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CONVENTIONAL ELECTRICITY IN DJIBOUTI

CHALLENGES AND OPPORTUNITIES FOR THE FUTURE

ENERGY SERVICE

NATIONAL INSTITUTE FOR HIGHER SCIENTIFIC
AND TECHNICAL RESEARCH

VOLUNTEERS IN TECHNICAL ASSISTANCE

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CONVENTIONAL ELECTRICITY IN DJIBOUTI
Challenges and Opportunities for the Future

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TABLE OF CONTENTS

	Page No.
ABSTRACT	v
LIST OF FIGURES	vii
ACKNOWLEDGEMENTS	xi
EXECUTIVE SUMMARY	xiii
RECOMMENDATIONS	xxiii
FUTURE ANALYSIS	xxv
CHAPTER 1. ELECTRICITY SUPPLY SYSTEM	1
General Background	3
Existing Electricity Generation System	4
Electricity End Use	8
Present Tariff Structure	14
Price Structure for Low-Tension Electricity	16
Price Structure for Medium-Tension Electricity	17
Price Structure Overview	21
CHAPTER 2. DEMAND FORECAST AND CAPACITY EXPANSION REQUIREMENTS	23
General Background	25
Demand Forecast for 1985-2000	25
Energy and Demand Forecast for 1985-2000	27
Capacity Expansion Planning Criteria	31
Capacity Expansion Requirements	33
CHAPTER 3. ENERGY CONSERVATION AND LOAD MANAGEMENT POTENTIALS	39
General Background	41
Load Management Technologies	41
Energy Conservation Technologies	42
Load Management	42
System Load Characteristics	43
System Load Impacts	47
Impacts on Generation Expansion Requirements	54
Power Factor Improvement	54
Benefits of a Power Factor Improvement Program	56
Estimated Savings Due to Power Factor Improvement	57
Effects of Power Factor on kVA Demand	60

Energy Conservation 62
Conservation Priorities 62
Impacts of Energy Conservation 67
Interruptible Rates 68
Operating Benefits of Interruptible Loads 68
Short-Range Capacity Savings 69
Other Options for Demand Reduction 71
Demand Subscription Service 71
Off-Peak Water Pumping 72
Load Shift Program for Large Customers 74

CHAPTER 4. SUPPLY SCENARIO ANALYSIS 77

General Background 77
Relative Cost of Electricity Production 79
Assumptions for Levelized Cost Calculations 82
Capital Costs 82
Fuel Costs 82
Operational and Maintenance Costs 84
Other Assumptions 84
Supply Scenario Analysis 84
Scenario #1: All Oil-Fired Generation 84
Scenario #2: All New Capacity Based on Geothermal 85
Scenarios #3 and #4: Load Management and Energy Conservation 87
Conclusions 91

GLOSSARY 99

CONVERSION TABLE 105

ABOUT THE AUTHOR 107

ABSTRACT

This report estimates the impacts of energy conservation and load management programs on future electricity demand, capacity planning, and electric prices for the Electricite de Djibouti (EdD) system. Potential changes in customer load levels and demand patterns resulting from the introduction of conservation and load management programs should be an important consideration in electricity demand forecasting and capacity planning. The impacts of these programs and new technologies will affect the levels and patterns of the total energy and capacity demands EdD must satisfy, and the generating capacity to meet those loads.

Specifically, this report quantifies the impacts of demand reduction programs and conservation measures for the 1985-2000 time period in terms of system expansion and revenue requirements. For load management and conservation programs, short-range, medium-range, and long-range "best estimate" scenarios were developed to evaluate the impacts on system capacity and revenue requirements.

LIST OF FIGURES

Ex. 1	EdD Electricity Demand Forecast
Ex. 2	Modified Electricity Demand Forecast
Ex. 3	EdD Peak Demand Forecast
Ex. 4	Modified Peak Demand Forecast
Ex. 5	Potential Peak Demand Reductions Due to Load Management Programs
Ex. 6	Potential Savings From Power Factor Improvement
Ex. 7	Potential Energy Savings from Power Factor Improvement
Ex. 8	Estimated Available Interruptible Loads
Ex. 9	Total Levelized Costs for Scenarios #1, #2, #3 and #4
Ex. 10	Imported Oil Requirements for Electricity Generation
1.1	Locations of Existing EdD Power Generation Sites in Djibouti
1.2	Electric Power Capacity in Djibouti
1.3	Existing Generating Plant Data: Boulaos
1.4	Privately-Owned Electric Generators
1.5	Historical Energy Production, Transmission, and System Loss Data for 1971-1972
1.6	Peak Demand: Monthly Values
1.7	Load Duration Curve for 1983 Electricity Demand
1.8	Electricity Consumption Breakdown for 1978-1981
1.9	1982 Electricity Consumption Breakdown for EdD Internal Market
1.10	Structure of Tariff II
1.11	Structure of Tariff III
1.12	Medium-Tension Electricity Price Structure
1.13	Overview of Electricity Price Structure
2.1	Demand Forecast for Various EdD Service Areas
2.2	Modified Demand Forecast
2.3	Energy Forecasts for 1985-2000
2.4	Historical Energy Production
2.5	Energy Production and Peak Demand Forecast for 1985-2000
2.6	Energy Sales by Load Sector Based on EdD Peak Demand Forecast
2.7	Energy Sales Load Sector Based on Modified Peak Demand Forecast
2.8	Generating Capacity Expansion Requirements and Load Data (Demand Forecast)
2.9	Generating Capacity Expansion Requirements and Load Data (Modified Demand Forecast)
2.10	Generation Expansion for the EdD Load Forecast

2.11 Generation Expansion for the Modified Load Forecast

3.1 Actual Data for 1983 and 1984
3.2 Actual Data for Energy and Temperature Correlation for 1984
3.3 1983 Peak Day Load Factor
3.4 1982 Monthly Peak Day Load Factor
3.5 1982 Monthly Load Factors
3.6 Air Conditioning Loads Available for Control During Peak Month of July
3.7 Increase in Demand Dut to Air Conditioning Loads and Usual System Growth in Demand
3.8 Maximum Possible Demand Reduction Due to Air Conditioning Load Cycling
3.9 Peak Demand Reduction Due to Pre-Cooling
3.10 Impacts of Air Conditioning Load Management Program on Generation Expansion (Demand Forecast)
3.11 Impacts of Air Conditioning Load Management Program on Generation Expansion (Modified Demand Forecast)
3.12 Present Power Factor and Energy Sales by Load Sector
3.13 Estimated Savings Due to Improved Power Factor
3.14 Case Study: Power Factor Improvement
3.15 Electricity Conservation Potential by Load Sector and End Use (Load Sector: Domestic)
3.16 Electricity Conservation Potential by Load Sector and End Use (Load Sector: Commercial and Government)
3.17 Electricity Conservaiton Potential by Load Sector and End Use (Load Sector: Industrial)
3.18 Electricity Conservation Potential by Load Sector and End Use (Load Sector: Miscellaneous Other Large Customers)
3.19 Effects of Interruptible Loads on Reserve Margin Requirements for the EdD System
3.20 Electric Demand Forecast for Water Pumping
3.21 Water Pumping Load Available for Deferral
3.22 Estimated Load Shift and System Peak Reduction for Large Customers

4.1 Fuel Oil Escalation Rates
4.2 Levelized Cost Data for Publicly-Owned Utilities (1990-2020)
4.3 Levelized Cost Analysis for Scenario #1: All Oil-Fired Generation
4.4 Hot Water-Dominated Resource Classification
4.5 Geothermal Sites in Djibouti
4.6 Levelized Cost Analysis for Scenario #2: All Geothermal Generation

4.7 Levelized Cost Analysis for Scenario #3: Load Management, Conservation and Oil-Fired Generation
4.8 Levelized Cost Analysis for Scenario #4: Load Management, Conservation and Geothermal Generation
4.9 Summary of Total Levelized costs for Four Supply Scenarios
4.10 Comparison of Estimated Amount of Oil Import Requirements for Four Supply Scenarios

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EXECUTIVE SUMARY

Over the next two decades, energy policy in the Republic of Djibouti will be dominated by three petroleum-related questions: (1) how to reduce petroleum imports; (2) how to shield the economy from petroleum supply disruptions and price increases; and (3) how to develop acceptable substitutes for petroleum-based products and services. Such issues will have a major impact on the electricity sector as the Electricité de Djibouti (EdD) struggles to reduce its dependence on imported oil. In the Republic of Djibouti, as elsewhere, the financial condition of the electric utility and the global scarcity and expense of new capital will make the transition from petroleum fuels to alternative energy resources long, difficult, and costly. All in all, the 1980s and 1990s promise to be a challenging period for energy planners in the Republic of Djibouti and particularly for EdD.

In formulating system expansion policy, EdD must be guided by two considerations. First, it must balance the nation's interests in growth and development, preservation of environmental quality, and conservation of natural resources. Second, EdD faces an era of limited financial resources. It cannot afford to misallocate these resources or waste them by pursuing unnecessarily capital-intensive energy options that offer only very long-term freedom from imported fuels. Given these considerations, the options that appear most appropriate for Djibouti are energy conservation (increasing the efficiency with which energy is used and eliminating wasteful or unnecessary uses) and limited geothermal resource development.

This report, which is based on an intensive study conducted from June 10 to July 8, 1984, addresses in a preliminary way the implications of implementing current EdD expansion plans for electricity production and use as well as the implications of a shift in emphasis toward the use of alternative resources (geothermal and energy conservation) for the 1985-2000 planning period.

Analysis of electric energy use in the EdD system shows that approximately 99 percent of the utility's sales is in the central system. Therefore, all the analysis reported herein pertains only to the central system of the EdD service area. All analysis was performed based on four electricity supply scenarios for the study period: Scenario #1 assumes all new capacity expansion is based on the current trend of oil-fired generation; Scenario #2 assumes all new generation beyond 1988 is based on small-scale geothermal (5 to 10 megawatts [MW]) resource development; and Scenario #3 and Scenario #4 examine the impact of load management (demand management) and energy conservation programs on Scenario #1 and Scenario #2, respectively.

Based on the results of this study, the following major conclusions can be drawn:

1. Peak demand for the EdD service area from 1983 through 2000 is estimated by EdD to grow at an average annual compound rate of 7.55 percent (see Figure 2.1). Total energy requirements area also anticipated to increase at an average annual compound rate of 9.5 percent through the year 2000.

2. At present, a total of 8 MW of unserved demand (suppressed demand) is estimated to exist in the EdD system due to load shedding during peak hours (see Figure 3.1) and customers waiting for electricity supply. The capacity and energy demand forecasts were developed based on an EdD peak demand forecast and a modified peak demand forecast, which includes suppressed demand of 8 MW.

3. The capacity and energy demand forecasts for the proposed supply scenarios are presented in Figures Ex.1 and Ex.2.

4. The EdD expansion plan does not include any programs for energy conservation, peak demand reduction, system efficiency improvement, loss reduction, or use of alternative renewable resources. A prominent feature of the present expansion plan is the rapid growth in the use of imported oil.

5. Two reserve margin planning criteria have been used to determine future capacity expansion needs: (1) a sufficient margin to allow the loss of the largest generating unit in the EdD system; and (2) an additional 5 percent margin to cover any load forecast error and other uncertainties (see discussion on capacity expansion planning criteria in Chapter 2). Figures Ex.3 and Ex.4 indicate the additional installed capacity requirements for the study period (1985-2000) to meet the above reserve margin criteria.

6. A substantial amount of generation capacity could be either delayed or cancelled if peak reduction and system improvement programs are initiated. Figure Ex.5 indicates both the potential demand reductions for the study period due to load management programs, and the impact of such reductions on generation expansion needs.

7. A preliminary study indicates that a substantial amount of system losses (at present, about 18 percent annually) can be reduced by power factor (PF) improvement in all customer sectors. The potential savings are given in Figure Ex.6 (see Figure 3.13).

   Installation of capacitor banks and inclusion of a power factor penalty in the rate schedule will have the following immediate, positive impacts on the system:

FIGURE EX.1

EdD Electricity Demand Forecast

	1985	1986	1987	1988	1989	1990	1995	2000
Peak Demand (MW)	36.1	39.7	43.3	47.2	51.3	55.3	73.8	98.0
Energy Production (GWh)	174.0	191.2	208.6	227.4	247.1	271.2	374.9	497.9

Source: EdD.

FIGURE EX.2

Modified Electricity Demand Forecast (Includes Unserved Demand)

	1985	1986	1987	1988	1989	1990	1995	2000
Peak Demand (MW)	40.1	48.1	52.4	57.1	62.0	66.8	89.1	118.3
Energy Production (GWh)	193.2	231.7	252.5	275.1	298.7	327.7	452.7	601.0

Source: EdD.

FIGURE EX.3

EdD Peak Demand Forecast

	1985	1986	1987	1988	1989	1990	1995	2000
Peak Demand (MW)	36.1	39.7	43.3	47.2	51.3	55.3	73.8	98.0
Planned Capacity (MW)	48.0	58.0	58.0	58.0	54.2	54.2	49.4	44.6
Reserve Margin Require-ments (%)	38.2	35.2	33.0	30.4	28.3	26.6	21.2	17.2
Additional Capacity Require-ments (MW)	2.0	--	--	3.5	11.6	16.0	40.0	70.5

FIGURE EX.4

Modified Peak Demand Forecast

	1985	1986	1987	1988	1989	1990	1995	2000
Peak Demand (MW)	40.1	48.1	52.4	57.1	62.0	66.8	89.1	118.3
Planned Capacity (MW)	48.0	58.0	58.0	58.0	54.2	54.2	49.4	44.6
Reserve Margin Require-ments (%)	35.0	30.0	28.0	26.0	24.3	23.0	18.4	15.1
Additional Capacity Require-ments (MW)	6.1	4.8	9.1	13.9	22.8	27.9	56.0	91.5

FIGURE EX.5

Potential Peak Demand Reductions Due to Load Management Programs

	1985	1986	1987	1988	1989	1990	1995	2000
Peak Demand Reduction Due to Load Management Programs (MW)	-2.5	-2.8	-3.0	-3.3	-3.6	-3.9	-5.2	-6.7
Installed Capacity Requirement for EdD Forecast (MW)	47.2	50.7	54.3	58.1	62.0	65.9	83.9	107.5
Installed Capacity Requirement For Modified Forecast (MW)	51.1	58.9	63.1	67.1	72.5	77.2	99.0	127.6

FIGURE EX.6

Potential Savings from Power Factor Improvement

	1985	1990	1995	2000
Potential Savings (DF x 10^6)	3075.5	1109.8	1184.6	1405.0

- reduced system losses;
- recovery of transmission and distribution capacity, thus deferring capital expenditures for expansion of the transmission and distribution system; and
- improved voltage regulation.

The maximum savings of PF correction will be realized in the early years due to an improvement of PF in the existing system from 0.65 to 0.9. In the late 1980s, less savings will be realized due to a high overall system PF.

8. Energy conservation measures in domestic, commercial, industrial, and other sectors can reduce overall energy consumption by 5 percent annually during the study period. Figure Ex.7 summarizes the potential energy conservation savings, for domestic, commercial and government, industrial, and other large customers in the EdD system (see Figures 3.15, 3.16, 3.17, and 3.18 for a breakdown by end use of each sector's potential conservation).

9. Interruptible rates can be designed to encourage small customers to install self-generation capacity and large customers to disconnect during peak hours or in emergencies. The estimated available interruptible loads in the EdD system for 1985, 1990, 1995, and 2000 are given in Figure Ex.8.

   The forecasted peak demand can be reduced by dropping interruptible loads. This load management technique can have a significant effect on future capacity expansion needs.

10. The Demand Subscription Service (DSS) program discussed in this report (see pp. 39-40) allows customers to subscribe to a fixed level of kilowatt (kW) demand. The DSS program has the potential of reducing demand during peak hours as much as 1.5 MW during the study period.

11. The load shift program for large customers and the off-peak water pumping program will affect peak demand reduction only during the morning and afternoon peak hours. This program will have very little effect on evening peak reduction. Nonetheless, during the morning and afternoon peak hours, demand reduction can be accomplished by implementing a load shift program.

12. There are several potential geothermal sites in Djibouti that can be developed by 1988/1989 to meet all future electricity demand. Djibouti's geothermal resource is primarily water-dominated. With a few notable exceptions, small-scale commercial (1 to 15 MW) electric systems that use a moderate

FIGURE EX.7

Potential Energy Conservation Savings

Load Sectors	Total Energy Reduction (GWh)		
	Short Range (By 1985)	Medium Range (By 1990)	Long Range (By 1995)
Domestic	- 8.66	-11.66	-16.66
Commercial & Government	- 5.06	-10.16	-12.16
Industrial	- 0.19	- 1.79	- 4.99
Other Large Customers	- 4.8	- 8.7	-10.6
Total	-18.71	-32.31	-44.41

FIGURE EX.8

Estimated Available Interruptible Loads

	1985	1990	1995	2000
Interruptible Loads (MW)	4.5	5.6	7.2	8.5

temperature range resource, 90 degrees - 150 degrees °C (190 degrees - 300 degrees °F), are feasible.

13. To examine the relative cost of electricity supply plans, the following four scenarios were examined as they would affect the price of electricity in future years:

    Scenario #1: All future capacity addition is based on oil-fired generation.

    Scenario #2: All future capacity addition is based on geothermal.

    Scenario #3: Implementation of demand management and energy conservation programs plus oil-fired generation to meet future load growth.

    Scenario #4: Implementation of demand management and energy conservation programs plus geothermal- based capacity development to satisfy future load growth.

    The relative costs of electricity supply for the four scenarios are calculated based on levelized cost methodology. The levelized cost of an electric generating plant is the average cost of electricity produced over the life of the plant. The total cost of electricity generation includes three categories of costs: capital-related expenses; fuel costs; and operation and maintenance (0 & M) costs.

    The total levelized costs for the above four scenarios are summarized in Figure Ex.9.

14. The imported oil requirements for electricity generation for each of the four scenarios are given in Figure Ex.10.

15. Under Scenario #1, escalating fuel (imported oil) costs and the poor performance of oil-fired generating equipment would significantly increase electricity prices in Djibouti during the period 1985-2000. The nation as a whole will be more vulnerable to foreign oil price increases or disruption of supply.

FIGURE EX.9

Total Levelized Costs for Scenarios #1, #2, #3, and #4 ($ x 10^6)

	1985	1986	1987	1988	1989	1990	1995	2000
Scenario #1	8.4 to 10.9	---	4.2 to 5.96	7.0 to 9.1	7.0 to 9.1	7.0 to 9.1	32.2 to 41.9	43.4 to 56.5
Scenario #2	7.45 to 7.74	---	3.75 to 3.93	6.2 to 6.4	6.2 to 6.4	6.2 to 6.4	23.42 to 29.8	38.6 to 40.2
Scenario #3	---	---	---	6.3 to 10.7	15.5 to 19.2	6.08 to 8.48	32.7 to 40.7	46.5 to 57.9
Scenario #4	---	---	---	6.2 to 6.46	11.2 to 11.6	4.97 to 5.20	23.6 to 24.6	33.6 to 34.9

FIGURE EX.10

Imported Oil Requirements for Electricity Generation
(millions of barrels)

	1985	1990	1995
Scenario #1	288	446	489
Scenario #2	288	332	278
Scenario #3	231	360	473
Scenario #4	231	318	275

RECOMMENDATIONS

This report examines the implications of continuing current trends for electricity production and use and whether a redirection of those trends toward the use of demand management, marginal pricing of electricity, energy conservation, and alternative resource (i.e., geothermal) development would be desirable for the 1985-2000 time period.

The following recommendations should be considered for the EdD system expansion investment program:

1. While conservation is the cheapest and most readily available energy source, the initial costs of eliminating wasteful use, purchasing conservation devices, and increasing energy efficiency inhibit otherwise economical conservation investments by consumers. To overcome this obstacle, EdD and/or the Government of Djibouti should establish a conservation service that will provide energy audits, arrange installation of energy-saving devices, and inform customers of financial incentives for energy conservation.

2. EdD needs to develop suitable incentives for energy conservation, including:

   - true value pricing of available energy sources; and
   - greater consumer understanding of short- and long-range supply options and implications.

   Instead of mandatory energy conservation programs, EdD should establish voluntary programs (demand and capacity) that provide incentives to consumers to save energy.

   Domestic, commercial, government, and other large customers should analyze their present energy use and levels of use during the study period to determine where the greatest savings can be made.

3. For the mid term and beyond, serious consideration should be given to the development of Djibouti's geothermal resources to meet all future electricity needs and to reduce the vulnerability to imported fuels.

4. The Government of Djibouti and EdD should establish a comprehensive national policy for guiding the growth of electricity services and geothermal and other alternative resource development. This is necessary to ensure that the development of the utility is consistent with overall energy

goals such as appropriate investment in energy conservation, system efficiency improvement, and development of alternative energy resources.

5. EdD should develop comprehensive load management and conservation planning practices on a par with their present capacity planning capability.

FUTURE ANALYSIS

The following recommendations should be considered for future analysis to assess the viability of current EdD expansion plans.

1. An independent demand forecast (capacity and energy) should be developed for different load sectors based on end-use methodology. The forecast should incorporate the achievable energy conservation and load management reductions during the study period.

2. An extensive set of conservation strategies consisting of both individual technologies and combinations of technologies should be developed. The impact of each strategy upon the total system load curve should be evaluated for each year of the study period. In addition, the impact of each conservation strategy upon the electric utility's system reliability and generation expansion planning should be quantified. Finally, a rigorous cost-effectiveness evaluation of each conservation strategy for the EdD system should be conducted.

3. An air conditioner cycling strategy that maximizes the operating economics of the cycling program for the EdD system should be developed. Operating economies could be achieved through:

   - fuel savings,
   - spinning reserve reduction,
   - unit commitment reductions, and
   - improved maintenance scheduling.

4. The relationship between the time, frequency, and duration of a service interruption and the cost savings to the utility of the interruption should be determined.

5. The impacts of load management and other demand reduction programs on transmission and distribution systems should be evaluated.

6. The impacts of conservation, thermal storage, active and passive solar systems, and time-of-day rates on load duration curve, load levels, and capacity planning for the EdD system should be estimated.

7. The effects of a modified base case, consisting of the best estimated penetrations of load control and conservation programs, on EdD load duration curves, load levels, capacity expansion plans, electric rates, and external financing requirements should be estimated.

8. A detailed energy audit program should be established for the industrial, commercial, and residential sectors to identify and quantify the opportunities for energy savings over the short- (1985-1986) and long-range (1990-1995).

9. The proposed Demand Subscription Service (DSS), interruptible rates, power factor penalty rate, lifeline rate, and time-of-use rates should be investigated to determine the cost-effectiveness of such tariffs.

Chapter 1

ELECTRICITY SUPPLY SYSTEM

General Background
Existing Electricity Generation System
Electricity End Use
Present Tariff Structure

GENERAL BACKGROUND

Djiboutians use electricity to meet 28 percent of their energy needs. Electricity supplies approximately 35 percent of the country's domestic energy needs and approximately 12 percent of the energy used in the commercial and industrial sectors. The nation's electricity is, produced and distributed by a single utility, the Electricité de Djibouti (EdD). It accounts for almost 98 percent of the country's generating capacity.

