### 8.2.5 Rehabilitation of the Low Voltage Distribution Network

(1) Outline of Work

Rehabilitation work on the existing distribution network will be carried out in the following locations. The following is an overview of the construction work involved.

| | Trunk line (km) | Branch line (km) |
|---|---|---|
| a. Base II - Rue 10 | 0.45 | 0.6 |
| - El Mansour | 0.85 | 1.0 |
| - Rue 10 x 11 | 0.45 | 0.7 |
| - Rue 10 x Bene | 0.50 | 0.7 |
| - Canal IV | 0.45 | 0.7 |
| - Amite II | 0.60 | 0.8 |
| Sub-Total | 3.30 | 4.5 |
| b. Base III - Yoff Layenes | 1.4 | 3.0 |
| - Yoff Centre | 0.7 | 2.0 |
| - Yoff Village | 1.0 | 2.4 |
| - N'Gor | 1.1 | 2.3 |
| - Ouakam Boulga | 1.0 | 1.7 |
| - Ouakam Taglou | 0.7 | 0.6 |
| - Ouakam Ecole | 0.8 | 0.6 |
| Sub-Total | 6.7 | 12.6 |
| Total | 10.0 | 16.6 |

Figs. 8.2.5-1 (1/3 - 3/3) show the existing distribution network in the Yoff Village, N'Gor and Ouakam areas.

(2) Supports

Similarly to Section 8.2.4, it is also anticipated that the tubular steel poles will be employed for supports. The supports shall have a length of 9 m. In the areas due for rehabilitation the existing distribution lines shall have a standard span of approx. 50 m. It is not considered necessary to replace all supports when the rehabilitation work is executed, and it is estimated that about half of all supports may need replacing.

(3) Conductors

Refer to Section 8.2.4 for further details on the conductors.

Table 8.1.4-1 Fuel Composition (1/2)

| Test Items | Standard | | Units | No. 01 | No. 02 | No. 03 | No. 04 | Specified value Dated 19/03/94 | Reference value diesel oil |
|---|---|---|---|---|---|---|---|---|---|
| | | | | 01/07/94 | 08/07/94 | 15/07/94 | 22/07/94 | | |
| Specific gravity | ASTM | D4052 | | 0.9948 | 0.9949 | 0.9973 | 0.9978 | 0.995 | 0.855 |
| Flash point | ISO | 2719 | °C | >70 | >70 | >70 | >70 | 66 | 77 |
| Viscosity at 50°C | ISO | 3104 | Cst | 260.0 | 275.0 | 330.0 | 358.0 | 380.0 | 10.1 |
| Viscosity at 100°C | ISO | 3104 | Cst | 25.2 | 25.4 | 28.5 | 30.1 | - | 35.0 |
| Moisture (Water content) | ISO | 3733 | % V/V | 0.4 | 0.4 | 0.4 | 0.4 | 1.0 | 0.1> |
| Carbon residue | ISO | 10370 | % weight | 16.8 | 16.9 | 16.1 | 16.3 | 18.0 | 0.07 |
| Ash content | ISO | 6245 | % weight | 0.12 | 0.12 | 0.08 | 0.07 | 0.12 | 0.002 |
| Asphalt content | IP | 143 | % weight | 11.5 | 11.5 | 11.1 | 10.2 | 11 | - |
| Sulfur content | ISO | 8754 | % weight | 2.76 | 2.64 | 2.87 | 2.95 | 4.00 | 0.39 |
| Aluminum content | IP | 377 | ppm | 7 | 7 | 15 | 19 | 30 | - |
| Silica content | IP | 377 | ppm | 16 | 14 | 18 | 20 | - | - |
| Cross calorific value | ISO | 8217 | kcal/kg | 10,122 | 10,131 | 10,107 | 10,100 | 9,000~10,500 | 10,909 |
| Net calorific value | ISO | 8217 | kcal/kg | 9,579 | 9,588 | 9,567 | 9,557 | | 10,249 |

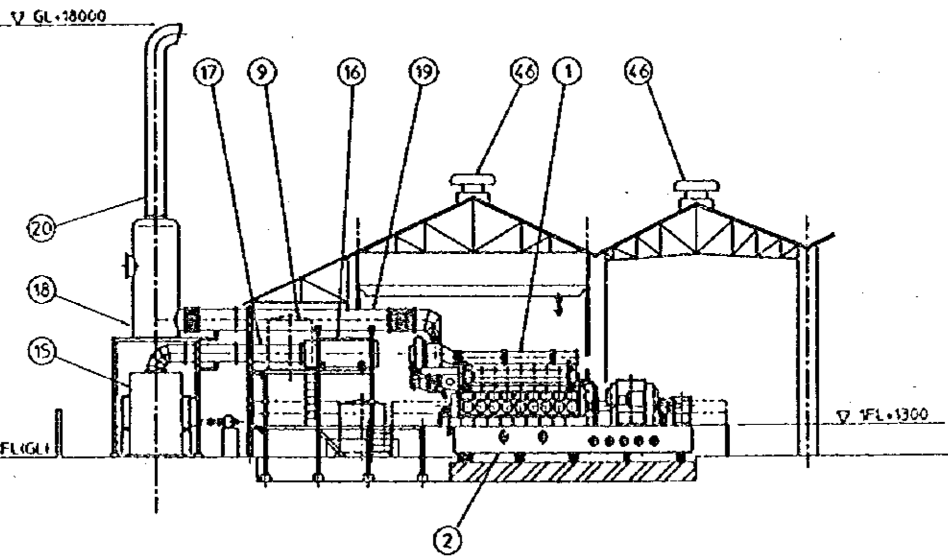
Table 8.1.4-1 Fuel Composition (2/2)

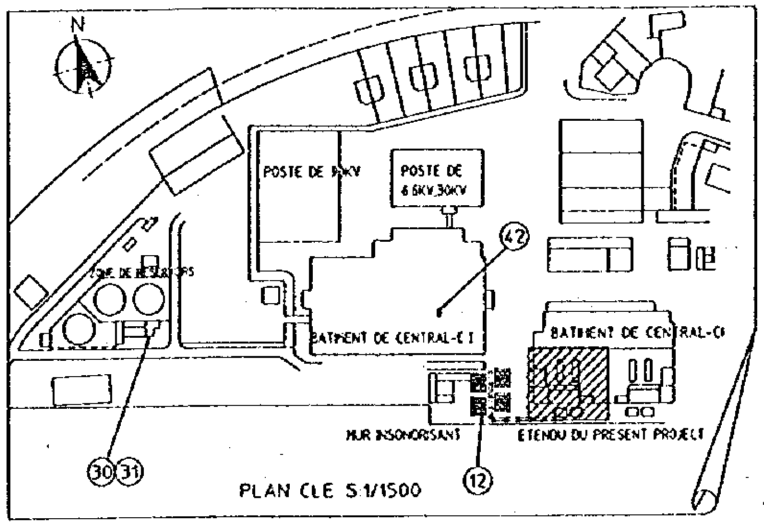
| Test items | Standard | | Units | No. 41 | No. 42 | No. 43 | No. 44 | No. 45 | No. 46 | No. 47 | No. 48 | Specified value Dated 19/03/94 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | 07/04/95 | 14/04/95 | 21/04/95 | 28/04/95 | 05/05/95 | 12/05/95 | 19/05/95 | 26/05/95 | |
| Specific gravity | ASTM D4052 | | | 0.9453 | 0.9415 | 0.9440 | 0.9456 | 0.9399 | 0.9418 | 0.9428 | 0.9423 | 0.995 |
| Flash point | ISO | 2719 | °C | >70 | >70 | >70 | >70 | >70 | >70 | >70 | >70 | 66 |
| Viscosity at 50°C | ISO | 3104 | Cst | 138 | 199 | 129 | 149 | 98 | 88 | 116 | 110 | 380.0 |
| Viscosity at 100°C | ISO | 3104 | Cst | 16.2 | 20.6 | 15.4 | 16.7 | 13.0 | 12.6 | 14.6 | 14.0 | - |
| Moisture | ISO | 3733 | % V/V | <0.1 | <0.1 | <0.1 | <0.1 | <0.1 | <0.1 | <0.1 | <0.1 | 1.0 |
| Carbon residue | ISO | 10370 | % weight | 4.2 | 4.9 | 3.4 | 3.6 | 3.4 | 5.0 | 4.0 | 4.2 | 18.00 |
| Ash content | ISO | 6245 | % weight | 0.01 | 0.02 | 0.01 | 0.01 | 0.01 | 0.02 | 0.01 | 0.02 | 0.12 |
| Asphalt content | IP | 143 | % weight | 0.8 | 1.8 | 0.8 | 0.4 | 0.5 | 2.1 | 0.8 | 1 | 11 |
| Sulfur content | ISO | 8754 | % weight | 0.52 | 0.81 | 0.47 | 0.35 | 0.40 | 0.81 | 0.57 | 0.58 | 4.00 |
| Aluminum content | IP | 377 | ppm | 1 | 1 | <1 | 1 | 1 | 2 | 1 | 1 | 30 |
| Silica content | IP | 377 | ppm | 1 | 2 | 1 | 2 | 2 | 8 | 2 | 5 | - |
| Gross calorific value | ISO | 8217 | kcal/kg | 10,560 | 10,510 | 10,569 | 10,572 | 10,591 | 10,552 | 10,564 | 10,543 | 9,000–10,500 |
| Net calorific value | ISO | 8217 | kcal/kg | 9,964 | 9,921 | 9,971 | 9,976 | 9,993 | 9,954 | 9,971 | 9,950 | |

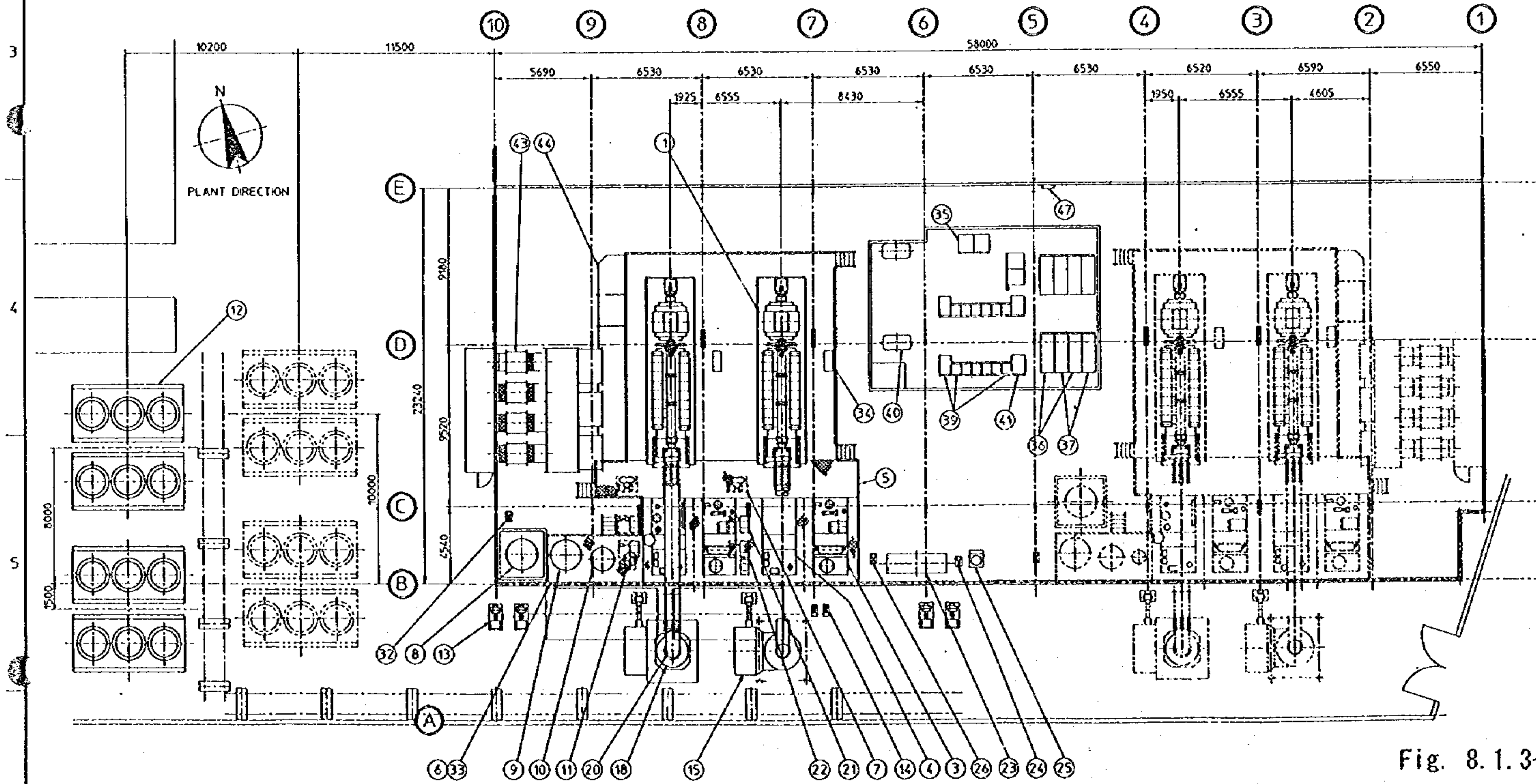
Table 8.2.2-1 Rating of Circuit Breakers for Each Feeder

| Name of Substation | Feeder name | Rating of circuit breakers 7.2kV/630A | 7.2kV/1,250A | 36 kV/630 A |
|---|---|---|---|---|
| Centre Ville | Tr. No. 1 | | | 1 |
| | Tr. No. 2 | | | 1 |
| | Hotel Nina | 1 | | |
| | Res. Cap Vert | 1 | | |
| | Foncier Zola | 1 | | |
| | Credit Foncier | 1 | | |
| | Mohamad V Carnot | 1 | | |
| | Sub-total | 5 | 0 | 2 |
| Universite | Tr. No. 1 | | | 1 |
| | Tr. No. 2 | | | 1 |
| | Fann | 1 | | |
| | Mermoz | 1 | | |
| | Pointe E | 1 | | |
| | Secours Mermoz | 1 | | |
| | Abass N'Dao | 1 | | |
| | Sub-total | 5 | 0 | 2 |
| Aeroport Yoff | Tr. No. 1 (Pri.) | | | 1 |
| | Tr. No. 2 (Pri.) | | | 1 |
| | Tr. No. 1 (Sec.) | | 1 | |
| | Tr. No. 2 (Sec.) | | 1 | |
| | Batterie Yoff | 1 | | |
| | Sub-total | 1 | 2 | 2 |
| Thiaroye | Icotaf | 1 | | |
| | Dagoudane Pikine | 1 | | |
| | Sub-total | 2 | 0 | 0 |
| | Total | 13 | 2 | 6 |

| PLAN RECORD | REF DRAWING NO | | REF ORDER NO | |
|---|---|---|---|---|




| No. | DESIGNATION | Q' TE | REMARQUES |
|---|---|---|---|
| 47 | TABLEAU DE DISTRIBUTUON D' ECLARAGE | 1+1 | |
| 46 | VENTILATEUR DE TOIT | 8+8 | FOURNITURE |
| | | | |
| 44 | CONDUITES DE VENTILATION | 1+1 | |
| 43 | COMPRENDRA DES SOUFFLANTES DE VENTILATION | 4+4 | |
| 42 | TABLEAU DE SURVEILLANCE A DISTANCE | 1 | |
| 41 | TABLEAU D' ALIMENTATION CC | 1+1 | |
| 40 | TRANSFORMATEUR AUXILIAIRE | 1+1 | |
| 39 | TABLEAU DE COMMANDE DES MACHINES AUXILIAIRES | 1+1 | |
| 38 | | | |
| 37 | TABLEAU DE CIRCUIT DE L'EXCITATEUR | 2+2 | |
| 36 | TABLEAU DE DISJONCTEUR D' ALTERNATEUR | 2+2 | |
| 35 | TABLEAU DE COMMANDE D' ALTERNATEUR | 2+2 | |
| 34 | TABLEAU D' INSTRUMENTS DE MOTEUR DIESEL | 2+2 | |
| 33 | SUPPORT DE RESERVOIR | 1+1 | |
| 32 | POMPE DE TPANSFERT D' HUILE | 1+1 | |
| 31 | POMPE DE TPANSFERT DE CARBURANT DIESEL | 2 | |
| 30 | POMPE DE TPANSFERT DE MAZOUT | 2 | |
| 29 | | | |
| 28 | | | |
| 27 | | | |
| 26 | POMPE DE TRANSFERT D' HUILE USEE | 1 | |
| 25 | SEPARATEUR D' EAU HUILEUSE | 1 | |
| 24 | POMPE DE TRANSFERT D' EAU HUILEUSE | 1 | |
| 23 | RESERVOIR DE SEPARATION DE BOUE | 1 | |
| 22 | UNITE D' RESERCOIR DE BOUE | 2+2 | |
| 21 | UNITE D' RESERCOIR DE VIDANGE DE GAS OIL | 2+2 | |
| 20 | CHEMINEE | 2+2 | |
| 19 | GAINE D' ECHAPPEMENT | 2+2 | |
| 18 | SILENCIEUX D' ECHAPPEMENT | 2+2 | |
| 17 | GAINE D' ASPRIRATION | 2+2 | |
| 16 | SILENCIEUX D' ASPIRATION | 2+2 | |
| 15 | FILTER D' ADMISSION D' AIR | 2+2 | Type a inertie et a bain d' huile |
| 14 | POMPE D' ALIMENTATION D' EAU | 2 | |
| 13 | POMPE D' EAU DE REFROIDISSEMEN SECONDAIRE | 2+2 | |
| 12 | RADIATEUR D' EAU DE REFROIDISSEMENT | 2+2 | |
| 11 | RESERVOIR D' EXPONSION D' EAU DE REFROIDISSEMENT DE CHEMISE | 1+1 | 500 l |
| 10 | RESERVOIR DE SERVICE DE CARBURANT DIESEL | 1+1 | 2500 l |
| 9 | RESERVOIR DE SERVICE DE MAZOUT | 1+1 | 5000 l |
| 8 | RESSERVOIR TANPON DE MAZOUT | 1+1 | 5000 l |
| 7 | UNITE D' SURALIMENTATION GRAISSAGE | 2+2 | |
| 6 | SKID D' EQUIPMENT AUXLIAIRE (4) | 2+2 | Tuyouterie |
| 5 | SKID D' EQUIPMENT AUXLIAIRE (3) | 1+1 | Epuroteur de mazout |
| 4 | SKID D' EQUIPMENT AUXLIAIRE (2) | 2+2 | Unite d' alimentation de gas oil, epurateur d' huile de graissage |
| 3 | SKID D' EQUIPMENT AUXLIAIRE (1) | 2+2 | Unite d' huile de graissage,unite d'eau de refroidissement,unite d' comprime |
| 2 | SOCLE COMMUN | 2+2 | Et reservir collecteur |
| 1 | MOTEUR DIESEL ET ALTERNATEUR | 2+2 | |

Fig. 8.1.3-1 Arrangement of C-I Building

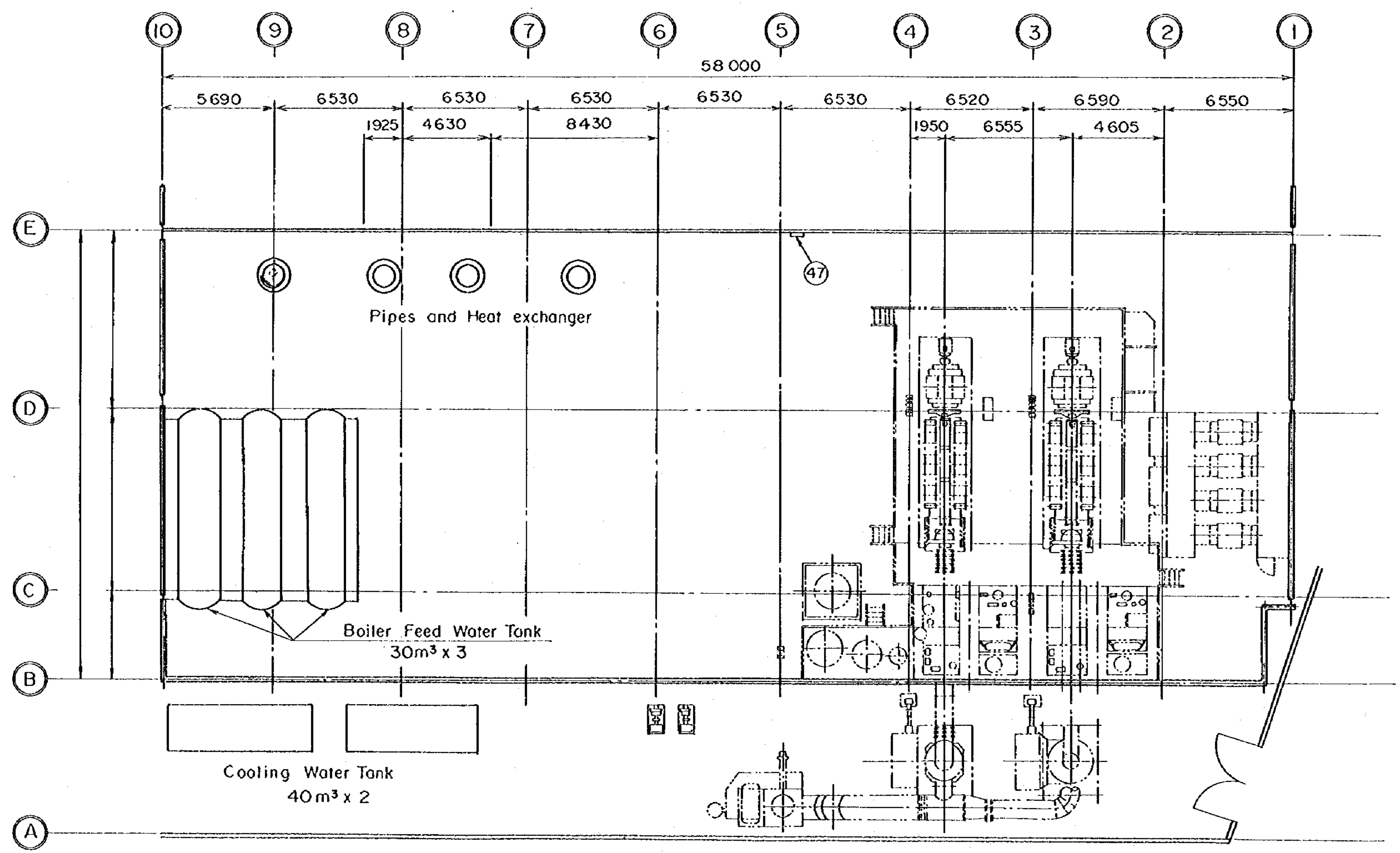



Fig. 8.1.3-2 Removal Facilities

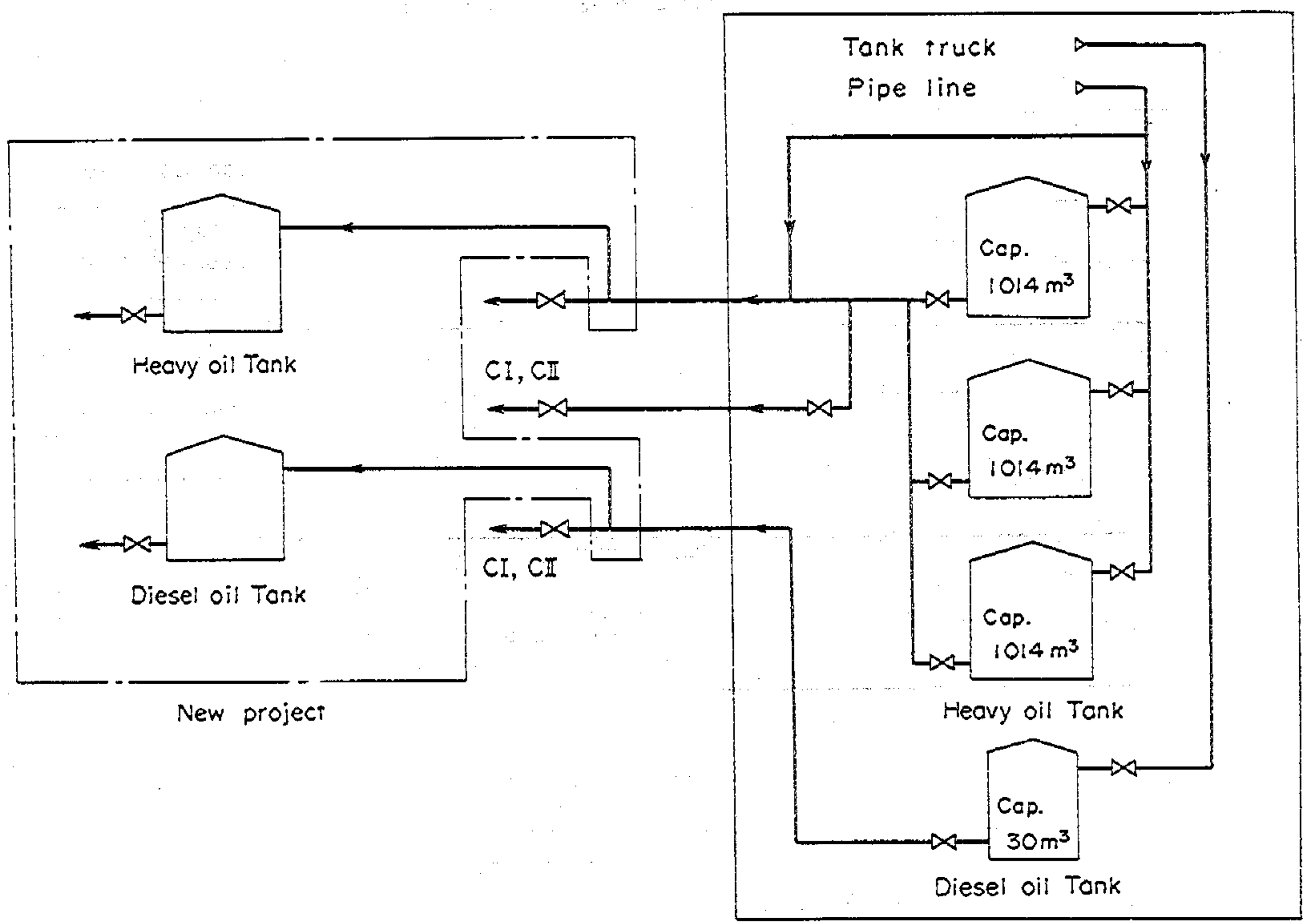



Fig. 8.1.3-3 Fuel Oil System

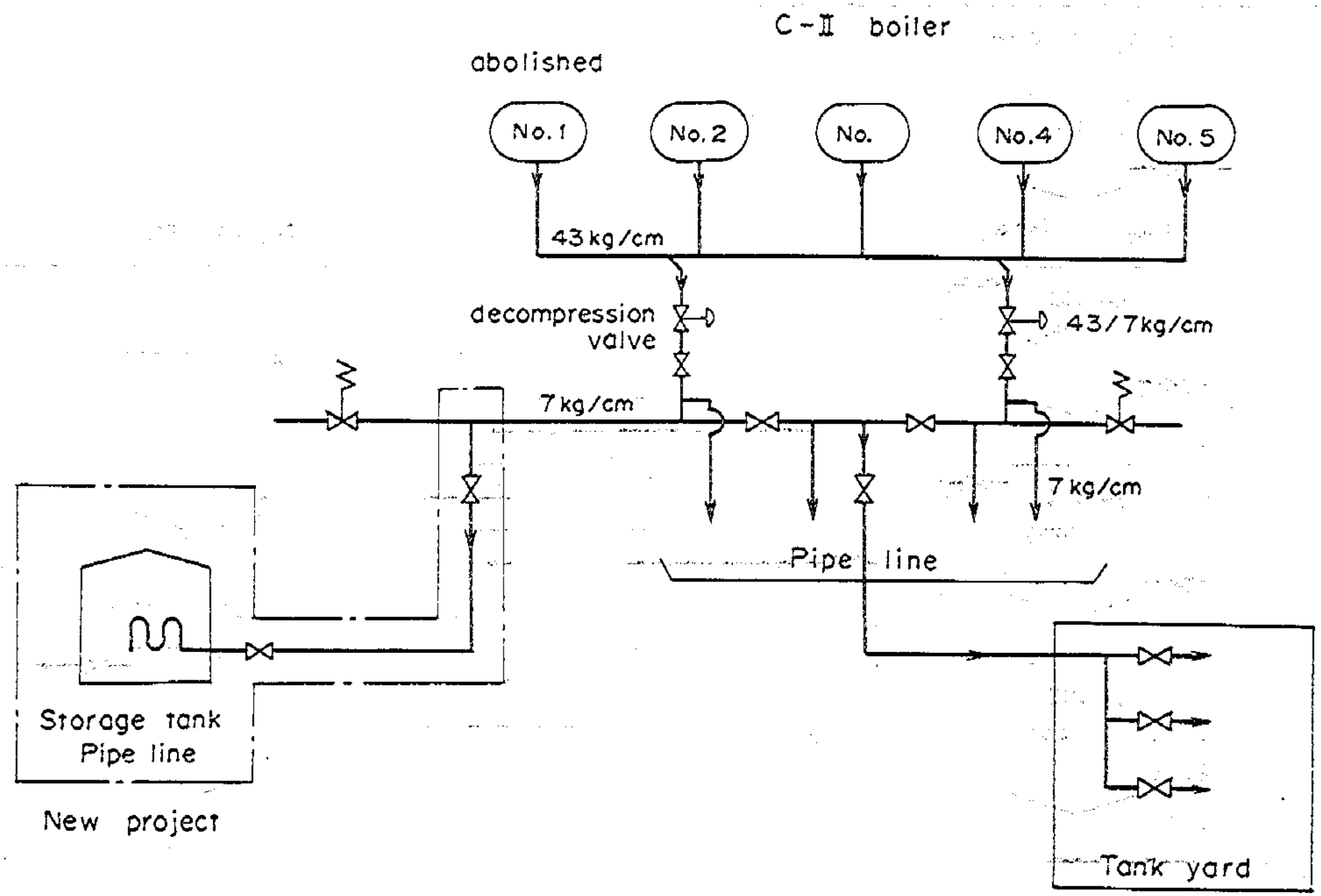



Fig. 8.1.3-4 Steam System

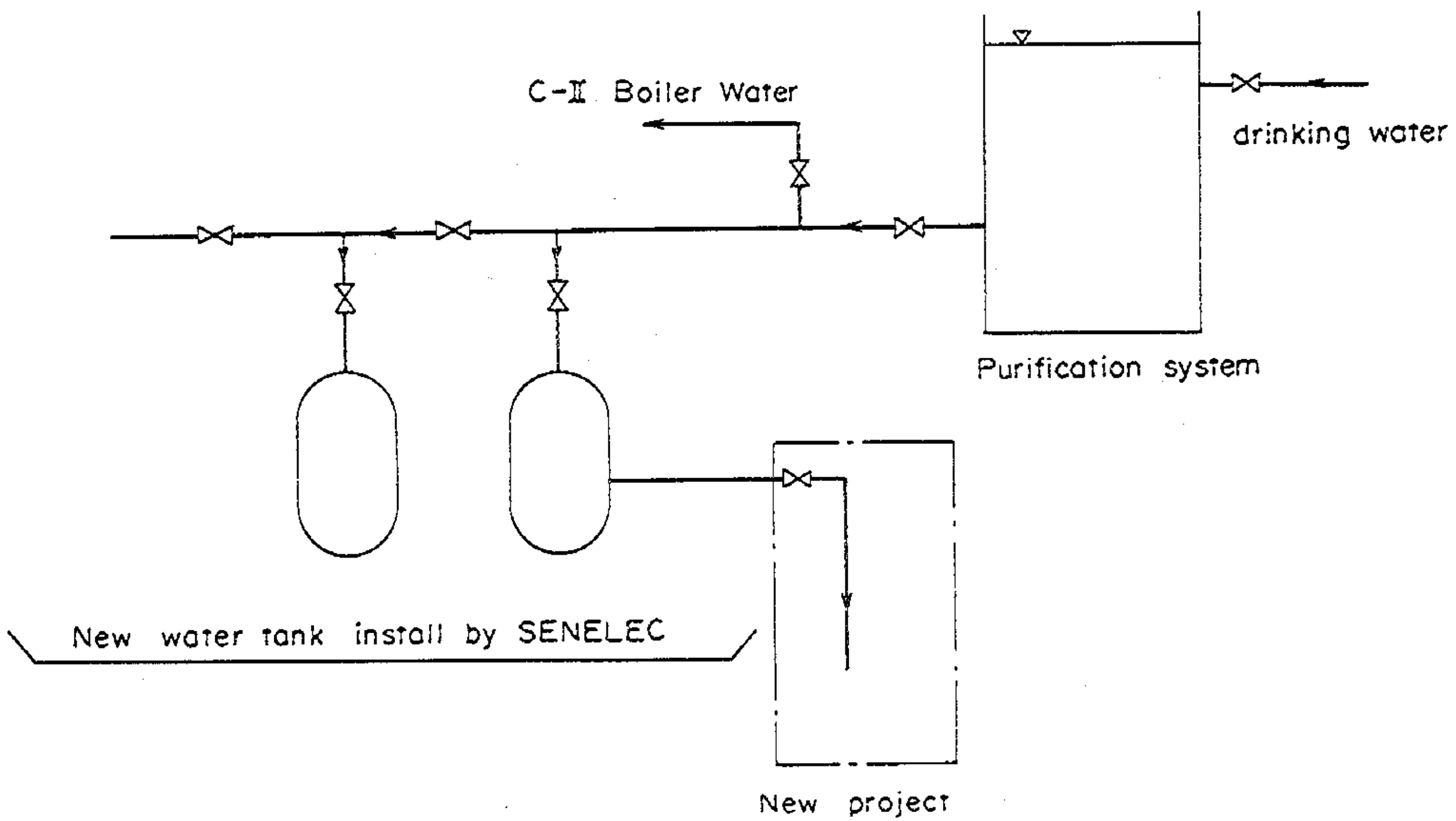



Fig. 8.1.3-5 Cooling Water System

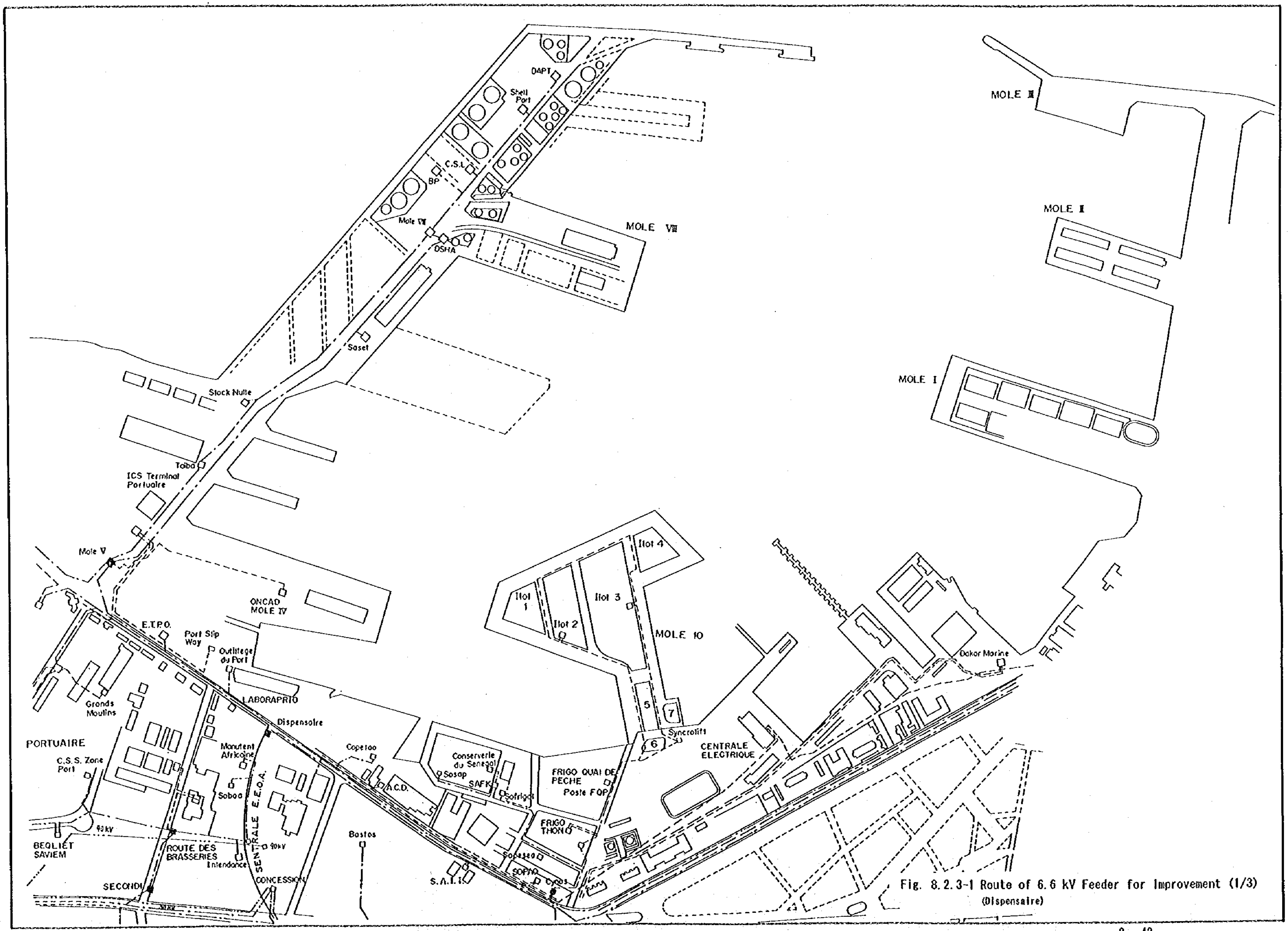



Fig. 8.2.3-1 Route of 6.6 kV Feeder for Improvement (1/3)
(Dispensaire)

