPDS0056
N033	A	2C	Calculate SPDS0057
N034	A	Suppression pool water temp 2D	Calculate SPDS0058
N035	A	2E	Calculate SPDS0059
N036	A	2F	Calculate SPDS0060
N037	A	2G	Calculate SPDS0061
N038	A	2H	Calculate SPDS0062
SPDS0055	HAVE	Supp. pool temp healthy avg 1A, 2A	L2.4, calc SPDS0094
SPDS0056	HAVE	avg 1B, 2B	L2.4, calc SPDS0095

Table 3-1. Data Points for Generating Cooper SPDS Displays (continued).

Point ID*	Point Type**	Variable Name	Use***
SPDS0057	HAVE	avg 1C, 2C	L2.4, calc SPDS0096
SPDS0058	HAVE	avg 1D, 2D	L2.4, calc SPDS0097
SPDS0059	HAVE	avg 1E, 2E	L2.4, calc SPDS0098
SPDS0060	HAVE	avg 1F, 2F	L2.4, calc SPDS0099
SPDS0061	HAVE	avg 1G, 2G	L2.4, calc SPDS0100
SPDS0062	HAVE	avg 1H, 2H	L2.4, calc SPDS0101
SPDS0063	HAVE	Overall avg supp pool water temp (healthy avg SPDS0055 to 0062)	L2.4, L3.1, L3.5, L3.8, L3.9, Calculate SPDS0064 & SPDSBOX4
SPDS0064	TRAN	Avg supp pool temp rate-of-change (ROC SPDS0063)	L2.4
SPDS0084	EXTR	Delta T heat capacity (limit minus SPDS0063)	L3.2
N019	A	Suppression pool level (0-30') A	Calculate SPDS0065
N020	A	B	Calculate SPDS0065
SPDS0065	HAVE	Avg supp pool wide range level (healthy avg N019, N020)	L2.4, L3.2, L3.3, SFI, calculate SPDS0066 & SPDSBOX4
SPDS0066	TRAN	Avg supp pool wide level rate-of-change (ROC SPDS0065)	L2.4
N021	A	Containment water level (0-100') A	Calculate SPDS0067
N022	A	B	Calculate SPDS0067
SPDS0067	HAVE	Avg cont. wide range level (healthy avg N021, N022)	L3.4
N079	A	ERP normal range rad monitor	L2.5, Calc SPDS0070, SPDS0071 & SPDSBOX5
SPDS0070	LOG	Log of ERP normal range (LOG N079)	L2.5
SPDS0071	TRAN	ERP effluent rate-of-change (ROC N079)	L2.5
N073	A	AOG & RW effluent normal range rad mon	L2.5, Calc SPDS0072, SPDS0073 & SPDSBOX5
SPDS0072	LOG	Log of AOG & RW normal range (LOG N073)	L2.5
SPDS0073	TRAN	AOG & RW eff rate-of-change (ROC N073)	L2.5

Table 3-1. Data Points for Generating Cooper SPDS Displays (continued).

Point ID*	Point Type**	Variable Name	Use***
N074	A	Rx bldg effluent rad monitor	L2.5, Calc SPDS0074, SPDS0075 & SPDSBOX5
SPDS0074	LOG	Log of Rx bldg effluent (LOG N074)	L2.5
SPDS0075	TRAN	Rx bldg effluent rate-of-change (ROC N074)	L2.5
N069	A	Turbine bldg effluent normal range rad mon	L2.5, Calc SPDS0076, SPDS0077 & SPDSBOX5
SPDS0076	LOG	Log of turb bldg effluent (LOG N069)	L2.5
SPDS0077	TRAN	Turb bldg eff rate-of-change (ROC N069)	L2.5
N082	A	SJAE radiation monitor A	Calculate SPDS0078
N083	A	B	Calculate SPDS0078
N084	A	SJAE A air flow	Calculate SPDS0078
N085	A	B air flow	Calculate SPDS0078
SPDS0078	EXTR	Calculated SJAE effluent	L2.5, Calc SPDS0079, SPDS0081 & SPDSBOX5
SPDS0081	LOG	LOG of SJAE effluent (LOG SPDS0078)	L2.5
SPDS0079	TRAN	SJAE effluent rate-of-change (ROC SPDS0078)	L2.5
SPDS000B	EXTR	Supp. pool heat cap. temp lim.	L2.4 EOPSI
SPDS001B	EXTR	Supp. pool heat cap. level lim.	L2.4 EOPSI
SPDS002B	EXTR	Supp. pool load lim.	L2.4 EOPSI
SPDS004B	EXTR	Containment pressure lim.	L2.4 EOPSI
SPDS006B	EXTR	Drywell spray init press lim.	L2.4 EOPSI
SPDS007B	EXTR	Drywell hydrogen lim.	L2.4 EOPSI
SPDS009B	EXTR	Drywell oxygen lim.	L2.4 EOPSI
SPDS010B	EXTR	Torus oxygen lim.	L2.4 EOPSI
SPDS011B	EXTR	NPSH lim.	L2.2 EOPSI
SPDS021B	EXTR	Constant 100 psig	L3.15 EOPSI
SPDS022B	EXTR	Constant 425 psig	L3.15 EOPSI
SPDS023B	EXTR	RPV press hi/level inc.	L3.15 EOPSI
SPDS024B	EXTR	RPV press int/level inc.	L3.15 EOPSI
SPDS025B	EXTR	RPV press low/level inc.	L3.15 EOPSI
SPDS026B	EXTR	RPV press hi-int/level dec.	L3.15 EOPSI
SPDS027B	EXTR	RPV press low/level dec.	L3.15 EOPSI
SPDS028B	EXTR	RPV sat temp lim	L1.0, L2.2 & L3.15 EOPSI
IAD_EOP	GC	SAA "E" driver	SAA "E"

Table 3-1. Data Points for Generating Cooper SPDS Displays (continued).

Point ID*	Point Type**	Variable Name	Use***
SPDSBOX1	EXTR	Reactivity control SFI driver	SFI
SPDSBOX2	EXTR	Core cooling SFI driver	SFI
SPDSBOX3	EXTR	Coolant sys integrity SFI driver	SFI
SPDSBOX4	EXTR	Containment integrity SFI driver	SFI
SPDSBOX5	EXTR	Radioactive release SFI driver	SFI
SPDS01DS	EXTR	APRM (SPDS0008) DNSC ind	L1.0 & L2.1 DNSCI
SPDS02DS	EXTR	RPV press (SPDS0030) DNSC ind	L1.0 & L2.3 DNSCI
SPDS03DS	EXTR	RPV level avg NR (SPDS0019) DNSC ind	L1.0 DNSCI
SPDS04DS	EXTR	Drywell press (SPDS0043) DNSC ind	L1.0 DNSCI
SPDS05DS	EXTR	SRM (SPDS0014) DNSC ind	L2.1 DNSCI
SPDS06DS	EXTR	RPV level NR A (B021) DNSC ind	L2.2 DNSCI
SPDS07DS	EXTR	B (N011)	L2.2 DNSCI
SPDS08DS	EXTR	C (N012)	L2.2 DNSCI
SPDS09DS	EXTR	RPV level WR A (G032) DNSC ind	L2.2 DNSCI
SPDS10DS	EXTR	B (G033)	L2.2 DNSCI
SPDS11DS	EXTR	RPV level FZ A (N009) DNSC ind	L2.2 DNSCI
SPDS12DS	EXTR	B (N010)	L2.2 DNSCI
SPDS13DS	EXTR	Drywell press (SPDS0045) MR DNSC ind	L2.3 & L2.4 DNSCI
SPDS14DS	EXTR	Containment rad (SPDS0082) DNSC ind	L2.3 DNSCI
SPDS15DS	EXTR	Drywell temp (SPDS0051) DNSC ind	L2.4 DNSCI
SPDS16DS	EXTR	Supp. pool level WR (SPDS0065) DNSC ind	L2.4 DNSCI
SPDS17DS	EXTR	Supp. pool temp avg (SPDS0063) DNSC ind	L2.4 DNSCI
SPDS18DS	EXTR	ERP eff (SPDS0070) DNSC ind	L2.5 DNSCI
SPDS19DS	EXTR	AOG & RW eff. (SPDS0072) DNSC ind	L2.5 DNSCI
SPDS20DS	EXTR	Rx bldg. eff. (SPDS0074) DNSC ind	L2.5 DNSCI
SPDS21DS	EXTR	Turb. bldg eff (SPDS0076) DNSC ind	L2.5 DNSCI
SPDS22DS	EXTR	SJAE eff. (SPDS0078) DNSC ind	L2.5 DNSCI
SPDS01NV	EXTR	Average APRM (SPDS0008) NV	L1.0 & L2.1 NVI
SPDS02NV	EXTR	Average SRM (SPDS0014) NV	L2.1 NVI

Table 3-1. Data Points for Generating Cooper SPDS Displays (continued).

Point ID*	Point Type**	Variable Name	Use***
SPDS03NV	EXTR	Average narrow range RPV level (SPDS0019) NV	L1.0 NVI
SPDS04NV	EXTR	Average wide range RPV level (SPDS0023) NV	L2.2 & L3.15 NVI
SPDS05NV	EXTR	Average FZ range RPV level (SPDS0027) NV	L2.2 NVI
SPDS06NV	EXTR	Maximum drywell temp (SPDS0051) NV	L2.4 & L3.11 NVI
SPDS07NV	EXTR	Average RPV pressure (SPDS0030) NV	L1.0, L2.2, L2.3, L2.4, L3.1, L3.3, L3.11 & L3.15 NVI
SPDS08NV	EXTR	Avg NR drywell pressure (SPDS0043) NV	L1.0 NVI
SPDS09NV	EXTR	Avg MR drywell pressure (SPDS0045) NV	L2.3, L2.4, L3.4 to L3.9 NVI
SPDS10NV	EXTR	Supp pool 1A, 2A temp (SPDS0055) NV	L2.4 NVI
SPDS11NV	EXTR	Supp pool 1B, 2B temp (SPDS0056) NV	L2.4 NVI
SPDS12NV	EXTR	Supp pool 1C, 2C temp (SPDS0057) NV	L2.4 NVI
SPDS13NV	EXTR	Supp pool 1D, 2D temp (SPDS0058) NV	L2.4 NVI
SPDS14NV	EXTR	Supp pool 1E, 2E temp (SPDS0059) NV	L2.4 NVI
SPDS15NV	EXTR	Supp pool 1F, 2F temp (SPDS0060) NV	L2.4 NVI
SPDS16NV	EXTR	Supp pool 1G, 2G temp (SPDS0061) NV	L2.4 NVI
SPDS17NV	EXTR	Supp pool 1H, 2H temp (SPDS0062) NV	L2.4 NVI
SPDS18NV	EXTR	Supp pool WR level (SPDS0065) NV	L2.4, L3.2 & L3.3 NVI
SPDS19NV	EXTR	Containment WR level (SPDS0067) NV	L3.4 NVI
SPDS0100	PSEU	Spare	
SPDS0101	PSEU	Spare	
SPDS0102	PSEU	Spare	
SPDS0103	PSEU	Spare	
SPDS0104	PSEU	Spare	
SPDS0105	TRAN	Spare	
SPDS0106	TRAN	Spare	
SPDS0107	TRAN	Spare	

Table 3-1. Data Points for Generating Cooper SPDS Displays (continued).

Point ID*	Point Type**	Variable Name	Use***
SPDS0108	TRAN	Spare	
SPDS0109	TRAN	Spare	
SPDS0110	BOOL	Spare	
SPDS0111	BOOL	Spare	
SPDS0112	BOOL	Spare	
SPDS0113	BOOL	Spare	
SPDS0114	BOOL	Spare	
SPDS0115	EXTR	Spare	
SPDS0116	EXTR	Spare	
SPDS0117	EXTR	Spare	
SPDS0118	EXTR	Spare	
SPDS0119	EXTR	Spare	
SPDS0120	EXTR	Spare	
SPDS0121	EXTR	Spare	
SPDS0122	EXTR	Spare	
SPDS0123	EXTR	Spare	
SPDS0124	EXTR	Spare	

Notes:

* Four digit point ID numbers indicate analog or digital points available on PMIS. Eight digit point ID numbers prefaced with the characters "SPDS" are composed points.

