ALTERNATIVE FEASIBILITY STUDIES FOR ALTIPARMAK DAM AND HEPP

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ABSTRACT

ALTERNATIVE FEASIBILITY STUDIES FOR ALTIPARMAK DAM AND HEPP

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Hydropower is the most important domestic energy source of Turkey. Thus, wise planning and development of the unused hydropower potential of the country is vital. There are many hydroelectric power plants under planning stage in our country. Altıparmak HEPP is one of them. General Directorate of Electrical Power Resources Survey and Development Administration (EİE) and ANC Enerji conducted two separate feasibility studies for Altıparmak HEPP in 2001 and 2009, respectively. Traditionally, the energy income calculations for HEPPs are based on DSİ or EİE Methods in Turkey. Both of these methods evaluate the firm and the secondary energy generations separately. Besides they use fixed prices for these two types of energies. However, hourly electricity prices are used for electricity trading in Turkey. A detailed economic analysis of Altıparmak HEPP is conducted in this study. The economic analysis included various factors, such as tailwater level change, varying operating levels for different seasons and precipitation and evaporation amounts which are not conventionally included in feasibility studies. Moreover, the energy income calculations are conducted with four different methods, the DSİ Method, the EİE Method, the ANC Method and the Variable Price Method (VPM). The VPM is developed in this study and it allows utilization of hourly electricity prices in calculating energy income of the HEPP.

To shed some light on how hourly electricity prices develop, this thesis includes a chapter on the electricity market which explains the details of electricity trading in our country after the Electricity Market Balancing and Settlement Regulation became active in 2009.

Keywords: Hydropower, Electricity Market, Hourly Electricity Prices, Reservoir Operation Study, Economic Analysis

ÖZ

ALTIPARMAK BARAJI VE HES İÇİN ALTERNATİF FİZİBİLİTE ÇALIŞMALARI

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Hidroelektrik, Türkiye'nin en önemli yerli enerji kaynağıdır. Bu nedenle, ülkenin kullanımda olmayan potansiyelinin akıllıca planlanması ve geliştirilmesi büyük öneme sahiptir. Türkiye'de planlama aşamasında olan pek çok hidroelektrik santrali bulunmaktadır. Altıparmak HES, bunlardan biridir. Elektrik İşleri Etüt İdaresi (EİE) ve ANC Enerji, Altıparmak HES için sırasıyla 2001 ve 2009 yıllarında iki farklı yapılabilirlik çalışması gerçekleştirilmiştir. Türkiye'de hidroelektrik santraller için enerji geliri hesaplamaları, geleneksel olarak, DSİ ve EİE'nin yöntemleri kullanılarak yapılmaktadır. Her iki yöntem, birincil ve ikincil enerji üretimlerini ayrı ayrı değerlendirmektedir. Ayrıca, bu iki çeşit enerji için sabit fiyatlar kullanmaktadır. Fakat, Türkiye'deki elektrik piyasasında saatlik elektrik fiyatları kullanılmaktadır. Bu çalışmada, Altıparmak HES için ayrıntılı bir ekonomik analiz gerçekleştirilmiştir. Bu ekonomik analiz; kuyruk suyu seviyesi değişimi, mevsimlere göre değişen işletme seviyeleri ve yağış ve buharlaşma miktarları gibi, yapılabilirlik çalışmalarında genellikle yer verilmeyen kavramları içermektedir. Ayrıca, enerji geliri hesaplamaları; DSİ Yöntemi, EİE Yöntemi, ANC Yöntemi ve Değişken Fiyat Yöntemi (DFY) olmak üzere dört farklı yöntemle yürütülmüştür. DFY, bu çalışmada geliştirilmiştir ve bu yöntem, hidroelektrik santralin enerji gelirinin hesaplanmasında saatlik elektrik fiyatlarının uygulanmasını mümkün kılmıştır. Bu tez, ülkemizde saatlik elektrik fiyatlarının nasıl oluştuğunun anlatıldığı, 2009 yılında yürürlüğe giren Elektrik Piyasası Dengeleme ve Uzlaştırma Yönetmeliği'nden sonra oluşan, elektrik piyasasının ayrıntılarını açıklayan bir Elektrik Piyasası bölümünü de içermektedir.

Anahtar Kelimeler: Hidroelektrik, Elektrik Piyasası, Saatlik Elektrik Fiyatı, Hazne İşletme Çalışması, Ekonomik analiz.

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ABBREVIATIONS

AEG : Annual Energy Generation

AEI : Annual Energy Income

AIC : Annual Investment Cost

CBRT : Central Bank of the Republic of Turkey

DAMP : Day-Ahead Market Price

DMİ : Turkish State Metrological Services

DSİ : General Directorate of State Hydraulic Works

EİE : General Directorate of Electrical Power Resources Survey and Development Administration

EMRA : Electricity Market Regulation Authority

ESHA : European Small Hydropower Association

FDC : Flow Duration Curve

HEPP : Hydroelectric Power Plant

IC : Installed Capacity

IHA : International Hydropower Association

MOS : Metrological Observation Station

MWU : Maximum Water Usage in a Month

NB : Net Benefit

RCC : Roller Compacted Concrete Dam

ROS : Reservoir Operation Study

RTP : Real Time Price

TEİAŞ : Turkish Electricity Transmission Company

TFEG : The water Volume for total Residual Water Requirement in a month

UNEP : United Nations Environment Programme

USACE : United State Army Corps of Engineers

VPM : Variable Price Method

WEC : World Energy Council

LIST OF SYMBOLS

SYMBOLS

A_t : Time Interval

A(t) : Reservoir Surface Area

A_{min} : Minimum Reservoir Surface Area

A_{max} : Maximum Reservoir surface area

A' : Steel Cross-section Area of the Penstock

A_o : Outer Cross-section Area of the Penstock

D_p : Penstock Diameter

D_t : Tunnel Diameter

E : Energy Production

e_d : The Product of the Turbine and Generator Efficiencies when the Design Discharge (Q_d) Is Passing Through the Turbines

e(t) : The Product of the Turbine and Generator Efficiency

El_{ave} : Average Reservoir Elevation in the Month

El_{max} : Maximum Reservoir Elevation

El_p : Elevation of any Point in the Penstock

El(t) : Reservoir Elevation at the Beginning of the Month

El(t+1) : Reservoir Elevation at the End of the Month

El_{tw} : Tail Water Elevation

Ev(t) : Evaporation in hm^3

ev(t) : Evaporation in mm

F : The Force Developed on the Wall of the Penstock

Fr : Froude Number

g : Gravitational Acceleration

H : Tail Water Depth

h_{ave} : Average Gross Head

$H_n(t)$: Net Head at Any Time

$H_g(t)$: Head Difference between the Reservoir Level and the Tail Water Level

H_{nd} : Design Net Head

H_{min} : Head Difference between the Maximum Operating Level and the Tail Water Level

h_{sta} : Static Pressure Head Developed in the Penstock

I(t) : Reservoir Total Inflow

L : Total Length of the Penstock

NI(t) : Net Inflow
O(t) : Reservoir Total Outflow
O'(t) : Total Outflow Except Spilling
P : Power
P_{ins} : Installed Capacity
P_{max} : Maximum Amount of Power Generation
P_{min} : Minimum Amount of Power Generation
Pr(t) : Precipitation in hm^3
pr(t) : Precipitation in mm
Q(t) : Discharge of Any Time Passing Through Turbines
Q_d : Design Discharge
Q_{max} : Maximum Discharge
Q_{min} : Minimum Discharge
Q_{tw} : Tail Water Discharge
Rw(t) : Residual Water in hm^3
rw(t) : Residual Water in m^3/s
S_{max} : Maximum Reservoir Storage
S_{min} : Minimum Reservoir Storage
S_c : The Critical Submergence Measured from the Top of the Intake Structure
Sp(t) : Spilling
Sf(t) : Streamflow
S(t) : The Reservoir Storage at the Beginning of Month *t*
S(t+1) : The Reservoir Storage at the End of Month *t* and the Beginning of Month *(t+1)*
T : Temperature
T_c : The Shortest Duration in the Valve Can Be Closed
Tr(t) : Turbine Releases
V : Average Water Velocity in the Penstock at Design Discharge
W : Weight of the Penstock Part
wt : Wall Thickness
$\varepsilon_t(t)$: Ratio of the Net Potential Energy Running the Turbines to the Converted Mechanical Energy
ε_h : Ratio of the Net Head to Gross Head
ρ : Specific Density of Water
σ_s : Strength of Steel
$\forall$: Volume of the Penstock Part
Δh_{max} : Maximum Dynamic Pressures
ΔS : Change in Reservoir Storage
Δt : Time Interval
γ : Specific Weight of Water

CHAPTER 1

INTRODUCTION

With increasing living standards and population, energy demand increases continuously. To meet this additional demand, new facilities are being constructed throughout the world (WEC, 2007). In Turkey, increasing demand is mostly met by new thermal and hydroelectric power plants. Especially, runoff river and storage type of hydropower plants are preferred since Turkey has a considerable amount of undeveloped hydropower potential.

In Turkey, most of the electricity is generated from imported natural gas and high quality coal (TEİAŞ, 2011). Because of this, Turkey is highly dependent on foreign energy sources and this constrains the economic growth. Moreover, fossil fuels are accepted as the main sources of greenhouse gas emission, thus they cause environmental problems, such as air pollution, acid rains, etc. (UNEP, 2007). To accelerate sustainable development domestic and renewable resources should be exploited as much as possible.

Hydropower composes 92% of all renewable energy sources in the world (IHA, 2011) and it is the most commonly used renewable energy resource in Turkey as well. There are many hydropower plants in planning and under construction stages in Turkey. One such plant at the planning stage is the Altıparmak Hydroelectric Power Plant (HEPP) and this thesis focuses on the feasibility study of this HEPP.

Altıparmak HEPP is planned to be constructed in Artvin, a province in the north-eastern region of Turkey. General Directorate of Electrical Power Resources Survey and Development Administration (EİE) conducted a feasibility study and developed a hydropower project formulation with an installed capacity of 50 MW for Altıparmak HEPP. ANC Enerji (it will be referred to as ANC from now on), a private company intending to construct this power plant, worked on a different formulation with an installed capacity of 70 MW with technical help provided by Yolsu Engineering and Consultancy Company. There is a considerable difference in the installed capacities selected by these two entities. These two formulations result in different amounts of annual energy generations and associated benefits.

In this thesis, comprehensive economic analyses are performed for the two alternative projects suggested by EİE and ANC and their formulations are reevaluated in terms of costs and benefits. As a result of the economic analysis, the best installed capacities are identified for the two formulations. Reservoir operation studies are conducted for both formulations to estimate energy generations.

The optimum installed capacities are selected based on economic analysis. Two different energy income calculation methods are suggested by EİE and State Hydraulic Works (DSİ) for evaluation of hydropower projects in Turkey. These two methods are based on the firm and the secondary energy generations and associated unit prices for these two different types of energies. ANC, on the other hand, chose to use a simple method where a uniform price is assigned for each MW of electricity generated. None of these methods consider hourly electricity price variations. In order to evaluate impact of hourly electricity price variations on the energy income, an alternative method, the Variable Price Method (VPM) is suggested here. In this study, the two methods suggested by EİE and DSİ, ANC method and the VPM which considers hourly electricity prices are used to compare the net benefits of two alternative formulations.

At present, the electricity market in Turkey works on an hourly basis. A balance between the hourly supplies and demands is sought, bids are collected from the producers and consumers and hourly prices are determined as a result of this procedure. The electricity market is put in action in December 2009, in accordance with the Electricity Market Balancing and Settlement Regulation published in official gazette numbered 27200 (EMRA, 2011). Since this is a very new practice, the details of how the electricity market works are not known to the researchers and new hydropower investors. Information in Appendix A about the current electricity market in Turkey is provided in this thesis to shed some light on how the hourly electricity prices develop and how the market works in general.

The projects developed by EİE and ANC are introduced and the location of the project site and hydrological, meteorological, and seismic conditions are summarized in Chapter 2. In Chapter 3, required data and information necessary to carry out the reservoir operation study are provided and the procedure used to determine the best installed capacity is outlined. Energy income is estimated using four different methods: the EİE Method, the DSİ Method, the ANC Method and the Variable Price Method (VPM). The VPM is an alternative energy income estimation method which utilizes hourly energy prices. In Chapter 4, the results of the economic analysis are provided and the comparison of EİE and ANC formulations is made. Some ideas for possible future research are outlined at the end of this chapter as well. Conclusions are provided in Chapter 5. Finally, in Appendix A, electricity market in Turkey and development of the hourly energy prices are explained in detail.

CHAPTER 2

PROJECT DESCRIPTION

2.1 Description of the Project Site

To harvest the water energy between the elevations of 1230 m and 840 m of Parhal Stream, a branch of Çoruh River in Artvin, two alternative formulations for Altıparmak HEPP were developed by EİE and ANC. Location of the project site on a map of Turkey is given Figure 2.1. A more detailed map is provided in Figure 2.2.

Figure 2.1 Location of the Project Site on a Map of Turkey

Figure 2.2 The Project Site

2.2 EİE and ANC Formulations

Characteristics of two alternatives are given in Table 2.1 (EİE, 2001; Yolsu, 2009). The longitudinal profile of Parhal Stream and alternative hydropower plant formulations of EİE and ANC are given in Figure 2.3. The map showing these two alternative projects is given in Figure 2.4.

Table 2.1 Characteristics of EİE and ANC Projects

Physical Characteristics	EİE Formulation	ANC Formulation
Thalweg Elevation (m)	1095	1160
Max Water Elevation (m)	1230	1230
Tail Water Elevation (m)	840	840
Drainage Basin Area (km^2)	317.84	306.67
Max Reservoir Area (km^2)	1.48	0.37
Tunnel Length (m)	6785	8635
Storage Volumes (hm^3)	13.99	3.43
Penstock Length (m)	467	687
Installed Capacity (MW)	50	70
Construction Duration (years)	6	4
Firm Energy Generation (GWh)	122.5	37.04
Secondary Energy Generation (GWh)	78.07	161.40
Total Energy Generation (GWh)	200.57	198.44

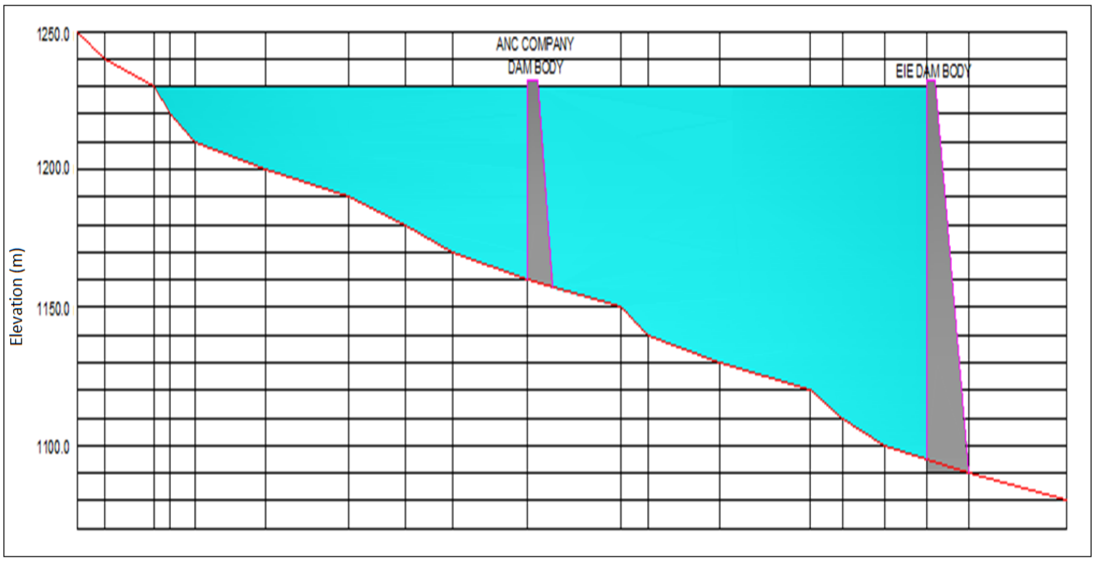

Figure 2.3 The Longitudinal Profile of Parhal Stream and Recommended Dam Body Locations by EİE and ANC (Not to Scale)

EİE formulation is composed of an arch dam at a thalweg elevation of 1095 m, a 6,785 m long energy tunnel to convey the water from the reservoir to the power plant located at Sarıgöl, and a 467 m penstock and a power plant house. On the other hand ANC planned a roller compacted concrete (RCC) dam at a thalweg elevation of 1160 m. The energy tunnel and the penstock lengths for this project are 8,635 m and 687 m, respectively.

Both alternatives have their own advantages and disadvantages. To select the best alternative, a comprehensive economic, social and environmental analysis need to be carried out. In this study, feasibility level economic analysis is conducted. The results of this analysis provide valuable information for the comparison of the two alternative formulations.

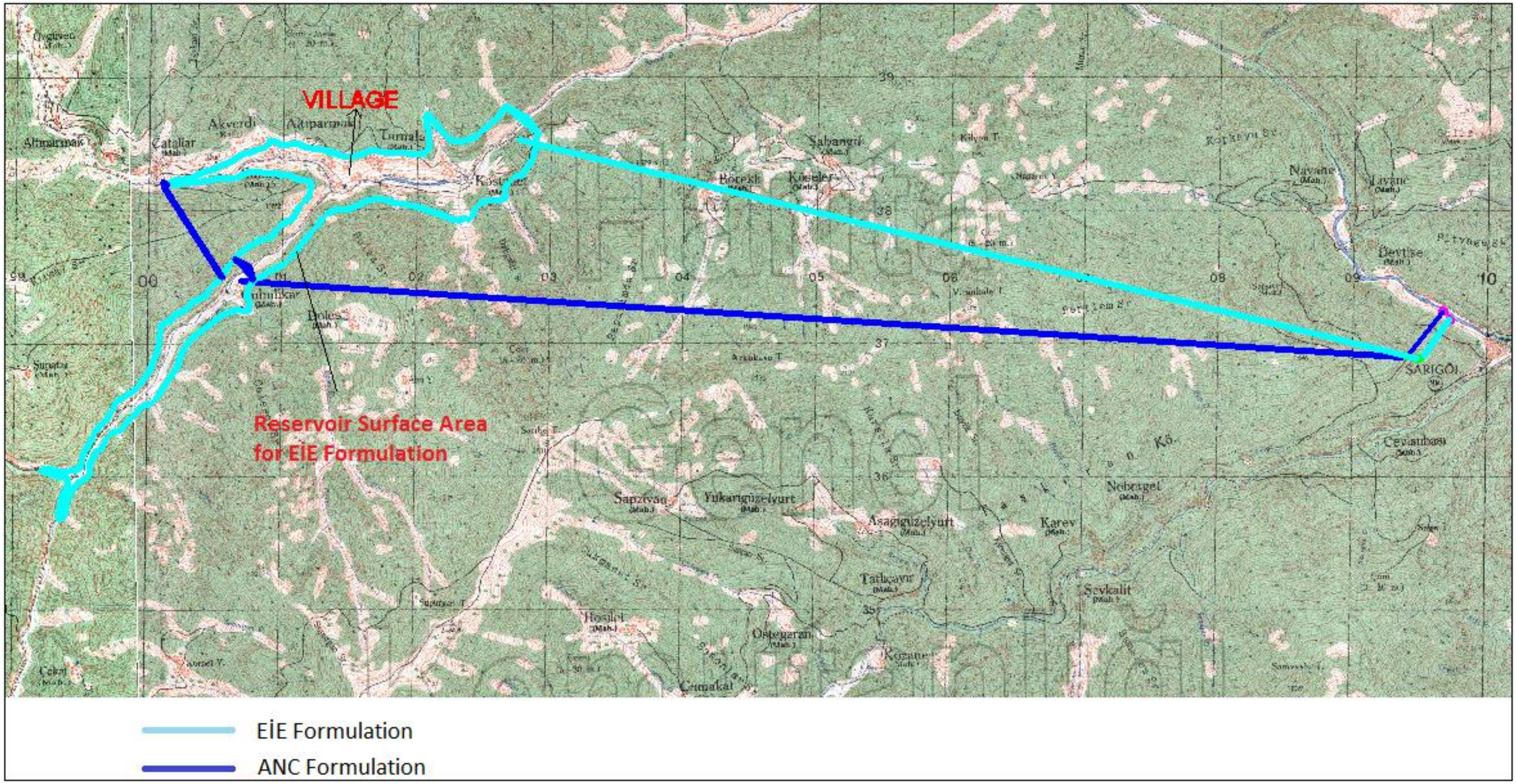

Figure 2.4 Altıparmak HEPP Formulations Developed by EİE and ANC (Not to Scale)

2.3 The Advantages and Disadvantages of EİE formulation

The main advantages of EİE project are its larger storage volume and shorter energy tunnel and penstock compared to those of ANC's. The larger storage volume allows flexibility in reservoir operation and increases efficiency of water usage for energy generation. Shorter energy tunnel and penstock cause energy losses to decrease and consequently increase the annual energy generation. In addition, expected costs of these structures are less compared to those of ANC formulation.

The drainage areas are different for the two alternatives. EİE project has bigger drainage area with a lower thalweg elevation. There is an intermediary basin fed by many tributaries located between the alternative dam body locations. This basin increases the incoming water to the reservoir and consequently increases the energy generation of the EİE project.

As can be seen in Figure 2.3, a considerably taller dam is planned by EİE. Although different types of dams are proposed by EİE and ANC, the construction cost of a taller dam is expected to be more. Another disadvantage of EİE project is that the larger reservoir area increases the cost of the expropriation. As can be seen in Figure 2.4 there is a village within the reservoir area and EİE formulation requires relocation of this village. In addition to economic burden, relocation of the villagers may cause negative social impacts.

2.4 The Advantages and Disadvantages of ANC formulation

Main advantage of ANC Project is its expected lower cost due to the smaller dam and less expropriation cost. In addition, the expected construction duration is set as 6 years by EİE, while it is set as 4 years by ANC. The construction time is important in terms of the return of the project investment. In addition, the lengthening of the construction period causes extended disturbance on the local people.

In ANC formulation, water from Şoral Stream is diverted into the dam's reservoir through a tunnel system (see Figure 2.4). This tunnel system increases the water input to the reservoir; however it also introduces additional costs for the diversion weir and the tunnel.

Effects of these items in terms of economics of the two different formulations are investigated through a benefit-cost analysis.

2.5 Information about the Project Area

2.5.1. Hydrological Conditions

Drainage areas for EİE and ANC formulations are 317.84 km^2 and 306.67 km^2, respectively (see Figure 2.5). EİE has two stream gauging stations in the vicinity of these drainage basins. EİE-2342 (the Parhal-Altıparmak gauge) and EİE-2321 (the Parhal-Dutdere gauge) are marked in Figure 2.6. EİE-2342 gauge is located at an elevation of 1080 m and has a drainage basin area of 322.11 km^2. The elevation and drainage basin area of EİE-2321 gauge is 705 m and 586.00 km^2, respectively. The observation periods for EİE-2342 and EİE-2321 are 15 and 36 years, respectively. These two stream gauging stations are used in this study to determine water potential of the Parhal Stream.

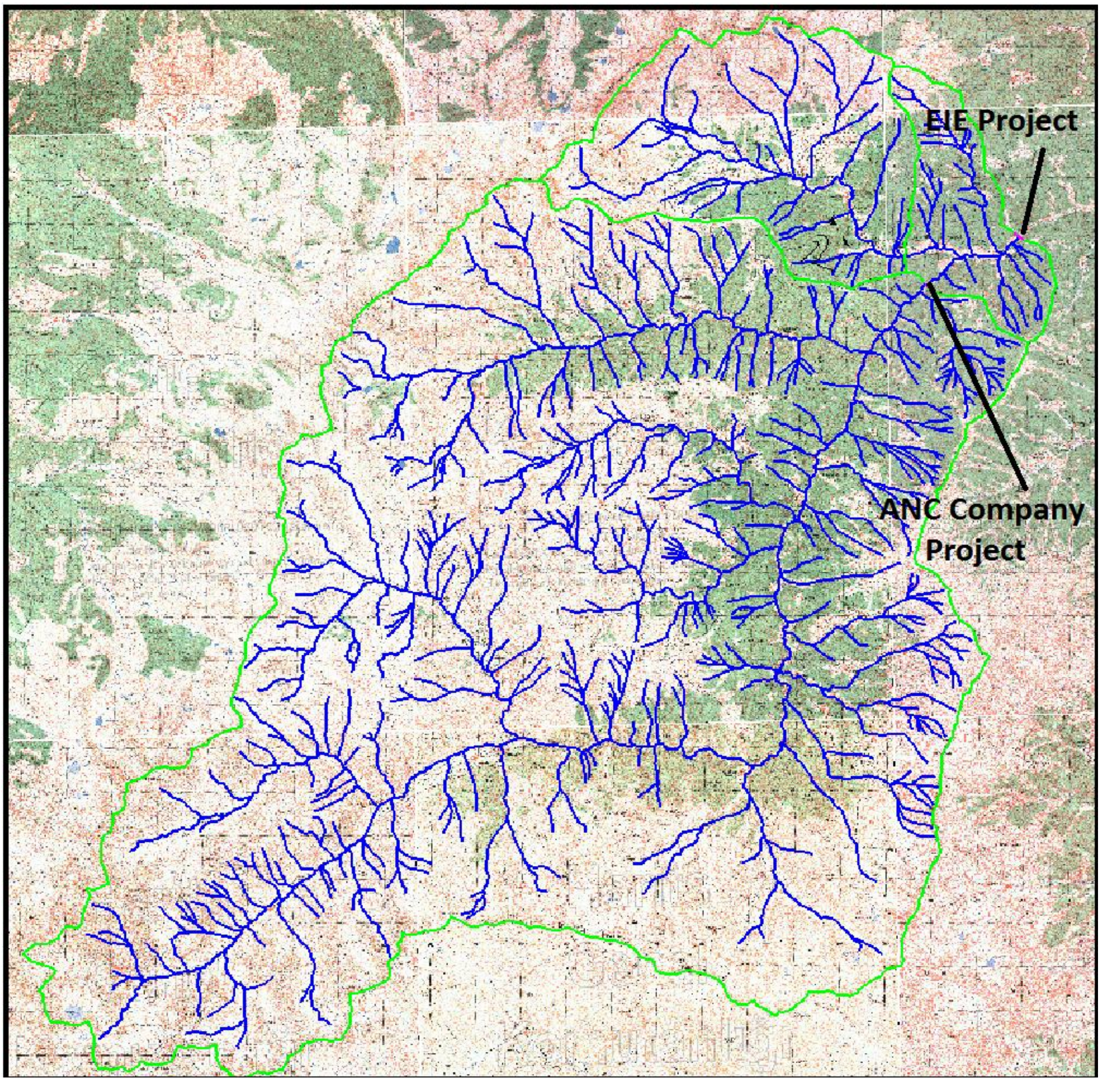

Figure 2.5 The Drainage Basin Areas for Two Alternative Formulations (Not to Scale)

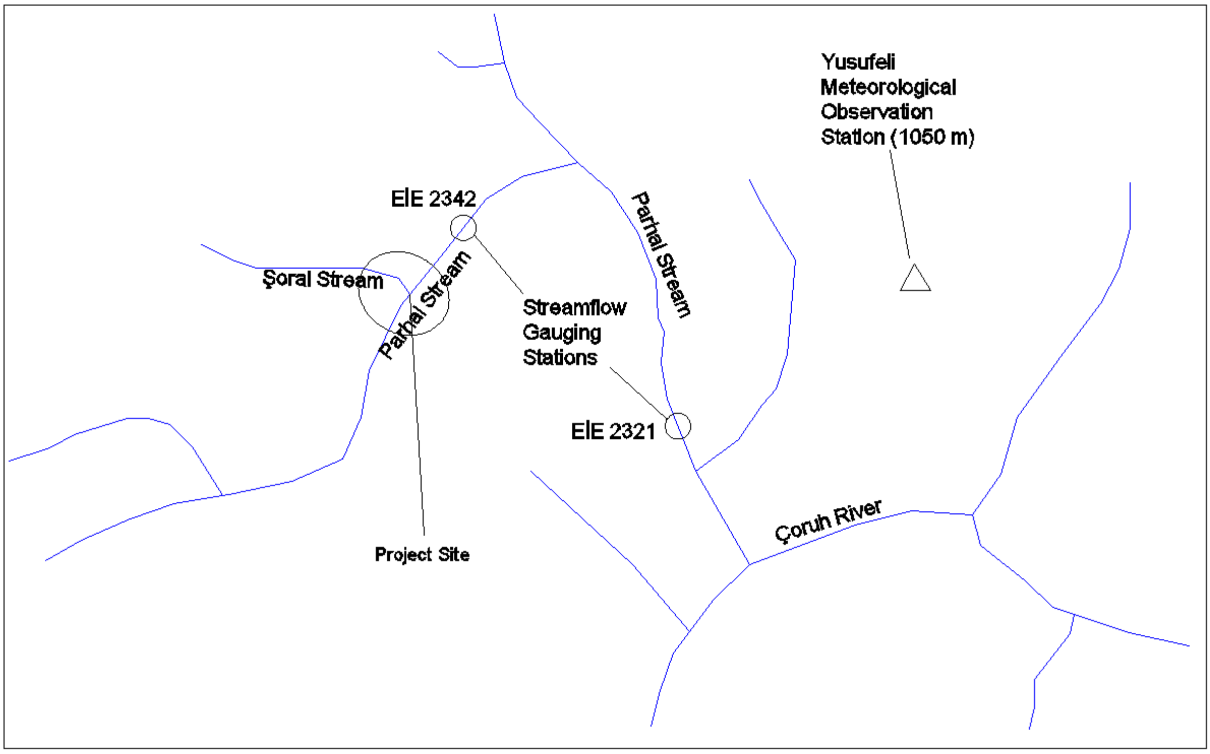

Figure 2.6 Stream Gauging Stations and Meteorological Observation Station (MOS)

2.5.2 Meteorological Conditions

Monthly precipitation and evaporation values are required to calculate changes in storages of the reservoirs. The closest meteorological station to the project area is Yusufeli Meteorological Observation Station (MOS) (see Figure 2.6). Yusufeli MOS is located at an elevation of 1150 m and the observation period of this station is 22 years. The average annual precipitation observed in this station is 307.2 mm which is well below the average of Turkey (640.9 mm) (DMİ, 2011). Evaporation measurements are not conducted at Yusufeli MOS. Bayburt MOS is identified as the closest station to the project area at which evaporation measurements are conducted. Therefore, evaporation data of Bayburt MOS are used in this study.

2.5.3 Earthquake Conditions

Parhal Stream is a branch of Çoruh River and is located at Yusufeli District. Project sites are located at the 3rd degree earthquake zone as can be seen from Figure 2.7.

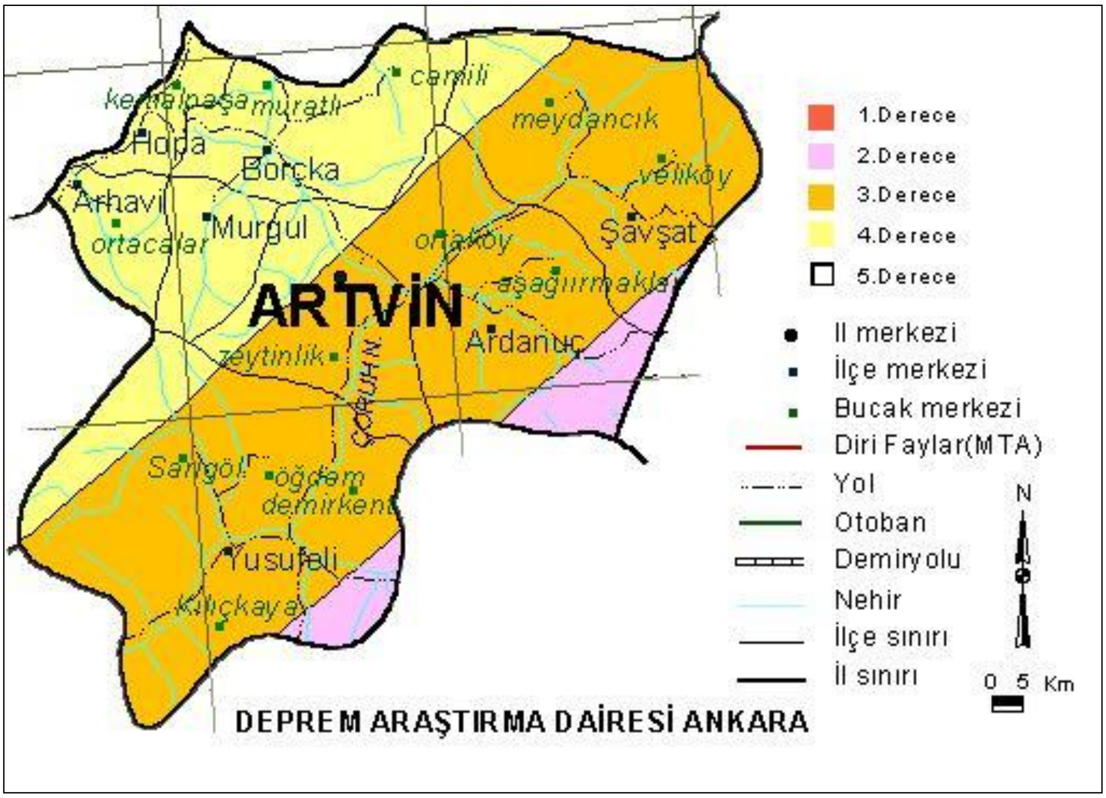

Figure 2.7 Earthquake Map of Artvin Province, 1999 (AFAD, 2010)

CHAPTER 3

ECONOMIC ANALYSIS

3.1 Methodology

Costs and benefits of a hydropower plant change with respect to its installed capacity. As the installed capacity increases the annual energy generation (AEG), thus the associated annual energy income (AEI) and the related annual investment cost (AIC) increases (see Figure 3.1). In this thesis, a set of alternative design discharges are selected by using flow-duration curves of the alternative formulations and for this set of alternative design discharges, the corresponding installed capacities are determined. Then, for each alternative, the corresponding annual energy generation income, the annual investment cost and the resulting net benefit is estimated. Installed capacity corresponding to the design discharge with the highest net benefit is selected as the optimum installed capacity. The flowchart of the methodology is outlined in Figure 3.2.

