PN-AAQ-997

ENERGY POLICY AND PLANNING ASSISTANCE
TO DEMOCRATIC REPUBLIC OF THE SUDAN

RECOMMENDATIONS FOR THE SHORT-RANGE (1981-1986) RELIABILITY IMPROVEMENT PROGRAMS

PUBLIC ELECTRICITY AND WATER CORPORATION KHARTOUM, SUDAN

PROJECT REPORT NO.1

PREPARED FOR

U.S. Agency For International
Development (USAID)
Contract No. DAN:5703:C:00:1024

AUGUST, 1981

BY

INTERNATIONAL SCIENCE AND
TECHNOLOGY INSTITUTE, INC.,

E/DI ENERGY DEVELOPMENT
INTERNATIONAL, INC.

PN-AAQ997

ISN: 36538

ACKNOWLEDGEMENTS

The International Science and Technology Institute, Inc., Energy/Develorment International and this consultant wish to express their indebtedness to Dr. Shareff El-Touhami, Minister of Energy and Mines, and to Mr. Mohammed El-Amin Mukhtar, Director General of the National Energy Administration, for their guidance and encouragement during the course of this work. Appreciation is also extended to the following professionals for their helpful advice and assistance during the course of this research work:

- Abdel Bagi Osman
- Ahmed El-Zein El-Hassan
- Dr. John Gindi Boutros
- Moh'd El-Amin Suleiman
- Abdel Satar Ali
- Amin Sabri
- Abbas Hiddayat-Allah
- Ishag Adam El-Beshir
- Jaafer El-Faki Ali
- Shyed Hamza
- Ms. Michele Foster

ABSTRACT

The phenomenal growth of electric power requirements in Sudan has surpassed the ability of the Public Electricity and Water Corporation (PEWC) system to meet the daily peak demands at present for the short-range period (1981-1986). There is a significant imbalance in the demand and supply of electricity generating resources in the Blue Nile Grid (BNG) system which generates over 90 percent of the PEWC's energy requirements.

This report estimates the impacts of energy conservation, demand management, and other programs for the short-range period (1981-1986) on improving the system reliability of the BNG service area. Potential changes in consumer load levels and patterns resulting from the introduction of conservation and load management programs should be an important consideration for the short-range operating system reliability improvement. Most of the programs analyzed in this report for the PEWC system are technically feasible and commercially available.

The implementation of different recommended programs during the study period not only will help to eliminate the capacity/energy shortages for the BNG system but also have the potential to produce significant savings in operating cost.

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A. EXECUTIVE SUMMARY

The objective of this report is to present a realistic assessment of the problems confronting the Public Electricity and Water Corporation (PEWC) in Sudan and recommend feasible solutions for the short-range period (1981-1986) to improve the operating system's reliability. Due to inadequate reserve margins necessary for maintenance and repairs, as well as unforeseen equipment failure, a power shortage has developed in the PEWC service area especially during periods of peak power use. Operating with insufficient generation capacity to meet customer's demands exposes the entire system to frequent collapse.

Analysis of energy use in the PEWC system shows that approximately 90 percent of the corporation's sales is in the Blue Nile Grid (BNG) system. Therefore, all the analysis reported herein pertains only to the BNG system of the PEWC service area. All analyses were performed based on two resource scenarios for the study period -- Scenario #1 assumes capacity availability as planned and Scenario #2 considers the slippage of Rosieres Unit #5 and #6 for a six month period to assess the maximum possible capacity shortage in the BNG system. Based on the results of this study, the following major conclusions were drawn:

1. For the BNG service area, 1982 is a critical year. The short-range reserve capacities (MW) for the two base case scenarios are as follows:

Base Case Scenario	1981	1982	1983	1984	1985	1986
#1	-54	-79	+87	+108	+85	-30
#2	-54	-79	-32	- 19	- 3	-29

2. Air conditioning load in the commercial and residential sectors contributes over 25 percent of the peak demand during the morning and evening peak hours. Therefore, any load cycling program of air conditioning load will reduce the short-range capacity shortage. The results of air conditioning load management programs are as follows:

Scenario #1

Items	1981	1982	1983	1984	1985	1986
1. Base Case Reserve (MW)	-54	-79	+87	+108	+85	-30
2. Peak Reduction due to A/C LM Programs	- 14.4	- 17.4	- 19.4	- 21.0	- 22.8	- 24.6
3. Equivalent Generating Capacity in MW	+19.0	+22.0	+26.0	+ 27.0	+23.0	+32.0
4. Modified Reserve (MW)	-35	-57	+113	+135	+108	+ 2

Scenario #2

Items	1981	1982	1983	1984	1985	1986
1. Base Case Reserve (MW)	-54	-79	-32	-19	- 3	-29
2. Peak Reduction due to A/C LM Programs	-14.4	-17.4	-19.4	-21.0	-22.8	-24.6
3. Equivalent Generating Capacity (MW)	+19.0	+22.0	+26.0	+27.0	+23.0	+32.0
4. Modified Reserve (MW)	-35	-57	- 6	+ 8	+20	+ 3

3. Energy conservation measures in the commercial, residential, industrial and agricultural sectors will be able to reduce energy sales by 11.5 percent by 1986. The results are summarized in the following table:

Items	Short-Range Programs 1983	Medium-Range Programs 1986
1. Forecasted Sales (GWh)	1376	1737
2. Reduction in GWh	-65.14	-201.19
3. Percent Reduction	4.7	11.5

4. The daily load factor of the BNG system is as low as 75 percent in the summer months, which indicates the opportunity of load management programs. A high daily load factor indicates fewer opportunities for load management or demand reduction techniques.

5. The power factor in different load sectors are very poor and as low as 0.70 in some industrial loads. The installation of capacitor banks and a power factor penalty in the rate schedule will have the following immediate positive effects on the system:

   a. Reduction in system losses,
   b. Recover transmission and distribution capacity thus deferring of capital expenditures for expansion in T & D system.
   c. Improved voltage regulation.

6. The total savings resulting from the power factor corrections to 0.95 in different load sectors are as follows:

	81/82	82/83	83/84	84/85	84/85
US$ X 10^6	20.44	2.79	1.71	2.07	2.46

The maximum savings of Power Factor (PF) correction will be realized in the early years due to improvement of PF from 0.75 to 0.95 in the existing

system. In the late 1980s, less savings will be realized due to high overall system power factor

7. In the BNG service area, there are hundreds of self-generating facilities which customers use as a backup capacity for electricity. The present estimate indicates that the total installed capacity of the dispersed self-generators is about 50 to 60 MW.

   Interruptible rates can be designed to encourage the customers with self-generators to disconnect during the peak hours or at emergencies. The estimated immediate peak reduction for the study period is about 24 MW.

8. The repowering of older conventional oil fired steam power plants consists of their conversion into a combined cycle plant by integrating one or more combustion turbines. This allows an increased capacity and reduces heat rates as compared with the existing inefficient plant. The repowering potentials for the study period are as follows:

	1981	1982	1983	1984	1985	1986
Repowering Capacity of Combined Cycle	--	+20	--	+15	+55	--

9. The Demand Subscription Service (DSS) program discussed in this report allows customers to subscribe a fixed level of kW demand. The DSS program has the potential of reducing peak demand 5.0 to 7.7 MW during the study period.

10. The industrial customers load shift program will affect the 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 peak hours the following demand reduction may be accomplished by implementing an industrial load shift program:

Action	1981	1982	1983	1984	1985	1986
Morning Peak Reduction Due to Industrial Load Shift Program (MW)	--	-26.5	-30.1	-32.2	-35.0	-38.0

11. Further demand management of the agricultural and water pumps during the system peak hours will reduce the peak demand for the study period. The system peak reduction due to irrigation and water pumps management are as follows:

Action	1981	1982	1983	1984	1985	1986
Agricultural and Water Pumps Demand Management	-5.8	- 6.4	-7.0	-7.7	-8.5	-9.3

12. The availability improvement for the existing power plants will also have significant effects on system reserve requirements. Approximately, 1 percent forced outage rate improvement results in a 1 percent reduction in reserve margins. For the study period, the following permanent increase in the capacity and/or improvement in the forced outage rate of

existing BNG system generation facilities can be expected:

Action	1981	1982	1983	1984	1985	1986
Availability Improvement of Existing Power Plants	--	-7.0	-13.0	-14.0	-15.0	-17.0

13. The removal of transmission and distribution (T & D) system 'bottle-necks' will increase the generating capacity by 30 MW (10 MW at Rosieres and 20 MW at Kenana) and relieve the T & D system component loadings. It has been concluded that the T & D expansion programs are desireable but they are not achievable during the study period due to financial and lead time constraints.

14. The BNG system requires high operating and planning reserve margins due to large size of Rosieres units. For system reliability purposes, the size of the largest unit in a system should not exceed more than 10-15 percent of the system size.

15. The results of all recommended programs for the short-range period are summarized in Table A-1. It should be noted than in evaluating the system impacts of the individual program, the explicit inter-relationship between the programs are not quantified. For example, the demand subscription service program will have an effect on the magnitude of air conditioning load management program or the industrial load shift program,

etc. However, the results of Table A-1 indicate that there are several options available for the PEWC management to improve the operating system's reliability significantly for the short-range period.

TABLE A-1

SUMMARY RESULTS OF ALL PROGRAMS FOR THE
SHORT-RANGE SYSTEM RELIABILITY IMPROVEMENT

BNG SERVICE AREA

Items	1981	1982	1983	1984	1985	1986
1. PEAK REDUCTION PROGRAMS						
a. A/C Load Management	-14.4	-17.4	-19.4	-21.0	-22.8	-24.6
b. Self-Generating Customers Peak	-24	-24	-24	-24	-24	-24
c. Demand Subscription Service	- 5.0	- 5.45	- 5.9	- 6.5	- 7.1	- 7.7
d. Off-Peak Water Pumping	- 5.8	- 6.4	- 7.0	- 7.7	- 8.5	- 9.3
e. Industrial Load Shift Program	--	-26.5	-30.1	-32.2	-35.0	-38.0
2. SYSTEM CAPACITY IMPROVEMENT PROGRAMS						
a. Repowering Program	--	+20		+15	+55	
b. Availability Improvement Program	--	+ 7.0	+13.0	+14.0	+15.0	+17.0
c. Transmission and Distribution System 'Bottleneck' Removals	--	--	--	+30	+30	+30
3. ENERGY SAVINGS (GWH)						
a. Conservation Measures	--	--	-65.14	--	--	-201.19
b. Power Factor Improvement	341	46.5	28.4	34.6	38.0	

B. RECOMENDATIONS

The following recommendations should be considered for the short-range system reliability improvement in the BNG service area:

1. Survey the marketplace to determine the engineering, economic, and demographic characteristics of different load sectors as a function of their electric energy usage stratum.

2. For an extensive set of conservation strategies, for individual technologies and combinations thereof, evaluate the impact of each strategy upon the total system load curve for each year of the study period.

3. Quantify the impact of each of the conservation strategies upon the electric utility's system reliability, and generation expansion planning; and conduct a rigorous cost-effectiveness evaluation of each conservation strategy for the BNG system by using production cost and reliability programs.

4. In considering the kW and kWh impacts in the resource plan, determine the cost-effectiveness of commercial, business, and residential cycling of air conditioners to the utility and also under alternative programs.

   Alternative programs could be specified by identifying alternative penetration rates and alternative cycling strategies (7.15 or 30 minutes over

half hour for 4, 6, or 10 hours per day for 10, 20, or 50 days per year).

5. For air conditioner cycling, determine the cycling strategy that maximizes the operating economics of the cycling program for the BNG system.

   Operating economics would be achieved through:

   a. Fuel savings
   b. Spinning reserve reduction
   c. Unit commitment reductions
   d. Improved maintenance scheduling

6. Determine the relationship between time, frequency, and duration of a service interruption and the cost savings to the utility of the interruption.

7. Evaluate the impacts on transmission and distribution systems of load management and other demand reduction programs.

8. Estimate the impacts on load duration curves, load levels, and capacity planning of conservation, thermal storage, active/passive solar systems and time-of-day rates for the BNG system.

9. Estimate the interaction effects of various combinations of conservation, load management, and time-of-day policies.

10. Estimate the effects on BNG load duration curves, load levels, capacity expansion plans, electric rates, and external financial requirements, of a modified base case, consisting of the best estimate penetrations of load control and conservation programs.

11. Initiate a detailed energy audit program in the industrial, commercial and residential sector to identify and quantify the opportunities for energy savings in the short-range and long-range periods.

12. Initiate immediate testing and evaluation of load management programs to determine the customer acceptance level.

13. Utilization of all equipment with an inductive reactance load component should have a power factor of not less than 95 percent lagging under rated load conditions. Power factor corrective devices installed to comply with this criterion should be switched with the utilization equipment. Lower power factor causes greater losses in transmission and distribution of electricity. Most public buildings, during the non-air conditioning period, should have a power factor of at least 0.95, unless the power factor is reduce by reactive loads such as flourescent lighting units and elevator motors. Where the loads of the building are such that they create a power factor at the building service of less than 0.95 lagging, capacitance corrective devices should be placed at those loads or at the feeder to those loads to maintain 0.95.

14. Initiate a program to evaluate the repowering feasibility of existing old plants in the combined cycle mode to increase generation capacity and to improve the overall efficiency of the repowered plant.

15. The proposed Demand Subscription Service and interruptible rates for the self-generating customers should be further investigated to evaluate the cost-effectiveness of such tariffs.

16. Develop bulk power system (generation and transmission) planning criteria for the PEWC system as outlined in Appendix B of this report.

1. INTRODUCTION

Demand of electric energy in the Blue Nile Grid (BNG) and Eastern Grid (EG) regions of the Public Electricity and Water Corporation (PEWC) have risen rapidly over the last decade in Sudan. Growth in the consumption of electric energy has been particularly dramatic, with capacity (MW) and energy (GWh) demand increasing at an average rate of 9 and 13 percent respectively per year since 1976. Economic expansion, driven by the rising living standards, and changing patterns of energy use have accounted for this growth in electricity consumption.

The phenomenal growth of electric power requirements in the BNG and EG regions has surpassed the ability of the PEWC system to meet the daily peak demands at present. Because of delays and financial constraints, construction of new generating plants has been universally impeded in Sudan so that all implications point to a tight electric power supply situation in the 1980s. Even with the immediate start of planned new generation, it may be impossible to bring these new facilities into service in time to fully meet the load growth.

More importantly, because of impending fuel and spare parts shortages, it may not be possible to operate all the existing generating units at the rated capacity all the time, thereby culminating an energy shortage. Anything that can be done to reduce the risk of an electrical energy shortage or improvement of present operating system reliability through energy conservation, peak shaving, power factor improvement, and load deferrment will

help to allevaite the danger of short-range capacity and energy shortages. Conservation and peak load management will have the most immediate effect upon the existing fuel supply and plant capacity.

1.1 OBJECTIVE AND SCOPE OF THE REPORT

This report was prepared for the Ministry of Energy and Mines as one element of the Energy Work Program. It represents the first part of a two-phase project to address the need for electric power in Sudan, particularly in the BNG service area.

The objective of this report is to estimate the immediate impacts of different energy conservation and demand reduction programs for the short-range period 1981 to 1986 which will improve the day-to-day operating reliability of the PEWC system. The nongeneration energy technologies include methods to reduce peak demand as well as energy conservation measures that allow more efficient and timely use of electrical energy from the existing facilities.

1.2 DEMAND MANAGEMENT AND ENERGY CONSERVATION POTENTIALS

Energy conservation technologies may be defined as actions that can be taken by electric consumers to either reduce the wasteful consumption of energy or increase the efficiency of the overall generation and distribution system. In this sense, the definition of conservation tech-

nologies encompasses the body of knowledge needed to being about reduction in or more efficient use of energy, electricity in particular.

Demand management (or load management) is defined as any action taken by a utility to modify its daily load curve in a positive manner. It 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 gamut of concepts, from consumer education programs and general appeaks to time-differentiated rates and customer-owned and operated load controllers.

The following load management and energy conservation technologies are analyzed for the PEWC system to evaluate the effects on system operating reliability for the short-range period.

1.3 DEMAND REDUCTION TECHNOLOGIES

1.3.1 DIRECT LOAD CYCLING OF AIR CONDITIONERS

The air conditioner load in the residential and commercial sectors of the PEWC system constitutes over 25 percent or 50 MW of the peak demand. Therefore, the direct control or cycling of air conditioning load has the potential for immediate peak reduction of the PEWC system.

1.3.2 POWER FACTOR IMPROVEMENT

Most utilities define poor reactive power, or low power factor, as anything less than 0.9. In the PEWC system, the power factors in different load sectors varies from 0.7 to 0.85. Primary advantages for power factor improvement programs are:

1. To reduce transmission and distribution losses (I^2R losses),
2. The recovering of system capacity resulting in deferring of capital expenditure for expansion,
3. Releasing circuit capacity for applications of additional load, and
4. Improved voltage reduction.

1.3.3 OFF-PEAK OPERATION OF WATER PUMPS

The total noncoincident demand for water pumping stations in 1980 was 58.0 MW. Part of the water pumping load can be shifted from the peak hours (2 to 4 hours daily) to the off-peak hours if appropriate water pressure is maintained by high elevation water reservoir tanks.

1.4 ENERGY CONSERVATION TECHNOLOGIES

Many specific techniques can be investigated to conserve energy in the PEWC system. From this plethora of opportunities, three general cate-

gories emerge: efficiency of production, efficiency of product use, and control of the rate of energy use. Each of these can be thought of in the context of three broad classes of users - residential, commercial and industrial.

In order to quantify the options for energy conservation, the following specific load sectors were analyzed for the short-range period, (1981-1986):

1. Commercial Sector
2. Residential Sector
3. Industrial Sector
4. Agricultural Sector
5. Miscellaneous

The data for energy conservation opportunities in the above sectors were derived from the report provided by the PEWC staff and '1980 Power Survey Report'.

1.5 OTHER SYSTEM IMPROVEMENT PROGRAMS

1.5.1 AVAILABILITY IMPROVEMENT OF EXISTING UNITS

From time to time generating units are out of service for maintenance reasons. These scheduled and unscheduled (forced outages) outages reduce productivity and available capacity to meet the

dmenad. The purpose of this program is to determine the value of certain benefits which result from a permanent increase in the capability and/or imrpovement in the forced outage rate of the existing PEWC generation facilities.

1.5.2 REMOVAL OF TRANSMISSION AND DISTRIBUTION 'BOTTLE-NECKS'

The increases in generating capacity made by the PEWC in the past have not always been matched by required necessary increases in the transmission and distribution system. One example, the inadequate transmission circuit out of Rosieres and capacity limitation of transformer. For the short-range period, substantial network capacity can be improved by eliminating T & D systems "bottle-necks".

1.5.3 REPOWERING

Repowering consists of converting an existing conventional gas- and oil-fired steam boiler power plant into a combined cycle plant by integrating one or more combustion turbines. This allows an increase in capacity and reduced heat rate as compared with the existing plant.

1.5.4 INCENTIVES FOR SELF-GENERATING CUSTOMERS

The total self-generating capacity of the residential commercial and light industrial customers in the BNG and EG service areas in 1980 was over 20 percent of the PEWC system peak demand. An incentive program can be developed based on the 'avoided cost' concept for the customers with self-generating capacity to disconnect from the main feeder during the peak hours. This will release generating capacities to other customers and also will relieve the transmission and distribution system component loading.

1.5.5 SHIFTING OF INDUSTRIAL LOAD

One means of satisfying the need for additional generation capability is the development of a policy which supports a shifting of peak power demands of individual industrial customers within the daily load requirements. Such a demand shift would tend to flatten out the daily load curve, thus postponing the need for routine load shedding and increasing generation capacity.

1.5.6 DEMAND SUBSCRIPTION SERVICE

Demand Subscription Service (DSS) is a concept which will allow the customer to choose the minimum level of service which will

satisfy his comfort needs during the critical system peak hours. In return, the customer will be compensated through the monthly bill in accordance with the level of service chosen.

In the following section, the capacity and energy savings for each of the above items are quantified to evaluate the supply/demand balance for the short-range period (1982-1986).

2. SHORT-RANGE SUPPLY AND OUTLOOK DEMAND OUTLOOK

2.1 EXISTING SUPPLY SYSTEM

The PEWC system has sixteen independent electricity supply systems which supplied about 680 GWh of energy to about 182,000 customers in 1978/79 with a historical maximum demand of about 165 MW. The total 1981 installed capacity of the PEWC system is 280 MW. The Blue Nile Grid (BNG) system produces about 90 percent of PREC's total energy and supplies 125,000 customers from Damazine near the border with Ethiopia to Khartoum The peak demand in the BNG system in 1978/79 was 137 MW. The location and size of the existing generating units are included in Table 2.1.

2.2 POWER-III GENERATION EXPANSION PLAN

The operating reliability of the BNG system will be significantly improved when the new generating facilities of the so called Power III project are completed, The generation expansion program for the study period (1981-1986) are as follows:

1. Burri Power Station Extension
   - Installation of 4 X 10 MW (Total 40 MW) diesel units.

TABLE 2.1

PEWC SYSTEM
BLUE NILE GRID
EXISTING GENERATING PLANT

Plant Name	Type	Year Installed	Name Plate Rating (MW)	Present Maximum Output (MW)
Burri	Diesel	1964	15	10
Burri	Diesel	1981	15	15
Burri	Steam	1956	30	10
Kilo X	GT	1969	15	13.5
Rosieres	Hydro	1971-80	130*	120*
Sennar	Hydro	1962	15	15
Wad Medani	Diesel	1950-67	8	4
Other			2	1.5
			230	189
Kenana Extension	Steam		40*	20*
TOTAL			270	209

* Please note that for both Rosieres and Kenana, maximum capacity equals rated capacity, but inadequate transmission and transformer capacility limit the output of the generating units.

2. Rosieres Extension

   - Installation of 2 X 40 MW (Total 80 MW - Set #5 and #6) and embedded parts of Set #7.

3. Khartoum North

   - Phase I: Installation of 2 X 30 MW steam generating units.

In Table 2.2, the information related installation dates and planned capacity expansion in the BNG service area is included.

2.3 LOAD FORECASTS

Several techniques can be used to produce a forecast of future load for the BNG system. For example:

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

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

c. An estimated based on national economic or development guidelines, (e.g., estimated growth of Gross National Product, or similar

TABLE 2.2

SHORT-RANGE CAPACITY EXPANSION PROGRAM

BNG-SYSTEM

Supply System	Year 1981*	1982	1983	1984	1985
Hydro	145 MW		1-40 MW June	1-40 MW April	
Steam	70 MW		2-30 MW March		
GT	15 MW				
Diesel	40 MW	1-10 MW December	1-10 MW January 1-10 MW February 1-10 MW March		
TOTAL	270 MW	280 MW	400 MW	450 MW	

* Maximum output of the existing system is only 209 MW.

economic indicators, 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.

PEWC develops its market forecast 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 market forecast presented here is based on PEWC '1980 Development Plan Report'. Historical development of the power market from 70/71 to 79/80 with growth expressed in terms of peak demands can be characterized by three different periods:

a. 1970/1973, when the growth rate averaged 10.3 percent per year;
b. 1973/1976, when the growth rate declined 5.3 percent in response to increases in the real average price of electricity in Sudan; and
c. 1976/1980, when demand grew at an average rate of 11.0 percent per year.

In Table 2.3, the peak demand and energy forecasts for the BNG system are included for the short-range period. The average peak demand growth rate is assumed to be 11 percent. The transmission and distribution losses are approximately 14 percent of gross generation. In Table 2.3, the system annual load factor is computed based on gross generation rather than actual energy sales to different classes of customers.

TABLE 2.3

PEAK DEMAND AND ENERGY FORECASTS

BNG-SYSTEM

Year	Annual Energy Sales (GWh) Residential	Industrial	Agriculture	Other	Total	System Loss (GWh)	Gross Energy Generation (GWh)	Peak Demand (MW)	Load Factor
80/81	285	321	216	74	896	143	1039	198	60%
81/82	314	380	269	81	1044	167	1211	231	60%
82/83	343	453	301	89	1186	190	1376	262	60%
83/84	367	484	324	98	1273	204	1477	281	60%
84/85	390	528	353	108	1379	221	1600	304	60%
85/86	423	573	383	117	1496	241	1737	329	60%

Source: 1980 Development Plan for Electricity, Technical Supplement (Public Electricity and Water Corporation; July 1980) Table A-25.

