OPERATION STRATEGIES OF PUMPED STORAGE HYDROPOWER PLANTS UNDER ELECTRICITY SPOT MARKET: CASE STUDY OF ULUABAT HYDROPOWER PLANT

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ABSTRACT

OPERATION STRATEGIES OF PUMPED STORAGE HYDROPOWER PLANTS UNDER ELECTRICITY SPOT MARKET: CASE STUDY OF ULUABAT HYDROPOWER PLANT

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In recent years, energy has been one of the most challenging problems around the world. In particular, energy is the building block for commercial and social settings in the modern world. Therefore, energy is a critical element for economic and human development. Diminishing fossil fuel resources and detrimental effects of facilities operated on fossil fuels have brought forward renewable energy today, and renewable energy resources will continue to play a significant role in the future. However, renewable energy sources are unable to adjust their output to meet fluctuating power demands. In other words, the integration of renewable energy resources into the grid is a concern since the renewable sources have an intermittent nature. This intermittent nature of most renewable energy sources makes them less advantageous. Significantly large energy storage capacity is required to balance power production and demand. Pumped Storage Hydropower Plant (PSHP) technology is accepted to be an efficient and economical way of storing energy obtained from intermittent energy resources. Variety of optimization methods were established in order to evaluate the advantages of PSHPs in the literature. However, detrimental environmental impacts of PSHP and high investment cost are still unfavorable aspects of PSHP. Therefore, the installation of PSHPs on the existing hydropower infrastructure is a more beneficial option that eliminates aforementioned disadvantages of PSHPs. In this study, an existing conventional hydropower plant that diverts turbined water to a natural lake is hypothetically transformed to a PSHP. A generation schedule that maximizes the revenue of PSHP due to oscillations in electricity prices is proposed using historical water inflows to the reservoir and electricity prices under different reservoir management strategies. The optimization study is based on hourly time steps and performed for each water year from 2013 to 2018. The results guide Generation Company (GenCo) to develop operation strategies under the assumption that variations in these five years will be similar to those that will be experienced in the near future. The results are compared with revenues of the optimized generation schedule of the conventional hydropower plant and the actual generation realized between 2013 and 2018 as well.

Keywords: Renewable Energy, Pumped Storage Hydropower Plant, PSHP, Operation Strategy, Reservoir Management Strategy

ÖZ

ELEKTRİK SPOT PİYASASINDA POMPAJ DEPOLAMALI HİDROELEKTRİK SANTRALLERİNİN OPERASYON STRATEJİLERİ: ULUABAT HİDROELEKTRİK SANTRALİ ÖRNEĞİ

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Son yıllarda, enerji dünyadaki en zorlu problemlerden bir olmuştur. Özellikle modern dünyada enerji, ekonomik ve sosyal faaliyetlerin yapı taşıdır. Bu nedenle, enerji, ekonomik büyüme ve insani gelişme için kritik bir unsurdur. Azalan fosil yakıt kaynakları ve fosil yakıtla çalışan tesislerin zararlı etkileri bugün yenilenebilir enerji konusunu gündeme getirmiştir. Yenilenebilir enerji kaynakları gelecekte de önemli bir rol oynamaya devam edecektir. Ancak, yenilenebilir enerji kaynakları değişken güç taleplerini karşılamakta güçlük çekmektedir. Diğer bir deyişle, yenilenebilir enerji kaynaklarının şebekeye entegrasyonu yenilenebilir enerji kaynaklarının süreksizliği nedeniyle endişe vericidir. Bu durum yenilenebilir enerji kaynaklarını daha az avantajlı kılmaktadır. Enerji üretimini organize etmek ve fiziksel talebi karşılamak için önemli ölçüde büyük depolama kapasitelerine ihtiyaç vardır. Pompaj Depolamalı Hidroelektrik Santrali (PDHS) teknolojisi sürekliliği olmaksızın üretim yapan enerji kaynaklarından elde edilen enerjiyi depolamak için en verimli ve ekonomik yoldur. Literatürde, çeşitli optimizasyon yöntemleri ile PDHS'lerinin faydaları değerlendirilmiştir. Bununla birlikte, PDHS'nin zararlı çevresel etkileri ve yüksek yatırım maliyeti hala PDHS'nin olumsuz yönleri olarak karşımıza çıkmaktadır. Bu nedenle mevcut hidroelektrik santrali altyapıları kullanılarak PDHS'lerin kurulması

PDHS'nin bu olumsuz yönlerini ortadan kaldıran daha faydalı bir seçenektir. Bu çalışmada türbinlenen suyun doğal bir göle iletildiği mevcut bir geleneksel hidroelektrik santrali hipotetik olarak PDHS'ye dönüştürülmüştür. Farklı reservuar yönetimi stratejileri altında geçmiş yıllara ait rezervuara giren su ve elektrik fiyatları kullanılarak, elektrik fiyatlarındaki dalgalanmalar sayesinde geliri maksimize eden bir üretim programı önerilmiştir. Optimizasyon çalışması 2013-2018 yılları arasındaki her bir su yılı için saatlik zaman aralıkları ile gerçekleştirilmiştir. Bu beş yıldaki değişikliklerin yakın gelecekte yaşanacak olanlara benzer olacağı varsayımı ile, sonuçlar Üretim Şirketi'ne operasyon stratejileri geliştirmeleri için rehberlik etmektedir. Aynı zamanda bu sonuçlar mevcut hidroelektrik santralinin optimize edilmiş üretim programının gelirleri ve 2013-2018 yılları arasında gerçekleşmiş üretimin gelirleri ile kıyaslanmıştır.

Anahtar Kelimeler: Yenilenebilir Enerji, Pompaj Depolamalı Hidroelektrik Santrali, PDHS, Operasyon Stratejisi, Rezervuar Yönetim Stratejisi

Dedicated to my beloved family; especially to my daughter, Nil Mavi

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CHAPTER 1

INTRODUCTION

1.1. Overview

Energy storage is a critical element of electricity systems for which the integration of extensive intermittent renewable energy is considered. In order to maintain the instantaneous energy balance and adjust the impact of power, proper and sufficient control is required in the electricity grid. Thus, adequate energy storage for the electricity grid is necessary for improving the effectiveness of sustainable energy systems as well as renewable energy sources (Dell & Rand, 2001).

Out of the available storage technologies, pumped storage hydropower plants are found to be an appealing solution for load balancing as well as energy storage (Táczi & Szörényi, 2016). PSHPs are one of the most cost-effective energy storage options all over the world, and PSHPs constitute 99% of electric energy storage capacity corresponding to more than 150 GW installed capacity (Táczi & Szörényi, 2016). Systems with PSHPs can offer auxiliary features at higher ramp rates as well as other advantages in terms of intraday energy price variations through providing energy during peak hours and purchasing energy during low-demand hours. Benefits of PSHPs can offer a significant advantage in intermittent energy sources integration (i.e., wind power) in terms of providing balance and storage on demand side.

The increase in renewable energy around the world is making PSHPs role even more critical. The International Renewable Energy Agency (IRENA) developed a technology roadmap until 2030, and accordingly, the total installed capacity of PSHPs is expected to go up to two folds from 150 GW to 325 GW (Kempener & Vivero, 2015). On the other hand, PSHP may demonstrate specific problems such as environmental impacts due to the construction of reservoirs and difficulty in locating topographically suitable areas having adequate water capacity for profitable system installation. Therefore, the installation of PSHPs on the existing hydropower infrastructure is a more beneficial option that eliminates concerns regarding environmental damage (Hirsch, Schillinger, Weigt, & Burkhardt-Holm, 2014). Thus, it is essential to prioritize existing cascade systems and hydropower facilities located near natural reservoirs to be converted to PSHPs.

1.2. Goals and Objectives

This study is performed to research the management of PSHPs in an electricity market. The objective of this study is to investigate a PSHP from an economic point of view using retrospective data and to provide prospective operation guidance that maximizes the revenues of the PSHP.

Specific goals of this study are as follows:

i. To conduct a basic analysis of the Turkish electricity market in order to identify decision-making guidelines that may play a significant role in the generation schedule.
ii. To develop optimization models to maximize the revenue of the Electricity Generation Company, which is the owner of the PSHP.
iii. To propose new generation schedules under different scenarios.

Throughout the thesis, the following main assumptions are made:

i. This study is designed based on a pool market in which offers are made once in a day. Bilateral agreements are not taken into account.
ii. Time frame taken into account in the optimization models is one year with hourly time steps (i.e., t=1, 2,…, 8760).
iii. Transmission is not taken into consideration. Therefore, transmission losses or congestion are not taken into consideration in the established models, either.
iv. Consumed power’s effect on pool market prices is not considered.

1.3. Thesis Outline

The literature review is presented in Chapter 2, which includes general concepts of PSHP, configurations of PSHPs, and development of various optimization models for PSHP. Next, Electricity market structure, market functions, and their properties are presented. In addition to the explanation of electricity market structure, an overview of the Turkish electricity market, relevant organizations and statutes, and system structure are presented in Chapter 2.

Description of the case study and statistical analysis of historical data for inflows to reservoir and electricity prices used in this study are provided in Chapter 3. The statistical analysis aims to provide valuable insights for prospective operational strategies when evaluated with the optimization results. In other words, the analysis provides a guideline on what kind of operational strategy should be implemented if similar fluctuations of inflows and electricity prices occur in the future.

Optimization methodology implemented in this study is presented in Chapter 4. In this chapter, in order to see effects of pumped storage on the revenue, two models are presented; namely conventional hydropower plant model and pumped storage hydropower plant model. These models are run under two scenarios to evaluate the effect of different reservoir management strategies, as well.

Optimization results and proposed generation schedules are provided in Chapter 5. According to the optimization results, guidelines for prospective operational strategies are presented.

Finally, conclusions are provided in Chapter 6. Further research initiatives are provided in the closure, as well.

CHAPTER 2

LITERATURE REVIEW

This literature review aims to provide background information relating to the approach used in this study. Characteristics of pumped storage hydropower plants (PSHPs) are presented in the first section. Next, current trends in the PSHP operation are presented along with different optimization models. Afterward, the Turkish Electricity Market is introduced. Finally, the positioning of this study in the literature is discussed.

2.1. Pumped Storage Hydropower Plants

PSHPs are hydropower plants that rely on two reservoirs at different elevations to allow water to be stored when demand is low and then used to generate electricity during peak consumption. The general idea used in PSHPs is as follows: water is pumped from the lower-level reservoir to the higher-level reservoir to store energy in the form of potential energy. When there is demand for energy, water is released back to the lower-level reservoir through turbines to generate electricity.

PSHPs are widely used bulk energy storage systems in the world. Development of PSHPs gained importance recently as they increase variability in generation. Table 2.1 depicts the capacity development of PSHPs by countries.

Table 2.1. *PSHP Capacity Development around the World (adapted from Energy Regulators Regional Association, 2016)*

Country	Installed Capacity (MW)
Japan	27,438
China	21,545
USA	20,858
Italy	7,071
Spain	6,889
Germany	6,388
France	5,894
India	5,072
Austria	4,808
South Korea	4,700

In addition to the current installed capacities, PSHP installed capacity is expected to increase from 150 GW to 325 GW according to the technology roadmap executed by the International Renewable Energy Agency (Táczi & Szörényi, 2016).

2.1.1. Main Characteristics of Pumped Storage Hydropower Plants

PSHPs are generally constituted of a higher-level reservoir and a lower-level reservoir connected with a pump and turbine system. Water is released/turbined from the higher-level reservoir to the lower-level reservoir to generate electricity and sent/pumped from the lower-level reservoir to the higher-level reservoir to store water for future energy generation. Pumps are driven by motors that consume electricity during pump operation, and turbines drive generators to generate electricity during turbine operation. Conveyance of water is provided by a penstock, and electricity is transmitted by a switchyard and transmission lines. Figure 2.1 shows a basic configuration for a standard PSHP project. The structure of the components shown in Figure 2.1 varies depending on configurations, which are presented in Section 2.1.2.

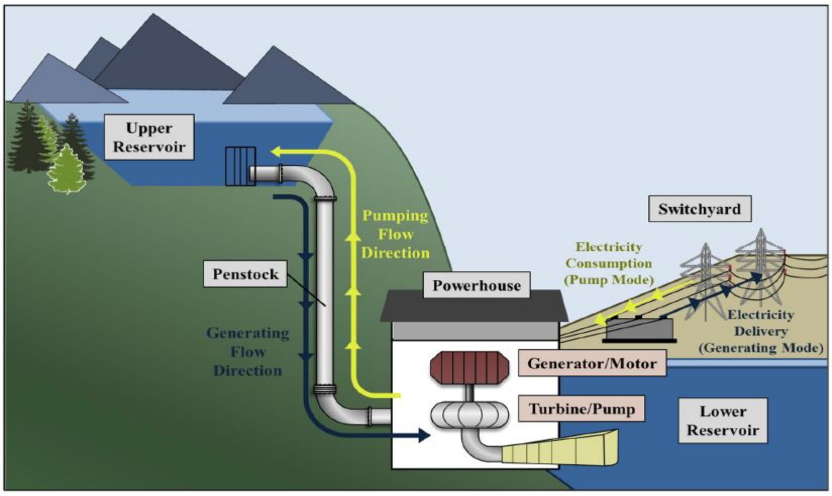

Figure 2.1. Pumped Storage Hydropower Plant Schematic (adopted from Witt et al., 2015)

Recently, the existing conventional hydropower plants are converted to PSHPs, especially in Europe. There is a significant number of projects prepared as an extension for existing hydropower plants or to upgrade/repower existing PSHPs (Deane, Ó Gallachóir, & McKeogh, 2010).

2.1.2. Pumped Storage Hydropower Plants Configurations

In the history of PSHPs, several equipment configurations are used. Different configurations are using different number of hydraulic and electrical equipment. They can be categorized as follows (J.I. Pérez-Díaz et al., 2014):

- Binary set, which has one pump-turbine and one electrical equipment (motor/generator).
- Ternary set, which has one turbine, one pump and one electrical equipment (motor/generator).
- Quaternary set, which has one turbine driving one generator and one pump driven by one motor.

There are advantages and disadvantages for each configuration. The binary set is the most common set used around the world (J.I. Pérez-Díaz et al., 2014). It uses a pump-turbine connected directly to the grid. The set rotates in one direction when supplying energy to the grid and in the other direction, when consuming energy from the grid. A basic illustration of the binary set is shown in Figure 2.2.

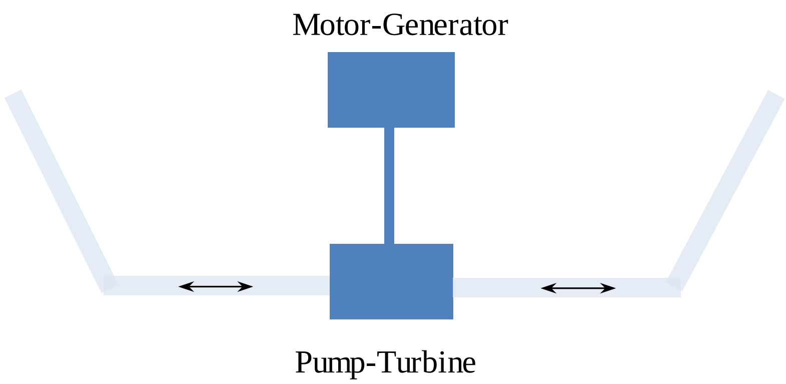

Figure 2.2. Binary Set Schematic

Ternary set is constituted of a turbine, an electrical motor/generator, and a pump, all of which are coupled on the same shaft. Turbine and pump rotate in the same direction in either mode. Electrical motor/generator is often a synchronous machine. Unlike the binary set where pump-turbine design, both turbine and pump designs are optimized in the ternary set. In general, start-up times are less than that in binary units since start-up is performed with the assistance of the turbine connected on the same shaft and shaft rotation direction change is not required to switch from pumping to turbine operation (J.I. Pérez-Díaz et al., 2014). A basic illustration of the ternary set is shown in Figure 2.3.

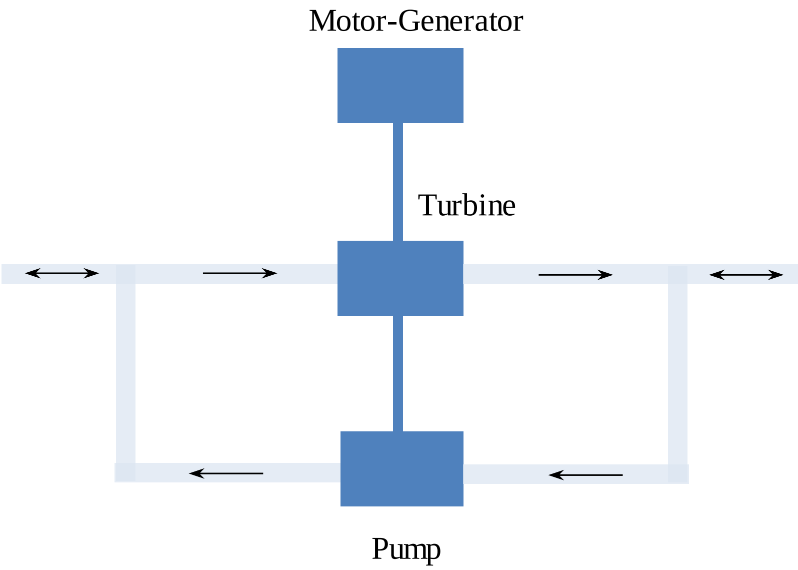

Figure 2.3. Ternary Set Schematic

The quaternary set consists of different powerhouses. One of them is for the pump units while the other one is for the turbine units. Thus, in quaternary configurations, pumps and turbines are operated without coupling of the pumps and the turbines. Operation in the production mode is similar to the ternary set configuration, but there is no need for compressed air in the turbine chamber (J.I. Pérez-Díaz et al., 2014). A basic illustration of the quaternary set is shown in Figure 2.4.

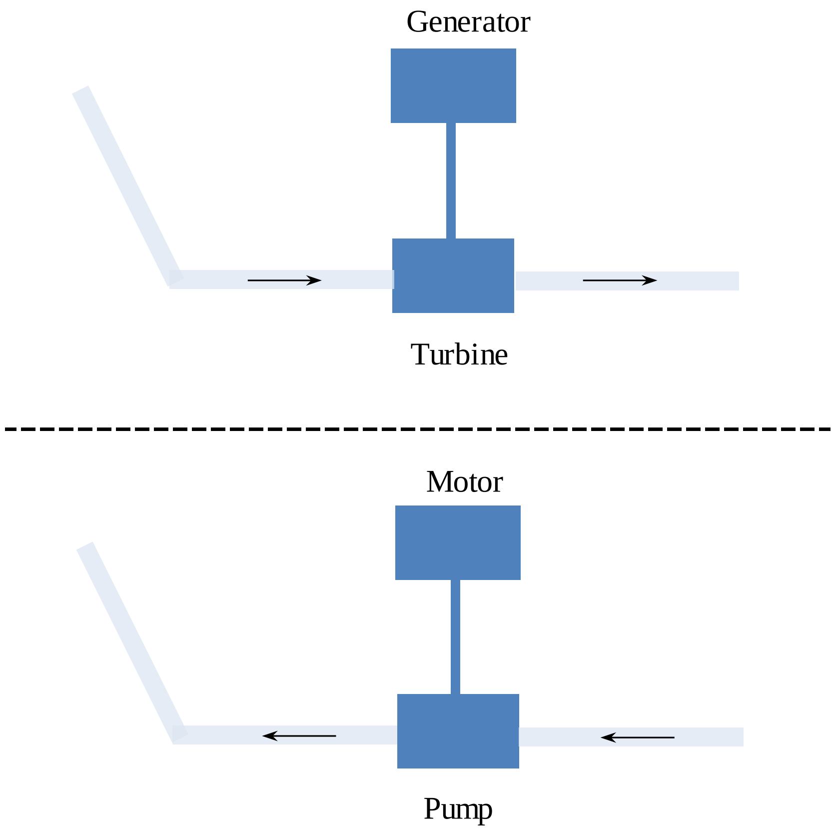

Figure 2.4. Quaternary Set Schematic

In this study, an existing conventional hydropower plant is converted to PSHP, which already has turbines. The idea is to integrate new pump units to the existing hydropower plant to reduce the initial investment cost of conversion. It is assumed that the new pump units are connected to existing penstock in a conjunction point. Since both pump and turbine operations are carried out using the existing penstock, both operations are not allowed to perform simultaneously. Therefore, the quaternary set is utilized with minor modifications to the existing hydropower plant in this study.

2.2. Review of Pumped Storage Hydropower Plant Trends

In the literature, most of the optimization problems have been derived in a specific electricity market with various generation technologies. Nevertheless, most of the proposed approaches apply to a wide range of electricity markets with small alterations.

Deb (2000) discusses the benefits of PSHP in California Energy Market. In his study, it is revealed that PSHP can increase its profit in ancillary service market rather than bidding in Day-Ahead Market. Kanakasabapathy and Shanti Swarup (2010) apply a strategy to schedule operation of PSHP for one week period within the framework of the New York Independence System Operator Market. Based on forecasted hourly Market Clearing Price, a nonlinear optimization model is developed to maximize the profit of PSHP.

Connolly et al. (2011) develop practical operation strategies utilizing Day-Ahead Market Prices in 13 electricity spot markets without considering Market Clearing Prices. According to the results, annual profits vary over the 5 year period (2005-2009). The authors conclude that PSHP is a risky investment as the profit is not predictable. Due to uncertainties of profits along with environmental concerns, investors show interest in the integration of PSHP to existing conventional hydropower plants. The evaluation of existing hydropower plants are discussed in the literature (Deane et al., 2010; Gimeno-Gutiérrez & Lacal-Arántegui, 2013; Kucukali, 2014).

As expressed above, the uncertainties in market prices have an adverse impact on profits of PSHP. Kazempour et al. (2009) study a set of uncertainties in electricity prices and power commitments. Considering the uncertainties, they propose a dynamic self-scheduling to solve the mixed-integer programming problem by maximizing the revenue. Fleten and Kristoffersen (2006) develop a mixed-integer linear programming for short term generation schedule under uncertainties of electricity price and water inflows. Electricity prices and water inflows are forecasted using a time series method characterized by seasonal changes, periodic cycles, and stochastic variations. In another study, Catalão et al. (2007) propose a neural network approach for forecasting next week's electricity prices based on historical electricity prices of 2002 for the Spanish Market. The accuracy of the neural network approach is computed as a function of actual electricity prices. The mean percentage errors for the neural network approach are 5.23%, 5.36, 11.40% and 13.65% for winter, spring, summer, and fall, respectively. Additionally, the electricity prices are forecasted by a time series method, ARIMA. The mean percentage errors for the ARIMA approach are 6.32%, 6.36, 13.39% and 13.78% for winter, spring, summer, and fall, respectively. According to the results, the neural network approach outperforms the ARIMA approach. Mazengia and Tuan (2008) forecast electricity prices using the multiple linear regression approach. After an investigation of price patterns, the authors find that the electricity prices are correlated with the previous day's electricity price at the same hour and the price of the previous week on the same day.

Ikudo (2009) proposes a dynamic programming model for a PSHP to maximize gross margin, which is the difference between the revenue of electricity generation and the cost of electricity consumption. The time horizon is two weeks and discretized into one-hour intervals. The model considers the uncertainty in both electricity prices and water inflow. The uncertainty in electricity prices is dealt with different price scenarios, while water inflow rates are forecasted assuming the transition in water inflow rates follows a Markov process. Water inflow rates are simulated using a transition matrix based on the historical inflow rates.

Haddad et al. (2013) discuss pumped storage model and conventional hydropower model. Two nonlinear programming models are developed to maximize the annual net benefits and solved the problem using LINGO 11.0 Software. The models are compared based on four criteria: i) net benefit, ii) benefit/cost ratio, iii) system efficiency, and iv) mean, firm, and secondary energies. In the study, inflow values are estimated using time series method based on historical inflow values, whereas two types of electricity prices are considered: i) one single electricity price for peak hours and ii) one single electricity price of off-peak hours. The results show that the pumped storage model has higher outcomes than the conventional hydropower model based on criteria mentioned above. However, the uncertainties of electricity prices remain a challenge in the study. Pérez-Díaz et al. (2015) review the current trends in the PSHP operation. Optimal PSHP operation strategies are presented in their study. Rehman et al. (2015) review technological development, practices, operation and maintenance, environmental aspects and economics of PSHP and hybrid systems (i.e. wind-hydro, solar-hydro and wind-solar-hydro).

Muche (2014) suggests a stochastic programming model to obtain the optimized generation schedule of PSHP considering electricity price uncertainty. Time series method is used for forecasting electricity prices for every week of 2011. Daily and weekly optimizations are performed keeping storage level at the end of the optimization period equal to the level at the beginning of the optimization period. The results indicate that the revenue of daily optimization is less than the revenue of weekly optimization.

Jia (2013) presents short term scheduling model for cascade PSHP hydropower systems. The non-linear power function is linearized by piecewise linear interpolation. Then, the model is formulated as a mixed-integer linear programming problem to maximize daily revenue and is solved using ILOG CPLEX 9.0 Software. The results show that PSHP increases the revenue of the systems.

Ak et. al (2017) develop operating strategies for cascade PSHP hydropower systems consisting of existing hydropower plants. In order to obtain average annual revenues, nonlinear mathematical models are developed under the uncertainties of inflows and electricity prices. Monthly historical inflows are used as inputs to generate operating rule curves. A scenario-based approach is developed based on past electricity prices for the uncertainty in electricity price variations. The models are solved for five different scenarios based on electricity prices for years 2013–2017. The results show that revenue increase ranges between 2.9% and 10.4%. The authors conclude that the operation of the cascade hydropower plant system in the pumped-storage mode results in additional revenue.

Moore (2000) compares two models that maximize revenue of cascade PSHP hydropower systems under different electricity price scenarios: i) a nonlinear mixed-integer model and ii) a discretized linear mixed-integer model. The nonlinear mixed-integer model is solved using LINGO whereas the discretized linear mixed-integer model is solved using CPLEX. Based on the results, the mixed-integer linear formulation provides global optimal solution while the solution space for the nonlinear mixed-integer formulation is non-convex; and the optimal solution is local.

It is also worth to mention the studies about the combined operation of pumped storage hydropower plants and wind power plans. As the prediction of electricity generation of wind power plants is difficult, pumped storage hydropower plants can be used to balance the unstable output (i.e., intermittent nature) of wind power plants by adjusting its generation to compensate wind power prediction errors (Song et al., 2013). Thus, investigation of pumped storage hydropower plants to balance the unstable output of wind power plants is an active research area.

Castronuovo and Lopes (2004) develop a linear programming to maximize the combined operation of a wind power plant and a pumped storage hydropower plant in the Portuguese Market. Daily and yearly simulations are performed in the study. The daily simulation results show an increase in the profit with 13.2%, whereas the weekly simulations provide an 11.9% increase in the profit. Anagnostopoulos and Papantonis (2007) present a model to find optimum sizing and design of pump units in a combined operation of a wind power plant and a pumped storage hydropower plant. The model aims to maximize the net present value of the investment, and a stochastic optimization based on an evolutionary algorithm is implemented. Based on the optimization results, guaranteed energy during peak demand hours, which equals to 6 hours in a day, is provided by 15 MW turbine power, wind generators of 600 kW each, and a reservoir capacity with 500,000 m^3.

González et al. (2008) proposed a combined optimization of a wind power plant and a pumped storage hydropower plant in the Spanish Market. His optimization model is developed as a two-stage stochastic programming problem with two random parameters: market prices (modeled using Markov chains) and wind generation (modeled using a statistical-numerical approach). A combined configuration is created and compared to individual operation in the study. The study shows that the combined operation model provided higher revenue than that of the individual operation revenues. Expected revenue increase was 2.53%, while the imbalance penalty in the combined-operation model was reduced by approximately 36 %.

Guzman (2010) develops long-term and short-term stochastic linear optimization models to evaluate the benefits of pumped storage hydropower plants and the impacts of wind power integration. The models aim to maximize the annual benefit of a generation company by simulating operations of the pumped storage hydropower plant and wind power, considering different load and stochastic wind scenarios. A financial feasibility analysis is conducted using average annual benefits of 5 normal water years, three wet water years and two dry water years. According to the feasibility study, payback periods vary from 14.5 years to 15.3 years depending on wind power scenarios. Many recent studies (i.e., Bueno and Carta, 2006; Ding et al., 2012; Dursun et al., 2011; Reuter et al., 2012) focus on optimization of the combined operation of pumped storage hydropower plants and wind power plans.