In a cost and income versus installed capacity graph (Figure 3.1), the net benefit (NB), which is the difference between AEI and AIC, increases up to specific point, and then it starts to decrease. The peak of the net benefit curve corresponds to the optimum installed capacity of the plant. Therefore, to select the optimum installed capacity, annual energy income (AEI) which is a function of the annual energy generation (AEG) and annual investment cost have to be determined. The AEI curve is a parabola and it levels off after the optimum capacity. In other words the annual energy generation and the related annual energy income do not change considerably with the increasing installed capacity after the optimum capacity.

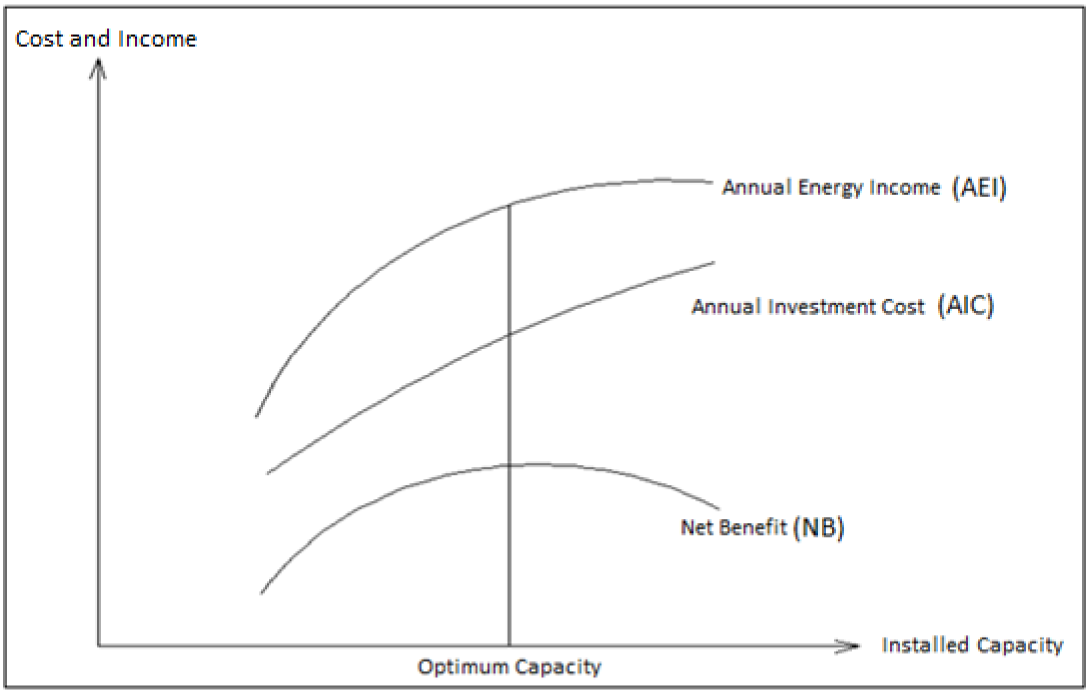

Figure 3.1 Cost and Income versus Installed Capacity Chart for a Hydropower Plant (Aydın, 2010)

To estimate the annual energy generation of a hydropower plant, a reservoir operation study (ROS) needs to be carried out. The sequential streamflow routing (SSR) method is the preferred method for ROS of hydropower projects with storages (USACE, 1985). Since Altıparmak HEPP has a reservoir, SSR is used in this study. The SSR method is used here to compute the energy output for each month in the period of analysis. Then, energy incomes corresponding to each month's energy generation is calculated by using hourly energy prices (Pritchard et al., 2004). The energy generation during each month is assumed to be realized when the energy prices are the highest within the day.

To determine the net benefits of the alternative installed capacities, the related investment costs of the alternatives should be determined as well. The costs (tunnel, dam body, expropriation costs, etc.) which are not significantly affected by the installed capacity, are not included into the economic analysis. On the other hand, the costs, which vary considerably with the installed capacity, such as costs associated with the penstock, the turbine, and the generator are taken into account. As the final step the incomes and costs associated with each alternative installed capacity are combined into a net benefit value and the best alternative is identified. The lifetime of Altıparmak HEPP is assumed to be 50 years, which is a common practice in Turkey. The economic analysis is then conducted for this time period (EİE, 2001; Yolsu 2009).

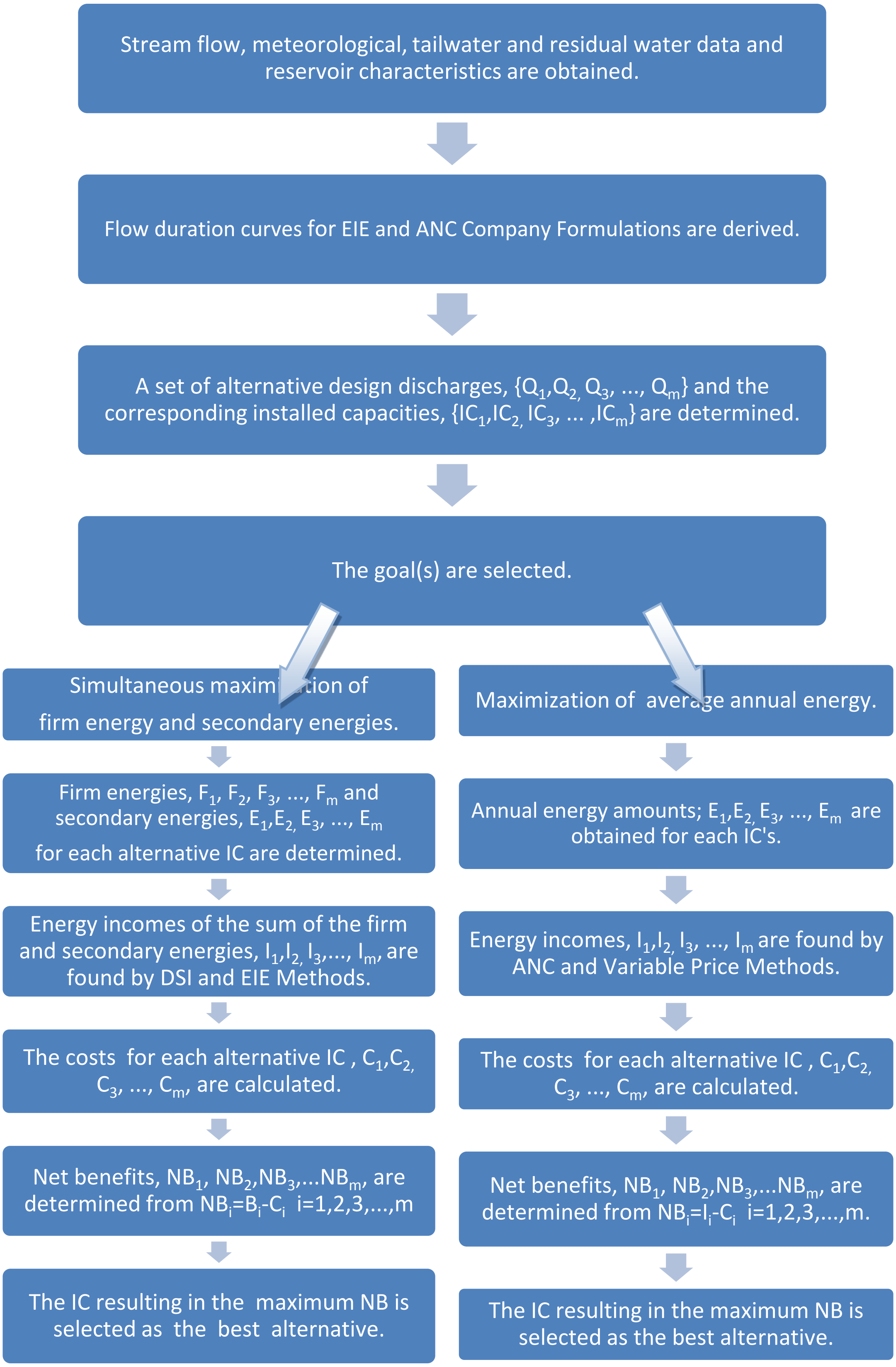

Figure 3.2 Economic Analysis Procedures

EİE and ANC conducted two different feasibility studies for the Altıparmak HEPP and as a result of these studies, the optimum installed capacities were determined by EİE and ANC as 50 MW and 70 MW, respectively (see Table 2.1). The economic analysis outlined in the previous paragraphs is carried out for both projects (i.e. EİE and ANC formulations) and the installed capacities are reevaluated. The results obtained in this study are compared with those of EİE and ANC results.

3.2 Preparation of Required Data and Information

3.2.1 Hydrological Data

Incoming water to the reservoir is one of the main factors which affects the energy generation. Therefore, historical streamflow records are of great importance in hydrological studies. In order to determine the amount of streamflow incoming to the reservoir, data obtained from the streamflow gauging stations in the vicinity of the project area are utilized. The streamflow measured at any gauging station can be transferred to any point on the same stream by the drainage area ratio method if the calculated ratio of the areas is between 0.5 and 1.5 (Hortness, 2006).

Time interval between consecutive streamflow records and record duration are other factors that play an important role in the ROS. Monthly streamflow data are adequate for the analyses if the variation of daily discharges is small and the reservoir is big enough to eliminate the fluctuations in the streamflow (Karamouz et al., 2003). Since these conditions are satisfied for this project, monthly streamflow data belonging to project sites are utilized for both alternative formulations. A streamflow record of 30 years is accepted to be adequate for hydrological analyses but it is not possible to have that much data most of the time. For the locations where the streamflow records are taken for a period less than 36 years, correlation studies need to be performed and the available streamflow should be extended (USACE, 1985).

3.2.1.1 Determination of the Drainage Basins

The drainage areas for the thalweg elevations of 1160 m and 1095 m corresponding to EİE and ANC formulations are estimated as 306.67 km^2 and 317.84 km^2, respectively (see Figure 2.5). The closest stream gauging station to these drainage basins is EİE 2342. This station is located at a thalweg elevation of 1080 m and its drainage basin is estimated as 322.11 km^2 by encircling the basin area on a 1/25000 scaled map. The drainage basin area for this gauging station is determined as 318.4 km^2 by EİE which is not much different from the value determined in this thesis study. The difference may be due to utilization of different scales of the related maps.

3.2.1.2 Drainage Area Ratio Method

The drainage basins associated with the alternative dam axes and the stream gauging station are very close to each other, so the observed flows of EİE 2342 stream gauging station (see Figure 2.6) are transferred to the dam axes of EİE and ANC formulations by multiplying the available values with the drainage area ratios. The drainage area ratios are 0.952 and 0.987 for EİE and ANC formulations, respectively.

3.2.1.3 Correlation Study

The observation period for EİE 2342 Parhal – Altıparmak stream gauging station is 15 years (1993-2007) which is not enough for the ROS. Therefore, the streamflow data have to be extended by performing a correlation study.

EİE 2321 Parhal – Dutdere stream gauging station (see Figure 2.6) is on Parhal Stream and has a 36-year observation period between 1972 and 2007. The common observation period for EİE 2342 and EİE 2321 is from 1993 to 2007. A regression analysis is performed to evaluate the correlation of the streamflow data corresponding to EİE 2342 and EİE 2321. As can be seen from Figure 3.3, equation of the fitted line is Q_{2342} = 0.6542 x Q_{2321} - 0.18 (valid for 2.05 $m^3/s < Q_{2321} < 65.5$ m^3/s); where Q_{2342} and Q_{2321} are the flow rate values for EİE 2342 and EİE 2321 stations, respectively. The correlation coefficient (R^2) is 0.9637 which means that there is a good statistical correlation between these two stations' streamflow values. The regression equation is used to derive monthly streamflow values for EİE 2342 from streamflow data of EİE 2321 for years between 1972 and 1993. Then the resulting streamflow values are transferred to the drainage basins of EİE and ANC projects by using drainage area ratio method.

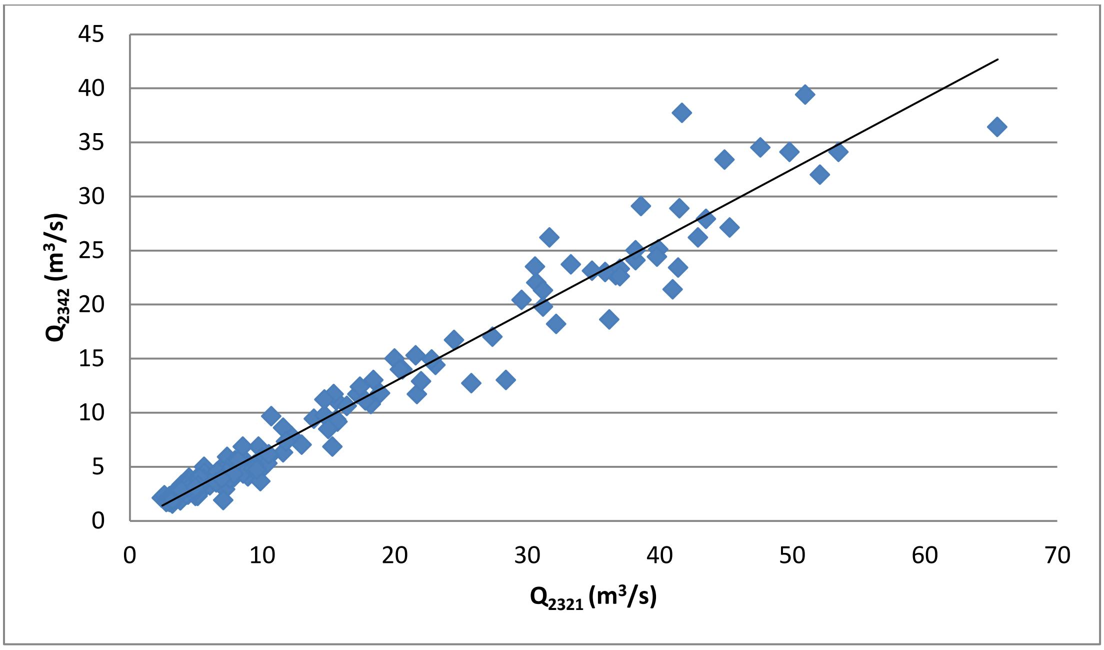

Figure 3.3 The Correlation Between EİE 2342 and EİE 2321 Stream Gauging Stations

3.2.2 Meteorological Data

The evaporation from and the precipitation to the reservoir surface should be taken into consideration in the ROS. Since, the alternative formulations have small reservoir surface areas; data from the closest meteorology station to the project area is used for precipitation and evaporation calculations.

Yusufeli Meteorology Station is at an elevation of 1150 m and is located in the close vicinity of the reservoir areas (see Figure 2.6). This station has 22 years of precipitation data. Average monthly precipitation values are given in Table 3.1 and these average values are used in the ROS.

Table 3.1 Average Monthly Precipitation Values (mm) for Yusufeli Meteorology Station

January	February	March	April	May	June
18.6	16.7	25.7	33.9	42.4	43.7
July	**August**	**September**	**October**	**November**	**December**
24.3	15.2	16.9	20.3	25.1	24.4

Since evaporation measurements are not available at Yusufeli Meteorology Station, the next closest station (Bayburt Meteorology Station), at which both evaporation and temperature measurements are conducted, is utilized in this study. The elevation difference between Yusufeli MOS and Bayburt MOS and the distance between them are 500 m and 140 km, respectively. EİE developed a correlation equation between the temperature and evaporation data of Bayburt Meteorology Station as follows: Ev=10.161xT–24.883 (valid for T > 2.45 C^o) (R^2 = 0.72) (EİE, 2001). In this equation, *Ev* and *T* stand for evaporation and temperature, respectively. This equation is utilized for estimating the evaporation values for Yusufeli Meteorology Station. Evaporation data derived for Yusufeli Meteorology Station is given in Table 3.2.

Table 3.2 Estimated Monthly Evaporation Values (mm) for Yusufeli Meteorology Station

January	February	March	April	May	June
18.6	26.7	60,28	122.3	168.7	203.6
July	**August**	**September**	**October**	**November**	**December**
236.6	236.1	198.6	136.5	64.31	25.03

The evaporation measurements belonging to Bayburt Meteorology Station are conducted with a metal pan. Therefore, the measurements are greater than the real values. A reduction factor is used to obtain more realistic evaporation estimates. Estimated evaporation values are reduced by a factor of 0.7 in EİE project (EİE, 2001; Usul, 2009). A similar approach is applied here and the evaporation values used in the ROS are reduced to 70% of the estimated values.

3.2.3 Reservoir Characteristics

The reservoir level and the corresponding surface area change with respect to the amount of water stored (i.e. storage) in the reservoir. In the ROS, reservoir elevations and surface areas corresponding to various storages are used in estimating the energy generation. Surface areas and storage volumes corresponding to various reservoir levels are determined by utilizing a 1/25000-scaled map of the project site. Contour lines having an interval of 10 meters are encircled in AutoCAD and areas corresponding to each contour line are calculated. Then, amount of storage (i.e. volume of water) between two successive contour lines are calculated by multiplying the interval height (10.0 m) with the average of the successive surface areas. Linear interpolation is used for the ROS to estimate intermediate surface areas and storages. Reservoir elevation versus surface area and storage curves are given for EİE and ANC formulations in Figures 3.4 and 3.5, respectively. Reservoir area-elevation and storage-elevation values and of Altıparmak Dam for EİE and ANC formulations are given in Tables 3.3 and 3.4, respectively.

Table 3.3 Altıparmak Reservoir Area-Elevation and Storage-Elevations Values for EİE Formulation

Elevation (m)	Area (m^2)	Elevation (m)	Intermediary Volume (m^3)	Total Volume (m^3)
1095	0	1095-1100	32550	32550
1100	13020	1100-1110	220335	252885
1110	31047	1110-1120	480210	733095
1120	64995	1120-1130	1011025	1744120
1130	137210	1130-1140	1864975	3609095
1140	235785	1140-1150	2778145	6387240
1150	319844	1150-1160	3740380	10127620
1160	428232	1160-1170	4864915	14992535
1170	544751	1170-1180	6040755	21033290
1180	663400	1180-1190	7300840	28334130
1190	796768	1190-1200	8873025	37207155
1200	977837	1200-1210	10641365	47848520
1210	1150436	1210-1220	12340510	60189030
1220	1317666	1220-1230	13991795	74180825
1230	1480693			

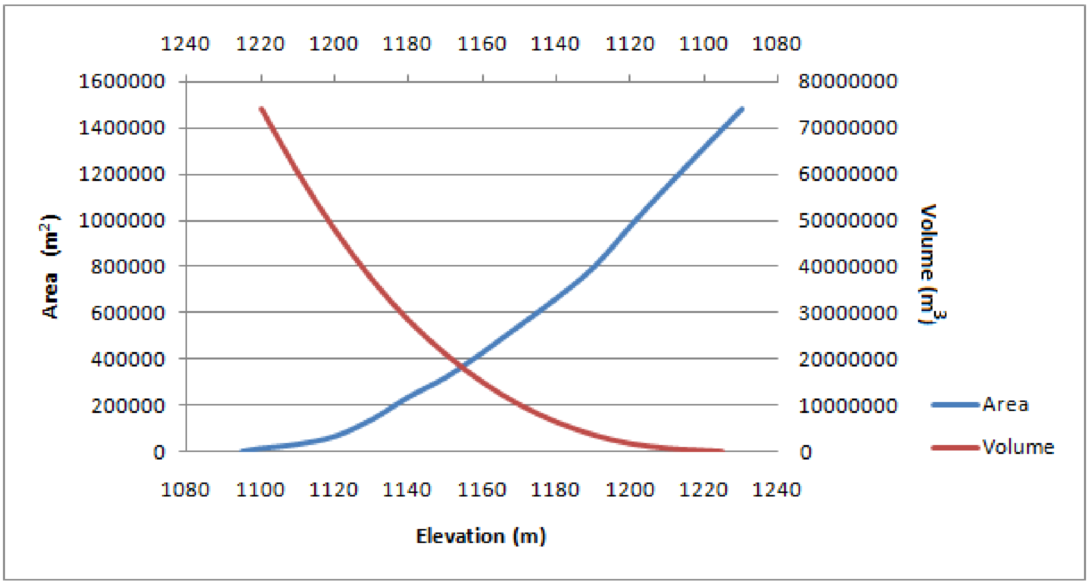

Figure 3.4 Reservoir Elevation versus Surface Area and Storage Graphs for EİE Formulation

Table 3.4 Altıparmak Reservoir Area-Elevation and Storage-Elevation Values for ANC Formulation

Elevation (m)	Area (m^2)	Elevation (m)	Intermediary Volume (m^3)	Total Volume (m^3)
1160	36	1160-1170	80175	80175
1170	15999	1170-1180	328710	408885
1180	49743	1180-1190	732900	1141785
1190	96837	1190-1200	1408590	2550375
1200	184881	1200-1210	2180230	4730605
1210	251165	1210-1220	2821025	7551630
1220	313040	1220-1230	3426695	10978325
1230	372299			

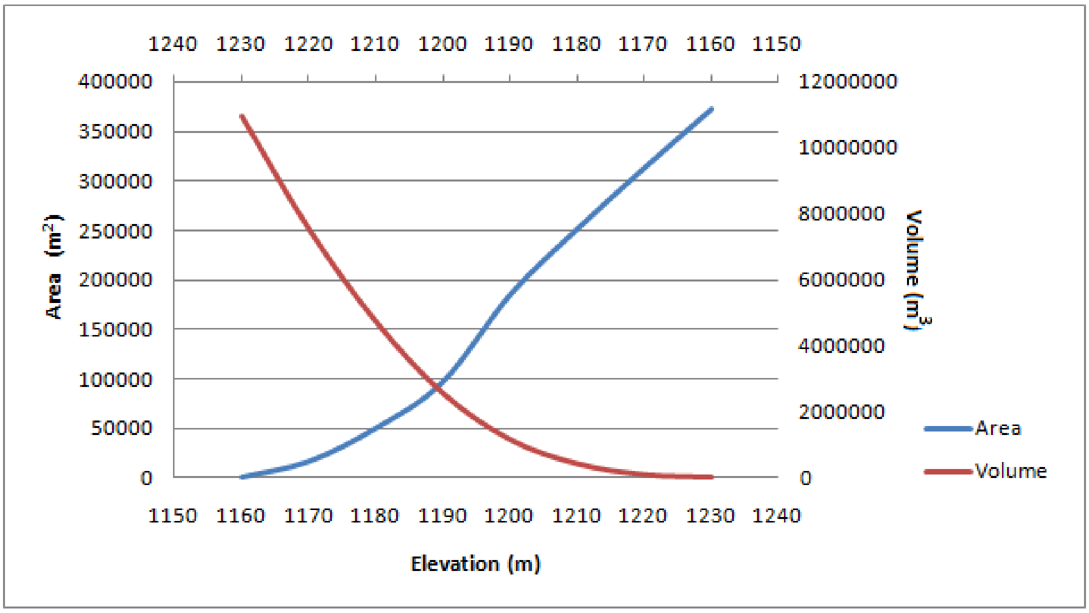

Figure 3.5 Reservoir Elevation versus Surface Area and Storage Graphs for ANC Formulation

3.2.4 Tailwater Rating Curve

The gross head is calculated by subtracting the tailwater level from the reservoir water level. Tailwater level changes with respect to discharge and this fact should be taken into consideration in the ROS for more accurate results. Tailwater flow consists of the discharge through turbines, the residual water for the downstream requirement and the excessive spilled water. The relation between the flow rate and tailwater level can be represented by a rating curve.

HEC-RAS is used in this study to estimate tailwater levels corresponding to different flow rates. To do this, 40 cross-sections are specified each having a spacing of 50 m along the stream bed. The coordinates of these cross-sections are determined from the related maps by AutoCAD. Then, the tailwater levels are estimated for 18 different discharge values between 2 m^3/s and 60 m^3/s (see Table 3.5). These water levels are used to obtain the tailwater rating curve through regression analysis. The equation of the fitted curve is h = 0.326 x $Q_{tw}{}^{0.397}$ (R^2 = 0.9998) where h is the tailwater depth in m and Q_{tw} is the tailwater discharge in m^3/s (see Figure 3.6). This tailwater rating curve is used in ROSs.

Table 3.5 Tailwater Flow versus Elevation Values

Discharge (m^3/s)	Elevation (m)	Elevation Calculated from the Equation (m)
2.00	840.43	840.43
4.00	840.56	840.57
6.00	840.67	840.66
8.00	840.75	840.74
10.00	840.81	840.81
12.00	840.87	840.87
14.00	840.93	840.93
16.00	840.98	840.98
18.00	841.03	841.03
20.00	841.07	841.07
25.00	841.17	841.17
30.00	841.26	841.26
35.00	841.34	841.34
40.00	841.41	841.41
45.00	841.48	841.48
50.00	841.54	841.54
55.00	841.60	841.60
60.00	841.66	841.66

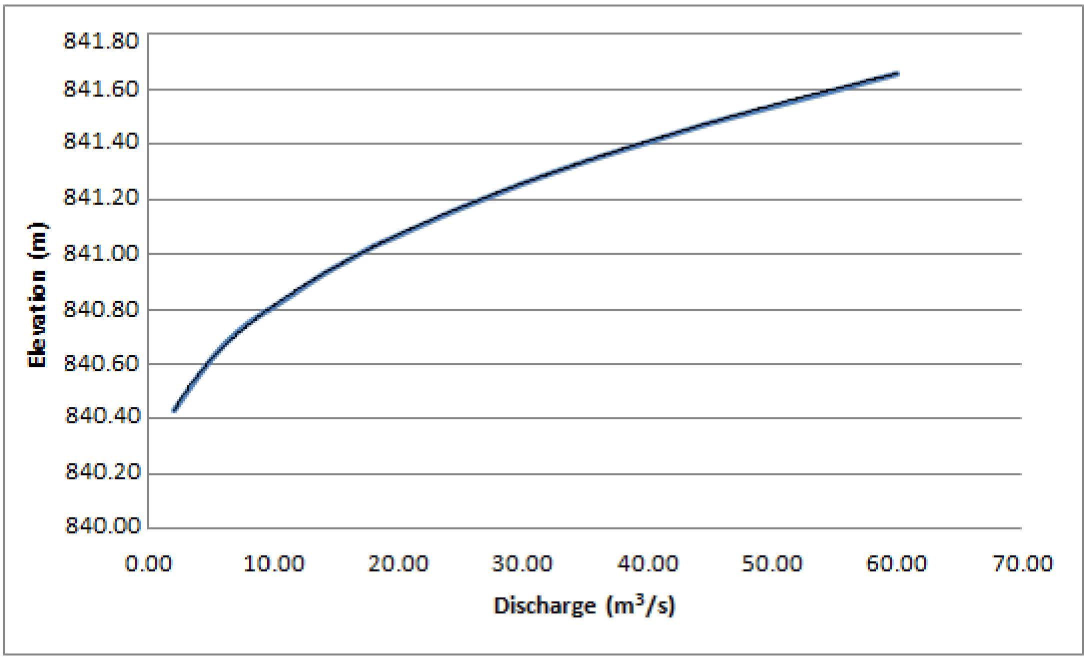

Figure 3.6 Tailwater Rating Curve

3.2.5 Residual Water Flow

A minimum amount of water has to be released from the reservoir in order to maintain the downstream aquatic environment. This minimum amount is called the residual water flow. According to DSİ, 10% of the average of the last ten years' streamflow at the diversion point (dam body location) can be taken as the residual water flow in a feasibility study (DSİ, 2009). The average streamflow values of the last ten years are 8.741 m^3/s and 8.431 m^3/s for the EİE and ANC formulations, respectively. Ten percent of these values are used as residual water flow in the ROSs.

The sufficiency of the released water should be observed and evaluated by experts for different seasons during the operation of the hydropower plant. If necessary, the amount of released water should be increased.

3.2.6 Flow-Duration Curve

Historical streamflow data are well represented by a flow-duration curve (FDC). In this study, the FDC is used to determine the range from which alternative design discharges are selected. An FDC illustrates the time proportion during which the discharge observed on a given location equals or exceeds certain values (ESHA, 2004).

In order to construct the FDC for a given location, observed streamflow data are arranged in descending order. This set of data can be utilized to specify the percentage of time for each discharge magnitude to be equaled or exceeded. Flow-duration relationship is, then, illustrated by plotting this time percentage against the streamflow magnitude. Flow-duration curve data used for EİE and ANC formulations are given in Appendix Tables B-1 and B-2, respectively. FDCs of the two alternative formulations are given in Figure 3.7.

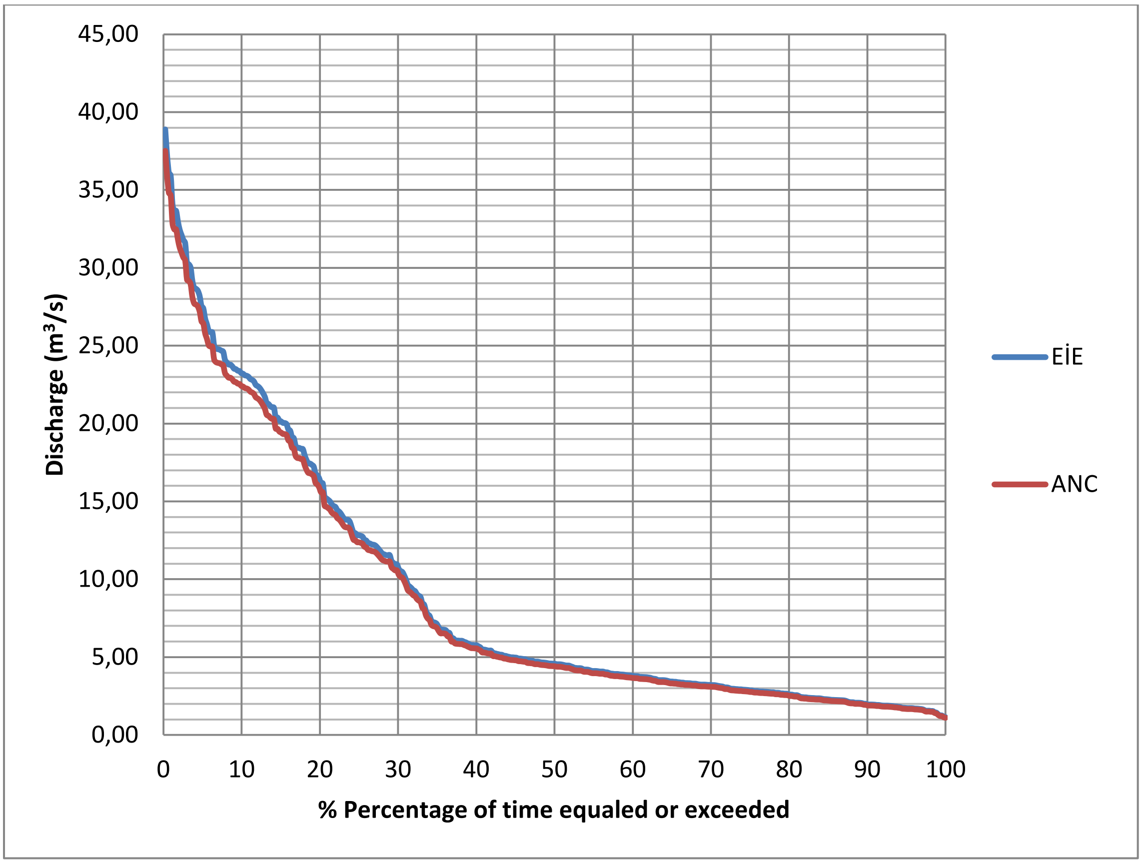

Figure 3.7 Flow-duration Curves for EİE and ANC Formulations

3.2.7 Water Losses

The water losses due to leakage through or around the dam body and other embankment structures are not taken into account in this study due to lack of data.

