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EBASCO OVERSEAS CORPORATION
A Subsidiary of Ebasco Services Incorporated

In Association With

BLACK & VEATCH INTERNATIONAL
SHELADIA ASSOCIATES, INC.
ARAB CONSULTING ENGINEERS
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1.0 Executive Summary

This report examines the feasibility of a pumped storage project in Egypt. The study was performed for the United States Agency for International Development (USAID) and was administered by the Hydro Power Plants Executive Authority (HPPEA) in conjunction with the Egyptian Electricity Authority (EEA). The Study was performed by Ebasco Overseas Corporation in association with Black and Veatch International (BVI), Sheladia Associates, Inc., Arab Consulting Engineers, and Sabbour Associates.

1.1 Introduction

The objective of the study is to assist the HPPEA in evaluating the advisability of undertaking the project. The study integrates the technical, environmental, financial, and economic aspects of the pumped storage project.

The study is being performed in three separate but related phases:

- Phase 1 consists of an appraisal of the future generating capacity requirements based on demand and energy forecasts, identification of capacity additions to meet an appropriate reserve capacity level, an evaluation of alternative capacity additions, including pumped storage, to meet the projected demand and energy forecast and identification of the least cost alternative project.
- Phase 2 will be dependent upon pumped storage hydro capacity being identified in Phase 1 as the least cost alternative capacity. Phase 2 will consist of the evaluation of the potential sites for a pumped storage hydro plant and the consultant's selection of the best site for the plant.
- Phase 3 will consist of the preparation of a full engineering/economic feasibility study of the pump storage site identified in Phase II.

1.2 Background

Pumped storage hydro plants use lower cost off-peak generation to pump water into an upper reservoir. That same water is then used on peaks to displace higher cost generation. The pumped storage hydro project is envisioned to be on the west side of the Gulf of Suez approximately 85 km south of Suez City. The upper reservoir would be on the El Galala Plateau. The Gulf of Suez would be used as the source of water and would be desalinated to fill the lower reservoir and to provide makeup water during plant operation.

The data and assumptions used to perform this study were developed in close cooperation with the EEA and the HPPEA. As agreed upon in discussions and correspondence with EEA and HPPEA, two base cases were evaluated for the generation expansion plan. One case assumed that all combined cycle and combustion turbines would use natural gas. The second case assumed that the combustion turbines would run on No. 2 oil. The pumped storage project was substituted into each base plan, replacing equivalent combustion turbine capacity.

The economic evaluation was accomplished by performing a generation production cost run including the years 1995 through 2024. Production costs include fuel, operation and maintenance, and unit startup expenses. Annual capital costs were combined with production costs to determine a total annual generation cost. The basis of the comparison was the 1993 cumulative present worth of the annual cash flows for the study period.

Screening curve analysis indicated that combined cycle units are the most economical baseload option. However, prudent utility practice precludes the addition of one type of unit to the exclusion of all others. Thus, as agreed with EEA, combined cycle capacity was limited to a maximum of 15 percent of the total capacity. Similarly, coal fueled capacity was limited to 5 percent of the total installed capacity.

A pumped storage project provides benefits other than fuel savings. The pumped storage project does not have the capacity derate experienced by combustion turbines due to high ambient temperature, and, at the same time, has a higher reliability (lower forced outage rate) than do combustion turbines. Consequently, more combustion turbine capacity than pumped storage capacity is required to achieve equivalent reliability. To account for the temperature derate and the difference in reliability, the capital cost of the combustion turbines was adjusted accordingly.

Electrical generation systems must be prepared to respond to generation outages. To accomplish this, utilities keep more thermal generation on line than is required to serve the load. This excess on-line generation is called spinning reserve. Pumped storage units can be brought on line in very short order, thus reducing, but not eliminating, this need for spinning reserve.

1.3 Economic Evaluation

The economic evaluation indicates that under the base assumptions, the pumped storage project in the natural gas expansion plan has a comparative 1993 cumulative present worth cost over the study period years 1995 through 2024 which is

$51 million higher than the same plan without pumped storage. Figure 1-1 presents the differential annual comparative cash flows.

Figure 1-1 indicates that the project costs approximately $10 million more annually for the first 20 years. There is a large step in the year 2023 at which point the project provides a savings of approximately $26 million. The pumped storage plan has six fewer gas turbines installed in 2003 than the plan without pumped storage. In 2023 these six additional gas turbines must be replaced in the plan without pumped storage because their life is assumed to be 20 years. Because the pumped storage life is assumed to be 50 years, the six gas turbines do not need to be replaced in the pumped storage case. Therefore, additional capital must be expended in the plan without pumped storage in 2023, making it more expensive at that point.

Consideration of the remaining years of life of the pumped storage project from 2025 through 2052, called the end-effects period, is important to the present worth evaluation of the project, as demonstrated on Figure 1-1. The end-effects period evaluation takes into consideration the higher capital cost due to escalation of the replacement combustion turbines in 2023 and again in 2043, as well as the production cost savings of the pumped storage project from 2025 through 2052.

The end-effect period produces a 1993 cumulative present worth savings for the pumped storage plan of $56 million. Thus, over the assumed 50 year life of the pumped storage project, the 1993 present worth total generation cost savings of the pumped storage plan is $5 million, as shown in Table 1-1.

The economic evaluation of the second expansion plan with combustion turbines burning No. 2 oil indicates that the plan with pumped storage provides a comparative 1993 cumulative present worth savings over the years 1995 through 2024 of $49 million over the plan without pumped storage. Figure 1-2 shows the differential annual comparative costs for both plans.

Figure 1-2 indicates that in the plan with combustion turbines on No. 2 oil, the pumped storage project produces lower annual cash flows beginning in 2008. The project also becomes more economical on a cumulative present worth basis in 2013.

Consideration of the end-effects period adds a 1993 cumulative present savings of $143 million for the pumped storage plan. Table 1-1 shows a 1993 present worth total generation cost savings of $192 million for the pumped storage plan over its assumed 50 year life.

As previously stated, pumped storage projects can provide benefits beyond pure fuel savings. Such supplementary benefits are frequently identified as dynamic

benefits and have been assessed in this study. The total potential dynamic benefit available to the storage alternative is estimated at $35 million.

The construction of a pumped storage project in lieu of equivalent combustion turbines will provide a larger positive economic benefit to the Egyptian economy. During the assumed construction period, this benefit will inject $148 million (1993 dollars) more into the local economy while, during the same period, providing approximately 3,000 additional person years of employment. The Total Economic Evaluation, summarized in Table 1-2, includes the dynamic and socioeconomic benefits in addition to the total generation savings. Inclusion of these items increases the pumped storage benefits to $188 million and $375 million for the two base expansion plans.

1.4 Conclusions

- In the natural gas expansion plan the pumped storage project has a small primary benefit present worth savings of $5 million over the lifetime of the project. Inclusion of secondary benefits increases the present worth savings to $188 million.
- In the plan with combustion turbines on No. 2 oil, the pumped storage project produces significant present worth savings of $192 million over the lifetime of the project. Inclusion of secondary benefits increases the present worth savings to $375 million.

Table 1-1
Economic Evaluation
1993 Present Worth
($ Million)

	Natural Gas	No. 2 Oil
Cumulative Present Worth of Pumped Storage Cost Savings		
Study Period	(51)	49
End Effects Period	56	143
Life of Project Benefit	5	192

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Table 1-2
Total Economic Evaluation
1993 Present Worth
($ Million)

	Natural Gas	No. 2 Oil
Cumulative Present Worth		
Total Generation Cost Savings	5	192
Dynamic Benefits	35	35
Socioeconomic Benefits	148	148
Total Project Benefit	188	375

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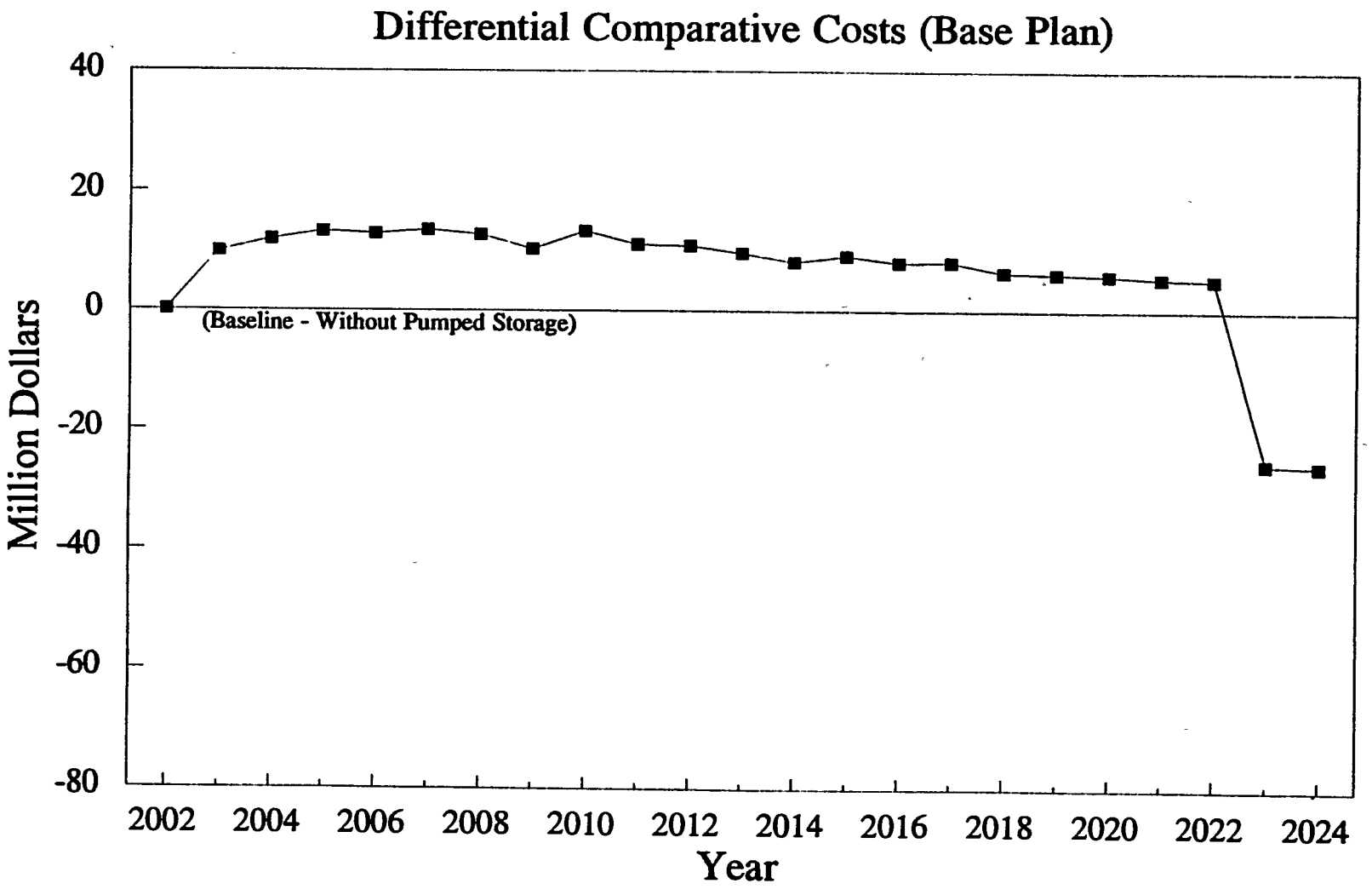

Differential Comparative Costs
Figure 1-1

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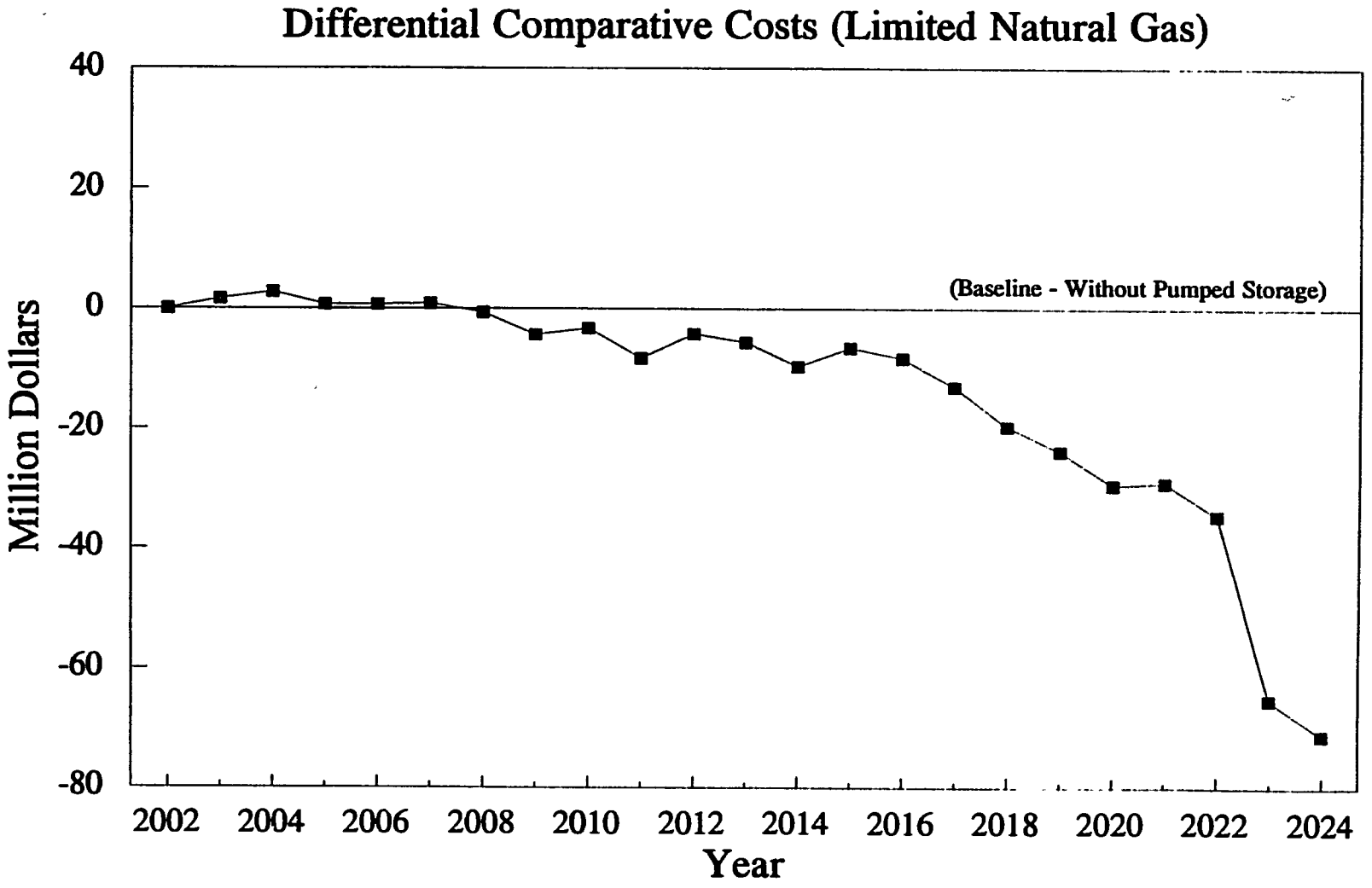

Differential Comparative Costs
Figure 1-2

2.0 Introduction

2.1 General

This report presents the results of Phase I of the Pump Storage Hydroelectric Power Station Study (Study). The Study was performed for the United States Agency for International Development (USAID) in conjunction with the Government of the Arab Republic of Egypt acting through the Egyptian Electricity Authority (EEA) and the Hydro Power Plant Executive Authority (HPPEA). HPPEA is designated for planning and implementation of construction projects related to hydraulic generation of electric energy. Upon completion of a hydroelectric power station, the facilities are transferred to EEA for operation and maintenance. The Study was performed by Ebasco Overseas Corporation (Ebasco) in association with Black & Veatch International (BVI), Sheladia Associated, Inc., Arab Consulting Engineers, and Sabbour Associates. Phases II and III of the Study, if approved by USAID, will be performed later.

2.2 Background

The basic concept of pumped storage hydro involves pumping water from a lower reservoir for storage into an upper reservoir, and then generating electricity by using the same water flowing from the upper reservoir through turbine generators back into the lower reservoir. The cycle is repeated on a daily or weekly basis.

The economic benefit of pumped storage comes from pumping with low-cost off-peak energy (generally at night) and generating on peak to displace high-cost energy. Since both pumping and generating cycles involve inefficiencies, the net result is a loss of energy in the overall pumped storage cycle. If the total cycle efficiency is greater than the ratio of low-cost to high-cost energy, then there is the potential for fuel cost savings. Additional production costs may be saved by such things as reduced operation and maintenance costs, reduced unit startup costs, reliability enhancement, voltage and VAR support, load following, and a reduced spinning reserve requirement. However, for pumped storage to be economical, sufficient production costs must be saved to cover the capital cost and other fixed costs associated with the project.

HPPEA is contemplating the construction of a 600 MW pumped storage hydro power station on the west side of the Gulf of Suez. A number of sites are under consideration at this time. Site selection is the subject of Phase II of the study.

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Several alternative pumped storage development schemes have been considered. For the purpose of this study, the closed cycle type of development has been assumed. Makeup water will be obtained from the Gulf of Suez and will be desalinated.

2.3 Methodology

2.3.1 General

The study identifies electricity production costs associated with the optimal expansion plan without pumped storage through the year 2024. Production costs include fuel and O&M costs as well as capital costs for any new generation projects incorporated. Production costs are modeled by POWRPRO which is described in Appendix A. The optimal pumped storage hydroelectric power station expansion plan is evaluated against the production and capital costs of the optimal non-pumped storage expansion plan. The basis for the economic evaluation is a comparison of the cumulative present worth of total annual cost for both plans through the study period.

2.3.2 Existing and Committed Facilities

Section 3.0 describes the existing and committed facilities on the Unified Power System (UPS), which includes both thermal and hydroelectric generation. Section 3.0 also describes units which are committed to be in operation by the year 2000. Appendix B describes the existing transmission system and substations.

2.3.3 Load Forecast

The load forecast is the basis for the generation capacity expansion plan and the production costs required to serve future UPS requirements. EEA provided the load forecast that was used as the base case. A description of the load forecast methodology is given in Section 4.0.

2.3.4 Load Model Development

Section 5.0 describes the process which was undertaken to build an hourly load file for the study period. The hourly load file is developed using historical hourly load data and the projected fiscal year peak de nand and energies.

2.3.5 Capacity Expansion Requirements

Section 6.0 discusses the capacity expansion requirements through 2024. Capacity expansion is based on the load forecast, existing unit retirements, and a 20 percent reserve margin.

2.3.6 Evaluation Criteria

Evaluation criteria including economic assumptions and fuel price projections are provided in Section 7.0. The economic criteria were used to determine fixed costs associated with various capacity addition projects. The fuel cost projections were based on estimates made by the World Bank . The fuel cost projections were used during production cost modeling to calculate total system fuel costs associated with the optimal generation expansion plans with and without pumped storage.

2.3.7 Generation Expansion Alternatives

Section 8.0 describes various types of generation which were tested to economically satisfy future generation requirements. This section provides capital costs as well as all operating characteristics required for production cost modeling.

2.3.8 Economic Evaluation

Section 9.0 contains the economic evaluation which compares the optimal generation expansion plans with and without the pumped storage project. Initially, optimal expansion plans without pumped storage were developed. The optimum expansion plans without pumped storage were developed considering both production costs and financing costs associated with new generation additions. The production cost model POWRPRO was used to provide production cost, including fuel, operation and maintenance, and startup costs. POWRPRO is a chronological (hourly) production cost model which has the ability to model pumped storage generation units.

The pumped storage expansion plans were then developed. These plans also included both production costs and capital costs. Costs in future years were discounted by the present worth factor. The optimal generation expansion plans with and without the pumped storage unit were compared on the basis of 30 years of present worth production and financing costs (1995 through 2024).

The optimal expansion plans with and without the pumped storage project were also evaluated for sensitivity to changes in certain selected parameters.

2.4 Dynamic Benefits of Pumped Storage

Section 10.0 discusses the dynamic benefits of pumped storage:

- Reduced spinning reserve.
- Load following enhancement.
- Unit commitment savings.
- Reduced system minimum loading.
- Voltage and power factor correction.
- Frequency regulation.
- Reduced thermal plant cycling.
- Improved system reliability.

The value for the dynamic benefits is estimated in Section 10.0.

2.5 Environmental Evaluation

Section 11.0 presents the benefits and environmental effects of the combustion turbine versus pumped storage alternatives. The differences in social and economical impacts between combustion turbine construction and pumped storage construction are also considered.

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3.0 Description of Existing Capacity

The Unified Power System (UPS) consists of approximately 11,330 MW of installed capacity. Approximately 24 percent (2,715 MW) is hydro; the remaining 76 percent (approximately 8,615 MW) is fossil fueled. Only about 9,462 MW is available to serve load because of unit derates and average available water flow.

3.1 Thermal Units

The UPS oil and gas fueled facilities consist of steam and combustion turbine units. Approximately 18 percent is combustion turbine capacity, and the remainder is steam capacity. A summary of the units including size, fuel type, commercial operation date, and projected date of retirement is provided in Table 3-1.

3.2 Hydroelectric Resources

Hydro facilities for the UPS consist of a block of capacity located in the Upper Egypt zone. The block consists of 13 units at the Aswan Dam and 12 units at the High Dam. Approximately 2,045 MW of hydroelectric capacity is available during an average water year. A summary of the units, including size and commercial operation date, is provided in Table 3-1. The hydroelectric resource model for the study is described in Appendix C.

3.3 Committed Capacity Expansion Plan

UPS committed generation expansion plan consists of adding approximately 5,194 MW of capacity by 2000. Approximately 13 percent (690 MW) of the capacity additions consist of converting existing combustion turbines to combined cycle; 3.5 percent (184 MW) consists of new hydroelectric unit resources. The remainder of the additions consist of natural gas and heavy oil fueled steam units. Summaries of the committed generation expansion plan and projected hydroelectric unit additions are provided in Table 3-2 and Table 3-3.

Table 3-4 presents the derivation of the total new capacity for 1993. Table 3-4 shows one new unit (Tulkha Ext 1) and three combined cycle conversions (Demiatta 1, 2, and 3) in 1993, for a total net available capacity of 1,293.3 MW. However, the existing Demiatta GTs 1 through 6 were converted into combined cycle units. Thus, 615 MW must be subtracted from 1,293.3 MW to provide a net increase of 681.3 MW in 1993.

Similarly, Tables 3-5 and 3-6 present the net increase in capacity for 1994 and 1995 respectively. Later years do not have any unit conversions so that net additions are simply taken from Table 3-2.

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Table 3-1
Summary of Capacity for the Unified Power System

Delta Zone							
Unit Name	Fuel Type	Gross Rated Capacity (MW)	Gross Available Capacity (MW)	Net Available Capacity (MW)*	Commercial Operation Date	Year of Conversion to Combined Cycle	Retirement Date
Kafar El Dawar 1	HFO	110	80	74.5	1980		2015
Kafar El Dawar 2	HFO	110	80	74.5	1980		2015
Kafar El Dawar 3	HFO	110	80	74.5	1984		2019
Kafar El Dawar 4	HFO	110	80	74.5	1986		2021
Talkha 4	HFO	30	25	23.5	1966		2001
Talkha 5	HFO	30	25	23.5	1966		2001
Talkha 6	HFO	30	25	23.5	1967		2002
Talkha CC 1	NG,HSD	284	230	222.9	1989		2014
Damanhour 1	HFO	15	10	9.3	1960		1995
Damanhour 2	HFO	15	10	9.3	1960		1995
Damanhour 3	NG,HFO	65	40	36.8	1968		2003
Damanhour 4	NG,HFO	65	40	36.8	1968		2003
Damanhour 5	NG,HFO	65	40	36.8	1969		2004
Damanhour 6	NG,HFO	300	270	255.0	1990		2025
Damanhour GT1	NG,HSD	24	20	19.5	1985	1994	2019
Damanhour GT2	NG,HSD	24	20	19.5	1985	1994	2019
Damanhour GT3	NG,HSD	24	20	19.5	1985	1994	2019
Damanhour GT4	NG,HSD	24	20	19.5	1985	1994	2019
Mahmoudia GT1	NG,HSD	45	36	35.1	1981		2001
Mahmoudia GT2	NG,HSD	45	36	35.1	1981		2001
Mahmoudia GT3	NG,HSD	45	36	35.1	1981		2001
Mahmoudia GT4	NG,HSD	45	36	35.1	1982		2002
Mahmoudia GT5	NG,HSD	24	20	19.5	1983	1994	2019
Mahmoudia GT6	NG,HSD	24	20	19.5	1983	1994	2019
Mahmoudia GT7	NG,HSD	24	20	19.5	1983	1994	2019
Mahmoudia GT8	NG,HSD	24	20	19.5	1983	1994	2019
Mahmoudia GT9	NG,HSD	24	20	19.5	1983	1994	2019
Mahmoudia GT10	NG,HSD	24	20	19.5	1983	1994	2019
Mahmoudia GT11	NG,HSD	24	20	19.5	1983	1994	2019

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Table 3-1 (Continued)
Summary of Capacity for the Unified Power System

Delta Zone (Continued)							
Unit Name	Fuel Type	Gross Rated Capacity (MW)	Gross Available Capacity (MW)	Net Available Capacity (MW)*	Commercial Operation Date	Year of Conversion to Combined Cycle	Retirement Date
Mahmoudia GT12	NG,HSD	24	20	19.5	1983	1994	2019
Demiatta 1	NG,HSD	125	105	102.5	1989	1993	2018
Demiatta 2	NG,HSD	125	105	102.5	1989	1993	2018
Demiatta 3	NG,HSD	125	105	102.5	1989	1993	2018
Demiatta 4	NG,HSD	125	105	102.5	1989	1993	2018
Demiatta 5	NG,HSD	125	105	102.5	1989	1993	2018
Demiatta 6	NG,HSD	125	105	102.5	1989	1993	2018
Delta Zone		2,559	2,049	1,964.8			

*Net available capacity is calculated by applying typical auxiliary load requirements to the gross available capacity ratings.

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Table 3-1 (Continued)
Summary of Capacity for the Unified Power System

Canal Zone							
Unit Name	Fuel Type	Gross Rated Capacity (MW)	Gross Available Capacity (MW)	Net Available Capacity (MW)*	Commercial Operation Date	Year of Conversion to Combined Cycle	Retirement Date
Abu Soltan 1	NG,HFO	150	135	127.5	1983		2018
Abu Soltan 2	NG,HFO	150	135	127.5	1983		2018
Abu Soltan 3	NG,HFO	150	135	127.5	1984		2019
Abu Soltan 4	NG,HFO	150	135	127.5	1986		2021
Attaka 1	NG,HFO	150	135	127.5	1985		2020
Attaka 2	NG,HFO	150	135	127.5	1985		2020
Attaka 3	NG,HFO	300	270	255.0	1987		2022
Attaka 4	NG,HFO	300	270	255.0	1989		2024
Suez 1	COAL,HFO	22	20	18.2	1965		2000
Suez 2	COAL,HFO	22	20	18.2	1965		2000
Suez 3	COAL,HFO	22	20	18.2	1965		2000
Suez 4	COAL,HFO	22	20	18.2	1965		2000
Suez 5	COAL,HFO	97	97	89.2	1990		2025
Suez GT1	NG,HFO	17	10	8.6	1976		1996
El Shabab GT1	NG,HSD	33	25	24.3	1982		2002
El Shabab GT2	NG,HSD	33	25	24.3	1982		2002
El Shabab GT3	NG,HSD	33	25	24.3	1982		2002
Port Said GT1	NG,HSD	21	16	15.6	1977		1997
Port Said GT2	NG,HSD	23	16	15.5	1977		1997
Ismailia GT1	HSD	20	16	15.6	1977		1997
Canal Zone		1,866	1,660	1,565.6			

*Net available capacity is calculated by applying typical auxiliary load requirements to the gross available capacity ratings.

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Table 3-1 (Continued)
Summary of Capacity for the Unified Power System

Alexandria Zone							
Unit Name	Fuel Type	Gross Rated Capacity (MW)	Gross Available Capacity (MW)	Net Available Capacity (MW)*	Commercial Operation Date	Year of Conversion to Combined Cycle	Retirement Date
Abu Kir 1	NG,HFO	150	135	127.5	1983		2018
Abu Kir 2	NG,HFO	150	135	127.5	1983		2018
Abu Kir 3	NG,HFO	150	135	127.5	1984		2019
Abu Kir 4	NG,HFO	150	135	127.5	1984		2019
Abu Kir 5	NG,HFO	300	270	255.0	1991		2026
El Siouf 1	HFO	27	23	21.7	1961		1996
El Siouf 2	HFO	27	23	21.7	1961		1996
El Siouf 3	HFO	30	23	21.5	1969		2004
El Siouf 4	HFO	30	23	21.5	1969		2004
El Siouf GT1	NG,HSD	20	22	21.6	1980		2000
El Siouf GT2	NG,HSD	33	22	21.3	1981		2001
El Siouf GT3	NG,HSD	33	22	21.3	1981		2001
El Siouf GT4	NG,HSD	33	22	21.3	1982		2002
El Siouf GT5	NG,HSD	33	22	21.3	1983		2003
El Siouf GT6	NG,HSD	33	22	21.3	1983		2003
El Siouf GT7	NG,HSD	33	22	21.3	1983		2003
Alexandria Zone		1233	1,056	1,001.0			

*Net available capacity is calculated by applying typical auxiliary load requirements to the gross available capacity ratings.

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Table 3-1 (Continued)
Summary of Capacity for the Unified Power System

Cairo Zone							
Unit Name	Fuel Type	Gross Rated Capacity (MW)	Gross Available Capacity (MW)	Net Available Capacity (MW)*	Commercial Operation Date	Year of Conversion to Combined Cycle	Retirement Date
Shoubra 1	NG,HFO	315	300	284.3	1984		2019
Shoubra 2	NG,HFO	315	300	284.3	1985		2020
Shoubra 3	NG,HFO	315	300	284.3	1985		2020
Shoubra 4	NG,HFO	315	300	284.3	1988		2023
Shoubra GT1	NG	35	0	0.0	1986		2006
Cairo West 1	HFO	88	75	70.6	1966		2001
Cairo West 2	HFO	88	75	70.6	1966		2001
Cairo West 3	HFO	88	75	70.6	1966		2001
Cairo West 4	HFO	88	75	70.6	1979		2014
Cairo South 3	HFO	60	55	52.0	1957	REHAB 93	2003
Cairo South 4	HFO	60	55	52.0	1957	1995	2020
Cairo South 5	HFO	60	55	52.0	1965	1995	2020
Cairo South 6	HFO	60	55	52.0	1965	1995	2020
Cairo South GT1	NG,HSD	110	90	87.8	1989	1995	2020
Cairo South GT2	NG,HSD	110	90	87.8	1989	1995	2020
Cairo South GT3	NG,HSD	110	90	87.8	1989	1995	2020
El Tebbin 1	HFO	15	13	12.3	1958		1993
El Tebbin 2	HFO	15	13	12.3	1958		1993
El Tebbin 3	HFO	15	13	12.3	1959		1994
El Tebbin GT1	NG,HSD	23	20	19.5	1979		1999
El Tebbin GT2	NG,HSD	23	20	19.5	1979		1999
Heliopolis GT1	NG,HSD	13	10	9.8	1980		2000
Heliopolis GT2	NG,HSD	13	10	9.8	1980		2000
Heliopolis GT3	NG,HSD	13	10	9.8	1980		2000
Helwan GT1	NG,HSD	24	20	19.5	1980		2000
Helwan GT2	NG,HSD	24	20	19.5	1980		2000
Helwan GT3	NG,HSD	24	20	19.5	1980		2000
Helwan GT4	NG,HSD	24	20	19.5	1980		2000
Helwan GT5	NG,HSD	24	20	19.5	1980		2000

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Table 3-1 (Continued)
Summary of Capacity for the Unified Power System

Cairo Zone (Continued)							
Unit Name	Fuel Type	Gross Rated Capacity (MW)	Gross Available Capacity (MW)	Net Available Capacity (MW)*	Commercial Operation Date	Year of Conversion to Combined Cycle	Retirement Date
Wadi Houf GT1	NG,HSD	33	27	26.3	1985		2005
Wadi Houf GT2	NG,HSD	33	27	26.3	1985		2005
Wadi Houf GT3	NG,HSD	33	27	26.3	1985		2005
Cairo Zone		2,564	2,280	2,172.6			

*Net available capacity is calculated by applying typical auxiliary load requirements to the gross available capacity ratings.

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Table 3-1 (Continued)
Summary of Capacity for the Unified Power System

Upper Egypt Zone							
Unit Name	Fuel Type	Gross Rated Capacity (MW)	Gross Available Capacity (MW)	Net Available Capacity (MW)*	Commercial Operation Date	Year of Conversion to Combined Cycle	Retirement Date
Assuit 1	HFO	30	24	22.5	1966		2001
Assuit 2	HFO	30	24	22.5	1967		2002
Assuit 3	HFO	30	24	22.5	1967		2002
Assuit EXT 1	NG,HFO	300	300	285.0	1992		2027
Aswan 1-1	Hydro	46			1960		
Aswan 1-2	Hydro	46			1960		
Aswan 1-3	Hydro	46			1960		
Aswan 1-4	Hydro	46			1960		
Aswan 1-5	Hydro	46			1960		
Aswan 1-6	Hydro	46			1960		
Aswan 1-7	Hydro	46			1960		
Aswan 1-8	Hydro	12			1960		
Aswan 1-9	Hydro	12			1960		
Aswan 2-1	Hydro	68			1985		
Aswan 2-2	Hydro	68			1985		
Aswan 2-3	Hydro	68			1985		
Aswan 2-4	Hydro	68			1985		
High Dam 1	Hydro	175			1967		
High Dam 2	Hydro	175			1967		
High Dam 3	Hydro	175			1967		
High Dam 4	Hydro	175			1968		
High Dam 5	Hydro	175			1968		
High Dam 6	Hydro	175			1969		
High Dam 7	Hydro	175			1969		
High Dam 8	Hydro	175			1969		
High Dam 9	Hydro	175			1970		

Table 3-1 (Continued)
Summary of Capacity for the Unified Power System

Upper Egypt Zone (Continued)							
Unit Name	Fuel Type	Gross Rated Capacity (MW)	Gross Available Capacity (MW)	Net Available Capacity (MW)*	Commercial Operation Date	Year of Conversion to Combined Cycle	Retirement Date
High Dam 10	Hydro	175			1970		
High Dam 11	Hydro	175			1970		
High Dam 12	Hydro	175	2045**	2045.0			
Upper Egypt Zone		3108	2417	2397.5			
Total All Zones		11,330	9,462	9,101.3			

*Net available capacity is calculated by applying typical auxiliary load requirements to the gross available capacity ratings.

**Total hydro.

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Table 3-2
Summary of Committed Capacity for the Unified Power System Through 2000

Unit Name	Fuel Type	Gross Rated Capacity (MW)	Gross Available Capacity (MW)	Net Available Capacity (MW)*	Commercial Operation Date	Retirement Date
Talkha EXT 1	NG,HFO	210	210	199.5	1993	2028
Talkha EXT 2	NG,HFO	210	210	199.5	1997	2032
Cairo West EXT 1	NG,HFO	300	300	285.0	1994	2029
Cairo West EXT 2	NG,HFO	300	300	285.0	1995	2030
Kurimat 1	NG,HFO	600	600	570.0	1996	2031
Kurimat 2	NG,HFO	600	600	570.0	1997	2032
Assuit EXT 2	NG,HFO	300	300	285.0	1995	2030
Demiatta CC1						
Demiatta 1 (existing)		125				
Demiatta 2 (existing)		125				
Steam Turbine (new)		125				
	NG	375	375	365.6	1993	2018
Demiatta CC2						
Demiatta 3 (existing)		125				
Demiatta 4 (existing)		125				
Steam Turbine (new)		125				
	NG	375	375	365.6	1993	2018
Demiatta CC3						
Demiatta 5 (existing)		125				
Demiatta 6 (existing)		125				
Steam Turbine (new)		125				
	NG	375	375	365.6	1993	2018
Cairo South CC1	NG	165	165	160.9	1995	2020
Cairo South CC2						
Cairo South GT1 (existing)		110				
Cairo South 4 (existing)		55				
	NG	165	165	160.9	1995	2020
Cairo South CC3						
Cairo South GT2 (existing)		110				
Cairo South 5 (existing)		55				
	NG	165	165	160.9	1995	2020
Cairo South CC4						
Cairo South GT2 (existing)		110				
Cairo South 6 (existing)		55				
	NG	165	165	160.9	1995	2020

*New available capacity is calculated by applying typical auxiliary load requirements to the gross available capacity ratings.

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Table 3-2 (Continued)
Summary of Committed Capacity for the Unified Power System Through 2000

Unit Name	Fuel Type	Gross Rated Capacity (MW)	Gross Available Capacity (MW)	Net Available Capacity (MW)*	Commercial Operation Date	Retirement Date
Damanhour CC1						
Damanhour GT 1 (existing)		24.2				
Damanhour GT 2 (existing)		24.2				
Damanhour GT 3 (existing)		24.2				
Damanhour GT 4 (existing)		24.2				
Steam Turbine (new)		50				
	NG	146.8	146.8	143.1	1994	2019
Mahmoudia CC1						
Mahmoudia GT5 (existing)		24.2				
Mahmoudia GT6 (existing)		24.2				
Mahmoudia GT7 (existing)		24.2				
Mahmoudia GT8 (existing)		24.2				
Mahmoudia GT9 (existing)		24.2				
Mahmoudia GT10 (existing)		24.2				
Mahmoudia GT11 (existing)		24.2				
Mahmoudia GT12 (existing)		24.2				
Steam Turbine (new)		100				
	NG	293.6	293.6	286.3	1994	2019
Sidi Krir 1	NG,HFO	300	300	285.0	1998	2033
Sidi Krir 2	NG,HFO	300	300	285.0	1998	2033
Sidi Krir 3	NG,HFO	300	300	285.0	1999	2034
Sidi Krir 4	NG,HFO	300	300	285.0	1999	2034
Ayoun Mousa 1	NG,HFO	300	300	285.0	2000	2035
Ayoun Mousa 2	NG,HFO	300	300	285.0	2000	2035

*Net available capacity is calculated by applying typical auxiliary load requirements to the gross available capacity ratings.

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Table 3-3
Projected Hydroelectric Unit Additions

Unit Name	Fuel Type	Gross Rated Capacity (MW)	Gross Available Capacity (MW)	Net Available Capacity (MW)	Commercial Operation Date	Retirement Date
Esna	Hydro	87		87.0	1994	
Naga Hammadi	Hydro	57		56.5	2003	
Assuit	Hydro	40		40.0	2010	

Table 3-4
1993 Capacity Additions

1993 Units	Net Available Capacity (MW)
Tulkha Ext 1[a]	199.5
Demiatta CC1[b]	365.6
Demiatta CC2[c]	365.6
Demiatta CC3[d]	365.6
Total Final Capacity	1,296.3
Converted Units	
Demiatta GT1	(102.5)
Demiatta GT2	(102.5)
Demiatta GT3	(102.5)
Demiatta GT4	(102.5)
Demiatta GT5	(102.5)
Demiatta GT6	(102.5)
Total Converted Capacity	(615)
Total New Capacity	681.3

[a]New unit.

[b]Conversion of Demiatta 1 and 2 GTs to CC1.

[c]Conversion of Demiatta 3 and 4 GTs to CC2.

[d]Conversion of Demiatta 5 and 6 GTs to CC3.

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Table 3-5
1994 Capacity Additions

1994 Units	Net Available Capacity (MW)
Cairo West Ext 1*	285.0
Esna (hydro)*	87.0
Damanhour CC1**	143.1
Mahmoudia CC1***	286.3
Total Final Capacity	801.4
Converted Units	
Damanhour GT1	(19.5)
Damanhour GT2	(19.5)
Damanhour GT3	(19.5)
Damanhour GT4	(19.5)
Mahmoudia GT5	(19.5)
Mahmoudia GT6	(19.5)
Mahmoudia GT7	(19.5)
Mahmoudia GT8	(19.5)
Mahmoudia GT9	(19.5)
Mahmoudia GT10	(19.5)
Mahmoudia GT11	(19.5)
Mahmoudia GT12	(19.5)
Total Converted Capacity	(234)
Total New Capacity	567.4

*New unit.

**Conversion of Damanhour 1 through 4 GTs to CC1.

***Conversion of Mahmoudia 5 through 12 GTs to CC1.

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Table 3-6
1995 Capacity Additions

1995 Units	Net Available Capacity (MW)
Cairo West Ext 1[a]	285.0
Assuit Ext 2[a]	285.0
Cairo South CC1[a]	160.9
Cairo South CC2[b]	160.9
Cairo South CC3[c]	160.9
Cairo South CC4[d]	160.9
Total Final Capacity	1,213.6
Converted Units	
Cairo South GT1	(87.8)
Cairo South Steam 4	(52.0)
Cairo South GT2	(87.8)
Cairo South Steam 5	(52.0)
Cairo South GT3	(87.8)
Cairo South Steam 6	(52.0)
Total Converted Capacity	(419.4)
Total New Capacity	794.2

[a]New unit.

[b]Conversion of Cairo South GT1 and Steam 4 to CC2.

[c]Conversion of Cairo South GT2 and Steam 5 to CC3.

[d]Conversion of Cairo South GT3 and Steam 6 to CC4.

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4.0 Load Forecast

4.1 General

The objective of the load forecast was to develop a projection of the Unified Power System's (UPS) annual net energy for load and peak demand for the study period. The expected (base case) load forecast is used as the basis for developing the generation expansion plan and evaluating the pumped storage hydroelectric project. EEA supplied Ebasco with three load forecast scenarios: a base medium scenario; a base medium adjusted scenario (adjusted for price elasticity impacts); and a base low scenario. These three load forecast scenarios are presented in Table 4-1 and shown graphically on Figure 4-1. The base medium adjusted scenario was used as the base case load forecast for this study. Hereafter, the base medium adjusted scenario will be referred to as the base load forecast. Ebasco also developed an alternate load forecast scenario to be used for sensitivity and risk analyses. The alternate load forecast is discussed in Section 4.5. Both the base and alternate load forecasts are shown on Figure 4-2. The following sections discuss the development of the base case and alternate load forecasts.

4.2 UPS Historical Data

The following sections present the UPS historical data that were used as the basis for EEA's load forecast.

4.2.1 Historical Sales

The load forecast developed by EEA is based on the following customer sectors:

- VHV (very high voltage) Industrial.
- Non-VHV Industrial.
- Agriculture.
- Public Utilities.
- Commercial.
- Residential.
- Government.

Table 4-2 lists the historical sales by customer sector and total UPS sales for Fiscal Years 1980/81 through 1990/91. The fiscal year is from the previous July 1 through the present June 30; i.e., fiscal 1993 is from July 1, 1992, through June 30, 1993. The historical sales data indicate that two customer sectors, residential and non-VHV industrial, make up a significant portion of the total UPS sales. Residen-

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tial sales accounted for approximately 33 percent of total UPS sales in 1990/91, while non-VHV sales accounted for approximately 29 percent.

4.2.2 Historical Growth

Table 4-3 lists the annual growth rates in sales for each customer sector and total UPS sales for Fiscal Years 1980/81 through 1990/91. Table 4-4 lists the average annual growth rates for each customer sector and total UPS sales and gross peak demand for the periods 1980/81 through 1985/86 and 1985/86 through 1990/91. The data in these tables indicate that EEA experienced significant average annual growth in the first half of the 1980s: 10.8 percent for total UPS sales and 11.0 percent for gross peak demand. However, the growth rates in the last half of the 1980s have been less: 6.7 percent for total UPS sales and 5.5 percent for gross peak demand. Total UPS sales increased by 5.2 percent during Fiscal Year 1990/91.

4.3 Baseload Forecast

This section briefly discusses the methodology and results of the baseload forecast developed by EEA.

4.3.1 Methodology

EEA developed their forecast of customer sector sales using RATS, a software package made available to EEA by Stone & Webster. RATS uses multiple linear regression to determine the historical relationships between customer sector electricity consumption and a set of econometric (independent) variables. The independent variables tested were population and gross domestic product (GDP) and the price of electricity. Other independent variables tested were variations of population and GDP, such as inverse population and GDP per population. Various regression relationship forms were tested, including direct linear, log-linear, and log-log.

Once the historical relationships were developed, customer sector sales were projected through Fiscal Year 2001/02, based on the regression equations and projections of the selected independent variables. Customer sector sales were then adjusted for electric tariff increases, according to their expected response to the tariff increases.

Total UPS sales were calculated as the sum of the customer sector sales adjusted for price elasticity impacts less isolated system (ISO) sales. UPS noncoincident peak demand was developed by an hours-use model, which computes a peak demand for

each customer sector on the basis of a projected hours-use value for each customer sector. Total system losses (transmission, distribution) and generation auxiliary consumption were also forecasted by EEA. Total UPS gross energy is the sum of total UPS sales plus total losses and generation auxiliary consumption. Total UPS coincident gross peak demand is the sum of all noncoincident peak demands for each customer sector plus total losses and generation auxiliary consumption, multiplied by a projected coincidence factor. This process resulted in EEA's projection of total UPS gross peak demand and energy through Fiscal Year 2001/02. EEA then used a trend projection to develop UPS gross demand and energy through Fiscal Year 2014/15.

4.3.2 Independent Variables

Table 4-5 lists the historical values of population and GDP used to develop the regression equations. EEA used RATS to test these independent variables to determine their significance in explaining historical customer sector electricity consumption.

4.3.3 Baseload Forecast (Gross)

Table 4-6 lists the results of the baseload forecast for the period from 1991/92 through 2014/15. Customer sector sales projections for this forecast are based on a projected GDP with an annual growth rate of 5.0 percent and the effect of rapidly increasing electricity prices. Table 4-6 lists the projections of total UPS sales, nonsales energy, and UPS gross energy and peak demand. Nonsales energy consists of transmission and distribution losses and generation auxiliary consumption.

4.3.4 Baseload Forecast (Net)

Table 4-7 lists the baseload forecast on a net basis. The gross demand and energy forecast was converted to net for the purpose of production cost modeling for UPS. Total UPS sales is total sector sales less sales to the isolated systems. The projection of net energy includes transmission and distribution losses, but not generation auxiliary consumption. HPPEA indicated that generation auxiliary consumption is 4.0 percent of total gross UPS energy. UPS net energy is UPS gross energy less the energy associated with generation auxiliary consumption. UPS net demand is UPS gross demand less the coincident demand associated with generation auxiliary consumption. Coincident demand for generation auxiliary consumption was

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calculated on the basis of EEA's assumptions for the hours-use and coincidence factor associated with this quantity.

4.3.5 Long-Range Baseload Forecast

The projections of UPS net demand and energy are extended through the Year 2025 to allow adequate time to assess the feasibility of pumped storage capacity on EEA's system. Table 4-8 lists the long-range base net load forecast. The long-range forecast after the Year 2014/15 is based on increasing UPS net energy at 4.50 percent, the same annual increase as for the Year 2014/15. The UPS net load factor was assumed to remain constant at 68.4 percent for this period. UPS net demand is calculated on the basis of the projections of net energy and net load factor.

4.4 Load Forecast Review

Ebasco reviewed the methodology and results of EEA's current peak demand and energy forecast. In addition, EEA asked Ebasco to attempt to develop a relationship between consumption and the price of electricity. The following sections discuss the review and the results of the price elasticity analysis.

4.4.1 Methodology Review

Ebasco reviewed the methodology used by EEA to prepare the load forecast. The use of econometric multiple linear regression coupled with an hours-use model is an acceptable methodology. In EEA's load forecasts, electricity consumption for all customer sectors is dependent solely on GDP based on regression study. Ebasco believes that while GDP may be a good measure of commercial and industrial activity, population or a combination of population and other variables may be a better indicator of residential consumption, especially if the statistical relationship is valid. However, the RATS model used by EEA is limited by its sole statistical significance (the Student test or t statistic). This limitation does not allow RATS to test for various combinations of independent variables; therefore, GDP was chosen as the best indicator of customer sector consumption.

4.4.2 Ebasco Methodology

Ebasco concentrated its efforts on the residential sector, since this is the largest consumer group. SPSSPC + Version 2.0, a commercially available statistical software package from SPSS Inc. was used to perform the analyses. SPSS is not a load forecasting package like RATS; rather, it is a statistical analysis package. SPSS per-

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forms most statistical calculations in addition to least squares multiple linear regression analysis.

The historical data were analyzed by multiple linear regression techniques to determine the statistical relationships between customer class consumption (dependent variable) and econometric and demographic (independent) variables such as population and GDP. The relationships (equations) developed by this method express changes in the dependent variable (such as commercial consumption) as a function of one or more influencing factors. The underlying assumption of these equations for projections is that the dependent variable will be affected in the future by the same key factors (independent variables) as in the past, and that the relationships will remain the same. Also, projections of the independent variables must be available in order to project the dependent variable into the future.

The historical relationship between the dependent and one independent variable developed by the method of simple least squares linear regression has the following form:

$$Y = a + bx + e,$$

where

Y = dependent variable,

a,b = coefficient terms,

x = independent variable, and

e = error term.

The line represented by a least squares equation represents the set of points that minimize the sum of the squares of the differences between the actual data and the points on the line. Multiple linear regression is an extension of this concept with additional independent variables and their corresponding coefficients.

An important consideration in regression analysis is the selection of variables. Independent variables are used to explain historical changes or variations in the dependent variable. Therefore, sufficient historical data for both dependent and independent variables must be available to develop a meaningful statistical relationship. Also, the independent variables must have the potential to be projected into the future, so that the equations developed can be used to project the dependent variable.

The statistical validity of equations developed by the technique of multiple linear regression must be tested. Some of the more common statistical tests are discussed below:

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- Adjusted R^2 is the coefficient of determination corrected for reduced degrees of freedom due to the inclusion of additional independent variables in the regression equation. The coefficient of determination is the proportion or percentage of variation in the dependent variable that is explained by the independent variables.
- The F statistic is a test of the significance of the relationship between the dependent variable and the entire set of independent variables.
- The Student test (t statistic) is used to evaluate the individual significance of the regression coefficients. This test is not a good measure of the overall significance if the regression relationship contains more than one independent variable.