The monthly peak demand and energy sales for the study period are included in Table 2.4. It should be noted from Table 2.4, that the BNG system's peak demand historically occurs in the summer months and the average monthly load factors are about 70 percent.

The energy sales and peak demands of Table 2.4, are used in the succeeding section to evaluate the impact of different conservation measures and load management programs.

2.4 PLANNING CRITERIA

Determination of an adequate measure of reliability or service quality for the BNG system is a difficult task because of the unavailability of complete system data and the budget limitation of this report. It seems that no single criterion of system reliability describes the system's abaility to supply satisfactory service. The following planning criteria for system reserve margin were used to determine the capacity expansion requirements for future years.

a Installed capacity margin (installed capacity minus annual peak demand) should be sufficient to allow the loss of the two largest generating units (or the two largest system risks).

At present in the BNG system, the hydro unit #4 (40 MW) at Rosieres and steam unit at Kenana extension (40 MW) are the two largest

TABLE 2.4

MONTHLY CAPACITY AND ENERGY FORECASTS

BNG-SYSTEM

Year	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
80/81												
MW	158	142	153	172	175	176	161	172	185	190	185	198
GWh	78.7	70.6	72.9	88.1	82.1	84.0	83.8	80.8	93.7	98.5	98.1	106.5
81/82												
MW	184	166	178	201	204	205	188	201	216	222	216	231
GWh	91.7	82.3	84.9	102.6	95.7	97.9	97.6	95.2	110.2	114.8	114.3	124.1
82/83												
MW	220	206	226	243	230	219	195	205	221	253	250	262
GWh	114.2	99.6	108.3	124.8	107.5	104.3	101.3	96.2	111.9	131.5	132.6	136.1
83/84												
MW	245	222	248	261	250	237	210	213	235	267	265	281
GWh	122.9	110.9	117.7	133.9	117.1	112.9	109.3	103.8	118.9	138.8	140.7	146.9
84/85												
MW	265	241	269	282	272	259	227	239	251	288	296	304
GWh	132.3	120.4	127.7	144.6	127.5	124.2	115.0	112.4	127.3	149.5	152.4	160.1
85/86												
MW	287	261	291	305	294	280	246	259	272	312	320	329
GWh	144.2	131.2	139.2	157.6	138.9	135.4	125.4	122.5	138.7	162.9	166.1	174.5

system risks. However, the capacity of both of the above units are derated due to transmission limitation (See Table 2.1). Therefore, the two largest generating unit risks would be the loss of two 30 MW units at Rosieres. The single largest system risk is the loss of 200 kV circuit out of the Rosieres hydro plant to Khartoum.

b. A three percent installed reserve margin criterion in addition to the two largest risks is used to cover the uncertainties due to load forecast error, and slippage of service dates of new generating units.

The above installed capacity margin criteria is based on the principle that for the more common contingency outages there should be no loss of system load, nor adverse effects on the system. This criteria recognizes the necessity for load shedding for those outage contingencies that are credible but of such low probability that it is not feasible to protect the system against the loss of load. The event "loss of two largest units" may be encountered when one unit is on scheduled maintenance and the other unit suffers a forced outage.

2.5 GENERATION EXPANSION PLANS

The planning for generating facilities is complex, and major investment decisions must be made years in advance. Figure 2.1 and Table 2.5, indicate the present generating capacity expansion plans for the study period. In Figure 2.1, the steps in the dependable installed capacity curve indicate the addition of new generating units to the system. The "Reserve Margin Criteria" curve indicates the installed capacity margin requirements for system reliability purposes each year. It is important to note from Figure 2.1, that the adopted reserve margin criteria will be violated in 1982, part of 1983, and every month after mid-1985 for the study period. After the installation of Rosieres units #5 and #6 and 3-10 MW diesel units at Burri, there will be adequate capacity available from mid-1983 through the end of 1985 to satisfy the peak demands. However, in the near-term, 1981, 1982, and 1983 during peak months, there will be severe capacity shortages without any load management programs. The BNG system will be required to implement a regular load shedding or a rotating blackout program. The capacity shortages in 1985 and 1986 can be alleviated by installing new deisel or gas turbine units after 1984.

Table 2.6 and Figure 2.2, show critical capacity and energy shortage may occur in the BNG system throughout the study period if there is a slippage of installation dates of Rosieres #5 and #6 units. From Figure 2.2, it should be noted that the reserve margin criteria for

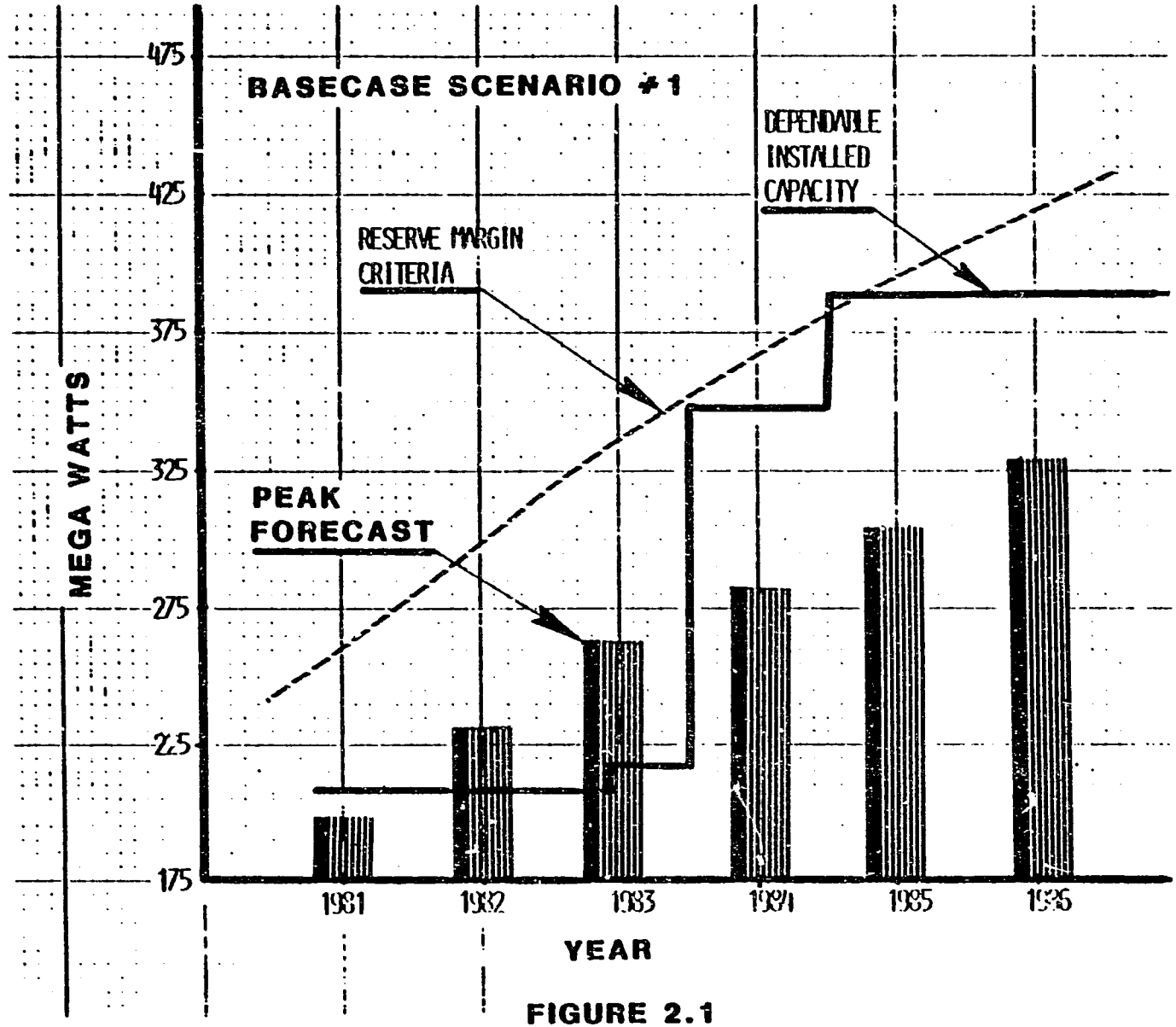

FIGURE 2.1

BASE CASE GENERATION EXPANSION AND LOAD FORECAST

TABLE 2.5

GENERATING CAPACITY EXPANSION AND LOAD DATA

BASE CASE SCENARIO #1 (AS PLANNED)

Items	1981	1982	1983	1984	1985	1986
1. Peak Demand (MW)	198	231	262	281	304	329
2. Capacity Expansion in MW	--	+ 10	+130	+ 40	--	--
3. Dependable Installed Capacity in MW	209	219	349	389	389	389
4. Installed Reserve Margin in MW	11	- 12	87	108	85	60
5. Reserve Margin in Percent	5.5	- 5.2	33.2	38.4	28.0	18.2
6. Required Reserve Margin to Meet the Planning Criteria in Percent	33.0	29.0	30.0	31.0	29.0	27.0
7. Capacity Shortage (MW)	- 54	- 79	--	--	- 3	-30
8. System ROR	15	15	15	15	15	15

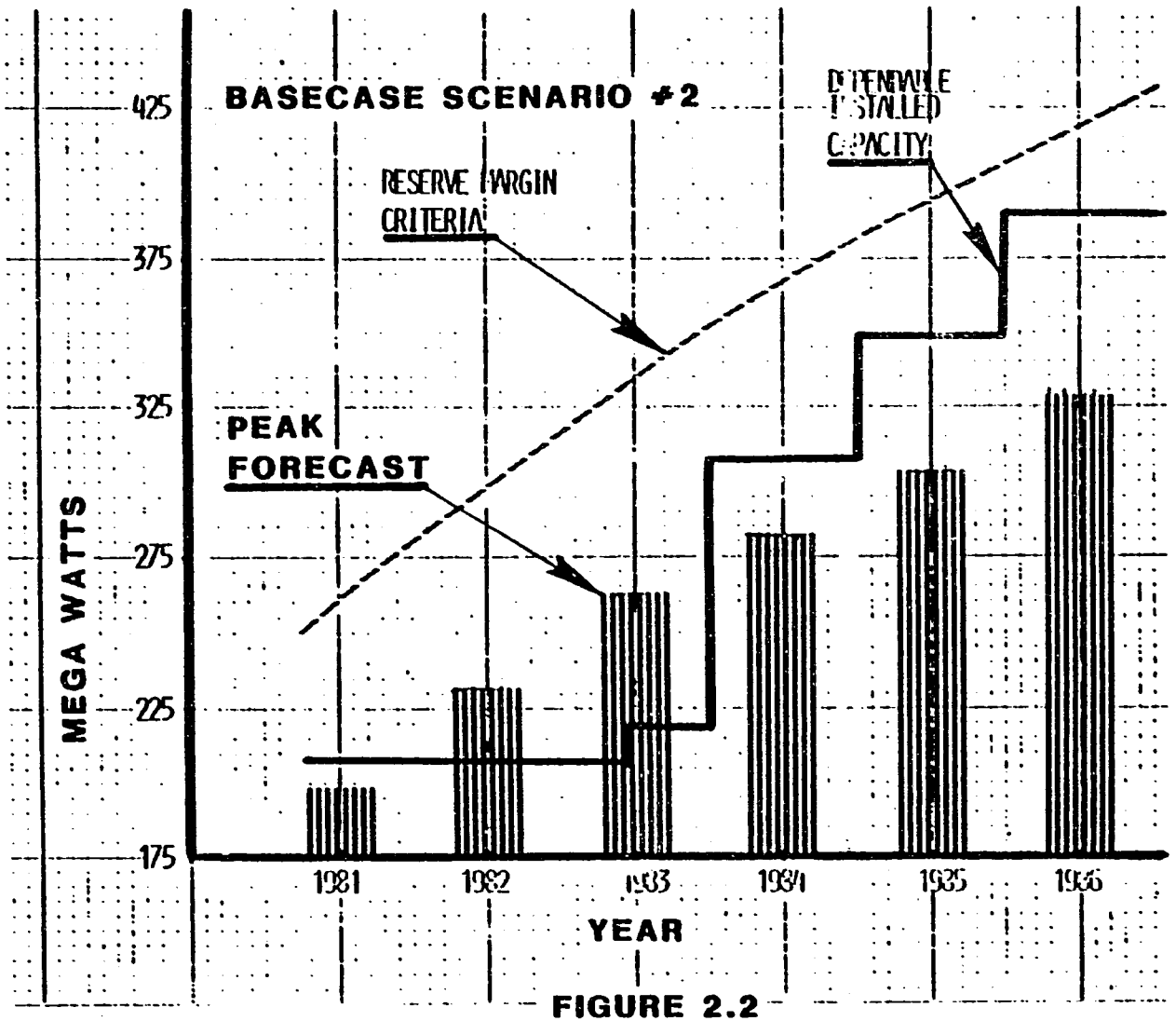

FIGURE 2.2

BASE CASE GENERATION EXPANSION AND LOAD FORECAST

this basecase scenario will be violated every year during the 1981-1986 time period. Even in 1983 and 1984 during peak months, for any single contingency of 30 MW units or 40 MW units, the BNG system will be required to implement a routine load shedding or a rotating blackout program.

From Table 2.5 and 2.6, it should be noted that the cumulative capacity addition in the BNG system for the study period 1981-1986 is 180 MW. The peak demand growth is also 180 MW (209 - 389 = 180 MW) for the study period. The peak demand and generation expansion plans up to 1986 were taken from the '1980 Development Plan for Electricity Report' of PEWC. Also in Table 2.5 and 2.6, the BNG system's generating units random outage rate (ROR) values for the study period are included. The system ROR values indicate for the given generating units mix on the average what percent of the system's installed capacity will be on forced outage. Therefore, the net generating capacity before any scheduled maintenance is given by:

$$\text{Net Generating Capacity} = \begin{pmatrix}\text{Installed}\\ \text{Capacity}\end{pmatrix} \times \begin{pmatrix}\text{System}\\ \text{ROR Value}\end{pmatrix}$$

For example, Table 2.5 shows that in 1984 the net generating capacity available before scheduled outage will be approximately 330.6 MW (389 MW X 0.85 = 330.6 MW).

TABLE 2.6

GENERATING CAPACITY EXPANSION AND
LOAD DATA

BASE CASE SCENARIO #2
(Six Months or One Year Slippage of Hydro Units #5 and #6)

Items	1981	1982	1983	1984	1985	1986
1. Peak Demand	198	231	262	281	304	329
2. Capacity Expansion in MIW	--	+ 10	+ 90	+ 40	+ 40	--
3. Dependable installed Capacity in MW	209	219	309	349	389	389
4. Installed Reserve Margin in MW	11	- 12	47	68	85	60
5. Reserve Margin in Percent	5.5	- 5.2	18.0	24.0	28.0	18.2
6. Required Reserve Margin to Meet the Planning Criteria in Percent	33.0	29.0	30.0	31.0	29.0	27.0
7. Capacity Shortage in MW	- 54	- 79	- 32	- 19	- 3	- 29
8. System ROR	15	15	15	15	15	15

2.6 BNG SYSTEM LOAD CHARACTERISTICS

The demand for electricity fluctuates on an hourly, daily, and seasonal basis. For load management and conservation programs studies, it is important to analyze the daily and seasonal characteristics of system load curves. Figures 2.3 (a), (b), (c) and 2.4 (a), (b), illustrate the typical peak day load profiles for the months of April and May. The daily load characteristics of 1979, 1980, and 1981 indicate that the BNG system peak demand hours have been shifted from the morning to evening hours. The primary reason for this shift may be due to increasing electrification of houses and growing air conditioning loads in the existing residential customers. In the BNG system, April, May, June, July and August months are considered to be summer months when maximum demand occurs.

The opportunities for demand reduction programs can be easily evaluated for the characteriwtics of the daily load profiles. A low daily load factor value indicates needle peaking characteristics. Usually any daily load factor value under 85 percent indicates the opportunities for load management programs. In Table 2.7, the peak day load factors for summer months (April, May, June, July, August, and September) for 1979 and 1980 are included. From Table 2.7, it should be noted that the average peak day load factor of the BNG system is approximately 78 percent. Also, the other interesting point to note is that the 1980 summer months average daily load factor is lower than the 1979

TABLE 2.7

SUMMER MONTHS PEAK DAY LOAD FACTORS

Month	1979	1980
April	0.79	0.77
May	0.76	0.76
June	0.80	0.76
July	0.78	0.78
August	0.79	0.76
September	0.78	0.72
Average	0.783	0.760

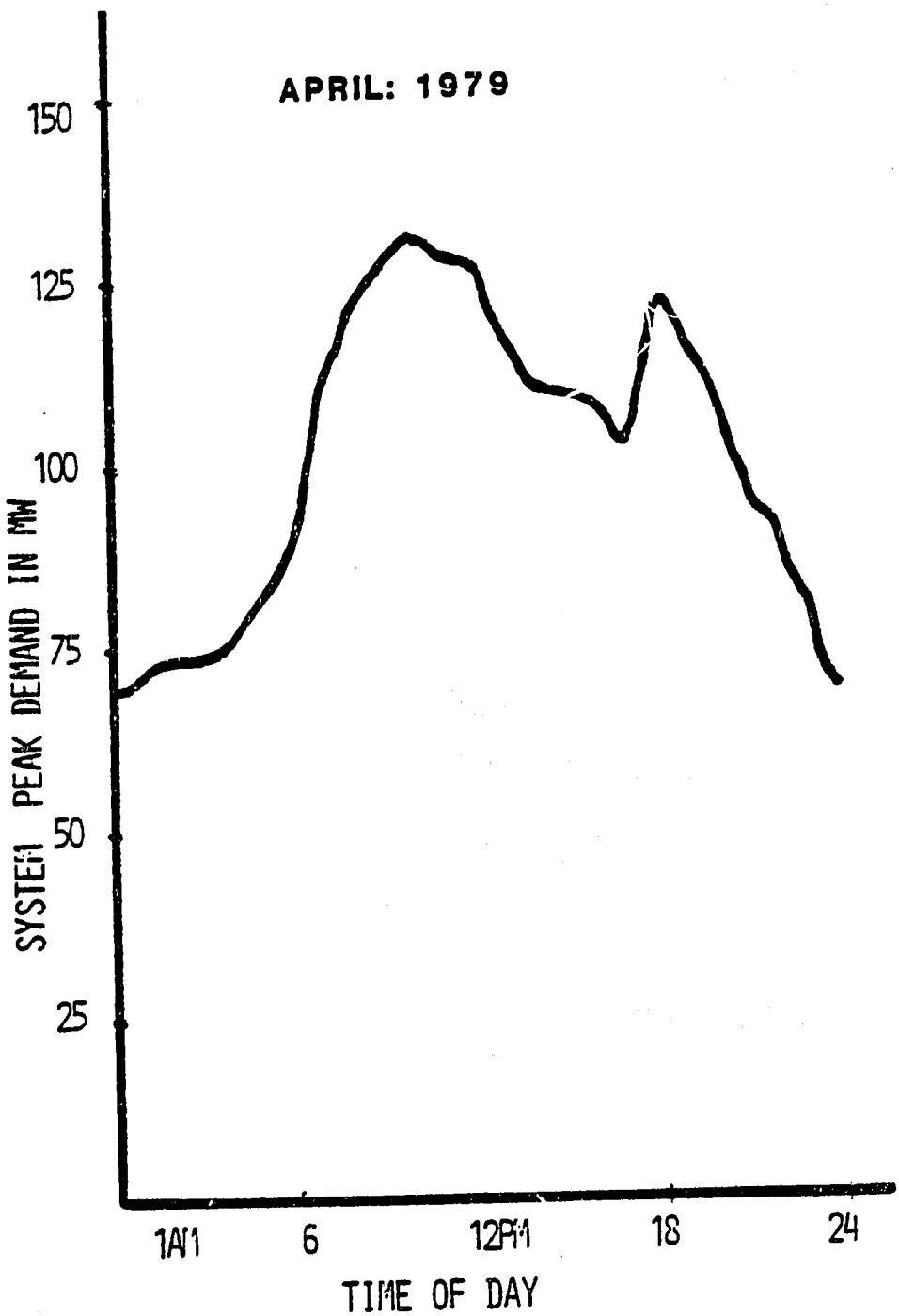

FIGURE 2.3(a)

SUMMER MONTHS PEAK DAY LOAD PROFILE

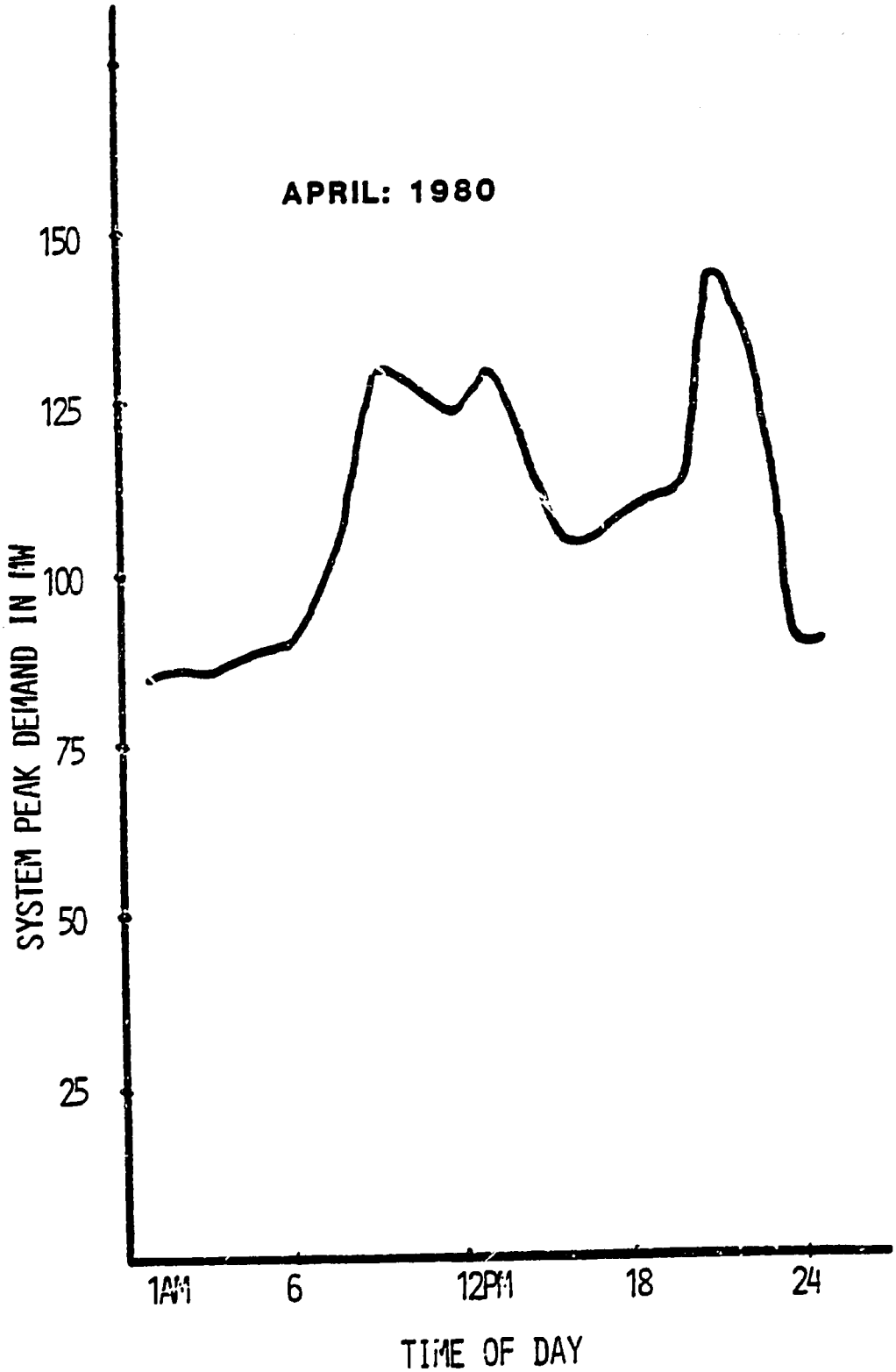

FIGURE 2.3(b)

