CHAPTER 8

ELECTRIC POWER GENERATION PLAN

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8.1 ADDITION OF NO. 3 UNIT OF TIS ABBAY POWER STATION

8.1.1 Present Situation and Particulars of Existing Power Station

The existing Tis Abbay Power Station is a run-of-river type power station provided in 1964 at the right bank of the Blue Nile approximately 35 km downstream of Lake Tana. The present situation at this power station is greatly affected by the runoff conditions of the Blue Nile and in the dry season output is lowered to 50 ~ 30% due to extreme reduction in river discharge, while in the rainy season, due to rising of the water level at the power station tailrace outlet accompanying rise in the water level of the Blue Nile, head is reduced and output is lowered.

The installed capacity is 3,840 kW x 2 units = 7,680 kW, but the waterway structures and the powerhouse have been designed taking installation of a No. 3 unit into consideration, and in case of addition of a unit, all that would be necessary is to simply install a turbine and generator. However, unless the annual flow of the Blue Nile is improved through construction of a regulating dam at Lake Tana, the present drawbacks of the power station will only be aggravated by the additional installation.

The elevation of the powerhouse assembly hall is 1581.93 m (relative elevation 61.00 m) with no access road, and hauling in of equipment is done by a derrick crane provided at the outdoor switchyard (El. 1,620.50 m).

Operation of the power station is done by a manual control system.

The basic particulars of the power station are as indicated below.

Maximum available discharge		20 m^3/sec
Standard effective head		46 m
Maximum output		7,680 kW (3,840 kW x 2)
Waterway		Trapezoidal open canal Cross-sectional area 100.6 m^2 Length 330 m
Penstock		Vertical shaft, 1 line Inner dia. 3.20 m x length 62 m
Turbine	Type	Vertical Francis
	Rated output	3,960 kW
	Available discharge	10 m^3/sec
	Head	46 m
	Speed	375 rpm
	Number	2 units

Generator	Type	3-phase, synchronous
	Rated output	4,800 kVA
	Frequency	50 Hz
	Rated voltage	6 ± 5% kV
	Rated power factor	0.8
	Number	2 units
Main Transformer		
	Type	3-phase, 2 windings, oil-immersed, selfcooled
	Rated output	4,800 kVA
	Rated voltage	47.25/6.3 kV
	Frequency	50 Hz
	Number	2 units

8.1.2 Addition of No.3 Unit

The existing waterway structures have sufficient capacities for inclusion of the No. 3 unit as stated in 8.2.1, and at present there are bulkheads provided at the end of the penstock and in front of the outlets.

As for electrical equipment, an inlet valve, draft tube and distribution panel are already provided.

Blockouts have been provided where the turbine and generator are to be installed, and with regard to civil work, about the only thing left to be performed is concrete placement around casings.

The relation between the turbine center and the water level at the outlet is designed matching the No. 1 and No. 2 units. Therefore, it is judged to be most advantageous both technically and economically to add electrical equipment of identical specifications to the No. 1 and No. 2 units.

With respect to the control system, it is to be a manual control system as with the No. 1 and No. 2 units according to the result of consultations with EELPA.

Further, for pressurized oil apparatus, main equipment cooling systems and protective systems, thorough examinations will be made at the stage of a definite study.

8.2 TIS ABBAY NO. 2 POWER STATION

8.2.1 Hydraulic Study of Existing Waterway

Tis Abbay No. 2 Power Station is to be provided at the right bank of the Blue Nile approximately 100 m downstream from the existing power station. It is thought the method of conducting water by newly providing a waterway branching from the downstream end of the existing waterway (open canal) will be the most economical. Consequently, a hydraulic study will be made of the capacity of the existing waterway.

(1) Preconditions

i. Leakage from the existing diversion cofferdam will not be considered.

ii. Damage of the left-bank wall of the deepened Abbay branch will not be considered.

iii. The discharge is to be the planned discharge based on the rule curve for the standard water surface level and studies will be made for the two cases of a maximum of 160 m^3/sec and a minimum of 60 m^3/sec.

(2) Hydraulic Calculations
[Water Surface Gradients of Waterway System]

The water surface gradients of the waterway system from the deepened Abbay branch to the penstock were determined for Q = 60 m^3/sec and Q = 160 m^3/sec, and the water passage volumes at various parts were calculated for the depths of water at the particular parts. The results are that the part producing the minimum volume of water passage gives the maximum water passage volume of this waterway system.

The calculations were made in accordance with the procedure below.

i. Waterway System Divided into 3 Sections

Section	a	between diversion cofferdam and front surface of intake curtain wall
Section	b	between curtain wall and starting point of main water canal
Section	c	between starting point of main water canal and penstock

ii. The overflow water depth of the diversion cofferdam is obtained and the water level at this time is taken to be the water level at the front surface of the curtain wall. Further, the head loss at the intake gate is considered from this water level, and this is taken as the water level at the starting point of the open canal.

With this water level as the end of the backwater of the open canal, the water level at the intake orifice of the penstock is assumed, and the water surface shape is trial-calculated. In this case, the water level of the penstock orifice is the problem, but it may be considered that the above conditions are satisfied if it is found to be around 100m.

The following equation is used for calculations:

For cofferdam overflow depth

$$Q = CBH^{3/2} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (1)$$

where

Q : overflow quantity = (60 - 45), (160 - 45)

C : overflow coefficient = 2.1

B : overflow width = 105 m

H : overflow depth

For open canal backwater calculation:

$$h = H_1 - H_2 = Z_2 - Z_1 + \alpha \frac{Q^2}{2g} \left(\frac{1}{A_2^2} - \frac{1}{A_1^2} \right)$$

$$- \frac{1}{2} \left(\frac{1}{R_1^{4/3} A_1^2} + \frac{1}{R_2^{4/3} A_2^2} \right) n^2 Q^2 \Delta x - h_e \quad \ldots\ldots \quad (2)$$

where

h : water level difference sought

H_1 : water depth at downstream cross section

H_2 : water depth at upstream cross section

Z : potential heads at respective cross sections

α : correction factor = 1

Q : discharge = 45 m^3/sec

A : cross-sectional area of flow

R : hydraulic mean depth

n : roughness coefficient = 0.025

Δx : distance between cross sections

h_e : head loss due to vortex = 0

The results of calculations according to the above are indicated in Fig. 8-2-2. According to these, the penstock orifice water level is 99.5 m in case of Q = 60 m^3/sec, and 100.0 m in case of Q = 160 m^3/sec, and the end of the open canal backwater is contracted. This indicates that there is water backing up at the open canal, which in effect means that the open canal has the function of a head tank.

Fig. 8-2-1 Rating Curve of Waterway

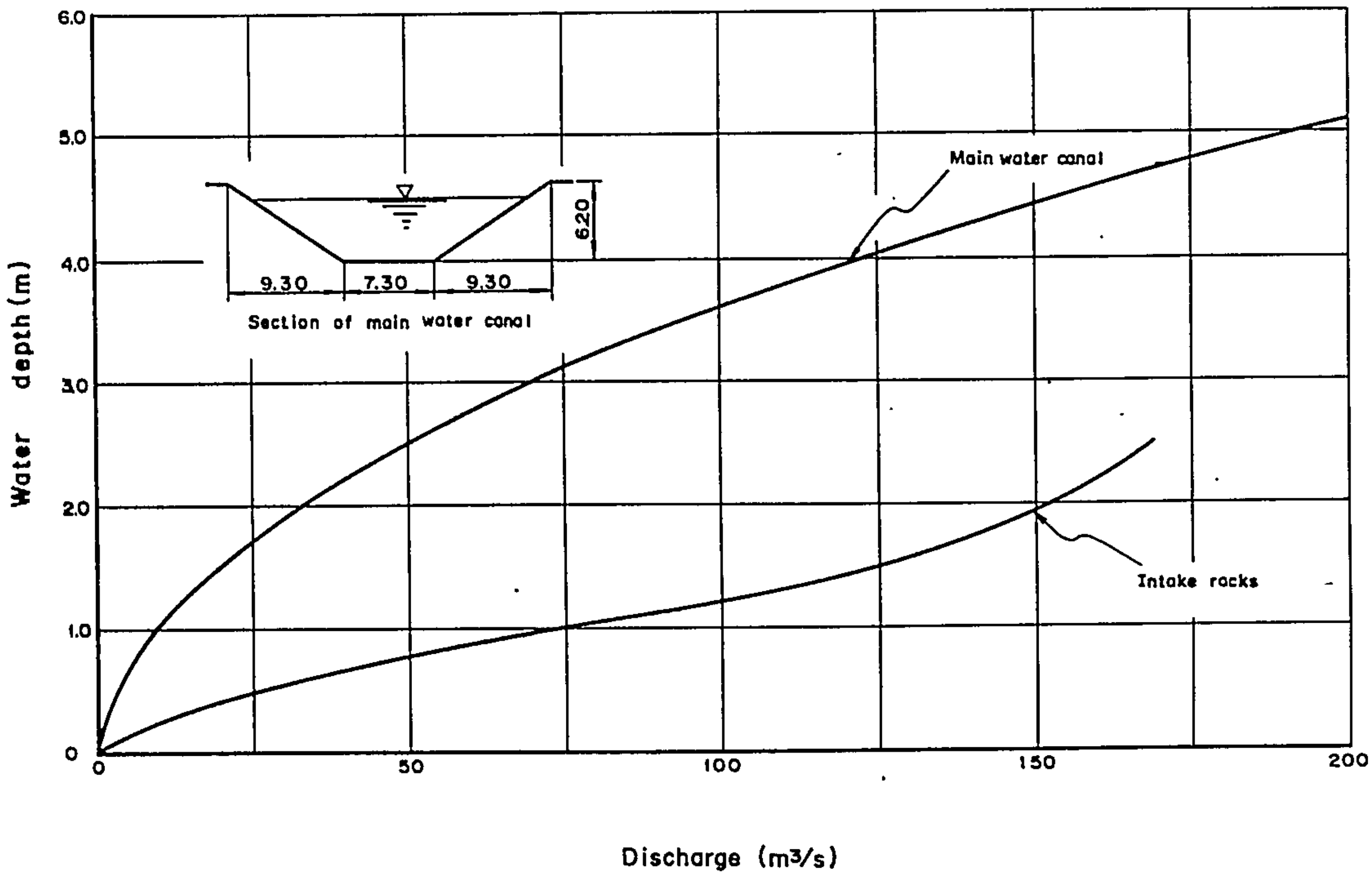
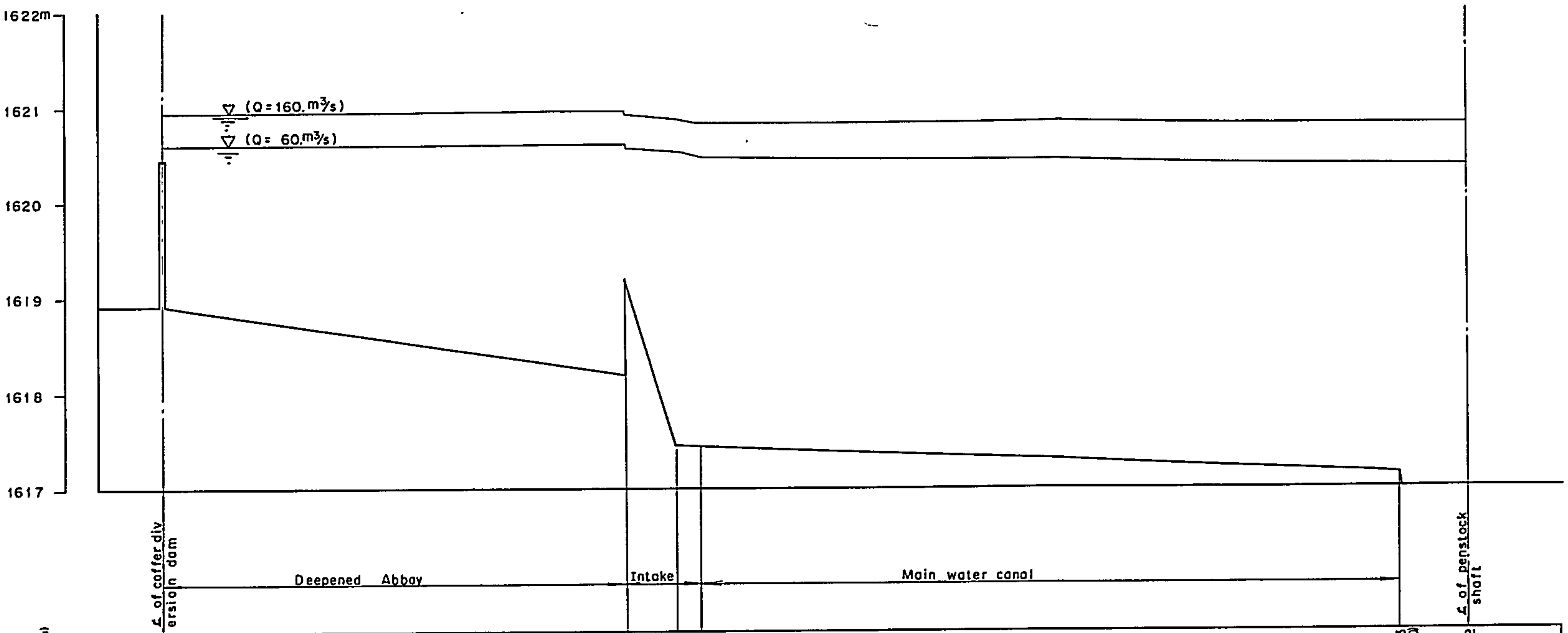


Fig. 8-2-2 Water Surface Gradients



Water surface level (Q=160m³/s)	1621.10	1621.10 1621.07	1621.02	162098	162093 (10000)	162092
Water surface level (Q=60m³/s)	162066	162066 162062	1620.57	162052	162043 (99.50)	162042
Channel level	162043	1619.18	1617.43	1617.43	1617.13	
Cumulative distance	0	200.0	221.0	231.0	531.0	561.0
Section distance	0	200.0	21.0	10.0	300.0	30.0
Station	0	1	2	3	4	5

[Water Passage Volume]

The Q-H curve at the curtain wall portion of the intake and the open canal are shown in Fig. 8-2-1.

The free water passage volumes of the various parts applying the depths of water determined from the water surface gradients are the following:

Intake portion	118 m^3/sec and 146 m^3/sec, respectively
Open canal	70 m^3/sec and 86 m^3/sec, respectively

From the results above it is seen that the volume of water passed in the existing waterway system is governed by the open canal, but there is sufficient capacity even if the quantity of water to be used by the No. 2 Power Station is taken into account.

[Existing Facilities]

Although one of the conditions in the hydraulic study was that there are no damaged parts, actually, a considerable amount of repairs is necessary. If this were to be left alone, no matter how much the discharge conditions may be improved through the regulating dam, there will be large amounts of overflow along the waterway system and the water level required at the intake will not be secured.

8.2.2 Power Generation Plan

(1) Outline

This power generation plan calls for intake of a maximum 15 m^3/sec from the downstream end of the headrace of the existing Tis Abbay Power Station and conducting the water by a non-presurized conduit to a tableland on the right bank of the Blue Nile approximately 100 m downstream from the existing power station and producing an additional maximum output of 5, 700 kW with the standard effective head of 46 m obtained.

The particulars of the plan are as indicated below.

Power generation system	Run-of-river
Power generation particulars	
Max. available discharge	15 m^3/sec
Standard effective head	46 m
Max. output	5, 700 kW
Waterway	Semi-circular top, rectangular bottom non-pressurized conduit, 1 line, inner width 2.48 m hight 2.73 m, length 187.6 m

Head tank	Capacity 1,800 m^3	
Penstock (vertical shaft, 1 line),	inner dia. 1.8 m x length 89.7 m	
Turbine,	vertical Francis	5,950 kW
Generator		7,100 kVA
Annual energy production possible		47.4 GWh

(2) Examination of Scale

The scale of the output of the No. 2 power station must be examined keeping the Upper Beles Project in mind. Although it is not clear at the present moment when the Upper Beles Project will be commissioned into the ICS System, on the predication that it will be realized sooner or later, it will be necessary to consider diversion of an average of approximately 50 ~ 55 m^3/sec from Lake Tana as described in 7.3.2.

Meanwhile, when the geographical conditions of the power station site are considered, since the site is located topographically at the entrance of the Blue Nile Gorge, it is difficult for ample space to be obtained, while since the conduit will pass through the compounds of the existing power station, there will be restrictions placed from this aspect also, and it will not be advantageous to make it very large.

At the Tis Abbay site, an available discharge of 40 m^3/sec to 45 m^3/sec combining the existing and new stations will be a reasonable level. Accordingly, comparison studies will be made for the following two proposals.

Alternative ① Available discharge 10 m^3/sec

Alternative ② Available discharge 15 m^3/sec

The results of the examination are indicated below.

Item	Alternative ①	Alternative ②	Remarks
Max. available discharge	10 m^3/sec	15 m^3/sec	
Standard effective head	46 m	46 m	
Max. output	3,840 kW	5,700 kW	
Energy production possible	31,612 MWh	47,414 MWh	Table 8-2-2
Turbine output	3,970 kW	5,950 kW	
Turbine speed	375 rpm	375 rpm	
Turbine type	vertical Francis	vertical Francis	
Generator output	4,800 kVA	7,100 kVA	
Generator power factor	0.8 (lag)	0.8 (lag)	
Generator voltage	6.6 kV	6.6 kV	

Item	Alternative ①	Alternative ②	Remarks
Main transformer output	4,800 kVA	7,100 kVA	
Main transformer voltage	45/6.6 kV	45/6.6 kV	

Table 8-2-1 Comparison of Construction Costs (Unit : Eth. $)

Item	Alternative ①	Alternative ②	Remarks
Civil works			
Access road	185,000	185,000	
Waterway, Headtank and Penstock	1,782,000	2,075,000	
Foundation Power house	1,240,000	1,351,000	
Control building	150,000	200,000	
Foundation Switchyard	22,000	22,000	
Sub-total	3,379,000	3,833,000	
Hydrolic Equipment	231,000	291,000	
Total	3,610,000	4,124,000	
Electrical Equipment			
Turbine, Generator	3,285,710	4,064,290	
Maintransformer and Others	1,507,140	1,771,430	
Total	4,792,850	5,835,720	
Contingency	967,150	1,150,280	
Grand total	9,370,000	11,110,000	
Max. Output	3,840	5,700	
Possible Energy Production	31,612	47,414	Case ④⑤ - Case ③
Construction cost per kW	2,440	1,949	
Construction cost per kWh	0.296	0.234	

Based on the results, Alternative ② is adopted considering economy and future demand.

8.2.3 Energy Production

Calculations of energy production after Lake Tana regulation were carried out en bloc for the cases of increased energy production of the existing facilities and the energy production after addition of the No. 3 unit at Tis Abbay Power Station and after construction of Tis Abbay No. 2 Power Station.

The runoff at the intake of Tis Abbay Power Station is the planned discharge according to the standard water surface level operation rule for the Lake Tana regulating dam to which the remaining runoff between the outlet of the lake and the intake is added.

Calculations were made of daily runoff during the 11 year period of 1965 ~ 1975 for the five cases below.

Case ①	Before Lake Tana regulation	Present state Qmax = 20 m^3/sec
Case ②	After Lake Tana regulation	Qmax = 20 m^3/sec
Case ③	ditto	No. 3 unit added Qmax = 30 m^3/sec
Case ④	ditto	No. 2 PS constructed (10 m^3/sec) Qmax = 40 m^3/sec
Case ⑤	ditto	ditto (15 m^3/sec) Qmax = 45 m^3/sec

(1) Available discharge

The available discharges are calculated for the runoffs below in regard to the respective cases.

Case ① Gaging Station No. 9 runoff + Blue Nile remaining runoff + Andassa River runoff

Case ②~⑤ Lake Tana regulated discharge + Blue Nile remaining runoff + Andassa River runoff

Leakage from the diversion cofferdam and loss caused by damage to the deepened Abbay branch wall are not considered.

(2) Effective Head

The basic values for calculation of effective head are the following:

Head tank water level = 100.50 m (average water level)

Head loss = 0.5 m (constant)

Tailrace water level: varies according to Blue Nile runoff

Note) See Dwg. A6-114 of EELPA for head tank water level. Tailrace water levels established for 50 m^3/sec based on Dwg. A4-77 of EELPA.

The effective heads are tabulated below.

Blue Nile Runoff	Head Tank Water Level -Head Loss	Tailrace Water Level	Effective Head
0 ~ 50 m^3/sec	100.0	54.0	46.0
51 ~ 100	100.0	55.3	44.7
101 ~ 150	100.0	56.4	43.6
151 ~ 200	100.0	57.2	42.8
201 ~ 250	100.0	58.0	42.0
251 ~ 300	100.0	58.7	41.7
301 ~ 350	100.0	59.4	40.6
351 ~ 400	100.0	60.0	40.0
401 ~ 450	100.0	60.6	39.4
451 ~ 500	100.0	61.2	38.8
501 ~ 550	100.0	61.9	38.1
551 ~ 600	100.0	62.5	37.5
601 ~ 650	100.0	63.2	36.8
651 ~ 700	100.0	63.8	36.2
701 ~ 750	100.0	64.4	35.6
751 ~ 800	100.0	65.1	34.9

The standard effective head was taken at 46 m based on Fig. 8-2-8 (EELPA DWG, A 4-77), and in making definite designs it will be necessary to carry out a study using a more accurate rating curve for tailrace water level-discharge.

(3) Energy Production Possible

Theoretical equation $P = 9.8\,Q \cdot H_e$ (kW)

Power generation $P = 9.8\,yt \cdot y_G \cdot Q \cdot H_e$ (kW) where

P : output, kW

Q : available discharge, m^3/sec

H_e : effective head, m

y_t : turbine efficiency = 0.88

y_G : generator efficiency = 0.96

∴ Power generation $P = 8.3 Q . H_e$

Energy production $E = P . h$ (kWh)

The results of the calculations are indicated in Tables 8-2-2, 8-2-4 (1) ~ (5). Comparisons made on picking up dry years are given in Table 8-2-3, Fig. 8-2-7. Further, the discharge durations at the intake for the present state and after regulation are indicated in Figs. 8-2-3 (1), (2) and 8-2-4 (1), (2), respectively. As for the comparisons of discharge durations before and after regulation for the average year, 1969, they are given in Fig. 8-2-5.

The additional energy production for the present state ($Q_{max} = 20 m^3/sec$) is 4,850 MWh against 58,446 MWh, while the capacity factor becomes 99.5% from 91.5% to reach approximately 100%. With respect to the capacity factor, the present 91.5% is generally speaking an extremely high factor for a run-of-river power station.

The problem, as seen in the case of the dry year of 1973, is when the capacity factor drops to around 80% where for a period of approximately 75 days concentrated in April to June the output falls and no other power source can be obtained during this time, which can be comprehended also from the discharge duration curve. The improvement in the discharge durations for dry years is especially pronounced. For example, the number of days when discharge is under $20m^3/sec$ is 135 days in 1973, but after regulation, there is an improvement to 15 days and the energy production possible from April to June becomes 13,585 MWh from 4,922 MWh.

Table 8-2-2 Summarization of Energy Production

1965 - 1975 11 Years

Month	Case (1) Existing Qmax. =20m³/s			Case (2) After Reg. Qmax. =20m³/s				Case (3) After Reg. Qmax. =30m³/s			Case (4) After Reg. Qmax. =40m³/s			Case (5) After Reg. Qmax.=45m³/s		
	Turbine discharge (m^3/s-day)	He (m)	E (10^3kwh)	Turbine discharge (m^3/s-day)	He (m)	E (10^3kwh)	ΔE (10^3kwh)	Turbine discharge (m^3/s-day)	E (10^3kwh)	ΔE (10^3kwh)	Turbine discharge (m^3/s-day)	E (10^3kwh)	ΔE (10^3kwh)	Turbine discharge (m^3/s-day)	E (10^3kwh)	ΔE (10^3kwh)
Jan.	620	44.50	5,495	620	44.25	5,466	-29	930	8,198	2,703	1,240	10,929	5,434	1,394	12,292	6,797
Feb.	562	45.08	5,046	563	44.12	4,747	-99	844	7,415	2,369	1,125	9,883	4,837	1,265	11,118	6,072
Mar.	605	45.79	5,519	619	44.06	5,430	-89	928	8,142	2,623	1,237	10,855	5,336	1,391	12,211	6,692
Apr.	514	45.97	4,703	600	43.85	5,241	538	900	7,862	3,159	1,200	10,483	5,780	1,350	11,793	7,090
May	377	46.00	3,458	609	43.83	5,310	1,852	912	7,958	4,500	1,216	10,607	7,149	1,368	11,928	8,470
June	357	46.00	3,267	584	43.74	5,083	1,816	874	7,606	4,339	1,164	10,128	6,861	1,309	11,390	8,123
July	590	45.31	5,322	620	42.70	5,273	-49	930	7,910	2,588	1,240	10,546	5,224	1,395	11,864	6,542
Aug.	620	42.49	5,247	620	42.34	5,229	-18	930	7,844	2,597	1,240	10,459	5,212	1,395	11,766	6,519
Sept.	600	40.47	4,837	600	42.84	5,120	283	900	7,681	2,844	1,200	10,241	5,404	1,350	11,521	6,684
Oct.	620	41.16	5,084	620	43.29	5,347	263	930	8,020	2,936	1,240	10,693	5,609	1,395	12,030	6,946
Nov.	600	42.53	5,083	600	44.60	5,331	248	900	7,996	2,913	1,200	10,661	5,578	1,350	11,994	6,911
Dec.	620	43.60	5,385	620	44.68	5,519	134	930	8,278	2,893	1,240	11,037	5,652	1,395	12,417	7,032
Total	6,685		58,446	7,275		63,296	4,850	10,908	94,910	36,464	14,542	126,522	68,076	16,357	142,324	83,878
Mean	18.3 (m^3/s)	44.08		19.9 (m^3/s)	43.69			29.9 (m^3/s)			39.8 (m^3/s)			44.8 (m^3/s)		

Table 8-2-3 Comparison Table of Energy Production in Dry Years between Case (1) and Case (2)

Year : 1972

Month	Case (1) Existing Qmax. =20m³/s			Case (2) After Reg. Qmax. =20m³/s			Case (2) - Case (1)		
	Turbine discharge (m^3/s-day)	He (m)	E (10^3kwh)	Turbine discharge (m^3/s-day)	He (m)	E (10^3kwh)	Turbine discharge (m^3/s-day)	He (m)	E (10^3kwh)
Jan.	620	44.70	5,521	620	44.70	5,521	0	0	0
Feb.	580	45.01	5,201	580	44.66	5,160	0	-0.35	- 41
Mar.	620	46.00	5,681	620	44.45	5,490	0	-1.55	- 191
Apr.	540	46.00	4,946	600	43.71	5,224	60	-2.29	278
May	331	46.00	3,037	620	43.60	5,385	289	-2.40	2,348
June	281	46.00	2,570	600	43.60	5,211	319	-2.40	2,641
July	610	45.92	5,578	620	42.83	5,289	10	-3.09	- 289
Aug.	620	44.01	5,435	620	42.91	5,300	0	-1.10	- 135
Sept.	600	42.80	5,115	600	43.60	5,211	0	0.80	96
Oct.	620	43.24	5,340	620	43.60	5,385	0	0.36	45
Nov.	600	44.19	5,281	600	44.70	5,343	0	0.51	62
Dec.	620	44.87	5,541	620	44.70	5,521	0	-0.17	- 20
Total	6,642		59,246	7,320		64,040	678		4,794
Mean	18.2 (m^3/s)	44.90		20.0 (m^3/s)	43.92		1.8 (m^3/s)	-0.98	

Year : 1973

Month	Case (1) Existing Qmax. =20m³/s			Case (2) After Reg. Qmax. =20m³/s			Case (2) - Case (1)		
	Turbine discharge (m^3/s-day)	He (m)	E (10^3kwh)	Turbine discharge (m^3/s-day)	He (m)	E (10^3kwh)	Turbine discharge (m^3/s-day)	He (m)	E (10^3kwh)
Jan.	620	46.00	5,681	620	44.70	5,521	0	-1.30	- 160
Feb.	560	46.00	5,131	560	44.70	4,986	0	-1.30	- 145
Mar.	457	46.00	4,184	620	44.70	5,521	163	-1.30	1,337
Apr.	212	46.00	1,940	600	44.70	5,343	388	-1.30	3,403
May	144	46.00	1,320	497	45.04	4,434	353	-0.96	3,114
June	181	46.00	1,662	426	45.18	3,808	245	-0.82	2,146
July	528	45.87	4,827	620	43.19	5,334	92	-2.68	507
Aug.	620	43.51	5,373	620	42.67	5,270	0	-0.84	- 103
Sept.	600	42.00	5,020	600	43.52	5,202	0	1.52	182
Oct.	620	41.89	5,174	620	43.57	5,382	0	1.68	208
Nov.	600	43.09	5,151	600	44.70	5,343	0	1.61	192
Dec.	620	44.17	5,455	620	44.70	5,521	0	0.53	66
Total	5,762		50,918	7,003		61,665	1,241		10,747
Mean	15.8 (m^3/s)	44.71		19.2 (m^3/s)	44.27		3.4 (m^3/s)	-0.44	

Fig.8-2-3(1) Unregulated Discharge Duration Curves at Intake of Tis Abbay P.S 1964~1969
Blue Nile Riv C.A = 16.669 km²

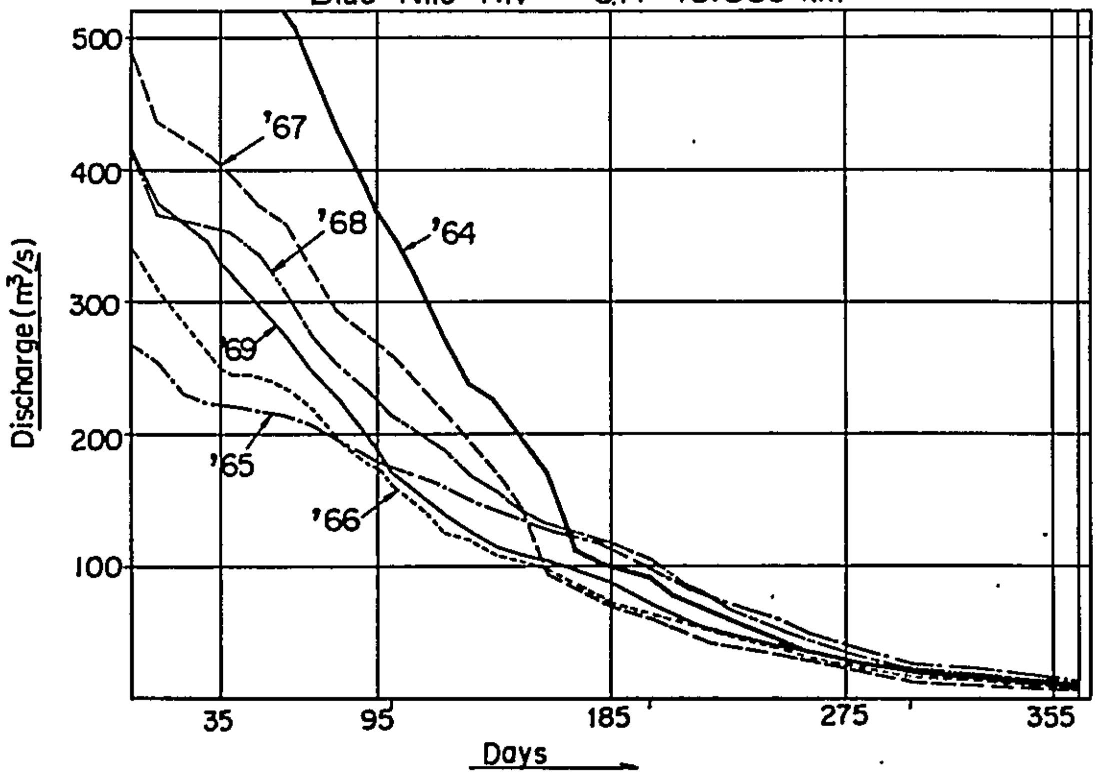


Fig.8-2-3(2) Unregulated Discharge Duration Curves at Intake of Tis Abbay P.S 1970 ~ 1975
Blue Nile Riv C.A =16.669 km²

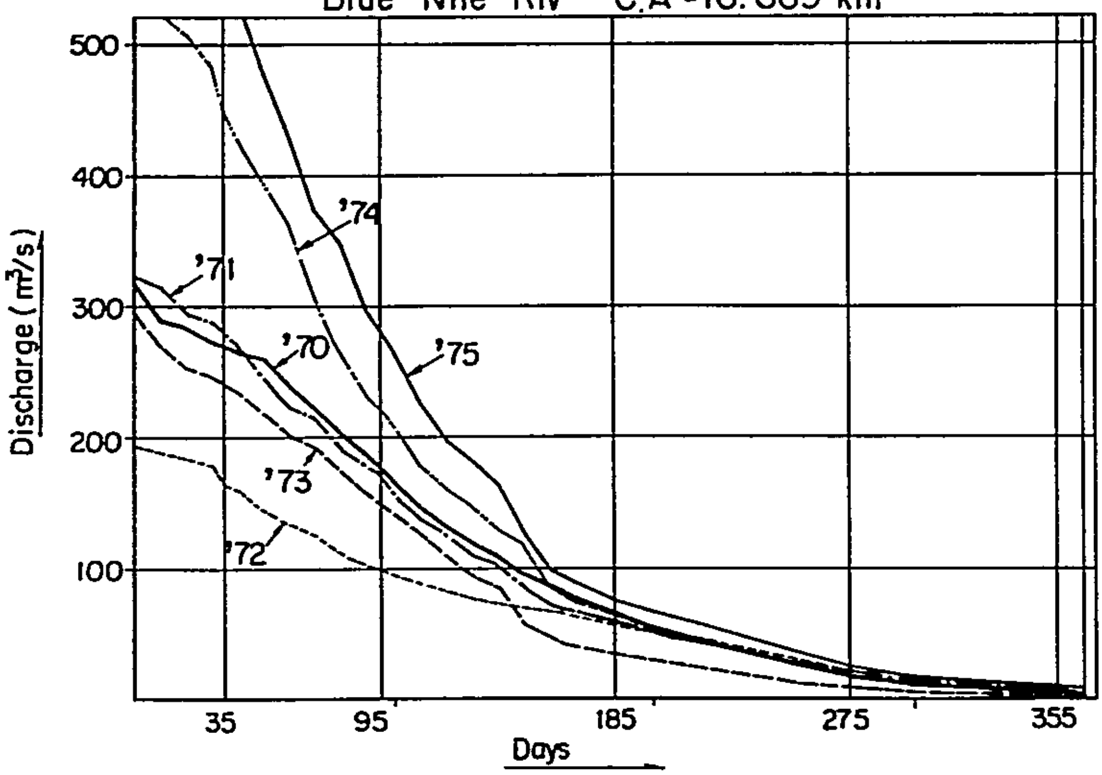


Fig. 8-2-4(1) Regulated Discharge Duration Curve at Intake of Tis Abbay P. S 1964 ~ 1969
Blue Nile Riv C.A = 16.669 km²

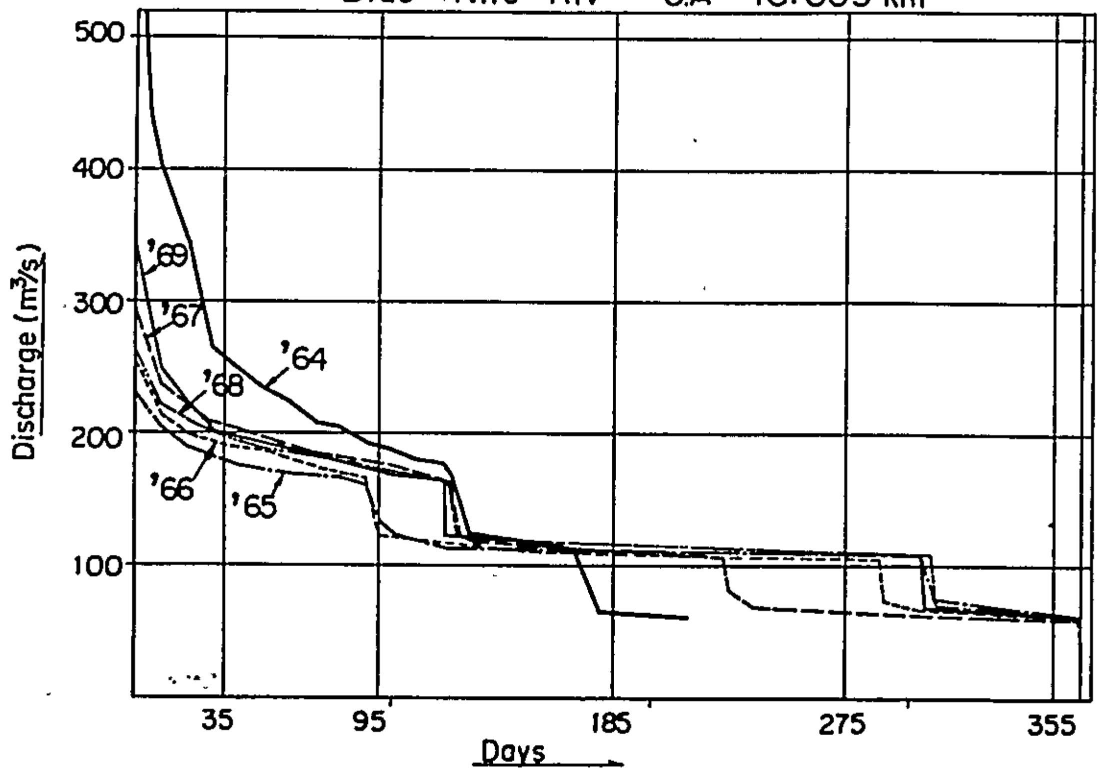


Fig. 8-2-4(2) Regulated Discharge Duration Curve at Intake of Tis Abbay P.S 1970 ~ 1975
Blue Nile Riv C.A = 16.669 km²

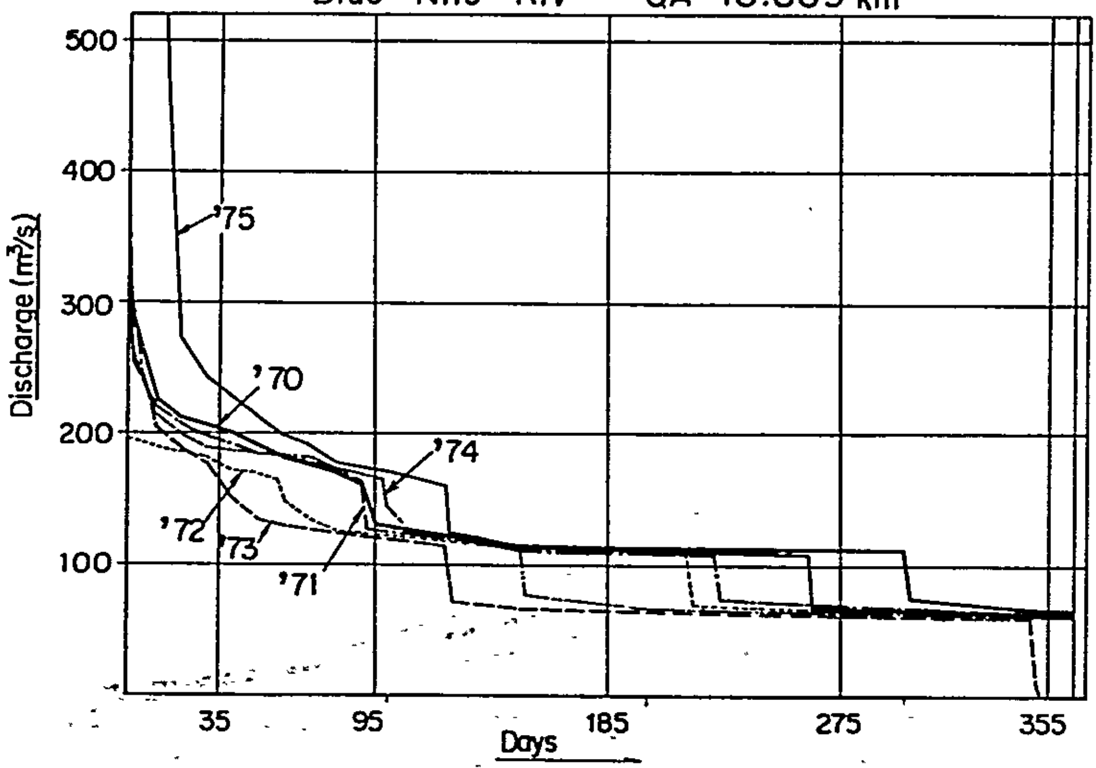


Fig. 8-2-5 Comparison Between Unregulated and Regulated Discharge at Intake of Tis Abbay Power Station in 1969.

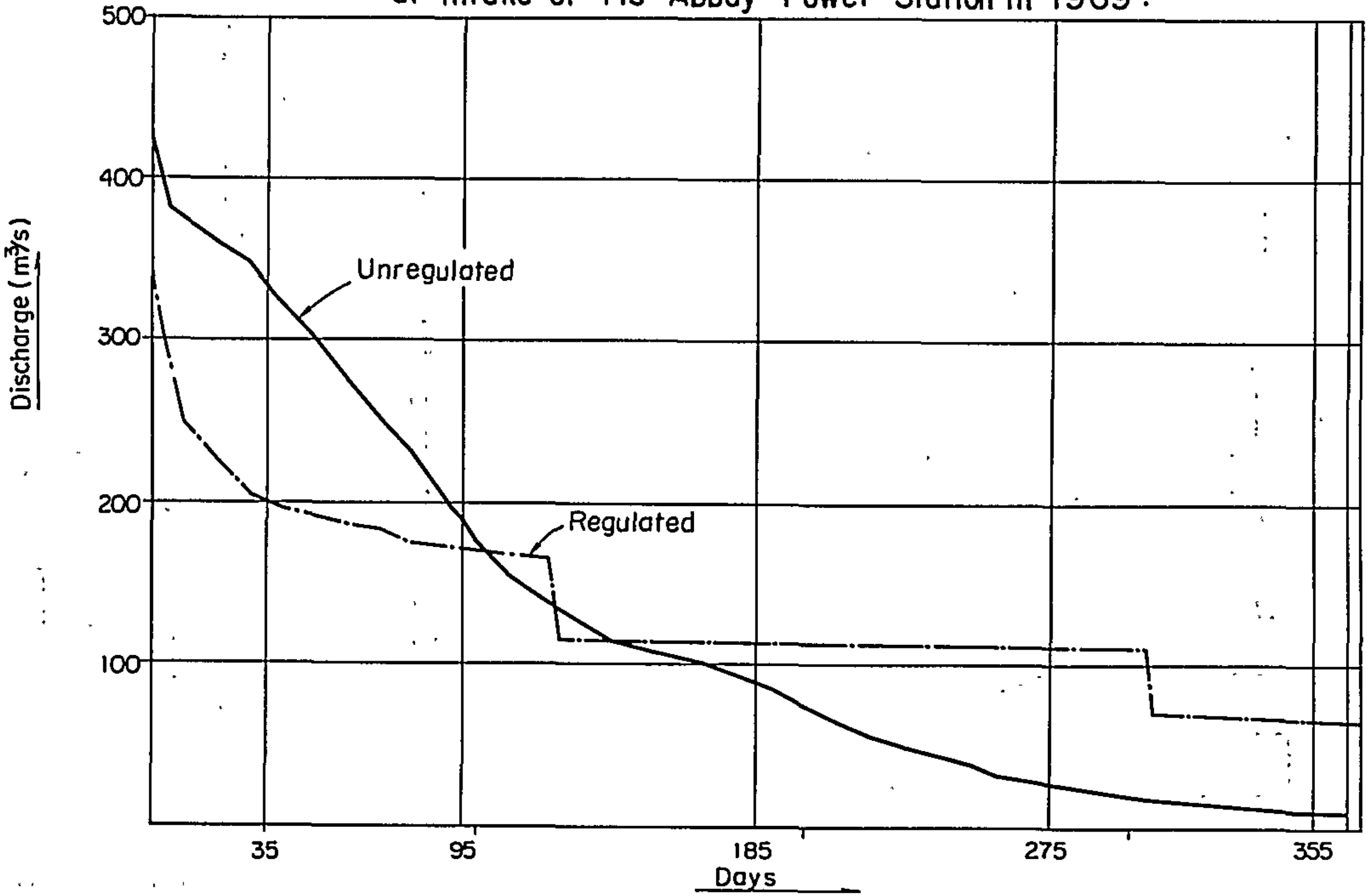


Fig. 8-2-6 Average Energy Production for 1965~1975

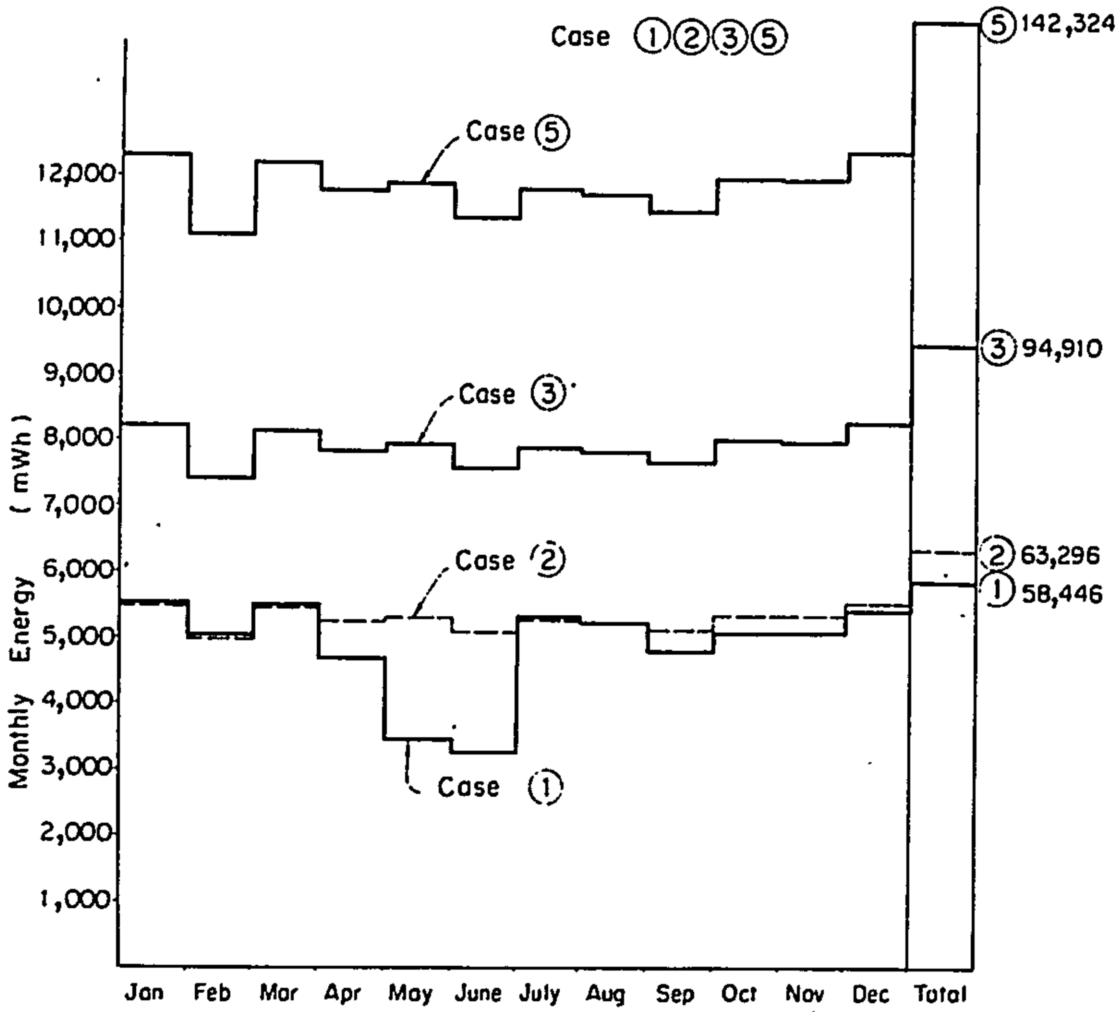


Fig. 8-2-7 Energy Production for Dry Year 1973

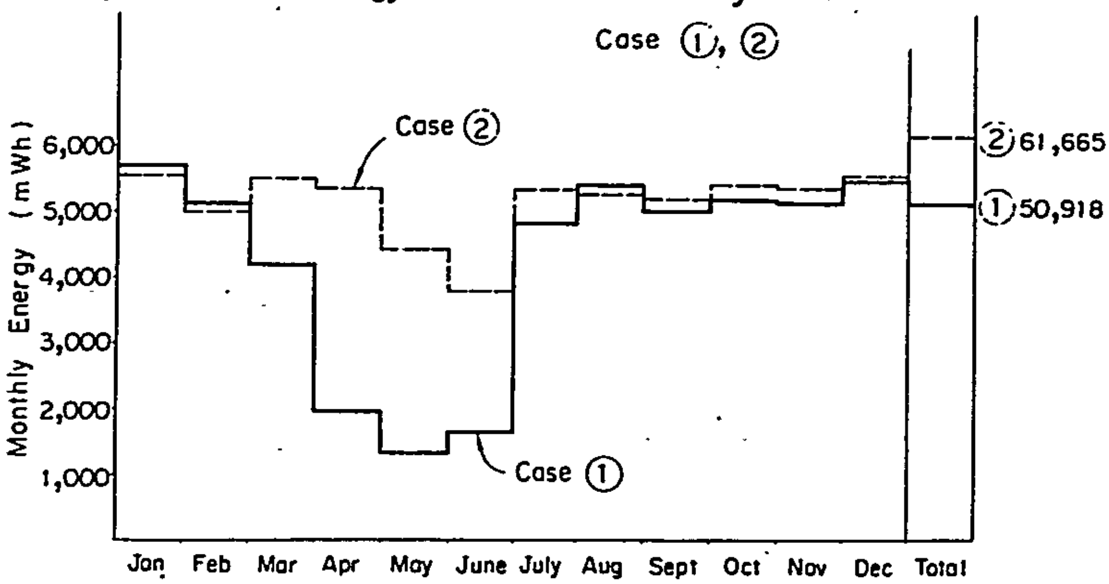
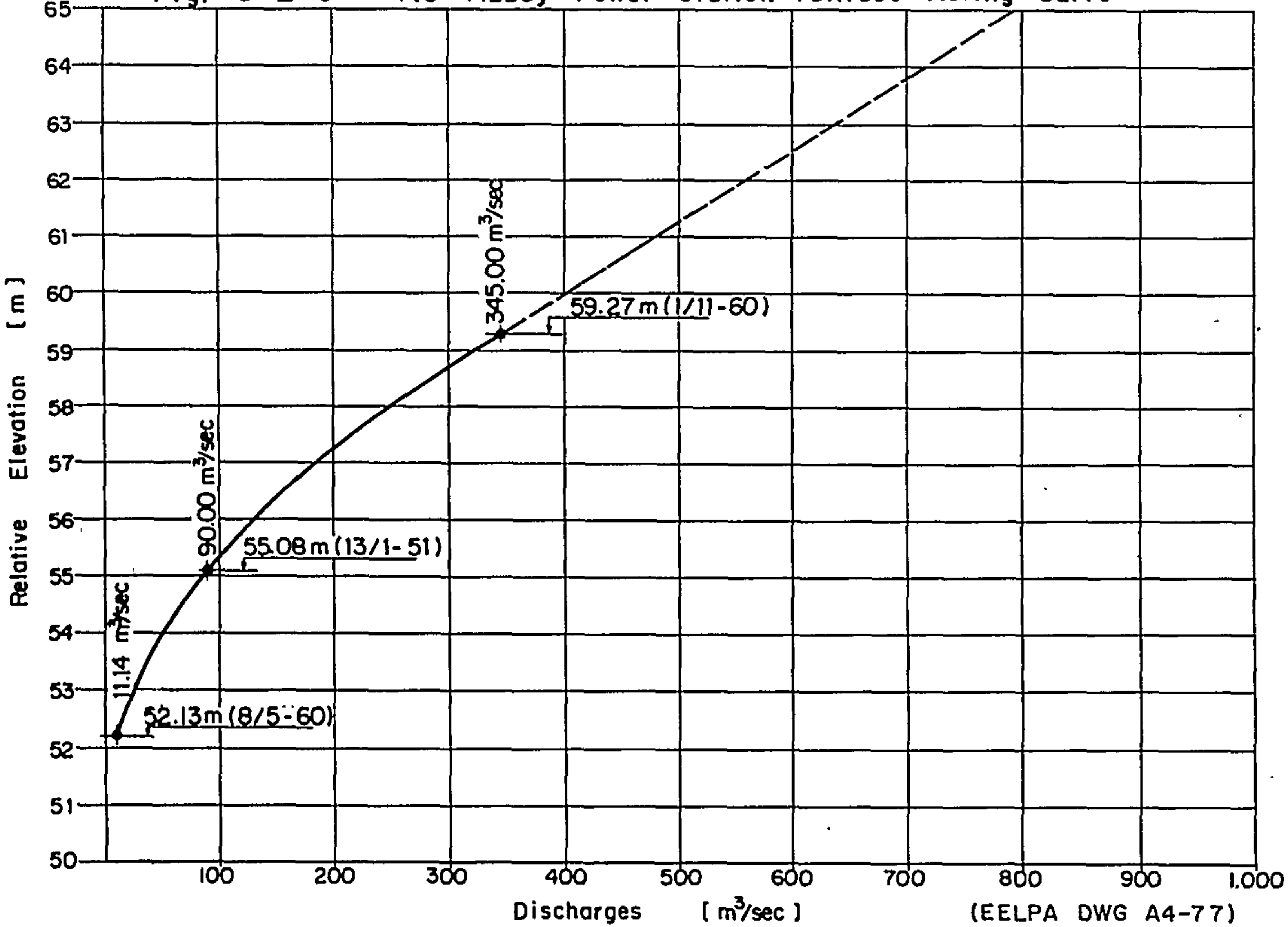


Fig. 8-2-8 Tis Abbay Power Station Tailrace Roting Curve



8.3 LOW-HEAD POWER STATION CONSTRUCTED AT REGULATING DAM

The idea of constructing a low-head power station accessory to the regulating dam was proposed by EELPA as an alternative to Tis Abbay No. 2 Power Station. The economics of such a power station are briefly examined below.

8.3.1 Scale

A study is made of the following plan taking the Lake Tana regulation project and the future Upper Beles Project into consideration.

Available discharge	Maximum	100 m^3/sec
	Normal	60 m^3/sec
Effective head	Maximum	4.1 m
	Standard	2.8 m
	Minimum	1.6 m
Output	Maximum	2,260 kW
	Minimum	700 kW
Turbine	Output	1,180 kW
	Speed	75 rpm
	Number	2 units
Generator	Output	1,420 kVA
	Power factor	0.8
	Number	2 units

The outline of the power station is given in Fig. 8-3-1.

8.3.2 Energy Production Possible

The average available discharges by month are as indicated in Table 8-3-1, and the energy production is determined assuming average available discharge at 86.7 m^3/sec and average effective head at 2.8 m.

$$E = 9.8 \times y_t \times y_G \times 86.7 \times 2.8 \times 365 \times 24 = 17,650 \text{ MWh}$$

8.3.3 Approximate Construction Cost

(1) Work quantities

Work quantities are calculated based on Fig. 8-3-1, not including the dam part.

(2) Construction Cost

Civil work	E$ 7,465,000
Electrical work	8,860,000
Total	E$ 16,325,000
Unit cost per kW	E$ 7,223/kW
Unit cost per kWh	E$ 0.925/kWh

8.3.4 Conclusions

The construction cost of Tis Abbay No. 2 Power Station is as indicated in Table 8-2-1, and when compared with this, the construction cost of the low-head power station is far higher than in any other case. Further, a great reduction in output cannot be avoided in case of diversion to the Upper Beles Project.

In this respect, the low-head power station is not advantageous at all as an alternative to Tis Abbay No. 2 Power Station.

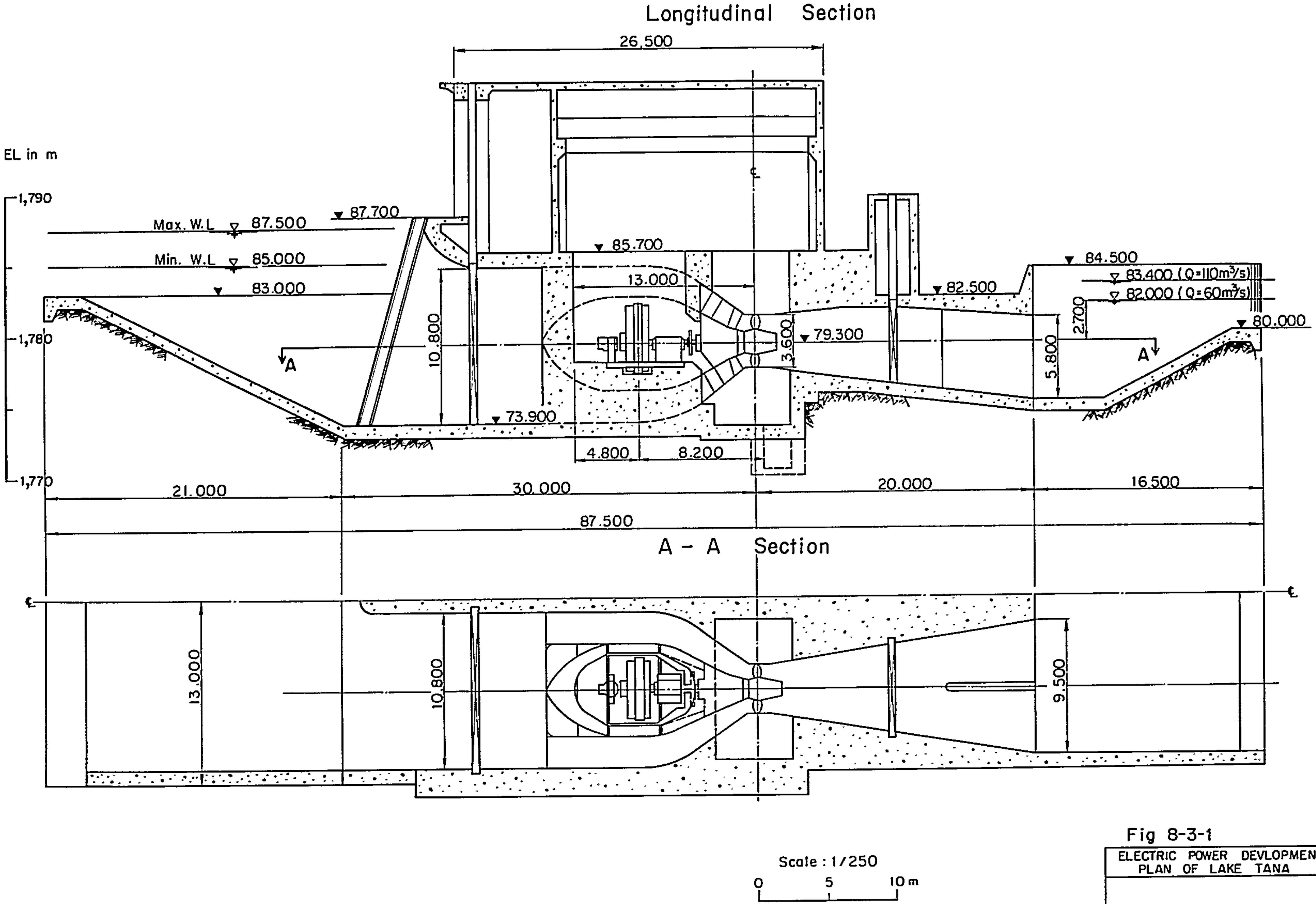


Fig 8-3-1

ELECTRIC POWER DEVLOPMENT PLAN OF LAKE TANA	
LOWHEAD POWER STATION	

Table 8-2-4 (1) Energy Production

Case (1) Existing Qmax. = 20 m^3/s

Year : 1965

Month	No.9 discharge (m^3/s-day)	Additional discharge (m^3/s-day)	Total (m^3/s-day)	Turbine discharge (m^3/s-day)	He (m)	E (10^3kwh)
Jan.	4,494	134	4,628	620	43.24	5,340
Feb.	2,925	90	3,015	560	43.95	4,903
Mar.	2,127	82	2,209	620	44.70	5,521
Apr.	1,317	42	1,359	600	45.65	5,456
May	722	45	767	616	46.00	5,643
June	411	54	465	465	46.00	4,254
July	803	609	1,412	596	45.40	5,384
Aug.	3,558	984	4,542	620	43.41	5,361
Sept.	6,255	371	6,626	600	42.00	5,020
Oct.	7,099	382	7,481	620	41.89	5,174
Nov.	5,588	294	5,882	600	42.40	5,068
Dec.	4,156	177	4,333	620	43.34	5,353
Total	39,455	3,264	42,719	7,134		62,477
Mean	108.1(m^3/s)	8.9(m^3/s)	117.0(m^3/s)	19.6(m^3/s)	44.00	

Year : 1966

Month	No.9 discharge (m^3/s-day)	Additional discharge (m^3/s-day)	Total (m^3/s-day)	Turbine discharge (m^3/s-day)	He (m)	E (10^3kwh)
Jan.	2,814	82	2,896	620	44.35	5,477
Feb.	1,700	56	1,756	560	44.70	4,986
Mar.	1,218	47	1,265	620	45.96	5,676
Apr.	661	39	700	581	46.00	5,328
May	378	41	419	419	46.00	3,840
June	297	156	453	448	46.00	4,107
July	719	632	1,351	620	45.50	5,619
Aug.	3,716	1,291	5,007	620	43.08	5,320
Sept.	7,848	979	8,827	600	41.17	4,921
Oct.	7,266	333	7,599	620	41.92	5,178
Nov.	5,336	240	5,576	600	42.56	5,087
Dec.	3,674	131	3,805	620	43.61	5,386
Total	35,627	4,027	39,654	6,929		60,924
Mean	97.6(m^3/s)	11.0(m^3/s)	108.6(m^3/s)	19.0(m^3/s)	44.24	

Case (1) Existing $Q_{max.} = 20\ m^3/s$

Year : 1967

Month	No.9 discharge (m^3/s-day)	Additional discharge (m^3/s-day)	Total (m^3/s-day)	Turbine discharge (m^3/s-day)	He (m)	E (10^3kwh)
Jan.	2,329	91	2,420	620	44.70	5,521
Feb.	1,260	69	1,329	542	45.49	4,909
Mar.	893	72	965	620	46.00	5,681
Apr.	544	52	596	554	46.00	5,076
May	309	48	357	356	46.00	3,266
June	166	103	269	263	46.00	2,408
July	759	1,071	1,830	568	45.13	5,099
Aug.	6,346	1,951	8,297	620	41.51	5,127
Sept.	11,511	836	12,347	600	39.64	4,738
Oct.	11,624	692	12,316	620	39.75	4,909
Nov.	7,911	319	8,230	600	41.56	4,967
Dec.	5,624	211	5,835	620	42.65	5,267
Total	49,276	5,515	54,791	6,583		56,968
Mean	135.0(m^3/s)	15.1(m^3/s)	150.1(m^3/s)	18.0(m^3/s)	43.69	

Year : 1968

Month	No.9 discharge (m^3/s-day)	Additional discharge (m^3/s-day)	Total (m^3/s-day)	Turbine discharge (m^3/s-day)	He (m)	E (10^3kwh)
Jan.	3,721	122	3,843	620	43.60	5,385
Feb.	2,352	94	2,446	580	44.62	5,156
Mar.	1,491	77	1,568	620	45.25	5,588
Apr.	787	58	845	600	46.00	5,498
May	449	66	515	515	46.00	4,715
June	425	169	594	519	46.00	4,755
July	2,106	1,164	3,270	620	44.13	5,451
Aug.	7,463	1,455	8,918	620	41.20	5,088
Sept.	10,121	799	10,920	600	40.00	4,781
Oct.	9,208	446	9,654	620	40.89	5,050
Nov.	6,086	238	6,324	600	42.30	5,056
Dec.	4,364	165	4,529	620	43.26	5,343
Total	48,573	4,853	53,426	7,134		61,864
Mean	132.7(m^3/s)	13.3(m^3/s)	146.0(m^3/s)	19.5(m^3/s)	43.60	

Case (1) Existing Qmax. = 20 m^3/s

Year : 1969

Month	No.9 discharge (m^3/s-day)	Additional discharge (m^3/s-day)	Total (m^3/s-day)	Turbine discharge (m^3/s-day)	He (m)	E (10^3kwh)
Jan.	2,950	128	3,078	620	44.17	5,455
Feb.	1,706	94	1,800	560	44.70	4,986
Mar.	1,178	90	1,268	620	45.96	5,676
Apr.	696	68	764	599	46.00	5,484
May	456	66	522	517	46.00	4,742
June	258	80	338	338	46.00	3,097
July	788	1,180	1,968	611	45.02	5,474
Aug.	5,468	2,167	7,635	620	41.83	5,166
Sept.	10,103	804	10,907	600	40.10	4,793
Oct.	8,156	359	8,515	620	41.48	5,123
Nov.	5,194	227	5,421	600	42.69	5,103
Dec.	3,352	178	3,530	620	43.88	5,420
Total	40,305	5,441	45,746	6,925		60,520
Mean	110.4(m^3/s)	14.9(m^3/s)	125.3(m^3/s)	19.0(m^3/s)	43.98	

Year : 1970

Month	No.9 discharge (m^3/s-day)	Additional discharge (m^3/s-day)	Total (m^3/s-day)	Turbine discharge (m^3/s-day)	He (m)	E (10^3kwh)
Jan.	2,162	120	2,282	620	44.70	5,521
Feb.	1,226	101	1,327	560	45.49	5,074
Mar.	790	97	887	620	46.00	5,681
Apr.	354	75	429	430	46.00	3,936
May	121	74	195	195	46.00	1,786
June	213	132	345	344	46.00	3,155
July	352	894	1,246	530	45.55	4,802
Aug.	3,636	1,827	5,463	620	42.90	5,298
Sept.	7,791	728	8,519	600	41.59	4,971
Oct.	7,448	518	7,966	620	41.80	5,162
Nov.	5,192	231	5,423	600	42.69	5,103
Dec.	3,428	152	3,580	620	43.81	5,411
Total	32,713	4,949	37,662	6,359		55,899
Mean	89.6(m^3/s)	13.6(m^3/s)	103.2(m^3/s)	17.4(m^3/s)	44.37	

Case (1) Existing Qmax. = 20 m^3/s

Year : 1971

Month	No.9 discharge (m^3/s-day)	Additional discharge (m^3/s-day)	Total (m^3/s-day)	Turbine discharge (m^3/s-day)	He (m)	E (10^3kwh)
Jan.	1,843	131	1,974	620	44.70	5,521
Feb.	1,168	90	1,258	560	45.77	5,105
Mar.	830	80	910	620	46.00	5,681
Apr.	435	66	501	493	46.00	4,514
May	223	79	302	302	46.00	2,775
June	161	153	314	311	46.00	2,854
July	664	665	1,329	587	45.50	5,322
Aug.	3,931	1,704	5,635	620	42.81	5,288
Sept.	8,281	816	9,097	600	41.11	4,914
Oct.	7,177	367	7,544	620	41.89	5,174
Nov.	4,704	303	5,007	600	42.96	5,135
Dec.	3,092	173	3,265	620	44.03	5,437
Total	32,509	4,627	37,136	6,554		57,719
Mean	89.1(m^3/s)	12.7(m^3/s)	01.7(m^3/s)	18.0(m^3/s)	44.39	

Year : 1972

Month	No.9 discharge (m^3/s-day)	Additional discharge (m^3/s-day)	Total (m^3/s-day)	Turbine discharge (m^3/s-day)	He (m)	E (10^3kwh)
Jan.	2,372	125	2,497	620	44.70	5,521
Feb.	1,533	97	1,630	580	45.01	5,201
Mar.	996	86	1,082	620	46.00	5,681
Apr.	522	42	564	540	46.00	4,946
May	281	51	332	331	46.00	3,037
June	177	103	280	280	46.00	2,570
July	596	517	1,113	610	45.92	5,578
Aug.	2,426	840	3,266	620	44.01	5,435
Sept.	4,815	652	5,467	600	42.80	5,115
Oct.	4,405	304	4,709	620	43.24	5,340
Nov.	2,701	192	2,893	600	44.19	5,281
Dec.	1,717	137	1,854	620	44.87	5,541
Total	22,541	3,146	25,687	6,642		59,246
Mean	61.6(m^3/s)	8.6(m^3/s)	70.2(m^3/s)	18.2(m^3/s)	44.90	

Case (1) Existing $Q_{max.} = 20\ m^3/s$

Year : 1973

Month	No.9 discharge (m^3/s-day)	Additional discharge (m^3/s-day)	Total (m^3/s-day)	Turbine discharge (m^3/s-day)	He (m)	E (10^3kwh)
Jan.	1,074	62	1,136	620	46.00	5,681
Feb.	647	39	686	560	46.00	5,131
Mar.	423	34	457	457	46.00	4,184
Apr.	181	31	212	212	46.00	1,940
May	88	57	145	144	46.00	1,320
June	90	91	181	181	46.00	1,662
July	415	509	924	528	45.87	4,827
Aug.	2,831	1,444	4,275	620	43.51	5,373
Sept.	6,477	727	7,204	600	42.00	5,020
Oct.	7,068	445	7,513	620	4,189	5,174
Nov.	4,596	207	4,803	600	43.09	5,151
Dec.	2,954	135	3,089	620	44.17	5,455
Total	26,844	3,781	30,625	5,762		50,918
Mean	73.5(m^3/s)	10.4(m^3/s)	83.9(m^3/s)	15.8(m^3/s)	44.71	

Year : 1974

Month	No.9 discharge (m^3/s-day)	Additional discharge (m^3/s-day)	Total (m^3/s-day)	Turbine discharge (m^3/s-day)	He (m)	E (10^3kwh)
Jan.	1,974	96	2,070	620	44.70	5,521
Feb.	1,235	65	1,300	560	45.49	5,074
Mar.	847	41	888	620	46.00	5,680
Apr.	421	36	457	457	46.00	4,189
May	318	70	388	388	46.00	3,554
June	364	85	449	448	46.00	4,108
July	1,480	544	2,024	620	45.00	5,556
Aug.	7,090	1,440	8,530	620	41.49	5,124
Sept.	14,069	1,070	15,139	600	38.34	4,582
Oct.	11,755	460	12,215	620	39.85	4,922
Nov.	6,318	237	6,555	600	42.23	5,048
Dec.	3,993	171	4,164	620	43.42	5,362
Total	49,864	4,315	54,179	6,773		58,721
Mean	136.6(m^3/s)	11.8(m^3/s)	148.4(m^3/s)	18.6(m^3/s)	43.70	

Case (1) Existing Qmax. = 20 m^3/s

Year : 1975

Month	No. 9 discharge (m^3/s-day)	Additional discharge (m^3/s-day)	Total (m^3/s-day)	Turbine discharge (m^3/s-day)	He (m)	E (10^3kwh)
Jan.	2,604	101	2,705	620	44.59	5,507
Feb.	1,702	70	1,772	560	44.70	4,986
Mar.	1,243	60	1,303	620	45.83	5,660
Apr.	649	56	705	586	46.00	5,370
May	317	50	367	367	46.00	3,363
June	216	113	329	324	46.00	2,969
July	927	585	1,512	601	45.34	5,426
Aug.	6,438	1,898	8,336	620	41.61	5,139
Sept.	18,144	1,549	19,693	600	36.42	4,353
Oct.	15,601	449	16,050	620	38.20	4,718
Nov.	8,799	221	9,020	600	41.14	4,917
Dec.	5,556	163	5,719	620	42.59	5,260
Total	62,196	5,315	67,511	6,738		57,669
Mean	170.4(m^3/s)	14.6(m^3/s)	185.0(m^3/s)	18.5(m^3/s)	43.2	

Table 8-2-4 (2) Energy Production

Case (2) After Regulation Qmax. = 20 m^3/s

Year : 1965

Month	Regulated discharge (m^3/s-day)	Additional discharge (m^3/s-day)	Total (m^3/s-day)	Turbine discharge (m^3/s-day)	He (m)	E (10^3kwh)
Jan.	3,410	134	3,544	620	43.60	5,385
Feb.	3,080	90	3,170	560	43.60	4,864
Mar.	3,410	82	3,492	620	43.60	5,385
Apr.	3,300	42	3,342	600	43.60	5,211
May	3,410	45	3,455	620	43.60	5,385
June	3,300	54	3,354	600	43.60	5,211
July	4,960	609	5,569	620	42.65	5,267
Aug.	4,960	984	5,944	620	42.57	5,257
Sept.	4,750	371	5,121	600	42.83	5,119
Oct.	3,410	382	3,792	620	43.60	5,385
Nov.	1,800	294	2,094	600	44.70	5,343
Dec.	1,910	179	2,087	620	44.60	5,516
Total	41,700	3,264	44,964	7,300		63,326
Mean	114.2(m^3/s)	8.9(m^3/s)	123.1(m^3/s)	20.0(m^3/s)	43.55	

Year : 1966

Month	Regulated discharge (m^3/s-day)	Additional discharge (m^3/s-day)	Total (m^3/s-day)	Turbine discharge (m^3/s-day)	He (m)	E (10^3kwh)
Jan.	2,609	82	2,691	620	44.21	5,460
Feb.	3,080	56	3,136	560	43.60	4,864
Mar.	3,410	47	3,457	620	43.60	5,385
Apr.	3,300	39	3,339	600	43.60	5,211
May	3,410	41	3,451	620	43.60	5,385
June	3,300	156	3,456	600	43.60	5,211
July	4,960	632	5,592	620	42.80	5,286
Aug.	4,960	1,291	6,251	620	42.47	5,245
Sept.	4,750	979	5,729	600	42.59	5,091
Oct.	3,410	333	3,743	620	43.60	5,385
Nov.	1,800	240	2,040	600	44.70	5,343
Dec.	1,860	131	1,991	620	44.70	5,521
Total	40,849	4,027	44,876	7,300		63,385
Mean	111.9(m^3/s)	11.0(m^3/s)	123.0(m^3/s)	20.0(m^3/s)	43.59	

Case (2) After Regulation Qmax. = 20 m^3/s

Year : 1967

Month	Regulated discharge (m^3/s-day)	Additional discharge (m^3/s-day)	Total (m^3/s-day)	Turbine discharge (m^3/s-day)	He (m)	E (10^3kwh)
Jan.	1,910	91	2,001	620	44.66	5,516
Feb.	1,780	69	1,849	560	44.62	4,978
Mar.	2,036	72	2,108	620	44.59	5,507
Apr.	3,300	52	3,352	600	43.60	5,211
May	3,410	48	3,458	620	43.60	5,385
June	3,300	103	3,403	600	43.60	5,211
July	4,960	1,071	6,031	620	42.48	5,247
Aug.	4,960	1,951	6,911	620	42.00	5,187
Sept.	4,800	836	5,636	600	42.75	5,109
Oct.	4,960	692	5,652	620	42.75	5,280
Nov.	2,196	319	2,515	600	44.41	5,307
Dec.	1,910	211	2,121	620	44.66	5,516
Total	39,522	5,515	45,037	7,300		63,454
Mean	108.3 (m^3/s)	15.1 (m^3/s)	123.4 (m^3/s)	20.0 (m^3/s)	43.64	

