Year		From To	Item of T/L				Unit Price (US$x10³)		Construction Cost (US$x10³)			Remark
			Vg	C.C.T.	Route L.	Conductor	F.C.	L.C.	F.C.	L.C.	F.C.+L.C.	
21	Ⅲ	(Paiton, Krian) – Sukolilo π Incomer	500	2	20	Dove x 4	341.483	137.334	6,830	2,747	9,577	
22	"	Perak – Sukolilo 2nd Stage (From Ujung)	150	2	12.5	330mm²	92.523 x 1.1	80.398	356	210	566	3.5KM 4cct Tw
							59.161 x 1.1	46.531	325	233	558	4KM Existing
23	"	Kediri – Tulungagung	150	2	30.0	330mm²	53.295	35.318	1,599	1,060	2,659	
24	"	Lesti – Kepanjen P/S – Kepanjen s/s	70	2	10.0	300 MCM	29.214	10.791	292	108	400	
25	"	(Sukolilo, Kenjeran) – Simokerto π Incomer	150	2	3.5	330mm²	31.664	4.400	111	15	126	Existing Tw
26	"	(Semanbung, Sukolilo) – Ngiwo π Incomer	150	2	0.5	Twin 330mm²	99.283	57.600	50	29	79	
27	"	(Krian, Babatan) – Trosobo π Incomer	150	2	0.5	330mm²	59.161	46.531	30	23	53	
28	"	(Ponorogo, Pacitan) – Tegalombo Grindulu Branch	70	2	10,0	300 MCM	29.214	10.791	292	108	400	
29	"	Kebonagung – Sengkaling	150	2	15.0	330mm²	55.463 x 1.1	36.591	121	73	194	13. KM Existing
30	"	Krian – Kebonagung	150	2	75.0	Twin 330mm²	91.887	43.789	6,892	3,284	10,176	
31	"	Situbondo – Banyuwangi	150	2	86.0	330mm²	53.295	35.318	4,583	3,037	7,620	
32	"	(Bangil, Kebonagung) – Blimbing π Incomer	150	2	5.0	330mm²	55.463 x 1.1	36.591	277	183	460	
33	"	Karang Pilang – Ketintang	150	2	5.8	800mm²	574.000	11.000	3,329	638	3,967	Under Ground Cable
		Total 150kV, 70kV							18,257	9,001	27,258	
		Total EHV							6,830	2,747	9,577	
34	Ⅳ	Sukolilo – Sidosermo	150	2	4.5	800mm²	574.000 x 1.1	11.000	2,583	495	3,078	Under Ground Cable
35	"	Krian – Kedri 1st Stage (to Mojokerto)	150	2	28.0	Twin 330mm²	91.887	43.789	2,573	1,226	3,799	
36	"	(Situbondo, Banyuwangi) – Asembagus 2π Incomer	150	2	2.0	330mm²	124.187 x 1.1	81.498	273	163	436	
		Total							5,429	1,884	7,313	
		G. Total 150kV, 70kV							33,283	15,005	48,288	
		G. Total E.H.V.							6,830	2,747	9,577	
		G. Total G. Total							40,113	17,752	57,865	

Table 4.1-3 Group Unit Cost

As of Apr. 1984

		F.C. (US$)	L.C. (Rp.x.10^6)
150/70kV Transformer	kVA	10.7864	.0015
150/20kV Transformer	kVA	11.6856	.0015
70/20kV Transformer	kVA	10.7864	.0015
150kV Line bay	bay	339,000	148.00
150kV Bus coupler	bay	167,000	128.00
150kV Transformer bay	bay	280,000	128.00
70kV Line bay	bay	189,000	104.00
70kV Bus coupler	bay	122,000	104.00
70kV Transformer bay	bay	168,000	104.00
New Substation building			587.00
20kV Switchgear	unit	16,854	5.83

Table 4.1-4 Group Unit Cost of Transformer

F.C. $ x 10^3
L.C. Rp x 10^6

Voltage	Cap. (MVA)	Pry side		Tr		2ry side		Total		
		F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	Total
150kV/70kV	35	280	128	378	52.5	(1F)168	104	826	284.5	1110.5
	50	280	128	539	75	(1F)168	104	987	307	1294
	100	280	128	*906	150	(1F)168	104	1354	382	1736
150kV/20kV	10	280	128	116	15	(3F) 51	17	447	160	607
	20	280	128	233	30	(4F) 67	23	580	181	761
	30	280	128	350	45	(6F)101	35	731	208	939
	50	280	128	584	75	(10F)169	58	1033	261	1294
	100	280	128	*982	150	(12F)204	68	1466	346	1812
70kV/20kV	10	168	104	108	15	(3F) 51	17	327	136	463
	20	168	104	216	30	(4F) 67	23	451	157	608
	30	168	104	324	45	(6F)101	35	593	184	777

* Note: Cost of 100MVA Tr. = 1.68 x Cost of 50MVA Tr.

Table 4.1-5 Breakdown of Group Unit Cost (sheet 1/2)

As of Apr. 1984

a) 150 kV Line Feeder Bay

Item	Quantity	Cost (US$)
		1st bay
Circuit Breaker	1	39,326
Busbar Isolator	2	22,472
Line Isolator	1	11,236
Current Transformer	3	13,483
V.T.	1	11,236
C.C.P.D.	2	39,326
Surge Diverter	3	8,989
Control & Relay Panels	1 Lot	44,944
Busbar Structures, etc.	1 Lot	28,090
Supervisory/Protection	1 Lot	120,000
		339,102

b) 150 kV Bus Coupler Bay

Item	Quantity	Cost (US$)
Circuit Breaker	1	39,326
Busbar Isolator	2	22,472
Current Transformer	6	26,966
Control & Relay Panels	1 Lot	44,944
Busbar Structures, etc.	1 Lot	33,708
		167,416

c) 150 kV Transformer Bay

Circuit Breaker	1	39,326
Busbar Isolator	2	22,472
Current Transformer	3	13,483
Surge Diverter	3	8,989
Control & Relay Panels	1 Lot	50,562
Tap Change control panel	1 Lot	73,034
V,T. (busbar-mounted)	3	33,708
Busbars, Structures, etc.	1 Lot	39,326
		280,900

Table 4.1-5 Breakdown of Group Unit Cost (sheet 2/2)

d) 70 kV Line Feeder Bay

Item	Quantity	Cost (US$)
		1st bay
Circuit Breaker	1	20,225
Busbar Isolator	2	15,730
Line Isolator	1	7,865
Current Transformer	3	6,742
C.C.P.D.	2	20,225
V.T.	1	2,247
Surge Diverter	3	3,371
Control & Relay Panels	1 Lot	33,708
Busbar, Structures etc.	1 Lot	13,483
Supervisory/protection	1 Lot	66,204
		189,800

e) 70 kV Bus Coupler Bay

Circuit Breaker	1	20,225
Busbar Isolator	2	15,730
Current Transformer	6	13,483
Control & Relay Panels	1 Lot	44,944
Busbars, Structures, etc.	1 Lot	28,090
		122,472

f) 70 kV Transformer Bay

Circuit Breaker	1	20,225
Busbar Isolator	2	15,730
Current Transformer	3	6,742
Control & Relay Panels	1 Lot	39,326
Busbars, Structures, etc.	1 Lot	28,090
Tap Change Control Panel	1 Lot	47,191
Grounding Resistors	1 Lot	11,236
		168,540

Table 4.1-6 Construction Quantity of Substation (exclude Connecting Transformer) (1/3)

Substations	II (89 ~ 93)						III (94 ~ 98)						IV (99 ~ 2003)					
	C.Y	Feeder		Tr		Relative	C.Y	Feeder		Tr		Relative	C.Y	Feeder		Tr		Relative
		150kV	70kV	150kV	70kV			150kV	70kV	150kV	70kV			150kV	70kV	150kV	70kV	
Sawahan	89	2		50x2		Tandes 150Fx2	97			100x1								
Tandes																100x1		
Segoromadu							96			50x2								
Simokerto							96	2		50x2								
Benowo	92	2		50x1												50x1		
Waru																100x1		
Sukolilo																100x1		
Driyorejo	93	2		50x1												50x1		
Buduran	93	4		50x1			94			50x1						100x1		
Kenjeran							94			50x1						100x1		
Rungkut							94			100x1								
Simpang							94			50x1						100x1		
Darmo Grand							94			50x1						50x1		
Babatan							97			50x1						100x1		
Ngiwo							97	2		50x2						100x1		
Semanbung	90	4		50x2												100x1		
Karang Pilang	89	4		50x1			97			50x1						100x1		
Ketintang							98	2		50x2		Karang pilang 150Fx2				100x1		
Trosobo							97	2		50x1						50x1		
Sidosermo														2		50x2		Sukolilo 150Fx2
Bojonegoro																20x1		
Kebonagung							94			50x1								
Polehan	90	2		50x1			97			50x1								

Note C.Y : Completion Year

Table 4.1-6 Construction Quantity of Substation (exclude Connecting Transformer) (2/3)

Substation	II (89 ~ 93)						III (94 ~ 98)						IV (99 ~ 2003)					
	C.Y	Feeder		Tr		Relative	C.Y	Feeder		Tr		Relative	C.Y	Feeder		Tr		Relative
		150kV	70kV	150kV	70kV			150kV	70kV	150kV	70kV			150kV	70kV	150kV	70kV	
Blimbing							94	2		50x2								
Sengkaling							97	2		50x1		Kebonagung 150Fx2						
Lawang	92	2		50x1												50x1		
Sukorejo													99				20x1	
Turen							94				30x1							
Sengguruh	92				10x1	(P/S)												
Karangkates							98			10x1								
Kepanjèn	90		4		30x1	Kebonagung 70Fx2	95		2									
Probolingo							98			50x1								
Plered	89				30x1													
Bangil							95			50x1								
Pandaan	92				50x1													
Porong																	20x1	
Leces																50x1		
Kraksaan																30x1		
Kediri							96			50x1								
Tulungagung							96	2		50x2		Kediri 150Fx2						
Blitar	89				20x1													
Plta Wlingi							95				20x1							
Jombang	89		2		10x1												20x1	
Kertosono																	30x1	
Mojokerto	91			50x1			97			100x1				2				Krian 150Fx2
Manisrejo							95			50x1						50x1		
Ponorogo													99				20x1	
Dolopo	89				20x1													

Note C.Y : Completion Year

Table 4.1-6 Construction Quantity of Substation (exclude Connecting Transformer) (3/3)

Substations	II (89 ~ 93) C.Y	II Feeder 150kV	II Feeder 70kV	II Tr 150kV	II Tr 70kV	II Relative	III (94 ~ 98) C.Y	III Feeder 150kV	III Feeder 70kV	III Tr 150kV	III Tr 70kV	III Relative	IV (99 ~ 2003) C.Y	IV Feeder 150kV	IV Feeder 70kV	IV Tr 150kV	IV Tr 70kV	IV Relative
Lumajang							98			30x1								
Bondowoso							98			20x1								
Tanggul	89	4		20x1												20x1		
Asembagus														4		10x1		
Banyuwangi							95	2		50x1								
Genteng	89	4		20x1			96			50x1								
Situbondo	89	2				Paiton 150Fx1 Jember 150Fx1						Situbondo 150Fx2						
Bangkalan																20x1		
Sampang																20x1		
Pamekasan							97			20x1								
Sumenep							97			20x1								
Babat	89	1				Tuban 150Fx1												
Trenggalek	89		2															
Tulungagung	89		2															
Kebonagung	91		2				95		2									
"							III	2				Krian 150Fx2						
Wlingi	89		2			(P/S)												
Krian-Tandes							94	2										
Sukolilo							94 94	150Fx2 500Fx2										
Perak							94	2										
Grand Total		33	14	20x2 50x11	10x2 20x2 30x2 50x1	70Fx2 150Fx5		24 500Fx2	4	10x1 20x3 30x1 50x28 100x3	20x1 30x1	150Fx10		8		10x1 20x4 30x1 50x9 100x11	20x4 30x1	150Fx4

Note C.Y : Completion Year

Table 4.1-7 Construction Quantity of Connecting Transformer

	Completion Year	II (89 ~ 93)		Completion Year	III (94 ~ 98)		Completion Year	IV (99 ~ 2003)	
		500kV/150kV	150kV/70kV		500kV/150kV	150kV/70kV		500kV/150kV	150kV/70kV
Sawahan	89		(50x2 from Tandes)						
Bangil						100x1			
Sengkaling				98		50x1			
Grand Total						50x1 100x1			
Paiton	89	300x1							
"	90	500x1							
Sukolilo				94	500x1				
"				95	500x1				
Krian	89	500x1			1000x1			1000x1	
Grand Total		300x1 500x2			500x2 1000x1			1000x1	

Table 4.1-8 Construction Cost of Substation

(Unit : US$x10³)

Stage (Installation / Currency)		Feeder and Dis. Tr.			Connecting Tr.			Total			500kV Feeder and Tr.		
		F.C.	L.C.	Total	F.C.	L.C.	Total	F.C.	L.C.	Total	F.C.	L.C.	Total
II	1989	13,891	7,853	21,744									
	1990	6,860	3,653	10,513									
	1991	1,411	469	1,880									
	1992	4,626	2,074	6,700									
	1993	4,100	1,410	5,510									
	Total	30,888	15,459	46,347				30,888	15,459	46,347	15,080	3,284	18,364
III		49,566	17,394	66,960	2,341	689	3,030	51,907	18,083	69,990	20,850	4,974	25,824
IV		35,386	11,009	46,395				35,386	11,009	46,395	8,090	1,368	9,458
Total		115,840	43,862	159,702	2,341	689	3,030	118,181	44,551	162,732	44,020	9,626	53,646

Table 4.1 - 9 Forecast of Pole Transformer Capacity

	L.V. Peak Load (MW)		Pole Tr. Capacity (MVA)		*** Utility Factor
	S/S	*Pole Tr.	Total Cap.	** Inc. Cap.	
1983	223.81	217.1	1,098.4	-	0.267
88	409.78	397.5	1,827.86	729.46	0.294
89	455.04	441.4	1,990.7	162.8	0.300
90	505.30	490.1	2,167.0	176.3	0.306
91	561.11	544.3	2,352.8	185.8	0.313
92	623.08	604.4	2,563.5	210.7	0.319
93	691.92	671.2	2,785.7	222.2	0.326
89 - 93				957.8	
98	1,045.57	1,014.2	3,801.1	1,015.4	0.361
2003	1,430.25	1,387.3	4,692.5	891.4	0.400
89 - 2003				2,864.6	

