The steel top tube pole is superior in respect of the mechanical strength and comparatively easier to erect since it will be possible to adopt a method of transportation and assembling divided parts at sites. Besides, the configuration of completed supports look beautiful. On the other hand, costs to be incurred will be the most expensive out of the three types of items stated above.

As to wooden pole, although the life time is shorter than that of the other two types, TANESCO has already had many experiences in handling wooden poles and besides it seems that TANESCO might be in a position of supplying such wooden poles by themselves in the future. It is considered that the cost of procurement of these wooden poles will be the most economical compared with other two types, even if the wooden poles are imported. Thus wooden poles were selected as supports of the 33 kV lines. Figs. 9-4-1 and 9-4-2 show typical 33 kV line structures for single and double circuits arrangement, respectively.

9.4.2 Summary of facilities

The 33 kV subtransmission line facilities to be constructed anew or modified are to be composed of nine (9) items and can be summarized as follows:

Line Voltage:	33 kV
Electrical System:	3 phase 3 line
Frequency:	50 Hz
Conductor:	ACSR 120 mm^2
Shield Wire:	GSW 30 mm^2
Insulator:	

33 kV pin type insulator - for the tangent support and jumper line on the angle/deadend support

250 mm suspension type, 3 pcs connected in series - for the angle and deadend support

(1) Ilala to City Centre, New Line

Line length: 2.8 km

Support : Wooden pole, 2 circuit vertical arrangement

(2) System switching-over of Kurasini Line

Solely interconnection work to Ilala substation. No construction and/or expansion work are included.

(3) Re-conductoring of Ilala to Oysterbay Line

Line length: 5.0 km

Conductor : Existing ACSR 50 mm^2 is removed and replaced with ACSR 160 mm. Wooden poles and insulators which are much deteriorated due to be replaced.

(4) Mikocheni Branch Line

Line length: 1.0 km

Support : Wooden pole, 2 circuit vertical arrangement

(5) Ubunga to Factory Zone III, New Line

Line length: 7.0 km

Support : Wooden pole, 2 circuit vertical arrangement

(6) Factory Zone III to Factory Zone II, Interconnection

Line length: 0.6 km

Support : Wooden pole, single circuit horizontal arrangement

One set of line switch for system switchover due to be installed.

(7) Factory Zone III to New Airport, Interconnection

Line length: 0.7 km

Support : Wooden pole, single circuit horizontal arrangement

(8) Factory Zone III to Factory Zone I, Interconnection

Line length: 1.5 km

Support : Wooden pole, single circuit horizontal arrangement

(9) Factory Zone to Kurasini, Interconnection

Line length: 6.5 km

Support : Wooden pole, single circuit horizontal arrangement

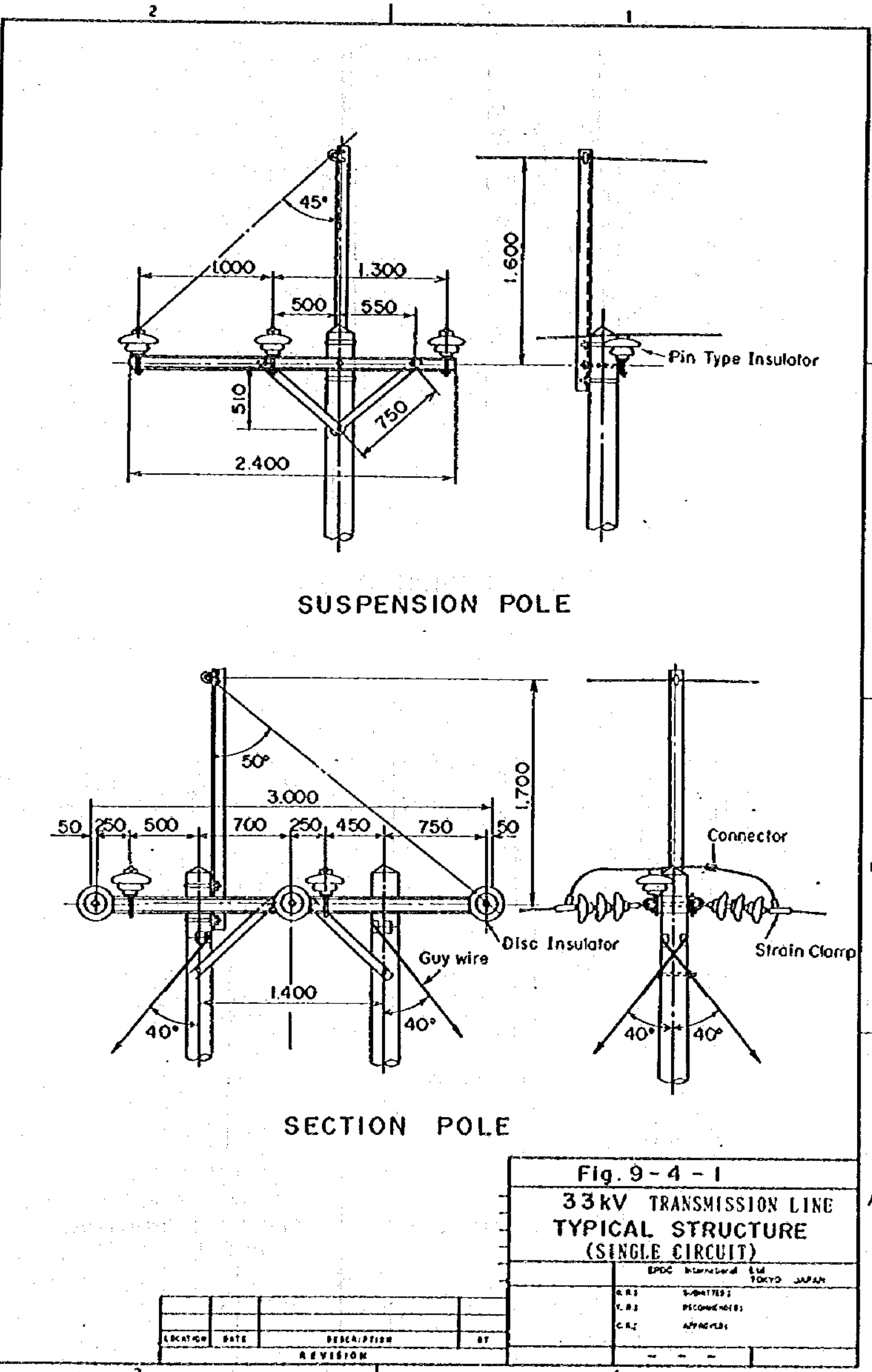


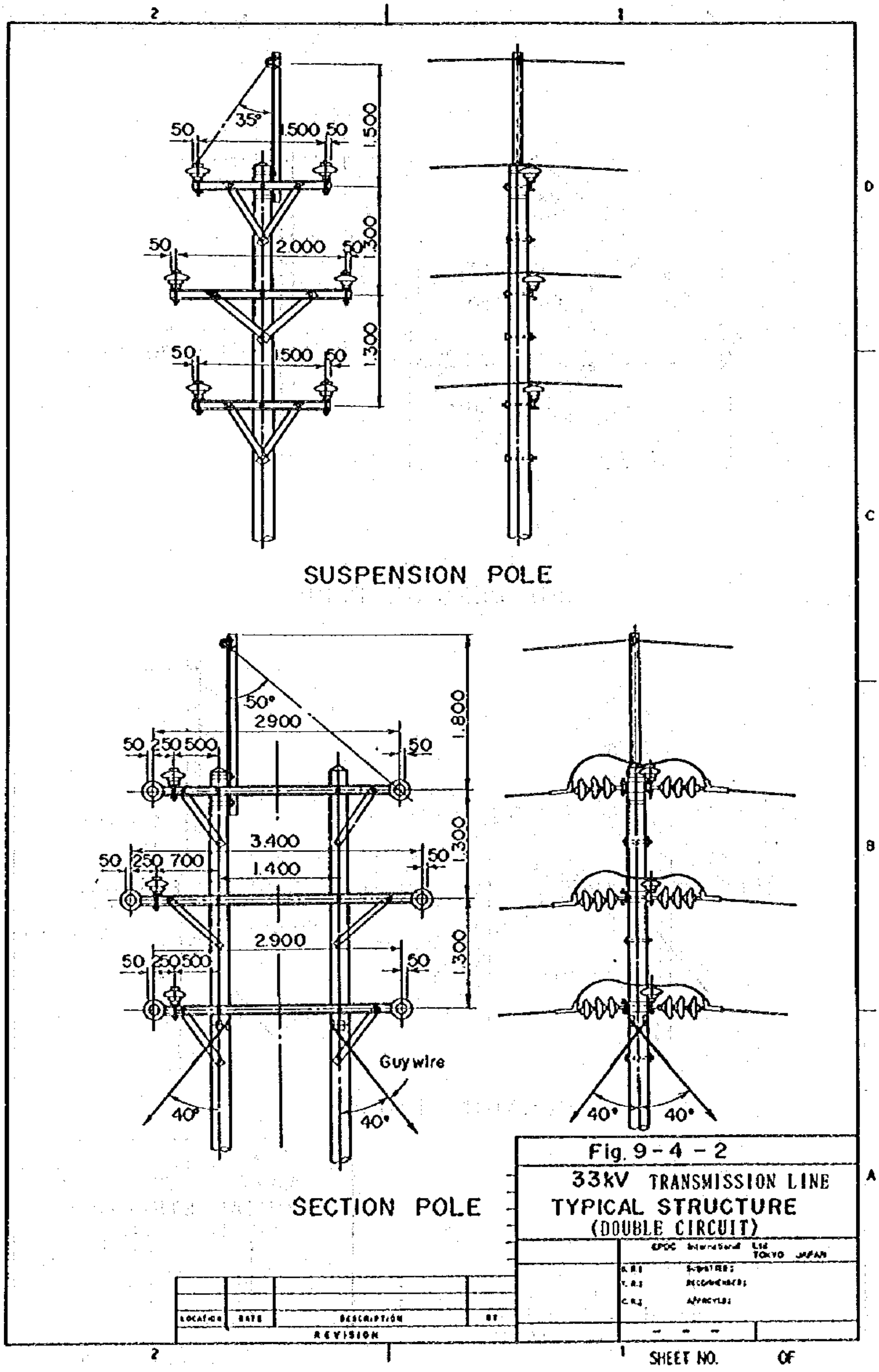
Fig. 9-4-1

33kV TRANSMISSION LINE
TYPICAL STRUCTURE
(SINGLE CIRCUIT)

EPDC International Ltd TOKYO JAPAN

REVISION | LOCATION | DATE | DESCRIPTION | BY

SHEET NO. OF



35°
50
1.500
50
1.500
50
2.000
50
1.300
50
1500
50
1.300
SUSPENSION POLE
50°
2900
50
250
500
50
1.800
3.400
50
250
700
1.400
50
1.300
2.900
50
250
500
50
1.300
Guy wire
40°
40°
40°
40°
SECTION POLE
Fig. 9 - 4 - 2
33kV TRANSMISSION LINE
TYPICAL STRUCTURE
(DOUBLE CIRCUIT)
LOCATION
DATE
DESCRIPTION
BY
REVISION
SHEET NO.
OF

9.5 11 KV DISTRIBUTION LINE

9.5.1 Basic way of thinking on design

The 11 kV line design aims at improving the service reliability including the decrease of power interruptions and improvement of voltage and specifically it mainly consists of a new installation for system interconnection, etc., replacement of deteriorated lines and reinforcement of the supports. In order to promote an effective system operation, installation of appropriate section switches was also planned.

In designing them, the harmony and coordination with the existing facilities were taken into due consideration.

9.5.2 Nominal voltage and electric system

Nominal voltage: 11 kV

Distribution system: 3-phase 3-line system (neutral point direct earthing)

Line form: tree branch system

Limit of voltage decrease: 5% (when normal)

9.5.3 Maximum voltage drop in 11 kV distribution line

(1) Trunk line portion

ACSR 120 mm^2

Voltage drop $$V_1 = \frac{\sqrt{3}}{2} Re \times L (I_1 + I_2) \quad (V)$$

Load current: 3-phase balanced uniform distribution load

Re : Equivalent resistance = $R \cos\theta + X \sin\theta = 0.373$ (Ω/km)

R : AC resistance of electric wire (50°C) = 0.261 (Ω/km)

X : Reactance of electric wire = 0.285 (Ω/km)

$\cos\theta$: 0.85

L : Distance of trunk line portion = 7 (km)

I_1 : Current at sending end = 160 (A)

I_2 : Current at receiving end = 20 (A)

$$V_1 = \frac{\sqrt{3}}{2} \times 0.373 \times 7\ (160 + 20) = 407\ (V)$$

(2) Branch line portion

ACSR 58 mm^2

Voltage drop $V_2 = \frac{\sqrt{3}}{2} R'e \times L' (I_1' + I_2')\ (V)$

Load current: same as the above (1)

Re' : Equivalent resistance = $R' \cos\theta + X' \sin\theta = 0.69$ (Ω/km)

R' : AC resistance of electric wire (40°C) = 0.606 (Ω/km)

X' : Reactance of electric wire = 0.336 (Ω/km)

cosθ: 0.85

L' : Distance of branch line portion = 2 (km)

I_1' : Current at sending end = 20 (A)

I_2' : Current at receiving end = 10 (A)

Voltage drop $V_2 = \frac{\sqrt{3}}{2} \times 0.69 \times 2(20 + 10) = 36\ (V)$

(3) Total voltage drop of 11 kV distribution line

Total voltage drop $V = V_1 + V_2 = 407 + 36 = 443\ (V)$

9.5.4 Wire arrangement and assembling

As for the wire arrangement method, there are several methods such as horizontal arrangement, vertical arrangement and triangle arrangement, and the following will show the advantages and disadvantages of the representative arrangement methods.

(1) Horizontal arrangement

(a) Advantage:

- The length of the pole can be reduced.

- The lead-down of pole mounted equipment is easy.

(b) Disadvantage:

- The electric wire width increases and it is difficult to secure the separation from house, tree, etc.

- Wind effect must be considered when the distance between wires is decided.

(c) Suitable area:

Suitable for the area where the occupying space for distribution line can be easily secured.

(2) Vertical arrangement

(a) Advantage:

- Since the electric wire width is reduced, it is easier to secure the separation from the house, tree, etc.

- No need of considering the wind rolling effect.

(b) Disadvantage:

- The length of the pole increases

- The lead-down of the pole mounted equipment becomes complicated.

(c) Suitable area:

- Suitable for house crowded area where it is difficult to secure the line occupying space.

(3) Triangle arrangement

(a) Advantage:

- The electric wire width is relatively small.

- The pole length is shorter than for the vertical arrangement.

- The lead-down of the pole mounted equipment is relatively easy.

(b) Disadvantage:

- The pole length is longer than for the horizontal arrangement.

(c) Suitable area:

- Suitable for house crowded area where it is difficult to secure the line occupying space.

The field survey reveals that most of the assemblings in Dar es Salaam city are of the wish-bone type and those in other areas are of the horizontal arrangement. Since the wish-bone type assembling has a complicated arm shape and is not very much produced in Japan, it was decided to adopt an economically advantageous triangle arrangement which can also be harmonized with the wish-bone type.

For the other areas (except the urban area), the same horizontal arrangement as the present assembling is adopted.

9.5.5 Specifications of electric wire

Item	Unit	ACSR 120 mm^2	ACSR 58 mm^2
Stranding Al/St	-	2.3mmø x 30/2.3mmø x 7	3.5mmø x 6/3.5mmø x 1
Actual Cross Section Al/St	mm^2	124.7/29.09	57.73/9.621
Overall Diameter	mm	16.1	10.5
Standard Weight	kg/m	0.5737	0.2331
Calculated Breaking Load	kg	5,540	1,980
D.C. Resistance (at 20°C)	/km	0.233	0.497
Safety Current (at 90°C)	A	388	236

9.5.6 Standard span

The present span used for the 11 kV distribution in Dar es Salaam city is varied from 40 m to 100 m, but many of them are less than 65 m and therefore the maximum design span was decided to be 65 m.

