No. 2

JAPAN INTERNATIONAL COOPERATION AGENCY (JICA)

CEYLON ELECTRICITY BOARD
THE DEMOCRATIC SOCIALIST REPUBLIC OF SRI LANKA

MASTER PLAN STUDY
FOR
DEVELOPMENT OF THE TRANSMISSION SYSTEM
OF
THE CEYLON ELECTRICITY BOARD

FINAL REPORT

APPENDIX

JANUARY 1997

NIPPON KOEI CO., LTD.
TOKYO, JAPAN

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CONTENTS

LIST OF TABLES

LIST OF FIGURES

CHAPTER A1

INTRODUCTION

CHAPTER A1
INTRODUCTION

A1.1 Personnel Related to the Study

(Reference to Clause 1.4 Personnel Related to the Study)

(1) List of CEB counterparts

1.	Mr. K.A. Ranaweera	General Manager Ceylon Electricity Board
2.	Mr. D.G.D.C. Wijeratne	Additional General Manager (Planning) Planning Division
3.	Mrs. Yamuna Samarasinghe	Deputy General Manager (Transmission Planning)
4.	Mr. Ranil Lokubalsooria	Former Deputy General Manager (Transmission Planning)
5.	Mr. M.A.W. Ranasinghe	Chief Engineer (Transmission Planning)
6.	Mr. J. Nanthakumar	Chief Engineer (Generation Planning)
7.	Mr. G.R. Fernando	Chief Engineer (Transmission Designs)
8.	Mr. Susantha Perera	Chief Engineer (Load Forecasting and tariff Branch)
9.	Mr. A.C.S. Wijayatilake	Electrical Engineer (Transmission Planning Branch)
10.	Mr. A.V.S.N. Vithana	Electrical Engineer (Transmission Planning Branch)
11.	Mrs. C.D. Satharasinghe	Electrical Engineer (Transmission Planning Branch)
12.	Mr. M.J.W. Wickramarathe	Electrical Engineer (Transmission Design Branch)
13.	Mrs. Mrs. S.H. Diddeniya	Electrical Engineer (Transmission Design Branch)
14.	Mr. Vitanage Indunil Jayatissa	Electrical Engineer (Generation Planning Branch)
15.	Mrs. Amali Senevirathne	Electrical Engineer (Load Forecasting and tariff Branch)

16.	Mr. P.N.S.K. Boteju	Chief Engineer (Distribution Planning)
17.	Mrs. B.D.N. Mendis	Chief Engineer (System Control)
18.	Mr. P.S. Ranasinghe	Chief Engineer (Communication)
19.	Mrs. D. Tilakasena	Chief Engineer (Protection Development)

(2) List of JICA Study Team

1.	Mr. Sumio TSUKAHARA	Team Leader
2.	Mr. Yoshiaki MIYAGAWA	Deputy Team Leader / Power System Planner
3.	Mr. J. WOODHOUSE	Power Supply Reliability Specialist *1
4.	Mr. M. K. DEIF	Former staff for the first site works
5.	Mr. Tomoyasu FUKUCHI	Power System Analysis Engineer
6.	Mr. M. J. FULLER	Transmission Line Engineer
7.	Mr. Yasuo KADOWAKI	Substation Engineer *1
8.	Mr. Hisami OISHI	Former staff for the first site works
9.	Mr. Yasushi AZUMA	Communication Engineer
10.	Mr. Nobuhiro MORI	Economist
11.	Mr. Jun-ichi FUKUNAGA	Secretary

*1 Messrs. M. K. Deif and Hisami Oishi participated in the first site works and Messrs. J. Woodhouse and Yasuo Kadowaki in the second and third site works.

CHAPTER A3

CURRENT STATUS OF ELECTRIC POWER SECTOR

A3.1 Telecommunication System

Table A 3.1 - 1 Existing PLC/UHF at December 1995

1. Power Line Carrier (PLC) terminal

Ref.	Section	Voltage (kV)	No. of cct.	Distance (km)	PLC type (ch)	Carrier freqency (kHz)
2L1.	Biyagama - Kotugoda	220	2	19.6	ETI22 (2ch)	456-472
					ETI21 (1ch)	268-276
2L2.	Biyagama - Kotmale	220	2	70.5	ETI22 (2ch)	96-112
					ETI21 (1ch)	120-128
2L3.	Kotmale - Victoria	220	2	30.1	ETI22 (2ch)	128-144
					ETI21 (1ch)	112-120
2L4.	Victoria - Randenigala	220	1	16.4	ETI22 (2ch)	160-176
					ETI21 (1ch)	144-152
2L5.	Randenigala - Rantembe	220	1	3.1	ETI22 (2ch)	352-368
					KTI (1ch)	N/A
1U1.	Kelanitissa - Fort (F)	132	1	4.9	No communication facility	
1U2.	Fort - Kollupitiya (E)	132	1	2.7	No communication facility	
1U3.	Kollupitiya - Kolonnawa	132	1	5.4	No communication facility	
1L1.	Biyagama - Pannipitiya *1	132	2	15.5	ETI22 (2ch)	308-324
1L2.	Biyagama - Kelanitissa *1	132	2	12.5	ETI22 (2ch)	240-256
1L3.	Biyagama - Sapugaskanda DPS	132	2	2.1	KTI (1ch x 2)	N/A
1L4.	Kolonnawa - Kelanitissa	132	2	2.2	ETI22 (2ch)	208-224
1L5.	Kolonnawa - Pannipitiya	132	2	12.9	ETI22 (2ch)	224-240
1L6.	Kolonnawa -Sapugaskanda(T)	132	2	6.6	ETI22 (2ch)	276-292
1L7.	Sapugaskanda (T) - Kotugoda (Kolonnawa - Kotugoda)	132	2	16.7	ETI22 (2ch)	292-308
1L8.	Sapugaskanda (T) - SS	132	2	4.6	N/A	
1L9.	Kotugoda - Bolawatta(T)	132	2	21.0	ETB (1ch)	208-220
					ETB (1ch)	200-208
	(Kotugoda - Puttalam)				ETI22 (2ch)	308-324
1L10.	Bolawatta(T) - Chillaw (T) (Bolawatta - Puttalam)	132	2	22.6	*2 ETL41 (1ch)	256-264
1L11.	Chillaw (T) - Puttalam	132	2	61.4	No plan.	
	(Chillaw - Kotugoda)				? (2ch)	472-488
1L12.	Chillaw (T) - SS	132	2	6.8	N/A	
1L13.	Kolonnawa - Oruwala (T)	132	2	14.0	ETI22 (2ch)	352-368
1L14.	Oruwala (T) - SS	132	2	3.4	N/A	
1L15.	Oruwala (T) - Thulhiriya (T)	132	2	36.0	No communication facility	
1L16.	Thulhiriya (T) - SS	132	2	23.9	N/A	
1L17.	Thulhiriya (T) - Polpitiya	132	2	28.0	ETI22 (2ch)	424-440
1L18.	Kolonnawa - Avissawella (T)	132	2	31.9	*2 ETI22 (2ch)	128-144
1L19.	Avissawella (T) - SS	132	2	0.5	N/A	

1L20.	Avissawella (T) - Polpitiya	132	2	34.4	*2 ETI 21 (1ch)	120-128
	(Kolonnawa - Polpitiya)				ETI22 (2ch)	328-344
					ETI21 (1ch)	404-416
					*2 ETB (1ch)	156-164
					ETB (1ch)	144-152
	(Kolonnawa - Polpitiya - Laxpana)				ETI102 (2ch)	176-192
1L21.	Pannipitiya - Ratmalana	132	2	6.9	ETI22 (2ch)	72-88
1L22.	Pannipitiya - Panadura (T)	132	2	12.3	*3 ETI22 (2ch)	292-308
	(Pannipitiya - Matugama)	132			ETI22 (2ch)	256-272
1L23.	Panadura (T) - Matugama	132	2	29.1	*3 ETL41 (1ch)	200-208
1L24.	Panadura (T) - SS	132	2	4.7	N/A	
1L25.	Polpitiya - Laxapana	132	2	8.3	ETB (1ch)	164-172
1L26.	Laxapana - Wimalasurendra	132	2	5.1	ETI22 (2ch)	240-256
1L27.	Laxapana - New Laxapana	132	2	0.6	ETB (1ch)	192-200
1L28.	New Laxapana - Polpitiya	132	2	8.0	ETI21 (1ch)	200-208
1L29.	New Laxapana - Canyon	132	1	10.0	ETI22 (2ch)	308-324
1L30.	Polpitiya - Kotmale	132	1	29.5	ETI22 (2ch)	72-88
1L31.	Kotmale - Kiribathkumbra	132	1	22.5	ETI22 (2ch)	288-304
1L32.	Kiribathkumbra - Anuradhapura	132	1	143.9	ETI101 (1ch)	304-312
					ETI101 (1ch)	320-328
1L33.	Polpitiya - Ukuwela	132	1	59.3	ETI22 (2ch)	244-260
1L34.	Ukuwela - Habarana	132	1	82.3	No communication facility	
	Ukuwela - Habarana - Anuradhapura	132	1	131.2	ETI102 (2ch)	216-232
1L35.	Habarana - Anuradhapura	132	1	48.9	ETB (1ch)	268-288
					ETB (1ch)	208-240
1L36.	Ukuwela - Bowatenna	132	1	30.0	ETB (1ch)	440-448
					ETB (1ch)	448-456
1L37.	Kiribathkumbra - Kurunegala	132	2	34.6	ETI22 (2ch)	176-192
1L38.	Habarana - Valaichchenai	132	1	99.7	No communication facility	
1L39.	Anuradhapura - Trincomalee	132	2	103.3	ETBB (2ch)	336-352
1L40.	New Laxapana - Balangoda	132	2	43.9	ETI22 (2ch)	292-308
1L41.	Balangoda - Samanalawewa	132	2	19.0	ETI22 (2ch)	340-356
1L42.	Samanalawewa - Embilipitiya	132	2	38.0	ETI22 (2ch)	404-420
1L43.	Balangoda - Deniyaya (T)	132	2	44.2	ETI22 (2ch)	308-324
1L44.	Deniyaya (T) - Galle	132	2	57.3	No communication facility	
	(Balangoda - Galle)				ETI102 (2ch)	324-340
1L45.	Rantembe - Badulla	132	1	37.0	ETI22 (2ch)	176-192
1L46.	Badulla - Inginiyagala	132	1	79.9	ETI22 (2ch)	192-208
1L47.	Anuradhapura - Kilinochchi(T)	132	2	128.8	ETI102 (2ch)	192-208
1L48.	Kilinochchi (T) - Chunnakam	132	2	67.2	ETB (1ch)	244-256
					ETB (1ch)	228-240

Note:

*1: 220 kV design currently operated at 132 kV.

*2: These PLC are procured and removed by OECF loan project (TSADP).

In addition to the above, following PLC links on 132 kV lines are planned by TSADP and TGDP.

-TSADP-

(1)	Laxapana - Badulla	132	2	ETL82 (2ch)	224-240
(2)	Nuwra Eliya (T) - Badulla			ETL41 (1ch)	276-284
(3)	Nuwra Eliya (T) - Laxapana	132	2	ETI22 (2ch)	260-276

This PLC link is trnasferred from Norton Bridge - Nuwara Eliya on 66 kV.

-TGDP-

(1)	Ukuwela - Kribathkumbura	132	1	ETL41 (1ch)	352-360
(2)	Embilipitiya - Matara	132	2	ETL42 (2ch)	420-436
(3)	Puttalam - Anuradhapura	132	2	ETL42 (2ch)	160-176

There are the existing PLC terminals of following 33 and 66 kV lines. CEB will transfer them in the future.

(1) Kolonnawa (π)- Padukka (T)	66 kV	ETB (1ch)	168-176
(2)		ETB (1ch)	196-200
(3) Padukka (T) - Avissawella (T)	66kV	ETI21 (1ch)	456-464
(4) Avissawella (T) - Laxpana	66kV	ETI22 (2ch)	208-224
(5) Laxpana - Norton Bridge (T)	66kV	ETI22 (2ch)	144-160
(6)Nuwara Eliya (T) - Badulla (π)	66kV	ETI22 (2ch)	160-176
(7) Balangoda - Uda Walawe	33kV	ETB (1ch)	200-208
(8)		ETB (1ch)	172-180

2. UHF radio for Remote Subscirber /Data channel

Ref.	Station	Frequecncy (MHz?)	Chamnel
R1.	Pannipitiya - RAT. Area Office (A.O)	430/440	1
R2.	Sapugaskanda - DGM. A.O.	408/418	1
R3.	Kolonnawa - HD office	430/440	8
R4.	Bolawatte - NEGOMBO A.O.	440/430	1
R5.	Habarana - Minneriya A.O.	440/430	1
R6.	Kiribatkumbura - * Primrose hill	408/418	1
	* Primrose hill - Kandy office	430/440	1
	Kandy office - MC office	440.275/450.275	1
R7.	Kurunegala - A.O.	440/430	1
R8.	Kotmale - Nilambe PS	450.025/460.025	2
R9.	Galle - DGM A.O.	440/430	1
R10.	Nuwara Eliya - A.O.	440/430	1
R11.	Inginiyagala - A.O.	440/430	1
R12.	Anuradhapura - A.O.	440/430	1

Note *: Back to Back Carrier set at Primrose is a repeater equipment.

