OPTIMUM BIDDING STRATEGY FOR HYDRO, WIND AND SOLAR POWER PLANTS IN DAY AHEAD ELECTRICITY MARKET

A THESIS SUBMITTED TO
THE GRADUATE SCHOOL OF NATURAL AND APPLIED SCIENCES OF
MIDDLE EAST TECHNICAL UNIVERSITY

BY
MEHMET ÖZCAN

IN PARTIAL FULFILLMENT OF THE REQUIREMENTS
FOR
THE DOCTOR OF PHILOSOPHY
IN
EARTH SYSTEM SCIENCE

SEPTEMBER 2021

Approval of the thesis:

OPTIMUM BIDDING STRATEGY FOR WIND AND SOLAR POWER PLANTS IN DAY AHEAD ELECTRICITY MARKET

submitted by **MEHMET ÖZCAN** in partial fulfillment of the requirements for the **Degree of Doctor of Philosophy in Earth System Science Department**, Middle East Technical University

Prof. Dr. Halil Kalıpçılar
Dean, Graduate School of **Natural and Applied Sciences** _______________

Prof. Dr. Bülent Akınoğlu
Head of Department, **Earth System Science Department** _______________

Assist. Prof. Dr. Ozan Keysan
Supervisor, **Electrical and Electronics Engineering** _______________

EXAMINING COMMITTEE MEMBERS:

Prof. Dr. Bülent Akınoğlu
Physics, METU _______________

Assist. Prof. Ozan Keysan
Electrical and Electronics Engineering, METU _______________

Prof. Dr. Uğur Soytaş
Department of Technology, Management and Economics,
Technical University of Denmark _______________

Prof. Dr. Ramazan Sarı
DTU Management, Technical University of Denmark _______________

Assist. Prof. Ayşe Selin Kocaman
Industrial Engineering, Bilkent University _______________

Date:08.09.2021

I hereby declare that all information in this document has been obtained and presented in accordance with academic rules and ethical conduct. I also declare that, as required by these rules and conduct, I have fully cited and referenced all material and results that are not original to this work.

Name, Surname: Mehmet Özcan

Signature:

ABSTRACT

OPTIMUM BIDDING STRATEGY FOR WIND AND SOLAR POWER PLANTS IN DAY AHEAD ELECTRICITY MARKET

Özcan, Mehmet
PhD, Department of Earth System Science
Supervisor: Assist. Prof. Dr. Ozan Keysan

September 2021, 117 pages

The main challenge related to the trade of electricity from renewable energy sources is their intermittency due to stochastic nature of their generation output. This leads to the imbalance cost in day ahead markets (DAM) and raise the concerns for collaboration. There are 2 possible strategies for wind power plants (WPPs) and solar power plants (SPPs) to maximize their income in day ahead markets (DAM) in the presence of imbalance cost: Joint Bidding (JB) via collaboration by participating to balancing groups and deployment of storage technologies. There are limited studies in the literature covering the comparative analysis of “collaborative joint bidding strategy” with “battery deployment strategy”. In the existence of balancing responsibility, the comparative analysis of these strategies is the main contribution of this study to the literature. Second contribution is the analysis of the impact of different regulatory regimes, which are set by the regulatory authority, on total income. Joint Bidding Model, which is the model for joint bidding via different collaboration groups, is developed for the analysis of first strategy, Battery Deployment Model, which is the model covering the deployment of storage technology, is developed for the analysis of second strategy. The impact of each strategy on total income is analyzed. According to the analysis of the results of the models, while the first strategy, which is sensitive to the regulatory regime, increases the total annual income of the collaboration groups up to 1.38%, second strategy seems not feasible and financially viable. On the other hand, extra income values per MW of battery for SPP is between $218 and $400 /MW-year, while these values are between $2,460-$6,795/MW-year for the group of 15 WPPs. Therefore, deployment of battery for WPPs creates extra income more than 10 fold of that of SPP. Second strategy can be viable if the levelized cost of deployment of battery drops below the extra income values achieved per MW of battery.

Key words: trade of renewable energy**;** day ahead electricity market; optimum bidding; optimization

ÖZ

RÜZGAR VE GÜNEŞ SANTRALLERİ İÇİN GÜN ÖNCESİ ELEKTRİK PİYASASINDA OPTİMUM TEKLİF STRATEJİSİ

Özcan, Mehmet
Doktora, Yer Sistem Bilimi Bölümü
Tez Yöneticisi: Assist. Prof. Dr. Ozan Keysan

Temmuz 2021, 117 pages

Yenilenebilir enerji kaynaklarından elektrik üretilmesine ilişkin olarak ana zorluk yenilebilir enerji kaynaklarının üretimlerinin stokastik bir yapıya sahip olmasından kaynaklı olarak kesintili olmasıdır. Bu durum gün içi piyasalarında dengesizlik maliyetlerine sebebiyet vermekte ve üretivciler arasında işbirliği imkanlarını gündeme getirmektedir. Dengesizlik maliyetleri söz konusu olduğunda, rüzgar güç santralleri ve güneş güç santrallerinin gün öncesi piyasasında gelirlerini arttırabilmeleri için 2 farklı strateji mümkündür: dengeleme grupları oluşturulması suretiyle ortak teklif verilmesi ve depolama teknolojilerinden faydalanılması. Literatürde işbirliğine dayalı ortak teklif verilmesi stratejisi ile depolama teknolojileri kullanılması stratejilerinin karşılaştırmalı olarak analiz edildiği çalışmalar son derece kısıtlıdır. Dengeleme sorumluluğu altında, sözkonusu stratejilerin karşılaştırmalı analizi bu çalışmanın literature ana katkılarından birisidir. Diğer katkı ise düzenleyici kurum tarafından uygulamaya konulan farklı düzenleyici yaklaşımların toplam gelire olan etkisinin ortaya konmasıdır. Farklı işbirliği gruplarını kapsayacak şekilde geliştirilen ortak teklif modeli, ilk stratejinin analizi için; depolama teknolojilerinin kullanımını

kapsayan batarya kullanım modeli ise ikinci stratejinin analizi için geliştirilmiştir. Her bir stratejinin gelire olan etkisi analiz edilmiştir. Modellerin sonuçları analiz edildiğinde düzenleyici yaklaşıma duyarlı olan ilk stratejinin işbirliği gruplarının toplam gelirlerine %0.65 oranına ulaşan oranlarda artış sağladığı, ikinci stratejinin ise finansal olarak uygulanabilir olmadığı görülmüştür. Diğer taraftan, her bir MW batarya kullanımının güneş santrali için 400 dolar/MW-yıl gelir sağladığı, 15 adet rüzgar güç santrali için bu ilave gelirin 2,460 ile 6,795 dolar/MW-yıl aralığında olduğu görülmüştür. Dolayısıyla, bataryanın rüzgar güç santraleri için kullanımı güneş santrallerine göre 10 kattan daha fazla ilave gelir imkanı yaratmaktadır. İkinci stratejinin uygulanabilir olması için seviyelendirilmiş batarya maliyetlerinin, bahsi geçen ilave gelirlerin altına inmesi gerekmektedir.

Anahtar Kelimeler: Yenilenebilir enerjinin ticareti, gün öncesi elektrik piyasası, optimum teklif, optimizasyon

ACKNOWLEDGMENTS

First and foremost, I would like to express my sincere gratitude and respects to my supervisor Assist. Prof. Dr. Ozan Keysan for his advice, guidance, and supports throughout this study.

I would like to convey my profound gratitude to Assist. Prof. Dr. Benhür Satır, Prof. Dr. Bülent Akınoğlu and Prof. Dr. Uğur Soytaş. It would not be possible for me to succeed without their everlasting love and continuous encouragement.

Last but certainly not least, my special thanks go to my wife Beyza Neriman ÖZCAN for her steadfastness, toleration, support, and trust in me. This work would have never been done without her.

TABLE OF CONTENTS

LIST OF TABLES

TABLES

LIST OF FIGURES

FIGURES

LIST OF ABBREVIATIONS

BM	: Battery Deployment Model
BSR	: Balancing and Settlement Regulation
CEER	: Council of European Energy Regulators
CTC	: Constant Tolerance Coefficient
DAM	: Day-Ahead Electricity Market
DAP	: Day-Ahead Offered Generation
DTC	: Differentiated Tolerance Coefficient
EMRA	: Energy Market Regulatory Authority
EPIAS	: Electricity Market Operator
EÜAŞ	: Electricity Generation Company
FIT	: Feed-in Tariff
GAMS	: The General Algebraic Modeling System
GP	: Guaranteed Price
HPP	: Hydro Power Plant
IC	: Imbalance Coefficient
JB	: Joint Bidding
JBMHM	: Joint Bidding Multi-Hydro Model
JBSHM	: Joint Bidding Single-Hydro Model
LOSSI	: Loss of Income due to Imbalance
MCP	: Market Clearing Price
MW	: Megawatt
PFC	: Primary Frequency Control
PV	: Photovoltaic
RES	: Renewable Energy Sources
RG	: Realized Generation
RV	: Reservoir Volume
SFC	: Secondary Frequency Control
SMP	: System Marginal Price

SPP	: Solar Power Plant
TC	: Tolerance Coefficient
TEAŞ	: Turkish Electricity Generation Company
TEDAŞ	: Turkish Electricity Distribution Company
TEİAŞ	: Turkish Electricity Transmission Company
TWh	: Terawatt hours
USD	: United States Dollar
VRFB	: Vanadium Redox Flow Battery
WPP	: Wind Power Plant
YEKDEM	: Renewable Energy Sources Support Mechanism

CHAPTER 1

INTRODUCTION

In the light of the growing concerns for pollution, climate change, decarbonisation, import dependency, ensuring supply diversity and supply security, installed capacity of renewable energy plants is expanding globally. This expansion is reported by the "World Energy Outlook 2020" Report of International Energy Agency [1]. According to the findings of this report, there is a rapid grow in renewables in all our scenarios, with solar at the center of this new constellation of electricity generation technologies. With sharp cost reductions over the past decade, solar PV is consistently cheaper than new coal- or gas fired power plants in most countries, and solar projects now offer some of the lowest cost electricity ever seen. In the Stated Policies Scenario, which is based on the today's announced policy intentions and targets, renewables meet 80% of the growth in global electricity demand to 2030. Hydropower remains the largest renewable source of electricity, but solar is the main driver of growth as it sets new records for deployment each year after 2022, followed by onshore and offshore wind.

Considering this expansion, there is a growing challenge for the management of the power systems that includes more and more renewable energy generation [2, 3] and the arising need for the change of the design and architecture of the conventional power systems [4]. The main game changer is the intermittency of renewable energy sources, such as solar and wind energy-based generators. These generators create a high degree of uncertainty to the power system due to the stochastic nature of solar irradiation and wind speed [5], therefore the electricity produced by solar and wind power plants is considered as non dispatchable [6]. Therefore, dispatchable energy sources such as thermal power plant, nuclear power plant, and hydropower plant with sufficiently large reservoir or energy storage systems are strongly needed to cope with stochastic, non-dispatchable power generation for real time balancing of supply and demand without any interruption.

Electricity energy could be traded either bilaterally or via spot markets. In long-term trades, two participants (one buyer and one seller) negotiate and agree on the terms of bilateral contracts. The price and other detailed information are limited to the parties involved. In spot market, traders offer their bids in the markets such as day-ahead and intraday (a few hour-ahead) [7]. However, offered generation may not match with the realized generation which is the frequently experienced by non dispatchable power generation. In such cases, balancing markets usually functions for the real time balancing of supply and demand.

The intermittency in renewable energy generation is the main challenge for the optimal bidding in the day ahead markets. Uncertainty creates imbalances between planned and realized generation. This imbalance incurs cost for power plants. In many spot markets with balancing responsibility, participants are allowed to form balancing groups, in which the power plants with non-dispatchable power generation mostly collaborates with dispatchable energy sources to minimize the cost of imbalance. In the literature, hydropower plants, thermal power plants and energy storage systems are the most widely used dispatchable energy sources to counterbalance the deviations sourced by the stochastic nature of non dispatchable sources such as wind and solar PV power plants. The generation by the hydropower plants with sufficiently large water-storage reservoirs are dispatchable and adjustable unlike the non dispatchable run-of-the-river type hydro power plants whose output is dependent on seasonal variation in river flow [8]. The input-output hydro generation function describing the relation between discharged water and generated power is widely represented by piece-wise linearized hydro-unit performance curves [9][10] . Expected price of water (opportunity cost of water) is also used for the revenue maximization model of the hydropower plant with large reservoir in the day ahead market [11] and profit maximization in the intraday market [12].

Most frequently used optimization models for bidding in day ahead market is the mixed integer linear optimization models and/or stochastic optimization models. Stochastic optimization model developed for coordinated bidding of wind and photovoltaic energy [13], stochastic mixed integer programming for mixed bidding of wind and thermal power plant [14], stochastic mixed integer programming for aggregated bidding of wind, photovoltaic and thermal power plants [15], day ahead stochastic coordinated scheduling for thermal-hydro-wind-photovoltaic systems [9], stochastic coordination of joint wind and photovoltaic systems with energy storage [16], stochastic optimization model for combined hydro and wind power plants [10], stochastic programming-based optimal bidding of compressed air energy storage with wind and thermal generation [17] lead to increase in total profit compared to individual bidding case. In addition to stochastic optimization models, information gap decision theory for determining the optimal bidding strategies in day ahead market [18], multi objective optimization for bidding strategy of wind-thermal-photovoltaic system [19], optimization model with forecasting, scenario generation and scenario reduction methods for joint operation of wind farm, photovoltaic, pump-storage and energy storage devices are also used in the literature[20] .

Mixed integer linear optimization for optimal coordination on wind-pumped-hydro operation [21], for joint market bid of a hydroelectric system and wind parks [22] and for sustainable aggregation of clean energy in day ahead market [23], mixed integer convex program for scheduling of a wind and storage power plant in day ahead and reserve markets are also used[24]. This study does not cover generation forecasting or scenario development. The forecasted generation by power plants, already available in data set, are used assuming that these power plants are already conducting their forecasts based on the best available forecasting tools. Therefore, mixed integer linear optimization and linear optimization models are deployed instead of deployment of stochastic models or scenario generation and scenario reduction methods. In addition, the input-output hydro generation function which is widely represented by piece-wise linearized hydro-unit performance curves in the literature is also deployed to quantify the relationship between discharged water and generated power.

Energy storage is also a possible strategy to counterbalance the deviations of non dispatchable energy sources such as wind or solar power plants. The storage technology that has recently drawn attention is the vanadium redox flow battery (VRFB) which is one of the most promising storage technologies for application at power plants to compensate the fluctuations of renewable energy based power generation [9, 25]. It has also been shown that VRFB can compete with high capacity lead-acid batteries used in stationary applications [26].

There are several successful applications of VRFB in sizes from several kilowatts to some megawatts [27]. VRFB energy storage systems projects in operation with the largest scale as of end of 2017 are given in Table 1.1 [28].

Table 1.1 VRFB Projects in Operation

Name	Commissioning date	Energy (MWh)	Power (MW)	Duration (hours)	Country
Minami Hayakita Substation	2015	60	15	4	Japan
Woniushi, Liaoning	-	10	5	2	China
Tomamae Wind Farm	2005	6	4	1.5	Japan
Zhangbei Project	2016	8	2	4	China
SnoPUD MESA 2 Project	2017	8	2	4	USA
San Miguel Substation	2017	8	2	4	USA
Pullman Washington	2015	4	1	4	USA
Pfinztal, Baden	2019	20	2	10	Germany

In the existence of balancing responsibility for the intermittent renewable energy sources, the comparative analysis of “collaborative joint bidding strategy” with “battery deployment strategy” in day ahead electricity markets (DAM) is the main contribution of this study to the literature. Second contribution is the analysis of the impact of different regulatory regimes, which are set by the regulatory authority, on total income.

Optimization models are developed for each strategy. These models are developed for the day ahead bidding in day ahead electricity market and they do not cover intraday market or balancing market.

The organization of this thesis is as follows. In Chapter 2, information is given about power market, Turkish Electricity Market Structure, Turkish balancing and settlement mechanism with specific emphasis on the day ahead market.

Chapter 3 is dedicated to problem definition, identification of the available data and analysis of the available data for wind power plants, solar power plant, hydro power plants with limited reservoir capacity and hydropower plant with large reservoir capacity. This chapter also explains the methodology for different possible strategies for wind power plants and solar power plant and the models developed for different strategies.

Chapter 4 covers the model outputs and the analysis of the outputs for each model. Outputs are analyzed for different collaboration groups with different regulatory regimes.

Chapter 5 explains the conclusion and future line of work.

CHAPTER 2

ELECTRICITY MARKET

Power market consists of four main components which are generation, transmission, distribution and supply. Before the worldwide deregulation and restructuring activities, in most of the countries large, often state owned, monopolies were responsible for generation, transmission, and distribution of electric power. Deregulation took place in various forms, but the common aim was to stimulate competition in the electricity sector. Usually the way to achieve this was to split up vertically integrated power producers (vertical unbundling) and privatize state owned utilities [29]. However, despite the vertical unbundling, privatization and liberalization activities, in most of the countries transmission and distribution networks are still owned by monopolies due to their natural monopolistic feature. The main challenge in the deregulated power markets is to form a competitive market environment on the generation and supply side while infrastructure (transmission and distribution) is managed by monopoly subject to regulation.

2.1. Turkish Electricity Market:

Electricity market was ruled as a state-owned monopoly with the establishment of TEK in 1970. In 1994 TEK was decomposed into two publicly owned legal entities which are Turkish Electricity Generation (TEAŞ) and Turkish Electricity Distribution Company (TEDAŞ). With the enactment of Electricity Market Law in 2001, TEAŞ was further vertically unbundled into three different publicly owned legal entities, which are Turkish Electricity Transmission Company (TEİAŞ) as the transmission system operator, Electricity Generation Company (EÜAŞ) for power generation and Turkish Electricity Trading and Contracting

Company (TETAŞ) for trade [30]. Turkish Electricity Transmission Corporation (TEİAŞ) was included in the scope of the country's privatization process, according to Presidential Decision published in Turkey's Official Gazette on July 3. According to the decision, the privatization preparations will be carried out in cooperation with the Energy and Natural Resources Ministry and the Privatization Administration.

Balancing and Settlement Regulation (BSR) was announced in 2004 and it came into effect in 2006. Day-ahead planning started in 2009 and Day-Ahead Market, Balancing Power Market and Ancillary Service Market were established between 2009 and 2011. Real time balancing is today provided in Balancing Power Market and Ancillary Service Market, which are controlled by TEİAŞ. Intra-Day Market was established in 2015 in order to give more flexibility to the operators while balancing their portfolios. TETAŞ was abrogated in 2018 and their trade agreements were transferred to EÜAŞ [31].