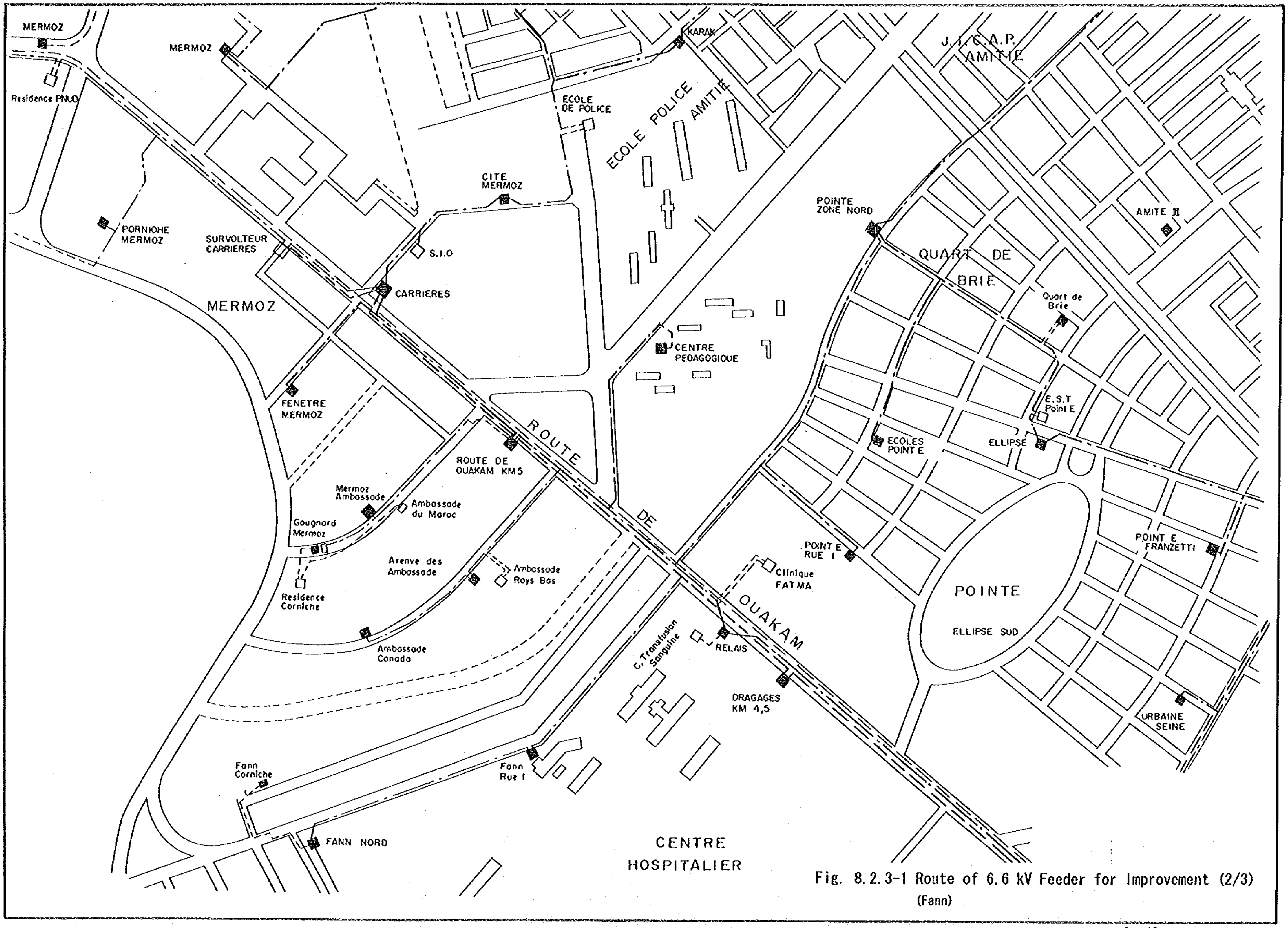



Fig. 8.2.3-1 Route of 6.6 kV Feeder for Improvement (2/3)
(Fann)

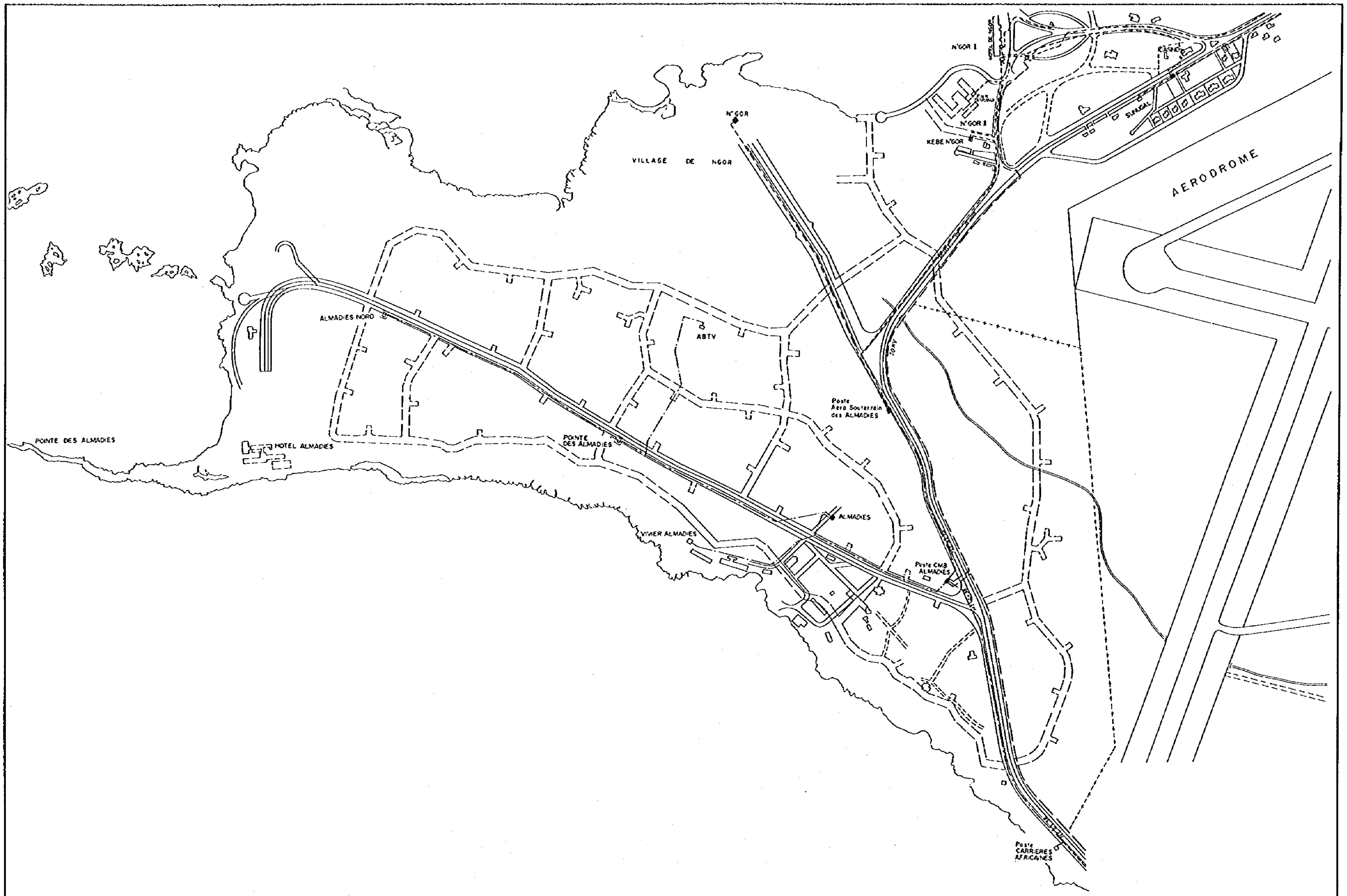
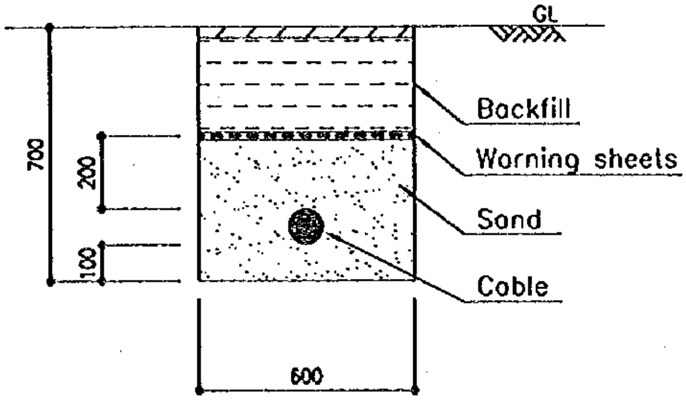



Fig. 8.2.3-1 Route of 6.6 kV Feeder for Improvement (3/3)
(Batterie Yoff)

a. Under the sidewalk




b. Under paved road (Asphalt)

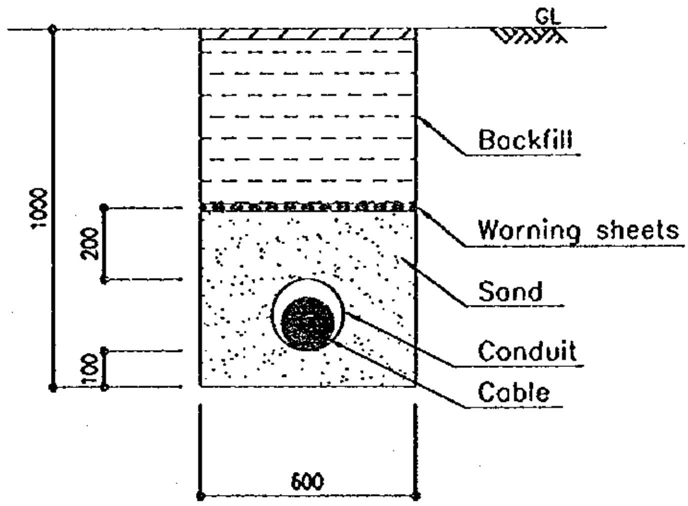
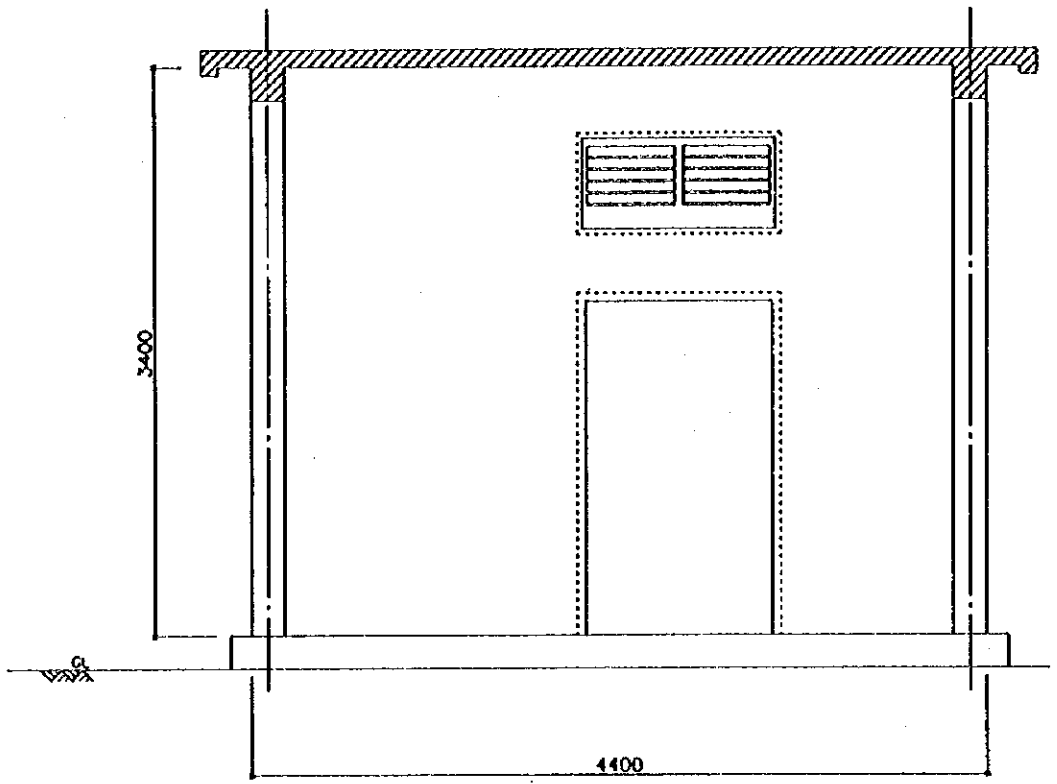
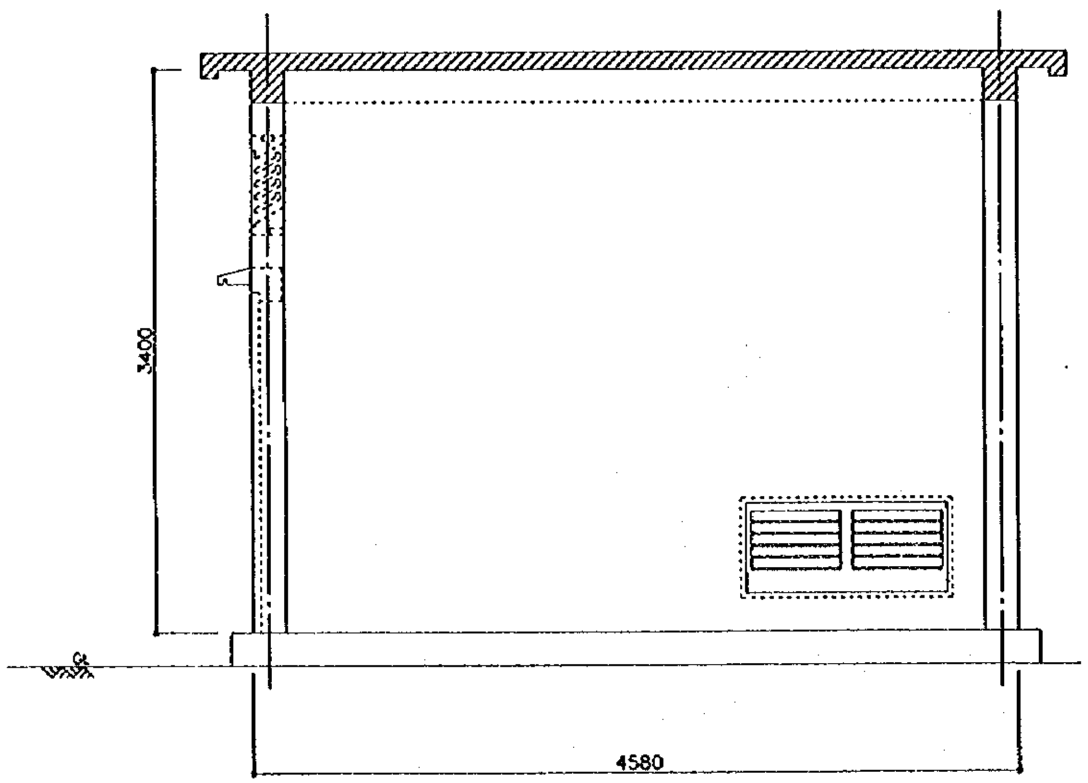


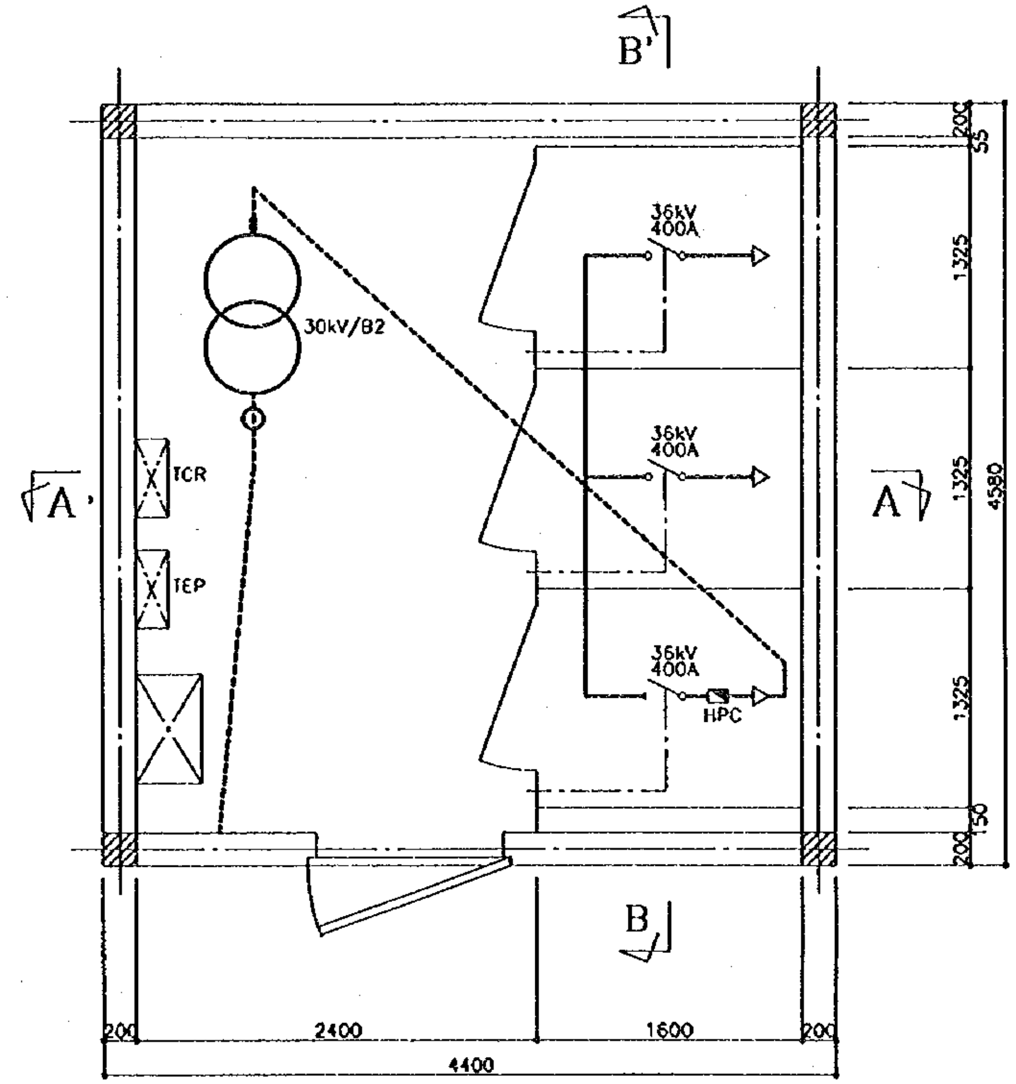

Fig. 8.2.3-2 Cable Laying




Section A – A'



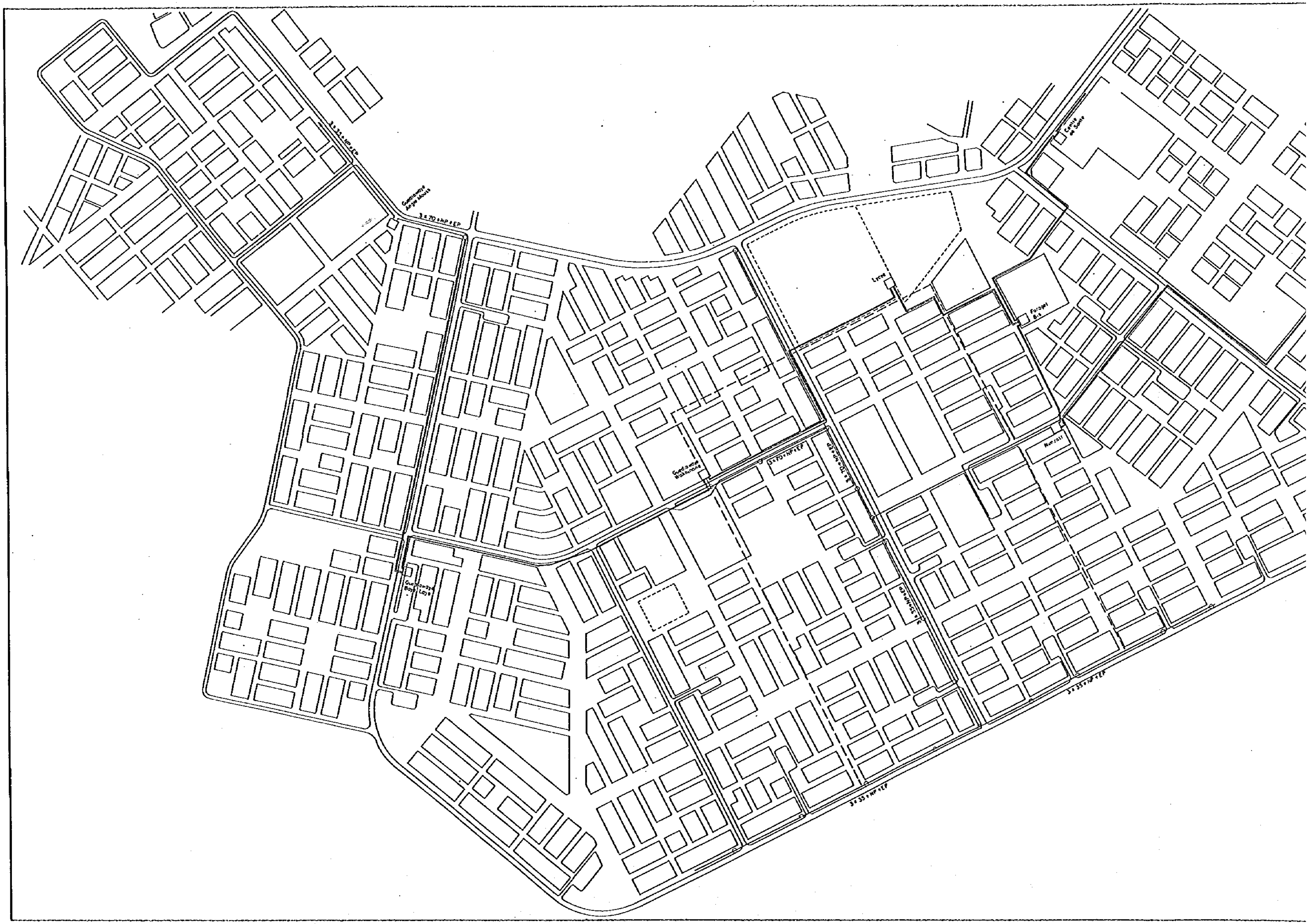

Section B – B'




SOCIETE NATIONALE D' ELECTRICITE DU SENEGAL
Feasibility Study on Development of Electric Power system in Dakar Area

Fig. 8.2.3-3 Typical Type of Distribution Poste

| | | |
|---|---|---|
| SENELEC | EPDC INTERNATIONAL LTD. TOKYO JAPAN | |
| | D.R.: | SUBMITTED: |
| | T.R.: | RECOMMENDED: |
| | C.K.: | APPROVED: |
| | — — — | DATE |



Guediawaye Angle Mousse
3 x 70 + NP + EP
3 x 70 + NP + EP
3 x 70 + NP + EP
Lycée
Centre de Santé
3 x 35 + NP + EP
3 x 35 + NP + EP

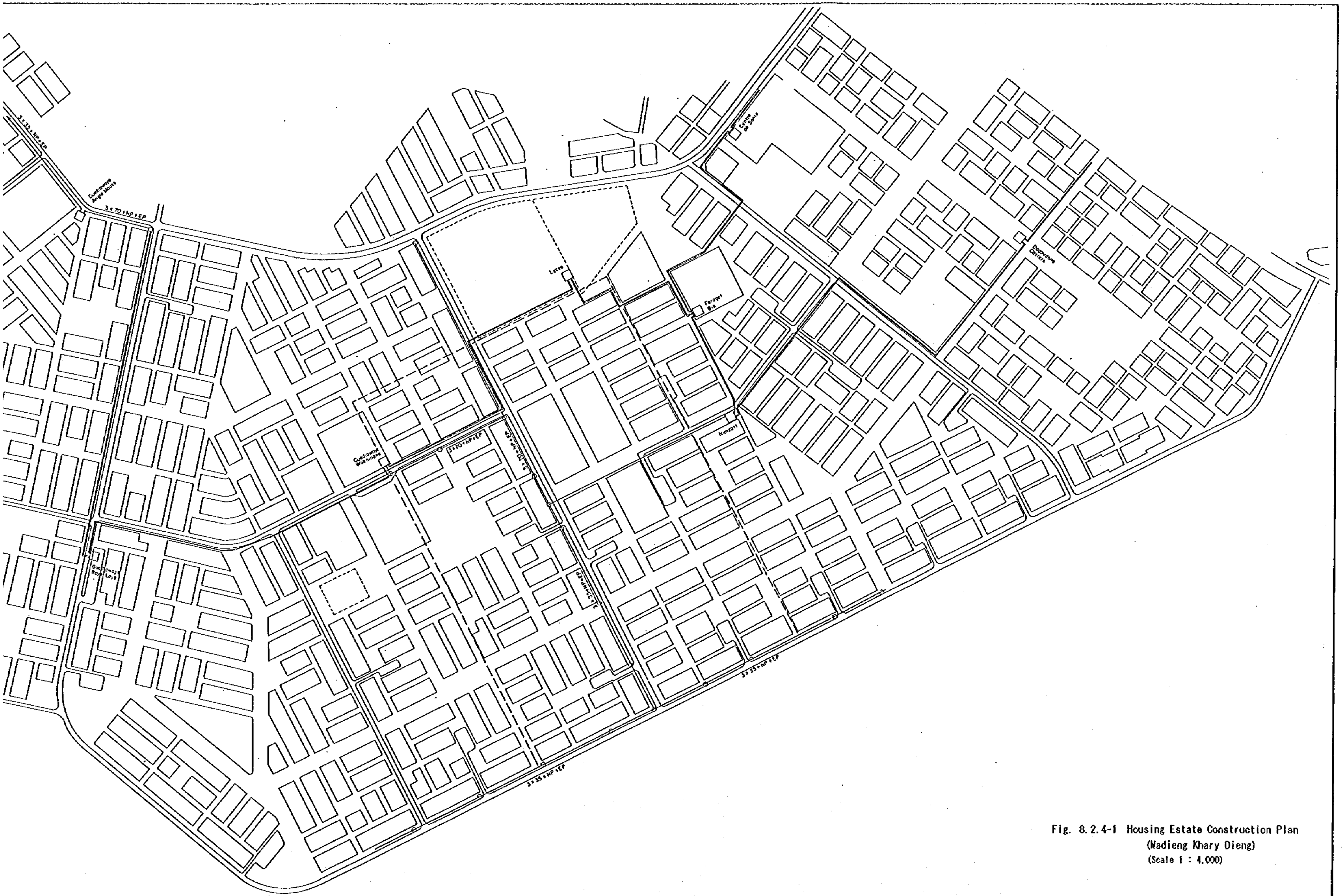


Fig. 8.2.4-1 Housing Estate Construction Plan
(Wadieng Khary Dieng)
(Scale 1 : 4,000)

# CHAPTER 9

# CONSTRUCTION PLAN

## CHAPTER 9 CONSTRUCTION PLAN

### 9.1 Power Generating Facilities

Plant and machines related to power generating facilities shall be transported to the site for erection, and the necessary foundation and installation work and commissioning test shall be performed.

#### 9.1.1 Details of Construction Work

1) Diesel engines, generators and ancillary equipment
2) Transformers, circuit breakers, supervisory and control panels, and cables
3) Operation control room
4) Connection to the existing equipment
5) Other necessary construction work

#### 9.1.2 Removal Work

The existing equipment listed below shall be removed at the cost and expense of SENELEC prior to the installation of the new equipment. This removal work will be required as the existing equipment is liable to obstruct and hinder the installation work for the new equipment.

| | | | |
|---|---|---|---|
| 1) | C-I building | : | Water tank for the C-II boiler - 30 $m^3$ x 3 |
| 2) | C-I building | : | Indoor piping and heat exchangers etc. - 1 lot |
| 3) | Outdoor | : | Cooling water tank - 40 $m^3$ x 2 |
| 4) | Outdoor | : | Residual oil incinerator - 1 lot |

The tanks given in 1) and 3) above shall be removed and replaced by equivalent tanks of identical capacity at the cost and expense of SENELEC prior to the commencement of the installation work.

Fig. 8.1.3-2 shows the facilities to be removed.

#### 9.1.3 Work at the Cost and Expense of SENELEC

Apart from the plant removal work shown in section 9.1.2, SENELEC shall also arrange for the following work to be executed at its cost and expense.

1) Sealing off the apertures of the C-I building (south wall)

2) Installation of a soundproofed wall (on the boundary with the tobacco factory)

3) Making available of sufficient site area required for the construction work (materials yard, works office)

4) Making available all electricity, water, steam, fuel oil and light oil required for the execution of the construction work.