3. Cable Carrier Terminal for 4W connection

Ref.	Station	Type	Channel
C1	Kolonnawa - Stanley RS	KTI	1
C2	Randenigala - Rantembe	KTI	1

Table A 3.1 - 2 Telephone Number List of Station

No.	Name	Voltage (kV)	Station No. PAX & ECS-400
1.	Kotugoda	220/132	16
2.	Biyagama	220/132	72
3.	Kotmale P/S	220/132	73
4.	Victoira P/S	220/12.5	74 & 75
5.	Randenigala P/S	220/12.5	76 & 77
6.	Rantembe P/S	220/138	78 & 79
7.	Sapugaskanda DPS	142/11	71
8.	Bolawatta	132/33	10
9.	Puttalam	132/33	13
10.	Chilaw	132/33	?
11.	Kolonnawa	132/33	11 & 12
12.	Sapugaskanda	132/33	17
13.	Pannipitiya	132/33	14
14.	Ratamalana	132/33	19
15.	Matugama	132/33	15
16.	Fort	132/33	Future
17.	Kollupitiya	132/33	Future
18.	Kelanitissa P/S	132/33	18
19.	Padukka	66/33	41
20.	Avissawella	132/33	42
21.	Oruwala/Steel	132/33	Future
22.	Polipitiya	132/33	25
23.	Thulhiriya	132/33	26
24.	Ukuwela	132/33	21
25.	Bowatenna P/S	132/12.5	24
26.	Anuradhapura	132/33	69 & 64
27.	Kiribathkumbra	132/33	61
28.	Kurunegala	132/33	23
29.	Trincomalee	132/33	67
30.	Kikinochchi	132/33	65
31.	Chunnakam	132/33	66
32.	Habarana	132/33	63
33.	Old & New Laxpana P/S	132/33	27 & 28
34.	Wimalasurenda P/S	132/11	29
35.	Canyon P/S	132/12.5	38
36.	Balangoda	132/33	51
37.	Deniyaya	132/33	53
38.	Galle	132/33	52
39.	Samanalawewa P/S	138/10.5	55
40.	Embilipitiya	132/33	56
41.	Uda Walawe	66/33	54
42.	Norton Bridge	66/33	31
43.	Nuwala Eliya	132/33	32
44.	Inginiyagala P/S	132/33	34
45.	Badulla	132/33	33
46.	Panadura	132/33	18
47.	Matra	132/33	57

Note 1.Extension number is 2 digits such as 10.

Table A 3.1 - 3 Existing RTU List

No.	Name	Voltage (kV)	SCADA signal/VFT
1.	Kotugoda	220/132	S-4
2.	Biyagama	220/132	S-5
3.	Kotmale P/S	220/132	S-5
4.	Victoira P/S	220/12.5	S-4
5.	Randenigala P/S	220/12.5	S-4
6.	Rantembe P/S	220/132	S-4
7.	Sapugaskanda DPS	132/11	S-5
8.	Kolonnawa	132/33	S-2
9.	Pannipitiya	132/33	S-2
10.	Kelanitissa P/S	132/33	S-3
11.	Polipitiya	132/33	S-3
12.	Ukuwela	132/33	S-2
13.	Anuradhapura	132/33	S-2
14.	Habarana	132/33	S-2
15.	Kiribathkumbra	132/33	S-3
16.	Kurunegala	132/33	S-3
17.	Laxpana P/S	132/33	S-0
18.	Balangoda	132/33	S-0
19.	Samanalawewa P/S	13210.5	S-0
20.	Test station	N/A	N/A

Note

1. SCADA signal: 200 Bauds, CCITT, 360 Hz, R.38B and 480 Hz, R38A.

   S-0: 2520 Hz

   S-1: 2520 Hz

   S-2: 2520 Hz

   S-3: 2520 Hz

   S-4: 3060 Hz (R38B)

   S-5: 2700 Hz (R38B)

2. Route of PLC is shown in Fig.3.4-6-2.

Table A 3.1 - 4 List of Party Line System (PLTS)

Direction 1

No.	PLT No	Name of station
1.	101	Old Laxapana
2.	102	Avissawella
3.	103	Canyon
4.	104	Balangoda
5.	105	Uda Walawe
6.	106	Deniyaya
7.	107	Galle
8.	108	
9.	109	Samanalawea
10.	110	Embilipitiya
11.	111	New Laxapana

Direction 2

No.	PLT No	Name of station
1.	201	
2.	202	
3.	203	Wimalasurendra
4.	204	Norton Bridge
5.	205	Nuwara Eliya
6.	206	Badulla (old)
7.	207	Inginiyagala
8.	208	
9.	209	Badulla (new)
10.	210	

Direction 3

No.	PLT No	Name of station
1.	301	Polpitiya
2.	302	Thulhiriya
3.	303	Ukuwela
4.	304	Bowatenna
5.	305	
6.	306	
7.	307	
8.	308	
9.	309	
10.	310	

Direction 4

No.	PLT No	Name of station
1.	401	Anuradhapura
2.	402	Kiribathkumbra
3.	403	Habarana
4.	404	
5.	405	Trincomalee
6.	406	Kilinochi

7.	407	Chunnakan
8.	408	
9.	409	Kurunegala
10.	410	

Direction 5

No.	PLT No	Name of station
1.	501	Kelanitissa
2.	502	Biyagama
3.	503	Kotmale
4.	504	Victoria
5.	505	Randenigala
6.	506	Ratembe
7.	507	Sapugaskanda DPS
8.	508	Kotamale
9.	509	Nilambe
10.	510	Kelanitissa (GT)

Direction 6

No.	PLT No	Name of station
1.	601	
2.	602	Kotugoda
3.	603	Bolawatta
4.	604	Puttalam
5.	605	
6.	606	
7.	607	
8.	608	
9.	609	
10.	610	

Direction 7

No.	PLT No	Name of station
1.	701	Kolonnawa
2.	702	Oruwela
3.	703	Padukka
4.	704	Matugama
5.	705	Pannipitiya
6.	706	Ratmalana
7.	707	Sapugaskanda
8.	708	
9.	709	
10.	710	

Note Route of PLC is shown in Fig 3.4.6-2.

Table A 3.1 - 5 List of Telex System

Direction 1

No.	Signal No	Name of station
1.	T-5	Sapugaskanda
2.	T-7	Kelanitissa
3.	T-9	Kelanitissa

Direction 2

No.	Signal No	Name of station
1.	T-1	Kotmale
2.	T-2	Rantembe
3.	T-8	Victoria

Direction 3

No.	Signal No	Name of station
1.	T-5	Canyon
2.	T-10	Laxapana Old

Direction 4

No.	Signal No	Name of station
1.	T-2	Polipitiya
2.	T-4	Ukuwela
3.	T-10	Bowatenna
4.	T-12	MC office

Direction 5

No.	Signal No	Name of station
1.	T-2	Laxapana
2.	T-10	Wimalasurendra
3.	T-11	Samanalawea

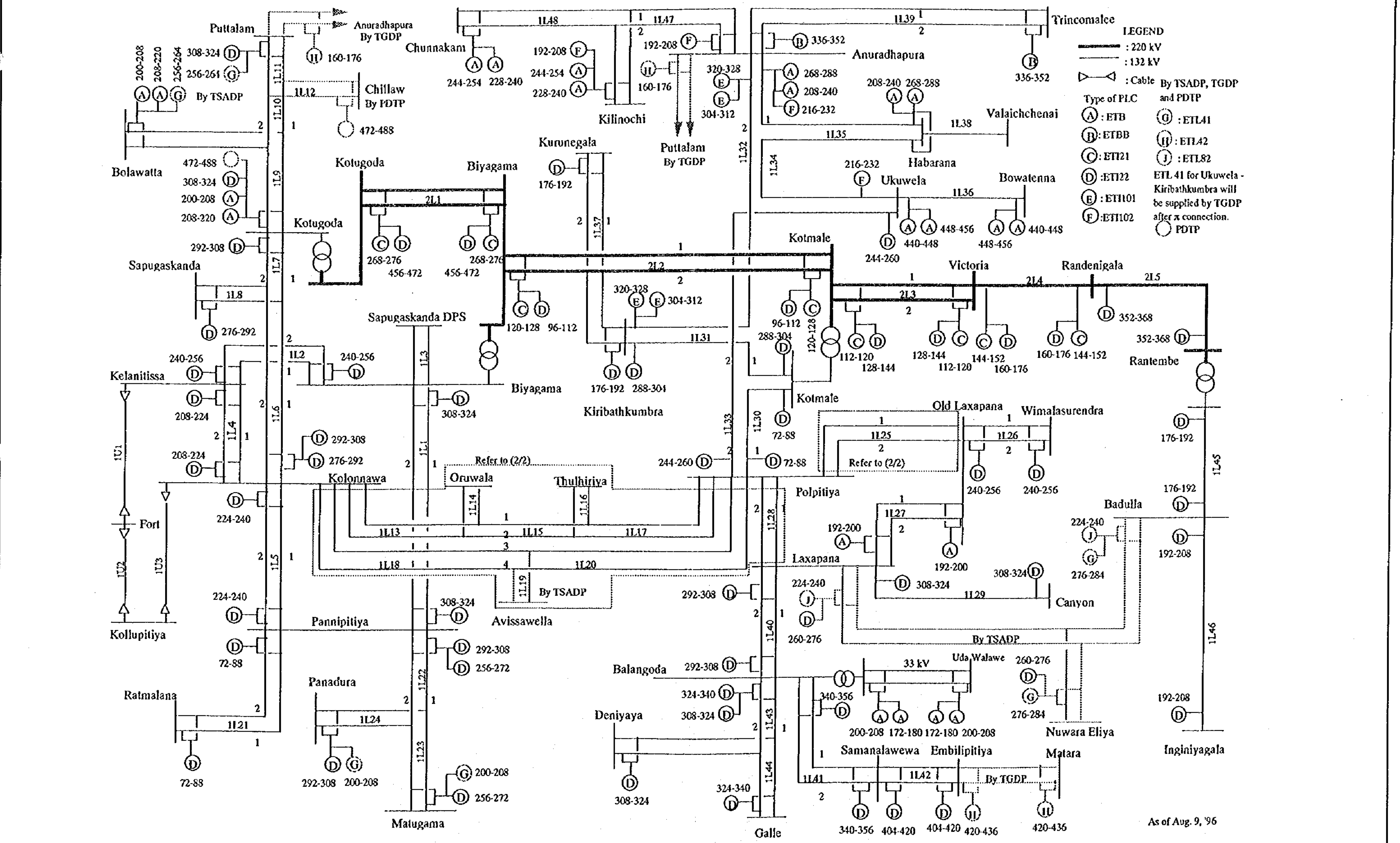
Note

Telex signal: 50 Bauds, 120 Hz, R.35

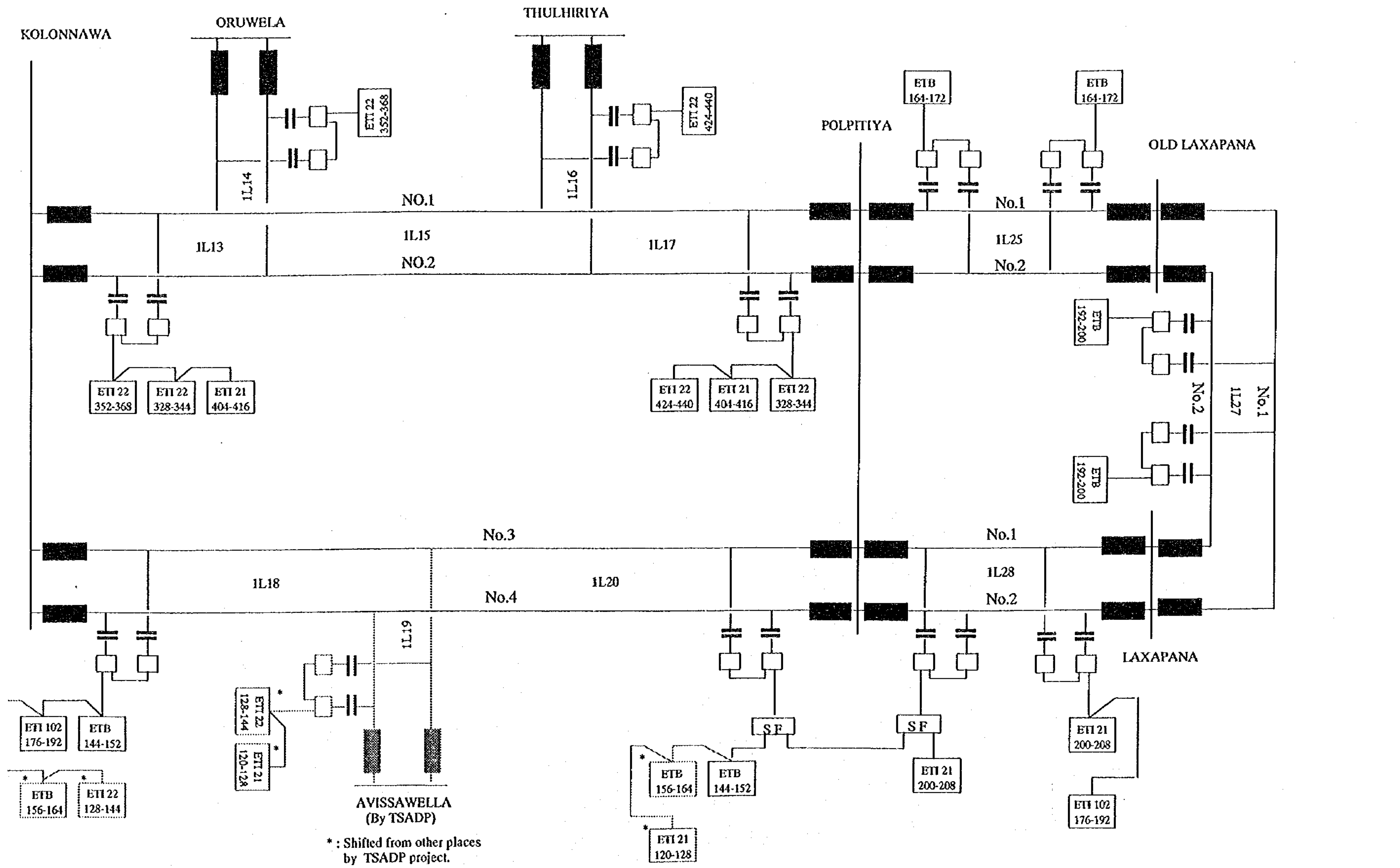
T-0: 2080 Hz	T-6: 3060 Hz	T-12: 3430 Hz
T-1: 2220 Hz	T-7: 3180 Hz	
T-2: 2340 Hz	T-8: 3300 Hz	
T-3: 2460 Hz	T-9: 3420 Hz	
T-4: 2580 Hz	T-10: 2700 Hz	
T-5: 2820 Hz	T-11: 2940 Hz	