* Peak Load of Pole Tr. = Peak Load of L.V. at S/S x 0.97

** Increasing Capacity

*** Utility Factor = $\dfrac{\text{Peak Load x 1.15}}{\text{Tr. Capacity x 0.85}}$

1.15 : 1 + Diversity(0.05) + Allowance(0.10)

0.85 : Power Factor

Table 4.1-10 M.V. Line Planning

	1983	1988	1993	1998	2003
L.V. Peak Load (MW) - A	223.81	409.78	691.92	1,045.57	1,430.25
M.V. Peak Load (MW) - B	91.92	196.16	412.52	797.07	1,408.35
B/A	0.411	0.479	0.596	0.762	0.985
M.V. Line Length (KM) - C	*3,963	6,788	10,603	14,760	18,933
C/A+B (KM/MW)	12.55	11.20	9.60	8.01	6.67
Increas. of M.V. Line (KM)	-	2,825	3,815	4,157	4,173
Sectional Switch (Unit)	-	-	503	533	468

Note * M.V. Line Length = 6kV Line Length x $\frac{6}{20}$ + 20kV Line Length

Table 4.1-11 L.V. & M.V. Peak Demand and M.V. Line Planning

Item / Year	East Java			Surabaya			Malang		
	* P.D. (MW)	Inc. P.D.(MW)	M.V. Line(KM)	P.D. P.D.(MW)	Inc. P.D.(MW)	M.V. Line(KM)	P.D. P.D.(MW)	Inc. P.D.(MW)	M.V. Line(KM)
1988	605.94	-	-	326.5	-		69.9	-	-
89	690.11	84.17	633	373.8	47.3	356	78.1	8.2	62
90	781.79	91.68	693	427.8	54.0	408	87.4	9.3	70
91	880.93	99.14	757	489.8	62.0	473	97.7	10.3	79
92	988.18	107.25	827	560.7	70.9	547	109.2	11.5	89
93	1,104.44	116.26	905	641.8	81.1	631	122.1	12.9	100
89 - 93	-	498.50	3,815	-	315.3	2,415	-	52.2	400
98	1,842.64	738.20	4,157	1,109.3	467.5	2,633	190.0	67.9	382
2003	2,838.60	995.96	4,173	1,808.6	699.3	2,930	272.7	82.7	347
89-2003	-	2,232.66	12,145	-	1,482.1	7,978	-	202.8	1,129

Note

P.D. : Peak Demand

Breakdown of M.V. Line Planning

(In Km)

Item / Year	Surabaya		Malang		Other Cabang		Total	
	O.H.	U.G.C.	O.H.	U.G.C.	O.H.	U.G.C.	O.H.	U.G.C.
1989	267	89	58	4	213	2	538	95
90	306	102	65	5	213	2	584	109
91	355	118	73	6	203	2	631	126
92	410	137	83	6	189	2	682	145
93	473	158	93	7	172	2	738	167
II	1,811	604	372	28	990	10	3,173	642
III	1,909	724	350	32	1,131	11	3,390	767
IV	2,051	879	312	35	887	9	3,250	923
Total	5,771	2,207	1,034	95	3,008	30	9,813	2,332

Table 4.1-12 Ratio of Under Ground Cable to Total M.V.Line

(%)

	Surabaya	Malang	Other Chabin
II	25.0	7.0	1.0
III	27.5	8.5	1.0
IV	30.0	10.0	1.0

Table 4.1-13 L.V. Line Planning in Feasibility Study

	Other Loan	Scope	Total
L.V. Line Length (KM)	3,760.84	4,016.85	7,777.7
Pole Transformer (Unit)	3,347	2,709	6,056
L.V. Line Length/P.Tr. Unit	1.12	1.48	1.3

Table 4.1-14 L.V. Line Planning at Long Term Master Plan

	1983	1988	1993	1998	2003
Increase of Pole Tr. (Unit)(A)	-	4.559	5.986	6.346	5.571
Increase of L.V. Line (KM)(B)	-	6.438	7.782	8.250	7.242
(B) / (A) (KM/Unit)	-	1.41	1.30	1.30	1.30

Table 4.1-15 Service Equipment Application

	Residential	Commercial	Public	Industry
L.V.₁ (Mostly use Single Phase Meter System)	○		○	
L.V.₂ (Mostly use 3 Phase Meter System)		○		○
M.V.		○	○	○

Table 4.1-16 No. of Consumers in East Java

Residential and Commercial/Public

$(\times 10^3)$

	Residential (L.V.1)		Commercial / Public					
			L.V.				M.V.	
	No. of Con.	Add.	No. of Con.	Add.	*Public (LV_1)	Commercial (LV_2)	No. of Con.	Add.
1983	683.2	-	44.685	-	-	-	0.050	-
88	1,408.9	725.7	81.9	37.2	12.4	24.8	0.092	0.042
89	1,568,8	159.9	91.4	9.5	3.2	6.3	0.102	0.010
90	1,746.8	178.0	101.9	10.5	3.5	7.0	0.114	0.012
91.	1,945.1	198.3	113.7	11.8	3.9	7.9	0.127	0.013
92	2,165.8	220.7	126.8	13.1	4.4	8.7	0.142	0.015
93	2,411.7	245.9	141.4	14.6	4.9	9.7	0.158	0.016
II	-	1,002.8	-	59.5	19.9	39.6	-	0.066
III	3,614.2	1,202.5	214.0	72.6	24.2	48.4	0.239	0.081
IV	4,752,0	1,137.8	283.9	69.9	23.3	46.6	0.318	0.079
II+III+IV	-	3,343.1	-	202.0	67.3	134.7	-	0.226

* Note Public : Commercial = 1:2

Industry

	Energy (GWH) / Year			NO. of New Consumer			
	Ene./ Year	Ene./ Consu.	NO. of Con.	Total	$L.V_2$ (0.9053)	M.V. (0.0924)	H.V. (0.0023)
1983	1,053.5	0.350	3,009	-	-	-	-
88	2,622.1	0.408	6,427	3,418	3,094	316	8
89	3,011.0	0.415	7,255	828	750	76	2
90	3,457.5	0.422	8,193	938	849	87	2
91	3,970.2	0.429	9,254	1,061	961	98	2
92	4,559.0	0.436	10,456	1,202	1,088	111	3
93	5,235.2	0.442	11,844	1,388	1,256	129	3
II	-	-	-	5,417	4,904	501	12
III	9,849.5	0.468	21,046	9,202	8,331	850	21
IV	17,938.9	0.487	36,836	15,790	14,295	1,459	36
II+III+IV	-	-	-	30,409	27,530	2,810	69

Table 4.1-16 Total NO. of New Consumers (2/2)

Item / Year	L.V. ($x10^3$)			M.V.			H.V.
	Residential Public (LV_1)	Commercial Industry (LV_2)	Total	Commercial Public	Industry	Total	Industry
I	738.1	27.9	766.0	42	316	358	8
1989	163.1	7.0	170.1	10	76	86	2
90	181.5	7.8	189.3	12	87	99	2
91	202.2	8.9	211.1	13	98	111	2
92	225.1	9.8	234.9	15	111	126	3
93	250.8	11.0	261.8	16	129	145	3
II	1,022.7	44.5	1,067.2	66	501	567	12
III	1,226.7	56.7	1,283.4	81	850	931	21
IV	1,161.1	60.9	1,222.0	79	1,459	1,538	36
II+III+IV	3,410.4	162.2	3,572.6	226	2,810	3,036	69

Table 4.1-17 Construction Cost of Distribution Line

Unit US$x3

Item / Year	Pole Tr.			M.V. Line (O.H.)			L.V. Line			Sectional Switch			M.V. Line (U.G.C.)		
	Unit	F.C. (1.613)	L.C. (0.075)	KM	F.C. (9.405)	L.C. (4.310)	KM	F.C. (4.977)	L.C. (1.618)	Unit	F.C. (7.7)	L.C. (0.075)	KM	F.C. (59.627)	L.C. (11.451)
1989	1,017	1,640	76	538	5,060	2,319	1,322	6,500	2,139	85	654	6	95	5,664	1,088
90	1,102	1,778	83	584	5,492	2,517	1,433	7,132	2,319	92	708	7	109	6,499	1,248
91	1,161	1,873	87	631	5,935	2,720	1,509	7,510	2,441	98	755	8	126	7,513	9,443
92	1,317	2,124	99	682	6,414	2,939	1,712	8,521	2,770	111	855	8	145	8,646	1,660
93	1,389	2,240	104	738	6,941	3,181	1,806	8,988	2,922	117	901	9	167	9,958	1,912
II	5,986	9,655	449	3,173	29,842	13,676	7,782	38,731	12,591	503	3,873	38	642	38,280	7,351
III	6,346	10,236	476	3,390	31,883	14,611	8,250	41,060	13,348	533	4,104	40	767	45,734	8,783
IV	5,571	8,986	418	3,250	30,566	14,007	7,242	36,043	11,718	468	3,604	35	923	55,036	10,569
Total	17,903	28,877	1,343	9,813	92,291	42,294	23,274	115,834	37,657	1,504	11,581	113	2,332	139,050	26,703

Item / Year	Service Equipment											Total Construction Cost		
	L.V.1 (Residen./Public)			L.V.2 (Commer./Indust.)			M.V.			Sub-Total				
	NO. of Consx10^3	F.C. (0.058)	L.C. (0.017)	NO. of Consx10^3	F.C. (0.072)	L.C. (0.021)	NO. of Consumer	F.C. (20.33)	L.C. (1.702)	F.C.	L.C.	F.C.	L.C.	F.C.+L.C.
1989	163.1	9,460	2,773	7.0	504	147	86	1,748	147	11,712	3,067	31,310	8,695	40,005
90	181.5	10,527	3,085	7.8	562	164	99	2,013	168	13,102	3,417	34,711	9,591	44,302
91	202.2	11,728	3,437	8.9	641	187	111	2,256	189	14,625	3,813	38,211	10,512	48,723
92	225.1	13,056	3,827	9.8	705	206	126	2,562	214	16,323	4,247	42,883	11,723	54,606
93	250.8	14,546	4,264	11.0	792	231	145	2,948	247	18,286	4,742	47,314	12,870	60,184
II	1,022.7	59,317	17,386	44.5	3,204	935	567	11,527	965	74,048	19,286	194,429	53,391	247,820
III	1,226.7	71,148	20,854	56.7	4,082	1,190	931	18,927	1,584	94,157	23,628	227,174	60,886	288,060
IV	1,161.1	67,344	19,739	60.9	4,385	1,279	1,538	31,268	2,618	102,997	23,636	237,232	60,383	297,615
Total	3,410.5	197,809	57,979	162.1	11,671	3,404	3,036	61,722	5,167	271,202	66,550	658,835	174,660	833,495