The wire dip is set at about 1.7 m with the wire temperature 90°C.

9.5.7 Calculated dip and tension

Following table shows calculated dip and tension under the allowable temperature of conductor.

(at 90°C)

Span (m)		30	35	40	45	50	55	60	65
Dip (m)	ACSR 120 mm^2	0.64	0.76	0.90	1.04	1.35	1.35	1.51	1.69
	ACSR 58 mm^2	0.62	0.75	0.88	1.02	1.17	1.33	1.50	1.69

Note) Max. Tension: 500 kg (ACSR 120 mm^2), 280 kg (ACSR 58 mm^2)

9.5.8 Length of pole

(1) Horizontal arrangement

$$L \geqq \frac{6}{5} (H + D + C)$$

$$\geqq \frac{6}{5} (6.0 + 1.7 + 0.25) = 9.54 \text{ (m)}$$

where;

L: Length of pole
H: Length of pole above ground level
D: Dip
C: Clearance of overhead conductor above ground level

Taking into consideration the above and some allowance, the pole length is decided 11 m and 12.

(2) Triangle arrangement

The pole length is decided 12 m.

9.5.9 Kind of pole

As for the kind of pole, there are wooden poles, concrete poles and steel poles, and the following will show the advantages and disadvantages of them.

	Wooden Pole	Concrete Pole	Steel Pole	Panzermast
Mechanical Strength	x	o	Δ	Δ
Economical Efficiency	o	Δ	x	x
Work Efficiency	Δ	x	o	o
Appearance	x	Δ	o	Δ

Note) o: Fine Δ: Tolerable x: Inferior

The steel poles are used in the urban area of Dar es Salaam and the wooden poles used in the other areas.

Since the main aim of this design is to rehabilitate the existing facilities, the steel poles will be used mainly in the urban area and the wooden poles will be used in the other areas, taking into consideration of the harmony with the existing facilities.

9.5.10 11 kV underground line

(1) Burying method

Direct buried

(2) Cable

(a) 11 kV CVTAZV 3C x 200 mm^2

(b) 11 kV CVTAZV 3C x 200 mm^2

(3) Allowable bending radius

More than 8D (D: Overall Diameter of Cable)

9.5.11 Specifications of major materials (including L.T line materials)

(1) Support

(a) Wooden pole

For Suburbs

Material	Creosote treated Pine Tree		
Length (m)	9	11	12
Dia. at Top (mm)	170	190	190
Usage	L.T Line	11 kV Line	

For Urban Area

Material	JIS G 3101 (Class 2 - 5), JIS G 3106 JIS G 3444 (Class 2 - 5), JIS G 3445 (Class 13 - 17)	
Length (m)	9	12
Usage	L.T Line	11 kV Line
Thickness of Steel (mm)	More than 2.3	

(2) Conductors

(a) ACSR (JEC 130)

For 11 kV Distribution Lines

Nominal Sectional Area (mm^2)	Composition (Nos./mm)		Diameter (mm)	Tensile Load (kg)	Resistance at 20°C (Ω/km)	Weight (kg/km)
	Aℓ	St				
120	30/2.3	7/2.3	16.1	more than 5,550	0.233	573.7
58	6/3.5	1/3.5	10.5	more than 1,980	0.497	233.1

(b) HAL-OW

For LT Lines

Nominal Sectional Area (mm^2)	Composition (Nos.)	Thickness of Insulation (mm)	Diameter (mm)	Tensile Load (kg)	Resistance at 20°C (Ω/km)	Weight (kg/km)
125	7/SB	1.6	16.5	more than 1,820	0.238	460
55	7/SB	1.4	12.0	more than 817	0.540	225

(c) DV wire

For Service Lines

	Diameter or Sectional Area	Thickness of Insulation (mm)	Insulation Resistance at 60°C (M -km)	Resistance at 20°C (Ω/km)
DV 2R	3.2 mm	1.2	0.15	2.28
"	22 mm^2	1.6	0.1	0.832
DV 4R	3.2 mm	1.2	0.15	2.28
"	22 mm^2	1.6	0.1	0.832
"	38 mm^2	1.8	0.1	0.492

(3) Insulators

(a) 11 kV pin insulator: ANSI C 29.5

- Nominal voltage	13.2 kV
- Withstand voltage wet	35 "
- 50% impulse flash-over voltage (positive)	105 "
- " (negative)	130 "
- Failing load	1,350 kg

(b) Suspension insulator: JIS C 3812

- Withstand voltage wet	45 kV
- 50% impulse flash-over voltage	125 "
- Failing load	4,000 kg

(4) <u>Section switch</u>

(a) 12 kV section switch (MLBS): IEC

- Rated voltage	12 kV
- Rated current	400 A
- Rated frequency	50 Hz
- BIL	95 kV
- Power-frequency withstand voltage	36 "
- Rated short time current (1 sec)	12.5 kA
- Rated number of interruptions	400A 100 times or more

(b) Primary cutout switch: ANSI

- Maximum	15 kV
- Rated current	100 A
- Rated frequency	50 Hz
- BIL	95 kV
- Power-frequency withstand voltage	36 kV
- Interrupting current	8 kA

(5) <u>Transformers: JEC 204</u>

- Rated capacity	100, 200, 300, 500 kVA
- Phase	3
- Rated frequency	50 Hz
- Rated voltage	11 kV/400V, 230V
- Tap	±2.5%, ±5%
- Connection	Delta-Star with neutral point brought out
- Temperature rise	Windings 55°C Oil 50°C

(6) <u>Arrestor: JEC 203</u>

- Rated voltage	14 kV
- Power-frequency sparkover voltage	21 "
- Impulse sparkover voltage	50 "
- Nominal discharge current	5 kA
- Residual voltage	50 kV

(7) Multi circuit switch box (for underground line): IEC

- Rated voltage	12 kV
- Rated current	400 A
- BIL	75 kV
- Rated short time current (1 sec)	12.5 kA
- Numbers of operations	400A 100 times or more

(8) Distribution pillar: JEC

- Rated voltage	460V
- No-fuse breakers	200A x 3 (300 kVA Tr.)
	200A x 4 (500 ")
	200A x 3, 250A x 2 (750 ")

(9) 11 kV armored CV cable: JIS, IEC

- Number of cores	3
- Sectional area of component wire	200 mm^2
- Thickness of insulation	5.5 mm
- Overall diameter	80 mm
- Resistance at 20°C	0.0933 Ω/km
- Insulation resistance	2,000 MΩ-km or more
- Power-frequency withstand voltage	26 kV/10 min
- Impulse withstand voltage	140 kV/3 times

9.6 LOW VOLTAGE DISTRIBUTION LINE

As in the case of the 11 kV distribution line, the design for the low voltage distribution line also consists of wire replacement work and new installation work partially as new demand measures, mainly aiming at prevention of power interruptions and voltage improvement. The following designs are prepared for the new installation work, but they should also be fully utilized for the repair work to enhance the work efficiency.

9.6.1 Distribution voltage and distribution method

Standard voltage: 400 V, 230 V

Distribution method: 3-phase 4-wire system (trunk line portion)
Single-phase 2-wire system (branch line portion)

Distribution system: Tree branch system

9.6.2 Electric wire arrangement

Considering the harmony with the existing facilities, the vertical arrangement will be adopted. The conductor spacing of the existing facilities is 220 mm, but 250 mm will be adopted to give some allowance.

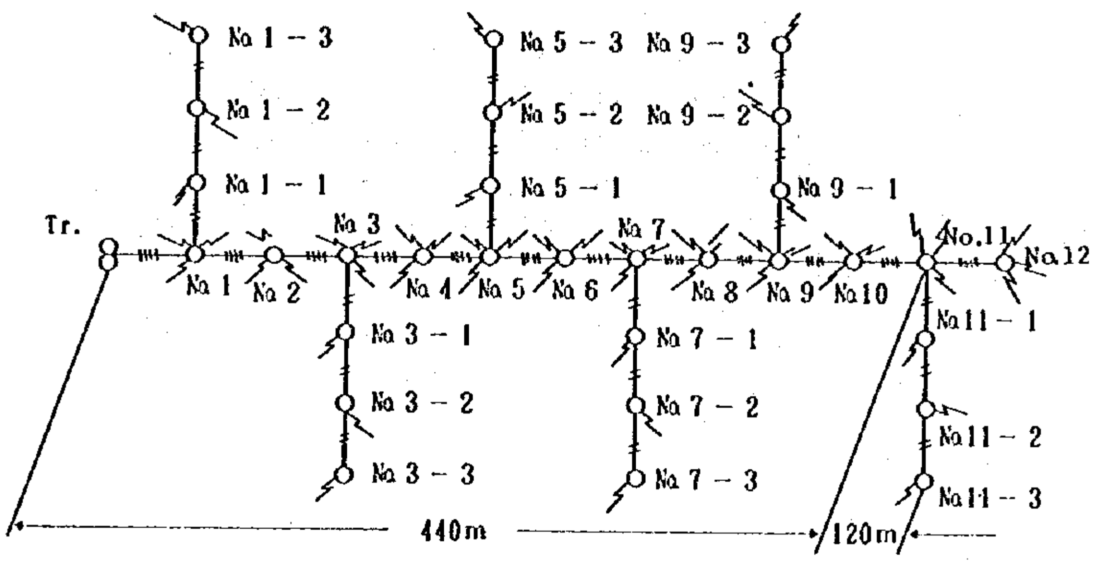
9.6.3 Type of wire for low voltage line

HAL-OW 125 mm^2
HAL-OW 55 mm^2

9.6.4 Maximum voltage drop of low tension line

The followings are examples of voltage drop of low tension lines.

(1) A low voltage feeder is designed as follows:



- Standard span: 40 m
- Trunk line : 3P4W (HAL-OW 125 mm^2)
- Branch Line : 1P2W (HAL-OW 55 mm^2)

(2) Assume that the load current is balanced, maximum load current is 180A and the load current at No. 11 pole is 30A.

(3) Calculations

(a) Trunk lines (Tr. - No. 11)

Voltage drop $V1 = \frac{1}{2} r_1 \cdot \ell_1 (i_1 + i_2)$

Where;

r_1: AC resistance of lines at 50°C = 0.269 (Ω/km)
ℓ_1: Length of trunk line = 0.44 (km)
i_1: Current at sending end = 180 (A)
i_2: Current at receiving end = 30 (A)

Therefore;

$$V1 = \frac{1}{2} \times 0.269 \times 0.44 (180 + 30) = 12.43 (V)$$

(b) Branch lines

Voltage drop $V2 = \frac{1}{2} r_2 \cdot 2\ell_2 \cdot (i'_1 + i'_2)$

Where;

r_2: AC resistance of lines at 40°C = 0.589 (Ω/km)
ℓ_2: Length of branch line = 0.12 (km)
i'_1: Current at sending end = 30 (A)
i'_2: Current at receiving end = 10 (A)

Therefore;

$$V_2 = \frac{1}{2} \times 0.589 \times 2 \times 0.12 \times (30 + 10) = 2.83 (V)$$

(c) Service lines (DV 3.2 mm x 2C)

r_3: Resistance at 40°C = 2.48 (Ω/km)

ℓ_3: Length of service line = 0.03 (km)

i_3: Load current = 10 (A)

Voltage drop of service line $V_3 = r_3 \cdot 2\ell_3 \cdot i_3$

$= 2.48 \times 2 \times 0.03 \times 10$

$= 1.49$ (V)

(4) Total voltage drop of low voltage lines

Total voltage drop $V = V_1 + V_2 + V_3$

$= 12.43 + 2.83 + 1.49$

$= 16.75$ (V)

9.6.5 Dip on low voltage lines

Low voltage line is to be hung on a high tension line pole at some points, therefore, dip is set at about the same as high tension line.

(1) Maximum span: 50 m or 30 m for road crossing

(2) Dip and tension

Dip at 60°C

(unit: m)

Span (m)	30	35	40	45	50
HAL-OW 125 mm^2	0.50	0.60	0.72	0.85	1.00
HAL-OW 55 mm^2	0.46	0.59	0.69	0.83	0.98

Note) Max. Tension: HAL-OW 125 mm^2 = 450 kg
HAL-OW 55 mm^2 = 270 kg

(3) Length of pole

$$L \geqq \frac{6}{5}(H + D + C)$$

Where;

L: Length of pole

H: Length of pole above ground level

D: Dip

C: Clearance of overhead conductor from the top of the pole

(a) Road way crossing: Span is under 30 m.

$$L \geqq \frac{6}{5}\{6.0 + 0.5 + (0.25 + 0.75)\} = 9.0 \text{ (m)}$$

(b) Others: Span is under 50 m

$$L \geqq \frac{6}{5}\{5.0 + 1.0 + (0.25 + 0.75)\} = 8.4 \text{ (m)}$$

9.6.6 Support

(1) Kind of support: Wooden pole and steel pole

(2) Insulator: Shackle insulator

(3) Hand ware: D-Iron

9.6.7 Joint use pole

(1) Standard span

Standard span of low voltage line which is hanging on the high tension pole is less than 50 m, but in case of road crossing with triangle assembling the standard span is less than 40 m.

(2) Clearance

Minimum clearance between 11 kV line conductor and low voltage line conductor is 1.2 m.

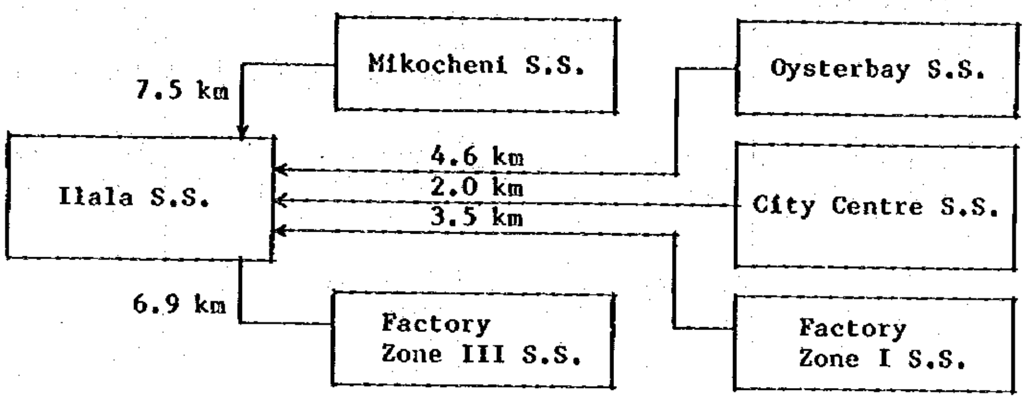
(3) Pole assembling

Vertical arrangement is adopted.

9.7 LOAD DISPATCHING AND SUPERVISORY COMMUNICATION SYSTEM

(1) Objected substation

Load dispatching and supervisory communication system between the Ilala S.S. and each distribution substation is due to equip and mend completely follows:



(2) Data for load dispatching and supervision

Collected data requiring for the load dispatching and supervision through the communication system are classified into the following elements, which is displayed on the automatic supervisory board.

No.	Data name	Number of elements
1	33 kV Circuit CB Trip	1
2	11 kV Feeder Reclosure work	1
3	" Reclose failure	1
4	Protection relay work	1
5	LTC, Station service equipment failure	1
6	Door open	1
7	A telephone circuit	1

Summarizing method of collected information/data at each substation is as shown in the next table.

No.	Equipment	Fault condition	Follower station alarm/display	Master station alarm/display
1	33 kV CB	CB Trip	33 kV CB Trip	33 kV CB Trip
2	11 kV Feeder "	OC work OCG "	Reclosure work	Reclosure work
3	"	"	Reclose failure	Reclose failure
	Transmission line	OC work OCG "	Line protection relay work	Prot. relay work
4	MTr.	Dif work OCG " OC " SEF " 96 " Gas " Winding temperature rise Oil temperature rise	MTr. prot. relay work	
	LTC Station service	Tap max. " min. " difference " delay P.T. voltage failure Aux. voltage failure NFB Trip 27 80 Charger failure	LTC prot. relay work	LTC, station service relay work
6	Entrance door	Door open	Door open	Door open
7	A telephone circuit	A telephone	A telephone	A telephone

(3) Automatic supervisory board

Master station is located on the Ilala S.S. and remote station is located on five substations, Oysterbay, Mikocheni, City Center, Factory Zone I and Factory Zone III substations respectively.