** Point type:
- A = analog
- D = digital
- PSEU = pseudo analog, spare
- HMAX = pseudo analog, maximum of healthy inputs
- HAVE = pseudo analog, healthy average
- LOG = pseudo analog, logarithm
- TRAN = transform, rate-of-change
- BOOL = Boolean, spare
- HOR = Boolean, healthy OR
- HAND = Boolean, healthy AND
- EXTR = external (real)
- GC = PMIS global common variable

*** If the variable appears in a display, the display is identified as follows:

- Level 1 display
  L1.0 = overview bar

Table 3-1. Data Points for Generating Cooper SPDS Displays (continued).

- Level 2 displays
  In this table, Level 2 displays are identified only by their first two digits. The third digit in the Level 2 display designation uniquely identifies multiple displays related to the same function as follows: L2.1 are reactivity control displays, L2.2 are core cooling displays, L2.3 are coolant system integrity displays, L2.4 are containment integrity displays, and L2.5 are radioactive release displays. The full set of Level 2 displays are the following:

  L2.1.1 = reactivity control (bar)
  L2.1.2 = reactivity control (trend)
  L2.2.1 = RPV water level (bar/RPV mimic)
  L2.2.2 = core cooling (trend)
  L2.3.1 = coolant system integrity (bar)
  L2.3.2 = coolant system integrity (trend)
  L2.4.1 = containment integrity (bar)
  L2.4.2 = containment integrity (trend)
  L2.4.3 = suppression chamber mimic
  L2.5.1 = radioactive release (bar)
  L2.5.2 = radioactive release (trend, page 1/2)
  L2.5.3 = radioactive release (trend, page 2/2)

- Level 3 displays
  L3.1 = heat capacity temperature limit
  L3.2 = heat capacity level limit
  L3.3 = suppression pool load limit
  L3.4 = containment pressure limits
  L3.5 = drywell spray initiation pressure limit
  L3.6 = drywell hydrogen and oxygen status
  L3.7 = suppression chamber hydrogen and oxygen status
  L3.8 = RHR pump NPSH limits
  L3.9 = LPCS pump NPSH limits
  L3.11 = RPV saturation temperature limit
  L3.12 = maximum core uncovery time limit
  L3.15 = RPV pressure/level status matrix

- Status indicators

  SFI = safety function indicator (on all SPDS displays)
  ESI = equipment status indicator
  EOPSI = emergency operating procedure limit status indicator
  DNSCI = downscale indicator
  NVI = not-valid indicator

Table 7-1. Plant Variables Expected to be Monitored by Cooper Nuclear Station SPDS.

Variables	Technical Basis: EPGs	Technical Basis: Safety Function	Technical Basis: Remarks	Variable Currently Available On CNS PMIS
Average power range monitor (APRM) power level	X	X		Yes
Intermediate range monitor (IRM) log power			For continuity, used in BWROG GDS	Yes
IRM range			Necessary for interpreting IRM log power reading	Yes
IRM position			Necessary for interpreting IRM log power reading	Yes
Source range monitor (SRM) count rate		X		Yes
SRM position			Necessary for interpreting SRM count rate	Yes
All-rods-in status			In lieu of individual control rod position	Yes
Scram demand status	X			Yes
Reactor pressure vessel (RPV) water level				
- narrow range (0" to +60")	X	X		Yes
- wide range (-150 to +60")	X	X		Yes
- refueling range (0" to +400")	X	X		(1)
- fuel zone range (-100" to +200")	X	X		Yes
RPV pressure	X	X		Yes
RPV isolation demand status				
- Group 1 (MSIV)	X	X	In lieu of isolation valve position	Yes
- Group 2 to 7		X	In lieu of isolation valve position	Yes
Safety/Relief Valve (SRV) position	X			Yes
High pressure coolant injection (HPCI) pump flow rate	X			Yes
Reactor core isolation cooling (RCIC) pump flow rate	X			Yes
Low pressure core spray (LPCS) pump flow rate	X			Yes
Low pressure coolant injection (LPCI, or RHR) pump flow rate	X			Yes

Notes: (1) Possible future addition to CNS PMIS. Variables will be available on the SPDS if they are added to the PMIS.

Table 7-1. (Continued).

Variables	Technical Basis: EPGs	Technical Basis: Safety Function	Technical Basis: Remarks	Variable Currently Available On CNS PMIS
Drywell pressure	X	X		Yes
Drywell temperature				
- average	X	X		(3)
- local (individual)	X			Yes
Drywell hydrogen concentration	X	X		Yes
Drywell oxygen concentration	X	X		Yes
Drywell sump collection rate (sump pump flow rate)		X	In lieu of sump level	Yes
Containment activity (area radiation)		X		Yes
Suppression chamber (torus) pressure	X	X		Yes
Suppression pool (torus) water temperature				
- average	X	X		(3)
- delta T heat capacity (calculated)	X			(2)
Suppression pool (torus) water level	X	X		Yes
Suppression chamber (torus) hydrogen concentration	X	X		(1)
Suppression chamber (torus) oxygen concentration	X	X		Yes
Secondary containment (reactor building) differential pressure	X			Yes
Secondary containment (reactor building) area temperature alarm status	X		Alarm status in lieu of analog value	(1)
Secondary containment (reactor building) HVAC exhaust radiation level alarm status	X		Alarm status in lieu of analog value	(1)
Secondary containment (reactor building) area radiation level	X			Yes
Secondary containment (reactor building) floor drain sump water level and torus area water level monitor	X		Alarm status in lieu of analog value	(1)

Notes: (1) Possible future addition to CNS PMIS. Variables will be available on the SPDS if they are added to the PMIS.

(2) Calculated by SPDS as the difference between suppression pool heat capacity temperature limit and suppression pool average temperature.

(3) Calculated from multiple points on PMIS for this variable.

Table 7-1. (Continued).

Variables	Technical Basis			Variable Currently Available On CMS PMIS
	EPGs	Safety Function	Remarks	
Offsite radioactive release rate from plant release points	X	X		
- elevated release point (ERP) effluents				Yes
- Augmented off-gas (AOG) and radwaste (RW) building effluent				Yes
- Reactor building effluent				Yes
- Turbine building effluent				Yes
- Steam jet air ejector (SJAE) monitors				Yes

Attachment 2

Commitment to provide a highly reliable power supply system for the SPDS and a description of the power supply system in terms of its impact on total SPDS reliability (flow charts or diagrams may be helpful).

DESIGN CALCULATIONS COVER SHEET

JOB NUMBER: 22886-1052 UNIT NUMBER: ________ DISCIPLINE: EE

NPPD CALCULATION NUMBER: NEDC-84-076

TITLE: MTBF Calcs for the Power Supply System to the PMIS Equipment NUMBERS OF SHEETS: 15

STRUCTURE: NA PREPARED BY: W. C. Fischer

SYSTEM: PMIS CHECKED BY: C. D. Ehrenberg

COMPONENT: UPS System ENGINEERING SUPERVISOR: E C Walt 1/13/85

SUPERSEDED CALCULATION NUMBER: MDC 84-37G

*STRESS REPORTS SHALL BE APPROVED BY REGISTERED PE.

CALCULATION DESCRIPTION: This calculation provides Mean Time Between Failure (MTBF) estimates for each of the power supplies to the PMIS Equipment through the UPS System.

DESIGN BASIS OR REFERENCES: SAI requirement per letter to Jim Murphy (NPPD) from John Skinner (SAIC), dated November 13, 1984.

USAR CHECKED X USAR CHANGE REQUIRED ___ USAR CHANGE NOTIFIED INITIATED ___

REVISION NUMBER	REVISION	BY	DATE	CHECKED BY	APPROVED BY*	DATE

Title: MTBF Calcs for the Power Supply System to the PMIS Equipment
Prepared by W.C. Purcha Date 12-6-84
Checked by [illegible] Date 1-11-85

I. SCOPE

This calculation develops the Mean Time Between Failures (MTBF) in hours as requested in Reference 3, attached.

II. APPROACH

Site specific data will be used whenever it is available. Where no site specific data is available generic data will be used. The generic data will be obtained from References 1, 2, 9, 10, and 13.

Wherever possible, system reliability data will be utilized versus computing the reliability of a system using the reliability factors of individual components. Whenever the reliability of a system is calculated, approximation methods are used. A rigorous analysis would require the use of a computer. This type of rigorous analysis is outside the scope of this calculation.

III. RESULTS

Listed below are the MTBF figures requested by SAI and developed in Section IV.

A. MCC "L" in Control Building Basement: MTBF = 5,557 hours.

B. MDP2 in MPF: MTBF = 73,556 hours
Repair time = 8.40 hours

C. UPS Equipment: UPS - MTBF = 100,000 hours
Batteries - MTBF - 18,727 hours
Battery repair time = .85 hours

D. MDPI in MPF: MTBF = 73,556 hours
Repair time = 8.40 hours

IV. DEVELOPMENT

A. This sections shows the actual calculation of the MTBF for the power supplies requested in Reference 3.

B. UPS Equipment

The MTBF is 100,000 hours. This number was given by Solid State Control, Inc. in NPPD Contract 84-32, page G-14.

A 30 minute battery bank was purchased from Exide, PO 231066. The 125 volt battery bank utilizes 60 Ex-27 batteries with a 20 year warranty. Exide did not have MTBF information available on these batteries.

Title: MTBF Calcs for the Power Supply System to the PMIS Equipment

Prepared by W.C. Pircher Date 12-10-84
Checked by Craig E. Ebeling Date 1-11-85

Various reference information will be analyzed to obtain a conservative MTBF for the battery bank.

From Reference 10, station batteries had 23 failures in 48.2428×10^6 hours for a failure rate λ of

$$\lambda = \frac{23}{48.2428 \times 10^6} = .47676 \text{ Failures}/10^6 \text{ hours}$$

This is the failure rate for one battery. For a system of 60 batteries in series.

$$\lambda = (60)\frac{.47676}{10^6} = 28.605 \text{ Failures}/10^6 \text{ hours}$$

$$\text{MTBF} = \frac{1}{\dfrac{28.605 \text{ Failures}}{10^6 \text{ hours}}} = 34{,}959 \text{ hours}$$

From Reference 13, station batteries (storage), lead acid stationery, float service composite, the failure rate is

$$\lambda = .89 \text{ Failures}/10^6 \text{ hours}$$

$$\text{For 60 batteries in series} = \frac{(60)\ (.89)}{10^6} = 53.4 \text{ Failures}/10^6 \text{ hours}$$

$$\text{The MTBF} = \frac{1}{\dfrac{53.4 \text{ Failures}}{10^6 \text{ hours}}} = 18{,}727 \text{ hours}$$

The composite given in Reference 10 did include NUREG-0666 (A Probabilistic Safety Analysis of DC Power Supply Requirements of Nuclear Power Plants) April, 1981. The failure rate used from NUREG-0666 was

$$\lambda = \frac{.99 \text{ Failures}}{10^6 \text{ hours}} \text{ and MTBF} = \frac{1}{\dfrac{(.99)\ (60) \text{ Failures}}{10^6 \text{ hours}}} = 16{,}835 \text{ hours}$$

It appears that Reference 10 data yields too high a MTBF. The composite given by Reference 13 gives a better estimate of the MTBF.

Title: MTBF Calcs for the Power Supply System to the PMIS Equipment
Prepared by W.C. [illegible] Date 12-10-84
Checked by [illegible] Date 1-11-85

The estimate of the MTBF for batteries for this calculation will be 18,727 hours.