4.4.3 Historical Independent Variables

Table 4-9 lists the historical independent variables used by Ebasco to develop equations for customer sector consumption. Actual residential rates were converted to constant 1990/91 values by Consumer Price Index deflators supplied by EEA.

4.4.4 Price Elasticity

Historical residential sector sales were tested for price elasticity. Price elasticity is the ratio of two percentages: a percent change in price causes a percent change in the amount of a product consumed. For example, if a 10 percent price increase caused a 1.0 percent decrease in use, then the price elasticity is minus 0.1. Price elasticity, as opposed to conservation, is a short-term phenomenon. It reflects the immediate reduction in use due to a price increase. Conservation includes the long-term effects of replacing existing equipment with more efficient equipment.

An additional consideration is that price elasticity changes through time. For instance, as the real price of electricity increases, it may be relatively easy for the consumer to reduce usage initially. However, each additional consumption reduction, for a corresponding real price increase, becomes more difficult. Therefore, the price elasticity generally decreases as the real price of the electricity continues to change, until a point is reached where there will be very little reduction in consumption with additional increases in the real price. Conversely, if the price of electricity decreases in real terms (as was the case in the 1980s for residential customers), then use should increase more rapidly than would otherwise be expected from additional customers alone. However, there is a saturation point where consumers would not use additional electricity even if the price were extremely low.

4.4.4.1 Residential Sector. A significant historical regression relationship relating residential sector consumption to the constant residential rate and population was developed. The equation has the following form:

Residential GWh = -15,914 + 532.92 * POP - 37.267 * RESRATE,

where

RESRATE = the residential rate in constant 1990/91 value,
POP = population in millions,
F statistic = 488.2, and
Adjusted R^2 = 0.9909.

The historical increase in residential consumption was caused by the combined impacts of both real price reductions and population increases. The effect of population increases must be removed in order to determine the impact of real price reductions on historical residential consumption. The residential consumption equation was used to estimate historical price elasticity by holding population constant and changing the real price of electricity. The equation was then used to hindcast (estimate the historical data) with the population parameter held constant at the 1981/82 value. This procedure provides an estimate of the increase in consumption due only to the decrease in the real price of electricity. The data indicate that the real residential rate decreased 56.6 percent from 1981/82 to 1990/91, and the consumption due to the price reductions alone increased by 36.4 percent. It was also noted that for similar decreases in the real price, subsequent consumption increases attributed to price decreases were smaller. This indicates that a saturation level was reached, beyond which consumption would not be very sensitive to further price reductions.

Estimates of the expected impact of increases in the real price of electricity on future residential consumption were based on the following assumption: consumption impacts due to real price increases are approximately the same as for real price decreases. Therefore, the full impact of real price increases on residential consumption would be realized at a real price point based on the historical relationship. In other words, the full impact of real price decreases was realized when the real price reached approximately 60 percent of the initial 1981/82 value. It is assumed that the full impact of real price increases on residential consumption will also reach a point of diminishing impact. The base value for residential rates in 1981/82 was 75.36 mill/kWh. It is estimated that the full impact will be realized at the point when the real price of electricity increases to approximately 120 mill/ kWh. After

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this point in the projection of residential consumption, the real price of electricity is held constant.

The impact of future real price increases on residential consumption is only an estimate. It is difficult to predict the human equation. Nonetheless, this is a method to determine the impact of price increases on consumption. The equation provides price elasticities from -0.10 to -0.35 for the period 1991/92 through 2000/01. These values fall within the published range of expected price elasticity values.

4.5 Alternate Load Forecast

This section discusses the alternate load forecast that will be used as a sensitivity analysis in this study. The alternate forecast was developed by substituting Ebasco's projection of residential sector consumption for the residential sector consumption in the baseload forecast. Ebasco's residential sector projection is based on the regression equation presented in Subsection 4.4.4.1.

4.5.1 Independent Variable Projections

Table 4-10 lists projections of the independent variables used to project residential sector sales. Population projections were based on data approved by the Central Agency for Public Mobilization and Statistics. The annual growth rate for population was assumed to be 2.80 percent in 1991/92. The annual growth rate was decreased by 0.10 percent each year until it coincided with the long-term population growth rate of 1.4 percent provided by the Central Agency for Public Mobilization and Statistics. The population growth rate reached 1.4 percent in Fiscal Year 2005/06.

The projected real price of electricity for the residential sector was provided by EEA. These real price increases are required to bring EEA rates in line with the actual cost of producing electricity. The projection of the real price for the residential sector becomes constant at 120 mill/kWh (approximately 60 percent above the 1980/81 constant value), at which point the impact of price on consumption is expected to have reached its maximum.

4.5.2 Alternate Forecast Results (Gross)

Table 4-11 lists the projection of UPS gross demand and energy for the alternate forecast. Total sector sales is the sum of Ebasco's residential consumption projection and the baseload forecast's consumption projections for the nonresidential customer sectors. Total UPS sales are total sector sales less sales to the isolated system. Total UPS nonsales energy (percent of gross generation) is projected by EEA and consists

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of transmission and distribution losses and generation auxiliary consumption. UPS gross generation is the sum of total UPS sales, losses, and generation auxiliary consumption. UPS gross peak demand is the sum of the noncoincident demands from each customer sector, system losses, and generation auxiliary consumption adjusted by an EEA forecasted coincidence factor. EEA projects noncoincident customer sector demands with an hours-use model.

The alternate forecast is similar to EEA's base low forecast, being approximately 1,200 MW lower in 2014/15. The alternate load forecast is intended to be used only for sensitivity analyses for this Study and is suitable for this purpose.

4.5.3 Alternate Forecast Results (Net)

Table 4-12 lists the alternate forecast on a net basis. The demand and energy associated with generation auxiliary consumption were removed from the gross demand and energy forecast to produce UPS net requirements. As in the baseload forecast, generation auxiliary consumption was assumed to be 4.0 percent of total gross generation. The remaining nonsales energy is for transmission and distribution losses.

4.5.4 Long-Range Alternate Projection

Table 4-13 lists the long-range projection of the alternate forecast. The long-range projection is based on increasing the net energy at 4.23 percent, the same annual increase as for the Year 2014/15. The UPS net load factor was assumed to remain constant at 68.1 percent. The load factors differ slightly from those in base net load forecast because the two load forecasts have different residential components. Calculations of UPS net demand are based on the projections of net energy and net load factor.

Table 4-1
EEA Gross Load Forecast Scenarios

Fiscal Year	Base Medium		Adjusted Base Medium*		Base Low	
	Energy (GWh)	Demand (MW)	Energy (GWh)	Demand (MW)	Energy (GWh)	Demand (MW)
1992/93	48,032	7,781	47,638	7,717	46,864	7,587
1993/94	50,985	8,282	49,909	8,106	48,996	7,952
1994/95	54,356	8,852	52,141	8,490	51,801	8,430
1995/96	58,320	9,520	54,499	8,895	54,747	8,930
1996/97	62,515	10,225	57,226	9,359	57,817	9,450
1997/98	67,282	11,043	60,550	9,938	61,347	10,063
1998/99	72,359	11,914	64,319	10,590	65,077	10,712
1999/00	77,736	12,834	68,722	11,346	68,974	11,389
2000/01	83,434	13,808	73,690	12,196	73,051	12,096
2001/02	89,414	14,826	79,067	13,110	77,260	12,822
2002/03	95,800	15,885	84,730	14,049	81,713	13,607
2003/04	102,410	16,981	90,576	15,018	86,207	14,356
2004/05	109,374	18,135	96,735	16,040	90,862	15,131
2005/06	116,702	19,350	103,216	17,114	95,678	15,933

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Table 4-1 (Continued)
EEA Gross Load Forecast Scenarios

Fiscal Year	Base Medium		Adjusted Base Medium*		Base Low	
	Energy (GWh)	Demand (MW)	Energy (GWh)	Demand (MW)	Energy (GWh)	Demand (MW)
2006/07	124,288	20,608	109,925	18,227	100,557	16,746
2007/08	132,118	21,906	116,851	19,375	105,484	17,566
2008/09	140,177	23,243	123,978	20,557	110,442	18,392
2009/10	148,448	24,614	131,293	21,770	115,412	19,219
2010/11	156,909	26,017	138,777	23,010	120,375	20,046
2011/12	165,382	27,422	146,271	24,253	125,310	20,868
2012/13	173,817	28,820	153,731	25,490	130,197	21,682
2013/14	182,160	30,204	161,110	26,713	135,015	22,484
2014/15	190,357	31,563	168,360	27,916	139,740	23,271

*Selected as the baseload forecast for the study.

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Table 4-2
Historical Customer Sector Sales, GWh

Fiscal Year	VHV	Non-VHV	Agricultural	Public	Commercial	Residential	Government	Total UPS*
1980/81	4,186	5,023	777	1,159	423	3,355	672	15,595
1981/82	4,139	5,514	836	1,324	564	4,124	723	17,223
1982/83	4,152	6,233	897	1,683	701	5,055	821	19,524
1983/84	4,774	6,688	1,007	1,739	885	6,237	929	22,179
1984/85	4,624	7,167	1,108	1,752	1,043	7,121	965	23,674
1985/86	4,910	7,903	1,197	1,964	1,194	8,059	983	26,092
1986/87	5,371	8,315	1,166	2,192	1,380	8,864	1,041	28,197
1987/88	5,935	8,838	1,221	2,207	1,441	9,844	1,051	30,349
1988/89	6,270	9,421	1,265	2,165	1,526	10,440	1,218	32,107
1989/90	6,629	10,011	1,299	2,403	1,679	11,220	1,229	34,257
1990/91	6,667	10,488	1,367	2,612	1,813	12,062	1,285	36,033

*Total sector sales less sales to the isolated system.

Table 4-3
Historical Customer Sector Annual Growth, percent

Fiscal Year	VHV	Non-VHV	Agricultural	Public	Commercial	Residential	Government	Total UPS*
1981/82	-1.1	9.8	7.6	14.2	33.3	22.9	7.6	10 4
1982/83	0.3	13.0	7.3	27.1	24.3	22.6	13.6	13.4
1983/84	15.0	7.3	12.3	3.3	26.2	23.4	13.2	13.6
1984/85	-3.1	7.2	10.0	0.7	17.9	14.2	3.9	6.7
1985/86	6.2	10.3	8.0	12.1	14.5	13.2	1.9	10.2
1986/87	9.4	5.2	-2.6	11.6	15.6	10.0	5.9	8.1
1987/88	10.5	6.3	4.7	0.7	4.4	11.1	1.0	7.6
1988/89	5.6	6.6	3.6	-1.9	5.9	6.1	15.9	5.8
1989/90	5.7	6.3	2.7	11.0	10.0	7.5	0.9	6.7
1990/91	0.6	4.8	5.2	8.7	8.0	7.5	4.6	5.2

*Total sector sales less sales to the isolated system.

Table 4-4
Historical Average Annual Growth, percent

Customer Sector	Period	
	1980/81 to 1985/86	1985/86 to 1990/91
VHV	3.2	6.3
Non-VHV	9.5	5.8
Agriculture	9.0	2.7
Public	11.1	5.9
Commercial	23.1	8.7
Residential	19.2	8.4
Government	7.9	5.5
Total UPS Sales*	10.8	6.7
UPS Peak**	11.0	5.5

*Total sector sales less sales to the isolated system.

**Gross system peak.

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Table 4-5 Historical Independent Variables		
Fiscal Year	GDP	Population (millions)
1980/81	42,752	42.11
1981/82	47,393	43.33
1982/83	50,931	44.50
1983/84	54,058	45.77
1984/85	57,643	46.99
1985/86	59,202	48.35
1986/87	60,702	49.86
1987/88	63,127	51.30
1988/89	64,688	52.92
1989/90	65,524	54.50
1990/91	67,490	56.20

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Table 4-6
Baseload Forecast of UPS Gross Demand and Energy

Fiscal Year	Total Sector Sales (GWh)	ISO Sales (GWh)	Total UPS Sales* (GWh)	Nonsales** (percent)	Total UPS Energy (GWh)	Total UPS Demand (MW)	UPS Load Factor
1992/93	39,961	374	39,587	16.9	47,638	7,717	0.7047
1993/94	41,973	449	41,524	16.8	49,909	8,106	0.7028
1994/95	43,973	539	43,433	16.7	52,141	8,490	0.7011
1995/96	46,099	647	45,452	16.6	54,499	8,895	0.6975
1996/97	48,560	776	47,783	16.5	57,226	9,359	0.6980
1997/98	51,270	650	50,620	16.4	60,550	9,938	0.6955
1998/99	54,335	500	53,835	16.3	64,319	10,590	0.6933
1999/00	57,939	350	57,589	16.2	68,722	11,346	0.6895
2000/01	62,026	200	61,826	16.1	73,690	12,196	0.6898
2001/02	66,517	100	66,417	16.0	79,067	13,110	0.6885
2002/03	71,173	0	71,173	16.0	84,730	14,049	0.6885
2003/04	76,084	0	76,084	16.0	90,576	15,018	0.6885
2004/05	81,257	0	81,257	16.0	96,735	16,040	0.6885
2005/06	86,702	0	86,702	16.0	103,216	17,114	0.6885

Table 4-6 (Continued)
Baseload Forecast of UPS Gross Demand and Energy

Fiscal Year	Total Sector Sales (GWh)	ISO Sales (GWh)	Total UPS Sales* (GWh)	Nonsales** (percent)	Total UPS Energy (GWh)	Total UPS Demand (MW)	UPS Load Factor
2006/07	92,337	0	92,337	16.0	109,925	18,227	0.6885
2007/08	98,154	0	98,154	16.0	116,851	19,375	0.6885
2008/09	104,142	0	104,142	16.0	123,978	20,557	0.6885
2009/10	110,286	0	110,286	16.0	131,293	21,770	0.6885
2010/11	116,573	0	116,573	16.0	138,777	23,010	0.6885
2011/12	122,867	0	122,867	16.0	146,271	24,253	0.6885
2012/13	129,134	0	129,134	16.0	153,731	25,490	0.6885
2013/14	135,332	0	135,332	16.0	161,110	26,713	0.6885
2014/15	141,422	0	141,422	16.0	168,360	27,916	0.6885

*Total sector sales less sales to the isolated system.

**Includes transmission and distribution losses, and generation auxiliary consumption.

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Table 4-7
Baseload Forecast of UPS Net Demand and Energy

Fiscal Year	Gross UPS Energy (GWh)	Gross UPS Demand (MW)	Generation Aux Consumption		Generation Aux Consumption Coincident with Peak (MW)*	Net UPS Energy (GWh)	Net UPS Demand (MW)
			(percent)	(GWh)			
1992/93	47,638	7,717	4.0	1,906	262	45,732	7,454
1993/94	49,909	8,106	4.0	1,996	275	47,913	7,831
1994/95	52,141	8,490	4.0	2,086	287	50,055	8,203
1995/96	54,499	8,895	4.0	2,180	300	52,319	8,595
1996/97	57,226	9,359	4.0	2,289	315	54,936	9,044
1997/98	60,550	9,938	4.0	2,422	334	58,128	9,604
1998/99	64,319	10,590	4.0	2,573	354	61,746	10,236
1999/00	68,722	11,346	4.0	2,749	379	65,973	10,968
2000/01	73,690	12,196	4.0	2,948	406	70,743	11,790
2001/02	79,067	13,110	4.0	3,163	436	75,905	12,675
2002/03	84,730	14,049	4.0	3,389	467	81,340	13,582
2003/04	90,576	15,018	4.0	3,623	499	86,953	14,519
2004/05	96,735	16,040	4.0	3,869	533	92,866	15,507

Table 4-7 (Continued)
Baseload Forecast of UPS Net Demand and Energy

Fiscal Year	Gross UPS Energy (GWh)	Gross UPS Demand (MW)	Generation Aux Consumption		Generation Aux Consumption Coincident with Peak (MW)*	Net UPS Energy (GWh)	Net UPS Demand (MW)
			(percent)	(GWh)			
2005/06	103,216	17,114	4.0	4,129	569	99,088	16,546
2006/07	109,925	18,227	4.0	4,397	605	105,528	17,621
2007/08	116,851	19,375	4.0	4,674	644	112,176	18,731
2008/09	123,978	20,557	4.0	4,959	683	119,019	19,874
2009/10	131,293	21,770	4.0	5,252	723	126,041	21,046
2010/11	138,777	23,010	4.0	5,551	764	133,226	22,246
2011/12	146,271	24,253	4.0	5,851	806	140,420	23,447
2012/13	153,731	25,490	4.0	6,149	847	147,581	24,643
2013/14	161,110	26,713	4.0	6,444	887	154,665	25,826
2014/15	168,360	27,916	4.0	6,734	927	161,625	26,988

*Based on hours-use of 6,100 and coincidence factor of 84 percent.

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Table 4-8
Long Range UPS Base Forecast

Fiscal Year	UPS Net Energy (GWh)	Net Load Factor (percent)	UPS Net Demand (MW)
2015/16	168,898	68.4	28,203
2016/17	176,499	68.4	29,472
2017/18	184,441	68.4	30,798
2018/19	192,741	68.4	32,184
2019/20	201,414	68.4	33,632
2020/21	210,478	68.4	35,146
2021/22	219,949	68.4	36,727
2022/23	229,847	68.4	38,380
2023/24	240,190	68.4	40,107
2024/25	250,998	68.4	41,912
2025/26	262,293	68.4	43,798

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Table 4-9
Historical Independent Variables

Fiscal Year	Population (millions)	Residential Electricity Rate (mill/kWh, constant 1990/91 value)
1980/81	42.11	--
1981/82	43.33	75.36
1982/83	44.50	68.55
1983/84	45.77	61.56
1984/85	46.99	53.71
1985/86	48.35	58.37
1986/87	49.86	48.07
1987/88	51.30	42.90
1988/89	52.92	37.24
1989/90	54.50	33.64
1990/91	56.20	32.66

Table 4-10
Independent Variable Projection

Fiscal Year	Population (millions)	Residential Electricity Rates (mill/kWh, constant 1990/91 value)
1992/93	59.33	45.20
1993/94	60.88	56.40
1994/95	62.40	70.40
1995/96	63.90	87.80
1996/97	65.37	109.50
1997/98	66.80	120.00
1998/99	68.21	120.00
1999/00	69.57	120.00
2000/01	70.89	120.00
2001/02	72.17	120.00
2002/03	73.39	120.00
2003/04	74.57	120.00
2004/05	75.69	120.00
2005/06	76.75	120.00
2006/07	77.82	120.00
2007/08	78.91	120.00
2008/09	80.02	120.00
2009/10	81.14	120.00
2010/11	82.27	120.00
2011/12	83.42	120.00
2012/13	84.59	120.00
2013/14	85.78	120.00
2014/15	86.98	120.00

Table 4-11
Alternate Load Forecast of UPS Gross Demand and Energy

Fiscal Year	Total Sector Sales (GWh)	ISO Sales (GWh)	Total UPS Sales* (GWh)	Nonsales** (percent)	Total UPS Energy (GWh)	Total UPS Demand (MW)	UPS Load Factor
1992/93	40,229	374	39,855	16.9	47,960	7,769	0.7047
1993/94	41,658	449	41,209	16.8	49,530	8,045	0.7028
1994/95	42,863	539	42,324	16.7	50,809	8,273	0.7011
1995/96	44,020	647	43,373	16.6	52,006	8,512	0.6975
1996/97	45,107	776	44,331	16.5	53,091	8,683	0.6980
1997/98	46,802	650	46,152	16.4	55,205	9,061	0.6955
1998/99	49,113	500	48,613	16.3	58,080	9,563	0.6933
1999/00	51,780	350	51,430	16.2	61,373	10,161	0.6895
2000/01	54,757	200	54,557	16.1	65,026	10,762	0.6898
2001/02	57,980	100	57,880	16.0	68,905	11,425	0.6885
2002/03	61,329	0	61,329	16.0	73,011	12,123	0.6875
2003/04	64,820	0	64,820	16.0	77,167	12,858	0.6851
2004/05	68,458	0	68,458	16.0	81,498	13,551	0.6866

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Table 4-11 (Continued)
Alternate Load Forecast of UPS Gross Demand and Energy

Fiscal Year	Total Sector Sales (GWh)	ISO Sales (GWh)	Total UPS Sales* (GWh)	Nonsales** (percent)	Total UPS Energy (GWh)	Total UPS Demand (MW)	UPS Load Factor
2005/06	72,249	0	72,249	16.0	86,011	14,308	0.6862
2006/07	76,189	0	76,189	16.0	90,701	15,093	0.6860
2007/08	80,274	0	80,274	16.0	95,564	15,903	0.6860
2008/09	84,499	0	84,499	16.0	100,594	16,740	0.6860
2009/10	88,858	0	88,858	16.0	105,783	17,603	0.6860
2010/11	93,341	0	93,341	16.0	111,121	18,491	0.6860
2011/12	97,872	0	97,872	16.0	116,515	19,389	0.6860
2012/13	102,427	0	102,427	16.0	121,937	20,291	0.6860
2013/14	106,981	0	106,981	16.0	127,359	21,193	0.6860
2014/15	111,508	0	111,508	16.0	132,748	22,090	0.6860

*Total sector sales less sales to the isolated system.

**Includes transmission and distribution losses, and generation auxiliary consumption.

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Table 4-12
Alternate Load Forecast of UPS Net Demand and Energy

Fiscal Year	Gross UPS Energy (GWh)	Gross UPS Demand (MW)	Generation Aux Consumption		Generation Aux Cons Coinc Peak (MW)*	Net UPS Energy (GWh)	Net UPS Demand (MW)
			(percent)	(GWh)			
1992/93	47,960	7,769	4.0	1,918	264	46,041	7,505
1993/94	49,530	8,045	4.0	1,981	273	47,549	7,772
1994/95	50,809	8,273	4.0	2,032	280	48,776	7,993
1995/96	52,006	8,512	4.0	2,080	286	49,926	8,225
1996/97	53,091	8,683	4.0	2,124	292	50,967	8,390
1997/98	55,205	9,061	4.0	2,208	304	52,997	8,757
1998/99	58,080	9,563	4.0	2,323	320	55,757	9,243
1999/'00	61,373	10,161	4.0	2,455	338	58,918	9,822
2000/01	65,026	10,762	4.0	2,601	358	62,425	10,404
2001/02	68,905	11,425	4.0	2,756	380	66,148	11,045
2002/03	73,011	12,123	4.0	2,920	402	70,091	11,721
2003/04	77,167	12,858	4.0	3,087	425	74,080	12,433
2004/05	81,498	13,551	4.0	3,260	449	78,238	13,102

Table 4-12 (Continued)
Alternate Load Forecast of UPS Net Demand and Energy

Fiscal Year	Gross UPS Energy (GWh)	Gross UPS Demand (MW)	Generation Aux Consumption		Generation Aux Cons Coinc Peak (MW)*	Net UPS Energy (GWh)	Net UPS Demand (MW)
			(percent)	(GWh)			
2005/06	86,011	14,308	4.0	3,440	474	82,570	13,834
2006/07	90,701	15,093	4.0	3,628	500	87,073	14,593
2007/08	95,564	15,903	4.0	3,823	526	91,742	15,376
2008/09	100,594	16,740	4.0	4,024	554	96,571	16,186
2009/10	105,783	17,603	4.0	4,231	583	101,552	17,020
2010/11	111,121	18,491	4.0	4,445	612	106,676	17,879
2011/12	116,515	19,389	4.0	4,661	642	111,854	18,747
2012/13	121,937	20,291	4.0	4,877	672	117,060	19,620
2013/14	127,359	21,193	4.0	5,094	702	122,264	20,492
2014/15	132,748	22,090	4.0	5,310	731	127,438	21,359

*Based on hours-use of 6,100 and coincidence factor of 84 percent.

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Table 4-13
Long-Range UPS Alternate Forecast

Fiscal Year	UPS Net Energy (GWh)	Net Load Factor (percent)	UPS Net Demand (MW)
2015/16	132,831	68.1	22,263
2016/17	138,452	68.1	23,205
2017/18	144,311	68.1	24,187
2018/19	150,418	68.1	25,210
2019/20	156,783	68.1	26,277
2020/21	163,418	68.1	27,389
2021/22	170,333	68.1	28,548
2022/23	177,541	68.1	29,756
2023/24	185,054	68.1	31,016
2024/25	192,885	68.1	32,328
2025/26	201,047	68.1	33,696

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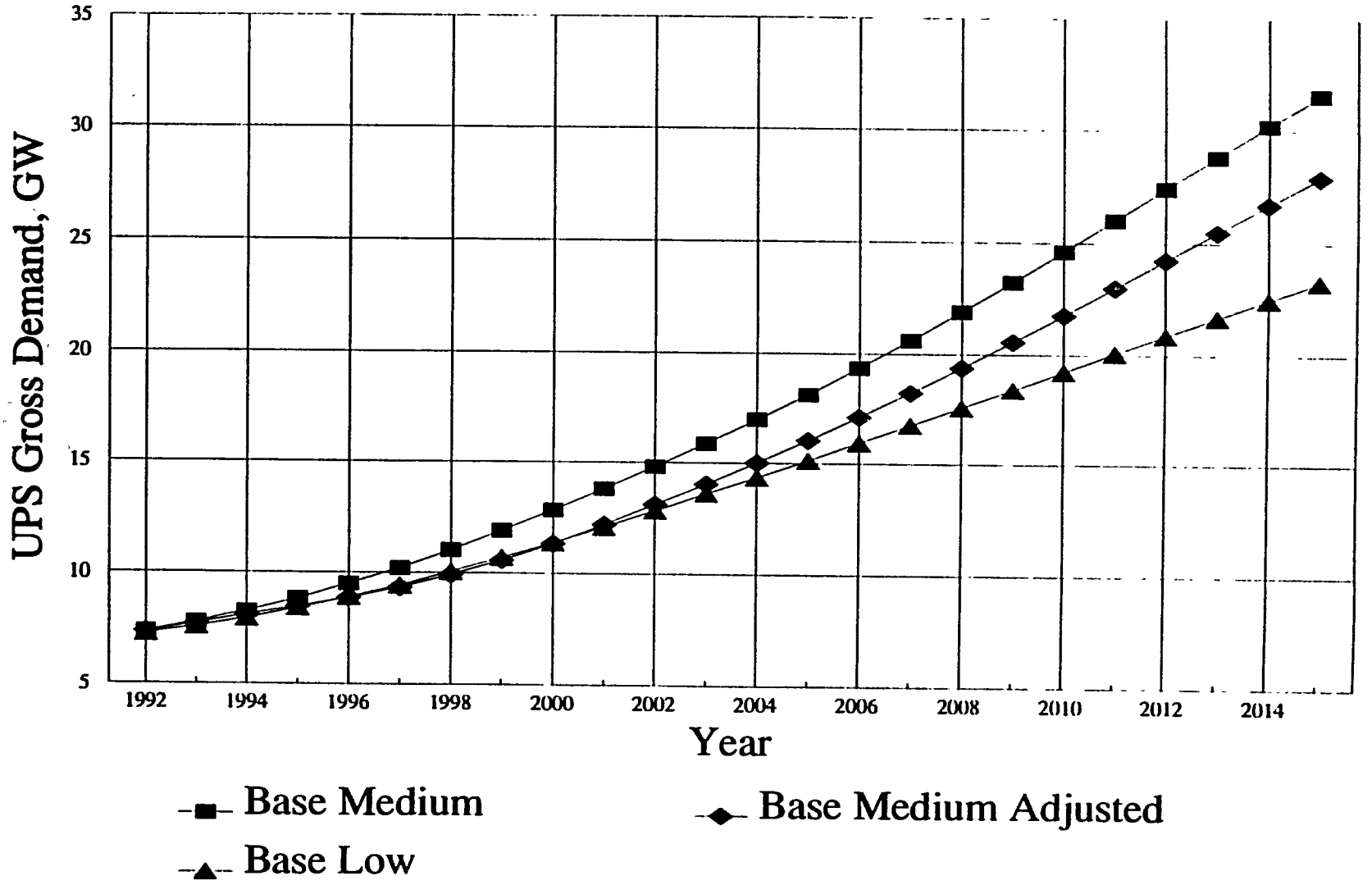
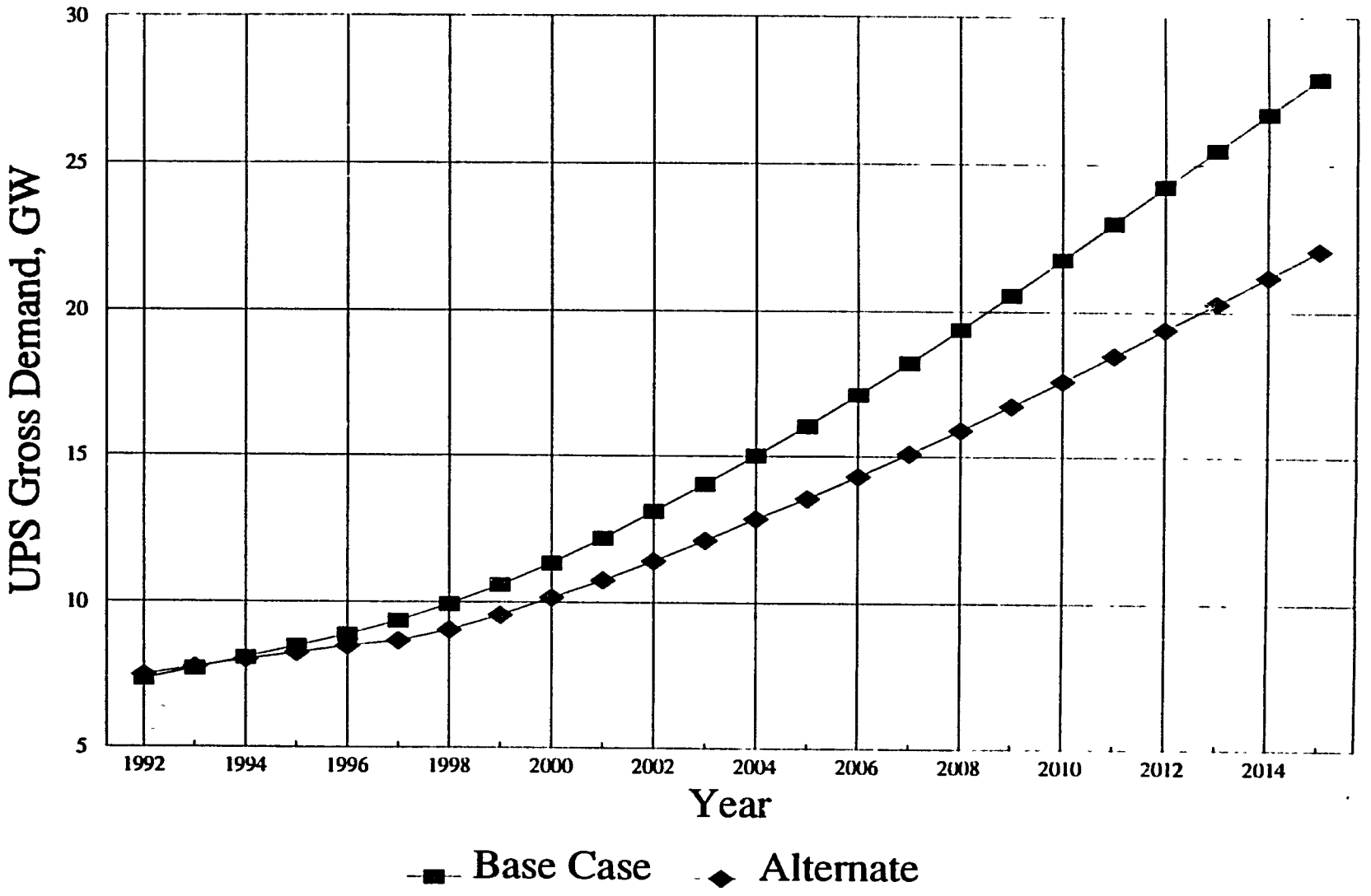


EEA Load Forecasts
Figure 4-1



Study Load Forecasts
Figure 4-2

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5.0 Load Model Development

5.1 General

Historical load data were used to develop a load model used by the production cost program. EEA provided 10 years of monthly historical data and 5 years of hourly historical data.

The chronological production cost program POWRPRO was used in the economic evaluation for this Study. POWRPRO requires a system hourly load file as input. This hourly load model contains the projected hour by hour system loads for the entire study period. The program LMODEL was used to create the UPS hourly load model for this Study. The following sections briefly discuss the data requirements, procedure, and results for the development of the UPS hourly load model for this Study.

5.2 Load Duration Curves

Five years of hourly load data were supplied by EEA. These data were supplied on a calendar year basis, but were converted to a fiscal year basis. When data were converted from calendar to fiscal year, the first half of 1987 and the last half of 1991 were lost. The data were sufficient to provide four years of hourly fiscal year historical data.

Load duration curves representing the four fiscal years, 1988 through 1991, are presented on Figures 5-1 through 5-4. The load duration curves represent the percent of time that the load is at or above a certain percent of the peak annual load. The hourly loads for the entire year are sorted from highest to lowest and plotted as shown on the figures. The UPS load duration curves represented on Figures 5-1 through 5-4 are relatively flat, indicating a high load factor.

5.3 Data Requirements

The minimum input data requirements for LMODEL are one year of historical hourly loads and a projection of annual demand and energy through the study period. LMODEL can use up to 10 years of historical monthly demand and energy data and five years of hourly load data, if available.

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5.4 Hourly Load Model

The program LMODEL was used to develop a projected hourly load demand file. The following sections describe the procedure used by LMODEL to create the UPS hourly load demand used as input for the production cost model POWRPRO.

5.4.1 Selecting a Typical Year

The first step performed by LMODEL is to select a typical (most normal) year from the available historical data. LMODEL computes the load factor for all months of historical data, then calculates the average load factor for all Januarys, Februarys, etc. LMODEL then finds the specific January in the historical data with a load factor closest to the average for all Januarys. This is done for all 12 months and results in the typical year, a collection of months that are the most typical according to the historical data. This collection of typical months is the basis for the hourly load profile shapes through the study period.

5.4.2 Allocating Monthly Demand and Energy

In the next step, LMODEL determines the representative distribution of month-to-month demand and energies. LMODEL determines the relative magnitude of demand and energy for each month according to the available historical data. The procedure is applied to the historical monthly demands and energies and consists of normalizing, averaging, and ranking to identify typical month-to-month relationships of demand and energy. The results of this step determine the relative magnitude of monthly demands and energies in the hourly load profile created by LMODEL.

5.4.3 Creating the Load Model

LMODEL creates a base year by adjusting the typical year defined in Subsection 5.3.1 to the annual demand and energy of the first simulation year and the month-to-month relative distributions defined in Subsection 5.3.2. The remaining years are obtained by adjusting this base year to new specified annual demands and energies. In basic terms, the base year is adjusted by changing all hourly demands by the ratio of new peak to old, then adjusting off-peak hours to obtain the desired load factor. This results in an hourly load model for each year of the study period with monthly load shapes and relative demands and energies based on the typical patterns in the historical data.

5.5 UPS Load Profile

The UPS base net load forecast developed in Section 4.0 is on a fiscal year basis, so the load model was also developed on a fiscal year basis. EEA provided Ebasco with historical monthly demand and energy data and hourly load data on a calendar year basis. Ebasco converted these data to a fiscal year basis by combining the appropriate months. For example, EEA's fiscal year 1992 is from July 1, 1991, through June 30, 1992. Using fiscal year historical data and a fiscal year load forecast as input, LMODEL created a fiscal year hourly load model.

The fiscal year hourly load model was converted to a calendar year hourly load model by removing the first six months, July through December, from the beginning of the load model file. Since a calendar year is six months out of phase with a fiscal year, calendar year demands and energies are not the same as for fiscal years.

5.6 Load Duration Curve for 2005

A load duration curve for the calendar year 2005 was developed from the hourly load data produced for 2005 by LMODEL. Figure 5-5 presents the load duration curve for 2005.

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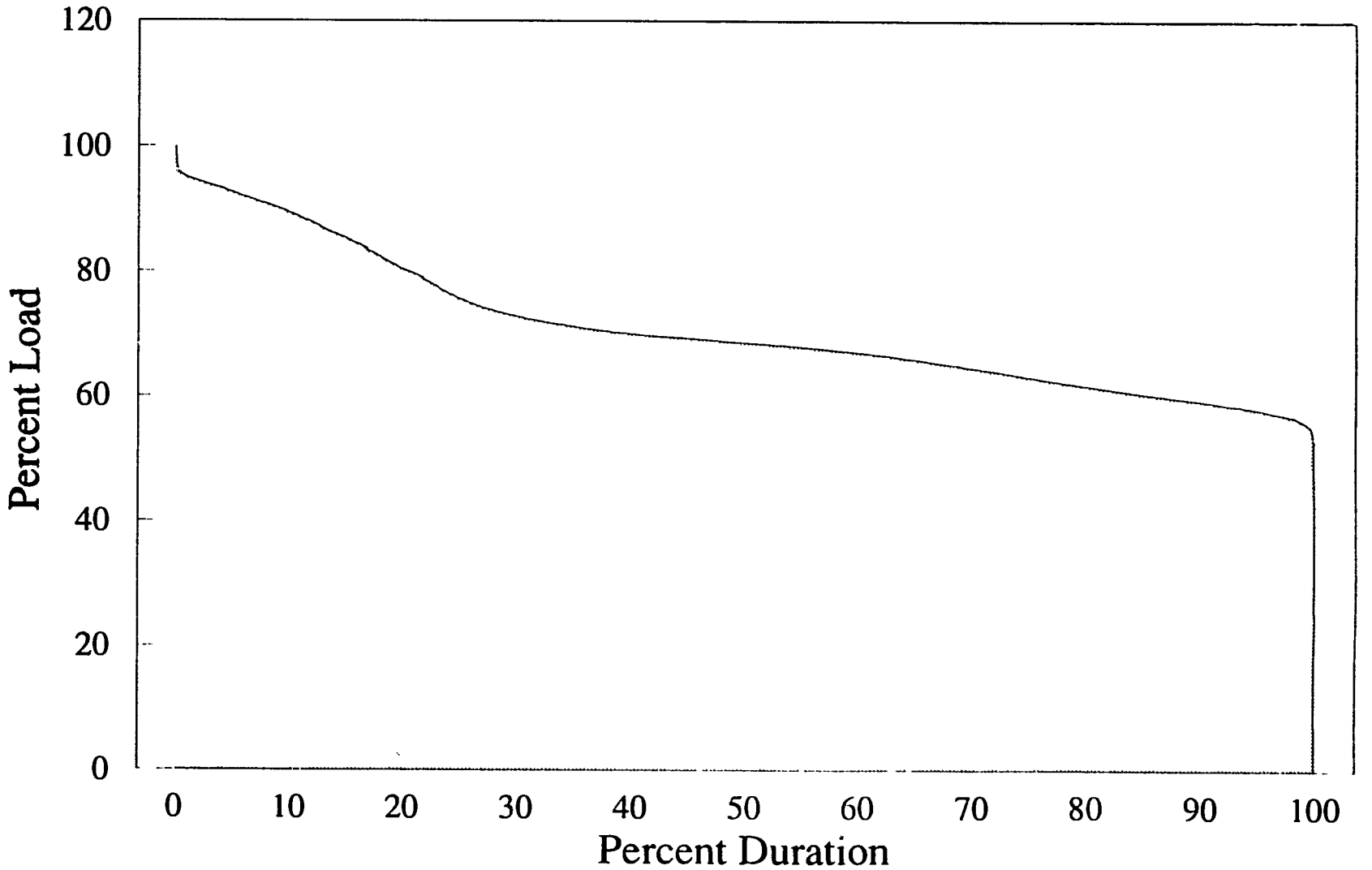
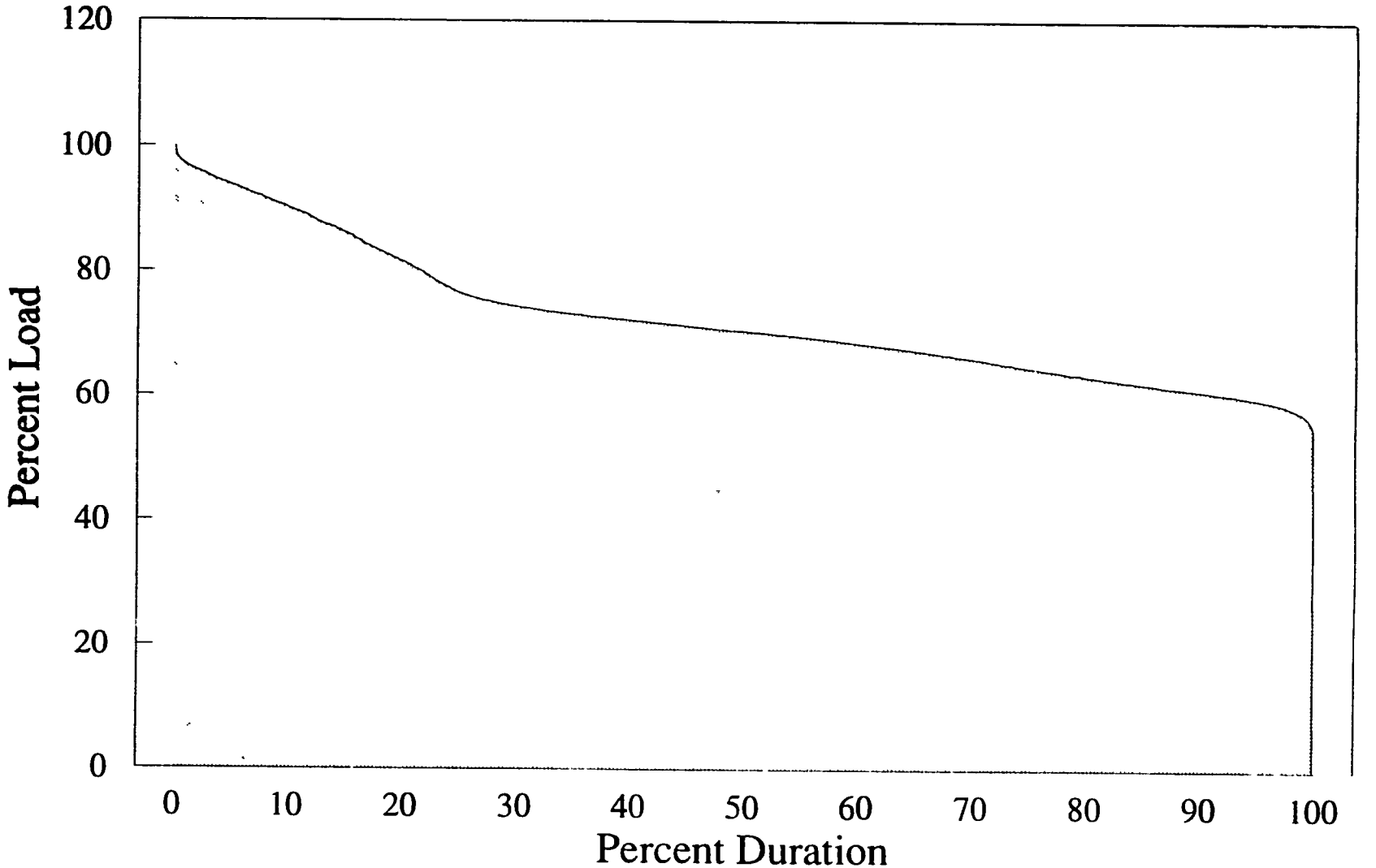
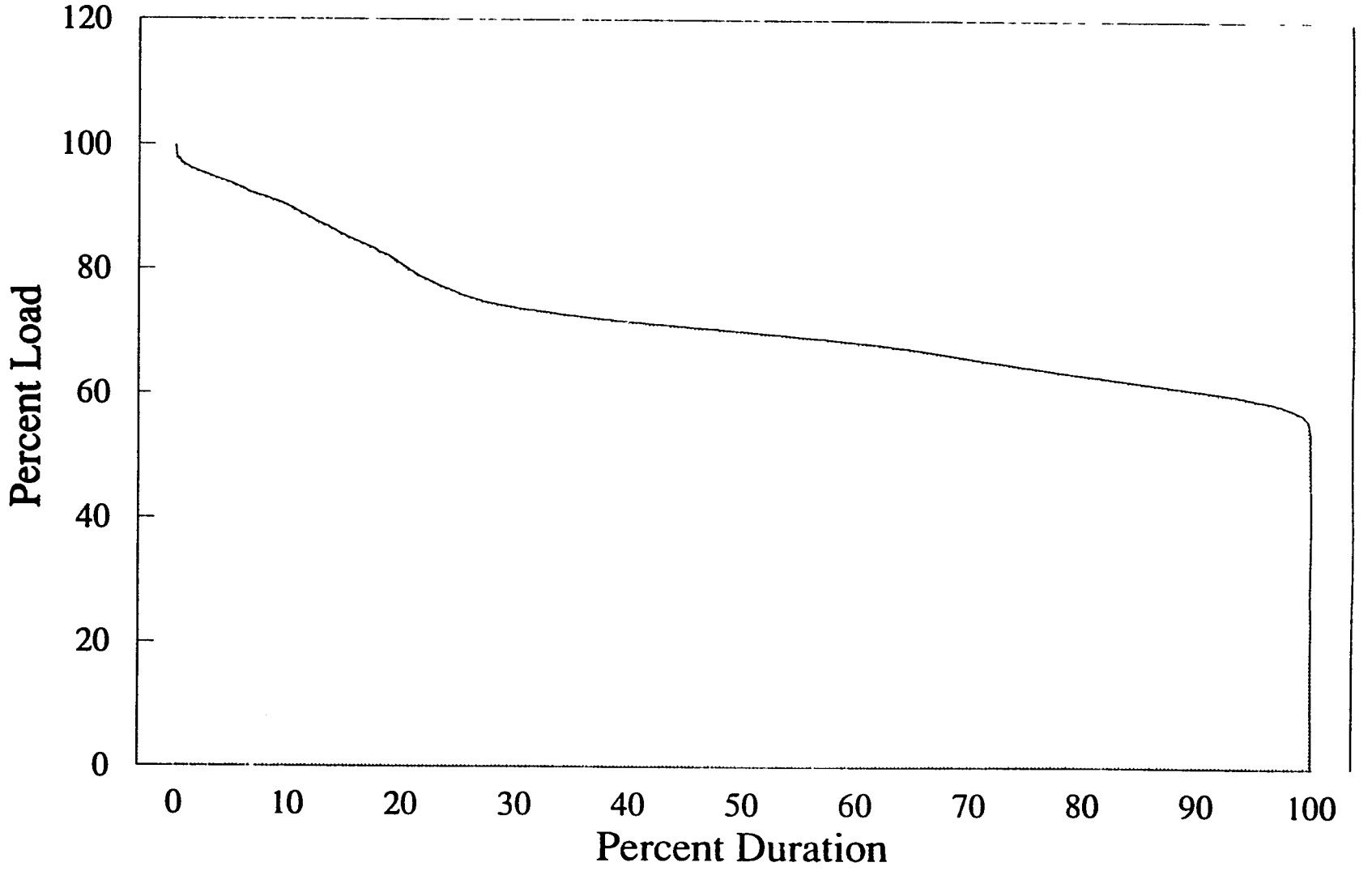


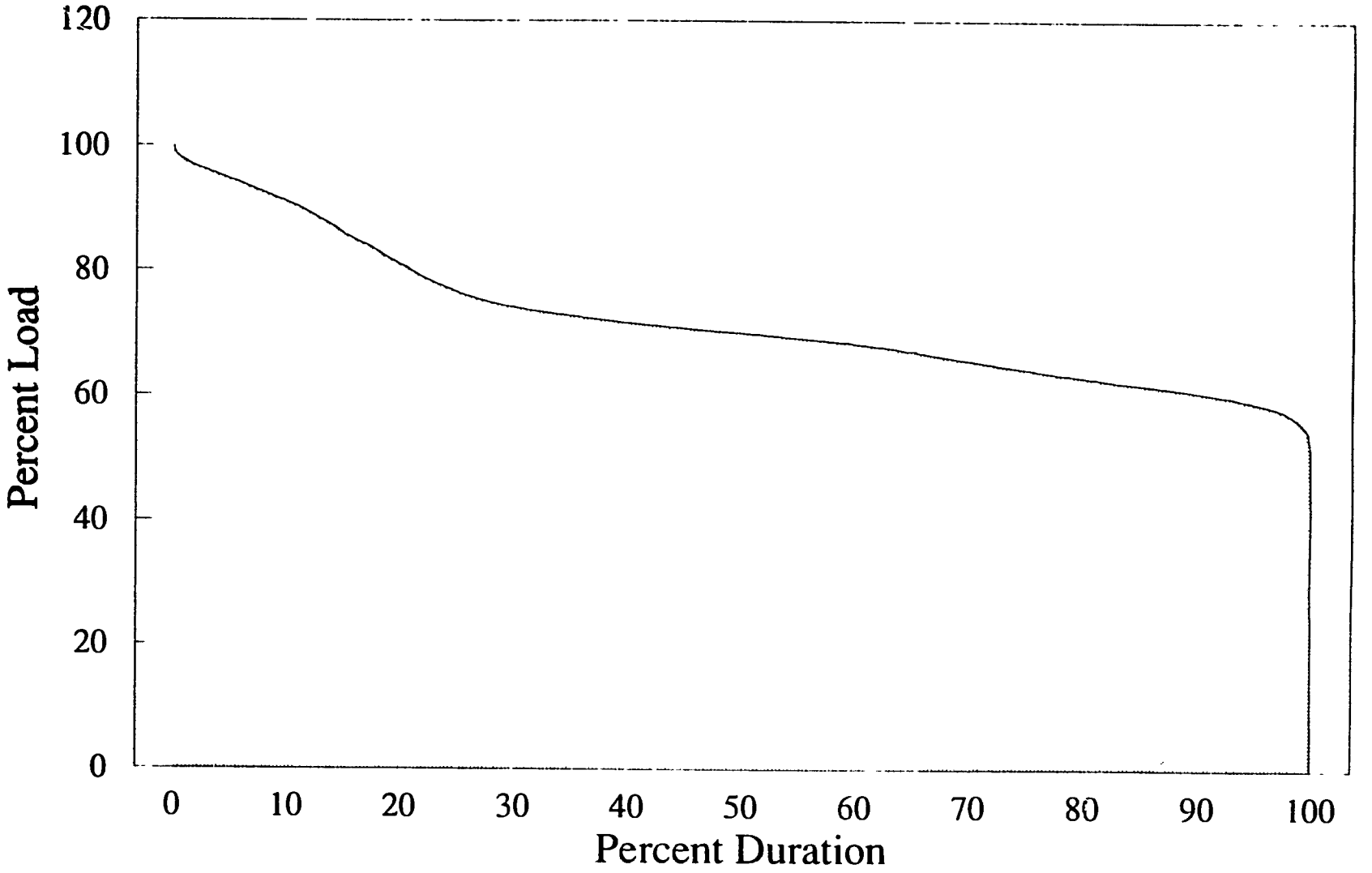
Fiscal Year 1988 (July 1, 1987 - June 30, 1988)
Load Duration Curve
Figure 5-1



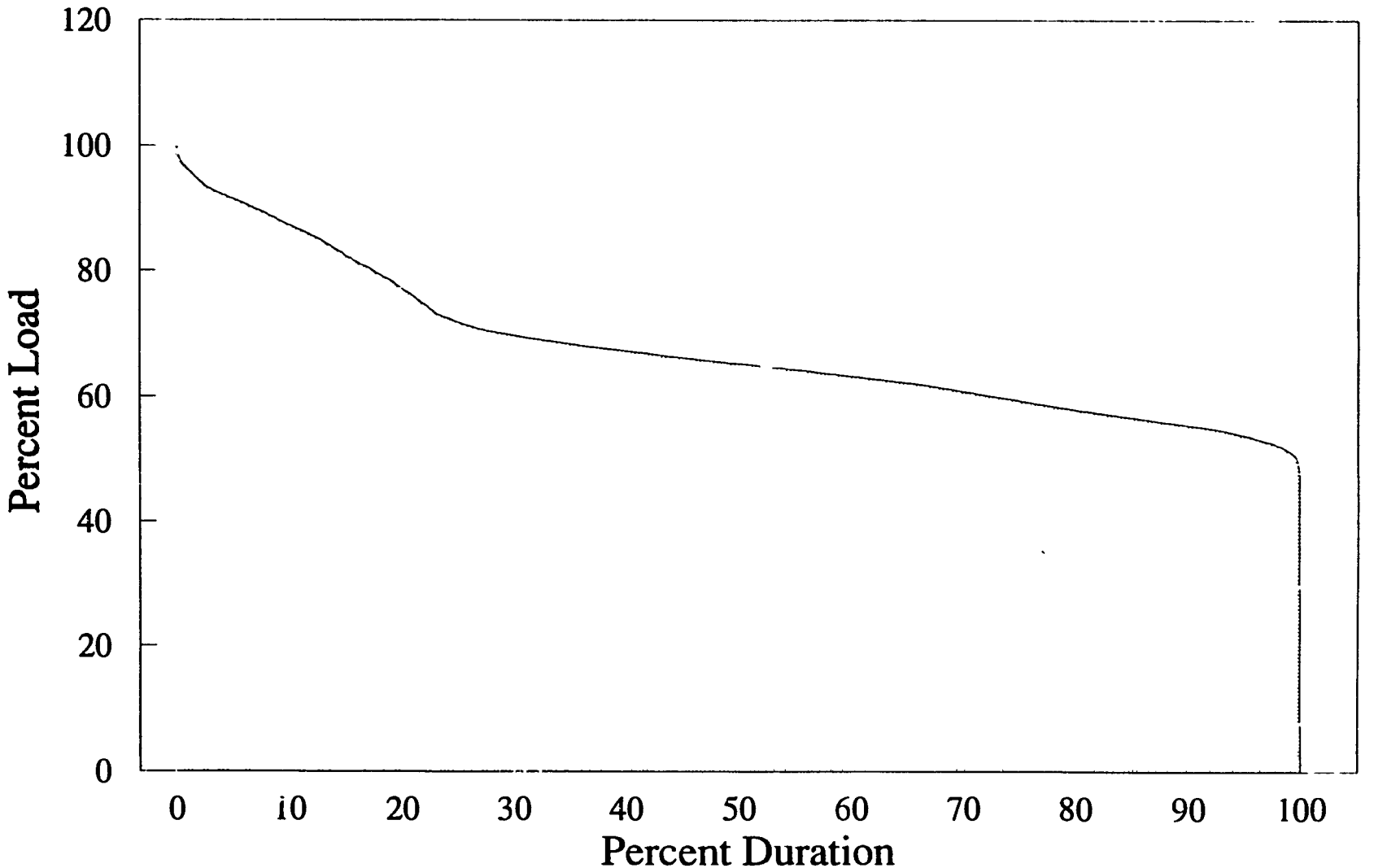
Fiscal Year 1989 (July 1, 1988 - June 30, 1989)
Load Duration Curve
Figure 5-2



Fiscal Year 1990 (July 1, 1989 - June 30, 1990)
Load Duration Curve
Figure 5-3



Fiscal Year 1991 (July 1, 1990 - June 30, 1991)
Load Duration Curve
Figure 5-4



Calendar Year 2005 Load Duration Curve
Figure 5-5

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6.0 Capacity Fxpansion Requirements

Table 6-1 presents the capacity expansion requirements for the UPS throughout the study period. Projected capacity expansion requirements are based on the UPS load forecast, reserve margin requirements, existing UPS capacity, and expected unit retirement dates.