### 9.1.4 Connection to the Existing Equipment

All works connecting to the existing plant, including the piping and cabling, shall be carried out by prior consultation with SENELEC to agree with SENELEC's operating schedules in such a manner that the installation work should coincide, wherever possible, with SENELEC's timing of the regular maintenance work for its existing plant so as to avoid any interference with SENELEC's power generation schedule.

### 9.1.5 Transportation Routes and Methods

(1) Assembly and Transportation of Equipment

After assembling and performance test of diesel generator set at the manufacturer's factory, the equipment will be disassembled only to the minimum possible degree and transported to the site in the practically fully assembled condition. This method will simplify and facilitate the assembly and installation work required at the site and also help to reduce the time required for setup, adjustments and test-runs. This will also contribute to minimizing the initial difficulties ("teething troubles") after the commissioning and startup of the plant.

Those parts of the main equipment which are susceptible to shock and humidity and extremely vulnerable to high temperatures require special measures to ensure that their performance and/or shape will not be impaired during transportation.

In practical terms this means that distribution panels containing a large number of shock-sensitive measuring instrument should be immobilized during packaging and the humidity-sensitive stators and rotors of the generator should be vacuum-packed to prevent the ingress of humidity, and items with paint coats that are very vulnerable to high temperatures should be packaged in a non-igniting form of packaging. The packaging is required to be seaworthy and shall be checked prior to lading.

(2) Transportation Route

Maritime transport of the equipment for this project shall be on the Japan-Europe-Dakar route to reduce shipping time.

This routing procedure entails that the cargo will be carried by two different vessels, one for the Japan-Europe and one for the Europe-Dakar sections, with the cargo being reloaded in the European port. The time required on the via-Europe route from Japan to Dakar Port is about one and a half months. This is about one month less than the direct sea route from Japan to Dakar.

While direct sea transportation from Japan to Dakar does away with the need for reloading (transferring) the cargo, the voyage with its many calls at ports en route takes about two and a half months until arrival in Dakar. These stops en route carry a certain risk of theft or loss of the equipment and materials on board.

(3) Port and Transportation

The Port of Dakar with a water depth of 10 m has three berths exclusively used for heavy cargo on the south side. These are constructed of concrete blocks and robust enough to withstand loads of up to 4 $t/m^2$. The berths are therefore suitable for vessels registered in the 30 ～40,000 DWT class. However, the berths are not equipped with special stevedoring cranes. Cargo handling capacity is available, however, in the form of a 60 t load-lifting capacity floating crane with very conspicuous signs of aging. Its boom, said to have a real load lifting capacity of approximately 50 t is not suitable for practical use because of its short length of only 5 m. It will therefore be necessary to use a ship's crane for unloading the cargo.

The land transportation route from Dakar Port to the Bel-Air Power Station is about 1.5 km. The port and the power station are linked by a two-lane, fully asphalt-surfaced road so that the onward transportation from the port should present no problem.

For onward land transportation, it will be necessary to use heavy tackle, a 100 t low bed trailer and a 70 t crane, all of which should be easy to obtain locally.

### 9.1.6 Work Schedule

The work will take a total of 14 months to complete. This includes all incidental works from the signing of the contracts with the contractors, the designing of the equipment, the manufacturing and transportation thereof, the installation, setup, adjustments, commissioning and trial operation of the plant. Work schedule of this work is shown in Fig. 9.1.6.

## 9.2 Distribution Line Facilities

The present situation on SENELEC's distribution network in the Dakar area is that the reinforcement, expansion and rehabilitation work needed to meet the rapidly increasing power demand in the city area of Dakar has not and is not being carried out as it ought to have been for reasons mainly due to the lack of funds and the shortage of materials. This has given rise to a variety of problems which are in evidence everywhere in the distribution network. These problems include in particular the occurrence of excessive voltage drops as a result the use of conductors and underground cables of a size not matching the supplied power or due to the absoluteness of the power distribution equipment so that it is not possible for SENELEC to assure a reliable supply of a high-quality electric power to the consumer households.

At the same time, the situation is aggravated by the overpopulation problem in the densely populated Dakar city area and the influx of a migrant population into the city from the regions. To resolve these problems, policy measures have been adopted to resolve the urban overpopulation issue by creating new housing estates on the suburban fringe of the city. The reality is that these housing estates do not have adequate power supply services.

To overcome these problems, there is strong hope that the expansion and rehabilitation work on the distribution network will take place.

### 9.2.1 Details of Construction Work

The construction work due to be implemented under this project breaks down as follows.

(1) Replacement of circuit breakers
(2) Improvement of medium voltage distribution lines
(3) Expansion of the low voltage distribution network
(4) Rehabilitation of the low voltage distribution network

### 9.2.2 Implementation Method and System

All construction works under this Project, including the installation of the equipment, shall be executed by SENELEC. The present construction work shall also include the replacement of the medium voltage circuit breakers and

improvement of the medium voltage distribution lines, including the voltage step up of the system.
The execution of the construction work will have a wide influence so that it will be necessary to ensure that the following points will be given due consideration in the implementation of the construction work:

a. Preparation of construction plans to ensure effective project implementation
b. Defining the scope and range of work and the work process in order to minimize the influence range of the project
c. Selection of such work methods and operations/sequences as will ensure safety during work

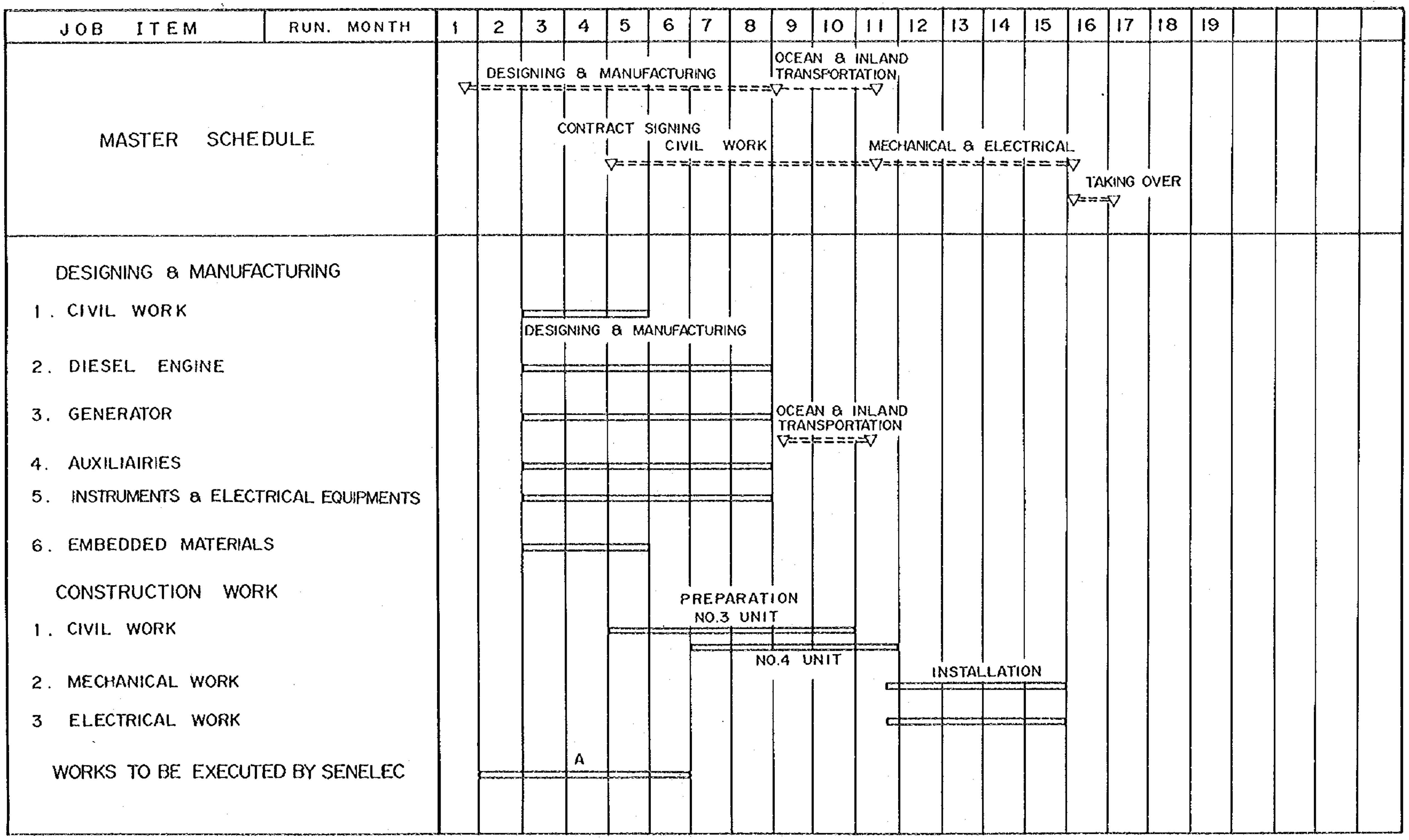
At the same time, consideration shall also be given to the following:

d. Assuring the safety of the residential population
e. Giving consideration to environmental issues
f. PR activities for the construction work

### 9.2.3 Construction Schedule

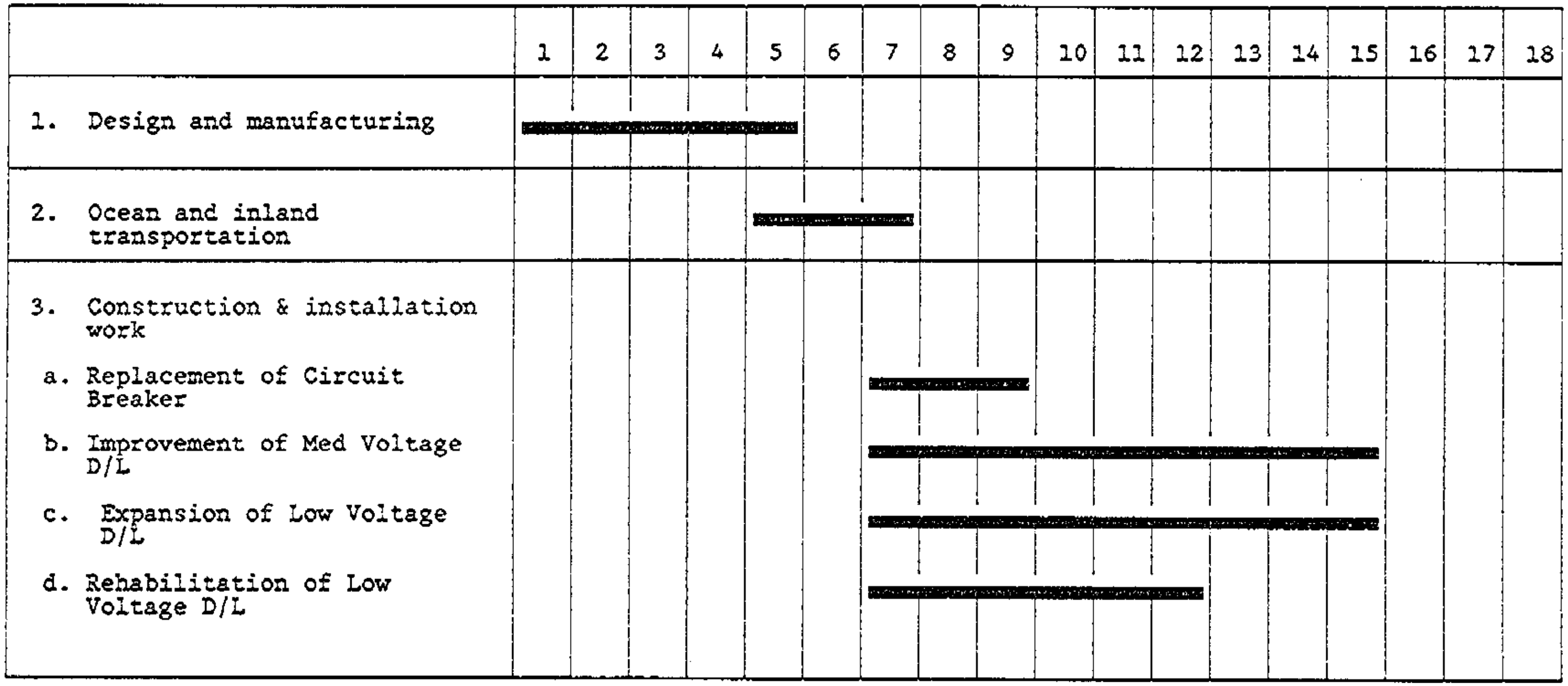
The construction period has been provisionally fixed at 15 months. Fig. 9.2.3-1 shows the construction work schedule.

## Fig. 9.1.6 Standard Schedule for 5,000kW Diesel Engine




※ A REMOVAL of BOILER WATER TANK
REMOVAL of COOLING WATER TANK
REMOVAL of OIL INCINERATOR

Fig. 9.2.3-1 Schedule for Distribution Lines



# CHAPTER 10

# CONSTRUCTION COSTS

# CHAPTER 10 CONSTRUCTION COSTS

The construction cost for power generating facilities and distribution line facilities is estimated roughly.

## 10.1 Prerequisites for Construction Cost Estimation

To estimate the construction cost, the following conditions are taken into account;

(1) Material and Equipment Costs

All FOB prices are based on the fiscal 1995 price index and while allowance has been made for price escalation, no import duty levied by the Senegalese authorities has been allowed for.

(2) Transportation Costs and Insurance

Transportation costs include maritime freight charges and the costs of inland transportation to the destination site. Allowance has also been made for insurance premiums which have been added to the FOB prices given in (1) to arrive at the CIF prices.

(3) Labor Costs

Labor costs have been determined on the basis of the standard labor costs currently applicable to the Dakar region and the costs for similar construction work in Japan.

(4) Contingent Expense

A reserve of 15% has been allowed for both on the foreign and the local (Senegalese) currency portions.

(5) Engineering Fee

(Power generating facilities)
Engineering fees for the power generating facilities has been estimated at an amount equivalent to 15% of the total construction costs.

(Distribution line facilities)
On the assumption that the materials/equipment will be supplied but the supervisory management of the construction work will not be included, the engineering fees for the distribution line facilities have been estimated at an amount equivalent to 10% of the total construction costs.

(6) Technical Staff Training Cost

(Power generating facilities)
The costs required for providing the technical training and instruction for the operation of the power generating facilities to the SENELEC staff have been estimated.

(Distribution line facilities)
Allowance has been made for the supply of the materials and equipment but not for the technical training to the SENELEC staff.

(7) Exchange Rates

The exchange rates used for the cost estimation are as stated below.

1 US$ = ¥99.85
1 US$ = FCFA 528
1 FF = ¥19.1

## 10.2 Foreign and Local Currency Portions

The demarcation between the foreign and local currency portions in the construction project shall be as follows.

(1) Foreign Currency Portion

a. Materials and equipment:
All items, except gravel, sand, cement and reinforcing bars

b. Vehicles and tools:
Vehicles, tools and measuring equipment required for the construction work

c. Transportation costs and insurance premiums:
Maritime freight transport and inland road transportation, insurance premiums

d. Labor costs:
Costs for engineers traveling to the site for major plant installation and adjustment as part of the construction work on the power station.

e. Consulting fees and technical training fees

(2) Local Currency Portion

a. Labor costs

b. Material costs:
All minor items requiring to be procured on a local basis for the construction work, such as gravel, sand, cement and reinforcing bars.

## 10.3 Construction Costs

The total construction costs for the development of electric power system are as stated below.

| | Foreign currency portion (Million Yen) | Local currency portion (Million Yen) | Total (Million Yen) |
|---|---|---|---|
| 1) Power generating facilities (Incl. contingency) | 1,675.0<br>1,926.3 | 91.9<br>105.7 | 1,766.9<br>2,032.0 |
| 2) Distribution line facilities (Incl. contingency) | 681.3<br>783.4 | 104.7<br>120.4 | 786.0<br>903.8 |
| (Breakdown of distribution line facilities) | | | |
| a. Replacement of circuit breakers | 28.6 | 2.4 | 31.0 |
| b. Improvement of medium voltage distribution lines | 300.4 | 47.8 | 348.2 |
| c. Expansion of the low voltage distribution network | 278.9 | 41.5 | 320.4 |
| d. Rehabilitation of the low voltage distribution network | 73.4 | 13.0 | 86.4 |

Notes

(1) Breakdown of Construction Costs Borne by the Senegal

1) Power generating facilities
   - Removal and construction of de-mineralized water tank (30 t) x 3 inside the C-I building
   - Removal of de-mineralized water tank (40 t) x 2 outside the building
   - Removal of pipes and heat exchangers inside the C-I building
   - New construction of de-mineralized water tank

2) Distribution line facilities
   a. Replacement of circuit breakers
      - Removal of existing equipment
      - Modification of installation site
      - Equipment installation

b. Improvement of medium voltage distribution line

- Removal of existing overhead distribution lines
- New erection and modification of distribution postes
- Equipment installation in distribution postes
- Laying of the underground cables

c. Expansion of the low voltage distribution network

- Modification of existing distribution postes
- Construction of new distribution postes
- Laying of the underground cables
- Pole erection and stringing work
- Connection to consumers

d. Rehabilitation of the low voltage distribution network

- Removal of existing facilities
- Pole erection and stringing work
- Connection to consumers

# CHAPTER 11

# FINANCIAL AND ECONOMIC EVALUATION

## CHAPTER 11 FINANCIAL AND ECONOMIC EVALUATION

This chapter consists of four sections. The first section primarily discusses the methodology we employ in the financial and economic evaluation of the Project. The second and the third sections, which are entitled 'financial analysis' and "economic analysis", and are the main components of this chapter, examine the viability of the Project from the financial and economic viewpoints, respectively. Conclusions are presented in the final section.

### 11.1 Objectives and Methodology

The overall goal of the financial and economic analyses is to assess both the financial (or commercial) and economic soundness of a project.[1] The difference between financial and economic analyses is that the former is concerned mainly with the profitability (or the efficiency) of the investment in the proposed action <u>for the project authority</u> (e.g., SENELEC), whereas the latter is interested in the profitability of the investment <u>for the society as a whole (or the country's economy)</u>. This difference is often reflected in the approach in which different prices are used for the same inputs (costs) and/or outputs (benefits) in the financial and economic analyses (i.e., market and so-called economic prices, respectively).[2]

In this study, financial and economic profitabilities or viabilities are determined on the basis of the internal rate of return (IRR) of the Project, which is a factor equalizing the net present value of the Project to zero. The net present value of a project is defined as the balance between the total value of the project's in-flows (benefits) and that of the project's out-flows (costs) discounted at a fixed rate. For a project to be considered to be feasible, the IRR is expected to exceed or be equal to a pre-determined discount rate, which is synonymous with the opportunity cost of capital, and is often equal either to the actual rate of interest on long-term loans

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1. The Project has already been identified as the least-cost optimum solution for meeting the projected power demand of the electrical system concerned, and hence, it is important to note, the analysis of this chapter does not include any discussion comparing the Project with other alternatives. Discussions related to the identification of the least-cost solution are found earlier in this report.

2. In the financial analysis, market prices are applied for the inputs and outputs of a project, as they are "factual" to the project. The economic analysis is concerned with real costs and benefits of the project's inputs and outputs to the nation, which may not be represented necessarily by their market prices. Market prices can be distorted by the monopolistic practices of industries, as well as taxes, subsidies, and other regulatory measures of the country. Such distorted prices, in the economic analysis, have to be "shadow priced" to reflect real economic values. For this shadow pricing procedure, as we demonstrate later in the economic analysis, we apply conversion factors for the local currency components of the Project's inputs.

available in the international capital market for comparable projects with similar levels of risk involved or to the loan interest rate usually applied to the borrower by commercial banks. SENELEC usually pays an interest rate of around 12 percent on their loans. We, thus, assume the discount rate of the Project at 12 percent.

In our analysis, we calculate three types of IRR: the financial internal rate of return (FIRR) and economic internal rate of return (EIRR) of the Project and the FIRR of the equity invested in the Project. The FIRR of the Project is computed on the basis of the streams of financial benefits and costs, and the EIRR of the Project on the basis of the streams of economic benefits and costs. From the investor's viewpoint, the FIRR of the equity invested on a project is often more important than the FIRR of the project per se. It takes into account financial costs under an assumed financing scenario, whereas the FIRR of the project, which is concerned with the non-distorted, fundamental soundness of the project, does not. For the Project to be regarded as viable, the above-mentioned IRRs must be equal to or exceed 12%.

The Project will have to satisfy not only the requirements by the investor but also those by the lender of its loan. A lender is normally concerned with a possibility of the borrower failing to fulfill the debt service of the loan. This possibility is measured usually by the debt coverage ratio of the project in question, which is the ratio of the project's annual cash generation to its annual debt service. This ratio, we assume, must be 1.5 at the lowest for the Project, which is a normal requirement by lenders. The ratio increases as the ratio of the equity to the loan increases. However, the borrower's ability to raise the equity ratio is often limited. It is reported that in the case of SENELEC, the maximum feasible equity ratio (to the total investment) is 30%.[3] Thus, the minimum debt coverage ratio of 1.5 must be attained at the maximum ratio of equity (to the total investment) of 30%. In sum, financial and economic feasibility requirements for the Project are as follows:

3. This can also be inferred from the SENELEC's current financial position.

- FIRR of the Project ≥12%
- EIRR of the Project ≥12%
- FIRR of the equity invested in the Project ≥12%
- Debt coverage ratio of the Project ≥1.5

(Equity ratio to the total investment =30%)

We test both the FIRR and EIRR of the Project for sensitivity. The primary objective of the sensitivity analysis is to assess how the profitability of a project is affected by modifications in the assumptions used on key variables. The sensitivity analysis allows a judgement on the riskiness of the project under alternative assumptions. Usually, in the analysis, modifications are made for such variables that may significantly change the projected costs or benefits of the project and that involve high levels of uncertainty. In our analysis, we examine the changes in the IRR for an increase in the total capital costs and a decrease in the total benefits.

The Project comprises the following three components: (The second component consists of three sub-components.)

Component 1 An addition of two 5 MW diesel generation units to the Bel Air power station

Component 2 Rehabilitation of the distribution network in some areas, including,

(a) replacement of circuit breakers at distribution substations (Medium Voltage),

(b) replacement of 6.6 kV overhead lines by underground cables, and voltage boosting of some feeders from 6.6 kV to 30 kV, and

(c) intensive rehabilitation of the low voltage network involving replacement of deteriorating equipment

Component 3 Expansion of the existing distribution network

The remaining part of this section briefly discusses the conceptual framework of the economic costs and benefits of those components.

Costs

Project inputs are often classified into three broad categories: (1) traded goods, (2) non-traded goods, and (3) so-called primary production factors including land and labor. The main traded goods, as far as the Project is concerned, are power generation units and distribution equipment for power distribution. Non-traded goods are those which by their nature are supplied locally; and they cover overhead expenses, and construction materials such as gravels and sand. The primary production factors of the Project are limited practically to labor.[4] The unskilled labor required for the Project will be procured domestically, whereas the skilled labor required will be obtained internationally as well as domestically.

In the economic analysis, economic prices or shadow prices have to be identified for all the inputs. For traded goods, international prices, or so-called border prices are used. The border price of an imported commodity would be its c.i.f. (cost including insurance and freight) value at the Dakar Port plus local transportation cost. Financial costs of imported goods often include duties and taxes, which are regarded as transfer payments from the viewpoint of national economy. The Project, which is likely to be financed by a loan from a bilateral or international financing institution, will be exempted from all such payments and thus, financial and economic costs for imported goods for investment will be the same.

SENELEC receives a "subsidy" for its import fuel oil. The "subsidy" is derived from the surplus of the so-called "stabilization fund," whose purpose is said to cross-subsidize petroleum product prices, and possibly from excess profits from the refinery. In our study, we regard the "subsidy" as an excess profit charged on the imported oil by the government, and thus do not consider it to be a transfer payment.

Both non-traded goods and labor need to be shadow-priced. Costs of none of the non-traded goods consumed by the Project are comparatively large. Therefore, for simplicity, we use a single factor to derive shadow prices for all the non-traded goods. This factor is meant to serve as an average of the conversion factors for various non-traded

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4. As far as the land is concerned, the Project is not required to acquire any land, since a part of an existing power house at the Bel Air plant site accommodates new generation units. Strictly speaking, the Project has to "pay" the cost of the land (or the space) which is made available for it. However, because the cost of the land would be a negligible fraction of the total project costs, and because the foregone cost of not using the land for other purposes (i.e., economic cost) would be insignificant, the land cost is disregarded in our analysis.

goods.[5] Labor is usually divided into skilled and unskilled. The job market in Dakar and its surrounding area is not very tight even for those skilled workers who have merely compulsory education or primary job training. Therefore, what the Project pays to skilled workers it employs would basically reflect the opportunity cost of those workers (to the society) in the absence of the Project. Unskilled labor, on the other hand, is clearly in excess in the labor market. Unemployed unskilled labor may collect firewood which can be sold at the market to compensate a part of the economic loss of the day resulting from not being employed. Based on those observations, appropriate conversion factors for skilled and unskilled labor will be determined. Financial costs for local-currency, investment components include a 20-percent VAT. This transfer payment must be substracted for the economic costs of those components.

<u>Benefits</u>

Regarding the benefits of a project, we first have to identify them, and then assign prices to them. Benefits can be direct or indirect. Direct benefits can be defined as an immediate gain to those who acquire outputs of a project, and indirect benefits as a gain not to them but to the society. In this study, we limit the benefits of the Project only to direct benefits, because of the difficulties of measuring indirect benefits, and because of a general tendency that indirect benefits are not significant enough to affect a feasibility judgement for a project in question. It is important to note that in benefit-cost analyses or project feasibility studies, benefits can be costs saved, since the net benefit is total benefits minus total costs.

Direct benefits derived from individual components of the Project are as follows. The benefit of Component 1 includes (1) the consumption

5. This factor is called standard conversion factor (SCF), and computed by the following formula:

$$SCF = \frac{M+X}{(M+T_m)+(X-T_x)}$$

where;
M : cif value of imports
X : fob value of exports.
Tm: all taxes (duties) on imports
Tx : all taxes (subsidies) on exports
By applying the relevant statistical figures for 1994 (in billion FCFA), SCF is computed as follows:

$$SCF = \frac{627.8+431.1}{(627.8+127)+(431.1-0)} = 0.89$$

benefit of the additional electricity made available by the investment (i.e., a net addition of energy supplies), and (2) fuel savings by displacing relatively inefficient generation units. The benefit of the Component 2 consists of (1) the consumption benefit of the electricity that would be continuously lost or unserved due to outages under existing conditions and hence would not be made available to consumers in the absence of the rehabilitation work and (2) generation cost savings due to the reduction of the total generation requirements, which results from the reduction of transmission loss by the voltage boosting of some feeders from 6.6 kV to 30 kV. The benefit of Component 3 is the consumption benefit customers newly connected under the Project will receive by being connected or being satisfied with their power demand.

Consumption benefits can be measured by what is called "the willingness to pay of the consumers for the good concerned". And the best measure of the willingness to pay is often the market price of the good.[6] In this study, we use the prevailing electricity tariffs as an indicator of the willingness to pay for the benefits of Components 2-(c) and 3 as well as a part of Component 1, which is concerned with a net addition of supplies. Although the collection rate of electricity bills in Senegal is by no means satisfactory by the international standard, it is considered to be high enough to judge that the level of the willingness to pay for electricity exceeds the current tariff rates. In measuring the benefits of Component 2-(a) and a part of Component 2-(b) involving the consumption benefit, we estimate the level of the willing to pay to avoid interruption of power service due to an outage.[7,8] The benefit arising fuel or generation cost savings, which a part of Component 1 and a part of Component 2-(b) are concerned with, is measured by actual fuel costs.

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6. A consumer's willingness to pay is at least as high as the market price; otherwise he would not purchase the good in question. The difference between the willingness to pay and the market price is called the consumer surplus.

7. Components 2-(a) and 2-(b) aim at the reduction of outages through the replacement of equipment and the installment of underground cables. (Component 2-(c), which involves extensive rehabilitation works on the distribution network in some areas, is regarded as construction of new distribution facilities, as found in Component 3.)

8. To measure residential outage costs, net income earning rates are often used, with an assumption that all electricity is used for productive purposes. The willingness to pay by industrial consumers is associated with the losses incurred from an interruption of production activities.

It must be noted that the replacement of overhead lines by comparatively costly underground cables (a part of Component 2-(b) and a very small portion of Component 2-(c)) is mainly for aesthetic purposes, and its contribution to the increase in consumption benefit in the form of reduction of outage costs is minimum. This project element is designed simply to be in consistent with the relevant policy of the city of Dakar. For this reason, basically, no opportunity costs are accrued, and therefore it is not necessary to include the element in the computation of the EIRR of the Project.

## 11.2 Financial Analysis

In this section, we explore financial implications of the Project for the project proponent, namely, SENELEC. First, we analyze the existing tariffs, on the basis of which the Project's financial benefits are determined. Secondly, the financial position of SENELEC is reviewed. Thirdly, the FIRR of the Project is calculated to assess the financial profitability of the Project. Fourthly, the Project's cash in- and out-flows are projected with the impact of debt financing taken into account. Under assumed financing scenarios, the FIRR on the equity invested is computed and the debt service coverage is assessed. The debt service coverage is an important index to measure the financial soundness of a project, particularly from the lender's viewpoint.

### 11.2.1 Tariff Analysis

Current tariff rates are determined based on the long-run marginal cost pricing. The average sale price of electricity (i.e., the sales revenue per kWh of billed consumption) was 69.9 FCFA/kWh for the Dakar and interconnected systems in 1994. Present tariff rates are felt to be very high by medium income households, as the bills for electricity are estimated to be approximately 15% of their disposable incomes.

Tariff structure

Tariffs are differentiated first by voltage levels--low, medium, and high voltage levels (see Figure 11.1). Low voltage customers consist of three customer categories--domestic, non-domestic (or professional), and street lighting. Domestic customers are divided further into two categories--special (for those whose service load is 5 amp. maximum each) and general. Non-domestic customers consist of those whose power demand is less than 32 kW each, and whose bills do not specifically include a peak demand charge (or a fixed premium) and the others with a fixed premium being changed.

Medium voltage customers are divided into three groups depending on the total yearly hours of use--short-hour use, general, and long-hour use. Customers classified as general are expected to use electric power for 1,000-4,000 hours a year.

High voltage customers consist of three industrial entities, namely, TAIBA (a phosphate plant), SOCOCYM (a cement plant), and ICS (a chemical plant). Different tariff rates are applied to the last one, as it has a special agreement with SENELEC, under which it can sell its excess electricity to SENELEC. The total power demand by the three establishments was approximately 45.5 MW in 1994. The number of customers, the sales revenue, and the electric energy consumption by respective customer groups are exhibited in Appendix 11.1.

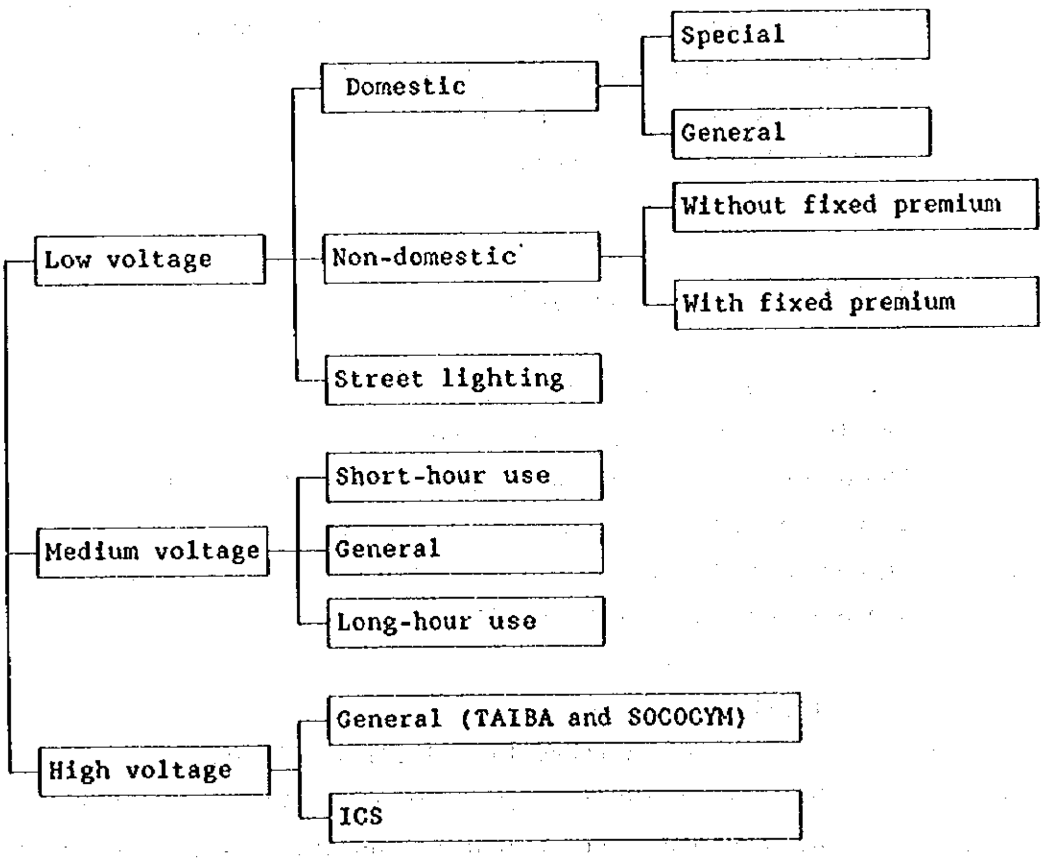


Fig. 11.1 Tariff Structure

Tariff level

Tariff rates were revised twice in recent years (see Table 11.1). The revision made in 1991, by which only energy charges were changed, was due basically to the sharp decline in the world oil price since 1986. The revision in January 1994 reflected the change in the fixed exchange rate against the French Franc (FF) which was put into effect in that month, and in which the local currency of FCFA lost half of its value.

