No. 52

THE REPUBLIC OF TURKEY
ELEKTRİK İŞLERİ ETÜD İDARESİ
GENEL MÜDÜRLÜĞÜ

FEASIBILITY STUDY
ON
ERMENEK HYDROELECTRIC POWER
DEVELOPMENT PROJECT

VOLUME 2
MAIN REPORT

DECEMBER 19[illegible]

JAPAN INTERNATIONAL COOPERATION AGENCY
TOKYO, JAPAN

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PREFACE

In response to the request from the Government of the Republic of Turkey, the Government of Japan decided to conduct a feasibility study on Ermenek Hydroelectric Power Development Project and entrusted the study to the Japan International Cooperation Agency(JICA).

JICA sent to Turkey a study team headed by Mr. Ichiro Kuno, Nippon Koei Co., Ltd., five times between March 1989 and September 1990.

The team held discussions with the officials concerned of the Government of Turkey and conducted field surveys. After the team returned to Japan, further studies were made and the present report was prepared.

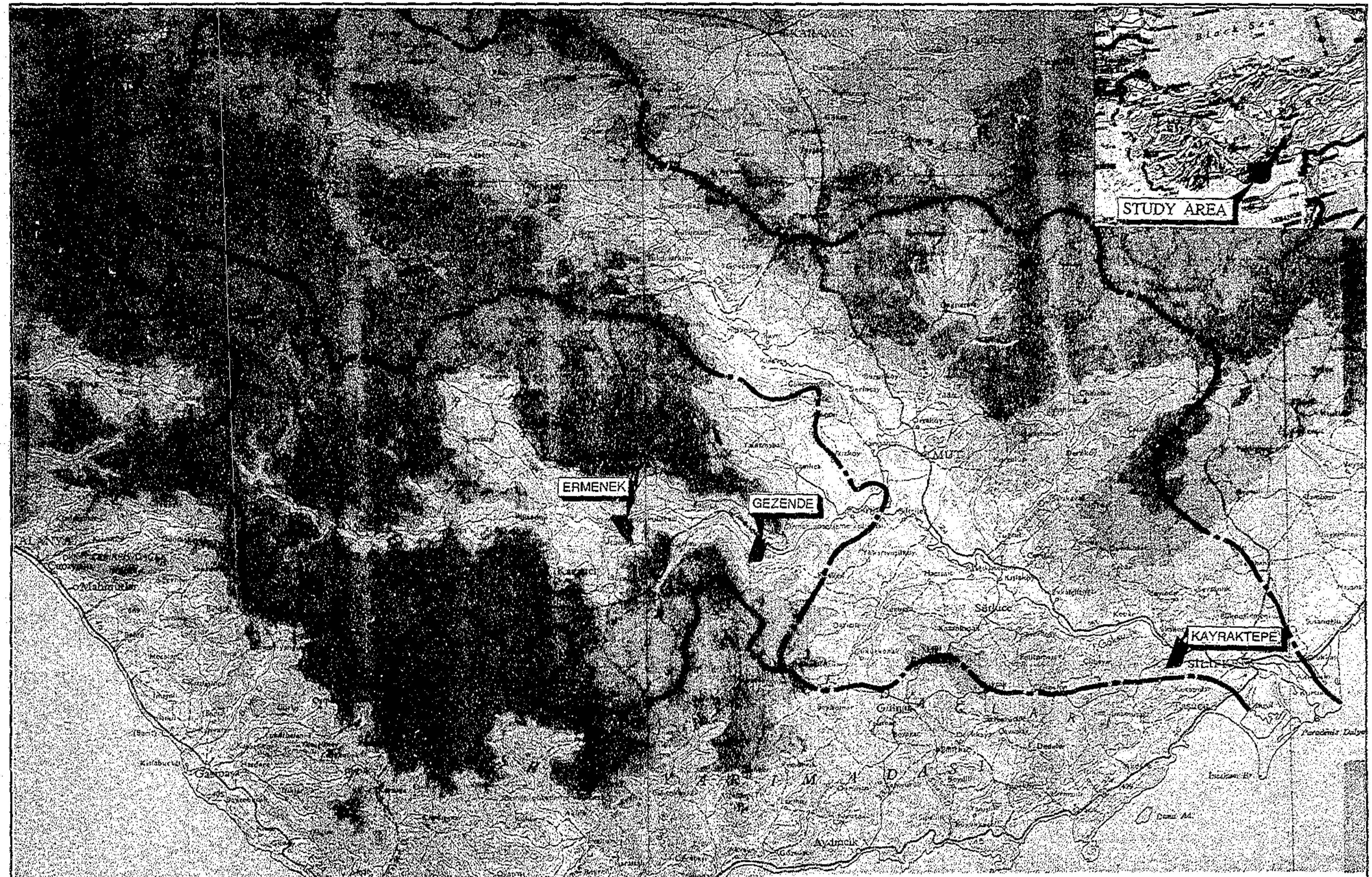
I hope that this report will contribute to the development of the project and to the promotion of friendly relations between our two countries.

I wish to express my sincere appreciation to the officials concerned of the Government of Turkey for their close cooperation extended to the team.

December 1990

Kensuke Yanagiya

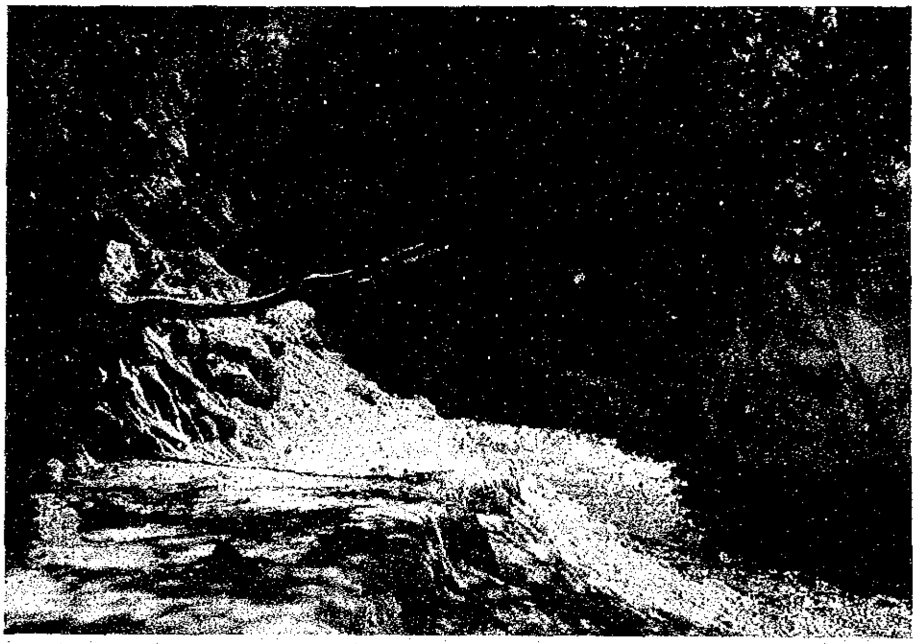
Kensuke Yanagiya
President
Japan International Cooperation Agency



THE REPUBLIC OF TURKEY ELEKTRİK İŞLERİ ETÜD İDARESİ GENEL MÜDÜRLÜĞÜ	ERMENEK HYDROELECTRIC POWER DEVELOPMENT PROJECT JAPAN INTERNATIONAL COOPERATION AGENCY	TITLE **Location Map**

FIG. NO.

A distant view of the Görmel Gorge, in which Ermenek dam site is located, viewed from upstream (July 1989)



Erik intake weir site viewed from downstream (July 1989)

THE REPUBLIC OF TURKEY ELEKTRİK İŞLERİ ETÜD İDARESİ GENEL MÜDÜRLÜGÜ	ERMENEK HYDROELECTRIC POWER DEVELOPMENT PROJECT JAPAN INTERNATIONAL COOPERATION AGENCY	TITLE **Photographs (1/3)**	