2.3. Review of Turkish Electricity Market

In order to evaluate the integration of PSHPs into the electricity market, a basic understanding of Turkish electricity market is necessary. Thus, the review and analysis of the electricity market structure are carried out and provided in this section. Firstly, the development of the Turkish electricity market is presented. Afterward, spot markets are discussed as hydropower management in a spot market is investigated in this study

2.3.1. Development of Electricity Market in Turkey

The current Turkish electricity market structure is based on spot markets characterized by transactions being settled immediately and the bilateral contracts executed by buyers and sellers. As the electricity market operation requires metering and information technology infrastructure as well as adequately organized market players, a gradual implementation of market rules has been in place. Benchmarks of implementation are provided in Figure 2.5.

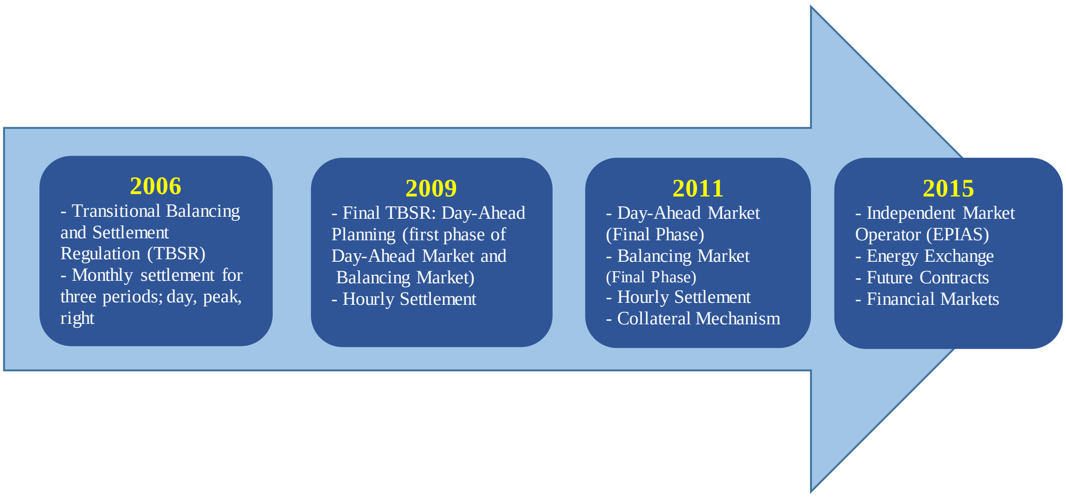

Figure 2.5. Benchmarks in Market Development (adopted from EMRA, 2017)

Rules for the Electric Market were initially designed in 2003. Legislative framework, which is the first Balancing and Settlement Regulation, referred to as Transitional Balancing and Settlement Regulation, or “TBSR” was completed in November 2004. However, the operation started in the pilot mode in August 2006. A basic balancing and settlement were in place until 2006 where provide power balancing over regulated purchase and sales prices. Once TBSR was implemented, a trading platform was established for the market players.

The mechanism used between 2006 and 2009 was also referred to as "Day-Ahead Balancing Market." It was a "Day-Ahead Scheduling mechanism (DAS)." Producers send their hourly production schedules and prices twice in a month if they were used in the Day-Ahead balancing market and the real-time balancing for the upcoming 15 days. Electricity demand on a daily basis was identified by National Load Dispatch Center (NLDC) per hour for the next day, and system balance was ensured based on the physical capacity nominations from producers. The marginal price for the supply-demand set point was identified based on the bids and offers. Thus, the system was balanced by NLDC one day before. The production schedule was issued by NLDC and notified to the producers. Additionally, the Turkish Electricity Transmission Company (TEIAS) carried out real-time balancing according to the information given by producers.

Along with the infrastructural development, rules for the second stage of TBSR were developed in detail. The second stage was put into effect in April 2009 and implemented in December 2009. This phase was composed of a more complex DAS mechanism. Producers sent their bids and offers on a daily basis for every hour of the next day instead of sending them on 15 days intervals. Marginal prices were calculated and announced one Day-Ahead. NLDC identified the demand for the next day.

The final phase of TBSR was introduced in December 2011. Existing balancing market was evolved into real Day-Ahead Market (DAM) and Balancing Market that is voluntary power exchange where supply and demand are balanced according to the supplier bids and offers as well as those of the consumers.

Intraday Market preparation efforts in Turkey started in June 2011. Software to be used in this market was developed by the late 2012s. Several improvements were made on the software during 2013. Introduction of the Intraday Market was made by Energy Market Operations Company (EPIAS) in July 2015. This market is useful specifically for intermittent renewable energy producers. This market enables the intermittent renewable energy producers to facilitate estimations for the production compared to Day-Ahead Market.

2.3.2. Spot Markets

The electricity spot market is defined as a central feature of the decentralized electricity market, and spot markets are characterized by transactions being settled immediately or at a short-term notice.

Spot markets are categorized as follows:

i. Day-Ahead Market
ii. Intraday Market
iii. Balancing Market

Generally, market operators run Day-Ahead Market and Intraday Market whereas a transmission system operator runs Balancing Markets.

2.3.2.1. Day-Ahead Market

In spot markets around the world, Day-Ahead Market (DAM) generally runs similarly. Market players submit their hourly offers for several trading periods in Day-Ahead Markets. The market operator sorts these offers from the lowest to highest price for each hour. In the meantime, consumers submit their hourly demands for the trading periods in Day-Ahead Markets. The intersection point of supply and demand curves determines electricity market prices for relevant hours, called the Market Clearing Price (MCP). Once the MCP is determined, electricity market prices and the amount of supply are announced to the market players (Stoft, 2002). The representation of MCP is demonstrated in Figure 2.6.

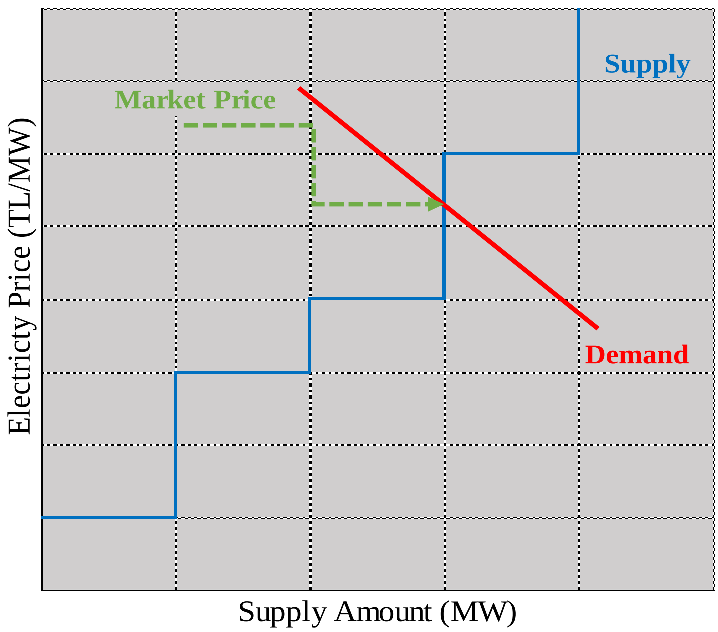

Figure 2.6. MCM Formation in DAM (adopted from Weron, 2014*)*

In Turkey, DAM is operated within the organizational structure of Energy Exchange Istanbul (EXIST). According to Balancing and Settlement Regulation, DAM activities are carried out hourly. Days are divided to hours starting at 00:00 and ending on the next day at 00:00 hours. Daily bidding time starts five days before the relevant day and ends at 11:30 a.m. on the previous day. Market Operator assess the proposals for DAM according to the provisions of Balancing and Settlement Regulation Article 57 (EMRA, 2009). The Market Operator calculates DAM prices for every hour of the next day and announces all commercial transaction approvals as well as purchase and sales quantities of each player. The market players participating in DAM verify those approvals announced by the Market Operator and players can raise their objections regarding transaction approvals. The market operator evaluates objections, if any, and announces the results of the evaluation to the market players. Market Operator announces finalized prices and matched volumes for 24 hours of the next day at 2:00 p.m.

2.3.2.2. Intraday Market

After a formal Day-Ahead Market, Intraday Market players keep adjusting their positions based on the new information on production, consumption, and general system status. Therefore, intraday trading can also be considered as an extension of day-ahead adjustment.

The most significant driver for the market players to make intraday trading is the discrepancies in the supply-demand balance. Following factors affect this balance in the intraday time frame (Economics, 2005):

- Wind forecast deviations
- Outages of power stations
- Electric load forecast deviations
- Import and export changes

In Turkey, Intraday Market is within the organizational structure of Energy Exchange Istanbul (EXIST). According to Balancing and Settlement Regulation, the Intraday Market bidding basis shall be portfolios just like in Day-Ahead Market. Days are divided into hours, starting at 00:00 hours, closing on the next day at 00:00 hours. Intraday Market opening time is 18:00, which is four hours after the results of Day-Ahead Market are announced. Transactions are possible up to two hours before delivery. Intraday Market trading through the relevant time frame corresponds to a predetermined supply or demand level. Intraday Market evaluation cannot be made independent from the Day-Ahead Market. In theory, they are part of Day-Ahead Markets and complementary mechanisms. Thus, market players can re-organize their short-term positions. This opportunity is provided due to the long-time frame between contract settlement in the Day-Ahead Market and actual real-time delivery.

2.3.2.3. Balancing Market

Generally, power production and consumption must match all the time. In order for the system operator to ensure electric supply security in real-time, trading activities must be completed before the actual delivery. Failure to do so may result in difficulties for the system operator to maintain supply and demand balance.

In addition to supply and demand balance in real-time; frequency response, control of voltage and reactive power support, etc. are also carried out in real-time. Market players can present their price offers and bids once Day-Ahead Market is closed and specify the prices which they need to increase production or decrease consumption, or vice versa for a specific volume.

In Turkey, the National Load Dispatch Center, under the organization of the Turkish Electricity Transmission Company (TEIAS), acting in its capacity as the transmission system operator, operates the Balancing Market.

Balancing Market is established as a system to ensure a balance between physical supply and demand via the transparent market application. Balancing is particularly needed due to the failure of a market player to meet its accepted bids/offers in the Day-Ahead Market. Once the Day-Ahead Market is closed, the system should be in balance, meaning the total energy production equals to the total energy consumption for the next day. Whereas in real-time, market player's productions can be less or more than their usual daily production, therefore imbalances may occur. In case of imbalance, flexible producers or consumers are needed to load or unload the system at short notice to maintain the balance back. In the balancing power market, bids/offers from flexible producers or consumers are sending in the Day-Ahead Market for use in real-time.

Balancing and Settlement Regulation Article (9) part c stipulates: The imbalances of balance responsible parties arising from their balance responsibilities shall be settled over the system imbalance price to be determined on a settlement period basis. The system imbalance price applicable for each settlement period is a single price to be determined equal to the hourly System Marginal Price established in the balancing power market for the settlement period (EMRA, 2009).

Day-Ahead Market players receive their payments following the amount specified in their bids over the Market Clearing Price. Then the imbalance is calculated. Imbalances of parties responsible for balance are settled over the system marginal price. If the producer delivers more load than in its offer, the producer earns extra payment. If the producer delivers fewer loads than in its offer, the producer makes a refund based on the amount of deficit.

If the imbalance is positive, amounts to be paid to producers is determined based on the minimum Market Clearing Price and System Marginal Price. When the imbalance is negative, then amounts to be paid to producers are determined based on the maximum Market Clearing Price and System Marginal Price. If there is a negative imbalance, then the System Marginal price is higher than the Market Clearing Price, and if there is a positive imbalance, then vice versa. The same applies to bilateral agreements as well (EMRA, 2009).

2.4. The Positioning of This Study in the Literature

In this study, a conventional hydropower plant is converted hypothetically to a PSHP in order to investigate potential revenue change due to the operation of the plant as a PSHP. In this regard, two optimization models are established by nonlinear programming formulation within the time frame of one year with hourly time steps (i.e., $t = 1,2,3,\ldots, 8760$): i) conventional hydropower plant model, and ii) PSHP model. Hourly head variations in the reservoir, the efficiency of the turbines and pumps with respect to the turbine discharge and pump discharge and head losses with respect to the discharges are also taken into consideration in these models. Optimizations that maximize annual revenue of PSHP are performed for each water year from 2013 to 2018. The model results are compared with actual generations of the conventional hydropower plant, and additional benefits of the hypothetical PSHP are quantified.

In this study, historical hourly inflow and DAM prices between 2013 and 2018 are the inputs to the optimization models. We assume that the variations in these five years will be similar to those that will be experienced in the near future. Thus, the results obtained for these five models will guide Generation Company (GenCo) to develop operation strategies that will increase their revenue in the near future years.

In this study, the models are performed under two different scenarios to evaluate the effect of different reservoir management strategies, as well. The first scenario is established providing GenCo's actual initial and final storage values for each of the water years in the simulation period are used in the optimization models. Thus, the revenues of GenCo for each of the simulation years are comparable with those obtained from the optimization models developed in this study for the first scenario. The second scenario provides that the starting and ending storages in the reservoir are the same.

The results of the analysis provide a prospective guideline on what kind of operational strategy should be implemented if similar fluctuations of inflows and electricity prices occur in the future.

As expressed in Section 2.2, the main challenge of PSHPs is uncertainties in the revenues of PSHPs. In this study, hourly optimizations are performed for each year in order to evaluate revenues of PSHPs more accurately. Furthermore, an extensive analysis of inputs (i.e., inflows and electricity prices) and results are analyzed on monthly, seasonal and annual basis under different scenarios to study all various factors that affect the revenue.

In recent years, a remarkable number of renewable energy sources have been penetrated the Turkish Electricity Market. Consequently, storage of the energy to mitigate intermittency of such renewable energy sources has become a significant problem. PSHPs, which do not exist in Turkey, are a viable solution to mitigate this problem.

CHAPTER 3

CASE STUDY

This chapter provides information about the case study that has been investigated in this study. It first explains the characteristics of the hydropower plant, which is the subject of the case study. Next, it discusses the statistical analysis of historical data of electricity prices and inflows to the reservoir of the hydropower plant. Additionally, historical energy generation data of the hydropower plant is investigated along with the electricity prices and the inflows.

3.1. Case Study

Uluabat Hydropower Plant (UHP), located on Orhaneli River in the western part of Turkey, is selected for the case study. UHP has an installed capacity of 100 MW, consisting of two identical units. For each unit, Francis turbines of 50 MW are driven by water supplied from Çınarcık Dam with a tunnel and a penstock. Water diverted from Çınarcık Dam through the tunnel, and the penstock reaches the power station on the southern bank of a natural lake, Lake of Uluabat. The water is discharged from the power station to the Lake of Uluabat through an open channel, which has a length of 1,200 m.

Çınarcık Dam has a height of 123 meters, and its crest length is 325 m (Akenerji, 2009). The power tunnel has a diameter of 4 m and a length of 11,461 m (Akenerji, 2009). The surge tank, which has a diameter of 18 m, is located on the tunnel and 10770 m away from Çınarcık Dam (Akenerji, 2009). Following the power tunnel, a penstock continues with a diameter of 3.2 m and 1,150 m length up to the branch point (Akenerji, 2009). At the branch point, the penstock is divided into two branches and reaches to the powerhouse structure. A basic illustration of UHP is shown in Figure 3.1.

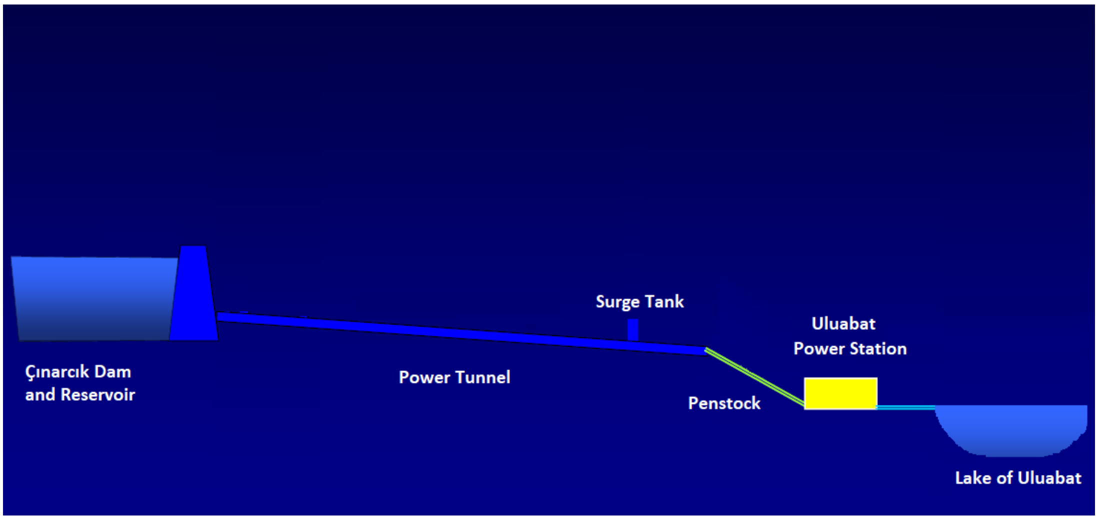

Figure 3.1. Uluabat Hydropower Plant Schematic

Dam and reservoir, spillway, tunnel, penstock, tailrace elevation, and turbine characteristics of UHP are given in Table 3.1, Table 3.2, Table 3.3, Table 3.4, Table 3.5, and Table 3.6, respectively.

Table 3.1. *Dam and Reservoir Characteristics (adopted from Akenerji, 2009)*

Dam Body Type	Claycore Rock Fill Dam
Height	123.00 m
Talveg Elevation	210.00 m
Crest Elevation	333.00 m
Crest Width	12.00 m
Crest Length	325.00 m
Reservoir Area at normal water elevation	10.14 km^2
Reservoir Volume at normal water elevation	372.940 hm^3
Minimum Water Elevation for Operation	304.75 m
Maximum (Normal) Water Elevation	330.00 m

Table 3.2. *Spillway Characteristics (adopted from Akenerji, 2009)*

Type	Frontal type, Radial Gates
Dimensions (width-length-height)	12 m x 319 m x 125 m
Number of gates and dimensions	5 - 9 m x 15 m
Maximum Discharge Capacity	5192.00 m^3/s
Spillway Crest width	12.00 m
Spillway Crest Elevation	315.00 m

Table 3.3. *Tunnel Characteristics (adopted from Akenerji, 2009)*

Discharge Capacity	38 m^3/s
Length	11461.636 m
Diameter	4.00 m

Table 3.4. *Penstock Characteristics (adopted from Akenerji, 2009)*

Number	1
Diameter	3.20 m - 3.00 m - 2.90 m - 1.50 m.
Length	1150.00 m
Discharge Capacity	38 m^3/s

Table 3.5. *Tailrace Elevation Characteristics (adopted from Akenerji, 2009)*

Maximum (2 units are in operation)	7.60 m
Minimum (1 unit is in operation)	6.80 m

Table 3.6. *Turbine Characteristics (adopted from Akenerji, 2009)*

Type	Francis (Vertical Axis)
Number	2
Unit Power Capacity	50 MW
Total Power Capacity	100 MW
Unit Discharge	19 m^3/s (for each unit)
Maximum Discharge	38 m^3/s
Minimum Discharge	7 m^3/s

This study aims to investigate potential revenue change due to the operation of the existing conventional UHP as a pumped storage hydropower plant. Thus, it is assumed that the conventional hydropower plant, UHP, is converted hypothetically to a pumped storage hydropower plant (from here after will be referred to as UPSHP) in quaternary configuration (see Section 2.1.2). The main reason behind the selection of Uluabat Hydropower Plant in this study is the existence of a natural lake, namely Uluabat Lake which can act as a lower reservoir. Utilization of a natural lake as the lower reservoir is expected to make the system more economic, efficient and environmentally acceptable. Çınarcık Dam and Lake of Uluabat are illustrated in Figure 3.2.

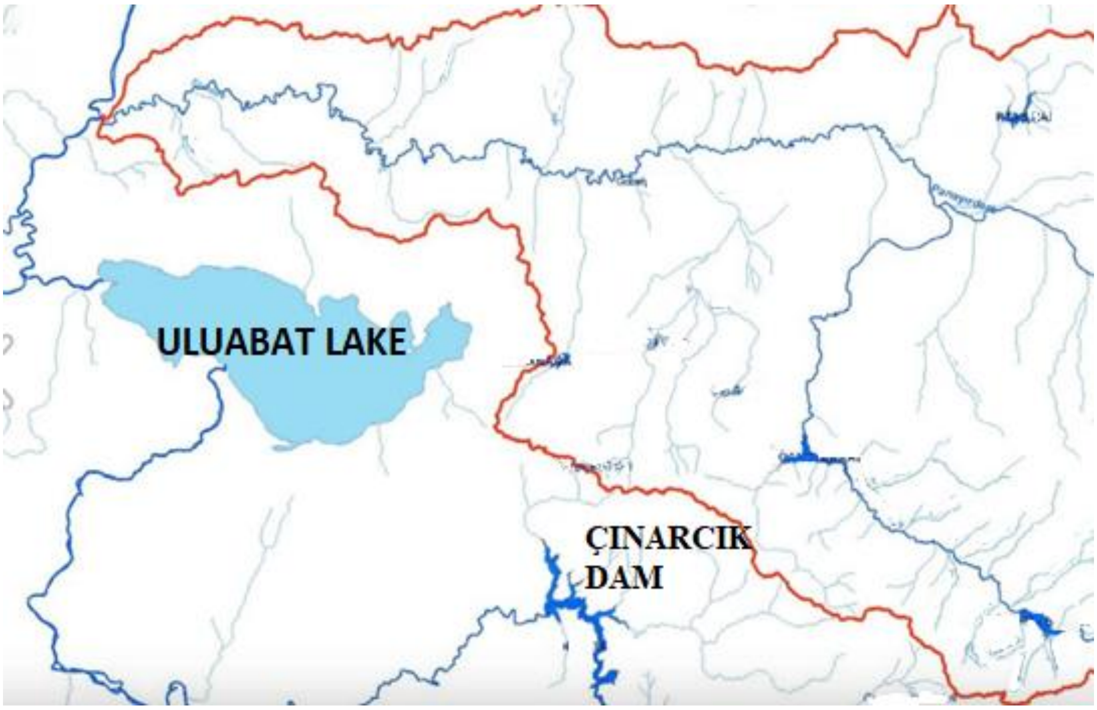

Figure 3.2. Susurluk River Basin (adopted from General Directorate of State Hydraulic Works, 2010)

3.2. Statistical Analysis of Historical Records of Inflows to Çınarcık Reservoir and Electricity Prices

As expressed in the previous sections, variation in electricity prices and inflows to the reservoir are key factors for the assessment of pumped storage hydropower plants. In this regard, historical records of inflows and electricity between January 2011 and August 2018 are analyzed in this chapter.

3.2.1. Inflow Analysis

Historical records of inflow to Çınarcık Reservoir are obtained from the Generation Company (GenCo), which is the owner of UHP. GenCo measures daily water level within the reservoir in addition to daily turbined, spilled, and residual water amounts. The amount of daily stored water is calculated using the stage-storage relationship of Çınarcık Reservoir shown in Figure 3.3.

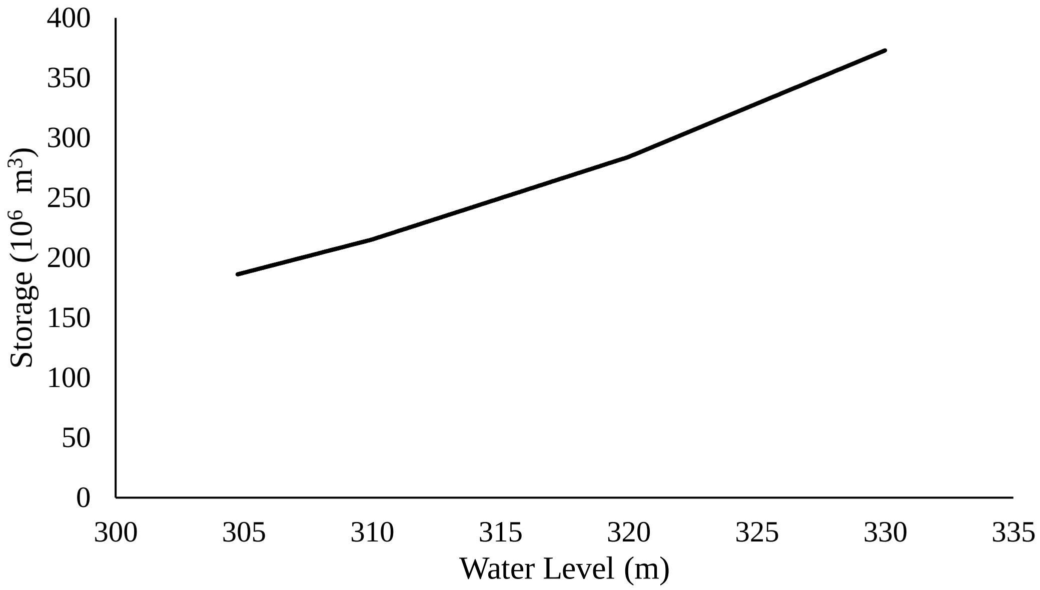

Figure 3.3. Stage – Storage Relationship of Çınarcık Reservoir (adopted from Akenerji, 2009)

The difference in water storage of two consecutive days equals the change in the stored water in Çınarcık reservoir in 24 hours. The change in the storage is the summation of the water used for energy generation, the spilled water and the residual water released to the downstream to maintain the aquatic life. Therefore, daily inflows to the reservoir are calculated by subtracting the summation of daily water used for energy generation, the spilled water and the residual water from the change in storage.

Using this methodology, all historical inflow values are obtained, and statistical analysis of these inflows values for the duration of January 2011 and August 2018 is performed. Mean and standard deviations of inflows for each month are given in Table 3.7, and graphical demonstration is shown in Figure 3.4.

Table 3.7. *Statistical Analysis of the Inflows*

Months	Mean (m^3/s)	Standard Deviation (m^3/s)
January	24.52	17.26
February	29.14	22.34
March	36.04	20.23
April	36.71	27.18
May	21.93	9.30
June	17.37	7.49
July	9.77	5.49
August	8.27	3.76
September	8.32	3.59
October	9.44	3.16
November	9.39	2.65
December	11.91	5.06

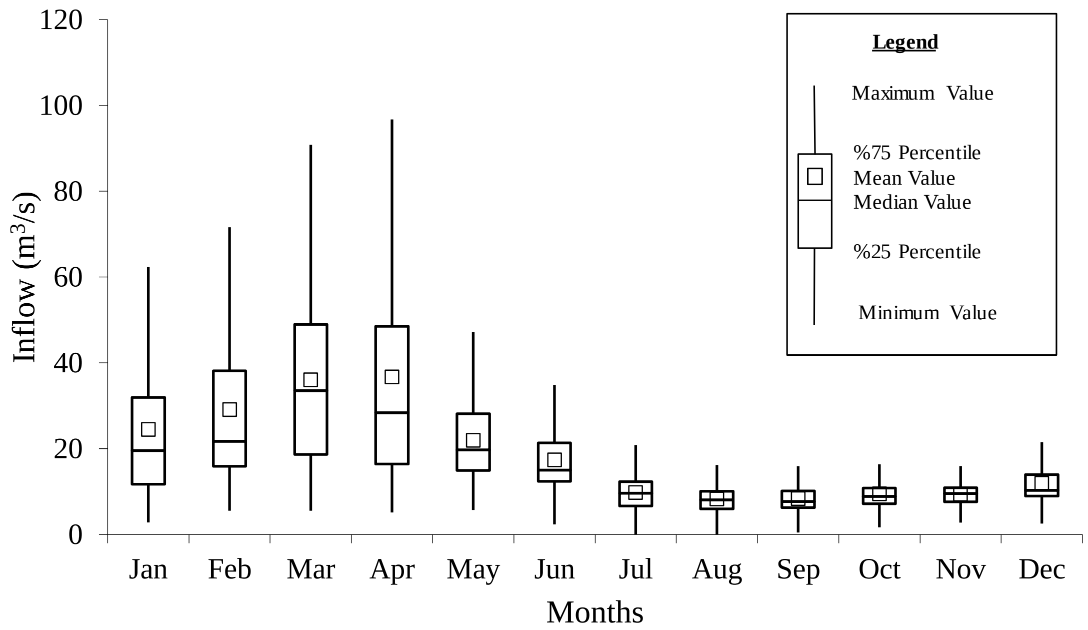

Figure 3.4. Monthly Average Inflow Values

As can be seen in Figure 3.4, from January to April, inflows are considerably higher and have high variability. In the summer season, inflow values and their variability drop significantly. During September to December, inflows behave similarly to the summer season. This results in lower electricity generation of UHP from June to December.