3.3 Basic Definitions

Some basic definitions related with ROS and SSR are provided in this section.

The gross head ($H_g(t)$) is the head difference between the reservoir level and the tail water level. It changes significantly with time, t, in the storage projects (see Figure 3.8).

The net head ($H_n(t)$) is the remaining head after hydraulic losses are subtracted from the gross head (see Figure 3.8). This is the available head for energy generation.

The hydraulic efficiency (ε_h) is the ratio of the net head to gross head.

$$\varepsilon_h = \frac{H_n\,(t)}{H_g(t)} \tag{3.1}$$

The turbine efficiency ($\varepsilon_t(t)$) is the ratio of the net potential energy running the turbines to the converted mechanical energy. It depends on the turbine type and its value changes within the related discharge and head range.

The generator efficiency ($\varepsilon_g(t)$) is the ratio of the energy generation converted by the generator to the mechanical energy. Generator efficiency is usually assumed to remain constant at 98 percent for large units and 95 to 96 percent for units smaller than 5 MW (USACE, 1985).

Power ($P\ (kW)$) is the rate of energy production and can be estimated as follows:

$$P\ = e(t)\ \gamma\ \ Q(t)\,H_n(t) \tag{3.2}$$

where, $e(t)$ is the product of the turbine and generator efficiencies (i.e. $e(t)\ =\ \varepsilon_t\ (t) \times \varepsilon_g\ (t)$), γ is the specific weight of water (9.81 kN/m^3), $Q(t)$ is the discharge at any time passing through turbines (m^3/s), and $H_n(t)$ is the related net head (m).

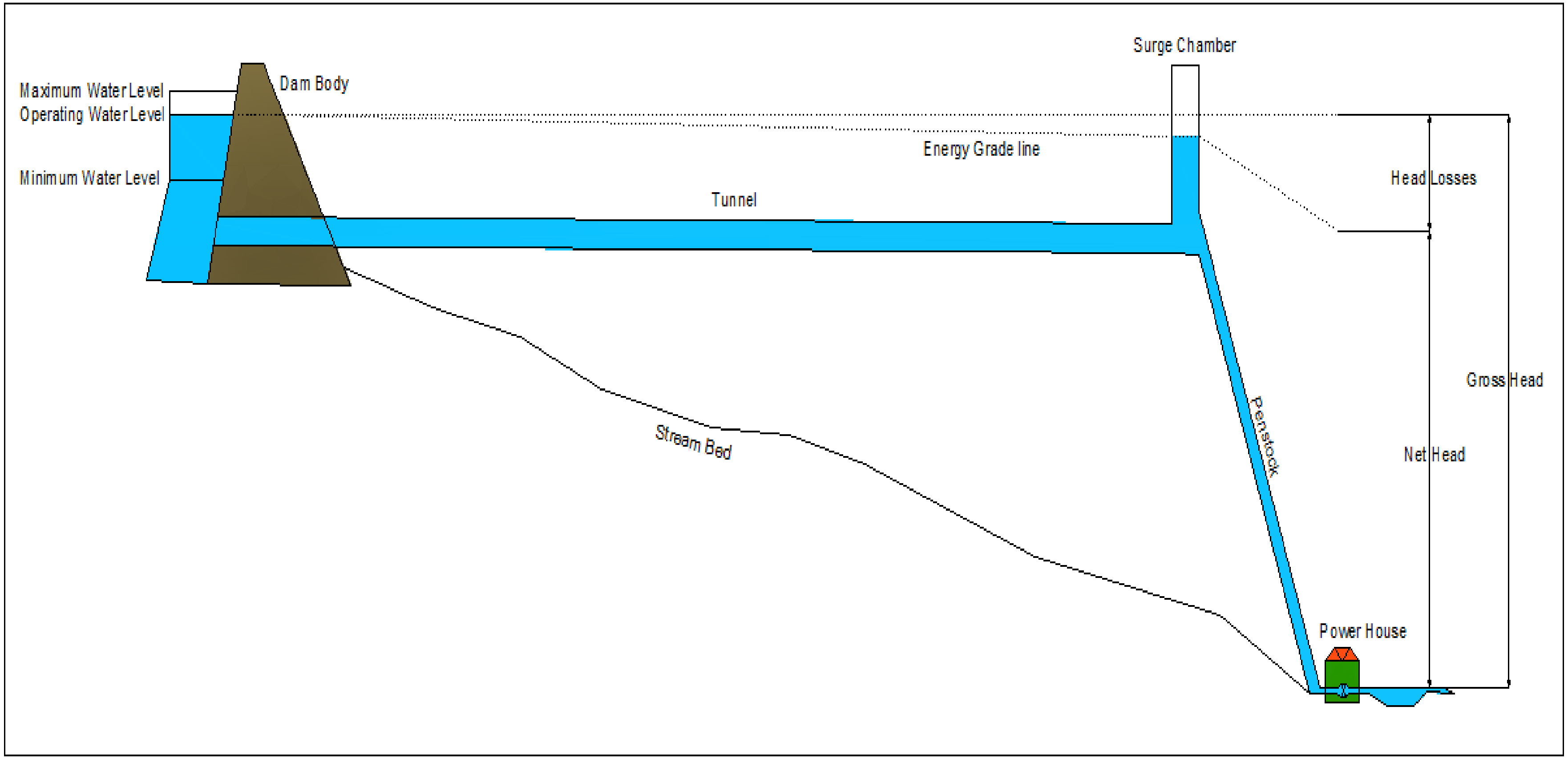

Figure 3.8 Demonstration of a HEPP with Tunnel and Penstock (Not to Scale)

Installed Capacity (P_{ins}) is the maximum power in MW which can be developed by the generators (Yanmaz, 2006).

$$P_{ins} = e_d \ \gamma \ Q_d \, H_{nd} \tag{3.3}$$

where, e_d is the product of the turbine and generator efficiencies when the design discharge (Q_d) is passing through the turbines, and H_{nd} is the related design net head.

The energy production (E) is calculated by taking the integral of the power within the defined period:

$$E = \int P \, dt = \int e(t) \ \gamma \ Q(t) \ H_n(t) \ dt \tag{3.4}$$

For larger time intervals, such as an hour or greater, the energy production, E can be estimated from:

$$E = \sum_{t=1}^{t=N} e(t) \ \gamma \ Q(t) \ H_n(t) \ \ \Delta t \tag{3.5}$$

The values of $e(t)$, $Q(t)$, and $H_n(t)$ may change within the selected time interval Δt. However, average values can be used in the calculations (Karamouz et al., 2003).

Firm energy is defined as the power that can be delivered by a specific plant during a certain period of the day with at least 95% certainty (ESHA, 2004).

Secondary energy is defined as the generated energy in excess of firm energy (USACE, 1985).

Operating level is the ideal (predetermined) water level at which energy generation is planned to be realized in accordance with the reservoir operation policy. Operating level may change from season to season. A rule curve is a graph which provides operating levels for different seasons within a year. Ideally, the water level within the reservoir has to be kept at operating levels (USACE, 1985).

3.4 Reservoir Operation Study

Development of a reservoir operation policy is a complex process restricted by unique constraints of each project. Thus, there is no universal approach for identifying the most efficient reservoir operation policy which will satisfy the project specific goal(s) and constraints. So each system has to be evaluated based on its own limitations and requirements and the best reservoir operation guidelines for that specific system has to be determined (Bosona and Gebresenbet, 2010).

There are mainly two different types of reservoirs: single-purpose and multipurpose. Different reservoir operation guidelines are used for operating single and multiple-purpose reservoirs. Multipurpose reservoirs are constructed to achieve goals such as flood control, hydropower generation, water supply for irrigation or other demands, navigation and restoration works. For multipurpose reservoirs, maximizing the benefits of conflicting objectives is a very difficult task. On the other hand, some reservoirs are only used for hydropower generation. Maximizing the benefits of hydropower generation depends on many factors, such as hydrological and meteorological data, variation of the reservoir level and area, energy demand and prices, type of the turbines, etc. Therefore, maximizing annual energy generation of single-purpose dams is a complex process as well.

Three commonly used ROS methods are the non-sequential or flow-duration curve method, the sequential streamflow routing (SSR) method and the hybrid method which is the combination of these two (Karamouz et al., 2003). The flow-duration curve method is generally used for the high-head and run-of-river type hydropower projects where the change in the head is limited and head varies with discharge. SSR is commonly used for hydropower projects with reservoirs. In the SSR method the energy generations are computed sequentially for each time interval in the period of analysis. Altıparmak HEPP has a reservoir, thus SSR is used in this study. An Excel spreadsheet is prepared to carry out sequential streamflow routing.

A ROS needs to be conducted to determine energy income of a hydropower plant. However, hydropower plants are designed and operated to maximize generation of various forms of energy, such as the firm energy, the average annual energy or the dependable capacity (i.e. the load-carrying ability under adverse flow and load conditions) or a combination of these (Karamouz et al., 2003). Each one of these goals requires a different reservoir operation policy. The reservoir operation policy must try to accomplish the selected goal(s) while satisfying all the constraints. If there are multiple goals, they have to be accomplished simultaneously.

Energy income calculations of EİE and DSİ methods are based on the firm energy and the secondary energy generations. In both of these methods firm energy is assumed to be financially more beneficial than the secondary energy generation. However, from an investor's point of view, maximizing the net benefit (i.e. annual energy income) is always the main goal. Thus, the Excel worksheet, which is developed to conduct the SSR, is formulated such that it allows simultaneous maximization of the firm and secondary energies. Determination of the firm and the average annual energy generation is explained in the following paragraphs.

The Determination of Firm Energy Generation

Firm energy is the energy generation that can be guaranteed during a certain period of a day with at least 95% certainty. A trial and error procedure is used to identify the firm energy generation. Initially a firm energy discharge is selected and a SSR is conducted with this firm energy discharge. Then discharge used for energy generation for each day is calculated. These results are evaluated to determine in what percent of the time through the streamflow data the firm energy discharge is satisfied. If the firm energy discharge is satisfied in more than 95% of the time then the initial guess for firm energy discharge is increased, otherwise it is decreased. As a result of this procedure a maximum firm energy output (i.e. firm energy discharge) is determined for the plant.

The Determination of Average Annual Energy Generation

Secondary energy is generated from the available water remaining after the firm energy generation. If the firm energy generation is not required, all the storage can be used for secondary energy generation. After the firm energy generation is satisfied, secondary energy generation is tried to be maximized according to the reservoir operation rules.

3.4.1 Sequential Streamflow Routing Method

Sequential streamflow routing method is primarily used to evaluate a single storage project or a system of storage projects. The method is based on the continuity equation. The ROS, which is carried out to determine the energy generation of a project, is performed considering consecutive time intervals (i.e. days, weeks, months, etc.). Selection of the time interval depends on the project characteristics, available data, and the reservoir capacity (USACE, 1985). In this thesis, reservoir operation study is performed for monthly time intervals using the spreadsheets.

3.4.1.1 The Continuity Equation

The difference between the volumes of the incoming water and the released water is the net change of volume ΔS (hm^3) in the reservoir storage. Continuity equation is stated as:

$$S(t+1) - S(t) = \Delta S = I(t) - O(t) \qquad t = 1, 2, 3, \ldots . T \qquad (3.6)$$

$S(t)$ (hm^3) is the reservoir storage at the beginning of month t. Consequently, $S(t+1)$ (hm^3) represents the reservoir storage at the end of month t and beginning of month $t+1$. The change in volume, ΔS, can be controlled by the total outflow in accordance with the reservoir operation policy. The period of analysis involves a total of T months.

Reservoir Inflow $I(t)$ (hm^3) is the total flow volume coming to the reservoir and can be calculated by summing the streamflow $Sf(t)$ (hm^3) and the precipitation $Pr(t)$ (hm^3).

$$I(t) = Sf(t) + Pr(t) \qquad t = 1, 2, 3, \ldots . T \qquad (3.7)$$

Precipitation, $Pr(t)$ (hm^3) to the reservoir area is calculated by multiplying the reservoir surface area $A(t)$ (km^2) at the beginning of the month, with the precipitation amount $pr(t)$ (m) in month t.

$$Pr(t) = A(t) \; pr(t) \qquad t = 1, 2, 3, \ldots T \qquad (3.8)$$

The total outflow volume $O(t)$ (hm^3) is the sum of the outflow released through turbines to generate electricity, evaporation losses from the reservoir surface area, and released water for downstream requirements. The water spilled in the high-flow season is included in the outflow as well.

$$O(t) = Tr(t) + Sp(t) + Rw(t) + Ev(t) \qquad t = 1, 2, 3, \ldots T \qquad (3.9)$$

Turbine releases $Tr(t)$ (hm^3) is determined in accordance with the reservoir operation policy. Spilling $Sp(t)$ (hm^3) occurs when reservoir surface level is higher than spillway crest elevation. $Rw(t)$ (hm^3) is the residual water volume. $O'(t)$ is the total outflow except spilling.

$$O'(t) = Tr(t) + Rw(t) + Ev(t) \qquad t = 1, 2, 3, \dots T \tag{3.10}$$

$$Sp(t) = I(t) - \Delta S - O'(t) \qquad t = 1, 2, 3, \dots T \tag{3.11}$$

For simplicity, residual water rw (m^3/s) released for the downstream habitat is considered to be constant in this study. However, it changes with respect to the number of days (*n*) in a month. $Rw(t)$ in (hm^3) can be calculated as follows:

$$Rw(t) = [rw \times 3600 \times 24 \times n]/10^6 \qquad t = 1, 2, 3, \dots T \tag{3.12}$$

Evaporation loss $Ev(t)(hm^3)$ is calculated similar to the precipitation:

$$Ev(t) = A(t)\ ev(t) \qquad t = 1, 2, 3, \dots T \tag{3.13}$$

$A(t)$ (km^2) is the reservoir surface area at the beginning of the month, $ev(t)$ (m) is the evaporation from the reservoir surface area in month *t*.

Net inflow $NI(t)$ (hm^3) can then be obtained from:

$$NI(t) = Sf(t) + Pr(t) - Ev(t) \qquad t = 1, 2, 3, \dots T \tag{3.14}$$

3.4.1.2 Constraints

Energy generation of a hydropower project is limited by some factors, such as the design discharge, head, reservoir storage, etc., and ROS is conducted by considering these limitations. The constraints of hydropower generation are listed below:

1. The discharge released for the energy generation is limited by the minimum and the maximum discharge passing through the turbines.

$$Q_{min} \leq Q(t) \leq Q_{max} \qquad t = 1, 2, 3, \dots . T \tag{3.15}$$

where, Q_{min} (m^3/s) is the minimum discharge corresponding to the minimum turbine capacity. Q_{max} (m^3/s) is the discharge released through turbines when all turbine wicket gates are fully open (i.e. the design discharge).

2. Minimum and maximum reservoir levels limit the gross head $H_g(t)$ (m) of the project.

$$H_{min} \leq H_g(t) \leq H_{max} \qquad t = 1, 2, 3, \dots . . T \tag{3.16}$$

H_{min} (m) is the head difference between the minimum reservoir level (the related calculations are explained in Section 3.4.1.2.1) and the tailwater level. Similarly, H_{max} (m) is the head difference between the maximum operating level which is the spillway crest elevation and the tailwater level.

3. The constraint on power generation $P(t)$ is defined by maximum capacity and the minimum power requirement.

$$P_{min} \leq P(t) \leq P_{max} \qquad t = 1, 2, 3, \dots . . T \tag{3.17}$$

P_{min} (kW) is the minimum amount of power generated using the minimum allowable discharge while running the turbine with the minimum capacity. Reservoir water level is at the minimum allowed level in that situation. P_{max} (kW) is the generated power by all turbines running with discharge corresponding to full capacity (i.e. installed capacity). Water level of the reservoir is at the level of spillway crest elevation (maximum operating level) when the maximum power is maintained during the operation of the facility.

4. The reservoir storage is limited by minimum and maximum reservoir storages.

$$S_{min} \leq S(t) \leq S_{max} \qquad t = 1, 2, 3, \ldots..T \tag{3.18}$$

S_{min} (hm^3) and S_{max} (hm^3) are the minimum and the maximum storage volumes which are observed when the water levels are at the minimum and maximum reservoir levels, respectively.

5. The reservoir area is similarly constrained by minimum and maximum reservoir levels.

$$A_{min} \leq A(t) \leq A_{max} \qquad t = 1, 2, 3, \ldots..T \tag{3.19}$$

A_{min} (km^2) and A_{max} (km^2) are the minimum and the maximum reservoir surface areas which are observed when the water levels are at the minimum and maximum reservoir levels, respectively.

Minimum and Maximum Reservoir Operating Levels

Minimum reservoir operating level is determined considering the vortex formation over the tunnel entrance. Vortex study is carried out based on the relations proposed by Gordon (1970). According to Gordon, the geometry of the approach flow, the critical submergence measured from the top of the intake structure, S_c (m), and the dimensions of the intake structures have influence on the vortex formation. The relation proposed by Gordon is given as:

$$\frac{S_c}{D_t} = 1.72Fr \tag{3.20}$$

where, S_c (m) is the critical submergence, D_t (m) is the tunnel diameter and Fr is the Froude number.

In this study, the diameter of the tunnel is taken as 3.0 m for both EİE and ANC formulations. Froude number is calculated according to the maximum alternative design discharge which is taken as 30.0 m^3/s.

Critical submergence is calculated as 4.02 m but to be on the safe side, this value is rounded to 5.0 m and used in the calculations.

The entrance elevation of the tunnel can be estimated by considering sedimentation (i.e. dead storage). The sedimentation amount estimated by EİE is 42,317 m^3/year (EİE, 2001). The economic life of the HEPP is assumed to be 50 years. The amount of sediment coming to the reservoir during the operation period of the project is found as 2,115,850 m^3. Since the drainage area of the project implemented by ANC is slightly smaller than that of EİE formulation, estimated amount of sedimentation in the EİE feasibility report is directly taken from the ANC formulation. The corresponding dead storage elevations are estimated by using volume-elevation curves as 1122.0 m and 1186.92 m for EİE and ANC formulations, respectively.

Adding the tunnel height, 3.6 m (see Figure 3.17), and the vortex height, 5.0 m to the estimated dead storage elevations, the corresponding minimum reservoir elevations are calculated as 1130.6 m and 1195.52 m for EİE and ANC formulations, respectively.

Since the spillway is uncontrolled, the maximum reservoir operating level is taken as the crest elevation of the spillway (i.e. 1227 m).

3.4.2 Identification of the Set of Alternative Design Discharges

As mentioned before, the selection of the most profitable design discharge and the corresponding installed capacity is based on the energy generation, consequently the energy income and the initial investment costs. Selection of the best design discharge is an optimization problem. Since this study is a feasibility level work instead of an optimization problem a decision making problem is formulated and among a set of alternative design discharges the best one is selected.

To identify alternative design discharges, the flow-duration curve is utilized. Generally, discharges equaled or exceeded between 5% and 30% of the time are considered in selecting the best design discharge. The installed capacity corresponding to the best design discharge is then identified as the best installed capacity.

Discharge equaled or exceeded 5% and 30% of the time for EİE and ANC formulations are determined using the related flow duration curves and provided in Table 3.6. As can be seen in Table 3.6, it is reasonable to select alternative design discharges between 9.0 m^3/s and 30.0 m^3/s. In this study, a total of 22 alternative design discharge values are selected starting from 9.0 m^3/s and increasing with 1 m^3/s increment: Alternative design discharges (m^3/s): {9, 10, 11, 12,…, 29, 30}.

Table 3.6 Discharges (m^3/s) Corresponding to %5 and %30 of the Time for Each Project

% Time Equaled or Exceeded	Discharges (m^3/s)	
	EİE	ANC
5%	27.40	26.43
30%	10.66	10.28

3.4.3 Identification of the set of Alternative Operating Levels

Reservoir operating level (i.e. the ideal level which will result in the maximum energy output) changes from season to season. Plotting the reservoir operating levels for each season of a year on a graph gives the rule curve. Rule curve can be defined as a curve or family of curves showing how to operate a reservoir under specific conditions to achieve the desired goal(s) (USACE, 1985). The reservoir operation rules are formulated such that the rule curve is not violated during the analysis period. There are only two exceptions for which the rule curve can be violated (i.e. water level within the reservoir may fall below the operating level): (i) if HEPP is forced to satisfy a firm energy requirement and (ii) when there is not enough water within the reservoir to provide residual water.

The reservoir operating levels which will form the rule curve are determined through an iterative search process in this study. The water year is divided into four equal intervals (i.e. 3 months in each section) and six alternative reservoir operating levels are identified. Spillway crest elevation is taken as the first operating level; then five more levels are selected by subtracting two meters from the spillway crest elevation (i.e. 1227.0 m). Therefore, the alternative operating levels are {1227.0 m, 1225.0 m, 1223.0 m, 1221.0 m, 1219.0 m, 1217.0 m}. A ROS is performed for all possible combinations of the reservoir operating levels for four seasons.

3.4.4 Determination of the Rule Curves

As explained above the reservoir operating levels which form the rule curve are determined through an iterative search process in this study. A ROS for all possible combinations of six alternative operating levels is conducted and the associated energy generations are calculated. Energy generations corresponding to each of the six operating levels (i.e. assuming that the rule curve is composed of a fixed operating level) and operating level combinations that resulted in the maximum and minimum energy generations are given in Table 3.7 and Table 3.8 for EİE and ANC formulations, respectively. The operating level combinations providing the maximum energy generation is used to form the rule curve. The rule curves developed for Altıparmak HEPP according to the EİE and ANC formulations for design discharges of 18 m^3/s are given in Figure 3.9 and Figure 3.10, respectively.

Table 3.7 Energy Generations of EİE Formulation for Different Operating Level Combinations

Operating Levels (m)	Situation	Energy Generation Amount (GWh)
1217-1217-1227-1225	Maximum Energy Generation	212.12
1227-1227-1217-1217	Minimum Energy Generation	200.08
1227	Constant Level	202.49
1225	Constant Level	204.29
1223	Constant Level	206.03
1221	Constant Level	207.71
1219	Constant Level	209.03
1217	Constant Level	210.05

Table 3.8 Energy Generations of ANC Formulation for Different Operating Level Combinations

Operating Levels (m)	Situation	Energy Generation Amount (GWh)
1221-1217-1227-1227	Maximum Energy Generation	197.53
1217-1227-1217-1217	Minimum Energy Generation	194.36
1227	Constant Level	196.35
1225	Constant Level	196.28
1223	Constant Level	196.19
1221	Constant Level	196.08
1219	Constant Level	195.94
1217	Constant Level	195.74

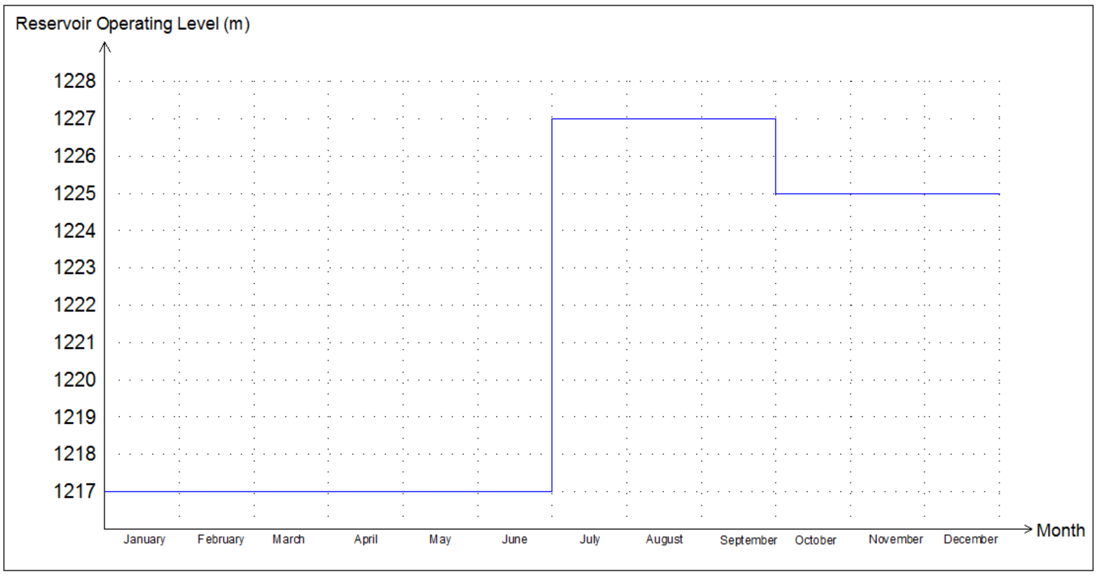

Figure 3.9 Rule Curve for Altıparmak HEPP - EİE Formulation

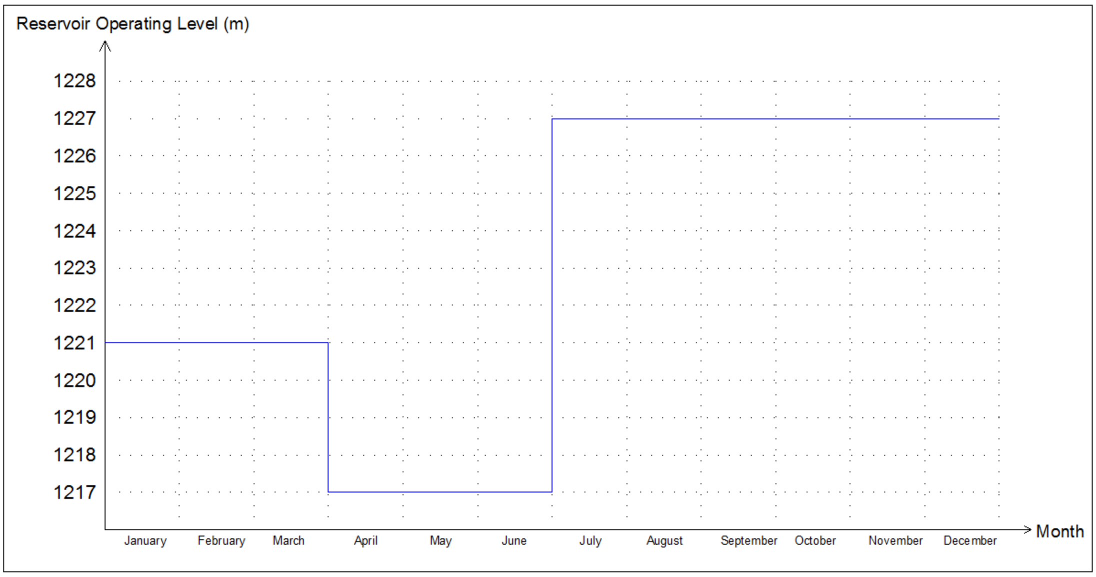

Figure 3.10 Rule Curve for Altıparmak HEPP - ANC Formulation

As seen from Table 3.7, the best and worst combination of reservoir operating levels results in approximately 6% change in the energy generation for EİE formulation. On the other hand, for ANC formulation this difference is only 1.6%. The dam axis for EİE and ANC formulations are different, therefore, amount of storages between specific elevations change (i.e. between 1217 m and 1227 m, EİE formulation has a storage volume of 13.50 hm^3, while ANC formulation has only 3.24 hm^3) are different for these two formulations. This may be reason why there is significant difference between amounts of energy generation for different operating level combinations for EİE formulation while different operating level combinations do not cause significant variations in energy generation for ANC formulation.

As can be seen from Figures 3.9 and 3.10, the operating levels for each season change considerably. Amount of inflow to the reservoir in different seasons govern the shape of the rule curve. In the ROS, keeping the reservoir level in its maximum value increases the available head and consequently the energy generation. However, during the wet periods, if the reservoir level is at its maximum value, the incoming inflow generally exceeds the design discharge and the excess water is spilled from the spillway or bottom outlet. The spilled water is wasted in terms of energy generation. This results in potential energy or benefit loss. Therefore, before the wet (or flood) periods, it may be preferable to reduce the reservoir level in order to store incoming flood water. The available head for energy generation decreases with this policy and it may seem like an energy loss for the system. However, utilization of the stored flood water during the dry months increases the energy generation and the benefits. On the other hand, keeping the reservoir level always at lower elevations will probably result in energy loss. Thus, a balance needs to be maintained. Keeping the reservoir level at higher elevations as much as possible and at the same time minimizing the spills is the most beneficial operation policy. The rule curve helps to achieve these goals.

3.4.5 Operating Rules

An Excel Spreadsheet program is developed to carry out the ROS for Altıparmak HEPP. The reservoir operation policy is based on the maximization of the firm and the secondary energy generations (which is average annual energy generation when firm energy is not desired) The Excel spreadsheet can also be used for only maximization of the average annual energy generation by assigning a zero to the firm energy discharge. Reservoir operation policy uses the following operating rules:

1. No matter what happens, the minimum allowed reservoir elevation cannot be violated.

2. The residual water to maintain the downstream river habitat has the first priority.

3. If the water level is at the operating level, then the releases are allocated in the following order: the residual water, water for the firm energy generation, and water for the secondary energy generation. The secondary energy is generated during the peak hours (i.e. high electricity prices) and if water remains, continues during the off-peak hours. During wet periods, the net incoming water is generally greater than the maximum water needed for energy generation (i.e. the sum of water required for the firm and the secondary energy). The excess water is stored until water level reaches to the maximum water level (spillway crest elevation). After the maximum water level is reached, if there is still inflow into to reservoir this water will be spilled from the spillway or the bottom outlet. The maximum water usage, MWU (hm^3), for both firm and secondary energy generation can be estimated by multiplying the design discharge with the total amount of seconds in a month and is given by Equation (3.21).

$$MWU = \frac{Q_d \times 3600 \times 24 \times n}{10^6} \tag{3.21}$$

where $Q_d (m^3/s)$ is the design discharge and n is the number of days in a month.

4. If the reservoir water level is close to the minimum allowed reservoir elevation, and also the sum of the net incoming water and the available storage (water storage above the minimum allowed reservoir level) is equal to or smaller than the water requirement for the downstream, then all the net incoming water and available storage are released as the residual water. In this situation there will be no energy generation (not even for firm energy).

5. If the water level is between the minimum allowed reservoir elevation and the operating level, and the sum of net incoming water and the available storage is greater than the residual water requirement, the requirement for residual water is met and the excess water is used for the firm energy generation. After fulfilling the firm energy generation (for twenty four hours of a day), if there is still additional incoming water, it is stored in the reservoir until water level reaches to the operating level. If the incoming water is enough to fill the reservoir up to the operating level, the excess water can be used for the secondary energy generation keeping the water level at the operating level (see Figure 3.11 and Figure 3.12).