Table A 3.1 - 6 Battery (d.c.48V) and Battery Charger for PLC/SCADA

No.	Name	Battery charger Type Capacity	Battery Type Capacity.
1.	Kotugoda	Systronic 60A	Lead-Acid 200Ah
2.	Biyagama	Systronic 60A	Ni-Cd 200Ah
3.	Kotmale P/S	PS DC ?	Lead-Acid 700Ah
4.	Victoira P/S	Systronic 40+80A	Ni-Cd 105+200Ah
5.	Randenigala P/S	PS DC ?	Lead-Acid ?Ah
6.	Rantembe	PS DC ?	Lead-Acid ?Ah
7.	Sapugaskanda DPS	Systronic 60A	Ni-Cd 170Ah
8.	Bolawatta	Gutor 40A	Lead-Acid 120Ah
9.	Puttalam	Gutor 40A	Lead-Acid 120Ah
10.	Chilaw	Nife	
11.	Kolonnawa	EAO 40A	Lead-Acid 120Ah
12.	Sapugaskanda	Gutor 40A	Lead-Acid 120Ah
13.	Pannipitiya	Systronic 40A	Lead-Acid 200Ah
14.	Ratamalana	Electrona 15A	Lead-Acid 90Ah
15.	Matugama	Oerlikon 40A	Lead-Acid 120Ah
16.	Fort	Future	
17.	Kollupitiya	Future	
18.	Kelanitissa P/S	Gutor 40A	Lead-Acid 210Ah
19.	Padukka	Gutur	
20.	Avissawella	Gutur	
21.	Oruwala/Steel	EAO	
22.	Polipitiya	Statron 105A	Lead-Acid 400Ah x 2
23.	Thulhiriya	OLTEN 40A	Lead-Acid 120Ah
24.	Ukuwela	Gutor 40A	Lead-Acid 400Ah
25.	Bowatenna P/S	Oerlikon 40A	Lead-Acid 200Ah
26.	Anuradhapura	Statron 85A	Lead-Acid 300Ah
27.	Kiribathkumbra	Systronic 60A	Ni-Cd 170Ah
28.	Kurunegala	Systronic 60A	Ni-Cd 170Ah
29.	Trincomalce	Oerlikon 40A	Lead-Acid 90Ah
30.	Kikinochchi	Gutor 40A	Lead-Acid 120Ah
31.	Chunnakam	Gutor 40A	Lead-Acid 120Ah
32.	Habarana	Systronic 60A	Ni-Cd 200Ah
33.	New Laxpana P/S	Statron 105A	Lead-Acid 400Ah x 2
34.	Wimalasurenda P/S	Gutor 40A	Lead-Acid 120Ah
35.	Canyon P/S	Oerlikon 40A	lead-Acid 200Ah
36.	Balangoda	Systronic 40A	Ni-Fe 200Ah
37.	Deniyaya	Gutor 40A	Lead-Acid 120Ah
38.	Galle	Gutor 40A	Lead-Acid 120Ah
39.	Samanalawewa P/S	Yuasa ?A	Lead-Acid 1400Ah
40.	Embilipitiya	Gutor 40A	Lead-Acid 170Ah
41.	Uda Walawe	EAO	
42.	Norton Bridge	Gutur	
43.	Nuwala Eliya	Gutur	
44.	Inginiyagara P/S	Gutur	
45.	Badulla	Gutor 60A	Ni-Cd ?Ah
46.	Panadura	Nife	
47.	Matara	Future	



CEYLON ELECTRICITY BOARD	JAPAN INTERNATIONAL COOPERATION AGENCY NIPPON KOEI CO., LTD. Consulting Engineer, TOKYO JAPAN	MASTER PLAN STUDY FOR DEVELOPMENT OF THE TRANSMISSION SYSTEM OF THE CEYLON ELECTRICITY BOARD IN THE DEMOCRATIC SOCIALIST REPUBLIC OF SRI LANKA	TITLE Fig. A 3.1 - 1 (1/2) PLC Line Coupling System (End of December 1995)



* : Shifted from other places by TSADP project.

CEYLON ELECTRICITY BOARD	JAPAN INTERNATIONAL COOPERATION AGENCY NIPPON KOEI CO., LTD. Consulting Engineer, TOKYO JAPAN	MASTER PLAN STUDY FOR DEVELOPMENT OF THE TRANSMISSION SYSTEM OF THE CEYLON ELECTRICITY BOARD IN THE DEMOCRATIC SOCIALIST REPUBRIC OF SRI LANKA	TITLE Fig. A 3.1 -1 (2/2) PLC line coupling system for Kolonnawa - Oruwala - Thulhiriya - Avissawella - Polpitiya - Laxapana

CHAPTER A5

RELIABILITY CRITERIA
FOR
TRANSMISSION PLANNING

CHAPTER A5

RELIABILITY CRITERIA FOR TRANSMISSION PLANNING

A5.1 INTRODUCTION

The objective of this chapter is to present a brief overview and an introduction to the concept and theory of supply reliability planning, investigate the current practice, and determine the extent of the possible application of reliability planning within any constraints that may be imposed due to any possible limitations that might be inherent within the existing records.

This section is presented in five main sections and can be summarised as follows :

Section A5.2:	Describes and assesses the various transmission system reliability criteria/indices in use or under consideration;
Section A5.3:	Reports on a survey of indices presently used by utilities world-wide, and reports on a survey of present transmission network performance world-wide and on the methods for performance monitoring;
Section A5.4:	Reviews the present status of analytical tools to calculate differing types of indices;
Section A5.5:	Reviews methodologies for setting transmission planning criteria; and

The work reported here is in part based on consultant's own independent assessment of present practice and its applicability to Sri Lanka, but the consultant has also drawn on materials in the following two documents :

1. Transmission System Reliability Methods, EPRI Research Project 1530, Report Volume 1, July 1982.
2. Power System Reliability Analysis, Application Guide, CIGRE working group 03 of SC 38 (Power System Analysis and Techniques) - published 1987.

The consultant have also taken the opportunity to incorporate additional materials presented to the CIGRE Symposium on Electric Power Systems Reliability held in Montreal in September 1991. In particular we have drawn upon the Report prepared by CIGRE Task Force 38-03-10 entitled :

"Composite Power System Reliability Analysis - Application to the New Brunswick Power Corporation System."

A5.2 TRANSMISSION RELIABILITY CRITERIA

A5.2.1 INTRODUCTION

This section of the report has the objective of reviewing transmission reliability criteria which are either in use or are being considered by utilities around the world. Transmission reliability indices fulfil a number of functions including providing a basis for planning systems and for communicating system performance history to management and consumers.

The criteria which have been surveyed include some which have only recently been developed from a theoretical standpoint, but which nevertheless are potentially suitable for adoption by utilities in the foreseeable future.

Indices may relate to the performance of the system as a whole (interconnected power indices), or to the reliability of supplies at specific points on the network (load point indices).

A5.2.2 THE NATURE OF RELIABILITY

The concept of reliability is that it provides measures of the ability of a interconnected power system to deliver electricity to all points of utilisation within acceptable standards and in the amount desired. Interconnected power system reliability can be described by two basic and functional attributes - adequacy and security.

- Adequacy is essentially consideration of steady state reliability. It is considered the system's capability to meet system demand within the constraints imposed by major component ratings and by the presence of scheduled and unscheduled outages of network components. For adequacy assessment, steady state conditions are assumed. To the extent that transient conditions are considered in adequacy assessment, interest is limited to considering the capability of the system to meet the load following the disturbance and after the operation of any automatic devices as well as adjustments which can be made by an operator. System failure occurs when service interruption is necessary to continue normal system operation. System adequacy can generally be quantified through the use of load flow models.
- Security is essentially consideration of critical dynamic conditions. It may be defined as the systems capability to withstand disturbances arising from faults and unscheduled outages of an interconnected power supply component without further loss of facility or cascading. Security assessment can be subdivided into instability, overload cascading and voltage collapse. Dynamic models which recognise equipment response limitations are generally required to calculate the appropriate reliability indices.

This Study has concentrated on system adequacy since the study's interest primarily relates to the degree of reliability or redundancy which should be built into the network, rather than with the dynamics of system protection operation or generator post fault response.

A5.2.3 CATEGORIES OF FAILURE

The following three possible categories of power supply system failure can be identified:

- Technical quality deficiencies: These include unacceptable levels of voltage and frequency and service voltage, excessive harmonics and unbalance in polyphase supplies.
- Power system emergencies: Such emergencies arise due to demand exceeding supply capability due to shortfall in resources. System response to such events include curtailment of load, voltage reduction and/or load management control. Load shedding is accepted during major emergencies.

- Power system interruptions: Such interruptions are caused by failure in the interconnected power system, these differ in nature, frequency and extent of effect. Whilst most events resulting in service interruptions arise on the distribution system, the number of customers affected in each case is usually limited. On the other hand, disturbances arising on the interconnected power system are fewer but can affect a large number of consumers and can have a widespread social and economic impact.

A5.2.4 RELIABILITY OBJECTIVES

Using the concepts presented above, utilities can be expected to adopt the following objectives when planning and operating an interconnected power system:-

- To preserve system adequacy, i.e. to supply the aggregate electric power and energy requirements with acceptable technical quality and service continuity.
- To preserve system security in such a way that recovery from more probable contingencies can be achieved without load curtailment or interruption and avoiding excessive stress on the system and its components.
- To preserve system integrity, such that more severe, less probable contingencies, including sequences of contingencies, will not result in uncontrolled separation of major portions of the system.
- To limit the extent of failure and minimise the risk of widespread shutdown.
- To promote rapid restoration following shutdown.

A5.2.5 MAIN TYPES OF RELIABILITY CRITERIA

Reliability criteria can be viewed as conditions that should be satisfied by the generation and transmission system in order to achieve the required reliability. These fall into two categories: performance test and index criteria.

Performance-based criteria take the form of sets of conditions, such as one or more generation or transmission incidents, that the system must be capable of withstanding. The definition of incident includes the pre-disturbance as well as the disturbance itself. These criteria form the basis of deterministic contingency evaluation, although it is not necessarily the case that no supply interruptions occur for all contingencies considered.

Index criteria are numerical parameters which provide target levels of reliability, or more usually, upper bounds on unreliability, i.e. expected energy not supplied or expected frequency failure. The use of such criteria forms the basis of probabilistic reliability assessments.

Probabilistic criteria are intended to recognise the random nature of outage events and provide measures of system reliability on the basis of the outage statistics of the system components.

A5.2.6 UNCERTAINTY IN RELIABILITY EVALUATION

Uncertainties in power system reliability predictions may arise at any stage of a reliability investigation, particularly as inaccuracies or even errors may occur at each step of the investigation.

Because of the inherent uncertainties, reliability indices have a probability distribution with a considerable deviation. Account should, therefore, be taken of variances of the calculated indices when using reliability criteria to make planning decisions. These variances can be calculated. Full information on predicted system behaviour is contained within the probability distributions of the indices. Ideally, reliability criteria should be based on these distributions, however, in practice the planner must settle for less, making use of the expected values of the indices.

The uncertainty in predicting system behaviour depends on the reliability index. The uncertainty is especially high for the predicted interrupted energy index, which means that evaluations of interrupted-energy costs based on this index are also forced to deal with significant uncertainty.

A5.2.7 CHARACTERISTICS OF INDICES

The need to set criteria for assessing adequate system performance is applicable whether probabilistic or deterministic assessments are being used. The appropriate criteria determines boundaries between what is acceptable and adequate and what is not. Historically, both system performance indicator and the acceptable level are fixed deterministic values, specified and calculated using deterministic techniques. Uncertainties have always been recognised, therefore, deterministic safety factors are always taken into account when deterministic measures are applied.

Although this concept recognises that variability exists, it does not recognise the likelihood of the variations and thus can impose excessive safety if the dispersions of the characteristics are small or, at the other extreme, inadequate safety if the dispersions are very large.

Therefore, the application of probability theory to the assessment of system reliability enables the probabilistic or statistical variations to be taken into account.

Absolute and relative measures are frequently encountered in practical assessments. Absolute indices are values expected to be exhibited by a system, these can be monitored for past performance as long as data is available. However, they are extremely difficult, if not impossible, to predict for future performance with a high degree of confidence.

The reason is that future performance contains considerable uncertainties particularly associated with numerical data and predicted system requirements. Also the models used are frequently approximations which is not necessarily an accurate representation of the plant or system behaviour.

Relative reliability indices on the other hand are easier to interpret and considerable confidence can generally be placed in them. In these cases, system behaviour is evaluated before and after the consideration of design or operating change. The benefit of the change is assessed by evaluating the relative improvement in the index.

Therefore, indices are compared with each other rather than against a specified target. This tends to ensure that uncertainties in data and system requirements are embedded in all the indices and therefore reasonable confidence can be placed in relative differences.

In practice, a number of design or operating scenarios are compared and a ranking of the benefits due to each alternative can be obtained.

Appropriate indices can be determined, however, a single all purpose formula or technique does not exist. The approach used and any indices obtained depend upon the assumptions adopted and the validity of the analysis is directly related to the validity of the model used to represent the system.

The most important aspect to remember is that it is necessary to have a complete understanding of the engineering implications of the system and no amount of probability theory can circumvent this important engineering function.

Therefore, it is evident that probability theory is only a tool that enables the operators and planners to transform their knowledge of the system into a prediction of its likely future behaviour. Only after this understanding has been achieved can a model be derived and the most appropriate evaluation technique chosen. Therefore, the steps involved are:

- understand the way the components and system work;
- identify the ways in which the system can fail;
- establish the consequences of the failure;
- derive models to represent these characteristics; and
- only then select the evaluation technique.

In order to calculate probabilistic indices, estimates of the event probabilities and frequencies are required. If sufficient data are available, the probabilities and frequencies of the events can be calculated to include all dependencies and correlations between events.

However, the assumption commonly made is that events are independent, thus simplifying the mathematics. It should be noted that this assumption may have a significant effect on the value of the indices. Assuming independence usually results in an optimistic value for the reliability indices.