3.2.2. Electricity Price Analysis

In Section 2.3, the principles of electricity markets in Turkey and electricity pricing mechanism are presented. In this study, optimization is performed using Day-Ahead Market (DAM) prices on an hourly basis. DAM prices between January 2011 and August 2018 are obtained from EPİAŞ and statistical analysis of DAM Price for this period is performed. Means and standard deviations of DAM Price for each month are given in Table 3.8, and graphical demonstration is shown in Figure 3.5.

Table 3.8. *Statistical Analysis of the DAM Prices*

Months	**Mean (TL)**	**Standard Deviation (TL)**
January	160.44	46.64
February	151.09	76.60
March	128.58	40.30
April	132.76	48.52
May	135.59	47.58
June	142.47	45.85
July	163.53	45.91
August	177.98	63.12
September	157.47	44.78
October	147.33	36.65
November	154.83	41.26
December	172.18	65.19

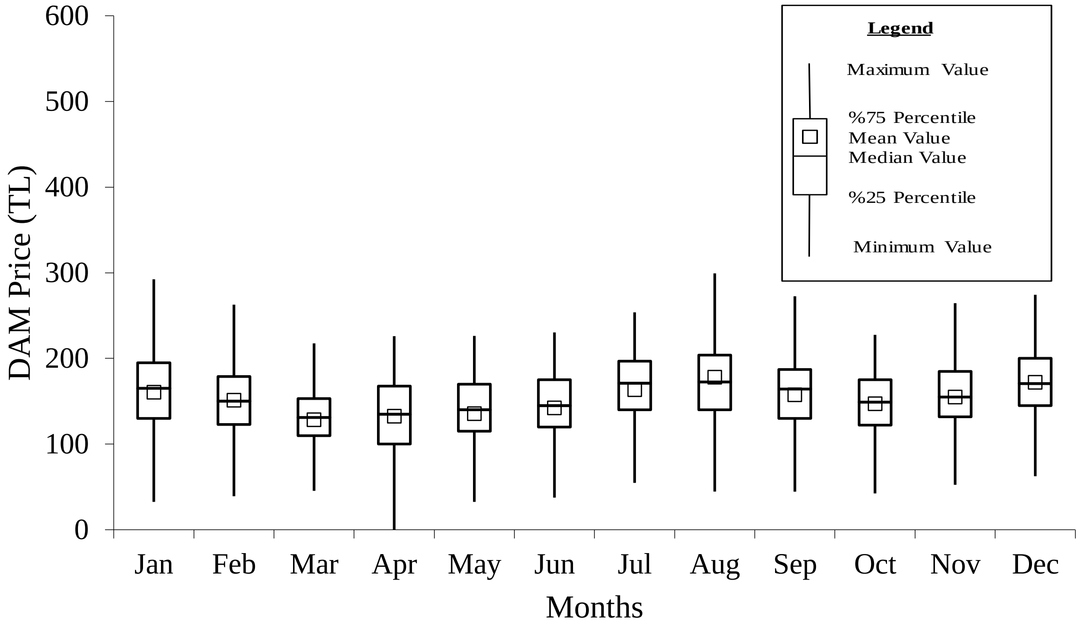

Figure 3.5. Monthly Average DAM Prices

As can be seen in Figure 3.5, lower mean DAM prices occur in March, April, and May, while during summer, especially in August, high mean DAM prices are observed. Evaluation of inflows and electricity prices shows that when water is abundant (i.e., inflows are high), the electricity prices are lower. In this study, it is aimed to increase revenue from electricity generation when DAM prices are at their peaks providing flexibility in the utilization of the stored water by transforming UHP to UPSHP.

3.2.3. Energy Generation Analysis

In Sections 3.2.1 and 3.2.2, statistical analysis of the inflows and the DAM Prices are presented. In this section, GenCo's energy generations for inflow to the reservoir and DAM prices are investigated between January 2011 and August 2018. Monthly energy generations, monthly average DAM prices and monthly inflow to the reservoir for each year from 2011 to 2018 is obtained from Akenerji (2018) and presented in Figures 3.6 to 3.13, respectively.

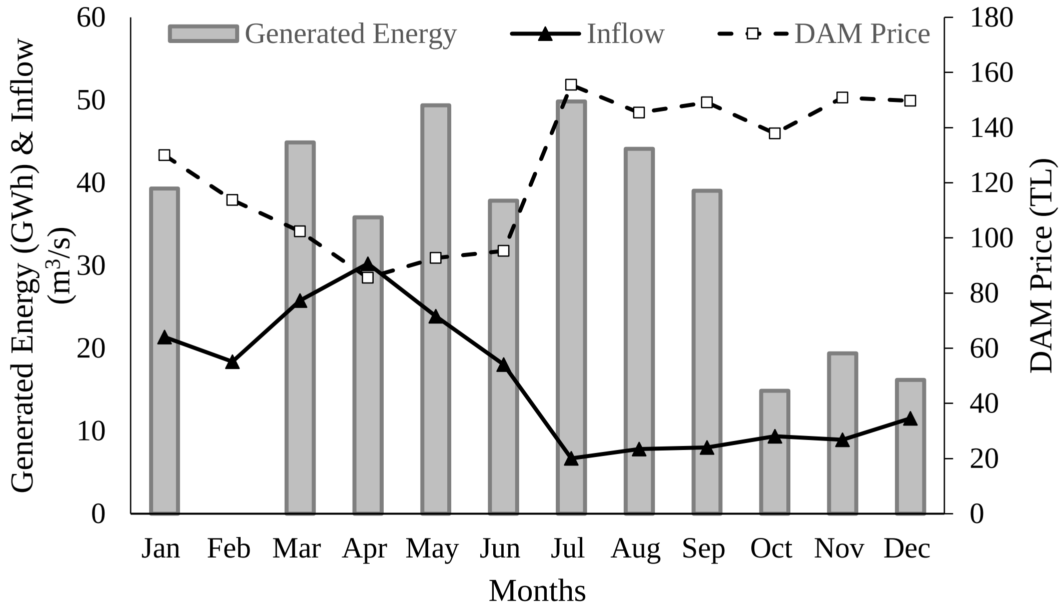

Figure 3.6. GenCo's Monthly Energy Generation - Monthly Average DAM Prices - Monthly Average Inflows for 2011

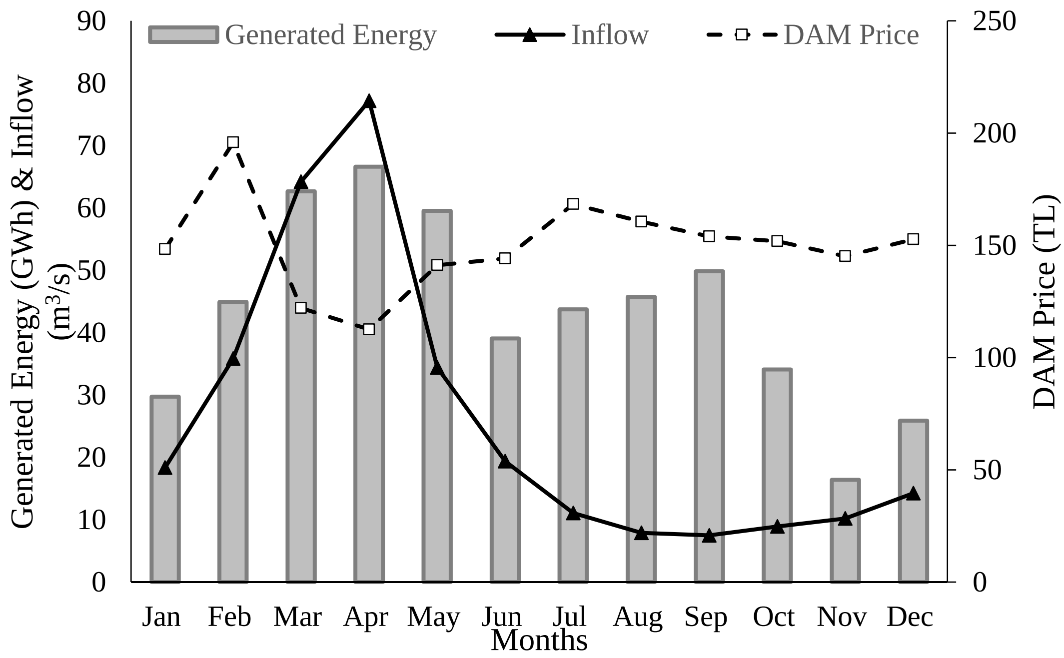

Figure 3.7. GenCo's Monthly Energy Generation - Monthly Average DAM Prices - Monthly Average Inflows for 2012

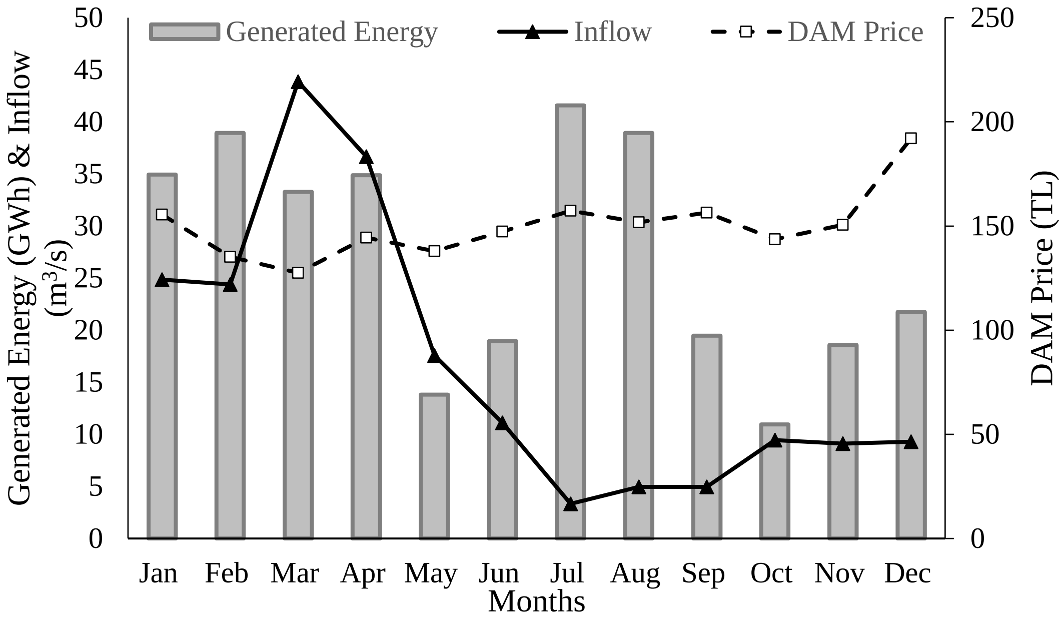

Figure 3.8. GenCo's Monthly Energy Generation - Monthly Average DAM Prices - Monthly Average Inflows for 2013

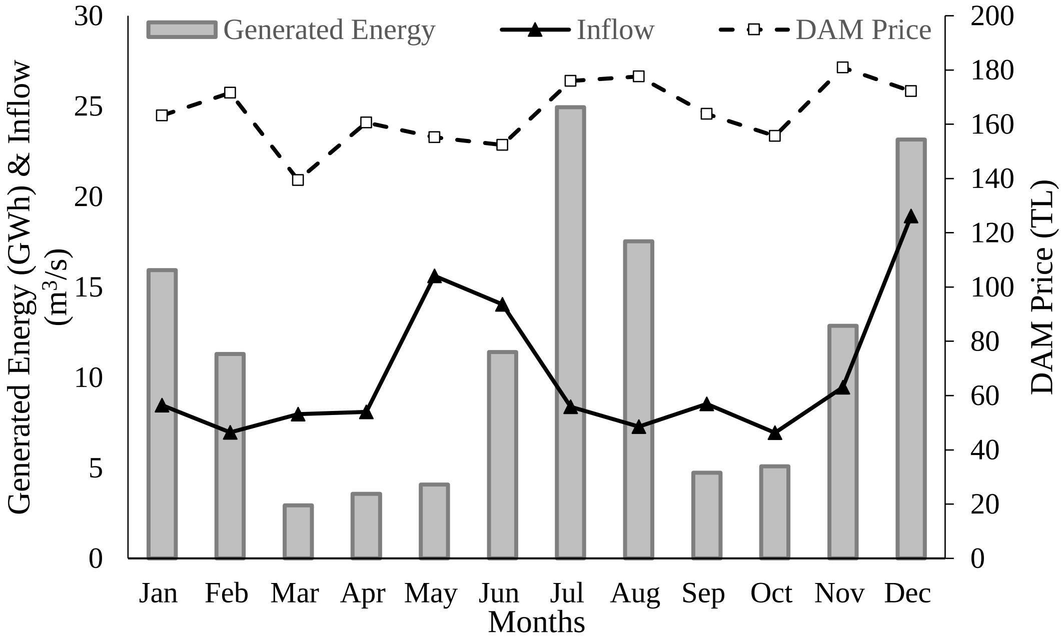

Figure 3.9. GenCo's Monthly Energy Generation - Monthly Average DAM Prices - Monthly Average Inflows for 2014

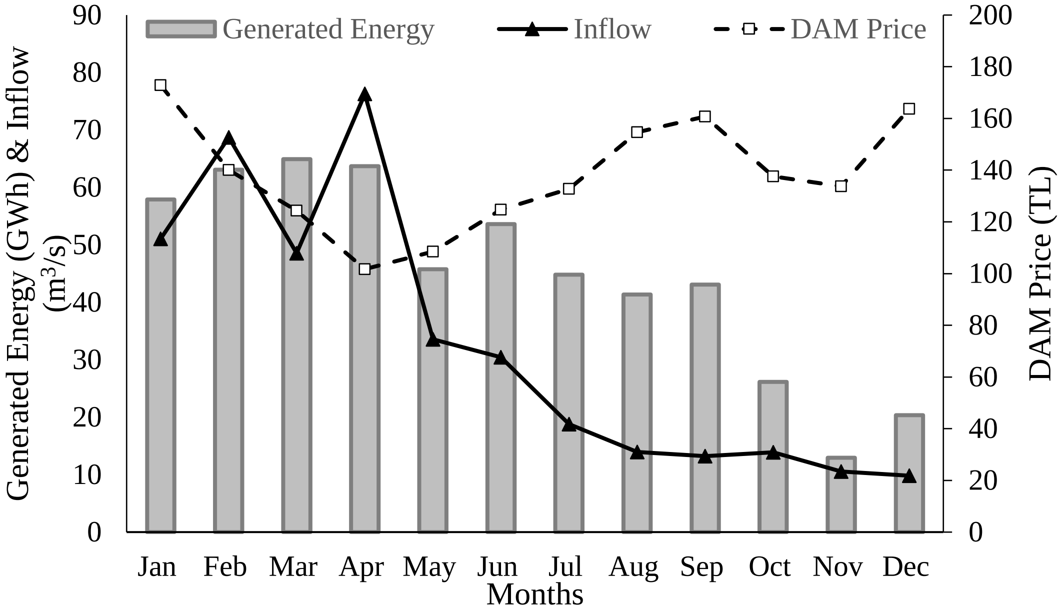

Figure 3.10. GenCo's Monthly Energy Generation - Monthly Average DAM Prices - Monthly Average Inflows for 2015

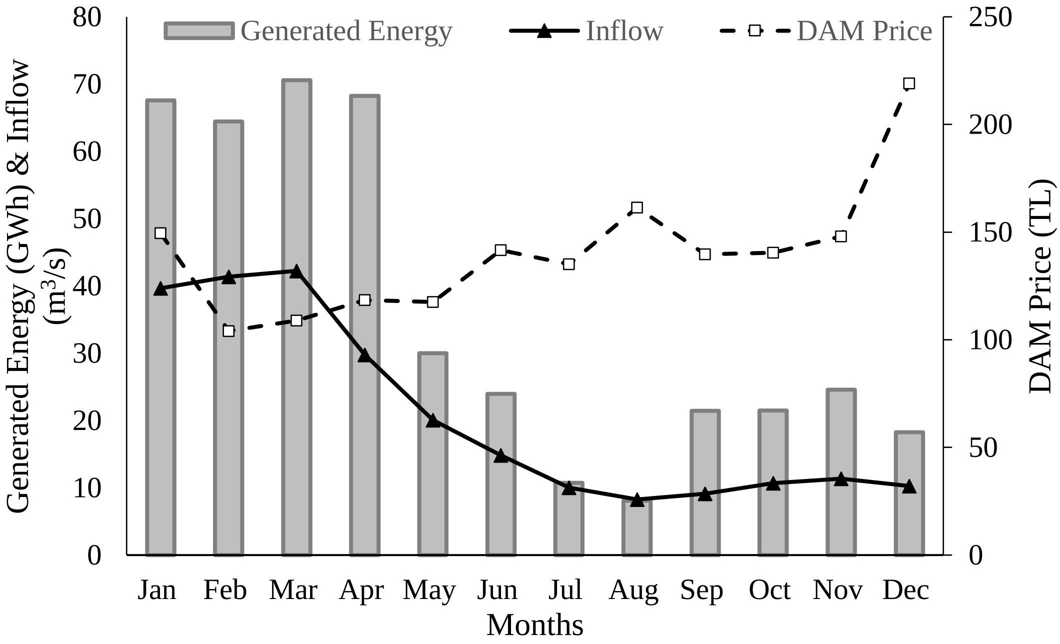

Figure 3.11. GenCo's Monthly Energy Generation - Monthly Average DAM Prices - Monthly Average Inflows for 2016

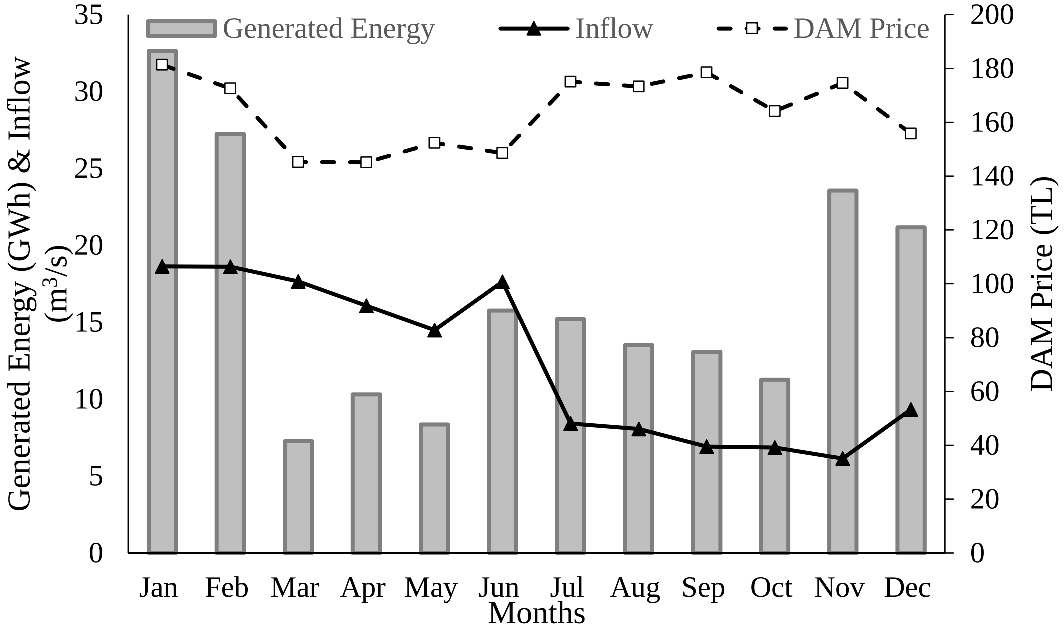

Figure 3.12. GenCo's Monthly Energy Generation - Monthly Average DAM Prices - Monthly Average Inflows for 2017

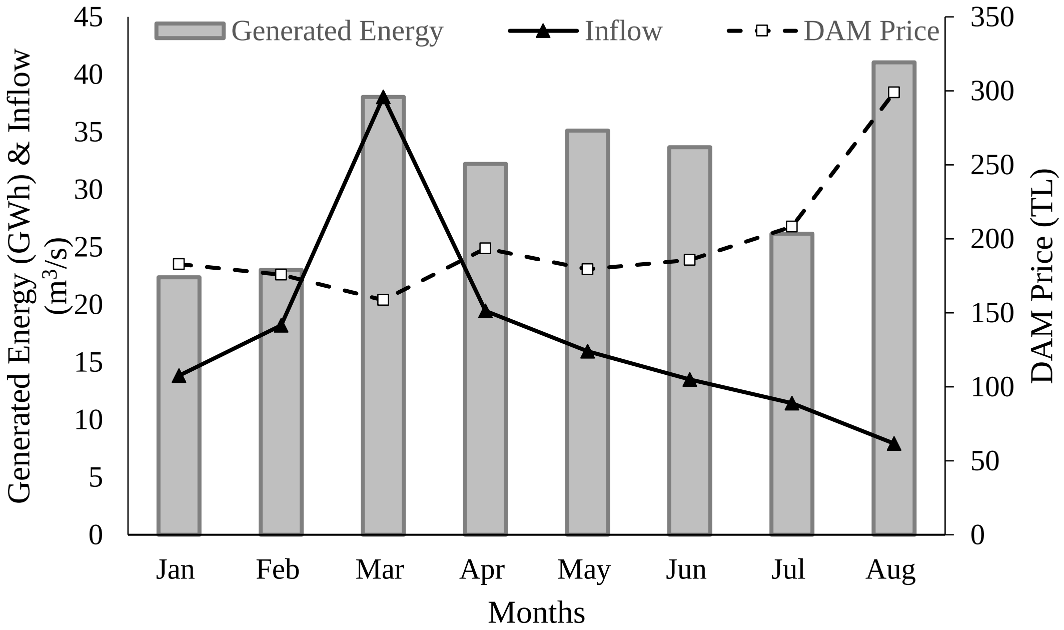

Figure 3.13. GenCo's Monthly Energy Generation - Monthly Average DAM Prices - Monthly Average Inflows for 2018

These analyses reveal that the amount of GenCo's energy generation generally decreased when the amount of inflow to the reservoir dropped. In the meantime, DAM Prices maintained relatively higher levels when GenCo's energy generation decreased. In this study, it is aimed to propose an optimized schedule that increases GenCo's energy generation at the time of the highest DAM prices.

3.2.4. Inflow – Electricity Price Comparison

In this section, electricity prices are categorized based on the price interval for January 2011 and August 2018. The amount of energy generation for each price interval is revealed along with average inflow values for the respective price interval. The amount of energy generation for each price interval and average inflows occurred in the same price interval are obtained from Akenerji (2018) and presented in Figures 3.14 to 3.21, respectively.

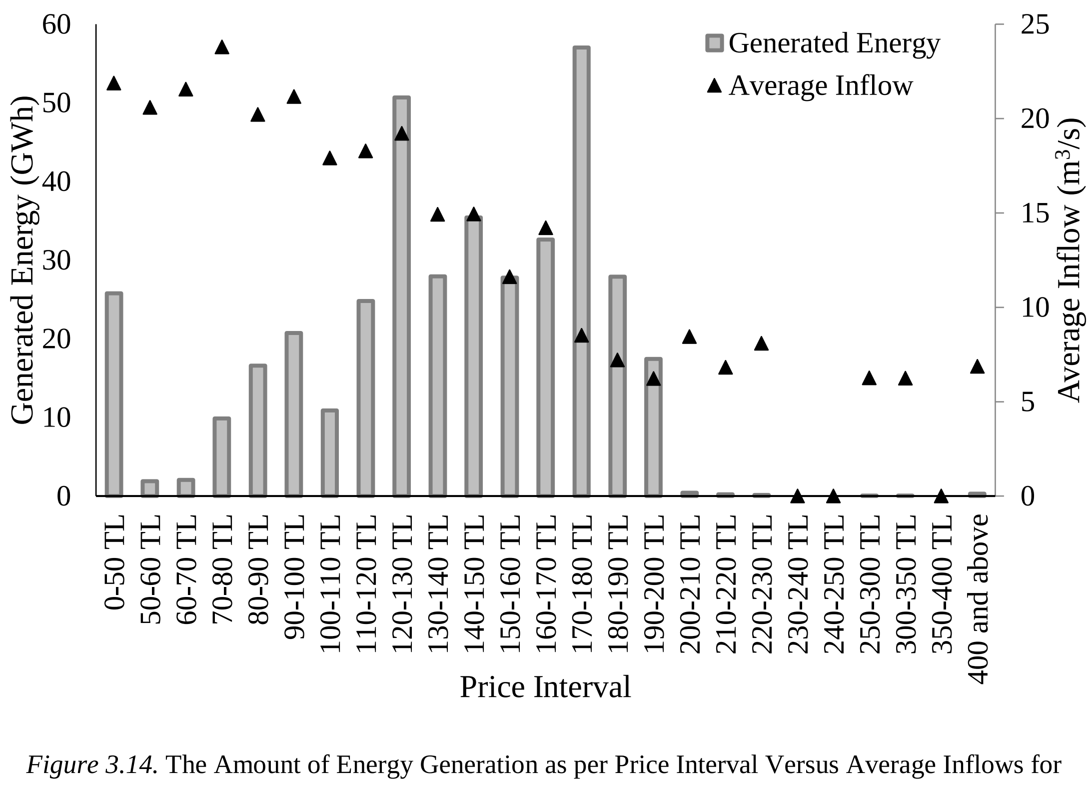

Figure 3.14. The Amount of Energy Generation as per Price Interval Versus Average Inflows for respective price interval for 2011

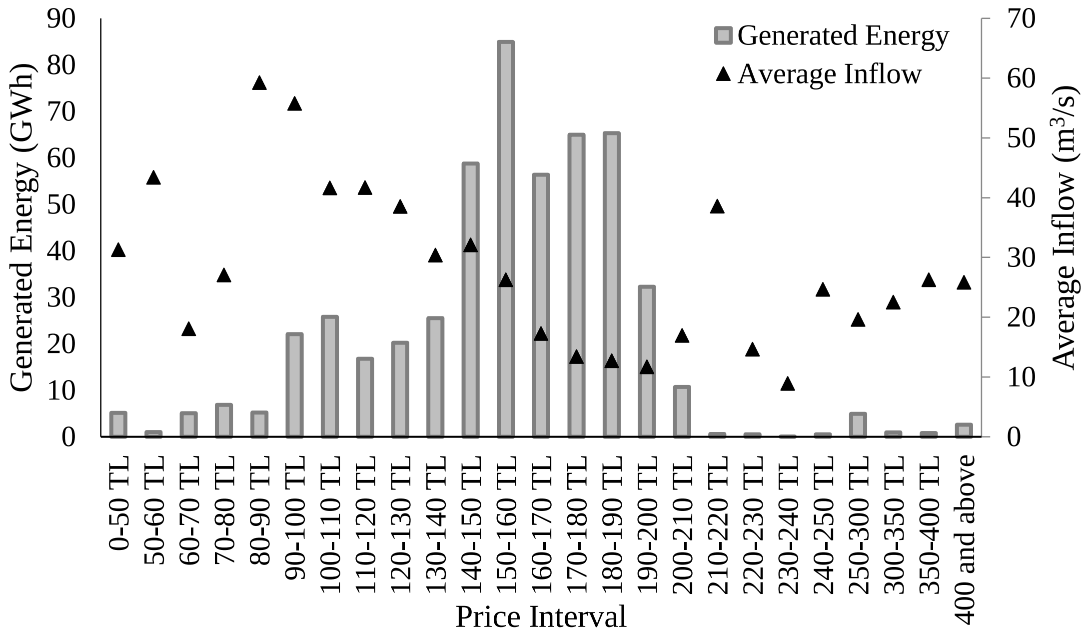

Figure 3.15. The Amount of Energy Generation as per Price Interval Versus Average Inflows for respective price interval for 2012