Unlike other forms of energy, electricity cannot be stored in large quantities and therefore must be generated when it is needed. Thus, electricity demand is measured both by the total sales (energy demand), usually expressed in kilowatt-hours (kWh) per year, and by the peak generating capacity (capacity demand) needed at any period during the year, usually measured in megawatts (MW). During 1983, for example, Djiboutians bought 147,614,000 kWh of electricity, and on one day the EdD demand peaked at 28.4 MW. On June 17, 1984, demand reached 31.0 MW and was expected to surpass 31.0 MW in the peak month of July.

In order reliably to meet demand for electricity at all times, EdD must have sufficient generating capacity to meet the peak loads that occur only a few hours each year. Consequently, some generating units are maintained for use even though they rarely operate, while other efficient units are operated throughout the year to meet "base load" needs.

Demand for electricity nationwide is growing more slowly today than in the past. The historical growth rates of the electricity sector (energy demand) for 1955 through 1983 are as follows:

1955 - 1960	12.0 %
1960 - 1965	19.1 %
1965 - 1970	14.1 %
1970 - 1975	11.8 %
1975 - 1980	9.3 %
1980 - 1983	9.1 %

Between 1955 and 1983 energy demand grew at an average annual rate of 12.5 percent. Similarly, the capacity demand growth rate for 1979-1983 averaged 10.0 percent annually for the greater Djibouti Ville (City of Djibouti) area.

In 1982, EdD distributed electricity to a total of 16,438 customers: 274 medium-tension and 16,164 low-tension. In 1983, 1,047 new customers were added: 607 subscribed for 1 kilovolt-ampere (kVA), 433 for 3-18 kVA, and only 7 for more than 18 kVA. Those who subscribed for 1 kVA are small residential customers with only lighting and a few appliances. The customers with 3-18 kVA

are a mix of residential (with air conditioning, refrigerator, etc.) and small commercial. Those who subscribe for more than 18 kVA are commercial and industrial customers.

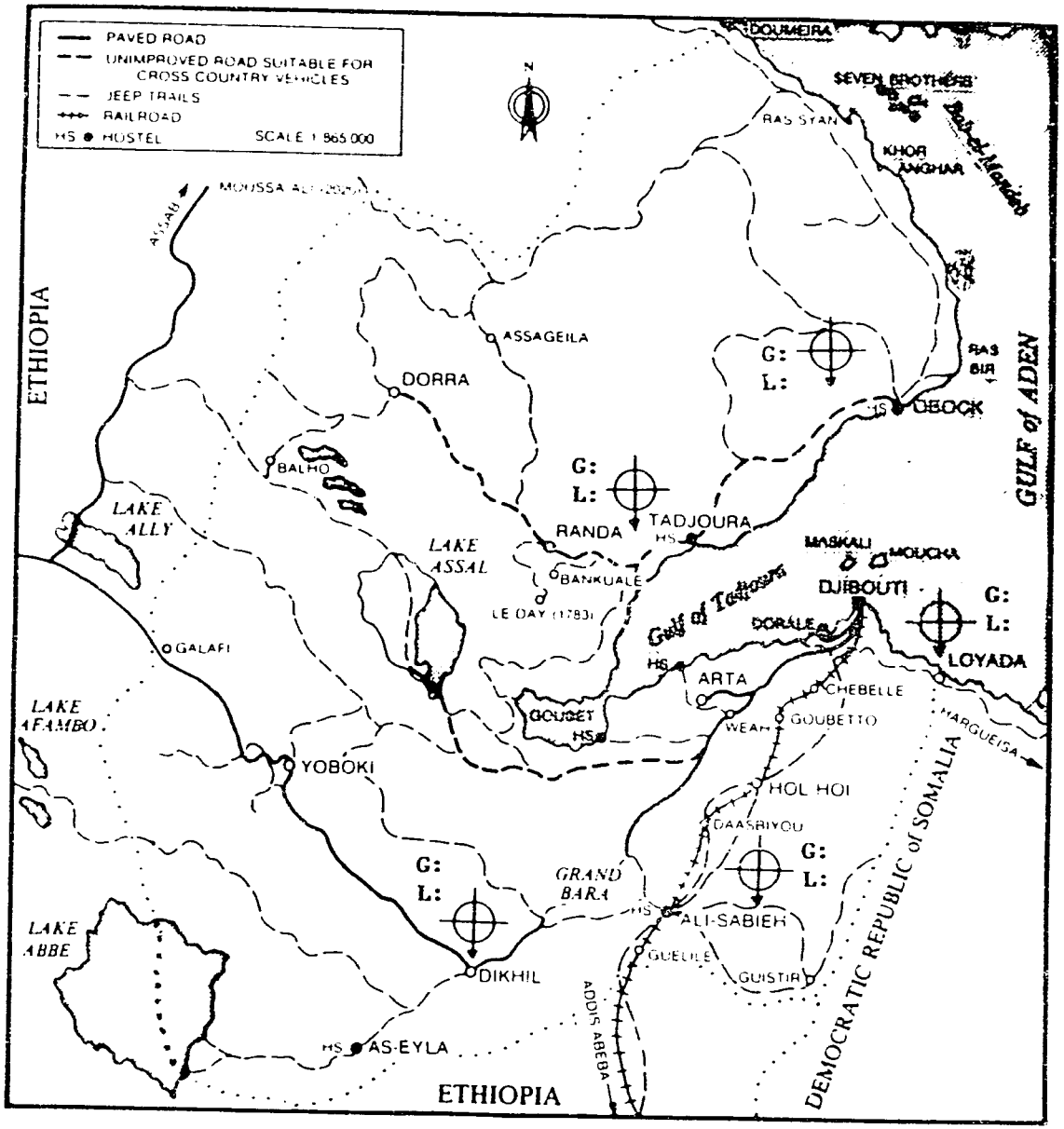
EXISTING ELECTRICITY GENERATION SYSTEM

The electric utility sector is both a major energy (fuel oil) consumer and producer. In 1983, the electricity sector consumed 28 percent of the country's total energy supplies. Of this amount, slightly over one-third was actually delivered to customers. The difference between energy consumed by EdD and delivered to customers represents a net loss of 70 percent as primary energy was converted into electricity and transmitted to customers. The system loss, after production and transmission, is about 20 percent. Despite these inefficiencies, electricity is an important form of energy that cannot be replaced in many applications, such as lighting, air conditioning, and running machinery motors or appliances.

One central system in Djibouti Ville and four other isolated systems (Tadjourah, Dikhil, Obock, and Ali-Sabieh) under the management of EdD generate almost all the electricity in Djibouti. The electric utility reports directly to the Ministry of Industry (MOI) on all financial and other performance matters. Figure 1.1 gives the geographical locations of all electricity supply systems in Djibouti. This figure also indicates the present available capacity and 1983 system loads in these service areas. At present, there is no national grid or transmission system interconnecting all the service areas. The maximum transmission system voltage is 20 kilovolts (kV) and the distribution voltage level is divided into 220 and 380 volts in the Djibouti Ville service area.

Electricity in Djibouti Ville is generated primarily by burning light fuel oil (600 seconds). In the outlying districts (Cercles), only diesel fuel is used. In Figure 1.2, the installed capacities and available capacities of all generating units in the EdD system are given. It is important to note that all of EdD's generators are diesel cycle engines. The available, or dependable, capacity in Djibouti Ville is only 34.3 MW even though the system's installed capacity is about 45.1 MW.

The derating of generating units is primarily due to the age of the units and to the environmental conditions in Djibouti. Usually, the wear-out life of a diesel generator is considered to be about 15 years. However, Figure 1.3 indicates that four generating units in the Boulaos power plant are over 15 years of age. The overall performance of these units is reflected in their capacity factors, given in Figure 1.3. EdD is considering retiring generating units G2, G3, G4, and G5, or using them for standby operation as new generating units come on-line.



G: Available installed capacity (June 17, 1984): 34 MW

L: 1983 demand (June 17, 1984): 31.5 MW

FIGURE 1.1

Locations of Existing EdD Power Generation Sites in Djibouti

FIGURE 1.2

Electric Power Capacity in Djibouti

Plant Name	Generator	Installed Capacity (kW)	Available Capacity (kW)	Date Installed	Retirement Date
Marabout	G1	2,400	1,500	1965[a]	1984
	G5	2,400	1,500	1963[a]	1984
Boulaos	G1	6,000	4,200	1976	1991
	G2	4,500	3,500	1971	1986
	G3	4,500	3,500	1969[a]	1984
	G4	4,500	3,500	1969[a]	1984
	G5	4,200	3,200	1965[a]	1984
	G6	5,200	3,800	1974	1989
	G7	5,700	4,800	1980	1995
	G8	5,700	4,800	1982	1997
Subtotal		45,100	34,300		
Tadjourah		4 x 400	1,200		
Dikhil		3 x 200	400		
Obock		135) 2 x 80)	230		
Ali-Sabieh		2 x 135) 80)	135		
TOTAL		47,945	36,265		

Source: EdD.

[a] These units have passed the usual retirement age of 15 years.

FIGURE 1.3

Existing Generating Plant Data
Plant Name: Boulaos (July 1984)

Unit Number	Year Installed	Age	Installed Capacity (MW)	Total Hours of Operation (1/1/84)	Typical Annual Hours of Operation	Capacity Factor
G1	1976	8	5.5	46,462	6,000	0.66
G2[a]	1971	13	4.0	57,811	4,500	0.50
G3[a]	1969	15	4.0	66,381	4,500	0.50
G4[a]	1967	17	4.0	66,534	4,000	0.44
G5[a]	1965	19	3.6	64,702	3,400	0.38
G6	1974	10	4.5	45,527	4,500	0.51
G7	1980	4	5.1	18,516	5,000	0.52
G8	1982	2	5.1	12,468	8,000	0.71

Source: EdD report, May 1984.

[a] These units have passed the usual retirement age of 15 years.

In Djibouti, there are a number of privately-owned generators; however, they are primarily for emergency back-up use. At present, the estimated installed capacity of all private generators is about 3.5 MW, and the available capacity of all private generators is about 1.2 MW. Figure 1.4 includes a partial list of all EdD customers with private generating capacity. There are also many generators run by Genie Rural (Djibouti's rural engineering agency) that supply electricity and water to villages, which are not included in Figure 1.4.

ELECTRICITY END USE

During the period 1982-1983 Djiboutians used a total of 126.56 GWh of energy in their homes, businesses, industries, and other areas. Figure 1.5 shows the historical electricity production, and transmission and system losses from 1971 to 1982 in Djibouti. The total electricity use in the country is increasing at a rate of about 10 percent annually. The average annual growth rate in total electricity use for the last 25 years has been approximately 12.8 percent. Although this figure reflects the extremely high annual growth rates of the 1960s, the annual average over the last ten years still approaches 9.8 percent. The total system losses for the EdD system were about 18 percent annually from 1979 to 1983 and about 14 percent from 1975 to 1979. This indicates that the overall supply efficiency of the EdD system has deteriorated in recent years.

For the Djibouti Ville system, demand for electricity follows a definite seasonal pattern as illustrated in Figure 1.6. Because a large portion of electricity end use consists of air conditioning loads, the capacity demand climbs to a maximum level during the hot season (May to September), peaking in July. Figure 1.6 graphically illustrates the peak demand for each month of 1982 and 1983. Both the differences in seasonal demand, from a low in January to the annual peak in July, and the overall growth in demand from 1982 to 1983, are clearly apparent. Figure 1.7 is a Load Duration Curve (LDC) for the 1983 seasonal demand profile of Figure 1.6. Figure 1.7 plots two variables: percentage of total annual hours (8.760 hours); and percentage of yearly peak demand (28.4 MW). It is interesting to note that at least 30 percent of the time, or 2,628 hours during the summer months, the peak demand remains within 98 percent of the annual peak demand. Also, the EdD system base load is about 46 percent of the annual peak demand.

A breakdown of electricity use by sector for the period between 1978 and 1981 is presented in Figure 1.8. The larger private customers, which include the French Army base, consume the most electricity, followed by residential customers and then the government. On the average, commercial consumption makes up 6 percent and industry only 4 percent of total electric consumption.

FIGURE 1.4

Privately-Owned Electric Generators

Owner	Installed Capacity (kW)	Available Capacity (kW)
A. Connected to EdD Grid		
Base Aérienne Française	1,000	1,000
Coubêche (coke bottling)	650	500
C.T.A. Centre de Transmission de L'Armée	180	160
C.T.I.M. Centre de Transmission	300	240
R.G.R. Police	120 + 100	---
SOFREAVIA	200	70
S.T.I.D. Transmission Aéroport	160	70
Etat Major Armée Française	160	140
B.C.I. Banque pour le Commerce et l'Industrie	90	70
Pierront	300	130
Prisunic	80	70
Arta Résidence du President	90	---
Radio Djibouti	---	---
Résidence du Premier Ministre	90	---
Présidence	---	---
U.S. Embassy	---	---
B. Off the Grid		
PK 20 (Agricultural Project)	N/A	---
Mouloud (Génie Rural)	N/A	---
Hol Hol (Génie Rural)	N/A	---
Numerous Small Villages (Génie Rural)	N/A	---

Source: EdD.

FIGURE 1.5

Historical Energy Production, Transmission, and System Loss Data for 1971-1982

	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982
Gross Energy Production (GWh)	43.204	48.463	56.342	61.584	72.983	82.030	89.070	92.800	102.500	113.658	119.505	126.563
Power Plant Loss (%)	3.54	3.65	3.75	3.47	3.21	5.64	7.24	6.84	7.26	7.78	7.19	9.10
Net Energy Transmission (GWh)	41.676	46.694	54.229	59.450	70.641	77.400	82.620	86.450	95.060	104.810	110.913	115.049
Total Sales (GWh)	36.840	42.155	47.712	52.563	64.162	69.092	73.793	75.938	88.786	91.744	96.897	101.60
Transmission and Distribution Losses (%)	11.6	9.7	12.0	11.6	9.2	10.73	10.68	12.15	6.6	12.46	12.63	11.6
Total System Loss (GWh)	6.364	6.308	8.63	9.021	8.821	12.938	15.277	16.862	13.714	21.914	22.608	24.96
Loss as Percentage of Gross Production	14.5	13.0	15.3	14.6	12.0	16.0	17.1	18.1	17.0	19.2	19.0	19.7

Source: EdD report, May 1984.

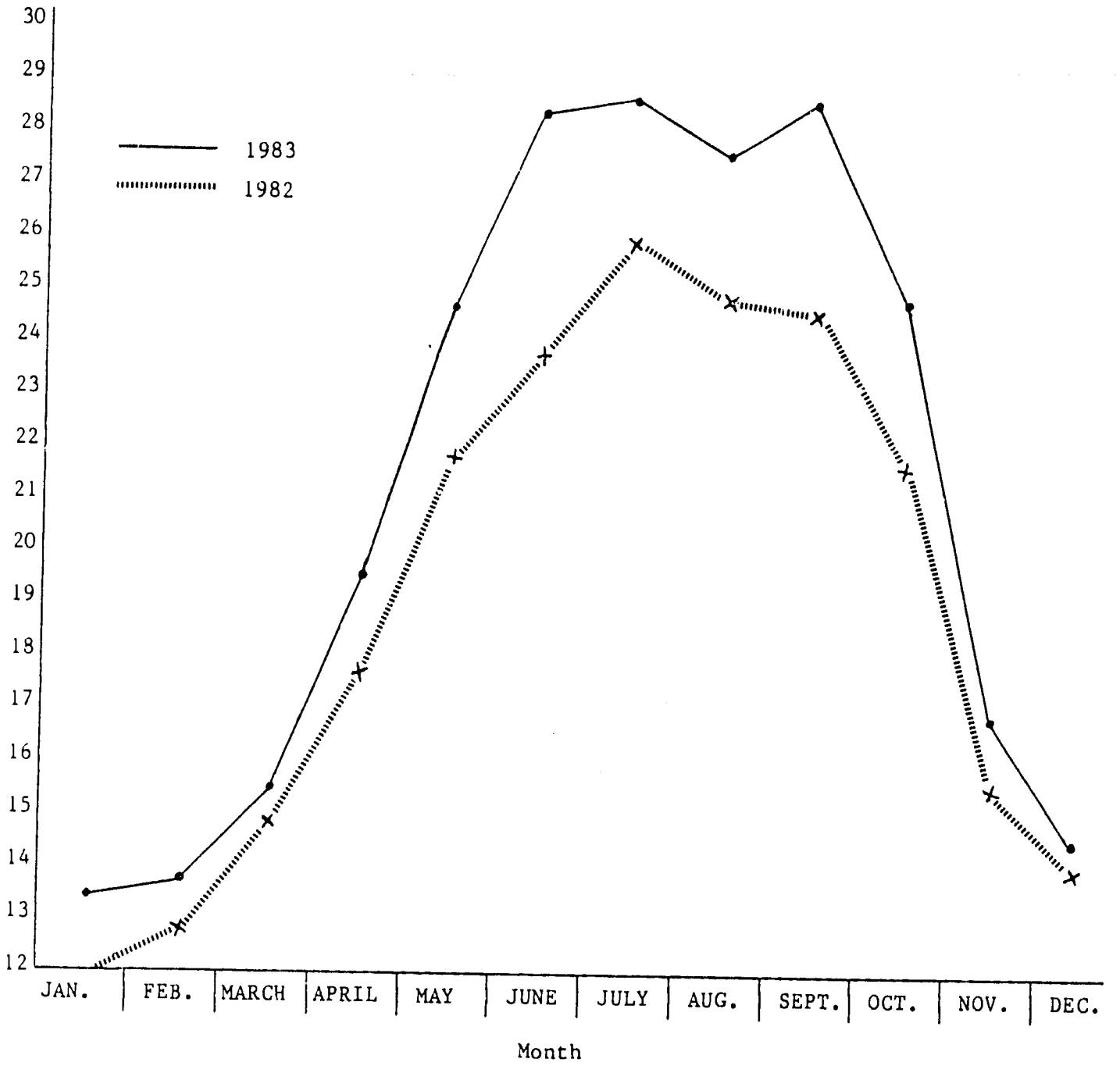


FIGURE 1.6

Peak Demand: Monthly Values (1982 and 1983)

Source: EdD.

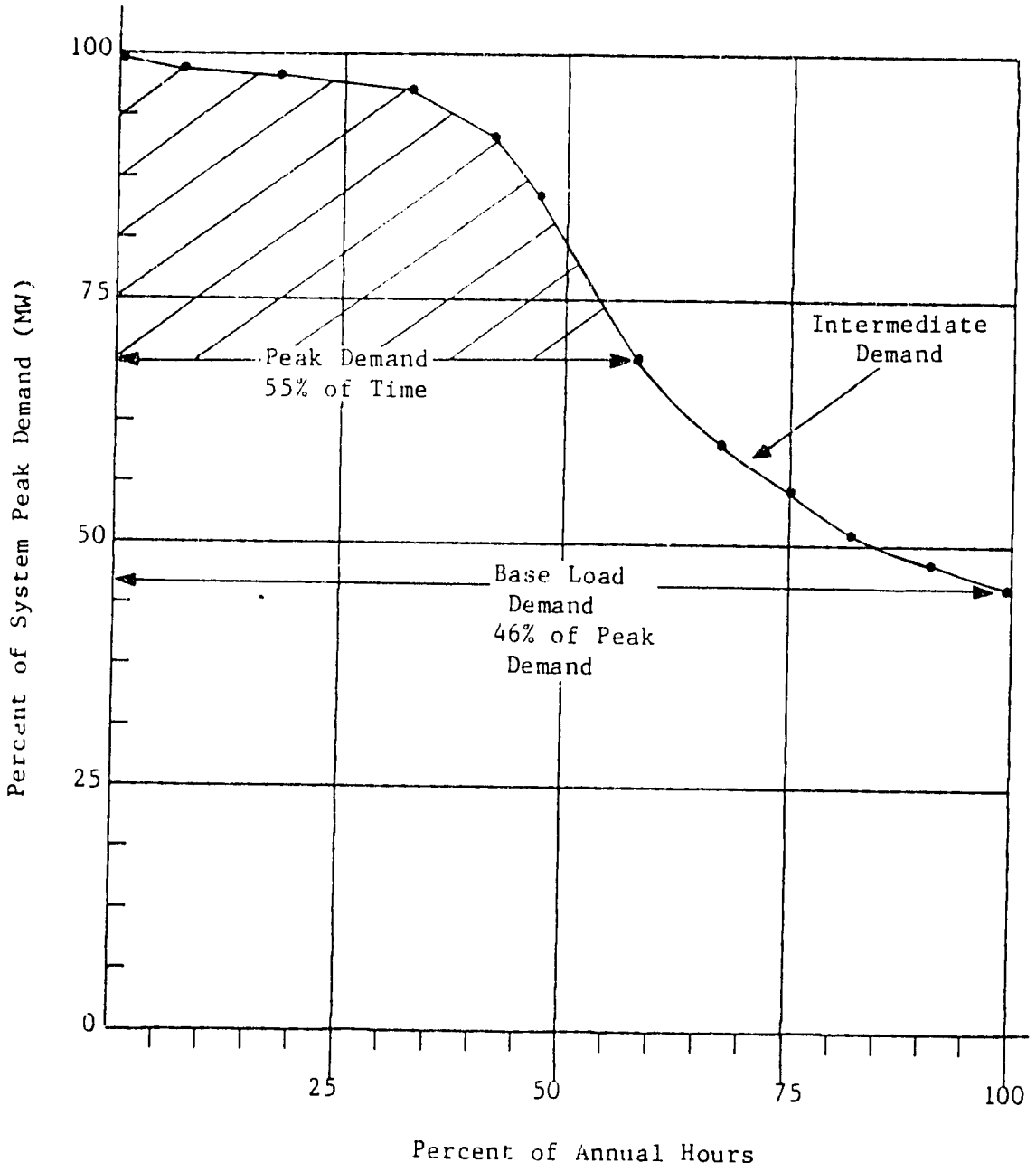


FIGURE 1.7

Load Duration Curve for 1983 Electricity Demand

Source: EdD.

FIGURE 1.8

Electricity Consumption Breakdown for 1978-1981 (GWh)

Year	Residential	Commercial	Industrial	Government and Street Lighting	Other Large Customers (Including French Army)	Total
1978	25.003	3.949	3.754	13.252	29.982	75.940
1979	29.828	4.207	4.479	15.812	34.464	88.790
1980	31.648	5.155	4.856	16.037	34.042	91.738
1981	33.594	6.425	5.299	16.581	34.834	96.733

Source: EdD report, May 1984.

In Figure 1.9, electricity consumption in residential, commercial, and government buildings during 1982 is included. Excluding public lighting and water pumping, these three sectors combined used 82,000 megawatt-hours (MWh) or 79 percent of the total electricity consumed in Djibouti Ville in 1982. However, since we count the French Army as an "export," it may be said that 90 percent of the electricity consumed in Djibouti's "internal market" (i.e., not including re-exported petroleum products) is consumed in buildings.

A breakdown by end use for electricity consumption in buildings during 1982 is also presented in Figure 1.9. Electricity in buildings is consumed for air-conditioning (65 percent), refrigeration (15 percent), lighting (15 percent), and other appliances (5 percent). The striking conclusion of this analysis is that about 60 percent of all electricity consumed in Djibouti's internal market is for air-conditioning. This breakdown of end uses is based on a study of energy consumption in seven representative buildings in Djibouti. It should be noted, however, that this study provides only a rough estimate of the allocation of end uses in the entire buildings sector of Djibouti.

PRESENT TARIFF STRUCTURE

A tariff of electricity rates and charges serves two purposes:

1. it raises revenue to pay for, or at least contribute to, the cost of operating the utility; and

2. it serves as a tool for implementing government policy.