Year : 1968

Month	Regulated discharge (m^3/s-day)	Additional discharge (m^3/s-day)	Total (m^3/s-day)	Turbine discharge (m^3/s-day)	He (m)	E (10^3kwh)
Jan.	3,410	122	3,532	620	43.60	5,385
Feb.	3,190	94	3,284	580	43.60	5,037
Mar.	3,410	77	3,487	620	43.60	5,385
Apr.	3,300	58	3,358	600	43.60	5,211
May	3,410	66	3,476	620	43.60	5,385
June	3,300	169	3,469	600	43.60	5,211
July	4,960	1,164	6,124	620	42.47	5,245
Aug.	4,960	1,455	6,415	620	42.34	5,229
Sept.	4,800	799	5,599	600	42.72	5,106
Oct.	4,960	446	5,406	620	42.80	5,286
Nov.	2,000	238	2,238	600	44.55	5,325
Dec.	1,910	165	2,075	620	44.66	5,516
Total	43,610	4,853	48,463	7,320		63,322
Mean	119.2 (m^3/s)	13.3 (m^3/s)	132.4 (m^3/s)	20.0 (m^3/s)	43.43	

Case (2) After Regulation Qmax. = 20 m^3/s

Year : 1969

Month	Regulated discharge (m^3/s-day)	Additional discharge (m^3/s-day)	Total (m^3/s-day)	Turbine discharge (m^3/s-day)	He (m)	E (10^3kwh)
Jan.	3,410	128	3,538	620	43.60	5,385
Feb.	3,080	94	3,174	560	43.60	4,864
Mar.	3,410	90	3,500	620	43.60	5,385
Apr.	3,300	68	3,368	600	43.60	5,211
May	3,410	66	3,476	620	43.60	5,385
June	3,300	80	3,380	600	43.60	5,211
July	4,960	1,180	6,140	620	42.48	5,246
Aug.	4,960	2,167	7,127	620	41.99	5,186
Sept.	4,800	804	5,604	600	42.75	5,109
Oct.	4,910	359	5,269	620	42.83	5,289
Nov.	1,800	227	2,027	600	44.70	5,343
Dec.	1,910	178	2,088	620	44.66	5,516
Total	43,250	5,440	48,690	7,300		63,129
Mean	118.5 (m^3/s)	14.9 (m^3/s)	133.4 (m^3/s)	20.0 (m^3/s)	43.41	

Year : 1970

Month	Regulated discharge (m^3/s-day)	Additional discharge (m^3/s-day)	Total (m^3/s-day)	Turbine discharge (m^3/s-day)	He (m)	E (10^3kwh)
Jan.	3,260	120	3,380	620	43.71	5,398
Feb.	3,080	101	3,181	560	43.60	4,864
Mar.	3,410	97	3,507	620	43.60	5,385
Apr.	3,300	75	3,875	600	43.60	5,211
May	3,410	74	3,484	620	43.60	5,385
June	3,300	132	3,432	600	43.60	5,211
July	4,960	894	5,854	620	42.54	5,254
Aug.	4,960	1,827	6,787	620	42.05	5,193
Sept.	4,750	728	5,478	600	42.75	5,109
Oct.	3,410	518	3,928	620	43.60	5,385
Nov.	1,800	231	2,031	600	44.70	5,343
Dec.	1,860	152	2,012	620	44.70	5,521
Total	41,500	4,949	46,449	7,300		63,258
Mean	113.7 (m^3/s)	13.6 (m^3/s)	127.3 (m^3/s)	20.0 (m^3/s)	43.50	

Case (2) After Regulation Qmax. = 20 m^3/s

Year : 1971

Month	Regulated discharge (m^3/s-day)	Additional discharge (m^3/s-day)	Total (m^3/s-day)	Turbine discharge (m^3/s-day)	He (m)	E (10^3kwh)
Jan.	1,910	131	2,041	620	44.66	5,516
Feb.	2,130	90	2,220	560	44.35	4,947
Mar.	2,660	80	2,740	620	44.13	5,451
Apr.	2,650	66	2,716	600	44.08	5,268
May	3,410	79	3,489	620	43.60	5,385
June	3,300	153	3,453	600	43.60	5,211
July	4,960	665	5,625	620	42.75	5,280
Aug.	4,960	1,704	6,664	620	42.25	5,219
Sept.	4,750	816	5,566	600	42.75	5,109
Oct.	3,410	367	3,777	620	43.60	5,385
Nov.	1,800	303	2,103	600	44.70	5,343
Dec.	1,860	173	2,033	620	44.70	5,521
Total	37,800	4,627	42,427	7,300		63,633
Mean	103.6(m^3/s)	12.7(m^3/s)	116.2(m^3/s)	20.0(m^3/s)	43.76	

Year : 1972

Month	Regulated discharge (m^3/s-day)	Additional discharge (m^3/s-day)	Total (m^3/s-day)	Turbine discharge (m^3/s-day)	He (m)	E (10^3kwh)
Jan.	1,860	125	1,985	620	44.70	5,521
Feb.	1,790	97	1,887	580	44.66	5,160
Mar.	2,201	86	2,287	620	44.45	5,490
Apr.	3,150	42	3,192	600	43.71	5,224
May	3,410	51	3,461	620	43.60	5,385
June	3,300	103	3,403	600	43.60	5,211
July	4,910	517	5,427	620	42.83	5,289
Aug.	4,740	840	5,580	620	42.91	5,300
Sept.	3,300	652	3,952	600	43.60	5,211
Oct.	3,410	304	3,714	620	43.60	5,385
Nov.	1,800	192	1,992	600	44.70	5,343
Dec.	1,860	137	1,997	620	44.70	5,521
Total	35,731	3,146	38,877	7,320		64,040
Mean	97.7(m^3/s)	8.6(m^3/s)	106.3(m^3/s)	20.0(m^3/s)	43.92	

Case (2) After Regulation Qmax. = 20 m^3/s

Year : 1973

Month	Regulated discharge (m^3/s-day)	Additional discharge (m^3/s-day)	Total (m^3/s-day)	Turbine discharge (m^3/s-day)	He (m)	E (10^3kwh)
Jan.	1,860	62	1,922	620	44.70	5,521
Feb.	1,680	39	1,719	560	44.70	4,986
Mar.	1,860	34	1,874	620	44.70	5,521
Apr.	1,800	31	1,831	600	44.70	5,343
May	1,418	57	1,475	497	45.04	4,434
June	1,159	91	1,250	426	45.18	3,808
July	4,160	509	4,669	620	43.19	5,334
Aug.	4,210	1,444	5,654	620	42.67	5,270
Sept.	3,300	727	4,027	600	43.52	5,202
Oct.	3,410	445	3,855	620	43.57	5,382
Nov.	1,800	207	2,007	600	44.70	5,343
Dec.	1,860	135	1,995	620	44.70	5,521
Total	28,517	3,781	32,298	7,003		61,665
Mean	78.1(m^3/s)	10.4(m^3/s)	88.4(m^3/s)	19.2(m^3/s)	44.27	

Year : 1974

Month	Regulated discharge (m^3/s-day)	Additional discharge (m^3/s-day)	Total (m^3/s-day)	Turbine discharge (m^3/s-day)	He (m)	E (10^3kwh)
Jan.	1,860	96	1,956	620	44.70	5,521
Feb.	1,680	65	1,745	560	44.70	4,986
Mar.	1,860	41	1,901	620	44.70	5,521
Apr.	1,800	36	1,836	600	44.70	5,343
May	1,910	70	1,980	620	44.66	5,516
June	3,300	85	3,385	600	43.60	5,211
July	4,960	544	5,504	620	42.77	5,283
Aug.	4,960	1,440	6,400	620	42.45	5,243
Sept.	4,750	1,070	5,820	600	42.61	5,093
Oct.	3,715	460	4,175	620	43.45	5,367
Nov.	1,800	237	2,037	600	44.70	5,343
Dec.	1,860	171	2,031	620	44.70	5,521
Total	34,455	4,315	38,770	7,300		63,946
Mean	94.4(m^3/s)	11.8(m^3/s)	106.2(m^3/s)	20.0(m^3/s)	43.97	

Case (2) After Regulation Qmax. = 20 m^3/s

Year : 1975

Month	Regulated discharge (m^3/s-day)	Additional discharge (m^3/s-day)	Total (m^3/s-day)	Turbine discharge (m^3/s-day)	He (m)	E (10^3kwh)
Jan.	1,910	101	2,011	620	44.66	5,516
Feb.	2,229	70	2,299	552	44.28	4,866
Mar.	2,704	60	2,764	606	44.10	5,315
Apr.	3,300	56	3,356	600	43.60	5,211
May	3,410	50	3,460	620	43.60	5,385
June	3,300	113	3,413	600	43.60	5,211
July	4,960	585	5,545	620	42.70	5,273
Aug.	4,960	1,898	6,858	620	42.06	5,194
Sept.	4,800	1,549	6,349	600	42.40	5,067
Oct.	4,960	449	5,409	620	42.80	5,286
Nov.	2,700	221	2,921	600	44.04	5,264
Dec.	1,910	163	2,073	620	44.66	5,516
Total	41,143	5,315	46,458	7,278		63,108
Mean	112.7(m^3/s)	14.6(m^3/s)	127.3(m^3/s)	19.9(m^3/s)	43.54	

Table 8-2-4 (3) Energy Production

Case (3) After Regulation Qmax. = 30 m^3/s

Month	Year : 1965 Turbine discharge (m^3/s-day)	E (10^3kwh)	1966 Turbine discharge (m^3/s-day)	E (10^3kwh)	1967 Turbine discharge (m^3/s-day)	E (10^3kwh)	1968 Turbine discharge (m^3/s-day)	E (10^3kwh)
Jan.	930	8,077	930	8,190	930	8,274	930	8,077
Feb.	840	7,295	840	7,295	840	7,466	870	7,556
Mar.	930	8,077	930	8,077	930	8,261	930	8,077
Apr.	900	7,817	900	7,817	900	7,817	900	7,817
May	930	8,077	930	8,077	930	8,077	930	8,077
June	900	7,817	900	7,817	900	7,817	900	7,817
July	930	7,900	930	7,929	930	7,870	930	7,868
Aug.	930	7,886	930	7,868	930	7,780	930	7,844
Sept.	900	7,672	900	7,636	900	7,664	900	7,659
Oct.	930	8,077	930	8,077	930	7,919	930	7,929
Nov.	900	8.014	900	8,014	900	7,961	900	7,988
Dec.	930	8,274	930	8,281	930	8,274	930	8,274
Total	10,950	94,989	10,950	95,078	10,950	95,180	10,980	94,983
Mean(m^3/s)	30. 0		30. 0		30. 0		30. 0	

Month	Year : 1965 Turbine discharge (m^3/s-day)	E (10^3kwh)	1970 Turbine discharge (m^3/s-day)	E (10^3kwh)	1971 Turbine discharge (m^3/s-day)	E (10^3kwh)	1972 Turbine discharge (m^3/s-day)	E (10^3kwh)
Jan.	930	8,077	930	8,097	930	8,274	930	8,281
Feb.	840	7,295	840	7,295	840	7,420	870	7,740
Mar.	930	8,077	930	8,077	930	8,176	930	8,235
Apr.	900	7,817	900	7,817	900	7,902	900	7,836
May	930	8,077	930	8,077	930	8,077	930	8,077
June	900	7,817	900	7,817	900	7,817	900	7,817
July	930	7,869	930	7,881	930	7,919	930	7,934
Aug.	930	7,779	930	7,790	930	7,828	930	7,950
Sept.	900	7,664	900	7,664	900	7,664	900	7,817
Oct.	930	7,934	930	8,079	930	8,077	930	8,077
Nov.	900	8,014	900	8,014	900	8,014	900	8,014
Dec.	930	8,274	930	8,281	930	8,281	930	8,281
Total	10,950	94,694	10,950	94,887	10,950	95,449	10,980	96,058
Mean(m^3/s)	30. 0		30. 0		30. 0		30. 0	

Case (3) After Regulation Qmax. = 30 m^3/s

Month	Year : 1973 Turbine discharge (m^3/s-day)	E (10^3kwh)	1974 Turbine discharge (m^3/s-day)	E (10^3kwh)	1975 Turbine discharge (m^3/s-day)	E (10^3kwh)
Jan.	930	8,281	930	8,281	930	8,274
Feb.	840	7,480	840	7,480	822	7,244
Mar.	930	8,281	930	8,281	906	7,947
Apr.	900	8,014	900	8,014	900	7,817
May	737	6,574	930	8,274	930	8,077
June	616	5,500	900	7,817	900	7,817
July	930	8,001	930	7,924	930	7,910
Aug.	930	7,904	930	7,864	930	7,792
Sept.	900	7,802	900	7,640	900	7,601
Oct.	930	8,072	930	8,050	930	7,929
Nov.	900	8,014	900	8,014	900	7,895
Dec.	930	8,281	930	8,281	930	8,274
Total	10,473	92,204	10,950	95,920	10,908	94,577
Mean(m^3/s)	28.7		30.0		29.9	

Table 8-2-4 (4) Energy Production

Case (4) After Regulation Qmax. = 40 m^3/s

Month	Year : 1965 Turbine discharge (m^3/s-day)	E (10^3kwh)	1966 Turbine discharge (m^3/s-day)	E (10^3kwh)	1967 Turbine discharge (m^3/s-day)	E (10^3kwh)	1968 Turbine discharge (m^3/s-day)	E (10^3kwh)
Jan.	1,240	10,770	1,237	10,897	1,240	11,032	1,240	10,770
Feb.	1,120	9,727	1,120	9,727	1,120	9,955	1,160	10,075
Mar.	1,240	10,770	1,240	10,770	1,240	11,015	1,240	10,770
Apr.	1,200	10,422	1,200	10,422	1,200	10,422	1,200	10,422
May	1,240	10,770	1,240	10,770	1,240	10,770	1,240	10,770
June	1,200	10,422	1,200	10,422	1,200	10,422	1,200	10,422
July	1,240	10,534	1,240	10,572	1,240	10,493	1,240	10,491
Aug.	1,240	10,515	1,240	10,491	1,240	10,374	1,240	10,459
Sept.	1,200	10,237	1,200	10,182	1,200	10,218	1,200	10,212
Oct.	1,240	10,770	1,240	10,770	1,240	10,559	1,240	10,572
Nov.	1,200	10,685	1,200	10,685	1,200	10,615	1,200	10,650
Dec.	1,240	11,032	1,240	11,041	1,240	11,032	1,240	11,032
Total	14,600	126,654	14,597	126,749	14,600	126,908	14,640	126,645
Mean(m^3/s)	40.0		40.0		40.0		40.0	

Month	Year : 1969 Turbine discharge (m^3/s-day)	E (10^3kwh)	1970 Turbine dishcarge (m^3/s-day)	E (10^3kwh)	1971 Turbine discharge (m^3/s-day)	E (10^3kwh)	1972 Turbine discharge (m^3/s-day)	E (10^3kwh)
Jan.	1,240	10,770	1,240	10,796	1,240	11,032	1,240	11,041
Feb.	1,120	9,727	1,120	9,727	1,120	9,894	1,160	10,320
Mar.	1,240	10,770	1,240	10,770	1,240	10,901	1,240	10,980
Apr.	1,200	10,422	1,200	10,422	1,200	10,536	1,200	10,448
May	1,240	10,770	1,240	10,770	1,240	10,770	1,240	10,770
June	1,200	10,422	1,200	10,422	1,200	10,422	1,200	10,422
July	1,240	10,492	1,240	10,508	1,240	10,559	1,240	10,578
Aug.	1,240	10,372	1,240	10,386	1,240	10,437	1,240	10,600
Sept.	1,200	10,218	1,200	10,218	1,200	10,218	1,200	10,422
Oct.	1,240	10,578	1,240	10,770	1,240	10,770	1,240	10,770
Nov.	1,200	10,685	1,200	10,685	1,200	10,685	1,200	10,685
Dec.	1,240	11,032	1,240	11,041	1,240	11,041	1,240	11,041
Total	14,600	126,258	14,600	126,515	14,600	127,265	14,640	128,077
Mean(m^3/s)	40.0		40.0		40.0		40.0	

Case (4) After Regulation Qmax. = 40 m^3/s

Month	Year : 1973		1974		1975	
	Turbine discharge (m^3/s-day)	E (10^3kwh)	Turbine discharge (m^3/s-day)	E (10^3kwh)	Turbine discharge (m^3/s-day)	E (10^3kwh)
Jan.	1,240	11,041	1,240	11,041	1,240	11,032
Feb.	1,120	9,972	1,120	9,972	1,092	9,621
Mar.	1,240	11,041	1,240	11,041	1,206	10,578
Apr.	1,200	10,685	1,200	10,685	1,200	10,422
May	977	8,713	1,240	11,032	1,240	10,770
June	806	7,191	1,200	10,422	1,200	10,422
July	1,240	10,668	1,240	10,566	1,240	10,546
Aug.	1,240	10,540	1,240	10,485	1,240	10,389
Sept.	1,200	10,403	1,200	10,186	1,200	10,134
Oct.	1,240	10,763	1,240	10,734	1,240	10,572
Nov.	1,200	10,685	1,200	10,685	1,200	10,527
Dec.	1,240	11,041	1,240	11,041	1,240	11,032
Total	13,943	122,743	14,600	127,890	14,538	126,045
Mean	38.2		40.0		39.8	

Table 8-2-4 (5) Energy Production

Case (5) After Regulation Qmax. = 45 m^3/s

Month	Year : 1965		1966		1967		1968	
	Turbine discharge (m^3/s-day)	E (10^3kwh)	Turbine discharge (m^3/s-day)	E (10^3kwh)	Turbine discharge (m^3/s-day)	E (10^3kwh)	Turbine discharge (m^3/s-day)	E (10^3kwh)
Jan.	1,395	12,116	1,387	12,216	1,395	12,412	1,395	12,116
Feb.	1,260	10,943	1,260	10,943	1,260	11,200	1,305	11,334
Mar.	1,395	12,116	1,395	12,116	1,395	12,392	1,395	12,116
Apr.	1,350	11,725	1,350	11,725	1,350	11,725	1,350	11,725
May	1,395	12,116	1,395	12,116	1,395	12,116	1,395	12,116
June	1,350	11,725	1,350	11,725	1,350	11,725	1,350	11,725
July	1,395	11,850	1,395	11,893	1,395	11,805	1,395	11,802
Aug.	1,395	11,829	1,395	11,802	1,395	11,670	1,395	11,766
Sept.	1,350	11,517	1,350	11,454	1,350	11,495	1,350	11,488
Oct.	1,395	12,116	1,395	12,116	1,395	11,879	1,395	11,893
Nov.	1,350	12,021	1,350	12,021	1,350	11,942	1,350	11,981
Dec.	1,395	12,412	1,395	12,421	1,395	12,412	1,395	12,412
Total	16,425	142,486	16,417	142,548	16,425	142,773	16,470	142,474
Mean(m^3/s)	45.0		45.0		45.0		45.0	

Month	Year : 1969		1970		1971		1972	
	Turbine discharge (m^3/s-day)	E (10^3kwh)	Turbine discharge (m^3/s-day)	E (10^3kwh)	Turbine discharge (m^3/s-day)	E (10^3kwh)	Turbine discharge (m^3/s-day)	(10^3kwh)
Jan.	1,395	12,116	1,395	12,145	1,395	12,412	1,395	12,421
Feb.	1,260	10,943	1,260	10,943	1,260	11,131	1,305	16,610
Mar.	1,395	12,116	1,395	12,116	1,395	12,264	1,395	12,352
Apr.	1,350	11,725	1,350	11,725	1,350	11,853	1,350	11,754
May	1,395	12,116	1,395	12,116	1,395	12,116	1,395	12,116
June	1,350	11,725	1,350	11,725	1,350	11,725	1,350	11,725
July	1,395	11,804	1,395	11,822	1,395	11,879	1,395	11,901
Aug.	1,395	11,668	1,395	11,685	1,395	11,742	1,395	11,925
Sept.	1,350	11,495	1,350	11,495	1,350	11,495	1,350	11,725
Oct.	1,395	11,901	1,395	12,116	1,395	12,116	1,395	12,116
Nov.	1,350	12,021	1,350	12,021	1,350	12,021	1,350	12,021
Dec.	1,395	12,412	1,395	12,421	1,395	12,421	1,395	12,421
Total	16,425	142,042	16,425	142,330	16,425	143,175	16,470	144,087
Mean(m^3/s)	45.0		45.0		45.0		45.0	

Case (5) After Regulation Qmax. = 45 m^3/s

Month	Year : 1973 Turbine discharge (m^3/s-day)	E (10^3kwh)	1974 Turbine discharge (m^3/s-day)	E (10^3kwh)	1975 Turbine discharge (m^3/s-day)	E (10^3kwh)
Jan.	1,395	12,421	1,395	12,421	1,395	12,412
Feb.	1,260	11,219	1,260	11,219	1,227	10,811
Mar.	1,395	12,421	1,395	12,421	1,356	11,894
Apr.	1,350	12,021	1,350	12,021	1,350	11,725
May	1,093	9,747	1,395	12,412	1,395	12,116
June	901	8,037	1,350	11,725	1,350	11,725
July	1,395	12,001	1,395	11,886	1,395	11,865
Aug.	1,395	11,857	1,395	11,796	1,395	11,687
Sept.	1,350	11,703	1,350	11,460	1,350	11,401
Oct.	1,395	12,109	1,395	12,075	1,395	11,893
Nov.	1,350	12,021	1,350	12,021	1,350	11,843
Dec.	1,395	12,421	1,395	12,421	1,395	12,412
Total	15,674	137,978	16,425	143,878	16,353	141,784
Mean(m^3/s)	42.9		45.0		44.8	

Table 8-2-5 Regulated Discharge Duration at Tis Abbay P. S.

Blue Nile River C. A. = 16, 669 Km^2

(Unit: m^3/s)

Year	Max.	35 days	95 days	185days	275days	355days	Min.	Mean
1964	727. 88	257. 14	192. 67	66. 02	-	-	-	
1965	232. 39	181. 46	133. 80	112. 88	111. 44	64. 63	63. 73	
1966	257. 34	192. 67	122. 49	112. 05	111. 18	62. 55	37. 49	
1967	296. 09	207. 40	177. 73	111. 50	65. 73	72. 05	57. 51	
1968	263. 63	197. 25	175. 31	113. 73	111. 89	64. 96	64. 12	
1969	342. 57	202. 42	172. 55	113. 20	111. 89	65. 67	64. 96	
1970	295. 05	203. 80	130. 39	113. 38	112. 27	64. 53	63. 55	
1971	321. 08	195. 76	125. 31	112. 40	65. 19	62. 27	61. 89	
1972	197. 67	178. 43	122. 89	111. 55	64. 32	62. 15	61. 33	
1973	314. 86	161. 18	122. 30	63. 70	61. 26	0. 60	0. 55	
1974	374. 60	190. 19	167. 09	66. 33	62. 21	60. 88	60. 69	
1975	1121. 15	232. 71	172. 67	112. 07	66. 07	61. 92	5. 57	
Average	395. 36	200. 04	151. 26	100. 73	78. 82	39. 38	18. 37	

Table 8-2-6 Unregulated Discharge Duration at Intake of Tis Abbay P.S.

Blue Nile River C.A. = 16,669 Km^2

(Unit: m^3/s)

Year	Max.	35 days	95 days	185 days	275 days	355 days	Min.	Mean
1964	808.82	620.29	368.09	103.28	30.18	10.83	8.55	
1965	269.20	223.18	178.96	115.66	41.88	15.37	13.11	
1966	341.03	250.94	175.49	74.30	26.18	12.13	11.31	
1967	490.58	398.75	269.03	71.88	22.51	7.52	1.91	
1968	416.00	356.51	225.20	119.12	35.17	14.90	14.11	
1969	420.98	330.71	190.52	88.81	27.97	10.16	8.22	
1970	317.57	270.37	175.33	65.27	16.55	5.77	2.27	
1971	322.81	278.99	170.08	59.21	20.37	7.83	6.69	
1972	194.89	165.12	97.10	56.72	22.27	7.89	6.95	
1973	297.07	242.25	149.33	34.62	10.16	3.92	3.55	
1974	550.75	449.09	219.90	65.32	19.96	11.35	10.16	
1975	834.79	562.10	286.58	75.21	26.18	8.25	6.75	
Average	438.71	345.69	208.38	77.45	24.95	9.66	7.81	

Table 8-3-1 Summarization of Turbine Discharge for Lowhead Power Station

Month	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	Average
Jan.	100	84	62	100	100	96	61	60	60	60	61	76.7
Feb.	100	100	62	100	100	100	73	61	60	60	75	81.0
Mar.	100	100	63	100	100	100	81	69	60	60	74	82.5
Apr.	100	100	100	100	100	100	83	96	60	60	100	90.8
May	100	100	100	100	100	100	100	100	46	61	100	91.5
June	100	100	100	100	100	100	100	100	39	100	100	94.5
July	100	100	100	100	100	100	100	100	100	100	100	100.0
Aug.	100	100	100	100	100	100	100	98	100	100	100	99.8
Sept.	100	100	100	100	100	100	100	100	100	100	100	100.0
Oct.	100	100	100	100	100	100	100	100	100	99	100	99.9
Nov.	60	60	71	65	60	60	60	60	60	60	76	62.9
Dec.	62	60	61	61	61	60	60	60	60	60	61	60.5
Average	93.5	92.0	84.9	93.8	93.3	93.0	84.8	83.7	70.4	76.7	87.3	86.7

CHAPTER 9

TRANSMISSION LINE, SUBSTATION AND TELECOMMUNICATION PLANS

CHAPTER 9 TRANSMISSION LINE, SUBSTATION AND TELECOMMUNICATIONS PLANS

9.1 POWER TRANSMISSION PLAN

9.1.1 Outline of Transmission Line Plan

The power transmission system for supply of electricity to the surrounding area of Lake Tana at the time of commissioning will be an independent system with the power generated at Tis Abbay Power Station as the supply source. Tis Abbay Power Station will have its total installed capacity increased to 11,520kW through addition of its No. 3 unit, after which in accordance with increase in demand Tis Abbay No. 2 Power Station will be constructed so that the total installed capacity of the Tis Abbay System will become 17,220kW, sufficient to cope with demand as an independent system until 1990, but after which, it will be necessary for supply to be made from some other power sources. In regard to this supplementary power source, as indicated in 4.5.2 and 4.5.3 of Chapter 4, Load Forecast, electric power from new projects such as Upper Beles in the neighboring area would be looked forward to. This power transmission plan, besides the Tis Abbay power generating system, considers interconnection in 1991 with Upper Beles Power Station planned as a future project for coping with increase in power demand in the area surrounding Lake Tana.

The transmission lines of this project, as indicated in the outline diagram of the power transmission plan (Fig. 9-1-1), utilizes the existing 45 kV line between Tis Abbay Power Station and Bahar Dar Substation, and for power supply to the surrounding area other than the city of Bahar Dar, a 66 kV trunk transmission line is to be constructed between Bahar Dar and Gondar, with a 45 kV line branched on the way from Wereta to Debre Tabor, and another 45 kV line from Gondar to Kola Diba, while to the region south of the lake, there is to be direct leading out by a 45 kV transmission line.

The outline of the transmission line facilities is as follows:

(1) Trunk Transmission Line (Bahar Dar - Gondar)

The design is to be for 66 kV, 160 mm^2 AAAC, 1 cct, with supports to be wood poles except for mountainland where steel towers are to be used.

(2) Other Transmission Lines

The design is to be for 45 kV, 80 mm^2 ACSR, 1 cct, with supports to be wood poles except for mountainland where steel towers are to be used.

The details, of the facilities are described in Chapter 10, but it might be said here that in selection of the transmission voltage for the trunk line, although with no performance record in Ethiopia as yet, 66 kV which is under consideration as the voltage to be used in the future, was subjected to technical and economic comparisons with 45 kV, as a result of which 66 kV was adopted. As for supports, economic comparisons were made of the three alternatives of imported steel towers, wood poles imported from Kenya, and precast concrete poles cast in the field, based on which the types of supports were determined. The results of economic comparisons of supports are as shown in Table 9-1-1.

In carrying out economic analyses at equal levels of supports having different lengths of service life, a perpetual replacement factor was considered and it was determined that the case of using wood poles would be the cheapest compared with steel towers and concrete poles. Moreover, the initial investment on wood poles will be small, and such poles to be imported from Kenya are considered to be desirable judging from the regional economy. If obtainable locally, the cost would be reduced. Consequently, it was decided that wood poles would be adopted as the supports for the greater part of the routes.

Table 9-1-1 Economic Comparisons of Supports

(Unit : Eth$)

Item \ Type of Support	Wood Pole		Concrete Pole		Steel Tower	
Standard Span	150 m		180 m		250 m	
Service Life	25 years		50 years		50 years	
Construction Cost per km	33,040		46,690		44,740	
Discount Rate	8 %	10 %	8 %	10 %	8 %	10%
Annual Expense Converted to Present Worth per km						
Cost of not considering P.R.F.	3,096	3,641	3,814	4,711	3,655	4,514
Cost of considering P.R.F.	3,625	4,012	3,898	4,753	3,735	4,554

P.R.F. : perpetual replacement factor

Discount rates of 8% and 10% adopted

Amounts in table standard unit prices per km

9.1.2 System Analysis

(1) Outline of System Analysis

Examinations of items such as voltage adjustment, stability and short-circuiting power were made for the isolated system at the start of operation with the Tis Abbay power system as the power source, the system at the point of time (1991) when supplementary power from Upper Beles Power Station is tied in at Bahar Dar Substation, and the system at the time (2000) when the 66 kV trunk transmission line will reach the limits of its transmission capacity to supply demand.

Fig. 9-1-1 Transmission Line Route Map

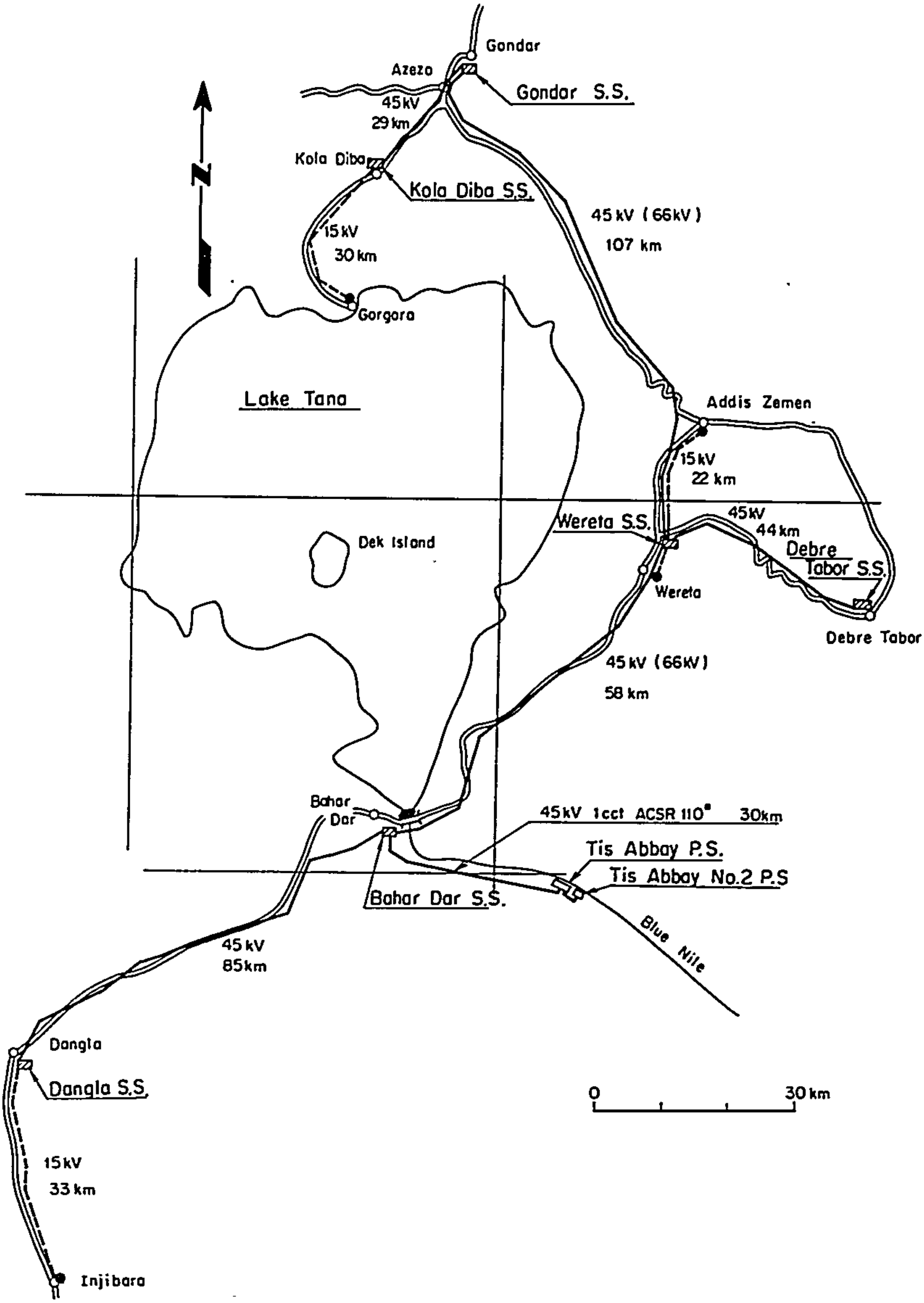


Fig. 9-1-2 System Diagram (1982 ~ 1990)

Bahar Dar–Gondar 45kV (66kV Design) 1 cct

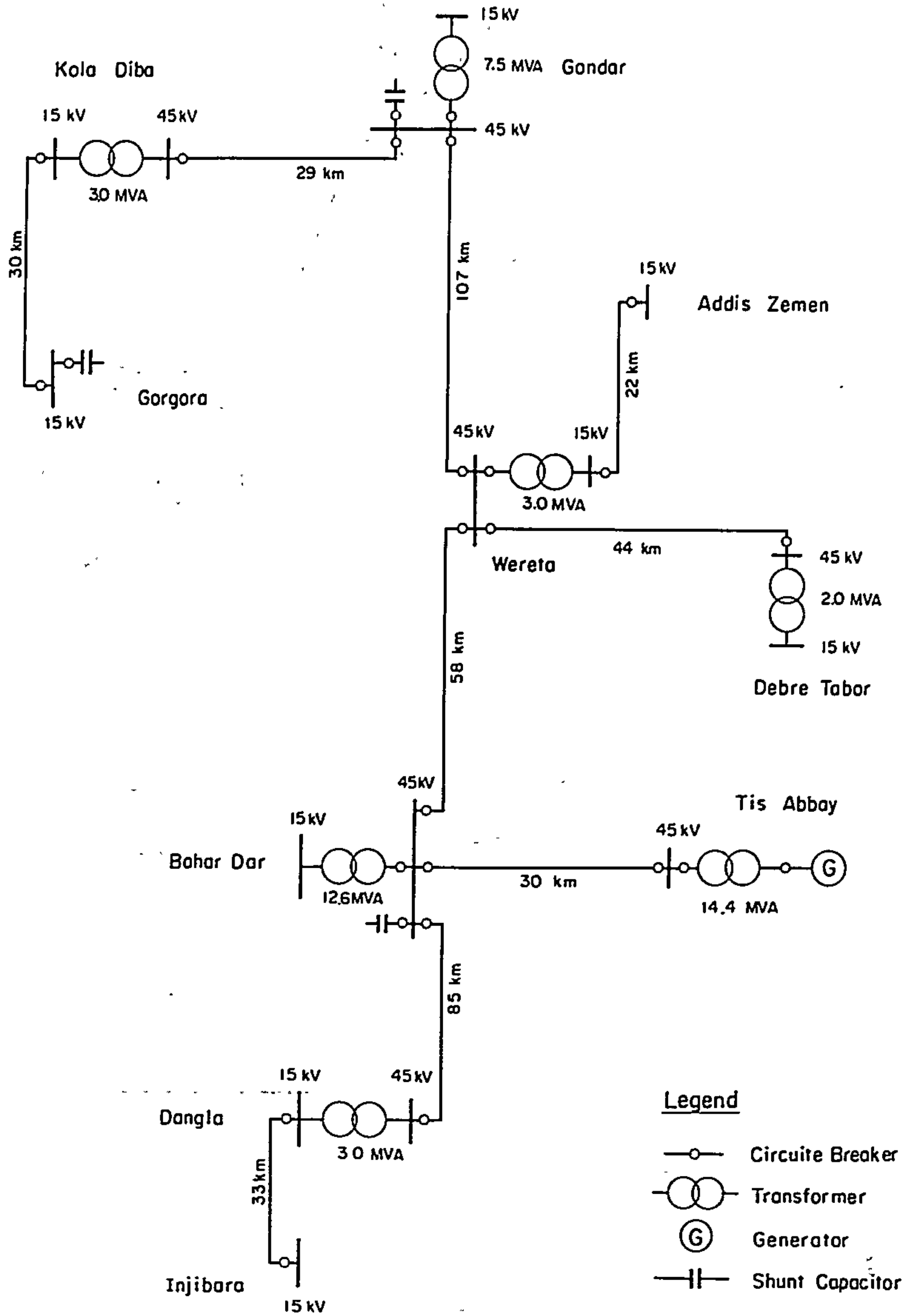
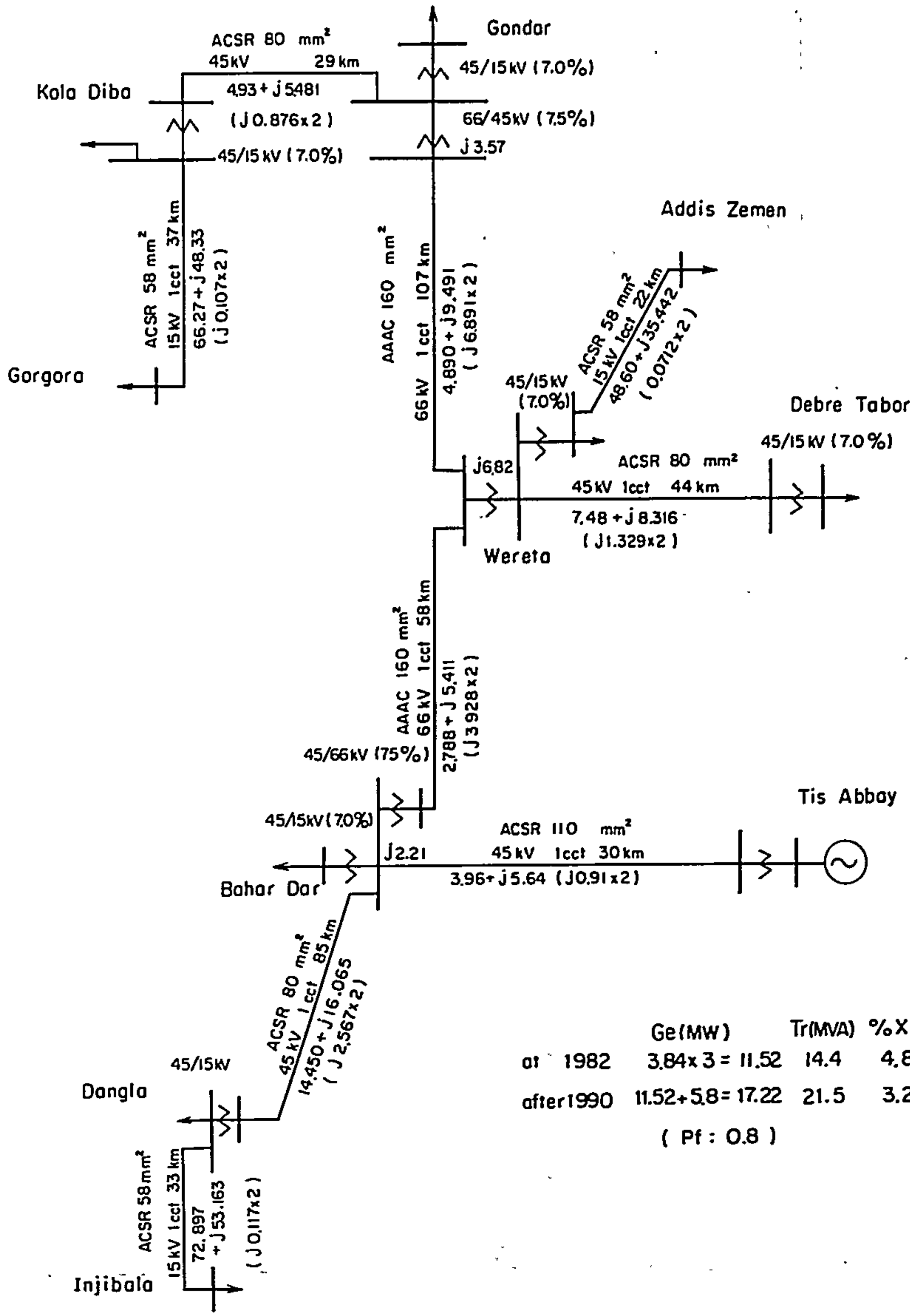


Fig. 9-1-3 Impeadance Map

Bahar Dar-Gondar 66kV Design 1 cct



	Ge(MW)	Tr(MVA)	%X
at 1982	3.84x3 = 11.52	14.4	4.86
after 1990	11.52+5.8 = 17.22	21.5	3.26

(Pf: 0.8)

A system diagram and an impedance diagram for the time of start of operation (1982) are given in Fig. 9-1-2 and Fig. 9-1-3, respectively.

(2) Voltage Adjustment

Reactive power can be supplied from Tis Abbay Power Station while load is small, but as load increases Tis Abbay alone will become insufficient. Since transmission loss can be reduced more by supplying reactive power from the load end, it was decided that phase modifying equipment would be provided at substations as necessary.

The capacities of phase modifying equipment required to maintain load-side 15 kV bus voltages at 90% or higher during peak hours are as indicated in Table 9-1-2. The tap voltages of transformers in such cases are all in the range between 90% and 100% as a result of calculations and pose no special problems. However, transformers at principal points in voltage regulation of the system and 66 kV/45 kV transformers will show voltage rises during times of light load to require tap changing, and these transformers will be requied to be equipped with on-load tap-changer.

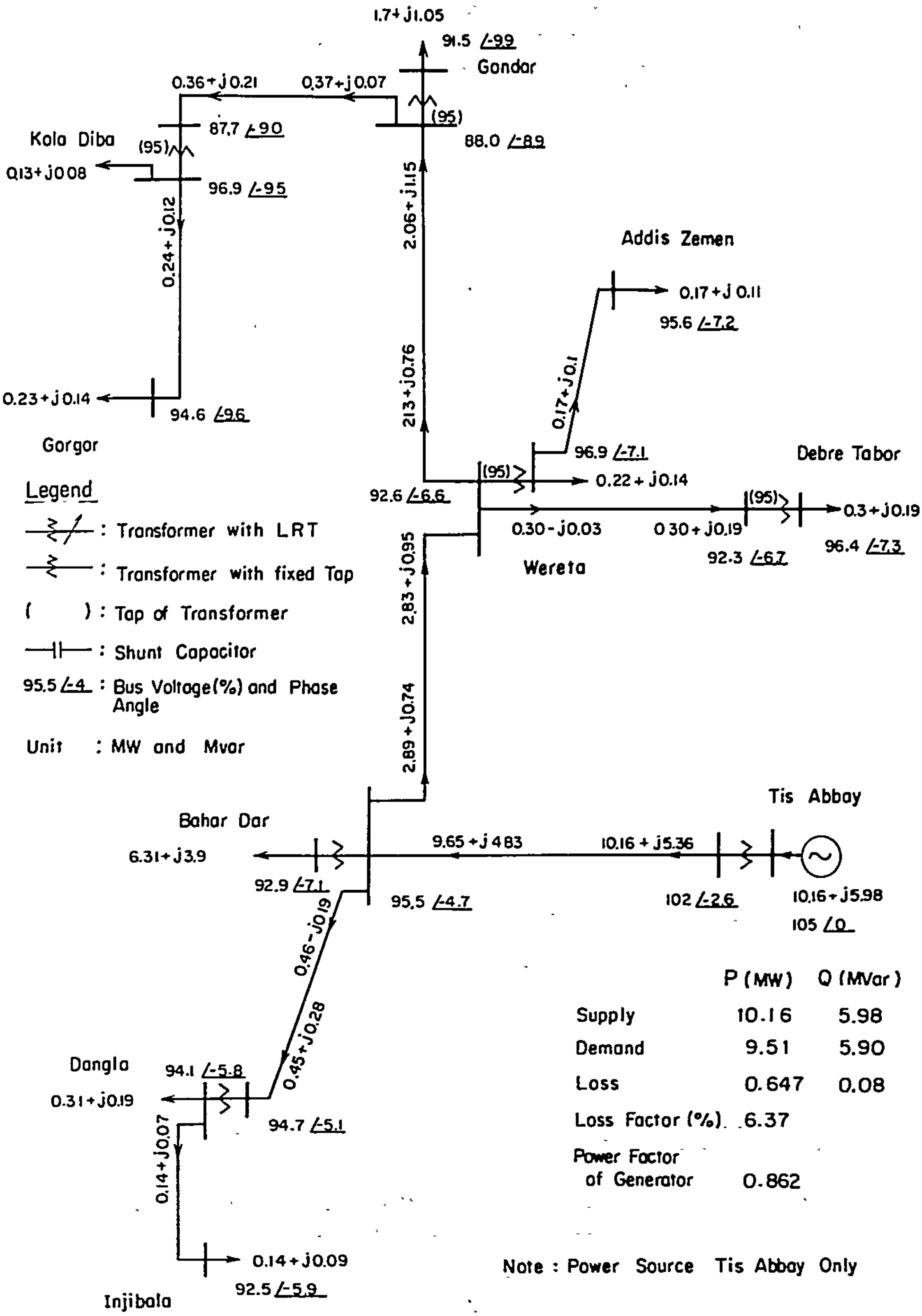
Table 9-1-2 Phase Modifying Equipment Capacities

(Unit : MVar)

Year	Sub station	Required Capacity	
1990 (45kV operation)	Bahar Dar SS 45 kV Bus side	3.01	
	Gondar SS "	5.46	
	Gondar SS 15 kV Bus side	0.43	
	Total		8.90
1991 (66kV operation)	Bahar Dar SS 45 kV Bus side	5.66	
	Total		5.66
1995 (66kV operation)	Bahar Dar SS 45 kV Bus side	8.75	
	Gondar SS "	1.45	
	Injibala SS 15 kV Bus side	0.45	
	Gorgora SS "	1.32	
	Total		12.04
2000 (66kV operation)	Bahar Dar SS 45 kV Bus side	11.33	
	Gondar SS "	3.91	
	Injibala SS 15 kV Bus side	1.81	
	Addis Zemen SS "	0.20	
	Gorgora SS "	3.17	
	Total		24.42

Fig. 9-1-4 Power Flow and Voltage Regulation at Peak Time in 1982

Bahar Dar — Gondar 45 kV (66 kV Design) 1 cct



	P (MW)	Q (MVar)
Supply	10.16	5.98
Demand	9.51	5.90
Loss	0.647	0.08
Loss Factor (%)	6.37	
Power Factor of Generator	0.862	

Note : Power Source Tis Abbay Only

(3) Transmission Line Current and Phase Angle

In 1982, the 15 kV bus voltage of Kola Diba Substation, the farthest from the Tis Abbay Power Station generator-side bus voltage, will be 96% of the standard voltage, while the phase angle will be approximately 10 degrees so that there will be no problem, but around 1990, the voltage drop will be more than 10% even with compensation by phase modifying equipment to result in a large transmission loss, and step-up of voltage will be necessary.

However, in the year 2000, in order to secure the 15kV bus voltage within a drop of 10% it will be necessary to install phase modifying equipment corresponding to approximately 70% of the power demand, while transmission loss will also be great. Meanwhile, the phase angle between Tis Abbay Power Station and Kola Diba Substation will become 31.6 degrees. It will therefore be necessary around the year 2000 for measures to be taken either of expanding the transmission line between Bahar Dar Substation and Gondar Substation or of adding a new power source at the Gondar Substation side.

9.1.3 Transmission Line Voltages

(1) General

There are three classes of voltage presently being used in Ethiopia, 230 kV, 132 kV and 45 kV. The load forecast for the East and North Regions of Lake Tana in 2000 is for 18,060 kW at receiving end during peak hours, and if selection of voltage were to be made from the three classes mentioned above, the trunk transmission line between Bahar Dar and Gondar would be 45 kV 2 cct or 132 kV 1 cct. However, with 132 kV the capital investment would be excessive at 1.5 times that for 66 kV 1 cct, and this voltage is not suitable when considered from standpoints such as economy. Consequently, it was decided to study the case of a single circuit of 66 kV, which although without a performance record in Ethiopia, is being contemplated for adoption for use.

Accordingly, the voltages for the power system were planned on the basis of the existing voltage of 45kV and, in addition, 66 kV.

It may be further noted that in view of the distribution of power demand in Ethiopia there will be an increase in 66 kV as the voltage for transmission lines of power systems covering areas of small demand and distances of 100 km to 200 km as in the case of the present project.

(2) Transmission Line between Bahar Dar Substation (Bahar Dar City) and Gondar Substation (Gondar City)

For the reasons given above, economic comparisons of the following three cases were made with regard to this trunk transmission line.

Case I. Construction initially of 45 kV 1 cct and addition of 45 kV 1 cct in accordance with increased demand.

Case II. Construction of 66 kV 1 cct, operation initially at 45 kV, and step-up to 66 kV in accordance with increased demand.

Case III. Construction of 66 kV 1 cct and operation at 66 kV from beginning.

The investment amounts of the transmission line facilities of the three alternatives converted to present worth as of the beginning of 1982 show Case I to be approximately 1.2 times higher and Case III approximately 1.1 times higher than Case II, and thus, it is judged that Case II will be the least costly and therefore advantageous, and this is to be adopted.

The results of the economic comparisons are as indicated in Table 9-1-3.

Table 9-1-3 Economic Comparison by Voltage of Transmission Line between Bahar Dar S.S and Gondar S.S.

(Unit : Eth$)

Construction Cost \ Discount Rate \ Case		I		II		III	
		8 %	10 %	8 %	10 %	8 %	10 %
Transmission Facilities	1982	5,490,000		6,007,000		6,007,000	
	1991	5,490,000		-		-	
	Sub Total	10,980,000		6,007,000		6,007,000	
	Annual Cost at Present Worth	9,644,000	8,616,000	7,034,000	6,620,000	7,034,000	6,620,00
Substation Facilities	1982	2,393,000		2,393,000		3,614,000	
	1991	1,264,000		2,843,000		400,000	
	1995	1,136,000		-		1,707,000	
	Sub Total	4,793,000		5,236,000		5,721,000	
	Annual Cost at Present Worth	3,822,000	3,457,000	4,235,000	3,818,000	4,931,000	4,539,00
Total Annual Cost		13,466,000	12,073,000	11,269,000	10,438,000	11,965,000	11,159,00

Service life : 25 years for transmission line due to wood poles, 30 years for substation facilities.

Discount rates of 8% and 10% applied.

(3) Transmission Line between Tis Abbay Power Station and Bahar Dar Substation

The ultimate installed capacity of the Tis Abbay System in this project is to be 17,220 kW. In case of transmission of 17,220 kW by the existing transmission line (45 kV 1 cct), the transmission loss will be slightly high at 7.6%, but with respect to thermal capacity there is sufficient transmission capacity (27 MW). Further, when the Tis Abbay Power System becomes interconnected with Upper Beles Power Station, ample supply of power to Bahar Dar Substation can be looked forward to, and expansion of the existing transmission line, was not considered. However, in case power supply from Upper Beles cannot be expected even when 1991 comes about, the addition of 45 kV 1 cct should be considered.

(4) Branch Transmission Lines

45kV transmission lines could supply sufficient power, and these are to be adopted.

In this case, 66 kV/45 kV transformers should be installed in 1991 at the junctions of the trunk line and the branch lines, as described in 9.1.3 (2) and 9.2.4 (2).

(5) Closure

An economic comparison between case A (recommendation of the Mission) and case B (construction of 66 kV with operation at 66 kV for all facilities) are shown in Table 9-1-4.

Comparing the construction costs converted into the present worths, case A is 6 ~ 7% lower than case B in case of the discount rates 8 and 10%. Therefore, transmission line system of 66 kV and 45 kV were selected from the view point of economy.

However, if a policy of unification of transmission voltage into 66 kV instead of 45 kV would be adopted in future for the transmission system in whole Ethiopia, the voltage of transmission lines at this region should be re-studied at the detailed study stage to convert into 66 kV.

Table 9-1-4 Economic comparison between unified (66kV) and combined (66kV and 45kV) transmission lines.

(Unit : Eth$)

Construction Cost \ Discount Rate \ Case		A		B	
		8 %	10 %	8 %	10 %
Transmission Facilities	1982	10,604,000		11,354,000	
	1991	-		-	
	Sub Total	10,604,000		11,354,000	
	Annual Cost at Present Worth	12,418,000	11,686,000	13,295,000	12,512,000
Substation Facilities	1982	3,036,000		3,703,000	
	1991	3,786,000		3,005,000	
	Sub Total	6,822,000		6,708,000	
	Annual Cost at Present Worth	5,472,000	4,924,000	5,779,000	5,281,000
Total Annual Cost		17,890,000	16,610,000	19,074,000	17,993,000

Case A : Transmission system recomended by the Survey Team. (Report case II of Fig.9-1-3)

Case B : Construction of 66 kV with operation at 66 kV for all facilities.

9.1.4 Protection of Transmission Lines

The present scheme is for single circuits in view of economy with the consideration that power failures for short periods of time must be tolerated. Accordingly, a system is adopted whereby automatic breaking is done through protective relays at times of transmission line faulting and automatic forced line charging is done from the power source end after the line has been brought to no-voltage condition.

The neutral grounding systems for the transmission lines are to be solid grounded system for the 66 kV line and non-grounded system for 45 kV lines, while taking into consideration that the power supply sources are concentrated at the 45 kV side of Bahar Dar, the protection systems are to be as follows:

(a) 66 kV transmission Line

(Power source End)

Short-circuit protection: 3-stage distance relaying system

Ground fault protection : Combination system of ground directional overcurrent relay and ground overcurrent relay.

(Load End)

Both short-circuit and ground fault protection : under voltage relay

(b) 45 kV transmission Lines

(Power source End)

Short-circuit protection: overcurrent relay with inverse-time characteristic

Ground fault protection : ground over voltage relay

(Load End)

Both short-circuit and ground fault protection : under voltage relay

9.2 POWER TRANSFORMATION PLAN

9.2.1 Outline

With construction of transmission lines in the Lake Tana Area it will become necessary to construct new substations at Gondar, Wereta, Dangla, Debre Tabor and Kola Diba, and addition of facilities at Bahar Dar Substation. In order to supply electric power to these substations, it will be necessary to add a No. 3 unit to the existing Tis Abbay Power Station and to construct Tis Abbay No. 2 Power Station, and further, interconnected transmission line between the Tis Abbay Power System and the Upper Beles Power System, the completion of which is looked forward to for 1991.

9.2.2 Power System

(1) Present State of Power Systems in Surrounding Area of Lake Tana

Electric power supply at communities in the surrounding area of Lake Tana is presently being carried out at five places including small-scale systems. These are all independent power systems. The largest of these power systems is comprised of Tis Abbay Hydroelectric Power Station (7,680 kW), Bahar Dar Substation and a single-circuit, 45 kV transmission line. The next largest is the 15 kV power system of Gondar ~ Azezo ~ Kola Diba where power supply is being carried out directly from Gondar Diesel Power Station (1,450 kW). The three other power systems (Wereta, Dangla, Debre Tabor) where power supply is also being carried out directly from small-scale diesel generating stations through distribution lines.

The existing power systems are indicated in Fig. 9-2-1.

(2) Expansion of Tis Abbay Power System

In order to supply the hydroelectric energy of Tis Abbay Power Station and Tis Abbay No. 2 Power Station which will become nucleus of interconnected power system to unelectrified districts in the area around Lake Tana and the five existing power system, these power systems and the unelectrified district are to be interconnected with the existing Tis Abbay Power System and Tis Abbay No. 2 Power Station. The power system at the time of start of operation of transmitting and substation facilities is illustrated at shown in Fig. 9-2-2.

At present, electric power is being supplied from Tis Abbay Power Station to Bahar Dar Substation through a 45 kV transmission line, 1 cct. Between this existing Bahar Dar Substation and a new Gondar Substation a 66 kV transmission line, 1 cct (to be operated initially at 45 kV) is to be costructed, and part way along this line, a new Wereta Substation is to be connected by a T-branch, and power is to be supplied to these new substations through these transmission lines from Tis Abbay Power Station and Tis Abbay No. 2 Power Station. New 45 kV transmission lines are to lead out from each of the above substations and new substations, Dangla and Debre Tabor are to be connected at the respective ends of these 45 kV transmission lines.

The transmission line between Bahar Dar and Gondar is to be designed for a rated voltage of 66 kV, but until 1990 the power necessary to satisfy the demand in the area can be transmitted at a voltage of 45 kV. However, since from 1991 the demand will be increased to a limit of the available transmission capacity, a step-up of the transmission line voltage will be made from 45 kV to 66 kV. The power system diagram as of 1991 is indicated in Fig. 9-2-3.

With additional installation of a No. 3 unit at the existing Tis Abbay Power Station and construction of Tis Abbay No. 2 Power Station, the supply capacity of the Tis Abbay Power System will be increased to 11,520 kW (dependable output 10,560kW) by addition of the No. 3 unit, of Tis Abbay Power Station 17,220 kW (dependable output 15,820 kW) after completion of No. 2 Power Station. According to the balance of demand and supply in Table 4-7 of Chapter 4, the total load of the system in 1990 will be 15,620 kW (20,390 kW in case the load of electric boilers coincide with the peak load of the system), and from 1991, there will be a shortage produced in the power power demand and supply balance. It was assumed that this shortage would be filled by a 66 kV transmission line to Bahar Dar Substation from Upper Beles Power Station, the construction of which in the future is looked forward to.

9.2.3 Substation Facilities Plan

(1) Capacities of Substations

The capacities of the substations taking into consideration power demand of each substation based on the load forecasts for the respective service areas and investment required for additional transformers due to in crease in demand of the substation construction funds have been selected as shown in Table 9-2-1.

Transforming facilities required upon addition of the No. 3 unit at the existing Tis Abbay Power Station and construction of Tis Abbay No. 2 Power Station are to be installed at the existing Tis Abbay Switchyard.

(2) Voltages of Substations

The receiving or transmitting voltages of substations are to be the two levels of 66 kV and 45 kV, the selections of which have been described in detail in 9.1, "Power Transmission Plan." For the distribution voltage, the present standard distribution voltage in Ethiopia of 15 kV was adopted.

In 1991, when the voltage of the transmission line between Bahar Dar and Gondar is stepped up from 45 kV to 66 kV, new transforming facilities of 66 kV will become necessary at the substations of Bahar Dar, Wereta and Gondar.

(3) Short-circuit capacity of System

The short-circuit capacity of the system was studied in order to decide on the ratings of circuit breakers for the various substations. As a result of analysis, the short-circuit capacity required in the year 2000 is as shown in Fig. 9-2-4, and the short circuit capacity of the individual substations are as follows:

Fig. 9-2-1 EXISTING POWER SYSTEM

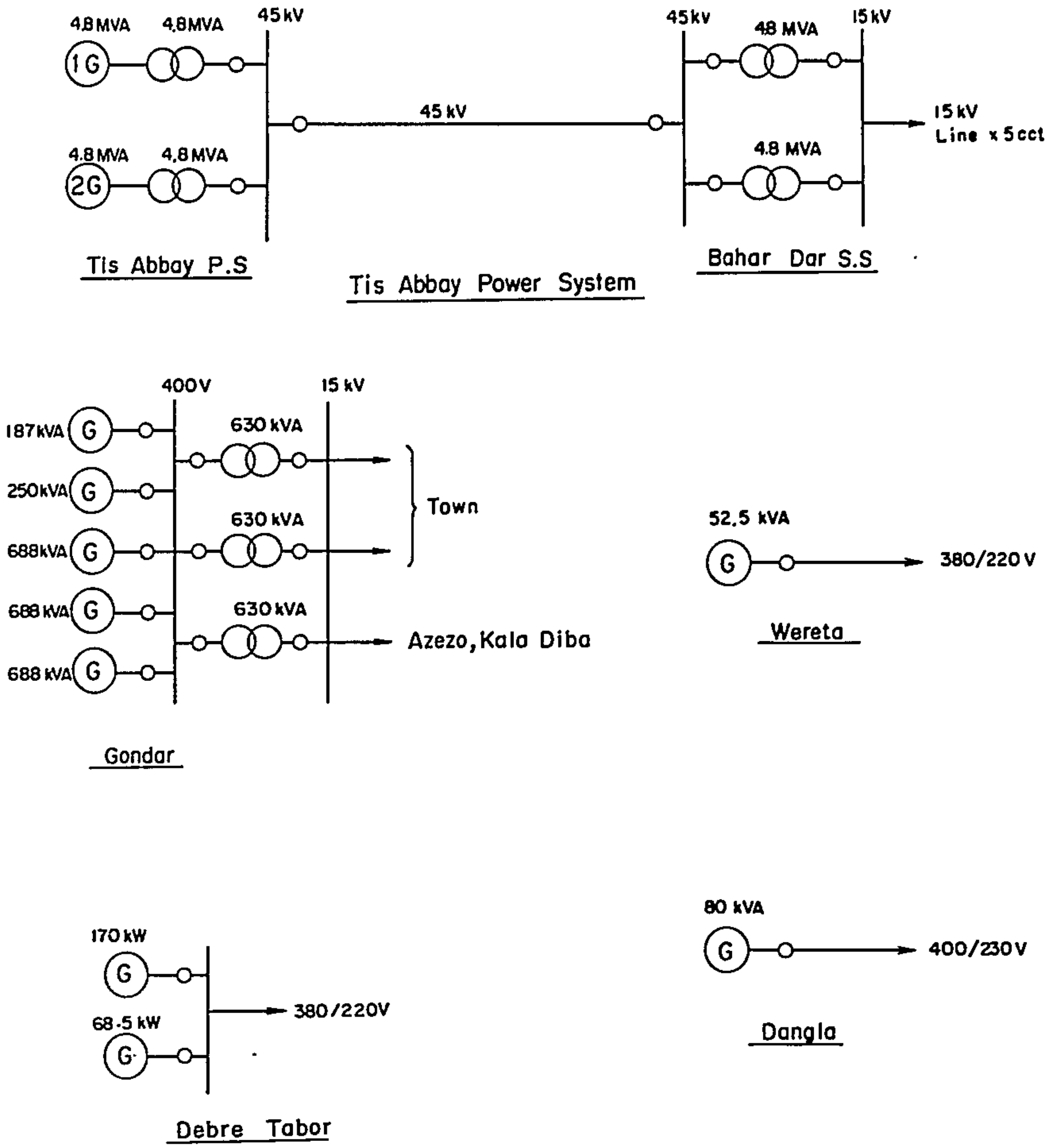
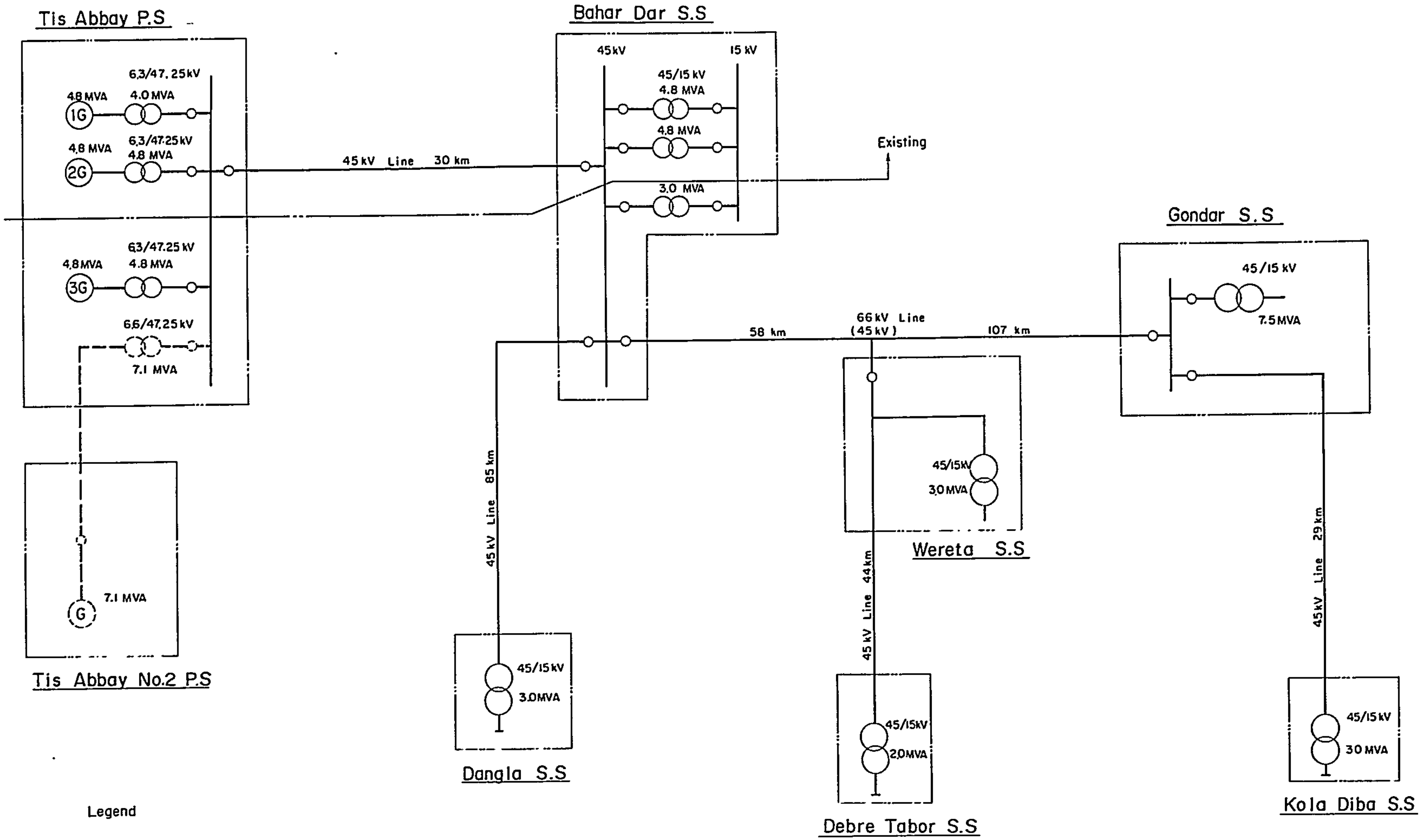


Fig. 9-2-2 SINGLE LINE DIAGRAM IN 1982



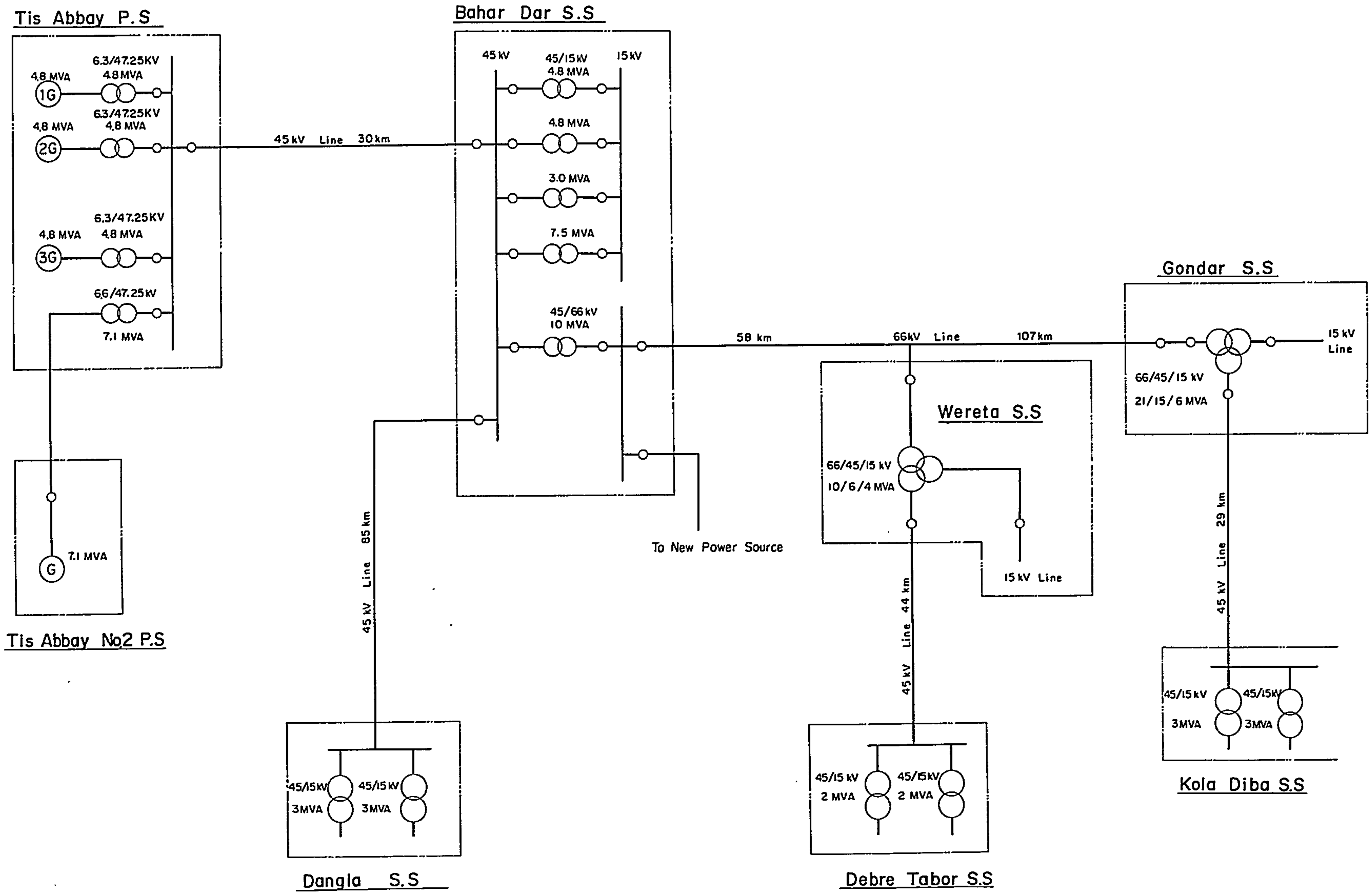
Legend

G : Generator

: Transformer

: Circuit Breaker

Fig. 9-2-3 SINGLE LINE DIAGRAM IN 1991



(a) 66 kV Systems

The maximum short-circuit capacity of the systems in the year 2000 and the rated breaking capacities of circuit breakers which will newly be provided are as indicated below.

Substation	System Short-Circuit Capacity	Circuit Breaker Rating
Bahar Dar	102 MVA	1,000 MVA
Wereta	79 MVA	"
Gondar	48 MVA	"

Compared with the short-circuit capacity of the system, there are ample allowances in the breaking capacities of circuit breakers.

(b) 45 kV Systems

The maximum short-circuit capacity of the systems in the year 2000 and the rated breaking capacities of existing circuit breakers or those which will be provided newly are as indicated below.

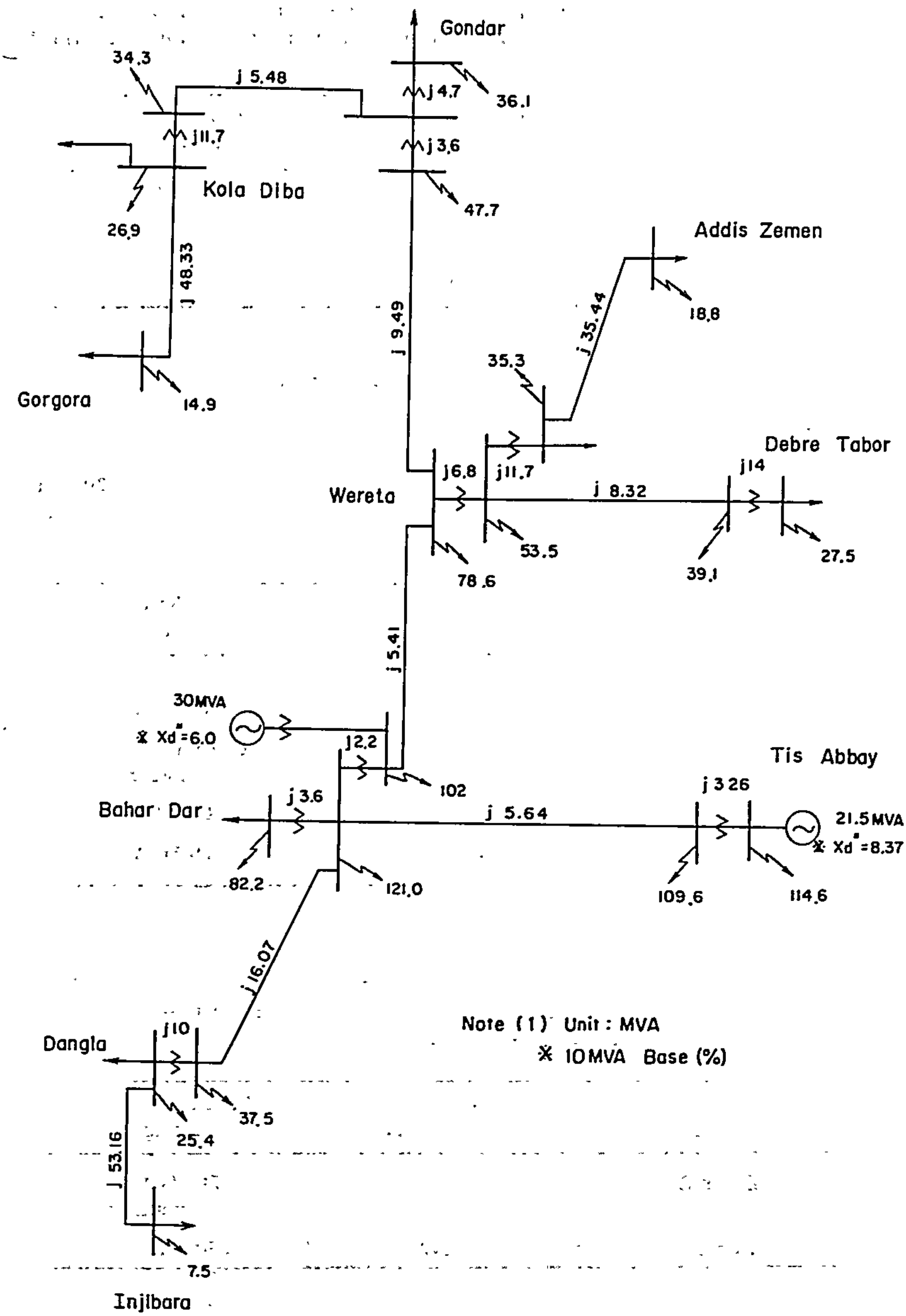
Substation	System Short-Circuit Capacity	Circuit Breaker Rating
Tis Abbay	110 MVA	600 MVA (existing)
Bahar Dar	121 MVA	600 MVA (existing)
Wereta	54 MVA	1,000 MVA
Gondar	42 MVA	1,000 MVA

(c) 15 kV Systems

The maximum short-circuit capacity of the systems in the year 2000 and the rated breaking capacities of existing circuit breakers or those which will be provided newly are as indicated below.

Substation	System Short-Circuit Capacity	Circuit Breaker Rating
Bahar Dar	39 MVA	250 MVA (existing)
Wereta	23 MVA	250 MVA

Fig. 9-2-4 SHORT-CIRCUIT CAPACITY (As of 2000)



Substation	System Short-Circuit Capacity	Circuit Breaker Rating
Gondar	21 MVA	250 MVA
Dangla	14 MVA	"
Debre Tabor	18 MVA	"
Kola Diba	17 MVA	"

9.2.4 Substation Plan

(1) Operation of Substation

The existing Bahar Dar Substation has operating personnel stationed there at all times for supervision and operation of equipment, and this system is to be continued in the future.