The remainder of this section of the report is dedicated to the introduction and definition of most of the deterministic and probabilistic indices that are used to evaluate reliability levels of power systems. Analytical techniques and evaluation methods are discussed elsewhere in this report.

A5.2.8 DETERMINISTIC INDICES

Deterministic indices are set on the basis of assessing the extent to which the system demand can be met following predetermined relatively frequent outage events. These are often expressed as "N-1" (single outage contingency) or "N-2" (double outage contingency) criteria which refer to the implications of a single or a double outage event. It is not necessarily the case that no supply interruptions occur for all contingencies, and indices can be defined for single or multiple outage events.

The outage events which are normally considered are the loss of network components such as cables, lines, generators, transformers, etc. In some utilities more serious cases are considered such as the loss of a set of busbars, or cascade trips.

Utilities often classify parts of their network differently with major bulk interconnectors having a higher reliability standard (say "N-2"), compared to a lower voltage feeder circuit which may only be able to withstand a single outage event, or may even have only a single supply circuit. These criteria may equally apply to transmission interconnection components as well as substation components.

Several deterministic indices which have been used are discussed below. These indices can be defined assuming that not all possible contingencies are evaluated, and the extent to which this approach is adopted depends in part on the likelihood of a particular outage occurring and in part on the feasibility of being able to study all possible contingencies.

Typical deterministic indices include :

- **Maximum Load Not Supplied;** This index involves determining the maximum MW not supplied by the system due to the contingencies studied. It involves summating the shortfalls in MW supplied at each busbar for each contingency in turn, and then comparing the summated shortfalls and identifying the maximum value. It is also possible to identify which of the contingency events are the most critical since they will be the ones most regularly giving rise to the greater shortfalls.

  The actual magnitude of the load curtailed depends on the solution method adopted. It should for example be clearly stated if generation despatch, and in particular redespatch following an outage, is considered in determining the events resulting in loss of load.

- **Maximum Energy Not Supplied;** This index is similar to the previous one, except that energy rather than power is of interest. The computational requirement are the same as for the previous index, except that the duration of the outage is required so that the energy not supplied may be assessed given that the MW magnitude is known. This is very difficult to quantify since a time dependent load model would be required for each load point. More readily available would be average or historical values of duration which could be used.

- **Minimum Load Supplying Capability;** The load supplying capability (LSC) of a system is defined as the maximum system load that the system can supply with no line overload. The LSC is calculated by raising the loads at each bus and varying the generation despatch until no more power can be despatched without overloading some transmission line. This limiting point is defined as the LSC of the system.

The manner in which the bus loads are increased would obviously affect the result since the distribution of the load will affect the line flows and thus the point at which the transmission becomes limiting.

If the LSC calculation is carried out for each contingency studied, the results give an indication of the relative severity of the events and thus the reliability of the network. It is required to calculate the load supplying capability of the network for each contingency, and then to establish the minimum of these values.

- **Minimum Simultaneous Interchange Capability;** The simultaneous interchange capability (SIC) is defined as the maximum power that can be imported or transferred between areas within the system. In this case the load is fixed and the amount of power transferred is maximised. If this is repeated for all contingencies of interest, the minimum SIC could be used as a measure for the reliability of the system.

- **Maximum Line Flow;** This index is an indication of the impact of contingencies on the power flow of a particular circuit. This index gives an indication to the size necessary for a new line and requires that the flow on selected lines is monitored for the different contingencies, and the maximum values identified. It is also useful for planning purposes to know how many contingencies resulted in the flow in a particular line exceeding a certain flow.

A5.2.9 PROBABILISTIC INDICES

One of the key weaknesses of the deterministic indices is lack of information on frequency or duration of outages. An index applied to a load point in particular may suggest a poor level of reliability as measured in terms of, say, maximum load not supplied. However if that event is only likely to occur extremely infrequently compared to some other events, the reliability of supplies at that point may appear significantly poorer than could in fact be expected.

Probabilistic criteria overcome these difficulties and have three fundamental attributes :

1. frequency of events
2. duration of events
3. severity of events

Not all indices necessarily have all three of these attributes. The most common adequacy indices can be classified into two types. The first type is a single parameter to define the behaviour of any system component without specifying the related duration or frequency characteristics. These indices provide a measure of the average system behaviour during the period under investigation, without stating whether the risk situation corresponds to a single long event or a number of short events.

The second type of risk indices are expressed by two parameters, usually the annual expected value of the quantity representing the system deficiency and the related annual frequency, or the expected value of a single deficiency and its frequency. Assuming the same unit of time, the product of frequency and duration of a single occurrence gives the corresponding total expected value in the selected unit of time.

It should be borne in mind that adequacy indices take account of faults of relatively long duration, since these require repair and therefore constitute what is commonly defined as permanent faults as opposed to transient faults.

Indices may also be differentiated according to the way that the severity of events are measured. In particular as:

- system problem indices; these describe the probability of problems arising such as overloads, voltage limit violations or islanding occurring.
- system state indices; these describe the extent of the problem in terms of the probability of the system being in a predefined state of insecurity in accordance with a utility's own practices, where the state of insecurity is likely to be defined in terms of a scale, or number of levels.
- load curtailment indices; these are indices where the severity of an event is expressed in terms of failure to supply, or load curtailment.

Typical problem indices include:

- Overload indices (frequency, duration, probability or amount of overload),
- High or low load voltage indices (frequency, duration, probability or average amount outside limits),

- Island indices (frequency or average percentage generation deficiency).

In this report, the problem indices have been concentrated on load curtailment indices as these are the indicators which consumers have most interest in, although in the longer term. CEB may wish to consider the merits of extending their interest in system adequacy to areas more concerned with problems rather than loss of supplies.

A number of load curtailment indices may be defined which generally arise from the three measures of frequency, duration and load curtailment. These may be equally applied on a system wide basis or for individual load points. These include:

- **Loss of Load Probability (LOLP);** The LOLP for a transmission system measures the probability of not being able to meet the peak load due to transmission system outages.

Conceptually the LOLP calculation can be extended to the

- **Loss of Load Expectation (LOLE);** This is defined as the number of days per year when a set of loads or distribution of loads cannot be supplied. As in generation planning this could be calculated for all 8760 hourly loads over the year by adding the probabilities for every day of the year when the available capacity is unable to meet the daily peak due to transmission outages.

  This period calculation would require a significant amount of computation if the system quantities had to be completely recalculated. Consequently the LOLE calculation is generally restricted to meeting the 365 daily peak loads, or other representative sets of load distribution. It is however possible, by making the simplifying assumption that the load at each node remains a constant fraction of system load, to use the load supplying capability (LSC) concept described earlier to simplify the calculation.

  Care must be taken in adopting these indices without considering system operational realities. It may, for example, be the case that the critical loading period for the transmission system may occur at a time different to system peak load time. In such cases the set of load points to be considered is critical.

- **Frequency of Loss of Load (FLOL);** the frequency of loss of load due to transmission outages combines consideration of the number of times that individual outages can occur with the probability that loads at each busbar exceed the load carrying capability of the system at the time of the outage.

- **Expected Energy Not Served (EENS);** This is defined as the expected energy not served due to transmission system outages. For a given load level the unsupplied energy is the amount of shortage for each outage times the probability of the outage, summed for all outages.

  This quantity can be summed over all desired loads to find the unserved energy per period (e.g. per year). An index may also be defined giving the Expected Energy Not Served per Outage; though this is less useful as it lacks information on the frequency of the loss of supplies.

- **Expected Load Curtailed (ELC);** This is a subset of EENS, and excludes consideration of the duration of the outage.

- **Expected Number of Load Curtailments;** This expresses the number of times that a failure not meeting the load occurs.

- **Expected Duration of Load Curtailments;** This expresses the average duration of supply not meeting the load. It may alternatively be expressed in terms of the total number of hours per year that load curtailment occurs. In this case it becomes very similar to LOLP.

A5.2.10 LOAD POINT INDICES

As noted above, all the indices referred to in Clause A5.2.9 may be used as load point or system indices if the load point values are aggregated.

It is important to appreciate that if these indices are calculated for a single load level and expressed on the basis of one year, they should be designated as annualised values. Annualised indices calculated at the system peak load level are usually much higher than the actual annual indices and therefore, should only be used for comparing different alternatives of system structure and not for optimisation.

The effect of a variable load level can be included in order to produce a more representative annual index. However, this would be at the expense of considerable computer time. The increase in cost depends on the degree to which the load variation is modelled.

A5.2.11 SYSTEM INDICES

In addition to aggregating the load point indices, a further set of indices for the overall system have been proposed as given below.

- **Bulk Power Interruption Index (BPII);** The BPII is defined as the average number of MW of system or area load interrupted per MW of system or area load served. This is the ratio of total load interrupted to annual peak load. Its calculation calls for the study of sufficient load levels to be able to adequately define the system reliability.

- **Bulk Power Energy Curtailment Index (BPECI);** The BPECI is an extension of the BPII and relates the annual energy not supplied EENS to the peak load. It is also known as the

- **Severity Index;** and is the severity associated with each outage event. It is defined as the total unsupplied energy because of that event, expressed in megawatt minutes, divided by the peak system load in megawatts. Severity is therefore expressed in 'system minutes' and is numerically 6 of times the value of the BPECI. One system minute is equivalent to an interruption of the total system load for one minute at peak load. It does not represent a real system outage time because the interruptions need not occur at the time of peak load. A further variant on the BPECI is the

- **Energy Unreliability Index;** This is the ratio of the energy not supplied to the total energy demanded.

- **Bulk Power Supply Average Power Curtailment Index;** This indicates the average MW curtailed per disturbance on a system wide basis.

A.5.2.12 SUMMARY

Reliability indices may be classified as being deterministic or probabilistic, with the latter representing the area of most development. Probabilistic indices have the advantage that they enable the nature of any unreliability to be quantified in terms which can be understood by planners, managers and users alike. They reflect the random nature of outage events and provide a far greater lucidity than deterministic indices.

Both types of index may be applied to bulk system reliability determination as well as load points. Range of indices have been defined for possible use. The selection of the appropriate one for a particular utility will depend on the individual circumstances and the particular objectives of adopting indices within an organisation.

A5.3 SURVEY OF PRESENT UTILITY PRACTICE

A5.3.1 INTRODUCTION

The objective of this Section is to review and establish current practices being adopted by utilities world-wide and applied to the planning of their transmission systems for reliable supplies. The consultant has undertaken own review on the basis of three approaches :

1. A survey of 62 utilities world-wide was undertaken;
2. Existing literatures for results of earlier surveys were reviewed; and
3. Consultant's own knowledge of the practices adopted by utilities with whom the consultant is familiar were referred to.

A5.3.2 MOTT EWBANK PREECE (MEP) SURVEY OF UTILITY PRACTICE

A5.3.2.1 General Approach

In this section MEP review the results of a survey MEP have undertaken late 1991 of present utility practices. MEP survey was based around a questionnaire which was sent to 62 selected utilities. In order to give as broad a view as possible of the planning criteria used, MEP have made a random selection of utilities and have not restricted the analysis to utilities of similar sized systems or level of interconnection.

The questionnaire was designed with the objectives of establishing answers to the following key questions:

1. Did the utility have an agreed transmission reliability planning criteria?
2. If so, did they use deterministic or probabilistic criteria, or both?
3. What was the specific criteria used?
4. Did they differentiate between different parts of the network by using different standards of supply for different supply points?
5. Were both system wide and load point indices used?

Questionnaires were sent to the 62 utilities indicated on Table A5.3.1, and replies have been received from 18 as indicated.

A5.3.2.2 Detailed Review of Responses

The main responses to our questionnaire sent to utilities world-wide are summarised below.

BRITISH COLUMBIA HYDRO, CANADA

BC Hydro is increasingly paying attention to the probabilistic approach in its overall system planning. It does not however, see this as replacing traditional deterministic criteria but rather, allows them to evaluate plans produced by deterministic criteria and modify them to be less or more conservative, as each case justifies.

The aim of system planning within BC Hydro is to talk in terms of operating margins from limits and the probability of entering those margins. The limits are those of thermal limits, transient stability and voltage stability.

Deterministic planning is based on :

- the amount of allowable generation to be shed; and
- the amount of the allowable load to be shed.

Probabilistic indices are at present being developed, and MEP's discussions with BC Hydro indicate that the development of suitable computational systems is presently a high priority. The only indices being used at present are Bulk Electricity Supply (BES) point indices. Single contingency criteria are normally used, but in the case of small substations there can be single transformer stations backed up by a mobile unit.

MANITOBA HYDRO

System planning is based on deterministic reliability indices using Forced Outage Rate values in a methodology that determines a 'Load Carrying Capability' in the generation and major transmission system.

Single outage contingency is used by Manitoba Hydro. Double outage contingency is not used as a general criteria, but is considered for special situations. Reliability indices are only used for the major transmission and HVDC system.

STATE COMMISSION OF WESTERN AUSTRALIA

The Australian utilities are organised on a state basis with little transfer of power between states other than between Victoria and New South Wales and also to South Australia.

The State Commission of Western Australia (SECWA) employs both deterministic and probabilistic criteria in transmission planning. N-1 criterion is used for deterministic reliability for lines and transformers. Single outage contingency is normally employed; double outage contingency is used for system load less than or equal to 80% of peak demand.

Probabilistic indices used are based on average duration and frequency of failure. They are used to supplement deterministic criterion. SECWA have commented that they are restricted in using reliability indices in transmission planning because the computer software available to perform such studies is not sufficiently developed.

QUEENSLAND ELECTRICITY COMMISSION

The Queensland Electricity Commission has established reliability criteria and network design rules for use in the early stages of formulating and comparing proposals for systems development. In the final analysis, however, each project is considered on its merits and these criteria may not apply in all cases. The following criteria and network design rules are observed:

- Sufficient transmission will be provided to allow merit order operation without loss of supply with any one item of system plant out of operation.
- System stability to be maintained following a three phase to ground fault and subsequent clearance of any one circuit or shunt element within a clearing time of 0.1 second.
- Normal (continuous or nameplate) ratings of plant will not be exceeded during average ambient conditions with all plant in service.
- Immediately following a single outage, loading of remaining plant will be within its cyclic rating for the expected load cycle and ambient conditions.
- System voltages will be stable and within the range 100 to 108% of nominal voltage for normal and single contingency situations, after the operation of transformer tap changers and switched reactive devices.
- Overlapping outages (double contingencies) should not cause overloads resulting in major system interruption. Allowance may be made for re-scheduling generation or transferring load in determining transmission capacity under overlapping outage conditions, although some load shedding and out of merit operation may be necessary.