The relative extent to which revenue is raised from customers can vary greatly between one electric utility and another. In general, three lines of revenue policy may be pursued:

1. Self-sufficiency. A tariff may be framed with the aim of raising sufficient revenue to enable the enterprise to pay its own way (no more and no less).

2. Subsidization. Where the public served by an electric utility is believed to be unable to pay the full cost of the services offered and where those services are regarded as sufficiently important, either as an amenity that directly raises the standard of living or as a means of achieving indirect economic benefits (e.g., more jobs), then a tariff may be deliberately framed to raise revenue amounting only to a fraction of the cost of operating the utility; the balance of the cost is borne by the government.

FIGURE 1.9

1982 Electricity Consumption Breakdown for EdD Internal Market

Breakdown of Djibouti's Internal Market	Electricity Delivered (MWh)	% of Djibouti's Internal Consumption
Buildings Sector (Total) [a]	82,000	80.5
Air Conditioning	53,300	52.3
Refrigeration	12,300	12.1
Lighting	12,300	12.1
Other Appliances	4,100	4.0
Industry (Total)	3,500	3.5
Coubêche	1,700	1.7
Petroleum Companies	600	0.6
Port of Djibouti	700	0.7
Eau de Tadjourah	200	0.2
Other Industries	300	0.3
Public Lighting	2,100	2.0
Water Pumping	3,400	3.2
French Army	11,000	10.8
TOTAL	102,000	100.0

Source: EdD.

[a] Includes residential, commercial, and government buildings.

3. Profit-making. A tariff may be so framed as to raise more revenue than is required to meet the cost of operating the enterprise, creating a profit which can be devoted to other purposes ranging from the renumeration of shareholders to the funding of social services.

The present price structure for electricity in Djibouti was not specifically designed for Djibouti, but was borrowed from other countries in Africa. There are five different tariffs for low-tension electric sales and one for medium-tension. Each tariff has its own fixed charges (or monthly fixed costs) and cost per kWh. Some tariffs include a maximum power limit which, if exceeded, brings a penalty upon the subscriber. The penalty is designed to reduce peak load. One element of the EdD price structure is a "declining block rate." With this rate, the price per kWh is reduced as electricity consumption increases. The declining block rate structure is designed to encourage consumption, and thus is inappropriate for Djibouti.

In the sections that follow all prices are expressed in constant 1982 Djiboutian Francs (DF). Many prices are also given in U.S. dollars to assist the Western reader. The conversion factor used is DF 177 = US $1.00.

Price Structure for Low-Tension Electricity

Tariff I: General. Tariff I is for all uses except public lighting and residential consumption. The tariff structure is quite simple with a fixed monthly charge of DF 350 (US $1.98) per kW for subscribers with less than or equal to 36 kW installed, and DF 37 ($0.21) per kW for an installation of more than 36 kW. A third option allows customers with a maximum power indicator on their meters to pay a fixed monthly charge of DF 46 ($0.26) per kW installed. This option, of course, is only attractive to those with installed power of less than 36 kW. Beyond the subscriber's fee, the cost of electricity is DF 46 ($0.26) per kWh.

Tariff II: Residential. Tariff II is for residential buildings only. However, some commercial establishments subscribe as residential customers in order to benefit from the lower rates.

This tariff has two tiers with a declining block rate structure. The tiers are divided by kWh consumed and are a function of the subscribed power (see Figure 1.10). The monthly subscriber's fee is also a function of the power subscribed and is presented in Figure 1.10.

Those who subscribe for 1 kW are given a special rate of DF 29 ($0.16) per kWh for the first tier and DF 25 ($0.14) for the second. Subscribers of greater than 1 kW pay DF 37 ($0.21) per kWh for the first tier and DF 35 ($0.20) per kWh for the second. No maximum power indicators are used on residential meters.

The declining block rate structure encourages electric consumption in residential buildings, i.e., the more electricity consumed, the lower the average cost. Furthermore, large consumers are given an advantage in the subscriber's fee, which decreases as kW installed increases. It should be noted that at DF 29 per kWh, the 1 kW subscribers are being subsidized.

Tariff III: Declining/Double Declining. Tariff III is for everything other than public lighting and residential consumption. It is divided into two subtariffs: "declining block rate" and "double declining block rate." Each subtariff has four tiers that are a function of the number of hours of subscribed power used per month. There are also fixed monthly charges that vary as a function of the subscribed power, and which differ slightly between the two subtariffs. (see Figure 1.11).

Tariff IV: Public Lighting. Tariff IV covers public lighting in Djibouti Ville, Arta, and Oueah. The price of electricity is fixed at DF 36/kWh ($0.203/kWh).

Tariff V: Arta, Oueah, Ali-Sabieh, Dikhil, Obock, and Tadjourah. This tariff is for all towns other than Djibouti Ville. It covers all uses except public lighting in Arta and Oueah. For Arta and Oueah, the price per kWh is fixed at DF 46 ($0.26). For Ali-Sabieh, Dikhil, Obock, and Tadjourah, the price per kWh is fixed at DF 39 ($0.22).

The monthly subscribers' fees are DF 350 ($1.98) per kW subscribed for subscriptions less than or equal to 36 kW and DF 38 ($0.21) per kW for those in excess of 36 kW.

Price Structure for Medium-Tension Electricity

Medium-tension electricity is delivered to commercial, industrial, and government establishments. It is sold in two tiers with a declining block rate structure. The tiers are a function of subscribed power and are presented in Figure 1.12. Also presented in Figure 1.12 are the monthly subscribers' fees, which decline as subscribed power increases.

For medium-tension customers, there is a minimum annual consumption of 1,200 hours of the subscribed power. If this is not met, the customer is required to pay the difference between the minimum consumption and the electricity actually consumed. Some customers, however, are excepted from the 1,200-hour minimum consumption requirement. The minimum annual consumption for educational institutions, for example, is 800 hours.

This price structure encourages larger consumers and higher consumption by reducing the average price as consumption increases. It also gives industry a generally low price (in Djibouti Ville,

FIGURE 1.10

Structure of Tariff II

		Subscriber's Fee	
Subscribed Power (kW)	First Tier [a] (kWh/month)	1982 DF	1982 DF per kWh Subscribed
1	90	350	360
3	105	560	187
6	120	630	105
9	135	770	86
12	150	880	73
15	165	880	59
18	180	880	49
24	210	880	37
27	225	880	35
30	240	880	29
36	270	880	24

Source: Republic of Djibouti, EdD, Government Decree, February 1983.

Note: Price per kWh:

For subscription = 1 kW:

1st Tier: DF 29 (U.S. $.1640)

2nd Tier [a]: DF 25 (U.S. $.141)

For subscription greater than 1 kW:

1st Tier: DF 37 (U.S. $.209)

2nd Tier [a]: DF 35 (U.S. $.198)

[a] Second Tier is anything in excess of the first.

FIGURE 1.11

Structure Of Tariff III

	Price per kWh		Size of Tier (hours of subscribed power)	
	1982 DF	1982 US $	Declining	Double Declining
1st Tier	46	.26	75	95
2nd Tier	42	.24	90	110
3rd Tier	37	.21	100	125
4th Tier	43	.24	100	125

Source: Republic of Djibouti, EdD, Government Decree, February 1983.

Note: Monthly fixed charges per kWh subscribed:

Declining

DF 300 for subscribed power less than or equal to 10 kW.
DF 880 for subscribed power greater than 10 kW.

Double Declining

DF 300 for subscribed power less than or equal to 8 kW.
DF 1,100 for subscribed power greater than 8 kW.

FIGURE 1.12

Medium-Tension Electricity Price Structure

Price per kWh:

	1982 DF (1982 US $)			
	Djibouti, Arta, Oueah		Ali-Sabieh, Dikhil, Obock, Tadjourah	
Tier 1	32.0	(.181)	46.0	(.260)
Tier 2	26.1	(.147)	39.1	(.221)

Fixed Monthly Charges and Tier Definition:

Subscribed Power (kW)	Size of Tier I (monthly hours of subscribed power)	Monthly Fee per kW Subscribed 1982 DF	1982 US$
0 - 8	250	300	1.69
9 - 200	250	1,100	6.21
201 - 500	200	1,100	6.21
501 - 900	175	1,045	5.90
901 - 1,300	175	990	5.59
Beyond 1,300	175	935	5.28

Source: Republic of Djibouti, EdD, Government Decree, February 1983.

Arta, Oueah), which functions as a subsidy. Individual contracts with large consumers are also allowed within the existing price structure. It should be noted that at DF 32/kWh this consumer class is being subsidized.

Price Structure Overview

Figure 1.13 lists each tariff and the price per kWh for the first two tiers. In general, the Djibouti tariff structure subsidizes small residential and industrial consumers. These subsidies are paid for by the higher tariffs for other consumer classes.

Internal subsidization of EdD's price structure means that some classes of consumers are being supplied electricity at an actual loss. Where an electricity supply system is newly, it may be necessary to grant a temporary subsidy during the first year or two while the demand is being built up to a level sufficient for the utility to become self-supporting. However, this is not the case for the EdD system.

Chapter 5 presents a detailed discussion of utility rates that reflect the true cost of providing energy and encourage conservation through increased efficiency.

FIGURE 1.13

Overview of Electricity Price Structure (DF/kWh)

	Price of Electricity (1982 DF/kWh)	
	Tier I	Tier II
Tariff I (General)	46	--
Tariff II (Residential):		
1 kWh subscribed	29	25
More than 1 kWh subscribed	37	35
Tariff III (Commercial, Government, and Industrial):		
Declining [a]	46	42 [b]
Double Declining [a]	46	42 [b]
Tariff IV (Public Lighting)	36	--
Tariff V (Cercles):		
Arta and Oueah	46	--
Others	39	--
Medium Tension:		
Djibouti, Arta, and Oueah	32	26
Ali-Sabieh, Dikhil, Obock, and Tadjourah	46	39

Source: EdD.

Note: DF 177 = US $1.00. Estimated cost of kWh delivered = DF 34.

[a] The tiers for "Double Declining" are wider than those for "Declining."

[b] Tiers 3 and 4 for these tariffs are DF 37/kWh and DF 43/kWh.

Chapter 2

DEMAND FORECAST AND CAPACITY EXPANSION REQUIREMENTS

General Background
Demand Forecast for 1985-2000
Energy and Demand Forecast for 1985-2000
Capacity Expansion Planning Criteria
Capacity Expansion Requirements

GENERAL BACKGROUND

Accurate demand forecasts are an important input into the planning of future capacity additions and future electric rate levels. Plants planned and sited today become a large part of the electric rate base in the future. Potential changes in customer load levels and patterns brought about by the introduction of new rate structures, conservation and load management programs, and new technologies should be an important consideration in forecasting and capacity planning. These programs and technologies will affect the levels and patterns of total electric demand EdD must satisfy, and the generating capacity needed to meet these loads.

This chapter presents a demand forecast (both capacity and energy) for the period 1985-2000 and an estimate of the capacity expansion needed to satisfy the demand at a reasonable level of system reliability. The modified demand forecast and generation expansion plans were developed from EdD's demand forecast data (June 1984).

DEMAND FORECAST FOR 1985-2000

Several techniques can be used to produce a forecast of future load for the EdD system, for example:

1. A "trend" estimate based on historical data. This may be either a continuation of an existing trend or a reasoned derivation from it.

2. An estimate built up from estimates for various classes of consumers, which in turn are based on trends or long-term targets set by government agencies (e.g., plans for industry or agriculture, the rate of new home construction, etc.)

3. An estimate based on national economic or development guidelines (e.g., estimated growth of gross national product or similar indicator, or a percentage development rate set in a national plan). To employ this method, one must be able to relate past electricity consumption to the indicator chosen.

EdD develops its demand forecasts on the basis of an analysis of historical trends and knowledge of major projects that will have an impact on electricity demand over the medium-term future. The demand forecast presented in Figure 2.1 is based on EdD's June 1984 demand forecast for various service areas (zones). This

demand forecast is modified in Figure 2.2 to include unserved demand in the EdD system.

The following demand growth rates were used in developing the peak demand forecast for the Djibouti Ville and four other service areas (Tadjourah, Obock, Dikhil, and Ali-Sabieh):

Time Period	Growth Rates
1983-1989	10.36%
1983-1990	10.00%
1983-2000	7.55%

It is interesting to note that EdD has assumed a system power factor (PF) of 0.665 in calculating the megawatt peak demand for each year (power factor = MVA demand/MW demand). At present, the EdD system power factor is about 0.65. Based on EdD's assumed power factor of 0.665, it is clear that the utility is not contemplating any PF improvement over the next 15 years to reduce the system's production and transmission losses.

The peak demand for 1984 reached 31.5 MW (June 17, 1984), and it was expected to surpass 31.5 MW during the peak month of July. However, the present available capacity at Djibouti Ville is only 34 MW, including standby generators at the Marabout power station. This indicates that the existing system has a significant amount of suppressed or unserved demand. Based upon a discussion held with an EdD staff engineer, it is estimated that the total load of unserved large customers in the Djibouti Ville system may be as high as 8 to 10 MW. Even though the EdD system is at present operating without any reserve margin, it does not have a realistic policy regarding electricity supply connections for small residential customers. EdD usually connects all new, small customers (1 to 18 kVA) and later on uses a rotating blackout policy to maintain a minimum level of system security.

In this report, a suppressed demand of 8 MW is used for EdD system analysis. This suppressed demand is composed of two components:

1. an estimated 4 MW of unserved demand during the rotating blackouts of the last few years; and

2. an estimated 4 MW of unserved demand by customers waiting for electricity hookups (e.g., the Balbala housing project).

In planning future capacity expansion, it is important to recognize the amount of unserved load in the system.

A major program of capacity expansion is underway at the Boulaos generating station in Djibouti Ville. One 15-MW unit (available

capacity is about 12 MW) is stated to come on-line in December 1984; another 15-MW unit is scheduled to start up in early 1985. These two generating units will each add 12 MW to available capacity, for a post-installation total of 24 MW in Djibouti Ville. Once on-line, these units will alleviate unserved demand problems for two or three years. Based on this information, a modified energy forecast has been developed for the EdD Djibouti Ville system, and is presented in Figure 2.3. It is assumed that the total 8 MW of unserved load will be corrected by 1986 and that the demand growth rates listed in Figure 2.1 will remain the same for the 1985-2000 period.

Total capacity demand (32.5 MW for 1984) will more than triple over the next 15 years if the existing unserved load is included in the demand forecast. In the following section, an energy forecast for the EdD central system (Djibouti Ville) is developed based on both the peak demand forecast and the modified demand forecast presented in Figure 2.2.

ENERGY AND DEMAND FORECAST FOR 1985-2000

Historical development of the power market in Djibouti from 1974 to 1983 is presented in Figure 2.4. As indicated in Figure 2.4, this development is characterized by four different periods:

1. 1974-1977, when the energy production growth rate averaged 12.2 percent annually;

2. 1978-1981, when the average growth rate dropped to 7.66 percent per year;

3. 1982, when sales declined 5.9 percent in response to several outages and blackouts, and a probable increase in the real average price of electricity; and

4. 1983, when sales grew at a rate of 12.34 percent.

The average growth rate for the entire 1974-1983 period was about 9.76 percent annually. In Figure 2.5, the latest capacity, energy, and load factor forecasts by EdD for the period 1985-1990 are given. It is interesting to note that EdD is planning a decline in system load factor*, which reflects poor use of electricity-producing facilities. Historically, the EdD system load factor has been in the range of 52 to 55 percent.

$$*\text{Load Factor} = \frac{\text{Total Energy Production (MWh)}}{\text{Peak Demand (in MW)} \times 8{,}760 \text{ Hours}}$$

FIGURE 2.1

Demand Forecast for Various EdD Service Areas

Zone	Location	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000
1		1.9	2.7	3.0	3.4	3.5	3.7	4.0	4.3	5.5	7.3
2		2.0	2.4	3.1	3.7	4.2	4.5	4.8	5.1	6.2	7.0
3		4.4	4.9	5.5	6.0	6.4	6.8	7.1	7.5	8.5	9.6
4		8.3	8.6	9.0	9.4	9.8	10.2	10.6	11.0	13.0	15.0
5		3.1	3.5	3.9	4.3	4.9	5.6	6.4	7.3	9.0	10.5
6		3.2	3.4	3.5	3.7	3.9	4.1	4.3	4.5	5.7	7.3
7		12.4	14.2	15.2	16.3	17.4	18.7	20.0	21.4	28.0	36.0
8		--	--	0.3	0.6	1.0	1.4	1.8	2.2	4.0	7.0
9		4.4	5.8	6.2	6.6	7.2	7.9	8.7	9.5	13.5	18.0
10		0.8	1.0	2.2	2.9	3.7	4.6	5.6	6.2	11.0	20.0
11		0.8	0.9	1.0	1.1	1.3	1.5	1.8	2.0	3.9	6.0
12		1.4	1.5	1.6	1.7	1.8	1.9	2.0	2.1	2.7	3.5
Total (MVA)		42.7	48.9	54.3	59.7	65.1	70.9	77.1	83.1	111.0	147.2
Total Capacity Demand (MW)		28.4	32.5	36.1	39.7	43.3	47.2	51.3	55.3	73.8	98.0
	Obock	0.2	0.3	0.3	0.4	0.5	0.5	0.6	0.6	0.8	1.0
	Tadjourah	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.3	2.0	3.0
	Dikhil and Ali-Sabieh	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.5	2.2	3.4
	Subtotal MVA	1.6	1.9	2.1	2.4	2.7	2.9	3.2	3.4	5.0	7.4
	Subtotal MW	0.96	1.14	1.26	1.44	1.62	1.74	1.92	2.04	3.00	4.44

Source: EdD, June 1984.

FIGURE 2.2

Modified Demand Forecast (Includes Unserved Loads) (MW)

	1985	1986	1987	1988	1989	1990	1995	2000
EdD Forecast (from Table 2.1)	36.1	39.7	43.3	47.2	51.3	55.3	73.8	98.0
Total Unserved Load Connected	4	4	--	--	--	--	--	--
Modified Demand Forecast	40.1	48.1	52.4	57.1	62.0	66.8	89.1	118.3

FIGURE 2.3

Energy Forecasts for 1985-2000

Year	EdD Peak Demand Forecast		Modified Peak Demand Forecast		System Load Factor
	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)	
1985	36.1	174.0	40.1	193.2	0.55
1986	39.7	191.2	48.1	231.7	0.55
1987	43.3	208.6	52.4	252.5	0.55
1988	47.2	227.4	57.1	275.1	0.55
1989	51.3	247.1	62.0	298.7	0.55
1990	55.3	271.2	66.8	327.7	0.56
1995	73.8	374.9	89.1	452.7	0.58
2000	98.0	497.9	118.3	601.0	0.58

FIGURE 2.4

Historical Energy Production (Gross)

Year	Total Energy Production (GWh)	Percentage Increase over Previous Year
1983	142.18	12.34
1982	126.56	5.9
1981	119.50	5.14
1980	113.65	10.92
1979	102.46	10.41
1978	92.80	4.2
1977	89.06	8.58
1976	82.03	12.39
1975	72.98	18.42
1974	61.58	9.30
		9.76% Growth Rate per Annum

Source: EdD.

FIGURE 2.5

Energy Production and Peak Demand Forecasts For 1985-2000

Year	Peak Demand (MW)	Total Energy Production (GWh)	System Load Factor
1985	36.1	184	0.58
1986	39.7	206	0.59
1987	43.3	219	0.57
1988	47.2	232	0.56
1989	51.3	245	0.54
1990	55.3	259	0.53

Source: EdD.

A gross energy production forecast for both the EdD-forecasted peak demand (Figure 2.1) and the modified peak forecast (Figure 2.2) is presented in Figure 2.3. It is assumed the system load factor will remain at 0.55 from 1979-1983 and then it will increase 1 percent per year to 0.58 due to various load management and energy conservation programs. In addition, transmission, distribution, and production losses are assumed to remain at the present level of about 18-20 percent.

Projected energy sales for the 1985-2000 peak demand forecast for each load sector are included in Figure 2.6. These projections are based on the following breakdown of the historical average energy sales data for the 1979-1983 period:

Domestic	35.0 %
Industrial	6.6 %
Commercial	5.4 %
Government and Street Lighting	17.0 %
Large Customers (French Army, etc.)	36.0 %
Total	100.0 %

Energy sales for the modified peak demand forecast, which includes present unserved loads, are given in Figure 2.7. The total system loss is assumed to remain at the present level of 18 percent of gross energy production. Figures 2.6 and 2.7 show that residential, government, and other large customers are the largest consumers of electricity in the EdD system. Therefore, energy conservation and load management programs should be directed at these customers for maximum energy savings over the short-range.

CAPACITY EXPANSION PLANNING CRITERIA

Determining an adequate level of reliability or service quality for the EdD system is a difficult task because of the unavailability of complete system data and the time constraints in carrying out this study. At present, EdD does not apply any operating or planning reserve margin criteria due to the high growth rates in recent years and the budget limitations for new capacity expansion. It seems that no single criterion of system reliability describes the system's ability to supply satisfactory service.

FIGURE 2.6

Energy Sales by Load Sector Based on EdD Peak Demand Forecast

Year	Total System Loss (GWh)	Net Energy Sales (GWh)	Domestic Sector (GWh)	Indus-trial Sector (GWh)	Commer-cial Sector (GWh)	Govern-ment and Street Lighting (GWh)	Other Large Customers (GWh)
1985	31.32	142.68	49.93	9.41	7.70	24.25	51.36
1986	34.42	156.78	54.87	10.34	8.46	26.65	56.44
1987	37.55	171.00	59.85	11.28	9.23	29.07	61.55
1988	40.93	186.46	65.26	12.30	10.06	31.69	67.12
1989	44.47	202.62	70.91	13.37	10.94	34.44	72.94
1990	48.81	222.38	77.83	14.67	12.00	37.80	80.05
1995	67.48	307.40	107.59	20.28	16.59	52.25	110.66
2000	89.62	408.28	142.89	26.94	22.04	69.40	146.98

FIGURE 2.7

Energy Sales by Load Sector Based on Modified Peak Demand Forecast (Includes Existing Unserved Demand)

Year	Total System Loss (GWh)	Net Energy Sales (GWh)	Domestic Sector (GWh)	Indus-trial Sector (GWh)	Commer-cial Sector (GWh)	Govern-ment and Street Lighting (GWh)	Other Large Customers (GWh)
1985	34.7	158.4	55.4	10.4	8.5	26.9	57.0
1986	41.7	190.0	66.5	12.4	10.3	32.3	68.4
1987	45.4	207.0	72.5	13.7	11.2	35.2	74.5
1988	49.5	225.6	78.9	14.9	12.2	38.3	81.2
1989	53.8	244.9	85.7	16.2	13.2	41.6	88.2
1990	59.0	268.7	94.0	17.7	14.5	45.7	96.7
1995	81.5	371.2	129.9	24.5	20.1	63.10	133.6
2000	66.8	534.2	186.9	35.3	28.8	90.8	192.3

The following reserve margin planning criteria were used by the author to determine the capacity expansion requirements for future years:

- The installed capacity margin (installed capacity minus annual peak demand) should be sufficient to allow the loss of at least one of the largest generating units. In 1985, the largest units at risk in the EdD system are two new 15-MW units.

- In addition to the largest generating unit outage risk, a 5 percent installed reserve margin is used to cover a load forecast error, slippage of service start-up dates of new generation capacity, or other uncertainty.

The above installed capacity margin criteria are based on the principle that there should be no loss of system load, nor adverse effects on the system from the common contingency outages. These criteria, however, recognize the necessity for load shedding for those outage contingencies that are possible but of such low probability that protection of the system against such contingencies are not justified economically.