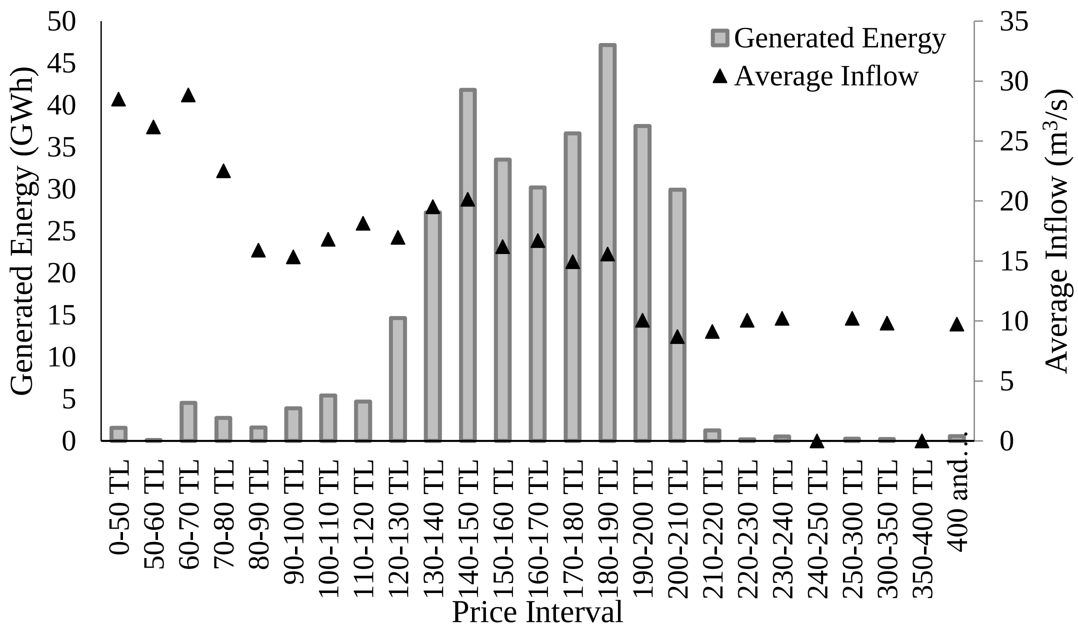

Figure 3.16. The Amount of Energy Generation as per Price Interval Versus Average Inflows for respective price interval for 2013

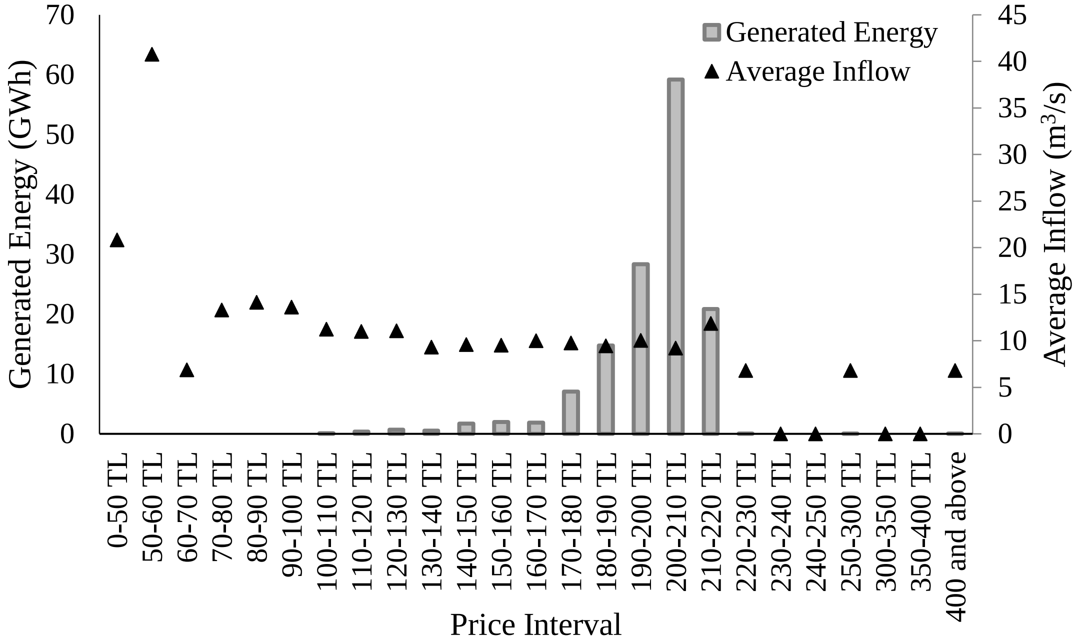

Figure 3.17. The Amount of Energy Generation as per Price Interval Versus Average Inflows for respective price interval for 2014

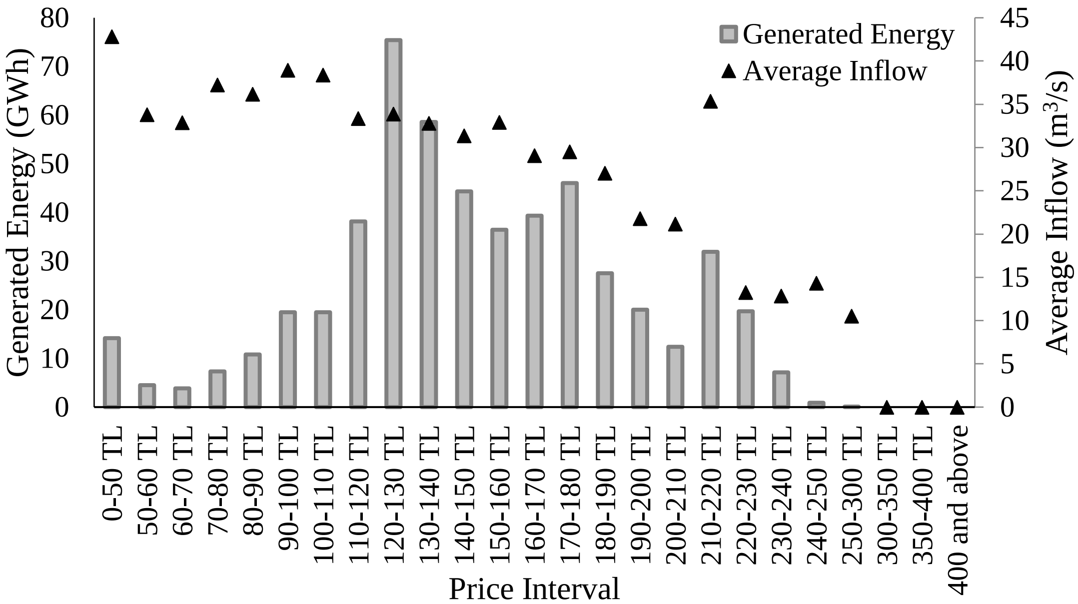

Figure 3.18. The Amount of Energy Generation as per Price Interval Versus Average Inflows for respective price interval for 2015

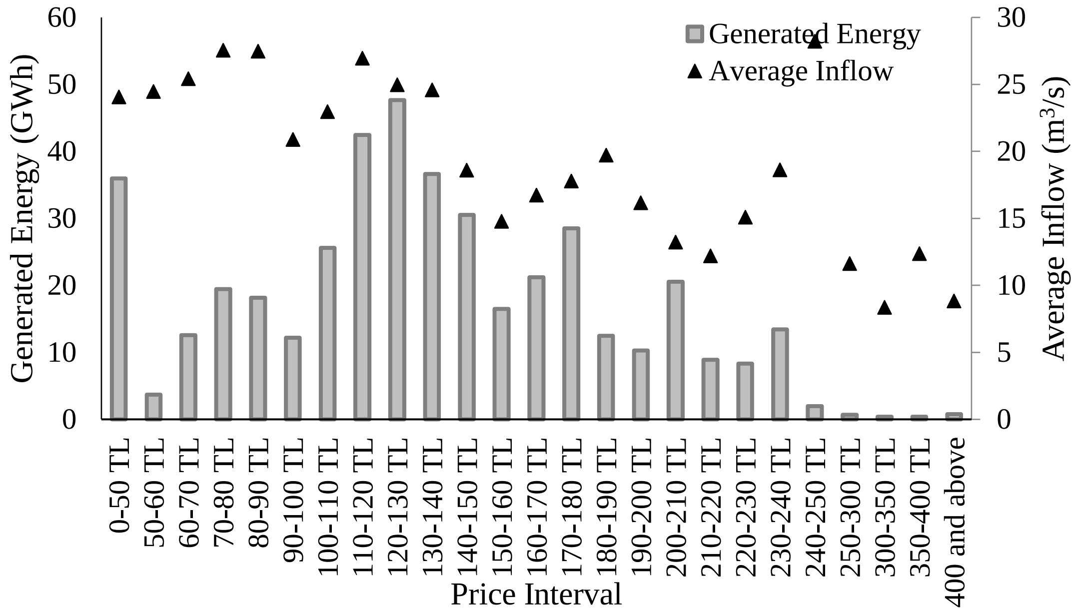

Figure 3.19. The Amount of Energy Generation as per Price Interval Versus Average Inflows for respective price interval for 2016

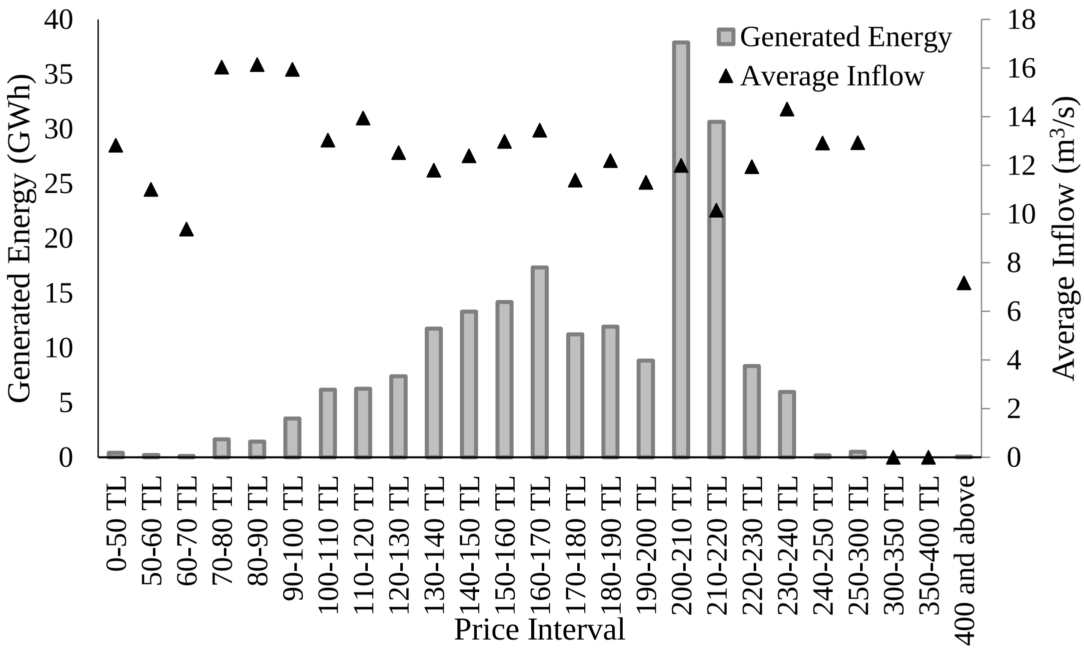

Figure 3.20. The Amount of Energy Generation as per Price Interval Versus Average Inflows for respective price interval for 2017

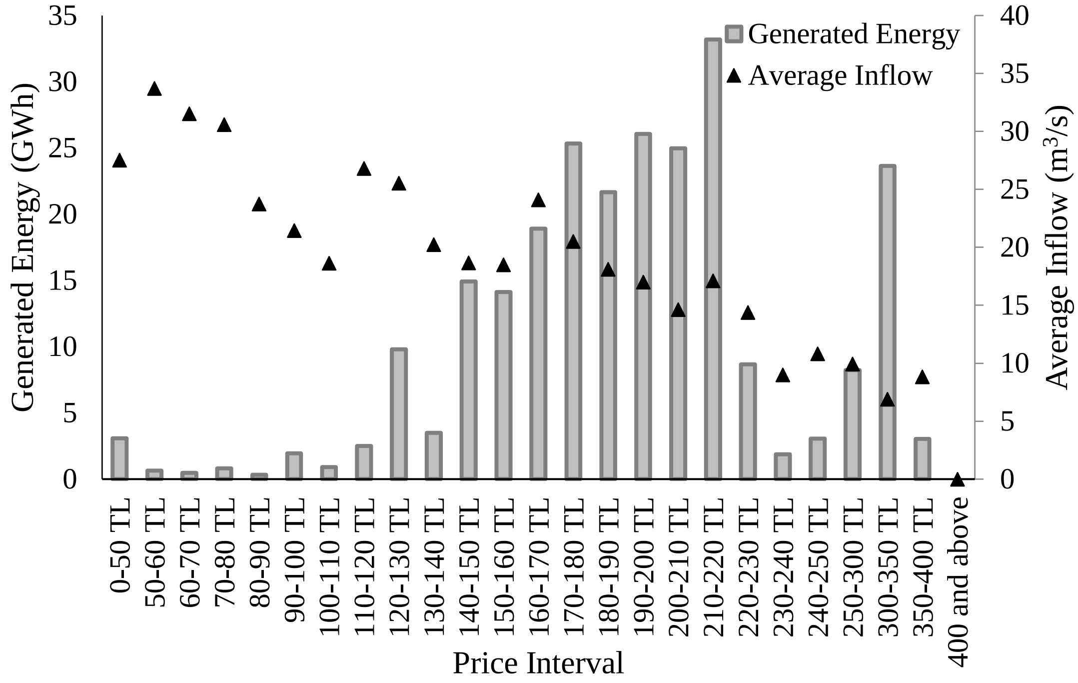

Figure 3.21. The Amount of Energy Generation as per Price Interval Versus Average Inflows for respective price interval for 2018

As can be seen in Figures 3.14 to 3.21; generally, energy generation is low during low DAM prices. Therefore, as a general operation strategy, storing water in the reservoir when DAM prices are low, and releasing the stored water to generate electricity when the prices increase seems to be efficiently implemented by GenCo. However, it is also observed that energy generation during the highest DAM prices is commonly very low or zero. Introducing pumping from the lower reservoir to the upper reservoir may improve this situation and lead to higher revenues.

CHAPTER 4

METHODOLOGY

The goal of this study is to obtain operation strategies for a PSHP that maximizes the benefit. This is achieved through a nonlinear optimization model. This chapter provides information about the methodology implemented in this study. It first presents scenarios that have been studied. Next, the optimization model, its objective function, and constraints are introduced. Further, assumptions and detailed explanation of constraints are discussed. Finally, nonlinear optimization models are explained.

The optimization model aims to maximize the annual revenue of a PSHP. The optimization study is based on hourly time steps and performed for each water year from 2013 to 2018. Although historical inflow data between 1 January 2011 and 31 August 2018 are available, the optimization study is performed for the duration between 1 September 2013 and 31 August 2018. The reason for this selection of the duration is the fact that DAM was introduced in December 2011 and was not constituted in its final structure until 2013. Therefore, hourly electricity prices are only available after 2013. In this regard, the optimization model is run for 2013, 2014, 2015, 2016 and 2017 water years.

In this study, historical hourly inflow and DAM prices are the inputs to the optimization models. Although monthly time-steps are sufficient in determining operation strategies of hydropower plants with reservoirs, since electricity prices vary hourly, hourly-time steps are necessary for pumped storage power plants. Thus, in this study, we implemented hourly-time steps. However, utilization of hourly-time steps for long simulation periods is challenging due to the curse of dimensionality. To overcome this problem, we run the optimization model for the duration of one water year for five different years. The availability of water and oscillations in electricity prices in these five years is investigated in Chapter 3. We assume that the variations in these five years will be similar to those that will be experienced in the near future. Thus, the results obtained for these five models will guide for GenCo to develop operation strategies that will increase their revenue in the future years.

4.1. Scenarios

In this study, two optimization models are built; the conventional hydropower plant model and the pumped storage hydropower plant model. These two models will allow investigation of GenCo's revenue increase if UHP (i.e., the conventional hydropower plant) is transformed into a pumped storage hydropower plant (i.e., Uluabat Pumped Storage Hydropower Plant, UPSHP).

As discussed in Section 3.2, reservoir operation data of GenCo is available for the selected duration (i.e., 2013-2017 water years). To be able to compare the performance of the optimization model developed in this study with the realized revenues, two scenarios are considered for the conventional hydropower plant model and the pumped storage hydropower plant model. In Scenario 1, the actual (i.e., realized due to GenCo's operation) initial, $S_{int\_observed}$ and final storage values, $S_{fin\_observed}$, for each of the water years in the simulation period (Table 4.1) are used in the optimization models. Thus, the real electricity revenues of GenCo for each of the simulation years are comparable with those obtained from the optimization models developed in this study for Scenario 1. As Scenario 2, to represent a more general case, it is assumed that the final storage value, S_{fin} of the reservoir will be equal to the initial realized storage value $S_{int\_observed}$ of the current year. The results of Scenario 2 will provide insight into the range of possible revenues that can be obtained due to operation of UHP in the PSHP mode, provided that the starting and ending storages in the reservoir are the same. Therefore, the reservoir will not be depleted, and the revenues obtained for Scenario 2 will be only due to the inflows to the reservoir. The initial and final storage values used in each optimization model for Scenario 2 are given in Table 4.2.

Table 4.1. *Initial and Final Storage Amounts for Scenario 1 (adopted from GenCo's records, 2018)*

	01.09.2013 / 31.08.2014	**01.09.2014 / 31.08.2015**	**01.09.2015 / 31.08.2016**	**01.09.2016 / 31.08.2017**	**01.09.2017 / 31.08.2018**
$S_{int\_observed}$ (hm^3)	217.15	196.88	279.26	221.07	247.47
$S_{fin\_observed}$ (hm^3)	196.88	279.26	221.07	247.47	209.60

Table 4.2. *Initial and Final Storage Amounts for Scenario 1 (adopted from GenCo's records, 2018)*

	01.09.2013 / 31.08.2014	**01.09.2014 / 31.08.2015**	**01.09.2015 / 31.08.2016**	**01.09.2016 / 31.08.2017**	**01.09.2017 / 31.08.2018**
$S_{int\_observed}$ (hm^3)	217.15	196.88	279.26	221.07	247.47
S_{fin} (hm^3)	217.15	196.88	279.26	221.07	247.47

4.2. Optimization Models

In this study, two separate optimization models are developed for the conventional hydropower plant (i.e., UHP) and the pumped storage hydropower plant (i.e., UPSHP). The optimization models for UHP and UPSHP are presented in this section. First, the sets, the scalars, the parameters, and the variables are presented for the UPSHP model. Then, the necessary modifications for the UHP model are provided.

Sets:

t : time step (hour) ($t \in$ T = {1,2, 3,…, 8760})

Parameters:

$C(t)$: Electricity price at t (TL/MW)

$I(t)$: Inflow to the reservoir at t (m^3/hr)

$SP(t)$: Spilled water at t (m^3/hr)

$RW(t)$: Residual water released at t (m^3/hr)

Scalars:

S_{min} : Minimum reservoir volume (m^3)

S_{max} : Maximum reservoir volume (m^3)

S_{int} : Initial reservoir volume (m^3)

S_{fin} : Final reservoir volume (m^3)

QT_{min} : Minimum turbine discharge (m^3/s)

QT_{max} : Maximum turbine discharge (m^3/s)

QP_{min} : Minimum pump discharge (m^3/s)

QP_{max} : Maximum pump discharge (m^3/s)

A_S : First coefficient of the stage-storage relationship

B_S : Second coefficient of the stage-storage relationship

A_E : First coefficient of the efficiency-discharge curve

B_E : Second coefficient for efficiency-discharge curve

C_E : Third coefficient for efficiency-discharge curve

D_E : Fourth coefficient for efficiency-discharge curve

A_L : First coefficient of the head loss-discharge curve

B_L : Second coefficient for head loss-discharge curve

C_L : Third coefficient for head loss-discharge curve

TR : Tailrace elevation (m)

Variables:

$H(t)$: Gross head at t (m)

$FB(t)$: Forebay elevation at t (m)

$S(t)$: Reservoir storage at t (m^3)

$HLT(t)$: Head loss during turbine operation at t (m)

$HLP(t)$: Head loss during pump operation at t (m)

$etaT(t)$: Turbine efficiency at t

$etaP(t)$: Pump efficiency at t

$QT(t)$	:	Discharge for the turbine at t (m^3/s)
$QP(t)$	:	Discharge for the pump at t (m^3/s)
$PT(t)$	:	Power generated by the turbine at t (MW)
$PP(t)$	:	Power consumed by the pump at t (MW)
$RE(t)$	:	Revenue at t (TL)

As the UHP model represents the conventional hydropower plant (i.e., water is only turbined to generate electricity), the scalars and the variables associated with pump operation are not necessary. Thus, the sets, the scalars, the parameters and the variables presented above for UPSHP model is applicable for the UHP model excluding QP_{min}, QP_{max}, $HLP(t)$, $etaP(t)$, $QP(t)$, and $PP(t)$.

4.3. Mathematical Formulation of the Optimization Models

As explained in Section 4.2, two optimization models are developed for UHP and UPSHP separately. These mathematical formulations are presented in this section. First, the objective function and the constraints for UPSHP model are presented. Then, the necessary modifications for the UHP model are given.

4.3.1. Mathematical Formulation for the Pumped Storage Hydropower Plant Model

UPSHP problem is formulated as a nonlinear optimization problem, with maximization of the annual revenue (Z) as the objective function:

$$Maximize\ Z = \sum_{t} C(t)[PT(t) - PP(t)] - D * PT(t) * PP(t) \tag{4.1}$$

where $C(t)$ is DAM price at time t (TL/MW) and $t \epsilon T = \{1, 2, 3, \ldots, 8760\}$, $PT(t)$ and $PP(t)$ are power generated by the turbine at time t (MW) and power consumed by the pump at time t (MW), respectively. D is a very big number (i.e., 10^6) used as the penalty coefficient to prevent operation of the pump and the turbine units at the same time.

The gross head, $H(t)$ (m) is a key variable for power generation and consumption, and is defined as follows:

$$H(t) = FB(t) - TR \tag{4.2}$$

where $FB(t)$ is the forebay elevation at time t (m) and TR is the tailrace elevation (m). While forebay elevation is taken as the water level in the reservoir at time t, tailrace elevation is assumed to be constant, as explained later in this section.

The power generated by the turbine at time t (MW), $PT(t)$ is calculated as follows:

$$PT(t) = \ etaT(t)\, \gamma\ [H(t) - HLT\ (t)]\ QT(t) \tag{4.3}$$

where $etaT(t)$ is the efficiency of the turbine, γ is the specific weight of the water (kN/m^3), $HLT(t)$ is the head loss during turbine operation at time t (m) and $QT(t)$ is the discharge for the turbine at time t (m^3/s).

The head loss during turbine operation at time t, $HLT(t)$, is defined as follows:

$$HLT\ (t) = \ A_L\ QT^2(t) + B_L QT(t) + C_L \tag{4.4}$$

where $QT(t)$ is the turbine discharge at time t (m^3/s) whereas $A_L, B_L$and C_L are coefficients that are obtained from the head loss-turbine discharge relationship presented in Figure 4.1. $QT(t)$ is restrained by the upper and lower limits as follows:

$$QT_{min}\ \le QT(t) \le QT_{max} \tag{4.5}$$

where QT_{min} and QT_{max} are the minimum and the maximum turbine discharges (m^3/s), respectively.

The turbine efficiency, $etaT(t)$, which depends on the turbine discharge is formulated as follows:

$$etaT(t) = A_E\ QT^3(t) + B_E\ QT^2(t) + C_E\ QT(t) + D_E \tag{4.6}$$

where $A_E,\ B_E, C_E$ are D_E are the coefficients obtained from the technical specification of the existing turbines. Detailed information about the efficiencies of the existing turbines is given in Figure 4.2.

The power consumption by the pump at time t (MW), $PP(t)$ is calculated as follows:

$$PP(t) = \ etaP(t)\gamma\ [H(t) - HLP(t)]\ QP(t) \tag{4.7}$$

where $etaP(t)$ is the efficiency of the pump, $HLP(t)$ is the head loss during pump operation at time t (m) and $QP(t)$ is the discharge for the pump at time t (m^3/s).

The head loss during pump operation at time t, $HLP(t)$, is defined as follows:

$$HLP\ (t) = \ A_L\ QP^2(t) + B_L QP(t) + C_L \tag{4.8}$$

where $QP(t)$ is the pump discharge at time t (m^3/s) whereas $A_L,\ B_L$ and C_L are coefficients of the head loss-pump discharge relationship presented in Figure 4.1. $QP(t)$ is restrained by upper and lower limits as follows:

$$QP_{min}\ \leq QP(t) \leq QP_{max} \tag{4.9}$$

where QP_{min} and QP_{max} are the minimum and the maximum pump discharges (m^3/s), respectively.

The pump efficiency, $etaP\ (t)$, which depends on the pump discharge is formulated as follows:

$$etaP(t) = A_E\ QP^3(t) + B_E\ QP^2(t) + C_E\ QP(t) + D_E \tag{4.10}$$

where $A_E,\ B_E, C_E$ are D_E are coefficients of the efficiency, which is assumed to be the same as the turbine efficiency. Detailed information on the turbine and pump efficiencies are given in Figure 4.2.

The reservoir storage at time t, $S(t)$ (m^3), and forebay elevation at time t, $FB(t)$ (m), are associated by the following formulation:

$$S(t) = A_S\ FB(t) - B_S \tag{4.11}$$

where A_S and B_S are the coefficients obtained from the curve representing the relation between the amount of stored water in the reservoir and the water level which is given Figure 4.3.

The relation between $S(t)$ and $S(t + \Delta t)$ is given by the following continuity equation:

$$S(t + \Delta t) = S(t) - 3600\, QT(t)\Delta t + 3600\, QP(t)\Delta t + I(t)\Delta t - SP(t)\Delta t - RW(t)\Delta t \quad (4.12)$$

where $I(t)$ is the inflow to reservoir at time t (m^3/hr), $SP(t)$ is spilled water at time t (m^3/hr) and $RW(t)$ is the residual water at time t (m^3/hr), and Δt is 1 hour.

The reservoir storage, $S(t)$, is constrained by the following formulation:

$$S_{min} \leq S(t) \leq S_{max} \quad (4.13)$$

where S_{min} and S_{max} are the minimum and the maximum reservoir storage amounts (m^3), respectively.

As explained in Section 4.1, two scenarios are considered in this study. For Scenario 1, the following constraints are implemented:

$$S_{int} = S_{int\_observed} \quad (4.14)$$
$$S_{fin} = S_{fin\_observed}$$

For each of the simulation years, the initial storage, S_{int} and the final storage, S_{fin} are taken equal to the actual initial reservoir storage, $S_{int\_observed}$ and actual final reservoir storage, $S_{fin\_observed}$ values realized in that year (see Table 4.1).

For Scenario 2, Eq (4.14) is replaced with the following constraint:

$$S_{fin} \text{ of } y \leq S_{int} \text{ of } y \quad (4.16)$$

where y is the simulation year and in this study, $y = 2013, 2014, 2015, 2016, 2017$ (see Table 4.2). In other words, the reservoir is forced not to drain below the initial storage value.

As discussed before, the utilization of hourly-time steps for long simulation periods is challenging due to the curse of dimensionality. It is observed that assigning guidance for the pumping operation facilitates the solution. Thus, in this study, the following constraint that forces the pump operation is introduced into the model:

$$if\ C(t) < C_{int}\ then\ QP(t) = 38\ m^3/s\ and\ QT(t) = 0 \qquad (4.17)$$

where $C(t)$ DAM Price at time t (TL/MW), C_{int} is the electricity price below which pumping operation should start (TL/MW), $QP(t)$ is pump discharge and $QT(t)$ is turbine discharge. In this study, C_{int} value is determined by the trial-error approach while $QP(t)$ is kept as a constant value at 38 m^3/s which results in the highest efficiency (see Figure 4.2)

The formulation presented above is a nonlinear programming problem. The objective function given in Eq (4.1) aims to maximize the revenue by subtracting the cost of the power consumed by the pump from the revenue gained from the power generated by the turbine.

Eq (4.2) defines the gross head, which varies due to power generation and power consumption. The gross head is obtained by subtracting the constant tailrace elevation from the forebay elevation, which varies as a function of the stored water in the reservoir. Despite tailrace is a function of the turbine discharge, for the sake of simplicity, it is considered to be constant in the model formulation. The tailrace elevation of UHP varies between 6.8 m to 7.6m. Thus, in this study, it is taken as 7.2 m, the average of the upper and the lower limits.

Eq (4.3) is the formulation of power generation. The power is a function of the turbine efficiency, turbine discharge, and the net head, which is obtained by subtracting the head loss from the gross head.