SUMMER MONTHS PEAK DAY LOAD PROFILE

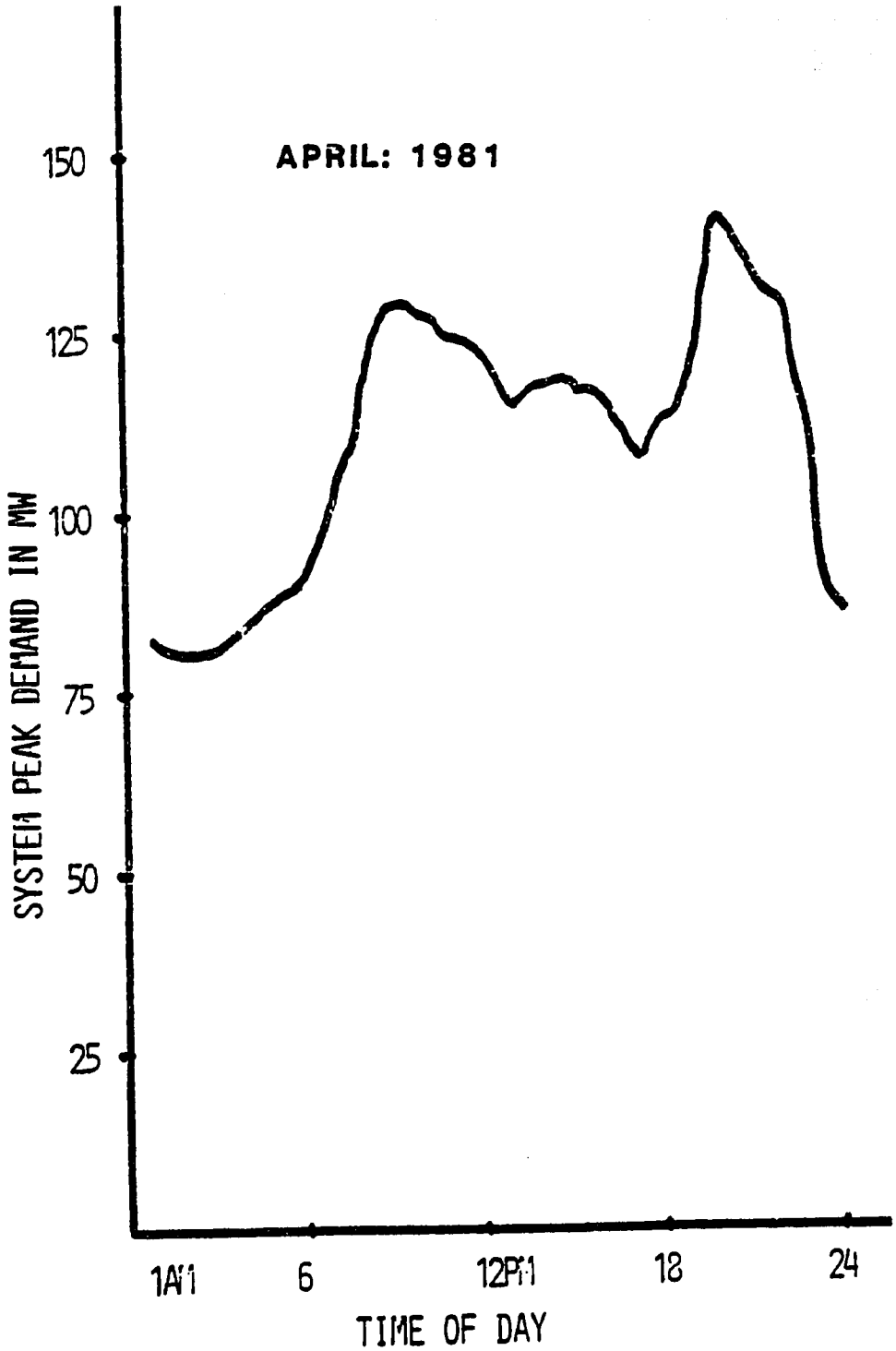

FIGURE 2.3(c)

SUMMER MONTHS PEAK DAY LOAD PROFILE

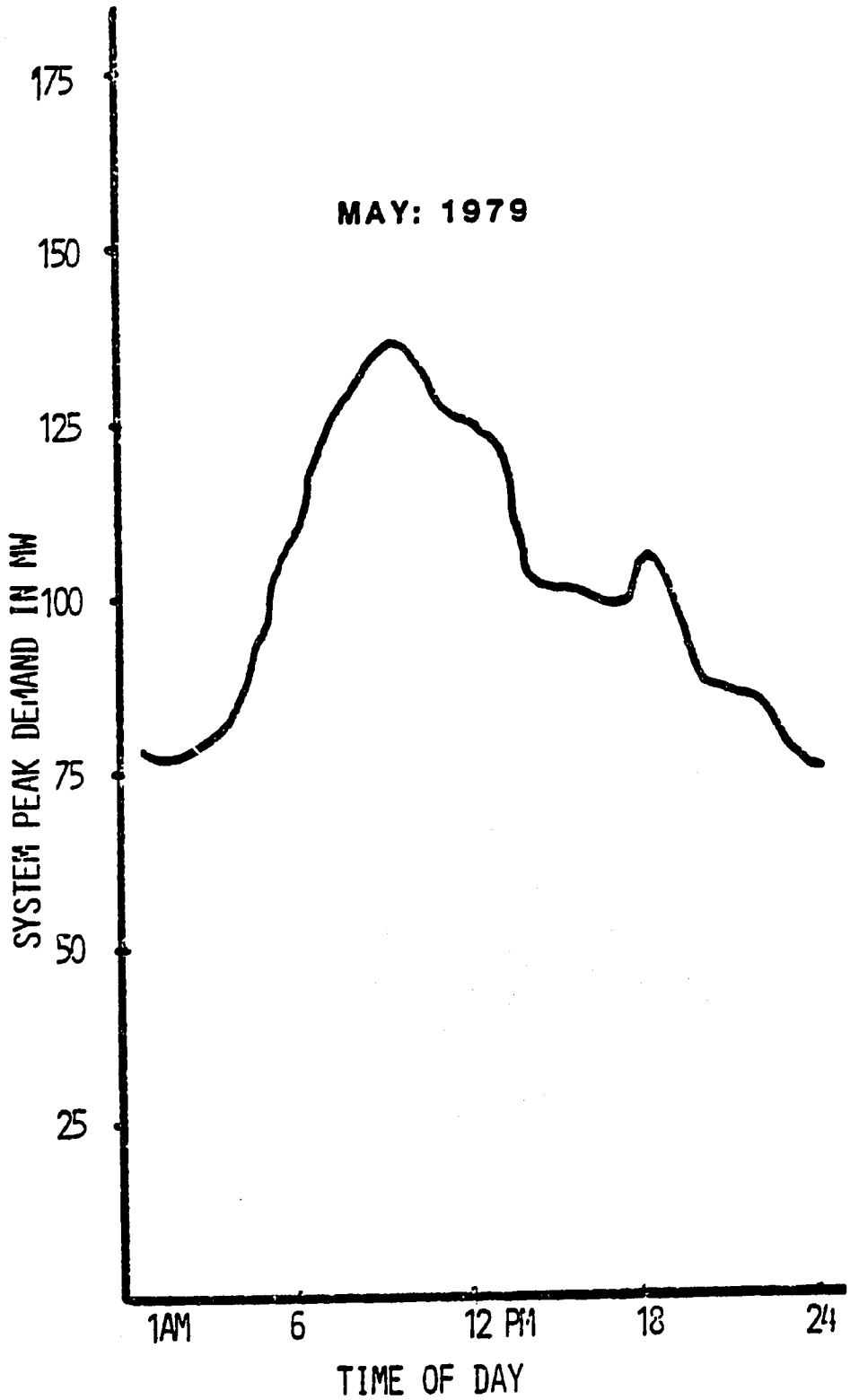

FIGURE 2.4(a)

SUMMER MONTHS PEAK DAY LOAD PROFILE

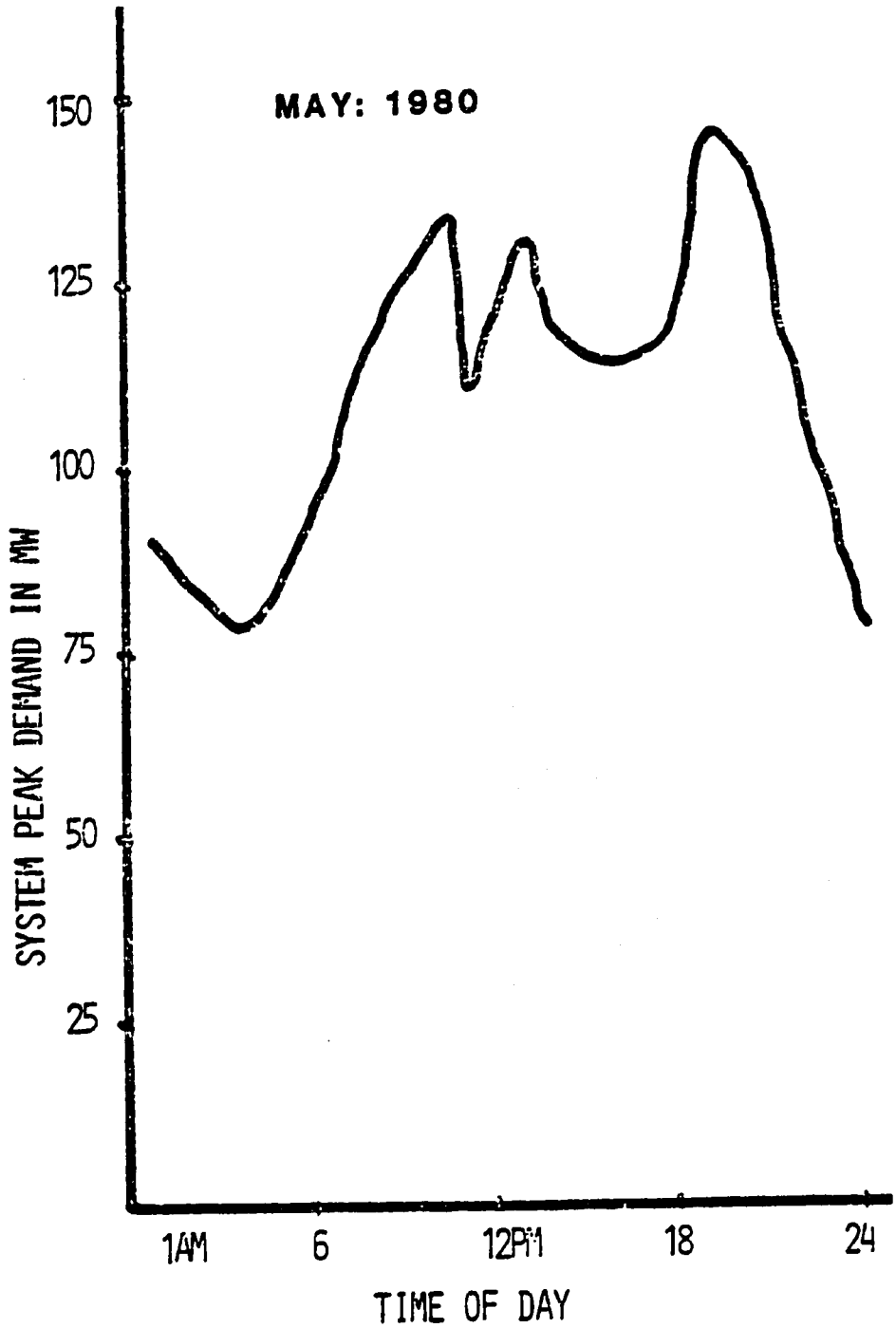

FIGURE 2.4(b)

SUMMER MONTHS PEAK DAY LOAD PROFILE

summer months average daily load factor. This indicates the growth of air conditioning load and needle-point characteristics.

3. DIRECT LOAD MANAGEMENT ADOPTION SCENARIO AND SYSTEM LOAD IMPACTS

This section describes the development of estimates of the BNG system load impacts from the direct load management program. Specifically, the direct cycling of air conditioning loads during the peak hours are 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 BNG service area.

Load management is often divided into "use management" and "supply management". Use management is the direct and voluntary control of selected loads of the end-use customers. Supply management, on the other hand, concentrates on increased coordination of the planning and operating needs of utilities to insure the availability of capacity. Use management can be accomplished through four primary functions:

a. Price control through rate structure,
b. Voluntary load management by customers,
c. Customer storage devices, and
d. Direct mechanical control.

This section deals exclusively with the mechanical control of air conditioning loads in the BNG system.

3.1 AIR CONDITIONING LOADS

The source of data used in this section to determine the maximum contribution of air conditioning load at peak hours is derived from the total number of air conditioners sold in Sudan during 1976-1980 period by major manufacturers. In Table 3.1, the estimated number of air conditioners in the BNG service area is included. The number of air conditioners sold in Sudan during 1976-1978, in Table 3.1, are the actual figures provided by the Ministry of Energy and Mining (MEM) staff. The number of air conditioners sold during 1979-1981 are the estimated figures derived from previous years manufacturing and sale trends. However, the MEM staff's recommended an estimate of at least 10 percent to 20 percent more air conditioners in determining the actual contribution of the total air conditioning load. The primary reason for this is to account for the approximate number of imported air conditioners from the neighboring countries.

It has been assumed that approximately 80 percent of the total number of air conditioners are in the BNG service area. Therefore, the total available air conditioners for cycling during the summer months would be about 34214. It should be noted that the air conditioning loads in the business and commercial sectors are not available for cycling during the evening peak hours. Approximately 70 percent of the total air conditioning load in the BNG service area is assumed available for cycling during the evening peak hours. During the morning peak hours,

TABLE 3.1

TOTAL NUMBER OF AIR CONDITIONERS
SOLD IN SUDAN

Source	1976	1977	1978	1979	1980	1981	TOTAL
Manufactured in Sudan	4085	4828	5719		8017	9460	38880
Imported	408	483	572	677	802	946	3888
TOTAL							42768

TABLE 3.2

APPROXIMATE NUMBER OF AIR CONDITIONERS
AND AVAILABLE LOAD FOR CYCLING
(Based on 1981 Estimate)

Items	Morning Hours	Evening Hours
Number of air conditioners	17107	23950
Air conditioning load in MW	34.0	48.0

Assumption :

a. Average size of air conditioner is assumed to be 2.5 kW rating.

approximately 50 percent of the total number of air conditioners are assumed to be cycled.

In Table 3.2, for available air conditioning load for direct control or cycling is computed using the following formula:

$$\text{Available Air Conditioning Load (kW)} = \left(\text{Utilization Factor}\right) \times \left(\text{Number of Air Conditioners}\right) \times \left(\text{Average kW rating of an Air Conditioner}\right)$$

In Table 3.2, a utilization factor of 0.8 is assumed to account for air conditioners not in use or out of service. Also, the number of air conditioners based on average unit size of 2.5 kW are included in Table 3.2 which will be available for cycling during morning and evening peak hours. The projected peak demand for 1981 is 198 MW for the BNG system. Therefore, the air conditioning loads in the morning and evening hours are approximately 34.0 and 48.0 percent, respectively.

3.2 SYSTEM LOAD IMPACTS

In Sudan, no load research and demonstration effort has been expended to date on air conditioning load control. However, some data are available in the United States which can be used to estimate load impacts of controlling air conditioners.

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 some resultant degradation of comfort levels within the home. The standard method of remote air conditioner cycling involves the shut off of the compressor via the interruption of low voltage control lines for some fixed period of time each hour. Typically this period is 7½ minutes each half-hour which translates to 15 minutes each hour. It is theorized that such a forced cycling scenario will result in reduction of the normal on-time of the air conditioner's compressor thereby resulting in a lower integrated demand for the unit. It is from the lowering of the integrated demands of the air conditioners on the utility's system that the desired reduction of demand is realized.

The limiting of these cycling times results in degradation of comfort levels within the home in direct proportion to the amount of load relief obtained. For example, assume that a particular air conditioners with a connected load of 4 kW is sized such that it is operating at 100 percent capacity during the entire period in which the utility wishes to exercise control. At this time the unit's integrated demand is essentially its connected load. If the utility cuts its natural on-cycle (60 minutes per hour) by 25 percent to 15 minues per hour, then its integrated demand over that hour will essentially be reduced from 4 kW to 3 kW or a resultant 1 kW reduction in demand. The result of this demand reduction in terms of comfort levels of the home would mean a rise of approximately 2.8°C (5°F), assuming an outdoor temperature of 32°C (90°F) and a normal indoor temperature setting of 21°C (70°F).

If this change in temperature represents the maximum level which the customer is willing to tolerate, based on his attitude toward the utility and/or financial incentive offered to him, then this cycling scenario represents the maximum level or optimum level of acceptable control and load relief. If on the other hand, this temperature change exceeds the maximum tolerable level, then the customer is being overcontrolled. If this change is less than the maximum tolerable level, then the customer is being undercontrolled.

Due to expected systemwide variation in customer tolerance levels and air conditioner sizing, any program which 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 withdrawls, it may be necessary for a utility to utilize a more conservative cycling scenario which produces less than optimal demand reduction.

Table 3.3 lists five electric utilities in the United States, each with air conditioning cycling control projects along with reported or desired coincident diversified demand reduction obtained per point of control.

The averge of the coincident demand reduction potential shown in Table 3.3 is approximately 1.1 kW per point of control Although it is not possible to identify an air conditioner control demand reduction potential figure that would be applicable to BNG service area, however, a 0.75 kW

TABLE 3.3

AVERAGE COINCIDENT DIVERSIFIED

DEMAND REDUCTION PER AIR CONDITIONER

Reference: Survey of Utility Load Management and Energy Generation Projects
EPRI Report EM-1606
TPS 78-8-7, November 1980

Utility	Demand (kw) Reduction
Arizona Public Service Co.	0.5 - 1.5
Cobb EMC	1.3
Pacific Gas and Electric Co.	0.25 - 1.15
Mississippi Power and Light	1.0
Lubebee River	1.4

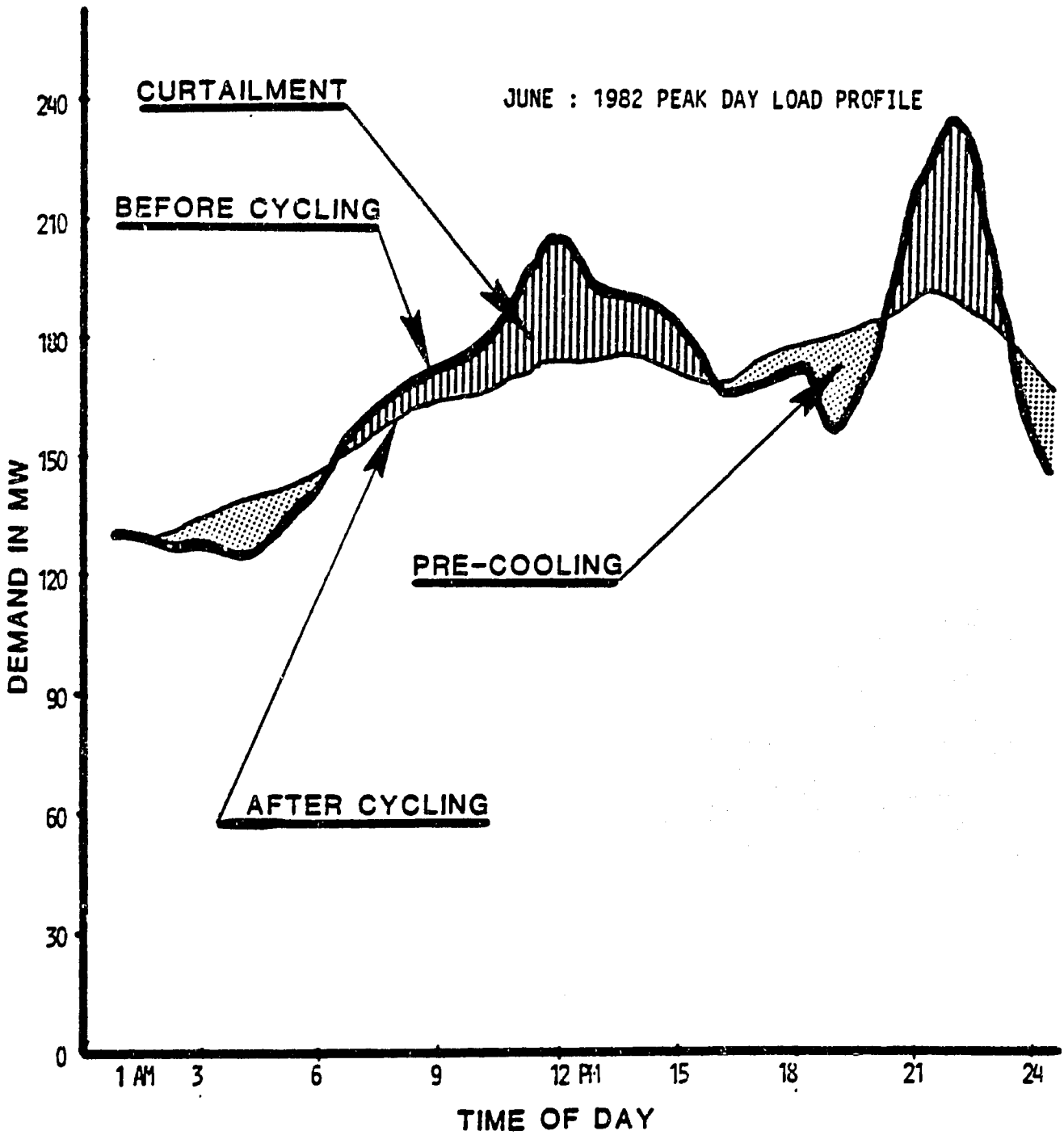

FIGURE 3.1

EFFECTS OF AIR CONDITIONER LOAD CYCLING
OR DIRECT LOAD CONTROL

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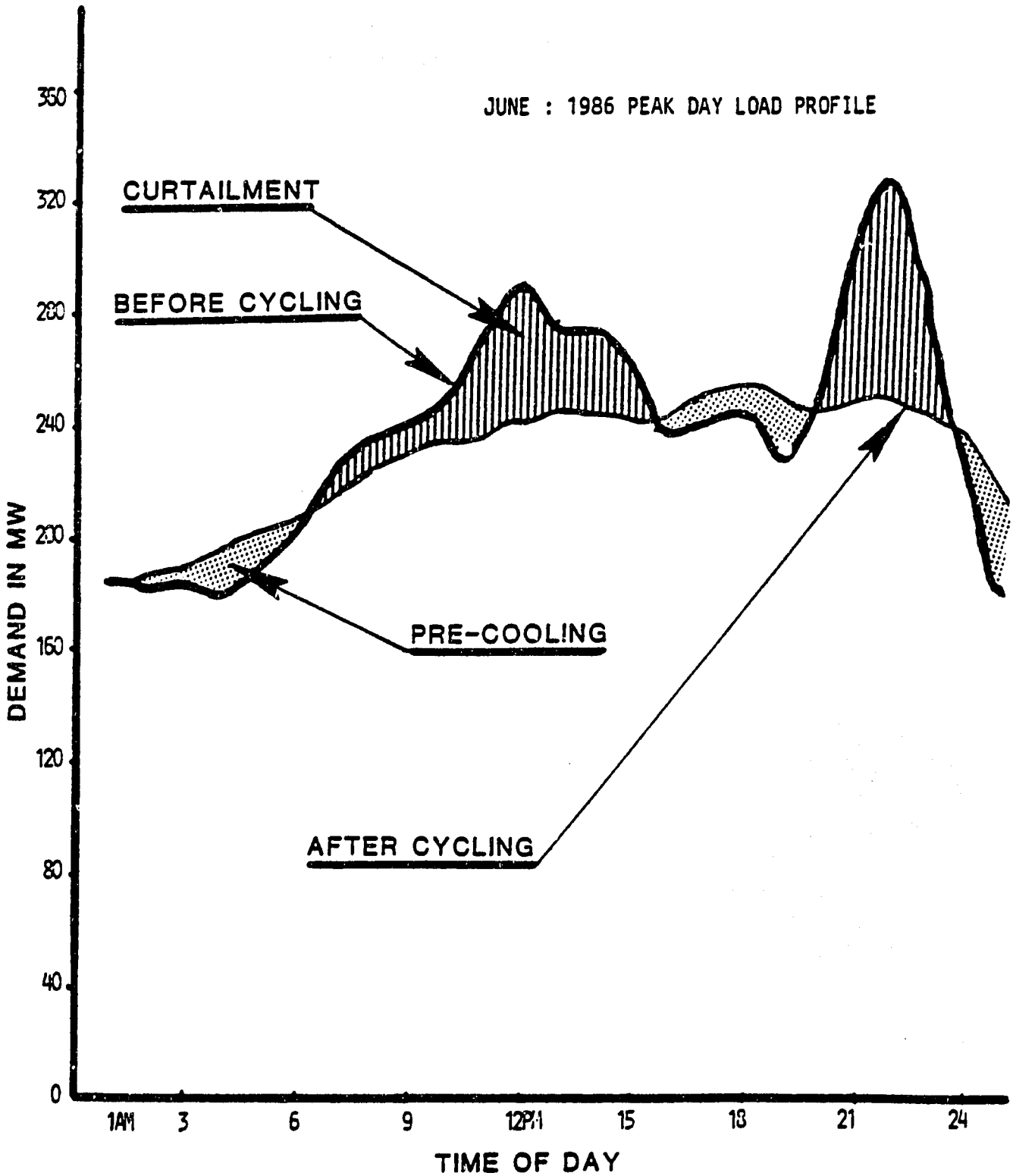

FIGURE 3.2

EFFECTS OF AIR CONDITIONER LOAD CYCLING
OR DIRECT LOAD CONTROL

TABLE 3.4

PEAK REDUCTION DUE TO DIRECT
CONTROL OF A/C LOAD IN THE BNG SYSTEM

	Total A/C Loads			
Year	Morning Hours	Possible Peak Reduction	Evening Hours	Possible Peak Reduction
1981	34	10.2	48	14.4
1982	37	11.1	58	17.4
1983	42	12.6	65	19.4
1984	45	13.5	70	21.0
1985	49	14.7	76	22.8
1986	53	15.9	82	24.6

day in the month of June 1982 and 1986. The load profile used in developing Figures 3.1 and 3.2 is the peak day profile of June 1980.