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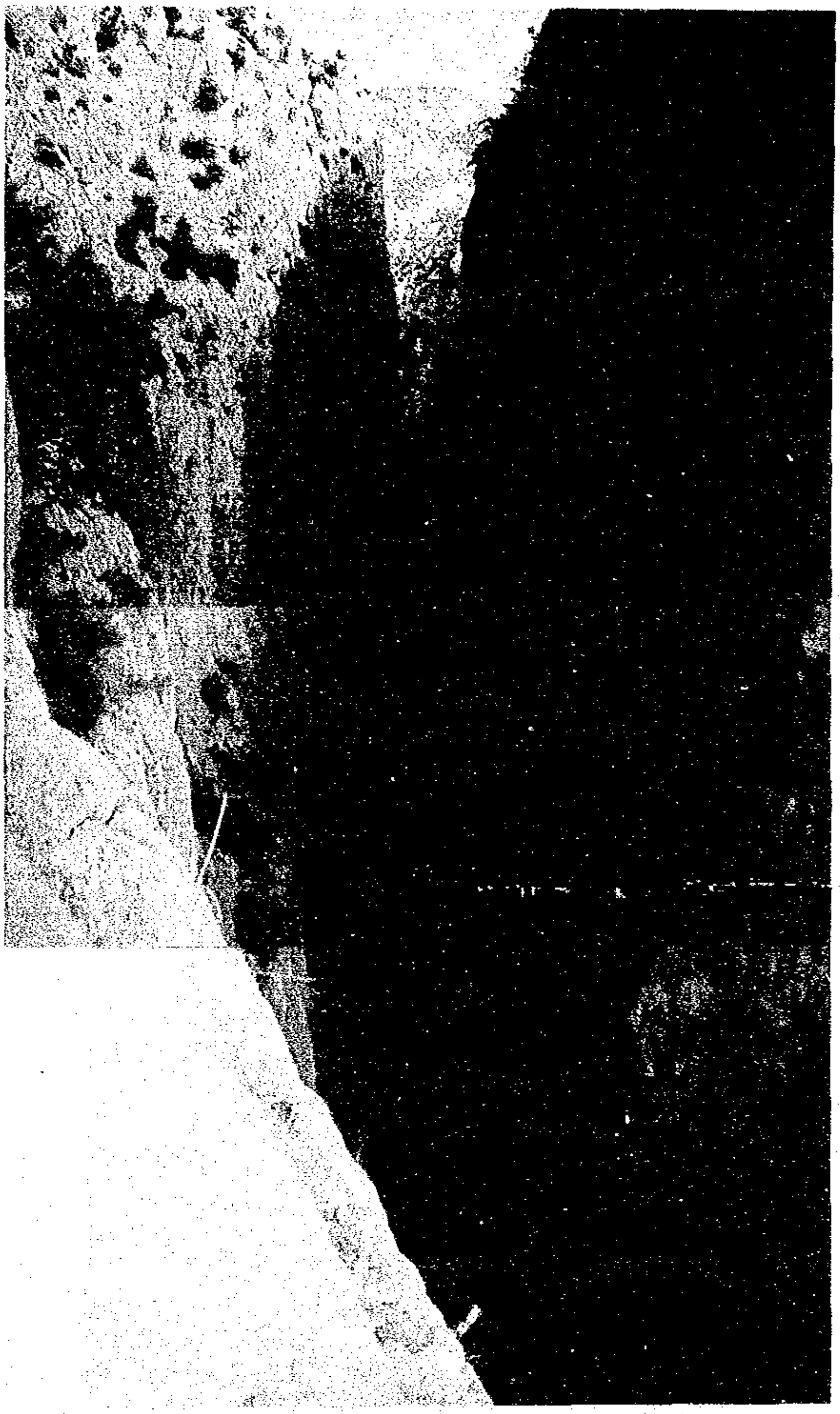
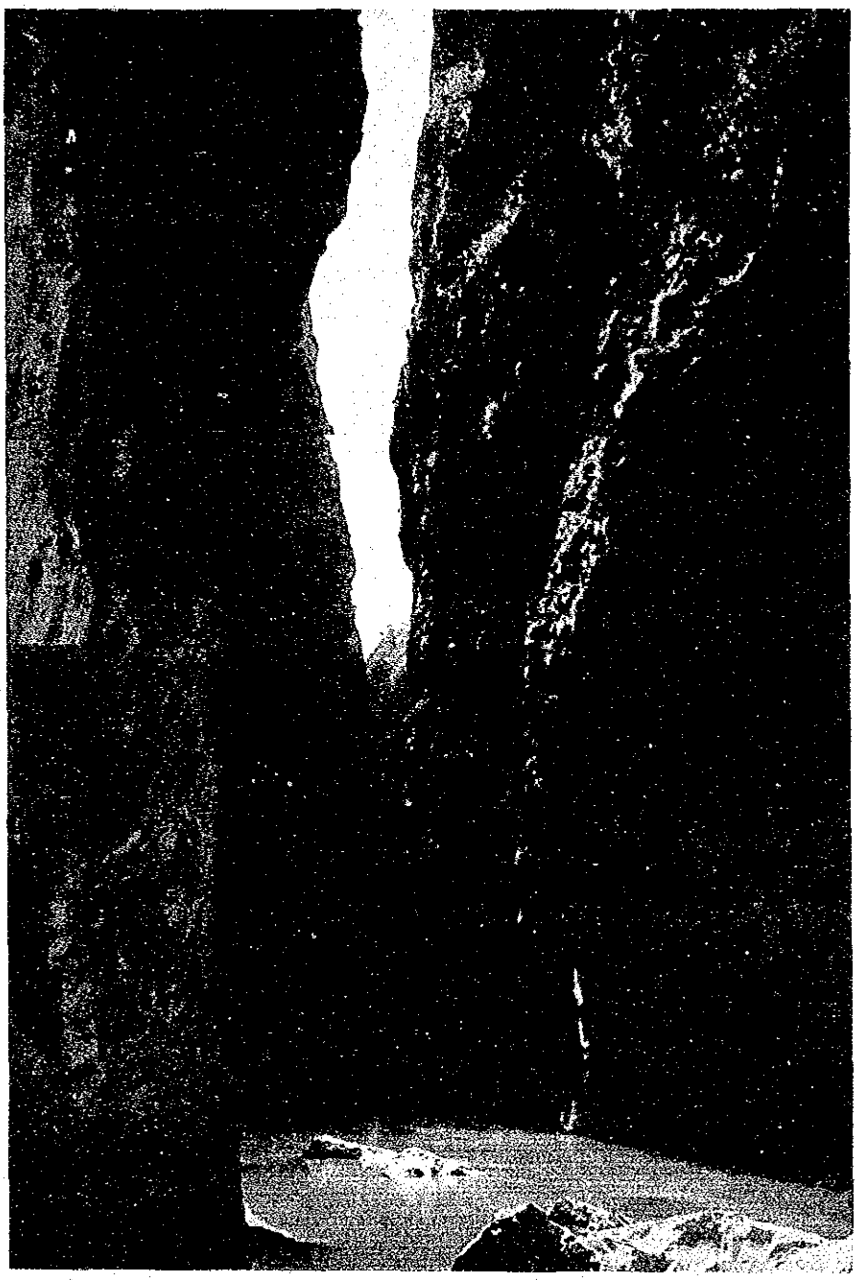


I-Cc dam site, looking downstream from the left bank
(July 1989)

	THE REPUBLIC OF TURKEY ELEKTRİK İŞLERİ ETÜD İDARESİ GENEL MÜDÜRLÜĞÜ	ERMENEK HYDROELECTRIC POWER DEVELOPMENT PROJECT JAPAN INTERNATIONAL COOPERATION AGENCY	TITLE **Photographs (2/3)**

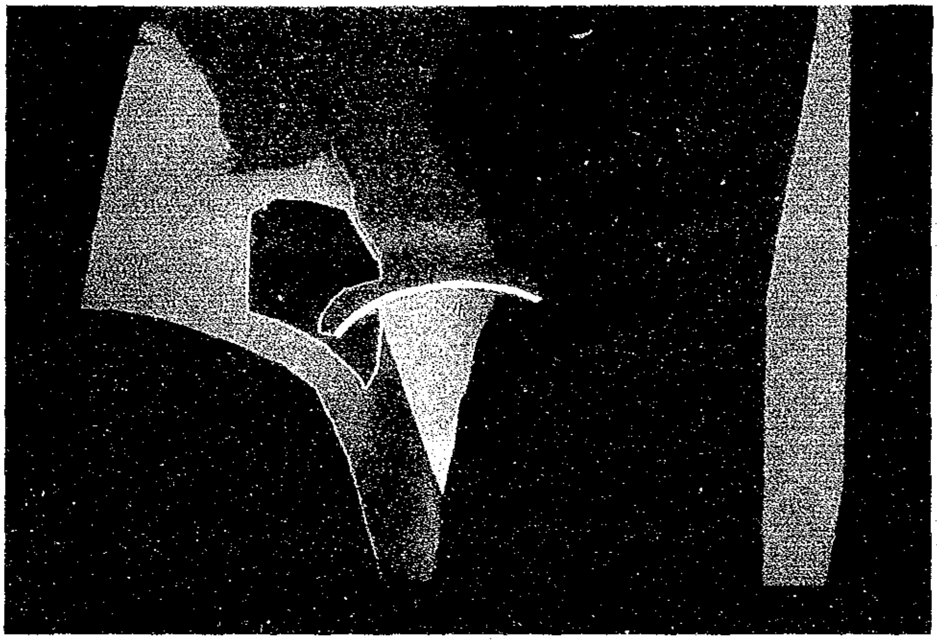
FIG. NO.



I-Cc dam site viewed from downstream (July 1989)

THE REPUBLIC OF TURKEY ELEKTRİK İŞLERİ ETÜD İDARESİ GENEL MÜDÜRLÜĞÜ	ERMENEK HYDROELECTRIC POWER DEVELOPMENT PROJECT JAPAN INTERNATIONAL COOPERATION AGENCY	TITLE **Photographs (3/3)**

FIG. NO.



HWL: 675 m Dam height: 190 m

P: 320 MW Annual energy: 1,054 GWh

	THE REPUBLIC OF TURKEY ELEKTRİK İŞLERİ ETÜD İDARESİ GENEL MÜDÜRLÜGÜ	ERMENEK HYDROELECTRIC POWER DEVELOPMENT PROJECT JAPAN INTERNATIONAL COOPERATION AGENCY	TITLE Bird's-eye View of Proposed Ermenek Dam

PRINCIPAL FEATURES

(1) Hydrology and reservoir

1.1	Catchment area at dam site	:	2,156 km^2
1.2	Catchment area at Erik intake	:	239 km^2
1.3	Mean annual inflow	:	1,466 MCM

Unit	Ermenek	Erik	Total
m^3/s	43.0	3.5	46.5
MCM	1,356	110	1,466
mm	629	460	612

1.4	HWL	:	675 m
1.5	LWL	:	615 m
1.6	Drawdown	:	60 m
1.7	Reservoir area at HWL	:	48.4 km^2
1.8	Dead storage capacity	:	1,190 MCM
1.9	Effective storage capacity	:	2,339 MCM
1.10	Gross storage capacity	:	3,529 MCM
1.11	Capacity - inflow ratio (2,339 / 1,466)	:	160 %
1.12	Design inflow flood of dam (PMF)		
	- Winter season	:	5,400 m^3/s
	- Spring season	:	5,000 m^3/s
1.13	Design inflow flood for river diversion works (5-yr probable)	:	900 m^3/s
1.14	Design flood of Erik intake weir (100-yr probable)	:	400 m^3/s

(2) River diversion works

2.1	Upstream coffer dam		
	- Type	:	Concrete arch
	- Concrete volume	:	1,300 m^3
2.2	Diversion tunnel		
	- Type	:	Concrete lined horseshoe section
	- Nos. of tunnel	:	1 lane
	- Diameter x length	:	7 m x 365 m

2.3 Downstream coffer dam

- Type	:	Concrete gravity
- Concrete volume	:	2,600 m^3

(3) <u>Dam and curtain grouting works</u>

3.1 Dam site	:	I-Çc axis
3.2 Type of dam	:	Thin concrete arch of double-curvatured parabolic type
3.3 Crest elevation	:	680.0 m
3.4 Design flood water level (DFWL)	:	678.3 m
3.5 Maximum height above foundation	:	190 m
3.6 Crest length	:	165.8 m
3.7 Dam volume	:	270,000 m^3
3.8 Length of curtain grout hole	:	386,000 m
3.9 Length of grouting tunnel	:	13,580 m

(4) <u>Spillway system</u>

4.1 Overall discharge capacity at DFWL	:	2,600 m^3/s
4.2 Bottom outlets		
- Type of gate	:	High pressure slide gate
- Dimension of gate	:	W2.5m x H4.0m
- Number of gates	:	2
- Center elevation of gates	:	EL. 545.0 m
- Discharge capacity at DFWL	:	940 m^3
- Discharge capacity at LWL	:	670 m^3/s
4.3 Tunnel spillway		
- Type of tunnel	:	Concrete/steel lined circular to semi-horseshoe
- Section of tunnel	:	D7m to W7m x H7m
- Length of tunnel x lane	:	263 m x 1 lane
- Type of gate	:	High pressure fixed wheel gate
- Dimension of gate	:	W3.0m x H7.0m