The head loss for turbine operation is formulated in Eq (4.4) with respect to the turbine discharge. The head loss is a function of frictional losses due to the conveyance of water through UHP's power tunnel and penstock. Associated head losses were calculated during the design phase of UHP (Hidro Dizayn, 2005). Using the head loss equations derived by Hidro Dizayn, the head losses for different discharges between the minimum and maximum limits are calculated, and a curve is fitted to discharge versus head loss (Figure 4.1). The coefficients of the discharge-head loss relation (i.e., of Eq (4.4)) are obtained from this curve as follows: $A_L = 0.024, B_L = 7 \times 10^{-15}$ and $C_L = 0.0082$.

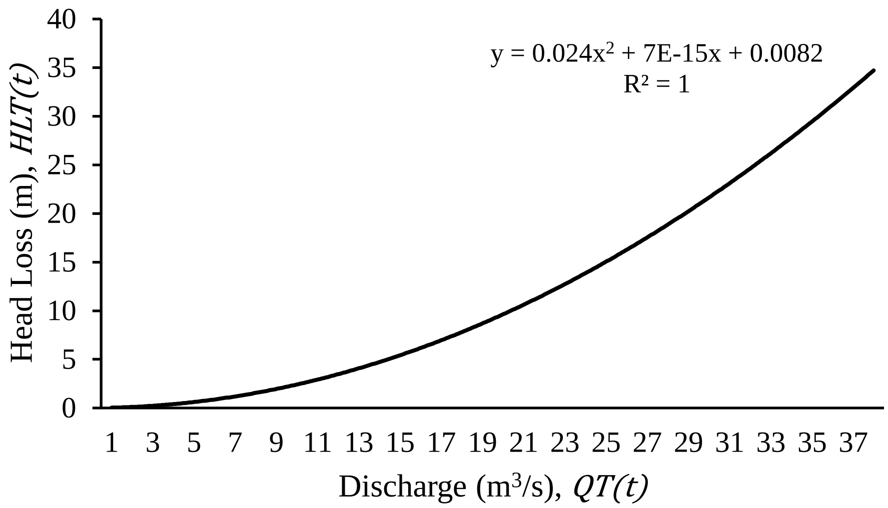

Figure 4.1. Discharge-Head Loss Relationship

Eq (4.5) determines the flow limits for the turbine discharge. As described in Section 3.1, UHP consists of two identical turbines each with a capacity of 50 MW and a design discharge of 19 m^3/s. For the sake of simplicity, a single turbine with an installed capacity of 100 MW and a design discharge of 38 m^3/s is assumed in this study. Thus, the flow limits are adapted to the single unit. This introduces some error into the analysis; however it eased the solution of the nonlinear model significantly. Thus, this point should be kept in mind while evaluating the comparisons of optimization model results and realized revenues.

Eq (4.6) formulates the efficiency of the turbine, which directly depends on the turbine discharge. Voith-Siemens have designed turbines of UHP and technical specification of the turbines is available (Voith-Siemens, 2008). Therefore, the relationship between the turbine discharge and the efficiency (called the efficiency curve) is obtained from the turbine technical specification of UHP. As explained in the previous paragraph, two identical turbines, each with a capacity of 50 MW, is modeled as a single turbine with an installed capacity of 100 MW in this study. The efficiency curve provided for a 50 MW turbine is adopted to 100 MW turbine by multiplying turbine discharge value by two. For different discharges, efficiencies are estimated and plotted with the full line in Figure 4.2. Then a third-order polynomial is fit to these points, and it is given with the dotted line in Figure 4.2. The coefficients of the discharge efficiency relation given in Eq (4.6) are obtained from this curve as follows: $A_E = 0.0009, B_E = -0.1065, C_E = 3.9026$ and $D_E = 49.198$.

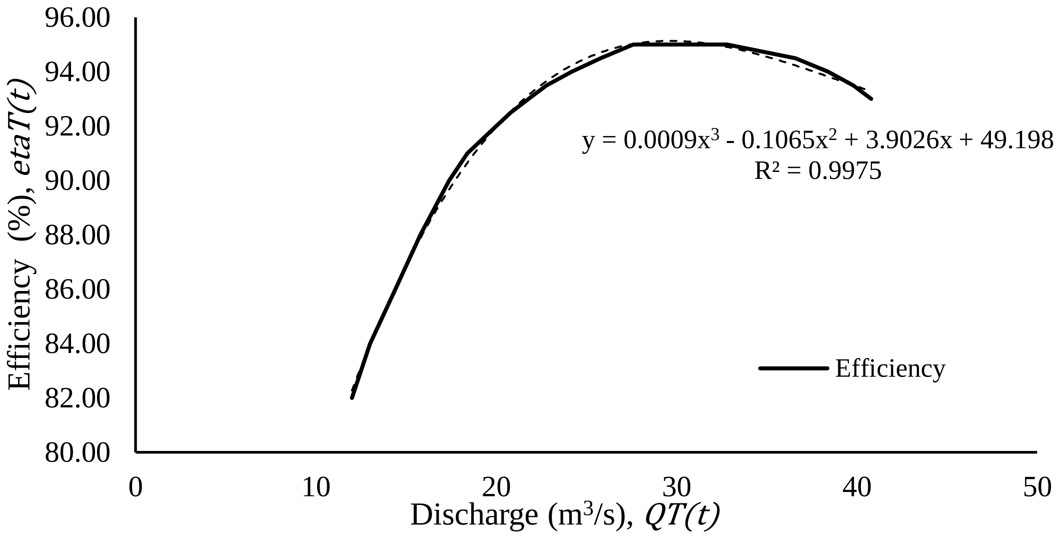

Figure 4.2. Turbine Efficiency Curve of the Singe Unit

Eq (4.7) formulates power consumption by the pump. In this study, a single pump is assumed to be integrated into the existing UHP to transfer it to a pumped storage hydropower plant in a quaternary configuration, which is described in Chapter 2 in detail.

The head loss for the pump operation is formulated in Eq (4.8) as a function of the pump discharge. In this study, it is assumed that the existing penstock and the tunnel are utilized during pump operation, and the pump discharge range is the same as the turbine discharge range (Antal, 2014). In other words, the head loss due to pump operation and turbine operation for the same discharge are assumed to be the same. Hence, in this study, the discharge-head loss curve of the turbine (Figure 4.1) is used for the pump operation as well.

Eq (4.9) determines flow limits for the pump discharge, $QP(t)$. In this study, the flow limits for the pump discharge are assumed to be the same as the limits used for the turbine discharge.

Eq (4.10) formulates the efficiency of the pump, which directly depends on pump discharge. Turbine efficiency curve is assumed to be the same for the pumped-storage system (GE Energy, 2016). Hence, the turbine efficiency curve shown in Figure 4.2 is used for the pump operation.

The relationship between the amount of stored water in the reservoir and the water level (called the forebay elevation) is defined in Eq (4.11). In previous sections, it is specified that power is the function of gross head and discharge. On the other hand, the gross head depends on the water level, and discharge directly affects the amount of stored water in the reservoir as well as the water level of the reservoir. Thus, it is essential to establish a relationship between the forebay elevation and the amount of the stored water in the reservoir. The amount of the stored water for each forebay elevation has been calculated by Hidro Dizayn and is available in GenCo's record (Akenerji, 2018). The forebay elevation storage relationship taken from GenCo was given in Figure 4.3. A straight line is fitted to this curve and plotted as the dashed line in Figure 4.3. The coefficients forebay elevation-storage relation of Eq (4.11) are obtained from the fitted line as follows: $A_S = 7.426$ and $B_S = 2086.1$.

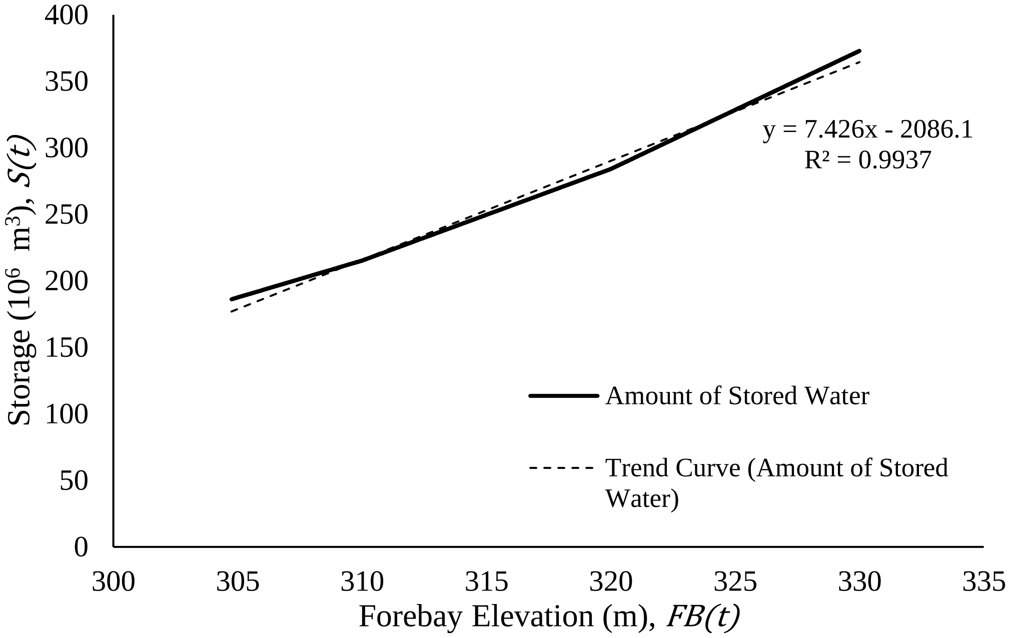

Figure 4.3. Storage – Forebay Elevation Relationship

The continuity equation is given in Eq (4.12), and the amount of stored water is constrained by Eq (4.13) following the physical limitations of Çınarcık reservoir, which is used as the upper reservoir. Note that Lake Uluabat's storage capacity, which is the lower reservoir, has no constraint since Lake Uluabat diverts its water to Marmara Sea through Kocasu Stream.

Eq (4.14) and Eq (4.15) forces the final storage levels of the optimization period, as described in Section 4.1.

4.3.2. Mathematical Formulation for the Conventional Hydropower Plant Model

The objective function and constraints for the UPSHP model are given in Section 4.3.1. In this section, the necessary modifications for the conventional hydropower plant model (i.e., UHP) for the objective function and power generation constraints are given. As pump operation is not performed in the UHP model, the objective function presented in Eq (4.1) is replaced with the following equation:

$$Maximize\ Z = \sum_t C(t)PT(t) \tag{4.18}$$

Constraints related to the pumping operation (i.e., Equations (4.7), (4.8), (4.9), (4.10), and (4.17)) are not used in the UHP model. Moreover, Eq (4.12) is modified as follows:

$$S(t+\Delta t) = S(t) - 3600\ QT(t)\Delta + I(t)\Delta t - SP(t)\Delta t - RW(t)\Delta t \tag{4.19}$$

CHAPTER 5

RESULTS AND DISCUSSIONS

In this chapter, the results of the optimization model under two scenarios presented in Section 4.1 are discussed. The optimal solutions are found in 600 seconds on average by using the CONOPT Solver of GAMS Software.

As discussed in Section 4.3, guidance, as given in Eq (4.17), is assigned for the pumping operation in order to facilitate the solution. For both scenarios, the UPSHP model is performed by using different values for the electricity price below which pumping operation should start, C_{int} in Eq (4.17). The optimal UPSHP model that maximizes the revenue is determined. The results are given in this chapter along with the output of energy generation, energy consumption and distribution of operation hours based on the operation mode.

Moreover, the results of the optimal UPSHP model are compared with GenCo's actual operation (called Actual UHP). In addition to these comparisons, the number of generation hours and the amount of energy generation for each price interval is analyzed. Next, revenues, energy generations and energy consumptions of Actual UHP, UHP and UPSHP are compared and presented on an annual basis.

5.1. Results for Scenario 1

In Scenario 1, the actual (i.e., realized due to GenCo's operation) initial, S_{int} and actual final storage values, S_{fin} for each of the water years in the simulation period (Table 4.1) are used in the optimization models, as discussed in Section 4.1. In this study, UPSHP model is performed by forcing the model to operate the pump when the electricity price is below a certain value, C_{int} as discussed in Section 4.3. The best C_{int} value which maximizes the revenue is found through a trial and error approach.

Tables 5.1, 5.2, 5.3, 5.4 and 5.5 demonstrate the results of UPSHP for water years 2013, 2014, 2015, 2016 and 2017, respectively.

Table 5.1. *Results of UPSHP for 2013 (Scenario 1)*

Cases	**Pump Operation Forced Below 50 TL***	**Pump Operation Forced Below 100 TL**	**Pump Operation Forced Below 120 TL**	**Pump Operation Forced Below 130 TL**	**Pump Operation Forced Below 140 TL**	**Pump Operation Forced Below 150 TL**
Revenue (TL)	31,758,704	34,728,012	34,348,317	**35,446,449**	34,157,311	31,091,723
Number of pumping hours	154	291	1,116	1,965	2,606	3,386
Number of turbine hours	1,999	2,034	3,026	3,740	4,370	5,154
Number of idle hours	6,607	6,435	4,618	3,055	1,784	220
Generated Energy (MWh)	176,889	191,317	269,535	350,300	411,622	479,752
Consumed Energy (MWh)	20,602	39,281	151,153	268,070	355,778	457,716
Net Energy (MWh)	156,287	152,036	118,382	82,230	55,844	22,036

***** Pump Operation Forced below 50 TL is implemented in the optimization model through organizing Eq (5.17) as follows: $if\ C(t) < 50\ then\ QP(t) = 38\ m^3/s\ and\ QT(t) = 0$

Table 5.2. *Results of UPSHP for 2014 (Scenario 1)*

Cases	Pump Operation Forced Below 50 TL	Pump Operation Forced Below 60 TL	Pump Operation Forced Below 70 TL	Pump Operation Forced Below 80 TL
Revenue (TL)	80,057,814	80,475,419	**80,717,258**	80,315,856
Number of pumping hours	540	609	661	718
Number of turbine hours	5,681	5,784	5,820	5,876
Number of idle hours	2,539	2,367	2,279	2,166
Generated Energy (MWh)	535,995	543,273	547,482	550,321
Consumed Energy (MWh)	75,015	84,577	91,863	99,395
Net Energy (MWh)	460,980	458,697	455,618	450,926

Table 5.3. *Results of UPSHP for 2015 (Scenario 1)*

Cases	**Pump Operation Forced Below 40 TL**	**Pump Operation Forced Below 50 TL**	**Pump Operation Forced Below 60 TL**	**Pump Operation Forced Below 70 TL**	**Pump Operation Forced Below 80 TL**
Revenue (TL)	83,567,145	84,465,646	84,465,646	**84,505,110**	84,319,657
Number of pumping hours	898	865	865	1,097	1,281
Number of turbine hours	5,706	5,529	5,529	5,866	6,008
Number of idle hours	2,180	2,390	2,390	1,821	1,495
Generated Energy (MWh)	531,784	526,198	526,198	550,694	564,984
Consumed Energy (MWh)	123,981	119,875	119,875	152,104	173,628
Net Energy (MWh)	407,802	406,324	406,324	398,590	391,356

Table 5.4. *Results of UPSHP for 2016 (Scenario 1)*

Cases	Pump Operation Forced Below 50 TL	Pump Operation Forced Below 100 TL	Pump Operation Forced Below 120 TL	Pump Operation Forced Below 130 TL	Pump Operation Forced Below 140 TL
Revenue (TL)	48,588,486	47,302,606	**51,287,722**	50,706,508	49,055,953
Number of pumping hours	462	786	1,536	2,060	2,843
Number of turbine hours	2,669	3,282	3,815	4,438	5,126
Number of idle hours	5,629	4,692	3,409	2,262	791
Generated Energy (MWh)	254,216	288,905	362,054	413,168	483,855
Consumed Energy (MWh)	63,237	107,941	212,457	284,212	390,896
Net Energy (MWh)	190,980	180,964	149,597	128,955	92,959

Table 5.5. *Results of UPSHP for 2017 (Scenario 1)*

Cases	Pump Operation Forced Below 50 TL	Pump Operation Forced Below 100 TL	Pump Operation Forced Below 110 TL	Pump Operation Forced Below 120 TL
Revenue (TL)	68,493,174	69,195,254	**69,386,257**	68,043,494
Number of pumping hours	263	235	295	413
Number of turbine hours	3,530	3,421	3,519	3,727
Number of idle hours	4,967	5,104	4,946	4,620
Generated Energy (MWh)	320,102	318,259	324,679	334,536
Consumed Energy (MWh)	35,775	32,226	40,502	56,219
Net Energy (MWh)	284,327	286,033	284,177	278,317

As can be seen from Tables 5.1 to 5.5, optimal operations maximizing the revenue are provided by forcing the model to pump water from the lower-level reservoir to higher-level reservoir when DAM price is below 130 TL, 70 TL, 70 TL, 120 TL and 110 TL for the water years 2013, 2014, 2015, 2016 and 2017, respectively.

As discussed in the previous chapters, this study aims to investigate potential revenue change due to the operation of the existing conventional UHP in the pumped storage hydropower plant (UPSHP) mode. Utilizing the best C_{int} values for UPSHP, a general comparison including the total revenue, the number of pumping, the turbine and idle hours, energy generated, energy consumed, and net energy is conducted among Actual UHP, UHP, and UPSHP models. Table 5.6, Table 5.7, Table 5.8, Table 5.9 and Table 5.10 demonstrate the comparison for the water years 2013, 2014, 2015, 2016 and 2017, respectively.

Table 5.6. *Comparison of Actual UHP, UHP and UPSHP for 2013 (Scenario 1)*

Cases	**UHP Actual Operation**	**UHP Optimal Operation**	**UPSHP Optimal Operation**
Revenue (TL)	31,001,000	33,285,095	35,446,449
Number of pumping hours	0	0	1,965
Number of turbine hours	3,454	1,831	3,740
Number of idle hours	5,306	6,929	3,055
Generated Energy (MWh)	162,456	164,851	350,300
Consumed Energy (MWh)	0	0	268,070
Net Energy (MWh)	162,456	164,851	82,230

Table 5.7. *Comparison of Actual UHP, UHP and UPSHP for 2014 (Scenario 1)*

Cases	**UHP Actual Operation**	**UHP Optimal Operation**	**UPSHP Optimal Operation**
Revenue (TL)	70,907,492	75,903,746	80,717,258
Number of pumping hours	0	0	661
Number of turbine hours	5,987	5,261	5,820
Number of idle hours	2,773	3,499	2,279
Generated Energy (MWh)	480,901	485,733	547,482
Consumed Energy (MWh)	0	0	91,863
Net Energy (MWh)	480,901	485,733	455,618

Table 5.8. *Comparison of Actual UHP, UHP and UPSHP for 2015 (Scenario 1)*

Cases	**UHP Actual Operation**	**UHP Optimal Operation**	**UPSHP Optimal Operation**
Revenue (TL)	60,560,456	75,806,983	84,505,110
Number of pumping hours	0	0	1,097
Number of turbine hours	6,286	4,686	5,866
Number of idle hours	2,498	4,098	1,821
Generated Energy (MWh)	446,126	442,651	550,694
Consumed Energy (MWh)	0	0	152,104
Net Energy (MWh)	446,126	442,651	398,590

Table 5.9. *Comparison of Actual UHP, UHP and UPSHP for 2016 (Scenario 1)*

Cases	UHP Actual Operation	UHP Optimal Operation	UPSHP Optimal Operation
Revenue (TL)	36,620,181	44,625,573	51,287,722
Number of pumping hours	0	0	1,536
Number of turbine hours	5,380	2,190	3,815
Number of idle hours	3,380	6,570	3,409
Generated Energy (MWh)	216,099	207,956	362,054
Consumed Energy (MWh)	0	0	212,457
Net Energy (MWh)	216,099	207,956	149,597

Table 5.10. *Comparison of Actual UHP, UHP and UPSHP for 2017 (Scenario 1)*

Cases	UHP Actual Operation	UHP Optimal Operation	UPSHP Optimal Operation
Revenue (TL)	62,496,820	64,824,592	69,386,257
Number of pumping hours	0	0	295
Number of turbine hours	6,929	3,315	3,519
Number of idle hours	1,831	5,445	4,946
Generated Energy (MWh)	320,744	294,183	324,679
Consumed Energy (MWh)	0	0	40,502
Net Energy (MWh)	320,744	294,183	284,177

As can be seen in Tables 5.6 to 5.10, the revenue of Actual UHP is lower than the optimal result of UHP model for all water years. This is an expected result since Actual UHP operation is performed under uncertainties of DAM prices while the UHP model finds the optimal energy generation using realized DAM prices. However, these results demonstrate that the formulation of the optimization model is realistic and generates reasonable results.

This analysis reveals that revenue increases while total net energy generation decreases when UHP is transformed into UPSHP (see Tables 5.6 to 5.10). This result is reasonable since pumped storage hydropower plants do not generate extra energy, rather they consume energy. However, they increase revenue. The reason behind the revenue increase is the possibility of energy generation during higher DAM prices using the storage capability of UPSHP.

In addition to the above findings, it is observed that the number of turbine operation hours increase while idle hours decrease when UHP is transformed into UPSHP. It means that UPSHP operates the turbines for longer durations but still manages to increase the revenue.

The above results provide strong indications that energy is stored at lower DAM prices and sold at higher DAM prices. The amount of energy generation for each DAM price interval is investigated, and the results are presented in Tables 5.11, 5.12, 5.13, 5.14 and 5.15 for water years 2013, 2014, 2015, 2016 and 2017, respectively.

Table 5.11. *Comparison of Actual UHP, UHP, and UPSHP with respect to DAM Price Interval for 2013 (Scenario 1)*

Price Interval	Energy Generation of UHP Actual Operation (MWh)	Energy Generation of UHP Optimal Operation (MWh)	Energy Generation of UPSHP Optimal Operation (MWh)	Net Energy of UPSHP Optimal Operation (MWh)
0-50 TL	0			-1,362
50-60 TL	0			-134
60-70 TL	0			-3,811
70-80 TL	24			-3,955
80-90 TL	0			-2,702
90-100 TL	0			-14,365
100-110 TL	450			-36,202
110-120 TL	330			-89,825
120-130 TL	1,604			-115,715
130-140 TL	2,359		2,598	2,598
140-150 TL	6,395		12,316	12,316
150-160 TL	9,462		23,207	23,207
160-170 TL	5,181	757	23,671	23,671
170-180 TL	13,995	7,120	41,395	41,395
180-190 TL	21,975	20,458	55,455	55,455
190-200 TL	38,061	42,707	84,029	84,029
200-210 TL	54,601	81,238	94,680	94,680
210-220 TL	6,187	9,569	9,869	9,869
220-230 TL	235	458	481	481
230-240 TL	513	831	868	868
240-250 TL				
250-300 TL	279	571	577	577
300-350 TL	211	285	289	289
350-400 TL				
400 and Above	594	856	866	866

Table 5.12. *Comparison of Actual UHP, UHP, and UPSHP with respect to DAM Price Interval for 2014 (Scenario 1)*

Price Interval / Generated Energy	Energy Generation of UHP Actual Operation (MWh)	Energy Generation of UHP Optimal Operation (MWh)	Energy Generation of UPSHP Optimal Operation (MWh)	Net Energy of UPSHP Optimal Operation (MWh)
0-50 TL	13,635			-60,520
50-60 TL	4,302			-13,053
60-70 TL	3,772	626		-10,811
70-80 TL	6,914	4,502	7,353	6,528
80-90 TL	9,918	8,905	12,595	10,867
90-100 TL	17,552	15,455	20,488	18,218
100-110 TL	18,945	18,142	23,525	20,869
110-120 TL	32,735	26,548	38,011	38,011
120-130 TL	69,696	68,256	80,072	80,072
130-140 TL	53,010	55,919	56,819	56,819
140-150 TL	38,796	40,302	42,489	42,489
150-160 TL	31,097	32,638	35,011	35,011
160-170 TL	29,046	36,025	37,676	37,676
170-180 TL	34,346	42,455	45,079	45,079
180-190 TL	23,320	29,430	31,836	31,836
190-200 TL	18,821	21,378	25,373	25,373
200-210 TL	22,555	20,171	24,843	24,843
210-220 TL	41,023	51,711	53,039	53,039
220-230 TL	6,505	7,782	7,784	7,784
230-240 TL	4,467	4,992	4,995	4,995
240-250 TL	350	396	397	397
250-300 TL	96	97	97	97
300-350 TL				
350-400 TL				
400 and Above				

Table 5.13. *Comparison of Actual UHP, UHP, and UPSHP with respect to DAM Price Interval for 2015 (Scenario 1)*

Price Interval / Generated Energy	Energy Generation of UHP Actual Operation (MWh)	Energy Generation of UHP Optimal Operation (MWh)	Energy Generation of UPSHP Optimal Operation (MWh)	Net Energy of UPSHP Optimal Operation (MWh)
0-50 TL	34,273			-99,199
50-60 TL	3,644			-13,096
60-70 TL	12,396			-32,134
70-80 TL	18,369		4,978	-2,697
80-90 TL	17,269	2,465	9,249	9,249
90-100 TL	10,715	2,651	6,444	6,444
100-110 TL	20,879	6,481	17,848	17,848
110-120 TL	42,666	22,884	42,223	42,223
120-130 TL	48,296	33,092	55,657	55,657
130-140 TL	37,577	37,202	48,225	48,225
140-150 TL	27,509	35,587	44,058	44,058
150-160 TL	15,882	26,451	36,088	36,088
160-170 TL	25,911	43,079	50,028	50,028
170-180 TL	34,046	59,515	62,369	62,369
180-190 TL	17,805	32,560	32,595	32,595
190-200 TL	16,912	31,793	31,852	31,852
200-210 TL	15,838	34,867	34,957	34,957
210-220 TL	11,190	23,893	23,958	23,958
220-230 TL	20,091	33,993	34,059	34,059
230-240 TL	12,057	13,305	13,282	13,282
240-250 TL	2,429	2,456	2,450	2,450
250-300 TL	186	188	188	188
300-350 TL				
350-400 TL	186	188	188	188
400 and Above				

Table 5.14. *Comparison of Actual UHP, UHP, and UPSHP with respect to DAM Price Interval for 2016 (Scenario 1)*

Price Interval / Generated Energy	Energy Generation of UHP Actual Operation (MWh)	Energy Generation of UHP Optimal Operation (MWh)	Energy Generation of UPSHP Optimal Operation (MWh)	Net Energy of UPSHP Optimal Operation (MWh)
0-50 TL	2,457			-15,833
50-60 TL	321			-2,203
60-70 TL	345			-3,011
70-80 TL	3,066			-16,297
80-90 TL	3,045			-16,400
90-100 TL	6,366			-49,518
100-110 TL	8,450			-43,422
110-120 TL	10,953			-65,774
120-130 TL	10,494		4,900	4,900
130-140 TL	12,284		15,062	15,062
140-150 TL	17,762	2,834	20,568	20,568
150-160 TL	16,470	5,552	18,389	18,389
160-170 TL	17,958	5,276	25,946	25,946
170-180 TL	13,867	5,181	27,547	27,547
180-190 TL	9,028	10,447	24,958	24,958
190-200 TL	6,421	11,634	17,734	17,734
200-210 TL	37,357	76,290	97,989	97,989
210-220 TL	18,459	36,738	51,963	51,963
220-230 TL	8,460	23,578	25,777	25,777
230-240 TL	9,843	23,011	23,621	23,621
240-250 TL	264	476	487	487
250-300 TL	1,021	2,760	2,825	2,825
300-350 TL	393	951	977	977
350-400 TL	222	951	977	977
400 and Above	793	2,276	2,334	2,334

Table 5.15. *Comparison of Actual UHP, UHP, and UPSHP with respect to DAM Price Interval for 2017 (Scenario 1)*

Price Interval / Generated Energy	Energy Generation of UHP Actual Operation (MWh)	Energy Generation of UHP Optimal Operation (MWh)	Energy Generation of UPSHP Optimal Operation (MWh)	Net Energy of UPSHP Optimal Operation (MWh)
0-50 TL	3,213			-7,108
50-60 TL	809			-2,076
60-70 TL	530			-1,516
70-80 TL	883			-2,348
80-90 TL	489			-1,638
90-100 TL	2,555			-7,878
100-110 TL	3,973			-17,263
110-120 TL	3,333	510		-675
120-130 TL	12,008	4,210	74	74
130-140 TL	7,708	3,516	470	470
140-150 TL	19,357	10,628	3,257	3,257
150-160 TL	17,887	9,550	4,314	4,314
160-170 TL	24,103	15,794	13,279	13,279
170-180 TL	30,260	24,433	23,367	23,367
180-190 TL	27,306	22,541	29,440	29,440
190-200 TL	30,896	21,694	27,130	27,130
200-210 TL	35,820	29,860	41,385	41,385
210-220 TL	49,557	56,560	83,194	83,194
220-230 TL	10,019	21,825	25,596	25,596
230-240 TL	2,038	4,606	4,625	4,625
240-250 TL	3,050	8,261	8,297	8,297
250-300 TL	8,220	18,437	18,463	18,463
300-350 TL	23,638	36,888	36,920	36,920
350-400 TL	3,039	4,773	4,775	4,775
400 and Above	53	94	94	94

As can be seen in Tables 5.11 to 5.15, the turbines are operated in similar manners for UHP Actual, UHP Optimal, and UPSHP Optimal; however, the number of turbine operation hours increases when UHP is converted to UPSHP. UPSHP optimizes its generation schedule to generate energy by working longer durations when DAM prices are higher. Therefore, UPSHP enhances storage capability of UHP and ensures extra revenue due to fluctuations in DAM prices.