As presented in Section 5.0, an hourly load model was created on the basis of the baseload forecast of UPS net demand and energy. The capacity expansion requirements were developed from the load model. Although EEA is historically a winter peaking system, the combination of a relatively high summer peak and degradation of unit performance due to temperature makes the summer months critical with respect to capacity requirements. A review of temperature data complied by the United States Air Force for the Cairo area shows the mean frequency of occurrence of temperatures greater than 100 F to be the highest in the month of June. Therefore, the peak demand for June was selected for determining capacity expansion requirements.

The total UPS capacity requirement is the sum of the June peak and reserve margin requirements. A capacity reserve margin of 20 percent was provided by EEA for use in this study.

Total UPS available capacity for any one year is UPS existing capacity plus committed and required unit additions that would be operational by then, less the capacity associated with units projected to be retired by then. The information regarding existing UPS capacity and projected retirements is presented in Section 3.0. Annual capacity excess or deficit is total available UPS capacity less total capacity requirements. Table 6-1 indicates that the UPS will require approximately 41,000 MW of additional capacity through the year 2024.

Table 6-1
UPS Capacity Expansion Requirements

Year	Net UPS Summer Peak Demand (MW) [a]	Reserve Margin (MW) [b]	Total UPS Requirements (MW)	UPS Existing Capacity (MW)	Projected Retirements (MW)	Committed Unit Additions (MW)	Total UPS Capacity (MW)	Capacity Excess (Deficit) (MW)
1993	7,454	1,491	8,945	9,101.3	25	681.3[c]	9,758	813
1994	7,831	1,566	9,397		12	567.4[d]	10,313	916
1995	8,203	1,641	9,844		19	794.2[e]	11,089	1,245
1996	8,595	1,719	10,314		52	570[f]	11,607	1,293
1997	9,044	1,809	10,853		47	769.5[f]	12,330	1,477
1998	9,604	1,921	11,525		0	570[f]	12,900	1,375
1999	10,236	2,047	12.283		39	570[f]	13,431	1,147
2000	10,968	2,194	13,162		221	570[f]	13,779	618
2001	11,790	2,358	14,148		429	0	13,350	(798)
2002	12,675	2,535	15,210		198	0	13,152	(2,058)
2003	13,582	2,716	16,298		190	56.5[g]	13,019	(3,279)
2004	14,519	2,904	17,423		80	0	12,939	(4,484)
2005	15,507	3,101	18,608		79	0	12,860	(5,748)
2006	16,546	3,309	19,855		0	0	12,860	(6,995)
2007	17,621	3,524	21,145		0	0	12,860	((8,285)
2008	18,731	3,746	22,477		0	0	12,8[illegible]	((9,617)
2009	19,874	3,975	23,849		0	0	12,860	(10,989)
2010	21,046	4,209	25,255		0	40.0[g]	12,900	(12,355)
2011	22,246	4,449	26,695		0	0	12,900	(13,795)
2012	23,447	4,689	28,136		0	0	12,900	(15,236)
2013	24,643	4,929	29,572		0	0	12,900	(16,671)
2014	25,826	5,165	30,991		294	0	12,607	(18,384)
2015	26,988	5,398	32,386		149	0	12,458	(19,928)
2016	28,203	5,641	33,844		0	0	12,458	(21,386)

Table 6-1 (Continued)
UPS Capacity Expansion Requirements

Year	Net UPS Summer Peak Demand (MW) [a]	Reserve Margin (MW) [b]	Total UPS Requirements (MW)	UPS Existing Capacity (MW)	Projected Retirements (MW)	Committed Unit Additions (MW)	Total UPS Capacity (MW)	Capacity Excess (Deficit) (MW)
2017	29,472	5,894	35,366		0	0	12,458	(22,909)
2018	30,798	6,160	36,958		1,607	0	10,851	(26,107)
2019	32,184	6,437	38,621		1,171	0	9,680	(28,941)
2020	33,632	6,726	40,358		1,467	0	8,213	(32,145)
2021	35,146	7,029	42,175		202	0	8,011	(34,164)
2022	36,727	7,345	44,072		255	0	7,756	(36,316)
2023	38,380	7,676	46,056		284	0	7,472	(38,584)
2024	40,107	8,021	48,128		255	0	7,217	(40,912)

[a] June peak demand. (see Table 4-7)

[b] Reserve margin is 20 percent of June peak demand.

[c] See Table 3-4.

[d] See Table 3-5.

[e] See Table 3-6.

[f] See Table 3-2.

[g] See Table 3-3.

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7.0 Evaluation Criteria

This section presents the assumptions used as the basis for the economic evaluation of the pumped storage project as part of the UPS. Evaluation criteria include both economic evaluation criteria as well as the fuel price forecast.

7.1 Economic Criteria

7.1.1 Inflation Rate

The inflation rates used for this study were provided by EEA and are listed below:

Fiscal Year	Local Component percent	Foreign Component percent
1993	15.0	2.2
1994	9.0	1.7
1995	6.0	2.5
1996 and thereafter	5.0	3.1

An expected foreign inflation rate of 3.1 percent is used for 1996 and thereafter. The local inflation rate is projected to be 5 percent for 1996 and thereafter. These numbers were used to develop future capital costs for generation alternatives based on the foreign and local content. In the long run, the percent difference in inflation rates is theoretically expected to equal the percent increase in exchange rate. Therefore, the exchange rate is not used in the report and is not included in the economic criteria.

7.1.2 Escalation Rate

This study assumes that the escalation rate for capital costs and operation and maintenance (O&M) costs are the same as the inflation rate. The capital cost escalation rates are used to adjust capital costs for new capacity additions to their commercial operation dates. The escalation rates will also be applied to the pumped storage project capital cost estimate.

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7.1.3 Interest Rate

The interest rate is the cost of capital at which new capacity additions will be financed during the evaluation. The cost of capital is composed of foreign and local components. The interest rate for the base scenario is 7-1/2 percent for a commercial loan from foreign sources. It is assumed that 60 percent of foreign sources will be from commercial loans, and 40 percent will be from soft loans with interest rates of 3 percent. The interest rate for a local loan is assumed to be 12 percent.

It is further assumed that both foreign and local loans will have the same financing terms (e.g., 5 year grace period and 15 year payback period). The terms are assumed to be the same for all projects.

For the lower interest rate sensitivity analysis, the 60 percent hard loan is assumed to be 6.5 percent.

7.1.4 Present Worth Discount Rate

The present worth discount rate is used to evaluate various alternatives on a present worth basis. This discount rate is the average cost of money to UPS for all projects which is assumed to consist of 80 percent foreign and 20 percent local loans. This provides a discount rate of 6.96 percent which was used for the base cases, and 6.48 percent is used for the lower interest rate sensitivity case.

7.1.5 Interest During Construction

Interest during construction (IDC) is used to acquire capital during the construction phases of a project. The IDC rate is determined as the weighted cost of money, and is therefore dependent on the percentage of foreign and local plant content for each type of plant. The IDC rate is expressed as a per annum percent and is therefore independent of the construction period. Table 7-1 presents the IDC rate for the various generation technologies for the base case. Table 7-2 presents the IDC rate for the lower interest rate sensitivity analysis.

7.1.6 Fixed Charge Rate

The fixed charge rate is a factor used to convert a capital cost to an equivalent uniform annual series of payments over the life of the project. A levelized fixed charge rate for each type of plant was calculated for use in the economic evaluation based on consideration of the loan type described for Egypt in Subsection 7.1.3. The fixed charge rates were calculated from the cash flows which were determined by the financing terms, interest rates, and percent foreign and domestic plant content. The

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levelized fixed charge rate is properly used in engineering economic studies because it produces the same present worth of revenue requirements as the actual cash flows determined by the financing terms and allocates the capital charges over the life of the plant.

The fixed charge rate calculations are included in Appendix D. The fixed charge rates are summarized in Tables 7-1 and 7-2 and for the base cases are 6.83 percent for CTs, 6.41 percent for CCs, 6.36 percent for steam units, and 5.75 percent for the pumped storage project. The fixed charge rate for a nuclear plant as used in the screening analysis is calculated to be 6.03 percent.

7.2 Fuel Price Forecast

A fuel price forecast was developed for this Study and used to determine the electricity generation production costs associated with future UPS requirements. A fuel price forecast was developed for mazout (No. 6 oil), solar (No. 2 oil), natural gas, coal, and nuclear fuels. Fuel used for electrical generation is presently subsidized by the government. These subsidies are expected to be gradually reduced through 1996, at which time fuel will be valued at the international (border) price.

The fuel price forecast used for this study is shown in Table 7-3. The forecasts for oil and coal are based on estimates made by the World Bank and published in "Price Prospects for Major and Primary Commodities, 1990-2005." The World Bank forecast provides annual constant dollar price projections for coal and petroleum through 1995. Long range projections are also provided for the years 2000 and 2005. The constant dollar values provided by the World Bank were converted to nominal dollars based on the international inflation rates provided in Subsection 7.1.1. World Bank staff in Washington, DC, were contacted concerning extending their projections through the year 2025. The World Bank indicated that no real price increases for coal or petroleum are expected after 2005. Therefore, these prices were increased at the international inflation rate after 2005.

No. 6 oil prices were estimated from the World Bank projections for crude oil. No. 6 oil is a residual byproduct of the distillation of crude oil; therefore, its value was assumed to be approximately 75 percent of the price of crude oil. No. 2 oil is a product of the distillation process; therefore, its value was assumed to be 130 percent of crude oil.

Currently, the production of natural gas is insufficient to supply all of the generation requirements of UPS. Therefore, No. 6 oil is also used for generation, reducing the amount available for export. It is unknown whether future natural gas

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supplies will be sufficient to meet all generation requirements. However, No. 6 oil is assumed to be the backup fuel for natural gas and will be used in the event of natural gas shortages. Since natural gas will displace the use of No. 6 oil, the international (shadow) price of natural gas is assumed to be equivalent to the value of No. 6 oil.

The coal price forecast was also based on projections of the World Bank. The constant dollar forecast was adjusted for the international inflation rate presented in Subsection 7.1.1.

The nuclear fuel price forecast is based on present values and an analysis of the current nuclear fuel market situation. Currently, the nuclear fuel market is depressed as nuclear fuel production capabilities are greater than demand. This situation is expected to continue. Some nuclear fuel production facilities are expected to be removed from active operation. However, these facilities could be reactivated with minimal expense as demand increases. In addition, expended nuclear fuel, which is presently being stored, could be reprocessed, providing an economical supply of fuel. Finally, fast breeder reactors are expected to be available by approximately 2010, also reducing the demand for conventional nuclear fuel. On the basis of these considerations, the price of nuclear fuel for this study is escalated at the international inflation rate from its present value.

For sensitivity analysis it was assumed that the natural gas and oil prices escalation rates would be one percent per year higher than the base case. The sensitivity analysis natural gas and oil price forecast is presented is Table 7-4. All other fuel escalation rates remain the same.

Table 7-1
Base Financial Parameters

Cost of Money--Foreign		60 percent Commercial Loans @ 7-1/2 percent and 40 percent Soft Loans @ 3 percent			
Cost of Money--Local, (percent)		12.0			
Discount Rate, (percent)		6.96			
Plant Content, (percent)	CT	CC	Steam (Oil/NG)	Steam (Coal)	Pumped Hydro
Foreign	85	80	70	70	70
Local	15	20	30	30	30
IDC Rate, (percent)	6.65	6.96	7.59	7.59	7.59
Assumed Life-(Years)	20	25	30	30	50
Weighted Cost of Money, (percent)	4.08	3.83	3.97	3.97	3.57
Depreciation	2.45	2.23	2.09	2.09	1.88
Insurance	0.10	0.10	0.10	0.10	0.10
Administration	0.20	0.20	0.20	0.20	0.20
Fixed Charge Rate, (percent)	6.83	6.41	6.36	6.36	5.75

Table 7-2
Lower Interest Rate Financial Parameters

Cost of Money--Foreign		60 percent Commercial Loans @ 6-1/2 percent and 40 percent Soft Loans @ 3 percent			
Cost of Money--Local, (percent)		12.0			
Discount Rate, (percent)		6.48			
Plant Content, (percent)	CT	CC	Steam (Oil/NG)	Steam (Coal)	Pumped Hydro
Foreign	85	80	70	70	70
Local	15	20	30	30	30
IDC Rate, (percent)	6.14	6.48	7.17	7.17	7.17
Assumed Life-Yr	20	25	30	30	50
Weighted Cost of Money, (percent)	3.83	3.65	3.77	3.77	3.34
Depreciation	2.58	2.23	2.18	2.18	1.93
Insurance	0.10	0.10	0.10	0.10	0.10
Administration	0.20	0.20	0.20	0.20	0.20
Fixed Charge Rate, (percent)	6.71	6.18	6.25	6.25	5.57

Table 7-3
Fuel Price Forecast, $/MBtu

Year	No. 6 Oil	No. 2 Oil	Coal	Natural Gas	Nuclear
1993	2.07	4.01	1.89	2.07	0.79
1994	2.21	4.27	1.92	2.21	0.80
1995	2.34	4.53	1.97	2.34	0.82
1996	2.53	4.90	2.07	2.53	0.85
1997	1.084	5.29	2.18	2.73	0.87
1998	1.084	5.72	2.29	2.96	0.90
1999	3.19	6.18	2.42	3.19	0.93
2000	3.45	6.68	2.54	3.45	0.96
2001	3.52	6.82	2.62	3.52	0.99
2002	3.60	6.96	2.70	3.60	1.02
2003	3.67	7.11	2.79	3.67	1.05
2004	3.75	7.26	2.87	3.75	1.08
2005	3.83	7.41	2.96	3.83	1.11
2006	3.95	7.64	3.06	3.95	1.15
2007	4.07	7.88	3.15	4.07	1.18
2008	4.20	8.12	3.25	4.20	1.22
2009	4.33	8.38	3.35	4.33	1.26
2010	4.46	8.64	3.45	4.46	1.30
2011	4.60	8.90	3.56	4.60	1.34
2012	4.74	9.18	3.67	4.74	1.38
2013	4.89	9.46	3.78	4.89	1.42
2014	5.04	9.76	3.90	5.04	1.47
2015	5.20	10.06	4.02	5.20	1.51
2016	5.36	10.37	4.15	5.36	1.56
2017	5.52	10.69	4.27	5.52	1.61

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Table 7-3 (Continued)
Fuel Price Forecast, $/MBtu

Year	No. 6 Oil	No. 2 Oil	Coal	Natural Gas	Nuclear
2018	5.70	11.03	4.41	5.70	1.66
2019	5.87	11.37	4.54	5.87	1.71
2020	6.05	11.72	4.68	6.05	1.76
2021	6.24	12.08	4.83	6.24	1.81
2022	6.44	12.46	4.98	6.44	1.87
2023	6.63	12.84	5.13	6.63	1.93
2024	6.84	13.24	5.29	6.84	1.99

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Table 7-4
Sensitivity Case Fuel Price Forecast, $/MBtu

Year	No. 6 Oil	No. 2 Oil	Natural Gas
1993	2.09	4.05	2.09
1994	2.25	4.35	2.25
1995	2.41	4.66	2.41
1996	2.63	5.09	2.63
1997	2.87	5.55	2.87
1998	3.12	6.05	3.12
1999	3.41	6.60	3.41
2000	3.72	7.19	3.72
2001	3.83	7.42	3.83
2002	3.95	7.65	3.95
2003	4.07	7.89	4.07
2004	4.20	8.13	4.20
2005	4.33	8.38	4.33
2006	4.51	8.73	4.51
2007	4.69	9.09	4.69
2008	4.89	9.46	4.89
2009	5.09	9.85	5.09
2010	5.29	10.25	5.29
2011	5.51	10.67	5.51
2012	5.74	11.11	5.74
2013	5.97	11.56	5.97
2014	6.22	12.04	6.22
2015	6.47	12.53	6.47
2016	6.74	13.04	6.74
2017	7.01	13.58	7.01
2018	7.30	14.13	7.30

Table 7-4 (Continued)
Sensitivity Case Fuel Price Forecast, $/MBtu

Year	No. 6 Oil	No. 2 Oil	Natural Gas
2019	7.60	14.71	7.60
2020	7.91	15.32	7.91
2021	8.24	15.95	8.24
2022	8.58	16.60	8.58
2023	8.93	17.28	8.93
2024	9.29	17.99	9.29

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8.0 Generation Expansion Alternatives

8.1 Conventional Alternatives

This section characterizes the conventional generation alternatives which will be used to meet future UPS generation requirements during development of the optimal base expansion plan. The total capacity and timing of future generation additions were discussed in Section 6.0. Section 9.0 determines the optimal mix of conventional generation alternatives based on economics and operational constraints. Capital cost and performance data for the conventional alternatives used in this study are summarized in Table 8-1.

8.1.1 Combustion Turbines

Combustion turbines burning either natural gas or No. 2 oil are available in a wide variety of sizes. Combustion turbines are generally used for peaking and reserve capacity purposes, because of their relatively low capital costs and high operating costs compared with base and intermediate capacity. Combustion turbines have the additional benefit of providing quick startup capability. Combustion turbines are assumed to be installed at a site with common facilities for a total generation capacity of 600 MW.

8.1.1.1 Combustion Turbine Temperature Considerations. The combustion turbine is generally rated by the manufacturer according to ISO conditions which are as follows:

- Ambient air temperature = 59 F.
- Inlet pressure loss = 0 inches H_2O.
- Exhaust back pressure = 0 inches H_2O.
- Elevation of site at sea level.
- Fuel used = natural gas.

Any deviation from the above results in a change in turbine output.

Combustion turbines are very sensitive to ambient temperature. As the temperature increases, the capacity of combustion turbines decreases. Temperature data for the Cairo area and Egypt were examined. Combustion turbines were derated to their output at 100 F in order to meet the summer peak demand.

For the purpose of this study, it was assumed that the following conditions would prevail:

- Ambient air temperature = 100 F.
- Inlet pressure loss = 4 inches H_2O.

- Exhaust back pressure = 0 inches H_2O.
- Elevation = 30 meters above sea level.
- Fuel used:
  - -- Natural gas.
  - -- No. 2 oil.

The data presented in Table 8-1 indicate that the combustion turbine's capital cost in $/kW at the above conditions.

8.1.1.2 Combustion Turbine Reliability Considerations. A pumped storage project generally involves a significant investment on the part of the Owner for providing peaking service on load. This service can also be provided by combustion turbines at considerably less capital expenditure than the pumped storage project. However, when evaluating combustion turbines versus pumped storage, one must consider the relative reliability of the two types of capacity.

In general, pumped storage plants are more reliable than thermal power plants. The North American Electric Reliability Council (NERC) collects and publishes performance data on different types of generating units on an annual basis. Reference was made to this publication and utilization of its most recent data for the years 1987 through 1991 to calculate an Adjusted Equivalent Forced Outage Rate (AEFOR). Calculations are contained in Appendix E, which result in an AEFOR for the combustion turbines and pumped storage plants of 19.44 percent and 3.74 percent, respectively.

The larger AEFOR of the CTs requires that the CT alternative plan have more capacity than the pumped storage plan in order to have the same reliability. The additional required CT capacity provides a significant advantage for the pumped storage plant which must be taken into account in the economic evaluation.

The additional CT capacity required for reliability reasons can be determined by a loss of load probability (LOLP) program or can be approximated by the following equation:

$$\text{CT capacity} \times (1 - \text{AEFOR}_{CT}) = \text{PS Capacity} \times (1 - \text{AEFOR}_{PH})$$

$$\text{CT capacity (MW)} = 600 \text{ MW} \times \frac{(1-.0374)}{(1-.1944)}$$

$$= 716.9 \text{ MW}$$

Accordingly, in the economic evaluation, the 600 MW of CTs that are compared with the 600 MW pumped hydro plant are evaluated at the CT capital cost of Table 8-1 multiplied by the ratio of $\frac{716.9}{600}$ or 1.194 as listed below:

	CT Natural Gas	CT No. 2 Oil
Capital Cost, $/kW*	431	440
Capital Cost Including Reliability Consideration, $/kW*	515	525

*Includes direct cost, indirect cost, and contingency. Does not include escalation or interest during construction.

8.1.2 Combined Cycle

In combined cycle technology, the hot exhaust gases from one or several combustion turbines are passed through a heat recovery steam generator. The steam generated is expanded through a steam turbine which drives an additional generator. The use of the exhaust gases results in combined cycle units being more efficient than simple cycle combustion turbines. Generally, approximately two-thirds of the power output from a combined cycle unit is from the combustion turbines, and one-third is from the heat recovery steam generator.

Combined cycle units can burn either natural gas or No. 2 oil. Combined cycle heat rates are generally very good; however, their fuel costs are usually higher than the fuel costs for coal or nuclear units. The combustion turbine portion of a combined cycle unit can be synchronized quickly, whereas the steam cycle portion requires additional time. Combined cycle units have the additional benefit of cycling capability. Combined cycles are assumed to be installed at a site with common facilities for a total generation capacity of 600 MW.

Combined cycle units are sensitive to ambient temperature as are combustion turbines. Table 8-1 presents the capital cost of combined cycles at the 100 F output level.

8.1.3 Natural Gas/Oil Steam

Natural gas/oil steam unit heat rates are generally higher than those for similar size modern combined cycle units. However, one advantage of steam units is that they are able to burn No. 6 oil, whereas combined cycles cannot. Natural gas/oil

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steam units are generally used for intermediate and base capacity, and are capable of being cycled on relatively short time schedules.

8.1.4 Coal

Coal steam units are more complicated than natural gas/oil steam units. Coal steam units require a substantial amount of additional equipment for coal and ash handling and pollution control. Maintenance requirements are also higher for coal units because of the abrasive nature of the fuel and waste products. While coal units are generally more capital cost intensive than natural gas/oil units, their fuel costs are generally less. Coal units are used for base capacity and are generally not cycled on a regular basis.

8.1.5 Nuclear

Nuclear steam units are also considered as a base capacity generation alternative for this study. Nuclear units generally have high capital and operational costs and low fuel costs when compared to other technologies.

8.2 Pumped Storage Hydroelectric

8.2.1 General

Pumped storage hydroelectric generation is a technology designed to take advantage of the differential costs of generating electricity between on- and off-peak periods. In simple terms, water is pumped into an upper storage reservoir during off-peak (low incremental cost) periods and then allowed to return to the lower reservoir thus generating electricity during on-peak (high cost) periods. The economic benefits of pumped storage depend on the differentials between on- and off-peak energy costs and the efficiency of the pumping/generating cycle. The following sections discuss the assumptions used for the pumped storage hydroelectric plant during this study.

8.2.2 Configuration

The pumped storage plant location has not been determined, but for the purpose of this study it is assumed to be located at a site near Wadi Araba. The plant is assumed to operate as a closed system with both an upper and lower reservoir. Makeup water will be obtained from the Gulf of Suez and will be desalinated. The project is expected to have an average head of approximately 800 meters. A pumped storage plant of 600 MW is the base size for this study. The 600 MW plant is assumed to consist of four 150 MW units configuration, with four separate reversible pumping/ generating sets. Each pumping/generating set is expected to have a

noncoincident planned outage of 2 weeks per year for inspection and maintenance procedures.

8.2.3 Operational Parameters

The key operational parameters in the evaluation of pumped storage capacity are reservoir size and overall cycle efficiency. This evaluation assumes that the upper reservoir will be capable of storing enough energy for 10 hours of full load generation, or 6,000 MWh for the 600 MW plant size. The overall pumping and generating cycle efficiency factor has been calculated to be 1.35 for this study. This means that 1.35 MWh of energy is consumed by the plant for every MWh of energy generated. This efficiency includes generator, motor, turbine, pump, flowline, transformer, and transmission losses. Appendix F contains the calculation of cycle efficiency.

8.2.4 Capital and Operating Costs

The project capital cost estimates are based on historical costs for actual pumped storage plants in the United States escalated to January 1992. The pumped storage capital cost was estimated to be $760/kW in 1992 dollars and $822/kW in 1993 dollars for the Wadi Araba site. The O&M cost estimate for the pumped storage plant was $1.30/MWh in 1992 dollars and $1.41/MWh in 1993 dollars. These capital costs do not include land, interest during construction, or transmission line costs required for the project.

The capital cost for the pumped storage hydro plant assumes that makeup will be obtained from the Gulf of Suez; that the makeup water will be desalinated and the plant will operate as a closed system with both an upper and lower reservoir.

For preliminary cost estimating of pumped storage hydro projects to be used in Phases I and II Ebasco developed a cost curve based on construction costs for pumped storage hydro projects installed and/or designed since 1980. Historical cost data excluding land, transmission, and interest during construction for projects in the United States escalated to January 1992 were used in the analysis. The cost curve and detailed capital cost estimates are contained in Appendix F.

8.2.5 Transmission Capital Cost

A geographic map with transmission network configuration as planned for 2000 was provided by EEA and is included as Figure 8-1. The map shows 500 kV transmission from Tabbin to Zaafarana and from Zaafarana to Suez. It is understood that the 500 kV line from Tabbin to Zaafarana is planned to go through Wadi Araba. Transmission interconnects for the pumped hydro plant would therefore be

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a relatively short distance. This study assumes that a maximum of 8 km of single circuit 500 kV transmission line will be required to interconnect the project with the existing grid. The expected cost of this transmission line is $150,000 per km or $1.2 million in 1992 dollars. A substation with a 1992 capital cost of $10 million will also be required at the interconnection point with the UPS grid. The total additional cost for transmission line and substation cost is estimated to be $11.2 million in 1992 dollars. This cost is assumed to be over and above the cost of combustion turbine interconnect requirements.

Table 8-1
Conventional Generation Alternative
(All costs in January 1993 dollars)

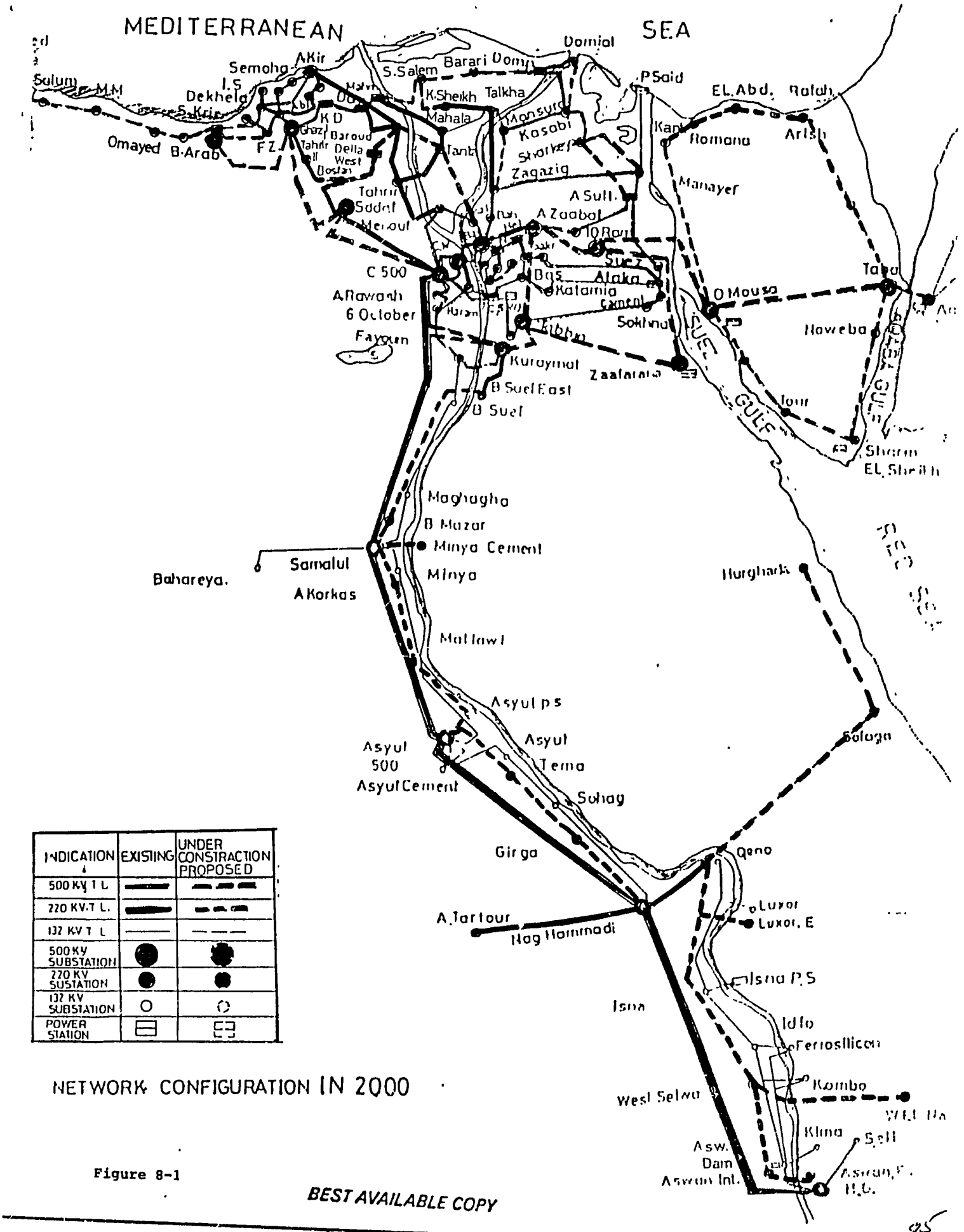
	Combustion Turbine		Combined Cycle	Natural Gas/Oil Steam		Coal Steam		Nuclear
	Natural Gas	No. 2 Oil						
Net Plant Output, MW (nominal)	100*	100*	300*	300	600	300	600	600
Total Capital Cost, $/kW	458**	467**	629**	1,150	886	1,401	1,165	2,272
O&M Fixed, $/MW-yr	2,162	2,162	2,825	4,504	3,964	13,911	11,421	39,268
O&M Variable, $/MWh	2.87	2.87	2.07	0.46	0.46	1.84	1.78	12.62
Full Load Net Plant Heat Rate, Btu/kWh***	12,500	12,097	8,300	9,900	9,800	9,600	9,500	10,600
Forced Outage Rate, percent	19.4	19.4	6.0	6.0	6.0	7.0	8.0	17.0
Maintenance, weeks/year	2.5	2.5	3.0	3.0	3.0	4.0	5.0	12.0
Construction Period, months	18	18	33	42	48	54	60	96

Note: Includes direct cost, indirect cost, and contingency. Does not include escalation or interest during construction.

*Output at 100 F.

**Capital cost in $/kW is based on unit rating at 100 F and a 600 MW plant size.

***Provided by Egyptian Electric Authority except for No. 2 oil fired combustion turbine.



INDICATION	EXISTING	UNDER CONSTRACTION PROPOSED
500 KV T L		
220 KV.T L.		
132 KV T L		
500 KV SUBSTATION		
220 KV SUSTATION		
132 KV SUBSTATION		
POWER STATION		

NETWORK CONFIGURATION IN 2000

Figure 8-1

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9.0 Economic Evaluation

9.1 Introduction

The economic evaluation was completed by first performing a screening analysis and then a detailed economic evaluation. The detailed economic evaluation, including production cost modeling and capital costs, provided optimal long-range expansion plans. The pumped storage plant was then substituted into the long-range expansion plans replacing equivalent combustion turbine capacity, and the cumulative present worth of the plans with and without the pumped storage project were compared.

As agreed upon in our discussions and correspondence with EEA and HPPEA, two base cases were evaluated. One case assumed that all combined cycle and combustion turbines would use natural gas. The second case assumed that the combustion turbines would be run on No. 2 oil.

9.2 Screening Analysis

The generation addition alternatives described in Section 8.0 were screened to determine which alternatives provided the most economic promise for the UPS. Those alternatives showing little merit were eliminated from detailed production cost modeling and economic analyses.

The screening analysis is based on developing 20 year levelized total costs versus capacity factor for the various generation alternatives. Total costs include fuel, O&M, and capital costs and are based on the generation alternative characteristics in Table 8-1 and the fuel price forecast in Table 7-1. The screening curves developed are shown on Figures 9-1 and 9-2.

Figure 9-1 shows the screening curves developed for base and intermediate load generation alternatives. Figure 9-1 includes screening curves for natural gas fired/No. 6 oil fired steam and combined cycle units. coal fired units, and nuclear units. Figure 9-1 indicates that a gas fired combined cycle unit is the most economical choice and a nuclear unit is the least economical choice. Additionally, the base and intermediate capacity screening evaluation ranks the 600 MW gas/oil fired steam unit as the second most economical unit at capacity factors of less than 55 percent. At capacity factors greater than 55 percent, the 600 MW coal unit replaces the gas/oil fired steam unit as the second most economical unit.

The screening curves shown on Figure 9-2 were developed to compare the various oil and gas fired generation alternatives. Figure 9-2 indicates that a gas fired

combined cycle unit is the most economical generation alternative at capacity factors greater than approximately 10 percent. At capacity factors less than approximately 10 percent, a gas fired combustion turbine is the most economical alternative. An oil fired combustion turbine is not as economical as a gas fired combustion turbine. Figure 9-2 also indicates that a No. 6 oil fired steam unit is more economical than a No. 2 oil fired combined cycle unit above 15 percent. This indicates that combined cycles should not be constructed if a firm supply of natural gas is not available. If natural gas use is curtailed to the point where it is not available for combined cycle units, then steam units that can use No. 6 oil should be constructed.

Based on the results of the screening analysis, the economically optimal expansion plans developed for the UPS were composed of combustion turbines, 600 MW gas/oil steam, 600 MW coal-steam, and 300 MW gas fired combined cycle unit additions.

9.3 Detailed Economic Evaluation

The viability of the pumped storage project on the UPS depends on its economic merit to replace thermal generating capacity. Therefore, the optimal long-range expansion plans developed for the UPS were tested with and without the pumped storage project and an economic comparison was made. The following paragraphs discuss the development of the optimal expansion plans, and the economic comparison with and without the pumped storage project.

9.3.1 Methodology

The detailed economic evaluation was completed in two parts. First, long-range expansion plans were developed on the basis of economic criteria presented in Section 7.0 and the capital costs presented in Section 8.0. Second, the pumped storage project was integrated into the long-range expansion plan to determine its economic viability.

The optimization process involves developing the cumulative present worth of UPS comparative costs for the years 1995 through 2024 for a series of different capacity expansion plans.

The EEA expansion plan (as provided by EEA) was used through the year 2000. The long-range expansion plan was developed for 2001 through 2024. The basis for comparison of alternative expansion plans was cumulative present worth costs including both production costs and fixed charges.

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The production costs are determined by simulation of the entire UPS by the POWRPRO software. Production costs include fuel and variable and fixed O&M for all existing and future units.

The fixed charge component is calculated by applying the fixed charge rates developed in Section 7.0 to the capital cost of various alternatives developed in Section 8.0. The capital cost includes escalation and interest during construction as calculated by POWRPRO spreadsheet software.

9.3.2 Long-Range Expansion Plans

The long-range capacity expansion plans from 2001 through 2024 were developed from the technologies which passed the screening analysis. The technologies tested are as follows:

- 100 MW combustion turbine.
- 300 MW combined cycle gas.
- 600 MW gas/oil steam.
- 600 MW coal.

Screening curves described in Section 9.2 indicate that combined cycle units are the most economical baseload option. However, prudent utility practice precludes the addition of one type of unit to the exclusion of all others. Thus, as agreed with EEA and HPPEA, combined cycle capacity was limited to a maximum of 15 percent of the total capacity. Similarly, coal fueled capacity was limited to 5 percent of the total installed capacity.

Each long-range expansion plan was developed by evaluating numerous plans. Each plan was developed with unit additions to meet the 20 percent reserve margin each year as described in Section 6.0. The expansion plan development was an interactive process. Engineering judgment was used to produce a "starting point" expansion plan. The production cost model, POWRPRO, was run for the study period. A spreadsheet was then developed which added annual fixed charges for all new generation plants to the annual production costs and provided a 1993 cumulative present worth cost. The cumulative present worth cost was used as the basis for economic comparison.

The "starting point" expansion plan was then changed by replacing one type of generation with another type. The production cost model was rerun, and the spreadsheet recalculated fixed charges and cumulative present worth. The new cumulative present worth cost was compared to the previous cost. If the cost was less, the process was repeated until savings were no longer produced by similar replacements.

Next, different capacity substitutions were made and the cumulative present worth costs were compared. This process was repeated numerous times until no further cumulative present worth cost reductions were identified by any combination of unit addition schedules.

Tables 9-1 and 9-2 present the long-range expansion plans, the annual production costs, annual fixed costs, total annual costs, and cumulative present worth costs. The long-range capacity expansion plans shown in Tables 9-1 and 9-2 are consistent with conclusions drawn from the screening curve analysis. Production cost simulations show that the most economical long-range expansion plans consist of adding combined cycle and coal units as soon as possible without compromising their respective 15 and 5 percent capacity limits. Plans which either delayed or eliminated combined cycle or coal unit additions produced higher cumulative present worth costs. The remainder of unit additions are either gas/oil fired steam units or combustion turbines.

A review of Tables 3-1 and 3-2 indicates that by the year 2005, almost all of the UPS combustion turbine (peaking) units will have been converted to combined cycle or retired. Thus, an increased demand for peaking capacity requires a large number of combustion turbines in 2001 through 2005. As the combustion turbines that are installed in 2000 through 2004 reach retirement in 2020 through 2024, additional combustion turbines must be added to maintain the appropriate peaking/intermediate/base capacity mix. The second case with combustion turbines on No. 2 oil requires relatively fewer combustion turbines and more No. 6 oil steam capacity because of the higher production costs of combustion turbines on No. 2 oil.

9.3.3 Pumped Storage Evaluation

The pumped storage plant was evaluated by comparing the long-range expansion plans with and without the pumped storage unit. The pumped storage unit is expected to be approximately 600 MW. The long-range expansion plans were modified by removing six 100 MW (rating at 100 F) combustion turbines and adding the pumped storage unit. The pumped storage plant is modeled as four 150 MW units.

Figures 9-3 and 9-4 show the UPS load duration curve for 2005 with and without pumped storage for each expansion plan. Each curve shows the expected thermal generation instead of total generation. Thermal generation does not include any load supplied by hydro generation. The line representing the case without pumped storage displays the thermal load duration curve. The line representing pumped storage case was produced by subtracting the hourly peak shaving generation and adding the

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hourly pumping generation to the original thermal load file. Evident on Figures 9-3 and 9-4 is the effect of pumped storage to tend to smooth out the load duration curve. The smoothing effect, filling in the valleys and clipping the peaks on an hourly basis, translates to decreased fluctuations in demand for the thermal units. The baseload units operating in conjunction with pumped storage are allowed to operate more consistently and at higher, more efficient unit output. Additionally, less starts are required by the peaking units reducing unnecessary thermal stresses and reducing the amount of maintenance required by the peaking units.

9.4 Results

The results of the two plans without pumped storage are provided in Tables 9-1 and 9-2, and the results with pumped storage are provided in Tables 9-3 and 9-4. Tables 9-1 through 9-4 give the results for the study period years of 1995 through 2024. The tables show that the 1993 cumulative present worth cost for the natural gas long-range expansion plan without pumped storage is $51,511 million; the cumulative present worth cost for the same plan with pumped storage is $51,563 million. This indicates that the plan with pumped storage is approximately $51 million more than the plan without pumped storage.

In the second expansion plan, the peaking units (combustion turbines) are fired by No. 2 oil and natural gas is conserved for combined cycle units. Plans without and with pumped storage were developed for the No. 2 oil scenario. Table 9-2 indicates that the cumulative present worth cost of the No. 2 oil plan without pumped storage is $52,630 million, and Table 9-4 shows that the cumulative present worth cost with pumped storage is $52,581 million. The plan with pumped storage is $49 million less than the plan without pumped storage. The savings achieved by the pumped storage plan result from the increased differential cost between the base generation units, primarily burning low cost No. 6 fuel oil, and peaking units burning the higher cost No. 2 fuel oil.

To complete the economic evaluation, consideration must be given to the remaining years of life of the pumped storage project from 2025 through 2052. During this end-effects period, the pumped storage plant has both fixed charge and production cost benefits over the combustion turbine alternative. The combustion turbine alternative with its shorter life (which is assumed to be 20 years), must be replaced in 2023 and again in 2043. Calculation of end-effects period benefits are included in Appendix G.

Addition of end-effects period results to study period results is summarized in Table 9-5. The natural gas plan with pumped storage has a $56 million end-effects

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period savings over the same plan without pumped storage, which gives pumped storage a $5 million net savings over the life of the project. The No. 2 oil plan with pumped storage has a $143 million end-effects period savings over the same plan without pumped storage which give pumped storage a $192 million net savings over the life of the project.

9.5 Sensitivity Analysis

In addition to the evaluation under the base study parameters, two more analyses were performed to assess the sensitivity of the study to uncertainties in projected study parameters. Sensitivity to changes in the fuel price forecast and selected financial parameters were evaluated. The evaluation criteria for each of the sensitivity analyses are identified in Section 7.0.

The methodology consisted of taking the two base long-range expansion plans developed previously, and testing the plans with modified parameters. In the case of the fuel price sensitivity, new production cost simulation was performed.

9.5.1 Fuel Price Sensitivity

For the analysis, it was assumed that natural gas and oil price escalation rates would be 1 percent per year higher than in the base cases. Sensitivity fuel prices are provided in Table 7-3. All other fuel escalation rates are assumed to remain the same as in the base fuel price forecast.

Tables 9-6 and 9-7 present the cumulative present worth costs of the natural gas long-range expansion plan with and without pumped storage. Tables 9-8 and 9-9 present the cumulative present worth costs for the No. 2 oil plan.

9.5.2 Financial Sensitivity

An interest rate of 7-1/2 percent and a corresponding discount rate of 6.96 percent were the base parameters. Additionally, it was assumed that loans from foreign sources for capital additions would be comprised of 60 percent commercial loans at 7-1/2 percent and 40 percent soft loans at 3 percent. For the sensitivity analysis, an interest rate of 6-1/2 percent, a discount rate of 6.48 percent, and commercial loans from foreign sources at 6-1/2 percent were assumed. Financial sensitivity parameters are provided in Table 7-2.

Tables 9-10 and 9-11 present the cumulative present worth costs of the natural gas long-range expansion plan with and without pumped storage. Tables 9-12 and 9-13 present the cumulative present worth costs for the No. 2 oil plan.

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9.5.3 Sensitivity Results

Table 9-14 summarizes the results of the sensitivity analysis during the study period years 1995 through 2024. Table 9-15 summarizes the results with end-effects period results included.

9.5.3.1 Fuel Price Sensitivity. Higher natural gas and oil prices make the pumped storage project more feasible because the difference between pumping cost and peaking cost is greater. Thus, there is more fuel savings to be derived from reducing peaking thermal generation. In the natural gas case, the production cost savings due to pumped storage were increased by approximately $4 million in the study period compared to using the expected fuel price forecast and by an additional $5 million in the end-effects period. However, in the No. 2 oil case, the production cost savings were increased by $30 million in the study period and by an additional $35 million in the end-effects period.

In the natural gas case, both the pumping and peaking generations are fueled by the same priced natural gas or No. 6 oil. Therefore, the difference in pumping and peaking costs result mainly from the difference in efficiency of the units. In the No. 2 oil case, the cost difference includes not only the efficiency difference but also a fuel cost difference.

In the natural gas case, the fuel for both pumping and peaking generations increased at the same rate. In the No. 2 oil case, both fuels also increased at the same rate; however, the absolute difference between the fuels is greater because the No. 2 oil has a higher price. Thus, it is expected that the fuel price sensitivity has a greater effect on the No. 2 oil case.

9.5.3.2 Financial Sensitivity. Lower interest rates would affect all generation expansion technologies. However, the effect on the pumped storage project is greater than on the combustion turbines which it replaces. Therefore, it is expected that the capital cost component of the cumulative present worth costs would decrease more for the pumped storage cases than for the nonpumped storage cases.

In the natural gas case, the reduced interest rates reduce the cumulative present worth loss by approximately $3 million in the study period and provide an additional savings of $13 million in the end-effects period compared to using the expected interest rates. In the No. 2 oil case, the reduced interest rates provide an increase in present worth savings of $13 million in the study period and an additional $32 million in the end-effects period.

The lower interest rates not only lower the fixed charge rates, but also lower the present worth discount rate. Tables 7-1 and 7-2 indicate that the discount rate is

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reduced from 6.96 percent to 6.48 percent. A reduction in the discount rate causes future savings (or losses) to have greater value at present.

In the natural gas case, the pumped storage project produces annual losses through 2021. These losses, brought back at a lower discount rate, represent a greater loss in today's dollars compared to the base parameters. The lower discount rate reduces the effect of the lower interest rates.

In the No. 2 oil case, the pumped storage project provides annual savings starting in 2009. The annual losses before 2009 tend to cancel the annual savings after 2009. Thus, the effect of the lower discount rate is reduced in the No. 2 oil case, and the effect of the lower interest rates is more pronounced.

9.5.3.3 Results. The sensitivity analysis indicates that the natural gas case is relatively insensitive to fuel price and interest rates. The sensitivity analysis does not change the conclusions for this case. The No. 2 oil case is more sensitive to fuel price and interest rates with the pumped storage project providing greater savings under both assumptions.