3.4 IMPACTS OF GENERATION EXPANSION REQUIREMENTS

The impacts of direct air conditioners cycling load control during the peak hours on generating capacity requirement are summarized in Table 3.5 and 3.6, From Table 3.6, it can be observed that even though the modified peak demand for 1986 have been reduced by 24.6 MW, the generation expansion requirements by 1986 has been reduced by 32 MW. (See Table 2.5.) The required generating capacity in Table 2.5 is 419 MW (389 MW + 30 MW) to satisfy the reserve margin criteria and the required capacity in Table 3.5 is only 387 MW for the same reliability criteria. Therefore, it may be concluded that a peak reduction of 24.6 MW is equivalent to 32 MW of installed capacity if same level of reliability is maintained on the BNG system. In Table 3.6, the equivalent generating capacity reduction for the study period is included. Table 3.7 summarizes the potential capacity shortage reductions due to load management programs for the two basecase scenarios. From Table 3.7, it should be noted that the serious capacity shortages in Scenario #2 for the slippage of Rosieres hydro units in 1983 and 1984 has been reduced significantly by air conditioning load management programs. Figures 3.3 and 3.4 illustrate the results of Table 3.5, 3.6, and 3.7 graphically.

It is important to note from Table 3.7, that the potential capacity

TABLE 3.5

IMPACTS OF A/C LOAD MANAGEMENT
ON GENERATION EXPANSION REQUIREMENT
1981-1986

Year	Peak Demand (MW)	Peak Reduction Due to A/C Load Management (MW)	Modified System Peak Demand (MW)	Reserve Margin Criteria (%)	Installed Capacity Requirement (MW)
1981	198	-14.4	183.6	33	244
1982	231	-17.4	213.6	29	276
1983	262	-19.4	242.6	30	315
1984	281	-21.0	260.0	31	341
1985	304	-22.8	281.2	29	363
1986	329	-24.6	304.4	27	387

TABLE 3.6

EFFECTS OF A/C LOAD MANAGEMENT
ON POTENTIAL GENERATING CAPACITY REDUCTION

Year	Peak Reduction Due to A/C Load Management (MW)	Equivalent Generating Capacity Reduction (MW)
1981	-14.4	19.0
1982	-17.4	22.0
1983	-19.4	26.0
1984	-21.0	27.0
1985	-22.8	23.0
1986	-24.6	32.0

TABLE 3.7

EFFECTS OF A/C LOAD MANAGEMENT
ON POTENTIAL CAPACITY SHORTAGE REDUCTION

Year	With A/C Load Management Installed Capacity (MW) Requirements	Effects on Reserve Capacity			
		Base Case Scenario #1		Base Case Scenario #2	
		Without LM	With LM	Without LM	With LM
1981	244	-54.0	-35.2	-54.0	-35.2
1982	276	-79.0	-56.5	-70.0	-56.5
1983	315	+ 8.4	+33.6	-32.0	+ 6.4
1984	341	+20.9	+48.4	-19.0	+ 8.4
1985	363	- 3.0	+26.2	- 3.0	+26.2
1986	387	- 3.0	+ 3.0	-29.0	+ 3.0

Note: In calculating the reserve capacity with load management, the reserve margin criteria of Table 2.5 and 2.6 are used.

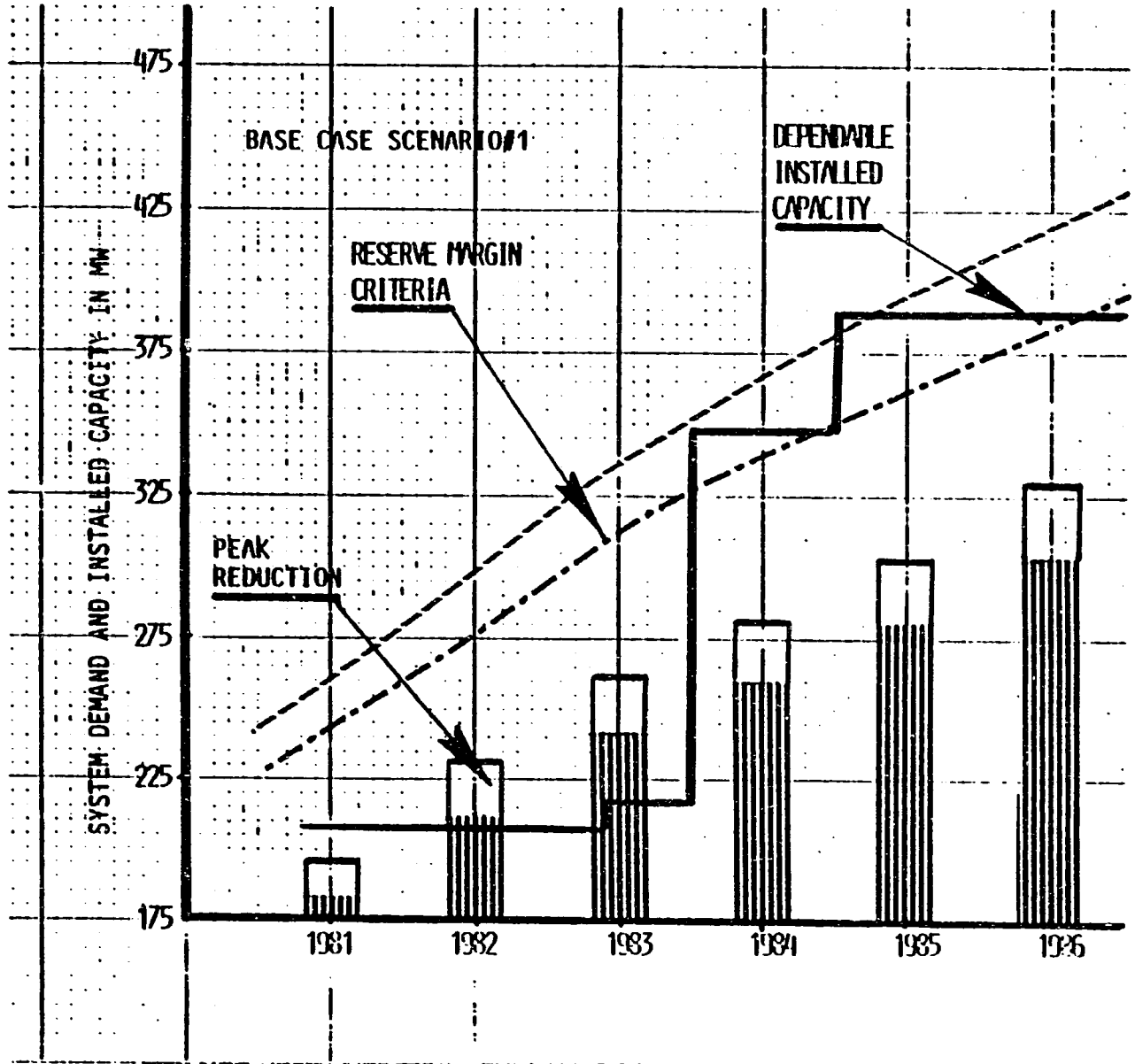

FIGURE 3.3

IMPACTS OF AIR CONDITIONER LOAD CYCLING
ON GENERATION EXPANSION REQUIREMENTS

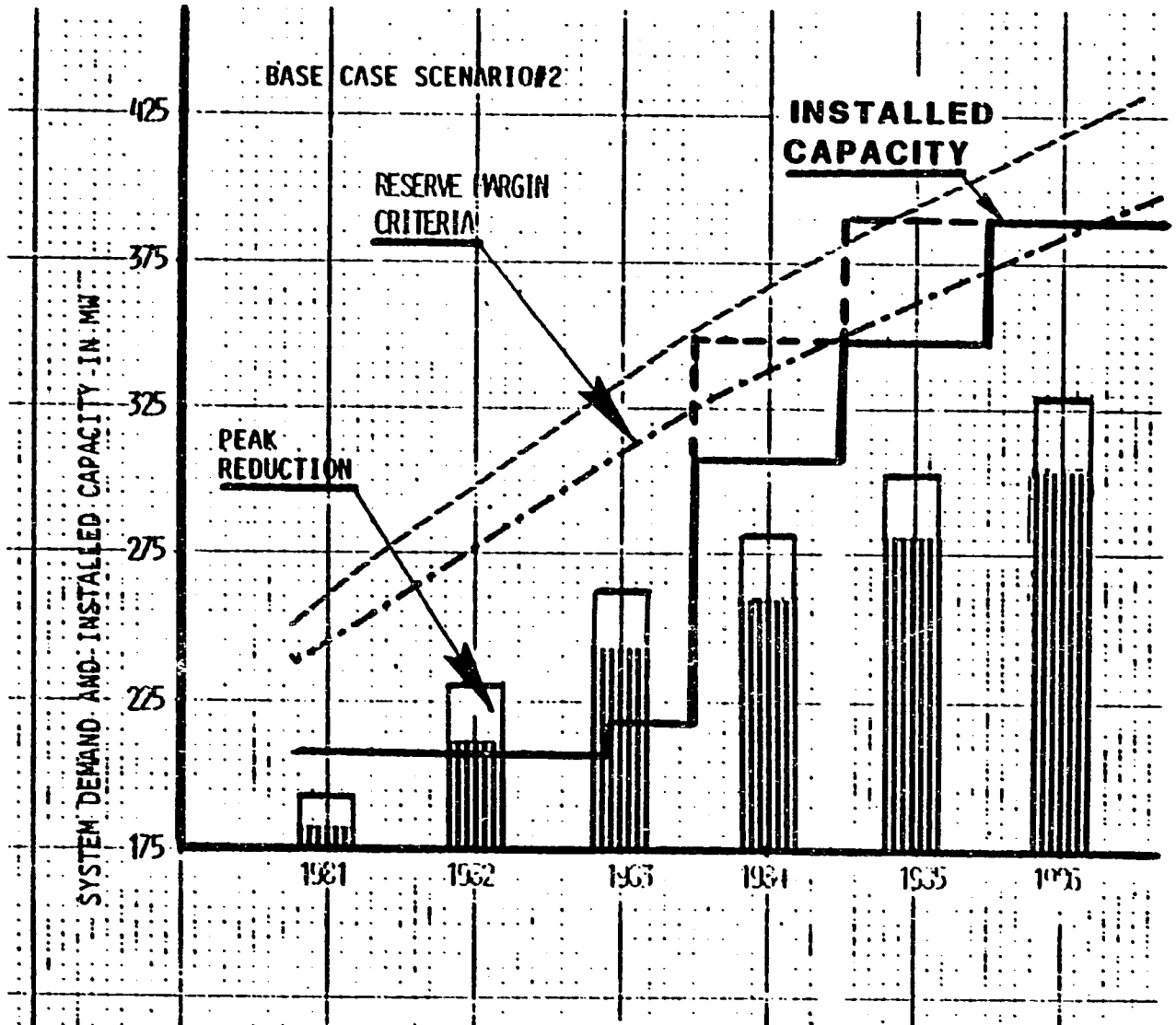

FIGURE 3.4

IMPACTS OF AIR CONDITIONER LOAD CYCLING
ON GENERATION EXPANSION REQUIREMENTS

shortages can be eliminated in 1983, 1984, 1985,1986 and the magnitude of capacity shortages are reduced significantly in 1981 and 1982. Also, it should be noted that the installed capacity in 1982 will go up by 10 MW only in December. Therefore, there is a great potential for capacity shortage during the summer months in 1982. The direct control or cycling of air conditioning loads during peak hours will reduce the frequency and likelihood of load shedding or of rotating blackouts in 1982.

4. FINANCIAL INCENTIVES OF POWER FACTOR IMPROVEMENT

1. GENERAL BACKGROUND

Power factor is the ratio of the product of voltage and current where they coincide to the product of the maximum instantaneous values of voltage and current.

$$\text{power factor} = \frac{\text{Working Power (kW)}}{\text{Total Kilowatt Ampere (kVA)}}$$

Usually electric utilities require a power factor of 0.9 or better, indicating that something should be done to increase the power factor. In PEWC system, the power factor in different load sectors varies between 0.7 and 0.85 during the day. The primary reasons for improving power factor in the different load sectors are:

a. To reduce system losses,
b. To imrpove voltage regulations, and
c. To improve system network capacity, thus deferring capital expenditure for expansion.

Alternatine current (AC) circuit loads, in general exhibit inductive as well as resistive impedence characteristics. The inductive reactance in an AC circuit requires an additional quadrature current com-

ponent and a reactive power, which is a measure of the energy stored in the magnetic field associated with the inductance. The additional current flows also through the network system, producing additional voltage drops in the lines and reducing the overall efficiency of transmission. Furthermore, the energy stored in the magnetic field during each half-cycle and returned to the source unused must be provided by the manufacturer and distributor of electrical energy, and since the utility has the additional burden of providing the equipment necessary to generate and distribute this additional energy, although it is only borrowed temporarily, the utility needs to be compensated. Hence, energy that oscillates between the source and the circuit must be kept track of and accounted for in the distribution of AC energy. The electric utilities include in their rate schedules bonus and penalty provisions to finance equitable and various amounts of these services required by different consumers. At present a low power factor penalty is not included in the PEWC rate schedule.

4.2 BENEFITS OF POWER FACTOR IMPROVEMENT

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

a. Power demand is recorded in kVA,

b. A kVAR, or power factor, penalty clause is part of the electricity rate,

c. Present capacity limits growth, and

d. The consumer experiences low voltage or regulation of same.

Power factor improvement will save money in each of the situations listed above because it will reduce purchased power cost if electricity is brought on a kVA demand rate, it will improve voltage regulation and ease any low voltage problems, and it will increase the power-carrying capabilities of transformers and feeders. Significantly, power factor improvements in these areas 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 main reasons.

a. Losses are reduced in the circuits between the loads and the metering point,

b. Voltage is raised near the loads, giving better motor performance,

c. Capacitors kVAR can be reduced automatically as the load drops off by installing some of the capacitors directly on loads so they are switched off at the loads.

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

4.3 EFFECTS OF POWER FACTOR IMPROVEMENT ON THE PEWC SYSTEM

In Table 4.1, the estimated present power factor of different load sectors and projected energy sales are included. The financial savings due to improved power factor can be calculated as follows:

For example, the commercial sector consumed about 76.88 million kWh in 1980/81 at an average of 6 cents per kWh and has a power factor of 0.75. If this sector's power factor is improved to 0.95, the total savings per year would be:

$$\left[\left(\frac{\text{kWh sales/year}}{\text{Present PF}}\right) - \left(\frac{\text{kWh sales/year}}{\text{Improved PF}}\right)\right] \text{ kWh rate}$$

$$= \frac{76.88 \times 10^6}{0.75} - \frac{76.88 \times 10^6}{0.95} \times \text{U.S.\$ } 0.06$$

$$= \text{U.S.\$ } (102.5 - 80.92) \times 10^6 \times 0.06$$

$$= \text{U.S.\$ } 1.3 \times 10^6$$

TABLE 4.1

FORECASTED ENERGY CONSUMPTION BY LOAD SECTORS

BNG SYSTEM

Load Sectors	80/81	81/82	82/83	83/84	84/85	85/86	Assumed Power Factor
1. Domestic	399.0	465.02	528.4	567.17	614.4	672.58	0.80
2. Commercial	76.88	89.61	101.82	109.30	118.4	127.94	0.80
3. Heavy Industrial	432.2	503.78	273.41	614.43	665.6	719.26	0.70
4. Agricultural	78.96	92.03	104.57	112.25	121.6	131.40	0.75
5. Others	51.95	60.55	68.8	73.85	80.0	86.45	0.75
TOTAL	1039	1211	1376	1477	1600	1729	

TABLE 4.2

ENERGY SAVINGS DUE TO IMPROVED POWER FACTORS

Load Sectors	Present Estimated P. F.	Improved P.F.	Potential Energy (GWh) Savings				
			81/82	82/83	83/84	84/85	85/86
1. Domestic	0.80	0.95	91.7	12.5	7.6	9.3	11.5
2. Commercial	0.80		17.7	2.4	1.5	1.8	1.8
3. Heavy Industrial	0.70		189.4	25.8	15.8	19.2	20.2
4. Agricultural	0.75		25.3	3.5	2.1	2.6	2.7
5. Others	0.75		16.9	2.3	1.4	1.7	1.8
TOTAL ENERGY SAVINGS			341	46.5	28.4	34.6	38.0

TABLE 4.3

ESTIMATED SAVINGS DUE TO IMPROVED POWER FACTORS

Load Sectors	Potential Savings US$ X 10^6				
	81/82	82/83	83/84	84/85	85/86
1. Domestic	5.5	0.75	0.46	0.56	0.69
2. Commercial	1.06	0.14	0.09	0.11	0.11
3. Heavy Industrial	11.36	1.55	0.95	1.15	1.21
4. Agricultural	1.52	0.21	0.13	0.15	0.16
5. Others	1.0	0.14	0.08	0.10	0.29
TOTAL SAVINGS	20.44	2.79	1.71	2.07	2.46
CUMULATIVE SAVINGS	20.44	23.23	24.94	27.01	29.47

In Table 4.2, the estimated energy savings due to improved power factor to 0.95 are calculated for 1981/82, 1982/83, 1983/84, 1984/85 and 1985/86. The corresponding financial savings are given in Table 4.3 for the study period.

AN EXAMPLE OF COSTS AND SAVINGS DUE TO IMPROVED P.F.

The costs and savings due to P.F. correction was discussed in a technical paper by Mr. Roger Thorpe at the first Caribbean Electric Utilities Conference held in Barbados (May 27-29, 1981). The following example has been taken from the paper by Mr. Thorpe.

Total capacitance of a 5.5 MVAR was applied to a substation (10/13 MVA, 24/11 kV transformer) to raise the P.F. from 0.72 to 0.866. It has been estimated that ignoring revenue gained due to improvements in the voltage condition, the total savings per year is about US$ 140,127.0. The average cost of capacitor installation per KVAR is US $ 14. Therefore, the total cost of P.F. correction was 0.866 is US$ 14 X 5500 = US$ 38,500. The results of improved P.F. is summarized in Table 4.4. It is quite evident that the savings due to P.F. correction far outweigh the initial capital expenditure.

4.5 EFFECTS OF POWER FACTOR ON KVA DEMAND

The most practical and economical method of power factor improvement

TABLE 4.4

A CASE STUDY OF POWER FACTOR IMPROVEMENT PROGRAM

Items	Before P.F. = 0.72	After P.F. = 0.866
1. Losses	1.24 MW	0.72 MW
2. Voltage Regulation	9.92 kV	10.30 kV
3. Recovery of System Capacity	a. 24 kV line loading = 18.33 MVA	a. 24 kV line loading = 13.86
	b. Feeder loading = 3.66 MVA	b. Feeder loading = 2.83 MVA

involves the use of capacitors. Generally, utilities use either of two methods for improving power factor with capacitors. The first method is bank installation, 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 penalty charges of a 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 group 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. Companies often use oversized fan motors to ensure a safe startup condition. Hence, for a fan that requires 67 brake horsepower (bhp), the company uses a 100 hp induction motor to provide power during startup. The power factor of the 100 hp motor at 67 bhp is 0.79; the resulting kVA is:

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

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

$$\frac{67 \text{ bhp} \times 0.76}{0.83} = 60.22 \text{ kVA}$$

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

5. SYSTEM IMPACTS OF ENERGY CONSERVATION MEASURES

In commercial and modern residential (upper income class) buildings more than 80 percent of the electrical energy is consumed by air conditioners and lighting. 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 Sudan. Most buildings now in use in Sudan were designed and constructed when fuels and electric power were readily available and inexpensive and the need for energy conservation was not recognized. The structures and their mechanical and electrical systems were designed to minimize initial construction costs, not energy usage. Generally, buildings are overcooled, overlighted, overventilated year-round, and inefficiently operated. Each year they consume increasing amounts of energy because systems and building components deteriorate as maintenance and service become more costly and neglected.

5.1 CONSERVATION PRIORITIES

In Sudan, the system that consume the most energy in order of magnitude are (1) lighting, (2) air conditioning and ventilating, and (3) equipment and process. However, the relative order of magnitude of energy use among the three systems will change depending on building construction; use and mode of operation; and type of control, and efficiency of mechanical and electrical equipment.

In residential sectors the amount of energy required for air conditioning generally ranges from 40-50 percent of total energy used at a facility. However, it can be more significant in some facilities, such as hospitals. In retail stores, with high levels of general illumination and display lighting or a large number of commercial refrigeration units, electricity consumes the greatest amount of energy. The equipment and processes systems, include motors, compressors, and pumps primarily in the industrial sector.

5.2 QUANTIFICATION OF ENERGY CONSERVATION MEASURES

Table 5.1 through 5.5, the energy conservation measures for the short-range and medium-range periods are quantified for different load sectors in the BNG system. The energy conservation measures in the short-range period (by 1983) include those technologies which are proven to be cost-effective in the United States and that can be implemented immediately. The medium conservation measures include technologies which are known to be energy efficient but will require 3 to 5 years to implement. For example, the window air conditioners which are extensively used in the residential sector, can be replaced by more efficient central air conditioning systems. In developing Tables 5.1 through 5.5, it has been assumed that any conservation measures which will require redesign or replacement of existing equipment will only occur after the wear-out period of that piece of equipment, i.e., in the medium and long-range periods.