Fig. 4.1-1 Moment Current Carrying Capacity of AW

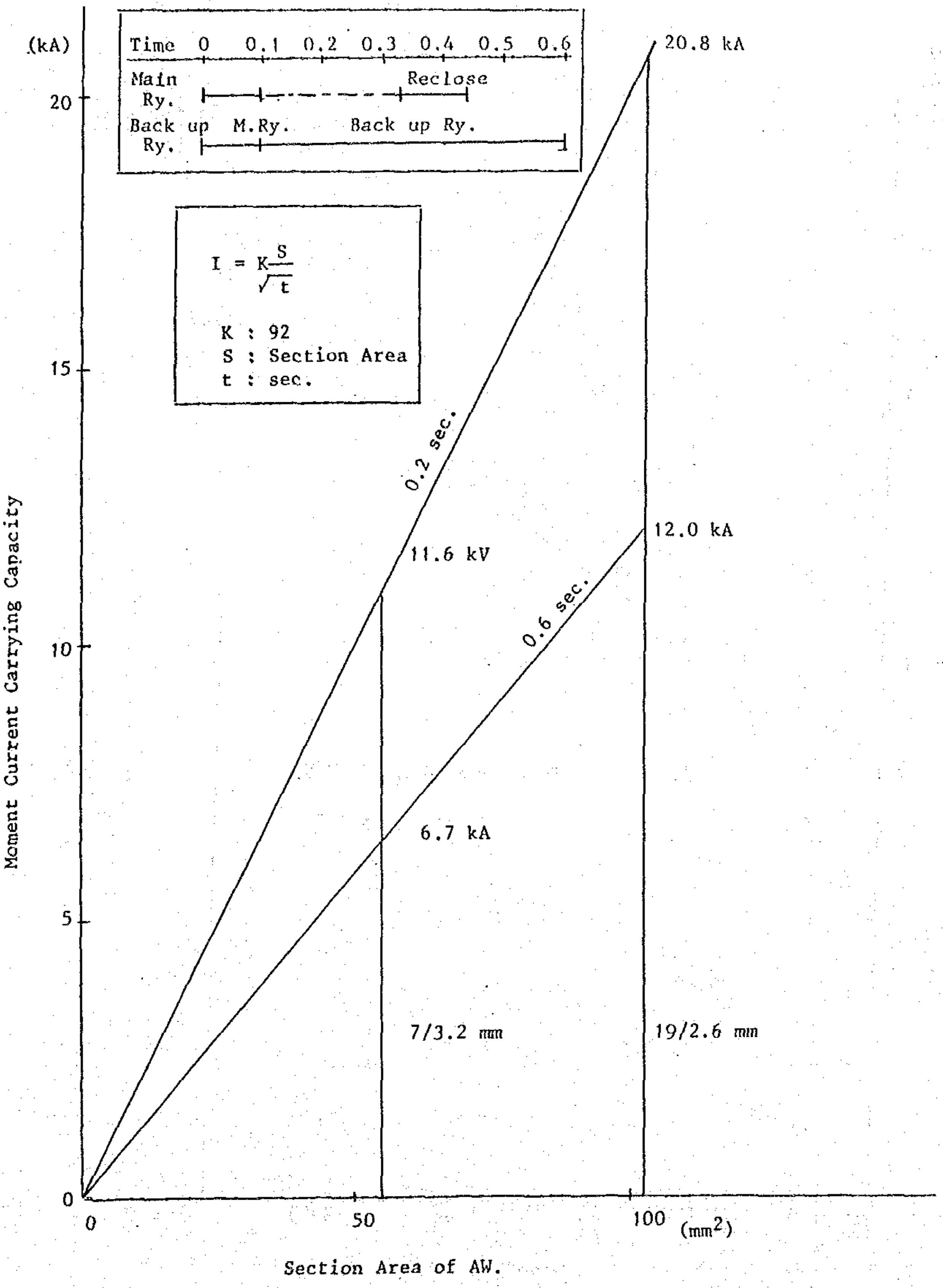


Fig. 4.1-2 Distribution Pole Tr. Capacity, Load and Utility Factor

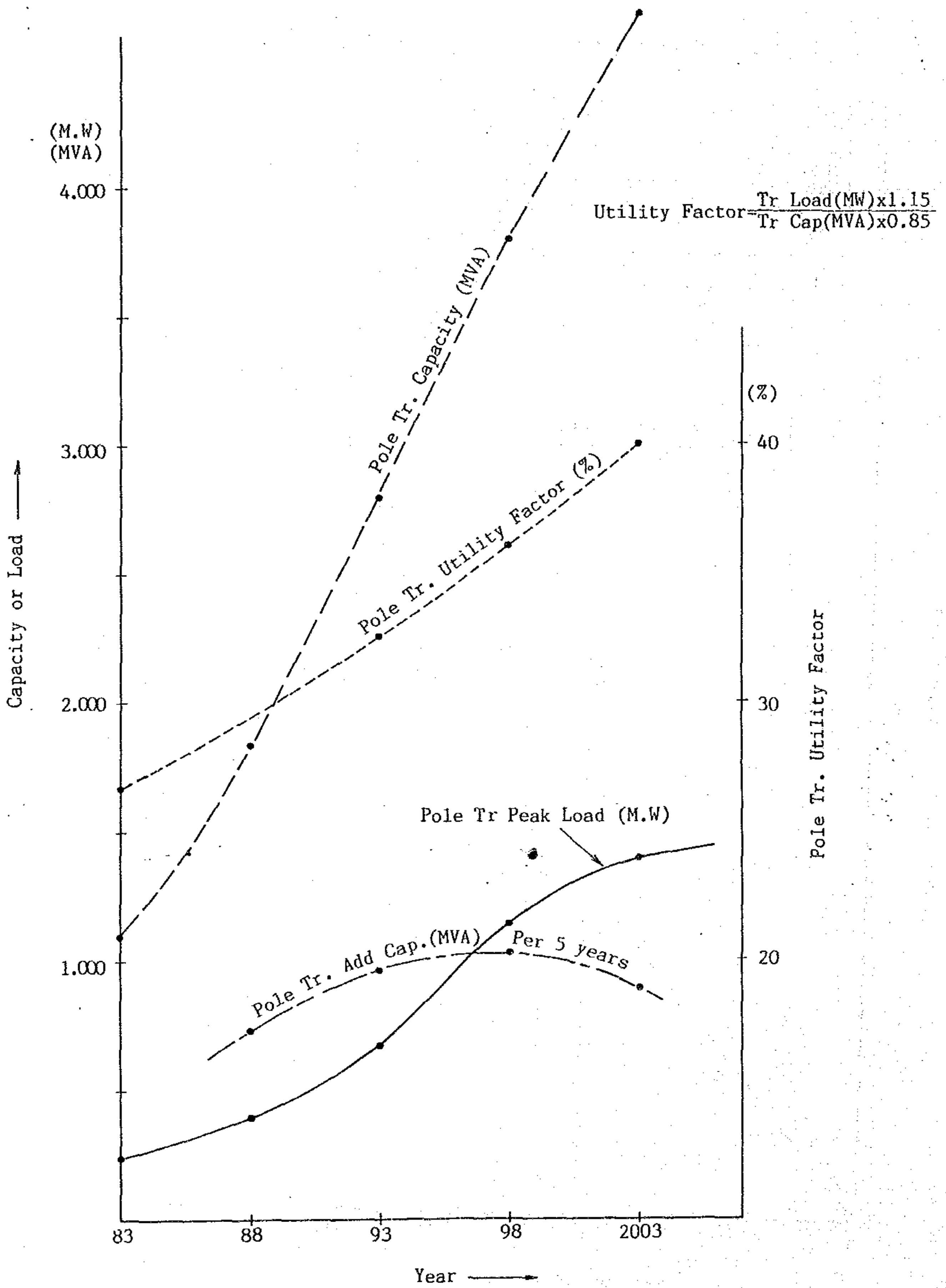


Fig. 4.1-3 Characteristic of M.V. Line

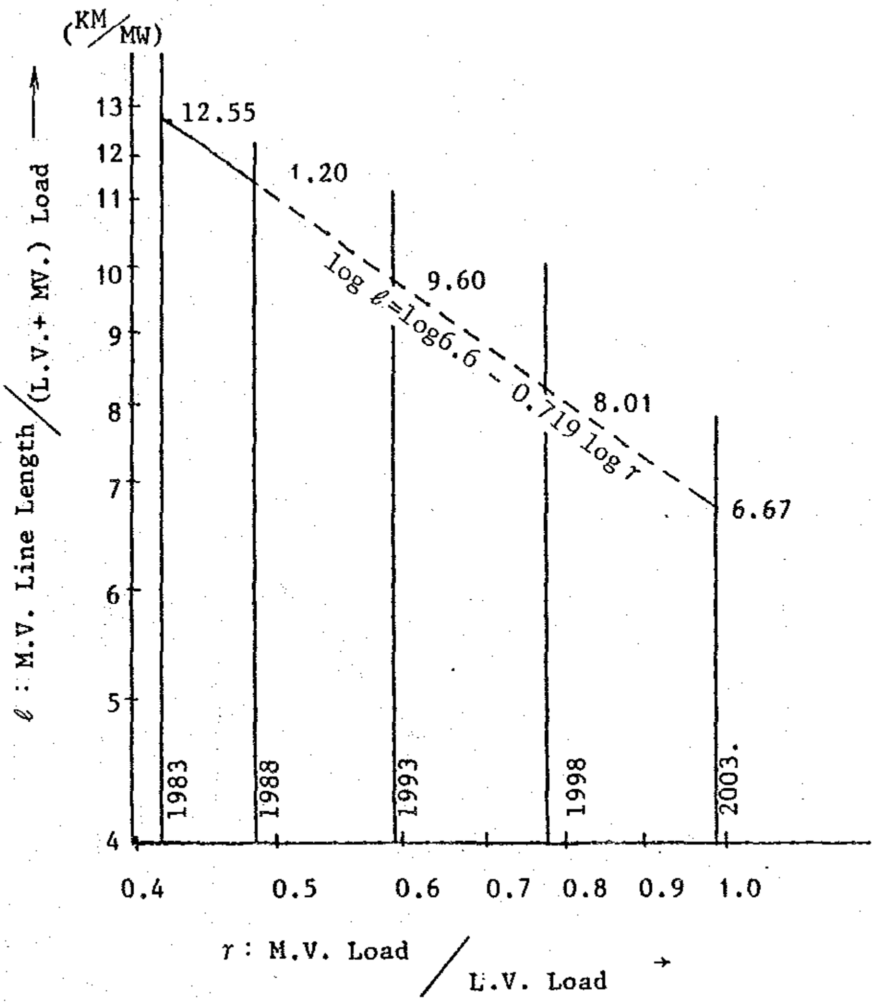
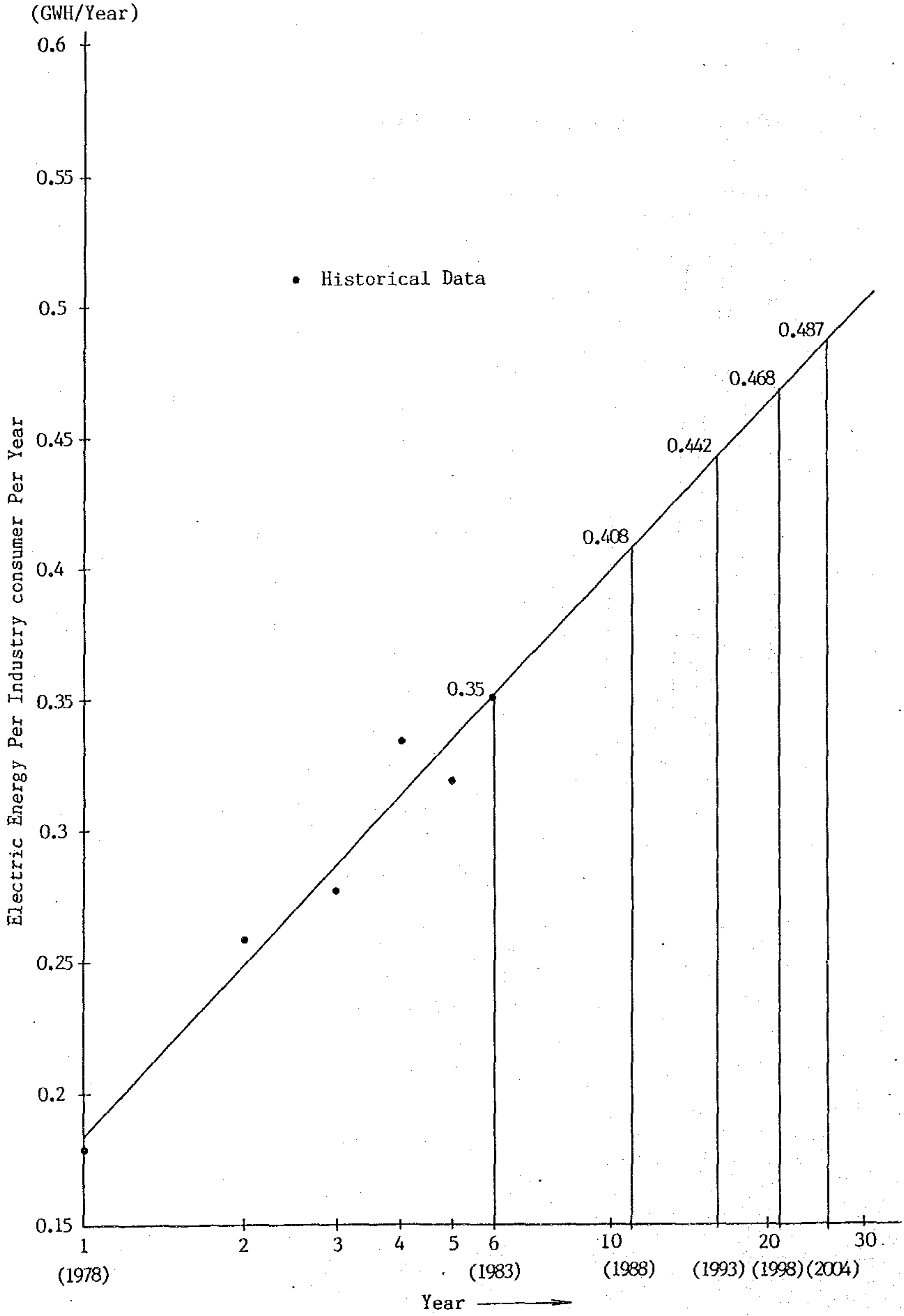


Fig. 4.1-4 Electric Energy Per Industry Consumer Per Year



4.2. Economic Evaluation of Mid/Long-Term Plan

The mid-term plan is planned by every fiscal year as like the short-term plan. On the other hand, the long term plans are the whole plan by every five (5) years. Accordingly, two different methods of economic evaluation were adopted as follows:

4.2.1. Economic Evaluation of Mid-term plan

The Internal Rate of Return (I.R.R.) calculated by the Present Worth Method, which was the same as the short-term plan, was adopted to evaluate the economic efficiency of mid-term plan.

(1) Project cost

Project cost is the sum of investment and operation & maintenance (O & M) costs. The Investment is an economic cost composed of direct cost, physical contingency and consultant fee. The operation & maintenance cost was calculated by the product of O & M ratio to the economic costs and the investment by facility. Adopted figures for O & M ratio were as follows:

Transmission facility	:	1.0%
Substation facility	:	2.5%
Distribution facility	:	3.0%

(2) Benefit

The benefit of mid-term plan was obtained by reducing the increment receiving cost at 150 kV bus bar from the increment revenue since 1988/89.

The unit revenue and receiving costs are based on the following unit prices calculated by PLN.

Unit revenue = Rp.98.3/kWh = 98.3 mills/kWh
Connecting charge = Rp.9.00/kWh = 9.0 mills/kWh
Unit receiving costs = Rp.70/kWh = 70 mills/kWh
(Exchange rate : US$1.- = Rp.1,000.-)

The receiving energy is the sum of the energy sales estimated in Section 2.1 and the loss energy to be estimated by the following loss rates.

	Sectional loss rate	Loss rate at 150 kV
Transmission loss rate	3% at 150 kV	3.0%
Distribution loss rate	10% at 20 kV	9.7%
Total loss rate		12.7%

(3) Internal rate of return

The discount rate which equalizes the present worth of the cost to that of the benefit, namely I.R.R. was 15.7% as shown in Table 4.2-2 and also shown in Fig. 4.2-1.

(4) Conclusion of economic evaluation for the mid-term plan

The following is the results of I.R.R. estimated by the above methods on every case.

Sensitivity test

Case			I.R.R. in %
(1)	Base Case		15.7
(2)	Energy sales	10% increase	17.8
(3)	Energy sales	10% decrease	13.5
(4)	Planning cost	10% increase	13.7
(5)	Planning cost	10% decrease	18.0
(6)	Receiving cost	10% increase	4.1
(7)	Receiving cost	10% decrease	24.3
(8)	Revenue including connecting charge		25.6

As it is obvious from this Table, the economic efficiency mid-term plan is extremely higher than that of short-term plan. This is considered that the main transmission/substation facilities, especially transmission facilities are to be constructed before the mid-term.

As for 150/20 kV system in particular, it is considered that economic efficiency thereof has been increased in mid-term in spite of its severe situation up to short term because of a large initial investment for the system.

4.2.2. Economic Evaluation of Long-term Plan

Since long-term plan is planned by every five (5) years, the following simple benefit/cost comparison method was adopted as the economic evaluation of long-term plan. Simple benefit/cost comparison method, in this case, means the method to evaluate the economic efficiency by comparing the levelized cost during the operation period of facilities to be constructed during these five (5) years with the yearly benefic produced by these facilities.

(1) Levelized cost

The levelized cost during operation period is the sum of levelized capital cost, O & M cost and other costs. The levelized capital cost can be calculated by the product of construction cost including interest during construction (I.D.C.) and capital recovery factor.

The above is shown in the following formulas :

$$CC = EC \times (1 + r)^{nc}$$

where

CC = construction cost including interest during construction period

EC = economic cost

r = interest rate

nc = construction period

$$CA = CC \times RF$$

where

CA = levelized capital cost

RF = capital recovery factor

$$RF = r \times (1 + r)^n/((1 + r)^n - 1)$$

where

r = interest rate

n = service life

O & M cost can be calculated by the product of the above construction cost and O & M ratio. Other costs are assumed at 40% of O & M cost.