Remote station collects its own data and displays them at the remote station and transmit the data to the master station. Telephone is set at each remote station.

Outline of the supervisory board is shown in Fig. 9-7-1.

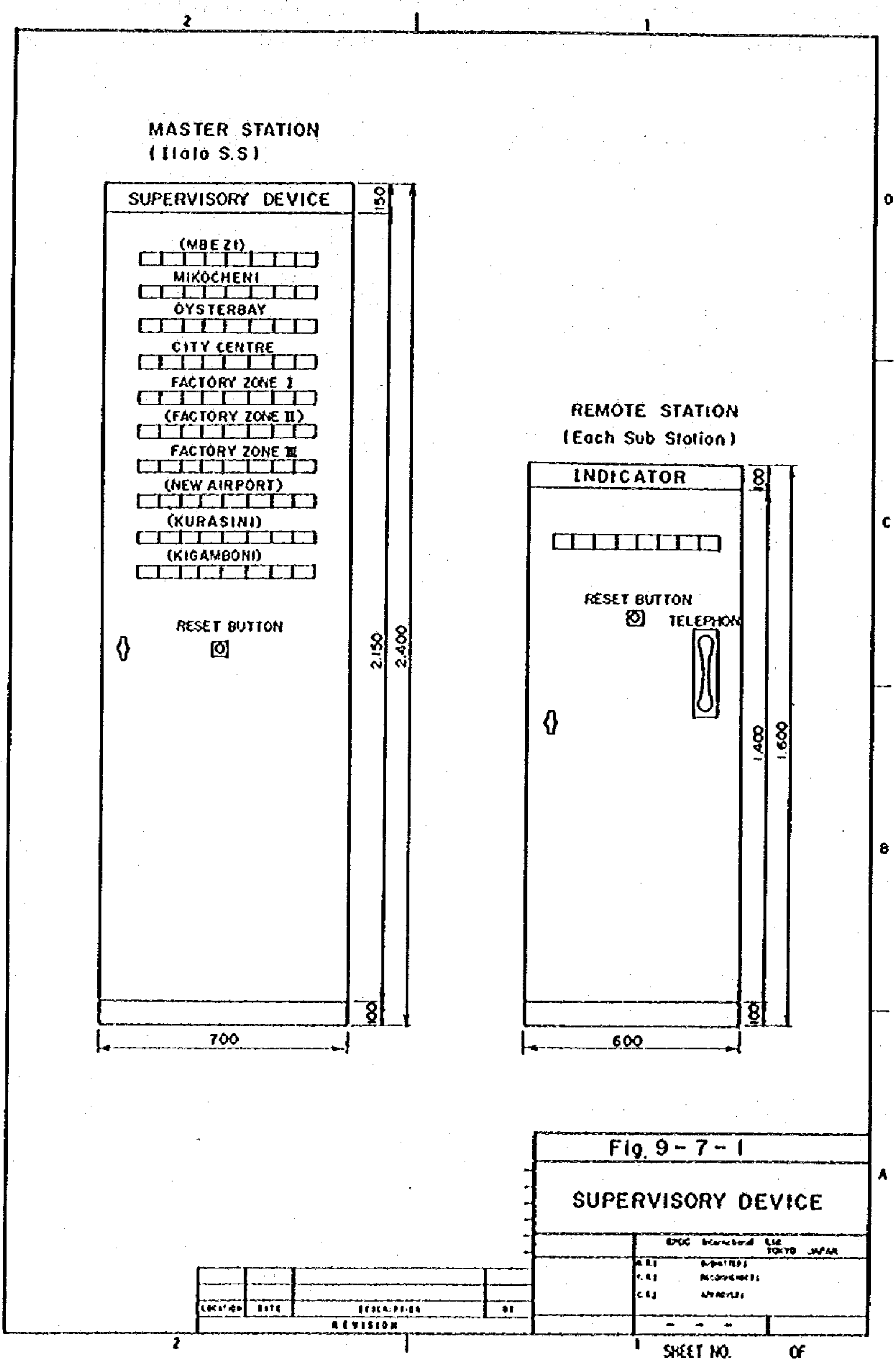


Fig. 9-7-1

SUPERVISORY DEVICE

CHAPTER 10

PREVENTIVE MAINTENANCE OF THE FACILITIES

CHAPTER 10 PREVENTIVE MAINTENANCE OF THE FACILITIES

10.1 NECESSARY STANDARDS FOR MAINTENANCE AND OPERATION 10-1

10.2 RECOMMENDATION ON POWER LOSS REDUCTION 10-4

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CHAPTER 10 PREVENTIVE MAINTENANCE OF THE FACILITIES

10.1 NECESSARY STANDARDS FOR MAINTENANCE AND OPERATION

Maintenance, improvement and operation of transmission and distribution facilities for an electric power supply should be usually carried out so that a good quality electric power may be constantly and safely supplied to the consumers. Especially, the distribution facilities widely exist covering a wide region and they are very complicated. Therefore, the overall and detailed grasp of the facilities takes time and labor. However, unless these efforts are taken, the maintenance operations as scheduled become impossible to take place and it results in the facilities' deterioration.

In order to rationally operate the distribution facilities and manage it efficiently, the below mentioned standards must be followed and the consolidated methods in accordance with these standards must be adopted. This is indispensably important.

The real preventive maintenance of facilities can be achieved by the constant efforts based on these standardized methods.

(1) Maintenance standards

The maintenance standards should be decided. They include 1) insulation resistance value of power lines (including the indoor wiring), 2) vertical clearance of conductor, 3) distance between conductor and trees and/or buildings, 4) grounding resistance value of electric equipment, 5) others.

(2) Regulations for maintenance

The basic regulations including 1) person in charge of maintenance, 2) allocation of maintenance work, 3) regular inspection patrol, 4) maintenance work to prevent an accident from occurring, and 5) restoration work, 6) others, should be made clear and a smoother maintenance operation would be effected.

(3) Regulations for a regular inspection patrol

The regulations for 1) an interval of regular inspection patrol, 2) method of regular inspection patrol, 3) inspection items, 4) others, are defined.

When the inspection patrol takes place, the inspection cards must be carried and the necessary check points must be in writing. The written inspection cards are classified by each category, i.e., 1) urgent repair within the same day, 2) repair within 10 days, 3) repair on the future plan.

These data are used as important basic data for maintenance and repairing construction.

(4) Regulations for maintenance and repairing work

This regulates 1) planning of the emergency work and scheduling maintenance and repairing construction, 2) work instructions channels, 3) responsible persons, 4) others.

(5) Measuring manual of voltage and current of distribution lines

(i) Measuring of service voltage to the consumer

The measuring of service voltage is carried out both at the consumers located near the transformer facility and at the consumer located at the far edge area where the transformer facility is being installed. This measuring must be done for 24 hours once a year or more according to the needs by the sampling method. The obtained data are compiled for the basic data to be used for the facilities' improvement program.

(ii) Measuring of load current

The load current of the transformer and/or low-tension line is measured by means of an overhead conductor type maximum demand ammeter once a year or more than once according to the needs. They are used for proper load controlling.

(6) Schematic diagram of distribution lines

The booklet describing the schematic diagram of distribution lines (on a scale of 1 to 5,000) is prepared and used. This booklet includes 1) location of pole, 2) pole number, 3) distance between poles, 4) kinds and sizes of conductors, 5) location and capacity of transformer, 6) location of section switch, 7) location and name of large volume consuming clients. Since the systems operations and/or the restoration work of power supply interruption are carried out according to this booklet, whenever any amendment or change of the facility occurs, the necessary amendment must be immediately shown on this schematic diagram.

Thus, at all times, the present situation of the related facilities must coincide with the data on the schematic diagram.

(7) General information card on facilities

Since there are many facilities and the changes occur many times, the below specified card must be prepared for the facilities' management.

(i) Card for the transformer

This card is used for referring 1) usage history of the transformer, 2) supply area of low-tension line, 3) tap to be used, 4) voltage, 5) load current, 6) grounding resistance value. In addition, the load per each pole can be realized by recording the load facilities of the individual consumers on this card. By doing so, the voltage drop of a low-tension line can also be calculated. Accordingly, this card is indispensably important for load and voltage control.

(ii) Card for the other devices

Concerning 1) section switch, (2) devices such as arrester, etc. provided on the pole, and 3) devices of underground line, nameplates, location of installation, contents of inspection, maintenance and repair are recorded on this card. These data are used for management purposes of the facilities.

(8) Restoration works guideline of distribution line fault

In restoration works for distribution interruption, in order to shorten an interruption as possible the guide line of initial movement, investigation, restoration works should be set up.

(9) Regulations for managing the power supply reliability

The data such as 1) achievement rate of appropriate voltage, 2) the frequency of power supply interruption due to line fault, 3) the frequency of power supply interruption due to the scheduled maintenance and operation works, 4) how long the power supply interruption has continued are recorded classified per each distribution line. These are utilized as the basic data for facility improvement program in the future.

10.2 RECOMMENDATION ON POWER LOSS REDUCTION

Decreasing of the power loss caused by the transmission facility is fundamentally important for effective utilization of valuable electrical energy. It has a big economical effect and is also important from the viewpoint of efficient operation of the facilities concerned.

The rehabilitation works generally accompanies a voltage improvement and power loss reduction at the same time. Accordingly, by the restoration of high and/or low-tension line in the Msasani area which is conducted under the scheme of grant aid emergency overhaul material supply and various countermeasures planned in this project, a high power loss reduction can be expected.

10.2.1 Loss Reduction Measure

By means of upgrading the capacity of the 132/33 kV transformers of Ilala S.S. from 20 to 90 MVA, 80% load sharing on 132 kV line (Ubungo to Ilala line) comes to realize. At the same time power supply from Ilala S.S. to Oysterbay S.S. and Kurasini S.S. can be realized. Thus the effect of reducing the loss which would be occurred in 33 kV lines will be remarkable.

As for the countermeasures to reduce a power loss at the substation, the following points must be taken in consideration for the operation.

(1) Execution of appropriate voltage control

The higher the transmission voltage within the permitted range is, the smaller the loss is. Therefore, it is necessary that the voltage control must be done in the consideration of 1) a correct grasp of the daily voltage operation condition, and 2) a daily check of operation situation of equipment. Concerning the settled target value of line voltage, the standardization of rules seems to have been preparing at present. However, it is necessary to carry out a more eleborate monitoring and data analyses by the automation of LTC.

(2) Power-factor improvement

As far as we have observed during the site survey this time, the power-factor situation was not so bad that an improvement is required. So, we have basically judged that an improvement of the power-factor is not necessary. However, if there will be any consumer who has a poor power-factor situation, an improvement measure will become necessary. We have decided on the figures of 0.8 - 0.85 as a tentative criterion. A power-factor less than this value must be improved.

(3) Inspection of connection troubles of bus conductor, breaker and equipment terminals

A regular checking must be carried out daily based on the check points not only from decreasing of a power loss but also from the prevention of accidents. If such abnormal parts as strand's cutting, color change, abnormal sounds, etc. are found, a prompt repair must be executed.

(4) Appropriate load allocation on every feeders

The lower the operation temperature of equipment is, the longer its life span is. It is preferable that the feeder is operated under a well-balanced load current condition because high temperature affects a bad influence to surrounding instruments, especially in the cubicle.

10.2.2 Power loss reduction of distribution lines

(1) Physical countermeasures for the facilities

(i) 11 kV feeders

From a theoretical viewpoint, a reducing of line resistance is the most effective way of countermeasure. For the existing 11 kV feeder, various types of conductors such as HDCC 35 mm^2, 25 mm^2, ACSR 100 mm^2 and 50 mm^2, are used. Except for ACSR 100 mm^2 which is in good condition, the main part (about 60 km in total length) of these trunk lines will be size-up to ACSR 120 mm^2. Accordingly, the reducing effect of a power loss becomes big. Since all of the inferior connections of the lines are going to be repaired completely, the loss reduction in this field can also be expected.

(ii) Low-tension distribution lines

The distribution of power losses in Dar-es-Salaam may be judged to have occurred mainly on the low-tension line based on the assumption of 1) the total length of the low-tension distribution lines, and 2) an average current value per one line. Accordingly, the priority of power loss reduction works should be placed mainly on the low-tension line.

Replacing the deteriorated conductors with HAL-OW 125 mm^2 or HAL-OW 55 mm^2, drastic reduction of power failure, power loss, and improvement of voltage stabilization can be expected.

(iii) Distribution transformers

Concerning the existing transformers, the operational countermeasures are taking into consideration and as to the newly purchasing transformers which will be made available for the increasing demands, the economic evaluation on a new type, low loss transformer will be made in order to ascertain its merit.

(2) Operational countermeasures

(i) Dissolution of unbalanced current

The complete dissolution of the unbalanced current of 3-phase 4-wire low-tension distribution trunk line is extremely difficult. However, by effectively using of the measuring instruments, etc. which are supplied by the emergency construction material and machine supply aid, the capacity of each phase current can be realized and the unbalanced current can be largely dissolved by appropriate connection change of single phase branch line and incoming line.

The unbalanced current raises, not only an increase of power loss, but also an unbalanced situation of three phase voltage at the points on the line caused by a non-uniform situation of a voltage drop. This brings about the efficiency slow-down of the load machine. Thus, this situation is not good for the operation of a line.

If the unbalanced current of a low-tension trunk line is largely dissolved, the unbalanced current of 11 kV feeder can also be improved and furthermore it gives a good influence on upper system.

(ii) Dissolution of the heavy-load feeder

The load sharing is made possible by using the section switch and as much as possible the load allocation of each feeder is uniformalized.

(iii) Operational rationalization of the distribution transformer

For enhancing the transformer utilization ratio and operational efficiency rate per day, such means as exchanging the excessive capacity existing transformer and the capacity shortage existing transformer for each other so as to suit the desirable one are also effective methods of operational rationalization.

Since the transformer for the distribution line has about 20% overload capacity in general, the performance of individual transformers can be checked so that the scope of the overload operation can be made clear.

Thus, the efficiency of investment to the transformer can be enhanced and an economic effect can be expected.

(iv) Installation of a low-tension condenser for power-factor improvement

Concerning the inductive load below the standard power-factor, it is effective that the consumer has the obligation to install a condenser which has an appropriate capacity as a condition of power supply. However, it is necessary that the preferential treatment for the electricity tariff such as the load factor discount must be carried out.

(v) Control of measuring instruments

(a) Fairness of electric power supply business transaction

The testing system of measuring instruments must be established and the business transaction must be carried out within its tolerance.

(b) Dissolution of power supply to those who have no measuring instrument installation to the greatest extent, the power supply to those who have no measuring instrument installation must be limited. If such a power supply is obliged to be made, the supply volume will have to be at the appropriate level of the agreement and at the same time make an effort to prevent

(c) Dissolution of the measuring error

At fixed intervals the checking of the measuring indicator must be made so that the measuring error will be absolutely abolished.

(d) Fairness of the agreement

In order to accomplish the fairness of agreement, the installation of a current limiter corresponding to the agreed capacity must be recommended.

(vi) Clearness of the control method for power loss

The power loss ratio under the distribution line is explained by use of the following formula.

Power loss ratio under the distribution line

$$= \frac{\text{(A) - (Sales power volume + Power volume for business operation)}}{\text{Transmission power volume to be substation for distribution (A)}} \times 100\ (\%)$$

However, actually, there are such problems as errors caused by watthour meter observation and the method of checking the electric power volume in the case of a "no measuring" installation basis agreement.

