ESMAP

Energy Sector Management Assistance Programme

ESM 0136

Tunisia

Power Efficiency Study

Report No. 136/91

Public Disclosure Authorized

JOINT UNDP / WORLD BANK
ENERGY SECTOR MANAGEMENT ASSISTANCE PROGRAMME (ESMAP)

PURPOSE

The Joint UNDP/World Bank Energy Sector Management Assistance Programme (ESMAP) was launched in 1983 to complement the Energy Assessment Programme, established three years earlier. ESMAP's original purpose was to implement key recommendations of the Energy Assessment reports and ensure that proposed investments in the energy sector represented the most efficient use of scarce domestic and external resources. In 1990, an international Commission addressed ESMAP's role for the 1990s and, noting the vital role of adequate and affordable energy in economic growth, concluded that the Programme should intensify its efforts to assist developing countries to manage their energy sectors more effectively. The Commission also recommended that ESMAP concentrate on making long-term efforts in a smaller number of countries. The Commission's report was endorsed at ESMAP's November 1990 Annual Meeting and prompted an extensive reorganization and reorientation of the Programme. Today, ESMAP is conducting Energy Assessments, performing preinvestment and prefeasibility work, and providing institutional and policy advice in selected developing countries. Through these efforts, ESMAP aims to assist governments, donors, and potential investors in identifying, funding, and implementing economically and environmentally sound energy strategies.

GOVERNANCE AND OPERATIONS

ESMAP is governed by a Consultative Group (ESMAP CG), composed of representatives of the UNDP and World Bank, the governments and institutions providing financial support, and representatives of the recipients of ESMAP's assistance. The ESMAP CG is chaired by the World Bank's Vice President, Operations and Sector Policy, and advised by a Technical Advisory Group (TAG) of independent energy experts that reviews the Programme's strategic agenda, its work program, and other issues. The Manager of ESMAP, who reports to the World Bank's Vice President, Operations and Sector Policy, administers the Programme. The Manager is assisted by a Secretariat, headed by an Executive Secretary, which supports the ESMAP CG and the TAG and is responsible for relations with the donors and for securing funding for the Programme's activities. The Manager directs ESMAP's two Divisions: The Strategy and Programs Division advises on selection of countries for assistance, carries out Energy Assessments, prepares relevant programs of technical assistance, and supports the Secretariat on funding issues. The Operations Division is responsible for formulation of subsectoral strategies, preinvestment work, institutional studies, technical assistance, and training within the framework of ESMAP's country assistance programs.

FUNDING

ESMAP is a cooperative effort supported by the World Bank, UNDP and other United Nations agencies, the European Community, Organization of American States (OAS), Latin American Energy Organization (OLADE), and countries including Australia, Belgium, Canada, Denmark, Germany, Finland, France, Iceland, Ireland, Italy, Japan, the Netherlands, New Zealand, Norway, Portugal, Sweden, Switzerland, the United Kingdom, and the United States.

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TUNISIA

POWER EFFICIENCY STUDY

FEBRUARY 1992

ESMAP Operations Division
The World Bank
Washington, D.C. 20433

FOREWORD

This study, which was carried out at the request of the Tunisian Electricity and Gas Utility (STEG) in agreement with the Industry and Energy Division of the Bank's Maghreb Department, was seen as a challenge from the beginning. STEG has good performance compared to that of most utilities in developing countries, with transmission and distribution losses of about 13 to 14% compared to 30 to 40% for many utilities of the same size.

In addition to reduction of network losses, the study identifies technical, organizational, and institutional changes that would increase the overall efficiency of Tunisia's power system, and recommends the measures and/or additional studies needed to implement the proposed changes.

This study was financed according to a special grant procedure, the "Trust Funds - Extended Agreement" with the assistance of Mrs. J. Ferry of the Multilateral Aid Division of the French Foreign Ministry.

The study was carried out within the framework of a contract between ESMAP and Electricité de France (EdF, the Consultant), with the active participation of a task force composed of representatives of the relevant STEG departments, coordinated by the Planning and General Studies Department, on behalf of STEG Management. The preliminary report of the study was examined at a meeting of STEG's Board of Directors on November 6, 1990, and a number of the recommendations made in the report were adopted.

The EdF team members were: Messrs. Henri Boyé (project manager), Gérard Aubert (generation specialist), Jean-Paul Barret (transmission specialist), Jean-François Bruel (computer distribution specialist), Raymond Sinus (distribution operation specialist), Marie-Line Marcin (technical distribution specialist), Olivier Gourlay (customer management specialist), and Alain Polvent (customer management specialist).

The STEG task force members were: Messrs. Hédi Turki and Hassen Mahmoud (Planning and General Studies Directorate), Messrs. Mahmoud Lakhoua, Mekki Ayed, Chekib Ben Rayana, Lamjed Fekih, Mohamed El Kamel (Operations Directorate), Messrs. Khaled Hammou, Hédi Turki, Chedly Jeddi, Taoufik Barbouche, Belgacem Ghariani (Distribution Directorate).

Noureddine Berrah (Senior Economist and task manager, ESMAP) supervised the project, and wrote this report, basing it on the reports submitted by the Consultant and on the comments of the STEG task force. F. Jouve (Power Engineer, ESMAP) contributed extensively to the final preparation of the report.

ACRONYMS AND ABBREVIATIONS

AME	Agence de Maîtrise de l'Energie
BCC	Bureau central de conduite (Distribution Control Center)
BDM	Bureau des méthodes (Procedures Department)
CAO	Consumption ascertained during operation
CL	Core losses
COMELEC	Comité maghrébin de l'électricité
DD	Distribution Directorate
DPTG	Département des techniques générales (Technical Facilities Department)
EdF	Electricité de France
GT	Gas turbine
GTD	Gestion technique des ouvrages
HHV	High heating value of fuel
HR	Heat rate (actual)
HV	High voltage
JL	Joule losses
LV	Low voltage
MSI	Mise en service industrielle (Commercial Operation)
MV	Medium voltage
NORDEL	Nord Electricité
OBC	Optimum base consumption
OD	Operations Directorate (Direction de l'exploitation)
SME	Service des Mouvements d'Energie
ST	Steam turbine
STEG	Société tunisienne d'électricité et du gaz (Tunisian Electricity and Gas Utility)
tan phi	Tangent of power factor angle
UCPTE	Union de coordination des producteurs et transporteurs d'électricité
VHV	Very high voltage

ELECTRICITY MEASURES

GWh	Gigawatt hour
J	Joule
kcal	kilocalory
kV	kilovolt
kVA	kilovolt amperes
kW	kilowatt
MJ	mega joule
MVA	megavolt ampere
MW	megawatt
TJ	tera joule
toe	ton of oil equivalent
V	volt

CURRENCY EQUIVALENT

1 US$ = 0.9 Tunisian Dinar

FISCAL YEAR

January 1 - December 31

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EXECUTIVE SUMMARY

1. In the past few years, the Tunisian Electricity and Gas Utility (STEG) has made significant progress in improving its operations and reducing losses in the electricity network. Fuel consumption per GWh produced has been reduced by about 23% in five years (from 309 toe/GWh in 1985 to 278 toe/GWh in 1987 and 251 toe/GWh in 1989) and the overall efficiency of the transmission network has been improved by about 2.5% in five years (from 83% in 1985 to 85.5% in 1989).1/

2. The diagnostic study carried out as part of the joint World Bank/UNDP Energy Sector Management Assistance Programme (ESMAP), with the active participation of STEG experts and support from the Industry and Energy Division of the Maghreb Department (EM2IE), has shown that:

(a) because of the progress STEG has achieved in electricity network operation and in customer management, the power loss rate in Tunisia is among the lowest to be found in the developing countries, especially with regard to nontechnical losses; however, preserving this achievement requires sustained efforts to improve management, rigorous application of existing procedures, and improvement of the statistical system and efficiency monitoring;

(b) additional savings can be made by introducing more advanced operating methods and by making economically justifiable power efficiency investments both in generation (heat rate reduction in the power plants) and in transmission and distribution (reduction of technical and non-technical losses).

3. Power generation. The audit of generation activities confirmed STEG's efficient performance in this area, despite certain weaknesses. The principal recommendations of the study entail:

(a) in the short term, (i) continuing rehabilitation and renovation of the old steam thermal plants so as to improve availability and efficiency; and (ii) standardization and upgrading of statistical data on fuel consumption and on generating unit availability;

(b) in the medium term, (i) minor organizational changes to ensure better coordination of operation and maintenance; and (ii) introduction of more advanced management methods to improve the efficiency of existing and future generating units, especially as the utility is still faced with a high tempo of investment.

4. Rehabilitation and renovation of old thermal power plants. STEG has begun to renovate its old steam thermal plants, which has significantly increased the efficiency of the units involved. The mission recommends that STEG continue these actions and that it establish a rehabilitation and renovation

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1/ *The overall efficiency of the network is defined as the ratio of energy billed to energy supplied, measured at the plant terminals.*

program for all the units in the La Goulette and Ghannouch power stations. STEG's experience has confirmed the conclusion ESMAP has reached in a number of countries, that well-planned investments in renovation and rehabilitation have high economic rates of return. The investments made at Goulette II to improve control systems and the installation of pre-heating equipment were recovered in nine months through energy savings alone, without taking into account the fact that renovation of the equipment extends its life and improves its availability, and hence enables investment in new generating units to be deferred.

5. Improving data quality and availability. This effort should be part of the overall review of the utility's statistical system and its computer master plan, after the Planning Directorate has completed an audit. However, certain measures, such as improving gas metering to make the relationships between the Gas Directorate and the Operations Directorate more transparent, and standardizing and improving the data on heat rate and generating unit availability, (the plant operators record these data monthly and annually), are urgently needed and essential to improved monitoring of the performance of the generating system.

6. Organizational measures. The mission recommends three minor structural changes to the Operations Directorate to improve coordination and prepare for the introduction of more effective maintenance methods and procedures:

(a) create the position of manager for steam turbine generation with the same level of responsibility as for existing positions related to gas turbine and hydropower generation. Creation of this position would improve coordination and standardization of procedures between the power plants and would strengthen the Operations Director's role as the overall manager and arbiter;

(b) establish a "Procedures Department" (Bureau des Méthodes - BDM) to enhance coordination of operation and maintenance of the combustion turbines. This department could be integrated into the existing BDM for the steam thermal plants and located at La Goulette so as to benefit from the assistance of the Technical Facilities Department (Département des Techniques Générales - DPTG); and finally

(c) create a small unit (starting with one engineer and one technician), perhaps within the BDM, to develop maintenance procedures and coordinate and monitor their implementation through the maintenance programs.

7. Implementation of online efficiency monitoring of the steam turbines. The report recommends study and implementation of computerized online efficiency monitoring of the steam turbines based on continuous comparison of the performance parameters obtained with unit reference parameters to ensure that fuel consumption approximates optimum base consumption (OBC) as closely as possible. The economic return on this investment is high since the investment payback period, even using conservative cost and benefit assumptions, would be around 11 months (see para. 2.50).

8. Introduction of "conditional" or predictive maintenance. The report recommends the study and introduction of "conditional" or predictive maintenance programs. STEG could use such programs, which are increasingly being adopted in the developed countries, for each component or family of components, using STEG in-house, centralized research resources (DPTG). ESMAP's experience in this area shows that such projects have very high internal rates of return, for companies less efficient than STEG. The estimated reduction in STEG's maintenance costs is around 8% to 10%, i.e., a saving of between US$1 million and US$1.25 million in 1990 and of between US$1.2 million and US$1.5 million in 1995.

Transmission

9. Simulations of the transmission network lead to two conclusions (see paras. 3.2 to 3.4):

(a) in all operating systems examined, theoretical power losses are about 1% to 1.2%, or only about one third of actual identified losses in 1989, which were around 3.6%. The reason for this discrepancy needs to be found: it could originate from metering irregularities and/or from failure to account for the substations' own power consumption, or to a discrepancy between the model (reference condition, electrical characteristics of lines and equipment) and actual operating conditions;

(b) the system power factor is abnormally low during the day, particularly during the morning peak period, around 0.82% in 1989 for the situations studied. Unless STEG implements reactive power compensation, the situation will grow worse over the medium term.

10. Analysis of the causes of technical losses in the network highlighted the need for three kinds of action:

(a) increasing the network operating voltage levels and selective reinforcement of the reactive power compensation equipment;

(b) improvements in the operation and maintenance of the transmission network; and

(c) progressive actions that contribute indirectly to increasing the efficiency of the transmission network, viz., strengthening the planning function and making organizational changes.

Voltage upgrading

11. The simulations show that raising the maximum voltage level from 210 kV to 225 kV reduces active power losses by some 2 MW for a load of 1,000 MW (peak demand in 1993). This upgrade, valued at the incremental cost for a kW of energy at the HV transmission level, produces a savings of about TD 400,000, or US$444,000, per year.

12. The mission therefore recommends the study and determination of suitable criteria to monitor and control the performance of the network, thus detecting weak points and anticipating low voltage conditions that may arise. This would allow the operators to take timely measures to restore voltage levels and maintain satisfactory service quality, and would avoid the risks of unplanned load shedding. The benefits due to improved service quality are hard to quantify but experience in other countries has shown that a 5% drop in nominal voltage at customer level leads statistically to a 2% drop in load. Poor service quality causes economic losses to customers and financial losses for the utility (see paras. 3.7 to 3.10).

13. The study showed that the system power factor is abnormally low, especially during the morning peak period, and that the situation will worsen unless measures are taken to enhance compensation by:

(a) using the gas turbines at Tunis Sud as synchronous compensators, and/or

(b) installing additional capacitors: in 1989, for example, 120 to 130 Mvar was needed to improve the power factor from 0.8 to 0.9. By 1993, 211 Mvar would be needed to maintain tan phi, the reactive to active power ratio, at 0.9 (see paras. 3.19 to 3.21).

14. Reducing transmission network losses cannot by itself guarantee a return on investments in compensation equipment, but such investments help to improve voltage control and, hence, to improve service quality and network reliability. Since detailed studies to evaluate all the advantages of compensation are beyond the scope of this study, the mission recommends that STEG undertake a study to identify, for all voltage levels, the number and types of compensation devices needed to ensure satisfactory network operation from a technical standpoint while keeping investment costs to a minimum.

Improving operations

15. The operation of STEG's transmission network is satisfactory, but to reduce the effects of insulator flashover, which is most marked in the 150 kV lines, and to reduce outages attributable to chemical and marine pollution, the mission recommends that STEG:

(a) undertake a study to measure cable sag and conduct a technical and economic analysis of the need to re-tension some cables; and

(b) improve insulator cleaning procedures in areas where frequent flashovers occur due to chemical and marine pollution, and study the feasibility of introducing procedures for hot line cleaning of insulators. In particularly polluted areas, it is advisable to introduce special types of insulators, at least on an experimental basis, and to undertake detailed technical/economic studies on the introduction of Gas Insulated Stations (GIS).

Organization and planning

16. To better fit the management responsibilities for operation and customer management to the technical demarcation between the transmission and distribution functions, two minor organizational changes are recommended :

(a) divide the responsibility for management and operation of the protective equipment according to the functional difference between transmission and distribution; and

(b) create a unit within the Operations Directorate to take over the management of high-voltage consumers from the Distribution Directorate.

17. The quality of network analyses should be improved and they should be integrated into periodic power system planning studies. For this purpose it is necessary to:

(a) provide additional data processing resources for the Planning Directorate;

(b) improve the methodology used in economic appraisal of investment projects; and

(c) systematize and computerize both data collection and statistical analysis.

Interconnection

18. Investigation of the operation of the Maghreb interconnection is beyond the scope of this study; however, it should be noted that the present interconnection between the Maghrebian networks is not being used optimally, essentially because tariff rates for the energy exchanged are not set on the basis of economic costs and there is no regular coordination and ongoing exchange of data between the three networks that are currently interconnected.

19. The mission recommends that COMELEC (Comité Maghrébin de l'Electricité) make an economic and technical study to determine whether it is economically feasible to set up a coordination and control center, based on a preliminary review of international experience in regional interconnections, such as that of NORDEL (Nord Electricité) and of UCPTE (Union de Coordination des Producteurs et Transporteurs de l'Electricité).

Distribution

20. In view of the great extent and diversity of STEG's distribution network, the study focussed on three representative network samples, selected in three areas according to the following criteria:

(a) network efficiency as defined by the ratio of energy billed to energy supplied;

(b) the ratio: km of MV lines/km of LV lines (see para 4.4).

Network data collection

21. A small portion of the data necessary for loss reduction and planning studies was either not available or not sufficiently reliable or consistent. Therefore, STEG must give priority to:

(a) continuing to build network data bases (structure, technical characteristics, loads); the existing database system, Gestion Technique des Ouvrages (GTD), should be improved to include all relevant facilities and their components (equipment);

(b) maintaining standardized network mapping (possibly computerized);

(c) improving the data system: collection, circulation and filing of network data and measurements, particularly in the case of the Distribution Control Center (Bureau Central de Conduite - BCC); and

(d) continuing and expanding studies to measure voltage drops and current losses on the network, within the framework of the GTD system.

Reducing MV losses

22. The estimated loss factor for the entire STEG network is 3.5% of total peak power. It can be reduced to about 3% by network reinforcement, i.e., by increasing the conductor size on 639 km of MV lines (see paras. 4.19 to 4.23). The overall cost of the investment is estimated at TD 3.6 million, or about US$4 million. The investment payback period is 3.3 years on average, but analysis of the sample shows that about 20% of the improvements have payback periods of less than two years; these should be implemented first (see para. 4.25).

Table 1: REDUCTION OF MV NETWORK LOSSES

Area	1	2	3 a/	STEG network
Length of MV network to be reinforced (km)	103	536	None	639
Cost (thousand TD)	996	2627	-	3623
Peak load gain (kW)	894	2190	-	3084
Financial savings (thousand TD)	322	790	-	1112
Payback period (years)	3	3.3	-	3.3

a/ See para. 4.22(c): the special case of the Charguia feeder line.

Reducing LV losses

23. The estimated loss rate for STEG's LV network is about 6.8%, but it could be decreased to 3.8% by reconductoring 944 km of LV lines, or about 3.1% of the total LV network, for a total cost of some TD 8 million, or about US$9 million. The payback period is about 3.7 years.

Table 2: REINFORCEMENT OF THE LV NETWORK

Area	1	2	3 a/	STEG Network
Length of LV Network to be reinforced (km)	832	-	112	944
Cost (thousand TD)	7184	-	962	8146
Peak load gain (kW)	3950	-	754	4704
Financial savings (thousand TD)	1862	-	355	2217
Payback period (years)	3.9	-	2.7	3.7

The report recommends that this program start with the reconductoring of those network sections with the highest return (see para. 4.30).

24. The Tunis city networks are a special case because reconductoring these lines would be more expensive and less cost-effective. However, it is essential to continue upgrading the voltage from 110 V (L1) to 220 V (L2) and to complete this program quickly (two to three years), since the indirect economic effects of this standardization on distribution equipment cost, on the one hand, and on the cost of household electric appliances on the other hand, are greater than the savings to be obtained from reducing losses.

Reducing transformer losses

25. Although losses in the HV/MV transformers are low, about 0.69% of peak demand, savings of about 3 GWh and 346 kW of peak demand, equivalent to TD 126,000, or about US$140,000, can be achieved merely by changing the operating practice of the 8 HV/MV substations. It is therefore recommended that STEG:

(a) during normal operation, keep only one transformer energized in the eight substations where this is clearly economically advantageous and technically feasible, without installing any additional switching equipment. The anticipated savings from reduced core losses are about TD 78,500 (US$87,000) per year;

(b) carry out technical/economic studies for the five substations where improvements are necessary, comparing the savings of about TD 47,000 a year (about US$53,000) from reduced losses with the cost of the work required (remote-controlled HV switches in particular).

26. Extrapolation of the results obtained from the MV/LV transformer study sample gave a loss rate of 3.3% at peak load. Reducing this percentage will require a better adjustment of the size of

each transformer to the peak load. The technical/economic study of the 10 kV network indicated that it was economic to interchange about fifty 500 kVA transformers and fifty 630 kVA transformers, for a total cost of about TD 11,000 (US$12,100) and an annual saving of about TD 6,000 (US$6,600), i.e., the payback period is less than two years (see para. 4.46). The standardized transformer sizes STEG has adopted produce significant threshold effects. The 400 kVA category appears to be the least cost in some situations; therefore, STEG should reconsider its announced intention to phase out its use.

27. It should also be noted that reducing the stock of transformers from 10% to 5% of total current inventory (about 1,000 units) would reduce associated costs (for storage, acquisition and delivery) by at least around TD 263,000 (US$290,000) per year.

Customer Management

28. Since 1986, STEG has made major improvements in customer management, aimed mainly at reducing technical losses and recovering debts. It has:

(a) trained its personnel in the detection of fraud;

(b) checked all the LV meters between 1986 and 1989 and monitored them since then;

(c) made an annual check of all MV meter records; and

(d) made a significant effort to reduce customer connection time and recover debts.

29. These actions have significantly improved STEG's overall performance, making it one of the best power utilities in the developing countries. STEG's nontechnical losses are estimated at less than 4% of total power sales.

30. The mission's recommendations are designed to complement STEG's program and consolidate these achievements by:

(a) enhancement and rigorous application of existing procedures; and

(b) adoption by STEG of management techniques and methods used in more advanced power utilities.

Metering

31. STEG's meter organization and meter reading procedures are effective and minimize the risks of fraud. They are based both on encouraging company personnel to combat fraudulent practices,

and on deterrence of these practices, supported by legal provisions that clearly equate fraud with the theft of electricity.

32. Experience in a number of countries shows that electricity theft spreads rapidly and is difficult to eradicate once it becomes pervasive; it is therefore recommended that STEG:

(a) ensure that procedures are strictly applied and strengthen deterrence through organizing swift, targeted meter monitoring campaigns, based on statistical analysis of metering data in areas where problems are frequent; and conducting monitoring campaigns in response to a specific type of problem or a specific client category (e.g., large customers, poor payers, those with billing irregularities, etc.). To increase their deterrent effect upon consumers, these campaigns should be well publicized in the appropriate media;

(b) increase procedural monitoring of the billing and data processing that is done at the end of each billing cycle to detect irregularities in consumption due to metering evasions or metering irregularities;

(c) introduce computerized management of the meters in service;

(d) encourage installation of meters on the outside of plant buildings; and

(e) where justified, gradually introduce electronic metering, which is more reliable and more adapted to monitoring multiple and complex tariffs.

Billing

33. Customer billing is done automatically in two computerized centers, Tunis and Sfax. Billing is generally satisfactory, since STEG agents deliver the statements to customers within three to five days. It is recommended that STEG:

(a) use a stricter management criterion for signing on new customers (see para. 5.17); and

(b) begin distributing bills by mail once the quality of the postal service, tested by pilot mailings, is considered to be adequate for STEG's needs.

Debt recovery

34. The management measures STEG has taken have enabled customer arrears in payment to be reduced from the equivalent of 64 days of average turnover in 1984 to 49 days in 1985 and 30 days in 1988 (see para. 5.26). Three-quarters of the arrears are attributable to government agencies, local authorities, and public corporations.

35. The mission recommends that STEG establish a long-term objective of reducing arrears to the equivalent of 20 days of average turnover by:

(a) focusing on enhancing recovery of debts from public and parastatal organizations by: improving the budgeted prepayment system to avoid difficulties in collecting the balance of the debt at the end of the year (see para. 5.25); statistical analysis of the power consumption of clients using this system, which would enable them to better forecast their electricity consumption when they prepare their annual budgets, and extending budgeted prepayment practices to the local government bodies, adapting the system as necessary to meet their special circumstances;

(b) encouraging professional clients, particularly the government corporations and agencies, to pay their bills through direct debits from their bank account; and

(c) incorporating into the computer applications now being developed an indicator that would monitor the level of debts outstanding after 20, 30 and 55 days. Such an indicator would improve information on the customer arrears and increase personnel awareness of the need for quick debt recovery.

Conclusions

36. The main investment programs and actions proposed are summarized in the table below.

Table 3: PROPOSED ACTIONS

Actions	Costs (US$ 000)	Annual savings (US$ (000)	Payback period (years)	Rate of return (%)
1. Set up continuous economic efficiency monitoring of steam turbines	1,000	1,250	< 1	> 100
2. Reinforce MV network	3,300	1,300	2.5	40
3. Reinforce LV network	9,000	2,500	3.6	28
4. Better management of MV and LV transformers	Low	150	1.2	-
5. Decrease the customer portfolio to 20 days turnover	Low or nil	780	-	-
6. Other improvement actions: maintenance, technical and financial management	Low or nil	1,720	-	-

37. Estimates of the economic impact of power plant emission reduction programs vary in a wide range, 1 to 10, according to existing studies. However, additional environmental benefits from the proposed power loss reduction programs can be conservatively estimated at US$7 million, that is about half of the total investments needed for their implementation.

38. To complement this supply-side program, it is recommended that STEG set up a task force to:

(a) study, in coordination with the Agence de Maîtrise de l'Energie (AME), the promotion of well targeted end-use electricity conservation programs that are economically and financially viable for the utility, the consumer, and the local authorities; and

(b) participate in their implementation through better customer information, possibly in association with partners, local authorities, and/or private promoters interested in promoting such programs.

MAIN RECOMMENDATIONS - SHORT-TERM

Area	Description	Means recommended	Benefits	Comments
Power generation	1. Continue equipment renovation (La Goulette) and circuit changes to reduce consumption of heat transport fluids (Gabès)	STEG audit.	Reduced consumption - of fuel - of water (SONEDE)	
	2. Set up monthly efficiency monitoring based on monitoring of heat rate variations.	STEG/consultant study (6 man-months, 2 of them for the consultant).	Reduced average heat rate. Monitoring of maintenance and performance problems.	Should be preceded by updating data on optimum base consumption by unit.
	3. Continue perfecting the software for online efficiency monitoring.	STEG study.	Improved operations.	
Transmission	4. Manage transformer taps.	STEG study.	Improved voltage control (very low cost).	
	5. Optimize the operating regimes.	STEG study.	Improved power factor - reduced losses.	Disconnection of one transformer. Energization of unloaded lines.
	6. Improve demand forecasting.	STEG/consultant study (1 man-month, consultant).	Fuel savings. Less demand on the units.	Should be done by setting up a demand forecasting unit.
Distribution (technical)	7. Improve network data collection.	Develop a network data base. Possibly set up computerized network mapping. Develop and extend measurement campaigns.	Improved network operation, which will contribute to reducing losses.	
	8. Reconductor 1st section of network.	Estimated cost of TD 4 million (US$4.5 million)	Reduced losses (estimated payback period of 2.5 years).	Applies to the LV network.
	9. Continue upgrading voltage from 127/220V to 220/380V in Tunis.		Reduced losses + national savings on cost of household appliances.	Action already underway.
Distribution (customer management)	10. Rapid campaigns for at-risk areas or directed to target consumers.	Localized action: very low cost.		Dissuasive effect.
	11. Install meters outside customer premises.	Very low cost for STEG if the client installs the (meter) box.	Increased productivity.	
	12. Regularly test and calibrate the meters of MV and LV customers who receive triphase current.	Very low cost.	Cash flow savings.	
	13. Launch campaigns to persuade high-volume consumers to pay their bills through direct debits from their bank account.	Implement in pilot areas.	Cash flow savings.	

MAIN RECOMMENDATIONS - MEDIUM-TERM

Area	Description	Means to be used	Benefits	Comments
Generation	1. Organizational measures.	Create a position of manager of the steam turbines. Create a Procedures Planning Dept. Create an office responsible for maintenance at plant level.	Improved coordination of operations and maintenance.	
	2. Write a maintenance policy and establish maintenance data.	Office, personnel (2), computer and data storage equipment.	Adaptive maintenance: change from preventive to conditional maintenance.	
Transmission	3. Provide network compensation.	Study the advisability of placing condensers at HV clients' facilities. Feasibility study of the use of gas turbines for synchronous compensation. Additional consultant study (2 man-months).	Reduction of losses. Improved operating reliability.	Estimated compensation requirements are 130 Mvar. Some of this compensation will be obtained through improved network operation.
	4. Improve operations.	+ measurement of voltage drops. + resolution of the problem of pollution of the insulators.	Will allow network operation at a higher voltage level (210 to 225 kV upgrade reduces losses by 2MW. Will improve network reliability.	
	5. Improve demand forecasting and planning.	Valorization study of demand forecasting deficiencies. Establishment and monitoring of a rotating reserve. Creation of a tariff schedule for thermal power. Additional equipment for data collection and storage.	More detailed planning studies. More efficient management of the generating units.	
	6. Study the advisability of setting up a Coordination and Control Center.	Feasibility study.	Improved efficiency of the interconnection between the Maghreb country networks.	
Distribution (technical)	7. Reduce transformer inventory.	Effective inventory census.	Estimated savings on fixed investment costs: TD 1.5 million (US$1.7 million). Savings on associated costs: TD 263,000 (US$290,000) per year.	The purpose of this action is to reduce inventory to 5% of total stock (about 1000 units).
	8. Provide network compensation.	Study of the advisability of placing condensers on the MV network.	Reduction of losses (IRR ≈ 30%).	
	9. Reconductor 2nd section of network	Cost: TD 8.2 million (US$9 million).	Reduction of losses: TD 2 million (US$2.2 million).	Reconductoring of MV and LV lines.
	10. Interchange the MV/LV transformers.	Cost: TD. 11,100 million (US$12,300).	Reduction of losses: TD 6,500 (US$7,250) per year.	Adaptation of unit sizes to unit loads.
Distribution (customer management)	11. Improve computerized data management.	Detection of abnormal power consumption (billing). Warning signal of the ratio of debts due according to the number of days of delay in payment (debt recovery). Computerized meter management (customer management).	Monitoring of measurement anomalies. Monitoring of speed of payment of bills.	Adapt to the local context.
	12. Bill customers by mail.		Increased productivity.	Monitor the quality of mail distribution.
	13. Introduce electronic metering gradually.		More flexible response to complex tariffs.	
	14. Encourage general use of budgeted prepayment for public and para-public client entities.	Very low cost.	The utility will save public funds.	

I. INTRODUCTION

1.1 In 1986, the Tunisian Electricity and Gas Utility (STEG) initiated a program to reduce losses in the electricity network. As a result, the overall efficiency of the system has been improved through reduction of:

(a) the heat rate of power stations from 309 toe/GWh in 1985 to 278 toe/GWh in 1987 and 251 toe/GWh in 1989; and

(b) transmission and distribution losses from almost 17% of power supplied in 1985 to 14.5% in 1987 and 1989.

1.2 It nonetheless became clear that an overall review covering the origins of losses from generation to distribution, network operating methods and customer management would enable STEG to consolidate the results achieved. Such an approach would also make it possible to establish priorities for enhancing the overall efficiency of the power supply system: investments to be made to reduce losses, introduction of new management methods, collection of the data needed for network control and for improved monitoring of system performance. By agreement with the Industry and Energy Division of the Maghreb Department (EM2IE), the Tunisian Government decided to undertake this study as part of the joint World Bank/UNDP Energy Sector Management Assistance Program (ESMAP).

Organizational Structure of the Tunisian Electricity and Gas Utility

1.3 STEG is a statutory government corporation, of a commercial and industrial nature, established by Decree Law No. 62-8 of April 3, 1962 on nationalization. This law makes STEG responsible for the generation, transmission, distribution, import and export of electricity and fuel gas under the supervision of the Ministry of the National Economy.

1.4 STEG has five (5) departments and ten (10) directorates which report to the chairman and managing director and are responsible for operating the electricity and gas systems and managing the utility. A more detailed description, as well as the corporation's organization chart, is provided in Annex 1.

1.5 STEG's Board of Directors has 14 members:

- 1 Chairman and Managing Director
- 1 Assistant Managing Director
- 8 directors representing the State
- 2 directors representing employees
- 1 financial controller
- 1 technical controller.

Neither consumer representatives nor any nongovernmental organizations active in the energy field or in environmental protection are represented on STEG's board; if they were, more consideration might be given to the problems that gas and electricity consumers experience and to involving consumers in the development of the sector.

Demand Growth

1.6 From 1962 to 1989, total electricity consumption grew at a very high average annual rate of some 11%. Since 1982, the pace of growth has slowed somewhat, but it is still substantial, about 7.5% between 1982 and 1989, as shown in Table 1.1 below.

Table 1.1: ELECTRICITY BALANCE

Year	1982	1987	1989	1996
1. National production (GWh)	3174	4549	5235	7400
a. STEG	2738	4016	4562	6680
b. Self-generated	436	533	673	7200
2. National consumption (GWh)	2792	4031	4605	6660
a. Delivered by STEG	2374	3544	3987	6000
b. Self-generated	418	487	618	660
3. STEG network losses				
a. in GWh (1a - 2a)	409	514	575	830
b. in % of power supplied	17.2	14.5	14.6	13.8

Source: STEG.

1.7 STEG's medium-term forecasts show that the growth in electricity consumption will slow slightly from 1989 to 1996 but will continue to be significant, about 6% a year. Thus, to minimize the investments required to meet future demand, STEG should consolidate the actions already taken to reduce losses and enhance the efficiency of the system.

Study objective and methodology

1.8 The principal aim of this study, therefore, is to analyze:

(a) STEG's three main technical functions, viz., the generation, transmission and distribution of electricity -- so as to identify the actions and investments needed to reduce the technical losses linked to the generation, transmission, and distribution of electricity; and

(b) customer management, in order to reduce nontechnical losses -- which are attributable not only to meter fraud as generally understood but also to the reliability of the meters used and the utility's policy for connection of new customers -- and to optimize the financial cycle by improving customer billing and the recovery of arrears in payment.

1.9 The following four tasks were carried out:

(a) a technical audit of power generation based on visits to the principal sites, working sessions with power station managers and staff from the central departments, a review of operating procedures, and an analysis of available statistical documents;

(b) technical audit of transmission based on site visits, discussions with transmissions staff, an analysis of operating procedures, and computerized network simulations;

(c) a technical audit of distribution based on field surveys, discussions with headquarters and regional staff, and computerized simulations of the medium-voltage network and of a representative sample of STEG's diverse low-voltage network.

(d) a review of the procedures used throughout STEG's customer management cycle, from metering and meter reading to bill collection.

1.10 Task objectives were to assess the losses in each area considered and to identify the actions required to reduce them to economically acceptable levels. To ensure the overall consistency of the approach and the recommendations, a preliminary study was made to estimate the incremental costs of the equipment at the various stages involved -- generation, transmission and distribution -- as well as fuel costs. To ensure that the recommendations proposed would be compatible with STEG's usual selection criteria, the method used for the calculations and the results contained in Annex 2 were submitted to and discussed with STEG officials before the economic evaluation was made.

Local participation and skills transfer

1.11 STEG participated actively and effectively in all phases of the study: diagnosis, economic evaluation, and review of the consultants' preliminary reports. The study was monitored by a task force comprising representatives of all the directorates involved, and coordinated by the Planning and General Studies Directorate.

1.12 Two study visits to France were organized, enabling six (6) members of the task force to visit transmission and distribution facilities in France, to familiarize themselves with the network

models used by the consultant, and, in the case of transmission, to participate in simulations of the Tunisian network.

1.13 To ensure lasting benefits from the effort undertaken to reduce losses, and to strengthen the network analysis function within STEG, the study was complemented by:

(a) organization of a seminar to increase awareness of the problems of network losses, and presentation of the analytical methods and models needed for loss reduction; and

(b) transfer of a PC-computer model for study of the distribution networks, and training of engineers in its use.

Action (b) was made possible thanks to STEG's participation in financing the local costs of the project.

Report organization

1.14 The report layout reflects the approach adopted for the study. Following a short introduction focusing on the background to the study and the methodology adopted (Chapter I), four chapters present the results of the analyses, and recommendations for reducing losses and improving management in the areas of generation (Chapter II), transmission (Chapter III), distribution (Chapter IV) and customer management (Chapter V). Chapter VI summarizes the main conclusions of the study.

II. ELECTRIC POWER GENERATION

2.1 Installed capacity rose from 273 MW in 1972 to 1,179 MW in 1989, in three stages:

(a) installation of a 30 MW steam turbine (La Goulette, Ghannouch);

(b) installation of gas turbines (particularly in the south) using gas from El Borma and gas oil;

(c) installation of 150 MW steam turbines (Sousse, Radès).

The detailed list of generating equipment given in Table 2.1 (on following page) reveals that, although hydropower capacity doubled between 1972 and 1989, it is still limited (about 5% of installed power).

Table 2.1: STEG GENERATING EQUIPMENT in 1991

Plant	Unit	Year brought into service	Net installed capacity (MW)	Maximum capacity (MW)	Fuel used
1. Steam turbines					
Goulette 2	ST1	1965	28	22	Fuel oil
	ST2	1965	28	22	Fuel oil
	ST3	1968	28	22	Fuel oil
	ST4	1968	28	22	Fuel oil
Ghannouch	ST1	1972	30	28	Fuel oil/Gas
	ST2	1972	30	28	Fuel oil/Gas
Sousse	ST1	1980	150	140	Fuel oil/Gas
	ST2	1980	150	140	Fuel oil/Gas
Radès	ST1	1985	160	150	Fuel oil/Gas
	ST2	1985	160	150	Fuel oil/Gas
Total ST			790	724	
2. Gas turbines					
Ghannouch	GT1	1971	15	15	Gas
	GT2	1973	22	20	Gas
	GT3	1973	22	20	Gas
	GT4	1983	34	30	Gas
Bouchemma	GT1	1977	31	25	Gas
	GT2	1977	31	25	Gas
Tunis South	GT1	1975	22	20	Gas
	GT2	1975	22	20	Gas
	GT3	1978	22	20	Gas
Sfax	GT1	1977	22	20	Gasoil
	GT2	1977	22	20	Gasoil
M. Bourguiba	GT1	1978	22	20	Gasoil
	GT2	1978	22	20	Gasoil
Metlaoui	GT1	1978	22	20	Gasoil
Korbe	GT1	1978	22	20	Gas
	GT2	1984	34	30	Gas
Kasserine	GT1	1984	34	30	Gas
	GT2	1984	34	30	Gas
Robbana	GT1	1984	34	30	Gasoil
Total GT			489	435	
3. Hydropower					
Nebeur	1	1956	6.5		Hydropower
	2	1956	6.5		Hydropower
El Aroussia	1	1956	4.9		Hydropower
Fernana	1	1958	9.7		Hydropower
Kesseb	1	1969	0.7		Hydropower
Sidi Salem	1	1983	36.0		Hydropower
Total hydropower			64.3	20	
Total inventory			1343.3	1179	

Steam Turbines

2.2 STEG's steam thermal equipment consists of the following:

(a) six 30 MW units with a single-stage turbine (Ghannouch 1 and 2; La Goulette 3 and 4) or a double-stage turbine (La Goulette 1 and 2);

(b) four 150 MW units, of more recent design, and equipped with three-stage turbines (Sousse 1 and 2; Radès 1 and 2).

Because the two categories are different in age and design, there are considerable differences between their reference heat rates (as determined during the commissioning tests when they were brought into service). The 30 MW units are rated at 2950 kcal/kWh, while the most recent 150 MW units (Radès, using natural gas) are rated at 2350 kcal/kWh. The difference in performance between the 30 MW and 150 MW units is mainly due to:

- higher steam temperature (540°C instead of 500°C) and higher pressure (145 bar instead of 66 bar) at the turbine intake;
- addition of a steam superheater;
- an increased number of stages.

These improvements increase cycle performance and reduce the heat rate.

Heat rate monitoring

2.3 Heat rates are regularly monitored in the plants and recorded in the operating logbooks. In the plants visited, the logbooks were up-to-date and well maintained. Monthly and annual statistics are produced by unit, by plant, and by unit size. All deviations from the heat rates recorded in the commissioning tests are analyzed and included in the monthly reports, copies of which are forwarded to the Operations Directorate (OD).

2.4 STEG's Research and Development Service is developing efficiency monitoring software at the Sousse plant, and intends to supply it to other plants once it becomes operational.

2.5 The software processes data on the operating parameters of the equipment, including: boiler, turbine, and alternator efficiencies, and heat rates. The parameters are currently measured through brief tests at flat power outputs. The heat rate values thus obtained are compared, after correction, with their reference values. It should be noted that the Radès plant has one computing device

per unit; these devices print out lists of values on demand, and can perform operations such as integration, derivation, and averaging. The La Goulette plant has on-line computing resources (the Bailey micro Z system), in the central control room for the four units.

2.6 Analysis of the heat rates obtained from the various readings on the equipment operating parameters (aggregated in Table 2.2) reveals that:

(a) the Sousse and Radès plants, which account for over 80% of steam-driven installed capacity and about 50% of total installed capacity, perform very well. Heat rates for the two plants are very close to the reference values, particularly if allowance is made for deviations due to output variations and to operating guidelines that require the fuel-burning circuits of gas fueled units to be kept heated (Radès). At Sousse, however, the very wide discrepancies in monthly heat rates compared with the annual average should be noted (see Annex 4).

(b) the performance of Gabès is quite poor. The average heat rate for 1988 exceeds the reference value by 17.4%, a considerable difference, even allowing for the age of the equipment and variations in load; and

(c) in La Goulette, heat rates have definitely been improving since the following major improvements were made to the plants: (i) new boiler controls; (ii) more efficient fuel heaters and fuel pumps brought into service; (iii) riser tubes replaced (unit 2) and intermediate superheater and economizer replaced (unit 4); (iv) units 2 and 3 overhauled and turbines repaired (blades and seals).

Table 2.2: STEAM PLANT HEAT RATES IN 1988

Plant		Annual heat rate (kcal/kWh)	Reference heat rate (kcal/kWh)	Efficiency difference kcal/kWh	Efficiency difference %
Sousse	1	2630	2565	65	2.5
	2	2613	2565	48	1.9
Radès	1	2428	2350	78	3.3
	2	2437	2350	87	3.7
Gabès	1	3357	2860	497	17.4
Goulette	1	3215	2889	326	11.3
	2	3215	2889	326	11.3
	3	3215	2958	257	8.7
	4	3215	2958	257	8.7

Note: Annual heat rates are not directly comparable with reference values because the latter were measured at nominal output when delivered and thus take no account of load variations. Nevertheless the efficiency differences noted can be considered indicative of unit performance.