The repair time per Reference 13 is .85 hours.

C. Motor Control Center (MCC) "L" in the Control Building Basement.

MCC "L" is classified as critical or essential at CNS and is connected to a diesel generator. During a loss of offsite power (LOOP), Diesel Generator 1 will provide power to MCC "L". See References 19, 20, 21, and 22 for the actual bus schemes.

From Reference 10, the Emergency Diesel Systems surveyed had 7 failures in $1,825.9 \times 10^3$ calendar hours.

$$\text{The Failure Rate } \lambda \text{ is } \frac{7 \text{ Failures}}{1,825.9 \times 10^3 \text{ hours}} = 3.834 \text{ Failures}/10^6 \text{ hours}$$

$$\text{MTBF} = \frac{1}{\frac{3.834 \text{ Failures}}{10^6 \text{ hours}}} = 260,843 \text{ hours}$$

This is for diesels after start up and does not consider failure to start.

At CNS on Diesel Generator 1 (DG-1) from December 27, 1978 to September 4, 1984, there have been 9 failures to run for more then 1 hour with more the a 50 percent continuous rating per Reference 22.

This would equate to a failure rate of

$$\lambda = \frac{9 \text{ Failures}}{(2,084 \text{ days})\ (24 \text{ hour/days})} = 179.9 \text{ Failures}/10^6 \text{ hours}$$

$$\text{MTBF} = \frac{1}{\text{Failure Rate}} = \frac{1}{\frac{179.8}{106}} = \underline{5,557 \text{ hours}}$$

The MTBF figure calculated using actual CNS data appears to provide a more conservative figure.

To check the appropriateness of the calculated MTBF to other nuclear plants, data from Reference 2 was reviewed.

Per Table 2-2 of Reference 2, there was a total of 152 failures to start of the diesels at various nuclear plants.

The diesels in question had 177.9 years of diesel experience.

$$\text{Failure Rate} = \frac{152}{(177.9)\ (365)\ (24)} = 97.5 \text{ Failures}/10^6 \text{ hours}$$

$$\text{MTBF} = \frac{1}{\dfrac{97.5 \text{ Failures}}{10^6 \text{ hours}}} = 10{,}253 \text{ hours}$$

It appears that DG-1 at CNS is below the norm for the nuclear plants analyzed in Reference 2. However, the MTBF of 5,557 hours appears to be a valid and reasonable estimate.

NOTE:

It should be noted the MTBF number calculated for MCC "L" is a very conservative figure. It assumes that the diesel is the only source to MCC "L", which is not the case. However, the final determination on the reliability of MCC "L" is the diesel generator.

D. MDP1 and MDP2 in the Multi Purpose Facility (MPF).

MDP1 and MDP2 are fed from separate transformers from the 12.5 kV plant Loop as shown on Reference 18.

The primary feed to the Loop is through a 13.8/12.5 kV transformer. The 13.8 kV is provided from the tertiary of the 345/161/13.8 kV transformer in the 345 kV substation (Reference 19).

In computing the MTBF of MDP1 and MDP2, the first step is to compute the MTBF of the feed into the 12.5 kV Loop, starting at the 13.8/12.5 kV transformer.

The transformer was put into service November 4, 1982 (Reference 4). Since then there has been one forced outage on the transformer. This occurred November 29, 1984 and lasted for 3 hours 52 minutes.

$$\lambda = \frac{1 \text{ Failure (forced outage)}}{2 \text{ years } (365 \text{ day}) \dfrac{}{\text{year}}\ 24 \text{ hours} \dfrac{}{\text{day}} + (38 \text{ days})\ 24 \text{ hours} \dfrac{}{\text{day}}} = 54.25 \text{ Failures}/10^6 \text{ hours}$$

$$MTBF = \frac{1}{\dfrac{54.25 \text{ Failures}}{10^6 \text{ hours}}} = 18,432 \text{ hours}$$

This number appears low if we consider the loss of the 345/161/13.8 kV transformers since the plant has kept records, References 1 and 7. This information indicates that in 10.81 years and there has been only one incident where this transformer had a forced outage.

$$\lambda = \frac{1}{(10.81)\ (365)\ (24)} = 10.56 \text{ Failures}/10^6 \text{ hours}$$

$$MTBF = \frac{1}{\dfrac{10.56}{10^6}} = \underline{94,696 \text{ hours}}$$

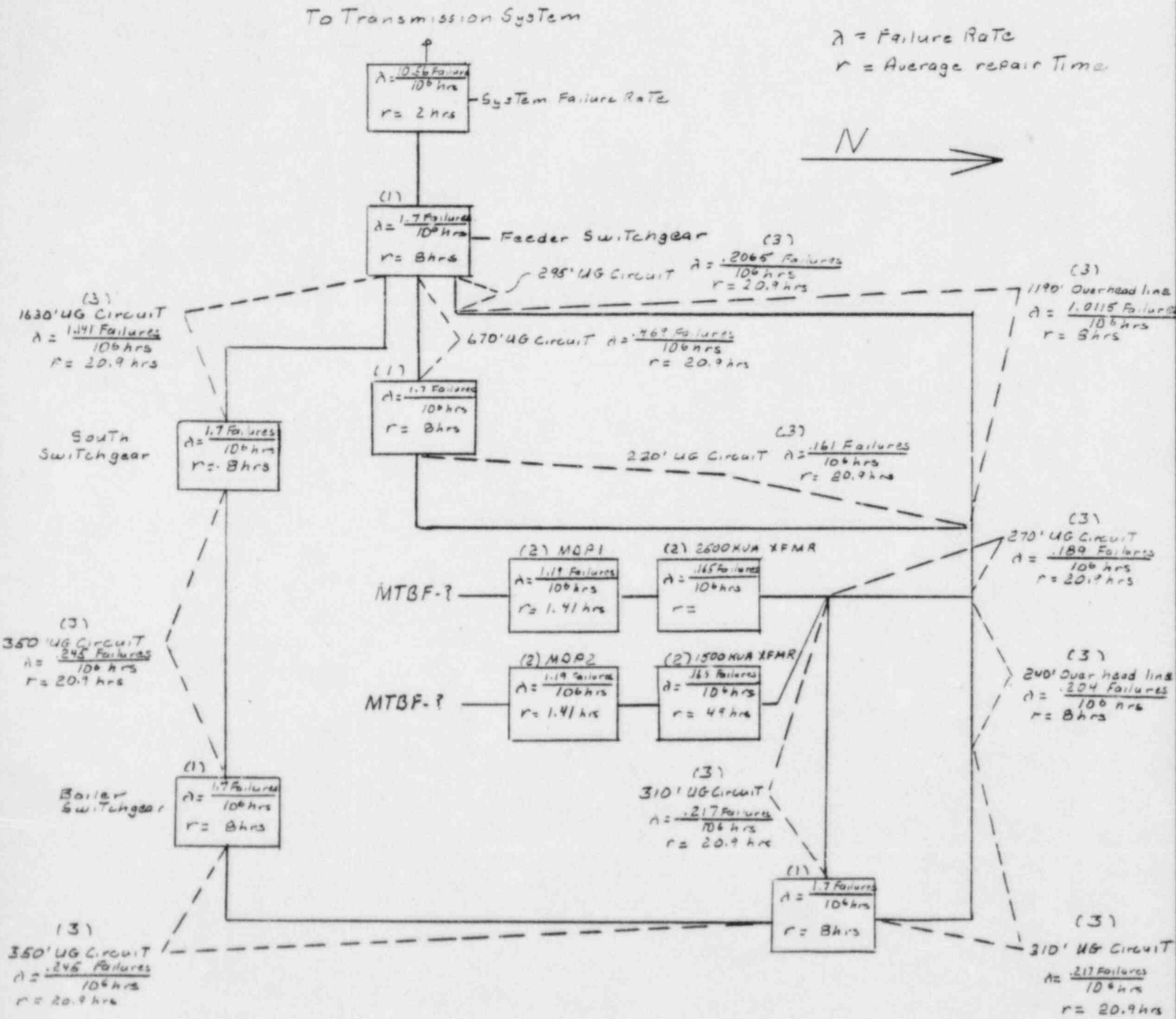
← This is a more realistic number of the MTBF for the plant 12.5 kV Loop feed.

Title: MTBF Calcs for the Power Supply System to the PMIS Equipment

Prepared by W.C. Rusk(?) Date 12-12-84

Checked by [illegible] Date 1-11-85

Shown below is a failure rate diagram for the 12.5 kV plant loop. The equipment in the Loop, including the 12.5 kV line sections, have been given a failure rate derived from the various references.



(1)- Failure Rate Info From Ref. 10

(2)- Failure Rate Info from Ref. 13

(3)- Failure Rate Info From Ref. 15

Total of above Two line Sections

$$\lambda_T = \frac{.204 + .217}{10^6} = \frac{.421 \text{ Failures}}{10^6 \text{ hrs}}$$

$$r_T = \frac{(.204)(8) + (.217)(20.9)}{.421}$$

$$r_T = 14.65 \text{ hrs}$$

Title: MTBF Calcs for the Power Supply System to the PMIS Equipment

Prepared by W.C. Rudy Date 12-20-84
Checked by [illegible] Date 1-11-85

The failure rate diagram will be reduced using the following approximation formulas (Reference 16).

Series System

$\lambda_1, r_1 \quad \lambda_2, r_2$

λ = failure rate per 10^6 hours
r = average hours of down time per repair

$$\lambda_T = \lambda_1 + \lambda_2 \quad \frac{\text{Failure}}{10^6 \text{ hours}}$$

$$r_T = \frac{\lambda_1 r_1 + \lambda_2 r_2}{\lambda_T} \quad \frac{\text{hours}}{\text{Failure}}$$

Parallel System

λ_1, r_1

λ_2, r_2

$$\lambda_T = \lambda_1 \lambda_2 (r_1 + r_2)$$

$$r_T = \frac{r_1 r_2}{r_1 + r_2}$$

Northwest Series System -

$$\lambda_T = \frac{.2065 + 1.0115}{10^6} = 1.218 \text{ Failures}/10^6 \text{ hours}$$

$$r_T = \frac{(.2065)(20.9) + (1.0115)(8)}{1.218} = 10.19 \text{ hours}$$

Title: MTBF Calcs for the Power Supply System to the PMIS Equipment

Prepared by W. C. Parker Date 12-20-84
Checked by Craig E. Sterling Date 1-11-85

South Series System -

$$\lambda_T = \frac{1.141 + 1.7 + .245 + 1.7 + .245}{10^6} = 5.031 \text{ Failures}/10^6 \text{ hours}$$

$$r_T = \frac{(1.141)\ (20.9) + (2)\ (1.7)\ (8) + (2)\ (.245)\ (20.9)}{5.031} = \underline{12.18} \text{ hours}$$

Middle Series System -

$$\lambda_T = \frac{.469 + 1.7 + .161}{10^6} = 2.33 \text{ Failures}/10^6 \text{ hours}$$

$$r_T = \frac{(.469)\ (20.9) + (1.7)\ (8) + (.161)\ (20.9)}{2.33} = 11.49 \text{ hours}$$