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Table 9-1
Natural Gas Expansion Plan Without Pumped Storage

	Unit Additions					UPS Production Costs				Levelized Capital Costs	Total Revenue Requirements	
Year	100 MW CT	600 MW Oil-ST	600 MW Coal	300 MW CC	600 MW PS	Fuel ($1,000)	O&M ($1,000)	Startup ($1,000)	Total ($1,000)	Total ($1,000)	Annual ($1,000)	1993 Cumulative Present Worth ($1,000)
1995						887,769	41,201	2,439	931,409	0	931,409	761,160
1996						1,017,189	44,503	3,082	1,064,773	0	1,064,773	1,574,687
1997						1,174,294	47,707	3,815	1,225,816	0	1,225,816	2,450,312
1998						1,370,765	51,366	4,692	1,426,824	0	1,426,824	3,403,200
1999						1,601,097	55,795	5,417	1,662,309	0	1,662,309	4,441,115
2000	0	0	0	0		1,885,859	60,527	5,643	1,952,030	0	1,952,030	5,580,618
2001	8	0	0	0		2,104,581	72,141	4,996	2,181,717	33,374	2,215,091	6,789,542
2002	7	0	1	0		2,296,691	100,984	5,585	2,403,260	132,282	2,535,542	8,083,311
2003	6	1	0	0	0	2,524,480	115,381	6,310	2,646,171	217,309	2,863,480	9,449,337
2004	12	0	0	0		2,799,779	132,818	7,504	2,940,101	272,628	3,212,729	10,882,242
2005	10	0	0	1		3,084,278	157,875	8,581	3,250,734	339,480	3,590,213	12,379,312
2006	3	1	0	1		3,410,762	182,586	9,654	3,603,003	433,408	4,036,411	13,952,917
2007	1	2	0	0		3,769,445	203,550	10,926	3,983,920	561,426	4,545,346	15,609,625
2008	11	0	0	1		4,167,958	235,969	12,086	4,416,013	640,624	5,056,637	17,332,761
2009	4	1	0	1		4,577,836	268,185	13,404	4,859,425	750,466	5,609,891	19,120,033
2010	2	1	1	0		4,959,785	317,184	15,032	5,292,001	921,889	6,213,889	20,970,914
2011	5	1	0	1		5,430,310	356,400	16,563	5,803,273	1,045,546	6,848,819	22,878,171
2012	6	1	0	1		5,915,207	398,001	18,013	6,331,222	1,179,630	7,510,852	24,833,687
2013	8	1	0	0		6,461,828	437,494	19,747	6,919,069	1,305,691	8,224,760	26,835,732
2014	11	0	0	2		6,981,620	495,009	21,548	7,498,176	1,428,655	8,926,831	28,867,278
2015	1	2	0	1		7,527,430	544,654	23,293	8,095,378	1,626,331	9,721,709	30,935,755
2016	8	1	0	0		8,171,792	593,696	25,083	8,790,571	1,766,332	10,556,903	33,035,773

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Table 9-1 (Continued)
Natural Gas Expansion Plan Without Pumped Storage

	Unit Additions					UPS Production Costs				Levelized Capital Costs	Total Revenue Requirements	
Year	100 MW CT	600 MW Oil-ST	600 MW Coal	300 MW CC	600 MW PS	Fuel ($1,000)	O&M ($1,000)	Startup ($1,000)	Total ($1,000)	Total ($1,000)	Annual ($1,000)	1993 Cumulative Present Worth ($1,000)
2017	7	1	0	1		8,823,887	653,910	27,107	9,504,904	1,933,142	11,438,046	35,163,015
2018	8	1	1	4		9,537,532	768,585	29,600	10,335,718	2,325,376	12,661,094	37,364,496
2019	7	2	0	3		10,260,153	867,228	32,459	11,159,840	2,660,935	13,820,776	39,611,246
2020	5	3	0	3		11,109,635	971,922	35,176	12,116,733	3,090,973	15,207,706	41,922,591
2021	19	1	0	1		12,040,755	1,067,892	37,681	13,146,328	3,346,825	16,493,153	44,266,190
2022	20	1	0	1		13,083,931	1,176,388	40,847	14,301,166	3,624,365	17,925,531	46,647,578
2023	13	2	0	1		14,119,401	1,287,714	44,454	15,451,570	3,969,552	19,421,122	49,059,766
2024	21	2	0	1		15,288,554	1,410,314	48,044	16,746,913	4,366,237	21,113,150	51,511,472

Table 9-2
No. 2 Oil Expansion Plan Without Pumped Storage

	Unit Additions					UPS Production Costs				Levelized Capital Costs	Total Revenue Requirements	
Year	100 MW CT	600 MW Oil-ST	600 MW Coal	300 MW CC	600 MW PS	Fuel ($1,000)	O&M ($1,000)	Startup ($1,000)	Total ($1,000)	Total ($1,000)	Annual ($1,000)	1993 Cumulative Present Worth ($1,000)
1995						887,775	41,199	2,437	931,410	0	931,410	761,162
1996						1,017,214	44,494	3,081	1,064,789	0	1,064,789	1,574,700
1997						1,174,356	47,659	3,806	1,225,821	0	1,225,821	2,450,329
1998						1,370,807	51,373	4,663	1,426,843	0	1,426,843	3,403,230
1999						1,601,216	55,790	5,427	1,662,433	0	1,662,433	4,441,223
2000	0	0	0	0		1,885,847	60,499	5,659	1,952,005	0	1,952,005	5,580,711
2001	2	1	0	0		2,094,701	70,845	5,529	2,171,075	58,020	2,229,095	6,797,278
2002	1	1	1	0		2,284,501	100,058	6,561	2,391,120	182,463	2,573,583	8,110,458
2003	6	1	0	0		2,518,262	113,900	7,726	2,639,888	268,127	2,908,015	9,497,728
2004	0	2	0	0		2,782,717	130,284	8,693	2,921,694	378,452	3,300,146	10,969,622
2005	4	1	0	1		3,061,511	153,618	10,242	3,225,371	474,278	3,699,648	12,512,325
2006	3	1	0	1		3,393,006	178,294	11,397	3,582,697	568,502	4,151,199	14,130,681
2007	1	2	0	0		3,757,745	200,481	13,051	3,971,277	696,622	4,667,898	15,832,058
2008	5	1	0	1		4,146,984	230,159	14,706	4,391,849	808,465	5,200,314	17,604,154
2009	4	1	0	1		4,563,443	261,626	16,397	4,841,467	918,743	5,760,210	18,439,317
2010	2	1	1	0		4,957,367	311,790	18,286	5,287,443	1,090,391	6,377,834	21,339,030
2011	5	1	0	1		5,436,203	349,718	20,183	5,806,104	1,214,630	7,020,734	23,294,162
2012	0	2	0	1		5,906,519	391,741	22,265	6,320,525	1,386,213	7,706,738	23,300,678
2013	2	2	0	0		6,439,619	428,963	24,092	6,892,675	1,551,502	8,444,177	27,356,134
2014	5	1	0	2		6,946,965	483,792	27,010	7,457,767	1,715,625	9,173,392	29,443,791
2015	1	2	0	1		7,507,311	536,544	28,592	8,072,446	1,913,434	9,985,880	31,568,475
2016	2	2	0	0		8,133,626	583,085	31,122	8,747,833	2,097,481	10,845,315	33,725,865

Table 9-2 (Continued)
No. 2 Oil Expansion Plan Without Pumped Storage

	Unit Additions					UPS Production Costs				Levelized Capital Costs	Total Revenue Requirements	
Year	100 MW CT	600 MW Oil-ST	600 MW Coal	300 MW CC	600 MW PS	Fuel ($1,000)	O&M ($1 000)	Startup ($1,000)	Total ($1,000)	Total ($1,000)	Annual ($1,000)	1993 Cumulative Present Worth ($1000)
2017	7	1	0	1		8,799,185	641,535	33,869	9,474,589	2,265,287	11,739,875	35,909,242
2018	8	1	1	4		9,527,582	752,233	36,938	10,316,753	2,658,696	12,975,449	38,165,382
2019	7	2	0	3		10,271,156	850,973	40,714	11,162,843	2,995,319	14,158,162	40,466,979
2020	5	3	0	3		11,149,141	955,130	44,039	12,148,311	3,426,142	15,574,453	42,834,063
2021	7	2	0	1		12,063,576	1,045,454	47,258	13,156,287	3,712,375	16,868,662	45,231,020
2022	8	2	0	1		13,091,866	1,146,755	51,837	14,290,458	4,021,868	18,312,326	47,663,793
2023	7	3	0	1		14,117,291	1,256,973	55,909	15,430,173	4,425,177	19,855,350	50,129,914
2024	9	2	0	1		15,322,399	1,376,710	59,969	16,759,077	4,771,143	21,530,221	52,630,051

Table 9-3
Natural Gas Expansion Plan With Pumped Storage

	Unit Additions					UPS Production Costs				Levelized Capital Costs	Total Revenue Requirements	
Year	100 MW CT	600 MW Oil-ST	600 MW Coal	300 MW CC	600 MW PS	Fuel ($1,000)	O&M ($1,000)	Startup ($1,000)	Total ($1,000)	Total ($1,000)	Annual ($1,000)	1993 Cumulative Present Worth ($1,000)
1995						887,769	41,201	2,439	931,409	0	931,409	761,160
1996						1,017,189	44,503	3,082	1,064,773	0	1,064,773	1,574,687
1997						1,174,294	47,707	3,815	1,225,816	0	1,225,816	2,450,312
1998						1,370,765	51,366	4,692	1,426,824	0	1,426,824	3,403,200
1999						1,601,097	55,795	5,417	1,662,309	0	1,662,309	4,441,115
2000	0	0	0	0		1,885,859	60,527	5,643	1,952,030	0	1,952,030	5,580,618
2001	8	0	0	0		2,104,581	72,141	4,996	2,181,717	33,374	2,215,091	6,789,542
2002	7	0	1	0		2,296,743	100,991	5,585	2,403,320	132,282	2,535,602	8,083,342
2003	0	1	0	0	1	2,521,522	115,653	5,580	2,642,756	230,711	2,873,468	9,454,132
2004	12	0	0	0		2,799,101	132,736	6,845	2,938,681	286,030	3,224,711	10,892,380
2005	10	0	0	1		3,085,098	157,639	7,858	3,250,595	352,881	3,603,477	12,394,981
2006	3	1	0	1		3,410,948	182,446	9,059	3,602,453	446,810	4,049,263	13,973,597
2007	1	2	0	0		3,770,636	203,409	10,025	3,984,070	574,828	4,558,898	15,635,245
2008	11	0	0	1		4,168,369	235,687	11,329	4,415,385	654,026	5,069,411	17,362,733
2009	4	1	0	1		4,576,407	267,518	12,516	4,856,441	763,868	5,620,310	19,153,325
2010	2	1	1	0		4,960,792	316,977	14,219	5,291,989	935,291	6,227,279	21,008,194
2011	5	1	0	1		5,429,518	356,019	15,547	5,801,084	1,058,948	6,860,032	22,918,573
2012	6	1	0	1		5,914,081	397,622	17,144	6,328,847	1,193,032	7,521,879	24,876,960
2013	8	1	0	0		6,459,983	436,662	18,743	6,915,388	1,319,093	8,234,481	26,881,372
2014	11	0	0	2		6,978,788	493,812	20,488	7,493,089	1,442,057	8,935,146	28,914,810
2015	1	2	0	1		7,525,148	543,930	22,164	8,091,242	1,639,733	9,730,975	30,985,258
2016	8	1	0	0		8,168,794	592,738	23,810	8,785,341	1,779,734	10,565,075	33,086,902

Table 9-3 (Continued)
Natural Gas Expansion Plan With Pumped Storage

	Unit Additions					UPS Production Costs				Levelized Capital Costs	Total Revenue Requirements	
Year	100 MW CT	600 MW Oil-ST	600 MW Coal	300 MW CC	600 MW PS	Fuel ($1,000)	O&M ($1,000)	Startup ($1,000)	Total ($1,000)	Total ($1,000)	Annual ($1,000)	1993 Cumulative Present Worth ($1,000)
2017	7	1	0	1		8,820,673	653,204	25,909	9,499,786	1,946,544	11,446,330	35,215,685
2018	8	1	1	4		9,533,306	767,378	28,177	10,328,861	2,338,778	12,667,639	37,418,304
2019	7	2	0	3		10,255,752	866,007	31,045	11,152,804	2,674,337	13,827,141	39,666,089
2020	5	3	0	3		11,104,813	970,791	33,827	12,109,431	3,104,375	15,213,806	41,978,360
2021	19	1	0	1		12,035,446	1,066,701	36,302	13,138,449	3,360,227	16,498,676	44,322,744
2022	20	1	0	1		13,078,570	1,175,179	39,354	14,293,103	3,637,767	17,930,870	46,704,842
2023	7	2	0	1		14,113,580	1,286,319	42,830	15,442,730	3,952,854	19,395,584	49,113,857
2024	21	2	0	1		15,282,515	1,408,821	46,344	16,737,679	4,349,538	21,087,218	51,562,552

Table 9-4
No. 2 Oil Expansion Plan With Pumped Storage

	Unit Additions					UPS Production Costs				Levelized Capital Costs	Total Revenue Requirements	
Year	100 MW CT	600 MW Oil-ST	600 MW Coal	300 MW CC	600 MW PS	Fuel ($1,000)	O&M ($1,000)	Startup ($1,000)	Total ($1,000)	Total ($1,000)	Annual ($1,000)	1993 Cumulative Present Worth ($1,000)
1995						887,775	41,199	2,437	931,410	0	931,410	761,162
1996						1,017,214	44,494	3,081	1,064,789	0	1,064,789	1,574,700
1997						1,174,356	47,659	3,806	1,225,821	0	1,225,821	2,450,329
1998						1,370,807	51,373	4,663	1,426,843	0	1,426,843	3,403,230
1999						1,601,216	55,790	5,427	1,662,433	0	1,662,433	4,441,223
2000	0	0	0	0		1,885,847	60,499	5,659	1,952,005	0	1,952,005	5,580,711
2001	2	1	0	0		2,094,701	70,845	5,529	2,171,075	58,020	2,229,095	6,797,278
2002	1	1	1	0		2,284,501	100,058	6,561	2,391,120	182,463	2,573,583	8,110,458
2003	0	1	0	0	1	2,507,713	114,816	6,256	2,628,785	280,892	2,909,677	9,498,522
2004	0	2	0	0		2,773,107	131,340	7,269	2,911,717	391,218	3,302,935	10,971,659
2005	4	1	0	1		3,050,008	154,641	8,660	3,213,308	487,043	3,700,351	12,514,655
2006	3	1	0	1		3,381,411	179,394	9,842	3,570,647	581,268	4,151,915	14,133,290
2007	1	2	0	0		3,746,023	201,754	11,576	3,959,352	709,387	4,668,740	15,834,974
2008	5	1	0	1		4,134,041	231,347	13,090	4,378,478	821,231	5,199,709	17,606,863
2009	4	1	0	1		4,546,777	262,878	14,694	4,824,349	931,509	5,755,858	19,440,640
2010	2	1	1	0		4,941,491	313,228	16,641	5,271,360	1,103,156	6,374,517	21,339,365
2011	5	1	0	1		5,415,781	351,011	18,268	5,785,060	1,227,395	7,012,456	23,292,191
2012	0	2	0	1		5,889,775	393,296	20,464	6,303,535	1,398,979	7,702,514	25,297,608
2013	2	2	0	0		6,421,230	430,692	22,319	6,874,241	1,564,268	8,438,509	27,351,684
2014	5	1	0	2		6,925,228	485,334	24,839	7,435,401	1,728,390	9,163,791	29,437,156
2015	1	2	0	1		7,487,827	538,411	26,834	8,053,071	1,926,200	9,979,271	31,560,434
2016	2	2	0	0		8,113,063	584,901	28,797	8,726,761	2,110,247	10,837,008	33,716,171

Table 9-4 (Continued)
No. 2 Oil Expansion Plan With Pumped Storage

	Unit Additions					UPS Production Costs				Levelized Capital Costs	Total Revenue Requirements	
Year	100 MW CT	600 MW Oil-ST	600 MW Coal	300 MW CC	600 MW PS	Fuel ($1,000)	O&M ($1,000)	Startup ($1,000)	Total ($1,000)	Total ($1,000)	Annual ($1,000)	1993 Cumulative Present Worth ($1,000)
2017	7	1	0	1		8,773,371	643,318	32,022	9,448,711	2,278,052	11,726,763	35,897,109
2018	8	1	1	4		9,496,054	753,849	34,323	10,284,227	2,671,462	12,955,688	38,149,814
2019	7	2	0	3		10,235,596	852,586	38,047	11,126,230	3,008,084	14,134,314	40,447,534
2020	5	3	0	3		11,108,191	956,664	41,210	12,106,064	3,438,907	15,544,972	42,810,138
2021	7	2	0	1		12,022,645	1,047,060	44,672	13,114,377	3,725,140	16,839,517	45,202,953
2022	8	2	0	1		13,046,279	1,148,217	48,645	14,243,141	4,034,634	18,277,775	47,631,136
2023	1	3	0	1		14,071,495	1,258,637	52,778	15,382,909	4,407,240	19,790,150	50,089,159
2024	9	2	0	1		15,270,630	1,378,248	56,931	16,705,810	4,753,207	21,459,016	52,581,028

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Table 9-5
1993 Cumulative Present Worth of Pumped Storage Savings
($ Million)

	Natural Gas	No. 2 Oil
Study Period	(51)	49
End Effects Period	56	143
Life of Project Benefit	5	192

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Table 9-6
Natural Gas Expansion Plan Without Pumped Storage - Fuel Sensitivity

	Unit Additions					UPS Production Costs				Levelized Capital Costs	Total Revenue Requirements	
Year	100 MW CT	600 MW Oil-ST	600 MW Coal	300 MW CC	600 MW PS	Fuel ($1,000)	O&M ($1,000)	Startup ($1,000)	Total ($1,000)	Total ($1,000)	Annual ($1,000)	1993 Cumulative Present Worth ($1,000)
1995						913,820	41,195	2,511	957,527	0	957,527	782,504
1996						1,056,670	44,520	3,203	1,104,393	0	1,104,393	1,626,301
1997						1,233,413	47,844	4,010	1,285,267	0	1,285,267	2,544,394
1998						1,443,208	51,822	4,945	1,499,975	0	1,499,975	3,546,136
1999						1,708,978	56,542	5,790	1,771,310	0	1,771,310	4,652,109
2000	0	0	0	0		2,031,413	61,030	6,087	2,098,531	0	2,098,531	5,877,132
2001	8	0	0	0		2,287,613	72,814	5,436	2,365,863	33,374	2,399,236	7,186,557
2002	7	0	1	0		2,506,272	101,752	6,116	2,614,140	132,282	2,746,422	8,587,928
2003	6	1	0	0	0	2,784,052	116,279	6,944	2,907,275	217,309	3,124,584	10,078,514
2004	12	0	0	0		3,117,795	133,859	8,435	3,260,089	272,628	3,532,717	11,654,136
2005	10	0	0	1		3,466,624	158,932	9,690	3,635,246	339,480	3,974,725	13,311,543
2006	3	1	0	1		3,871,836	183,756	11,054	4,066,646	433,408	4,500,054	15,065,901
2007	1	2	0	0		4,318,185	204,665	12,549	4,535,399	561,426	5,096,825	16,923,614
2008	11	0	0	1		4,824,411	237,124	14,125	5,075,660	640,624	5,716,284	18,871,536
2009	4	1	0	1		5,350,693	269,367	15,773	5,635,834	750,466	6,386,300	20,906,167
2010	2	1	1	0		5,822,357	318,421	17,789	6,158,567	921,889	7,080,456	23,015,164
2011	5	1	0	1		6,437,983	357,670	19,833	6,815,487	1,045,546	7,861,032	25,204,302
2012	6	1	0	1		7,090,511	399,313	21,761	7,511,585	1,179,630	8,691,215	27,467,136
2013	8	1	0	0		7,810,299	438,860	24,126	8,273,286	1,305,691	9,578,977	29,798,821
2014	11	0	0	2		8,529,972	496,354	26,603	9,052,929	1,428,655	10,481,584	32,184,193
2015	1	2	0	1		9,272,605	546,146	29,002	9,847,752	1,626,331	11,474,083	34,625,520
2016	8	1	0	0		10,175,205	595,113	31,626	10,801,945	1,766,332	12,568,276	37,125,648

Table 9-6 (Continued)
Natural Gas Expansion Plan Without Pumped Storage - Fuel Sensitivity

	Unit Additions					UPS Production Costs				Levelized Capital Costs	Total Revenue Requirements	
Year	100 MW CT	600 MW Oil-ST	600 MW Coal	300 MW CC	600 MW PS	Fuel ($1,000)	O&M ($1,000)	Startup ($1,000)	Total ($1,000)	Total ($1,000)	Annual ($1,000)	1993 Cumulative Present Worth ($1,000)
2017	7	1	0	1		11,096,977	655,356	34,294	11,786,627	1,933,142	13,719,770	39,677,245
2018	8	1	1	4		12,046,023	770,050	37,875	12,853,947	2,325,376	15,179,323	42,316,589
2019	7	2	0	3		13,101,169	868,550	41,938	14,011,656	2,660,935	16,672,592	45,026,940
2020	5	3	0	3		14,328,133	973,371	45,979	15,347,483	3,090,973	18,438,456	47,829,310
2021	19	1	0	1		15,689,176	1,069,228	49,760	16,808,164	3,346,825	20,154,989	50,693,239
2022	20	1	0	1		17,205,914	1,177,657	54,431	18,438,001	3,624,365	22,062,367	53,624,201
2023	13	2	0	1		18,774,493	1,289,050	59,884	20,123,427	3,969,552	24,092,980	56,616,654
2024	21	2	0	1		20,506,966	1,411,443	65,231	21,983,640	4,366,237	26,349,877	59,676,460

Table 9-7
Natural Gas Expansion Plan With Pumped Storage - Fuel Sensitivity

	Unit Additions					UPS Production Costs				Levelized Capital Costs	Total Revenue Requirements	
Year	100 MW CT	600 MW Oil-ST	600 MW Coal	300 MW CC	600 MW PS	Fuel ($1,000)	O&M ($1,000)	Startup ($1,000)	Total ($1,000)	Total ($1,000)	Annual ($1,000)	1993 Cumulative Present Worth ($1,000)
1995						913,820	41,195	2,511	957,527	0	957,527	782,504
1996						1,056,670	44,520	3,203	1,104,393	0	1,104,393	1,626,301
1997						1,233,413	47,844	4,010	1,285,267	0	1,285,267	2,544,394
1998						1,443,208	51,822	4,945	1,499,975	0	1,499,975	3,546,136
1999						1,708,978	56,542	5,790	1,771,310	0	1,771,310	4,652,109
2000	0	0	0	0		2,031,413	61,030	6,087	2,098,531	0	2,098,531	5,877,132
2001	8	0	0	0		2,287,613	72,814	5,436	2,365,863	33,374	2,399,236	7,186,557
2002	7	0	1	0		2,506,320	101,758	6,116	2,614,194	132,282	2,746,476	8,587,956
2003	0	1	0	0	1	2,779,494	116,469	6,125	2,902,088	230,711	3,132,800	10,082,461
2004	12	0	0	0		3,116,977	133,654	7,657	3,258,288	286,030	3,544,318	11,663,257
2005	10	0	0	1		3,467,653	158,642	8,922	3,635,218	352,881	3,988,099	13,326,240
2006	3	1	0	1		3,872,136	183,416	10,311	4,065,863	446,810	4,512,673	15,085,517
2007	1	2	0	0		4,319,959	204,511	11,596	4,536,066	574,828	5,110,894	16,948,359
2008	11	0	0	1		4,825,269	236,680	13,212	5,075,161	654,026	5,729,187	18,900,678
2009	4	1	0	1		5,349,461	268,666	14,836	5,632,963	763,868	6,396,831	20,938,664
2010	2	1	1	0		5,823,538	318,013	16,748	6,158,299	935,291	7,093,590	23,051,573
2011	5	1	0	1		6,437,196	357,223	18,584	6,813,003	1,058,948	7,871,951	25,243,752
2012	6	1	0	1		7,090,274	398,952	20,609	7,509,835	1,193,032	8,702,867	27,509,619
2013	8	1	0	0		7,808,550	437,976	22,899	8,269,425	1,319,093	9,588,518	29,843,626
2014	11	0	0	2		8,525,705	495,206	25,349	9,046,260	1,442,057	10,488,317	32,230,531
2015	1	2	0	1		9,269,408	545,277	27,667	9,842,352	1,639,733	11,482,085	34,673,561
2016	8	1	0	0		10,171,942	594,306	30,116	10,796,364	1,779,734	12,576,098	37,175,244

Table 9-7 (Continued)
Natural Gas Expansion Plan With Pumped Storage - Fuel Sensitivity

	Unit Additions					UPS Production Costs				Levelized Capital Costs	Total Revenue Requirements	
Year	100 MW CT	600 MW Oil-ST	600 MW Coal	300 MW CC	600 MW PS	Fuel ($1,000)	O&M ($1,000)	Startup ($1,000)	Total ($1,000)	Total ($1,000)	Annual ($1,000)	1993 Cumulative Present Worth ($1,000)
2017	7	1	0	1		11,092,241	654,489	32,918	11,779,648	1,946,544	13,726,192	39,728,035
2018	8	1	1	4		12,041,500	768,984	36,168	12,846,651	2,338,778	15,185,429	42,368,442
2019	7	2	0	3		13,095,748	867,449	40,107	14,003,303	2,674,337	16,677,641	45,079,613
2020	5	3	0	3		14,322,725	972,250	44,043	15,339,018	3,104,375	18,443,393	47,882,734
2021	19	1	0	1		15,681,381	1,068,118	48,236	16,797,735	3,360,227	20,157,962	50,747,085
2022	20	1	0	1		17,198,551	1,176,484	52,472	18,427,508	3,637,767	22,065,275	53,678,434
2023	7	2	0	1		18,767,129	1,287,647	57,664	20,112,440	3,952,854	24,065,294	56,667,447
2024	21	2	0	1		20,498,729	1,409,945	62,909	21,971,583	4,349,538	26,321,122	59,723,915

Table 9-8
No. 2 Oil Expansion Plan Without Pumped Storage - Fuel Sensitivity

	Unit Additions					UPS Production Costs				Levelized Capital Costs	Total Revenue Requirements	
Year	100 MW CT	600 MW Oil-ST	600 MW Coal	300 MW CC	600 MW PS	Fuel ($1,000)	O&M ($1,000)	Startup ($1,000)	Total ($1,000)	Total ($1,000)	Annual ($1,000)	1993 Cumulative Present Worth ($1,000)
1995						913,859	41,193	2,512	957,564	0	957,564	782,535
1996						1,056,697	44,511	3,203	1,104,410	0	1,104,410	1,626,345
1997						1,233,480	47,794	4,001	1,285,275	0	1,285,275	2,544,443
1998						1,443,252	51,829	4,915	1,499,996	0	1,499,996	3,546,199
1999						1,709,106	56,537	5,801	1,771,443	0	1,771,443	4,652,255
2000	0	0	0	0		2,031,344	61,019	6,108	2,098,471	0	2,098,471	5,877,243
2001	2	1	0	0		2,276,771	71,546	6,011	2,354,328	58,020	2,412,348	7,193,824
2002	1	1	1	0		2,492,756	100,871	7,199	2,600,827	182,463	2,783,290	8,614,007
2003	6	1	0	0		2,776,733	114,864	8,609	2,900,206	268,127	3,168,333	10,125,463
2004	0	2	0	0		3,098,485	131,359	9,735	3,239,578	378,452	3,618,031	11,739,136
2005	4	1	0	1		3,440,894	154,790	11,578	3,607,263	474,278	4,081,541	13,441,083
2006	3	1	0	1		3,851,437	179,513	13,060	4,044,009	568,502	4,612,511	15,239,283
2007	1	2	0	0		4,305,261	201,776	15,120	4,522,158	696,622	5,218,779	17,141,447
2008	5	1	0	1		4,800,475	231,473	17,120	5,049,068	808,465	5,857,534	19,137,502
2009	4	1	0	1		5,333,875	262,964	19,272	5,616,111	918,743	6,534,854	21,219,461
2010	2	1	1	0		5,819,790	313,164	21,708	6,154,662	1,090,391	7,245,053	23,377,486
2011	5	1	0	1		6,445,073	351,122	24,181	6,820,376	1,214,630	8,035,006	25,615,072
2012	0	2	0	1		7,080,002	393,237	27,077	7,500,317	1,386,213	8,886,530	27,928,757
2013	2	2	0	0		7,783,146	430,474	29,551	8,243,171	1,551,502	9,794,674	30,312,946
2014	5	1	0	2		8,487,427	485,344	33,326	9,006,[illegible]	1,715,625	10,721,721	32,752,968
2015	1	2	0	1		9,246,536	538,182	35,920	9,820,639	1,913,434	11,734,073	35,249,613
2016	2	2	0	0		10,127,061	584,747	39,014	10,750,822	2,097,481	12,848,304	37,805,445

Table 9-8 (Continued)
No. 2 Oil Expansion Plan Without Pumped Storage - Fuel Sensitivity

	Unit Additions					UPS Production Costs				Levelized Capital Costs	Total Revenue Requirements	
Year	100 MW CT	600 MW Oil-ST	600 MW Coal	300 MW CC	600 MW PS	Fuel ($1,000)	O&M ($1,000)	Startup ($1,000)	Total ($1,000)	Total ($1,000)	Annual ($1,000)	1993 Cumulative Present Worth ($1,000)
2017	7	1	0	1		11,064,933	643,238	43,030	11,751,201	2,265,287	14,016,488	40,412,225
2018	8	1	1	4		12,033,444	753,946	47,230	12,834,620	2,658,696	15,493,316	43,106,166
2019	7	2	0	3		13,115,188	852,679	52,714	14,020,581	2,995,319	17,015,900	45,872,326
2020	5	3	0	3		14,378,418	956,858	57,613	15,392,889	3,426,142	18,819,031	48,732,538
2021	7	2	0	1		15,720,089	1,047,226	62,126	16,829,441	3,712,375	20,541,816	51,651,432
2022	8	2	0	1		17,216,098	1,148,548	68,976	18,433,623	4,021,868	22,455,491	54,634,621
2023	7	3	0	1		18,771,628	1,258,817	74,754	20,105,199	4,425,177	24,530,376	57,681,400
2024	9	2	0	1		20,552,886	1,378,557	81,352	22,012,796	4,771,143	26,783,939	60,791,611

Table 9-9
No. 2 Oil Expansion Plan With Pumped Storage - Fuel Sensitivity

	Unit Additions					UPS Production Costs				Levelized Capital Costs	Total Revenue Requirements	
Year	100 MW CT	600 MW Oil-ST	600 MW Coal	300 MW CC	600 MW PS	Fuel ($1,000)	O&M ($1,000)	Startup ($1,000)	Total ($1,000)	Total ($1,000)	Annual ($1,000)	1993 Cumulative Present Worth ($1,000)
1995						913,859	41,193	2,512	957,564	0	957,564	782,535
1996						1,056,697	44,511	3,203	1,104,410	0	1,104,410	1,626,345
1997						1,233,480	47,794	4,001	1,285,275	0	1,285,275	2,544,443
1998						1,443,252	51,829	4,915	1,499,996	0	1,499,996	3,546,199
1999						1,709,106	56,537	5,801	1,771,443	0	1,771,443	4,652,255
2000	0	0	0	0		2,031,344	61,019	6,108	2,098,471	0	2,098,471	5,877,243
2001	2	1	0	0		2,276,771	71,546	6,011	2,354,328	58,020	2,412,348	7,193,824
2002	1	1	1	0		2,492,756	100,871	7,199	2,600,827	182,463	2,783,290	8,614,007
2003	0	1	0	0	1	2,764,616	115,815	6,986	2,887,416	280,892	3,168,308	10,125,451
2004	0	2	0	0		3,086,820	132,410	8,137	3,227,367	391,218	3,618,585	11,739,372
2005	4	1	0	1		3,428,154	155,840	9,786	3,593,780	487,043	4,080,823	13,441,019
2006	3	1	0	1		3,836,728	180,585	11,216	4,028,530	581,268	4,609,797	15,238,161
2007	1	2	0	0		4,290,032	202,920	13,240	4,506,192	709,387	5,215,579	17,139,159
2008	5	1	0	1		4,785,078	232,730	15,160	5,032,968	821,231	5,854,199	19,134,078
2009	4	1	0	1		5,314,757	264,261	17,182	5,596,200	931,509	6,527,709	21,213,760
2010	2	1	1	0		5,800,112	314,584	19,635	6,134,330	1,103,156	7,237,486	23,369,531
2011	5	1	0	1		6,420,969	352,449	21,928	6,795,346	1,227,395	8,022,741	25,603,702
2012	0	2	0	1		7,057,923	394,751	24,883	7,477,557	1,398,979	8,876,536	27,914,785
2013	2	2	0	0		7,760,717	432,125	26,966	8,219,809	1,564,268	9,784,077	30,296,395
2014	5	1	0	2		8,460,142	486,888	30,622	8,977,652	1,728,390	10,706,042	32,732,849
2015	1	2	0	1		9,222,911	540,003	33,444	9,796,358	1,926,200	11,722,557	35,227,044
2016	2	2	0	0		10,102,050	586,630	36,253	10,724,932	2,110,247	12,835,179	37,780,265

Table 9-9 (Continued)
No. 2 Oil Expansion Plan With Pumped Storage - Fuel Sensitivity

	Unit Additions					UPS Production Costs				Levelized Capital Costs	Total Revenue Requirements	
Year	100 MW CT	600 MW Oil-ST	600 MW Coal	300 MW CC	600 MW PS	Fuel ($1,000)	O&M ($1,000)	Startup ($1,000)	Total ($1,000)	Total ($1,000)	Annual ($1,000)	1993 Cumulative Present Worth ($1,000)
2017	7	1	0	1		11,032,372	645,073	40,796	11,718,241	2,278,052	13,996,294	40,383,289
2018	8	1	1	4		11,993,730	755,606	44,016	12,793,352	2,671,462	15,464,814	43,072,275
2019	7	2	0	3		13,067,994	854,349	49,734	13,972,078	3,008,084	16,980,162	45,832,625
2020	5	3	0	3		14,328,180	958,464	54,262	15,340,906	3,438,907	18,779,814	48,686,876
2021	7	2	0	1		15,665,399	1,048,920	59,307	16,773,626	3,725,140	20,498,767	51,599,654
2022	8	2	0	1		17,155,329	1,150,140	65,667	18,371,135	4,034,634	22,405,769	54,576,237
2023	1	3	0	1		18,708,627	1,260,597	71,452	20,040,676	4,407,240	24,447,916	57,612,774
2024	9	2	0	1		20,483,719	1,380,232	77,711	21,941,662	4,753,207	26,694,869	60,712,642

Table 9-10
Natural Gas Expansion Plan Without Pumped Storage - Financial Sensitivity

	Unit Additions					UPS Production Costs				Levelized Capital Costs	Total Revenue Requirements	
Year	100 MW CT	600 MW Oil-ST	600 MW Coal	300 MW CC	600 MW PS	Fuel ($1,000)	O&M ($1,000)	Startup ($1,000)	Total ($1,000)	Total ($1,000)	Annual ($1,000)	1993 Cumulative Present Worth ($1,000)
1995						887,769	41,201	2,439	931,409	0	931,409	771,500
1996						1,017,189	44,503	3,082	1,064,773	0	1,064,773	1,599,795
1997						1,174,294	47,707	3,815	1,225,816	0	1,225,816	2,495,335
1998						1,370,765	51,366	4,692	1,426,824	0	1,426,824	3,474,289
1999						1,601,097	55,795	5,417	1,662,309	0	1,662,309	4,545,402
2000	0	0	0	0		1,885,859	60,527	5,643	1,952,030	0	1,952,030	5,726,653
2001	8	0	0	0		2,104,581	72,141	4,996	2,181,717	32,670	2,214,387	6,985,118
2002	7	0	1	0		2,296,691	100,984	5,585	2,403,260	129,095	2,532,356	8,336,706
2003	6	1	0	0	0	2,524,480	115,381	6,310	2,646,171	212,124	2,858,295	9,769,417
2004	12	0	0	0		2,799,779	132,818	7,504	2,940,101	266,275	3,206,376	11,278,794
2005	10	0	0	1		3,084,278	157,875	8,581	3,250,734	331,319	3,582,053	12,862,401
2006	3	1	0	1		3,410,762	182,586	9,654	3,603,003	422,626	4,025,628	14,533,804
2007	1	2	0	0		3,769,445	203,550	10,926	3,983,920	547,469	4,531,389	16,300,699
2008	11	0	0	1		4,167,958	235,969	12,08[illegible]	4,416,013	624,555	5,040,568	18,146,525
2009	4	1	0	1		4,577,836	268,185	13,404	4,859,425	731,369	5,590,794	20,069,248
2010	2	1	1	0		4,959,785	317,184	15,032	5,292,001	898,383	6,190,384	22,068,617
2011	5	1	0	1		5,430,310	356,400	16,563	5,803,273	1,018,669	6,821,942	24,137,877
2012	6	1	0	1		5,915,207	398,001	18,013	6,331,2[illegible]	1,149,135	7,480,357	26,268,770
2013	8	1	0	0		6,461,828	437,494	19,747	6,919,069	1,272,243	8,191,312	28,460,184
2014	11	0	0	2		6,981,620	495,009	21,548	7,498,176	1,391,530	8,889,706	30,693,708
2015	1	2	0	1		7,527,430	544,654	23,293	8,095,378	1,583,843	9,679,221	32,977,599
2016	8	1	0	0		8,171,792	593,696	25,083	8,790,571	1,720,563	10,511,134	35,306,851

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Table 9-10 (Continued)
Natural Gas Expansion Plan Without Pumped Storage - Financial Sensitivity

	Unit Additions					UPS Production Costs				Levelized Capital Costs	Total Revenue Requirements	
Year	100 MW CT	600 MW Oil-ST	600 MW Coal	300 MW CC	600 MW PS	Fuel ($1,000)	O&M ($1,000)	Startup ($1,000)	Total ($1,000)	Total ($1,000)	Annual ($1,000)	1993 Cumulative Present Worth ($1,000)
2017	7	1	0	1		8,823,887	653,910	27,107	9,504,904	1,882,914	11,387,818	37,676,603
2018	8	1	1	4		9,537,532	768,585	29,600	10,335,718	2,263,334	12,599,051	40,139,260
2019	7	2	0	3		10,260,153	867,228	32,459	11,159,840	2,589,157	13,748,997	42,662,938
2020	5	3	0	3		11,109,635	971,922	35,176	12,116,733	3,006,992	15,123,725	45,270,013
2021	19	1	0	1		12,040,755	1,067,892	37,681	13,146,328	3,256,366	16,402,694	47,925,487
2022	20	1	0	1		13,083,931	1,176,388	40,847	14,301,166	3,526,933	17,828,099	50,636,076
2023	13	2	0	1		14,119,401	1,287,714	44,454	15,451,570	3,863,258	19,314,827	53,393,995
2024	21	2	0	1		15,288,554	1,410,314	48,044	16,746,913	4,249,937	20,996,849	56,209,633

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Table 9-11
Natural Gas Expansion Plan With Pumped Storage - Financial Sensitivity

	Unit Additions					UPS Production Costs				Levelized Capital Costs	Total Revenue Requirements	
Year	100 MW CT	600 MW Oil-ST	600 MW Coal	300 MW CC	600 MW PS	Fuel ($1,000)	O&M ($1,000)	Startup ($1,000)	Total ($1,000)	Total ($1,000)	Annual ($1,000)	1993 Cumulative Present Worth ($1,000)
1995						887,769	41,201	2,439	931,409	0	931,409	771,500
1996						1,017,189	44,503	3,082	1,064,773	0	1,064,773	1,599,795
1997						1,174,294	47,707	3,815	1,225,816	0	1,225,816	2,495,335
1998						1,370,765	51,366	4,692	1,426,824	0	1,426,824	3,474,289
1999						1,601,097	55,795	5,417	1,662,309	0	1,662,309	4,545,402
2000	0	0	0	0		1,885,859	60,527	5,643	1,952,030	0	1,952,030	5,726,653
2001	8	0	0	0		2,104,581	72,141	4,996	2,181,717	32,670	2,214,387	6,985,118
2002	7	0	1	0		2,296,743	100,991	5,585	2,403,320	129,095	2,532,415	8.336,737
2003	0	1	0	0	1	2,521,522	115,653	5,580	2,642,756	224,485	2,867,242	9,773,933
2004	12	0	0	0		2,799,101	132,736	6,845	2,938,681	278,637	3,217,318	11,288,461
2005	10	0	0	1		3,085,098	157,639	7,858	3,250,595	343,680	3,594,276	12,877,472
2006	3	1	0	1		3,410,948	182,446	9,059	3,602,453	434,987	4,037,440	14,553,779
2007	1	2	0	0		3,770,636	203,409	10,025	3,984,070	559,830	4,543,900	16,325,552
2008	11	0	0	1		4,168,369	235,687	11,329	4,415,385	636,917	5,052,302	18,175,675
2009	4	1	0	1		4,576,407	267,518	12,516	4,856,441	743,731	5,600,172	20,101,623
2010	2	1	1	0		4,960,792	316,977	14,219	5,291,989	910,745	6,202,733	22,104,980
2011	5	1	0	1		5,429,518	356,019	15,547	5,801,084	1,031,031	6,832,115	24,177,327
2012	6	1	0	1		5,914,081	397,622	17,144	6,328,847	1,161,497	7,490,344	26,311,064
2013	8	1	0	0		6,459,983	436,662	18,743	6,915,388	1,284,604	8,199,993	28,504,801
2014	11	0	0	2		6,978,788	493,812	20,488	7,493,089	1,403,892	8,896,981	30,740,152
2015	1	2	0	1		7,525,148	543,930	22,164	8,091,242	1,596,205	9,687,447	33,025,984
2016	8	1	0	0		8,168,794	592,738	23,810	8,785,341	1,732,924	10,518,265	35,356,817

Table 9-11 (Continued)
Natural Gas Expansion Plan With Pumped Storage - Financial Sensitivity

	Unit Additions					UPS Production Costs				Levelized Capital Costs	Total Revenue Requirements	
Year	100 MW CT	600 MW Oil-ST	600 MW Coal	300 MW CC	600 MW PS	Fuel ($1,000)	O&M ($1,000)	Startup ($1,000)	Total ($1,000)	Total ($1,000)	Annual ($1,000)	1993 Cumulative Present Worth ($1,000)
2017	7	1	0	1		8,820,673	653,204	25,909	9,499,786	1,895,276	11,395,062	37,728,276
2018	8	1	1	4		9,533,306	767,378	28,177	10,328,861	2,275,695	12,604,556	40,191,809
2019	7	2	0	3		10,255,752	866,007	31,045	11,152,804	2,601,518	13,754,322	42,716,464
2020	5	3	0	3		11,104,813	970,791	33,827	12,109,431	3,019,354	15,128,785	45,324,412
2021	19	1	0	1		12,035,446	1,066,701	36,302	13,138,449	3,268,728	16,407,177	47,980,611
2022	20	1	0	1		13,078,570	1,175,179	39,354	14,293,103	3,539,294	17,832,397	50,691,854
2023	7	2	0	1		14,113,580	1,286,319	42,830	15,442,730	3,846,154	19,288,883	53,446,068
2024	21	2	0	1		15,282,515	1,408,821	46,344	16,737,679	4,232,833	20,970,512	56,258,174

Table 9-12
No. 2 Oil Expansion Plan Without Pumped Storage - Financial Sensitivity

	Unit Additions					UPS Production Costs				Levelized Capital Costs	Total Revenue Requirements	
Year	100 MW CT	600 MW Oil-ST	600 MW Coal	300 MW CC	600 MW PS	Fuel ($1,000)	O&M ($1,000)	Startup ($1,000)	Total ($1,000)	Total ($1,000)	Annual ($1,000)	1993 Cumulative Present Worth ($1,000)
1995						887,775	41,199	2,437	931,410	0	931,410	771,502
1996						1,017,214	44,494	3,081	1,064,789	0	1,064,789	1,599,809
1997						1,174,356	47,659	3,806	1,225,821	0	1,225,821	2,495,353
1998						1,370,807	51,373	4,663	1,426,843	0	1,426,843	3,474,320
1999						1,601,216	55,790	5,427	1,662,433	0	1,662,433	4,545,513
2000	0	0	0	0		1,885,847	60,499	5,659	1,952,005	0	1,952,005	5,726,748
2001	2	1	0	0		2,094,701	70,845	5,529	2,171,075	56,605	2,227,680	6,992,768
2002	1	1	1	0		2,284,501	100,058	6,561	2,391,120	177,829	2,568,949	8,363,887
2003	6	1	0	0		2,518,262	113,900	7,726	2,639,888	261,480	2,901,368	9,818,188
2004	0	2	0	0		2,782,717	130,284	8,693	2,921,694	369,053	3,290,747	11,367,282
2005	4	1	0	1		3,061,511	153,618	10,242	3,225,371	462,238	3,687,609	12,997,555
2006	3	1	0	1		3,393,006	178,294	11,397	3,582,697	553,834	4,136,532	14,715,004
2007	1	2	0	0		3,757,745	200,481	13,051	3,971,277	678,777	4,650,054	16,528,169
2008	5	1	0	1		4,146,984	230,159	14,706	4,391,849	787,575	5,179,424	18,424,843
2009	4	1	0	1		4,563,443	261,626	16,397	4,841,467	894,815	5,736,282	20,397,601
2010	2	1	1	0		4,957,367	311,790	18,286	5,287,443	1,062,049	6,349,492	22,448,358
2011	5	1	0	1		5,436,203	349,718	20,183	5,806,104	1,182,905	6,989,009	24,568,295
2012	0	2	0	1		5,906,519	391,741	22,265	6,320,525	1,349,796	7,670,320	26,753,301
2013	2	2	0	0		6,439,619	428,963	24,092	6,892,675	1,511,009	8,403,684	29,001,531
2014	5	1	0	2		6,946,965	483,792	27,010	7,457,767	1,670,282	9,128,049	31,294,938
2015	1	2	0	1		7,507,311	536,544	28,592	8,072,446	1,862 725	9,935,172	33,639,222
2016	2	2	0	0		8,133,626	583,085	31,122	8,747,833	2,042,234	10,790,067	36 030,286

Table 9-12 (Continued)
No. 2 Oil Expansion Plan Without Pumped Storage - Financial Sensitivity

	Unit Additions					UPS Production Costs				Levelized Capital Costs	Total Revenue Requirements	
Year	100 MW CT	600 MW Oil-ST	600 MW Coal	300 MW CC	600 MW PS	Fuel ($1,000)	O&M ($1,000)	Startup ($1,000)	Total ($1,000)	Total ($1,000)	Annual ($1,000)	1993 Cumulative Present Worth ($1,000)
2017	7	1	0	1		8,799,185	641,535	33,869	9,474,589	2,205,560	11,680,148	38,461,075
2018	8	1	1	4		9,527,582	752,233	36,938	10,316,753	2,587,130	12,903,883	40,983,111
2019	7	2	0	3		10,271,156	850,973	40,714	11,162,843	2,913,994	14,076,837	43,566,965
2020	5	3	0	3		11,149,141	955,130	44,039	12,148,311	3,332,598	15,480,909	46,235,613
2021	7	2	0	1		12,063,576	1,045,454	47,258	13,156,287	3,611,319	16,767,607	48,950,163
2022	8	2	0	1		13,091,866	1,146,755	51,837	14,290,458	3,912,758	18,203,216	51,717,785
2023	7	3	0	1		14,117,291	1,256,973	55,909	15,430,173	4,305,556	19,735,729	54,535,804
2024	9	2	0	1		15,322,399	1,376,710	59,969	16,759,077	4,642,587	21,401,664	57,405,727

Table 9-13
No. 2 Oil Expansion Plan With Pumped Storage - Financial Sensitivity

	Unit Additions					UPS Production Costs				Levelized Capital Costs	Total Revenue Requirements	
Year	100 MW CT	600 MW Oil-ST	600 MW Coal	300 MW CC	600 MW PS	Fuel ($1,000)	O&M ($1,000)	Startup ($1,000)	Total ($1,000)	Total ($1,000)	Annual ($1,000)	1993 Cumulative Present Worth ($1,000)
1995						887,775	41,199	2,437	931,410	0	931,410	771,502
1996						1,017,214	44,494	3,081	1,064,789	0	1,064,789	1,599,809
1997						1,174,356	47,659	3,806	1,225,821	0	1,225,821	2,495,353
1998						1,370,807	51,373	4,663	1,426,843	0	1,426,843	3,474,320
1999						1,601,216	55,790	5,427	1,662,433	0	1,662,433	4,545,513
2000	0	0	0	0		1,885,847	60,499	5,659	1,952,005	0	1,952,005	5,726,748
2001	2	1	0	0		2,094,701	70,845	5,529	2,171,075	56,605	2,227,680	6,992,768
2002	1	1	1	0		2,284,501	100,058	6,561	2,391,120	177,829	2,568,949	8,363,887
2003	0	1	0	0	1	2,507,713	114,816	6,256	2,628,785	273,219	2,902,004	9,818,507
2004	0	2	0	0		2,773,107	131,340	7,269	2,911,717	380,792	3,292,509	11,368,431
2005	4	1	0	1		3,050,008	154,641	8,660	3,213,308	473,977	3,687,285	12,998,560
2006	3	1	0	1		3,381,411	179,394	9,842	3,570,647	565,573	4,136,220	14,715,880
2007	1	2	0	0		3,746,023	201,754	11,576	3,959,352	690,516	4,649,868	16,528,972
2008	5	1	0	1		4,134,041	231,347	13,090	4,378,478	799,313	5,177,791	18,425,049
2009	4	1	0	1		4,546,777	262,878	14,694	4,824,349	906,554	5,730,903	20,395,957
2010	2	1	1	0		4,941,491	313,228	16,641	5,271,360	1,073,788	6,345,148	22,445,311
2011	5	1	0	1		5,415,781	351,011	18,268	5,785,060	1,194,644	6,979,704	24,562,425
2012	0	2	0	1		5,889,775	393,296	20,464	6,303,535	1,361,534	7,665,069	26,745,935
2013	2	2	0	0		6,421,230	430,692	22,319	6,874,241	1,522,748	8,396,989	28,992,374
2014	5	1	0	2		6,925,228	485,334	24,839	7,435,401	1,682,020	9,117,421	31,283,110
2015	1	2	0	1		7,487,827	538,411	26,834	8,053,071	1,874,464	9,927,535	33,625,593
2016	2	2	0	0		8,113,063	581,901	28,797	8,726,761	2,053,973	10,780,733	36,014,589

Table 9-13 (Continued)
No. 2 Oil Expansion Plan With Pumped Storage - Financial Sensitivity