In Turkey; demand for electricity has an increasing tendency while the rate of demand increase has slowed down since 2011 and the demand declined in 2019. The distribution of peak demand and the rate of change in demand with respect to years is shown in Figure 2.1

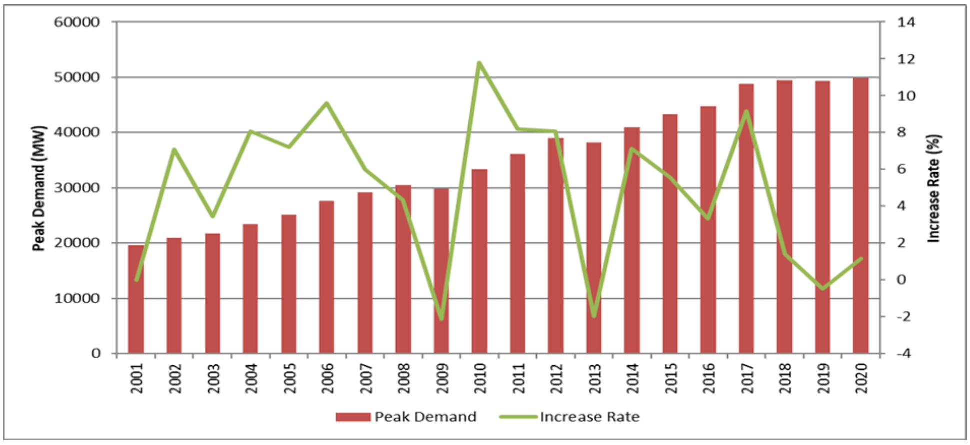

Figure 2. 1. Peak Demand and Increase Rate Over Years [32]

Electricity generation[1] according to resource type is given in Table 2.1. [32].

Table 2. 1. Electricity Generation According to Resource Type

RESOURCE TYPE	GENERATION (GWh)	SHARE (%)
Hydro-electric	78,149	23.3
Natural Gas	69,278	20.6
Import Coal	62,466	18.6
Lignite	38,164	11.4
Wind	24,681	7.4
Geothermal	9,929	3.0
Biomass	24,954	7.4
Hard Coal	3,416	1.0
Asphaltite Coal	2,223	0.7
Solar	22,068	6.6
Fuel Oil	313	0.1
Diesel	1	0.0
Total	335,642	

According to the Table 2.1, the sum of shares of hydraulic, wind, solar, biomass and geothermal (renewable energy sources) account for the 47.7% of the total electricity generation in 2020.

The share of installed capacity of renewable energy based power plants is increasing while the share of installed capacities of thermal power plants is declining especially since the year 2006. Distribution of share of installed capacities with respect to resource type is shown in Figure 2.2 [32].

[1] Generation covers both licensed and unlicensed generation

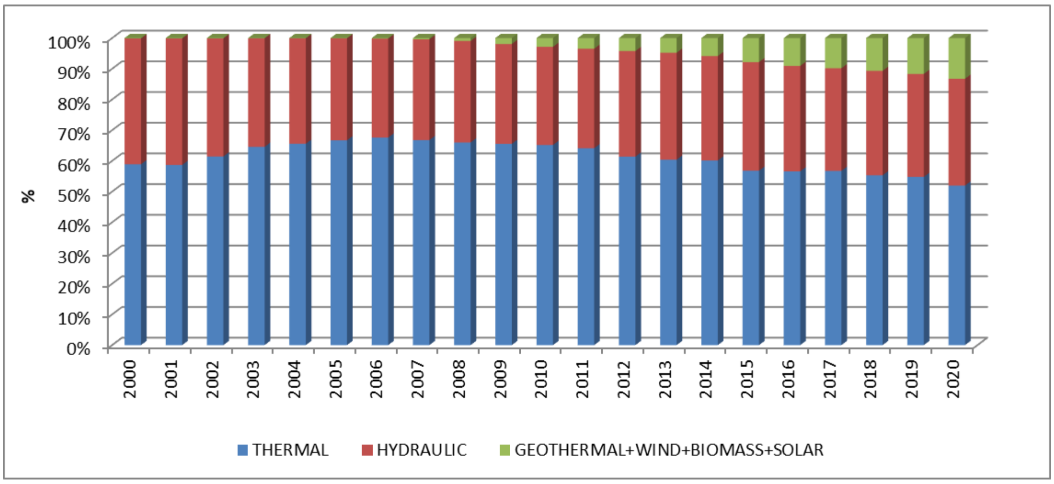

Figure 2. 2. Distribution of Share of Installed Capacities with Respect to Resource Type

Deregulation process for energy sector in last decades also affects the market structure in Turkey. With the aim of being reliable, transparent, nondiscriminatory, and competitive, current structure of Turkish electricity market can be seen in Figure 2.3.

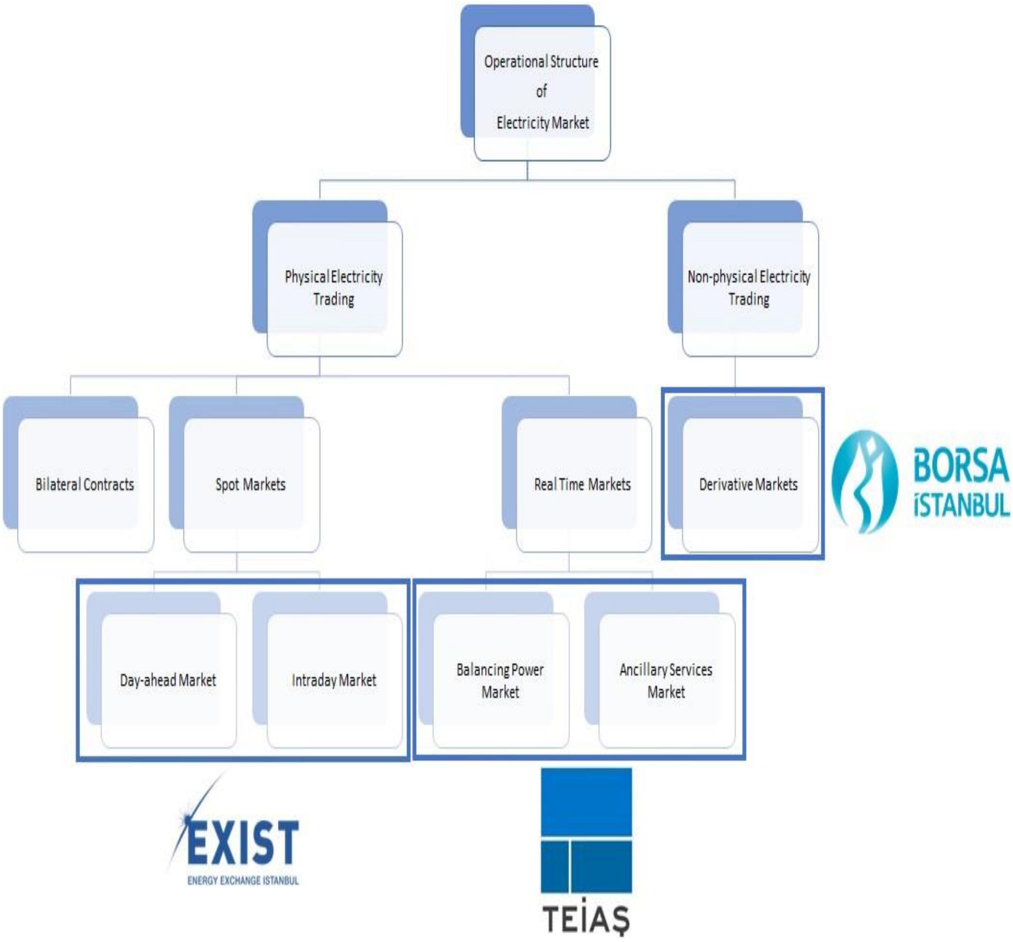

Figure 2. 3. Electricity Market Structure in Turkey [33].

As can be seen from Figure 2.3, physical electricity trading can conducted by bilateral contracts, spot markets or real time markets. Spot markets cover day-ahead market and intraday market.

2.1.1. Spot Market

Spot market is operated by independent electricity market operator (EPIAS) who is Energy Exchange ˙Istanbul, EXIST, in Turkey. Spot markets cover day-ahead and intraday markets.

2.1.1.1. Day-ahead Market

Day-ahead market is the mechanism where market participants, energy buyers and energy sellers, can actively participate to trade energy. Day-Ahead Market transactions are performed daily on hourly basis. Market participants can submit their hourly offers at day (D) for next day (D+1) or up to next 5 days (D+5). Indeed, the deadline to submit a bid is at 12:30 on day (D) [30]. Day-ahead market offers are validated by EPIAS between 12:30 and 13:30 on day (D), and then the optimization model, which aims the maximization of total surplus (producer surplus plus consumer surplus), is solved to balance the supply and demand at each hour [31]. Optimization model provides the market clearing prices and the amount of matched volumes for each hour of the day (D+1).

2.1.1.2. Intraday Market

While the day-ahead markets cover the offered amounts of bids and associated prices for at least 1 day later, intraday market enables market participants to trade 60 minutes before the physical delivery. Intraday Market transactions are executed on an hourly basis every day to minimize the imbalances between demand and supply.

2.1.2. Real Time Market

Real time market covers power balancing market and ancillary services market. Turkish Electricity Transmission Corporation (TEIAS) operates the real time market.

2.1.3. Power Balancing Market

Day-ahead and intraday markets under the responsibility of EPIAS aim to balance the demand and the supply. However, realized generation may not match with offered (planned) amounts of power generation due to the forecasting errors or unforeseen events. In such cases, real time power balancing is conducted by TEIAS in a manner to ensure the supply quality at the desired frequency level of 50 Hz. The system guarantees the security of the system against any danger, constraint or abnormality.

Participation of market participants, which are balancing units, to power balancing market is obligatory. Balancing Units are defined as the power generation plants capable of loading or de-loading at least 10 MW within 15 minutes. Canal, river, type hydroelectric power plants; wind, solar, wave, tide, cogeneration and geothermal power plants are exempt from balancing unit. Balancing units should submit loading and deloading bids to the market. System marginal price, system direction (surplus or deficit) and the net volumes are determined by TEIAS based on the bids submitted by balancing units.

2.1.4. Ancillary Services Market

Ancillary services market covers primary and secondary frequency control and supply of reactive power support. Primary Frequency Control (PFC) brings the system frequency to a new equilibrium point by automatically increasing or decreasing the unit active power with the speed regulator in response to the decrease or rise of the system frequency. In secondary frequency control, active output is set to a value by central system. Last, reactive power support helps to balance reactive power in case it is needed.

Figure 2.4 shows the general framework of electricity trade in Turkish market from long term to real-time to balance the supply and demand continuously. In general, bilateral contracts and financial markets can be considered as the long-term electricity trade instruments. Day-ahead markets cover the bids of market participants for the next day or up to for the next 5 days. Intraday markets provide opportunity to bid 60 minutes before the physical delivery. Real-time markets aim to ensure the supply quality at the desired frequency level of 50 Hz continuously.

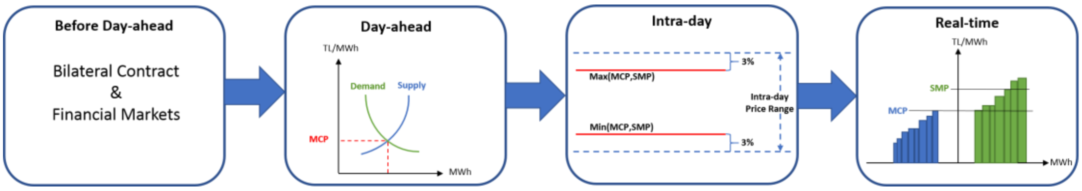

Figure 2. 4. Timeline of Turkish Electricity Market [33]

According to the Electricity Market Report of Electricity Market Operator (EPIAS) for June, 2021 [34]; total monthly market volume is 41,583 GWh. 56.9% of the monthly market volume consists of bilateral contracts, 39.5% consists of Day Ahead Market, 1.6% consists of Balancing Power Market and 2% consists of Intraday Market in Turkey. The number of EPIAS registered market participants is 1,432 with a total installed capacity of 97,620 MW.

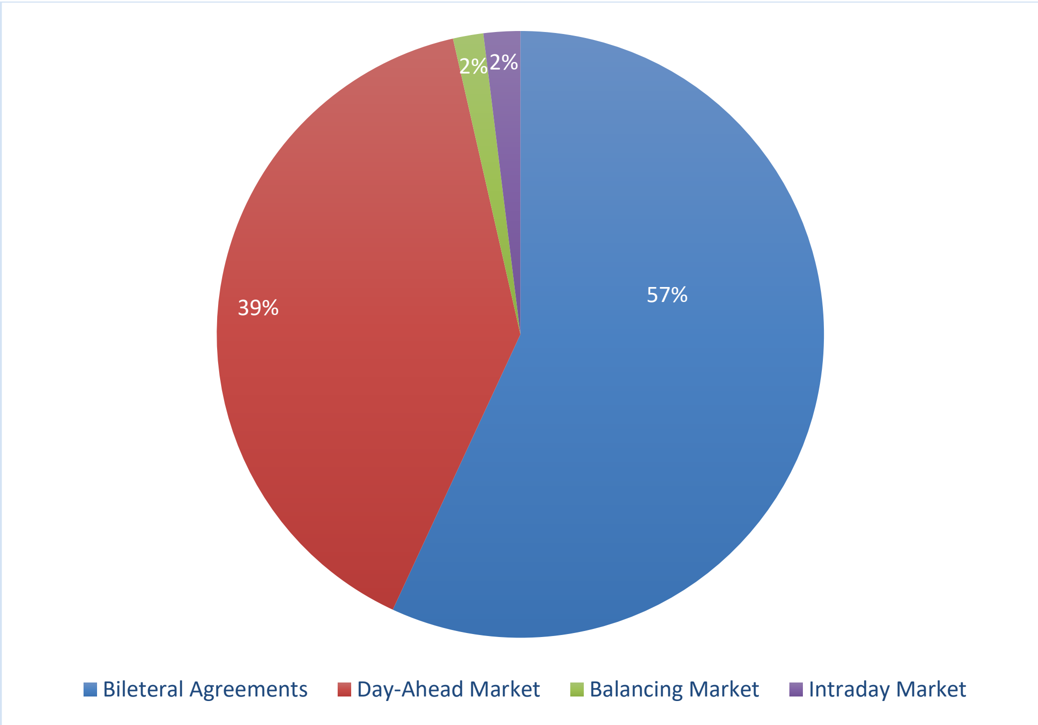

Figure 2. 5. June, 2021 Market Volume Share [34]

In Turkey, Law on Utilization of Renewable Energy Resources No (YEKDEM Law) [35] has undergone fundamental amendments in 2010 and the current legal background for mechanism to support renewable energy was laid down through these amendments.

Based on YEKDEM Law and Regulation on the Documentation and Supporting of the Renewable Energy Sources (YEKDEM Regulation) [36] the incentives for the use of renewables in power generation include Feed-in tariffs (FIT), purchase guarantees, connection priorities, lowered license fees, license exemptions etc.. YEKDEM Law provides a differentiated feed-in tariff (FIT) scheme for different types of renewable energy sources which will be commissioned till the end of 2020. The guaranteed prices are applicable for ten years after commissioning and are shown in Table 2.2.

Table 2. 2. Feed-in Tariffs Set by YEKDEM Law

Type of Renewable Energy Source	Feed-in Tariff (USD/MWh)
Hydro	73
Wind	73
Geothermal	103
Biomass	133
Solar	133

The incentive scheme introduced in 2010 has attracted little interest during the first years. However, eligible plants increasingly started to approach the mechanism due to two facts: First, the reference electricity prices emerged from the day-ahead market which is the market clearing price (MCP) stagnated. Second, US currency started to appreciate against the Turkish Lira (TL). Thus, the spread between the feed-in tariffs and the spot day-ahead prices (MCP) widened in the course of 2014 and 2015. Figure 2.6 depicts the MCP and the feed-in tariff levels for geothermal, wind/hydro and solar comparatively. MCP data has been received from the web page of EPIAS[37]. TL/USD average annual exchange rates are received from the web page of Turkish Central Bank [38].

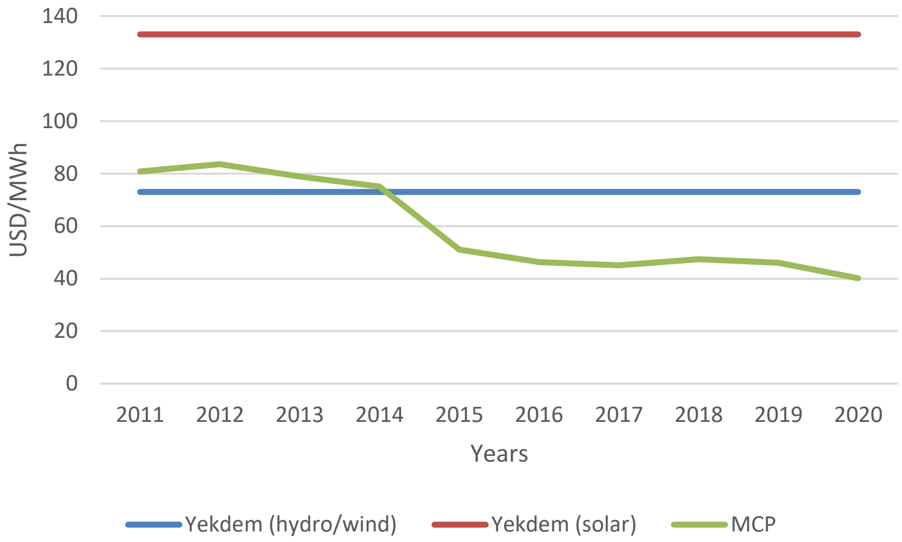

Figure 2. 6. Day Ahead Market Price (MCP) vs YEKDEM Prices

As depicted in the graph, in 2015 the average MCP revolved around US$51, whereas the feed-in tariffs has a constant value of 73 USD/MWh for hydro and wind and 133 USD/MWh for solar. The spread represents the extra revenue generated from participating within the YEKDEM portfolio. As the gap between the feed-in tariffs and MCP was widened; the installed capacity of renewable energy based power stations within YEKDEM increased substantially.

However; According to the Presential Decree published in Official Gazette on 30th of January[39], the new YEKDEM scheme will apply to power plants holding a Renewable Energy Source Certificate which will be commissioned between 1 July 2021 and 31 December 2025. The most significant novelty the Decree brings is basing YEKDEM feed-in tariff payments in TRY, which were previously denominated in USD. Similar to the previous structure, the feed-in tariff prices will vary for different types of renewable energy-based power plants, which are categorized under Annex 1 of Decree as hydroelectric, wind, geothermal, biomass and solar. The prices as of 1st of July 2021 are as shown in Table 2.3.

Table 2. 3. YEKDEM Prices as of 1st of July

Type of the Generation Facility	Price (TL/MWh)	Support Mechanism Period (Year)	Price Cap (USD /MWh)	Local Content Premium (TL/MWh)	Local Content Premium Period (year)
Hydro-electric	400	10	64	80	5
Wind	320	10	51	80	5
Geothermal	540	10	88	80	5
Biomass	320-540[2]	10	Between 51-86[2]	80	5
Solar	320	10	51	80	5

In addition, the guaranteed prices will be updated on a quarterly basis based on the inflation rate and change in exchange rates of euro and USD in compliance with the formula given in the Presidential Decree.

On the other hand, arithmetic average of hourly market clearing prices during July, 2021 was 537 TL/MWh according to the data published by EPIAS [37]. The current guaranteed prices are below the market clearing prices if the local content premium is not taken into account. However, the fact that the guaranteed prices will be renewed on a quarterly basis is another ambiguity for market players.

Turkey's total installed capacity including the renewable energy was 91,461 MW as of end of June, 2021[34]. The installed capacity of power stations benefitted from renewable energy support mechanism in 2021 is 24,568 MW comprising the 26.9% of total installed capacity based on the YEKDEM list published by EMRA[40].