Analysis of deviations

2.7 Differences of actual heat rates from rated values are usually divided into the following three categories:

(a) Internal differences due to unit control: These may result when shift teams do not respect correct operating procedures;

(b) Internal differences due to the equipment: These are caused by the condition of the equipment (e.g. wear in some components, partial unavailability etc.); and

(c) External differences: These are essentially the result of meteorological changes (air temperature, temperature of the cooling source, etc.), which have a direct impact on performance. Also included in this category are differences resulting from operating procedures imposed by the national control center (variations in load and frequent unit start-ups seriously affect heat rates).

Internal differences due to unit management and equipment condition (maintenance) are indicative of the quality of unit operation, but operators have no control over external differences. In these cases, only the operators of the National Control Center can effect any improvements.

2.8 Consequently, unit performance can be described as follows:

Heat rate = Adjusted rated value
+ external differences + internal differences due to unit management
+ internal differences due to equipment condition + unexplained differences

As STEG's existing information system does not enable a distinction to be made between the various categories of difference, the following analysis of differences is more qualitative than quantitative; it is based on visits to plants and conversations with operators.

2.9 Internal differences due to unit control and operator training: In STEG these are minimal. Detailed inspections of control rooms and conversations with unit control teams show that:

(a) shift supervisors and command console operators are well aware that compliance with the reference variables for the main operating parameters (steam pressure and temperature, condenser vacuum, excess oxygen, etc.) has a positive impact on efficiency;

(b) the staff are familiar with the operating procedures, operating diagrams, and instructions, and these are kept updated;

(c) panel equipment readings that are obviously wrong or inconsistent with other parameters are reported to the Technical Service so that it can carry out repairs or recalibrate the instruments; and

(d) on the whole, recruitment and training of operations staff are satisfactory.

2.10 However, to alleviate the scheduling problems connected with providing training and skills upgrading for the rotating shifts (who ensure round-the-clock operation of the plants), the following improvements to in-service training are recommended:

(a) the preparation of training packages, comprising both text and diagrams. Each package would deal with a specific subject (the alternator, the feedwater system, the turbine, etc.) and the complete set of training packages would constitute a body of training appropriate to the functions and level of each staff member. The packages would be distributed to the various members of the shift teams, who would study them individually. Consequently, each team would work together to upgrade the group's expertise. The department superintendent would be responsible for the overall management of the training program; and

(b) training center instructors should receive frequent feedback from operations to ensure that a proper balance is maintained, at the control level, between technical knowledge itself and the transferability of such knowledge.

2.11 Internal differences due to equipment: A large number of localized technical problems partly account for the high or even random heat rate values obtained from some units:

(a) in Sousse, substantial air leaks from the air preheaters;

(b) condensers are frequently clogged by algae and marine organisms; as a result, residual pressure in the condensers increases, leading to impaired performance. This problem is particularly serious in Gabès, where, in addition, the condenser tubes are often blocked by phosphogypsum, a viscous substance discharged by phosphate companies in the ore-washing process; and

(c) the quality of the heavy fuel oil being used has deteriorated (higher specific gravity). As a result of improvements in the distillation and cracking processes, the oil supplied to the thermal plants has a higher viscosity (the percentage of heavy components has increased); therefore, new and more efficient precombustion fuel heating systems must be installed; consequently, steam consumption by the auxiliary equipment has increased, and heat rates have risen slightly.

2.12 Numerous improvements currently underway (particularly to older equipment) should reduce the internal differences due to equipment and thus improve plant performance:

(a) in addition to the extensive repairs in La Goulette described in para. 2.6(c), circuit modifications and other improvements have been completed or are in progress in Ghannouch and La Goulette;

(b) improved fuel preheating in La Goulette enables the use of fuels of international standard (i.e., with a viscosity between 310 cSt and 380 cSt instead of between 110 cSt and 310 cSt), so that savings can be made when the fuel is purchased;

(c) due to improvements to the control assembly, at La Goulette, the boilers can operate using only small amount of excess air; thus, boiler efficiency is increased, since dry gas losses have been substantially reduced; and

(d) routine repair of leaks in the demineralized water system (analysis of water samples, checking for packing leaks) reduces the differences due to water losses.

2.13 In the Ghannouch plant, substantial savings in well water have been achieved by:

(a) use of filtered sea water instead of brackish well water to regenerate the membranes in the water demineralization system;

(b) use of seawater to ensure the watertightness of the circulation pumps;

(c) use of seawater to clean the main condenser.

2.14 The Technical Service tests the measuring devices at the operators' request. The oxygen meter readings are checked on site with a simple, portable exhaust gas analyzer, which gives rapid and sufficiently accurate results. The device (similar to the ORSAT) operates on the principle that the various components of a known sample of gas are absorbed when they are passed through various solutions that have the appropriate chemical properties. Such tests, made only when operators request them, ensure the measuring devices in the plants are reliable.

2.15 To ensure that the measures STEG has undertaken are sustainable, and to refine the results already achieved, it is recommended that routine tests be carried out on all equipment (at intervals to be determined). Priority should be given to testing the components that affect the heat rate (checks for leaks, monitoring of pump performance, recording the performance indices of the auxiliary electric and steam equipment, checking fuel combustion, etc.). The results should be entered regularly into logbooks reserved for that purpose, and should be used to anticipate and plan for maintenance operations.

2.16 Unexplained differences: The high heat rates (and the wide discrepancies among them) recorded for the Ghannouch and Sousse units when these are burning gas are not only due to problems of unit control or to the condition of the equipment. Inspections performed by the STEG Operations Directorate have revealed that, in these plants, measurements of gas flow were highly inaccurate. Gabès (which uses gas from the El Borma field) has an additional problem with fluctuations in the high heat value (HHV). Routine gas chromatography measurements in Gabès indicate that the composition of the incoming gas varies in relation to the amount of propane extracted from it by the upstream liquefaction facility; these variations in gas content account for the fluctuations in HHV.

2.17 To make gas flow measurements more reliable, STEG staff plan to install gas gauges at the high pressure stage (before pressure reduction) in addition to the meters at the Sousse and Radès plants (done exclusively for large-scale customers). Such measures will not solve the problems related to gas metering, which make any heat rate calculation less accurate. Even where dual meters are installed, it is recommended that the gauges be calibrated by means of standard meters which have counters that adjust for flow according to variations in pressure, temperature, and density. Before the calibrations are made, a precision recorder should be used to read gas flow under a constant load and for a reasonably long period (several days). Using this method, abnormal variations in gas flow could be identified at the same time as heat rates are being computed, over a significant time period.

2.18 To ensure continuous measurement of gas HHV, one solution would be to install an online gas spectrum analyzer to provide regular readings of mean values at 20-minute intervals. Because the equipment is expensive and gas reserves in El Borma are limited, an additional economic feasibility study is needed to determine if such an investment is justified.

Setting up efficiency monitoring in the STEG plants

2.19 The method STEG uses to calculate the heat rate, which consists of comparing the electrical energy registered at the terminals of the main transformer with the thermal energy contained in the fuel, provides accounting parameters essential to the management of generating equipment. However, the results do not give a precise indication of the quality of operation of the units, because:

(a) they do not clearly show the impact on heat rate of the various aspects of equipment maintenance or of unit management (the internal differences); and

(b) they include items unrelated to plant operation such as differences due to generating schedule changes imposed by the National Control Center.

2.20 Because STEG recognizes the importance of optimal management of fuel consumption, and its impact on efficiency, it is taking steps to monitor heat rates in the plants. Unit heat rates are included in the contracts between STEG headquarters and plant managers, as one of the performance criteria to be monitored.

2.21 In addition, efficiency monitoring software is being tested in the plants. This software should enable heat rates to be calculated in conformity with international standards by assessing the various components of the units -- boilers, turbines, alternators -- and evaluating condenser cleanliness.

2.22 Although these measures are important, they do not ensure effective monitoring of the quality of plant operations because they do not provide continuous monitoring of differences between actual heat rates and optimum base consumption (OBC). Consequently, the following recommendations are made:

(a) evaluate the software now under development and estimate the resources that would be needed to complete it and adapt it to the method of continuous efficiency monitoring summarized in Annex 5;

(b) evaluate existing efficiency monitoring software that could be adapted to STEG's needs;

(c) compare the three possible solutions (internal development of a new system, purchase and adaptation of existing software, or a combination of the two), taking into account the cost, the resources required in each case, time required to implement the system, etc.;

(d) during a first phase, apply the method selected to one 30-MW plant and one 160-MW plant; and

(e) in a second phase, extend the measures to the remaining plants.

Annex 6 contains terms of references outlining the specific tasks to be performed and the technical assistance required to complete them.

Unavailability rates (1988)

2.23 As defined by UNIPEDE in 1977 (see Annex 7), unavailability rates for STEG plants in 1988 are the sum of the following:

(a) unavailability rates resulting from scheduled maintenance work; and

(b) miscellaneous unavailability rates, that is, any factors attributable to plant operation.

2.24 The unavailability rate is as follows for the various plants visited:

(a) Sousse: The mean unavailability rate for the two units was 13.5% in 1988.

(b) Radès: A steam leak from the HP cylinder seal in unit 1 caused available power to be restricted to 15%-20% from April 1988 until the unit was overhauled the following year.

(c) Ghannouch: Taking into account only unavailability due to plant operations, in 1988 the mean unavailability rate for the two steam units was 18.13%.

(d) La Goulette: The low unavailability rate for unit 1 (13.6% in 1988) is partly due to overhaul of the unit and to renovation work done in the previous year. Unavailability rates for the other units are: Unit 2: 55.5%; Unit 3: 88%; Unit 4: 69%. These figures are high because of prolonged shutdowns of the units for renovation work (similar to that previously performed on unit 1).

Although some individual results are similar to the mean values recorded for similar units in the United States and Europe over a 5-year period, the lack of statistical data limits the scope for any real comparison. Commissioning of some units such as Radès 1 and 2 has been performed too recently for the availability data on these units to be regarded as reliable indicators of the quality of operation. Other plants have only recently begun to use units that can exchange heat; that situation in addition to the presentation of operating results in the form of averages makes it difficult or even erroneous to make assessments of unit performance.

2.25 To improve both the number and the quality of statistics on equipment unavailability, a unified format should be developed for the annual report of activities for all the STEG plants, to facilitate data analysis and comparison of the results according to unit capacities. It would also be desirable to present the results by month and by unit in the form of tables and bar charts or graphs, and to avoid the use of overall averages (heat rates, unavailability rates, unit utilization rates, etc.).

Maintenance

2.26 STEG currently practices routine preventive maintenance in its plants, modified step by step, in the light of experience (see Annex 8 for definitions of the various types of maintenance). A group comprised of representatives of the various units and the Studies Directorate is developing "maintenance" software at the Sousse plant and will supply it to the other plants when it is ready for use. The software complies with STEG's maintenance policy; it is programmed to schedule routine maintenance, taking into account maintenance done in response to current work orders, as well as the operating record of the equipment, so that the time periods between routine maintenance interventions can be modified accordingly.

2.27 Routine maintenance also depends on continuous monitoring of significant parameters or of operating parameters that reflect changes in the performance or degree of wear of a component, as follows:

(a) vibration readings on the main turbogenerators, in compliance with manufacturers' standards (using portable or fixed equipment);

(b) analysis of oil samples (turbines, diesel engines) since this often indicates the condition of the interior parts; and

(c) vibration analysis (of the steam and gas turbine blades) by the Technical Facilities Department (DPTG) to detect cracks.

This type of maintenance, "modulated" by the equipment operating record and by permanent monitoring of the equipment while it is in service or during scheduled shutdowns, is increasingly practiced in developed countries, particularly in the United States, where it is referred to as "conditional or predictive maintenance."

2.28 The maintenance procedures developed by power utilities depend on the type of equipment being used, taking the safety of personnel and the impact of unavailability on overall service quality into consideration. International experience has shown that conditional maintenance is advantageous for generating equipment, particularly for high-powered units; for example, in developed countries -- particularly in the United States -- conditional maintenance has reduced maintenance costs for some components (such as feedwater flow controls) of 300 MW and 500 MW nuclear and thermal power units to about 30% of their previous level.

2.29 For Tunisia, it is recommended that a small task force be established at the central management level, responsible for developing maintenance guidelines specific to STEG equipment and adapting maintenance procedures to match these guidelines, so as to improve equipment availability and reduce overall maintenance costs.

2.30 Considering that units with increasingly high power levels are being introduced, the following measures should be taken to develop conditional maintenance for the generating equipment:

(a) increased -- and more routinized -- vibration recordings of the turbogenerators, at least for the most recent equipment, that used in 150 MW or larger systems), and adoption of routine inspection procedures (analysis of oils, monitoring of insulator status), needed to improve monitoring of the pattern of change in the various components; and

(b) more efficient use of DPTG's technical and human resources by introducing routine gas turbine inspection procedures (ultrasound, thermography).

2.31 The introduction of conditional maintenance procedures complements the establishment of plant efficiency monitoring; financial resources dedicated to monitoring equipment components will serve both objectives. Routine monitoring of some components could later be incorporated into more advanced computerized systems (expert systems) that could be used to determine the type of work to be performed during equipment shutdowns so that routine maintenance on components that do not require it could be avoided.

Inventory management

2.32 Inventory management software is being developed for the plants. This conventional inventory management model has the following features:

(a) cataloguing and categorization of equipment;

(b) (automatic) request for replenishment of items once they fall below a predetermined level; and

(c) adjustment of this level to match actual inventory turnover.

This software is being tested at Sousse and will soon be supplied to the other plants.

2.33 Inventory levels in STEG's plants are higher than those maintained in power utilities in developed countries because the observed average time lapse between order and delivery is, in some cases, as long as two years. This excessively long delay has the following consequences:

(a) large numbers of staff are required to follow up on orders, analyze the bids, and issue new requests for bids in cases of nondelivery; and

(b) substantial funds are tied up in "precautionary" purchases of items to be kept in reserve to guard against the risk that a unit's unavailability will be extended when it is overhauled, due to a lack of spare parts (lack of inventory).

2.34 Although some operations are either unavoidable or cannot be performed in less than the time allotted, an in-depth analysis should be made of the various stages of the spare parts procurement process, from the decision to obtain supplies to the delivery of equipment at the storage facility, to identify the causes of delays. The analysis should lead to:

(a) internally, elimination of superfluous operations, changes in certain management rules, and/or possible changes in signature requirements; and

(b) externally, preparation of documents to be discussed with government authorities, with a view to reducing the length of time needed for importing goods; the documents would enumerate the benefits to be expected from simplification of import procedures.

2.35 For the procurement of consumables (for the central warehouse), the utility should further standardize supplies in order to simplify acquisition procedures, without jeopardizing the utility's ability to encourage competition between the various suppliers in order to obtain the most advantageous financial conditions.

Combustion Turbines

Heat rates

2.36 Design considerations (exhaust gas temperature) restrict the performance of the combustion turbines. The observed decrease in the performance of the turbines in service is mainly due to dirt blocking the air prefilters and filters. The unit control operators constantly monitor performance. Filters are regularly changed and the compressor blades are cleaned either manually or by the use of carboplast. Average heat rates are classified by site and by year (see Table 2.3); this practice illustrates the need for more detailed investigation to discover the reason for these differences and to use the results to implement a program for reducing fuel consumption. For example, a 1% reduction in heat rate in 1989 could have produced fuel savings of about 15 million thermies or 1500 toe.

Maintenance

2.37 Because of their marginal use, combustion turbines are installed ad hoc in locations where power generation is insufficient. They are often used in spite of their high heat rates,2/ because they can be installed rapidly and require a lower capital investment than steam thermal units. Because these low-capacity units are widely dispersed, maintenance resources are also dispersed; thus, it is difficult to plan overall gas turbine maintenance, manage inventory, and take prompt maintenance actions when necessary. STEG's combustion turbine maintenance resources are inadequate:

(a) a general storage facility at La Goulette 1 (on the site of the former plant);

(b) a maintenance office in the Operations Directorate; and

(c) on-site teams to provide unit control and preventive maintenance.

STEG does not have enough personnel to ensure adequate maintenance of the gas turbines, and the professional experience of existing personnel is insufficient (of the 15 members of the maintenance staff, 10 have less than two years' experience).

2/ *The steady progress made in increasing the reliability of combustion turbines and improving their heat rates, and the advantages of incorporating a steam cycle, should be noted.*

Table 2.3: STEG - STATISTICS FOR THE COMBUSTION TURBINES 1988-1990

Centrale	TG	Puiss. MW	1988					1989					1990					Cumul des H. de marche fin août 1990	Cumul des H. de démarrage fin août 1990
			HM	ND	CS	TD	Fiab D	HM	ND	CS	TD	Fiab D	HM	ND	CS	TD	Fiab D		
Ghannouch TG	1	15	3064,3	100	3853	51,1	73	755	39	3311	65,2	31,5	104,1	23	4311	75,7	33,6	82736	-
	2	22	494	38	3450	10	94,7	3200,7	226	3468	93,7	36,7	1638,3	134	3550	98,5	92,2	74547,6	2775
	3	22	4758	172	3565	96,9	89,5	4642,3	165	3481	97,2	95,7	370,2	24	3753	43,4	95,3	90324,9	3135
	4	34	-	-	-	-	-	399,1	22	3754	93	100	2360,6	123	3740	99,7	93,3	20280,8	570
Bouchemma	1	31	4118	54	3913	76	98,1	1530	26	3735	19,3	88,4	1808,1	37	3797	94,6	100	67877,8	841
	2	31	4016,8	75	3861	96,3	83,5	4780	34	3915	93,4	100	39,1	4	3707	100	100	64301,2	983
Tunis Sud	1	22	261,3	30	4445	68,8	98,7	390,5	151	3850	96,9	93,3	363,2	108	3880	99,5	100	26196,7	5803
	2	22	413,2	154	3833	66,8	84,8	329,7	133	4514	91,8	96,2	415,3	130	3758	93,1	100	24273,1	3775
	3	22	623,1	144	3635	99,5	97,7	397,3	155	3754	99,1	98,7	253	89	3645	83	93	23635	3474
Korba	1	22	809,1	173	3527	93,6	94,4	597,3	1661	3543	92,6	92,3	590,2	161	3485	94,9	35,4	19693,8	3418
	2	34	1433,9	229	3550	93,3	95,6	1934,8	322	3328	94,2	89,5	1565,7	226	3777	94,9	90,2	14457,2	1370
Kasserine	1	34	1260	193	3705	89,3	89,5	1110,9	203	3771	97	91,3	1278,7	204	3743	73,7	85,8	12170,3	1436
	2	34	1417	210	3450	93,1	88,1	1305,7	221	3572	96,3	96,5	1417,5	203	3509	99,3	94,9	10235,8	1104
H. Bourguiba	1	22	22,3	22	4531	93,5	86,4	29,3	33	4637	64	85,9	11,3	9	4042	75,3	93,4	12132,3	2173
	2	22	55,4	53	4740	67,8	67,3	41	52	4389	93,6	100	43,1	14	4127	63,2	100	12254,3	2001
SFAX	1	22	55	68	4970	70,6	73,5	33	21	3889	98,7	95,2	25,6	19	3875	98,7	78,9	8490,2	1480
	2	22	76	57	4648	78,9	79	32,8	24	4302	79,7	83,3	19,6	12	4041	99,1	100	6782,9	1990
Metlaoui	1	22	49,2	28	4848	99,7	100	26,5	17	4383	98,8	100	51	13	4058	96,4	100	5634,5	1254
Robbana	1	34	175,8	50	5231	95	100	83,7	26	4683	99,6	92,3	37,2	22	4223	97	68,2	1700	496

HM: Hours of Operation; ND: Number of Startups; CS: Heat Rate (kcal/kwh)
TD: Availability Rate (%); Fiab. D: Startup Reliability (%)

2.38 To facilitate maintenance and planning operations for all combustion turbine installations, we recommend that STEG establish a "Procedures Department" (Bureau des Méthodes - BDM), which would have the same responsibilities as the existing BDM for the steam thermal plants. This unit could be located close to the general storage facility at La Goulette so that it could perhaps benefit from support from the DPTG (in the form of laboratories and workshops). It should be provided with a drafting office and should have a documents manager who would be responsible for putting together a complete set of technical information on the various units. The set would include flowsheets, repair charts, the operating records of the machines, and information on the range of maintenance actions to be taken.

2.39 With regard to training, the consultant proposes that staff members who have attended short training courses abroad (organized by the manufacturers) should organize seminars, possibly with assistance from the Khledia training center, to pass on their knowledge to others.

Unavailability

2.40 If more resources are provided for maintenance and training, equipment availability and start-up reliability should be improved. The equipment start-up average (about 88% in 1988 and 1989) is too low. (Under normal conditions, the average should be between 95% and 100%.)

Hydropower Generation

2.41 The hydroelectric installations in the west of Tunisia are used mainly to:

(a) regulate water flow from the wadis when water levels are high;

(b) irrigate farmland; and

(c) provide drinking water for the large towns.

The remaining capacity is used to power turbines following an hourly quota managed in cooperation with the National Control Center. (The water is used mainly during peak hours, to avoid starting up more expensive equipment, such as gas turbines.)

Efficiency/Availability

2.42 The performance of foot-of-the-dam hydropower installations that receive highly sedimented water is generally poor. In such cases, turbine blades suffer wear (as at Nebeur) and the

turbines have to be remetalled. This technical problem is under control in the STEG installations, and there is no real problem of unavailability.

Maintenance

2.43 Equipment scarcity and equipment aging are the main causes of maintenance problems. Consequently, operators have considerable autonomy in performing maintenance. The equipment operators handle routine maintenance, while teams that include personnel from other plants perform major maintenance and overhauls, with support from DPTG when necessary.

Conclusions and Recommendations

2.44 The audit of STEG's generating operations confirmed that the utility performs these functions well, despite some shortcomings. Improved procedures for equipment management and operation and improvements in the operators' technical knowledge would help overcome these shortcomings, consolidate the considerable progress achieved over recent years, and increase the efficiency of existing and future generating resources, bearing in mind that STEG is still facing a rapid tempo of investment.

2.45 STEG is aware of the need to increase the efficiency of its system and has taken a number of steps in recent years to:

(a) reduce fuel consumption in the plants by: (i) overhauling and modifying the systems in its aging units, particularly in the Ghannouch and La Goulette plants; (ii) developing a software application to improve monitoring of fuel consumption in the steam plants. STEG's experience confirms the conclusions reached by ESMAP in several countries, that investment in renovation produces high economic returns. In Gabès, modifications and improvements to systems by the plant's maintenance personnel have produced savings of about TD 105,000 (about US$117,000) per year through reductions in water losses, and the investments made in improving regulation and in installing fuel heaters at La Goulette 2 were recovered in nine months through the energy savings obtained; and

(b) improve management and equipment operation by modifying procedures and developing computerized systems that enabled better maintenance in the steam plants (through a pilot project at the Sousse plant) and better inventory management by the plants.

Short-term recommendations

2.46 The following measures are recommended:

(a) continue to renovate those aging thermal steam generating plants whose renovation has been proven cost-effective in STEG studies, which, incidentally, considered only the savings to be made from reduced water loss (Gabès) and reduced fuel consumption (La Goulette). In addition to these benefits, renovation extends the useful life of equipment and defers the need to invest in new generating equipment;

(b) evaluate the "fuel efficiency monitoring" and "maintenance" software being used in the steam thermal plants to ascertain whether it can be adapted to more advanced management methods such as online efficiency monitoring based on the continuous monitoring of deviations from optimum base fuel consumption together with "conditional predictive maintenance" based on continuous monitoring of the units while they are in operation; and

(c) improve the availability and quality of the data needed for introducing more advanced management and operating procedures in the plants. This measure could be incorporated into a thorough review of STEG's data gathering and processing system, but some measures, such as improved gas metering at the Ghannouch and Sousse plants, are urgently needed.

Medium-term recommendations

2.47 Continuation and consolidation of its existing activities will enable STEG to upgrade the quality of its management and adopt the most advanced methods for operating its generating units and monitoring their performance.

2.48 Organizational measures: To improve coordination and prepare for implementation of more efficient maintenance procedures, three minor structural changes in the Operations Directorate are recommended:

(a) create the position of manager for steam turbine generation with the same level of responsibility as for existing positions related to gas turbine generation, hydropower generation, and transmission. Providing an intermediary between the plant managers and the Operations Director would ensure (i) separation between the management and operation functions; (ii) individual representation of steam generation in the Operations Directorate, similar to that for the other generation functions; and (iii) reinforcement of the Operations Director's coordination role;

(b) create a "Procedures Department" (Bureau des Méthodes - BDM) to enhance and coordinate maintenance and operation of the combustion turbines. This department, which should play the same role as the existing BDM for the steam thermal plants, could be located at La Goulette so as to benefit from the assistance of the DPTG; and

(c) create a small unit (consisting initially of one engineer and one technician), to be responsible for developing maintenance procedures and programs and updating them in line with equipment operating records supported by operating reports from the generating plants and by the results of inspections and monitoring of equipment in operation.

2.49 Individualized training for steam turbine operators: It is recommended that STEG develop an individualized training strategy for the operations shift teams, by preparing a set of training packages based on operating documents (procedures, instructions, etc.). The advantage of this strategy is that specialized staff can receive well-synchronized training and advanced training despite the problems connected with shift rotation.

2.50 Installation of on-line steam turbine efficiency monitoring: The mission recommends installation of an efficiency monitoring system for the steam turbines, based on continuous computerized monitoring of performance parameters and their comparison with unit reference parameters, to ensure that actual fuel consumption approximates optimum base consumption as closely as possible.

2.51 According to the consultant's estimates (confirmed by previous ESMAP studies) the cost of preparing and implementing the project would be about US$1 million. If implemented, the benefits would be about US$1.1 million in 1991, based on the following very moderate assumptions:

(a) a 1% gain in heat rate for STEG's steam thermal equipment, or 2.6 toe/GWh on the basis of 1988 operating conditions; and

(b) a toe/fuel oil cost at the 1988-89 level of US$100/toe.

The payback period, about 11 months uder the conditions assumed by ESMAP, indicates the definite benefits of the project. STEG should define and prepare the project in more detail following the terms of reference provided in Annex 6.

2.52 Implementation of conditional (predictive) maintenance programs: It is recommended that STEG implement conditional, predictive maintenance programs (being used increasingly in the developed countries) for each equipment component or group of components, based on updated operating records and on development of local and centralized inspection and monitoring (in DPTG). Such a program would provide improved data on component aging and would considerably reduce maintenance costs by decreasing routine maintenance. The financial benefits of the program are difficult to estimate, as STEG does not itemize maintenance costs for accounting purposes. A reliable estimate of the savings to be expected from such a project would require a very detailed financial and technical study of STEG's

maintenance program, which is beyond the scope of the present study. However, ESMAP's experience in this area indicates that such projects have very high internal rates of return (about 45% in the case of Syria: complete reorganization of the maintenance management system). By way of illustration, Tunisia's estimated maintenance costs for thermal equipment were TD 11.25 million, or US$12.5 million, in 1989, and are likely to be between TD 13.5 and TD 14.5 million (between US$15 million and US$16 million) in 1995, based on a standard cost, observed in a number of developed countries, of US$10 per kW. It follows that a mere 10% saving on maintenance costs would reduce STEG's operating expenses by US$1.25 million in 1990 and US$1.5 million in 1995.

III. TRANSMISSION

3.1 In 1989 the STEG network comprised:

(a) 2,852 km of lines divided between three voltage levels: 920 km at 220 kV, 1,256 km at 150 kV and 676 km at 90 kV; and

(b) 41 transformer substations, with a total installed power of 3,805 MVA for 92 transformers of sizes ranging from 15 MVA to 200 MVA.

The map at the end of this report provides a simplified diagram of the network.

Simulation of Transmission Network Operations

3.2 An in-depth study of selected operating situations on the transmission network (selected in close cooperation with Tunisian counterparts) was carried out in three phases:

(a) collection and preparation of the data needed to create a representation of the network compatible with the computer model used;

(b) simulation of network operations and determination of losses in accordance with the operating samples selected (differentiated according to consumption level, available power, degree of compensation, and voltage level); and

(c) loss analysis, and a search for solutions appropriate to the problems identified.

The data used in the study, related to the present and projected network, are given in Annex 9.

3.3 Studies of network operation under several operating scenarios were made for the years 1989 and 1993, using the following parameters:

(a) demand: Three demand scenarios were used: (i) maximum, or evening, peak, exceeded for only one or two hours in the year under study: 700 MW in 1989 and 1000 MW in 1993; (ii) average, or morning, peak, exceeded for about 1000 hours in the year under study: 646 MW in 1989 and 829 MW in 1993; and (iii) off-peak, or night, period, exceeded for about 7600 hours in the year under study: 420 MW in 1989 and 542 MW in 1993;

(b) voltage levels: The minimum acceptable voltage on the 225 kV network is 200 kV. For the maximum voltage, three values were used: 210, 225, and 235 kV, to enable an assessment of the sensitivity of reactive energy compensation and of power losses to the voltage level;

(c) 1989 compensation status: Three compensation situations were considered for 1989 (situation at the time the study was made): (i) a total absence of compensation; (ii) compensation using only existing resources; and (iii) additional compensation obtained by installing new equipment to obtain an overall tan phi of 0.5 as viewed from the HV network;

(d) 1993 compensation status: Two compensation situations were considered for 1993: (i) a total absence of compensation; and (ii) compensation needed to obtain an overall tan phi of 0.5, as viewed from the HV network.

Tan phi was set at 0.5 as this is the value at which the network can operate satisfactorily; it avoids large transmissions of reactive power and guarantees a large margin of security against voltage collapses; and

(e) available power status: Three scenarios for power generation and/or exchanges of power with Algeria were examined: (i) imports from Algeria without compensation; (ii) a supply of up to 250 MW from a thermal plant at Cap Bon; (iii) installation of gas turbines to produce an additional 200 MW (see Annex 9, page 4). The latter two cases were examined with and without additional compensation in 1993.

There is little or no likelihood that power will be supplied in 1993 from a plant in Cap Bon, but this hypothetical case, studied at STEG's request, is useful to understanding the longer-term problems facing network operations if this plant is brought into service.

3.4 The simulations of transmission operations, the results of which are given in Annex 9, leads to two major conclusions:

(a) theoretical energy losses in 1989 total between 0.9% and 1.3% under the operating conditions studied; they represent only about one third of actual identified losses, which were about 3.6%. In the medium term, these losses should not increase under any of the conditions studied provided that STEG adopts measures for improving tan phi through increased compensation. The sensitivity study shows that these losses vary as follows: (i) for the morning peak in 1989, total losses are about 7 MW, the sensitivity of losses to compensation is about 0.2%, i.e., 1.6 MW for 170 Mvar of compensation; and (ii) for the morning peak in 1993, total losses vary from 6 MW to 18 MW depending on the generation hypothesis considered; the sensitivity of losses to compensation is about 0.15%, i.e., 1.2 MW for 218 Mvar of compensation; and

(b) the values for tan phi are abnormally high during the day, particularly at the morning peak, about 0.7% in 1989 for the cases studied. There are no prospects for improvement in the medium term and there will even be some deterioration unless steps are taken to improve compensation. By 1993, 211 Mvar (i.e., 171 Mvar more than the present 40 Mvar) will be needed to maintain tan phi at its overall 1989 level, whatever generation hypothesis is used.

Actions Needed to Reduce Losses

3.5 It is difficult to draw distinctions between direct and indirect causes of technical losses in transmission networks, as electrical phenomena are complex and interactive. Nevertheless, the study findings, the results of additional work undertaken, and the outcome of discussions with STEG transmission network managers and operators favor three types of action, that would ensure:

(a) improved system control, through optimization of flows to maintain a high voltage level, thereby guaranteeing a secure supply, and a sound management of compensation capacity;

(b) improved operation and maintenance of the transmission network, with particular attention to managing the transformers, maintaining the transmission network in good condition, and maintaining the equipment; and

(c) progressive actions that contribute indirectly to increasing the efficiency of the transmission network: additional resources for planning and network studies, organizational changes, and training for operations and maintenance personnel.

STEG Network Control

3.6 The network control system STEG has implemented is satisfactory and enables collection of the data needed for making real-time responses to any incident or contingency. Nevertheless, the simulation of network operations has shown that network efficiency could be significantly improved by means of improved system control and investments in compensation.

Voltage levels

3.7 For voltage levels of 150 kV and under, the transformer on-line tap changers ensure that the proper operating voltage is supplied, provided that the transformers do not reach their operating limits. However, the 225 kV level that STEG uses as its primary operating voltage level is too low and, as a result, the voltage level drops off when outages or difficult operating conditions occur.

3.8 The simulations of network operations indicated that raising the maximum operating voltage level from 210 kV to 225 kV reduces active power losses by about 2 MW for a load of 1000 MW (the maximum demand forecast for 1993); this reduction, valued at the incremental cost of the cost of 1kW of HV power (see Annex 2) gives a financial saving of about TD 400,000, or US$444,000.

3.9 When overall voltage levels are increased, service quality improves, and the risks of unplanned load shedding due to voltage drops and to engine re-start failures, are reduced. Statistically, a 5% drop in nominal voltage produces a 2% drop in peak load. Thus, low supply voltages, in addition to being detrimental to consumers, also cause financial losses to the utility.

3.10 It is therefore recommended that STEG:

(a) study and determine performance criteria for network operation, such as a minimum of voltage levels and possible deviations from those norms (operational planning). Establishing such criteria will enable STEG to: (i) identify weak points in the network, especially if changes may have been made in operating guidelines or if there have been losses of reactive energy generation capacity; (ii) determine the reactive power capacity available from connected generating units, on the basis of manufacturers' charts indicating their ability to supply reactive power at the alternator terminals; and (iii) anticipate the onset of a voltage collapse so that timely measures (such as: connecting capacitors, disconnecting reactors, increasing the demand for reactive power from the alternators, blocking tap-changers on the VHV/HV transformers, and load shedding) can be taken to raise voltage; and

(b) update its manual procedures for secondary voltage regulation. Even if automatic secondary voltage regulation theoretically improves the quality of voltage regulation and allows coordination of the alternator outputs, it is much better to maintain voltage levels by reactive power compensation. Substantial loss reduction will also be realized by reactive compensation.

Compensation

3.11 To ensure acceptable service quality and satisfy demand at least cost, i.e., by limiting voltage drops and reducing active energy losses, one must have sufficient compensation capacity (reactors and capacitors) and operate it correctly so that the production and consumption of reactive power can be suitably controlled. Simulations of network operations, and discussions with the operators, during the main mission, showed that STEG can make much progress by: (i) providing compensation by operating the existing reactors more efficiently; (ii) possibly using gas turbines as synchronous compensators; (iii) properly managing the step-up transformer taps on the generating units; and (iv) installing additional capacitors.

3.12 Operation of the reactors: STEG's method of operation of its reactors does not always enable it to maintain continuous control over the generation and consumption of reactive energy and, subsequently, to maintain a high enough voltage level to provide adequate service quality and minimize losses. For example, all reactors are disconnected manually between 7:00 a.m. and 11:00 p.m. (16 hours a day), except for the 6-Mvar reactor at the Ghannouch substation (Robbana feeder) which is not equipped with a breaker. This means that during the morning peak when there is a shortage of reactive energy (see Annex 10), the additional 6 Mvar of demand causes additional losses. Annex 12 shows, however that loss reduction alone is insufficient economic justification for installing a breaker.

3.13 Use of the Tunis South gas turbines as synchronous compensators: Should difficulties in maintaining voltage level arise that jeopardize network reliability, one solution would be to use the gas turbines in the Tunis South plant as synchronous compensators, providing a margin of security of 3 x 20 Mvar. The results given in Annex 10 show that the power loss reduction obtained is less than the gas turbine consumption (0.8 MW). The only justification for using this equipment, therefore, is to resolve local constraints connected with maintaining voltage levels.

3.14 Management of step-up transformer taps on the generating units: Current management of these taps is inefficient, because taps have to be selected before the transformers are energized. This practice sometimes leads to unbalanced taps on the same site, with no possibility for the Service des Mouvements d'Energie (SME) to intervene. Because taps can only be set when the units are tripped, it is recommended that the SME be made responsible for managing taps and that it develop a seasonal management procedure that would allow savings in reactive energy, and would contribute to improving the voltage level at almost no cost (labor costs, about twice a year). STEG's operations forecast for 1989 indicated that a preliminary study of such procedures had been made, but no subsequent action was taken. A complementary study should be made on the autotransformer taps, which are also set manually.

3.15 Installation of supplementary capacitors: A convenient measure of reactive level is the ratio of the reactive power to the active power. This ratio is given by the tangent of the power factor angle and is termed "tan phi" hereafter. The simulation of transmission network operations showed that, in 1989, an additional 130 Mvar would have been necessary (124 Mvar if the Ghannouch reactor had been fitted with a breaker) to reduce the overall tan phi from 0.7 (the value recorded at that time) to 0.5, the value usually regarded in similar networks as being the upper limit needed to ensure a reasonable loss level. In the medium term, 211 Mvar will be needed by 1993 in order to maintain the overall tan phi at 0.5.

3.16 A more detailed study was made for substations with a reactive to active power ratio exceeding 0.6 (for the year 1989). The compensation requirements at these substations to reduce the ration to 0.5 were also determined. The results of the study are given in the tables and network diagrams provided in Annex 10.

3.17 Examination of the results obtained, particularly in the sensitivity studies, shows that the reduction of losses obtainable on the transmission network by means of reactive power compensation would not be sufficient to justify installation of compensation equipment on the VHV and HV networks (see Annex 12). On the other hand, compensation plays a useful role in maintaining a high voltage level under both normal and abnormal conditions, thereby considerably improving operating reliability. Furthermore, installing compensation as close as possible to the load, i.e., close to HV customers that have a high reactive load (cement works), or in MV substations, can be justified by means of specific studies carried out on a case-by-case basis. It is recommended that STEG, before making any decisions on investment, increase its tariff incentives to encourage its customers to make their own investment in compensation equipment.

3.18 Taking equipment out of service in off-peak hours. Taking equipment, particularly transmission lines, out of service during off-peak hours ensures better control of the voltage level. It also provides the generating units with a wider operating margin for possible exchange of reactive power. To be effective, these measures must not compromise network reliability under normal conditions or under contingency conditions (tripping of one line or one unit). Taking VHV/HV or HV/MV transformers out of service may reduce the losses caused by these transformers at low load (by eliminating the core losses of the transformers that are removed). The transformers should only be taken out of service while observing the n-1 rule (the "n-1" rule is respected if tripping of one line or unit enables the load to be supplied without overload or any unacceptably low frequency or voltage). The equipment must be returned to service quickly when required by an increase in load or to restore the n-1 condition.

Operation

3.19 STEG's operation of its transmission network is satisfactory on the whole, but additional measures should be taken to improve management of the VHV/HV transformers, improve the mechanical tension on some lines, reduce the effects of pollution on the insulators, and improve inventory control.

3.20 Management of the VHV/HV transformers. Some of the equipment appears to be oversized in relation to the load transmitted. The low load levels observed on some occasions should lead the dispatchers to undertake more rigorous management, such as

(a) taking some transformers out of service; and

(b) avoiding circulating currents of reactive power by installing automatic devices when units are operating in parallel.

Despite existing constraints, such as the ring-bus in the design of most of the transmission stations, and the operational practices for the distribution system, it appears that new operating guidelines can be established after an appropriate study. Also, transformer procurement practice should take into account

losses over the desired lifetime of the equipment. The discounted cost of the losses are to be added to the investment cost for the transformer.

3.21 Mechanical tension on some lines: Some lines have a high degree of sag and the effects of creep are particularly noticeable on the 150 kV network. The mission recommends that STEG make field measures of cable sag to obtain the data required for a technical and economic study of the need to re-tension some cables.

3.22 Effects of pollution on the insulators: In some areas where the network is affected by pollution from chemicals and algae, and by sandstorms, STEG sometimes has to reduce the network's operating voltage. In addition to manual cleaning and silicone treatment of the insulators, two procedures currently in use in Tunisia, it is recommended, wherever water is available, that STEG study the feasibility of spraying the insulators with water, as this can be done without interrupting the voltage supply to the system. STEG is also interested in current research on specific insulator types (such as the aerofoil design) suitable for areas where the rainfall is too low to clean the insulators without human intervention, and has set up a committee to study pollution problems as well as the feasibility of installing Gas Insulated Stations (GIS) in certain regions.

3.23 Maintenance: The Operations Directorate is currently reorganizing work procedures and maintenance. The reorganization, based on decentralization, creation of regional storage facilities, and computerized inventory control, should improve the maintenance of the transmission network and thus improve equipment availability. It is recommended that STEG complete this program, placing greater emphasis on:

(a) decentralization, except for equipment that is very expensive, or is sensitive to climate changes. An air-conditioned storage facility will be maintained in Tunis. It should be noted that the current inventory control system is too centralized, and there is no justification for centralization of some equipment, relay protective devices, for example;

(b) staff expertise and quality; and

(c) development of a system of data exchange between the storage facilities and networking of computerized management systems.

Additional Actions Needed to Improve the Efficiency of the Transmission Network

3.24 In addition to the measures recommended previously to improve unit control and operation, actions needed to enhance the overall efficiency of the transmission network include minor organizational changes, improved network planning methods, improved and increased personnel training, and increased coordination with the other Maghreb countries in order to improve the efficiency of use

of the interconnection through creation of a coordination and control center for the Maghrebian interconnection.