	Unit Additions					UPS Production Costs				Levelized Capital Costs	Total Revenue Requirements	
Year	100 MW CT	600 MW Oil-ST	600 MW Coal	300 MW CC	600 MW PS	Fuel ($1,000)	O&M ($1,000)	Startup ($1,000)	Total ($1,000)	Total ($1,000)	Annual ($1,000)	1993 Cumulative Present Worth ($1,000)
2017	7	1	0	1		8,773,371	643,318	32,622	9,448,711	2,217,298	11,666,009	38,442,435
2018	8	1	1	4		9,496,054	753,849	34,323	10,284,227	2,598,868	12,883,095	40,960,408
2019	7	2	0	3		10,235,596	852,586	38,047	11,126,230	2,925,732	14,051,962	43,539,696
2020	5	3	0	3		11,108,191	956,664	41,210	12,106,064	3,344,337	15,450,401	46,203,085
2021	7	2	0	1		12,022,645	1,047,060	44,672	13,114,377	3,623,058	16,737,435	48,912,750
2022	8	2	0	1		13,046,279	1,148,217	48,645	14,243,141	3,924,497	18,167,638	51,674,964
2023	1	3	0	1		14,071,495	1,258,637	52,778	15,382,909	4,287,240	19,670,150	54,483,618
2024	9	2	0	1		15,270,630	1,378,248	56,931	16,705,810	4,624,271	21,330,081	57,343,942

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Table 9-14
Sensitivity Summary for Study Period

	1993 Cumulative Present Worth Cost		
	Without Pumped Storage (1) ($1,000)	With Pumped Storage (2) ($1,000)	Savings (Loss) (1)-(2) ($1,000)
Natural Gas Long-Range Expansion Plan			
Expected Parameters	51,511,472	51,562,552	(51,080)
Fuel Sensitivity	59,676,460	59,723,915	(47,455)
Financial Sensitivity	56,209,633	56,258,174	(48,541)
No. 2 Oil Long-Range Expansion Plan			
Base Parameters	52,630,051	52,581,028	49,023
Fuel Sensitivity	60,791,611	60,712,642	78,969
Financial Sensitivity	57,405,727	57,343,942	61,785

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Table 9-15
Sensitivity Summary Including End-Effects Period
1993 Present Worth of Pumped Storage Savings
($Million)

	Natural Gas	No. 2 Oil
Fuel Sensitivity		
Study Period	(47)	79
End-Effects Period	62	178
Life of Project Benefit	15	257
Financial Sensitivity		
Study Period	(48)	62
End-Effects Period	69	175
Life of Project Benefit	21	237

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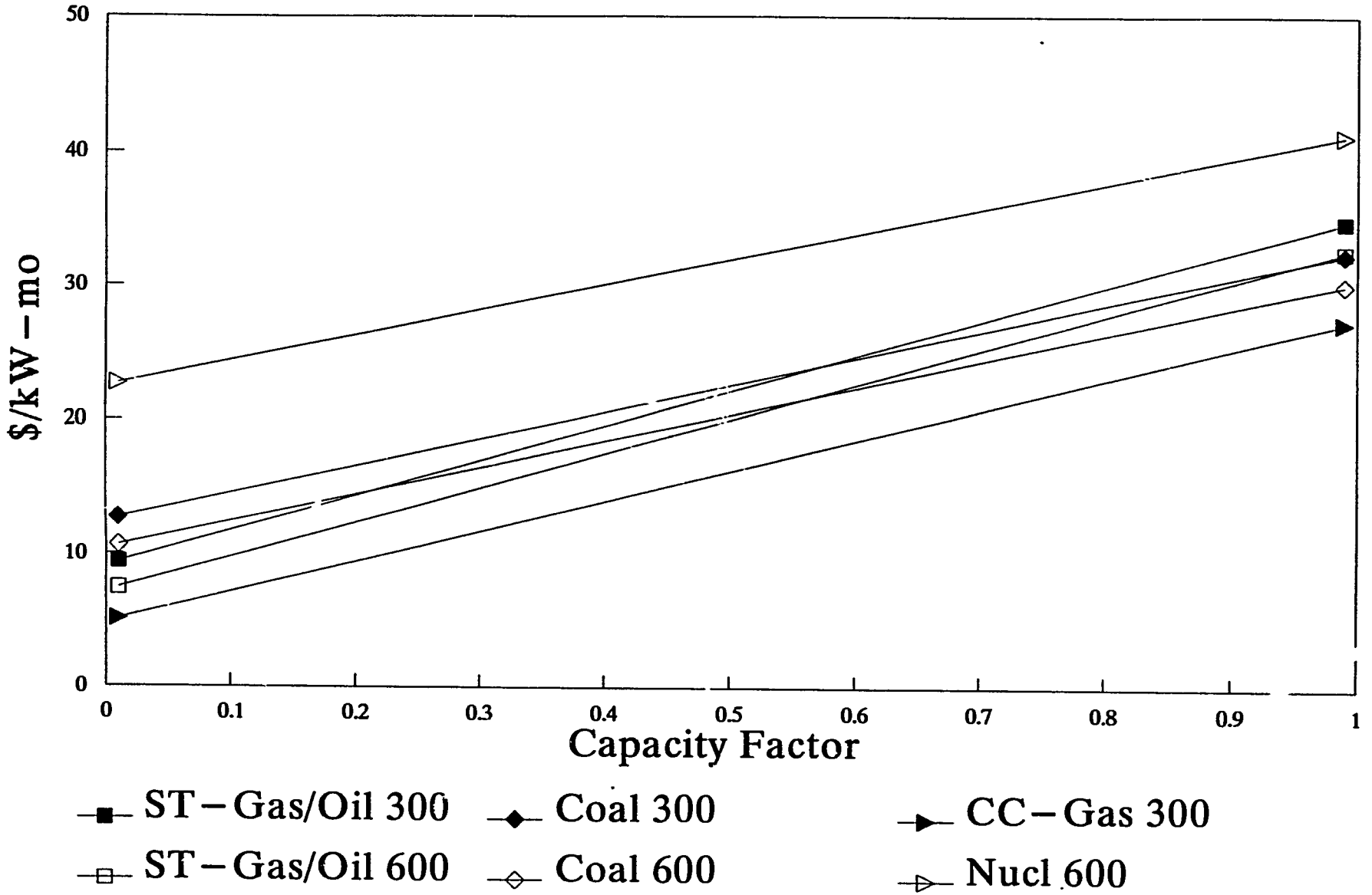
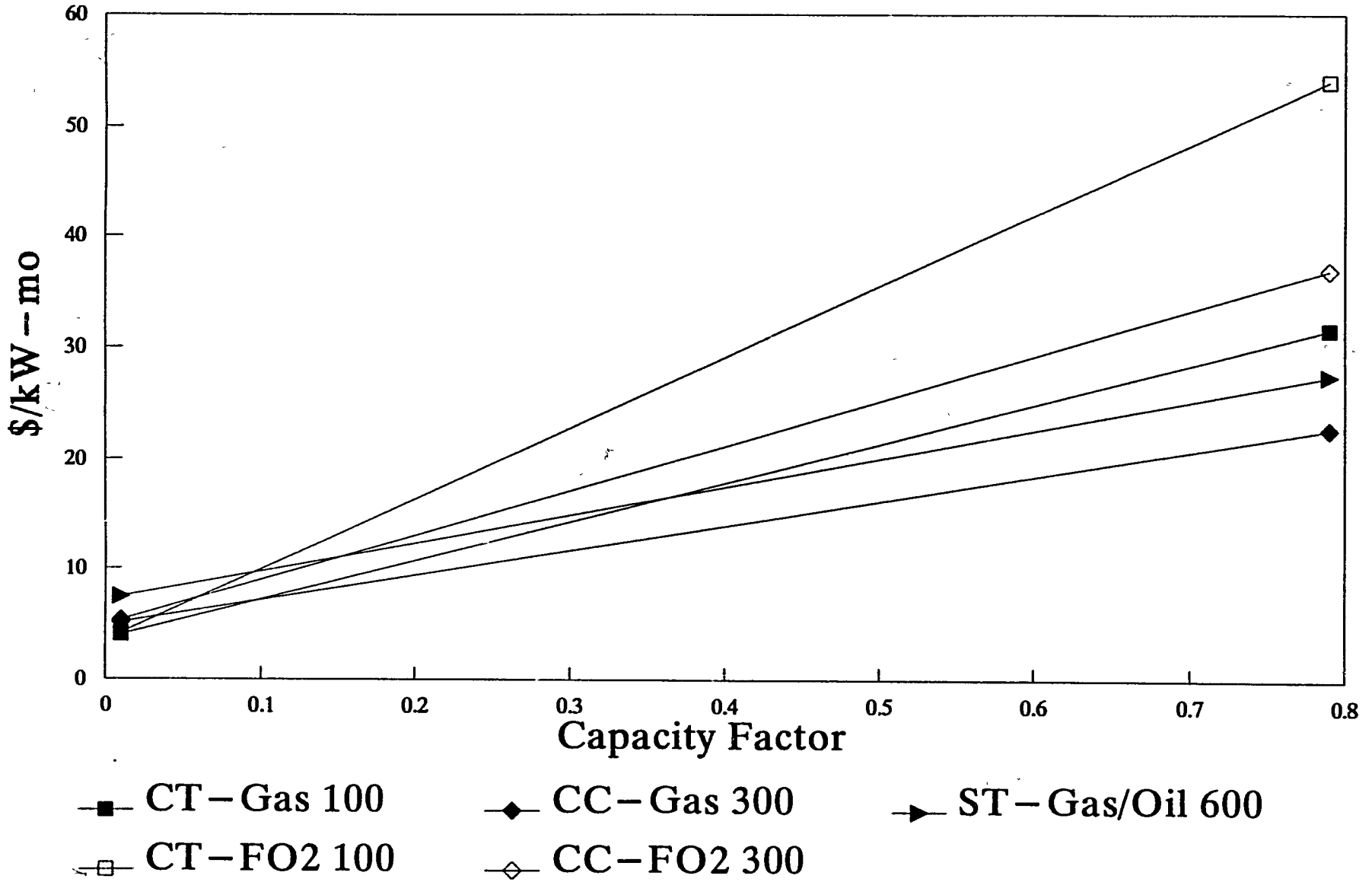
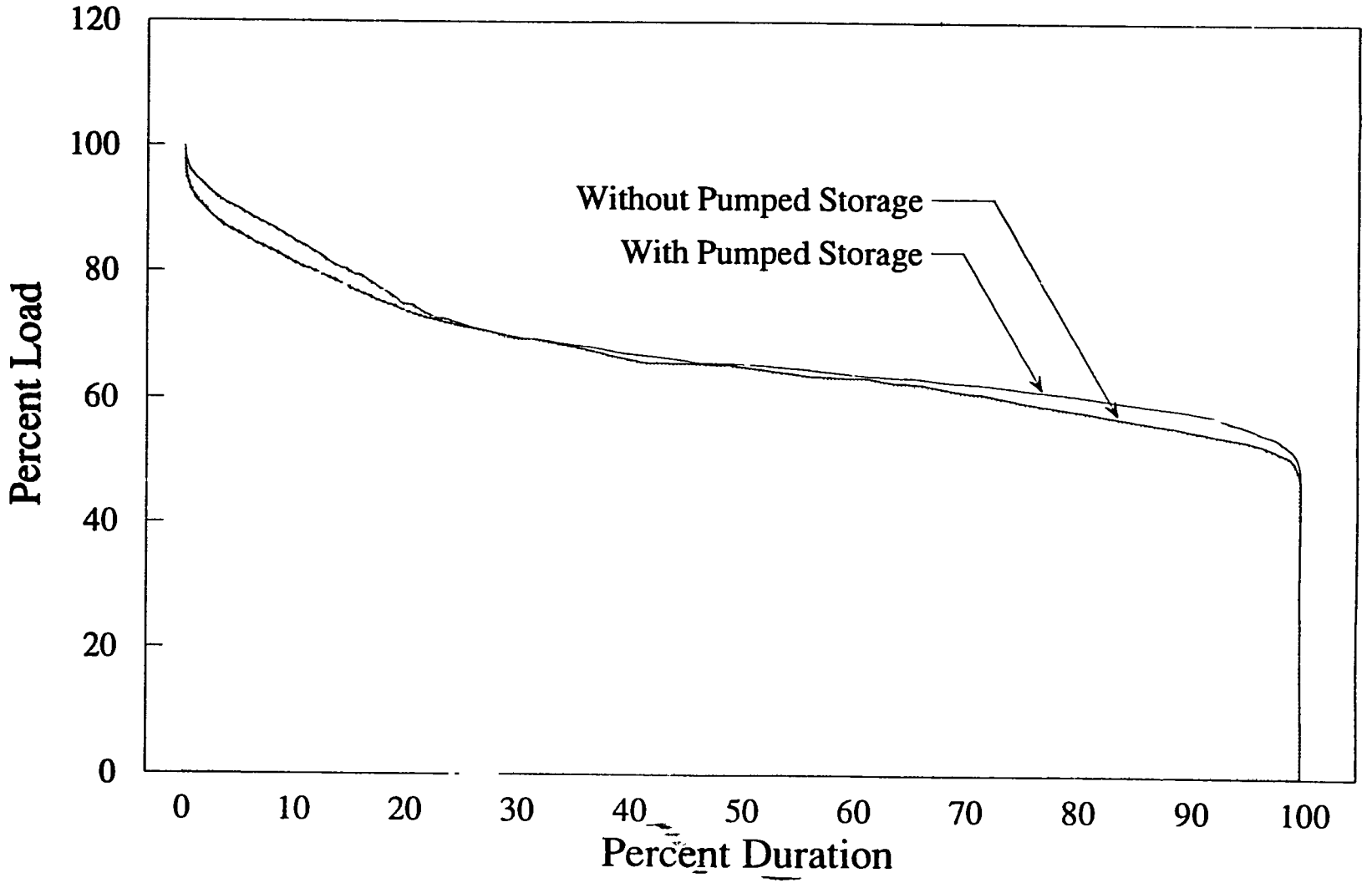


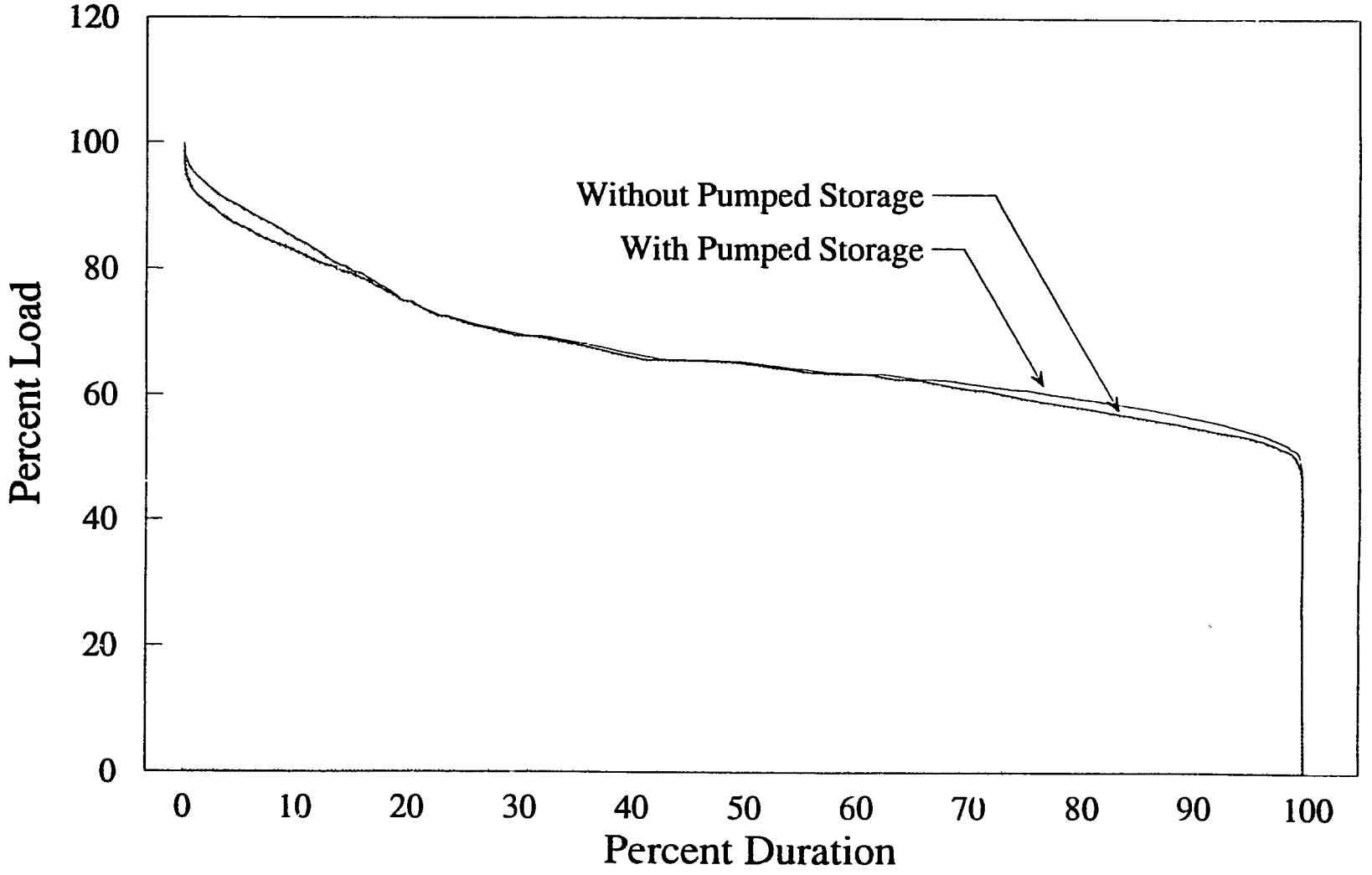
20 Year Levelized Screening Curve 2000-2019
Figure 9-1



20 Year Levelized Screening Curve 2000-2019
Figure 9-2



Calendar Year 2005 Thermal Load Duration Curve - Natural Gas Expansion Plan
Figure 9-3



Calendar Year 2005 Thermal Load Duration Curve - No. 2 Oil Expansion Plan
Figure 9-4

10.0 Dynamic Benefits of Pumped Hydro

The operating flexibility of a pumped hydro plant provides dynamic duty benefits in addition to the direct benefits of dependable capacity over the peak and economical energy transfer from off-peak periods to peak load periods. The dynamic benefits are due to the physical ability of a pumped hydro plant to respond quickly to changing system dispatch requirements. The potential dynamic benefits, also called secondary benefits, may include the following:[1]

- Spinning reserve.
- Load following.
- Unit commitment.
- Reduced system minimum loading.
- Voltage and power factor correction.
- Frequency regulation.
- Reduced thermal plant cycling.
- Improved system operating reliability.

When pumped storage provides the dynamic duties, it relieves steam units of such duties and results in lower system operating costs. The dynamic benefits are by their nature electric system, or geographical site-specific, and must be evaluated for a specific application. The cost savings due to dynamic benefits can be difficult to quantify, but have received increasing attention in recent years. The topic of dynamic benefits received international attention at the 1984 International Symposium and Workshop on the Dynamic Benefits of Energy Storage Plant Operations in Boston sponsored by EPRI and the US Department of Energy. The various dynamic benefits were estimated under a wide range of utility conditions.[2] These estimates were also included in the EPRI "Pumped-Storage Planning and Evaluation Guide."[1]

Each of the potential dynamic benefits are discussed below:

10.1 Spinning Reserve

Spinning reserve is the spare generating capacity or disconnectable load which can respond rapidly to a sudden loss of a generating unit or imported power. Strictly speaking, spinning reserve should be synchronized to the system.

Since most thermal units are designed to a given maximum efficiency at or near their rated output, running a unit at part-load in order to provide synchronized spinning reserve is not the most efficient use of its capacity. When these units are

prevented from running at full load because of the spinning reserve duty, the spinning reserve carried by these units incurs an opportunity cost.

Pumped storage generating at less than its full capacity provides high quality spinning reserve and has a high value during the peak period when spinning reserve is expensive. The POWRPRO software captures this economic benefit of pumped storage but its value is embedded in the annual production cost. This benefit is therefore included in the primary economic evaluation of Section 9.3. No additional secondary benefit will be included in this section for spinning reserve.

Other spinning reserve benefit opportunities may exist for pumped storage. When a pumped storage plant is pumping, its pumping load can be tripped instantaneously, providing a high quality spinning reserve. However, spinning reserve is generally plentiful when the system load is low, and the pumped storage spinning reserve during the pumping mode may not be worth much. Pumped storage in the standby mode may or may not be classified as spinning reserve. Neither of these are included in POWRPRO evaluation.

An additional spinning reserve benefit could be realized by operation of the pumped storage plant in a synchronized but unloaded mode at those times when it is neither in a generating nor pumping mode.

10.2 Load Following

Thermal units cannot change their output instantaneously and sustain it. Oil fired or gas fired units typically have a ramp rate limit of about 1 to 3 percent of maximum capacity per minute. In contrast, pumped storage has a ramp rate capability in the range of 10 to 30 percent per minute.

The UPS daily load swings between the minimum and maximum may require multiple units or even CTs to pick up load at the same time because of thermal ramping limitations. These units would then operate at part-load capacities with resulting increased costs. On the other hand, pumped storage can operate full pumping at light load, and as load grows, individual pumps can be turned off one at a time and then reversed to generation, thus following the load.

Reference 2 estimates the equivalent capital cost benefit of load following to be 10 $/kw in 1982 dollars. Load following benefits are partially captured by POWRPRO with modeling of ramp rates and hourly loads. Time steps of 30 minutes or less are needed to fully represent the effect of ramp rate limits. Ebasco estimates the load following benefits not captured by POWRPRO to be $5/kW in 1982 dollars.

10.3 Unit Commitment

Unit commitment benefits refer to the potential savings related to the reduced number of startups and shutdowns of thermal generating units in the system due to the operation of the pumped storage plant. Unit commitment savings include the savings of starting costs, but also the savings from avoiding minimum loading of units at lower efficiency, and reducing the wear and tear of thermal units, etc.

POWRPRO's methodology includes unit commitment and the savings of startup costs that are captured. The reduction in wear and tear on thermal units from less frequent shutdowns and startups is difficult to quantify, but may provide substantial benefits in reduced maintenance for the UPS system. POWRPRO did not capture the reduced maintenance benefits and no additional benefit is included.

10.4 Reduced System Minimum Loading Problem

Minimum loading problem occurs when the sum of the minimum operating capacities of all thermal units on line exceeds the system load at that time, generally at night when the load is low. This can require thermal units to be shut down. Other operating problems at light load periods include system stability problems, as well as voltage and frequency regulation problems. The storage pumping load helps alleviate the minimum loading problem.

On the UPS system during periods of high water, High Dam must run at constant high output, which requires that thermal units either be shut down during light load or run at minimum load with resulting part-load inefficiency. The older thermal units are not designed to cycle and so, if shut down, must be put on cold standby. This problem is expected to get worse as load growth occurs, since the peak is growing faster than the minimum load. Pumping load would alleviate this problem. No additional benefit has been taken for alleviating this problem.

10.5 Voltage and Power Factor Correction

Pumped storage can be equipped to regulate voltage in its vicinity. The units can provide power factor correction and voltage regulation in the generating or pumping mode and can also operate unloaded as synchronous condensers.

It is expected that the pumped hydro plant will be connected into the 500 kV transmission planned for the Wadi Araba region as discussed in Section 8.2.5. The 500 kV transmission is planned from Tabbin to Zaafarana to Suez with possible interconnection to neighboring countries. The pumped storage plant would be expected to provide important voltage regulation for the 500 kV system, and may provide savings from replacing otherwise needed static var compensators (SVC).

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Voltage regulation capabilities provide benefits which include enhancing system stability and providing higher transfer limits. Many large power systems currently are having operating limitations due to voltage regulation. Characteristics of a pumped storage plant would provide important operating advantages to the UPS system.

These benefits are not evaluated by POWRPRO, and would require evaluation by system studies including load flow and transient stability studies. Reference 2 estimates this benefit to be $5/kW in 1982 dollars.

10.6 Frequency Regulation

Pumped storage is potentially ideal for frequency regulation with its fast ramping capability. Its efficiency does not degrade as steeply as steam units when the operating point deviates from the base point. Frequency regulation costs money because it requires a certain amount of spare generating capacity to be dedicated and reserved. The advantage of having pumped storage for frequency regulation is that it may allow a steam unit to be taken off frequency control and loaded to its maximum economic level. POWRPRO does not provide an estimate of this benefit as frequency regulation is not modeled. Reference 2 estimates this benefit to be 10 $/kW in 1982 dollars.

10.7 Reduced Thermal Plant Cycling

Pumped storage potentially reduces the number of thermal unit startups. Load following and frequency regulation capabilities reduce the random fluctuations of system generation output. Utilization of these capabilities translate into reduced wear and tear on thermal units, lower maintenance costs, higher reliability, better efficiency and longer equipment lives. Reduced forced outage rates for thermal units would result in lower annual production costs. POWRPRO does not quantify these benefits. Reference 2 estimates this benefit to be $10/kW in 1982 dollars.

10.8 Improved System Operating Reliability

The fast response time of pumped storage makes it ideal for covering forced outages. Pump load can be disconnected instantaneously. In standby mode, units can be started and brought to full power in a few minutes. When the units are already on line, they can be ramped up much faster than steam units. All these characteristics result in more reliable system operation. The value of the improved system reliability is not estimated by POWRPRO. Reference 2 estimates this benefit to be $5/kW in 1982 dollars.

10.9 Estimates of Dynamic Benefits

A summary of Ebasco estimates of dynamic benefits for a 600 MW pumped storage plant on the UPS is contained in Table 10-1. These benefits are from Reference 2 and are escalated to 1993 by 5 percent per year. The total benefit to UPS is estimated to be $58/kW in 1993 dollars.

10.10 References

1. EPRI, *Pumped Storage Planning and Evaluation Guide*, Research Project 1745-30, January 1990.

2. A. Ferreira and C. E. Carver, "The Importance to Utilities of Dynamic Duty Benefits from Pumped Storage," Presented at the International Symposium and Workshop on the Dynamic Benefits of Energy Storage Plant Operation, May 7-11, 1984, Boston, MA, Sponsored by US Department of Energy and Electric Power Research Institute.

Table 10-1 Ebasco Estimate of Dynamic Benefits Equivalent Capital Cost (1993 Dollars per Kilowatt)	
Load Following	8
Voltage Regulation	8
Frequency Regulation	17
Reduced Thermal Plant Cycling	17
Improved System Operating Reliability	8
Total	58

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11.0 Environmental Evaluation

11.1 General

This section presents the benefits and generic environmental effects of the combustion turbine/combined cycle alternatives and the pumped storage alternative. It focuses on the differences between the generation expansion plan with pumped storage and the generation expansion plan without pumped storage.

To assess the benefits and environmental effects of the alternatives, it is necessary to consider the components of the alternatives that could affect the environment during either construction or operation. Construction of 600 MW of combustion turbine/combined cycle units would typically require a site or sites totalling less than 50 acres. Construction would take from 1 to 3 years, depending on whether combustion turbines or combined cycle units were being constructed. Several hundred workers would be required; however, most of the capital cost would be for equipment manufactured outside of Egypt. Construction would include site improvements, a gas and/or oil pipeline spur, a weather enclosure, water supply facilities, cooling towers, stack, switchyard, and a transmission line linking the regional grid. During operation, the greatest potential for impacts would be from air emissions. It is assumed that because of the small site requirements, the plant/plants could be sited in areas where other environmental impacts are minor.

Environmental impacts caused by construction and operation of pumped storage plants are more sensitive to specific sites and pumped storage schemes. Potential sites and schemes under consideration are discussed in Appendix H. Appendix I provides a description of the alternative sites. Site-specific impacts will be discussed in subsequent phases of this study. For this report, it is assumed that the pumped storage plant would be located in the vicinity of Ain Sukhna. The selected site would be several hundred acres and would need to be close (within a few miles) to a water supply source. It would take about 5 years and require several thousand workers to complete the pumped storage project. A construction camp complete with a self-supporting infrastructure would be required. The project would entail an upper and lower reservoir, a powerhouse, switchyard, and transmission line connecting with the regional grid. During operation, pumping energy would likely be supplied by natural gas or oil fired combined cycle or steam units.

11.2 Benefits and Environmental Impacts Associated With Combustion Turbine and Combined Cycle Units

Typically, combustion turbines and combined cycle units are sited close to load centers, existing transmission lines, a fuel supply, and a cooling water supply. Because of air quality concerns in the vicinity of Cairo, it is assumed that the combustion turbines and combined cycle units would be located south of Cairo, along the Nile River.

Construction of the combustion turbines and combined cycle units would likely require the temporary loss of a few acres of agricultural land in order to obtain access to an adequate supply of cooling water. It is assumed that the plant locations themselves could be located outside the irrigated strip of land that parallels the Nile. However, a water supply and a discharge line would need to be constructed from the water source to the plant location. Construction could temporarily affect agricultural production along the route of the water supply and discharge lines, but such a disruption would be a minor short-term impact. Similarly, it is assumed that the plant would tie into the north-south transmission line paralleling the Nile River. Construction of the transmission line to the existing transmission line would likely be a minor short-term impact.

Because of the small site requirements, it is assumed that the combustion turbine/combined cycle plants could be located in industrial or unpopulated areas where construction dust and noise would not pose a significant problem. Construction of the combustion turbine/combined cycle alternative would have positive socioeconomic impacts on the region. A comparison of these impacts with those of the pumped storage alternative is presented in Section 11.5.

The primary impact of the plants during operation would be the air quality impacts. Emissions of sulfur dioxide, nitric oxides, and particulates would exacerbate the existing air quality problems in the region. However, because the units would burn either natural gas or No. 2 oil, air quality impacts would be minimized.

Because of the small site requirements and consequently large number of possible site locations, it is assumed that there would be no significant recreational or touristic impacts. There could be an adverse visual impact of the power plant stack if the site is situated in a visually sensitive area. The power plants themselves would have no unique features that would make them attractive as touristic sites.

11.3 Benefits and Environmental Impacts Associated With Natural Gas/Oil Steam Units

Construction impacts attributed to natural gas/oil steam units would be similar to those of combustion turbines and combined cycle units. Natural gas/oil steam units would require a site area similar to those of combined cycle units. However, steam units have a higher capital cost and require a longer construction period. Therefore, noise and fugitive dust impacts would extend over a longer period, but these impacts would not likely be significant. The most significant difference between steam units and combustion turbine/combined cycle units would occur during project operation when steam units are fired by No. 6 oil. Burning of No. 6 oil would cause higher emissions of sulfur dioxide, nitric oxides, and particulates that would reduce regional air quality.

11.4 Benefits and Environmental Impacts Associated With Pumped Storage Hydroelectric Plant

The pumped storage project has the potential to affect recreation and tourism within the project area. The Governorate of Suez is promoting development of tourism in the Gulf of Suez region (Appendix I). Seven touristic villages have been built or are under construction in the Governorate of Suez including one that is adjacent to an alternative pumped storage site. Construction of the pumped storage at this site has the potential to adversely affect recreation and tourism through increased noise and fugitive dust during the 5 year construction period. Further, operation of the pumped storage project has the potential to adversely affect tourism and recreation by reducing the beach and nearshore area available for recreation, particularly if the pumped storage project uses the open cycle concept (Appendix H). However, the pumped storage development could also complement recreation and tourism development.

Alternative sites that are several thousand feet away from touristic villages and the more densely used beach areas may be available. This would result in minimal fugitive dust and noise impacts. Further, standard measures that minimize noise and fugitive dust may also be employed. The location of the intake could also be selected to minimize disruption to the beach and associated recreation. The jetty or breakwater constructed for the plant water supply could serve as protection for a marina which also could be constructed by private development to enhance the area's touristic value.

It is assumed that the construction workers would not relocate their families to the project site. However, the alternative sites are too far from population centers

to permit daily commuting. Therefore, the construction workers would stay at the construction camp and return to their homes on a weekly, biweekly, or monthly basis. Depending on the percent utilization of the touristic villages, these villages also could be used to house construction and operation personnel.

The camp would have infrastructure services including a hospital, a school for children of foreign nationals, shops and services, water supply, and a wastewater treatment facility. If determined appropriate by HPPEA, the camp facilities could be made available to the local population during or after construction. This would be a positive socioeconomic impact, since few infrastructure facilities presently exist in the Ain Sukhna area. After construction is completed, the construction camp facilities could be converted to permanent facilities for use by the local population or as touristic facilities. Desalinated water required for the construction camp and possible reservoir filling could also be made available to the local area.

The pumped storage project would have a significant positive economic effect on the local and regional economy. This is discussed further in Section 11.5.

The impact of the project on marine life is expected to be minor because this area of the Gulf of Suez has been devastated by the Egypt-Israeli war and oil exploration and development.

The pumped storage facility itself, because of its uniqueness, could become a tourist attraction. Projects of this type are often constructed with visitors' centers. However, for national security reasons, this may not be feasible for the pumped storage project.

Pumping energy for the pumped storage plant is expected to come from gas fired combined cycle units or natural gas/oil steam units. It is also assumed that the pumped storage plant would displace gas fired combustion turbines (Section 9.0). If combined cycle units provide the pumping energy, there would be a fuel savings and a 10 to 20 percent reduction in air emissions even with the efficiency losses in the pumped storage system. However, because air emissions from natural gas fired units are not considered significant, the reduction in air emissions is also not considered significant. If natural gas fired steam units provide the pumping energy, there would be about a 10 percent increase in air emissions.

If No. 6 fuel oil is used to fire steam turbines and the steam turbines are providing the pumping energy, there would be about a 10 percent increase in fuel consumption (on an equivalent Btu basis). However, because natural gas would be displaced by No. 6 oil, air emissions would be increased and regional air quality would decrease.

11.5 Socioeconomic Impacts Associated With Pumped Storage Hydroelectric Plant and Thermal Alternative

This section considers the differences in socioeconomic impacts between the pumped storage and combustion turbine generation expansion alternatives.

11.5.1 Types of Economic Impacts

The proposed alternative projects would stimulate economic activity during their respective construction phases. Economic impacts would result from material purchases, construction payrolls, and related indirect and induced spending, or "multiplier effects" which would take place in Egypt. In assessing the economic impacts of the proposed alternative projects, it is important to recognize that economic benefits associated with construction would occur for a relatively limited time during the actual construction phase (approximately 5 years).

11.5.2 Economic Assessment Methodology

The basis for the multiplier selected for this analysis is an input-output model developed by the US Department of Commerce, Bureau of Economic Analysis (BEA). The model provides the basic methodology for the assessment of potential regional economic impacts, with modifications to produce multipliers specific to the region of the proposed action. Quantification of the effects of material purchases, during the construction phase, relies upon the following:

- Estimates of material expenditures.
- Determination of specific goods and services required.
- Estimates of local purchases.
- Application of multipliers to evaluate potential project impacts on the regional economy.

Quantification of the effects of payroll-related impacts, during the construction phase, relies upon the following:

- Estimates of the payroll expenditures.
- Adjustments for fringe benefits, taxes, and other payroll deductions.
- Adjustment for employment of nonlocal labor.
- Application of an appropriate multiplier to determine total impacts on the local economy.

However, the determination of an appropriate multiplier for this project also takes into account various misalignments in the Egyptian economy. These misalignments result in a need for revaluation of labor costs, capital costs, and foreign exchange costs. Coupled with the existence of a large parallel (black) market, these

misalignments require the modification of the above methodology because of the lack of clear and discernible input-output relationships between various industrial sectors.

11.5.3 Assumed Impact Area

For the purpose of quantifying the difference in socioeconomic impacts from construction of the pumped storage project and natural gas combustion turbine facilities, it is assumed that relevant impacts of material purchases and payrolls during the construction phases of both alternatives are those taking place in Egypt. These expenditures are estimated at $148 and $49 million, respectively (1993 dollars). The estimates are based on the assumption that 30 percent of the estimated $493 million capital cost for the pumped storage facility and 15 percent of the estimated $328 million capital cost for the construction of the natural gas combustion turbines would take place in Egypt.

11.5.4 Economic Impacts During the Construction Phase

In lieu of a detailed breakdown of projected construction and materials and salary expenditures, a combined regional impact analysis was conducted. In conducting the analysis, the following assumptions were made:

- An output multiplier of 1.5 was assumed. That is, it is estimated that for every $1 of initial construction expenditures, an additional $1.5 in expenditures within the country will be generated.
- An employment multiplier of 20 jobs per million dollars was assumed. That is, it is estimated that for every one million dollars in additional expenditures, 20 jobs would be created.

Construction impacts for the proposed project are projected as follows:

- Pumped Storage Plant--With $148 million in local expenditures, it is estimated that this project would result in the creation of an additional $222 million of output in Egypt. The $222 million in additional output is expected to create an additional 4,440 person years of employment in Egypt.
- Natural Gas Turbine Plant--With $49 million in local expenditures, it is estimated that this project would result in the creation of an additional $74 million of output in Egypt. The $74 million in additional output is expected to create an additional 1,480 person years of employment in Egypt.

The pumped storage plant would have a much larger positive impact on Egypt by injecting $151 million more into the economy and providing approximately 3,000 additional person years of employment.

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Appendix A
POWRPRO Description

POWRPRO - Production Costing Model

Program Manual

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Introduction

POWRPRO is a computer based, chronological production costing model developed for use in power supply systems planning. It was developed to enable more detailed study of systems than is possible with simulations based on load duration curves. The effect of time related features may be examined, such as ramp rates, startup and shutdown times and costs and minimum uptimes and downtimes. This in turn means that the roles of generation unit types (baseload, peaking, etc.) can be more realistically defined than is possible with load duration based models.

Since POWRPRO models details which many other programs do not, it requires additional input data. POWRPRO has been designed with the flexibility to operate in a simpler mode which uses default values for some of the data. In this mode, POWRPRO performs similar to other existing models. This flexibility to use either minimal or detailed input in the same framework makes POWRPRO a powerful tool for a wide range of system planning.

The computer program for the model is written in FORTRAN language and adheres to 1978 ANSI Standards (FORTRAN 77). Versions are executable on mainframe, mini, and desktop computers.

The production costing model simulates the operation of a power supply system over periods of up to 30 years. Unit commitment and dispatch are explicitly treated at each hour. Unscheduled outages are randomly assigned. Maintenance periods may be user specified or automatically scheduled by the model. Unit commitment decisions employ unit priority ordering. A nominal ordering is calculated based on average cost of energy at a user specified fraction of maximum capacity. The average may include energy only or energy plus variable operation and maintenance. When capacity must be added on-line the nominal ordering is modified to reflect the effects of current hourly demand shape, startup costs, ramp rates, and minimum up- and downtimes as well as a look ahead for future load requirements. Power sources are dispatched based on the criterion of equal incremental cost operation. The incremental cost may be fuel only or fuel plus variable O&M cost.

Overview

The production costing model simulates the hour by hour operation of a power supply system over a period of up to 30 years. Each hour is analyzed in detail. The on-line commitment of the previous hour is examined to determine whether units should be replaced by more efficient off line units that have become available. If the

capacity of the on-line commitment exceeds demand and spinning reserve requirements the feasibility of taking units off line is evaluated. If the on-line capacity must be increased a priority ordering is calculated for the available off-line units to guide the selection of capacity additions. Calculation of the priority ordering takes account of how long the additional capacity is needed, startup and shutdown costs, ramp rates, and other time associated factors.

The governing model criterion is identification of the least cost way to operate the system to meet hourly demands and reserve requirements while simultaneously satisfying all constraints. The considered cost is fuel plus startup and shutdown costs; optionally, variable operation and maintenance cost may be included.

The simulation allows for the use of substantial data input. Generating unit data includes fuel type and burn rate characteristics, ramp rates and other time related features, maintenance requirements, etc. If the user desires or if more detailed data are not available, simplified data can be used such as a single heat rate for a unit instead of a heat rate curve and dynamic time related features such as ramp rates and startup times can be eliminated by setting the ramp rates very high and setting startup times to zero. The result of using simplified data is that the model will then function in a manner similar to less sophisticated load duration curve based models. Fuel prices and hourly demands must be provided for the entire simulation period. Unit start and retirement times must be given and purchase availability times specified if applicable. Data variations such as seasonal changes in generator capacity may be described.

Simulation output consists of summary reports. An annual report is always prepared, consisting of a breakdown by unit of generation amounts, fuel costs, operation and maintenance costs, and hours on-line. Optional reports include startup and shutdown summaries and pollutant emission summaries. There are options to obtain these same reports by month or by arbitrary time periods.

The principle parts of the model are:

- Input processing.
- Forced outage handling.
- Maintenance scheduling.
- System parameter updating.
- Unit commitment and dispatch.
- Output reports.

Input preprocessing consists of scanning the input data file for errors and inconsistencies, and logging the commercial operation and retirement of power sources. A data echo is optionally printed.

Forced outages are simulated by causing units to be unavailable for service at randomly selected intervals in periods of 1 to 4 days.

Maintenance periods may be explicitly scheduled or the program will schedule an annual period of requested length.

Generating unit and purchase parameters may be updated during the simulation period. Updates are scheduled by date and become effective the first hour of a day.

Hour by hour unit commitment and dispatch, including the impact of pumped storage plants and fuel limits, are processed as described above.

A summary flow chart of model logic is shown on Figure 1.

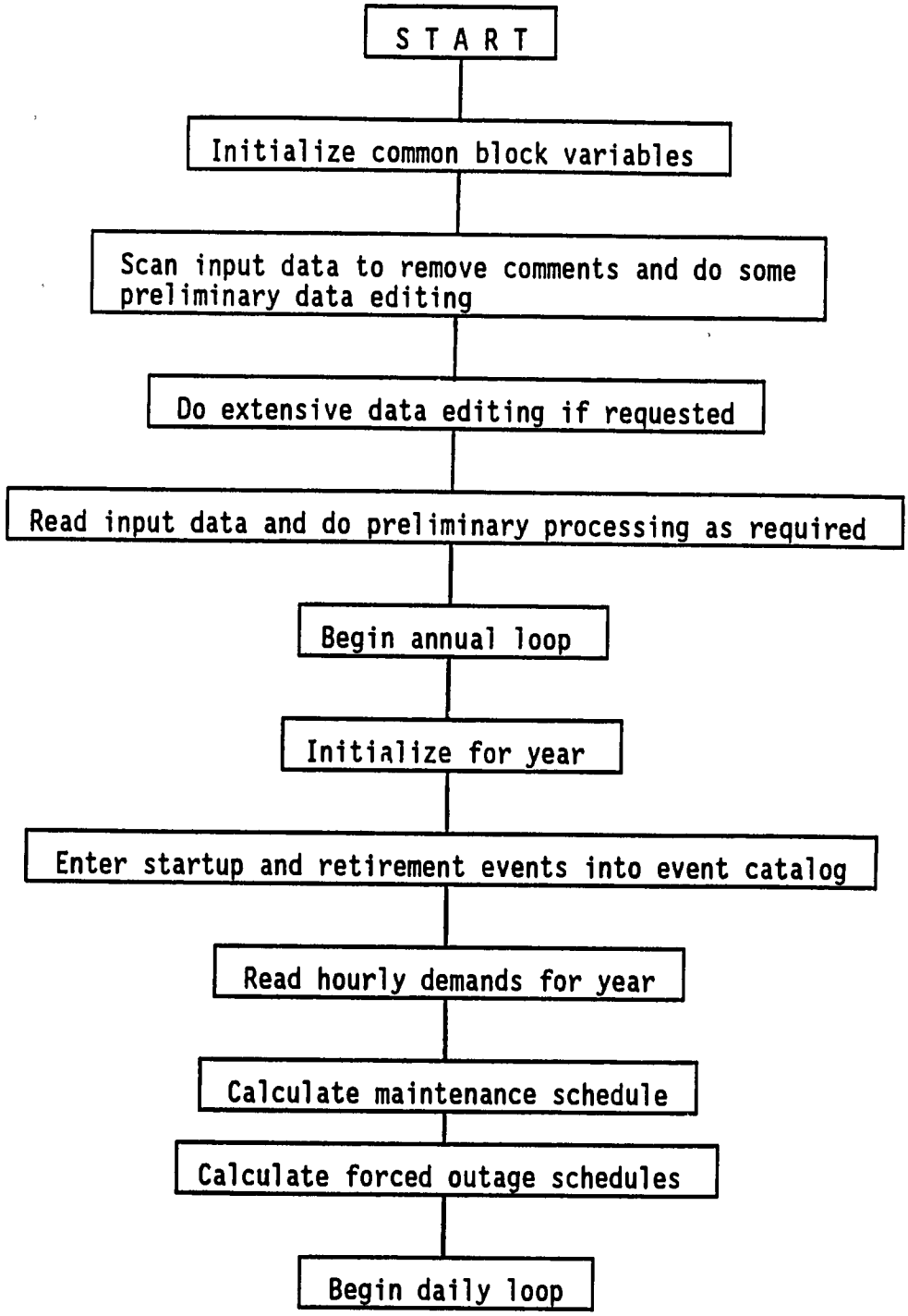

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Figure 1 - Model Flowchart

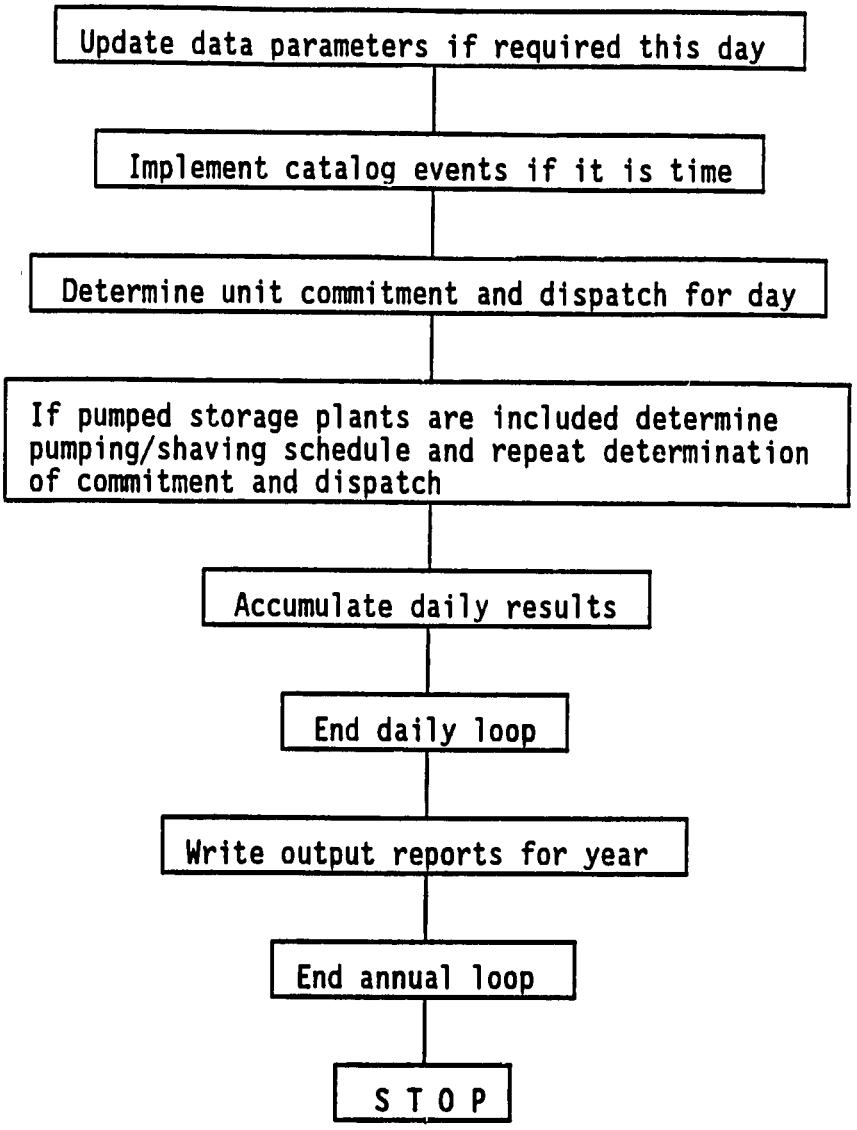

Figure 1 - Model Flowchart (Concluded)

Input/Output Summary

The following categories of input data are used by the production costing model:

- Run control parameters.
- Hourly demands.
- Generator descriptions.
- Purchase option descriptions.
- Fuel and purchase prices.
- Reserve requirements.
- Generator commercial operation and retirement schedule.
- Parameter updates.
- Pumped storage plant descriptions.
- Fuel limits parameters.
- Output requests.

Model output always includes an annual cost summary report. This report contains a breakdown by generator and purchase option of energy generated or purchased, fuel used, fuel or purchase cost, hours on-line, heat rate, variable and fixed O&M costs, and operating and average capacity factors. Optional output includes annual summaries of number and cost of startups and shutdowns, maintenance and outage hours, and emission amounts.

The same reports may be obtained on monthly intervals, or for arbitrary periods specified in the input.

There are also output options for obtaining specific data written to separate output files. These data include:

- System hourly incremental fuel cost.
- System hourly average fuel cost.
- Annual totals of summary data.
- Hourly generation by a specified generating unit.

Generator Representation

Power generators must be described to a detail consistent with the commitment/dispatch detail of the model. The following data are required.

- Maximum and minimum rated capacity.
- Type (must-run, quick-start, or neither).
- Forced outage rate.
- Fuel price.

- Variable and fixed operation and maintenance cost rates.
- Fuel burn rate parameters.
- Maintenance requirements.
- Ramp rates.
- Required minimum on-line and off-line times.
- Startup times.
- Startup fuel amount.
- Shut down cost.
- Capacity first hour on-line.
- Pollutant emission rates.

Fuel price is specified by annual escalation parameters or by reference to a price table of annual values. Variable and fixed operation and maintenance cost rates are specified by annual escalation parameters.

Fuel burn rate is specified by the coefficients of a second order burn rate equation or by a table of incremental burn rates and a reference average burn rate. If equation coefficients are specified a two point incremental table and a reference burn rate are generated. Two operations are performed on the incremental burn rate data to accommodate the dispatch procedure. Linear curve fits are calculated for the table segments and integral over each segment are calculated and stored.

Maintenance requirements are specified in one of two ways. The required number of maintenance days may be specified and one annual period will be automatically scheduled. Alternately, up to two periods per year may be manually scheduled by specifying number of days and a beginning date.

Start up times and costs are handled by specifying

- Time to start from cold condition.
- Time to start from warm condition.
- Time to cool to warm condition.
- Cost to start from cold condition.