- Number of gates : 2
- Center elevation of gates : EL. 630.0 m
- Discharge capacity at DFWL : 1,160 m^3/s

4.4 Normal overflow crest
- Crest elevation : EL. 675.0 m
- Crest length x nos. : 40 m x 1 no.
- Discharge capacity at DFWL : 500 m^3/s

4.5 Emergency overflow crests
- Crest elevation : EL. 678.0 m
- Crest length x nos. : 30 m x 2 nos.

(5) <u>Waterway</u>

5.1 Design discharge : 116.6 m^3/s

5.2 Headrace tunnel : D6.1 m x 9,042 m

5.3 Pressure shaft : D3.6 m x 553 m x 2 lanes

5.4 Tailrace tunnel : D6.1m x 1,764 m

(6) <u>Power station</u>

6.1 Type of power house : Underground

6.2 Dimensions of power house : 27.0 m (W)
98.0 m (L)
38.5 m (H)

6.3 Maximum discharge in total : 116.6 m^3/s

6.4 Generating equipment (main) : 160 MW x 2 units
= 320 MW

6.5 Erik power station : 6.7 MW x 1 unit

6.6 Annual power output

		Ermenek	Erik	Total
- 90% dependable power (MW)	:	294	3	297
- Firm energy (GWh)	:	925	19	944
- Secondary energy (GWh)	:	97	13	110
- Annual energy (GWh)	:	1,022	32	1,054

6.7 Firm-up effect on the Gezende Power Station (Installed capacity; 150 MW)

- Installed capacity	:	150 —> 150 MW
- 90% dependable power	:	41 —> 150 MW
- Firm energy	:	118 —> 526 GWh
- Secondary energy	:	448 —> 115 GWh
- Annual energy	:	566 —> 641 GWh

(7) <u>Generating facilities of Ermenek power station</u>

7.1 Hydraulic turbines

- Type	:	Vertical shaft Francis
- Rated head	:	308 m
- Rotation speed	:	333 rpm
- Rated output x unit	:	163.5 MW x 2

7.2 Generators

- Type	:	Vertical shaft, revolving field, 3-phase, synchronous alternator
- Rated output x unit	:	180 MVA x 2
- Rated voltage	:	14.4 kV
- Rated power factor	:	88.9 % under normal operation 93.3 % under 5 % overload operation
- Rotation speed	:	333 rpm

7.3 Main transformers

- Type	:	Single phase, two winding
- Cooling system	:	water-cooled, forced oil circulation
- Capacity	:	60 MVA
- Number of units	:	3 units x 2 banks = 6 units
- Voltage ratio	:	14.4/380 kV

(8) Erik intake weir

8.1	Normal water level	:	820 m
8.2	Type of weir	:	Concrete non-gated gravity
8.3	Overflow crest elevation	:	820.0 m
8.4	Design flood water level	:	824.5 m
8.5	Maximum height above riverbed	:	14.0 m
8.6	Crest length	:	21.0 m

(9) Erik diversion waterway

9.1	Design discharge	:	6.0 m^3/s
9.2	Erik Diversion tunnel (free flow type)	:	W2.2 m x H2.3 m x L3,580 m
9.3	Headtank	:	W4 m x L15 m x H2 m
9.4	Penstock	:	D1.2 m x 240 m
9.5	Tailrace chamber		
	- Maximum water level	:	693.93 m
	- Normal tailwater level	:	675.00 m
	- Lowest water level	:	592.08 m
	- Diameter of chamber	:	4.0 m
9.6	Diameter of inlet shaft (semi-horseshoe type)	:	3.5 m

(10) Generating facilities of Erik power station

10.1	Hydraulic turbine		
	- Type	:	Vertical shaft Francis
	- Rated head	:	133 m
	- Rotation speed	:	750 rpm
	- Rated output x unit	:	6,950 kW x 1
10.2	Generator		
	- Type	:	Vertical shaft, revolving field, 3-phase, synchronous alternator
	- Rated output x unit	:	8,375 kVA x 1
	- Rated voltage	:	6.6 kV
	- Rated power factor	:	0.8
	- Rotation speed	:	750 rpm

10.3 Transformer

- Capacity x unit : 8,375 kVA x 1
- Voltage ratio : 6.6/34.5 kV

(11) Transmission lines

11.1 380 kV line to Seydişehir : 160 km
1-cct, 3 x 954 MCM

11.2 34.5 kV line to dam site, etc.: 16 km

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ABBREVIATIONS

(1) Domestic organization

DMİ	:	Devlet Meteoroloji İsleri (State Meteorological Service)
DSİ	:	Devlet Su İsleri (General Directorate of State Hydraulic works)
EİE	:	Elektrik İsleri Etüd İdaresi (Electrical Power Resources Survey and Development Administration)
DİE SIS	:	Devlet İstatistik Enstitüsü (State Institute of Statistics)
DPT SPO	:	Devlet Planlama Teskilati (State Planning Organization)
TEK	:	Türkiye Elektrik Kurumu (Turkish Electricity Authority)

(2) Foreign organization

JICA : Japan International Cooperation Agency

(3) Measurement

Length

mm	=	millimeter
cm	=	centimeter
m	=	meter
km	=	kilometer

Electrical Measures

V	=	Volt
kW	=	kilowatt
MW	=	Megawatt
kWh	=	kilowatt hour
MWh	=	Megawatt hour
GWh	=	Gigawatt hour

Area

km^2	=	square kilometer

Money

TL	=	Turkish lira
US$	=	US dollar
US¢	=	US cent
¥	=	Japanese Yen

Volume

MCM	=	million cubic meter
m^3	=	cubic meter

Weight		
kg	=	kilogram
ton	=	metric ton

Time		
sec, s	=	second
min	=	minute
hr	=	hour
yr	=	year

Other Measures		
%	=	per cent
°	=	degree
'	=	minute
"	=	second
m^3/s	=	cubic meter per second

(4) Economy and finance

EIRR	:	Economic Internal Rate of Return
FIRR	:	Financial Internal Rate of Return
FC	:	Foreign Currency
LC	:	Local Currency
GDP	:	Gross Domestic Product
GNP	:	Gross National Product
GRDP	:	Gross Regional Domestic Product
OMR	:	Operation, Maintenance and Replacement
LS	:	Lump Sum

(5) Elevation

EL.	:	Elevation above mean sea level
FWL	:	Flood water level
HWL	:	High water level
LWL	:	Low water level

(6) Exchange rates (as of November 1989)

US$1.00 = TL2,300 = Japanese ¥143

TEXT

CHAPTER 1. INTRODUCTION

The Ermenek Hydroelectric Power Development Project (the Project) had been identified at a reconnaissance level as a promising project to further develop the rich potential of the Göksu river basin which drains the Toros mountains by constructing a dam at a site which is located 370 km to the south of Ankara.

This Feasibility Study on Ermenek Hydroelectric Power Development Project (the Study) was carried out between March 1989 and December 1990 by a Study Team of the Japan International Cooperation Agency (JICA), the official agency responsible for implementation of the technical cooperation programs of the Government of Japan, in collaboration with a Counterpart Team of the General Directorate of Electrical Power Resources Survey and Development Administration (EİE), Ministry of Energy and Natural Resources, the Republic of Turkey, in accordance with a Scope of Work which was agreed between EİE and JICA on September 22, 1988 in Ankara.

The objective of the Study was to formulate an optimum development plan for the Project and to assess the technical, financial and economic feasibility of the Project.

The Study was divided into three stages; the Preliminary Investigation Stage, Additional Detailed Investigation Stage, and Feasibility Grade Design Stage. In the preliminary Investigation Stage of March to July 1989, the existing development schemes were reviewed, alternative frameworks of the Project were compared and a detailed work plan was prepared, based on the results of data collection and field reconnaissance. The Additional Detailed Investigation Stage of May 1989 to February 1990 was devoted to various survey works including topographic survey, geological core boring and seismic exploration. In the Feasibility Grade Design Stage of December 1989 to September 1990, an optimum plan was prepared in terms of the scale and structural arrangement of the Project, based on the physical site conditions and the projected power demand and supply balance. The main dimensions of the Project facilities were determined and the construction cost was estimated. The economic and financial feasibilities of the Project were evaluated and the environmental impact was assessed.

The results of all the stages of the Study are compiled in this report.

Grateful acknowledgement is made of the assistance and cooperation provided by officials of the Republic of Turkey and other individuals who have provided information and data, participated in discussions, given valuable advice and provided other forms of assistance to the Study. Heartfelt gratitude is also due to officials of the Government of Japan who have provided support in performance of the Study. The Study Team is especially indebted to the counterpart personnel of EİE, who have provided every assistance to the Study Team and efficiently performed the field works overcoming various difficulties.

CHAPTER 2. BACKGROUND

2.1 Physical Aspects of Turkey

Turkey has a land area of 781,000 km^2. Its main land consists of the Anatolian peninsula in west Asia and a part of Thrace in Europe. The largest dimension is 1,600 km in the east-west direction and 650 km in the north-south direction, respectively. The land looks out upon the Black Sea in the north, and the Aegean Sea and the Mediterranean Sea in the southwest. It neighbours with the U.S.S.R., Iran, Iraq and Syria across the eastern and southeastern borders and Greek and Bulgaria in the northwest.

Turkey belongs to the Alps-Himalayas tectonic belt. It is characterized by folding mountains generally running in the east-west direction and highlands in between. The Kuzey Anadolu mountains located along the Black Sea coast have cliffs to the north and a structural valley to the south. Rivers run in structural valleys developed in the east-west direction and north-south direction and Rias coasts are formed in the Aegean coastland. The Bati Toros mountains are folding mountains located along the Mediterranean Sea coast and these continue to the Orta Toros mountains which trends to the northeast. The central interior of the Anatolian peninsula is the Anatolian plateau, in the southeastern part of which there are active volcanoes such as Mt. Erciyas (EL. 3,916 m) and Mt. Hasan (EL. 3,253 m). Eastern mountains are the Armenian highlands, which southerly decline to the Dicle (Tigris) and Firat (Euphrates) river basins. The average ground elevation is 1,125 meters, with the highest peak of Mt. Ararat (EL. 5,165 m) on the eastern border.

Located between 36° and 42° north in latitude, Turkey is under the influence of polar air mass of prevailing northwest winds in winter and tropical air mass of prevailing north winds in summer. The Black Sea coast is generally wet and has moderate air temperature. The Anatolian plateau and Armenian highlands are arid with low precipitation and a cold winter. The Aegean and Mediterranean sea coasts have a mild winter and a hot summer. Wet southwest winds sometimes cause heavy storms. The winter is wet in the coastal areas. Annual precipitation is 500 to 700 mm on the Aegean and Mediterranean seacoasts and 2,500 mm along the Black Sea on an average. Annual rainfall in the interior is 250 to 450 mm, May being the wettest month.