3.25 Organization: Two minor organizational changes are recommended so that the responsibilities for operations and customer management will more closely match the technical demarcation between transmission and distribution:

(a) division of responsibility for setting up and managing the relay protective devices along the same lines as the functional demarcation between networks, because: (i) transmission and distribution operating policies and procedures are different; (ii) assigning the responsibility for the policy of protecting its network relays to the Distribution Directorate (DD) should improve its ability to manage and coordinate network operations;

(b) creation of a unit within the Operations Directorate to take over the management of HV customers, currently the responsibility of the DD. Creation of this unit should lead to agreements between the OD and its major technical and commercial customers. This unit would be responsible for the billing and management of HV customer contracts, including those with the distribution centers, which would be considered to be HV customers. This change would create a climate favorable to: (i) increased authority for managers in each center; (ii) greater transparency in their relationships; and (iii) greater incentives to efficiency.

3.26 Planning: Existing network studies are based only on projected annual peaks. The scope of the studies is insufficient, because major operating problems can arise at other times. Planning studies, particularly the evaluation of network losses, require study of network operations according to several demand scenarios (seasonal, daily, or even hourly). For example, the network simulations performed have shown that excess reactive energy demand is more cause for concern during the morning peak than during the evening peak. Consequently, improvements to the Planning Directorate's data processing resources are recommended, to enable it to manage the increased workload required for making the kind of network studies needed to improve medium- and long-term planning. Predictive planning models are available that are well-suited to these kinds of problem and enable a network development master plan to be prepared, to be used as a decisionmaking guide for the short term.

3.27 It is therefore recommended that:

(a) STEG's economic unit prepare and implement standard economic appraisal techniques for investment projects and/or development options; among other things, STEG should include in its economic appraisals a cost of unsupplied energy, defining the effort it is prepared to make to improve service quality; and

(b) that the data processing unit routinize and computerize its data gathering and statistical work, to increase the progress STEG has already made in this area.

Training

3.28 STEG is currently making considerable efforts to train and upgrade the technical skills of its personnel. Most training is transmitted informally on the job from one operator to another, a method which, contrary to the conventional wisdom, has been shown by experience to be the most expensive and unsatisfactory form of training. It leads to widely varying levels of knowledge among the operators, because workers are qualified without objective and consistent evaluation of their skills at the corporate level.

3.29 More precise and targeted training is recommended, to be achieved by investigating and implementing a training plan that provides more homogeneous training for staff, taking into account their career development and the utility's needs for qualified personnel. For technical and techno-economic training, it would be preferable to designate several trainers from the operating units. These designated trainers would then receive additional technical training and instruction in teaching methods, outside Tunisia, in power or gas utilities, or with the equipment manufacturers. Upon their return, they will be expected to develop training programs that fit STEG's needs and to disseminate the information.

3.30 Type of training needed. Operator qualification is currently based on job descriptions and on seniority. This situation can be improved, and incorrect equipment operation and its consequences can be reduced, by means of short training courses at the Khledia Vocational Training Center (Centre de Formation Professionnelle de Khledia). With adequate training materials and competent instructors, the operators could receive their operator's qualification following national tests that would be uniformly established.

Interconnection

3.31 Investigation of the operation of the Maghrebian interconnection is beyond the scope of this study. However, it should be noted that the network interconnection between the three Maghrebian countries (currently Tunisia, Algeria and Morocco, to be joined later by Libya and possibly Mauritania) is not used optimally, mainly because tariffs for the exchanges are not based on economic costs and because there is no coordination or ongoing data exchange between the three currently interconnected networks.

3.32 Creation of a coordination and control center -- serving as a locus for pooling information and data, but with no operational authority over the control of each country's own networks -- could make for more efficient use of the interconnection, but, more particularly, it could serve to centralize technical information and disseminate it rapidly. For example, an analysis of past technical incidents, particularly the one that occurred on January 17 1990, shows that the values of primary and secondary reserves are too low and this often leads to under-frequency load shedding (shedding through frequency relays). The proposed "control center" could deal with this problem as follows:

(a) establish an indicator for monitoring the primary control of the Maghrebian system. At times of significant disturbance, the frequency variation would be analyzed and each partner would be provided with an estimate of the static gain of the primary control (in MW/Hz) of the interconnected network. The indicator, used comparatively, would give an assessment of the degree to which the primary reserve has been drawn upon, at least for the frequency variations noted; and

(b) coordinate and optimize in real time the value of the secondary control, since (by definition) this is distributed among all the countries in the system. Exchanges of telemetered data between the countries would enable country operators to optimize the corresponding networks in their network load flow calculation models.

3.33 Clearly, there are costs involved in participating in the primary and secondary control systems, as in the above example, and for the other operating measures that would be needed. These costs must be determined and allocated optimally among the various networks so as to minimize the costs of supplying power. It is therefore recommended that COMELEC (Comité Maghrébin d'Electricité) study the feasibility and cost-effectiveness of establishing a Maghrebian coordination and control center, basing its study on previous international cooperation experiences in power interconnections, such as those of NORDEL (Nord Electricité) and UCPTE (Union de Coordination des Producteurs et Transporteurs de l'Electricité).

IV. DISTRIBUTION

4.1 The STEG distribution network operates on four voltage levels: 30, 15, and 10 kV in the medium voltage (MV) range and 400/230 V in the low voltage (LV) range.

4.2 The MV network is radial and comprises:

(a) 13,000 km of 30-kV overhead three-phase lines and 4,000 km of single-phase lines at 17.3 kV. The neutral of the three-phase overhead network is distributed and grounded; it is therefore a "4-wire" system;

(b) 1,000 km of 10-kV lines, mostly underground, supplying cities in the north like Tunis and Bizerte; and

(c) 354 km of 15-kV lines, supplying large towns in the south like Gabès and Gafsa.

4.3 Through 17,000 MV/LV transforming substations (including 6,700 customer substations), this MV network supplies a 30,600-km LV network, 97% of which is overhead. Following a major drive to change voltage, almost all MV/LV substations (98%) now operate at a secondary voltage of 400 V, while the remainder (2%), more than two thirds of which are concentrated in the Tunis region, operate at a secondary voltage of 230 V. Annex 13 provides a detailed description of the STEG distribution network.

4.4 Given the extent and diversity of STEG distribution networks, it was not possible within the scope of this study to make an overall analysis comparable to that made of the transmission network. It was therefore decided, in agreement with the STEG task force, to concentrate analysis on three zones representative of Tunisia's various regions which, as may be seen from Table 4.1, can be divided into three homogeneous categories.

Table 4.1: KEY FEATURES OF STEG DISTRIBUTION ZONES

Zones	Efficiency a/	No. of mLV b/ per LV consumer	No. of mMV per LV and MV consumer	Ratio mMV/mLV
Tunis	0.907	15	6	0.40
North	0.911	27	14	0.52
Northwest	0.960	30	26	0.87
Center	0.890	25	14	0.56
South	0.870	34	17	0.50
Southwest	0.970	29	31	1.07

a/ Efficiency = energy billed/energy supplied.
b/ mLV: meters of LV circuit.

(a) the first category groups the regions characterized by low efficiency (Energy billed/Energy supplied) and a ratio of length of MV to LV circuits of about 0.5. This category includes the North, Center, and South (zone 1);

(b) the second category groups the regions characterized by high efficiency (Energy billed/Energy supplied) even though the ratio of length of MV to LV circuits per customer is high. This category includes the Northwest and Southwest (zone 2); and

(c) Tunis constitutes a separate category (zone 3), characterized by low efficiency (Energy billed/Energy supplied) and a low ratio of length of MV circuits to LV circuits per customer. One can predict *a priori* that nontechnical losses are higher in this zone (zone 3).

4.5 One district was selected from each category: (i) Nabeul, where farming, tourism and industry are major activities, is representative of the first category; (ii) Siliana, a rural district, is representative of the second; and (iii) the city of Tunis, an urban district, and Ezzahra, a suburban district, are representative of the third. From the standpoint of electric power supply, these districts also meet the following representativity criteria: voltage levels of 10 and 30 kV, both overhead and underground networks, a three-phase and single-phase distribution system, and medium and low voltage customers. A detailed technical description of the districts selected is provided in Annex 13.

Data Collection and Loss Assessment Method

4.6 Since collection of data necessary to network analysis is an essential prerequisite to a diagnostic study of the operation and management of distribution networks, a detailed questionnaire was formulated and sent to the STEG task force, with a request to collect data on the following:

(a) the configuration and the physical and electrical characteristics of the MV and LV networks: type, length, and cross-section diameter of the conductors, power level on each outgoing feeder;

(b) the characteristics of the HV/MV and MV/LV transformers: technology employed, core losses, Joule-effect losses;

(c) the organization of network operation, control, and maintenance;

(d) STEG's standardization policy;

(e) network planning; and

(f) procurement practices and procedures.

For the districts studied, maps showing all the MV networks and some typical LV outgoing feeders were collected and examined. In addition, to enable an estimate of losses on the MV and LV network, STEG distribution staff were asked to measure power flows into outgoing MV feeders and to take measurements at MV/LV substations and on representative outgoing LV feeders.

Status of available data

4.7 The data-gathering exercise, and discussions with the staff of various STEG distribution service units, revealed a lack of the kind of reliable and consistent data needed for distribution network planning studies and for continuous monitoring of losses at medium and low voltage levels.

4.8 Examination of maps of the distribution system showed that these are not up to date and that the types of map and the information they provide vary from one zone to another. This finding indicates that neither the map standardization policy nor the procedures introduced for updating the maps have been entirely successful.

4.9 Archival storage of telemetered data at the Distribution Control Center (Bureau Central de Conduite - BCC) in Tunis is inadequate. This facility, the only one of its kind in the country, has a daily data storage capacity of only 20 telemeter readings, (i.e., 20 different values), while its archival capacity is limited to 20 values over 5 days. This total storage capacity of only 400 values is clearly insufficient, either to enable studies on various situations, or, where necessary, to play back a given operating problem. It is therefore impossible to obtain data on the daily peak demand of each outgoing MV feeder in this major district, whereas data is available for the other districts, because the HV/MV substation supervisors record and file the hourly loads of all the MV outgoing feeders.

4.10 Measurements of reactive energy are lacking throughout the distribution network.

4.11 With regard to the transformers, data on nominal power losses are available in the manufacturers' catalogues, but the load loss figures are only partly available; these figures are collected when specific measurement drives are conducted.

Recommendations

4.12 STEG has begun to establish a technical data base on the MV distribution network -- as part of the operation known as Gestion Technique des Ouvrages (GTD). This action should be continued and completed, making sure that reliable information is collected on:

(a) type, cross-section diameter, length, and number of conductors, for both the MV and the LV networks; and

(b) installed capacity, equipment type, year installed, and sizes of the MV/LV transformers, supplemented with data on the subscribed power of the consumers supplied by each transformer, and on substation sizes (to ascertain the space that would be available in the event that new transformers are installed).

4.13 A general recommendation is to improve control and updating of the network mapping system and of the technical data system and to consider developing computerized mapping, at least by acquiring, as a first step, a Computer-Aided Design system that can create network diagrams. Discussions on ways to improve the technical data system and to computerize mapping could start as soon as the distribution system planning and load flow model recommended in this study has been supplied.

4.14 Archiving of telemetered data, practiced at the BCC in Tunis and at the Regional Control Centers, should be extended to all the main substations. It would then be possible to record all the telemetered data by outgoing feeder. STEG would then dispose of a complete set of data for its studies on the planning and operation of distribution networks. Eventually, STEG should consider collecting telemetered data throughout its system and storing the data on optical disks, but meanwhile it should at least move to computer storage of the data recorded manually by the substation supervisors.

4.15 For the LV network, STEG should continue routine measurement of voltage drops in the urban areas, but it would be useful to make some of these measurements on a fixed, representative sample over a long period (around 5 years), so that changes in the pattern of network losses can be followed.

Loss assessment method

4.16 Once data gathering was completed, technical loss assessment was performed in three stages:

(a) for the districts selected, estimation of losses from the MV and LV networks and the MV/LV transformers;

(b) assessment of losses throughout the STEG distribution network by extrapolation from the results obtained; and

(c) assessment of transformer losses.

Simulations of network operation were performed using a model that runs on main-frame computers, but based on the same algorithms and methodology used with the PRAO model, which runs on a micro-computer, which was given to STEG as part of this study so that the utility could develop distribution network studies and ensure their continuity.

Reduction of MV Network Losses

Assessment of MV network losses

4.17 Table 4.2 presents the results of the calculations of MV network losses. The table gives the percentage power loss for each outgoing feeder as well as the percentage of use of the line, i.e., the ratio of effective peak demand to total installed capacity. It will be noted that:

(a) Losses from the Charguia feeder in the city of Tunis are significantly higher than the average for the district, which is 1.22%. This difference can be explained by the fact that this line, although equipped for 30 kV operation, is operated at 10 kV, and the entire load is carried forward to the end of the feeder. This feeder has therefore not been included in the estimation of peak capacity loss in the Tunis urban district, which therefore is:

$$\frac{334.6}{25007} \times 100 = 1.34\%$$

(b) The Haouaria feeder, in the district of Nabeul, has a high loss rate because it is too long, 250 km, whereas mean feeder length in the district is 81 km; this feeder is therefore not included in the estimate of peak capacity loss for the district of Nabeul, which therefore is:

$$\frac{1156.8}{28867} \times 100 = 4.01\%$$

(c) The widely varying results in the district of Siliana can be attributed to factors common to rural networks. The Kesra outgoing feeder carries a low load and is significantly shorter than the Lakmes feeder (135 km compared to 547 km). This type of pattern can be explained (and is justifiable in rural networks) by the fact that the main substation locations are optimized in relation to the transmission network rather than to the load center of the distribution network. This situation results, in some zones, as in the case of Siliana, in an imbalance between the load and the length of the MV feeders. The Kesra and Lakmes feeders are thus both included in the estimate of peak power loss in this district, which is:

$$\frac{11.1 + 0.67}{2} \times 100 = 5.89\%$$

Table 4.2: NETWORK LOSSES: MV SAMPLE

District/feeder	Peak load (kW)	Peak power loss (kW)	% power loss	% line use
City of Tunis				
Tanit	2146	20.1	0.83	42
Imer	3082	98.1	3.18	54
B. Miled	1936	19.0	0.98	34
BCT	2912	23.1	0.79	43
Agricultor	1595	8.2	0.51	26
Turquie	1626	7.2	0.44	24
El Hafir	2958	38.8	1.31	43
Dandet	3206	52.6	1.64	56
Avenir 11	2256	23.5	1.04	33
Avenir 22	3020	44.0	1.46	44
Charguia	4290	447.0	10.43	76
Nabeul				
B. Argoub (1201)	6912	240.3	3.48	48
Mazraa (1302)	8319	227.9	2.74	69
Kelibia (1304)	5751	263.5	4.58	31
Haouria (1305)	5691	607.9	10.68	32
Belli (5001)	7885	425.1	5.39	49
Siliana				
Lakmes	6125	623.2	11.1	24.3
Kesra	868	5.8	0.7	20.7

4.18 The overall peak power loss for the STEG MV network can now be estimated by calculating the average of the individual zones, weighted by the MV consumption for the zone (see Annex 13). This may be stated as follows:

$$\frac{(4.01 \times 1312.4) + (5.89 \times 743.3) + (1.34 \times 1125.4)}{3181.1} = 3.5\%$$

Reduction of MV network losses

4.19 Improved location of the main substations: For the MV network, it is recommended that STEG reduce the length of the feeders and locate the main substations closer to the load centers of the distribution network loads. This means that technical/economic studies on the location of main substations should include costs of losses from the transmission and the distribution networks.

4.20 Reconductoring: Use of larger conductor sizes reduces the losses for equal amounts of power transmitted. The method used for calculating "power thresholds" (the power levels at which reconductoring becomes cost-effective for STEG) is described in Annex 14.

4.21 This method is then applied to all the MV feeders studied in order to identify those segments whose power level exceeds the "power threshold" at which reconductoring becomes cost-effective. For each possible strengthening, savings are assessed by valuing the MV kW at TD 360.5 (see Annex 2) and the "current annual rate of return" is calculated,3/ defined as the ratio of expected savings in TD to the total investment cost in TD. The detailed results of these calculations are given in Annex 14.

4.22 For the samples studied, these results show that:

(a) in the district of Nabeul, it would be necessary to reinforce 13.34 km of the 695.47 km of line studied, or nearly 1.92% of the network, in order to reduce losses by a little over 0.3%. The mean "current annual rate of return" for the proposed action would be 32%, and thus the investment payback period would be slightly over three years;

(b) in the district of Siliana, it would be necessary to reinforce 29.5 km of the 682 km of line studied, or nearly 4.3% of the network, in order to reduce losses by nearly 1.5%. The "current annual rate of return" for the proposed action would be 30%, and thus the investment payback period would be slightly over three years; and

(c) the network in the district of Tunis is much better adapted to demand. The only change to be considered is to put the first section of the Charguia feeder underground so as to reduce losses on this feeder from 10.3% to 6.21% at a capital cost of about TD 407,000, recoverable in a little over 6 years.

4.23 By extrapolating the results obtained for the samples studied to the zones they represent, we obtain results for the entire STEG distribution network (see Table 4.3).

3/ *The investment payback period (initial investment/annual saving) or its inverse, the "current annual rate of return," is the indicator generally used by electric utilities to evaluate the economic feasibility of this type of investment. Annex 3 provides a table comparing the "current annual" and internal rates of return for periods of 10, 20, or 30 years. It should be noted that investments to reduce losses should have immediate effects on the network, otherwise installation of new generating units and network extensions change the context very quickly. An investment in this area can be considered to have a "lifetime" of about 10 years. Using this hypothesis, it is not advisable to make an investment with a "current annual rate of return" of less than 18%, or with an investment payback time of more than 6 years, which corresponds to an internal rate of return of 12%.*

Table 4.3: REDUCTION OF LOSSES FROM MV NETWORKS

Zone	1	2	3 a/	STEG Network
Length of network to be reinforced (km)	103	536	None	639
Cost (thousand TD)	996	2627	-	3627
Peak load savings (kW)	894	2190	-	3084
Financial savings (thousand TD)	322	790	-	1112
Investment payback period (years)	3	3.3	-	3.3

a/ See para. 4.22(c): the special case of the Charguia feeder line.

These changes would reduce the loss factor throughout STEG's MV network by 0.5% (to 3.02% from the present 3.5%) with a mean payback period of three years. However, it should be noted that many of the line reinforcement projects (nearly 20% of them) have payback periods of less than two years and should be undertaken on a priority basis (see Annex 14).

Reduction of LV Network Losses

Assessment of LV network losses

4.24 Technical losses from STEG's LV network were assessed for an LV feeder sample considered to be representative of the networks in the districts selected; the method used is described in Annex 13. Since the districts are representative of STEG distribution networks, the overall loss for the LV network was taken to be the mean of the percentage losses calculated for those districts weighted by their share of total LV load.

4.25 Table 4.4 shows the results obtained for the sample of feeders examined:

Table 4.4: PEAK POWER LOSSES; LV FEEDER SAMPLE

District	LV feeder	Method of distribution	Maximum capacity (kW)	Losses (kW)	Losses %
City of Tunis	Hiver	L1 tri	48.0	5.70	11.9
	Ezzitouna	L2 tri	155.0	5.40	3.5
	El Djazira	L2 tri	41.5	0.80	1.9
Ezzahra	Onas	L2 tri	50.0	1.80	3.6
	Independance	L2 tri	77.0	4.30	5.6
	Ghandi	L2 tri	16.5	0.40	2.4
	Kahena	L2 tri	39.0	0.70	1.8
Nabeul	Ecart Nord A1	L2 tri	53.0	5.90	11.1
	Ecart Nord A2	L2 tri	55.6	5.30	9.5
	Ecart Nord A3	L2 tri	35.0	4.30	12.3
	Ecart Nord A4	L2 tri	63.8	5.70	8.9
	Kaounia	L2 tri	80.3	13.55	16.9
	Karsoline	L2 mono	20.9	2.10	10.0
Siliana	Gabre Ghoul 341-A1	L2 mono	7.3	0.21	2.9
	Gabre Ghoul 341-A2	L2 mono	2.4	0.03	1.3
	Gabre Ghoul 342	L2 mono	7.9	0.16	2.0
	Gabre Ghoul 343	L2 mono	8.4	0.41	4.3

4.26 The percentage losses for each district are then estimated as the ratio of total LV feeder losses to total maximum capacity, giving the following results:

District	Overall Losses
City of Tunis	4.9%
Ezzahra	3.9%
Nabeul	11.4%
Siliana	3.1%

From this result, we obtain overall LV losses of 6.8% for the STEG network.

Reduction of LV network losses

4.27 Phase balancing: For the three-phase network, we recommend a better distribution of load between phases to prevent current flow through the neutral and reduce losses, which are proportional to the square of the current. For instance, the Kaounia feeder in the district of Nabeul is seriously unbalanced, since the current carried on the second phase is more than triple the current carried on the third phase (I1 = 100A, I2 = 200A and I3 = 65A). A better distribution of the load between the three phases, a simple and inexpensive action, would reduce the losses on this feeder from 16.9% to 10.1%.

4.28 Voltage changes: It is recommended that STEG complete the ongoing change of voltage in the city of Tunis, since the move from L1 to L2 makes it possible -- for any given power level -- to reduce LV network losses by roughly two-thirds. For instance, in the sample studied, raising the voltage of the Hiver feeder from L1 (110 V) to L2 (220 V) would bring the present loss figure of 11.9% down to 3.96%. More generally, if all L1 feeders in the Tunis district were operated at L2, the district loss factor would be around 3.3%, instead of the present figure of 4.9%.

4.29 An operation of this kind requires not only that MV/LV transformers be changed but also that customers' LV electrical equipment be adapted to the change in voltage level. The total cost for this operation is given in Table 4.5, based on an estimated cost of TD 150 per LV customer.

Table 4.5: ESTIMATED COSTS OF UPGRADING THE STEG LV NETWORK TO 220V

Region	No. of 110V MV/LV substations	No. of LV consumers per STEG LV substation	Cost (TD)	Cost (US$)
Tunis	168	204	5,140,800	5,710,500
North	10	126	189,000	210,000
Northwest	0	76	0	0
Center	26	121	471,900	524,200
South	0	79	0	0
Southwest	43	98	632,100	702,200
Total	247	-	6,433,800	7,146,900

It is assumed that the changeover from L1 to L2 on all the feeders considered would save a capacity equivalent to that estimated for the Hiver feeder, namely 37 W/customer, so that total peak demand would be reduced by 1,587 kW. Anticipated savings would total TD 748,114, or US$831,237, and the payback period would be between 8 and 9 years. It must be noted, however, that these calculations do not take into account the improvement in service quality that would accrue from the changeover or the fact that much of the equipment to be replaced is already obsolete and needs replacing independently of any loss-reduction measures. Moreover, the voltage conversion program has already reached an advanced stage and bringing it to a speedy conclusion would make it possible to standardize electrical equipment in Tunisia; this standardization would have a favorable economic impact considerably greater than the mere savings achieved by reducing losses.

4.30 As for the medium-voltage lines, reconductoring is economically justified as soon as loss savings per kilometer are higher than or equal to the ratio between the annual return on the investment required (discounted at 10%), expressed in TD/kW, and the value put on losses from the LV network, expressed in TD/kW. For each conductor studied, the "power threshold" beyond which it is cost-effective to change to a larger-diameter cable is calculated. In the case of the STEG LV network, these calculations were made on the assumption that changes would be made exclusively to two standardized cross-sections: 35mm^2 Alu and 70mm^2 Alu. Table 4.6 summarizes the results given in detail in Annex 14.

Table 4.6: NETWORK REINFORCEMENT; LV FEEDER SAMPLE

District	LV feeder	Max. capacity (kW)	Losses after reinforcement	Cost (TD)	Investment payback period (years)
City of Tunis	Hiver	48.0	1,900	15,300	8.3
	Ezzitouna	155.0	4,823	520	1.9
	El Djazira	41.0	459	852	5.3
Ezzahra	Onas	50.0	1,248	1,053	4.1
	Indépendance	77.0	2,050	2,081	2.0
	Ghandi	16.5	-	-	-
	Kahena	39.0	602	347	7.5
Nabeul	Ecart Nord A1	53.0	3,331	5,679	4.8
	Ecart Nord A2	55.6	4,055	3,121	5.3
	Ecart Nord A3	35.0	1,830	4,769	4.2
	Ecart Nord A4	63.8	2,658	6,589	4.7
	Kaounia	80.3	9,324	3,685	1.9
	Karsoline	20.9	1,206	2,409	5.6
Siliana	Gabre Ghoul 337				
	Gabre Ghoul 342-A1	7.3			
	Gabre Ghoul 342-A2	2.4	no reinforcement		
	Gabre Ghoul 342	7.9	" "		
	Gabre Ghoul 343	8.4	" "		

4.31 Extrapolation of the results obtained for the samples studied to the zones of which they are representative indicates a reduction in losses on STEG's LV network of approximately 3% after reconductoring of 944 km of lines, almost 3.1% of the LV network, for a total cost of TD 8.146 million, and an investment payback period of around 3.7 years (see Table 4.7).

Table 4.7: REINFORCEMENT OF THE LV NETWORK

Zone	1	2	3	STEG network
Length of LV network to be reinforced (km)	832	-	112	944
Peak load savings (kW)	3950	-	754	4704
Cost (thousand TD)	7184	-	962	8146
Financial savings (thousand TD)	1862	-	355	2217
Investment payback period (years)	3.9	-	2.7	3.7

It is recommended that STEG begin by reconductoring those sections that show the highest rates of return.

Assessment and Reduction of Losses from Transformers

4.32 Losses from transformers forming part of the distribution network are of two kinds:

(a) core losses or no-load losses which correspond to losses by hysteresis and eddy currents in the magnetic cores as soon as voltage is applied to the equipment. They are not dependent on load; and

(b) winding or Joule losses, which are those induced by the Joule effect in the conductors that form the windings. The manufacturers provide information on Joule-effect losses at rated power. In calculating losses for a given load, the loss at rated output must be weighted by the square of the coefficient of utilization of the transformer; this coefficient is equal to the ratio of demand to rated capacity.

Losses in the HV/MV transformers

4.33 STEG has 74 HV/MV transformers, as follows:

Power in MVA	15	20	25	30	40	50
Number	12	2	3	19	37	1

Since the characteristics of the 20, 25, and 50 MVA transformers are not known, it was assumed for calculation purposes that their characteristics were identical to those of the ones nearest to them in size, which gave the following basis for calculation:

Power in MVA	15	30	40
Number	14	22	38

4.34 Table 4.8 shows core losses (CL) and Joule-effect losses (JL) for the three sizes of transformer selected:

Table 4.8: LOSSES IN THE HV/MV TRANSFORMERS

Transformers (kW)	CLi a/ (kW)	Number of transformers	CL (kW)	JLi a/ (kW)	Number of transformers	JL
15 MVA	18	14	252	100	14	513
30 MVA	23	22	506	160	22	824
40 MVA	26	16	416	195	38	2087
	34	22	748	-	-	-
Total	-	74	1922	-	74	3424

a/ CLi represents individual transformer core losses. JLi represents individual transformer joule losses.

Note: Total joule losses = individual joule losses X (utilization factor)^2.

Losses total 5,346 kW for a total peak demand of 771 MW, giving a loss factor in the HV/MV transformers of 0.69%.

Reduction of losses in the HV/MV transformers

4.35 Reduction of losses in the HV/MV transformers should be based on a review of:

(a) the operating procedures currently used to reduce core losses; and

(b) criteria for reinforcing existing transformers and installing new equipment so as to improve the transformer utilization factor.

4.36 Operation of existing transformers: STEG operates its HV/MV transformers by keeping one of them on stand-by -- in other words on-line and unloaded -- even when peak load is less than the rated output of one of the two transformers available in the substation. This policy is mainly a result of the fact that, for roughly a quarter of the main substations, the HV busbar system is constructed according to a ring-bus scheme; this means that, in order to disconnect the transformers, various circuit-breakers connecting to the feeders must be opened, and the HV disconnectors of the transformers are not remote-controlled.

4.37 Strictly from the standpoint of loss reduction, when a single transformer is sufficient to provide power the second transformer should be disconnected if no-load losses are to be avoided. If for any reason there is no alternative but to apply voltage to the second, the more economical course is to use both transformers so as to balance loads and reduce Joule-effect losses by half for any given power level. Moreover, disconnecting the second transformer would not disrupt operations except in very cold weather, which is unlikely in Tunisia, and would better protect the equipment against voltage surges due to lightning.

4.38 The two methods of operation, with one transformer or with two, were compared. By applying the first method to the STEG network, using data for 1989 and a power factor of 0.9, it was possible to identify the HV/MV substations for which operation with a single transformer is economically more advantageous (see Annex 15).

4.39 Substantial savings of about 3 GWh and 346 kW of peak demand for the year 1989, with a value of TD 126,000, or US$140,000, are theoretically possible. Nearly two-thirds of these savings require no investment, and can be achieved simply by changing the method of operation of eight HV/MV substations. A little over one-third of the savings require technical adjustments at the five substations equipped with ring-buses. It is recommended that STEG:

(a) adopt the practice of connecting only one transformer at the eight substations for which this method of operation has been shown to be financially advantageous as well as technically feasible without any other adjustment. Anticipated annual savings through reduction of core losses would amount to TD 78,500, or US$87,200; and

(b) carry out technical/financial studies for the five substations where technical changes are necessary, by comparing the annual savings from loss reduction, about TD 47,800, or US$53,000, with the cost of the necessary changes (in particular, the cost of remote control of the HV disconnectors).

Improving the transformer utilization factor

4.40 According to data collected for the year 1989, the utilization factor for the HV/MV transformers in the STEG system is 2.85. 4/ Although satisfactory, it could be improved by:

(a) redistributing transformers among the substations to ensure optimal use of this class of equipment; and

(b) refining the criteria for reinforcing and installating transformers in new substations.

4.41 Exchanging transformers among substations is difficult, considering the many types of transformers currently in the STEG network: 20 different types among 74 units in use. STEG's decision to standardize equipment should mitigate this problem.

4.42 Substation expansion criteria should take into account possible transfer of flows between substations in cases where a transformer is tripped, and it should be accepted that, at peak periods, the rated capacity of the other transformer might be exceeded. Generally speaking, international standards allow temporary overloading of transformers by between 1.20 and 1.25 of nominal current. Obviously economic calculations should allow for Joule-effect losses due to equipment overload.

4/ *Transformer utilization factor = total installed capacity x cos phi ÷ total peak load.*

4.43 Finally, it is recommended that STEG take greater account of the capitalized value of core and Joule-effect losses over 20 or 30 years when comparing bids to supply transformers. The cost of losses should be calculated using the incremental cost of a kW at the HV/MV level. For instance, the cost of core losses capitalized over 20 years for a 40-MVA transformer of the type installed at the La Goulette substation is nearly TD 40,000, or US$44,000, higher than the cost of losses from a 40-MVA transformer of the type installed at the Oued Zarga substation. This amount is not insignificant and should be compared to the difference in purchase price between the two types of equipment.

Losses in the MV/LV transformers

4.44 Assessment of the losses in the MV/LV transformers was undertaken in the same districts selected for the study of the MV and LV networks, namely, the city of Tunis, Nabeul, Siliana, and Ezzahra (see Annex 13). STEG provided the data on transformer specifications, particularly on core and Joule losses.

4.45 Both core and Joule losses were calculated using the same formulas as those used for the HV/MV transformers 5/ for all transformers in the Nabeul, Siliana, and Ezzahra districts, and for the transformers installed on the 11 outgoing feeders selected in the city of Tunis. The results obtained are given in Table 4.9:

Table 4.9: LOSSES IN THE MV/LV TRANSFORMERS

District	Nabeul	Siliana	Tunis-ville	Ezzahra	STEG Total
Losses in MW	1.2	0.4	0.6	5.6	23.1
% of max. capacity	3.0	5.6	2.1	2.1	3%

4.46 In the interests of loss reduction, the report recommends redistribution of those transformers that are not being used optimally. For a given type of transformer, the method used consists of calculating losses in kWh over a year, then comparing the cost of these losses to the cost of moving the transformer. Moving the transformer is economically justifiable if the cost of moving it is less than the difference in loss costs between the transformer proposed to be moved out and the new equipment to be installed. Calculations were made for nine classes of STEG MV/LV transformers. They demonstrate that, for the 10-kV network, improved management of 500 and 630 kVA transformers would

5/ *The formula used for customer transformers differs slightly from that used for the STEG networks:*

$$JL = \text{Joule losses at rated output} \frac{(\text{customer subscribed power})^2}{(\text{total customer installed capacity})^2}$$

lead to annual savings of TD 6,885, or US$7,500. Similar calculations could not be made for all classes of transformer, however, since their utilization factors, particularly at the 30-kV level, were not available. It is recommended that STEG make these calculations, based on utilization factors determined following a measurement campaign. STEG's decision to eliminate the 400-kVA class of transformers from the 10-kV system should be reviewed and carefully scrutinized in light of the redistribution of power demand among MV/LV substations and of the useful life of the 10-kV network.

4.47 Widely differing data were obtained on the number of MV/LV transformers in current inventory, ranging from 2,050 (10% of the number in use) to 7,852 (38% of the number in use). Both figures are too high, and substantial savings could be achieved through suitable adjustment of inventory levels. It is recommended that inventory be limited to 5% of the transformers in use, which would permit annual savings of about TD 263,000 to TD 1,740,000, or US$290,000 to US$1,900,000, depending on the real extent of current inventory.

Table 4.10: SAVINGS ACHIEVABLE BY REDUCING THE INVENTORY OF MV/LV TRANSFORMERS

In Use	Current inventory	Recommended inventory	Excess inventory	Excess cost of inventory (TD)	Annual savings (TD)
20361	7852	1018	6834	10,251,000	1,740,000
20361	2052	1018	1032	1,548,000	263,000

The cost of superfluous inventory is estimated using an average figure of TD 1,500 per transformer, or US$1,700 (taking into account the age of each set), while annual savings are estimated at 17% of total inventory value (15% in holding costs and 2% in procurement costs).

Reactive energy compensation

4.48 Any energy transmitted by way of alternating current consists of active or useful power and reactive, non-useful, power. Reactive power is induced by the effects of electromagnetic fields; in other words, reactive power is magnetizing energy.

4.49 Distribution networks always consume reactive energy because of:

(a) applications that exploit the properties of magnetic fields (static or spinning) rather than those of electrical fields; and

(b) the structure of the network itself, since the reactive energy consumed by lines and transformers is greater than that produced by cables.

4.50 The objective of reactive power compensation policies is to prevent the networks from carrying a parasitical flow of reactive energy, and hence to reduce network losses and voltage drops. From the technical standpoint, the ideal solution is to produce reactive energy at the point of consumption. From the economic standpoint, the optimal solution is the one that ensures that the average annual capital cost of providing one supplementary Mvar of compensation equals the cost of the active energy losses occasioned during the year by the generation and transmission of one additional Mvar at peak periods while maintaining voltage levels at the various points in the network.

4.51 Reactive power compensation policies are based on two types of measures:

(a) technical measures that the power company implements based on their expected economic returns; and

(b) regulatory and tariff measures, generally implemented to encourage large consumers of reactive energy to generate it themselves, using their own equipment, or to consume less by improving the energy efficiency of their installations.

4.52 Since the flow of reactive energy burdens upstream networks, the study of the technical measures needed for the STEG networks was conducted at the transmission network level. The results showed that supplementary compensation amounting to 124 Mvar is needed as soon as possible in order to reduce tan phi to 0.5% (see technical and economic justification, para. 3.16).

4.53 With regard to tariff measures, STEG's method of billing the reactive energy supplied to its HV and MV customers gives them little incentive to install compensation equipment. Exonerating these customers from payment for the reactive power they consume up to a level equivalent to 75% of their active energy consumption, and applying surcharges (or penalties) to consumption above this level is not consistent with the effort to reduce tan phi to the target ratio of 0.5.

Reactive power billing

4.54 In France, the power distributor supplies reactive power free of charge at the point of delivery under the following conditions:

(a) up to the equivalent of 40% of the active energy consumed (tan phi = 0.4) during scheduled or unscheduled peak hours and during full-load hours in winter, from November to March;

(b) without limit during off-peak hours in winter and throughout the summer tariff period, from April to October inclusive.

When the limits are in force, any reactive energy consumed beyond tan phi = 0.4 is billed monthly at the rates listed in current price schedules (e.g., 12.65 centimes/kvarh for the "green" tariff, applied over a range of 250 kVA to 10 MW).

Consumption is billed as follows:

- Wa (kWh), for the energy consumed per month during the period subject to limits;

- Wr (kvarh), for the reactive energy consumed per month during the period subject to limits;

- Wfr or 0.4 Wa, for the amount of reactive energy supplied free of charge;

The amount of reactive energy billed will be: Wb = Wr - Wfr = Wa (tan phi 0.4). The charge will be: Wb x a, where a is the price of reactive energy.

4.55 The study of the STEG MV network showed that it is not overloaded and that a decision on a voltage change, particularly from 10 kV to 15 kV, is not urgently needed. However, in view of the rapid growth in MV and LV consumption in Tunisia, to avoid saturation of the network and increasing losses, a change in voltage, particularly the economic timeliness of a change from 10 kV to 15 kV, should be studied, and incorporated into a relatively long-term MV network development strategy. STEG does not currently conduct planning studies of this type on the distribution network, as it does not have the necessary tools (distribution models) and computer resources.

4.56 It is recommended that STEG develop distribution network planning studies for the medium and longer terms, using the model and data-processing resources acquired through this project. During a first phase, these studies would be carried out at STEG headquarters, but they should subsequently be decentralized to the regional and/or district levels, once their scope has been defined at the plant level, and once it has been ascertained at the regional level that the specialized personnel needed to conduct such studies are available.

Additional Problems Associated with Operation of the MV/LV Networks

4.57 Two other problems associated with operation of the MV and LV networks should be mentioned: maintenance of MV/LV structures, and environmental and safety problems created by transformers and capacitors that use pyralene as a dielectric.

Maintenance

4.58 The maintenance of MV and LV structures is generally fairly satisfactory, but varies from one district to another because STEG has no stated maintenance policy, and there are no written procedures for the various types of structure.

4.59 As with its other functions, STEG should study and implement measures for the maintenance of MV and LV structures that will guarantee an acceptable level of reliability at least cost and should prepare written procedures for use by the MV and LV network operators. Annex 16 presents the issues to consider in preparing a study of this type. A maintenance study would provide a good opportunity to decentralize STEG management and give greater decisionmaking responsibilities to operations personnel. Particular attention should be given to the levels of expertise required and to arrangements for internal monitoring of maintenance.

Prevention of risks associated with the use of PCB

4.60 Environmental studies the Bank has conducted in Tunisia, as well as discussions with senior STEG officials, have indicated that STEG fully understands the risks associated with equipment that uses insulants containing PCB (polychlorobiphenyl) or PCT (polychloroterphenyl), and that the utility has undertaken protective measures as well as measures to sensitize customers who own equipment of this type. The report recommends that STEG strengthen and systematize preventive measures to be taken in case of accident and increase its efforts to inform and sensitize its customers. In future, STEG should avoid installing equipment with insulating oils containing PCBs.

V. CUSTOMER MANAGEMENT

5.1 In addition to reducing technical losses (see preceding chapters), STEG needs to improve its customer management so as to minimize the financial losses it incurs when the power it supplies is consumed. These losses, called "nontechnical" to distinguish them from the technical losses discussed earlier, are associated with:

(a) recording consumption (metering);

(b) customer billing; and

(c) debt recovery.

5.2 The program introduced some years ago to improve customer management has enabled STEG to reduce customer losses to a low level. For the distribution network, for instance, the study arrived at a figure of 10.3% for overall losses in 1989, 7.2% technical and 3.1% nontechnical. STEG's performance in this area is comparable to that of more advanced electric utilities. The utility needs, therefore, to consolidate its gains through rigorous management of the existing system and to progress further by adopting technical and organizational management techniques that are new to Tunisia.

Metering

5.3 Losses at the metering stage have three possible causes:

(a) unmetered consumption (illegal connections and temporary installations);

(b) third party interference with metering; and

(c) technical defects in the meters.

Unmetered consumption

5.4 It has become clear through field visits, review of connection procedures, and discussions with customer management staff that the risks of unmetered consumption, though present, have been minimized.

5.5 Illegal connections: To avoid this problem, frequently observed in peripheral urban areas characterized by uncontrolled development, STEG has established a highly deterrent policy, based on the following:

(a) meter readers routinely monitor the network and meters, and are required to report all technical and administrative anomalies they observe on their rounds;

(b) meter readers are rotated frequently from one district to another to minimize the risks of collusion with customers;

(c) as an incentive to meter readers to detect frauds, STEG offers them a bonus of TD 5, about 50% of a supervisor's average daily salary, for each case of fraud they identify;

(d) STEG uses insulated cables for networks and supply lines, making clandestine hook-ups difficult; and

(e) strict internal anti-fraud regulations provide for the denunciation of frauds by officially designated staff; such denunciations are followed by legal action, since the Tunisian Penal Code equates thefts of electric power with fraud.

5.6 To warn against and prevent the spread of illegal connections and other types of electricity fraud, STEG should organize swift, targeted field operations to increase consumer awareness of fraud and prevent its occurrence. To be effective and have a major impact, such operations should be preceded by finetuned statistical analyses (see para. 5.12(a)), widely publicized in the appropriate media, targeted to specific geographic areas and to high-risk customers, and conducted over short time periods by mobilizing the required staff and physical resources.

5.7 Anti-fraud campaigns of this type are not costly. For instance:

(a) a half-day campaign conducted by 10 STEG staff (1 executive, 2 foremen, and 7 operatives) would cost about TD 104; and

(b) an anti-fraud team tackling one type of problem (large customers, delinquent customers, billing anomalies) over a 400-hour period would cost about TD 1800.

The cost would be recovered by reducing frauds by an average of 1.5 MWh, in the first case, and 28 MWh in the second.

5.8 However, the major benefit from actions of this type is psychological -- they warn against fraud and deter potential evaders. Experience in various countries shows that fraud spreads rapidly and is difficult to eradicate once it becomes pervasive. Systematic analysis of the results of the campaigns it has carried out so far will give STEG a more accurate idea of their effectiveness and of what

organizational changes it can make to continue the campaigns and incorporate them into its internal monitoring program.