The tariffs for low voltage customers are characterized basically by declining three blocks with or without fixed demand charges, and those for medium and high voltage ones by separate peak and off-peak energy charges with fixed demand charges. The majority of households pay about 115 FCFA/kWh for the first 20 kWh of the consumption of the month, 83 FCFA/kWh up to 49 kWh, and 59 FCFA/kWh for the consumption over 49 kWh.

As mentioned earlier, current tariff rates are based on the long-run marginal cost pricing. Although SENELEC updates a medium-term (5-year) system expansion plan every year, peak demand charges of the present tariffs are determined not by the discounted, estimated capital costs (of that plan) in relation to the discounted, projected peak demand increments, but simply by the annuitized, per-kilowatt investment cost of a 21MW gas turbine. This practice, according to SENELEC, is attributable to an assumption that the peak demand will continuously not be met in the immediate future. In computing the annuitized cost, SENELEC assumes a discount factor of 10% and a life expectancy of 20 years.[9]

9. SENELEC calculates the annuitized generation capacity cost including O&M at 54,700 FCFA/kW/year in 1995 price.

## Table 11.1 Changes in Electricity Tariff Rates in Recent Years

| Tariff category | January 1994-Present | | | | July 1991-January 1994 | | | | July 1989-July 1991 | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Fixed premium (per KW, monthly) | Energy price (per KWh) | | | Fixed premium (per KW, monthly) | Energy price (per KWh) | | | Fixed premium (per KW, monthly) | Energy price (per KWh) | | |
| | | 1st step | 2nd step | 3rd step | | 1st step | 2nd step | 3rd step | | 1st step | 2nd step | 3rd step |
| A. Low Voltage (LV) - 220 and 380 V | | | | | | | | | | | | |
| a. Domestic | | | | | | | | | | | | |
| (1) Special [1] | - | 91.15 | 101.73 | 59.19 | - | 72.92 | 81.38 | 47.35 | - | 81.02 | 80.68 | 51.19 |
| (2) General [2] | - | 114.84 | 83.13 | 59.19 | - | 91.87 | 66.50 | 47.35 | - | 101.27 | 67.17 | 51.19 |
| b. Non-domestic [3] | | | | | | | | | | | | |
| (1) Without fixed premium [4] | - | 119.49 | 107.18 | 73.09 | - | 95.59 | 85.74 | 58.47 | - | 97.16 | 87.10 | 59.97 |
| (2) With fixed premium [5] | 1,768.75 | 80.95 | 73.09 | - | 1,415 | 64.76 | 58.47 | - | 1,415 | 67.43 | 59.97 | - |
| c. Street lighting (municipalities) | 2,048.75 | 82.56 | - | - | 1,639 | 66.13 | - | - | 1,639 | 68.02 | - | - |
| | | Off-peak hours | Peak hours (7-11 pm) | | | Off-peak hours | Peak hours (7-11 pm) | | | Off-peak hours | Peak hours (7-11 pm) | |
| B. Medium Voltage (MV) - 5.5, 6.6, and 30 kV | | | | | | | | | | | | |
| a. Short-hour use (less than 1,000 h, annually) | 594.36 | 77.64 | 112.04 | | 468 | 61.13 | 88.22 | | 468 | 64.07 | 92.47 | |
| b. General (1,000 h - 4,000 h) | 2,529.84 | 55.88 | 80.63 | | 1,992 | 44.00 | 63.49 | | 1,992 | 46.82 | 67.55 | |
| c. Long-hour use (more than 4,000 h) | 6,106.16 | 45.89 | 66.24 | | 4,808 | 36.13 | 52.16 | | 4,808 | 39.02 | 56.28 | |
| C. High Voltage (HV) - 90 KV | | | | | | | | | | | | |
| a. General [6] | 6,197.85 | 36.48 | 46.55 | | 4,591 | 27.02 | 34.48 | | 4,591 | 29.89 | 35.58 | |
| b. ICS [7] | 2,755.35 | 48.57 | 58.19 | | 2,041 | 35.98 | 43.18 | | 2,041 | 37.05 | 44.09 | |
| Rates of taxes charged to customers | | | | | | | | | | | | |
| National tax | 10% | | | | 7% | | | | 7% | | | |
| Municipal tax | 2.5% | | | | 2.5% | | | | 2.5% | | | |

Note:
1 For customers requiring less than 20 KWh a month.
1st step: 0 - 20 KWH
2nd step: 21 - 44 KWh
3rd step: Above 44 KWh
2 1st step: 0 - 20 KWh
2nd step: 21 - 49 KWh
3rd step: Above 49 KWh
3 For commercial and industrial establishments with small operations as well as small public facilities.
4 For customers with a power requirement of less than 32 KW.
1st step: 0 - 30 h/month
2nd step: 31 - 100 h/month
3rd step: Above 100 h/month
5 1st step: 0 - 70 h/month
2nd step: Above 70 h/month
6 There are two customers in the category, including
(1) TAIBA - a phosphate plant with a contract load of 20 MW.
(2) SOCOCYM - a cement plant with a contract load of 12 MW.
Approximately 16-18% of their electricity consumption is made during the peak hours.
7 ICS (Senegal Chemical Industry) has a captive capacity of 3.5 MW.
Under an agreement with SENELEC, ICS purchases electricity from SENELEC, if necessary, and sells excess electricity to SENELEC.
Approximately 16% of the ICS's purchase of electricity occurs during the peak hours.

Source: SENELEC.

The marginal cost for the generation capacity is distributed to both peak and off-peak hour uses on the basis of loss of load probabilities (i.e., probabilities of the system's failing to meet power requirements during peak and off-peak hours). Customers at each voltage level are charged with only upstream costs for the transmission and distribution capacity. The coincidence factor (i.e., the probability of the power use during the system's peak hours) of each voltage level is estimated at 100 percent for HV and 75% for both MV and LV.

The energy charges of peak and off peak hours are determined first by computing the marginal energy costs of different hours (a day is divided into 7 different hours or time zones), and then by computing the average of the marginal costs of peak hours and that of the marginal costs of off peak hours.[10] Peak hours are from 7 pm to 11 pm. It is estimated that the peak-hour energy use among different consumer categories varies in a narrow range of 14-18 percent of the total energy use. The corresponding figures for the domestic consumers are 23%, 26% and 51% for the first, the second and the third steps, respectively.[11] The system loss was 23.5 percent in 1944 (see Figure 11.2). In determining actual peak demand and energy charges, various adjustments were made in strict marginal costs, with socio-economic considerations.

| | Generation --> | High voltage --> | Medium voltage --> | Low voltage |
|---|---|---|---|---|
| Loss factor (Cumulative) | 6% | 1.5% (7.5%) | 6% (13.5%) | 10% (13.5%) |

Figure 11.2 System Loss (1994)

The taxes collected on the sale of electricity are important revenue sources for both central and municipal governments. The value added tax rate is 10 percent, and the municipal tax rate 2.5 percent. The latter tax is not applicable to street lighting, for which municipalities are responsible.

10. Current marginal energy costs are approximated at; (1 barrel of crude oil = US$18, 1US$ = 528 FCPA)
peak hours: 44.26 FCPA/kWh
off-peak hours: 23.74 FCPA/kWh
The above figures correspond to the figures originally given by SENELEC, which were based on the exchange rate of US$1 to 300 FCPA—25.15 FCPA/kWh for peak hours and 13.49 FCPA/kWh for off peak hours.

11. These estimates as well as the coincidence factors referred to earlier are derived from a study which was carried out in 1985. We expect that no significant changes in them have occurred.

Expenditure on electricity in relation to the net household income

The household electrification rate remains low in spite of the fact that no fixed monthly demand charges are asked, and that the initial payment (in the form of deposit) required is kept lower than the actual hook-up cost. It is safe to say that current electricity bills are heavy for most households. No statistical data are available on the household income distribution or the medium household income. There are approximately 200,000 wage earners in the country, among whom, 66,000 are employed by the Government. It is reported that workers in the private sector are paid often twice as much as their counterparts in the public sector. Monthly salaries of high-ranking government officials are around 150,000 FCFA. The minimum wage is 183 FCFA an hour, which is equivalent to approximately 35,000 FCFA a month. Given a general tendency that the medium income is lower than the mean income, the medium household income is estimated at 50,000 - 60,000 FCFA a month, about 20 percent of which is deducted for income tax. We roughly estimate the average expenditure on electricity among medium income households at 6,500 FCFA a month, based on an estimated 90 kWh of monthly consumption per household. Based on these approximations, the ratio of the expenditure on electricity to the net income is calculated around 15% for medium income households.

Average tariff rate

The average sales price per kWh of energy sold was 69.9 FCFA in 1994, as shown in Table 11.2. (See also Appendix 11.1 for original data on sales record.) Considerable changes in the per-kWh revenue are observed for 1991 and 1994, when tariff rates were revised. Otherwise, the average per-kWh revenue would have fluctuated little. The figure of 69.9 FCFA/kWh includes both demand and energy charges, and does not include any taxes charged to customers on the sale.

As compared with the average tariff rate of 69.9 FCFA/kWh, the marginal cost of energy including the kWh-equivalent capacity cost can roughly be estimated as follows:

1. Capacity cost for generation including O&M: (see page 11-9)
   54,700 FCFA/kW/year

2. Assume the ratios of the capacity costs for generation, transmission, and distribution at: 60% : 10% : 30%

3. Then,
   (1) capacity cost for transmission : 9,117 FCFA/kW/year
   (2) capacity cost for distribution : 27,350 FCFA/kW/year

4. At an estimated load factor of 70% and a total system loss of 23.5% (including a station use of 6%, a transmission loss of 7.5%, and a distribution loss of 10%)*, the total marginal capacity cost is equivalent to : 18.34 FCFA/kWh[12]

5. Estimated marginal energy costs : (see page 11-11)
   (1) Peak hours : 44.26 FCFA/kWh
   (2) Off-peak hours : 23.74 FCFA/kWh

6. At an estimated ratio of the peak hour energy use to the off peak use of 20 to 80%, and a total system loss factor of 23.5%, the "average" marginal energy cost is : 36.39 FCFA/kWh

7. Thus, the total marginal cost at consumer-end is estimated at: 54.73 FCFA/kWh (=18.34+36.39)

   * Assume kW loss factors are equal to these kWh loss factors.

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12. ((54,700 ÷ (1-23.5%) + 9,117 ÷ (1-13.5%) + 27,350 ÷ (1-10%)) ÷ 8,7 60h ÷ 70% = 18.34

Table 11.2 Average Energy Consumption and Sales Revenue per Connection (1988 - 1994)
Dakar and Interconnected System

(MWh)

| Average energy consumption per connection | 1988 | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 |
|---|---|---|---|---|---|---|---|
| A. LV | 1.19 | 1.25 | 1.25 | 1.19 | 1.27 | 1.34 | 1.31 |
| Domestic | 1.05 | 1.09 | 1.07 | 1.06 | 1.07 | 1.15 | 1.12 |
| General | 1.24 | 1.29 | 1.25 | 1.24 | 1.24 | 1.29 | 1.22 |
| Special | 0.48 | 0.42 | 0.46 | 0.40 | 0.41 | 0.51 | 0.57 |
| Non-domestic | 1.76 | 1.78 | 1.82 | 1.62 | 1.91 | 1.90 | 1.85 |
| Street lighting | 74.80 | 109.61 | 116.36 | 62.82 | 123.81 | 120.77 | 122.46 |
| B. MV | 348.4 | 328.8 | 354.8 | 366.8 | 421.2 | 387.7 | 410.9 |
| C. HV | 56,254.0 | 53,969.7 | 53,044.3 | 53,251.3 | 62,036.3 | 53,216.7 | 53,303.7 |
| Total | 3.7 | 3.6 | 3.5 | 3.3 | 3.5 | 3.2 | 3.2 |

(CFAF/kWh)

| Average sales price, | 1988 | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 |
|---|---|---|---|---|---|---|---|
| A. LV | 70.2 | 70.3 | 75.6 | 69.0 | 65.4 | 65.3 | 79.8 |
| Domestic | 65.2 | 65.5 | 72.1 | 64.5 | 60.6 | 60.0 | 72.8 |
| General | 64.8 | 65.0 | 72.2 | 63.5 | 60.2 | 59.5 | 72.5 |
| Special | 68.1 | 70.3 | 71.6 | 75.9 | 65.1 | 65.1 | 75.6 |
| Non-domestic | 84.6 | 84.2 | 84.6 | 82.2 | 78.7 | 78.6 | 98.9 |
| Street lighting | 79.6 | 75.2 | 79.2 | 75.6 | 65.5 | 77.3 | 86.9 |
| B. MV | 60.2 | 59.6 | 63.2 | 38.2 | 53.4 | 56.3 | 69.1 |
| C. HV | 40.6 | 41.0 | 42.6 | 41.3 | 37.8 | 38.7 | 51.1 |
| Total | 58.5 | 58.8 | 62.8 | 49.8 | 54.1 | 56.4 | 69.9 |

It is estimated, based on the data given by SENELEC, that the average sales price is higher than the marginal cost (to supply additional one kWh of energy) by 15.17 FCFA/kWh[13].

Power demand charges, which appear in Table 11.1 as fixed premium, are somewhat lower than the marginal capacity costs calculated above, even with the coincidence factors taken into account. This is particularly true for LV consumers, as the monthly marginal capacity cost at LV is estimated at 112,432 FCFA/kW. On the contrary, energy charges are grossly higher than the estimated marginal energy costs.

It appears that not only because the current tariffs are unlikely to be underpriced but also because they are felt to be high for most households, it is not easy for the Government to raise the current tariffs. In this study, we assume no increases in the tariff rates in the future.

### 11.2.2 Financial Position of SENELEC

As part of the assessment of the impact the Project on SENELEC in financial terms, we review the financial position of SENELEC in recent and forthcoming years. Appendixes 11.2.1 to 11.2.3 exhibit income statements, balance sheets, and funds flow statements of SENELEC, both actual and projected, for a period between 1988 and 1998.

Appendix 11.2.1 shows income statements. Until 1993, the total revenue increased at a slower rate than the total operating expenditures, and, as a result, the interest was not fully covered by the operating income in 1992 and 1993. The increase in the total revenue markedly surpassed that in the total expenses in 1994. Between 1994 and 1998, the total revenue is expected to grow only moderately at an average annual rate of 4.8% (or from 62 billion FCFA to 75 billion FCFA), as compared to 6.6% in the previous 6 years. At a projected yearly increase rate of 5.9% for the total operating expenses, the net operating income is expected to decrease slightly to 8.9 billion FCFA in 1998 from 9.4 billion FCFA in 1994. Because of the improvement in the non-operating income, which is currently negative, the net income before provision (special tax exemption) is expected to rise to some extent, from 1.9 billion

13. As discussed later in this report, customer costs, both recurrent and non-recurrent ones, are not specifically charged, and therefore they have to be covered by a part of the power demand and energy charges.

FCFA in 1994 to 3.4 billion FCFA in 1998. However, the net income after provision is expected to remain negative, since not only the interest but also the provision will rise significantly. The provision, which is a 5 % of gross fixed assets in operation, is designed to be reserved for future funding of capital projects.

Appendix 11.2.2 exhibits balance sheets. The total fixed assets increased at a rate of 7.6% a year during the intervening 6 years between 1988 and 1993. The corresponding rate during the subsequent 4 years is projected at 7.3%. The total current assets decreased slightly from 29.5 billion FCFA in 1988 to 28.7 billion FCFA in 1993, and is expected to remain at a similar level until 1998. The total assets are projected at 204.5 billion FCFA in 1998, as compared to 182.3 billion FCFA in 1994. During the next 5 years from 1994, the total equity is expected to increase only by 18 billion FCFA, as compared to the increase in the total long-term debt of nearly 40 billion FCFA. During the last 6 years until 1994, the total equity decreased from 56 billion FCFA to 51 billion FCFA, whereas the long-term debt increased by 14 billion FCFA from 31 billion FCFA to 45 billion FCFA. The total current liabilities is expected to remain around 20 billion FCFA in 1998, as compared to 27 billion FCFA in 1993, and 24 billion FCFA in 1988.

The current ratio (i.e., a ratio of current assets to current liabilities), which is a liquidity measure, has been low, in a range of 1.1 to 1.4; and the ratio is expected to remain at the same level in the near future. It is also important to note that about a half of the total current assets is receivables which includes possible losses on customer accounts. Current assets may need to be increased. SENELEC does not anticipate any direct subsidy from the Government of Senegal (GOS) in the near future. The debt-equity ratio (i.e., the total debt divided by the total equity) is expected to rise by more than 20 points from 68% in 1994 to 91% in 1998.

Appendix 11.2.3 shows funds flow statements. The net internal cash generation (NICG) will continue to be far short of meeting capital requirements. The difference will be financed entirely by long-term borrowings. The capital requirements during the 4 years from 1994 to 1998 is projected at around 100 billion FCFA in total, as compared to 40 billion FCFA during the preceding 4 years. (A cumulative inflation of 27.3% is projected between 1995 and 1998.)

It is anticipated that the debt service coverage ratio (i.e., the ratio of cash generation to debt service), which fell below one in 1993, will recover to 2.0 in the near future.

The average net internal cash generation (the average NICG) is a value obtained by dividing the capital expenditure of a year concerned by the average of the NICGs of three years including that year and years before and after. This value indicates the self-financing ability for capital investments. In the past, the average NICG often fluctuated significantly and was generally low (e.g., 4% in 1992 and 19% in 1994). In the future, the NICG is expected to cover about a half of capital needs in the near future.

It is not likely that the SENELEC's financial position will be improved much in the foreseeable future. As discussed earlier, tariffs, which are determined on the basis of long-run marginal cost pricing, are felt high for most customers. It is not reasonable to assume that current tariffs can be raised substantially in the near future. On the other hand, SENELEC needs urgently to expand or improve its facilities to cope with increasing demand for electricity. To improve its financial position, SENELEC may need to improve the operation efficiency.

### 11.2.3 FIRR Analysis

After calculating the Project's benefits and costs, the FIRR of the Project will be computed and then tested for sensitivity. The FIRR of the equity invested in the Project will also be computed under assumed financing scenarios.

#### (1) Financial Benefits

Financial benefits are realized through the increase of electricity charges to be billed and the operating costs saved, and can be measured, respectively by applying tariffs to incremental electricity sold and assessing the difference in the operating costs between the "with Project" case and the "without Project" case. A reduction of the number of outages and the replacement of deteriorating equipment by new one, which Components 2 and 3 are concerned with, will certainly reduce the maintenance and labor costs. However, because of the lack of data available regarding the O&M costs for distribution capacity, this benefit can not be measured. The benefit is minor, compared to another benefit, namely, the benefit expected from the reduction of sales loss.

Financial benefits of the individual components of the Project are identified as shown in Table 11.3. All the benefits are measured (or monetarized) by the existing tariffs and actual fuel costs. Assumptions concerning the quantification of the benefits are stated in the table.

Table 11.3 Project's Financial Benefits

| Component | Benefit | Measure of benefit |
|---|---|---|
| 1 | (Addition of 10 MW generation capacity) | |
| | Incremental sale of power and energy: net addition of supplies | Tariff (energy and demand charges) |
| | The plant utilization factor is expected at 75%. With an assumed load factor of 68% and the system loss of 21% including 3.5% for the station use, an additional 47.1 MWh of energy will be sold annually. | |
| | Cost saved: fuel savings | |
| | The fuel cost of the least efficient generation units is approximately 18.24 FCFA/kWh. The total energy produced for this purpose is approximately 6.1 MWh a year. | Difference of fuel costs |
| 2-(a) | (Replacement of circuit breakers) | |
| | Incremental sale of energy: reduction of unserved energy | Tariff (energy charge) |
| | Effect will be mostly on the 6.6 kV network, and outages which are attributable to the fault of equipment or the default of protection will be reduced by one-third. The energy loss due to the outages concerned totaled to 67,824 kWh in 1994 (see Table 11.4). About 20% of all the consumers will be benefited. | |
| 2-(b) | (Replacement of 6.6 kV overhead lines by underground cables and voltage boosting) | |
| | Incremental sale of energy: reduction of unserved energy by replacing deteriorating lines | Tariff (energy charge) |
| | The same as Component 2-(a). | |
| | Cost saved: voltage boosting | Fuel cost |
| | This component affects approximately 30 percent of the transmission grid. The transmission loss at medium voltage is expected to be reduced by 1.5% from the current level of 6%. Accordingly, the total generation requirements will decrease, hence reducing the total generation cost. | |

| Component | Benefit | Measure of benefit |
|---|---|---|
| 2-(c) | (Intensive rehabilitation of the LV network in some areas)<br><br><u>Incremental sale of power (capacity charge for distribution facilities)</u>:<br><br>This component covers the replacement of deteriorated distribution facilities in some areas, which otherwise would cause interruption of power supply at any time. The extent of the rehabilitation work required is so intensive that the component is regarded as a renewal of entire distribution facilities in the areas concerned. In the first year, approximately 1,500 households and 75 street lightings, and in the second year 2,500 households and 125 street lightings will be benefited. For the third year and thereafter, the number of household customers in the areas concerned is projected to increase by 5% annually whereas no increases are expected in the number of street lightings. Without the Project, none of the new customers would be satisfied with their power demand either. The average power demand by household, and that by street lighting in 1994 were estimated at 300 W and 40 W, respectively. The annual average demand increase is projected at 3% for households and 0% for street lightings. | <br><br>Tariff (demand charge-portion for distribution facilities) |
| 3 | (Expansion of the existing distribution network)<br><br><u>Incremental sale of power (capacity charge for distribution facilities)</u>:<br><br>Customers newly connected will include 3,000 households and 150 street lightings for the first year, and 2,000 households and 100 street lightings for the second year. The same assumptions that are used for Component 2-(c) are applied for the annual percentage increases in the number of consumers and the power demand. | <br><br>Tariff (demand charge-portion for distribution facilities) |

Table 11.4 Outage and Unserved Energy Record (1992 - 1994)

| Cause of outage | 1992 | | | | | 1993 | | | | | 1994 | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Number of outage | | Unserved energy kWh | | Average unserved energy/outage (kWh) | Number of outage | | Unserved energy kWh | | Average unserved energy/outage (kWh) | Number of outage | | Unserved energy kWh | | Average unserved energy/outage (kWh) |
| 30 kV Network | | | | | | | | | | | | | | | |
| 1. Fault of equipment | 39 | 13% | 113,243 | 34% | 2,904 | 42 | 7% | 137,545 | 36% | 3,275 | 60 | 11% | 62,394 | 25% | 1,040 |
| 2. Default of protection | 37 | 13% | 25,232 | 8% | 682 | 52 | 9% | 30,821 | 8% | 593 | 91 | 17% | 27,311 | 11% | 300 |
| Sub-total | 76 | 26% | 138,475 | 42% | 1,822 | 94 | 17% | 168,366 | 44% | 1,791 | 151 | 28% | 89,705 | 36% | 594 |
| 3. Other | 217 | 74% | 190,824 | 58% | 879 | 470 | 83% | 217,546 | 56% | 463 | 394 | 72% | 160,565 | 64% | 408 |
| Total | 293 | 100% | 329,299 | 100% | 1,124 | 564 | 100% | 385,912 | 100% | 684 | 545 | 100% | 250,270 | 100% | 459 |
| 6.6 kV Network | | | | | | | | | | | | | | | |
| 1. Fault of equipment | 30 | 9% | 21,542 | 19% | 718 | 35 | 8% | 35,183 | 21% | 1,005 | 61 | 16% | 60,553 | 38% | 993 |
| 2. Default of protection | 21 | 7% | 11,572 | 10% | 551 | 33 | 8% | 29,788 | 17% | 903 | 41 | 11% | 7,271 | 5% | 177 |
| Sub-total | 51 | 16% | 33,114 | 29% | 649 | 68 | 16% | 64,971 | 38% | 955 | 102 | 27% | 67,824 | 42% | 665 |
| 3. Other | 267 | 84% | 82,441 | 71% | 309 | 354 | 84% | 106,002 | 62% | 299 | 278 | 73% | 92,430 | 58% | 332 |
| Total | 318 | 100% | 115,555 | 100% | 363 | 422 | 100% | 170,973 | 100% | 405 | 380 | 100% | 160,254 | 100% | 422 |

(2) Financial Costs

The Project's costs consist of capital costs, and operating costs or operation and maintenance (O & M) costs. O&M costs are classified into two categories, namely, fixed O&M costs and variable O&M costs, the latter of which include, in this study, fuel oil (heavy oil) and lubricating oil. Viewed from a different angle, the Project's costs include capacity costs for generation and energy costs (Component 1), as well as capacity costs for distribution (Components 2 and 3). (See Figure 11.3.)

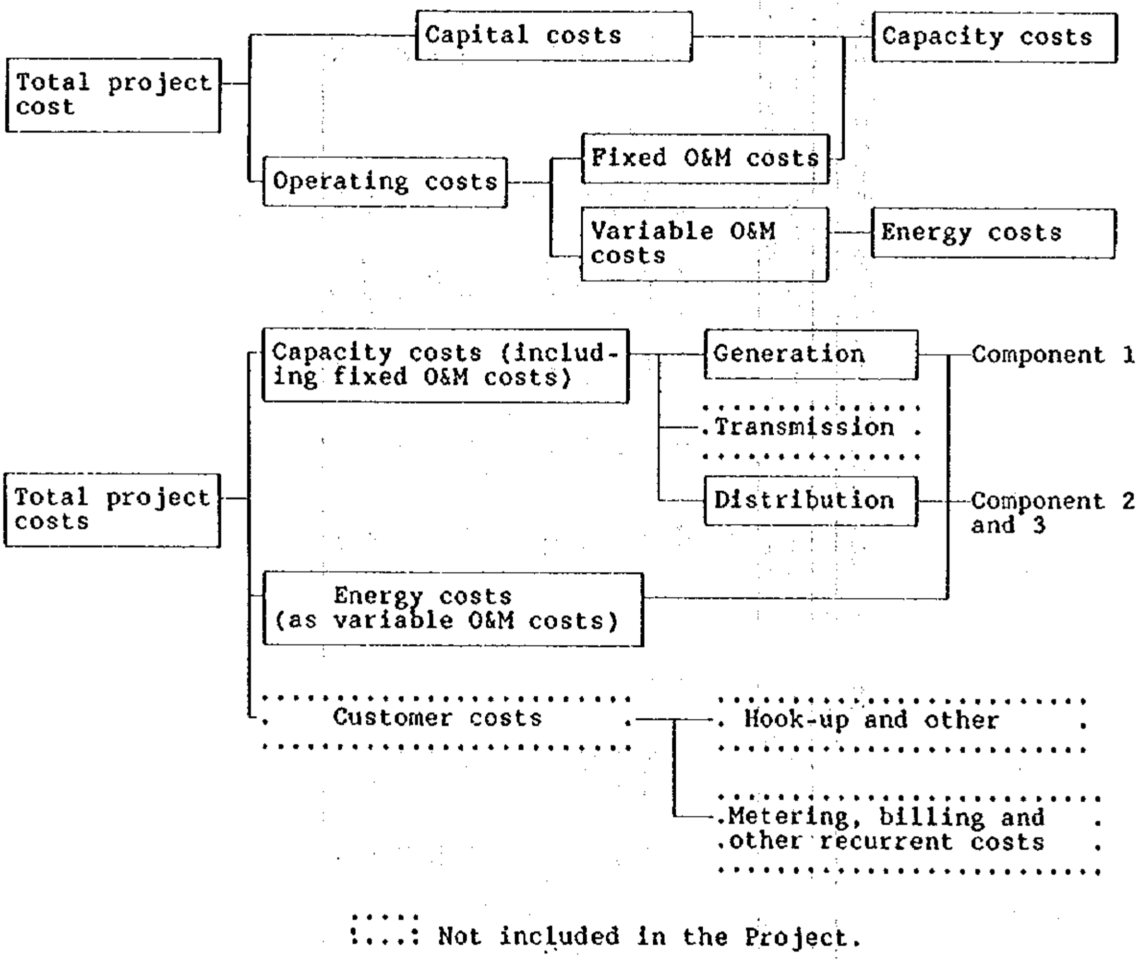


Fig. 11.3 Cost Classification

Capacity costs

Capacity costs include capital costs and (annual) fixed O&M costs. The capital costs required for each component of the Project are exhibited in a table in the preceding chapter. Based on the SENELEC's operating costs record and our data, the following percentages to the total costs of equipment and installation are assumed for the annual fixed O&M costs of 5 MW generation units (Component 1) and those of distribution facilities (Components 2-(c) and 3).

Annual fixed O&M costs of 5 MW generation units : 3%
Annual fixed O&M costs of distribution facilities : 2%

It must be noted that Components 2-(a) and 2-(b) do not require any incremental fixed O&M costs, as no incremental capacity charges (power demand charges) are included in the benefits of those components. The costs of individual components are exhibited in Table 11.5.

Table 11.5 Project's Costs

| Component | Cost |
|---|---|
| 1 | Capital costs<br>Fixed O&M costs<br>Energy costs (as variable O&M costs) |
| 2-(a) | Capital costs |
| 2-(b) | Capital costs |
| 2-(c) | Capital costs<br>Fixed O&M costs |
| 3 | Capital costs<br>Fixed O&M costs |

Energy costs

Since February, 1995, SENELEC has been authorized to procure fuel oil from the international market by itself. Formerly, a refinery company named SAR, which is owned jointly by the GOS and private firms, was exclusively entrusted with the import of all the oil needed in the country. Table 11.6 shows the costs of diesel oil and heavy oil to SENELEC since January 23, 1994, when the local currency of FCFA was devaluated to half against the FF from 50 FCFA to 1 FF to 100 FCFA to 1 FF[14]. SENELEC is exempted from import duties and VAT.

14. The calorific value (net specific energy) of the fuel oil currently supplied to SENELEC is as follows:
Heavy oil 9,567 kcal/kg
Diesel oil 10,249 kcal/kg

Table 11.6 Fuel Costs (revised on January 23, 1994)

(FCFA/ton)

| | Description | Diesel | Heavy oil |
|---|---|---|---|
| 1. | Crude oil and SAR's charges | 113,068 | 51,900 |
| 2. | Port storage and handling charges | 28,267 | 12,975 |
| 3. | Tax base for import duty (1+2) | 141,335 | 64,875 |
| 4. | Import duty (3x20%) | 28,267 | 12,975 |
| 5. | State subsidy to SENELEC (as a non-transfer payment) | -28,999 | -17,420 |
| 6. | SENELEC's cost (3+5) | 112,336 | 47,455 |
| 7. | SENELEC's cost if import duty included (4+6) | 140,603 | 60,430 |
| 8. | Distributor's charges | 19,047 | 4,547 |
| 9. | (of which transportation cost) | 1,797 | 1,797 |
| 10. | Tax base for VAT (6+8) | 131,383 | 52,002 |
| 11. | VAT (10x20%) | 26,277 | 10,400 |
| 12. | Total cost to SENELEC (6+8) | 131,383 | 52,002 |

Source: SENELEC.

The change in the oil procurement system is not expected to bring down the oil prices for SENELEC substantially.[15] It is reported that the fees to procure oil from the international market charged by a new agent (supplier) would not be much different from what SENELEC pays to SAR, if the state subsidy is taken into account. We assume that the SENELEC's oil purchasing prices will not change in the future.

The variable O&M costs for Component 1, which cover the fuel oil and the lubricating oil costs, are computed as follows:

15. It is reported that the oil (particularly heavy oil) provided by SAR is low in quality. The low-quality oil is affecting the fixed O&M costs for generation facilities. SENELEC expects that the change in the source of oil will reduce those costs, expand the economic life of generation units, and lower the frequency of outage.

1. Fuel cost (Heavy oil)

1 kW = 1,000 joule/second

1 kcal = 4,185.5 joule

1 kWh = 1,000 x 60 x 60 = 3,600,000 joule

$$\frac{3,600,000}{4,481.5} = 860.11 \text{kcal/kWh}$$

Thermal efficiency = 34%

$$\text{Heat rate} = \frac{860.11 \text{kcal/kWh}}{34\%} = 2,529.74 \text{kcal/kWh}$$

Heavy oil price = 52,002 FCFA/ton

Heat content = 9,557 kcal/kg

$$\text{Fuel consumption rate} = \frac{\text{Heat rate}}{\text{Heat content}} = \frac{2,529.74}{9,557} = 0.2647 \text{kg/kWh}$$

Fuel cost = Heavy oil price x Fuel consumption rate

= 52.002 x 0.2647

= 13.765 FCFA/kWh

2. Lubricating oil cost

Lubricating oil price = 418.037 FCFA/kg

Lubricating oil consumption rate = 1.50g/kWh

Lubricating oil cost = Lubricating oil price x Lubricating oil consumption rate

= 418.037÷1,000x1.5 = 0.627 FCFA/kWh

3. Total variable costs = 14.392 FCFA/kWh

Consumer costs

Consumer costs are those directly attributable to consumers including the initial hook-up cost as non-recurrent cost and metering and billing as recurrent cost. A typical household is asked to deposit about 20,000 FCFA at the time of connection. This amount does not cover the actual cost to hook-up to the system.[16] The deposit required is kept low to encourage people to hook up.