Middle and Northwest Parallel System -

$$\lambda_T = \frac{(1.218)\ (2.33)\ (10.19 + 11.49)}{(10^6)\quad(10^6)} = \frac{61.38 \text{ Failures}}{10^{12} \text{ hours}} = .00006138 \text{ Failures}/10^6 \text{ hours}$$

$$r_T = \frac{(10.19)\ (11.49)}{(10.19 + 11.49)} = 5.4 \text{ hours}$$

MDP1 + 2,500 kVA Transformer (series system)

$$\lambda_T = \frac{1.19 + .165}{10^6} = 1.355 \text{ Failures}/10^6 \text{ hours}$$

$$r_T = \frac{(1.19)\ (1.41) + (.165)\ (49)}{1.355}$$

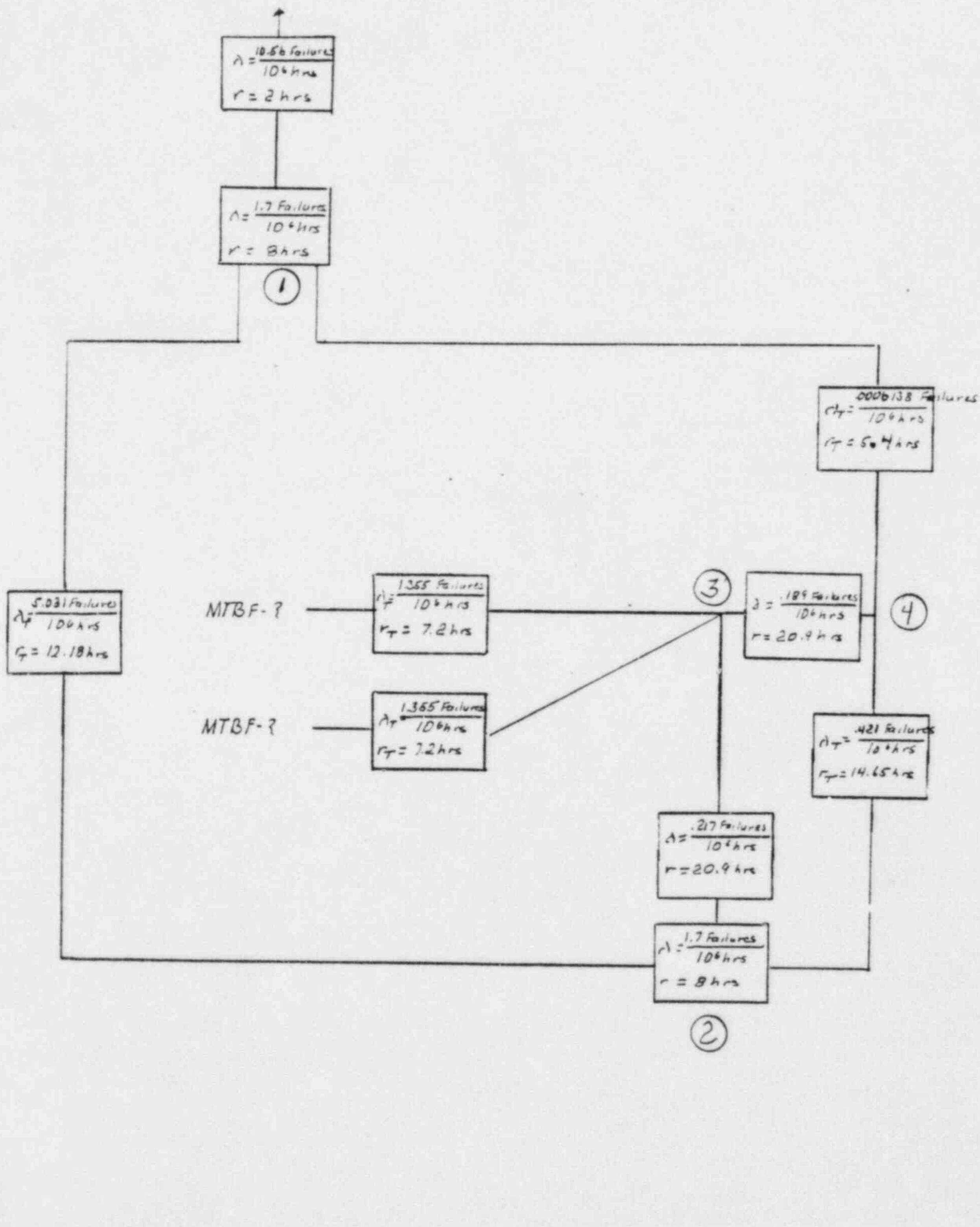
$$r_T = 7.2 \text{ hours}$$

MDP1 + 1500 kVA Transformer: Same as above

Title: MTBF Calcs for the Power Supply System to the PMIS Equipment

Prepared by W.C. Pisechy Date 12-20-84
Checked by Craig E. Shirley Date 1-11-85

The previous calculations reduce the failure rate diagram to:



The failure rate diagram is again reduced by combining parallel and series systems.

In order to facilitate the further reduction of this diagram, the UG Line Section from Node 3 to Node 4 will be added to each Line Section from Node 1 to Node 4 and Node 2 to Node 3. This will reduce the diagram to simple parallel systems.

Addition of Line Section Node 3 to Node 4 and Node 1 to Node 4.

$$\lambda_T = \frac{.00006138 + .189}{10^6} = .18906138 \text{ Failures}/10^6 \text{ hours}$$

$$r_T = \frac{(.189)\ (20.9)\ + (.00006138)\ (5.4)}{.18906138} = 20.89 \text{ hours}$$

Addition of Line Section Node 3 to Node 4 and Node 2 to Node 4.

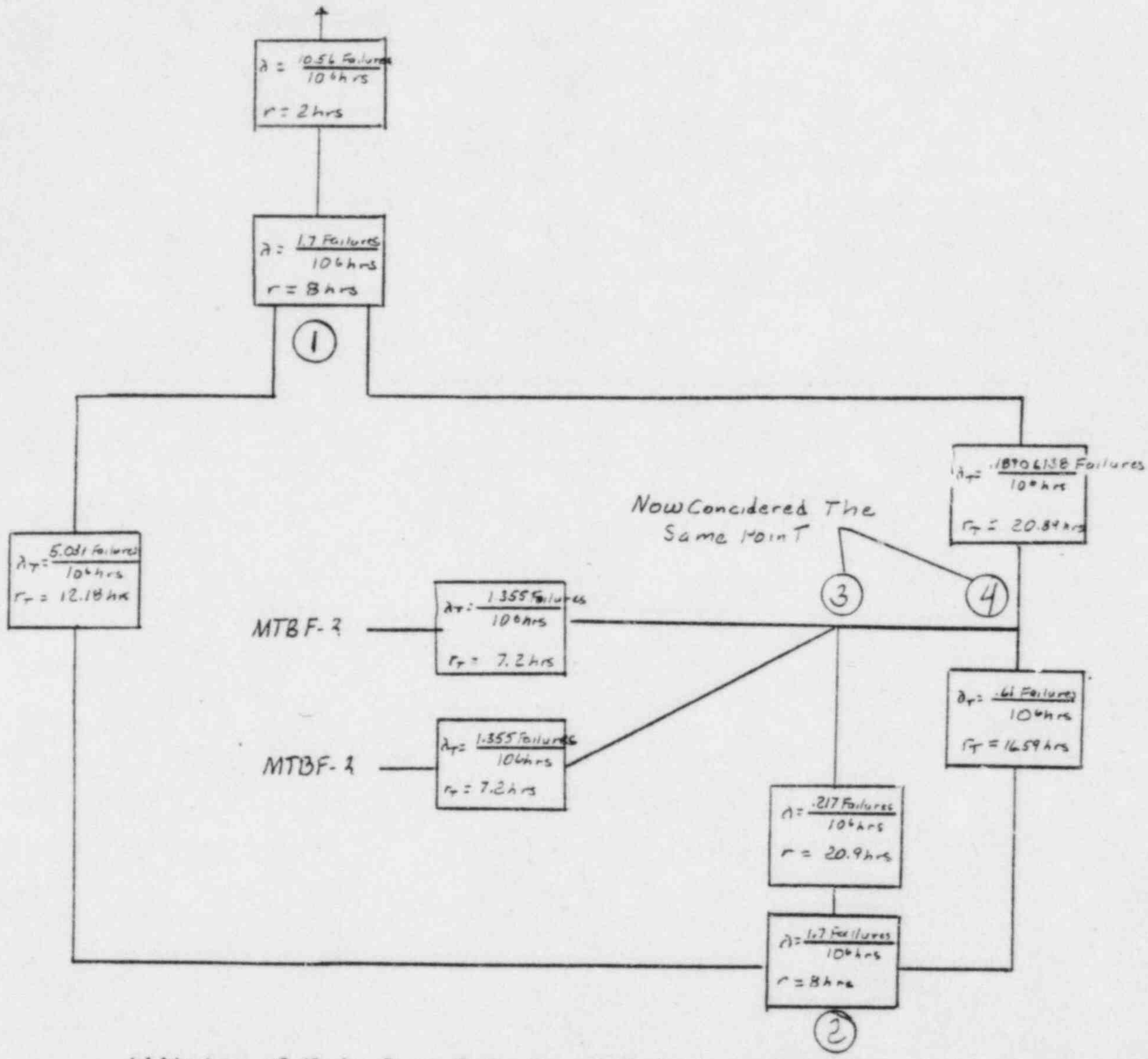
$$\lambda_T = \frac{.421 + .189}{10^6} = .610 \text{ Failures}/10^6 \text{ hours}$$

$$r_T = \frac{(.189)\ (20.9) + (.421)\ (14.65)}{.61} = 16.59 \text{ hours}$$

Title: MTBF Calcs for the Power Supply System to the PMIS Equipment

Prepared by W.C. Risch Date 12-20-84
Checked by [illegible] Date 1-11-85

Reduced Diagram:



Addition of Node 3 to Node 2 and Node 4 to Node 2, parallel systems.

$$\lambda_T = \frac{(.217)\ (.61)}{(10^6)\ (10^6)}\ (20.9 + 16.59) = \frac{4.96}{10^{12}} = .00000496 \text{ Failures}/10^6 \text{ hours}$$

$$r_T = \frac{(20.9)\ (16.59)}{(20.9 + 16.59)} = 9.25 \text{ hours}$$

Title: MTBF Calcs for the Power Supply System to the PMIS Equipment

Prepared by W.C. Rush Date 12-20-84

Checked by Craig E. Sterling Date 1-11-85

With the previous parallel system reduction there is a series system consisting of Node 1 to Node 2 to Node 3 and Node 4.

Reducing this series system:

$$\lambda_T = \frac{5.031}{10^6} + \frac{1.7}{10^6} + \frac{.00000496}{10^6} = 6.73100496 \text{ Failures}/10^6 \text{ hours}$$

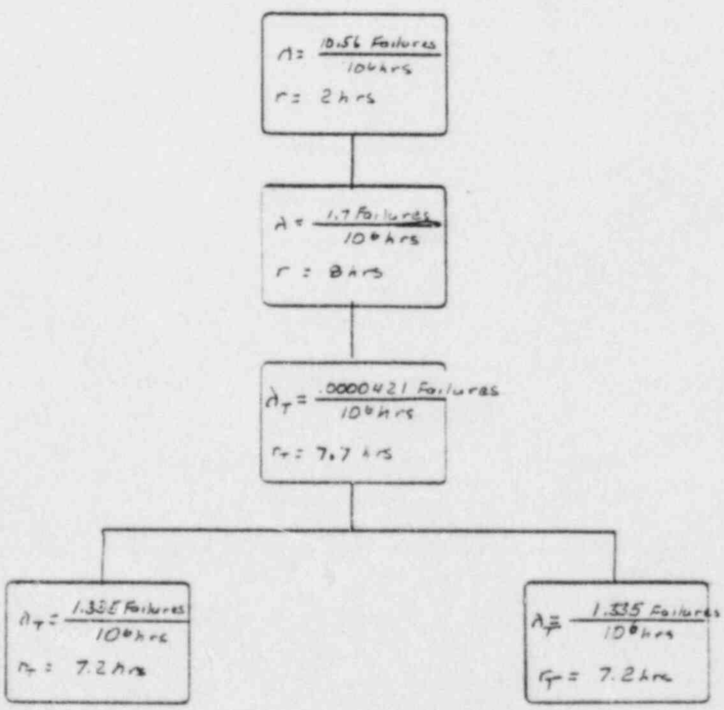
$$r_T = \frac{(5.031)\ (12.18) = (1.7)\ (8) + .00000496\ (9.25)}{6.73100496} = 11.12 \text{ hours}$$