The following are some of the factors which are taken into account in determining the scope and timing of specific projects, and which may lead to departures from the above criteria:

- the type of load (e.g. continuous process, CBD, general supply) and consequence of an interruption.
- the availability and capacity of alternative supplies, e.g. high cost generating plant, subtransmission back-up capacity.
- the size of the load group affected.
- the probability and expected duration of critical outages and cost of avoidance.
- the short time emergency overload ratings of plant.
- the real and reactive power variation of the load with voltage and frequency when determining stability and voltage conditions during disturbances.

THE SOUTH EAST QUEENSLAND ELECTRICITY BOARD

The general philosophy adopted by SEQEB is the N-1 criteria. That is to provide 100% capability with any one circuit or item of equipment out of service. In applying this criteria, SEQEB take account of:

- equipment thermal capabilities (i.e. cyclic, emergency or two hour rating as applicable).

- system voltage control, including use of transformer taps, capacitors and AVRs. (noting that voltage variation limits are 6% at LV supplies, 5% at 22 kV supplies, and agreed variations at higher voltages).
- automatic load transfer capacity.
- manual load transfer capacity.

There are some cases when adoption of the N-1 criteria is not considered by SEQEB to be economically justified:

- rural substations of limited loading.
- non-permanent loads such as sand mining.
- loads which would involve high capital expenditure not justified by rate of revenue return.

CENTRAIS ELETRICAS BRASILEIRAS SA, BRAZIL

The criteria used in transmission planning is based on both deterministic and probabilistic reliability indices. N-1 criterion is used as a deterministic reliability index for single outage contingencies.

Probabilistic indices used are unsupplied energy, failure frequency and duration. These are used for planning to bulk supply points on the network.

SARAWAK ELECTRICITY SUPPLY CORPORATION

Sarawak Electricity Supply Corporation employ both deterministic and probabilistic reliability indices. These include Loss of Load Probability and Expected Energy Not Supplied. These are used for planning to bulk supply points on the network and are applied in the form of a composite generation and transmission criteria.

OSLO LYSVERKER

Only deterministic reliability indices are used by this Norwegian utility. No details were given of the types used. These are used for bulk supply points on the network.

CARIBBEAN UTILITIES COMPANY

This utility, in the West Indies, does not employ reliability indices or any criteria for its transmission since the highest voltage on the system is 69kV, of which there is only 20 miles within the total system.

ELECTRICITY AUTHORITY OF CYPRUS

The Electricity Authority of Cyprus applies deterministic criteria for the expansion of its system during its present 10 year development plan:

1. The N-1 Criterion

   The N-1 principle is applied throughout the Authority's transmission network both on the 132 kV as well as the 66 kV transmission lines. The same planning criterion is also applied in the design of the 132/11 kV and 66/11 kV substations in order to ensure firm transformer capacity in all the transmission substations.

2. The N-2 Criterion

The transfer of power between the major load centres should use the N-2 criterion, in order to ensure that the loss of a double circuit line between these centres will still allow the transfer of the required power through alternative interlinked lines.

Other conditions which must be met include:

- No cyclic overload capacity must be permitted on any of the equipment under normal or outage conditions.
- Reactive compensation is necessary when it is established that the system demand exceeds the MVar capability of the available generators.
- The system is designed so that voltage control need not be accomplished by switching out an overhead line or cable circuits.
- System voltages are controlled within the following limits for normal and outage conditions:

  132 KV + 10 to - 10%
  66 kV + 6 to - 6%
  11 kV + 6 to - 8%

TAIWAN POWER COMPANY

The Taiwan Power Company uses deterministic reliability indices in its transmission planning. This is on the basis of one trunk line shut down for maintenance, and another trunk line on forced outage. This is only valid for 345 kV and 161 kV bulk power system, with one line outage valid for lower voltage. No double outage contingency is used.

No probabilistic reliability indices are used.

UNITED STATES OF AMERICA

Every operating, interconnected electric system in the USA is a member of the North American Electric Reliability Council (NERC). As members of NERC, every system must adhere to certain operating and planning criteria and guide-lines to assure the integrity of the overall integrated system. While, in general, transmission planning is considered 'deterministic' and resource planning is considered 'probabilistic', there are some of both types of criteria in each.

In general, deterministic indices used are based on outage rates e.g. hours/year, hours/consumer/year. Probabilistic indices used include LOLP, LOLE etc. These are calculated for a Composite Transmission and Generation reliability index. On the whole, there are no differing criteria used for different voltage levels and substations. They use the same basic criteria, but each have different standards of performance.

American Electric Power (AEP)

There are eight operating utilities within the American Electric Power System. Planning for all facilities other than distribution is handled by the AEP Service Corporation.

The AEP uses a combination of contingency planning and probabilistic analysis for EHV (i.e. 345 kV and up) planning. For other voltages, the approach is primarily probabilistic. Both single and double outage contingencies are used in transmission planning. The company has developed its own risk analysis for probabilistic analysis. Reliability indices are used both for the final consumer network and bulk supply points on the network.

BELGIUM

Belgium is looking at the development of integrated generation/transmission planning. Deterministic methods will be retained with complementary use of probabilistic techniques. The introduction of large nuclear units has led to the use of a probabilistic representation of nuclear unit refuelling periods.

UEBERLANDWERK UNTERFRANKEN

This West German utility uses the N-1 criterion in deterministic reliability indices. Single outage contingency is used. Differing criteria are used for different voltage levels:

- 110 kV: N-1 criterion (a line can be down without supply failing)
- 20 kV: N-1 criterion is used only for parallel feeder lines

The reliability indices are used only for bulk supply points on the network.

No probabilistic reliability indices are used.

RWE ENERGIE

RWE Energie, with headquarters in Essen, West Germany, operates the following criteria for its transmission and distribution networks:

Transmission Network

In general the N-1 principle is used (active reserve)

1. for 380/220 kV interconnection network:
   a. Single fault (circuit): restoration of N-1 security by changing the generation schedules;
   b. Busbar fault: only a regional limited disturbance accepted; and
   c. Fault of a double circuit line: no extension to a major disturbance accepted

2. 110 kV:
   a. In urban cable networks: N-2 principle;
   b. Busbar fault: no service interruption in the whole regional 110 kV network accepted (if achievable with a justifiable expense);
   c. Fault of a double-circuit line: no total service interruption for a prolonged time in an extended region accepted; and
   d. Transformer fault: switchable reserve (transformer between 110 kV and medium voltage)

Distribution Network

1. Medium Voltage:
   a. In principle, reserve switchable after fault location, restoration of supply normally within one hour.

2. Low voltage/Supply point:
   a. No N-1 security; and
   b. In case of disturbances: repair or provisional arrangements, restoration of supply within several hours.

TIROLERWASSERKRAFTWERKE

This Austrian utility uses the N-1 deterministic criterion in transmission reliability. No probabilistic indices are used in transmission reliability planning. Judgement is used in determining whether or not there should be differing criteria for different voltage levels and substations; this is decided on an individual basis depending on the importance of the supply areas.

The utility is at present undertaking a 'Network Information System' project. This will consider the integration of reliability indices for planning purposes. This is at present under discussion.

VATTENFALL TRANSMISSION

This Swedish company uses the NORDEL design criteria in determining reliability planning. The NORDEL countries (Denmark, Finland, Norway and Sweden) have decided to adopt common reliability criteria and to plan their interconnected network as a single system. Deterministic criteria are used as a base. The consequences of severe outages are analysed. Measures are taken when economically motivated. The analysis is confined to 400 kV and 220 kV lines. Bulk supply points on the network are examined.

LANDSVIRKJUN

Landsvirkjun (The National Power Company of Iceland), only uses deterministic reliability indices in its transmission planning. The criterion used is N-1. There are no differing criteria for different voltage levels and substations. Reliability indices are used for transmission planning both for the final consumer network and bulk supply points on the network.

(Note:)

The Japanese Power Companies apply only deterministic criteria for transmission system planning. The probabilistic approach like LOLP, LOLE, etc. is used for generation planning. Though application of probabilistic method was once studied for the transmission system, its necessity was not acknowledged.

For a trunk transmission system, actually there shall be no supply interruption nor generation restriction due to 'N-1' criteria. Even under the 'N-2' criteria, there shall be no serious supply interruption or system separation.

For a local system, some supply interruption is allowed but shall be restored in a short time when a 'N-1' fault occurred.

Particulars of practice are enclosed in Attachment of this clause.

A5.3.2.3 Summary of Survey Results

The results of responses to MEP's survey are summarised on Table A5.3.2 with particular reference to the extent to which the different utilities have adopted probabilistic as opposed to deterministic criteria.

A5.3.3 REVIEW OF CRITERIA BY CIGRE (1984)

In addition to the responses from the questionnaire sent out, the results of a review by CIGRE (WG 37.01) were also included into the reliability criteria for the planning of transmission and interconnection networks in 16 countries. This was undertaken in 1984 and although dated, is still of some relevance.

An examination of these results, which are reproduced as Table A5.3.3, shows the widespread use of the N-1 deterministic criteria in all countries, as at the mid-1980's.

A5.3.4 REVIEW OF OTHER INFORMATION

As major international consultants, Ewbank Preece (now Mott Ewbank Preece) has worked in a number of countries both on assignments associated with system planning as well as project implementation. MEP are consequently well placed to appreciate the planning procedures being followed in such countries. The particular countries which MEP have considered in this study are:

- The United Kingdom;
- Kenya;
- Western Malaysia;
- Thailand;
- Malta;
- States of Victoria and New South Wales (Australia);
- Libya;
- Egypt;
- Pakistan;
- Indonesia; and
- Bangladesh.

The majority of these countries adopt an N-1 deterministic criteria. Variations on this are for example in Kenya, Indonesia and Pakistan where the N-1 is not rigidly applied for financial reasons, and in the UK where N-2 is generally applied to power station connections.

Switchyard configurations are also varied in several countries depending whether a power station connection is involved, with higher security being designed in for such installations.

A5.3.5 ANALYSIS OF DATA

According to the data received to date, the predominant method used for transmission planning criteria is deterministic. Whereas there has been a movement away from deterministic indices to probabilistic indices for generation systems, the situation has been much more complicated in transmission system planning. Since transmission system configurations can be varied and their performance also determined by weather and other factors, the analysis of transmission performance can be complex.

Transmission system behaviours are varied, depending on the type of faults, duration of faults, and the condition of the system before and after clearance of faults. For example, a fault in a critical transmission line may lead to system instability causing generators to be out of synchronism with each other, resulting in system break-up. It is also conceivable that an overload condition could develop into a cascading sequence. Analysis of transmission system overloading and of busbar voltage violations has to be carried out using load flow analysis which is required to be performed for each fault that can be envisaged. This involves various combinations of transmission outages, and if a transmission system is large, the number of outage combinations can run to a large number requiring extensive computer time.

In some countries, composite indices are calculated from a reliability analysis which incorporates both generator and transmission failure probabilities. Again, calculation is not simple to perform because of the large number of modes of failure which can occur in a power system. Composite analysis is used in Canada, Italy and France. In the Canadian model the cost of the undelivered energy is converted into a reliability criterion which is then used in planning. The reliability indices used are undelivered energy and the duration and frequency of unsatisfied load. The French and Italian models examine a large number of generation and network outage cases using a random sampling method. In Italy, the composite index used is 0.1% expected energy not supplied.

Overall, there is no one uniform practice which is used for reliability planning. However, the most widespread criteria used would appear to be N-1 and N-2, depending on the number of network components involved in the loss. The N-1 criterion, the most widely used, consists of the simulated loss of one network component (i.e. line, transformer, reactive power compensation component, etc.). Less frequent use is made of N-2, which consists of the simulated loss of two system components, either two network components or one network and one generation component. Its use is generally restricted to major load centres and is used less frequently than N-1 criterion, since simultaneous failures are generally considered to be negligible.

Some countries and utilities simulate N-2 incidents by building on the base cases examined according to the N-1 criterion. Others examine cases of double incidents that would be most serious for their transmission systems, e.g. the loss of two main lines in cascade. In some utilities, even more serious incidents are considered, such as :

- loss of a set of busbars (and corresponding lines)
- multiple incidents or cascade tripping which may cause major disturbances.

Generally, utilities rely on operating manoeuvres to avoid system collapse as a result of cascade tripping, such as the introduction of reactive reserves, network switching etc.

Overall therefore, the consensus view is that probabilistic indices are advantageous in that they provide a superior basis for evaluation, but the main drawback is the lack of appropriate analytical tools for actually calculating them. Indeed the thrust in some utilities is to develop suitable computer programs for the purpose. These conclusions should however be considered in the context that there is also evidence that some utilities are starting to develop and use composite generation and transmission indices. These have the conceptual advantage that the supplies to consumers ultimately rely on reliability in both the generation and transmission systems, and there is a degree of randomness in the timing of failures in each system.

A5.3.6 SURVEY OF NETWORK PERFORMANCE

During the course of the survey, a copy of a new CIGRE paper on Bulk Electricity Supply Operational Performance Measurement prepared by Working group 05 of Study Committee 39 were provided. This report covers a survey carried out on the operational performance of 198 utilities.

Data was presented in the form of disturbances per year, and the results were categorised by size of utility, its location within an interconnected system, and the nature of system limits (thermal or stability/voltage limits). Disturbances were also categorised by severity :

⇒ Degree 1 - from 1 to 9 system minutes

⇒ Degree 2 - from 10 to 99 system minutes

⇒ Degree 3 - from 100 to 999 system minutes

It was found that on average the frequencies with which a utility suffers the different degrees of disturbance was :

⇒ Degree 1 - 2.5 years
⇒ Degree 2 - 8.8 years
⇒ Degree 3 - 83.3 years.