Theft of electric power, loss of leaked current, etc. are also unexpectedly big. Accordingly, there are many problems to solve these problems rather than the physical loss of electric power. When the countermeasures for power loss improvement occurring at the distribution lines are carried out, it is first necessary to check that all the transmission power volume is correctly calculated within the range of permitted error. And, the calculation of power volume sold at a fixed price must be reviewed whether it is rational or not. In this way, under the fixed premise, the control method must be made clear. A real physical loss must be realized after selection from the clarified loss administration data so that it may be used for technological improvement in the future.

CHAPTER 11

CONSTRUCTION SCHEDULE

CHAPTER 11 CONSTRUCTION SCHEDULE

11.1 WORK METHOD 11-1

11.2 WORK SYSTEM 11-1

11.3 WORK SCHEDULE 11-2

CHAPTER 11 CONSTRUCTION SCHEDULE

The transmission and distribution facilities in the Dar-es-Salaam district, which are the objectives of this project, are in a catastrophic state beyond our comprehension. Power supply failures and burnout accidents of home electric appliances caused by voltage fluctuation occur frequently. Early facility rehabilitation is strongly desired and badly needed.

We recommend the following work method, system and schedule in order to implement this project efficiently and safely.

11.1 WORK METHOD

The construction works will be directly executed by TANESCO. In the expansion work of Ilala S.S., and construction works of new Mikocheni S.S. and Factory zone III S.S., only the civil engineering works will be directly owned, and the equipment will be supplied from the manufacturers including assembly, installation and adjustment, on semi-turnkey basis. The transmission lines and substations should be constructed step by step. For the distribution line work, the work area should be divided into the supply areas of the four objective distribution substations of this project and work should proceed concurrently in all four areas.

11.2 WORK SYSTEM

Being a facility rehabilitation project, this project involves little new construction; it is concentrated more on renovation, improvement and replacement of existing facilities, which essentially means the power supply must be suspended frequently.

Since the objective area includes office areas of government and business firms and densely populated living quarters surrounding these areas, it is feared that suspending power for long periods of time would be extremely difficult.

Accordingly, when implementing this project, it is essential that a special team is organized to prepare the designs, work schedule and work instructions and to efficiently supervise all working teams, and thereby realizing efficient, safe work with minimal power suspension. We plan to install a VHF transceiver in each vehicle involved in this project, so that instruction and communication measures which are an extremely crucial factor during the work are secured and the work proceeds efficiently.

11.3 WORK SCHEDULE

Based on the work method and work system as described in the above, we have determined a tentative work schedule as shown in Table 11-1.

Table 11-1 Construction Schedule

SUBSTATION:

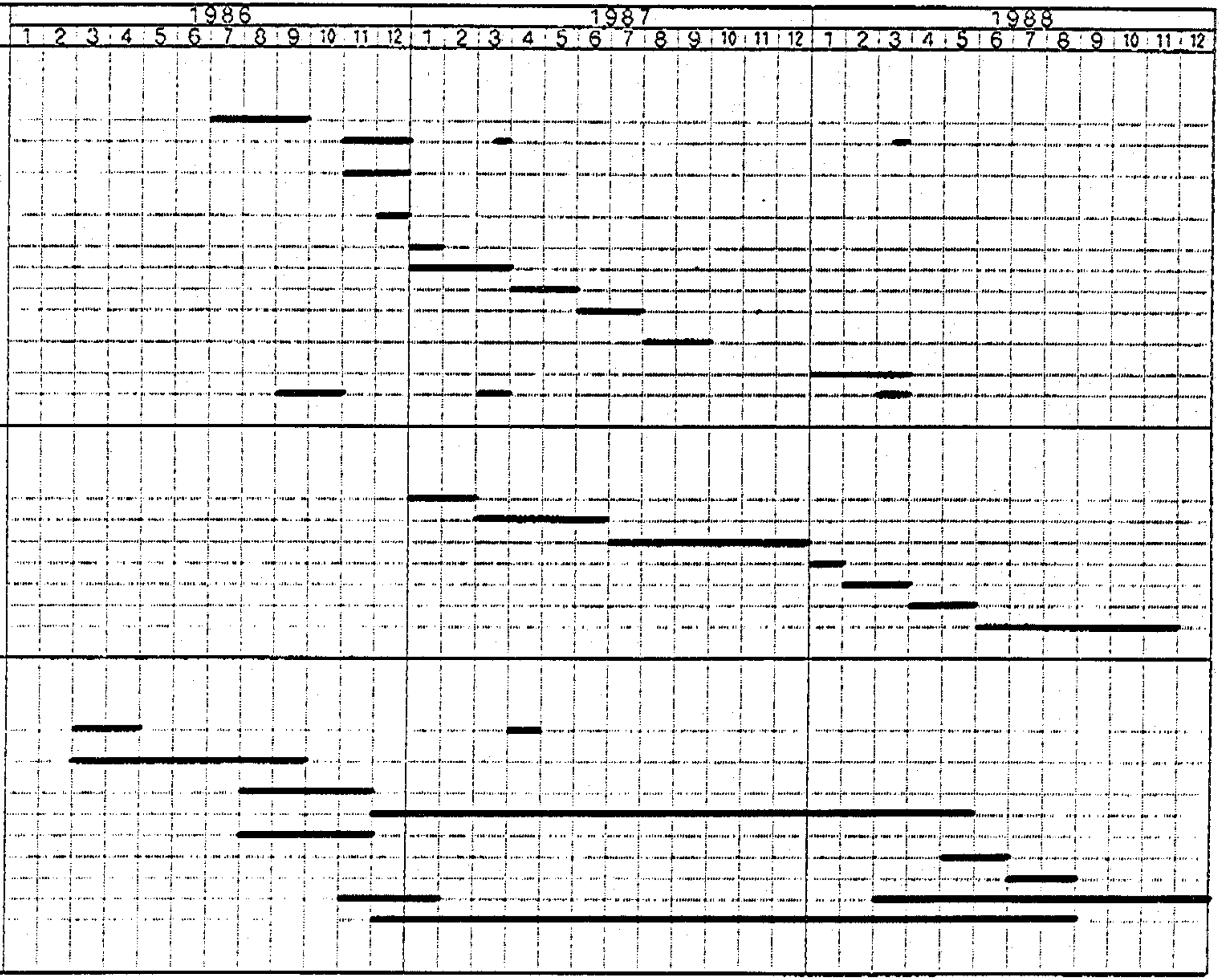
1. Ilala S.S Extension
2. Automatic LTC
3. DC Power Supply System - Oysterbay, City Center, Factory Zone I S.S
4. Incoming Feeders - Oysterbay and City Center S.S
5. System Changeover - Kurasini S.S
6. Construction of Mikocheni S.S
7. Improvement of Ubungo S.S
8. Inspection of Existing Transformers
9. Improvement of Factory Zone I S.S and Kurasini S.S
10. Construction of Factory Zone III S.S
11. Supervisory Monitor

TRANSMISSION LINE:

1. Mikocheni Branch Line
2. Ilala — Oysterbay Line
3. Ubungo — Factory Zone III
4. Factory Zone III — Factory Zone II
5. Factory Zone III — New Airport
6. Factory Zone III — Factory Zone I
7. Factory Zone I — Kurasini

DISTRIBUTION LINE:

1. System Interconnection
2. Improvement of Protective Device on Distribution Transformers
3. Re-Conductoring on HT Lines
4. Re-Conductoring on LT Lines
5. Installation of Lightning Arresters
6. Extension of Branch Lines
7. New Feeders from New Substations
8. Extension of Service Lines
9. Improvement of Service Lines



CHAPTER 12

CONSTRUCTION COSTS

CHAPTER 12 CONSTRUCTION COSTS

12.1 PREMISES FOR THE CALCULATION OF CONSTRUCTION COSTS 12-1

12.2 CLASSIFICATION OF FOREIGN AND DOMESTIC CURRENCY 12-2

CHAPTER 12 CONSTRUCTION COSTS

As shown in Table 12-1, the construction expenses of this project have been calculated for substations, 33-kV sub-transmission lines, distribution lines, automobiles and tools individually.

12.1 PREMISES FOR THE CALCULATION OF CONSTRUCTION COSTS

We have adopted the following premises for the calculation of construction costs.

(1) Unit prices of construction materials and machines

Concerning FOB prices, the calculation is to be made based on the prices in 1985 and an annual price increasing rate which is to be estimated at 2%. The import taxes in Tanzania are not calculated.

(2) Transportation expenses and insurance premium

The transportation expenses include both ocean freight and inland transportation costs. The insurance premium is added and CIF prices are calculated based on the above FOB prices multiplied by the below mentioned ratio.

(i) Construction materials and machines for substations: 15%
(ii) Wooden poles and steel tube poles: 21%
(iii) Line materials: 9%
(iv) Automobiles: 21%
(v) Others: 9%

(3) Labor costs

Based on the present standards of labor costs in Tanzania and the actual business records of similar construction cases in Japan, the labor cost ratio to the construction materials and machines is decided as follows:

(i) Substation

(a) Dismantling work: 17%
(b) Installing work: 33%

(ii) Transmission and distribution lines

(a) Dismantling and repairing work: 35%

(b) Newly construction work: 3%

In the above (i), the extension construction of the Ilala Substation and the newly constructions of the Mikocheni Substation and the Factory Zone III Substation should be taken place under semi-turn-key basis.

(4) Contingency

A 10% of each of the total foreign currency and domestic currency is estimated.

(5) Engineering fee

A 8% of the overall direct construction costs is estimated.

(6) Technical training

The cost for dispatching TANESCO personnel to an advanced country for training, and the cost of compiling manuals are counted.

The training of work technique provided at the site will be on-job trainings, which cost is included in the engineering fee.

(7) Conversion rate

The conversion rate: 1 T.Sh. = ¥13.71

12.2 CLASSIFICATION OF FOREIGN AND DOMESTIC CURRENCY

The foreign currency portion and the domestic currency portion which are used for the construction expenses are shown as follows:

(1) Foreign currency portion

(i) Materials and equipment:

All items excluding gravel, sand and cement.

(ii) Automobiles and tools:

Automobiles, tools and measuring instruments used for the construction work

(iii) Transportation expenses and insurance premium:

Ocean freight, domestic transportation costs and insurance premium

(iv) Labor costs:

Dispatching expenses of engineers who work for semi-turn-key basis construction and the large-sized equipment installation

(v) Engineering fee, Training expenses

(2) Domestic currency portion

(i) Labor cost

- Labor cost related to improvement and construction works executed by TANESCO, for transmission, distribution and substation facilities

(ii) Construction materials expenses

- Cost of domestic materials: ballast, sand, cement and small indigenous materials

(iii) Cost of civil works for substation facilities

(3) Estimate of construction cost

Presented in Table 12-1.

Table 12-1 Construction cost

	Materials	Construction		Total		
	FC 10^6 Yen	FC 10^3 Yen	DC 10^3 T.Shs	FC 10^6 Yen	DC 10^3 T.Shs	Total 10^6 Yen
I. Construction Cost						
1. Substation	556	55	11,225	611	11,225	765
2. 33 kV Sub-transmission Line	88		1,926	88	1,926	114
3. Distribution Line	1,342		30,160	1,342	30,160	1,756
4. Vehicles & Tools	120			120		120
Sub-total	(2,106)	(55)	(43,311)	(2,161)	(43,311)	(2,755)
II. Engineering Fee						
1. Engineering Fee				221		221
2. Technical Training Fee				30		30
Sub-total				(251)		(251)
III. Contingency				216	4,331	276
Total				2,628	47,642	3,282

Note) Conversion rate: T.Sh 1 = Yen 13.71

CHAPTER 13

ECONOMIC EVALUATION

CHAPTER 13 ECONOMIC EVALUATION

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CHAPTER 13 ECONOMIC EVALUATION

13.1 METHODOLOGY

The economic evaluation of the distribution network rehabilitation project shall be made by calculating the internal rate of return which equalizes the total discounted costs of the project to the total discounted benefits brought about by the project. In this calculation the costs and benefits are classified as follows:

Costs: (a) Investment costs of the project

(b) Operation and maintenance costs of the project

Benefits: (c) Increase in electricity consumption due to installation of transformers at selected substations

(d) Decrease in power interruption due to improvement of the existing distribution facilities

(e) Economy in operation and maintenance costs of the existing distribution facilities due to the above improvement works

The benefit of the additional electricity consumption in items c) and d) must be expressed in monetary terms by using a unit benefit per kWh. For this purpose, the share of distribution sector in the total supply costs of electricity (excluding interest and net income) must be calculated by analyzing financial statements of TANESCO. Then, the unit benefit for the distribution sector can be obtained based on this share and quantity of energy (kWh) distributed.

In addition to the above benefits, there are intangible benefits such as decrease in damages of consumer's electrical machines and apparatus due to frequency drop and voltage variation, as well as, decrease in inconveniences and discomforts of living due to frequent interruption of electricity supply. But, these benefits shall not be included in this economic evaluation because they are difficult to be evaluated in monetary terms.

13.2 CONDITIONS FOR EVALUATION

(1) Prices

Consistent with the principles of economic evaluation, all items shall be expressed in real terms of 1984, i.e. excluding any future inflation. All costs and benefits in the future shall be converted to the present worth as of the beginning of 1984.

(2) Currency exchange rates

The currency exchange rates adopted in this study are the following:

1 US$ = T.Shs. 17.5 = 240 Yen
1 Yen = T.Shs. 0.0729
1 T.Shs. = 13.71 Yen

(3) Period of calculation

According to accounting policies of TANESCO, depreciation period on fixed assets are 40 years for transmission lines, 30 years for 11 kV feeders and 20 years for substations and transformers. But, in fact the mechanical lives of distribution facilities are longer than 20 years. Therefore, economic evaluation shall be carried out over the period up to 2010.

(4) Distribution loss factor

Although data on the actual distribution loss factor in Dar-es-Salaam is not available for the reasons stated in paragraph 3.3.2 of Chapter 3, some reports show that it was ranged from 7% to 12% for the period up to 1978. With the execution of improvement works on the existing distribution facilities, the loss factor will decrease slightly. Taking these into account, a distribution loss factor of 10% shall be adopted in this study.

(5) Load factor

As shown in Chapter 6, load factor shall be estimated at 65% for the period from 1986 to 1990 and 66% thereafter.

13.3 COSTS

13.3.1 Investment costs of the project

The direct construction costs of the project are estimated at 2,755 million yen (2,161 million yen for foreign currency portion and T.Shs. 43.30 million for local currency portion), and the total construction costs including contingencies and engineering fee are estimated at 3,282 million yen (2,628 million yen for foreign currency portion and T.Shs. 47.68 million for local currency portion) as shown in Table 13-1.

Of the above costs, costs required for improving the distribution facilities are estimated at T.Shs. 99.0 million (1,356.1 million Yen) as shown in Table 13-2. This investment will have an effect of decreasing operation and maintenance costs of the existing facilities. The remaining costs of T.Shs. 140.3 million (1,925.5 million Yen) are required for increasing distribution capacities to meet the growing demand for electricity.

From the above tables, the annual disbursements of costs for improvement works (Investment A) and costs for increasing distribution capacities (Investment B) can be summarized as follows:

(T.Shs. million)

Year	Investment A	Investment B	Total
1986	35.4	56.2	91.6
1987	43.7	30.4	74.1
1988	19.9	53.7	73.6
Total	99.0	140.3	239.3

13.3.2 Operation and maintenance cost and its economy

Statistically, the operation and maintenance cost is about 3% of the construction costs. Therefore, the present facilities which will be improved and reinforced with additional transforming capacity by the total investment of T.Shs. 239.3 million will necessitate additional operation and maintenance cost of about T.Shs. 7.2 million annually.