Cool down times are assumed to be in the same ratio as start up times, and start up costs are assumed to be proportional to start up times. Given these data and assumptions, a functional relationship is established between start up time and cost and length of time off-line.

Shutdown is assumed to occur instantaneously. Shutdown cost is a fixed dollar amount.

Pollutant emissions are assumed to be directly proportional to amount of fuel burned. Emission rates are specified in pounds/million BTU burned.

Purchase Representation

The following data describes a purchase option.

- Maximum and minimum limits on power available for purchase.
- Type (must-run, quick-start, or neither).
- Forced outage rate.
- Price.

For regular purchase options annual price is specified by escalation parameters or by reference to a price table. Provision is also made for purchases with prices which vary from hour to hour. These latter prices must be provided in separate input files.

Two-point, pseudo incremental burn rate tables are constructed for purchases for uniformity with generation units in the dispatch procedure. The slope of the incremental curve is made small to approximate a uniform price.

Maintenance Scheduling

Automatic maintenance scheduling may be requested for one period per year, or up to 2 periods per year may be user scheduled.

A generator is not taken down for maintenance in the year of retirement. In the startup year, automatic scheduling is bypassed unless the unit starts on the first day of the year. User scheduled periods are observed in the startup year.

Automatic scheduling is designed to minimize the impact on ability of the system to meet demand. Units to be automatically scheduled are ranked in order of potential impact. The ranking measure chosen is the product of rated maximum capacity times number of maintenance days required, times one minus the forced outage rate. The peak hourly demand (daily peak) is identified for each day of the year. The highest ranking unit is scheduled for maintenance in the contiguous set of days with the smallest sum of daily peaks. The daily peaks in the maintenance period are adjusted upward by the rated capacity of the unit scheduled and the next unit in rank order is scheduled. The process is continued until all automatic scheduling is completed.

Forced Outages

Units are taken out of service in forced outage periods of 1 to 4 days. The period length for a unit is determined from the specified outage rate. The interval between periods is randomly scheduled.

The impact of forced outage is solely to make a unit unavailable for service. Startup and shutdown times and costs are not assessed. If a unit is on-line at the beginning of outage it is returned to on-line at the end of the outage period. The accounting of on-line and off-line time is not interrupted.

Outage schedules are determined at the beginning of a year for the entire year. The procedure for a given unit is as follows.

- Determine the length of the outage period from the forced outage rate and the criterion that, on average, the unit should experience about 30 outage cycles per year.
- Calculate the average time between outages from the forced outage rate and the length of the outage period.
- Calculate the required number of outage cycles per year.
- Calculate time from beginning of year to first outage by generating a uniformly distributed random number between 0 and 1 and entering an exponential distribution with mean equal to the average time between outages.
- Calculate time between outages as described in the previous step until the required number of outages are scheduled.
- In general, the total time occupied by the outage cycles will exceed one year. Compress the time between outages in proportion to fit the cycles into a year.

The outage schedule so determined is stored and referenced as the year is simulated.

Unit Commitment

The object of the unit commitment procedure is to retain those power sources on-line which most economically satisfy demand and reserve requirements while observing operational constraints such as ramp rates, required minimum on-line times, etc.

An economic priority ordering of generators and purchase options is determined based on average cost ($/MWh) at an input specified fraction of maximum rated

capacity plus (optionally) variable operation and maintenance cost rate. Initial conditions for the simulation are obtained by selecting power sources in priority order until the sum of rated capacities is sufficient to satisfy the demand of the first hour, and then dispatching this commitment.

The ongoing selection of on-line commitments for simulation hours begins by reviewing the commitment and dispatch of the previous hour. Units (or purchase options) which have become unavailable are set aside. Units which are of lower priority than available off-line units are tentatively removed.

If the capacity of the reduced commitment is enough to satisfy the current demand and reserve requirement, low priority units are examined for removal. Account is taken of required minimum on-line time, how long it will be before additional capacity will be needed, and the cost to stop and start the unit compared with keeping it on-line at minimum generation.

If the capacity of the reduced commitment is not sufficient to meet the current demand and reserve requirement, a temporary priority ordering for the off-line units is calculated and units are selected for service in priority order until there is enough capacity on-line. The temporary priority ordering takes account of the average additional capacity needed and for how long, start up times and costs, unit size compared with additional capacity needed, maintenance schedules, and required minimum on-line and off-line times.

Dispatching

After an on-line commitment is selected for an hour, an economical distribution of loading for the power sources is determined. The dispatch criteria is that the power sources all be operating at the same incremental cost.

For a given on-line commitment a "curve" is constructed of incremental cost versus system power output. The curve is a continuous line composed of linear segments connected at points of discontinuous slope. It is a monotonically increasing, single valued curve. The points of slope discontinuity lie at the incremental costs corresponding to the points of the incremental burn rate tables.

The model dispatch procedure finds the two slope discontinuity points which bracket the dispatch demand. The incremental cost at the dispatch point is then found by linear interpolation and the individual power source loadings follow directly. The procedure is a table search, not an iteration.

For a given on-line commitment the slope discontinuity points are identified and sorted in descending order of incremental cost. It is not necessary to calculate the system power output level corresponding with each point. The table search begins at the highest incremental cost point and proceeds downward until the bracketing points are found. Power output levels need to be calculated only at the points examined in the search.

Once the dispatch incremental cost is determined the individual unit loadings are determined from precalculated integral of the incremental burn rate table segments. Again, a table search and linear interpolation are required, not an iteration.

Reserve Requirements

Spinning and operating reserve requirements are modeled. The compliance criteria are:

- On-line capacity must equal or exceed demand plus spinning reserve.
- On-line capacity plus available off-line quick start capacity must equal or exceed demand plus operating reserve.

Reserve requirements are specified as a fixed megawatt amount, a fraction of demand, or a combination of both.

Emissions

Generator emission rates for SO_2 and NO_x are input specified in lbs/MBtu burned. Emission in tons calculated from amount of fuel burned is an optional output.

Emission control by unit commitment and dispatch may be examined. An emission cost parameter ($/ton) may be input and used in conjunction with the specified emission rate of SO_2 (lb/MBtu) to calculate a pseudo fuel price adder ($/MBtu) to be used for unit commitment and dispatch. Simulations with and without the emission cost parameter can be run and the cost of emission reduction in $/ton can be obtained by comparing production costs and emission amounts from the two simulations.

Parameter Updates

Generating unit characteristics and other system parameters may be adjusted during the course of a simulation. Parameter updates comprise the last part of the

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input data. They are entered in chronological order and read and implemented as the simulation progresses.

Some updating consists simply in replacing an old value with a new one, e.g., redefining a forced outage rate. Other updating may require some reprocessing. For example, changing the burn rate characteristics of a generator will require reestablishing its position in the priority order.

Provision is made for updating all significant parameters. Updates are scheduled by date and made effective in the first hour of the day.

Event Catalog

Some of the simulation activities are coordinated using an event catalog. The activities include:

- Initiation of a forced outage.
- Termination of a forced outage.
- Initiation of scheduled maintenance.
- Termination of scheduled maintenance.
- Unit beginning commercial operation.
- Unit retirement.
- End of year.

Events are stored by activity code and scheduled hour in arrays (catalog) in chronological order. At the beginning of a simulation hour events scheduled for the hour are implemented and removed from the catalog.

Combined Cycle Units

A combined cycle unit is represented as a set of up to three mutually exclusive modes.

- Combustion turbine.
- Combustion turbine and heat recovery steam generator.
- Combustion turbine and heat recovery steam generator with supplemental firing.

Each mode is described in input as a distinct unit. The combustion turbine mode is required. One or both of the other modes may be defined.

Forced outages are scheduled for the combustion turbine. When the combustion turbine goes down the other modes are taken down also.

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Maintenance may be requested for the combustion turbine either by specifying a maintenance period or requesting automatic scheduling. The other modes share the maintenance schedule of the combustion turbine.

The combined cycle modes are independently prioritized so it is necessary to define rules to apply when units are selected for service from a priority list. The following rules are observed.

- The combustion turbine may be brought on-line if neither mode is on-line. The combustion turbine may be displaced by either of the other modes.
- The combustion turbine or the heat recovery steam turbine mode may be brought on-line if the supplemental firing mode is not on-line. Either may be displaced by the supplemental firing mode.
- The supplemental firing mode always takes precedence.

When a regular generator is brought on-line there is no effect on the commitment and dispatch of previous hours during the start up process because the unit is not capable of generating until the current hour. If a higher mode of a combined cycle unit is brought on-line and the combustion turbine is not already on-line there is an effect on the previous hours. There is a period before the current hour when the combustion turbine can generate. Account is taken of this effect by adding the combustion turbine to the commitment for that period and redispatching. The start up time for the higher mode is taken to be the time period over which the adjustment is required.

The requirement to adjust the commitment and dispatch for hours previous to the current hour means the simulation must run past the end of a year before all hours of the year can be finalized.

Pumped Storage Plants

Pumped storage plants are modeled by altering the given hourly demands, nominally reducing peak demands (shaving) and increasing low demands (pumping). Economic criteria guide the selection of the shaving and pumping schedule.

Plants may be specified to operate on 1-day or 1-week reservoir cycles. Pumping may occur in blocks of less than maximum capacity. Generation (shaving) may be at any level between minimum and maximum capacity. Plants may have individual reservoirs or may share a common reservoir. Pumping inefficiency may be specified. Up to two maintenance periods may be scheduled and forced outage rates may be specified.

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Each year of the analysis periods is run twice, first to determine a pumping/shaving schedule and then to simulate the operation of the system in response to the modified hourly demands.

In the first pass energy source commitment and dispatch are determined as if there were no pumped storage plants. Pumping costs are calculated by dispatching the selected commitment for the hourly demand and for the demand plus pumping blocks. Pumping costs are calculated for all plants and all pumping blocks. Pumping capability is based on the excess capacity of the commitment over the demand. Capacity is not brought on line for the sole purpose of pumping however, pumping can occur from spinning reserve.

The system dispatch for each hour is examined for high average cost energy blocks (unit generations or purchases). The highest average cost blocks are saved for each hour up to the total capacity of the pumped storage plants.

For plants which operate on 1-day reservoir cycles pumping and shaving schedules are determined by examining periods of two days. A period length of two days is selected to accommodate late hour pumping. The procedure is as follows. The highest cost energy blocks are sorted in descending order within each hour and then in descending order of hourly demand (to slant shaving toward the high demand hours). The hour of the lowest cost pumping block is selected. The highest dispatch average cost hours subsequent to the pumping hour are examined to determine whether expensive energy blocks can be deducted from the hourly demands in the amount of energy pumped. If the demand reduction can be accomplished the pumping/shaving match is accepted if:

- The fuel cost savings realized by reducing the demands is greater than the pumping cost, and
- The pumping/shaving can be accomplished without underflowing or overflowing the reservoir.

If the pumping/shaving match is acceptable the hourly demands are modified accordingly and the next lowest cost pumping block is selected for examination. The process is continued until there are no more pumping candidates. It is not necessary to examine all pumping blocks for all hours since some blocks may not be feasible because they exceed the capacity of the commitment, and hours in which the demand is shaved are ineligible for pumping.

For plants which operate on weekly reservoir cycles pumping/shaving schedules are obtained by examining periods of eight days.

An approximation is used to facilitate calculation of pumping costs and savings resulting from demand shaving. At each hour when the commitment is dispatched, tables are generated of system incremental cost vs. system fuel cost vs. system generation. Table points are generated at incremental costs corresponding with the points of the individual incremental tables of the units and purchases of the commitment. In using the tables it is assumed that generation and system cost varies linearly between table points. Use of the table replaces the need for repeated dispatching of the commitment as the pumping/shaving schedule is determined, and reduces the amount of data which must be stored.

After the pumping/shaving schedule has been determined for the entire year, the year is reprocessed for the modified hourly demands.

Fuel Limits

A set of generating units may be identified as sharing a common fuel of limited supply. The model will determine the most economical way to use the fuel. The fuel supply limits are specified in MBtu by time periods which may be any combination of:

- Annual
- Monthly
- Weekly
- Daily
- Arbitrarily defined

Units which share the limited fuel are assigned an unlimited supply of alternate fuel.

Commitment/dispatch is simulated three times for each year. The purpose of the first two simulations is to identify the best days in which to use the limited supply fuel and set daily limits. If only daily limits are specified the first two simulations are not needed.

For the first pass the limited supply fuel is assumed to be available in unlimited supply and its daily use (MBtu) and the daily system fuel cost ($) are saved. For the second pass the limited supply fuel is assumed to be unavailable and the daily system fuel costs are saved. At the end of the second pass daily fuel cost savings per MBtu of limited fuel used are calculated from:

$$\frac{\text{Second pass system fuel cost - first pass system fuel cost}}{\text{MBtu of limited fuel used in first pass}}$$

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and used to select the best days for using the limited supply fuel. The daily unit cost savings are sorted in descending order. Fuel limits are assigned to the days in sorted order, equal to the amount of fuel used in the first simulation pass. As the days are processed, usage accumulations are monitored relative to the specified period limits and appropriate daily limits are set to zero when period limits are reached.

After the daily fuel limits are determined the final simulation for the year is processed. In this pass the simulation for each day is iterated if necessary to satisfy the limits. In the first run of the day the fuel supply is assumed to be unlimited and the amount used by each unit is accumulated and saved. If the total fuel used does not exceed the limit for the day no iteration is required.

If the amount of fuel used in the first run of the day exceeds the daily limit the 'marginal' unit is identified by summing the fuel used by the units taken in the normal priority order. The unit for which the fuel used first exceeds the limit is designated the marginal unit. For subsequent iterations, higher priority units are permitted unlimited supply of the limited fuel, lower priority units have no access to the limited fuel, and the marginal unit uses a mixture of the limited fuel and its alternate fuel. The mixture proportion is iterated to obtain the daily usage of limited fuel under the implied assumption that 'best' operation results from use of the fuel up to the limit.

Economy Purchases

Economy purchases are modeled as 'split the savings' transactions. Hourly selling price quotes are a required input. The system energy sources (generation units and purchase availabilities) are marked as to whether or not they may be bought against when on-line. Units described as quick start may be bought against when off-line.

The system incremental cost is compared with the price quote at every hour. If the price quote is larger than an input threshold (e.g., 90 percent) of the system incremental cost there is no transaction.

If the price quote is less than the threshold the economics of a purchase transaction are examined in the following steps.

- Calculate the system fuel cost to generate the demand and determine the minimum possible generation (sum of on-line minimum capacities).
- Find the maximum amount of energy which may be purchased equal to the amount the qualifying on-line units may be backed down in an input fraction of the hour (e.g., 1/3 hour), plus the capacity of off-line quick start units.

- Find the maximum amount of energy which may be purchased based on the economic criterion that the system may not operate at an incremental cost less than an input multiplier (e.g., 1.10) times the quote price.
- Based on the controlling maximum purchase from the previous two steps calculate the system fuel cost corresponding to the allowable reduced system generation.
- Calculate the transaction price as the average of the price quote and the average fuel cost saving effected by the reduction of system generation.
- If the economic criterion above or the minimum possible generation of the on-line commitment limits the amount of energy which may be purchased, check whether more energy may be purchased by taking expensive quick start units off-line. For each on-line quick start unit calculate the average fuel cost at its reduced generation level. If this average cost is greater than the projected transaction price and the required minimum on-line time is satisfied, take the unit off-line and add its generation amount to the permissible purchase amount. When all off-line quick start units are processed, if the permissible purchase amount has been increased calculate the new transaction price.

After final determination of purchases transaction amount and price is completed the new on-line configuration and dispatch is recorded for the hour.

Appendix B
Existing Transmission and Substation Data

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Existing Substations 500 kV

Location	Type of Constr.	Number of Trans	Capacity MVA	Voltages kV
H. Dam	Conventional	2	2 x 320	500/132
Naga Hamady	Conv.	3	3 x 285	500/132
Samalout	Conv.	1	1 x 285	500/132
Assuit 500	GIS.	2	2 x 375	500/220
Naga Hamady	Conv.	2	2 x 375	500/220/11
Cairo 500	Conv.	3	3 x 500	500/220
Basous 500	GIS.	1	1 x 500	500/220

Existing Substations 220 kV

Location	Type of Constr.	Number of Transf.	Capacity MVA	Voltages kV
Cairo North	GIS.	3	3 x 125	220/66/11
Heliopolis	Conv.	3	3 x 125	220/66/11
Cairo West	Conv.	2	2 x 125	220/66/11
El Hadaba	Conv.	3	3 x 125	220/66/11
Cairo East	Conv.	3	3 x 75	220/66/11
Cairo South	Conv.	3	3 x 75	220/66/11
Saptia	Conv.	3	3 x 125	220/66/11
Bahteem	GIS.	2	2 x 125	220/66/11
Wadi Houf	Conv.	3	3 x 125	220/66/6.6
Basateen	GIS	3	3 x 125	220/66/11

Existing Substations 220 kV

Location	Typte of Constr.	Number of Transf.	Capacity MVA	Voltages kV
Sakr	GIS.	2	2 x 125	220/66/11
Katamia	GIS.	2	2 x 125	220/66/20
Abu Zaabal	GIS.	1	1 x 40	220/66/11
6 October	GIS.	3	2 x 125 1 x 40	220/66/20
South Tebin	GIS.	2	2 x 125	220/66/6.3
Zagazig	Conv.	3	3 x 75	220/66/11
Manayef	Conv.	2	2 x 125	220/66/11
Port Said	Conv.	2	2 x 125	220/66/11
Seuzes	Conv.	2	2 x 125	220/66/11

Existing Substations 220 kV

Location	Type of Constr.	Number of Transf.	Capacity MVA	Voltages kV
10 Ramadan	Conventional	2	2 x 75	220/66/11
Sokhna	Conventional	3	2 x 60	220/11
Cement	Conv.	2	2 x 75	220/11
Kafr El Dawar	Conv.	1	1 x 125	220/66/11
Damanhour	Conv.	2	2 x 50	220/66
Kafr El Sh.	Conv.	2	2 x 75	220/66/11
Mahmoudia	Conv.	2	2 x 125	220/66
El Sadat	Conv.	2	2 x 75	220/66/11
Tahrir Badi	Conv.	3	3 x 40	220/66/11
Tanta	Conv.	3	1 x 125 2 x 40	220/66/11

Existing Substations 220 kV

Location	Type f Constr.	Number of Transf.	Capacity MVA	Voltages kV
Menouf	GIS.	2	2 x 125	220/66/11
Kasaby	GIS.	2	2 x 125	220/66/11
Mehala	GIS.	2	2 x 125	220/66/11
Damietta	GIS.	2	2 x 125	220/66/11
Talkha	GIS.	3	3 x 125	220/66/11
Hay El Barod	GIS.	2	2 x 125	220/66/11
K.El Dawar (Ext)	Conv.	1	1 x 125	220/66
K.El Shiekh (Ext)	Conv.	1	1 x 75	220/66/11
Ameria	Conv.	2	2 x 125	220/66/11

Existing Substations 220 kV

Location	Type of Constr.	Number of Transf.	Capacity MVA	Voltages kV
Tahrir II	Conv.	2	2 x 125	220/66/11
Ghazal	Conv.	2	2 x 125	220/66/11
Abu Kir	Conv.	2	2 x 75	220/66/11
Iron And Steel	Conv.	2	2 x 125	220/66/11
Dekhela	GIS.	2	2 x 125	220/66/11
Somid	Conv.	2	2 x 60	220/11
Semoha	GIs.	2	2 x 125	220/66/11
Abis	GIS.	2	2 x 125	220/66/11
B. Arab	GIS.	2	2 x 125	220/66/11
Free Zone	GIS.	2	2 x 125	220/66/11

Existing Substations 132 kV

Location	Type of Constr.	Number of Transf.	Capacity MVA	Voltages kV
Samalout	Conv.	2	2 x 32	132/33/11
El Sail	Conv.	2	2 x 25	132/33/11
Kom Imbo	Conv.	3	3 x 25	132/33/11
Idfo	Conv.	2	2 x 25	132/33/11
Isna	Conv.	2	2 x 50	132/33/11
El Okser	Conv.	2	2 x 32	132/33/11
El Ferro	Conv.	4	4 x 40	132/33/6
Sohage	Conv.	2	2 x 50	132/33/11
Qena South	Conv.	2	2 x 50	132/33
Assuit	Conv.	2	2 x 50	132/33

Existing Substations 132 kV

Location	Type of Constr.	Number of Transf.	Capacity MVA	Voltages kV
Malawy	Conv.	2	2 x 32	132/33/11
El Menia	Conv.	2	2 x 32	132/33/11
Maghagha	Conv.	2	2 x 25	132/33/11
El Wahat El Baharia	Conv.	2	2 x 16	132/33/6.3
Beni Suif	Conv.	2	2 x 50	132/66/33
Assuit Cem.	GIS.	3	3 x 35	132/6.3
Kima	Conv.	8	5 x 55 3 x 32	132/3.3 132/6
Alnm	conv.	6	6 x 90	132/10.5

Existing Substations 132 kV

Location	Type of Constr.	Number of Transf.	Capacity MVA	Voltages kV
Assuit 500	GIS.	2	2 x 50	132/33
Assuit Cem. II	GIS.	3	3 x 35	132/6.3
El Sail Reh.	Conv.	2	2 x 32	132/33/11
Malawy Reh.	Conv.	2	2 x 50	132/33/11
El Menia Cem.	Conv.	2	2 x 25	132/6.3

Existing Substations 220 kV

Location	Type of Constr.	Number of Transf.	Capacity MVA	Voltages kV
Assuit 500	GIS.	2	2 x 125	220/132
Gerga	Conv.	2	2 x 75	220/ 66/33
Abo Tartor	Conv.	2	2 x 75	220/66/20

EXISTING TRANSMISSION LINES 500 kV

Name of Line		Year of Constr.	Type And Size	Number of Circuits	Length km	Ampacity	Transmission Circuit Losses
From	To						
High Dam	Naga Hamady	1967	ACO 3 x 500	2	236	2050	N.A
Naga Hamady	Samalout	1968	ACO 3 x 500	2	343	2050	N.A
Samalout	Cairo	1968	ACO 3 x 500	2	209	2050	N.A
New Way Naga Hamady	Samalout	1988/89	ACO 3 x 500	1	1.5	2050	N.A
Cairo 500	Basous	1968	ACO 3 x 500	1	17	2050	N.A
Basous	Abu Zaabal	1989	ACO 3 x 500	1	22	2050	N.A

EXISTING TRANSMISSION LINES 220 kV

Name of Line		Year of	Type And	Number of	Length	Ampacity	Transmission Circuit Losses
From	To	Constr.	Size	Circuits	km		
Cairo 220	Cairo West	1968	ACSR 400	2	11	670	N.A
Cairo 220	Basous	1986	ACSR 400	2	16	670	N.A
Cairo 220	Wadi Houf	1987	ACSR 400	1	40	670	N.A
Basous	Cairo West	1987	ACSR 400	2	5	570	N.A
Basous	Shoubra	1985 1989	H.P.O.F.C 1250	4	4	900	N.A
Basous	Cairo North	1986	AL 400	2	4	670	N.A
Basous	Heliopolis	1986	ACSR 2 x 400	2	26	1210	N.A
Basous	Bahteem	1986	ACSR 400	2	18	670	N.A
Shoubra	Cairo Norht	1984	H.P.O.F.C 1250	1	4.2	900	N.A
Shoubra	Saptia	1984	H.P.O.F.C 1250	2	8.4	900	N.A
Cairo Norht	Heliopolis		ACO 2 x 240	2	19.2	850	N.A

EXISTING TRANSMISSION LINES 220 kV

Name of Line		Year of Constr.	Type And Size	Number of Circuits	Length km	Ampacity	Transmission Circuit Losses
From	To						
Cairo Norht	Saptia	1984	H.P.O.F.C 1250	2	8.5	900	N.A
Heliopolis	Cairo East	1981	H.P.O.F.C 850	1	15	750	N.A
Cairo West	Hadaba	1982	ACSR 400	2	23	670	N.A
Hadaba	Cairo South	1982	ACSR 400	2	29	670	N.A
Cairo East	Katamia	1986	ACSR 400	2	26	670	N.A
Cairo East	Basateen	1987	ACSR 2 x 400	2	15	1210	N.A
Cairo East	Sakr	1985	ACSR 400	2	15	670	N.A
Cairo South	Wadi Houf	1988	ASCR 2 x 240	1	3	850	N.A
Cairo South	Basateen	1987	ACSR 400	2	18	670	N.A
Wadi Houf	New South Tebin	1988	ACSR 400	2	25	670	N.A
Sakr	Suez	1986	ACSR 400	2	90	670	N.A

EXISTING TRANSMISSION LINES 220 kV

Name of Line		Year of Constr.	Type And Size	Number of Circuits	Length km	Ampacity	Transmission Circuit Losses
From	To						
Attaka	Katamia	1988	ACSR 2 x 400	2	130	1210	N.A
6 October	Fayoum	1988	ACSR 2 x 400	2	100	1210	N.A
Basous	Kaliobia	1989	ACSR 2 x 400	2	40	1210	N.A
Port Said	Manayef	1985	ACSR 400	2	80	670	N.A
Manayef	Abo Soltan Gen	1987	ACSR 400	2	38	670	N.A
Abo Soltan Gen	10 Ramadan	1986	ACSR 400	2	60	670	N.A
Abo Soltan Gen	Suez 2	1983	ACSR 400	2	77	670	N.A
Suez 2	Old Suez Gen	1984	ACSR 400	2	9	670	N.A
Suez 2	Attaka 1	1984	ACSR 400	2	6	670	N.A
Attaka 1	Suez Cement	1984	AAAC 2 x 236	2	56	850	N.A
Suez Cement	Sokhna	1981	AAAC 2 x 236	2	26	850	N.A

EXISTING TRANSMISSION LINES 220 kV

Name of Line		Year of Constr.	Type And Size	Number of Circuits	Length km	Ampacity	Transmission Circuit Losses
From	To						
Sokhna	Wadi Houf	1980	ACSR 400	2	106	670	N.A
Manayef	Zagazic	1980	ACSR 400	2	75	670	N.A
Talkha	Zagazic	1980	ACSR 400	1	60	670	N.A
Zagazic	Bahteem	1985	ALO 400	2	40	670	N.A
Suez 2	Sakr Kurish	1984	ACSR 400	2	90	670	N.A
Kafr El Dawar	Damanhour	1970	ACSR 400	2	34	670	N.A
ATF	Damanhour	1984	ACSR 400	2	20	670	N.A
Talkha	Tanta	1970	ACSR 400	1	50	670	N.A
Damanhour	Tahrir Badr	1975	ACSR 400	2	63	670	N.A
Tanta	Tahrir Badr	1975	ACSR 400	1	43	670	N.A
Talkha	Kafr El Shiekh	1981	ACSR 400	2	39	670	N.A

EXISTING TRANSMISSION LINES 220 kV

Name of Line		Your Of Constr.	Type And Size	Number Of Circuits	Length km	Ampacity	Transmission Circuit Losses
From	To						
Talkha	Mansoura	1983	ACSR 400	2	12	670	N.A
Sadat	Cairo 220	1984	ACSR 400	2	71	670	N.A
ATF	Tanta	1985	ACSR 2 x 400	2	75	1210	N.A
Mansoura	Gamalia	1987	ACSR 2 x 400	2	75	1210	N.A
Menouf	Cairo 220	1986	ACSR 400	2	60	670	N.A
Menouf	Tahrir Badr	1986	ACSR 400	2	43	670	N.A
Menouf	Kalyobia	1986	ACSR 2 x 400	2	41.5	1210	N.A
Kalyobia	Basous	1989	ACSR 2 x 400	2	21	1210	N.A
Abo Kir	Damanhour	1986	AAAC 2 x 236	2	40	850	N.A
Tahrir II	Sadat	1984	ACSR 2 x 400	2	61	1210	N.A
Kafr El Dawar	Abis	1987	ACSR 2 x 400	2	20	1210	N.A

EXISTING TRANSMISSION LINES 220 kV

Name of Line		Year of Constr.	Type and Size	Number of Circuits	Length km	Ampacity	Transmission Circuit Losses
From	To						
Kafr El Dawar	Ameria	1987	AAAC 236	2	40	550	N.A
Damanhour	Damanahour Gen.	1986	ACSR 400	2	0.8	670	N.A
Talkha	Zagazig	1984	ACSR 400	2	60	670	N.A

EXISTING TRANSMISSION LINES 132 kV

Name of Line		Year of Constr.	Type and Size	Number of Circuits	Length km	Ampacity	Transmission Circuit Losses
From	To						
H.Dam	El Saif	1971	ACSR 322/60	2	16	580	N.A
H. Dam	Aswan	1971	ACSR 322/60	2	11	580	N.A
Aswan	Kima	1972	ACSR 322/60	2	11	580	N.A
Aswan	Kom Imbo	1972	ACSR 322/60	2	57	580	N.A
Aswan	Idfo	1973	ACSR 322/60	2	112	580	N.A
Idfo	Kom Imbo	1973	ACSR 322/60	2	60	580	N.A
Idfo	El Ferro.	1975	ACSR 322/60	2	3	580	N.A
Idfo	Isna	1975	ACSR 322/60	2	51	580	N.A
Isna	El Okser	1975	ACSR 322/60	2	66	580	N.A
Isna	Qena	1973	ACSR 322/60	2	110	580	N.A
El Oksor	Qena	1975	ACSR 322/60	2	60	580	N.A

EXISTING TRANSMISSION LINES 132 kV

Name of Line		Year of Constr.	Type and Size	Number of Circuits	Length km	Ampacity	Transmission Circuit Losses
From	To						
Qena	Naga Hamady	1973	ACSR 322/70	2	46	580	N.A
Naga Hamady	Aluminum	1975	ACSR 380/80	6	3	670	N.A
Naga Hamady	Soahag	1974	ACSR 120/20	2	98	370	N.A
Sohag	Assuit TH.	1974	ACSR 120/20	2	92	370	N.A
Assuit TH.	Assuit Gem.	1989	ACSR 120/20	2	20	370	N.A
Assuit Gem.	Malawy	1985	ACSR 120/20	2	62	370	N.A
Malawy	EL Menia	1974	ACSR 120/20	2	41	370	N.A
El Menia	Samalout	1974	ACSR 120/20	2	40	370	N.A
Samalout	Baharia	1982	ACSR 120/20	2	203	370	N.A
Samalout	Maghagha	1976	ACSR 120/20	2	54	370	N.A
Maghagha	Beni Suif	1977	ACSR 120/20	2	60	370	N.A

EXISTING TRANSMISSION LINES 220 KV

Name of Line		Year of Constr.	Type And Size	Number of Circuits	Length km	Ampacity	Transmission Circuit Losses
From	To						
Beni Suif	Fayom	1976	ACSR 120/20	2	35	370	N.A
New Way		1988/89	ACSR 120/20	2	69	370	N.A
Assuit Cement	Malawy						
Naga Hamady	Abo Tartor	1990/91	ACSR 380/50	2	287	670	N.A
Naga Hamady	Gerga	1990/91	ACSR 380/50	2	60	670	N.A
Samalout	El Menia Cem.	1990/91	ACSR 380/50	2	15	670	N.A
Assuit 500	Assuit Cem. II	1990/91	ACSR 380/50	2	4	670	N.A

Appendix C
Hydroelectric Resources Model

APPENDIX C - HYDROELECTRIC RESOURCES MODEL

EEA informed Ebasco at the beginning of the project that 1991 was considered to be a typical year as far as hydro generation was concerned. It was agreed that the study would be based on a normal water year, and that wet and dry years were not required.

With respect to the existing conventional hydro plants, EEA provided peak and base demand (Mw) and generation (GWH) by months for the year 1991 as shown in Table 1. This data was presented on the basis that 1991 was a "very typical" year and could be used in the analysis.

In the performance of economic evaluations for alternative expansion plans, average monthly values for demand and generation from hydro are normally used. On less than average years the pumped storage plant would be penalized due to the fact that with reduced generation from the conventional hydro more thermal generation will be required resulting in higher cost thermal being used to pump during off-peak hours. Conversely, on greater than average years more conventional hydro generation will benefit the pumped storage since less generation requirements from thermal will result in lower cost thermal being available to pump during off-peak hours. In economic evaluations of alternatives over a long period of 20 years or more it is commonly assumed that the use of an average hydrologic year will adequately represent the long time average generation available from the conventional hydro plants. Accordingly, Ebasco requested additional data from HPPEA and EEA on hydro generation in order to determine whether the provided 1991 generation data was a reasonable representation of an average or "very typical" year. The supplementary data provided included monthly generation for the years 1982 through 1991, where available, for Aswan I & II and High Dam. This data as provided is contained in Appendix F, EEA Provided Hydroelectric Data Base. However, the supplementary data did not include information regarding demand (Mw).

Utilizing the ten years of generation data (1982 through 1991) from High Dam, a frequency analysis was made for each month to determine the 50 percent probability generation which was then compared with the 1991 monthly generation in Table 2. Also included for each month is the average, maximum, and minimum generation by months from High Dam:

TABLE 1

SUMMARY AND DISTRIBUTION OF HYDRO ENERGY (1991)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
DEMAND (MW)[1]													
BASE	325	530	660	550	964	1433	1250	1156	850	683	633	583	1433
PEAKING	960	1250	1070	1225	844	612	610	594	969	1063	1125	1027	1250
TOTAL	1285	1780	1730	1775	1808	2045	1860	1750	1819	1746	1758	1610	2045
ENERGY (GHW)[2]													
BASE	241.8	356.2	491.0	396.0	717.4	1031.8	930.0	860.3	612.0	508.2	455.8	433.8	7034.3
PEAKING	175.9	296.7	256.5	342.6	252.7	191.0	251.9	228.8	191.1	183.6	167.1	171.7	2709.6
TOTAL	417.7	652.9	747.5	738.6	970.1	1222.8	1181.9	1089.1	803.1	691.8	622.9	605.5	9743.9

SOURCE: (1) EEA MONTHLY ENERGY REPORTS
(2) EEA MONTHLY LOAD DURATION CURVES

TABLE 2

Generation from High Dam - GWH
(Based on Supplementary HPPEA/EEA data)

Mo.	1991	50 Percent Probability	Average	Maximum	Minimum
J	290.3	415.0	446.1	789.1	256.3
F	471.8	526.0	538.7	716.0	379.5
M	541.2	575.0	583.6	775.9	395.0
A	531.8	560.0	571.6	762.5	412.2
M	718.8	642.0	690.8	847.7	508.6
J	897.2	890.0	901.8	1062.6	689.5
J	866.3	862.0	871.8	1078.7	628.8
A	757.7	775.0	779.3	972.0	634.3
S	585.2	620.0	628.6	782.3	495.8
O	507.5	540.0	548.8	753.8	410.0
N	449.2	485.0	494.6	649.1	346.9
D	435.4	468.0	479.8	649.3	347.0
Total	7052.4	7358.0	7545.5	9839.0	5503.8

Since Aswan 2 was placed in operation in October of 1985, the evaluation of base hydro generation from Aswan I & II was made starting in 1986. A comparison of the hydro generation from Aswan I and 2 in 1991 with generation for the period 1986 through 1991 is contained in Table 3.

TABLE 3

Generation from Aswan 1 and 2 (GWH)
(Based on supplementary HPPEA/EEA data)

		For Years 1986 through 1991		
Mo.	1991	Avg	Max	Min
J	133.4	140.1	164.5	97.0
F	190.4	190.5	200.7	181.0
M	217.2	210.2	217.2	199.8
A	218.2	211.4	218.2	209.6
M	263.8	254.4	266.4	245.7
J	336.0	314.9	336.0	298.0
J	326.9	317.2	337.6	295.4
A	303.8	292.9	303.8	278.8
S	228.0	227.3	238.9	220.6
O	195.7	194.9	214.4	184.7
N	181.8	183.0	193.7	176.2
D	177.3	178.8	190.9	168.0
Total	2772.5	2715.6	2882.3	2554.8

A comparison of the 1991 monthly generation for both High Dam and Aswan I & II with the average for the period as shown on Tables 2 and 3 respectively, indicates that (with the exception of January) there is a reasonably good correlation between the monthly generation data for 1991 (taken from the supplementary data) and the average and/or 50% probability generation for the period reviewed.

The 1991 monthly generation data for Aswan I & II was then added to that for High Dam. The resulting total hydro generation is shown in Table 4which also lists the "very typical" EEA data originally proposed by EEA for the study.

As indicated in Table 4, the monthly generation values from the two sources of information for the year 1991 are quite close. Excluding May, the variance is positive and is in the range of 1.3%. May, which is not a peak load month, has a negative variance of 67.4 MwH or about 7%.

TABLE 4

1991 Generation from all Hydro

Mo.	HPPEA/EEA Supplementary Data	EEA "Very Typical" Data (Exhibit A)	Variance	Percent Variance %
	MwH	MwH	MwH	
J	423.7	417.7	6.0	1.44
F	662.1	652.9	9.2	1.41
M	758.4	747.5	10.9	1.46
A	750.1	738.6	11.5	1.56
M	902.7	970.1	(67.4)	(6.95)
J	1233.4	1222.8	10.6	0.87
J	1193.2	1181.9	11.3	0.96
A	1101.5	1189.1	12.4	1.14
S	813.2	803.1	10.1	1.26
O	703.2	691.8	11.4	1.65
N	631.0	622.9	8.1	1.30
D	613.6	605.5	8.1	1.34

As previously noted, the supplementary data did not include information concerning demand in Mw by months for the other years. Consequently it was not possible to determine directly whether the demand data obtained for the year 1991 was representative of an average year. However, it can be concluded that it is reasonable to assume that monthly capacities given for the year 1991 are representative of an average year based on the following:

1) The capacity from any hydro plant is based on the flow through the units, the head on the units and the plant efficiency.

2) The Aswan reservoir which is the tailwater for High Dam plant, regulates the peaking flow coming in from High Dam each day such that the releases downstream are fairly uniform. The water level in Aswan Reservoir fluctuates very little, and since Aswan 2 was constructed all releases from the dam pass through the units. Therefore Aswan 1 & 2 are operated on base and output is related directly to irrigation releases.

3) High Dam Reservoir has sufficient storage to regulate inflows such that the irrigation requirements, which vary from month to month, can be met. During high inflow years the excess inflow is stored, while during low flow years the reservoir is drawn down to implement the low flows and meet the monthly irrigation requirements. Since irrigation is of primary importance,

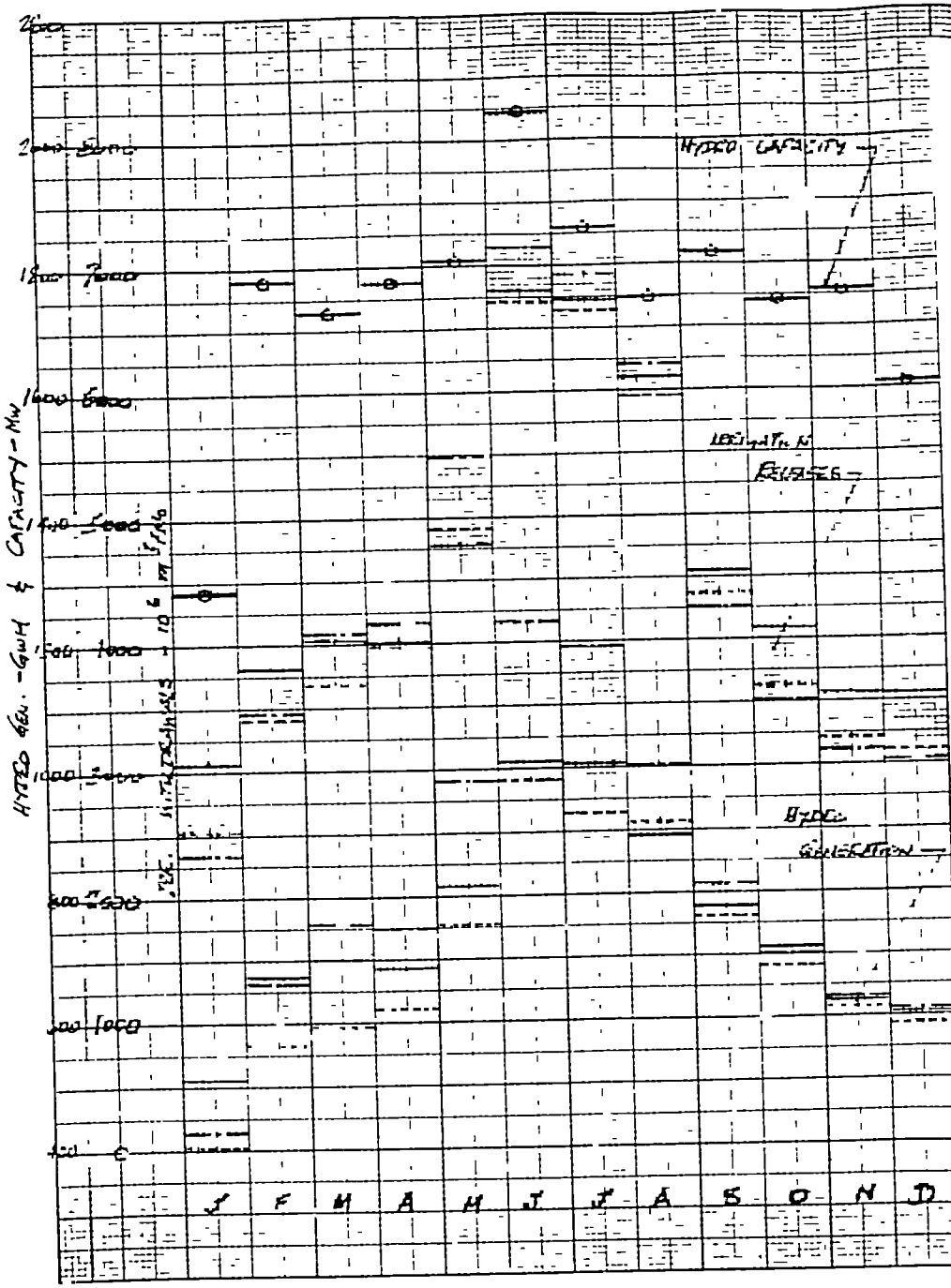
the annual releases from High Dam do not vary significantly (Ref. Exhibit B). Monthly releases do fluctuate a greater amount in accordance with irrigation needs, however the monthly distribution from year to year does not vary significantly.

4) The water level in High Dam reservoir can fluctuate from 147 m to 180 m. Historically, from 1970 through 1991, the water level ranged from a minimum of 150.62 m to a maximum of 177.81 m. In any given year, the range of water levels in High Dam reservoir is considerably less. The water level in High Dam reservoir at average volume is about 167 m. In 1991, the water level fluctuated from a minimum of 162.23 m to a maximum of 169.35, which is around the average storage level. Since the water level at Aswan Reservoir fluctuates relatively little, the head at High Dam hydro plant was also around average in 1991.

5) Since the release from High Dam for each month does not vary significantly from year to year and the water level in the reservoirs in 1991 was at or near average level, it follows that the generation from High Dam was also about average as indicated in the discussion and Tables 2, 3 and 4 above.

6) For a given release through the turbine units, the maximum capacity from the High Dam plant is directly related to the head. Therefore, if the head at High Dam is average based on corresponding water levels at High Dam and Aswan, the potential capacity from the units at High Dam must also be average.

Accordingly, the data presented in Table 1 was used without modification in the analysis.



IRRIGATION RELEASES - 10^6 m³

Mo	Years 1986	1988	1991
J	3080	2525	2335
F	3817	3409	3465
M	4015	3692	4095
A	4050	3975	4175
M	4759	4908	5491 *
J	6810	6727	7150
J	6735	6645	6930
A	6110	5960	6225
S	4550	4375	4261
O	4100	3645	3510
N	3575	3335	3118
D	3565	3120	3040
	55176	52216	53795

HYDRO GENERATION GWH

1986	1988	1991
511.1	403.5	423.7
672.1	566.7	662.1
700.5	594.8	758.4
685.9	621.9	750.0
817.2	754.3	982.6
1113.3	984.3	1233.8
1073.5	929.2	1173.2
896.0	913.1	1061.5
778.8	761.5	813.2
711.0	680.6	705.2
624.6	616.0	631.0
606.5	586.9	612.7

HYDRO CAPACITY MW

1991
1285
1780
1730
1775
1808
2045
1860
1750
1819
1746
1758
1610

DATA SOURCE: EEA & HPPEA

* Calculated

Figure C-1

Appendix D
Fixed Charge Rate Calculations

BASE FINANCIAL PARAMETERS

Cost of Money - Foreign	60% Commercial Loan @ 7½% and 40% Soft Loan @ 3%
Cost of Money - Local	12.0%
Discount Rate	6.96%

Plant Content, %	**CT**	**CC**	**Steam (Oil/NG)**	**Steam (Coal)**	**Pumped Hydro**
Foreign	85	80	70	70	70
Local	15	20	30	30	30
IDC Rate %	6.65	6.96	7.59	7.59	7.59
Fixed Charge Rate %					
Assumed Life - Yrs	20	25	30	30	50
Wgt'd Cost Money %	4.08	3.88	3.97	3.97	3.57
Depreciation	2.45	2.23	2.09	2.09	1.88
Insurance	0.10	0.10	0.10	0.10	0.10
Administration	0.20	0.20	0.20	0.20	0.20
	6.83	6.41	6.36	6.36	5.75

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Base Fixed Charge Rate Calculations

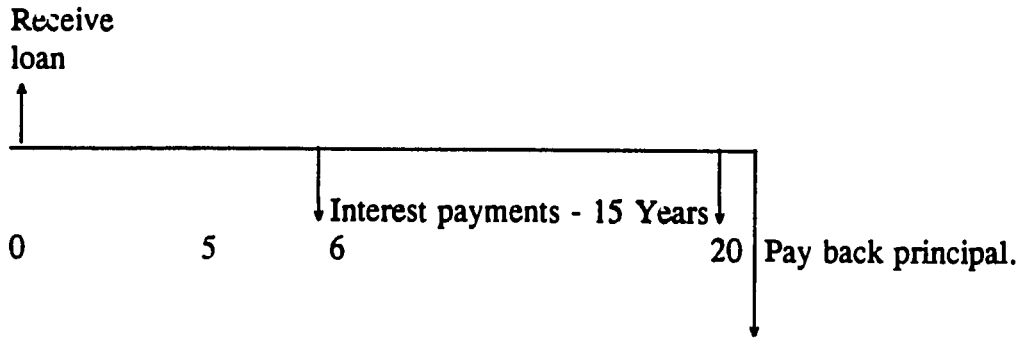
Goal: A levelized fixed charge rate over the life of the plant will be calculated.

Assumptions:

1) Both local and foreign loan terms are 20 years with a 5 year grace period.

2) Local loan is at 12% interest.
Foreign loan is 60% commercial loan at 7½% and 40% soft loan at 3%.

The fixed charge rate (FCR) for each type of capacity must be calculated for use in POWRPRO including consideration of the loan type described for Egypt. The foreign and local loans can be obtained with a 5 year grace period and a 15 year payment period. A cash flow diagram is as follows:



The cash flow payments in the diagram must be expressed by an equivalent levelized annuity (FCR) over the life of the facility. The actual cash flow payments and the levelized annuity are identical when they both have the identical present worth (PW) value.

Interest on the loan plus payback of the loan are two components of the FCR. These components can be calculated in two ways.

1) FCR = Capital Recovery Factor = $\frac{i\,(1+i)^n}{(1+i)^n - 1}$

This contains both interest & payback uniformly as in an annuity.

2) FCR = Interest + Sinking Fund Factor = $i + \frac{i}{(1+i)^n - 1}$

Note that these are equal.

$$i + \frac{i}{(1+i)^n - 1} = \frac{i\,(1+i)^n}{(1+i)^n - 1}$$

The following calculates a levelized FCR over the life of the facility, by components of:

i) Interest (Weighted cost of money)

ii) Sinking Fund Factor (depreciation component).

Calculations follow.

Discount rate is the average cost of money to UPS for all projects. Assume it to consist of 80% foreign and 20% local loans.