2.2 Human Aspects of Turkey

The population in Turkey was 50.3 million (1985 population census), and its average growth rate was 2.5 per cent per annum between 1980 and 1985. The average population density is 64 per km^2, but the population is concentrated in the Thrace area and the coastlands of the Marmara, Aegean and Black seas. The proportion of urban population was 53 per cent in 1985. The populations in major towns were 3.3 million in Ankara, 5.8 million in Istanbul, 2.3 million in Izumir, 1.7 million in Adana and 1.3 million in Bursa including suburbs. Of the total labor force of 18.5 million in 1985, 11.1 million or 60 per cent was engaged in agriculture, 2.4 million or 13 per cent in manufacturing and 2.4 million or 13 per cent in community and service.

Total land area of 78.1 million ha is classified into 36.3 million ha (46.5 %) of agricultural land, 20.2 million ha (25.9 %) of forest, and 21.6 million ha (27.6 %) of other lands and water surfaces. The agricultural land is further divided into cultivated land of 24.5 million ha, perennial crop land of 3.0 million ha and pasture of 8.8 million ha.

Turkey is administratively divided into 73 provinces each headed by a provincial governor. A province is divided into counties each under an administrator. A county is further divided into districts each under a director. The provincial capital, district capital and each town of more than 2,000 in population are recognized as municipalities.

Gross domestic product (GDP) in 1987 at current prices was estimated to be 50.7 trillion Turkish Liras or US$59.2 billion in the OECD Economic Survey of Turkey, September 1986. This indicates a per capita GDP of US$1,120 in 1987 and a real growth rate of 6.0 per cent per annum on an average between 1982 and 1987. The composition of GDP by output sector in 1987 was estimated in this OECD document to be 17.4 per cent for agriculture, forestry and fishery sector, 32.2 per cent for industry sector, 4.1 per cent for construction sector, and 46.2 per cent for service sector.

Inflation has become a severe problem in the Turkish economy. The estimates of the wholesale price indices by the State Institute of Statistics for the past six years (1982-1988) show that the index has climbed from 127.0 to 1,027.3 (1981=100), which corresponds to an annual inflation rate of 42 per cent.

The Turkish economy entered a turning point in the 1980s with the introduction of policies to increase export oriented production, decreasing subsidies and encouraging foreign investments. More recent developments include privatization of some State Economic Enterprises and the build-operate-transfer (BOT) policies. The 5th Five Year Development Plan (1985-1989) has set long-term structural objectives, in which the State has less direct involvement in the production and investment process. During the next plan period, covering 1990-1994, the GNP is expected to grow at an annual rate of 5.8 per cent, while the per capita GNP is expected to grow at the rate of 3.8 per cent.

2.3 Energy Supply Prospects

The main aim in the energy sector is to provide sufficient, reliable, cheap and good quality energy. The Government's energy policies and production targets are to secure the energy supply to all the consuming sectors for fostering of economic and social developments.

During the 5th Five Year Plan period, the primary energy production in Turkey has increased at a 4.8 per cent growth rate per annum. In 1989, the last year of the 5th Five Year Plan period, the total energy production amounted to 27.9 million tonnes of oil equivalent (toe), while the energy consumption was 51.2 million toe. This implies a self-sufficiency ratio of 54.5 per cent. The shares of the consuming sectors in the total primary energy consumption are estimated to be 30.1 per cent for industry, 27.5 per cent for residential and commercial, 26.4 per cent for electricity generation, and 16.1 per cent for transportation.

In meeting the growing demand for energy, priority is to be given to the use of resources indigenous to the country. However, since there are some limitations in the development and use of these indigenous energy resources, the import of primary energy will continue to increase in the future. It is forecast that primary energy consumption will grow at an annual rate of 8.0 per cent during the 6th Five Year Plan period, but production in Turkey can be expanded at an annual rate of only 5.2 per cent, resulting in a reduction in the self-sufficiency ratio to 48 per cent by 1994.

In order to maintain the reliability of the energy sector structure, the Government's diversification policy of energy resources for power generation will be promoted both in the domestic energy production and the import of primary energy. Hydroelectric potential and lignite have been major indigenous energy resources. The development of the former will be continued in the future and geothermal power will also be developed, but the development pace of lignite power will slow down because of the limitation in exploitable reserves as well as of environmental impacts. During the 6th Plan period, natural pipeline gas from the U.S.S.R. is expected to displace a lot of petroleum products. An imported coal-fired thermal plant is going to be introduced to the Turkish power system in the first half of the 1990s. Thereafter construction of imported coal thermal plants will be continued. Thus, coal together with natural gas will be major energy sources for thermal power generation. Considering the importance of nuclear energy in the long-run, studies on the nuclear technology will be started soon for commissioning of the first unit by 2010.

In all the stages of production and consumption of energy, suitable technologies with maximum efficiencies will be used and projects for energy conservation will be supported with suitable incentives.

Studies for promotion of privatisation and private sector investment in the energy sector will be evaluated in order to support the public sector in the field of financing and economic efficiency.

CHAPTER 3. POWER STUDY

3.1 Organization for Power Supply in Turkey

The electric power supply activities in Turkey are undertaken by three public organizations; Turkish Electricity Authority (TEK) and the Electrical Power Resources Survey and Development Administration (EİE), both under the Ministry of Energy and Natural Resources, and the State Hydraulic Works (DSİ) under the Ministry of Public Works and Settlement.

EİE is in charge of survey, research and studies for the stages of master plan, feasibility and final design of hydroelectric power projects. For several years now, EİE has been responsible for rational utilization of energy sources, energy conservation and development of new and renewable resources of energy (solar and wind). The organization chart of EİE is shown in Fig. 3.1.

The principal functions of DSİ are to plan, design, construct and operate flood protection, irrigation, water supply, land drainage works and so forth. DSİ is also in charge of overall management of hydraulic works in the country. DSİ manages the construction of all hydroelectric power projects in Turkey and it also has similar functions as EİE for the hydroelectric power development, either related to multi-purpose river development or located in the river basin allocated to DSİ. The organization chart of DSİ is shown in Fig. 3.2.

TEK is responsible for generation, transmission, distribution including rural electrification and commercialization of electric energy in the country. TEK has the monopoly for operation of generation and transmission facilities all over the country except for the four provinces which are under concession by ÇEAS and KEPEZ. TEK operates and maintains hydroelectric power projects which are handed over to them by the Government, and plans, designs, constructs and operates thermal power plants and transmission and distribution systems. The electric energy sales of TEK are performed by the two Generation and Transmission Enterprises on a bulk basis at a transmission voltage of 66 kV and above, and by the Distribution Enterprises, which are supplying power to consumers in 21 regions all over the country. TEK is also responsible for planning the overall development of the electricity sector, which covers power demand forecasting, provision of the optimal strategy for evolution of the generating plant mix, progress in development stages of hydroelectric power projects, and so forth. TEK's outline organization chart is shown in Fig. 3.3.

Along the Mediterranean sea near the Ermenek project site, there are two private power companies; Çukurova Electric Power Company (ÇEAS) with its concession area in Adana, Mersin and Hatay, and Kepez and Antalya Area Electric Power Company (KEPEZ) for the Antalya area. These companies are encouraged to construct hydroelectric power plants and interconnect with the national power network of TEK, and are operating and maintaining their power systems under the control of TEK. They are requested to operate their power plants according to instructions of the TEK's load dispatching center. Energy interchange with TEK is made on a special tariff system.

A new law for privatisation of power supply business will be introduced in the near future, probably in 1990. Under this law, private enterprises will be encouraged to undertake power supply activities.

3.2 Existing Power Supply System

3.2.1 Power generating facilities

The total installed capacity of generating facilities in Turkey as of 1988 was 14,518 MW, which consisted of 6,218 MW of hydro plants (42.8 % of the total) and 8,300 MW of thermal plants (57.2 % of the total). Of the total installations, 89.4 per cent was owned by TEK, 2.6 per cent by concessionary power companies, and 8.0 per cent by self-generation. The composition of power plants in 1988 based on energy sources is presented in Table 3.1.

The historical development of installed capacity classified into hydro and thermal for the period of 1975 through 1988 is shown in Table 3.2 and depicted in Fig. 3.4. The historical share of energy generation by energy sources is shown in Table 3.3 and Fig. 3.5. The share of hydro installations has been slightly exceeding 40 per cent. As for thermal installations, the oil thermal plants were major installations of Turkey in 1975. However, their total capacity has remained almost unchanged since then and the share in the energy generation has been gradually decreasing. This tendency conforms to the Government's policy to curtail oil consumption. On the other hand, the total installed capacity of lignite thermal plants increased significantly and occupied 53.7 per cent of the whole thermal in 1988 as seen in Table 3.1. Operation of natural gas and geothermal plants started in 1984 and their capacity has been increasing rapidly.

The historical increase rates of the total installed capacity are compared with the growth rates of power demand below:

Year	Installed Capacity MW Value	Installed Capacity Growth	Energy Generation GWh Value	Energy Generation Growth
1975	4,186.6		15,719.0	
		4.1 %		9.4 %
1980	5,118.7		24,616.6	
		12.2 %		8.1 %
1985	9,119.1		36,361.3	
		16.8 %		10.0 %
1988	14,518.1		48,430.0	

It is noted from the above table that the increase in installed capacity has not been coordinated very well with the steady growth of energy demand. During the period from 1975 to 1980, the increase rate of installed capacity was much lower than the growth rate of demand, and due to the shortage in supply capacity Turkey was obliged to import electric power after 1975 from Bulgaria and the U.S.S.R. However, the installed capacity increased at a rate much higher than the demand growth after 1980. The balance between demand and supply capacity turned from supply shortage to supply surplus in 1987. The thermal energy generation, which has lower priority than hydro generation in actual operation of the power system, recorded its historical maximum in 1986, but it recorded some decrease in 1987 due to the supply surplus. The surplus has become further conspicuous in 1988. The share of hydro energy generation increased much from 42 per cent in 1987 to 60 per cent in 1988 owing to the commissioning of additional units of the Karakaya and Altinkaya power plants (1,125 MW in total), and the thermal power generation decreased remarkably in spite of the increase in installed capacity. The historical share of energy generation by various energy sources is tabulated in Table 3.4 and depicted in Fig. 3.6.

3.2.2 Power transmission facilities

Operation of the first 380 kV transmission line in Turkey was commenced in 1971 to send generated power from the Keban hydro power station on the Euphrates river to

Istanbul and Ankara. This 380 kV transmission system has been extended and reinforced gradually, to form a national power grid and now it interconnects major power stations and load centers throughout the country. Regional transmission systems are composed of 154 kV and 66 kV (small scale only) transmission lines and 34.5 kV distribution lines, which are interconnected with the 380 kV national grid through transformers.