At present, EdD staff are recommending use of a planning reliability criterion of 25 percent reserve margin for future expansion studies. This reserve margin, however, is not adequate to cover the loss of the largest unit in the system, which will be 15-MW installed capacity and 12.0-MW available capacity in 1985 and beyond. The criteria used in this report to determine future capacity requirements (i.e., loss of largest unit plus 5 percent for system uncertainty) will provide a slightly higher installed reserve margin. In the absence of detailed computer simulations, the selected criteria provide a good level of system reliability for EdD system generation expansion studies.

CAPACITY EXPANSION REQUIREMENTS

The planning of electric generating facilities is complex. Moreover, major investment decisions must be made years in advance. To ensure reliable electric service, EdD's planning of new capacity must be guided by three major concerns. First, EdD must have sufficient capacity to generate more electricity than it anticipates their customers will demand. Second, power plants must be held in reserve in case other facilities break down. Finally, EdD must replace generating units that are retired. In general, as newer, more efficient power plants are built to meet new electrical load growth, older units are retired or used only during emergency situations. Planning for only enough electrical capacity to meet new load growth and reserve margin needs is not sufficient because not all of the current generating units will

be available in the future. At present, EdD is planning to retire about 23.6 MW of generating capacity by the year 2000.

Figures 2.8 and 2.9 indicate the EdD system generating capacity expansion requirements during the 1985-2000 time frame that will satisfy the EdD demand forecast and the modified demand forecast (which includes existing suppressed demand in the EdD system). Figures 2.10 and 2.11 present the capacity expansion requirements schematically. These requirements were developed based on the capacity expansion planning criteria outlined in the preceding subsection.

In Figure 2.10, the steps in the generation capacity curve indicate the addition of new generating units and/or retirement of units from the existing system. In Figure 2.11, the "planning criteria" curve indicates the installed (available) reserve margin requirements for system reliability purposes each year. It is important to note from Figures 2.10 and 2.11 that the adopted reserve margin criteria will be violated almost every year during the study period for the EdD demand forecast (Figure 2.10) and every year for the modified demand forecast (Figure 2.11). After the installation of two 15-MW units in December 1984 and in the early part of 1985, and the installation of an additional two 6.5-MW diesel units (available capacity 10 MW) in 1986, there will be adequate capacity available from 1986 through the middle of 1987 to satisfy the EdD-forecasted peak demand (Figure 2.10). However, if the present suppressed demand is taken into account in the capacity planning process, a capacity shortage will occur over the short-term. The shaded areas in Figures 2.10 and 2.11 indicate the total capacity shortages in the EdD system for both demand forecasts. Critical capacity and energy shortages may occur in 1984, 1985, and 1986 if there is a slippage of installation dates of the two 15-MW units and the two 6.5-MW units.

In Figures 2.8 and 2.9, the minimum capacity expansion requirements for the EdD system for the study period 1985-2000 are included for both demand forecasts. The additional capacity installation requirements in the EdD system for the study period is about 70.5 MW for the EdD demand forecast and 91.56 MW for the modified demand forecast.

FIGURE 2.8

Generating Capacity Expansion Requirements and Load Data (Based on EdD Demand Forecast)

	1985	1986	1987	1988	1989	1990	1995	2000
Peak Demand (MW) (EdD Forecast)	36.1	39.7	43.3	47.2	51.3	55.3	73.8	98.0
Capacity Retirement (MW) (see Figure 1.2)	-10.2	---	---	---	-3.8	---	-4.8	-4.8
Present Capacity Expansion Plans (MW)	+24.0	+10.0	---	---	---	---	---	---
Available Capacity (MW)	48.0	58.0	58.0	58.0	54.2	54.2	49.4	44.6
Available Reserve Margin (MW)	11.9	18.3	14.7	10.8	2.9	-1.1	-24.4	-53.8
Reserve Margin (%)	33.0	46.1	34.0	23.0	5.6	-2.0	-33.0	-54.8
Required Reserve Margin to Meet Planning Criteria (%)	38.2	35.2	33.0	30.4	28.3	26.6	21.2	17.2
Additional Capacity Requirements (MW)	2.0	---	---	3.5	11.6	16.0	40.0	70.5
Total System Available Capacity Requirements (MW)	50.0	58.0	58.0	61.5	65.8	70.2	89.4	115.1

FIGURE 2.9

Generating Capacity Expansion Requirements and Load Data (Based on Modified Demand Forecast)

	1985	1986	1987	1988	1989	1990	1995	2000
Peak Demand (MW) (EdD Forecast)	40.1	48.1	52.4	57.1	62.0	66.8	89.1	118.3
Capacity Retirement (MW) (see Figure 1.2)	-10.2	---	---	---	-3.8	---	-4.8	-4.8
Present Capacity Expansion Plans (MW)	+24.0	+10.0	---	---	---	---	---	---
Available Capacity (MW)	48.0	58.0	58.0	58.0	54.2	54.2	49.4	44.6
Available Reserve Margin (MW)	7.9	9.9	5.6	0.9	-7.8	-12.6	-39.7	-73.7
Reserve Margin (%)	19.7	20.0	10.6	1.6	-12.5	-18.7	-44.5	-62.3
Required Reserve Margin to Meet Planning Criteria (%)	35.0	30.0	28.0	26.0	24.3	23.0	18.4	15.1
Additional Capacity Requirements (MW)	6.13	4.8	9.1	13.93	22.8	27.9	56.0	91.56
Total System Available Capacity Requirements (MW)	54.13	62.80	67.10	71.93	77.00	82.10	105.40	136.16

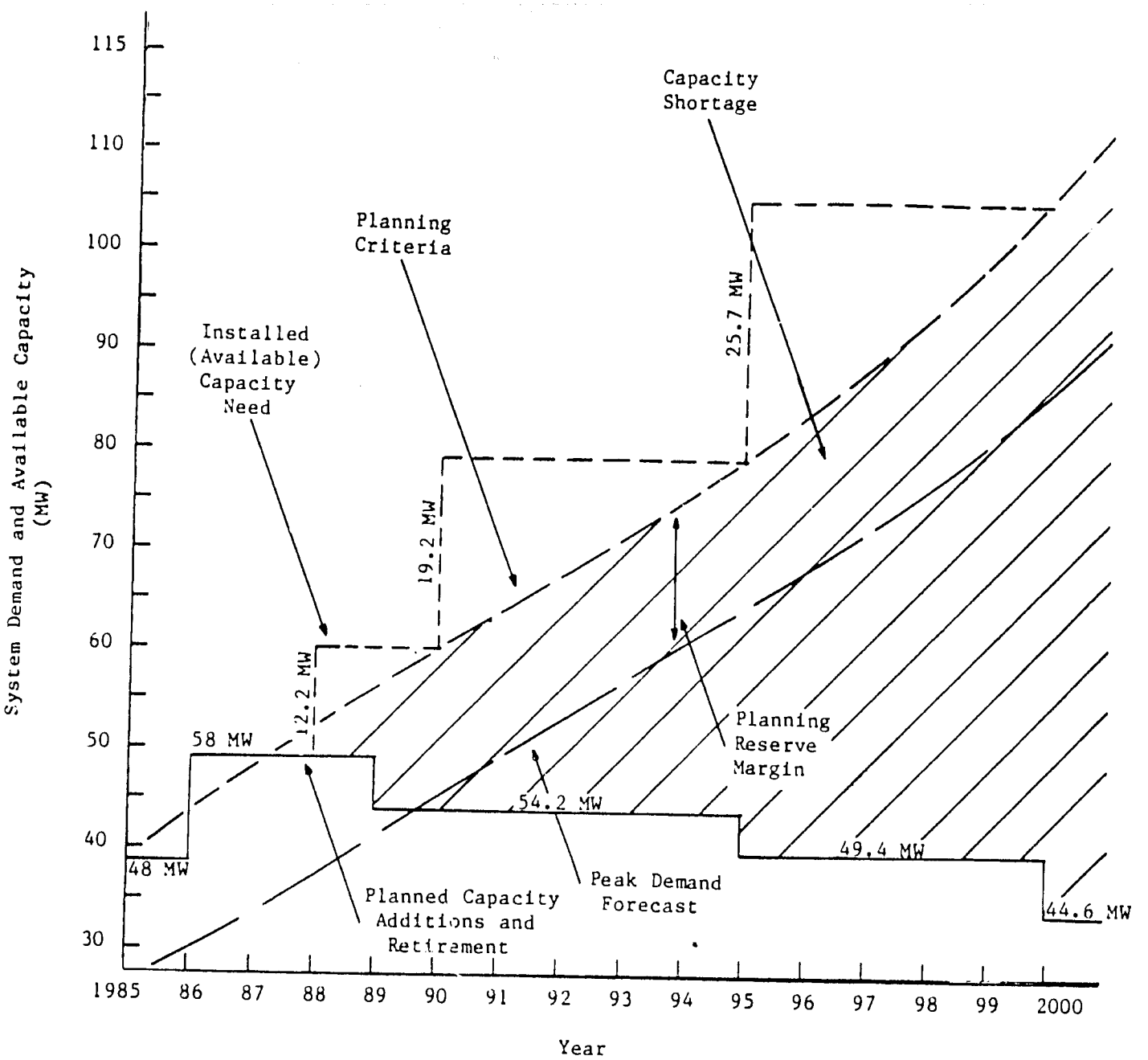


FIGURE 2.10

Generation Expansion for the EdD Load Forecast

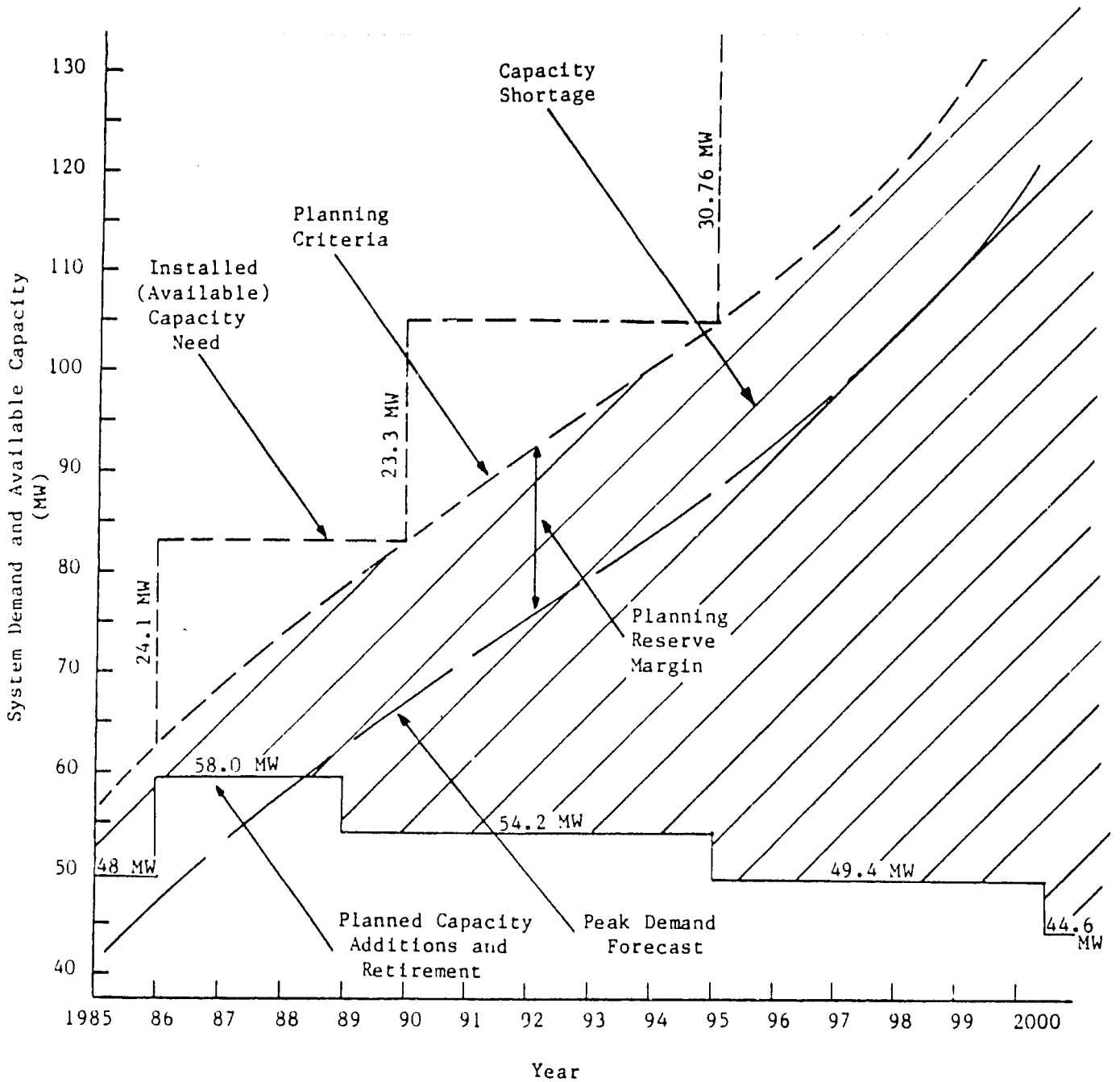


FIGURE 2.11

Generation Expansion for the Modified Load Forecast

Chapter 3

ENERGY CONSERVATION AND LOAD MANAGEMENT POTENTIALS

General Background
Load Management
Power Factor Improvement
Energy Conservation
Interruptible Rates
Other Options for Demand Reduction

GENERAL BACKGROUND

Over the last few years, public attention in Djibouti has been drawn increasingly to the country's energy problems. More effective and better organized efforts must be undertaken to resolve these energy problems. The rapidly escalating price of electricity has created a need for conservation and load (demand) management programs that will reduce electric power consumption. Conservation measures are those actions that can be taken by electric consumers either to reduce the wasteful consumption of energy or to increase the efficiency of the overall generation and distribution system.

Load (demand) management is defined as any action taken by a utility to modify its daily load curve in a positive manner. The utility may elect to do this either actively or passively. Active load management is any act that controls the amount of energy a consumer can use, and includes interruptible rates and control of customer loads through various signaling and mechanical devices. Passive load management covers a wide gamut of activities, from consumer education programs and general appeals to time-differentiated rates and customer-owned and operated load control technologies.

Electric energy conservation--the substitution of energy efficient measures and practices for traditional electric energy uses--can provide consumers with desired electricity services at a lower cost. Conservation can reduce the economic shock of both sudden electricity price hikes caused by an interruption in energy supplies and the long-term upward trend in energy prices. Cost-effective conservation directly increases a family's disposable income and indirectly increases real income by holding down electricity prices and reducing inflation. In fact, energy conservation was an important strategy in breaking the oil price-induced stagflation of the 1970s.

Several load management and energy conservation technologies that can be implemented in Djibouti in the near future are described below. The impacts of these technologies on system capacity expansion requirements are discussed later in this Chapter.

Load Management Technologies

Three load management techniques can reduce peak demand in the EdD system: (1) direct load cycling of air conditioners; (2) demand subscription service; and (3) power factor improvement.

Direct Load Cycling of Air Conditioners. Air conditioning loads in the residential, commercial, and government building sectors in Djibouti account for over 80 percent of peak demand during the

summer months (May to September). Therefore, the direct control or cycling of air conditioners has the potential for immediate peak demand reduction in the EdD system.

Demand Subscription Service (DSS). Under the demand subscription service, each customer is provided with a demand alarm device that indicates the level of electric demand. Whenever the subscribed level of demand is exceeded, the device gives an alarm signal and disconnects the load (customer).

Power Factor Improvement. In the EdD system, the power factors in different load sectors vary from 0.65 to 0.8. The primary advantages of power factor improvement are:

- reduced transmission and distribution losses (I^2R losses);
- recovery of system capacity and deferral of capital expenditure for expansion;
- release of circuit capacity for applications of additional load; and
- improved voltage regulation.

Energy Conservation Technologies

In Djibouti, the opportunities for energy conservation fall into three general categories: (1) efficiency of production; (2) efficiency of product use; and (3) control of the rate of energy use. The opportunities within each category were evaluated for each of the four classes of users (i.e., residential, government, large customers, and commercial and industrial combined). In order to quantify the savings from the implementation of conservation measures, these sectors were analyzed for the short-range (by 1990), medium-range (by 1995), and long-range (by 2000) time periods. The data on energy conservation opportunities in the above sectors were derived from various USAID reports on Energy Initiatives in Africa projects in the sub-Saharan countries.

LOAD MANAGEMENT

The development of estimates of EdD system load impacts from the implementation of a direct load management program is described in this section. In particular, the direct cycling of air conditioning loads during peak hours is considered. Through load management, the patterns of electric energy supply and use can be modified to improve the production and delivery of electric energy in the EdD system.

Load management is often divided into "use management" and "supply management." Use management is the direct and voluntary control of selected loads of end-use customers. Supply management, on the other hand, concentrates on the coordination of the planning and operating needs of utilities to ensure the availability of needed capacity.

Use management can be accomplished through four principal means:

- o price control through the rate structure;
- o voluntary load management by customers;
- o customer-owned energy storage devices; and
- o direct mechanical control such as DSS.

The discussion that follows deals exclusively with the mechanical control of air conditioning loads in the EdD system.

System Load Characteristics

The demand for electricity fluctuates on an hourly, daily, and seasonal basis. For load management program studies, it is important to analyze the daily and seasonal characteristics of system load curves. Figure 3.1 illustrates the typical annual load profile of the EdD system in relation to temperature variations. It is interesting to note in the graph the saturation of air conditioning loads (indicated by the flat peak) during the months of June, July, August, and September. The saturation of the peak load during the summer months may be due to the running of all available air conditioners. However, it is much more likely that the saturation is due to the rotating blackouts that occur on peak days of the summer months due to capacity shortages.

Throughout the year, the EdD system load closely follows the ambient temperature variation; therefore, it is logical to assume that during the summer months this trend will continue (if there were no supply restrictions). Figure 3.2 illustrates the correlation between energy consumption and seasonal temperature variation in the EdD system. Figure 3.3 illustrates the 1983 peak day 24 hours load profile. The annual load curve of Figure 3.1 indicates the distinct seasonal characteristics of EdD system demand. In general, during May, June, July, August, and September, the peak demand occurs during the period from 12 noon to 3:00 p.m. However, during the winter months the system peak demand is about 50 percent of the summer peak demand, and occurs during the evening hours (usually at 7:00 p.m.).

The opportunities for demand reduction programs can be easily evaluated from the daily and monthly load factor values. A low daily load factor value indicates needle-like peaking characteristics. Usually, any daily load factor value under 85 percent indicates opportunities for load management programs. In Figure 3.4, the peak day load factors for the twelve months of 1982 are