The above is formularized as follows :

$$O\ \&\ M = CC \times OMR$$

$$OTC = 0.4 \times O\ \&\ M$$

where

O & M = O & M cost

OMR = O & M ratio

OTC = other cost

Therefore, levelized cost (c) during operation period can be expressed as follows :

$$C = CA + 1.4 \times O\ \&\ M$$

In this cost calculation, the construction period was assumed 1.5 years.

(nc : construction period = 1.5 years)

The following figures were adopted for service life and O & M ratio by facility.

	T/L	S/S	D/L	ES
n = Service life (years)	35	25	15	25
OMR = O & M ratio (%)	1.0	2.5	3.0	-

The follwoing Table shows the costs calculated with interest rate r as a parameter:

Interest rate (%)	8	10	12	15	20
Former (US$ x 10^6)	74.0	84.0	94.9	112.8	146.6
Latter (US$ x 10^6)	69.4	78.6	88.4	104.7	135.4

(2) Benefit

The benefit of long-term plans is obtained by reducing increment receiving cost from increment revenue.

As shown in Section 2.1, energy sales in each fiscal year are 9,003 GWh in 1993/94, 15,275 GWh in 1998/99 and 24,849 GWh in 2003/04. Besides, transmission loss rate is assumed at 12.7%. Assuming that the unit revenue is @Rp.98.3/kWh and receiving cost is @Rp.70.0/kWh, the benefit is shown as follows :

Term/Item	Unit Price mills/kwh	Increment Energy GWh	Amount US$ x 10^6
Former L-T			
Revenue	98.3	6,272	616.5
Receiving Cost	70.0	7,184	502.9
Benefit			113.6
Latter L-T			
Revenue	98.3	9,574	941.1
Receiving Cost	70.0	10,967	767.7
Benefit			173.4

(Exchange rate : US$1.0 = Rp.1,000.-)

(3) Conclustion

Adopting the interest rate as a parameter, the calcualted net benefit and B/C ratio are tabulated as shown in Table 4.2-3. The said Table leads to the conclusions as follows:

(a) B/C ratio in the former long-term plan is 1.2 at interest rate of 12% and 1.0 at interest rate of 15%. Thus I.R.R. is to be estimated at 15.0%. This value shows the economic adequacy of the former long-term plan. The economic efficiency of the former long-term plan is rathre lower than that of the mid-term plan. The cause for this is considered that the project in the former long-term plan includes strongly preinvested projects.

(b) B/C ratio in the latter long-term plan is 1.0 at 25% interest rate. The economic efficiency thereof will be very high. This is considered that the latter long-term plan includes few projects with preinvestment contrary to the former.

(c) B/C ratio in the whole long-term plan is 1.0 at 20% interest rate. The result of the calculation shows that the economic efficiency of the whole long-term plan is the average level between the former half plan and the latter half plan.

TABLE 4.2-1 ECONOMIC COSTS AND O&M COSTS IN MID-TERM PROJECTS

UNIT IN MILLION DOLLARS

	86/87	87/88	88/89	89/90	90/91	91/92	92/93	93/94
MID TERM								
T/L	0.0	5.228	5.784	2.169	0.762	0.716	0.363	0.066
S/S	0.0	11.627	15.506	8.176	5.580	6.178	3.309	0.606
D/L	0.0	20.759	41.831	50.550	56.153	62.305	34.383	6.621
E.S.	0.556	1.969	2.921	4.405	4.296	3.952	2.817	1.694
TOTAL	0.556	39.583	66.042	65.300	66.791	73.151	40.872	8.987

*

O & M COST

UNIT IN MILLION DOLLARS

	OMR	87/88	88/89	89/90	90/91	91/92	92/93	93/94	94/95	95/96
MID TERM										
T/L	0.010	0.0	0.0	0.052	0.110	0.132	0.139	0.147	0.150	0.151
S/S	0.025	0.0	0.0	0.291	0.678	0.883	1.022	1.177	1.259	1.275
D/L	0.030	0.0	0.0	0.623	1.878	3.394	5.079	6.948	7.979	8.178
TOTAL		0.0	0.0	0.966	2.666	4.409	6.240	8.271	9.389	9.603

COST : BASE
BENEFIT : BASE

TABLE 4.2-2 : INTERNAL RATE OF RETURN IN MID-TERM PROJECTS

(USD X1000)

		COST						BENEFIT			PRESENT WORTH		I.R.R.
NO	YEAR	INVESTMENT T/L	S/S	D/L	E.S.	O&M	TOTAL	REVENUE	REC.COST	TOTAL	COST	BENEFIT	15.68 % FACTOR
1	1986	0	0	0	556	0	556	0	0	0	744	0	1.3383
2	1987	5228	11627	20759	1969	0	39583	0	0	0	45791	0	1.1568
3	1988	5784	15506	41831	2921	0	66042	0	0	0	66042	0	1.0000
4	1989	2169	8176	50550	4405	966	66266	70678	-57652	13026	57282	11260	0.8644
5	1990	762	5580	56153	4296	2666	69457	151087	-123242	27845	51901	20807	0.7472
6	1991	716	6178	62305	3952	4409	77560	238672	-194685	43987	50099	28413	0.6459
7	1992	363	3309	34383	2817	6240	47112	324587	-264765	59822	26306	33403	0.5584
8	1993	66	606	6621	1694	8271	17258	418463	-341340	77123	8330	37225	0.4827
9	1994	0	0	0	0	9389	9389	418463	-341340	77123	3917	32179	0.4172
10	1995	0	0	0	0	9603	9603	418463	-341340	77123	3464	27816	0.3607
11	1996	0	0	0	0	9603	9603	418463	-341340	77123	2994	24045	0.3118
12	1997	0	0	0	0	9603	9603	418463	-341340	77123	2588	20786	0.2695
13	1998	0	0	0	0	9603	9603	418463	-341340	77123	2237	17968	0.2330
14	1999	0	0	0	0	9603	9603	418463	-341340	77123	1934	15532	0.2014
15	2000	0	0	0	0	9603	9603	418463	-341340	77123	1672	13426	0.1741
16	2001	0	0	0	0	9603	9603	418463	-341340	77123	1445	11606	0.1505
17	2002	0	0	20759	0	9603	30362	418463	-341340	77123	3950	10033	0.1301
18	2003	0	0	41831	0	9603	51434	418463	-341340	77123	5784	8673	0.1125
19	2004	0	0	50550	0	9603	60153	418463	-341340	77123	5847	7497	0.0972
20	2005	0	0	56153	0	9603	65756	418463	-341340	77123	5525	6481	0.0840
986 - 2005		15088	50982	441895	22610	137574	668149	6225043	-5077764	1147279	347853	327149	
006 - 2015		0	0	103309	0	96030	199339	4184630	-3413400	771230	10990	31695	
986 - 2015		15088	50982	545204	22610	233604	867488	10409673	-8491164	1918509	358844	358844	

PRESENT WORTH

	DISCOUNT RATE (%)		(6.0)	(8.0)	(10.0)	(12.0)	(15.0)	(20.0)	(25.0)
COST	INVESTMENT	T/L	14988	14972	14963	14961	14970	15010	15079
	INVESTMENT	S/S	48771	48166	47618	47121	46461	45561	44869
	INVESTMENT	D/L	348640	313602	286837	266030	242587	216346	199077
	INVESTMENT	E.S.	20427	19819	19260	18746	18051	17065	16257
	O&M		104368	83429	67973	56332	43701	30416	22440
	TOTAL		537194	479988	436651	403190	365769	324399	297722
BENEFIT	REVENUE		4736743	3812982	3129098	2612361	2049188	1452268	1089952
	REC.COST		-3863758	-3110247	-2552404	-2130901	-1671521	-1184614	-889073
	TOTAL		872984	702735	576694	481459	377666	267654	200879
	B/C		1.625	1.464	1.321	1.194	1.033	0.825	0.675
	B-C		335790	222746	140043	78269	11897	-56745	-96843

Table 4.2-3 Benefits and Costs in Long-term Projects

unit in Million US Dollers

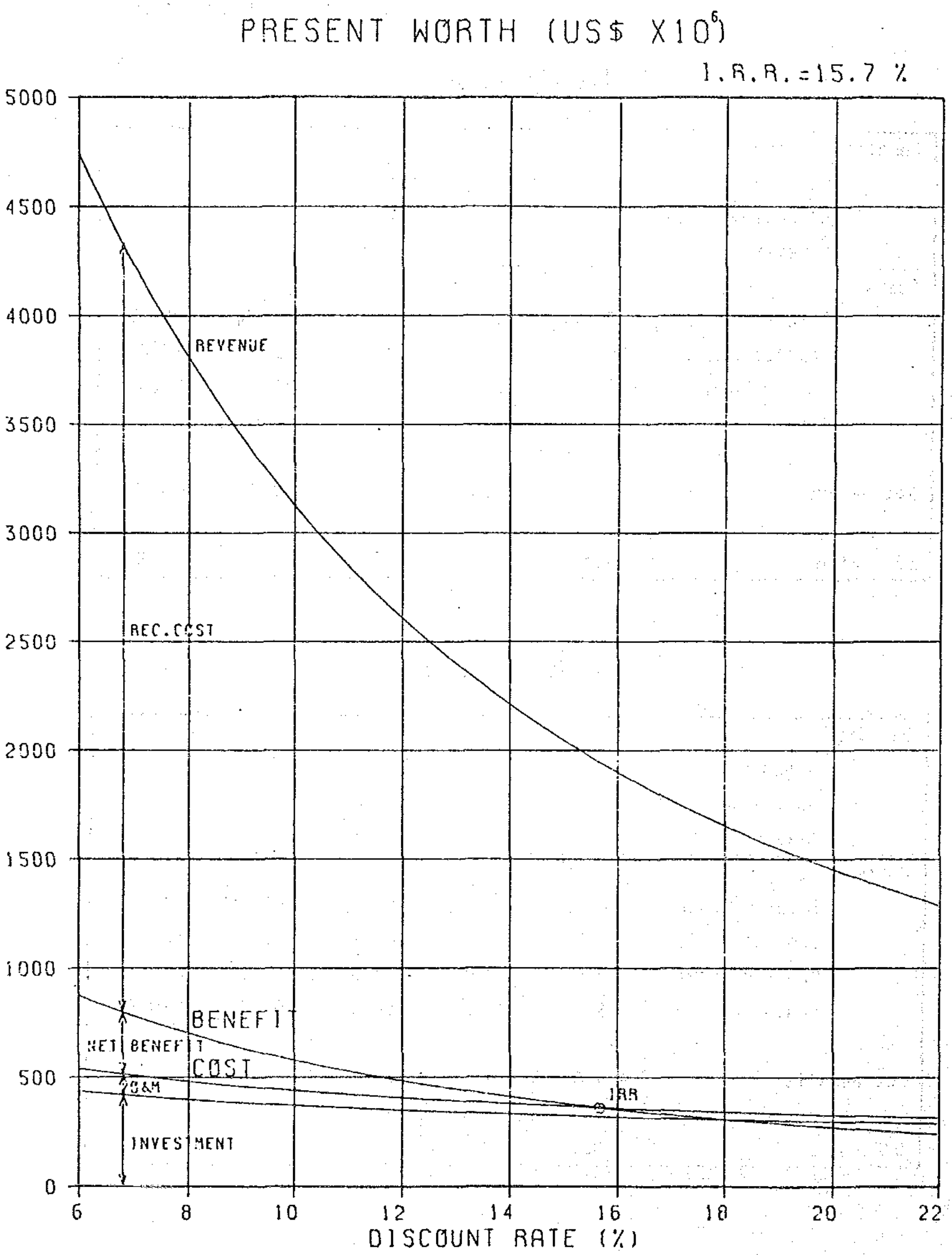
Former Long-term

Benefit					
Revenue			616.5		
Receiving costs			502.9		
Benefit			113.6		
Costs					
Interest rate	8 %	10 %	12 %	15 %	20 %
Capital costs	55.5	65.1	75.4	92.6	125.0
O&M and others	18.4	18.9	19.5	20.2	21.6
Costs	73.9	84.0	94.9	112.8	146.6
Net benefit	39.7	29.6	18.7	0.8	-33.0
B/C ratio	1.5	1.4	1.2	1.0	0.8

Latter Long-term

Benefit					
Revenue			941.1		
Receiving costs			767.7		
Benefit			173.4		
Costs					
Interest rate	8 %	10 %	12 %	15 %	25 %
Capital costs	51.9	60.5	69.9	85.4	148.6
O&M and others	17.5	18.0	18.5	19.3	21.9
Costs	69.4	78.5	88.4	104.7	170.5
Net benefit	104.0	94.9	85.0	68.7	2.9
B/C ratio	2.5	2.2	2.0	1.7	1.0

FIGURE 4.2-1 PRESENT WORTH OF BENEFIT AND COST IN MID-TERM PROJECTS



CHAPTER 5

TECHNICAL STUDIES

CHAPTER 5 TECHNICAL STUDIES

5.1. Study of System Planning

5.1.1. Load Dispatching System after Interconnection between Java and Bali Island

At present, there exists no interconnection line between East Java and Bali Island. The interconnection project by submarine cable is under planning to be completed by 1988.

(1) Load Dispatching System before Interconnection

Load dispatching control of main power sources and trunk line in Java system has been made by J.C.C. (Java Control Center).

On the other hand, the load dispatching from 150 kV system to distribution line has been controlled by A.C.C. (Areal Control Center). And load dispatching control at load side in whole East Java area has been made by Waru A.C.C.

Bali Island has no general load dispatching system, but some individual systems, separately operating.

(2) Load Dispatching System just after Interconnection

System condition in East Java just after interconnection by submarine cable is expected to be such a condition that a part of 150 kV line system is added to the existing system in East Java. Therefore, same as the interconnection between Java and Madura Island, the load dispatching to Bali Island should be controlled by Waru A.C.C. However, some times in the past, not only Japan but European countries had bitter experience in submarine cable accidents. The most required is to take the necessary countermeasures against the submarine cable accidents and communication system troubles in dispatching.

5.1.2 Countermeasures against Flicker caused by Arc Furnace

At present, East Java power system has a big furnace demand using the materials of scraps.
Since this load is a cause of flicker, the flicker is requested to be limited within allowable level.
The load of this flicker consumer is near Waru substation, having the contracted MVA of 32 MVA at present and the total installed transformer capacity of 70 MVA.
In this report, the study was made on the voltage fluctuation and the countermeasures to limit the allowable level.