Many major power stations of Turkey, such as three large hydro power stations on the Euphrates river, Keban (1,330 MW), Karakaya (1,800 MW) and Atatürk (2,400 MW), and Elbistan lignite thermal power station (1,360 MW extendible to 6,120 MW), are located in the eastern half of the country. While, major load centers such as Istanbul, Ankara, Izmir and so forth are located on the western side of the country. Therefore, the main power flow in the 380 kV national power grid is generally from the east to the west and this situation will continue for the foreseeable future.

The total length of transmission lines and high tension distribution lines for the period of 1979 through 1988 is tabulated in Table 3.5 and the development of numbers and total capacity of transformers in Table 3.6. The length of 380 kV lines has been increasing rapidly and became 2.5 times during the recent 9-year period. 154 kV transmission lines were formerly used for major transmission lines, but are at present applied to secondary transmission systems. 220 kV transmission lines are used only for interconnection with foreign 220 kV power systems. 66 kV lines have been used for some separated local systems, but they will no longer be extended. 34.5 kV lines are being used for main distribution systems and 15/6.6 kV lines for small scale power supply in both urban and rural areas. The low tension distribution voltage is 380/220 V, 3-phase, 4-wire.

3.2.3 Rural electrification

The recent development of village electrification and its present situation are presented in Tables 3.7 and 3.8 respectively. The village electrification ratio exceeded 50 per cent in 1980 and reached 99 per cent in 1988. By 1990, the village electrification works will be completed except for extremely difficult remote locations. All the villages in Konya and Karaman provinces have already been electrified.

3.3 Power Market

3.3.1 Supply area of the Project

In planning power supply from a power plant in a large country like Turkey, not only the national balance between demand and supply capacity but also the regional balance must be taken into account. The Ermenek Project site is located in the southern part of Karaman province near its border with the Içel province. As the regional supply areas of the Ermenek Project, the Konya and Karaman provinces located to the north of the Project and the western half of Içel province are conceivable. As mentioned in Section 3.2.2, the general power flow in the 380 kV national power grid is from the east to the west. Therefore, there will be no need to send power from the Ermenek power station to Adana and Mersin which are located to the east of the Project. Power to the west Içel will be supplied from the planned Akkuyu nuclear and or from Kayraktepe hydro power station, and also from the Gezende power station.

Accordingly, the supply area of the Ermenek power station will be the Konya and Karaman provinces. As the Ermenek power station will be connected with the Seydisehir substation through a 380 kV transmission line, power to these two provinces will be delivered through this substation.

3.3.2 Power demand in the past

(1) Whole country

A historical summary of the power system operation in Turkey is presented in Table 3.9. The gross energy requirement, the sum of generation in the country and import, has recorded an average growth rate of 8.0 per cent per annum in the recent 10 years and 10.4 per cent in the later half of the period. It is noted from the table that the demand growth was very high after 1983. However, the growth was declined after 1987; 7.8 per cent from 1987 to 1988 and 7.5 per cent from 1988 to 1989. The peak demand of 1988 was 7,613 MW, which corresponded to a per capita demand of 141 W. The annual load factor had been around 70 per cent or slightly higher during these 10 years and the daily load factor was slightly higher than 80 per cent.

The energy consumption records by consumers' categories for the period of 1979 through 1986 are tabulated in Table 3.10. The total energy consumption by various manufacturing sectors occupied 61 per cent of the total consumption in 1986. The share of household consumption was 15.6 per cent, being relatively low among developing countries.

The 1988 electric power demand data of the country may be summarized as follows:

	Total	Per Capita
-Generation capacity	14,518 MW	0.268 kW
-Peak generation	7,613 MW	0.141 kW
-Generated energy	48,049 GWh	---
-Imported energy	381 GWh	---
-Total energy	48,430 GWh	894 kWh
-Annual load factor	72.0 %	---
-Consumed energy	39,356 GWh	726 kWh
-Loss and station power	18.7 %	---
-Loss factor	14.5 %	---

(2) <u>Konya and Karaman provinces</u>

The power demand of these two provinces can be classified into the following two categories:

- General power demand, being supplied by Meram Distribution Enterprise of TEK

- An aluminium smelting plant operating in the Seydişehir area, being supplied by Generation-Transmission Enterprise of TEK

The Meram Distribution Enterprise supplies electricity to three provinces, Konya, Karaman and Nigde, by receiving power from the Generation-Transmission Enterprise of TEK and by generating at its own mini-hydro power plants. The total electric energy requirements for the Konya and Karaman provinces in 1986 through 1988, were as given below:

Year	Energy (MWh)	Growth Rate (%)
1986	597,077	----
1987	649,788	8.7
1988	671,077	3.4

The record of received energy of the Meram Distribution Enterprise including interchange with other provinces and its own generation in 1988 is tabulated in Table 3.11. Energy consumption by consumers of various categories in 1988 is tabulated in Table 3.12. According to the peak demand and energy data of the Konya I and Konya II substations, the annual load factor of the overall distribution system was approximately 54 per cent and the peak demand of these two provinces 140 MW. Within these two provinces, Konya city was the largest demand center, consuming 57 per cent of the total general energy demand.

The per capita consumption of the general demand in the two provinces in 1988 was 316 kWh, or 43.5 per cent of the national average. It is noted that the energy consumption by the industry sector not including the aluminium smelting plant was about 37 per cent of the total general energy demand and was lower than the share of the whole country. These two provinces are land-locked provinces with not many large scale industrial activities except for the aluminium smelter. The ratio of urban population to the total in 1985 was 48.2 per cent and was lower than the national average of 53.0 per cent.

The percentage power loss in 1988 was 3.0 per cent for station service and 8.7 per cent for transmission and distribution.

The aluminium smelting plant had a peak power demand of 146 MW and a total energy demand of 1,114 GWh in 1989. This plant is receiving power at 380 kV from the Seydişehir substation of TEK. This demand will remain at this level unless the plant is expanded.

Therefore, the total 1988 demand in the two provinces amounted to 286 MW in peak demand and 1,785 GWh in energy requirement.

3.3.3 Power tariff structure

The current power tariff structure, which has become effective from 1 September 1989, is shown in Table 3.13. The overall average tariff is estimated at TL131.23 per kWh. Principal features of the tariff system are mentioned below.

(1) Against the power sales by the Generation-Transmission Enterprise (to very large consumers at transmission voltage) and Distribution Enterprises (to large to small consumers at distribution voltage), two different series of tariff system, one for each enterprise, are applied as seen in Table 3.13.

(2) There are two kinds of tariff, one is a two-part tariff which is charged according to contracted kW value and consumed kWh, and the other is a one-part tariff which is charged according to consumed kWh only. Consumers with contract power of 700 kW or more can choose either of one- or two-part tariff, and consumers with smaller contract power are charged based on the one-part tariff.

(3) For the two-part tariff system, three different tariffs are applied according to the development levels of the provinces; the highest tariffs are applied to the 6 special provinces of Istanbul, Kocaeli, Izmir, Ankara, Bursa and Adana, the lowest tariffs to the first and second priority provinces, 28 in total number, and the normal tariffs to the remaining provinces. In the Konya and Karaman provinces, the normal tariffs are applied. Special lower tariffs are applied to arc oven consumers and 5 per cent discounted tariffs are ap-

plicable to approved industries and small industries. These lower tariffs were introduced to encourage industrial activities.

(4) For two-part tariff consumers, time-defined tariffs are applied as given below:

Peak period:	17:00 to 22:00
Night period:	22:00 to 06:00
Day period:	06:00 to 17:00

However, the above periods are subject to revision by the General Directorate of TEK according to the longitude of place and seasons.

(5) So as to reduce power distribution losses and to improve voltage regulation, large consumers are required to operate their systems with a high power factor of between 0.9 and 1.0 lagging. The reactive power tariff is charged on reactive kVarh when the power factor of a consumer is below 0.9.

3.4 Power Demand Forecast

3.4.1 TEK's demand forecast

(1) <u>Long-term demand forecast</u>

The long-term power demand forecast of Turkey up to the year 2010 was prepared by TEK in 1988 based on two scenarios; high and low. The starting demand in 1989 of the high scenario forecast was 4.3 per cent larger than the low scenario one and was more than 10 per cent larger than the actual 1989 demand of 52,061 GWh. The high scenario forecast estimated growth rates of energy demand higher than or similar to the low scenario ones up to the year 2000 and lower rates thereafter. The high scenario energy demand in 2000 was 6.6 per cent larger than the low scenario one, however the 2010 demand was almost identical for the two forecasts. The high and low scenario forecasts are presented in Table 3.14 and a summary for comparison is given below:

	High Scenario		Low scenario	
Year	Energy (GWh)	Growth (%)	Energy (GWh)	Growth (%)
1989	57,925	---	55,545	---
1990	64,910	12.0	61,760	11.0
1995	105,930	10.3	101,210	10.4
2000	166,830	9.5	156,515	9.1
2005	231,530	6.8	222,710	7.3
2010	323,850	6.9	323,295	7.7

The low scenario demand forecast has been approved by the Government. The demand is forecast at the low scenario to become 2.8 times the initial demand in 1989 by the year 2000, and 5.8 times by 2010.

(2) Review of the demand forecast

The above demand forecast is reviewed macroscopically based on the estimated growth of the national economy.

According to the World Development Report 1989 of the World Bank, the per capita GNP of Turkey in 1987 was US$1,210. The GNP growth for the period of 1980 to 1989 was approximately 4.8 per cent per annum. The 6th Five Year Plan envisages an annual rate of 5.8 per cent for the GNP growth during the plan period. While, the World Bank recommended adoption of a more conservative plan with a growth rate of 5 per cent or lower for the coming several years. Taking into account the various development plans of the Government, the long-term economic growth rate was herein assumed at 5.5 per cent per annum.

The relationship between growth rates of GDP and those of gross energy consumption of the middle income (per capita GDP of US$500-2,000-6,000) and high income (per capita GDP of over US$6,000) countries for the two periods of 1965 to 1980 and 1980 to 1987 are presented in Table 3.15 by reference to the above World Bank Report. The growth rates in electric energy consumption for the period of 1980 to 1987 in the OECD countries are also shown in the same tables to show the relationship between the growth rates of gross energy consumption and those of electric energy consumption.

The main points noted from data in the World Bank Report are as follows.

(A) The two oil crises which took place in the 1970s greatly affected economy of every country. The GDP growth rates for the period 1980 to 1987 were lower than those for the period 1965 to 1980 for most of countries. The growth of energy consumption was also much decreased, especially in high income countries.