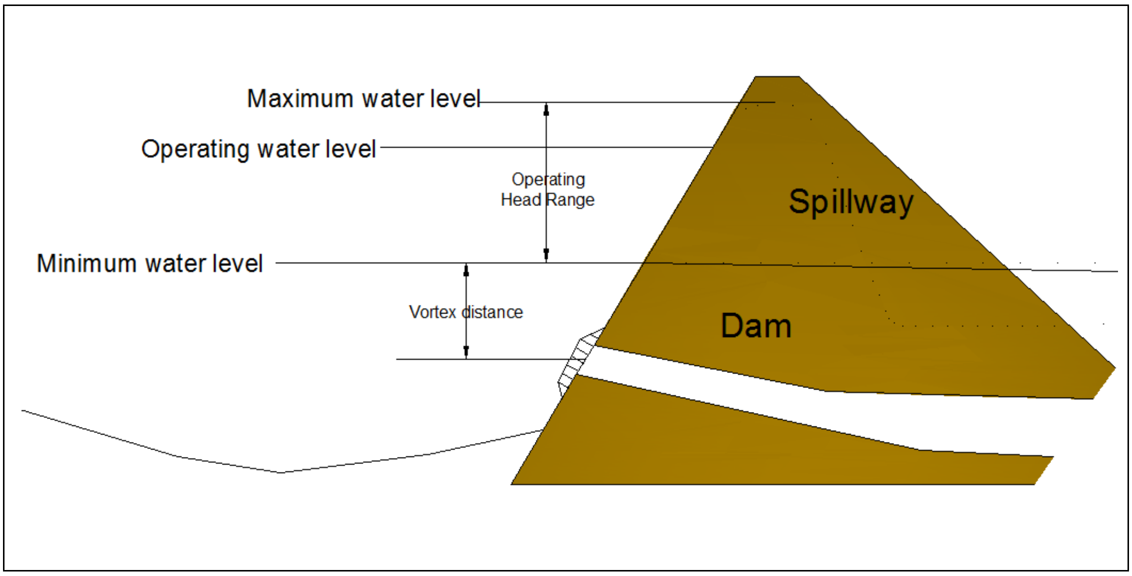

Figure 3.11 Water Level Constraints in Reservoir Storage

6. If the water level is above the operating level, the net incoming water and the available storage above the operating level are successively used for the residual water requirement, the firm energy generation, and the secondary energy generation. If the net incoming water is greater than the sum of the residual water requirement, the maximum water usage for firm and the secondary energy generation, the excess water is stored until it reaches to spillway crest elevation and the remaining water is spilled from the spillway or bottom outlet. Reservoir operation rules are presented in a flowchart in Figure 3.13. The abbreviations which are used in the reservoir policy logic chart are given below:

$NI(t)$	:	Net inflow water (hm^3) coming to the reservoir in a month
$Rw(t)$	:	The water volume (hm^3) for total residual water requirement in a month
$TFEG(t)$	:	The water volume (hm^3) for total firm energy generation in a month
$S(t)$	:	The reservoir storage volume (hm^3) at the beginning of the month
$Sopr$	:	The reservoir storage volume (hm^3) at the reservoir operating level
S_{min}	:	The reservoir storage volume (hm^3) at the reservoir minimum level
S_{max}	:	The reservoir storage volume (hm^3) at the spillway crest elevation
MWU	:	Maximum water usage for total energy generation (hm^3) (firm and secondary)

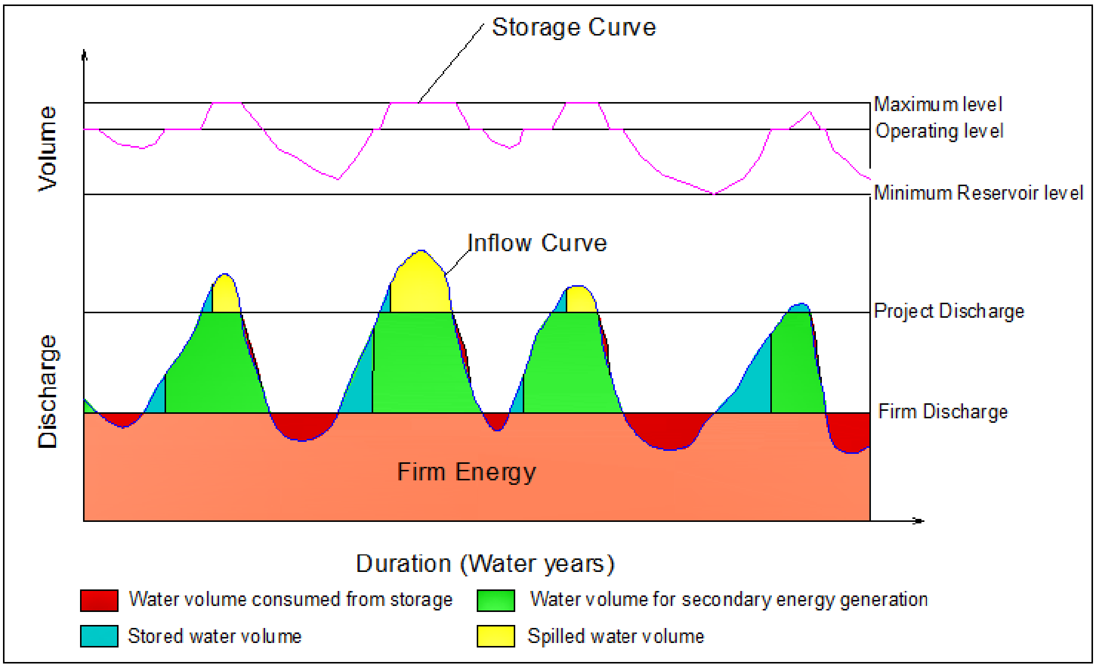

Figure 3.12 Demonstration of Reservoir Operation Policy (ASCE, 1989)

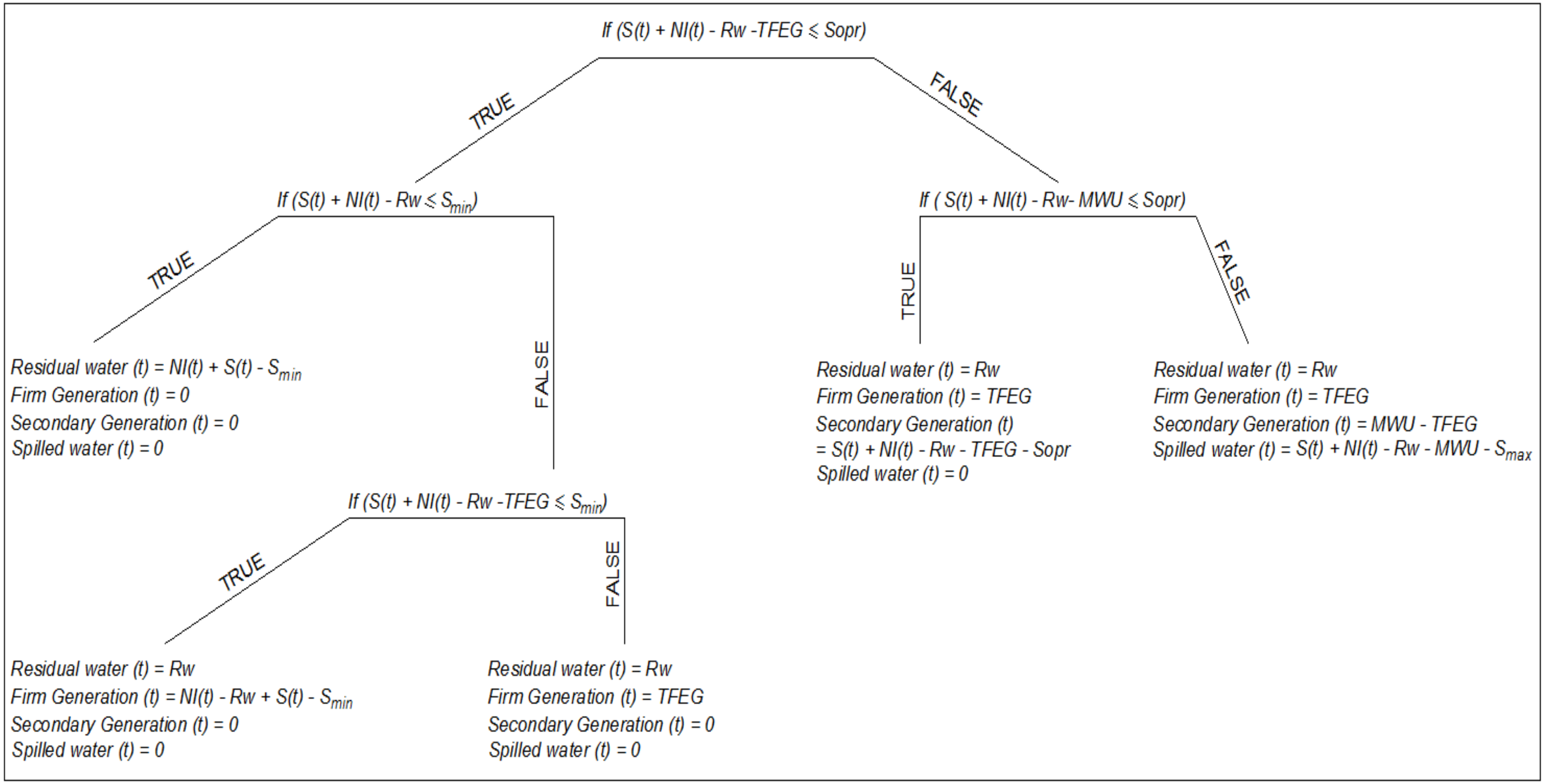

Figure 3.13 Reservoir Operation Rules

3.5 Energy Calculations

After determining amount of water allocated for the firm and the secondary energy generations in a month, associated energies generated by the HEPP are estimated using Equation (3.5).

The Turbine Efficiency

Efficiency, the usable head range, and the minimum discharge are various turbine characteristics. The energy output is affected from these values and it may change significantly with the selected turbine type. The allowable head and discharge ranges for the selected turbine type, must be checked for the each time interval of the ROS (USACE, 1985).

Three commonly used turbine types are Francis, Pelton, and Kaplan. The selection of the turbine is based on the economy and the constraints associated with the turbines. Charts such as the one given in Figure 3.14 are developed by various researchers to provide guidance on the selection of the turbine type. Using Figure 3.14, Francis type turbine is found suitable for this study.

The relation between discharge and efficiency of various turbines is given in Figure 3.15 and this graph is used to estimate the turbine efficiencies during ROS. In this figure, Q and Q_o are the discharge used for the related month and the design discharge, respectively.

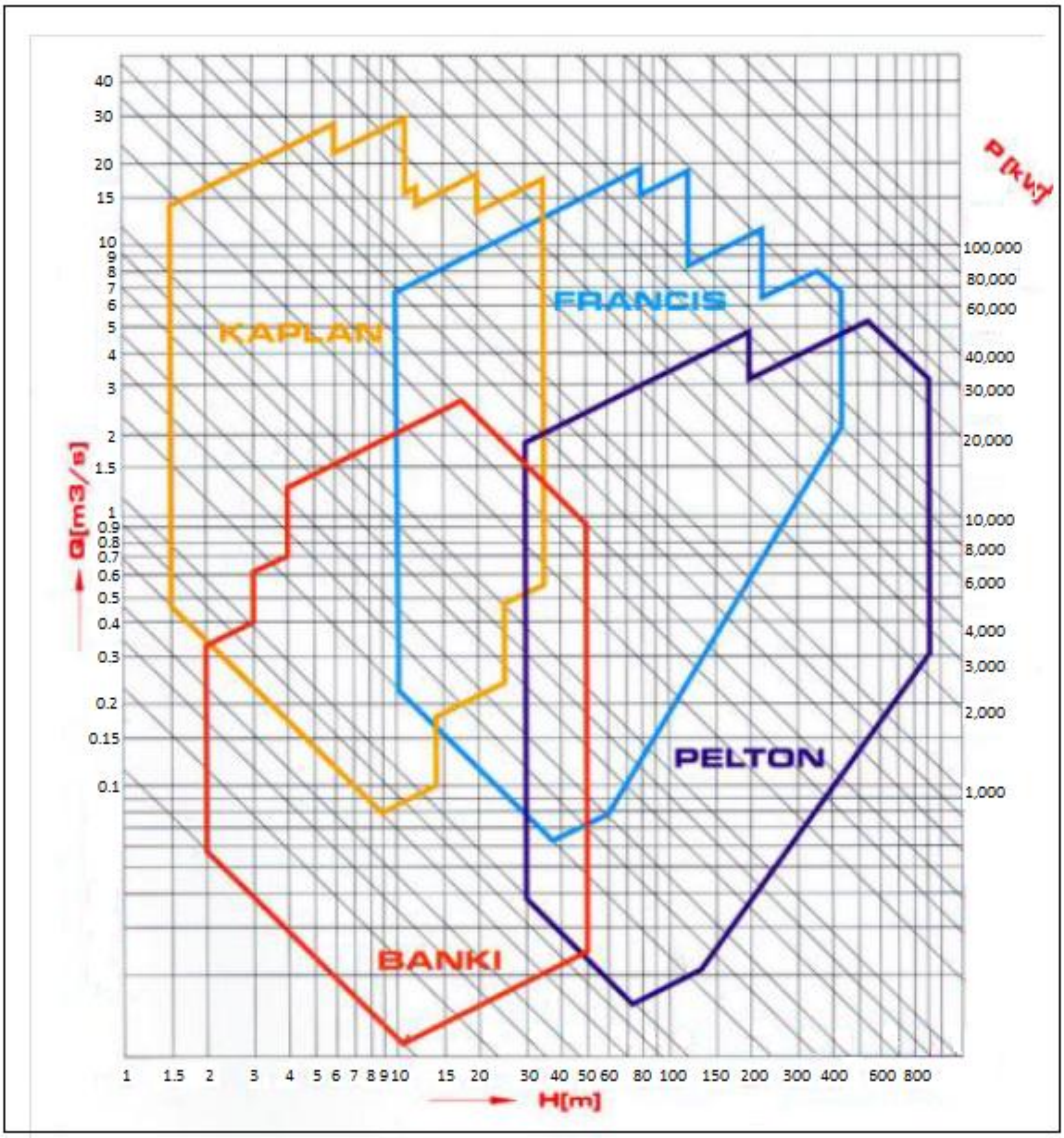

Figure 3.14 Chart Proposed by Mavel for Turbine-Type Selection (Mavel, 2009)

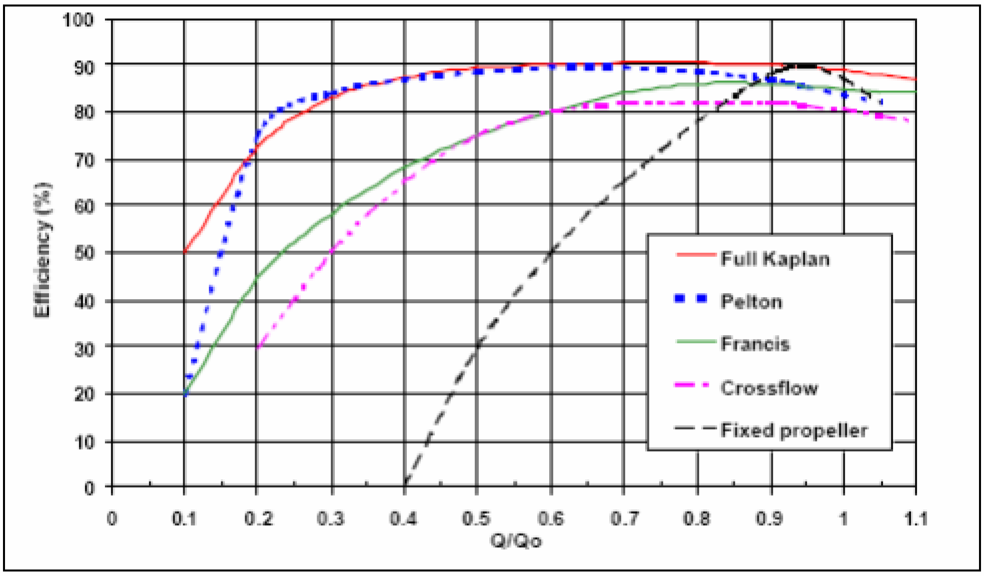

Figure 3.15 Efficiency of Various Turbines Based on Discharge Rate (University of Technology, 2011)

<u>The Discharge</u>

The discharge, $Q(t)$, is determined through a decision making procedure for each month. First, a set of alternative discharges between the minimum turbine discharge and the design discharge are selected. Then the available water is routed through the reservoir using each one of these alternative discharges and corresponding energy outputs are calculated. Finally the discharge which provides maximum energy output is selected as the discharge for that specific month. The energy output corresponding to this selected discharge is used to calculate energy income for that month.

<u>The Net Head</u>

The elevation, $El(t)$ (m), which is the reservoir elevation at the beginning of the month, is calculated using the change in storage of the reservoir for that month. The change in volume is calculated using the continuity equation (see Equation (3.6)). Then the reservoir storage at the end of the month is estimated using the change in volume. The corresponding reservoir elevation, $El(t+1)$, at the end of the month is then estimated by using the volume-elevation curves (see Figure 3.4 and Figure 3.5). Time interval is chosen as one month in this study; thus the average reservoir elevation El_{ave} (m) is calculated by taking the average of the elevations at the beginning and end of the month.

$$El_{ave}(t) = \frac{El(t)+El(t+1)}{2} \tag{3.22}$$

where the average gross head, $h_{ave}(t)$ (m) is the difference between the $El_{ave}(t)$ (m) the average reservoir elevation and $El_{tw}(t)$ (m) , the tail water elevation.

$$h_{ave}(t) = El_{ave}(t) - El_{tw}\ (t) \tag{3.23}$$

Then the net head is calculated by deducting the head losses from the gross head. The frictional and minor losses need to be computed.

3.6 Determination of the Energy Incomes

In this study, four different methods are used to evaluate energy income of the Altıparmak HEPP: (i) EİE method, (ii) DSİ Method, (iii) ANC Method; and (iv) alternative method which considers hourly electricity prices. The alternative price method will be referred to as Variable Price Method (VPM).

EİE and DSİ Methods are similar in the sense that they both classify the energy generation in two groups, the firm and the secondary energy generations. EİE and DSİ assume value of the firm and the secondary energy is different, firm energy being more expensive. The prices for the firm and the secondary energy used by EİE and DSİ are given in Table 3.9. In addition to the firm and secondary energy, EİE and DSİ evaluate another item, called the "peak power benefit" in the economic analysis (Bakır, 2010). Estimation of peak power benefit by DSİ and EİE is provided below:

Peak Power Benefit – DSİ: The unit benefit due to peak power is calculated as follows. First the cost per average power is calculated using the summation of the annual investment cost of a combined natural gas thermal power plant which is assumed to be the type of power plant which supplies peak power and the reduced fuel cost which is the difference between cost of coal and cost of natural gas. Unit benefit due to peak power is assumed to be about the half of this value (M.D. Pekçağlıyan, 2005) Contribution made to the peak power can be expressed by the following formula:

$$\text{Peak Power (kW)} = \text{Installed Capacity(kW)} - \frac{\text{Annual Firm Energy (kWh)}}{8760\times0.72\ \text{(hours)}} \tag{3.24}$$

Peak Power Benefit – EİE: The peak power is actually an approximation of the dependable firm power. This peak power is assumed to cost annual investment cost required to generate one kW power from a thermal power plant combination. Peak power is calculated by the following formula (M.D. Pekçağlıyan, 2005)

$$\text{Peak Power (kW)} = \frac{\text{Annual Firm Energy (kWh)}}{0.33 \times 8760 \text{ (hours)}} \tag{3.25}$$

In Table 3.9, benefits related to firm energy, secondary energy and peak power are given for both DSİ and EİE definitions.

Table 3.9 Benefits for DSİ and EİE Methods

Type of Energy Benefit	Prices	
	DSİ	EİE
Firm Energy	6.0 cent/ kWh	4.5 cent/kWh
Secondary Energy	3.3 cent/ kWh	3.5 cent/kWh
Peak Power	85.0 $/kW	240.0 $/kW

The third method is the one used by ANC. It is the simplest among four and assumes a fixed price (i.e. 8.25 cent/kWh) for the generated energy (DOKAY, 2011).

The Variable Price Method is formulated as an alternative energy income calculation method. VPM utilizes hourly energy prices in estimating the energy income. Energy prices of the last 12 months are given in Table B-3 in Appendix B. As explained in Appendix A, the energy prices change hourly in Turkey. Hourly electricity prices are generated in the electricity market and these prices are governed by electricity demands and supplies. Hours in which the electricity prices are relatively higher are called peak hours, while the rest of the hours are called off-peak hours. The corresponding prices are called peak prices and off-peak prices, respectively (Olivares, 2008).

Energy incomes of HEPPs are commonly estimated from average energy prices (Olivares, 2008). However the actual incomes are usually underestimated with this assumption, due to energy sales during peak hours. In order to improve this simplification, various studies are conducted by using two different average prices, the peak and off-peak prices (Grygier and Stedinger, 1985; Trezos and Yeh, 1987). Another approach implemented by Jacobs (1995) utilized varying prices during four sub-periods (i.e. six hours) in a day.

In this study, hourly electricity prices are used in estimating energy incomes. Hourly electricity prices for each month are adapted from energy prices of the last 12 months. In calculating the energy income of a month, it is assumed that the energy generation is realized during the peak hours first then carried on in the off-peak hours. For example, if the HEPP is able to generate energy for only three hours in a day, it will generate this three hours during which the electricity price is the highest. Using hourly variable prices energy income of each month of the year within the analysis period is calculated and they are summed up to find the annual energy income of that year. We believe that VPM results in more realistic energy income estimates.

3.7 Determination of the Costs

Investments costs associated with each alternative installed capacity are determined in a similar manner to that of energy incomes. Since annual energy incomes associated with each alternative installed capacity are calculated the investment costs are converted to equivalent annual costs. The total investment cost of the project includes costs associated with the dam body, the tunnel, the penstock, the surge tank, the diversion tunnel, the power house, the turbine, the transformer, the generator, and expropriation. Some of these cost items vary significantly with the selected installed capacity due to the variation in dimension of the related structures. Costs of the penstock, the tunnel, the powerhouse, the turbine, the transformer, and the generator change considerably with the installed capacity and this factor is taken into consideration in the economic analysis. Other cost items are not affected from the installed capacity; therefore, in the decision making procedure (i.e. selection of the best installed capacity) these costs are not taken into account. However, these costs are still estimated for the comparison of the two alternative formulations. The net benefits are estimated by subtracting the equivalent annual costs from the annual energy incomes. The installed capacity that results in the maximum net benefit is selected as the best installed capacity.

Investment costs associated with various parts of the HEPP are converted to equivalent annual investment costs using the capital recovery factor. The calculation of the equivalent annual costs is explained in the following section.

3.7.1 Equivalent Annual Costs

To obtain the equivalent annual cost of a project part, the investment cost of the associated part is converted into equal payments throughout the economic life of the project by using a capital recovery factor (CRF).

In this study, the economic life and the annual interest rate are assumed to be 50 years and 9.5%, respectively and the CRF is calculated as 0.096. This is a common practice in Turkey.

3.7.2 The Penstock Cost

The penstock is one of the main cost items of HEPP projects. An economic analysis is performed in order to find out the best penstock diameter. In this study, a set of penstock diameters are selected and they are evaluated for each alternative design discharge. The penstock diameter resulting in the highest net benefit is selected as the best diameter. As the diameter of the penstock increases, the investment cost also increases while the cost stemmed from energy losses decreases. Therefore, to identify the economically best penstock diameter, investment cost associated with each alternative penstock (i.e. each alternative penstock has a different diameter) is calculated and converted to the equivalent annual cost. The corresponding energy income calculated through the ROS is used together with the equivalent annual cost to calculate the net benefit.

The Investment Cost of the Penstock

Steel cost is the main item of the total penstock investment cost (Plansu, 2010). The amount of steel to be used for the construction of penstock is related to the length of the penstock and the cross-section area of steel which is a function of the penstock diameter and wall thickness (see Equation (3.29)).

Penstock wall thickness is determined such that it can resist the maximum pressure developed throughout the penstock. Water hammer phenomena results in the maximum amount of dynamic pressure (Çalamak, 2010). The related static pressure developed for fully closed valve is added to the specified dynamic pressure to obtain the corresponding maximum pressure. This maximum pressure is used for the wall thickness calculations in this study (see Equation (3.27)).

Static Pressure Calculations

Static water pressure at any point is the elevation difference between the maximum reservoir elevation and the considered point in the penstock (see Equation (3.26)).

$$h_{sta} = El_{max} - El_p \tag{3.26}$$

where h_{sta} (m) is the static pressure, El_{max} (m) is the maximum reservoir elevation, and El_p (m) is the elevation of any point in the penstock.

Dynamic Pressure Calculations

Due to rapid closing of the turbine valve, very high pressures arise at the bottom of the penstock and propagate to the upper parts (Çalamak, 2010). Penstock wall thickness is specified in such a way that, penstock will stay intact under dynamic and static pressures simultaneously. To obtain a safer wall thickness value (also for corrosion), 2.0 mm of clear cover is added to the calculated wall thickness. Dynamic pressure head of water hammer effect Δh_{max} , is calculated by the formula given below (Plansu, 2010).

$$\Delta h_{max} = \frac{2 \; V \, L}{g \; T_c} \tag{3.27}$$

where $V(m/s)$ is the average water velocity in the penstock at design discharge, L (m) is the total length of the penstock and T_c (s) is the shortest duration in which the valve can be closed. The total pressure developed in the penstock just before the valve is calculated by considering the effect of water hammer and the wall thickness. The following statement includes these effects:

$$(h_{sta} + \Delta h_{max}) \, p \; D_p \, (m) \leq 2 \, F \tag{3.28}$$

where h_{sta} (m) and Δh_{max} (m) are the maximum static and dynamic pressures developed, respectively. F (kgf/m) is the force developed in the wall of the penstock (having a circular cross-section and unit length) , p (kgf/m^3) is the specific density of water and D_p (m) is the penstock diameter (see Figure 3.16) (ESHA, 2004).

By using the Equation (3.29), the critical penstock wall thickness $wt\ (mm)$ is calculated

$$F = \frac{wt\ \sigma_s}{1000} \tag{3.29}$$

In this equation, $\sigma_s\ (kgf/m^2)$ is the strength of steel and $F\ (kgf/m)$ is the force developed in the wall of the penstock (see Figure 3.16).

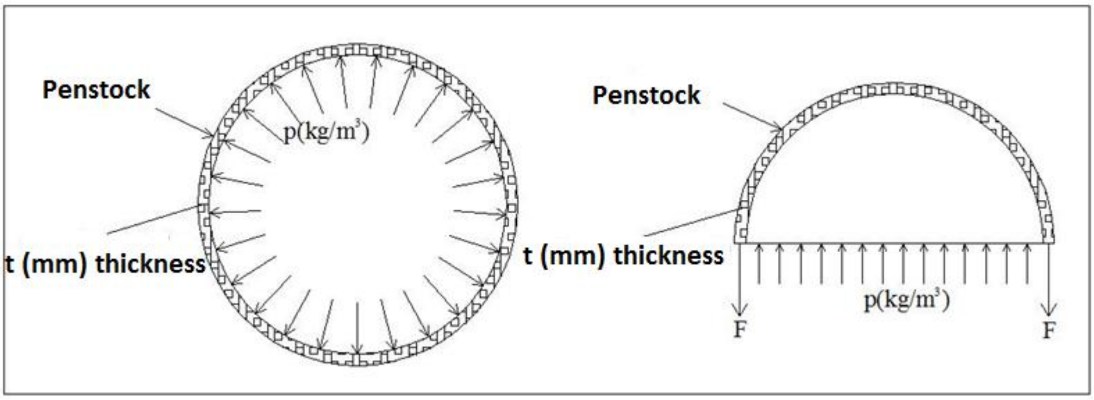

Figure 3.16 Penstock Cross-Section and the Forces and Pressures on it (Çalamak, 2010)

The specified wall thickness is rounded up to the next commercially available thickness. Penstock cost is estimated based on the commercially available thickness. Static and dynamic pressures vary throughout the penstock. Parts of penstock having higher elevations face lower static and dynamic pressures. Therefore, it is wise to design the structure considering variable wall thickness values for different parts. This approach makes the design more economic. The design is made by dividing the structure into a number of sections and wall thicknesses of each section are calculated considering the maximum pressure developed at the end of each section (Plansu, 2010). A sample calculation (i.e. optimum penstock diameter corresponding to the best installed capacity of ANC formulation) for selection of the penstock diameter is given in Table 3.10.

Table 3.10 The Penstock Calculations for the Optimum Diameter of the Best Installed Capacity of ANC Formulation

A-Part Number	B-Static Pressure in the Beginning of the Penstock (m)	C-Vertical Projection of the Penstock (m)	D- Interval distance for Penstock (m)	E-Length of the Penstock (m)	F-Water Hammer Hydraulic Pressure Head (m) (Equation(3.27))	G-Total Hydraulic Pressure Head (m) (B + C + F)	H-The Calculated Thickness (mm) (Equations (3.28) and (3.29))	I-Commercially Available Thickness for Penstock (mm)	J- Weight of the Penstock (ton) (Equation (3.32))	K-Total Weight of the Penstock (ton)
1	80.00	19.24	43.01	43.01	7.74	106.97	8.38	12.00	29.43	38.26
2	80.00	31.24	26.83	69.85	12.57	123.80	9.70	12.00	18.36	23.87
3	80.00	43.24	26.83	96.68	17.39	140.63	11.02	14.00	21.44	27.87
4	80.00	55.24	26.83	123.51	22.22	157.46	12.34	16.00	24.52	31.88
5	80.00	67.24	26.83	150.34	27.05	174.29	13.65	16.00	24.52	31.88
6	80.00	79.24	26.83	177.18	31.88	191.11	14.97	18.00	27.61	35.89
7	80.00	91.24	26.83	204.01	36.71	207.94	16.29	20.00	30.70	39.92
8	80.00	103.24	26.83	230.84	41.53	224.77	17.61	20.00	30.70	39.92
9	80.00	115.24	26.83	257.67	46.36	241.60	18.93	22.00	33.80	43.95
10	80.00	127.24	26.83	284.51	51.19	258.43	20.25	24.00	36.91	47.98
11	80.00	139.24	26.83	311.34	56.02	275.25	21.56	24.00	36.91	47.98
12	80.00	151.24	26.83	338.17	60.85	292.08	22.88	26.00	40.02	52.03
13	80.00	163.24	26.83	365.01	65.67	308.91	24.20	28.00	43.13	56.08
14	80.00	175.24	26.83	391.84	70.50	325.74	25.52	28.00	43.13	56.08
15	80.00	187.24	26.83	418.67	75.33	342.56	26.84	30.00	46.26	60.13
16	80.00	199.24	26.83	445.50	80.16	359.39	28.16	32.00	49.38	64.20
17	80.00	211.24	26.83	472.34	84.98	376.22	29.47	32.00	49.38	64.20
18	80.00	223.24	26.83	499.17	89.81	393.05	30.79	34.00	52.51	68.27
19	80.00	235.24	26.83	526.00	94.64	409.88	32.11	36.00	55.65	72.34
20	80.00	247.24	26.83	552.84	99.47	426.70	33.43	36.00	55.65	72.34
21	80.00	259.24	26.83	579.67	104.30	443.53	34.75	38.00	58.79	76.43
22	80.00	271.24	26.83	606.50	109.12	460.36	36.07	40.00	61.94	80.52
23	80.00	283.24	26.83	633.33	113.95	477.19	37.38	40.00	61.94	80.52
24	80.00	295.24	26.83	660.17	118.78	494.02	38.70	42.00	65.09	84.62
25	80.00	307.24	26.83	687.00	123.61	510.84	40.02	44.00	68.25	88.72

After determining the penstock thickness, steel cross-section area is calculated by subtracting the inner cross-section area from the outer cross-section area (See Figure 3.16).

$$Area\ of\ steel\ (m^2) = A' = Ao - Ai = \pi \frac{(D_p+2wt)^2}{4} - \pi\ \frac{(D_p)^2}{4} \tag{3.30}$$

where $Ao\ (m^2)$ and $Ai\ (m^2)$ are the outer and inner cross-section areas, respectively, $D_p\ (m)$ is the inner diameter and $wt\ (m)$ is the wall thickness of the cross-section. This value is multiplied by the length of the related part to calculate the volume. This volume is multiplied by the specific weight of steel to estimate the weight of that part.

$$Volume\ of\ part\ (m^3)\ = \forall = A'\ L \tag{3.31}$$

$$Weight\ of\ part\ (kgf) = W\ = 7.85\ \forall \tag{3.32}$$

After calculating the weights of each part of the penstock, the overall weight of the structure is estimated by summing weights of all parts. The additional weights stemmed from the braces placed to satisfy the stability of the structure are also taken into account. To do that, the calculated weight of the structure is increased by 30% as suggested by Plansu (2010).

<u>Selection of the Penstock Diameter</u>

Economic analysis conducted using VPM for corresponding to the best installed capacities identified for EİE and ANC formulations are given in Table 3.11 and Table 3.12, respectively. As can be seen from Table 3.11 and Table 3.12, a 2-m diameter gives the highest net benefit for both EİE and ANC formulations. Flow velocities in the penstock (see Tables 3.11 and 3.12) are below the maximum allowable velocity, 7.5 m/s (US Department of the Interior, 1987).