(1) Limitation of Flicker

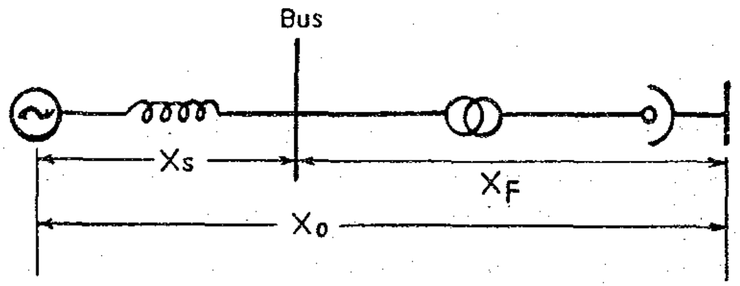
So far the international standard has not yet been settled on the calculation method of flicker and its limitation.
Therefore, this report adopted the standard calculation method and limitation usually used in Japan.
Namely, the limitation of flicker is expressed as follows:

$$\Delta V10max \leqq 0.45V \text{ (100V base)}$$

where, $\Delta V10max$ is the maximum effective value obtained by converting the generated voltage fluctuation to 10 Hz.

(2) Fundamental and Practical equation of flicker

(a) % Impedance map



(b) Fundamental equation of flicker

$\Delta Qmax = (100/X_0) \times (\sin^2\theta_S - \sin^2\theta_R) \times 10$ (MVar)·······(1)

$\Delta Vmax = (Xs/10) \times \Delta Qmax$ (V) 100 V base·····(2)

$\Delta V10max = K \times \Delta Vmax$ (V) 100 V base·····(3)

$Qmax = (100/X_0) \times 10$ (MVar)·······(4)

where

X_o : % reactance from furnace at 10 MVA base

X_s : % reactance from bus at 10 MVA bace

θ_s : Circuit impedance phase under three phase short circuit

θ_R : Circuit impedance phase under normal operation of arc furnace

ΔQ_{max} : Maximum reactive power fluctuation of arc furnace (MVar)

ΔV_{max} : Maximum voltage fluctuation calculated (100V base : V)

ΔV_{10max} : Maximum of ΔV_{10} calculated (100V base : V)

K : Proportional coefficient (1/3.6)

Q_{max} : maximum reactive power of arc furnace (MVar)

(c) Practical equation reduced from fundamental equation and calculation of voltage flicker

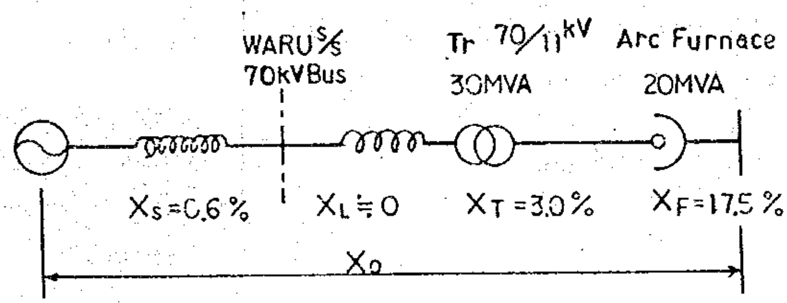
$\sin\theta_s = 1$, $\sin^2\theta_R = 1-\cos^2\theta_R$, $\cos\theta_R = 0.85$

substitute above factors for the expression (1) and reduced the flowing practical equation from expression (1),(2) and (3)

$$\Delta V_{10max} = (100/3.6)\times(X_s/X_o)\times\cos^2\theta_R \cdots\cdots(5)$$

(3) Case1:In case of one furnace with a capacity of 20 MVA

(a) Impedance map (10MVA base)



(b) Calculation of ΔV_{10max}

$X_s = 0.6\%$ at 10MVA

$X_T = 9\%$ at 30MVA base $=$ 3.0% at 10MVA base

$X_F = 35\%$ at 20MVA base $=$ 17.5% at 10MVA base

$\therefore X_o = 0.6+3.0+17.5 = 21.1\%$ at 10MVA base

$Q_{max} = (100/21.1)\times 10 = 47.4$(MVar)

$\Delta V_{10max} = (100/3.6)\times(0.6/21.1)\times(0.85)^2$

$= 0.571$ (V) at 100V base

(c) Rate of flicker reduction : R

$\Delta V10max \leqq 0.45(V)$
$R = (0.571-0.45)/0.571 \times 100$
$= 22$ (%)

(d) Required TQC capacity : Q

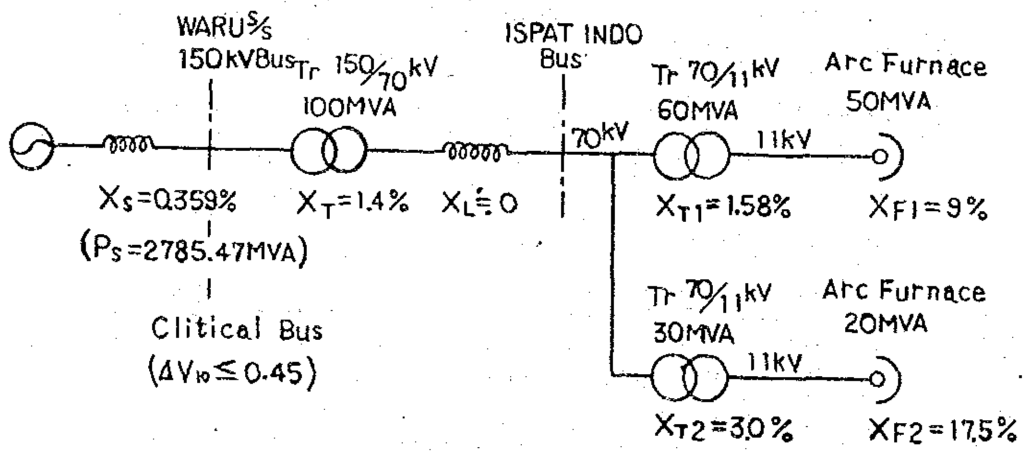
Rate of reactive power compensation will be got from the curve in the next page.

$Q = 47.4(MVA) \times 0.24 = 12(MVA)$

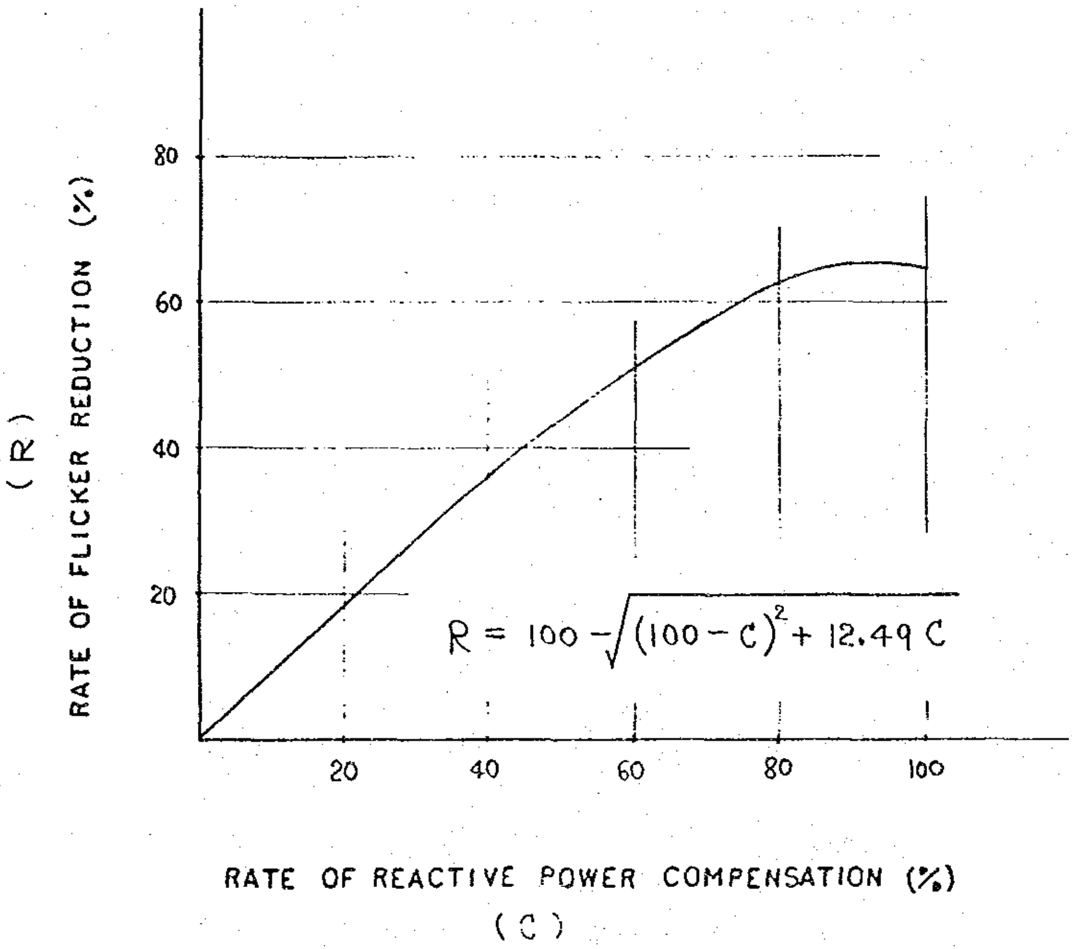
The rate is 24% when R is equal to 22%.
Accordingly, the required TQC capacity is 12MVA.

(4) Case2: In case of two furnaces with capacities of 20 MVA and 50 MVA

(a) Inpedance map



X_s = 0.359% (Ps=2785.47MVA)
X_T = 1.4% (14% at 100MVA base)
X_L = 0% (negligible small)
X_{T1} = ※1.58% (9.5% at 60MVA base)
X_{T2} = ※3.0% (9% at 30MVA base)
X_{F1} = ※9% (45% at 50MVA base)
X_{F2} = ※17.5% (35% at 20MVA base)
Note: ※ shows estimated figures.



FLICKER REDUCTION CHARACTERISTICS

(b) Conditions of calculation.

Δ V10max of each furnace will be calculated by the same manner descrived above.

The compound figures of furnaces will be calculated by method of Pitagoras-sum.

(c) Results of the calculation

The next table shows the results of the calculation.

Results of calculation on flicker

Arc furnace		20MVA	50MVA
X_s	(%)	0.359	0.359
X_T	(%)	1.4	1.4
$X_{T1,2}$	(%)	3.0	1.58
$X_{F1,2}$	(%)	17.5	9.0
X_o	(%)	22.259	12.339
$Q_{max1,2}$	(MVar)	44.93	81.04
ΔV_{10max}	(V)	0.324	0.584

Compound ΔV_{10max}	(V)	0.67
Rate of flicker reduction	(%)	32.8
Rate of reactive power compensation	(%)	36.3
Compound Q_{max}	(MVA)	92.66
Required TQC capacity	34	

(5) Conclusion

The limitation of flicker (Δ V10max) at critical bus should be not larger than 0.45V at 100V base.

The countermeasures to keep the above limitation are as follows;

(a) In case of one furnace with a capacity of 20 MVA
TQC with a capacity of 12 MVA should be installed in the premise of the flicker consumer.

(b) In case of two furnaces with capacities of 20 MVA and 50 MVA
The transformer (150/70KV) should be installed in the Waru substation to transmit electric power for the flicker consumer through exclusive transmission line.
Further, TQC of 34 MVA should be installed in the premise of the flicker consumer.

5.1.3 Study of DCC System

After a study of its present situation and the future prospect in Japan as well as in Europe and U.S.A., the automatic control of distribution line is considered as follows:

(1) Purpose of D.C.C. and its expected effects

With the increase of the power demand, such tendencies as the increase of power supply facilities and their complication and the demand of high reliability are recognized. To cope with this, the automatic control of distribution line is going to be accelerated positively.

D.C.C. is the principal function to control distribution line automatically and its purpose is to improve the supply reliability of distribution facilities and to increase the efficiency of maintenance and operation.

To achieve the purpose to the fullest extent, facilities should be functioned and fitted to the operation and maintenance with much more effectiveness by reduction of manpower.

(2) Technical Problems

(a) Apparatuses and equipments related to DCC, such as computer, supervisory control equipment, circuit breaker, automatic recloser, etc., are required to be of high reliability, and in particular, programs and softwear to combine them systematically and properly are very important.

This softwear should be determined with the organization and staff to be in charge of operation and maintenance of PLN's power system taken totally into account.

(b) It is necessaty to establish the communication system between D.C.C. and substation.
For this purpose, it is better to adopt the duplication transmission facilities to the main Substation.

(c) Taking consideration of future increment of power demand, it is recommended that SCADA Master station have enough capacity. And as the need arises, the acting item should be added.
For the first step, the required is to make the existing automatic operation system of distribution line in perfect working order, and to reconfirm its mechanical function, then the study should be made on the trasmission to D.C.C. of the accident information such as where the distribution line trouble took place, which is the cause of trouble, ground or short circuit, and how is the ground current. etc.

(d) DCC is added to the existing distribution facilities to have a supervisory and remote control, thereof. The interface between those facilities is a very important facility to ensure a success of this system. It should be based on a precise, matching both theoretically and practically between those both facilities with all conditions studied sufficiently. For this, it is advisable to procure the interface from the manufacturers of the existing automatic control equipment.

(e) As for the aspects of operation and maintenance, it is important to be well informed of those facilities for actual use and also to be well prepared for any case of disorder of facilities by training the operators so that a quick recovery of operation can be ensured.

(3) Conclusion

To accelerate the D.C.C. is considered to be an appropriate plan to cope with the increase of power demand and the technical innovations. In the executon of the plan, it is desirable to pay careful attention to the concrete design and method of procurement of the interface and its proper operation and maintenance, etc. after foreseeing its effect of installation systematically.
It is recommended to perform the Implementation schedule of the plan in the following in Sequence.

(a) By considering D.C.C. system, to investigate and study the Organization and Staff of Operation and maintenance of distribution line, in consideration of DCC.

(b) To define the function of DCC, after the above investigation and study.

(c) To adopt the Dplication (bi-usage of normal and stand-by) of Communication facilities to the main Substation.

(d) To add the transfer to DCC of trouble informations such as place of accident, trouble conditions, etc.

(e) To perform the trial implementation of D.C.C. and accumulate the technology of DCC, in Surabaya area.

(f) To prepare the plan for DCC developmat in other regions, based on the result and effect obtained in the execution of Item(e) above.

5.1.4. Load Shedding for Total Blackout Prevention

According to the record of Waru Area Control Center, blackouts in East Java took place at the following times.