This reduced series systems is in parallel with Node 1 to Node 4. Reducing this parallel system:

$$\lambda_T = \frac{(.18906138)}{10^6} \frac{(6.73100496)}{10^6} (12.18 + 20.89) = .0000421 \text{ Failures}/10^6 \text{ hours}$$

$$r_T = \frac{(12.18)\ (20.89)}{12.18 + 20.89} = 7.7 \text{ hours}$$

Reduced System



Title: MTBF Calcs for the Power Supply System to the PMIS Equipment

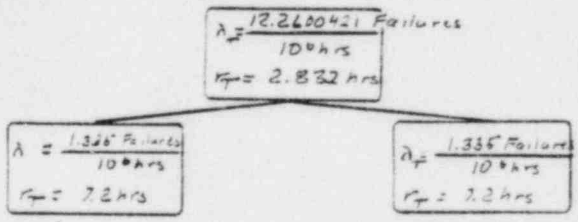
Prepared by *W.C. [signature]* Date *12-20-84*
Checked by *[signature]* Date *1-11-85*

Combine Series System

$$\lambda_T = \frac{10.56 + 1.7 + .0000421}{10^6 \text{ hours}} = 12.2600421 \text{ Failures}/10^6 \text{ hours}$$

$$r_T = \frac{(10.56)\ (2) + (1.7)\ (8) + (.0000421)\ (7.7)}{12.2600421} = 2.832 \text{ hours}$$

Resultant System



To made the final reduction, the plant system will be considered to be in series with MDP1 and MDP2. Although this is not technically correct, it will provide a conservation estimate.

$$\text{Failure rate at MDP1} = \frac{12.2600421 + 1.335}{10^6} = 13.5950421 \text{ Failures}/10^6 \text{ hours}$$

Failure rate at MDP2 is = MDP1 = 13.5950421 Failures/10^6 hours

Repair time at MDP1 and MDP2 =

$$r_T \frac{(12.2600421)\ (2.832) + (1.335)\ (7.2)}{13.5950421} = \underline{3.261 \text{ hours}}$$

$$\text{Calculation of MTBF} = \frac{1}{\text{Failure Rate}}$$

$$= \frac{1}{\frac{13.5950421}{10^6}} = 73{,}556 \text{ hours}$$

$$\text{MTBF in years} = \frac{73,556}{8,760} = 8.4 \text{ years}$$

Considering the reliability of the network feeding the 12.5 kV Loop, this number appears realistic.

V. REFERENCES

1. Loss of offsite power at Nuclear Power Plants: Data and Analysis, EPRI NP-2301, March, 1982.

2. Diesel Generator Reliability at Nuclear Power Plants: Data and Preliminary Analysis.

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4. Telephone Memo, Jerry Debban to Bill Fischer, Subject: Forced Outages on 13.8/12.5 kV Transformer which feeds 12.5 kV Plant Loop.

5. Cooper Nuclear Station One Line Diagram UPS System.

6. Guide for Reporting Failure Data for Power Transformers and Shunt Reactors.

7. Loss of Offsite Power Events from January 1, 1984, to July 27, 1984.

8. Draft - Appendix A Development of Loss of Offsite Power Frequency and Duration Relationships.

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15. IEEE Std 493-1980, IEEE Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems.

16. NPPD Drawing NC 29546, Cooper Nuclear Station Transmission Line Routes, Rev. 1.

17. NPPD Drawing NC 45396, Cooper Substation One Line Switching Diagram 12.5 kV Boiler Source Rev. 5.

18. NPPD Drawing NC 02161, Cooper Substation One Line Switching NPPD Diagram 345-161 Plant Rev. 15.

19. Burns and Roe Drawing 3001, Main One Line Diagram Rev. 2.

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22. Letter from L. G. Kuncl to Darrell G. Eisehut, Dated October 1, 1984. Subject: Response to "Proposed Staff Action to Improve and Maintain Diesel Generator Reliability" (Generic Letter 84-15).

23. Military Handbook Reliability Prediction of Electronic Equipment, MIL-HOBK-217D.

24. NPPD Drawing CNS EE-2, Cooper Nuclear Station 12.5 kV Underground Cable Routing Sheets 1 and 2.

25. Telephone Memo, Bill Fischer (NPPD) to Steve Plandria, Subject: Availability/Reliability Data on 345 kV Breakers and Cooper Nuclear Station.

Bev Kapel

SAIC
Science Applications International Corporation

22886-1050

PMIS System Integration
Agreement #83-C5
NPPD-0198

November 13, 1984

Bill Fisher,
Please provide this
info ASAP.
JCM
11-19-84

Nebraska Public Power District
1414 15th St.
P. O. Box 499
Columbus, Nebraska 68601

Attn: Mr. Jim Murphy
Project Manager, PMIS

Subject: Effect on SPDS/PMIS Availability/Reliability of Prime and Alternate Power Supply Reliability

Dear Mr. Murphy:

In order to include the effect of alternate primary power supplies on the final availability/reliability of the PMIS (SPDS), it will be necessary to have the mean-time between failures (MTBF in hours) for each of the four power supplies shown in the CNS One-Line Diagram UPS System. These power supplies are defined as follows:

1. MCC "L" Control Building Basement
2. MPD2 in MPF
3. UPS Equipment
4. MPD1 in MPF

It would also be of value to have the mean-time to repair (MTTR in hours) for each power supply or an estimate of this value.

It will be assumed, unless directed otherwise, that a failure of 2 above results in an immediate switch to 1 above. Similarily, a failure in 3 results in an immediate automatic switch to 4. Further, a switch to 4 removes 1 and 2 from further consideration.

The UPS Stand-Alone Back-Up Time is also required. - 30 minutes

Sincerely,

SCIENCE APPLICATIONS INTERNATIONAL CORPORATION

John Skinner

John Skinner
Project Engineer

JS/bh

PMIS File A.L. Rev.
Date Rev'd NOV 1 ... File Copy
Rush - Hand Carry
Normal Routing
Disp.
Route | Date | Copy
Copy: X = needs a copy ✓ = has a copy
Routings: Please date, then X for copy or mark out name

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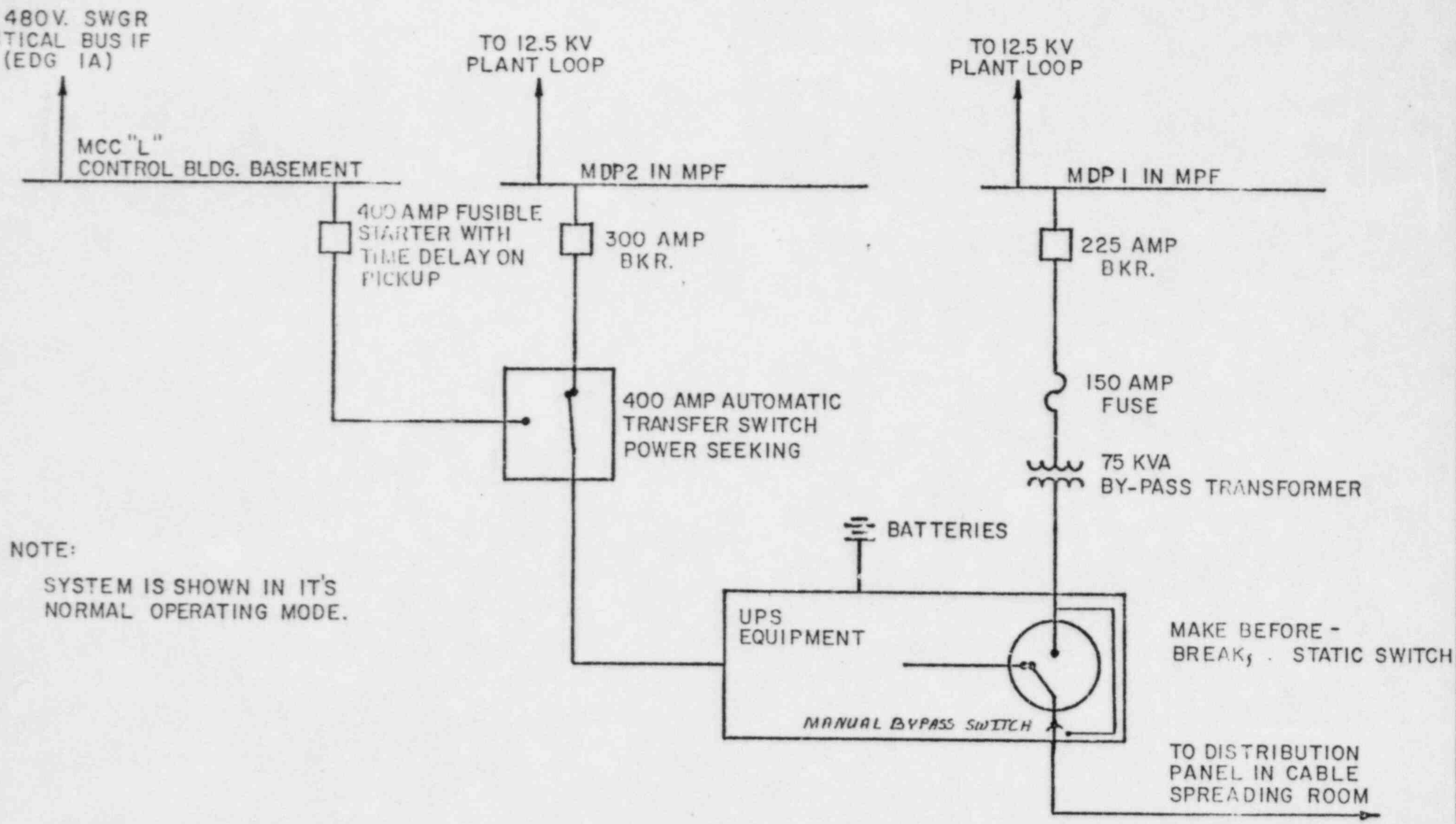


NOTE:

SYSTEM IS SHOWN IN IT'S NORMAL OPERATING MODE.

SIGNIFICANT NUMBER						
GROUP	1	2	3	4	5	6

DRAWN DJF DATE 10-4-84

CHECKED DATE

APPROVED DATE

FILMED

REVISION

Nebraska Public Power District

COOPER NUCLEAR STATION
ONE-LINE DIAGRAM
UPS SYSTEM

REVISION

NO.

E50-774

NEBRASKA PUBLIC POWER DISTRICT
RECORD OF TELEPHONE CONVERSATION

Sheet 1 of 1
Date 11-28-84
Time

FROM:
Name Bill Fischer
Company NPPD GO

TO:
Name Steve Polandre
Company NPPD York

SUBJECT: Availability/reliability data on 345KV Breaker at Cooper Substation

TOPICS OF CONVERSATION:

Steve indicated the 345KV Breakers at Cooper had the following forced outage time and availability, from Jan 1, 1980 to 2-21-1984

Breaker #	Outage Time	Availability
3302	63 hrs 7 min	99.83
3304	70 hrs 45 min	99.805
3306	1 hr 45 min	99.709
3308	134 hrs 2 min	99.631
3310	49 hrs 11 min	99.864
3312	32 hrs 5 min	99.912

Bill Fischer
11-30-84

DISTRIBUTION:

E50-774

NEBRASKA PUBLIC POWER DISTRICT
RECORD OF TELEPHONE CONVERSATION

Sheet 1 of 1
Date 11-08-84
Time 4:30 AM

FROM:	TO:
Name Gerry [illegible]	Name Bill Fischer
Company [illegible]	Company [illegible]

SUBJECT: Forced outages on The 13.8 [illegible] KV Transformer which feeds The 12.5 KV plant Loop

TOPICS OF CONVERSATION:

Gerry Indicated That since The subject Transformer has gone into service in 11-4-82 There has been 5 hours & 58 minutes of forced outages To date, 11-08-84.