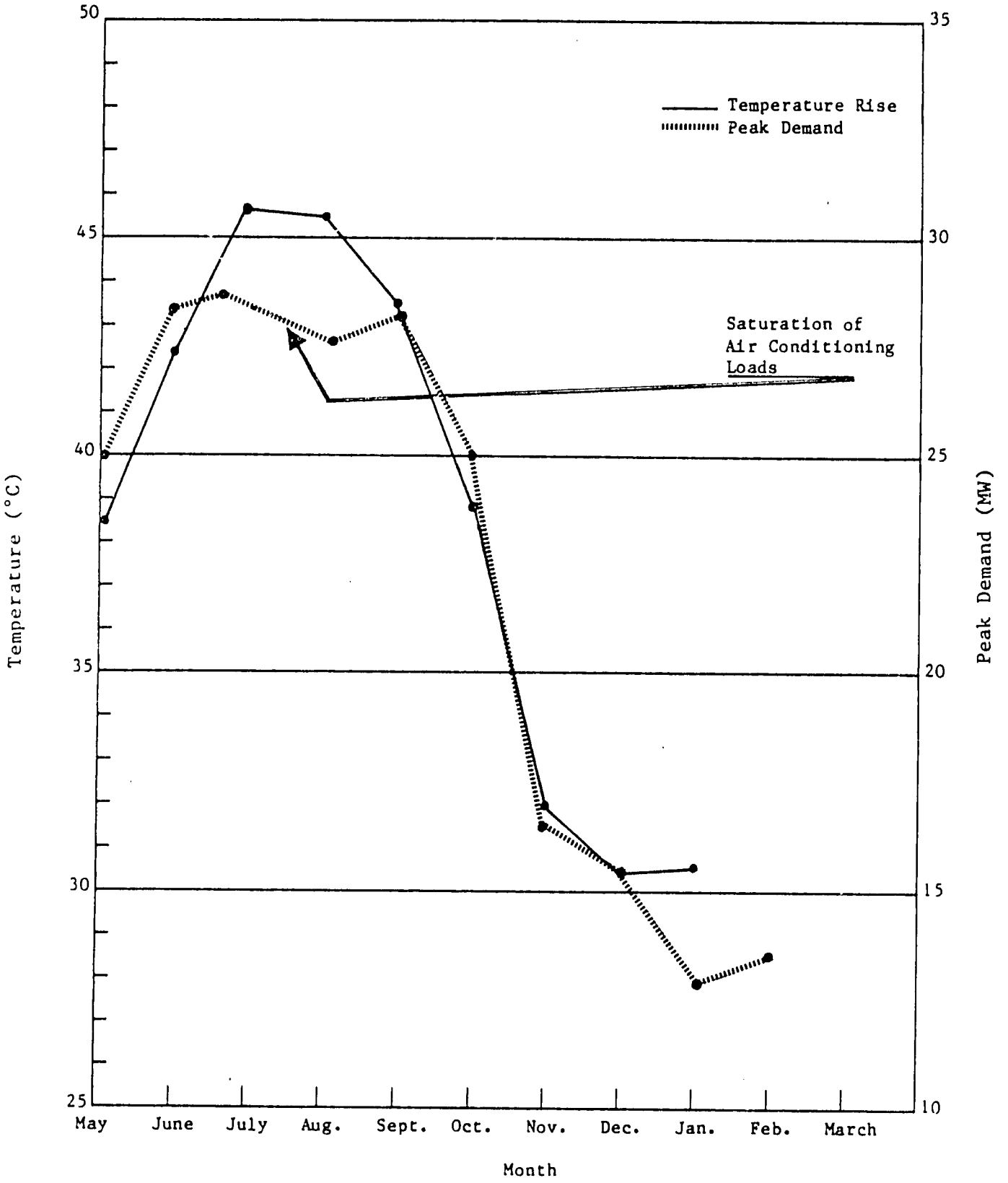


FIGURE 3.1

Actual Data for 1983 and 1984

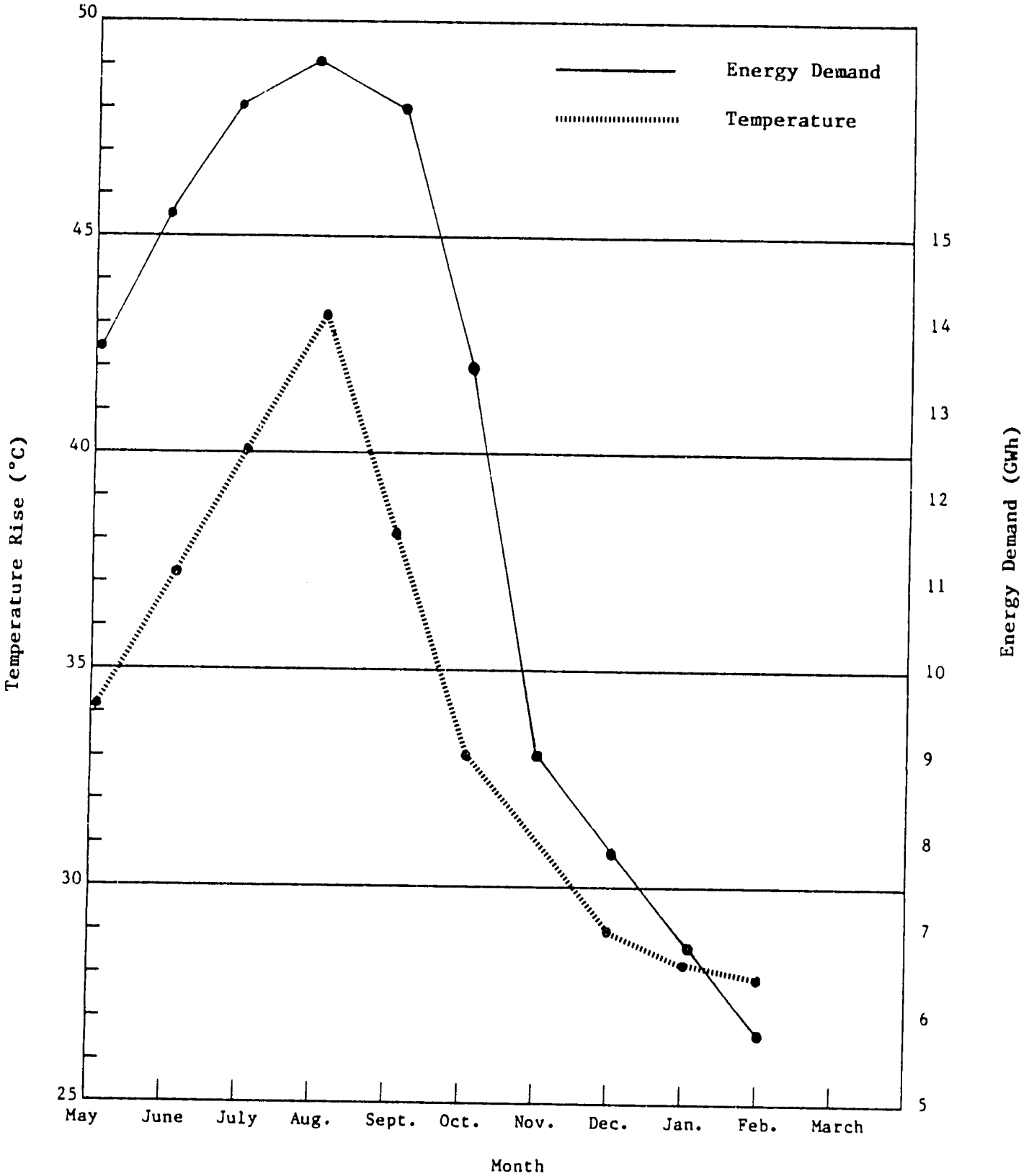


FIGURE 3.2

Actual Data for Energy and Temperature Correlation for 1984

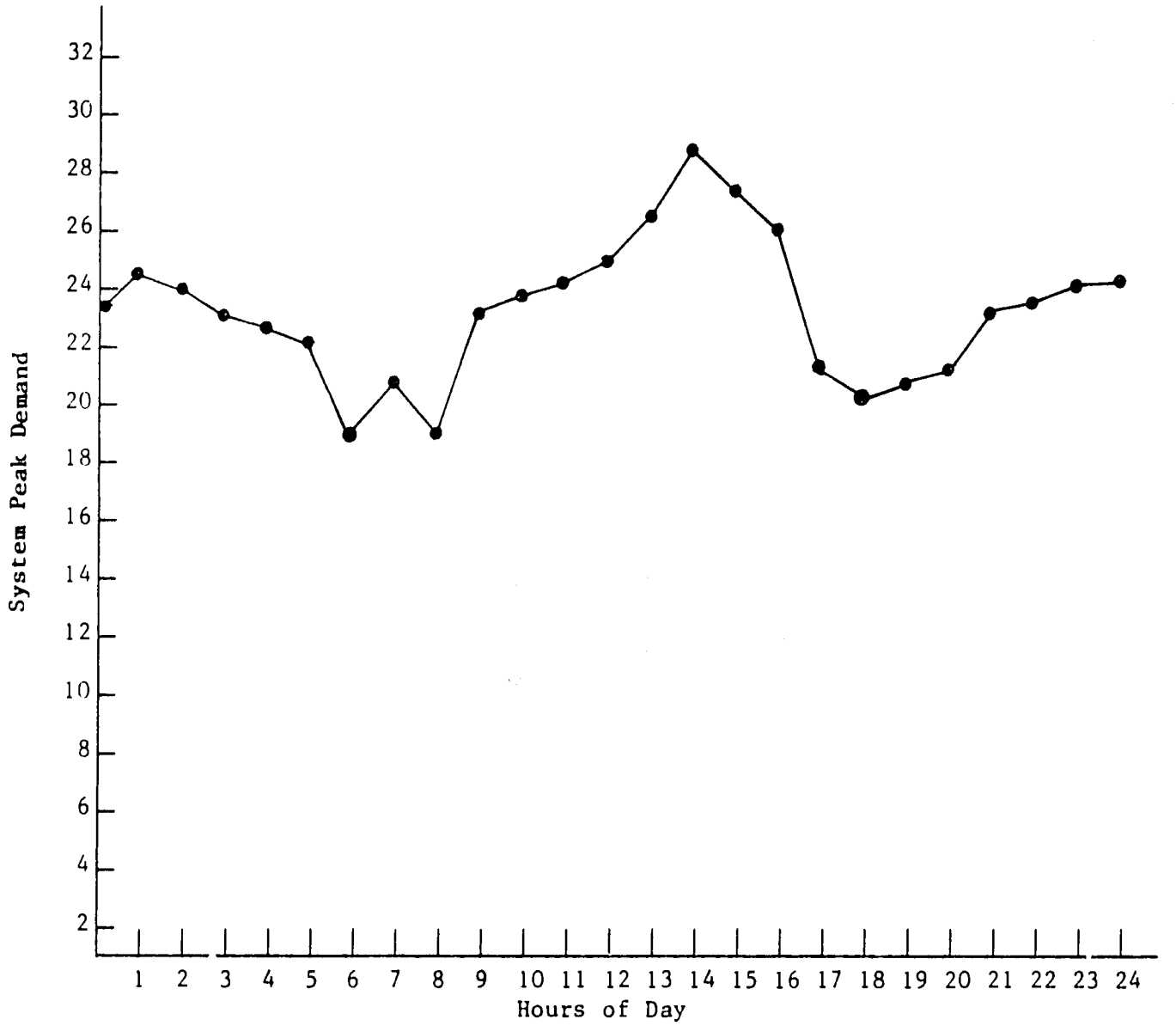


FIGURE 3.3

1983 Peak Day Demand Profile (July)

given. As shown in Figure 3.4, the average daily load factor of the EdD system is approximately 79.5 percent, including three power outage days, and about 84 percent excluding those power outage days. In Figure 3.5, the monthly load factors for 1982 are presented. It is quite evident from Figures 3.4 and 3.5 that the opportunities for significant peak demand reduction on both a daily and seasonal basis are very limited for the EdD system.

In Figure 3.6, the estimated total air conditioning loads available for cycling in a 24-hour period during the month of July are included. The air conditioning load data given in Figure 3.6 was developed from the graph depicted in Figure 3.7, which shows the actual increase in demand from December 1982 to the peak month of July 1983. In Figure 3.6, the air conditioning loads for a 24-hour period were adjusted for six months growth, and it is assumed that 80 percent of the net increase in seasonal demand is due to air conditioning loads. Similar tables can be developed for the other summer months (May, June, August, and September).

System Load Impacts

In Djibouti, no load research and demonstration efforts have been attempted to date on air conditioning load control. However, air conditioning load control data from other countries can be used to roughly estimate the system load impacts of controlling air conditioners in the residential, commercial, government, and other large customer sectors.

An air conditioner is not really a deferrable load in the sense that it cannot be cycled off for any length of time beyond its own natural off-cycle time without lowering comfort levels within the home or office to some degree. The standard method of remote air conditioning cycling involves the shutting off of the compressor via the interruption of low voltage control lines for some fixed period of time each hour. Typically, this period is 7-1/2 minutes each half hour, or 15 minutes each hour. It is theorized that such a forced cycling scenario will reduce the normal on-time of the air conditioner compressor, thereby resulting in a lower integrated demand by the unit. It is from the lowering of the integrated demand by the air conditioner on the utility's system that the desired reduction in demand is realized.

Due to anticipated system-wide variation in customer tolerance levels and air conditioner sizing, any program that relied on control via fixed time cycling could be expected to produce some mix of over, under, and optimum control among customers. In order to minimize customer complaints and withdrawals, it may be necessary for a utility to utilize a more conservative cycling scenario which produces less than optimal demand reduction.

Figure 3.8 lists the maximum possible hourly demand reduction due to air conditioning load cycling. The demand reduction numbers in

FIGURE 3.4

1982 Monthly Peak Day Load Factor

Month	Peak Day Load Factor (%)	Peak Hours
January	80	19
February	83	19.5
March	86	12
April	52 [a]	22
May	77 [a]	22.5
June	84	15
July	83	14
August	84	15
September	68 [a]	23
October	87	14
November	86	11
December	85	19

Source: EdD.

[a] Power outages or rotating blackouts.

FIGURE 3.5

1982 Monthly Load Factors

Month	Load Factor (%)
January	92
February	89
March	91
April	83
May	92
June	73 [a]
July	93
August	90
September	75 [a]
October	80
November	94
December	88

Source: EdD.

[a] Power outages or rotating blackouts.

FIGURE 3.6

Air Conditioning Loads Available for Control During Peak Month of July [a]

Hours	Seasonal (July) Increase in Demand (MW)	Air Conditioning Loads (MW)
1	13.8	10.6
2	13.8	10.9
3	13.5	10.4
4	13.2	10.2
5	12.4	9.5
6	9.4	7.1
7	10.3	7.8
8	7.3	5.4
9	9.2	6.8
10	9.4	6.7
11	9.5	7.0
12	9.5	7.0
13	13.9	10.6
14	16.9	13.0
15	16.0	12.3
16	14.2	10.9
17	12.5	9.5
18	5.8	4.2
19	5.5	3.8
20	6.0	4.2
21	8.7	6.3
22	10.3	7.7
23	12.3	9.4
24	11.1	8.4

Notes: Seasonal growth from December 1982 to July 1983 is assumed to be 5 percent.

It is assumed that 80 percent of the net increase, after seasonal growth adjustment, is due to air conditioning loads on the EdD system.

[a] Values are derived from 1982 and 1983 load data.

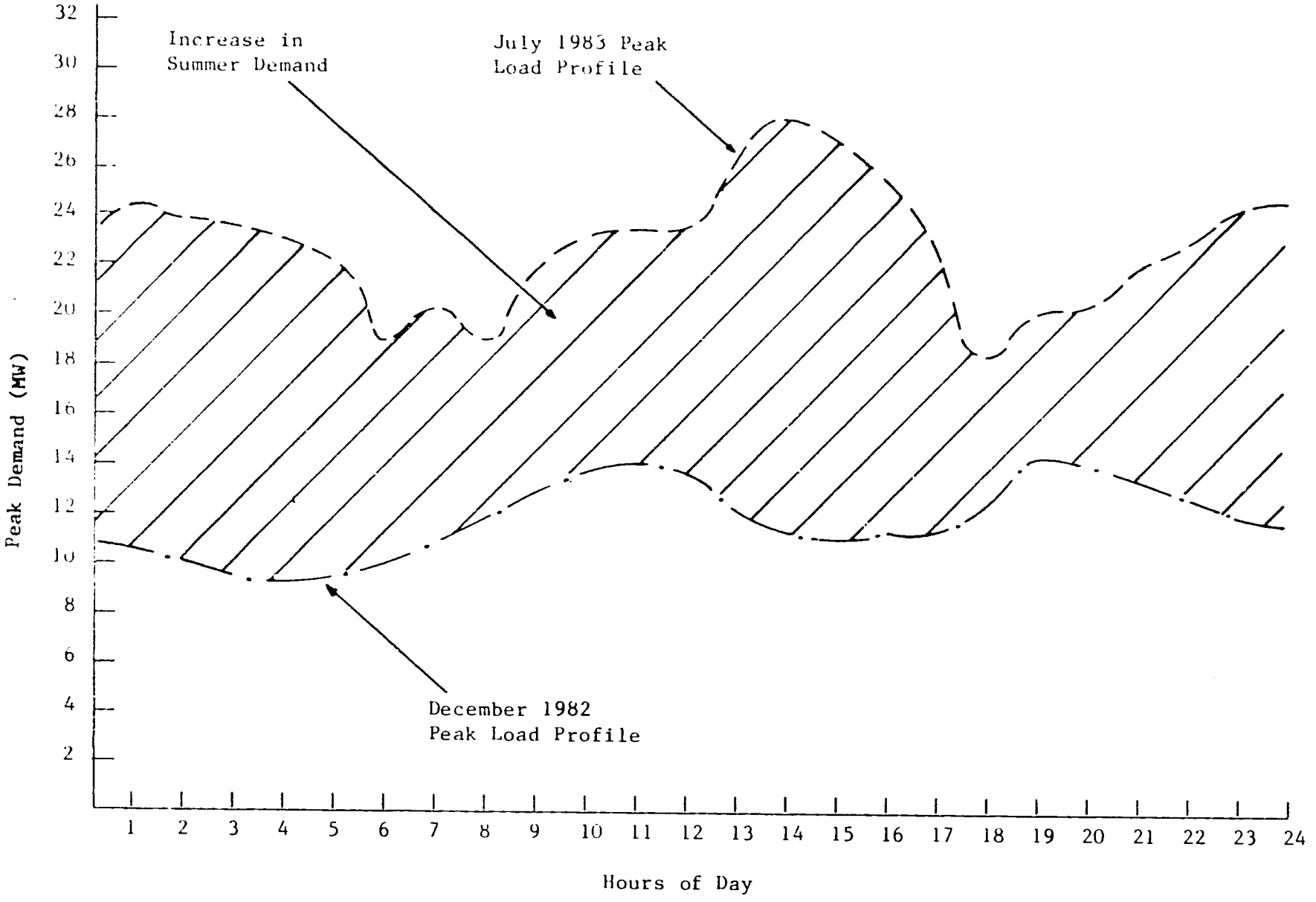


FIGURE 3.7

Increase in Demand Due to Air Conditioning Loads and Usual System Growth in Demand

FIGURE 3.8

Maximum Possible Demand Reduction Due to Air Conditioning Load Cycling (July 1983)

Hours	Peak Demand Reduction (MW)
1	2.65
2	2.72
3	2.60
4	2.55
5	2.37
6	1.77
7	1.95
8	1.35
9	1.70
10	1.67
11	1.75
12	1.75
13	2.65
14	3.25
15	3.07
16	2.72
17	2.37
18	1.05
19	0.95
20	1.05
21	1.57
22	1.92
23	2.35
24	2.10

Note: The average demand reduction for 24 hours is about 2.0 MW.

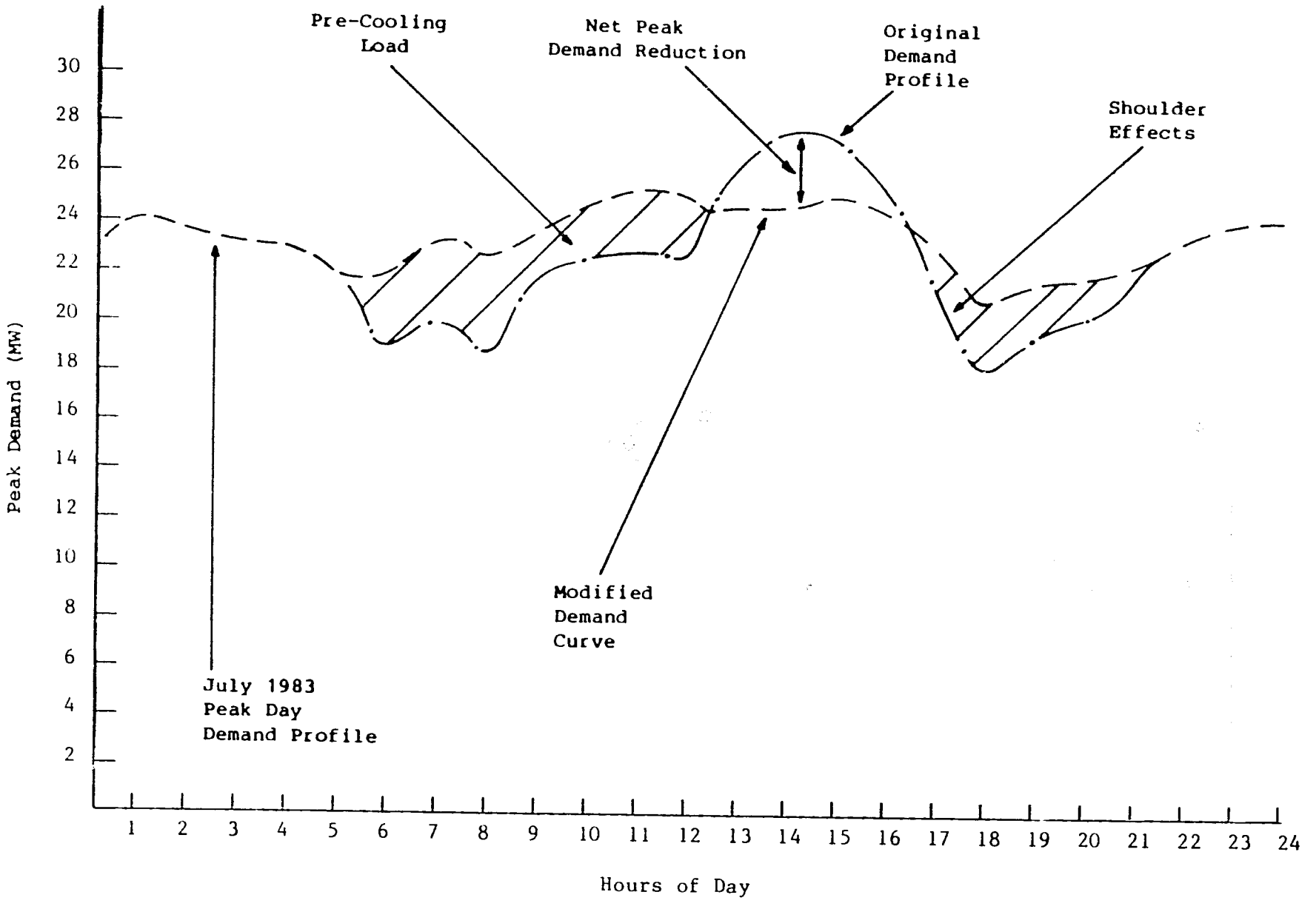


FIGURE 3.9

Peak Demand Reduction Due to Pre-Cooling

FIGURE 3.10

Impacts of Air Conditioning Load Management Program on Generation Expansion (EdD Demand Forecast)

Year	EdD Demand Forecast (MW)	Peak Demand Reduction Due to Air Conditioning Load Management Program (MW)	Modified System Peak Demand (MW)	Reserve Margin Criteria (%)	Available (Installed) Capacity Requirement (MW)
1985	36.1	-2.5	33.5	41.0	47.2
1986	39.7	-2.8	36.9	37.5	50.7
1987	43.3	-3.0	40.3	34.7	54.3
1988	47.2	-3.3	43.9	32.3	58.1
1989	51.3	-3.6	47.7	30.1	62.0
1990	55.3	-3.9	51.4	28.3	65.9
1995	73.8	-5.2	68.6	22.3	83.9
2000	98.0	-6.7	91.1	18.1	107.5

Figure 3.8 are based on a 25 percent demand reduction due to turning off air conditioners 7-1/2 minutes every half hour. Figure 3.9 shows graphically how the peak demand can be reduced by pre-cooling during off-peak hours or a few hours before the peak hours. The effect of pre-cooling and the net decrease in peak demand depend on the type of building facility and the insulation materials used in its construction. At any rate, for the historical year 1983, the average reduction in demand for a 24-hour period is about 2.0 MW, which translates to 7 percent of the peak demand (28.5 MW).

Impacts on Generation Expansion Requirements

The impacts of direct air conditioning cycling during peak hours on generation system expansion requirements are summarized in Figures 3.10 and 3.11 for the EdD demand forecast and the modified demand forecast. As indicated in Figures 3.10 and 3.11, even though the reserve margin requirements for the study period are slightly higher than those for the base case (see Figures 2.10 and 2.11), the generation expansion requirement by the year 2000 has been reduced by 8.0 MW for the EdD demand forecast and 9.0 MW for the modified demand forecast. It is important to note that the system reliability levels in the base case and load management case are the same since all satisfy the same planning reserve margin criteria. Direct control of air conditioning loads during peak hours may reduce the likelihood of load shedding or of rotating blackouts in future years.

POWER FACTOR IMPROVEMENT

Power factor (PF) is the ratio of actual (kW) to apparent (kVA) power. It also may be expressed as the cosine of the phase angle between the expressed voltage and the current.

$$PF = \frac{\text{Working Power (kW)}}{\text{Total Kilovolt-Amperes (kVA)}}$$

Usually, electric utilities require a power factor of 0.9 or better. However, a power factor of 0.9 indicates the need for power factor improvement. In the EdD system, the power factors for the different load sectors vary between 0.6 and 0.8 during the day.

The primary benefits of power factor improvement are:

- reduced system losses;
- improved voltage regulation; and
- recovery of system network capacity and deferral of capital expenditure for expansion.

FIGURE 3.11

Impacts of Air Conditioning Load Management Program on Generation Expansion (Modified Demand Forecast)

Year	Modified Demand Forecast (MW)	Peak Demand Reduction Due to Air Conditioning Load Management Program (MW)	Modified System Peak Demand (MW)	Reserve Margin Criteria (%)	Available (Installed) Capacity Requirements (MW)
1985	40.1	-2.80	37.30	37.1	51.1
1986	48.1	-3.36	44.73	31.8	58.9
1987	52.4	-3.66	48.73	29.6	63.1
1988	57.1	-3.99	53.10	27.6	67.7
1989	62.0	-4.34	57.66	25.8	72.5
1990	66.8	-4.67	62.12	24.3	77.2
1995	89.1	-6.23	82.86	19.5	99.0
2000	118.3	-8.28	110.0	16.0	127.6

In general, alternating current circuit loads exhibit inductive as well as resistive impedence characteristics. The inductive reactance in an air conditioning circuit requires an additional quadrature current component and a reactive power, which is a measure of the energy stored in the magnetic field associated with the inductance. This additional current also flows through the network system, producing voltage drops in the lines and reducing the overall efficiency of transmission. Moreover, even though the energy stored in the magnetic field during each half-cycle is returned to the source unused, it must be provided by the manufacturer and distributor of electrical energy. A utility also has the burden of providing the equipment needed to generate and distribute this additional energy. In order to compensate a utility adequately for the expenses of generation and distribution, energy that oscillates between the source and the circuit must be monitored and accounted for in the distribution of air conditioning energy. Electric utilities include in their rate schedules bonus and penalty provisions that equitably finance the various amounts of this service required by different customers. At present, a penalty for low power factor is not included in the EdD rate schedule.