[2] Depending on the type of resource

Concerns on the burden of such a substantially increasing YEKDEM volume are still among the most challenging topics in the Turkish power market. Considering that the peak load was 44,341 MW in 2016 and 15,083 MW renewable portfolios without balancing responsibility and with substantially higher guaranteed prices compared to day ahead market prices (MCP), the amendment in YEKDEM Regulation was published on 29th April 2016, and they became applicable for the 2016 portfolio as well. The fundamental changes are as follows:

- Eligible plants are expected to sell their generation on the free market including the bilateral market, the day-ahead market and the intra-day market.
- The spread between the feed-in tariff and the hourly day-ahead market price (which is apparently the MCP) is to be paid to the plants separately (or paid by the plants if MCP>FIT).
- The plants became responsible for balancing thus have to incur costs associated with imbalances.
- A tolerance coefficient is introduced.

Till the end of April 2016, on a yearly basis, the plants who participated the renewable energy support mechanism (RESM) were not allowed to exit the system or to sell on other platforms other than the portfolio. In return, the entire generation counted by their meters was purchased by the system operator according to the feed-in tariffs, leaving the plants without price, volume and currency risks. These plants were also exempt from balancing responsibility so were not obliged to forecast their future generation as well. In other words, there was no cost for imbalance between planned amount generation and realized amount of generation. Obligation to forecast came into force on 29th of April in 2016 in Turkey.

Among Council of European Energy Regulators (CEER) member countries, Renewable Energy Source (RES) producers independently of their size or technology face the same balancing responsibilities as conventional producers in 10 of the Member Countries (Belgium, Bulgaria, Estonia, Finland, Netherlands, Norway, Romania, Spain, Sweden and the UK). In 8 Member countries (Denmark, Hungary, France, Germany, Italy, Latvia, Luxemburg, and Portugal), only selected RES producers bear full balancing responsibilities. In parallel, all RES producers falling under a FIT scheme are exempted from balancing responsibilities in the abovementioned countries. In 9 Member Countries, no balancing responsibilities have been introduced for RES producers at all (Austria, Croatia, Cyprus, Czech Republic, Greece, Ireland, Lithuania, Malta, and Poland) [41]. In Turkey, FIT regime and balancing responsibility coexist unlike CEER member countries.

In Turkey, before the obligation for balancing responsibility, entire realized generation was purchased by the system operator at guaranteed prices without any obligation and concern of the power plants to forecast their generation.

After the introduction of balancing responsibility with the amendment in legislation, total income consists of 3 different income components.

The first component is the income from the day ahead market (IDAM) which is simply calculated by the multiplication of day ahead planned amount of generation (offered and accepted amount by market operator) with market clearing price (MCP).

Due to the fact that FIT regime and balancing responsibility coexist, the second component (COMP) is the income for the compensation of the difference between guaranteed price (GP) and MCP for realized generation (RG) and can be calculated for collaboration group c consisting of power plants g in period p as:

$$COMP_{p,c} = \sum_{g \in S^{cg}} RG_{p,c} \cdot [(GP_{p,g} \cdot PUSD_p) - MCP_p \cdot TC_g] \quad \text{Eq. 2.1}$$

Between 1st of May 2016 and 31st of December 2017 the tolerance coefficient (TC) was fixed and equal to 0.98 for all resource types. However, Turkish Energy Market Regulatory Authority (EMRA) has set different tolerance coefficients for different resource types; tolerance coefficients determined by Board Decision of EMRA [42] for each resource type as of 1st of January 2018 are given in Table-2.4:

Table 2. 4. Coefficient of Tolerance for Each Energy Type

Resource Type	Tolerance Coefficients
Channel type hydro	0.98
Hydro with Reservoir	1
Wind	0.97
Geothermal	0.995
Biomass	0.99
Solar	0.98

With the amendment in TC values depending on the type of renewable energy source, more flexibility has been given for WPPs and no flexibility has been given for HPPs with reservoir.

The third component is cash flow (CF) due to the imbalance between realized and planned amount of generation for collaboration group c in period p:

$$CF_{p,c} = [min\{XIA_{p,c}, 0\} \cdot max\{MCP_p, SMP_p\} \cdot (1 + IC)] + [max\{XIA_{p,c}, 0\} \cdot min\{MCP_p, SMP_p\} \cdot (1 - IC)] \quad \text{Eq. 2.2}$$

In order to avoid a possible arbitration between the day-ahead market and the balancing market, EMRA adopted a "min-max approach" when settling the imbalances. Given the fact that plants may be in a lack of generation or excess generation position in real time and they will be buying or selling on the balancing market where buying price would be max (MCP, SMP) and selling price would be min (MCP, SMP). That is, imbalances are being settled on a “buy expensive, sell cheap” approach. Thus, opportunity to profit from arbitrage between the day-ahead market and the balancing market is eliminated. In addition, imbalance coefficient (IC) represent monetary penalties applied for the imbalances. The authority to determine these coefficients belongs to EMRA Board. For the time being, IC have been set as 0.03 which means the cost of imbalance escalates three percent of MCP or SMP depending upon the position of the power plant and the values of MCP and SMP. If the imbalance coefficient is set to higher value, imbalance cost will increase accordingly and the forecasting to match realized generation with day ahead offered generation will be more critical for market players.

The core of the new system introduced by EMRA is the balancing responsibility. This will incur new costs for the power plants thus power plants with intermittent generation have to manage their production on an hourly basis or seek ways to participate in a balancing group.

In this chapter, brief information about the electricity market, Turkish electricity market structure and market outlook is provided in addition to the Turkish balancing and settlement mechanism with specific focus on day ahead market. In Chapter 3, the problem is defined, available data are analyzed and proposed methodology and models for each of the proposed strategies is explained.

CHAPTER 3

PROBLEM DEFINITION AND MODEL DEVELOPMENT

3.1. Problem Definition:

The intermittency in renewable energy generation is the main challenge for the optimal bidding in day ahead markets. Uncertainty creates imbalances between planned and realized power generation. This imbalance incurs cost for power plants. The complexity of preparing optimal bidding strategy for generation companies arises from the fact that they must make a decision based on imperfect information on market prices which are defined by the interaction of behavior of the offering strategy of market participants. In addition regulatory coefficients such as the coefficients to penalize imbalances and the tolerance coefficient specified by EMRA also have substantial impact on the bidding strategy of generation companies. Intermittency is not the same for different types of power plants participating in YEKDEM. For instance, it is reasonable to argue that hydro-power plants with reservoir or thermal power plants are less vulnerable compared to solar and wind. Thus, a constant tolerance coefficient will likely to leave some plants with extra costs incurred due to imbalances, while some plants with less intermittency will be handed over extra revenues. However; as of 1st of January 2018, EMRA has set different tolerance coefficients for each type of energy source as explained before. In addition, EPIAS allows power plants to participate in balancing groups to better mitigate individual imbalances. One of the most effective strategies to reduce the cost of imbalance and increase the profit is to set balancing groups and follow a combined bidding strategy for bidding and operating in day ahead market. Another possible strategy is the deployment of battery technologies. Conventional power plant’s main concern is the uncertainty of electricity prices, tolerance coefficients, and imbalance prices while the intermittency of generation is also a critical and additional concern for renewable energy producers. Therefore, an optimization model is needed to incorporate all the changing parameters such as:

- The coefficients to penalize imbalances and the tolerance coefficient specified by EMRA
- Differences in intermittencies in different types of renewable power plants which creates a potential to mitigate the cost of imbalance through balancing groups (such as wind power generation company may involve in a balancing group with hydro power generation company with reservoir)
- Differences in feed-in tariffs
- Continuously changing market clearing price (MCP) and system marginal price (SMP)
- Battery parameters

3.2. Available Data and Analysis of Data

Initially, the data regarding the hourly realized generation (RG), hourly day ahead planned generation (DAP) and offered prices for these hours for 20 hydropower plants (HPPs), 20 wind power plants (WPPs) and 1 solar power plant (SPP) were received for 8,760 hours of the year 2017. The data for all of these 40 plants were analyzed in detail and only 15 wind power plants with total installed capacity of 937 MW and 10 hydropower plants with an installed capacity of 311 MW were included in the scope of this study with respect to the quality of data. Having realized that these 10 HPPs have very limited reservoir capacity, a state owned HPP with large reservoir capacity is also included within the scope of this study. The available data are summarized in Table 3.1:

Table 3. 1. Available Data

Type of Power Plant	Number of Power Plant	Total Installed Power (MW)
Solar Power Plant	1	180*
Hydro Power Plants with limited reservoir capacity	10	311
Hydro Power Plants with large reservoir capacity	1	80
Wind Power Plants	15	937
Total	27	1,508

*This installed capacity and all real generation and day ahead planned amount of generation were multiplied by 20 and taken into account as 180 MW for the ease of calculations. The original and real installed capacity is 9 MW.

Hourly realized power generation (RG) and hourly day ahead planned generation (DAP) for the calendar year 2017 (8,760 hours) are available for each of these 27 power plants with a total installed capacity of 1,508 MW. All of these power plants are assumed to be price takers, since their total installed capacity of 1,508 MW is considerably low compared to the approximately 90,000 MW of total installed power in Turkey.

3.2.1. Analysis of Wind Power Plants:

Total annual realized generation for 15 WPPs with 937 MW of installed capacity is 2,639,801 MWh which is equal to a 28.2% capacity factor.

Cumulative hourly realized power generation for 15 WPPs in 2017 are shown in Figure 3.1. There are substantial variations in realized amounts of generation. Realized generation is comparatively higher in July.

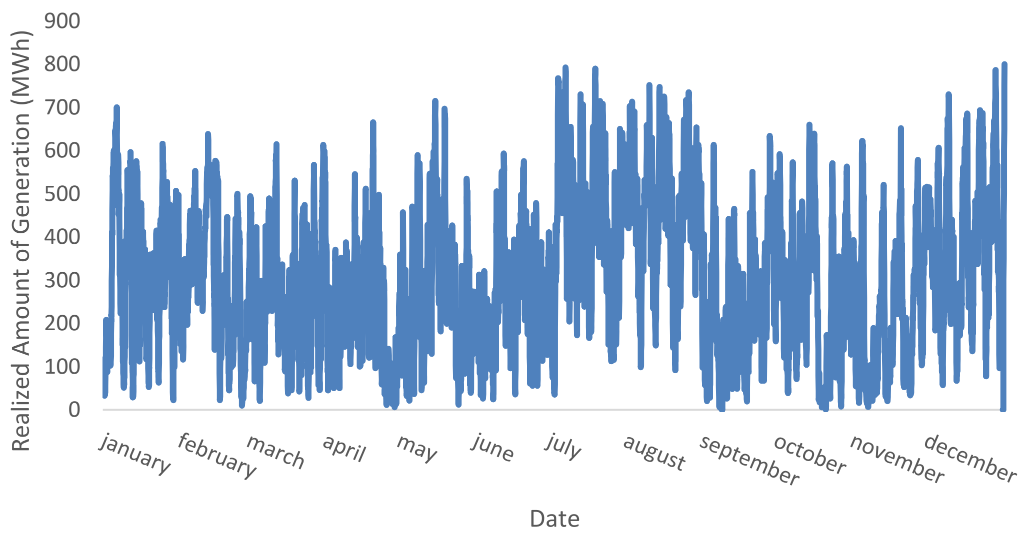

Figure 3. 1. The Distribution of Hourly Realized Generation Values for Wind Power Plants in 2017 (MWh)

Distribution of WPPs' realized energy generation is shown in Figure 3.2.

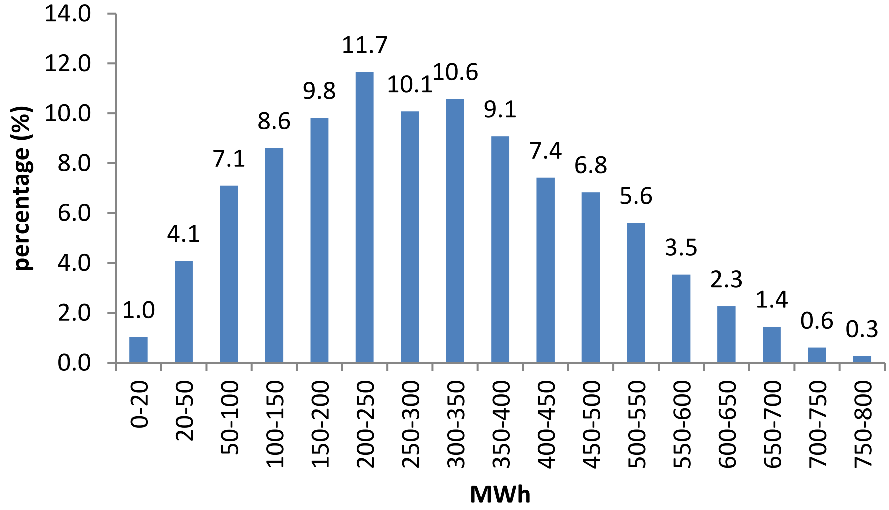

Figure 3. 2. Distribution of Hourly Realized Energy Generation Values for wind Power Plants with a Total Installed Capacity of 937 MWs

Percentage of deviation of realized generation from day ahead planned generation for WPPs are shown in Figure 3.3. The deviations show substantial variations but comparatively lower during July and August. During these months, day ahead expected power generation for WPPs seems to be more predictable.

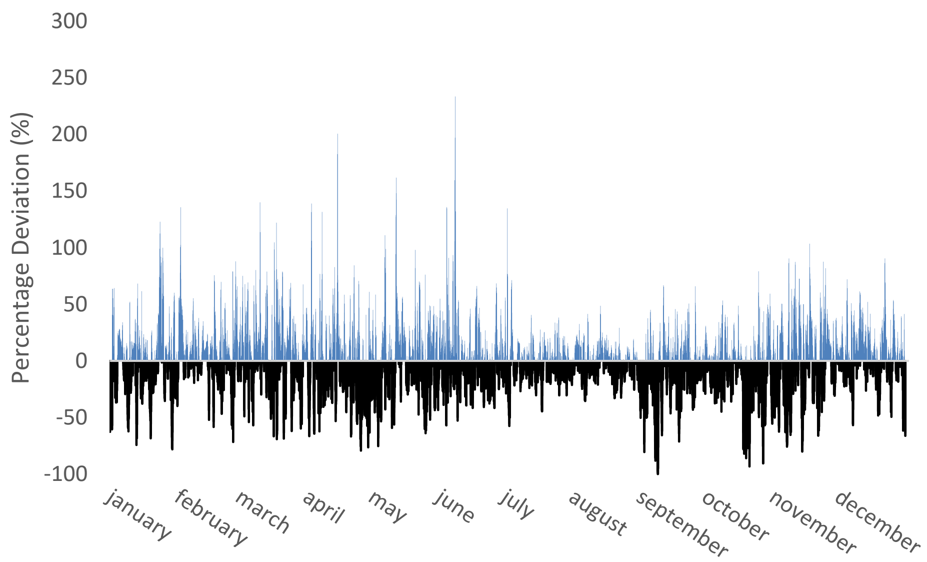

Figure 3. 3. Percentage of Deviation of Realized Generation from Day Ahead Planned Generation for WPPs with a Total Installed Capacity of 937 MWs

Imbalance happens when the realized generation is different than the day ahead planned generation, which is calculated by the difference between realized amount of generation and day ahead planned amount of generation (RG-DAP). The frequency distribution of imbalances for WPPs is depicted in Figure 3.4. Minus (-) values represent the cases when RG is less than the DAP (lack of generation) and plus (+) values represent the cases when there is an over generation.

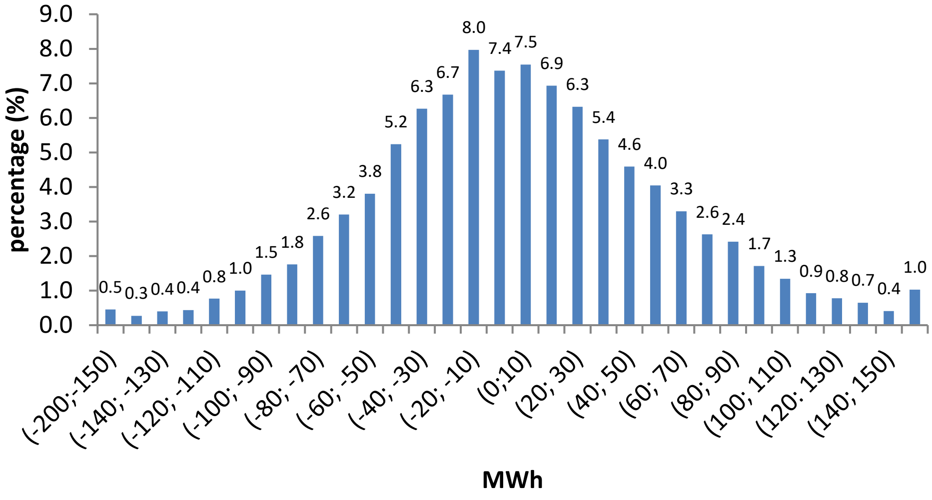

Figure 3. 4. Distribution of Hourly Imbalance Amounts for Wind power Plants with a Total Installed Capacity of 937 MWs

If the distribution of imbalances is analyzed, it is easily observable that the range of deviations is wide.

3.2.2. Analysis of Solar Power Plant:

Total annual realized amount of generation for Solar Power Plant with 180 MW of installed capacity is 300,706 MWh which is equal to a 19% capacity factor.

Distribution of daily sum of hourly realized amount of generation values for SPP is given in the Figure 3.5. Only non-zero values (4,599 data out of 8,760 data) are included. Zero values mostly belong to non-daylight hours

As expected; the generation values are more stable during the summer.

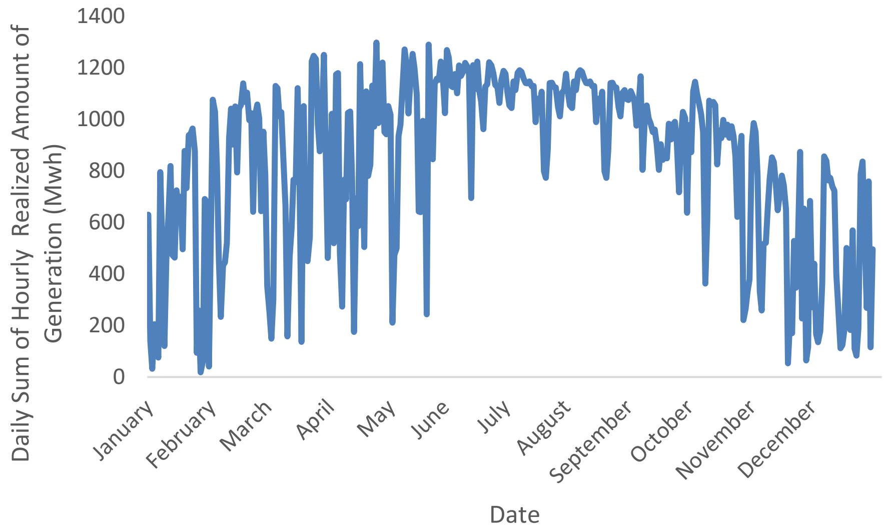

Figure 3. 5. The Distribution of Daily Sum of Hourly Realized Generation Values for Solar power Plant with a Total Installed Capacity of 180 MWs

The frequency distribution of realized amount of generation for SPP for the whole calendar year is shown in Figure 3.6. Only non-zero values (4,599 data out of 8,760 data) are included for the frequency distribution.