However, the investment A of T.Shs. 99.0 million represents the assets which should have already been incorporated with the present facilities for their normal operation, and corresponding operation and maintenance cost of T.Shs. 3.0 million (99.0 x 3%) or more due to deterioration of facilities would have been expended annually. Since this cost is included in the above operation and maintenance cost of T.Shs. 7.2 million, the net operation and maintenance cost of the project is estimated at T.Shs. 4.2 million (7.2 - 3.0 = 4.2), of which annual disbursement is as follows:

(T.Shs. million)

Year	Cumulative total investment	Cumulative investment A	Balance	Operation and maintenance cost
1986	91.6	35.4	56.2	
1987	165.7	79.1	86.6	1.7
1988	239.3	99.0	140.3	2.6
1989				4.2
....				...
2010				4.2

13.4 BENEFITS

13.4.1 Increase in electricity consumption due to installation of transformers at selected substations

(1) Ilala and City Center areas

Peak load at Ilala substation is forecasted to grow to 13.2 MW in 1984. This means that its transformer capacity of 15 MVA cannot meet the growing power demand after 1985. On the other hand, the transformer capacity of 30 MVA of City Center substation is large enough to meet the growing power demand in its area for coming years (peak load in 1984 is estimated at 17.8 MW). Therefore, by connecting these two substations and replacing an existing 7.5 MVA transformer of Ilala substation by a 15 MVA unit, it is possible to meet the growing power demand for the period up to 1993.

(2) Oysterbay and Mikocheni areas

Peak load at Oysterbay substation is forecasted to grow to 13.3 MW in 1985. This means that its transformer capacity of 15 MVA cannot meet the growing power demand after 1986. However, by constructing a new substation (15 MVA) at Mikocheni in the service area of Oysterbay substation, it is possible to supply these areas with power for the period up to 1999.

(3) Factory Zone I and Factory Zone III areas

Peak load at Factory Zone I substation is forecasted to grow from 12.6 MW in 1983 to 14.7 MW in 1988. This means that its transformer capacity of 15 MVA cannot meet the growing power demand after 1988. However, by constructing Factory Zone III substation (15 MVA) in the neighbourhood of Factory Zone I substation, it is possible to supply these areas with power for the period up to 1993.

The increase in electricity consumption made available by the execution of the project is shown in Table 13-3.

13.4.2 Decrease in power interruption due to improvement of the existing distribution facilities

Although effects of improvement works will be produced from the whole distribution system in Dar-es-Salaam, the greater part will be produced from four service areas of Ilala, City Center, Oysterbay and Factory Zone I substations on which main improvement efforts are planned to be placed. Therefore, effects of decrease in power interruption shall be evaluated on these four services areas.

It is considered that the effects of improvement works will be produced after 1987. By that time frequency of power interruption will increase every year due to superannuation of facilities and insufficiency of maintenance. Quantity of energy which can be decreased from total interrupted energy in 1986 is estimated in the following manner:

(1) Average load by 11 kV feeder

The aggregated peak load at Ilala, City Center, Oysterbay and Factory Zone I substations is forecasted to grow to 60.5 MW in 1986. The total number of 11 kV feeders in service of these substations is 18. Therefore, the average maximum load by 11 kV feeder is 3.36 MW as shown below:

(1986)

Substation	Peak load (MW)	Number of 11 kV feeders	Maximum load by feeder (MW)
Oysterbay	13.9	5	2.78
Ilala	14.3	5	2.86
City Center	19.5	4	4.88
Factory Zone I	12.8	4	3.20
Total	60.5	18	3.36

Power interruption occurs both in the peak load time and in the low load time, but generally concentrates in the peak load time. From this, it is considered that the median between peak load and average load well represents the load at the time of power interruption. This median is calculated to be 2.77 MW as shown below:

$$\frac{3.36 + (3.36 \times 65\%)}{2} = 2.77 \text{ MW} \quad \text{(Load factor: } 65\%)$$

(2) Average duration of power interruption

According to power interruption review for April 1984 given in Table 13-4, the average duration of power interruption for the Dar-es-Salaam distribution system as a whole is 1.87 hours as shown below:

- Frequency of power interruption	49 times
- Total duration of power interruption	91.4 hours
- Average duration of power interruption	1.87 hours

(3) Frequency of power interruption

According to Table 13-4, frequency of power interruption in the service areas of Ilala, City Center, Oysterbay and Factory Zone I substations in April 1984 was 22 times. Since variation of monthly frequency would be small, the annual interruption of electricity supply in 1984 will amount to 260 to 270 times against which frequency of power interruption in 1982 and 1983 was 87 times and 169 times, respectively. This represents an annual growth rate of 94% in 1983 and 56% in 1984. Judging from the actual conditions of distribution facilities, frequency of power interruption will grow at an annual rate of at least 50% to reach 590 to 600 times in 1986 as shown below:

	1982	1983	1984	1985	1986
Oysterbay	20	57	(7)	-	-
Ilala	27	45	(5)	-	-
City Center	28	45	(5)	-	-
Factory Zone I	12	22	(5)	-	-
Total	87	169	260-270	390-400	590-600
Annual growth rate	-	94%	56%	50%	50%

Note: Figures in parentheses show frequency of power interruption in April 1984.

The total number of 11 kV feeders in service of these four substations is 18, therefore the average frequency of power interruption per feeder is estimated to be about 33 times per annum.

In this context, it is to be noted that the above power interruption is due to trip of 11 kV circuit breakers only. Therefore, the total frequency of power interruption would be much more when considering power interruption at 33 kV and low voltage systems. However, from conservative standpoint, the power interruption by trip of 11 kV feeders only shall be taken into consideration in this economic evaluation.

(4) Decrease in power interruption by improvement works

As described in Chapter 4, the actual frequency of power interruption is estimated to be decreased to less than 3 times per feeder per annum by the execution of appropriate improvement works and scheduled maintenance on the existing distribution facilities.

Based on the above data, i.e. annual power interruption of 590-600 times, annual interruption per feeder of 33 times, average load per feeder of 2.77 MW and average duration of power interruption of 1.87 hours, the quantity of energy at consumers end which will be decreased from total interrupted energy in 1986 can be estimated as follows:

$$595 \text{ times} \times (33 - 3)/33 \times 2.77 \text{ MW} \times 1.87 \text{ h} \times 0.9 = 2.5 \text{ GWh}$$

Note: Distribution loss factor is estimated at 10%.

If appropriate improvement works are not executed, frequency of power interruption will further increase and the existing distribution facilities will fall into collapse. But it is impossible to forecast such an abnormal frequency of power interruption over long period in the future. Therefore, from conservative standpoint, 2.5 GWh was adopted as the annual decrease in power interruption for the future.

13.4.3 Unit benefit of energy distributed

The supply costs of electricity are so-called operating expenses including costs of generation, transmission and distribution sectors. Costs of each sector consist of operation and maintenance cost, depreciation cost and administration cost. The electricity tariff is determined to cover the overall costs which include the above supply costs, interests and profit of the company.

The supply costs and the overall costs in 1982 were T.Shs. 425,988 thousand and T.Shs. 523,001 thousand, respectively, against the total energy sold of 737.2 GWh. Therefore, the supply costs and the average rate per unit sold were 57.8 Cents/kWh and 70.9 Cents/kWh, respectively.

In the revenue account of TANESCO, the cost of sales is not classified into three sectors of generation, transmission and distribution. Depreciation and interest are not also divided into these three sectors. Therefore, for the purpose of study, the cost of sales was classified into these three sectors in the following manner:

(a) In the most countries, between transmission and distribution, values of fixed assets are about 40% for transmission and 60% for distribution. Using these ratios, the sum of transmission and distribution expenses in the cost of sales shall be divided into 40% for transmission and 60% for distribution.

(b) In some examples in which ratios of capacities between hydro and thermal power stations are similar to those of TANESCO, values of fixed assets are about 60% for power stations, 16% for transmission lines and 24% for distribution facilities. Using these ratios, administration expenses and interests in the cost of sales shall be divided into 60% for generation, 16% for transmission and 24% for distribution.

(c) According to accounting policies of TANESCO, period of depreciation is about 50 years for dams and power plants, 40 years for transmission lines and 25 years for distribution facilities. These periods and ratios of fixed assets by sector described in item (b) above lead to allocate depreciation cost in the proportion of 46% to generation, 15% to transmission and 39% to distribution. Therefore, depreciation on fixed assets shall be divided into these three sectors in this proportion.

Using the above method, the revenue account of TANESCO for the year 1982 was rearranged as follows:

(T.Shs. thousand)

Item	Amount	Remarks
Operating revenue	523,001	
Supply costs		
(a) Operation and maintenance cost		
Generation	206,925	
Transmission (40%)	16,385	} 40,986
Distribution (60%)	24,597	
Sub-total	247,907	
(b) Depreciation cost		
Generation (46%)	32,867	
Transmission (15%)	10,718	
Distribution (39%)	27,865	
Sub-total	71,450	
(c) Administration cost		
Generation (60%)	63,978	
Transmission (16%)	17,060	
Distribution (24%)	25,593	
Sub-total	106,631	
(d) Total supply costs		
Generation (71%)	303,770	/737.2 GWh = 41.2 Cents/kWh
Transmission (10%)	44,163	/737.2 GWh = 6.0 Cents/kWh
Distribution (19%)	78,005	/737.2 GWh = 10.6 Cents/kWh
Total	425,988	/737.2 GWh = 57.8 Cents/kWh
Interests	89,728	
Net income	7,285	
Overall costs	523,001	/737.2 GWh = 70.9 Cents/kWh

The above table shows that, in 1982, against the average tariff rate of 70.9 Cents/kWh the supply cost was 57.8 Cents/kWh of which 10.6 Cents/kWh was the share of distribution sector. Since then, the tariff rates were raised two times in accordance with price rise of general commodities; the first time in January 1983 and the second time in January 1984. At the current tariff which is effective from January 1984, the average rate per unit sold is estimated at around 105 Cents/kWh. Assuming that the supply costs have also increased proportionally, the share (unit benefit) of distribution sector in the total supply costs is estimated to be about:

10.6 Cents/kWh x 105/70.9 = 15.7 Cents/kWh

The above-mentioned costs and benefits are all expressed in terms of marked prices, but does not include interests and taxes. Since it is considered that these costs and benefits reflect their shadow prices, there would be no problem to use them in the economic evaluation of the project.

13.4.4 Annual benefits

The benefits brought about by the project are a) increase in power consumption due to installation of additional transformers at selected substations (Table 13-3) and b) decrease in power interruption due to execution of improvement works on the existing distribution facilities (2.5 GWh annually). Since the unit benefit of energy distributed is estimated at 15.7 Cents/kWh, the annual benefits of the project will be calculated as follows:

Year	Increase in power consumption (GWh)	Decrease in power interruption (GWh)	Total (GWh)	Annual benefits (T.Shs. million)
1986	4.1	2.5	6.6	1.0
1987	13.4	2.5	15.9	2.5
1988	37.4	2.5	39.9	6.3
1989	61.0	2.5	63.5	10.0
1990	82.5	2.5	85.0	13.3
1991	96.8	2.5	99.3	15.6
1992	115.0	2.5	117.5	18.4
1993	139.0	2.5	141.5	22.2
1994	146.3	2.5	148.8	23.4
1995	152.5	2.5	155.0	24.3
1996	159.2	2.5	161.7	25.4
1997	166.0	2.5	168.5	26.5
1998	173.8	2.5	176.3	27.7
1999-2010	175.3	2.5	177.8	27.9

13.5 INTERNAL RATE OF RETURN

From the above-mentioned costs and benefits, the internal rate of return (equalizing discount rate) of the project is calculated as follows (See Table 13-5):

Internal rate of return: 5.1%

13.6 CONCLUSION

At present, the IBRD applies an interest rate of higher than 11% to most projects and the export and import banks have a guideline of applying an interest rate of 9.5% to high interest rate countries and 8.3% to low interest rate countries. Therefore, it will be appropriate to use a social rate of discount of around 9.5% in the economic evaluation of the project as the basis for judging its economic feasibility. In this case, the above internal rate of return (equalizing discount rate) of 5.1% means that this project is not so sound from economic viewpoint. However, when considering that in this economic evaluation the benefit of decreasing power interruption is underestimated and that the project will also bring about such an intangible social benefits as described in paragraph 13.1, it is judged that the economic contribution of the project becomes large enough to be worth executing.

Table 13-1 Investment costs of the distribution network rehabilitation project

(Million Yen)

Item	1986	1987	1988	Total
I. Construction cost				
33 kV line				
Foreign currency		47.8	40.1	87.9
Local currency		14.4	12.0	26.4
Total		62.2	52.1	114.3
Substations				
Foreign currency	364.6	131.6	114.8	611.0
Local currency	104.2	27.8	21.8	153.8
Total	468.8	159.4	136.6	764.8
Distribution lines				
Foreign currency	457.6	488.3	516.0	1,461.9
Local currency	108.1	153.6	151.8	413.5
Total	565.7	641.9	667.8	1,875.4
II. Engineering cost				
Engineering fee (F.C.)	88.4	66.3	66.3	221.0
Training of TANESCO staff (L.C.)	30.0	-	-	30.0
Total	118.4	66.3	66.3	251.0
III. Contingencies				
Foreign currency	80.8	67.3	68.0	216.1
Local currency	22.4	18.8	18.8	60.0
Total	103.2	86.1	86.8	276.1
Total Investment				
Foreign currency	1,021.4	801.3	805.2	2,627.9
Local currency	234.7	214.6	204.4	653.7
Grand Total	1,256.1	1,015.9	1,009.6	3,281.6
(Shs million)	(91.6)	(74.1)	(73.6)	(239.3)

Table 13-2 Costs required for improving the existing facilities (Investment A) and costs required for increasing distribution capacities (Investment B)

(Million Yen)

Year	Item	Investment A FC	Investment A LC	Investment A Total	Investment B	Total
1986	- Erection and connection of 33 kV incoming lines to Oyster Bay and City Center SS	12.8	4.1	16.9		
	- Improvement of remote control and supervising facilities	23.4	7.0	30.4		
	- Interconnection of high voltage distribution lines	73.9	23.7	97.6		
	- Improvement of primary and secondary transformers	142.0	45.6	187.6		
	- Replacement of high voltage distribution lines	115.2	37.0	152.2		
	Total	367.3	117.4	484.7	771.4	1,256.1
	(T.Shs million)	(26.8)	(8.6)	(35.4)	(56.2)	(91.6)
1987	- Erection and connection of 33 kV incoming lines to Factory Zone I and Kurasini SS	14.5	4.7	19.2		
	- Improvement of Ubungo SS	8.8	2.8	11.6		
	- Improvement of remote control and supervising facilities	3.0	0.9	3.9		
	- Inspection and improvement of transformers	6.5	1.1	7.6		
	- Replacement of low voltage distribution lines	410.6	131.2	541.8		
	- Replacement of 33 kV line - Oyster Bay SS	12.0	3.6	15.6		
	Total	455.4	144.3	599.7	416.2	1,015.9
	(T.Shs million	(33.2)	(10.5)	(43.7)	(30.4)	(74.1)
1988	- Improvement of remote control and supervising facilities	3.0	0.9	3.9		
	- Replacement of low voltage distribution lines	202.2	65.6	267.8		
	Total	205.2	66.5	271.7	737.9	1,009.6
	(T.Shs million)	(15.0)	(4.9)	(19.9)	(53.7)	(73.6)
	Total investment	1,027.9	328.2	1,356.1	1,925.5	3,281.6
	(T.Shs million)	(75.0)	(24.0)	(99.0)	(140.3)	(239.3)

Table 13-3 Increase in electricity consumption due to installation of transformers at selected substations