1) Before interconnection with Central Java System

- July 1, 1979 at 17:35
- August 7, 1980 at 8:21
- July 16, 1981 at 15:12

2) After interconnection on 28th July, 1981

- November 25, 1981 at 13:35
- January 20, 1982 at 4:40
- August 24, 1982 at 15:39
- September 17, 1982 at 4:40
- October 18, 1982 at 17:55
- November 18, 1982 at 16:52
- November 19, 1982 at 18:30

The primary causes of above failures are various, but all of secondary cause are the drop of system frequency, which result in momentary successive trips of each generator of thermal and hydroelectric power. This is called "system collapse". Besides, it is remarkable that these collapses take place more frequently after interconnection with whole island.

In general, according to the development of power system or increase in system capacity, the power variation required for the generation or the load variation to restore the frequency of electric system increases in rough proportion to the system capacity, although the normal frequency itself tends to become stabler.

On the other hand, the unbalance of supply and demand caused by the breaks of trunk transmission lines or generators becomes greater in quantity, by the appearance of large capacity power plants which is connected to the extra high voltage transmission lines.

Therefore, a kind of data process and instruction system which is composed of automatic information transmission system accompanied with a computer, will become necessary for some specified large power sources respectively, so that the frequency drop will not incur the system collapse and so as to avoid occurrence of any local overload. Generally in addition to the above system, various system protection devices which immediately detect without delay an occurrence of a noticeable unbalance of demand and supply by means of measuring the system frequency and power flows of interconnection lines will also become necessary.

These processes correspond to automatization of emergency load sheddings executed by operators in a load dispatching office, and hereafter those will be called "load shedding".

(a) B.S.S. (Block System Stabilizer)

This is a kind of wide area integrated system protection scheme which has the following features, and we tentatively call it B.S.S. (Block System Stabilizer).

- Judgement standards and operation procedures of imaginable accidents on major power plants are put into a computer program.

- Various present conditions of the system are always automatically transmitted to the computer.

- The computer always processes these data immediately and some necessary outputs are updated and stored.

- When one major signal to meet the condition specified on the program is put in the computer, the output of the optimum operations for each stations can be obtained automatically.

- The information obtained is immediately transmitted to respective stations.

- Eventually, all the stations given this instruction automatically execute necessary operations respectively.

(b) U.F.R. (Under Frequency Relay)

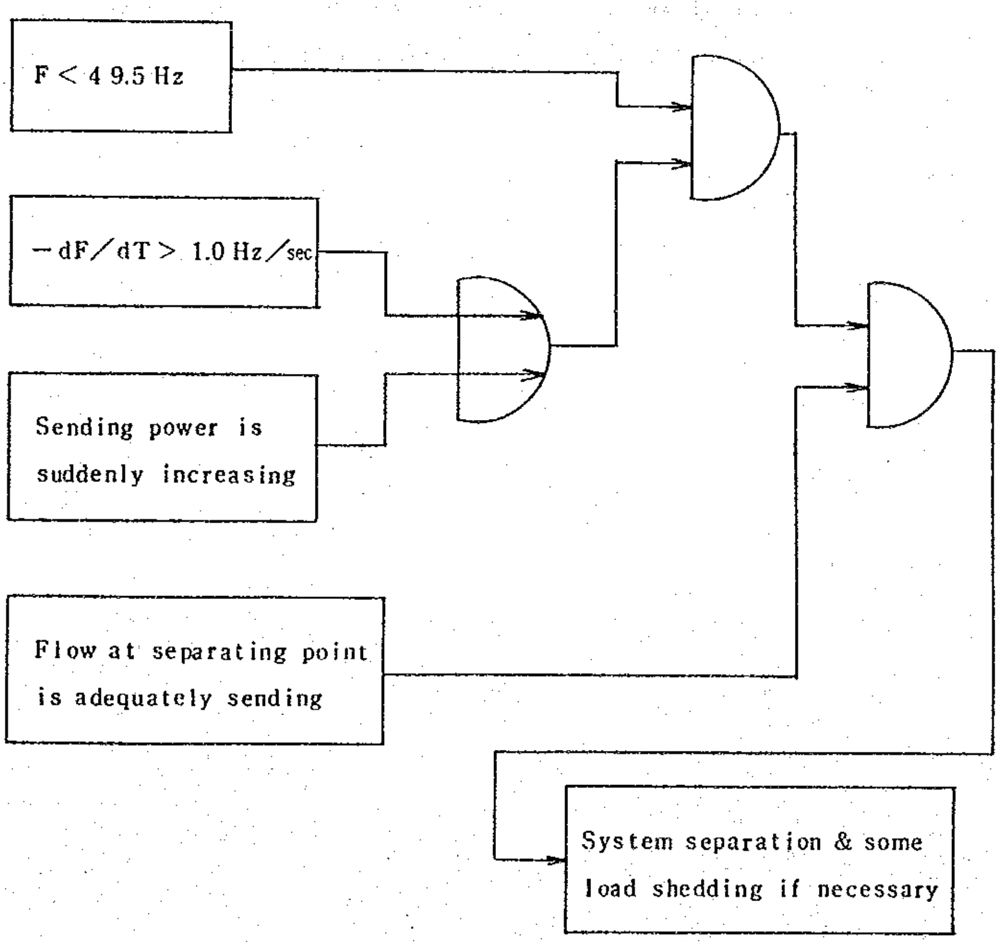
The system protection devices are needed for the back-up protection of B.S.S. and for limiting the collapsed range of the system and restoring the system as quick as possible at the time of frequency drop or sudden change of currents of interconnection lines. The devices can find the occurrence of a sudden unbalance of demand and supply, when a frequency drop or sudden change of currents are detected on the interconnection lines. The devices are divided into following two (2) kinds according to the object of use.

1) System Separation Relay

System separation relay are recommended as one of the system protection devices, in the following consideration.

Most of the total blackouts often recorded in Java Power System, could have been limited to the less extent of collapsed range of the system by successful separated operation of power plants, if the system had been separated without delay at adequate system separation points.

Therefore, it is recommendable that simpler system configurations should be considered so that the separated system can be easily made at the time of blackout, and that system separation relays as illustrated below should be installed at adequate system separation points. In this case, it is desirable to keep the power flow at those points slightly out of the line, if possible.



ii) Automatic Load Restricting Relay

As a back-up of various load sheddings above-mentioned, the automatic load restricting schemes detecting a frequency drop and acting by classified frequency are recently introduced to execute the urgent load restrictions automatically and specifically prior to the instructions given by a dispatching office.

This is an effective measure against comparatively slow frequency drops, so it is recommendable to spread successively to the further extent of the adoption of this kind of relay.

Those various load shedding methods are collectively tabulated on the following table together with the ordinary frequency control methods.

	Operation Method	Subjected Disturb- and to Control	Target Range of Frequency	Objects of Control
Ordinary time	Governor free operation of generator	Random fringy fluctuation	50 ± 0.1 Hz	Specified principal power plants
	AFC			
	ELD	Random fringy fluctuation & hourly fluctuation of daily load curve		
	Manual		50 ± 0.3 Hz	General power plants
On accidents	B.S.S. (Block system stabilizer)	Falling off of a large capacity (e.g. more than 100 MW) generation	Over 49.5 Hz	. Paiton and other sub-stations for Paiton P/S . Segoromadu line others for Gresik P/S
	System Separation Relay			. 500 kV bus tie at Paiton S/S . Krian line at Gresik P/S, etc.
	Automatic Load Restricting Relay	Bak-up protection	Over 49.0 Hz	Specified feeder of distribution substa-tions, etc.
	Manual		Over some 48.0 Hz	Specified transmission line, etc.

5.2. Study of Transmission Line Facilities

5.2.1. Study of Design Criteria and Recommendation for Standardization of Facilities

(1) Study of Design Criterial

Design criteria and design data made by French and Belgium Loans could be obtained in the first field investigation. Design criteria of East Java (I Stage to III Stage) which has been made by NEWJEC are compared as follows with French Loan criteria, which are more detailedly reported than Belgium ones.

First, with regard to the electrical design, NEWJEC's data have been confirmed to be standardized in East Java. That is to say, there is no difference between NEWJEC's and French loan's criteria such as number of insulator in string, standard horn gap length, insulation clearance and conductor height above the ground. Secondly, with regard to the mechanical design, design condition of the said two is same at the wind velocity at maximum mean value, temperature and allowable swing angle, but different at the wind pressure value. The comparison thereof is shown in Table 5.2-1. Studying the difference, design figures recommendable to be adopted are shown as follows:

(2) Wind Pressure on Tower

Wind pressure on tower means wind pressure per unit surface area to tower. This is shown in the following general formula.

$$P = \frac{1}{2}\rho\ CxV^2 \qquad (kg/m^2)$$

where, P : Wind pressure (kg/m²)
ρ : Air density (kg S²/m⁴)
Cx: Drag coefficient
V : Wind velocity (m/s)

ρ is fixed by climatic conditions and Cx is also fixed by solidity ratio of members in space. Test results of Cx by wind tunnel test is shown in Fig. 5.2-1. When the steel angle is used, Cx takes almost constant value to the wind velocity.

Wind pressure (P) of square type steel tower is defined at 290 kg/m^2 by JEC-127 (1965), when the tower height is less than about 40 m at the basic mean wind velocity of 40 m/s.

The following calculation was made by simply converting the wind pressure (P) into the wind velocity of 25 m/s, in order to apply the result to East Java Project

$$290 \times \left(\frac{25}{40}\right)^2 = 113.3 \ (kg/m^2)$$

From the view point of safety side, 120 kg/m^2 will be appropriate for the wind pressure on tower.

However, for applying this to East Java, reestimation is required to meet the climatic conditions in East Java.

(a) Air density ρ is generally shown in the following formula.

$$\rho = \frac{1,293 + 273}{T + 273} \cdot \frac{H}{760} \cdot \frac{1}{9.8} \ (Kg.S^2/m^4)$$

Where, T : Temperature (°C)

H : Air pressure (mmHg)

Record of temperature and air pressure for past twenty years in Surabaya city is shown in Table 5.2.2.

In case of using an average annual lowest temperature of 23.5°C and an annual average air pressure of 1008.1 M Bar, the air density is calculated as follows;

$$\rho_o = \frac{1,293 \times 273}{23.5 + 273} \cdot \frac{756}{760} \cdot \frac{1}{9.8} = 0.1208$$

1,008.1 M Bar = 756 (mmHg)

(b) Cx

Since the wind pressure on the tower is much influenced by the height and shape of the tower, it is advisable to calculate the wind pressure in each height for strength calculation of the tower. But for the purpose of simplifying the design, calculated equivalent wind pressure can be obtained by calculating the wind pressure of the same moment as that of the ground line of the tower caused by the wind pressure of each height.

Formula is expressed as follows.

$$\Sigma Cx \cdot An \cdot h = Cxe \Sigma An \cdot h$$

Where, h : Height of panel from the ground (m)

Ah : Area of panel at the height of h (m^2)

Cx : Drag Coefficient of panel as the height of h

Cxe : Equivalent drag Coefficient

Equivalent drag coefficient (Cxe) of the tower in 150kV transmission lines is as follows.

$$Cxe = \frac{\Sigma Cx \cdot An \cdot h}{\Sigma An \cdot h} = \frac{365.0}{126.9} = 2.876$$

(c) Wind pressure per unit area (P)

Using the values mentioned above, wind pressure value per unit area of the tower for 150kV transmission lines in East Java is obtained in the following calculation.

$$P = \frac{1}{2} \cdot \rho \cdot Cxe \cdot V^2$$

$$= \frac{1}{2} \times 0.1208 \times 2.876 \times 25^2$$

$$= 108.6 \ (Kg/m^2) < 10 \ (Kg/m^2)$$

Judging from the result of above calculation, 110 (Kg/m^2) wind pressure recommended by NEWJEC now seems to be fully reasonable. The values used in the above calculation therefore are, however, only for the normal tower for 150kV. In the following cases, wind pressure value should be obtained after further examination.

a. In case that tower is high.
----- Wind velocity value at the upper air is necessary to be used.

b. In case that the lines pass through the highlands.
----- ρ is changed in connection with temperature and air pressure.

c. In case that special panel is used.
----- Solidity ratio is necessary to be amended.

(3) Wind Pressure on Wire

General formula of wind pressure on wire is as same as that of wind pressure on tower, however, Cx is changed greatly in connection with wind velocity value, because section of wire is nearly circle. Reynolds number is generally used as a method of watching the change.

$$Re = \frac{D \times V}{\nu}$$

D : Cable outside diameter (m)
V : Wind velocity value (m/s)
ν : Dynamic viscosity coefficient of air (m^2/sec)

Fig. 5.2-2 shows the example of connection between Reynolds number and drag coefficient. According to this, the connection between Reynolds number and drag coefficient is changed in connection with the ratio between outer strand diameter and outside diameter.

In JEC-127(1965), 100 kg/m^2 as wind pressure of wire is used against wind velocity of 40 m/s and 0.115 ($kg.S^2/m^4$) as air density at the time of typhoon is used. Drag coefficient at the wind velocity of 40 m/s is obtained by the following formula.

$$Cx = \frac{P}{\frac{1}{2}\cdot\rho\cdot V^2} = \frac{100}{\frac{1}{2} \times 0.115 \times 40^2} = 1.087$$

This value may be within the safety sphere of figures compared with Fig. 5.2-2.

In case of wind velocity of 40 m/s, Reynolds number reads around the lowest position of drag coefficient. However, in case of East Java, because of lowness of wind velocity value, Reynolds number becomes fairly less than the lowest position of Cx value and it is feared that drag coefficient goes up. Therefore, by obtaining Cx value of standard wires applied to the case of East Java, wind pressure is examined. Table 5.2-3 shows the result of calculation of wind pressure of various wires at the same weather conditions as it was applied to the study of wind pressure on tower. According to this Table, it seems suitable to apply to wind pressure of 40 kg/m^2 for wires thicker than Ostrich type and that of 45 - 50 kg/m^2 for wires thinner than Pigeon type. However, in case of new transmission lines for 70 kV and 150 kV, there is no problem of applying to wind pressure of 40 kg/m^2 including ground wire as NEWJEC proposed for the purpose of simplifying design, because the wire thicker than Ostrich type is generally applied to as the standard wire. Judging from the result of examination mentioned above, as for the wire thicker than the standard wire (Ostrich) for 70 kV, it turns out that there is no problem of applying to wind pressure on wire of 40 kg/m^2. However, in case of new installation or rehabilitation of transmission lines thinner than Pigeon type, wind pressure on wire of 45 - 50 kg/m^2 is necessary to be applied to.