The newly constructed Gondar Substation is for distribution of power to a major city in the area of this power system, while Wereta Substation is a substation connected by T-branch part way along the transmission line between Bahar Dar and Gondar. Operating personnel will not be assigned to these two substations for the reasons given below.

In consideration of the system structure and equipment quantities, it is thought handling of equipment will be extremely infrequent. For routine maintenance and operation, a number of technicians can be posted near the respective substations and these technicians can operate the equipment whenever necessary. Since it will be possible to quickly reach substations from the posts of the technicians, there will be no problem with respect to power supply. Further, through installation of remote supervisory apparatus between the substations of Gondar, Wereta, and Bahar Dar, it will be possible for the operating conditions at the two substations of Gondar and Wereta to be monitored at Bahar Dar Substation at all times, and there will be practically no lowering of operating reliability.

The substations of Dangla, Debre Tabor and Kola Diba are less important and are of smaller capacities than the Wereta and Gondar substations, and operating reliabilities can be amply maintained through patrols and inspections now and then of operating conditions.

With respect to Gondar Substation, it is desirable to change it to a attended substation from 1995 when its importance in supply will have been increased due to increase in demand.

(2) Selection of Transformers

For the capacities, number of units, and voltages of the transformers of the substations, the four cases as indicated in Fig. 9-2-5 were studied. The results as given in Table 9-2-2 show that of transformers which can cope with demands in 2000, those of Case 3 to be installed in 1991 will be the most economical, and therefore Case 3 was adopted. However, since it will be undesirable for full outage over a long period of time for maintenance works of electrical equipment at Gondar Substation which covers Gondar, the principal city in the North Region of Lake Tana, it will be worthwhile to examine Case 4 in which two banks of three phase transformer would be installed for the sake of supply reliability. Which of the two, Case 3 or Case 4, is to be adopted should be decided in the latter part of 1985 taking into consideration supply reliability of the power system.

The differences between the cases, 1 through 4, are as described below.

Case 1: Voltage is to be stepped up from 45 kV to 66 kV in 1991, and 3-phase, 2-winding transformers are to be installed at Bahar Dar (10 MVA), Wereta (10 MVA), and Gondar (21 MVA) substations.

Case 2: Voltage is to be stepped up from 45 kV to 66 kV in 1991, and a 3-phase, 2-winding transformer (10 MVA) is to be installed at Bahar Dar Substation, and 3-phase, 3-winding transformers of 5/3/2 MVA and 11/7.5/3 MVA at Wereta and Gondar Substation, respectively. Further, 3-phase, 3-winding transformers of 5/3/2 MVA and 11/7.5/3 MVA are to be added at Wereta and Gondar Substations, respectively, in 1995.

Case 3: Voltage is to be stepped up from 45 kV to 66 kV in 1991, and at Wereta and Gondar Substations, 3-phase, 3-winding transformers of capacities double those of the transformers in Case 2, 10/6/4 MVA and 21/15/6 MVA, respectively, are to be installed.

Case 4: Voltage is to be stepped up from 45 kV to 66 kV in 1991, and a transformer of the same capacity (10/6/4 MVA) is to be installed at Wereta Substation. At Gondar Station, for the sake of improving supply dependability, a transformer of the same capacity as in Case 2 (11/7.5/3 MVA) is to be installed in 1991, and another of the same capacity as that of 1991 (11/7.5/3 MVA) is to be installed in 1995.

All of the substations to be newly commissioned at the end of 1982 are to be equipped with one 45/15 kV, 3-phase transformer respectively. Also, one 45/15 kV, 3-phase transformer is to be installed at Bahar Dar Substation. These transformers will be capable of coping with power demand up to 1994. One 3-phase transformer is to be added at the existing Tis Abbay Switchyard in each of the years, 1982 and 1983. In 1991, when the transmission voltage between Bahar Dar and Gondar is to be stepped up from 45 kV to 66 kV, one 45/66 kV, 3-phase transformer is to be installed at Bahar Dar Substation, and one 66/45/15 kV, 3-phase transformer each at Wereta and Gondar Substations.

In view of the fact that one 3-phase transformer costs approximately 80% of what three single-phase transformers amounting to the same capacity would cost, and is thus cheaper, and since fault of transformers has been greatly reduced in recent years through improvements in designing and manufacturing techniques for transformers so that operating reliability has been increased, 3-phase transformers are to be adopted.

(a) Gondar Substation

The transformer to be installed in 1991 will be of voltage of 66/45/15 kV, which is a 3-winding transformer with on-load tap-changer, and its capacity will be sufficient to cope with demand up to the year 2000. The transformer installed in 1982 is to be diverted to Bahar Dar Substation in 1991 for expansion of that substation.

(b) Wereta Substation

The transformer to be installed in 1991 will be of voltage of 66/45/15 kV, and will be a 3-winding type with on-load tap-changer, and with this capacity power demand up to 2000 can be supplied. The transformer installed here in 1982 is to be transfered to Debre Tabor Substation in 1991.

(c) Bahar Dar Substation

The transformer to be installed in 1991 is to be of voltage of 66/45 kV, and two winding type with on-load tap-changer. The capacity will be determined in consideration of the following:

(i) The power demand on Bahar Dar Substation in 1992 will exceed the generating capacity of the Tis Abbay hydroelectric system. As the electric power of the Upper Beles System will be supplied to the 66 kV bus of Bahar Dar Substation in 1991, the electric power lacking will be supplied to Bahar Dar Substation through this 66/45 kV transformer.

(ii) Further, in case of faulting of the largest-capacity unit of the Tis Abbay power stations, the power shortage will be supplied through this 66/45 kV transformer.

(d) Dangla, Kola Diba and Debre Tabor Substations A

Additional transformers will be installed in 1991. These transformers will be capable of supplying power to loads up to the year 2000.

Fig. 9-2-5 COMPARISON FOR SUBSTATIONS PLAN

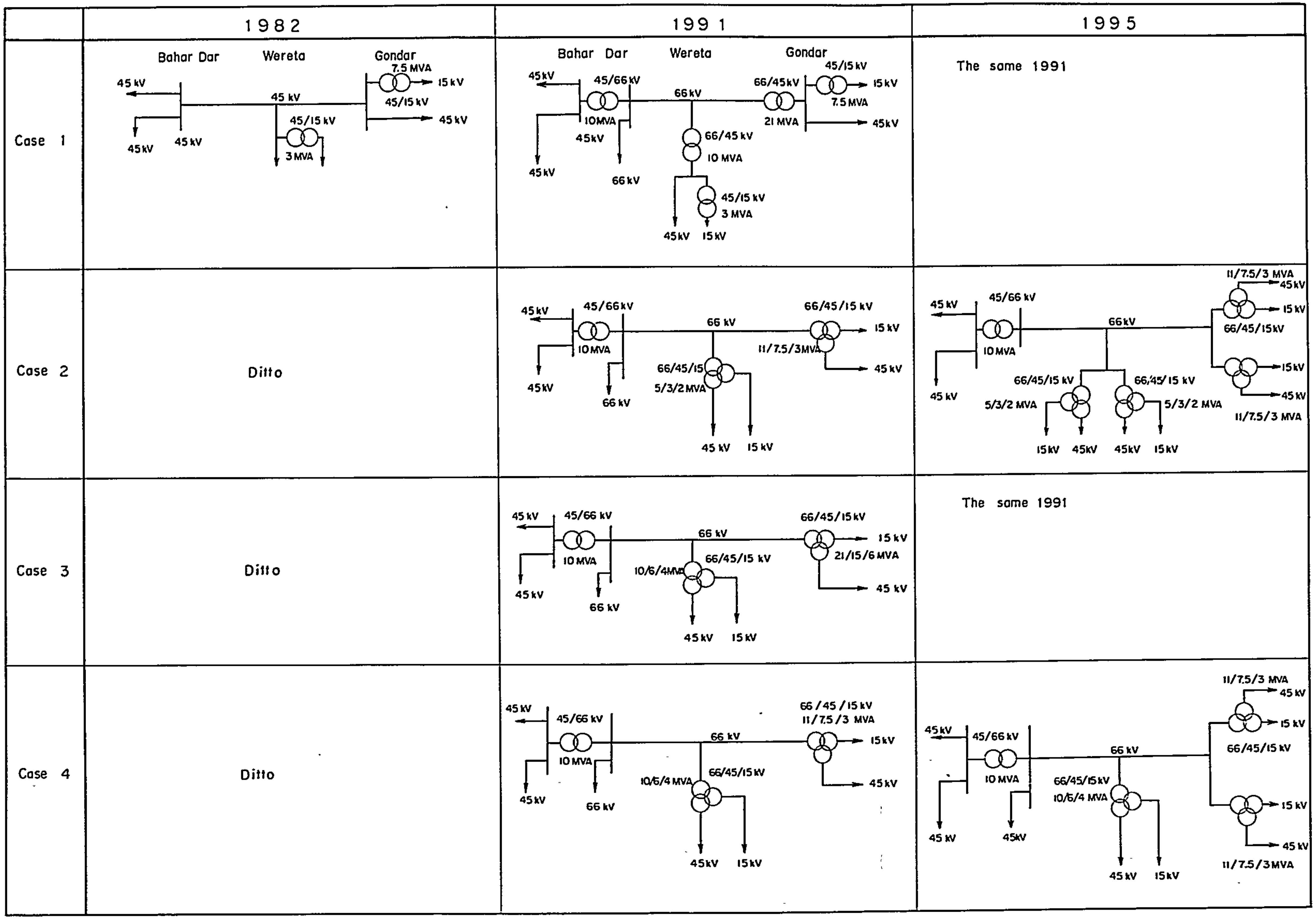


Table 9-2-2 Comparisons of Construction Costs

Unit 10^3 E$

		Case 1				Case 2				Case 3				Case 4			
		Bahar Dar	Wereta	Gondar	Total	Bahar Dar	Wereta	Gondar	Total	Bahar Dar	Wereta	Gondar	Total	Bahar Dar	Wereta	Gondar	Total
Construction Cost	1982	1093	393	907	2393	1093	393	907	2393	1093	393	907	2393	1093	393	907	2393
	1990	1379	1279	1050	3708	1379	507	629	2515	1379	607	857	2843	1379	607	629	2615
	1995	-	329	429	758	-	736	943	1679	-	-	-	-	-	-	943	943
	Total	2472	2001	2386	6859	2472	1636	2479	6587	2472	1000	1764	5236	2472	1000	2479	5951

Case 1

Construction Cost at Present Worth	Bahar Dar Interest Rate 8 %	Bahar Dar Interest Rate 10 %	Wereta Interest Rate 8 %	Wereta Interest Rate 10 %	Gondar Interest Rate 8 %	Gondar Interest Rate 10 %	Total Interest Rate 8 %	Total Interest Rate 10 %
1. Case Considering P.R.F.	1871	1657	1229	1007	1650	1436	4750	4100
Construction Cost Ratio %							124	118
2. Case Not Considering P.R.F.	1707	1579	1121	986	1514	1379	4342	3944
Construction Cost Ratio %							124	121
3. Economical Order	4							

Case 2

Construction Cost at Present Worth	Bahar Dar Interest Rate 8 %	Bahar Dar Interest Rate 10 %	Wereta Interest Rate 8 %	Wereta Interest Rate 10 %	Gondar Interest Rate 8 %	Gondar Interest Rate 10 %	Total Interest Rate 8 %	Total Interest Rate 10 %
1. Case Considering P.R.F.	1871	1657	879	764	1521	1343	4271	3754
Construction Cost Ratio %							111	108
2. Case Not Considering P.R.F.	1707	1579	800	714	1386	1264	3893	3557
Construction Cost Ratio %							111	109
3. Economical Order	3							

Case 3

Construction Cost at Present Worth	Bahar Dar Interest Rate 8 %	Bahar Dar Interest Rate 10 %	Wereta Interest Rate 8 %	Wereta Interest Rate 10 %	Gondar Interest Rate 8 %	Gondar Interest Rate 10 %	Total Interest Rate 8 %	Total Interest Rate 10 %
1. Case Considering P.R.F.	1871	1657	664	643	1300	1179	3835	3479
Construction Cost Ratio %							100	100
2. Case Not Considering P.R.F.	1707	1579	600	564	1179	1114	3486	3257
Construction Cost Ratio %							100	100
3. Economical Order	1							

Case 4

Construction Cost at Present Worth	Bahar Dar Interest Rate 8 %	Bahar Dar Interest Rate 10 %	Wereta Interest Rate 8 %	Wereta Interest Rate 10 %	Gondar Interest Rate 8 %	Gondar Interest Rate 10 %	Total Interest Rate 8 %	Total Interest Rate 10 %
1. Case Considering P.R.F.	1871	1657	664	643	1521	1343	4056	3643
Construction Cost Ratio %							106	105
2. Case Not Considering P.R.F.	1707	1579	600	564	1386	1264	3693	3407
Construction Cost Ratio %							106	105
3. Economical Order	2							

Note :

1) Case 2, 3 and 4 take into account removal-diversion of equipment.

2) Economic service life of electrical equipment to be 30 years.

3) P.R.F. : Perpetual replacement factor

9.3 TELECOMMUNICATIONS PLAN

For maintenance and operation of the electric power system to be expanded or newly constructed, a telecommunication channel utilizing power line carrier equipment will be installed among the respective substations and power stations.

In the way of load dispatching telephones, a telephone channel whereby conversation can be carried on between substations by selective calling will be newly installed.

Although Gondar and Wereta Substations have been planned to be unattended, since they are important substations in the power system, a remote supervisory telecommunications channel is to be provided between Bahar Dar and Gondar as well as Wereta for monitoring of the operating conditions at Gondar and Wereta Substations from Bahar Dar Substation, thereby aiming for improvement in operating reliability.

CHAPTER 10

PRELIMINARY DESIGN

CHAPTER 10 PRELIMINARY DESIGN

10.1 REGULATING DAM

10.1.1 Selection of Dam Location

A number of proposals have been made in the past for the damsite, but here, a comparison study will be made on the site proposed by Acres International (hereafter called upstream proposal) and the site proposed by the Survey Mission at the time of its first-stage survey as an alternative (hereafter called downstream proposal).

(1) Topography and Geology

The vicinity of the outlet of Lake Tana Comprises an extremely complex topography. As shown in Dwg No. 4, the lava deposited at around 1 km upstream from Abbay Bridge has been eroded by outflow from the lake, and there are numerous reefs and islets existing in chain fashion. The main outlets are the Debre Marian Lagoon considered to comprise the mainstream of the Blue Nile (river width approx. 600 m) and an opening called "Mesera" adjacent to the right-bank side (river width approx. 100 m).

The downstream ends of the two outlets are naturally obstructed by the beforementioned reefs and islets so that free outflow from the lake is hindered, and a natural regulating action of Lake Tana takes place.

Especially, there are reefs which cross the outlet of Debre Marian Lagoon, and these reefs become a submerged weir during the rainy season, while the greater part of it is exposed during the dry season. The reefs at the right-bank side of the Blue Nile continue from here toward the downstream area in chain-form down to the vicinity of Abbay Bridge.

Other small outlets exist along narrow openings between reefs, but almost all of them are dried during the dry season to form swamps. The left-bank side is a flat tableland consisting of cultivated fields except for a partial low area which is inundated in the rainy season by the Chimble River flowing in from the left-bank side.

The upstream proposal consists of closing off the section between the peninsular tableland protruding from the left-bank immediately downstream of Debre Marian Lagoon and the popularly-called Chara Chara site to provide dam connected to the reef continuing along the right-bank. Regulating gates would be provided at the Chara Chara site for regulation of the surface water level of Lake Tana.

The site called Kamforo Apids approximately 200 m upstream of Abbay Bridge is a point at which reefs from the upstream area change over to a massive tableland, and although there are islets at the riverbed, these do not present complications.

The left-bank side is gently sloped and continues on up to the tableland, while at the right-bank side, the tableland protruding from the national highway and the reef from the upstream side join in a V-form to comprise a topography whereby a swamp called Tekorit is formed.

The downstream proposal is for dam to be provided at this site with regulating gates installed slightly to the right-bank side of the middle of the stream by which the water surface level of Lake Tana is to be regulated.

The geology of the surrounding area including the damsites of the two proposals is comprised of deposits of lava called "Young Basalt," which is a rock of gray or black color, porous but extremely hard. Details are given in Chapter 6, "Geology."

(2) Approximate Construction Costs

The results of comparisons of the approximate construction costs made based on Dwg. No. 5 and Dwg. No. 6 are shown in Table 10-1-1.

Table 10-1-1 Comparison Table for Construction Cost

(Unit : Eth$)

Description of Work	①Upstream site	②Downstream site	① - ②
Care of river during Construction	572,000	572,000	0
Arrangement of Riverbed	1,574,400	1,574,400	0
Common excavation	100,800	46,480	54,320
Rock excavation	270,400	275,200	Δ 4,800
Embankment	440,640	413,100	27,540
Concrete in sill	936,440	936,440	0
Concrete in pier	424,215	424,215	0
Concrete in wall	148,988	148,988	0
Concrete in others	50,393	50,393	0
Reinforcement	404,120	404,120	0
Cement grouting	222,060	144,339	77,721
Drilling for grout hole	425,700	283,800	141,900
Access road	46,800	—	46,800
Miscellaneous	633,044	466,525	166,519
Sub total	6,250,000	5,740,000	510,000
Contingency sum	940,000	870,000	70,000
Gate	2,160,000	2,160,000	0
Administration building and others	510,000	510,000	0
Grand total	9,860,000	9,280,000	580,000

(3) Construction Conditions

The conditions for making comparisons of the two proposals will roughly be the following:

(i) It is desirable for the water level of Lake Tana and the outflow to be close as possible to their natural states during construction. In such case it is desirable for the site of the regulating dam to be selected where the shape of the existing lake outlet will not be greatly changed even during construction.

(ii) It is desirable for gate operation to be possible at the time work on deepening the riverbed is started in order to avoid an abnormal change in the lake water surface level.

(iii) As care of river during dam construction, it is conceivable for half-river coffering to be utilized and it will be required for a cross-sectional area of the stream sufficient to pass the natural discharge to be secured. Unless this is considered it may be expected that the surface level of Lake Tana will rise, especially during the rainy season. Therefore, it is desirable for a site where diversion of the river flow can be readily achieved and ample cross-sectional area of the stream can be secured.

(iv) Transportation of construction materials must be easy to accomplish.

A discussion of the two proposals based on the above conditions would be as follows:

(Upstream Proposal)

(i) As stated in (1), the damsite would be located immediately downstream of the portion where the main riverbed is deepened and since the dam foundation would overlap with the deepened riverbed part it is assumed the shape of the outlet would be changed considerably during construction. There is no way of regulating the change in outflow resulting from this.

(ii) If work to deepen the riverbed were to be started after installation of gates, this would mean the dam will exist in the middle of the deepened section, which is undesirable from the standpoint of safety.

(iii) An access road of approximately 1, 300 m will be required to be newly constructed for hauling in materials and equipment.

(Downstream Proposal)

(i) There is practically no necessity for deepening of the riverbed at this part, and consequently there will be very few restrictions imposed in execution of work.

(ii) There is hardly any need for an access road for hauling in materials and equipment.

(iii) Because of proximity to a national highway and residences there will be some necessity for measures to be taken regarding safety during construction.

(iv) The area of inundation at the left-bank side will be slightly larger than for the upstream proposal.

(4) Conclusion

As a result of the comparison study on the two proposals on selection of a damsite it is seen that the downstream proposal is superior with respect to construction cost and work conditions.

Besides the above, to give some consideration to the aspect of maintenance and administration, it is thought the downstream proposal would be superior with regard to the conditions of location of the administrative building as well as roads for administration, power distribution lines for service, road lighting facilities, etc.

If any drawback of the downstream proposal were to be considered, it might be that a low area at the left-bank side upstream of the site will be inundated, but this should not be much of a problem. This can be solved at detailed design stage because the cost is very small.

Consequently, the downstream proposal should be adopted for the damsite.

10.1.2 Riverbed Deepening

(1) Conditions for Determining Scale

The scale of deepening of the riverbed is determined by the following conditions:

(i) That a water passage capacity is possessed whereby it will be possible for discharge to keep the water surface level of Lake Tana within limits even in case of considering 100 year probability flood.

(ii) That for this purpose a cross-sectional area of stream is possessed whereby the relation between Lake Tana water surface level and discharge (Q_u) based on the rule curve during flood indicated in Fig. 7-2-5 is satisfied.

(2) Result of Study

The results of hydraulic studies based on the above conditions and using Eq. (2) in 8.2.1 (2) are indicated in Dwg. No. 5.

In effect, as shown in Dwg. No. 5, the reef at Debre Marian Lagoon is to be lowered to 1,784 m, and a trapezoidal canal of a gradient of 1/2,000 and a bottom width of 125 m is to be provided. Further, the maximum water passage capacity for the cross-sectional area obtained by this canal plus the existing cross section is 1,280 m^3/sec at Lake Tana water level of 1,787.5 m.

10.1.3 Gate Capacity

The gate capacity is automatically determined by the scale of deepening of the riverbed described in the preceding section.

Calculation of gate capacity is done by the equation below.

$$Q = C \cdot aB\sqrt{2g\,\Delta h}$$

where

C : coefficient of discharge = 2.1

a : gate opening

B : gate width

h : water level difference between upstream and downstream sides of gate

The results of calculations are indicated as Dwg. No. 5, "Rating Curve."

10.1.4 Dam

Giving consideration to the results of studies made in the preceding chapters, the preliminary design of the regulating dam is made based on the following fundamental conditions:

Lake Tana Water Surface Level		
	Maximum	El. 1,787.50 m
	Minimum	El. 1,785.00 m
Design Flood Discharge, 100-year flood		2,300 m^3/sec
Dam Over flow crest, concrete		El. 1,783.00 m
Non-overflow portion, earthfill		El. 1,788.00 m
Riverbed Deepening		
Bottom width 125 m,		
gradient 1/2,000, open cut		

The preliminary design is shown in Dwg. No. 5.

For concrete aggregates, it is thought most economical to collect rock from a quarry located approximately 4 km southwest of Bahar Dar and haul this to the site where aggregate manufacturing would be done. However, only the overflow section is designed to be a concrete structure since there would be some question as to quantity if the entire dam were to be made of concrete.

The "Young Basalt" existing in the surrounding area of the site, according to the results of tests on a number of samples, has specific gravities of 2.36 in saturated surfacedry condition and 2.28 in oven-dry condition, while absorption is 3.40%. This absorption is high compared with ordinary concrete aggregates so that control of water-cement ratio will be slightly difficult and at the present this rock is thought to be unsuitable as aggregate.

Earthfill material may be obtained at Taima Hill on the left-bank side approximately 200 m downstream from Abbay Bridge. This material is residual clay having satisfactory properties with respect to impermeability and shear, while it has been confirmed there is sufficient quantity.

Details of materials are given in Chapter 6, "Geology."

Further, with progress in surveys hereafter, the accuracy of data on the geology of the site, and qualities and quantities of construction materials should be improved at which stage the structures of the various parts of the dam should be studied.

10.1.5 Basic Specifications

Lake Tana Water Surface Level	
Maximum	El. 1,787.50 m
Minimum	El. 1,785.00 m
Effective depth	2.5 m
Design Flood Discharge, 100-year Flood	2,300 m^3/sec
Dam	
Overflow section, concrete structure	
Crest	El. 1,783.00 m
Dam length	93.0 m
Dam height (max water level above foundation)	7.5 m
Dam volume	4,100 m^3
Non-overflow section, earthfill structure, wet masonry facing	
Crest	El. 1,788.00 m
Dam length	347.0 m
Dam height	7.0 m
Dam volume	27,000 m^3
Slope gradient, upstream	1 : 2.5
downstream	1 : 3.0

Spillway gates, steel roller gate

W 15.0 m x H 5.0 m — 5 ea

Maximum water passage — 1,280 m^3/sec

Riverbed Deepening

Open cut, trapezoidal canal

W 125.0

Gradient 1/2,000

Lowering depth, at Debre Marian Lagoon

Depth 1.5 m ~ 2.0 m to El. 1,784.00 m

Excavation quantity — approx. 66,000 m^3

10.2 TIS ABBAY NO.2 POWER STATION

10.2.1 Civil Structures

(1) Intake

A morning glory-type intake is to be provided at the right-bank side of the downstream end of the existing canal, a spindle-type manually-operated gate (width 2.48 m x height 5.20 m) installed. The Q-H curve of the gate is indicated in Dwg. No. 8.

(2) Waterway

Water is to be conducted to a head tank provided on a tableland at the right-bank of the Blue Nile by a non-pressurized concrete headrace of semicircular top and rectangular bottom cross section (width 2.48 m x height 2.73 m) connecting to the intake. Taking into account the fact that the route of the headrace will pass inside the compounds of the existing power station, the headrace is to be provided underground as much as possible, and because of this the gradient is to be 1/600 in consideration of the ground surface line. The waterway characteristic curve is indicated in Dwg. No. 8.

(3) Head Tank

The scale of the head tank, considering the water level fluctuation conditions caused at the time of starting the turbine and by load fluctuations, is designed for a capacity of approximately 1,800 m^3 and head tank area of 720 m^2. Also, a spillway is provided as an appurtenant facility to safely discharge the excess water when load is suddenly cut off.

(4) Penstock

The power station site is narrow and when the topographical conditions are considered it is not practical to install the penstock along the ground as a surface penstock because of the relation to the powerhouse. Therefore, the design is to be for a concrete penstock consisting of a vertical shaft and a horizontal shaft of inner diameter of 1.8 m and length of 89.7 m (vertical shaft 41.2 m, horizontal section 48.5 m). Further, when seen from a geologic viewpoint, the surrounding natural ground consists of hard lava, and in this sense it is judged that a concrete structure will be adequate, but the effect of water hammer when load is suddenly cut is a problem which must be studied in the future.

(5) Powerhouse

The powerhouse is designed in consideration of the topographical conditions with the main equipment hall and downstream facilities provided underground. The draft tube is an L-type and one gate is to be provided in front of the tailrace outlet. The outlet, in order to prevent occurrence of whirlpools due to flowing water, is to be twisted by approximately 30 degrees in relation to the downstream direction so that the water will merge smoothly with the center line of the Blue Nile's stream. Since there is no room for an outdoor switchyard to be provided next to the powerhouse it is to be located adjacent to an existing outdoor switchyard on the right-bank tableland.

10.2.2 Electrical Equipment

This power station is to be a run-of-river type with an effective head of 46 m and available discharge of 15 m^3/sec. A Francis turbine would best suit these conditions. The output of the turbine is to be 5,880 kW and the speed 375 rpm. A butterfly valve is to be equipped at the inlet.

The generator is to be a 3 phase synchronized generator of 7,100 kVA at rated power factor of 0.8 (lagging), voltage of 6.6 kV and frequency of 50 Hz. The cooling system is to be a closed air duct circulating type. The synchronization system is to be a low-voltage synchronization system whereby station power supply can be readily secured.

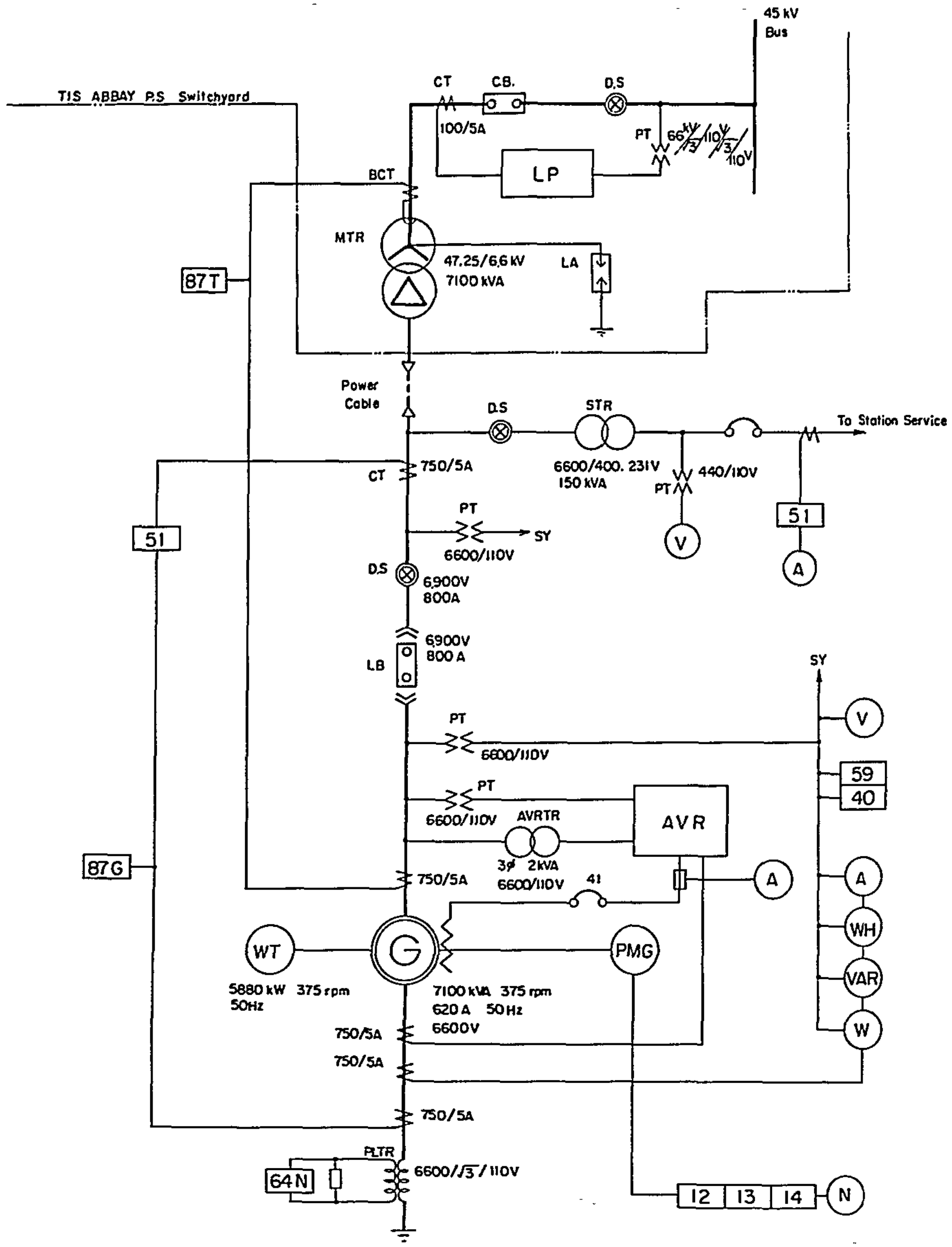
The outdoor switchyard to be provided adjacent to the existing Tis Abbay Switchyard will have one 47.25/6.6 kV, 7,100 kVA, 3-phase, oil-immersed, self-cooled transformer, and the distance between the power station and the switchyard of approximately 100 m will be connected by a 6.6 kV power cable.

The power station is to be unattended and will be remotecontrolled from the distribution panel room of the existing Tis Abbay Power Station.

Of the equipment at the existing outdoor switchyard, the circuit transformer of the Bahar Dar transmission line facilities will need to be replaced at the time the No. 3 unit of Tis Abbay Power Station is added, as will the blocking coil at the time of construction of Tis Abbay No. 2 Power Station, both due to insufficient current capacity.

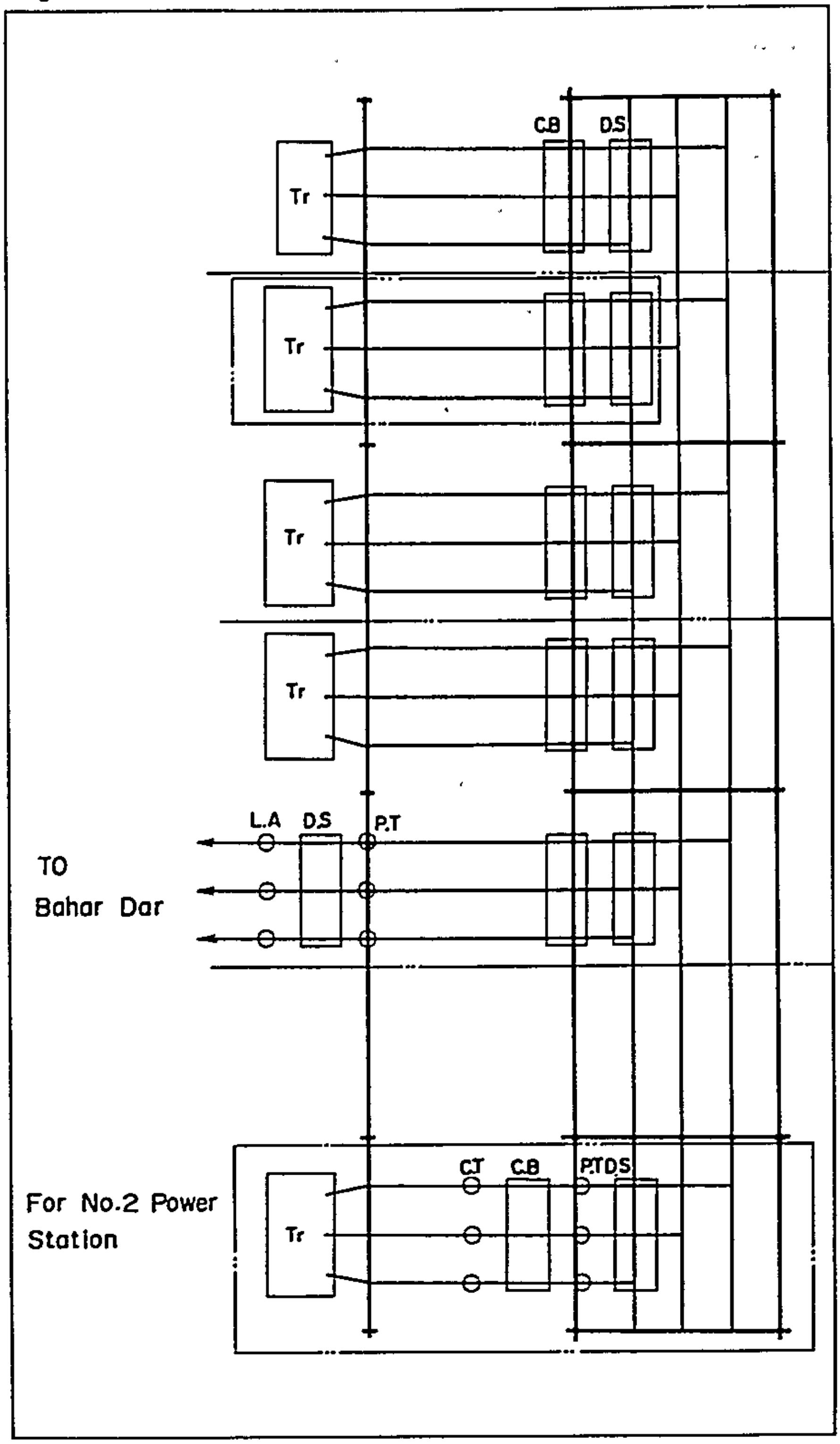
The single line diagram is given in Fig. 10-2-1 and the layout of outdoor switchyard in Fig. 10-2-2.

Fig.10-2-1 TIS ABBAY No.2 POWER STATION SINGLE LINE DIAGRAM



G	Synchronous Generator	12	Over Speed Relay
WT	Water Turbine	13	Synchronous Speed Relay
MTR	Main Transformer	14	Under Speed Relay
STR	Station Service Transformer	40	Loss of Field Relay
CB	Circuit Breaker	41	Field Circuit Breaker
DS	Disconnecting Switch	51	AC Time Over Current Relay
PT	Potential Transformer	64N	Ground Over Voltage Relay
CT	Current Transformer	87G	Generator Ground Differential Relay
LA	Lightning Arrester	87T	Transformer Differential Relay
PLTR	Pole Transformer		
AVR	Automatic Voltage Regulator		
PMG	Permanent Magnet Generator		
A	Ammeter		
V	Voltmeter		
W	Wattmeter		
WH	Watthourmeter		
VAR	Var meter		
N	Speedmeter		
SY	Synchroscop		
BCT	Bushing Type Current Transformer		
LP	Line Protection		

Fig. 10-2-2 TIS ABBAY SWITCHYARD



Legend

(dashed box)	Indicates Scope of this Study		
C.B :	Circuit Breaker	P.T :	Potential Transformer
D.S :	Disconnecting Switch	L.A :	Lightning Arrester
C.T :	Current Transformer	Tr :	Transformer

10.2.3 Specifications

Power Generation System		Run-of-river	
Waterway			
Intake	Reinforced concrete, morning glory type		
	Maximum intake	$15\ m^3/sec$	
	Gate type	spindle type, manual	
	Gate dimensions	H 5.2 m x W 2.48 m	
Headrace	Reinforced concrete, non-pressurized, 1 line		
	Length	187.6 m	
	Shape	semi-circular top, rectangular bottom	
	Inner diameter	H 2.73 m x W 2.48 m	
Head Tank	Reinforced concrete, ordinary water tank		
	Capacity	$1,800\ m^3$	
	Area	$720\ m^2$	
Penstock	Reinforced concrete, 1 line		
	Length	Vertical shaft	41.2 m
		horizontal shaft	48.5 m
	Inner diameter		1.8 m

Powerhouse

Reinforced concrete

powerhouse dimensions L 14.5 m x W 12.0 m x H 8.3 m

Electrical Equipment

Turbine	Vertical Francis	1 unit
	Output	5,880 kW
	Speed	375 rpm
Generator	3-phase, air duct circulating type	
	Capacity	7,100 kVA
	Voltage	6.6 kV
	Frequency	50 Hz

Main transformer

3-phase, oil-immersed, self-cooled		1 unit
Capacity	7,100 kVA	
Voltage	47.25/6.6 kV	

Outdoor Switchyard

Transmitting voltage	47.25 kV
Compound area	7.2 m x 24.5 m

10.3 TRANSMISSION LINE

10.3.1 Outline of Facilities :

(1) 66 kV Transmission Line

Section	:	Bahar Dar Substation to Gondar Substation
Length	:	165km (Bahar Dar Substation-Wereta Substation 58km) (Wereta Substation-Gondar Substation 107km)
Voltage	:	66 kV
Electric Supply System	:	3 phase, 3 wire
Number of Circuits	:	1 circuit
Conductor	:	160 mm^2 AAAC
Overhead Ground Wire	:	22 mm^2 GSC
Insulator	:	254 mm dia suspension insulator
Supports	:	Wood pole and Steel tower
Grounding System	:	Solid grounded system

(2) 45 kV Transmission Line

Section	Bahar Dar Substation—Dangla Substation	Wereta Substation —Deble Tabor Substation	Gondar Substation —Kora Diba Substation
Length	85 km	44 km	29 km
Voltage	45 kV	45 kV	45 kV
Electric Supply System	3 phase, 3 wire	3 phase, 3 wire	3 phase, 3 wire
Number of Circuits	1 circuit	1 circuit	1 circuit
Conductor	80 mm^2 ACSR	80 mm^2 ACSR	80 mm^2 ACSR
Overhead Ground Wire	22 mm^2 GSC	22 mm^2 GSC	22 mm^2 GSC
Insulator	254 mm dia suspension insulator	254 mm dia suspension insulator	254 mm dia suspension insulator
Supports	wood pole	wood pole and steel tower	wood pole
Grounding System	Non-grounded system	Non-grounded system	Non-grounded system

10.3.2 Design Conditions

(1) Transmission Line Routes

There is a 45 kV transmission line between the existing Tis Abbay Power Station and Bahar Dar Substation. The transmission lines of this project are the 66 kV transmission line of 165 km from Bahar Dar City to Gondar City via Wereta, and three 45 kV transmission lines from the above three to Dangla, Kola Diba and Debre Tabor, respectively.

Except for the route of the 66 kV transmission line which passes mountainland of elevation between 2,300 to 2,500 m in parts near Addis Zemen and midpoint between Wereta and Debre Tabor, the routes are generally at the elevations of flat land around Lake Tana of 1,800 to 2,000 m. Near Bahar Dar, there is a necessity to cross the Blue Nile and there are also marchlands, while there is a city planning scheme around Gondar City which restrict where the transmission lines are to pass, but otherwise, selection of routes is easy.

Routes have been selected along roads to facilitate construction and maintenance, and because of this they will come close to the existing telecommunications lines so that inductive trouble cannot be avoided, but where such trouble is anticipated, it will be necessary to investigate the telecommunications facilities in detail and provide suitable measures for protection.

Regarding geology, details have been described in Chapter 6, Geology, but put briefly, along the 66 kV transmission line route, approximately 20% is a silty clay of high cohesiveness while approximately 70% is residual soil and weathered bedrock, both of which possess sufficient bearing capacity. However, the remaining section of 10% consists of talus deposits where there is risk of landslides and care will be required in selection of locations for supports. The 45 kV transmission line routes generally pass where there is residual soil and weathered bedrock and bearing capacity is ample.

(2) Meteorological Conditions

The meteorological data studied of the project area are for the past ten years at Bahar Dar and Gondar. The temperatures at Bahar Dar (El. 1,800 m) are a maximum of 34.8°C and a minimum of 2.0°C, while at Gondar (El. 2,300 m) they are a maximum of 33.4°C and a minimum of 5.0°C. Maximum value of average wind speed is 15.6 m/sec. Annual precipitation is 1,300 mm to 1,700 mm in Bahar Dar, 850 to 1,450 mm in Gondar, but the year is divided into a rainy season and dry season with precipitation in the rainy season from July through September.

Lightning averages between 130 and 60 times annually according to observation data, but the operation records of Tis Abbay Power Station show that power stoppages of the existing 45 kV transmission line near Bahar Dar City are few in number averaging between zero and 4 times annually. Based on the above, the meteorological conditions for design are the following:

Temperature	Maximum :	$35^{\circ}C$
	Minimum :	$0^{\circ}C$
	Mean :	$20^{\circ}C$
Wind pressure	Wind pressure equivalent to wind velocity of 25 m/sec	
IKL	[Isoceraunic (or Isokeraunic) level] Practically zero	

(3) Insulation Design

In insulation design of the transmission lines, since there is a 45 kV line which is to be interconnected with the existing line, 45 kV lines will be non-grounded system to match to existing line, while the 66 kV line is to be solid grounded system in consideration of economy of substation equipment.

Since the transmission line route will be between elevations of 1,800 m and 2,500 m, adjustments for elevation were made in insulation design. In this case, the elevation of 2,500 m was considered as the standard for adjustment.

The basis of the insulation level is placed on switching surge voltage produced in the system, and for abnormal voltages due to lightning strokes, arcing horns are to be attached to insulator strings to prevent damage to insulators. Faulting surges and sustained abnormal voltages are lower than switching surge voltages, while there are no sources of salt pollution and dust trouble in this area, and hence these are not to be considered.

Table 10-3-1 Insulation Design Values

Item	66 kV System	45 kV System
Number of insulators (ea)	5	4
Horn gap (cm)	58	47
Standard insulating spacing (cm)	65	55
Minimum insulating spacing (cm)	40	36
Minimum grounding clearance (m)	6	6

(4) Lightning Protection Design

Lightning phenomena in the area occur between 60 to 130 times annually on the average according to observation data, but faulting due to lightning at the 45 kV transmission line in the vicinity of Bahar Dar has occurred very infrequently, only four times at most annually. The reason for this is judged to be the effect of the overhead ground wire, and therefore, one overhead ground wire is to be provided throughout the lengths of the transmission lines similarly to the existing line. The type of overhead ground wire is to be 22 mm^2 G.S.C., and the shielding angle of conductor is to be less than 30^o at locations of supports.

By lowering grounding resistance of supports, since there will be the effect of preventing back flashover in case of lightning strokes on overhead ground wire, earthing angles are to be attached to supports.

(5) Conductors

With regard to transmission lines of this project, as a result of comprehensive examinations of transmission capacity, resistance loss, voltage drop, and technical and economic aspects, it was decided that 160 mm^2 AAAC should be used for the 66 kV trunk transmission line. The characteristics of this conductor are as indicated in Table 10-3-2.

Although it is conceivable for ACSR conductor to be used, economic comparisons based on construction costs and transmission losses show 160 mm^2 AAAC to be more advantageous, and so this was adpted. The results of the economic comparison are as given in Table 10-3-3.

Of the three 45 kV transmission lines, the one between Bahar Dar Substation and Dangla Substation is the longest and supplies the largest demand, and for this 80 mm^2 ACSR by which the 15 kV bus voltage at Dangla Substation can be maintained at 90% of standard voltage was adopted, and for the other 45 kV transmission lines, it was decided that the same conductor should be used from the standpoint of maintenance tools and materials. The characteristics of this conductor are as indicated in Table 10-3-2.

Further, dampers are to be attached to conductors for the purpose of prevanting mechanical fatigue due to vibration.

(6) Supports

Wood poles are to be used as supports for approximately 93% of the total length with steel towers used for approximately 7% in crossing rivers and mountainland where transportation will be difficult.

Almost all of the transmission line routes will be on flat land along national highways, with small parts crossing mountainland and hills, and generally, the topography is comparatively smooth with little load applied to supports.

With regard to supports, the three kinds of imported steel towers, wood poles imported from Kenya, and precast concrete poles made in the field with domestic concrete importing steel molds and reinforcement were studied, and as a result, it was judged that transmission lines using wood poles would be advantageous. However, for mountainland where it would be difficult to haul long, heavy poles, and for crossing rivers where loads would be large, steel towers are to be used.

The results of economic comparisons are as indicated in Table 9-1-1.

The structures of supports are shown in Fig. 10-3-1.

Table 10-3-2 Characteristics of Conductors

Item		Unit	160mm² AAAC	80mm² ACSR
Stranding	Aluminum	No/mm	19/3.3	6/4.2
	Steel		-	1/4.2
Diameter		mm	16.5	12.6
Calculated sectional area	Aluminum	mm^2	162.5	83.10
	Steel		-	13.85
Approximate weight		kg/km	453.5	335.5
Maximum resistance at 20°C		Ω/km	0.199	0.345
Minimum tensils strungth		kg	4,820	2,770

A.A.A.C. : All Aluminum Alloy Conductors

A.C.S.R. : Aluminum Conductor Steel Reinforced

Table 10-3-3 Economic Comparisons of Conductors

(Unit : Eth$)

Conductor Type / Comparison Item	A.A.A.C.			A.C.S.R.		
	$150mm^2$	$160mm^2$	$180mm^2$	$120mm^2$	$160mm^2$	$200mm^2$
Construction cost (Eth$/km)	33,040	33,040	34,810	34,090	36,340	40,400
Effective transmission power factor (%)	95.5	96.0	96.4	95.3	96.3	97.0
Construction cost-effective power factor ratio	34.6	34.4	36.1	36.6	37.7	41.6
Comparison	100.6	100	104.5	106.4	109.6	120.9

A.A.A.C. : All Aluminum Alloy Conductors

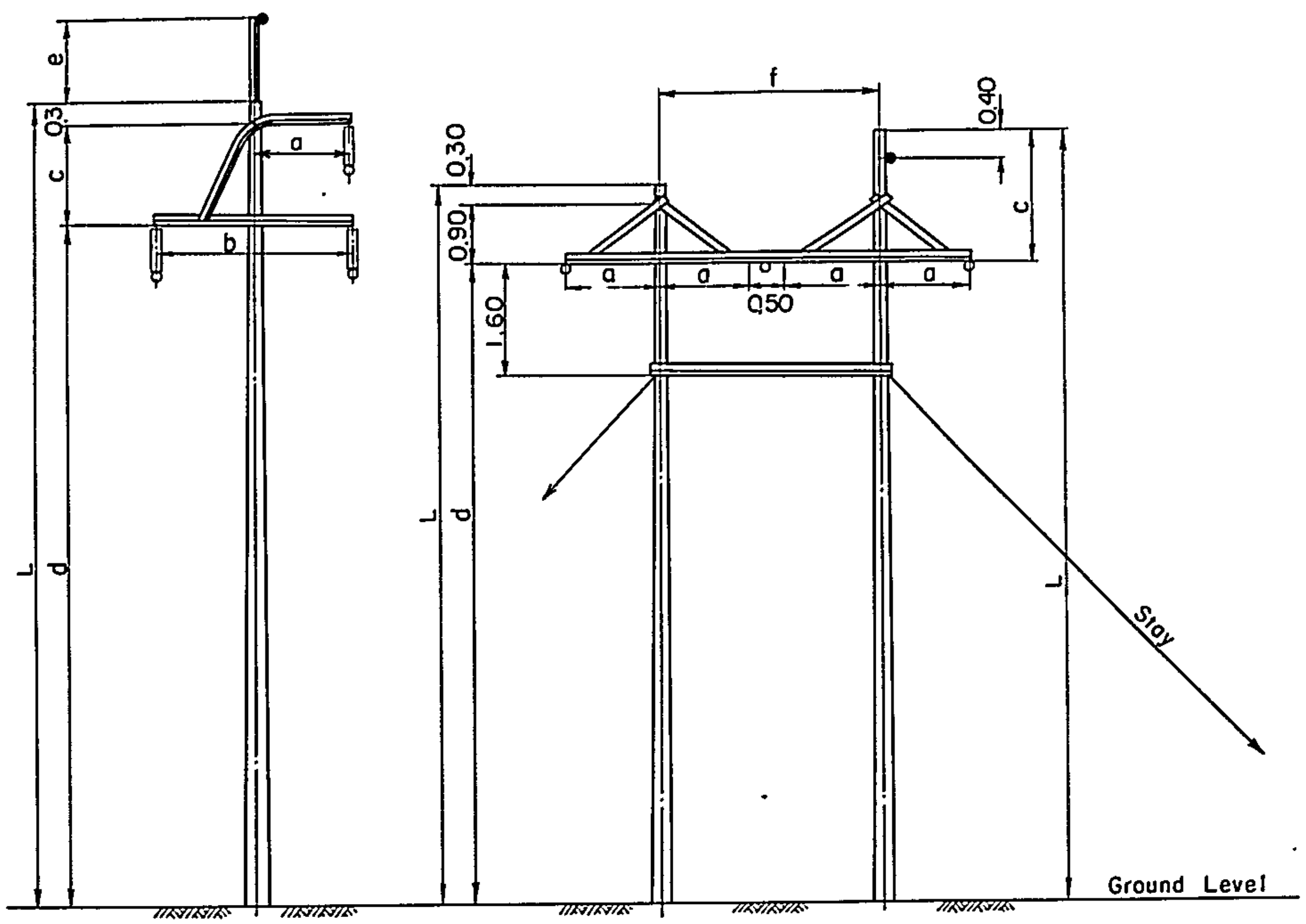
A.C.S.R. : Aluminum Conductor Steel Reinforced

Fig. 10-3-1 Standard Supports for Transmission Line

Unit : Meter

66 kV, 45 kV Standard Wood Pole

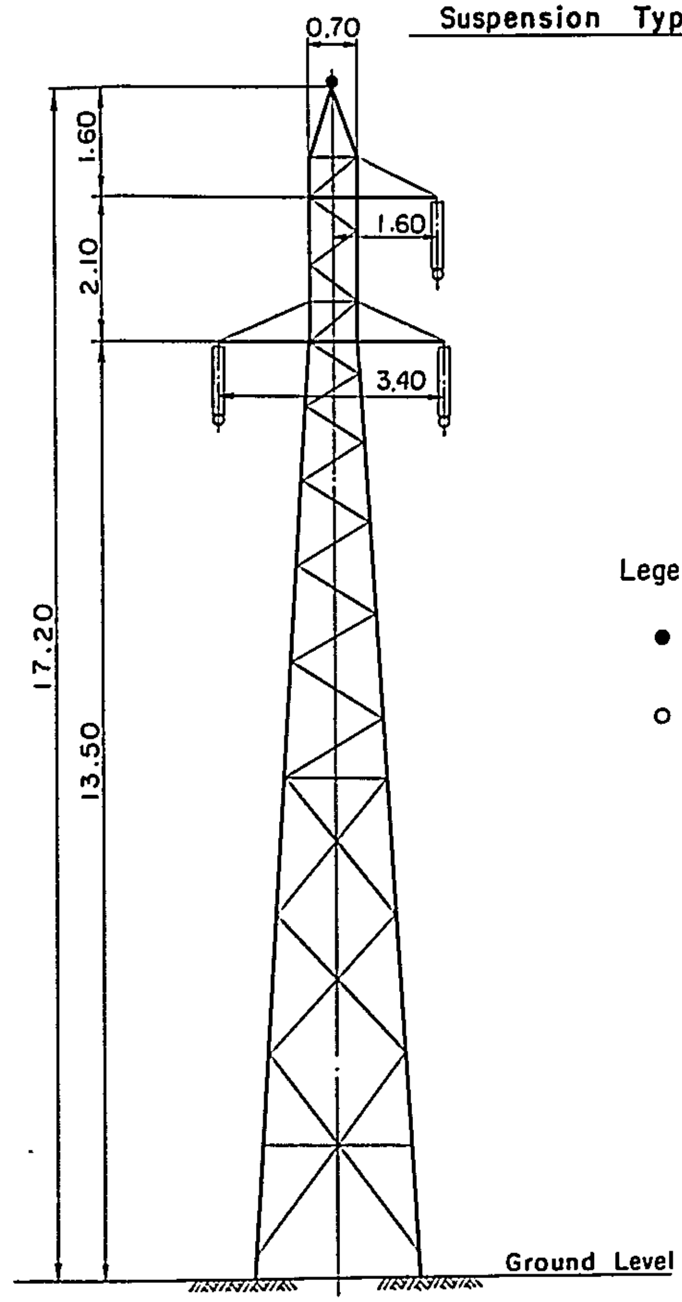
Suspension Type　　　　Strain Type



Normal Span 150 (m)　　　　Normal Span 150 (m)

66 kV Standard Steel Tower

Suspension Type



Normal Span 250 (m)

Legend

● : Overhead Ground Wire

o : Conductor

Main Dimension

Voltage / Kinds / Remarks	66 kv			45 kv		
	Suspen	Strain		Suspen	Strain	
		Short	long		Short	long
a	1 50	1.50		1.20	1.40	
b	3.20			2.60		
c	2.10		2.00	1.80		1.70
d	9.90	8.70	8.70	9.20	8.20	8.20
e	1.30			0.80		
f		3.50			3.30	
L	12.30	9.90	11.10	11.30	9.00	10.30

10.4 SUBSTATION

10.4.1 Additional Installation at Bahar Dar Substation

(1) Existing Facilities

The existing facilities at Bahar Dar Substation are the following:

(a)	Incoming 45 kV facilities of transmission line from Tis Abbay Power Station :	1 circuit
(b)	Transformers for Bahar Dar city load, 45/15 kV, 4.8 MVA :	2 units
(c)	Outgoing 15 kV distribution lines :	5 circuits

(2) Additional Facilities

The additional facilities are to be installed adjacent to the existing facilities.

(a)	45 kV outgoing facilities for transmission to Gondar, Wereta :	1 circuit
(b)	45 kV outgoing facilities for transmission to Dangla :	1 circuit
(c)	Transformer for Bahar Dar city load, 45/15 kV, 3 MVA :	1 unit

The layout of equipment was determined considering additional installation of incoming facilities for 66 kV from the Upper Beles Project scheduled for interconnection in 1991 and a transformer for step-up of the 45 kV transmission line to Gondar and Wereta to 66 kV.

The operating system of equipment will conform with the system for the existing equipment with circuit breakers remote-controlled while disconnecting switches will all be manually operated.

The additional control and relay panels are to be installed in the existing control panel room in line with the existing panels.

Further, of the existing facilities, it will be necessary to replace the current transformer of the 45 kV incoming facilities of transmission line from Tis Abbay Power Station at the time of addition of the No. 3 unit at Tis Abbay Power Station, and the line trap at the time of construction of Tis Abbay No. 2 Power Station, both due to insufficient current capacity.

The single line diagram is given in Fig. 10-4-1, and the equipment layout in Fig. 10-4-2.

10.4.2 New Construction of Wereta Substation

The site for this substation was selected on a small hill at a point approximately 4 km north of the village of Wereta, at the intersection of the road (presently under construction) branching from National Route No. 1 and leading to Debre Tabor.

There is a flat area at the side of this hill which is optimum for leading out the transmission line to Debre Tabor and the distribution lines to Wereta located to the south and Addis Zemen located to the north.

The facilities to be installed at this new substation are the following:

(1)	Outgoing 45 kV facilities for transmission to Debre Tabor :	1 circuit
(2)	Transformer for Wereta and Addis Zemen loads :	45/15 kV, 3 MVA, 1 unit

Circuit breakers will be remote-controlled from the new control panel room in the substation, while disconnecting switches are to be manually operated.

The circuit breaker for the 45 kV transmission line to Debre Tabor will be equipped with an auto-reclosing apparatus, and after a certain period after opening due to fault, forced line charging will be carried out.

The layout of equipment was determined taking into consideration the possibility of future additions.

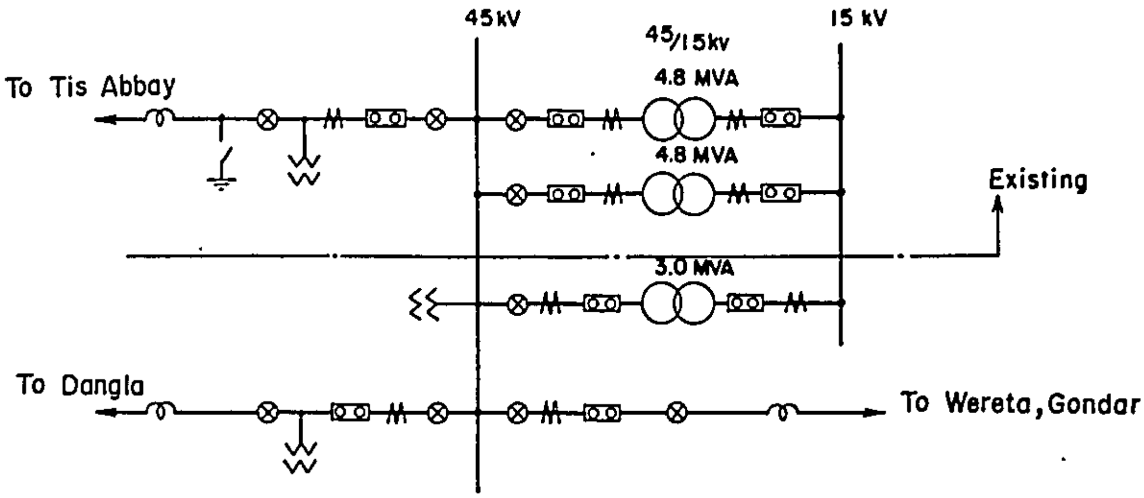
10.4.3 New Construction of Gondar Substation

The site for this substation was selected at a flat area adjacent on the north side of Cotton Ginning & Processing Company located at a point along National Route No. 1 approximately 4 km southwest from the center of Gondar. This site takes into consideration future city planning, and is the most advantageous for leading transmission and distribution lines in and out.

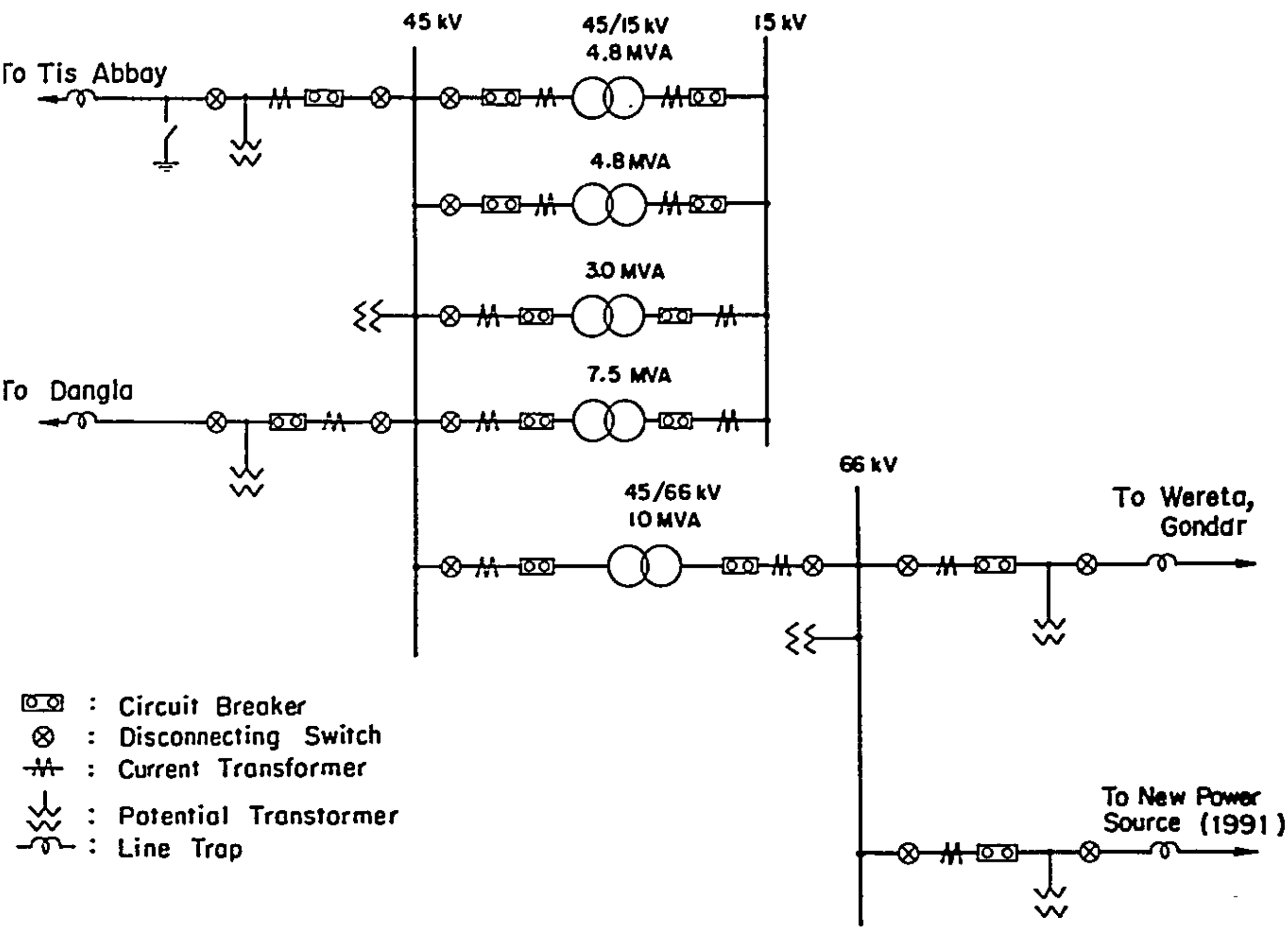
The facilities to be installed at this new substation are the following:

(1)	Incoming 45 kV facilities from Bahar Dar :	1 circuit
(2)	Outgoing 45 kV facilities for transmission to Kola Diba.:	1 circuit
(3)	Transformer for Gondar city load :	45/15 kV, 7.5 MVA, 1 unit

Fig. 10-4-1 BAHAR DAR S.S SINGLE LINE DIAGRAM

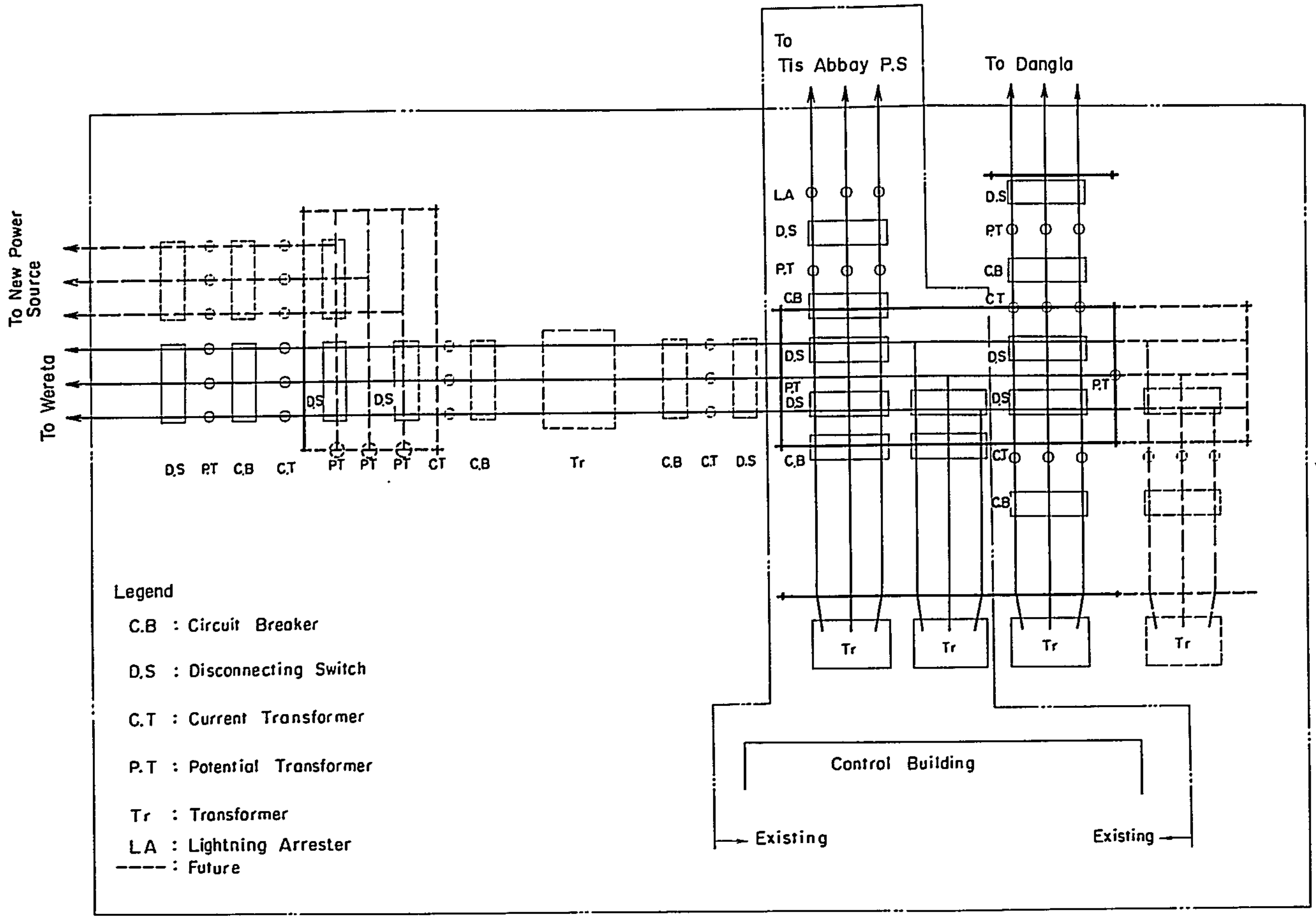


In 1982



In 1991

Fig. 10-4-2 BAHAR DAR SUBSTASION



Circuit breakers will be remote-controlled from the new distribution panel room in the substation, while disconnecting switches are to be manually operated.

The circuit breaker for the 45 kV transmission line to Kola Diba will be equipped with an auto-reclosing apparatus, and after a certain period after opening due to fault, forced line charge will be carried out.

The single line diagram is given in Fig. 10-4-3, and the equipment layout in Fig. 10-4-4.

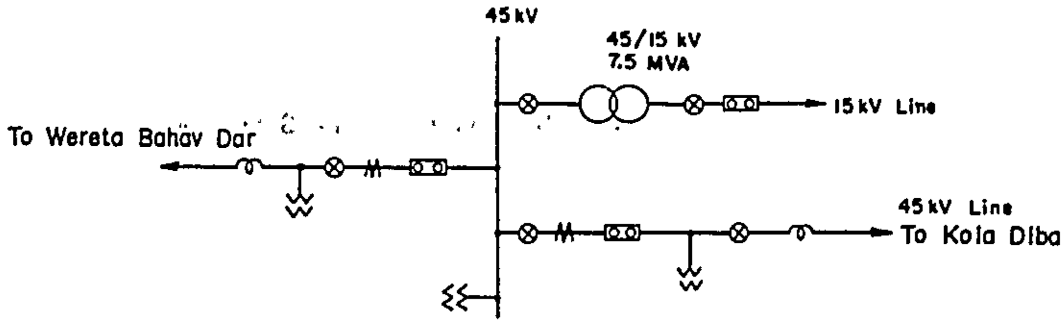
10.4.4 New Construction of Dangla, Debre Tabor and Kola Diba Substation

The substations indicated below will be newly constructed at the terminals points of the respective 45 kV transmission lines.

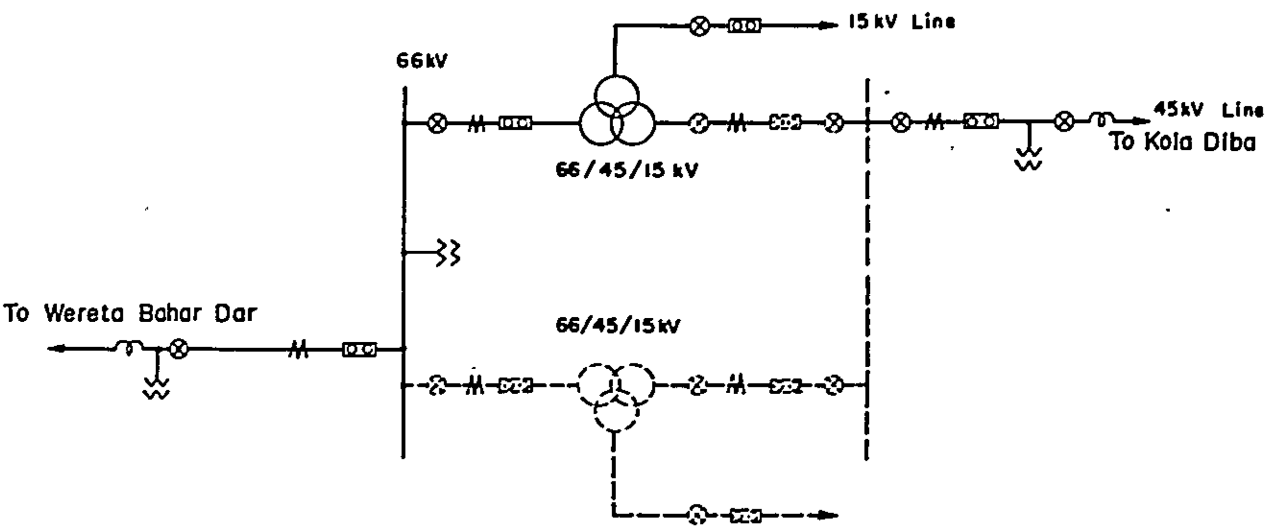
The capacities of transformers to be installed are as follows :

Dangla	45/15 kV transformer, 3 MVA, 1 unit
Debre Tabor	45/15 kV transformer, 2 MVA, 1 unit
Kola Diba	45/15 kV transformer, 3 MVA, 1 unit

Fig. 10-4-3 GONDAR S.S. SINGLE LINE DIAGRAM

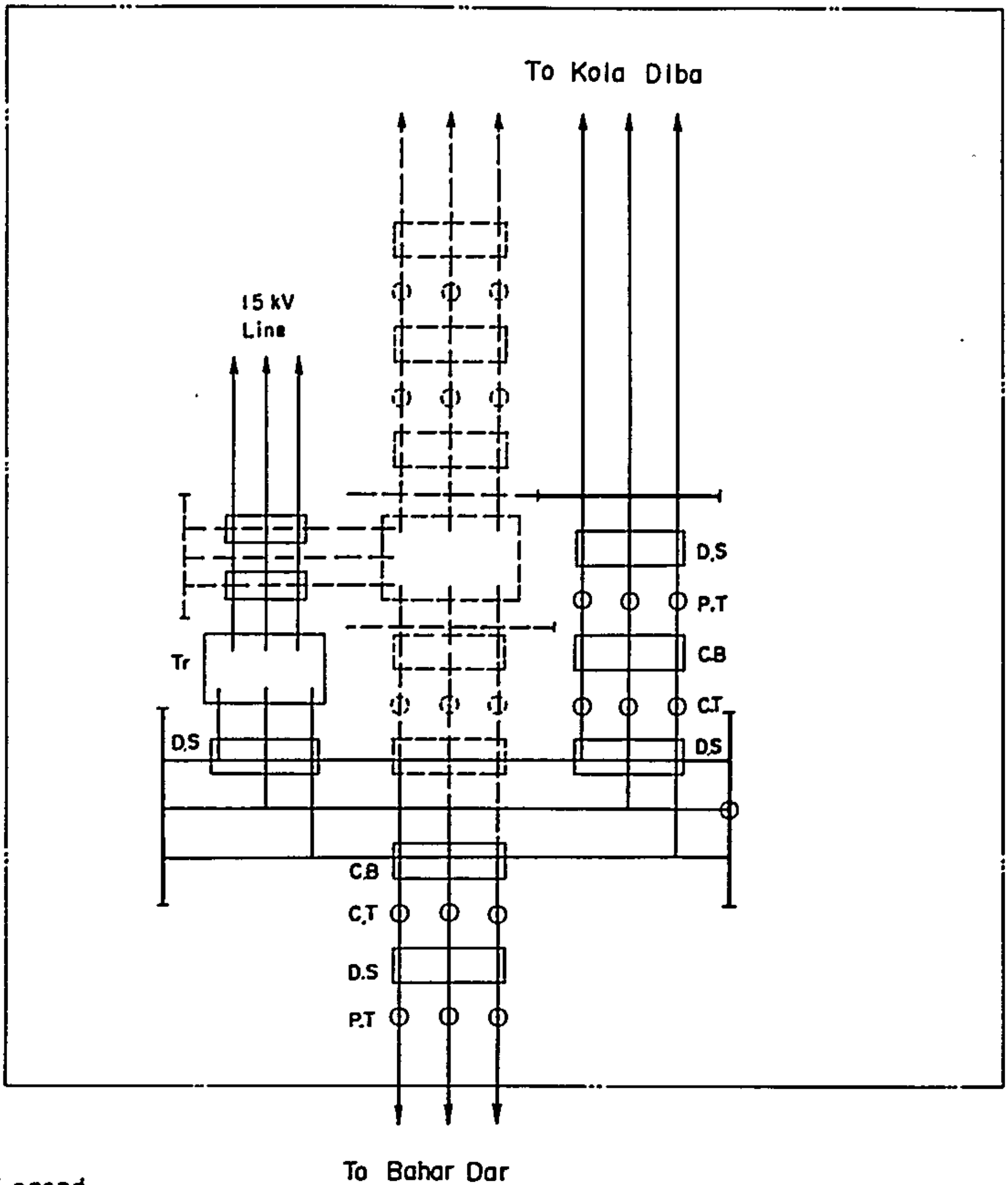


in 1982



in 1991

Fig. 10-4-4 GONDAR SUBSTATION



Legend

C.B : Circuit Breaker
D.S : Disconnecting Switch
C.T : Current Transformer
P. T : Potenical Transformer
Tr : Transformer
---- : Future

10.5 TELECOMMUNICATIONS

As an existing telecommunication channel there is the telephone channel between Bahar Dar Substation and Tis Abbay Power Station utilizing power line carrier equipment.

Telecommunication facilities to be newly provided are as described below (see Figs. 10-5-1, 10-5-2).