Substation	Transformer capacity		Maximum power demand (MW)																
	MVA	MW	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000-2010
Ilala (Existing)	15.0	13.5	13.2	14.2															
					14.3	14.8	16.5	16.6	17.2	18.0	19.0	20.3	21.3						
(Increase by re- placement)	7.5	6.7																	
City Center	30.0	27.0	17.8	19.2	19.5	21.7	21.8	22.0	22.2	23.3	24.7	26.2	27.3						
Total	52.5	47.2			33.8	36.5	38.3	38.6	39.4	41.3	43.7	46.5	48.6						
Oysterbay	15.0	13.5	12.4	13.3	13.9 }	14.8	16.6	17.1	17.2	18.0	19.0	20.3	21.4	22.6	23.9	25.2	26.7	28.1	
Mikocheni (Planned)	15.0	13.5																	
Total	30.0	27.0																	
Factory Zone I	15.0	13.5	12.6	12.6	12.8	12.9 }	14.7	18.9	22.2	23.1	24.9	26.7	29.0						
Factory Zone III (Planned)	15.0	13.5																	
Total	30.0	27.0																	
Increase in maximum power demand due to installation of transformers (MW)																			
Ilala/City Center					0.8	1.3	3.0	3.1	3.7	4.5	5.5	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
Oysterbay						1.3	3.1	3.6	3.7	4.5	5.5	6.8	7.9	9.1	10.4	11.7	13.2	13.5	13.5
Factory Zone I/ Factory Zone III							1.2	5.4	8.7	9.6	11.4	13.2	13.5	13.5	13.5	13.5	13.5	13.5	13.5
Total					0.8	2.6	7.3	12.1	16.1	18.6	22.4	26.7	28.1	29.3	30.6	31.9	33.4	33.7	33.7
Increase in energy consumption (GWh)																			
Load factor					65%	65%	65%	65%	65%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%
Energy sent-out from substations					4.6	14.8	41.6	67.8	91.7	107.5	127.8	154.4	162.5	169.4	176.9	184.4	193.1	194.8	194.8
Energy distributed - consumers-end (10% loss)					4.1	13.4	37.4	61.0	82.5	96.8	115.0	139.0	146.3	152.5	159.2	166.0	173.8	175.3	175.3

Table 13-4 Power interruption review (April 1984)

(Minutes)

No.	Feeder	Duration	No.	Feeder	Duration
1	33 kV Kurasini feeder	10	34	BMO - Ubungo	1
2	D2 Ilala	47	35	ALAF - Ubungo	270
3	03 Oysterbay	113	36	U2 Ubungo	286
4	D9 Ilala	25	37	WAZO I	126
5	F4 Buguruni	138	38	02 Oysterbay	54
6	Kundachi feeder	143	39	Kundachi feeder	24
7	Kundachi feeder	70	40	Industrial feeder-Kurasini	95
8	BMO Ubungo	5	41	C2 City Center	33
9	33 kV City Center	-	42	F2 Buguruni	6
10	WAZO I - Ubungo	6	43	Kilwa Rd. feeder	63
11	U2 Ubungo	1	44	Factory Zone I	65
12	U2 Ubungo	80	45	U2 Ubungo	1440
13	U2 Ubungo	35	46	D9 Ilala	397
14	03 Oysterbay	10	47	F4 Buguruni	235
15	WAZO II	7	48	F5 Buguruni	26
16	Textile II	31	49	D10 Ilala	64
17	TAZARA - Buguruni	5			
18	Kilwa Rd. - Kurasini	28			
19	TAZARA/F5	95			
20	02 Oysterbay	20			
21	F23 - G/Mboto	351			
22	D10 and U2	11			
23	Kilwa Rd. feeder	60			
24	TAZARA feeder	30			
25	02 Oysterbay	317			
26	U6 Ubungo	6			
27	05 Oysterbay	32			
28	Textile feeder	46			
29	F22 - G/Mboto	110			
30	ALAF - Ubungo	197			
31	U2 Ubungo	46			
32	05 Oysterbay	15			
33	TAZARA feeder	210			

Total: 5,485 minutes (91.4 hrs)

Average duration of power interruption:

5,485/49 - 1.87 hrs

Table 13-5 Calculation of internal rate of return

(T.Shs million)

No.	Year	Annual costs	Present worth Discount rate 5.0%	5.1%	5.2%	Note
1	1984	-	-	-	-	
2	1985	-	-	-	-	(a) Cumulative present worth of the annual costs from 1989 to 2010 is calculated by the following formula:
3	1986	91.6	79.1	78.9	78.6	
4	1987	75.8	62.3	62.1	61.9	
5	1988	76.2	59.7	59.4	59.1	$4.2 \times \frac{(1+i)^{22} - 1}{i(1+i)^{22}} \frac{1}{(1+i)^5}$
(a)	1989 -2010	4.2	43.3	42.7	42.1	Where: i = discount rate
	Total	336.0	244.4	243.1	241.7	

No.	Year	Annual benefit	Present worth Discount rate 5.0%	5.1%	5.2%	Note
1	1984	-	-	-	-	
2	1985	-	-	-	-	
3	1986	1.0	0.9	0.9	0.9	(b) Cumulative present worth of the annual benefit from 1999 to 2010 is calculated by the following formula:
4	1987	2.5	2.1	2.1	2.1	
5	1988	6.3	4.9	4.9	4.9	
6	1989	10.0	7.5	7.4	7.4	
7	1990	13.3	9.4	9.4	9.3	$27.9 \times \frac{(1+i)^{12} - 1}{i(1+i)^{12}} \frac{1}{(1+i)^{15}}$
8	1991	15.6	10.5	10.5	10.4	
9	1992	18.4	11.8	11.8	11.6	Where: i = discount rate
10	1993	22.2	13.6	13.5	13.4	
11	1994	23.4	13.7	13.5	13.4	
12	1995	24.3	13.5	13.3	13.1	
13	1996	26.5	13.5	13.3	13.1	
14	1997	27.7	13.4	13.2	13.0	
15	1998	27.9	13.3	13.1	12.9	
(b)	1999 -2010	27.9	118.9	116.5	114.2	
	Total	551.4	247.0	243.5	239.7	
Benefit-Cost			2.6	0.4	-2.0	

CHAPTER 14

FINANCIAL ANALYSIS

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CHAPTER 14 FINANCIAL ANALYSIS

14.1 METHODOLOGY

It is appropriate for financial analysis of the project to be conducted in the following manner:

(1) Analysis-1: Profit and loss and cash-flow

(a) To calculate the ratio of operating income (operating revenue - operating expenses) to net fixed assets in operation. This ratio is the rate of return in the financial meaning, and serves basis for evaluating profitability of the project. The operating income comprises interest and net income (or loss).

(b) To assume a conceivable repayment period of the borrowing and estimate cash reserves for repayment which will be accumulated during the above repayment period. These reserves are the sum of operating income and depreciation cost.

(c) To determine an allowable rate of interest in the limit of the above cash reserves, and conduct profit and loss calculation and cash-flow analysis.

(2) Analysis-2: "Financial internal rate of return"

To calculate "financial internal rate of return" which equalizes present worth of the cost stream (construction cost and operation and maintenance cost) to present worth of the operating revenue stream. The equalizing discount rate thus obtained is evaluated in comparison with social discount rate (social time preference rate).

14.2 FUND REQUIREMENTS

The total construction costs are estimated at T.Shs. 239.3 million (3,281.6 million yen) including T.Shs. 191.7 million (2,627.9 million yen) for foreign currency portion and T.Shs. 47.6 million (653.7 million yen) for local currency portion. Their annual disbursement is as follows:

	(T.Shs. million)			(Million yen)		
	F.C.	L.C.	Total	F.C.	L.C.	Total
1986	74.5	17.1	91.6	1,021.4	234.7	1,256.1
1987	58.5	15.6	74.1	801.3	214.6	1,015.9
1988	58.7	14.9	73.6	805.2	204.4	1,009.6
Total	191.7	47.6	239.3	2,627.9	653.7	3,281.6

14.3 ANALYSIS-1: PROFIT AND LOSS AND CASH-FLOW

14.3.1 Debt financing

(1) Operating revenue

The operating revenue is produced by increase in power consumption and decrease in power interruption due to execution of the project. These additional energies made available to consumers are described in paragraph 13.4.4. The share of distribution sector in the total supply costs of electricity is estimated at 19% and the average rate per unit sold is estimated at around 105 Cents/kWh as described in paragraph 13.4.3. Therefore, the unit revenue per kWh for the distribution sector is:

105 Cents/kWh x 0.19 = 20 Cents/kWh

From the above, annual revenue of the project is calculated as follows:

Year	Energy sold (GWh)	Unit revenue (Cents/kWh)	Annual revenue (T.Shs. million)
1986	6.6	20	1.3
1987	15.9	"	3.2
1988	39.9	"	8.0
1989	63.5	"	12.7
1990	85.0	"	17.0
1991	99.3	"	19.9
1992	117.5	"	23.5
1993	141.5	"	28.3
1994	148.8	"	29.8
1995	155.0	"	31.0
1996	161.7	"	32.3
1997	168.5	"	33.7
1998	176.3	"	35.3
1999-2010	177.8	20	35.6

(2) Operation and maintenance cost

The operation and maintenance cost is described in paragraph 13.3.2. Its annual disbursement is as follows:

Year	Amount (T.Shs. million)
1987	1.7
1988	2.6
1989-2010	4.2

(3) Depreciation cost

In accordance with accounting policies of TANESCO, depreciation on the fixed assets is calculated on the straight line method to write off (without scrap value) the costs of the fixed assets over the period up to 2010.

(4) Administration cost

Since the project aims at mainly improving the existing distribution facilities and partly increasing transforming capacities, there will be almost no additional personnel and general expenses at Head Office. Therefore, administration cost shall not be included in the operating expenses of the project.

14.3.2 Rate of return and cash reserves for repayment

Annual operating revenue, operating expenses and operating income of the project are shown in Table 14-1. From this table, the rate of return (ratio of operating income to net fixed assets in operation) and cash reserves for repayment of the borrowings are calculated as follows:

(1) Rate of return

The rate of return of the project varies annually. For this project, the average rate of return for the period of 10 years, 15 years, 20 years and 22 years (whole period) after completion of the project is calculated as follows:

Period	Accumulated operating income (T.Shs. million)	Accumulated net fixed assets (T.Shs. million)	Rate of return (%)
10 years (1989-1998)	114.0	2,186.3	5.2
15 years (1989-2003)	219.5	2,649.8	8.3
20 years (1989-2008)	325.0	2,855.8	11.4
Whole period (1989-2010)	367.2	2,866.1	12.8

As described before, the operating income consists of returns on the capital invested (interest) and on the effort of business operation of the company (net income).

(2) Cash reserves for repayment

Examples of loans obtained from foreign countries for projects of TANESCO show that the terms of loans have generally been 5 to 9% interest with the repayment period of 15 to 22 years after moratorium period of 3 to 5 years. There was an exceptionally soft loan in which interest rate was 1.5% and repayment period was 20 years after moratorium period of 10 years.

In case of this project, if repayment period is 20 years for foreign currency portion and 13 years for local currency portion, each after moratorium period of 3 years, the borrowings will be written off in 2008, and cash reserves accumulated by 2008 will amount to T.Shs. 543.7 million as shown below:

Accumulated operating income	T.Shs. 325.0 million
Accumulated depreciation cost	T.Shs. 218.7 million
Total	T.Shs. 543.7 million

14.3.3 Calculation for determining interest rate

For local currency loan, an example shows that terms of loan (Mwanza power station) applied by the Tanzania Investment Bank to TANESCO were interest rate of 9% with repayment period of 13 years.

If the above terms are also applied to local currency loan of this project, the repayment of principal and interest will amount to T.Shs. 89.3 million including interest during construction of T.Shs. 6.6 million.

6.6 + 47.6 x 0.133566 (capital recovery factor) x 13 years
= T.Shs. 89.3 million

In most countries, the ratio of net income to net fixed assets in operation of the electric utility ranges generally from 2.3% to 4.7% with around 3% in average. For the sound business operation, it will be necessary to earn net income of about 3%.

If net income of 3% is to be secured from the project, its accumulated amount during the period of 20 years (up to 2008) after completion of the project will be T.Shs. 85.7 million.

Accumulated net fixed assets T.Shs. 2,855.8 x 0.03
= T.Shs. 85.7 million

Therefore, cash reserves for repayment of foreign currency loan will be T.Shs. 368.7 million (total cash reserves 543.7 - repayment of local currency loan 89.3 - net income 85.7 = T.Shs. 368.7 million). From this, annual repayment amount will be T.Shs. 18.4 million in average.

368.7 ÷ 20 years = T.Shs. 18.4 million

Since foreign currency portion of the construction cost is T.Shs. 191.7 million, the capital recovery factor is calculated at 0.09598.

18.4 ÷ 191.7 = 0.09598

Therefore, interest rate to be applied to foreign currency loan (i) for the repayment period of 20 years can be obtained by the following equation:

$$\frac{i(1 + i)^{20}}{(1 + i)^{20} - 1} = 0.09598$$

From the above:

$i = 7.3\%$

However, the above-mentioned cash reserves T.Shs. 368.7 million for the repayment of foreign currency loan must include payment of interest during construction.

At the interest rate of 7.3%, the interest during construction amounts to T.Shs. 22.0 million. Therefore, the above capital recovery factor must be changed to approximately:

(368.7 - 22.0)   20 years   191.7 = 0.09042

The interest rate which corresponds to the above capital recovery factor is 6.5%. This means that the upper limit of interest rate to be applied to foreign currency loan of the project is 6.5%.

14.3.4 Profit and loss calculation and cash-flow analysis

The profit and loss calculation and cash-flow analysis, carried out at the interest rate of 9% with the repayment period of 13 years for local currency loan and the interest rate of 6.5% with the repayment period of 20 years for foreign currency loan, are shown in Tables 14-2, 14-3 and 14-4.

As clearly seen in Table 14-4, the net income accumulated during the whole repayment period (up to 2008) will amount to T.Shs. 87.6 million which represents a rate of return of 3% on the accumulated net fixed assets in operation of T.Shs. 2,855.8 million, but after completion of the project deficit in cash balance will continue up to 4th year (1992) in the annual balance and up to 13th year (2001) in the accumulated balance.

14.4 ANALYSIS-2: FINANCIAL INTERNAL RATE OF RETURN

The so-called "financial internal rate of return" (FIRR) is defined as the discount rate which equalizes present worth of the cost stream (construction cost and operation and maintenance cost) to present worth of the operating revenue stream. For this project, this equalizing discount rate is calculated as follows (See Table 14-5):

FIRR: 7.8%

The FIRR is different from rate of return calculated from accounting viewpoint. The former is evaluated in comparison with social time preference rate, the latter is used as the basis for evaluating financial profitability of the project.

The economic internal rate of return (EIRR), as obtained in Chapter 13, is calculated based on the social cost and benefit which reflect shadow price and/or opportunity cost from viewpoint of national economy. As compared with this, the FIRR is calculated based on the actual cost and income on the company basis. (In case of this project, cost is the same for both the FIRR and EIRR because taxes and other cost items which require to consider shadown price and/or opportunity cost such as unskilled labor wages are not included in the cost). Difference is thus produced between FIRR and EIRR.

14.5 CONCLUSION

As described in paragraph 13.6, the social time preference rate (social discount rate) to be used in the project evaluation is considered to be 9 to 10%. The EIRR of 7.8% of the project is fairly lower than the standard. This means that a good financial performance cannot be anticipated from the project.

The rate of return on the net fixed assets in operation will mark a high rate of 12.8% for the whole period of 22 years. However, from practical financial viewpoint it is appropriate for the rate of return to be evaluated for the period of 10 to 15 years from completion of the project. In this case, the rate of return of the project will be only 5.2% and 8.3% for the period of 10 years and 15 years, respectively.

When applying the interest rate of 9% with the repayment period of 13 years for local currency loan and the interest rate of 6.5% with the repayment period of 20 years for foreign currency loan, a net income of 3% will be secured but deficit in the accumulated cash balance will continue up to 13th year from completion of the project.

From the above, it is hoped that financial cooperation at long-term and low interest rate be offered for this project.