TABLE 5.1

Electricity Conservation Potential by Load Sector

and End-Use

Load Sector: Commercial Sectors

S: SHORT-RANGE M: MEDIUM-RANGE

Conservation Measures	Total Energy Sales (GWh)		Reduction in %		Short-Range Reduction in GWh	Medium-Range Reduction in GWh
	1983	1986	S	M		
Air Conditioning Loads (47%)	47.86	60.13				
1. Reduce Infiltration			6		2.87	
2. Clean Coil & Filter			3		1.44	
3. Replace with Central A/C						
4. Reduce hours of use			10		4.78	
5. Increase temp to 78°			5		2.39	
					-11.48	
Lighting Loads (48%)	48.87	61.41				
1. Switch to more efficient lights			5		2.44	
2. Energy Efficient design				8		3.91
3. Add light controls			7		3.42	
4. Delamp						
					-5.86	-3.91
Subtotal	96.73	121.54				
Other Miscellaneous Use	5.09	6.40				
TOTAL SALES	101.82	127.94	TOTAL PRODUCTION		-17.34	-21.25

TABLE 5.2

ELECTRICITY CONSERVATION POTENTIAL BY LOAD SECTOR
AND END-USE

LOAD SECTOR: RESIDENTIAL SECTOR (DOMESTIC)

S: SHORT-RANGE M: MEDIUM-RANGE

Conservation Measures	Total Energy Sales (GWh)		Reduction in %		Short-Range Reduction in GWh	Medium-Range Reduction in GWh
	1983	1986	S	M		
A. A/C Load (33%)	174.37	221.95				
Reduce Infiltration			6		10.66	
Clean Coils/Furnace			3		5.33	
Reduce hours of use			10		17.4	
Increase temp to 78°			5		8.72	
Replace with central air						
					-41.81	
B. Lighting (60%)	317.04	403.55				
Convert to more efficient source				5		15.85
Convert to high efficiency flourescent				5		15.85
Improve lighting control				5		15.85
Delamp			5		1.32	
						-47.56
C. Refrigeration (5%)	26.42	33.63				
Reduce Infiltration				5	1.32	
Install high efficieny units						
D. Miscellaneous (20%)	10.57	13.45				
Good Housekeeping			1		-1.0	
TOTAL SALES	528.4	672.58	TOTAL REDUCTION		-59.98	-107.54

TABLE 5.3

ELECTRICITY CONSERVATION BY LOAD SECTOR
AND END-USE

LOAD SECTOR: INDUSTRIAL SECTOR

S: SHORT-RANGE M: MEDIUM-RANGE

Conservation Measures	Total Energy Sales (GWh)		Reduction in %		Short-Range Reduction in GWh	Medium-Range Reduction in GWh
	1983	1986	S	M		
A. Motors (80%)	457.98	575.41				
1. Replace with more efficient and proper size motors				5		28.77
2. Other Miscellaneous Improvements				5		28.77
3. Good Housekeeping			2		11.51	
B. Other US (20%)	114.48	143.85				
TOTAL USE	572.41	719.26			-11.51	-57.54

TABLE 5.4

ELECTRICITY CONSERVATION POTENTIAL BY LOAD SECTOR
AND END-USE

LOAD SECTOR: AGRICULTURAL SECTOR

S: SHORT-RANGE M: MEDIUM-RANGE

Conservation Measures	Total Energy Sales (GWh)		Reduction in %		Short-Range Reduction in GWh	Medium-Range Reduction in GWh
	1983	1986	S	M		
A. Motors (95%)	99.34	124.83				
1. More efficient motors				5		6.24
2. Other (5%)	5.23	6.57				
TOTAL SALES	104.57		TOTAL REDUCTION			-6.24

TABLE 5.5

ELECTRICITY CONSERVATION POTENTIAL BY LOAD SECTOR
AND END-USE

LOAD SECTOR: MISCELLANEOUS

S: SHORT-RANGE M: MEDIUM-RANGE

Conservation Measures	Total Energy Sales (GWh)		Reduction in %		Short-Range Reduction in GWh	Medium-Range Reduction in GWh
	1983	1986	S	M		
A. Lighting Load (50%)	34.4	43.22				
Switch to more efficient lights			5		1.72	
Switch to efficiency fixtures			5		1.72	
Add light control				8		3.46
Delamp			5		1.72	
OTHER USE (50%)	34.4	43.22				3.46
TOTAL SALES	68.8	86.44	TOTAL REDUCTION		-5.16	-8.62

There are many conservation measures in commercial and industrial buildings that are not identified due to time constraints of this project and lack of available data. For example, substantial energy conservation in the commercial and apartment buildings can be achieved in the medium and long-range periods by implementing the following architectural measures:

1. Select building configurations which minimize southeast-southwest wall or window exposures to reduce cooling loads.

2. Utilize building configuration and wall exterior arrangements that provide self-shading.

3. Reduce heat gains through windows by considering the following:

   a. Reduced glazing;
   b. Using double glazing or double reflective glazing to reduce transmission of heat;
   c. Shading windows from direct solar load year round.

4. Reduce electric energy consumption within the building by using natural light;

5. Use light color materials for walls and ceilings; and

6. Use adequate insulation.

5.4 SUMMARY OF CONSERVATION MEASURES

The information relating the total effects of the conservation measures during the short-range and medium-range periods are included in Table 5.6. In the short-range period, the BNG system can reduce about 4.7 percent of its forecasted energy sales (1376 GWh). This is equivalent to 10.85×10^6 barrels of oil consumption per year for the BNG system. In the medium-range periods about 6 percent of forecasted energy can be conserved.

Figure 5.1 illustrates the total impact of energy conservation in terms of oil consumption for the BNG system. The energy conservation values for intermediate years 1984, and 1985 can be roughly estimated from Figure 5.1.

TABLE 5.6

SUMMARY OF ENERGY CONSERVATION MEASURES

BNG SYSTEM

Load Sectors	Short-Range 1983			Medium-Range 1986		
	Forecast in GWh	Reduction in GWh	Modified Forecast GWh	Forecast in GWh	Reduction in GWh	Modified Forecast GWh
1. Commercial	101.82	- 17.34		127.94	-21.25	
2. Domestic	528.4	-59.98		672.58	-107.54	
3. Industrial	572.41	-11.51		729.26	-57.54	
4. Agricultural	104.57	--		131.40	- 6.24	
5. Miscellaneous	68.8	- 5.16		86.45	- 8.62	
TOTAL	1376	-65.14		1737	-201.19	

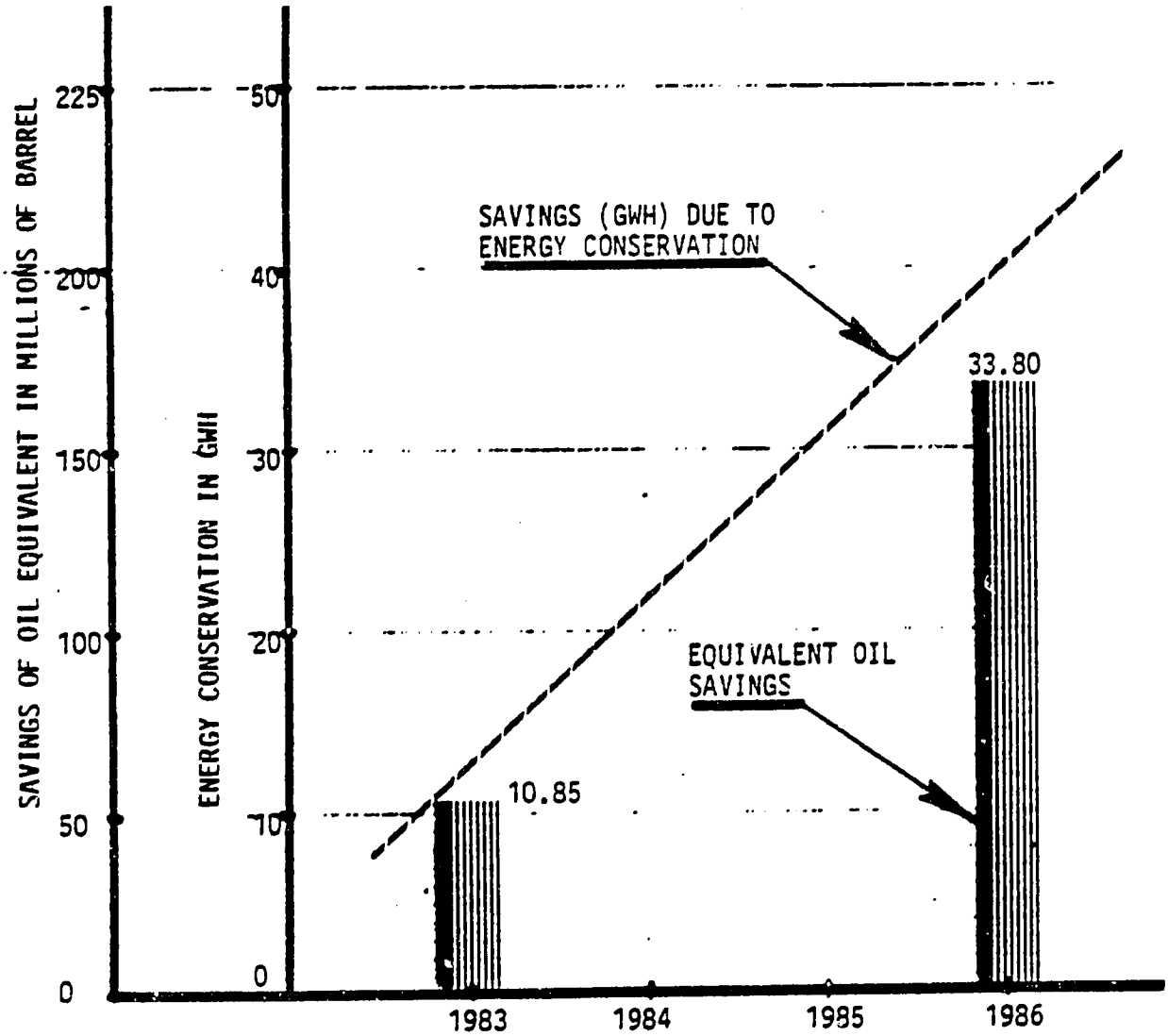

FIGURE 5.1

TOTAL ENERGY SAVINGS DUE TO CONSERVATION MEASURES FOR THE STUDY PERIOD

6. INTERRUPTIBLE RATES SELF-GENERATING CUSTOMERS

Interruptible or curtailable power may be defined as electric service of lower reliability than firm power service, in that it may be interrupted during conditions of system emergency such as inadequate total available capacity, inadequate energy capability, or inadequate operating reservoirs, in order to maintain a high degree of reliability of service supply 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, interruptible power is offered at a discount of the firm demand (kW) rates.

In the BNG service area, there are hundreds of self-generating facilities installed by the commercial, industrial and residential customers as a back-up supply for electricity. Table 6.1 is a partial list of the major self-generating facilities in the BNG region. It has been estimated that a total of 50 MW to 60 MW self-generating capacity are installed in the BNG service area. Interruptible rates can be designed to encourage the customers with self-generating facilities to disconnect during the peak periods or in the event of supply/demand imbalance to present cascating outages. This will not only release the generating capacity but also relieve the transmission and distribution network components significantly.

In the following section the short-range operating benefits of interruptible rates for the self-generating customers are discussed.

TABLE 6.1

LIST OF SELF-GENERATING
FACILITIES IN BNG SERVICE AREA

Name	Type of Business	Available Capacity in kW
1. Sudanese Kaoli Animal Production Company	Production of milk, eggs, chickens, etc.	140
2. Elgazira Weaving Factory	Textile	450
3. Cotton Textile Mills	Textile	760
4. Ortashl Seed Oil Mill	Cooking Oil	381
5. Abuelila	-----	381
6. Elgazeva Oil Mill	Cooking Oil	660
7. Amdurman Soap and Chemical Factory	Soap and Chemicals	150
8. Soba Oil Mill and Pealing	Food Oil and Oil Seed Pealing	150
9. Elshiek Clothing Factory (Medani)	Ready made clothes	25
10. Taha Elrobi Transport (Kht.)	Transport Company	100
11. Taha Elrobi Transport (Port Sudan)	Transport Company	60
12. Taha Elrobi Transport (Medani)	Transport Company	20
13. Salim Skin Preservation (Medani)	Animal Skin	80
14. Tabaldi Battery Factory	Battery Production	140

TABLE 6.1 (Con't.)

Name	Type of Business	Available Capacity in kW
15. Modern Plastic Factory (General)	Blastic Production	175
16. Petroleum Corporation	Offices	104
17. Eldinder Oil Mills	Oil Food Production	505
18. Aman Clothing Factory	Ready mande clothing	50
19. Hilton Hotel	-----	880
20. Altahrir Perfume Administration	Perfume Production	25
21. Packing Company, Ltd.	-----	200
22. Omer Abdelsalam Factories	-----	25
23. Alabas Seed Grinding Mills	-----	55
24. Eljak Macaroni Factory	-----	25
25. Medani Sheria Factory	-----	25
26. Slshaab Steel Works	-----	88
27. Saad Sweets Factory	Sweets Production	210
28. Elshiek Oil Mills (Port Sudan)	Oil Seed Production	915
29. Gemera Spinning and Weaving Company	-----	5000
30. New Manufacturing Company	Production of Mineral Water	328
31. Elniel Ice Production Company	-----	400

TABLE 6.1 (Con't.)

Name	Type of Business	Available Capacity in kW
32. Modern Refrigeration Factory	-----	88
33. Yassin Plastic Co.	-----	2--
34. Sudanese Koati Aluminum Company	-----	172
35. Gulf International Co.	Asbestos Production	250
36. Blue Nile Sweet Factories	Sweet Production	100
37. Sudanese Mild Steel Factory	Corrogated Sheet	200
38. Ganieb Weaving Factory	Corrogated Sheet	110
39. Friendship Plastic Company	-----	80
40. Modern Distilling Company	Production of Alcohol	117.4
41. Blue Nile Weaving and Spinning Co. (Menani)	-----	2080
42. Gazera Managil Weaving Company	-----	25
43. Modern Ice Cream and Sweet Factory	-----	33
44. Eltofieg Soup Factory	-----	120
45. National Plankets Factory	-----	256
46. Elhelanien Soap and Chemical Factory	-----	324
47. Kenoz Soap and Glycerin Factory	-----	256
48. Astra Metal Industry Ltd.	-----	140
49. O durman Clothing Factory	-----	40

TABLE 6.1 (Con't.)

Name	Type of Business	Available Capacity in kW
50. Eltamadun Printing Ltd.	-----	200
51. Commercial Bank (Indus. area)	-----	40
52. Commercial Bank (Onduman)	-----	50
53. Commercial Bank (Khatsua)	-----	80
54. Commercial Bank (Headquarters)	-----	180
55. Unity Bank (Onduman)	-----	47
56. Sharton Spinning and Weaving Company	-----	4800
57. Tolla Sweet Factory	-----	450
58. Elmadih Oil Mills	-----	660
59. Karam Biscuit Company	-----	629
60. Kother Ice Factory (Albura)	-----	100
61. Saad Sweets	-----	21-
62. Unduanban School of Agricultu	-----	550
63. Modern Match Production and Distribution Co.	-----	220
64. Fissal Islamic Bank	-----	40
65. Sennar Biscuit Factory	-----	400

TABLE 6.1 (Con't.)

LIST OF SELF-GENERATING
FACILITIES IN BNG SERVICE AREA

Name	Type of Business	Available Capacity in kW
66. Unity Bank (Khartown)	-----	400
67. United Perfumes and Cosmetics		40
68. White Nile Plastic Company		200
69. Cosmetics Lab		45
70. Sudanese Produce Company		40
71. Modern Shoe Industry		250
72. Saeed Farm	Food Processing	760
73. Mustafa Sati and Sons	Soap Prod.	240
74. Eloaha Oil Co.		685
75. Sudanese Oil Seed Processing Co.		1340
76. Akasha Plastic		500
77. Abutanig Enterprises		48
78. Asim Ice Factory		225
79. Usab Oil Mills		200
80. Eldali and Maizmom Company		16
81. Slaiyam Printing		103
82. People Weaving Factory (Omd.)		140

TABLE 6.1 (Con't.)

Name	Type of Business	Available Capacity in kW
83. Kubaba Medical Company		16
84. Free Market (Offices)		40
85. ZIP Siudanese Factory		92
86. Ramsies Eng.		29
87. Hajjar Cigarettes and Tabocco Factory		200
88. Sudanese Saving Bank		10
89. Blue Nile Cigarettes Company		120
90. Sudanese Mint Factory		600
91. Slkatani Plastic Factory		400
92. Elkatani Oil Mills		400
93. Elkatani Anial Food Prod. Co.		800
94. The Nile Paint Works		200
95. Elgezira Managil Weaving Co.		120
96. Commercial Development Enterprise		120
97. Eldoiem Oil and Coap Factory		250
98. Ellaka Hotel Co.		50
99. Sudanese Wire Factory (Furniture)		300

TABLE 6.1

Name	type of Business	Available Capacity in kW
100. Mekauri Factory (Furniture)		300
101. Rajab Oil Mill Factory		407
102. Sheik Oil Mill		600
103. Sudanese Stationary		279
104. Modern Plastic Co.		279
105. Shell Chemical Co.		60
106. Mekki Refrigeration Co.		279
107. Elmagran Enf.		40
108. People Cooperation Bank		125
109. Sudanese Mining Administration		100
110. Kordufan Factory		200
		36,562.4

Note: There are more than 100 private small units installed in the different embassies and in residential areas varying between 3 kVA to 10 kVA.

6.1 OPERATING BENEFITS OF INTERRUPTIBLE LOADS

From the standpoint of system operations, interruptible loads, constitute a form of available capacity, in that cutting the loads has the same effect on available reserve as increasing capacity. One important difference between the two is that whereas the system operator has precise information on the status of capacity, he does not know with the same precision how much interruptible loads he has available for dropping at any moment. However, at the present time his knowledge is accurate enough for operating purposes. An estimate of all the self-generating customers' daily load profiles can be gathered which will provide information on how much interruptible load is available at any instant.

At present the BNG system is operating with inadequate operating and spinning reserves due to firm 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 class of interruptible loads may be cut to effect daily economy savings. Examples of the savings are in avoiding starting up combustion turbine units.

In the long-run, selling more interruptible rates to self-generating customers would save BNG system the cost of generation equal to the load which would otherwise be firm, plus the corresponding reserve margin needed to support this firm load. The value to the system and hence the justification for getting this class of service at reduced rates, depends upon the right to interrupt. Also important is the effectiveness of the measure in terms of the amount of curtailable power available at any given time, and its response time.

6.2 SHORT-RANGE CAPACITY SAVINGS

The value of self-generating customer's interruptible loads arising from the possibility of reducing peak generation for the study period is hard to assess, First, there is the problem of determining the exact potential savings in kilowatts of peak generation corresponding to each kilowatt of interruptible load. Factors such as the following must be taken into account:

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

2. During cuts, the customer 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;

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

However, items #2 and #3 are institutional issues. The PEWC may decide that the self-generating customers who subscribe the interruptible rates will not be allowed to convert to firm rates for two or three years. Similarly, the cutting floor tolerance option may be totally eliminated from the rate structure.

The chief use of interruptible power is to reduce peak load at times of system emergency or during the capacity shortage years, i.e., 1982 or if there is any slippage of installation dates of new units. It follows then that PEWC should relate the value of interruptible power loads of self-generating customers to the cost of the marginal plant or peaking capacity along with an allowance for additional requirements for reserve generation. Table 6.2 illustrates the effects of self-generating customers interruptible loads on supply/demand balance for the short-range period. It should be noted that in Table 6.2 the available capacity of the self-generating customer is assumed to be 50 MW and a outage factor of 20 percent is used to account for the unavailablility of the interruptible loads. The resultant 40 MW available capacity is

TABLE 6.2

EFFECTS OF SELF-GENERATING CUSTOMERS
INTERRUPTIBLE LOADS FOR THE
SHORT-RANGE PERIOD

Base Case Scenarion #1 (As Planned)

Items	1981	1982	1983	1984	1985	1986
1. Peak Demand (MW)	198	231	262	281	304	329
2. BNG System Dependable Capacity (MW)	209	219	349	389	389	389
3. Reserve Contribution from Interruptible Loads (MW)	24 / 233	24 / 243	24 / 373	24 / 413	24 / 413	24 / 413
4. Reserve Margin Criteria (%)	33	29	30	31	29	27
5. Capacity Shortage (MW)	-30	-55	+32	+45	3.0	- 5.0

multiplied by the diversity factor of 60 percent to account for the customer usage pattern. It is quite evident that the capacity shortages for the study period have significantly been reduced when compared with Table 2.5 in Section 2.

6.3 SHORT-RANGE OPERATING BENEFITS

Hypothetical examples may help to make the benefits of self-generating customers interruptible power service clear:

First, a brief example of outage probabilities will illustrate the underlying principles for calculating Loss-of-Load Probability (LOLP). Assume a two-unit utility with the characteristics given in the following table:

	Capacity	Forced Outage	Availability
Unit #1	10 MW	0.10	0.90
Unit #2	20 MW	0.05	0.95

Probabilities may now be calculated for the various levels of generating capacity that could be available, as in the following table:

Available Capacity	Probability Distribution of Available Capacity
0	0.1 X 0.05 = 0.005
10	0.9 X 0.05 = 0.045
20	0.1 X 0.95 = 0.095
30	0.9 X 0.95 = 0.855
	1.000

Thus, the probability that the hypothetical system will have generating capacity of less than 20 is 0.045, or roughly one in twenty. To protect this level of system reliability, the utility needs a certain level of system reserve and/or interruptible power.

A second example illustrates the role and value of self-generating customers interruptible power within the total BNG system.

The following brief description of the composition of the BNG system 1982 capacity will serve as an introduction to the hypothetical operating condition of Table 6.3.

System Capacity = Total Internal Generation
= 220 MW

Total Internal Generation = On-Line Generation + Idle Capacity

On-Line Generation = BNG System Primary Load and Spinning Reserve

BNG System Primary Load = Customers Load Without Self-Generating + Self-Generating Customers Demand

Idle Capacity = Units out on planned maintenance + Noninterruptible ready reserve + Noninterruptible slow pick up + Cold reserve (spare units).

System Reserve = Operating Reserve + Slow Pick up reserve + Cold Reserve

Operating Reserve = Spinning Reserve + Self-Generating Customer's Demand

TABLE 6.3

HYPOTHETICAL EXAMPLE OF SELF-GENERATING CUSTOMERS ISE AS INTERRUPTIBLE LOADS
YEAR: 1982

(1) System Capacity (MW)	(2) On-Line Generation (MW)	(3) Firm Load (MW)	(4) Int Loads (MW)	(5) Spinning Reserve (MW)	(6) Idle Capacity (MW)
220	200	160	30	10	20
Note: (1) = (2) + (6) and (2) = (3) +(4) + (5) Now, assume that the system suffers a 30 MW Rosieres unit loss. The immediate result is:					
190	170	160	30	10	20
Within ten minutes, spinning reserve and disconnection of self-generating customers (interruptible load) portion of ready reserve will restore the system as follows:					
190	170	160	10	0	20
At the same time, the nonsynchronized portion of ready reserve will be loaded to restore spinning reserve as follows:					
190	180	160	10	10	10
Assume that at this time the system suffers another 10 MW Burri unit loss. The immediate system conditions are as follows:					
180	170	160	10	10	10
At this point, the second phase of interruptible loads will provide the backup reserve to restore the supply/demand balance as follows:					
180	170	160	0	10	10
As soon as additional units are available from idle capacity, the system load will be restored as follows:					
180	180	160	10	10	0
When the faulty generators are repaired the system is restored to its original conditions.					
220	200	160	30	10	20

Therefore, the role of self-generating customers interruptible power as ready and slow pick up reserve for BNG system should be evident. Increasing participation of self-generating customers would make more ready and slow pick up reserve available for the short-range period. If the total system reserve level (and thus the LOLP), should remain unchanged, then the BNG system would need to maintain less cold reserve. Without interruptible power, more generating, transmission and distribution capacities would be needed to supply loads for which neither construction lead time nor financial resources are available for the study period.