Table 3.11 Penstock Diameter Estimation Study for EİE Formulation (Optimum Design Discharge)

Alternative Design discharge(m^3/s)	Penstock Diameter (m)	Total Energy Generation (GWh)	Annual Energy Income (TL)	Annual Investment Cost (TL)	Net Benefit (TL)	Flow Velocity in Penstock (m/s)
20.00	1.6	205.62	23,282,656	914,392	22,368,264	9.95
	1.7	207.71	23,678,691	1,022,414	22,656,277	8.81
	1.8	209.22	23,873,429	1,097,945	22,775,484	7.86
	1.9	210.33	24,021,608	1,196,281	22,825,327	7.05
	2	***211.16***	***24,120,866***	***1,294,186***	***22,826,681***	***6.37***
	2.1	211.79	24,183,946	1,390,961	22,792,985	5.77
	2.2	212.27	24,245,372	1,505,476	22,739,896	5.26
	2.3	212.64	24,306,115	1,622,355	22,683,760	4.81

Table 3.12 Penstock Diameter Estimation Study for ANC Formulation (Optimum Design Discharge)

Alternative Design discharge(m^3/s)	Penstock Diameter (m)	Total Energy Generation (GWh)	Annual Energy Income (TL)	Annual Investment Cost (TL)	Net Benefit (TL)	Flow Velocity in Penstock (m/s)
22.00	1.6	202.66	23,800,540	1,900,185	21,900,356	10.94
	1.7	205.69	24,233,830	2,065,348	22,168,482	9.69
	1.8	207.87	24,483,160	2,236,020	22,247,139	8.65
	1.9	209.46	24,799,409	2,412,394	22,387,015	7.76
	2	***210.69***	***25,055,003***	***2,625,170***	***22,429,833***	***7.00***
	2.1	211.63	25,186,063	2,813,901	22,372,162	6.35
	2.2	212.34	25,336,679	3,031,922	22,304,757	5.79
	2.3	212.90	25,399,774	3,265,895	22,133,880	5.30

3.7.3 The Tunnel Cost

The tunnel diameter governs the tunnel cost. Although determination of the tunnel diameter can be achieved through a decision making procedure similar to the one used for selection of the best penstock diameter, it is not always necessary. The tunnel excavator machine is capable of boring holes with minimum three-meter diameter. Thus, less than three meters as the tunnel diameter is not feasible (EİE, 2001). Thus a decision making analysis is not necessary if the best tunnel diameter is less than three meters; since it will be rounded up to three meters.

If a velocity in the range of 3 m/s to 5 m/s is maintained in the tunnel, then the diameter of the tunnel is acceptable (Netsu, 2011; Coleman, 2004). The velocity of the flow for the maximum value of the alternative design discharge range (i.e. 30.00 m^3/s) is estimated as 4.24 m/s for the minimum possible tunnel diameter.

The flow velocity, even for the maximum alternative design discharge is very close to 4.0 m/s. Lower flow velocities will be generated for lower discharges. Thus, selecting the minimum possible value, which is three meters, is reasonable for this study. The cross-section being used for the tunnel is given Figure 3.17. This section is also recommended by EİE (EİE, 2001).

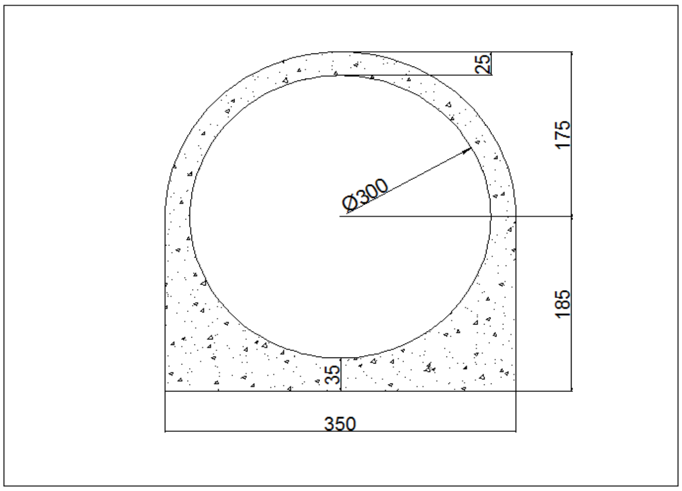

Figure 3.17 Tunnel Cross-section Recommended by EİE (All dimensions are in cm)

<u>**The Investment Cost of the Tunnel**</u>

Costs associated with the tunnels for EİE and ANC formulations are the most important cost item. Excavation, concrete works and the formwork are the three main components of the tunnel cost. Therefore, for the sake of simplicity costs associated with these three items are calculated in this feasibility study and they are increased by 20% to compensate for the rest of the tunnel components (Netsu, 2011).

The area of excavation can be calculated using the following equation in accordance with the cross-section provided in Figure 3.17:

$$3.50 \times 1.85 + \frac{\pi\, 3.25^2}{8} = 10.62\, m^2 \tag{3.33}$$

This value is increased by 10% for the unexpected excavation requirements that may occur during the construction works. Thus area of excavation is taken as 11.68 m^2.

The surface area of the concrete is calculated by deducting the area of the tunnel from the total area.

$$10.62\, m^2 - \frac{\pi\, 3.0^2}{4} = 3.55\, m^2 \tag{3.34}$$

Volume of the excavation and concrete required for the tunnel are simply calculated by multiplying the relative areas with the length of the tunnel. Since tunnel lengths for the two formulations are different, both volume of excavation and amount of concrete required for the tunnel vary for EİE and ANC formulations. Cement to reinforcement ratio of 300 kg to 190 kg for a cubic meter of concrete is recommended by EİE (2001) and this ratio is used for the tunnels (EİE, 2001).

For the formwork calculations of the tunnel, only the circular inner region is taken into account (EİE, 2001). For the inner part of the tunnel, area of curved formwork of 1 m length is calculated as:

$$\pi D_t = \pi \times 3.0 = 9.42\, m^2/m \tag{3.35}$$

where $D_t(m)$ is the tunnel inner diameter. The total required formwork area is estimated simply by multiplying this value with the length of the tunnel.

The estimated investment costs belonging to EİE and ANC formulations are given in Tables 3.13 and 3.14, respectively.

Table 3.13 Tunnel Cost for EİE Formulation

Item Number	Definition of work	Unit	Unit Price	Amount	Price (TL)
32.001	Tunnel Excavation	m^3	99.49	87,174	8,673,127
B-16.538	Concrete	m^3	116.16	24,087	2,797,917
B-16.501/A	Cement	tons	140.31	7,226	1,013,884
B-23.002/1	Reinforced	tons	1934.91	4,576	8,855,082
B-21.D/1	Formwork	m^2	43.04	63,915	2,750,889
32.006	Transportation of excavation	tons	7.72	87,174	672,981
B-07.D/1	Transportation of cement	tons	20.94	7,226	151,313
B-07.D/2	Transportation of reinforced	tons	127.66	4,576	584,234
-	Other Costs (15%)	-	-	-	5,099,885
			Total Price (TL)		**30,599,311**

Table 3.14 Tunnel Cost for ANC Formulation

Item Number	Definition of work	Unit	Unit Price	Amount	Price (TL)
32.001	Excavation	m^3	99.49	112,612.72	11,204,121
B-16.538	Concrete	m^3	116.16	31,115.75	3,614,406
B-16.501/A	Cement	tons	140.31	9,334.73	1,309,755
B-23.002/1	Reinforced	tons	1934.91	5,911.99	11,439,173
B-21.D/1	Formwork	m^2	43.04	82566.3	3,553,654
32.006	Transportation of excavation	tons	7.72	112,612.72	869,370
B-07.D/1	Transportation of cement	tons	20.94	9,334.73	195,469
B-07.D/2	Transportation of reinforced	tons	127.66	5,911.99	754,725
-	Other Costs (15%)	-	-	-	6,588,135
			Total Price (TL)		**39,528,808**

3.7.4 Other Cost Items

The Power House, the Turbine, the Transformer and the Generator

In this study, a unit cost of $450/kW is used (Hidromark, 2010) for the costs of the power house, the turbine, the transformer and the generator which is a common practice in Turkey.

The Dam Body

Cost of the dam body is estimated by summing of the related costs of various items associated with the construction of the dam body (see Table 3.15). Unit price of each item is multiplied by the corresponding amount to calculate the price of that component. Amounts are directly taken from EİE (EİE, 2001) and ANC feasibility reports (Yolsu, 2009) and unit prices are updated to 2011 prices (DSİ, 2011). Costs associated with the construction of the dam bodies for EİE and ANC are given in Tables 3.15 and 3.16, respectively.

Table 3.15 Dam Body Cost for EİE Formulation

Item Number	Item	Unit	Unit Price	Amount	Price (TL)
B-15.301	Soft Excavation	m^3	1.79	20,480	36,659
B-15.310	Hard Excavation (Rock)	m^3	10.54	92,940	979,588
B-16.503	Concrete	m^3	101.00	626,409	63,267,309
B-16.501/B	Cement	tons	160.00	187,923	30,067,632
B-21.024/2	Curved Formwork	m^2	76.61	72,450	5,550,395
B-21.015/3	Smooth Formwork	m^2	50.81	33,000	1,676,730
B-23.002/1	Reinforcement	tons	1934.91	2,500	4,837,275
32.006	Transportation of excavation	tons	7.72	113,420	875,602
B-07.D/1	Transportation of cement	tons	20.94	187,923	3,935,101
B-07.D/2	Transportation of reinforced	tons	127.66	2,500	319,150
-	Other Costs (10%)	-			11,154,544
			Total Price (TL)		**122,699,985**

Table 3.16 Dam Body Cost for ANC Formulation

Item Number	Item	Unit	Unit Price	Amount	Price (TL)
B-15.301	Soft Excavation	m^3	1.79	31,493	56,372
B-15.310	Hard Excavation (Rock)	m^3	10.54	73,483	774,511
B-16.590	Roller Compacted Concrete	m^3	101.10	282,472	28,557,919
B-16.503	Concrete	m^3	101.00	12,500	1,262,500
B-16.501/B	Cement	tons	160.00	24,935	3,989,600
B-21.024/2	Curved Formwork	m^2	76.61	410	31,410
B-21.015/3	Smooth Formwork	m^2	50.81	2,100	106,701
B-23.002/1	Reinforcement	tons	1934.91	250	483,728
32.006	Transportation of excavation	tons	7.72	104,976	810,415
B-07.D/1	Transportation of cement	tons	20.94	24,935	522,139
B-07.D/2	Transportation of reinforced	tons	127.66	250	31,915
			Total Price (TL)		**43,952,652**

The Expropriation Cost

Expropriation is necessary for the reservoir area and the construction site. Expropriation cost of EİE formulation is conducted by using the study which is carried out by EİE in 2001 (EİE, 2001). The cost estimated by EİE in 2001 is carried to the present time by consulting the interest rates published by Central Bank of the Republic of Turkey (CBRT) (2011) as provided in Table 3.17. ANC calculated the expropriation costs using a unit price of 4 TL/m^2 in its feasibility study (Yolsu, 2009). The unit price for expropriation is revised to 5 TL/m^2 using interest rates for 2010 and 2011 and cost of expropriation for ANC is estimated with this unit price. Results of previous studies and estimated current expropriation costs are summarized in Table 3.18.

Table 3.17 Interest Rates (2001-2011) (CBRT, 2011)

Year	2001	2002	2003	2004	2005	2006
Interest Rate (%)	61.31	49.18	32.64	22.31	16.57	16.99
Multiplier	1.61	1.49	1.33	1.22	1.17	1.17
Year	**2007**	**2008**	**2009**	**2010**	**2011**	**Total**
Interest Rate (%)	17.15	19.12	10.31	8.97	9.65	979.27
Multiplier	1.17	1.19	1.10	1.09	1.10	9.79

Table 3.18 Expropriation Cost Estimation (EİE, 2001; Yolsu, 2009)

	ANC Formulation	EİE Formulation
Reservoir Area (m^2)	372,299	1,480,693
Other Areas (m^2)	128,000	128,000
Total Area (m^2)	500,299	1,608,693
2009 Unit Price (TL/m^2)	4.0	-
2011 Unit Price (TL/m^2)	5.0	-
2001 Cost (TL)	-	2,822,674,000,000
2011 Cost (TL)	2,501,495	27,633,978

The Surge Tank

Cost estimations of the items associated with the construction of the surge tank are provided in the feasibility reports prepared by EİE (EİE, 2001) and ANC (Yolsu, 2009). The required amounts are directly used from the feasibility reports while the unit prices are updated with the current ones (DSİ, 2011). Surge tank prices are given in Tables 3.19 and 3.20 for EİE and ANC formulations, respectively.

Table 3.19 Surge Tank Cost for EİE Formulation

Item Number	Item	Unit	Unit Price	Amount	Price (TL)
32.001	Tunnel Excavation	m^3	99.49	14,000	1,392,895
B-16.538	Concrete	m^3	116.16	5,800	673,728
B-16.501	Cement	tons	140.31	1,740	244,139
B-23.002/1	Reinforcement	tons	1934.91	330	638,520
B-21.D/1	Curved Formwork (Tunnel)	m^2	43.04	8,000	344,320
32.006	Transportation of excavation	tons	7.72	14,000	108,080
B-07.D/1	Transportation of cement	tons	20.94	1,740	36,436
B-07.D/2	Transportation of reinforced	tons	127.66	330	42,128
-	Other Costs (20%)	-			696,049
			Total Price (TL)		**4,176,295**

Table 3.20 Surge Tank Cost for ANC Formulation

Item Number	Item	Unit	Unit Price	Amount	Price (TL)
32.001	Tunnel Excavation	m^3	99.49	33,285	3,311,633
B-16.538	Concrete	m^3	116.16	11,537	1,340,104
B-16.501/A	Cement	tons	140.31	1,011	141,794
B-23.002/1	Reinforcement	tons	1934.91	143	276,383
B-21.D/1	Curved Formwork (Tunnel)	m^2	43.04	4,555	196,061
32.006	Transportation of excavation	tons	7.72	33,285	256,962
B-07.D/1	Transportation of cement	tons	20.94	1,011	21,162
B-07.D/2	Transportation of reinforced	tons	127.66	143	18,235
-	Other Costs (20%)	-			1,112,467
			Total Price (TL)		**6,674,800**

The Diversion Tunnel

Cost estimations of the items associated with the construction of the diversion tunnel are provided in the feasibility reports prepared by EİE (EİE, 2001) and ANC (Yolsu, 2009). The required amounts are directly taken from the feasibility reports but current unit prices (DSİ, 2011) are used instead of those provided in the feasibility reports. Costs related with the construction of the diversion tunnel are given in Tables 3.21 and 3.22 for EİE and ANC formulations, respectively.

Table 3.21 Diversion Tunnel Cost for EİE Formulation

Item Number	Item	Unit	Unit Price	Amount	Price (TL)
32.001	Tunnel Excavation	m^3	99.49	5,573.00	554,472
B-16.538	Concrete	m^3	116.16	2306.00	267,865
B-16.501/A	Cement	tons	140.31	691.80	97,066
B-23.002/1	Reinforced	tons	140.31	116.00	16,276
B-21.D/1	Curved Formwork (Tunnel)	m^2	43.04	3,267.00	140,612
31-7838/D	Injection Hole Drilling	m^3	267.61	51.00	13,648
32.006	Transportation of excavation	tons	7.72	5,573.00	43,024
B-07.D/1	Transportation of cement	tons	20.94	691.80	14,486
B-07.D/2	Transportation of reinforced	tons	127.66	116.00	14,809
-	Other Costs (15%)	-			174,339
			Total Price (TL)		**1,336,596**

Table 3.22 Diversion Tunnel Cost for ANC Formulation

Item Number	Item	Unit	Unit Price	Amount	Price (TL)
32.001	Tunnel Excavation	m^3	99.49	3,705.00	368,620
B-16.538	Concrete	m^3	116.16	1095.00	127,195
B-16.501/A	Cement	tons	140.31	510.00	71,558
B-23.002/1	Reinforced	tons	140.31	38.00	5,332
B-21.D/1	Curved Formwork (Tunnel)	m^2	43.04	2,323.00	99,982
31-7838	Injection Hole Drilling	m^3	267.61	76.00	20,338
32.006	Transportation of excavation	tons	7.72	3,705.00	28,603
B-07.D/1	Transportation of cement	tons	20.94	510.00	10,679
B-07.D/2	Transportation of reinforced	tons	127.66	38.00	4,851
-	Other Costs (15%)	-			110,574
			Total Price (TL)		**847,732**

The Road Relocation Cost

EİE formulation requires a lot of road relocation and new road construction work. Relocation and new road cost for EİE formulation is assumed to be 14% of total cost in the feasibility report (EİE, 2001).

On the other hand, the road cost is estimated as 250,000 TL in ANC feasibility report (Yolsu, 2009). In this study, the value acquired by ANC is used by increasing 20% considering the interest rates for 2010 and 2011.

Energy Transmission Line

For both formulations, the same energy transmission line can be used. ANC formulation requires 40 km of energy transmission line to be built between Altıparmak Dam and Artvin Transformer Station (Yolsu, 2009). The cost of the line is estimated as $100,000 per every km of the line (Yolsu, 2009). Thus, the total cost of the transmission line is $4,000,000 which is 7,000,000 TL. A conversion rate of 1.75 TL/$ is used according to the CBRT (2011).

The Diversion Weir, the Settling Basin and the Diversion Tunnel for ANC

Total cost of the diversion regulator, the settling basin and the diversion tunnel for ANC formulation was calculated as 4,224,160 TL (Yolsu, 2009). This value is updated to

5,068,992 TL by using the interest rates (1.09 and 1.10) for 2010 and 2011 as given in Table 3.17.

The Project, Surveying and Control

For both formulations, the project, surveying and control costs are assumed to be 10% of the total cost of the project as suggested by Hidromark (2010).

Unforeseen Costs

For both formulations, unforeseen costs are assumed to be 10% of the total cost of the project as suggested by Hidromark (2010). In this study, some of the social and environmental cost items are not considered. Operation and maintenance costs are also ignored.

3.8 Determination of the Net Benefits

As explained before a set of alternative installed capacities are calculated using the selected set of design discharges. Installed capacities corresponding to alternative design discharges and corresponding net heads are calculated using a turbine efficiency of 0.92 and a generator efficiency of 0.98. The results are given in Tables 3.23 and 3.24 for EİE and ANC formulations, respectively.

Table 3.23 Alternative Installed Capacities for EİE Formulation

Design Discharge (m^3/s)	Net Head (m)	Installed Capacity (MW)	Design Discharge (m^3/s)	Net Head (m)	Installed Capacity (MW)
9.00	376.72	29.99	20.00	365.51	64.66
10.00	376.72	33.32	21.00	363.51	67.52
11.00	374.75	36.46	22.00	363.29	70.69
12.00	374.95	39.80	23.00	361.34	73.51
13.00	372.86	42.87	24.00	359.03	76.21
14.00	373.29	46.22	25.00	358.93	79.37
15.00	371.41	49.28	26.00	356.71	82.03
16.00	371.39	52.56	27.00	354.07	84.55
17.00	369.51	55.56	28.00	354.35	87.76
18.00	367.52	58.51	29.00	355.073	91.07
19.00	367.5	61.76	30.00	353.821	93.88

Table 3.24 Alternative Installed Capacities for ANC Formulation

Design Discharge (m^3/s)	Net Head (m)	Installed Capacity (MW)	Design Discharge (m^3/s)	Net Head (m)	Installed Capacity (MW)
11.00	368.68	35.87	21.00	354.50	65.85
12.00	369.42	39.21	22.00	355.02	69.08
13.00	366.55	42.15	23.00	352.17	71.64
14.00	367.26	45.48	24.00	352.36	74.80
15.00	364.50	48.36	25.00	341.52	75.52
16.00	365.08	51.66	26.00	342.87	78.85
17.00	362.40	54.49	27.00	339.22	81.01
18.00	359.57	57.24	28.00	336.06	83.23
19.00	356.58	59.92	29.00	332.47	85.28
20.00	357.41	63.22	30.00	328.76	87.23

For each of the alternative installed capacity, a ROS is conducted according to the operating rules provided in Section 3.4.5 and the associated energy incomes and costs are calculated. Amount of waters allocated for the firm and the secondary energy generations are estimated by routing the available water through the reservoir of Altıparmak HEPP using SSR for the period of study, which is 36 years. Energy income calculations are carried out using four different methods (i.e. the DSİ Method, the EİE Method, the ANC Method, and the VPM) as explained in Section 3.4.5. As a result, annual energy incomes associated with each alternative installed capacity for both EİE and ANC formulations are estimated using these methods.

Cost calculations included the costs of the items which vary significantly with the installed capacity, such as the costs of the penstock, turbine, transformer, and the generator. For each alternative, installed capacity investment costs of all of these items are calculated and converted to equivalent annual cost using the capital recovery factor. Cost items, which do not vary considerably with the installed capacity, are not included in the economic analysis, they are calculated only for the purpose of the estimation of the total cost of the HEPP.

As the final step, for each alternative installed capacity, the annual cost is subtracted from the annual energy income to calculate the associated net benefit. Since four different methods are used for estimating the energy incomes, for different sets of net benefits are calculated for two different formulations (i.e. the EİE and the ANC formulations). Net benefits associated with the set of alternative installed capacities for EİE formulation with four different methods are given in Tables 3.25 through 3.28. The same sets of results for ANC formulation are given in Tables 3.29 through 3.32.

Table 3.25 Net Benefits for the EİE Formulation Using DSİ Method for the Energy Income

Design Discharge (m^3/s)	Firm Energy Generation (GWh)	Secondary Energy Generation (GWh)	Firm Energy Generation Benefit (TL)	Secondary Energy Generation Income (TL)	Installed Capacity (MW)	Peak Power Benefit (TL)	Total Energy Generation Income (TL)	Annual Penstock Cost (TL)	Annual Turbine, Transformer, Generator, Power House Costs (TL)	Net Benefit (TL)
9.00	165.98	14.82	17,428,302	856,037	29.99	546,112	18,830,450	733,407	2,267,085	15,829,958
10.00	166.35	19.67	17,466,547	1,135,701	33.32	1,033,172	19,635,420	824,611	2,518,993	16,291,816
11.00	166.20	24.02	17,451,098	1,387,098	36.46	1,503,676	20,341,871	835,358	2,756,355	16,750,157
12.00	166.48	28.14	17,480,730	1,625,059	39.80	1,993,279	21,099,068	930,999	3,008,572	17,159,498
13.00	166.36	31.64	17,468,204	1,827,115	42.87	2,453,582	21,748,901	938,593	3,241,084	17,569,224
14.00	166.65	34.95	17,497,919	2,018,612	46.22	2,945,433	22,461,964	1,045,431	3,494,452	17,922,080
15.00	167.74	38.02	17,612,689	2,195,371	49.28	3,373,671	23,181,731	1,049,429	3,725,200	18,407,102
16.00	167.86	40.74	17,625,025	2,352,831	52.56	3,859,124	23,836,981	1,141,038	3,973,332	18,722,610
17.00	167.74	42.99	17,613,144	2,482,499	55.56	4,308,364	24,404,007	1,158,129	4,200,295	19,045,583
18.00	167.68	45.08	17,606,038	2,603,509	58.51	4,748,978	24,958,526	1,179,295	4,423,420	19,355,810
19.00	167.82	47.01	17,621,618	2,714,686	61.76	5,228,506	25,564,810	1,298,689	4,668,912	19,597,209
20.00	167.72	48.52	17,611,066	2,802,295	64.66	5,662,014	26,075,376	1,298,689	4,888,031	19,888,655
21.00	167.64	49.86	17,602,130	2,879,269	67.52	6,089,647	26,571,047	1,298,689	5,104,349	20,168,008
22.00	167.86	51.46	17,624,968	2,971,839	70.69	6,556,395	27,153,202	1,414,421	5,344,174	20,394,607
23.00	166.67	52.03	17,500,474	3,004,550	73.51	7,003,319	27,508,343	1,419,134	5,557,105	20,532,104
24.00	166.64	52.73	17,497,239	3,045,373	76.21	7,406,404	27,949,016	1,433,246	5,761,598	20,754,172
25.00	166.61	53.29	17,493,943	3,077,304	79.37	7,876,367	28,447,614	1,442,672	6,000,073	21,004,868
26.00	166.74	54.06	17,507,534	3,122,112	82.03	8,269,545	28,899,190	1,564,551	6,201,451	21,133,188
27.00	166.71	54.47	17,504,883	3,145,517	84.55	8,645,491	29,295,891	1,569,517	6,392,218	21,334,156
28.00	166.81	54.95	17,514,749	3,173,237	87.76	9,119,596	29,807,582	1,699,597	6,634,301	21,473,684
29.00	***166.88***	***55.36***	***17,522,703***	***3,196,862***	***91.07***	***9,611,593***	***30,331,158***	***1,820,843***	***6,885,260***	***21,625,056***
30.00	167.01	55.83	17,535,922	3,224,352	93.88	10,026,360	30,786,635	2,080,884	7,097,568	21,608,183

Table 3.26 Net Benefits for the EİE Formulation Using EİE Method for the Energy Income

Design Discharge (m^3/s)	Firm Energy Generation (GWh)	Secondary Energy Generation (GWh)	Firm Energy Generation Benefit (TL)	Secondary Energy Generation Income (TL)	Installed Capacity (MW)	Peak Power Benefit (TL)	Total Energy Generation Income (TL)	Annual Penstock Cost (TL)	Annual Turbine, Transformer, Generator, Power House Costs (TL)	Net Benefit (TL)
9.00	165.98	14.82	13,071,226	907,918	29.99	24,115,541	38,094,686	733,407	2,267,085	35,094,193
10.00	166.35	19.67	13,099,910	1,204,531	33.32	24,168,461	38,472,903	824,611	2,518,993	35,129,299
11.00	166.20	24.02	13,088,323	1,471,164	36.46	24,147,084	38,706,571	835,358	2,756,355	35,114,857
12.00	166.48	28.14	13,110,548	1,723,547	39.80	24,188,087	39,022,182	930,999	3,008,572	35,082,611
13.00	166.36	31.64	13,101,153	1,937,849	42.87	24,170,755	39,209,757	938,593	3,241,084	35,030,079
14.00	166.65	34.95	13,123,439	2,140,952	46.22	24,211,871	39,476,262	1,045,431	3,494,452	34,936,379
15.00	***167.74***	***38.02***	***13,209,516***	***2,328,424***	***49.28***	***24,370,677***	***39,908,618***	***1,049,429***	***3,725,200***	***35,133,989***
16.00	167.86	40.74	13,218,769	2,495,427	52.56	24,387,747	40,101,943	1,141,038	3,973,332	34,987,573
17.00	167.74	42.99	13,209,858	2,632,954	55.56	24,371,308	40,214,120	1,158,129	4,200,295	34,855,696
18.00	167.68	45.08	13,204,529	2,761,297	58.51	24,361,475	40,327,301	1,179,295	4,423,420	34,724,586
19.00	167.82	47.01	13,216,213	2,879,212	61.76	24,383,032	40,478,458	1,298,689	4,668,912	34,510,857
20.00	167.72	48.52	13,208,300	2,972,131	64.66	24,368,433	40,548,864	1,298,689	4,888,031	34,362,143
21.00	167.64	49.86	13,201,598	3,053,771	67.52	24,356,068	40,611,437	1,298,689	5,104,349	34,208,398
22.00	167.86	51.46	13,218,726	3,151,951	70.69	24,387,668	40,758,345	1,414,421	5,344,174	33,999,750
23.00	166.67	52.03	13,125,356	3,186,644	73.51	24,215,407	40,527,406	1,419,134	5,557,105	33,551,168
24.00	166.64	52.73	13,122,929	3,229,941	76.21	24,210,929	40,563,800	1,433,246	5,761,598	33,368,956
25.00	166.61	53.29	13,120,457	3,263,807	79.37	24,206,369	40,590,633	1,442,672	6,000,073	33,147,888
26.00	166.74	54.06	13,130,650	3,311,331	82.03	24,225,175	40,667,156	1,564,551	6,201,451	32,901,153
27.00	166.71	54.47	13,128,662	3,336,155	84.55	24,221,506	40,686,323	1,569,517	6,392,218	32,724,588
28.00	166.81	54.95	13,136,062	3,365,554	87.76	24,235,158	40,736,774	1,699,597	6,634,301	32,402,876
29.00	166.88	55.36	13,142,027	3,390,611	91.07	24,246,165	40,778,803	1,820,843	6,885,260	32,072,700
30.00	167.01	55.83	13,151,942	3,419,768	93.88	24,264,456	40,836,166	2,080,884	7,097,568	31,657,714

Table 3.27 Net Benefits for the EİE Formulation Using ANC Method for the Energy Income

Design Discharge (m^3/s)	Firm Energy (GWh)	Secondary Energy (GWh)	Total Energy (GWh)	Annual Energy Income (TL) (Single Price)	Annual Penstock Cost (TL)	Installed Capacity (MW)	Annual Turbine, Transformer, Generator, Power House Costs (TL)	Net Benefit (TL)
15.00	0.00	197.95	197.95	28,579,062	1,049,429	49.28	3,725,200	23,804,433
16.00	0.00	203.67	203.67	29,405,416	1,141,038	52.56	3,973,332	24,291,045
17.00	0.00	208.33	208.33	30,077,603	1,158,129	55.56	4,200,295	24,719,179
18.00	0.00	212.12	212.12	30,625,040	1,179,295	58.51	4,423,420	25,022,325
19.00	0.00	215.85	215.85	31,163,949	1,298,689	61.76	4,668,912	25,196,348
20.00	0.00	218.34	218.34	31,522,595	1,298,689	64.66	4,888,031	25,335,874
21.00	***0.00***	***220.25***	***220.25***	***31,797,957***	***1,298,689***	***67.52***	***5,104,349***	***25,394,919***
22.00	0.00	221.74	221.74	32,014,186	1,414,421	70.69	5,344,174	25,255,592
23.00	0.00	223.24	223.24	32,230,416	1,419,134	73.51	5,557,105	25,254,177
24.00	0.00	224.09	224.09	32,352,373	1,433,246	76.21	5,761,598	25,157,529
25.00	0.00	225.49	225.49	32,554,748	1,442,672	79.37	6,000,073	25,112,003
26.00	0.00	225.94	225.94	32,619,760	1,564,551	82.03	6,201,451	24,853,758
27.00	0.00	226.43	226.43	32,690,678	1,569,517	84.55	6,392,218	24,728,943
28.00	0.00	227.39	227.39	32,829,897	1,699,597	87.76	6,634,301	24,495,999

Table 3.28 Net Benefits for the EİE Formulation Using VPM for the Energy Income

Design Discharge (m^3/s)	Firm Energy (GWh)	Secondary Energy (GWh)	Total Energy (GWh)	Annual Energy Income (TL) (Various Prices)	Annual Penstock Cost (TL)	Installed Capacity (MW)	Annual Turbine, Transformer, Generator, Power House Costs (TL)	Net Benefit (TL)
15.00	0.00	197.95	197.95	24,034,786	1,049,429	49.28	3,725,200	19,260,157
16.00	0.00	203.67	203.67	24,447,771	1,141,038	52.56	3,973,332	19,333,400
17.00	0.00	208.33	208.33	24,910,403	1,158,129	55.56	4,200,295	19,551,979
18.00	0.00	212.12	212.12	25,198,182	1,179,295	58.51	4,423,420	19,595,467
19.00	0.00	215.85	215.85	25,512,346	1,298,689	61.76	4,668,912	19,544,745
20.00	***0.00***	***218.34***	***218.34***	***25,912,522***	***1,298,689***	***64.66***	***4,888,031***	***19,725,802***
21.00	0.00	220.25	220.25	26,029,072	1,298,689	67.52	5,104,349	19,626,034
22.00	0.00	221.74	221.74	26,222,499	1,414,421	70.69	5,344,174	19,463,904
23.00	0.00	223.24	223.24	26,505,612	1,419,134	73.51	5,557,105	19,529,374
24.00	0.00	224.09	224.09	26,652,302	1,433,246	76.21	5,761,598	19,457,458
25.00	0.00	225.49	225.49	26,967,419	1,442,672	79.37	6,000,073	19,524,673
26.00	0.00	225.94	225.94	27,245,007	1,564,551	82.03	6,201,451	19,479,005
27.00	0.00	226.43	226.43	27,431,012	1,569,517	84.55	6,392,218	19,469,277
28.00	0.00	227.39	227.39	27,697,191	1,699,597	87.76	6,634,301	19,363,293

Table 3.29 Net Benefits for the ANC Formulation Using DSİ Method for the Energy Income