5.9 Temporary installations: An in-depth analysis of the procedures STEG has developed to prevent unmetered service connections (following a breakdown in meter inventories or requests from the authorities for urgent hook-up) shows that these are well designed and complete. They appear to be well-applied in the distribution districts. To minimize financial losses, STEG should continue to apply them forcefully.

5.10 Interference by third parties: Meter fraud is increasing in many countries. The fraud generally consists of modifying or damaging the meter to reduce the amount of energy registered, or to ensure that it is not registered at all. Subscribers commonly use simple methods (damaging the meter intentionally, immobilizing the disks, applying magnets, etc.), but more technically sophisticated methods, which require the complicity of STEG employees or professional electricians (by-passing the meters, additional connections made in series, and resale of the energy to take advantage of a special tariff) are also observed.

5.11 STEG is making great efforts to eliminate practices of this kind, through:

(a) regular meter monitoring (see para. 5.5);

(b) routine meter inspection campaigns;

(c) printing of meter cards for disconnected customers as well as for regular customers; the data processing equipment reads and checks these cards, and automatically indicates any fraudulent consumption;

(d) producing a computerized listing of subscribers who have abnormally low consumption or none at all.

5.12 Three actions are recommended to consolidate STEG's achievements, simplify meter reading, improve checks and controls, and introduce new meter reading techniques:

(a) increase the use of data-processing techniques to detect abnormal consumption due to fraud or metering anomalies, through routine monitoring at the central level, during the billing process, by (i) comparing the customer's current consumption with past consumption, if a record is available, and/or with average consumption for the category to which the customer belongs (this requires defining homogeneous customer groups, and standard consumer profiles); and/or (ii) monitoring the use of subscribed demand. The results can be used following various criteria, adjusted for each district; the current reading may be rejected, forcing a re-reading, and/or consignment of the invoice to a special category; or an error message may be produced, addressed to the operating entity

concerned, which would decide -- in light of local conditions -- on the course of action to be followed. To supplement this automatic control mechanism, and to ensure that local controls are better designed and targeted, STEG could give local managers access to customers' files, using a simple interface device. Initially, the districts could access abbreviated customer files of the type that can be processed and used on a PC. Decisions as to the kinds of processing to be undertaken, the hardware configurations to be used locally, and the cost of the operation should be incorporated into STEG's master data-processing plan, which should be developed in close association with local managers;

(b) install meters on the outside of buildings, to reduce the number of missed readings, deter fraud, and simplify the detection of fraud and meter anomalies by making meters more accessible to STEG staff. Even if the problem of accessibility does not seem too serious at present, STEG should study a policy of maintaining permanent access to meters, taking into account the economic and social problems unique to Tunisia and the types of metering technique now available (the relevant technical information can be found in an annex to the report that the Consultant has submitted to STEG). In France, the additional operating costs due to meter inaccessibility have been estimated at F 250/year/inaccessible meter, or 5% of an average annual bill (in Tunisia's case, this would amount to TD 4 at 1989 prices); and

(c) gradually introduce electronic metering methods. These methods may be more reliable and accurate because they monitor the maximum load, are more complex to defraud, and can accommodate multiple and complex tariffs when necessary.

5.13 Technical defects in meters: By following a strict policy of surveillance by meter readers and conducting meter calibration campaigns at irregular intervals, STEG keeps meter defects at a minimum throughout its networks. The report recommends that STEG:

(a) formalize its meter verification procedure, following a clearly stated schedule, taking into account both the risks of loss of revenue and the capacity of the regional calibration centers. Yearly intervals are proposed for large-scale customers, and a realistically determined schedule for all others; and

(b) computerize management of the meters in use; with computerization, a series of meters can be analyzed statistically to detect operating problems, and steps can be taken to replace, repair, and/or calibrate the defective meters. STEG should study such a system in the context of its overall data-processing plan, to determine what types of information should be included and link it with the customer data file. If computerized management proves too complex or too costly because of the large number of meters in use, STEG should consider alternatives such as gradually building up a data file on the meters assigned to new customers or a file on new and overhauled meters -- in the medium term, these data would provide an adequate statistical base for rigorous meter management.

If either one of these alternatives proves too hard to implement, STEG should at least develop a PC data file of meter readings for the large MV-users, and for multi-rate metering; about two man-months would be needed to set up the file.

Customer Billing

5.14 Customers are billed automatically from two centers in Tunis (two mini-computers) and one in Sfax (one mini-computer). Billing is generally satisfactory -- STEG agents deliver statements to customers' business address or residence within three to five days. Customers are not billed by mail, as postal services are considered unreliable. The new customer-oriented computer application that is being developed should improve the present billing system. The probable causes of losses, and the improvements to be made over the complete cycle, from connection of a new customer to issue of the bill, are reviewed. below.

Processing new customers

5.15 Delays in registering new customers (meters) in the billing files or in updating the files in response to metering or address changes can lead to late payments, or to loss of income for the utility due to failure to bill.

5.16 The procedure STEG has instituted is reliable and should prevent situations of this type where ordinary subscribers are concerned. However, the procedure must be strictly applied to all hirerarchical levels, and it would be advisable to extend it to all classes of customer, including local authorities and government bodies and agencies. The report also recommends that STEG use as its management criterion for the districts "number of subscribers awaiting inclusion for more than two months," to replace the existing criterion of "number of subscribers awaiting inclusion for more than four months." This new criterion, which puts more constraints on management, would improve the utility's cash flow and enable annual financial savings of about TD 2,300, or US$2,500.

Meter reading

5.17 Meter-reading losses may be caused by errors in reading, recording, or transmitting the measurements, by collusion between the meter reader and the customer, or by the customer's absence at the time the meter is read. STEG has introduced several operating practices and procedures that have improved the quality and reliability of meter readings, as follows:

(a) at the district level, meter readings are no longer entered manually in a register, but are recorded on computers;

(b) particular attention is given to recruitment and to providing regular additional training;

(c) meter readers are rotated regularly from one zone to another to avoid collusion, the effects of routine, etc.; and

(d) readers are monitored individually for the quality of their work.

However, meter inaccessibility is beginning to cause problems (see para. 5.12).

5.18 STEG should maintain and further develop its program to train meter readers and improve the quality of readings. Simultaneously, it should begin studying and introducing -- even if only on an experimental basis -- more advanced customer management methods such as the use of portable data readers to record readings.

Monitoring special-tariff customers

5.19 Losses are principally due to insufficient monitoring of customers who benefit from special tariffs and of unauthorized access to these tariffs by some customers (e.g., some customers have two meters at the same address, one of which benefits from a special tariff, such as STEG's special tariff for agricultural uses). Although STEG has instituted hierarchical procedures and controls aimed at eliminating error and fraud, it should consider:

(a) supplementing internal hierarchical controls with specific statistical monitoring of customers who benefit from special tariffs -- see para. 5.12 (a); and

(b) eventually, eliminating special tariffs and disallowing multiple metering at the same address.

Billing procedures and correction of anomalies

5.20 STEG's billing procedures and the associated controls it has set up are reliable; under normal circumstances, they prevent any failure to bill energy consumption measured or arrears due. Established procedures ensure that billing anomalies and bill correction are monitored regularly and systematically and are subject to strict controls at all hierarchical levels.

5.21 STEG should strengthen its internal controls, focussing on correct application of procedures. In particular, it should improve the current arrangements for handling billing anomalies by using its data-processing capability to pinpoint anomalies that have been identified but not dealt with (i.e., in cases where bills have been confirmed or corrected), within a period to be determined, but which evidently must be shorter than the usual billing interval.

Distribution of bills

5.22 Distribution of STEG bills is effective, given that meter readers deliver them to the customers' residences or places of business within three to five days of the last reading. However, these arrangements are quite costly. STEG accounting records show that hand delivery of bills costs TD 244,833; since there are two deliveries per cycle, the total cost per cycle is TD 490,000. The estimated cost of mailing bills is only TD 390,000, on a per-bill basis of TD 0.15 in stamps and TD 0.0125 in miscellaneous costs. By mailing bills, therefore, STEG could achieve gross savings of TD 100,000 per billing cycle, which amounts to TD 300,000 per year (US$330,000) at 1990 prices.

5.23 Although it is difficult to provide a more precise calculation of the effect of these two modes of distribution on STEG's cash position within the scope of this study, the above simple computation, considered together with the rapid increase in the number of consumers of electric power, indicates clearly that STEG should monitor changes in the postal services closely and start to use the mails as soon as they are judged to be performing well enough to answer its needs at least cost.

5.24 STEG should conduct regular pilot mailing tests and begin dispatching bills by mail as soon as this becomes more advantageous from the cost standpoint at the same level of service. Urban and rural zones could be treated separately.

Debt Recovery

5.25 In recent years, STEG has taken several steps to improve recovery of outstanding debts, by:

(a) computerized repeat billings of unpaid invoices, routine and monitored;

(b) adaptation to special or seasonal customers -- e.g., meter reading, billing, and collection are performed every two weeks when the vegetable oil mills are operating;

(c) use of a special indicator (number of days of accounts receivable outstanding), included in district performance charts, to monitor customer arrears;

(d) offering customers the possibility of paying their bills by mail;

(e) negotiation with central government departments and agencies of special provisions (budgetized prepayment), providing for them to pay 80% of their electric power costs to STEG at the beginning of the year, and 20% at the end of the year (against presentation of statements of actual consumption). STEG hopes to extend these arrangements to the communes in the near future; and

(f) disconnection of customers when the first bill is in arrears, and initiation of legal proceedings for recovery when the second bill is not paid.

5.26 These measures led to a reduction in customer arrears from 64 days of turnover in 1984 to 49 days in 1985 and 30 days in 1988, as Table 5.1 indicates. It should be noted that 75%-78% of arrears are owed by governmental agencies, local authorities, and public companies, whose relative share of debt due rose slightly between 1985 and 1988.

Table 5.1: CHANGE IN DEBT DUE TO STEG (1985 to 1988)
(In Tunisian Dinars)

Year	1985	1986	1987	1988
State-funded consumers	2,801,159	4,396,899	3,888,928	5,249,250
Consumers with autonomous budgets	2,161,566	1,316,651	1,233,360	1,421,023
Local authorities	8,938,854	9,984,765	7,672,618	7,510,415
National companies and public agencies	6,038,607	4,879,219	4,039,243	2,271,364
Sub-total 1	19,940,186	20,577,534	16,834,149	16,451,052
% of total	75	75	73	78
Industrial MV consumers	1,582,874	1,509,524	683,767	428,236
Miscellaneous claims for payment	1,119,451	1,578,931	1,822,955	1,826,297
Regular LV consumers	3,805,282	3,800,294	3,635,867	2,277,088
Sub-total 2	6,507,607	6,888,749	6,142.589	4,531,621
% of total	25	25	27	22
Total outstanding debt	26,447,793	27,466,283	22,976,738	20,983,673
Turnover	193,395,850	203,108,671	231,624,963	256,939,417
Ratio (days)	49	48	36	30

5.27 Although considerable improvement has been made, there is still room for further reduction of the arrears ratio to 20 days of turnover -- the average figure for some of the highly developed power companies, while those with the best-managed debt recovery programs show ratios of 15 days. Reducing STEG's arrears ratio by 10 days would reduce arrears by TD 7 million, or US$7.8 million, enabling cash flow savings of TD 700,000 (US$780,000).

5.28 If STEG is to achieve this goal, it should:

(a) prepare statements quantifying the effect on its financial position of late payment by public and parastatal entities, and initiate action to improve debt recovery; in particular, STEG needs to: (i) improve its budgeted prepayment procedure and assist company managers when they prepare their electricity budgets, to avoid difficulties in collecting the balance due at the end of the year -- a common problem for STEG, principally due to agencies' underestimation of their power expenses when they prepare their annual

budgets; and (ii) extend budgeted prepayment to local authorities, adapting it as necessary to meet their particular circumstances;

(b) launch campaigns to encourage professional clients to make their payments by means of direct debits from their bank accounts, to improve the recovery of large debts; it would be particularly advantageous to propose this formula to national corporations and public authorities; and

(c) integrate into the data-processing applications now being developed an indicator that would monitor arrears according to the number of days -- 20, 30, and 55 -- that they are overdue; this indicator would provide a better reading of the age of the debt and would make debt-collection personnel more aware of the problem.

5.29 STEG could improve both cash flow and debt recovery by:

(a) reading the meters of large-scale LV customers every two months instead of every four months. The preliminary detailed calculations contained in the Consultant's report show the advantage of bi-monthly meter reading and monthly billing of customers whose annual consumption exceeds TD 600;

(b) offering a monthly payment system that would enable customers who wished to do so to spread their electric power expenditure over the whole year. Interested customers would make 10 equal monthly payments, calculated on the basis of their previous year's consumption. At the end of the year, the balance owed on actual consumption during the current year would be settled over one month or two. In France, estimates show that each customer who opts for the monthly payment plan saves the power company 0.8% of his annual bill. Assuming this figure applies for STEG also, if only 10% of customers chose the monthly payment plan, annual savings of TD 65,000, or US$72,000, would be achieved.

These preliminary results show the interest for STEG in undertaking in-depth studies in these two areas and, with regard to the monthly payment plan, in making test runs to try out customer reaction to this new service and get more accurate estimates of the profitability of the approach.

Tariff Policy

5.30 Since 1971, several studies have been made of STEG's tariff system, leading to nine tariff adjustments over the period to preserve the utility's financial balance.

5.31 STEG bases its pricing policy on charging for power at its marginal cost and keeping rates in line with the cost of providing electricity. Notwithstanding, some problems persist in the area of LV service because the utility has retained some preferential rates and others that are based on special uses.

5.32 It is recommended that STEG:

(a) study the elimination of preferential and special tariffs, to avoid distorted signals to consumers and, consequently, waste of energy. By way of example, the LV tariff for agricultural users (not applied during peak hours) is equal to if not less than the general HV tariff, although LV supply costs are appreciably higher than HV supply costs. If the authorities wish to subsidize certain consumer groups, it would be preferable, in the interest of economic consistency, sound management, and transparency, to choose direct methods of subsidization rather than to distort prices; and

(b) decide quickly on an LV hourly tariff to offer to all large-scale LV customers as well as to customers who benefit from special-usage tariffs for purposes such as central heating, air conditioning, and water heating. An hourly rate tariff could even replace specific tariffs such as the one available to "vegetable oil mills and the like." An hourly rate would simplify the tariff system and, consequently, customer management, since it would eliminate double metering at the same site, a situation that generates additional expenses and can lead to fraud.

VI. CONCLUSIONS

6.1 This diagnostic study has shown that investments and measures to reduce network losses and save energy are possible and can produce economic returns even in a utility that performs well, such as STEG. In addition, these actions and investments have a positive, though modest, impact on the environment.

6.2 Measures that make the supply of power more efficient are important and relatively easy to implement since they are based on decisions made at the central level and STEG gives them sustained attention. However, these measures can be complemented by measures at the final user level (these are harder to implement, but STEG's organizational capacity is adequate to the task), which can contribute just as much, or even more, to improving the overall efficiency of the electric power sector.

Main actions proposed

6.3 The main actions and investments proposed are summarized in Table 6.1. The proposed program would enable STEG to reduce peak power losses by about 1.5%, or by about 10 MW currently, and by about 15 MW by 1993. The reduction in energy losses can be estimated as 2% to 3% of total electricity consumption.

Table 6.1: MAIN ACTIONS PROPOSED

Actions	Costs (US$ 000)	Annual savings (US$ (000)	Payback period (years)	Rate of return (%)
1. Set up continuous economic efficiency monitoring of steam turbines	1,000	1,250	< 1	> 100
2. Reinforce MV network	3,300	1,300	2.5	40
3. Reinforce LV network	9,000	2,500	3.6	28
4. Better management of MV and LV transformers	Low	150	-	-
5. Decrease the customer portfolio to 20 days turnover	Low or nil	780	-	-
6. Other improvement actions: maintenance, technical and financial management	Low or nil	1,720	-	-

Impact on the environment

6.4 The recommended measures, to improve generating unit efficiency and reduce network technical losses, will have a beneficial, though modest, impact on the environment;

(a) improving the performance of the steam turbines by at least 1% would be the equivalent, in 1990 conditions, of reducing fuel consumption by about 9,000 toe, or almost 400 TJ, which corresponds to a reduction in CO_2 emissions of about 90,000 t and a reduction in NOx emissions of about 240 t; 6/

(b) a reduction of technical losses by about 1.5% of peak demand corresponds to an average reduction of electricity consumption of about 2.5% and to fuel savings, under 1990 conditions, of about 30,000 toe, or almost 1,350 TJ. These savings correspond to a reduction in emissions of about 300,000 t of CO_2 and 850 t of NOx.

6.5 Estimations of the economic impact of reducing emissions from utility plants vary greatly, in a range of 1 to 10, according to different studies and different technical experts. By totaling the savings considered in the present study at the cost for reducing the emissions, one obtains a value of US$7 million, indicating the supplementary benefits to be obtained from the proposed loss reduction program, about half the sum of the investments proposed to accomplish the loss reduction program.

Power conservation at the level of final use

6.6 Many electric utilities in the developed countries, faced with the problem of finding the sites and capital needed to increase the power supply, have undertaken programs of promoting customer conservation of energy. STEG has the required organizational and management capacity to promote these kinds of programs, which have been proven to be economically and financially advantageous in several countries.7/

6.7 Investigation of the technical, economic, and financial conditions required to implement such a program is beyond the scope of the present study, but studies conducted in several countries have demonstrated the advantage of such programs, precisely targeted and supported by adequate financial resources. It is therefore recommended that STEG create a task force to study:

6/ *Note that, to improve the performance of the electric generating system and to reduce the consumption of fuel per GWh produced, STEG has taken the decision to install a 300 MW combined cycle plant. This decision, which will allow STEG to better evaluate the technical and economic parameters of the combined cycle, will undoubtedly have a significant impact on STEG's generating system and, consequently, on this technology in the region.*

7/ *Experience has shown that electric utilities, particularly in the United States, have given up the easy solution -- to increase supply -- in response to the pressure of financial constraints and shortage of suitable sites, on the one hand, and to the entry of independent producers into the market following partial deregulation of the sector, on the other. STEG can reach this innovative phase (new thinking) without waiting to be confronted with these constraints, and can thus reduce the need for large investments that it already faces.*

(a) in association with the Agence de Maîtrise de l'Energie, the promotion of programs designed to save power at the level of final use, that are economically and financially profitable for the utility, the consumer, and the local authorities, and

(b) implementation of the programs by providing better information to consumers, possibly in association with any partners, local authorities, and or private promoters, who would be affected by the promotion of such programs.

STEG ORGANIZATIONAL STRUCTURE

STEG is managed by a Board of Directors with 14 members:

- 1 Chairman and Managing Director
- 1 Assistant Managing Director
- 8 Directors representing the State
- 2 Directors representing employees
- 1 Financial Controller
- 1 Technical Controller

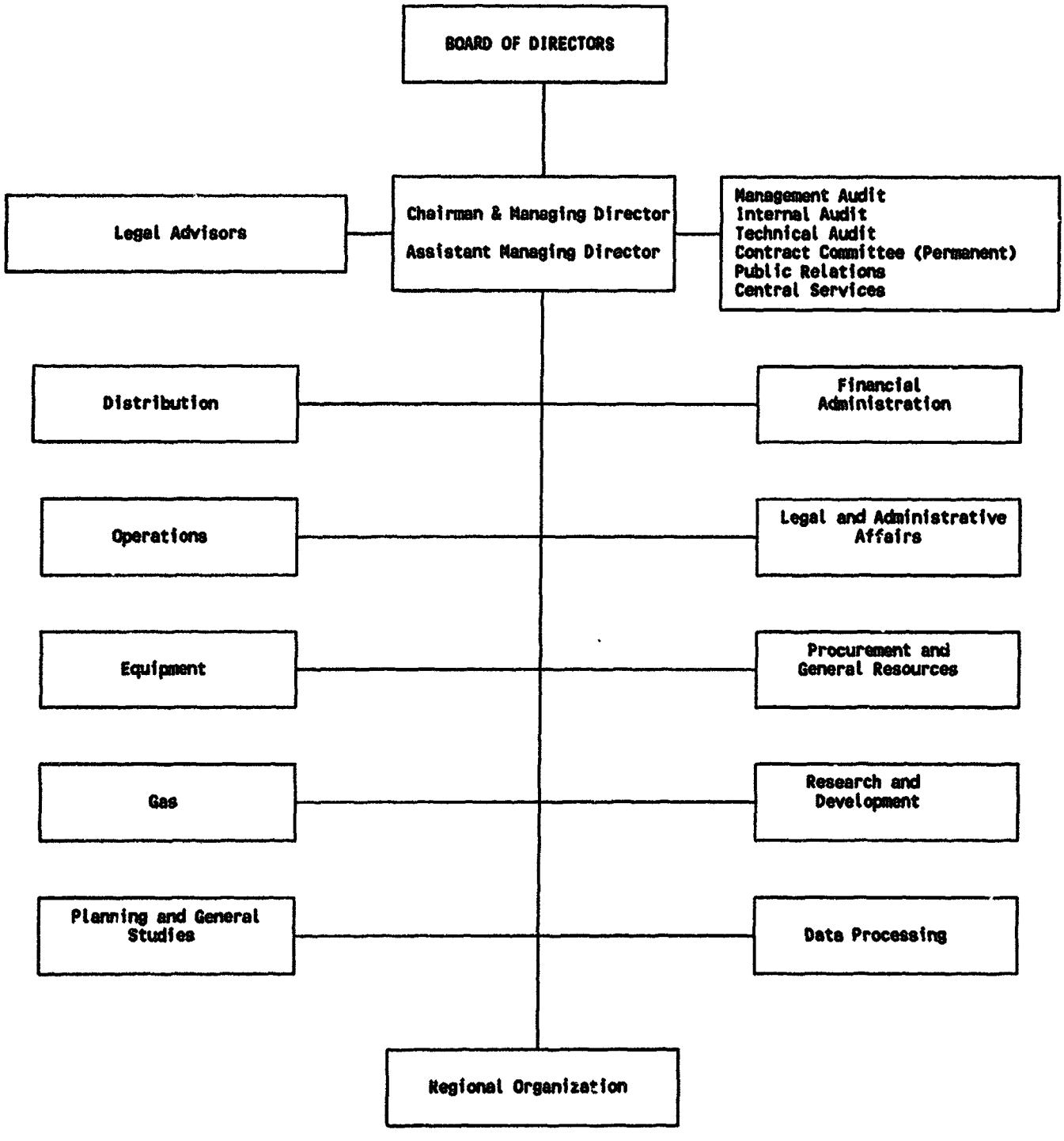
Ten Directorates and five Departments, reporting to the Chairman and Managing Director, are the backbone of the company's structure.

The five departments are:

- Management Audit
- Internal Audit
- Technical Audit
- Public Relations
- Central Services

The ten directorates are:

- Data Processing
- Planning and General Studies
- Distribution
- Operations
- Equipment
- Gas
- Financial Affairs
- Legal and Administrative Affairs
- Procurement and General Resources
- Research and Development


BOARD OF DIRECTORS
Legal Advisors
Chairman & Managing Director
Assistant Managing Director
Management Audit
Internal Audit
Technical Audit
Contract Committee (Permanent)
Public Relations
Central Services
Distribution
Financial Administration
Operations
Legal and Administrative Affairs
Equipment
Procurement and General Resources
Gas
Research and Development
Planning and General Studies
Data Processing
Regional Organization

CALCULATION OF LOSSES

METHOD

Short-term Marginal Cost

Definition

1. The short-term marginal cost is the generation, transmission and distribution cost entailed in supplying one additional kWh in a given year with a fixed amount of equipment.

Structure

2. The short-term marginal cost is based on the establishment of a reference cost for fuel, based on the load curve at J-1 or a study of projections. The reference cost takes account of the real cost of fuel and an opportunity cost that takes account of real-time contingencies in fuel supply. In the case of projections, it is necessary to add unit start-up costs (usually from 45 minutes to one hour of fuel cost at full plant load), together with transmission costs. The marginal short-term generation costs are used for projecting operating costs. In France, the reference costs over five years are based on fuel costs. These costs are updated in line with changes in the macroeconomic situation and discount rates. Projections of hourly or daily marginal costs make it possible to optimize allocations in accordance with probable availability and problems with generating equipment. Likewise, they enable an optimum generation schedule to be determined. For Tunisia, a five-year study of marginal generation costs would compare the economic benefits to be derived from either operating the power plants simultaneously, as is done at present, or staggering unit shutdowns and startups.

Long-Term Marginal Cost

3. The long-term marginal cost is the additional generation, transmission and distribution cost entailed in supplying one additional kWh in any given year in cases when the utility is able to increase generating capacity. It takes into account fuel, operating and capital costs. Long-term marginal cost is also calculated on the basis of the incremental cost. In fact, the system is adapted to the new load level by making the necessary capital investment one year ahead of schedule. The cost of this early investment is the sum of the following three items: the annual financial charges (discounted),

depreciation over the first year, and the fixed costs of operation and maintenance of the equipment for one year.

4. The estimated savings from loss reduction (presented below) are calculated by taking into account the incremental costs of equipment at the various study levels (generation, transmission, and distribution), as well as fuel costs.

Calculating Fuel Costs

5. The 1989 load duration curve for all Tunisia was used to calculate fuel costs. The results appear in the STEG tariff study of April 1988.

Load Duration Curve (see Fig. 1)

6. This is the curve showing demand for the 8,760 hours per year, in decreasing order, from the maximum to the minimum load peak. The load curve for generation at national level in 1989 has been used. It is based on 13 values, as shown in the table in Figure 1.

7. Calculations would have been more precise if the load duration curves for each of the HV/MV substations had been used, because consumption patterns can vary depending on the type of area served (e.g. urban and predominantly residential areas, urban and predominantly industrial areas, agricultural areas, sparsely populated areas, etc.). In addition, the load diagram for high-voltage industrial customers may also differ from that of customers connected to the distribution network. The national load duration curve refers to an annual duration of peak power utilization totaling 5,830 hours (see section below). The annual duration of peak power utilization for the main substations in question is about 5,900 hours. The difference is thus negligible.

8. It is therefore proposed that the load duration curve for the country as a whole be used in determining the share of fuel costs in the annual cost of 1 kW of losses at peak periods. This approach is consistent with the degree of accuracy of other data used in the various calculations of losses.

Marginal Cost of Fuel

9. The STEG tariff study gives marginal fuel costs for 1994 for the peak, day and night tariff periods based on both domestic Tunisian prices and international market prices. The latter values will be used, since they reflect the real cost to the country.

Calculation of Costs

10. Available data relate to different time periods, since we have:

- the load duration curve for 1989; and

- the marginal fuel costs for 1994.

11. However, the curve for 1994 is likely to be very similar to that for 1989. In fact, no extensive equipment modifications are planned for the short term, and even if new applications develop or pricing adjustments are made, they would not have a significant impact on the shape of the load curve in so short a space of time.

12. Fuel costs for 1994 relate to the future generating system over the medium term. They can thus be regarded as entirely representative and used to measure the effects of the recommendations proposed for reducing losses in the medium term.

Annual fuel costs due to losses will be calculated for the following two cases:

Joule-effect losses: the following assumptions will be made:

Peak power use: 5,900 hours;

Load level depends on the shape of the national load duration curve (see Figure 1);

Hourly fuel costs are as shown in the STEG pricing study (April 1988).

Core losses in transformers: the following assumptions are made:

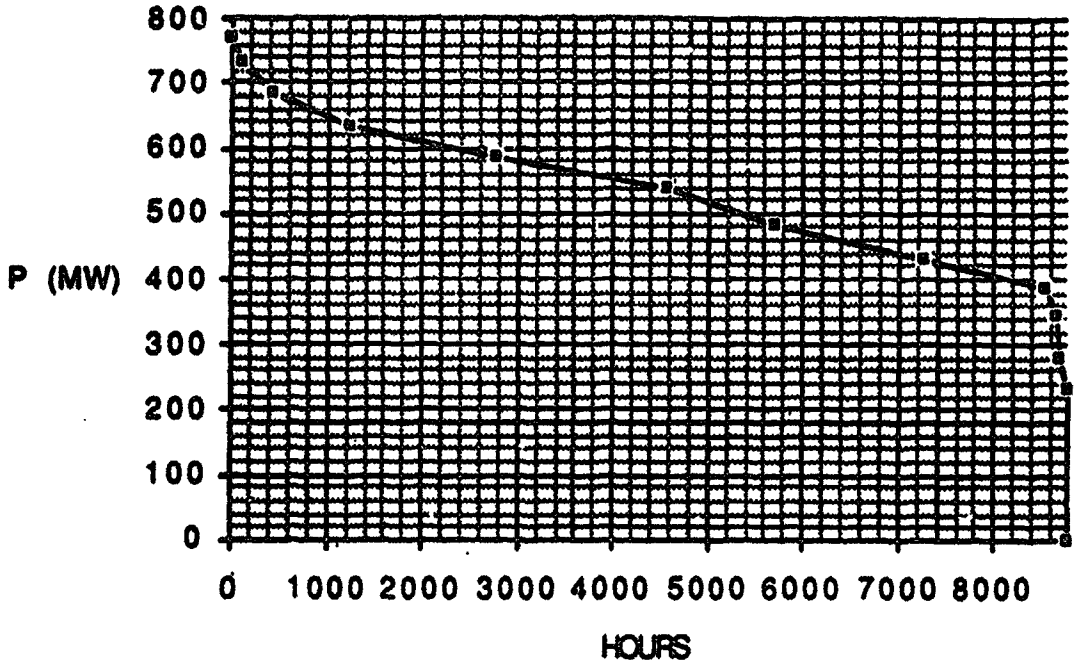
Use: 8,760 hours;

Hourly fuel costs are the same as above.

LOAD DURATION CURVE 1989

Peak power : 771 MW
Minimum power : 230 MW
Average power : 513 MW

FIGURE 1



VALUES TAKEN INTO ACCOUNT

Relative P	POWER MW	Half-hours	Hours
150	770	3	1.5
142.7	732	245	124
133.8	686	623	435.5
123.8	635	1605	1238
114.1	585	3093	2784.5
104.8	538	3584	4576
94.4	484	2273	5713
84.2	432	3093	7259.5
75.7	388	2568	8543.5
66.7	342	227	8657
54.5	280	70	8692

Calculation of Fuel Costs Resulting from Joule-effect Losses

13. Joule-effect losses are proportional to the square of the load. The standard loss curve can therefore be calculated from a curve derived as follows from the load duration curve: a time variation in the ordinate is proportional to the square of such variations in the load duration curve (see curve in Fig. 2).

The curve is divided into three periods:

- a first period of 1,252 hours, corresponding to the peak;

- a second period of 4,223 hours, corresponding to the daytime hours;

- a night period of a total duration of 9 h x 365 = 3,285 hours.

14. The annual Joule-effect for each of the above periods is determined on a chart by constructing equivalent rectangles with a surface area equal to the areas subtended by the curve representing lost energy.

The following results are obtained (see Fig. 2):

- 78% of the peak losses for the peak period;
- 54 of the peak losses for the daytime period;
- 32% of the peak losses for the night period.

Annual energy losses corresponding to 1 kW of losses are therefore as follows:

- peak:	0.78 x 1,252	= 976 kWh;
- daytime hours:	0.54 x 4,223	= 2,280 kWh;
- night hours:	0.32 x 3,285	= 1,051 kWh;

The marginal costs in millimes/kWh considered for 1994 are given in the April 1988 STEG tariff study).

- peak: 38.2
- daytime period: 30.3
- night period: 23.

The annual fuel cost for 1 kW of peak losses will therefore be as follows:

(976 x 38.2) + (2,280 x 30.3) + (1,051 x 23) = 130,540 millimes = TD 130.

CALCULATION OF ANNUAL FUEL COSTS

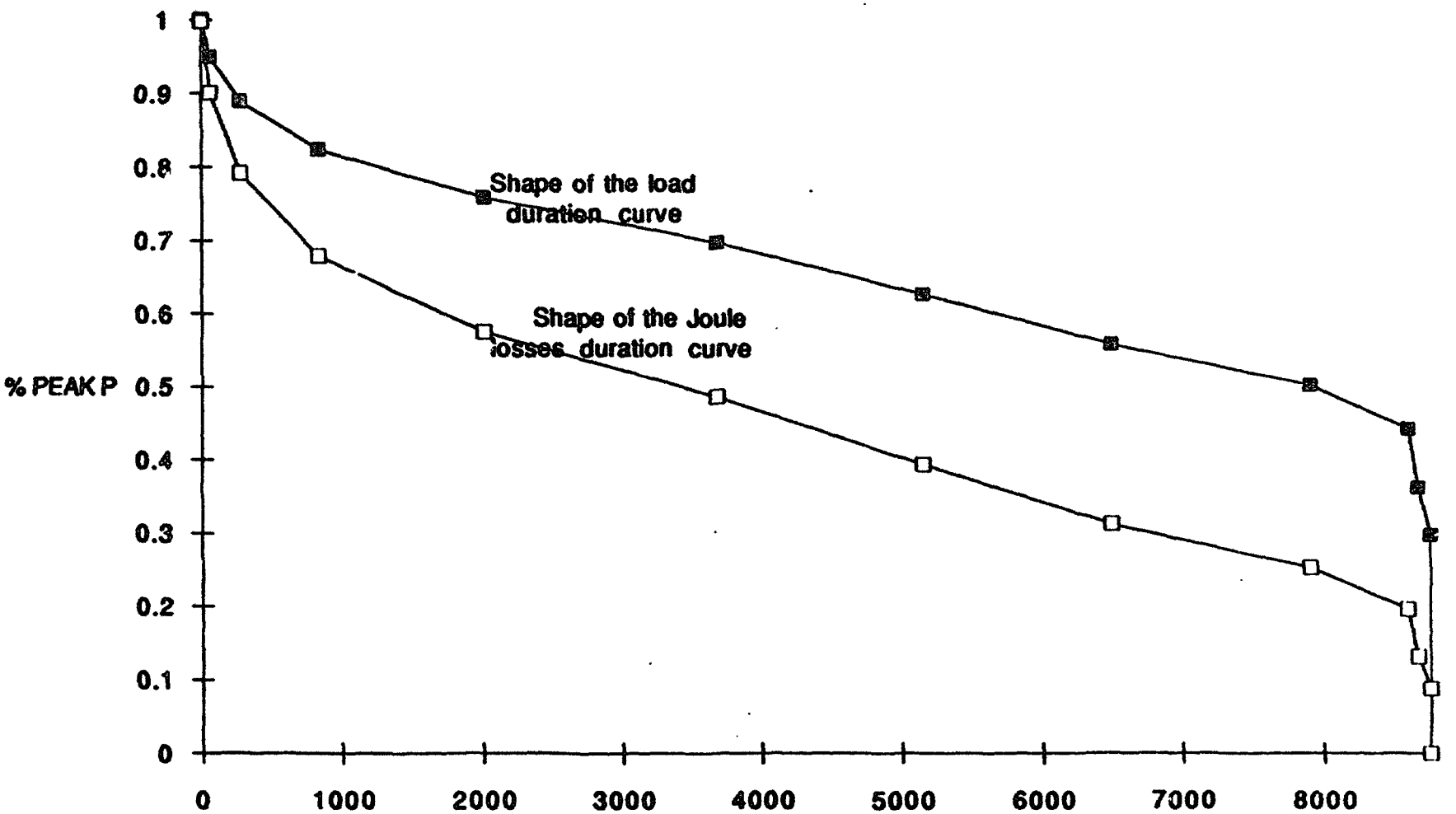


FIGURE 2

Note: The cost calculated above relates to the power output level. At each point on the network, losses will be calculated for the corresponding supply network. The above calculation refers to the duration of the following peak power utilization: average load (see Fig. 2) is 513 MW. Thus, annual power output is:

$$513 \times 8{,}760 = 4{,}493 \text{ GWh.}$$

Peak power is 771 MW; the duration of peak power utilization is therefore:

$$\frac{4.493 \times 10^3}{771} = 5{,}828 \text{ hours}$$

The load factor $\frac{P_{average}}{P_{peak}}$ is as follows:

$$\frac{513}{771} = 0.66$$

Calculation of the Fuel Costs Resulting from Core Losses in the Transformers

15. In this case, the load duration curve is horizontal. For 1kW, power output levels per period are as follows:

- Peak: 1 kW x 1.252 h = 1,252 kWh
- Daytime: 1 kW x 4.223 h = 4,223 kWh
- Night: 1 kW x 3.285 h = 3,285 kWh

The annual fuel cost at the power output level will therefore be as follows:

$$(1{,}252 \times 38.2) + (4{,}223 \times 30.3) + (3{,}285 \times 23) = 251.3 \times 10^3 \text{ millimes, } = \text{TD } 251.$$

INCREMENTAL COSTS IN TUNISIA

General

16. The purpose of this study is to propose values for the incremental costs per kilowatt, so that savings from loss reductions can be estimated. Most of these costs are taken from the April 1988 STEG tariff study. Consequently, the financial data given below are expressed in 1989 Tunisian Dinars.

Generating Costs

17. The incremental cost for generating equipment is based on the installation cost of the 150-MW unit to be installed at Radès. The gross development cost is determined as follows (based on an installation cost of TD 673 per kw):

Depreciation (over 30 years):	TD 22.4/kW
Financial charges (10%):	TD 67.3/kW
Fixed operating costs:	TD 8.0/kW
Total	TD 97.7/kW

Fuel savings are calculated to be TD 41 per kW, which leads to a net incremental cost of TD 56.7 per kW, rounded to TD 57 per kW. The number of kW installed per additional kW at the peak is 1.25 (see STEG load curve). The incremental cost is thus 57 x 1.25, i.e.: Incremental cost for generation: TD 71 per kW.

Transmission Cost

Incremental Cost for HV Transmission

18. The investment program for transmission scheduled in the 1987-91 plan is TD 15 million, for a total of 117 km of lines. The investment cost per km of lines is TD 128,000. The technical components of the transmission program call for construction of 0.32 m of lines per additional installed kVA HV/MV and 1.825 installed kVA HV/MV per additional peak kW. Investment in HV transmission per additional peak kW is thus: 128 x 0.32 x 1.825, i.e., TD 75 per kW.

The incremental cost is therefore:

Depreciation (over 30 years):	TD 2.5/kW
Financial charges (10%):	TD 7.5/kW
Fixed operating costs:	TD 0.7/kW
Total	TD 10.7/kW

Incremental Costs for HV/MV Substations

19. The investment program for transmission scheduled in the 1987-91 plan is TD 21 million, for a volume of 363 MVA of installed capacity. The investment cost per installed MVA is TD 57,500. The technical components of the transmission program call for construction of 1.825 installed kVA HV/MV per additional peak kW. Investment in HV transmission per additional peak kW is thus 57.5 x 1.825 = TD 105/kW.

The incremental cost is therefore:

Depreciation (over 30 years):	TD 3.5/kW
Financial charges (10%):	TD 10.5/kW
Fixed operating costs:	TD 0.9/kW
Total	TD 14.9/kW

Distribution Costs

Medium Voltage

20. General: The total investment in distribution is given in the directives of the distribution master plan for the 1987-91 period of the VIIth Plan.

Table A2.1: SUMMARY OF INVESTMENTS IN MV SUBSTATIONS
(thousand TD)

	STEG financing	Third party financing	Total
Rural investments	3,200	26,000	29,200
Urban investments	4,500	0	4,500
Industrial investments	0	17,000	17,000
Sanitation investments	17,200	0	17,200
Total	24,900	43,000	67,900

21. Incremental Cost: The value of the MV marginal cost is equal to the ratio of total MV investment to the increase in MV peak power. The latter represents 86% of the increase in total power, i.e.:

Total peak power in 1987: 710 MW
Total peak power in 1991: 910 MW
Difference: 200 MW
Difference on MV network: 172 MW
(ratio of 86% for MV and LV at peak power)

22. Total MV investment for the period is TD 67.9 million from all sources in the Tunisian economy, regardless of origin; STEG's investment is TD 24.9 million.

- This gives an incremental cost (excluding losses, and considering only STEG's investment):

Investment per additional peak kW:

$$\frac{24{,}900}{172} = \text{TD 144 per peak kW}$$

Depreciation (over 30 years):	TD 4.8/kW
Financial charges (10%):	TD 14.4/kW
Fixed operating costs:	TD 3.0/kW
Incremental cost	TD 22.2/kW

- This gives the following total incremental cost (excluding losses, and including all sources of investment):

Investment per additional peak kW:

$$\frac{67{,}900}{172} = \text{TD } 395/\text{peak kW}$$

Depreciation (over 30 years):	TD 13.2/kW
Financial charges (10%):	TD 39.5/kW
Fixed operating expenses:	TD 3.0/kW
Incremental cost	TD 55.7/kW

MV/LV Substations

23. General: The total investment in distribution is given in the directives of the distribution master plan for the 1987-91 period of the VIIth Plan.

Table A2.2: SUMMARY OF INVESTMENTS IN MV/LV SUBSTATIONS
(thousand TD)

	STEG Financing	Third Party Financing	Total
Rural investments	1,000	6,300	7,300
Urban investments	7,000	0	7,000
Industrial investments	0	0	0 (Cl. Ind.)
Sanitation investments	8,600	0	8,600
Total	16,600	6,300	22,900

24. Incremental cost: The marginal cost of 1 MV/LV kW is equal to the ratio of total investment to the increase in LV peak power. The latter is equivalent to 48% of the increase in total power, i.e.:

Total peak power in 1987:	710 MW
Total peak power in 1991:	910 MW
Difference:	200 MW
Difference for MV/LV substations:	96 MW

25. Total investment in MV/LV substations for the period is TD 22,900 million from all sources in the Tunisian economy, regardless of origin; STEG's investment is TD 16 million.