Besides alleviating load shedding and power interruption, the class of interruptoble power may provide annual operating savings consisting of two parts:

6.3.1 OPERATING RESERVE BENEFITS

Even without load drops, self-generating customer loads can affect savings be reducing the generation held as daily operating reserve: that is to say, interruptible loads are part of the reserve available to the system and capable of being fully activated within ten/fifteen minutes. The high load plateau on the BNG system last roughly between 10 and 14 hours. For the rest of the time, hydro capacity and a partly loaded diesel/steam units provide all the required reserve. Therefore, interruptible loads are useful mainly during the peak period.

6.3.2 DIFFERENTIAL ENERGY-PRODUCTION COSTS (ECONOMY SAVINGS)

Daily economy savings from using interruptible power, associated with not starting up peaking units (mainly inefficient units in the BNG system) at heavy load periods or nor using water in the less efficient hydro plants could amount to thousands of dollars.

6.4 PROPOSED INTERRUPTIBLE RATES FOR SELF-GENERATING CUSTOMERS

To reduce the frequency and duration of load shedding and power interruptions during the study period, it is recommended that the PEWC should make available to its customers with self-generating capacities the following types of interruptible rates:

a. Designated Class 1, with higher risk, to be used as ready reserve as well as for system emergencies;

b. The second, designated as Class 2, with a lower risk, to be used for system emergency conditions only, subject to thirty minutes notice to conform with system requirements for slow pick up reserve.

7. REPOWERING AS A RESOURCE

7.1 BACKGROUND AND CONCEPT

Repowering consists of converting an existing older conventional gas and oil fired steam boiler power plant into a combined cycle plant by integrating one or more combustion turbines. This allows an increased capacity and reduced heat rate compared to the existing plant.

In the process of repowering the steam-electric generating unit, the existing oil (gas) fired boilers are replaced by waste heat recovery steam generators which are connected to the combustion gas turbine exhaust which are connected to the combustion gas turbine exhaust to utilize the heat energy contained in the exhaust gases as the thermal source for the steam generation and supply steam to the steam turbine generator. The resulting repowered combined cycle system configuration provides a very substantial increase in the plant generating capacity as well as a radical increase in the generating plant efficiency which results in significant fuel savings of the combined cycle system compared to the previously existing steam-electric generating unit. Thus, the combined cycle repowering of an existing oil (gas) fired electrical generating plant provides the utility with at least the same benefits as those which could be derived from the installation of a new combined cycle generating facility. However, there are other possible more compelling reasons why repowering of existing facilities is being seriously

pursued by both utilities and regulatory agencies alike in U.S.A.

The dramatically changing economic and environmental factors coupled with uncertainties in future energy resources have a fundamental impact upon the decisions electrical utilities must make in formulating their generating supply plan. These factors include the costs of rising inflation, record high interest rates along with the unpredictable anomalies in future energy demands caused by the "energy crisis" and the related unprecedented increase in fuel oil prices (i.e., from about 35 cents/10^6 Btu in 1970 to about 270 cents/10^6 Btu in 1977), with similar increases in the price of natural gas and coal.

The new electrical generating plant construction lead time (i.e., from plant initial inception, engineering, regulatory permitting process through construction completion to commercial operation) is approximately 5-10 years. Before the new generating plant additions can be completed, however, the elctrical energy load demand, which will persist to grow, will have to be supplied from the existing generating plant resources with capacity additions which can be accomplished within a very shortened fram of time. It is in this particular interim near term that repowering of existing oil (gas) fired generating plants has substantial advantages to offer in partial solution of the electric utilities' immediate problem in augmenting the current electric generation resource base. The repowering of existing generating facilities into combined cycle system configuration may be particularly attractive in the cases

where the electric utility has identified the need for installation of new combined cycle generating units to meet the growing generating capacity demands.

Specifically, some of the benefits and advantages of repowering are instrumental in the following conditions:

7.1.1 COMBINED CYCLE EFFICIENCY

To minimize the cost increase in generating electrical energy caused by large price increase of fuel oil, the electrical utilities are proceeding to adopt the high efficiency of combined cycle systems for the installation of new generating plant capacity. Since a very substantial portion of the electrical energy will continue to be generated from fuel oil, it is essential that available oil resources be utilized in the most efficient manner possible in generating electrical energy. Repowering the existing lower efficiency power plants into a combined cycle system configuration is an approach that has been adopted by the electrical utilities to affect a significant improvement in electrical generating plant efficiency and a significant improvement in electrical generating plant efficiency and additional new generating plant capacity. These older existing generating plants, due to their low efficiency, have been designated for use in intermediate generation service or to serve as peaking units. The addition of combustion gas turbine generators coupled with heat recovery steam generators to provide the steam supply to the existing facility, provides the

utility with an opportunity to increase the plant generating capacity with a significant improvement in system efficiency at minimum financial investment.

7.1.2 SITE AND ENVIRONMENTAL CONSIDERATIONS

Repowering of existing installation minimizes the total environmental impact which might otherwise arise with site selection and the regulatory permitting process for new generation facilities. Since the combustion gas turbines are basically air cooled systems and the steam turbine cycle need not be changed, the plant cooling water requirements under existing operating restrictions should remain unaffected. Existing air pollution emission restrictions can be met with current control technology and with clean distillate fuel oil that meets the sulfur content restrictions. The possible selecting of repowering of an existing oil (gas) fired generating plant removes the normal problems associated with siting of new plants and consequently also tends to minimize the envitonmental impact of additional generation.

7.1.3 CAPITAL COSTS

The capital cost of a repowered plant are minimal in comparison to the capital investment required in a new installation of conventional steam-electrical generation units or new combined cycle units on new plant sites. These capital cost savings are realized in repowering by preserving the use of existing steam turbine generator plant and associated auxiliary systems and adding new gas turbine generators

with heat recovery steam generators in substitution for the existing conventional boilers, as opposed to a complete new combined cycle system installation.

7.1.4 INSTALLATION LOAD TIMES AND ESCALATION

Escalation in the cost of all types of power generating equipment and plant installation may be considered to be proportional to the respective load times involved in the planning, engineering and construction. Consequently, the repowering of an existing facility, having a much shorter lead time compared to the additions of new generating plants, is subject to cost escalation to a proportionately lesser degree.

In another respect, the very long lead times required for the addition of new generating plant capacity currently in the range of 5-10 years, poses a serious problem to the utilities which must increase the overall generating system capacity in the interim time to meet the rising electrical energy laod demands of the immediate future. For the interim solution of the near term generating capacity problem, the utilities have to depend on the relatively short lead time combustion turbine and combined cycle systems for the necessary generating capacity additions. Repowering of an existing generating facility provides the utility with the same benefits of added gas turbine generating capacity in essentially the shortest possible time, considering that installation takes place at an existing plant and

therefore there is no need for the acquisition and approvals of a new plant site.

According to the above, combined cycle type of repowering of an existing reliable oil (gas) fired steam-electric generating facility may offer a number of general advantages in resolving some of the BNG systems current difficulties of increasing their system's generating capacity for the near term future to meet the increased demand for electrical energy supply. Some of these advantages associated with repowering are:

a. Increasing plant generating capacity, with improvement in plant efficiency reducing the fuel oil consumption per unit of generation.

b. Reducing lead time and problems associated with siting and constructing of new plants.

c. Minimizing additional environmental impacts of the existing plant site due to plant expansion.

d. Allowing for efficient generation capacity addition in the shortest time possible, regulatory circumstances per mitting.

e. Minimizing plant cost per kW of generating capacity and kWh of electrical energy.

However, not all of the above identified advantages may be applicable to a given existing facility which may be considered as a potential candidate for repowering due to either site or plant related constraints and imposed limitations.

7.2 REPOWERING POTENTIALS FOR BNG SYSTEM

Prior to making any evaluation about the potential plants for repowering in the BNG system, it is necessary to identify those units which are non reheat units. This decision is based on the knowledge that:

1. Most reheat units are of more recent origin and operating at higher efficiency and therefore are being utilized at a higher load capacity factor by the utilities.

2. The limitation of a relatively small addition in capacity by gas turbines in relation to the reheat steam turbine capacity in the combined cycle causes in reheat steam turbines to less less likely candidates for repowering even if proved feasible.

In Table 7.1, the list of all potential repowering plants in the BNG system are included. It was concluded that attempts to repower existing reheat units would be more complex and costly, while obtaining a minimal increase in generation capacity in relation to the existing capacity. All units comprised of reheated steam turbine generators were thus eli-

TABLE 7.1

LIST OF POTENTIAL REPOWERING

PLANTS IN BNG SYSTEM

Power Station	Type of Prime Mover	Date of Installations	Installed Capacity (MW)
Burri	Diesel	Post 1964	15
	Steam Turbine	1957	10
	Steam Turbine	1959/61	20
Kilox	Gas Turbine	1969	15.04
Wad Medani	Diesel	1963	5.75
TOTAL			65.79

minated from further consideration in repowering evaluation. In addition to the requirement that that units be considered for repowering would be non-reheat units, several other requirements were established to be considered in the evaluation:

1. That the existing equipment be suitable for an extended life.

2. Moderate expenditure for restoration or repair.

3. That the existing plant site have adequate space for the installation of the new generation equipment, together with the auxiliary equipment which would be required for the increased capacity of the repowered plant.

4. Adequate space availability for increased switchrack and power transmission capacity.

5. Increased fuel handling and storage facilities.

6. Space for the installation of the new heat recovery steam generators.

7.3 REPOWERING EXPERIENCE OF OTHER UTILITIES

The consulting firm Burns and Roe conducted a study for the California Energy Commission on the feasibility of repowering older, lower efficiency, oil burning power plants (without steam reheat turbines) in California. Their analysis showed about 2800 MW of existing capacity could be repowered to achieve a total capacity of over 8000 MW. In addition to adding new capacity, overall efficiency can be expected to increase by approximately 30 percent. Repowering would involve removing the existing boiler and installing combustion turbine generators and a waste heat recovery steam generator to supply the existing steam turbine system.

Westinghouse examined alternative repowering configurations for modern oil-fired plants with reheat steam turbines. Repowering arrangements considered for plants consisted of adding the combustion turbine generators and other modifications to allow compatibility with the existing plants. A wide variety of repowering configurations are possible depending on whether the primary goal is to minimize heat rate, increase capacity, or minimize air pollutant emissions.

The Westinghouse study reported the following results for a 330 MW oil-fired boiler, considered a typical repowering case:

a. 8240 Btu/kWh heat rate with combustion turbines supplying 23 percent of the plant output, and

b. 32 percent increase in plant capacity and 8 percent improvement in heat rate.

In Table 7.2 (a) and 7.2 (b) two typical examples of repowering are included. It should be noted that by repowering older units in Table 7.2 (a) the rated plant output has been increased from 97 MW to 304 MW an increase of 213 percent. In Table 7.2 (b), the rated plant output is increased by 200 percent. Similar improvements in energy output, heat rates and capacity factors can be determined from Table 7.2.

TABLE 7.2 (a)

REPOWERING FEASIBILITY STUDY IN CALIFORNIA

PLANT EVALUATION

EL CENTRO POWER PLANT - UNITS 1, 2, & 3
Imperial Irrigation District
El Centro, Imperial County, California

Existing Plant

Unit 1	20,000 KW	TCSF	710 PSIA	825°F
Unit 2	33,000 KW	TCDF	850 PSIA	900°F
Unit 3	44,000 KW	TCDF	1250 PSIA	950°F
Unit 4	80,000 KW	TCDF	1500 PSIA	1000°F/1000°F

Repowered Plant Potential

	Proposed Gas Turbine Installation Base-Load Rating	Rated GT Plant Capacity MW	Steam Capacity MW	Rated Repowered Plant Capacity-MW	Estimated Unit Net Heat Rate BTU/KWH
Unit 1	One - 69 MW	60	20	80	8717
Unit 2	One - 69 MW	67	33	100	8710
Unit 3	Two - 45 MW	80	44	124	8692
TOTAL		207	97	304	

Repowered Plant Summary

	Existing Plant	Repowered Plant
Rated Generation Capacity - MW	97	304
Load Factors (estimated) - %	25	65
Annual Generation - 10^6 MWH	212.	1731
Plant Heat Rates - BTU/KWH	11,700	8705
Plant Efficiencies - %	29.7	39.2
Fuel Oil Requirements - 1000 bbl/yr	397	2598
Ratio - Total Capacity to Existing Capacity	1	3.13
NOx Emissions - LBS/MWH	11.15	1.83
@ Full Load - LBS/HR	1082	556
SO_2 Emissions - LBS/MWH	12.12	0.87
@ Full Load - LBS/HR	1176	265
Particulate Emissions - LBS/MWH	1.0	0.09
@ Full Load - LBS/HR	97	27
Condenser Cooling Water Flow - 1000 GPM	Unknown	- -

TABLE 7.2 (b)

REPOWERING FEASIBILITY STUDY IN CALIFORNIA

PLANT EVALUATION

OLEUM POWER PLANT - UNITS 1 & 2
PACIFIC GAS & ELECTRIC CO.
Oleum, Contra Costa County, California

Existing Plant

Unit 1	40,000 KW	TCSF	1500 PSIG	950°F
Unit 2	40,000 KW	TCSF	1500 PSIG	950°F

Repowered Plant Potential

	Proposed Gas Turbine Installation Base-Load Rating	Rated GT Plant Capacity MW	Steam Capacity MW	Rated Repowered Plant Capacity-MW	Estimated Unit Net Heat Rate BTU/KWH
Unit 1	Three - 60 MW	85	40	125	9184
Unit 2		85	40	125	9184
TOTAL		170	80	250	

Repowered Plant Summary

	Existing Plant	Repowered Plant
Rated Generation Capacity - MW	80	250
Load Factors (estimated) - %	25	65
Annual Generation - 10^6 MWH	175	1424
Plant Heat Rates - BTU/KWH	14,500	9184
Plant Efficiencies - %	23.5	37.2
Fuel Oil Requirements - 1000 bbl/yr	406	2255
Ratio - Total Capacity to Existing Capacity	1	3.13
NOx Emissions - LBS/MWH	10.57	1.93
@ Full Load - LBS/HR	846	482
SO_2 Emissions - LBS/MWH	7.65	0.92
@ Full Load - LBS/HR	612	230
Particulate Emissions - LBS/MWH	0.79	0.09
@ Full Load - LBS/HR	63	23
Condenser Cooling Water Flow - 1000 GPM	75	75
Thermal Discharge: Ext. Cycle - 10^6 BTU/HR	456	456
C.W. ΔT - °F	12.2	12.2
Non-Extraction Cycle--10^6 BTU/HR	—	560
C.W. ΔT - °F	—	14.9

7.4 SYSTEM IMPACTS OF REPOWERING ON THE BNG SYSTEM

Within the BNG system, there are three plants, (Burri, Kilox, and Wad Medani) with diesel/steam electric generating stations, believed to be of such age and condition as to be potential candidates for repowering in the combined cycle method of operation. A survey should be made of these plants, on a unit by unit basis, to evaluate the actual feasibility of repowering the individual units. However, based on other utilities experiences and feasibility studies, the following are the short-range system impacts of the BNG:

a. The total existing generating of the three plants in 65 MW. Of this total it is believed that 45 MW could be repowered in the combined cycle method with the addition of 90 MW of gas turbine capacity, resulting in a total repowered combined cycle capacity of 135 MW.

b. The efficiency of the existing units is relatively low, with an estimated average heat rate in excess of 12,000 Btu/kWh. The repowered units should provide a marked improvement in efficiency, with an average net heat rate of approximately 8,800 Btu/kWh, an improvement of approximately 30 percent. This increased efficiency would restore these units for base or intermediate load operation.

c. The capital investment for this new base/intermediate load capacity is moderated by repowering the existing equipment. Based on 1980 prices, the capital cost should not exceed $275.00 per kilowatt of total capacity for those units believed to be acceptable for consideration in repowering.

In Table 7.3 and 7.4, the system impacts for two base case scenarios are included. It is important to note that the capacity improvement of existing units in Table 7.3 and 7.4 are estimated based on only age and types of diesel and steam units in the BNG system. A detailed evaluation of existing units' characteristics as outlined in the survey forms of Appendix A is necessary to estimate the cost-effectiveness of repowering.

The repowering for older gas- or oil-fired plants without reheat turbines is a commercially available technology. The PEWC should initiate a feasibility study of older units to determine the actual capacity and energy than can be generated from the existing units for the short-range period.

TABLE 7.3

SYSTEM IMPACTS OF REPOWERING OLDER UNITS

BASE CASE SCENARIO #1 (AS PLANNED)

Items	1981	1982	1983	1984	1985	1986
1. Peak Demand (MW)	198	231	262	281	304	329
2. Present Capacity Expansion Plans	209	219	349	389	389	389
3. Repowering Capacity of Combined Cycle	--	+20	--	+15	+55	
4. Total BNG System Capacity (MW)	209	239	369	424	479	479
5. Reserve Margin (%)	5.5	3.4	41.0	50.0	57.5	45.5
6. Required Reserve Margin (%) To Meet Reliability Criteria	33	29	30	31	29	27
7. Capacity Shortage in MW	-54	-59	-0-	-0-	-0-	-0-

TABLE 7.4

SYSTEM IMPACTS OF REPOWERING OLDER UNITS

BASE CASE SCNEARIO #2 (SLIPPAGE OF ROSIERES UNIT #5 AND #6)

Item	1981	1982	1983	1984	1985	1986
1. Peak Demand (MW)	198	231	262	281	304	329
2. Capacity Expansion Plans	209	219	309	349	389	389
3. Repowering Capacity of Combined Cycle	--	+20	--	+15	+55	
4. Total BNG System Capacity (MW)	209	239	329	384	479	479
5. Reserve Margin (%)	5.5	3.4	7.6	36.6	57.5	45.5
6. Required Reserve Margins (%)	33	29	30	31	29	27
7. Capacity Shortage in MW	-54	-59	-11.6	-0-	-0-	-0-

8. OTHER OPTIONS FOR IMPROVING SHORT-RANGE OPERATING RELIABILITY

In Sudan, disturbing trends are emerging in the electric utility industry that are causing not only routine power shortages and load sheddings but also affecting the economic growth of the industry. These trends relate to the adequacy of capacity to meet future electric load and energy requirements. The projected growth rate for the BNG service area indicates that 1982 is a critical year because of supply/demand imbalance. The expected capacity shortage at the time of system peak demand may be as high as 80 MW. In the following section, a few other options for improving short-range operating system's reliability are discussed. The system reliability improvement options may be divided into two categories such as 'institutional solution' and 'engineering solution'. The 'institutional solution' options require less capital investment compared to the 'engineering solution' options.

8.1 DEMAND SUBSCRIPTION SERVICE (DSS)

Air conditioners are only one of many household appliances which contribute to the BNG 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 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 period. It follows that customers would be more receptive to a program which allows them freedom to select which appliance they desire to use during peak period than limiting the use of the one particular piece of equipment which they value most at that time.

Demand Subscription Service (D.S.S.) is a concept which will allow the customers to choose the minimum level of service which will satisfy comfort needs during the critical system peak periods. This program is the first major attempt by an electric utility in the United States to experiment with a load management deivce which 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-controlled 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.

8.1.1. PROGRAM OBJECTIVES FOR THE BNG SYSTEM

The objectives of the Demand Subscription Service Program can be defined both in terms of the short-term test and evaluation phase as

well as the long-term potential for systemwide implementation.

a. Short-Term Objectives

Short-term objectives include an overall evaluation of the cost effectiveness of the concept. The evaluation will include four primary considerations:

- o Customer acceptance and long-term retention of reduced demand levels.
- o Impact of reduced individual customer conservation and diversified group demand which are coincident with the system peak.
- o The reliability of equipment performance.
- o The cost of equivalent generating capacity and energy.

The short-term objectives of the D.S.S. Program include determination of the optimum combination of incentive levels and activation strategies to provide maximum load reduction while retaining an acceptable level of customer satisfaction.

b. Long-Term Objectives

The long-term objective of the program, should it prove to be cost-effective, is to gain the systemwide acceptance of the subscription service concept as a condition of service by demonstrating that the concept allows for complete freedom of choice by the customer of the level of service which he prefers. When implemented as a condition of service, the concept would provide an equitable basis for rewarding lower 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 resource planning and reduce the need for new generation capacity. For the short-range period, the D.S.S. program has the potential of reducing the peak demand by 5 MW in the BNG system.

8.2 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. Table 8.1 lists major electrical water pumps on agricultural schemes in BNG and EG service areas. In the PEWC service area, the total water pumping load is about 58 MW. Most of the agricultural water pumping is done in the off-peak hours to relieve

TABLE 8.1

MAJOR ELECTRICAL WATER PUMPS
ON AGRICULTURAL SCHEMES

Scheme	Number of Pumps	kW Rating of Each Pump	Total Demand in MW	Annual Energy (GWh) Consumption
1. Rahad	11	1500	16.5	5.000
2. Suki	4	1500	6.0	0.984
3. Sennar Sugar Plantation	4	1500	6.0	2.750
4. Abn Naama	4	1400	5.6	0.430
5. El-Guneid	4	1000	4.0	1.500
6. Tumbul	3	500	1.5	0.200
7. El Ghirba	4	515	2.6	0.223
8. Assaliyya 1	5	1148	5.7	1.528
9. Assaliyya 2	4	750	3.0	1.120
10. Assaliyya 3	4	625	2.5	0.810
11. Assaliyya 4	3	364	1.1	0.250
12. El Hadad (W)	3	515	1.0	0.130
13. El-Hadad (E)	2	268	0.05	0.030
14. El-Jamuliyya	2	331	0.66	0.080
15. El-Cuneid	2	1000	2.0	1.667
TOTAL	59		58.21	16.702

capacity shortages. However, it has been estimated that another 5 MW to 10 MW demand shift can be achieved by implementing an interruptible rate for the water pumping loads. The main purpose of further control of municipal and agricultural pumping load management is aimed at reshaping the load curves rather than reducing total energy use.

For the short-range analysis it has been assumed that during the peak hours (7 p.m. to 10 p.m.) only 50 percent of the available water pumping load can be deferred. The growth rate for the water pumping load is assumed to be 7 percent for the study period 1981-1986.

Table 8.2 includes the summary of total water pumping loads which may be directly controlled by the PEWC to reduce the peak demand.

TABLE 8.2

TOTAL ESTIMATED PEAK REDUCTION
DUE TO CONTROL OF WATER PUMPING LOADS

Year	Total Pumping Loads (MW)	Available For Peak Reduction (MW)	Forecasted Peak Demand (MW)	Modi1 Peak Demanc (MW)
1981	58.2	5.8	198	192.2
1982	64.0	6.4	231	224.6
1983	70.4	7.0	262	255.0
1984	77.5	7.7	281	273.3
1985	85.2	8.5	304	295.5
1986	93.7	9.3	329	319.7

8.3 INDUSTRIAL LOAD SHIFT

As the aggregate demand for electric energy continues to grow at an exponential rate in the BNG system, the ability of PEWC to continuously meet load requirements are beginning to be less certain due to two principal constraints. The first of these constraints -- the potential shortages of energy resources -- is becoming increasingly important to a number of relevant groups such as industrial customers. The second of these constraints on the BNG system's ability to meet load requirements is the necessary duration and complexity of power development. The second constraint has caused a growing public awareness of imminent power shortages. The need for load reduction through load shedding has made these shortages particularly apparent.

One means of balancing the short-range supply/demand for BNG service area is the development of a policy which supports a shifting of the peak power demands of 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 the generation capacity. The industrial customer offers this opportunity. The commercial and residential sectors would require extra time to arrive at any general recommendations due to the diversification of their member's characteristics and schedules of electricity usage patterns.