16. Metering hardware is rented to consumers from SENELEC.

The Project will result in increases in the number of customers and thus consumer costs. In this study, we assume that all the consumer costs, both recurrent and non-recurrent ones, are fully recovered by the initial deposit and part of monthly fixed charges to customers, and thus that no specific considerations are made to consumer costs in computing the Project's costs.

(3) FIRR of the Project

Table 11.7 exhibits annual cost and benefit streams expressed in constant prices at the beginning of 1995. In the capital costs, no price contingencies, or interest during the implementation period are included. Also, no considerations are made regarding financing costs, working capital requirements, or taxes during the project life, which, similar to inflation, could distort the underlying viability of the Project and make it difficult to compare the attractiveness of the Project with that of other urgent projects. The FIRR of the Project is computed at 14.2%, whereas the FIRR of Component 1 alone is calculated at 19.8%. A project is acceptable, if its FIRR equals or exceeds the opportunity cost of capital (i.e., discount rate), which is a common criterion for assessing a project. At an assumed discount rate of 12%, the Project is considered to be financially feasible.

# Table 11.7 FIRR of the Project

Thousand FCFA

| Project year | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Calendar year | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | Total |
| **I. Component 1 Addition of generation capacity** | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 1 Total installed capacity (MW) | | | | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | | | | | | |
| 2 Total operation hours | | | | 6,570 | 6,570 | 6,570 | 6,570 | 6,570 | 6,570 | 6,570 | 6,570 | 6,570 | 6,570 | 6,570 | 6,570 | 6,570 | 6,570 | 6,570 | 6,570 | 6,570 | 6,570 | 6,570 | 6,570 | | | | | | |
| 3 Energy generated (MWh) | | | | 65,700 | 65,700 | 65,700 | 65,700 | 65,700 | 65,700 | 65,700 | 65,700 | 65,700 | 65,700 | 65,700 | 65,700 | 65,700 | 65,700 | 65,700 | 65,700 | 65,700 | 65,700 | 65,700 | 65,700 | | | | | | |
| 4 Energy sold (MWh) | | | | 51,903 | 51,903 | 51,903 | 51,903 | 51,903 | 51,903 | 51,903 | 51,903 | 51,903 | 51,903 | 51,903 | 51,903 | 51,903 | 51,903 | 51,903 | 51,903 | 51,903 | 51,903 | 51,903 | 51,903 | | | | | | |
| A. Revenue | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 1 Sale of energy and power | | | | 3,289,405 | 3,289,405 | 3,289,405 | 3,289,405 | 3,289,405 | 3,289,405 | 3,289,405 | 3,289,405 | 3,289,405 | 3,289,405 | 3,289,405 | 3,289,405 | 3,289,405 | 3,289,405 | 3,289,405 | 3,289,405 | 3,289,405 | 3,289,405 | 3,289,405 | 3,289,405 | | | | | | 65,788,091 |
| 2 Fuel savings | | | | 29,308 | 29,308 | 29,308 | 29,308 | 29,308 | 29,308 | 29,308 | 29,308 | 29,308 | 29,308 | 29,308 | 29,308 | 29,308 | 29,308 | 29,308 | 29,308 | 29,308 | 29,308 | 29,308 | 29,308 | | | | | | 586,158 |
| Total | | | | 3,318,712 | 3,318,712 | 3,318,712 | 3,318,712 | 3,318,712 | 3,318,712 | 3,318,712 | 3,318,712 | 3,318,712 | 3,318,712 | 3,318,712 | 3,318,712 | 3,318,712 | 3,318,712 | 3,318,712 | 3,318,712 | 3,318,712 | 3,318,712 | 3,318,712 | 3,318,712 | | | | | | 66,374,248 |
| B. Cost | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 1 Capital cost | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Foreign | | | 10,186,170 | | | | | | | | | | | | | | | | | | | | | | | | | | 10,186,170 |
| Local | | | 279,351 | 279,351 | | | | | | | | | | | | | | | | | | | | | | | | | 558,702 |
| Sub-total | | | 10,465,521 | 279,351 | | | | | | | | | | | | | | | | | | | | | | | | | 10,744,871 |
| 2 Operating cost | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Fixed O & M | | | | 191,628 | 191,628 | 191,628 | 191,628 | 191,628 | 191,628 | 191,628 | 191,628 | 191,628 | 191,628 | 191,628 | 191,628 | 191,628 | 191,628 | 191,628 | 191,628 | 191,628 | 191,628 | 191,628 | 191,628 | | | | | | 3,832,560 |
| Variable O & M | | | | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | | | | | | 18,908,460 |
| Sub-total | | | 0 | 1,137,051 | 1,137,051 | 1,137,051 | 1,137,051 | 1,137,051 | 1,137,051 | 1,137,051 | 1,137,051 | 1,137,051 | 1,137,051 | 1,137,051 | 1,137,051 | 1,137,051 | 1,137,051 | 1,137,051 | 1,137,051 | 1,137,051 | 1,137,051 | 1,137,051 | 1,137,051 | | | | | | 22,741,020 |
| Total | | | 10,465,521 | 1,416,402 | 1,137,051 | 1,137,051 | 1,137,051 | 1,137,051 | 1,137,051 | 1,137,051 | 1,137,051 | 1,137,051 | 1,137,051 | 1,137,051 | 1,137,051 | 1,137,051 | 1,137,051 | 1,137,051 | 1,137,051 | 1,137,051 | 1,137,051 | 1,137,051 | 1,137,051 | | | | | | 33,485,891 |
| C. Net benefit (A - B) | | | -10,465,521 | 1,902,311 | 2,181,661 | 2,181,661 | 2,181,661 | 2,181,661 | 2,181,661 | 2,181,661 | 2,181,661 | 2,181,661 | 2,181,661 | 2,181,661 | 2,181,661 | 2,181,661 | 2,181,661 | 2,181,661 | 2,181,661 | 2,181,661 | 2,181,661 | 2,181,661 | 2,181,661 | | | | | | 32,888,357 |
| D. FIRR | 19.8% | | | | | | | | | | | | | | | | | | | | | | | | | | | | |

Assumptions:

1 Plant utilization factor: 75% including 68% for net addition of supplies, and 11% for the fuel saving of 3.85 FCFA/kWh

2 System loss (including station use): 31.0%

3 Tariff (demand and energy charges): 69.9 FCFA/kWh

4 Annual fixed O & M: 3% of the equipment&installation costs of 6,387,600 thousand FCFA

5 Variable O & M (fuel and lubrl. oil): 14.39 FCFA/kWh

6 Economic life: 20 years

| | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **II. Component 2-(a) Replacement of circuit breakers** | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 1 Reduced loss of energy (kWh) | 4,522 | 4,748 | 4,985 | 5,234 | 5,496 | 5,771 | 6,059 | 6,362 | 6,680 | 7,014 | 7,365 | 7,733 | 8,120 | 8,526 | 8,952 | 9,400 | 9,870 | 10,364 | 10,883 | 11,426 | 11,997 | 12,597 | 13,227 | 13,888 | 14,583 | 15,312 | 16,077 | 16,881 | 259,552 |
| A. Revenue | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Sale of energy | | | | 366 | 384 | 403 | 424 | 445 | 467 | 490 | 515 | 541 | 568 | 596 | 626 | 657 | 690 | 724 | 761 | 799 | 839 | 881 | 935 | 971 | 1,019 | 1,070 | 1,124 | 1,180 | 17,462 |
| B. Cost | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Capital cost | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Foreign | | | 173,910 | | | | | | | | | | | | | | | | | | | | | | | | | | 173,910 |
| Local | | | 7,400 | 7,400 | | | | | | | | | | | | | | | | | | | | | | | | | 14,801 |
| Sub-total | | | 181,310 | 7,400 | | | | | | | | | | | | | | | | | | | | | | | | | 188,710 |
| C. Net benefit (A - B) | | | -181,310 | -7,035 | 384 | 403 | 424 | 445 | 467 | 490 | 515 | 541 | 568 | 596 | 626 | 657 | 690 | 724 | 761 | 799 | 839 | 881 | 935 | 971 | 1,019 | 1,070 | 1,124 | 1,180 | -171,248 |

Assumptions:

1 % of consumers benefited: 20%

2 % of outages avoided which are attributable to the fault of equipment or the default of protection: 33% (=1/3)

3 % increase of average annual energy consumption: 5%

4 Economic life: 25 years

Note:

1 Effect will be mostly on the 6.6 kV network.

2 Energy loss due to the outages concerned amounted to 67,824 kWh in 1994.

Thousand FCFA

III. Component 2-(b) Replacement of 6.6 kV overhead lines by underground cables, and voltage boosting of some feeders from 6.6 kV to 30 kV

| Project year / Calendar year | 1994 | 1995 | 1 / 1996 | 2 / 1997 | 3 / 1998 | 4 / 1999 | 5 / 2000 | 6 / 2001 | 7 / 2002 | 8 / 2003 | 9 / 2004 | 10 / 2005 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 Reduced loss of energy (kWh) (due to the outage reduction) | 4,522 | 4,748 | 4,985 | 5,234 | 5,496 | 5,771 | 6,059 | 6,362 | 6,680 | 7,014 | 7,365 | 7,733 |
| 2 Reduction of generation requirements (due to the voltage boosting for some feeders) | | | | | | | | | | | | |
| a. Total generation requirements without Project (GWh | 980 | 1,024 | 1,070 | 1,118 | 1,169 | 1,221 | 1,276 | 1,334 | 1,394 | 1,456 | 1,522 | 1,590 |
| b. Reduction of generation requirements (MWh) | | | | 5,033 | 5,359 | 5,496 | 5,743 | 6,001 | 6,271 | 6,554 | 6,849 | 7,157 |
| A. Revenue | | | | | | | | | | | | |
| 1 Sale of energy | | | | 366 | 384 | 403 | 424 | 445 | 467 | 490 | 515 | 541 |
| 2 Reduction of total generation cost | | | | 75,488 | 78,885 | 82,435 | 86,145 | 90,021 | 94,072 | 98,305 | 102,729 | 107,352 |
| Sub-total | | | | 75,854 | 79,269 | 82,838 | 86,568 | 90,466 | 94,539 | 98,796 | 103,244 | 107,892 |
| B. Cost | | | | | | | | | | | | |
| Capital cost | | | | | | | | | | | | |
| Foreign | | | 1,826,621 | | | | | | | | | |
| Local | | | 145,215 | 145,215 | | | | | | | | |
| Sub-total | | | 1,971,835 | 145,215 | | | | | | | | |
| C. Net benefit (A - B) | | | -1,971,835 | -69,361 | 79,269 | 82,838 | 86,568 | 90,466 | 94,539 | 98,796 | 103,244 | 107,892 |

| Project year / Calendar year | 11 / 2006 | 12 / 2007 | 13 / 2008 | 14 / 2009 | 15 / 2010 | 16 / 2011 | 17 / 2012 | 18 / 2013 | 19 / 2014 | 20 / 2015 | 21 / 2016 | 22 / 2017 | 23 / 2018 | 24 / 2019 | 25 / 2020 | 26 / 2021 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 Reduced loss of energy (kWh) (due to the outage reduction) | 8,120 | 8,526 | 8,952 | 9,400 | 9,870 | 10,364 | 10,882 | 11,426 | 11,997 | 12,597 | 13,227 | 13,888 | 14,583 | 15,312 | 16,077 | 16,881 | 259,552 |
| 2 Reduction of generation requirements (due to the voltage boosting for some feeders) | | | | | | | | | | | | | | | | | |
| a. Total generation requirements without Project (GWh | 1,662 | 1,737 | 1,815 | 1,897 | 1,982 | 2,071 | 2,164 | 2,262 | 2,363 | 2,470 | 2,581 | 2,697 | 2,818 | 2,945 | 3,078 | 3,216 | |
| b. Reduction of generation requirements (MWh) | 7,479 | 7,815 | 8,167 | 8,535 | 8,919 | 9,320 | 9,739 | 10,178 | 10,636 | 11,114 | 11,614 | 12,137 | 12,683 | 13,254 | 13,850 | 14,474 | 224,276 |
| A. Revenue | | | | | | | | | | | | | | | | | |
| 1 Sale of energy | 558 | 596 | 626 | 657 | 690 | 724 | 761 | 799 | 839 | 881 | 925 | 971 | 1,019 | 1,070 | 1,124 | 1,180 | 17,462 |
| 2 Reduction of total generation cost | 112,183 | 117,231 | 122,506 | 128,019 | 133,780 | 139,800 | 146,091 | 152,665 | 159,535 | 166,714 | 174,216 | 182,056 | 190,248 | 198,809 | 207,756 | 217,105 | 3,364,145 |
| Sub-total | 112,750 | 117,827 | 123,132 | 128,676 | 134,470 | 140,524 | 146,852 | 153,464 | 160,373 | 167,594 | 175,141 | 183,037 | 191,268 | 199,850 | 208,880 | 218,285 | 3,381,607 |
| B. Cost | | | | | | | | | | | | | | | | | |
| Capital cost | | | | | | | | | | | | | | | | | |
| Foreign | | | | | | | | | | | | | | | | | 1,826,621 |
| Local | | | | | | | | | | | | | | | | | 290,429 |
| Sub-total | | | | | | | | | | | | | | | | | 2,117,050 |
| C. Net benefit (A - B) | 112,750 | 117,827 | 123,132 | 128,676 | 134,470 | 140,524 | 146,852 | 153,464 | 160,373 | 167,594 | 175,141 | 183,037 | 191,268 | 199,850 | 208,880 | 218,285 | 1,264,557 |

Assumptions:

a. Outage reduction

| | | |
|---|---|---|
| 1 Tariff (demand and energy charges) | 69.9 | FCFA/kWh |
| 2 % of consumers benefited | 20% | |
| 3 % of outages avoided which are attributable to the fault of equipment or the default of protection | 33% | (=1/3) |
| 4 % increase of average annual energy consumption | 5% | |
| 5 Economic life | 25 | years |

b. Reduction of generation requirements

| | | |
|---|---|---|
| 6 Average increase in generation requirements | 4.5% | a year |
| 7 % of the transmission grid affected | 30% | |
| 8 Transmission loss reduction | 1.5% | |
| 9 Average generation cost (fuel savings only) | 15 | FCFA/kWh |

IV. Component 2-(c) Intensive rehabilitation of LV Network

| Project year / Calendar year | 1994 | 1995 | 1 / 1996 | 2 / 1997 | 3 / 1998 | 4 / 1999 | 5 / 2000 | 6 / 2001 | 7 / 2002 | 8 / 2003 | 9 / 2004 | 10 / 2005 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 Domestic | | | | | | | | | | | | |
| (1) Number of connections benefited | | | | 1,500 | 2,500 | 2,625 | 2,756 | 2,894 | 3,039 | 3,191 | 3,350 | 3,518 |
| (2) Average power demand (kW) | 0.30 | 0.31 | 0.32 | 0.33 | 0.34 | 0.35 | 0.36 | 0.37 | 0.38 | 0.39 | 0.40 | 0.42 |
| (3) Total power demand (kW) | | | | 492 | 844 | 913 | 987 | 1,068 | 1,155 | 1,249 | 1,351 | 1,461 |
| 2 Street lighting | | | | | | | | | | | | |
| (1) Number of connections benefited | | | | 75 | 125 | 125 | 125 | 125 | 125 | 125 | 125 | 125 |
| (2) Average power demand (kW) | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 |
| (3) Total power demand (kW) | | | | 3 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| A. Revenue | | | | | | | | | | | | |
| Sale of power (capacity charge for distribution facilities) | | | | 15,034 | 25,804 | 27,895 | 30,156 | 32,601 | 35,246 | 38,106 | 41,199 | 44,545 |
| B. Cost | | | | | | | | | | | | |
| 1 Capital cost | | | | | | | | | | | | |
| Foreign | | | 446,280 | | | | | | | | | |
| Local | | | 39,490 | 39,490 | | | | | | | | |
| Sub-total | | | 485,771 | 39,490 | | | | | | | | |
| 2 O & M cost (fixed) | | | | 7,264 | 7,264 | 7,264 | 7,264 | 7,264 | 7,264 | 7,264 | 7,264 | 7,264 |
| Total | | | 485,771 | 46,755 | 7,264 | 7,264 | 7,264 | 7,264 | 7,264 | 7,264 | 7,264 | 7,264 |
| C. Net benefit (A - B) | | | -485,771 | -31,720 | 18,540 | 20,631 | 22,892 | 25,337 | 27,982 | 30,842 | 33,935 | 37,280 |

| Project year / Calendar year | 11 / 2006 | 12 / 2007 | 13 / 2008 | 14 / 2009 | 15 / 2010 | 16 / 2011 | 17 / 2012 | 18 / 2013 | 19 / 2014 | 20 / 2015 | 21 / 2016 | 22 / 2017 | 23 / 2018 | 24 / 2019 | 25 / 2020 | 26 / 2021 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 Domestic | | | | | | | | | | | | | | | | | |
| (1) Number of connections benefited | 3,694 | 3,878 | 4,072 | 4,276 | 4,490 | 4,714 | 4,950 | 5,197 | 5,457 | 5,730 | 6,017 | 6,317 | 6,633 | 6,965 | 7,313 | 7,679 | |
| (2) Average power demand (kW) | 0.43 | 0.44 | 0.45 | 0.47 | 0.48 | 0.50 | 0.51 | 0.53 | 0.54 | 0.56 | 0.57 | 0.59 | 0.61 | 0.63 | 0.65 | 0.67 | |
| (3) Total power demand (kW) | 1,580 | 1,709 | 1,848 | 1,998 | 2,161 | 2,338 | 2,528 | 2,734 | 2,957 | 3,198 | 3,458 | 3,740 | 4,045 | 4,375 | 4,731 | 5,117 | |
| 2 Street lighting | | | | | | | | | | | | | | | | | |
| (1) Number of connections benefited | 125 | 125 | 125 | 125 | 125 | 125 | 125 | 125 | 125 | 125 | 125 | 125 | 125 | 125 | 125 | 125 | |
| (2) Average power demand (kW) | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | |
| (3) Total power demand (kW) | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | |
| A. Revenue | | | | | | | | | | | | | | | | | |
| Sale of power (capacity charge for distribution facilities) | 48,163 | 52,075 | 56,307 | 60,884 | 65,833 | 71,187 | 76,976 | 83,237 | 90,008 | 97,332 | 105,252 | 113,818 | 123,081 | 133,100 | 143,935 | 155,654 | 1,767,427 |
| B. Cost | | | | | | | | | | | | | | | | | |
| 1 Capital cost | | | | | | | | | | | | | | | | | |
| Foreign | | | | | | | | | | | | | | | | | 446,280 |
| Local | | | | | | | | | | | | | | | | | 78,981 |
| Sub-total | | | | | | | | | | | | | | | | | 525,261 |
| 2 O & M cost (fixed) | 7,264 | 7,264 | 7,264 | 7,264 | 7,264 | 7,264 | 7,264 | 7,264 | 7,264 | 7,264 | 7,264 | 7,264 | 7,264 | 7,264 | 7,264 | 7,264 | 181,606 |
| Total | 7,264 | 7,264 | 7,264 | 7,264 | 7,264 | 7,264 | 7,264 | 7,264 | 7,264 | 7,264 | 7,264 | 7,264 | 7,264 | 7,264 | 7,264 | 7,264 | 706,867 |
| C. Net benefit (A - B) | 40,898 | 44,811 | 49,043 | 53,620 | 58,569 | 63,922 | 69,712 | 75,973 | 82,744 | 90,067 | 97,988 | 106,553 | 115,817 | 125,836 | 136,671 | 148,359 | 1,060,560 |

Assumptions:

| | | |
|---|---|---|
| 1 Annual increase in average power demand | | |
| (1) Domestic | 3% | |
| (2) Street lighting | 0% | |
| 2 Annual increase in the number of connections after 1999 | | |
| (1) Domestic | 5% | |
| (2) Street lighting | 0% | |
| 3 Annual capacity charge for distribution facilities | 30,389 | FCFA/kW/year |
| 4 Annual O & M cost | 2% | of the equipment&installation costs of 363,212 Thousand FCFA |
| 5 Economic life | 25 | years |

Thousand FCFA

| Project year | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Calendar year | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | Total |
| V. Component 3 Expansion of Distribution Network | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 1 Domestic | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| (1) Total number of connections | | | | 3,000 | 5,000 | 5,250 | 5,513 | 5,788 | 6,078 | 6,381 | 6,700 | 7,036 | 7,387 | 7,757 | 8,144 | 8,553 | 8,979 | 9,428 | 9,900 | 10,395 | 10,914 | 11,460 | 12,033 | 12,635 | 13,266 | 13,930 | 14,626 | 15,358 | |
| (2) Average power demand (kW) | 0.30 | 0.31 | 0.32 | 0.33 | 0.34 | 0.35 | 0.36 | 0.37 | 0.38 | 0.39 | 0.40 | 0.42 | 0.43 | 0.44 | 0.45 | 0.47 | 0.48 | 0.50 | 0.51 | 0.53 | 0.54 | 0.56 | 0.57 | 0.59 | 0.61 | 0.63 | 0.65 | 0.67 | |
| (3) Total power demand (kW) | | | | 983 | 1,688 | 1,826 | 1,975 | 2,136 | 2,310 | 2,498 | 2,701 | 2,922 | 3,160 | 3,417 | 3,696 | 3,997 | 4,333 | 4,675 | 5,056 | 5,468 | 5,914 | 6,396 | 6,917 | 7,481 | 8,090 | 8,750 | 9,463 | 10,234 | |
| 2 Street lighting | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| (1) Total number of connections | | | | 150 | 250 | 220 | 220 | 220 | 220 | 220 | 220 | 220 | 220 | 220 | 220 | 220 | 220 | 220 | 220 | 220 | 220 | 220 | 220 | 220 | 220 | 220 | 220 | 220 | |
| (2) Average power demand (kW) | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | |
| (3) Total power demand (kW) | | | | 6 | 10 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | |
| A. Revenue | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Sale of power (capacity charge for distribution facilities) | | | | 30,068 | 51,608 | 55,753 | 60,275 | 65,166 | 70,455 | 76,175 | 82,362 | 89,053 | 96,289 | 104,114 | 112,578 | 121,731 | 131,630 | 142,337 | 153,915 | 166,438 | 179,980 | 194,627 | 210,467 | 227,599 | 246,126 | 266,164 | 287,834 | 311,271 | 3,534,016 |
| B. Cost | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 1 Capital cost | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Foreign | | | 1,695,903 | | | | | | | | | | | | | | | | | | | | | | | | | | 1,695,903 |
| Local | | | 126,276 | 126,276 | | | | | | | | | | | | | | | | | | | | | | | | | 252,552 |
| Sub-total | | | 1,822,179 | 126,276 | | | | | | | | | | | | | | | | | | | | | | | | | 1,948,455 |
| 2 O & M cost (fixed) | | | | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 669,418 |
| Total | | | 1,822,179 | 153,053 | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 26,777 | 2,617,873 |
| C. Net benefit (A - B) | | | -1,822,179 | -122,984 | 24,832 | 28,976 | 33,499 | 38,389 | 43,678 | 49,399 | 55,585 | 62,276 | 69,512 | 77,338 | 85,801 | 94,954 | 104,854 | 115,560 | 127,138 | 139,661 | 153,204 | 167,850 | 183,691 | 200,822 | 219,349 | 239,387 | 261,057 | 284,494 | 916,143 |

Assumptions:

1 Annual increase in average power demand
- (1) Domestic: 3%
- (2) Street lighting: 0%

2 Annual increase in the number of connections after 1999
- (1) Domestic: 5%
- (2) Street lighting: 0%

2 Annual capacity charge for distribution facilities: 30,389 FCFA/kW/year

3 Annual O & M cost: 2% of the equipment&installation costs of 1,338,836 Thousand FCFA

4 Economic life: 25 years

| VI. Total Components | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A. Revenue | | | | 3,410,727 | 3,446,470 | 3,456,294 | 3,466,827 | 3,478,082 | 3,490,111 | 3,502,972 | 3,516,724 | 3,531,435 | 3,547,173 | 3,564,017 | 3,582,047 | 3,601,353 | 3,622,028 | 3,644,176 | 3,667,908 | 3,693,341 | 3,720,605 | 3,749,838 | 3,781,189 | 525,413 | 561,494 | 600,214 | 641,773 | 686,389 | 74,488,603 |
| B. Cost | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 1 Capital cost | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Foreign | | | 14,328,884 | 0 | | | | | | | | | | | | | | | | | | | | | | | | | 14,328,884 |
| Local | | | 597,732 | 597,732 | | | | | | | | | | | | | | | | | | | | | | | | | 1,195,464 |
| Sub-total | | | 14,926,616 | 597,732 | | | | | | | | | | | | | | | | | | | | | | | | | 15,524,347 |
| 2 Operating cost | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Fixed O & M | | | 0 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 34,041 | 34,041 | 34,041 | 34,041 | 34,041 | 4,683,584 |
| Variable O & M | | | 0 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 0 | 0 | 0 | 0 | 0 | 18,908,460 |
| Sub-total | | | 0 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 34,041 | 34,041 | 34,041 | 34,041 | 34,041 | 23,592,044 |
| Total | | | 14,926,616 | 1,768,824 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 34,041 | 34,041 | 34,041 | 34,041 | 34,041 | 39,116,391 |
| C. Net benefit (A - B) | | | -14,926,616 | 1,641,903 | 2,275,379 | 2,285,202 | 2,295,735 | 2,306,990 | 2,319,019 | 2,331,880 | 2,345,632 | 2,360,343 | 2,376,082 | 2,392,925 | 2,410,955 | 2,430,261 | 2,450,936 | 2,473,084 | 2,496,816 | 2,522,249 | 2,549,513 | 2,578,745 | 2,610,097 | 491,372 | 527,453 | 566,173 | 607,733 | 652,348 | 35,372,212 |
| D. FIRR | 14.3% | | | | | | | | | | | | | | | | | | | | | | | | | | | | |

(4) Sensitivity to the FIRR of the Project

The primary objective of the sensitivity analysis is to test how the profitability of an investment is affected by modifications in the assumptions used on key variables. This analysis essentially allows a judgement as to the riskiness of the project under alternative assumptions. We test the sensitivity to the FIRR of the Project obtained earlier.

Usually, in the sensitivity analysis, modifications are made for such variables that may significantly change the projected costs or benefits of the project and that involve high levels of uncertainty. In this study, we assume the following three scenarios with modified assumptions.

Scenario 1 10% increase in the initial capital costs
Scenario 2 10% decrease in benefits (for such reasons as lower-than-expected plant availability, slow increases in the number of consumers, etc.)
Scenario 3 Scenarios 1 and 2 combined.

Table 11.8 compares the net present values and the FIRRs under different scenarios.

Table 11.8 Sensitivity Analysis for the FIRR of the Project

| | Project with original assumptions | Scenario 1 | Scenario 2 | Scenario 3 |
|---|---|---|---|---|
| FIRR | | | | |
| (1) Component 1 | 19.8% | 17.8% | 16.5% | 14.7% |
| (2) Total components | 14.2% | 12.6% | 11.6% | 10.2% |

Under Scenarios 2 and 3, the FIRR of the Project (Total components) becomes lower than the pre-determined cut-off rate of 12%. The assumed 10% increase in the capital costs required does not affect the profitability of the Project as much as the assumed 10% decrease in the Project's benefits does. It appears that Component 1 alone does not involve any significant risk.

(5) FIRR on the Equity Invested in the Project

SENELEC seeks the finance for its capital projects from various sources. The World Bank has been assisting Senegal in improving the efficiency of its power sector. The First Energy Sector Rehabilitation Project, which was implemented between 1986 and 1993, was financed partially by an World Bank loan. The loan was rented to the GOS at a concessional rate, and then re-rented to SENELEC at a prevailing bank interest rate. The same arrangement is being sought for the Second Energy Sector Rehabilitation Project.

For the 20 MW gas turbine unit installed at the Cap des Biches power plant and commissioned in January 1995, SENELEC obtained 80% of the finance required, from a commercial bank (11% interest rate for the first 17 months, based on the FCFA value of the loan, and 8% for the remaining period based on the FF value, 5 year amortization), with the rest being covered by the supplier's credit. The repayment of this loan is guaranteed by major customers of SENELEC. SENELEC hopes that an additional 20 MW capacity, which is scheduled to be commissioned in 1997 will be financed mostly by the Saudi Fund at a low interest rate. This arrangement has not yet been finalized at the time of this writing.

Sources of finance for the Project have not been identified. We tentatively assume the following for the financing of the Project:

1. Equity-loan ratio : 30%:70% (the maximum equity ratio for SENELEC)

2. Loan (commercial bank loan)
   Interest rate : 12%
   Amortization : 10 years

3. Price contingencies (during the period between 1995 and 1997 only)
   Foreign currency components : 2% annually
   Local currency components : 10% in 1995, 5% in 1996 and 1997

4. Depreciation and special provision for tax exemption

| | | |
|---|---|---|
| Depreciation | : | 20 year straight line (i.e., annual 5% of the total investment costs) |
| Special provision for tax exemption | : | Annual 5% of the gross fixed assets of the Project |

In total, 10% of the aggregate investment costs annually.

5. Income tax rate : 35%

Based on the assumptions listed above, tables were prepared, as shown below, concerning the total investment costs, the cash flows during the operation period, financing, and the FIRR of the equity invested in the Project.

Table 11.9 shows the total construction costs including price contingencies, and Table 11.10 exhibits the disbursement of the initial investment costs and the flow of the financial resources consisting of equity capital and a commercial bank loan. The financial requirement totals approximately 18.2 billion FCFA, including 2 billion FCFA for the loan interest during the implementation period.

Table 11.11 exhibits a projected cash flow during the operation period which extends from 1997 to 2021. The Project is expected to generate a total net operating income of approximately 53 billion FCFA by 2021, when the Project is expected to complete its economic life. (The residual of the Project will be minimal.)

Table 11.12 shows the projected cash flow including debt service. The commercial loan amounting to approximately 12.7 billion FCFA is scheduled to be amortized in 10 years. The debt service coverage is expected to be at 1.03 for the first year of the loan repayment. The ratio will be improved only a little to 1.05 for the fifth year and 1.08 for the tenth year. Table 11.13 summarizes the cash in- and out-flows. The IRR on the equity invested is calculated at 14.6%.

## Table 11.9 Total Construction Costs (in prices at the beginning of 1995)

Thousand FCFA

| Item | 1996 FC | 1996 LC | 1996 TC | 1997 FC | 1997 LC | 1997 TC | Total FC | Total LC | Total TC |
|---|---|---|---|---|---|---|---|---|---|
| 1 Base costs | 14,328,884 | 597,732 | 14,926,616 | 0 | 597,732 | 597,732 | 14,328,884 | 1,195,464 | 15,524,347 |
| (in thousand Japanese yen) | (2,709,733) | (113,037) | (2,822,770) | (0) | (113,037) | (113,037) | (2,709,733) | (226,074) | (2,935,807) |
| 2 Price contingencies | 429,867 | 74,716 | 504,583 | 0 | 104,603 | 104,603 | 429,867 | 179,320 | 609,186 |
| | 81,292 | 14,130 | 95,422 | 0 | 19,781 | 19,781 | 81,292 | 33,911 | 115,203 |
| 3 Total construction costs (Items 1 and 2) | 14,758,750 | 672,448 | 15,431,199 | 0 | 702,335 | 702,335 | 14,758,750 | 1,374,784 | 16,133,534 |
| | 2,791,025 | 127,167 | 2,918,192 | 0 | 132,818 | 132,818 | 2,791,025 | 259,985 | 3,051,010 |

Note: 1 Exchange rates:
US$1= 99.85 yen
US$1= 528 FCFA
1 yen= 5.29 FCFA

2 Base costs include physical contingencies, engineering fees and administration expenses as well as direct construction costs.

3 Inflation rates:

| | 1995 | 1996 | 1997 |
|---|---|---|---|
| Foreign currency components (FC): | 2% | 2% | 2% |
| Local currency components (LC) | 10% | 5% | 5% |

(Price contingencies are computed on the middle of year accounting basis (MOY)).