The general conclusion based on system characteristics were that :

- Thermally limited systems experience less disturbances than stability limited systems being located at the centre of an interconnected system gave rise to less disturbances were not generally related to system size.
- The survey reported on system wide or bulk performance, although there is a suggestion that further work may be done on load point performance.

A5.4 CALCULATION OF RELIABILITY INDICES

A5.4.1 INTRODUCTION

The review of present utility transmission reliability planning practice in the preceding section has highlighted the advantages of probabilistic based criteria, but has indicated that their widespread adoption is being hampered by computational constraints. For any criteria to be successfully applied, it is necessary for the planner to be able to both predict system behaviour, as well as to monitor it.

This section of the report outlines the methodologies for undertaking these computations and reviews some existing models.

A5.4.2 DETERMINISTIC CRITERIA

Deterministic criteria are applied in a framework which desires the system response to fall within prescribed limits relative to permissible ranges of voltage and frequency, permissible limits on component loadings and maintenance of synchronism. Although deterministic in nature, there is nevertheless an underlying consideration of the relative likelihood of disturbances and their consequences.

In practice, an exhaustive search of the implications of all contingencies is prohibitively time consuming. Therefore, deterministic criteria are derived by examining a pre-defined number of constraining events to check the soundness of the transmission system. Based on the operator's experience these situations represent the critical events of the system.

The underlying hypothesis is that if the system function can be assured for these critical cases, the same should be true in all other more favourable cases. Although some differences in practice have been noted, the most widespread deterministic criteria can be grouped in two classes referred to as N-1 and N-2 conditions, according to the number of components involved in the event.

The N-1 criterion, the most widely used in practice, consists of simulating the loss of one network component. Few of the countries adopting this criterion for transmission planning, take into account generation outages as one of the contingency events.

The N-2 criterion consists of the simulated loss of two system components. The use of this criterion is not as widely used as the N-1 because simultaneous failures are generally considered unlikely. The underlying idea is that two items would have to trip in the same region during a critical operating situation such as peak load period (the time duration of which is relatively short), for the double failure to have serious consequences. The likelihood of such an incident to occur is thought to be very small.

The general procedure in calculating the indices is first to select one or several base cases considering system loading and generation despatch conditions. Operator experience is important in ensuring that critical conditions are included. Each base case is then subjected to the predefined outage conditions (the N-1 or N-2 conditions).

Load flows are then calculated for each case to determine the extent to which the system can withstand the outages. Key factors to monitor are line flows and busbar voltages. Depending on the precise criteria adopted, the planner will either be seeking to ensure that no violations occur under the outages studied, or else any violations are aggregated into system or point load indices.

The advantages of deterministic criteria can be summarised as follows:

- conceptual clarity;
- limited number of cases to be examined; and
- comparatively simple analytical tools may be used, e.g. ac load flow which provides a detailed and precise description of system performance.

The limitation of the deterministic approach is that one is explicitly investigating the initial system problems for a few contingencies which are selected based on a mixture of the judgement and the experience of the planner/operator. Hence there is always a risk of omitting some cases, a risk that is ever-increasing as the nature of the critical cases can change in time in subtle ways which are sometimes barely perceptible. Furthermore, this criteria has the disadvantage of failing to take account of the probability of occurrence of these events and the weight of their effects.

Generation planners have accepted that the concept of random phenomena can be handled in a probabilistic manner and computational algorithms have been relatively easy to develop and implement. Direct analytical techniques can be used and the general trend for planning generating systems is now heading away from deterministic to probabilistic methods.

On the other hand, for transmission systems the implementation of probabilistic methods is much more complicated. Firstly, the problem has a spatial dimension, and the fundamental laws of electric circuits must be satisfied. Secondly, despite the efforts of researchers and analysts, recourse to probability indices for the reliability evaluation of large transmission systems still calls for the implementation of sophisticated models, powerful computer programs and the associated hardware.

A5.4.3 PROBABILISTIC CRITERIA

A5.4.3.1 General Considerations

The main reasons that probabilistic methods have not been widely used in the past therefore include :

- Shortage of data,
- Limitations of computational resources,
- Lack of realistic reliability techniques,

- Aversion to the use of probabilistic techniques, and
- Misunderstanding of the significance of probabilistic criteria and risk indices.

The availability of suitable data on transmission system component reliability remains a difficult problem. Although many utilities now have reliability data bases, these data cannot readily be assumed to be valid in other utilities as geographical, ambient, design and operational circumstances may differ. Records for certain types of equipment may therefore only be available for a comparatively short operational period.

Computing facilities on the other hand have been greatly enhanced and many engineers now have a working understanding of probabilistic techniques.

There are two distinct philosophical approaches to transmission reliability evaluation; the Monte Carlo approach and the state enumeration or selective analysis of outage events.

The Monte Carlo simulation methods estimate the reliability indices by simulating the actual process and random behaviour of the overall system as well as its components. Meanwhile, the state enumeration technique represents the system by simplified mathematical models and evaluates the reliability indices using mathematical solutions.

Each approach has its advantages and disadvantages. Due to the large amount of computing time required by the Monte Carlo simulations it is not generally used if alternative analytical methods are available. However, in theory, the Monte Carlo approach can include any system process or effect which would otherwise have to be approximated.

The two approaches can evaluate the same risk indices, however, a comparison of the numerical values obtained offers a better understanding of their limits. Salvaderi and Billinton presented a comparison between the two approaches in evaluating composite reliability for power systems and discussed the reasons giving rise to differences in numerical values and the impact of such differences on the adequacy of networks.

Salvaderi and Billinton; "A Comparison Between Two Fundamentally Different Approaches to Composite System Reliability Evaluation"; IEEE PAS Vol. 104, No. 12, December 1985.

A5.4.3.2 The Monte Carlo Approach

This method consists of randomly selecting the disruptive event and the state of the load, and subsequently simulating the effects on the system. The basic approach can be applied to each hour of the year in chronological order or the hours of the study time can be considered at random. The random selection of system states and load is taken from their respective probability distributions. This procedure normally requires a statistic load model and a component failure model.

The simulation of the randomly selected conditions is done with the use of load flows, dispatch algorithms, and preselected operating policies. These results are utilised in the computation of appropriate reliability indices.

The key issues in this approach are the fact that the number of disruptive events must be large enough to adequately capture all possibilities of adverse effects on the system, and that the analysis of the events of a specific disruptive event must be as close to the real world as possible and as efficient.

The Monte Carlo approach has several advantages and disadvantages. The random selection of disruptive events and subsequent analysis of the system performance results in many unnecessary simulations since most of them will be problem free. However, to obtain meaningful results, it is imperative that a sufficiently large number of problematic system conditions are captured and simulated.

This implies that the Monte Carlo method calls for the expenditure of considerable computing time in order to obtain sufficient confidence in the results.

On the other hand, the method allows the analysis of complex systems without forcing the system model to become unrealistic. In addition, it offers the planning engineer a synthesis of the final results and a detailed description of the events that caused these results.

A5.4.3.3 The State Enumeration Approach

State enumeration or the selective analysis of outage events recognises the fact that the majority of system outages do not cause adverse effects on system reliability. This approach therefore, consists of the systematic selection and evaluation of disturbances, the classification of each disturbance according to failure criteria and the accumulation of reliability indices.

Selective analysis or contingency enumeration techniques are structured so as to minimise the number of events that need to be analysed. This is achieved by testing, to the extent possible, only those disturbances which are sufficiently severe and frequent to have an impact on the indices to be quantified. Tests may be carried out for example by using algorithms which review the result from the first iteration of the load flow calculation for each contingency and discarding cases where the results apparently show no system performance criteria being violated.

In some respects the technique is similar to the process described for deterministic index computation in that a number of base cases are selected and subjected to a series of incidents, the results then being examined to establish the system's ability to withstand such events from the point of view of power flows and voltage changes. Thus the outage events which may have adverse effects are identified and subsequently analysed to determine the effects. A key difference however is the inclusion of information on the frequency and/or duration of the outage events.

The constituent parts of this approach are:

- Contingency selection,
- Network solution,
- Corrective action, and
- Accumulation of reliability indices.

A5.4.3.4 Contingency Selection

The first step is normally to define the types of events which will be studied. The selection of the type of event usually depends on the analytical technique adopted.

Contingency selection involves the determination of the most likely outage events and a procedure for preselecting the most severe of these events for testing.

Since most transmission line systems are designed to the N-1 criteria, i.e. to withstand the loss of a single major component, the contingency selection is generally concerned with multiple outages, be it independent overlapping outages or other dependent multiple outages.

Dependent multiple forced outages involve multiple components failure in a local area and are almost always severe enough to warrant testing. On the other hand, independent overlapping outages, or forced outages overlapping scheduled outages are severe only if the various components out have an adverse impact on the same system problem.

The structure of a power system is such that for each multiple outage of the latter type, there may be a very large number of other outages that have no adverse effect. Therefore, while most dependent multiple outages may all have to be tested, there is a need for screening methods to identify the independent overlapping outages that need to be tested.

A5.4.3.5 Network Solution

The selection of the method chosen for solving the power system equations is critical to the reliability evaluation procedure since both the accuracy and the interpretation of the index are dependent on the network solution.

Strictly speaking, the network equations are a set of simultaneous, complex, non-linear equations driven by the values of generation, load and voltage at the different nodes around the network. Since these bus quantities vary continuously with time, the network results are also time varying.

Detailed power system models are rarely used for reliability calculations. The major deterrents to detailed modelling are the excessive computer time required, the lack of meaningful data and the requirement for human judgement to interpret the results and make the correct decision for planning or operational purposes.

Therefore, in reliability index computations, speed of network solutions is of essence; more so than solution accuracy. If the system problems to be detected are restricted to line overloads and network separation, dc load flow techniques are considered satisfactory. Alternatively, if bus voltages need to be computed, approximate linearised solutions or fast decoupled load flow solution methods could be applied.

A5.4.3.6 Corrective Action

Corrective action may be taken automatically by the system or put in effect by the operator. In practice automatic corrective action is presently restricted to exceptional system situations which are of particular concern, and most corrective actions which need to be accounted for in reliability index computations involve operator initiated actions.

A number of utilities are reluctant to include the possible benefits arising from remedial operator actions in reliability calculations. This is partly due to the planning and system design philosophy adopted, and partly due to the large number of arbitrary assumptions that have to be made in defining the characteristics of the corrective action.

One practical assumption is to ignore the time factor represented by the time; a system problem occurs and the time the appropriate corrective action is identified and executed, and apply maximum corrective action available. In this case the reliability indices computed would be representative of the post-disturbance conditions, but would not reflect the possible more severe system conditions existing during the time of corrective action. It is clear that such indices would be optimistic, while indices based on the initial system problems would be pessimistic.

When remedial actions have been executed, any one of a number of mathematical optimisation techniques can be applied to determine the effectiveness of these actions. For example, linear programming can be used to reschedule generation and minimise load curtailment.

A5.4.3.7 Accumulation of Reliability Indices

Event probabilities and frequencies can be calculated and accumulated into system indices or bus indices. The indices formed by considering all tested contingencies that are logged as failures according to a specified failure criterion constitute a lower bound on the reliability index. These lower bound indices would have a higher numerical value if additional, generally more severe and less likely contingencies were tested.

The reliability index appears therefore, to be a function of the number of contingencies tested. Since this is somewhat unsatisfactory, it is of interest to compute an upper bound of the indices as well, thus bracketing the indices that would be derived if all contingencies were tested.

Such an upper bound can be obtained by considering all contingencies tested that do not fail as well as all contingencies not tested but presumed not to cause system failure based on the pre-screening of contingencies.

The accumulation of probability and frequency indices represents a major undertaking where the main challenge is to perform the accumulation in such a way that events considered are mutually exclusive, such that "double counting" is avoided.

A5.4.4 EFFECTIVENESS ANALYSIS

Utilities, and in particular privately owed ones, are having to face the dilemma of trading off their customer's demand for reliability with their own interest in achieving an adequate return on their investments. Therefore, reliability of supply is being considered more and more as a commodity that can be priced and marketed.

The effectiveness analysis approach is based on economic comparison between planning alternatives, where there is no specific reliability level to be met. Each alternative is optimised by minimising its overall costs which comprise capital expenditure, annual operating costs and the cost of risk of failure. Thus the least cost plan incorporates the optimum reliability level for the network.

It should be noted that attempts to evaluate the economic consequence of load interruptions and curtailments have shown that the cost assigned by the different consumers varies greatly and depends on considerations that are extremely subjective. Moreover, account must be taken of the fact that the consequences of system failure include many that can not be evaluated in economic terms. These issues are considered further in Section A5.5 of this report.

A5.4.5 COMPUTER MODELS FOR POWER SYSTEM RELIABILITY ASSESSMENT

This Clause presents a review to some of the general purpose digital computer models described in the literature.

1. Both ENEL, the Italian utility, and EDF, the French utility, have developed Monte Carlo simulation models. ENEL's has been referred to as SICRET whilst EDF's are known as MEXICO and ANASEC. CEPEL in Brazil are believed to follow the general principles identified earlier in this section.

   SICRET is a composite generation and transmission reliability model and the Monte Carlo simulation is carried out for a representatively wide number of time intervals, or sampled hours. For each hour a possible system configuration is randomly determined based on the availability probability distribution of each system component and from the anticipated loading. A dc load flow is then run and the process repeated for different contingencies. Load shedding and generation rescheduling are incorporated.

   EDF's MEXICO program is very similar in concept although use is made of the load duration curve to average out the results over a year.

2. The University of Saskatchewan is home of some key work in the enumeration field. The team under Professor Billinton have published numerous papers and are continually evolving more sophisticated algorithms taking into account a range of effects such as :

   - station originated outages,
   - common mode outages,
   - weather effects,
   - load forecast uncertainty.

   Their model is a composite generation and transmission reliability program referred to as COMREL, and is under continual development, as well as being applied to practical systems. Billinton's work has also included composite generation and transmission reliability assessment and models have been built which calculate a number of different indices.