Benefits of a Power Factor Improvement Program

A power factor improvement program is appropriate for any firm that purchases electricity at large commercial or industrial rates, or maintains one or more of its own substations. Specifically, power factor improvement is worthwhile if electricity use is characterized by any of the following situations:

- power demand is recorded in kVA;
- a kilovolt-ampere reactive (kVAR), or power factor, penalty is included in the electricity rate schedule;
- present capacity limits growth; or
- the consumer experiences low voltage or regulation of voltage.

Power factor improvement can save money in each of the above situations in three ways: (1) power factor improvement will reduce purchased power cost if electricity is bought on a kVA demand rate; (2) it will improve voltage regulation and ease any low voltage problems; and (3) it will increase the power-carrying capabilities of transformers and feeders. Significantly, power factor improvements in the areas of transmission, distribution, and end use will release locked up capacity and increase the efficiency with which the copper and aluminum in the electric system are used.

Capacitors should be installed as near the load as possible or near the ends of feeders for three reasons:

1. losses are reduced in the circuits between the loads and the metering point;

2. voltage is raised near the loads, giving better motor performance;

3. the capacitors' kVAR can be reduced automatically as the load drops off by installing some of the capacitors directly on the loads, thereby allowing the capacitors to be switched off at the loads.

The reduction in losses can be easily determined by investigating the length of the circuits, and the transformations, if any. Additional gains may result from released transformer capacity and reduction in losses in transformers and circuits. Also, the effect of the capacitor is to raise the voltage permanently at any given point where it is connected. This boost in voltage, superimposed on the normal voltage, is practically constant from no load to full load on the feeder.

Estimated Savings Due to Power Factor Improvement

The estimated present power factors and projected energy sales of Djibouti's different load sectors are presented in Figure 3.12. Improvements in each load sector's power factor can produce substantial financial savings. The annual savings from power factor improvement are easily calculated using the following equation:

$$\left[\frac{\text{(kWh sales/year)}}{\text{(present PF)}} - \frac{\text{(kWh sales/year)}}{\text{(improved PF)}}\right] \times \text{kWh rate}$$

For example, the domestic sector will consume about 50 million kWh of energy in 1985 at an average of DF 33/kWh (Tariff II, 1 kWh subscribed DF 37; average price is DF 33/kWh), and has a power factor of 0.70. If this sector's power factor is improved to 0.95, the total annual savings would be:

$$\left[\frac{(50.0 \times 1{,}000{,}000)}{(0.70)} - \frac{(50.0 \times 1{,}000{,}000)}{(0.95)}\right] \times \text{DF } 33$$

$$= \text{DF } (104.4 - 52.6) \times 10^6 \times 33$$

$$= \text{DF } 1{,}709.4 \times 10^6 \ (\text{US \$}9.768 \times 10^6)$$

The estimated savings due to power factor improvement are calculated for 1985, 1990, 1995 and 2000 in Figure 3.13. The estimated

FIGURE 3.12

Present Power Factor and Energy Sales by Load Sector (GWh)

Load Sector	Estimated Present Power Factor	Energy Sales							
		1985	1986	1987	1988	1989	1990	1995	2000
1. Domestic	0.70	49.93	54.87	59.85	65.26	70.91	77.83	107.6	142.89
2. Industrial	0.65	9.41	10.34	11.28	12.30	13.37	14.67	20.28	26.94
3. Commercial	0.70	7.70	8.41	9.23	10.06	10.94	12.00	16.59	22.04
4. Government & Street Lighting	0.70	24.20	26.65	29.07	31.69	34.44	37.80	52.25	69.40
5. Other Large Customers (including French Army)	0.65	51.36	56.44	61.55	67.12	72.94	80.05	110.66	146.98

Source: EdD.

FIGURE 3.13

Estimated Savings Due to Improved Power Factor

Load Sector	Estimated Present Power Factor	Improved Power Factor	Potential Savings (DF x 10^6)			
			1985	1990	1995	2000
1. Domestic	0.70	0.95	1,709.4	346.1	369.3	438.0
2. Industrial	0.65	0.85	156.7	87.6	93.4	110.9
3. Commercial	0.70	0.90	112.4	62.8	67.0	79.6
4. Government & Street Lighting	0.70	0.90	353.4	198.6	211.0	250.4
5. Other Large Customers (including) French Army	0.65	0.85	743.6	414.7	443.9	525.9
Total Savings			3,075.5	1,109.8	1,184.6	1,405.0

Source: EdD.

Note: The following electricity rates have been assumed for different load sectors: domestic = DF 33/kWh; commercial, industrial, and government = DF 46/kWh; and other large customers = DF 40/kWh.

savings for other years can be computed from Figure 3.13 for each load sector's PF value.

A comparison of the estimated savings and costs of power factor correction indicates that the savings resulting from power factor improvement far outweigh the initial capital expenditure. For example, total capacitance of 5.5 megavolt-ampere reactive (MVAR) is applied to a substation (10/13 MVA, 24/11 kV transformer) to raise the PF from 0.72 to 0.866. The effects of this improved PF on the system are summarized in Figure 3.14. The average cost of capacitor installation per kVAR is US $14. Therefore, the total cost of PF correction to 0.866 is (US $14 x 5,500 = US $77,000) US $77,000, or DF 13.5 x 10^6. Excluding revenue gained from improvements in the voltage condition, the estimated savings per year is about DF 24.5 x 10^6. Therefore, it is quite evident that the savings due to PF correction far outweigh the initial capital expenditure.

Effects of Power Factor on kVA Demand

The most practical and economical method of power factor improvement involves the use of capacitors. In general, utilities use two methods for improving power factor with capacitors. The first method is bank installations, in which a group of capacitors is connected at a central point such as the main substation. In most cases, this method only reduces the losses at the utility company. However, it is slightly less expensive than the alternate method, which involves installation of individual capacitors directly at the source of poor power factor (at an induction motor, for example). Although more expensive, this method has all the benefits of the bank installation plus the advantages of released system capacity, improved voltage regulation, and reduced power loss.

The following example demonstrates the effect of low power factor on kVA demand: companies often use oversized fan motors to ensure a safe start-up condition. Hence, for a fan that requires 67 brake horsepower (bhp), the company uses a 100 horsepower (hp) induction motor to provide driving power. The power factor of the 100 hp motor at 67 bhp is 0.79; the resulting kVA is:

$$\frac{67 \text{ bhp} \times 0.746 \text{ kW/hp}}{0.79} = 63.27 \text{ kVA}$$

Had the company elected to use a 75 hp induction motor, the power factor of 67 bhp would have been higher--about 0.83. For this condition, the resulting kVA would have been:

$$\frac{67 \text{ bhp} \times 0.746 \text{ kW/hp}}{0.83} = 60.22 \text{ kVA}$$

FIGURE 3.14

Case Study: Power Factor Improvement

	Before	After
	PF = 0.72	PF = 0.866
1. Losses	1.24 MW	0.72 MW
2. Voltage Regulation	9.92 kV	10.3 kV
3. Recovery of System Capacity	a. 24 kV line loading = 18.33 MVA b. Feeder Loading = 3.66 MVA	a. 24 kV Line Loading = 13.86 MVA b. Feeder Loading = 2.83 MVA

This result is 3.05 kVA lower than the 100 hp motor. If motor efficiency were taken into account, the 75 hp motor would probably run at a higher efficiency, thus widening the gap.

ENERGY CONSERVATION

In domestic, commercial, and government buildings, more than 80 percent of the electrical energy is consumed by air conditioners and lighting during the summer months. Reducing energy in all buildings by 10-20 percent without impairing the environment--the equivalent of cutting present oil imports by 5-10 percent during the study period--is a realistic possibility for Djibouti. Most buildings in Djibouti were designed and constructed when fuels and electric power were readily available and inexpensive and the need for energy conservation was not recognized. Building structures and their mechanical and electrical systems were designed to minimize initial construction costs, not energy use. Buildings in Djibouti are usually overcooled, overlighted, overventilated, and inefficiently operated year-round. Each year they consume increasing amounts of energy because their electrical systems and building components deteriorate as maintenance and servicing become more costly and neglected.

Conservation Priorities

In Djibouti, the end uses that consume the most energy are, in order of magnitude:

1. air conditioning;
2. lighting; and
3. equipment and processes.

However, the relative order of magnitude of energy consumption among these end uses will change depending on building construction; use and mode of operation; and type of control and efficiency of mechanical and electrical equipment such as elevators and refrigerator motors. In the domestic sector (upper income class), the amount of energy required for air conditioning typically ranges from 40-60 percent of total energy used in a facility. However, this percentage may be much higher in some facilities, such as hotels and hospitals. In retail stores, high levels of general illumination and display lighting or a large number of commercial refrigeration units consume the greatest amount of electricity. Equipment and processes and systems include motors, compressors, and pumps that are primarily used in industry, large government buildings, and hotels.

FIGURE 3.15

Electricity Conservation Potential by Load Sector and End Use [a]
Load Sector: Domestic

Conservation Measures	Total Energy Sales (GWh)			Reduction (%)			Short-Range Reduction (GWh)	Medium-Range Reduction (GWh)	Long-Range Reduction (GWh)
	Short-Range (1985)	Medium-Range (1990)	Long-Range (2000)	Short-Range (1985)	Medium-Range (1990)	Long-Range (2000)			
Air Conditioning Loads (45%)	24.9	42.3	84.1						
1. Reduce infiltration	--	--	--	6	--	--	1.50	--	--
2. Clean coil and filter	--	--	--	3	--	--	0.75	--	--
3. Replace with central air conditioning	--	--	--	--	--	6	--	--	5.0
4. Reduce hours of use	--	--	--	10	--	--	2.50	--	--
5. Increase temperature to 80°C	--	--	--	5	--	--	1.25	--	--
SUBTOTAL							-6.00	0.0	-5.0
Lighting Loads (40%)	22.2	37.6	74.8						
1. Switch to more efficient lights	--	--	--	5	--	--	1.11	--	--
2. Energy efficient design	--	--	--	--	8	--	--	3.0	--
3. Add light controls	--	--	--	7	--	--	1.55	--	--
4. Delamp	--	--	--	--	--	--	--	--	--
SUBTOTAL							-2.66	-3.0	0.0
Other Miscellaneous Use (15%)	8.3	14.1	28.0						
TOTAL SALES	55.4	94.0	186.9	TOTAL REDUCTION (GWh)			-8.66	-11.66	-16.66

[a] Data is derived from Figure 2.9.

FIGURE 3.16

Electricity Conservation Potential by Load Sector and End Use [a]
Load Sector: Commercial and Government

Conservation Measures	Total Energy Sales (GWh)			Reduction (%)			Short-Range Reduction (GWh)	Medium-Range Reduction (GWh)	Long-Range Reduction (GWh)
	Short-Range (1985)	Medium-Range (1990)	Long-Range (2000)	Short-Range (1985)	Medium-Range (1990)	Long-Range (2000)			
Air Conditioning Loads (45%)	15.90	27.10	53.80						
1. Reduce infiltration	--	--	--	6	--	--	0.95	--	--
2. Clean coil and filter	--	--	--	3	--	--	0.48	--	--
3. Reduce hours of use	--	--	--	10	--		1.60	--	--
4. Increase temperature to 80°	--	--	--	5	--	--	0.80	--	--
5. Replace with central air conditioning	--	--	--	--	--	10	--	--	1.60
Cooking (2%)	0.71	1.20	2.40						
1. Improve operation	--	--	--	1.5	--	--	0.01	--	--
2. Replace electric with gas	--	--	--	--	--	1.5	--	--	0.04
Lighting (47%)	16.64	28.30	56.21						
1. Convert to more efficient source	--	--	--	--	5	--	--	1.40	--
2. Convert to high efficiency flourescent	--	--	--	--	5	--	--	1.40	--
3. Improve lighting control	--	--	--	--	8	--	--	2.30	--
4. Delamp	--	--	--	7	--	--	1.16	-5.10 --	--
Refrigeration (3%)	1.06	1.08	3.6						
1. Reduce infiltration	--	--	--	5	--	--	0.05	--	--
2. Install high efficiency units	--	--	--	--	--	10	--	--	0.36
Miscellaneous (3%)	1.06	1.8	3.6						-2.00
1. Good housekeeping				1			0.01		
TOTAL SALES	35.4	60.2	119.6	TOTAL REDUCTION (GWh)			-5.06	-10.16	-12.16

*Data is derived from Figure 2.9.

FIGURE 3.17

Electricity Conservation Potential by Load Sector and End Use [a]
Load Sector: Industrial

Conservation Measures	Total Energy Sales (GWh)			Reduction (%)			Short-Range Reduction (GWh)	Medium-Range Reduction (GWh)	Long-Range Reduction (GWh)
	Short-Range (1985)	Medium-Range (1990)	Long-Range (2000)	Short-Range (1985)	Medium-Range (1990)	Long-Range (2000)			
Motors (90%)	9.36	15.93	31.77						
1. Replace with more efficient and proper size motors	--	--	--	--	5	5	--	0.80	1.60
2. Other miscellaneous improvements	--	--	--	--	5	5	--	0.80	1.60
3. Good housekeeping	--	--	--	2	--	--	0.19	--	
SUBTOTAL							-0.19	-1.60	3.20
Other Use (10%)	1.04	1.77	3.53						
TOTAL SALES	10.40	17.70	35.30	TOTAL REDUCTION			-0.19	-1.79	-4.99

[a] Data is derived from Figure 2.9.

FIGURE 3.18

Electricity Conservation Potential by Load Sector and End Use [a]
Load Sector: Miscellaneous Other Large Customers

Conservation Measures	Total Energy Sales (GWh)			Reduction (%)			Short-Range Reduction (GWh)	Medium-Range Reduction (GWh)	Long-Range Reduction (GWh)
	Short-Range (1985)	Medium-Range (1990)	Long-Range (2000)	Short-Range (1985)	Medium-Range (1990)	Long-Range (2000)			
Lighting Load (50%)	28.5	48.4	96.2						
1. Switch to more efficient lights	--	--	--	5	--	--	1.4	--	--
2. Switch to efficient fixtures	--	--	--	5	--	--	1.4	--	--
3. Add light control	--	--	--	--	8	--	--	3.90	--
4. Delamp	--	--	--	7	--	--	2.0	--	--
Other Use (50%)	28.5	48.4	96.2			10			1.9
TOTAL SALES	57.0	96.8	192.4				-4.8	-8.7	-10.6

[a] Data is derived from Figure 2.9.

Impacts of Energy Conservation

The impacts of an energy conservation program for the short- and medium-range periods are quantified for each load sector in Figures 3.15 through 3.18. The energy conservation measures in the short-range period (by 1986) include technologies that are proven to be cost-effective in developing countries and that can be implemented immediately. The medium-range conservation measures include technologies that are known to be energy efficient but will require three to five years to implement. For example, window air conditioners, which are used extensively in domestic and government buildings, can be replaced by more efficient central air conditioning systems. In developing Figures 3.15 through 3.18, it has been assumed that any conservation measures requiring redesign or replacement of existing equipment will only be implemented after the wear-out period of that piece of equipment.

There are many conservation measures that can be taken in domestic and government buildings which are not identified in Figures 3.15 through 3.18 due to lack of available data and time constraints in carrying out this study. For example, substantial energy conservation in domestic and government buildings can be achieved in the medium- and long-range periods by implementing the following design and construction modifications:

- o selection of building configurations that minimize southeast-southwest wall or window exposures to reduce cooling loads;
- o selection of building configurations and wall exterior arrangements that provide self-shading;
- o reduction of heat gain through windows can be achieved through:
  - reduced glazing;
  - use of double glazing or double reflective glazing to reduce transmission of heat; and
  - shading windows year-round from direct solar radiation;
- o use of natural light to reduce electric energy consumption;
- o use of light-colored materials for walls and ceilings; and
- o installation of adequate insulation.

INTERRUPTIBLE RATES

Interruptible or curtailable power may be defined as electric service of lower reliability than "firm" (or guaranteed) power services. Interruptible power may be cut off during conditions of system emergency, such as inadequate total available capacity, inadequate energy capability, or inadequate operating reserve, in order to maintain a high degree of reliability of service to users of firm power. Because it may be interrupted, this type of power enables the utility to reduce the amount of peak generation capacity it would otherwise need to provide. Therefore, the rates for interruptible power are lower than firm demand (kW) rates.

In the EdD service area, there are quite a few private electric generating facilities installed by commercial, industrial, and residential customers as a backup supply for electricity. It has been estimated that a total of 2.5 to 3.0 MW of self-generating capacity is installed in the EdD service area. Interruptible rates can be designed to encourage customers with self-generating facilities to disconnect during peak periods or during a supply/demand imbalance, to prevent outages. Use of this backup supply during such special periods will not only release generating capacity but also significantly relieve the network's transmission and distribution load.

Operating Benefits of Interruptible Loads

From the standpoint of system operations, an interruptible load constitutes a form of available capacity, in that cutting the load has the same effect on available reserve as increasing capacity. One important difference between the two is that, whereas the system operators have precise information on the status of capacity, they do not know with the same precision how much interruptible load is available for dropping at any moment. However, an estimate of all the self-generating customers' and other interruptible customers' load profiles can be gathered that will provide information on how much interruptible load is available at any instant.

At present, the EdD system is operating with inadequate operating reserve due to an installed capacity shortage. An interruptible load can be considered as "non-spinning" reserve, i.e., the capacity is available for loading within 15 to 30 minutes. The interruptible power will serve as insurance against a system failure so that sufficient spinning reserve is available if another failure should occur. Also, different classes of interruptible loads may be cut to effect daily economy savings.

In the long run, selling more interruptible power to self-generating customers would save the EdD system the cost of generation equal to the load that would otherwise be firm, plus the corres-

ponding reserve margin needed to support this firm load. The value to the system, and hence the justification for providing this class of service at reduced rates, depend upon the right to interrupt. Also important is the amount of curtailable power available at any given time, and its response time.

Short-Range Capacity Savings

The value of self-generating and other customers' interruptible loads in reducing peak generation for the study period is hard to assess without a detailed load survey. In particular, the exact potential savings in kilowatts of peak generation corresponding to each kilowatt of interruptible load can be difficult to determine. In making this determination, the following factors must be taken into account:

1. the diversity among the interruptible loads, and the diminishing effectiveness of successive increments of interruptible load sold;

2. during cuts in power, customers may be allowed a tolerance of, for example, five percent on the cutting floor without penalty;

3. customers may be allowed to convert from interruptible to firm power on short notice; and

4. the additional administrative costs, system losses, and savings in generating reserve that would result from the load's being interruptible rather than firm.

However, the second and third factors above are institutional issues. EdD may decide that interruptible customers will not be allowed to convert to firm power for two or three years. Similarly, the cutting floor tolerance option may be totally eliminated from the structure. The chief use of interruptible power is to reduce peak load at times of system emergency, during years of capacity shortage, or if there is any slippage of installation dates of new units. For this reason, EdD should compare the value of interruptible capacity to the cost of the marginal plant or peaking capacity and an allowance for additional capacity requirements for reserve margin.

Figure 3.19 illustrates the effects of interruptible loads on the supply/demand balance and the reserve margin requirements for the EdD system. It should be noted that the estimated available capacity of the interruptible loads in Figure 3.19 is assumed, based on a diversity factor of 10 percent, to account for the unavailability of some interruptible loads. When compared with the minimum capacity expansion requirements presented in Figure 2.10, it is quite evident from Figure 3.19 that the capacity shortages for the study period can be substantially reduced.

FIGURE 3.19

Effects of Interruptible Loads on Reserve Margin Requirements for the EdD System

	1985	1990	1995	2000
1. Peak Demand (MW) [a]	40.1	66.8	89.1	118.3
2. EdD Dependable Capacity (MW) [b]	48.0	54.2	49.4	44.6
3. Reserve Contribution from Interruptible Customers (MW)				
a. Customers with self-generators	3.0	3.0	3.5	3.5
b. Other large customers	2.0	3.3	4.5	6.0
Total (MW)	5.0	6.3	8.0	9.5
4. Available Interruptible Loads (MW) [c]	4.5	5.6	7.2	8.5
5. Reserve Margin Requirements (MW) (d)	18.9	18.8	19.4	20.4
6. Modified Reserve Margin Requirements (MW) [e]	14.4	13.2	12.2	11.9

[a] From Figure 2.3.

[b] From Figure 2.8.

[c] 90 percent of item 3.

[d] From Figure 2.9 (1985: 54.13 MW x 35% = 18.9 MW).

[e] Item 5 minus item 4 (Example: 18.9 MW - 4.5 MW = 14.4 MW).

OTHER OPTIONS FOR DEMAND REDUCTION

Three other demand reduction options for the study period are discussed below: (1) demand subscription service; (2) off-peak water pumping; and (3) a load shift program for large customers. All these options will require detailed system analysis to quantify the overall system impact. These options, however, may be divided into two categories: (1) "institutional solution" and (2) "engineering solution." The institutional solution options will require less capital investment than the engineering solution options.

Demand Subscription Service (DSS)

Air conditioners are only one of many household appliances that contribute to the EdD system peak demand. The direct control of air conditioning is a highly sensitive issue with customers, largely because such control will inevitably result in reduced comfort levels. This is easily understood when one considers the high cost of installed air conditioning equipment relative to the low cost of the electrical energy necessary to power the equipment. The residential customer has a number of alternatives available, other than air conditioning, which will allow reductions in electrical usage during system peak periods. Clearly, customers would be more receptive to a program that allows them the freedom to select which appliance they wish to use during peak periods rather than a program that limits the use of the one particular piece of equipment which they value most at that time.

The demand subscription service (DSS) concept allows customers to choose the minimum level of service that will satisfy their comfort needs during critical system peak periods. A DSS program is the first major attempt by an electric utility in the United States to experiment with a load management device that places a limit on the customer's electrical demand. In return, the customer will be compensated through the monthly bill in accordance with the level of service chosen. The demand limiting device is radio- or mechanically-controlled and is activated only during times of system peak. When activated, the device will trip (shut-off) the total house load only if the previously agreed level of demand is exceeded. The customer may manually reset the device only after reducing his household load below his subscription level.

A DSS program includes a testing and evaluation phase and a system-wide implementation phase. Each phase has specific objectives. The short-term objectives of the testing and evaluation phase include an evaluation of the cost effectiveness of the program. Four factors should be considered in determining the program's cost effectiveness:

1. customer acceptance and long-term adherence to reduced demand levels;

2. impact of reduced individual customer conservation and diversified group demand which are coincident with the system peak;

3. the reliability of equipment performance; and

4. the cost of equivalent generating capacity and energy.

Another short-term objective of the DSS program is a determination of the optimum combination of incentive levels and activation strategies to provide maximum load reduction while retaining an acceptable level of customer satisfaction.

If the program proves to be cost-effective, the long-term objective of the implementation phase is to gain the system-wide acceptance of the subscription service concept by demonstrating that the concept allows customers complete freedom to choose the level of service they prefer. When implemented as a condition of service, allowing customers to select their own level of service would provide an equitable basis for rewarding low demand customers and penalizing high demand customers through their rates. The established demand limits will make customers acutely aware of the peak load problem and will result in long-term load reduction, which can be counted on for extended periods of time. This will greatly facilitate generating resource planning and reduce the need for new generation capacity. For the short-range period, the DSS program has the potential of reducing peak demand by 2 MW.

Off-Peak Water Pumping

Load management for water pumping and agricultural power seeks to shift some pumping load from on-peak to off-peak hours by creating incentives for energy conservation. Municipal and agricultural pumping load management is aimed at reshaping load curves rather than reducing total energy use. In the EdD service area, the total water pumping load is about 1.3 MW at present, and demand is expected to grow at an annual rate of 6.5 percent. The forecasted water pumping loads for the study period are given in Figure 3.20.