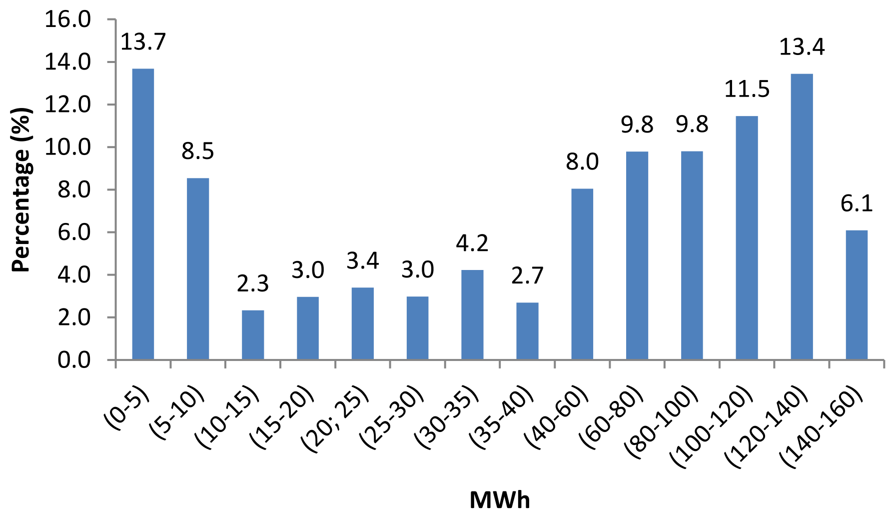

Figure 3. 6. Distribution of Hourly Realized Generation Values for Solar Power Plant with an Installed Capacity of 180 MWs

Percentage of Deviation of RG from DAP for SPP is given in Figure 3.7. Deviations are minimum from June to October.

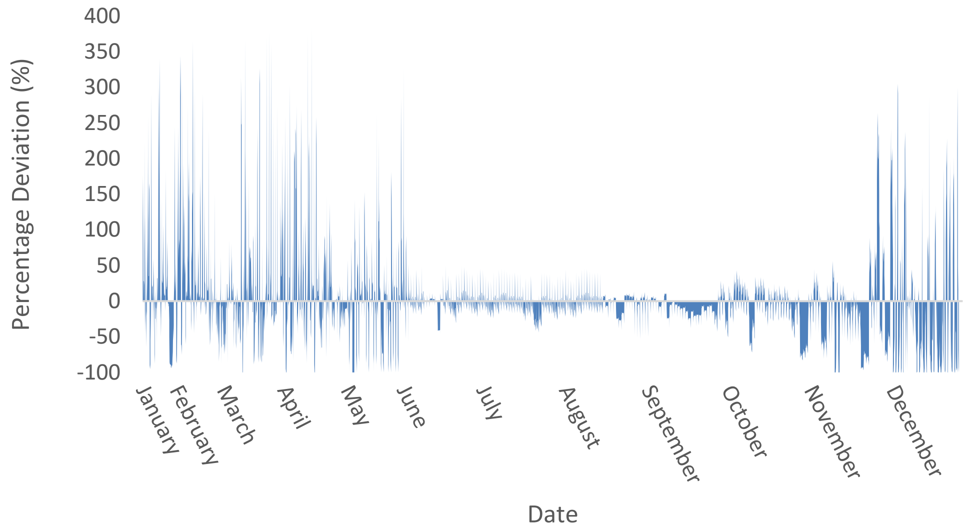

Figure 3. 7. Percentage of Deviation of Realized Generation from Day Ahead Planned Generation for Solar Power Plant

Frequency distribution of imbalance amount of solar power plant is depicted in Figure 3.8.

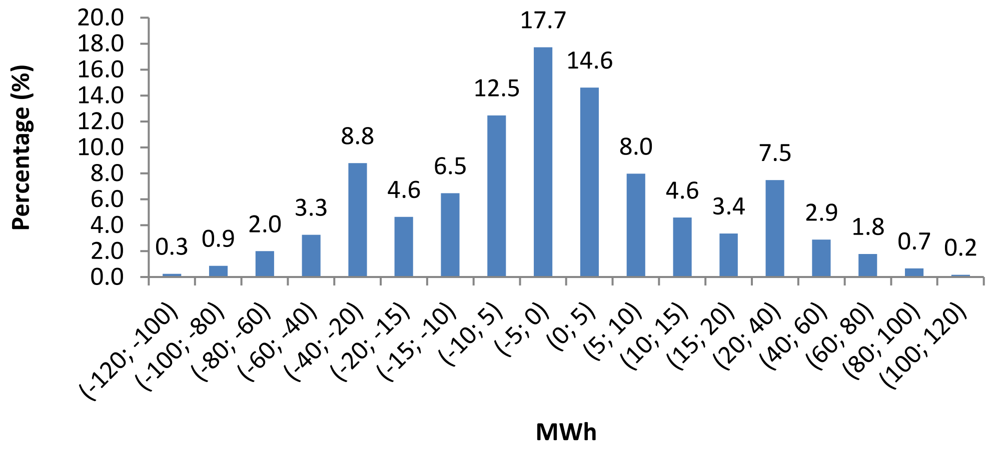

Figure 3. 8. Frequency Distribution of Amount of Imbalances for SPP

According to Figure 3.8, more than 50% of the time, imbalance amount is within the range of -10 and plus 10 MWh for the solar plant with an installed capacity of 180 MW.

3.2.3. Analysis of Hydropower Plants with Limited Reservoir Capacity

Total annual realized amount of generation for 10 hydro power plants with 311 MW of installed capacity is 753,785 MWh which is equal to a 27.7% capacity factor.

If the distribution of hourly realized amount of generation values of 10 hydropower plants is analyzed in Figure 3.9, it is clearly observable that the generation amount peaks in spring season when the incoming water to the reservoir is also higher due to the rains and the melting of the snow. This is an indication that these HPPs have mostly limited reservoir capacity since the power output is dependent on seasonal variation in river flow unlike the hydropower plants with large reservoir capacity.

From the beginning of March to the end of May there is a tendency of increase in the level of generation. May is the month with highest level of electricity generation. As of the beginning of June the peak generation starts to fall down.

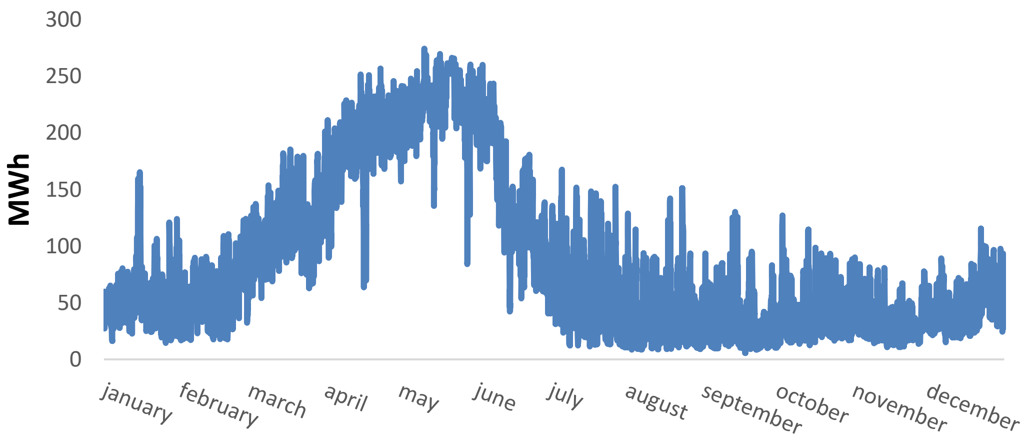

Figure 3. 9. The Distribution of Hourly Realized Generation Values of HPPs (MWh)

If the distribution of the hourly cumulative real generation of 10 hydropower plants (total installed power is 311 MW) is analyzed in Figure 3.10, it is clear that the real generation is between 0 and 50 MWh with 43.7% frequency and it is 25.7% for the interval between 50 and 100 MWh. In other words approximately 70% percent of the time hydropower plants generated less than 100 MWh.

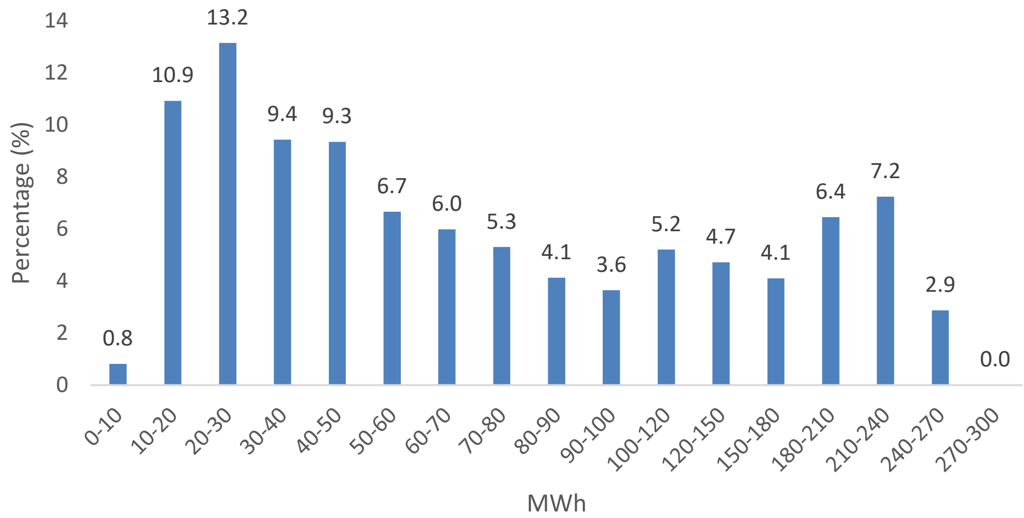

Figure 3. 10. The Distribution of Hourly Realized Generation Values of Hydro Power Plants with a Total Installed Capacity of 311 MW

Percentage of Deviation of Realized Generation from Day Ahead Planned Generation ($\frac{RG-DAP}{DAP} * 100$) for HPPs are shown in Figure 3.11. According to Figure 3.11, percentage of deviations are minimum from the beginning of March to mid of June when the generation peaks as given in Figure 3.10. Deviations are highest during July, August and September due to the lack water in the reservoir. This is an indication that when the reservoir lacks water, hydro power plants are non-dispatchable like the wind or solar power.

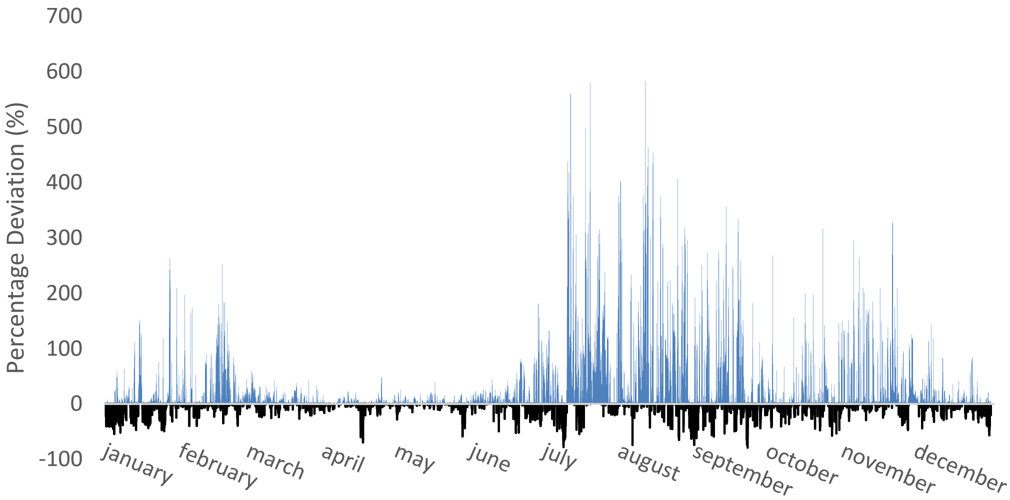

Figure 3. 11. Percentage of Deviation of Realized Amount of Generation from day Ahead Planned Amount of Generation for Hydro Power Plants with a Total Installed Capacity of 311 MW

According to the distribution of imbalances shown in Figure 3.12, realized generation was higher than the day ahead planned generation up to 5 MWh for 31.3% of the time in 2017. DAP was higher than RG up to 5 MWh for 24.4% of the time in 2017 as shown in Figure 3.12.

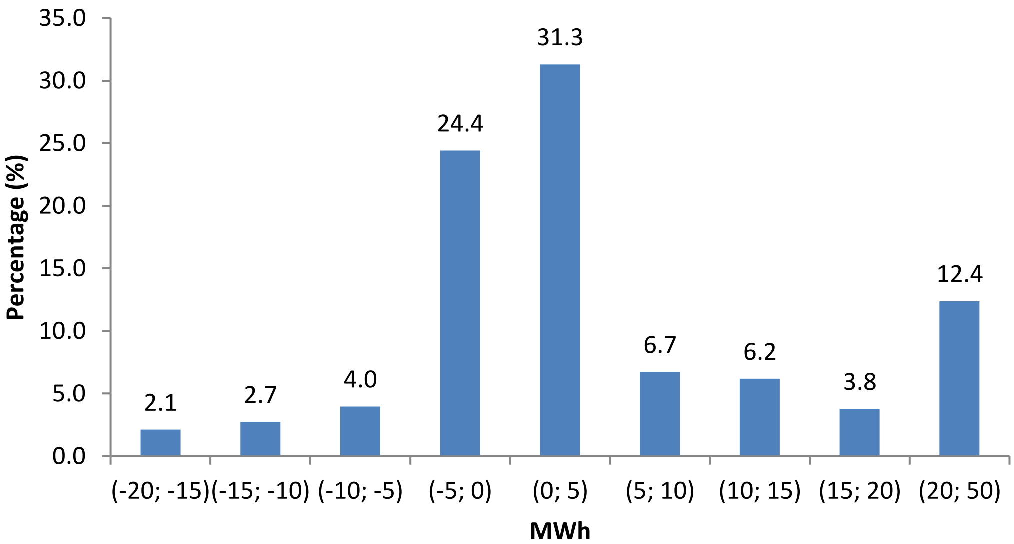

Figure 3. 12. Distribution of Hourly Imbalance Amounts for Hydro Power Plants with a Total Installed Capacity of 311 MW

In addition; if the deviations between realized generation and planned generation is reviewed for hydropower plants, positive deviations (real generation is higher than planned amount of generation) are more often compared to negative deviations.

3.2.4. Analysis of Hydropower Plant with Large Reservoir Capacity

Based on the available data set, total annual realized amount of generation for hydro power plant with large reservoir capacity and 80 MW of installed capacity is 406,041 MWh which is equal to a 58% capacity factor. This capacity factor is slightly more than the double of the capacity factor of 10 HPPs with limited reservoir capacity.

The HPP with large reservoir capacity is a state owned HPP with an installed power of 80 MW. Its reservoir volume is approximately 3 billion m^3. Its minimum allowed reservoir capacity is 1.67 billion m^3 and its maximum allowed reservoir capacity is 2.55 billion m^3.

If the hourly realized amount of power generation of the HPP is analyzed in Figure 3.13, it is clearly observable that the generation amount is more stable compared to the HPPs with limited reservoir capacity which is given in Figure 3.9.

In 877 hours of 8,760 hours of the calendar year 2017, realized generation and day ahead planned generation is equal to zero. In addition in April and November there are many occurrences (354 hours in November and 324 hours in June) of power interruption due to the maintenance works (mainly due to insufficient level of cooling water discharge) and restrictions related to the release of water to downstream

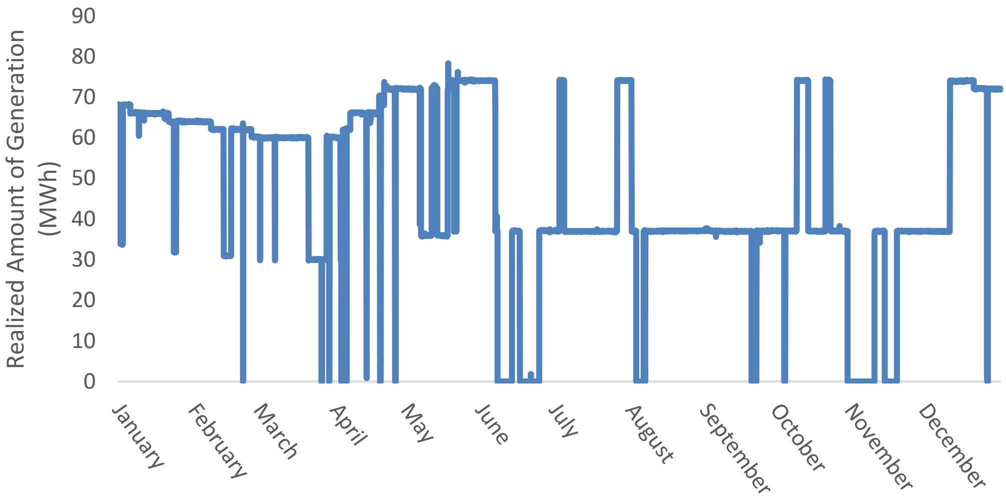

Figure 3. 13. The Distribution of Hourly Real Generation Values of Hydro Power Plant with a Total Installed Capacity of 80 MWs (MWh)

If the distribution of the hourly realized generation amounts of HPP with installed capacity of 80 MW) is analyzed in Figure 3.14, it is clear that the realized power generation is above 30 MWh with 88% frequency and it is 43% for the realized generation above 60 MWh.

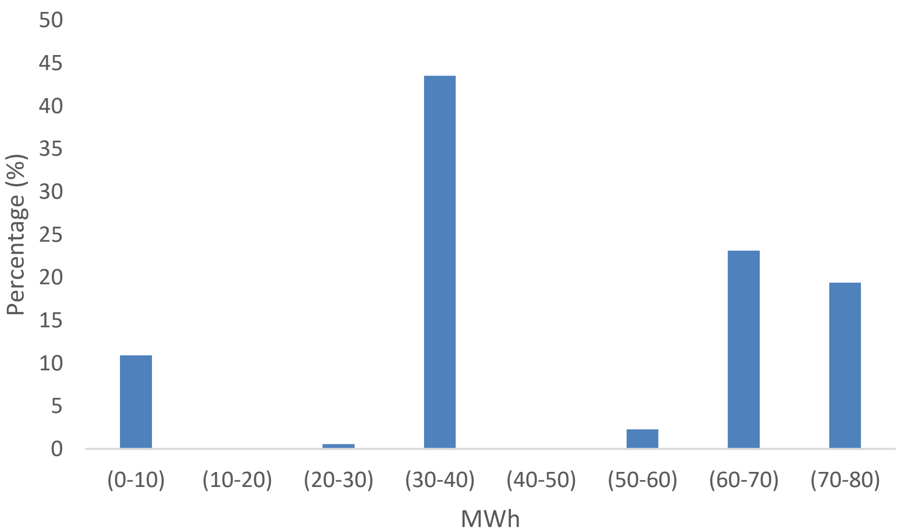

Figure 3. 14. The Distribution of Hourly Real Generation Values of Hydro Power Plant with a Total Installed Capacity of 80 MWs

Percentage of Deviations of RG from DAP ($\frac{RG-DAP}{DAP} * 100$) for HPP with large reservoir capacity are shown in Figure 3.15. According to Figure, occurrences of deviations are rare. This means generation amounts are mostly in compliance with the day ahead offered amount. Therefore, generation from this HPP can be considered as dispatchable energy resource. Among the 8,760 hours of the data set, there are 61 occurrences when the DAP is positive while the RG is equal to zero (deviations with -100%). The main causes of the -100% deviations are the insufficient level of cooling water and the unexpected events on the river bed (such as accidents) which prevents the operation of the HPP. There are 37 occurrences when the RG is positive while DAP is equal to zero. The main causes of these deviations are due to the early run or postponed stop of the units due to the demand for power for internal uses.