(1) Telephone Channel

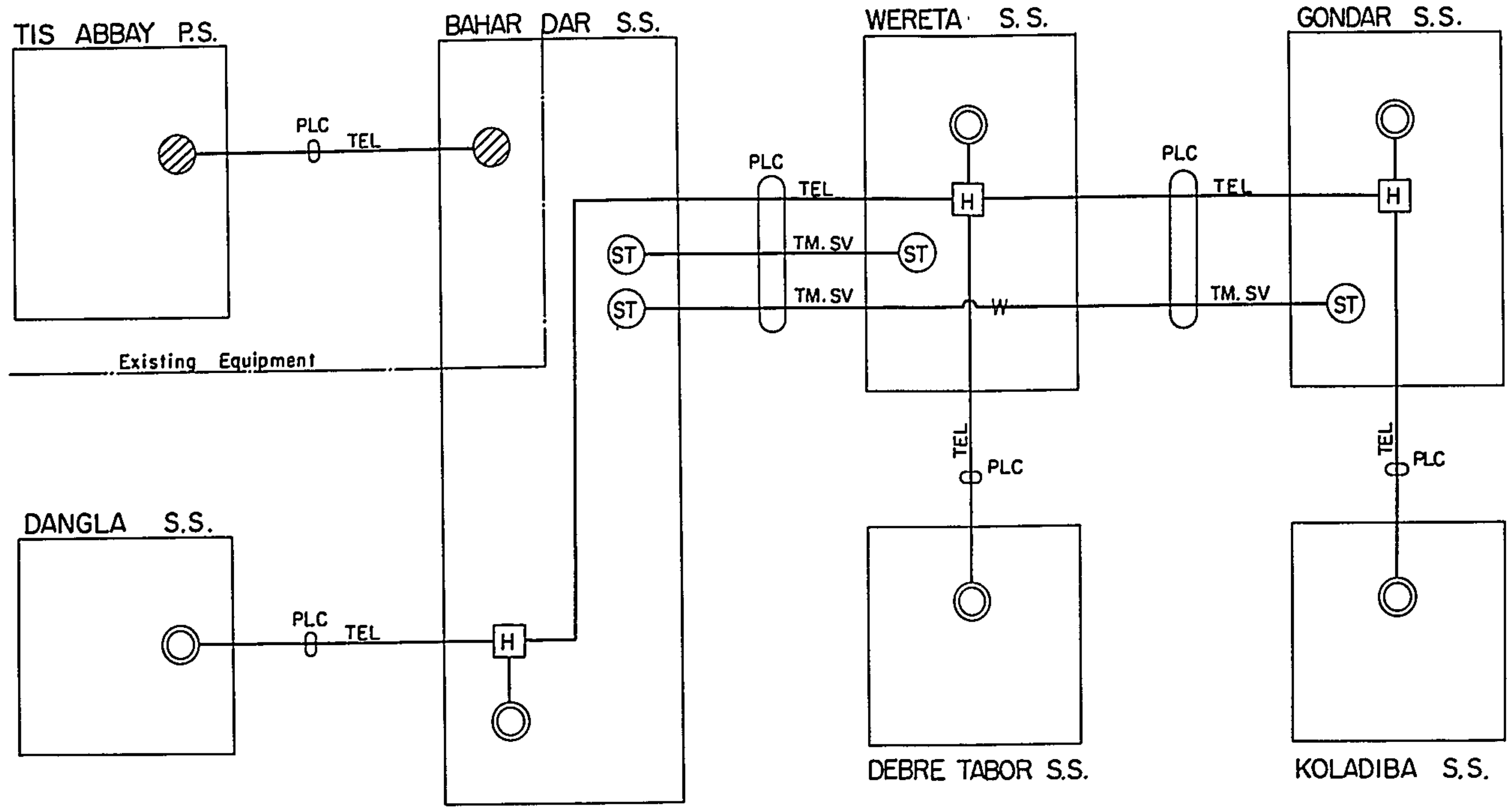
A party line telephone channel is to be composed for load dispatching during equipment operation, in normal and emergencies in power system.

This is to consist of a single power line carrier channel between Bahar Dar, Dangla, Wereta, Debre Tabor, Gondar and Kola Diba Substations connected to tone-ringer apparatus at the substations and this tone-ringer apparatus has function of selective calling to the respective substations.

(2) Remote Supervisory Telecommunication Channels

Since the new Wereta and Gondar substations will be unattended, while they will be important substations in system operation, telemeter and supervision channels will be structured between Bahar Dar, Gondar and Wereta Substations, and the situations at Wereta and Gondar will be remote-supervised from Bahar Dar Substation.

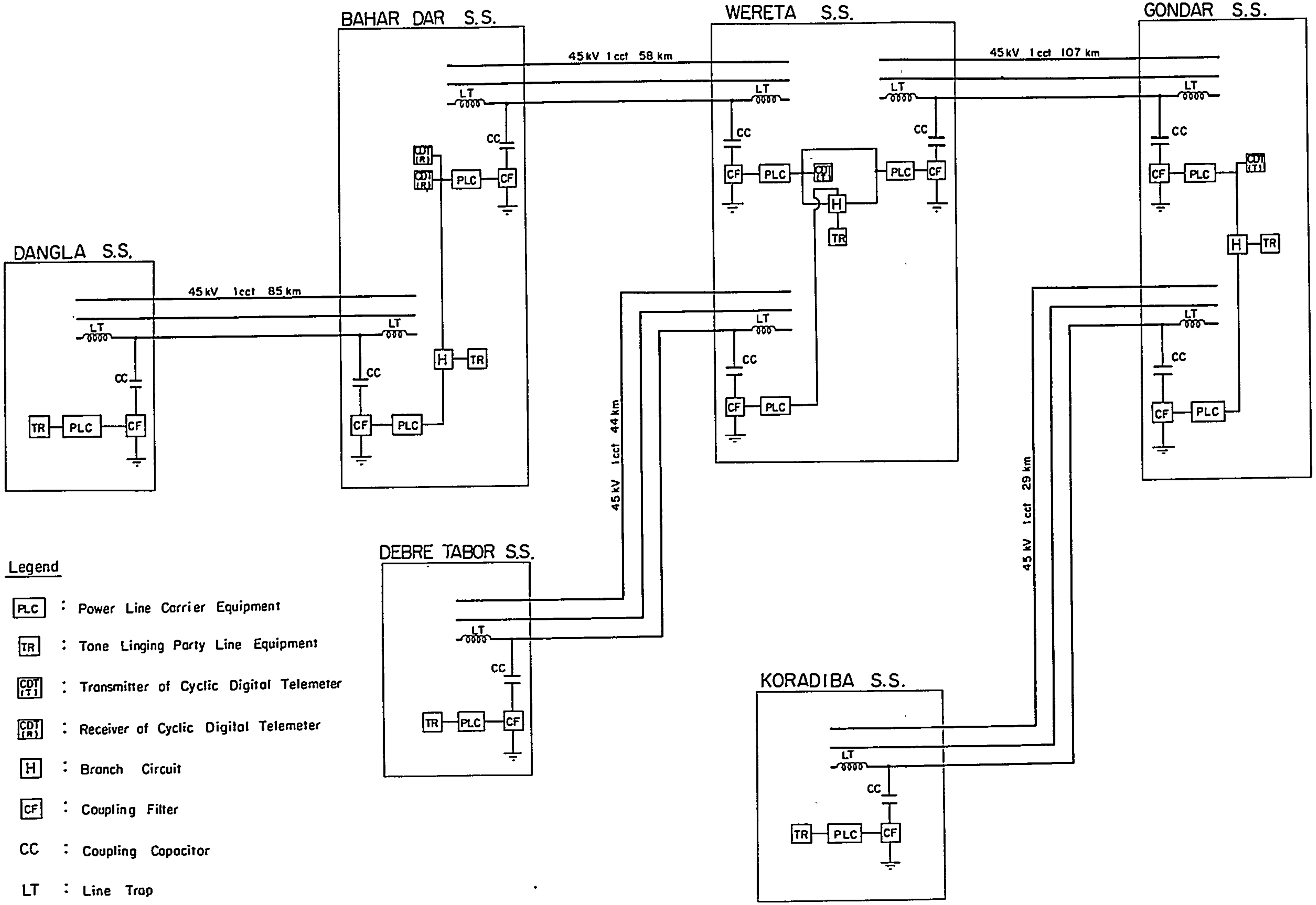
Fig. 10-5-1 TELECOMMUNICATION CIRCUIT DIAGRAM



Legend

◎———◎	:	Channel for Load Dispatching
(ST)———(ST)	:	Channel for data Transmmission
—[H]—	:	Branch Connection
—W—	:	Four - wire Connection
PLC	:	Power Line Carrier Connection
TM	:	Telemeter
SV	:	Supervision
TEL	:	Telephone
⊘———⊘	:	Existing Channel

Fig. 10-5-2 TELECOMMUNICATION SYSTEM DIAGRAM



Legend

- PLC : Power Line Carrier Equipment
- TR : Tone Linging Party Line Equipment
- CDT (T) : Transmitter of Cyclic Digital Telemeter
- CDT (R) : Receiver of Cyclic Digital Telemeter
- H : Branch Circuit
- CF : Coupling Filter
- CC : Coupling Capacitor
- LT : Line Trap

CHAPTER 11

CONSTRUCTION COST AND CONSTRUCTION SCHEDLE

CHAPTER 11 CONSTRUCTION COST AND CONSTRUCTION SCHEDULE

11.1 CONSTRUCTION SCHEDULE AND CONSTRUCTION METHOD

11.1.1 Construction Schedule

The construction period for the Lake Tana Project, as a result of studies taking into consideration the scale of the project, geographical and natural conditions, the sizes of structures and construction capabilities of contractors is thought to require 3 years for the regulating dam and 2.5 years for Tis Abbay No. 2 Power Station. The construction period required for addition of the No. 3 unit of the existing power station is 1 year 2 months, which is almost entirely for installation of electrical equipment.

From the standpoint of electric power demand, the regulating dam and the No. 3 unit must be commissioned at the end of 1982 and Tis Abbay No. 2 Power Station at the end of 1985.

Calculating backward based on the above conditions to obtain the times for work starts, it will be necessary for work on the regulating dam to be commenced in 1979, the No. 3 unit in 1981, and the No. 2 Power Station in 1983. However, since approximately 24 months will be required for design and manufacture of electrical equipment such as turbines and generators on the part of manufacturers, the timing for ordering such equipment will be still earlier, and ordering must be completed by the end of 1979 for the No. 3 unit and by the beginning of 1982 for equipment of the No. 2 Power Station.

The construction schedule is shown in Fig. 11-1-1.

11.1.2 Work Execution Plan

(1) Regional Conditions and Related Matters

(a) Transportation Route

The site of the Lake Tana regulating dam is located inside the city limits of Bahar Dar approximately 330 km north of Addis Ababa, while Tis Abbay Power Station is located immediately below Tis Issat Falls which is approximately 35 km to the east of the damsite downstream on the Blue Nile.

The principal materials to be used for the project will be supplied from Addis Ababa. The transportation road will be National Route No. 3 and the length of the road between Addis Ababa and Bahar Dar is approximately 578 km. Of this length a stretch of about 230 km from Addis Ababa until the Blue Nile is crossed is an asphalt-paved highway beyond which is an unpaved sector, but the condition of the surface of the road appears to be good on the whole. However, it will be necessary to investigate in advance the allowable loads of the group of bridges which are encountered along the route.

Imported materials and equipment would all be hauled via Addis Ababa from Assab Port on the Red Sea approximately 870 km northeast of Addis Ababa.

According to the Survey Mission's investigations on the length of time required for transport of construction materials and equipment from Assab to Addis Ababa, it is anywhere between 20 to 115 days. This difference is far too much, and if this is the actual situation in transportation, it will be extremely difficult to establish a transportation plan, which will then greatly affect the construction schedule. In this sense, it is desirable for detailed investigations to be made of the situation along with investigations on road conditions.

The road from Bahar Dar to Tis Abbay Power Station is a gravel road and it is expected that the surface condition will be considerably impaired during the rainy season. Consequently, there will be a necessity for periodical maintenance to be carried out after start of construction.

There will be no problems about the roads to the aggregate quarry and soil materials borrow area.

(b) Motive Power Facilities for Construction

As indicated in the construction schedule, the rainy season will be avoided and work on the project done mainly during the dry season. For this reason it will be difficult to rely on electric power as the motive power source for construction in view of the present situation at Tis Abbay Power Station, and use of machines equipped with engines must be considered as much as possible.

The principal plants and equipment for construction are thought to consist of a concrete plant, an aggregate plant, air compressors, boring and grouting equipment, power generators for lighting and various pumps, all of which can be equipped with engines.

(c) Purchasing of Construction Materials

The principal materials to be used for construction are approximately 3,800 tons of cement, 400 tons of steel bars and 40 tons of dynamite. Of these materials, the cement and steel bars may be procured domestically, but dynamite will be required to be imported.

As for concrete aggregates a total of approximately 25,000 m^3 will be required, but this will be produced on the job.

(2) Construction of Major Structures

(a) Regulating Dam

This work will be started from care of river to the right-bank side of the overflow section. The care of river method will be half-river cofferdamming, but in order to minimize the effect on the area around Lake Tana due to rise in upstream water level caused by the cofferdam, and also due to the necessity of keeping the cofferdam as low as possible, the work will be done concentrated in the dry season.

As shown in the construction schedule, the end of the rainy season of the first year will be awaited upon which construction materials and equipment will be delivered and temporary works started with the first closure performed at the beginning of the second year. After following this with riverbed excavation and boring and grouting for foundation treatment, placement of dam concrete and embankment will be carried out. Since it will be impossible to complete all of the overflow section by the end of the dry season, the cofferdam will be removed leaving a number of piers for arrival of the rainy season.

During this period the gates will be ordered.

The second closure is to be done at the beginning of the third year, the remaining work on the overflow section completed, following which installation of the gates will be finished.

From the beginning of the fourth year the leftbank side of the stream will be closed and flow will be diverted to the overflow section. After following this with foundation excavation, boring and grouting, embankment of the dam will be carried out. Simultaneously, the riverbed deepening work will be done at the upstream part at which time the flow is to be regulated by the regulating gates which will have been completed.

(b) Additional Installation of No. 3 Unit

This work is mainly installation of electrical equipment with civil work consisting only of finishing around the draft tube, placement of concrete when installing the electrical equipment and removal of the concrete bulkhead on the tailrace side. Consequently, the work may be started in the third year of the dam construction work when considered from the construction schedule, but ordering of the electrical equipment must be done immediately after starting the dam work.

(c) Tis Abbay No. 2 Power Station

Work on the No. 2 Power Station is to be started in the year following commissioning of the No. 3 unit. In the first year, excavation for the head tank and work on the access road will lead off, followed by excavation for the powerhouse and for the vertical shaft part of the penstock.

When the bottom of excavation for the powerhouse has reached the center of the turbine, work will be shifted to the horizontal part of the penstock, and after completion of this excavation, concrete lining will immediately be provided including the vertical shaft part. Electrical equipment will be ordered at the beginning of 1982.

In the second year, excavation for the lower part of the powerhouse will be continued, followed by installation of the draft tube, placement of the side walls of the powerhouse, work on the main building, and installation of the overhead travelling crane. During this time gates and accessories will be ordered.

In the third year, installation of the turbine and generator, and installation of outdoor switchyard equipment will be finished to complete all of the construction project.

11.2 CONSTRUCTION COST

11.2.1 Basic Conditions

(1) General

The construction cost has been calculated taking into consideration natural conditions, regional conditions, scale of project, and the technological level conceivable at this time, while providing necessary allowances.

The construction cost may be divided into a portion which can be paid for with domestic currency and a portion requiring foreign currency. Wages of domestic laborers, living expenses in Ethiopia of engineers and technicians required for work supervision and foreign workers (foremen, mechanics, tunnel laborers, grouting crew,) costs of construction materials which can be procured domestically such as cement, steel bars, lumber, and fuel and lubricating oils, and domestic transportation costs of imported materials and equipment were included in the domestic currency portion. All other items were included in calculations as constituting the foreign currency portion.

Unit prices as of March 1976 were used for the costs of domestic labor and materials on top of which performances in construction in Ethiopia, Japan and other countries were taken into account along with regional conditions to calculate the unit construction costs as of 1976.

It was considered that the actual work would be performed by a contractor based on a contract with EELPA, the owner of this project, according to the design and under the supervision of a consulting engineer, and the construction cost was calculated with certain assumptions regarding the mutual relations between the owner, engineer and contractor, and definitions of the responsibilities of the three parties.

Administrative costs were calculated lumping together detail surveying and designing costs and construction supervision costs.

The costs of acquiring land required for construction, and of various compensatory payments accompanying implementation of the project were not included.

As contingency funds, 15% was taken into consideration for civil work, 10% for hydraulic equipment, 10% for electrical equipment, and 12% for transmission line and substation work.

Since the interest rate on funds procured is unknown, interest during construction for domestic and foreign currency portions is not considered in the construction cost in this chapter.

Rates of exchange employed for calculations are the following:

US$ 1 = Eth$ 2.07

US$ 1 = Y 290

Eth$ 1 = Y 140

(2) Dam and Power Generation Facilities

For the cost of civil work for the dam and power generating facilities, direct costs consisting of labor costs, materials costs, rentals and operating expenses of construction machinery, and other expenses were calculated, besides which all expenses required for construction roads, construction buildings, construction facilities, rentals of equipment in common, and labor for enabling smooth operation of the above construction machinery and facilities, and the indirect expenses of the contractor were added to calculate the construction cost.

For the construction costs of hydraulic equipment such as dam regulating gates, intake gates, sand flush gates, and outlet gates, the costs of importation, transportation and installation of the products were included.

For the construction costs of electrical equipment, the costs of manufacture, transportation and installation of turbines and other equipment were included.

(3) Transmitting, Transforming and Telecommunications Facilities

The costs of materials, transportation and installation of equipment, telecommunications facilities, steel towers, concrete poles, conductors and insulators required for the transmission lines between Bahar Dar and Gondar, Bahar Dar and Dangla, Wereta and Debre Tabor, and Gondar and Kola Diba, and the accompanying substations were calculated as costs of transmission lines, substations, and telecommunications facilities.

11.2.2 Summarization of Construction Costs

The total construction cost for this project is Eth$ 43,300,000 the breakdown of which is given in Table 11-2-1 and Table 11-2-2.

(Unit : Eth$)

Item	Total	Foreign Currency	Domestic Currency
Regulating Dam	10,174,000	6,162,000	4,012,000
Tis Abbay PS No. 3 Unit	4,238,000	3,691,150	546,850
Tis Abbay No. 2 PS	12,052,000	8,706,430	3,345,570
Transmission Lines, Substations & Telecomunications System	16,836,000	9,878,420	6,957,580
Total	43,300,000	28,438,000	14,862,000

The funding plan by year of the construction cost prepared based on the construction schedule is indicated in Table 11-2-3. The terms of payment in this case are considered to be as follows.

For civil work, 10% of the contracted amount is to be paid as an advance, and after start of work 10% of the value of the work performed monthly is to be applied to repayment of the advance, and after the cumulative amount reaches the amount of the advance, 10% of the monthly work performed is to be withheld and paid in lump sum to the contractor at the time of start of operation.

For electrical work, 10% of the total is to be paid on signing of the contract, 50% at the time of loading on board ship, and 40% at the time of start of operation.

For gates and other equipment, 10% of the total is to be paid on signing of the contract, 60% at the time of loading on board ship, 20% on completion of installation, and 10% after passage of water.

For transmission lines, 20% of the materials cost is to be paid on signing of the contract, and 80% of the materials cost at the time of loading on board ship. Construction is to be paid for on the basis of monthly work performed. However, 10% is to be withheld each month and paid as a lump sum at the time of start of operation.

Table 11-2-1 Construction Costs of Project

(Unit : Eth$)

Item	Total	Foreign Currency	Domestic Currency
Regulating Dam	10, 174, 000	6, 162, 000	4, 012, 000
Construction cost	8, 216, 000	4, 853, 000	3, 363, 000
Administration cost	893, 000	691, 000	202, 000
Contingency	1, 065, 000	618, 000	447, 000
Tis Abbay PS, No. 3 unit	4, 238, 000	3, 691, 150	546, 850
Construction cost	3, 681, 430	3, 218, 290	463, 140
Administration cost	190, 000	152, 000	38, 000
Contingency	366, 570	320, 860	45, 710
Tis Abbay No. 2 PS	12, 052, 000	8, 706, 430	3, 345, 570
Construction cost	9, 959, 720	7, 183, 290	2, 776, 430
Administation cost	943, 000	731, 000	212, 000
Contingency	1, 150, 280	793, 140	357, 140
Transmission Lines, Substations & Telecommunication System	16, 836, 000	9, 878, 420	6, 957, 580
Construction cost	14, 254, 280	8, 482, 640	5, 771, 640
Administration cost	944, 000	436, 000	508, 000
Contingency	1, 637, 720	959, 780	677, 940
Total	43,300, 000	28, 438, 000	14, 862, 000

Table 11-2-2 Summary of Construction Costs

(Unit : Eth$)

Item	Total	Foreign Currency	Domestic Currency
Regulating Dam	9,280,000	5,470,000	3,810,000
Dam	4,165,600	1,956,000	2,209,600
Deepening of River-bed	1,574,400	984,000	590,400
Hydraulic Equipment	1,965,000	1,682,000	283,000
Control Building	360,000	130,000	230,000
Miscellaneous	150,000	100,000	50,000
Contingency	1,065,000	618,000	447,000
Tis Abbay PS, No. 3 unit	4,048,000	3,539,150	508,850
Foundation	110,000	54,000	56,000
Turbine & Generator	2,864,290	2,621,430	242,860
Main Transformer, Others	707,140	542,860	164,280
Contingency	366,570	320,860	45,710
Tis Abbay No. 2 PS	11,110,000	7,976,430	3,133,570
Access Road	185,000	106,000	79,000
Waterway, Head Tank, Penstock	2,075,000	1,005,000	1,070,000
Foundation of Power House	1,351,000	618,000	733,000
Power House	200,000	70,000	130,000
Turbine & Generator	4,064,290	3,642,860	421,430
Main Transformer, Others	1,771,430	1,521,430	250,000
Hydraulic Equipment	291,000	220,000	71,000
Foundation of Switchyard	22,000	-	22,000
Contingency	1,150,280	793,140	357,140
Transmission Lines, Substations & Telecommunication System	15,892,000	9,442,420	6,449,580
Transmission Lines, 66 kV	6,007,000	3,274,050	2,732,950
Transmission Lines, 45 kV	4,597,280	2,294,310	2,302,970
Substations	3,035,710	2,407,140	628,570

(Unit : Eth$)

Item	Total	Foreign Currency	Domestic Currency
Telecommunication System	614,290	507,140	107,150
Contingency	1,637,720	959,780	677,940
Administration Costs	2,970,000	2,010,000	960,000
Surveying Fee	470,000	10,000	460,000
Engineering Fee	2,500,000	2,000,000	500,000
Total	43,300,000	28,438,000	14,862,000

P : Preperation work
E : Excavation
C : Concrete
T : Turbine
G : Generator
M : Manufacture

Fig. 11-1-1 Construction Schedule

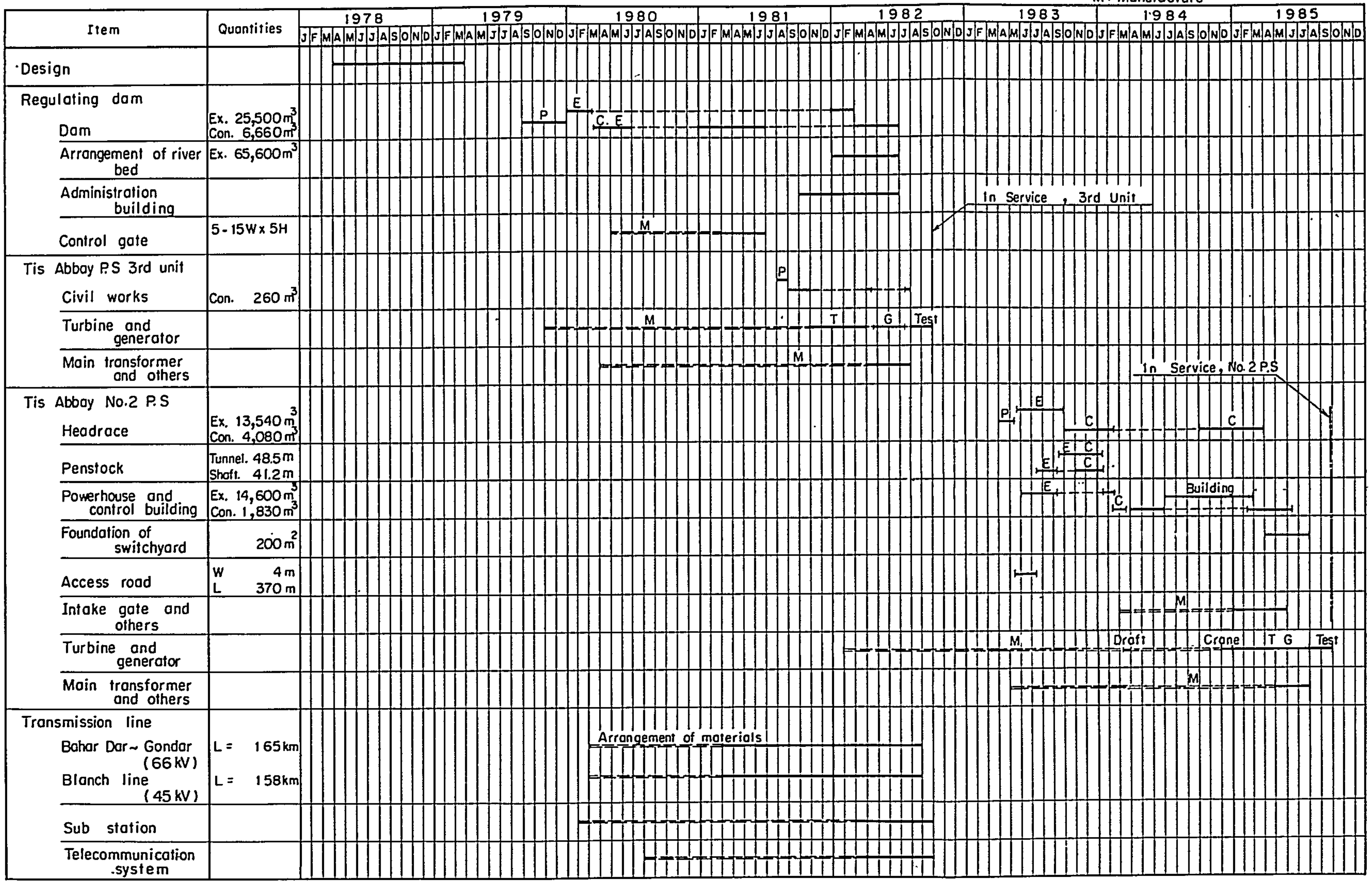


Table 11-2-3 Annual Expenditure Schedule (Unit : 10^3 Eth $)

Item	Total fund requirement			1978			1979			1980			1981			1982			1983			1984			1985		
	Total	F.C	L.C	Total	F.C	L.C	Total	F.C	L.C	Total	F.C	L.C	Total	F.C	L.C	Total	F.C	L.C	Total	F.C	L.C	Total	F.C	L.C	Total	F.C	L.C
Engineering fee	2,500	2,000	500	600	480	120	240	192	48	200	160	40	420	336	84	520	416	104	300	240	60	220	176	44			
Surveing	470	10	460	400	-	400	46	7	39				1	0	1	23	3	20									
Regulating dam	9,280	5,470	3,810				681	352	329	3,771	2,483	1,288	1,759	918	841	3,069	1,717	1,352									
Dam	4,946	2,382	2,564				681	352	329	2,259	1,188	1,071	991	320	671	1,015	522	493									
Arrangement of river bed	1,814	1,108	706													1,814	1,108	706									
Administration building	360	130	230										120	43	77	240	87	153									
Control gate	2,160	1,850	310							1,512	1,295	217	648	555	93												
Tis Abbay P.S 3rd unit	4,048	3,539	509				314	287	27	78	60	18	1,966	1,741	225	1,690	1,451	239									
Civil work	120	59	61													120	59	61									
Turbine and generator	3,150	2,883	267				314	287	27				1,576	1,442	134	1,260	1,154	106									
Transformer and others	778	597	181							78	60	18	390	299	91	310	238	72									
Tis Abbay No.2 P.S	11,110	7,977	3,133													447	401	46	5,089	3,563	1,526	2,229	1,394	835	3,345	2,619	726
Headrace and Penstock	2,381	1,153	1,228																1,799	923	876	207	76	131	375	154	221
Powerhouse and control building	1,746	776	970																641	344	297	823	312	511	282	120	162
Fundation of switchyard	26	0	26																						26	0	26
Access road	217	124	93																217	124	93						
Intakegate and others	320	242	78																			224	169	55	96	73	23
Turbine and generator	4,470	4,007	463													447	401	46	2,236	2,004	232				1,787	1,602	185
Transformer and others	1,950	1,675	275																196	168	28	975	887	138	779	670	109
Transmission line, Sub-station and Telecommunication system	15,892	9,442	6,450							4,173	4,092	81	7,241	4,068	3,173	4,478	1,282	3,196									
Transmission, 66kV	6,728	3,667	3,061							2,200	2,200	0	2,691	1,467	1,224	1,838	0	1,838									
" 45kV	5,149	2,569	2,580							1,571	1,571	0	2,542	998	1,544	1,035	0	1,035									
Sub-station	3,339	2,648	691							334	265	69	1,670	1,324	346	1,335	1,059	276									
Telecommunication	676	558	118							68	56	12	338	279	59	270	223	47									
Grand total	43,300	28,438	14,862	1,000	480	520	1,281	838	443	8,222	6,795	1,427	11,387	7,063	4,324	10,227	5,270	4,957	5,389	3,803	1,586	2,449	1,570	879	3,345	2,619	726

CHAPTER 12

ECONOMIC ANALYSIS

CHAPTER 12 ECONOMIC ANALYSIS

12.1 BASIC CONSIDERATIONS

12.1.1 Purpose of Analysis

The objectives of the electric power development scheme for the area surrounding Lake Tana are to produce cheap hydroelectric power utilizing the aboundant discharge of the Blue Nile, construct an interconnecting transmission lines to supply power produced to electrified communities such as Gondar ~ Azezo, Debre Tabor, Wereta and Dangla, and to other communities not as yet electrified, thereby converting the comparatively costly diesel power generation and supply system to an inexpensive hydroelectric power generation and supply system.

In fact, there is no question that it will be more economical to change over to a hydroelectric power generation and supply system through transmission lines rather than to continue with isolated diesel power generation when seen from the standpoint of fuel costs. However, in case of hydro, since the weight of the construction cost of facilities for transmitting and transforming power is great, the economics will depend on the scale of electric power demand.

Accordingly, the main point of this economic analysis is to find the timing for conversion from the diesel power alternative to the transmission alternative for realizing electric power supply of minimum cost. In reality, unless interconnecting transmission lines are constructed, it will be difficult to prove the appropriateness of building the regulating dam. This is because the enormous construction cost of the regulating dam would need to be covered with the demand of only the Bahar Dar area unless power supply is made to other regions by transmission lines, and this would be impossible when seen from the scale of the demand in the Bahar Dar area.

12.1.2 Conditions for Cost Estimate

(1) Shadow Pricing

This project which has as its objective rural electrification must not only be useful in improving the financial state of EELPA as a government agency, but also must be effective for the national economy as a whole. Therefore, it is desirable for all costs applied in economic analysis to be shadow prices or opportunity costs reflecting the true costs for Ethiopia. In this connection, the following conversion factors have been indicated for the foreign currency portions, wages for laborers and other items concerning development projects in "A Guide to Project Planning in Ethiopia" published by the Planning Commision Office in 1972.

(a) Foreign currency portions are to be increased by 33% over the official rate of the Ethiopian dollar.

(b) Labor wages are to be 70% of actual rates.

(c) Construction is to be 90% of actual price.

Of the above, the opportunity costs of wages should be applied to laborers who would be unemployed unless there was employment necessitated by this project, in effect, chiefly unskilled laborers, but the wages of such laborers constitute only a fractional proportion of the total investment amount for the project. Accordingly, it is thought permissible to disregard this particular conversion factor.

As for the conversion factor of 90% for construction, this may be considered as the average value of economic cost/financial cost of various construction works in case of taking into account the opportunity costs of wages of mainly unskilled laborers. In this respect, the weight of wages of unskilled laborers in this project will be negligible and it is thought unnecessary for the above conversion factor to be applied.

Therefore, in the present economic analysis, two studies will be made - one an analysis based on so-called financial costs expressing market prices, and the other an analysis based on economic cost applying the conversion factor for the foreign currency portion. Regarding taxes and levies, since these merely indicate transfers of moneys within the country, they will be excluded from all costs.

(2) Cost Escalation

According to estimations recently made by the IBRD on construction costs in Ethiopia, it is expected that there will be rised in costs of 12% annually up to 1979 and 10% annually thereafter in case of civil work, while for equipment it is expected the rises will be 8% annually until 1979 and 7% annually thereafter.

However, in the case of the present economic analysis, the greater part of the cost of the diesel power alternative, the proposal on one side, is taken up by fuel costs and it is practically impossible to accurately predict the future trend in these costs.

Consequently, all investment costs and operation and maintenance costs in the economic analysis to follow will be based on prices as of 1976 and escalation will not be applied. However, a general discussion will be made at the end of this Chapter on which of the alternatives, diesel power or transmission, will be more favorably affected in case of application of cost escalation.

12.1.3 Discount Rate

Regarding the opportunity cost for capital in the economic evaluation of a project in Ethiopia, the Planning Commission Office estimates that the proper rate would be around 10%.

Meanwhile, the long term rate of interest of the IBRD from whom funds have been procured in the past for projects such as large-scale power generation in Ethiopia is presently approximately 8% per annum. It should be permissible to look upon this interest rate as being a long-term stable and risk-free interest rate for capital in the international market.

From the above viewpoints, the two discount rates below will be applied in the present economic analysis.

- 10 % per annum.
- 8 % per annum.

12.1.4 Load Forecast

The two cases below as described in Chapter 4 are conceivable as power demand forecasts to serve as bases for analysis, and the economics of this project are analyzed based on the predictions of demand in the respective cases.

- Case A ..... Case of supplying power to electric boilers only during off-peak hours.
- Case B ..... Case of power supply with peak load of electric boilers occurring overlapping with peak load of the whole power system.

12.2 METHOD OF ANALYSIS

12.2.1 Items of Analysis

As stated at the beginning, the essence of the economic analysis is to determine the optimum timing for converting from the diesel alternative to the transmission alternative through the discounted present worth method, and construction of the regulating dam and power generation facilities would be carried out in step with this timing.

This optimum timing is defined as a year at which the sum of the cumulative total cost of the diesel power alternative up to a year of conversion and the total cost of the transmission alternative from this year of conversion to infinity is a minimum. Further, the total cost of the transmission alternative includes not only costs of transmission lines and substations, but also costs of regulating dam and power stations.

With determination of the abovementioned optimum timing for conversion, the following factors will be computed:

- Economical internal rate of return

- Amount of savings in power supply costs obtained through conversion to transmission alternative compared with continued diesel power supply alternative.

12.2.2 Basic Year for Analysis and Interest during Construction

Since the analysis is to be made based on discounted cash flow method, it is necessary to establish a basic year as a starting point for calculations. In this economic analysis, the beginning of 1982 thought to be the earliest when the power generating, transmitting and transforming facilities of the project can be completed and start operation, in case all technical, economic and financial conditions are assumed to be satisfied, is taken as the starting point of calculations.

As for calculation of so-called capital cost including interest during construction in investment cost, since this project is still at the stage of a feasibility study, the approximate method below used by EPDC in Japan will be applied. In effect,

$$\text{Capital cost} = \text{Investment cost} \times (1 + 0.4\,RT)$$

where,

R = interest rate

T = construction period (yr)

12.2.3 Structure of Diesel Power Alternative

The regulating dam and the additional power generation facilities are planned for supply of electricity to the project area surrounding Lake Tana, and this area also includes Bahar Dar which has been supplied with hydroelectric power from the past. For the diesel power alternative, therefore, not only should the regions of diesel power generation from the past be included, but also a case of meeting future power shortages of Bahar Dar with diesel power generation must be assumed. Further, as one form of the diesel power alternative, it is conceivable to provide large-scale diesel power stations at Bahar Dar and Gondar to supply the respective surrounding areas through transmission lines, but such a proposal would clearly be more costly than isolated diesel power systems with diesel power stations provided at each community, so that only isolated diesel power systems will be considered as the alternative to the transmission supply system.

12.2.4 Construction Timing for Transmission Alternative

The transmission lines in accordance with this scheme may be broadly divided into a 66-kV trunk transmission line for supply to the north and east regions of Lake Tana (with a branch line of 45 kV between Wereta on the way and Debre Tabor) and a 45-kV transmission line for supply to the south region of Lake Tana. Strictly speaking it would be most desirable for the optimum timing for construction of each transmission line to be determined, but for such a purpose the following conditions will need to be satisfied:

(a) The case of the regulating dam and additional power generating facilities such as the additional No.3 unit at Tis Abbay Power Station and Tis Abbay No.2 Power Station already completed, and therefore the energy cost of the Tis Abbay power system including these facilities being known, or

(b) The case it being possible for the costs (capital costs and operation and maintenance costs) of the above new and additional power generating facilities in common for the entire project area to be allocated to each region.

Actually, however, these new and additional power generating facilities are to be constructed in step with construction of the transmission lines, while moreover, it will be impossible for a single facility to be split and constructed as first stage, second stage, etc. Accordingly, for the transmission alternative, the transmission lines to the north, east and south regions of Lake Tana are all to be constructed in the same period, and this proposal is to be compared with the diesel power alternative.

12.2.5 *System Considerations and Period of Analysis*

The period of analysis must be the period until the scale of power demand supplied by the transmission line reaches the limit of transmission capacity within the range of voltage drop of 10%. In this case, the transmission capacities of the various lines and the years in which the scales of demand reach these capacities are the following:

Transmission Line	Specification		Transmission Capacity	Scale of Demand after Reaching Transmission Capacity		
	Voltage (kV)	Number of cct.	(kW)	(yr)	(kW)	(MWh)
- Bahar Dar ~ Gondar	66	1	21,800	2001	18,700	62,250
- Gondar ~ Kola Diba	45	1				
- Wereta ~ Debre Tabor	45	1				
- Bahar Dar ~ Dangla	45	1	19,000	2019	17,860	68,840
- Tis Abbay PS ~ B. Dar	45	1	17,100	2011 (A)	15,800	86,750 (A)
				2006 (B)		69,480 (B)

The transmission capacities in the above are those at the outlet of Bahar Dar Substation. As for the values of power demand of the various regions when these transmission capacities are reached, they have been calculated considering the load factors and transmission losses of these areas in the year the transmission capacities are reached. It is considered that these power demands will be supplied constantly each year to infinity from the years that these capacities are reached.

Accordingly, the costs of power supplied from the years that the transmission capacities are reached are capitalized as of the years the capacities are reached.

12.2.6 Analysis Procedure

(1) First Stage ..... Cost Calculation of Diesel Power Alternative

The total amount for each year of capital cost, fuel cost, and operation and maintenance cost of diesel power stations added in step with demand is converted to present worth for each area with the beginning of 1982 as the basis, and the cumulative total for each year is calculated. This is done until the end of the period of analysis described in item 12.2.5 above.

(2) Second Stage ..... Cost calculation of transmission alternative

Each year from 1982 is assumed to be the year of conversion from the diesel power alternative to the transmission alternative, and the total amount of the capital cost of generating, transmitting and transforming facilities in that year and the capitalized amount of operation and maintenance cost from that year to inifinity is calculated, after which that total amount is converted to present worth with the beginning of 1982 as the basis. Further, in this case, the operation and maintenance costs of the existing Tis Abbay Power Station, Bahar Dar Substation and the 45-kV transmission line are calculated to obtain capitalized amounts based on the present performance records, while for the energy cost of Upper Beles Project in the future, the unit cost of that power station in ICS is estimated by approximate calculations, based on which the energy cost to be included in this project is calculated.

(3) Third Stage ..... Determination of Optimum Year of Conversion by Minimum Total Cost

On adding together the cumulative present worth of the diesel power alternative of each of the years from 1982 up to a particular year and the present worth of the capitalized amount of the transmission alternative from that particular year to infinity, the total cost of power supply for each year of conversion is obtained. Of these, the year in which the minimum total cost is obtained is the optimum year of conversion.

12.2.7 Replacement of Equipment and Capitalization

The calculations for the diesel power alternative consist of computing the total amounts of equalized yearly installments of capital cost, and fuel costs, operation and maintenance costs, administration costs, etc., for each of the years, after which these total amounts are converted to present worths with the beginning of 1982 as the basis, and also computing these amounts converted into present worth in terms of the cumulative amount for each year. Accordingly, the replacement costs of equipment will already have been included in the equalized installments for each year.

In contrast, the calculation for the transmission alternative consists of aggregating the infinitely incurred costs at the year of conversion, and it is necessary for capital cost, operation and maintenance costs and energy cost to be multiplied by the following factors:

(1) Perpetual Replacement Factor

With initial capital investment as Inv, service life as n, discount rate as i, the total amount of "initial capital investment + perpetual replacement cost" will be as indicated below.

$$\lim S = \text{Inv} + \frac{\text{Inv}}{(1+i)^n} + \frac{\text{Inv}}{(1+i)^{2n}} + \ldots\ldots$$

$$= \frac{\text{Inv}}{1 - \frac{1}{(1+i)^n}} = \text{Inv} \times \frac{(1+i)^n}{(1+i)^n - 1}$$

The transmission and transforming facilities are considered to be replaced at each expiration of service lives to infinity. Therefore, the capital costs of these facilities are to be multiplied by the above perpetual replacement factor.

(2) Capitalization Factor

Operation and maintenance costs in case of transmission alternative may be considered as being constant for each year. The energy costs from the years that the transmission capacities are reached are also considered as being constant for each year. Therefore, all these costs are divided by the discount rate i for capitalization at the beginning of the year of conversion. And, for the purpose of calculating capitalized costs at the end of year of conversion, the costs should be multiplied by $(1+i)/i$.

12.3 BASIC CONDITIONS IN CALCULATIONS

12.3.1 Diesel Power Alternative

(1) Erected Cost of Diesel Power Station (Financial Cost)

The construction cost of diesel power station is assumed to be 80% a foreign currency portion consisting of manufacturer's fabrication costs, ocean freight, insurance, etc., and 20% a domestic currency portion consisting of inland transportation in Ethiopia, installation costs, building, etc. In addition, on studies referring to some quotations submitted recently to EELPA from various countries, the result was that rises in the prices of diesel generators were found to be higher than for other heavy electrical equipment. Accordingly, the prices by unit capacities of individual generators are as shown in Fig. 12-1. (The unit prices in Fig. 12-1 include civil work (building and foundation), fuel tanks, and all auxiliary equipment such as panels, circuit breakers and transformers).

Since it only complicates calculations with no concrete effects to apply the unit price by capacity each time to additional generators, the average unit prices obtained from Fig. 12-1 will be applied in the present analysis.

Unit capacity (kW)	Erected cost (Eth$/kW)
100 ~ 300	1,750
500 ~ 1,000	1,400
1,000 ~ 2,500	1,100

(2) Economic Service Life

It is assumed that all power generating facilities consist of newly installed equipment at the starting point of calculations, and economic service life is taken to be 15 years in accordance with the criterion of EELPA.

(3) Criterion for Reserve Capacity

The reserve capacity to be maintained at a power station is taken to be 25% of peak load in accordance with the criterion of EELPA. Therefore, an additional generator is to be installed at a time when the peak load of the area reaches 80% of the existing installed capacity.

(4) Specific Fuel Consumption

The fuel consumption rate is reduced as the unit capacity of a power station is increased, and as load factor becomes higher. However, the range of variation will be no more than only about 5% when a unit generator fluctuates between load factors of 50% and 100%. As for the relation with elevation, since power stations must all be constructed at high altitudes of El. 2,000 ~ El. 2,500 m in case of this project, super-chargers are to be provided at all power stations to augment oxygen intake and prevent reduction in output. Therefore, the standard rate for low altitudes are to be applied for the fuel consumption rate. However, on scrutinizing performances in Ethiopia, actual fuel consumption rates are about 10% higher than theoretical rates because of reasons such as partial operation. Fig. 12-2 gives theoretical and actual values of fuel consumption rates, and actual values will be applied for the present economic analysis.

Further, similarly to the case of construction cost per kW of (1) above, it would be complicated to apply individual fuel consumptions by unit capacity of equipment, so that in the analysis, studies will be made considering the average consumption rates below obtained from Fig. 12-2 and compositions of power stations according to capacities of individual units.

Unit capacity (kW)	Specific consumption (gr/kWh)
100 ~ 300	300
500 ~ 1,000	270
1,000 ~ 2,500	260

(5) Fuel Price (Financial Cost)

The fuel prices applied to diesel power stations of EELPA are exempted from taxes and levies. Gondar ~ Azezo ~ Kola Diba and Debre Tabor are the only two districts in the project area being supplied by EELPA and the current fuel prices for these have been confirmed, but for other towns, there is no clear information about fuel prices exempt of taxes and levies. Accordingly, in case of assuming that EELPA will carry out diesel power supply at these areas, the following estimation is made regarding the fuel prices to be applied.

In effect, along National Route No.3, the fuel price of EELPA at Debre Markos at a point 300 km away from Addis Ababa is Eth$340/1,000 lt, while the fuel prices at Gondar 750 km away and Debre Tabor 690 km away are Eth$400/1,000 lt and Eth$375/1,000 lt respectively. It is thought the price differences between these localities are due to differences in transportation costs and distributor's charges. Therefore, taking the prices at the three districts of Debre Markos, Debre Tabor and Gondar as bases, and considering the distances from Addis Ababa, the fuel prices not including taxes and levies for the various districts may be estimated to be as indicated below (with kg/lt ratio of diesel oil at 1,208 lt = 1 ton).

Locality	Fuel Price (Eth$) (per 1,000 lt)	(per ton)
Bahar Dar	365	440
Gondar district (inc. Azezo, Kola Diba)	400	483
Chewahit	406	490
Gorgora	408	493
Debre Tabor	375	453
Wereta	370	447
Addis Zemen	372	449
Dangla	357	431
Injibara Addis Kidame	} 353	} 426

(6) Specific Consumption of Lubricating Oil and Price

The consumption rates of lubricating oil by capacities of units are assumed to be the following:

- Unit capacity 500 kW and over 4 g/kWh
- Unit capacity up to 500 kW 6 g/kWh

The price of lubricating oil would also differ according to the locality, but since consumption is small unlike fuel oil, price differences will not have a great influence on economic calculations. Therefore, the uniform price below will be applied.

- Eth $ 1.50 /kg

(7) Operation and Maintenance Cost (Financial Cost)

The average operation and maintenance cost of diesel power stations of the self-contained systems as a whole, including items such as salaries and wages, materials for maintenance and travel expenses according to actual records for 1975, was E¢ 2.62/kWh as shown in the table below. Since the rate of increase in operation and maintenance cost per kWh of 1975 was approximately 4% over that in the previous year, the same rate of increase is applied to 1976, and for 1976 the estimate is E¢ 2.73/kWh.

(Eth $)

Item	Diesel PS	Tis Abbay PS	Total SCS
Salaries and wages	867,062	96,489	963,551
Materials for maintenance	250,920	30,684	281,604
Travel expenses	50,691	3,033	53,724
Sub-total	1,168,673	130,206	1,298,879
Fuel cost	4,918,154	4,713	4,922,879
Depreciation	813,618	214,898	1,028,516
Total	6,900,445	349,817	7,250,262
Energy production (MWh)	44,485	20,487	64,972

Operation and maintenance cost per kWh for diesel power station

= Eth $ 1,168,673/44,485 MWh = E¢ 2.62/kWh

(8) Administration Cost

The calculation criterion of EELPA for administration costs is 10% of total variable cost consisting of operation and maintenance cost including fuel cost and lubricating oil cost, and this criterion will be applied in the present economic analysis.

12.3.2 Transmission Alternative

(1) Economic Service Life

The facilities to be included in the transmission alternative are the regulating dam, power stations, transmission lines, substations and distribution lines, and regarding their economic service lives, the following are adopted in accordance with EELPA criteria:

(a) New and Additional Facilities

- Regulating dam — 50 years
- No.2 power station — 40 years
  (25 years for electrical equipment)
- Transmission lines
  - Steel tower line — 50 years
  - Wood pole line — 25 years
  - 15-kV distribution line — 25 years
- Substation — 30 years

(b) Existing Facilities

The existing Tis Abbay Power Station, Bahar Dar Substation and the 45-kV transmission line connecting the two were put into service in 1964. Therefore, the existing power station will reach the end of its economic service life in the year 2003. However, in the case of the No.2 Power Station connected with the existing power station, when this new power station is constructed there will be replacement of facilities as required for the related structures of the existing power station, so that the economic service life of the No.2 Power Station will be 40 years irrespective of the remaining service life of the existing power station (further, as for actual periods of depreciation of existing facilities, those of the power station, the substation, and the transmission line are scheduled for completion in 30 years, 27 years and 25 years respectively, but these are based on financial requirements).

Further, of the abovementioned existing facilities, the electrical equipment of the power station and substation will reach their replacement ages in 1988 and 1993, respectively.

(2) Capital Cost and Adjusted Cost (Financial Cost)

Since it is considered reconstruction will not be done for the civil structures of the dam and power station after their service lives have expired, it is not necessary for perpetual replacement factors to be considered for them. In contrast, transmitting and transforming facilities may be considered to be renewed to infinity, and it is necessary for the capital costs of these to be adjusted multiplying by perpetual replacement factors. The capital costs and the adjusted capital costs of the various facilities are as indicated in Table 12-5.

Further, in renewal of facilities, the replacement costs of the facilities of the existing Tis Abbay Power Station, Bahar Dar Substation, etc., are required to be reevaluated in terms of 1976 values. The capital costs of these existing facilities as of 1976 are Eth $ 1,874,000 for Tis Abbay Power Station (assuming approximately 30% of the total cost of the power station of Eth $ 6,245,000 to consist of electrical equipment), Eth $ 362,500 for Bahar Dar Substation, and Eth $ 295,000 for the 45-kV transmission line.

Subsequently, the rise in prices of electrical equipment up to 1976, according to the wholesale price index of Japan, has been approximately 1.7 times, while the unit construction cost of 45 kV transmission line is presently Eth $ 35,700/km. In consideration of these factors, the replacement costs of existing facilities may be reevaluated approximately as indicated below.

- Electrical equipment of Tis Abbay PS — Eth $ 3,186,000
- Bahar Dar Substation — Eth $ 616,000
- 45-kV Transmission Line — Eth $ 6,071,000

(3) Capital Costs and Operation and Maintenance Costs of Existing Facilities (Financial Costs)

(a) Capital Costs

The initial costs and annual depreciation costs of the existing Tis Abbay Power Station, Bahar Dar Substation and 45-kV transmission line are as shown below.

	Initial Cost	Annual Depreciation Cost
Tis Abbay PS	Eth $ 6,245,000	Eth $ 214,900
Bahar Dar SS	Eth $ 362,500	Eth $ 13,320
45-kV line	Eth $ 295,000	Eth $ 11,820

All of the above facilities were commissioned in 1964 so that 18 years of depreciation will have been carried out by 1981, and the book values of these facilities at the beginning of 1982 may be estimated as being Eth $ 2,376,800 for power station, Eth $ 122,740 for substation and Eth $ 82,240 for transmission line.

The capital costs each year of existing facilities in the present economic analysis are the book values calculated based on the abovementioned book values at the beginning of 1982, and the service lives indicated in item 12.3.2 (1) will be applied for depreciation in this case.

(b) Operation and Maintenance Costs

The actual operation and maintenance costs for 1975 were Eth $ 150,390 as indicated below.

- Tis Abbay Power Station	Eth $ 134,920
- Bahar Dar Substation	Eth $ 14,310
- 45-kV Transmission Line	Eth $ 1,160
Total	Eth $ 150,390

The actual operation and maintenance costs for 1976 could not be confirmed, but since it can be estimated that they would have risen by approximately 4 % over the previous year, they are assumed to be the following in terms of 1976 values.

- Tis Abbay Power Station	Eth $ 140,320
- Bahar Dar Substation	Eth $ 14,900
- 45-kV Transmission Line	Eth $ 1,140
Total	Eth $ 156,360

The operation and maintenance costs of existing facilities for each year included in the economic calculations are amounts converted to present worths (beginning of 1982) of capitalized amounts of the above costs.

(4) Operation and Maintenance Costs of New Facilities

The annual operation and maintenance costs of the regulating dam, the additional No.3 unit of the existing power station, Tis Abbay No.2 Power Station, and power transmitting and transforming facilities will be assumed to be as follows:

- Regulating dam and generating facilities .... 2 % of investment cost
- Transmission and distribution lines .... 2.5 % of investment cost
- Substations .... 2.5 % of investment cost

(5) Cost of Supplementary Power Supplied from Upper Beles Power Station (Financial Cost)

Since it will become necessary for supplementary power to be supplied from Upper Beles Power Station from 1991, the cost of that power must be included in the overall supply cost of the transmission alternative. However, since studies on the Upper Beles Project are still not past the preliminary stage, the unit energy cost of that power station calculated below is a strictly tentative one.

(a) Approximate Investment Amount (1976 values)

The approximate investment amount for the Upper Beles Project was estimated at Eth$ 220,880,000 in the preliminary report of Acres International of 1971, in which Eth$5,720,000 is included as the construction cost of the Lake Tana Regulating Dam. Therefore, on deducting the latter amount from the total investment amount and making adjustments for contingency, engineering and other costs, the breakdown of the investment amount would be as indicated below.

Civil work	Eth$ 95,540,000	(60 %)
Electrical equipment	Eth$ 65,760,000	(40 %)
Sub-total	Eth$ 161,300,000	(100 %)
Contingency	Eth$ 24,192,000	
Engineering, etc.	Eth$ 27,823,000	
Total	Eth$ 213,315,000	

If contingency and engineering fee were to be allocated at the rate of 60% to civil work and 40% to electrical work, the total investment amount may be estimated to consist of Eth$ 128,000,000 for civil work and Eth$ 85,315,000 for electrical equipment work.

In estimating the abovementioned total investment amount at prices as of 1976, if the wholesale price index of Japan were to be applied with respect to electrical equipment it is approximately 1.50 times the 1971 value, while regarding civil work, since the EPDC estimate for the regulating dam construction work is Eth$9,370,000 (upstream proposal) as compared with the Acres International estimate of Eth$5,720,000, this is roughly 1.70 times the 1971 value. Therefore, if the above total investment amount is revised in terms of capital costs in 1976 including interest during construction of 4 years, they would be as shown below.

(1,000 Eth$)

Interest Rate	Investment Cost	Interest during Construction	Capital Cost
8 %	345,600	44,200	389,800
10 %	345,600	55,300	400,900

(b) Salable Energy

The greater part of the electric power of proposed Upper Beles Power Station would be supplied to the Interconnected System (ICS) where the load factor has been more or less constant at 60% from the past. Consequently, the annual energy production at full utilization of Upper Beles Power Station with its installed capacity of 200 MW may be calculated as being 200 MW x 8,760 hours x 0.60 = 1,051,200 MWh. However, as stated in item 4.5.3, the timing of development of Upper Beles Project calls for start-up of the No.1 and No.2 units totalling 100 MW in 1991, while in 1995 it will become necessary for the No.3 and No.4 units totalling 100 MW to be started up. And, the full utilization of this power station is estimated to be realized from 1998. Therefore, it may be roughly calculated that the total energy production of the initial 7 years from 1991 to 1997 would amount to approximately 3.5 years of full utilization. Accordingly, if it were to be assumed that the service life of this power station is 40 years, the average annual energy production for the entire service life would be the following:

Total energy production for entire service life

.... 1,051,200 MWh x 36.5 yr = 38,368,000 MWh/yr

Average annual energy production

.... 38,368,800 ÷ 40 yr = 959,220 MWh/yr

The transmission lines in this project will be 230-kV, 2 circuits, with a transmission distance to ICS of 450 km, and it is estimated that the transmission loss in terms of electric energy will be approximately 8%. Therefore, the annual salable energy at substation inlet of ICS will be as indicated below.

Salable energy

.... 959,220 MWh x 0.92 = 882,482 MWh

(c) Unit Cost per kWh

In case of supply of electricity from Upper Beles Power Station to the Lake Tana Project area from 1991, it is thought that power supplied will be received at Bahar Dar Substation, and it is thought permissible to apply the unit cost per kWh in ICS to Lake Tana Project area.

The unit costs assuming discount rates of 8% and 10% respectively will be as shown below.

Item	Discount Rate (8 %)	Discount Rate (10 %)
Amortization of capital cost	Eth$32,689,000	Eth$40,972,000
Operation and maintenance cost	Eth$ 6,912,000	Eth$ 6,912,000
Total annual cost	Eth$39,601,000	Eth$47,884,000
Average annual energy supply (at substation inlet)	882,482 MWh	882,482 MWh
Unit cost per kWh	E¢ 4.48/kWh	E¢ 5.43/kWh

(d) Cost of Supplementary Power

The amount obtained through multiplication of the supplementary energy from 1991 by the above unit cost is calculated for each year from 1991, after which these amounts are converted to present worths with the beginning of 1982 as a basis.

Further, after the limit of transmission capacity has been reached, it may be considered that energy at this limit will be supplied constantly every year. Therefore, the cost of this constant power supply is capitalized in the year that this limit is reached, and then, this capitalized amount is converted to present worth with the beginning of 1982 as the basis.

12.4 CALCULATION OF ECONOMIC COSTS

In item 12.1.2 (1) it was shown that shadow pricing should be applied for the foreign currency portions of equipment costs and operation and maintenance costs to calculate their economic costs as basis for economic evaluation.

12.4.1 Shadow Pricing in Diesel Power Alternative

(1) Economic Cost of Diesel Power Station

Of the erected cost of a diesel power station with taxes exempted, the proportion of the foreign currency portion is estimated to be about 80% of the whole. Since 133% of the official exchange rate is set as the shadow price of foreign currency, in order to obtain the economic cost of erected cost it will suffice to multiply the financial erected cost by a conversion factor of 1.264.

$$0.8 \times 1.33 + 0.2 = 1.264$$

(2) Economic Cost of Fuel Oil

The import price of heavy oil at the port of Assab (CIF price) since June 1976 has been US$94.97/ton (≒ Eth$197/ton), while the price of diesel oil at the exit of the refinery at Assab is Eth$314/ton (Eth$260/kl). Therefore, it is estimated that the processing cost at the refinery is Eth$314 - Eth$197 = Eth$117/ton.

The prices of fuel oil consumed at the various diesel power stations are the total of above price of fuel delivered at Assab refinery and transportation costs and distributor's cost.

According to a study made by EELPA, the proportions of the foreign and domestic currency portions of the fuel price are estimated as indicated below and these will be followed in the present economic analysis.

- Heavy oil import price — 100% foreign currency
- Processing cost at refinery — 70% foreign currency
- Transportation cost — 50% foreign currency
- Distributor's cost — 100% domestic currency

Next, the difference between the price of fuel delivered at a power station and the price of fuel delivered at the Assab refinery is to be divided between transportation cost and distributor's cost, the breakdown of which according to the EELPA study is estimated to be approximately 60% transportation cost and 40% distributor's cost.

Based on the above, the economic cost of fuel at Gondar Power Station (Eth$ 483/ton at the market price) is calculated as being the following:

(Eth$/ton)

Item	Financial Cost			Economic Cost		
	Domestic Currency	Foreign Currency	Total	Domestic Currency	Foreign Currency	Total
Import price of heavy oil		197	197		262	262
Processing cost	35	82	117	35	109	144
Ex-refinery price	35	279	314	35	371	406
Transportation cost	51	51	102	51	68	119
Distributor's cost	67		67	67		67
Delivered price at PS	154	329	483	154	438	592

Similarly, the economic costs of fuel at the various localities indicated in item 12.3.1(5) are calculated to be as follows:

(Eth$/ton)

Locality	Financial Cost	Economic Cost
Bahar Dar	440	545
Gondar district	483	592
Chewahit	490	599
Gorgora	493	603
Debre Tabor	453	559
Wereta	447	552
Addis Zemen	449	556
Dangla	431	535
Injibara - Addis Kidame	426	529

(3) Economic Cost of Lubricating Oil

The market price of lubricating oil is presently Eth$1.50/kg as described in item 12.3.1(6), and according to the study of EELPA, it is estimated that 70% of this consists of a foreign currency portion, and 30% a domestic currency portion. Therefore, the economic cost will be Eth$1.85/kg.

$$\text{Eth\$}1.50 \times 0.7 \times 1.33 + \text{Eth\$}1.50 \times 0.3 = \text{Eth\$}1.85$$

(4) Operation and Maintenance Cost

At indicated in the table in item 12.3.1(7), the operation and maintenance cost of diesel power stations for the whole country was Eth$1.168,673 in 1975 according to performance records, of which materials for maintenance comprised Eth $ 250,920, or approximately 22 %. According to the EELPA study, it is estimated that 80 % of the cost of materials for replacement and other purposes is the foreign currency portion. As indicated in the same item, the unit price of operation and maintenance cost as of 1976 is estimated to be E¢ 2.73/kWh, and therefore, the economic cost thereof will be E¢ 2.89/kWh.

E¢ 2.73 x (0.78 + 0.22 x 0.2) + E¢ 2.73 x 0.22 x 0.8 x 1.33

= E¢ 2.89

(5) Administration Cost

The administration costs can be estimated to consist entirely of domestic currency, and economic cost is therefore considered to be equal to financial cost.

(6) Economic Replacement Cost of Electrical Equipment of Tis Abbay Power Station and Bahar Dar Substation

The replacement cost of the subject electrical equipment is taken into account in the costs of both the diesel power alternative and the transmission alternative. The reevaluated amounts of such equipment as of the present time, as indicated in item 12.3.2 (2), are Eth $ 3,186,000 for power station and Eth $ 616,000 for substation. Of these costs, since 70 % of the whole may be estimated to comprise a foreign currency portion and 30 % a domestic currency portion, the economic cost by category of equipment will be as indicated below.

- Power station equipment

  Eth $ 3,186,000 x (0.7 x 1.33 + 0.3) = Eth $ 3,922,000

- Substation equipment

  Eth $ 616,000 x (0.7 x 1.33 + 0.3) = Eth $ 758,000

12.4.2 Shadow Pricing in Transmission Alternative

(1) Economic Capital Costs of New and Additional Facilities

The financial cost of the investment amount for each facility, the domestic and foreign currency portions thereof, and the economic capital cost accordingly calculated are shown in attached Table 12-5.

(2) Economic Capital Costs of Existing Facilities

These costs concern depreciation of capital already invested, and as stated in item 12.3.2 (3) (a), the book values of each year are applied without alternation.

(3) Economic Costs of Operation and Maintenance of Existing Facilities

As indicated in item 12.3.2 (3) (b), the operation and maintenance cost of these existing facilities as of the present is estimated to be Eth$ 156,360/yr. Of this operation and maintenance cost, approximately 90% is that of Tis Abbay Power Station, but on investigation of the record for 1975, Eth$35,397 (26%) of the operation and maintenance cost of Eth$ 134,919 for this power station is comprised by materials for maintenance, lubricating oil and the like. As indicated in item 12.4.1(4), it is estimated that approximately 80% of the cost of these materials requires foreign currency, and therefore, the economic costs of operation and maintenance of existing facilities can be calculated by multiplying financial cost of operation and maintenance by the following conversion factor:

- Conversion factor = (0.74 + 0.26 x 0.2) + (0.26 x 0.8 x 1.33)

  = 1.069

(4) Economic Cost of Operation and Maintenance of New and Additional Facilities

Following the case of the preceding item, considering that 26% of the total operation and maintenance cost is the cost of materials of which 80% requires foreign currency, the economic cost is obtained by multiplying the financial cost of operation and maintenance given in item 12.3.2(4) by the conversion factor 1.069.

(5) Economic Cost of Supplementary Power Supplied from Upper Beles Power Station

As indicated in item 12.3.2(5)(a), the approximate investment amount for Upper Beles Power Station is estimated as of 1976 to be about Eth$345,600,000, of which about 60% is considered to comprise the cost of civil work and about 40% the cost of electrical work. Of these costs, it is estimated that the ratios of foreign and domestic currency portions will be 50% foreign currency and 50% domestic currency for civil work, and 70% foreign currency and 30% domestic currency for electrical work. Overall, therefore, the proportions of foreign currency and domestic currency requirements will be as follows:

- Foreign currency portion

  Civil 0.6 x 0.5 + Electrical 0.4 x 0.7 = 0.58

- Domestic currency portion

  Civil 0.6 x 0.5 + Electrical 0.4 x 0.3 = 0.42

Accordingly, the conversion factor for revising financial cost into economic cost will be 0.42 + 0.58 x 1.33 = 1.191, and the economic capital costs including interest during construction of 4 years will be the following:

- Case of interest rate of 8 %

  ..... Eth$389,800,000 x 1.191 = Eth$464,252,000

- Case of interest rate of 10 %

  ..... Eth$400,900,000 x 1.191 = Eth$477,472,000

Further, the economic cost of the operation and maintenance is as follows:

Eth$6,912,000 x 1.069 = Eth$7,396,000

Therefore, the unit cost per kWh for the respective cases of discount rates of 8% and 10% are as given below.

Item	Discount Rate 8 %	Discount Rate 10 %
Amortization of capital cost	Eth$38,904,000	Eth$48,797,000
Operation and maintenance cost	Eth$ 7,396,000	Eth$ 7,396,000
Total annual cost	Eth$46,300,000	Eth$56,193,000
Average annual energy supply (at substation inlet)	882,482 MWh	882,482 MWh
Unit cost per kWh	E¢5.25/kWh	E¢6.36/kWh

12.5 ANALYSIS

12.5.1 Cumulative Present Worth Cost by Year of Diesel Power Alternative

(1) Required Installed Capacity, Capital Cost and Fuel Consumptio Rate

When assuming that electric power is supplied to each locality through diesel generation, the reductions in fuel consumption rates in proportion to increases in the installed capacity, the corresponding equipment cost, and the unit capacities of generators are as shown in Tables 12-1 (1) ~ (9).

However, of these localities, the Bahar Dar area alone requires special consideration. The reason for this is that unlike other localities, electricity is being supplied by the existing Tis Abbay Hydroelectric Power Station so that conversion to diesel power generation will be after the time that the supply capability of Tis Abbay Power Station no longer can meet the demand. In this case, the balance of demand and supply of this area, as described in Chapter 4, will be either of the two cases below in the method of power supply to electric boilers installed at Bahar Dar Textile Mills S.C.

Case A : Supply to electric boilers only at off-peak hours of the system

Case B : Supply to electric boilers without restriction even at peak hours of the whole system

Meanwhile, in the case of the diesel power alternative the regulating dam would not be constructed, while the existing facilities would remain as they are so that the average supply capability of Tis Abbay Power Station would be calculated as follows based on Table 8-2-2:

(a)	Annual average output	6,670 kW
(b)	Firm capacity	4,610 kW
(c)	Annual energy production to be calculated on the assumption that a discharge of $20 m^3/sec$ is to be always available	64,100 MWh
(d)	Annual average production	58,446 MWh
(e)	Decreased energy production during dry season (c - d)	5,654 MWh
(f)	Firm energy production	40,384 MWh
(g)	Secondary energy	18,062 MWh

Further, as described in Chapter 8, during the dry season the output of Tis Abbay Power Station lowers for approximately 75 days in average. Consequently, the approximate figures of decreased energy production due to a shortage of turbine discharge based on output duration curves would be obtained as follows:

(Maximum capacity - Firm capacity) x 900 hours.

After installation of diesel power stations, the decreased energy production would be covered by diesel power stations, and at the same time the secondary energy would also be utilized effectively in accordance with load curves.

Accordingly, in the present economic analysis it is assumed that the part of power demand exceeding firm capacity of Tis Abbay Power Station is to be supplied by diesel power stations, and that annual energy supplied by these diesel power stations be calculated in multyplying the said exceeding power to be required by 900 hours.

Further, it is to be noted that unlike Case A of the transmission alternative, in Case A of the diesel power alternative a part of power demand by electric boilers will be forced to be restricted during over 10 years to come.

(2) Cumulative Present Worth Costs by Year

The cumulative present worth costs by year for each locality of the diesel power alternative are calculated for the two cases of discount rate of 8% and discount rate of 10%.

Tables 12-2 (1) ~(11) are cumulative present worth financial costs, whereas Table 12-3 (1) ~(11) are cumulative present worth economic costs.

The cumulative present worth costs by year for the entire diesel power alternative totalling the cumulative present worth costs of the various localicites is as shown in Table 12-4.

12.5.2 Present Worth Capital Costs and Operation and Maintenance Costs by Year of Transmission Alternative

In Table 12-5 are indicated investment costs and capital costs for new facilities consisting of regulating dam, additional No.3 unit, No.2 Power Station, transmission lines, substations and telecommunication facilities, and for existing power station, substation and transmission line, calculated respectively in terms of financial costs and economic costs, together with adjusted costs taking into consideration perpetual replacement.

The capitalized amounts of operation and maintenance costs of the above facilities are also given in the same table.

The total costs by year of the transmission alternative calculated based on the above adjusted capital costs and the capitalized operation and maintenance costs are as described below.

(1) Present Worth Capital Costs of New Facilities from Year of Conversion

The present worth capital costs by year of new facilities corresponding to Case A and Case B are as indicated in Tables 12-6 (1) ~ (4). The present worth replacement costs of existing facilities are also included in these tables.

(2) Present Worth Capital Costs of Existing Facilities

The book values of the existing Tis Abbay Power Station, Bahar Dar Substation and 45-kV transmission line as of the beginning of 1982 have been indicated under item 12.3.2(3)(a). With these as bases and converting to present worths the book values by year during remaining service lives as designated, they are as shown in Table 12-7.

(3) Present Worths Capitalized Amounts by Year of Operation and Maintenance Cost

On actualizing by year the capitalized amounts of operation and maintenance costs of new and existing facilities, they will be as shown in Tables 12-8(1) ~ (4). The existing Tis Abbay Power Station will have reached the limit of its 40-year service life in the year 2003, and operation and maintenance costs thereafter will not be included in the economic analysis. Consequently, the operation and maintenance costs of the additional No.3 unit to be installed at this power station also will not be included from 2004.

As for the electrical equipment of the existing power station and substation, these will be replaced in 1988 and 1993 respectively at reevaluated values (as of 1976), but it is considered that the operation and maintenance costs of these existing facilities will not be changed as a whole.

12.5.3 Present Worth Energy Costs by Year to be Included in Transmission Alternative

As described in item 4.5.3 of Chapter 4, the supply capacity of the existing and No.2 Tis Abbay power stations in terms of kW will become insufficient to meet the demand in 1991 and after (in Case B the shortage will occur in 1986, but the total demand of the system can be satisfied by shifting the kW load of the electric boilers to off-peak hours until 1990). Consequently, there will be a necessity for supplementary power to be received from some other power station from 1991, and as the power source in such case, the development of Upper Beles Power Station is assumed for the present economic analysis.

Accordingly, it will become necessary to include the cost of power received from Upper Beles Power Station from 1991 in the transmission alternative. The calculation procedure for this is as described below.

(1) Supplementary Power to be supplied from Upper Beles and Energy Cost by Year

The regions to the north and east of Lake Tana centered around Gondar and Debre Tabor respectively, and the south region centered around Dangla and the Bahar Dar area will differ in the years that the scales of their power demand will reach the transmission capacities of related transmission lines (see item 12.2.5).

Next, the energy supplied from the power stations of the Tis Abbay System will be 71,144 MWh in 1990, but the existing Tis Abbay Power Station will reach the end of its economic service life in 2003. Therefore, it is considered that operation of this power station will be only for short periods of peak supply. The supply capacity after 2004 will not be considered in the economic analysis. In this case, when the energy supply from the remaining No.2 Power Station is allocated at the ratio between the dependable capacity of the existing Tis Abbay Power Station (including the additional No.3 unit) and that of the No.2 Power Station, this will be 23,620 MWh.

It is most reasonable to consider that the supplementary energy from Upper Beles Power Station will be the portion over and above the energy supplied from power stations of the Tis Abbay System.

Based on the above considerations, the supplementary energy supplied from Upper Beles Power Station and the energy costs corresponding to respective cases and discount rates when calculated will be as shown in Table 12-9.

(2) Present Worth Energy Cost by Year

Capitalizing the energy costs from the year that the scale of demand reaches transmission capacity as of that year, and further combining with the energy costs for the past years up to that time and then converting these costs to present worth by year, they will be as shown in Table 12-10.

12.5.4 Present Worth Total Costs by Year of Transmission Alternative

The present worth total costs by year of the transmission alternative including all of the capital costs, operation and maintenance costs described in items 12.5.2 and 12.5.3 will be as indicated in Table 12-11.

12.6 RESULTS OF ANALYSIS AND CONCLUSIONS

12.6.1 Optimum Timing for Implementation of the Lake Tana Project

Table 12-12, totalling the cumulative costs of the diesel power alternative each year indicated in Table 12-4 and the capitalized amounts of the transmission alternative in the same year indicated in Table 12-11, shows the total supply costs to infinity in case of conversion from a diesel power supply system to a transmission supply system in that year.

The above tables have been prepared based on the two different discount rates of 8% and 10%, two different estimations of financial cost and economic cost, and two different load forecasts for Case A and Case B, and on plotting cost-time curves based on these tables, the results will be as shown in Figs. 12-3 (1) ~ (4) and Figs. 12-4 (1) ~ (4).

The following conclusions may be drawn from the above tables and figures:

(a) The total supply cost becomes higher the lower the discount rate.

(b) Development scheme corresponding to Case A will require less total supply costs than development scheme corresponding to Case B at all times. For example, when 1983 is adopted as the year of conversion, the differences in the total costs of Case A and Case B will be the following:

(1000 Eth $)

Classification	Financial Costs		Economic Costs	
	Discount Rate 8 %	Discount Rate 10 %	Discount Rate 8 %	Discount Rate 10 %
Case B	96,108	85,563	113,773	101,371
Case A	92,789	81,093	109,560	95,866
Difference	3,319	4,470	4,213	5,505

(c) In case of a discount rate of 8%, it will be most economical for the regulating dam and transmitting and transforming facilities to start operations at the beginning of 1982 regardless of whether estimations are made of financial costs or economic costs, and whether Case A or Case B.

(d) In case of a discount rate of 10%, the conclusion obtained is that it will be most economical to convert to the transmission alternative in 1988 for Case A and 1985 for Case B, but the gradients of cost-time curves between 1983 and 1988 are extremely gentle and practically horizontal.

(e) The economic calculations are as given above, but when considering the fact that a discount rate of 8% reflects long-term international interest rates, it is thought suitable for various preparations to be made hereafter for starting operation of the regulating dam and transmission lines and substations of this project at a time as early as possible from 1982. In this case, it would be appropriate for the additional No.3 unit and Tis Abbay No.2 Power Station to be put into service in accordance with the construction timing of Case A indicated in item 4.5.3 of Chapter 4.

12.6.2 Savings to be Obtained by Transmission Alternative in Contrast to Continued Diesel Power Supply

The total supply costs in case of continued diesel power supply and the total supply costs in case of implementing the Lake Tana Project are compared and the amount of savings to be obtained by the latter contrasted to the former are shown below. In this case, 1983 is considered as the year of conversion to the transmission alternative.

(1000 Eth$)

Classification	Discount Rate 8 %		Discount Rate 10 %	
	Case A	Case B	Case A	Case B
(Financial Costs)				
Continued diesel	177,849	185,221	122,975	131,623
Transmission	92,789	96,108	81,093	85,563
Savings	85,060	89,113	41,882	46,060
(Economic Costs)				
Continued diesel	214,565	224,000	148,257	159,059
Transmission	109,560	113,773	95,866	101,371
Savings	105,005	110,227	52,391	57,688

In essence, the result will be that the total supply costs of this Lake Tana Project will be 50~55% of the total supply costs of continued diesel power supply in case of a discount rate of 8%, and 60~65% in case of a discount rate of 10%.