   In particular, Billinton and Weynan described some of the basic modelling concepts used in a computer program MECORE developed at the University of Saskatchewan for composite generation and transmission reliability assessment.

   A novel characteristic of the MECORE model is that it recognises the effects of regional weather differences including situations in which transmission lines traverse several geographical regions undergoing different weather conditions.

   Impacts of bus load uncertainty and correlation can be simulated and practical load curtailment philosophies have been incorporated in order to obtain realistic bus indices.

   This was described by them in their paper "Composite System Reliability Assessment Using a Monte Carlo Approach" which was presented at the PMAPS third Conference in London in July 1991.

   COMREL is able to handle up to 4 generation units out at one time and up to three transmission lines. In combination the options are :

Lines	Units
1	1
2	1
1	2

3. EPRI in the USA have sponsored a considerable amount of work in this area. Perhaps the most promising work was carried out by Power Technologies, Inc. (PTI) of Schenectady, New York under EPRI contract 1530-1. Their final report was published in July 1982 and includes a description of the SYREL program which is a usable contingency enumeration based program.

   At the time PTI acknowledged their use of some existing techniques for the automatic ranking of contingencies based on circuit overloads, dc load flow, decoupled ac load flow, linear programming algorithm to redespatch generation, adjust phase-shifters to relieve overloads, and overload cascading simulation. They also developed some new modelling techniques including :

   - automatic contingency ranking for low voltage problems,
   - a method to prevent the decoupled ac load flow from diverging so that voltage problems could be categorised by location and severity including voltage collapse,
   - efficient enumeration scheme for multi-level outages,
   - improved techniques for computing the upper and lower bounds of reliability indices to determine the depth of contingencies required,
   - procedures for computing reliability indices valid over a period such as a week or a year accounting for variations in load and other system conditions.

   PTI's work has developed to the stage that commercial models are now available. These are TPLAN and MAREL. TPLAN is a composite generation and transmission single area reliability program which incorporates a considerable degree of detail, whilst MAREL is a multi-area model designed for generation reliability analysis. TPLAN allows up to 3 simultaneous line or unit outages in a similar scope to the COMREL program.

4. *Horne & Schoenberger; "TRAP": An Innovative Approach to Analysing the Reliability of Transmission Plans"; IEEE. PAS. Vol. 101 No. 1 January 1982.*

   Horne & Schoenberger presented a program for calculation of transmission reliability measures using the load supply capability (LSC) of a network as the basis for determining system failure. The Transmission Reliability Analysis Program (TRAP) provides the planners with information on the capacity of the system and the probability that transmission events will result in loss of load. The indices calculated provide a quantitative measure of the impact of new line additions, allowing alternative plans to be compared numerically or tested for acceptability.

5. *Noferi, Paris and Salvaderi; "Monte Carlo Methods for Power System Reliability Evaluations in Transmission and Generation Planning"; 1975 Proceedings, Annual Reliability and Maintainability Symposium.*

   Noferi, Paris and Slavaderi selected a simulation algorithm to study and assess the expected performance of planned outage schedules. To accommodate very large systems, the simulation was restricted to modelling maintenance outages, extensions to planned outages and deviation of load from forecast. Forced outages risk was determined by analytical means incorporated within the computer program.

At the time of publishing the work, operating experience with the programme was insufficient to draw firm conclusions regarding the effectiveness of the method. However, preliminary studies with the program indicated satisfactory computational efficiency and flexibility sufficient to provide adequate representation of the scheduling situations encountered with maintenance outage.

6. *Mehopoulos, Bakirtizis, Kouacs and Beck; "Bulk Power System Reliability Assessment - Experience with the RECS Program"; IEEE Transactions on Power Systems, Vol. PWRS-1, No.3, August 1986.*

   Meliopoulos et al, described the philosophy, objectives and experience in bulk power system reliability assessment using the RECS program. RECS stands for reliability evaluation via Contingency Simulation. It is a modular and expandable program for assessing the reliability of the composite power system. The paper describes the concepts, models, computational techniques and data requirement by the program. Emphasis has been placed on the experience gained using the program for reliability studies of the Southern Company System.

   Sub program RECS-FEA (failure effect analysis) processes the data and enumerates and analyses contingencies. Subprogram RECS-SP (service program) computes system reliability indices and branch and bus summaries.

7. Electricidade de Portugal (EDP) have a model referred to as ZANZIBAR. It is a composite generation and transmission model using a Monte Carlo approach. Both hydro and thermal stations are included and three different hydrological conditions are allowed for. Generation scheduling and rescheduling is based on minimising generation costs and network losses. As with other Monte Carlo models, a dc load flow technique is used to limit the computational time compared to that which would be needed if a full ac load flow calculation were carried out.

A5.4.6 COMPARISON OF MODELS

As part of the 1991 CIGRE Symposium on Electric Power Systems Reliability held in Montreal, an exercise was reported on in which eight organisations provided composite generation and transmission reliability models were used to analyse the New Brunswick Power Corporation System.

These organisations, with their models were :

GROUP	COUNTRY	MODEL	METHODOLOGY
ENEL	Italy	SICRET	MC
EDP	Portugal	ZANZIBAR	MC
Un of Sask	Canada	COMREL	SE
		MECORE	MC
NGC	UK	ESCORT	MC
UMIST	UK	COMPASS	MC
		RELACS	SE
EDF	France	MEXICO	MC
PTI	USA	MAREL/TPLAN	SE
NB Power	Canada	NB HL1	SE/MC

(note : MC - Monte Carlo, SE - State Enumeration)

The models were run for generation outages only, and then for generation and transmission outages. The models all gave reasonably consistent results for the basic measure of system reliability - Expected Energy Not Served. All the models identified the same facilities as being the most critical in the basic system and showed the reliability improvements gained through reinforcement.

Generation reliability calculations were more consistent than composite reliability calculations. This difference was ascribed to differences in modelling techniques, and in particular the sampling of the periods studied.

The study drew no specific conclusions about the merits of the different models and modelling techniques. Rather it confirmed that techniques are available which are workable, and that the results should be treated for their relative indication of reliability rather than absolute values.

A number of areas were identified where further work is required. These related specifically to the capability to handle phase shifting transformers, contract sales, consistent approaches to load curtailment, voltage considerations, security considerations and generation dispatch implications, weather effects, and common mode failures. The lack of standard output indices was also recognised as a problem.

A5.4.7 SUMMARY

Our studies have shown that a significant amount of research work has been carried out to extend the range of computational tools available to transmission planners. These address not only the computation of deterministic, but also probabilistic indices. This work has seen limited application in utilities, and it is almost certain that the work that has been done will require developing and tailoring to the needs of particular organisations.

In addition to the need to further develop software, the collection of appropriate data on component outage rates is essential if probabilistic techniques are to be successfully applied.

A5.5 SETTING RELIABILITY CRITERIA

A5.5.1 INTRODUCTION

Reliability standards for electricity generation and transmission in most countries have been largely based on previous engineering experience and rules of thumb. With the development of increasingly sophisticated computer programmes, however, it is now possible to create more sophisticated reliability standards for both generation and, to a lesser extent, transmission reliability.

In selecting an appropriate planning criteria, a number of factors must be taken into account including:

- what is the objective of the criteria,
- can the criteria be calculated for planning purposes,
- is suitable data available for its calculation,
- are there any constraints influencing the degree of reliability (e.g. financial, economic, etc.)?

Two aspects have to be considered in the selection - the type of index, and its value. The type of index is influenced by the objectives and the practicality considerations. The value is more influenced by economic and financial considerations.

Increasing the reliability costs money, and it is therefore necessary that this expenditure is justified by the planners. A number of approaches are possible:

- follow existing practice,
- determine level of reliability where additional investment gives maximal additional improvement,
- determine level of reliability which is optimised with respect to the consumers valuation of unserved energy,
- select a value based on international practice.

The first of these is safe in that presumably the majority of consumers are satisfied, but there may be overinvestment.

The third one follows the practice increasingly being adopted by generation planners, but suffers from the need to estimate the value of unserved energy, which theoretically will vary between load point with mix of consumer type.

The second approach is a compromise between the two. It has the advantage of avoiding the need to value unserved energy, but its success relies on the cost/reliability function having a form which enable the point of diminishing return to be established.

The fourth approach is not necessarily sound because transmission systems vary between utilities, and particularly for probabilistic indices, there is very little precedent to go on.

In the next section we consider in more detail the question of valuing reliability.

A5.5.2 VALUING RELIABILITY

A5.5.2.1 Introduction

Reliability standards for electricity generation and transmission in most countries have been largely based on previous engineering experience and rules of thumb. With the development of increasingly sophisticated computer programmes, however, it is now possible to create more sophisticated reliability standards for both generation and, to a lesser extent, transmission reliability.

As with any other aspect of planning, the need to evaluate transmission reliability in quantitative terms is essential. The basis for comparing reliability planning alternatives should ideally be one which does not assume any fixed reliability level but, rather, makes economic comparisons among possible alternatives. Each alternative would be optimised by minimising its total cost i.e. capital, running and risk costs. The reliability level of each alternative would be its optimal level and alternatives could be compared on the basis of their respective overall cost.There are, however, problems which will be encountered in evaluating the economic cost to consumers of outages, since the cost in terms of both lost economic output and convenience can vary greatly from one sector or consumer to another. Moreover, there is the problem, particularly for private electricity utilities, of trading off their customers' demand for reliability against making an adequate return on investments.

Reliability is increasingly seen as a product which can be differentiated, priced and marketed. The quality of supply can thus be set at a level at which an incremental investment in distribution just equals the incremental outage costs to consumers and the economy attributable to the investment, measured as the potential cost to consumers and the economy of loss of supply at that reliability standard.

Within any transmission system, it should be possible to:

- identify costs associated with those parts of the system whose sole function is to secure supplies against failure,
- calculate the outage cost savings to consumers and the economy by safeguarding supplies,
- broadly determine the optimum quality of supply reliability.

A5.5.2.2 Identification of Costs of Transmission Design and Planning

The first approaches to system design and planning were intuitive and relied heavily on the experience of the engineers involved in the planning. In contrast, the more advanced mathematical methods currently used by some utility companies rely on optimisation models. The aim of the exercise is to minimise an objective function, usually the present discounted value of system costs, subject to constraints, such as meeting the load and reliability targets, and not violating technical and operating requirements.

Transmission planning typically involves the solution of a dynamic network-type problem, in which the basic objective is to select, at least-cost, the type, timing and location of line additions that would connect the various sources or generating stations to the different load centres. In addition, the requirements imposed by the load, reliability level, technical and other constraints must be satisfied.

In the conventional approach to transmission system planning, forecast loads are imposed on the existing distribution system at specific future times, and the network is systematically strengthened to meet the loads adequately. Meeting consumer demand within acceptable voltage limits would determine the location of new substations and primary feeders and the upgrading of existing ones. Loading under normal and emergency (or fault) conditions, as well as peak and off-peak periods is also usually examined.

When the model of the physical system has been identified, the supply costs must be determined and valued. Two methods can be used for this:

- the financial viewpoint of a private electric power utility is adopted. This is the method normally used in the USA. The items in the costing exercise are based primarily on accounting concepts. They include physical assets, services, depreciation, interest and taxes that may be affected by regulatory requirements. The values placed on them are the private financial costs occurred by the utility. These include the purchase cost of assets and services, financing charges, and the cost of raising capital based on the debt-equity mix.
- the second method is basically economic and more appropriate for the national economy as a whole. Goods and services used as physical inputs to the electric power system are considered scarce economic resources and valued accordingly.

The process of system planning is often complicated by uncertainties in demand forecasts, errors in cost estimates, construction delays, etc. In this case, the approach is to build up different scenarios to provide a range of alternative choices.

A5.5.2.3 Estimation of Outage Costs

The term 'outage costs' is used to encompass all the economic costs suffered by society when the supply of electricity is not perfectly reliable or when it is not expected to be perfectly reliable. Establishing a value for reliability is difficult to achieve. Direct evaluation is not feasible and the approach which is normally used is to evaluate the impacts and financial losses resulting from supply interruptions. The costs of these interruptions are not equal to the value of reliability but, rather, a surrogate for it.

Outage costs can be broadly classified into direct and indirect costs. Direct costs are those which occur as a direct result of supply outages and include such impacts as lost industrial production, ruined or spoiled raw materials, the loss of personal leisure time, and possible injury or loss of life. Indirect costs could include an increase in robbery and other crime during outages, a loss of business to competitors not affected by outages or a relocation of business if outages are frequent.

The main problem for the estimation of outage costs is, therefore, the quantification of such outage losses. As an initial step, it is necessary to understand the nature and variety of economic and social impacts of outages on customers, i.e. whether the outages are short or long-term, localised or widespread, direct or indirect, economic or social.

Various methods have been used in recent years in an attempt to quantify the costs of outages.

A5.5.2.4 Financial Valuation

For an individual, private organisation, the use of economic analysis to measure the social and industrial costs may not be entirely appropriate. The main function of a private electricity utility or distribution company is to maximise its profits while satisfying customers of a regular and reliable supply of electricity. From the individual electricity company's point of view, therefore, the cost of outages will be in terms of lost income from energy not served. The methodology for a cost-benefit analysis will basically be the same as for the economic analysis. The main difference will be in the estimation of outage costs. These will not be the value of economic output lost, but rather the revenue lost to the utility as a result of outages incurred. Supply costs will be their actual financial value rather than adjusted to reflect scarce resources, as would be used in economic analysis.

By discounting at an appropriate financial rate both the costs of increasing reliability and assessing benefits in terms of revenue from energy supplied in the absence of outages, it is possible to determine the level at which the cost of increased reliability just equals the additional revenue gained from no or fewer outages.

A5.5.3 THE COST OF INCREASING SYSTEM RELIABILITY

An alternative approach to estimating a value for supply reliability, which may in practice vary from node to node on the system, is to consider the reliability/investment cost curve. As expenditure is increased to further reinforce a network, there will be diminishing advantages in terms of measurable improvements in reliability.

A curve may be plotted indicating the incremental improvement in reliability as a function of the incremental investment costs. The precise shape of this curve will be system specific, but chances are that there will be a turning point at some identifiable level of reliability which could be considered to be a pragmatic level to adopt for planning purposes. This turning point will be when the additional investment has minimal impact on the level of reliability.