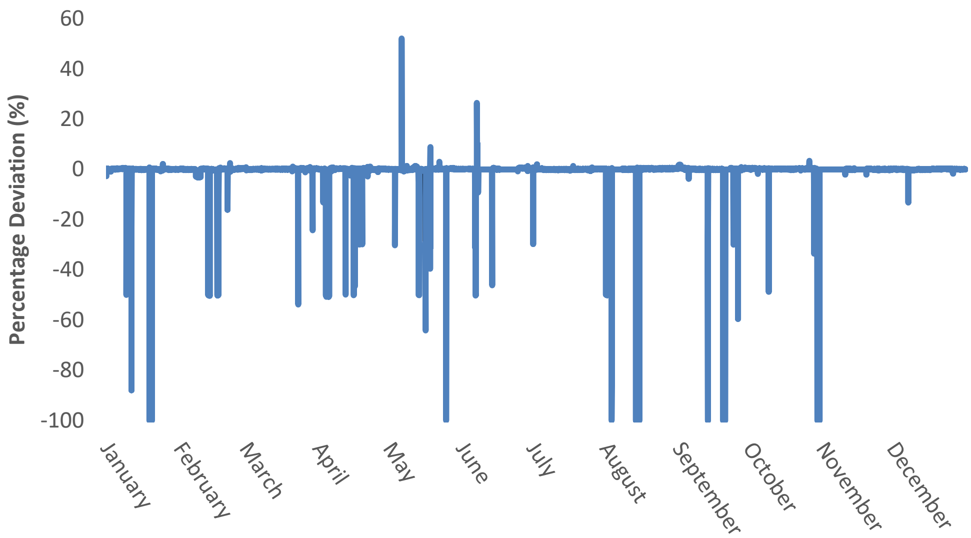

Figure 3. 15. Percentage of Deviation of RG from DAP for HPP

The generation output of HPP depends on the inflow to the water turbine and water level difference between forebay (the water reservoir) and the tailrace (the channel that carries water away from the water turbine) [20]. Since this HPP has large reservoir capacity, the impact of water level difference can be neglected. The piecewise linearized hydro unit performance curve is presented in Figure 3.16 to avoid computational burden caused by non-linearity. These curve represents the relation between water inflow to the turbine and power output. This curve is developed based on the data related to the daily amount of water inflow to the turbine and daily power output available in the data set.

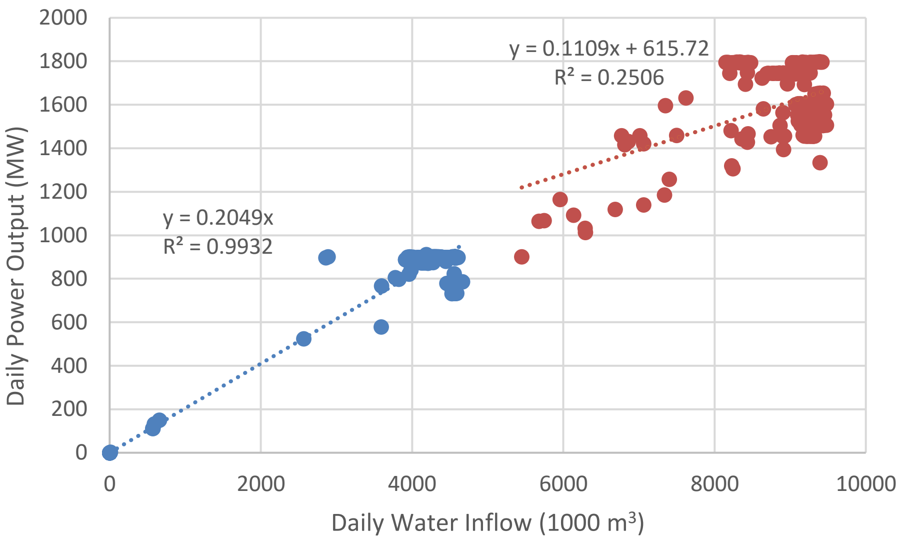

Figure 3. 16. Piece-wise Linearized Hydro-Unit Performance Curve

The slopes of these linearized Hydro-Unit performance curve represent the marginal efficiency. According to the linearized curve, threshold water inflow volume separating the low and high marginal efficiency curves is approximately 200,000 m^3 per day. Up to 200,000 m^3 per day, the marginal efficiency is 0.2049 MW day/ m^3, after this value it drops to 0.1109 MW day/ m^3. The decrease in water level due to the higher rate of water inflow to the turbine leads to the loss in marginal efficiency.

3.3. Methodology

According to the analysis of data for WPPs and SPP in the previous section, there are substantial deviations between RG and DAP values. Therefore, there are imbalances between RG and DAP and these imbalances lead to cost of imbalance in the day-ahead electricity market. There are 2 possible strategies for WPPs and SPP to minimize their imbalances:

1. Joint Bidding (JB) in DAM via collaboration by participating to balancing groups
2. Deployment of battery storage technologies

The data set covers the 27 different power plants (15 WPPs, 1 SPP, 10 HPPs with limited reservoir capacity and 1 HPP with large reservoir capacity).

3 different models will be developed for WPPs and SPP:

Joint Bidding Multi Hydro Model (JBMHM) (JB with HPPs with Limited Reservoir Capacity): The model for Joint Bidding via different collaboration groups including 10 HPPs with no or limited reservoir capacity

Joint Bidding Single Hydro Model (JBSHM) (JB with HPP with Large Reservoir Capacity): The model for Joint Bidding via different collaboration groups including the HPP with large reservoir capacity

Battery Deployment Model (BM): The model with the deployment of storage technologies.

The strategies to minimize imbalances and the models to be developed are categorized in Table 3.2.

Table 3. 2. Models to be Developed for Each Strategy

Strategy	**Models to be developed**
Joint Bidding in DAM via collaboration by participating to balancing groups	JBMHM (JB with HPPs with Limited Reservoir Capacity) and JBMSHM (JB with HPP with Large Reservoir Capacity)
Deployment of storage technologies	BM (Battery Deployment Model)

The data set of JBMHM, JBSHM and BM are given in Table 3.3.

Table 3. 3. The Data Set for Each Model

Model to be developed	Data set for the model
JBMHM	15 WPPs, 1 SPP, 10 HPPS with limited reservoir capacity
JBMSHM	15 WPPs, 1 SPP, 1 HPP with large reservoir capacity
BM	15 WPPs, 1 SPP and battery

The methodology for Joint Bidding Multi Hydro Model is given in Figure 3.17:

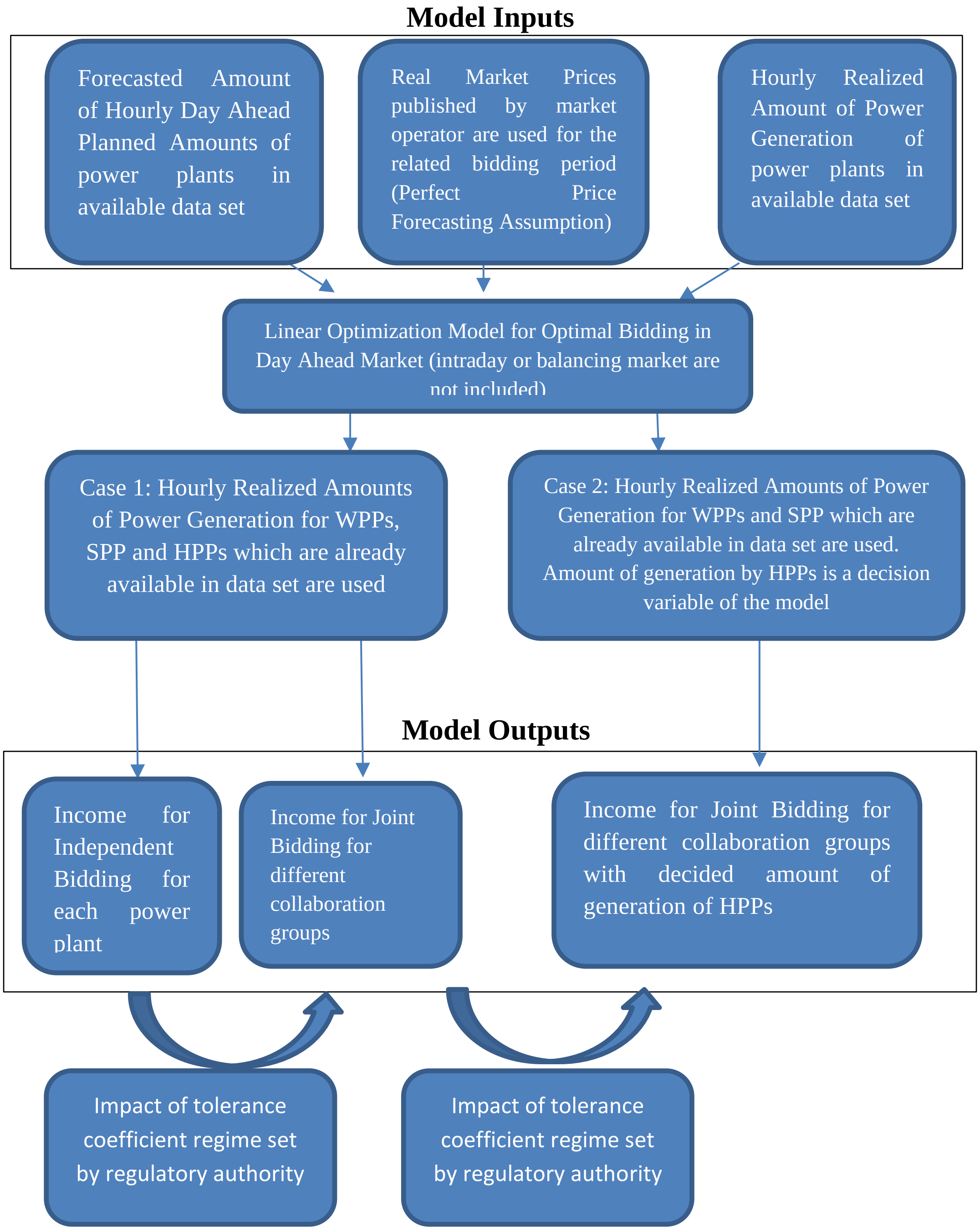

Figure 3. 17. Methodology for Joint Bidding Multi Hydro Model

As shown in Figure 3.17, forecasted and day ahead offered generation values by companies in data set are used assuming that these companies are already using the best available forecasting tools.

Perfect price forecasting is also assumed and the published market clearing and system marginal prices by market operator (EPIAS) are used in the model.

The model includes 2 different cases. In the first case, only the realized generation values of the power plants, which are already available in the data set, are used. In the second case, the amount of power generation by HPPs is identified as the decision variable and achieved by the model output.

Income with independent bidding of power plants are compared with the income achieved by the joint bidding for different collaboration groups for two different cases identified. The comparisons for both cases are also conducted for constant tolerance coefficient (CTC) regime and differentiated tolerance coefficient (DTC) regime to be able to analyze the impact of tolerance coefficient regimes set by the regulatory authority on the outcomes of joint bidding.

Therefore, JBMHM is developed to see the impact of joint bidding for 2 different cases with different tolerance coefficient regimes set by EMRA to be able to analyze:

- The impact of joint bidding on income for different collaboration groups.
- The impact of different tolerance coefficients regimes set by EMRA on the incomes achieved by joint bidding for different collaboration groups (how the outcomes of the joint biddings are effected by the different tolerance coefficient regimes.)

The methodology for JBSHM is given in Figure 3.18.

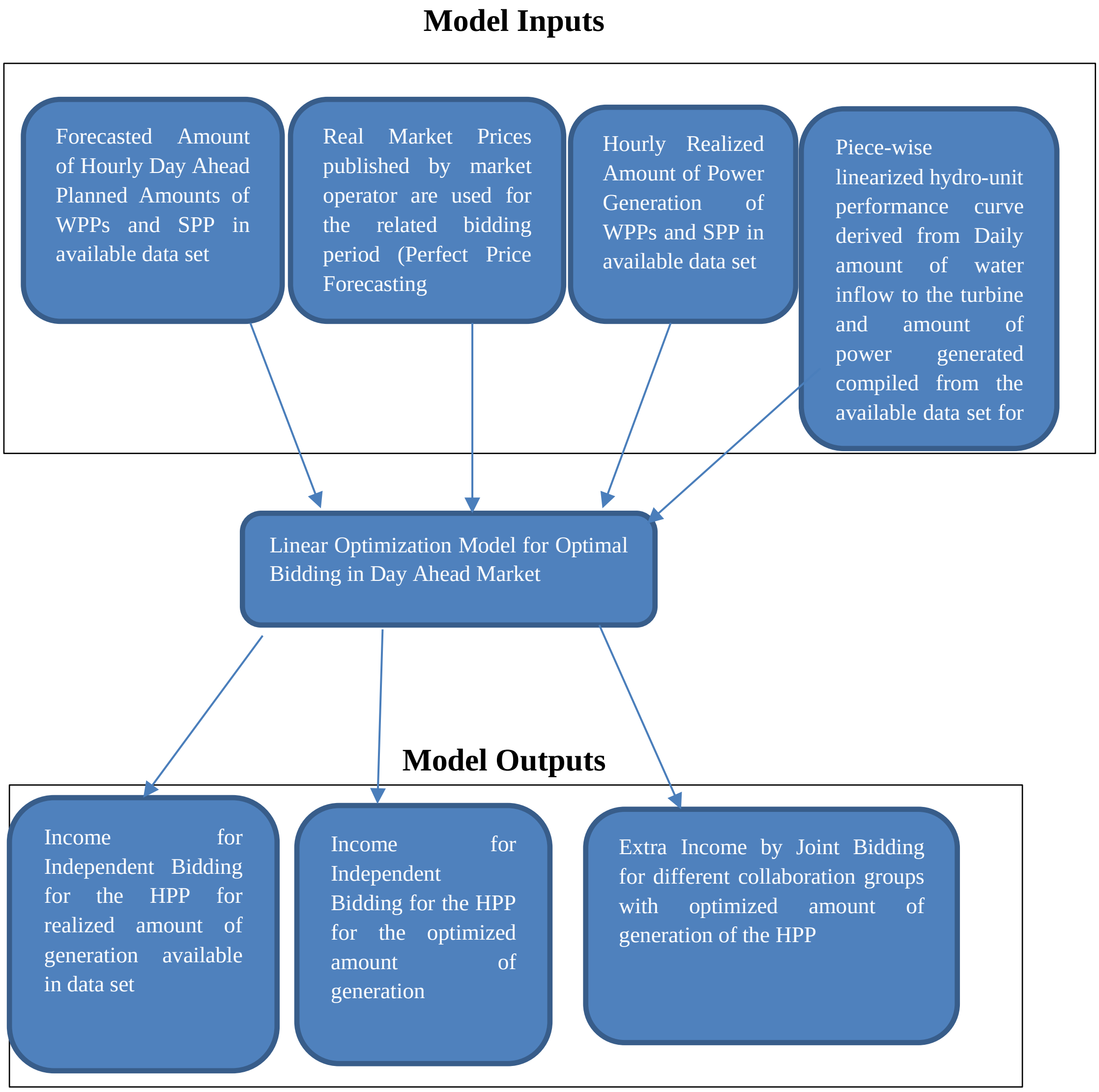

Figure 3. 18. Methodology for Joint Bidding Single-Hydro Model

As shown in Figure 3.18, in JBSHM (similar to JBMHM), rather than deploying forecasting tools, forecasted and day ahead offered generation by companies in data set are used assuming that these companies are already using the best available forecasting tools for their planned amount of generation. Perfect price forecasting is also assumed and the published market clearing and system marginal prices by market operator (EPIAS) are used in the model.

The model includes 2 different cases. In the first case, only the realized amount of generation values of the power plants, which are already available in the data set, are used. In the second case, the amount of power generation by HPPs is identified as the decision variable and achieved by the model output.

Income with independent bidding of power plants are compared with the income achieved by the joint bidding for different collaboration groups for two different cases identified. The comparisons for both cases are also conducted for CTC regime and DTC regime to be able to analyze the impact of tolerance coefficient regimes set by the regulatory authority on the outcomes of joint bidding.

Therefore, JBSHM is developed to see the impact of joint bidding for 2 different cases with different tolerance coefficient regimes set by EMRA to be able to analyze:

- The impact of joint bidding on income for different collaboration groups.
- The impact of different tolerance coefficients regimes set by EMRA on the incomes achieved by joint bidding for different collaboration groups (How the outcomes of the joint biddings are effected by the different tolerance coefficient regimes).

The methodology for Battery Deployment Model is given in Figure 3.19.

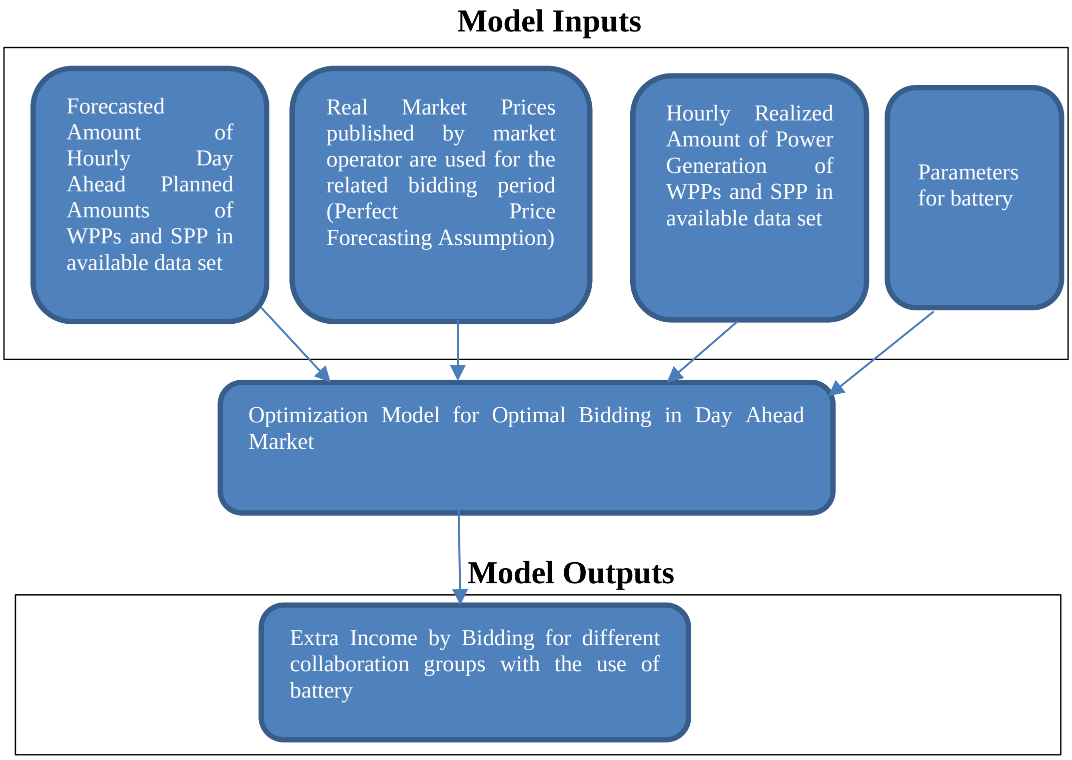

Figure 3. 19. Methodology for Battery Deployment Model

3.4. Model Development:

As described in Section 2.3, 3 different models will be developed.