Most water pumping should take place during off-peak hours to relieve capacity shortages. It has been estimated that at least 20 to 25 percent of water pumping demand can be shifted to off-peak hours by establishing interruptible rates for water pumping loads. This load shift to off-peak hours, however, may require the construction of additional water storage tanks for Djibouti Ville.

FIGURE 3.20

Electric Demand Forecast for Water Pumping

	1985	1990	1995	2000
Water Pumping Demand (MW)	1.3	1.7	2.2	2.8

FIGURE 3.21

Water Pumping Load Available for Deferral

	1985	1990	1995	2000
Load Available for Deferral (MW)	0.65	0.85	1.1	1.4

The operating characteristics of the water pumps in Djibouti indicate that at least 50 percent of the available water pumping load during peak hours can be deferred. Figure 3.21 indicates the total water pumping loads that can be dropped by EdD to reduce peak demand.

Load Shift Program for Large Customers

As the aggregate demand for electric energy continues to grow at an exponential rate in Djibouti, the ability of EdD to continuously meet load requirements is beginning to be less certain for two reasons. First, Djibouti is faced with potential shortages of energy resources in future years. Such potential shortages are becoming increasingly important to a number of customer groups, such as the new housing project at Balbala and other large customers. Second, power development is a lengthy and complex process, which seriously strains EdD's limited resources. Public awareness in Djibouti of this fact has grown increasingly in recent years as the result of power shortages (rotating blackouts) and electricity price increases. The need for demand reduction through load shedding has made these shortages particularly apparent.

One means of balancing the short-range supply/demand for the EdD service area is through the development of a policy that supports a shifting of the peak power demands of large individual customers within the daily load requirements. Such demand shifts would tend to flatten out the daily load curve, thus postponing the need for increasing generation capacity. Industrial customers offer an immediate opportunity for load shifting. For the commercial and residential sectors, additional time would be required for making appropriate recommendations due to the diversification of their members' characteristics and electricity use patterns.

In the EdD system, almost 50 percent of the peak demand is contributed by the large customers during daylight hours. In developing a load shift program for large customers, concern should be focused on the feasibility of its implementation and its probable side effects. To determine the feasibility of such a program, a load shift study should be carried out. As part of this feasibility study, the following three criteria for selecting large customers should be considered:

- fluctuations in the daily load curve other than those fluctuations due to traditional startup and stop day operations and lunch;
- a low load factor where load factor is defined as the ratio of average demand over a given time period to the maximum demand occurring in that period; and
- a low number of hours within a month where billing demand (maximum half hour) is used.

The feasibility of a policy to flatten a large customer's daily load curve depends on a number of economic, social, and technical issues. Such issues are not independent of one another. While there are technical improvements that could increase the efficiency of power usage, they usually demand a large capital investment. Such improvements may come from investments in new equipment or the placement of controls on old equipment (e.g., demand limiter attachments, permissive load controllers, or computers). These improvements regulate equipment operations according to their effect on the total power supply. At this time, the cost of power, relative to other operating costs, is probably not high enough to encourage such marginal capital investments.

An alternative to technical improvements as a means of flattening out the daily load curve is to vary the current labor and/or equipment operating schedules in a manner that would redistribute the power peaks. With respect to machine schedules, more effective scheduling may discourage simultaneous operation of high-powered equipment. Thus, equipment may be rescheduled to off-peak hours. Scheduled work breaks may be staggered to avoid a complete shutdown of the plant or office and minimize the re-sulting start-up peaks. Rescheduling of labor shifts to permit high power inputs to off-peak time periods is another option.

When considering the feasibility of proposed changes to labor and equipment operation schedules, the variety of production processes involved limit the degree of generalization that can be made for large customers. It is for this reason that individual interviews with companies are necessary instead of undertaking a generalized study of industrial scheduling.

Figure 3.22 presents an estimate of the total large customer load shift potential (in MW) for the study period. It should be noted that almost 12.5 percent of the peak demand can be shifted to off-peak hours. This shift in demand will significantly relieve the network's transmission and distribution load and thus will eliminate some of the cascading outages and load shedding requirements in future years.

FIGURE 3.22

Estimated Load Shift and System Peak Reduction for Large Customers

Year	System Peak Demand (MW) (1)	Contribution of Large Customers (2) = 50% of (1)	Estimated Load Shift (MW) (3) = 25% of (2)
1985	40.1	20.0	5.0
1990	66.8	33.4	8.35
1995	89.1	44.5	11.12
2000	118.3	59.1	14.77

Chapter 4

SUPPLY SCENARIO ANALYSIS

General Background
Relative Cost of Electricity Production
Assumptions for Levelized Cost Calculations
Supply Scenario Analysis

GENERAL BACKGROUND

Electricity supply plans are rarely, if ever, implemented exactly as they were originally proposed. Since unexpected events can significantly alter the implementation of a particular resource plan, major changes have been the norm rather than the exception in recent years. These unexpected events have ranged from delays in the construction of power plants due to financial constraints, to changes in the fuel price and supply situation. If anything is to be learned from these experiences, it is that no supply plan will progress smoothly. The key is whether or not the plan is so vulnerable that a small change destroys it or whether it has been thought out strategically so that it is robust and flexible enough to survive unexpected obstacles.

To illustrate the degree of capital investment diversity of different supply plans, the following four scenarios were examined as they would affect the price of electricity in future years:

Scenario #1: All future capacity addition is based on oil-fired generation.

Scenario #2: All future capacity addition is based on geothermal generation.

Scenario #3: All oil-fired generation plus implementation of demand management (load management) and energy conservation programs.

Scenario #4: All geothermal generation plus implementation of demand management and energy conservation programs.

RELATIVE COST OF ELECTRICITY PRODUCTION

This chapter presents the costs of electricity production for the above four scenarios on a levelized basis. Such levelized cost estimates will enable EdD to identify a constant level of revenue to recover all construction and operating expenses for each supply plan over its economic lifetime. In calculating the cost of generation, it is assumed that the power plant is constructed, owned, and operated by a public utility. The levelized cost of each supply scenario refers to the average cost of electricity produced by each technology (i.e., oil, geothermal, load management, and energy conservation) over a 30-year period. The commonly used technique of levelizing (or annualizing) costs provides a convenient method of comparing the various types of expenses involved in electricity generation.

The total cost of electricity generation includes three categories of costs: (1) capital-related expenses, (2) fuel costs, and (3) operation and maintenance (O&M) costs. Capital expenses are fixed costs, and are not subject to futher escalation once they are entered into the rate base as a lump sum at the beginning of a plant's useful life. Fuel and O&M costs are recurring expenses and can escalate over the lifetime of the plant. By converting each type of expense into a uniform annual equivalent amount, they become additive. Total plant costs may then be expressed as a levelized amount, or range, thus facilitating comparisons among scenarios.

In this report, the total levelized cost for each scenario is expressed as a range which reflects, to a degree, the uncertainty inherent in projecting future costs. Of the three components of total cost (capital, fuel, and O&M), the capital and fuel portions are by far the most important, since the O&M component is small--typically less than 10 percent of total cost.

Estimating plant capital costs can be difficult due to two major factors: (1) financial uncertainty (affects in-service cost estimates) and (2) uncertainty concerning plant hardware costs (affects instant cost estimates). Changes in financial factors, such as the cost of borrowing money, can greatly affect the total cost of those technologies that require substantial capital investments and have relatively long construction times.

Several other factors can make estimating plant costs difficult:

- changes in project specifications;
- uncertainty due to site-specific influences;
- degree of technological maturity; and
- level of production--modular technologies (which consist of numbers of identical components) can benefit from cost reduction due to the efficiencies of mass production and improvements in manufacturing techniques as experience is accumulated.

The future costs of power plant fuels are especially difficult to estimate since price changes occur not only due to technological reasons but also because of market pressures, which are influenced by many factors: political forces, interrelationships among different fuels, economic changes, etc. In the supply scenario analysis presented later in this chapter, the levelized fuel cost ranges for oil-fired generation are based on low, mid, and high fuel cost estimates as shown in Figure 4.1. These ranges are not intended to reflect specific price projections but rather represent escalation rates that might result from various political and economic scenarios which many consider plausible.

FIGURE 4.1

Fuel Oil Escalation Rates
(Percent per Year)

Period	Low Case		Mid Case		High Case	
	Real	Nominal	Real	Nominal	Real	Nominal
1983-1990	0.5	8.2	1.0	8.8	1.5	9.3
1990-2020	1.6	8.2	2.5	9.2	3.4	10.1

Although the relative cost of electricity production for the four scenarios is the focus of this chapter, it is only one consideration (although an important one) in electric energy supply planning. There are many additional factors that influence supply scenario choices (e.g., system diversity, fuel supply, power plant reliability, vulnerability to fuel shortages, load-following characteristics, and environmental impacts), and thus could ultimately affect their relative ranking. A balanced utility system would have a variety of generation technologies requiring different fuels. As a result, the system's vulnerability to shortages of any one particular fuel and the effects of government policy changes on a single generation technology would be lessened.

The assumptions used in calculating the levelized cost of electricity supply for each of the four scenarios are discussed below.

ASSUMPTIONS FOR LEVELIZED COST CALCULATIONS

The assumptions used to calculate the levelized cost for each supply scenario are given in Figure 4.2. A discussion of these assumptions follows.

Capital Costs

Capital costs can be expressed as either instant or in-service. The instant capital cost refers to the cost of land, labor, and materials as if all construction took place in a single year, and does not reflect any price increases during construction. Instant costs are presented (in Figure 4.2) in 1982 dollars. The in-service capital cost represents the actual dollar cost of the plant to the utility. It reflects all expenses related to construction, including price increases that may occur over the construction period and the cost of interest on borrowed construction funds. The utility must recover in-service capital costs over the economic life of the plant.

Fuel Costs

Fuel costs are expressed (in Figure 4.2) in dollars per million British thermal units of heat content ($/million Btu), and include purchase, transportation, and preparation costs. The cost of fuel is subject to potential price increases that may occur prior to plant start-up as well as during the plant's operational life. Estimates of potential price changes are expressed (in Figure 4.1) as annual percentage rates in both real and nominal terms.

FIGURE 4.2

Levelized Cost Data for Publicly-Owned Utilities
1990 - 2020

(Nominal US$)

Technology (Fuel)	Instant Capital Cost (5) (1982 $ per kW)	In-Service Capital Costs (3) (1990 $ per kW)	Capital Escalation (% per year)	Fuel Cost (1982 $ per 10^6 Btu)	Heat Rate (Btu per kWh)	Capacity Factor (%)	Fixed Charges Level (4) (¢ per kWh)	Fuel Level (1) (¢ per kWh)	O&M Level (1,2) (¢ per kWh)	Total Levelized Cost (Nominal US$)
Conventional Steam										
1. Residual Oil	695	1,280	8.3	4.88	9,400	80	1.9	17.5 - 23.5	0.6	20.0 - 26.0
2. Combustion Turbine Distillate	343	607	7.8	5.52	11,000	10	7.1	23.2 - 31.1	1.6	31.9 - 39.8
3. Combined Cycle Distillate	640	1,178	8.3	5.52	8,370	70	2.0	17.6 - 23.7	0.7	20.3 - 26.4
4. Geothermal Dry Steam	530-780	1,058 - 1,557	9.9	1.44	22,800	80	1.6-2.3	12.7	0.2	14.5 - 15.2

Operational and Maintenence Costs (O&M)

Operational and maintenance expenses consist of fixed and variable costs. Fixed O&M costs are yearly expenses that are unrelated to the level of plant operation and must be paid regardless of how much electricity is generated. Fixed O&M costs include items such as general upkeep, security, painting, etc. Variable O&M costs are directly related to the extent to which the plant is operated: as more electricty is generated, more expense is incurred.

Other Assumptions

The other assumptions (in Figure 4.2) used to calculate the levelized cost for each scenario are listed below.

- A discount rate of 13 percent was used to compute the levelized values.
- Fixed and variable O&M costs are assumed to escalate at a real annual rate of 1 percent.
- Total in-service costs include (a) an allowance for funds used during construction (AFDC), calculated at 8.4 percent (nominal) annually for publicly-owned utilities; and (b) capital escalation, using rates specific to each technology.
- Calculation assumes a fixed rate of 10.3 percent (nominal), for technologies with 30-year lifetimes (oil, geothermal, etc.).
- No escalation on allowance for funds used during construction.
- 1983 year cost expressed in 1982 dollars.

SUPPLY SCENARIO ANALYSIS

Scenario #1: All Oil-Fired Generation

A total of 78 MW will be added to the EdD system during the period 1985-2000. At present, the EdD system relies heavily on fuel oil and diesel oil for generating electricity. Under this scenario, EdD would become more dependent on imported oil. Availability of fuel oil could become a problem. Oil is vulnerable to supply interruptions and price escalation in the future. It is possible that the prices of imported fuel oils will increase significantly over the study period.

In Figure 4.3, an analysis of levelized cost data for Scenario #1 is presented. Item #12 indicates the total levelized costs for the installed capacities (item #3) for the study period. In items #13 and 14, the total energy production in GWh and Btu equivalent for this supply scenario are given. Item #15 indicates the barrels of fuel oil equivalent for the total energy production during the study period.

Scenario #2: All New Capacity Based on Geothermal

In Djibouti, all future generation expansion programs can be based on the country's geothermal resources. Aquater's recent study* indicated that there are several potential geothermal sites in Djibouti characterized by thermal manifestations (hot water springs and/or active fumaroles). Some of these sites are located in the following areas:

- Hanle' area--the estimated temperatures at a depth of 1,000 - 1,500 meters are at least 150 degrees C and the area's extension covers the entire Hanle' plain.
- Lake Abbé' area--the most promising sites are located near the hot water springs on the Lake's shores, as well as on the Lobaad plain.
- Caggade area--the geothermal region is very wide (about 500 kilometers); at present, no data is available on the quality of fluids (salinity) and on the reservoir depth.
- Lake Asal area--two boreholes have been drilled; one of these is productive and is presently under study.
- Alol area--hot water resources are numerous and situated along main coastal faults; their temperatures vary between 40 and 60 degrees C.
- Arta-Dorra area--this area is characterized by minor fumaroles and located along tectonic structures; rather low temperatures of 100 - 150 degrees C have been registered.
- Ghoubet area--this area is dense with fumaroles, and has surface temperatures around 100 degrees C.
- Obock-Tadjourah area--numerous hot water springs, with temperatures approximately 70 degrees C, can be found in the preshore region in the vicinity of Obock.

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*Aquater, "Technical Economic Study of Geothermal Prefeasibility" (ISERST), March 1982.

FIGURE 4.3

Levelized Cost Analysis for Scenario #1: All Oil-Fired Generation

	1985	1986	1987	1988	1989	1990	1995	2000
1. Planned Available Capacity (MW)	48.00	58.0	58.00	58.00	54.20	54.2	49.4	44.6
2. Required Capacity to Meet Peak Demand (MW)	54.13	62.8	67.10	71.93	77.00	82.10	105.40	136.16
3. Required Capacity Addition (MW)	6.00	--	3.00	5.00	9.00	5.0	28.0	35.5
4. Cumulative Capacity Addition (MW)	6.00	6.0	9.00	14.00	23.00	28.0	56.0	91.56
5. Instant Capital Cost (1982 $ x 10^6)	4.17	--	2.10	3.48	6.25	3.48	19.5	24.7
6. In-Service Capital Cost (1990 $ x 10^6)	7.68	--	3.48	6.40	11.5	6.4	35.84	45.4
7. Fuel Cost (1982 $ x 10^6)	1.95	--	0.976	1.60	2.89	1.60	9.0	11.41
8. Fixed Charges Level ($ x 10^6)	0.80	--	0.40	0.66	1.07	0.66	3.72	4.72
10. Fuel Level ($ x 10^6)	7.35 -9.88	--	3.67 -4.94	6.13 -8.23	11.02 -14.82	6.13 -8.23	31.9 -42.8	44.15 -59.28
11. O & M ($ x 10^6)	0.252	--	0.125	0.21	0.377	0.21	1.095	1.492
12. Total Levelized Cost ($ x 10^6)	8.40 -10.93	--	4.2 -5.46	7.00 -9.10	12.467 -16.267	7.0 -9.1	36.715 -47.615	50.362 -65.492
13. Total Energy Production (GWh)	193.20	231.7	252.5	275.10	298.7	327.7	452.7	601.0
14. Btu Production (x 10^6)	1,816.1	2,178.0	2,373.5	2,586.0	2,807.8	3,080.4	4,255.4	5,649.4
15. Barrels of Residual Oil (x 10^6)	288.20	345.7	376.7	410.50	445.7	488.9	675.4	896.7

Note: 9,400 Btu = 1 kWh.

6.3×10^6 Btu = 1 barrel of oil.

Water-dominated geothermal resources are found throughout Djibouti. Figure 4.4 classifies the country's water-dominated resources according to temperature range. With a few notable exceptions, small-scale commercial (1 MW - 15 MW) electric systems that use a moderate temperature range resource, 90 - 150 degrees C (190 - 300 degrees F), are feasible. Djibouti's resource base in the moderate temperature range can provide sufficient electric energy for the rest of this century (78 MW), a potentially significant addition to electric energy resource.

Three technologies--flashed steam, ORC, and total flow--can produce electricity from water-dominated geothermal resources in Djibouti. The flashed steam cycle is commercially proven and usually associated with high-temperature reservoirs over 180 degrees C (355 degrees F). ORC technology, also known as binary cycle technology, can use moderate temperature reservoirs, possibly as low as 96 degrees C (205 degrees F). Total flow technologies use both heat and pressure to generate electricity. However, total flow designs are in various stages of development and, with one possible exception, are not expected to be commercially available for geothermal applications until the late 1980s.

Figure 4.5 shows all the potential sites of geothermal development and possible transmission line right-of-ways to interconnect all loads in Djibouti. If aggressive development steps are taken, it is quite possible to supply all future electric generation needs in Djibouti from the country's geothermal resources.

The results of an analysis of levelized cost data based on geothermal resource development are summarized in Figure 4.6. If all future electric power development is based on geothermal, then existing oil-fired generating units can be used for load following and peaking generation.

The levelized cost data for geothermal generation is based on dry-steam resource development. It should be noted that for water-dominated geothermal resource development, the cost will be slightly higher. At any rate, the total levelized cost of geothermal power addition will be lower than that of oil-fired generation over a 30-year plant lifetime. It is assumed that the earliest the small-scale geothermal plant (5 MW) can come on-line is 1988.

The reduction in oil-fired generation and barrels of oil requirements for this scenario are also included in Figure 4.6.

Scenarios #3 and #4: Load Management and Energy Conservation

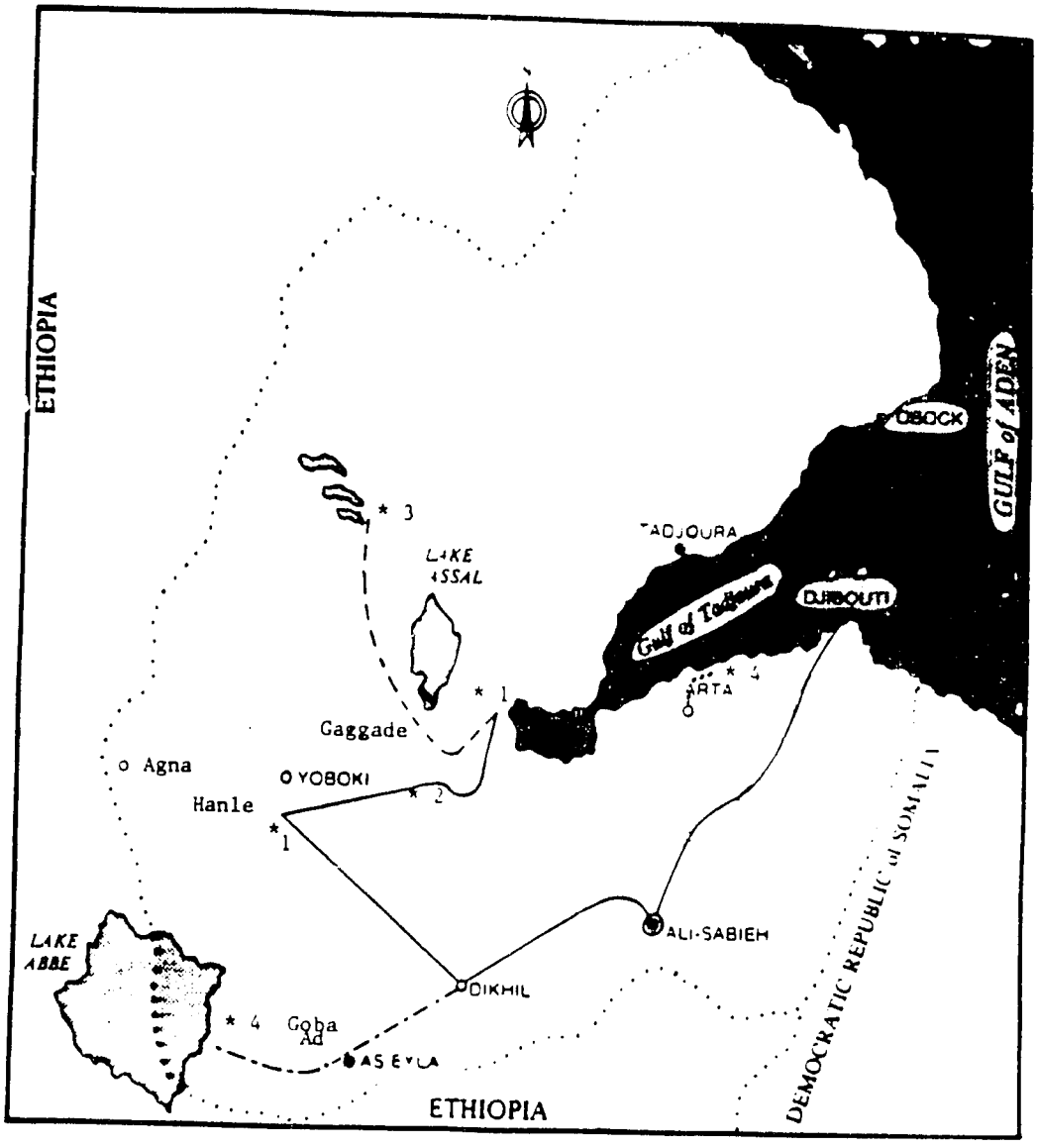
Demand for electricity in the Republic of Djibouti has risen rapidly over the last decade. Growth in the consumption of electric energy has been particularly dramatic, with capacity

FIGURE 4.4

Hot Water-Dominated Resource Classification

Resources	Temperature Range
High Temperature	150° - 350°C (300° - 660°F)
Moderate Temperature	90° - 150°C (190° - 300°F)
Low Temperature	Less than 90°C (less than 190°F)

Source: California Energy Commission, Geothermal Report.



LEGEND

NETWORK CONSTRUCTION SEQUENCE

—— FIRST POWER NETWORK
- - - SECOND POWER NETWORK
-·-·- THIRD POWER NETWORK
•••• FOURTH POWER NETWORK

POWER PLANT CONSTRUCTION SEQUENCE

1 Assal 3 Alol
1 Hanlé 4 Abbé
2 Gaggade * Arta (Indipendente)

FIGURE 4.5

Geothermal Sites In Djibouti

Source: EdD.