Design Discharge (m^3/s)	Firm Energy Generation (GWh)	Secondary Energy Generation (GWh)	Firm Energy Generation Benefit (TL)	Secondary Energy Generation Benefit (TL)	Installed Capacity (MW)	Peak Power Benefit (TL)	Total Energy Generation Income (TL)	Annual Penstock Cost (TL)	Annual Turbine, Transformer, Generator, Power House Costs (TL)	Net Benefit (TL)
11.00	70.10	86.25	4,048,486	4,981,183	35.87	3,682,281	12,711,950	1,487,501	2,711,749	8,512,700
12.00	70.22	93.51	4,055,071	5,400,304	39.21	4,176,324	13,631,699	1,670,495	2,964,206	8,996,998
13.00	70.08	99.45	4,047,306	5,742,981	42.15	4,616,416	14,406,703	1,693,496	3,186,264	9,526,943
14.00	70.19	105.79	4,053,333	6,109,393	45.48	5,109,255	15,271,980	1,876,449	3,437,993	9,957,538
15.00	70.07	110.96	4,046,598	6,408,141	48.36	5,540,735	15,995,475	1,906,829	3,655,889	10,432,757
16.00	70.16	116.70	4,051,663	6,739,691	51.66	6,030,483	16,821,836	2,107,018	3,905,847	10,808,971
17.00	70.07	121.23	4,046,255	7,000,941	54.49	6,453,104	17,500,300	2,126,353	4,119,515	11,254,432
18.00	69.98	125.29	4,041,442	7,235,415	57.24	6,864,722	18,141,579	2,145,674	4,327,715	11,668,189
19.00	69.90	128.95	4,036,643	7,446,575	59.92	7,264,955	18,748,173	2,165,079	4,530,132	12,052,963
20.00	70.00	133.19	4,042,269	7,691,947	63.22	7,753,659	19,487,876	2,385,072	4,779,676	12,323,127
21.00	70.35	137.37	4,062,526	7,933,087	65.85	8,135,392	20,131,005	2,398,796	4,977,891	12,754,319
22.00	70.01	139.45	4,043,099	8,053,492	69.08	8,624,616	20,721,206	2,625,170	5,222,499	12,873,537
23.00	69.96	141.20	4,040,169	8,154,084	71.64	9,006,573	21,200,826	2,632,342	5,416,015	13,152,469
24.00	70.04	143.42	4,044,858	8,282,316	74.80	9,474,250	21,801,425	2,866,702	5,654,679	13,280,044
25.00	69.73	142.32	4,026,787	8,219,016	75.52	9,588,403	21,834,206	2,487,367	5,708,945	13,637,894
26.00	69.85	144.31	4,033,992	8,334,087	78.85	10,081,167	22,449,246	2,711,319	5,960,880	13,777,047
27.00	69.84	144.96	4,033,140	8,371,584	81.01	10,402,747	22,807,471	2,725,594	6,124,141	13,957,736
28.00	69.81	145.48	4,031,352	8,401,660	83.23	10,733,576	23,166,588	2,739,925	6,291,909	14,134,754
29.00	69.78	145.82	4,029,841	8,420,912	85.28	11,039,348	23,490,101	2,768,752	6,447,000	14,274,349
30.00	***69.75***	***146.24***	***4,028,300***	***8,445,345***	***87.23***	***11,330,810***	***23,804,455***	***2,797,799***	***6,594,811***	***14,411,844***

Table 3.30 Net Benefits for the ANC Formulation Using EİE Method for the Energy Income

Design Discharge (m^3/s)	Firm Energy Generation (GWh)	Secondary Energy Generation (GWh)	Firm Energy Generation Benefit (TL)	Secondary Energy Generation Income (TL)	Installed Capacity (MW)	Peak Power Benefit (TL)	Total Energy Generation Income (TL)	Annual Penstock Cost (TL)	Annual Turbine, Transformer, Generator, Power House Costs (TL)	Net Benefit (TL)
11.00	70.10	86.25	5,520,663	5,283,073	35.87	10,185,255	20,988,991	1,487,501	2,711,749	16,789,740
12.00	70.22	93.51	5,529,642	5,727,595	39.21	10,201,822	21,459,059	1,670,495	2,964,206	16,824,358
13.00	70.08	99.45	5,519,054	6,091,040	42.15	10,182,287	21,792,381	1,693,496	3,186,264	16,912,620
14.00	70.19	105.79	5,527,272	6,479,659	45.48	10,197,448	22,204,379	1,876,449	3,437,993	16,889,937
15.00	***70.07***	***110.96***	***5,518,088***	***6,796,514***	***48.36***	***10,180,505***	***22,495,107***	***1,906,829***	***3,655,889***	***16,932,390***
16.00	70.16	116.70	5,524,995	7,148,157	51.66	10,193,247	22,866,398	2,107,018	3,905,847	16,853,533
17.00	70.07	121.23	5,517,621	7,425,241	54.49	10,179,642	23,122,504	2,126,353	4,119,515	16,876,635
18.00	69.98	125.29	5,511,057	7,673,925	57.24	10,167,534	23,352,515	2,145,674	4,327,715	16,879,126
19.00	69.90	128.95	5,504,514	7,897,882	59.92	10,155,461	23,557,857	2,165,079	4,530,132	16,862,646
20.00	70.00	133.19	5,512,185	8,158,126	63.22	10,169,615	23,839,926	2,385,072	4,779,676	16,675,177
21.00	70.35	137.37	5,539,808	8,413,880	65.85	10,220,577	24,174,266	2,398,796	4,977,891	16,797,579
22.00	70.01	139.45	5,513,316	8,541,582	69.08	10,171,701	24,226,600	2,625,170	5,222,499	16,378,931
23.00	69.96	141.20	5,509,321	8,648,271	71.64	10,164,331	24,321,923	2,632,342	5,416,015	16,273,566
24.00	70.04	143.42	5,515,716	8,784,275	74.80	10,176,128	24,476,119	2,866,702	5,654,679	15,954,738
25.00	69.73	142.32	5,491,073	8,717,138	75.52	10,130,663	24,338,874	2,487,367	5,708,945	16,142,562
26.00	69.85	144.31	5,500,899	8,839,183	78.85	10,148,792	24,488,873	2,711,319	5,960,880	15,816,674
27.00	69.84	144.96	5,499,737	8,878,953	81.01	10,146,648	24,525,337	2,725,594	6,124,141	15,675,602
28.00	69.81	145.48	5,497,298	8,910,852	83.23	10,142,148	24,550,297	2,739,925	6,291,909	15,518,464
29.00	69.78	145.82	5,495,238	8,931,270	85.28	10,138,349	24,564,857	2,768,752	6,447,000	15,349,105
30.00	69.75	146.24	5,493,136	8,957,184	87.23	10,134,469	24,584,790	2,797,799	6,594,811	15,192,179

Table 3.31 Net Benefits for the ANC Formulation Using ANC Method for the Energy Income

Design Discharge (m^3/s)	Firm Energy (GWh)	Secondary Energy (GWh)	Total Energy (GWh)	Annual Energy Income (TL) (Single Prices)	Annual Penstock Cost (TL)	Installed Capacity (MW)	Annual Turbine, Transformer, Generator, Power House Costs (TL)	Net Benefit (TL)
15.00	0.00	183.47	183.47	26,489,103	1,906,829	48.36	3,655,889	20,926,386
16.00	0.00	189.39	189.39	27,343,186	2,107,018	51.66	3,905,847	21,330,321
17.00	0.00	193.66	193.66	27,959,887	2,126,353	54.49	4,119,515	21,714,019
18.00	0.00	197.53	197.53	28,518,666	2,145,674	57.24	4,327,715	22,045,276
19.00	0.00	200.91	200.91	29,006,737	2,165,079	59.92	4,530,132	22,311,526
20.00	0.00	205.01	205.01	29,598,438	2,385,072	63.22	4,779,676	22,433,689
21.00	0.00	207.30	207.30	29,928,658	2,398,796	65.85	4,977,891	22,551,971
22.00	0.00	210.49	210.49	30,389,373	2,625,170	69.08	5,222,499	22,541,704
23.00	***0.00***	***211.99***	***211.99***	***30,606,027***	***2,632,342***	***71.64***	***5,416,015***	***22,557,670***
24.00	0.00	214.28	214.28	30,936,796	2,866,702	74.80	5,654,679	22,415,415
25.00	0.00	212.78	212.78	30,719,620	2,487,367	75.52	5,708,945	22,523,307
26.00	0.00	215.00	215.00	31,040,567	2,711,319	78.85	5,960,880	22,368,368

Table 3.32 Net Benefits for the ANC Formulation Using VPM for the Energy Income

Design Discharge (m^3/s)	Firm Energy (GWh)	Secondary Energy (GWh)	Total Energy (GWh)	Annual Energy Income (TL) (Various Prices)	Annual Penstock Cost (TL)	Installed Capacity (MW)	Annual Turbine, Transformer, Generator, Power House Costs (TL)	Net Benefit (TL)
15.00	0.00	183.47	183.47	21,949,769	1,906,829	48.36	3,655,889	16,387,052
16.00	0.00	189.39	189.39	22,587,056	2,107,018	51.66	3,905,847	16,574,191
17.00	0.00	193.66	193.66	23,050,878	2,126,353	54.49	4,119,515	16,805,009
18.00	0.00	197.53	197.53	23,421,114	2,145,674	57.24	4,327,715	16,947,724
19.00	0.00	200.91	200.91	23,628,848	2,165,079	59.92	4,530,132	16,933,637
20.00	0.00	205.01	205.01	24,153,107	2,385,072	63.22	4,779,676	16,988,358
21.00	0.00	207.30	207.30	24,455,017	2,398,796	65.85	4,977,891	17,078,331
22.00	***0.00***	***210.49***	***210.49***	***25,035,488***	***2,625,170***	***69.08***	***5,222,499***	***17,187,818***
23.00	0.00	211.99	211.99	25,200,867	2,632,342	71.64	5,416,015	17,152,510
24.00	0.00	214.28	214.28	25,502,381	2,866,702	74.80	5,654,679	16,981,000
25.00	0.00	212.78	212.78	25,225,484	2,487,367	75.52	5,708,945	17,029,171
26.00	0.00	215.00	215.00	25,533,550	2,711,319	78.85	5,960,880	16,861,350

Annual incomes, annual costs and net benefits associated with alternative installed capacities are calculated and used in selecting the best installed capacity for two different formulations. Therefore, these results were presented in Section 3.8, Tables 3.25 through 3.32. For the sake of completeness, the same results are presented graphically as well. The annual income, the annual cost, and the net benefits associated with the set of alternative installed capacities for EİE formulation with four different methods are illustrated in Figures 3.18 through 3.21. The same sets of results for ANC formulation are given in Figures 3.22 through 3.25.

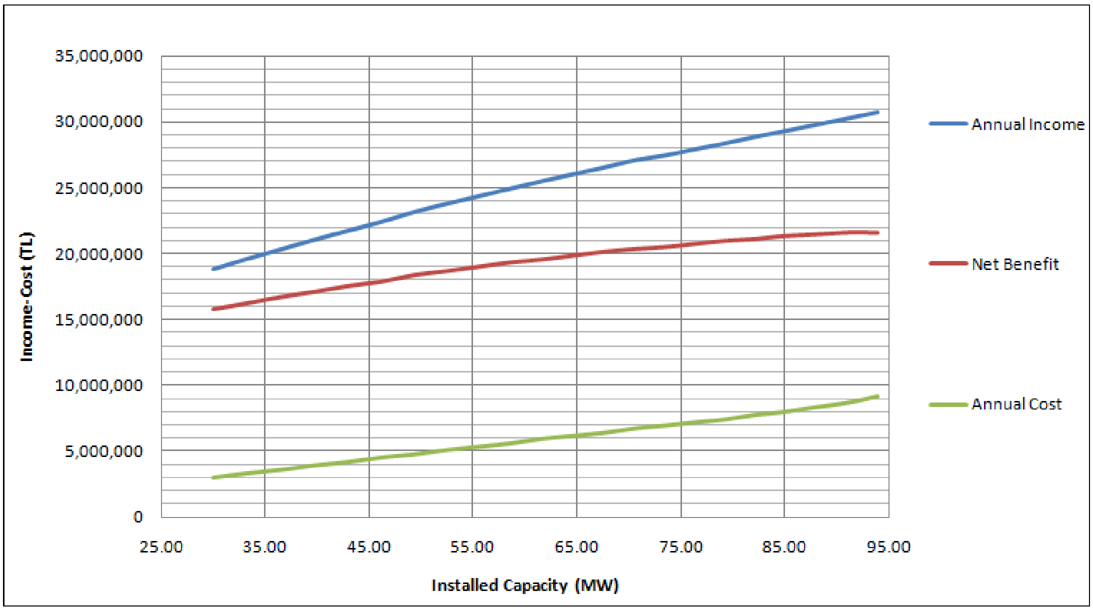

Figure 3.18 Annual Income, Annual Cost, and Net Benefit for EİE Formulation - DSİ Method

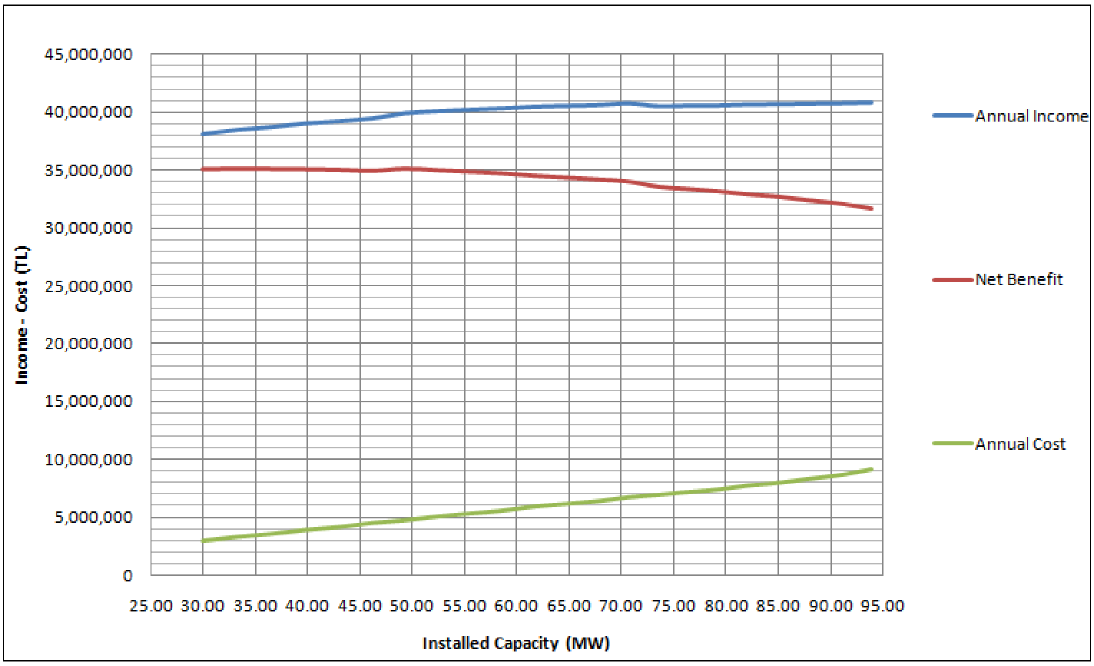

Figure 3.19 Annual Income, Annual Cost, and Net Benefit for EİE Formulation - EİE Method

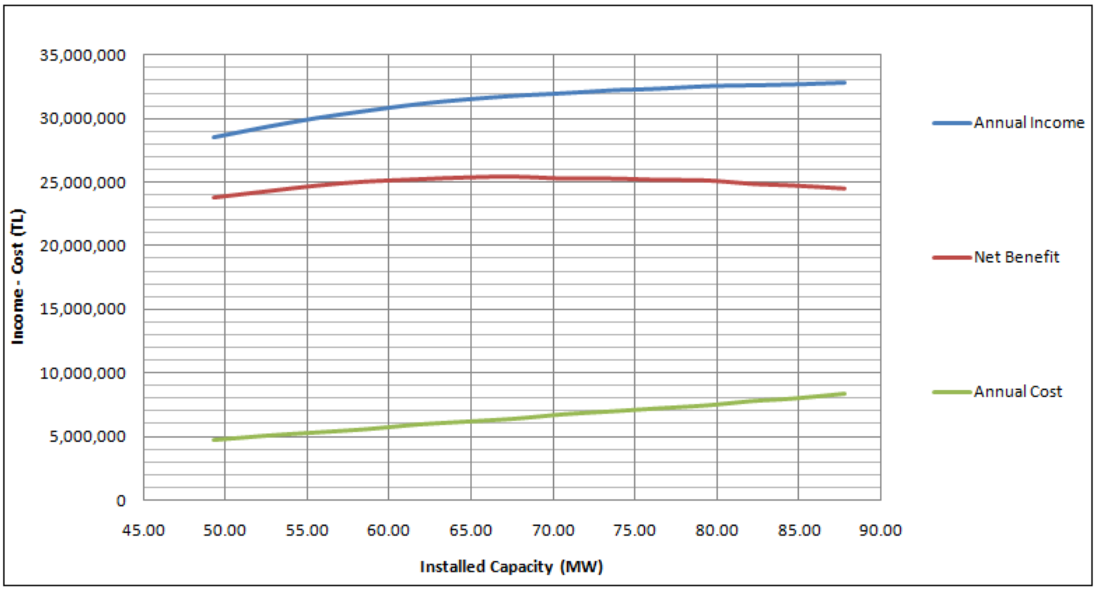

Figure 3.20 Annual Income, Annual Cost, and Net Benefit for EİE Formulation - ANC Method

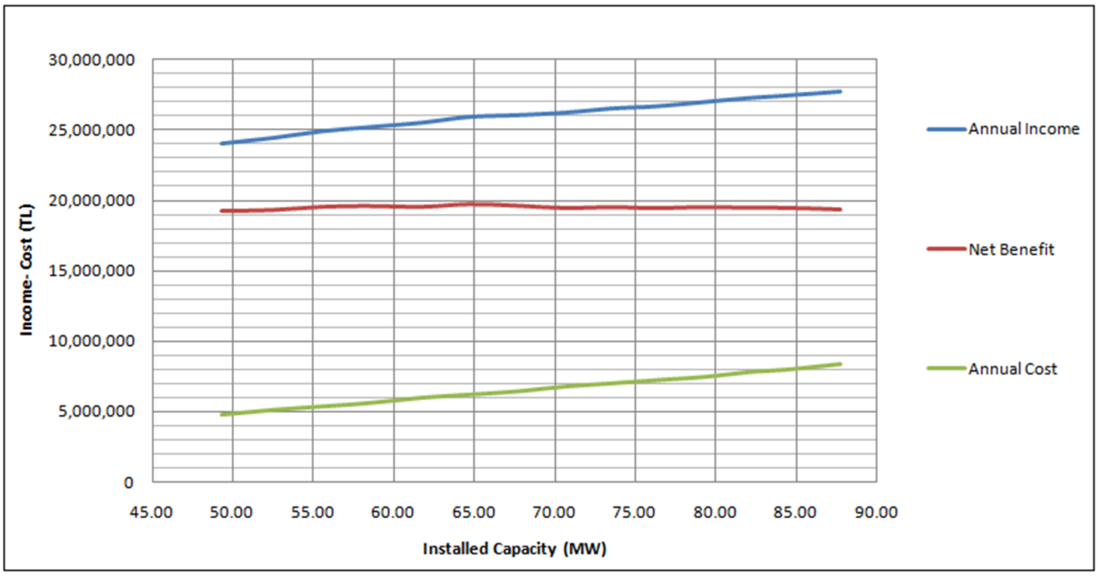

Figure 3.21 Annual Income, Annual Cost, and Net Benefit for EİE Formulation - VPM Method

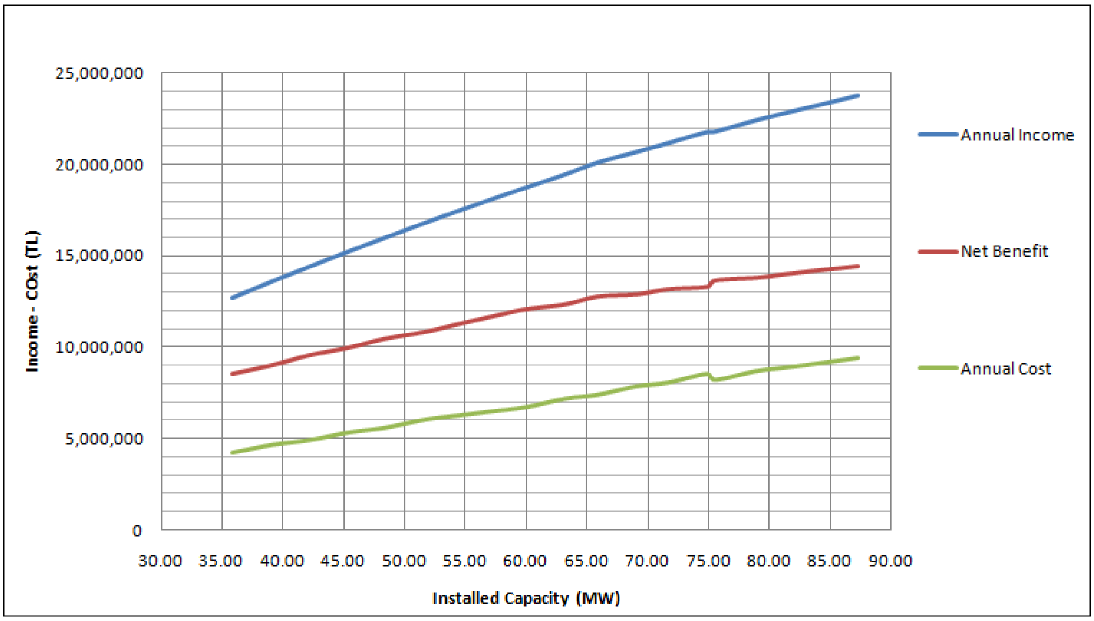

Figure 3.22 Annual Income, Annual Cost, and Net Benefit for ANC Formulation - DSİ Method

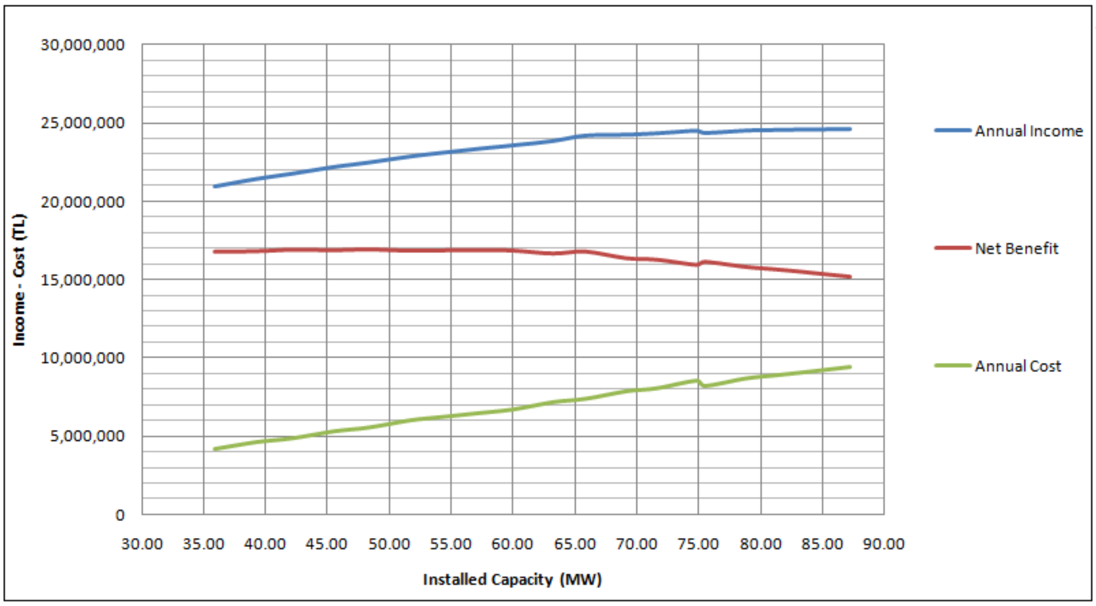

Figure 3.23 Annual Income, Annual Cost, and Net Benefit for ANC Formulation - EİE Method

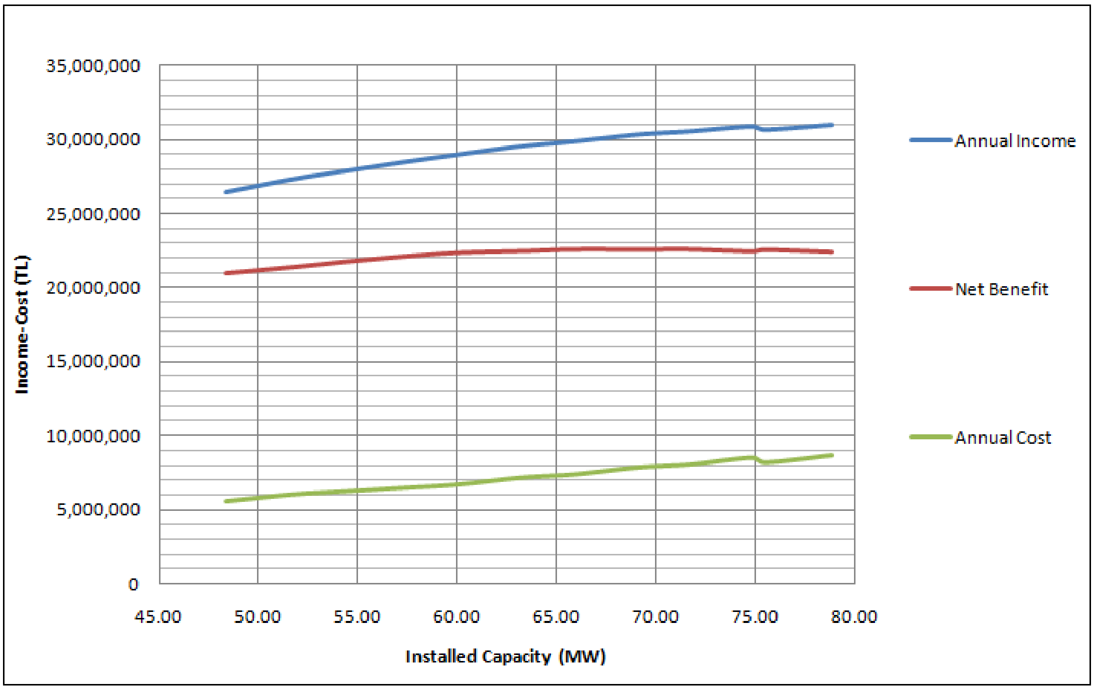

Figure 3.24 Annual Income, Annual Cost, and Net Benefit for ANC Formulation - ANC Method

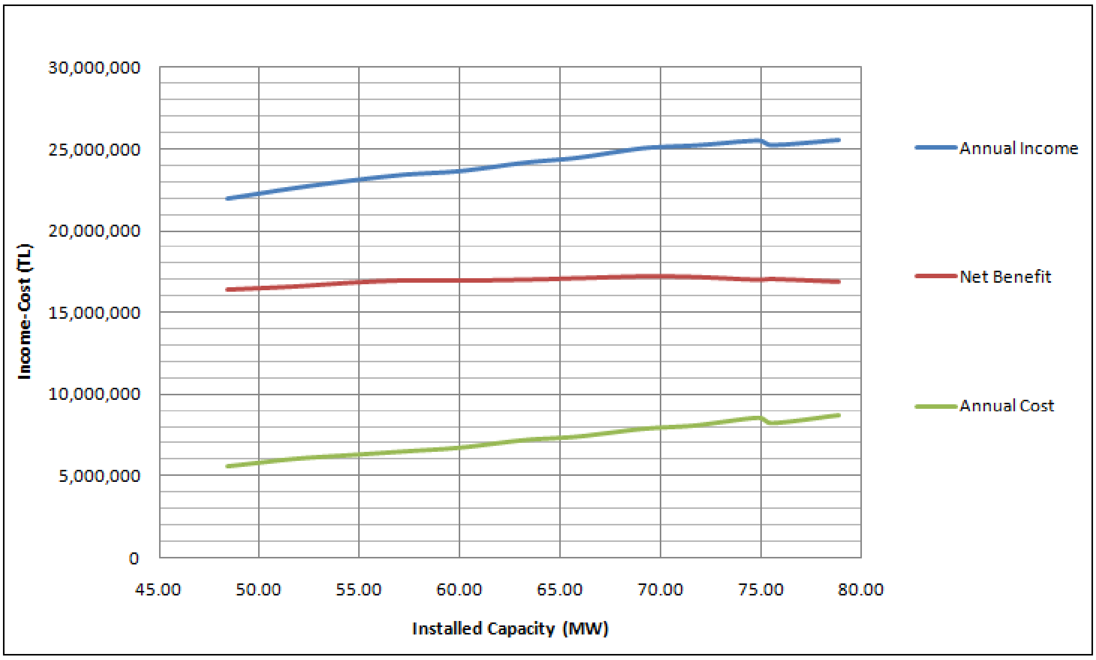

Figure 3.25 Annual Income, Annual Cost, and Net Benefit for ANC Formulation - VPM Method

3.9 Selection of the Best Installed Capacity and Evaluation of the Results

The best installed capacity is the one which results in the highest net benefit. A summary of the best net benefits calculated for EİE and ANC formulations using four different methods for energy income estimates are provided in Table 3.33.

Table 3.33 Best Installed Capacities for EİE and ANC Formulations

Formulation	Installed Capacity (MW)	Net Benefit (TL)
EİE formulation		
DSİ Method	91.07	21,625,056
EİE Method	49.28	35,133,989
ANC Method	67.52	25,394,919
VPM	64.66	19,725,802
ANC formulation		
DSİ Method	87.23	14,411,844
EİE Method	48.36	16,932,390
ANC Method	71.64	22,557,670
VPM	69.08	17,187,818

As can be seen from Table 3.33 the best installed capacities calculated by four different energy income methods vary significantly. For EİE formulation EİE Method results in a best installed capacity of 50 MW while DSİ Method provides 90 MW as the best installed capacity. Similar results are obtained for the ANC formulation as well.

CHAPTER 4

RESULTS AND DISCUSSIONS

4.1 Discussion of the Energy Income Calculation Methods

One of the main differences between four different energy income calculation methods is the unit prices used for the firm and secondary energies. DSİ Method utilizes 6 cent/kWh for the firm energy while EİE uses only 4.5 cent/kWh. Although unit prices for the secondary energy are similar, they use very different values for the peak power as well (see Table 3.9). On the other ANC method and VPM do not require firm energy generation; and evaluates income based on the average annual energy generation (in the absence of firm energy this corresponds to the secondary energy). ANC method assigns a fixed rate of 8.25 cent/kWh for the generated energy which is much higher than those used for the firm energy generations in DSİ and EİE Methods. Different than all of these three methods the VPM uses hourly electricity prices which range between 1.62 and 25.59 kuruş/kWh as can be seen in Appendix B, Table B-3. Since these four methods use quite different approaches for estimating the energy incomes, it is not possible to compare the results and identify the best method. However, it can be concluded that among these four methods the VPM represents the real situation the best. Thus, utilization of the VPM method will provide realistic results in terms of the costs and benefits of a HEPP.

As explained in Section 3.6, unlike ANC Method and VPM, both DSİ and EİE methods use peak power benefits. The evaluation of peak power benefit by DSİ is based on the installed capacity rather than the amount of generated energy (see Equation (3.24)). Thus higher installed capacity means more benefit in the DSİ Method, and preferred. On the other hand, the EİE Method assess' the peak power with respect to the firm energy generation (see Equation (3.25)). Therefore, higher installed capacities which do not considerably increase the firm energy generation are not financially favorable in the EİE method (see Table 3.26 and Table 3.30). Thus smaller installed capacities which provide similar firm energy generations are desirable. Higher installed capacities lead to higher amounts of secondary energy generation. However EİE evaluates the secondary energy generation with lower benefits. To summarize, EİE method results in smaller installed capacities. The EİE Method seems to utilize a more reasonable approach compared to that of the DSİ Method.

These results also show the importance of the selected goal(s) for the economic analysis. DSİ and EİE Methods are based on energy incomes from the firm and the secondary energy generations. First the firm energy requirement is satisfied since its economical income is higher than the remaining water is used to generate secondary energy. On the other hand, ANC Method and VPM do not enforce a firm energy requirement but tries to maximize annual energy generation.

The firm energy generation of a hydropower plant is important when hydropower carries a large portion of a power systems load. The secondary energy which is the excess generation apart from the firm energy is not of concern in these systems. On the other hand when hydropower represents a small portion of the total energy generation; maximizing the annual average energy generation should be the main goal (US Army Corps of Engineers, 1985). In Turkey, hydropower is used for supplying the peak loads, rather than supplying the firm energy demand. Thus, DSİ and EİE Methods which first require satisfaction of a firm energy requirement do not represent the real situation. Maximization of the annual energy generation is a more realistic goal for the HEPPs in Turkey. Thus, ANC Method and VPM are more representative of the real situation in our country.

The ANC method which is based on a fixed price of 8.25 cent/ kWh results in similar best installed capacities that are identified by the VPM. The VPM method uses hourly electricity prices. The average electricity price of the last 12 months was 6.96 cent/kWh (see Appendix B, Table B-3). Although the average price is less than the one used in the ANC Method, it should be remembered that the VPM Method assumes electricity generation is realized when the energy prices are the highest.