In the BNG system during day-light hours almost 50 percent of the peak demand is contributed by the industrial customers. In the development of a load shifting policy for the industrial customers, concern should be focused on the feasibility of its implementation and its likely side effects. As a basis for selection of industrial customers load shift feasibility study the following three criteria should be considered:

1. Fluctuation in the daily load curve other than the traditional start up and stop day operations and lunch.

2. A low load factor where load factor is defined as the ratio of the average demand over a given time period to the maximum demand, occurring in the period.

3. A low number of hours within a month where billing demand (maximum half-hour) is used.

8.3.1 FEASIBILITY OF SHIFTING ELECTRIC POWER DEMAND

When the question of feasibility is considered in developing a policy to flatten an industry's daily load curve, a number of economic, social, and technical issues must be brought into the analysis. These issues are not independent. There are obvious economic and social trade-offs to be made for any economic and social changes.

While there are technical investments which could improve the efficiency of power usage, they usually demand large capital investment. The improvement may come from investment in new equipment or the placement of controls of old equipment such as demand limiter attachments, permissive load controllers or computers. These regulate machine operations according to their effect on the total power supply. At this time the cost of power, relative to other industrial operating costs, is not significant enough to encourage such marginal capital investments. Only one of the ten industries may be concerned enough with its monthly power bill to investigate the power consumption of individual equipment.

An alternative to technical investments as a means of flattening out the daily load curve is to vary the current labor and/or machine operating schedules in a manner which 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 (11 p.m. to 7 a.m.). Scheduled work breaks may be staggered to avoid a complete shut down of the plant and minimize the resultant start up peaks. Rescheduling of labor shifts, which require a high power input to off-peak time periods is another option.

TABLE 8.3

AN ESTIMATE OF INDUSTRIAL CUSTOMERS LOAD SHIFT AND SYSTEM PEAK REDUCTION

Year	System Peak Demand (MW) (1)	Maximum Peak Demand (MW) 7 am to 2 pm (2) (2) = 0.92 (1)	Contribution of Industrial Load (3) (3) = 0.50 (2) (MW)	Estimated Load Shift Feasibility in MW (4) = 0.25 (3) (MW)
1981	198	--	--	--
1982	231	212.5	106.2	26.5
1983	262	241.0	120.5	30.1
1984	281	258.5	129.2	32.2
1985	304	280.0	140.0	35.0
1986	329	302.6	151.3	38.0

When considering the feasibility of these alternative schedules, the variety of production processes involved limit the degree of generalization that can be made for the industrial customers. It is for this reason that individual interviews with companies are necessary as opposed to a generalized study of industrial scheduling.

Table 8.3 includes an estimation of total MW load shift for the study period. It should be noted that almost 11 percent of the peak demand can be shifted to off-peak hours in 1982. This will allow a significant relief to transmission and distribution systems components loading and this will eliminate some of the cascading outage events and load shedding requirements.

8.4 EXISTING POWER PLANTS AVAILABILITY IMPROVEMENTS

Power plant productivity and performance improvements refer to increasing the time that a plant is available for operation, reducing the time that a plant is not available at rated power and improving plant online efficiency. In the PEWC system, power plant productivity has been adversely affected by:

1. Deficiencies in design and manufacture of plant equipment.

2. Deficiencies in the design and construction of power plants.

3. Deficiencies in operating and maintenance practices.

4. Deteriorating fuel quality.

Even though the 1980 installed capacity for the BNG system is 270 MW, the available capacity is only 209 MW. This includes 30 MW (10 MW at Rosieres and 20 MW at Kenana) capacity restrictions due to transmission limitations. In the thermal systems, over 31 MW of rated generating units capacity is not available at present due to various reasons such as shortage of spare parts. The operating diesel and steam units forced outage rates are also in the range of 25 to 30 percent

The present availability improvement in various diesel, steam and even hydro units in the BNG system will result in systemwide improvement in the weighted average of the Forced Outage Rate (FOR) of the system. Power plant availability improvement will lead to benefits in capacity and fuel use. The capacity savings will reduce reserve requirements for the short-range period to serve the forecasted load. The availability can be improved by decreasing the generator forced outage rate or scheduled outage rate. The forced outage rate is the factor that influences system reserve and capacity improvement and any improvement in availability that does not come from reduction of the forced outage rate (random outage rate) may not yield the promised reserve and capacity savings. Although availability improvement may increase the generator readiness it may not contribute directly to all over system reliability, improved system operations or quality of service since these factors are influenced directly by the F.O.R.

The capacity savings due to availability improvement will not go totally to support the system load. Part of this savings will contribute to system load and the other part will contribute to improvement in system reliability or system reserve. To determine the capacity savings to the system due to improved reliability, an analysis using LOLP or LOLE approach should be conducted.

TABLE 8.4

EFFECTS OF GENERATING UNITS
AVAILABILITY IMRPOVEMENTS

Items	1981	1982	1983	1984	1985	1986
1. Peak Demand (MW)	198	231	262	281	304	329
2. Dependable Capacity (MW)	209	219	349	389	389	389
3. Availability Improvement of Existing Units in Percent	--	3	5	5	5	5
4. Reserve Requirements for Reliability Purposes	33.0	26	25	26	24	22
5. Capacity Shortages (MW)	-54	-72	+21.5	+35	+12	-13
6. Net Capacity Effects of Availability Improvement (MW)	--	+ 7	+13	+14	+15	+17

Various studies in California and Michigan have indicated approximately one percent of the system reserve requirement can be reduced for one percent reduction in system forced outage rates. For the BNG system during the short-range period the FOR can be reduced by 3 to 5 percent if proper preventative maintenance schedules are developed. The availability improvement program results in significant reduction of short-range capacity and energy shortages. Table 8.4 indicates the probable effects of an availability improvement program for the base case scenario #1. It should be noted that the reserve margin requirements for system reliability purposes have been reduced by 5 percent when compared with Table 2.5. In Table 8.4, the net effects of availability improvement of generating units by the end of the study period is approximately 17 MW, i.e., an increase in the system reserve level.

8.5 REMOVAL OF TRANSMISSION 'BOTTLENECKS'

In the PEWC system, there are several transmission and distribution 'bottle-necks' due to inadequate system planning. The modest increases in generating capacity made by the corporation in the past have not always been matched by corresponding substations, and distribution network capacities. One unique example is the inadequate transformer at the Rosieres plant which is limiting the output of the plant by 10 MW. Another example of transmission 'bottle-necks' is the inadequate transmission capability of Kenana plant which is reducing the BNG system capacity by 20 MW. The replacement of the transformer at the

Rosieres should be one of the top priority projects for the short-range period.

It has been concluded that the removal of the T and D systems bottle-neck will release significant generating and transmission capacities, but such projects are much more capital intensive when compared with load management and conservation efforts. Also, the T and D system improvement projects will require 2 to 4 years lead time, which means that these projects are not going to solve the short-range energy shortage problems. Therefore, the detailed system impacts of T and D system improvements are not analyzed further.

APPENDIX A

REPOWERING FEASIBILITY EVALUATION FORMS

FACILITY REPOWER STUDY

Site Survey Data

UTILITY _____

PLANT NAME
AND LOCATION _____

PERSONNEL CONTACTED: _____
(NAME, POSITION, TEL.) _____

UNIT SURVEYED _____

SIZE _____

OTHER UNITS AT SITE _____

SITE INFORMATION

SITE AREA _____

SITE PLAN AVAILABLE? _____

MISC. (e.g., Is space available outside of Building for gas turbines and HRSG?) _____

STEAM TURBINE GENERATOR

MFG. _____ TYPE _____

YEAR INSTALLED _____

MAX. RATING _____ KW, _____ power factor

_____ volts, _____ KVA _____ SCR

THROTTLE CONDITIONS _____ °F, _____ PSIA,

_____ inches HgA, _____ RPM, _____ LBS/HR

TYPE OF SEALS _____

EXTRACTION POINTS _____

SERVICE TO DATE _____ NUMBER OF STARTS _____

EXISTING BOILERS

TYPE _____

NUMBER _____

CAPACITY _____

STEAM CONDITIONS _____

EXISTING STACKS _____

BOILER BUILDING (e.g., With Boiler removed what space is available for Gas Turbines and HRSG.) _____

CONDENSER

MANUFACTURER_____

1) MAX. RATING_____LBS/HR AT_____"HgA

CIRC. WATER TEMP_____°F AND FLOW_____GPM

SURFACE AREA_____SQ.FT. DIVIDED WATERBOX yes no

NO. OF PASSES_____ DEAERATION LEVEL_____cc/l

TUBE MATERIAL_____ TUBE SIZE_____"OD _____B.W.G.

TUBE SHEET MATERIAL_____ TUBE LENGTH _____ft.,_____in.

HOTWELL STORAGE_____

EXISTING CONNECTIONS_____

TUBES PLUGGED?_____

2) MAINTENANCE RECORDS (RECENT OVERHAULS, RETUBING, MAJOR REPAIRS, FORCED OUTAGES, ETC.)

_____

_____

_____

_____

_____

_____

_____

_____

_____

3) CONDENSER AUXILIARIES

VACUUM PUMPS_____

AIR EJECTORS_____

_____

_____

_____

4) DOES UNIT HAVE A MAIN STEAM BYPASS TO CONDENSER?

CIRCULATING WATER SYSTEM

1) CIRC. WATER PUMPS NO._____, _____GPM

_____FT. OF HEAD TYPE_____

_____RPM BEARING LUBRICATION_____

MANUFACTURER_____

EFFICIENCY_____% _____HP AT DESIGN

MAINTENANCE_____

_____

_____

_____

_____

2) INTAKE - TYPE_____

_____

_____

TRAVELING SCREENS, TRASH RACKS

_____

_____

_____

_____

_____

_____

_____

COOLING TOWER yes, no, _____

_____

_____

_____

_____

_____

_____

CONDENSATE PUMPS

MANUFACTURER_____

NO._____ AT_____GPM, _____FT. OF HEAD _____RPM

EFFICIENCY_____% _____HP AT DESIGN

TYPE_____

SUBMERGENCE/NPSH_____

RATED MOTOR _____HP, ____PHASE, _____HERTZ, _____VOLT,

_____RPM TYPE_____

MAINTENANCE RECORD_____

_____

_____

_____

_____

_____

BOILER FEED PUMPS

MANUFACTURER_____

1) PUMP DESIGN NO._____ AT _____GPM, _____

FT. OF HEAD, _____RPM, EFFICIENCY_____% _____HP

TYPE_____

NPSH _____ FT

2) MOTOR DRIVE yes, no RATED _____HP, _____PHASE

_____ VOLT, _____RPM, TYPE_____

3) TURBINE DRIVE yes, no RATED FLOW_____LBS/HR

OF_____PSIA STEAM FROM_____

_____

_____

_____

DEAERATOR

MANUFACTURER_____

1) DESIGN TYPE_____

_____LB/HR OF_____PSIA STEAM, _____LB/HR OF

_____°F CONDENSATE, _____LB/HR OF _____

LB/HR OF_____ LB/HR OF _____

PRESSURE _____PSIA OPERATING _____ PSIA DESIGN

TEMP._____°F OPERATING, _____°F DESIGN, 0._____cc/l

2) MAINTENANCE RECORD_____

WATER TREATMENT EQUIPMENT

1) MAKE-UP WATER TREATMENT PLANT

TYPE, SIZE, ETC._____

WATER ANALYSIS AVAILABLE?_____

ADDITIONAL WATER AVAILABILITY_____

FUEL SUPPLY SYSTEM

1) TYPE OF FUEL AVAILABLE AND STORAGE CAPACITY

NO. 2 OIL _____

NO. 6 OIL _____

NATURAL GAS _____

OTHER _____

_____

2) SUPPLY CAPACITY AND PRESSURE

NO. 2 OIL _____ GPM _____ PSIA

NO. 6 OIL _____ GPM _____ PSIA

NAT. GAS _____ CFM _____ PSIA

PIPELINES TO SITE _____

_____

OTHER _____

_____

3) FUEL RATES FOR OTHER UNITS

UNIT _____ _____

UNIT _____ _____

UNIT _____ _____

UNIT _____ _____

UNIT _____ _____

UNIT _____ _____

UNIT _____ _____

UNIT _____ _____

UNIT _____ _____

UNIT _____ _____

ELECTRICAL SWITCHYARD AND SUBSTATION

EXISTING EQUIPMENT

1) TRANSFORMERS _____

_____

_____

KVA RATING OF STATION _____

_____

2) TRANSMISSION VOLTAGE _____ KV

3) GENERATOR VOLTAGE _____ KV

4) SUBSTATION _____

_____

_____

_____

5) R.O.W. FOR ADDITIONAL TRANSMISSION? _____

_____

6) OTHER _____

_____

_____

_____

_____

_____

_____

_____

_____

ELECTRICAL SWITCHYARD AND SUBSTATION

EXISTING EQUIPMENT

1) TRANSFORMERS _____

_____

_____

KVA RATING OF STATION _____

_____

2) TRANSMISSION VOLTAGE _____ KV

3) GENERATOR VOLTAGE _____ KV

4) SUBSTATION _____

_____

_____

_____

5) R.O.W. FOR ADDITIONAL TRANSMISSION? _____

_____

6) OTHER _____

_____

_____

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APPENDIX B

POWER SYSTEM PLANNING CRITERIA

POWER SYSTEM PLANNING CRITERIA EVALUATION AND JUSTIFICATIONS

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ABSTRACT

The purpose of this paper is to discuss the necessity for power system planning criteria evaluation and justifications. The greatest conflicts in the development of power system planning criteria is the lack of meaningful measures of performance requirements of three major system components: generation, transmission and distribution. Recently, there are other factors that have been introduced in the planning process which must be given much greater consideration than in the past. These are social and environmental considerations. The optimum structure of bulk power systems will undoubtedly concern engineers for many generations to come. The paper speculates on planning criteria for the optimum balance in structure within the system to achieve a given standard of sytem quality and reliability of the system as a whole with respect to the consumer.

1. INTRODUCTION

Power systems are designed and planned so that for any predicted future loads and system condition, the generation and transmission capacity will always be adequate to prevent any single incident from precipitating a second incident. This planning philosophy will prevent the first stage in what could develop into a cascading series of events and a split-up of the system. The power system load grows more or less continuously, but the transmission and generation equipment is added in finite steps so that the operating margins change and the operating limits may alternate between generation and transmission systems. It is uneconomical to add too much capacity too soon. Therefore, the system planning objectives can be defined as the preparation of a rational program for the orderly and economical development of a reliable electric power system.

Figure 1 is a block diagram for the various processes involved in power system planning. In order to determine the future system capacity, the system planner requires forecasts of the peak loads. The planner needs detailed load shape and load duration forecasts throughout the year to determine the most efficient generation mix (base, cycling, and peaking.) To ensure the system's ability to meet the instantaneous load demand, it is also necessary to know how the future load will be influenced by the weather and by other short-term external factors. Overestimating the demand may result in the premature addition of generation and transmission facilities. Underestimating the demand, on the other hand, may result in insufficient generation and transmission capacity to serve the load, leading to possible unreliable operation and load curtailments. Figure 1 also shows the various constraints which often dictate planning and designing processes.

The development of power system planning criteria is a matter of balancing the cost of providing additions to the system on one side, against the risks of interruption of supply or socio-economic and environmental degradation, etc. on the other side. In many cases, it is hard to put specific figures on the risks; hence, judgment and experience intervene. If planning process is to proceed reasonably, then its base must be acceptable to various interests involved in the decision making. Accordingly, it is necessary first to draw up a set of tentative standards and/or criteria by which plans can be constructed, tested or considered. Such standards are vital to giving the planning process a consistent basis from one year to another and from one area to another. The set standards or planning criteria must be:

- Clearly understandable to those making decisions.
- Usable from the system planner's point of view.
- Not unduly restrictive from the point of view of design or construction departments wishing to develop new designs or layout.
- Agreed upon and accepted by those interested and
- Subject to amendment or alteration in view of experience.

In the power system planning process, the optimum structure of bulk power systems will undoubtedly concern engineers for many generations to come. What is the optimum balance in structure within the system to achieve a given standard of system quality or what is the optimum quality or reliability of the system as a whole with respect to the consumer? Ideally, system reliability should be improved to the point where its incremental cost equals its incremental worth. An obvious application is the reliability of a bulk power supply system by adopting a set of criteria. The cost of satisfying a particular reliability or planning criterion, whether deterministic or probabilistic, can be determined. Figure 2 shows a curve for incremental change in reliability vs. incremental cost $/kW. In reality, there is no corresponding way of determining the worth of reliability. Consequently, the worth of reliability must be based on quantitative estimates. As the situation now stands in power system planning, most of the reliability or planning criteria are established with little regard to cost and without knowing what value the consumer would place on reliability if he had a choice and knew what it meant. In the following sections, the different planning criteria and their justifications are discussed.

2. SYSTEM RELIABILITY PLANNING

Determination of an adequate measure of reliability or service quality at the planning stage of a power system is a difficult task. It seems that no single criterion of system reliability is completely descriptive of the system's ability to supply satisfactory service. From a system reliability viewpoint, it is necessary to:

1. Define the reliability goals.
2. Evaluate the failure mode and effect.

In developing system reliability models, one must realize that all systems and equipment are subject to failure and that the real problem is to properly balance system reliability requirements against system costs. The developed reliability criteria must recognize and take into consideration the physical phenomena of the power system such as random outage of system components, potential network limitations, errors imbedded in load forecasting, starting time of generators and switching circuits, etc. It is imperative to point out that appropriate planning criteria must be able to determine optimum generation reserves, types, size, and location as well as supporting inter- and intra-transmission facilities. Also, careful attention must be given to operating policies with respect to generation and transmission reserve levels, maintenance procedures, and protection policies. To accomplish this, one must first establish the decision rule, i.e., the criterion for making planning decisions. Secondly, one should express the effectiveness of each in terms of some physical attribute. The general procedure involves developing mathematical models which simulate the possible outcomes of each planning policy alternative. In this way, it is possible to compare them and choose the optimum policy.

In power system planning criteria evaluation, the question of the cost resources required for alternate strategies reliability evaluation is a

A paper recommended and approved for presentation at the 1978-IEEE Canadian Conference on Communications and Power, Montreal, October 18-20, 1978.

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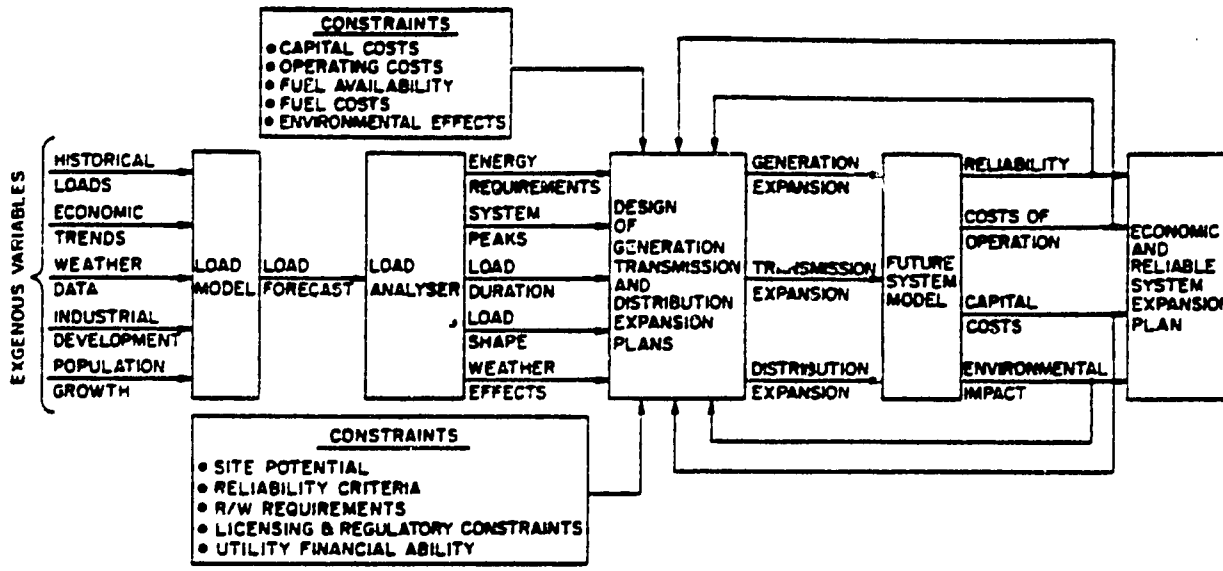

FIGURE 1

POWER SYSTEM PLANNING PROCESS

part of the information that enters into all planning decision problems. The problem can be stated thus: What is the most cost-effective method to improve the steady-state availability (or reliability) of a given system from a base line value to a given availability (or reliability) goal? However, in system planning, it is probably safer to approach the problem first in terms of system needs, secondly in terms of cost, and finally to re-evaluate and adjust the criteria. Relationships must be developed for each planning criteria between the cost and its associated improvement in system reliability. The goal in any tradeoff study is to determine the most cost-effective method of proceeding. It should be noted that these relationships are not necessarily linear or even continuous functions. In recent years, probability methods have been developed so that it is now possible to design and plan a complete power supply system based on customer service quality. But, the question is: what is the acceptable quality of service? In developing the planning reliability criteria, more emphasis should be given to customer service quality criteria rather than bulk power system reliability criteria alone. This will provide equitable service quality to all customers.

3. FACTORS OF UNCERTAINTY

There are many problems associated with developing planning criteria or measures of effectiveness. In the first place, it is not always possible to express quantitatively all the factors of interest in a model. Many of these factors cannot be well defined nor their significance adequately interpreted. Secondly, the measures of a system's effectiveness can change over time. What may be effective or satisfactory today may not be effective tomorrow, due to the fact that one may choose an incorrect measure of effectiveness which defines mathematical models. Unfortunately, many elements in a system planning model cannot be well-defined. For example, there may be uncertainty about the assumptions represented by the variables in planning models.

A number of recent developments have upset well-established patterns of the electric power industry. These developments most notably include:

(1) The international energy supply crisis.
(2) The high rate of inflation.
(3) The increased financial difficulties.
(4) Substantially higher labor costs.
(5) Extraordinary increases in the price of fuel.
(6) The dramatically higher electric rates.
(7) Increasing costs due to many delays in licensing and construction of new plants and transmission lines.

In the process of selecting power system planning criteria, the impact of these types of unusual developments should be recognized. A unique example is the capital costs for nuclear power plants which appeared to be quite optimistic in the planning studies in the early 1960's and were revised in the late 1960's. A few years ago, sweeping generalizations were made in the U.S. regarding future fuel prices to use for generation studies. Today, however, system planners are basing studies on future coal prices, which have risen 150 percent to 200 percent over their previous value. These variations naturally affect the development of optimum system planning criteria. Because of this change in the economic climate, the electric utility industry has entered the greatest period of uncertainty as to future load growth, fuel supply, equipment and material deliveries, construction lead times, environmental standards, and licensing and siting regulations. Most important point to recognize in the development of planning criteria is that these factors of uncertainty will always exist and the future system must be able to cope with these uncertainties. Figure 3 shows the possible errors in peak load forecast. It should be noted that as lead time increases, the percent error also increases almost linearly. In the planning criteria for power systems, the factors of uncertainty which must be recognized are:

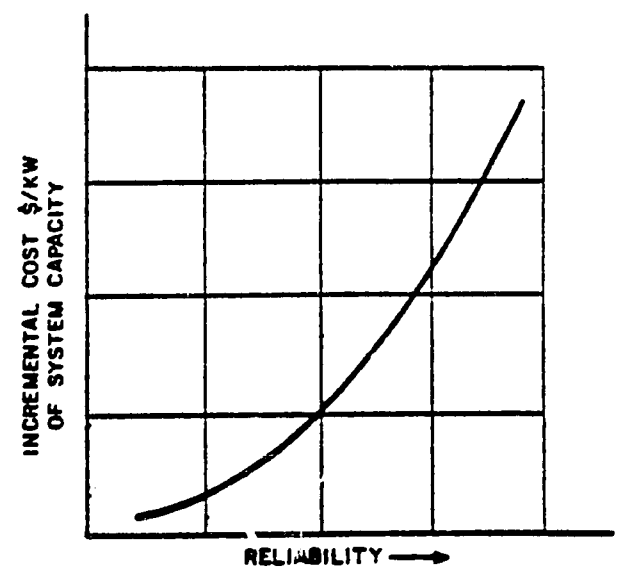

FIGURE 2

INCREMENTAL CHANGE IN RELIABILITY

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(1) Service dates of new generation and new transmission.
(2) Load forecasting error.
(3) Contingencies and outages.
(4) System operating conditions.
(5) Impact of outages.
(6) Scheduled maintenance.