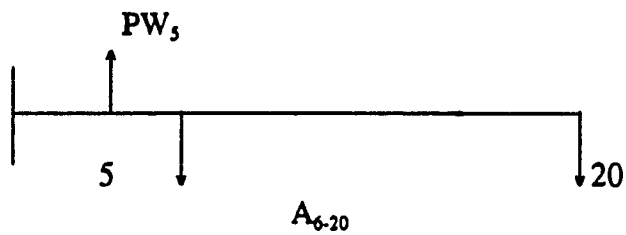
$$\text{Discount rate} = (.2)(.12)+(.8)[(.60)(.075)+(.4)(.03)]$$

$$= .0696 = 6.96\%$$

1. <u>Pumped Hydro</u>

Wgt cost of money = .7(.6 x .075 + .4 x .03) + .3 (.12) = 7.59%

i) Wgt cost of money component



$$PW_5 = A_{6\text{-}20}\,[P/A,\ 6.96\%, 15] = .0759\left[\frac{(1.0696)^{15} - 1}{(.0696)(1.0696)^{15}}\right] = .0759\,(9.131) = .6930$$

$$PW_1 = PW_5\,[P/F,\ 6.96\%,\ 5] = .6930\left[\frac{1}{(1.0696)^5}\right]$$

$$PW_1 = .4950$$

Convert to equivalent annuity over life of plant

$$A_{1\text{-}50} = PW_1 \times [A/P, 6.96\%, 50]$$

$$= .4950 \times \frac{[(.0696)(1.0696)^{50}]}{(1.0696)^{50} - 1} = .4950 \times (.0721)$$

$$= .0357 = 3.57\%$$

ii) Depreciation Component

$$PW_1 = F_{20} \; [P/F, 6.96\%, 20]$$

$$= 1.0 \left[\frac{1}{(1.0696)^{20}} \right]$$

$$= .2604$$

convert to equivalent annuity over life of plant (levelized).

$$A_{1\text{-}50} = PW_1 \; [A/P, 6.96\%, 50]$$

$$= .2604 \; \frac{[(.0696)(1.0696)^{50}]}{(1.0696)^{50-1}}$$

$$= .0188 = 1.88\%$$

FCR

Assumed Life - yrs	50
Wgt Cost of Money	3.57%
Depreciation	1.88%
Insurance	0.1 %
Administration	0.2 %
	5.75%

2. <u>Combustion Turbine</u>

Wgt Cost of Money = .85 (.6 x .075 + .4 x .03) + .15 x .12 = .0665

i) Wgt Cost of Money Component

$$PW_5 = A_{5\text{-}20}\,[P/A,\ 6.96\%,\ 15] = .0665\ \frac{[(1.0696)^{15} - 1]}{(.0696)(1.0696)^{15}}$$

$$= .0665\ (9.1310)$$

$$= .6072$$

$$PW_1 = PW_5\,[P/F,\ 6.96\%,\ 5] = .6072\ \frac{[\ 1\ ]}{(1.0696)^5} = .4337$$

$$A_{1\text{-}20} = PW_1\,[A/P,\ 6.96\%,\ 20]$$

$$= .4337\ \frac{[(.0696)(1.0696)^{20}]}{(1.0696)^{20}-1}$$

$$= .0408 = 4.08\%$$

ii) Depreciation Component

$$PW_1 = F_{20}\,[P/F,\ 6.96\%,\ 20] = .2604 \text{ as before}$$

$$A_{1\text{-}20} = PW_1\,[A/P,\ 6.96\%, 20]$$

$$= .2604\ \frac{[(.0696)(1.0696)^{20}]}{(1.0696)^{20} - 1}$$

$$= .0245 = 2.45\%$$

FCR

Assumed Life - yrs	20
Wgt Cost of Money	4.08%
Depreciation	2.45%
Insurance	0.1 %
Administration	0.2 %
	6.83%

3. Steam

Wgt Cost of Money = .7 (.6 x .075 + .4 x .03) + .30 x .12 = 7.59%

i) Wgt Cost of Money Component

$PW_5 = A_{5\text{-}20}$ [P/A, 6.96% 15] = .0759 (9.1310)

= .6930

$PW_1 = PW_5$ [P/F, 6.96%, 5] = .6930 $\left(\frac{1}{1.0696}\right)^5$
= .4950

$A_{1\text{-}30} = .4950 \left[\frac{(.0696)(1.0696)^{30}}{(1.0696)^{30} - 1}\right] = .4950\ (.0802)$
= .0397 = 3.97%

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ii) Depreciation Component

$$PW_1 = F_{20}\,[P/F,\ 6.96\%,\ 20] = .2604 \text{ as before}$$

$$A_{1\text{-}30} = PW_1\,[A/P,\ 6.96\%, 30]$$

$$= .2604\left[\frac{(.0696)(1.0696)^{30}}{(1.0696)^{30} - 1}\right] = .2604(.0803)$$

$$= .0209 = 2.09\%$$

<u>FCR</u>

Assumed Life - Yrs	30
Wgt Cost of Money	3.97%
Depreciation	2.09
Insurance	0.1
Administration	0.2
	6.36%

4. <u>Combined Cycle</u>

Assume 25 yr. Life

Wgt Cost of Money = .80 (.6 x .075 + .4 x .03) + .20 x .12 = .0696

i) Wgt Cost of Money Component

$PW_5 = A_{5\text{-}20}$ [P/A, 6.96%, 15] = (0.696) (9.131) = .6355

$PW_1 = PW_5$ [P/F, 6.96%, 5] = .4540

$$A_{1\text{-}25} = PW_1 \text{ [A/P, 6.96\%, 25]} = .4540 \left[\frac{(.0696)(1.0696)^{25}}{(1.0696)^{25} - 1} \right]$$

$$= .0388 = 3.88\%$$

ii) Depreciation Component

$PW_1 = F_{20}$ [P/F, 6.96%, 20] = .2604 as before

$A_{1\text{-}25} = PW_1$ [A/P, 6.96%, 25]

$$= .2604 \left[\frac{(.0696)(1.0696)^{25}}{(1.0696)^{25} - 1} \right] = .2604(.0855)$$

$$= .02226 = 2.23\%$$

FRC

Assumed Life - Yrs	25
Wgt Cost of Money	3.88%
Depreciation	2.23%
Insurance	0.1%
Administration	0.2%
	6.41%

LOWER INTEREST RATE FINANCIAL PARAMETERS

Cost of Money - Foreign	60% Commercial Loan @ 6½% and 40% Soft Loan @ 3%
Cost of Money - Local	12.0%
Discount Rate	6.48%

Plant Content, %	**CT**	**CC**	**Steam (Oil/NG)**	**Steam (Coal)**	**Pumped Hydro**
Foreign	85	80	70	70	70
Local	15	20	30	30	30
IDC Rate %	6.14	6.48	7.17	7.17	7.17
Fixed Charge Rate %					
Assumed Life - Yrs	20	25	30	30	50
Wgt'd Cost Money %	3.83	3.65	3.77	3.77	3.34
Depreciation	2.58	2.23	2.18	2.18	1.93
Insurance	0.10	0.10	0.10	0.10	0.10
Administration	0.20	0.20	0.20	0.20	0.20
	6.71	6.18	6.25	6.25	5.57

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Lower Interest Fixed Charge Rate Calculations

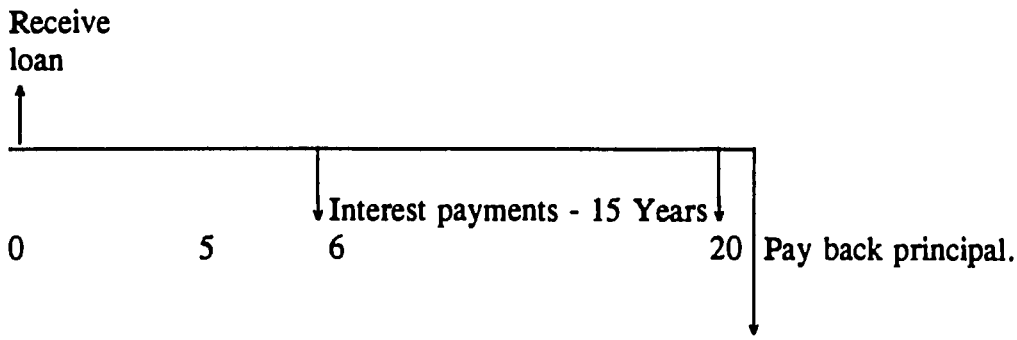
Goal: A levelized fixed charge rate over the life of the plant will be calculated.

Assumptions:

1) Both local and foreign loan terms are 20 years with a 5 year grace period.

2) Local loan is at 12% interest.
Foreign loan is 60% commercial loan at 6½% and 40% soft loan at 3%.

The fixed charge rate (FCR) for each type of capacity must be calculated for use in POWRPRO including consideration of the loan type described for Egypt. The foreign and local loans can be obtained with a 5 year grace period and a 15 year payment period. A cash flow diagram is as follows:



The cash flow payments in the diagram must be expressed by an equivalent levelized annuity (FCR) over the life of the facility. The actual cash flow payments and the levelized annuity are identical when they both have the identical present worth (PW) value.

Interest on the loan plus payback of the loan are two components of the FCR. These components can be calculated in two ways.

1) FCR = Capital Recovery Factor = $\dfrac{i\,(1+i)^n}{(1+i)^n - 1}$

This contains both interest & payback uniformly as in an annuity.

2) FCR = Interest + Sinking Fund Factor = $i + \dfrac{i}{(1+i)^n - 1}$

Note that these are equal.

$$i + \frac{i}{(1+i)^n - 1} = \frac{i\,(1+i)^n}{(1+i)^n - 1}$$

The following calculates a levelized FCR over the life of the facility, by components of:

i) Interest (Weighted cost of money)

ii) Sinking Fund Factor (depreciation component).

Calculations follow.

Discount rate is the average cost of money to UPS for all projects. Assume it to consist of 80% foreign and 20% local loans.

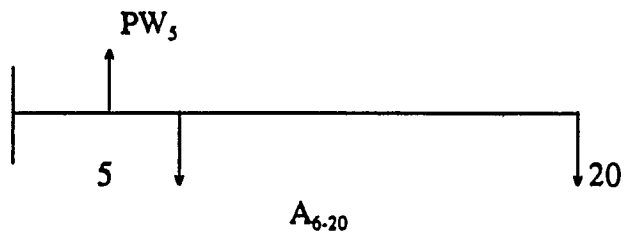
$$\text{Discount rate} = (.2)(.12)+(.8)[(.60)(.075)+(.4)(.03)]$$

$$= .0648 = 6.48\%$$

1. <u>Pumped Hydro</u>

Wgt cost of money = .7(.6 x .065 + .4 x .03) + .3 (.12) = 7.17%

i) Wgt cost of money component



$$PW_5 = A_{6\text{-}20}\,[P/A,\ 6.48\%, 15] = .0717\left[\frac{(1.0648)^{15} - 1}{(.0648)(1.0648)^{15}}\right] = .0717\,(9.414) = .6750$$

$$PW_1 = PW_5\,[P/F,\ 6.48\%,\ 5] = .6750\left[\frac{1}{(1.0648)^5}\right]$$

$$PW_1 = .4950$$

Convert to equivalent annuity over life of plant

$$A_{1\text{-}50} = PW_1 \times [A/P, 6.48\%, 50]$$

$$= .4931 \times \frac{[(.0648)(1.0648)^{50}]}{(1.0648)^{50} - 1} = .4931 \times (.0679)$$

$$= .0334 = 3.34\%$$

ii) Depreciation Component

$$PW_1 = F_{20} \; [P/F, 6.48\%, 20]$$

$$= 1.0 \left[\frac{1}{(1.0648)^{20}} \right]$$

$$= .2849$$

convert to equivalent annuity over life of plant (levelized).

$$A_{1\text{-}50} = PW_1 \; [A/P, 6.48\%, 50]$$

$$= .2849 \left[\frac{(.0648)(1.0648)^{50}}{(1.0648)^{50-1}} \right]$$

$$= .0191 = 1.93\%$$

FCR

Assumed Life - yrs	50
Wgt Cost of Money	3.34%
Depreciation	1.93%
Insurance	0.1 %
Administration	0.2 %
	5.57%

2. <u>Combustion Turbine</u>

Wgt Cost of Money = .85 (.6 x .065 + .4 x .03) + .15 x .12 = .0614

i) Wgt Cost of Money Component

$$PW_5 = A_{5\text{-}20}\,[P/A,\ 6.48\%,\ 15] = .0614\ \frac{[(1.0648)^{15} - 1]}{(.0665)(1.0665)^{15}}$$

$$= .0614\ (9.414)$$

$$= .5781$$

$$PW_1 = PW_5\,[P/F,\ 6.48\%,\ 5] = .5781\ \frac{[\ 1\ ]}{(1.0648)^5} = .4223$$

$$A_{1\text{-}20} = PW_1\,[A/P,\ 6.48\%,\ 20]$$

$$= .4223\ \frac{[(.0648)(1.0648)^{20}]}{(1.0648)^{20}-1}$$

$$= .0383 = 3.83\%$$

ii) Depreciation Component

$$PW_1 = F_{20}\,[P/F,\ 6.48\%,\ 20] = .2849 \text{ as before}$$

$$A_{1\text{-}20} = PW_1\,[A/P,\ 6.48\%, 20]$$

$$= .2849 = \frac{[(.0648)(1.0648)^{20}]}{(1.0648)^{20} - 1}$$

$$= .0258 = 2.58\%$$

FCR

Assumed Life - yrs	20
Wgt Cost of Money	3.83%
Depreciation	2.58%
Insurance	0.1 %
Administration	0.2 %
	6.71%

3. Steam

Wgt Cost of Money = .7 (.6 x .065 + .4 x .03) + .30 x .12 = 7.17%

i) Wgt Cost of Money Component

$PW_5 = A_{5\text{-}20}$ [P/A, 6.48% 15] = .0717 (9.414)

= .6750

$PW_1 = PW_5$ [P/F, 6.48%, 5] = $.6750 \left(\frac{1}{1.0648}\right)^5$
= .4931

$A_{1\text{-}30} = .4931 \left[\frac{(.0648)(1.0648)^{30}}{(1.0648)^{30} - 1}\right] = .4931\ (.0764)$
= .0377 = 3.77%

ii) Depreciation Component

$$PW_1 = F_{20}\,[P/F,\ 6.48\%,\ 20] = .2849 \text{ as before}$$

$$A_{1\text{-}30} = PW_1\,[A/P,\ 6.48\%, 30]$$

$$= .2849\ \left[\frac{(.0648)(1.0648)^{30}}{(1.0648)^{30} - 1}\right] = .2849(.0764)$$

$$= .02177 = 2.177\%$$

<u>FCR</u>

Assumed Life - Yrs	30
Wgt Cost of Money	3.77%
Depreciation	2.18
Insurance	0.1
Administration	0.2
	6.25%

4. <u>Combined Cycle</u>

Assume 25 yr. Life

Wgt Cost of Money = .80 (.6 x .065 + .4 x .03) + .20 x .12 = .0648

i) Wgt Cost of Money Component

$PW_5 = A_{5\text{-}20}$ [P/A, 6.48%, 15] = (0.648) (9.414) = .6100

$PW_1 = PW_5$ [P/F, 6.48%, 5] = .4456

$$A_{1\text{-}25} = PW_1 \text{ [A/P, 6.48\%, 25]} = .4456 \left[\frac{(.0643)(1.0648)^{25}}{(1.0648)^{25} - 1} \right]$$

$$= .0365 = 3.65\%$$

ii) Depreciation Component

$PW_1 = F_{20}$ [P/F, 6.48%, 20] = .2849 as before

$A_{1\text{-}25} = PW_1$ [A/P, 6.48%, 25]

$$= .2849 \left[\frac{(.0648)(1.0648)^{25}}{(1.0648)^{25} - 1} \right] = .2849(.0818)$$

$$= .0233 = 2.23\%$$

FRC

Assumed Life - Yrs	25
Wgt Cost of Money	3.65%
Depreciation	2.23%
Insurance	0.1%
Administration	0.2%
	6.18%

Appendix E
Combustion Turbine Reliability

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APPENDIX E - COMBUSTION TURBINE RELIABILITY

In general pumped storage plants are more reliable than thermal power plants. The North American Electric Reliability Council (NERC) collects and publishes performance data on different types of generating units on an annual basis. Reference was made to this publication and utilization of its most recent data for the years 1987 through 1991 was made for an assessment of the reliability of combustion turbines and pumped storage. As indicated by the NERC-GADS report, a measure of the reliability of any type of generating facility is the Equivalent forced Outage Rate (EFOR). The EFOR for the Pumped Storage and Combustion Turbines in the United States for the years 1987-1991 are 10.44% and 62.72% respectively. However, as pointed out in the EPRI "Pumped-Storage Planning and Evaluation Guide" dated January 1990, these values are unrealistically high for peaking plants such as Pumped Storage and Combustion Turbines. EPRI recommended an adjustment be made to the NERC EFOR equation to account for the duty cycle of these peaking units. The suggested modification to the NERC EFOR are based on a paper written by P F Albrecht, W D Marsh and F H Kindle of General Electric titled "Gas Turbines Require Different Outage Criteria" which appeared in Electrical World, April 27, 1970. As described in the NERC-GADS report, the formula for the Equivalent Forced Outage Rate is as follows:

$$EFOR = \frac{FOH + EFDH}{FOH + SH + EFDHRS} \times 100\ (\%)$$

where;

FOH	=	Forced Outage Hours
EFDH	=	Equivalent Forced Derated Hours
SH	=	Service Hours
EFDHRS	=	Equivalent Forced Derated Hours During Reserve Shutdowns

The adjustment recommended in the EPRI manual and the above referenced paper for peaking units is to multiply the Service Hours (SH) by the ratio of 24/D, where D represents the average operating time expected each day from the plant. For the CTs and PS units, D selected was 4 and 8 hours, respectively. Utilizing the results of the last 5 years of record from 1987-1991 in the NERC-GADS report we obtain the Adjusted Equivalent Forced Outage Rate (AEFOR) as follows:

$$AEFOR = \frac{FOH + EFDH}{FOH + (SH)\left(\frac{24}{D}\right) + EFDHRS} \times 100\ (\%)$$

where;

FOH	=	Forced Outage Hours
EFDH	=	Equivalent Forced Derated Hours
SH	=	Service Hours
EFDHRS	=	Equivalent Forced Derated Hours During Reserve Shutdowns

Data From NERC-GADS (1987-1991)

Terms	Combustion Turbines (HRS)	Pumped Storage (HRS)
FOH	303.59	261.23
EFDH	42.16	2.23
SH	245.41	2262.02
D	4	8
SH (24/D)	1472.46	6786.06
EFDHRS	2.18	0

Substituting in the above formula we obtain an AEFOR for the Combustion Turbines and Pumped Storage plants of 19.44% and 3.74% respectively.

Appendix F
Pumped Storage Operational Parameters and Capital Cost

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APPENDIX F - PUMPED STORAGE OPERATIONAL PARAMETERS AND CAPITAL COSTS

Operational Parameters

The overall pumping and generating cycle efficiency factor has been calculated to be 1.35 for this study. This means that 1.35 MWh of energy is consumed by the plant for every MWh of energy generated. This efficiency includes generator, motor, turbine, pump, flowline, transformer, and transmission losses.

For the same volume of water transported during generation and pumping, the cycle efficiency can be represented by the following formula:

$$(1) \quad \text{Cycle Efficiency} = \frac{H_n \times E_p \times E_g}{TDH} = \frac{\text{Generating Output}}{\text{Pumping Energy Input}}$$

The reciprocal of the Cycle Efficiency is an indication of how much energy is taken out of the system when pumping water up to the upper reservoir as compared to how much energy is obtained from the Hydro Pumped Storage when generating.

In the above formula, E_p represents the product of all the efficiencies of the equipment when acting in the pumping mode, while E_g represents the product of all efficiencies when in the generating mode.

For the Ain Sukhna site reference was made to the VPL report - Annex 2/4-5 where equipment and flowline efficiencies were given.

Assuming that two units are operating on each conduit and each unit is operating at best gate when generating and at 100% gate when pumping we have the following:

Average Gross Head = 588m
Flowline losses, generating = 5.9m
Net Head = H_n = 582.1m
Flowline losses, pumping = 5.7m
Total Dynamic Head = TDH = 593.7m
Efficiency of Plant in the generating mode (excluding Flowline Efficiency) at 80% power = 100 x (0.896 x 0.986 x 0.996 x 0.993) = 0.874 x 100 = 87.4%
Efficiency of Plant in the pumping mode (excluding Flowline Efficiency) at 100% power = 100 x (0.902 x 0.99 x 99.8 x 98.9) = 0.881 x 100 = 88.1%

Therefore, the cycle efficiency as indicated by formula (1) is equal to:

$$(2) \quad \text{Cycle Efficiency} = \frac{H_n \times E_p \times E_g}{TDH} = \frac{(582.1 \times 0.881 \times 0.874)}{593.7} = 75.5\%$$

and the reciprocal of the cycle efficiency is 1.325

For the 800m head hypothetical pumped storage hydro plant, the following basic parameters were utilized:

Average Gross Head = 801
Flowline Flow, generating = 3104cfs
Flowline Losses, generating = 13.4m
Net Head = H_n = 787.6m
Flowline Flow, pumping = 0.76 x 3104cfs = 2359cfs
Flowline losses, pumping = 7.7m
Total Dynamic Head = 801 + 7.7 = 808.7m
Efficiency of Plant in the generating mode (excluding Flowline Losses) (assume same as VPL) = 87.4%
Efficiency of Plant in the pumping mode (excluding Flowline Losses) - 88.1%

Therefore, the cycle efficiency as indicated by formula (1) is equal to:

$$(3) \quad \text{Cycle Efficiency} = \frac{H_n \times E_p \times E_g}{TDH} = 100 \times \frac{(5787.6 \times 0.881 \times 0.874)}{808.7}$$

$$= 75.0\%$$

and the reciprocal of the cycle efficiency is 1.334

Conservatively we have used a cycle efficiency of 1.35 in this study.

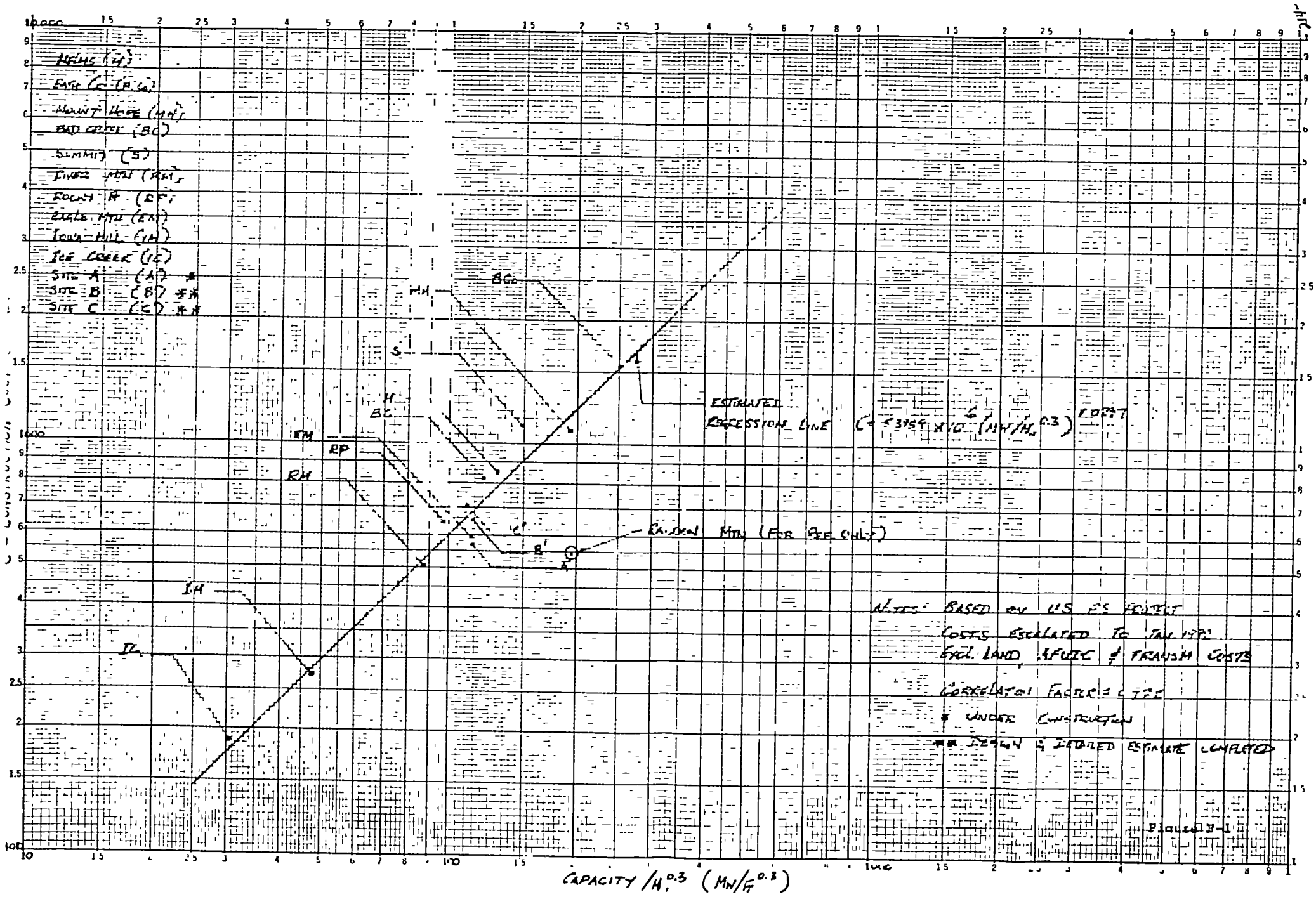
Capital Cost

For preliminary cost estimating of pumped storage hydro projects to be used in Phases I and II Ebasco developed a cost curve based on construction costs for pumped storage hydro projects installed and/or designed since 1980. Historical cost data excluding land, transmission and interest during construction for projects in the United States escalated to January 1992 were utilized in the analysis. The present day project costs were plotted on log-log paper against a parameter of capacity in Mw divided by net head raised to the 0.3 power as shown on the attached Figure F-1. A regression analysis of the sets of data was performed which resulted in the following generalized formula:

$$\text{Capital Costs (C)} = 5.3959 \times 10^6 \times (MW/H_n^{0.3})^{1.0237}$$

Accordingly, for the Wadi Araba site with 600 Mw capacity installation and an average net head of 800 m the capital cost for the HPS plant would be $\$335.8 \times 10^6$.

As indicated above, the data base used were hydro pumped storage projects constructed after 1980. Those projects that were constructed prior to 1980 were built in a more favorable environmental climate with less government constraints and tended to be less costly. A case in point would be the Raccoon Mountain project which was placed in service in 1978. This project has a capacity of 1530 Mw and a head of 968 ft. The stated actual total costs excluding interest during construction and transmission line costs adjusted to January 1988 was $\$477 \times 10^6$. Further


HELMS (H)
BATH CO (B.Co)
MOUNT HOPE (MH)
BIG CREEK (BC)
SUMMIT (S)
FIVER MTN (RM)
FOCUS H (F)
EAGLE MTN (EM)
TOWN HILL (TH)
ICE CREEK (IC)
SITE A (A) *
SITE B (B) **
SITE C (C) **
ESTIMATED EXCESSION LINE
EXISTING MTN (FOR REF ONLY)
CAPACITY /H^0.3 (MW/F^0.3)
NOTES: BASED ON US 75 PROJECT
COSTS ESCALATED TO JAN 1979
EXCL. LAND, AFUDC & TRANSM COSTS
CORRELATION FACTOR = 0.992
* UNDER CONSTRUCTION
** DESIGN & DETAILED ESTIMATE COMPLETED
PLOTTED B-1

escalation to January 1992 which is the reference point used for the cost curve shown on Figure F-1 gives a construction cost of $544.3x10^6$ excluding IDC and transmission. Based on the stated capacity of 1530 Mw as given in the EPRI report, the unit cost would be $356/kw as compared to Ebasco's estimated unit cost of $760/kw for the Wadi Araba site. Although the cost of Raccoon Mountain was not included in developing the cost curve, its position is noted on Figure F-1 for comparison.

In addition to this basic cost the following capital expenditures in US $ were included:

Reservoir lining	$9.9x10^6$
Makeup Pipe Line	$13.4x10^6$
Intake, Pumps/Motors	$2.0x10^6$
Energy for filling Pond (2 yrs)	$0.6x10^6$
Capitalized O&M	$0.9x10^6$
Subtotal (incl. basic cost)	362.6x10
Contingency	$54.4x10^6$
Total =	$417.0x10^6$
Desalinization including Contingencies	$37.5x10^6$
Total Cost	$454.5x10^6$
Cost/kw =	757.5$/kw

In addition to developing a cost curve for the basic pump storage project, curves were also prepared for the cost of desalinization including the capitalized cost of operating and maintenance and plotted against average net head as indicated on Figure F-2. Also shown on Figure F-2 are curves of makeup requirements and pond sizes plotted against average net head. All curves presented were based on the following assumptions:

Plant size	600 Mw
Reservoir Storage	6000 Mwh
Reservoir Drawdowns:	
Upper	70 ft (21.3 m)
Lower	40 ft (12.2 m)
Reservoir Configuration:	Encircling Type
Annual Evaporation:	5 meters/yr

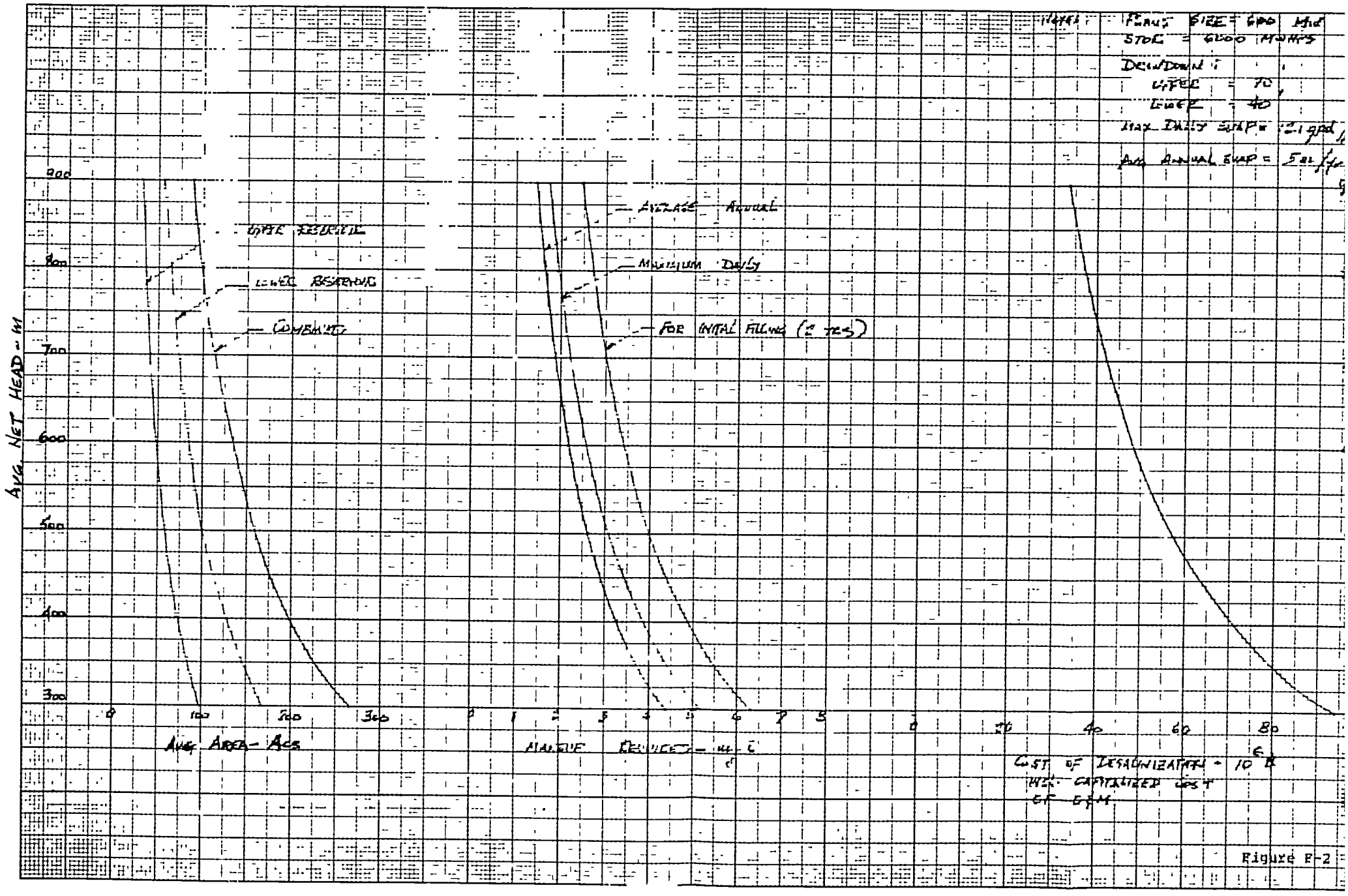


Figure F-2

K+E MADE IN U.S.A. KEUFFEL & ESSER CO. 4/1240

Appendix G
End-Effect Period Calculations

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Summary of End-Effects

(Natural Gas Case)

	$ x 10^6	
	ANNUAL SAVINGS	1993 PW SAVINGS
2025 to 2043		
Capital Chrg Savings	$16.78	$19.66
Production Cost Savings		13.73
Total		$33.39
2043 to 2053		
Capital Chrg Savings	$75.29	$18.32
Production Cost Savings		4.44
Total		$23.59
2025 to 2053		
Capital Chrg Savings		$37.98
Production Cost Savings		18.17
Grand Total		$56.15

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Summary of End-Effects

(No. 2 Oil Case)

	$ x 10^6	
	ANNUAL SAVINGS	1993 PW SAVINGS
2025 to 2043		
Capital Chrg Savings	$16.78	$19.66
Production Cost Savings		79.50
Total		$96.16
2043 to 2053		
Capital Chrg Savings	$75.29	$18.32
Production Cost Savings		25.70
Total		$44.02
2025 to 2053		
Capital Chrg Savings		$37.98
Production Cost Savings		105.20
Grand Total		$143.18

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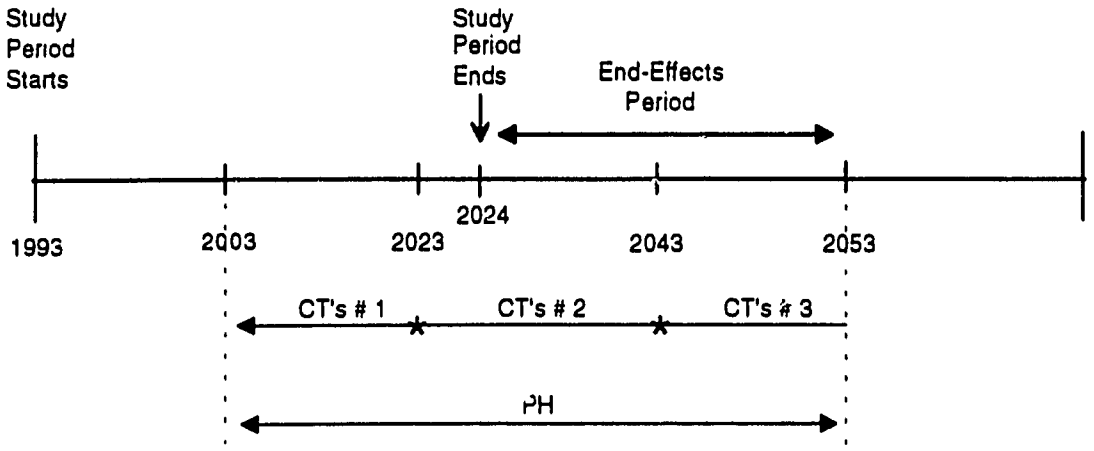
Study
Period
Starts
Study
Period
Ends
End-Effects
Period
1993
2003
2023
2024
2043
2053
CT's # 1
CT's # 2
CT's # 3
PH

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References

1. *Principle of Engineering Economy*, Grant, Ireson, and Leavenworth, pg. 99.

2. *Pumped Storage Planning and Evaluation Guide*, EPRI, pg. 9-31.

3. *Least-Cost Electric Utility Planning*, Stoll, pg 47-49.

4. *Engineering Economic Analysis: Overview and Current Applications, IEEE Tutorial Course, Course Text 91 EH 0345-9-PWR.*

End-Effects Calculation

(Natural Gas Case)

I. 2023 Replacement CT's

1. 6 CT's

Capital Cost = 600,000 kW x 515 $/kW x (1.0827) x (1.0412) x (1.028) x (1.03) x $(1.03385)^{[2023-1996]}$

= 600,000 x 515 x [1.193638] x $(1.03385)^{27}$

= $906.12 x 10^6

Ann. Chrg = $906.12 x 10^6 x .0683

= $61.89 x 10^6

2. pH (installed in 2003)

Capital Cost = 600,000 kW x 760 $/kW x 1.1034 x 1.0604 x 1.0389 x 1.0355 x $(1.0367)^{[7]}$

= $738.69 x 10^6 (w/o IDC)

Ann. Chrg IDC (from spreadsheet and hand calcs) = (12.843 - 10.211) x 10^6

= $ 2.632 x 10^6

Annual Charge = $738.69 x 10^6 x 0.0575 = $42.475 x 10^6 Cap

+ 2.632 x 10^6 IDC

$45.107 x 10^6

3. **1993 PW of CT vs. PH Annual Chrgs from 2025 to 2043**

1993 PW = $(61.89 - 45.107) x 10^6 x [P/A, 6.96%, 18] x [P/F, 6.96, 32]$^{[2025-1993]}$

$$= \$16.783 \; X \; 10^6 \; X \left[\frac{1.+0.0696^{18}-1}{(0.0696)(1.0695)^{18}}\right] X \left[\frac{1}{(1.0696)^{32}}\right]$$

= $16.783 x 10^6 X [10.0882] X [.116122]

= $19.661 x 10^6

II. 2043 Replacement CT's

1. 6 CT's

Capital Cost = Cost in 2023 escalated to 2043

= $906.12 x 10^6 x $(1.03385)^{20}$

= $1763.337 x 10^6

Ann. Chrg = $1763.337 x 10^6 x .0683

= 120.4 x 10^6

2. PH (installed in 2003)
Capital Cost = 738.69×10^6 (+ IDC)
Ann. Chrg = $\$45.107 \times 10^6$ no change from pg. 1

3. 1993 PW of CT vs. PH Annual Chrgs from 2043 to 2053
1993 PW = $\$(120.4 - 45.107) \times 10^6 \times [P/A, 6.96\%, 10] \times [P/F, 6.96\%, 50]$

$$= \$75.293 \; X \; 10^6 \; X \left[\frac{1.+0.0696^{10}-1}{(0.0696)(1.0696)^{10}} \right] X \left[\frac{1}{(1.0696)^{50}} \right]$$

$= \$75.293 \times 10^6$ X (7.036587) X (.0345884)
$= \$18.325 \times 10^6$

1993 PW of PH Prod. Cost Savings from 2025 to 2043

2024 Prod Savings = 16,746,913 - 16,737, 679 = $\$9.234 \times 10^6$

>1.03

2023 Prod Savings = 15,451,570 - 15,442,730 = $\$8.840 \times 10^6$

>1.12

2022 Prod Savings = 14,301,166 - 14,293,103 = $\$8.063 \times 10^6$

Assume annual savings are $\$9.5 \times 10^6$ in 2025 and escalates by 3% per annum to 2043. This is of the form of a uniform annual inflation series:

$$A\,[1,\ 1 + a,\ (1 + a)^2,\ ----,\ (1 + a)^{n-1}$$

Where: A = $\$9.5 \times 10^6$

a = .03

n = number of years, 18

$$1993\ PW = \frac{A\left[1-\left(\frac{1+a}{1+i}\right)^n\right]}{i-a}\ X\ [P/F,\ 6.96\%,\ 32]$$

$$= \frac{\$9.5 \times 10^6 \left[1 - \left(\frac{1+.03}{1+.0696}\right)^{18}\right]}{.0696 - .03}\ X\ \frac{1}{(1.0696)^{32}}$$

$= \$13.73 \times 10^6$

Prod. Cost Savings from 2043 to 2053

$A = \$9.5 \times 10^6 \times (1.03)^{18} = \$16.17 \times 10^6$

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$$1993\ PW = \frac{\$16.17 \times 10^6\ X \left[1 - \left(\frac{1.03}{1.0696} \right)^{10} \right]}{.0696 - .03}\ X\ [\ P/F,\ 6.96\%,\ 50\ ]$$

$$= \$4.44 \times 16^6$$

Total 1993 PW Prod. Cost Savings = [\$13.73 + \$4.44] x 10^6 = \$18.17 x 10^6

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Supplement to End-Effects for No. 2 Oil Case

	PROD. COST w/o PH ($ x 10^6)	PROD. COST w/PH ($ x 10^6)	PROD. COST SAVINGS ($ x 10^6)
2022	14,290.458	14,243.141	47.3
2023	15,430.173	15,382.909	47.3
2024	16,759.077	16,705.810	53.3

Assume annual production cost savings of $55.0 x 10^6 in 2025 and escalates by 3% per annum to 2043.

1993 PW of PH Prod. Cost Savings from 2025 to 2043

$$1993\ PW = \frac{A\left[1 - \left(\frac{1+a}{1-i}\right)^n\right]}{1-a}\ X\ [P/F,\ 6.96\%,\ 32]$$

$$= \frac{55 \times 10^6\left[1 - \left(\frac{1.03}{1.0696}\right)^{18}\right]}{.0696 - .03}\ X\ \frac{1}{(1.0696)^{32}}$$

$$= \$79.50 \times 10^6$$

1993 PW of PH Prod. Cost Savings from 2043 to 2053

$A = \$55 \times 10^6 \times (1.03)^{18} = \$93.63 \times 10^6$

$$1993\ PW = \$93.63 \times 10^6 \times \left[\frac{1 - \left(\frac{1.03}{1.0696}\right)^{10}}{.0696 - .03}\right]\ X\ [P/F, 6.96\%, 50]$$

$$= \$25.70 \times 10^6$$

1993 PW Total Prod. Cost Savings

Total 1993 PW Prod. Cost Savings = $(79.50 + 25.70) \times 10^6$
= $\$105.20 \times 10^6$

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Summary of End-Effects - Fuel Sensitivity

(Natural Gas Case)

	$ x 10^6	
	ANNUAL SAVINGS	1993 PW SAVINGS
2025 to 2043		
Capital Chrg Savings	$16.78	$19.66
Production Cost Savings		17.92
Total		$37.58
2043 to 2053		
Capital Chrg Savings	$75.29	$18.32
Production Cost Savings		5.79
Total		$24.11
2025 to 2053		
Capital Chrg Savings		$37.98
Production Cost Savings		23.71
Grand Total		$61.69

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End-Effects

(Fuel Sensitivity)

I. Natural Gas Case

2024 Prod. Savings	=	$21,983,640 - $21,971,583 x 10^3 = $12.057 x 10^6	
			> 1.10
2023 Prod. Savings	=	$20,123,427 - $20,112,440 x 10^3 = $10.987 x 10^6	
			> 1.03
2022 Prod. Savings	=	$18,438,001 - $18,427,508 x 10^3 = $10.493 x 10^6	

Assume annual savings are $12.4 x 10^6 in 2025 and escalates by 3% per annum to 2043.

1993 PW of PH Prod. Cost Savings from 2025 to 2043

$$1993\ PW = \frac{12.4 \times 10^6 \left[1 - \left(\frac{1.03}{1.0696} \right)^{18} \right]}{.0696 - .03} \times \frac{1}{(1.0696)^{32}}$$

$$= \$17.92 \times 10^6$$

1993 PW of PH Prod. Cost Savings from 2043 to 2053

A = $12.4 x 10^6 x $(1.03)^{18}$ = $21.11 x 10^6

$$1993\ PW = \$21.11 \times 10^6 \times \left[\frac{1 - \left(\frac{1.03}{1.0696} \right)^{10}}{.0696 - .03} \right] \times \frac{1}{(1.0696)^{50}}$$

$$= \$5.79 \times 10^6$$

1993 PW Total Prod. Cost Savings

Total 1993 PW Prod. Cost Savings = (17.92 + 5.79) x 10^6

= $23.71 x 10^6

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Summary of End-Effects - Fuel Sensitivity

(No. 2 Oil Case)

	$ x 10^6	
	ANNUAL SAVINGS	1993 PW SAVINGS
2025 to 2043		
Capital Chrg Savings	$16.78	$19.66
Production Cost Savings		106.09
Total		$125.75
2043 to 2053		
Capital Chrg Savings	$75.29	$18.32
Production Cost Savings		34.30
Total		$52.62
2025 to 2053		
Capital Chrg Savings		$37.98
Production Cost Savings		140.39
Grand Total		$178.37

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II. No. 2 Oil Case

	PROD. COST w/o PH ($ x 10^3)	PROD. COST w/PH ($ x 10^3)	PROD. COST SAVINGS ($ x 10^6)
2022	18,433,623	18,371,135	62.488
			>1.03
2023	20,105,199	20,040,676	64,523
			>1.10
2024	22,012,796	21,941,662	71.143

Assume annual savings are $73.4 x 10^6 in 2025 and escalates by 3% per annum to 2043.

1993 PW of PH Prod. Cost Savings from 2025 to 2043

$$1993\ PW = \frac{\$73.4 \times 10^6 \left[1 - \left(\frac{1.03}{1.0696}\right)^{18} \right]}{.0696 - .03} \times \frac{1}{(1.0696)^{32}}$$

$$= \$106.09 \times 10^6$$

1993 PW of PH Prod. Cost Savings from 2043 to 2053

$A = \$73.4 \times 10^6 \times (1.03)^{18} = \$124.96 \times 10^6$

$$1993\ PW = \$124.96 \times 10^6 \times \left[\frac{1 - \left(\frac{1.03}{1.0696}\right)^{10}}{.0696 - .03} \right] \times \frac{1}{(1.0696)^{50}}$$

$$= \$34.30 \times 10^6$$

1993 PW Total Prod. Cost Savings

Total 1993 PW Prod. Cost Savings $= (106.09 + 34.30) \times 10^6$

$$= \$140.39 \times 10^6$$

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Lower Interest Rate

Summary of End-Effects

(Natural Gas Case)

	$ x 10^6	
	ANNUAL SAVINGS	1993 PW SAVINGS
2025 to 2043		
Capital Chrg Savings	$17.02	$23.84
Production Cost Savings		16.48
Total		$38.19
2043 to 2053		
Capital Chrg Savings	$73.21	$22.82
Production Cost Savings		5.69
Total		$29.82
2025 to 2053		
Capital Chrg Savings		$46.66
Production Cost Savings		22.17
Grand Total		$68.83

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Lower Interest Rat

Summary of End-Effects

(No. 2 Oil Case)

	$ x 10^6	
	ANNUAL SAVINGS	1993 PW SAVINGS
2025 to 2043		
Capital Chrg Savings	$17.02	$23.84
Production Cost Savings		95.40
Total		$119.24
2043 to 2053		
Capital Chrg Savings	$73.21	$22.82
Production Cost Savings		32.95
Total		$55.77
2025 to 2053		
Capital Chrg Savings		$46.66
Production Cost Savings		128.35
Grand Total		$175.01

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End Effects
Lower Interest Rate

FCR
CT = 6.71%
PH = 5.57%

Discount Rate = 6.48%

I. 2023 Replacement CT's

1. 6 CT's

Capital Cost	=	600,000 kW x 515 $/kW x [1.193638] x $[1.03385]^{27}$
	=	$906.12 x 10^6
Ann. Chrg	=	$906.12 x 10^6 x .0671
	=	$60.80 x 10^6

2. PH

Capital Cost	=	$738.69 x 10^6 (w/o IDC)
Ann. Chrg	=	$738.69 x .0557 = $41.14 x 10^6
Ann. Chrg IDC	=	$2.632 x 10^6
Ann. Chrg	=	$43.78 x 10^6

3. 1993 PW of CT vs. PH Ann. Chrgs from 2025 to 2043

$$\text{1993 PW} = (60.80 - 43.78) \times 10^6 \times \frac{[(1+.0648)^{18}-1]}{(.0648)(1.0648)^{18}} X \left[\frac{1}{(1.0648)^{32}}\right]$$

= $17.02 x 10^6 x 10.448 x .134098
= $23.84 x 10^6

II. 2043 Replacement CT's

1. 6 CT's

Cap Cost	=	$1763.337 x 10^6
Ann. Chrg.	=	$1763.337 x 10^6 x .0671
	=	$118.32 x 10^6

2. PH

Ann. Chrg.	=	$45.107 x 10^6

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3. 1993 PW of CT vs. PH Ann. Chrgs from 2043 to 2053

$$1993\ PW = (118.32-45.11) \times 10^6 \times \left[\frac{(1.0648)^{10}-1}{(.0648)(1.0648)^{10}}\right] X \left[\frac{1}{(1.0648)^{50}}\right]$$

$$= \$73.21 \times 10^6 \times 7.195584 \times .043311$$

$$= \$22.82 \times 10^6$$

III. **Natural Gas Case - Lower Interest Rate**

1993 PW of PH Prod. Cost Savings from 2025 to 2042

$$1993\ PW = 9.5 \times 10^6 \times \frac{\left[1 - \left(\frac{1.03}{1.0648}\right)^{18}\right]}{.0648 - .03} X \frac{1}{(1.0648)^{32}}$$

$$= \$16.48 \times 10^6$$

2043 to 2053

$$1993\ PW = 9.5 \times 10^6 \times (1.03)^{18} X \frac{\left[1-\left(\frac{1.03}{1.0648}\right)^{10}\right]}{.0648-.03} X \frac{1}{(1.0648)^{50}}$$

$$= \$5.69 \times 10^6$$

1993 PW Total Prod. Cost Savings

Total 1993 PW PW Prod. Cost Savings = $(16.49 + 5.69) \times 10^6$

$= \$22.17 \times 10^6$

No. 2 Oil Case - Lower Interest Rate

1993 PW of PH Prod. Cost Savings from 2025 to 2043

$$1993\ PW = \$55 \times 10^6 \times \frac{\left[1 - \left(\frac{1.03}{1.0648}\right)^{18}\right]}{.0648 - .03} X \frac{1}{(1.0648)^{32}}$$

$$= \$95.40 \times 10^6$$

2043 to 2053

$$1993\ PW = 55 \times 10^6 \times (1.03)^{18} X \frac{\left[1-\left(\frac{1.03}{1.0648}\right)^{10}\right]}{.0648-.03} X \frac{1}{(1.0648)^{50}}$$

$$= \$32.95 \times 10^6$$

1993 PW Total Prod. Cost Savings = (95.40 + 32.95) x 10^6

= \$128.35 x 10^6

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Appendix H
Pumped Storage Alternatives Evaluation

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Appendix H Pumped Storage Alternatives Evaluation

The Phase I Report assumes that the pumped storage project would be a closed cycle type of development located in the Wadi Araba region. However, there are five types of pumped storage developments foreseen for a number of alternative sites. Subsequent phases of the subject study will identify a preferred scheme and preferred site. The five pumped storage development schemes include the following.

Type 1--Open Cycle

This open cycle type of development includes a manmade upper reservoir and uses the Gulf of Suez as the lower reservoir. The fluid used in the pumping-generating cycle is salt water and a direct hydraulic connection exists between the upper reservoir and the Gulf. The Ain Sukhna scheme, recommended by Verbund-Plan GmbH in their 1981 report, is of this type.

Type 2--Closed Cycle with Initial Filling and Makeup by Pumping from the Gulf

The closed cycle type of development includes both manmade upper and lower reservoirs with the lower reservoir isolated from the Gulf. The fluid used in the pumping-generating cycle is salt water. A pumping station is required taking suction from the Gulf to permit initial filling of the lower reservoir. This same station would also provide makeup water during plant operation to compensate for evaporation and other losses from the system. Other than for the pumping station and its delivery line, there is no direct hydraulic connection between the reservoir system and the Gulf. The Ataqa scheme, studies by Verbund-Plan GmbH in their 1981 report, is of this type.

Type 3--Closed Cycle with Initial Filling and Makeup Provided by Desalinated Water

This type of closed cycle development is similar to Type 2 but includes a desalination plant with feedstock pumped from the Gulf and delivering fresh water to the lower reservoir. The desalination plant would be sized to fill the lower reservoir in a period of approximately 2 years and would also provide makeup water during plant operation to compensate for evaporation and other losses from the system. This type of development would operate on fresh water so that special provisions in flow line design and equipment specification would not be required.

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Type 4--Closed Cycle with Desalination Plant (Ground Water Feedstock)

This type of closed cycle development is similar to Type 3 but with the desalination plant taking feedstock from ground water. Such ground water, if available, could be brackish rather than freshwater. This could reduce the load on the desalination plant significantly. The other features of the Type 3 development would not change.