(B) For middle income countries, the growth rate of energy consumption was several per cent higher than that of GDP before 1980 but the two rates became almost equal to each other after 1980. For high income countries, the growth rate of energy consumption was about 80 per cent of the GDP growth rate before 1980, but the growth rate became marginal thereafter owing to energy saving efforts.

(C) In all the OECD countries, the growth rate of electric energy consumption was higher than that of gross energy consumption. This trend matched the world-wide trend for the share of electric energy to increase faster than total energy consumption.

Although Turkey at present belongs to the lower middle income group of countries (per capita GDP of US$600-2,000), it will increase GDP and in future will upgrade its ranking to a more developed group. As the result of analysis of past trends in Turkey, the growth rate of total energy consumption for a GDP growth of 5.5 per cent per annum is estimated at 6.5 to 7.5 per cent per annum. Taking into account that rural electrification activity in Turkey has already been completed, the past ratio of the growth of electric energy consumption to that of total energy consumption, being 1.33 for the period of 1980 to 1987, is assumed to fall to 1.1 to 1.2 in the future. Thus, the growth of electric energy consumption for an average economic growth of 5.5 per cent per annum is estimated at 7.0 to 8.5 per cent per annum. The high growth rate of 10.4 per cent in energy demand between 1983 and 1988 will no longer continue, because such high growth was attributable to the mitigation of the electricity shortage and expeditious rural electrification, both of which took place during the above-mentioned period.

The estimated energy demand as described above is compared with the TEK's forecast as tabulated in Table 3.16. The TEK's forecast appears to be considerably larger than the estimated demand as above. However, it is close to the high-side forecast herein estimated, if it is adjusted based on the actual 1989 demand. In principle, power development plans have to be prepared so as to satisfy the demand even though a relatively high growth may be realized at a future stage. In conclusion, the TEK's forecast is judged to be within a reasonable range, though it seems on a high side when viewed from macroscopic parameters in other countries.

(3) <u>Daily load variation</u>

Weekly load curves, which consist of 7 daily load curves in a week, in the year 2000 are estimated by TEK for three seasons, April (for spring and autumn), July (for summer) and December (for winter). The daily load curves of weekdays and Sunday, and their load duration curves are presented in Figs. 3.9 to 3.12. The load factors of peak and base portions of the daily load curve are shown in Fig. 3.13 for weekdays.

Major features of the daily load curves are summarized in Table 3.17 and the following are noted:

(A) The maximum demand in a day occurs around nightfall and therefore its occurrence time shifts with season. The evening peak duration is long in December when it becomes dark early.

(B) The ratio of the minimum demand to the maximum demand in a day ranges between 0.6 and 0.7.

(C) The Sunday peak demand is 0.8 to 0.85 of the weekly peak demand and the Saturday peak demand is almost equal to the minimum of weekdays' peak demand.

(D) The daily load factor is 0.8 or slightly higher throughout a week in all seasons, and the Sunday load factors are slightly lower than those of weekdays.

3.4.2 Regional demand forecast

The general power demand of Konya and Karaman provinces is assumed to grow at the same rates as the rates of the whole Turkey. As for the rural electrification, all the villages in the region have already been electrified by 1988. It is understood that for the time being there is no plan to expand the aluminium smelting plant in Seydişehir. However, large scale industrial demand, which is at present represented by the aluminium smelter, is estimated to grow at an annual rate of 3.0 per cent taking into account the recent tendency to construct industrial estates. The annual load factor of such industrial demand is estimated at 60 per cent. Thus, the future power demand of these two provinces is estimated as shown in Table 3.18. The peak demand of approximately 300 MW in 1989 is estimated to become 640 MW in 2000 and 1,200 MW in 2010.

3.5 Power System Development Plan

3.5.1 TEK's development plan up to 2010

(1) Power generating facilities

The long-term development plan for generating facilities for the period up to 2010 was prepared by TEK so as to satisfy the forecast demand, and is presented in the 1988 Long Term Generation-Consumption Study (1994-2010). The plan involves many scenarios based on various situations such as a hydro-intensive development will be adopted or not, progress of BOT projects for both thermal and hydro, and so forth. The following are noted as the results of reviewal of the plans of all the scenarios:

(A) High priority is given to the development of hydroelectric projects. However, only the hydro power development is not enough to meet the future growing demand, and therefore a balanced development of hydro and thermal sources is envisaged.

(B) The future hydroelectric power projects for completion by around 2010 consist of 26 to 30 groups (the differences depending on development scenarios), each having a total installed capacity of 200 to 1,200 MW. The number of projects in one group ranges from one (large project) to more than 30 (medium to small projects from various parts of the country). In the long-term study, the completion year of hydro projects is scheduled for every group. The completion of the group to which the Ermenek Project belongs is scheduled in 2002 to 2004 depending on the development scenarios.

(C) The share of hydroelectric projects in the whole system installation is for most scenarios planned to be approximately 46 per cent in 2000 and 36 per cent in 2010. In the hydro-intensive development scenario, the share becomes higher being at 51 to 57 per cent in 2000 and 42 to 45 per cent in 2010.

(D) No additions to fuel oil and "motorin" (light diesel oil) fired thermal power plants are envisaged.

(E) As the amount of lignite reserve in the country which is appropriate for thermal power generation is limited and is not enough to meet the growing demand in future and the air pollution caused by burning low quality lignite is of great concern of the public, the present intensive development of lignite thermal plants will be converted to the development of imported coal thermal plants though its timing will vary due to various factors.

(F) The major thermal power plants in the future will be a combination of imported coal thermal plants and natural gas combined cycle power plants, and the total installed capacity of coal thermal plants will be about 20 per cent larger than that of natural gas plants.

(G) The first nuclear power plant will be commissioned by the end of the first decade of the 2000s.

Both for the thermal and hydro power projects, the Government wishes to promote implementation on a BOT basis.

The identified economic potential of exploitable hydro-electric power in Turkey is at present estimated at 34,000 MW and is classified into the following 9 categories based on development stages:

Development Stage	Nos. of Plant	Installed Capacity (MW)	Energy Output Average (GWh)	Energy Output Firm (GWh)
1. Existing	55	6,502	24,078	18,646
2. Under construction	26	4,742	15,517	11,282
3. F/D ready	20	4,193	13,464	8,749
4. F/D going on	9	563	1,785	1,233
5. Equipment installation	3	51	183	95
6. F/S ready	71	4,630	15,831	9,240
7. F/S going on	52	3,359	11,001	5,966
8. M/P study ready	34	2,175	7,195	4,218
9. Rec. report ready	211	8,044	32,420	18,021
Total	481	34,259	121,474	77,450

Note: F/D --- Final design
F/S --- Feasibility study
M/P --- Master plan
Rec. -- Reconnaissance

Turkey has at present a considerable number of hydroelectric power projects, for which the necessary studies have been completed and are now awaiting construction.

(2) Power transmission systems

As mentioned in Sub-section 3.2.1, enough generating facilities for the current demand were installed as of 1988 and completion of the Atatürk project is expected in the first half of the 1990s. Therefore, during the 6th 5-year Plan period from 1990 to 1994 not much additional generating capacity will be required and TEK's efforts will be directed to extension and reinforcement of transmission and distribution systems in accordance with the progress of power development planning. TEK's ability in transmission system planning has been acknowledged by international agencies like the World Bank.

The transmission system diagram of the area around the Ermenek Project is shown in Plate P30 of Volume 5, Drawings, and the location map of each component is shown in Plate P29. The current 380 kV transmission system is planned to be much reinforced along with installation of several hydro and thermal power plants in the area. The Ermenek power station is planned to be connected to the 380 kV transmission line between the Akkuyu nuclear power station and the Seydişehir substation. The proposed commissioning date of the Akkuyu power station is later than that of the Ermenek Project. Therefore, under the Ermenek Project, only the section between the Ermenek power station and the Seydişehir substation, 160 km in route length, will be constructed and the construction cost of this section is included in the Project cost. The section between the Akkuyu and Ermenek will be constructed under the

Akkuyu nuclear power project.

3.5.2 Operation mode of Ermenek power station

It is a principle of power system operation to operate coal thermal and nuclear power plants for base power supply and hydro power plants and gas turbine plants for peak power supply.

In the neigbouring area of the Ermenek Project, four power development projects are planned for completion by 2010; two hydro power projects, Ermenek (320 MW) and Kayraktepe (420 MW), Konya-Ilgun lignite thermal project (300 MW) and Akkuyu nuclear project (1,000 MW). The above-mentioned principle is applicable also to this case; the Konya-Ilgun and Akkuyu power stations will supply base power and the Ermenek and Kayraktepe power stations will be operated for peak power supply.

Meanwhile, the Ermenek Project will have a very large reservoir to regulate annual river flow; the reservoir will have a storage capacity corresponding to 1.6 times the average annual inflow. Therefore, the Ermenek power station can supply quite reliable power throughout the year. In other words, this power station will have a large firm generating capacity and a small secondary capacity. A hydro power station having a large storage capacity will be operated for peak power supply all year round. It is also possible to reduce the generation and to store water in the Ermenek reservoir during the rainy season when other hydro power stations can increase outputs, and to increase generation during the dry season when outputs of other stations decrease.

According to TEK's long-term study, hydroelectric power projects in Turkey are usually planned with an annual capacity factor of approximately 40 per cent on average and 20 to

30 per cent for their firm energy.

It is recommended that a capacity factor of 33 per cent for firm energy generation, which corresponds to 8 hours full output operation a day, be applied to the Ermenek Project to supply the middle peak load, from the viewpoint of cost-effectiveness under the condition that the Project is of dam-waterway type with a headrace tunnel of about 9 km in length, while the Kayraktepe hydro plant is of dam type having been planned with a capacity factor of 17 per cent for firm energy.

In this case, the average annual capacity factor will be about 36 per cent including the secondary energy and the Ermenek power station will be able to be operated with a daily capacity factor of about 40 per cent on weekdays but reducing generation on weekends. According to Fig. 3.13, peak portion load factor of the weekday load curve, the peak power supply with the load factor of 40 per cent corresponds to the supply to top about 30 per cent of the load duration curve.

3.6 Power values

The economic benefits of a hydroelectric power project are usually assessed as the costs of a least-cost alternative thermal plant, and are used for economic evaluation of the project. The alternative thermal power plant is selected as an appropriate least cost thermal plant which will be required when the project is not implemented.