In Section 3.2.3, UHP Actual's energy generation is analyzed in monthly basis. In this section, comparison of monthly energy generations of UHP Actual, UHP and UPSHP are presented in Figures 5.1, 5.2, 5.3, 5.4 and 5.5 for water years 2013, 2014, 2015, 2016 and 2017, respectively.

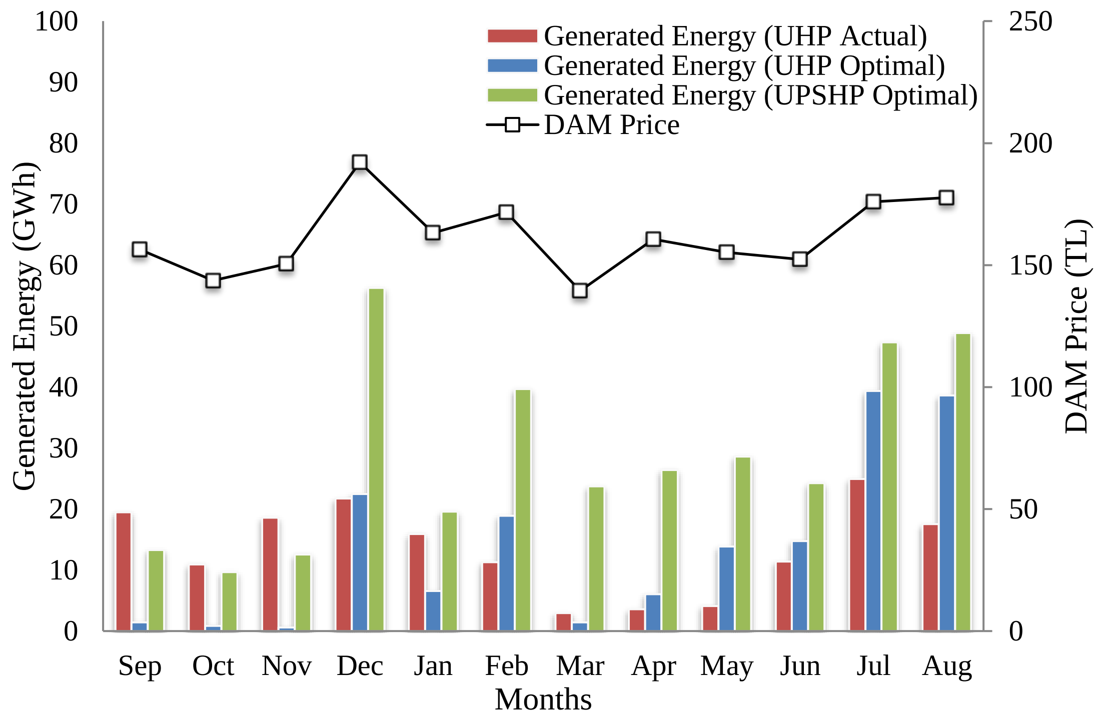

Figure 5.1. Monthly Energy Generations of UHP Actual, UHP, and UPSHP for 2013 (Scenario 1)

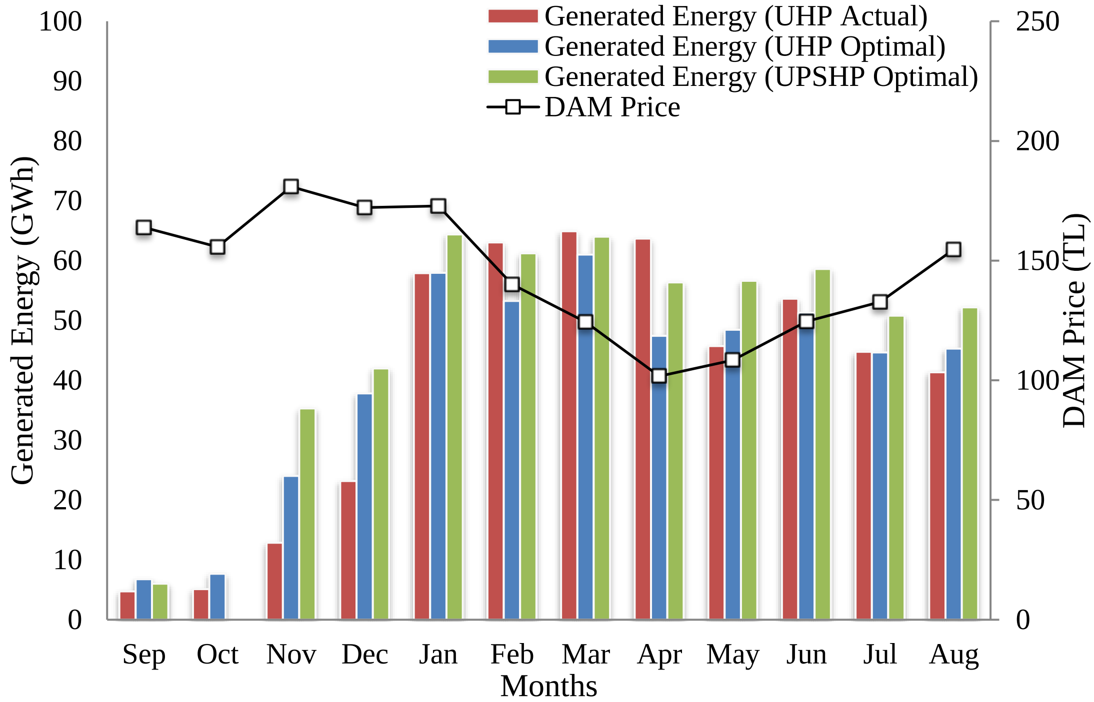

Figure 5.2. Monthly Energy Generations of UHP Actual, UHP, and UPSHP for 2014 (Scenario 1)

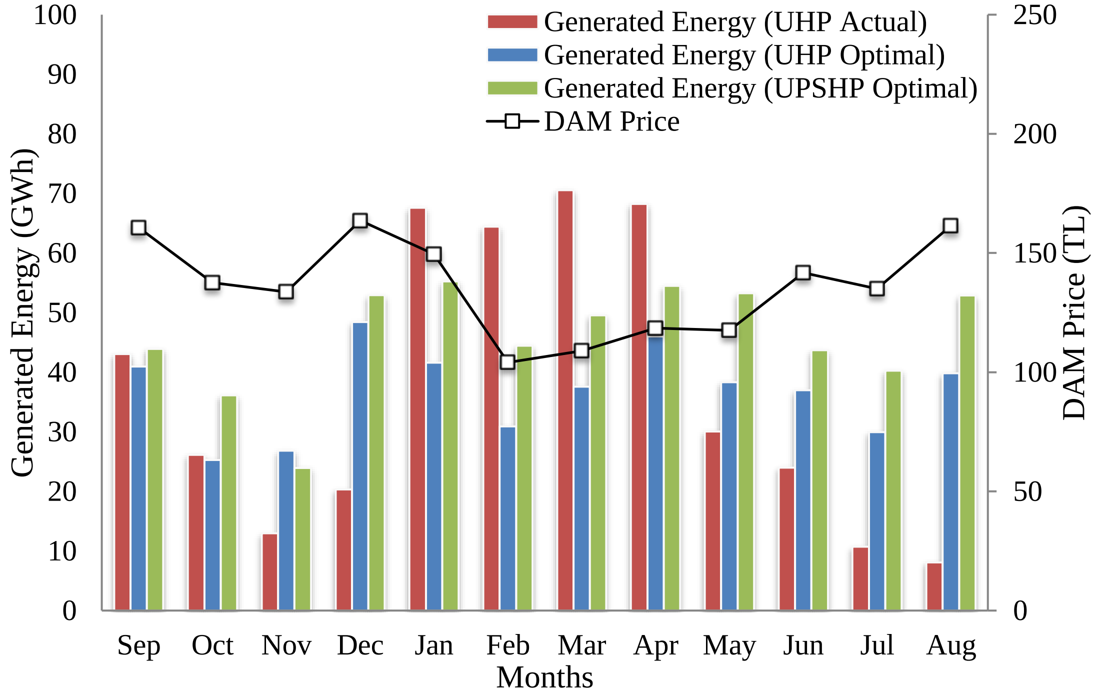

Figure 5.3. Monthly Energy Generations of UHP Actual, UHP, and UPSHP for 2015 (Scenario 1)

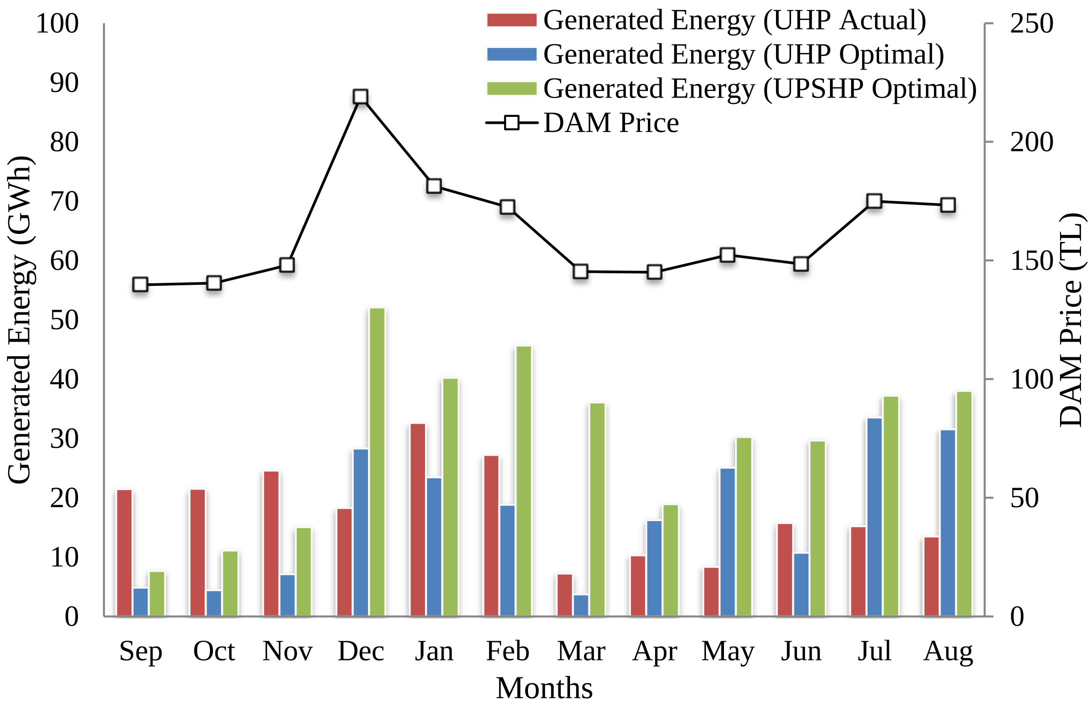

Figure 5.4. Monthly Energy Generations of UHP Actual, UHP, and UPSHP for 2016 (Scenario 1)

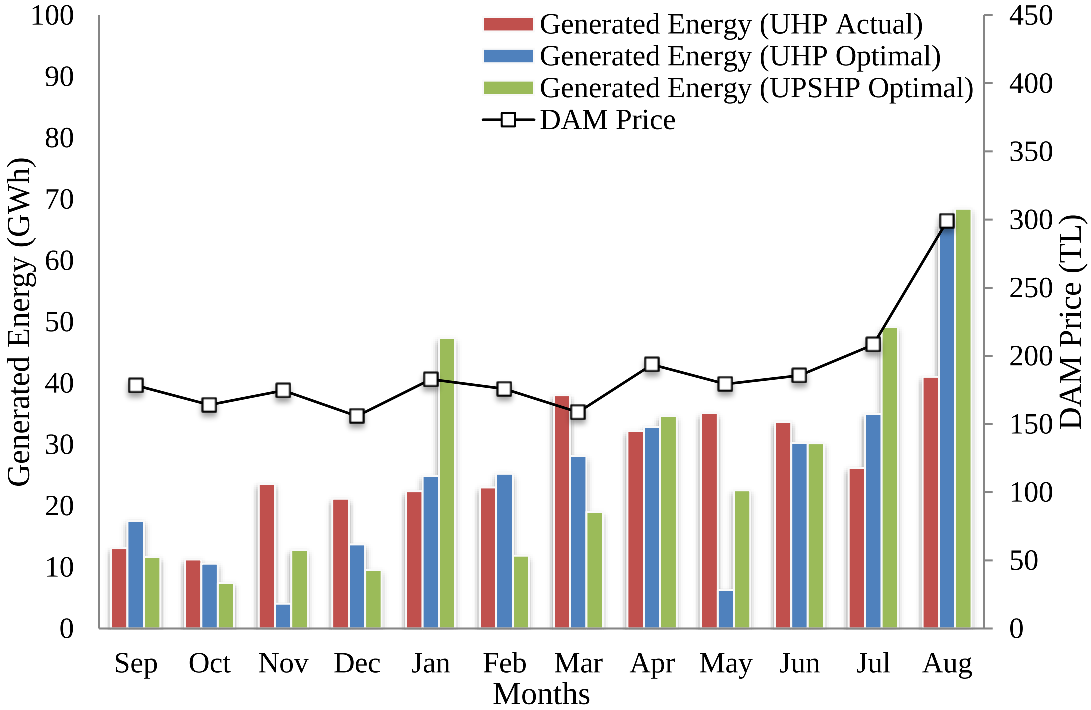

Figure 5.5. Monthly Energy Generations of UHP Actual, UHP, and UPSHP for 2017 (Scenario 1)

As seen in Figures 5.1 to 5.5, the amount of energy generation of UPSHP model increases at the time of higher DAM prices. Therefore, these results meet the objectives discussed in section 3.2.3.

In addition to the above analyses, the revenues are presented on seasonal basis in Figures 5.6, 5.7, 5.8, 5.9 and 5.10 for water years 2013, 2014, 2015, 2016 and 2017, respectively.

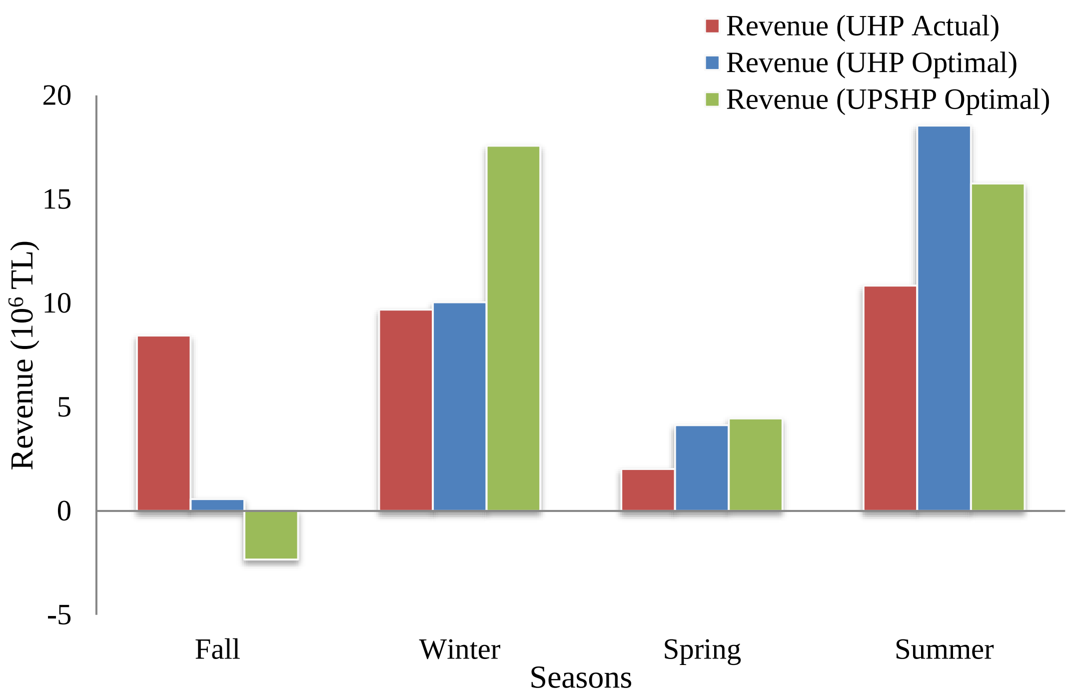

Figure 5.6. Seasonal Revenues of UHP Actual, UHP, and UPSHP for 2013 (Scenario 1)

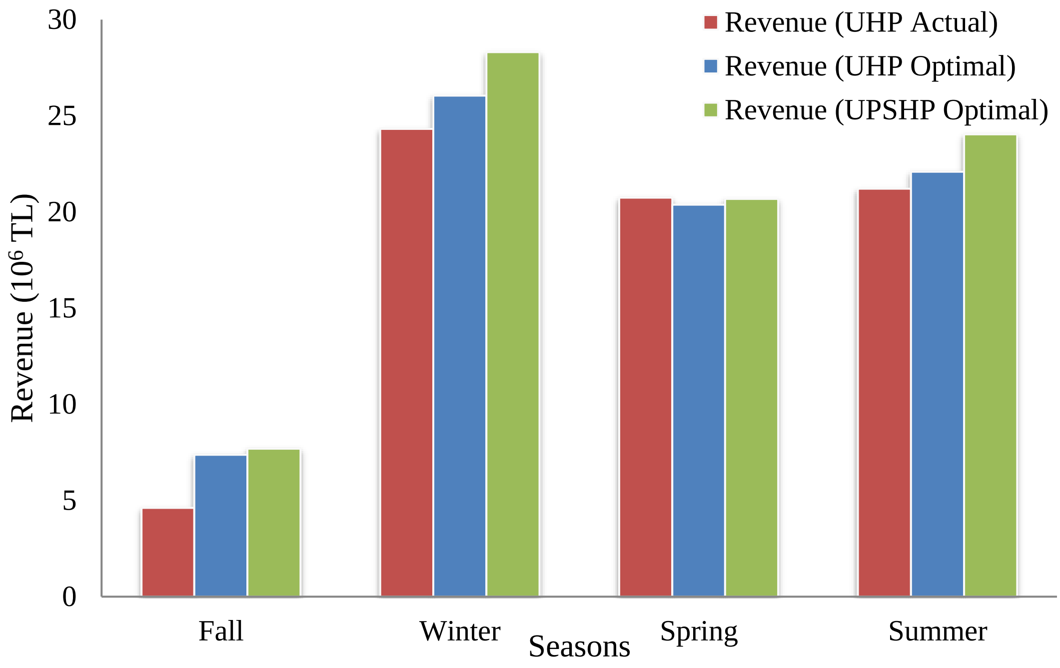

Figure 5.7 Seasonal Revenues of UHP Actual, UHP, and UPSHP for 2014 (Scenario 1)

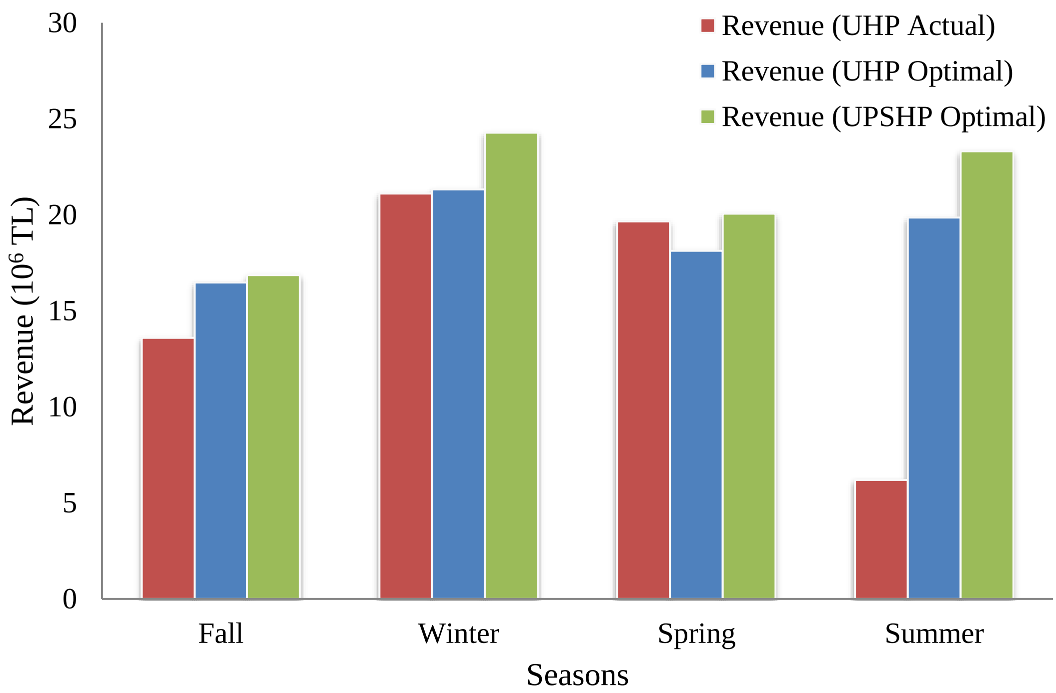

Figure 5.8. Seasonal Revenues of UHP Actual, UHP, and UPSHP for 2015 (Scenario 1)

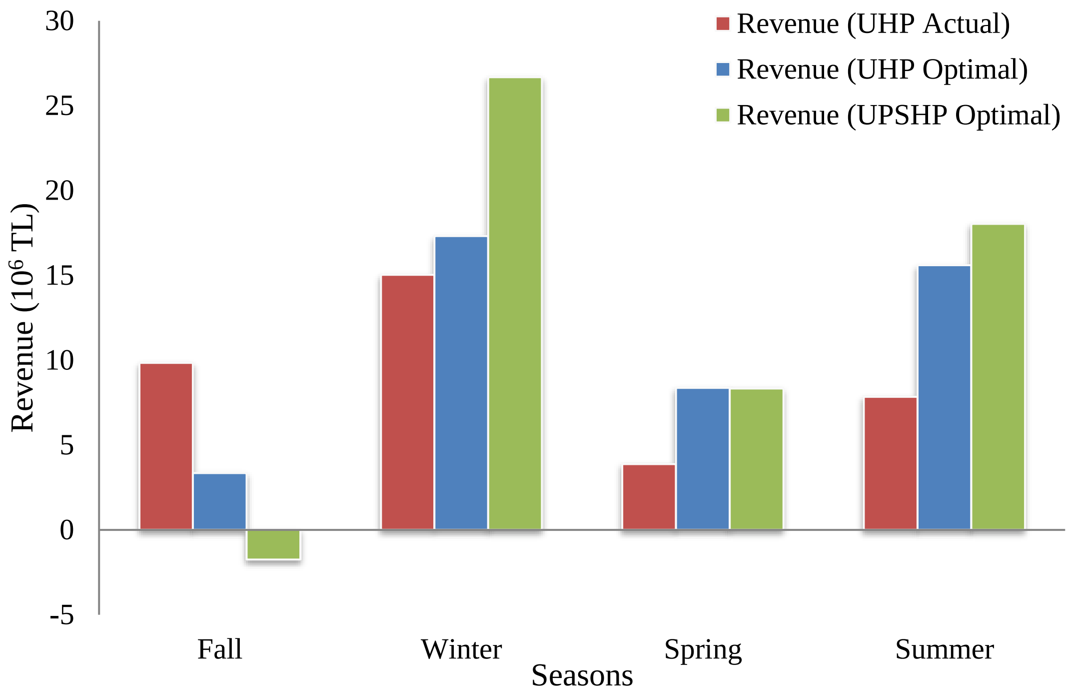

Figure 5.9 Seasonal Revenues of UHP Actual, UHP, and UPSHP for 2016 (Scenario 1)

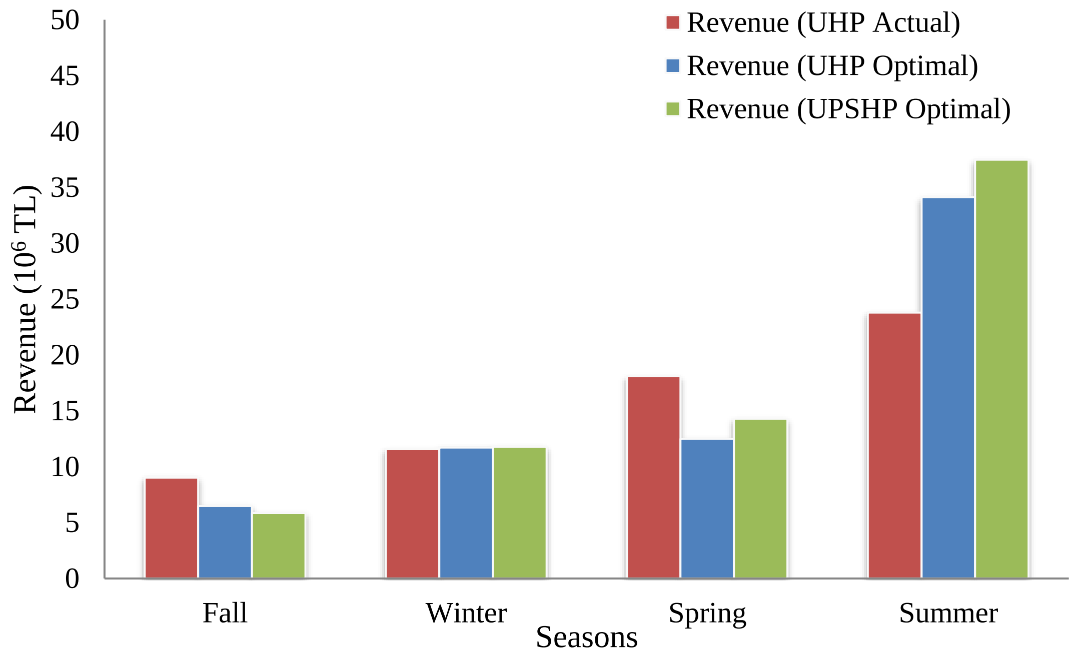

Figure 5.10. Seasonal Revenues of UHP Actual, UHP, and UPSHP for 2017 (Scenario 1)

These analyses reveal that UPSHP model increases the revenue during summer and winter seasons, where DAM prices at higher. In the fall seasons of 2013 and 2016, UPSHP model has negative revenue. It means that UPSHP consumes electricity for pump operation more than its generation. Therefore, UPSHP generates more electricity in winter seasons, when DAM prices are higher, by releasing the water from the high-level reservoir to the low-level reservoir.

In the above sections, comparisons of the revenues and energy generations are presented for each year. Revenue and energy generation results for each water year are summarized in Table 5.16 and the revenue differences are presented in Table 5.17 as percentages.