Since there are too many variables in the economic analysis, it is hard to evaluate individual impacts of various factors such as forcing a firm energy generation, assigning a fixed price for generated energy, assigning hourly energy prices on the results based on this feasibility study. More detailed analysis has to be conducted to identify individual impacts of various components of the economic analysis. This may be the subject of a future research.

4.2 Comparison of the EİE and ANC Formulations

The goal of the economic analysis is to select the best installed capacity and estimate associated costs and benefits. As explained in the previous section, it is believed that the VPM represents the real situation most realistically thus the results obtained from this method are used to compare the costs and benefits of two alternative formulations. Investment costs of different items of the HEPP and the associated equivalent annual energy cost, annual energy income, and the net benefit corresponding to the best installed capacity (i.e. 64.66 MW for the VPM) for the EİE formulation are given in Table 4.1. The summary of economic analysis for the ANC formulation is given in Table 4.2. Results provided in Table 4.2 correspond to an installed capacity of 69.08 MW which is determined as the best installed capacity with the VPM. The annual energy incomes provided in Tables 4.1 and 4.2 include all the cost items calculated in Section 3.8, not only those items which vary considerably with the installed capacity. Thus the annual costs presented in Tables 4.1 and 4.2 are different than those provided in Tables 3.25 and 3.32 and for the same reason the net benefits are different than those provided in Tables 4.1 and 4.2. To stress the difference in Tables 4.1 and 4.2, they are referred to as the “Net benefit of the project”.

Table 4.1 Summary of Economic Analysis for EİE Formulation

Item	Cost and Benefit (TL)
Dam body	122,699,985
Tunnel	30,599,311
Penstock	13,481,104
Surge Tank	4,176,295
Power House, Turbine, Transformer, Generator (450 $/kW) (64.66 MW)	50,919,750
Diversion Tunnel	1,336,596
Energy Transmission Lines	7,000,000
Road Relocation	34,531,956
Project Surveying and Controlling	21,382,525
Unforeseen Cost	21,382,525
Expropriation	27,633,978
Total Investment Cost	335,144,025
Annual Investment Cost	32,173,826
Annual Energy Income	25,912,522
Net Benefit of the Project	-6,261,304
Benefit/Cost Ratio	0.81

Table 4.2 Summary of Economic Analysis for ANC Formulation

Item	Cost and Benefit (TL)
Dam body	43,952,652
Tunnel	39,528,808
Penstock	27,345,521
Surge Tank	6,674,800
Power House, Turbine, Transformer, Generator (450 $/kW) (69.08 MW)	54,400,500
Diversion Tunnel	847,732
Diversion Weir, Settling Basin and Diversion Tunnel	5,068,992
Energy Transmission Lines	7,000,000
Road Relocation	300,000
Project Surveying and Controlling	13,071,850
Unforeseen Cost	13,071,850
Expropriation	2,501,495
Total Investment Cost	213,764,200
Annual Investment Cost	20,521,363
Annual Energy Income	25,035,488
Net Benefit of the Project	4,514,125
Benefit/Cost Ratio	1.22

Benefit-cost ratio is defined as the ratio of the equivalent value of benefits to the equivalent value of costs. A benefit-cost ratio greater than or equal to 1.0 indicates that the project evaluated is economically feasible (Kahraman, 2001). The benefit-cost ratio for the EİE formulation is calculated as 0.81 which is lower than 1.0. This indicates that the EİE formulation is not a feasible alternative in terms of economics. On the other hand, the benefit-cost ratio of the ANC formulation is 1.22 which demonstrates the economic feasibility of this formulation.

In addition to economic feasibility, ANC formulation is expected to have comparatively less social impacts since it requires smaller amounts of expropriation and road relocation. Thus, evaluation of the results show that the ANC formulation is preferable compared to the EİE formulation.

CHAPTER 5

CONCLUSION

In Turkey, feasibility studies conducted for the HEPPs are based on fixed unit energy prices. Energy incomes are generally calculated according to either the DSİ Method or the EİE Method. Both of these methods use fixed prices for the firm and the secondary energy generations. However, after the establishment of the private electricity market in 2009, electricity has been priced hourly in Turkey. Depending on the balance between the supplies and the demands significantly different electricity prices develop within a day as explained in Appendix A. We believe that utilization of hourly varying prices in the energy income calculations of HEPPs will result in more realistic estimates. Thus, in this study an alternative energy income method, namely the Variable Price Method (VPM) is developed and used to conduct economic analysis of Altıparmak HEPP.

In this study, an economic analysis is conducted for Altıparmak HEPP with four different energy income methods: the DSİ Method, the EİE Method, the ANC Method, and the VPM. The ANC and the VPM methods do not distinguish between the firm and the secondary energy, but calculates energy incomes based on average annual energy generation. These approaches are more representative of the real situation in Turkey; since HEPPs are not used for supplying the peak loads, rather than supplying the firm energy demand. The difference between the ANC Method and the VPM is that ANC assigns a high fixed energy price rather than utilizing hourly varying electricity prices. We believe that the VPM represents the real situation in Turkey in the best way and results in more realistic energy income estimates compared to the other three methods.

Two different formulations were proposed by EİE and ANC Energy for Altıparmak HEPP. EİE conducted a feasibility study for Altıparmark HEPP in 2001 (EİE, 2001) and ANC hired Yolsu Engineering and Consultancy Inc. to conduct the feasibility study for them in 2009. Best installed capacities identified by EİE and Yolsu were 50 MW and 70 MW for EİE and ANC formulations, respectively. As a result of the economic analysis conducted in this study the best installed capacities for EİE and ANC formulations are identified as 64 MW and 69 MW using the VPM. Comparison of the results obtained by the other energy income calculation methods in this study is given in Table 5.1.

Table 5.1 Best Installed Capacities Identified for Each Formulation

Energy Income Method	EİE (2001)	ANC (Yolsu, 2011)	Current Study	
			EİE Formulation	ANC Formulation
DSİ Method	-	-	91.07 MW	87.23 MW
EİE Method	50.00 MW	-	49.28 MW	48.36 MW
ANC Method	-	70.00 MW	67.52 MW	71.64 MW
VPM	-	-	64.66 MW	69.08 MW

As can be seen from Table 5.1 there are significant differences in the selected installed capacities based on four different methods. These differences are mainly due to evaluation of the firm and the secondary energy generations separately in DSİ and EİE Methods while type of energy does not matter for the ANC Method and VPM. Of course the other important factor is the utilization of hourly varying or fixed energy prices in these methods. In addition to utilization of various energy income calculation methods, the economic analysis conducted in this study included various other components which are not traditionally used in such studies.

Conventionally, feasibility studies conducted for HEPPs in Turkey are based on simple assumptions and detailed analyses are not involved. In this study, the following factors are included in the economic analyses: (i) tailwater level change, (ii) varying operating levels in different seasons, and (iii) precipitation and evaporation amounts. Thus, the economic analysis conducted in this study is different and probably more comprehensive than those conducted by EİE and ANC. Hence, direct comparison of the results (i.e. selected best installed capacities) is not possible. However, we believe that utilization of varying hourly electricity prices and inclusion of above stated factors makes the results of this study more representative of the real situation. Hydropower is the most important domestic energy resource of Turkey, thus its wise planning and development is necessary to lower dependency of our country on foreign energy sources. This may only be achieved by conducting detailed feasibility studies for the HEPPs.

Recommendations for future research

- Re-evaluation of reservoir operating levels with reference to critical submergence and return period of flood.
- Rule curve generation using smaller intervals.

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APPENDIX A

ELECTRICITY MARKET

The electricity market has been operated since December 1^{st} 2009, in accordance with a new regulation which came into force by 14.04.2009 dated and 27200 numbered official newspaper about the Electricity Market Balancing and Settlement Regulation (EMRA, 2009). The most important amendments in the new system are "hourly contract" and "balancing responsibility" concepts. The "hourly contract" means the participants of the system can bid for every individual hour rather than bidding only twice a month as was the case in the previous system. The "balancing responsibility" means that the power plants (i.e. power suppliers or producers) are responsible for balancing the system by taking additional loads (i.e. additional loading) or reducing previously proposed loads (i.e. load shedding). In addition to hourly bids, block bids (i.e. the offer consists of the same quantity of power for a period of consecutive hours) and flexible bids (i.e. the offer consists of a specific power for any hour in the given duration) are available to the producers.

The new system has two important components namely, **the day-ahead market** and **intra-day market** also referred to as hour-ahead or adjustment market. First, two sets of bids (one for the day-ahead market and another for the intra-day market) are collected from the suppliers and the consumers for each hour of the following day. In the day-ahead market, the system is balanced with the first set of collected bids. As a result of the day-ahead market electricity supply of each supplier and consumption of each consumer for each hour of the following day is determined. However, producers and consumers real time supplies and consumptions may be different than their day-ahead values, thus another balance is sought in the intra-day market. The system is balanced again with the second set of bids for each hour of the following day at the end of the intra-day market. Therefore, electricity pricing for each hour of the day is performed twice for each hour of a day to balance the system and two separate prices arise: **day-ahead market price** (DAMP)**,** and **real time price**, (RTP) (Pehlivantürk, 2010). In addition to market prices (i.e. DAMP and RTP), the government guarantees to pay a fixed price for renewable energy (such as wind, run-of-river hydropower, solar). However, the guaranteed price is usually much less than the average market prices thus the power plants prefer to bid and sell their energy at market prices.

A.1 Collection of the Bids

Two separate sets of bids for each hour of the following day are collected for the day-ahead market and the intra-day market. For a power supplier the first set of bid which is utilized for the day-ahead market is composed of power supplies in MW, additional loadings in MW and load sheddings in MW and their associated prices for each hour of the next day. Inclusion of additional loadings and load sheddings to the bids are optional. For a power consumer the bid is composed of power demands in MWs for each hour of the next day. The second set of bid which is for the intra-day market is only provided by the power suppliers and is composed of the additional loadings and load sheddings and their associated prices for each hour of the next day.

First bids are collected from the suppliers and the consumers till 10:30 am for each hour of the following day and these bids are used to calculate the DAMP. The consumers and suppliers are allowed to submit their objections to DAMP and these objections are evaluated and resolved by the system until 13:00 pm. At the end of this process, around 14:30 pm, the final DAMP prices are identified. However, the suppliers and consumers may not satisfy their day-ahead bids in real time. Thus, a second round balancing might be necessary to identify the real time prices. The suppliers submit their second set of bids for additional loading or load shedding between 14:30 and 16:00 and these bids will be used to balance the intra-day market (Özçelik, 2009).

A.2 The Day-Ahead Market

The day-ahead market develops through the suppliers and consumers entrance of their power supply and power demand plans till 10:30 am for each hour of the following day. There are two types of suppliers: ones that have bilateral plans with specific consumers (i.e. the supplier has an agreement with a specific consumer to supply a certain amount of power) and ones without bilateral plans. The Suppliers (i.e. the power plants) with bilateral contracts should try to input their power supply plans, (i.e. hourly power generation plans) in accordance with their bilateral contracts. They can choose to input additional power supply bids to the system. If they enter less than what they have in their bilateral contracts they will be penalized for the deficiency if the system does not balance (i.e. the demand exceeds the supply). The suppliers which do not have bilateral contracts are free to input any power supply plan to the system. Similarly, the consumers (i.e. electricity distribution companies or the factories which consume high amount of electricity like iron- steel factories) input their power demand plans into the system. These day-ahead market bids are used to balance the system (i.e. the total power demand and the total power supply plans have to be matched) (EMRA, 2011).

There are a large number of suppliers and consumers in the system, thus initially the system never balances with the day-ahead market bids. As a result of the day-ahead market bids either the demand exceeds the supply or vice versa. Two different approaches are utilized to balance the system. If the demand is greater than the supply, the prices given by suppliers for additional loading are arranged in the ascending order. Then the offers are approved starting from the top of the list until the system is balanced (i.e. the total supply matches the total demand). The last approved price becomes DAMP. On the other hand, in the situation of power surplus in the system, the bids for load shedding from the suppliers are evaluated. The offered prices by the suppliers are arranged in the descending order, and again until a balance is reached the offers are approved starting from the top of the list. The resulting final price is DAMP. Several examples for a sample system are provided below to better explain how day-ahead market works (EMRA, 2011).

Sample System

The sample system consists of five power plants (i.e. suppliers or producers) and four consumers. The suppliers are named as **A**, **B**, **C**, **D,** and **E** and consumers as **T1**, **T2**, **T3**, and **T4**. Existing bilateral contracts between the suppliers and the consumers are summarized in Table A.1.

The suppliers (i.e. power plants)

A – Thermal Power Plant running with lignite (Installed Capacity: 60 MW)

B – Thermal Power Plant running with natural gas (Installed Capacity: 45 MW)

C – Hydroelectric Power Plant with storage (Installed Capacity: 40 MW)

D – Run-of-river Hydroelectric Power Plant (Installed Capacity: 5 MW)

E – Thermal Power Plant running with fuel oil (Installed Capacity: 10 MW)

The total installed capacity of the system is 160 MW.

The consumers

T1 – Consumer (An Electricity Distribution Company)

T2 – Consumer (An Electricity Distribution Company)

T3 – Consumer (An Electricity Distribution Company)

T4 – Consumer (An iron-steel factory)

Table A.1 Existing Bilateral Contracts between the Suppliers and the Consumers

Supplier	Consumer	Installed Capacity (MW)	Price (TL/MWh)
A	T1	20	100
A	T2	20	105
B	T1	25	110
B	T4	10	110
C	T3	20	120

Example 1.

The day-ahead bids for producers are composed of power supplies, additional loadings and load sheddings and their associated prices for each hour of the next day. As an example, power demand and supplies, the amounts of additional loading and load shedding and their associated prices for 8:00-9:00 are provided in Tables A.2, A.3 and A.4, respectively. The day-ahead bids for consumers are composed of only power demands and the power demands for 8:00-9:00 are given in Table A.2.

Table A.2 Day-Ahead Bids: Power Supplies and Power Demands 08:00-09:00

Consumers	T1	T2	T3	T4	Total
Power (MW)	50	20	25	15	**110**

Producers	A	B	C	D	E	Total
Power (MW)	40	35	20	0	5	**100**

Table A.3 Day-Ahead Bids: Additional Loadings for 08:00-09:00

Producers	Power (MW)	Price (TL/MWh)	
Plant A	5	120	
Plant B	5	**130**	**DAMP**
Plant C	10	135	
Plant D	5	150	

Table A.4 Day-Ahead Bids: Load Sheddings for 08:00-09:00

Producer	Power (MW)	Price (TL/MWh)
Plant B	5	90
Plant A	5	80
Plant C	5	75

As can be seen from Table A.2 the difference between the power demand and the supply is 10 MW. This power deficiency must be balanced by using the bids for additional loading and their associated prices. The collected bids for additional loading from suppliers are arranged in the ascending order as given in Table A.3. An additional 10 MW loading is needed to be granted to the best bidders. As can be seen from Table A.3, Plant A and B made the lowest bids for additional loadings of 5 MW. Thus, the system grants 5 MW additional loading to Plant A and Plant B. This balances the system and gives rise to a DAMP of 130 TL/MW. DAMP is determined as follows. Plant B is the last plant which is granted an additional loading. Thus, the price offered by Plant B for the additional loading (i.e. 130 TL/MW) becomes the DAMP. As a result, both Plant A and Plant B will provide 5 MW additional loading at a price of 130 TL/MWh. The resulting incomes and expenses of the suppliers and consumers for this example are provided in Tables A.5 and A.6, respectively.

Table A.5 Energy Incomes of the Suppliers for 08:00-09:00

Suppliers							Power(MW)	Total Income (TL)
Plant A	20 x 100	+	20 x 105	+	5 x 130		45	4750
	Bilateral Contract with T1		Bilateral Contract with T2		Income formed by DAMP			
Plant B	25 x 110	+	10 x 110	+	5 x 130		40	4500
	Bilateral Contract with T2		Bilateral Contract with T4		Income formed by DAMP			
Plant C	20 x 120						20	2400
	Bilateral Contract with T3							
Plant D	-						0	0
	-							
Plant E	5 x 130						5	650
	Income formed by DAMP							
					Total Power (MW)		**110**	**12300**

Table A.6 Energy Expenses of the Consumers for 08:00-9:00

Consumers							Power (MW)	Total Expense (TL)
Consumer T1	20 x 100	+	25 x 110	+	5 x 130		50	5400
	Bilateral Contract with A		Bilateral Contract with B		Expense formed by DAMP			
Consumer T2	20 x 105						20	2100
	Bilateral Contract with A							
Consumer T3	20 x 120	+	5 x 130				25	3050
	Bilateral Contract with C		Expense formed by DAMP					
Consumer T4	10 x 110	+	5 x 130				15	1750
	Bilateral Contract with B		Expense formed by DAMP					
					Total Power (MW)		**110**	**12300**

As seen in Table A.5, Plant E earns 650 TL although it has no bilateral contract. Plants A, B and C earn money through their bilateral contracts. Plants A and B earn additional money (i.e. 5x130=650 TL each) due to balancing the initial deficiency formed in the system. Consumer T2 pays according to its bilateral contract (i.e. is not affected from the resulting price, DAMP). On the other hand, Consumers T1, T3 and T4, must pay for the additional power demand (i.e. additional to their bilateral contracts) at DAMP.

In this example, the demand is more than the supply and only bids for the additional loadings are needed to balance the system. However, for the sake of completeness (i.e. to present a complete set of bids for day-ahead market) load sheddings are provided (Table A.4) as well. In the following examples, for simplicity, only the required components of the day-ahead bids are given.

Example 2.

Power demand and supply inputs of the consumers and suppliers, respectively for 16:00-17:00 are given in Table A.7:

Table A.7 Day-Ahead Bids: Power Supplies and Power Demands for 16:00-17:00

Consumers	T1	T2	T3	T4	Total
Power (MW)	45	15	20	5	**85**

Producers	A	B	C	D	E	Total
Power (MW)	40	35	20	5	0	**100**

Analysis of day-ahead supply and demand bids results in a total of 15 MW power surplus in the system. In this situation, the collected load shedding offers from the suppliers are arranged in the descending order. Bids for load sheddings provided by the producers are given in Table A.8.

Table A.8 Day-Ahead Bids: Load Sheddings for 16:00 – 17:00

Producers	Power (MW)	Price (TL/MWh)	
Plant B	5	90	
Plant A	5	80	
Plant C	5	**75**	**DAMP**

As can be seen from Table A.8, Plant B offers to decrease what it has previously offered to supply (i.e. 35 MW) by 5 MW for a price of 90 TL/MWh. Similarly, Plants A and C offer to supply 5 MW less for prices of 80 TL/MWh and 75 TL/MWh, respectively. Since the surplus in the system is 15 MW, Plants A, B, and C are all granted to shed their loads by 5 MW. Thus the DAMP is set as 75 TL/MWh (see Table A.8). When there is a surplus in the system, the price offered by last producer which is granted a load shedding is set as the DAMP (see Table A.8).

The resulting incomes and expenses of the suppliers and consumers for this example are provided in Tables A.9 and A.10, respectively. As can be seen from Table A.9, Plant A supplies only 35 MW, and its net income is 3725 TL (i.e. 20x100+15x105+5x(105-75)=3725 TL) for one hour. The price of 5 MW that Plant A forfeit supplying is 5x(105-75)=150 TL.

Table A.9 Energy Incomes of the Suppliers for 16.00-17:00

Suppliers						Power (MW)	Total Income (TL)
Plant A	20 x 100	+	20 x 105	-	5 x 75	35	3725
	Bilateral Contract with T1		Bilateral Contract with T2		Expense formed by DAMP		
Plant B	25 x 110	+	10 x 110	-	5 x 75	30	3475
	Bilateral Contract with T2		Bilateral Contract with T4		Expense formed by DAMP		
Plant C	20 x 120	-	5 x 75			15	2025
	Bilateral Contract with T3		Expense formed by DAMP				
Plant D	5 x 75					5	375
	Income formed by DAMP						
Plant E	-					0	0
	-						
					Total Power (MW)	**85**	**9600**

Table A.10 Energy Expenses of the Consumers for 16:00-17:00

Consumers				Power (MW)	Total Expense (TL)
Consumer T1	20 x 100	+	25 x 110	45	4750
	Bilateral Contract with A		Bilateral Contract with B		
Consumer T2	20 x 105	-	5 x 75	15	1725
	Bilateral Contract with A		Income formed by DAMP		
Consumer T3	20 x 120			20	2400
	Bilateral Contract with C				
Consumer T4	10 x 110	-	5 x 75	5	725
	Bilateral Contract with B		Income formed by DAMP		
			Total Power (MW)	**85**	**9600**

Plants A, B and C earn money in accordance with their bilateral contracts although they do not supply power as stated in their bilateral contracts. However, they become indebted to the related consumers for the power that they did not supply. In other words, the consumers are responsible for paying the difference between the bilateral contract price and the resulting lower price (DAMP).

Consumers T1 and T3 requests power in accordance with their bilateral contracts. Therefore they only pay the price stated in their bilateral contracts. Consumers T2 and T4 are responsible for the payment of the difference between the power demands determined as a result of the day-ahead market and demands stated in their bilateral contracts. As these results show, the system encourages the consumers to make their bilateral contracts in accordance with their realistic power demand projections.

Example 3.

The consumer's power demand and the supplier's power supply plans input to the system for the duration of 18:00-19:00 are given in Table A.11. As can be seen from Table A.11 Plant B stopped its generation totally due to failure or maintenance.

Table A.11 Day-Ahead Bids: Power Supplies and Power Demands for 18:00 – 19.00

Consumers	T1	T2	T3	T4	Total
Power (MW)	45	20	20	10	**95**

Producers	A	B	C	D	E	Total
Power (MW)	40	0	30	5	0	**75**

There is 20 MW power deficiency in the system. Therefore, the prices associated with load shedding offers of the producers are arranged in the ascending order as can be seen in Table A.12.

Table A.12 Day-Ahead Bids: Additional Loadings for 18:00 – 19:00

Producers	Power (MW)	Price (TL/MWh)	
Plant A	10	110	
Plant C	5	120	
Plant E	5	**140**	**DAMP**

Plants A, C and E are granted additional loadings according to Table A.12. The price offered by the last producer which is granted additional loading is 140 TL/MWh. Thus, the DAMP is set to 140 TL/MWh. The resulting incomes and expenses of the suppliers and consumers for this example are provided in Tables A.13 and A.14, respectively.

Table A.13 Energy Incomes of the Suppliers for 18:00-19:00

Suppliers				Power (MW)	Total Income (TL)
Plant A	20 x 100 (Bilateral Contract with T1)	+ 20 x 105 (Bilateral Contract with T2)	+ 10 x 140 (Income formed by DAMP)	50	5500
Plant B	25 x 110 (Bilateral Contract with T2)	+ 10 x 110 (Bilateral Contract with T4)	- 35 x 140 (Expense formed by DAMP)	0	-1050
Plant C	20 x 120 (Bilateral Contract with T3)	+ 15 x 140 (Income formed by DAMP)		35	4500
Plant D	5 x 140 (Income formed by DAMP)			5	700
Plant E	5 x 140 (Income formed by DAMP)			5	700
			Total Power (MW)	**95**	**10350**

Table A.14 Energy Expenses of the Consumers for 18:00-19:00

Consumers			Power (MW)	Total Expense (TL)
Consumer T1	20 x 100 (Bilateral Contract with A)	+ 25 x 110 (Bilateral Contract with B)	45	4750
Consumer T2	20 x 105 (Bilateral Contract with A)		15	2100
Consumer T3	20 x 120 (Bilateral Contract with C)		20	2400
Consumer T4	10 x 110 (Bilateral Contract with B)		5	1100
		Total Power (MW)	**85**	**10350**

In this example, Plant B chose to input no supply to the system and this caused a deficiency that must be fulfilled by the other producers. Plants A, C, and E increased their power supplies to balance the system.

All the consumers input their power demands in accordance with their bilateral contracts, thus they only pay prices stated in their bilateral contracts. The power deficiency is due to Plant B, so it must pay all the extra money (i.e. 1050 TL) to the producers which take additional loading (see Table A.13). As can be seen in this and the previous example, the consumer or the supplier which causes imbalance in the system pays the resulting price difference. In Example 3, Plant B stopped its generation and caused 20 MW deficiency in the system. Thus Plant B is responsible for paying the resulting price difference of 35x140 TL.

Example 4.

In this example, Plant B cannot fulfill its power supply commitment totally, and Plant D bids to supply an amount equal to Plant B's deficiency (i.e. 5 MW) (see Table A.15).

Table A.15 Day-Ahead Bids: Power Supplies and Power Demands for 14:00 – 15.00

Consumers	T1	T2	T3	T4	Total
Power (MW)	45	20	20	10	**95**

Producers	A	B	C	D	E	Total
Power (MW)	40	30	20	5	0	**95**

In this example, the system is balanced. Perfect balance in real life is not possible due to the large number of participants (both consumers and suppliers) of the system. Although theoretically possible such a situation never occurs in real market.

Evaluation of day-ahead market bids and balancing the system for various cases are studied in these four examples. In addition to the hourly offers, the producers can also place block bids or flexible bids to the system. These two types of bids are explained in the following paragraphs.

A.3 The Block Bid and the Flexible Bid

The Block bid is composed of an offer with a fixed quantity of power generation or power shedding for a fixed period of consecutive hours. As the name implies block bids can only be rewarded as a block. Block bids are suitable for thermal plants since loading and load shedding for short periods are difficult for such plants.

The Flexible bid is a power generation offer from a supplier without a specific time interval. The system may choose to use this generation any time to balance the system.

A.4 The Intra-Day Market

Although a balance is obtained during the day-ahead market, the real time situation may force the suppliers and the consumers to act differently. For example, a run-of-river type hydropower plant may end up supplying a different amount of power than the amount determined as a result of the day-ahead market based on the real time flow conditions or a wind turbine may deviate from its initial power supply amounts (i.e. ones approved as a result of the day-ahead market) due to real time wind situation. Thus, another round of balancing has to be done using the second set of bids collected the previous day to match real time supplies and demands. This is called balancing for the intra-day market and it is similar to that of the day-ahead market. Several examples demonstrating the balancing of the intra-day market is provided below.

Example 5.

Let us investigate the intra-day market for the situation given in ***Example 1.*** The day-ahead the real time demands and supplies are given in Table A.16.

Table A.16 Day-Ahead and Real Time Power Supplies and Power Demands for 08:00-09:00

	Consumers	T1	T2	T3	T4	Total
Day-Ahead	Power (MW)	50	20	25	15	**110**
Real Time	Power (MW)	50	25	30	15	**120**

	Producers	A	B	C	D	E	Total
Day-Ahead	Power (MW)	45	40	20	0	5	**110**
Real Time	Power (MW)	45	40	20	0	5	**110**

In the real time, Consumers T2 and T3 demand 5 MW additional power while Consumers T1 and T4 do not revise their day-ahead market demands. As can be seen from Table A.16, the total demand is 120 MW while the total supply is only 110 MW. Therefore, an additional 10 MW supply is required to balance the system. In this situation, previously collected bids from the suppliers are used to balance the system. The additional loadings are arranged again in the ascending order as given in Table A.17.

Table A.17 Real Time Bids: Additional Loadings for 08:00 – 09:00

Producers	Power (MW)	Price (TL/MWh)	
Plant A	5	140	
Plant C	**5**	**150**	**RTP**
Plant B	5	160	
Plant E	5	180	

Similar to day-ahead market balance, additional loadings are sorted in ascending order according to the additional loading bid prices and plants are granted additional supplies starting from the top of the list until all the deficiency is met. The additional real time power demand caused the electricity price to increase. As can be seen from Table A.17, the resulting real time price (RTP) is 150 TL/MWh while the DAMP was 130 TL/MWh (see Table A.3). The resulting incomes and expenses of the suppliers and consumers for this example are provided in Tables A.18 and A.19, respectively.

Table A.18 Energy Incomes of the Suppliers for 08:00 – 09:00

Suppliers					Power (MW)	Total Income (TL)
Plant A	20 x 100 (Bilateral Contract with T1)	+ 20 x 105 (Bilateral Contract with T2)	+ 5 x 130 (Income formed by DAMP)	+ 5 x 150 (Income formed by RTP)	50	5500
Plant B	25 x 110 (Bilateral Contract with T2)	+ 10 x 110 (Bilateral Contract with T4)	+ 5 x 130 (Income formed by DAMP)		40	4500
Plant C	20 x 120 (Bilateral Contract with T3)	+ 5 x 150 (Income formed by RTP)			25	3150
Plant D	-				0	0
Plant E	5 x 130 (Income formed by DAMP)				5	650
				Total Power (MW)	120	13800

Table A.19 Energy Expenses of the Consumers for 08:00 – 09:00

Consumers				Power (MW)	Total Expense (TL)
Consumer T1	20 x 100 (Bilateral Contract with A)	+ 25 x 110 (Bilateral Contract with B)	+ 5 x 130 (Expense formed by DAMP)	50	5400
Consumer T2	20 x 105 (Bilateral Contract with A)	+ 5 x 150 (Expense formed by RTP)		25	2850
Consumer T3	20 x 120 (Bilateral Contract with C)	+ 5 x 130 (Expense formed by DAMP)	+ 5 x 150 (Expense formed by RTP)	30	3800
Consumer T4	10 x 110 (Bilateral Contract with B)	+ 5 x 130 (Expense formed by DAMP)		15	1750
			Total Power (MW)	120	13800

Consumers T2 and T3 caused an imbalance in the system in real time; therefore they are obligated to pay for their additional power demand at the higher RTP. On the other hand, Consumers T1 and T2 are not affected from the RTP because of their successful power demand bids in the day-ahead market. Plant A and C compensates the deficiency of the system and made additional profit through selling additional power from RTP.

Example 6.

The real time situation for ***Example 2*** is considered here. The day-ahead and the real time supplies and demands are given in Table A.20.

Table A.20 Day-Ahead and Real Time Power Supplies and Power Demands for 16:00-17:00

	Consumers	T1	T2	T3	T4	Total
Day-Ahead	Power (MW)	45	15	20	5	**85**
Real Time	Power (MW)	45	15	20	10	**90**

	Producers	A	B	C	D	E	Total
Day-Ahead	Power (MW)	35	30	15	5	0	**85**
Real Time	Power (MW)	35	30	15	0	0	**80**

In the real time, Consumer T4 realizes that it needs additional energy, thus requests an additional 5 MW. On the other hand, Plant D realized that it cannot produce the 5 MW which was granted to it as a result of the day-ahead market. The reason for such a load shedding may be a breakdown at Plant D or not having estimated amount of water in the river to feed the turbines.

As can be seen in Table A.20, there is a total of 10 MW energy shortage in real time. As can be seen in Table A.7, there was an energy surplus of 15 MW in the day-ahead market. Second set of bids collected from the suppliers are used to balance the system. The additional loadings are arranged in ascending order as provided in Table A.21

Table A.21 Real Time Bids: Additional Loadings for 16:00 – 17.00

Producers	Power (MW)	Price (TL/MWh)	
Plant A	5	110	
Plant C	5	**120**	**RTP**
Plant B	5	130	
Plant E	5	150	

Plants A and C are granted 5 MW additional loading and RTP is set as 120 TL/MWh. RTP corresponds to price offered by the last producer which is granted additional loading (see

Table A.21). The resulting incomes and expenses of the suppliers and consumers for this example are provided in Tables A.22 and A.23, respectively.

Table A.22 Energy Incomes of the Suppliers for 16:00 – 17:00

Suppliers								Power (MW)	Total Income (TL)
Plant A	20 x 100 (Bilateral Contract with T1)	+	20 x 105 (Bilateral Contract with T2)	-	5 x 75 (Expense formed by DAMP)	+	5 x 120 (Income formed by RTP)	40	4325
Plant B	25 x 110 (Bilateral Contract with T2)	+	10 x 110 (Bilateral Contract with T4)	-	5 x 75 (Expense formed by DAMP)			30	3475
Plant C	20 x 120 (Bilateral Contract with T3)	-	5 x 75 (Expense formed by DAMP)	+	5 x 120 (Income formed by RTP)			20	2625
Plant D	5 x 75 (Income formed by DAMP)	-	5 x 120 (Debt formed by RTP)					0	-225
Plant E	- (-)							0	0
							Total Power (MW)	90	10200

Table A.23 Energy Expenses of the Consumers for 16:00 – 17:00

Consumers						Power (MW)	Total Expense (TL)
Consumer T1	20 x 100 (Bilateral Contract with A)	+	25 x 110 (Bilateral Contract with B)			45	4750
Consumer T2	20 x 105 (Bilateral Contract with A)	-	5 x 75 (Income formed by DAMP)			15	1725
Consumer T3	20 x 120 (Bilateral Contract with C)					20	2400
Consumer T4	10 x 110 (Bilateral Contract with B)	-	5 x 75 (Income formed by DAMP)	+	5 x 120 (Expense formed by RTP)	10	1325
					Total Power (MW)	90	10200

In this example, Plant D caused an imbalance in the system and was obligated to pay the cost of not producing the power granted to it at the end of the day-ahead market. Although Consumer T4 had a bilateral contract in agreement with what it consumed in the real time, it become indebted to the system due to the wrong power demand bid it submitted to the day-ahead market.