There are 15 WPPs and 1 SPP within the scope of this study. These WPPs and SPP can participate a balancing group with

- 10 HPPs with limited reservoir capacity (JBMHM),
- 1 HPP with large reservoir capacity (JBSHM)

Or they may bid in Day-Ahead Market with the use of battery (BM).

The results of JBMHM and JBSHM will reveal about the impact of reservoir capacities of HPPs on the income gains through joint bidding in Day-Ahead

Market via different collaboration groups with WPPs and SPP for different tolerance coefficient regimes.

Battery Deployment Model will reveal about the possible income gains for WPPs and SPP with the deployment of battery in Day-Ahead Market.

Based on the comparison of the results of these 3 different models, different strategies for WPPs and SPP will be assessed.

Sets, parameters and decision variables used for Joint Bidding Models and Battery Deployment Model are described in Nomenclature.

NOMENCLATURE

SETS		
S^d	=	$\{d: 1, \dots, d, \dots, 365\}$ set of days
S^t	=	$\{t: 1, \dots, t, \dots, 24\}$ set of hours
S^p	=	$\{p: 1, \dots, p, \dots, 365 * 24\}$ set of all hourly time slots of a year
S^h	=	$\{h: 1, \dots, h: \dots, H\}$ set of Hydropower plants
S^w	=	$\{w: 1, \dots, w, \dots, W\}$ set of Wind power plants
S^s	=	$\{s: 1, \dots, s, \dots, S\}$ set of Solar power plants
S^g	=	$\{g: 1, \dots, g, \dots, H + W + S\}$ set of all generation plants
S^g	=	$\{g: 1, \dots, H, H + 1, H + 2, \dots, H + W, H + W + 1, \dots, H + W + S\}$
For any collaboration, the following set of definitions are used:		
S^c	=	$\{c: 1, \dots, c, \dots, C\}$ set of collaborations
S^{cg}	=	$\{(c, g)\}$ set of generation plants existing in collaborations
S^{w-bat}	=	$\{w: w \in S^w\}$ set of WPPs with battery
S^{w-bat}	$\subseteq$	S^W
S^{s-bat}	=	$\{w: w \in S^s\}$ set of SPPs with battery
S^{s-bat}	$\subseteq$	S^S

PARAMETERS		
MCP_p	:	Market Clearing Price in period p (USD/MWh)
SMP_p	:	System Marginal Price in period p (USD/MWh)
$RG_{p,g}$	:	Real generation for plant g in period p (MWh)
$DAP_{p,g}$	:	Day − ahead planned generation for plant g in period p (MWh)
GP_g	:	Guaranteed Price for plant g (USD/MWh)
TC_g	:	Tolerance Coefficient for plant g determined by Energy Market Regulatory Authority
IC	:	Coefficient of imbalance determined by Energy Market Regulatory Authority
$IDAM_{p,g}$	:	Income of plant g from Day Ahead Market (DAM)sales in period p (USD)
$MAXI_{p,g}$	:	Maximum Achievable Income, which happens in case of perfect forecasting, of plant g from Day Ahead Market (DAM)sales in period p (USD)
$LOSSI_{p,g}$	:	Loss of Income of plant g from Day Ahead Market (DAM)sales in period p (USD) due to imbalance
$CAP_{d,g}$	:	Maximum amount of hourly realized amount of generation within day d for HPP g
$IA_{p,c}$	:	is the amount of imbalance between decided amount of generation and day ahead planned amount of generation for collaboration c in period p (MWh).
ME_g^{low}	:	Marginal efficiency of HPP with reservoir for low water inflow (MWh day/m^3)
ME_g^{high}	:	Marginal efficiency of HPP with reservoir for high water inflow (MWh day/m^3)
FR_g^{th}	:	Threshold water inflow level separating low and high marginal efficiencies (m^3/day)
PO_g^{th}	:	Threshold power output level separating low and high marginal efficiencies (MW)
FR_g^{max}	:	Maximum water inflow rate level for HPP g (m^3/day)
PO_g^{max}	:	Maximum power output level for HPP g (MW)
$w_{0,g}$	:	Initial water volume in reservoir of HPP g (m^3)
$IW_{d,g}$	:	Incoming Water volume to the reservoir of HPP in day d (m^3)
RV_g^{min}	:	Minimum required water volume of reservoir of HPP g (m^3)
RV_g^{max}	:	Maximum allowed water volume of reservoir of HPP g (m^3)
PW^{dc-max}	:	Maximum power from the battery (discharge) (MWh)

PW^{ch-max}	:	Maximum power to the battery (charge) (MWh)
ES^{max}	:	Maximum amount of energy that can be stored in battery (MWh)
η^{ch}	:	Charging efficiency of the battery
η^{dc}	:	Discharging efficiency of the battery
e_0	:	Initial amount of energy that is stored in battery (MWh)
DECISION VARIABLES		
$X_{p,g}$	:	Decided generation for plant g in period p (MWh)
$COMP_{p,c}$	:	Amount of compensation provided for YEKDEM participants for collaboration c in period p for the difference between guaranteed price and market clearing price taking into account the tolerance coefficient (USD).
$CF_{p,c}$	:	Cash − Flow for collaboration c in period p due to imbalance (USD) If the real generation is higher than the day ahead planned amount of generation, the excess amount is bought by the market with the minimum of market clearing price and system marginal price and if the real generation is less the remaining amount is purchased from the market with the maximum of market clearing price and system marginal price taking into account the coefficient of imbalance determined by Energy Market Regulatory Authority.
$IA_{p,g}$	:	Amount of imbalance between decided amount of generation and day ahead planned amount of generation.
$TOTI_{p,c}$	:	Total Income of plant g in period p (USD)
ME_g^{low}	:	Marginal efficiency of HPP g for low water inflow (MWh day/m^3)
ME_g^{high}	:	Marginal efficiency of HPP g for high water inflow (MWh day/m^3)
FR^{th}	:	Threshold water inflow level separating low and high marginal efficie (m^3/day)
PO_g^{th}	:	Threshold power output level seperating low and high marginal efficiency for HPP g (MW)
FR_g^{max}	:	Maximum water inflow rate level for HPP g (m^3/day)
PO_g^{max}	:	Maximum power output level for HPP g (MW)
$w_{d,g}$	:	Water volume in reservoir of HPP g at the end of day d (m^3)
$u_{p,g}$	:	Water volume used for power generation at HPP g in period p (m^3)
$b_{p,g}$	=	$\begin{cases} 1 & \text{if } u_{p,g} \text{ is larger than } FR_g \\ 0 & \text{otherwise} \end{cases}$
$s_{d,g}$	:	Spilled water volume in reservoir of HPP g in day d (m^3)
a^0_{pg}, a^1_{pg}, a^2_{pg}	:	Positive variables less than or equal to 1 used for piecewise function
$PW^{dc}_{p,g}$	:	Power transferred from the battery to generation plant g in period p

$PW^{ch}_{p,g}$	:	Power transferred to the battery from generation plant g in period p
TPW^{dc}_{p}	:	Total power transferred from the battery in period p (MWh)
TPW^{ch}_{p}	:	Total power transferred to the battery in period p (MWh)
e_p	:	Amount of energy that is stored in battery in period p (MWh)

3.4.1. Development of Joint Bidding Multi Hydro Model

JBMHM covers the joint bidding of the SPP, 15 WPPs and 10 HPPs, which have limited reservoir capacity, for different collaboration groups.

The installed capacities of the power plants within the scope of the data set for Joint Bidding Multi Hydro Model is given in Table 3.4.

Table 3. 4. The Installed Capacities of Power Plants in Data Set of Joint Bidding Multi Hydro Model

Type of Power Plant	Number of Power Plants	Total Installed Power (MW)
HPPs with limited reservoir capacity	10	311
WPPs	15	937
SPP	1	180
Total	**26**	**1,197**

Linear optimization model has been developed considering the scope of available data which are based on the hourly bids in day ahead market and hourly realized generation for the calendar year 2017. Hourly market clearing prices and system marginal process are received from EPIAS.

Objective Function of JBMHM

$$Max\ Z = \sum_c \sum_p TOTI_{p,c} \qquad \text{Eq. 3.1}$$

Objective is to maximize the total income of collaboration group c for period p.

$c = 1$ defines the collaborations of all Hydro plants, so the set of collaborations is as follows: $S^{cg} = \{(c, g): (1,1), (1,2), \ldots, (1, H)\}$ for Hydro plants, where H represents the number of hydropower plants, and continues as $\{(2, H + 1), (3, H + 2), \ldots, (W + S + 1, H + W + S)\}$, which indicates each generation plant (which is NOT a hydro plant) belongs to a separate collaboration set, i.e., it does not collaborate (W represents the number of wind power plants and S represents the number of solar power plants).

Constraints of Joint Bidding Multi Hydro Model

$X_{p,g} = RG_{p,g}\ \forall p\ and\ g \in w(g) or\ s(g)$ Generation amounts cannot be decided for solar or wind due their stochastic nature. Therefore, realized hourly power generation available in data set will be used for WPPs and SPP.	Eq. 3.2
$X_{p,g} \leq CAP_{(d),g}$ The maximum amount of hourly generation possible for HPPs for a calendar day is the maximum amount of hourly realized amount of generation within that day (based on the realized generation available in data set).	Eq. 3.3
$\sum_{p \in d(p)} X_{p,g} \leq \sum_{p \in d(p)} RG_{p,g}\ where\ g \in h(g)$ The total daily realized amount of generation (based on the realized generation available in data set) is an upper bound for the sum of hourly decisions of HPP for the same day since the HPPs have limited reservoir capacity.	Eq. 3.4
$COMP_{p,c} = \sum_{g \in S^{cg}} X_{p,c} \cdot [(GP_{p,g}) - MCP_p \cdot TC_g]$	Eq. 3.5
$CF_{p,c} = [min\{IA_{p,c}, 0\} \cdot max\{MCP_p, SMP_p\} \cdot (1 + IC)] + [max\{IA_{p,c}, 0\} \cdot min\{MCP_p, SMP_p\} \cdot (1 - IC)]$	Eq. 3.6
$TOTI_{p,c} = \sum_{g \in S^{cg}} IDAM_{p,g} + COMP_{p,c} + CF_{p,c}$	Eq. 3.7

$IA_{p,c} = IA^{+}_{p,c} - IA^{-}_{p,c}$	Eq. 3.8
$IA_{p,c} = \sum_{g \in S^{cg}} X_{p,g} - \sum_{g \in S^{cg}} DAP_{p,g}$	Eq. 3.9
$MAXI_{p,g} = RG_{p,g} \cdot MCP_p + COMP_{p,g}$	Eq. 3.10
$LOSSI_{p,g} = MAXI_{p,g} - TOTI_{p,g}$	Eq. 3.11
$IDAM_{p,g} = DAP_{p,g} \cdot \ MCP_p$	Eq. 3.12

The model has been run for 2 different cases for different collaboration scenarios. As stated before, generation amount cannot be decided for solar or wind. However, hydropower plants have the capability to adjust their level of generation.

Case 1: In the first case only the hourly realized amounts of power generation which are already available in data set for year 2017 have been used for 15 WPPs, 10 HPPs and 1 SPP.

1^{st}Constraint (Eq. 3.2) of JBMHM is changed as follows:

$X_{p,g} = RG_{p,g} \; \forall g, p$	Eq. 3.13

Case:2: In the second case HPPs are given flexibility to make a decision for their hourly generation amount subject to 1 st, 2nd and 3 rd constraints (Eq. 3.2, Eq. 3.3 and Eq. 3.4).

It is assumed that generation amount cannot be decided (adjusted) for SPP or WPPs unlike HPPs as specified in 1^{st} Constraint (Eq. 3.2) of the model.

$$X_{p,g} = RG_{p,g} \; where \; g \in w(g) or \; s(g)$$

The input data of Joint Bidding Multi Hydro Model covers hourly RG, DAP, SMP and MCP values for the SPP, HPPs and WPPs.

3.4.2. Development of Joint Bidding Single Hydro Model

JBSHM covers the joint bidding of the SPP and 15 WPPs with HPP with reservoir.

The data set also covers the volume of water inflow to the turbine and the power output associated with water inflow. Therefore, piece-wise linearized hydro-unit performance curve is developed and the parameters for the development of this curve are included in JBSHM. Since reservoir capacity is considered as a constraint, initial reservoir capacity, incoming water to the reservoir, minimum and maximum allowed reservoir capacities are also included as parameters in JBSHM.

Due to the existence of piece-wise linearized hydro-unit performance curve for the HPP, Mixed Integer Linear Optimization Model is developed for JBSHM.
In JBSHM, in addition to the decision variables associated with income, water volume in reservoir, volume of water inflow to the turbine for power generation are defined as the decision variables as well as the variables associated with the piece-wise linearized hydro-unit performance curve ($b_{p,r}$ and $a_{p,r}$)as described in nomenclature. In case that the maximum allowed reservoir capacity is exceeded, spilled water volume is also included in the model as a decision variable.

Objective Function of JBSHM

$$Max\ Z = \sum_c \sum_p TOTI_{p,c} \qquad \text{Eq. 3.14}$$

Objective is to maximize the total income of collaboration group c for period p.

$c = 1$ defines the collaborations of all Hydro plants, so the set of collaborations is as follows: $S^{cg} = \{(c, g): (1,1), (1,2), \ldots, (1, H)\}$ for Hydro plants, where H represents the number of hydropower plants, and continues as $\{(2, H + 1), (3, H + 2), \ldots, (W + S + 1, H + W + S)\}$, which indicates each generation plant (which is NOT a hydro plant) belongs to a separate collaboration set, i.e., it does not collaborate (W represents the number of wind power plants and S represents the number of solar power plants).

Constraints of JBSHM

The first constraint is based on the assumption that WPPs and the SPPs can not adjust their generation amount due to stochastic nature of their generation output unlike the HPP whose generation output is defined as a decision variable and achieved by the model. Constraint sets from Eq. 3.15 to Eq. 3.22 are related to the income calculations in day ahead market. Since the HPP has large reservoir, it is assumed that there is no imbalance for the HPP and the realized generation is used for the income calculation for the HPP instead of day ahead planned generation (Eq. 3.22).

Constraints from Eq. 3.23 to Eq. 3.31 are related to the piece-wise linearized hydro-unit performance curves for the HPP. Constraint Eq. 3.32 is related to the reservoir volume conservation equation. Water volume in reservoir of HPP r at the end of day d is equal to the reservoir volume in previous day (d-1), plus incoming water to the reservoir in day d, minus water inflow to the turbine in day d, minus spilled amount of water in day d. Constraint Eq. 3.33 and Eq. 3.34 are the lower and upper bounds for reservoir volume.

$x_{p,g} = RG_{p,g}\ \forall p\ and\ g \in w(g) or\ s(g)$	Eq. 3.15
$Comp_{p,c} = \sum_{g \in S^{cg}} x_{p,c} \cdot [(GP_{p,g}) - MCP_p \cdot TC_g]$	Eq. 3.16
$Cf_{p,c} = [min\{IA_{p,c}, 0\} \cdot max\{MCP_p, SMP_p\} \cdot (1 + IC)] + [max\{IA_{p,c}, 0\} \cdot min\{MCP_p, SMP_p\} \cdot (1 - IC)]$	Eq. 3.17
$TOTI_{p,c} = \sum_{g \in S^{cg}} IDAM_{p,g} + COMP_{p,c} + CF_{p,c}$	Eq. 3.18
$IA_{p,c} = IA^{+}_{p,c} - IA^{-}_{p,c}$	Eq. 3.19
$IA_{p,c} = \sum_{g \in S^{cg}} X_{p,g} - \sum_{g \in S^{cg}} DAP_{p,g}$	Eq. 3.20
$IDAM_{p,g} = DAP_{p,g} \cdot\ MCP_p\ \forall p\ and\ g \in S^w\ or\ S^s$	Eq. 3.21
$IDAM_{p,g} = x_{p,g} \cdot MCP_p\ \forall p\ and\ g \in S^h$	Eq. 3.22
$a^0_{p,g} \leq (1 - b_{p,g})$	Eq. 3.23
$a^1_{p,g} \leq 1$	Eq. 3.24
$a^2_{p,g} \leq b_{p,g}$	Eq. 3.25
$a^0_{p,g} + a^1_{p,g} + a^2_{p,g} = 1$	Eq. 3.26
$u_{p,g} = a^0_{p,g} \cdot 0 + a^1_{p,g} \cdot FR^{th}_g + a^2_{p,g} \cdot FR^{max}_g$	Eq. 3.27
$x_{p,g} = a^0_{p,g} \cdot 0 + a^1_{p,g} \cdot PO^{th}_g + a^2_{p,g} \cdot PO^{max}_g$	Eq. 3.28
$FR^{th}_g \cdot b_{p,g} \leq u_{p,g}$	Eq. 3.29
$PO^{th}_g = FR^{th}_g\ \cdot\ ME^{low}_g$	Eq. 3.30
$u_{p,g} - FR^{th}_g \leq FR^{max}_g \cdot b_{p,g}$	Eq. 3.31
$w_{d,g} = w_{d-1,g} - \sum_{p \in S^p_d} u_{p,g} + IW_{d,g} - s_{d,g}$	Eq. 3.32
$w_{d,g} \geq RV^{min}_g$	Eq. 3.33
$w_{d,g} \leq RV^{max}_g$	Eq. 3.34

JBSHM has been run for different collaboration scenarios. As stated before, generation amount cannot be decided for SPP or WPPs. However, HPP has the capability to adjust its level of power generation due to its reservoir capacity. The impact of joint bidding of SPP and WPPs with HPP is aimed to be analyzed with JBSHM.

The input data of JBSHM covers hourly RG, DAP, SMP and MCP for the SPP and WPPs, SMP, MCP and the values given in Table 3.5 for the HPP.

Table 3. 5. Model Input Values for the HPP

Low marginal efficiency (MW.day)/m^3	ME^{low}_g	0.0046
High marginal efficiency (MW.day)/m^3	ME^{high}_g	0.0085
Threshold flow rate (million m^3/day)	FR^{th}_g	5.45
Threshold power output (MW)	PO^{th}_g	50
Maximum Flow rate (million m^3/day)	FR^{max}_g	9.38
Maximum power output (MW)	PO^{max}_g	75
Initial volume of reservaur billion (m^3)	$w0_g$	1.88
Minimum reservour volume billion (m^3)	RV^{min}_g	1.67
Maximum reservour volume billion (m^3)	RV^{max}_g	2.55

3.4.3. Development of Battery Deployment Model

BM covers the same 15 wind power plants and the solar power plant in JBMHM and JBSHM. However, BM is developed to be able to analyze the impact of use of battery on incomes achieved in day ahead electricity market. The data set for BM is given in Table 3.6

Table 3. 6. The Installed Capacities of Power Plants in Data Set of BM

Type of Power Plant	**Number of Power Plants**	**Installed Power (MW)**
WPPs	15	937
SPP	1	180
Total	**16**	**1,197**

Objective function is the same with JBMHM and JBSHM which is maximization of total income in day ahead electricity market.

Objective Function

$Max\, Z = \sum_c \sum_p TOTI_{p,c}$	Eq. 3.35

Objective is to maximize the total income (TOTI) of collaboration group c for period p.