- This gives the following incremental cost (excluding losses, and considering STEG's investment only):

Investment per additional peak kW:

$$\frac{16{,}600}{96} = \text{TD } 173/\text{peak kW}$$

Depreciation (over 30 years):	TD 5.7/kW
Financial charges (10%):	TD 17.3/kW
Fixed operating costs:	TD 2.0/kW
Incremental cost	TD 25.0/kW

If investment from all sources is included:

$$\frac{22{,}900}{96} = 239/\text{peak kW}$$

Depreciation (over 30 years):	TD 8.0/kW
Financial charges (10%):	TD 23.9/kW
Fixed operating costs:	TD 2.0/kW
Incremental cost	TD 33.9/kW

N.B.: The fixed operating costs for MV and LV were considered to be identical, in accordance with the STEG tariff study; i.e., TD 6 per kW for all the MV/LV substations and the LV network. Distributions of TD 2 per kW for MV/LV substations and TD 4 per kW for the LV network were assumed.

Low Voltage Network

26. General: The volume of investment in distribution is given in the directives of the distribution master plan for the 1987-91 period of the VIIth Plan.

Table A2.3: SUMMARY OF INVESTMENTS IN LV SUBSTATIONS
(thousand TD)

	STEG Financing	Third Party Financing	Total
Rural investments	2,800	23,700	26,500
Urban investments	10,500	10,500	21,000
Industrial investments	0	0	0
Sanitation investments	17,200	0	17,200
Total	30,500	34,200	64,700

27. Incremental Cost: The marginal cost of 1 LV kVA is equal to the ratio of total investment to the increase in LV peak power. The latter is equivalent to 48% of the increase in total power, i.e.:

Total peak power in 1987:	710 MW
Total peak power in 1991:	910 MW
Difference:	200 MW
Difference on LV network:	96 MW (200 MW x 48%)

28. Total low voltage investment for the period is TD 87.6 million (including non-STEG financing); STEG's investment is TD 47.1 million.

- This gives the following incremental cost (excluding losses, and considering STEG's investment only):

Investment per additional peak kW:

$$\frac{30{,}500}{96} = \text{TD } 318/\text{peak kW}$$

Depreciation (over 30 years):	TD 10.3/kW
Financial charges (10%):	TD 31.0/kW
Fixed operating costs:	TD 4.0/kW
Incremental cost	TD 46.4/kW

- This gives the following incremental cost (excluding losses, and including investment from all sources):

  Investment per additional peak kW:

  $$\frac{64.700}{96} = \text{TD } 674/\text{peak kW}$$

Depreciation (over 30 years):	TD 22.4/kW
Financial charges (10%):	TD 67.4/kW
Fixed operating expenses:	TD 4.0/kW
Incremental cost	TD 33.9/kW

Summary of Incremental Costs

29. Thus, the study leads to consideration of two scenarios, depending on whether funding consists of STEG financing alone or financing from all sources.

Incremental Costs: Scenario 1

- First scenario: STEG financing alone:

Incremental cost of generation:	TD 71.0/kW
Incremental cost of HV transmission:	TD 10.7/kW
Incremental cost of HV/MV substations:	TD 14.9/kW
Incremental cost of MV distribution:	TD 22.2/kW
Incremental cost of MV/LV substations:	TD 25.0/kW
Incremental cost of LV distribution:	TD 46.6/kW

(in relation to the marginal peak kW)

The distribution of losses over the entire network is approximately as follows:

2.5% for the HV network
2% for the HV/MV transformers
5% for the MV network
3% for the MV/LV transformers
6% for the LV network

Calculation of incremental cost per kW, taking upstream losses into account:

- HV network:	(71 + 10.7) x 1.015	= TD 83.7/kW
- HV/MV transformers:	(83.7 + 14.9) x 1.02	= TD 100.6/kW
- MV network:	(100.6 + 22.2) x 1.05	= TD 128.9/kW
- MV/LV transformers:	(128.9 + 25) x 1.03	= TD 158.5/kW
- LV network:	(158.5 + 46.4) x 1.06	= TD 217.2/kW

RESULTS

	HV	HV/MV Transformers	MV	MV/LV Transformers	LV
Incremental costs in TD/kW (including losses)	83.7	100.6	128.9	158.5	217.2

Incremental Costs: Scenario 2:

- Second scenario: taking into consideration total investments (STEG and others):

Incremental cost of generation:	TD 71.0/kW
Incremental cost of HV transmission:	TD 10.7/kW
Incremental cost of HV/MV substations:	TD 14.9/kW
Incremental cost of MV distribution:	TD 55.7/kW
Incremental cost of MV/LV substations:	TD 33.9/kW
Incremental cost of LV distribution:	TD 93.8/kW

(in relation to the marginal peak kW)

The distribution of losses over the entire network is approximately as follows:
2.5% for the HV network
2% for the HV/MV transformers
5% for the MV network
3% for the MV/LV transformers
6% for the LV network

Calculation of incremental cost per kW, taking upstream losses into account:

- HV network:	(71 + 10.7) x 1.025	= TD 83.7/kW
- HV/MV transformers:	(83.7 + 14.9) x 1.02	= TD 100.6/kW
- MV network:	(100.6 + 55.7) x 1.05	= TD 164.1/kW
- MV/LV transformers:	(164.1 + 33.9) x 1.03	= TD 203.9/kW
- LV network:	(203.9 + 93.8) x 1.06	= TD 315.6/kW

RESULTS

	HV	HV/MV Transformers	MV	MV/LV Transformers	LV
Incremental cost in TD/kW (including losses)	83.7	100.6	164.1	203.9	315.6

Conclusion

30. This second scenario will be used in calculating the cost of losses. In fact, it is closer to actual costs and takes into account all the power savings for the community. Generally, the marginal cost method should include all costs, so that tariffs can reflect energy costs as accurately as possible.

Total costs

31. As indicated above, the annual cost of 1 kW of peak losses is calculated by adding the annual fuel costs (as a function of the load duration curve), the incremental cost of generation equipment, and the incremental cost of the works upstream of the point selected.

The distribution of losses over the entire network is approximately as follows:

- HV network:	2.5%
- HV/MV transformers:	2%
- MV network:	5%
- MV/LV transformers:	3%
- LV network:	6%

The following two cases will be examined: the general case, which follows the profile of the load duration curve used in the calculation (about 5,900 hours of peak power use), and the case of transformer core losses (8,760 hours of power use).

The General Case

32. Calculation of the annual cost of one kW of peak losses. The incremental cost of one additional kW was given in a preceding paragraph. At this point, therefore, we need to calculate only the costs of fuel (including losses) at each level of the network:

- Generation:	TD 130/kW (see above)	
- HV network:	130 x 1.025	= TD 133.2/kW
- HV/MV transformers:	133.2 x 1.05	= TD 135.9/kW
- MV network:	135.9 x 1.05	= TD 142.7/kW
- MV/LV transformers:	142.7 x 1.03	= TD 147/kW
- LV network:	147 x 1.06	= TD 155.8/kW

Calculation of total costs:

- HV network:	83.7 + 133.2	= TD 216.9/kW
- HV/MV transformers:	100.6 + 135.9	= TD 236.5/kW
- MV network:	164.1 + 142.7	= TD 306.8/kW
- MV/LV transformers:	203.9 + 147	= TD 350.9/kW
- LV network:	315.6 + 155.8	= TD 471.4/kW

We obtain the following table:

Table A2.4: ANNUAL COST OF ONE KW OF PEAK LOSSES

Annual peak power use	Cost at this use level (TD/kW)				
	HV	HV/MV Transformers	MV	MV/LV Transformers	LV
5,900 hours	216.9	236.5	306.8	350.9	471.4

The Case of Transformer Core Losses

33. The incremental costs of the investments were calculated previously. To these we will add annual fuel costs (including losses) calculated for the network under consideration.

HV/MV Transformers. Calculation of annual fuel costs.

- Generation:	TD 251/kW (see above)	
- HV network:	251 x 1.025	= TD 257.2/kW
- HV/MV transformers:	257.2 x 1.02	= TD 262.4/kW

Total cost:

- HV network:	83.71 + 257.1	= TD 340.9/kW
- HV/MV transformers:	100.6 + 262.4	= TD 363/kW

MV/LV Transformers. Calculation of annual fuel costs:

- MV network:	262.4 x 1.05	= TD 275.5/kW
- HV/MV transformers:	275.5 x 1.03	= TD 283.8/kW

Total cost:

- HV network:	164.1 + 275.5	= TD 439.6/kW
- HV/MV transformers:	203.9 + 283.8	= TD 487.7/kW

We obtain the following table:

Table A2.5: TOTAL ANNUAL COST OF ONE KW OF CORE LOSSES IN THE TRANSFORMERS

Annual peak power use	Cost at this use level (in TD/kW)				
	HV	HV/MV Transformers	MV	MV/LV Transformers	LV
8,760 hours (core losses from transformers)	340.9	363	439.6	487.7	-

Summary

Table A2.6: ANNUAL COST OF ONE KW OF PEAK LOSSES

Annual peak power use	Cost at this use level (in TD/kW)				
	HV	HV/MV Transformers	MV	MV/LV Transformers	LV
5,900 hours	216.9	236.5	306.8	350.9	471.4
8,760 hours (core losses from transformers)	340.9	363	439.6	487.7	-

EQUIVALENCE BETWEEN THE IMMEDIATE RATE OF RETURN AND THE INTERNAL RATE OF RETURN

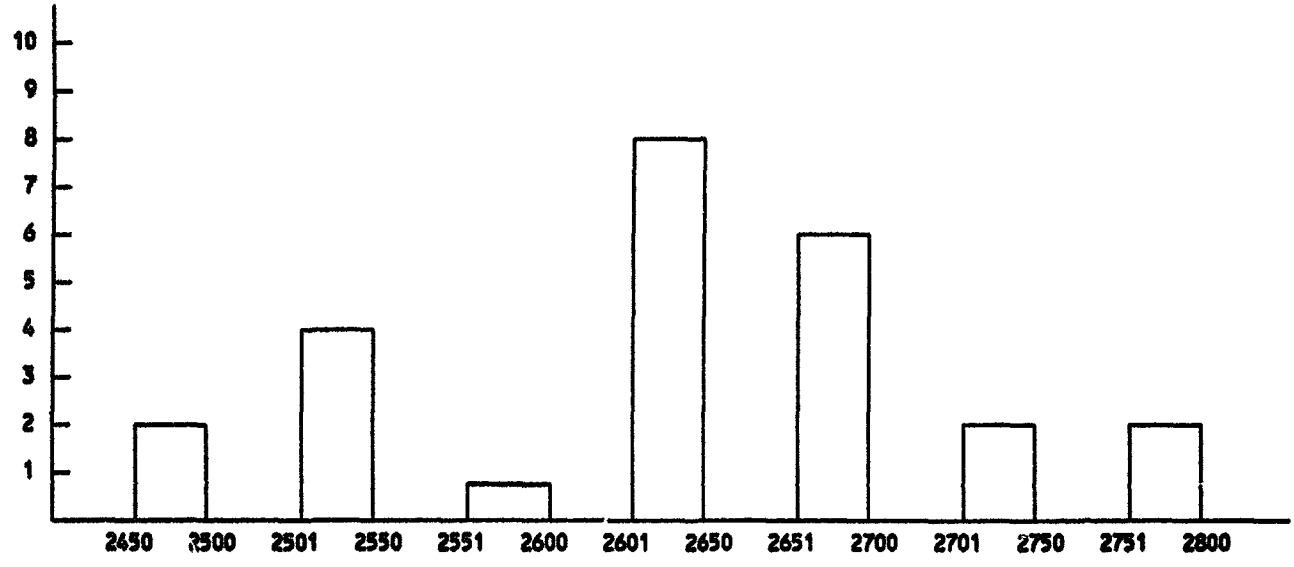
Table A3.1: CONVERSION OF IMMEDIATE RATE OF RETURN INTO INTERNAL RATE OF RETURN

Financial payback period	IRR Immediate	IRR Duration: 10 years	IRR Duration: 20 years	IRR Duration: 30 years
10 years	10	0	7.8	9
	11	1.8	9	10
	12	3.5	10	11.6
	13	5	11.5	12.6
	14	6.6	12.7	13.7
	15	8	14	14.8
	16	9.6	15	15.8
	17	11	16	16.8
	18	12	17.2	17.9
	19	13.7	18.4	18.9
5 years	20	15.1	19.4	19.9
	21	16.4	20.5	20.9
	22	11.7	21.6	21.9
	23	18.9	22.6	22.95
	24	20.2	23.4	24
	25	21.4	24.7	25
4 years	25	21.4	24.7	25
	30	27.3	29.8	30
3 years	35	33	34.9	35
	40	38.5	40	40
	45	43.8	45	45
2 years	50	49.1	5.0	50
< 2 years	55	54.3	55	55
	60	59.4	60	60
	65	64.6	65	65
	70	69.7	70	70
	75	75	75	75

HEAT RATES OF THE STEAM THERMAL PLANTS

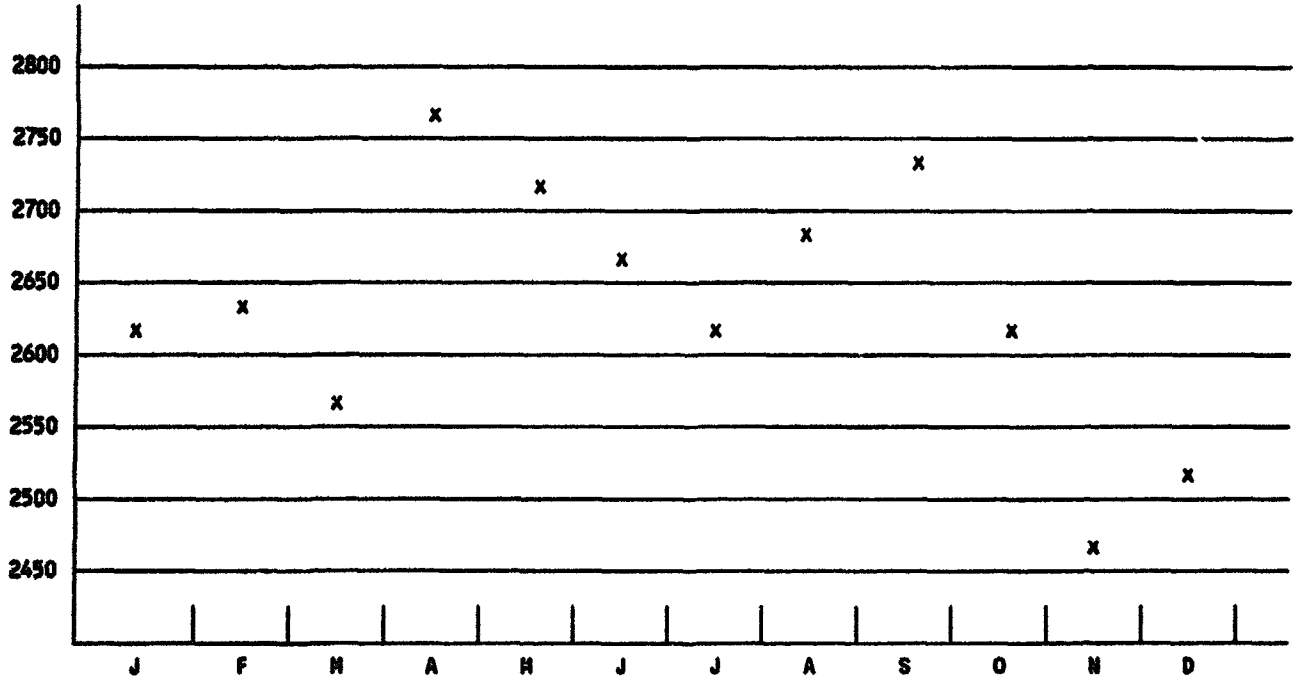
Sousse Power Plant - Units 1 and 2

Annual heat rates (1988)



Unit 1

Annual heat rate data distribution
Kcal/Kwh



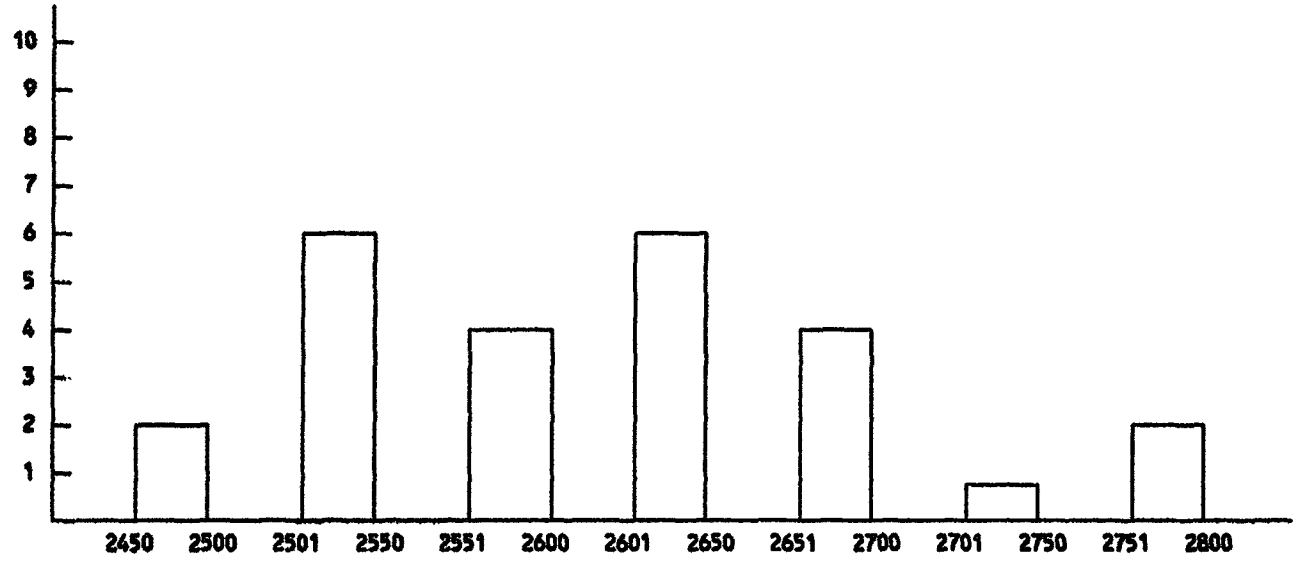
Mean: $\bar{x}_{m}$ = 2630 Kcal/Kwh

Standard deviation: σ_{m} = 86.9

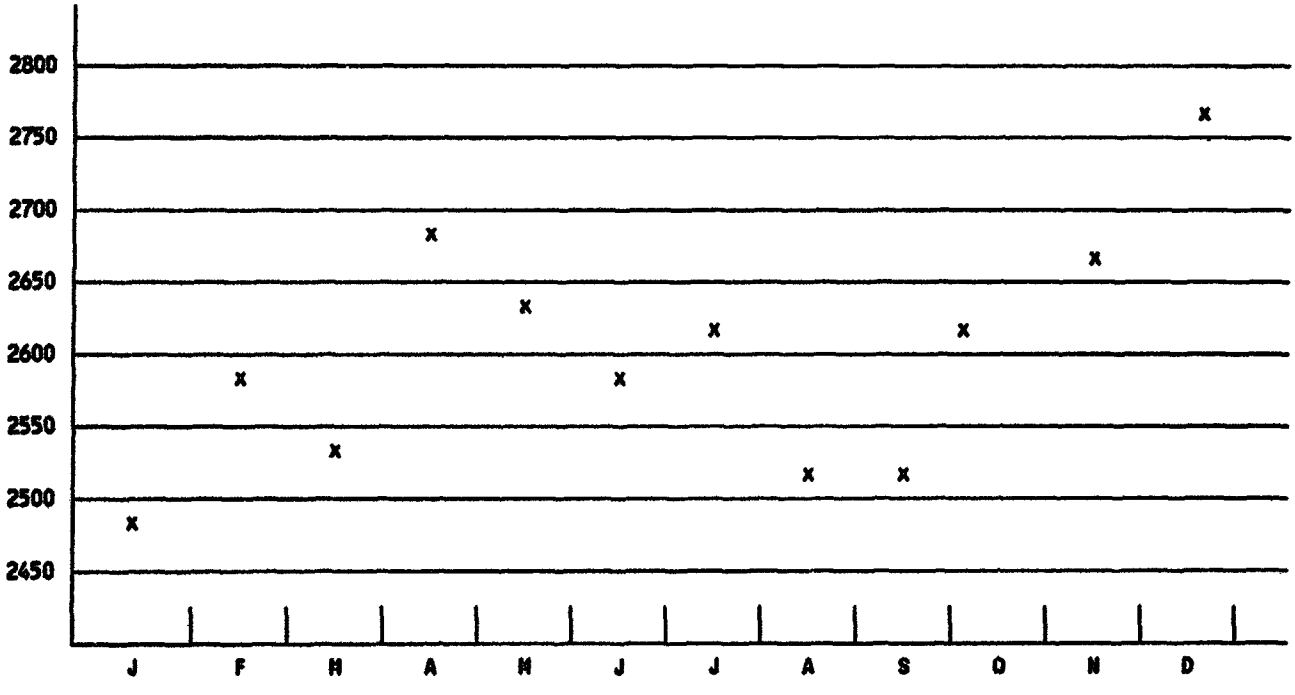
Reference value (for gas and at nominal load): 2565 Kcal/Kwh

Sousse Power Plant - Unit 2

Annual heat rate (1988)



Annual heat rate data distribution
Kcal/Kwh

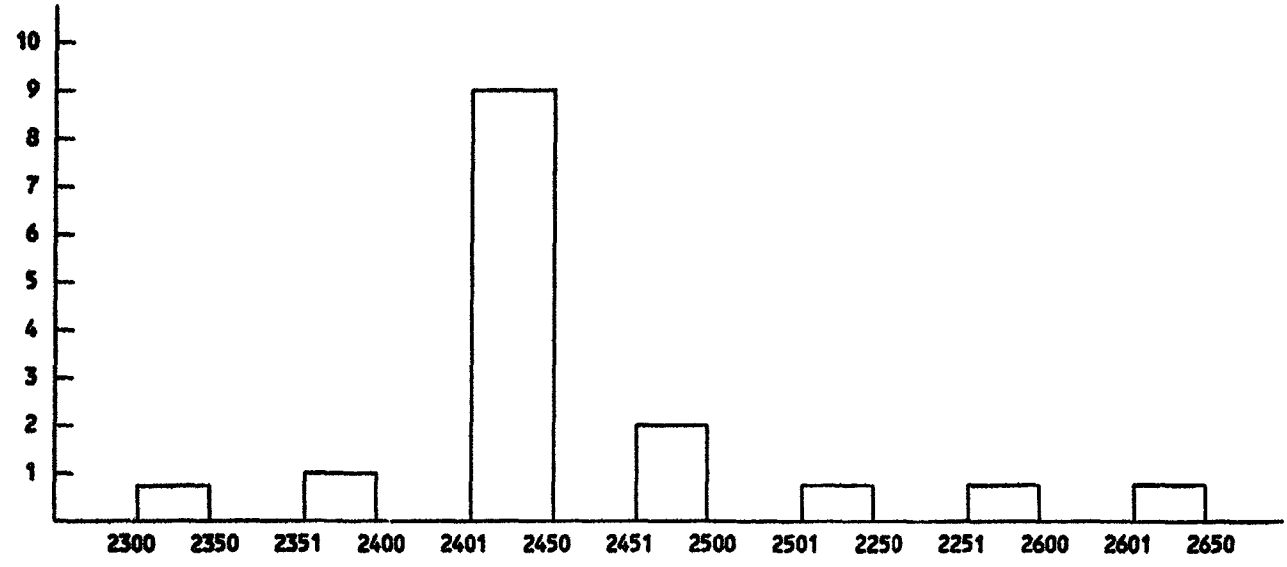


Mean: $\bar{x}_{ga}$ = 2613 Kcal/Kwh Standard deviation: σ_{ga} = 71.4

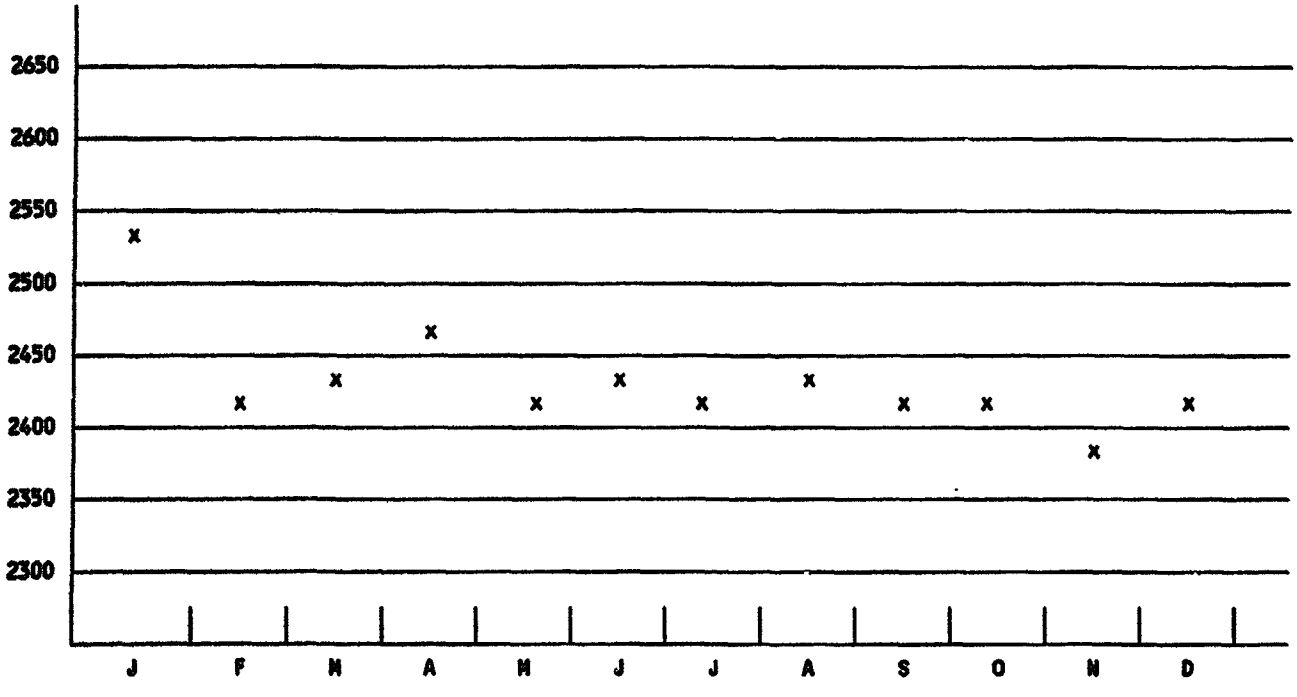
Reference value (for gas and at nominal load): 2565 Kcal/Kwh

Radès Power Plant - Unit 1

Annual heat rate (1988)



Annual heat rate data distribution
Kcal/Kwh

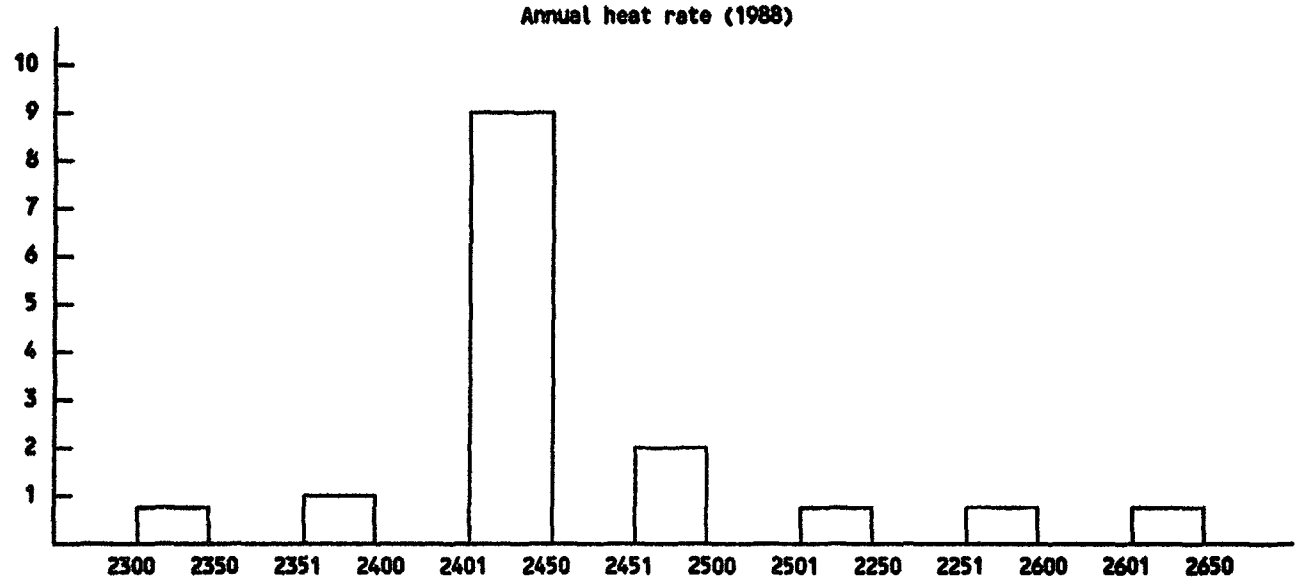


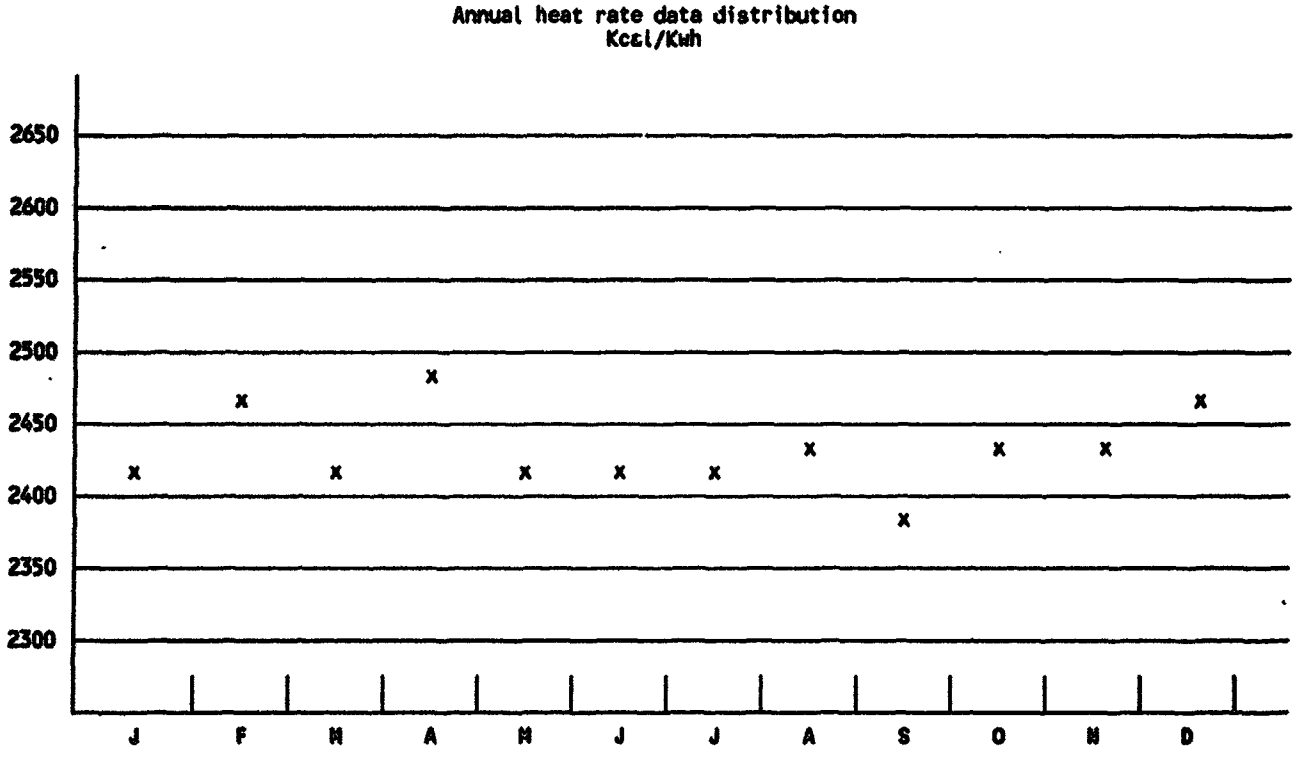
Mean: $\bar{x}_{an}$ = 2428 Kcal/Kwh

Standard deviation: σ_{an} = 28

Reference value (for gas and at nominal load): 2350 Kcal/Kwh

Radès Power Plant - Unit 2





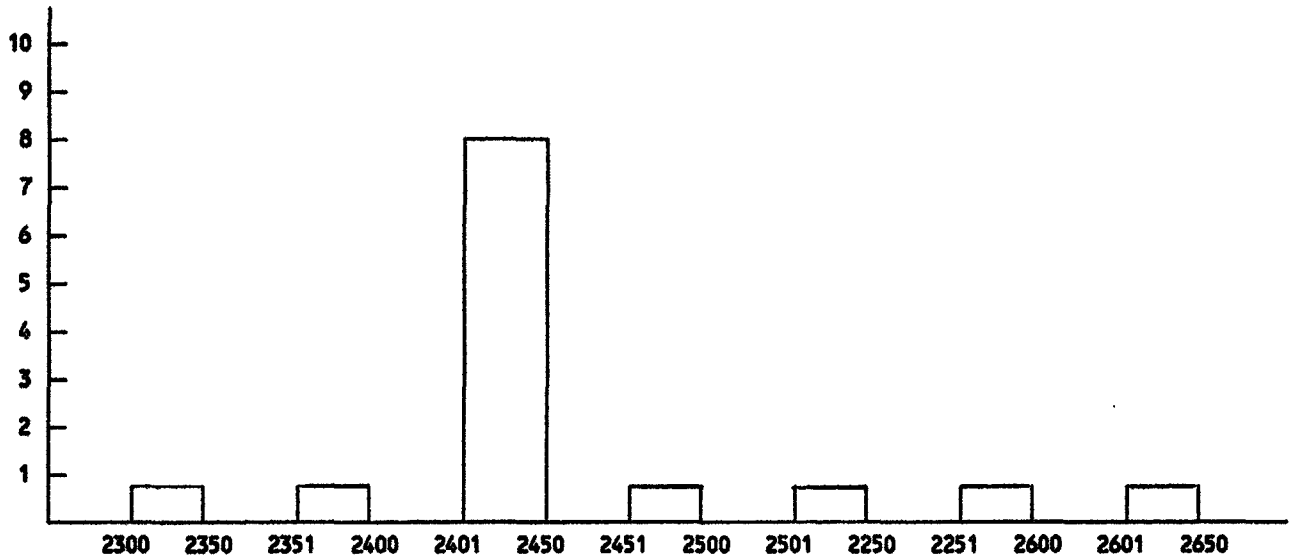
Mean: $\bar{x}_{cs}$ = 2437 Kcal/Kwh

Standard deviation: σ_{x} = 17

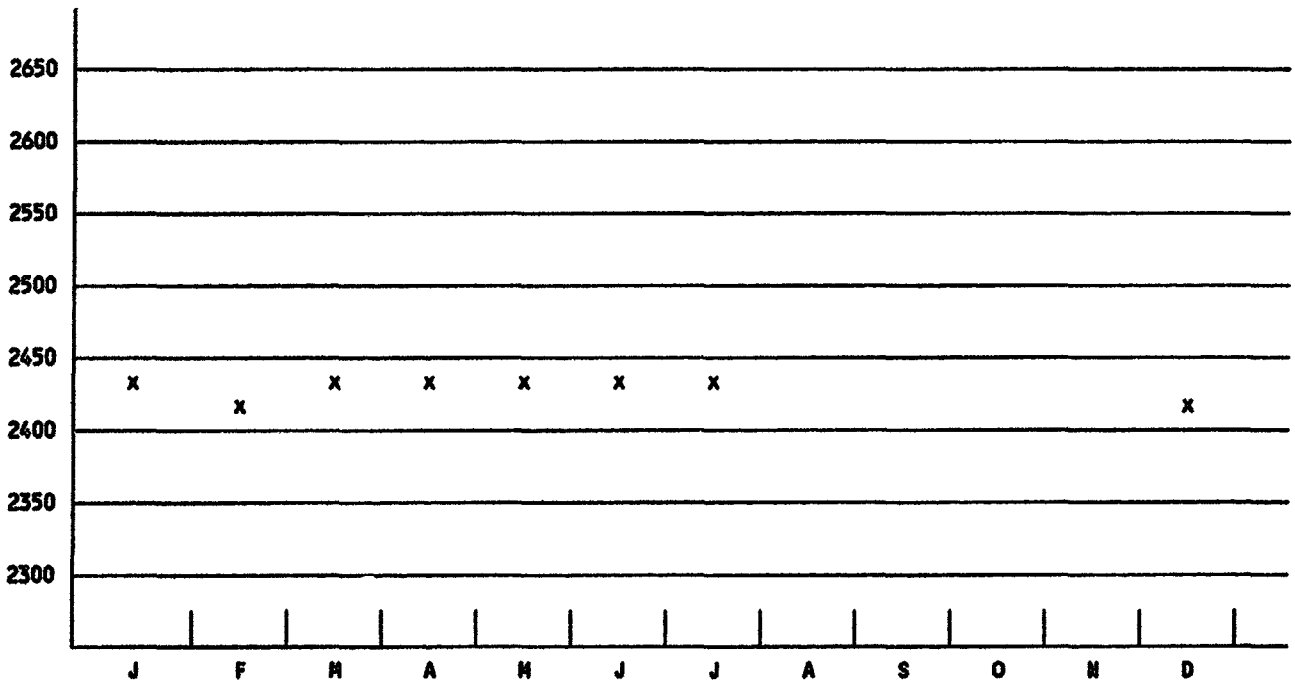
Reference value (at nominal load): 2350 Kcal/Kwh

Radès Power Plant - Unit 1

Annual heat rate (1989)



Annual heat rate data distribution
Kcal/Kwh



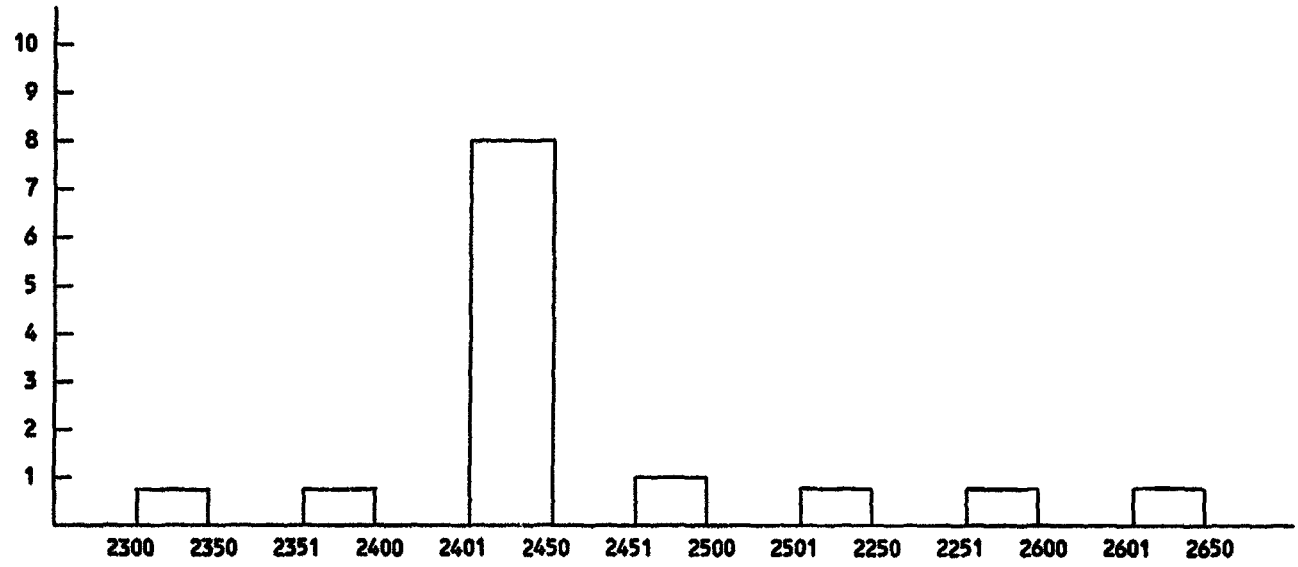
Mean: $\bar{x}_m$ = 2438 Kcal/Kwh

Standard deviation: σ_m = 13.4

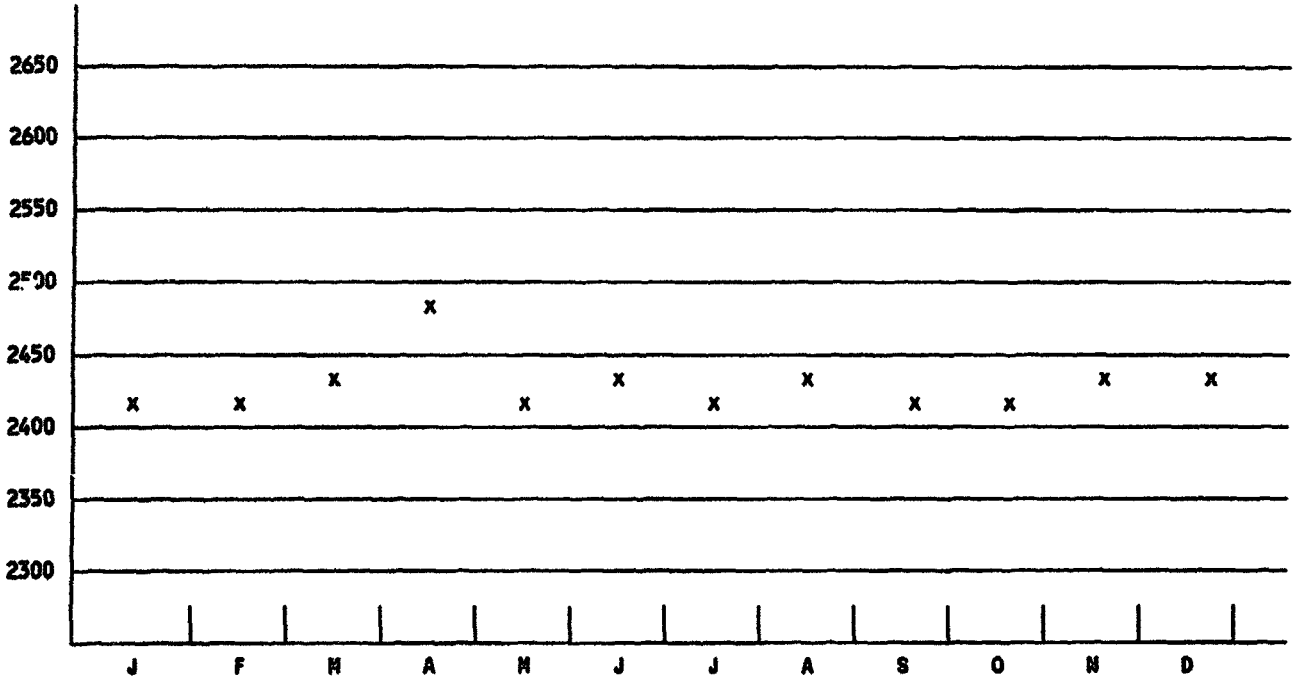
Reference value (at nominal load): 2350 Kcal/Kwh

Radès Plant - Unit 2

Annual heat rate (1989)



Annual heat rate data distribution
Kcal/Kwh



Mean: $\bar{x}_m$ = 2434 Kcal/Kwh

Standard deviation: σ_m = 11.7

Reference value (at nominal load): 2350 Kcal/Kwh

EFFICIENCY MONITORING

Monitoring Variations in Unit Heat Rates

1. The table on page 2 of this annex (Table A5.1) gives examples of variations in the operating parameters of a 115 MW unit (MONTEREAU) and of the magnitude of the corresponding increases in heat rate.