Table 5.16. *Summary of Comparison (Scenario 1)*

Years	UHP Actual Operation		UHP Optimum Operation		UPSHP Optimum Operation		
	Energy (MWh)	**Revenue (TL)**	**Energy (MWh)**	**Revenue (TL)**	**Energy (MWh)**	**Consumed Energy (MWh)**	**Revenue**
2013	162,456	31,001,000	164,851	33,285,095	350,300	268,070	35,446,449
2014	480,901	70,907,492	485,733	75,903,746	547,482	91,863	80,717,258
2015	446,126	60,560,456	442,651	75,806,983	550,694	152,104	84,505,110
2016	216,099	36,620,181	207,956	44,625,573	362,054	212,457	51,287,722
2017	320,744	62,496,820	294,183	64,824,592	324,679	324,679	69,386,257
TOTAL	**1,626,326**	**261,585,949**	**1,595,374**	**294,445,989**	**2,135,209**	**1,049,174**	**321,342,796**

Table 5.17. *Revenue Differences (Scenario 1)*

Years	Increase in Revenue for UHP Actual vs UPSHP Optimal	Increase in Revenue for UHP Optimal vs UPSHP Optimal)
2013	14.34%	6.49%
2014	13.83%	6.34%
2015	39.54%	11.47%
2016	40.05%	14.93%
2017	11.02%	7.04%
TOTAL	**22.84%**	**9.13%**

As can be seen in Tables 5.16 and 5.17, the revenue of UHP Actual Operation is lower than that of the UHP Optimal due to uncertainties of DAM Prices during real operation, as expressed previously. Therefore, it is more rational to compare UHP Optimal and UPSHP Optimal since DAM Prices are known during the optimization phase of both cases. As can be seen in Table 5.17, the revenue of UHP increases by 9.13% on the average due to transforming it to UPSHP.

5.2. Results for Scenario 2

In Scenario 1, it is assumed that the final storage value, S_{fin} of the previous year in the reservoir will be equal to the initial storage value S_{int} of the current year, as discussed in Section 4.1. Similar to Scenario 1, in Scenario 2, UPSHP is forced to operate its pump below a certain electricity price, C_{int} as given in Eq (4.17). The best C_{int} value which maximizes the revenue is found through a trial and error approach. Tables 5.18, 5.19, 5.20, 5.21 and 5.22 demonstrate the results of UPSHP for water years 2013, 2014, 2015, 2016 and 2017, respectively.

Table 5.18. *Results of UPSHP for 2013 (Scenario 2)*

Cases	**Pump Operation Forced Below 50 TL**	**Pump Operation Forced Below 100 TL**	**Pump Operation Forced Below 120 TL**	**Pump Operation Forced Below 130 TL**	**Pump Operation Forced Below 140 TL**	**Pump Operation Forced Below 150 TL**
Revenue (TL)	28,865,712	31,785,383	**33,593,197**	32,306,035	31,519,539	29,180,658
Number of pumping hours	180	259	1,116	1,965	2,606	3,386
Number of turbine hours	1,900	1,848	2,695	3,825	4,270	5,072
Number of idle hours	6,680	6,653	4,949	2,970	1,884	302
Generated Energy (MWh)	165,509	174,355	255,160	339,226	398,375	468,840
Consumed Energy (MWh)	23,976	34,824	152,767	266,355	355,463	458,620
Net Energy (MWh)	141,533	139,531	102,393	72,871	42,912	10,220

Table 5.19. *Results of UPSHP for 2014 (Scenario 2)*

Cases	Pump Operation Forced Below 50 TL	Pump Operation Forced Below 60 TL	Pump Operation Forced Below 70 TL
Revenue (TL)	85,704,433	**86,233,342**	85,536,619
Number of pumping hours	460	592	674
Number of turbine hours	6,116	6,251	6,225
Number of idle hours	2,184	1,917	1,861
Generated Energy (MWh)	580,309	592,711	592,971
Consumed Energy (MWh)	63,682	81,768	93,199
Net Energy (MWh)	516,627	510,943	499,772

Table 5.20. *Results of UPSHP for 2015 (Scenario 2)*

Cases	Pump Operation Forced Below 40 TL	Pump Operation Forced Below 50 TL	Pump Operation Forced Below 60 TL	Pump Operation Forced Below 70 TL
Revenue (TL)	77,544,904	**78,755,154**	78,437,556	77,731,279
Number of pumping hours	927	900	964	1,119
Number of turbine hours	5,276	5,096	5,259	5,587
Number of idle hours	2,581	2,788	2,561	2,078
Generated Energy (MWh)	494,487	487,733	497,196	514,788
Consumed Energy (MWh)	128,163	124,342	133,875	155,324
Net Energy (MWh)	366,324	363,391	363,321	359,464

Table 5.21. *Results of UPSHP for 2016 (Scenario 2)*

Cases	**Pump Operation Forced Below 50 TL**	**Pump Operation Forced Below 100 TL**	**Pump Operation Forced Below 120 TL**	**Pump Operation Forced Below 130 TL**	**Pump Operation Forced Below 140 TL**
Revenue (TL)	51,534,252	53,724,816	54,030,553	**54,348,095**	51,366,007
Number of pumping hours	419	746	1,536	2,060	2,843
Number of turbine hours	2,806	3,102	4,024	4,497	5,358
Number of idle hours	5,535	4,912	3,200	2,203	559
Generated Energy (MWh)	266,805	298,164	377,810	431,658	498,865
Consumed Energy (MWh)	57,205	102,706	211,190	285,684	388,452
Net Energy (MWh)	209,600	195,458	166,620	145,974	110,413

Table 5.22. *Results of UPSHP for 2017 (Scenario 2)*

Cases	Pump Operation Forced Below 50 TL	Pump Operation Forced Below 100 TL	Pump Operation Forced Below 110 TL	Pump Operation Forced Below 120 TL
Revenue (TL)	62,874,812	63,673,221	**63,835,378**	62,643,638
Number of pumping hours	271	200	290	413
Number of turbine hours	3,349	3,133	3,179	3,594
Number of idle hours	5,140	5,427	5,291	4,753
Generated Energy (MWh)	296,274	288,815	296,531	310,411
Consumed Energy (MWh)	36,831	27,527	23,525	56,150
Net Energy (MWh)	259,443	261,288	273,006	254,261

As can be seen in Tables 5.18 to 5.22, optimal operations maximizing the revenue are provided by forcing the model to pump the water from the lower-level reservoir to the higher-level reservoir when DAM price is below 120 TL, 60 TL, 50 TL, 130 TL and 110 TL for the water years 2013, 2014, 2015, 2016 and 2017, respectively.

Similar to Scenario 1, a comparison is performed among Actual UHP, UHP, and UPSHP models for Scenario 2. Table 5.23, 5.24, 5.25, 5.26 and 5.27 demonstrate the comparison for water years 2013, 2014, 2015, 2016 and 2017, respectively.

Table 5.23. *Comparison of Actual UHP, UHP, and UPSHP for 2013 (Scenario 2)*

Cases	**UHP Actual Operation**	**UHP Optimal Operation**	**UPSHP Optimal Operation**
Revenue (TL)	31,001,000	31,008,294	33,593,197
Number of pumping hours	0	0	1,116
Number of turbine hours	3,454	1,728	2,695
Number of idle hours	5,306	7,032	4,949
Generated Energy (MWh)	162,456	152,743	255,160
Consumed Energy (MWh)	0	0	152,767
Net Energy (MWh)	162,456	152,743	102,393

Table 5.24. *Comparison of Actual UHP, UHP, and UPSHP for 2014 (Scenario 2)*

Cases	UHP Actual Operation	UHP Optimal Operation	UPSHP Optimal Operation
Revenue (TL)	70,907,492	82,963,546	86,233,342
Number of pumping hours	0	592	592
Number of turbine hours	5,987	6,251	6,251
Number of idle hours	2,773	1,917	1,917
Generated Energy (MWh)	480,901	592,711	592,711
Consumed Energy (MWh)	0	81,768	81,768
Net Energy (MWh)	480,901	510,943	510,943

Table 5.25. *Comparison of Actual UHP, UHP, and UPSHP for 2015 (Scenario 2)*

Cases	UHP Actual Operation	UHP Optimal Operation	UPSHP Optimal Operation
Revenue (TL)	60,560,456	69,138,677	78,755,154
Number of pumping hours	0	0	900
Number of turbine hours	6,286	4,277	5,096
Number of idle hours	2,498	4,507	2,788
Generated Energy (MWh)	446,126	402,095	487,733
Consumed Energy (MWh)	0	0	124,342
Net Energy (MWh)	446,126	402,095	363,391

Table 5.26. *Comparison of Actual UHP, UHP, and UPSHP for 2016 (Scenario 2)*

Cases	**UHP Actual Operation**	**UHP Optimal Operation**	**UPSHP Optimal Operation**
Revenue (TL)	36,620,181	48,049,402	54,348,095
Number of pumping hours	0	0	2,060
Number of turbine hours	5,380	2,353	4,497
Number of idle hours	3,380	6,407	2,203
Generated Energy (MWh)	216,099	224,246	431,658
Consumed Energy (MWh)	0	0	285,684
Net Energy (MWh)	216,099	224,246	145,974

Table 5.27. *Comparison of Actual UHP, UHP, and UPSHP for 2017 (Scenario 2)*

Cases	**UHP Actual Operation**	**UHP Optimal Operation**	**UPSHP Optimal Operation**
Revenue (TL)	62,496,820	62,252,520	63,835,378
Number of pumping hours	0	0	290
Number of turbine hours	6,929	2,769	3,179
Number of idle hours	1,831	5,991	5,291
Generated Energy (MWh)	320,744	267,626	296,531
Consumed Energy (MWh)	0	0	39,742
Net Energy (MWh)	320,744	267,626	256,789

As can be seen in Tables 5.23 to 5.27, the revenue of Actual UHP operation is lower than the optimal result of UHP model for every water year similar to Scenario 1. This analysis reveals that the revenue increases while total net energy generation decreases when UHP is transformed into UPSHP. However, the revenue and amount of energy generation for Scenario 2 is lower than for Scenario 1 for the water years 2013, 2015, and 2017 while higher the water years 2014 and 2016. When storage constraints for the two scenarios defined in Section 5.1 are analyzed, the stored water amount is depleted for the water years 2013, 2015 and 2017, and results in higher energy generation according to Scenario 1. Therefore, the revenue and the amount of energy generation subject to Scenario 1 constraints are higher than Scenario 2. For this reason, it is vital to compare the two scenarios by the end of the 5-year period.

Similar to Scenario 1, the amount of energy generation for each DAM price interval is investigated in Scenario 2. Table 5.28, 5.29, 5.30, 5.31 and 5.32 demonstrate the amount of energy generation for each DAM price interval for water years 2013, 2014, 2015, 2016 and 2017, respectively.

Table 5.28. *Comparison of Actual UHP, UHP and UPSHP with respect to DAM Price Interval for 2013 (Scenario 2)*

Price Interval / Generated Energy	Energy Generation of UHP Actual Operation (MWh)	Energy Generation of UHP Optimal Operation (MWh)	Energy Generation of UPSHP Optimal Operation (MWh)	Net Energy of UPSHP Optimal Operation (MWh)
0-50 TL	0	0	0	-1,363
50-60 TL	0	0	0	-134
60-70 TL	0	0	0	-3,807
70-80 TL	24	0	0	-3,949
80-90 TL	0	0	0	-2,701
90-100 TL	0	0	0	-14,360
100-110 TL	450	0	0	-36,234
110-120 TL	330	0	0	-90,220
120-130 TL	1,604	0	0	0
130-140 TL	2,359	0	0	0
140-150 TL	6,395	0	881	881
150-160 TL	9,462	0	2,844	2,844
160-170 TL	5,181	168	10,271	10,271
170-180 TL	13,995	3,767	23,199	23,199
180-190 TL	21,975	18,275	42,337	42,337
190-200 TL	38,061	38,766	70,107	70,107
200-210 TL	54,601	79,396	92,515	92,515
210-220 TL	6,187	9,399	9,934	9,934
220-230 TL	235	447	479	479
230-240 TL	513	813	866	866
240-250 TL				
250-300 TL	279	569	576	576
300-350 TL	211	286	288	288
350-400 TL				
400 and Above	594	858	863	863

Table 5.29. *Comparison of Actual UHP, UHP and UPSHP with respect to DAM Price Interval for 2014 (Scenario 2)*

Price Interval / Generated Energy	Energy Generation of UHP Actual Operation (MWh)	Energy Generation of UHP Optimal Operation (MWh)	Energy Generation of UPSHP Optimal Operation (MWh)	Net Energy of UPSHP Optimal Operation (MWh)
0-50 TL	13,635	0	0	-60,130
50-60 TL	4,302	0	0	-12,990
60-70 TL	3,772	932	5,468	5,334
70-80 TL	6,914	5,233	9,579	8,896
80-90 TL	9,918	7,960	16,151	14,422
90-100 TL	17,552	16,181	23,699	21,452
100-110 TL	18,945	21,857	28,448	24,593
110-120 TL	32,735	35,963	41,938	41,938
120-130 TL	69,696	83,804	91,357	91,357
130-140 TL	53,010	62,248	64,268	64,268
140-150 TL	38,796	46,685	46,458	46,458
150-160 TL	31,097	35,261	37,041	37,041
160-170 TL	29,046	36,505	36,882	36,882
170-180 TL	34,346	43,276	43,922	43,922
180-190 TL	23,320	32,115	30,268	30,268
190-200 TL	18,821	24,717	24,968	24,968
200-210 TL	22,555	24,081	24,673	24,673
210-220 TL	41,023	48,450	54,684	54,684
220-230 TL	6,505	7,586	7,581	7,581
230-240 TL	4,467	4,846	4,843	4,843
240-250 TL	350	387	386	386
250-300 TL	96	94	94	94
300-350 TL				
350-400 TL				
400 and Above				

Table 5.30. *Comparison of Actual UHP, UHP and UPSHP with respect to DAM Price Interval for 2015 (Scenario 2)*

Price Interval / Generated Energy	Energy Generation of UHP Actual Operation (MWh)	Energy Generation of UHP Optimal Operation (MWh)	Energy Generation of UPSHP Optimal Operation (MWh)	Net Energy of UPSHP Optimal Operation (MWh)
0-50 TL	34,273	0	0	-99,444
50-60 TL	3,644	0	0	-7,471
60-70 TL	12,396	0	0	-10,447
70-80 TL	18,369	0	85	-6,331
80-90 TL	17,269	3,553	2,915	2,351
90-100 TL	10,715	3,169	4,260	4,260
100-110 TL	20,879	7,286	14,078	14,078
110-120 TL	42,666	23,779	32,313	32,313
120-130 TL	48,296	31,228	45,279	45,279
130-140 TL	37,577	32,506	41,440	41,440
140-150 TL	27,509	28,175	34,088	34,088
150-160 TL	15,882	19,339	23,459	23,459
160-170 TL	25,911	35,151	46,361	46,361
170-180 TL	34,046	48,502	69,238	69,238
180-190 TL	17,805	28,343	32,632	32,632
190-200 TL	16,912	31,622	31,942	31,942
200-210 TL	15,838	35,114	35,222	35,222
210-220 TL	11,190	24,083	24,131	24,131
220-230 TL	20,091	34,117	34,169	34,169
230-240 TL	12,057	13,298	13,294	13,294
240-250 TL	2,429	2,453	2,451	2,451
250-300 TL	186	188	188	188
300-350 TL				
350-400 TL	186	188	188	188
400 and Above				

Table 5.31. *Comparison of Actual UHP, UHP and UPSHP with respect to DAM Price Interval for 2016 (Scenario 2)*

Price Interval / Generated Energy	Energy Generation of UHP Actual Operation (MWh)	Energy Generation of UHP Optimal Operation (MWh)	Energy Generation of UPSHP Optimal Operation (MWh)	Net Energy of UPSHP Optimal Operation (MWh)
0-50 TL	2,457	0	0	-15,860
50-60 TL	321	0	0	-2,208
60-70 TL	345	0	0	-3,015
70-80 TL	3,066	0	0	-16,342
80-90 TL	3,045	0	0	-16,437
90-100 TL	6,366	0	0	-49,646
100-110 TL	8,450	0	0	-43,531
110-120 TL	10,953	0	0	-65,938
120-130 TL	10,494	0	0	-72,708
130-140 TL	12,284	0	17,790	17,790
140-150 TL	17,762	457	28,850	28,850
150-160 TL	16,470	1,198	31,541	31,541
160-170 TL	17,958	6,956	41,389	41,389
170-180 TL	13,867	10,055	37,367	37,367
180-190 TL	9,028	15,683	30,869	30,869
190-200 TL	6,421	13,178	20,443	20,443
200-210 TL	37,357	80,609	109,211	109,211
210-220 TL	18,459	40,429	56,367	56,367
220-230 TL	8,460	25,173	26,677	26,677
230-240 TL	9,843	23,090	23,568	23,568
240-250 TL	264	476	486	486
250-300 TL	1,021	2,759	2,819	2,819
300-350 TL	393	953	975	975
350-400 TL	222	953	975	975
400 and Above	793	2,279	2,330	2,330

Table 5.32. *Comparison of Actual UHP, UHP and UPSHP with respect to DAM Price Interval for 2017 (Scenario 2)*

Price Interval / Generated Energy	Energy Generation of UHP Actual Operation (MWh)	Energy Generation of UHP Optimal Operation (MWh)	Energy Generation of UPSHP Optimal Operation (MWh)	Net Energy of UPSHP Optimal Operation (MWh)
0-50 TL	3,213	0	0	-7,095
50-60 TL	809	0	0	-2,068
60-70 TL	530	0	0	-1,511
70-80 TL	883	0	0	-2,342
80-90 TL	489	0	0	-1,636
90-100 TL	2,555	0	0	-7,866
100-110 TL	3,973	0	0	-17,224
110-120 TL	3,333	0	0	0
120-130 TL	12,008	0	0	0
130-140 TL	7,708	0	0	0
140-150 TL	19,357	0	744	744
150-160 TL	17,887	0	4,303	4,303
160-170 TL	24,103	5,948	13,570	13,570
170-180 TL	30,260	16,760	25,390	25,390
180-190 TL	27,306	18,173	28,449	28,449
190-200 TL	30,896	19,577	24,145	24,145
200-210 TL	35,820	32,230	29,187	29,187
210-220 TL	49,557	76,035	71,467	71,467
220-230 TL	10,019	24,503	24,977	24,977
230-240 TL	2,038	4,690	4,591	4,591
240-250 TL	3,050	8,401	8,400	8,400
250-300 TL	8,220	18,776	18,774	18,774
300-350 TL	23,638	37,577	37,575	37,575
350-400 TL	3,039	4,863	4,863	4,863
400 and Above	53	94	94	94

As seen in Tables 4.28 to 4.32, the turbines are operated in similar manners for UHP Actual, UHP Optimal and UPSHP Optimal; however, the number of turbine operation hours increase when UHP is converted to UPSHP similar to Scenario 1. UPSHP optimizes its generation schedule to generate energy by working longer durations when DAM prices are higher. Therefore, UPSHP enhances storage capability of UHP and ensures extra revenue due to fluctuations in DAM prices.

Similar to Scenario 1, UHP Actual's energy generation is analyzed in a monthly basis in Scenario 2. Comparison of monthly energy generations of UHP Actual, UHP and UPSHP are presented in Figures 5.11, 5.12, 5.13, 5.14 and 5.15 for water years 2013, 2014, 2015, 2016 and 2017, respectively.

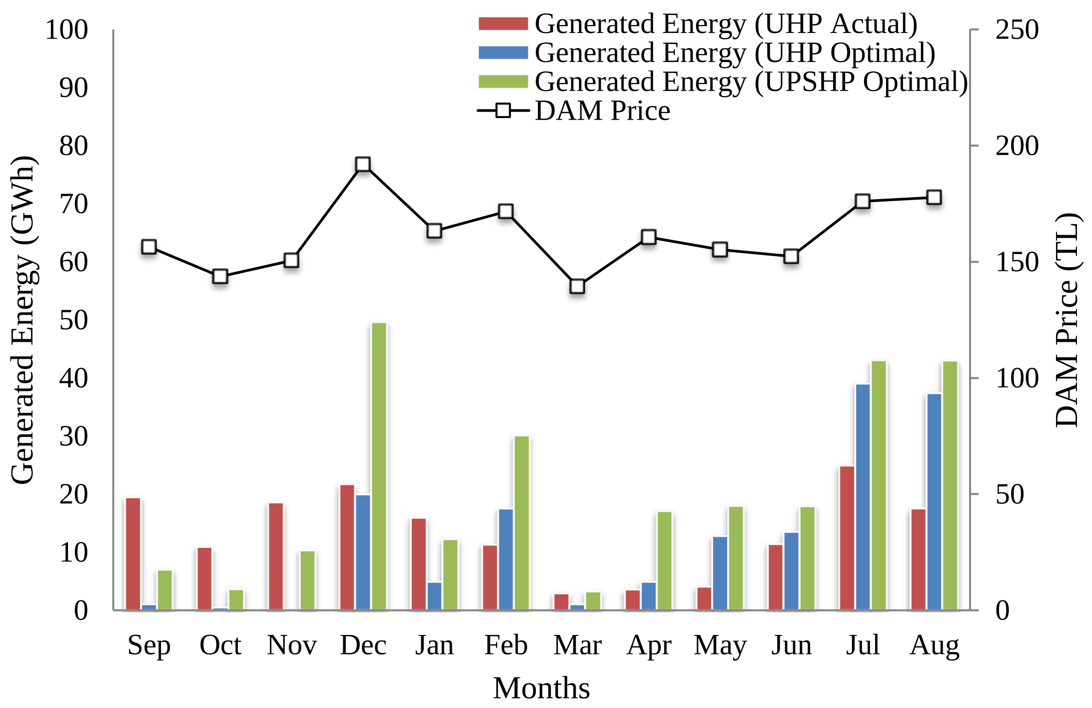

Figure 5.11. Monthly Energy Generations of UHP Actual, UHP, and UPSHP for 2013 (Scenario 2)

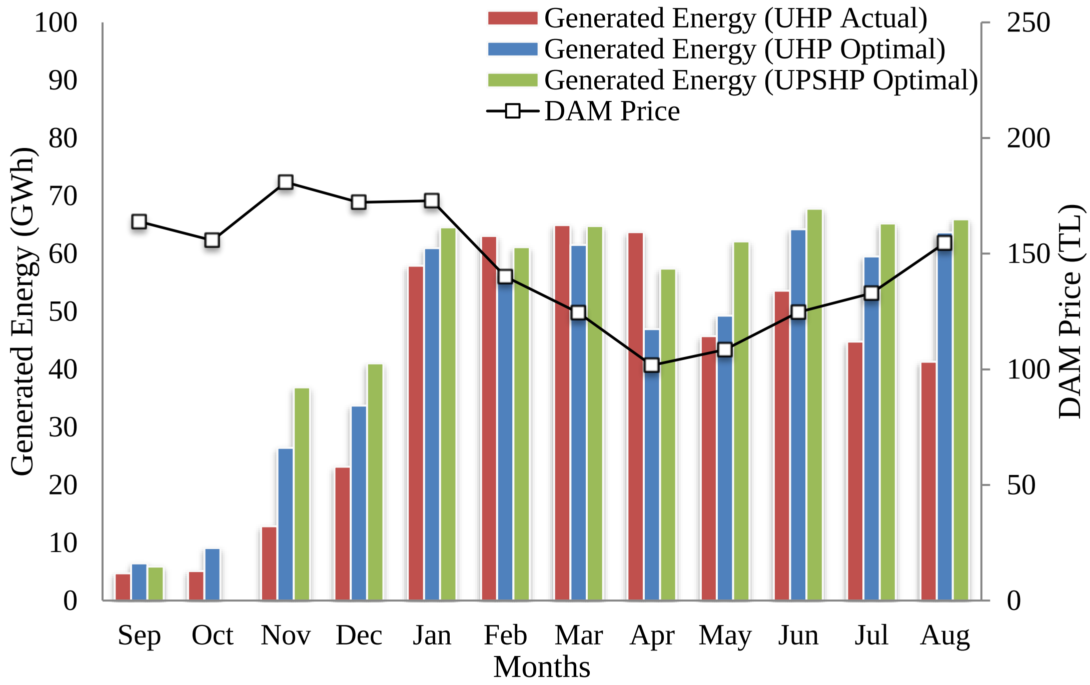

Figure 5.12. Monthly Energy Generations of UHP Actual, UHP, and UPSHP for 2014 (Scenario 2)

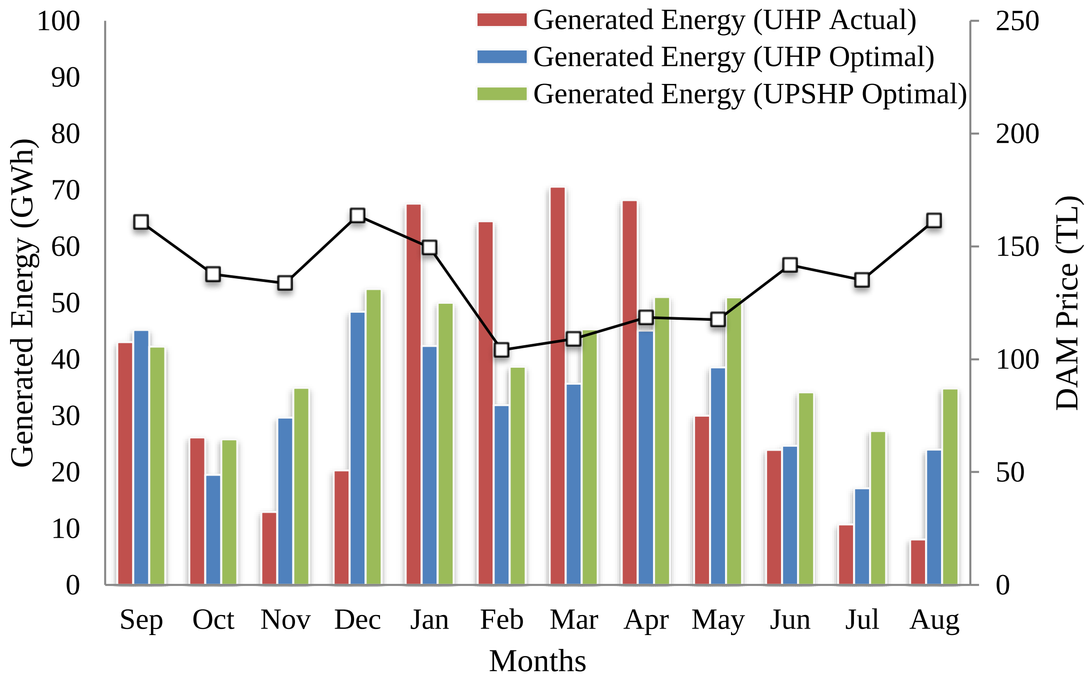

Figure 5.13. Monthly Energy Generations of UHP Actual, UHP, and UPSHP for 2015 (Scenario 2)

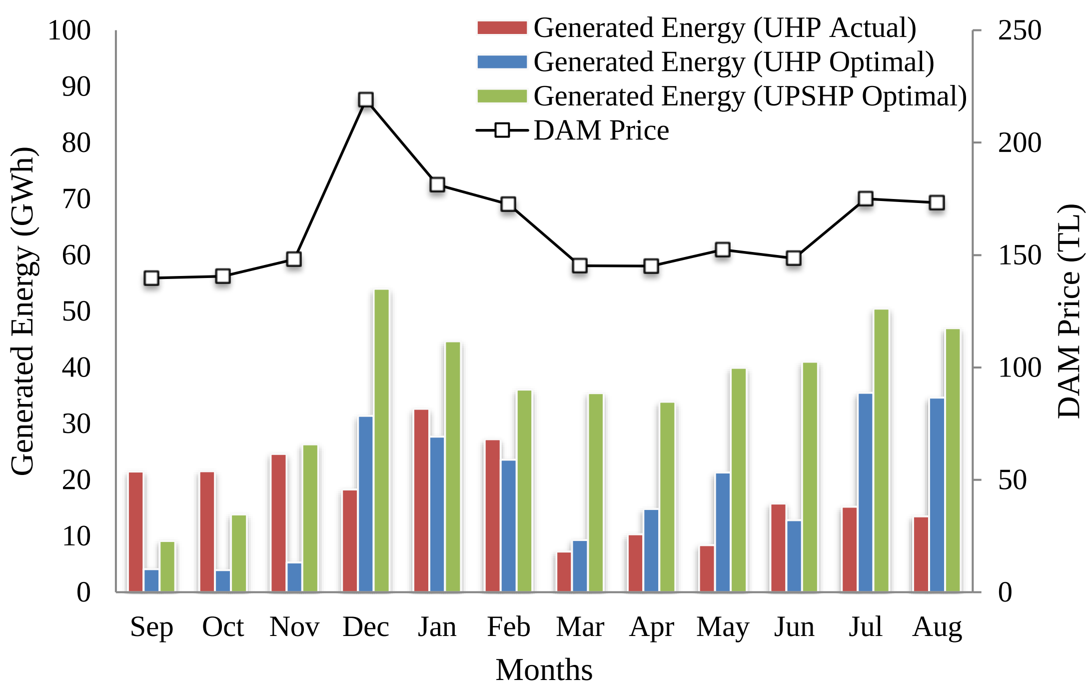

Figure 5.14. Monthly Energy Generations of UHP Actual, UHP, and UPSHP for 2016 (Scenario 2)

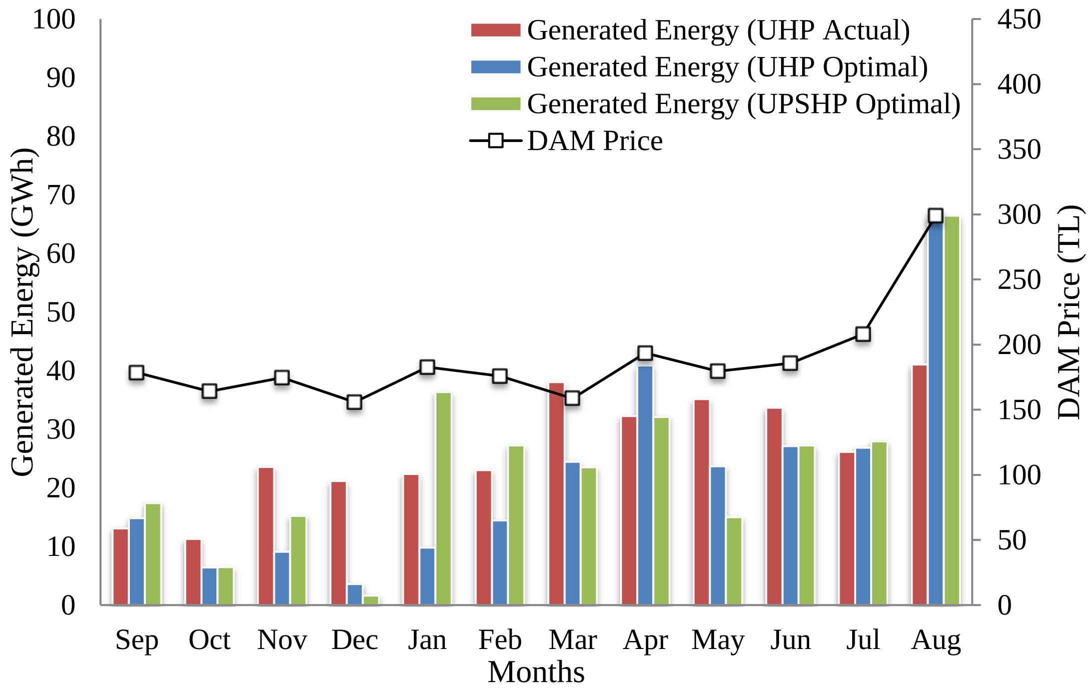

Figure 5.15. Monthly Energy Generations of UHP Actual, UHP, and UPSHP for 2017 (Scenario 2)

As can be seen in Figures 5.11 to 5.15, the amount of energy generation of the UPSHP model increases at the time of higher DAM prices. Therefore, these results meet the objectives discussed in Section 3.2.3.