CONSTRAINTS

Constraint 1 is related to the amount of energy that can be traded (sent to the grid) in DAM. Realized generation by wind or solar power plant (which are already available in data set) can be sent to the battery or realized generation can be supplemented by the energy available in the battery. Constraints from Eq. 3.36 to Eq. 3.42 are related to the income from DAM. Eq. 3.43, Eq. 3.44, Eq. 3.45 and Eq. 3.46 are related to the power storage constraints of the battery. Eq. 3.47 is the energy storage constraint, that is; the amount of energy stored in the battery in any period (p) cannot exceed the maximum amount of energy that can be stored in the battery. Eq. 3.48 is related to the energy storage equation.

$x_{p,g} = RG_{p,g} + PW^{dc}_{p,g} - PW^{ch}_{p,g} \quad \forall p\ and\ g \in S^{w-bat} or\ S^{s-bat}$ Realized generation can be sent to battery or realized energy can be supplemented by the energy available in the battery.	Eq.3.36

$TOTI_{p,c} = \sum_{g \in S^{cg}} IDAM_{p,g} + COMP_{p,c} + CF_{p,c}$	Eq.3.37
$COMP_{p,c} = \sum_{g \in S^{cg}} x_{p,c} \cdot [(GP_{p,g}) - MCP_p \cdot TC_g]$	Eq.3.38
$CF_{p,c} = [min\{IA_{p,c}, 0\} \cdot max\{MCP_p, SMP_p\} \cdot (1 + IC)] + [max\{IA_{p,c}, 0\} \cdot min\{MCP_p, SMP_p\} \cdot (1 - IC)]$	Eq.3.39
$IA_{p,c} = IA^{+}_{p,c} - IA^{-}_{p,c}$	Eq.3.40
$IA_{p,c} = \sum_{g \in S^{cg}} X_{p,g} - \sum_{g \in S^{cg}} DAP_{p,g}$	Eq.3.41
$IDAM_{p,g} = DAP_{p,g} \cdot MCP_p \ \forall p \ and \ g \in S^w \ or \ S^s$	Eq.3.42
$TPW^{dc}_p = \sum_{g \in S^{w-bat} or \ S^{s-bat}} PW^{dc}_{p,g}$ Total power transferred from the battery in period p is equal to the total power transferred from the battery to plant g in period p	Eq.3.43
$TPW^{ch}_p = \sum_{g \in S^{w-bat} or \ S^{s-bat}} PW^{ch}_{p,g}$ Total power transferred to the battery in period p is equal to the total power transferred to the battery by plant g in period p	Eq.3.44
$TPW^{dc}_p \leq PW^{dc-max}$ Total power transferred from the battery in period p cannot exceed maximum power from the battery	Eq.3.45
$Tpw^{ch}_p \leq PW^{ch-max}$ Total power transferred to the battery in period p cannot exceed maximum power to the battery	Eq.3.46
$e_p \leq ES^{max}$ Amount of energy stored in the battery can not exceed the maximum amount of energy that can be stored in the battery	Eq.3.47
$e_p = e_{p-1} + \eta^{ch} TPW^{ch}_p - \frac{1}{\eta^{dc}} TPW^{dc}_p$ Amount of energy stored in the battery in period p is equal to the amount of energy stored in the battery in period p-1 plus the total power transferred to the battery in period p minus total power transferred from the battery in period p according to the charging and discharging efficiencies of the battery.	Eq.3.48

The input data of BM covers hourly RG, DAP, SMP and MCP for the SPP and WPPs, the maximum power from the energy storage device (PW^{dc-max}), maximum power to the energy storage device (PW^{ch-max}), maximum amount of energy that can be stored in battery (ES^{max}), charging efficiency of the energy storage device (η^{ch}) and discharging efficiency of the energy storage device (η^{dc}) for the battery.

All the large scale VRFB systems in operation are mainly in Japan, China and USA. Energy to power ratio (E/P) is generally 4 hours. It means battery can be fully charged in maximum 4 hours. 4 hour E/P ratio is also assumed and used in BM of this study due its wide spread application.

The proposed strategies and the proposed models, model assumptions and the methodologies for the deployment of the proposed strategies are explained. Joint Bidding Multi-Hydro Model and Joint Bidding Single-Hydro Model are developed with the scope of 1st strategy. Battery Deployment Model is developed for 2nd strategy. Linear optimization model is developed for JBMHM and Battery Deployment Model. Mixed-integer linear optimization model is developed for JBSHM.

Model outputs and the analysis of the model outputs are explained in Chapter 4.

CHAPTER 4

MODEL OUTPUTS AND ANALYSIS OF RESULTS

The results of the developed and explained optimization models has been achieved via The General Algebraic Modeling System (GAMs) software program.

The results of the models are achieved for different collaboration groups and for different tolerance coefficient regimes (constant tolerance coefficient (CTC) regime and differentiated tolerance coefficient (DTC) regime set by the regulatory authority. In CTC regime which was in force before 2018, tolerance coefficients were fixed and equal to 0.98 for all power plants. As of 2018, DTC regime has been adopted by EMRA. Tolerance coefficients set in the new regime are 0.98 (implies a 2% tolerance for the imbalances) , 1 (no tolerance for imbalances) and 0.97 (implies a 3% tolerance for the imbalances) for solar power plants, hydropower plants and wind power plants respectively.

4.1. Outputs for Joint Bidding Multi Hydro Model:

Outputs of JBMHM has been received for 2 different cases. In the first case, realized generation values available in the data set are used. In the second model, optimized (decided) amounts of generation by HPPs are received from the model output of GAMs software program.

4.1.1. Outputs of Joint Bidding Multi-Hydro Model for Case 1:

As explained before Case 1 covers only the realized amount of generation which is already available in data set for year 2017. Therefore, for case 1; First constraint of Model is changed as follows:

$$X_{p,g} = RG_{p,g} \ \forall g, p \qquad \text{Eq. 4.1}$$

If the realized generation deviates from the day ahead planned generation, there is a loss of income due to imbalance. Loss of income is calculated by subtracting maximum income, which happens such a DAP is declared that planned amount of generation is equal to the realized amount of generation, from realized amount of income.

4.1.1.1. Model Outputs for Hydro Power Plants:

For each of the hydropower plants, loss of income is calculated and shown in Table 4.1. Table 4.1 shows the cases for 2 different tolerance coefficient values to be able to understand the impact of the value of tolerance coefficient which is set by EMRA.

The tolerance coefficient for HPPs was 0.98 before 2018 and it has been amended as 1.00 as of the beginning of 2018. That means no tolerance was provided for HPPs as of the beginning of 2018.

In case of individual bidding in day ahead market by each of hydropower plants, percentage of total loss of income in total income for 10 HPPs is equal to 0.85 % for the tolerance coefficient of 0.98 and 0.86 % for the tolerance coefficient of 1.00. In case of joint bidding with the same generation and day ahead planned amount this percentage is 0.476% for the tolerance coefficient of 0.98 and 0.481% for the tolerance coefficient of 1.00. Loss of Income (LOSSI) per MW of installed capacity is 1,566 USD/year in the case of individual bidding and it is 882 USD/year in case of joint bidding (44% reduction). As a result, total income is increased by 0.3% via joint bidding for both of the TC values.

Another interesting finding regarding HPPs is loss of income per MW of installed power varies substantially among HPPs. There is a 7 fold difference between minimum and maximum loss of income value per MW of installed capacity.

Table 4. 1. Loss of Income for Hydropower Plants

	Loss of Income due to Imbalance (1000 USD)	Installed Power (MW)	Annual Loss of income per MW (1000 USD)	Total Annual Income (TC=0.98) (1000 USD)	Total Annual Income (TC=1.00) (1000 USD)	Percentage of Loss of income in Total Income for TC=0.98 (%)	Percentage of Loss of income in Total Income for TC=1.00 (%)
HPP1	45.3	10	4.5	1,859	1,837	2.44	2.47
HPP2	70.1	20	3.5	4,752	4,694	1.48	1.49
HPP3	72.6	46	1.6	8,580	8,478	0.85	0.86
HPP4	26.3	13	2.0	2,467	2,438	1.07	1.08
HPP5	11.6	8	1.5	2,371	2,343	0.49	0.5
HPP6	109.3	62	1.8	10,060	9,934	1.09	1.1
HPP7	45.1	45	1.0	7,902	7,809	0.57	0.58
HPP8	12.4	9	1.4	1,232	1,217	1.01	1.02
HPP9	56.0	85	0.7	14,386	14,213	0.39	0.39
HPP10	38.0	13	2.9	3,885	3,840	0.98	0.99
Total in case of individual bidding	487.1	311	1.6	57,493	56,804	0.85	0.86
Total in case of joint bidding	274.2	311	0.9	57,667	56,977	0.476	0.481
Percentage Change in Total in case of joint bidding compared to individual bidding	-43.70	0	-43.68	0.30	0.30		

4.1.1.2. Model Outputs for WPPs:

For each of the wind power plants loss of income is calculated as shown in Table 3.2. Table 4.2 shows the cases for 2 different tolerance coefficient values again; the tolerance coefficient for WPPs was 0.98 before 2018 and it has been amended as 0.97 as of the beginning of 2018. That means higher level of tolerance was provided for the favor of WPPs. As can be seen from Table 3.2, in case of individual bidding in day ahead market by each of wind power plants, percentage of total loss of annual income in total annual income for 15 WPPs is equal to 2.58 % for TC=0.98 and 2.56 for TC=0.97. In case of joint bidding, this percentage is 1.21% for TC=0.98 and 1.20 for TC=0.97. Loss of annual income per MW of installed capacity drops 52% in case of joint bidding compared to individual bidding. Change in tolerance coefficient causes an increase in the total annual income by 0.61% in case of individual bidding and 0.60 % in case of joint bidding. Joint bidding increases the total annual income by 1.35% and 1.38% for TC=0.98 and TC=0.97 accordingly.

Compared to hydropower plants these percentages of loss of income in total income are considerably high due to the higher level and frequency of imbalances for WPPs.

Table 4. 2. Loss of Income for Wind Power Plants

	Loss of Income due to Imbalance (1000 USD)	Installed Power (MW)	Loss of income per MW (USD)	Total Income (TC=0.98) (1000 USD)	Total Income (TC=0.97) (1000 USD)	Percentage of Loss of Income in Total Income for TC=0.98	Percentage of Loss of Income in Total Income for TC=0.97
WPP1	499	120	4,162	26,209	26,368	1.91	1.89
WPP2	515	120	4,288	30,764	30,950	1.67	1.66
WPP3	245	38	6,448	8,683	8,735	2.82	2.8

Table 4.2. (Continued)

WPP4	227	37	6,138	5,112	5,143	4.44	4.42
WPP5	64	10	6,380	2,197	2,210	2.9	2.89
WPP6	320	50	6,400	10,050	10,112	3.18	3.16
WPP7	90	20	4,494	3,693	3,716	2.43	2.42
WPP8	313	64	4,886	10,380	10,444	3.01	2.99
WPP9	182	18	10,124	4,623	4,652	3.94	3.92
WPP10	1,101	200	5,506	32,620	32,820	3.38	3.36
WPP11	158	20	7,916	5,554	5,588	2.85	2.83
WPP12	652	132	4,943	25,087	25,243	2.6	2.58
WPP13	71	12	5,891	2,680	2,696	2.64	2.62
WPP14	138	21	6,583	4,672	4,701	2.96	2.94
WPP15	344	75	4,583	18,357	18,472	1.87	1.86
Total for individual bidding	4,919	937	5,250	190,680	191,850	2.58	2.56
Total for joint bidding	2,342	937	2,499	193,258	194,496	1.21	1.2
Percentage Change in Case of Joint Bidding Compared to Individual Bidding	-52.40	0	-52.40	1.35	1.38		

4.1.1.3. Model Outputs for SPP:

Percentage of loss of income in total income is 1.24% for solar power plant as shown in the Table 4.3. This percentage is higher than the most of hydropower plants and less than wind power plants. The tolerance coefficient has not been changed for SPPs. Tolerance coefficient has been kept constant (which is equal to 0.98) for SPPs.

Therefore, the impact of change of tolerance coefficient on income is not applicable for the SPP.

Table 4. 3. Loss of Income for Solar Power Plants

	Loss of Annual Income due to Imbalance (1000 USD)	**Installed Power (MW)**	**Loss of Annual Income per MW (1000 USD)**	**Total Annual Income (1000 USD)**	**Percentage of Annual Loss of income in Total Annual Income (%)**
SPP	490	180	2.7	39,532	1.24

4.1.1.4. Model Outputs for Different Collaboration Groups:

If all of the 26 power plants (15 WPPs (937 MW) +10 HPPs (311 MW) + 1 SPP (180 MW) =1,428 MW) bid individually without any collaboration, total annual loss of income is approximately 5.9 million USD (4,129 USD /MW). If they bid jointly, total annual loss of income is approximately 2.3 million USD (1,611 USD/MW). Therefore, 61% reduction in total annual loss of income is achieved by collaboration. This is summarized in the Table 4.4.

Table 4. 4. Annual Loss of Income for All Power Plants With a Total Installed Capacity of 1,428 MWS

	If All Power Plants bid individually	**If All Power Plants bid jointly**	**Percentage Change**
Annual Loss of Income (1000 USD)	5,897	2,302	61%
Annual Loss of Income per MW	4,129	1,611	61%

Impact of joint bidding on total income for different collaboration groups is analyzed for constant tolerance coefficient regime (CTC) and differentiated tolerance coefficient (DTC) regime in Table 3.5 and Table 3.6. Table 4.5 shows the impact of joint bidding for CTC regime (TC=0.98 for all power plants), while Table 3.6 shows the impact for DTC regime (TC=0.98 for SPP, TC=0.97 for WPP and TC=1 for HPP) to be able to understand the impact of regulated tolerance coefficients on joint bidding for different collaboration groups.

Table 4. 5. Impact of Collaboration With CTC Regime

Collaboration Group	Total Annual Income for Individual Bidding (1000 USD)	Total Annual Income for joint bidding (1000 USD)	Percentage Increase in Total Income via collaboration (%)
Solar Power Plant	39,532	Not applicable*	Not applicable*
Wind Group	190,680	193,258	1.35**
Hydro Group	57,494	57,667	0.30**
Solar Power Plant with Wind Group	230,212	233,193	1.29
Solar Power Plant with Hydro Group	97,025	97,396	0.38
Wind Group with Hydro group	248,173	251,464	1.33
Solar Power Plant, Wind Group and with Hydro Group	287,705	291,355	1.27

*There is only one SPP in data set.

**This is the percentage increase in total income when this group bids jointly compared to the sum of incomes of each individual plant, when each bids independently. Therefore this percentage can be considered as average percentage for the power plants in the group.

When the tolerance coefficient is the same for all plants, the impact of collaboration is highest for the collaboration group of wind power plants (wind group) with a 1.35% increase in income and collaboration of wind group with hydro group results in a 1.33% increase in income while it is 0.38% for the collaboration of solar power plant with hydro group. This extra margins are due to decrease in the cost of imbalance in case of joint bidding. The reason for the decrease in cost of imbalance is due to the decrease in imbalance amount due to joint bidding.

In case of DTC regime shown in Table 4.6, the collaboration among wind group and collaboration of wind group with the SPP yield higher percentage of increases in total income. In addition, in case of DTC regime, collaboration with HPPs is less attractive compared to the CTC regime since less tolerance for imbalances is given for HPPs in DTC regime.

Table 4. 6. Impact of Collaboration With DTC Regime

Collaboration Group	Total Annual Income for Individual Bidding (1000 USD)	Total Annual Income for Joint Bidding with (1000 USD)	Percentage Increase in Total Annual Income via Collaboration (%)
Solar Power Plant	39,538	not applicable	not applicable
Wind Group	191,850	194,495	1.38
Hydro Group	56,804	56,977	0.30
Solar Power Plant with Wind Group	230,212	233,346	1.36
Solar Group with Hydro Group	96,550	96,706	0.16
Wind Group with Hydro Group	248,868	251,944	1.23
Solar Group, Wind Group and Hydro Group	288,400	291,355	1.02

Comparison of total income for the joint bidding of different collaboration groups with CTC regime and DTC regime is shown in Table 4.7.

Table 4. 7. Effect of Tolerance Coefficient Regimes on Incomes for Joint Bidding

Collaboration Group	**Total** annual **income for JB for CTC Regime (1000 USD)**	**Total** annual **income for JB for DTC regime (1000 USD)**	**Percentage Increase in Total** Annual **Income due to the change in tolerance coefficient regime (%)**
Wind Group	193,258	194,496	0.64
Hydro Group	57,494	56,977	-0.89
Solar Group with Hydro Group	97,025	96,707	-0.33
Wind Group with Hydro group	251,464	251,945	0.19
Solar Group, Wind Group and with Hydro Group	291,356	291,356	0

Even though the joint bidding results in higher gains in income compared to individual bidding for both CTC regime and DTC regime as can be seen in Table 4.5 and Table 4.6, it can be concluded from Table 4.7 that in the existence of differentiated tolerance coefficients regime regulated by EMRA, the income-increasing positive impact of higher tolerance (less tolerance coefficient) for imbalance given for WPPs is counterbalanced by the tolerance removed (highest tolerance coefficient) from the HPPs. As a result of this counterbalancing effect, the total income for the whole group in data set remains the same under DTC regime.

4.1.2. Outputs of JBMHM for Case 2:

In Case-2, HPPs are given flexibility to make a decision for their hourly generation amount subject to 1 st, 2nd and 3 rd constraints of the model developed. Therefore, optimized (decided) generation values of HPPs are achieved by model output.

Case-2 analysis is also conducted for 2 different tolerance coefficient regimes. The first one includes CTC regime which was the case before 2018 and the second one includes DTC regime which has been the case as of beginning of 2018.

The impact of decision flexibility of HPPs (Case-2) on total income compared to Case-1 for joint bidding under CTC regime is summarized in Table 4.8.

Table 4. 8. Impact of Decision Flexibility of HPPS on Total in Come in Case of Joint Bidding Under CTC Regime

Collaboration Group	Hydro Group	Solar Group with Hydro Group	Wind group with hydro group	Solar Group, Wind Group and with Hydro Group
Total annual income for joint bidding without decision flexibility of HPPs over their generation amount (Case 1) (1000 USD)	57,667	97,396	251,464	291,356
Total annual income for joint bidding with decision flexibility of HPPs over their generation amount (case 2) (1000 USD)	57,873	97,775	252,396	292,321

Table 4.8. (Continued)

Increase in Annual Income (1000 USD)	206.7	378.2	931.2	965.1
Total Installed Power of the Group (MW)	311	491	1,248	1,428
Annual income increase per MW of Installed power (1000 USD)	0.66	0.77	0.75	0.68
Effect of decision flexibility of HPPs on total annual income for joint bidding case (%)	0.36	0.39	0.37	0.33

For Case-2, collaboration of HPPs with SPPs with decided (optimized) amounts of generation by HPPs creates the highest increase in total income (0.39%). The extra annual income per MW of installed capacity of this collaboration group due to the given flexibility to HPPs is 770 USD.

The collaboration of HPPs with WPPs also creates an 0.37% increase in total income which is equivalent to 746 USD per MW of installed power of the collaborating group.

The increase in total income values due to the decided generation by HPPs is given in Table 4.8. The breakdown of this increased income according to the months of the year is given in Table 4.9 to be able to determine the periods during which each collaboration yields greatest gains in total income.