Annual Excess Consumption of Fuel due to one Additional kcal/kWh

2. 30 MW System. For an annual utilization of 6,500 h, the energy generated will be:

$$6{,}500 \times 30{,}000 = 195{,}000{,}000 \text{ kWh}$$

Excess consumption of heat due to one additional kcal/kWh is 195,000,000 kcal. For example, if a fuel oil has a HHV of about 10,000 kcal/kg, excess annual consumption will be 19,500 kg (20 metric tons).

3. 160 MW System. On the same basis, excess fuel consumption will be:

$$\frac{6{,}500 \times 160{,}000}{10{,}000} = 104{,}000 \text{ kg (100 metric tons)}$$

4. Thus, continuous monitoring of heat rate variations -- and elimination of their causes -- makes considerable fuel savings possible, especially in the case of units with a high unit capacity rating.

Table A5.1: SAMPLE VARIATIONS IN OPERATING PARAMETERS AND THEIR EFFECTS ON THE HEAT RATE OF A 125 MW SET (FOR A BASIC OPTIMUM CONSUMPTION OF 2200 kcal/kWh)

Parameter causing the variation	Value of the physical parameter		Heat rate difference	
	COB	Consumption recorded	In kcal	In % of BOC
Output P	125 MW	60 MW	85	3.8
Output Q	COS ϕ = 1	COS ϕ = 0.9	6	0.3
Cooling water	3.5°C	13.5°C	25	1.14
Ambient air	26.5°C	16.5°C	10	0.45
Condenser temperature • Fouling • Air intake	33.6°C	+ 3°C	10	0.45
Sensible heat (Excess O2)	5%	10%	22	1
Superheated steam pressure	124.5 bar	- 10 bar	11	0.5
Superheated steam temperature	540°C	- 10°C	5	0.23
Resuperheated steam temperature	540°C	- 10°C	5	0.23
HP steam reheaters		HS	43	2
LP steam reheaters		HS	71	3.2

Efficiency Monitoring Methodology

5. The purpose of efficiency monitoring is to continually monitor fuel consumption per unit of power generated so that the causes of variations in the heat rate can be eliminated as quickly as possible.

Definitions

6. Heat Rate: kcal/kWh. This is the amount of fuel (expressed in heating value) used to produce 1 kWh.

Actual Heat Rate (HR): This is the heat rate obtained under normal operating conditions

- watt-hour meters; and
- fuel flow meters.

Optimum Base Consumption (OBC): This is the theoretical heat rate of the plant when all operating conditions are simultaneously at their optimum, i.e.:

- equipment in perfect condition;
- unit control parameters at their rated values;
- output at its rated level; and
- zero reactive power (Cos phi = 1).

Deviations: This refers to the various variations in heat rate attributable to the differences between the actual and optimum (OBC) values of the corresponding physical parameters.

Notes: These variations are always positive or zero values (if not, the OBC should be recalculated). Some variations in heat rate are independent of one another (e.g., steam water losses, unit output, etc.), whereas others are interrelated (e.g., temperature of the exhaust gases, atmospheric conditions, etc.). For overall calculation of interdependent variations, the approximation method is applied to dependent variations.

If:

Ei	=	relative deviation in consumption from the OBC
ei	=	absolute deviation (in kcal/kWh)
OBC	=	Optimum Base Consumption

$$ei = Ei \times OBC \times (1 + \alpha)$$

With CAO $= \dfrac{\sum_{i=1}^{i=n} ei}{2}$; giving 8/: $CS = OBC + \sum_{i=1}^{i=n} ei$

8/ *CAO: consumption ascertained during [unit] operation*

$$HR = OBC\,(1 + E1)\,(1 + E2)\ldots(1 + E3)\ldots(1 + En)$$
$$HR = OBC + e1 + e2 + \ldots + ei \ldots + en$$

The formula linking ei et Ei is obtained by developing the products and disregarding the terms › EiEj.

Calculation of Heat Rate Differences

7. The calculation of heat rate differences comprises the following three successive stages:

- processing of the data obtained for each load level (30MW and 150MW);
- calculation of differences for each load level;
- calculation of weighted average deviations.

Data Processing for Calculating Deviations. The energy produced for each load level is determined as follows:

- by using the load diagram;
- by using a meter calibrated for several tariff levels (the same number of tariff levels as of load levels).

Calculation of Averages: Each month, arithmetical averages are calculated for each operating difference for a given load level.

Notes: The deviations are much easier to calculate if a set of nomograms is developed giving direct readings of deviations corresponding to variations in physical quantities based on the OBC (see example at the end of this document). The deviations are classified as follows:

- external deviations (due to conditions unrelated to plant operation, such as the weather);
- internal deviations (due to equipment condition, unit control, etc.);
- deviations resulting from a combination of the above.

Calculating Weighted Average Deviations: Since deviations are calculated for each load level, the average for each deviation is obtained by introducing a weighting to take account of the energy generated at each load level. By applying the correction term of the dependence relation to the relative values of the deviations, we obtain the absolute value for each deviation.

HEAT RATE VARIATIONS DUE TO SHUTDOWN OF THE FEEDWATER SYSTEM

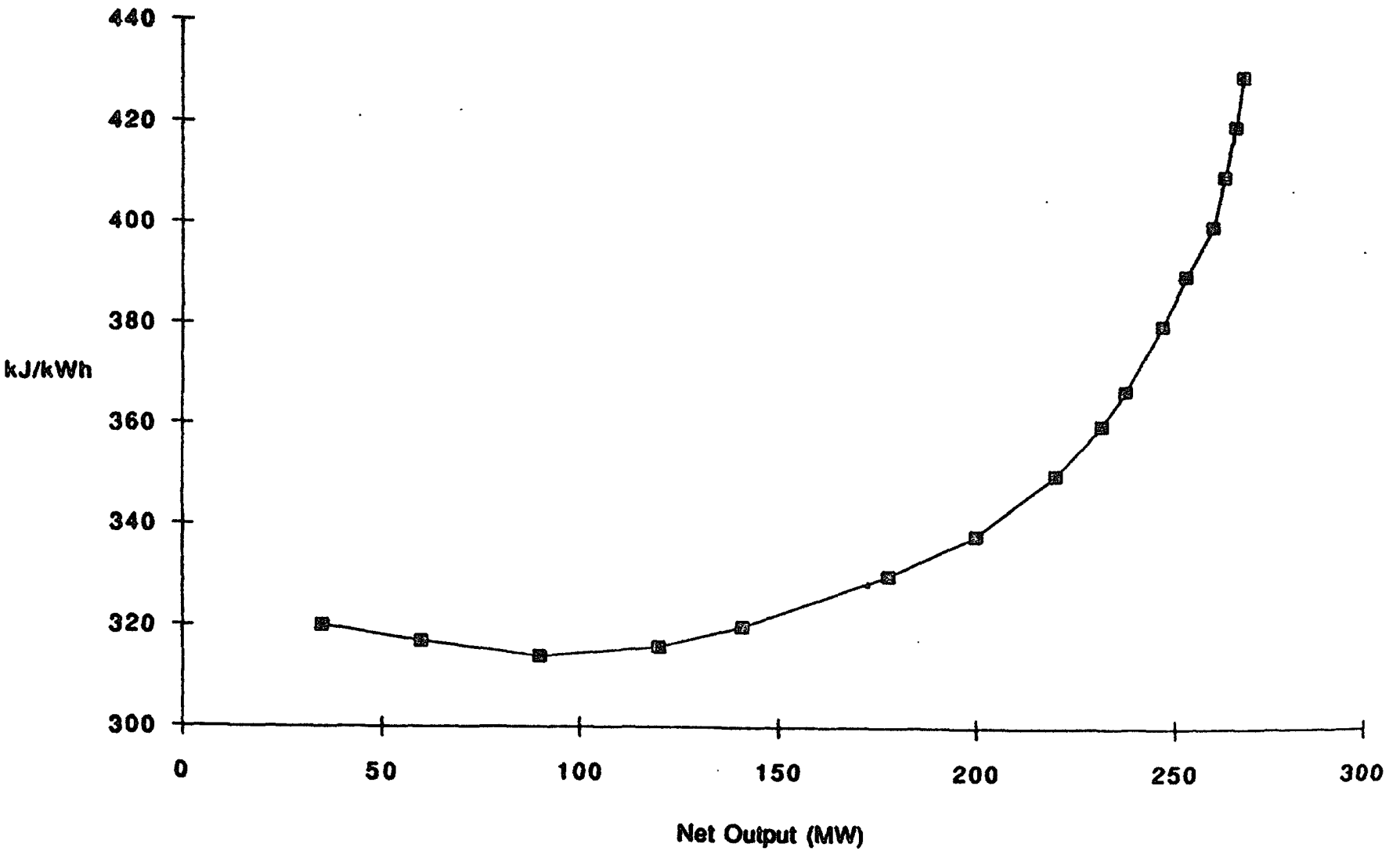


FIGURE 3

ON-LINE MONITORING OF THE OPERATING EFFICIENCY OF THE FUEL-BURNING THERMAL POWER PLANTS

Role

1. This data processing application is not intended to replace the monthly efficiency monitoring report, which is an accounting document, but to enable the operator to identify performance deviations in his equipment in real time. The computer will be located in the control room.

Parameters to be Monitored

2. These are listed in the following table:

Table A6.1: MEASUREMENTS NEEDED FOR EFFICIENCY MONITORING OF THE THERMAL POWER PLANTS

Deviations	Parameters to be monitored	Measurements needed
External	Cooling water temperature	Condensor intake temperature
	Load level	Active power
	Alternator efficiency	Reactive power
	Fuel used	Manual entry
	Other causes	Manual entry
Internal	Condensor	Turbine outlet pressure
	Feedwater system	HP outlet pressure Feedwater flow rate
	Steam characteristics	HP inlet pressure HP inlet temperature HP outlet pressure HP outlet temperature MP inlet pressure MP inlet temperature
	Fuel control	O2 at economizer outlet Manual entry of unburned residues
	Steam generator	Superheated desuperheat flow Resuperheated desuperheat flow O2 in boiler stack Exhaust gas temperature, RA outlet Temperature of ambient air
	Auxiliary electric equipment	Total power consumed
	Water vapor losses	Make-up water flow
	Other causes	Manual entry

3. The term "Measurements needed" means directly usable measurements that can be made using various sensors and calculation algorithms. A summary flow chart of the software is given on page 4.

4. When a parameter deviates from the reference value that indicates optimum efficiency, the computer in the control room displays in real time the amount of the deviation, the resulting increase in the heat rate, and the financial loss involved.

5. The continuous display of data related to the main unit managemement parameters that affect efficiency enables appropriate corrective measures to be adopted at any time.

6. This application also makes it possible to carry out performance tests that enable operators to check the specifications guaranteed by the manufacturers, and to monitor changes in the performance of the main components.

7. This aspect of continuous performance monitoring is especially important to maintenance planning (i.e., predictive maintenance).

Expected Savings

8. With this application, predictive maintenance and operating efficiency can be considerably improved. However, it is difficult to quantify in advance the savings that will be obtained.

9. Installation of similar equipment for comparable power units has shown that one can expect an overall heat rate saving of about 1% in the STEG steam facilities, or an expected saving of:

$$\frac{260}{100} = 2.6 \text{ toe/GWh}$$

$$2.6 \times 3{,}720 = 9{,}672 \text{ toe}$$

260 toe/GWh = fuel consumption in 1988
3,720 GWh = thermal steam power generation in 1988.

Assessment of costs

10. Because automated programs are already in operation (Radès) or under study (La Goulette II), before introducing software for the on-line monitoring of operating efficiency, there should be a study mission to:

- evaluate the "efficiency monitoring" application that STEG is currently testing;

- ensure that it is compatible with software for the on-line monitoring of operating efficiency;

- ascertain what additional hardware is necessary and how long it will take to adapt it (study + on-site installation).

11. A preliminary cost evaluation for a power plant with two generating units breaks down as follows:

Table A6.2: COST ESTIMATE FOR INSTALLATION OF AN EFFICIENCY MONITORING SYSTEM FOR TWO UNITS

		Cost (US dollars)	
		Unit cost	Total
Measurement sensors (10)	x 2	16,500	33,000
Measurement lines (20)	x 2	16,500	33,000
Data collection panels (40)	x 2	10,000	20,000
Data collection software	x 1	6,500	6,500
Data processing software	x 1	10,000	10,000
Computer	x 2	8,900	17,800
Travel, trips, study costs			66,700
Sub-total			187,000
Contingencies (11.5%)			21,505
Estimated Cost			208,505

Notes:

12. Study costs comprise:

- 2 weeks on site to assess feasibility (2 specialists);

- 2 weeks abroad for project study and preparation (2 specialists);

- 4 weeks on site to install and adjust the equipment and to train local staff (2 specialists).

If any of STEG's existing hardware is compatible with the project, a reassessment will be needed.

Summary of the Software Flow Chart

Measured power	Difference	Loss 1 due to reduced load level
Condenser inlet temperature	characteristic curves	Loss 2 due to ext. temp. + theoretical vacuum
Reactive power	Characteristic curves	Loss 3 due to alternator performance
Type of fuel used	Characteristic curve/unit	Loss 4 due to type of fuel used
Loss due to other causes		Loss 5 due to other causes
		Sum of losses 1 to 5 = EXTERNAL DEVIATIONS
Measured vacuum	Deviation from theoretical vacuum and loss curve MW f(vacuum loss)	Loss 6 due to condenser
Feedwater outlet temperature	Deviation from theoretical temperature obtained by a characteristic curve f (feedwater flow loss)	Loss 7 due to feedwater system
Pressure and temperature	2 curves	Loss 8 due to steam characteristics
HP outlet pressure	Deviation from P intake HP	Loss 9 due to resuperheater load loss
Pressure and temperature at HP inlet and outlet	Calculation of the real and isentropic enthalpies, then comparison with a performance curve f(P)	Loss 10 due to HP housing
O2 at economiser outlet	Comparison with theoretical O2 given by an O2 curve f (fuel used)	Loss 11 due to fuel combustion regulation
Flows of desuperheated steam	Comparison of flows of desuperheated steam with curves f(P)	Loss 12 due to excessive flow of superheated steam
Temperature at RA outlet	Deviation from ambient air temperature and use of a GV performance curve	Loss 13 due to performance
O2 in chimney stack	Deviation from economiser O2 measurement	Indicates entry of air into reheaters
		Sum of losses 1 to 6 = SUM OF EXPLAINED INTERNAL DEVIATIONS
		Reference power output - sum of losses 1 to 13 = SUM OF UNEXPLAINED DEVIATIONS

TERMS OF REFERENCE

Supply of an On-Line System for Monitoring the Operating Efficiency of Fuel-Burning Thermal Power Plants 9/

Main Objectives

13. STEG is inviting bids from consultants (corporations or public agencies) to design, supply and implement a system for the on-line monitoring of the operating efficiency of fuel-burning thermal power plants.

14. This system will be adapted to match the hardware already available in each of the units and the efficiency monitoring software being tested by STEG. The objective of this system is to reduce losses in unit performance by continuous control room monitoring of the main parameters, to enable operators to take corrective action in real time. This system also makes it possible to monitor the condition of the main components and to undertake maintenance actions as part of a conditional maintenance strategy.

15. This program consists of providing and installing a complete on-line operating efficiency monitoring system for 150 MW units (in Sousse) and 30 MW units (in Gabès), taking existing equipment into consideration.

16. In particular, the project consists of the following components:

- a feasibility study to be conducted on-site;

- an additional study to be conducted outside of Tunisia;

- on-site installation of the system, which comprises:

  . the computer;
  . the software;
  . data collection panels;
  . additional sensors and lines (if necessary)

9/ *In a first phase, these terms of reference apply only to the Sousse and Gabès plants.*

- commissioning of the equipment in the presence of STEG officials.

The project is estimated to require:

- 6 man-weeks at the sites for the feasibility study;

- 6 man-weeks outside Tunisia for project study and preparation;

- 16 man-weeks to install and adapt the equipment and to train local staff.

The total cost is estimated at F 2.07 million.

The project is financed by ....

Background of the Study

17. STEG is a commercial and industrial statutory government entity established by Nationalization Decree-Law No. 62-8 of April 3, 1962. This document makes STEG responsible for the generation, transmission, distribution, import and export of electric power and fuel gas under the supervision of the Ministry of the National Economy.

STEG has four steam power plants:

- Goulette II, with four 30-MW units consuming fuel oil;

- Ghannouch, with two 30-MW units consuming fuel oil or gas;

- Sousse, with two 150-MW units consuming fuel oil or gas;

- Radès, with two 160-MW units consuming fuel oil or gas.

STEG also has 19 gas turbines with capacities ranging from 15 MW to 30 MW.

18. This project, consisting of the installation of a system for the on-line monitoring of operating efficiency, results from a recommendation by the UNDP/World Bank mission for improving the performance of STEG's power generation system.

Project Description

19. The project includes all necessary resources for achieving the main objectives defined above. It will be implemented in the Sousse and Gabès power plants.

20. The sensing devices that are already installed and operating properly will be used to the extent possible. A data collection panel and appropriate software should be installed so that measurement signals can be made compatible with computer data input.

21. About 24 major measurements -- such as active power, steam characteristics, boiler characteristics, etc. -- will be used in the application. Curves and nomograms for calculating deviations will be established on the basis of commissioning tests. Conventional thermodynamics equations will be used to calculate heat, consumption, losses, etc. The computer, to be installed in the control room, should continuously indicate losses and their causes, in units of heat and in cost terms.

Division of Tasks and Responsibilities

22. The contracting party will be entirely responsible for project execution, and will provide all the services and equipment necessary for its proper implementation.

23. The bid should take the form of a turnkey project, to include computers, software, software interfaces, and installation. However, STEG will be responsible for importing the equipment and for providing experienced technical and data processing specialists to monitor installation and assist with wiring.

STEG will be responsible for the following:

. access to the power plants and to the necessary data;

. consultant travel within Tunisia;

. providing instrument specialists and electrical equipment, as needed;

. assistance in obtaining all administrative documents necessary to enable the contractor's personnel to enter Tunisia or to facilitate imports of equipment.

Contents of the Bid

24. The bid should include the following main elements:

- a work plan in line with the terms of reference;

- estimates of the time required, by specialty and by location;

- a description of the bidder and of its experience in similar projects;

- the personnel to be assigned to the project, with complete résumés and accounts of previous experience.

25. Bids must state the total price, and be sealed.

Nevertheless, bidders may suggest alternate methods of achieving the objectives stated in the terms of reference. Any alternative method must be clearly defined and should be submitted as a separate bid with itemized costs.

Payment Schedule

26. The payment schedule will be subject to negotiation.

The bidder must propose a schedule that takes into account the performance objectives.

Study costs

27. - 3 weeks on site to assess feasibility (2 specialists);

- 3 weeks abroad for project study and preparation (2 specialists);

- 8 weeks on site to install and adjust the equipment and to train local staff (2 specialists).

UNAVAILABILITY RATES AND AVAILABILITY STATISTICS FOR CONVENTIONAL THERMAL POWER UNITS 10/

1. The UNIPEDE/CME Mixed Committee described in the document "Availability and Unavailability Rates in Thermal Power Plants -- Definitions and Methods of Calculation," published in 1977, the typical unit sizes recommended for use in thermal power plants. The unavailability rate over a specified period is defined as the ratio of the energy that a capacity equal to the unavailable capacity could have produced during this period to the energy that the maximum capacity could have produced during the same period. The unavailable capacity is the difference between the maximum capacity possible (with all equipment supposed to be running properly) and the available capacity (maximum capacity at which the station can be operated under actual equipment conditions).

2. The overall unavailability rate is designated as G and is divided into unavailability rate due to planned maintenance, G1, and unavailability rate for all other reasons, G2 (G1 + G2 = G). The availability rate (ratio of the energy that the available capacity could have produced over a given period to the energy that the maximum capacity could have produced) is the difference between 1 and the overall unavailability rate G.

3. The conventional thermal units have been divided according to their unit capacity and their geographical location.

Annual unavailability rates for the years 1981 through 1985

4. The unavailability rates shown in the following table (Table A7.1) distinguish between unavailability due to maintenance work and unavailability for all other reasons (unplanned unavailability). The sum of the two rates represents the overall unavailability rate.

5. The results show that, for a given capacity range per set, unavailability rates are similar in Europe and in the United States. The unavailability rates for other countries are notably different than those calculated for Europe and the United States. The difference is significant in the 100-199 MW unit capacity category, where the overall unavailability rate for the other countries is on average some 6% higher than in Europe and the United States. Overall unavailability rates for a unit capacity of 100-199 MW are calculated as: 19% in Europe and the US; 25% in other countries.

10/ *Source: UNIPEDE/World Energy Conference.*

Table A7.1: CONVENTIONAL 100-199 MW THERMAL UNITS
ANNUAL UNAVAILABILITY RATES IN %

Year	Europe			United States			Other countries		
	A		T	A		T	A		T
1981	49,260		399	53,917		380	11,482		77
1982	48,400		393	57,778		412	11,785		80
1983	47,792		386	57,343		407	13,008		90
1984	47,435		380	56,678		401	13,158		91
1985	29,764		237				8,497		55
	G1	G2	G	G1	G2	G	G1	G2	G
1981	11.4	8.8	20.2	10.7	8.2	18.9	11.9	10.6	22.5
1982	11.6	8.0	19.6	11.9	7.2	19.1	13.0	10.6	23.6
1983	10.7	7.8	18.5	11.7	6.9	18.6	17.1	10.6	27.7
1984	9.6	7.3	16.9	11.6	5.9	17.5	13.5	10.8	24.3
1985	10.4	7.5	17.9				12.7	12.3	25.0
Average	10.8	7.9	18.7	11.5	7.0	18.5	13.8	10.9	24.7

Number of sets on January 1 = T.
Average maximum capacity of the units on January 1 = A (in MW).
Unavailability rate: G1 = annual maintenance program; G2 = all other causes; G = the sum of the two.

STANDARD MAINTENANCE CONCEPTS

Maintenance	Those activities necessary for enabling a machine to be maintained in -- or restored to -- a specific condition, or to fulfill a certain purpose.
Corrective Maintenance	Maintenance performed after the appearance of a malfunction. It includes:
- Detection	The identification of a malfunction or a malfunctioning component as a result of close inspection, whether continuous or periodic.
- Location	The identification of the specific components causing the malfunction.
- Diagnosis	The identification of the probable cause of the malfunction, using logical deduction based on a set of data. Diagnosis makes it possible to confirm, add to or modify hypotheses regarding the origins and causes of malfunctions, and to specify what corrective maintenance operations are necessary.
- Emergency service	Action taken on out-of-service equipment to get it back into working order, at least temporarily. Considering this objective, the results obtained can be temporary and the normal regulations governing procedures, costs and quality can be disregarded. In such a case, repair will follow.
- Repair	Thorough and specifically targeted corrective maintenance in response to a malfunction.
Preventive Maintenance	Maintenance performed according to predetermined criteria to reduce the likelihood of equipment malfunction, with its consequent impact on the services provided. There are two types of preventive maintenance:
Routine Preventive Maintenance	Maintenance performed according to a schedule based on time intervals or on actual equipment use.
Conditional Preventive Maintenance	Maintenance contingent upon certain predetermined events (self-diagnosis, sensor data, measurements of wear, etc.), indicating the degree of deterioration of the equipment.

Preventive maintenance comprises the following operations:

- Inspection — Examinations performed as part of a specific function. It is not necessarily limited to a comparison with pre-established data, and the characteristic method used is that of inspection "rounds."

- Monitoring — Ascertaining that equipment complies with pre-established data, at which point a judgment is made as to its condition. Monitoring can:

  . include data collection;
  . include a decision (acceptance, rejection or postponement of maintenance);
  . lead to initiation of corrective actions.

- Maintenance Examination — A detailed and predefined examination of all or part of the various components of the equipment (depending on whether the examination is general or specific). It may include first-level maintenance operations.

  Some corrective maintenance operations may be performed if anomalies are observed during the maintenance examination.

- Test — An operation enabling a system's responses to an appropriate and predetermined stimulus to be compared to those of a reference system or with a physical phenomenon that indicates it is operating correctly.

In addition to the actions defined above, maintenance also includes certain typical operations that are not systematically included in any one type of maintenance. They are:

- Overhauls — Examinations, monitoring and action for protecting equipment from any major or critical malfunction for a given time or for a given effective period of use. Depending on the scope of the operation, it is usual to distinguish between partial and general overhauls. In both cases, this operation involves removing various subunits. This distinguishes overhauls from maintenance examinations.

  An overhaul can be either a preventive or a corrective maintenance operation, depending on whether it is performed in response to a maintenance schedule, a measurement of wear, or a malfunction.

- Modifications — Operations of a definitive nature performed on equipment to improve its operation or to change its characteristics.

- Standard Exchange	Replacement of a component, assembly or subunit with an identical new or reconditioned item, in accordance with the manufacturer's specifications.

Finally, there are two standard maintenance operations concepts -- renovation and rebuilding -- that are closely related to manufacturing and are often performed by manufacturers. Consequently, they are beyond the scope of the maintenance carried out within power plants.

LOAD FLOW CALCULATIONS - HYPOTHESES AND SUMMARY OF RESULTS

Table A9.1: NODES: ACTIVE AND REACTIVE POWER

Plant	Rated kV	(1) P	(1) Q	(2) P	(2) Q	(3) P	(3) Q	(4) P	(4) Q
Rades	150	0	0	0	0	0	0	0	0
Rades	225	0	0	0	0	0	0	0	0
Tunis South	90	60	19	62	52	43	23	64	21
Tunis North	90	25	13	41	24	25	1	27	14
Tunis West	90	47	12	41	34	21	16	50	13
Mnila	90	0	0	0	0	0	0	0	0
Mnila	225	0	0	0	0	0	0	0	0
M. Jemil	90	16	9	13	10	8	5	17	10
Hammamet	90	0	0	0	0	0	0	0	0
Hammamet	150	23	14	24	12	17	4	25	15
Enfidha	150	20	11	17	12	7	5	21	12
Tajerouine	90	39	19	26	23	15	2	42	21
Tajerouine	150	0	0	0	0	0	0	0	0
Tajerouine	225	0	0	0	0	0	0	0	0
Aroussia	90	0	0	0	0	0	0	0	0
M. Bourguiba	90	40	13	22	14	32	13	42	14
Oued Zargua	90	10	5	8	5	6	2	11	6
Fernana	90	0	0	0	0	0	0	0	0
Jendouba	90	15	6	12	7	8	4	16	7
Nebeur	90	0	0	0	0	0	0	0	0
M'saken	150	40	11	31	26	18	11	42	12
Akouda	150	25	14	26	13	15	2	27	15
Nasen	90	0	0	0	0	0	0	0	0
Nasen	90	0	0	0	0	0	0	0	0
Nasen	225	0	0	0	0	0	0	0	0
Oueslatia	225	12	6	7	2	5	2	13	7
M. Mchergua	225	16	7	24	15	10	0	17	8
Sousse	150	15	6	12	6	12	3	16	7
Sousse	225	0	0	0	0	0	0	0	0
Grombalia	90	12	7	22	16	14	8	13	8
Korba	90	23	12	11	13	7	2	25	13
Tunis Center	90	10	5	10	8	2	8	11	6
Tunis Center	90	11	6	10	8	5	5	12	7
La Goulette	90	30	17	19	12	11	4	32	18
Zahrouni	90	21	11	16	12	15	9	22	12
Mdhila	150	13	8	9	2	3	2	14	9
Metlaoui	150	41	17	30	19	21	8	43	18
Kasserine Nord	150	0	0	0	0	0	0	0	0
Kasserine	150	19	9	11	7	14	5	20	10
Maknassy	150	8	3	6	3	7	4	9	4
Feriana	150	3	1	3	1	3	1	4	2
Sfax	150	49	22	36	31	21	10	52	24
Bouchemma	150	0	0	0	0	0	0	0	0
Bouchemma	225	0	0	0	0	0	0	0	0
Robbana	150	25	11	14	3	10	2	27	12
Zarzis	150	15	7	6	1	5	2	16	8
Ghannouch	150	43	21	34	45	20	27	46	23
S. Mansour	150	17	7	13	2	7	2	17	8
S. Mansour	225	0	0	0	0	0	0	0	0
S. Salem	90	0	0	0	0	0	0	0	0
Kairouan	225	7	2	8	4	6	1	8	3
Moknine	150	13	5	22	12	10	3	14	6
Mateur	90	7	3	0	0	0	0	8	4
Tabarka	90	6	2	0	0	0	0	7	3
Gammart	90	5	1	0	0	0	0	6	2
ALGERIAN BORDER NODES									
Elkala	90								
Aouinet	90								
Aouinet	225								
Djebel Onk	150								

Source: STEG, DEX, DPME, various studies.

(1) Evening peak (December 1989) Total load: 780 MW 342 MVAR (tg phi = 0.438)
(2) Morning peak (September 6, 1989) Total load: 646 MW 454 MVAR (tg phi = 0.703)
(3) Valley (September 1989) Total load: 420 MW 196 MVAR (tg phi = 0.467)
(4) Future network (December 1990) Total load: 836 MW 382 MVAR

Comment: Data include the capacitors and the reactors.

Table A9.2: GENERATING SET DATA

Plant		Turbine Manufacturer	Alternator Manufacturer	Year brought into service	Turbine type	Nominal cos phi	Cons. of Aux. Equip. (MW)	Cons. of Aux. Equip. (MVAR)	P. min (MW)	Connection node	Case (1) P	Case (2) P	Case (3) P
Rades	GR1	MITSUBISHI	MITSUBISHI	1985		0.8	8	20	40	Rades	145	0	0
Rades	GR2	MITSUBISHI	MITSUBISHI	1985		0.8	8	20	40	Rades	140	140	130
Sousse	GR1	KWU	KWU	1980		0.8	7	15	40	Sousse	120	120	90
Sousse	GR2	KWU	KWU	1980		0.8	7	15	40	Sousse	120	120	90
Goulette	GR1	CEM	CEM	1965		0.8	2	3	7	Goulette	20	23	15
Goulette	GR2	CEM	CEM	1965		0.8	2	3	7	Goulette	20	23	15
Goulette	GR3	AEG	AEG	1968		0.8	2	3	7	Goulette	0	20	15
Goulette	GR4	AEG	AEG	1968		0.8	2	3	7	Goulette	0	0	0
K. North	TG1	FIAT	ALSHTHOM	1984		0.8	1	1	10	K. Nord	30	30	0
K. North	TG2	FIAT	FIAT	1984		0.8	1	1	10	K. Nord	0	0	0
Korba	TG1	ALSHTHOM	ALSHTHOM	1978		0.8	0.8	0.6	5	Korba	0	0	0
Korba	TG2	FIAT	ALSHTHOM	1984		0.8	1	1	10	Korba	0	0	0
Robbana	TG1	FIAT	ALSHTHOM	1984		0.8	1	1	5	Robbana	0	0	0
Ghannouch	TG1	ALSHTHOM	ALSHTHOM	1971		0.8	0.8	0.6		Ghannouch	0	0	0
Ghannouch	TG2	ALSHTHOM	ALSHTHOM	1973		0.8	0.8	0.6	6	Ghannouch	0	0	0
Ghannouch	TG3	ALSHTHOM	ALSHTHOM	1973		0.8	0.8	0.6	6	Ghannouch	17	16	15
Ghannouch	TG4	FIAT	ALSHTHOM	1973		0.8	1	1	10	Ghannouch	30	30	20
Ghannouch	TV1	CEM	CEM	1972		0.9	2	3	11	Ghannouch	28	28	20
Ghannouch	TV2	CEM	CEM	1972		0.9	2	3	11	Ghannouch	27	27	20
T. South	TG1	ALSHTHOM	ALSHTHOM	1975		0.8	0.8	0.6	5	T. Sud	20	0	0
T. South	TG2	ALSHTHOM	ALSHTHOM	1975		0.8	0.8	0.6	5	T. Sud	0	0	0
T. South	TG3	ALSHTHOM	ALSHTHOM	1978		0.8	0.8	0.6	5	T. Sud	20	20	0
Bouchemma	TG1	FIAT	FIAT	1977		0.8	1	1	10	Bouchemma	25	25	0
Bouchemma	TG2	FIAT	FIAT	1977		0.8	1	1	10	Bouchemma	0	0	0
M. Bourguiba	TG1	ALSHTHOM	ALSHTHOM	1978		0.8	0.8	0.6	5	M. Bourguiba	0	0	0
M. Bourguiba	TG2	ALSHTHOM	ALSHTHOM	1978		0.8	0.8	0.6	5	M. Bourguiba	0	0	0
Sfax	TG1	ALSHTHOM	ALSHTHOM	1977		0.8	0.8	0.6	5	Sfax	0	0	0
Sfax	TG2	ALSHTHOM	ALSHTHOM	1977		0.8	0.8	0.6	5	Sfax	0	0	0
Metlaoui	TG	ALSHTHOM	ALSHTHOM	1978		0.8	0.8	0.6	5	Metlaoui	0	0	0
Fernana	GH			1958		0.8	0.5	0.2	0	Fernana	5	5	0
S. Salem	GH			1982		0.9	2	3	0	S. Salem	25	25	0
Nebeur	GH1			1956		0.8	0.2	0.2	0	Nebeur	4	4	0
Nebeur	GH2			1956		0.8	0.2	0.2	0	Nebeur	4	4	0

Source: STEG, DEX, DPME, various studies.

(1) Evening peak (December 1989) Total production: 800 MW
(2) Morning peak (September 1989) Total production: 660 MW
(3) Evening trough (September 1989) Total production: 430 MW

Data on the Existing Reactors and Capacitors

Installed Reactors, in night operation

- on the Oueslatia-Bouchema feeder : 20 Mvar
- on the Robanna-Ghannouch feeder : 6 Mvar
  (not equipped with a breaker)
- on the Maknassy-Ghannouch feeder : 6 Mvar
- on the Tajerouine-Oueslatia feeder : 20 Mvar
- on the Mdhila-Maknassy feeder : 6 Mvar

Total compensation in service

Night: - 58 Mvar (reactors only)

Capacitors installed (on the 30 kV MV busbars) in service during the day

- to Menzel Bourguiba : 9.6 Mvar
- to Tunis Ouest : 8.4 Mvar
- to Tunis Sud : 8.4 Mvar
  to M'saken : 9.6 Mvar
- to Metlaoui : 9.6 Mvar

Day: + 40 Mvar (capacitors and reactor - Ghannouch)

Acceptable Voltage levels:

Table A9.3: UNOM ± 10%

Voltage (kV)	Min.	Max.
90	81	99
150	135	165
225	202	247

Table A9.4: GENERATING UNITS EXPECTED TO BE IN OPERATION IN 1993 IN ADDITION TO THOSE IN SERVICE IN 1989

Sets		Morning peak	Evening peak	Evening trough
Metlaoui	1GT	X	X	
Sfax	2GT	X	X	
M. Bourguiba	2GT	X	X	
Robbana	1GT	X	X	
Korba	2GT	X	X	
La Goulette	2ST	1 Set	2 Sets	
Bouchema	1GT			X
Kasserine North	1GT			X
Tunis South	2GT			X
Sousse	2ST			X

Note: GT = gas turbine; ST = steam turbine.

Table A10.1: LOSSES IN % ON STEG'S HV NETWORK ONLY
(excluding losses on the interconnection with Algeria)
Evening peak

	1989			1993				
	Without compensation	With existing capacitors and reactors	With additional capacitors	Without compensation	Capacitors		Capacitors	
					Without	With	Without	With
Compensation (MVAR)	0	40	130	0	0	211	0	211
Voltage: 235 kV	1.26	1.23	1.19		1.9	1.8	0.8	0.7
225 kV	1.28	1.26	1.23	1.8	2.0	1.9	0.8	0.8
210 kV	1.30	1.31	1.26		2.3	2.1	0.9	0.9
Tan phi	0.489	0.438	0.278	0.489	0.489	0.278	0.438	0.278
Demand	780 MW			1000 MW				
Generating equipment hypotheses	Steam turbines : 620 MW Gas turbines : 140 MW Hydropower : 40 MW			218MW Contribution from Algeria	CAP BON P = 224 MW		GT in service P = 200 MW	
Exports to Algeria	10 MW			0 MW	5 MW		12 MW	

Table A10.2: LOSSES IN % ON STEG'S HV NETWORK ONLY
(Excluding losses on the interconnection with Algeria)
Morning peak

	1989			1993				
					Capacitors		Capacitors	
	Without compensation	With existing capacitors and reactors	With additional capacitors	Without compensation	Without	With	Without	With
Compensation (MVAR)	0	40	130	0	0	211	0	211
Voltage: 235 kV	1.13	1.05	0.94		1.4	1.2	0.8	0.7
225 kV	1.15	1.05	0.96	2.2	1.5	1.2	0.8	0.8
210 kV	1.21	1.11	1.02		1.6	1.4	0.8	0.8
Tan phi	0.764	0.703	0.501	0.764	0.764	0.703	0.764	0.703
Demand	646 MW			829 MW				
Generating equipment hypothesis	Gas turbines : 500 MW Gas turbines : 120 MW Hydropower : 40 MW				CAP BON P = 224 MW		GT in service P = 200 MW	
Exports to Algeria	7 MW			0 MW	40 MW		22 MW	

Table A10.3: LOSSES IN % ON STEG'S HV NETWORK ONLY
(Excluding losses on the interconnection with Algeria)
Night trough

	1989		1993		
	Without compensation	With existing reactors	Without reactors	Without reactors	Without reactors
Compensation (MVAR)	0	- 58	0	0	0
Voltage: 235 kV	0.95	0.90		1.0	0.9
225 kV	0.98	0.90	1.0	1.1	1.0
210 kV	1.24	1.09		1.3	1.1
Tan phi	0.328	0.467	0.328	0.328	0.328
Thermal output	420 MW		542 MW		
Generating equipment hypotheses	Gas turbines : 395 MW Gas turbines : 35 MW Hydropower : 0 MW		117 MW Contribution from Algeria	CAP BON P = 112 MW	GT in service P = 125 MW
Exports to Algeria	6 MW	3MW	0 MW	Imports of 7 MW	

REACTIVE POWER COMPENSATION SURVEY

Table A11.1: LIST OF 150 kV AND 90 kV SUBSTATIONS FOR WHICH TAN PHI IS GREATER THAN 0.5

Morning Peak in September	
Tunis South	0.839
Tunis West	0.829
M. Jemil	0.769
Tajerouine	0.885
M. Bourguiba	0.636
M. Saken	0.839
Grombalia	0.727
Korba	1.182
Tunis Center 1	0.800
Tunis Center 2	0.800
Zahrouni	0.750
Metlaoui	0.633
Kasserine	0.636
Sfax	0.861
Ghannouch	1.323

Including existing capacitors and reactors.