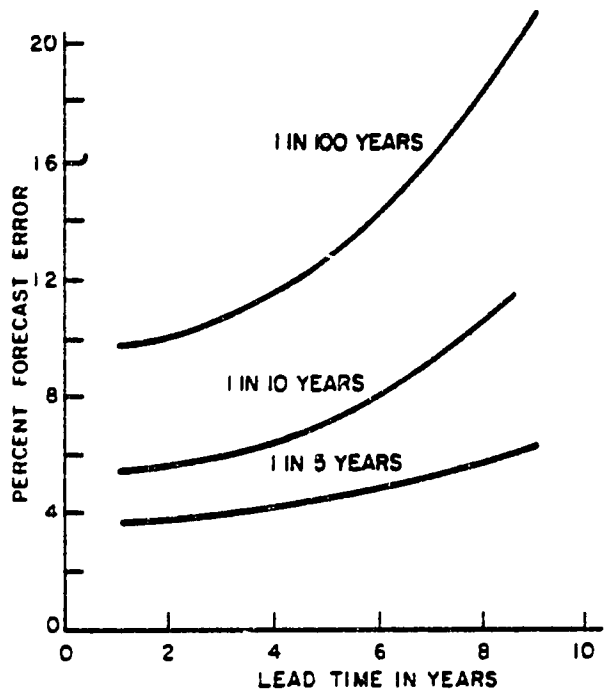

FIGURE 3

POSSIBLE PEAK FORECAST ERROR

4. CREDIBLE AND NON-CREDIBLE CONTINGENCIES

The necessary credible and non-credible contingency criteria in power system planning are the degree of abnormality which the power system should sustain without serious consequence to customer or equipment. These criteria are usually established based on day to day operational experience over the whole load cycle, including the effects of equipment outage on system capability and engineering economics. A credible contingency is one that the system has been designed specifically to meet. It is considered as an event and because of its frequency of occurrence in the past on a certain type or class of equipment, it can be expected to occur in the future on the same or similar equipment. Power systems are designed to meet credible contingencies at an acceptable cost. The expected frequency of the event over any part of a system can be calculated, and with or without this calculation, measures can be made at an acceptable cost to ensure that the event does not cause a loss of supply. Simple examples of credible contingencies would be the outage of a generator, transformer, reactor, cable or transmission lines. Credible contingencies on more important parts of the system include some simple combination of single events, i.e. generator plus a transmission equipment or generator plus two transmission items. The credible contingencies that are usually covered by the power system planning and operation criteria are listed in Table 1.

Non-credible contingencies are those not foreseen or those not economic to guard against in detail, including a single event which is very improbable or combination of several events. Any single combination of credible contingencies forms only one of many hundreds or even thousands of possible combinations. Because of the many possibilities, some non-credible contingencies cannot be specifically safeguarded, but their probability of occurrence may be considerably higher than an estimate of the probability as a combination of the number of uncorrelated events would suggest. The 1965 Northeast power failure in the United States and the freezing fog conditions in England and Wales which resulted in widespread and multiple trippings of transmission lines are examples of such non-credible contingencies.

TABLE 1

SUMMARY OF CREDIBLE CONTINGENCIES

Credible Contingency	Generally Accepted Criteria
A. Generation loss due to 1. Local fault 2. Transmission fault	1. Largest unit or two times largest unit 2. One circuit or two circuits
B. Transmission Loss 1. Local fault 2. Transmission system fault	1. Generally one circuit, double circuit in special circumstances. 2. Two-single circuits or one-double circuit tower outage with short-term overload on remaining circuits
C. Combined generation and transmission loss 1. Local network 2. Transmission system	1. Largest unit and one circuit 2. In some extraordinary circumstances combined loss of a line or a tie-line and generating unit may lead to over load and demand restriction

The concept of credible and non-credible contingencies discussed above is part of the power system operation and planning process. Before implementing any system planning or operating criteria, these must be assessed and their severity should be carefully evaluated. As might be expected, there is a significant difference in the approach by which these abnormalities are evaluated and incorporated in the planning process by electric utilities. However, the basic planning philosophy is to design a system which can sustain all credible contingencies and reduce the risk of all non-credible contingencies at an affordable cost.

In the United States, the Federal Power Commission (FPC) Advisory Committee's report recommends studies of the following extreme contingencies in interconnected system planning process:

(a) The outage of any power plant, both under steady-state conditions and following a three-phase fault.
(b) The outage of the most critical circuit as a result of a three-phase fault, during the outage of another critical line on the same or on an adjacent system.
(c) The outage of an entire transmission substation on any one of the interconnected systems.
(d) The outage of all transmission circuits on any one common right-of-way as the result of simultaneous three-phase faults.
(e) The sudden dropping of a large load or a major load center.
(f) The effect of power swing arising from outside disturbances.

The planning criteria should be developed such that the power system can withstand all credible contingencies without loss-of-load.

5. SYSTEM STABILITY REQUIREMENTS

In power system operation, stability is that attribute of the system which enables it to develop restoring forces equal to or greater than disturbing forces. The system settles in a finite time to a new state of equilibrium. In other words, a power system is stable under certain specified network conditions, if, upon being disturbed by some arbitrary forces, it tends to come back to original operating condition. The phenomenon of system stability constitutes a technical limitation in planning studies of power systems as well as in system operation. The simulation of system stability under both credible and limited non-credible contingency conditions is an integral part of power system planning. The developed system planning criteria must explicitly specify system stability requirements. The basic stability criterion which must be considered in the planning process is that the generators must maintain synchronism at the end of each transient period. The term "transient period", here refers to a system disturbance or dynamic behavior of the system.

Power system stability is a function of the control equipment, such as governors, generator voltage regulators, tie-line load frequency control equipment, and the state of the transmission network. Therefore, stability criteria should apply over the permissible operating range of generators, power output within leading and lagging reactive limits and network conditions. In the planning process, the generator stability and equipment safeguard are coordinated to minimize isolation time of faulty equipment within physical and economic con-

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straints. The strength of the power system after a disturbance or fault is a very important factor and can be controlled in the planning and design of the system. Figure 4 illustrates the importance of a power system's strength. The critical fault clearance time is plotted against the short-circuit MVA infeed from the system for the condition when the 700 MW generator is operating at unity power factor. At the lower values of short circuit infeed, the major factor is the disturbance caused by the loss of a circuit; i.e., the fault itself is not so important at the lowest values. The generator is unstable simply because the circuit is lost. The magnitude of the disturbance is very dependent on the power flows before the circuit is lost and the shape of the curve can vary considerably. However, the general shape of the curve does indicate that it is desirable in the basic planning and design of the power system network to keep the short-circuit infeeds above a certain minimum value, thus avoiding the steepest part of the curve. Of course, this is only a very rough guide to the stability of a power station, but it can be used to differentiate between those situations where stability is of no concern and those where stability requirements will need to be frequently reviewed because of system expansion. Many types of stability have been referred to in the literature, but there are no clearcut distinctions between them. In the power system planning process, the following three stability conditions are usually examined:

- Steady-State Stability
- Transient Stability
- Dynamic Stability

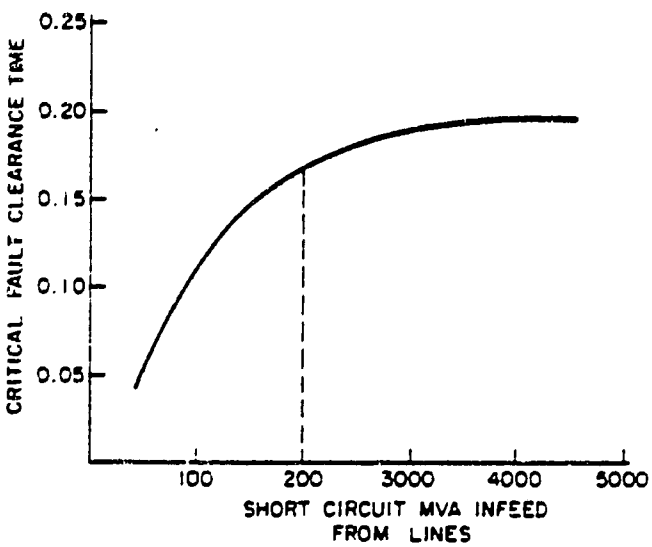


FIGURE 4

SHORT CIRCUIT INFEED FROM LINES AFTER FAULT

A detailed discussion of any of these stability conditions is out of the scope of this paper. The developed criteria for system planning should include the following stability requirements:

1. Under normal operating conditions the system should be stable in the dynamic sense.
2. With all lines in-service in the precontingency state, generators shall be stable subsequent to a single contingency cleared by primary relay protection.
3. With all lines in-service in the precontingency state, generators shall be stable subsequent to a double contingency cleared by backup relay protection.
4. With a circuit out-of-service in the precontingency state, generators shall be stable for a single contingency cleared by primary relay protection. Operating restrictions such as controlling generator real power output for extraordinary situations will be considered.
5. For situations which exceed these criteria the unstable generator shall be disconnected from the network by direct positive action, i.e., by out-of-step relaying on the generator or by protective relaying. The means used to disconnect an unstable generator shall minimize degradation of transmission network and loss of load. When generator out-of-step protection is ineffective, transmission circuit out-of-step blocking and transfer tripping of generation will be considered.

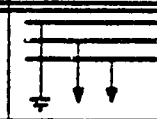
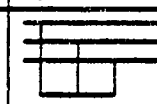
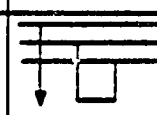
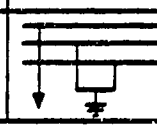
It should be emphasized here that this discussion is concerned only with the approach to stability studies which should be considered in the system planning process of a general power system. It is not intended to outline the absolute answer to all stability-related study requirements or to deal with problems of concern only to some power system such as subsynchronous resonance, HVDC lines, or others. The above mentioned criteria for system stability studies are by no means complete; however, they indicate the nature of the stability-related problems which a system planner must be aware of at the planning stage.

6. SHORT CIRCUIT KVA CONSIDERATIONS

In the power system planning process, it is necessary to calculate short circuit currents during different types of fault conditions to determine adequate protective relaying schemes. To adequately protect a power system against the short circuits that inevitably will occur requires calculation of short circuit currents at the various switching stations of the system. Usually, the three-phase short circuit and the single-phase to ground short circuit with distribution of current in the network at least one bus away from each fault are considered. Table 2 indicates different types of faults on transmission lines for which short circuit protections are usually provided in system design. The statistical distribution of different faults is also included in Table 2. In power system short range planning, it is necessary to make sure that the short circuit rating of every equipment in the station is greater than the expected three-phase bus fault level at the station.

TABLE 2

DISTRIBUTION OF DIFFERENT TYPES OF FAULTS

TYPES OF FAULT	SCHEMATIC ILLUSTRATION	PERCENT OF TOTAL FAULTS
1. SINGLE LINE TO GROUND FAULT		70%
2. THREE PHASE FAULTS		5%
3. LINE TO LINE FAULTS		15%
4. DOUBLE LINE TO GROUND FAULTS		10%

As system load grows, there is a greater possibility for a larger number of faults due to additional installed equipment and also due to the fact that in the event of a fault, the larger KVA of generating plant is capable of supplying an increased short circuit current. Figures 5 and 6 illustrate a system before and after expansion, respectively. A careful inspection of Figure 5(b) will show that the additional line between bus A and B has reduced the inherent impedance between bus A and B. This means that each fault after system expansion will be more severe compared to that in the original system. For the short range planning criteria, the fault currents must be within specified interrupting ratings of circuit breakers and relays with all facilities in service, and with generators and synchronous motors represented by their appropriate reactance (usually subtransient). In the power system planning process, the short circuit current arising from interconnection of two systems also requires careful evaluation. In Figure 6, the fault on either system A or system B before interconnection could be fed from their respective generating systems. However, with new interconnection X-Y, a fault on either system A or system B

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will require the whole generated KVA of both systems to feed it. Therefore, in the planning process, it is quite possible that in a certain location, some circuit breaker which was adequate for original system conditions may not be sufficient when new circuits or interconnections are added. In the later case, either the old circuit breaker will have to be scrapped, or, alternatively, the impedances of the expanded system will require an increase so as to keep short circuit current to a value for which the original circuit breakers were designed.

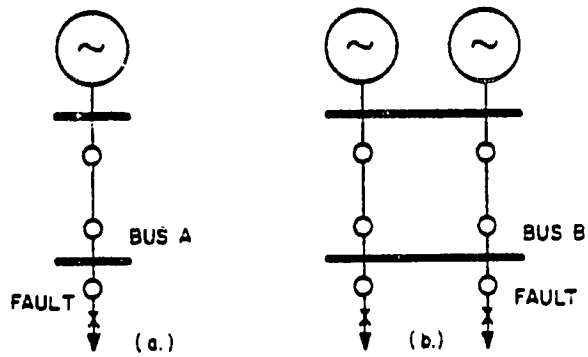

FIGURE 5

SHORT CIRCUIT CURRENTS FED FROM ONE AND TWO GENERATORS

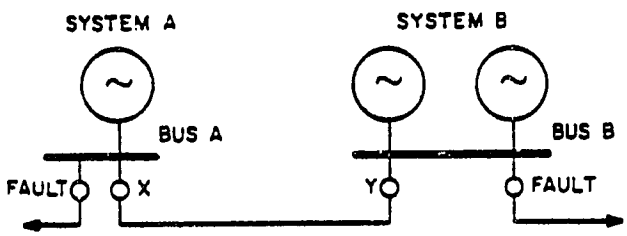

FIGURE 6

INCREASED SHORT CIRCUIT CURRENTS REQUIREMENTS FOR INTERCONNECTING STATIONS

7. INTERCONNECTION SUPPORT

In the process of developing planning criteria, the economic advantages resulting from the interconnection of neighboring power systems must be carefully evaluated. In many instances in the past, interconnections have been developed primarily to provide local support to continguous areas of adjoining power systems. Effective interconnected operation now requires the utilization of high voltage, high capacity ties with capabilities corresponding to modern unit sizes. Weak interconnections which join adjacent regions are of little value in improving reliability and, in fact, can be harmful. The appearance of strength by the mere presence of connecting links can be seriously misleading. The criteria for interconnection can be examined critically to determine whether the system has adequate capacity to remain in operation under a wide variety of assumed system serious emergencies.

Power system interconnection planning criteria should be able to identify and evaluate alternative bulk power arrangements in terms of load requirements, reliability, capability, resources, finances and social factors. System planners seek programs which can achieve the lowest construction and operating costs possible within the planning constraints of the utility or group of utilities. A detailed discussion of economic benefits of power system interconnection which should be considered at the planning stage is not possible here, since the agreements and clauses of contracts regarding interconnection assistance among power companies vary quite widely. However, in developing the interconnection planning criteria, the following three principal objectives must be thoroughly examined:

(a) The interconnections must be capable of supporting immediately any load area suddenly faced with a serious and unexpected deficiency in its normal generating supply. The network must have the capacity to handle, well within the stability limits, the automatic inflow of emergency power from the generators of the surrounding interconnected network.
(b) To transfer, without serious restriction, capacity and energy within regions to meet power shortages. Emergencies can arise from innumerable causes, such as delays in commercial operation of new generation, problems with new equipment, the failure of major generating units, or other elements of the system, and unexpected peak demands caused by weather extremes.
(c) To exchange power and energy in a regional and inter-regional scale, and to achieve important reductions in generating capacity investment and in cost of energy production.

The initial studies for interconnection planning should also be able to indicate whether it will offer an opportunity for the interconnecting areas to share reserves by taking advantage of the following factors:

(a) Daily and seasonal load diversity.
(b) The diversity in forced outages.
(c) The opportunity for integrating planned maintenance outages on pool basis.
(d) Possibility of bulk energy transfers over tie lines to take advantage of energy cost differentials between the areas.
(e) Improvement in transient stability.

The other important factors which the planning criteria should recognize for the interconnection support are:

(a) Short term capital gain from the postponement of some generation installation projects. This is, of course, contingent upon the type of interconnection agreements signed between the companies, for example:

    (i) Purchase of units for certain calendar years.
    (ii) Transfer of energy.

(b) The gain in the generation system reserve and reliability level. Figure 7 shows some of the tangible and intangible benefits which should be considered thoroughly in the process of development of interconnection planning criteria. The other important subsidiary benefit which must be recognized is the prospect for bulk amount of energy transfer for economic reasons between the two systems at times when their marginal costs of generation differ. These advantages are significant, especially for small systems.

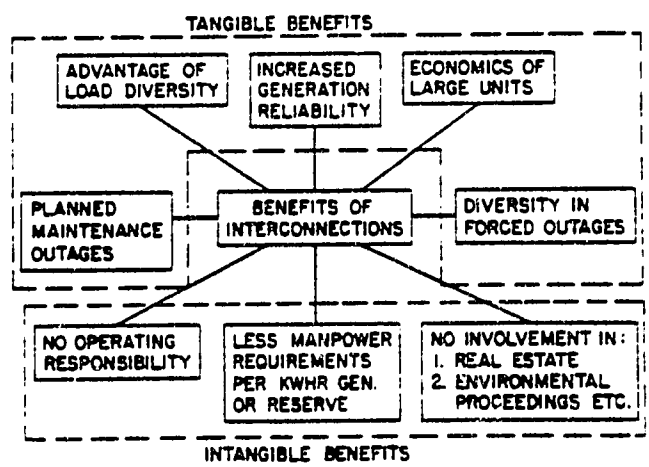

FIGURE 7

BENEFITS OF AN INTERCONNECTION

In general, well-developed numerical techniques are available today for satisfactory analysis of these problems. The same techniques can lead to the solution of problems such as extra network reinforcement, increase in permissible short circuit level, use of DC links, etc. Recourse to these methods is not, however, free and certainly increases the cost of interconnection - in all cases indepth technical and economic study is necessary. It is important to note that interconnection of systems must be considered on its own merits, since it involves

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expense for providing the lines between systems and at the same time an increased switch gear rating to be employed at different points in the system. Among the problems of interconnected system coordination are the equitable sharing of costs and the division of ownership of interconnecting facilities. Such problems appear to be especially acute where the systems differ greatly in size and in type of ownership. It is important to note that unless long-range plans are developed, there is the danger that interconnection support planning will be done on a short-term, incremental basis. This can result in lower reliability and higher cost. The developed criteria must test the adequacy on a total system basis before an economic choice is made.

8. PRESENT CRITERIA PRACTICES

(a) Generation Planning Criteria

In order to reliably serve the forecast loads, the generation planning criteria should be designed to meet or exceed the established criteria. Also, the accepted planning criteria should be re-evaluated often to analyze the effects of system's stochastic characteristics. In generation planning, probabilistic reserve calculations are used to reduce the various factors influencing installed reserve requirements. The commonly used reliability measures are:

(1) Loss of Load Expectation (Probability)
(2) Loss of Energy Expectation
(3) Frequency and Duration
(4) Loss of Load Index

Each of the measures of reliability may be useful as measurement tools. Because each calculation technique is intended to measure specific quantities, such as the expected magnitude of load loss or the expected amount of energy not served, the results of one calculation technique are not comparable with the results of another. Furthermore, none of the calculation techniques are intended to be an absolute measure of system reliability; rather they are intended to be useful as planning tools and may be useful in comparing the relative levels of reliability between alternative resource plans.

Most electric utilities in North America calculate loss of load probability (LOLP) index, loss of energy index, and the expected magnitude of load loss. It should be noted that none of these criteria is an explicit part of generation system planning criteria. They should be examined for reasonableness. Utilities generally use a probabilistic annual index as part of their minimum installed capacity reserve margin criteria. This reliability index represents the probability that a specified resource program will serve forecast loads (demand) and allow for planned generation maintenance and random forced outages for each hour of the year without requiring emergency assistance via interconnections in excess of amounts considered normally available. Some utilities use a minimum design reliability criteria.

It should be noted that in generation planning, a single criterion does not impose any constraint on absolute minimum spinning reserve requirement which is a common operating practice. Therefore, generation planning criteria should be developed based on the principle that for the common contingency outages, there should not be any loss of system load nor adverse effect on neighboring systems. Planning criteria should recognize the necessity for load loss only for those outage contingencies that are credible but of such low probability that it is not economical to protect the system against such loss of load. The planning criteria should also recognize past system performance experience, diminishing return of system reliability, and expectation of future generation system performance. The established planning criteria must reflect different interconnection operating practices and distribution of pool reserves.

In order to reliably serve the forecast loads, the generation resource program should be designed to meet or exceed the following criteria:

(1) Optimum LOLE criterion for isolated system.
(2) Optimum LOLE criteria for the power pool and interconnected systems with load loss sharing and without load loss sharing operating practices.
(3) A spinning reserve requirement and severity of contingency in generation planning practice. For example, the installed capacity margin after deducting scheduled maintenance should be sufficient to allow the loss of:
    (a) At least the two largest risks, or
    (b) Six percent of system demand (three percent spinning reserve and three percent quick start reserve) plus single largest risk or contingency.
(4) The adopted criteria should also represent the uncertainty in load forecast. The uncertainty, which includes the effects of weather variations, should be modelled as the probabilistic likelihood and expected magnitude of deviation from the forecast load.
(5) A system reliability index which will reduce the various factors influencing the installed reserve requirements to a common denominator of the aggregate effect of system reliability.
(6) Installed capacity margin criterion of x%, plus or minus two percent of the annual estimated peak demand.

It should be noted that in the calculation of the above mentioned criteria, all the units included in the generation planning program are assumed to be constructed as scheduled. However, uncertainties, such as increased regulatory delays, legislative intervention or construction delays are not included. Used appropriately, the above cited criteria can be used to compare the relative reliability of different utility systems or generation expansion plans which vary by reserve margins, plant types, and cost.

(b) Transmission Planning Criteria

A basic problem in transmission planning is the determination of transmission adequacy under normal and all possible system component outage conditions. Any steady state breach of security under normal and contingency conditions (single and double contingency) which results because the system is in a particular state at a particular time (this also implies to load level at that time), without regard for how long the system has been in that state or what sequence of events caused the system to be in that state, will require additional facilities to meet the system reliability criteria.

A general new project criteria for the transmission system can be postulated as follows:

(1) If, with all transmission and generation facilities in service, any transmission component (line, breaker, transformer, etc.) loading is outside the appropriate normal ratings, then new facilities are required in order to meet the quality of service standards.

(2) If, with all transmission generating facilities in service, station voltages are outside the defined limits, then new facilities are required in order to meet quality of service standards.

(3) If, for all possible single contingency outages (generator, circuit, tower line, or transformer, etc.), the system voltages for the bulk power system are less than a preselected percent of normal (prefault) values and the loading on any remaining elements over appropriate emergency ratings, then new facilities are required in order to alleviate any unacceptable risk levels. The appropriate rating is dependent upon the expected duration of the emergency loading and the type of equipment involved.

(4) If, for all acceptable combinations of any two system components out of service (except double circuit tower), the system voltages for the bulk power system are less than a preselected percent of normal (prefault value) and the initial loss of load is more than a preselected MVA value, then new facilities are required in order to alleviate any unacceptable risk levels.

A system operates most of the time under normal operating conditions without any forced outages. According to the above criteria, the transmission network is first tested for adequacy under normal operating conditions for the most economic generation schedule. If normal, single and double contingency outages violate the appropriate operating criteria, then a new project is to be initiated to bring the system reliability level to an acceptable value.

In general, the criteria are uniformly interpreted and utilized in the testing and planning of the system unless some deviation is justified as a result of special or unusual economic, political, or other considerations. Such instances should not necessarily be considered to conflict with this criteria or to justify revising the criteria, but should