This indicates There has been one forced outage since The Transformer has been in service.

$$\text{Failure Rate} = \frac{1}{(2)(365\,\text{days})(24\,\text{hrs/day}) + (25)(24)}$$

$$= 55.2\,\text{Failures} / 10^6\,\text{hours}$$

$$\text{MTBF} = \frac{1}{55.2 \times 10^{-6}} = 18{,}120\ \text{hours}$$

This would be The MTBF of The system Feeding The 12.5 KV Plant Loop

Bill Fischer
11-09-84

DISTRIBUTION:

GUIDE FOR REPORTING FAILURE DATA FOR POWER TRANSFORMERS AND SHUNT REACTORS

54●

Appendix

A2 Reliability Estimation and Mathematics

A2.1 Product Life Cycles

Complex products of all kinds often follow a common pattern of failure. Electronic systems, tractors, transformers or automobiles all have a similar life cycle in regard to when they fail and how often they fail.

This does not mean that tractors and transformers have the same life or the same reliability. It simply means that there are three distinct phases that a complex product goes through in its life cycle. The chances of failure are much different during each phase but most assemblies of a large number of component parts exhibit these three characteristic periods in their life -- called infant mortality, useful life and wear out.

The infant mortality is characterized by a rapidly decreasing failure rate. These failures are usually the result of identifiable causes such as errors in design or manufacture, acceptance of a weak batch of material and other weaknesses in Quality Control, or errors in use and application of the product. Some products can be debugged by simulated use or overstressing in a scheme of testing or burn-in. Other products are "serviced-in" during the first months of their life by replacing weak components under a warranty policy (automobiles for example).

The useful life phase in a product's life cycle begins after the rate of failure has decreased to some basic minimum and constant value for that product. During this phase, failures are relatively infrequent and random in occurrence. They are the result of limitations inherent in the design (as opposed to errors), manufacturing limitations and processing capabilities, plus accidents caused by usage or inadequate maintenance. If a product is properly applied, operated and maintained during its useful life, failures will be as infrequent as possible for that design. The only way to reduce failures further would be to redesign the product. For this reason, it is this phase of the life cycle and, specifically, the failure rate during this phase, that is of interest to those attempting to measure the reliablity of a specific product. It follows that when characterizing a group of products by failure rate, it is not enough to group them solely by manufacturer. It is important that the group be of the same model year (automobiles), generation of design (transformers) and have the same maintenance service and be applied under the same operating procedures and controls.

The wear out phase characterizes the end of a product's life cycle. Here, the failure rate (or the chance of failure) begins to increase. Failures are caused by embrittlement of metals, wear, aging of insulation, etc. Reliability improvement at this stage requires preventive replacement of these dying components before they result in a catastrophic failure.

Appendix

A2.2 Transformer Life Cycle

For the typical power transformer, the infant mortality phase has been significantly reduced by adherence to industry-wide testing standards. The art and science of power transformer testing has evolved over decades and is being constantly improved and fine-tuned year by year. Every area of a transformer's thermal, magnetic, mechanical and dielectric system is stressed and/or overstressed by an elaborate system of nationally standardized tests. Compared to many products sold today, power transformers offer few, if any, significant problems due to "infant mortality".

The useful life phase of a power transformer's life cycle begins, with commissioning into service and may last 30 years or more. The magnitude of the constant failure rate exhibited by a transformer during this phase varies with design, type of transformer and application. But as a class, power transformers have one of the lowest failure rates of all electrical equipment. For purposes of measuring this failure rate, it is practical to consider that the useful life of a transformer begins at energization.

When it comes to determining when the wear-out phase of a transformer's life begins, the effect of temperature over time is presently considered to be the most important factor. The control of mechanical and dielectric stresses will also have a significant effect on useful life. Extending the transformer's useful life to the fullest often depends upon following accepted standards for loading and operating transformers and, thereby, controlling the effects of temperature and other stresses on the insulation system. For example, there are often good reasons for loading beyond nameplate rating, but when done beyond accepted norms for the industry, it should be done with the realization that a shorter useful life will result. The implications for measurement of failure rate are obvious. Transformers operated beyond the agreed upon industry norms for transformer application and protection should not be part of the population being used to measure failure rate.

A2.3 Reliability Measures

It should be clear from the previous discussion of life cycles that the important phase of a power transformer's life (for purposes of measuring Reliability) is the time between its initial energization and the point at which it begins to wear out. During that period, and only during that period, is there something constant which can be measured -- namely, the failure rate. During that period, the failure rate is a measure of the basic design of the transformer as well as the operating and maintenance practices employed.

Appendix

A2.3 Reliability Measures (Continued)

Unfortunately, it is nearly impossible to measure when a transformer's useful life ends and the wear-out phase begins. To do so would require a 20 to 40 year history of a large group of transformers of the same design -- all operating on the same system, i.e. under the same operating principles and maintenance practices. A practical alternative is to set an arbitrary cut-off of 25 or 30 years to represent what experience tells us is the useful life phase of transformers in the population being measured. Transformers older than this cut-off age would not be used, then, to measure failure rate.

Failure rate can be defined as the number of random (unscheduled) occurrences of failure of a product to perform its intended function divided by the length of time the product was functioning. Using this definition, "failures per year" has no meaning. To be useful as a reliability measure, failure rate must be expressed in terms of failures <u>per transformer - years of service.</u> This means that care must be used when estimating failure rate from experience with a group of transformers of similar characteristics which have been in service for a different length of time. In this case, the failure rate for this group would be estimated by dividing the total number of failures experienced by the total service years of all transformers in the group.

Calculated in this way, failure rate - which is symbolized by the Greek letter lambda (λ) -- may be used to estimate the Reliability (R) of a transformer.

Reliability is really a statement of the probability of not failing for a stated period of time. It does not make sense, in other words, to state that the reliability of a product is 0.905. The statement is not complete without mentioning the period of time involved. It does make sense, though, to say that the 20 year reliability of a product is 0.905. That is the same as saying, for a given failure rate, this product has a 90.5 percent chance of surviving 20 or more years without a failure.

Failure rate and Reliability are related in the following way:

$R = e^{-\lambda t}$ Where t = time in years
λ = failure rate in failures per transformer-years of service
e = 2.718

Appendix

A2.3 Reliability Measures (Continued)

Example: Given a constant 0.5 percent failure rate ($\lambda = .005$), the probability of a transformer surviving t years of service without a failure would be as shown below.

For $\lambda = .005$

t	R
1	.995
5	.975
10	.951
20	.905
30	.861

Other measures of failure frequency in common use are the mean time between failures (MTBF) and the mean time to failure (MTTF). The concept of mean time between failures is meaningful for products which are frequently repaired after failure and placed back in service. Mean time to failure is used for products whose mission is either successful or it is not. ~~In either case, MTBF and MTTF are both considered to be the reciprocal of the failure rate for purposes of estimating reliability.~~

For instance: $R = e^{-t/MTTF}$

The idea of product or system Availability (A) is also commonly used and may be defined as the time a system is available to perform its intended function as a fraction of the total elapsed time. Availability is most simply calculated from the following formula:

$$A = \frac{MTTF}{MTTF + MTTR}$$ where MTTR is the mean time to repair the system

Availability is a common measure used in substation design. In which case, the failure rate (or MTBF) of the transformer and its mean time to repair would just be two of many component inputs. Similar data on all components of the substation may be pooled to calculate a MTBF and MTTR of the station -- hence, its availability. Availability recognizes the additional concepts of maintainability and minimum repair times.

MTTF
MTTB
MTTR } All must ~~be~~ have consistant units with T

Appendix

A2.4 Estimating Reliability

An extremely important consideration in the estimation of reliability parameters, such as failure rate, is the fact that we are working with estimates. All estimates are not equal predictors of the truth and not all estimates warrant equal confidence. The more information we have with which to make an estimate, naturally, the more confidence we can place in that estimate. Fortunately, there are ways to make quantitative judgments about the quality or the "confidence limit" of an estimate. Appraising an estimate by associating it with a confidence limit is important because there is no practical way to make estimates in which we have 100 percent confidence; in fact, some estimates of failure rates will be quite gross - either because of little data or because of "stretching" the definition of the population to get more data. All populations should be clearly defined and all estimates should be adjusted to reflect the desired level of confidence associated with them. The method for doing this is quite simple.

From the table of confidence limit factors provided, choose the desired level of confidence you wish to have in the estimate. Using that column of factors, choose the factor associated with the observed number of failures. Then multiply the failure rate estimate by the table factor.

Example: A certain utility has been purchasing transformers for 12 years with the BIL reduced two steps. These transformers are rated 12/16/20 MVA, 230 - 69 kV and have been purchased from several manufacturers.

Transformers bought to this specification and installed at various times during the past 12 years have accumulated a total of 162 transformer-years of service. To date there have been 6 dielectric failures in this group of transformers. The utility wants to estimate the failure rate of the population of transformers purchased to this specification with a confidence level of 95 percent.

The failure rate estimated by a sample of 6 failures is 6 failures divided by 162 transformer-years of service or 3.7 percent ($\hat{\lambda} = .0370$).

The upper confidence limit factor corresponding to a confidence level of 95 percent and an observed number of failures of 6 is 1.75. (See Table)

Appendix

A2.4 Estimating Reliability (Continued)

By multiplying the same estimate ($\hat{\lambda}$) by the upper confidence limit factor (1.75), the utility can now state, with 95 percent confidence, that the true failure rate (λ) of the population is no worse than 6.48 percent.

In other words:

$$\begin{aligned} \lambda &\leq 1.75\ \hat{\lambda} \\ &\leq 1.75\ (.0370) \\ &\leq .0648 \end{aligned}$$

By calculating failure rate estimates in this way, a valid comparison can be made with another population of transformers purchased with only one step reduced BIL. Because a confidence limit is applied which is based on the number of failures observed, comparisons can be made with populations having widely different numbers of observed failures.

Appendix

FACTORS FOR DETERMINING THE UPPER CONFIDENCE LIMIT ON ESTIMATES OF FAILURE RATE[1]

Number of failures observed (r)	Confidence Level 80%	90%	95%	99%
1	1.61	2.30	2.99	4.61
2	1.50	1.95	2.37	3.33
3	1.43	1.77	2.10	2.79
4	1.38	1.68	1.94	2.51
5	1.34	1.60	1.83	2.31
6	1.32	1.54	1.75	2.18
7	1.30	1.51	1.69	2.08
8	1.28	1.47	1.64	2.00
9	1.27	1.44	1.60	1.94
10	1.25	1.42	1.57	1.88
11	1.24	1.40	1.54	1.83
12	1.23	1.38	1.52	1.79
13	1.22	1.37	1.50	1.75
14	1.21	1.35	1.48	1.72
15	1.21	1.34	1.46	1.70
16	1.20	1.33	1.44	1.67
17	1.20	1.32	1.43	1.65
18	1.19	1.31	1.42	1.63
19	1.19	1.30	1.40	1.61
20	1.18	1.30	1.40	1.59
21	1.18	1.29	1.38	1.58
22	1.17	1.28	1.38	1.56
23	1.17	1.27	1.37	1.55
24	1.17	1.27	1.36	1.54
25	1.16	1.26	1.35	1.52
26	1.16	1.26	1.34	1.52
27	1.16	1.25	1.34	1.50
28	1.16	1.25	1.33	1.49
29	1.15	1.24	1.32	1.48
30	1.15	1.24	1.32	1.48

(1) From published tables of the upper tail chi-square (χ^2) distribution such that:

$$\lambda \leq \left(\frac{\chi^2_{\alpha;\, df=2r}}{2r}\right)\hat{\lambda}$$

where α = 1 - confidence level in per unit

df = degree of freedom

GUIDE FOR REPORTING FAILURE DATA FOR POWER TRANSFORMERS AND SHUNT REACTORS

Appendix

A3 References

A3.1 ANSI/IEEE C57.12.80 - 1978 - Terminology for power and distribution transformers.