12.6.3 Rate of Return Approach

Since only two discount rates have been applied in the present economic analysis, it is not possible to plot a curve for accurately confirming the economic internal rate of return. Figs. 12-5(1)~(4) show the total supply costs for the diesel alternative in the two cases of discount rates of 8% and 10% connected by a straight line, and similarly the total supply costs for the transmission alternative in the cases of discount rates of 8% and 10% also connected by a straight line, to find the intersecting point of the two straight lines (internal rate of return), but properly, these would not be straight lines but concave curves, and the actual rate of return would be to the right of the intersecting point of the straight lines. From these figures, it will be possible to conclude the following with respect to the economic internal rate of return of this project.

(a) There will be hardly any difference in the internal rates of return in terms of financial costs and economic costs and they will be several percent higher than 12%.

(b) In both financial and economic costs, the internal rates of return will be slightly higher for Case B.

12.6.4 General Considerations

In case of the transmission alternative the greater part of annual costs will be made up of capital costs and the weight of operation and maintenance costs will be relatively small. In contrast, in case of the diesel power alternative, 55~66% of annual costs will consist of fuel and lubricating oil costs. Therefore, future rises in oil prices will be of extreme disadvantage to the diesel power alternative, and accordingly, would work to the advantage of the transmission alternative to that extent, but price escalations in the future are not taken into account in this analysis, so that the present analysis is more severe on the transmission alternative.

Next, the timing for implementation of the transmission alternative will differ according to the scale of power demand. That is, the faster the tempo of increase in demand, the sooner will be the year for conversion to the transmission alternative. Therefore, in this regard, stimulation of power demand in the project area, especially measures to convert potential demand into actual load will be an important key to early realization of this project.

Fig. 12-1 Construction Cost of Diesel Power Station

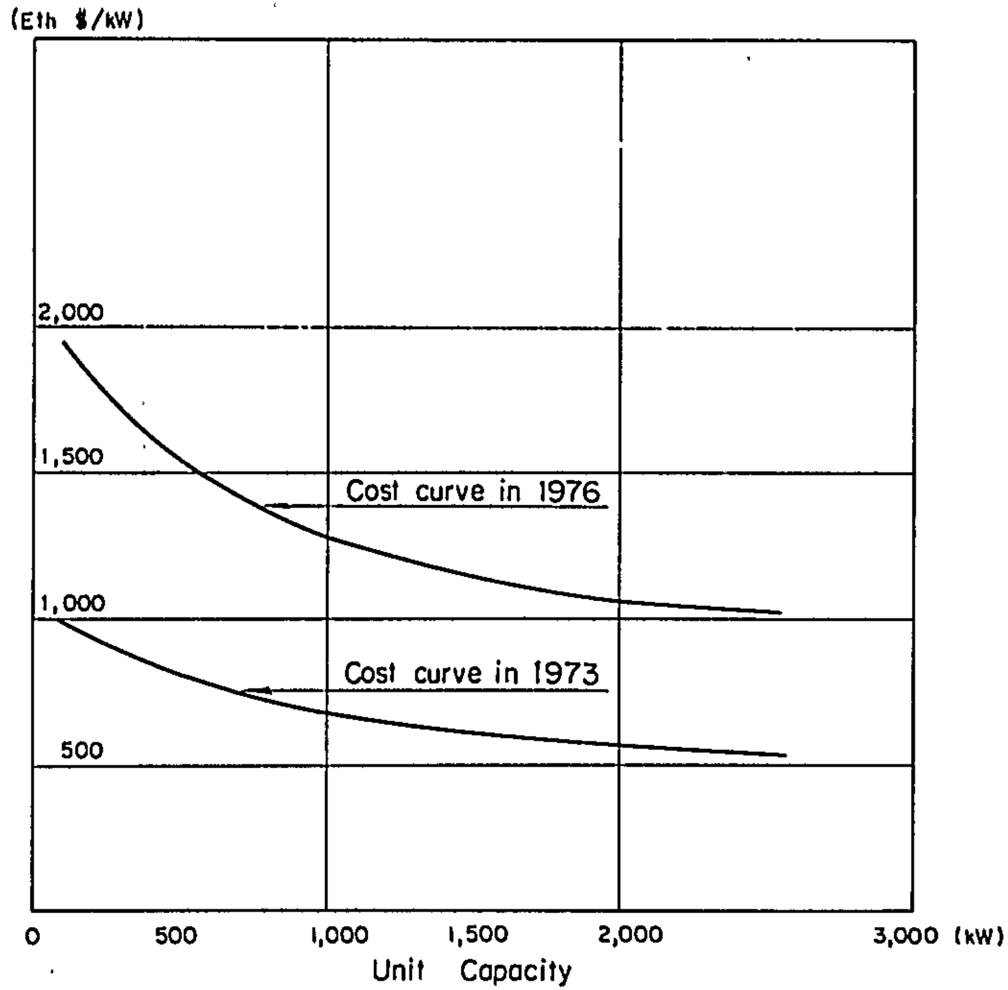
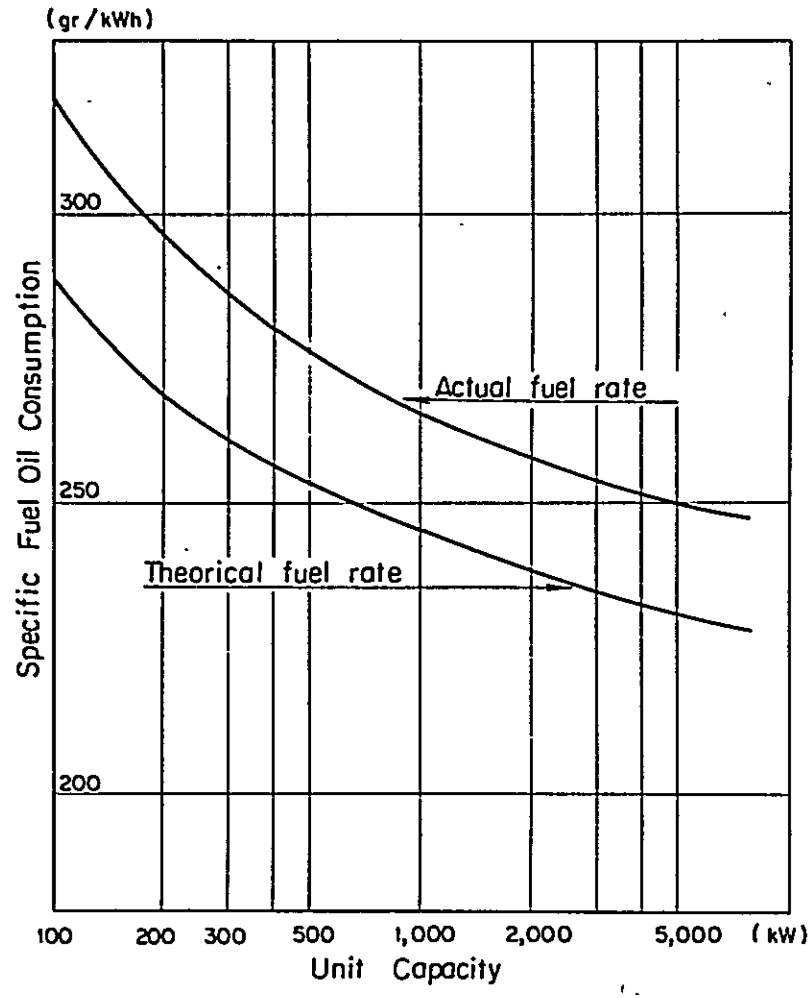


Fig. 12-2 Specific Consumption of Fuel Oil



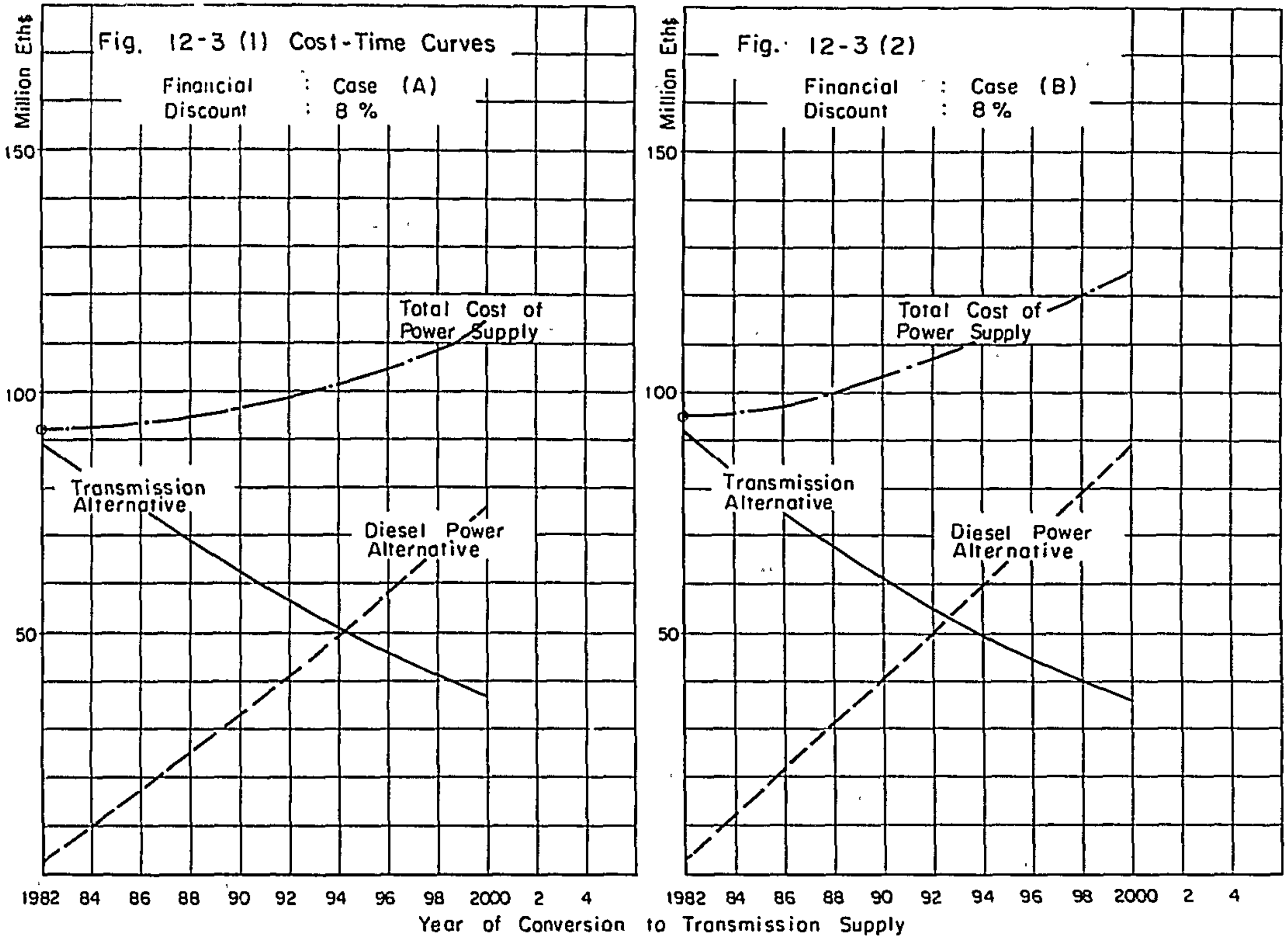


Fig. 12-3 (1) Cost-Time Curves
Financial : Case (A)
Discount : 8 %
Million Eth$
150
100
50
Total Cost of Power Supply
Transmission Alternative
Diesel Power Alternative
1982 84 86 88 90 92 94 96 98 2000 2 4
Fig. 12-3 (2)
Financial : Case (B)
Discount : 8 %
Million Eth$
150
100
50
Total Cost of Power Supply
Transmission Alternative
Diesel Power Alternative
1982 84 86 88 90 92 94 96 98 2000 2 4
Year of Conversion to Transmission Supply

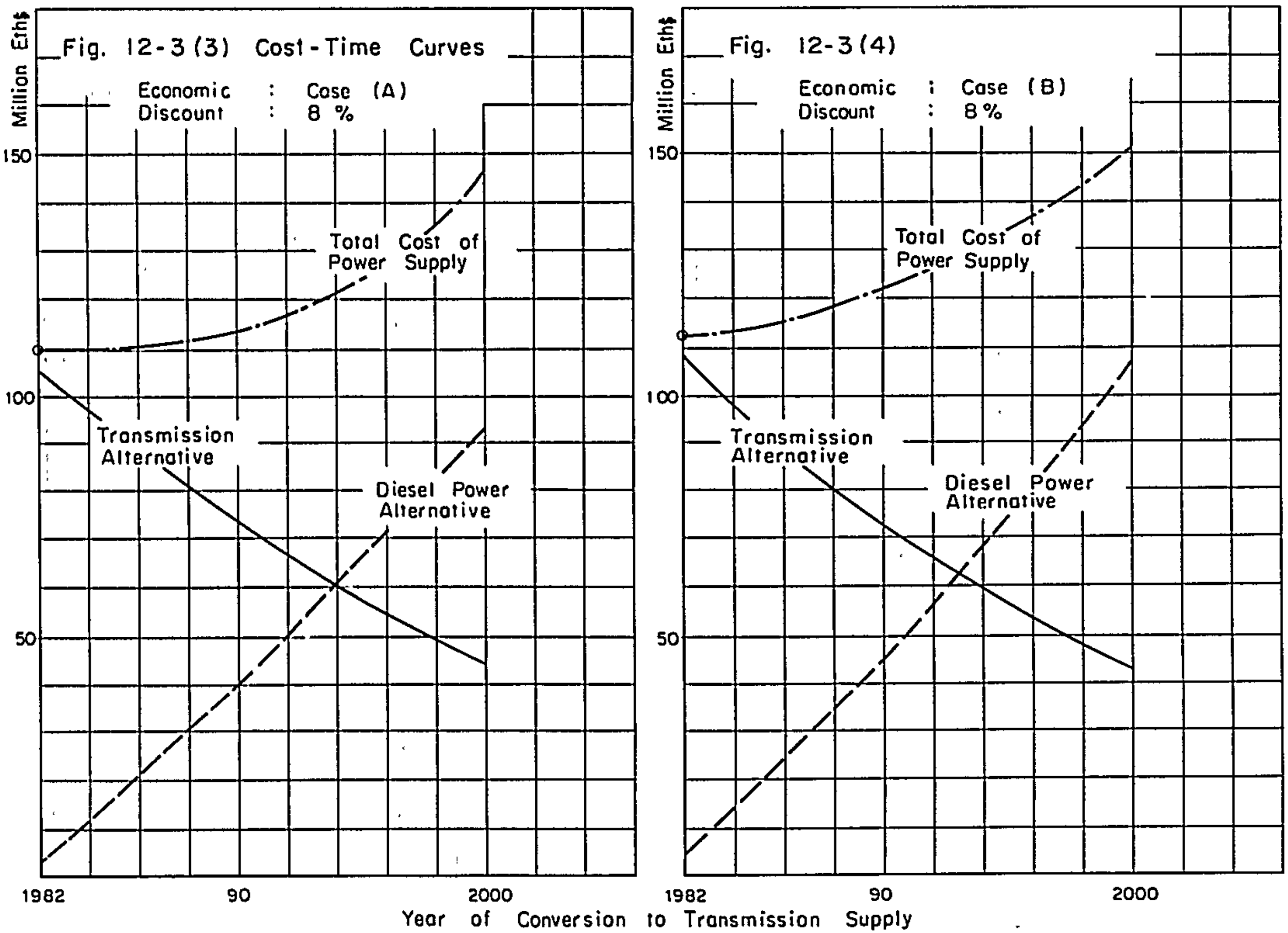


Fig. 12-3 (3) Cost-Time Curves
Economic Discount : Case (A) : 8 %
Million Eth$
150
100
50
Total Cost of Power Supply
Transmission Alternative
Diesel Power Alternative
1982
90
2000
Fig. 12-3 (4)
Economic Discount : Case (B) : 8 %
Million Eth$
150
100
50
Total Cost of Power Supply
Transmission Alternative
Diesel Power Alternative
1982
90
2000
Year of Conversion to Transmission Supply

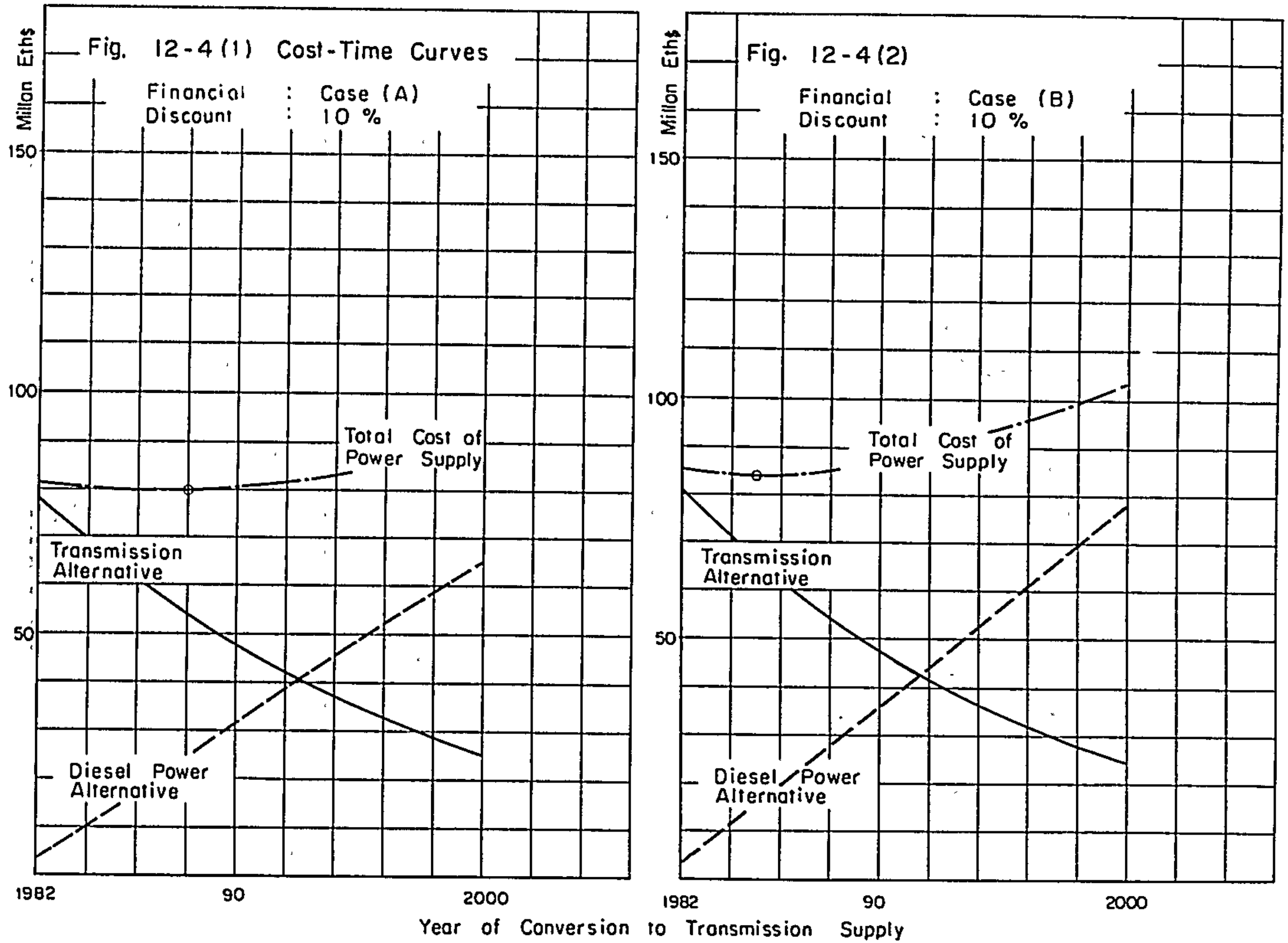
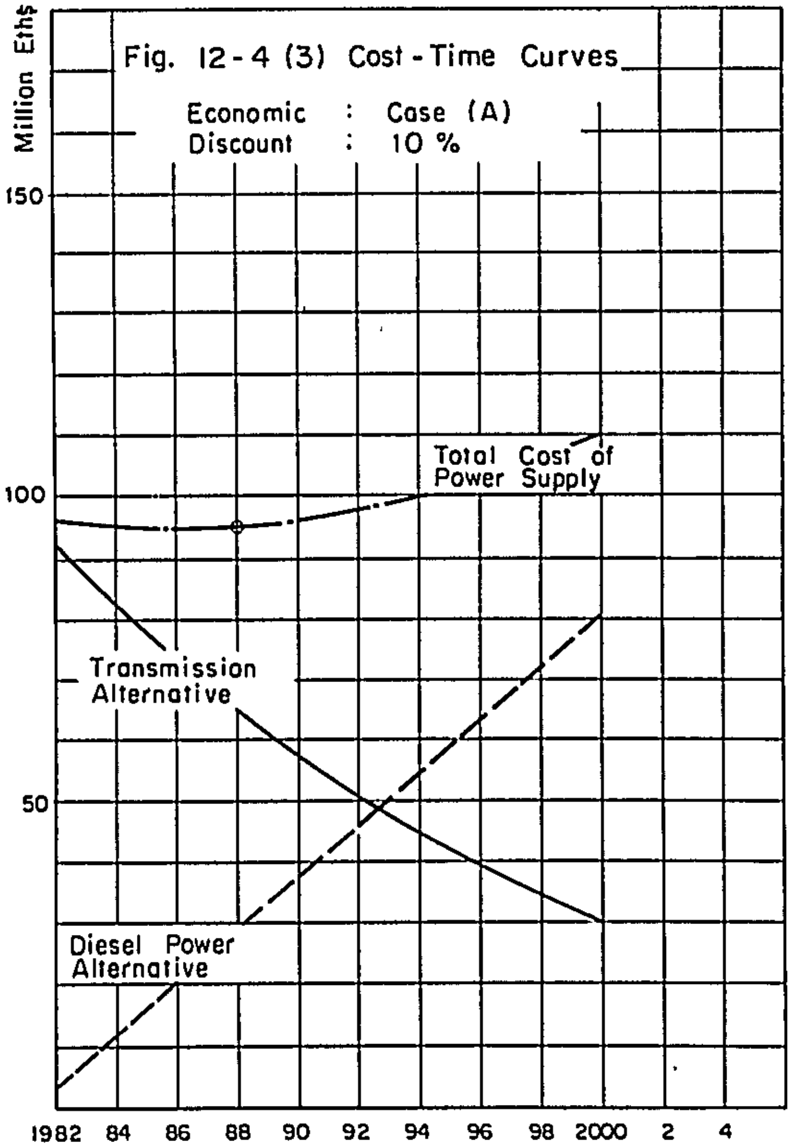
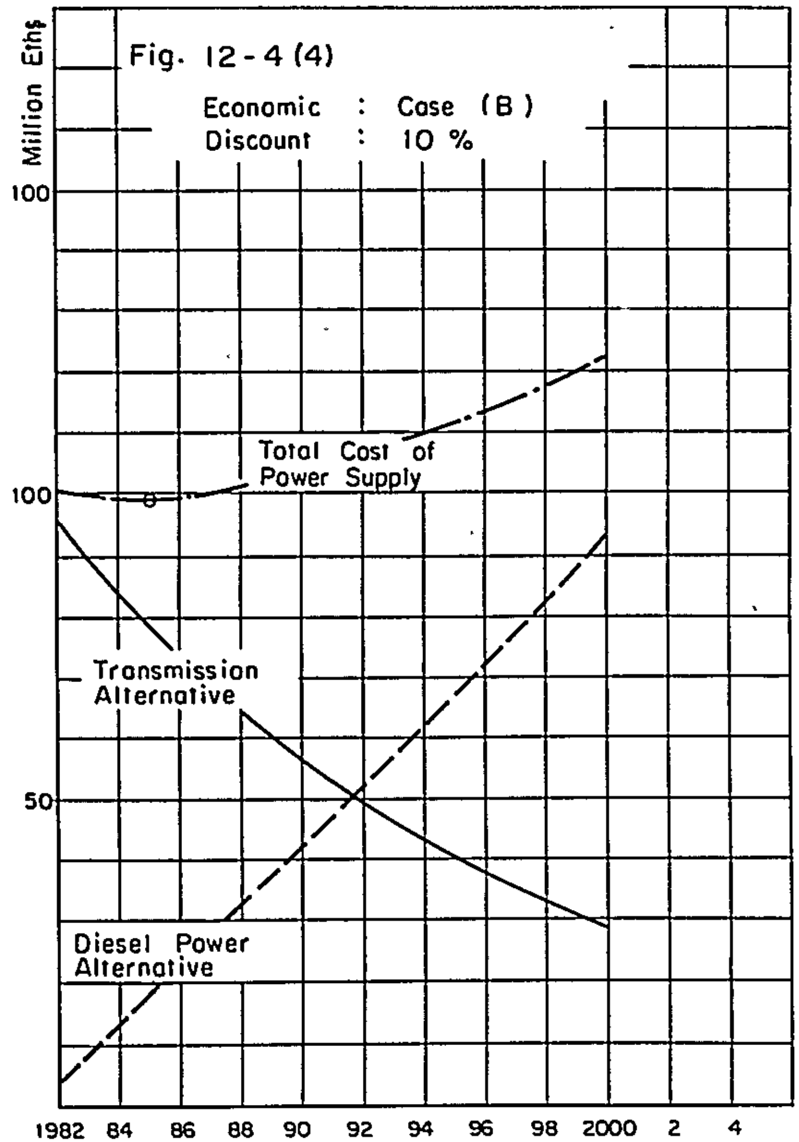


Fig. 12-4 (1) Cost-Time Curves
Financial Discount : Case (A) : 10 %
Millon Eth$
150
100
50
Total Cost of Power Supply
Transmission Alternative
Diesel Power Alternative
1982
90
2000
Fig. 12-4 (2)
Financial Discount : Case (B) : 10 %
Millon Eth$
150
100
50
Total Cost of Power Supply
Transmission Alternative
Diesel Power Alternative
1982
90
2000
Year of Conversion to Transmission Supply





Year of Conversion to Transmission Supply

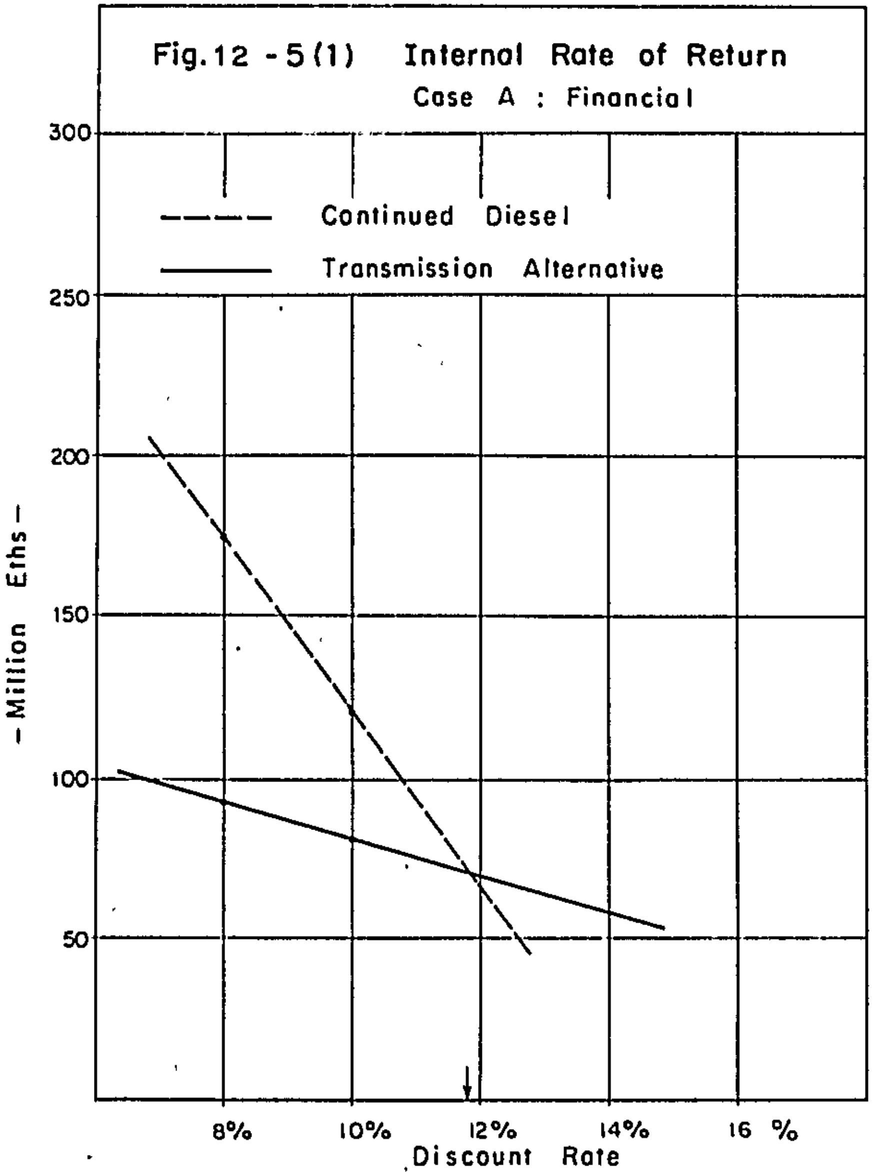


Fig.12 - 5 (1) Internal Rate of Return
Case A : Financial
Continued Diesel
Transmission Alternative
300
250
200
150
100
50
- Million Eths -
8%
10%
12%
14%
16 %
Discount Rate

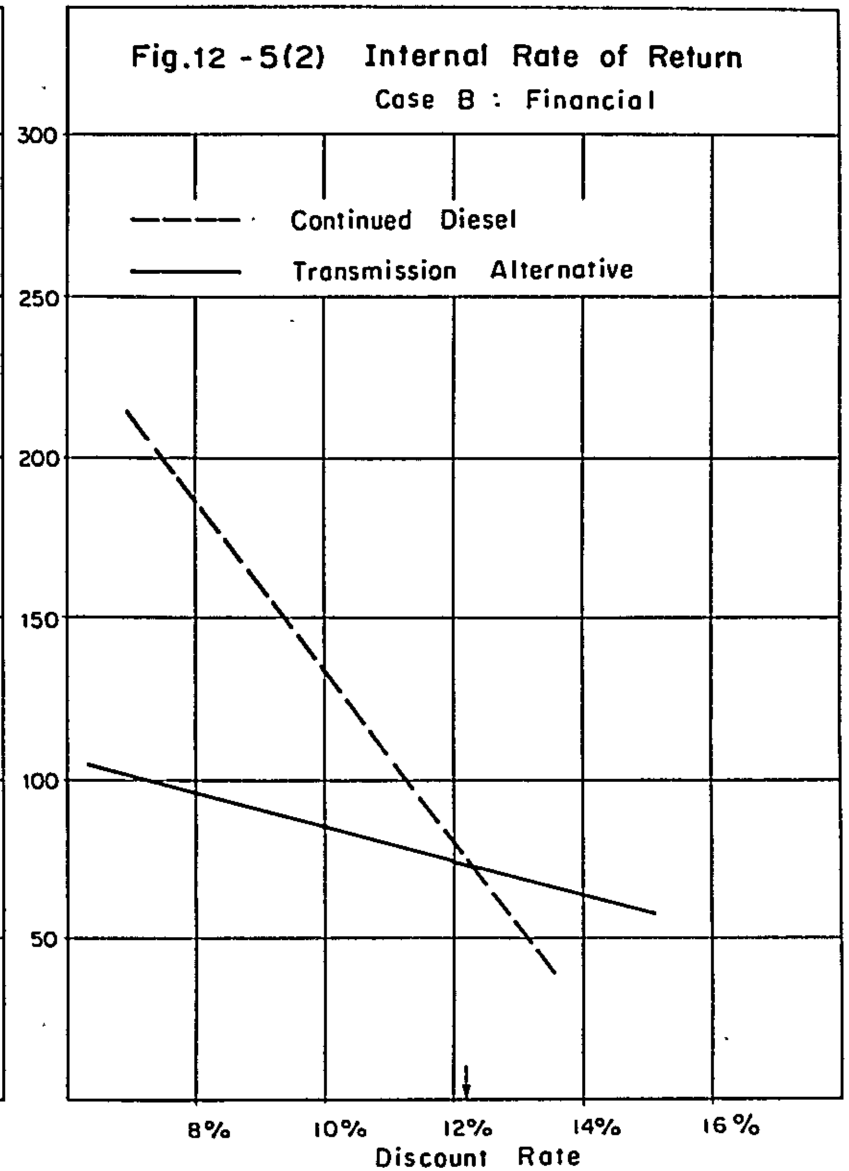


Fig.12 - 5(2) Internal Rate of Return
Case B : Financial
Continued Diesel
Transmission Alternative
300
250
200
150
100
50
8%
10%
12%
14%
16%
Discount Rate

Fig.12 -5(3) Internal Rate of Return
Case A : Economic

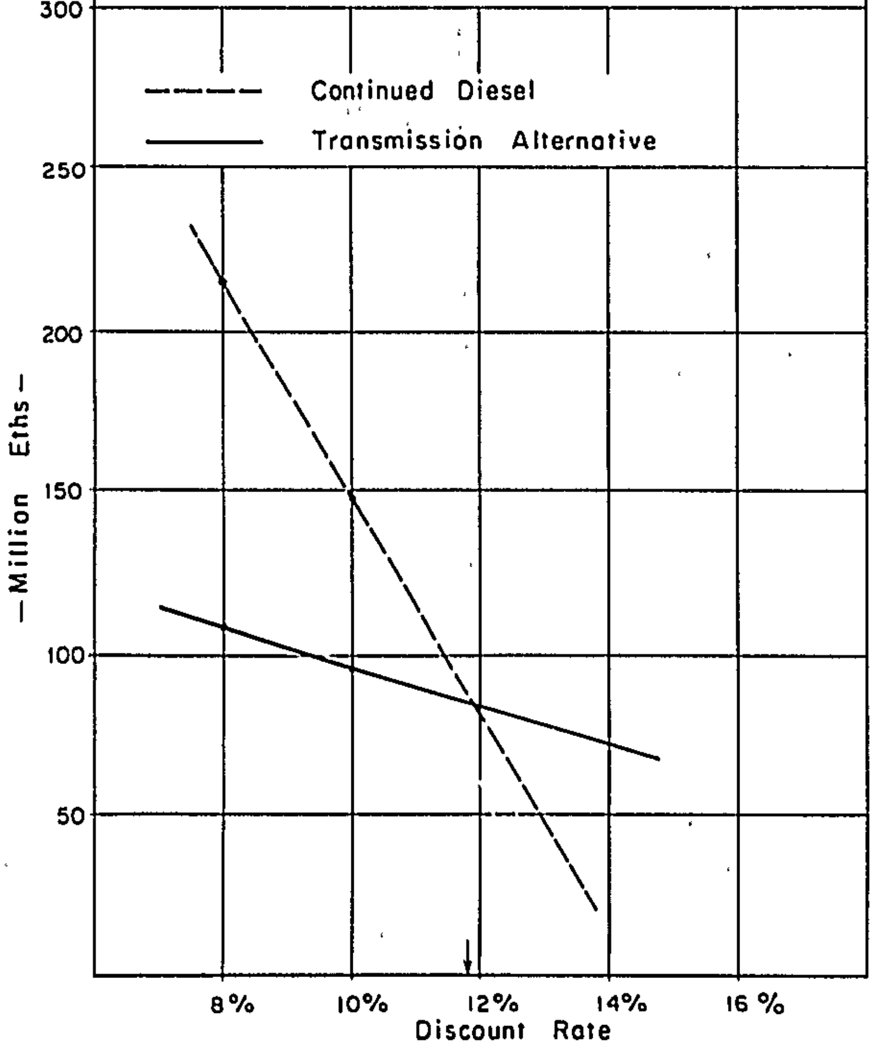


Fig.12 -5(4) Internal Rate of Return
Case B : Economic

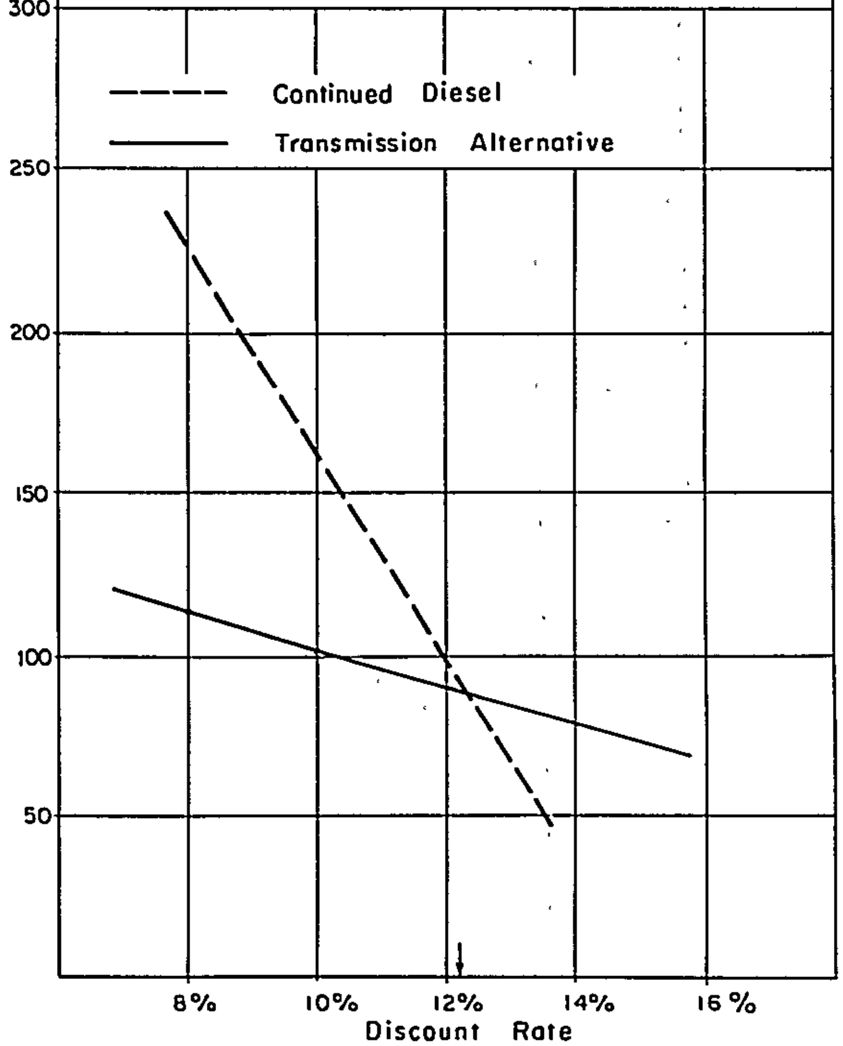


Table 12-1(1) Capital Cost and Specific Fuel Consumption of Diesel Alternative

Gondar area

Year	Energy Demand (MWh)	Maximum Demand (kW)	Installed Capacity		Specific Consumption		Capital Cost (1000 Eth$)
			Addit. (kW)	Total (kW)	Fuel oil (gr/kWh)	Lubricat. (gr/kWh)	
							(Financial)
1981	4,683	1,475		1,450	280	4	2,153
1982	5,717	1,830	2,000 x 1	3,450	260	4	4,353
1983	6,862	2,200		3,450	260	4	4,353
1984	7,581	2,430		3,450	260	4	4,353
1985	8,378	2,610		3,450	260	4	4,353
1986	9,256	2,880	2,000 x 1	5,450	260	4	6,553
1987	10,230	3,190		5,450	260	4	6,553
1988	11,303	3,430		5,450	260	4	6,553
1989	12,490	3,790		5,450	260	4	6,553
1990	13,801	4,180		5,450	260	4	6,553
1991	15,181	4,480	2,500 x 1	7,950	260	4	9,303
1992	16,699	4,930		7,950	260	4	9,303
1993	18,369	5,420		7,950	260	4	9,303
1994	20,207	5,820		7,950	260	4	9,303
1995	22,226	6,390	2,500 x 1	10,450	260	4	12,053
1996	24,449	7,030		10,450	260	4	12,053
1997	26,894	7,550		10,450	260	4	12,053
1998	29,584	8,310		10,450	260	4	12,053
1999	32,542	9,130	5,000 x 1	15,450	255	4	17,553
2000	35,542	9,810		15,450	255	4	17,553
2001	35,796	9,810		15,450	255	4	17,553
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Notes : Gondar area includes Gondar city, Azezo and Kola Diba.

Table 12-1 (2) Capital Cost and Specific Fuel Consumption of Diesel Alternative

Chewahit

Year	Energy Demand (MWh)	Maximum Demand (kW)	Installed Capacity Addit. (kW)	Installed Capacity Total (kW)	Specific Consumption Fuel oil (gr/kWh)	Specific Consumption Lubricat. (gr/kWh)	Capital Cost (1000 Eth$)
							(Financial)
1981							
1982	322	110	200 x 2	400	300	6	700
1983	713	240		400	300	6	700
1984	789	260		400	300	6	700
1985	871	280		400	300	6	700
1986	963	310		400	300	6	700
1987	1,063	340	300 x 1	700	300	6	1,225
1988	1,176	370		700	300	6	1,225
1989	1,299	410		700	300	6	1,225
1990	1,436	450		700	300	6	1,225
1991	1,578	490		700	300	6	1,225
1992	1,736	530		700	300	6	1,225
1993	1,911	590	300 x 1	1,000	300	6	1,750
1994	2,102	630		1,000	300	6	1,750
1995	2,311	690		1,000	300	6	1,750
1996	2,543	760		1,000	300	6	1,750
1997	2,797	820	500 x 1	1,500	290	6	2,450
1998	3,078	900		1,500	290	6	2,450
1999	3,384	990		1,500	290	6	2,450
2000	3,723	1,060		1,500	290	6	2,450
2001	4,072	1,160		1,500	290	6	2,450
....	...	...		...	...	.	...
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Table 12-1 (3) Capital Cost and Specific Fuel Consumption of Diesel Alternative

Gorgora

Year	Energy Demand (MWh)	Maximum Demand (kW)	Installed Capacity Addit. (kW)	Installed Capacity Total (kW)	Specific Consumption Fuel oil (gr/kWh)	Specific Consumption Lubricat. (gr/kWh)	Capital Cost (1000 Eth$) (Financial)
1981							
1982	262	120	200 x 2	400	300	6	700
1983	567	250		400	300	6	700
1984	627	270		400	300	6	700
1985	691	290		400	300	6	700
1986	764	320		400	300	6	700
1987	844	350	300 x 1	700	300	6	1,225
1988	933	380		700	300	6	1,225
1989	1,031	420		700	300	6	1,225
1990	1,140	460		700	300	6	1,225
1991	1,254	490		700	300	6	1,225
1992	1,379	540		700	300	6	1,225
1993	1,518	600	300 x 1	1,000	300	6	1,750
1994	1,669	640		1,000	300	6	1,750
1995	1,836	700		1,000	300	6	1,750
1996	2,020	770		1,000	300	6	1,750
1997	2,221	820	500 x 1	1,500	290	6	2,450
1998	2,443	900		1,500	290	6	2,450
1999	2,688	990		1,500	290	6	2,450
2000	2,957	1,060		1,500	290	6	2,450
2001	3,234	1,150		1,500	290	6	2,450
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Table 12-1(4) Capital Cost and Specific Fuel Consumption of Diesel Alternative

Debre Tabor

Year	Energy Demand (MWh)	Maximum Demand (kW)	Installed Capacity Addit. (kW)	Installed Capacity Total (kW)	Specific Consumption Fuel oil (gr/kWh)	Specific Consumption Lubricat. (gr/kWh)	Capital Cost (1000 Eth$)
							(Financial)
1981	500	230		238	310	6	417
1982	761	300	500 x 1	738	270	6	1,117
1983	1,556	610	500 x 1	1,238	270	6	1,817
1984	1,719	670		1,238	270	6	1,817
1985	1,899	720		1,238	270	6	1,817
1986	2,099	800		1,238	270	6	1,817
1987	2,319	880		1,238	270	6	1,817
1988	2,562	950		1,238	270	6	1,817
1989	2,832	1,040	500 x 1	1,738	270	5	2,517
1990	3,129	1,150		1,738	270	5	2,517
1991	3,442	1,230		1,738	270	5	2,517
1992	3,787	1,350		1,738	270	5	2,517
1993	4,164	1,480	500 x 1	2,238	270	5	3,217
1994	4,581	1,590		2,238	270	5	3,217
1995	5,040	1,740		2,238	270	5	3,217
1996	5,543	1,920	1,000 x 1	3,238	270	4	4,617
1997	6,098	2,050		3,238	270	4	4,617
1998	6,708	2,250		3,238	270	4	4,617
1999	7,378	2,470		3,238	270	4	4,617
2000	8,117	2,650	1,000 x 1	4,238	270	4	6,017
2001	8,358	2,720		4,238	270	4	6,017
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Table 12-1 (5) Capital Cost and Specific Fuel Consumption of Diesel Alternative

Wereta

Year	Energy Demand (MWh)	Maximum Demand (kW)	Installed Capacity Addit. (kW)	Installed Capacity Total (kW)	Specific Consumption Fuel oil (gr/kWh)	Specific Consumption Lubricat. (gr/kWh)	Capital Cost (1000 Eth$) (Financial)
1981	83	42		42	320	6	74
1982	481	220	300 x 2	642	300	6	1, 124
1983	961	440		642	300	6	1, 124
1984	1, 062	480		642	300	6	1, 124
1985	1, 173	520	500 x 1	1, 142	290	6	1, 824
1986	1, 297	570		1, 142	290	6	1, 824
1987	1, 433	630		1, 142	290	6	1, 824
1988	1, 583	670		1, 142	290	6	1, 824
1989	1, 750	740		1, 142	290	6	1, 824
1990	1, 933	820		1, 142	290	6	1, 824
1991	2, 127	870		1, 142	290	6	1, 824
1992	2, 339	950	500 x 1	1, 642	280	5	2, 524
1993	2, 573	1, 050		1, 642	280	5	2, 524
1994	2, 831	1, 110		1, 642	280	5	2, 524
1995	3, 113	1, 220		1, 642	280	5	2, 524
1996	3, 426	1, 350	500 x 1	2, 142	280	5	3, 224
1997	3, 767	1, 440		2, 142	280	5	3, 224
1998	4, 144	1, 570		2, 142	280	5	3, 224
1999	4, 559	1, 730	1,000 x 1	3, 142	270	4	4, 324
2000	5, 014	1, 850		3, 142	270	4	4, 324
2001	5, 486	2, 020		3, 142	270	4	4, 324
....	...	...		...	...	.	...
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Table 12-1(6) Capital Cost and Specific Fuel Consumption of Diesel Alternative

Addis Zemen

Year	Energy Demand (MWh)	Maximum Demand (kW)	Installed Capacity Addit. (kW)	Installed Capacity Total (kW)	Specific Consumption Fuel oil (gr/kWh)	Specific Consumption Lubricat. (gr/kWh)	Capital Cost (1000 Eth$)
							(Financial)
1981							
1982	422	170	300 x 2	600	300	6	525
1983	929	380		600	300	6	525
1984	1,027	420		600	300	6	525
1985	1,134	450		600	300	6	525
1986	1,254	490	500 x 1	1,100	290	6	1,225
1987	1,386	540		1,100	290	6	1,225
1988	1,531	580		1,100	290	6	1,225
1989	1,692	640		1,100	290	6	1,225
1990	1,869	710		1,100	290	6	1,225
1991	2,056	760		1,100	290	6	1,225
1992	2,262	830		1,100	290	6	1,225
1993	2,489	920	500 x 1	1,600	280	5	1,925
1994	2,737	980		1,600	280	5	1,925
1995	3,010	1,070		1,600	280	5	1,925
1996	3,311	1,180		1,600	280	5	1,925
1997	3,643	1,260		1,600	280	5	1,925
1998	4,008	1,390	500 x 1	2,100	280	5	2,625
1999	4,408	1,520		2,100	280	5	2,625
2000	4,849	1,630		2,100	280	5	2,625
2001	5,304	1,780		2,100	270	4	2,625
....	...	...		. .	...	.	...
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Table 12-1(7) Capital Cost and Specific Fuel Consumption of Diesel Alternative

Dangla

Year	Energy Demand (MWh)	Maximum Demand (kW)	Installed Capacity		Specific Consumption		Capital Cost (1000 Eth$)
			Addit. (kW)	Total (kW)	Fuel oil (gr/kWh)	Lubricat. (gr/kWh)	
							(Financial)
1981	178	76		76	320	6	133
1982	797	310	500 x 2	1,076	270	4	1,533
1983	1,531	600		1,076	270	4	1,533
1984	1,691	670		1,076	270	4	1,533
1985	1,869	710		1,076	270	4	1,533
1986	2,066	790		1,076	270	4	1,533
1987	2,282	870	500 x 1	1,576	270	4	2,233
1988	2,522	930		1,576	270	4	2,233
1989	2,787	1,030		1,576	270	4	2,233
1990	3,080	1,130		1,576	270	4	2,233
1991	3,388	1,210		1,576	270	4	2,233
1992	3,727	1,330	500 x 1	2,076	270	4	2,933
1993	4,100	1,460		2,076	270	4	2,933
1994	4,509	1,560		2,076	270	4	2,933
1995	4,960	1,720	1,000 x 1	3,076	270	4	4,033
1996	5,455	1,880		3,076	270	4	4,033
1997	6,002	2,020		3,076	270	4	4,033
1998	6,602	2,220		3,076	270	4	4,033
1999	7,262	2,440		3,076	270	4	4,033
2000	7,989	2,610	1,000 x 1	4,076	270	4	5,133
2001	8,740	2,850		4,076	270	4	5,133
2002	9,561	3,120		4,076	270	4	5,133
2003	10,459	3,320	1,500 x 1	5,576	260	4	6,783
2004	11,442	3,630		5,576	260	4	6,783
2005	12,519	3,970		5,576	260	4	6,783
2006	13,696	4,230		5,576	260	4	6,783
2007	15,701	4,580		7,576	260	4	8,983
2008	17,177	4,960		7,576	260	4	8,983
2009	18,792	5,370		7,576	260	4	8,983
2010	20,559	5,810		7,576	260	4	8,983
2011	22,493	6,290	2,000 x 1	9,576	260	4	11,183
2012	24,605	6,800		9,576	260	4	11,183
2013	26,918	7,370	3,000 x 1	12,576	260	4	14,483
2014	29,449	7,980		12,576	260	4	14,483
2015	32,217	8,630		12,576	260	4	14,483
2016	35,245	9,340		12,576	260	4	14,483
2017	38,559	10,120	3,000 x 1	15,576	260	4	17,783
2018	42,183	10,950		15,576	260	4	17,783
2019	45,090	11,740		15,576	260	4	17,783

Table 12-1(8) Capital Cost and Specific Fuel Consumption of Diesel Alternative

Injubara and Addis Kidame

Year	Energy Demand (MWh)	Maximum Demand (kW)	Installed Capacity Addit. (kW)	Installed Capacity Total (kW)	Specific Consumption Fuel oil (gr/kWh)	Specific Consumption Lubricat. (gr/kWh)	Capital Cost (1000 ES)
							(Financial)
1981							
1982	411	140	200 x 1	200	300	6	350
1983	906	300	300 x 1	500	300	6	875
1984	1,000	340		500	300	6	875
1985	1,107	370		500	300	6	875
1986	1,222	400		500	300	6	875
1987	1,352	440	300 x 1	800	300	6	1,400
1988	1,494	470		800	300	6	1,400
1989	1,651	520		800	300	6	1,400
1990	1,824	570		800	300	6	1,400
1991	2,118	650	300 x 1	1,100	300	6	1,925
1992	2,208	680		1,100	300	6	1,925
1993	2,429	740		1,100	300	6	1,925
1994	2,672	800		1,100	300	6	1,925
1995	2,940	880		1,100	300	6	1,925
1996	3,234	970	500 x 1	1,600	290	6	2,625
1997	3,558	1,040		1,600	290	6	2,625
1998	3,913	1,140		1,600	290	6	2,625
1999	4,303	1,260		1,600	290	6	2,625
2000	4,734	1,350	500 x 1	2,100	280	5	3,325
2001	5,180	1,480		2,100	280	5	3,325
2002	5,667	1,620		2,100	280	5	3,325
2003	6,199	1,730	1,000 x 1	3,100	270	4	4,425
2004	6,781	1,890		3,100	270	4	4,425
2005	7,419	2,070		3,100	270	4	4,425
2006	8,117	2,210		3,100	270	4	4,425
2007	8,162	2,390		3,100	270	4	4,425
2008	8,929	2,590	1,000 x 1	4,100	260	4	5,525
2009	9,768	2,800		4,100	260	4	5,525
2010	10,686	3,030		4,100	260	4	5,525
2011	11,689	3,280	1,500 x 1	5,600	260	4	7,175
2012	12,790	3,550		5,600	260	4	7,175
2013	13,992	3,850		5,600	260	4	7,175
2014	15,307	4,170		5,600	260	4	7,175
2015	16,746	4,510	1,500 x 1	7,100	260	4	8,825
2016	18,320	4,880		7,100	260	4	8,825
2017	20,042	5,280		7,100	260	4	8,825
2018	21,926	5,720	1,500 x 1	8,600	260	4	10,475
2019	23,750			8,600	260	4	10,475

Table 12-1 (9) Capital Cost and Specific Fuel Consumption of Diesel Alternative

Bahar Dar

Year	Annual Energy Demand	Maximum Power Demand (kW)		Supply Capability of Tis Abbay Power Station (without regulation)				Energy and Power to be supplied by Diesel Power Station				Capital Cost of Diesel Power Station (1000 Eth$)				Replacement of Existing Facilities	Specific Consump.	
		Case A	Case B	Case A		Case B		Case A		Case B		Case A		Case B			Fuel oil	Lubricat.
	(MWh)			Energy (MWh)	Power (kW)	Energy (MWh)	Power (kW)	Energy (MWh)	Power (kW)	Energy (MWh)	Power (kW)	(kW)	Costs	(kW)	Costs	(1000 Eth$)	(gr/kWh)	(gr/kWh)
1981	23,008			58,446	4,610	58,446	4,610											
1982	32,370	3,010	6,310	58,446	4,610	58,446	4,610	-	-	1,530	1,700			2,000 x 2	4,400		260	4
1983	39,018	3,430	7,720	58,446	4,610	58,446	4,610	-	-	2,800	3,110						260	4
1984	39,424	3,540	7,830	58,446	4,610	58,446	4,610	-	-	2,900	3,220						260	4
1985	39,877	3,660	7,970	58,446	4,610	58,446	4,610	-	-	3.020	3,360			2,000 x 1	2,200		260	4
1986	40,369	3,850	8,140	58,446	4,610	58,446	4,610	-	-	3,180	3,530						260	4
1987	40,917	3,980	8,270	58,446	4,610	58,446	4,610	-	-	3,290	3,660						260	4
1988	41,522	4,180	8,470	58,446	4,610	58,446	4,610	-	-	3,470	3,860						260	4
1989	42,191	4,390	8,680	58,446	4,610	58,446	4,610	-	-	3,660	4,070					3,186	260	4
1990	42,932	4,570	8,800	58,446	4,610	58,446	4,610	-	-	3,830	4,250						260	4
1991	43,711	4,820	9,110	58,446	4,610	58,446	4,610	190	210	4,050	4,500	300 x 3	1,580				260	4
1992	44,566	5,080	9,370	58,446	4,610	58,446	4,610	520	470	4,280	4,760						260	4
1993	45,507	5,300	9,590	58,446	4,610	58,446	4,610	620	690	4,480	4,980	500 x 2	1,400	2,000 x 2	4,400		260	4
1994	46,544	5,620	9,910	58,446	4,610	58,446	4,610	910	1,010	4,770	5,300					616	260	4
1995	47,682	5,970	10,260	58,446	4,610	58,446	4,610	1,220	1,360	5,090	5,650	500 x 2	1,400				260	4
1996	48,936	6,240	10,530	58,446	4,610	58,446	4,610	1,470	1,630	5,330	5,920						260	4
1997	50,314	6,650	10,940	58,446	4,610	58,446	4,610	1,840	2,040	5,700	6,330	1,000 x 1	1,100				260	4
1998	51,830	7,110	11,400	58,446	4,610	58,446	4,610	2,250	2,500	6,110	6,790						260	4
1999	53,499	7,470	11,760	58,446	4,610	58,446	4,610	2,570	2,860	6,440	7,150	1,000 x 1	1,100				260	4
2000	55,334	8,010	12,300	58,446	4,610	58,446	4,610	3,060	3,400	6,920	7,690			3,000 x 1	3,300		260	4
2001	57,230	8,560	12,850	58,446	4,610	58,446	4,610	3,560	3,950	7,420	8,240						260	4
2002	59,307	8,990	13,280	58,446	4,610	58,446	4,610	3,940	4,380	7,800	8,670	3,000 x 1	3,300				260	4
2003	61,578	9,640	13,930	58,446	4,610	58,446	4,610	4,530	5,030	8,390	9,320	3,000 x 2	6,600	3,000 x 2	6,600		260	4
2004	64,062	10,350	14,640					64,062	10,350	64,062	14,640						260	4
2005	66,780	10,900	15,190					66,780	10,900	66,780	15,190						260	4
2006	69,753	11,730	15,800					69,753	11,730	69,480	15,800	3,000 x 2	6,600				260	4
2007	72,857	12,450	15,800					72,857	12,450	...	...						260	4
2008	76,100	13,220	15,800					76,100	13,220	...	...						260	4
2009	79,485	14,030	15,800					79,485	14,030	...	...						260	4
2010	83,022	14,890	15,800					83,022	14,890	...	...						260	4
2011	86,750	15,800	15,800					86,750	15,800	...	...						260	4
....	...	...	...					...	...	...	...						260	4
....	...	...	...					...	...	...	...						260	4

Table 12-2(1) Present Worth Annual Costs of Diesel Alternative (Financial)

(1000 Eth$) Gondar Area

Year	Capital Costs Discount Rate 8 %	Capital Costs Discount Rate 10 %	Variable Costs Fuel oil	Variable Costs Lubricat.	Variable Costs O and M	Admini-stration	Present Worth Costs Discount Rate 8 % Yearly	Present Worth Costs Discount Rate 8 % Cumulat.	Present Worth Costs Discount Rate 10 % Yearly	Present Worth Costs Discount Rate 10 % Cumulat.
1981										
1982	509	572	718	34	156	90	1,396	1,396	1,428	1,428
1983	509	572	862	41	187	109	1,465	2,861	1,464	2,892
1984	509	572	952	45	207	120	1,455	4,316	1,425	4,317
1985	509	572	1,052	50	228	133	1,450	5,766	1,390	5,707
1986	766	862	1,162	56	252	147	1,622	7,388	1,540	7,247
1987	766	862	1,285	61	279	162	1,609	8,997	1,495	8,742
1988	766	862	1,419	67	308	179	1,598	10,595	1,455	10,197
1989	766	862	1,568	75	340	198	1,592	12,187	1,420	11,617
1990	766	862	1,733	83	376	219	1,590	13,777	1,388	13,005
1991	1,087	1,223	1,906	91	414	241	1,732	15,509	1,494	14,499
1992	1,087	1,223	2,097	100	455	265	1,717	17,226	1,451	15,950
1993	1,087	1,223	2,300	110	501	291	1,704	18,930	1,410	17,360
1994	1,087	1,223	2,537	121	551	320	1,697	20,627	1,377	18,737
1995	1,408	1,584	2,791	133	606	353	1,801	22,428	1,440	20,177
1996	1,408	1,584	3,070	147	667	388	1,791	24,219	1,402	21,579
1997	1,408	1,584	3,377	161	734	427	1,782	26,001	1,368	22,947
1998	1,408	1,584	3,715	178	807	470	1,778	27,719	1,336	24,283
1999	2,051	2,308	4,008	195	888	509	1,915	29,694	1,422	25,705
2000	2,051	2,308	4,409	214	977	560	1,903	31,597	1,385	27,090
2001	2,051	2,308	4,409	214	977	560				
...			...	...	...	...				
...			...	...	...	...				
...			...	...	...	...				
From 2001 to Infinity							23,787		13,850	
Total								55,384		40,940

Table 12-2 (2) Present Worth Annual Costs of Diesel Alternative (Financial)

(1000 Eth$) Chewahit

Year	Capital Costs Discount Rate		Variable Costs			Administration	Present Worth Costs			
	8 %	10 %	Fuel oil	Lubricat.	O and M		Discount Rate 8 % Yearly	Discount Rate 8 % Cumulat.	Discount Rate 10 % Yearly	Discount Rate 10 % Cumulat.
1981										
1982	82	92	48	3	9	6	137	137	144	144
1983	82	92	105	6	19	13	193	330	195	339
1984	82	92	117	7	22	14	192	522	190	529
1985	82	92	129	8	24	16	191	713	184	713
1986	82	92	142	9	26	17	188	901	178	891
1987	143	161	157	10	29	19	226	1,127	213	1,104
1988	143	161	174	11	32	21	223	1,350	205	1,309
1989	143	161	192	12	35	23	219	1,569	198	1,507
1990	143	161	212	13	39	26	217	1,786	192	1,699
1991	143	161	233	14	43	29	214	2,000	185	1,884
1992	143	161	256	16	47	31	212	2,212	179	2,063
1993	204	230	283	17	52	35	235	2,447	197	2,260
1994	204	230	311	19	57	38	231	2,678	190	2,450
1995	204	230	342	21	63	42	229	2,907	184	2,634
1996	204	230	376	23	69	46	227	3,134	178	2,812
1997	286	322	400	25	76	50	244	2,378	190	3,002
1998	286	322	440	28	84	55	242	3,620	184	3,186
1990	286	322	484	30	92	60	239	3,859	178	3,364
2000	286	322	532	34	102	66	237	4,096	173	3,537
2001	286	322	582	37	111	73				
...			...	..	...	..				
...			...	..	...	..				
...			...	..	...	..				
From 2001 to Infinity							2,925		1,680	
Total								7,021		5,217

Table 12-2 (3) Present Worth Annual Costs of Diesel Alternative (Financial)

(1000 Eth$) Gorgora

Year	Capital Costs Discount Rate 8 %	Capital Costs Discount Rate 10 %	Variable Costs Fuel oil	Variable Costs Lubricat.	Variable Costs O and M	Administration	Present Worth Costs Discount Rate 8 % Yearly	Present Worth Costs Discount Rate 8 % Cumulat.	Present Worth Costs Discount Rate 10 % Yearly	Present Worth Costs Discount Rate 10 % Cumulat.
1981										
1982	82	92	39	2	7	4	124	124	131	131
1983	82	92	84	3	15	10	167	291	169	300
1984	82	92	94	5	17	11	166	457	163	463
1985	82	92	102	6	19	12	163	620	158	621
1986	82	92	113	7	21	14	162	782	154	775
1987	143	161	125	8	23	15	198	980	188	963
1988	143	161	138	8	25	17	194	1,174	179	1,142
1989	143	161	152	9	28	18	189	1,363	172	1,314
1990	143	161	169	10	31	21	187	1,550	167	1,481
1991	143	161	185	11	34	23	184	1,734	160	1,641
1992	143	161	204	12	37	25	181	1,915	154	1,795
1993	204	230	225	14	41	28	204	2,119	189	1,984
1994	204	230	247	15	46	31	200	2,319	182	2,166
1995	204	230	272	17	50	34	197	2,516	175	2,341
1996	204	230	297	18	55	37	193	2,709	153	2,494
1997	286	322	317	20	61	39	211	2,920	166	2,660
1998	286	322	349	22	67	43	208	3,128	159	2,819
1999	286	322	384	24	73	48	204	3,332	153	2,972
2000	286	322	423	26	80	52	201	3,533	148	3,120
2001	286	322	462	29	88	57				
...			...	..	..	..				
...			...	..	..	..				
...			...	..	..	..				
From 2001 to Infinity							2,475		1,430	
Total								6,008		4,550

Table 12-2(4) Present Worth Annual Costs of Diesel Alternative (Financial)

(1000 Eth$) Debre Tabor

Year	Capital Costs		Variable Costs			Admini-stration	Present Worth Costs			
	Discount Rate		Fuel oil	Lubricat.	O and M		Discount Rate 8 %		Discount Rate 10 %	
	8 %	10 %					Yearly	Cumulat.	Yearly	Cumulat.
1981										
1982	130	147	93	7	21	12	244	244	255	255
1983	212	239	190	14	42	20	414	658	421	676
1984	212	239	210	15	46	27	405	1,063	404	1,080
1985	212	239	232	17	51	30	399	1,462	389	1,469
1986	212	239	256	19	57	33	393	1,855	375	1,844
1987	212	239	283	21	63	36	388	2,243	363	2,207
1988	212	239	313	23	70	40	384	2,627	352	2,559
1989	294	331	346	25	77	44	425	3,052	384	2,943
1990	294	331	382	28	85	49	420	3,472	371	3,314
1991	294	331	420	31	94	54	414	3,886	359	3,673
1992	294	331	463	34	103	60	409	4,295	348	4,021
1993	376	423	509	37	114	66	438	4,733	366	4,387
1994	376	423	560	41	125	72	432	5,165	354	4,741
1995	376	423	616	45	137	75	412	5,577	331	5,072
1996	545	610	678	50	151	83	461	6,038	366	5,438
1997	545	610	746	55	166	96	470	6,508	364	5,802
1998	545	610	820	60	183	106	464	6,972	352	6,154
1999	545	610	902	66	201	117	459	7,431	341	6,495
2000	703	791	992	73	221	128	491	7,922	361	6,856
2001	703	791	1,021	75	227	131				
...			...	..	...	...				
...			...	..	...	...				
...			...	..	...	...				
From 2001 to Infinity							5,775		3,330	
Total								13,697		10,186

Table 12-2(5) Present Worth Annual Costs of Diesel Alternative (Financial)

(1000 Eth$) Wereta

Year	Capital Costs Discount Rate 8 %	Capital Costs Discount Rate 10 %	Variable Costs Fuel oil	Variable Costs Lubricat.	Variable Costs O and M	Administration	Present Worth Costs Discount Rate 8 % Yearly	Discount Rate 8 % Cumulat.	Discount Rate 10 % Yearly	Discount Rate 10 % Cumulat.
1981										
1982	131	148	64	4	13	8	204	204	216	216
1983	131	148	129	9	26	16	267	471	271	487
1984	131	148	142	10	29	18	262	733	261	748
1985	213	240	152	11	32	19	314	1,047	310	1,058
1986	213	240	168	12	35	21	306	1,353	296	1,354
1987	213	240	185	13	39	23	298	1,651	283	1,637
1988	213	240	205	14	43	26	293	1,944	271	1,908
1989	213	240	226	16	48	29	288	2,232	261	2,169
1990	213	240	250	17	53	32	283	2,515	251	2,420
1991	213	240	275	18	58	35	278	2,793	242	2,662
1992	295	332	292	18	66	37	304	3,097	261	2,923
1993	295	332	322	19	70	41	297	3,394	250	3,173
1994	295	332	354	21	77	45	292	3,686	240	3,413
1995	295	332	389	23	84	49	286	3,972	231	3,644
1996	377	424	428	26	93	54	309	4,281	246	3,890
1997	377	424	471	28	102	60	303	4,584	236	4,126
1998	377	424	518	30	113	66	299	4,883	228	4,354
1999	505	568	550	30	124	70	320	5,203	242	4,596
2000	505	568	605	31	136	77	314	5,517	232	4,828
2001	505	568	662	33	149	84				
...			...	..	...	..				
...			...	..	...	..				
...			...	..	...	..				
From 2001 to Infinity							3,850		2,230	
Total								9,367		7,058

Table 12-2(6) Present Worth Annual Costs of Diesel Alternative (Financial)

(1000 Eth$)

Addis Zemen

Year	Capital Costs Discount Rate 8 %	Capital Costs Discount Rate 10 %	Variable Costs Fuel oil	Variable Costs Lubricat.	Variable Costs O and M	Administration	Present Worth Costs Discount Rate 8 % Yearly	Present Worth Costs Discount Rate 8 % Cumulat.	Present Worth Costs Discount Rate 10 % Yearly	Present Worth Costs Discount Rate 10 % Cumulat.
1981										
1982	61	69	56	4	12	7	130	130	135	135
1983	61	69	125	8	25	15	201	331	200	335
1984	61	69	138	9	28	17	201	532	196	531
1985	61	69	152	10	31	19	201	733	192	723
1986	143	161	163	11	34	21	254	987	243	966
1987	143	161	180	12	37	23	249	1,236	233	1,199
1988	143	161	199	14	41	25	247	1,483	226	1,425
1989	143	161	220	15	46	28	245	1,728	220	1,645
1990	143	161	243	17	51	31	243	1,971	214	1,859
1991	143	161	267	19	56	34	241	2,212	207	2,066
1992	143	161	294	20	61	37	238	2,450	202	2,268
1993	225	253	312	20	67	40	264	2,714	221	2,489
1994	225	253	344	21	74	44	261	2,975	214	2,703
1995	225	253	378	23	82	48	258	3,233	207	2,910
1996	225	253	416	25	90	53	255	3,488	201	3,111
1997	225	253	457	27	99	58	253	3,741	196	3,307
1998	307	345	504	30	109	64	274	4,015	208	3,515
1999	307	345	554	33	120	70	272	4,287	202	3,717
2000	307	345	610	35	132	76	269	4,556	196	3,913
2001	388	439	642	35	144	82				
...			...	..	...	..				
...			...	..	...	..				
...			...	..	...	..				
From 2001 to Infinity							3,237		1,850	
Total								7,793		5,763

Table 12-2(7) Present Worth Annual Costs of Diesel Alternative (Financial)

(1000 Eth$)

Dangla

Year	Capital Costs Discount Rate 8 %	Capital Costs Discount Rate 10 %	Variable Costs Fuel oil	Variable Costs Lubricat.	Variable Costs O and M	Administration	Present Worth Costs Discount Rate 8 % Yearly	Present Worth Costs Discount Rate 8 % Cumulat.	Present Worth Costs Discount Rate 10 % Yearly	Present Worth Costs Discount Rate 10 % Cumulat.
1981										
1982	179	202	93	5	21	12	286	286	302	302
1983	179	202	178	9	41	22	368	654	374	676
1984	179	202	197	10	46	25	363	1,017	360	1,036
1985	179	202	217	11	51	28	358	1,375	348	1,384
1986	179	202	240	12	56	30	352	1,727	335	1,719
1987	261	294	266	14	62	34	402	2,129	378	2,097
1988	261	294	294	15	68	37	394	2,523	363	2,460
1989	261	294	324	17	76	41	389	2,912	350	2,810
1990	261	294	359	18	84	46	384	3,296	340	3,150
1991	261	294	394	20	92	50	379	3,675	328	3,478
1992	343	386	434	22	101	55	409	4,084	350	3,828
1993	343	386	477	25	112	61	404	4,488	338	4,166
1994	343	386	525	27	123	67	399	4,887	326	4,492
1995	471	530	577	29	135	74	438	5,325	354	4,846
1996	471	530	635	33	148	81	431	5,756	342	5,188
1997	471	530	699	36	163	89	425	6,181	329	5,517
1998	471	530	768	40	180	98	420	6,601	320	5,837
1999	471	530	845	44	198	108	417	7,018	310	6,147
2000	600	675	930	48	218	119	443	7,461	325	6,472
2001	600	675	1,017	52	238	130	436	7,897	314	6,786
2002	600	675	1,113	57	261	143	431	8,328	304	7,090
2003	792	892	1,172	63	285	152	453	8,781	315	7,405
2004	792	892	1,283	68	312	166	446	9,227	304	7,709
2005	792	892	1,403	75	341	181	440	9,667	294	8,003
2006	792	892	1,535	82	373	199	435	10,102	284	8,287
2007	1,094	1,180	1,758	94	411	226	484	10,586	304	8,591
2008			1,923	103	450	247	477	11,063	296	8,887
2009			2,104	112	492	270	471	11,534	286	9,173
2010			2,302	123	538	296	467	12,001	279	9,452
2011	1,306	1,469	2,519	134	589	324	483	12,484	286	9,738
2012			2,755	147	644	354	478	12,962	279	10,017
2013	1,738	1,903	3,014	161	705	388	510	13,472	290	10,307
2014			3,298	176	771	424	507	13,979	282	10,589
2015			3,608	193	844	464	499	14,478	273	10,862
2016			3,947	211	923	508	490	14,968	262	11,124
2017	2,077	2,336	4,318	231	1,010	555	507	15,475	270	11,394
2018			4,724	253	1,105	608	499	15,974	261	11,655
2019			5,050	270	1,181	650				
From 2019 to Infinity							6,112		2,560	
Total								22,086		14,215

Table 12-2(8) Present Worth Annual Costs of Diesel Alternative (Financial)

(1000 Eth$)

Injibara and Addis Kidame

Year	Capital Costs Discount Rate 8 %	Capital Costs Discount Rate 10 %	Variable Costs Fuel oil	Variable Costs Lubricat.	Variable Costs O and M	Administration	Present Worth Costs Discount Rate 8 % Yearly	Present Worth Costs Discount Rate 8 % Cumulat.	Present Worth Costs Discount Rate 10 % Yearly	Present Worth Costs Discount Rate 10 % Cumulat.
1981										
1982	41	46	52	4	11	6	106	106	109	109
1983	102	115	115	8	24	14	226	332	228	337
1984	102	115	128	9	27	16	224	556	222	559
1985	102	115	141	10	30	18	222	778	215	774
1986	102	115	156	11	33	20	219	997	208	982
1987	164	184	172	12	36	22	256	1,253	241	1,223
1988	164	184	190	13	40	24	252	1,505	232	1,455
1989	164	184	210	15	45	27	249	1,754	225	1,680
1990	164	184	233	16	50	30	247	2,001	218	1,898
1991	225	253	270	19	55	34	280	2,281	243	2,141
1992	225	253	282	20	60	36	267	2,548	228	2,369
1993	225	253	310	22	66	39	263	2,811	220	2,589
1994	225	253	341	24	73	43	259	3,070	212	2,801
1995	225	253	375	26	80	48	257	3,327	206	3,007
1996	307	345	399	29	88	51	276	3,603	218	3,225
1997	307	345	439	32	97	56	271	3,874	211	3,436
1998	307	345	483	35	106	62	269	4,143	204	3,640
1999	307	345	529	38	117	68	265	4,408	197	3,837
2000	388	437	564	38	129	73	276	4,684	203	4,040
2001	388	437	617	39	141	79	271	4,955	195	4,235
2002	388	437	676	42	154	87	267	5,222	189	4,424
2003	517	582	712	42	169	92	281	5,503	195	4,619
2004	517	582	779	43	185	100	276	5,779	188	4,807
2005	517	582	853	45	202	110	272	6,051	181	4,988
2006	517	582	933	47	221	120	269	6,320	178	5,166
2007			938	54	227	121	250	6,570	159	5,325
2008	645	725	991	56	235	128	256	6,826	162	5,487
2009			1,084	58	255	139	250	7,076	156	5,643
2010			1,186	64	279	152	248	7,324	151	5,794
2011	838	942	1,297	90	306	167	265	7,589	158	5,952
2012			1,419	76	335	183	262	7,851	153	6,105
2013			1,553	83	366	200	258	8,109	147	6,252
2014			1,699	91	401	219	253	8,362	144	6,396
2015	1,030	1,159	1,858	100	438	239	267	8,629	147	6,543
2016			2,033	110	479	262	262	8,891	141	6,684
2017			2,224	120	525	286	256	9,147	138	6,822
2018	1,223	1,376	2,435	131	574	314	266	9,413	140	6,962
2019			2,636	142	622	340				
From 2019 to Infinity							3,287		1,380	
Total								12,700		8,342