In the thermal power development plan of TEK's long-term study, a combination of coal thermal plants and natural gas combined cycle plants was selected as the future major thermal power plants for the national power system (Sub-section 3.5.1). The same combination will be required if the Ermenek Project is not implemented. Therefore, this combination with the following composition is taken as the alternative thermal plant for the Project:

	Power	Energy
Coal thermal	50 %	70 %
Gas combined cycle	50 %	30 %

Based on the above alternative, the unit power benefit was assessed as summarized below (see ANNEX-D in Volume 4 for details).

(1) Basic assumptions

Power generation costs of the alternative thermal plants were estimated on the basis of the basic assumptions given below:

		Coal Thermal	Combined Cycle
-Net construction cost	(\$/kW)	820 1/	500
-O&M cost	(\$/kW/yr)	2.8	1.5
-Construction period	(yr)	4	3
-Cost disbursement 2/	(%)	10,25,40,20,5	10,35,50,5
-Economic life time	(yr)	25	25
-Station service power	(%)	7.5	2.0
-Heat rate	(kcal/kWh)	2,400	2,200
-Fuel cost 3/	(US¢/10^6 kcal)	690	1,176

1/: Including environmental protection equipment.
2/: The last 5 per cent is for payment against retention to be released 1 year after the taking over.
3/: The calorific values and unit rates of fuel are as follows:
Coal : 5,800 kcal/kg and US\$40/ton
Natural gas: 8,500 kcal/m^3 and US\$100/1,000 m^3

(2) <u>Calculation of power costs of alternative plants</u>

In calculation of power costs of the alternative thermal power plants, the following factors were taken into account:

- The investment cost necessary for construction of the thermal power plants is calculated taking into account the engineering and administration costs, being assumed at 15 per cent of the net construction cost, and the interest during construction assuming an interest rate of 9.5 per cent per annum.

- The annual costs of thermal power plants are calculated as a product of the investment cost and the sum of capital recovery factor, assuming economic life of 25 years and discount rate of 9.5 per cent per annum, and operation and maintenance cost rate.

- The unit fuel costs for energy generation are obtained as the product of their heat rates and fuel cost per heat value.

  It is forecast by the World Bank that the price of fossil fuel resources such as oil, coal and natural gas will increase in 1990s at a higher rate than the prices of the other commodities due to the expected shortage of supply capacity to meet the growing demand in the world. Following this forecast, the current prices of coal and natural gas were adjusted for this relative rise of energy price to the other commodities. On the basis of the price forecast of World Bank, 1988, the relative rise of coal and natural gas was estimated, for the period from 1989 to the commissioning year of the Project, at 1.30.

- The generation costs of the alternative thermal power plants were adjusted for the advantages of the Project to the alternative thermal plants such as less power transmission loss owing to the closer location to the demand center, shorter period of regular maintenance, and so forth.

(3) Power values for economic evaluation

Capacity and energy costs

The capacity and energy costs of the alternative thermal plants are obtained as shown below:

- Capacity cost (US$/kW/yr)

Coal thermal	: US$119.36 x 1.328	= 158.51
Combined cycle	: US$68.37 x 1.209	= 82.66
Overall	: 0.5(158.51 + 82.66)	= 120.58

- Energy cost (US¢/kWh)

Coal thermal	: US¢2.153 x 1.084	= 2.334
Combined cycle	: US¢3.363 x 1.036	= 3.484
Overall	: 0.7x2.334 + 0.3x3.484	= 2.679

- Secondary energy cost: US¢2.334/kWh

Energy values

The above capacity and energy costs were integrated to an overall energy cost to generate 1.0 kWh/yr by allocating the capacity cost to the firm energy to be generated by unit capacity in one year (see ANNEX-Q for detailed calculation). The energy values of the Project were finally assessed as shown below:

- Overall energy value : US¢6.47/kWh
- Secondary energy value : US¢2.33/kWh

CHAPTER 4. REVIEW OF EXISTING PLANS AND PRELIMINARY STUDY

4.1 Review of Existing Hydroelectric Power Development Plans of the Göksu Basin

(1) Gezende hydroelectric power development project

The Gezende project, having an installed capacity of 150 MW, was under construction in March 1989 downstream of the proposed Ermenek dam site. Although this project was planned as a dam-waterway type, its reservoir capacity-annual inflow ratio is as low as 4.2 per cent due to the valley topography of its reservoir area. Accordingly, the firm energy is only 25 per cent of the mean annual energy; the firm energy 130 GWh, the annual energy 528 GWh (the Gezende feasibility study report).

By contrast, the Ermenek reservoir would have a capacity-annual inflow ratio of as large as 160 per cent, and would regulate the river flow almost to a constant except for very dry water years. Upon completion of the Ermenek Project, the Gezende power station can be benefited from this flow regulating effect of the Ermenek reservoir, and the mean reservoir water level could be maintained at a high level close to its HWL.

The Ermenek Project would have an substantial effect on the Gezende power station in stabilization of its power output and increasing its firm energy. In this respect, the Ermenek Project can also be regarded as the second stage or successive stage to the Gezende project.

(2) Kayraktepe hydroelectric power development project

A feasibility study on the Kayraktepe hydroelectric power development project was completed for EİE by EPDC Japan and 3 Turkish firms in March 1982. The detailed design of the project had also been performed. This project was planned as a peaking plant with an average annual capacity factor of 17.4 per cent for the firm energy (installed capacity 420 MW, firm energy 639 GWh).

Meanwhile, DSİ has been carrying out a feasibility study of a Water Diversion Scheme for the Konya Closed Basin. The study was scheduled to be completed by the end of 1990. This scheme envisaged diversion of water from the upper Göksu river to the Konya basin at a rate of about 490 MCM/yr (15.5 m^3/s). Of this water, 425 MCM would be for irrigation water supply and 65 MCM would be for the municipal water supply to and around Hotamis town.

This scheme would affect existing and planned power generation schemes both on the branch Göksu stream and the main Göksu stream. According to a DSİ official, the top priority for water allocation is given to domestic water supply; the second to irrigation; hydropower generation is ranked in the lowest position in view of the availability of alternative sources for power generation. Accordingly upon completion of this scheme, the average inflow into the Kayraktepe reservoir would decrease by about 15.5 m^3/s on an average, and the annual energy planned at 991 GWh would decrease to about 854 GWh, or to 86 per cent.

According to the feasibility study of Kayraktepe project, the secondary energy is estimated at 352 GWh, amounting to 36 per cent of the annual energy. Part of this secondary energy will be converted to the firm energy upon completion of the Ermenek Project.

(3) A cascade development plan of the Göksu branch stream

A master plan study was being carried out by EİE to develop the hydropower potential of the Göksu branch stream (see Plates P3 and P4 for the location and profile). The study was scheduled to be completed by the end of 1990.

On the Göksu branch stream, there is the Yerköprü power station. The station has 3 units of generating equipment, each of which has an installed capacity of 3,680 kW (11 MW in total). The station has been in operation for 31 years since 1959. The maximum turbine discharge is 16.0 m^3/s in total. When it was inspected on November 1, 1989 jointly by EİE and the Study Team, 2 units were in operation. The survey time was at the end of the dry season, and the then river flow was roughly estimated at about 10 m^3/s. It is considered that this flow is approximately the firm flow of the upper Göksu branch stream.

The Konya Diversion Scheme mentioned above is located on the upstream reaches from the Yerköprü power station, but a spring which is located near the Yerköprü intake and has a firm discharge of about 5 m^3/s will not be included in this scheme. Therefore, upon realization of this scheme, the Yerköprü power station will mainly depend on the discharge of this spring and the annual energy would substantially be affected.

The master plan study covers the river reaches of Göksu branch stream between the confluence with the Ermenek River and the Yerköprü power station. The plan envisages 4 hydropower projects for the condition after completion of the Konya Diversion Scheme; 3 run-of-river type and 1 dam type (Plate P4). The total installed capacity would amount to 57 MW, and the total energy output to 281 GWh.

Field investigations have been ongoing at the Mut dam site, including drilling works. Geological investigation for the other 3 schemes had been completed by November 1989.

(4) <u>Göktepe and Gökdere schemes</u>

EİE has an idea to develop hydropower potential of the upper Ermenek river, by 2 run-of-river type schemes and 1 dam type scheme (see Plates A2 and A3 for the locations). Of these, the Nadire dam scheme will be discussed in Sub-section 4.3.4.

A joint reconnaissance was made by EİE and the Study Team in the Göktepe area in October 1989. It was found that the river flow was less than the Erik flow. The river flow has been used for irrigation and, therefore, its diversion for hydropower generation, if implemented, would have to be suspended during the irrigation period.

Although the Gökdere area located on the upstream reaches could not be surveyed, the flow of the Günder river downstream was low being only a few m^3/s. Although it was in the later part of the dry season, it appeared that the hydropower potential of the upper Ermenek river was not as large as the Ermenek Project in the middle reaches.

EİE has a plan to carry out a master plan study of these schemes, succeeding to the Göksu master plan study.

4.2 Review of Existing Plan of the Ermenek Project

EİE studied 7 alternative development plans of the available head of 262 m between elevations 595 m (provisionally assumed as HWL of the Ermenek reservoir) and 333 m (HWL of the Gezende reservoir) for hydropower generation. These included 5 alternative dam sites: I-A, I-B and I-C on the upper reaches; II-A and II-B on the lower reaches near the confluence with the Erik river (see Plates A2 and A3 for the river profile and locations).

The I-A site is located in the middle part of a relatively steep river slope at an altitude of about 440 m, while the I-B and I-C sites are located on the gentle river slopes at an altitude of about 500 m. A wide river plain develops upstream from the I-B site. The I-B and I-C sites are situated at advantageous locations in view of the availability of a large reservoir capacity for flow regulation.

The head of about 60 m between the I-C and I-A sites can be developed even without a dam at the I-A site but by a less-costly headrace tunnel from the I-B or I-C site. In this regards, I-A site is inferior to I-B and I-C sites. In addition to this topographic disadvantage, this site has the risk of water leakage through karstic limestone located in the left abutment. It was found through an EİE's drilling investigation that the groundwater level in this limestone was low compared with the river water level. Thus I-A site was ruled out by EİE in the preliminary study stage. The Study Team agreed with the EİE's view.

The I-B site is located about 1 km upstream of the gorge, where the I-C site is located. The I-B site has a wide river section, while the I-C site presents a V-shaped steep and narrow gorge. The left abutment of the I-B site is covered with landslide debris deposits, which limit the maximum crest elevation of the I-B dam to around 600 m.

The topography of the penstock route, which was planned for an aboveground power station site by EİE, has a rather gentle slope with a hill at its middle point (Plate A29). An alternative using an underground pressure shaft combined with an underground power house and a tailrace tunnel is conceivable.