Table 14-1 Operating income and rate of return

(T.Shs. million)

No.	Year	Operating revenue: Yearly (A)	Operating revenue: Accumulated total	Operating expenses: Operation and maintenance cost	Depreciation cost: Investment in 1986	Depreciation cost: Investment in 1987	Depreciation cost: Investment in 1988	Depreciation cost: Annual total	Depreciation cost: Accumulated total	Total (B)	Operating income: Yearly (A)-(B)	Operating income: Accumulated total (C)	Net fixed assets in operation: Yearly	Net fixed assets in operation: Accumulated total (D)	Average rate of return (C)/(D)
	1986	1.3	1.3	-	-	-	-	-	-	-	1.3	1.3	91.6	91.6	
	87	3.2	4.5	1.7	3.9	-	-	3.9	3.9	5.6	-2.4	-1.1	161.8	253.4	
	88	8.0	12.5	2.6	3.9	3.3	-	7.2	11.1	9.8	-1.8	-2.9	228.2	481.6	
1	89	12.7	25.2	4.2	3.9	3.3	3.4	10.6	21.7	14.8	-2.1	-5.0	217.6	699.2	
2	1990	17.0	42.2	4.2	3.9	3.3	3.4	10.6	32.3	14.8	2.2	-2.8	207.0	906.2	
3	91	19.9	62.1	4.2	3.8	3.3	3.4	10.5	42.8	14.7	5.2	2.4	196.5	1,102.7	
4	92	23.5	85.6	4.2	3.8	3.3	3.4	10.5	53.3	14.7	8.8	11.2	186.0	1,288.7	
5	93	28.3	113.9	4.2	3.8	3.2	3.4	10.4	63.7	14.6	13.7	24.9	175.6	1,464.3	5.2%
6	94	29.8	143.7	4.2	3.8	3.2	3.4	10.4	74.1	14.6	15.2	40.1	165.2	1,629.5	
7	95	31.0	174.7	4.2	3.8	3.2	3.4	10.4	84.5	14.6	16.4	56.5	154.8	1,784.3	
8	96	32.3	207.0	4.2	3.8	3.2	3.4	10.4	94.9	14.6	17.7	74.2	144.4	1,928.7	
9	97	33.7	240.7	4.2	3.8	3.2	3.4	10.4	105.3	14.6	19.1	93.3	134.0	2,062.7	
10	98	35.3	276.0	4.2	3.8	3.2	3.4	10.4	115.7	14.6	20.7	114.0	123.6	2,186.3	
11	99	35.6	311.6	4.2	3.8	3.2	3.3	10.3	126.0	14.5	21.1	135.1	113.3	2,299.6	
12	2000	35.6	347.2	4.2	3.8	3.2	3.3	10.3	136.3	14.5	21.1	156.2	103.0	2,402.6	8.3%
13	01	35.6	382.8	4.2	3.8	3.2	3.3	10.3	146.6	14.5	21.1	177.3	92.7	2,495.3	
14	02	35.6	418.4	4.2	3.8	3.2	3.3	10.3	156.9	14.5	21.1	198.4	82.4	2,577.7	
15	03	35.6	454.0	4.2	3.8	3.2	3.3	10.3	167.2	14.5	21.1	219.5	72.1	2,649.8	
16	04	35.6	489.6	4.2	3.8	3.2	3.3	10.3	177.5	14.5	21.1	240.6	61.8	2,711.6	
17	05	35.6	525.2	4.2	3.8	3.2	3.3	10.3	187.8	14.5	21.1	261.7	51.5	2,763.1	
18	06	35.6	560.8	4.2	3.8	3.2	3.3	10.3	198.1	14.5	21.1	282.8	41.2	2,804.3	11.4%
19	07	35.6	596.4	4.2	3.8	3.2	3.3	10.3	208.4	14.5	21.1	303.9	30.9	2,835.2	
20	08	35.6	632.0	4.2	3.8	3.2	3.3	10.3	218.7	14.5	21.1	325.0	20.6	2,855.8	
21	09	35.6	667.6	4.2	3.8	3.2	3.3	10.3	229.0	14.5	21.1	346.1	10.3	2,866.1	12.8%
22	2010	35.6	703.2	4.2	3.8	3.2	3.3	10.3	239.3	14.5	21.1	367.2	0	2,866.1	
	Total	703.2		96.7	91.6	74.1	73.6	239.3		336.0	367.2				

Table 14-2 Repayment schedule

(T.Shs. million)

No.	Year	Borrowings			Repayment Schedule								Remarks
					Foreign Currency				Local Currency				
		Foreign currency	Local currency	Total	Interest	Principal	Total	Outstanding balance	Interest	Principal	Total	Outstanding balance	
	1986	74.5	17.1	91.6									
	87	58.5	15.6	74.1									
	88	58.7	14.9	73.6				191.7			47.6		
1	89				12.5	4.9	17.4	186.8	4.3	2.1	45.5	6.4	◦ Foreign currency (6.5%,
2	1990				12.1	5.3	17.4	181.5	4.1	2.3	43.2	6.4	20 years)
3	91				11.8	5.6	17.4	175.9	3.9	2.5	40.7	6.4	
4	92				11.4	6.0	17.4	169.9	3.7	2.7	38.0	6.4	Capital recovery
5	93				11.0	6.4	17.4	163.5	3.4	3.0	35.0	6.4	factor: 0.090756
6	94				10.6	6.8	17.4	156.7	3.2	3.2	31.8	6.4	
7	95				10.2	7.2	17.4	149.5	2.9	3.5	28.3	6.4	
8	96				9.7	7.7	17.4	141.8	2.5	3.9	24.4	6.4	◦ Local currency (9%, 13 years)
9	97				9.2	8.2	17.4	133.6	2.2	4.1	20.3	6.3	
10	98				8.7	8.7	17.4	124.9	1.8	4.5	15.8	6.3	Capital recovery
11	99				8.1	9.3	17.4	115.6	1.4	4.9	10.9	6.3	factor: 0.133566
12	2000				7.5	9.9	17.4	105.7	1.0	5.3	5.6	6.3	
13	01				6.9	10.5	17.4	95.2	0.7	5.6		6.3	
14	02				6.2	11.2	17.4	84.0					
15	03				5.5	11.9	17.4	72.1					
16	04				4.7	12.7	17.4	59.4					
17	05				3.9	13.5	17.4	45.9					
18	06				3.0	14.4	17.4	31.5					
19	07				2.1	15.3	17.4	16.2					
20	08				1.2	16.2	17.4	0					
	Total	191.7	47.6	239.3	156.3	191.7	348.0		35.1	47.6		82.7	

Table 14-3 Profit and loss statement

(T.Shs. million)

No.	Year	Operating revenue (A)	Operating expenses			Operating income (A)-(B)	Financial expenses					Net income	
			Operation and maintenance	Depreciation	Total (B)		Interest during construction		Interest after completion of the project		Total	Yearly	Accumulated total
							Foreign currency	Local currency	Foreign currency	Local currency			
	1986	1.3	-	-	-	1.3	2.4	0.8			3.2	-1.9	-1.9
	87	3.2	1.7	3.9	5.6	-2.4	6.7	2.2			8.9	-11.3	-13.2
	88	8.0	2.6	7.2	9.8	-1.8	10.5	3.6			14.1	-15.9	-29.1
1	89	12.7	4.2	10.6	14.8	-2.1			12.5	4.3	16.8	-18.9	-48.0
2	1990	17.0	4.2	10.6	14.8	2.2			12.1	4.1	16.2	-14.0	-62.0
3	91	19.9	4.2	10.5	14.7	5.2			11.8	3.9	15.7	-10.5	-72.5
4	92	23.5	4.2	10.5	14.7	8.8			11.4	3.7	15.1	-6.3	-78.8
5	93	28.3	4.2	10.4	14.6	13.7			11.0	3.4	14.4	-0.7	-79.5
6	94	29.8	4.2	10.4	14.6	15.2			10.6	3.2	13.8	1.4	-78.1
7	95	31.0	4.2	10.4	14.6	16.4			10.2	2.9	13.1	3.3	-74.8
8	96	32.3	4.2	10.4	14.6	17.7			9.7	2.5	12.2	6.3	-68.5
9	97	33.7	4.2	10.4	14.6	19.1			9.2	2.2	11.4	7.7	-60.8
10	98	35.3	4.2	10.4	14.6	20.7			8.7	1.8	10.5	10.2	-50.6
11	99	35.6	4.2	10.3	14.5	21.1			8.1	1.4	9.5	11.6	-39.0
12	2000	35.6	4.2	10.3	14.5	21.1			7.5	1.0	8.5	12.6	-26.4
13	01	35.6	4.2	10.3	14.5	21.1			6.9	0.7	7.6	13.5	-12.9
14	02	35.6	4.2	10.3	14.5	21.1			6.2		6.2	14.9	2.0
15	03	35.6	4.2	10.3	14.5	21.1			5.5		5.5	15.6	17.6
16	04	35.6	4.2	10.3	14.5	21.1			4.7		4.7	16.4	34.0
17	05	35.6	4.2	10.3	14.5	21.1			3.9		3.9	17.2	51.2
18	06	35.6	4.2	10.3	14.5	21.1			3.0		3.0	18.1	69.3
19	07	35.6	4.2	10.3	14.5	21.1			2.1		2.1	19.0	88.3
20	08	35.6	4.2	10.3	14.5	21.1			1.2		1.2	19.9	108.2
21	09	35.6	4.2	10.3	14.5	21.1						21.1	129.3
22	2010	35.6	4.2	10.3	14.5	21.1						21.1	150.4
	Total	703.2	96.7	239.3	336.0	367.2	19.6	6.6	156.3	35.1	217.6	150.4	

Table 14-4 Cash-flow

No.	Year	Cash inflow				Cash flow				Balance	
		Borrowing	Net income	Depre-ciation cost	Total	Construc-tion	Repayment of principal		Total	Yearly	Accumu-lated total
							Foreign currency	Local currency			
	1986	91.6	-1.9	-	89.7	91.6			91.6	-1.9	-1.9
	87	74.1	-11.3	3.9	66.7	74.1			74.1	-7.4	-9.3
	88	73.6	-15.9	7.2	64.9	73.6			73.6	-8.7	-18.0
1	89		-18.9	10.6	-8.3		4.9	2.1	7.0	-15.3	-33.3
2	1990		-14.0	10.6	-3.4		5.3	2.3	7.6	-11.0	-44.3
3	91		-10.5	10.5	0		5.6	2.5	8.1	-8.1	-52.4
4	92		-6.3	10.5	4.2		6.0	2.7	8.7	-4.5	-56.9
5	93		-0.7	10.4	9.7		6.4	3.0	9.4	0.3	-56.6
6	94		1.4	10.4	11.8		6.8	3.2	10.0	1.8	-54.8
7	95		3.3	10.4	13.7		7.2	3.5	10.7	3.0	-51.8
8	96		6.3	10.4	16.7		7.7	3.9	11.6	5.1	-46.7
9	97		7.7	10.4	18.1		8.2	4.1	12.3	5.8	-40.9
10	98		10.2	10.4	20.6		8.7	4.5	13.2	7.4	-33.5
11	99		11.6	10.3	21.9		9.3	4.9	14.2	7.7	-25.8
12	2000		12.6	10.3	22.9		9.9	5.3	15.2	7.7	-18.1
13	01		13.5	10.3	23.8		10.5	5.6	16.1	7.7	-10.4
14	02		14.9	10.3	25.2		11.2		11.2	14.0	3.6
15	03		15.6	10.3	25.9		11.9		11.9	14.0	17.6
16	04		16.4	10.3	26.7		12.7		12.7	14.0	31.6
17	05		17.2	10.3	27.5		13.5		13.5	14.0	45.6
18	06		18.1	10.3	28.4		14.4		14.4	14.0	59.6
19	07		19.0	10.3	29.3		15.3		15.3	14.0	73.6
20	08		19.9	10.3	30.2		16.2		16.2	14.0	87.6
21	09		21.1	10.3	31.4					31.4	119.0
22	2010		21.1	10.3	31.4					31.4	150.4
	Total	239.3	150.4	239.3	629.0	239.3	191.7	47.6	478.6	150.4	

Table 14-5 Financial internal rate of return

(T.Shs million)

No.	Year	Costs	Discount rate 7.7%	7.8%	7.9%	Remarks
1	1984	-	-	-	-	(a) Cumulative present worth of the annual costs from 1989 to 2010 is calculated by the following formula: $4.2 \times \frac{(1+i)^{22} - 1}{i(1+i)^{22}} \frac{1}{(1+i)^{5}}$ Where: i = discount rate
2	85	-	-	-	-	
3	86	91.6	73.3	73.1	72.9	
4	87	75.8	56.3	56.1	55.9	
5	88	76.2	52.6	52.3	52.0	
(a)	1989-2010	4.2	30.3	29.9	29.5	
	Total		212.5	211.4	210.3	
No.	Year	Revenue	Discount rate 7.7%	7.8%	7.9%	Remarks
1	1984	-	-	-	-	(b) Cumulative present worth of the annual revenue from 1999 to 2010 is calculated by the following formula: $35.6 \times \frac{(1+i)^{12} - 1}{i(1+i)^{12}} \frac{1}{(1+i)^{15}}$ Where: i = discount rate
2	85	-	-	-	-	
3	86	1.3	1.0	1.0	1.0	
4	87	3.2	2.4	2.4	2.4	
5	88	8.0	5.5	5.5	5.5	
6	89	12.7	8.1	8.1	8.0	
7	1990	17.0	10.1	10.0	10.0	
8	91	19.9	11.0	10.9	10.8	
9	92	23.5	12.0	11.9	11.8	
10	93	28.3	13.5	13.4	13.2	
11	94	29.8	13.2	13.0	12.9	
12	95	31.0	12.7	12.6	12.4	
13	96	32.3	12.3	12.1	12.0	
14	97	33.7	11.9	11.8	11.6	
15	98	35.3	11.6	11.4	11.3	
(b)	1999-2010	35.6	89.4	87.8	86.2	
	Total		214.7	211.9	209.1	
Revenue-Cost			2.2	0.5	-1.2	