Table 12-2(9) Annual Costs of Existing Facilities (Financial)

(1000 Eth$) Bahar Dar

Year	Equalized Installements of Capital Costs										O and M	Total Costs	
	Discount Rate 8 %					Discount Rate 10 %							
	Initial Facilities			Replacement		Initial Facilities			Replacement				
	Power Station	Sub-station	Trans-mission	Power Station	Trans-former	Power Station	Sub-station	Trans-mission	Power Station	Trans-former		Discount 8 %	Discount 10 %
1981													
1982	233	16	8			271	18	9			156	413	454
1983	233	16	8			271	18	9			156	413	454
1984	233	16	8			271	18	9			156	413	454
1985	233	16	8			271	18	9			156	413	454
1986	233	16	8			271	18	9			156	413	454
1987	233	16	8			271	18	9			156	413	454
1988	233	16	8			271	18	9			156	413	454
1989	233	16	8	372		271	18	9	419		156	785	873
1990	233	16	8	372		271	18	9	419		156	785	873
1991	233	16	8	372		271	18	9	419		156	785	873
1992	233	16	8	372		271	18	9	419		156	785	873
1993	233	16	8	372		271	18	9	419		156	785	873
1994	233		8	372	92	271		9	419	100	156	861	955
1995	233		8	372	92	271		9	419	100	156	861	955
1996	233		8	372	92	271		9	419	100	156	861	955
1997	233		8	372	92	271		9	419	100	156	861	955
1998	233		8	372	92	271		9	419	100	156	861	955
2000	233		8	372	92	271		9	419	100	156	861	955
2001	233		8	372	92	271		9	419	100	156	861	955
2002	233		8	372	92	271		9	419	100	156	861	955
2003	233		8	372	92	271		9	419	100	156	861	955

Table 12-2(10) Present Worth Annual Costs of Diesel Alternative (Financial)

(1000 Eth$)

Bahar Dar (Case A)

Year	Annual Costs of Tis Abbay P.S. Discount 8 %	Annual Costs of Tis Abbay P.S. Discount 10 %	Capital Costs of Diesel P.S. Discount 8 %	Capital Costs of Diesel P.S. Discount 10 %	Variable Costs of Diesel P.S. Fuel oil	Variable Costs of Diesel P.S. Lubricat.	Variable Costs of Diesel P.S. O and M	Variable Costs of Diesel P.S. Administration	Present Worth Costs Discount Rate 8 % Yearly	Present Worth Costs Discount Rate 8 % Cumulat.	Present Worth Costs Discount Rate 10 % Yearly	Present Worth Costs Discount Rate 10 % Cumulat.
1981												
1982	413	454							383	383	413	413
1983	413	454							354	737	376	789
1984	413	454							328	1,065	341	1,130
1985	413	454							304	1,369	310	1,440
1986	413	454							281	1,650	282	11,722
1987	413	454							261	1,911	257	1,979
1988	413	454							241	2,152	233	2,212
1989	785	873							423	2,575	407	2,619
1990	785	873							392	2,967	370	2,989
1991	785	873	185	208	21	1	5	3	465	3,432	393	3,382
1992	785	873	185	208	59	3	14	8	452	3,884	408	3,790
1993	785	873	348	392	71	4	16	9	489	4,373	434	4,224
1994	861	955	348	485	104	5	24	13	498	4,871	458	4,682
1995	861	955	512	576	139	7	32	18	533	5,404	454	5,136
1996	861	955	512	576	168	9	39	21	507	5,911	422	5,558
1997	861	955	640	720	210	11	48	27	523	6,434	428	5,986
1998	861	955	640	720	256	14	59	33	503	6,937	401	6,387
1999	861	955	768	864	293	15	67	37	510	7,447	402	6,789
2000	861	955	768	864	349	18	80	44	489	7,936	377	7,166
2001	861	955	768	864	406	21	93	52	471	8,407	353	7,519
2002	861	955	1,154	1,298	450	24	103	57	524	8,931	390	7,909
2003	861	955	1,925	2,165	517	27	119	66	643	9,574	469	8,378
2004			1,925	2,165	7,329	384	1,749	946	2,090	11,664	1,403	9,781
2005			1,925	2,165	7,640	400	1,823	986	2,005	13,669	1,314	11,095
2006			2,696	3,032	7,980	419	1,904	1,030	2,048	15,717	1,324	12,419
2007			2,696	3,032	8,334	437	1,948	1,071	1,955	17,672	1,245	13,664
2008			2,696	3,032	8,705	456	1,993	1,115	1,870	19,542	1,162	14,826
2009			2,696	3,032	9,093	476	2,082	1,165	1,813	21,355	1,094	15,920
2010			2,696	3,032	9,497	498	2,175	1,217	1,725	23,080	1,034	16,954
2011			2,696	3,032	9,924	520	2,272	1,271				
...			...	...	...	...	...	...				
...			...	...	...	...	...	...				
...			...	...	...	...	...	...				
From 2011 to Infinity									20,713		9,750	
Total										43,793		26,704

Table 12-2(11) Present Worth Annual Costs of Diesel Alternative (Financial)

(1000 Eth$)

Bahar Dar (Case B)

Year	Annual Costs of Tis Abbay P.S.		Capital Costs of Diesel P.S.		Variable Costs of Diesel P.S.				Present Worth Costs			
	Discount 8 %	Discount 10 %	Discount 8 %	Discount 10 %	Fuel oil	Lubricat.	O and M	Administration	Discount Rate 8 % Yearly	Discount Rate 8 % Cumulat.	Discount Rate 10% Yearly	Discount Rate 10% Cumulat.
1981												
1982	413	454	514	578	174	9	40	22	1,084	1,084	1,160	1,160
1983	413	454	514	578	319	17	73	40	1,180	2,264	1,223	2,383
1984	413	454	514	578	330	17	76	42	1,103	3,367	1,124	3,507
1985	413	454	770	867	345	18	79	44	1,227	4,594	1,234	4,741
1986	413	454	770	867	362	19	83	46	1,151	5,745	1,136	5,877
1987	413	454	770	867	375	20	86	48	1,079	6,824	1,043	6,920
1988	413	454	770	867	395	21	91	50	1,014	7,838	963	7,883
1989	785	873	770	867	407	22	96	53	1,158	8,996	1,084	8,967
1990	785	873	770	867	437	23	100	56	1,086	10,082	999	9,966
1991	785	873	770	867	462	24	106	59	1,021	11,103	920	10,886
1992	785	873	770	867	488	26	112	62	962	12,065	863	11,749
1993	785	873	1,285	1,445	511	27	117	65	1,110	13,175	966	12,715
1994	861	955	1,285	1,445	544	29	125	69	1,069	14,244	887	13,602
1995	861	955	1,285	1,445	580	31	133	74	1,008	15,252	846	14,444
1996	861	955	1,285	1,445	608	32	140	78	947	16,199	778	15,226
1997	861	955	1,285	1,445	650	34	149	83	894	17,093	719	15,945
1998	861	955	1,285	1,445	697	37	160	89	845	17,938	666	16,611
1999	861	955	1,285	1,445	734	39	169	94	796	18,734	615	17,226
2000	861	955	1,670	1,879	789	42	181	101	846	19,580	643	17,869
2001	861	955	1,670	1,879	847	45	194	108	798	20,378	596	18,465
2002	861	955	1,670	1,879	890	47	204	114	750	21,128	552	19,017
2003	861	955	2,441	2,746	957	50	220	123	856	21,984	620	19,637
2004			2,441	2,746	7,329	384	1,749	946	2,188	24,174	1,467	21,104
2005			2,441	2,746	7,640	400	1,803	986	2,093	26,265	1,378	22,482
2006			2,441	2,746	7,918	417	1,825	1,018				
...			...	...	...	...	...	...				
...			...	...	...	...	...	...				
...			...	...	...	...	...	...				
From 2006 to Infinity									24,900		12,870	
Total										51,165		35,352

Table 12-3 (1) Present Worth Annual Costs of Diesel Alternative (Economic)

(1000 Eth$)

Gondar Area

Year	Capital Costs		Variable Costs			Admini-stration	Present Worth Costs			
	Discount Rate		Fuel oil	Lubricat.	O and M		Discount Rate 8 %		Discount Rate 10 %	
	8 %	10 %					Yearly	Cumulat.	Yearly	Cumulat.
1981										
1982	643	723	880	42	165	90	1,683	1,683	1,727	1,727
1983	643	723	1,056	50	198	109	1,761	3,444	1,764	3,491
1984	643	723	1,166	55	219	120	1,746	5,190	1,714	5,205
1985	643	723	1,289	61	241	133	1,739	6,929	1,671	6,876
1986	968	1,090	1,424	68	266	147	1,953	8,882	1,856	8,732
1987	968	1,090	1,574	74	295	162	1,935	10,817	1,801	10,533
1988	968	1,090	1,739	82	326	179	1,920	12,737	1,752	12,285
1989	968	1,090	1,922	91	360	198	1,911	14,648	1,706	13,991
1990	968	1,090	2,123	101	398	219	1,904	16,552	1,666	15,657
1991	1,374	1,546	2,336	111	438	241	2,083	18,635	1,798	17,455
1992	1,374	1,546	2,569	122	482	265	2,059	20,694	1,744	19,199
1993	1,374	1,546	3,827	134	530	291	2,046	22,740	1,694	20,893
1994	1,374	1,546	3,199	147	583	320	2,030	24,770	1,148	22,541
1995	1,780	2,002	3,420	162	641	353	2,161	26,931	1,730	24,271
1996	1,780	2,002	3,762	179	706	388	2,146	29,007	1,682	25,953
1997	1,780	2,002	4,139	196	777	427	2,129	31,206	1,636	27,589
1998	1,780	2,002	4,553	217	854	470	2,126	33,332	1,594	29,183
1999	2,592	2,917	4,910	237	940	509	2,297	35,629	1,702	30,885
2000	2,592	2,917	5,402	260	1,034	560	2,274	37,903	1,658	32,543
2001	2,592	2,917	5,402	260	1,034	560				
...	...	...	...	...	...	...				
...	...	...	...	...	...	...				
...	...	...	...	...	...	...				
From 2001 to Infinity							28,425		16,580	
Total								66,328		49,123

Table 12-3 (2) Present Worth Annual Costs of Diesel Alternative (Economic)

(1000 Eth$) Chewahit

Year	Capital Costs Discount Rate 8 %	Capital Costs Discount Rate 10 %	Variable Costs Fuel oil	Variable Costs Lubricat.	Variable Costs O and M	Admini-stration	Present Worth Costs Discount Rate 8 % Yearly	Discount Rate 8 % Cumulat.	Discount Rate 10 % Yearly	Discount Rate 10 % Cumulat.
1981										
1982	104	116	58	4	10	6	168	168	176	176
1983	104	116	128	8	20	13	233	401	235	411
1984	104	116	142	9	23	14	231	632	228	639
1985	104	116	156	10	25	16	228	860	220	859
1986	104	116	173	11	28	17	226	1,086	214	1,073
1987	181	204	191	12	31	19	273	1,359	247	1,330
1988	181	204	211	13	34	21	268	1,627	248	1,578
1989	181	204	233	14	37	23	263	1,890	238	1,816
1990	181	204	258	16	41	26	261	2,151	231	2,047
1991	181	204	283	17	45	29	256	2,407	222	2,269
1992	181	204	312	19	50	31	253	2,660	215	2,484
1993	258	291	343	21	55	35	282	2,942	236	2,720
1994	258	291	378	23	60	38	279	3,219	228	2,948
1995	258	291	415	25	67	42	274	3,493	220	3,168
1996	258	291	457	28	73	46	271	3,764	214	3,382
1997	363	407	486	31	80	50	293	4,057	228	3,610
1998	363	407	534	34	89	55	289	4,346	220	3,830
1999	363	407	587	37	97	60	285	4,631	212	4,042
2000	363	407	647	41	108	66	282	4,913	206	4,248
2001	363	407	707	45	118	73				
...	...	...	...	..	...	..				
...	...	...	...	..	...	..				
...	...	...	...	..	...	..				
From 2001 to Infinity							3,487		2,000	
Total								8,400		6,248

Table 12-3 (3) Present Worth Annual Costs of Diesel Alternative (Economic)

(1000 Eth$) Gorgora

Year	Capital Costs Discount Rate 8 %	Capital Costs Discount Rate 10 %	Variable Costs Fuel oil	Variable Costs Lubricat.	Variable Costs O and M	Admini-stration	Present Worth Costs Discount Rate 8 % Yearly	Present Worth Costs Discount Rate 8 % Cumulat.	Present Worth Costs Discount Rate 10 % Yearly	Present Worth Costs Discount Rate 10 % Cumulat.
1981										
1982	104	116	47	3	7	4	152	152	161	161
1983	104	116	103	6	16	10	204	356	208	269
1984	104	116	113	7	18	11	201	557	199	568
1985	104	116	125	8	20	12	198	755	192	760
1986	104	116	138	8	22	14	194	949	185	945
1987	181	204	152	9	24	15	240	1,189	227	1,172
1988	181	204	169	10	26	17	234	1,423	218	1,390
1989	181	204	187	11	30	18	230	1,653	210	1,600
1990	181	204	206	13	33	21	227	1,880	203	1,803
1991	181	204	227	14	36	23	222	2,102	194	1,997
1992	181	204	249	15	29	25	214	2,316	182	2,179
1993	258	291	275	17	43	28	247	2,563	208	2,387
1994	258	291	302	18	49	31	242	2,805	200	2,587
1995	258	291	332	20	53	34	236	3,041	192	2,779
1996	258	291	365	22	58	37	233	3,274	185	2,964
1997	362	407	388	24	65	39	255	3,529	200	3,164
1998	362	407	427	27	71	43	252	3,781	192	3,356
1999	362	407	470	29	77	48	246	4,027	185	3,541
2000	362	407	517	33	85	52	242	4,269	178	3,719
2001	362	407	565	36	93	57				
...	...	...	...	..	..	..				
...	...	...	...	..	..	..				
...	...	...	...	..	..	..				
From 2001 to Infinity							2,975		1,710	
Total								7,244		5,429

Table 12-3 (4) Present Worth Annual Costs of Diesel Alternative (Economic)

(1000 Eth$) Debre Tabor

Year	Capital Costs		Variable Costs			Administration	Present Worth Costs			
	Discount Rate		Fuel oil	Lubricat.	O and M		Discount Rate 8 %		Discount Rate 10 %	
	8 %	10 %					Yearly	Cumulat.	Yearly	Cumulat.
1981										
1982	164	186	115	9	22	12	298	298	313	313
1983	268	186	234	17	44	24	503	801	513	826
1984	268	186	259	18	49	27	492	1,293	491	1,317
1985	268	186	286	21	54	30	484	1,777	474	1,791
1986	268	186	316	23	60	33	478	2,253	456	2,247
1987	268	186	349	25	67	36	469	2,722	440	2,687
1988	268	186	386	28	74	40	464	3,186	426	3,113
1989	372	418	427	30	82	44	516	3,702	466	3,579
1990	372	418	472	34	90	49	509	4,211	450	4,029
1991	372	418	519	38	100	54	502	4,713	434	4,463
1992	372	418	571	41	109	60	494	5,207	419	4,882
1993	475	535	628	45	121	66	530	5,737	444	5,326
1994	475	535	691	50	132	72	521	6,258	428	5,754
1995	475	535	760	55	145	75	513	6,771	413	6,167
1996	689	771	836	61	160	83	576	7,347	457	6,624
1997	689	771	920	67	176	96	567	7,914	441	7,065
1998	689	771	1,012	73	194	106	560	8,474	424	7,489
1999	689	771	1,113	81	213	117	554	9,028	411	7,900
2000	889	1,000	1,224	89	234	128	592	9,620	436	8,336
2001	889	1,000	1,260	91	240	159				
...	...	...	...	..	...	...				
...	...	...	...	..	...	...				
...	...	...	...	..	...	...				
From 2001 to Infinity							7,075		4,080	
Total								16,695		12,416

Table 12-3 (5) Present Worth Annual Costs of Diesel Alternative (Economic)

(1000 Eth$) Wereta

Year	Capital Costs Discount Rate 8 %	Capital Costs Discount Rate 10 %	Variable Costs Fuel oil	Variable Costs Lubricat.	Variable Costs O and M	Admini-stration	Present Worth Costs Discount Rate 8 % Yearly	Present Worth Costs Discount Rate 8 % Cumulat.	Present Worth Costs Discount Rate 10 % Yearly	Present Worth Costs Discount Rate 10 % Cumulat.
1981										
1982	166	187	80	5	14	8	253	253	267	267
1983	166	187	159	11	28	16	326	579	332	599
1984	166	187	175	12	31	18	319	898	318	917
1985	269	303	188	14	34	19	385	1,283	381	1,298
1986	269	303	208	15	37	21	374	1,657	362	1,660
1987	269	303	230	16	41	23	264	1,921	346	2,006
1988	269	303	254	17	46	26	357	2,278	332	2,338
1989	269	303	280	19	51	29	350	2,628	318	2,656
1990	269	303	309	21	56	32	344	2,972	306	2,962
1991	269	303	340	22	61	35	337	3,309	293	3,255
1992	373	420	362	22	70	37	370	3,679	319	3,574
1993	373	420	398	23	74	41	361	4,040	304	3,878
1994	373	420	438	25	82	45	353	4,393	292	4,170
1995	373	420	481	28	89	49	347	4,740	281	4,451
1996	477	536	530	31	98	54	375	5,115	299	4,750
1997	477	536	583	34	108	60	368	5,483	287	5,037
1998	477	536	641	37	120	60	363	5,846	276	5,313
1999	638	718	680	37	131	70	389	6,235	293	5,606
2000	638	718	748	38	144	77	380	6,615	281	5,887
2001	638	718	818	41	158	84				
...	...	...	...	..	...	..				
...	...	...	...	..	...	..				
...	...	...	...	..	...	..				
From 2001 to Infinity							4,662		2,700	
Total								11,277		8,587

Table 12-3 (6) Present Worth Annual Costs of Diesel Alternative (Economic)

(1000 Eth$)

Addis Zemen

Year	Capital Costs		Variable Costs			Admini-stration	Present Worth Costs			
	Discount Rate		Fuel oil	Lubricat.	O and M		Discount Rate 8 %		Discount Rate 10 %	
	8 %	10 %					Yearly	Cumulat.	Yearly	Cumulat.
1981										
1982	77	87	70	5	13	7	159	159	165	165
1983	77	87	155	10	26	15	243	402	243	408
1984	77	87	172	11	30	17	243	645	239	647
1985	77	87	189	12	33	19	242	887	232	879
1986	181	204	202	14	36	21	309	1,196	296	1,175
1987	181	204	223	15	39	23	303	1,499	284	1,459
1988	181	204	247	17	43	25	299	1,798	275	1,734
1989	181	204	272	18	49	28	296	2,094	266	2,000
1990	181	204	302	21	54	31	295	2,389	260	2,260
1991	181	204	332	23	59	34	292	2,681	251	2,511
1992	181	204	364	25	65	37	288	2,969	243	2,754
1993	284	320	388	25	71	40	321	3,290	269	3,023
1994	284	320	426	26	78	44	314	3,604	258	3,281
1995	284	320	469	28	87	48	312	3,916	250	3,531
1996	284	320	516	31	95	53	308	4,224	242	3,773
1997	284	320	568	33	105	58	305	4,529	236	4,009
1998	388	436	625	37	115	64	332	4,861	252	4,261
1999	388	436	687	41	127	70	328	5,189	244	4,505
2000	388	436	755	43	140	76	323	5,512	237	4,742
2001	490	552	796	44	152	82				
...	...	...	...	..	...	..				
...	...	...	...	..	...	..				
...	...	...	...	..	...	..				
From 2001 to Infinity							4,187		2,410	
Total								9,699		7,152

Table 12-3(7) Present Worth Annual Costs of Diesel Alternative (Economic)

(1000 Eth$) Dangla

Year	Capital Costs Discount Rate 8%	Capital Costs Discount Rate 10%	Variable Costs Fuel oil	Variable Costs Lubricat.	Variable Costs O and M	Administration	Present Worth Costs Discount Rate 8% Yearly	Present Worth Costs Discount Rate 8% Cumulat.	Present Worth Costs Discount Rate 10% Yearly	Present Worth Costs Discount Rate 10% Cumulat.
1981										
1982	226	255	115	6	22	12	352	352	373	373
1983	226	255	221	11	43	22	448	800	455	828
1984	226	255	244	12	49	25	440	1,240	439	1,267
1985	226	255	270	14	54	28	435	1,675	424	1,691
1986	226	255	298	15	59	30	427	2,102	407	2,098
1987	330	372	329	17	66	34	489	2,591	461	2,559
1988	330	372	364	18	72	37	479	3,070	443	3,002
1989	330	372	403	21	80	41	472	3,542	428	3,430
1990	330	372	445	22	89	46	466	4,008	413	3,843
1991	330	372	489	25	97	50	459	4,467	398	4,241
1992	434	488	538	27	107	55	497	4,967	425	4,666
1993	434	488	592	31	119	61	491	5,455	411	5,077
1994	434	488	651	33	130	67	483	5,938	396	5,473
1995	595	670	716	36	143	74	532	6,470	431	5,904
1996	595	670	768	41	157	81	523	6,993	416	6,320
1997	595	670	867	44	173	89	516	7,509	400	6,720
1998	595	670	954	49	191	98	510	8,019	398	7,108
1999	595	670	1,049	54	210	108	504	8,523	374	7,482
2000	758	853	1,154	59	231	119	538	9,061	395	7,877
2001	758	853	1,263	64	252	130	529	9,590	381	8,258
2002	758	853	1,382	70	276	143	522	10,112	368	8,626
2003	1,001	1,127	1,454	78	302	152	549	10,661	382	9,008
2004	1,001	1,127	1,591	84	330	166	540	11,201	368	9,376
2005	1,001	1,127	1,741	92	361	181	532	11,733	356	9,732
2006	1,001	1,127	1,905	101	395	199	526	12,259	344	10,076
2007	1,382	1,491	2,184	116	453	226	589	12,848	375	10,451
2008	1,382	1,491	2,383	127	496	247	579	13,427	361	10,812
2009	1,382	1,491	2,613	139	543	270	573	14,000	350	11,162
2010	1,382	1,491	2,859	152	594	296	565	14,565	339	11,501
2011	1,650	1,855	3,128	166	650	324	587	15,152	350	11,851
2012	1,650	1,855	3,422	182	711	354	581	15,733	339	12,190
2013	2,196	2,405	3,744	199	777	388	620	16,353	355	12,545
2014	2,196	2,405	4,090	217	851	424	613	16,966	343	12,858
2015	2,196	2,405	4,481	238	931	464	606	17,572	333	13,221
2016	2,196	2,405	4,902	260	1,018	508	600	18,172	322	13,543
2017	2,625	2,952	5,363	285	1,114	555	616	18,788	328	13,871
2018	2,625	2,952	5,867	312	1,219	608	615	19,403	322	14,193
2019	2,625	2,952	6,272	333	1,303	650				
From 2019 to Infinity							7,487		3,030	
Total								26,890		17,223

Table 12-3 (8) Present Worth Annual Costs of Diesel Alternative (Economic)

(1000 Eth$)

Injibara and Addis Kidame

Year	Capital Costs Discount Rate 8%	Capital Costs Discount Rate 10%	Variable Costs Fuel oil	Variable Costs Lubricat.	Variable Costs O and M	Administration	Present Worth Costs Discount Rate 8% Yearly	Present Worth Costs Discount Rate 8% Cumulat.	Present Worth Costs Discount Rate 10% Yearly	Present Worth Costs Discount Rate 10% Cumulat.
1981										
1982	52	58	65	5	12	6	130	130	133	133
1983	129	145	144	10	25	14	276	406	279	412
1984	129	145	159	11	29	16	273	679	270	682
1985	129	145	176	12	32	18	270	949	262	944
1986	129	145	194	13	35	20	266	1,215	252	1,196
1987	207	233	215	14	38	22	313	1,528	294	1,490
1988	207	233	237	16	42	24	307	1,835	283	1,773
1989	207	233	262	18	47	27	303	2,138	273	2,046
1990	207	233	289	20	53	30	300	2,438	265	2,311
1991	284	320	336	23	58	34	340	2,778	297	2,608
1992	284	320	350	24	64	36	325	3,103	278	2,886
1993	284	320	385	27	70	39	320	3,423	267	3,153
1994	284	320	424	29	77	43	315	3,738	258	3,411
1995	284	320	467	32	85	48	311	4,049	250	3,661
1996	388	436	496	36	93	51	335	4,384	266	3,927
1997	388	436	545	39	103	56	329	4,713	256	4,183
1998	388	436	600	43	112	62	325	5,038	248	4,431
1999	388	436	660	47	124	68	322	5,360	239	4,670
2000	490	552	701	47	137	73	335	5,695	247	4,917
2001	490	552	767	48	149	79	328	6,023	237	5,154
2002	490	552	839	52	163	87	323	6,346	228	5,382
2003	653	736	885	52	179	92	342	6,688	237	5,619
2004	653	736	968	53	196	100	335	7,023	229	5,848
2005	653	736	1,059	55	214	110	330	7,353	221	6,069
2006	653	736	1,159	60	234	120	325	7,678	213	6,282
2007	653	736	1,165	63	243	121	303	7,981	195	6,477
2008	815	916	1,227	66	258	128	311	8,292	197	6,674
2009	815	916	1,343	72	282	139	304	8,596	190	6,864
2010	815	916	1,469	79	308	152	302	8,898	184	7,048
2011	1,059	1,190	1,607	86	337	167	323	9,221	194	7,242
2012	1,059	1,190	1,758	94	369	183	318	9,539	186	7,428
2013	1,059	1,190	1,923	103	404	200	314	9,853	181	7,609
2014	1,059	1,190	2,104	113	442	219	310	10,163	174	7,783
2015	1,301	1,464	2,302	123	483	239	324	10,487	180	7,963
2016	1,301	1,464	2,519	135	529	262	320	10,807	174	8,137
2017	1,301	1,464	2,755	148	579	286	318	11,125	169	8,306
2018	1,545	1,739	3,014	162	633	314	328	11,453	172	8,478
2019	1,545	1,739	3,266	175	686	340				
From 2019 to Infinity							4,025		1,660	
Total								15,478		10,138

Table 12-3 (9) Annual Costs of Existing Facilities (Economic)

(1000 Eth$) Bahar Dar

Year	Equalized Installements of Capital Cost										O and M	Total Costs	
	Discount Rate 8%					Discount Rate 10%							
	Initial Facilities			Replacement		Initial Facilities			Replacement			Discount 8%	Discount 10%
	Power Station	Sub-station	Trans-mission	Power Station	Trans-former	Power Station	Sub-station	Trans-mission	Power Station	Trans-former			
1981													
1982	233	16	8			271	18	9			167	424	465
1983	233	16	8			271	18	9			167	424	465
1984	233	16	8			271	18	9			167	424	465
1985	233	16	8			271	18	9			167	424	465
1986	233	16	8			271	18	9			167	424	465
1987	233	16	8			271	18	9			167	424	465
1988	233	16	8			271	18	9			167	424	465
1989	233	16	8	458		271	18	9	515		167	882	980
1990	233	16	8	458		271	18	9	515		167	882	980
1991	233	16	8	458		271	18	9	515		167	882	980
1992	233	16	8	458		271	18	9	515		167	882	980
1993	233	16	8	458		271	18	9	515		167	882	980
1994	233		8	458	113	271		9	515	123	167	979	1,085
1995	233		8	458	113	271		9	515	123	167	979	1,085
1996	233		8	458	113	271		9	515	123	167	979	1,085
1997	233		8	458	113	271		9	515	123	167	979	1,085
1998	233		8	458	113	271		9	515	123	167	979	1,085
1999	233		8	458	113	271		9	515	123	167	979	1,085
2000	233		8	458	113	271		9	515	123	167	979	1,085
2001	233		8	458	113	271		9	515	123	167	979	1,085
2002	233		8	458	113	271		9	515	123	167	979	1,085
2003	233		8	458	113	271		9	515	123	167	979	1,085

Table 12-3(10). Present Worth Annual Costs of Diesel Alternative (Economic)

(1000 Eth$) Bahar Dar (Case A)

Year	Annual Costs of Tis Abbay P.S.		Capital Costs of Diesel P.S.		Variable Costs of Diesel P.S.				Present Worth Costs			
	Discount 8%	Discount 10%	Discount 8%	Discount 10%	Fuel oil	Lubricat.	O and M	Administration	Discount Rate 8% Yearly	Discount Rate 8% Cumulat.	Discount Rate 10% Yearly	Discount Rate 10% Cumulat.
1981												
1982	424	465							392	392	422	422
1983	424	465							363	755	385	807
1984	421	465							336	1,091	350	1,157
1985	424	465							311	1,402	318	1,475
1986	424	465							289	1,691	288	1,763
1987	424	465							267	1,958	263	2,026
1988	424	465							247	2,205	239	2,265
1989	882	980							476	2,681	457	2,722
1990	882	980							441	3,122	416	3,138
1991	882	980	233	263	26	1	6	3	533	3,655	492	3,630
1992	882	980	233	263	73	4	15	8	520	4,175	470	4,100
1993	882	980	440	495	88	5	18	9	573	4,748	508	4,608
1994	979	1,085	440	613	129	6	26	13	585	5,333	541	5,149
1995	979	1,085	647	728	172	9	35	18	632	5,965	539	5,688
1996	979	1,085	647	728	208	11	43	21	601	6,566	501	6,189
1997	979	1,085	808	910	260	14	53	27	623	7,189	510	6,699
1998	979	1,085	808	910	317	17	65	33	600	7,789	478	7,177
1999	979	1,085	970	1,092	363	18	74	37	610	8,399	478	7,655
2000	979	1,085	970	1,092	432	22	88	44	586	8,985	450	8,105
2001	979	1,085	970	1,092	503	26	103	52	563	9,548	424	8,529
2002	979	1,085	1,458	1,640	558	30	113	57	633	10,181	470	8,999
2003	979	1,085	2,433	2,736	641	33	131	66	784	10,965	577	9,576
2004			2,433	2,736	9,078	468	1,851	946	2,511	13,476	1,682	11,258
2005			2,433	2,736	9,463	487	1,930	986	2,402	15,878	1,584	12,842
2006			3,407	3,832	9,884	509	2,016	1,030	2,460	18,338	1,592	14,434
2007			3,407	3,832	10,323	589	2,105	1,296	2,386	20,724	1,520	15,954
2008			3,407	3,832	10,783	563	2,199	1,354	2,289	23,013	1,424	17,378
2009			3,407	3,832	11,263	588	2,297	1,414	2,200	25,213	1,338	18,716
2010			3,407	3,832	11,764	614	2,399	1,477	2,104	27,317	1,265	19,981
2011			3,407	3,832	12,292	641	2,507	1,544				
....			...	...	...	...	...	...				
....			...	...	...	...	...	...				
From 2011 to Infinity									25,237		11,960	
Total										52,554		31,941

Table 12-3(11) Present Worth Annual Costs of Diesel Alternative (Economic)

(1000 Eth$) — Bahar Dar (Case B)

Year	Annual Costs of Tis Abbay P.S.		Capital Costs of Diesel P.S.		Variable Costs of Diesel P.S.				Present Worth Costs			
	Discount 8%	Discount 10%	Discount 8%	Discount 10%	Fuel oil	Lubricat.	O and M	Admini-stration	Discount Rate 8% Yearly	Discount Rate 8% Cumulat.	Discount Rate 10% Yearly	Discount Rate 10% Cumulat.
1981												
1982	424	465	649	730	216	11	44	27	1,269	1,269	1,357	1,357
1983	424	465	649	730	396	21	81	50	1,389	2,658	1,440	2,797
1984	424	465	649	730	409	21	84	51	1,299	3,957	1,321	4,118
1985	424	465	973	1,096	428	22	87	54	1,482	5,439	1,470	5,588
1986	424	465	973	1,096	449	23	92	56	1,371	6,810	1,352	6,940
1987	424	465	973	1,096	465	25	95	59	1,286	8,096	1,243	8,183
1988	424	465	973	1,096	490	26	100	61	1,209	9,305	1,148	9,331
1989	882	980	973	1,096	517	27	106	65	1,388	10,693	1,300	10,631
1990	882	980	973	1,096	542	28	110	68	1,302	11,995	1,197	11,828
1991	882	980	973	1,096	573	30	117	72	1,226	13,221	1,104	12,932
1992	882	980	973	1,096	605	32	124	76	1,152	14,373	1,020	13,952
1993	882	980	1,624	1,826	633	33	129	80	1,342	15,715	1,170	15,122
1994	979	1,085	1,624	1,826	675	36	138	84	1,298	17,013	1,111	16,233
1995	979	1,085	1,624	1,826	719	38	147	90	1,223	18,236	1,027	17,260
1996	979	1,085	1,624	1,826	753	39	154	95	1,148	19,384	945	18,205
1997	979	1,085	1,624	1,826	806	42	164	101	1,081	20,465	873	19,078
1998	979	1,085	1,624	1,826	864	46	176	109	1,025	21,490	810	19,888
1999	979	1,085	1,624	1,826	910	48	186	114	966	22,456	746	20,634
2000	979	1,085	2,110	2,375	978	52	200	123	1,026	23,482	787	21,421
2001	979	1,085	2,110	2,375	1,050	55	214	132	973	24,455	727	22,148
2002	979	1,085	2,110	2,373	1,104	58	225	139	913	25,368	673	22,821
2003	979	1,085	3,085	3,470	1,187	62	243	150	1,044	26,412	760	23,581
2004			3,085	3,470	9,077	468	1,851	946	2,623	29,035	1,764	25,345
2005			3,085	3,470	9,462	488	1,930	986	2,504	31,539	1,658	27,003
2006			3,085	3,470	9,845	514	2,008	1,236				
....					...	...	...	...				
....					...	...	...	...				
From 2006 to Infinity									30,450		15,740	
Total										61,989		42,743

Table 12-4 Summary of Present Worth Cumulated Costs of Diesel Alternative

(1000 Eth$) Whole Project Area

Year	Financial Costs				Economic Costs			
	Discount 8%		Discount 10%		Discount 8%		Discount 10%	
	Case A	Case B	Case A	Case B	Case A	Case B	Case A	Case B
1981								
1982	3,010	3,711	3,133	3,880	3,587	4,464	3,737	4,672
1983	6,665	8,192	6,831	8,425	7,944	9,847	8,051	10,041
1984	10,261	12,563	10,393	12,770	12,225	15,091	12,399	15,360
1985	13,863	17,088	13,889	17,190	16,517	20,554	16,573	20,684
1986	17,640	21,733	17,100	21,655	21,031	26,150	20,489	26,066
1987	21,527	26,440	21,151	26,092	25,584	31,722	25,262	31,419
1988	25,353	31,039	24,667	30,338	30,159	37,259	29,478	36,544
1989	29,554	35,793	28,304	34,652	34,976	42,988	33,840	41,749
1990	33,335	40,450	31,815	38,792	39,723	48,596	38,050	46,740
1991	37,522	45,193	35,426	42,930	44,747	54,313	42,429	51,731
1992	41,711	49,892	39,007	46,966	49,767	59,965	46,724	56,576
1993	46,079	54,881	42,632	51,323	54,938	65,905	51,065	61,579
1994	50,281	59,651	46,185	55,105	60,058	71,738	55,314	66,398
1995	54,689	64,537	49,767	59,079	65,376	77,647	59,620	71,192
1996	59,139	69,430	53,295	62,963	70,674	83,492	63,882	75,862
1997	63,621	74,286	56,783	66,742	76,129	89,405	68,076	80,455
1998	68,078	79,076	60,175	70,398	81,486	95,187	72,148	84,859
1999	72,679	83,966	63,622	74,059	87,021	101,078	76,286	89,265
2000	77,302	88,946	67,022	77,725	92,573	107,070	80,374	93,690
....								
....								
From 2001 to Infinity	100,547	96,275	55,953	53,898	121,992	116,930	67,883	65,369
Total	177,849	185,221	122,975	131,623	214,565	224,000	148,257	159,059

Note : In case A, the power demand of electric boilers (Textile Mills S.C.) is assumed to be supplied always in off-peak hours of the power system.
In case B, peak load of electric boilers is assumed to be met in peak hours of the power system.

Table 12-5 Adjusted Capital Costs and Capitalized Costs of Operation and Maintenance of Transmission Alternative

Item	Economic service life (year)	Construction period (year)	Cost components (%) Foreign Currency	Cost components (%) Domestic Currency	Conversion factor	Investment Costs (1000 Eth$)	Financial Capital Costs (1000 Eth$): Capital Costs Discount 8%	Capital Costs Discount 10%	Adjusted Capital Costs Discount 8%	Adjusted Capital Costs Discount 10%	Economic Capital Costs (1000 Eth$): Capital Costs Discount 8%	Capital Costs Discount 10%	Adjusted Capital Costs Discount 8%	Adjusted Capital Costs Discount 10%
Initial Installation														
· Regulating dam	50	3	60	40	1.198	10,174	11,150	11,395	11,150	11,395	13,357	13,651	13,357	13,651
· No.3 Turbin-generator	25	2.3	87	13	1.287	4,238	4,550	4,629	4,550	4,629	5,855	5,957	5,855	5,957
· No.2 Power Station	40	3	72	28	1.237	12,052	13,209	13,498	13,209	13,498	16,339	16,697	16,339	16,697
· Transmission lines	25	2.5	55	45	1.182	12,526	13,528	13,778	15,841	15,183	15,990	16,285	18,724	17,946
· Substations, telecommunicat.	30	1.5	80	20	1.264	4,310	4,516	4,568	5,012	4,846	5,708	5,773	6,335	6,125
· 15kV distribution lines	25	1.5	40	60	1.132	1,151	1,206	1,220	7,412	1,344	1,365	1,381	1,598	1,521
Replacement of Existing Facil.														
· Power Station	25	1.5	80	20	1.264	3,186	3,338	3,377	3,908	3,721	4,219	4,268	4,939	4,703
· Substation	30	1.5	80	20	1.264	616	645	652	715	691	815	824	903	873
· Transmission line	50	1.5	80	20	1.264	1,071	1,122	1,135	1,145	1,145	1,418	1,434	1,446	1,446
Transformer Addition		1.5	78	22	1.257	3,786	3,990	4,043	4,429	4,289	5,015	5,082	5,567	5,392

Item	Capitalization (year)	Cost components (%) Foreign Currency	Cost components (%) Domestic Currency	Conversion factor	Base Costs (1000 Eth$)	Capitalized Costs (Fin.) (1000 Eth$) Discount 8%	Capitalized Costs (Fin.) Discount 10%	Capitalized Costs (Eco.) (1000 Eth$) Discount 8%	Capitalized Costs (Eco.) Discount 10%
Operation and Maintenance									
(A) Existing Facilities									
· Tis Abbay Power Station	22	21	79	1.069	140	1,428	1,228	1,526	1,313
· Bahar Dar Substation	Infinity	21	79	1.069	15	187	150	200	160
· 45kV transmission line	Infinity	21	79	1.069	1	13	10	14	11
(B) New Facilities									
· Regulating dam	50	21	79	1.069	203	2,483	2,013	2,654	2,152
· No.3 Turbin-generator	22	21	79	1.069	85	867	746	927	797
· No.2 Power Station	40	21	79	1.069	241	2,861	2,347	3,058	2,509
· Transmission lines	Infinity	21	79	1.069	313	3,912	3,130	4,175	3,340
· Substations, telecommunicat.	Infinity	21	79	1.069	108	1,350	1,080	1,437	1,150
· 15kV distribution lines	Infinity	21	79	1.069	28	350	280	374	299
Transformer Addition	Infinity	21	79	1.069	95	1,187	950	1,269	1,016

Table 12-6 (1) Present Worth Capital Costs of Transmission Alternative from Year of Conversion (Financial)

(1000 Eth$) Discount Rate : 8%

Year of Conversion	Initial Capital Costs		Cost Components											Cost from Year of Conversion	
			Dam, transmission, etc. (1)	No. 3 Turbin-generat.		No. 2 Power Station		Transformer Addition	Replacement of Existing Facil.			Total			
	Case A	Case B		Case A	Case B	Case A	Case B		Power Station	Substation	Transmission	Case A	Case B	Case A	Case B
1981															
1982	33,415	37,965	33,415	4,208	4,550	9,708	12,218	2,214	2,278	283	98	52,204	55,056	52,204	55,056
1983	37,965	51,174	33,415	4,550	4,550	10,474	13,209	2,301	2,462	306	105	53,703	56,438	49,723	52,255
1984	37,965	51,174	33,415	4,550	4,550	11,320	13,209	2,582	2,657	331	113	54,968	56,857	47,126	48,744
1985	37,965	51,174	33,415	4,550	4,550	12,218	13,209	2,790	2,872	357	122	56,324	57,315	44,709	45,450
1986	51,174	51,174	33,415	4,550	4,550	13,209	13,209	3,011	3,099	386	132	57,802	57,802	42,484	42,484
1987	51,174	51,174	33,415	4,550	4,550	13,209	13,209	3,255	3,349	416	143	58,337	58,337	39,669	39,669
1988	51,174	51,174	33,415	4,550	4,550	13,209	13,209	3,512	3,614	450	154	58,904	58,904	37,110	37,110
1989	55,082	55,082	33,415	4,550	4,550	13,209	13,209	3,795	3,908	486	167	59,530	59,530	34,706	34,706
1990	55,082	55,082	33,415	4,550	4,550	13,209	13,209	4,096	3,908	525	180	59,883	59,883	32,336	32,336
1991	59,511	59,511	33,415	4,550	4,550	13,209	13,209	4,429	3,908	567	195	60,273	60,273	30,149	30,149
1992	59,511	59,511	33,415	4,550	4,550	13,209	13,209	4,429	3,908	612	210	60,333	60,333	27,935	27,935
1993	59,511	59,511	33,415	4,550	4,550	13,209	13,209	4,429	3,908	661	227	60,399	60,399	25,899	25,899
1994	60,226	60,226	33,415	4,550	4,550	13,209	13,209	4,429	3,908	715	245	60,471	60,471	24,013	24,013
1995	60,226	60,226	33,415	4,550	4,550	13,209	13,209	4,429	3,908	715	265	60,491	60,491	22,236	22,236
1996	60,226	60,226	33,415	4,550	4,550	13,209	13,209	4,429	3,908	715	286	60,512	60,512	20,598	20,598
1997	60,226	60,226	33,415	4,550	4,550	13,209	13,209	4,429	3,908	715	309	60,535	60,535	19,080	19,080
1998	60,226	60,226	33,415	4,550	4,550	13,209	13,209	4,429	3,908	715	334	60,560	60,560	17,671	17,671
1999	60,226	60,226	33,415	4,550	4,550	13,209	13,209	4,429	3,908	715	360	60,586	60,586	16,376	16,376
2000	60,226	60,226	33,415	4,550	4,550	13,209	13,209	4,429	3,908	715	389	60,615	60,615	15,165	15,165
2001	60,226	60,226	33,415	4,550	4,550	13,209	13,209	4,429	3,908	715	421	60,647	60,647	14,051	14,051
2002	60,226	60,226	33,415	4,550	4,550	13,209	13,209	4,429	3,908	715	454	60,680	60,680	13,016	13,016
2003	60,226	60,226	33,415	4,550	4,550	13,209	13,209	4,429	3,908	715	491	60 717	60,717	12,058	12,058
2004	60,226	60,226	33,415			13,209	13,209	4,429		715	530	52,298	52,298	9,617	9,617
2005	60,226	60,226	33,415			13,209	13,209	4,429		715	572	52,329	52,329	8,911	8,911
2006	60,226	60,226	33,415			13,209	13,209	4,429		715	618	52,386	52,386	8,256	8,256
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2014	61,371	61,371	33,415			13,209	13,209	4,429		715	1,145	52,953	52,953	4,511	4,511

Notes : (1) ... Regulating dam Eth$ 11,150,000
Transmission lines Eth$ 15,841,000
Substations Eth$ 5,012,000
15kV distribution lines Eth$ 1,412,000
Total Eth$ 33,415,000

Table 12-6(2) Present Worth Capital Costs of Transmission Alternative from Year of Conversion (Financial)

(1000 Eth$) Discount Rate : 10%

Year of Conversion	Initial Capital Costs		Cost Components												Cost from Year of Conversion	
			Dam, transmission, etc. (1)	No. 3 Turbin generat.		No. 2 Power Station		Transformer Addition	Replacement of Existing Facil.			Total			
	Case A	Case B		Case A	Case B	Case A	Case B		Power Station	Sub-station	Trans-mission	Case A	Case B	Case A	Case B
1981															
1982	32,768	37,397	32,768	4,208	4,629	9,219	12,270	1,818	1,909	220	54	50,196	53,668	50,196	53,668
1983	37,397	50,895	32,768	4,629	4,629	10,141	13,498	2,000	2,100	242	59	51,939	55,276	47,217	50,269
1984	37,397	50,895	32,768	4,629	4,629	11,155	13,498	2,200	2,310	266	65	53,393	55,736	44,103	46,037
1985	37,397	50,895	32,768	4,629	4,629	12,270	13,498	2,421	2,541	293	72	54,994	56,224	41,300	42,224
1986	50,895	50,895	32,768	4,629	4,629	13,498	13,498	2,663	2,795	322	79	56,754	56,754	38,762	38,762
1987	50,895	50,895	32,768	4,629	4,629	13,498	13,498	2,929	3,075	354	87	57,340	57,340	35,551	35,551
1988	50,895	50,895	32,768	4,629	4,629	13,498	13,498	3,222	3,382	390	96	57,985	57,985	32,703	32,703
1989	54,616	54,616	32,768	4,629	4,629	13,498	13,498	3,544	3,721	429	105	58,694	58,694	30,110	30,110
1990	54,616	54,616	32,768	4,629	4,629	13,498	13,498	3,899	3,721	471	116	59,102	59,102	27,541	27,541
1991	58,905	58,905	32,768	4,629	4,629	13,498	13,498	4,289	3,721	519	127	59,551	59,551	25,250	25,250
1992	58,905	58,905	32,768	4,629	4,629	13,498	13,498	4,289	3,721	571	140	59,616	59,616	22,952	22,952
1993	58,905	58,905	32,768	4,629	4,629	13,498	13,498	4,289	3,721	628	154	59,687	59,687	20,890	20,890
1994	59,596	59,596	32,768	4,629	4,629	13,498	13,498	4,289	3,721	691	170	59,766	59,766	19,041	19,041
1995	59,596	59,596	32,768	4,629	4,629	13,498	13,498	4,289	3,721	691	187	59,783	59,783	17,313	17,313
1996	59,596	59,596	32,768	4,629	4,629	13,498	13,498	4,289	3,721	691	206	59,802	59,802	15,745	15,745
1997	59,596	59,596	32,768	4,629	4,629	13,498	13,498	4,289	3,721	691	226	59,822	59,822	14,315	14,315
1998	59,596	59,596	32,768	4,629	4,629	13,498	13,498	4,289	3,721	691	249	59,845	59,845	13,022	13,022
1999	59,596	59,596	32,768	4,629	4,629	13,498	13,498	4,289	3,721	691	274	59,870	59,870	11,842	11,842
2000	59,596	59,596	32,768	4,629	4,629	13,498	13,498	4,289	3,721	691	301	59,897	59,897	10,769	10,769
2001	59,596	59,596	32,768	4,629	4,629	13,498	13,498	4,289	3,721	691	331	59,927	59,927	9,798	9,798
2002	59,596	59,596	32,768	4,629	4,629	13,498	13,498	4,289	3,721	691	364	59,960	59,960	8,910	8,910
2003	59,596	59,596	32,768	4,629	4,629	13,498	13,498	4,289	3,721	691	401	59,997	59,997	8,106	8,106
2004	59,596	59,596	32,768			13,498	13,498	4,289		691	441	51,687	51,687	6,347	6,347
2005	59,596	59,596	32,768			13,498	13,498	4,289		691	485	51,731	51,731	5,773	5,773
2006	59,596	59,596	32,768			13,498	13,498	4,289		691	534	51,780	51,780	5,255	5,255
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2014	60,741	60,741	32,768			13,498	13,498	4,289		691	1,145	52,391	52,391	2,478	2,478

Notes : (1) ...

Regulating dam	Eth$	11,395,000
Transmission lines	Eth$	15,183,000
Substations	Eth$	4,846,000
15 kV distribution lines	Eth$	1,344,000
Total	Eth$	32,768,000

Table 12-6 (3) Present Worth Capital Costs of Transmission Alternative from Year of Conversion (Economic)

(1000 Eth$) Discount Rate : 8%

Year of Conversion	Initial Capital Costs		Cost Components												Cost from Year of Conversion	
			Dam, transmission etc. (1)	No. 3 Turbin-generat.		No. 2 Power Station		Trans-former Addition	Replacement of Existing Facil.			Total			
	Case A	Case B		Case A	Case B	Case A	Case B		Power Station	Sub-station	Trans-mission	Case A	Case B	Case A	Case B
1981															
1982	40,014	45,869	40,014	5,421	5,855	12,009	15,128	2,784	2,881	358	133	63,600	67,153	63,600	67,153
1983	45,869	62,208	40,014	5,855	5,855	12,970	16,339	3,007	3,112	387	143	65,488	68,857	60,635	63,754
1984	45,869	62,208	40,014	5,855	5,855	14,008	16,339	3,248	3,361	418	155	67,063	69,390	57,472	59,467
1985	45,869	62,208	40,014	5,855	5,855	15,128	16,339	3,508	3,630	451	167	68,753	69,964	54,576	55,537
1986	62,208	62,208	40,014	5,855	5,855	16,339	16,339	3,788	3,920	487	181	70,584	70,584	51,879	31,879
1987	62,208	62,208	40,014	5,855	5,855	16,339	16,339	4,091	4,234	526	195	71,254	71,254	48,452	48,452
1988	62,208	62,208	40,014	5,855	5,855	16,339	16,339	4,419	4,573	569	211	71,980	71,980	45,355	45,355
1989	67,147	67,147	40,014	5,855	5,855	16,339	16,339	4,772	4,939	614	228	72,761	72,761	42,448	42,448
1990	67,147	67,147	40,014	5,855	5,855	16,339	16,339	5,154	4,939	663	246	73,210	73,210	39,548	39,548
1991	72,714	72,714	40,014	5,855	5,855	16,339	16,339	5,567	4,939	716	265	73,695	73,695	36,862	36,862
1992	72,714	72,714	40,014	5,855	5,855	16,339	16,339	5,567	4,939	774	289	73,775	73,775	34,165	34,165
1993	72,714	72,714	40,014	5,855	5,855	16,339	16,339	5,567	4,939	836	310	73,860	73,860	31,671	31,671
1994	73,617	73,617	40,014	5,855	5,855	16,339	16,339	5,567	4,939	903	335	73,962	73,962	29,366	29,366
1995	73,617	73,617	40,014	5,855	5,855	16,339	16,339	5,567	4,939	903	361	73,978	73,978	27,194	27,194
1996	73,617	73,617	40,014	5,855	5,855	16,339	16,339	5,567	4,939	903	390	74,007	74,007	25,192	25,192
1997	73,617	73,617	40,014	5,855	5,855	16,339	16,339	5,567	4,939	903	422	74,039	74,039	23,337	23,337
1998	73,617	73,617	40,014	5,855	5,855	16,339	16,339	5,567	4,939	903	455	74,072	74,072	21,614	21,614
1999	73,617	73,617	40,014	5,855	5,855	16,339	16,339	5,567	4,939	903	492	74,109	74,109	20,054	20,054
2000	73,617	73,617	40,014	5,855	5,855	16,339	16,339	5,567	4,939	903	531	74,148	74,148	18,552	18,552
2001	73,617	73,617	40,014	5,855	5,855	16,339	16,339	5,567	4,939	903	574	74,191	74,191	17,190	17,190
2002	73,617	73,617	40,014	5,855	5,855	16,339	16,339	5,567	4,939	903	620	74,237	74,237	15,924	15,924
2003	73,617	73,617	40,014	5,855	5,855	16,339	16,339	5,567	4,939	903	669	74,286	74,286	14,753	14,753
2004	73,617	73,617	40,014			16,339	16,339	5,567		903	723	63,546	63,546	11,686	11,686
2005	73,617	73,617	40,014			16,339	16,339	5,567		903	781	63,604	63,604	10,831	10,831
2006	73,617	73,617	40,014			16,339	16,339	5,567		903	843	63,666	63,666	10,040	10,040
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2014	75,063	75,063	40,014			16,339	16,339	5,567		903	1,446	64,270	64,270	5,475	5,475

Notes : (1) ...

Regulating dam	Eth$	13,357,000
Transmission lines	Eth$	18,724,000
Substations	Eth$	6,335,000
15kV distribution lines	Eth$	1,598,000
Total	Eth$	40,014,000

Table 12-6(4) Present Worth Capital Costs of Transmission Alternative from Year of Conversion (Economic)

(1000 Eth$) Discount Rate : 10%

Year of Conversion	Initial Capital Costs		Cost Components												Cost from Year of Conversion	
			Dam, trans-mission, etc. (1)	No. 3 Turbin-generat.		No. 2 Power Station		Trans-former Addition	Replacement of Existing Facil.			Total			
	Case A	Case B		Case A	Case B	Case A	Case B		Power Station	Sub-station	Trans. mission		Case B		Case B
1981															
1982	39,243	45,200	39,243	5,415	5,957	11,404	15,179	2,286	2,413	278	68	61,107	65,424	61,107	65,424
1983	45,200	61,897	39,243	5,957	5,957	12,544	16,697	2,515	2,654	305	75	63,293	67,446	57,539	61,314
1984	45,200	61,897	39,243	5,957	5,957	13,799	16,697	2,766	2,920	336	82	65,105	68,001	53,801	56,196
1985	45,200	61,897	39,243	5,957	5,957	15,179	16,697	3,043	3,212	370	91	67,095	68,613	50,408	51,548
1986	61,897	61,897	39,243	5,957	5,957	16,697	16,697	3,348	3,533	407	100	69,285	69,285	47,321	47,321
1987	61,897	61,897	39,243	5,957	5,957	16,697	16,697	3,682	3,886	447	110	70,022	70,022	43,476	43,476
1988	61,897	61,897	39,243	5,957	5,957	16,697	16,697	4,051	4,275	492	121	70,836	70,836	39,980	39,980
1989	66,600	66,600	39,243	5,957	5,957	16,697	16,697	4,456	4,703	542	133	71,731	71,731	36,805	36,805
1990	66,600	66,600	39,243	5,957	5,957	16,697	16,697	4,901	4,703	596	146	72,243	72,243	33,701	33,701
1991	71,992	71,992	39,243	5,957	5,957	16,697	16,697	5,392	4,703	655	161	72,808	72,808	30,877	30,877
1992	71,992	71,992	39,243	5,957	5,957	16,697	16,697	5,392	4,703	721	177	72,890	72,890	28,099	28,099
1993	71,992	71,992	39,243	5,957	5,957	16,697	16,697	5,392	4,703	793	195	72,980	72,980	25,572	25,572
1994	72,865	72,865	39,243	5,957	5,957	16,697	16,697	5,392	4,703	873	214	73,073	73,073	23,281	23,281
1995	72,865	72,865	39,243	5,957	5,957	16,697	16,697	5,392	4,703	873	236	73,101	73,101	21,170	21,170
1996	72,865	72,865	39,243	5,957	5,957	16,697	16,697	5,392	4,703	873	260	73,125	73,125	19,254	19,254
1997	72,865	72,865	39,243	5,957	5,957	16,697	16,697	5,392	4,703	873	286	73,151	73,151	17,505	17,505
1998	72,865	72,865	39,243	5,957	5,957	16,697	16,697	5,392	4,703	873	314	73,179	73,179	15,923	15,923
1999	72,865	72,865	39,243	5,957	5,957	16,697	16,697	5,392	4,703	873	346	73,211	73,211	14,481	14,481
2000	72,865	72,865	39,243	5,957	5,957	16,697	16,697	5,392	4,703	873	380	73,245	73,245	13,169	13,169
2001	72,865	72,865	39,243	5,957	5,957	16,697	16,697	5,392	4,703	873	418	73,283	73,283	11,981	11,981
2002	72,865	72,865	39,243	5,957	5,957	16,697	16,697	5,392	4,703	873	460	73,325	73,325	10,896	10,896
2003	72,865	72,865	39,243	5,957	5,957	16,697	16,697	5,392	4,703	873	506	73,371	73,371	9,912	9,912
2004	72,865	72,865	39,243			16,697	16,697	5,392		873	557	62,762	62,762	7,707	7,707
2005	72,865	72,865	39,243			16,697	16,697	5,392		873	613	62,818	62,818	7,010	7,010
2006	72,865	72,865	39,243			16,697	16,697	5,392		873	674	62,879	62,879	6,382	6,382
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2014	74,311	74,311	39,243			16,697	16,697	5,392		873	1,446	63,651	63,651	3,010	3,010

Notes : (1) ...

Regulating dam	Eth$	13,651,000
Transmission lines	Eth$	17,946,000
Substations	Eth$	6,125,000
15kV distribution lines	Eth$	1,521,000
Total	Eth$	39,243,000

Table 12-7 Present Worth Capital Costs of Existing Facilities

(1000 Eth$)

Year of Conversion	Remaining Book Value				Costs from Year of Conversion	
	Tis Abbay Power Station	Bahar Dar Substation	45kV Transmission line	Total	Discount 8%	Discount 10%
1981						
1982	2,377	123	82	2,582	2,582	2,582
1983	2,269	113	79	2,461	2,276	2,237
1984	2,161	103	76	2,340	2,005	1,932
1985	2,053	93	73	2,219	1,759	1,666
1986	1,945	83	70	2,098	1,542	1,432
1987	1,839	73	67	1,977	1,344	1,225
1988	1,729	63	64	1,856	1,169	1,046
1989	1,621	53	61	1,735	1,011	890
1990	1,513	43	58	1,614	871	752
1991	1,405	33	55	1,493	747	633
1992	1,297	23	52	1,372	639	528
1993	1,189	13	49	1,251	535	437
1994	1,081		46	1,127	447	358
1995	973		43	1,016	372	293
1996	865		40	905	307	238
1997	757		37	794	250	189
1998	649		34	683	198	148
1999	641		31	572	154	112
2000	433		28	461	115	82
2001	325		25	350	80	57
2002	217		22	239	51	35
2003	109		19	128	25	17
2004			16	16	3	2
2005			13	13	2	2
2006			10	10	2	1

Table 12-8(1) Capitalized Costs of Operation and Maintenance of Transmission Alternative from Year of Conversion (Financial)

(1000 Eth$) Discount Rate : 8%

Year of Conversion	Existing Facilities: Power Station	Sub-Station	Trans-mission	Dam, trans-mission, etc. (1)	No. 3 Turbin-generat.: Case A	Case B	No. 2 Power Station: Case A	Case B	Trans-former Additions	Total: Case A	Case B	Present Worth: Case A	Case B
1981													
1982	1,428	187	13	8,095	802	867	2,102	2,649	593	13,220	13,832	13,220	13,832
1983	1,428	187	13	8,095	867	867	2,271	2,861	641	13,502	14,092	12,489	13,047
1984	1,428	187	13	8,095	867	867	2,452	2,861	692	13,734	14,143	11,775	12,126
1985	1,428	187	13	8,095	867	867	2,649	2,861	748	13,987	14,799	11,091	11,259
1986	1,428	187	13	8,095	867	867	2,861	2,861	807	14,258	14,258	10,479	10,479
1987	1,428	187	13	8,095	867	867	2,861	2,861	872	14,323	14,323	9,739	9,739
1988	1,428	187	13	8,095	867	867	2,861	2,861	942	13,393	14,393	9,067	9,067
1989	1,428	187	13	8,095	867	867	2,861	2,861	1,017	14,468	14,468	8,434	8,434
1990	1,428	187	13	8,095	867	867	2,861	2,861	1,099	14,550	14, 50	7,857	7,857
1991	1,428	187	13	8,095	867	867	2,861	2,861	1,187	14,638	14,638	7,322	7,322
1992	1,428	187	13	8,095	867	867	2,861	2,861	1,187	14,638	14,638	6,780	6,780
1993	1,428	187	13	8,095	867	867	2,861	2,861	1,187	14,638	14,638	6,277	6,277
1994	1,428	187	13	8,095	867	867	2,861	2,861	1,187	14,638	14,638	5,812	5,812
1995	1,428	187	13	8,095	867	867	2,861	2,861	1,187	14,638	14,638	5,382	5,382
1996	1,428	187	13	8,095	867	867	2,861	2,861	1,187	14,638	14,638	4,983	4,983
1997	1,428	187	13	8,095	867	867	2,861	2,861	1,187	14,638	14,638	4,614	4,614
1998	1,428	187	13	8,095	867	867	2,861	2,861	1,187	14,638	14,638	4,272	4,272
1999	1,428	187	13	8,095	867	867	2,861	2,861	1,187	14,638	14,638	3,956	3,956
2000	1,428	187	13	8,095	86:	867	2,861	2,861	1,187	14,638	14,638	3,663	3,663
2001	1,428	187	13	8,095	867	867	2,861	2,861	1,187	14,638	14,638	3,391	3,391
2002	1,428	187	13	8,095	867	867	2,861	2,861	1,187	14,638	14,638	3,140	3,140
2003	1,428	187	13	8,095	867	867	2,861	2,861	1,187	14,638	14,638	2,907	2,907
2004		187	13	8,095			2,861	2,861	1,187	12,343	12,343	2,269	2,269
2005		187	13	8,095			2,861	2,861	1,187	12,343	12,343	2,102	2,102
2006		187	13	8,095			2,861	2,861	1,187	12,343	12,343	1,945	1,945

Notes : (1) ...

Regulating dam	Eth$	2,483,000
Transmission lines	Eth$	3,912,000
Substations	Eth$	1,350,000
15kV distribution lines	Eth$	350,000
Total	Eth$	8,095,000

Table 12-8(2) Capitalized Costs of Operation and Maintenance of Transmission Alternative from Year of Conversion (Financial)

(1000 Eth$) Discount Rate : 10%

Year of Conversion	Existing Facilities			Dam, trans-mission, etc. (1)	No.3 Turbin-generat.		No.2 Power Station		Trans-former Additions	Total		Present Worth	
	Power Station	Sub-station	Trans-mission		Case A	Case B	Case A	Case B		Case A	Case B	Case A	Case B
1981													
1982	1,228	750	10	6,503	678	746	1,603	2,133	402	10,574	11,172	10,574	11,172
1983	1,228	750	10	6,503	746	746	1,763	2,347	443	10,843	11,427	19,857	10,388
1984	1,228	750	10	6,503	746	746	1,939	2,347	487	11,063	11,471	9,138	9,475
1985	1,228	750	10	6,503	746	746	2,133	2,347	536	11,306	11,520	8,490	8,651
1986	1,228	750	10	6,503	746	746	2,347	2,347	589	11,573	11,573	7,904	7,904
1987	1,228	750	10	6,503	746	746	2,347	2,347	648	11,632	11,632	7,211	7,211
1988	1,228	750	10	6,503	746	746	2,347	2,347	713	11,697	11,697	6,597	6,597
1989	1,228	750	10	6,503	746	746	2,347	2,347	785	11,768	11,769	6,037	6,037
1990	1,228	750	10	6,503	746	746	2,347	2,347	863	11,847	11,847	5,520	5,520
1991	1,228	750	10	6,503	746	746	2,347	2,347	950	11,934	11,934	5,061	5,061
1992	1,228	750	10	6,503	746	746	2,347	2,347	950	11,934	11,934	4,601	4,601
1993	1,228	750	10	6,503	746	746	2,347	2,347	950	11,934	11,934	4,182	4,182
1994	1,228	750	10	6,503	746	746	2,347	2,347	950	11,934	11,934	3,802	3,802
1995	1,228	750	10	6,503	746	746	2,347	2,347	950	11,934	11,934	2,456	3,456
1996	1,228	750	10	6,503	746	746	2,347	2,347	950	11,934	11,934	3,142	3,142
1997	1,228	750	10	6,503	746	746	2,347	2,347	950	11,934	11,934	2,856	2,856
1998	1,228	750	10	6,503	746	746	2,347	2,347	950	11,934	11,934	2,597	2,597
1999	1,228	750	10	6,503	746	746	2,347	2,347	950	11,934	11,934	2,361	2,361
2000	1,228	750	10	6,503	746	746	2,347	2,347	950	11,934	11,934	2,146	2,146
2001	1,228	750	10	6,503	746	746	2,347	2,347	950	11,934	11,934	1,951	1,951
2002	1,228	750	10	6,503	746	746	2,347	2,347	950	11,934	11,934	1,773	1,773
2003	1,228	750	10	6,503	746	746	2,347	2,347	950	11,934	11,934	1,612	1,612
2004		750	10	6,503			2,347	2,347	950	9,960	9,960	1,223	1,223
2005		750	10	6,503			2,347	2,347	950	9,960	9,960	1,111	1,111
2006		750	10	6,503			2,347	2,347	950	9,960	9,960	1,010	1,010

Notes : (1) ...

Regulating dam	Eth$	2,013,000
Transmission lines	Eth$	3,130,000
Substations	Eth$	1,080,000
15kV distribution lines	Eth$	280,000
Total	Eth$	6,503,000

Table 12-8(3) Capitalized Costs of Operation and Maintenance of Transmission Alternative from Year of Conversion (Economic)

(1000 Eth$) Discount Rate : 8%

Year of Conversion	Existing Facilities			Dam, trans-mission etc. (1)	No.3 Turbin-generat.		No.2 Power Station.		Trans-former Additions	Total		Present Worth	
	Power Station	Sub-station	Trans-mission		Case A	Case B	Case A	Case B		Case A	Case B	Case A	Case B
1981													
1982	1,526	200	14	8,640	858	927	2,247	2,831	634	14,119	14,772	14,119	14,772
1983	1,526	200	14	8,640	927	927	2,427	3,058	685	14,419	15,050	13,350	13,935
1984	1,526	200	14	8,640	927	927	2,621	3,058	740	14,668	15,105	12,570	12,944
1985	1,526	200	14	8,640	927	927	2,831	3,058	799	14,937	15,164	11,845	12,025
1986	1,526	200	14	8,640	927	927	3,058	3,058	863	15,228	15,228	11,192	11,192
1987	1,526	200	14	8,640	927	927	3,058	3,058	932	15,297	15,297	10,401	10,401
1988	1,526	200	14	8,640	927	927	3,058	3,058	1,007	15,372	15,372	9,685	9,685
1989	1,526	200	14	8,640	927	927	3,058	3,058	1,087	15,452	15,452	9,008	9,008
1990	1,526	200	14	8,640	927	927	3,058	3,058	1,174	15,539	15,539	8,391	8,391
1991	1,526	200	14	8,640	927	927	3,058	3,058	1,269	15,634	15,634	7,821	7,821
1992	1,526	200	14	8,640	927	927	3,058	3,058	1,269	15,634	15,634	7,241	7,241
1993	1,526	200	14	8,640	927	927	3,058	3,058	1,269	15,634	15,634	6,705	6,705
1994	1,526	200	14	8,640	927	927	3,058	3,058	1,269	15,634	15,634	6,208	6,208
1995	1,526	200	14	8,640	927	927	3,058	3,058	1,269	15,634	15,634	5,748	5,748
1996	1,526	200	14	8,640	927	927	3,058	3,058	1,269	15,634	15,634	5,322	5,322
1997	1,526	200	14	8,640	927	927	3,058	3,058	1,269	15,634	15,634	4,928	4,928
1998	1,526	200	14	8,640	927	927	3,058	3,058	1,269	15,634	15,634	4,563	4,563
1999	1,526	200	14	8,640	927	927	3,058	3,058	1,269	15,634	15,634	4,225	4,225
2000	1,526	200	14	8,640	927	927	3,058	3,058	1,269	15,634	15,634	3,912	3,912
2001	1,526	200	14	8,640	927	927	3,058	3,058	1,269	15,634	15,634	3,622	3,622
2002	1,526	200	14	8,640	927	927	3,058	3,058	1,269	15,634	15,634	3,354	3,354
2003	1,526	200	14	8,640	927	927	3,058	3,058	1,269	15,634	15,634	3,105	3,105
2004		200	14	8,640			3,058	3,058	1,269	13,181	13,181	2,423	2,423
2005		200	14	8,640			3,058	3,058	1,269	13,181	13,181	2,244	2,244
2006		200	14	8,640			3,058	3,058	1,269	13,181	13,181	2,077	2,077

Notes : (1) ...

Regulating dam	Eth$	2,654,000
Transmission lines	Eth$	4,175,000
Substations	Eth$	1,437,000
15kV distribution lines	Eth$	374,000
Total	Eth$	8,640,000

Table 12-8(4) Capitalized Costs of Operation and Maintenance of Transmission Alternative from Year of Conversion (Economic)

(1000 Eth$)

Discount Rate : 10%

Year of Conversion	Existing Facilities			Dam, trans-mission, etc. (1)	No.3 Turbin-generat.		No.2 Power Station		Trans-former Addition	Total		Present Worth	
	Power Station	Sub-station	Trans-mission		Case A	Case B	Case A	Case B		Case A	Case B	Case A	Case B
1981													
1982	1,313	160	11	6,941	724	797	1,713	2,280	430	11,292	11,932	11,292	11,932
1983	1,313	160	11	6,941	797	797	1,885	2,509	473	11,580	12,204	10,527	11,094
1984	1,313	160	11	6,941	797	797	2,073	2,509	521	11,816	12,252	9,764	10,120
1985	1,313	160	11	6,941	797	797	2,280	2,509	573	12,075	12,304	9,068	9,240
1986	1,313	160	11	6,941	797	797	2,509	2,509	630	12,361	12,361	8,442	8,442
1987	1,313	160	11	6,941	797	797	2,509	2,509	693	12,424	12,424	7,702	7,702
1988	1,313	160	11	6,941	797	797	2,509	2,509	763	12,494	12,494	7,046	7,046
1989	1,313	160	11	6,941	797	797	2,509	2,509	839	12,570	12,570	6,448	6,448
1990	1,313	160	11	6,941	797	797	2,509	2,509	923	12,654	12,654	5,896	5,896
1991	1,313	160	11	6,941	797	797	2,509	2,509	1,016	12,747	12,747	5,406	5,406
1992	1,313	160	11	6,941	797	797	2,509	2,509	1,016	12,747	12,747	4,914	4,914
1993	1,313	160	11	6,941	797	797	2,509	2,509	1,016	12,747	12,747	4,467	4,467
1994	1,313	160	11	6,941	797	797	2,509	2,509	1,016	12,747	12,747	4,061	4,061
1995	1,313	160	11	6,941	797	797	2,509	2,509	1,016	12,747	12,747	3,692	3,692
1996	1,313	160	11	6,941	797	797	2,509	2,509	1,016	12,747	12,747	3,356	3,356
1997	1,313	160	11	6,941	797	797	2,509	2,509	1,016	12,747	12,747	3,051	3,051
1998	1,313	160	11	6,941	797	797	2,509	2,509	1,016	12,747	12,747	2,774	2,774
1999	1,313	160	11	6,941	797	797	2,509	2,509	1,016	12,747	12,747	2,521	2,521
2000	1,313	160	11	6,941	797	797	2,509	2,509	1,016	12,747	12,747	2,292	2,292
2001	1,313	160	11	6,941	797	797	2,509	2,509	1,016	12,747	12,747	2,084	2,084
2002	1,313	160	11	6,941	797	797	2,509	2,509	1,016	12,747	12,747	1,894	1,894
2003	1,313	160	11	6,941	797	797	2,509	2,509	1,016	12,747	12,747	1,722	1,722
2004		160	11	6,941			2,509	2,509	1,016	10,637	10,637	1,306	1,306
2005		160	11	6,941			2,509	2,509	1,016	10,637	10,637	1,187	1,187
2006		160	11	6,941			2,509	2,509	1,016	10,637	10,637	1,079	1,079

Notes : (1) ...

Regulation dam	Eth$	2,152,000
Transmission lines	Eth$	3,340,000
Substations	Eth$	1,150,000
15kV distribution lines	Eth$	299,000
Total	Eth$	6,941,000

Table 12-9 Costs of Energy to be Supplied by Upper Beles Project for the Transmission Alternative

(1000 Eth$)

Year	Energy Demand (MWh): North and East of Lake Tana	Energy Demand (MWh): South of Lake Tana	Energy Demand (MWh): Bahir Dar Area Case A	Energy Demand (MWh): Bahir Dar Area Case B	Energy Demand (MWh): Total Case A	Energy Demand (MWh): Total Case B	Supply Capability of Tis Abbay Power System (MWh)	Energy to be Supplied by Upper Beles Power Station (MWh) Case A	Energy to be Supplied by Upper Beles Power Station (MWh) Case B	Financial Energy Cost, Discount Rate 8%: Case A (E¢ 4.48/kWh)	Financial Energy Cost, Discount Rate 8%: Case B (E¢ 4.48/kWh)	Financial Energy Cost, Discount Rate 10%: Case A (E¢ 5.43/kWh)	Financial Energy Cost, Discount Rate 10%: Case B (E¢ 5.43/kWh)	Economic Energy Cost, Discount Rate 8%: Case A (E¢ 5.25/kWh)	Economic Energy Cost, Discount Rate 8%: Case B (E¢ 5.25/kWh)	Economic Energy Cost, Discount Rate 10%: Case A (E¢ 6.36/kWh)	Economic Energy Cost, Discount Rate 10%: Case B (E¢ 6.36/kWh)
1982																	
....																	
....																	
1991	25,638	5,500	43,711		74,855		(1) 71,144	3,711		166		201		194		236	
1992	28,202	5,915	44,566		78,703		71,144	7,559		338		410		396		480	
1993	31,021	6,529	45,507		83,060		71,144	11,916		533		647		625		757	
1994	34,127	7,181	46,544		87,852		71,144	16,708		748		907		877		1,062	
1995	37,536	7,900	47,682		93,118		71,144	21,974		984		1,193		1,153		1,397	
1996	41,292	8,689	48,936		98,917		71,144	27,773		1,244		1,508		1,458		1,766	
1997	45,420	9,560	50,314		105,294		71,144	34,150		1,530		1,854		1,792		2,171	
1998	49,965	10,515	51,830		112,310		71,144	41,166		1,844		2,235		2,161		2,618	
1999	54,959	11,566	53,499		120,024		71,144	48,880		2,189		2,654		2,566		3,108	
2000	60,456	12,723	55,334		128,513		71,144	57,369		2,570		3,115		3,011		3,648	
2001	62,250	14,407	57,230		133,887		71,144	62,743		2,810		3,406		3,294		3,990	
2002	62,250	15,228	59,307		136,785		71,144	65,641		2,940		3,564		3,446		4,174	
2003	62,250	16,658	61,578		140,486		71,144	69,342		3,106		3,765		3,640		4,410	
2004	62,250	18,223	64,062		144,535		(2) 23,620	120,915		5,416		6,565		6,348		7,690	
2005	62,250	19,938	66,780		148,968		23,620	125,348		5,615		6,806		6,580		7,972	
2006	62,250	21,813	69,753	69,480	153,816	153,543	23,620	130,196	129,923	5,832	5,820	7,069	7,054	6,835	6,820	8,280	8,263
2007	62,250	23,863	73,005	69,480	159,118	155,593	23,620	135,498	131,973	6,070	5,912	7,357	7,166	7,113	6,928	8,617	8,393
2008	62,250	26,106	76,564	69,480	164,920	157,836	23,620	141,300	134,216	6,330	6,012	7,672	7,287	7,418	7,046	8,986	8,536
2009	62,250	28,560	80,457	69,480	171,267	160,290	23,620	147,647	136,670	6,614	6,122	8,017	7,421	7,751	7,175	9,390	8,692
2010	62,250	31,245	84,715	69,480	178,210	162,975	23,620	154,590	139,355	6,925	6,243	8,394	7,566	8,116	7,316	9,831	8,862
2011	62,250	34,182	86,750	69,480	183,182	165,912	23,620	159,562	142,292	7,148	6,374	8,664	7,726	8,377	7,470	10,148	9,049
2012	62,250	37,395	86,750	69,480	186,395	169,125	23,620	162,775	145,505	7,292	6,518	8,838	7,900	8,545	7,639	10,352	9,254
2013	62,250	40,910	86,750	69,480	189,910	172,640	23,620	166,290	149,020	7,449	6,676	9,029	8,091	6,730	7,823	10,576	9,477
2014	62,250	44,756	86,750	69,480	193,963	176,486	23,620	170,136	152,866	7,622	6,848	9,238	8,300	8,932	8,025	10,820	9,722
2015	62,250	48,963	86,750	69,480	197,963	180,693	23,620	174,343	157,073	7,810	7,036	9,466	8,529	9,153	8,246	11,088	9,989
2016	62,250	53,565	86,750	69,480	202,565	185,295	23,620	178,945	161,675	8,016	7,243	9,716	8,778	9,394	8,487	11,380	10,282
2017	62,250	58,601	86,750	69,480	207,601	190,331	23,620	183,891	166,717	8,242	7,468	9,990	9,052	9,659	8,752	11,701	10,602
2018	62,250	64,109	86,750	69,480	213,109	195,839	23,620	189,489	172,219	8,489	7,715	10,289	9,251	9,948	9,041	12,051	10,953
2019	62,250	68,840	86,750	69,480	217,840	200,570	23,620	(3) 194,220	176,950	108,763	99,092	105,461	96,083	127,436	116,123	123,523	112,540
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....	...	...	...	...	...	...	...	...	...								
....	...	...	...	...	...	...	...	...	...								