The water level around the confluence of the Erik and Ermenek rivers is about EL. 337 m, where the EİE's original plan envisaged to locating the aboveground power station and tailrace outlet. There is the possibility of developing the remaining head of 4 m between this elevation and the HWL of Gezende reservoir (333 m) by extending the tailrace tunnel if an underground power house is selected.

The Erik river joins the Ermenek river about 10 km downstream of the I-C dam site. In the case of a dam-waterway type development, the Erik flow can be diverted to a headrace tunnel of the Ermenek and can be used for the power generation at the proposed Ermenek power station. When the station is not in operation, the Erik water can be conserved in the proposed Ermenek reservoir through the headrace tunnel.

There is another hydropower scheme, the Nadire dam scheme, in the upstream reaches of the Ermenek reservoir. When the height of proposed Ermenek dam is raised beyond 100 m, the Nadire scheme will be affected.

4.3 Preliminary Study of Development Plan

The main objectives of the Preliminary Investigation Stage were: (1) to select the most promising development plan on the basis of the many alternative plans conceived by EİE including some additional ideas proposed by the JICA Study Team; (2) finally to identify the sites for the Additional Detailed Investigations.

The alternative studies performed at this stage were as listed below (see Fig. 4.1):

(1) Comparative study of alternative dam sites between I-B and I-C, assuming that the water leakage problem of the I-C dam site can be technically managed

(2) Preliminary economic examination of the newly proposed Erik Diversion Scheme

(3) Preliminary economic examination of the newly proposed underground power house combined with an underground pressure shaft and a tailrace tunnel, assuming that the power house can be situated in a limestone block

(4) Economic examination of the 2-step development plans:
(A) the Ermenek dam plus a downstream dam at II-A site;
(B) the Ermenek dam plus a downstream dam at II-B site;
(C) the Ermenek dam plus an upstream dam at Nadire

4.3.1 Site and type of Ermenek dam

An economic comparison was made to select the site of the Ermenek dam between the 2 conceivable sites: I-B and I-C. The comparison was made for a dam crest elevation of 600 m because of the limitation of dam height at I-B site due to the landslide debris deposits located on the left bank.

Plan and profile of the I-B dam are given in Plate Nos. A4 to A6. The crest length will amount to 1,300 m. Accordingly, rockfill type is considered suitable to the site and only the type practically possible, except for type of core. At this level of the study, the core was assumed as an earth core type.

Plan and profile of the I-C dam are given in Plates A35 and A37. The dam axis was assumed at I-Ca for its relatively low dam crest elevation at 600 m and the shape of valley (see Plate G5). A concrete arch dam was considered the least cost dam type because of the narrow valley topography. The dam shape was preliminarily designed as a parabolic type.

Results of the comparison of above 2 dams are as summarized below:

No.	Description	Unit	I-B Site	I-C Site
(1)	Dam type		rockfill	concrete arch
(2)	Dam volume	1000 m^3	14,700	150
(3)	Direct construction cost of civil works	mil.$	264	174

As shown above, the civil works costs of the I-B scheme were higher by US$90 million than that of I-C scheme, while the power outputs of the 2 alternatives were the same to each other.

When the I-B dam is designed as a rockfill dam of concrete facing type, its embankment volume would be reduced to about two thirds of that of the earth core type. According to a comparative study made on the type of core, the concrete facing type was cheaper by about 17 per cent than the earth core type (Foz do Areia Dam in Brazil, dam height 160 m, embankment volume 14 million m^3). The saving of dam construction cost in this order will not affect the cost advantage of the arch dam at I-C site.

It was concluded that the I-C site would be advantageous for a development scale of HWL 595 m. This economic advantage would become more prominent for a larger development scale as the dam volume at I-B site will increase at a higher rate than that of I-C site. The alternative dam site I-B was then ruled out from the further study.

4.3.2 Preliminary study of 1-step development plan

(1) Addition of Erik Diversion Scheme

The Erik river, which runs down beside the proposed power house site to join the Ermenek river (Plate A1), has an average runoff of 3.5 m^3/s. By constructing a tunnel, most of the Erik flow can be diverted to a headrace tunnel of the Project.

An intake weir site was first conceived on the Erik river at an altitude of about 700 m, from where the Erik flow could be diverted by a tunnel about 1,500 m long. The weir site was, however, shifted to an upstream point near the Erik spring because a large scale active landslide had been found on the upstream reaches.

An economic comparison was made for the 2 cases; with and without the Erik Diversion Scheme. The comparison showed that the Scheme would increase the annual net benefit by about US$2 million. It was judged that the Erik Diversion Scheme was highly worth study.

(2) Type of power house

An economic comparison was made for aboveground and underground types of penstock and power house. The tailwater level was assumed to be EL. 333 m for the underground type which will have a tailrace tunnel; and EL. 337 m for the aboveground type without a tailrace tunnel.

An economic comparison showed that the underground type yields a higher net benefit, mainly owing to the additional head of 4 m available for the underground type. It was decided to make a geological investigation for the underground power house site.

4.3.3 2-step development with a downstream dam

An economic comparison was made between 1-step and 2-step dam development plans for a head of 312 m available between elevations 645 m and 333 m. The elevation of 645 m was provisionally selected as the prospective high water level of the Ermenek reservoir.

In the case of the 1-step development, the head available between the I-C site and the Gezende Reservoir will be developed by headrace and tailrace tunnels of 11.3 km long in total. In the case of the 2-step development with a downstream dam crest at El. 400 m, this waterway length can be shortened by about 7.2 km; and by 8.2 km with a downstream dam crest at El. 450 m (see Plate A1). But the 2-step development requires a downstream dam. The main study objective of the 2-step development was to see if the cost saving owing to the shortened headrace tunnel would be larger than the additional cost required for the downstream dam.

A comparative study was carried out for 4 alternative cases; 2 downstream sites (II-A, II-B) and 2 crest elevations (400 m, 450 m) of the downstream dam. Dam site II-A is located downstream of the confluence of the Ermenek and Erik rivers; and II-B dam site upstream of the confluence.

As a result of economic comparison, it was concluded that 1-step development was much superior to 2-step development as summarized below (see ANNEX-D for details):

No.	Description	Unit	I-C-650	II-A-400	II-A-450	II-B-400	II-B-450
(1)	Dam step		1	2	2	2	2
(2)	Installed capacity	MW	270	260	270	250	260
	- Ermenek P.S.	MW	270	200	160	200	160
	- Second P.S.	MW	-	60	110	50	100
(3)	Total annual energy	GWh					
	- firm		799	752	777	741	763
	- secondary		134	143	143	144	141
	total		933	895	920	885	904
(4)	Length of headrace tunnel of Ermenek power station	m	9,480	2,315	1,265	2,315	1,265
(5)	Height of down-stream dam	m	-	90	140	80	130
(6)	Embankment volume of downstream dam	MCM	-	3.8	17.3	1.7	8.1
(7)	Construction cost	mil.$	319.1	368.6	458.5	339.9	391.2
	- upstream dam		319.1	252.6	228.5	252.0	228.5
	- downstream dam		-	116.6	230.0	87.9	162.7
(8)	Annual equivalent cost	mil.$	40.2	46.4	57.7	42.8	49.2
(9)	Annual benefit including firm-up benefit of Gezende	mil.$	72.0	68.4	70.3	67.7	69.1
(10)	Annual net benefit	mil.$	31.8	22.0	12.6	24.9	19.9

The annual equivalent cost above was obtained as construction cost x (1 + IDC) x CRF + O&M cost, where:

$$IDC = 1.095^{7yr \times 0.40} - 1$$

$$CRF = 0.0960$$

The interest during construction was calculated using an interest rate of 9.5 per cent and assuming a construction period of 7 years with a center of gravity at 40 per cent from the commissioning. The capital recovery factor was calculated assuming an amortisation period of 50 years after the commissioning.

As shown in the table above, the 1-step development will yield the highest annual energy among the 5 alternatives. This is because in the case of 1-step development the Erik water can be utilized for the full head of 312 m available between the HWL of the Ermenek reservoir assumed at 645 m and the HWL of Gezende reservoir at 333 m, while only for 112 m in the case of II-A-450 and II-B-450; and only for 62 m in the case of II-A-400 and II-B-400. Also, the flow regulation effect of the downstream second reservoir is small because most of the inflow will have been well regulated by the upstream Ermenek reservoir.

The 1-step development will yield much higher net benefit compared to the 4 alternatives of 2-step development. The difference in the annual net benefit amounts to US$6.9 million between the 1-step development and the second best, II-B-400. This difference is equivalent to that in the investment cost of about US$56 million.

The 2-step development with a downstream dam was then ruled out from the further investigations and studies.

4.3.4 2-step development with an upstream dam

The economic viability of the Nadire dam was provisionally studied to see if the head above a certain elevation, for example 645 m, should be developed either by raising the height of Ermenek dam or by construction of the Nadire dam.

The HWL of the Nadire dam was assumed at 710 m, which was the riverbed elevation around the confluence of the Ermenek and Günder rivers. This Nadire reservoir is situated on limestone strata, which are widely distributed around the confluence and in the adjacent basins crossing the basin boundaries. Therefore, the Nadire dam is subject to the geological conditions of this limestone. The economic study was made assuming that the Nadire dam scheme was geologically possible.

Construction costs of the Nadire dam were estimated for 2 alternative HWLs of the Ermenek reservoir: 595 m corresponding to the downstream Nadire dam; 645 m corresponding to the upstream Nadire dam (see Plates A23 and A26). A schematic profile, general plan and dam profile of the downstream and upstream Nadire dams are shown in Plate A23 to A28. Principal features and some economic indices of these dams are as summarized below (see ANNEX-D for details):

No.	Description	Unit	Downstream Nadire	Upstream Nadire
(1)	Dam height above foundation	m	130	80
(2)	Dam embankment volume	MCM	4.3	2.3
(3)	Installed capacity	MW	60	30
(4)	Dependable peak power	MW	22	7.3
(5)	Annual energy	GWh		
	- firm		62.8	21.0
	- secondary		155.4	96.7
	total		218.2	117.7
(6)	Construction cost	mil.$	123.4	80.2
(7)	Annual equivalent cost	mil.$	14.2	9.2
(8)	Annual benefit	mil.$	8.0	3.7
(9)	Annual net benefit	mil.$	-6.2	-5.5

The annual equivalent cost above was obtained in the same way as described in Sub-section 4.3.3 except for the construction period, which was assumed at 5 years for the Nadire dam.

As shown in the table above, both the upstream and downstream Nadire schemes will yield a negative net benefit, that is, these schemes would not be economically viable under the power values and discount rate used. Accordingly, it was judged that the Nadire dam scheme should not be combined with the Ermenek Project, and that the development scale of the Ermenek Project should be optimized by itself.