FIRR: 7.8%

APPENDIX

APPENDIX

1. FORMATION OF SURVEY TEAM
2. MAP OF DAL-ES-SALAAM CITY (1:25,000)

1. FORMATION OF SURVEY TEAM

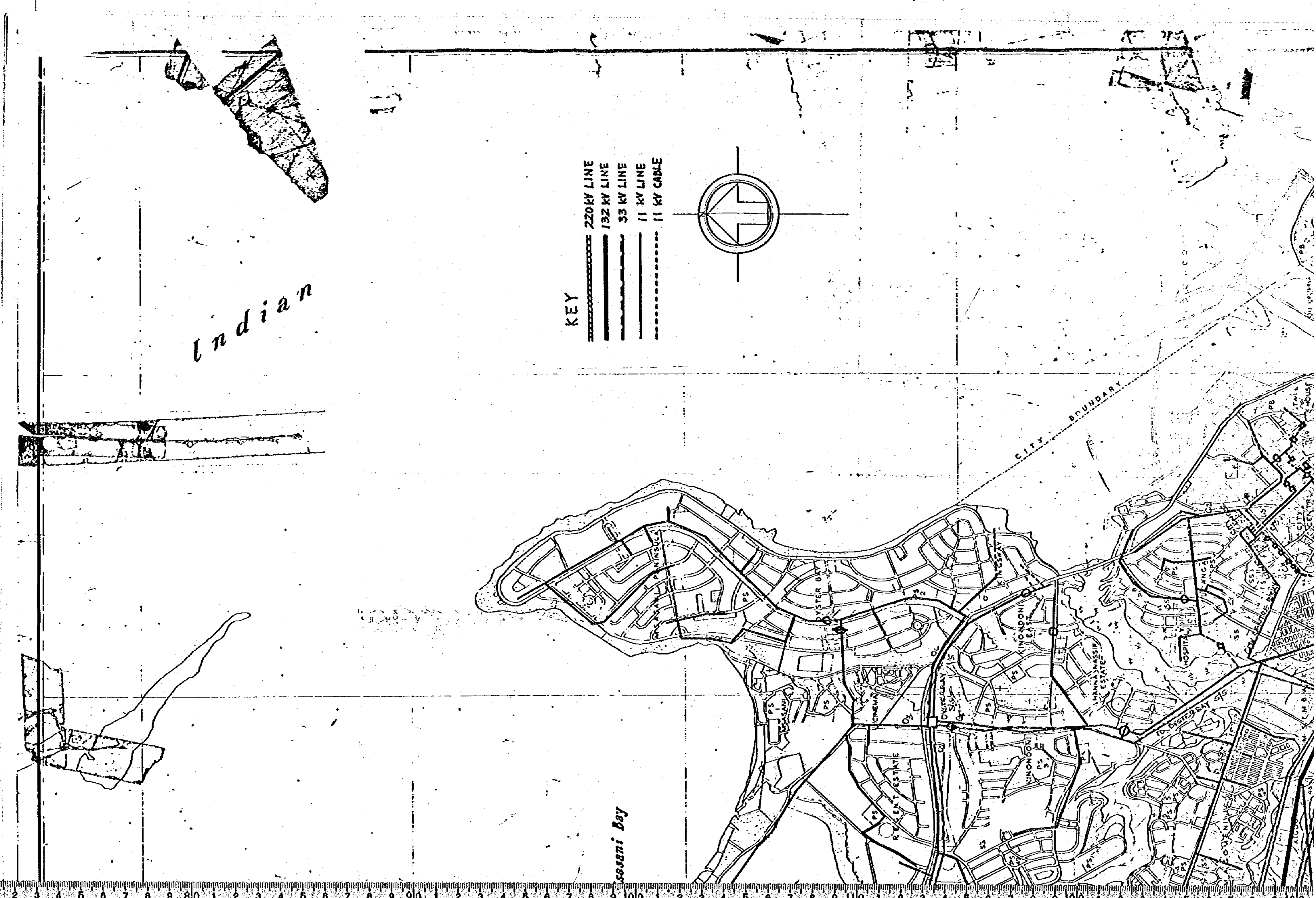
1) Members of field survey team

Name	Duties	Employer
Masashi KOIKE	Team Leader	EPDC International Ltd.
Tetsuro KOBAYASHI	Load Forecast and Economic Analysis	EPDC International Ltd.
Tadao SATO	Transmission & Power System Planning	EPDC International Ltd.
Morio WAKUI	Substation & Power Dispatching Planning	EPDC International Ltd.
Kiju ENDOH	Distribution Planning	Tohoku Electrical construction Co., Ltd.
Osamu KASHIWAGI	Distribution Facility and Equipment	Tohoku Electrical Construction Co., Ltd.
Hisaya NOGUCHI	Distribution Facility and Equipment	Tohoku Electrical Construction Co., Ltd.

2) Participants of the work in Japan

Tetsuya FUKUDA	Implementation Planning	EPDC International Ltd.
Tosaku OKABAYASHI	Power System Analysis	EPDC International Ltd.

2. MAP OF DAL-ES-SALAAM CITY (1:25,000)



Indian
KEY
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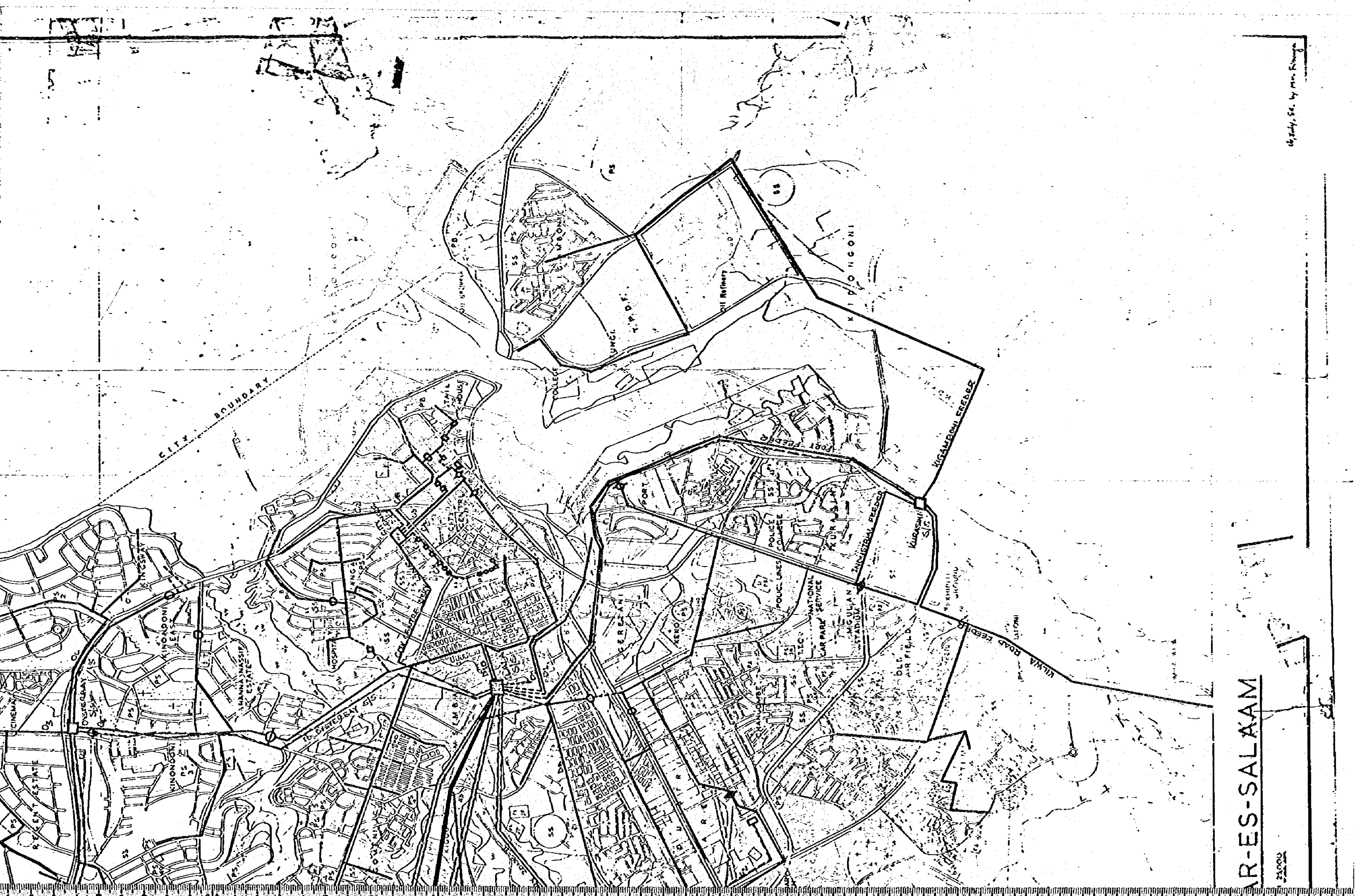
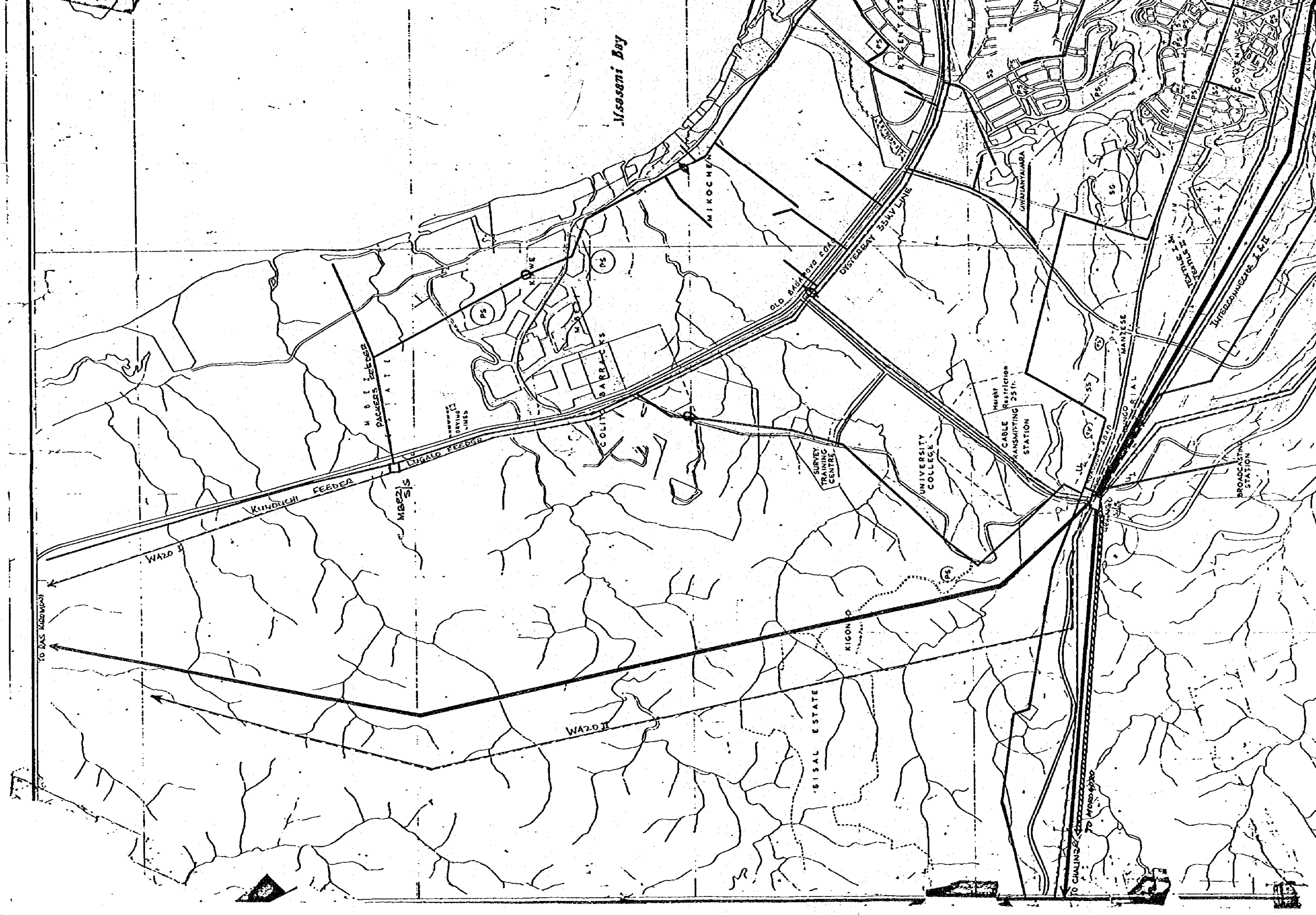
132 kV LINE
33 kV LINE
11 kV LINE
11 kV CABLE
CITY BOUNDARY
PENINSULA
OYSTER BAY
KINGSWAY
KINONDONI EAST
HANNA NASSIF ESTATE
CINEMA
sasani Bay


R-ES-SALAAM
CITY BOUNDARY
KIGAMBONI FEEDER
PORT FEEDER
INDUSTRIAL FEEDER
KURASINI S/S
KILWA ROAD FEEDER
T.P.D.F.
Oil Refinery
POLICE COLLEGE
NATIONAL SERVICE
OLD AIR FIELD
KINONDONI EAST
REGENT ESTATE
KINONDONI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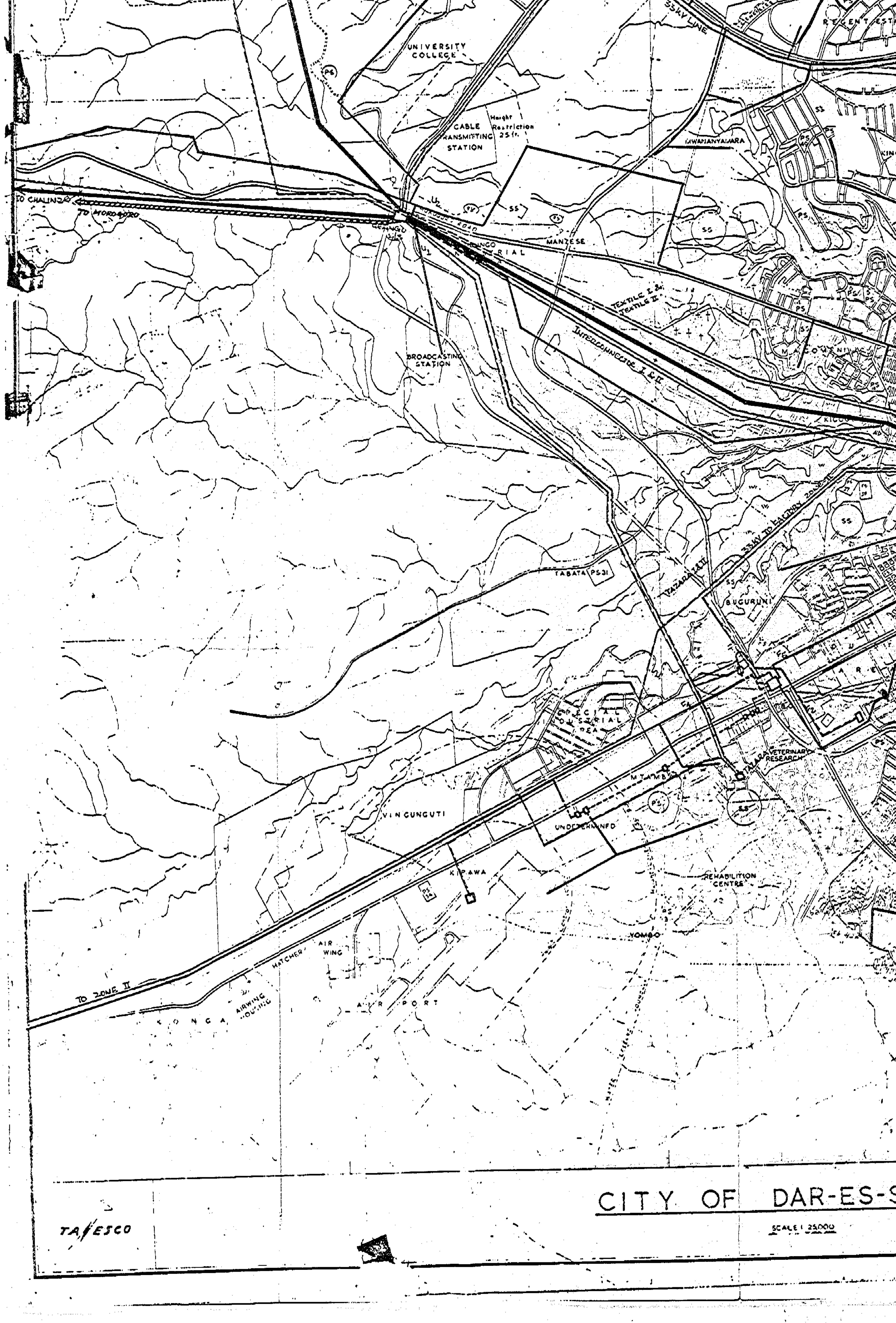
MIKOCHENI
OYSTERBAY 33KV LINE
OLD BAGAMOYO ROAD
KAWE
PS
MBEZI PACKERS FEEDER
LUGALO FEEDER
KUNDUCHI FEEDER
MBEZI S/S
WAZO I
WAZO II
COLITO BARRACKS
SURVEY TRAINING CENTRE
UNIVERSITY COLLEGE
Height Restriction 25 ft.
CABLE TRANSMITTING STATION
BROADCASTING STATION
SISAL ESTATE
TO CHALINZE
SS



UNIVERSITY COLLEGE
CABLE TRANSMITTING STATION
Height Restriction 25 ft.
33kV LINE
MWANANYAMALA
MANZESE
TEXTILE I & TEXTILE II
INTERCONNECTOR I & II
BROADCASTING STATION
TO CHALINZE
TO MOROGORO
TABATA PS31
BUGURUNI
TAZARA
VETERINARY RESEARCH
SPECIAL INDUSTRIAL AREA
VINGUNGUTI
KIPAWA
REHABILITION CENTRE
YOMBO
AIR WING
AIRPORT
KONGA
AIRWING HOUSING
TO ZONE II
TA/ESCO
CITY OF DAR-ES-S
SCALE 1:25000

JICA