Note : (1) ... Energy supplied by Tis Abbay power stations in 1990.
(2) ... Energy supplied by Tis Abbay No. 2 Power Station.
(3) ... Costs of Energy shown in final year include capitalized costs of future energy supply to in finity at constant rate corresponding to line capability.

Table 12-10 Present Worth Energy Costs of Transmission Alternative from Year of Conversion

(1000 Eth$)

Year	Yearly Discounted Costs								Present Worth Costs from Year of Conversion							
	Financial Costs				Economic Costs				Financial Costs				Economic Costs			
	Discount Rate 8%		Discount Rate 10%		Discount Rate 8%		Discount Rate 10%		Discount Rate 8%		Discount Rate 10%		Discount Rate 8%		Discount Rate 10%	
	Case A	Case B	Case A	Case B	Case A	Case B	Case A	Case B	Case A	Case B	Case A	Case B	Case A	Case B	Case A	Case B
1981																
1982	21,636	20,437	14,957	14,244	25,355	23,961	17,512	16,685	21,636	20,437	14,951	14,244	25,355	23,961	17,512	16,685
1983	23,368	22,073	16,446	15,669	27,383	25,878	19,263	18,353	21,636	20,437	14,951	14,244	25,355	23,961	17,512	16,685
1984	25,238	23,840	18,091	17,235	29,574	27,948	21,190	20,189	21,636	20,437	14,951	14,244	25,355	23,961	17,512	16,685
1985	27,256	25,746	19,900	18,959	31,940	30,184	23,309	22,207	21,636	20,437	14,951	14,244	25,355	23,961	17,512	16,685
1986	29,437	27,807	21,890	20,855	34,495	32,599	25,640	24,428	21,636	20,437	14,951	14,244	25,355	23,961	17,512	16,685
1987	31,792	30,031	24,079	22,941	37,254	35,207	28,204	26,871	21,636	20,437	14,951	14,244	25,355	23,961	17,512	16,685
1988	34,336	32,433	26,487	25,235	40,235	38,023	31,024	29,558	21,636	20,437	14,951	14,244	25,355	23,961	17,512	16,685
1989	37,083	35,028	29,136	27,758	43,454	41,065	34,127	32,514	21,636	20,437	14,951	14,244	25,355	23,961	17,512	16,685
1990	40,049	37,830	22,049	30,534	46,930	44,300	37,539	35,766	21,636	20,437	14,951	14,244	25,355	23,961	17,512	16,685
1991	43,254	40,857	35,255	33,588	50,685	47,899	41,294	39,343	21,636	20,437	14,951	14,244	25,355	23,961	17,512	16,685
1992	46,547	43,959	38,582	36,749	54,549	51,540	45,189	43,044	21,560	20,357	14,873	14,166	25,261	23,868	17,420	16,593
1993	49,937	47,142	42,051	40,015	58,516	55,266	49,230	46,870	21,412	20,214	14,727	14,021	25,091	23,698	17,250	16,423
1994	53,397	50,379	45,587	43,369	62,576	59,066	53,397	50,800	21,203	20,005	14,524	13,817	24,848	23,455	17 012	16,184
1995	56,924	53,663	49,241	46,801	66,706	62,916	57,676	54,820	20,925	19,726	14,260	13,553	24,521	23,127	16,702	15,875
1996	60,494	56,973	52,973	50,290	70,890	66,795	62,047	58,905	20,592	19,393	13,947	13,241	24,130	22,737	16,336	15,509
1997	64,091	60,288	56,764	53,812	75,104	70,688	66,487	63,031	20,201	19,002	13,583	12,877	23,672	22,279	15,910	15,083
1998	67,690	63,583	60,587	57,341	79,323	74,547	70,965	67,163	19,751	18,553	13,181	12,477	23,146	21,756	15,441	14,614
1999	71,260	66,824	64,411	60,840	83,508	58,351	75,444	71,262	19,254	18,055	12,740	12,034	22,563	21,170	14,922	14,095
2000	74,775	69,985	68,199	64,271	87,625	82,055	79,882	75,282	18,708	17,510	12,262	11,555	21,923	20,530	14,362	13,535
2001	78,186	73,012	71,905	67,584	91,626	85,611	84,224	79,164	18,115	16,916	11,756	11,049	21,229	19,836	13,770	12,943
2002	81,633	76,045	75,691	70,937	95,663	89,166	88,656	83,090	17,510	16,311	11,247	10,541	20,519	19,126	13,174	12,347
2003	85,224	79,189	79,698	74,469	99,872	92,855	93,350	87,228	16,925	15,726	10,767	10,060	19,834	18,441	12,611	11,784
2004	88,936	82,418	83,903	78,151	104,222	96,644	98,275	91,540	16,355	15,156	10,303	9,596	19,166	17,772	12,068	11,241
2005	90,638	83,598	85,729	79,402	106,214	98,029	100,414	93,006	15,435	14,236	9,567	8,861	18,088	16,694	11,206	10,379
2006	92,273	84,671	87,497	80,537	108,132	99,293	102,484	94,335	14,551	13,352	8,880	8,174	17,041	15,648	10,402	9,575

Table 12-11 Summary of Present Worth Costs of Transmission Alternative

(1000 Eth$)

Year	Financial Costs				Economic Costs			
	Discount 8%		Discount 10%		Discount 8%		Discount 10%	
	Case A	Case B	Case A	Case B	Case A	Case B	Case A	Case B
1981								
1982	89,642	91,907	78,303	81,666	105,656	108,468	92,493	96,623
1983	86,124	88,015	74,262	77,138	101,616	103,926	87,815	91,330
1984	82,542	83,312	70,124	71,688	97,408	98,377	83,009	84,933
1985	79,195	78,905	66,407	66,785	93,535	93,282	78,654	79,139
1986	76,141	74,942	63,049	62,342	89,968	88,574	74,707	73,880
1987	72,388	71,189	58,938	58,231	85,552	84,158	69,915	69,088
1988	68,982	67,783	55,297	54,590	81,564	80,170	65,584	64,757
1989	65,787	64,588	51,988	51,281	77,822	76,428	61,655	60,828
1990	62,700	61,501	48,764	48,057	74,165	72,771	57,861	57,034
1991	59,854	58,655	45,895	45,188	70,785	69,391	54,428	53,601
1992	56,914	55,711	42,954	42,247	67,306	65,913	50,961	50,134
1993	54,123	52,925	40,236	39,530	64,002	62,609	47,726	46,899
1994	51,495	50,277	37,735	37,018	60,869	59,476	44,712	43,884
1995	48,915	47,716	34,322	34,615	57,835	56,441	41,857	41,030
1996	46,480	45,281	33,072	32,366	54,951	53,558	39,184	38,357
1997	44,245	42,946	30,943	30,237	52,187	50,794	36,655	35,828
1998	41,892	40,694	28,948	28,244	49,521	48,131	34,286	33,459
1999	39,740	38,511	27,055	26,349	46,996	45,603	32,036	31,209
2000	37,651	36,453	25,259	24,552	44,502	43,109	29,905	29,078
2001	35,637	34,438	23,562	22,855	42,121	40,728	27,892	27,065
2002	33,717	32,518	21,965	21,795	39,848	38,455	25,999	25,172
2003	31,915	30,716	20,502	20,795	37,717	36,324	24,262	23,435
2004	28,244	27,045	17,875	17,168	33,278	31,884	21,083	20,256
2005	26,450	25,251	16,146	15,747	31,165	29,771	19,405	18,578
2006	24,754	23,555	15,146	14,440	29,160	27,767	17,864	17,037

Table 12-12 Summary of Total Present Costs of Power Supply

(1000 Eth$)

Year	Financial Costs				Economic Costs			
	Discount 8%		Discount 10%		Discount 8%		Discount 10%	
	Case A	Case B	Case A	Case B	Case A	Case B	Case A	Case B
1981								
1982	92,652	95,618	81,436	85,546	109,243	112,932	96,230	101,295
1983	92,789	96,108	81,093	85,563	109,560	113,773	95,866	101,371
1984	92,803	95,875	80,517	84,458	109,633	113,468	95,408	100,293
1985	93,058	95,993	80,296	83,975	110,052	113,836	95,227	99,823
1986	93,781	96,675	80,149	83,997	110,999	114,724	95,196	99,946
1987	93,915	97,629	80,089	84,323	111,136	115,880	95,177	100,507
1988	94,335	98,822	79,964	84,928	111,723	117,429	95,062	101,301
1989	95,341	100,381	80,292	85,933	112,798	119,416	95,495	102,577
1990	96,035	101,951	80,579	86,849	113,888	121,367	95,911	103,774
1991	97,406	103,848	81,321	88,118	115,532	123,704	96,857	105,332
1992	98,625	105,603	81,961	89,213	117,070	125,878	97,685	106,710
1993	100,202	107,545	82,868	90,853	118,940	128,514	98,791	108,478
1994	101,756	109,928	83,910	92,123	120,927	131,214	100,026	110,282
1995	103,604	112,253	84,089	93,694	123,211	134,088	101,477	112,222
1996	105,619	114,711	86,367	95,329	125,625	137,014	103,066	114,219
1997	107,866	117,226	87,726	96,979	128,316	140,199	104,731	118,283
1998	109,970	119,770	89,123	98,642	131,007	143,318	106,434	119,318
1990	112,437	122,507	90,677	100,408	134,017	146,681	108,322	120,480
2000	114,953	125,399	92,281	102,275	137,075	150,179	110,279	122,768

CHAPTER 13

FINANCIAL ANALYSIS

CHAPTER 13 FINANCIAL ANALYSIS

13.1 BASIC CONSIDERATIONS

13.1.1 Items of Analysis

The financial analysis for the Lake Tana Project is made concerning the following items :

(a) Evaluation of the financial soundness as seen from the Revenue/Cost ratio.

(b) Calculations of electric power costs at generating end and consumers end.

(c) Evaluation of the permissible borrowing terms in procurement of funds.

13.1.2 Applicable Costs

A financial analysis is made through actual cash flows of revenue and costs. Therefore, unlike the case of the economic analysis of Chapter 12, the concept of so-called economic cost is unnecessary, and only financial costs are applied throughout for analysis.

13.1.3 Applicable Rates of Interest

The proportion made up by capital costs in the power supply cost of this development project, including the regulating dam, power stations, transmission lines and substations is extremely high, and these capital costs will vary considerably depending on the rates of interest at which funds are procured.

In the economic analysis of Chapter 12, two discount rates were used. 10% as regulated by the Planning Commission Office of Ethiopia in case of economic evaluations of projects, and 8% considered to reflect long-term interest rates of international financial institutions.

The actual rates of interest at which the funds required for this development project are procured will probably differ for the foreign and domestic currency portions, while for the foreign currency portion, it is possible that loan conditions lower than the beforementioned 8% will be applied. However, a correlation with the economic analysis of Chapter 12 can be achieved more readily by using the two interest rates of 8% and 10% per annum in calculations for the analysis items (a) and (b) of item 13. 1. 1. Accordingly, the interest on procured funds will also be taken to be at the two rates of 8% and 10% per annum in the financial analysis.

13.1.4 Unit Prices of Energy Sold

The present tariff for electricity being applied to customers in the project area is the SCS tariff revised in 1972 and the unit prices by type of demand (residential, commercial, street lighting, small industrial, etc.) are practically the same as ICS charges. In case this development plan is implemented and the electricity generated at the Tis Abbay power stations begins to be supplied through transmission lines to customers in the project area, a case of the present SCS tariff being changed to ICS tariff is conceivable, but since there is little difference between the two, revenues from energy sales will be calculated by present SCS tariff.

However, it is necessary for special consideration to be given to the tariff applied to the electric boilers of Bahar Dar Textile Mills S.C. among the customers in the project area. That is, as described in item 4.2.1. (2). (d) of Chapter 4, the electricity sales contract is for power supply to boiler loads at off-peak hours, and a special rate of E¢1.30/kWh is being applied on the basis of energy charges not including capacity charges. As shown in the abovementioned item, however, when the heat generation cost of a furnace boiler equivalent to 1 kWh of heat generation is computed on the basis of the current price of heavy oil No. 6 in Ethiopia of Eth$252/ton, there is room for the present unit price of electric energy to be adjusted up to E¢2.52/kWh. Although the tariff to be applied to the electric boilers in the future is a matter to be decided upon discussions between EELPA and Bahar Dar Textile Mills S.C., so long as power supply to the electric boilers is limited to off-peak hours, E¢2.52/kWh may be considered as an upper limit. Therefore, in calculations of energy sales revenues in the present financial analysis, the following two cases will be considered.

- Present tariff proposal ..... Case of tariff applied to electric boilers being the present E¢1.30/kWh.
- Adjusted tariff proposal ..... Case of tariff applied to electric boilers being E¢2.52/kWh.

13.1.5 Load Forecast and Energy Sales

The load forecast of Chapter 4 has been made assuming that there will always be available power generating, transmitting and transforming facilities corresponding to demand from 1982, and in a sense it is a forecast of unlimited power demand, while in that forecast two possibilities of Case A and Case B were assumed for the system of power supply to the electric boilers of Bahar Dar Textile Mills.

With respect to the above, the following have been pointed out in Chapter 12, Economic Analysis.

(a) Application of Case A is more economical than Case B.

(b) The supply capacity of the Tis Abbay power stations will reach its limit in 1990, and from 1991 it is necessary for supplementary power to be obtained from another power source, for example, Upper Beles Power Station (future project).

(c) Since the existing Tis Abbay Power Station will reach the limit of its economic service life (40 years) in the year 2003, it is thought that supply after that year can be expected only for extremely short periods of time during peaks. (Consequently, as in the economic analysis, the cost and supply capacity of the existing Tis Abbay Power Station after 2004 is not considered in the financial analysis.)

(d) The transmission capacities of the transmission lines of this development project with Case A will approximately reach their limits in the year 2000 for the North and East Regions, in the year 2010 for the Bahar Dar Area, and the year 2018 in the South Region. Therefore, the quantity of energy sold under this project to each region from the year after the limit is reached will be constant.

The present financial analysis will be made keeping in mind the above items (a), (b), (c) and (d).

13.1.6 Period of Analysis

The construction schedule of Chapter 11 has been formulated in consideration of the conclusions shown in item 12.6.1.(e) of Chapter 12, and the various procedures to be taken hereafter. According to this schedule, the starts of operation of the regulating dam, additional No. 3 unit and the transmitting and transforming facilities are planned to be at the beginning of 1983, while the start of operation of the No. 2 Power Station is planned to be at the beginning of 1986. The economic service life of the No. 2 Power Station, as described in item 12.3.2. (1) of Chapter 12, is set at 40 years and the end of its operation will thus come in the year 2025. Consequently, the period of this financial analysis will be the 43 years from 1983 to 2025.

As described under (c) of the preceding item, the existing Tis Abbay Power Station (including the additional No. 3 unit) will come to the expiration of its economic service life in 2003, and taking into consideration the fact that only the supply capability of the No. 2 Power Station can be looked forward to thereafter in the way of supply capability of the Tis Abbay power system, calculations of Revenue/Cost ratio will be performed dividing into the two analysis periods below (provided, however, that calculations of electric power cost will be for the period up to 2003).

- 21 years from 1983 through 2003
- 43 years from 1983 through 2025

13.1.7 Relation with Upper Beles Project

The supply capability of the Tis Abbay power stations can only cope with demand up to around 1990. Meanwhile, the regulating dam possesses the role of a common facility with the future Upper Beles Project, and the power transmission plan has been formulated considering supplementary power from this future power source. In effect, the transmission capacities to the various regions according to this development plan have considerable allowances in excess of the supply capacity of the Tis Abbay power stations.

Consequently, similarly to the case of the economic analysis, it is necessary for supplementary power from the Upper Beles Project to be taken into consideration in the financial analysis. Therefore, the examination of the financial profitability through calculation of the Revenue/Cost ratio will be carried out for the two cases below.

- Case of taking supply capacity of the Tis Abbay power stations only.

- Case of including supplementary power from the Upper Beles Project in calculations.

13.2 REVENUE/COST RATIO

The most important theme of a financial analysis is to confirm whether earnings are comparable to invested capital. For this purpose, the average annual amount of power sales revenue converted to present worth, and similarly, the average annual amounts of capital cost, operation and maintenance cost, etc. also converted into present worths may be compared and judgments made.

13.2.1 Average Annual Power Revenue

(1) Energy Sales

As shown in item 12.2.5 of Chapter 12, the power demands of the regions north and east of Lake Tana will reach the limits of transmission capacity of the 66-kV transmission line to these regions in the year 2000, and in the following year 2001 and after, the power consumption with the transmitting and transforming facilities of this project cannot be other than constant every year. Similarly, the load of the 45-kV line to Dangla and Injibara will become constant from the year 2019, while the load of the Bahar Dar Area will be constant from 2011.

Meanwhile, the supply capacity of the Tis Abbay power stations will become insufficient to satisfy the total demand (kilowatt demand) of the project area in 1991, and it is forecast that supplementary power from some other power source will be necessary from that year, and as this power source, development of the Upper Beles Project is assumed in this study. In this case, the electric energy supplied by the Tis Abbay power stations from 1991, unless the form of the load curve does not vary greatly, may be most reasonably considered to be of the same degree as that of the previous year 1990. It is thought the supply capacity of the existing Tis Abbay Power Station (including the additional No.3 unit) can no longer be relied upon from 2004. for which case the electric power to be supplied by the remaining No.2 Power Station is calculated in this study based on the dependable output ratio between the existing and No.2 power stations (see item 12.5.3. (1) of Chapter 12).

The energy sales, viewed from the two points of scales of demand and unit prices of energy, may be broadly divided into energy sales to general customers including residential, commercial, street-lighting and small industrial demands, and energy sales to the large-industrial customer, Bahar Dar Textile Mills, S.C., for its motors and electric boilers.

In this financial analysis, it was considered that of the energy sold during 1991 ~ 2003, the power consumed by the motors and electric boilers of the textile company would all be supplied from the Tis Abbay power stations. The reasons for this are as given below.

(a) Upper Beles Power Station will be operated in accordance with fluctuation in demand in ICS (load factor 60%). In contrast, it is possible for the Tis Abbay power stations to be operated day and night throughout the year roughly at full capacity.

(b) The load factor of the motored equipment of the textile factory is approximately 72% while that of electric boilers is approximately 50% and the operating time is longer during the night. In particular, with the electric boilers, it is recommended in this study that they be operated at off-peak hours of the system as a whole.

(c) Consequently, it will be more economical for supply to the facilities of the textile company which have long night-time operating hours to be made from the Tis Abbay power stations.

However, from the year 2004, since the supply capacity of the No. 2 Power Station will be insufficient even for just the demand in the city of Bahar Dar, it was considered that both motors and electric boilers of the textile company would then be supplied from Upper Beles Project.

The electric energy supplied by the Tis Abbay power stations and Upper Beles Project divided based on the above will be as indicated in Table 13-1.

(2) Unit Prices of Energy Sold

The tariff of EELPA is based on a dual system of fixed charges and energy charges and differ according to type of demand, but since a great change in the composition of demand is not anticipated for the project area in the future, it is thought an estimated of electric power revenues can be grasped more or less accurately through application of the average unit price of energy sold to the three categories of general customers, textile motors, and electric boilers.

The unit prices of energy sold in the Bahar Dar and Gondar areas based on actual records for 1975 are the following:

Tariff No.	Category	Energy Sold (kWh)		Revenue (Eth$)		Unit Price (E¢/kWh)	
		B. Dar	Gondar	B. Dar	Gondar	B. Dar	Gondar
15	Residential	515,122	764,812	90,932	155,568	17.7	20.3
18	"	41,552	33,834	8	-	-	-
19	"	880	908	-	-	-	-
	Subtotal	557,554	799,554	90,940	155,568	16.3	19.5
25	Commercial	176,058	288,653	31,164	55,199	17.7	19.1
35	Street lighting	156,772	226,219	23,516	33,933	15.0	15.0
45	Industrial (small)	522,428	1,079,627	112,531	205,858	21.5	19.1
46	Industrial (large)	221,389	266,960	31,822	32,998	14.4	12.4
	Total	1,634,201	2,661,013	289,973	483,557	17.7	18.2

Tariff No.	Category	Energy Sold (kWh)		Revenue (Eth$)		Unit Price (E¢/kWh)	
		B. Dar	Gondar	B. Dar	Gondar	B. Dar	Gondar
42	Textile motor	8,489,000	-	385,740	-	4.55	-
Special	Textile boiler	9,684,000	-	133,027	-	1.37	-

(Note) The unit price for the electric boilers is E¢ 1.30/kWh as contracted, but in 1975 it came E¢ 1.37/kWh due to penalties under power factor clauses of the contract.

Based on the above, the unit price for general customers is put as E¢ 18.0/kWh taking the average for the two regions, while the unit price for textile mill motors is put as E¢ 4.55/kWh and that for electric boilers as E¢ 1.30/kWh, and the energy sales revenue estimated. Further, regarding electric boilers, sales revenue in case an adjusted tariff of E¢ 2.52/kWh is applied as described in 13.1.4 is calculated besides the above.

As for the cost of supplementary power from the Upper Beles Project, the following unit prices as calculated in item 12.3.2. (5) of Chapter 12, are applied:

- Case of interest rate of 8% E¢ 4.48/kWh
- Case of interest rate of 10% E¢ 5.43/kWh

(3) Average Annual Sales Revenue

Calculating revenues from energy sales based respectively on the present Lake Tana Project and the future Upper Beles Project according to the energy sales by year and the unit prices above, the results are as given in Table 13-2 (2).

It should be noted that the energy demand of general customers in the beforementioned Table 13-1 is for 15kV distribution line terminals, but since distribution loss of about 10% is estimated to occur at low-voltage distribution networks beyond these terminals, the energy sales revenue from general customers has been calculated taking such loss into consideration.

The average annual revenue from the abovementioned two varieties of tables converted to present worth may be summarized as follows:

(1,000 Eth$)

Calculation Period	Interest Rate 8%		Interest Rate 10%	
	Present Tariff	Adjusted Tariff	Present Tariff	Adjusted Tariff
1983 ~ 2003				
Lake Tana Project Sales Revenue	5,699	5,966	5,599	5,866
Upper Beles Project Sales Revenue	1,490	1,490	6,772	7,039
Total	7,189	7,456	6,772	7,039
1983 ~ 2025				
Lake Tana Project Sales Revenue	5,384	5,606	5,385	5,620
Upper Beles Project Sales Revenue	3,484	3,524	2,425	2,457
Total	8,868	9,130	7,810	8,077

The following facts may be pointed out based on the above results:

(a) Of the energy sales revenue converted to present worth, the revenue from electric power generated by the Tis Abbay power system is 55 ~ 60% of the whole in case of interest rate of 8%, and approximately 70% in case of interest rate of 10%

(b) Even if the tariff for electric boilers is adjusted to E¢2.52/kWh, it does not cause a large change in the total revenue, and there is only an increase of approximately 4% compared with the total revenue in case of the present tariff.

13.2.2 Average Annual Power Costs

In case of calculating power supply costs also, it is necessary to make the computations dividing into the period up to 2003, the limit of the service life of the existing Tis Abbay Power Station, and the period up to 2025, the limit of the service life of Tis Abbay No. 2 Power Station. The cost items may be broadly divided into amortized capital cost and operation and maintenance cost, and for the capital cost, the capital cost of new facilities to be built according to the Lake Tana Project and of existing power station, substation and transmission line as well as equipment replacement costs must be considered.

(1) Capital Costs

(a) Capital Costs of New Facilities

In connection with the subject capital cost, the service lives of transmission lines and 15kV distribution lines are both 25 years, while the service life of transforming facilities is 30 years. Consequently, these must be replaced at 25 years and 30 years respectively. Therefore, it was decided that the sums of the respective replacement costs converted to present worths and their respective initial investment amounts would be amortized over 50 years in case of transmission and distribution lines, and over 60 years in case of transforming facilities. Replacement of electrical equipment of the No.2 Power Station must be considered after 25 years, but in this case it was considered that the present worth of such replacement cost would be amortized over 43 years up to the end of operation of the power station.

As for the additional transformer to start operation from 1991, the first replacement will become necessary in 2020, and this should be considered in the calculations, but since this is a matter for the distant future, it would be practically neglible so far as influence on calculation results are concerned and thus is disregarded, and the initial investment amount converted to present worth is to be amortized over 43 years up to 2025.

(b) Capital Costs of Existing Facilities

The existing Tis Abbay Power Station, Bahar Dar Substation and the 45kV transmission line which were commissioned in 1964 will all require replacement of equipment during the period of the present analysis, and the replacement costs of these facilities converted to present worths are to be amortized in accordance with their respective service lives.

Regarding the unamortized remainders of the initial investment amounts for these facilities as of the beginning of 1983, these unamortized remainders are estimated from item 12.3.2. (3) of Chapter 12, and Table 12-7 upon which these initial investment costs would be amortized. In this case, the period of amortization is 21 years up to 2003 for Tis Abbay Power Station, while for Bahar Dar Substation and the 45kV transmission line, they ordinarily would be 11 years to 1993 and 31 years to 2013, respectively. However, unlike a power station, transmitting and transforming facilities would be replaced to infinity, and therefore, as mentioned previously, the first replacement costs of these are already included in the calculations. Therefore, for convenience of obtaining the average annual costs throughout the present analysis period, it was decided that the unamortized remainders of the existing transmitting and transforming facilities would be amortized over the 43 year period to 2025.

(2) Operation and Maintenance Costs

Of the operation and maintenance costs of the various facilities, those of the No.2 Power Station will be incurred from 1986, and those of the additional transformer from 1991. Those of other facilities will all be incurred from 1983, and constant amounts will be appropriated annually. Accordingly, in order to calculate the average annual cost during the analysis period starting from 1983, the operation and maintenance costs of the No. 2 Power Station and the additional transformer the respective capitalized amounts are converted to present worth as of the beginning of 1983, following which they are amortized over the periods of their respective service lives.

(3) Average Annual Power Costs

Calculating the average annual power costs by totalling the above capital costs and the operation and maintenance costs, the results are as shown in Table 13-3. With regard to the capital costs and operation and maintenance costs of the existing Tis Abbay Power Station (including the additional No. 3 unit), these would be appropriated for 21 years up to 2003, but in obtaining the average power cost for the entire analysis period up to 2025, these capital costs and operation and maintenance costs would be appropriated as average costs for a 43 year period. The average power supply costs by period are as indicated below.

Calculation Period	Interest Rate 8%	Interest Rate 10%
Av. Annual Cost for 1983 ~ 2003 (1,000 Eth$)	5,892	6,752
Av. Annual Cost for 1983 ~ 2025 (1,000 Eth$)	5,702	6,603

13.2.3 Revenue/Cost Ratio

On determining the revenue/cost ratio of the Lake Tana Project comparing the average annual sales revenue and average annual power cost converted to present worth obtained according to the foregoing, the result will be as follows:

(1,000 Eth$)

Calculation Period	Average Annual Revenue and Cost			
	Interest Rate 8%		Interest Rate 10%	
	Present Tariff	Adjusted Tariff	Present Tariff	Adjusted Tariff
1983 ~ 2003				
Sales Revenue				
Lake Tana Project	5,699	5,966	5,599	5,866
Upper Beles Project	1,490	1,490	1,173	1,173
Total	7,189	7,456	6,772	7,039
Power Cost	5,892		6,752	

(1,000 Eth$)

Calculation Period	Average Annual Revenue and Cost			
	Interest Rate 8%		Interest Rate 10%	
	Present Tariff	Adjusted Tariff	Present Tariff	Adjusted Tariff
1983 ~ 2025				
Sales Revenue				
Lake Tana Project	5,384	5,606	5,385	5,620
Upper Beles Project	3,484	3,524	2,425	2,457
Total	8,868	9,130	7,810	8,077
Power Cost	5,702		6,603	

Calculation Period	Revenue/Cost Ratio			
	Interest Rate 8%		Interest Rate 10%	
	Present Tariff	Adjusted Tariff	Present Tariff	Adjusted Tariff
1983 ~ 2003				
Lake Tana Project alone	0.97	1.01	0.83	0.87
Incl. energy from Upper Beles Project	1.22	1.27	1.003	1.04
1983 ~ 2025				
Lake Tana Project alone	0.94	0.98	0.82	0.85
Incl. energy from Upper Beles Project	1.56	1.60	1.18	1.22

13.2.4 Conclusions Regarding Analysis Results

The following conclusions are obtained based on the table of the preceding item.

(1) Case of Adopting Period of 1983 ~ 2003

(a) In case of the Lake Tana Project alone, in effect, the case of relying on only the sales revenue from energy produced at the existing Tis Abbay Power

Station (including the additional No. 3 unit) and Tis Abbay No. 2 Power Station, only with the interest rate of the funds procured at 8%, and moreover, with unit sales price to the electric boilers adjusted to about E¢2.52/kWh, will revenue and cost barely balance, and in all other cases revenues will be less than costs.

(b) However, if the revenue obtained through supplementary energy from Upper Beles Project is included, revenue will exceed cost by more than 20% even with the present tariff rates in case of interest rate of 8%.
However, when the interest rate of the funds procured is 10%, revenue and cost will only barely balance even if revenue based on energy received from Upper Beles Project is included.

(2) Case of Adopting Entire Period of 1983 ~ 2025

(a) In case of the Lake Tana Project alone, since it will not be possible to look forward to the supply capacity of the existing power station from part way during the analysis period, the revenue and cost balance will be slightly worse than for the period of 1983 ~ 2003, and in any case the revenue will be less than the cost.

(b) However, if the revenue through power received from Upper Beles Project is taken into account, the transmitting and transforming facilities of the Lake Tana Project will be brought into full utilization in the latter half of the analysis period through this supplementary electric power, and the revenue/cost ratio will be greatly improved. In case of an interest rate of 8%, there will be an increase in revenue of more than 50% over cost, and even in the case of an interest rate of 10% the revenue will be higher than cost by about 20%.

13.3 ELECTRIC POWER SUPPLY COST

The power supply cost serves as a basis for determining electricity charges, but the charges actually are established considering other factors such as the outlook of cash flow over a comparatively short period of time. In this financial analysis, therefore, the power supply cost of the Tis Abbay power stations for the period up to the year 2003 will be computed separating into the two categories of generating end and 15kV distribution line terminal.

13.3.1 Annual Generating Cost and Transmitting, Transforming and Distributing Cost

Regarding the annual power cost, it is as already described in 13.2.2, and when indicated separated into power generating facilities and transmitting, transforming and distributing facilities for the period of 1983 through 2003, the result will be as shown below.

(1,000 Eth$)

Cost Item	Interest Rate 8%			Interest Rate 10%		
	Capital Cost	Oper. & Maint. Cost	Total	Capital Cost	Oper. & Maint. Cost	Total
Power Generating Cost						
Regulating Dam	911	203	1,114	1,149	203	1,352
Additional No. 3 Unit	454	85	539	535	85	620
No. 2 Power Station	871	189	1,060	1,031	180	1,211
Existing Tis Abbay PS	227	140	367	262	140	402
Equipment Replacement Cost:						
No. 2 Power Station	82	-	82	64	-	64
Existing T. Abbay PS	210	-	210	220	-	220
Subtotal	2,755	617	3,372	3,261	608	3,869

Cost Item	Interest Rate 8%			Interest Rate 10%		
	Capital Cost	Oper. & Maint. Cost	Total	Capital Cost	Oper. & Maint. Cost	Total
Transmitting, Trans-forming, 15kV Distributing Cost						
Transmission Line	1,106	313	1,419	1,389	313	1,702
Substation, Telecommu-nication Facilities	364	108	472	458	108	566
15kV Distribution Line	99	28	127	123	28	151
Additional Transformer	179	49	228	192	43	235
Existing Bahar Dar SS	9	15	24	11	15	26
Existing 45kV Trans-mission Line	7	1	8	8	1	9
Equipment Replacement Cost:						
Transmission Line	161	-	161	128	-	128
SS, Telecommunication	36	-	36	26	-	26
15kV Distribution Line	14	-	14	11	-	11
Existing B. Dar SS	23	-	23	23	-	23
Existing 45kV Line	8	-	8	6	-	6
Subtotal	2,006	514	2,520	2,375	508	2,883
Total	4,761	1,131	5,892	5,636	1,116	6,752

13.3.2 Energy Supply

The amounts of energy supplied year by year at 15kV distribution line terminals are as indicated in Table 13-1, of which the total energy supplied and the average annual energy supplied by the Tis Abbay power stations are the following:

- Total energy supplied 1,414,454 MWh
- Average annual energy supplied 67,355 MWh

13.3.3 Power Supply Cost

Calculating the power supply cost of this development project based on the average annual power cost and the average annual energy supplied as described above, the results will be the following:

(E¢/kWh)

Classification	Interest Rate 8%	Interest Rate 10%
Power Generating Cost	5.0	5.74
Transmitting, Transforming, & 15kV Distributing Cost	3.75	4.26
Total	8.75	10.02
Of which, Capital Cost	7.07	8.36
Oper. & Maint. Cost	1.68	1.66

The above supply cost is fairly high compared with the supply cost of ICS up to now and the main causes are as follows:

(a) The considerable rises in electrical equipment prices and civil engineering construction costs since the oil crisis.

(b) Because all of the capital cost and operation cost of the regulating dam which is a facility in common with the Upper Beles Project is borne.

However, if this is compared with the supply cost of diesel power generation, it may still be said to be extremely cheap. For example, as indicated in 12.3.1 (7) of Chapter 12, the diesel power generation cost in 1975 totalling Self-Contained Systems was Eth$ 6,900,445 (not including interest) for a total generation of 44,485 MWh, and the average supply cost was E¢ 15.5/kWh. Consequently, the supply cost of this development project including interest may be considered to be one half of that of existing diesel power stations, with moreover, the additional merit of stability of supply free of influence from changes in oil prices and other factors.

13.4 CALCULATION OF PERMISSIBLE BORROWING TERMS IN PROCUREMENT OF FUNDS

The final theme in financial analysis, is discerning of the allowable limits to borrowing terms in procuring funds, taking into account the energy sales revenue and operating cost of the project. The loan conditions will consist of the interest rate and repayment period, and according to the case, the grace period which should be considered in the repayment period. The analysis to follow indicates a criterion for the permissible borrowing terms of the Lake Tana Project.

13.4.1 Base Conditions

(1) Repayment Period

The periods of repayment in case of loans by international financial institutions to developing countries for electric power development are usually around 15 to 20 years. Therefore, in this financial analysis, it was decided to carry out the analysis establishing beforehand the two cases below, long and short, regarding the repayment period.

- Case (X) Case of repayment period maximum of 20 years
- Case (Y) Case of repayment period minimum of 15 years

The analysis consists of finding the maximum limit of interest rate and grace period for each of the cases above.

(2) Amount of Funds Procured

The construction funds will be divided into foreign currency and domestic currency portions with foreign currency to be borrowed from a foreign country or an international financial institution, and domestic currency to be borrowed in Ethiopia. In this way, the 15 kV distribution line construction funds are also to be included in the borrowed funds other than the amounts indicated in the financial schedule and construction schedule of this Report. Therefore, the total amount of these funds will be as indicated below. (Further, although interest during construction will be determined by the interest rate of funds borrowed, since this study is an analysis as a tentative approach, the construction cost in case of interest rate of 8% indicated in Chapter 12 is applied for analysis. The influence on the study as a whole is practically nil.)

(1,000 Eth$)

	Investment Amount	Total Construction Cost (incl. Interest during Construction)
Regulating Dam	10,174	11,150
Additional No. 3 Unit	4,238	4,550
No. 2 Power Station	12,052	13,209
Transmission Lines	12,526	13,528
Substations, Telecommunication Facilities	4,310	4,516
Additional Transformers	3,786	3,990
15 kV Distribution Lines	1,151	1,206
Total	48,237	52,149

(3) Equipment Replacement Costs

Equipment replacement costs which will become necessary during a maximum period of 20 years from 1983 are those for the electrical equipment of the existing Tis Abbay Power Station and the equipment of Bahar Dar Substation, but it was considered that these replacement costs would be payed for out of accumulated net operating profits and are excluded as loan objectives.

(4) Additional Transformers and Tis Abbay No. 2 Power Station

The No. 2 Power Station is to be commissioned in 1986 and the additional transformer in 1991, but for the sake of simplicity both will be assumed to start operation in 1983 in calculations for the analysis.

13.4.2 Analysis

(1) Operating Balance

Regarding power revenues, only those from the Tis Abbay power stations are considered, and the operation and maintenance cost of each year and the beforementioned equipment replacement costs are deducted from these amounts. The cumulative balance in the form of net operating income at 15 years and 20 years from start of operation in 1983 will be as given below (see Table 13-4).

- Cumulative net operating income at 15 years Eth$ 67,907,000
- Cumulative net operating income at 20 years Eth$ 95,847,000

As for depreciation reserves, these are to be earmarked for repayment of borrowings and are included in the above cumulative operating income.

(2) Average Annual Repayable Amount and Amortization Rate

Based on the above, the average annual repayable amounts and the amortization rates for Case (X) of 20 year repayment and Case (Y) of 15 year repayment will be as indicated below.

(a) Average Annual Repayable Amount

- Case (X) . . . Eth$ 95, 847, 000/20 yr = Eth$ 4, 793, 000/yr
- Case (Y) . . . Eth$ 67, 907, 000/15 yr = Eth$ 4, 527, 000/yr

(b) Amortization Rate

- Case (X) . . . Eth$ 4, 793, 000/Eth$ 52, 149, 000 = 0. 09191
- Case (Y) . . . Eth$ 4, 527, 000/Eth$ 52, 149, 000 = 0. 08681

(3) Permissible Borrowing Interest Rate

Putting the permissible borrowing interest rate as R, the permissible borrowing interest rates for Case (X) and Case (Y) will respectively be the following:

- Case (X) . . . $\frac{R}{1-(1+R)^{-20}} = 0.09191$

- Case (Y) . . . $\frac{R}{1-(1+R)^{-15}} = 0.08681$

In effect, the permissible borrowing interest rate (maximum limit) for Case (X) will be 6. 6% per annum, and that for Case (Y) will be 3. 5% per annum.

(4) Grace Period Required

The amounts of repayment of principal and interest in equal installments determined based on the above repayment periods and permissible interest rates will be Eth$ 4, 770, 000 annually for Case (X) and Eth$ 4, 528, 000 annually for Case (Y).

On taking into account and comparing these amounts and the yearly cumulative amounts of net operating income in Table 13-4, it may be seen that a grace period of 3 years is necessary in order not to produce a deficit in the balance after making a repayment. Accordingly the permissible limits of repayment conditions for the two cases will be as follows:

- Case (X) . . . Repayment period, 20 years (including grace period of 3 years)
  Interest rate, 6. 6%
  Annual repayment of principal and interest in equal installments, Eth$ 5, 195, 000
  Total repayment amount, Eth$ 88, 315, 000

- Case (Y) . . . Repayment period, 15 years (including grace period of 3 years)
  Interest rate, 3.5%
  Annual repayment of principal and interest in equal installments, Eth$ 5, 397, 000
  Total repayment amount, Eth$ 64, 764, 000

The repayment schedule of funds borrowed based on the above is as shown in Table 13-4.

13.5 OVERALL CONCLUSIONS

Based on the above results of analysis, it will be possible to draw the following conclusions with respect to the financial soundness of the Lake Tana Project.

13.5.1 Financial Soundness Seen from Revenue/Cost Ratio

The analysis of financial soundness of a project must cover the entire service life of the project. In this regard, this development plan has been formulated taking into consideration the future Upper Beles Project, and power transmitting and transforming facilities are provided with margins to allow supply of supplementary power from that project. Consequently, in making an overall judgment, the revenue from energy supplied from the Upper Beles Project should naturally be included. In such case, this development project will indicate an revenue/cost ratio of around 1.20 even at an interest rate of 10% on funds procured (more than 1.50 in case of interest rate of 8%), and it may be concluded that the project is amply sound from a financial standpoint.

Further, the above revenue/cost ratio is based on calculations that the capital cost and operation and maintenance cost of the regulating dam will be borne entirely by this Lake Tana Project. If a part of this common facility were to be allocated to the Upper Beles Project considering the water used and the period of utilization, the economic and financial soundness of this development project would be even greater.

13.5.2 Power Supply Cost

The power supply cost of this development project will be fairly high compared with that of the existing ICS, but this is mainly due to rises in commodity prices since the oil crisis. However, when compared with the cost of supply by diesel power generation, it is only one half, and moreover, the stability of supply is high. Therefore, when the cumulatively increasing deficit in the present diesel power supply is considered, it is believed that the implementation of this development plan will contribute greatly toward improvement of the financial state of EELPA.

13.5.3 Conditions for Procurement of Funds

The permissible conditions for procurement of funds for implementation of this development plan are an interest rate of 3.5% in case of a repayment period of 15 years and 6.6% in case of a repayment period of 20 years, and concrete loan conditions should be established within the range of these permissible conditions. These conditions, when viewed against the lending conditions of the I.B.R.D., for instance, are somewhat excessively soft, but are thought to be sufficiently feasible when seen from ordinary bilateral economic cooperation loan standards.

Table 13-1 Annual Energy Sold

(MWh)

Year	Energy Demand by Region				Energy Sold by Tana Project				Energy Sold by Upper Beles Project				Remarks
	Bahar Dar Area	North and East Reg.	South Region	Total	General Consumers	Textile motors	Textile boilers	Total	General Consumers	Textile motors	Textile boilers	Total	
1983	39,018	11,588	2,437	53,043	17,893	13,250	21,900	53,043					
1984	39,424	12,805	2,691	54,920	19,770	13,250	21,900	54,920					Energy sold shown in this table is estimated at 15kV terminal.
1985	39,879	14,146	2,976	57,001	21,851	13,250	21,900	59,001					
1986	40,369	15,633	3,288	59,290	24,140	13,250	21,900	59,290					
1987	40,917	17,275	3,643	61,835	26,685	13,250	21,900	61,835					*Distribution loss to supply* general consumers is estimated to be 10% for North and East regions, and South region of the lake, and 6% for city of Bahar Dar.
1988	41,522	19,088	4,016	64,626	29,476	13,250	21,900	64,626					
1989	43,191	21,094	4,438	67,723	32,573	13,250	21,900	67,723					
1990	42,932	23,308	4,904	71,144	35,994	13,250	21,900	71,144					
1991	43,711	25,638	5,506	74,855	35,994	13,250	21,900	71,144	3,711			3,711	
1992	44,566	28,202	5,935	78,703	35,994	13,250	21,900	71,144	7,559			7,559	
1993	45,507	31,024	6,529	83,060	35,994	13,250	21,900	71,144	11,916			11,916	
1994	46,544	34,127	7,181	87,852	35,994	13,250	21,900	71,144	16,708			16,708	
1995	47,683	37,536	7,900	93,118	35,994	13,250	21,900	71,144	21,974			21,974	
1996	48,936	41,292	8,689	98,917	35,994	13,250	21,900	71,144	27,773			27,773	
1997	50,314	45,420	9,560	105,294	35,994	13,250	21,900	71,144	34,150			34,150	
1998	51,830	49,965	10,515	112,310	35,994	13,250	21,900	71,144	41,166			41,166	
1999	53,499	54,959	11,566	120,024	35,994	13,250	21,900	71,144	48,880			48,880	
2000	55,334	60,456	12,723	128,513	35,994	13,250	21,900	71,144	57,369			57,369	
2001	57,230	62,250	14,407	133,887	35,994	13,250	21,900	71,144	62,743			62,743	
2002	59,307	62,250	15,228	136,785	35,994	13,250	21,900	71,144	65,641			65,641	
2003	61,578	62,250	16,658	140,486	35,994	13,250	21,900	71,144	69,342			69,342	
2004	64,062	62,250	18,223	144,535	23,620			23,620	85,765	13,250	21,900	120,915	
2005	66,780	62,250	19,938	148,968	23,620			23,620	90,198	13,250	21,900	125,348	
2006	69,753	62,250	21,813	153,816	23,620			23,620	95,046	13,250	21,900	130,196	
2007	73,005	62,250	23,863	159,118	23,620			23,620	100,348	13,250	21,900	135,498	
2008	76,564	62,250	26,106	164,920	23,620			23,620	106,150	13,250	21,900	141,300	
2009	80,457	62,250	28,560	171,267	23,620			23,620	112,497	13,250	21,900	147,647	
2010	84,715	62,250	31,245	178,210	23,620			23,620	119,440	13,250	21,900	154,590	
2011	86,750	62,250	34,182	183,182	23,620			23,620	124,412	13,250	21,900	159,762	
2012	86,750	62,250	37,395	186,395	23,620			23,620	127,625	13,250	21,900	162,775	
2013	86,750	62,250	40,910	189,910	23,620			23,620	131,140	13,250	21,900	166,290	
2014	86,750	62,250	44,756	193,756	23,620			23,620	134,986	13,250	21,900	170,136	
2015	86,750	62,250	48,963	197,963	23,620			23,620	139,193	13,250	21,900	174,343	
2016	86,750	62,250	53,565	202,565	23,620			23,620	143,795	13,250	21,900	178,945	
2017	86,750	62,250	58,601	207,601	23,620			23,620	148,831	13,250	21,900	183,781	
2018	86,750	62,250	64,109	213,109	23,620			23,620	154,339	13,250	21,900	189,489	
2019 to 2025	86,750	62,250	68,840	217,840	23,620	278,250		23,620	159,070	13,250	21,900	194,220	
Total				6,103,581	1,195,944	278,250	459,900	1,934,094	3,396,187	291,500	481,800	4,169,487	

Table 13-2 (1) Present Worth Average Annual Revenues from Sales of Energy Supplied by Tana Project

(1000 Eth$)

Year	Annual Revenues from Sales of Energy						Present Worth (Actual Tariff)				Present Worth (Adjusted Tariff)			
	General customers	Textile motors	Textile boilers		Total		Interest rate : 8%		Interest rate : 10%		Interest rate : 8%		Interest rate : 10%	
			Actual tariff	Adjusted tariff	Actual tariff	Adjusted tariff	Yearly	Cumulat.	Yearly	Cumulat.	Yearly	Cumulat.	Yearly	Cumulat.
1983	2,899	603	285	552	3,787	4,054	3,506	3,506	3,442	3,442	3,753	3,753	3,685	3,685
1984	3,203	603	285	552	4,091	4,358	3,507	7,013	3,380	6,822	3,736	7,489	3,601	7,286
1985	3,540	603	285	552	4,428	4,695	3,515	10,528	3,327	10,149	3,727	11,216	3,527	10,813
1986	3,911	603	285	552	4,799	5,066	3,527	14,055	3,277	13,426	3,724	14,940	3,460	14,273
1987	4,323	603	285	552	5,211	5,478	3,546	17,601	3,236	16,662	3,728	18,668	3,401	17,674
1988	4,775	603	285	552	5,663	5,930	3,568	21,169	3,197	19,859	3,736	22,404	3,347	21,021
1989	5,277	603	285	552	6,165	6,432	3,597	24,766	3,164	23,023	3,753	26,157	3,301	24,322
1990	5,831	603	285	552	6,719	6,986	3,630	28,396	3,134	26,157	3,773	29,930	3,259	27,581
1991	5,831	603	285	552	6,719	6,986								
....	5,831	603	285	552	6,719	6,986								
....	5,831	603	285	552	6,719	6,986	28,691		22,265		29,831		23,150	
....	5,831	603	285	552	6,719	6,986								
2003	5,831	603	285	552	6,719	6,986		57,087		48,422		59,761		50,731
2004	3,827				3,827	3,827								
....	3,827				3,827	3,827								
....	3,827				3,827	3,827	7,755		4,536		7,755		4,536	
....	3,827				3,827	3,827								
2025	3,827				3,827	3,827		64,842		52,958		67,516		55,267

Unit Price per kWh Sold

	Actual Tariff	Adjusted Tariff
• General customers	E¢ 18.0	E¢ 18.0
• Textile motors	E¢ 4.55	E¢ 4.55
• Textile boilers	E¢ 1.30	E¢ 2.52

Average Annual Revenues (Actual Tariff)

Interest Rate : 8%

- From 1983 to 2003 ... Eth$ 5,699
- From 1983 to 2025 ... Eth$ 5,384

Interest Rate : 10%

- From 1983 to 2003 ... Eth$ 5,599
- From 1983 to 2025 .. Eth$ 5,385

Average Annual Revenues (Adjusted Tariff)

Interest Rate : 8%

- From 1983 to 2003 ... Eth$ 5,966
- From 1983 to 2025 ... Eth$ 5,606

Interest Rate : 10%

- From 1983 to 2003 ... Eth$ 5,866
- From 1983 to 2025 ... Eth$ 5,620

Table 13-2 (2) Present Worth Average Annual Revenues from Sales of Energy Supplied by Upper Beles Project

(1000 Eth$)

Year	Annual Revenues from Sales of Energy						Annual Energy Costs		Present Worth (Actual Tariff)				Present Worth (Adjusted Tariff)			
	General customers	Textile motors	Textile boilers		Total				Interest rate : 8%		Interest rate : 10%		Interest rate : 8%		Interest rate : 10%	
			Actual tariff	Adjusted tariff	Actual tariff	Adjusted tariff	Interest rate: 8%	Interest rate:10%	Yearly	Cumulat.	Yearly	Cumulat.	Yearly	Cumulat.	Yearly	Cumulat.
1991	601				601	601	166	202	218	218	169	169	218	218	169	169
1992	1,225				1,225	1,225	339	410	410	628	315	484	410	628	315	484
1993	1,930				1,930	1,930	534	647	599	1,227	450	934	599	1,227	450	934
1994	2,707				2,707	2,707	749	907	780	2,007	574	1,508	780	2,007	574	1,508
1995	3,560				3,560	3,560	984	1,193	947	2,954	685	2,193	947	2,954	685	2,193
1996	4,499				4,499	4,499	1,244	1,508	1,108	4,062	787	2,980	1,108	4,062	787	2,980
1997	5,532				5,532	5,532	1,530	1,854	1,261	5,323	880	3,860	1,261	5,323	880	3,860
1998	6,669				6,669	6,669	1,844	2,235	1,408	6,731	965	4,825	1,408	6,731	965	4,825
1999	7,919				7,919	7,919	2,190	2,654	1,548	8,279	1,042	5,867	1,548	8,279	1,042	5,867
2000	9,294				9,294	9,294	2,570	3,115	1,682	9,961	1,111	6,978	1,682	9,961	1,111	6,978
2001	10,164				10,164	10,164	2,811	3,407	1,704	11,665	1,105	8,083	1,704	11,665	1,105	8,083
2002	10,634				10,634	10,634	2,941	3,564	1,650	13,315	1,051	9,134	1,650	13,315	1,051	9,134
2003	11,233				11,233	11,233	3,107	3,765	1,614	14,929	1,009	10,143	1,614	14,929	1,009	10,143
2004	13,894	603	285	552	14,782	15,049	5,416	6,566	1,722	16,651	1,008	11,151	1,771	16,700	1,042	11,185
2005	14,612	603	285	552	15,500	15,767	5,616	6,806	1,683	18,334	971	12,122	1,729	18,429	1,000	12,185
2006	15,397	603	285	552	16,285	16,552	5,833	7,070	1,648	19,982	935	13,057	1,690	20,119	962	13,147
2007	16,256	603	285	552	17,144	17,411	6,070	7,358	1,617	21,599	904	13,961	1,656	21,775	928	14,075
2008	17,196	603	285	552	18,084	18,351	6,330	7,673	1,589	23,188	874	14,835	1,625	23,400	896	14,971
2009	18,225	603	285	552	19,113	19,380	6,615	8,017	1,565	24,753	846	15,681	1,598	24,998	867	15,838
2010	19,349	603	285	552	20,237	20,504	6,926	8,394	1,542	26,295	822	16,503	1,573	26,571	840	16,678
2011	20,155	603	285	552	21,043	21,310	7,148	8,664	1,491	27,786	780	17,283	1,519	28,090	797	17,475
2012	20,675	603	285	552	21,563	21,830	7,292	8,839	1,418	29,267	729	18,012	1,444	29,534	745	18,220
2013	21,245	603	285	552	22,133	22,400	7,449	9,030	1,351	30,618	683	18,695	1,376	30,910	696	18,916
2014	21,868	603	285	552	22,756	23,023	7,622	9,238	1,290	31,908	640	19,335	1,312	32,222	653	19,569
2015	22,549	603	285	552	23,437	23,704	7,810	9,467	1,232	33,140	602	19,937	1,254	33,476	613	20,182
2016	23,295	603	285	552	24,183	24,450	8,017	9,717	1,181	34,321	566	20,503	1,200	34,676	576	20,758
2017	24,111	603	285	552	24,999	25,266	8,242	9,990	1,133	35,454	535	21,038	1,152	35,828	544	21,302
2018	25,003	603	285	552	25,891	26,158	8,489	10,289	1,090	36,544	505	21,543	1,106	36,934	513	21,815
2019-2025	25,769	603	285	552	26,657	26,924	8,701	10,546	5,420	41,964	2,306	23,849	5,501	42,435	2,345	24,160

Unit Price per kWh Sold

	Actual Tariff	Adjusted Tariff
- General customers	E₵ 18.0	E₵ 18.0
- Textile motors	E₵ 4.55	E₵ 4.55
- Textile boilers	E₵ 1.30	E₵ 2.52

Energy Costs of Upper Beles Project

- Interest rate : 8% ...... E₵ 4.48/kWh
- Interest rate : 10% ...... E₵ 5.43/kWh

Average Annual Revenues (Actual Tariff)

Interest Rate : 8%

- From 1983 to 2003 ... Eth$ 1,490
- From 1983 to 2025 ... Eth$ 3,484

Interest Rate : 10%

- From 1983 to 2003 ... Eth$ 1,173
- From 1983 to 2025 ... Eth$ 2,425

Average Annual Revenues (Adjusted Tariff)

Interest Rate : 8%

- From 1983 to 2003 ... Eth$ 1,490
- From 1983 to 2025 ... Eth$ 3,524

Interest Rate : 10%

- From 1983 to 2003 ... Eth$ 1,173
- From 1983 to 2025 ... Eth$ 2,457

Table 13-3 Present Worth Average Annual Costs of Power Supply (Costs of Tana Project)

(1000 Eth$)

Item	Investment Costs	Year of Commissioning	Capital Costs Interest Rate: 8%	Capital Costs Interest Rate: 10%	Present Worth (1983) Interest Rate: 8%	Present Worth (1983) Interest Rate: 10%	Amortization Period from 1983 (years)	Average Annual Costs Interest Rate: 8%	Average Annual Costs Interest Rate: 10%
Costs of Initial Facilities									
- Regulating dam	10,174	1,983	11,150	11,395	11,150	11,395	50	911	1,149
- No.3 turbine-generator	4,238	1,983	4,550	4,629	4,550	4,629	21	454	535
- No.2 Power Station	12,052	1,986	13,209	13,498	13,528	13,778	43	871	1,031
- Transmission lines	12,526	1,983	13,528	13,778	13,528	13,778	50	1,106	1,389
- Substations and telecommunication	4,310	1,983	4,516	4,568	4,516	4,568	60	364	458
- 15 kV distribution lines	1,151	1,983	1,206	1,220	1,206	1,220	50	99	123
- Additional transformers	3,786	1,991	3,990	4,043	2,155	1,886	43	179	192
Replacement of Initial Facilities									
- No.2 Power Station	6,420	2,008	6,728	6,805	982	628	43	82	64
- Transmission lines	12,526	2,008	13,528	13,778	1,975	1,271	50	161	128
- Substations and telecommunication	4,310	2,013	4,516	4,568	449	262	60	36	26
- 15 kV distribution lines	1,151	2,008	1,206	1,220	176	113	50	14	11
Replacement of Existing Facilities									
- Tis Abbay Power Station	3,186	1,989	3,338	3,377	2,103	1,906	21	210	220
- Bahar Dar Substation	616	1,994	645	652	276	229	43	23	23
- 45 kV transmission line	1,071	2,014	1,122	1,135	103	59	81	8	6
Amortization of Existing Facilities									
- Tis Abbay Power Station	2,269						21	227	262
- Bahar Dar Substation	(2) 113						43	9	11
- 45 kV transmission line	79						43	7	8
Sub-total								4,761	5,636
Operation and Maintenance Costs	Base Cost				Capitalized (1983)				
- Regulating dam	203				2,483	2,012	50	203	203
- No.3 turbin-generator	85				851	735	21	85	85
- No.2 Power Station	241				2,281	1,770	43	189	160
- Transmission lines	313				3,829	3,103	50	313	313
- Substations and telecommunication	108				1,337	1,076	60	108	108
- 15 kV distribution lines	28				343	278	50	28	28
- Additional transformers	95				598	427	43	49	43
- Tis Abbay Power Station	140				1,402	1,210	21	140	140
- Bahar Dar Substation	15				181	148	43	15	15
- 45 kV transmission line	1				12	10	43	1	1
Sub-total								1,131	1,116
Average Annual Costs (1983 to 2003)								5,892	6,752
(1) Average Annual Costs (1983 to 2025)								5,702	6,603

(1) Figures are calculated by amortizing the following costs over 43 years from 1983 :
- Capital cost of No.3 turbine generator.
- Replacement cost of electrical equipment of existing Tis Abbay Power Station.
- Remaining capital cost of existing Tis Abbay Power Station.
- O and M cost of existing Tis Abbay Power Station, including No.3 turbine-generator.

In this table, capital costs means investment costs plus interest during construction.

(2) Book values at the beginning of 1983.

Table 13-4 Cash Flow and Repayment Schedule (Tentative Approach)

(1000 Eth$)

No.	Year	Cash Flow				Net Income		Repayment Schedule					
		Power	Expenditures					Case (X)			Case (Y)		
		Revenues	O and M Expenses	Replacement Expenses	Total	Yearly	Cumulat. (A)	Funds Borrowed	Repayment (B)	Balance (A)-(B)	Funds Borrowed	Repayment (B)'	Balance (A)-(B)'
0								52,149			52,149		
1	1983	3,787	893		893	2,894	2,894			2,894			2,894
2	1984	4,091	893		893	3,198	6,092			6,092			6,092
3	1985	4,428	893		893	3,535	9,627			9,627			9,627
4	1986	4,799	1,082		1,082	3,717	13,344		5,195	8,149		5,397	7,947
5	1987	5,211	1,082		1,082	4,129	17,473		5,195	7,083		5,397	6,679
6	1988	5,663	1,082	3,338	4,420	1,243	18,716		5,195	3,131		5,397	2,525
7	1989	6,165	1,082		1,082	5,083	23,799		5,195	3,019		5,397	2,211
8	1990	6,719	1,082		1,082	5,637	29,436		5,195	3,461		5,397	2,451
9	1991	6,719	1,131		1,131	5,588	35,024		5,195	3,854		5,397	2,642
10	1992	6,719	1,131		1,131	5,588	40,612		5,195	4,247		5,397	2,833
11	1993	6,719	1,131	645	1,776	4,943	45,555		5,195	3,995		5,397	2,379
12	1994	6,719	1,131		1,131	5,588	51,143		5,195	4,388		5,397	2,570
13	1995	6,719	1,131		1,131	5,588	56,731		5,195	4,781		5,397	2,761
14	1996	6,719	1,131		1,131	5,588	62,319		5,195	5,174		5,397	2,952
15	1997	6,719	1,131		1,131	5,588	67,907		5,195	5,567		5,397	3,143
16	1998	6,719	1,131		1,131	5,588	73,495		5,195	5,960			
17	1999	6,719	1,131		1,131	5,588	79,083		5,195	6,353			
18	2000	6,719	1,131		1,131	5,588	84,671		5,195	6,746			
19	2001	6,719	1,131		1,131	5,588	90,259		5,195	7,139			
20	2002	6,719	1,131		1,131	5,588	95,847		5,195	7,532			
Total		121,491	21,661	3,983	25,644	95,847			88,315			64,764	

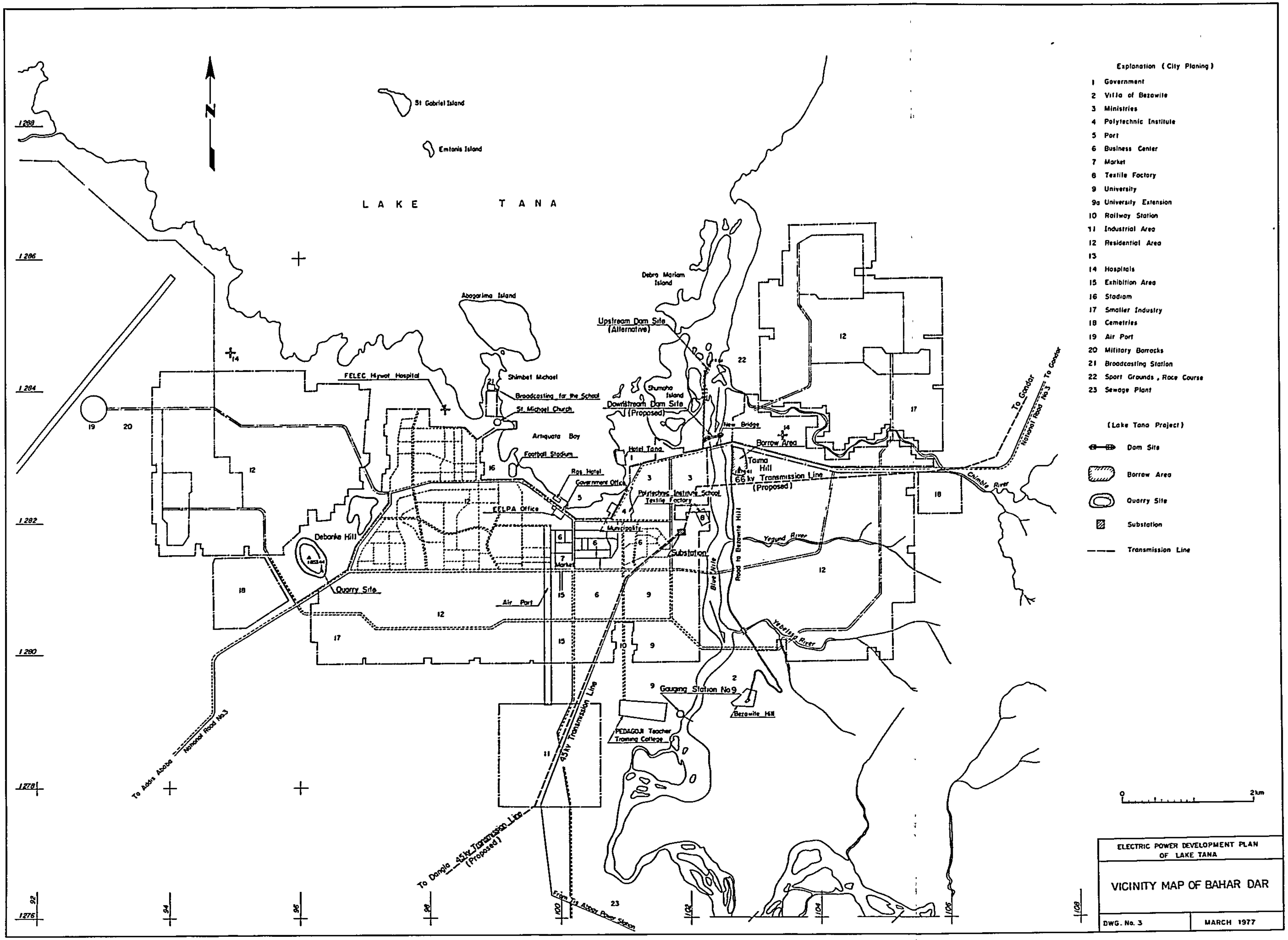
Note : Repayment includes capital and interest.

Loan conditions are as follows :

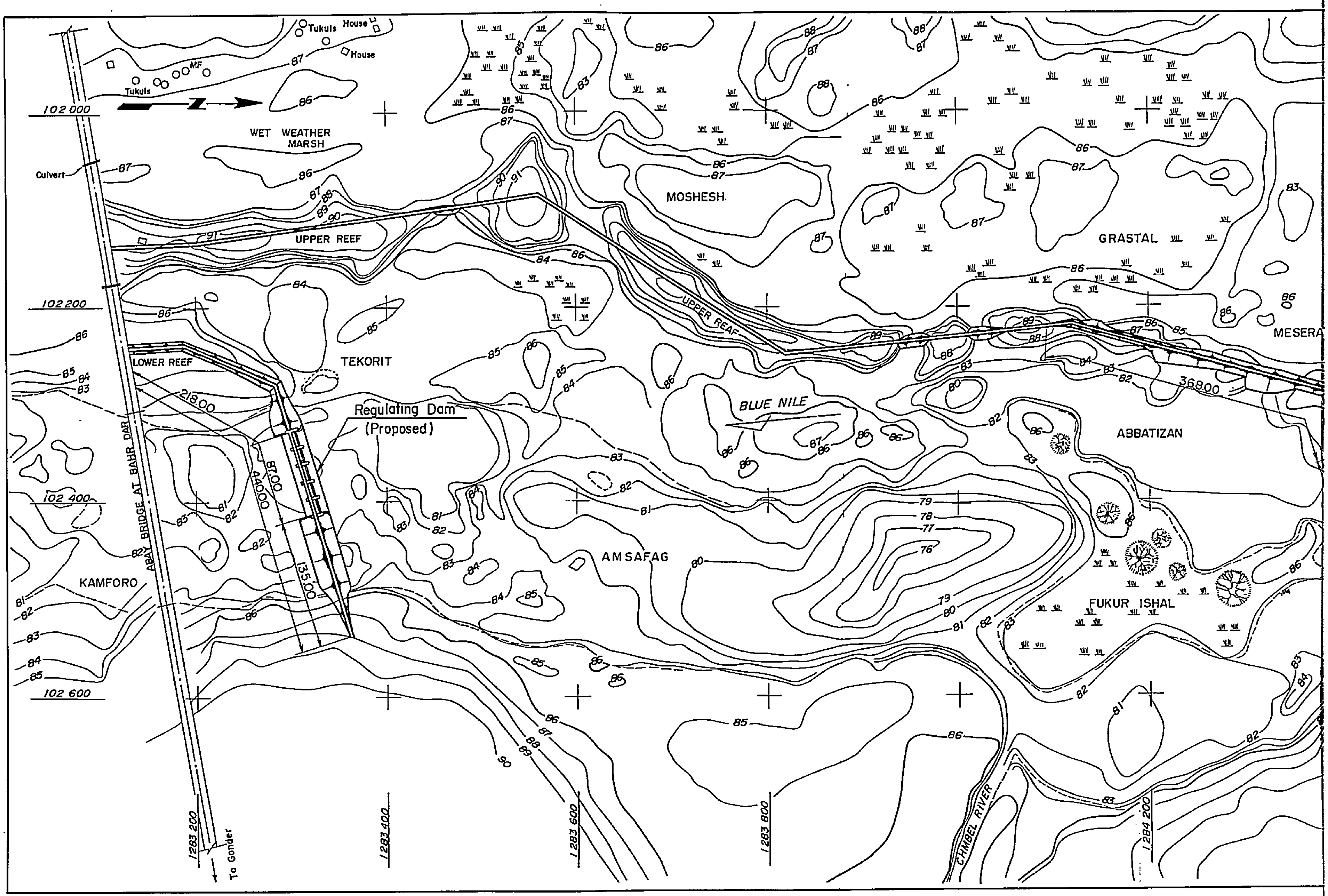
Case (X) .... Interest of 6.6% per year.
Repayment period of 20 years including grace period of 3 years.

Case (Y) .... Interest of 3.5% per year.
Repayment period of 15 years including grace period of 3 years.