Table A11.2: COMPENSATION REQUIRED BY SUBSTATION TO BRING TAN PHI BACK TO 0.5

Substations	September 89 Morning peak consumption		Existing capacitors MVAR	Capacitors required to reduce tan phi to 0.5
	MW	MVAR a/		
Tunis South	62	52	8.4	21
Tunis West	41	34	8.4	14
M. Jemil	13	10		3
Tajerouine	26	23		10
M. Bourguiba	22	14	9.6	3
M. Saken	31	26	9.6	11
Grombalia	22	16		5
Korba	11	13		7
Tunis Center 1	10	8		3
Tunis Center 2	10	8		3
Zahrouni	16	12		4
Metlaoui	30	19	9.6	4
Kasserine	11	7	9.6	4
Sfax	36	11	13	
Ghannouch b/	34	45		28
Total			45.6 in service from 7 a.m. to 11 p.m.	130

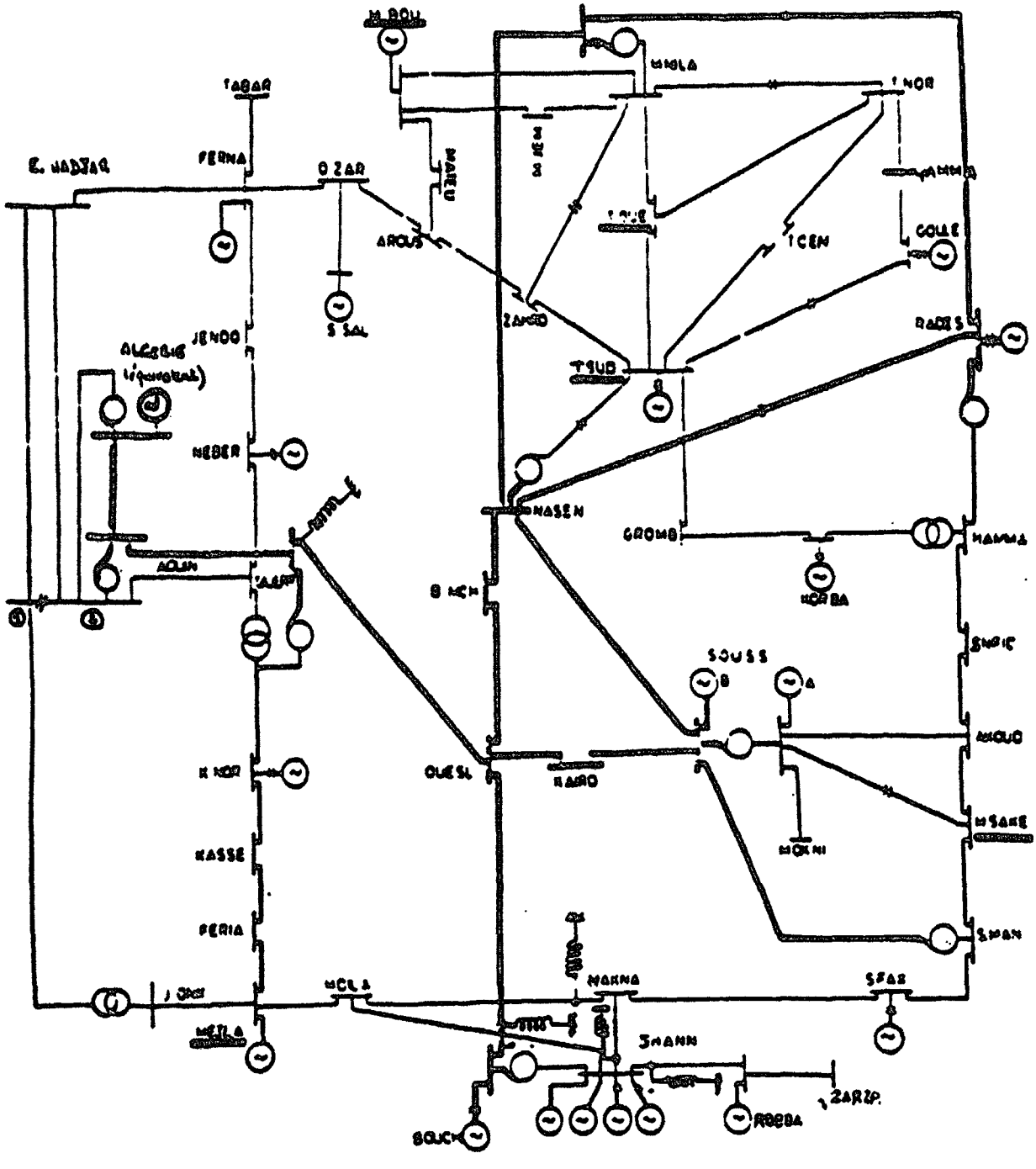
a/ These values take into account the existing capacitors and reactors.

b/ Currently, one 6 MVAR reactor on the Ghannouch-Robbana feeder is in service 24 hours a day, as it does not have a breaker.

Table A11.3: MEASURING THE EFFECT OF THE PROPOSED ADDITIONAL COMPENSATION

	Evening peak			Morning peak			Night trough	
	No capacitor	Capacitor + existing reactors	Additional capacitor (0 reactor)	No capacitor	Capac. + existing reactors	Additional capacitor (0 reactor)	0 reactor	With existing reactors
Tan phi	0.489	0.438	0.278	0.764	0.703	0.501	0.328	0.467

THE NETWORK IN 1989

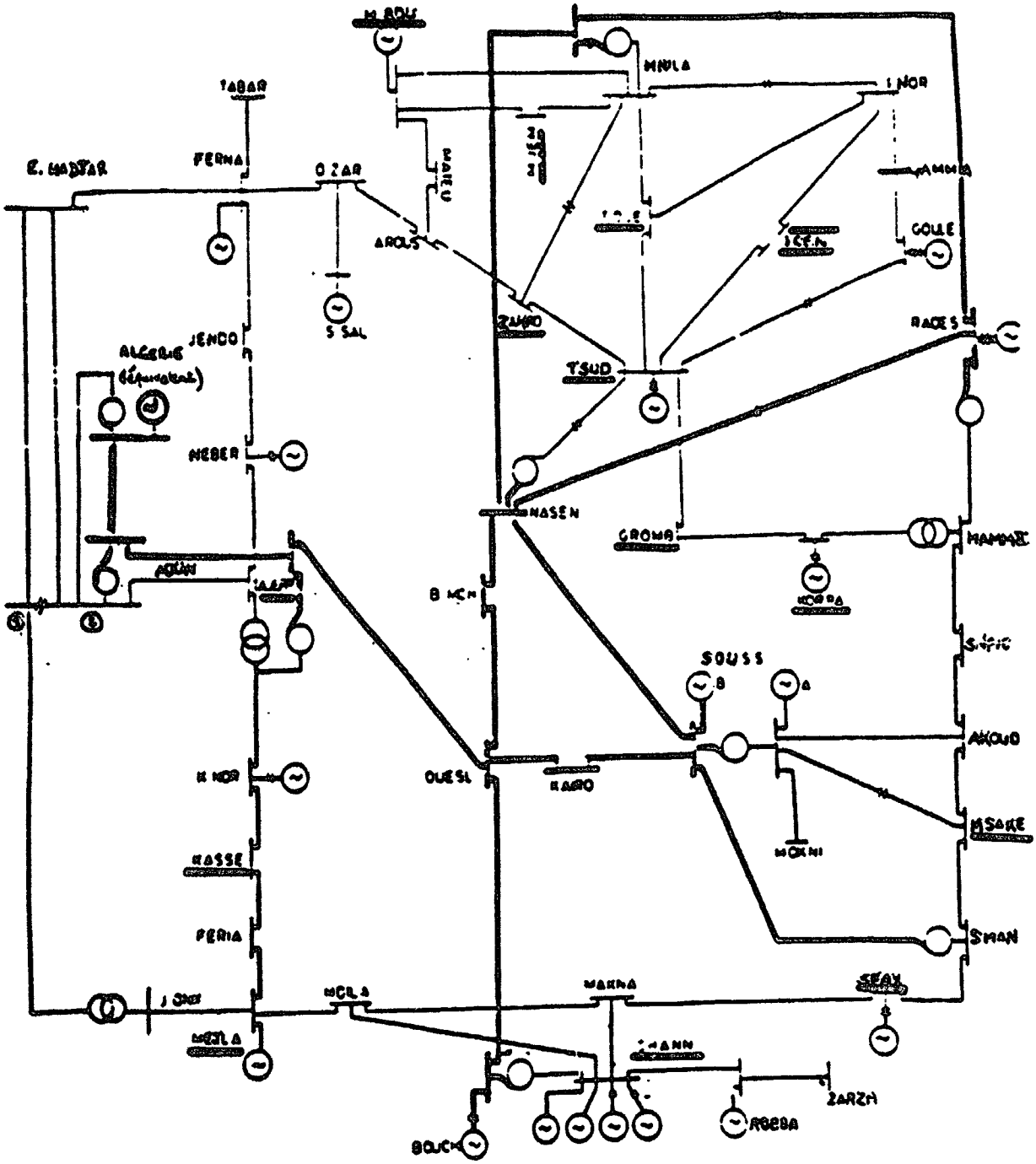


M BOU — Location of existing capacitors.

Reactors currently in service.

FIGURE 4

THE NETWORK BY 1993



M BOU Location of additional capacitors.

FIGURE 5

ECONOMIC ANALYSIS OF COMPENSATION

1. This economic study is a fairly summary calculation of the gains that could result from compensating for reactive energy. There is a twofold benefit, technical and economic, in compensating for part of the reactive energy absorbed by the loads.

(a) The technical benefit has already been mentioned: introducing compensation increases the network's operating margins, making operations easier and more reliable by reducing the scope for voltage instability.

(b) Compensation also offers a significant economic benefit by reducing losses on the network as a whole.

2. The purpose of this annex is to calculate the economic gains. The simulations made involved calculating the number of capacitors to be installed to improve the load factor, as "seen" from the VHV transmission network substations. The relevant numbers of capacitors must then be allocated among these substations and those on the lower voltage networks that they supply (HV and MV). In particular, they should be installed in MV substations as close as possible to the demand so as to secure the maximum reduction in losses on these MV networks.

Loss calculation

3. At peak hours, active losses on the network, in relation to the power supplied, are regularly reported to be around:

- 2.5% on VHV and HV networks
- 2% in HV/MV transformers
- 5% on the MV network
- 3% in MV/LV transformers
- 6% on the LV network

4. On the MV and HV networks, where the capacitors will preferably be installed, peak hour losses are generally 3 to 4 times greater than on the VHV network.

5. We have shown that the installation of capacitors "seen" from the VHV transmission network would reduce active losses on this network (Annex 9). The same is true for MV and LV network losses when capacitors are connected on these networks. It should, however, be noted that, given the small size of the capacitor banks to be installed on the MV network and other constraints involved, in particular the space available in the substations, installing capacitors on the MV network will not necessarily be optimal. The capacitor banks will be grouped and installed in the substations to the extent possible, producing a useful but not necessarily optimal reduction in MV losses.

6. Consequently, if the active losses on the MV and HV networks are 3 to 4 times higher than on the transmission network, the reduction in these losses through the use of "non-optimal" means of compensation will not be as large. We will arbitrarily reduce the ratio in question to 2 in order also to take account of the fact that only 86%, rather than 100%, of the power supplied to consumers passes through the MV network, and that there are losses in the transmission of reactive energy between the various voltage levels (VHV-HV-MV).

7. To quantify the reduction in losses resulting from compensation we will use the cost hypotheses from Annex 2.

ANNUAL COST OF 1 kW OF PEAK LOAD LOSSES
(Hours of Use: 5,900)

Level	HV	HV/MV	MV	MV/LV	LV
Cost in TD/kW	216.9	236.5	306.8	350.9	471.4

Simplified economic study

8. The aim is to examine the benefit to be gained from installing compensation resources on the transmission network and the MV networks. This requires a base compensation cost, i.e., banks of capacitors and reactors, of TD 10,000/Mvar, entailing annual investment costs of TD 1,000/Mvar.

Operation of the Ghannouch reactor

9. All the reactors are disconnected 16 hours a day. The Ghannouch reactor (6 Mvar), which is permanently connected to the network, is therefore in service for 16 hours too many each day, or during the 5,840 heaviest loaded hours of the year. The additional losses that this entails for the network (in addition to the internal losses due to its resistance) can be calculated as follows:

10. The simulations showed that 170 Mvar of compensation produced a gain of 1,2 MW (morning peak) and 0.4 MW (evening peak), or 0.8 MW on average. The annual gain can therefore be obtained from:

$$\frac{6 \text{ Mvar}}{170 \text{ Mvar}} \times 0.8 \text{ MW} \times \text{TD } 216{,}900/\text{MW} = \text{TD } 6{,}120$$

The cost of a breaker being estimated at 0.25 x TD 10^5, it does not seem economically justified to attach a breaker to the reactor.

Installation of capacitors on the transmission network

11. Using the same procedure as above produces a gain per Mvar of:

$$\frac{\text{TD } 216{,}900/\text{MW} \times 0.8 \text{ MW}}{170 \text{ Mvar}} \approx \text{TD } 1 \times 10^3/\text{Mvar}$$

or exactly the annual cost of installing compensation. Consequently, at the level of precision of our calculations, it is, economically speaking, immaterial whether or not capacitors are installed on the HV network. Only the advantages of increased network reliability in relation to a voltage collapse would justify installing capacitors at this voltage level.

Installation of capacitors at the MV level

12. The preceding arguments only apply, of course, to the capacitors that would be installed in the VHV/HV or VHV/MV substations, in other words to the capacitors "seen" directly from VHV. The number of capacitors required to make tan phi equal to 0.5 (170 Mvar in 1989 and 218 Mvar in 1993) must clearly be allocated over the entire network (VHV, HV, MV). From a technical and economic point of view it is more beneficial to install them close to the demand.

13. Installation of capacitors on MV would reduce losses not only on the VHV and HV networks, but also on the MV networks, and in much greater proportions. This ratio was put at 2 (see para. 6 of this annex), which leads to a gain per Mvar of:

$$\frac{0.8 \text{ MW} \times 2 \times 306{,}800 \text{ TD/MW}}{170 \text{ Mvar}} = 2.9 \times 10^3 \text{ TD/Mvar}$$

a figure that suggests an internal rate of return for the investment of about 30%.

Conclusion of the economic study on the installation of compensation

14. This brief study has shown that it would be economically justifiable, in order to reduce network losses, to install capacitors. These should be placed as close to the load as possible, in other words, preferably on the MV network.

15. This study is only a first approximation of the expected orders of magnitude of the benefits. It used a minimum number of network operating hypotheses and assumed that the gains achieved were a linear function of the numbers of capacitors installed. These gains could thus only be calculated by using two extreme hypotheses: no compensation, and compensation producing a tan phi of loads equal to 0.5. In practice, the gains are a parabolic function of the compensation. To obtain a more accurate idea of their magnitude, one would need to undertake a more precise analysis, incorporating a larger number of hypotheses to permit better modeling of the load curve, and to calculate actual network losses for each load level considered, rather than accepting a global evaluation that assumes that these losses are merely proportional to the square of the energy consumed. It is also necessary to calculate these losses for more realistic installations of capacitors, taking local conditions into account (space in the substations, minimal size of each capacitor), and evaluate more precisely, either using statistical surveys or by making calculations for "representative" networks, the losses on the MV and HV networks and the impact on these of a "realistic" installation of capacitors in the MV and HV substations.

16. This would reveal that the marginal gain (gain per Mvar installed) declines as a function of the overall amount of compensation. Knowledge of these "marginal gains" would enable optimum use to be made of the funds that may be allocated for reactive energy compensation.

SELECTION OF NETWORK SAMPLE

Presentation of Distribution

General description of the network

1. The STEG distribution network operates at four voltage levels:

- 30 kV, 15 kV and 10 kV in the medium voltage range (MV);
- 400 V/230 V in the low voltage range (LV).

2. The Distribution Directorate receives energy from the transmission network through 41 master stations with primary voltages of 225 kV, 150 kV and 90 kV.

3. The MV network has a radial structure and consists of:

- 13,000 km of three-phase overhead lines, and 4,000 km of single-phase spurs at 17.3 kV. The neutral of the three-phase overhead network is distributed and grounded; it is therefore a "four-wire" system.
- 1,000 km of mostly underground 10-kV network supplying cities in the north like Tunis and Bizerte.
- 354 km of 15-kV lines supplying large towns in the south: Gabès, Gafsa.

4. The total length of the MV network is 18,400 km, 1500 km of which is underground. This MV network supplies power to 30,600 km of LV lines (97% of which are overhead) through 17,000 MV/LV transforming substations, 6,700 of which are customer substations. Following a major campaign to change voltage levels, 98% of these MV/LV substations supply a secondary voltage of 400 V. Of the MV/LV substations providing a 230 V secondary voltage, 70% are concentrated in the Tunis region, particularly in the Tunis City district.

5. The following tables give a breakdown by district of the MV and LV networks and the MV/LV substations.

Table A13.1: MV/LV DISTRIBUTION NETWORK (1988)

Districts	Number of substations					Network length (km)			
	STEG		Private		Total	Medium voltage			Low voltage
	L1	L2	B1	B		Mono-phase	Tri-phase	Total	
Tunis City	168	259	37	497	961	-	454	454	753
Ariana	-	383	-	245	628	-	458	458	1020
Ezzahra	9	346	-	619	974	12	493	505	896
Le Kram	-	158	5	93	256	-	189	189	535
Le Bardo	-	319	-	246	565	3	381	384	1800
Zaghouan	-	1377	-	138	275	6	346	352	295
Bizerte	10	357	14	391	772	27	779	806	1659
Nabeul	-	849	-	629	1478	140	1088	1228	2715
Beja	-	266	-	228	494	109	550	659	684
Jendouba	-	525	-	233	758	244	559	803	1163
Le Kef	-	501	-	133	634	339	631	970	1131
Siliana	-	339	-	123	462	237	445	682	694
Sousse	26	490	13	467	996	156	643	799	1698
Monastir	-	200	-	256	456	19	315	334	664
Mokrine	-	205	-	148	353	56	171	227	800
Mahdia	-	379	-	122	501	162	490	652	849
Kairouan	-	435	1	242	678	205	810	1015	1261
Kasserine	-	305	-	139	444	254	515	769	729
Sidi Bouzid	-	464	-	149	613	457	479	936	904
Gafsa	-	413	-	180	593	129	909	1038	990
Tozeur	-	104	-	170	274	35	375	410	355
Sfax	43	1094	21	560	1718	604	1000	1604	4016
Gabès	-	451	-	216	667	314	666	980	979
Kebili	-	143	-	102	245	52	325	377	860
Zarzis	-	684	-	196	880	236	774	1010	2495
Tataouine	-	247	-	29	276	145	360	505	616
Total	256	10053	91	6551	16951	3941	14205	18146	30561

Table A13.2: TECHNICAL DISTRIBUTION RATIOS

Regions	Data for 1988						Share of total (%)					
	Networks (km)		No. of substations		No. of customers		Networks		Substations		Customers	
	MV	LV	STEG	Customers	MV	BV	MV	BV	STEG	Customers	MV	LV
Tunis	1990	5004	1642	1742	2043	334980	11	17	16	26	30	28
North	2386	4669	1353	1172	1240	169960	13	15	13	18	18	14
Northwest	3114	3672	1631	717	651	121220	17	12	16	11	9	10
Center	3027	5272	1735	1249	1264	211020	17	17	17	19	18	18
Southwest	3153	2975	1286	638	582	101530	17	10	12	9	9	8
South	4486	8966	2662	1124	1098	261610	25	29	26	17	16	22
Total Tunisia	18146	30561	10309	6642	6878	1200313	100	100	100	100	100	100

Regions	Ratio			
	No. of km of MV per substation (STEG + customers)	No. of km of LV per STEG substation	No. of meters of LV per LV customer	No. of LV customers per STEG substation
Tunis	0.589	3.045	15	204
North	0.945	3.450	27	126
Northwest	1.326	2.250	30	76
Center	1.014	3.039	25	121
Southwest	1.639	2.315	29	79
South	1.607	3.368	34	98
Total Tunisia	1.070	2.965	25	116

Power consumption zones

6. The following table gives the 1989 regional breakdown of power supplied for distribution and billed by this Directorate.

Table A13.3: BREAKDOWN BY REGION

Region	Energy supplied (GWh)	%	Energy billed (GWh)	%
Tunis	1240.63	28.25	1125.40	28.22
North	852.64	19.42	776.90	19.48
Northwest	333.90	7.60	320.60	8.04
Center	832.32	18.96	740.70	18.58
South	730.03	16.63	635.40	15.94
Southwest	401.24	9.14	388.40	9.74
Total	4390.76	100.00	3987.40	100.00

7. This breakdown shows an area of high consumption comprising the neighboring regions of Tunis and the north, which account for 47.70% of total domestic consumption, and some centers with an average level of consumption around Sousse and Gabès. The city of Tunis and its suburbs account for 28.22% of national power consumption.

Pattern of development of the distribution networks

8. The pattern of development of the MV and LV networks is greatly influenced by the expansion of rural electrification, which is one of the key elements in the Distribution Directorate's master plan, the goal of which is to achieve a 75% electrification rate in 1991 (the rate for 1976 was 13%, and that for 1987 was 58%). The following table shows changes in the network from 1976 to 1988.

Table A13.4: DEVELOPMENT OF THE NETWORKS

	1976	1981	1984	1985	1986	1987	1988
MV network (km)	6600	11000	14872	16163	16955	17529	18146
LV network (km)	7700	15100	22234	25016	27118	29234	30561
No. MV/LV substations							
Public			7354	8001	8500	9759	10309
Private			4804	5477	5562	6229	6642
Total	3900	9030	12158	13478	14062	15988	16951

9. The breakdown of sales by sector shows the importance of the construction industries (principally the cement works), which account for 19.30% of the energy billed; the cement works alone accounted for 64.5% of the HV energy consumed.

Table A13.5: HV/MV POWER SALES BY SECTOR (1989)

Sector	Consumption GWH	Difference between 1988 and 1989 (%)	Turnover (TD 000)		Average price per kWh (total) (TD)
			Total	Share	
Extractive industries	209.0	3.1	8813	7.3	42.2
Food and tobacco	195.8	2.0	9506	7.8	48.5
Textiles and clothing	172.7	10.5	8680	7.1	50.3
Paper and publishing	77.3	-4.2	3251	20.7	42.0
Chemical and petroleum industries	118.4	-4.2	6350	5.2	53.6
Construction	769.6	8.4	30056	24.8	39.0
Basic engineering	144.9	14.3	5810	4.8	40.1
Miscellaneous	182.9	9.6	9632	7.9	53.7
Total 1	1870.6	6.3	82098	67.6	43.9
Pumping: agricultural	154.5	0.0	6646	55.5	43.0
Pumping: water supply and sanitation	166.8	10.5	7530	6.2	45.1
Transportation and communications	91.2	3.6	4715	3.9	51.7
Tourism	157.2	9.7	8097	6.7	51.5
Services	216.7	3.5	12294	10.1	56.7
Total 2	786.4	5.4	39282	32.4	49.9
GRAND TOTAL	2657.0	6.0	121380	100.0	45.7

Table A13.6: POWER SALES TO HV CUSTOMERS

Customer	AE Code	Power (MW)	Consumption (GWh)		Turnover (TD 000)		Average price per kWh (TD)
			Total	Differ-ence	Total	Differ-ence	
Mine de Gafsa	300	26	131.3	0.9	4801	16.6	36.6
Cellulose Kasserine	25	10	37.8	-15.0	1364	4.7	36.1
El F. (aciérie)	220	9	76.3	4.7	2724	9.4	35.7
El F. (fours à arc)	220	7	29.4	18.1	1057	3.6	35.9
Cimenterie de Bizerte	211	10-16.5	70.4	8.3	2391	8.3	34.0
Cimenterie de Gabès	211	15	89.2	16.7	3045	10.5	34.1
Cimenterie de Kef	211	19-21	114.4	13.5	4092	14.1	35.8
Cimenterie Sousse	211	22.5-23.5	116.3	6.5	4279	14.8	36.8
Cimenterie de Zaghouan	211	23-26	102.9	14.6	3745	12.9	36.4
Métro léger Sousse	400	1.2	2.4	20.0	108	0.4	45.0
Ciment Blanc K.	211	6.6	26.8	5.9	944	3.2	35.2
SIAPE, Sfax	230	8	9.1	-9.0	429	1.5	47.1
		169.8	806.3	7.3	28979	100.0	35.9

Technical Aspects

Selection of reference networks

10. This study examines the various areas in which losses on the STEG distribution network have been detected. The loss rate at each of these points is determined by an "overall" method, and short, medium or long-term recommendations will be made, matching the type of problems identified.

11. Given the extent and diversity of STEG distribution networks and the time available to this mission, an exhaustive analysis of the networks was not possible. It was therefore decided to concentrate on the networks in zones where consumption was homogeneous and representative of the distribution system as a whole.

12. An initial analysis identified three major zones with a homogeneous pattern of consumption. As Table A13.17 indicates, the various regions of Tunisia can be divided into the following three categories:

- the first consists of regions characterized by a poor ratio of energy billed to energy supplied, and a ratio of about 0.5 between number of mMV and number of mLV. This category consists of the North, Center and South;

- the second is characterized by a high ratio of energy billed to energy supplied, despite a high ratio between number of mMV and number of mLV per consumer, the reason being that the network is more recent and therefore certainly more efficient. It consists of the Northwest and Southwest; and

- finally, Tunis is a special case, with a low ratio of energy billed to energy supplied, and also a low ratio between number of mMV and number of mLV per customer. This in itself suggests that nontechnical losses in this zone will be high.

Table A13.7: IDENTIFICATION OF ZONES

Zone	Ratio a/	No. of mLV per LV customer	No. of mMV per LV and MV customer	Ratio mMV/mLV
Tunis	0.907	15	6	0.40
North	0.911	27	14	0.52
Northwest	0.960	30	26	0.87
Center	0.890	25	14	0.56
South	0.870	34	17	0.50
Southwest	0.970	29	31	1.07

a/ Ratio = Energy billed/Energy supplied.

13. One typical district was selected from each category: Nabeul, where agriculture, tourism and industry are major activities; Siliana, a rural district, is representative of the second, and two districts (the city of Tunis, an urban district, and Ezzahra, a suburban district) were selected as representative of the region of Tunis, which alone consumes over 28% of the energy supplied in Tunisia.

14. In addition, these districts also meet the following criteria of representativity:

- voltage levels: 10 kV and 30 kV;
- network structure: overhead and underground;
- distribution system: three-phase and single-phase;
- energy utilization: at medium and low voltage.

Tables A13.8 to A13.18 present the technical specifications for these districts.

Interdependent Criteria

15. A representative sample of the MV network in a given district is selected by means of the following three interdependent criteria:

$$\text{Criterion 1} = \frac{\Sigma\, P\ inst}{P\ max}$$

$$\text{Criterion 2} = \frac{\Sigma\, P\ inst}{\text{Outgoing feeder length}} \quad \text{(kVA/m)}$$

$$\text{Criterion 3} = \frac{\Sigma\, P\ max}{\text{Outgoing feeder length}} \quad \text{(kVA/m)}$$

16. For each outgoing feeder in the zone, the value of each criterion is calculated, together with Σ P inst x outgoing feeder length, in order to identify those feeders assumed to have a high loss rate. This provides the data for Tables A13.7 to A13.12 for the City of Tunis district and A13.13 through A13.15 for the district of Siliana. From these tables can be determined the distribution of feeders according to the value of each criterion. This provides the material for Tables A13.16 to A13.18. This provides a "predominant interval" for each criterion; this is the interval defined by the largest number of feeders. All feeders are then identified and the predominant interval for the three criteria is also determined. This selection is weighted by taking one feeder in each interval adjacent to the predominant interval, up to a maximum of six additional feeders selected so as to provide feeders connected to most main substations.

Table A13.8: DISTRICT: CITY OF TUNIS
MAIN SUBSTATION: TUNIS SOUTH

Feeder	MV/LV Substations	Length (km)	ΣPinst (kVA)	P max (kVA)	ΣPinst / P max	ΣPinst / Length (kVA/m)	P max / Length (kVA/m)	Pinst*Length (kVA*km)
Charguia 1	1	3,840	5000			1.30		19200
Charguia 2	1	3,840	0					
Anabib	20	10,455	8943			0.86		93499
Izdihar	20	11,170	4875			0.44		54454
B. Arous	1	2,755	?					
B. Arous	1	2,755	?					
Montfleury	0		0					
Gare	0		0					
Bellevue 2	16	7,095	4995			0.70		35440
Kabaria	1	2,100	?					
Kabaria	1	2,100	?					
Abattoirs	17	12,240	7035	2563	274	0.57	0.21	86108
Naassens	20	10,645	6190	2165	286	0.58	0.20	65893
Erpe	27	9,776	10380	3446	301	1.06	0.35	101475
Violettes	20	6,210	7545	3117	242	1.21	0.50	46854
Bellevue 1	22	7,325	5778	1091	530	0.79	0.15	42324
Imer	18	8,357	6130	3446	178	0.73	0.41	51228
Tanit	10	5,155	4860	2095	232	0.94	0.41	25053
B. Miled	24	11,147	10509	2165	485	0.94	0.19	117144
Total	217	116,965	82240					

Table A13.9: DISTRICT: CITY OF TUNIS
MAIN SUBSTATION: TUNIS CENTER

Feeder	HV/LV Substations	Length (km)	ΣPinst (kVA)	P max (kVA)	ΣPinst / P max	ΣPinst / Length (kVA/m)	P max / Length (kVA/m)	Pinst*Length (kVA*km)
T. Marine	1	0,500	?					
T. Marine	0	0,500	0					
Gare	1	9,480	?					
Montfleury	1	5,700	?					
SNTTM	0		0					
H. Congress	1	2,300	1450			0.63		3335
H. Congress	0		0					
T. Marine	15	5,960	6530	1957	334	1.10	0.33	38919
Sûreté	17	5,640	7515	3585	210	1.33	0.64	42385
Biat	16	5,527	6455	3723	173	1.17	0.67	35677
Turquie	11	3,425	3370	1818	185	0.98	0.53	11542
Bejaoui	10	3,227	3761	1818	207	1.17	0.56	12137
Agricultor	11	3,460	5200	1784	291	1.50	0.52	17992
BCT	16	5,575	10905	3256	335	1.96	0.58	60795
Claridge	16	5,640	9910	4676	212	1.76	0.83	55892
Africa	9	2,615	5393	2234	241	2.06	0.85	14103
Kria	27	7,500	10525	4676	225	1.40	0.62	78938
Total	152	67,049	71014					

Table A13.10: DISTRICT: CITY OF TUNIS
MAIN SUBSTATION: TUNIS WEST 1

Feeder	HV/LV Substations	Length (km)	ΣPinst (kVA)	P max (kVA)	ΣPinst / P max	ΣPinst / Length (kVA/m)	P max / Length (kVA/m)	Pinst*Length (kVA*km)
Kerouan	19	5,060	5313			1.05		26884
RTT1	1	1,650	3400			2.06		5610
Mechtel	2	1,430	3630			2.54		5191
Bourricha	37	9,145	10065	4728	2.13	1.10	0.52	92044
Daudet	30	11,915	10079	3585	2.81	0.85	0.30	120091
Franceville	26	12,335	7315	4469	1.64	0.59	0.36	90231
Hilton	17	6,755	7245	4468	1.62	1.07	0.66	48940
Ben Harfa	29	12,010	10800	2511	4.30	0.90	0.21	129708
Plantation	19	5,740	7993	3793	2.11	1.39	0.66	45880
El Hafir	17	7,175	6755	3308	2.04	0.94	0.46	48467
SSSNT	3	6,170	8178	2909	2.81	1.33	0.47	50458
STIT	26	7,350	12685	3983	3.18	1.73	0.54	93235
Nettoiement	14	5,150	7215	3983	1.81	1.40	0.77	37157
Berthelot	10	3,590	4565	1766	2.58	1.27	0.49	16388
Miel	11	3,395	4360	3256	1.34	1.28	0.96	14802
Total	261	98,870	109598					

Table A13.11: DISTRICT: CITY OF TUNIS
MAIN SUBSTATION: TUNIS WEST 2

Feeder	MV/LV Substations	Length (km)	ΣPinst (kVA)	P max (kVA)	ΣPinst / P max	ΣPinst / Length (kVA/m)	P max / Length(kVA/m)	Pinst*Length (kVA*km)
RTT	0	1,550	0			0.00		0
Kartoum	2	1,380	1260			0.91		1739
CEN	1	0,085	1000			11.76		85
Filet	19	7,905	10945			1.38		86520
SNT	18	7,035	4420			0.63		31095
Carnaud	22	12,790	13880			1.09		177525
B. Saad	25	18,485	8395			0.45		155182
Romana	35	18,446	11850			0.64		218585
Frigorifique	22	9,895	6630			0.67		65604
Sidi Assica	14	8,665	4890			0.56		42372
Beaux Arts	5	3,430	2655			0.77		9107
Velwart	25	13,275	7610			0.57		101023
Nutrition	16	10,495	4180			0.40		43869
Total	204	113,436	60090					

Table A13.12: DISTRICT: CITY OF TUNIS
MAIN SUBSTATION: TUNIS NORTH

Feeder	MV/LV Substations	Length (km)	ΣPinst (kVA)	P max (kVA)	ΣPinst / P max	ΣPinst / Length (kVA/m)	P max / Length (kVA/m)	Pinst*Length (kVA*km)
Palestine	27	8,990	8600	1957	4.39	0.96	0.22	77314
Chebbi	15	4,385	6310	1212	5.21	1.44	0.28	27669
Syrie	7	0,520	2060	207	9.95	3.96	0.40	1071
Avenir 11	19	7,620	6340	2523	2.51	0.83	0.33	48311
Avenir 12	21	10,810	9090	3377	2.69	0.84	0.31	98263
Avenir 16	8	5,390	3255	2840	1.15	0.60	0.53	17544
Ibn Roch	12	3,958	3695	1090	3.39	0.93	0.28	14625
Mexique	44	22,060	15278	4607	3.32	0.69	0.21	337033
Charguia	41	14,650	10938	4797	2.28	0.75	0.33	160242
Tulipes	14	6.660	4505	3256	1.38	0.68	0.49	30003
Total	208	85,043	70071					

Table A13.13: DISTRICT: CITY OF TUNIS
MAIN SUBSTATION: ZAHROUNI

Feeder	DP Substations	Length (km)	ΣPinst (kVA)	P max (kVA)	ΣPinst / P max	ΣPinst / Length (kVA/m)	P max / Length (kVA/m)	Pinst*Length (kVA*km)
Rais	28	14,919	10645	2979	3.57	0.71	0.20	158813
Nouablia	19	13,770	7385	2702	2.73	0.54	0.20	101691
Marabou	21	13,080	6685	4538	1.47	0.51	0.35	87440
Total	68	41,769	24715					

Table A13.14: DISTRICT: NABEUL
MAIN SUBSTATION: HAMMAMET

Feeder	MV/LV Substations	Length (km)	ΣPinst (kVA)	P max (kVA)	ΣPinst / P max	ΣPinst / Length (kVA/m)	P max / Length (kVA/m)	Pinst*Length (kVA*km)
B. Argoub (1201)	120	88,384	18002	13302	1.35	0.20	0.15	1591
Enfidha (1202)	90	51,890	19773	7205	2.74	0.38	0.14	1026
Nabeul (1203)	156	72,425	50240	-	-	0.69	-	3639
Elkouin (1204)	19	-	8213	3948	2.08	-	-	-
Sultan (1205)	20	10,398	8313	3525	2.35	0.80	0.34	86
R. Jannet (1206)	19	10,469	9375	2950	3.17	0.89	0.28	98
Total	424	233,566	113916					

Table A13.15: DISTRICT: NABEUL
MAIN SUBSTATION: GROMBALIA

Feeder	MV/LV Substations	Length (km)	ΣPinst (kVA)	P max (kVA)	ΣPinst / P max	ΣPinst / Length (kVA/m)	P max / Length (kVA/m)	Pinst*Length (kVA*km)
Belli (5001)	87	70,954	19464	9222	2.11	0.27	0.13	1381
E. Nord (5002)	58	43,266	16420	9260	1.77	0.38	0.21	710
Soliman (5003)	136	112,085	23419	12153	1.92	0.21	0.11	2625
Zi Gromba (5004)	66	34,211	19710	8392	2.35	0.58	0.25	674
M. Bouzel. (5005)	138	88,384	22765	8504	1.77	0.26	0.10	2012
Total	485	388,900	101778					

Table A13.16: DISTRICT: NABEUL
MAIN SUBSTATION: KORBA

Feeder	MV/LV Substations	Length (km)	ΣPinst (kVA)	P max (kVA)	ΣPinst / P max	ΣPinst / Length (kVA/m)	P max / Length (kVA/m)	Pinst*Length (kVA*km)
Dressen (1301)	70	79,834	9539	2161	4.41	0.12	0.03	761
Nazraa (1302)	90	62,465	14697	10195	1.44	0.23	0.16	918
Korba (1303)	25	11,510	6275	2838	2.21	0.54	0.25	72
Kelibia (1304)	229	227,157	22265	7074	3.14	0.09	0.03	5058
Haouaria (1305)	190	246,518	20944	6625	3.16	0.08	0.03	5163
Total	604	388,900	101778					

Table A13.17: INTERDEPENDENT CRITERIA
DISTRICT: CITY OF TUNIS

Criterion 1	[0.1]	[1.2]	[2.3]	[3.4]	[4.5]	]5.∞[
Number of feeders	0	10	20	7	3	3
Criterion 2	[0;0.5]	[0.5;1]	[1;1.5]	[1.5;2]	]2;∞[	-
Number of feeders	0	22	15	4	2	-
Criterion 3	[0;0.25]	[0.25;0.5]	[0.5;0.75]	]0.75;∞[	-	-
Number of feeders	9	18	12	4	-	-

Table A13.18: INTERDEPENDENT CRITERIA
DISTRICT: NABEUL

Criterion 1	[0.1]	[1.2]	[2.3]	[3.4]	]4.∞[
Number of feeders	0	4	7	3	2
Criterion 2	[0;0.25]	[0.25;0.5]	[0.5;0.75]	[0.75;1]	-
Number of feeders	6	4	3	2	-
Criterion 3	[0;0.125]	[0.12;0.25]	[0.25;0.37]	-	-
Number of feeders	6	7	2	-	-

17. This gives the following feeders for the districts in question:

District: City of Tunis: Tanit - Imer - B.Miled - BCT - Agricultor - Turquie - El hafir - Daudet - Avenir 1 - Avenir 12 - Charguia.

District: Nabeul: B.Argoub - Mazzraa - Kelibia - Haouaria - Belli.

18. It should be noted that in the case of the District of Nabeul the intersection of the three criteria produces an empty set. Consequently priority has been given to those feeders assumed to have a high loss rate.

CROSS-SECTION CHANGE

Medium Voltage Network

1. Installing a cable with a larger cross section, and thus lower resistance per unit length, reduces losses per unit of power transmitted.

The loss reduction, in kW, is given by the following formula:

$$\text{gain} = 1000 \times L \times (r1 - r2)\ S^2/V^2$$

where:

ri	=	resistance per unit length of conductor i, in Ω/km
S	=	apparent power in kVA
U	=	interphase voltage, in kV

A section should be upgraded when the following is true:

$$\frac{\text{Annual capital investment cost}}{\text{Reduction of Losses [kW]}} < \text{Annual cost of one kW loss}$$

This ratio can be used to establish a threshold output S, beyond which investment is profitable.

Note: since the estimated discount rate is 10%, the annual cost of the works is 10% of the total investment cost.

2. For the overhead network, the total investment cost is the sum of the following costs:

installation of cable with cross section S2
+ removal of cable with cross section S1
+ installing new poles 11/

11/ *On average, one third of the existing poles would be replaced.*

3. For the underground network, the total investment cost is broken down as follows:

laying of cable with cross section S2
+ accessories (junctions and ends)
+ repairs
+ cable trenches

4. In the underground networks, removal of the original cable with cross section S1 is not financially worthwhile, even taking into consideration the possible recovery of copper from the conductors.

5. The following table shows the total investment cost for the various types of network and conductors:

Table A14.1: INVESTMENT COSTS FOR THE VARIOUS CONDUCTOR TYPES

New cable		Investment cost
Low voltage network		
	35² Alu	7.12 TD/m
	70² Alu	8.67 TD/m
Medium voltage network		
Overhead lines	54.6 Alm	5805 TD/km
	148.1 Alm	9670 TD/km
Underground cables	240² Alu	64592 TD/km

6. When the diameter of the cable is doubled, the strength of the current in any given section is halved, the losses for each line are divided by four, and total losses are therefore divided by two. The current strength corresponding to the economic break-even point for this operation is determined by the following formula:

Loss reduction > annual investment/annual cost of one kW of losses, from which we obtain:

$$I^2 > (\text{Annual Investment/annual cost of one kW of losses}) * \frac{2}{3000\,r}$$

r = linear resistance of the cable, in Ω/km

7. From the total number of feeders studied, we select those segments which convey current at a level of intensity greater than, or equal to, the threshold level for reconductoring the section. In each case, the total savings in Tunisian Dinars (TD) can be calculated, since a loss reduction of 1 kW produces an annual saving of TD 360.5 for the medium voltage network (see Annex 2, "Calculation of Losses").