If the cost function operates as described, there may be merit in considering this approach to setting the criteria as it avoids the need to make the estimates of reliability value. Whether the value deduced from the cost curve is acceptable to the utility may largely be a function of the financial cost of achieving the indicated level. It has to be recognised that this consideration may in any case apply for the methodology based on valuing unserved energy.

A5.5.4 DATA AVAILABILITY AND INDEX SELECTION

It is noted that an important constraint on the wider application of probabilistic indices has been the availability of suitable outage data. The scope of fault reporting schemes varies between utilities and is historically bound into the original motives for establishing a fault reporting scheme. For planning purposes data has to both collected and analysed.

Ideally data should be available covering both the **failure** process and the **restoration** process, and be held under the following classifications:

- rate or frequency of occurrence of an event; this is clearly the frequency with which failure events occur and requires agreement on the scope of the type of event to be reported as well as the actual collection of data.
- average duration of a state; this provides information on how long a particular failure event lasts on average and is subject to the same constraints as frequency oata.
- probability of a command failure; this covers the collection of data on the extent to which failures occur in, for example, breaker operation. Defining the scope of this is difficult and problems also arise in ensuring consistency between the number of failures and the number of commands (e.g. when a command is issued twice and the equipment responds the second time).

An area where practices differ between utilities is in the method of **classification**. Classification should be set in terms of the operational function and/or exposure conditions. Generally at least three classes are considered :

- Components of varying length,(lines and cables)
- static components, (all other items except switchgear)
- switching components.

Differences exist between utilities in the scoping of the components. In some reporting schemes particular data for a component may in fact include a number of sub-components. For example some users reporting on a transformer may include not only the transformer itself but the associated protection and switchgear. These approaches to whether data is collected in terms of units (groups of components) or components are distinct and not easily reconcilable. It is reported for example that in the UK and Canada the component approach is used, whilst in some US utilities the unit approach is preferred.

Data on failures can encompass a wide range of issues relating to **failure** modes covering:

- short circuit failures (permanent, temporary, or transient),
- open-circuit failures,
- switching failures,
- multiple failures, including common mode effects,

- environmental effects (e.g. weather),
- planned outages,
- population and exposure data.

Restoration can consist of either restoring supplies to the consumer or restoring a failed component to its working state, and these may involve quite different processes even though the end result for the consumer may appear the same. Restoration may be therefore categorised as a number of different types of event :

- repair
- replacement
- manual switching
- automatic reclose

Clearly the adoption of any new planning indices must reflect the scope of data presently available. A reasonable statistical base of operational history is required to enable the data to be meaningfully interpreted. A phasing in period can be envisaged during which more comprehensive data is collected, if that is considered desirable, but final selection of future planning criteria cannot be made in isolation from the scope of data.

CEB possess a large amount of well documented records for system faults for several years, unfortunately, these events are recorded by hand. A database has been recently created by which system faults can be stored on computer. We have studied the structure of this database and recommended some modification. These are discussed in the Clause 5.6 of the main report.

ATTACHMENT

POWER SUPPLY RELIABILITY CRITERIA IN JAPAN

1. Basic Ideas

Taking into account actual transmission facilities, social impacts of supply interruption, conditions of their fault and its restoration, etc., utmost effort shall be exerted to secure the following criteria of supply reliability:

(1) Against normally conceived faults, reliability of entire power facilities from power sources to distribution facilities shall be planned to be coordinated taking into account impacts of supply interruption, scale, duration and probability.

(2) Though probability of occurrence is low, the transmission system shall be planned to avoid collapse of the entire power system due to a very severe fault.

(3) Against facility faults caused by natural disasters such as earthquake, typhoon, flood, etc., the power facilities shall be designed to restore at earliest possible time from technical and economical viewpoint.

2. Assumed Maximum Power for Planning

The maximum demand to be taken into account in the fault analysis is the average of the largest three day's peak loads (H_3).

3. Planning of Facilities

Criteria for design of individual facilities to attain the power supply reliability are mentioned below.

(1) Generation

The target reliability criteria shall be attained even under expected fault of largest power sources, variation of load, output variation due to availability of water, etc.

(2) Major Transmission Network

(a) Against a single facility fault (one generator or transformer, or one circuit of line, not including bus fault):

1. There shall be no supply interruption: Except for small scale interruption which can be restored in short time (within one minute) automatically.

2. There shall be no generation restriction on major generators: Except for the case of unit transmission system.

(b) Against double facility fault (simultaneous fault of two facilities, including fault of one bus), there shall be no serious supply interruption without separation of power sources and systems.

Though the system is separated to two parts, each system shall be able to be operated stably with minimum of supply interruption.

(3) Local Transmission Network

(a) In case of single facility fault, some supply interruption is granted but the supply shall be restored in a short time required for network changeover. Amount of supply interruption and restoration time are to be determined taking into account affected supply areas and local conditions.

1. Substation: In case of separation of one transformer, the average of the maximum three day's peak loads (H_3) shall not exceed the short-duration over-load capacity of the remaining transformers taking into account of connection changes of secondary transmission or distribution networks.

   Note: Short-term over-load capacity of transformer is:
   130% of rated capacity for ONAN and OFAF type
   120% of rated capacity for OFWF type

2. Transmission line: In case of shutdown of one circuit out of two circuits, the power flow on the remaining circuit(s) shall not exceed the short-duration capacity of the remaining circuit under the H_3 loading condition, taking into account of diverting of some of power to another line.

   Note: The short-time current capacity of transmission line is calculated based on the temperature limit of 100°C against 90°C for continuous service.

(b) For very important customers, available measures shall be taken to avoid supply interruption due to a single facility fault.

(c) Even when some facilities are out of service for maintenance and repair, the reliability criteria, (a) and (b) above, shall be tried to be maintained under a light load condition.

(4) Distribution Network

(a) For MV distribution system, the power supply to healthy sections except the fault sections of single facility fault shall be planned to be restored within a short time necessary for connection change of distribution network.

For LV consumers, there shall be considerations that supply interruptions can be restored within an earliest possible time.

(b) For very important customers, possible countermeasures shall be taken to avoid supply interruption as far as possible.

(c) Even when some facilities are out of service for maintenance and repair, the reliability criteria, (a) and (b) above, shall be tried to be maintained under a light load condition.

Table A5.3.1 Utilities Involved in MEP Survey

BRAZIL	Centrais Electricas Brasileiras
SWEDEN	Sydkraft Swedpower Statens Vattenfallsverk
AUSTRIA	Oberoesterreichische Kraftwerke
AUSTRALIA	State Commission of Western Australia SMEC (Snowy Mountains Electricity Corporation) Queensland Electricity Commission South East Queensland Electricity Board Capricornia
USA	New York State Electricity and Gas Consolidated Edison Company Baltimore Gas and Electricity Company Appalachian Electric Power Company Edison Electrical Institute Hawaiian Electricity Company Alaska Power
TAIWAN	Taiwan Power Company
CANADA	Manitoba Hydro British Columbia Hydro Canadian Electrical Association Ontario Hydro Hydro Quebec
JAPAN	Japan Electric Power Information Centre Chubu Electric Power Company Tohoku Electric Power Company Kansai Electric Power Company
NORWAY	Oslo Lysverker Energieforsyningens Informasjonstjeneste
PORTUGAL	Electricidade de Portugal
HONG KONG	Hong Kong Electricity Company China Light and Power Company
GERMANY	Bayernwerk Berliner Kraft und Licht Vereinigung Deutscher Elektrizitatswerke VEW Isar-Amparwerke Elektrizitatswerke Wesertal Lech-Elektrizitatswerke Uberlandwerk Unterfranken Rheinisch-Westfalisches Elektrizitatswerke
AUSTRIA	Tiroler Wasserkraftwerke Steierische Wasserkraft u. Elektrizitat Oberoesterreichische Kraftwerke
CHILE	Empresa Nacional de Electricidad

PAPUA NEW GUINEA	Papua New Guinea Electricity Commission
SWITZERLAND	Centralschweizerische Kraftwerke
ICELAND	Landsvirkjen Hanovirkjun Rafmagnoveitur
IRELAND	Electricity Supply Board
CYPRUS	Electricity Authority of Cyprus
ANTIGUA	Antigua Public Utilities Authority
BARBADOS	Caribbean Utilities Company
URUGUAY	Comision de Integracion Electrica Regional
SOUTH AFRICA	South Africa Electricity Supply Commission
MALAYSIA	Sarawak Electricity Supply Corporation
NETHERLANDS	Electricitiets Prod Maatschappij Oost Nederland Samenwerkende Electricitiets-Produktiebedrijven
FINLAND	Mussalon Hoyryvoima OY Imatran Voima Oy
FIJI	Fiji Electricity Authority

Table A5.3.2 Summary of Survey of Present Practice

UTILITY	TYPE OF CRITERIA USED	
	Deterministic	Probabilistic
B.C. Hydro	Yes	Yes (limited)
Manitoba Hydro	Yes	Yes (limited)
SECWA	Yes	Yes
QEC	Yes	No
SEQEB	Yes	No
Centrias Electricas Brasilieras	Yes	Yes
Sarawak Electricity Supply Corporation	Yes	Yes
Oslo Lysverker	Yes	No
Caribbean Utilities Company	Yes	No
Electricity Authority of Cyprus	Yes	No
Taiwan Power Company	Yes	No
NERC	Yes	Yes (some)
American Electric Power	Yes	Yes (some)
Ueberlandwerk Unterfranken	Yes	No
RWE Energie	Yes	No
Tiroler Wasserkraftwerke	Yes	No
Vatenfall Transmission	Yes	Yes (limited)
Landsvirjun	Yes	No

Table A5.3.3 Reliability criteria for the planning of the transmission and interconnection networks

Source: CIGRE SC. 37 - Oslo Meeting

	AUSTRALIA	BELGIUM	BRAZIL	CZECHOSLOVAKIA	FED. REP. OF GERMANY
Case examined and remarks	The criterion depends on the role played by the component	Maximum load and reduced load (85% of max.) at 300 kV	Maximum load and off-peak load No switching (load shedding, generation, network)	Division of network into sub-systems examined at different load levels and in different base conditions	All possible and realistic basic conditions Special cases: Long- duration maintenance and faults
N-1 criterion	1 N under the following conditions: - injection lines: coal units at max. gen. hydro at av. gen. - loads supplied: normal loads	1 N or 1 G	1 N	1 nN(including 1 C) or 1 G Note: power cut during repair can be accepted	1 N or 1 G
N-2 criterion	$1\ N + 1\ N^m$, under the following conditions: - injection lines: ave. gen. -interconnection: all loads - loads supplied: normal loads	$(1\ N \text{ or } 1\ G) + 1\ N^m$		2(N, C or G) Note: power cut during repair cannot be accepted	No
Loss of busbars Multiple incidents	No (rare and reduced loads; resolved by remote control and reactive reserves)	at 380 kV		In local studies	X
Examination: - of transient flows - of voltage limits - of network splitting and collapse	X	X X	X X	X X	X X

Captions: The loss of components is indicate by n E, where
n = number of components lost : 1 or 2
E = type of component: G = generator, N = network (L or T). L = Line or Cable'
T = transformer, C = reactive compensation

The index "m" denotes a component on scheduled outage

Table A5.3.3 (cont'd) Reliability criteria for the planning of the transmission and interconnection networks

Source: CIGRE SC. 37 - Oslo Meeting

	FINLAND	HUNGARY	IRELAND	JAPAN	NETHERLANDS
Case examined and remarks	Several load ant network configuration conditions	Maximum of peak loads	Winter peak and Autumn peak		- Max. & 90% load -Criterion according to function: a) Service continuity b)economic despatching c) use of reserve
N-1 criterion	1 N under the following conditions: - injection lines: coal units at max. gen. hydro at av. gen. - loads supplied: normal loads	1 N or 1 G	1 N or 1G	1 N or 1 G	1 N or 1 G, under the following conditions: Max. Loads: a) 1 (N or G)^{m} b) no maintenance 90% loads: a) 2 (N or G)^{m} b) 1 N^{m} Combined with (N-1) criterion
N-2 criterion	1 N + 1 N^{m}, under the following conditions: - injection lines: ave. gen. -interconnection: all loads - loads supplied: normal loads	2 N at nuclear plant		2 L for the main interconnection lines)	
Loss of busbars Multiple incidents	No (rare and reduced loads; resolved by remote control and reactive reserves)	No			
Examination: - of transient flows - of voltage limits - of network splitting and collapse	X	X X	X X	X X	X X

Captions: The loss of components is indicate by n E, where n = number of components lost : 1 or 2
E = type of component: G = generator, N = network (L or T). L = Line or Cable'
T = transformer, C = reactive compensation

The index "m" denotes a component on scheduled outage

Table A5.3.3 (cont'd) Reliability criteria for the planning of the transmission and interconnection networks

Source: CIGRE SC. 37 - Oslo Meeting

	NORWAY	ROMANIA	SOUTH AFRICA	SWEDEN	UNITED KINGDOM
Case examined and remarks	- Various generation and load situations - Criterion according to role in the network - Local criterion can be less strict	- division of network into sub-systems	- Several hypotheses on loads, generation and hydrology - Special criteria for lines linking power stations to the network	No load shedding	Examination of the network by zones according to load level
N-1 criterion	1 N or 1 G	1 N	1 N	1 N or 1 G	For area with load < 60 MW 1 N (fault or maintenance)
N-2 criterion		Loss of 2 circuits of a nuclear power plant	1 L + (1 L or 1 T)	X	For area with load > 60 MW 1 N + 1 N^m
Loss of busbars	X	X			
Multiple incidents				No	
Examination:					
- of transient flows	X	X	X	X	X
- of voltage limits	X		X	X	
- of network splitting and collapse	X				

Captions: The loss of components is indicate by n E, where n = number of components lost : 1 or 2

E = type of component: G = generator, N = network (L or T). L = Line or Cable'
T = transformer, C = reactive compensation

The index "m" denotes a component on scheduled outage