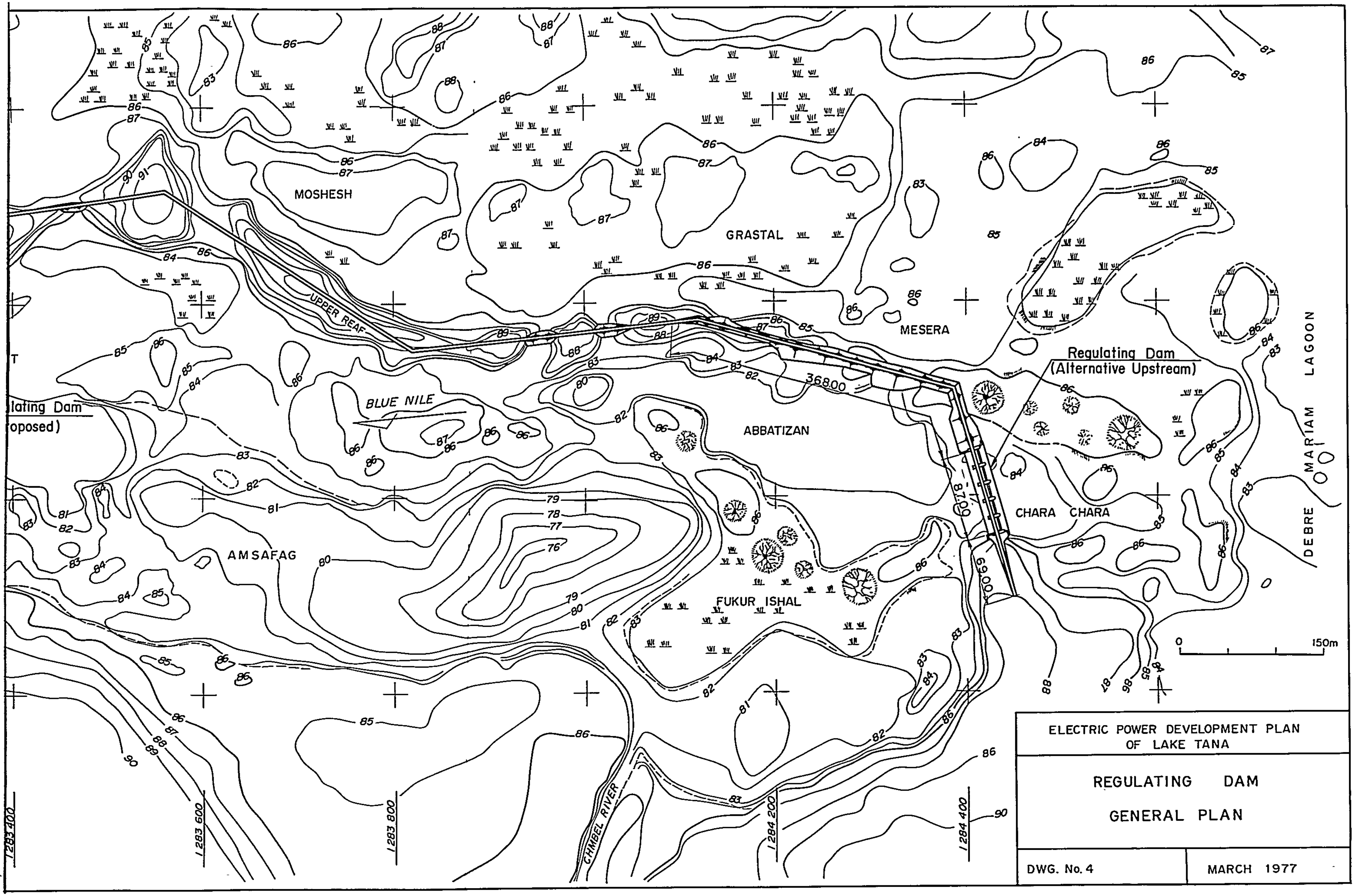
DRAWINGS

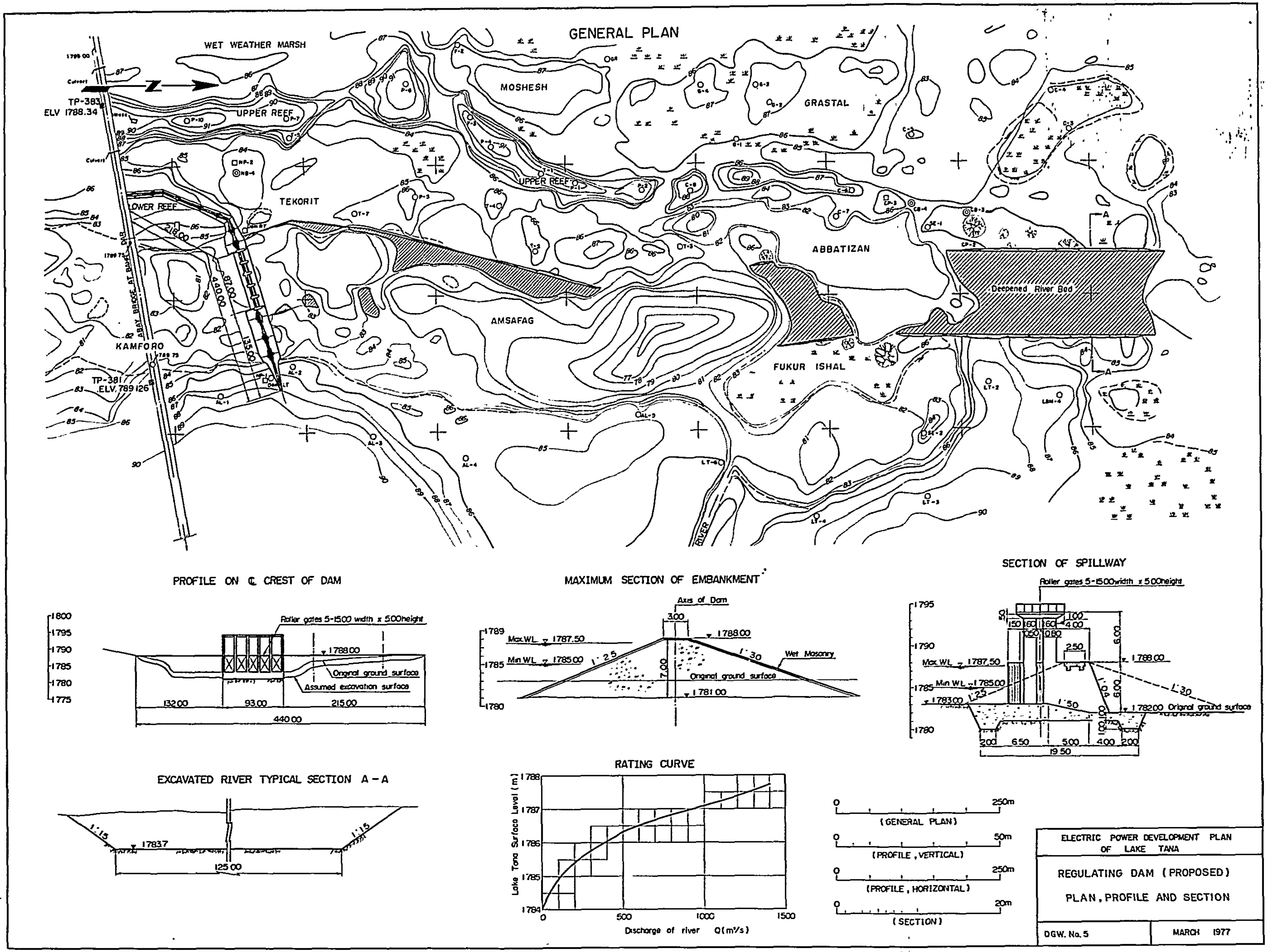


N
LAKE TANA
St Gabriel Island
Emtonis Island
Abagarima Island
Debra Mariam Island
Shumoho Island
Shimbet Michael
FELEC Hiywot Hospital
Broadcasting for the School
St Michael Church
Artiquata Bay
Football Stadium
Ras Hotel
Government Office
Hotel Tana
EELPA Office
Municipality
Market
Polytechnic Institute School
Textile Factory
Substation
Upstream Dam Site (Alternative)
Downstream Dam Site (Proposed)
New Bridge
Borrow Area
Taima Hill
66 kv Transmission Line (Proposed)
Debanke Hill
Quarry Site
Air Port
Blue Nile
Road to Bezawite Hill
Yegund River
Yebelsta River
Chimble River
Gauging Station No.9
Bezawite Hill
PEDAGOJI Teacher Training College
45kv Transmission Line
To Dangla 45kv Transmission Line (Proposed)
From Tis Abbay Power Station
To Addis Ababa National Road No.3
To Gondar National Road No.3 To Gondar
1 288
1 286
1 284
1 282
1 280
1 278
1 276
92
94
96
98
100
102
104
106
108
Explanation (City Planing)
1 Government
2 Villa of Bezawite
3 Ministries
4 Polytechnic Institute
5 Port
6 Business Center
7 Market
8 Textile Factory
9 University
9a University Extension
10 Railway Station
11 Industrial Area
12 Residential Area
13
14 Hospitals
15 Exhibition Area
16 Stadiam
17 Smaller Industry
18 Cemetries
19 Air Port
20 Military Barracks
21 Broadcasting Station
22 Sport Grounds, Race Course
23 Sewage Plant
(Lake Tana Project)
Dam Site
Borrow Area
Quarry Site
Substation
Transmission Line
0
2km
ELECTRIC POWER DEVELOPMENT PLAN OF LAKE TANA
VICINITY MAP OF BAHAR DAR
DWG. No. 3
MARCH 1977

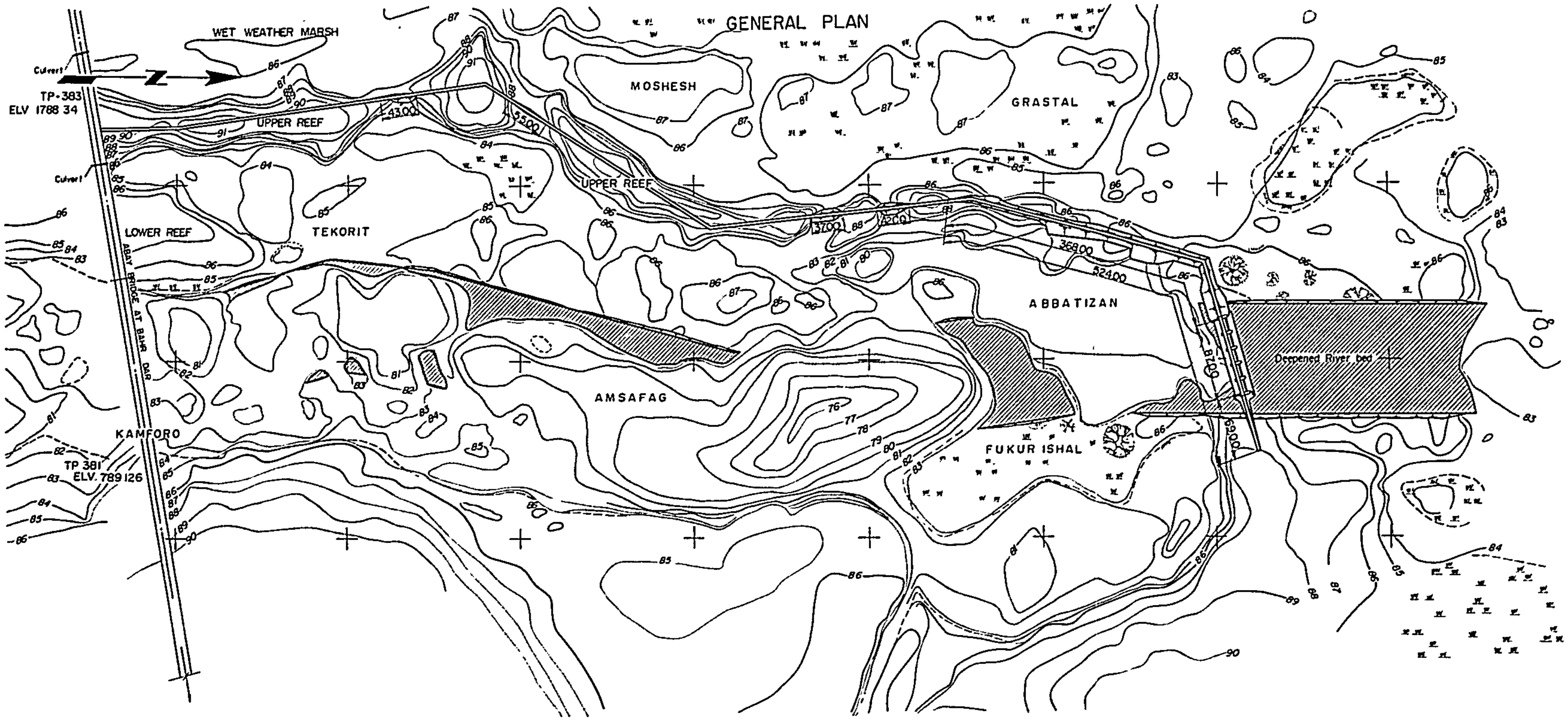


Tukuls
House
House
MF
Tukuls
102 000
WET WEATHER
MARSH
Culvert
UPPER REEF
MOSHESH.
GRASTAL
102 200
UPPER REAF
TEKORIT
LOWER REEF
MESERA
218.00
Regulating Dam
(Proposed)
BLUE NILE
368.00
ABBATIZAN
102 400
ABAY BRIDGE AT BAHR DAR
87.00
440.00
135.00
AMSAFAG
KAMFORO
FUKUR ISHAL
102 600
CHIMBEL RIVER
1283 200
To Gonder
1283 400
1283 600
1283 800
1284 200

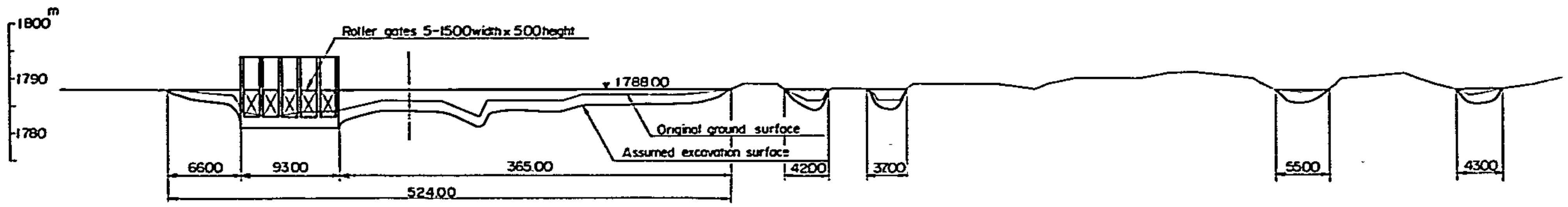

MOSHESH
GRASTAL
MESERA
UPPER REAF
BLUE NILE
ABBATIZAN
CHARA CHARA
AMSAFAG
FUKUR ISHAL
CHMBEL RIVER
DEBRE MARIAM LAGOON
Regulating Dam
(Alternative Upstream)
...lating Dam
...roposed)
368.00
609.8
600.9
0 150m
1 283 400
1 283 600
1 283 800
1 284 200
1 284 400
ELECTRIC POWER DEVELOPMENT PLAN
OF LAKE TANA
REGULATING DAM
GENERAL PLAN
DWG. No. 4
MARCH 1977

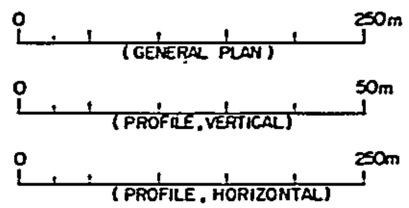

GENERAL PLAN
WET WEATHER MARSH
UPPER REEF
MOSHESH
GRASTAL
TEKORIT
LOWER REEF
ABBATIZAN
Deepened River Bed
AMSAFAG
KAMFORO
FUKUR ISHAL
RIVER
ABAY BRIDGE AT BAHR DAR
TP-383
ELV 1788.34
TP-381
ELV. 789.126
Culvert
440.00
87.00
135.00
PROFILE ON ℄ CREST OF DAM
Roller gates 5-15.00 width x 5.00height
1788.00
Original ground surface
Assumed excavation surface
132.00
93.00
215.00
440.00
MAXIMUM SECTION OF EMBANKMENT
Axis of Dam
3.00
Max.WL 1787.50
Min.WL 1785.00
1788.00
1:2.5
1:3.0
Wet Masonry
7.00
Original ground surface
1781.00
SECTION OF SPILLWAY
Roller gates 5-15.00width x 5.00height
Max.WL 1787.50
Min.WL 1785.00
1783.00
1788.00
1782.00 Original ground surface
19.50
EXCAVATED RIVER TYPICAL SECTION A - A
1:1.5
1783.7
125.00
RATING CURVE
Lake Tana Surface Level (m)
Discharge of river Q(m³/s)
(GENERAL PLAN)
(PROFILE, VERTICAL)
(PROFILE, HORIZONTAL)
(SECTION)
ELECTRIC POWER DEVELOPMENT PLAN OF LAKE TANA
REGULATING DAM (PROPOSED)
PLAN, PROFILE AND SECTION
DGW. No. 5
MARCH 1977

GENERAL PLAN

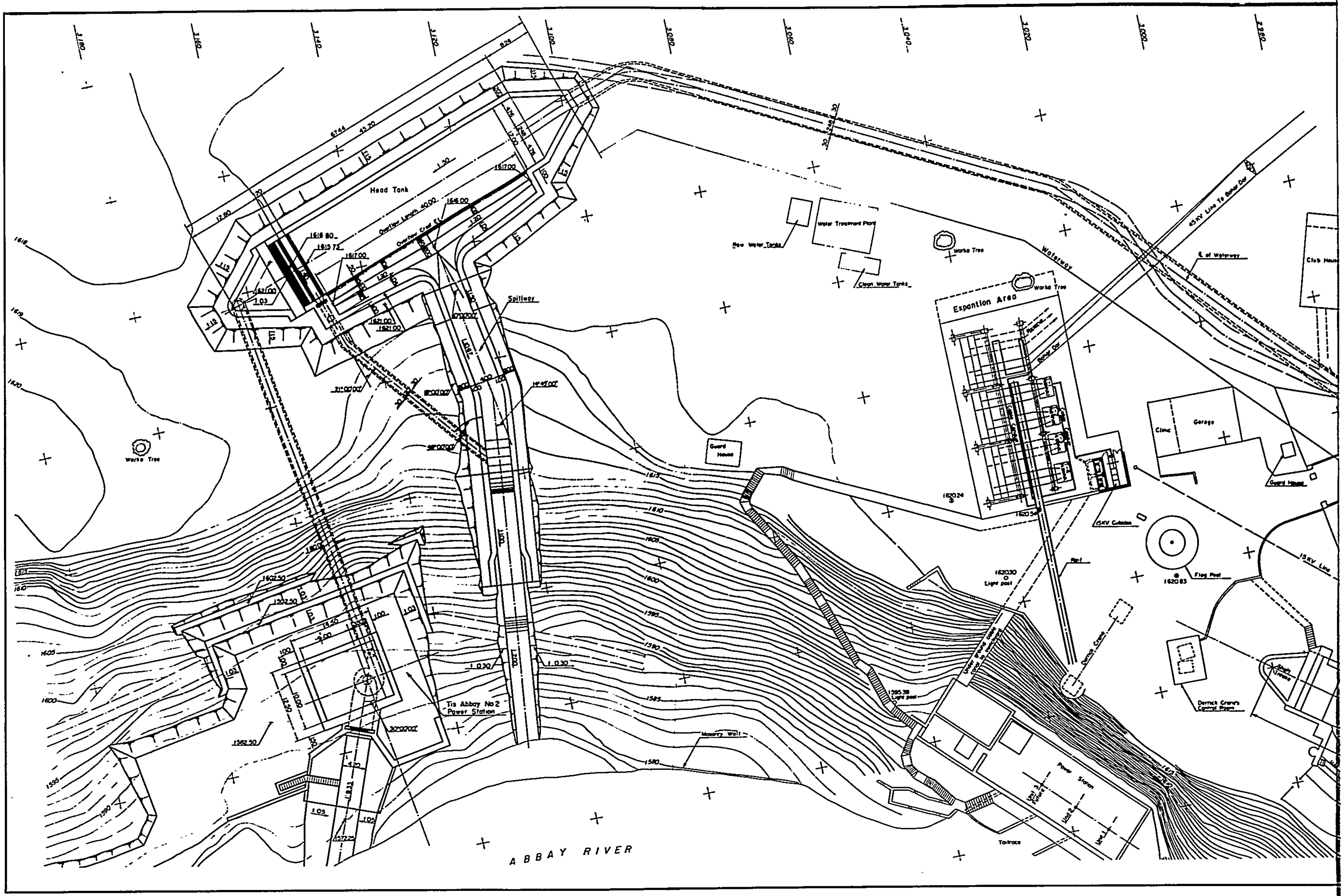


PROFILE OF ℄ CREST OF DAM

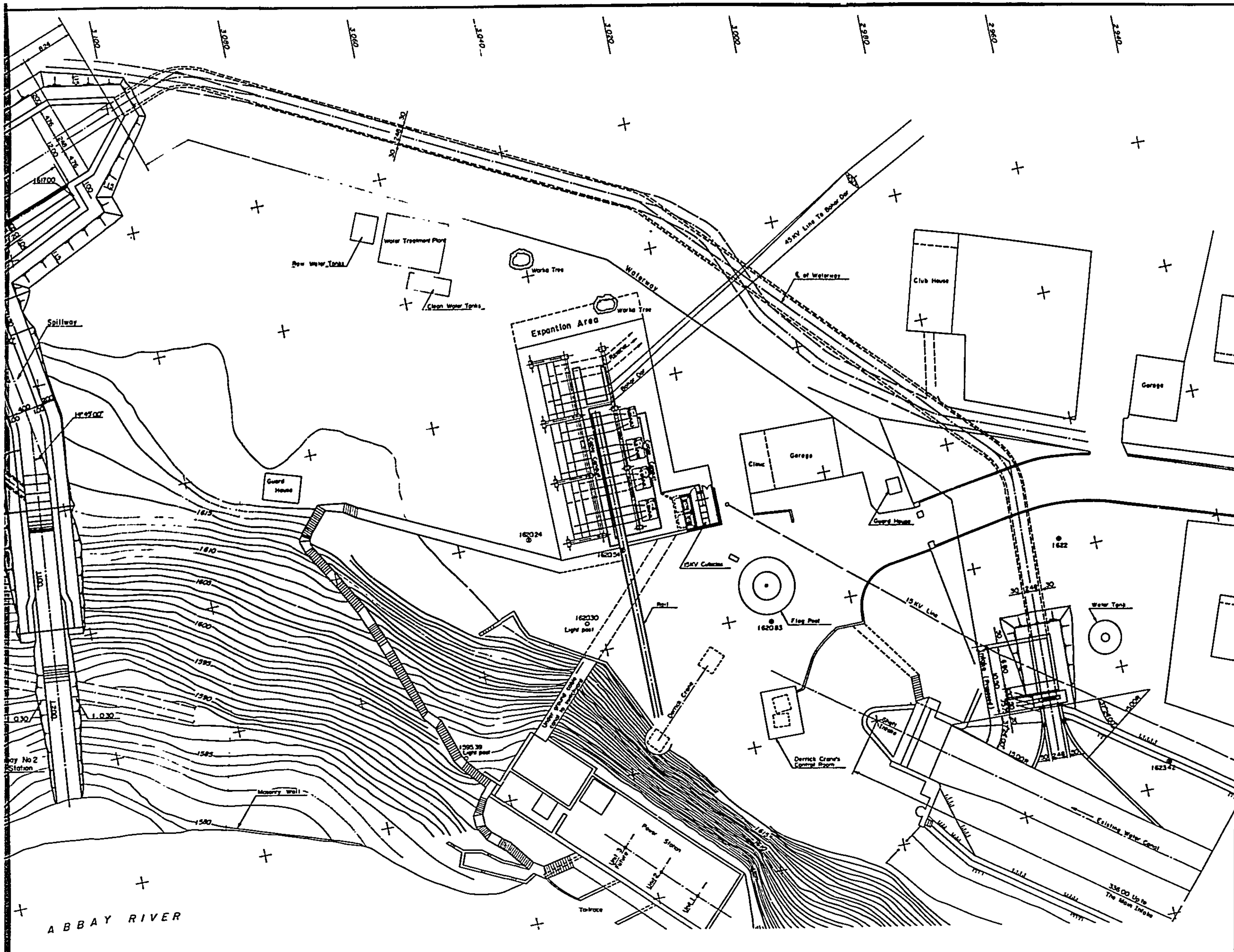




ELECTRIC POWER DEVELOPMENT PLAN OF LAKE TANA	
REGULATING DAM (ALTERNATIVE, UPSTREAM) PLAN AND PROFILE	
DWG. No. 6	MARCH 1977



Head Tank
Spillway
Water Treatment Plant
Raw Water Tanks
Clean Water Tanks
Worka Tree
Waterway
Expantion Area
Club House
Clinic
Garage
Guard House
Flag Pool
Light post
Power Station
Tailrace
Tis Abbay No 2 Power Station
Masonry Wall
A B B A Y   R I V E R



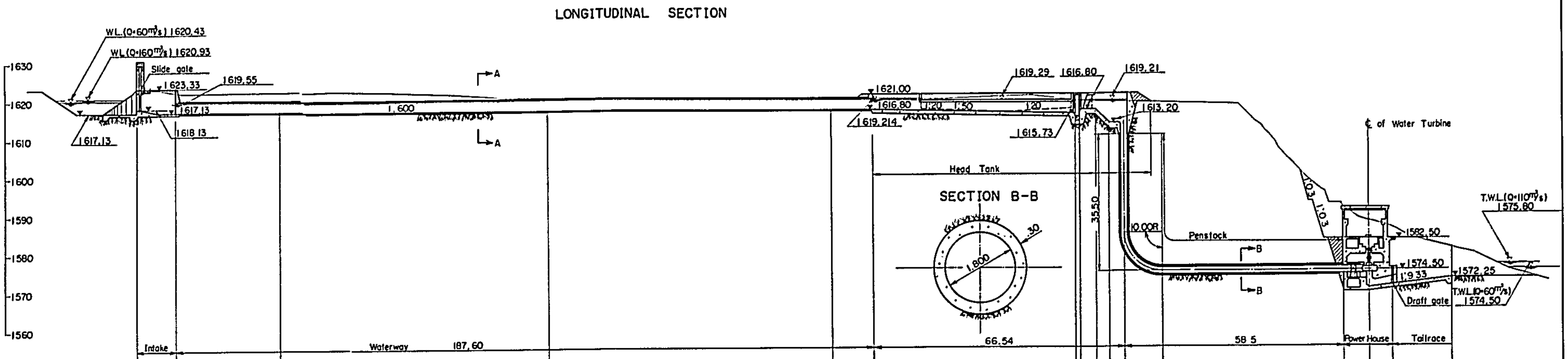
ELECTRIC POWER DEVELOPMENT PLAN OF LAKE TANA

TIS ABBY No.2 POWER STATION

GENERAL PLAN

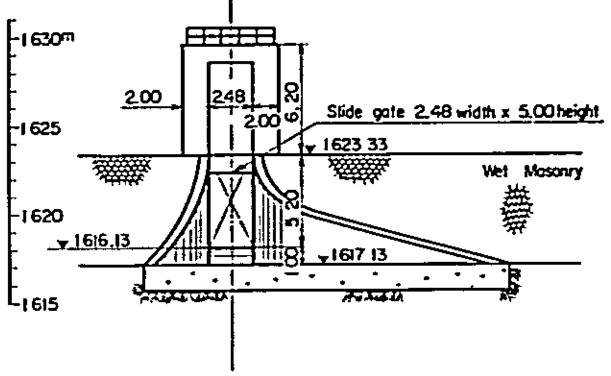
DWG. No. 7	MARCH 1977

LONGITUDINAL SECTION

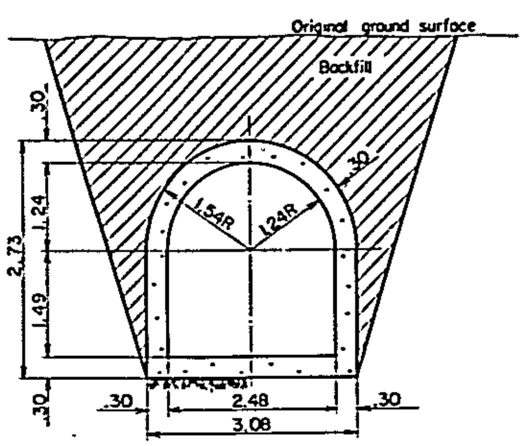


Station	Formation level	Ground surface level	Cumulative distance	Section distance
0	1618.13	1623.33	0	0
1	1617.13	1622.07	10.50	10.50
2	1617.08	1622.35	38.30	27.80
3	1616.95	1620.35	110.70	72.40
4	1616.82	1619.90	187.10	76.40
5	1616.80	1619.90	198.10	11.00
6	1615.73	1619.00	251.54	53.44
7	1616.80	1619.00	252.74	1.20
8	1616.80	1618.90	257.00	4.26
9	1613.20	1618.90	260.60	3.60
10	1613.20	1618.80	264.64	4.04
11	1574.50	1618.50	274.64	10.00
12	1574.50	1592.00	323.14	48.50
13	1574.50	1587.20	330.14	7.00
14	1570.56	1585.20	338.74	8.60
15	1572.25	1580.00	354.49	15.75

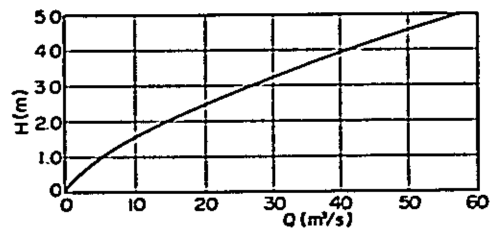
FRONT VIEW OF INTAKE



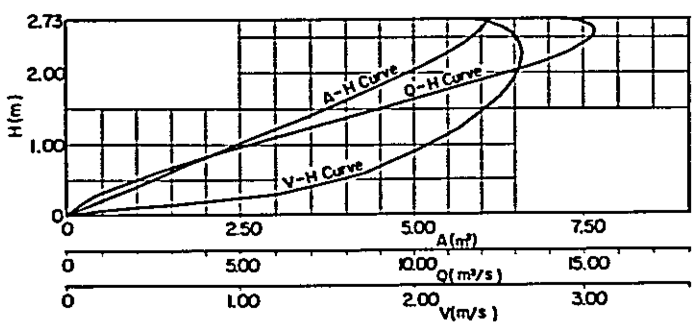
SECTION A-A

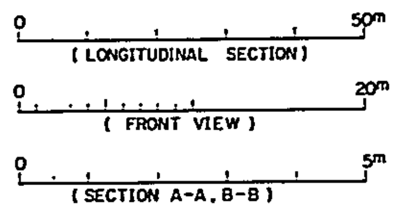


RATING CURVE OF INTAKE



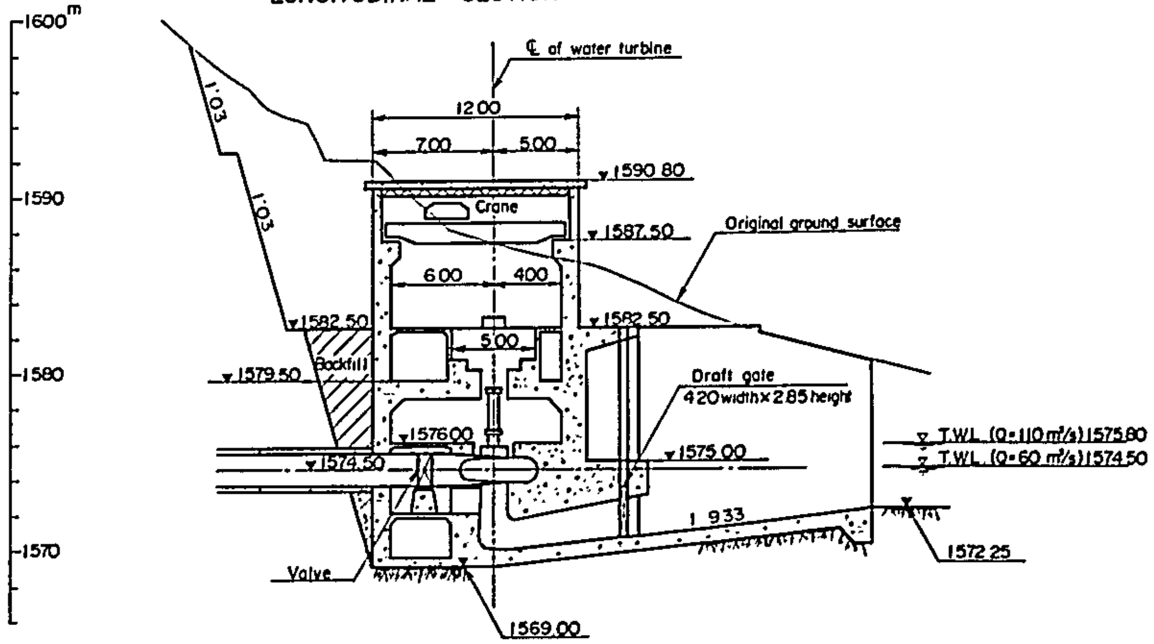
HYDRAULIC CHARACTERISTIC CURVE



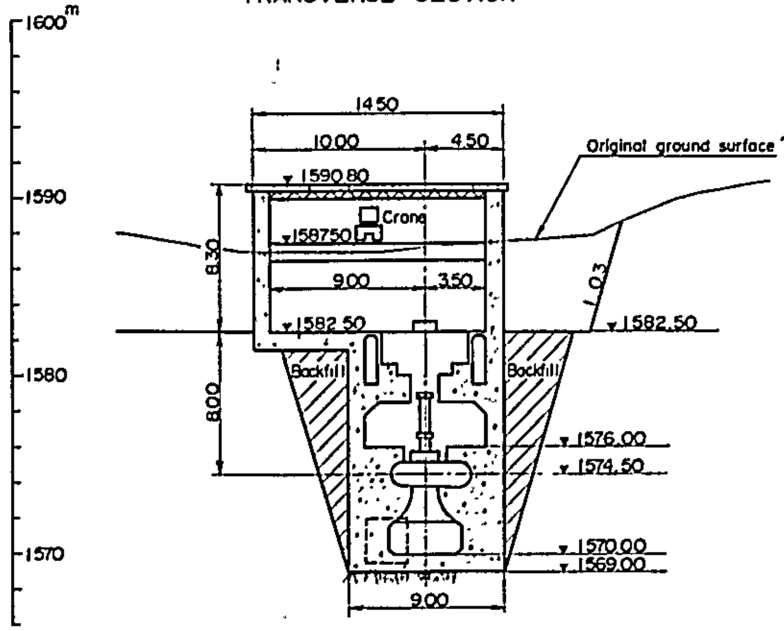


ELECTRIC POWER DEVELOPMENT PLAN OF LAKE TANA	
TIS ABBAY No.2 POWER STATION LONGITUDINAL SECTION OF WATERWAY	
DWG. No. 8	MARCH 1977

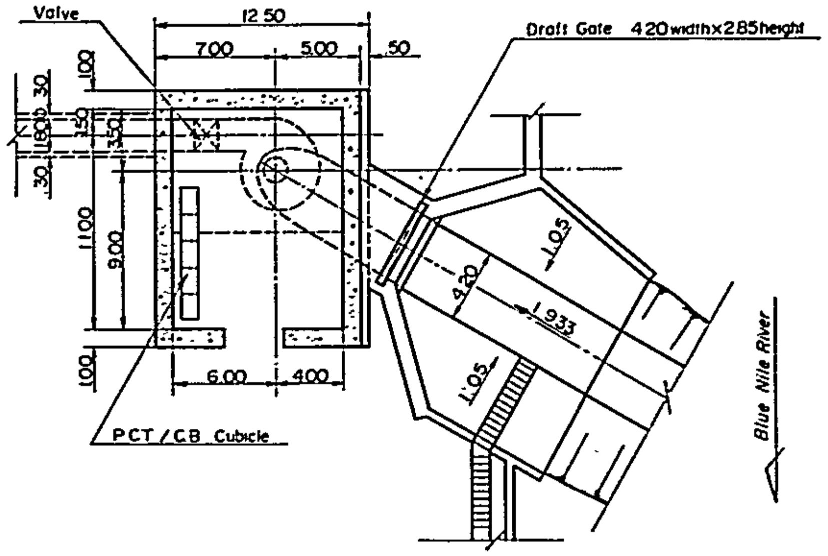
LONGITUDINAL SECTION



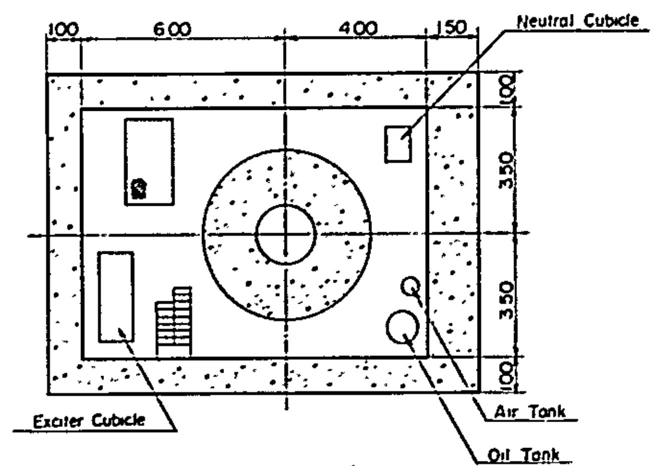
TRANSVERSE SECTION



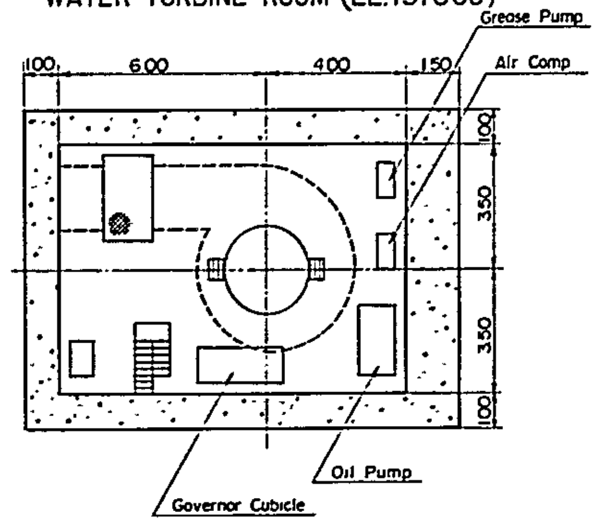
MACHINE ROOM (EL.1582.50)



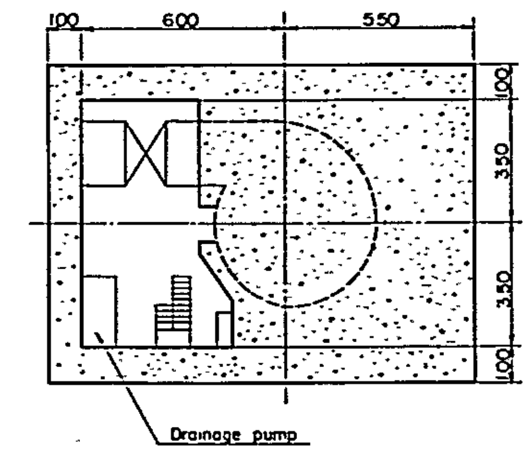
GENERATOR ROOM (EL.1579.50)

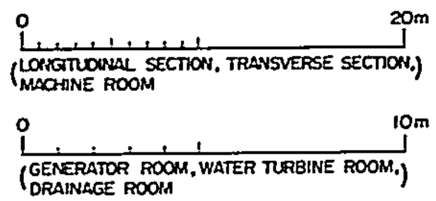


WATER TURBINE ROOM (EL.1576.00)



DRAINAGE PUMP ROOM (EL.1572.00)

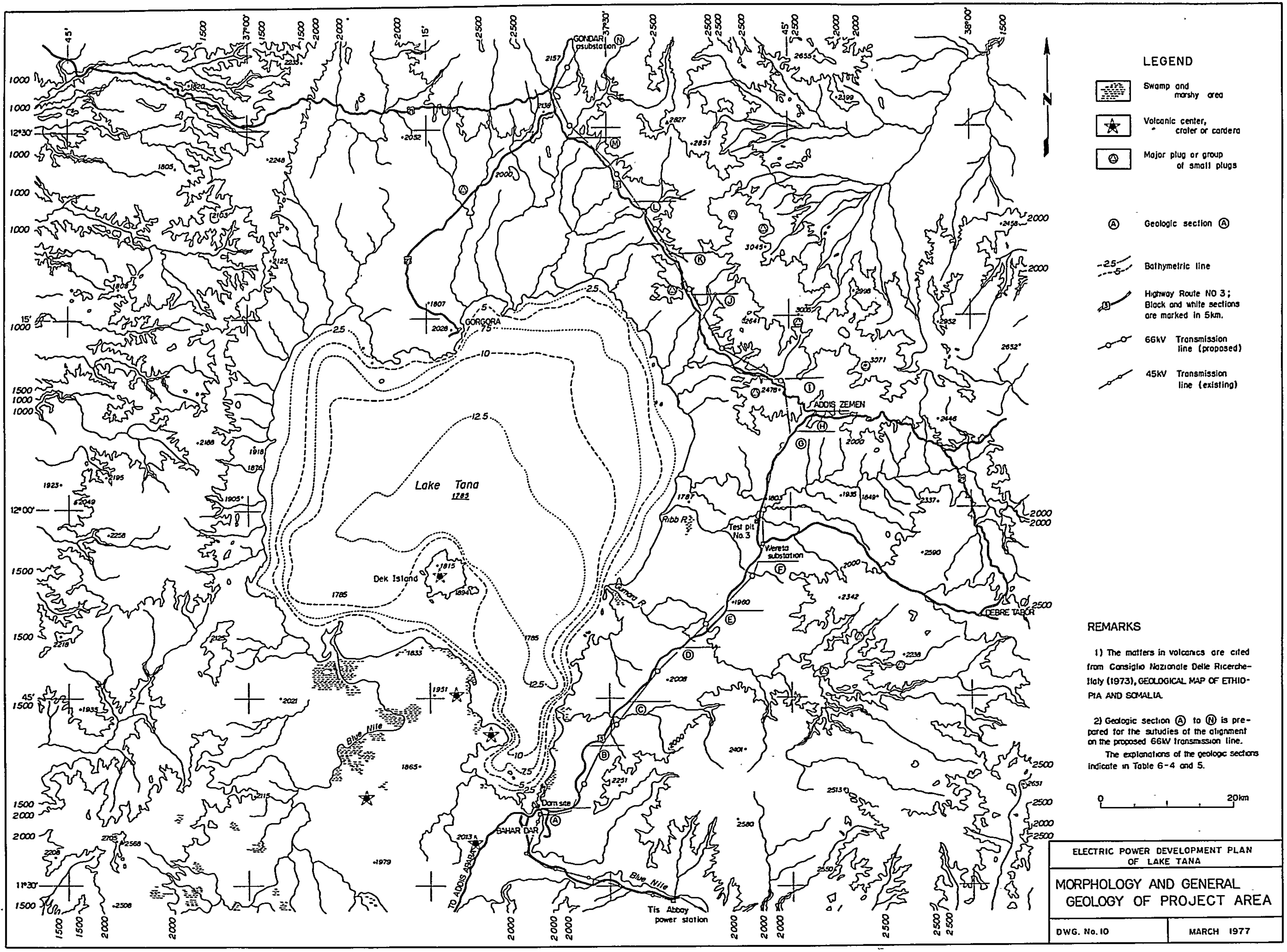


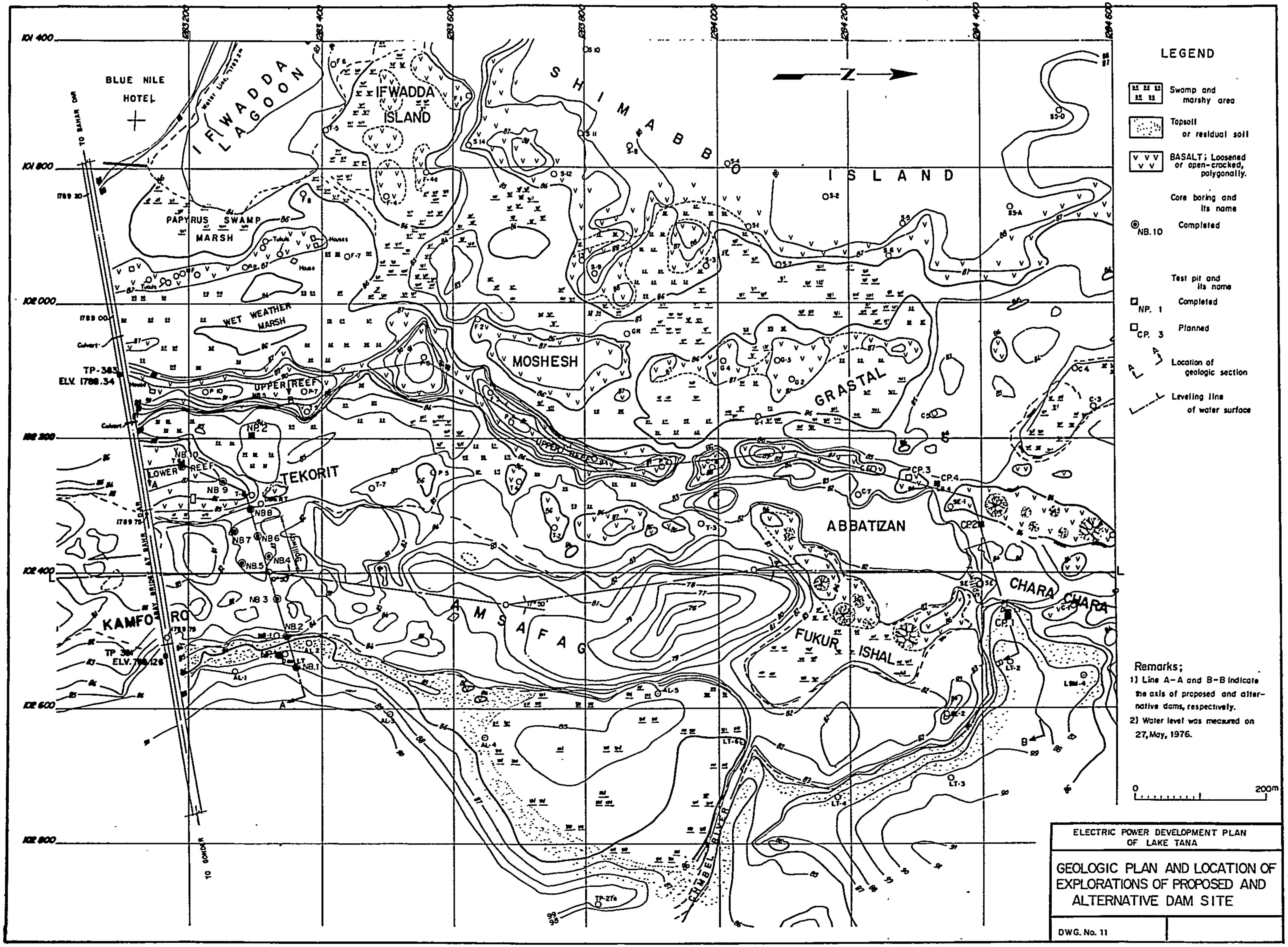


ELECTRIC POWER DEVELOPMENT PLAN
OF LAKE TANA

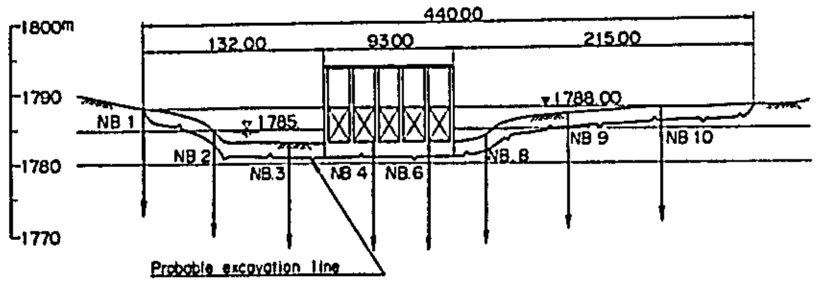
TIS ABBAY NO.2 POWER
STATION; PLAN AND SECTION

DWG. No. 9	MARCH 1977

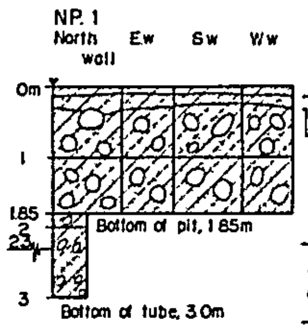

LEGEND
Swamp and marshy area
Volcanic center, crater or cardera
Major plug or group of small plugs
Ⓐ Geologic section Ⓐ
Bathymetric line
Highway Route NO 3; Black and white sections are marked in 5km.
66kV Transmission line (proposed)
45kV Transmission line (existing)
REMARKS
1) The matters in volcanics are cited from Consiglio Nazionale Delle Ricerche-Italy (1973), GEOLOGICAL MAP OF ETHIOPIA AND SOMALIA.
2) Geologic section Ⓐ to Ⓝ is prepared for the sutudies of the alignment on the proposed 66kV transmission line.
The explanations of the geologic sections indicate in Table 6-4 and 5.
0 20km
Lake Tana
1785
Dek Island
GONDAR substation
GORGORA
ADDIS ZEMEN
Ribb R.
Test pit No.3
Wereta substation
Gumara R.
DEBRE TABOR
Blue Nile
Dam site
BAHAR DAR
TO ADDIS ABABA
Tis Abbay power station
ELECTRIC POWER DEVELOPMENT PLAN OF LAKE TANA
MORPHOLOGY AND GENERAL GEOLOGY OF PROJECT AREA
DWG. No. 10
MARCH 1977


BLUE NILE HOTEL
IFWADDA LAGOON
IFWADDA ISLAND
SHIMABB ISLAND
PAPYRUS SWAMP MARSH
WET WEATHER MARSH
MOSHESH
GRASTAL
UPPER REEF
LOWER REEF
TEKORIT
ABBATIZAN
CHARA CHARA
AMSAFAG
FUKUR ISHAL
KAMFO RO
TP-383 ELV. 1788.34
TP 381 ELV. 1788.126
TO BAHAR DAR
TO GONDAR
LEGEND
Swamp and marshy area
Topsoil or residual soil
BASALT; Loosened or open-cracked, polygonally.
Core boring and its name
Completed
NB. 10
Test pit and its name
Completed
NP. 1
Planned
CP. 3
Location of geologic section
Leveling line of water surface
Remarks;
1) Line A-A and B-B indicate the axis of proposed and alternative dams, respectively.
2) Water level was measured on 27, May, 1976.
0 200m
ELECTRIC POWER DEVELOPMENT PLAN OF LAKE TANA
GEOLOGIC PLAN AND LOCATION OF EXPLORATIONS OF PROPOSED AND ALTERNATIVE DAM SITE
DWG. No. 11

SECTION A – A



NP. 1



Topsoil; Brown, silty clay, slightly sandy moist compact, with grass roots (0-15cm)

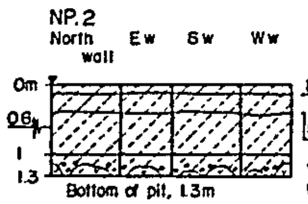
CLAY; Light brown, silty, sandy, gravelly, moist, compact (15-30cm)

BOULDERS; Vesicular basalt, subround to angular, some of boulders are larger than 1.5m in diameter. Boulders are filled with clay that is dark brown, silty, sandy gravelly, moist compact (30-185cm)

CLAY; Yellowish grey, silty, sandy, gravelly, wet, plastic, granules are yellow and black, angular, soft, crushed by press of finger nails (185-230cm)

CLAY and GRAVEL; Quantity of gravels increases below, otherwise similar to upper layer (230-300cm)

NP. 2

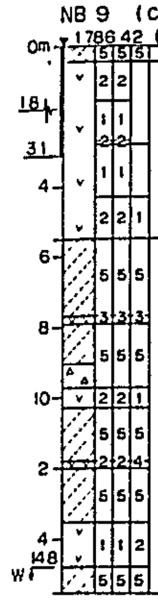


Topsoil; Brown, clay, silty, moist to wet, plastic, with grass roots (0-15cm)

CLAY; Grayish brown, swampy, very wet, soft, plastic (15-40cm)

CLAY; Dark gray, very wet to liquid, plastic, with boulders. Clay becomes sandy and gravelly toward the bottom. At a depth of 120cm to 130cm, there are basalt boulders, probably bed rock.

NB 9 (Core recovery = 84%)

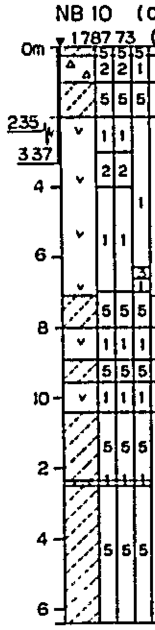


CLAY, Dark brown 0.45

BASALT; Dark grey
1.2, Joint tinged with hematite stain
1.2-1.8, Core recovery = 70°
2.25, 2.75 and 2.9, Joint tinged with hematite stain.
4.05 and 4.35, Joint tinged with hematite stain.
5.3-5.9, Core recovery = 70% 5.50

CLAY, Bright red, with thin beds of basalt and gravel in some places
7.7-7.95, BASALT.
9.05-9.75, GRAVEL with CLAY.
9.75-10.3, BASALT; Thin bed
11.8-12.0, BASALT
13.6-14.1, Core recovery = 50%
14.8, Drilling water completely leaked. 15.55

NB 10 (Core recovery = 93%)



0.25-1.0, Marly basalt boulder, dark, gray

CLAY; Dark brown to brown. 1)
0.8, Total leakage of drilling water. 2.0

BASALT; Dark grey
3.35, After casing was driven down, leakage of drilling water stoped.
4.35, Joint tinged with hematite stain. 7.1

CLAY; Brown to gray 2) 8.0

BASALT, Dark gray
8.8, Joint tinged with hematite stain 8.8

CLAY; Bright red 3) 9.55

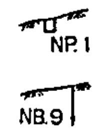
BASALT; Dark gray 10.4

CLAY, Reddish brown.
10.25-14.3, Core recovery = 80%
12.35-12.5, Basalt (boulder?), dark gray 16.42

Core recovery,
1) 0m-0.9m = 75% 3) 8.7m-9.5m = 60%
2) 7.85m-8.0m = 70%

LEGEND

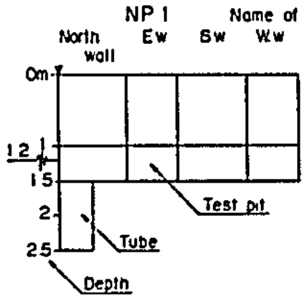
(SECTION A-A and B-B)



Test pit and its name

Core boring and its name

(GEOLOGIC LOG OF TEST PIT)



Name of test pit

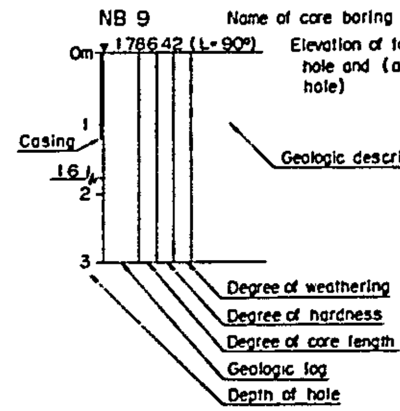
Wall of test pit

Elevation of top of test pit

E.w ; East wall
S.w ; South wall
W.w ; West wall

1.2 Water table and its depth, (Geologic log of core boring, in common)

(GEOLOGIC LOG OF CORE BORING)



Name of core boring

Elevation of top of hole and (angle of hole)

Geologic description

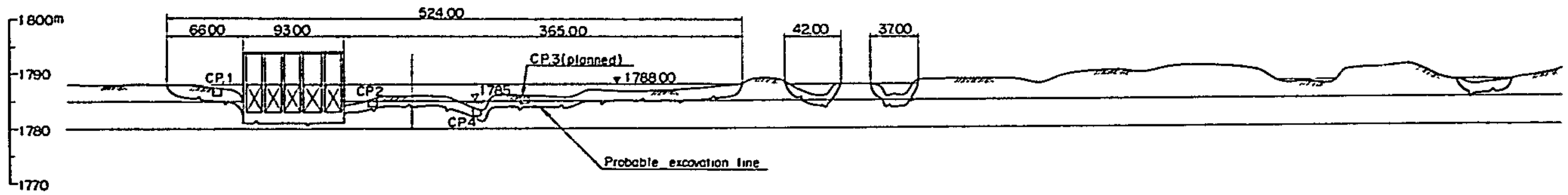
Degree of character of core

Weathering ; 1 (fresh) – 5 (decomposed)

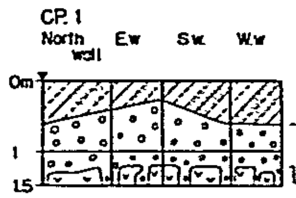
Hardness ; 1 (hard) – 5 (soft)

Core length ; 1 (stick)
2 (substick)
3 (piece)
4 (fragment)
5 (grain to particle)

SECTION B – B



CP. 1

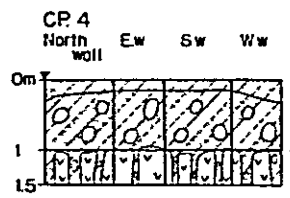


CLAY; Brown, silty, sandy, hard, friable, moist, plastic. The upper 15cm is topsoil with grass roots.

GRAVEL; Yellow to dark, angular, weathering products of underlying vesicular basalt. The gravels in part go down as much as 1.2m deep

BASALT; Dark to light gray, highly vesicular (some vesicles more than 3cm in diameter) secondary filling in vesicules is rare. Joints spaced as much as 10 to 20cm wide and filled with the clayey and gravelly matters.

CP. 4

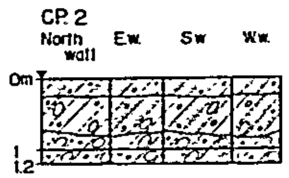


CLAY; Dark brown to dark, silty, sandy, loose, moist, plastic, with some boulders The gravels are weathering products of vesicular basalt and increase downward.

BOULDERS; Dark to light grey vesicular basalt with clay similar to above layer among them.

BASALT; Dark to light gray, highly vesicular, vesicules are coated with minerals, possibly quartz.

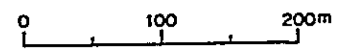
CP. 2



CLAY; Dark to dark gray, silty, sandy, gravelly, spongy, swampy, highly plastic, verywet, with lots of trees, shrubs and grass roots

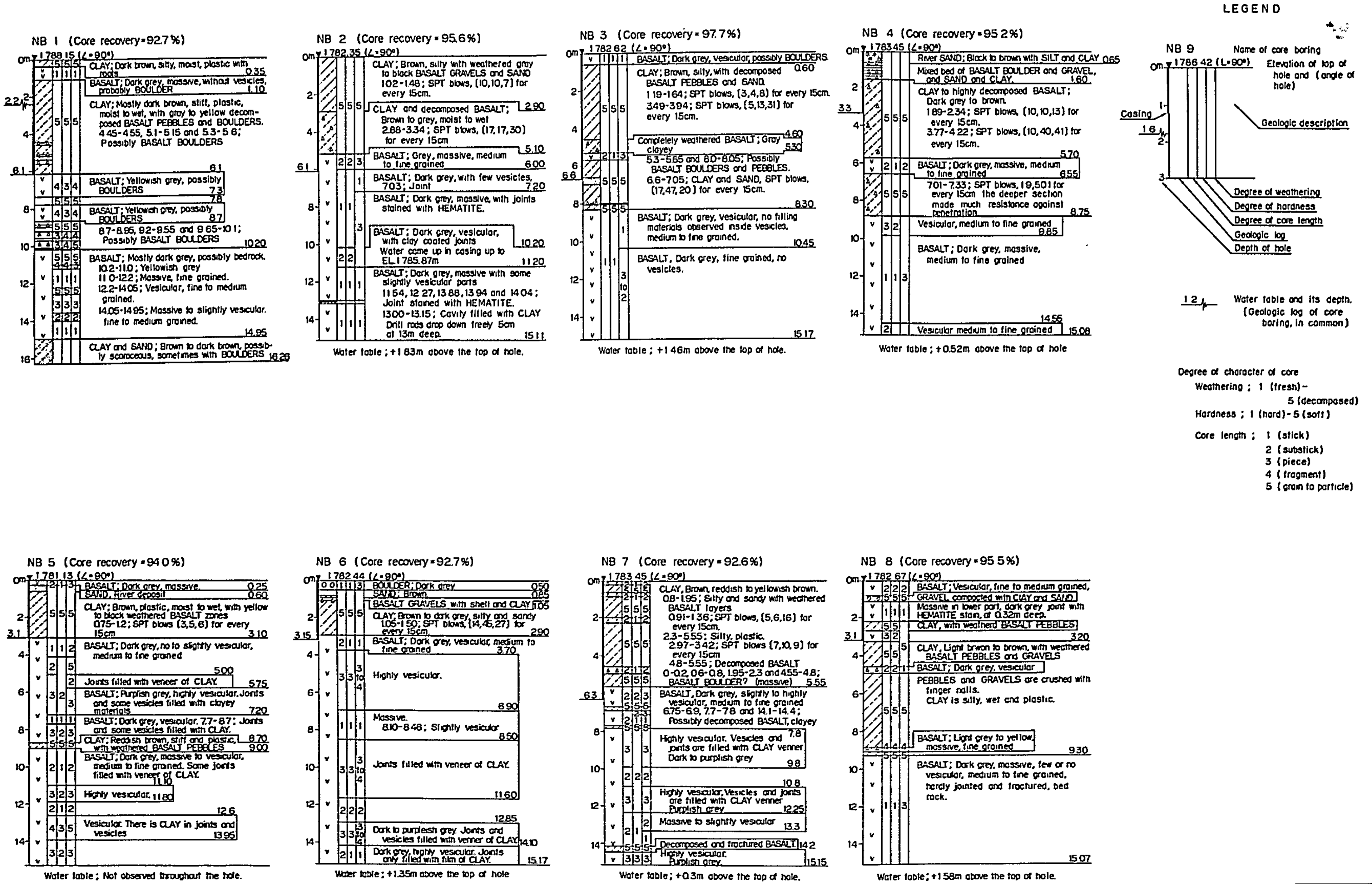
CLAY; Few boulders of basalt interbedded, otherwise, similar to above layer.

BOULDERS, Vesicular basalt, dark to light gray, with clay as described above among boulders The boulders tend to change to bedrock of jointed basalt below the deeper.



(Horizontal scale of section)

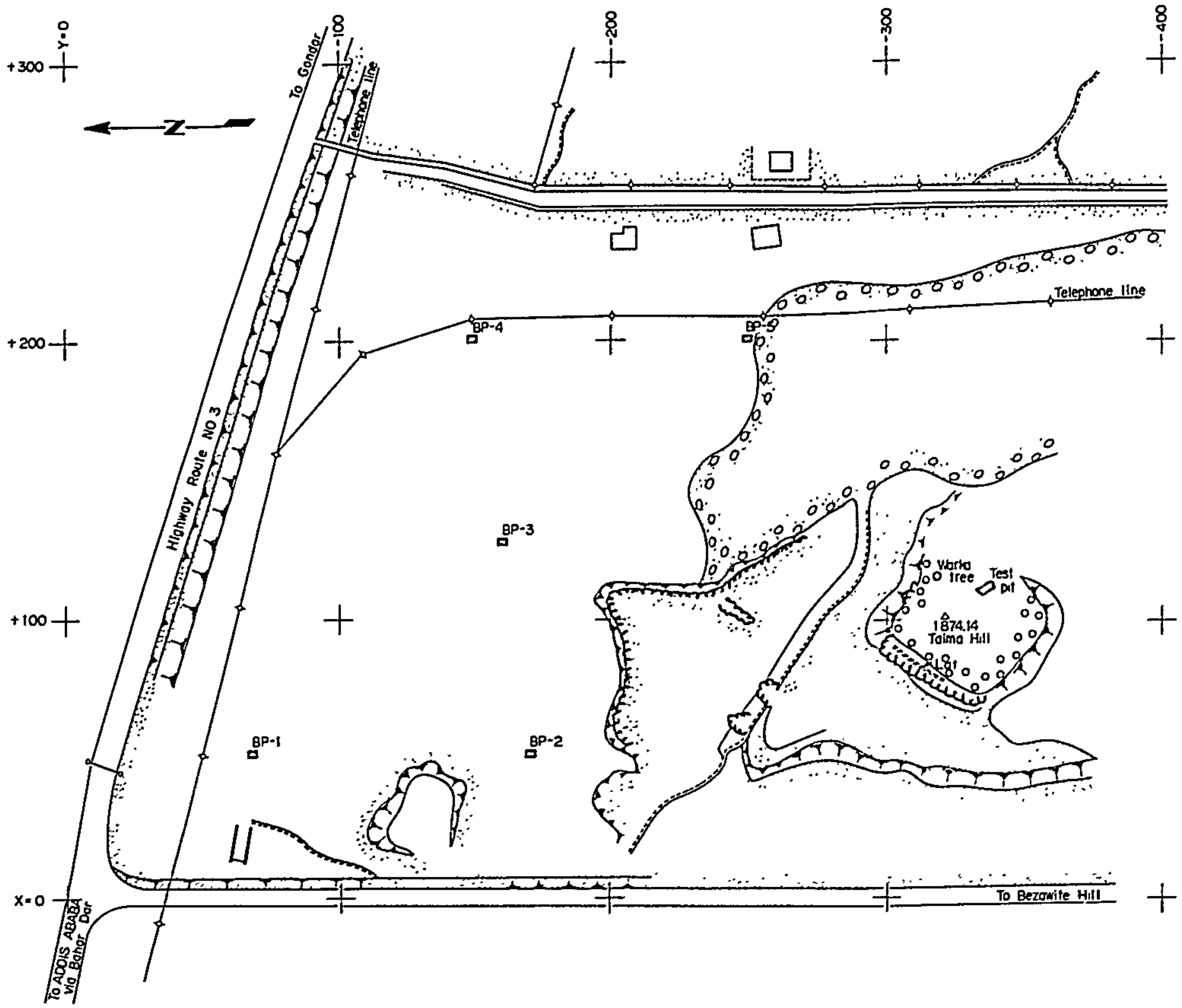
ELECTRIC POWER DEVELOPMENT PLAN OF LAKE TANA	
LOCATION OF EXPLORATION AND GEOLOGIC LOG OF TEST PIT AND CORE BORING AT DAM SITES (1-2)	
DWG. No 12-A	MARCH 1977

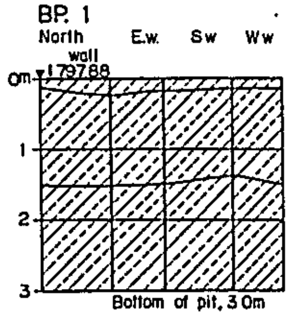


ELECTRIC POWER DEVELOPMENT PLAN OF LAKE TANA

LOCATION OF EXPLORATION AND GEOLOGIC LOG OF TEST PIT AND CORE BORING AT DAM SITES (2-2)

DWG. No. 12-B	MARCH 1977

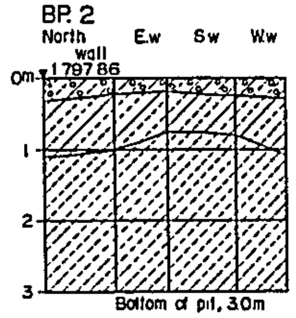




CLAY; Brown, silty, moist, stiff, plastic, with grass roots.

CLAY; Reddish brown, silty, moist, stiff, plastic.

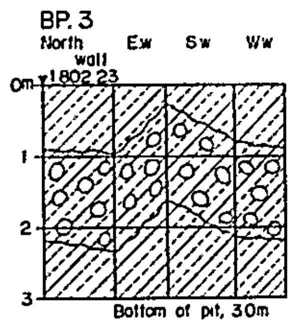
CLAY; Reddish to yellowish brown, silty moist, stiff, plastic, with occasional completely weathered basalt zones, giving yellowish dark to yellowish grey to the layer.



CLAY; Brown, silty, moist, stiff, with weathered and rounded basaltic gravels and pebbles, with grass roots.

CLAY; Reddish brown, silty, moist, stiff, plastic.

CLAY; Grayish green to yellowish brown. It is lightly weathered basalt, which has not yet completely changed to clay, like the upper layer. It is plastic, too soft to be called rock, but rater harder than soil. It is plastic when wet.



CLAY; Reddish brown, silty, moist, stiff, plastic. Roots penetrate down to 20cm, with spares penetration going deeper.

CLAY and BOULDER; Clay is similar to above. Boulders are basalts of vesicular and massive, diameter 1m in average. Contact between clay and boulder is tight. Boulder is 60% and clay about 40% in volume.

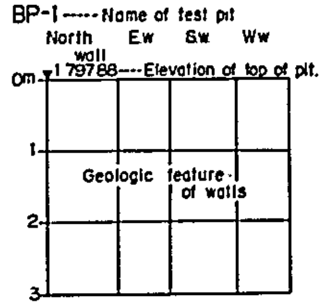
CLAY; Brown, silty, moist stiff, plastic, scattered with yellow or dark patches of weathered rock in some places. Weathered material bears sometimes in forms of soft gravel, pebble and sand, and is crushed with the fingers.

LEGEND

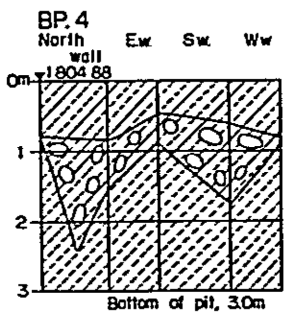
(GEOLOGIC PLAN)

- Residual SOIL; Reddish brown silty clay with small grains of weathered basalt.
- BOULDER scattered zone in residual soil
- River terrace deposit; Gravel, cobble and sandy soil
- Outcrop of rock; Highly weathered basalt.
- Lateritized zone; Nearly horizontal, 40cm thick.
- BP-1 Test pit and its name

(LOG OF TEST PIT)



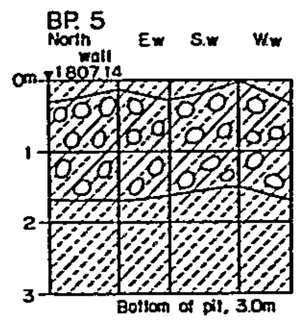
E.w. ; East wall
S.w. ; South wall
W.w ; West wall



CLAY; Reddish brown, silty, moist, stiff, plastic. Roots penetrate down to 20cm, with scattered roots going more deeper.

CLAY and BOULDER; Clay about 30% and boulder about 70%. Clay is similar to above. Boulders are basalt, rounded and massive, with diameter 1.5m to 2m in average. Filled up clay is fairly tight.

CLAY; Brown, with patches of yellow and dark grey, weathered basalt. The weathered bed rock comes sometimes in forms of pebbles, gravels and sand, and is crushed with pressing with fingers. It is plastic when wet.



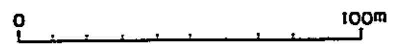
CLAY; Reddish brown, silty, moist, stiff. Roots penetrate down to 15cm, with scattered roots going more deeper

CLAY and BOULDER; Clay about 30% and boulder about 70% in volume. Clay is similar to above. Boulders are vesicular or massive basalt, with diameter 1.2m in average. Filled up clay is tight.

CLAY; Brown, silty, moist, stiff, plastic, scattered with yellow or dark grey in patches of weathered rock in some places. This weathered bed rock sometimes bears in forms of pebbles, gravels and sand, and is crushed with pressing of fingers.

Remaks;

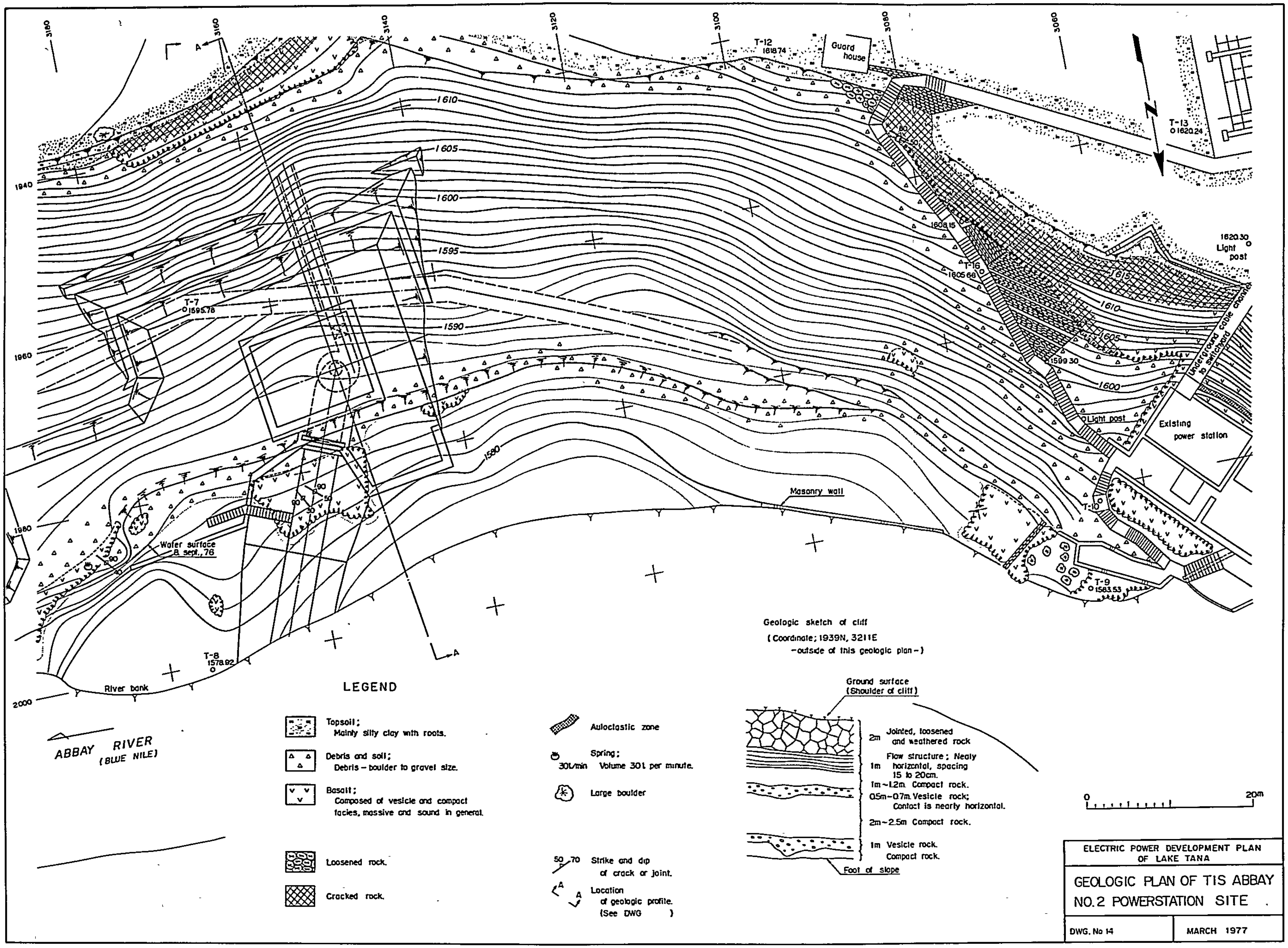
1. The geologic plan was measured by means of walking steps and locally meter tape.
2. The test pits were dug with the cross-section of 2m by 1.5m

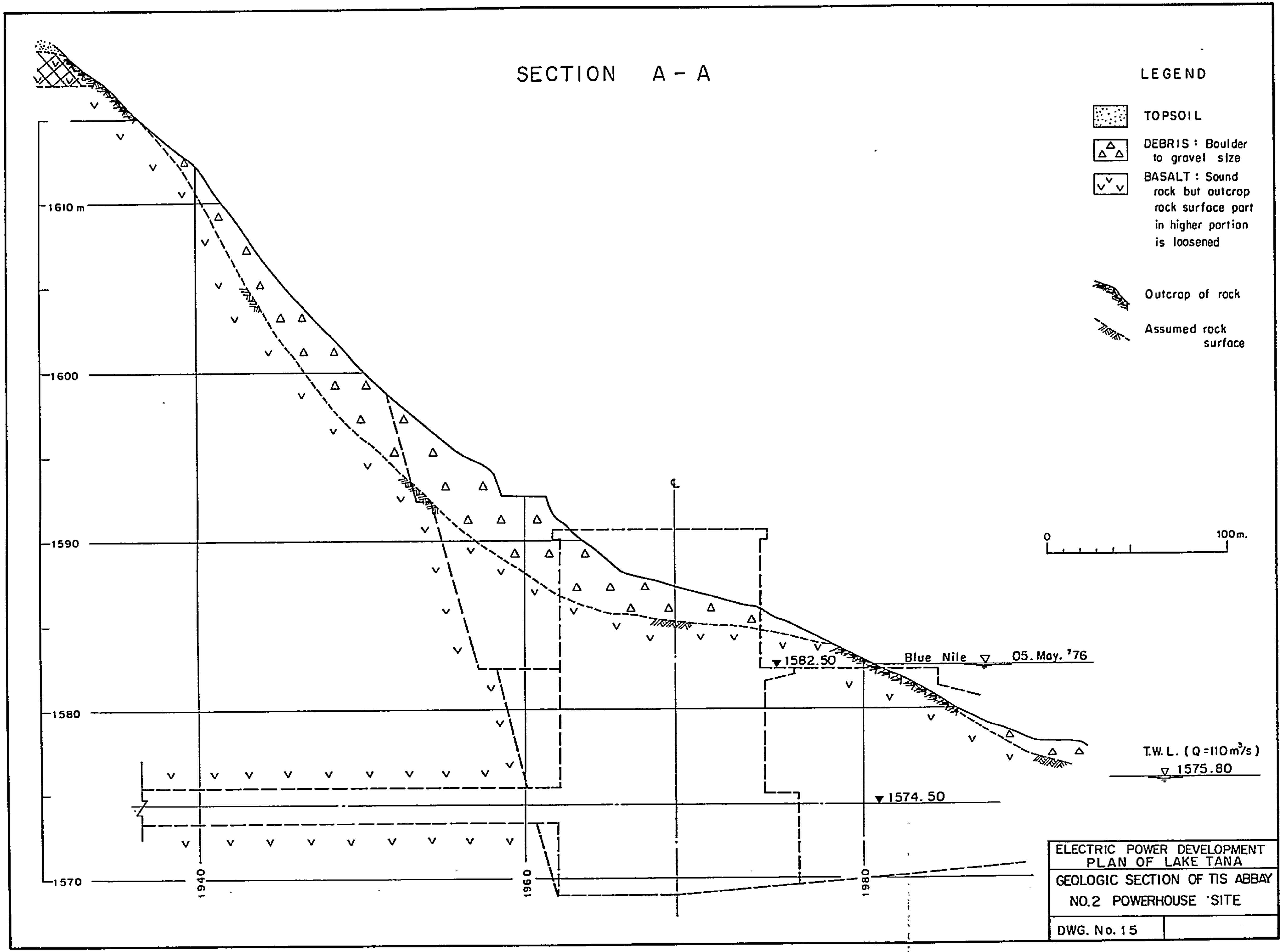


ELECTRIC POWER DEVELOPMENT PLAN OF LAKE TANA

GEOLOGIC PLAN AND LOG OF TEST PIT OF BORROW AREA

DWG. No 13	MARCH 1977


ELECTRIC POWER DEVELOPMENT PLAN OF LAKE TANA
GEOLOGIC PLAN OF TIS ABBAY NO.2 POWERSTATION SITE
DWG. No 14
MARCH 1977
LEGEND
Topsoil; Mainly silty clay with roots.
Debris and soil; Debris – boulder to gravel size.
Basalt; Composed of vesicle and compact facies, massive and sound in general.
Loosened rock.
Cracked rock.
Autoclastic zone
Spring; 30l/min Volume 30l per minute.
Large boulder
Strike and dip of crack or joint.
Location of geologic profile. (See DWG)
Geologic sketch of cliff
(Coordinate; 1939N, 3211E –outside of this geologic plan–)
Ground surface (Shoulder of cliff)
2m Jointed, loosened and weathered rock
1m Flow structure; Nealy horizontal, spacing 15 to 20cm.
1m~1.2m Compact rock.
0.5m~0.7m Vesicle rock; Contact is nearly horizontal.
2m~2.5m Compact rock.
1m Vesicle rock.
Compact rock.
Foot of slope
0 20m
ABBAY RIVER (BLUE NILE)
River bank
Water surface 8 sept., 76
Masonry wall
Guard house
Existing power station
Light post
Underground cable channel to switchyard
T-7 1595.78
T-8 1578.92
T-9 1583.53
T-10
T-12 1618.74
T-13 1620.24
T-16 1605.68
1620.30
1608.15
1599.30
1610
1605
1600
1595
1590
1580
1615
3180
3160
3140
3120
3100
3080
3060
1940
1960
1980
2000
A



SECTION A - A
LEGEND
TOPSOIL
DEBRIS : Boulder to gravel size
BASALT : Sound rock but outcrop rock surface part in higher portion is loosened
Outcrop of rock
Assumed rock surface
0
100m.
1610 m
1600
1590
1580
1570
1940
1960
1980
℄
1582.50
Blue Nile 05. May. '76
T.W.L. (Q=110m³/s)
1575.80
1574.50
ELECTRIC POWER DEVELOPMENT PLAN OF LAKE TANA
GEOLOGIC SECTION OF TIS ABBAY NO.2 POWERHOUSE SITE
DWG. No. 15