(4) Wind Pressure on Insulator String

Suspension string is swayed by wind, while, tension string is caused by the effect of tower-horizontal ange, that is, wind coming from oblique direction on insulator string. Therefore, wind pressure on insulator string is usually considered as maximum wind pressure from ablique wind. With the change of the configulation, insulator string varies the drag coefficient value with Reynolds number same as conductor. According to JEC-127 a coefficient of 1.4 is adopted as maximum drag coefficient, and the suspension insulator of 250 mm in diameter is regulated to have the wind pressure of 3 kg per unit at the wind velocity of 40 m/sec. Based on the above, Electric Companies apply the wind pressure of insulators including fittings, as follows:

T/L voltage (kV)	No. of Insulators	Wind/p./string (kg)
70	7	30
150	11	50

Simple conversion of the above to the wind pressure of 25 m/s results in the following table.

T/L voltage (kV)	No. of Insulators	Wind/p./string (kg)
70	7	11.7
150	11	19.5

In East Java, the wind pressure for the insulator string of double string per supporting point of tower will be enough at 25 kg for 70 kV line and at 40 kg for 150 kV line. Present design wind pressure of 60 kg per supporting point will be completely enough.

(5) Standardization of Facilities

Based on the design criteria, facilities are completed through the design, manufacturing, and construction. The facilities completed through this process are not always necessarily standardized even if design criteria has been standardized. As the concrete, comparable example the result of study about the T/L 150 kV 240 mm^2 A.C.S.R. is shown as Table 5.2-4.

Observing this example:-

When it comes to be diversified, the internationalized Consultant, it will be getting harder to standardize facilities.

Summerize those reasons as below:-

- o It is different in standardization of main equipment/ facilities by which Consultant utilize, and based on this Standard Code name are also different.

- o Regarding steel angle, Bolt for Iron tower are different in selection range of Grade, also differs from minimum size.

- o Like as insulator, Alumoweld conductor, there are some items limited in original country/region. By the Consultant's performance/experienced year, with recommended, dominant items of equipments by consultant therefore it can't be fixed.

As above studied result, owing to the adoptions regional-self centralized facility criteria by Consultant and Contractor, it comes to be difficult standardization of facilities.

If we wish to be unify, made interchangeability those facilities, we shall be selected Consultant of limited region and contractor, then it is hard to come true.

5.2.2. Study of Power Loss Reduction of Transmission Facilities

(1) Present situation and problem of Power-Loss

Table 5.2-5 shows the analysis results of power loss in power-system. Analysis was made based on the recent data in Indonesia and Japan that power loss of transmission and substation as well as distribution power loss in Indonesia are much more than those in Japan. Power loss of substation is very minor in comparison with transmission power loss. Therefore transmission power loss can be regarded as power loss of transmission and substation. In this case, transmission power loss in Indonesia is 1.7 times of that in Japan. It is estimated that such a big difference in power loss between both countries is caused by the great increase of power demand in recent years and contrarily by the old-type transmission facilities in Indonesia. Following countermeasures are considered for improvement.

(a) To select the kinds of conductors at the time of new T/L installation

(b) To improve the existing old T/L facilities

(c) To determine the timing of additional installation of second circuit on double c.c.t. tower with single circuit T/L

In this text, the timing of additional 2nd c.c.t. are studied, because it seems more practicable in the future and simpler for estimation.

(2) Conditions of Study

Following conditions were settled to estimate the proper timing of additional installation of 2nd c.c.t.

(a) The object of additional installation of 2nd c.c.t. is to increase the reliability and to reduce the power loss of transmission line. In this study, the suitable timing is estimated by considering the cost of loss reduction and the investment for additional installation. Therefore in case of planning additional installation earlier than this timing, a focus has to be put into the increase of reliability.

(b) In-put timing of investment, operations & maintenace costs, depreciation cost and revenue for additional second circuit are as shown in Table 5.2-6 for profit calculation.

(c) Both of annual current growth rate and loss factor of T/L are constant for calculation.

(d) Power unit cost of 150 kV, 70 kV bus-bar of T/L are as shown in Table 5.2-7.

(e) Additional installation cost of 2nd c.c.t. and additional construction cost of transmission line bay in substation are as shown in Table 5.2-8.

(f) Early investment is refunded at the time of necessary normal investment, and depreciation cost during this period (maximum 25 depreciation year) is considered for calculation.

(g) Operation and maintenance cost is regarded as 1.5% constantly of total investment.

(h) Profit is obtained by multiplying T/L loss reduction(/KWH) multiply by power unit cost of 150 kV bus-bar or 70 kV bus-bar.

(3) In case of only performing the additional second circuit construction of T/L

For the calculation of loss reduction, only the adding second circuit installation is considered. In this case, transmission is made with twin conductors by connecting the existing 2 circuit conductor at the T/L bay in substation.
The conditions in this case are as below.

o Kind of conductor

In case of 150 kV T/L: single conductor of 330 mm^2 ACSR.
In case of 70 kV T/L: 300 MCM ACSR.

o Loss factor, power growth ratio

When average load factor in East Java Project (67%) is applied to this calculation, the loss factor is computed as follows.

$$\begin{aligned}\text{Loss factor} &= 0.3 \times \text{load factor rate} + 0.7 \times \text{loss rate}^2 \\ &= 0.3 \times 0.67 + 0.7 \times 0.67^2 \\ &= 0.515\end{aligned}$$

Average power growth rate in East Java is 16.5% while the rate in this calculation is considered at 13% to 20%.

o Table 5.2-9, shows the calculation example of the maximum peak current per year, power loss reduction per km, and profit due to such power loss reduction. Using the above condition, economic calculations of plants/equipment investment were performed. Table 5.2-10, represents the examples of calculation in case of 150 kV T/L and 70 kV T/L. Personal computer is used for Discount Rate (D.R.) calculation. From these calculations and variation of early investment rate (n) D.R. for this study is obtained as shown in Fig. 5.2-3. Reading the curve line in this Figure enables us to get n which deserves D.R. of 10% and 15% and annual average current. And, in the same manner, each characteristic line can be obtained from the variation of growth rate. Such an annual average current as early investment is effective, was selected in this study, finally as a main factor. The economic borderline between this annual average current D.R. and growth rate is shown in Fig. 5.2-4, representing D.R. as para meter. This Figure shows that if in case of 70 kV 300 MCMACSR, the annual average current is higher than 7% ∿ 12% to the carrying current capacity, the additional second circuit installation is estimated more advantageous without much influence by growth rate. And in case of 150 kV 330 mm^2 ACSR, when it reaches to higher than 13% ∿ 20% to the carrying current capacity, the additional installation will also be more advantageous.

(4) In case of performing concurrently both of additional second circuit construction of T/L and additional transmission line bay in substation

In this case, transmission power loss is reduced, and the reliability to power system is increased, because even in case of a fault of single circuit line, power breakdown can be avoid. Additional transmission line bay in substation is to be installed at the both ends in substation. Therefore these costs are estimated at fixed costs without influence by T/L root length. This means that it is necessary to include the factors of root length, for the cost estimation per km. As mentioned above, the annual average current is not much influenced by growth rate, so, only the growth rate of 16.5% is considered in this cost calculation.

Table 5.2-11, shows the calculation results of construction cost and Operation & Maintenance cost per KM of both transmission and substation. Using above method and based on these investments and O/M costs, the economic borderline between the annual average current and T/L Route length was obtained at the growth rate of 16.5%. (See Fig. 5.2-5)

From these results and those mentioned in above Item (3), what is more profitable in cost estimate, can be cleared by kinds of work. Needless to say, in case that T/L Root length is short, and additional T/L bay in substation is installed, only the profitable results can be obtained with heavy current.

(5) Conclusion

As above mentioned, in order to take appropriate countermeasure of Power loss reduction, the study studied of was additional second circuit installation with simple calculation, the result of the study is easily applicable to the actual T/L installation. A topic for further discussion, we will study about the Rehabilitation of existing T/L and, by reinforcing those worn-out facilities step by step, also there is necessity to direct your efforts to reduce Power loss.

5.2.3. Investigation and Study of Insulation Level

(1) Investigation of insulation level for transmission line in East Java

The results of investigation of insulation level for transmission line in East Java are summarized as follows.

(a) Before Independence in 1945, the balanced insulation with 6 suspension insulators had been applied to 70 kV transmission line. By the recent rehabilitation, it was rehabilited partly to the unbalanced insulation with 5 and 6 suspension insulators.

(b) The unbalanced insulation was also applied to 150 kV new transmission line installed with Karankates Hydroelectric Development Project.

(c) All of 150 kV and 70 kV transmission lines after 1st stage East Java Project have applied the unbalanced insulation and arcing horn with gap which was designed by NEWJEC.

As seen in the above summary, the unbalanced insulation and arcing horn have been broadly used to the most of 150 kV and 70 kV transmission lines.

(2) Investigation of I.K.L.

The map of I.K.L. (Isokeraunic Level) of whole Indonesian fell into our hands by PLN, at the 3rd field investigation.
Fig. 5.2-6 is the result of plotting the enlarged I.K.L. map to the East Java power system. The Figure indicates that the maximum is 120 around Karankates and the values are gradually decreasing with going away from Karankates. Eastern peninsula portion of Surabaya City and Madura Island are of I.K.L. from 60 to 100. And I.K.L. of the existing transmission line is between 60 and 100, except for the line between Jember and

Banyuwangi. Averagely, it is regarded as 100. Such a high I.K.L. is one of the characteristics in tropical area.

(3) Result of investigation of transmission line tripout and its analyais

At the 3rd field investigation, data was into our hand regarding the tripout records and causes of 70 kV and 150 kV transmission line in East Java. A period of the 3rd investigation was the rainy season and lightning season from November 1983 to June 1984 (total 8 months). Table 5.2-12 shows the tripout records by cause, and Table 5.2-13 represents the tripout rate per 100 Km by voltage of double circuit transmission line at rainy season (lightning season). The tripout records at the previous year's rainy season show only the number of total tripouts which are big different in 150 kV transmission line in comparison with the records at the period from November 1983 to June 1984. Therefore, revised tripout rate was obtained by averaging the numbers of tripouts for above 2 rainy seasons. This revised tripout rate during 2 rainy seasons reaches to 1.6 time of the annual tripout rate in Japan. This means that annual tripout rate is estimated at about 2 times of that in Japan.

The tripout rate of 70 kV transmission line was analized by tripout cause. Table 5.2-14 represents the result of this analysis. According to this Table, the tripouts caused by human work including contact to trees and by bad weather condition show higher rates, and those by lightning indicate lower tripout rates in East Java than in Japan. This is a contradiction because I.K.L. in East Java reaches to about 100 in average. It will be reasonable for settling this contradiction to estimate that most of the tripouts due to bad weather conditions include those by lightning. Generally, Indonesia has the better climate conditions for transmission line than Japan. So, number of tripouts due to climate conditions shall be less in Indonesia. These phenomena also show that above estimation will be fully reasonable.

(4) Tripout rate forecast

In transmission lines in each country, there are various kinds of recommendable tripout forecast by lightning. These forecast methods are all based on I.K.L. Of around 30. The tripout rates are considered to be changed in simple proportion to I.K.L. The proportion method may be applicable to the area with I.K.L. of around 30, but it is considered impossible to use proportion method to the tropical area with I.K.L. of 100 in average. Substantial study of lightning at tropical area is delayed in comparison with the study at other areas. It would be therefore, difficult at present to estimate theoretically the tripout forecast by lightning to the transmission line.

In this Report, comparison was made between the calculated value by standard forecast method used to general area (not tropical area) and the actual measured value. Details of the standard forecast method being omitted in this Report, the lightning points and stroke points are forecasted as follows.

Tripout by lightning to transmission line	Strokes to towers -	Back-frash-over at tower
	Strokes to shield wire -	Back-frash-over at mid-span
	Strokes to phase conductor -	Frash-over at tower

Following conditions were determined as the standard design condition of lightning characteristics.

(a) Stroke frequency (N) per year to 1 km^2 area at I.K.L. of 30 : 2 times

(b) Stroke frequency per year to transmission line with 25 m high steel tower : 21.5 times

- Stroke to steel tower : 1/3 of 21.5 times
- Stroke to wire : 2/3 of 21.5 times

(c) Stroke frequency is proportionate to a square root of height

(d) Footing resistance : 10 Ω

(e) Stroke current probability in based on AIEE transmission line curve in 1950. (See Fig. 5.2-7)

(f) Strokes to the phase conductors are based on the calculation results obtained from expansion program by "Armstrong - Whitehead theory".

The tripout rate of unbalanced insulation on 70 kV and 150 kV transmission line in East Java was forecasted by use of the above design conditions. The results of this forecast is shown in Table 5.2-15. For the comparative study, the forecast results by standard insulation and by balanced high insulation are also shown in this Table.

(5) Comparative study between actually recorded tripout rate by lightning and forecasted one

(a) Comparison of tripout rate

Table 5.2-16 represent the comparison between the forecasted tripout rates calculated in the above Item (4) and the actual tripout rates only related to weather conditions of 150 kV double circuit transmission line in East Java.

As seen in this Table, the actual tripout rate at the lightning season for 2 years from 1982 to 1984 is 12% higher than the forecasted one. This difference is considered to be the tripout due to the pure bad weather condition without lightning.

The tripout rate caused by bad weather condition in Japan is 7.2/55.6 = 0.13, as shown in Table 5.2-14. This rate is almost equal to the difference above mentioned. This enables us to estimate that most of the tripouts recorded as the tripout by bad weather will be the tripouts actually caused by lightning.

If this estimation is possible, the average tripout rate by lightning in East Java is fit to the forecasted rate by standard condition, independently to I.K.L. of 100. The exact reason can not be got without basic data collection of lightning to be made in the future. It is estimated that lightning at the tropical zone is basically different from that at the temperate zone.

(b) Effect of unbalanced insulation

As mentioned above, the unbalanced insulation is mostly applied to the 70 kV and 150 kV transmission line in East Java. The unbalanced insulation is designed to decrease the 2 c.c.t. tripout at double circuit transmission line with double circuit steel tower. According to tripout record in Table 5.2-12, double circuit tripout was not caused by lightning but by bad weather. If bad weather includes lightning, it has to be considered. Fig.5.2-8 shows the comparison between all actual tripouts caused by weather condition and forecasted tripout by lightning to various kinds of insulations by voltage.

i) As indicated in the tripout record in 1983, double circuit 150 kV transmission line suffered 4 tripouts of which 3 were caused by bad weather conditions. Even if these 3 tripouts were regarded due to lightning, the tripout rate of double circuit line with unbalanced insulation shows lower rate. Unbalanced insulation is considered more effective than standard insulation.