A3.2 ANSI/IEEE C57.21-1981 - requirements, terminology and test code for shunt reactors over 500kVA.

A3.3 IEEE Standard 100 - ANSI C42.100 - IEEE Standard Dictionary of Electric and Electronic Terms.

A3.4 IEEE Standard 493-1980, IEEE Recommended Practice for Design of Reliable Industrial and Commercial Power Systems.

A3.5 ANSI C84.1 - 1977 - Voltage ratings for electric power systems and equipment (60 Hz).

A3.6 ANSI C92.2 - 1978 - Preferred voltage ratings for alternating-current electrical systems and equipment operating at voltages above 230 kilovolts nominal.

A3.7 Edison Electric Institute, Electrical System and Equipment Committee; Trouble Report Power Transformers - 2500 KVA and larger.

A3.8 IEEE Standard 346-1973, IEEE Standard Definitions in Power Operations Terminology Including Terms for Reporting and Analyzing Outages of Electrical Transmission and Distribution Facilities and Interruptions to Customer Service.

A3.9 ELECTRA No. 88 May 1983 - An International Survey on Failures in Large Power Transformers in Service. Paper presented in the name of Study Committee (Transformers) by Working Group 12.05; A. Bossi (Italy, Convenor), J. E. Dind (Canada), J. M. Frisson (Belgium), U. Khoudiakov (USSR), H. F. Light (USA), D. V. Narke (India), Y. Tournier (France), J. Verdon (France).

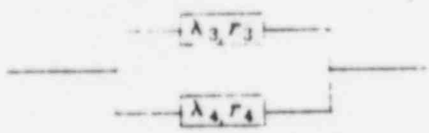
Taken from Reference # 16

$$f_s = \lambda_1 + \lambda_2$$

$$f_s r_s = \lambda_1 r_1 + \lambda_2 r_2$$

$$r_s = \frac{\lambda_1 r_1 + \lambda_2 r_2}{\lambda_1 + \lambda_2}$$

(a)



$$f_p = \frac{\lambda_3 \lambda_4 (r_3 + r_4)}{8760}$$

$$f_p r_p = \frac{\lambda_3 r_3 (\lambda_4 r_4)}{8760}$$

$$r_p = \frac{r_3 r_4}{r_3 + r_4}$$

(b)

Nomenclature:
f = frequency of failures
λ = failures per year
r = average hours of downtime per failure
s = series
p = parallel

Fig 11
Formulas for Reliability Calculations
(a) Reparable Components in Series (both must work for success)

(b) Reparable Components in Parallel (one or both must work for success)

minimal cut-set approach are given in Table 1. A sample using these formulas is shown in Fig 11 for two components in series and two components in parallel. In these samples the scheduled outages are assumed to be zero and the units for λ and r are, respectively, failures per year and hours downtime per failure. The formulas in both Table 1 and Fig 11 assume the following:

(1) The component failure rate is constant with age

(2) The outage time after a failure has an exponential distribution. (Probability of outage time exceeding r is e

(3) Each failure event is independent of any other failure event.

(4) The component "up" times are much larger than "down" times:

$$1 - \frac{\lambda_i r_i}{8760} >> \frac{\lambda_i r_i}{8760}$$

The reliability data to be used for the electrical equipment and the electric utility supply are given in 7.1.5.

7.1.5 *Reliability Data from 1973–1975 IEEE Surveys.* In order to make a reliability and availability analysis of a power distribution system, it is necessary to have data on the reliability of each component of electrical equipment used in the system. Ideally these reliability data should come from field use of the same type of equipment under similar environmental conditions and similar stress levels. In addition, there should be a sufficient number of field failures in order to represent an adequate sample size. It is believed that eight field failures are the minimum number necessary in order to have a reasonable chance of determining a failure rate to within a factor of 2. The

Taken from Reference # 1

PLANT NAME	REGIONAL RELIABILITY COUNCIL	DATE OF INITIAL CRITICALITY	DATA REPORTED THROUGH	SITE YEARS
Cooper Station	MARCA	2/21/74	2 11 84 ~~9/13/79~~	10.81 5.56

DATE OF EVENT	RECOVERY TIME	FAILURE LOCATION	CAUSE CATEGORY	EVENT DESCRIPTION
01/29/84	1:49			NONE

PLANT NAME	REGIONAL RELIABILITY COUNCIL	DATE OF INITIAL CRITICALITY	DATA REPORTED THROUGH	SITE YEARS
Crystal River 3	SERC	1/14/77	11/20/79	2.85

DATE OF EVENT	RECOVERY TIME	FAILURE LOCATION	CAUSE CATEGORY	EVENT DESCRIPTION
				NONE

$\lambda = 10.56$ failure $/10^6$ hrs

$MTBF = \dfrac{1}{\frac{10.56}{10^6}} = 94{,}696$ hrs

Taken from Reference # 2

Table 2-1

DIESEL FAILURE DATA

Facility	Vendor	#DG	Diesel Years	Single Failures	Double Failures	Triple Failures
Beaver Valley	W	2	5.3	20	0	-
Browns Ferry 1 ,2, 3	GE	4	25.5	9	0	0
Plant Z1 Plant Z2	GE GE	4	18.0	15	1	1
Cook 1	W	2	9.6	2	0	-
Cook 2	W	2	3.3	5	0	-
Crystal River 3	BW	2	7.9	9	1	-
Oyster Creek	GE	2	22.6	13	0	-
Peach Bottom 2 & 3	GE	4	32.9	12	1	0
Trojan	W	2	10.0	10	0	-
Zion 1 & 2	W	5	19.5	18	*	*
Plant X - 1 & 2	GE	5	8.4	38	*	*
Plant Y	W	4	14.9	20	*	*

177.9

Notes:

1) * Multiple failure counts not apparent from utility-supplied data.

2) At Plant Z, any of the four diesels may be demanded by either unit.

Table 2-2

DIESEL FAILURE COUNTS SEPARATED INTO FAILURE MODE CATEGORIES

Facility	Failures To Start	Failures To Continue To Run
Beaver Valley	16	4
Browns Ferry 1, 2, 3	8	1
Plant Z-1 & 2	19	1
Cook 1	2	0
Cook 2	2	3
Crystal River 3	7	4
Oyster Creek	8	5
Peach Bottom 2, 3	9	5
Trojan	5	5
Zion 1 & 2	18	0
Plant X-1 & 2	38	0
Plant Y	20	0

152

CE-RCW

sent to
Don Griggs

Nebraska Public Power District

GENERAL OFFICE
P.O. BOX 499, COLUMBUS, NEBRASKA 68601-0499
TELEPHONE (402) 564-8561

NLS8400021

October 1, 1984

Mr. Darrell G. Eisenhut, Director
Division of Licensing
Office of Nuclear Reactor Regulation
Washington, D.C. 20555

Subject: Response to "Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability" (Generic Letter 84-15)

Dear Mr. Eisenhut:

In accordance with 10CFR50.54(f), the Nebraska Public Power District submits the attached response to Generic Letter 84-15.

Should you have any questions or comments regarding this response, please contact me.

Sincerely,

L G Kuncl

RECEIVED
OCT 04 1984
K.C.W.

L. G. Kuncl
Assistant General Manager - Nuclear
Nebraska Public Power District

LGK:JRF:snl/9
Attachment

STATE OF NEBRASKA)
) ss
PLATTE COUNTY)

L. G. Kuncl, being first duly sworn, deposes and says that he is an authorized representative of the Nebraska Public Power District, a public corporation and political subdivision of the State of Nebraska; that he is duly authorized to submit this information on behalf of Nebraska Public Power District; and that the statements contained herein are true to the best of his knowledge and belief.

L G Kuncl

L. G. Kuncl

Subscribed in my presence and sworn to before me this 1st day of October, 1984.

Colleen M. Kita

NOTARY PUBLIC

COLLEEN M. KITA
GENERAL
NOTARY
COMMISSION
EXPIRES
AUG. 4, 198_
STATE OF NEBRASKA

1. REDUCTION IN NUMBER OF COLD FAST START SURVEILLANCE TESTS FOR DIESEL GENERATORS

Licensees are requested to describe their current programs to avoid cold fast start surveillance tests or their intended actions to reduce cold fast start surveillance tests from ambient conditions for diesel generators.

RESPONSE

The two diesel generators at Cooper Nuclear Station (CNS) were installed with several support systems recommended by the manufacturer. These included cooling water and lube oil bypass pumps and heaters to continuously maintain fluid temperatures near normal operating conditions. Also included was a prelubrication pump designed to operate five minutes every hour when the diesel generator is in standby. These support systems are always available for service so demonstrations of cold fast start testing from ambient conditions are never actually performed at CNS.

Various suggestions for operational improvement have also been incorporated into station procedures. Prior to, and after normal surveillance testing, the prelubrication pump is briefly operated to ensure the engine components are well lubricated. The surveillance procedure also specifies recommendations for loading and unloading the diesel generator to ensure proper warmup and cooldown. As described above, CNS has taken advantage of a majority of manufacturer recommendations in an effort to reduce unnecessary engine stress and wear.

In response to additional testing presently being performed at some earlier licensed operating facilities, CNS currently requires the diesel generators to be tested and proven operable whenever an emergency core or containment cooling subsystem or a standby gas treatment system is made or found to be inoperable. This has added significantly to the number of fast start tests that have been performed on the station diesel generators over the past several years. In order to reduce this number, and as recommended in Enclosure 1 of your letter, Nebraska Public Power District will submit proposed Technical Specification changes by approximately December, 1984, to delete testing the diesel generators when an emergency core or containment cooling subsystem or standby gas treatment system is inoperable.

In reference to the Attachment to Enclosure 1 describing acceptable Typical Technical Specifications, the applicable CNS Technical Specifications have been reviewed and determined to be generally equivalent. At present, CNS does not normally perform a test which verifies the ability to transfer unit power from the normal supply to the alternate supply regarding the off site transmission network and the on site Class 1E distribution system. Consideration will be given to implementing this test into our annual (vice 18 month) surveillance testing procedures.

2. DIESEL GENERATOR RELIABILITY DATA

Licensees are requested to report the reliability of each diesel generator at their plant for its last 20 and 100 demands. This should include the number of failures in the last 20 and 100 valid demands indicating the time history for these failures. Licensees are requested to indicate whether they maintain a record itemizing the demands and failures for each diesel generator unit and whether a yearly data report is maintained for each diesel generator's reliability in the manner outlined in Regulatory Guide 1.108 position C.3.a. Criteria for determining diesel generator reliability are as follows:

a. Valid demands and failures are to be determined in accordance with the recommendations of Regulatory Guide 1.108 position C.2.e.

b. The reliability of each diesel generator will be calculated based on the number of failures in the last 100 valid demands.

RESPONSE

Reliability of the Cooper Nuclear Station (CNS) diesel generators is reported in the attached Table 1 as well as the requested information on demands, failures, and time history. All determinations of valid demands and failures in Table 1 were based on recommendations of Regulatory Guide 1.108 position C.2.e. The CNS diesel generators, when evaluated in this manner and compared to the reliability information of the subject letter Enclosure 3, would indicate a need for increased surveillance testing.

However, as indicated in the response to Item 1, CNS Technical Specifications currently require the diesel generators to be tested and proven operable when core or containment cooling or standby gas treatment systems are made or found to be inoperable. For other than monthly tests, such as these, the station surveillance procedure only requires operability to be proven with a thirty minute run at fifty percent of rated load. These tests do not meet the criteria of Regulatory Guide 1.108 position C.2.e. They do contribute significantly (nearly double) to the number of additional tests performed on the CNS diesel generators and are reported in Table 2 for comparison. The reliability figures illustrated are more realistic than the Table 1 data in spite of the abbreviated test duration and are more in-line with the reliability levels presently being attained throughout the industry. Changes will be made to existing diesel generator surveillance test procedures which will require all operability runs to be a minimum of one hour to at least fifty percent of rated load in accordance with the criteria of Regulatory Guide 1.108.