Example 7.

The real time situation for ***Example 3*** is considered here. The day-ahead and the real time supplies and demands are given in Table A.24.

Table A.24 Day-Ahead and Real Time Power Supplies and Power Demands for 18:00-19:00

	Consumers	T1	T2	T3	T4	Total
Day-Ahead	Power (MW)	45	20	20	10	**95**
Real Time	Power (MW)	45	15	20	10	**90**

	Producers	A	B	C	D	E	Total
Day-Ahead	Power (MW)	50	0	35	5	5	**95**
Real Time	Power (MW)	50	20	40	5	5	**120**

As can be remembered from ***Example 3***, Plant B did not volunteer to supply power to the system due to maintenance or failure in the day-ahead market. Consequently, at the end of the day-ahead market it was not granted any power generation. However, the maintenance operations are completed earlier than expected so Plant B starts generating electricity for the system. Similarly, Plant C increases its generation from 35 MW (i.e. what was granted to it at the end of the day-ahead market) to 40 MW. In real time, there exists an energy surplus, which is due to additional supplies by Plants B and C (see Table A.24). This time load sheddings from second set of bids are used to balance the system. Load sheddings are given in Table A.25. As can be seen from Table A.25 Plants A, D and E are selected to balance the system through load shedding with an RTP of 60 TL/MWh.

Table A.25 Load Shedding Proposals (18:00 – 19:00)

Producers	Power (MW)	Price (TL/MWh)	
Plant A	20	100	
Plant D	5	80	
Plant E	5	**60**	**RTP**

The hydropower plants pay a certain amount of money to DSİ per each kWh electricity they generate. If the overall revenue of the hydropower plant according to DAMP considering the share of DSİ is expected to be lower than the overall revenue according to RTP (i.e. the case where the hydropower plant chooses load shedding and as a result do not generate any electricity) then load shedding might be preferable. This might be the reason why Plant D in the above example chooses load shedding. Although Plant D does not generate any electricity in the real time, because it balances the system, it makes money due to the price difference (see Table A.26). The resulting incomes and expenses of the suppliers and consumers for this example are provided in Tables A.26 and A.27, respectively.

Table A.26 Energy Incomes of the Suppliers for 18:00-19:00

Suppliers								Power (MW)	Total Income (TL)
Plant A	20 x 100	+	20 x 105	+	10 x 140	-	20 x 60	30	4300
	Bilateral Contract with T1		Bilateral Contract with T2		Income formed by DAMP		Expense formed by RTP		
Plant B	25 x 110	+	10 x 110	-	35 x 140	+	20 x 60	20	150
	Bilateral Contract with T2		Bilateral Contract with T4		Expense formed by DAMP		Income formed by RTP		
Plant C	20 x 120	+	15 x 140	+	5 x 60			40	4800
	Bilateral Contract with T3		Income formed by DAMP		Income formed by RTP				
Plant D	5 x 140	-	5 x 60					0	400
	Income formed by DAMP		Expense formed by RTP						
Plant E	5 x 140	-	5 x 60					0	400
	Income formed by DAMP		Expense formed by RTP						
							Total Power (MW)	90	10050

Table A.27 Energy Expenses of the Consumers for 18:00 -19:00

Consumers					Power (MW)	Total Expense (TL)
Consumer T1	20 x 100	+	25 x 110		45	4750
	Bilateral Contract with A		Bilateral Contract with B			
Consumer T2	20 x 105	-	5 x 60		15	1800
	Bilateral Contract with A		Income formed by RTP			
Consumer T3	20 x 120				20	2400
	Bilateral Contract with C					
Consumer T4	10 x 110				10	1100
	Bilateral Contract with B					
				Total Power (MW)	90	10050

Similar to that of the day-ahead market, suppliers and consumers that act in accordance with their power plans granted to them at the end of the day-ahead market are not affected from the higher prices (i.e RTP). On the other hand, the participants of the system which cannot fulfill their commitments granted to them at the end of the day-ahead market are exposed to RTP. As can be seen in these examples, the suppliers may earn money even if they do not generate electricity. In addition, consumers which were not able to predict their power demands can be indebted to the system for the energy that they do not consume. In summary, good planners do not cause imbalances in the system. In fact, they can earn extra money by only balancing the system. On the other hand, bad planners have to pay the penalty for causing imbalances in the system.

APPENDIX B

TABLES

Table B-1 Ranking of flows for EİE project (PTEE*: Percent Time Equaled and Exceeded)

Rank	Flow (m^3/s)	% PTEE*	Rank	Flow (m^3/s)	% PTEE*	Rank	Flow (m^3/s)	% PTEE*
1	38.89	0.23%	145	7.96	33.56%	289	3.33	66.90%
2	37.21	0.46%	146	7.75	33.80%	290	3.33	67.13%
3	36.09	0.69%	147	7.65	34.03%	291	3.32	67.36%
4	35.93	0.93%	148	7.34	34.26%	292	3.30	67.59%
5	34.05	1.16%	149	7.25	34.49%	293	3.30	67.82%
6	33.66	1.39%	150	7.22	34.72%	294	3.29	68.06%
7	33.66	1.62%	151	7.13	34.95%	295	3.27	68.29%
8	32.97	1.85%	152	6.93	35.19%	296	3.25	68.52%
9	32.43	2.08%	153	6.77	35.42%	297	3.24	68.75%
10	32.10	2.31%	154	6.77	35.65%	298	3.24	68.98%
11	31.79	2.55%	155	6.76	35.88%	299	3.24	69.21%
12	31.59	2.78%	156	6.73	36.11%	300	3.23	69.44%
13	30.31	3.01%	157	6.56	36.34%	301	3.22	69.68%
14	30.23	3.24%	158	6.55	36.57%	302	3.21	69.91%
15	30.01	3.47%	159	6.23	36.81%	303	3.21	70.14%
16	29.14	3.70%	160	6.22	37.04%	304	3.20	70.37%
17	28.72	3.94%	161	6.10	37.27%	305	3.19	70.60%
18	28.65	4.17%	162	6.07	37.50%	306	3.17	70.83%
19	28.53	4.40%	163	6.06	37.73%	307	3.15	71.06%
20	28.18	4.63%	164	6.05	37.96%	308	3.13	71.30%
21	27.54	4.86%	165	6.05	38.19%	309	3.11	71.53%
22	27.40	5.09%	166	5.99	38.43%	310	3.06	71.76%
23	26.75	5.32%	167	5.95	38.66%	311	3.06	71.99%
24	26.37	5.56%	168	5.89	38.89%	312	3.04	72.22%
25	25.94	5.79%	169	5.83	39.12%	313	2.99	72.45%
26	25.86	6.02%	170	5.78	39.35%	314	2.97	72.69%
27	25.86	6.25%	171	5.78	39.58%	315	2.97	72.92%
28	24.99	6.48%	172	5.76	39.81%	316	2.95	73.15%
29	24.83	6.71%	173	5.76	40.05%	317	2.95	73.38%
30	24.78	6.94%	174	5.70	40.28%	318	2.93	73.61%
31	24.75	7.18%	175	5.63	40.51%	319	2.93	73.84%
32	24.68	7.41%	176	5.50	40.74%	320	2.91	74.07%
33	24.62	7.64%	177	5.49	40.97%	321	2.91	74.31%
34	24.08	7.87%	178	5.47	41.20%	322	2.90	74.54%

Table B-1 (Continued)

Rank	Flow (m^3/s)	% PTEE*	Rank	Flow (m^3/s)	% PTEE*	Rank	Flow (m^3/s)	% PTEE*
35	23.93	8.10%	179	5.43	41.44%	323	2.89	74.77%
36	23.79	8.33%	180	5.42	41.67%	324	2.86	75.00%
37	23.79	8.56%	181	5.42	41.90%	325	2.86	75.23%
39	23.52	9.03%	183	5.25	42.36%	327	2.82	75.69%
40	23.49	9.26%	184	5.22	42.59%	328	2.82	75.93%
41	23.39	9.49%	185	5.19	42.82%	329	2.80	76.16%
42	23.37	9.72%	186	5.16	43.06%	330	2.79	76.39%
43	23.24	9.95%	187	5.15	43.29%	331	2.79	76.62%
44	23.20	10.19%	188	5.09	43.52%	332	2.78	76.85%
45	23.10	10.42%	189	5.08	43.75%	333	2.78	77.08%
46	23.07	10.65%	190	5.04	43.98%	334	2.76	77.31%
47	23.00	10.88%	191	5.02	44.21%	335	2.75	77.55%
48	22.86	11.11%	192	4.99	44.44%	336	2.74	77.78%
49	22.80	11.34%	193	4.99	44.68%	337	2.74	78.01%
50	22.70	11.57%	194	4.97	44.91%	338	2.71	78.24%
51	22.48	11.81%	195	4.96	45.14%	339	2.71	78.47%
52	22.41	12.04%	196	4.92	45.37%	340	2.70	78.70%
53	22.31	12.27%	197	4.91	45.60%	341	2.67	78.94%
54	22.15	12.50%	198	4.90	45.83%	342	2.67	79.17%
55	21.95	12.73%	199	4.88	46.06%	343	2.66	79.40%
56	21.72	12.96%	200	4.87	46.30%	344	2.66	79.63%
57	21.32	13.19%	201	4.80	46.53%	345	2.64	79.86%
58	21.26	13.43%	202	4.79	46.76%	346	2.60	80.09%
59	21.12	13.66%	203	4.78	46.99%	347	2.60	80.32%
60	21.04	13.89%	204	4.76	47.22%	348	2.57	80.56%
61	21.02	14.12%	205	4.72	47.45%	349	2.56	80.79%
62	20.40	14.35%	206	4.71	47.69%	350	2.56	81.02%
63	20.39	14.58%	207	4.71	47.92%	351	2.51	81.25%
64	20.20	14.81%	208	4.68	48.15%	352	2.44	81.48%
65	20.14	15.05%	209	4.66	48.38%	353	2.43	81.71%
66	20.04	15.28%	210	4.65	48.61%	354	2.42	81.94%
67	20.03	15.51%	211	4.64	48.84%	355	2.42	82.18%
68	19.96	15.74%	212	4.62	49.07%	356	2.40	82.41%
69	19.61	15.97%	213	4.59	49.31%	357	2.39	82.64%
70	19.54	16.20%	214	4.59	49.54%	358	2.38	82.87%
71	19.13	16.44%	215	4.58	49.77%	359	2.37	83.10%
72	19.07	16.67%	216	4.58	50.00%	360	2.36	83.33%
73	18.57	16.90%	217	4.55	50.23%	361	2.36	83.56%
74	18.44	17.13%	218	4.54	50.46%	362	2.36	83.80%
75	18.44	17.36%	219	4.54	50.69%	363	2.35	84.03%
76	18.37	17.59%	220	4.53	50.93%	364	2.32	84.26%
77	18.36	17.82%	221	4.50	51.16%	365	2.30	84.49%
78	17.96	18.06%	222	4.47	51.39%	366	2.30	84.72%
79	17.66	18.29%	223	4.46	51.62%	367	2.29	84.95%
80	17.45	18.52%	224	4.46	51.85%	368	2.28	85.19%

Table B-1 (Continued)

Rank	Flow (m^3/s)	% PTEE*	Rank	Flow (m^3/s)	% PTEE*	Rank	Flow (m^3/s)	% PTEE*
81	17.43	18.75%	225	4.41	52.08%	369	2.26	85.42%
82	17.35	18.98%	226	4.37	52.31%	370	2.26	85.65%
83	17.24	19.21%	227	4.32	52.55%	371	2.25	85.88%
85	16.68	19.68%	229	4.29	53.01%	373	2.24	86.34%
86	16.48	19.91%	230	4.29	53.24%	374	2.24	86.57%
87	16.16	20.14%	231	4.27	53.47%	375	2.23	86.81%
88	16.16	20.37%	232	4.21	53.70%	376	2.22	87.04%
89	15.26	20.60%	233	4.20	53.94%	377	2.19	87.27%
90	15.20	20.83%	234	4.20	54.17%	378	2.15	87.50%
91	15.10	21.06%	235	4.18	54.40%	379	2.11	87.73%
92	15.00	21.30%	236	4.14	54.63%	380	2.10	87.96%
93	14.81	21.53%	237	4.11	54.86%	381	2.10	88.19%
94	14.71	21.76%	238	4.11	55.09%	382	2.07	88.43%
95	14.65	21.99%	239	4.11	55.32%	383	2.07	88.66%
96	14.44	22.22%	240	4.10	55.56%	384	2.07	88.89%
97	14.35	22.45%	241	4.08	55.79%	385	2.06	89.12%
98	14.21	22.69%	242	4.08	56.02%	386	2.04	89.35%
99	14.03	22.92%	243	4.07	56.25%	387	2.01	89.58%
100	13.87	23.15%	244	4.03	56.48%	388	2.01	89.81%
101	13.82	23.38%	245	4.03	56.71%	389	1.96	90.05%
102	13.82	23.61%	246	3.99	56.94%	390	1.96	90.28%
103	13.68	23.84%	247	3.95	57.18%	391	1.96	90.51%
104	13.32	24.07%	248	3.94	57.41%	392	1.95	90.74%
105	13.00	24.31%	249	3.92	57.64%	393	1.95	90.97%
106	12.96	24.54%	250	3.92	57.87%	394	1.93	91.20%
107	12.83	24.77%	251	3.92	58.10%	395	1.93	91.44%
108	12.83	25.00%	252	3.89	58.33%	396	1.91	91.67%
109	12.79	25.23%	253	3.89	58.56%	397	1.89	91.90%
110	12.73	25.46%	254	3.88	58.80%	398	1.89	92.13%
111	12.54	25.69%	255	3.86	59.03%	399	1.89	92.36%
112	12.49	25.93%	256	3.84	59.26%	400	1.89	92.59%
113	12.32	26.16%	257	3.83	59.49%	401	1.88	92.82%
114	12.30	26.39%	258	3.82	59.72%	402	1.87	93.06%
115	12.24	26.62%	259	3.80	59.95%	403	1.85	93.29%
116	12.22	26.85%	260	3.79	60.19%	404	1.84	93.52%
117	12.18	27.08%	261	3.78	60.42%	405	1.83	93.75%
118	12.06	27.31%	262	3.77	60.65%	406	1.81	93.98%
119	11.92	27.55%	263	3.74	60.88%	407	1.80	94.21%
120	11.77	27.78%	264	3.73	61.11%	408	1.76	94.44%
121	11.65	28.01%	265	3.72	61.34%	409	1.75	94.68%
122	11.60	28.24%	266	3.72	61.57%	410	1.74	94.91%
123	11.55	28.47%	267	3.71	61.81%	411	1.73	95.14%
124	11.55	28.70%	268	3.69	62.04%	412	1.73	95.37%
125	11.55	28.94%	269	3.67	62.27%	413	1.73	95.60%
126	11.17	29.17%	270	3.63	62.50%	414	1.72	95.83%

Table B-1 (Continued)

Rank	Flow (m^3/s)	% PTEE*	Rank	Flow (m^3/s)	% PTEE*	Rank	Flow (m^3/s)	% PTEE*
127	11.06	29.40%	271	3.61	62.73%	415	1.70	96.06%
128	10.96	29.63%	272	3.59	62.96%	416	1.70	96.30%
129	10.96	29.86%	273	3.54	63.19%	417	1.69	96.53%
130	10.66	30.09%	274	3.53	63.43%	418	1.67	96.76%
131	10.54	30.32%	275	3.52	63.66%	419	1.66	96.99%
132	10.46	30.56%	276	3.52	63.89%	420	1.62	97.22%
133	10.24	30.79%	277	3.51	64.12%	421	1.56	97.45%
134	9.96	31.02%	278	3.49	64.35%	422	1.56	97.69%
135	9.63	31.25%	279	3.46	64.58%	423	1.56	97.92%
136	9.53	31.48%	280	3.44	64.81%	424	1.54	98.15%
137	9.43	31.71%	281	3.43	65.05%	425	1.54	98.38%
138	9.30	31.94%	282	3.42	65.28%	426	1.46	98.61%
139	9.24	32.18%	283	3.42	65.51%	427	1.43	98.84%
140	9.05	32.41%	284	3.39	65.74%	428	1.32	99.07%
141	8.95	32.64%	285	3.38	65.97%	429	1.26	99.31%
142	8.86	32.87%	286	3.36	66.20%	430	1.26	99.54%
143	8.47	33.10%	287	3.36	66.44%	431	1.18	99.77%

Table B-2 Ranking of flows for ANC project (PTEE*: Percent Time Equaled and Exceeded)

Rank	Flow (m^3/s)	% PTEE*	Rank	Flow (m^3/s)	% PTEE*	Rank	Flow (m^3/s)	% PTEE*
1	37.51	0.23%	145	7.68	33.56%	289	3.21	66.90%
2	35.89	0.46%	146	7.47	33.80%	290	3.21	67.13%
3	34.81	0.69%	147	7.38	34.03%	291	3.20	67.36%
4	34.66	0.93%	148	7.08	34.26%	292	3.18	67.59%
5	32.85	1.16%	149	6.99	34.49%	293	3.18	67.82%
6	32.47	1.39%	150	6.96	34.72%	294	3.18	68.06%
7	32.47	1.62%	151	6.88	34.95%	295	3.15	68.29%
8	31.80	1.85%	152	6.68	35.19%	296	3.13	68.52%
9	31.28	2.08%	153	6.53	35.42%	297	3.12	68.75%
10	30.96	2.31%	154	6.53	35.65%	298	3.12	68.98%
11	30.66	2.55%	155	6.52	35.88%	299	3.12	69.21%
12	30.47	2.78%	156	6.49	36.11%	300	3.11	69.44%
13	29.23	3.01%	157	6.33	36.34%	301	3.10	69.68%
14	29.16	3.24%	158	6.32	36.57%	302	3.10	69.91%
15	28.95	3.47%	159	6.01	36.81%	303	3.09	70.14%
16	28.11	3.70%	160	6.00	37.04%	304	3.09	70.37%
17	27.71	3.94%	161	5.88	37.27%	305	3.08	70.60%
18	27.64	4.17%	162	5.85	37.50%	306	3.05	70.83%
19	27.51	4.40%	163	5.85	37.73%	307	3.03	71.06%
20	27.18	4.63%	164	5.84	37.96%	308	3.02	71.30%
21	26.56	4.86%	165	5.84	38.19%	309	3.00	71.53%
22	26.43	5.09%	166	5.78	38.43%	310	2.95	71.76%
23	25.80	5.32%	167	5.74	38.66%	311	2.95	71.99%
24	25.44	5.56%	168	5.68	38.89%	312	2.93	72.22%
25	25.02	5.79%	169	5.63	39.12%	313	2.88	72.45%
26	24.94	6.02%	170	5.58	39.35%	314	2.87	72.69%
27	24.94	6.25%	171	5.58	39.58%	315	2.86	72.92%
28	24.11	6.48%	172	5.56	39.81%	316	2.85	73.15%
29	23.95	6.71%	173	5.56	40.05%	317	2.84	73.38%
30	23.90	6.94%	174	5.49	40.28%	318	2.83	73.61%
31	23.87	7.18%	175	5.43	40.51%	319	2.83	73.84%
32	23.80	7.41%	176	5.30	40.74%	320	2.81	74.07%
33	23.75	7.64%	177	5.29	40.97%	321	2.80	74.31%
34	23.23	7.87%	178	5.27	41.20%	322	2.80	74.54%
35	23.08	8.10%	179	5.24	41.44%	323	2.78	74.77%
36	22.94	8.33%	180	5.23	41.67%	324	2.76	75.00%
37	22.94	8.56%	181	5.23	41.90%	325	2.76	75.23%
38	22.84	8.80%	182	5.07	42.13%	326	2.73	75.46%
40	22.66	9.26%	184	5.03	42.59%	328	2.72	75.93%
41	22.56	9.49%	185	5.01	42.82%	329	2.70	76.16%
42	22.54	9.72%	186	4.98	43.06%	330	2.69	76.39%
43	22.41	9.95%	187	4.97	43.29%	331	2.69	76.62%
44	22.37	10.19%	188	4.91	43.52%	332	2.68	76.85%
45	22.28	10.42%	189	4.90	43.75%	333	2.68	77.08%
46	22.25	10.65%	190	4.87	43.98%	334	2.67	77.31%
47	22.18	10.88%	191	4.84	44.21%	335	2.66	77.55%
48	22.05	11.11%	192	4.82	44.44%	336	2.65	77.78%
49	21.99	11.34%	193	4.81	44.68%	337	2.65	78.01%
50	21.90	11.57%	194	4.80	44.91%	338	2.62	78.24%
51	21.68	11.81%	195	4.79	45.14%	339	2.62	78.47%

Table B-2 (Continued)

Rank	Flow (m^3/s)	% PTEE*	Rank	Flow (m^3/s)	% PTEE*	Rank	Flow (m^3/s)	% PTEE*
52	21.61	12.04%	196	4.74	45.37%	340	2.61	78.70%
53	21.52	12.27%	197	4.74	45.60%	341	2.58	78.94%
54	21.36	12.50%	198	4.72	45.83%	342	2.58	79.17%
55	21.17	12.73%	199	4.70	46.06%	343	2.56	79.40%
56	20.95	12.96%	200	4.69	46.30%	344	2.56	79.63%
57	20.56	13.19%	201	4.63	46.53%	345	2.54	79.86%
58	20.51	13.43%	202	4.62	46.76%	346	2.50	80.09%
59	20.37	13.66%	203	4.61	46.99%	347	2.50	80.32%
60	20.30	13.89%	204	4.59	47.22%	348	2.48	80.56%
61	20.28	14.12%	205	4.55	47.45%	349	2.47	80.79%
62	19.67	14.35%	206	4.55	47.69%	350	2.47	81.02%
63	19.67	14.58%	207	4.54	47.92%	351	2.42	81.25%
64	19.49	14.81%	208	4.51	48.15%	352	2.36	81.48%
65	19.42	15.05%	209	4.49	48.38%	353	2.35	81.71%
66	19.33	15.28%	210	4.49	48.61%	354	2.33	81.94%
67	19.32	15.51%	211	4.47	48.84%	355	2.33	82.18%
68	19.26	15.74%	212	4.46	49.07%	356	2.31	82.41%
69	18.92	15.97%	213	4.43	49.31%	357	2.30	82.64%
70	18.85	16.20%	214	4.43	49.54%	358	2.29	82.87%
71	18.45	16.44%	215	4.42	49.77%	359	2.29	83.10%
72	18.39	16.67%	216	4.42	50.00%	360	2.28	83.33%
73	17.92	16.90%	217	4.39	50.23%	361	2.28	83.56%
74	17.79	17.13%	218	4.38	50.46%	362	2.28	83.80%
75	17.79	17.36%	219	4.38	50.69%	363	2.27	84.03%
76	17.72	17.59%	220	4.37	50.93%	364	2.24	84.26%
77	17.71	17.82%	221	4.34	51.16%	365	2.22	84.49%
78	17.33	18.06%	222	4.31	51.39%	366	2.22	84.72%
79	17.03	18.29%	223	4.30	51.62%	367	2.21	84.95%
80	16.83	18.52%	224	4.30	51.85%	368	2.20	85.19%
81	16.81	18.75%	225	4.26	52.08%	369	2.18	85.42%
82	16.73	18.98%	226	4.22	52.31%	370	2.18	85.65%
83	16.63	19.21%	227	4.17	52.55%	371	2.17	85.88%
84	16.19	19.44%	228	4.15	52.78%	372	2.17	86.11%
85	16.08	19.68%	229	4.14	53.01%	373	2.16	86.34%
86	15.90	19.91%	230	4.14	53.24%	374	2.16	86.57%
87	15.59	20.14%	231	4.12	53.47%	375	2.15	86.81%
88	15.59	20.37%	232	4.07	53.70%	376	2.14	87.04%
89	14.72	20.60%	233	4.06	53.94%	377	2.12	87.27%
90	14.66	20.83%	234	4.05	54.17%	378	2.07	87.50%
91	14.57	21.06%	235	4.03	54.40%	379	2.04	87.73%
92	14.47	21.30%	236	3.99	54.63%	380	2.03	87.96%
93	14.28	21.53%	237	3.97	54.86%	381	2.03	88.19%
94	14.19	21.76%	238	3.97	55.09%	382	2.00	88.43%
95	14.13	21.99%	239	3.96	55.32%	383	2.00	88.66%
96	13.93	22.22%	240	3.95	55.56%	384	2.00	88.89%
97	13.84	22.45%	241	3.93	55.79%	385	1.99	89.12%
98	13.71	22.69%	242	3.93	56.02%	386	1.97	89.35%
99	13.53	22.92%	243	3.93	56.25%	387	1.94	89.58%
100	13.38	23.15%	244	3.88	56.48%	388	1.93	89.81%
101	13.33	23.38%	245	3.88	56.71%	389	1.89	90.05%

Table B-2 (Continued)

Rank	Flow (m^3/s)	% PTEE*	Rank	Flow (m^3/s)	% PTEE*	Rank	Flow (m^3/s)	% PTEE*
102	13.33	23.61%	246	3.85	56.94%	390	1.89	90.28%
103	13.19	23.84%	247	3.81	57.18%	391	1.89	90.51%
104	12.85	24.07%	248	3.80	57.41%	392	1.89	90.74%
105	12.53	24.31%	249	3.78	57.64%	393	1.88	90.97%
106	12.50	24.54%	250	3.78	57.87%	394	1.86	91.20%
107	12.38	24.77%	251	3.78	58.10%	395	1.86	91.44%
108	12.38	25.00%	252	3.76	58.33%	396	1.84	91.67%
109	12.34	25.23%	253	3.75	58.56%	397	1.83	91.90%
110	12.28	25.46%	254	3.74	58.80%	398	1.82	92.13%
111	12.09	25.69%	255	3.72	59.03%	399	1.82	92.36%
112	12.05	25.93%	256	3.70	59.26%	400	1.82	92.59%
113	11.89	26.16%	257	3.69	59.49%	401	1.81	92.82%
114	11.87	26.39%	258	3.68	59.72%	402	1.80	93.06%
115	11.81	26.62%	259	3.67	59.95%	403	1.79	93.29%
116	11.79	26.85%	260	3.65	60.19%	404	1.77	93.52%
117	11.74	27.08%	261	3.65	60.42%	405	1.77	93.75%
118	11.63	27.31%	262	3.64	60.65%	406	1.74	93.98%
119	11.50	27.55%	263	3.60	60.88%	407	1.73	94.21%
120	11.36	27.78%	264	3.60	61.11%	408	1.69	94.44%
121	11.23	28.01%	265	3.59	61.34%	409	1.69	94.68%
122	11.19	28.24%	266	3.59	61.57%	410	1.67	94.91%
123	11.14	28.47%	267	3.58	61.81%	411	1.67	95.14%
124	11.14	28.70%	268	3.56	62.04%	412	1.67	95.37%
125	11.14	28.94%	269	3.54	62.27%	413	1.67	95.60%
126	10.77	29.17%	270	3.50	62.50%	414	1.66	95.83%
127	10.66	29.40%	271	3.48	62.73%	415	1.64	96.06%
128	10.57	29.63%	272	3.47	62.96%	416	1.64	96.30%
129	10.57	29.86%	273	3.41	63.19%	417	1.63	96.53%
130	10.28	30.09%	274	3.40	63.43%	418	1.61	96.76%
131	10.16	30.32%	275	3.40	63.66%	419	1.60	96.99%
132	10.09	30.56%	276	3.40	63.89%	420	1.57	97.22%
133	9.88	30.79%	277	3.39	64.12%	421	1.51	97.45%
134	9.61	31.02%	278	3.37	64.35%	422	1.50	97.69%
135	9.29	31.25%	279	3.34	64.58%	423	1.50	97.92%
136	9.20	31.48%	280	3.31	64.81%	424	1.49	98.15%
137	9.10	31.71%	281	3.31	65.05%	425	1.48	98.38%
138	8.97	31.94%	282	3.30	65.28%	426	1.41	98.61%
139	8.91	32.18%	283	3.30	65.51%	427	1.38	98.84%
140	8.73	32.41%	284	3.27	65.74%	428	1.28	99.07%
141	8.63	32.64%	285	3.26	65.97%	429	1.22	99.31%
142	8.55	32.87%	286	3.24	66.20%	430	1.21	99.54%
143	8.17	33.10%	287	3.24	66.44%	431	1.14	99.77%
144	8.07	33.33%	288	3.22	66.67%	432	1.11	100.00%

Table B-3 Average Hourly Prices of Turkey Electricity Market for the Last 12 Months (TL/Mwh)

Hour	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11
00:00 - 01:00	160.27	169.16	150.46	125.06	135.41	124.61	123	108.96	105.3	85.71	101.26	105.01
01:00 - 02:00	146.64	165.56	133.36	101.85	123.59	98.71	100.23	90.32	80.88	67.46	82.02	80.33
02:00 - 03:00	139.11	159.62	124.77	102.1	118.63	88.72	90.02	81.93	57.27	53.36	54.76	72.72
03:00 - 04:00	129.46	149.54	106.93	84.18	117.23	61.3	64.49	56.41	42.45	36.86	40.52	52.24
04:00 - 05:00	123.65	143.41	96.5	74.74	115.44	52.86	57.64	52.27	39.23	31.69	30.51	38.73
05:00 - 06:00	109	125.99	84.06	69.12	116.91	64.15	69.96	63.3	56.66	36.15	20.54	28.49
06:00 - 07:00	87.5	95.29	58.67	66.06	115.48	67.77	86.31	75.36	59.12	36.03	16.23	26.64
07:00 - 08:00	113.13	123.97	91.88	91.04	120.13	91.77	94.58	82.41	76.65	54.43	67.07	65.53
08:00 - 09:00	151.94	159.62	143.3	139.31	130.63	124.08	142.06	115.42	110.57	93.74	104.24	109.03
09:00 - 10:00	162.22	167.05	152.73	154.67	143.46	139.78	153.06	130.42	123.64	108.07	119.95	112.23
10:00 - 11:00	168.53	175.04	164.3	162.26	156.39	150.95	160.02	142.05	137.53	123.95	137.39	126.73
11:00 - 12:00	176.64	217.25	168.87	167.26	163.28	151.61	161.6	147.71	139.61	130.58	151.09	139.3
12:00 - 13:00	166.62	177.69	166.14	151.83	153.63	130.85	153.14	132.06	109.47	100.93	105.39	114.23
13:00 - 14:00	167.71	186.82	168.5	154.41	149.08	134.39	156.04	135.27	119.71	102.25	109.77	119.42
14:00 - 15:00	177.19	255.9	169.85	158.59	150.23	142.61	157.04	140.16	125.71	108.98	121.27	125.18
15:00 - 16:00	168.25	220.82	166.55	156.61	149.98	139.4	154.96	135.45	116.61	100.83	112.54	123.58
16:00 - 17:00	160.96	189.03	163.43	150.39	157.83	149.38	159.62	137.85	116.11	88.6	98.35	115.48
17:00 - 18:00	152.2	182.94	149.89	127.53	164.88	145.43	163.96	145.62	121.95	78.26	94.89	107.05
18:00 - 19:00	130.93	164.2	135.18	130.26	158.17	128.48	160.03	141.65	132.4	80.21	89.03	95.4
19:00 - 20:00	120.7	158	141.5	142.31	151.32	111.44	151.64	131.57	124.26	104.58	102.47	87.92
20:00 - 21:00	147.46	166.49	150.2	136.82	146.1	106.24	142.85	125.53	119.33	114.1	124.21	107.87
21:00 - 22:00	155.79	168.56	146.98	125.96	141.47	93.87	135.96	115.99	114.75	103.85	118.39	112.63
22:00 - 23:00	168.17	174.46	166.93	157.86	142.12	160.26	147.8	126.86	119.47	115	121.7	114.78
23:00 - 00:00	164.68	172.82	162.91	151.03	138.86	148.44	134.76	115.44	109.24	96.47	102.52	103.9
Average	**147.86**	**169.55**	**140.16**	**128.39**	**140.01**	**116.96**	**130.03**	**113.75**	**102.41**	**85.50**	**92.75**	**95.18**