## Table 11.10 Disbursement of Investment Costs and Flow of Financial Resources

Thousand FCFA

| Project year | 1 | | | 2 | | | Total | | |
|---|---|---|---|---|---|---|---|---|---|
| Year | 1996 | | | 1997 | | | | | |
| | FC | LC | TC | FC | LC | TC | FC | LC | TC |
| 1 Total initial investment | | | | | | | | | |
| (1) Total construction costs | 14,758,750 | 672,448 | 15,431,199 | 0 | 702,335 | 702,335 | 14,758,750 | 1,374,784 | 16,133,534 |
| (2) Interest on loan accrued | 619,868 | 28,243 | 648,110 | 1,291,804 | 88,356 | 1,380,160 | 1,911,671 | 116,599 | 2,028,270 |
| Sub-total | 15,378,618 | 700,691 | 16,079,309 | 1,291,804 | 790,691 | 2,082,495 | 16,670,421 | 1,491,382 | 18,161,804 |
| 2 Total finance required | 15,378,618 | 700,691 | 16,079,309 | 1,291,804 | 790,691 | 2,082,495 | 16,670,421 | 1,491,382 | 18,161,804 |
| (Financial resources) | | | | | | | | | |
| 3 Equity capital paid | 4,613,585 | 210,207 | 4,823,793 | 387,541 | 237,207 | 624,749 | 5,001,126 | 447,415 | 5,448,541 |
| Cumulative | 4,613,585 | 210,207 | 4,823,793 | 5,001,126 | 447,415 | 5,448,541 | | | |
| 4 Bank loan | 10,765,032 | 490,484 | 11,255,516 | 904,263 | 553,484 | 1,457,747 | 11,669,295 | 1,043,968 | 12,713,263 |
| Cumulative | 10,765,032 | 490,484 | 11,255,516 | 11,669,295 | 1,043,968 | 12,713,263 | | | |
| 5 Total finance | 15,378,618 | 700,691 | 16,079,309 | 1,291,804 | 790,691 | 2,082,495 | 16,670,421 | 1,491,382 | 18,161,804 |
| Cumulative | 15,378,618 | 700,691 | 16,079,309 | 16,670,421 | 1,491,382 | 18,161,804 | | | |

Assumptions:

1 Equity-loan ratio
Equity: 30%
Loan: 70%

2 Loan interest 12%

Computation of interest
Outstanding loan x 12.0% (from previous years) + new loan x 6.0% (taken during year)

3 No working capital nor pre-operation expenditures assumed.

## Table 11.11 Projected Cash Flow before Debt Service (operation period 1997 - 2021)

Thousand FCFA

| | Project year | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Year | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 |
| 1 Revenue | | | 3,410,727 | 3,445,470 | 3,456,294 | 3,466,827 | 3,478,082 | 3,490,111 | 3,502,972 | 3,516,724 | 3,531,435 | 3,547,173 | 3,564,017 | 3,582,047 |
| 2 Operation cost | | | | | | | | | | | | | | |
| (1) Fixed O & M | | | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 |
| (2) Variable O & M | | | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 |
| Total | | | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 |
| 3 Net operating income (Item 1 - Item 2) | | | 4,581,819 | 2,275,379 | 2,285,202 | 2,295,735 | 2,306,990 | 2,319,019 | 2,331,880 | 2,345,632 | 2,360,343 | 2,376,082 | 2,392,925 | 2,410,955 |

| | Project year | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Year | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | Total |
| 1 Revenue | | 3,601,353 | 3,622,028 | 3,644,176 | 3,667,908 | 3,693,341 | 3,720,605 | 3,749,838 | 3,781,189 | 525,413 | 561,494 | 600,214 | 641,773 | 686,389 | 74,488,603 |
| 2 Operation cost | | | | | | | | | | | | | | | |
| (1) Fixed O & M | | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 34,041 | 34,041 | 34,041 | 34,041 | 34,041 | 4,683,584 |
| (2) Variable O & M | | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 0 | 0 | 0 | 0 | 0 | 18,908,460 |
| Total | | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 34,041 | 34,041 | 34,041 | 34,041 | 34,041 | 23,592,044 |
| 3 Net operating income (Item 1 - Item 2) | | 2,430,261 | 2,450,936 | 2,473,084 | 2,496,816 | 2,522,249 | 2,549,513 | 2,578,746 | 2,610,097 | 491,372 | 527,453 | 566,173 | 607,732 | 652,348 | 53,238,743 |

## Table 11.12 Cash Flow Table for Financial Planning (operation period 1997 - 2021)

| Project year | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 |
| 1 Net cash flow from operation | 4,581,819 | 2,275,379 | 2,285,202 | 2,295,735 | 2,306,990 | 2,319,019 | 2,331,880 | 2,345,632 | 2,360,343 | 2,376,082 | 2,392,925 | 2,410,955 | 2,430,261 |
| 2 Interest earned | 68,727 | 34,131 | 34,278 | 34,436 | 34,605 | 34,785 | 34,978 | 35,184 | 35,405 | 35,641 | 35,894 | 36,164 | 36,454 |
| 3 Working capital (net increase) | 195,182 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 4 Interest paid on debt | 0 | 1,525,592 | 1,438,657 | 1,341,290 | 1,232,240 | 1,110,103 | 973,310 | 820,101 | 648,508 | 456,333 | 241,076 | | |
| 5 Net income before depreciation | 4,455,364 | 783,918 | 880,823 | 988,881 | 1,109,355 | 1,243,702 | 1,393,548 | 1,560,716 | 1,747,240 | 1,955,400 | 2,187,743 | 2,447,120 | 2,466,715 |
| 6 Income tax paid | 923,714 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 48,727 | 130,047 | 220,829 | 227,687 |
| 7 After-tax cash flow | 3,531,650 | 783,918 | 880,823 | 988,881 | 1,109,355 | 1,243,702 | 1,393,548 | 1,560,716 | 1,747,240 | 1,906,673 | 2,057,696 | 2,226,291 | 2,239,028 |
| 8 Loan repayments | 0 | 724,455 | 811,389 | 908,756 | 1,017,807 | 1,139,943 | 1,276,737 | 1,429,945 | 1,601,538 | 1,793,723 | 2,008,970 | | |
| Outstanding principal | 12,713,263 | 11,988,808 | 11,177,419 | 10,268,663 | 9,250,856 | 8,110,913 | 6,834,176 | 5,404,231 | 3,802,693 | 2,008,970 | 0 | | |
| 9 After-debt service cash flow | 3,531,650 | 59,463 | 69,434 | 80,125 | 91,549 | 103,759 | 116,812 | 130,771 | 145,702 | 112,950 | 48,726 | 2,226,291 | 2,239,028 |
| Cummulative | 3,531,650 | 3,591,113 | 3,660,547 | 3,740,672 | 3,832,221 | 3,935,980 | 4,052,791 | 4,183,562 | 4,329,264 | 4,442,213 | 4,490,939 | 6,717,230 | 8,956,258 |
| 10 Debt service coverage (Items 5 + 4) / (items 4 + 8) | | 1.03 | 1.03 | 1.04 | 1.04 | 1.05 | 1.05 | 1.06 | 1.06 | 1.07 | 1.08 | | |

| Project year | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | Total |
| 1 Net cash flow from operation | 2,450,936 | 2,473,084 | 2,496,816 | 2,522,249 | 2,549,513 | 2,578,746 | 2,610,097 | 491,372 | 527,453 | 566,173 | 607,732 | 652,348 | 53,238,743 |
| 2 Interest earned | 36,764 | 37,096 | 37,452 | 37,834 | 38,243 | 38,681 | 39,151 | 7,371 | 7,912 | 8,493 | 9,116 | 9,785 | 798,581 |
| 3 Working capital (net increase) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | -195,182 | 0 |
| 4 Interest paid on debt | | | | | | | | | | | | | 9,787,199 |
| 5 Net income before depreciation | 2,487,700 | 2,510,181 | 2,534,268 | 2,560,083 | 2,587,756 | 2,617,427 | 2,649,248 | 498,743 | 535,365 | 574,665 | 616,848 | 857,316 | 44,250,125 |
| 6 Income tax paid | 235,032 | 242,900 | 251,331 | 260,366 | 270,052 | 280,436 | 291,574 | 174,560 | 187,378 | 201,133 | 215,897 | 300,060 | 4,461,722 |
| 7 After-tax cash flow | 2,252,668 | 2,267,281 | 2,282,937 | 2,299,717 | 2,317,705 | 2,336,991 | 2,357,675 | 324,183 | 347,987 | 373,532 | 400,951 | 557,255 | 39,788,403 |
| 8 Loan repayments | | | | | | | | | | | | | 12,713,263 |
| Outstanding principal | | | | | | | | | | | | | |
| 9 After-debt service cash flow | 2,252,668 | 2,267,281 | 2,282,937 | 2,299,717 | 2,317,705 | 2,336,991 | 2,357,675 | 324,183 | 347,987 | 373,532 | 400,951 | 557,255 | 27,075,140 |
| Cummulative | 11,208,926 | 13,476,207 | 15,759,144 | 18,058,861 | 20,376,566 | 22,713,557 | 25,071,233 | 25,395,415 | 25,743,402 | 26,116,934 | 26,517,885 | 27,075,140 | |
| 10 Debt service coverage (Items 5 + 4) / (items 4 + 8) | | | | | | | | | | | | | |

Assumptions:

1 Interest earned: Interest earned on a half of the net operating income of the year.
Depositing interest rate: 3%

2 Working capital : net increase to meet the operating cost of 2 months

3 Interest paid on debt in 1997 is included in the initial investment (see Table 11.10).

4 Loan amortization:
(1) Principal 12,713,263 Thousand FCFA
(2) Interest 12%
(3) Duration 10 years
(4) PRF 0.17698416
(Principal Recovery Factor)

5 Depreciation (including Special Provision for tax exemption)
Total 10% of the total investment costs

6 Income tax rate:
35%

## Table 11.13 FIRR on Equity Invested

| Project year | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 |
| 1 Cash inflow | | 3,479,454 | 3,480,601 | 3,490,572 | 3,501,263 | 3,512,687 | 3,524,897 | 3,537,950 | 3,551,909 | 3,566,840 | 3,582,815 | 3,599,911 | 3,618,212 |
| (1) Operation | | 3,410,727 | 3,446,470 | 3,456,294 | 3,466,827 | 3,478,082 | 3,490,111 | 3,502,972 | 3,516,724 | 3,531,435 | 3,547,173 | 3,564,017 | 3,582,047 |
| (2) Interest earned | | 68,727 | 34,131 | 34,278 | 34,436 | 34,605 | 34,785 | 34,978 | 35,184 | 35,405 | 35,641 | 35,894 | 36,164 |
| 2 Cash outflow | 4,823,793 | 1,991,022 | 2,094,806 | 3,421,138 | 3,421,138 | 3,421,138 | 3,421,138 | 3,421,138 | 3,421,138 | 3,421,138 | 3,421,138 | 3,469,865 | 3,551,185 |
| (1) Equity capital paid-in | 4,823,793 | 624,749 | | | | | | | | | | | |
| (2) Operation | | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 |
| (3) Net working capital | | 195,182 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (4) Interest paid on debt | | 0 | 0 | 1,525,592 | 1,438,657 | 1,341,290 | 1,232,240 | 1,110,103 | 973,310 | 820,101 | 648,508 | 456,323 | 241,076 |
| (5) Income (corporate) tax paid | | 0 | 923,714 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 48,727 | 130,047 |
| (6) Loan repayments | | 0 | 0 | 724,455 | 811,389 | 908,756 | 1,017,807 | 1,139,943 | 1,276,737 | 1,429,945 | 1,601,538 | 1,793,723 | 2,008,970 |
| 3 Net cash flow (A - B) | -4,823,793 | 1,488,432 | 1,385,795 | 69,434 | 80,125 | 91,549 | 103,759 | 116,812 | 130,771 | 145,702 | 161,677 | 130,046 | 67,027 |
| 4 Cumulative net CF | -4,823,793 | -3,335,361 | -1,949,566 | -1,880,132 | -1,800,007 | -1,708,458 | -1,604,699 | -1,487,888 | -1,357,117 | -1,211,415 | -1,049,739 | -919,693 | -852,666 |
| 5 Net present value | -4,823,793 | -2,978,001 | -1,554,182 | -1,338,241 | -1,143,937 | -969,425 | -812,991 | -673,045 | -548,117 | -436,849 | -337,988 | -264,390 | -218,858 |
| discount factor | 1.00 | 0.89 | 0.80 | 0.71 | 0.64 | 0.57 | 0.51 | 0.45 | 0.40 | 0.36 | 0.32 | 0.29 | 0.26 |
| 6 Cumulative NPV | -4,823,793 | -7,801,793 | -9,355,975 | -10,694,216 | -11,838,153 | -12,807,578 | -13,620,568 | -14,293,613 | -14,841,730 | -15,278,578 | -15,616,566 | -15,880,956 | -16,099,814 |

| Project year | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | Total |
| 1 Cash inflow | 3,637,807 | 3,658,792 | 3,681,273 | 3,705,360 | 3,731,175 | 3,758,845 | 3,788,519 | 3,820,340 | 532,784 | 569,406 | 608,706 | 650,889 | 696,174 | 75,287,184 |
| (1) Operation | 3,601,353 | 3,622,028 | 3,644,176 | 3,667,908 | 3,693,341 | 3,720,605 | 3,749,838 | 3,781,189 | 525,413 | 561,494 | 600,214 | 641,773 | 686,389 | 74,488,603 |
| (2) Interest earned | 36,454 | 36,764 | 37,096 | 37,452 | 37,834 | 38,243 | 38,681 | 39,151 | 7,371 | 7,912 | 8,493 | 9,116 | 9,785 | 798,581 |
| 2 Cash outflow | 1,391,921 | 1,398,779 | 1,406,124 | 1,413,992 | 1,422,423 | 1,431,458 | 1,441,143 | 1,451,528 | 325,615 | 208,601 | 221,419 | 235,174 | 54,756 | 55,702,708 |
| (1) Equity capital paid-in | | | | | | | | | | | | | | 5,448,541 |
| (2) Operation | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 34,041 | 34,041 | 34,041 | 34,041 | 34,041 | 23,592,044 |
| (3) Net working capital | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | -195,182 | |
| (4) Interest paid on debt | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 9,787,199 |
| (5) Income (corporate) tax paid | 220,829 | 227,687 | 235,032 | 242,900 | 251,331 | 260,366 | 270,052 | 280,436 | 291,574 | 174,560 | 187,378 | 201,133 | 215,897 | 4,161,661 |
| (6) Loan repayments | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 12,313,263 |
| 3 Net cash flow (A - B) | 2,245,886 | 2,260,013 | 2,275,149 | 2,291,368 | 2,308,752 | 2,327,390 | 2,347,376 | 2,368,812 | 207,169 | 360,805 | 387,287 | 415,715 | 641,419 | 19,584,476 |
| 4 Cumulative net CF | 1,393,220 | 3,653,233 | 5,928,382 | 8,219,750 | 10,528,502 | 12,855,892 | 15,203,268 | 17,572,080 | 17,779,250 | 18,140,055 | 18,527,342 | 18,943,057 | 19,584,476 | |
| 5 Net present value | 319,290 | 747,524 | 1,083,093 | 1,340,819 | 1,533,417 | 1,671,775 | 1,765,202 | 1,821,641 | 1,645,640 | 1,499,140 | 1,367,095 | 1,248,008 | 1,152,024 | 1,094,854 |
| discount factor | 0.23 | 0.20 | 0.18 | 0.16 | 0.15 | 0.13 | 0.12 | 0.10 | 0.09 | 0.08 | 0.07 | 0.07 | 0.06 | |
| 6 Cumulative NPV | -15,780,524 | -15,033,000 | -13,949,907 | -12,609,088 | -11,075,671 | -9,403,896 | -7,638,693 | -5,817,053 | -4,171,412 | -2,672,273 | -1,305,178 | -57,169 | 1,094,854 | |

7 Internal rate of return on equity (IRR) 14.6 %

Assumptions:

1 Discount rate: 12%

Although the IRR on the equity invested per se is high enough to justify the Project, the debt coverage ratio, which varies from 1.03 to 1.08, is far lower than the acceptable level of 1.5. Even if the loan amortization period is extended to 20 years, the coverage ratio is not expected to exceed 1.5 (e.g., 1.36 for the first year and 1.38 for the fifth year). If the equity ratio is raised to 50%, the coverage ratio will rise to 1.49 for the first year. The current financial position of SENELEC being considered, however, this assumption seems not practicable. Thus, an alternative financing scenario with a low interest rate will have to be envisioned. We, then, take the following alternative assumptions:

1. Equity-loan ratio : 30%:70% (no change)
2. Loan
   Interest rate : 3%
   Amortization : 10 years (no grace period)
   No changes in the other assumptions from the original financing scenario.

Financial tables prepared under the above alternative scenario are exhibited in Appendixes 11.3.1 to 11.3.4. The IRR on the equity invested is satisfactorily high, at 25%, and the debt service coverage ratio for the first year of the loan repayment is acceptably high, at 1.69. If no income taxes are required, the IRR will rise further to 31.4%. The Project is certainly feasible under the alternative financing scenario, although such low-interest loans are unlikely to be available at commercial banks.

## 11.3 Economic Analysis

The economic analysis is concerned primarily with whether or not a project will generate adequate economic benefits to the country to justify its costs. The necessity of the Project for the development of the power sector has been discussed earlier in this report.

### 11.3.1 Economic Benefits

The prevailing tariffs are based on the long-run marginal cost pricing. With an assumption that the existing tariffs are not substantially distorted from the strict long-run marginal costs to supply an additional one kWh of energy, we measure the economic benefits basically by using the tariffs. For Components 2-(a) and 2-(b), however, we do not use the tariffs. Those components are concerned mainly with a reduction of the frequency of outages. From the financial viewpoint, it is a reduction of the unrealized sale of energy due to outages, of which benefits can be measured by applying tariffs. Economic benefits, on the other hand, are represented by the consumer's willingness to pay to avoid the interruption of power supply due to outages, which normally exceeds the tariffs, or more precisely, the tariffs for the electricity of which sale is not realized.

As mentioned earlier, the project element involving the replacement of overhead lines by underground cables will not be included in the EIRR computation. This element is costly at a small financial return. Nonetheless, the element has been recommended, taking into account the fact that the city of Dakar basically requires all overhead lines to be underground. Aesthetic reasons are given for this municipal policy, which is not rigidly enforced presently. Thus, to quantify the true benefits of the element, the willingness to pay for the aesthetic value among citizens would have to be assessed.

In our analysis, the benefits of the element is regarded as unquantifiable. Because of the municipal regulation, the element is included in the Project, and thus, in principle, no opportunity costs are accrued. From the technical point of view, the least cost method will be employed to install underground cables. The unit cost for this work will be at the current average of the same work. In the calculation of the EIRR, we replace the costs for underground cables by the costs for overhead lines, in order to remove the benefit-cost factor of underground cables. The unit costs for underground cables and overhead lines are approximately 37,300 FCFA/m and 17,500 FCFA/m, respectively.

For the computation of the benefits of Components 2-(a) and 2-(b), which are concerned with the reduction of outage, we apply 1,830 FCFA for each kWh of energy that is not served due to outage, as discussed below. This figure is based on limited data available, and thus the benefits should be treated merely as indicative estimates. It should also be noted that the statistical data on the unserved energy due to outage is not complete, partly because not all the outages and hence unserved energy are recorded strictly.

The beneficiaries of those two components will be mostly residential customers. It is safe to assume that their willingness to pay to avoid the interruption of electricity supply exceeds what they actually would pay for the electricity they would consume during the interrupted period. Suppose that a household is using electric appliances of which total load is 100 W, and it faces a one-hour interruption of electricity service. Without the outage, the household would consume an additional 0.1 kWh. Given the fact that the sale unrealized would be only 10 FCFA at a tariff rate of 100 FCFA/kWh, we may easily say that the household may have been willing to pay more to avoid the disturbance caused by the outage.

For domestic consumers, electricity is used mostly for lighting at home at night, when family members including a bread earner are enjoying the leisure time of the day. It is not unreasonable to assume that a typical bread earner is willing to pay his/her net hourly income to avoid a one-hour interruption of electricity service. The current minimum hourly wage rate is 183 FCFA. If this rate represents more closely the consumption benefit which would be realized due to the reduction of outage, it can be said that the true economic benefit (expected to Components 2-(a) and 2-(b)) is 18.3 times higher than the corresponding financial benefit, which is equivalent hence to 1,830 FCFA/kWh.

Part of the energy produced under the Project (Component 1) will be for the displacement of higher-cost energy produced by the least efficient generation units. The cost saving from this is measured by the difference in fuel costs between the generation units installed under the Project and the existing least efficient generation units. Similarly, the reduction of the total generation cost due to the reduction of transmission loss expected from part of Component 2-(b)--voltage booting--is measured by the actual average fuel cost. These approaches for the measure of cost savings are the same as in the case of the computations of the corresponding financial benefits which were made earlier.

From the discussion above, the measure of the economic benefits of each component of the Project can be summarized as follows:

| Component | Measure of benefits |
| --- | --- |
| 1 | (1) Tariff (energy and demand charges)--for the net addition of supplies.<br>(2) Difference in actual fuel costs--for the reduction of fuel cost by displacing inefficient generation units. |
| 2-(a) | 1,830 FCFA for each kWh of energy that is not unserved due to outage |
| 2-(b) | (1) The same as Component 2-(a).<br>(2) Actual average fuel cost--for the reduction of the total generation cost. |
| 2-(c) | Tariff (demand charge-portion for distribution facilities) |
| 3 | The same as Component 2-(c). |

Note: Benefits generated from the installment of underground cables instead of overhead lines are disregarded. The costs for underground cables are replaced by the costs for overhead lines in the EIRR calculation. Some part of Component 2-(b) and a small portion of Component 3 are concerned with the above matter.

### 11.3.2 Economic Costs

Economic costs are defined as real costs to the nation; and therefore domestic transfer payments should not be counted, and market costs, if they do not represent true economic costs, have to be shadow-priced. Among the inputs of the Project, the local currency components invested initially (including non-tradable goods and labor) require the conversion of their financial costs into economic ones.

First, the 20-percent VAT included in the financial costs of those components must be substracted, as it is a domestic transfer payment. Secondly, the financial costs need to be shadow-priced at appropriate conversion factors. For simplicity, we use an average conversion factor for all the local currency components. This factor is estimated as follows:

| | % of total domestic cost components | Conversion factor | Weighted value |
|---|---|---|---|
| Non-tradable goods | 20% | 0.89 | 0.18 |
| Skilled labor | 40% | 1 | 0.4 |
| Unskilled labor | 40% | 0.9 | 0.36 |
| | Average conversion factor | | 0.94 |

The financial costs of the fuel oil include a "government subsidy". However, as explained earlier, we treat it as an excess charge by the government on the imported oil and refinery and not as a "subsidy". Thus, the economic costs for the fuel oil are identical to the corresponding financial costs.

### 11.3.3 EIRR of the Project

Table 11.14 exhibits projected streams of the economic benefit and cost of the Project. The total economic costs are lower than the total financial costs by approximately 900 million FCFA, whereas the total economic benefits are higher than the total financial benefits by 900 million FCFA. Consequently, the EIRR of the Project is higher than the FIRR of the Project. The EIRR is calculated at 15.5%. The EIRR is clearly higher than the assumed discount rate of 12%.

# Table 11. 14 EIRR of the Project

Thousand FCFA

I. Component 1 Addition of generation capacity

| Project year | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 |
|---|---|---|---|---|---|---|---|---|---|---|
| Calendar year | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 |
| 1 Total installed capacity (MW) | | | | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| 2 Total operation hours | | | | 6,570 | 6,570 | 6,570 | 6,570 | 6,570 | 6,570 | 6,570 |
| 3 Energy generated (MWh) | | | | 65,700 | 65,700 | 65,700 | 65,700 | 65,700 | 65,700 | 65,700 |
| 4 Energy sold (MWh) | | | | 51,903 | 51,903 | 51,903 | 51,903 | 51,903 | 51,903 | 51,903 |
| A. Benefit | | | | | | | | | | |
| 1 Additional energy and power | | | | 3,289,405 | 3,289,405 | 3,289,405 | 3,289,405 | 3,289,405 | 3,289,405 | 3,289,405 |
| 2 Fuel savings | | | | 18,650 | 18,650 | 18,650 | 18,650 | 18,650 | 18,650 | 18,650 |
| Total | | | | 3,308,055 | 3,308,055 | 3,308,055 | 3,308,055 | 3,308,055 | 3,308,055 | 3,308,055 |
| B. Cost | | | | | | | | | | |
| 1 Capital cost | | | | | | | | | | |
| Foreign | | | 10,186,170 | | | | | | | |
| Local | | | 210,072 | 210,072 | | | | | | |
| Sub-total | | | 10,396,242 | 210,073 | | | | | | |
| 2 Operating cost | | | | | | | | | | |
| Fixed O & M | | | | 188,953 | 188,953 | 188,953 | 188,953 | 188,953 | 188,953 | 188,953 |
| Variable O & M | | | | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 |
| Sub-total | | | | 1,134,376 | 1,134,376 | 1,134,376 | 1,134,376 | 1,134,376 | 1,134,376 | 1,134,376 |
| Total | | | 10,396,242 | 1,344,448 | 1,134,376 | 1,134,376 | 1,134,376 | 1,134,376 | 1,134,376 | 1,134,376 |
| C. Net benefit (A - B) | | | -10,396,242 | 1,963,607 | 2,173,679 | 2,173,679 | 2,173,679 | 2,173,679 | 2,173,679 | 2,173,679 |
| D. EIRR | 20.0% | | | | | | | | | |

| Project year | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 |
|---|---|---|---|---|---|---|---|---|---|---|
| Calendar year | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
| 1 Total installed capacity (MW) | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| 2 Total operation hours | 6,570 | 6,570 | 6,570 | 6,570 | 6,570 | 6,570 | 6,570 | 6,570 | 6,570 | 6,570 |
| 3 Energy generated (MWh) | 65,700 | 65,700 | 65,700 | 65,700 | 65,700 | 65,700 | 65,700 | 65,700 | 65,700 | 65,700 |
| 4 Energy sold (MWh) | 51,903 | 51,903 | 51,903 | 51,903 | 51,903 | 51,903 | 51,903 | 51,903 | 51,903 | 51,903 |
| A. Benefit | | | | | | | | | | |
| 1 Additional energy and power | 3,289,405 | 3,289,405 | 3,289,405 | 3,289,405 | 3,289,405 | 3,289,405 | 3,289,405 | 3,289,405 | 3,289,405 | 3,289,405 |
| 2 Fuel savings | 18,650 | 18,650 | 18,650 | 18,650 | 18,650 | 18,650 | 18,650 | 18,650 | 18,650 | 18,650 |
| Total | 3,308,055 | 3,308,055 | 3,308,055 | 3,308,055 | 3,308,055 | 3,308,055 | 3,308,055 | 3,308,055 | 3,308,055 | 3,308,055 |
| B. Cost | | | | | | | | | | |
| 1 Capital cost | | | | | | | | | | |
| Foreign | | | | | | | | | | |
| Local | | | | | | | | | | |
| Sub-total | | | | | | | | | | |
| 2 Operating cost | | | | | | | | | | |
| Fixed O & M | 188,953 | 188,953 | 188,953 | 188,953 | 188,953 | 188,953 | 188,953 | 188,953 | 188,953 | 188,953 |
| Variable O & M | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 |
| Sub-total | 1,134,376 | 1,134,376 | 1,134,376 | 1,134,376 | 1,134,376 | 1,134,376 | 1,134,376 | 1,134,376 | 1,134,376 | 1,134,376 |
| Total | 1,134,376 | 1,134,376 | 1,134,376 | 1,134,376 | 1,134,376 | 1,134,376 | 1,134,376 | 1,134,376 | 1,134,376 | 1,134,376 |
| C. Net benefit (A - B) | 2,173,679 | 2,173,679 | 2,173,679 | 2,173,679 | 2,173,679 | 2,173,679 | 2,173,679 | 2,173,679 | 2,173,679 | 2,173,679 |
| D. EIRR | | | | | | | | | | |

| Project year | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 | |
|---|---|---|---|---|---|---|---|---|---|
| Calendar year | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | Total |
| 1 Total installed capacity (MW) | 10 | 10 | 10 | | | | | | |
| 2 Total operation hours | 6,570 | 6,570 | 6,570 | | | | | | |
| 3 Energy generated (MWh) | 65,700 | 65,700 | 65,700 | | | | | | |
| 4 Energy sold (MWh) | 51,903 | 51,903 | 51,903 | | | | | | |
| A. Benefit | | | | | | | | | |
| 1 Additional energy and power | 3,289,405 | 3,289,405 | 3,289,405 | | | | | | 65,788,091 |
| 2 Fuel savings | 18,650 | 18,650 | 18,650 | | | | | | 373,010 |
| Total | 3,308,055 | 3,308,055 | 3,308,055 | | | | | | 66,161,100 |
| B. Cost | | | | | | | | | |
| 1 Capital cost | | | | | | | | | |
| Foreign | | | | | | | | | 10,186,170 |
| Local | | | | | | | | | 420,144 |
| Sub-total | | | | | | | | | 10,606,313 |
| 2 Operating cost | | | | | | | | | |
| Fixed O & M | 188,953 | 188,953 | 188,953 | | | | | | 3,779,054 |
| Variable O & M | 945,423 | 945,423 | 945,423 | | | | | | 18,908,460 |
| Sub-total | 1,134,376 | 1,134,376 | 1,134,376 | | | | | | 22,687,514 |
| Total | 1,134,376 | 1,134,376 | 1,134,376 | | | | | | 33,293,828 |
| C. Net benefit (A - B) | 2,173,679 | 2,173,679 | 2,173,679 | | | | | | 32,867,272 |
| D. EIRR | | | | | | | | | |

Assumptions:

1 Plant availability: 75% including 68% for net addition of supplies, and 7% for the fuel saving of 3.85 FCFA/kWh

2 System loss (including station use): 21.0%

3 Tariff (demand and energy charges): 69.9 FCFA/kWh

4 Annual fixed O & M: 3% of the equipment and installation cos 6,298,424 thousand FCFA

5 Variable O & M (fuel and lubri. oil): 14.39 FCFA/kWh

6 Economic life: 20 years

II. Component 2-(a) Replacement of circuit breakers

| Project year | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 |
|---|---|---|---|---|---|---|---|---|---|---|
| Calendar year | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 |
| 1 Reduced loss of energy (kWh) | 4,522 | 4,748 | 4,985 | 5,234 | 5,496 | 5,771 | 6,059 | 6,362 | 6,680 | 7,014 |
| A. Benefit | | | | | | | | | | |
| Energy supply interruption avoided | | | | 9,579 | 10,058 | 10,561 | 11,089 | 11,643 | 12,225 | 12,837 |
| B. Cost | | | | | | | | | | |
| Capital cost | | | | | | | | | | |
| Foreign | | | 173,910 | | | | | | | |
| Local | | | 5,565 | 5,565 | | | | | | |
| Sub-total | | | 179,475 | 5,565 | | | | | | |
| C. Net benefit (A - B) | | | -179,475 | 4,014 | 10,058 | 10,561 | 11,089 | 11,643 | 12,225 | 12,837 |

| Project year | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 |
|---|---|---|---|---|---|---|---|---|---|---|
| Calendar year | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
| 1 Reduced loss of energy (kWh) | 7,365 | 7,733 | 8,120 | 8,526 | 8,952 | 9,400 | 9,870 | 10,364 | 10,882 | 11,426 |
| A. Benefit | | | | | | | | | | |
| Energy supply interruption avoided | 13,478 | 14,152 | 14,860 | 15,603 | 16,383 | 17,202 | 18,062 | 18,965 | 19,914 | 20,909 |
| B. Cost | | | | | | | | | | |
| Capital cost | | | | | | | | | | |
| Foreign | | | | | | | | | | |
| Local | | | | | | | | | | |
| Sub-total | | | | | | | | | | |
| C. Net benefit (A - B) | 13,478 | 14,152 | 14,860 | 15,603 | 16,383 | 17,202 | 18,063 | 18,965 | 19,914 | 20,909 |

| Project year | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 | |
|---|---|---|---|---|---|---|---|---|---|
| Calendar year | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | Total |
| 1 Reduced loss of energy (kWh) | 11,997 | 12,597 | 13,227 | 13,888 | 14,583 | 15,312 | 16,077 | 16,881 | 259,552 |
| A. Benefit | | | | | | | | | |
| Energy supply interruption avoided | 21,955 | 23,053 | 24,205 | 25,415 | 26,686 | 28,020 | 29,423 | 30,893 | 457,168 |
| B. Cost | | | | | | | | | |
| Capital cost | | | | | | | | | |
| Foreign | | | | | | | | | 173,910 |
| Local | | | | | | | | | 11,130 |
| Sub-total | | | | | | | | | 185,040 |
| C. Net benefit (A - B) | 21,955 | 23,053 | 24,205 | 25,415 | 26,686 | 28,020 | 29,423 | 30,893 | 272,129 |

Assumptions:

1 Energy supply interruption avoided: 1,830 FCFA/kWh

2 % of consumers benefited: 20%

3 % of outages avoided which are attributable to the fault of equipment or the default of protection: 33% (=1/3)

4 % increase of average annual energy consumption: 5%

5 Economic life: 25 years

Note:

1 Effect will be mostly on the 6.6 kV network.

2 Energy loss due to the outages concerned amounted to 67,834 kWh in 1994.

Thousand FCFA

III. Component 2-(b) Replacement of 6.6 kV overhead lines by underground cables, and voltage boosting of some feeders from 6.6 kV to 30 kV

| Project year | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Calendar year | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 |
| 1 Reduced loss of energy (kWh) (due to the outage reduction) | 4,522 | 4,748 | 4,985 | 5,234 | 5,496 | 5,771 | 6,059 | 6,362 | 6,680 | 7,014 | 7,365 | 7,733 | 8,120 | 8,526 |
| 2 Reduction of generation requirements (due to the voltage boosting for some feeders) | | | | | | | | | | | | | | |
| a. Total generation requirements without Project (GWh | 980 | 1,024 | 1,070 | 1,118 | 1,169 | 1,221 | 1,276 | 1,334 | 1,394 | 1,456 | 1,522 | 1,590 | 1,662 | 1,737 |
| b. Reduction of generation requirements (MWh) | | | | 5,033 | 5,259 | 5,496 | 5,743 | 6,001 | 6,271 | 6,554 | 6,849 | 7,157 | 7,479 | 7,815 |
| A. Benefit | | | | | | | | | | | | | | |
| 1 Energy supply interruption avoided | | | | 9,579 | 10,058 | 10,561 | 11,089 | 11,643 | 12,225 | 12,837 | 13,478 | 14,152 | 14,860 | 15,603 |
| 2 Reduction of total generation cost | | | | 75,488 | 78,885 | 82,435 | 86,145 | 90,021 | 94,072 | 98,305 | 102,729 | 107,352 | 112,183 | 117,231 |
| Sub-total | | | | 85,067 | 88,943 | 92,996 | 97,233 | 101,664 | 106,297 | 111,142 | 116,207 | 121,504 | 127,042 | 132,834 |
| B. Cost | | | | | | | | | | | | | | |
| Capital cost | | | | | | | | | | | | | | |
| Foreign | | | 1,283,212 | | | | | | | | | | | |
| Local | | | 67,513 | 67,513 | | | | | | | | | | |
| Sub-total | | | 1,350,725 | 67,513 | | | | | | | | | | |
| C. Net benefit (A - B) | | | -1,350,725 | 17,554 | 88,943 | 92,996 | 97,233 | 101,664 | 106,297 | 111,142 | 116,207 | 121,504 | 127,042 | 132,834 |

| Project year | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Calendar year | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | Total |
| 1 Reduced loss of energy (kWh) (due to the outage reduction) | 8,952 | 9,400 | 9,870 | 10,364 | 10,882 | 11,426 | 11,997 | 12,597 | 13,227 | 13,888 | 14,583 | 15,312 | 16,077 | 16,881 | 259,552 |
| 2 Reduction of generation requirements (due to the voltage boosting for some feeders) | | | | | | | | | | | | | | | |
| a. Total generation requirements without Project (GWh | 1,815 | 1,897 | 1,982 | 2,071 | 2,164 | 2,262 | 2,363 | 2,470 | 2,581 | 2,697 | 2,818 | 2,945 | 3,078 | 3,216 | |
| b. Reduction of generation requirements (MWh) | 8,167 | 8,535 | 8,919 | 9,320 | 9,739 | 10,178 | 10,636 | 11,114 | 11,614 | 12,137 | 12,683 | 13,254 | 13,850 | 14,474 | 224,276 |
| A. Benefit | | | | | | | | | | | | | | | |
| 1 Energy supply interruption avoided | 16,383 | 17,202 | 18,062 | 18,965 | 19,914 | 20,909 | 21,955 | 23,053 | 24,205 | 25,415 | 26,686 | 28,020 | 29,422 | 30,893 | 457,168 |
| 2 Reduction of total generation cost | 122,506 | 128,019 | 133,780 | 139,800 | 146,091 | 152,665 | 159,535 | 166,714 | 174,216 | 182,056 | 190,248 | 198,809 | 207,756 | 217,105 | 3,364,145 |
| Sub-total | 138,889 | 145,221 | 151,842 | 158,765 | 166,005 | 173,574 | 181,490 | 189,766 | 198,421 | 207,471 | 216,934 | 226,830 | 237,177 | 247,998 | 3,821,313 |
| B. Cost | | | | | | | | | | | | | | | |
| Capital cost | | | | | | | | | | | | | | | |
| Foreign | | | | | | | | | | | | | | | 1,283,212 |
| Local | | | | | | | | | | | | | | | 135,027 |
| Sub-total | | | | | | | | | | | | | | | 1,418,239 |
| C. Net benefit (A - B) | 138,889 | 145,221 | 151,842 | 158,765 | 166,005 | 173,574 | 181,490 | 189,766 | 198,421 | 207,471 | 216,934 | 226,830 | 237,177 | 247,998 | 2,403,074 |

Assumptions:

a. Outage reduction

| | | |
|---|---|---|
| 1 Energy supply interruption avoided | 1,830 | FCFA/kWh |
| 2 % of consumers benefited | 20% | |
| 3 % of outages avoided which are attributable to the fault of equipment or the default of protection | 33% | (=1/3) |
| 4 % increase of average annual energy consumption | 5% | |
| 5 Economic life | 25 | years |

b. Reduction of generation requirements

| | | |
|---|---|---|
| 6 Average increase in generation requirements | 4.5% | a year |
| 7 % of the transmission grid affected | 30% | |
| 8 Transmission loss reduction | 1.5% | |
| 9 Average generation cost (fuel savings only) | 15 | FCFA/kWh |

IV. Component 2-(c) Intensive rehabilitation of LV Network

| Project year | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Calendar year | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 |
| 1 Domestic | | | | | | | | | | | | | | |
| (1) Number of connections benefited | | | | 1,500 | 2,500 | 2,625 | 2,756 | 2,894 | 3,039 | 3,191 | 3,350 | 3,518 | 3,694 | 3,878 |
| (2) Average power demand (kW) | 0.30 | 0.31 | 0.32 | 0.33 | 0.34 | 0.35 | 0.36 | 0.37 | 0.38 | 0.39 | 0.40 | 0.42 | 0.43 | 0.44 |
| (3) Total power demand (kW) | | | | 492 | 844 | 913 | 987 | 1,068 | 1,155 | 1,249 | 1,351 | 1,461 | 1,580 | 1,709 |
| 2 Street lighting | | | | | | | | | | | | | | |
| (1) Number of connections benefited | | | | 75 | 125 | 125 | 125 | 125 | 125 | 125 | 125 | 125 | 125 | 125 |
| (2) Average power demand (kW) | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 |
| (3) Total power demand (kW) | | | | 3 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| A. Benefit | | | | | | | | | | | | | | |
| Additional power (capacity charge for distribution facilities) | | | | 15,034 | 25,804 | 27,895 | 30,156 | 32,601 | 35,246 | 38,106 | 41,199 | 44,545 | 48,163 | 52,075 |
| B. Cost | | | | | | | | | | | | | | |
| 1 Capital cost | | | | | | | | | | | | | | |
| Foreign | | | 446,280 | | | | | | | | | | | |
| Local | | | 29,697 | 29,697 | | | | | | | | | | |
| Sub-total | | | 475,977 | 29,697 | | | | | | | | | | |
| 2 O & M cost (fixed) | | | | 6,959 | 6,959 | 6,959 | 6,959 | 6,959 | 6,959 | 6,959 | 6,959 | 6,959 | 6,959 | 6,959 |
| Total | | | 475,977 | 36,656 | 6,959 | 6,959 | 6,959 | 6,959 | 6,959 | 6,959 | 6,959 | 6,959 | 6,959 | 6,959 |
| C. Net benefit (A - B) | | | -475,977 | -21,622 | 18,845 | 20,935 | 23,196 | 25,642 | 28,286 | 31,146 | 34,240 | 37,585 | 41,203 | 45,116 |

| Project year | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Calendar year | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | Total |
| 1 Domestic | | | | | | | | | | | | | | | |
| (1) Number of connections benefited | 4,072 | 4,276 | 4,490 | 4,714 | 4,950 | 5,197 | 5,457 | 5,730 | 6,017 | 6,317 | 6,633 | 6,965 | 7,313 | 7,679 | |
| (2) Average power demand (kW) | 0.45 | 0.47 | 0.48 | 0.50 | 0.51 | 0.53 | 0.54 | 0.56 | 0.57 | 0.59 | 0.61 | 0.63 | 0.65 | 0.67 | |
| (3) Total power demand (kW) | 1,848 | 1,998 | 2,161 | 2,338 | 2,528 | 2,734 | 2,957 | 3,198 | 3,458 | 3,740 | 4,045 | 4,375 | 4,731 | 5,117 | |
| 2 Street lighting | | | | | | | | | | | | | | | |
| (1) Number of connections benefited | 125 | 125 | 125 | 125 | 125 | 125 | 125 | 125 | 125 | 125 | 125 | 125 | 125 | 125 | |
| (2) Average power demand (kW) | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | |
| (3) Total power demand (kW) | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | |
| A. Benefit | | | | | | | | | | | | | | | |
| Additional power (capacity charge for distribution facilities) | 56,307 | 60,884 | 65,833 | 71,187 | 76,976 | 83,237 | 90,008 | 97,332 | 105,252 | 113,818 | 123,081 | 133,100 | 143,935 | 155,654 | 1,757,427 |
| B. Cost | | | | | | | | | | | | | | | |
| 1 Capital cost | | | | | | | | | | | | | | | |
| Foreign | | | | | | | | | | | | | | | 446,280 |
| Local | | | | | | | | | | | | | | | 59,393 |
| Sub-total | | | | | | | | | | | | | | | 505,674 |
| 2 O & M cost (fixed) | 6,959 | 6,959 | 6,959 | 6,959 | 6,959 | 6,959 | 6,959 | 6,959 | 6,959 | 6,959 | 6,959 | 6,959 | 6,959 | 6,959 | 173,987 |
| Total | 6,959 | 6,959 | 6,959 | 6,959 | 6,959 | 6,959 | 6,959 | 6,959 | 6,959 | 6,959 | 6,959 | 6,959 | 6,959 | 6,959 | 679,661 |
| C. Net benefit (A - B) | 49,348 | 53,924 | 58,874 | 64,327 | 70,016 | 76,277 | 83,049 | 90,372 | 98,292 | 106,858 | 116,123 | 126,140 | 136,976 | 148,694 | 1,087,766 |

Assumptions:

| | | |
|---|---|---|
| 1 Annual increase in average power demand | | |
| (1) Domestic | 3% | |
| (2) Street lighting | 0% | |
| 2 Annual increase in the number of connections after 1999 | | |
| (1) Domestic | 5% | |
| (2) Street lighting | 0% | |
| 3 Annual capacity charge for distribution facilities | 30,359 | FCFA/kW/year |
| 4 Annual O & M cost | 2% | of the equipment&installation costs of 347,975 thousand FCFA |
| 5 Economic life | 25 | years |

Thousand FCFA

## V. Component 3 Expansion of Distribution Network

| Project year | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Calendar year | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 |
| 1 Domestic | | | | | | | | | | | | | | |
| (1) Total number of connections | | | | 3,000 | 5,000 | 5,250 | 5,513 | 5,788 | 6,078 | 6,381 | 6,700 | 7,036 | 7,387 | 7,757 |
| (2) Average power demand (kW) | 0.30 | 0.31 | 0.32 | 0.33 | 0.34 | 0.35 | 0.36 | 0.37 | 0.38 | 0.39 | 0.40 | 0.42 | 0.43 | 0.44 |
| (3) Total power demand (kW) | | | | 983 | 1,688 | 1,826 | 1,975 | 2,136 | 2,310 | 2,498 | 2,701 | 2,922 | 3,160 | 3,417 |
| 2 Street lighting | | | | | | | | | | | | | | |
| (1) Total number of connections | | | | 150 | 250 | 220 | 220 | 220 | 220 | 220 | 220 | 220 | 220 | 220 |
| (2) Average power demand (kW) | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 |
| (3) Total power demand (kW) | | | | 6 | 10 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| A. Benefit | | | | | | | | | | | | | | |
| Additional power (capacity charge for distribution facilities) | | | | 30,068 | 51,608 | 55,753 | 60,275 | 65,166 | 70,455 | 76,175 | 83,362 | 89,053 | 96,289 | 104,114 |
| B. Cost | | | | | | | | | | | | | | |
| 1 Capital cost | | | | | | | | | | | | | | |
| Foreign | | | 1,598,457 | | | | | | | | | | | |
| Local | | | 86,227 | 86,227 | | | | | | | | | | |
| Sub-total | | | 1,684,684 | 86,227 | | | | | | | | | | |
| 2 O & M cost (fixed) | | | | 35,418 | 35,418 | 35,418 | 35,418 | 35,418 | 35,418 | 35,418 | 35,418 | 35,418 | 35,418 | 35,418 |
| Total | | | 1,684,684 | 121,645 | 35,418 | 35,418 | 35,418 | 35,418 | 35,418 | 35,418 | 35,418 | 35,418 | 35,418 | 35,418 |
| C. Net benefit (A - B) | | | -1,684,684 | -91,577 | 16,190 | 20,335 | 24,857 | 29,748 | 35,037 | 40,757 | 46,944 | 53,634 | 60,870 | 68,696 |

| Project year | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Calendar year | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | Total |
| 1 Domestic | | | | | | | | | | | | | | | |
| (1) Total number of connections | 8,144 | 8,552 | 8,979 | 9,428 | 9,900 | 10,395 | 10,914 | 11,460 | 12,033 | 12,635 | 13,266 | 13,930 | 14,626 | 15,358 | |
| (2) Average power demand (kW) | 0.45 | 0.47 | 0.48 | 0.50 | 0.51 | 0.53 | 0.54 | 0.56 | 0.57 | 0.59 | 0.61 | 0.63 | 0.65 | 0.67 | |
| (3) Total power demand (kW) | 3,696 | 3,997 | 4,323 | 4,675 | 5,056 | 5,468 | 5,914 | 6,396 | 6,917 | 7,481 | 8,090 | 8,750 | 9,463 | 10,234 | |
| 2 Street lighting | | | | | | | | | | | | | | | |
| (1) Total number of connections | 220 | 220 | 220 | 220 | 220 | 220 | 220 | 220 | 220 | 220 | 220 | 220 | 220 | 220 | |
| (2) Average power demand (kW) | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | |
| (3) Total power demand (kW) | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | |
| A. Benefit | | | | | | | | | | | | | | | |
| Additional power (capacity charge for distribution facilities) | 113,578 | 121,731 | 131,630 | 142,337 | 153,915 | 166,438 | 179,980 | 194,627 | 210,467 | 227,599 | 246,126 | 266,164 | 287,834 | 311,271 | 3,534,016 |
| B. Cost | | | | | | | | | | | | | | | |
| 1 Capital cost | | | | | | | | | | | | | | | |
| Foreign | | | | | | | | | | | | | | | 1,598,457 |
| Local | | | | | | | | | | | | | | | 172,454 |
| Sub-total | | | | | | | | | | | | | | | 1,770,911 |
| 2 O & M cost (fixed) | 35,418 | 35,418 | 35,418 | 35,418 | 35,418 | 35,418 | 35,418 | 35,418 | 35,418 | 35,418 | 35,418 | 35,418 | 35,418 | 35,418 | 885,456 |
| Total | 35,418 | 35,418 | 35,418 | 35,418 | 35,418 | 35,418 | 35,418 | 35,418 | 35,418 | 35,418 | 35,418 | 35,418 | 35,418 | 35,418 | 2,656,367 |
| C. Net benefit (A - B) | 77,160 | 86,313 | 96,212 | 106,918 | 118,497 | 131,019 | 144,562 | 159,209 | 175,049 | 192,180 | 210,708 | 230,745 | 252,436 | 275,853 | 877,649 |

Assumptions:

1 Annual increase in average power demand
- (1) Domestic: 3%
- (2) Street lighting: 0%

2 Annual increase in the number of connections after 1999
- (1) Domestic: 5%
- (2) Street lighting: 0%

2 Annual capacity charge for distribution facilities: 30,389 FCFA/kW/year

3 Annual O & M cost: 2% of the equipment&installation costs of 1,770,911 thousand FCFA

4 Economic life: 25 years

## VI. Total Components

| Calendar year | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A. Revenue | | | | 3,429,153 | 3,465,818 | 3,476,609 | 3,488,157 | 3,500,479 | 3,513,628 | 3,527,664 | 3,542,651 | 3,558,658 | 3,575,758 | 3,594,031 |
| B. Cost | | | | | | | | | | | | | | |
| 1 Capital cost | | | | | | | | | | | | | | |
| Foreign | | | 13,688,029 | 0 | | | | | | | | | | |
| Local | | | 399,074 | 399,074 | | | | | | | | | | |
| Sub-total | | | 14,087,103 | 399,074 | | | | | | | | | | |
| 2 Operating cost | | | | | | | | | | | | | | |
| Fixed O & M | | | 0 | 231,330 | 231,330 | 231,330 | 231,330 | 231,330 | 231,330 | 231,330 | 231,330 | 231,330 | 231,330 | 231,330 |
| Variable O & M | | | 0 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 |
| Sub-total | | | 0 | 1,176,753 | 1,176,753 | 1,176,753 | 1,176,753 | 1,176,753 | 1,176,753 | 1,176,753 | 1,176,753 | 1,176,753 | 1,176,753 | 1,176,753 |
| Total | | | 14,087,103 | 1,575,828 | 1,176,753 | 1,176,753 | 1,176,753 | 1,176,753 | 1,176,753 | 1,176,753 | 1,176,753 | 1,176,753 | 1,176,753 | 1,176,753 |
| C. Net benefit (A - B) | | | -14,087,103 | 1,853,325 | 2,289,064 | 2,299,855 | 2,311,404 | 2,323,725 | 2,336,874 | 2,350,911 | 2,365,898 | 2,381,905 | 2,399,005 | 2,417,277 |
| D. EIRR 15.5% | | | | | | | | | | | | | | |

| Calendar year | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A. Revenue | 3,613,562 | 3,634,443 | 3,656,773 | 3,680,658 | 3,706,214 | 3,733,563 | 3,762,838 | 3,794,183 | 3,827,750 | 574,303 | 612,828 | 654,114 | 698,368 | 745,814 | 75,368,015 |
| B. Cost | | | | | | | | | | | | | | | |
| 1 Capital cost | | | | | | | | | | | | | | | |
| Foreign | | | | | | | | | | | | | | | 13,688,029 |
| Local | | | | | | | | | | | | | | | 798,148 |
| Sub-total | | | | | | | | | | | | | | | 14,486,177 |
| 2 Operating cost | | | | | | | | | | | | | | | |
| Fixed O & M | 231,330 | 231,330 | 231,330 | 231,330 | 231,330 | 231,330 | 231,330 | 231,330 | 231,330 | 42,378 | 42,378 | 42,378 | 42,378 | 42,378 | 4,838,497 |
| Variable O & M | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 0 | 0 | 0 | 0 | 0 | 18,908,460 |
| Sub-total | 1,176,753 | 1,176,753 | 1,176,753 | 1,176,753 | 1,176,753 | 1,176,753 | 1,176,753 | 1,176,753 | 1,176,753 | 42,378 | 42,378 | 42,378 | 42,378 | 42,378 | 23,746,957 |
| Total | 1,176,753 | 1,176,753 | 1,176,753 | 1,176,753 | 1,176,753 | 1,176,753 | 1,176,753 | 1,176,753 | 1,176,753 | 42,378 | 42,378 | 42,378 | 42,378 | 42,378 | 38,233,134 |
| C. Net benefit (A - B) | 2,436,808 | 2,457,689 | 2,480,019 | 2,503,905 | 2,529,460 | 2,556,809 | 2,586,084 | 2,617,429 | 2,650,997 | 531,925 | 570,450 | 611,736 | 655,991 | 703,437 | 37,134,881 |

### 11.3.4 Sensitivity to the EIRR

Table 11.15 shows the sensitivity to the EIRR. The sensitivity analysis employed the same alternative scenarios that were used earlier for the sensitivity test for the FIRR.

Table 11.15 Sensitivity Analysis for the EIRR of the Project

| | Project with original assumptions | Scenario 1 | Scenario 2 | Scenario 3 |
|---|---|---|---|---|
| EIRR | | | | |
| (1) Component 1 | 20.0% | 18.0% | 16.6% | 14.8% |
| (2) Total components | 15.5% | 13.9% | 12.8% | 11.3% |

Under any of the scenarios except Scenario 3, the EIRR of the Project (Total components) is higher than the assumed discount rate of 12%. The EIRR of Component 1 alone is sufficiently high even under Scenario 3. From the economic point of view, the Project does not involve much risk.

## 11.4 Conclusions

We have assessed the viability of the Project from both the financial and economic points of view, primarily by calculating the FIRR and EIRR of the Project and then comparing the two with an assumed discount rate of 12%. The FIRR of the Project was computed at 14.2%, and the EIRR of the Project at 15.5%. These results indicate that the Project is fundamentally sound.

Sensitivity tests were performed for these rates. It was found that the Project involved only a small risk in economic terms, as the EIRR fell below the cut-off rate of 12% only under the worst scenario, among three scenarios assumed, where the investment capital requirement for the Project exceeded its estimate by 10% and the Project's benefit was 10% lower than expected. Compared with the EIRR, the FIRR of the Project is more sensitive. It was found that the FIRR fell below the 12% level even under a scenario where the investment cost was not changed from the original estimate but the revenue was lowered by 10% from the original estimate.

The FIRR of the equity invested in the Project was computed at 14.6% under an assumed financing scenario where the equity-loan ratio was 30% to 70%, and the loan was repayable in 10 years at an interest rate of 12%, at the rate of which commercial loans are available for SENELEC. The FIRR is sufficiently high. However, the debt coverage rate, which is projected to vary from 1.03 for the first year of the loan repayment to 1.08 for the tenth year, will not be acceptable for lenders of the loan, who usually expect the ratio to be 1.5 or higher. It was found that the rate would be improved little, even if the loan amortization period was extended to 20 years. If the equity ratio is raised to 50%, the coverage ratio will rise to 1.45 for the first year of loan replacement. In view of the current financial position of SENELEC, a financing scenario with an equity ratio of 50% is unlikely to be practicable or feasible. With an assumed interest rate of 3 percent, the IRR on the equity invested becomes sufficiently high at 25%, and the debt coverage ratio acceptably high at 1.69 for first year of loan repayment. In sum, although the FIRR of the Project, which does not take the impact of financing costs into consideration, is satisfactorily high, it appears that the Project becomes financially feasible only if a loan is available at a considerably low interest.

## Appendix 11.1 Sales Record (1988-1994)--Dakar and Interconnected Systems

(MWh)

| Energy consumption | 1988 | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 |
|---|---|---|---|---|---|---|---|
| A. LV | 215,687 | 231,234 | 246,260 | 249,561 | 286,460 | 321,676 | 334,026 |
| Domestic | 158,766 | 167,147 | 174,384 | 183,787 | 201,315 | 228,642 | 236,479 |
| General | 139,998 | 151,640 | 157,502 | 168,699 | 185,299 | 211,262 | 216,836 |
| Special | 18,768 | 15,507 | 16,882 | 15,088 | 16,016 | 17,380 | 19,643 |
| Non-domestic | 51,386 | 55,099 | 61,636 | 58,047 | 73,012 | 78,904 | 80,770 |
| Street lighting | 5,535 | 8,988 | 10,240 | 7,727 | 12,133 | 14,130 | 16,777 |
| B. MV | 278,035 | 265,988 | 280,971 | 293,072 | 327,271 | 293,881 | 331,595 |
| C. HV | 168,762 | 161,909 | 159,133 | 159,754 | 186,109 | 159,650 | 159,911 |
| Total | 662,484 | 659,131 | 686,364 | 702,387 | 799,840 | 775,207 | 825,532 |

( Thousand FCFA )

| Sales revenue | 1988 | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 |
|---|---|---|---|---|---|---|---|
| A. LV | 15,137,267 | 16,265,068 | 18,606,423 | 17,209,133 | 18,742,812 | 21,001,246 | 26,659,838 |
| Domestic | 10,351,582 | 10,950,854 | 12,578,870 | 11,854,870 | 12,205,046 | 13,707,502 | 17,212,535 |
| General | 9,072,987 | 9,861,304 | 11,369,439 | 10,710,326 | 11,161,756 | 12,575,776 | 15,727,590 |
| Special | 1,278,595 | 1,089,550 | 1,209,431 | 1,144,544 | 1,043,290 | 1,131,726 | 1,484,945 |
| Non-domestic | 4,345,313 | 4,638,230 | 5,216,979 | 4,770,109 | 5,742,648 | 6,200,964 | 7,989,019 |
| Street lighting | 440,372 | 675,984 | 810,574 | 584,154 | 795,118 | 1,092,780 | 1,458,284 |
| B. MV | 16,735,442 | 15,854,521 | 17,747,348 | 11,202,357 | 17,476,069 | 16,548,471 | 22,916,328 |
| C. HV | 6,857,564 | 6,633,749 | 6,778,854 | 6,589,854 | 7,025,922 | 6,183,209 | 8,165,715 |
| Total | 38,730,273 | 38,753,338 | 43,132,625 | 35,001,344 | 43,244,803 | 43,732,926 | 57,741,881 |

| Number of connections (customers) | 1988 | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 |
|---|---|---|---|---|---|---|---|
| A. LV | 180,638 | 184,848 | 196,370 | 209,915 | 226,219 | 239,992 | 255,256 |
| Domestic | 151,386 | 153,840 | 162,355 | 174,041 | 187,854 | 198,285 | 211,554 |
| General | 112,557 | 117,206 | 125,546 | 136,110 | 149,056 | 164,369 | 177,117 |
| Special | 38,829 | 36,634 | 36,809 | 37,931 | 38,798 | 33,916 | 34,437 |
| Non-domestic | 29,178 | 30,926 | 33,927 | 35,751 | 38,267 | 41,590 | 43,565 |
| Street lighting | 74 | 82 | 88 | 123 | 98 | 117 | 137 |
| B. MV | 798 | 809 | 792 | 799 | 777 | 758 | 807 |
| C. HV | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| Total | 181,439 | 185,660 | 197,165 | 210,717 | 226,999 | 240,753 | 256,066 |

Source: SENELEC.

## Appendix 11.2.1 Income Statements (SENELEC)

(Million FCFA)

| Description | Actual 1988 | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | Forecast 1995 | 1996 | 1997 | 1998 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. Electricity sold (GWh) | 689.81 | 685.99 | 721.84 | 736.53 | 808.75 | 793.92 | 864.61 | 852.31 | 939.50 | 978.50 | 1,031.30 |
| 2. Average tariff (FCFA/kWh) | 58.59 | 59.97 | 60.51 | 59.35 | 56.16 | 58.34 | 70.25 | 72.19 | 74.47 | 71.02 | 70.26 |
| 3. Sales of electricity | 40,415 | 41,138 | 43,675 | 43,712 | 45,416 | 46,314 | 60,738 | 61,525 | 69,962 | 69,496 | 72,454 |
| 4. Other revenue[1] | 1,904 | 1,639 | 1,386 | 1,550 | 1,248 | 1,819 | 1,464 | 2,309 | 2,545 | 2,651 | 2,794 |
| 5. Total revenue | 42,319 | 42,777 | 45,061 | 45,262 | 46,664 | 48,133 | 62,202 | 63,834 | 72,507 | 72,147 | 75,248 |
| 6. Fuel | 18,318 | 18,744 | 18,012 | 15,813 | 15,699 | 17,781 | 22,302 | 19,190 | 19,577 | 18,780 | 19,643 |
| 7. RTS [2] | | | | 925 | 1,071 | 1,165 | 1,284 | 1,307 | 1,396 | 1,398 | 1,453 |
| 8. Personnel | 7,293 | 7,668 | 7,932 | 8,671 | 8,974 | 9,166 | 10,064 | 10,315 | 10,573 | 10,837 | 11,108 |
| 9. Materials/Services | 4,573 | 3,630 | 4,909 | 4,521 | 6,437 | 5,510 | 5,198 | 9,983 | 11,279 | 12,041 | 13,008 |
| 10. Others | 1,139 | 1,374 | 1,689 | 1,850 | 1,841 | 2,699 | 2,847 | 3,060 | 6,111 | 6,105 | 6,183 |
| 11. Depreciation | 7,365 | 8,076 | 9,213 | 10,341 | 10,511 | 10,844 | 11,098 | 11,484 | 11,484 | 13,292 | 14,967 |
| 12. Total operating expenses | 38,688 | 39,492 | 41,755 | 42,121 | 44,533 | 47,165 | 52,793 | 55,339 | 60,420 | 62,453 | 66,362 |
| 13. Operating income | 3,631 | 3,285 | 3,306 | 3,141 | 2,131 | 968 | 9,409 | 8,495 | 12,087 | 9,694 | 8,886 |
| 14. Non-operating income | -1,446 | -450 | -1,871 | 888 | -1,781 | -1,494 | -4,744 | -3,805 | 0 | 0 | 0 |
| 15. Interest | 1,595 | 1,628 | 1,334 | 1,449 | 2,926 | 2,692 | 2,728 | 2,379 | 4,585 | 5,101 | 5,495 |
| 16. Income before provision | 590 | 1,207 | 101 | 2,580 | -2,576 | -3,218 | 1,937 | 2,311 | 7,502 | 4,593 | 3,391 |
| 17. Provision [3] | 5,093 | 5,475 | 5,896 | 7,582 | 0 | 0 | 8,982 | 9,780 | 11,203 | 11,517 | 12,994 |
| 18. Net income | -4,503 | -4,268 | -5,795 | -5,002 | -2,576 | -3,218 | -7,045 | -7,469 | -3,701 | -6,924 | -9,603 |
| Inflation | | | | | | | | 10.0% | 5.0% | 5.0% | 5.0% |
| Cumulative | | | | | | | | 0.0% | 0.0% | 0.0% | 0.0% |

[1] Including the sale of electricity which has not yet been billed, hook-up charges collected in special cases, etc.

[2] Financial contribution to RTS, a TV/radio broadcasting service entity.

[3] Tax exemption--5% of gross fixed assets in operation.

Source: SENELEC.

Appendix 11.2.2 Balance Sheets (SENELEC)

(Million FCFA)

| Description | Actual | | | | | | | Forecast | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1988 | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 |
| 1. Gross fixed assets | 110,704 | 120,184 | 153,892 | 161,189 | 174,178 | 180,360 | 218,587 | 224,051 | 230,332 | 259,887 | 287,361 |
| 2. Less depreciation | 35,242 | 42,611 | 50,745 | 60,579 | 70,771 | 81,607 | 93,271 | 104,755 | 116,240 | 129,531 | 144,498 |
| 3. Net FA in operation | 75,462 | 77,573 | 103,147 | 100,610 | 103,407 | 98,753 | 125,316 | 119,296 | 114,092 | 130,356 | 142,863 |
| 4. Work in progress | 10,754 | 25,229 | 3,156 | 10,211 | 5,864 | 4,974 | 8,363 | 26,299 | 46,069 | 43,228 | 34,546 |
| 5. Other fixed assets | 525 | 468 | 470 | 604 | 486 | 612 | 688 | 688 | 688 | 688 | 688 |
| 6. Total fixed assets | 86,741 | 103,270 | 106,773 | 111,425 | 109,757 | 104,339 | 134,367 | 146,283 | 160,849 | 174,272 | 178,097 |
| 7. Cash | 3,433 | 2,948 | 2,630 | 2,645 | 3,047 | 4,260 | 5,684 | 1,719 | 105 | 404 | 2,168 |
| 8. Receivables | 19,639 | 21,568 | 17,088 | 13,262 | 21,883 | 11,114 | 24,964 | 13,465 | 14,014 | 12,741 | 13,283 |
| 9. Unbilled receivables [1] | 2,449 | 2,882 | 2,907 | 3,046 | 2,996 | 2,804 | 1,526 | 1,538 | 1,749 | 1,737 | 1,811 |
| 10. Tax return [2] | 1,756 | 3,464 | 4,743 | 5,643 | 5,588 | 5,647 | 6,592 | 3,249 | 3,581 | 3,730 | 3,931 |
| 11. Inventories | 1,329 | 1,346 | 1,351 | 1,478 | 1,610 | 2,159 | 3,102 | 2,669 | 2,723 | 2,612 | 2,732 |
| 12. Other current assets [3] | 899 | 750 | 1,060 | 2,523 | 1,839 | 2,691 | 6,063 | 2,500 | 2,500 | 2,500 | 2,500 |
| 13. Total current assets | 29,505 | 32,958 | 29,779 | 28,597 | 36,963 | 28,675 | 47,931 | 25,140 | 24,672 | 23,724 | 26,425 |
| 14. Total assets | 116,246 | 136,228 | 136,552 | 140,022 | 146,720 | 133,014 | 182,298 | 171,423 | 185,521 | 197,996 | 204,522 |
| 15. Capital | 63,000 | 63,000 | 63,000 | 63,000 | 63,000 | 63,000 | 63,000 | 63,000 | 63,000 | 63,000 | 63,000 |
| 16. Retained earnings | -23,622 | -27,890 | -33,685 | -38,687 | -41,264 | -44,482 | -51,528 | -58,998 | -62,699 | -69,624 | -79,228 |
| 17. Revaluation reserve | 16,360 | 21,835 | 27,731 | 32,564 | 32,564 | 32,564 | 39,903 | 49,683 | 60,886 | 72,402 | 85,397 |
| 18. Total equity | 55,738 | 56,945 | 57,046 | 56,877 | 54,300 | 51,082 | 51,375 | 53,685 | 61,187 | 65,778 | 69,169 |
| 19. Subsidies | 1,774 | 1,987 | 5,129 | 6,321 | 6,687 | 6,776 | 6,708 | 6,708 | 6,708 | 6,708 | 6,708 |
| 20. Provisions [4] | 978 | 642 | 415 | 1,249 | -34 | -346 | 28,893 | 25,994 | 23,263 | 20,623 | 18,047 |
| 21. Consumers' deposits | 3,096 | 3,443 | 3,716 | 4,094 | 4,382 | 4,698 | 5,236 | 5,162 | 5,690 | 5,926 | 6,246 |
| 22. Long-term debt | 36,311 | 51,343 | 52,235 | 56,249 | 58,425 | 50,340 | 62,455 | 61,648 | 72,336 | 84,514 | 90,673 |
| 23. Less current portion | 5,723 | 8,038 | 5,806 | 5,058 | 9,675 | 6,529 | 17,201 | 7,424 | 6,518 | 6,355 | 5,829 |
| 24. LT debt | 30,588 | 43,305 | 46,429 | 51,191 | 48,750 | 43,811 | 45,254 | 54,224 | 65,818 | 78,159 | 84,844 |
| 25. Suppliers | 8,236 | 7,102 | 6,126 | 7,893 | 7,625 | 13,241 | 13,995 | 8,260 | 5,780 | 3,803 | 2,728 |
| 26. Government | 2,540 | 4,281 | 2,439 | 1,093 | 1,552 | 864 | 3,577 | 3,623 | 4,120 | 4,093 | 4,267 |
| 27. Bank overdraft | 3 | 1,350 | 2,579 | 1,224 | 6,196 | 1,778 | 1,846 | 0 | 0 | 0 | 0 |
| 28. Other current liabilities | 7,571 | 9,135 | 6,868 | 5,024 | 7,588 | 4,581 | 8,212 | 6,342 | 6,438 | 6,552 | 6,685 |
| 29. Current portion of LT debt | 5,723 | 8,038 | 5,806 | 5,058 | 9,675 | 6,529 | 17,201 | 7,424 | 6,518 | 6,355 | 5,829 |
| 30. Total current liabilities | 24,073 | 29,906 | 23,818 | 20,292 | 32,636 | 26,993 | 44,831 | 25,649 | 22,856 | 20,803 | 19,509 |
| 31. Total liabilities | 116,247 | 136,228 | 136,553 | 140,024 | 146,721 | 133,014 | 182,297 | 171,422 | 185,522 | 197,997 | 204,523 |
| 32. Current ratio | 1.2 | 1.1 | 1.3 | 1.4 | 1.1 | 1.1 | 1.1 | 1.0 | 1.1 | 1.1 | 1.4 |
| 33. Debt/equity | 59% | 81% | 79% | 82% | 89% | 81% | 68% | 67% | 75% | 85% | 91% |

[1] Due to bimonthly metering and billing. [2] VAT payment for consumers, which is reimbursed from the Government.