However, in East Java the single and 3 phase reclosing scheme is generally applied to 150 kV transmission line.

So, a tripout to double circuit line will not result in whole breakout immediately.

Table 5.2-17 represents the actual tripout examples of solidly-grounded system in Japan. As seen in the Table, in case that single and 3 phase reclosing scheme is applied, high speed reclosing can be made of about 50% of all double circuit tripouts. It is, therefore, necessary to study the tripouts totally including single and double circuits tripouts. Further study and review of insulation system including balanced high insulation will be required from the above view points. The basically important for such study and review is to collect the detailed necessary analysis data of transmission line tripouts.

ii) Even if all of the tripouts by bad weather of 70 kV transmission line were regarded due to the lightning, the tripout rate of double circuit line shows lower rate. Unbalanced insulation is considered more effective than standard insulation. However, many tripouts due to human work are found on double circuit, and considerable effects by unbalanced insulation are not expected as a whole. Balanced high insulation has also very little effect. The most important in this stage is to decrease the tripout rate by other reasons than lightning.

(c) Corelation between I.K.L. and tripout rate

Basic data of lightning at tropical zone are very few, so the tripout rate by lightning can not be forecasted based on I.K.L. However, comparison of tripout rates was made to some areas with different I.K.L.

Most of the transmission line in East Java are at I.K.L. from 90 to 110. Transmission line route with lower I.K.L. is only between Jember and Banyuwangi. This route has single circuit transmission line with double steel tower, comparison of tripout rate by condition was made between this route and other transmission line with same circuit and steel tower conditions. Calculation results are shown in Table 5.2-18 according to which the tripout rate is decreasing in almost proportion to I.K.L.

(6) Conclusion

Tripout record data of transmission line in East Java are few and the states of tripouts are not detailed. So it will be difficult to draw a clear conclusion at this present. However, following estimation can be made from the tripout record from November 1983 to June 1984 and actual number of tripouts from November 1982 to June 1983.

(a) Tripout rate of transmission line in East Java is nearly 2 times of that in Japan, but the tripout rate by weather conditions shows low rate which is considered almost same as that in Japan.

(b) East Java transmission line has generally high I.K.L. from 90 to 110. But, the tripouts reported as "by lightning" are few and almost same as the tripouts by weather condition including lightning forecasted with standard I.K.L. of 30.

(c) Unbalanced insulation is applied to most of transmission line in East Java. As seen in Fig. 5.2-8, the effect is found in the actual number of tripouts in East Java. In case of 70 kV transmission line, the tripouts by human work are so many that the effect by the insulation are not revealed in sight. In case of 150 kV transmission line, single and 3 phase reclosing scheme is applied to protective relay of transmission line. In this case, high speed reclosing can be made at about 50% of all double circuit tripouts. Further study and review of insulation system will be required in the future.

(d) Date are few, but according to the data, the tripout rate is low at the area with low I.K.L. and it is decreasing almost in proportion to I.K.L.

For the standardization of insulation designing in the future, following consideration will be required together with try to decrease the tripout rate by other reasons than lightning.

i) To collect the basic data of lightning phenomenon at tropical zone, such as the relation among I.K.L., measurement of lightning-flash counters and number of strokes to earth, and the measurement of distribution of stroke amplitudes.

ii) Actively to study the causes of transmission line tripouts, to analyze the operation data of protective relay and to refer this analysis result to the actual tripout states in East Java.

5.2.4. Determination of the Characteristics of Conductor

(1) Investigation of transmission line voltage and conductor's size

The investigation was made to the conductor's size of 70 kV and 150 kV transmission line in East Java area. The reults are as shown in Table 3.2-19.

It was found out in the course of the investigation that 70 kV transmission line was constructed at old time, and 50 mm^2 HDCC or 85 mm^2 ACSR (Pigeon type) conductors had been broadly used before 1967. Piper and ostrich type conductor of 300 MCM (152 mm^2) ACSR appeared after 1970 with the increase in power demand in East Java.

The construction of 150 kV transmission line was started in 1970's as a main transmission line in East Java. The conductors are used of JIS (Metric system) ACSR, if they are designed by Japanese consultants. In this case, the size of conductors is mostly 330 mm^2 both in twin and single and partly 160 mm^2. When designed by European consultants, Hawk type conductor (242 mm^2) was applied as ASTM type (Inch Pound system) ACSR.

(2) Determination of conductor's size

Conductors have 2 kinds of system: one is Inch., Pound system, the other Metric system. Each system has various size of conductors.

Since the construction of 70 kV transmission line in East Java was started before World War II, Inch, Pound system conductors have been used up to present.

With localization of 70 kV transmission line, the conductors with maximum size of more than 300 MCM would not be considered in East Java. The study was therefore made to the conductors of less than 300 MCM.

At present, 2 kinds of conductors; Piper and ostrich are used for 300 MCM conductors. They have the same sectional area of aluminum but different sectional area of steel wire. As a whole, Piper type has more strength of conductor, but higher cost, bigger diameter and heavier weight. Therefore, if weather condition is not good and long spans are continuously required, Piper type is the recommendable one. But, East Java area has generally calm weather and topographic conditions require not so many long spans in this area. So, the Ostrich type will be more economical.

In case of 150 kV transmission line, 3 kinds of ACSR conductors with normal sectional areas of 160 mm^2, 240 mm^2 and 330 mm^2 have been used in East Java. In this case, current carrying capacity of each conductor is 455A, 595A and 720A, respectively. Difference in current capacity between 240 mm^2 and 330 mm^2 conductors is only 20%. Considering the future standardization of the equipment, it would be desirable to be unified to one from two.

Economical comparison was made as follows, between 240 mm^2 and 330 mm^2 conductors for studying which one is pforitable at one circuit T/L on double circuit tower.

(3) Comparison of construction unit cost and power loss of 150 kV transmission line

(a) Comparison of construction unit cost

At one circuit double circuit tower of 150 kV transmission line, the construction unit cost was compared between 330 mm^2 ACSR conductor and 240 mm^2 ACSR conductor. See Table 5.2-20)

This comparison shows that the construction unit cost of 240 mm^2 ACSR is US$3,748/km lower than that of 330 mm^2 ACSR.

(b) Comparison of power loss

Supposing that peak load A (MW) is transmitted in East Java by 150 kV one circuit transmission line, the difference is cost of annual power loss in transmission lines of 330 mm2 ACSR and 240 mm^2 ACSR conductors is obtained as follows.

At first, maximum current (Ip) is calculated in the following expression.

$$Ip = \frac{A \times 10^6}{\sqrt{3} \times 150{,}000 \times P.F.} = 3.85 \left(\frac{A}{P.F.} \right)$$

Difference in cost of annual power loss (L_{RP}) is obtained as below.

$$L_{RP} = 3(R_1 - R_2)\ I_p{}^2 \times L.F. \times 8{,}760 \times u \times 10^{-3}$$

where,

$R_1 - R_2$: Difference in electrical resistance between 240 mm^2 ACSR and 330 mm^2 ACSR
= 0.0335 Ω/km (According to Fig. 5.2-10)

C.F. : loss factor
= 0.595 (in case of standard loss, according to Fig. 5.2-11)

u : Electric unit cost of 150 kV bus bar at the receiving end = 70 Rp/kWh

Therefore,

$$L_{RP} = 3 \times 0.0335 \times 3.85^2 \left(\frac{A}{P.F.}\right)^2 \times 0.595 \times 8{,}760 \times 70 \times 10^{-3}$$

$$= 543.5 \left(\frac{A}{P.F.}\right)^2 \text{ Rp/Km.Year}$$

When Rp is converted to us dollar and P.F. is regarded as 0.9, the difference in cost of annual power loss L \$ (US\$/Km.Year) is computed as follows.

$$L\ \$ = 0.6765A^2 \text{ (US\$/Km.Year)}$$

Where,

A : Peak load in MW

(4) Economic calculation of transmission line for distribution substation

In case of new installation of one circuit transmission line for distribution substation in East Java, economic comparison between 330 mm^2 ACSR and 240 mm^2 ACSR was carried out as follows.

(a) Investment

Difference in construction cost of double circuit single line transmission line between 330 mm^2 ACSR and 240 mm^2 ACSR is calculated at US$3,748/Km, as shown in Table 5.2-20. This is the increase in investment when 330 mm^2 ACSR is applied.

No difference is found in the operation and maintenance costs between two conductors in actual operation. Difference is not considered in this comparison.

(b) Revenue

330 mm^2 ACSR transmission line is expected to have lower resistance and therefore less power loss than 240 mm^2 ACSR.

This is regarded as a profit in 330 mm^2 ACSR equivalent to the difference in power loss between two conductors.

Although the power loss is changed every year by load conditions, it is obtained on the assumption that the demand forecast in whole East Java is applicable for calculating the power loss of the transmission line for general distribution substation.

Growth rate is forecasted up to 2003, in short term, mid term and long term expansion program. But, according to short term expansion program, new installation of whole 150 kV transmission line is scheduled to be completed in 1987. Therefore, additional demand forecast is required for 25 years from 1988 to 2012. Growth rates from 2004 to 2012 are shown in Fig. 5.2-12 which indicates annual load conditions obtained when annual load in 1988 is required 1 MW. Based on the above premise, the profit due to the power loss at the maximum load in 1988 of 4 to 8 MW was calculated. The results are as shown in Table 5.2-21.

(c) Economic calculation

Based on the load forecast in 1988, the discount rate can be obtained form the investment and profit above calculated. Table 5.2-22 shows the calculation examples of discount rate at the maximum load of 7 MW in 1988.

By the same calculation method, discount rates at different forecasted loads in 1988 are obtained. Fig. 5.2-13 shows the characteristics curve representing a relation between discount rates and loads in 1988. This figure shows that 330 mm^2 ACSR will be profitable if discount rate is set at 10% from the economical standard view-points and if peak load in 1988 is expected more than 6,200 KW.

In case that the load is 6,200 KW in 1988, the load in 2012 (25 years after 1988) is forecasted of 79,000 KW. This means 57% of transmission line capacity in case of 240 mm^2 ACSR and 47% in case of 330 mm^2 ACSR. Both conductors have no problems in transmission line capacity. However, if the load in 1988 is more than 6,200 KW, earlier construction of transmission line is required in case of 240 mm^2 ACSR because of its smaller capacity. On the other hand, in consideration of economical construction schedule, 240 mm^2 ACSR transmission line construction is also required to be started earlier than 330 mm^2 ACSR. Therefore, 240 mm^2 ACSR transmission line is very uneconomical.

(5) Study of transmission line in Madura Island

In short term expansion program, there is a planning of 150 kV transmission line from Gili Timur Substation to Sumenep Substation in Madura Island. Since one circuit transmission line is planned in this route, the size of conductors is studied based on the above study results.

(a) Demand forecast in Madura Island

Maximum loads in East Java and Madura Island have been forecasted by PLN. Table 5.2-23 shows the annual demand forecast in 1984/85, 1988/89 and 1993/94 and annual growth rates at these areas, based on these PLN's data. The Table indicates that further power demand will be expected in Madura Island in the future than in East Java.

On the other hand, the demand forecast in Madura Island by JICA is based on that in whole East Java, without consideration of regional difference in power demand. The demand forecast in this Report is, therefore, made both with the demand forecast by JICA (no regional difference in power demand) and by PLN (regional difference between Madura Island and East Java).

Table 5.2-24 and Fig.5.2-14 show the demand forecast by PLN at East Java and Madura and that by JICA at East Java in 1988/89 and 1993/94 on the basis of maximum load in 1983/84.

The increase in power demand at Maruda Island is considered as follows.

i) It is 10 years, i.e. 5 years after and before 1988/89 when transmission line facilities are to be operated at Madura Island, that the growth rate of power demand that at whole East Java.

ii) Target power demand in 1993/94 forecasted on the basis of maximum load in 1983/84 is obtained by multiplying JICA's forecasted demand at whole East Java by the growth rate of power demand forecasted by PLN. This is calculated in the following expression.

Power demand in 1993/94 (on the basis of 1983/84)

$$= 3.921 \times \frac{7,175}{4,942} = 5.693$$

iii) When PLN's forecasted value is applied to the power demand in 1988/89 at Madura Island and when JICA's value is applied to the growth rate of power demand after 1988/89, the power demand in 1993/94 is approaching to the target power demand. This is regarded as the revised forecasted power demand at Madura Island.

Therefore, revision rate of demand forecast at Madura Island in 1988/89 is calculated as follows.

$$\text{Revision rate} = \frac{2,772}{2,100} \fallingdotseq 1.32$$

Demand forecast in 1988/89 by substation was made by use of the above revision rate. The results are as shown in Table 5.2-25.

Fig.5.2-15 represents the flow of power from each substation to transmission line system.

For the economical transmission line study, the discount rate is obtained by use of Fig. 5.2-13 from the power loads of each transmission line. As a result, 2 lines near to the Gili Timur Substation have the discount rate of more than 10%, and other 2 lines far from that Substation less than 10%. In the former 2 lines, 330 mm^2 ACSR is advantageous, in the latters it is not.

The equivalent load of transmission line in whole Madura Island is 6.74 MW as seen in Fig.5.2-15, which is based on the premise that all transmission lines have the same unit facilities for the effective maintenance and operation. In this case, discount rate is calculated at 11%, which results in the more advantage of 330 mm^2 ACSR transmission line.

(6) Summary

Above study and results are summarized as follows.

(a) As a results of the study of transmission line in East Java, it was found out that 70 kV, transmission line was already standarized but had 2 kinds of 300 MCM conductors (ostrich type and piper type). It is recommendable to be unified to ostrich type.

(b) 150 kV transmission line has 3 kinds of conductors; JIS type 160 mm^2 ACSR, JIS type 330 mm^2 ACSR and ASTM type 242 mm^2Hawk ACSR. There is only a difference in transmission capacity of 20% and construction cost of 9% between Hask ACSR and 330 mm^2 ACSR. It is recommendable to be unified to 330 mm^2 ACSR.

In Japan, many kinds of conductors had been used in the past. Nowadays, they are already arranged and unified, and standard lines are determined at 1.5 time interval in case of small capacity of transmission line and at 2.0 times interval in case of large capacity. Table 5.2-26 shows the actual example in KEPCO.

(c) Economic comparison by different size of conductors was made to the transmission line for distribution substation at Madura Island. As a result, 330 mm^2 ACSR was found advantageous, if all transmission line is unified to unit size for the effective maintenance of the facilities.

(d) In case of establishing the standard of transmission line facilities, the scope of standard and construction schedule of each transmission line shall be determined in due consideration of economic efficiency such as transmission line facilities and power loss.