In addition to the above analyses, the revenues are presented on a seasonal basis in Figures 5.16, 5.17, 5.18, 5.19 and 5.20 for water years 2013, 2014, 2015, 2016 and 2017, respectively.

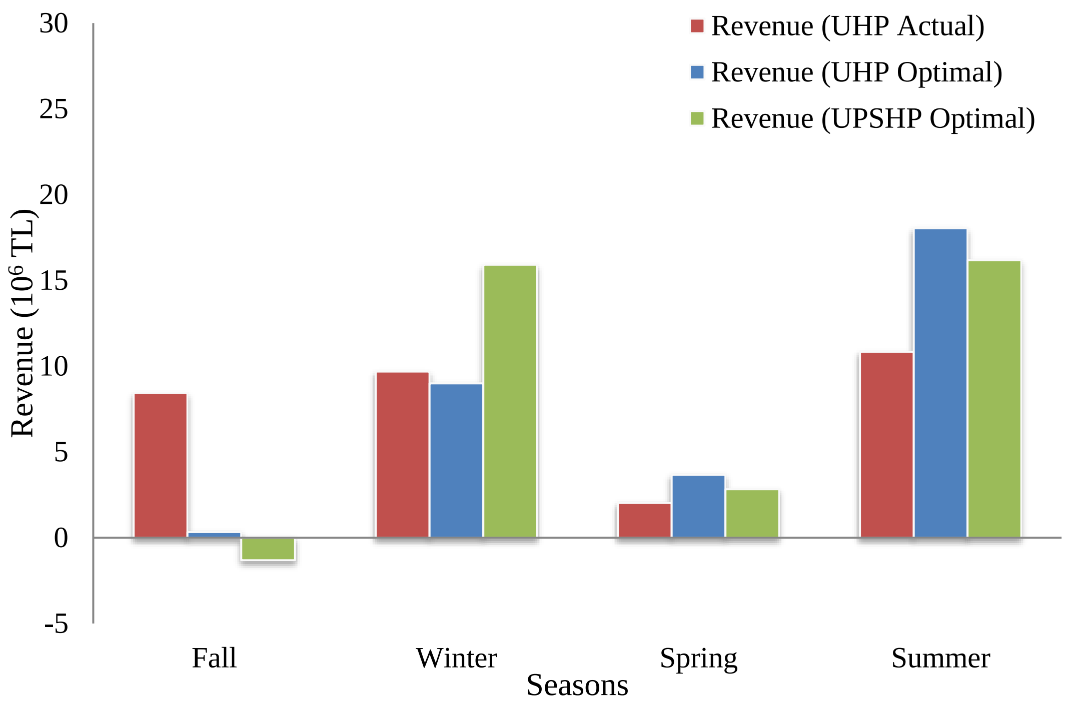

Figure 5.16. Seasonal Revenues of UHP Actual, UHP, and UPSHP for 2013 (Scenario 2)

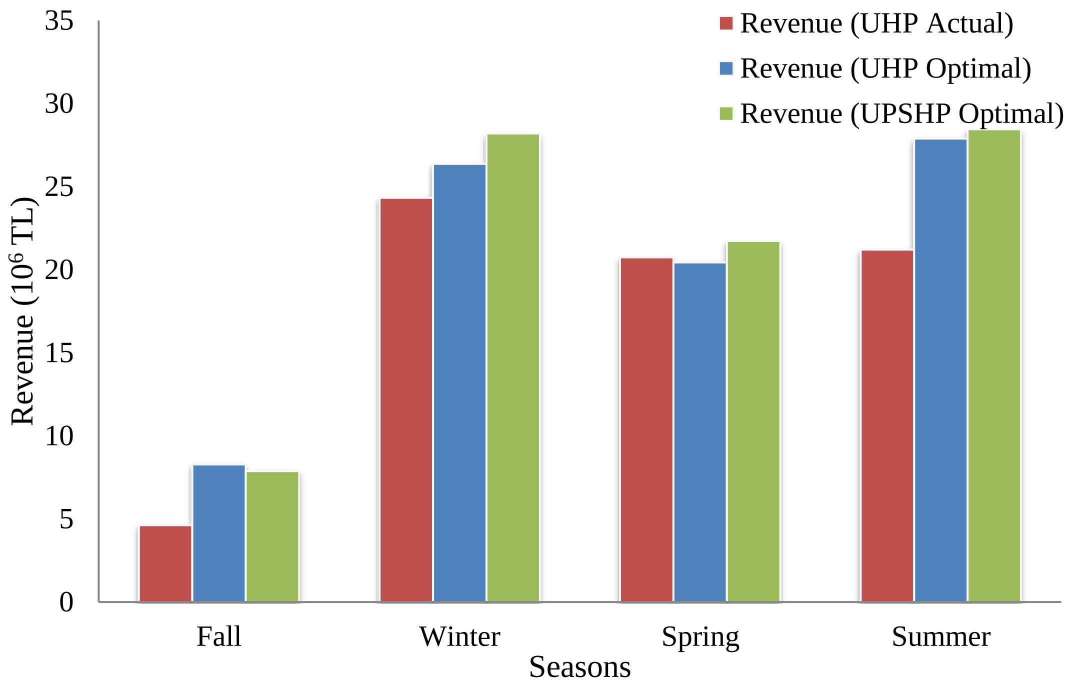

Figure 5.17. Seasonal Revenues of UHP Actual, UHP, and UPSHP for 2014 (Scenario 2)

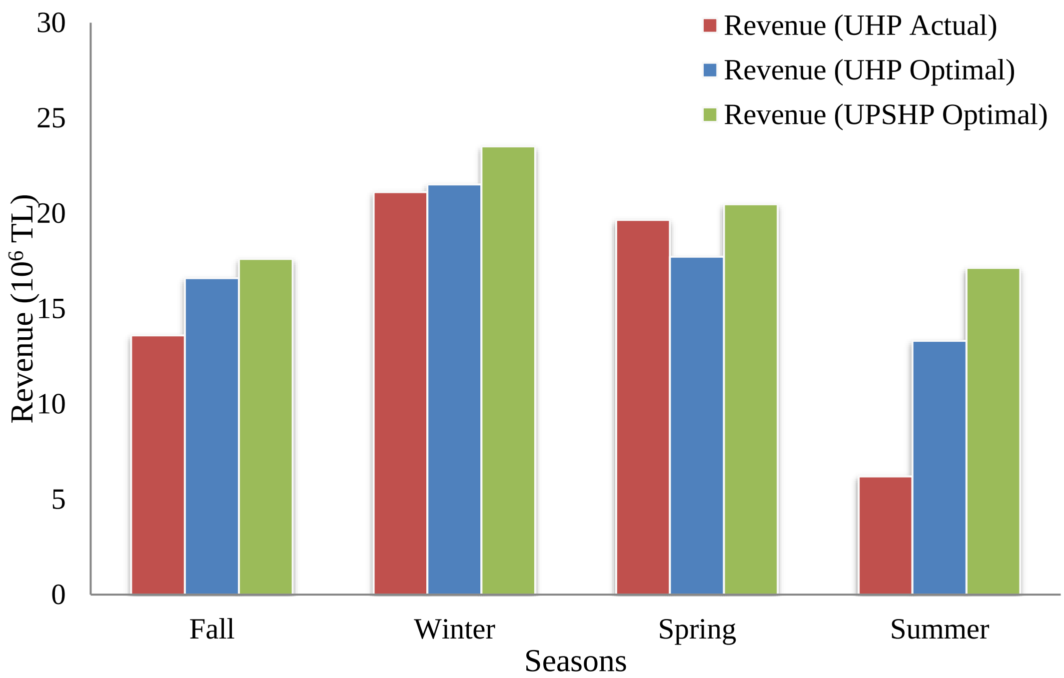

Figure 5.18. Seasonal Revenues of UHP Actual, UHP, and UPSHP for 2015 (Scenario 2)

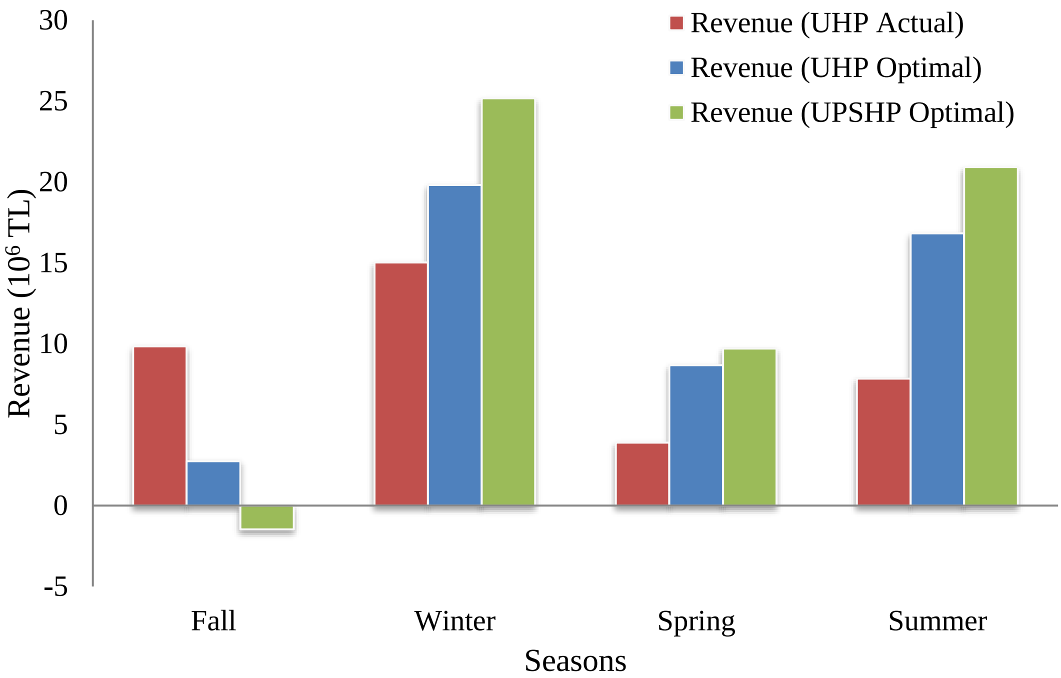

Figure 5.19. Seasonal Revenues of UHP Actual, UHP, and UPSHP for 2016 (Scenario 2)

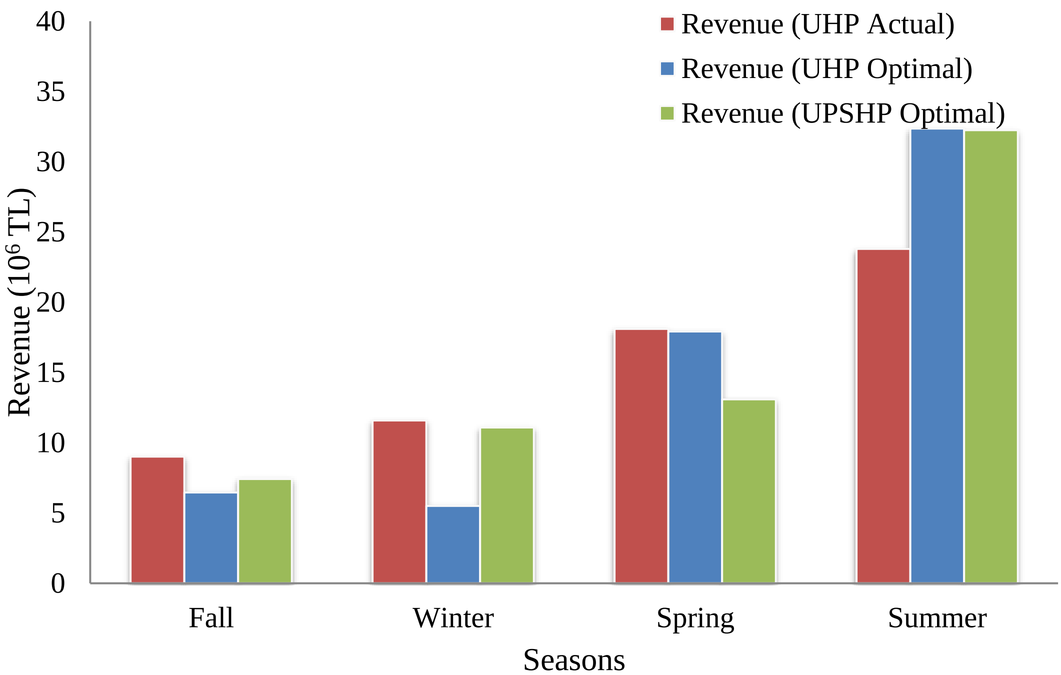

Figure 5.20. Seasonal Revenues of UHP Actual, UHP, and UPSHP for 2017 (Scenario 2)

These analyses reveal that the UPSHP model increases the revenue during summer and winter seasons, when DAM prices are high. In the fall seasons of 2013 and 2016, the UPSHP model has negative revenues similar to the results of Scenario 1. Therefore, UPSHP generates more electricity in winter seasons, when DAM prices are higher, by releasing the water from the high-level reservoir to the low-level reservoir.

In the above sections, comparisons of the revenues and energy generations are presented for each year. Revenue and energy generation results for each water year are summarized in Table 5.33 and the revenue differences are presented in Table 5.34 as percentages. As can be seen in Tables 5.33 and 5.34 , transforming UHP into UPSHP increases the revenue by 23.3 million TL which corresponds to a 7.96% revenue increase on the average.

Table 5.33. *Summary of Comparison (Scenario 2)*

Years	UHP Actual Operation		UHP Optimum Operation		UPSHP Optimum Operation		
	Generated Energy (MWh)	Revenue (TL)	Energy (MWh)	Revenue (TL)	Energy (MWh)	Consumed Energy (MWh)	Revenue
2013	162,456	31,001,000	152,743	31,008,294	255,160	152,767	33,593,197
2014	480,901	70,907,492	592,711	82,963,546	592,711	81,768	86,233,342
2015	446,126	60,560,456	402,095	69,138,677	487,733	124,342	78,755,154
2016	216,099	36,620,181	224,246	48,049,402	431,658	285,684	54,348,095
2017	320,744	62,496,820	267,626	62,252,520	296,531	296,531	63,835,378
TOTAL	**1,626,326**	**261,585,949**	**1,639,421**	**293,412,439**	**2,063,793**	**941,092**	**316,765,166**

Table 5.34. *Revenue Differences (Scenario 2)*

Years	Increase in Revenue for UHP Actual vs UPSHP Optimal	Increase in Revenue for UHP Optimal vs UPSHP Optimal)
2013	8.36%	8.34%
2014	21.61%	3.94%
2015	30.04%	13.91%
2016	48.41%	13.11%
2017	2.14%	2.54%
TOTAL	**21.09%**	**7.96%**

5.3. Evaluation of C_{int} Values

C_{int} values that maximize the revenue by forcing the models to operate the pump when the electricity price is below a certain value are obtained by trial and error approach. Table 5.35 demonstrates selected C_{int} values for each year.

Table 5.35 *C_int Values for Each Year*

Years	Scenario 1	Scenario 2
2013	130 TL	120 TL
2014	70 TL	60 TL
2015	70 TL	50 TL
2016	120 TL	130 TL
2017	110 TL	110 TL

As can be seen in Table 5.35, C_{int} values in 2014 and 2015 are relatively less than those of the other years. To further investigate this issue, DAM prices and inflows are analyzed in detail. Variation in DAM prices and inflows for each of the simulation years are given in Figures 6.1 and 6.2, respectively.

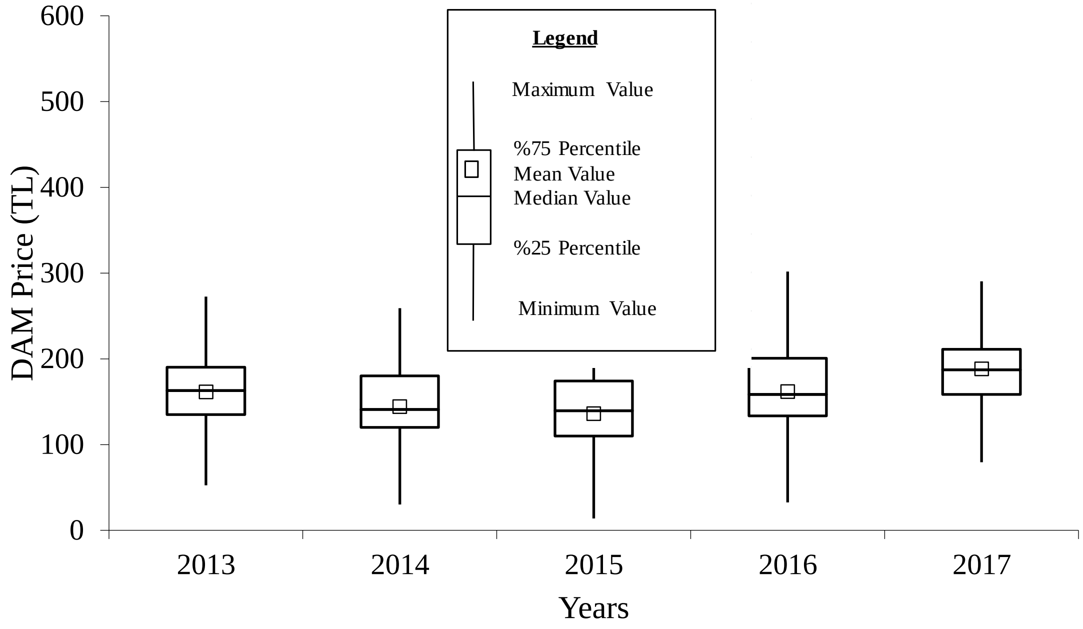

Figure 5.21 DAM Price Values

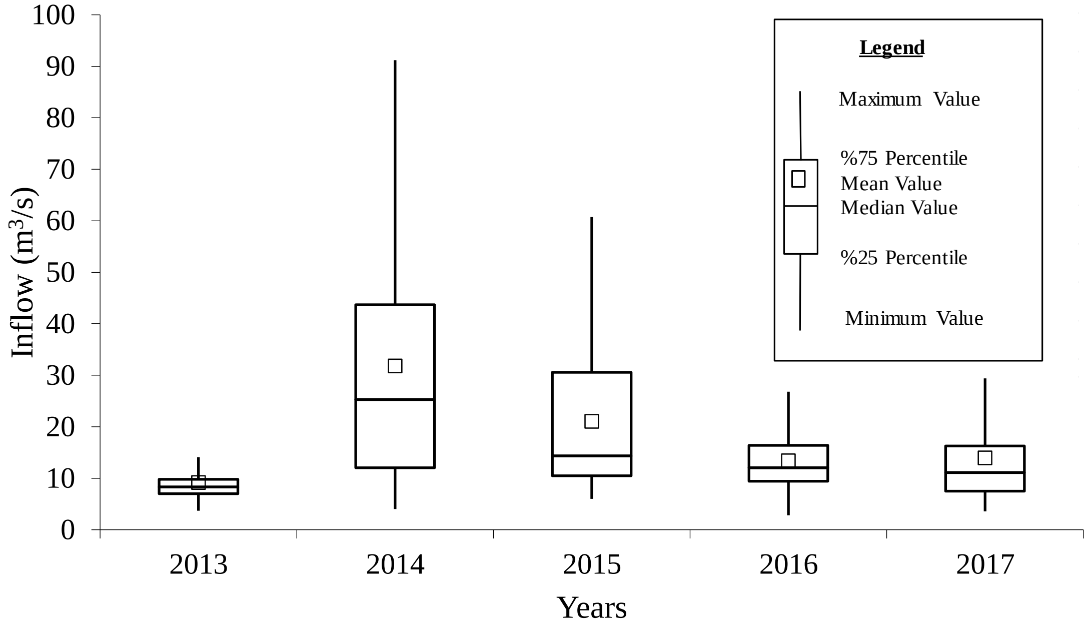

Figure 5.22 Inflow Values

The results shown in Figure 5.21 and 5.22 reveal that the best C_{int} value does not only depend on DAM prices but also inflows. Actually, the availability of water indirectly affects DAM prices. C_{int} and inflow is inversely proportional. These results provide additional guidance to the operator of a PSHP to decide the operation mode. For wet water years, lower C_{int} values may result in increased benefits.

In all the optimization models, pumping is forced when DAM prices drop below a certain value, C_{int}. To investigate the effect of C_{int} on the revenue, instead of using a single C_{int} for the whole year, a set of alternatives where different C_{int} values are implemented for different months are used for the water year 2013. The results are provided in Table 5.36.

Table 5.36 *Effect of C_{int} on the revenue of 2013 (Scenario 1)*

Months	C_{int} Value for Case 1 (TL)	C_{int} Value for Case 2 (TL)	C_{int} Value for Case 3 (TL)	C_{int} Value for Case 4 (TL)	C_{int} Value for Case 5 (TL)
Sep	C(t) < 130	C(t) < 130	C(t) < 120	C(t) < 130	C(t) < 100
Oct	C(t) < 130	C(t) < 130	C(t) < 120	C(t) < 130	C(t) < 100
Nov	C(t) < 130	C(t) < 130	C(t) < 120	C(t) < 130	C(t) < 100
Dec	C(t) < 130	C(t) < 130	C(t) < 120	C(t) < 130	C(t) < 100
Jan	C(t) < 130	C(t) < 100	C(t) < 100	C(t) < 110	C(t) < 130
Feb	C(t) < 130	C(t) < 100	C(t) < 100	C(t) < 110	C(t) < 130
Mar	C(t) < 130	C(t) < 100	C(t) < 100	C(t) < 110	C(t) < 130
Apr	C(t) < 130	C(t) < 100	C(t) < 100	C(t) < 110	C(t) < 130
May	C(t) < 130	C(t) < 100	C(t) < 100	C(t) < 110	C(t) < 130
Jun	C(t) < 130	C(t) < 100	C(t) < 100	C(t) < 110	C(t) < 130
Jul	C(t) < 130	C(t) < 130	C(t) < 120	C(t) < 130	C(t) < 100
Aug	C(t) < 130	C(t) < 130	C(t) < 120	C(t) < 130	C(t) < 100
Revenue (TL)	**35,446,449**	**36,126,017**	**35,780,984**	**34,139,430**	**33,693,974**

According to the results for the cases defined in Table 5.36, forcing the model by lower C_{int} value (i.e., Case 2: 100 TL instead of 130 TL) between January and June results in more revenue. As explained in Section 3.2. inflow values between January and June of 2013 were higher than those of the other years. These results reveal that heuristic implementations can give improved results in terms of revenue. For the months where higher inflow values are expected lower C_{int} values can be used.

CHAPTER 6

CONCLUSION

In this study, the management of PSHPs in an electricity market is investigated from an economic point of view to provide prospective operation guidance that maximizes the revenue of the selected PSHP. Optimization models are developed to maximize the revenue of the owner of the PSHP. Optimum operation strategies for five different years are generated using hourly time steps (i.e., t=1, 2,…, 8760) for simulation durations of one year. Based on the optimization results, the operation schedules under different reservoir management scenarios are proposed.

The important results and findings obtained from the results are given below:

- The revenue of UPSHP increases compared to that of UHP even when pumping is forced when electricity price drops below a prespecified value; however, the net energy decreases.
- Developing appropriate reservoir management strategies are critical for maximizing the benefit from hydropower plants, especially from PSHPs. The results show that the revenue of UPSHP increases by 9.13 % on the average compared to UHP (i.e., the strategy implemented by the owner of UHP for 5-year simulation duration) in Scenario 1. For Scenario 2, where initial and final storages are forced to be equal, the average revenue increase is 7.96 %.
- The nonlinear optimization problem cannot be solved with hourly time steps for a duration longer than one year if pumping and turbining are selected to be decision variables due to the curse of dimensionality. To maintain convergence, pumping is forced when the electricity price drops below a predefined value. This value is selected through a trial and error process. With this additional constraint, optimum operation strategies are obtained for

simulation periods of one year. The results showed that converting the existing hydropower plant into a pumped storage power plant brings additional revenue to the owner.

Recommendations to Further Studies

In this study, the revenue increase when a conventional hydropower plant is transformed into a pumped storage hydropower plant is investigated. However, additional costs of this conversion (i.e., the pump's initial costs, costs associated with necessary modifications, etc.) are not evaluated. As future work, the feasibility of such a conversion can be investigated.

This study only considers the conversion of a conventional HPP to a PSHP and uses daily price variations to increase the revenue. Ideally, PSHPs are more beneficial if they are operated together with another renewable energy source, such as wind. Intermittency in wind will be balanced through the use of the PSHP. For hybrid power systems such as wind-PSHP, the additional revenue is expected to be higher. In such hybrid systems, the PSHP is used to balance the unstable output of wind power plants by adjusting its generation to compensate wind power prediction errors. Additional benefits of the conversion from the conventional HPP to a PSHP obtained in this study can be evaluated as a lower bound of the conversion from the conventional HPP to a hybrid wind-PSHP plant. Total benefit of conversion to a hybrid system should be examined in detail as a future study.

In this study, hourly-time steps are implemented. However, utilization of hourly-time steps for long simulation periods is challenging due to the curse of dimensionality. To overcome this problem, we run the optimization model for the duration of one water year for five different years. However, better utilization of inflows can be maintained through a multi-year optimization, which can be possible if the mathematical model is simplified. For example, linearization of the model may allow identification of hourly optimum pumping and turbining rates for a multi-year simulation period. This will allow, the surplus of a wet water year to be used in the following dry years. In other words, the surplus energy in wet years can be utilized to keep the reservoir at higher levels providing more energy for dry years. Simplification of the mathematical model may allow removal of the constraint which forces pumping when electricity prices drop below a certain value. This is another potential future study topic.

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