[3] Lendings to SENELEC employees as well as pre-paid expenses such as insurance, etc. [4] Including exchange loss.

Source: SENELEC.

## Appendix 11.2.3 Funds Flow Statements (SENELEC)

(Million FCFA)

| Description | Actual | | | | | | | Forecast | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1988 | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 |
| 1. Operating income (before debt service) | 2,185 | 2,835 | 1,434 | 4,029 | 349 | -526 | 4,665 | 4,689 | 12,086 | 9,693 | 8,885 |
| 2. Plus depreciation | 7,365 | 7,369 | 8,134 | 9,834 | 10,192 | 10,836 | 11,665 | 11,484 | 11,484 | 13,292 | 14,967 |
| 3. Gross internal cash generation (1) | 9,550 | 10,204 | 9,568 | 13,863 | 10,541 | 10,310 | 16,330 | 16,173 | 23,570 | 22,985 | 23,852 |
| Less: | | | | | | | | | | | |
| 4. Debt service | 2,743 | 4,479 | 7,943 | 7,739 | 4,316 | 12,821 | 6,013 | 19,580 | 12,009 | 11,619 | 11,850 |
| 5. Interest | 1,595 | 1,628 | 1,334 | 1,449 | 2,926 | 2,692 | 2,728 | 2,379 | 4,585 | 5,101 | 5,495 |
| 6. Principal | 1,148 | 2,851 | 6,609 | 6,290 | 1,390 | 10,129 | 3,285 | 17,201 | 7,424 | 6,518 | 6,355 |
| 7. Taxes | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8. Variation working capital | -544 | 1,766 | 2,224 | 226 | 5,209 | -11,423 | 10,734 | -11,266 | 3,034 | 643 | 1,704 |
| 9. Bank overdraft repayment | 19 | 0 | 0 | 1,355 | 0 | 4,418 | 0 | 1,846 | 0 | 0 | 0 |
| 10. Other deductions | -1,016 | -224 | -3,188 | 346 | 628 | -93 | -3,121 | -2,824 | -3,259 | -2,877 | -2,896 |
| 11. Total operational requirements (2) | 1,202 | 6,021 | 6,979 | 9,666 | 10,153 | 5,723 | 13,626 | 7,336 | 11,784 | 9,385 | 10,658 |
| 12. Net internal cash generation (1)-(2) | 8,348 | 4,183 | 2,589 | 4,197 | 388 | 4,587 | 2,704 | 8,837 | 11,786 | 13,600 | 13,194 |
| 13. Capital expenditure | 12,833 | 23,898 | 11,637 | 14,487 | 8,522 | 5,418 | 11,830 | 26,299 | 28,783 | 29,354 | 21,368 |
| 14. Difference | 4,485 | 19,715 | 9,048 | 10,290 | 8,134 | 831 | 9,126 | 17,462 | 16,997 | 15,754 | 8,174 |
| Financed by: | | | | | | | | | | | |
| 15. Long-term borrowings | 5,134 | 17,883 | 7,500 | 10,304 | 3,565 | 2,044 | 10,483 | 13,496 | 15,382 | 16,055 | 9,937 |
| 16. Bank overdraft | | 1,347 | 1,229 | 0 | 4,972 | 0 | 68 | 0 | 0 | 0 | 0 |
| 17. Equity | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 18. Total | 5,134 | 19,230 | 8,729 | 10,304 | 8,537 | 2,044 | 10,551 | 13,496 | 15,382 | 16,055 | 9,937 |
| 19. Cash variation | 649 | -485 | -320 | 16 | 402 | 1,212 | 1424 | -3,965 | -1,614 | 299 | 1763 |
| 20. Cash begin-year | 2,785 | 3,433 | 2,948 | 2,630 | 2,645 | 3,047 | 4,260 | 5,684 | 1,719 | 105 | 404 |
| 21 Cash end-year | 3,434 | 2,948 | 2,628 | 2,646 | 3,047 | 4,259 | 5,684 | 1,719 | 105 | 404 | 2,167 |
| 22. Debt coverage ratio | 3.5 | 2.3 | 1.2 | 1.8 | 2.4 | 0.8 | 2.7 | 0.8 | 2.0 | 2.0 | 2.0 |
| 23. Average NICG | 45% | 26% | 16% | 36% | 4% | 53% | 19% | 40% | 42% | 51% | 52% |

Source: SENELEC.

## Appendix 11.3.1 Disbursement of Investment Costs and Flow of Financial Resources -- under Alternative Financing Scenario

Thousand FCFA

| Project year | 1 | | | 2 | | | Total | | |
|---|---|---|---|---|---|---|---|---|---|
| Year | 1996 | | | 1997 | | | | | |
| | FC | LC | TC | FC | LC | TC | FC | LC | TC |
| 1 Total initial investment | | | | | | | | | |
| (1) Total construction costs | 14,758,750 | 672,448 | 15,431,199 | 0 | 702,335 | 702,335 | 14,758,750 | 1,374,784 | 16,133,534 |
| (2) Interest on loan accrued | 154,967 | 7,061 | 162,028 | 313,188 | 21,644 | 334,832 | 468,155 | 28,705 | 496,860 |
| Sub-total | 14,913,717 | 679,509 | 15,593,226 | 313,188 | 723,979 | 1,037,167 | 15,226,905 | 1,403,488 | 16,630,393 |
| 2 Total finance required | 14,913,717 | 679,509 | 15,593,226 | 313,188 | 723,979 | 1,037,167 | 15,226,905 | 1,403,488 | 16,630,393 |
| (Financial resources) | | | | | | | | | |
| 3 Equity capital paid | 4,474,115 | 203,853 | 4,677,968 | 93,956 | 217,194 | 311,150 | 4,568,072 | 421,047 | 4,989,118 |
| Cumulative | 4,474,115 | 203,853 | 4,677,968 | 4,568,072 | 421,047 | 4,989,118 | | | |
| 4 Bank loan | 10,439,602 | 475,656 | 10,915,258 | 219,232 | 506,785 | 726,017 | 10,658,834 | 982,442 | 11,641,275 |
| Cumulative | 10,439,602 | 475,656 | 10,915,258 | 10,658,834 | 982,442 | 11,641,275 | | | |
| 5 Total finance | 14,913,717 | 679,509 | 15,593,226 | 313,188 | 723,979 | 1,037,167 | 15,226,905 | 1,403,488 | 16,630,393 |
| Cumulative | 14,913,717 | 679,509 | 15,593,226 | 15,226,905 | 1,403,488 | 16,630,393 | | | |

Assumptions:

1 Equity-loan ratio

Equity: 30%

Loan: 70%

2 Loan interest 3%

Computation of interest

Outstanding loan x 3.0% + new loan x 1.5%

(from previous years) (taken during year)

3 No working capital nor pre-operation expenditures assumed.

## Appendix 11.3.2 Projected Cash Flow before Debt Service (operation period 1997 - 2021) -- under Alternative Financing Scenario

Thousand FCFA

| | Project year | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Year | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | Total |
| 1 Revenue | | | 3,410,727 | 3,445,470 | 3,456,294 | 3,466,827 | 3,478,082 | 3,490,111 | 3,502,972 | 3,516,724 | 3,531,435 | 3,547,173 | 3,564,017 | 3,582,047 | 3,601,353 | 3,622,028 | 3,644,176 | 3,667,908 | 3,693,341 | 3,720,605 | 3,749,838 | 3,781,189 | 525,413 | 561,494 | 600,214 | 641,773 | 686,369 | 74,488,603 |
| 2 Operation cost | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| (1) Fixed O & M | | | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 225,669 | 34,041 | 34,041 | 34,041 | 34,041 | 34,041 | 4,683,584 |
| (2) Variable O & M | | | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 945,423 | 0 | 0 | 0 | 0 | 0 | 18,908,460 |
| | Total | | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 34,041 | 34,041 | 34,041 | 34,041 | 34,041 | 23,592,044 |
| 3 Net operating income (Item 1 - Item 2) | | | 4,581,819 | 2,275,379 | 2,285,202 | 2,295,735 | 2,306,990 | 2,319,019 | 2,331,880 | 2,345,632 | 2,360,343 | 2,376,082 | 2,392,925 | 2,410,955 | 2,430,261 | 2,450,936 | 2,473,084 | 2,496,816 | 2,522,249 | 2,549,513 | 2,578,746 | 2,610,097 | 491,372 | 527,453 | 566,173 | 607,732 | 652,348 | 53,238,743 |

## Appendix 11.3.3 Cash Flow Table for Financial Planning (operation period 1997 - 2021) -- under Alternative Financing Scenario

| Project year | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | Total |
| 1 Net cash flow from operation | 4,581,819 | 2,275,379 | 2,285,202 | 2,295,735 | 2,306,990 | 2,319,019 | 2,331,880 | 2,345,632 | 2,360,343 | 2,376,082 | 2,392,925 | 2,410,955 | 2,430,261 | 2,450,936 | 2,473,084 | 2,496,816 | 2,522,249 | 2,549,513 | 2,578,746 | 2,610,097 | 491,372 | 527,453 | 566,173 | 607,732 | 652,348 | 53,238,743 |
| 2 Interest earned | 68,727 | 34,131 | 34,278 | 34,436 | 34,605 | 34,785 | 34,978 | 35,184 | 35,405 | 35,641 | 35,894 | 36,164 | 36,454 | 36,764 | 37,096 | 37,452 | 37,834 | 38,243 | 38,681 | 39,151 | 7,371 | 7,912 | 8,493 | 9,116 | 9,785 | 798,581 |
| 3 Working capital (net increase) | 195,182 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | -195,182 | 0 |
| 4 Interest paid on debt | 0 | 349,238 | 318,774 | 287,396 | 255,076 | 221,787 | 187,500 | 152,183 | 115,807 | 78,340 | 39,749 | | | | | | | | | | | | | | | 2,005,851 |
| 5 Net income before depreciation | 4,455,364 | 1,960,271 | 2,000,706 | 2,042,775 | 2,086,519 | 2,132,017 | 2,179,358 | 2,228,634 | 2,279,941 | 2,333,383 | 2,389,070 | 2,447,120 | 2,466,715 | 2,487,700 | 2,510,181 | 2,534,268 | 2,560,083 | 2,587,756 | 2,617,427 | 2,649,248 | 498,743 | 535,365 | 574,665 | 616,848 | 857,316 | 53,031,473 |
| 6 Income tax paid | 977,314 | 104,031 | 118,183 | 132,908 | 148,218 | 164,142 | 180,712 | 197,958 | 215,915 | 234,620 | 254,111 | 274,428 | 281,286 | 288,631 | 296,499 | 304,930 | 313,965 | 323,651 | 334,036 | 345,173 | 174,560 | 187,378 | 201,133 | 215,897 | 300,060 | 6,569,740 |
| 7 After-tax cash flow | 3,478,051 | 1,856,240 | 1,882,523 | 1,909,868 | 1,938,301 | 1,967,875 | 1,998,647 | 2,030,676 | 2,064,025 | 2,098,762 | 2,134,959 | 2,172,692 | 2,185,428 | 2,199,069 | 2,213,681 | 2,229,338 | 2,246,118 | 2,264,105 | 2,283,392 | 2,304,075 | 324,183 | 347,987 | 373,532 | 400,951 | 557,255 | 45,461,733 |
| 8 Loan repayments | 0 | 1,015,474 | 1,045,939 | 1,077,317 | 1,109,636 | 1,142,925 | 1,177,213 | 1,212,529 | 1,248,905 | 1,286,373 | 1,324,964 | | | | | | | | | | | | | | | 11,641,275 |
| Outstanding principal | 11,641,275 | 10,625,801 | 9,579,862 | 8,502,546 | 7,392,909 | 6,249,984 | 5,072,771 | 3,860,242 | 2,611,336 | 1,324,964 | 0 | | | | | | | | | | | | | | | |
| 9 After-debt service cash flow | 3,478,051 | 840,766 | 836,584 | 832,551 | 828,665 | 824,950 | 821,434 | 818,146 | 815,120 | 812,390 | 809,996 | 2,172,692 | 2,185,428 | 2,199,069 | 2,213,681 | 2,229,338 | 2,246,118 | 2,264,105 | 2,283,392 | 2,304,075 | 324,183 | 347,987 | 373,532 | 400,951 | 557,255 | 33,820,458 |
| Cummulative | 3,478,051 | 4,318,816 | 5,155,400 | 5,987,951 | 6,816,616 | 7,641,566 | 8,463,000 | 9,281,145 | 10,096,265 | 10,908,655 | 11,718,651 | 13,891,343 | 16,076,771 | 18,275,840 | 20,489,521 | 22,718,859 | 24,964,977 | 27,229,063 | 29,512,474 | 31,816,549 | 32,140,732 | 32,488,719 | 32,862,252 | 33,263,203 | 33,820,458 | |
| 10 Debt service coverage (Items 5 + 4) / (items 4 + 8) | | 1.69 | 1.70 | 1.71 | 1.72 | 1.72 | 1.73 | 1.74 | 1.76 | 1.77 | 1.78 | | | | | | | | | | | | | | | |

Assumptions:

1 Interest earned: Interest earned on a half of the net operating income of the year.
Depositing interest rate: 3%

2 Working capital : net increase to meet the operating cost of 2 months

3 Interest paid on debt in1997 is included in the initial investment (see Table 11.10).

4 Loan amortization:
(1) Principal 11,641,275 Thousand FCFA
(2) Interest 3%
(3)Duration 10 years
(4) PRF 0.11723051
(Principal Recovery Factor)

5 Depreciation: (including Special Provision for tax exemption)
Total 10% of the total investment costs

6 Income tax rate:
35%

# Appendix 11.3.4 FIRR on Equity Invested -- under Alternative Financing Scenario

| Project year | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 |
|---|---|---|---|---|---|---|---|---|---|
| Year | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 |
| 1 Cash inflow | | 3,479,454 | 3,480,601 | 3,490,572 | 3,501,263 | 3,512,687 | 3,524,897 | 3,537,950 | 3,551,909 |
| (1) Operation | | 3,410,727 | 3,446,470 | 3,456,294 | 3,466,827 | 3,478,082 | 3,490,111 | 3,502,972 | 3,516,724 |
| (2) Interest earned | | 68,727 | 34,131 | 34,278 | 34,436 | 34,605 | 34,785 | 34,978 | 35,184 |
| 2 Cash outflow | 4,677,968 | 1,677,424 | 2,148,406 | 2,639,836 | 2,653,988 | 2,668,312 | 2,684,022 | 2,699,947 | 2,716,516 |
| (1) Equity capital paid-in | 4,677,968 | 311,150 | | | | | | | |
| (2) Operation | | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 |
| (3) Net working capital | | 195,182 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (4) Interest paid on debt | | 0 | 0 | 349,238 | 318,774 | 287,396 | 255,076 | 221,787 | 187,500 |
| (5) Income (corporate) tax paid | | 0 | 977,314 | 104,031 | 118,183 | 132,908 | 148,218 | 164,142 | 180,712 |
| (6) Loan repayments | | 0 | 0 | 1,015,474 | 1,045,939 | 1,077,317 | 1,109,636 | 1,142,925 | 1,177,213 |
| 3 Net cash flow (A - B) | -4,677,968 | 1,802,030 | 1,332,195 | 850,737 | 847,275 | 843,975 | 840,874 | 838,003 | 835,392 |
| 4 Cumulative net CF | -4,677,968 | -2,875,938 | -1,543,743 | -693,006 | 154,270 | 998,245 | 1,839,119 | 2,677,122 | 3,512,514 |
| 5 Net present value | -4,677,968 | -2,567,801 | -1,230,662 | -493,268 | 98,041 | 566,431 | 931,755 | 1,210,994 | 1,418,646 |
| discount factor | 1.00 | 0.89 | 0.80 | 0.71 | 0.64 | 0.57 | 0.51 | 0.45 | 0.40 |
| 6 Cumulative NPV | -4,677,968 | -7,245,769 | -8,476,431 | -8,969,699 | -8,871,657 | -8,305,227 | -7,373,472 | -6,162,478 | -4,743,832 |

| Project year | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 |
|---|---|---|---|---|---|---|---|---|---|
| Year | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
| 1 Cash inflow | 3,566,840 | 3,582,815 | 3,599,911 | 3,618,212 | 3,637,807 | 3,658,792 | 3,681,273 | 3,705,360 | 3,731,175 |
| (1) Operation | 3,531,435 | 3,547,173 | 3,564,017 | 3,582,047 | 3,601,353 | 3,622,028 | 3,644,176 | 3,667,908 | 3,693,341 |
| (2) Interest earned | 35,405 | 35,641 | 35,894 | 36,164 | 36,454 | 36,764 | 37,096 | 37,452 | 37,834 |
| 2 Cash outflow | 2,733,763 | 2,751,720 | 2,770,425 | 2,789,915 | 1,445,520 | 1,452,378 | 1,459,723 | 1,467,591 | 1,476,022 |
| (1) Equity capital paid-in | | | | | | | | | |
| (2) Operation | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 | 1,171,092 |
| (3) Net working capital | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (4) Interest paid on debt | 152,183 | 115,807 | 78,340 | 39,749 | 0 | 0 | 0 | 0 | 0 |
| (5) Income (corporate) tax paid | 197,958 | 215,915 | 234,620 | 254,111 | 274,428 | 281,286 | 288,631 | 296,499 | 304,930 |
| (6) Loan repayments | 1,212,529 | 1,248,905 | 1,286,373 | 1,324,964 | 0 | 0 | 0 | 0 | 0 |
| 3 Net cash flow (A - B) | 833,077 | 831,095 | 829,486 | 828,296 | 2,192,286 | 2,206,414 | 2,221,549 | 2,237,769 | 2,255,153 |
| 4 Cumulative net CF | 4,345,592 | 5,176,686 | 6,006,172 | 6,834,469 | 9,026,755 | 11,233,169 | 13,454,718 | 15,692,487 | 17,947,640 |
| 5 Net present value | 1,567,064 | 1,666,754 | 1,726,631 | 1,754,238 | 2,068,699 | 2,298,529 | 2,458,127 | 2,559,785 | 2,613,972 |
| discount factor | 0.36 | 0.32 | 0.29 | 0.26 | 0.23 | 0.20 | 0.18 | 0.16 | 0.15 |
| 6 Cumulative NPV | -3,176,768 | -1,510,014 | 216,617 | 1,970,855 | 4,039,554 | 6,338,083 | 8,796,210 | 11,355,995 | 13,969,967 |

| Project year | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 | |
|---|---|---|---|---|---|---|---|---|---|
| Year | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | Total |
| 1 Cash inflow | 3,758,848 | 3,788,519 | 3,820,340 | 532,784 | 569,406 | 608,706 | 650,889 | 696,174 | 75,287,184 |
| (1) Operation | 3,720,605 | 3,749,838 | 3,781,189 | 525,413 | 561,494 | 600,214 | 641,773 | 686,389 | 74,488,603 |
| (2) Interest earned | 38,243 | 38,681 | 39,151 | 7,371 | 7,912 | 8,493 | 9,116 | 9,785 | 798,581 |
| 2 Cash outflow | 1,485,057 | 1,494,743 | 1,505,128 | 379,214 | 208,601 | 221,419 | 235,174 | 54,756 | 48,497,968 |
| (1) Equity capital paid-in | | | | | | | | | 4,989,118 |
| (2) Operation | 1,171,092 | 1,171,092 | 1,171,092 | 34,041 | 34,041 | 34,041 | 34,041 | 34,041 | 23,592,044 |
| (3) Net working capital | 0 | 0 | 0 | 0 | 0 | 0 | 0 | -195,182 | |
| (4) Interest paid on debt | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2,005,851 |
| (5) Income (corporate) tax paid | 313,965 | 323,651 | 334,036 | 345,173 | 174,560 | 187,378 | 201,133 | 215,897 | 6,269,680 |
| (6) Loan repayments | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 11,641,275 |
| 3 Net cash flow (A - B) | 2,273,791 | 2,293,777 | 2,315,213 | 153,570 | 360,805 | 387,287 | 415,715 | 641,419 | 26,789,216 |
| 4 Cumulative net CF | 20,221,431 | 22,515,208 | 24,830,420 | 24,983,990 | 25,344,795 | 25,732,082 | 26,147,797 | 26,789,216 | |
| 5 Net present value | 2,629,587 | 2,614,168 | 2,574,089 | 2,313,508 | 2,094,557 | 1,898,718 | 1,722,672 | 1,575,830 | 31,392,097 |
| discount factor | 0.13 | 0.12 | 0.10 | 0.09 | 0.08 | 0.07 | 0.07 | 0.06 | |
| 6 Cumulative NPV | 16,599,553 | 19,213,722 | 21,787,811 | 24,100,319 | 26,194,877 | 28,093,595 | 29,816,267 | 31,392,097 | |

7 Internal rate of return on equity (IRR) 25.3%

Assumptions:

1 Discount rate: 12%

# CHAPTER 12

# ENVIRONMENTAL ASSESSMENT

# CHAPTER 12 ENVIRONMENTAL ASSESSMENT

In the execution of the Project, it has become more important to assess the influence of the project on the environment especially in recent years. This Report therefore purports to assess the environmental factors in terms of pollution and problems associated with the natural and social environment as well as other factors. If, in the project area, there are existing equipment facilities of the same type as those to be installed under the Project, it will be necessary to evaluate not only the environmental impact of the planned Project alone but rather assess the environmental consequences on an overall basis, including the existing and Project equipment as a whole.

This Chapter will make an environmental appraisal of the power generation and other power facilities.

## 12.1 Power Generating Facilities

### 12.1.1 Assessment of the Current Problems of Interference

Fields studies were performed in December 1994 and January/February 1995 to determine the present status of pollution by measuring the noise, vibrations and exhaust gas level in the vicinity of the Bel-Air and Cap des Biches Power Stations which are both located in the Dakar area and to assess the impact likely to arise from the additional construction of two 5,000 kW diesel generators.

(1) Vibration Measurements

The vibration measurements were carried out at and around the diesel engine plants of the Bel-Air and Cap des Biches Power Stations using vibration indicator (RION VH-51) brought over by the Study team from Japan.

The Table in the following page reports the measurements results obtained at and around the diesel engine plants.

At the Bel-Air Power Station, the vibration indicator registered vibrations in the order of 40 dB on the concrete surfaces 1 m apart from the diesel engines but did not detect any vibrations at a distance of 1 m apart from the engine building.

At the Cap des Biches Power Station, the vibration indicator recorded 74 dB on the concrete floor of the engine building and 58 dB on the concrete surface 1 m apart from the engine building but did not detect any vibrations at a distance of 15 m on the concrete surface apart from the engine building.

The data thus demonstrate that vibrations do not present a problem to the residential zone on the Station precincts as this housing area is at over 100 m from the Station.

Measurement Results of Vibration

(Unit: dB)

| | | Cap de Biches PS | Bel-Air PS |
|---|---|---|---|
| Date of measurements | | Dec. 1, 1994 | Nov. 30, 1994 |
| Measured by | | Mr. Nakaoji of EPDCI | Mr. Nakaoji of EPDCI |
| Witnessed by | | Mr. Mamadou SENE | Mr. Idiriss of MANE |
| Measuring equipment used | | RION Type VM-51 | RION Type VM-51 |
| Measure-ment points | No.1 diesel engine | 105 (Output 19 MW) | 107 |
| | No.2 diesel engine | 105 (Output 13 MW) | 105 |
| | Concrete floor on 1st floor | 74 | 45 |
| | Outside, concrete floor 1 m from bldg. | 58 | 40 or less |
| | Outside, concrete floor 14 m from bldg. | 40 or less | |

(2) Noise

The noise measurements were carried out at and around the main equipment of the two power stations and on the boundaries of the power station grounds using sound level meter (RION NL-04) brought over by the Study team from Japan.

Table 12.1.1 shows the noise levels measured at the main plant facilities in the power stations. Fig. 12.1.1-1 shows the distribution of the noise measurement data at the Cap des Biches and Fig. 12.1.1-2 at the Bel-Air Power Stations.

The Bel-Air Power Station is situated in an industrial zone, with factories, port facilities and warehouses in its vicinity. There is a residential zone with several houses in the Station's precincts. The building accommodating the diesel engines adjoins a tobacco factory and the port, and the maximum noise level recorded on the boundaries of the station complex stands at 76 dB.

At present, the entrance for machine deliveries and the windows of the diesel engine building are partly open. If these were closed it would be possible to reduce the noise level to 70 dB.

The Japanese Noise Control Regulations lay down a maximum day-time noise level of 70 dB and a maximum night-time level of 65 dB in an industrial zone.

Due to its location in an industrial zone, the Bel-Air Power Station, the following two measures should be implemented to meet day-time target noise level of 70 dB and a night-time level of 65 dB:

1) A soundproofed wall should be erected on the boundaries.

2) The entrance for machine deliveries to the station and all other apertures that are open at present, including windows, should be sealed.

The Cap des Biches is located on large space so that noise levels are dissipated by the distance, with 60 - 65 dB recorded on the boundaries facing the sea and the fields. Noise does therefore not present a real problem. On the boundary facing the residences for SENELEC's employees, the noise level registered 55 - 57 dB, that is, values well within the range laid down by the Japanese Noise Control Regulations.

### 12.1.2 Estimation of Exhaust Gas Concentrations

The data submitted by SENELEC for the fuel (heavy oil) were taken as the basis for estimating the exhaust gas emission concentrations from the present heavy oil combustion boilers (12,800 kW x 4 boilers) and the diesel generators (5,000 kW x 2) at the Bel-Air Power Station.

Also carried out were estimations of the additional exhaust gas emission levels arising from the commissioning of the two 5,000 kW diesel generator units under this Project.

(1) SOx Emission Regulations

The SOx emission levels are largely due to the sulfur content of the fuel used. The problem is that SENELEC has practically no means of controlling the sulfur content of the fuel so that we have taken the fuel sulfur level recorded in Table 8.2.2 for our SOx emission calculations.

The SOx Control Regulations specify, among other things, the K value and in the context of our calculations we have adopted K = 17.5 as corresponding to the category given in the Japanese regulations as "Other Zones."

In the calculations below we have used the most widely accepted formulae for calculating the diffusion of emission concentrations (Bosanquet's first equation and Sutton's diffusion equation) to determine the necessary stack height.

(2) Calculations for the Existing 5,000 kW Diesel Plant

Operational Conditions:

| | |
|---|---|
| Fuel sulfur content | 2.87 wt.% |
| Lower calorific value | 9,567 kcal/kg |
| Excess air ratio | 13% |
| Stack outlet temperature | 365°C |
| Stack height & Outlet diameter | 13 m & 0.85 mφ |
| Sox concentration at exhaust stack outlet | 731 ppm |

a. Formula used for calculating the effective stack height is based on the following (Bosanquet) equation.

$$Hm=\frac{4.77}{1+\frac{0.43u}{vg}}\ \frac{\sqrt{Q_{T1}vg}}{u}$$

$$Ht=6.37g\ \frac{Q_{T1}\Delta T}{u^3T_1}\ (\log_e \cdot J^2+\frac{2}{J}-2)$$

$$J=\frac{u^2}{\sqrt{Q_{T1}vg}}(0.43\sqrt{\frac{T_1}{g}(d\theta/dz)}\ -0.28\frac{vg}{g}\frac{T_1}{\Delta T})+1$$

where,

| | | |
|---|---|---|
| Hm | : | Updraft height due to gas velocity (m) |
| Ht | : | Updraft height due to buoyancy (m) |
| u | : | Average wind velocity (m/s) |
| vg | : | Stack outlet gas speed (m/s) |
| $Q_{T1}$ | : | Exhaust gas volume at $T_1$ ($m^3/s$) |
| $T_1$ | : | Temperature at which the exhaust gas density equals the atmospheric air density (°K) |
| $\Delta T$ | : | Difference between the exhaust gas temperature and $T_1$ (°K) |
| g | : | Earth's gravitational constant (9.81 $m/s^2$) |
| $d\theta/dz$ | : | Vertical gradient of potential temperature (°C/m) |

The calculations for the sulfur oxide emission standards according to the above equations give $T_1$ = 288°K.
$d\theta/dz$ = 0.0033°C/m, u = 6 m/s

The effective stack height He(m) should be determined by the following equation:

$$He = Ho + 0.65\ (Hm + Ht)$$

where,

Ho: stack height (m)

The relation between the K values and the effective stack height, however, can be determined by the following equation:

$$He=\sqrt{\frac{Q_s\times10^3}{K}}$$ (Qs : SOx emission rate ($Nm^3/h$)

If we introduce the actual numerical values into the above equation, we have:

$Q_{T1}$ = 8.6 $m^3/s$

$\Delta T$ = 350°K

vg = 33.5 m/s

J = 85.2

Hm = 12.54 m

Ht = 20.93 m

Qs = 21.1 $Nm^3/h$

K = 17.5

He = 34.7 m

so that : Ho = 12.9 m

The minimum effective stack height required in accordance with the above calculation is therefore 12.9 m and the exhaust gas flue outlet height is around 13 m. With these stack and flue outlet heights, it will therefore be possible to meet the K value specified in the Regulations.

With an actual stack height Ho of 13 m, we can now use Sutton's formula to calculate the maximum ground level concentration at place (Cm) and distance from stack (xm).

b. Suttons equation

$$Cm=\frac{2Q}{e\pi uH_e^2}\left(\frac{Cz}{Cy}\right)$$

$$xm=\left(\frac{He}{Cz}\right)^{2/(2-n)}$$

where, $\pi$: the ratio of the circumstance of a circle to its diameter, Cz = 0.07, Cy = 0.07/0.15 and n = 0.25.

Q = Sulfur oxide (SOx) emission rate at $T_1$ ($m^3/s$)

He = 13 + 0.65 (12.54 + 20.93) = 34.8 m

Cm = 0.030 ppm

xm = 1,201 m

Thus, the maximum SOx ground-level emission concentration at a distance of approximately 1.20 km from the project site under the current plant can be calculated as being 0.030 ppm.

(3) Calculations for the New 5,000 kW Diesel Plant

Operational conditions:

Stack height & outlet diameter: 18 m & 0.85 mϕ

Other conditions: Equal to those for the existing 5,000 kW diesel plant.

Using the same calculation formulae as those of Section (2) above, we have the following results. As the new diesel plant is designed with a stack height of 18 m, it meets K-value specified in the regulations with a comfortable margin.

| | |
|---|---|
| Effective stack height | : 39.8 m |
| Maximum ground-level concentration | : 0.023 ppm |
| Distance from stack | : 1,400 m |

(4) Existing Boilers (12,800 kW x 4)

Operational conditions:

| | |
|---|---|
| Fuel sulfur content | : 2.87 wt.% |
| Low calorific value | : 9,567 kcal/kg |
| Excess air ratio | : 6% |
| Stack outlet temperature | : 195°C |
| Stack height & diameter | : 45 m & 1.80 mϕ x 4 |

Using the same calculation formulae as those of Section (2) above, we have the following results.

The regulatory K-value is not met.

To meet the regulatory K-value, it will be necessary to raise the stack height to 132 m or higher.

| | |
|---|---|
| Maximum ground-level concentration | : 0.144 ppm |
| Distance from stack | : 2,807 m |

### 12.1.3 Examination and Forecast of Impact on the Social Environment

(1) Noise

The commissioning of the two new 5,000 kW diesel generators under this Project at the Bel-Air Power Station would lead to the possibility of the noise level's exceeding 76 dB on the station complex boundaries. While the adjacent area is an industrial zone without residential housing, noise reduction measures will be required in the form of sealing the entrance opening for machine deliveries during night hours and of erecting a soundproofed wall.

(2) Vibration

Vibration would not present any particular problem.

(3) Exhaust Gas Emissions

The fuel used by SENELEC is a heavy oil of poor quality with a high sulfur content of 2.87 wt.%, and the impact this has on the environment is considerable.

The present boiler plant (12,800 kW x 4) operated on this high-sulfur fuel has a low efficiency and involves high fuel costs. For these reasons the boiler plant in its present form does not meet the exhaust gas emission regulations as they stand in Japan.

There are plans for a gradual phasing out and scrapping of the four boilers, and if the replacement boilers are to be run on heavy fuel oil again it will be necessary to design them with particular attention to their environmental impact by allowing, in particular, for a better grade of fuel and for an appropriate stack height.