CNS does not currently maintain an itemized record of demands and failures experienced by each diesel generator nor is a formal yearly data report compiled which could be continuously updated. However, a study was conducted by Nebraska Public Power District which evaluated the performance and availability of the station diesel generators and recommended economical, feasible solutions to correct any problems. In addition, the study included a survey of other nuclear station diesel generator experience and a comparison to the CNS diesels. Several improvements have been made, or are in the process of being made, to the station units. It is acknowledged that establishing an effective trend program would be very beneficial; therefore, a trend program will be established.

TABLE 1

Demands and Failures Based on Regulatory Guide 1.108 C.2.e Criteria
(> 50% Continuous Rating for > 1 Hour)

	Starts	Failures	Reliability* (1-P)	Time History	Starts	Failures	Reliability* (1-P)	Time History Short	Time History Long	Time History Average
DG-1	20	1	.95	6.1 hr.	100	9	.91	1 hr.	17.8 hr.	6.6 hr.
DG-2	20	1	.95	59.5 hr.	100	6	.94	1.7 hr.	381.2 hr.	69.4 hr.**

TABLE 2

Demands and Failures Based on All CNS Diesel Runs
(> 50% Continuous Rating for > ½ Hour)

	Starts	Failures	Reliability* (1-P)	Time History	Starts	Failures	Reliability* (1-P)	Time History Short	Time History Long	Time History Average
DG-1	20	1	.95	6.1 hr.	100	5	.95	2.2 hr.	17.8 hr.	9 hr.
DG-2	20	0	1.		100	4	.96	1.7 hr.	11.5 hr.	7.9 hr.

* Where "P" is defined as the probability of failure per demand per diesel.
** Only 7 hours without the 381.2 hours (16 days) failure.

Data from
DG2 12-07-78 — 9-4-84
DG2 9-[illegible]-77 - 9-4-84

3. DIESEL GENERATOR RELIABILITY

Licensees are requested to describe their diesel generator reliability improvement program, if any, for attaining and maintaining a reliability goal. Licensees are requested to comment on, and compare their existing program or any proposed program with the enclosed example performance specification.

RESPONSE

Cooper Nuclear Station (CNS) does not currently have a structured, goal oriented reliability improvement program similar to the the example Performance Technical Specification provided in your Enclosure 3 attachment. The method utilized at CNS for maintaining and upgrading the diesel generator reliability is by assignment of two engineers, one electrical and one mechanical, to review all recorded performance data, perform periodic inspections both operating and shutdown, review current industry practices, and make design improvements and procedure changes as needed to enhance system performance.

Recommendations for improvement have been obtained from several industry sources. NUREG/CR-0660 made several recommendations which have been or, are still being, implemented into the diesel generator system. A copy of the preventative maintenance program being performed on new diesel generators has been obtained from the manufacturer to use in a comparison to the current station program and ensure all the latest philosophies and practices are being used.

Nebraska Public Power District requested a study to evaluate the performance and availability of the station diesel generators and to survey the performance of diesel units at other nuclear stations. The study indicated that the CNS units have shown continuous improvement in availability since they were originally installed. Several suggestions from this study have been, or are being, incorporated in an effort to increase the reliability even further.

Additionally, awareness of current problems and industry practices is maintained through INPO Operation and Maintenance Reminders and Information Exchanges. These, as well as NRC Information Notices, are evaluated for applicability and further action. The INPO Nuclear Plant Reliability Data System has been extremely useful in tracking failure information on the diesel generators.

The example Performance Technical Specification provided for review has merit. Although stringent reliability criteria are being proposed, they do appear to be attainable. Regarding the diesel generator inoperability limits, it is agreed that an increase in the current Technical Specification limit would be necessary and will be pursued along with the Technical Specification change discussed in Response No. 1. The overall actions being proposed to improve and maintain diesel generator reliability as outlined in the subject letter are considered to be generally acceptable, however, some flexibility would be needed in establishing site specific programs.

CNS does not presently perform any 18 month surveillance testing to verify the proper operation of the diesel generator during load shedding of either the largest single emergency load or of a continuous rating load. During any actual operating condition requiring the diesel generators, single loads are started and secured contingent on plant needs, including the largest single load. Any additional testing specifically designed for that same purpose is considered to be excessive and to contribute to increased degradation of the diesel generators which appears to be contrary to the recommendations being proposed. Full load reject of the diesel generators is considered to be even more unnecessary and impractical by station engineering personnel. The benefit gained from this test is minimal compared to the additional stress and wear the diesel generators would be subjected to.

mapp mid-continent area power pool

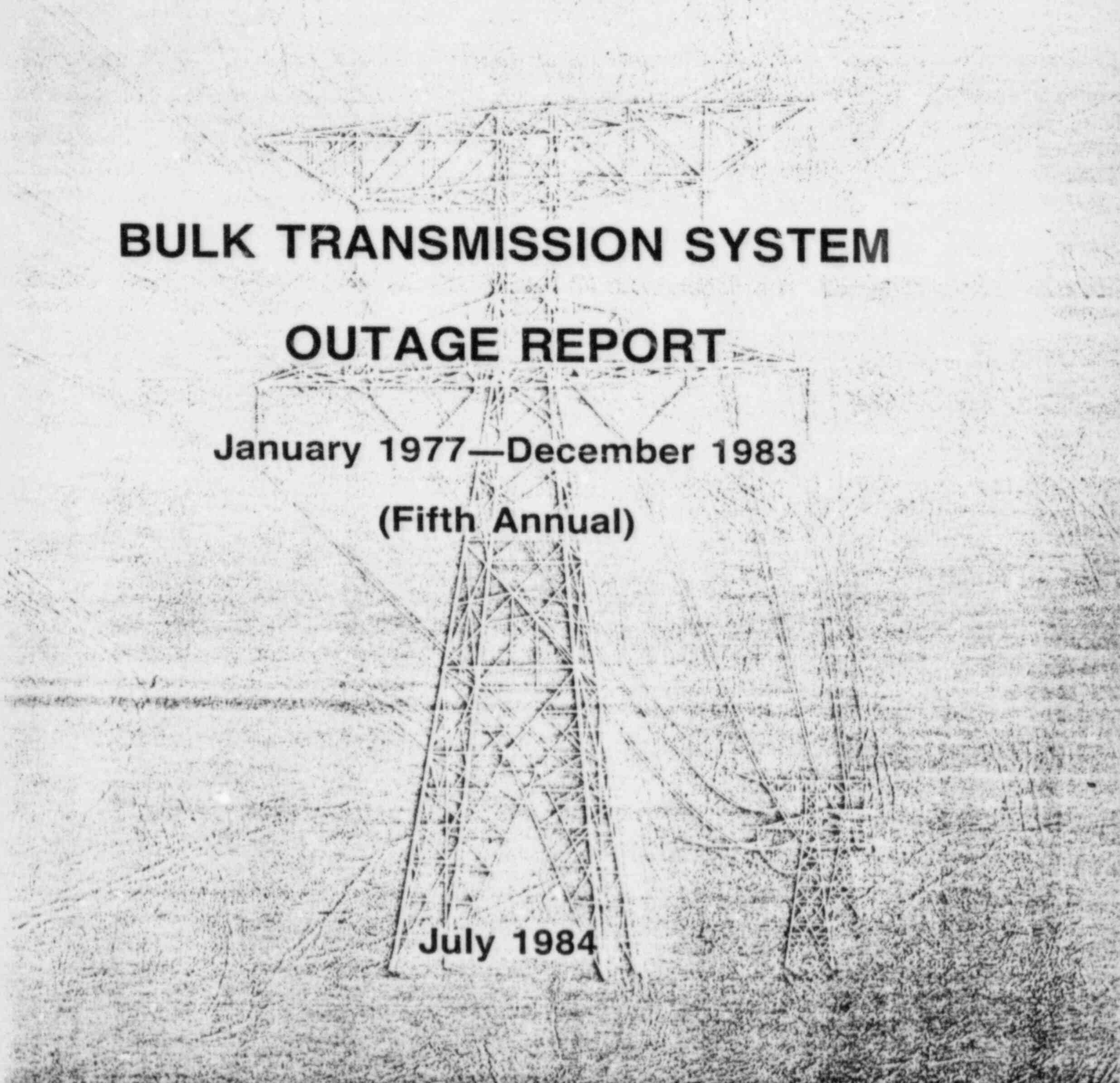
Mark Gerald Lauby
Assistant Reliability Engineer

mapp Coordination Center
1250 Soo Line Building
507 Marquette Avenue
Minneapolis, MN 55402

Area Code: 612
Bus. 330-6965
Res. 375-1567

mapp

mid-continent area power pool



BULK TRANSMISSION SYSTEM OUTAGE REPORT

January 1977—December 1983

(Fifth Annual)

July 1984

Planned outages for the 230 kV and 345 kV bulk transmission were less frequent in 1983 in comparison to the cumulative average of previous years. The Planned outage MTTR of 230 kV lines was smaller than the cumulative average of previous years while the 345 kV lines experienced longer MTTR for Planned outges. Overall, as illustrated by the 'COMBINED' grouping of MTTF and MTTR, 230 kV and 345 kV transmission reliability was better than the cumulative performance of previous years.

Table 2

MTTF and MTTR Values for All of the Bulk Transmission Lines
(In Hours per Line Section)

VOLTAGE	TIMESPAN	OUTAGE CLASSIFICATION				
		FORCED			PLANNED	COMBINED
		INDEPENDENT	SECONDARY	BOTH		
			MTTF			
230 kV						
	1977-1982	6,794	34,752	5,680	2,166	1,557
	1983	7,073	256,371	6,882	2,434	1,791
	1977-1983	6,837	40,348	5,844	2,205	1,590
345 kV						
	1977-1982	4,413	45,149	4,017	2,267	1,433
	1983	3,834	72,644	3,641	3,075	1,647
	1977-1983	4,297	48,543	3,946	2,382	1,469
			MTTR			
230 kV						
	1977-1982	16	4	14	44	36
	1983	10	11	10	27	22
	1977-1983	15	4	13	42	34
345 kV						
	1977-1982	21	1	20	49	38
	1983	10	7	9	71	42
	1977-1983	19	2	18	52	39

The availabilities of bulk transmission lines in MAPP are displayed in Table 3 for the three previously described timespans.

Table 3

Availability of MAPP Bulk Transmission Lines

VOLTAGE	TIMESPAN	FOR ALL OUTAGE CATEGORIES AVAILABILITY
230 kV		
	1977-1982	97.75 %
	1983	98.77 %
	1977-1983	97.91 %
345 kV		
	1977-1982	97.39 %
	1983	97.50 %
	1977-1983	97.41 %
230, 345, & 500 kV		
	1977-1982	97.62 %
	1983	98.29 %
	1977-1983	97.74 % *

* Calculated from MTTF and MTTR values

B. Fault Data Analysis

Table 4 shows fault types broken down into percentages of total line-related Faulted outages for three timespans (1977-1982, 1983, 1977-1983). The majority of faults in 1983 for 345 kV lines were Line-to-Ground. However, 230 kV lines experienced a large number of Line-to-Line faults due to conductor galloping caused by ice accumulation. The majority (79%) of the Line-to-Line faults occur on 230 kV line sections. For both voltages, Line-to-Line faults occur predominantly on lines using three specific types of structures: 26% single circuit steel towers, 25% single circuit wood "H" frame, and 41% double circuit steel towers. The remaining 9% is on miscellaneous structures with no identifiable trend.

Attachment 3

Certification report being prepared by CPI that discusses the acceptance criteria, testing procedures used to certify proper isolation, and the results of that testing.