Type 5--Closed Cycle with Fresh Water

This closed cycle type of development includes both manmade upper and lower reservoirs with fresh water used in the pumping-generating cycle. Water would be withdrawn from a fresh water source like the Nile River to permit initial filling of the lower reservoir and to provide makeup water during plant operation to compensate for evaporation and other losses from the system.

For Types 1-4, 10 alternative sites were preliminarily identified on the west coast of the Gulf of Suez as shown on the attached map. Table H-1 presents key physical characteristics of the 10 sites. A field reconnaissance of these sites was undertaken in June 1992 to confirm the availability of suitable sites along the Gulf coast other than Ataqa and Ain Sukhna which were previously identified by Verbund-Plan GmbH in their 1981 report.

The field reconnaissance confirmed that several of the 10 Gulf coast sites appeared to be suitable. A second site reconnaissance was undertaken in the Kureimat area to determine if topography and geology were favorable for a pumped storage development along this portion of the Nile River. No candidate sites were identified during this limited reconnaissance. The reconnaissance did not consider other sites in the upper Nile area. Such sites may be identified during later study phases. Additionally, further evaluation of the candidate sites will be undertaken in Phase II.

To facilitate the generic environmental assessment required for Phase I, a matrix identifying potential environmental impacts for each type of development was prepared (Table H-2). The matrix is conservative in that it is assumed to apply to all alternative sites. During Phases II and III, the degree of impact for the various sites and development types will be qualitatively and quantitatively addressed.

Table H-1					
SITE	U.RES m	L.RES m	HOR.DIST. m	MAKEUP km	HEAD m
A1	1,100	300	5,000	38	800 min
A2	1,100	300	5,000	31	800 min
B	1,100	300	5,500	17	800 min
C	1,100	300	4,500	20	800 min
D	540	100	6,000	1.5	440
E	800	200	2,500	0.5	600
F	500	100	2,000	0.5	400
G	570	100	2,500	0.5	470
H1	400	50	4,000	0.5	350
H2	400	100	1,500	0.5	300

Table H-2
Applicability of Issue to Alternatives

Issue	Pumped Storage				
	Open Cycle	Closed Cycle			
	Seawater Gulf	Seawater Gulf	Seawater Desalinated	Ground Water Desalinated	Fresh Water
Soil Erosion	0	0	0	0	0
Geology/Seismology	0	0	0	0	0
Ground Water Availability				0	
Ground Water Quality	0	0	0	0	0
Surface Water Quality	0	0	0		0
Dredging	0	0	0		0
Dredged Disposal	0	0	0		0
Breakwater Requirements	0				
Sediment Transport	0	0	0		0
Costal & Marine Res.	0	0	0		
Aquatic Ecology	0	0	0		0
Wetlands	0	0	0		0
Plants	0	0	0	0	0
Animals	0	0	0	0	0
Endangered Species	0	0	0	0	0
Land Use					
Tribal Peoples					
Aesthetics	0	0	0	0	0
Cultural Resources	0	0	0	0	0
Access & Transportation	0	0	0	0	0
Fugitive Dust	0	0	0	0	0
Air Emissions					
Haz. and Toxic Materials					
Infrastructure Reqmts.	0	0	0	0	0
Socioeconomics	0	0	0	0	0
Recreation	0	0	0	0	0
Tourism	0	0	0	0	0
Navigation	0				
Radiation					

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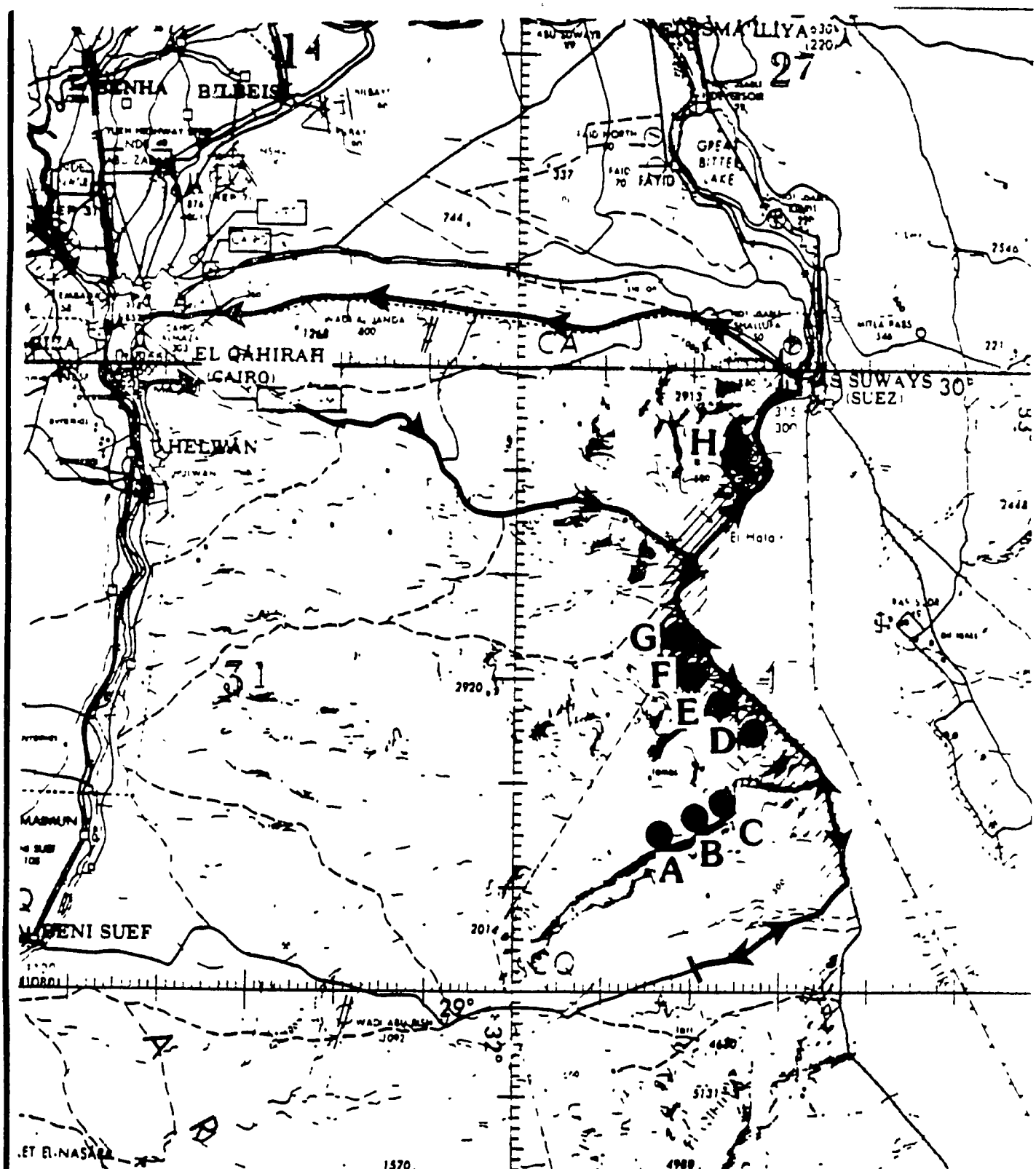

UNITED STATES AGENCY
FOR
INTERNATIONAL DEVELOPMENT
CAIRO, EGYPT

PUMP STORAGE HYDROELECTRIC
POWER STATION STUDY, EGYPT

SITE RECONNAISSANCE

JUNE 28, 1992

EBASCO OVERSEAS CORPORATION

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Appendix I
Description of Affected Environment at Alternative Pumped Storage Sites

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I. INTRODUCTION

Phase I studies indicated that there are a number of candidate sites in the Gulf of Suez region and potentially some sites along the Nile River that could be developed to provide pumped storage (see Appendix H). This appendix provides a general overview of the physical (i.e., geologic, climatic, aquatic, and terrestrial) and socioeconomic environment of the Gulf of Suez region and the physical environment of the Nile Valley between El-Minya and Asyut. A detailed description of the environment will be included in subsequent phases of the project.

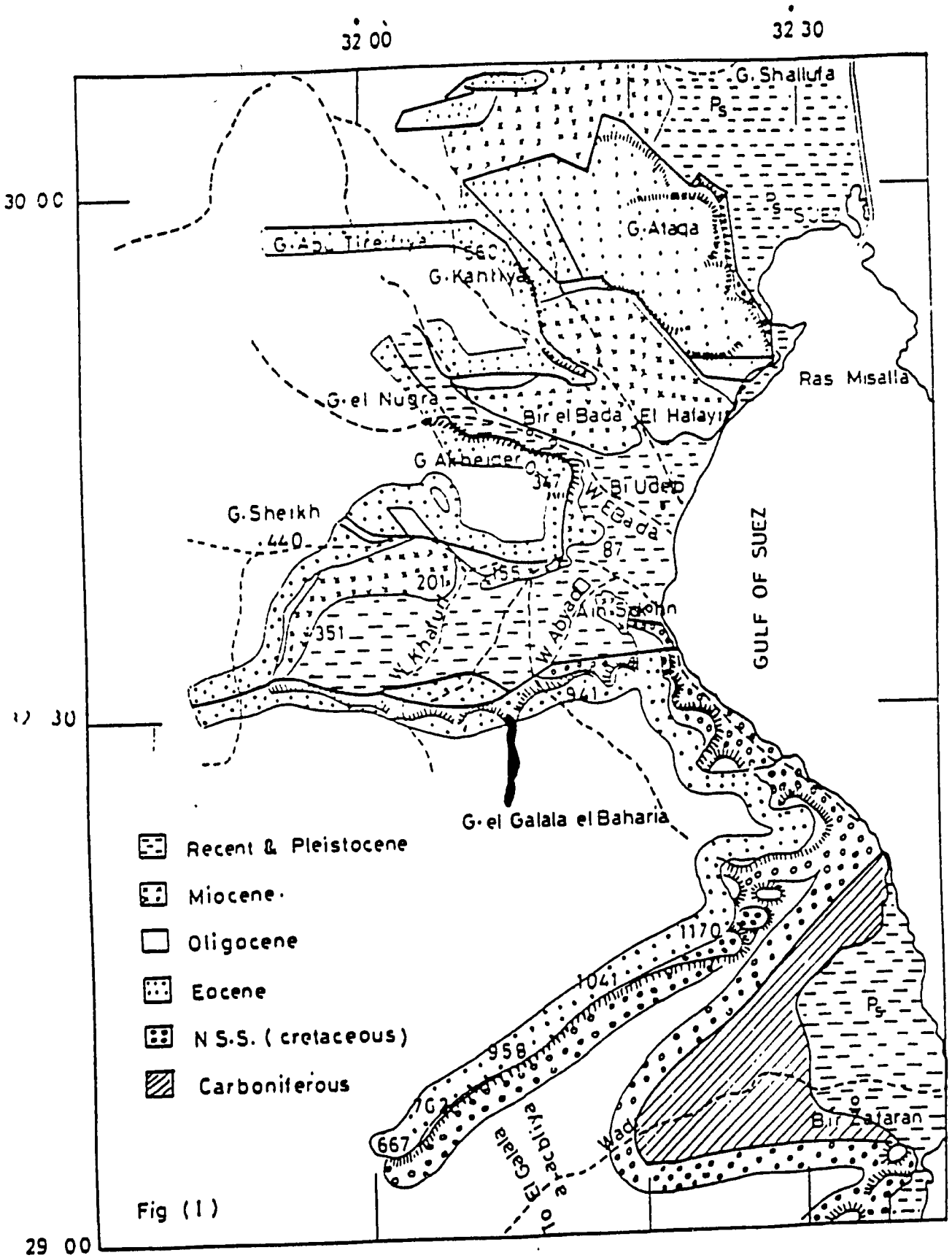
II. RED SEA AREA
THE DISTRICT BETWEEN THE SOUTHERN GALALA PLATEAU AND GEBEL ATAQA, GULF OF SUEZ

A. GEOGRAPHY AND GEOLOGY

The south Galala Plateau (elevation 1464 m), north Galala Plateau (1274 m), and Gebel Ataqa (871 m) are the main positive features of the area within which the Gulf of Suez alternative pumped storage sites are located (Figure 1). Intervening between these lofty features are two main depressions together with some major valleys and many small tributaries (Figures 1 and 2). A description of all these features follows.

1. Gebel Ataqa Mountain (Sites H1 and H2, Table 1, Appendix H)

The northern and eastern sides of this mountain are comprised of high vertical scarps up to 871 m above sea level making these areas of the mountain suitable for pumped storage. The elevation on the western and southern sides decreases gradually to about 600 m. At the southeastern corner, rounded limestone boulders cover the surfaces of the lower parts of Wadi Maghra and Wadi Gimal. The southern side of


32 00
32 30
30 00
29 00
G. Shallufa
G. Ataqa
G. Kantiya
Ras Misalla
G. el Nugra
Bir el Bada
El Halayib
G Akheiter
Bi Udeb
G. Sheikh
440
347
87
201
155
351
941
Ain Sudhan
GULF OF SUEZ
G. el Galala el Baharia
Recent & Pleistocene
Miocene
Oligocene
Eocene
N S.S. (cretaceous)
Carboniferous
1170
1041
958
667
Bir Zafaran
Fig (1)

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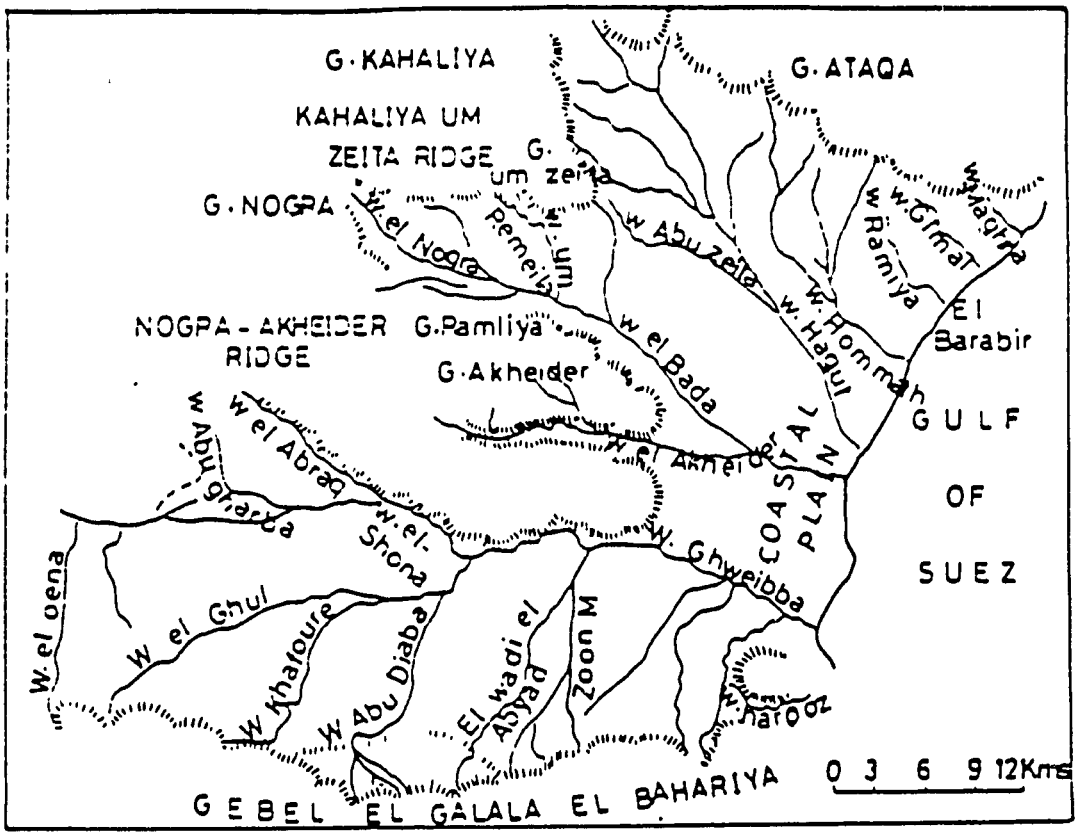
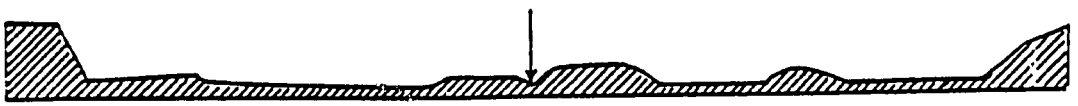

G·KAHALIYA
KAHALIYA UM
ZEITA RIDGE
G·NOGRA
G·ATAQA
G. um zeita
W el Nogra
W. um Pemeib
W Abu zeita
W. Hagul
W. Hommah
W Ramiya
W.GIMAT
W.Hagrya
El Barabir
NOGPA - AKHEIDER
RIDGE
G.Pamliya
G·Akheider
W el Bada
W el Akheider
COASTAL PLAN
GULF OF SUEZ
W el Abraq
W Abu grarba
W.el-Shona
W. Ghweibba
W el oena
W el Ghul
W Khafoure
W Abu Diaba
El wadi el Adyad
Zoon M
W.Haroor
0 3 6 9 12Kms
GEBEL EL GALALA EL BAHARIYA

Fig (2)



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Gebel Ataqa is dissected by many wadis that collect into three main drainage lines.

2. Wadi Hagul Drainage

This drainage occupies the wide valley between the Ataqa scarp and the long limestone ridge extending from Gebel Abu Treifiya to Gebel Kahaliya and ending in Gebel Um Zeita, (Figures 1 and 2). This wadi cuts its shallow channel first between the low scarps of Eocene limestone, then through the colored marks and grits of Upper Eocene. To the southeast, it traverses rocks of Miocene age that form banks not exceeding 10 m in height. The wadi bed is gravelly, but in its upper part changes to limestone boulders downstream of the confluence with tributaries from Ataqa and Gebel Um Zeita. The wadi widens out to a low-graded course bordered by low banks of alluvial gravels.

3. Gebel Kahaliya-Um Zeit Gebel Ridge

The name Kahaliya is given to the conspicuous bold peak rising above the rest of the ridge to about 600 m above sea level, while Gebel Um Zeita is merely a low plateau at the south-eastern end of the ridge, and is only about 200 m above sea level. (Figures 1 and 2). These areas are too remote from the Gulf of Suez to have feasible pumped storage sites.

4. Wadi El-Bada Drainage

This wadi occupies the flat valley between the faulted limestone ridges of Um Zeita and Akheider. Three tributaries join to form this wadi. The upper part of Wadi El-Bada is bounded to the south by the high faulted scarp of Gebel El-Akheider, while on the north, its low bank

slopes gradually northwards to the foot of Un Zeita plateau. There are small flat island hills located here that are comprised of marls and grits of Miocene age. The bed of the wadi is covered by boulders and gravels of limestone in a sandy matrix. Lower down, as the wadi leaves the Akheider scarp, the bed widens, between low hills of black flint gravels, and then spreads out into its alluvial fan over the center of the coastal plain.

5. Gebels Nogra-Ramliya-Akheider Ridge

a. Gebel Nogra

The maximum height of this ridge is about 436 m above sea level. The ridge is bounded to the northeast by a scarp overlooking Wadi Nogra.

b. Gebel El-Ramliya

The maximum height of this ridge is less than 300 m above sea level. It forms a plateau-like structure.

c. Gebel El-Akheider

The highest point of Gebel El-Akheider reaches 367 m above sea level. It is formed of a black, hill-shaped basaltic material, standing high above the rest of the plateau. Over most of its course, Wadi El-Akheider occupies a depression caused by a trough fault with Middle Eocene limestone forming scarps on either side. The depression itself is mainly occupied by Upper Eocene and even Miocene rocks.

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No suitable pumped storage sites were identified in these areas.

6. Wadi El-Ghweibba Drainage

This is the largest and most important drainage line in this depression. It extends about 70 km from east to west parallel to the line of the Galala escarpment (Figure 2).

7. El Galala El-Bahriya (Northern Galala) (Sites A1 thorough G, Table 1, Appendix H)

The Northern Galala extends as a high plateau bounded by scarps, that rise as vertical cliffs from the water of the Gulf. It is flanked to the north and south by the wide depressions of El-Ghweibba and Araba respectively.

a. Khashm El-Galala

This is a huge piece that has been faulted down from the rest of the Galala by E-W faulting, and tilted up with its beds dipping somewhat into the fault. The southern and western sides slope gradually down to the foot of the Galala escarpment. The highest point lies near the northeastern corner (about 600 m) above sea level. The southwest tilting caused the exposure of the oldest rocks (Jurassic) in the northeastern corner.

b. Gebel El-Meneidra

This is a triangular block of Eocene limestone that has been faulted down against the foot of the main escarpment. It forms a

low plateau not more than 90 m height above the surrounding plain, and is breached near its eastern end by El-Wadi El-Abyad which originates from the Galala cliff, Figure 2).

8. The Coastal Plain

The coastal plain measures about 25 km from the southeastern corner of Gebel Ataqa to the foot of Khashm El-Galala with a maximum width of more than 10 km at the center along wadi El-Bada. The slope of the coastal plain from the foot of the hills to the sea to is very gradual with a gradient of about 1 m/100 m. Near the hills, the surface of the plain is rich in coarse boulders and gravels transported by the wadis. Further away, the boulders become smaller and the gravel is finer and more sandy while along the shoreline, blown sand forms dominate.

9. Wadi Araba

Wadi Araba is considered as one of the greatest wadis on the western side of the Gulf of Suez. It is located between Gebel El-Galala El-Bahriya to the north and Gebel El-Galala El-Qibliya to the south (Figure 3). The elevations inside this wadi range between few meters near the Gulf to about 300 m at its western end. A great variety of rock units occupy this wadi.

10. Wadi Abu Karag

This is situated to the south of Wadi Araba and as can be seen from Figure 3, Quaternary deposits are dominant. However, some old deposits of Barboniferous, Permian, Triassic, Jurassic, and lower Cretaceous occur also.

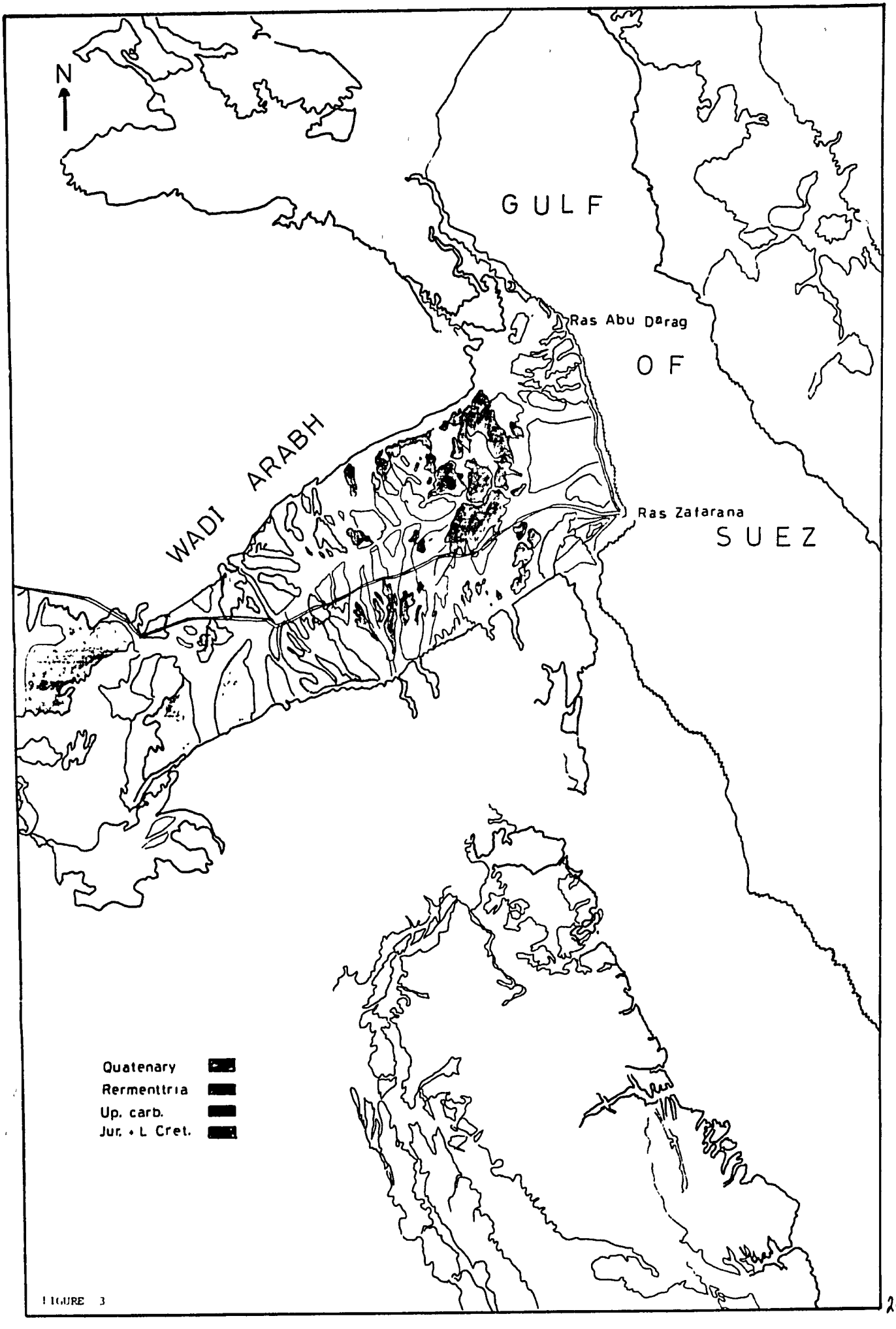
N
GULF
OF
SUEZ
Ras Abu Darag
Ras Zafarana
WADI ARABH
Quatenary
Rermenttria
Up. carb.
Jur. + L. Cret.

FIGURE 3

250-

B. ENVIRONMENTAL CONDITIONS

1. Climate

Temperature

The mean daily temperature in the Gulf of Suez region ranges from 15.5°C in winter to 30°C in summer. The daily fluctuation is about 12°C. The data recorded at Al-Gardaqa Meteorological Station and at Al-Ghardaqa Marine Biological Station are presented in Figure 4.

Rainfall

The area is located in an arid semi-desert zone, where the annual rainfall is very scarce. The annual average precipitation is 3.5 mm at Al-Ghardaqa. This is mainly in the form of showers or heavy rain in certain years. Sometimes, several years pass without rain.

Evaporation

No monthly evaporation values were measured in the study area. However, in the Red Sea the annual value of evaporation reaches well over 1900 mm. This phenomenon has a major influence on the salinity and currents in the Gulf of Suez.

Wind

The wind is mainly from the north and northwest during most years. However, in some years, the wind is from the south and southeast (Azyab). The wind generally follows a regular daily pattern; during summer, the nights and mornings are calm, and during the afternoon wind speed increases. Figure 5 shows the monthly frequency of wind at Al-Ghardaqa.

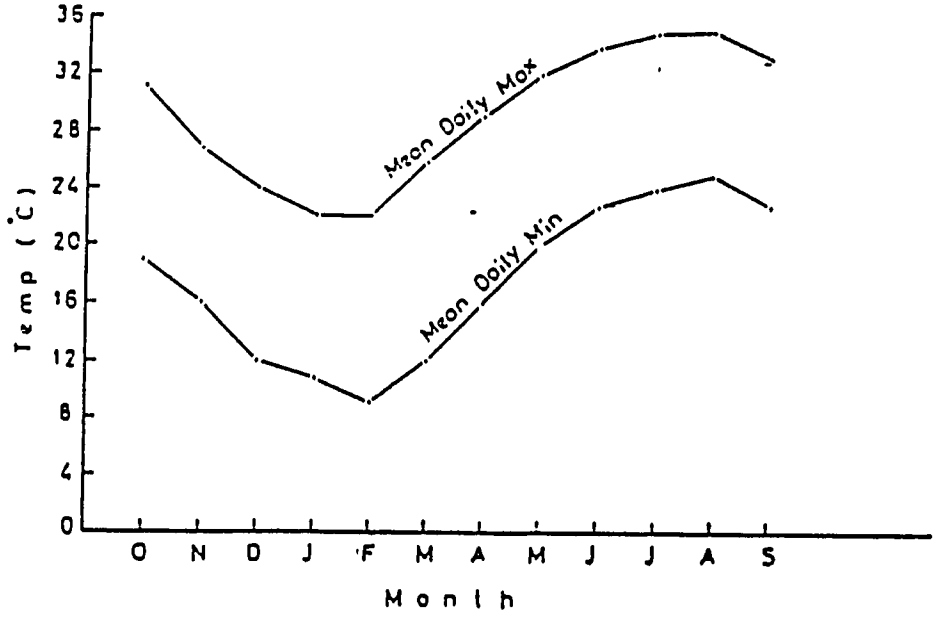

FIGURE (4)

Daily maximum and minimum air temperature at Al Ghardaqa.

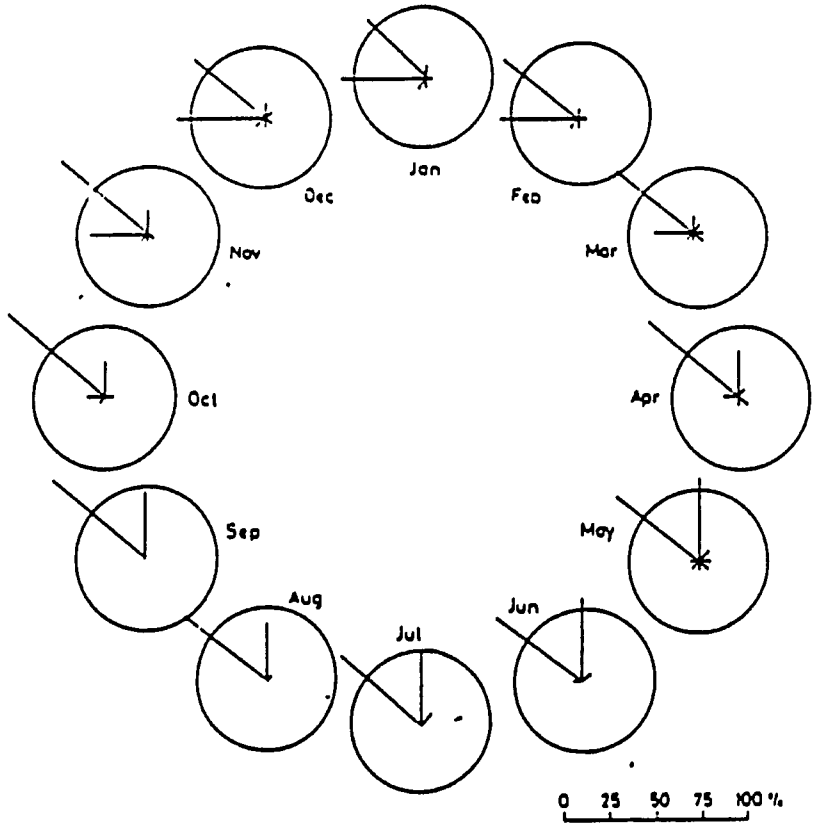

FIGURE : 5

Monthly frequency of wind blowing from a given direction.

2. Oceanography

Water Temperature

The Gulf of Suez was studied systematically and irregularly by several investigators (e.g., Mohamed 1934, Sherief 1953, Morcos 1970, Beltagy 1983, and El-Sabh and Beltagy 1983).

The surface temperature at the Strait of Jubal varies between 29.5°C in summer and 19.8°C in winter (Anwar, 1986). There is a general decrease in temperature with depth, and it reaches a minimum temperature near the bottom (ca. 21°C).

Salinity

The water salinity in the Gulf increases from south to north. Mohamed (1940) suggested the inflow of a warm and less saline surface current from the Red Sea into the Gulf, with an outflow of a bottom current of more saline and cooler water. The influx of these water into the Red Sea is clearly indicated; particularly in the area of Al-Ghardaqa archipelago. (Beltagy 1983, and Anwar, 1986).

According to El-Sabh and Beltagy (1983), the salinity of the Gulf water varies between 40.9 and 41.6 parts per thousand at the surface and near the bottom respectively during September. According to Anwar (1986) the surface water salinity decreases from February through May. It reaches minimum during August, then increases again during November. It follows from the variation of both temperature and salinity that the Gulf is expected to have a pronounced stratification pattern in the water column.

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Mean Sea Level

Mean sea level is a characteristic phenomenon for each area, with its seasonal variation which appears to be a characteristic feature throughout the world. Sea level variations are attributed to different causes including changes in atmospheric pressure, wind, evaporation, precipitation and astronomical factors (Sharaf El-Din, 1975). Along the Red Sea coast, the main factors affecting the sea level variations are the changes in atmospheric pressure, wind and evaporation.

The information on sea level seem to be mainly derived from the work of Vercilli (1923-1924) who studied the tide and its harmonic components during the Italian expedition to the Red Sea. Vercilli (1927) calculated the tidal harmonics for the Ashrafi area from data collected between February, 15 and March, 17 1923. However, Anwar (1986) had calculated the mean sea level at Al-Ghrdaqa during 1984 for over 9 months from March to November and found it to be 35.2 cm. Sharaf El-Din (1975) calculated the variation and the annual mean sea level at Port Tawfic (Suez), and found that the annual mean sea level in the period between 1956 and 1966 was about 35.17 cm (Table 1). Thus, it may be assumed that the annual mean sea level between Ghardaqa in the south and Port Tawfic in the north is 35.2 cm.

TABLE I
VARIATION IN MONTHLY AND ANNUAL MEAN SEA LEVEL
AT PORT TEWFIK, 1956 - 1966 (in cm).

Month	YEAR											Annual
	1956	1957	1958	1959	1960	1961	1962	1963	1964	1965	1966	Mean
January	53	53	53	59	51	66	35	63	42	28	22	48
February	67	46	42	42	39	51	33	65	38	30	21	43
March	57	55	46	34	35	32	49	49	29	21	41	
April	45	54	50	45	53	45	32	57	40	27	19	42
May	32	58	39	51	49	44	29	55	30	16	19	38
June	33	42	46	37	36	39	-	40	31	25	16	35
July	30	34	37	35	29	29	20	35	27	22	14	28
August	38	32	34	32	28	29	16	30	23	20	13	27
September	26	29	23	22	25	21	12	30	19	17	14	22
October	29	42	34	17	20	19	15	37	17	19	12	24
November	-	52	58	51	19	34	13	42	23	20	14	33
December	-	56	64	45	48	37	49	44	28	20	15	41

Tides and Tidal Currents

According to Morcos (1970) the tidal range in the Gulf of Suez decreases from the entrance of the Gulf towards the bank of Tor where it reaches a very small value, and it then increases again to about 1.5 m at Suez. A difference of six hours exists between the time of high water at the southern and northern ends of the Gulf. Thus, the tide has the shape of a standing wave, with high water in the north when it is low water in the Strait of Jubal.

Oxygen

A common feature of the Red Sea is the presence of dissolved oxygen stratificate in the 15 km coastal zone. As a rule, layers of low oxygen concentration exist at depths between 20-30 m and 60-80 m. This may be caused by the increased consumption of oxygen for oxidation of organic matter in these deeper areas. At these depths, sudden density change caused by

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accumulation of organic debris were also observed. However, the water in the upper layers is always saturated with oxygen. The thickness of the layer of supersaturated oxygen varies both from north to south and from east to west. At El-Ghardaqa the depth of this layer reaches 150-160 m. The degree of supersaturation in general is low. In the open waters of the Red Sea, a minimum oxygen concentration of about 15% of the saturated level was reported at a depth of 300-500 m in the southern part.

The oxygen content of the Gulf waters is generally lower than that of the Red Sea. Maximum oxygen concentrations of 4.28 ml/l occur at a 20 m depth near the center of the Gulf (El-Sabh and Beltagy 1983). Outside the Gulf in the deep water off Al-Ghardaqa, a minimum oxygen concentration of 1.8 ml/l was recorded at a depth of 400 m. The surface water of the southern extremity of the Gulf near the Strait of Jubal had a higher oxygen content. The high values at the entrance of the Gulf may reflect the importance of the gas exchange at the sea-air interface due to active mixing in this area. In general, the oxygen content of the water increases with depth except near the bottom. It is reported that photosynthesis and mixing and regeneration processes contribute to this phenomenon.

Nutrient Salts

Reactive phosphate concentration in the Gulf of Suez varies between a maximum of 3.5 mg/l and a minimum of 0.0 mg/l. Although the high concentration is present at subsurface layers, horizontal distribution of the phosphate ion does not show any particular trend. The average phosphate concentration in the Gulf is 2 mg/l. Compared with the waters of the Red Sea, the Gulf is relatively poor in phosphate ions.

Nitrogen components in the Gulf have never been studied and no information of any of the nutrients of this category are available.

Soluble silicate in the Gulf had a maximum concentration of 5 ug/l recorded at the subsurface layer at some stations. A minimum of 1 ug/l was recorded at the bottom at some other

stations. However, this trend was not always observed in different parts of the Gulf.

Oxidizable Organic Matter

The oxidizable organic matter in the Gulf shows a random distribution. The average value of the organic matter concentration is 0.44 mg $0_2/l$. Near the bottom, the average oxidizable organic carbon is much higher (0.74 mg $0_2/l$). Off the Jubal area in the deeper water of the Red Sea, very low oxidizable organic matter content was recorded (0.17 mg $0_2/l$). This low concentration of organic matter coincided with the layer with a minimum oxygen concentration.

Hydrogen Ion Concentration and Turbidity

No data were recorded for these two parameters in the Gulf Suez. However, some pH measurements were made at the Marine Biology Station, Al-Ghardaqa. These measurements indicate that the pH of the water varies between 8.2 and 8.9 depending on time of the day and degree of isolation of the body of water being analyzed.

3. Plant Life in Ataqa Region

The plant life in the area is controlled by two main environmental factors, these are: aridity and salinity. Along the coast, the growth of particular plants (halophytes) is affected by the zonation of the salinity along the coast as affected by the distance from the sea and the depth of the water table. Zonation of different plant communities is evident along the coast. The common halophytes are: Arthrocnemum macrostachyum, Cressa cretica, Juncus arabicus and Phragmites australis.

The plateau is dissected by wadis which collect the runoff water from a complex system of drainage ravines and runnels. The rainfall in the area is characterized by : scarcity (20-30 mm/year), irregularity from year to year, variability in space and time, accidental

thunderstorms leading to conspicuous runoff and flooding of the wadis. Such an irregularity is reflected by the plant life. The growth of plants is mainly confined to depressions, runnels and wadis which receive runoff water and the water borne sediments. The density of the plant growth is closely related to the soil depth and physical soil attributes.

The common plants growing in the area are usually confined to the wadis. These include trees, shrubs, undershrubs grasses and ephemerals appearing after the sporadic rainfall. The area is characterized by the occurrence of numerous springs from which water trickles all the year around. This creates special habitats in such a desert dry area. Hygrohalophytes grow in such habitats, which are alien to the desert, these include: Phragmites australis Juncus, arabicus. Some halophytes grow therein as Nitraria retusa, Reaumuria hirtella, Tamarix spp. The occurrence of such water resource was the main reason that monasteries were established in the area, e.g. St. Antonius at the foot of the northern side of south Galalah, St. Paul in Wadi El Deir opposite Zaafranah.

The name "Bir" is common for many sites in the area, denoting the presence of springs. Due to the availability of additional water resources other than the limited rainfall, the Monks in the monasteries have been able to cultivate numerous drought resistant trees as: figs, Ziziphus. Date Palm, Ceratonia siliqua (Kharroub)-Punica granatum (Pomegranate) and Olea europaea (Olives) and others as well as vegetables. It is to be noted that the water used and obtained from these springs is brackish to a great extent.

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II. THE NILE VALLEY BETWEEN EL-MINYA AND ASYUT

A. SURFACE GEOLOGY AND TOPOGRAPHY

Early Pleistocene in this part of the Nile Valley was characterized by its arid conditions. This arid time was interrupted by the initiation of the Protonile which is characterized by its gravelly-sized sediments composed of quartz and quartzite, (Figure 6). This Protonile was succeeded by two other rivers, the prenile and the Neonile. The deposits of each of these rivers are distinct in lithology, stratigraphy and mineral contents. The deposits of the Prenile are made up of massive, cross-bedded fluvial sands interbedded with dune sands. The mineral composition indicates that the Nile was connected for the first time with the Ethiopian highland across the elevated Nubia massives. This happened during the Middle Pleistocene when the channel of the river was occupied by ephemeral rivers depositing conglomerate derived from the uncovered basement complex of the Red Sea hills. During this time, a hyper-arid phase interrupted this period.

The Neonile deposits have different sediment types. The oldest of them is called α-Neonile and is formed of silt. The β,τ and δ-Neonile are formed of fluvial deposits and interfingering dune sands.

The wadi deposits which are, of fluvial type, are also dominant in the area (Figure 6). Many wadis were connected to the River Nile from its eastern side (e.g. Wadi El-Asyut, Wadi El-Makhazim, Wadi El-Ibrahimi, Wadi El-Imiani, and Wadi El-Barshawi). Besides these great variety of quaternary deposits, Plicoene and Eocene deposits dominate in the Nile Valley between the cliffs surrounding the valley. The Pliocene deposits are characterized by fluviatiles siltstone, sandstone and claystone changing into lacustrine limestone near the cliffs. The Eocene deposits are characterized by the well-bedded white to grey

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EBASCO

Date: September 27, 1993
Letter No: L-93EPS-016
File No: 5.21.3

Bureau for Program & Policy Coordination
Center for Development Information & Evaluation
Development Information Division
PPC/CDIE/DI, Acquisitions, Room 209
SA-18, Agency for International Development
Washington, D.C. 20523

Reference: Pumped Storage Hydroelectric Power Station Study
Contract No. 263-0215-C-00-2019-00
Phase I - Final Report

Gentlemen:

As per contract, enclosed are two (2) copies of the Phase I Final Report of the above referenced study.

Please do not hesitate to contact me if you have any questions or require any additional information.

Very truly yours,

L.R. Gertler
Project Manager

cc: T Kamal

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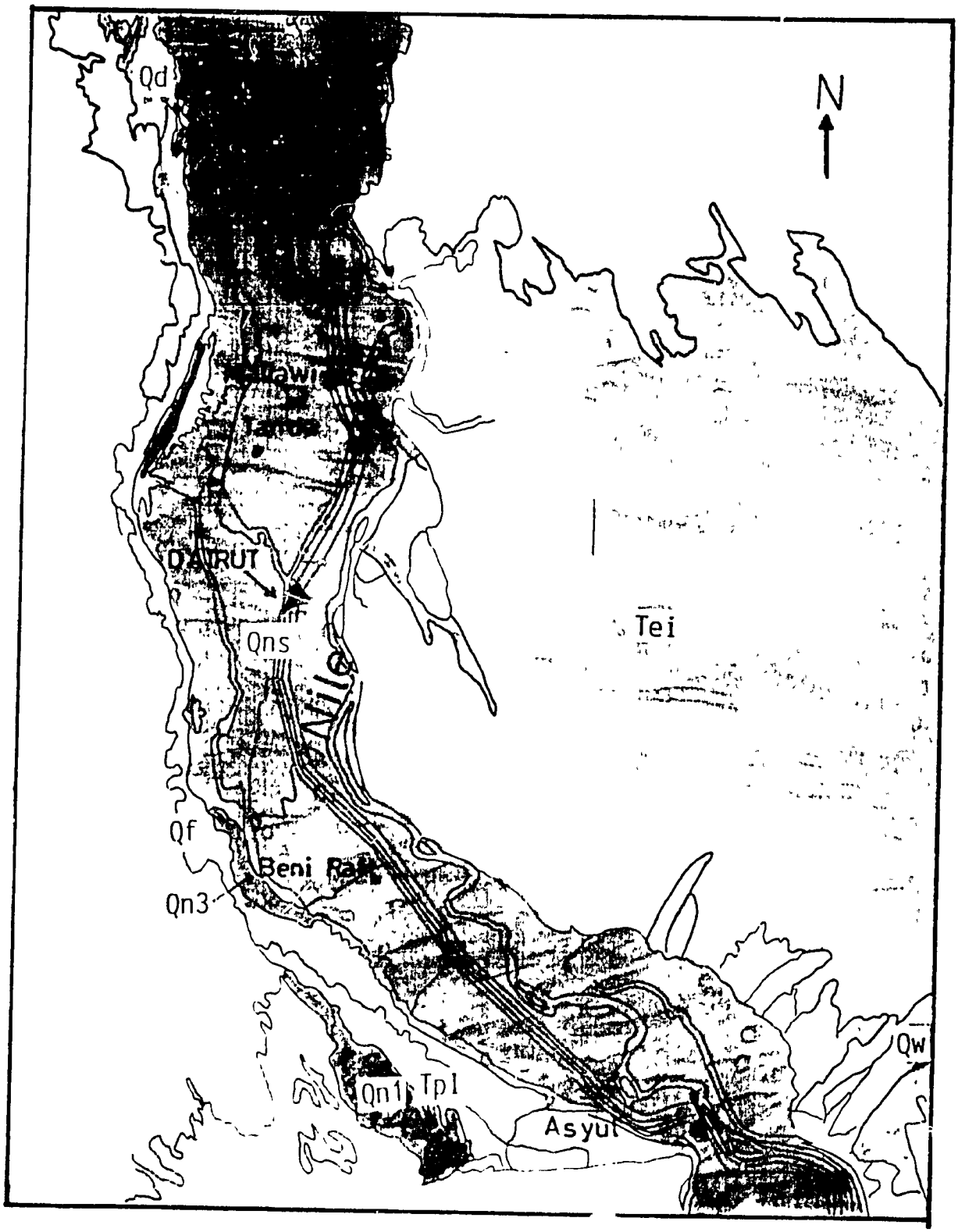

Qns	Nile silt	Qn1	Protonile deposits
Qd	Sand dunes	Tpl	Pliocene fluviatives, siltstone, sandstone and claystone.
Qf	Fan glomerate	Tei	Eocene, well bedded, white to grey alveolinid lagooned to marine l.s
Qw	Wadi deposits		
Qn3	Neonile deposits		
Qn2	Pronile deposits		

alveolinid lagoonal to marine limestone. The distribution of all these rock units is represented in Figure

6. The topography inside the valley is rather simple (the value of 20 m elevation dominates). Further to the east and west from the valley, however, higher elevations are recorded.

B. AQUATIC ENVIRONMENT

Several works dealt with the limnological features of the River Nile. The physico - chemical characteristics included: water temperature, depth, Secchi disc, electric conductivity, dissolved oxygen, total alkalinity, NO_3, PO_4 - P, SiO_3 - Si and total dissolved solids.

In general, due to the shallowness and swift current velocity in the Nile, its water is more or less homothermous. The highest temperatures occur in the summer months, while the lowest values occur in the winter months. The Secchi disc values reveal that the euphotic zone does not extend to the bottom. The electric conductivity values reach a maximum in the summer months, with minimums occurring in winter. Conductivity values are similar to those of freshwater environments. The pH values are always on the alkaline side. The water column is well oxygenated, a phenomenon that reveals the suitability of the Nile water for the survival of hetero trophic aquatic organisms.

The nutrient salts (NO_3 & PO_4 - P) always exceed the demands of primary producers, especially in June due to the discharge of agricultural drainage water at Assiut segment. In addition, the silicate levels are much higher than the demand of diatoms.

During a field investigation, two peaks of phytoplankton were recorded. The major one occurred in September, while the minor peak was recorded in May. The peak of zooplankton was recorded in September. The results revealed an

inverse relation between phytoplankton and zooplankton (r= -0152). The plankton species (phyto and zooplankton) recorded in the Nile were typically potamoplanktonic organisms.

III. OVERVIEW OF GULF OF SUEZ AREA

The proposed pumped storage sites in the Gulf of Suez region are located in the Suez Governorate. The Governorate lies northwest of the Suez Gulf at the southern part of Suez Canal. It is surrounded by four governorates: Ismailia to the north; Red Sea to the south; south Sinai to the east, and Cairo to the West. It is considered the southern entrance of the Suez Canal from the Red Sea. The total area of the governorate is 25,440 km2, but only 17,840 km2 is inhabited. It consists of four districts: Suez, Ataka, Al Arbain and Al Ganayen.

Suez Governorate is an important and vital area of Egypt. It includes ports at the Suez Gulf and is important for the petroleum industry and year round tourism. It is an urban governorate. The population was 413, 410 at the end of 1990.[1]

The pumped storage sites at Gebel El Galala are approximately 130 kilometers from Cairo and 60 kilometers south of the city of Suez. Two kilometers from the most northern pumped storage site (Ain Sukhna) is the Ain El Sokhna Hotel (km 55). A few meters from this site, is a primitive cafeteria that serves soft drinks.

Four kilometers south of the Ain Sukhna site is Maria Resort, a primitive village currently under construction (km 64 Suez-Hurghada road). Six kilometers south of the Ain Sukhna site is Mina Oasis Village resort (km 67 Suez-Red Sea). It has forty chalets, recreational activities, children's playgrounds and gardens and water sports. Further south is El Hegaz Oasis (km 69). The resort is still under construction.

The Ain Sukhna site is adjacent to the sea. This site is owned by the Ministry of Electricity and Energy. Land was given to the Ministry by the Governorate. The area around the site is sparsely inhabited.

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[1] Statistical Year Book, Suez Governorate, 1990.

A. Gebel Ataka

The Gebel Ataka sites are located more than 1500m inland. Near the sites are a high voltage transmission line and petroleum storage tanks. Misr Petroleum Company has a station close to this area and a nicely built resthouse.

Tourism Concerns

The Governorate of Suez is very concerned about the safety of the environment, the cleanliness of Suez, the development of tourism and the economy, and the welfare of the governorate. Near the Ain El Sukhna site, several high priced touristic and vacationing facilities have already been built or are under construction along the narrow beach strip. Consequently, it will be important to protect this area from pollution and maintain its privacy.

Suez Governorate is noted as a tourist resort. It has ten hotels in the city, six public gardens, four restaurants, six sports and cultural clubs, eight tourist resorts and beaches, four theaters, eight mosques, six churches and several historical monuments.

Al Ain El Sukhna is considered one of the most attractive sites for visitors and tourists from outside Suez. The natural beauty of the place, mountain and sea, allows visitors to fish and to see the beautiful corals of the Red Sea.

Ain El Sukhna is made up of natural water and is located 500 ms from Gebel El Galala.

On the whole, Suez governorate is undergoing a noticeable development of tourism. As mentioned before, seven touristic villages have been built or are under construction.