FIGURE 4.6

Levelized Cost Analysis for Scenario #2: All Geothermal Generation

	1985	1986	1987	1988	1989	1990	1995	2000
1. Required Capacity Additions (MW)	6.0	--	3.0	5.0	9.0	5.0	28.0	35.5
2. Instant Capital Cost (1982 $ x 10^6)	3.2 - 4.68	--	1.6 - 2.34	2.65 - 3.9	4.25 - 6.24	2.65 - 3.9	14.85 - 21.84	18.82 - 27.70
3. In-Service Capital Cost (1990 $ x 10^6)	6.35 - 9.34	--	3.2 - 4.67	5.29 - 7.78	9.55 - 14.01	5.29 - 7.78	29.62 - 43.54	32.8 - 48.26
4. Fuel Cost (1982 x 10^6)	1.4	--	0.7	1.15	2.1	1.15	6.43	7.16
5. Fixed Charges Level ($ x 10^6)	0.67 - 0.96	--	0.34 - 0.48	0.56 - 0.81	1.01 - 1.44	0.56 - 0.81	3.16 - 4.51	3.47 - 4.99
6. Fuel Level ($ x 10^6)	5.3	--	2.67	4.44	7.97	4.44	24.92	31.6
7. O & M Cost ($ x 10^6)	0.08	--	0.04	0.07	0.12	0.07	0.39	0.49
8. Total Levelized Cost ($ x 10^6)	7.45 - 7.74	--	3.75 - 3.93	6.22 - 6.47	11.20 - 11.67	6.22 - 6.47	34.9 - 36.25	42.72 - 44.24
9. Total Energy Production (GWh)	193.2	231.7	252.5	275.1	298.7	327.7	452.7	601.0
10. Geothermal Energy Production (GWh)	42.0	42.0	21.0	35.0	35.0	63.0	196.2	248.7
11. Cumulative Energy Production from Geothermal (GWh)	42.0	42.0	63.0	98.0	161.0	196.0	392.2	641.0
12. Energy from Oil (GWh)[a]	193.2	231.7	252.5	240.0	228.7	222.7	186.5	117.6
12a. Energy from Oil with Geothermal Plant in Operation (GWh)	151.2	189.7	189.7	177.1	137.7	131.7	60.5	---
13. Btu Equivalent (x 10^{12}) [a]	1,816.1	2,178.0	2,373.5	2,256.0	2,150.0	2,093.0	1,753.1	1,105.4
13a. Btu Equivalent of 12a	1,421.3	1,783.2	1,783.2	1,664.7	1,294.4	1,238.0	568.7	---
14. Barrels of Oil Needed (x 10^6)[a]	288.2	345.2	376.7	358.0	341.2	332.2	278.2	175.4
14a. Barrels of Oil Needed for 12a or 13a	225.6	283.0	283.0	264.2	205.4	196.5	90.2	---

Note: 6.3 x 10^6 Btu = 1 barrel of oil. 9,400 Btu = 1 kWh.

[a] The lead-time for geothermal resource development is a minimum of 4-5 years; therefore, the electricity generation based on oil-fired capacity will continue until 1988/1989.

(Peak demand - MW) demand and energy (GWh) demand increasing at an average annual rate of 10-12 percent since 1975. Economic expansion, driven by a rising standard of living, and changing patterns of energy use have accounted for this growth in electricity consumption. Because of various delays and financial constraints, the construction of new generating plants in Djibouti has been impeded, and all indicators point to a tight electric supply situation in the 1980s and 1990s. Even with the immediate start-up of the planned new generators (30 MW plus 10 MW), it may be impossible to bring all future facilities (additional 78 MW) into service in time to fully meet anticipated load growth. Improvements in present operating system efficiency through energy conservation, peak shaving system loss reduction, and load deferment will help to alleviate the need for large capacity expansion. Energy conservation, system loss reduction, and peak load management will have the most immediate effect upon new resource requirements during the study period.

The immediate impacts of different energy conservation and demand reduction programs on supply scenarios #1 and #2 are analyzed, based on the levelized cost data assumptions in Figure 4.2. The non-generation energy technologies described in Chapter 3 include methods to reduce peak demand as well as energy conservation measures that will allow more efficient and timely use of electrical energy from existing and future facilities.

Levelized cost analyses for Scenarios #3 and #4 are presented in Figures 4.7 and 4.8. The levelized cost estimate of Scenario #3 is based on load management and energy conservation programs plus oil-fired generation to satisfy future capacity and energy needs. Similarly, the levelized cost estimate of Scenario #4 is based on geothermal resource development, load management, and energy conservation programs.

Conclusions

It was previously noted that levelized costs remain constant over the life of the generating facility. While such a measure of electric generating costs is quite useful and allows much information to be synthesized into a single figure, it masks the behavior over time of the individual cost components. Figure 4.9 illustrates the range of total levelized costs for each of the four scenarios based on the assumptions in Figure 4.2. It is important to note that, in some cases, fuel costs may increase dramatically over the life of a facility and represent almost all of the total costs in later years. On the other hand, the capital-related component of costs (fixed costs) decreases over time as the facility is depreciated. The rates at which fuel costs escalate and the countervailing rates at which fixed costs decrease differ with each technology-fuel combination, resulting in various cash flow patterns. By presenting (in Figures 4.3, 4.6, 4.7 and 4.8) the costs of producing electricity in selected years

FIGURE 4.7

Levelized Cost Analysis for Scenario #3:
Load Management, Conservation, and Oil-Fired Generation

	1985	1986	1987	1988	1989	1990	1995	2000
Demand Reduction Potentials (MW)								
1. Load Management	-2.5	-2.8	-3.0	-3.3	-3.6	-3.9	-5.2	-6.7
2. Power Factor Improvement	-2.6	-3.2	-3.4	-3.8	-4.1	-4.4	-5.9	-7.8
3. Demand Subscription and Time-of-Day Rates	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5
Total Reduction (MW)	-6.6	-7.5	-8.0	-8.6	-9.2	-10.0	-14.0	-17.5
4. Peak Demand (MW)	40.1	48.1	52.1	57.1	62.0	66.8	89.1	118.3
5. Modified Peak Demand (MW)	33.5	40.6	44.1	48.5	52.8	56.8	75.1	100.8
6. Reserve Margin Requirement (%)	41.0	35.0	32.0	30.0	28.0	26.0	21.0	17.0
7. Installed Capacity Required (MW)	47.0	55.0	58.0	63.0	68.0	72.0	91.0	118.0
8. Planned Capacity Addition (MW)	48.0	58.0	58.0	58.0	54.2	54.2	49.4	44.6
9. Additional Capacity Needed (MW)	--	--	--	5.0	9.0	4.0	19.0	27.0
10. Cumulative Capacity Needed (MW)	--	--	--	5.0	14.0	18.0	37.0	64.0
11. Instant Capital Cost (1982 $ x 10^6)	--	--	--	3.47	6.25	2.78	13.2	18.76
12. In-Service Capital Cost (1990 $ x 10^6)	--	--	--	6.4	11.52	5.12	24.32	34.56

FIGURE 4.7—Continued

	1985	1986	1987	1988	1989	1990	1995	2000
13. Fuel Cost (1982 $ x 10^6)	--	--	--	1.6	2.9	1.28	6.1	8.68
14. Fixed Charges Level ($ x 10^6)	--	--	--	0.665	1.20	0.53	2.53	3.59
15. Fuel Level ($ x 10^6)	--	--	--	6.13 - 8.23	11.04 - 14.8	4.9 - 6.5	23.3 - 31.3	33.11 - 44.5
16. O & M Costs ($ x 10^6)	--	--	--	0.21	0.38	0.70	0.80	1.13
17. Total Levelized Cost ($ x 10^6)	--	--	--	6.34 - 10.70	15.52 - 19.28	6.08 - 8.48	32.73 - 40.73	46.51 - 57.9
18. Energy Production Needed (GWh) (Peak x DF x 8,760)	161.4	195.4	212.5	233.6	254.4	273.6	361.8	485.6
19. Btu Equivalent (x 10^{12})	1,517.0	1,838.6	1,997.5	2,195.8	2,391.3	2,571.8	3,400.9	4,564.6
20. Barrels of Oil Equivalent (x 10^6)	240.8	291.8	317.0	348.5	379.6	408.2	539.8	724.5
21. Energy Conservation Potentials (GWh)								
a. Domestic	8.66	--	--	--	--	11.60	16.66	--
b. Commercial & Govt.	5.06	--	--	--	--	10.16	12.16	--
c. Industry	0.19	--	--	--	--	1.79	4.99	--
d. Other	4.80	--	--	--	--	8.70	10.60	--
TOTAL	18.54					32.31	44.41	
22. Net Energy Production Requirement with Conservation (GWh)	142.86	--	--	--	--	241.3	317.4	--
23. Btu Equivalent (x 10^{12})	1,342.9	--	--	--	--	2,268.2	2,983.5	--
24. Oil Equivalent in Barrels (x 10^6)	213.0	--	--	--	--	360.0	973.0	--

Note: 6.3×10^6 Btu = 1 barrel of oil.
9,400 Btu = 1 kWh.

FIGURE 4.8

Levelized Cost Analysis for Scenario #4:
Load Management, Conservation, and Geothermal Generation

	1985	1986	1987	1988	1989	1990	1995	2000
1. New Capacity Required (MW)	--	--	--	5.0	9.0	4.0	19.0	27.0
2. Instant Capital Cost (1982 $ x 10^6)	--	--	--	2.65 - 3.90	4.77 - 7.0	2.12 - 3.12	10.1 - 14.82	14.3 - 21.1
3. In-Service Costs (1990 $ x 10^6)	--	--	--	5.3 - 7.8	9.5 - 14.0	4.2 - 6.2	20.1 - 29.6	28.5 - 42.1
4. Fuel Cost ($ x 10^6)	--	--	--	1.15	2.07	0.92	4.37	6.21
5. Fixed Charges Level ($ x 10^6)	--	--	--	0.56 - 0.8	1.0 - 1.45	0.45 - 0.64	2.13 - 3.06	3.02 - 4.35
6. Fuel Level ($ x 10^6)	--	--	--	4.44	8.0	3.55	16.9	24.0
7. O & M Costs ($ x 10^6)	--	--	--	0.07	0.126	0.056	0.266	0.378
8. Total Levelized Cost ($ x 10^6)	--	--	--	6.22 - 6.46	11.2 - 11.6	4.97 - 5.2	23.66 - 24.6	33.6 - 34.93
9. Energy Production Needed (GWh)	161.4	195.6	212.5	233.6	254.4	273.6	301.8	485.6
10. Energy from Geothermal (GWh)	--	--	--	35.0	63.1	28.0	133.1	189.2
10a. Cummulative Energy Production from Geothermal (GWh)	--	--	--	35.0	98.1	126.1	259.2	448.4
11. Energy from Oil (GWh)	161.4	195.6	212.5	198.6	156.3	147.5	42.6	37.2
12. Btu Equivalent (x 10^{12})	1,517.2	1,838.6	1,997.5	1,866.8	1,469.2	1,386.5	400.4	349.7
13. Barrels of Oil Equivalent (x 10^6)	240.8	291.8	317.1	296.3	233.2	220.0	63.5	55.5
14. Energy Conservation Potentials (GWh)	18.5	--	--	--	32.31	--	44.41	--
15. Net Energy Production from Oil (GWh)	142.9	--	--	--	124.0	--	--	--
16. Btu Equivalent (x 10^{12})	1,343.3	--	--	--	1,165.6	--	--	--
17. Oil Equivalent in Barrels (x 10^6)	213.0	--	--	--	185.0	--	--	--

Note: 6.3×10^6 Btu = 1 barrel of oil.
9,400 Btu = 1 kWh.

FIGURE 4.9

Summary of Total Levelized Costs for Four Supply Scenarios

	1985	1986	1987	1988	1989	1990	1995	2000
Scenario #1	8.4 to 10.9	--	4.2 to 5.46	7.0 to 9.1	7.0 to 9.1	7.0 to 9.1	32.2 to 41.9	43.4 to 56.5
Scenario #2	7.45 to 7.74	--	3.75 to 3.93	6.2 to 6.4	6.2 to 6.4	6.2 to 6.4	23.42 to 29.8	38.6 to 40.2
Scenario #3	--	--	--	6.3 to 10.7	15.5 to 19.2	6.08 to 8.48	32.7 to 40.7	46.5 to 57.9
Scenario #4	--	--	--	6.2 to 6.46	11.2 to 11.6	4.97 to 5.2	23.6 to 24.6	33.6 to 34.9

the first, eighth, and twentieth year of plant operation), estimated cash flow patterns reflecting fuel price changes, depreciation, and tax effects can be observed for each supply scenario. The results in Figure 4.9 can be used for a rough comparison of all four supply scenarios.

Figure 4.10 illustrates the estimated amount of imported oil required for electricity generation in the key years 1985, 1990 and 1995 under each scenario. It is important to note that the impact of geothermal resource development on imported oil requirements is not evident until 1990. However, the impact of energy conservation and load management programs on estimated imported oil requirements is quite obvious from 1985 onward in Figure 4.10.

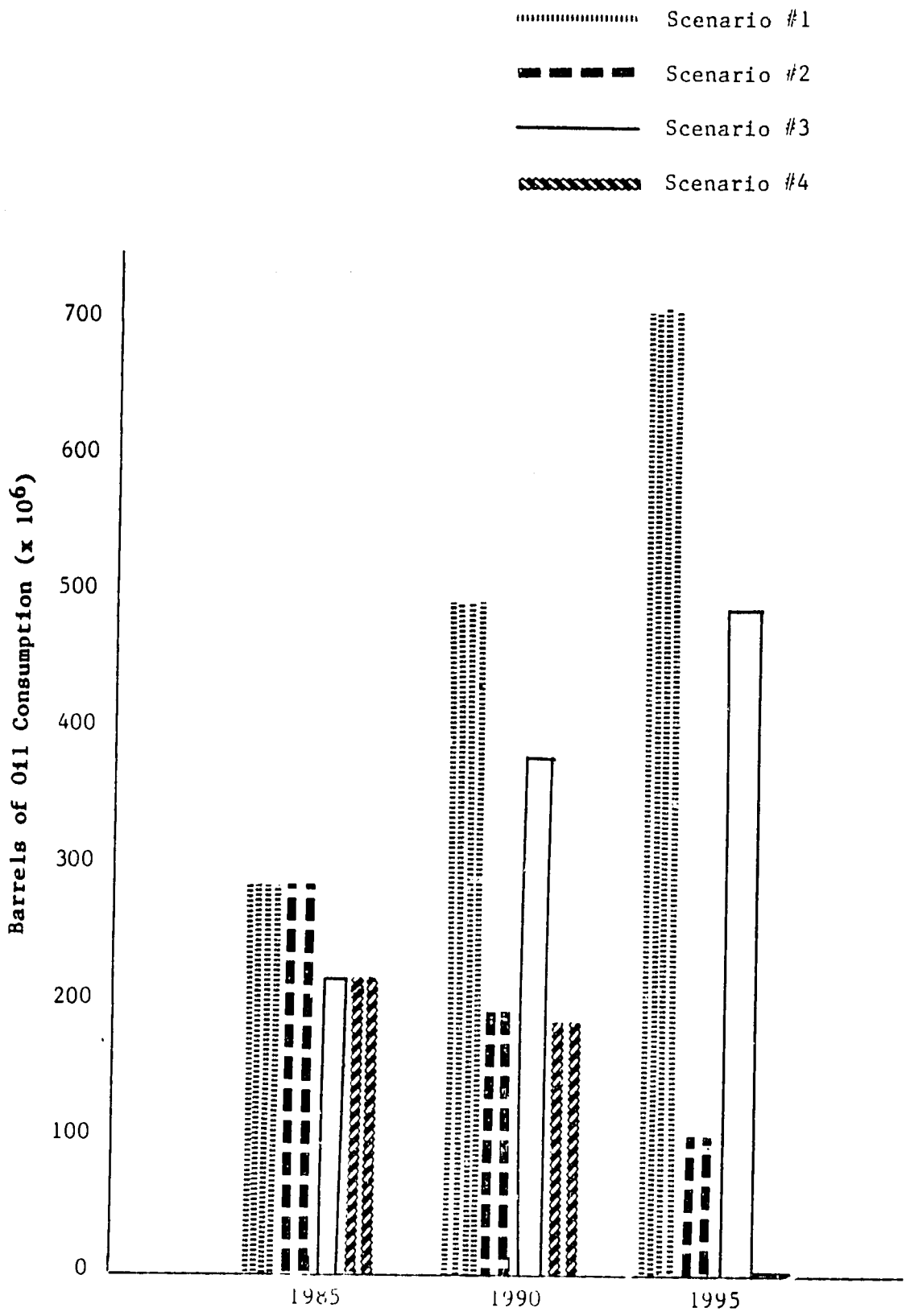


FIGURE 4.10

Comparison of Estimated Amount of Oil
Import Requirements for Four Supply Scenarios

GLOSSARY

A	Ampere; measure of electric current.
AC	Alternating current.
Alternating Current	An electric current that reverses its direction of flow periodically, as contrasted to direct current.
bhp	Brake horsepower.
Boulaos	Main EdD generating station in Djibouti Ville.
Btu	British thermal unit.
Capacity	Maximum power output for which a generation unit is designed, expressed in kilowatts or megawatts. In terms of transmission lines, this refers to the maximum load a line is capable of carrying.
Cercles	The districts of Djibouti outside the capital of Djibouti Ville: Obock, Tadjourah, Ali-Sabieh, and Dikhil.
DC	Direct current.
Demand	The rate which electric energy is delivered to or by a system, or generating unit, expressed in kilowatts or kilovolt-amperes, at a given instant or averaged over any designated period of time.
Demand Billing	The demand upon which billing to a customer is based, as specified in a rate schedule or contract. It may be based on the contract year, a contract minimum, or a previous maximum and, therefore, does not necessarily coincide with the actual measured demand of the billing period.
Demand Charge	The specified charge to be billed on the basis of the billing demand, under an applicable rate schedule or con-

DF	Djiboutian Franc (Franc Djiboutien).
Direct Current	Electricity that flows continuously in one direction as contrasted with alternating current.
Djibouti	Country of Djibouti.
Djibouti Ville	City of Djibouti.
Economy	Energy produced and supplied from one system, which is substituted for that which could be produced by a less economical source in another system.
EdD	Djibouti Electric (Electricité de Djibouti).
Energy	Power expended over time; electrical energy commonly measured in kilowatt-hours. A 100-watt light bulb burning for 10 hours uses one kilowatt-hour.
Energy Charge	That portion of the billed charge for electric service based upon the energy supplied, as contrasted with the demand charge.
Firm Energy	Electric energy that is considered assured to the customer to meet all agreed upon portions of the customer's load requirements over a defined period, at an agreed upon rate, and even under adverse conditions.
Genie Rural	Agency of the Government of Djibouti involved in rural engineering work.
Gigawatt	One billion watt-hours, or one million kilowatts.
Gigawatt-hour	One billion watt-hours, or one million kilowatt hours.
GW	Gigawatt (10 Watts).
GWh	Gigawatt hour.
hp	Horsepower.

Interruptible	Power made available under agreements that permit curtailment or cessation of delivery by the supplier.
k	Thousand.
Kilowatt	The electrical unit of power, equal to 1,000 watts, that measures the rate at which electricity is generated or consumed.
Kilowatt-hour	A basic unit of electrical energy equal to one kilowatt of power supplied to or taken from an electrical circuit steadily for one hour; a measure of the quanitity of electricity generated or consumed.
Load	The amount of electric power required at a given point on a system.
Load Diversity	That difference or variety of electric loads whereby individual daily or seasonal maximum demands occur at different times.
Loss (Losses)	The general term applied to energy (kilowatt-hours) and power (kilowatt) lost in the operation of an electric system. Losses occur principally as energy transformations from kilowatt-hours to wast heat in electrical conductors and apparatus. Line losses refer to kilowatt-hours and kilowatts lost in transmission and distribution lines under specified conditions.
Megawatt	One million watts, or one thousand kilowatts.
Megawatt-hours	One million watt-hours, or one thousand kilowatt-hours.
Minimum Generation	The required minimum generation level of a utility system's thermal units; the limit to which oil and gas steam boiler units can be throttled back offpeak and still be available for meeting peak demand.

m/s	Meters per second.
mV	Megavolt.
mVA	Megavolt-ampere.
MW	Megawatt (10 Watts).
MWh	Megawatt-hour.
Non-firm Energy	Energy that is subject to interruption or curtailment by the supplier on short notice (usually only a few hours notice).
Peak demand	The highest instantaneous demand for power during a stated period of time; usually measured in megawatts.
PF	Power factor.
Power	The rate at which work is performed; usually expressed as watts or horsepower.
Transmission	The act or process of transporting electrical energy in bulk from a source or sources of supply to the various parts of the utility service area.
Upgrade	Replacement or addition of electrical equipment resulting in increased transmission or generation capability.
Uprate	Increased rating of generation or transfer capability.
V	Volt; measure of electric potential.
Voltage of a Circuit	The voltage of a circuit in an electric system is the electric pressure of that circuit measured in volts. It is generally a nominal rating based on the maximum normal effective difference of potential between any two conductors of the circuit.

W	Watt; unit of power.
Wp	Peak watt; maximum attainable wattage.

CONVERSION TABLE

1 barrel of petroleum oil ($5.6\ ft^3$) = 5.8×10^6 Btu = 42 gallons

10^6 barrels of oil = 5.8×10^{12} Btu

1 Btu = 252 calories

10^{15} Btu = 172×10^6 barrels of oil

$1^\circ F = (5/9)^\circ C$

1 ft = 0.305 meters

1 ft^3 of natural gas = 10^3 Btu

1 gallon of gasoline = 125×10^3 Btu

1 gigawatt = 10^9 watts = 10^6 kilowatts

1 hp = 42.5 Btu/min = 0.7457 kw

1 in = 2.54 cm

1 kw = 10^3 watts = 1.341 hp = 56.9 Btu

1 km = 0.62 mile

1 kw-hr = 3413 Btu

1 lb = 0.4536 kg

1 lb force = 4.45 Newtons

1 lb of coal = 10 to 13×10^3 kilowatts

1 megawatt = 10^6 watts = 10^3 kilowatts

1 U.S. Gallon = 0.134 ft^3 = 0.0044 m^3 = 3.8 liters

10^6 = 1 (one) million

10^9 = 1 (one) billion

10^{12} = 1 (one) trillion

10^{15} = 1 (one) quadrillion

Note: Customary United States units have been used throughout this report. Some pertinent conversions are indicated above. Reference can also be made to ASME guide SI-1 "Orientation and Guide for Use of SI (Metric) Units," in 1976.

ABOUT THE AUTHOR

An electric power engineer, Shibu Dhar has over 16 years experience in power system planning and design in electric utilities and regulatory agencies in the United States and in developing countries. He was in charge of the System Planning Group of the California Energy Commission for four years and directed numerous technical studies related to California electric utilities. Previously, he was a senior engineer with the Detroit Edison Company in the Planning and Research Department. For the last five years he has been involved in electric utility systems design, planning, and energy conservation studies in various countries in Africa, South America, and the Caribbean.

Mr. Dhar lectures on power system modeling and planning in Canada, the United States, Mexico, South America, and Africa. He is widely published in the field and has taught a variety of courses and programs in power system analysis, planning methodology, numerical methods, system reliability study, and power system operation. He was a part-time and guest lecturer at the Univerity of California at Berkeley and at Los Angeles; California State University, Sacramento; Wayne State University, Detroit, Michigan; and University of Waterloo, Canada.