Thus, for each segment, and then for each outgoing feeder, the immediate rate of return (IRR) can be calculated. It is defined as follows:

$$TRI = \frac{\text{Discounted annual savings in TD}}{\text{Total investment cost in TD}}$$

For each outgoing feeder, the results are as follows:

Table A14.2: RECONDUCTORING OF THE HAOURIA OUTGOING HV FEEDER (DISTRICT OF NABEUL)

P (kW)	Length (m)	Sect 1	Sect 2	Loss reduction (W)	Total cost (TD)	IRR
2598	80	22 Cu	148.1 Alm	388	774	18%
2557	80	22 Cu	148.1 Alm	376	774	18%
2557	520	22 Cu	148.1 Alm	2445	5028	18%
2492	810	22 Cu	148.1 Alm	3617	7833	17%
2285	1540	22 Cu	148.1 Alm	5782	14892	14%
2235	900	22 Cu	148.1 Alm	3233	8703	13%
2026	430	22 Cu	148.1 Alm	1269	4158	11%
	4360			17111	42161	15%

Table A14.3: RECONDUCTORING OF THE BELLI OUTGOING MV FEEDER (DISTRICT OF NABEUL)

P (kW)	Length (m)	Sect 1	Sect 2	Loss reduction (W)	Total cost (TD)	IRR
4573	80	17 Cu	148.1 Al	1607	774	75%
4507	130	17 Cu	148.1 Al	2536	1257	73%
4446	140	17 Cu	148.1 Al	2658	1354	71%
4446	670	17 Cu	148.1 Al	12720	6479	71%
4427	280	17 Cu	148.1 Al	5270	2708	70%
4349	260	17 Cu	148.1 Al	4723	2514	68%
4310	610	17 Cu	148.1 Al	10883	5899	67%
4271	310	17 Cu	148.1 Al	5431	2998	65%
4232	230	17 Cu	148.1 Al	3956	2224	64%
3533	80	17 Cu	148.1 Al	959	774	45%
3533	370	17 Cu	148.1 Al	4436	3578	45%
3494	670	17 Cu	148.1 Al	7856	6479	44%
3302	270	17 Cu	148.1 Al	2827	2611	39%
3263	310	17 Cu	148.1 Al	3170	2998	38%
3244	220	17 Cu	148.1 Al	2224	2127	38%
3205	410	17 Cu	148.1 Al	4045	3965	37%
3205	200	17 Cu	148.1 Al	1973	1934	37%
3168	720	17 Cu	148.1 Al	6940	6962	36%
3149	400	17 Cu	148.1 Al	3810	3868	36%
2843	550	29 Cu	148.1 Al	2136	5319	14%
2715	840	29 Cu	148.1 Al	2975	8123	14%
2559	810	17 Cu	148.1 Al	5094	7833	23%
2438	140	29 Cu	148.1 Al	400	1354	11%
2316	280	29 Cu	148.1 Al	722	2708	10%
	8980			99351	86837	41%

Table A14.4: RECONDUCTORING OF THE LAKMES OUTGOING MV FEEDER (DISTRICT OF SILIANA)

r (kW)	Length (m)	Sect 1	Sect 2	Loss reduction (W)	Total cost (TD)	IRR
6168	2430	54 Alm	148.1 Alm	42855	23498	66%
6045	450	54 Alm	148.1 Alm	7623	4352	63%
5807	860	75 Alm	148.1 Alm	7588	8316	33%
4865	280	75 Alm	148.1 Alm	1734	2708	23%
4855	1000	75 Alm	148.1 Alm	6168	9670	23%
4836	750	75 Alm	148.1 Alm	4590	7253	23%
4797	540	75 Alm	148.1 Alm	3251	5222	22%
4782	860	75 Alm	148.1 Alm	5146	8316	22%
4772	1390	75 Alm	148.1 Alm	8283	13441	22%
4741	80	75 Alm	148.1 Alm	471	774	22%
4739	1790	75 Alm	148.1 Alm	10519	17309	22%
4711	80	75 Alm	148.1 Alm	465	774	22%
4708	660	75 Alm	148.1 Alm	3828	6382	22%
4708	140	75 Alm	148.1 Alm	812	1354	22%
4708	90	75 Alm	148.1 Alm	522	870	22%
4439	1150	75 Alm	148.1 Alm	5929	11121	19%
4210	500	75 Alm	148.1 Alm	2319	4835	17%
4190	650	75 Alm	148.1 Alm	2986	6286	17%
4115	150	75 Alm	148.1 Alm	665	1451	17%
4112	440	75 Alm	148.1 Alm	1770	3868	16%
2775	130	22 Cu	148.1 Alm	720	1257	21%
2760	390	22 Cu	148.1 Alm	2136	3771	20%
2663	160	22 Cu	148.1 Alm	816	1547	19%
2563	80	22 Cu	148.1 Alm	378	774	18%
2544	300	22 Cu	148.1 Alm	1396	2901	17%
2544	600	22 Cu	148.1 Alm	2792	5802	17%
2396	5580	22 Cu	148.1 Alm	23036	53959	15%
2296	7800	22 Cu	148.1 Alm	29569	75426	14%
2296	200	22 Cu	148.1 Alm	758	1934	14%
	29490			121572	145147	30%

Low Voltage Network

8. In order to evaluate the rate of technical losses on STEG's low voltage distribution network, losses were calculated for a number of low voltage outgoing feeders that were representative of the networks in each district selected for the study. As these districts themselves were characteristic and representative of Tunisian distribution networks, one can then determine the overall loss rate on the low voltage network.

Calculation of Losses on an Outgoing LV Feeder:

9. For these calculations, the following assumptions were made:

- the load is evenly distributed over the length of the outgoing feeder;
- losses in consumer connections were not taken into account.

10. If we know the power demand in the outgoing feeder and the distribution mode (three-phase or single-phase, L1 or L2, i.e, 380 V or 220 V), the following values can be determined successively:

- peak load percentage (i_{seg});
- intensity of current transmitted (I_{seg});
- losses ($Loss_{seg}$) for each segment; then
- loss rate for the outgoing feeder (% Loss)

by means of the following equations:

$$i_{seg} = (I/L) \times l_{seg}$$

$$Loss_{seg} = r_{seg}\, l_{seg}\, (I_{seg})^2$$

$$\%\ Loss = \Sigma\, Loss_{seg}/P_{max}$$

in which:

I = current intensity in the outgoing feeder, recorded at the MV/LV substation (A)

L = total length of outgoing feeder (km)

l_{seg} = length of segment (km)

r_{seg} = resistance per unit length of the segment (Ω/km)

P_{max} = power demand recorded at the outgoing feeder bay (kW).

X = Cost of network losses in TD/kW

Y = Annual investment cost in TD/km

And thus:

$$S \geq U\sqrt{\left[\frac{Y}{X \cdot 1000 \cdot (r1 - r2)}\right]}$$

11. This value is called the "threshold power," since it marks the break-even point for investment.

12. It should be noted that, since the estimated discount rate is 10%, the annual cost of the works is 10% of the total investment cost.

13. The following tables can be constructed:

Table A14.5: RECONDUCTORING INTO 35² ALU - THREE-PHASE NETWORK (B2)

Original cross-section	Threshold power (kVA)	Threshold current strength (A)
29² Alu	33.29	50.58
16² Alu	13.78	20.93
40/10 Cu	19 13	29.07
30/10 Cu	11.00	16.72
17.8² Cu	37.18	56.48
10² Cu	14.81	22.50
6² Cu	9.76	14.82

Table A14.6: RECONDUCTORING INTO 70² ALU - THREE-PHASE NETWORK (B2)

Original cross-section	Threshold power (kVA)	Threshold current strength (A)
50² Alu	37.34	56.73
40² Alu	27.26	41.42
38² Alu	25.73	39.09
35² Alu	23.61	35.87
29² Alu	19.86	30.17
16² Alu	12.78	19.42
40/10 Cu	15.74	23.91
30/10 Cu	10.80	16.40
17.8² Cu	20.46	31.09
10² Cu	13.44	20.42
6² Cu	9.79	14.88

14. In certain cases, it is planned to double the diameter of the cable (first section to 70²):

Conversion to 70^2 ------> 2×70^2 : I threshold = 41.41 A

15. The mission observed that in rural areas like Siliana the monophase network is generally correctly structured and has a low loss rate. Consequently, no reinforcement is planned for the single-phase network in this area.

Calculation of Gain

16. From the sample of feeders studied, those segments of outgoing feeders transmitting power equal to or greater than the most cost-effective threshold level for reinforcement are selected. Likewise, in each case, the savings in TD to be derived from this reinforcement are calculated, on the assumption that a 1 kW reduction in losses corresponds to a saving of TD 471.4 (see "Calculation of Losses"). The immediate rate of return (IRR) is then calculated for each section and feeder, in accordance with the following:

$$\text{IRR} = \frac{\text{Projected savings in TD}}{\text{Total investment cost in TD}}$$

Thus, once the break-even point has been reached for the two cross sections (35^2 al and 70^2 al), the option providing the higher IRR for the section is selected. Moreover, by classifying the outgoing feeders in descending order of IRR, a schedule of work can be prepared that spaces the work to be done over time. In effect, priority will be given to the feeders with the highest IRRs. This method of calculation also enables the loss rate subsequent to reinforcement to be determined for each outgoing feeder, together with the new loss rate for the district as a whole.

Results

17. The results per outgoing feeder for the low voltage network are as follows, when we apply the method and calculations defined in Annex 3:

Table A14.7: RECONDUCTORING OF THE EL DJAZIRA OUTGOING LV FEEDER (TUNIS CITY DISTRICT)

I (A)	Length (m)	Sect 1	Sect 2	Loss reduction (W)	Total cost (TD)	IRR
63.00 27.95	90 10	70^2 Alu 6^2 Alu	2*70^2 Alu 35^2 Alu	287 54	780 71	17% 36%
	100			341	851	19%

Table A14.8: RECONDUCTORING OF THE EZZITOUNA OUTGOING LV FEEDER (TUNIS CITY DISTRICT)

I (A)	Length (m)	Sect 1	Sect 2	Loss reduction (W)	Total cost (TD)	IRR
235.00 47.50	10 50	70^2 70^2	2*70^2 2*70^2	497 80	87 434	270% 12%
	60			577	521	52%

Tableau A14.9: RECONDUCTORING OF THE ONAS OUTGOING LV FEEDER
(DISTRICT OF EZZAHRA)

I (A)	Length (m)	Sect 1	Sect 2	Loss reduction (W)	Total cost (TD)	IRR
76.00′ 68.92 17.47	60 45 20	70² Alu 70² Alu 30/10 Cu	2*70² Alu 70² Alu 35² Alu	279 230 33	520 390 142	25% 28% 11%
	125			542	1052	24%

Table A14.10: RECONDUCTORING OF THE INDEPENDANCE OUTGOING LV FEEDER
(DISTRICT OF EZZAHRA)

I (A)	Length (m)	Sect 1	Sect 2	Loss reduction (W)	Total cost (TD)	IRR
116.00 59.07 51.86 43.22 33.14 20.07	75 25 30 35 45 30	70² Alu 16² Alu 16² Alu 16² Alu 16² Alu 16² Alu	2*70² Alu 70² Alu 70² Alu 70² Alu 70² Alu 70² Alu	812 425 394 319 241 59	650 217 260 303 390 260	59% 93% 71% 50% 29% 11%
	240			2250	2080	51%

Ezzahra District, Ghandi outgoing feeder: no reconductoring.

Table A14.11: RECONDUCTORING OF THE KAHENA OUTGOING FEEDER
(DISTRICT OF EZZAHRA)

I (A)	Length (m)	Sect 1	Sect 2	Loss reduction (W)	Total cost (TD)	IRR
38.48 59.00	20 20	35² Alu 70² Alu	70² Alu 2*70² Alu	42 56	173 173	12% 15%
	40			98	346	13%

Tabl A14.12: RECONDUCTORING OF THE ECART NORD A1 OUTGOING LV FEEDER (DISTRICT OF NABEUL)

I (A)	Length (m)	Sect 1	Sect 2	Loss reduction (W)	Total cost (TD)	IRR
80.48 65.88 47.85 31.07	125 110 270 150	38² Alu 38² Alu 38² Alu 17.8² Alu	70² Alu 70² Alu 70² Alu 70² Alu	975 575 744 276	1084 954 2341 1301	42% 28% 15% 10%
	655			2570	5680	21%

Table A14.13: RECONDUCTORING OF THE ECART NORD A2 OUTGOING LV FEEDER (DISTRICT OF NABEUL)

I (A)	Length (m)	Sect 1	Sect 2	Loss reduction (W)	Total cost (TD)	IRR
84.52 72.09 37.29	90 220 50	50² Alu 50² Alu 40/10 Cu	70² Alu 70² Alu 70² Alu	367 653 224	780 1907 434	22% 16% 24%
	360			1244	3121	19%

Table A14.14: RECONDUCTORING OF THE ECART NORD A3 OUTGOING LV FEEDER (DISTRICT OF NABEUL)

I (A)	Length (m)	Sect 1	Sect 2	Loss reduction (W)	Total cost (TD)	IRR
53.12 31.52	370 180	29² Alu 29² Alu	70² Alu 70² Alu	2109 361	3208 1561	31% 11%
	550			2470	4769	24%

Tableau A14.15: RECONDUCTORING OF THE ECART NORD A4 OUTGOING FEEDER (DISTRICT OF NABEUL)

I (A)	Length (m)	Sect 1	Sect 2	Loss reduction (W)	Total cost (TD)	IRR
96.88	120	70² Alu	2*70² Alu	906	1040	41%
82.88	160	70² Alu	2*70² Alu	884	1387	30%
28.02	480	40/10 Cu	70² Alu	1212	4162	14%
	760			3002	6589	21%

Table A14.16: RECONDUCTORING OF THE KAOUNIA LV OUTGOING FEEDER (DISTRICT OF NABEUL)

I (A)	Length (m)	Sect 1	Sect 2	Loss reduction (W)	Total cost (TD)	IRR
122.00	35	70² Alu	2*70² Alu	419	303	65%
106.60	50	35² Alu	70² Alu	812	434	88%
101.38	90	29² Alu	70² Alu	1869	780	113%
44.45	60	29² Alu	70² Alu	239	520	22%
51.70	40	40/10 Cu	70² Alu	344	347	47%
43.57	40	40/10 Cu	70² Alu	244	347	33%
29.05	110	40/10 Cu	70² Alu	297	954	15%
	425			4226	3685	54%

Table A14.17: RECONDUCTORING OF THE KARSOLINE OUTGOING SINGLE-PHASE LV FEEDER (DISTRICT OF NABEUL)

I (A)	Length (m)	Sect 1	Sect 2	Loss reduction (W)	Total cost (TD)	IRR
95.00	100	35²	70²	430	867	23%
73.88	120	35²	70²	312	1040	13%
34.01	70	6²	35²	186	498	18%
	290			928	2405	18%

TRANSFORMER OPERATION IN THE HV/MV SUBSTATIONS

Table A15.1: LIST OF SUBSTATIONS FOR WHICH IT IS MORE ECONOMICAL TO PUT ONLY ONE HV/MV TRANSFORMER INTO SERVICE, SWITCHING OFF THE SECOND TRANSFORMER (1989 DATA)

Substation	MVA Equipment	MW Ppeak	MVA Ppeak	Pcore kW	Pjoule kW	Annual Saving TD	Annual Gain MWh
Grombalia	2*40	16.0	17.7	25.3	195	4670	140
M. Jemil	2*40	19.5	21.6	25.3	195	2460	100
O. Zergua	2*40	16.0	17.7	25.3	195	4670	140
Jendouba	2*40	17.0	18.8	25.3	195	4080	130
Ouesiatia	2*30	15.0	16.6	25.0	160	3280	113
Zahrouni 90/10 kV	2*30	13.5	15.0	21.0	160	2890	98
Sidi Mansour	2*40	16.0	17.7	26.6	195	5130	151
Zarzis	2*40	13.0	14.4	34.0	195	9350	243
Zahrouni 90/30 kV	2*40	19.5	21.6	26.0	195	2700	128
Kairouan	2*40	11.0	12.2	25.3	195	7030	182
Tunis Center 90/10 kV	2*40	21.0	23.3	25.3	195	1340	80
Tunis Nord 90/10 kV	2*30	19.5	21.6	29.0	160	720	76
Mdhilla	2*40	16.0	17.7	34.0	195	7820	215
Total						56140	1796

GUIDE FOR PREPARING MAINTENANCE PROCEDURES

General: justification for maintenance operations in an electricity system

1. The purpose of maintenance operations is to maintain the power system in good condition so as to guarantee:

- the safety of personnel;
- proper operation of the equipment.

Personnel safety

2. The aim here is to reduce the possibility of exposing the public and the operating personnel to electrical risks. Electrical equipment is initially designed to conform to safety regulations; it is up to the distributor to ensure that it continues to do so throughout its useful life.

Proper operation of the equipment

3. This consists of reducing the risks of equipment breakdowns that could lead to interruptions in supply. These failures could be the result of:

- equipment working improperly as a result of age, wear, etc.;
- specific environmental conditions: pollution, corrosion, animals;
- exceptional circumstances (atmospheric conditions, damage caused by third parties, vandalism).

4. These objectives can be achieved through activities ranging from monitoring the equipment to replacing it, and encompasses all stages of maintenance.

5. It is not easy to define a maintenance policy since it basically involves selecting a series of measures in a context of multiple contradictory constraints.

6. It is obvious, for example, that a maintenance policy that guaranteed total service reliability by eliminating all network problems would be economically harmful, as would a very limited and timid maintenance policy, due to its effects on service continuity. A maintenance policy is therefore a

reasonable compromise between "doing everything" and "intervening only where and when necessary, just before the incident." This compromise consists in finding a balance between the economic cost of the measures taken and the cost for all equipment breakdowns.

Bases of a maintenance policy

7. The establishment of an appropriate maintenance policy should follow the following theoretical diagram:

Information ----> choice of actions----> actions----> validation.

8. An initial diagnostic analysis of the equipment should be made, to evaluate *a priori* the effectiveness of the policies selected, followed by an *a posteriori* validation of the actions that have been taken. However, this theoretical approach must be tempered by pragmatism in light of the operators' experience, since very often it is hard to determine the qualitative improvement to equipment and it can take several years to evaluate a maintenance policy.

Information systems

9. The prerequisite for all maintenance operations is the gathering of relevant data. As a first step this requires a diagnostic analysis of the equipment to provide data on the physical characteristics of system components, their location and age, and the sequence of events that may have affected their operation. It also involves preparing cartographic surveys of all or part of the electric power system, with permanent flagging of defects and incidents.

10. This information system must also make special provision for the upward flow of data from the operators: deficiencies detected during normal operations, searches for defects, emergency repairs, and maintenance work. In recording this information, duplication should be avoided; there must be one file, and only one, for each category of equipment -- for example, one file for each MV feeder, and so on.

11. Another very important source of data is comprehensive analysis of all incidents and defects that affect the components of the electric system, in order to understand their causes and, if possible, draw lessons for the future, especially in regard to decisions to be taken in similar conditions or relating to identical components.

Maintenance Criteria

12. A maintenance policy is based on observing a number of requirements.

(a) Regulatory aspects. These generally involve observing safety regulations, for example, minimum distances to maintain between conductors and the ground, between conductors and buildings, and maximum grounding resistances.

Verifying that equipment conforms to these safety regulations is an important part of maintenance activities. This verification will be performed on a case-by-case basis as maintenance work is done.

(b) Service continuity imperatives. These are expressed in the form of various indicators, such as the number of MV feeders, the number of permanent defects per 100 km, amount of energy unsupplied as the result of a breakdown, etc.

If the values of these indicators exceed predetermined thresholds, maintenance operations can be planned at the time the problems occur.

(c) Preventive maintenance. This is generally based on maintenance schedules recommended by equipment manufacturers, but also, and particularly, on the experience the operators acquire by operating and maintaining the equipment.

(d) Economic requirements. Defining a maintenance policy, as already noted, is a compromise between "doing everything" and very selective intervention just before the failure or breakdown. This compromise reflects a priority ranking of the various actions (which the data collected will suggest) using a cost/benefit method, in light of the savings to be expected from improvements in the continuity of supply and in productivity following a reduction in the number of failures and, hence, in the number of emergency repairs.

Maintenance program

General

13. A multiannual maintenance program, including actions by category, should be prepared in light of the preceding considerations and the resources available.

14. This program must also be consistent with investment programs that cover equipment rehabilitation and reinforcement, to avoid redundancy in maintenance actions or in the use of resources.

15. The program will be established according to equipment type, since it is impossible to establish maintenance rules valid for all the components of an electricity system. In practice the frequency of incidents varies from one piece of equipment to another in light of:

(a) the initial uneven quality of the equipment;

(b) the variety of external constraints;

(c) the uneven quality of previous maintenance work on the equipment.

16. The scope of the work to be planned will vary in light of the information available and the kind of equipment involved, ranging from occasional visits to routine maintenance, and including regular visits and light maintenance as and when necessary.

MV overhead network

17. Maintenance operations on this category of structures should not be routine. They will be undertaken on the basis of the following information:

(a) information supplied by operators. These are the specific problems detected by operating personnel. These deficiencies should be located on a map and attended to very rapidly. When problems the operators have identified are attended to promptly, the operators are encouraged to continue reporting problems and the information improves, both in quality and in quantity;

(b) overall analysis of incidents, which enables the detection of weak points to be monitored and, thus, helps determine general maintenance guidelines for each type of equipment;

(c) routine line inspections, as far as possible by helicopter at intervals of four years. The frequency of inspections could be adjusted in light of the number of failures per MV feeder. The inspections will serve to identify irregularities, locations where pruning is needed, and other weak spots so that the amount of work needed can be quantified. Repairs should be begun immediately following the inspections, as should pruning;

(d) occasional visits, at the request of the operators to confirm or deny the existence of less obvious problems on the network.

MV equipment

18. Overhead break switch: maintenance will be performed following line inspections. This should as far as possible be hot-line maintenance.

LV overhead network

19. No routine equipment inspection. Occasional inspections will be scheduled to vulnerable parts of the network known to the operators or identified by the statistical record on incidents. The resulting maintenance operations will be economically justified and assigned a priority ranking according to the savings expected.

Underground MV/LV network

20. No preventive maintenance is recommended.

Measurement of earthing quality

21. The frequency of measurements will vary according to the zone and equipment. The following intervals could be envisaged:

(a) HV/MV substations: annually

(b) overhead MV network:

. break switches: every 5 years

. poles: every 10 years

. surge arresters: every 10 years

(c) MV/LV substations:

. grounding connections: every 5 years

. neutral wire grounding: every 10 years.

MV/LV substations

22. The mission recommends:

(a) a routine inspection every five years to take measurements of earthing quality. However, the inspection schedule should be adjusted to the schedule of other actions in the substations, such as redistribution of the transformers, replacement of equipment, and operating maneuvers;

(b) occasional inspections:

. when problems occur;

. in specific cases known to the operators (substations along the coast, pollution, humidity).

These visits will lead to two kinds of maintenance:

. light maintenance performed at the time of, or right after, the visit;

. planned maintenance following technical and economic justification.

Main substations

23. Routine maintenance will be performed on these, firstly because of their sensitivity and the difficulty of calculating the probability of breakdowns, and secondly because of the disproportionate economic consequences of incidents that may affect them, when compared to the cost of maintaining them. However, the maintenance intervals should change in light of equipment improvements and operator experience. One can expect:

(a) a monthly inspection to verify:

. the overall good condition of the equipment: HV/MV transformer, remote control equipment, capacitors, MV breakers;

. the overall good condition of the automatic devices;

- the operating records of the breakers and reclosers;
- the indicator readings;
- lighting, heating and air conditioning;
- the condition of the premises.

(b) routine maintenance:

- breakers and their associated equipment, every 18 months for equipment that is insulated in oil;
- operation of capacitor banks, every 18 months:
- capacitors
  - capacitor batteries, annually;
  - capacitor bank break switches, at the same time as the capacitor breaker, in other words, every 18 months for equipment that is insulated in oil.

ENERGY SECTOR MANAGEMENT ASSISTANCE PROGRAMME

COMPLETED ACTIVITIES

Country	*Activity*	*Date*	*Number*
	SUB-SAHARAN AFRICA (AFR)		
Africa Regional	Anglophone Africa Household Energy Workshop	07/88	085/88
	Regional Power Seminar on Reducing Electric Power System Losses in Africa	08/88	087/88
	Institutional Evaluation of EGL	02/89	098/89
	Biomass Mapping Regional Workshops	05/89	--
	Francophone Household Energy Workshop	08/89	103/89
	Interafrican Electrical Engineering College: Proposals for Short- and Long-Term Development	03/90	112/90
	Biomass Assessment and Mapping	03/90	--
Angola	Energy Assessment	05/89	4708-ANG
	Power Rehabilitation and Technical Assistance	10/91	142/91
Benin	Energy Assessment	06/85	5222-BEN
Botswana	Energy Assessment	09/84	4998-BT
	Pump Electrification Prefeasibility Study	01/86	047/86
	Review of Electricity Service Connection Policy	07/87	071/87
	Tuli Block Farms Electrification Study	07/87	072/87
	Household Energy Issues Study	02/88	--
	Urban Household Energy Strategy Study	05/91	132/91
Burkina Faso	Energy Assessment	01/86	5730-BUR
	Technical Assistance Program	03/86	052/86
	Urban Household Energy Strategy Study	06/91	134/91
Burundi	Energy Assessment	06/82	3778-BU
	Petroleum Supply Management	01/84	012/84
	Status Report	02/84	011/84
	Presentation of Energy Projects for the Fourth Five-Year Plan (1983-1987)	05/85	036/85
	Improved Charcoal Cookstove Strategy	09/85	042/85
	Peat Utilization Project	11/85	046/85
	Energy Assessment	01/92	9215-BU
Cape Verde	Energy Assessment	08/84	5073-CV
	Household Energy Strategy Study	02/90	110/90
Comoros	Energy Assessment	01/88	7104-COM
Congo	Energy Assessment	01/88	6420-COB
	Power Development Plan	03/90	106/90
Côte d'Ivoire	Energy Assessment	04/85	5250-IVC
	Improved Biomass Utilization	04/87	069/87
	Power System Efficiency Study	12/87	--
	Power Sector Efficiency Study (French)	02/92	141/91
Ethiopia	Energy Assessment	07/84	4741-ET
	Power System Efficiency Study	10/85	045/85
	Agricultural Residue Briquetting Pilot Project	12/86	062/86
	Bagasse Study	12/86	063/86
	Cooking Efficiency Project	12/87	--

Country	*Activity*	*Date*	*Number*
Gabon	Energy Assessment	07/88	6915-GA
The Gambia	Energy Assessment	11/83	4743-GM
	Solar Water Heating Retrofit Project	02/85	030/85
	Solar Photovoltaic Applications	03/85	032/85
	Petroleum Supply Management Assistance	04/85	035/85
Ghana	Energy Assessment	11/86	6234-GH
	Energy Rationalization in the Industrial Sector	06/88	084/88
	Sawmill Residues Utilization Study	11/88	074/87
Guinea	Energy Assessment	11/86	6137-GUI
Guinea-Bissau	Energy Assessment	08/84	5083-GUB
	Recommended Technical Assistance Projects	04/85	033/85
	Management Options for the Electric Power and Water Supply Subsectors	02/90	100/90
	Power and Water Institutional Restructuring (French)	04/91	118/91
Kenya	Energy Assessment	05/82	3800-KE
	Power System Efficiency Study	03/84	014/84
	Status Report	05/84	016/84
	Coal Conversion Action Plan	02/87	--
	Solar Water Heating Study	02/87	066/87
	Peri-Urban Woodfuel Development	10/87	076/87
	Power Master Plan	11/87	--
Lesotho	Energy Assessment	01/84	4676-LSO
Liberia	Energy Assessment	12/84	5279-LBR
	Recommended Technical Assistance Projects	06/85	038/85
	Power System Efficiency Study	12/87	081/87
Madagascar	Energy Assessment	01/87	5700-MAG
	Power System Efficiency Study	12/87	075/87
Malawi	Energy Assessment	08/82	3903-MAL
	Technical Assistance to Improve the Efficiency of Fuelwood Use in the Tobacco Industry	11/83	009/83
	Status Report	01/84	013/84
Mali	Energy Assessment (French)	11/91	8423-MLI
Islamic Republic of Mauritania	Energy Assessment	04/85	5224-MAU
	Household Energy Strategy Study	07/90	123/90
Mauritius	Energy Assessment	12/81	3510-MAS
	Status Report	10/83	008/83
	Power System Efficiency Audit	05/87	070/87
	Bagasse Power Potential	10/87	077/87
Mozambique	Energy Assessment	01/87	6128-MOZ
	Household Electricity Utilization Study	03/90	113/90
Niger	Energy Assessment	05/84	4642-NIR
	Status Report	02/86	051/86
	Improved Stoves Project	12/87	080/87
	Household Energy Conservation and Substitution	01/88	082/88
Nigeria	Energy Assessment	08/83	4440-UNI
Rwanda	Energy Assessment	06/82	3779-RW
	Energy Assessment (English and French)	07/91	8017-RW
	Status Report	05/84	017/84
	Improved Charcoal Cookstove Strategy	08/86	059/86
	Improved Charcoal Production Techniques	02/87	065/87

Country	*Activity*	*Date*	*Number*
Rwanda	Commercialization of Improved Charcoal Stoves and Carbonization Techniques Mid-Term Progress Report	12/91	141/91
SADCC	SADCC Regional Sector: Regional Capacity-Building Program for Energy Surveys and Policy Analysis	11/91	--
Sao Tome and Principe	Energy Assessment	10/85	5803-STP
Senegal	Energy Assessment	07/83	4182-SE
	Status Report	10/84	025/84
	Industrial Energy Conservation Study	05/85	037/85
	Preparatory Assistance for Donor Meeting	04/86	056/86
	Urban Household Energy Strategy	02/89	0[illegible]/89
Seychelles	Energy Assessment	01/84	4[illegible]-SEY
	Electric Power System Efficiency Study	08/84	021/84
Sierra Leone	Energy Assessment	10/87	6597-SL
Somalia	Energy Assessment	12/85	5796-SO
Sudan	Management Assistance to the Ministry of Energy and Mining	05/83	003/83
	Energy Assessment	07/83	4511-SU
	Power System Efficiency Study	06/84	018/84
	Status Report	11/84	026/84
	Wood Energy/Forestry Feasibility	07/87	073/87
Swaziland	Energy Assessment	02/87	6262-SW
Tanzania	Energy Assessment	11/84	4969-TA
	Peri-Urban Woodfuels Feasibility Study	08/88	086/88
	Tobacco Curing Efficiency Study	05/89	102/89
	Remote Sensing and Mapping of Woodlands	06/90	--
	Industrial Energy Efficiency Technical Assistance	08/90	122/90
Togo	Energy Assessment	06/85	5221-TO
	Wood Recovery in the Nangbeto Lake	04/86	055/86
	Power Efficiency Improvement	12/87	078/87
Uganda	Energy Assessment	07/83	4453-UG
	Status Report	08/84	020/84
	Institutional Review of the Energy Sector	01/85	029/85
	Energy Efficiency in Tobacco Curing Industry	02/86	049/86
	Fuelwood/Forestry Feasibility Study	03/86	053/86
	Power System Efficiency Study	12/88	092/88
	Energy Efficiency Improvement in the Brick and Tile Industry	02/89	097/89
	Tobacco Curing Pilot Project	03/89	UNDP Terminal Report
Zaire	Energy Assessment	05/86	5837-ZR
Zambia	Energy Assessment	01/83	4110-ZA
	Status Report	08/85	039/85
	Energy Sector Institutional Review	11/86	060/86
	Power Subsector Efficiency Study	02/89	093/88
	Energy Strategy Study	02/89	094/88
	Urban Household Energy Strategy Study	08/90	121/90
Zimbabwe	Energy Assessment	06/82	3765-ZIM
	Power System Efficiency Study	06/83	005/83
	Status Report	08/84	019/84
	Power Sector Management Assistance Project	04/85	034/85
	Petroleum Management Assistance	12/89	109/89

Country	*Activity*	*Date*	*Number*
Zimbabwe	Power Sector Management Institution Building	09/89	--
	Charcoal Utilization Prefeasibility Study	06/90	119/90
	Integrated Energy Strategy Evaluation	01/92	8768-ZIM

EAST ASIA AND PACIFIC (EAP)

Asia Regional	Pacific Household and Rural Energy Seminar	11/90	--
China	County-Level Rural Energy Assessments	05/89	101/89
	Fuelwood Forestry Preinvestment Study	12/89	105/89
Fiji	Energy Assessment	06/83	4462-FIJ
Indonesia	Energy Assessment	11/81	3543-IND
	Status Report	09/84	022/84
	Power Generation Efficiency Study	02/86	050/86
	Energy Efficiency in the Brick, Tile and Lime Industries	04/87	067/87
	Diesel Generating Plant Efficiency Study	12/88	095/88
	Urban Household Energy Strategy Study	02/90	107/90
	Biomass Gasifier Preinvestment Study Vols. I & II	12/90	124/90
Malaysia	Sabah Power System Efficiency Study	03/87	068/87
	Gas Utilization Study	09/91	9645-MA
Myanmar	Energy Assessment	06/85	5416-BA
Papua New Guinea	Energy Assessment	06/82	3882-PNG
	Status Report	07/83	006/83
	Energy Strategy Paper	--	--
	Institutional Review in the Energy Sector	10/84	023/84
	Power Tariff Study	10/84	024/84
Solomon Islands	Energy Assessment	06/83	4404-SOL
South Pacific	Petroleum Transport in the South Pacific	05/86	--
Thailand	Energy Assessment	09/85	5793-TH
	Rural Energy Issues and Options	09/85	044/85
	Accelerated Dissemination of Improved Stoves and Charcoal Kilns	09/87	079/87
	Northeast Region Village Forestry and Woodfuels Preinvestment Study	02/88	083/88
	Impact of Lower Oil Prices	08/88	--
	Coal Development and Utilization Study	10/89	--
Tonga	Energy Assessment	06/85	5498-TON
Vanuatu	Energy Assessment	06/85	5577-VA
Western Samoa	Energy Assessment	06/85	5497-WSO

SOUTH ASIA (SAS)

Bangladesh	Energy Assessment	10/82	3873-BD
	Priority Investment Program	05/83	002/83
	Status Report	04/84	015/84
	Power System Efficiency Study	02/85	031/85
	Small Scale Uses of Gas Prefeasibility Study	12/88	--

Country	*Activity*	*Date*	*Number*
India	Opportunities for Commercialization of Nonconventional Energy Systems	11/88	091/88
	Maharashtra Bagasse Energy Efficiency Project	05/91	120/91
	Mini-Hydro Development on Irrigation Dams and Canal Drops Vols. I, II and III	07/91	139/91
Nepal	Energy Assessment	08/83	4474-NEP
	Status Report	01/85	028/84
Pakistan	Household Energy Assessment	05/88	--
	Assessment of Photovoltaic Programs, Applications, and Markets	10/89	103/89
Sri Lanka	Energy Assessment	05/82	3792-CE
	Power System Loss Reduction Study	07/83	007/83
	Status Report	01/84	010/84
	Industrial Energy Conservation Study	03/86	054/86
	EUROPE AND CENTRAL ASIA (ECA)		
Portugal	Energy Assessment	04/84	4824-PO
Turkey	Energy Assessment	03/83	3877-TU
	MIDDLE EAST AND NORTH AFRICA (MNA)		
Morocco	Energy Assessment	03/84	4157-MOR
	Status Report	01/86	048/86
Syria	Energy Assessment	05/86	5822-SYR
	Electric Power Efficiency Study	09/88	089/88
	Energy Efficiency Improvement in the Cement Sector	04/89	099/89
	Energy Efficiency Improvement in the Fertilizer Sector	06/90	115/90
Tunisia	Fuel Substitution	03/90	--
Yemen	Energy Assessment	12/84	4892-YAR
	Energy Investment Priorities	02/87	6376-YAR
	Household Energy Strategy Study Phase I	03/91	126/91
	LATIN AMERICA AND THE CARIBBEAN (LAC)		
LAC Regional	Regional Seminar on Electric Power System Loss Reduction in the Caribbean	07/89	--
Bolivia	Energy Assessment	04/83	4213-BO
	National Energy Plan	12/87	--
	National Energy Plan (Spanish)	08/91	131/91
	La Paz Private Power Technical Assistance	11/90	111/90
	Natural Gas Distribution: Economics and Regulation	01/92	125/92
	Prefeasibility Evaluation Rural Electrification and Demand Assessment	04/91	129/91
Chile	Energy Sector Review	08/88	7129-CH
Colombia	Energy Strategy Paper	12/86	--
Costa Rica	Energy Assessment	01/84	4655-CR
	Recommended Technical Assistance Projects	11/84	027/84
	Forest Residues Utilization Study	02/90	108/90

Country	*Activity*	*Date*	*Number*
Dominican Republic	Energy Assessment	05/91	8234-DO
Ecuador	Energy Assessment	12/85	5865-EC
	Energy Strategy Phase I	07/88	--
	Energy Strategy	04/91	--
Haiti	Energy Assessment	06/82	3672-HA
	Status Report	08/85	041/85
Honduras	Energy Assessment	08/87	6476-HO
	Petroleum Supply Management	03/91	128/91
Jamaica	Energy Assessment	04/85	5466-JM
	Petroleum Procurement, Refining, and Distribution Study	11/86	061/86
	Energy Efficiency Building Code Phase I	03/88	--
	Energy Efficiency Standards and Labels Phase I	03/88	--
	Management Information System Phase I	03/88	--
	Charcoal Production Project	09/88	090/88
	FIDCO Sawmill Residues Utilization Study	09/88	088/88
Mexico	Improved Charcoal Production Within Forest Management for the State of Veracruz	08/91	138/91
Panama	Power System Efficiency Study	06/83	004/83
Paraguay	Energy Assessment	10/84	5145-PA
	Recommended Technical Assistance Projects	09/85	--
	Status Report	09/85	043/85
Peru	Energy Assessment	01/84	4677-PE
	Status Report	08/85	040/85
	Proposal for a Stove Dissemination Program in the Sierra	02/87	064/87
	Energy Strategy	12/90	--
Saint Lucia	Energy Assessment	09/84	5111-SLU
St. Vincent and the Grenadines	Energy Assessment	09/84	5103-STV
Trinidad and Tobago	Energy Assessment	12/85	5930-TR

GLOBAL

Energy End Use Efficiency: Research and Strategy	11/89	--
Guidelines for Utility Customer Management and Metering (English and Spanish)	07/91	--
Women and Energy--A Resource Guide The International Network: Policies and Experience	04/90	--
Assessment of Personal Computer Models for Energy Planning in Developing Countries	10/91	--

TUNISIA
TUNISIE

POWER EFFICIENCY STUDY
ETUDE DE L'AMELIORATION DE L'EFFICACITE DU SYSTEME ELECTRIQUE

TRANSMISSION NETWORK OF ELECTRICAL POWER
RESEAU DE TRANSPORT D'ENERGIE ELECTRIQUE

PLANNED *EN PROJET* — EXISTING *EXISTANTES*

ELECTRIC LINES: *LIGNES ELECTRIQUES:*

- 225 kV
- 150 kV
- 90 kV

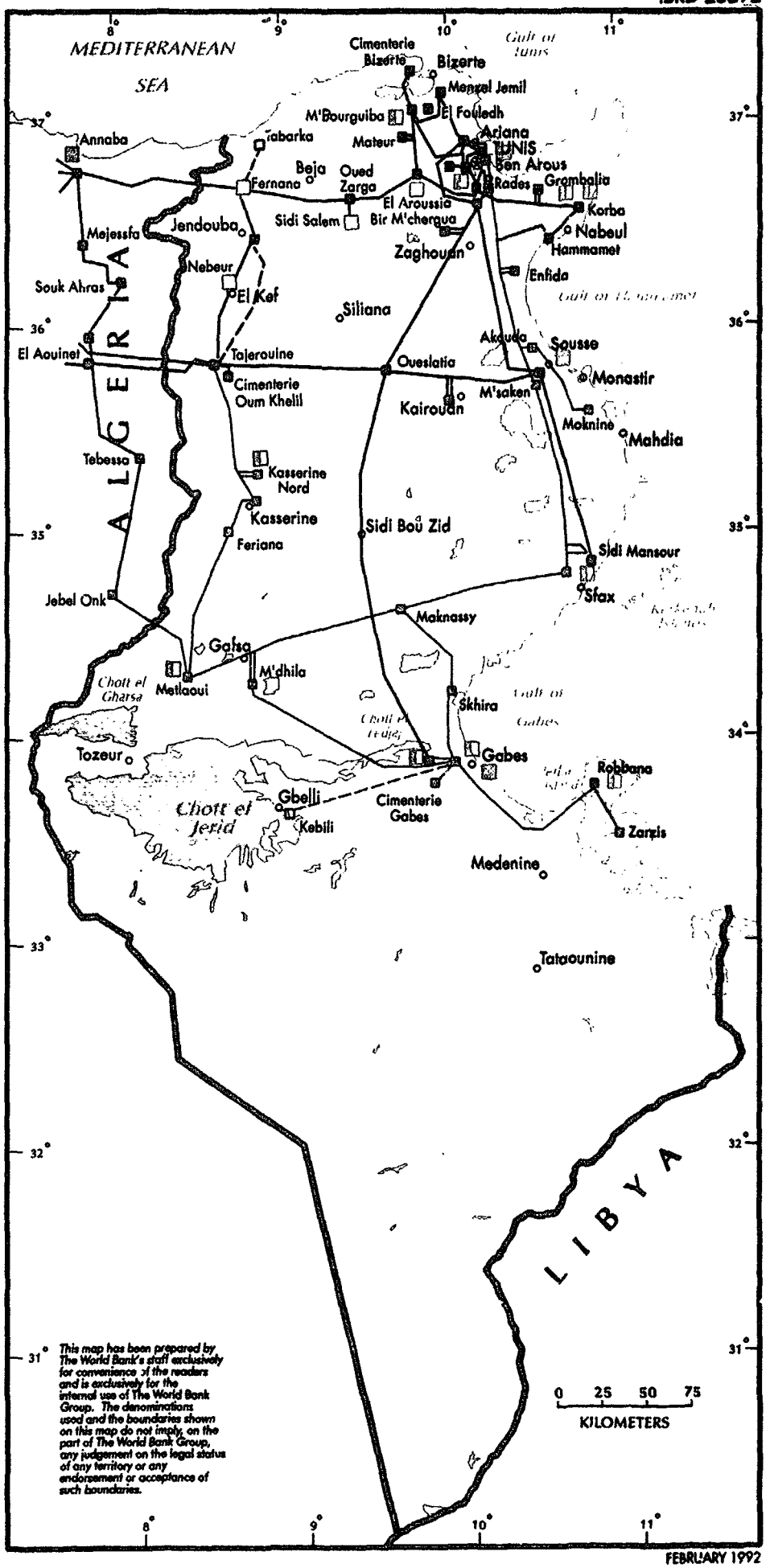
SUBSTATIONS: *POSTES:*

- 225 kV
- 150 kV
- 90 kV

POWER PLANTS: CENTRALES *ELECTRIQUES:*

- THERMAL *THERMIQUE*
- GAS TURBINE *TURBINE A GAZ*
- HYDRO *HYDRAULIQUE*

- SALT LAKES *LACS SALES*
- NATIONAL CAPITAL *CAPITALE DU PAYS*
- INTERNATIONAL BOUNDARIES *FRONTIERES INTERNATIONALE*



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FEBRUARY 1992