Table 4. 9. Monthly Breakdown of Increased Annual Income for Different Collaboration Groups Under CTC Regime

Months	HPPs with WPPs (1000 USD)	HPPs with WPPs (%)	HPPs with SPP (1000 USD)	HPPs with SPP (%)	HPPs, WPPs and SPP (1000 USD)	HPPs, WPPs and SPP (%)
January	83.1	8.9	42.9	11.3	93.4	9.7
February	65.4	7	34.8	9.2	75.7	7.8
March	119.5	12.8	43.4	11.5	123.6	12.8
April	103.1	11.1	41.2	10.9	107.5	11.1
May	95.4	10.2	37.1	9.8	97.0	10.1
June	76.8	8.2	30.3	8	80.1	8.3
July	88.9	9.5	15.8	4.2	86.1	8.9
August	76.6	8.2	16.8	4.4	75.1	7.8
September	57.1	6.1	23.2	6.1	52.0	5.4
October	56.7	6.1	37.1	9.8	59.2	6.1
November	41.2	4.4	21.3	5.6	44.7	4.6
December	67.4	7.2	34.6	9.1	70.4	7.3
Total	931.2	100	378.4	100	965.1	100

If the Table 4.9 is analyzed, March, April and May are the months during which the maximum increase in total income for the collaboration between HPPs and WPPs and for the collaboration between HPPs, WPPs and SPP happens. March, April and May are the months during which the generated amount of electricity is highest for HPPs. The sum of increases in total income during these 3 months is more than one third of the total annual increased income for both of these collaboration groups.

The collaboration between HPPs and SPP yields minimum increased income during July, August, September and November. July, August and September are the months during which the generated amount of electricity is most stable for SPP and it seems that during these months, collaboration with HPPs is comparatively less profitable for SPP.

The impact of decision flexibility of HPPs on total income for joint bidding with DTC regime compared to case 1 is summarized in Table 4.10.

Table 4. 10. Impact of Decision Flexibility of HPPS on Total Annual Income in Case of Joint Bidding Under DTC Regime

Collaboration Group	Hydro Group	Solar Group with Hydro Group	Wind group with hydro group	Solar Group, Wind Group and with Hydro Group
Total income for joint bidding without decision flexibility of HPPs (Case 1) (1000 USD)	56,977	96,707	251,945	291,356
Total income for joint bidding with decision flexibility of HPPs (case 2) (1000 USD)	57,193	97,097	252,887	292,321
Increase in Income (1000 USD)	216	390	943	965
Total Installed Power of the Group (MW)	311	491	1,248	1,428
Income increase per MW of Installed power (1000 USD)	0.69	0.79	0.75	0.68
Effect of decision flexibility of HPPs on total income for joint bidding case (%)	0.38	0.4	0.37	0.33

The increase in total income values due to the decided generation by HPPs under the DTC regime is given in Table 4.10. The breakdown of this increased income according to the months of the year is given in Table 4.11 to be able to determine the periods during which each collaboration yields greatest gains in total income

Table 4. 11. Monthly Breakdown of Annual Increased Income for Collaboration Groups With DTC Regime

Months	HPPs with WPPs (1000 USD)	HPPs with WPPs (%)	HPPs with SPP (1000 USD)	HPPs with SPP (%)	HPPs, WPPs and SPP (1000 USD)	HPPs, WPPs and SPP (%)
January	95.9	10.2	37.6	9.7	97.0	10.1
February	103.2	10.9	41.6	10.7	107.5	11.1
March	78.1	8.3	18.8	4.8	75.1	7.8
April	68.0	7.2	34.8	9.0	70.5	7.3
May	67.0	7.1	36.4	9.4	75.7	7.8
June	84.4	9.0	43.7	11.2	93.5	9.7
July	90.9	9.6	17.9	4.6	86.2	8.9
August	77.3	8.2	30.8	7.9	80.1	8.3
September	121.3	12.9	43.7	11.2	123.7	12.8
October	42.7	4.5	22.8	5.9	44.7	4.6
November	56.6	6.0	37.8	9.7	59.2	6.1
December	57.3	6.1	24.0	6.2	52.0	5.4
Total	942.7	100	389.9	100	965.1	100

While March, April and May are the months during which joint bidding of wind group and solar group with optimized generation by hydro group yield the highest rates of increase in income in CTC regime, periods with higher amount of increased income change considerably in case of differentiated tolerance coefficient regime. 1st and 3rd quarters of the year seems more profitable for WPPs to have a joint bidding with HPPs and it is mostly the first half of the year for SPPs to have joint bidding with HPPs. As a conclusion, tolerance coefficient regimes set by the regulatory authority not only changes the amount of income for different collaboration groups but also changes the periods with highest rates of income increase.

As a summary, collaboration of the power plants creates extra income opportunities in day-ahead markets due to the reduction in imbalance cost.

Income increases up to 1.38% under DTC regime and 1.35% under CTC regime. In addition, if the hydropower plants with limited reservoir capacity optimize their generation to maximize the income in day-ahead market, extra income increase due to the optimization of generation by hydro power plants goes up to 0.39%.

4.2. Analysis of Outputs of Joint Bidding Single-Hydro Model:

JBSHM includes a hydro power plant with large reservoir capacity. In the first part of the analysis of outputs of JBSHM, the model outputs will be presented for the case that the hydro power plant bids in day ahead market independently without any collaboration to be able to understand the whether there is a water scarcity in the reservoir or not even in the absence of any collaboration. In the second part collaboration of hydro power plant with different collaboration groups will be analyzed.

4.2.1. If HPP bids in day ahead market independently without any collaboration:

This part will be analyzed for 2 different cases to be able to understand the effect of reservoir volume constraints and the sensitivity of HPP to reservoir volume limitations. In the first case, it is be assumed that there is no reservoir volume limitation while the limitations are in place as defined in the model in the second case.

4.2.1.1. Without Reservoir Volume Limitations:

If there were no limit for the minimum and maximum reservoir volume, the change in the reservoir volume of the HPP by time is given in Figure 4.1. As can be seen from the Figure 4.1 minimum reservoir volume is exceeded by HPP substantially. While the minimum reservoir volume is constrained to 1.67 billion m^3 in the model, final reservoir volume could drop to approximately 0.6 billion m^3 in case of absence of this constraint and the total amount of water inflow to the turbine for power generation would be equal to 3.42 billion m^3. In this case, even the initial reservoir volume is never exceeded. Total annual income of the HPP for this case is equal to 63 million USD[3].

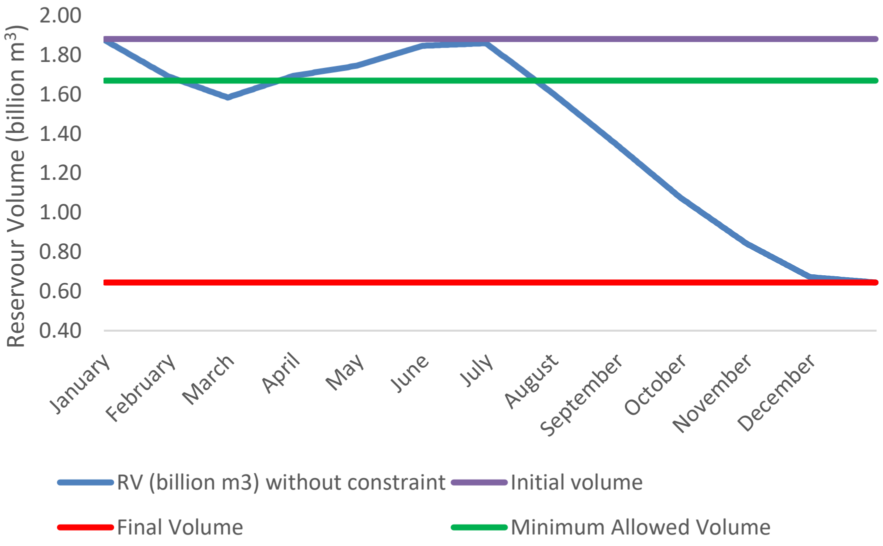

Figure 4. 1. Change in Reservoir Volume in the Absence of Reservoir Volume Limitations

4.2.1.2. With Reservoir Volume Limitations as Specified in the Model:

In this case reservoir volume never goes below the minimum reservoir volume limitation and also never exceeds the reservoir volume cap during the whole calendar year. According to the optimized water resource allocation of the developed model to maximize the total income in day ahead market in the existence of the constraints specified in the model, the reservoir volume reaches to a peak at the end of June and then drops continuously till it reaches the

[3] Model outputs are in Turkish Liras and converted to USD by the exchange rate published by Central Bank [38] .

minimum allowed reservoir volume as seen in Figure 4.2. Total amount of annual income from day ahead market for the HPP is 42.7 million USD.

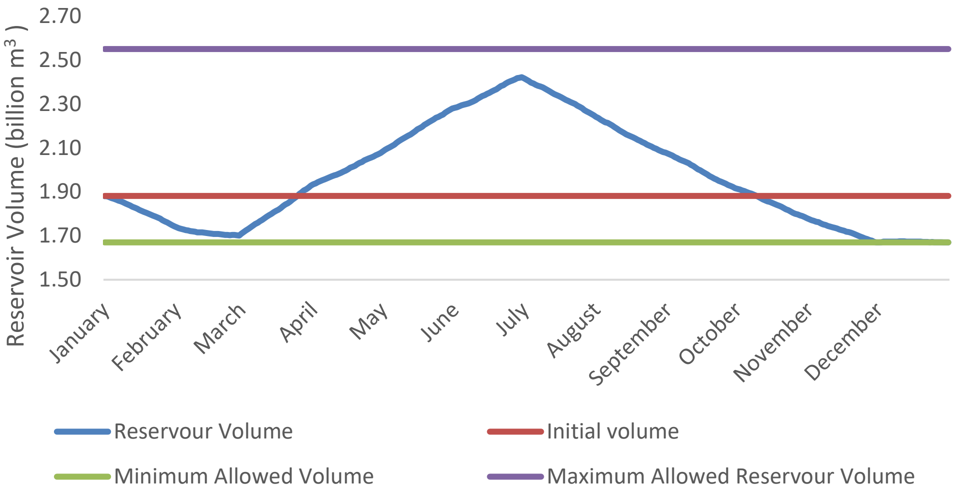

Figure 4. 2. Change in Reservoir Volume in the Existence of Reservoir Volume Limitations Specified in the Model

It can be concluded from the analysis of these 2 cases that the water scarcity exists for the HPP even in the case of independent bidding. In the second case total amount of water used (water inflow to the turbine) is equal to 2.4 billion m^3 which is approximately 1 billion m^3 less than the amount in the first case and total annual income is approximately 20.3 million USD less than that of the first case.

4.2.2. If HPP Bids Jointly Via Different Collaboration Groups in Day Ahead Market:

HPP with large reservoir capacity as a source of dispatchable energy source has the capability to counterbalance the imbalances of SPPs and WPPs.

The impact of collaborative joint bidding with the HPP in terms of extra income achieved for different groups of SPPs and WPPs is shown in Table 4.12.

Extra income is calculated by the difference between the total income of the whole collaboration group and the sum of incomes of the different subgroups in the whole group. For example, total income of the collaboration group consisting of HPP and 15 WPPs for CTC regime is 236,961,404 USD. The income of the HPP in the absence of any collaboration is 42,791,325 USD. The income of 15 WPPs as a group (as if they have the same owner and they bid together in day ahead market) is 193,257,701 USD. Therefore, the extra income achieved by the joint bidding of 15 WPPs with the HPP is calculated as income of the whole collaboration group (236,961,404)- income of the group of WPPs (193,257,701) – income of the HPP in the absence of collaboration (42,791,325), which is equal to 692,758 USD as shown in Table 4.12.

Table 4. 12. The Impact of Collaborative Joint Bidding With the HPP in Terms of Annual Extra Income Achieved for Different Collaboration Groups

Collaboration Group	Total Installed Capacity	Annual Extra Income achieved by JB with the HPP with optimized generation under CTC Regime (1000 USD)	Annual Extra Income achieved Joint Bidding with the HPP with optimized generation under DTC regime (1000 USD)	Percentage Change (%)
HPP with SPP	260	315.1	315.2	0.04
HPP with 4 WPPs	385	622.7	622.2	-0.07
HPP with 10 WPPs	550	692.8	692.1	-0.10
HPP with 15 WPPs	1,017	912.3	843.1	-7.60
HPP, 15 WPPs and SPP	1,197	1,291.9	1,222.7	-5.36
HPP, 15 WPPs and 3 SPP	1,557	1,641.1	1,571.6	-4.24
HPP, 15 WPPs and 10 SPP	2,817	2,005.7	1,935.9	-3.48

It is evident from the findings in Table 4.12 that CTC regime yields higher income gains through collaborative joint biddings compared to the DTC regime due to the fact that HPPs was given no flexibility with the introduction of DTC regime Tolerance coefficient was 0.98 (2% tolerance) under CTC regime, it became 1.00 (no tolerance) under DTC regime.

Extra income achievements via joint bidding with the HPP is given in Table 4.12, percentage changes in total income is shown in Table 4.13.

Table 4. 13. The Impact of Collaborative Joint Bidding With the HPP in Terms of Change in Total Annual Income for Different Collaboration Groups

Collaboration Group	**Total Installed Capacity**	**Percentage of Income Increase via JB with the HPP under CTC Regime (%)**	**Percentage of Income Increase via JB with the HPP under DTC regime (%)**
HPP with SPP	260	0.38	0.39
HPP with 4 WPPs	385	0.65	0.65
HPP with 10 WPPs	550	0.53	0.53
HPP with 15 WPPs	1,017	0.39	0.36
HPP, 15 WPPs and SPP	1,197	0.47	0.44
HPP, 15 WPPs and 3 SPP	1,557	0.46	0.44
HPP, 15 WPPs and 10 SPP	2,817	0.32	0.31

The results in Table 4.13 are also shown in Figure 4.3.

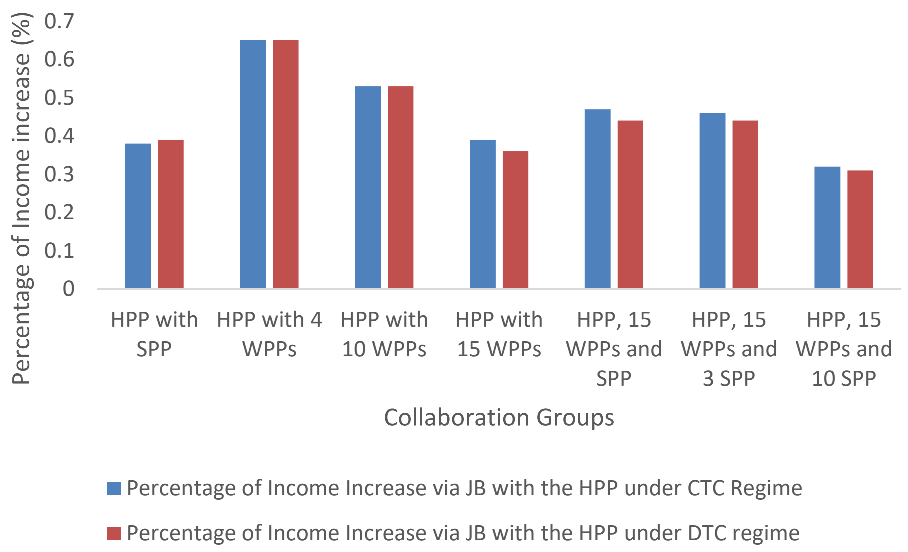

Figure 4. 3. Percentage of Income Increase for Different Collaboration Groups

It can be concluded from Table 13 and Figure 4.3 that joint bidding with hydro power plant leads to higher rates of income increase under CTC regime compared to DTC regime due to the fact that less tolerance for imbalance was given to HPPs under DTC regime.

The detailed and comprehensive results of the optimization model under CTC regime is given in Table 4.14.

Table 4. 14. Detailed Results of Optimization Model Under CTC Regime

	HPP bids independently	**HPP and SPP bids jointly**	**HPP and 4 WPPs * bid jointly**	**HPP and 10 WPPs** bid jointly**	**HPP and 15 WPPs bid jointly**	**HPP, 15 WPPs and SPP bid jointly**	**HPP, 15 WPPs and 3 SPP*** bid jointly**	**HPP, 15 WPPs and 10 SPP**** bid jointly**
Total Installed Power	80	260	385	550	1,017	1,197	1,557	2,817
Total Annual Amount of Electricity Generation of HPP (MWh)	509,398	509,297	508,577	508,396	507,902	507,825	507,587	507,243
Number of Hours during which power generated by HPP	8,439	8,448	8,369	8,352	8,276	8,269	8,235	8,190
Total Water Inflow to turbine for power generation (billion m^3)	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Total Annual Income of collaboration group with optimized generation amount of HPP (1000 USD)	42,800	82,600	96,300	131,300	237,000	276,900	356,300	633,400
Annual Extra Income created by joint bidding (1000 USD)		315.1	622.7	692.8	912.3	1,291.9	1,641.1	2,005.6
Percentage Increase in income (%)		0.38	0.65	0.53	0.39	0.47	0.46	0.32

Table 4.14. (Continued)

Total Extra Income created by joint bidding per MW of installed Power (1000 USD per MW)		1.21	1.62	1.26	0.90	1.08	1.05	0.71
Total Extra Income created by joint bidding per million m^3 of water inflow (1000 USD)		0.13	0.26	0.29	0.38	0.54	0.68	0.84

*4 WPPs (305 MW of installed capacity) in the data set with the largest percentage of loss of income due to imbalance

** 10 WPPs (470 MW of installed capacity) in the data set with the largest percentage of loss of income due to imbalance

***All values of SPP in data set are multiplied by 3

****All values of SPP in data set are multiplied by 10

According to the findings in the Table 4.15, amount of water inflow to the turbine for power generation is the same whether the HPP bids in day ahead market independently or bids jointly with different collaboration groups stated in the Table 4.15. Therefore, water resource is scarce within the boundaries of given constraints. It has already been shown that if there were no reservoir volume limitations specified in the constraints of the model and even when the HPP bids alone independently, it uses water resource 1 billion m^3 more compared to the case with the specified constraints.

Despite the existence of the same amount of annual water inflow to the turbine for all collaboration groups, total income increases as the total installed capacity of the collaboration group of HPP, WPP and SPP increases, however, the rate of increase decreases. The main reason for the decreasing rate of increase in income is due to the higher rate of power generation with less marginal efficiency as the total installed capacity of the group increases. This is also clearly visible from the total annual amount of electricity generation of HPP for different collaboration groups. As the total installed capacity of the group increases, the power generation of the HPP decreases despite the use of same amount of water inflow to the turbine.

In addition, extra income created per million m^3 of water inflow by joint bidding increases as the total installed capacity of the group increases since the total amount of water inflow is the same.

The detailed and comprehensive results of the optimization model for different collaboration groups with DTC regime are summarized in Table 4.15.

Table 4. 15. Detailed Results of the Optimization Model for Different Collaboration Groups With DTC Regime

	HPP bids independently	HPP and SPP bid jointly	HPP and 4 WPPs* bid jointly	HPP and 10 WPPs** bid jointly	HPP and 15 WPPs bid jointly	HPP, 15 WPPs and SPP bid jointly	HPP, 15 WPPs and 3 SPPs*** bid jointly	HPP, 15 WPPs and 10 SPPs**** bid jointly
Total Installed Power	80	260	385	550	1,017	1,197	1,557	2,817
Total Annual Amount of Electricity Generation of HPP (MWh)	509,403	509,288	508,550	508,367	507,901	507,805	507,556	507,257
Number of Hours Power Generated by HPP	8,441	8,449	8,364	8,352	8,277	8,271	8,234	8,195
Total Water Inflow to turbine for power generation (billion m^3)	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Total Income of collaboration group with optimized generation amount of HPP (1000 USD)	42,300	82,200	96,200	131,400	237,700	277,600	357,000	634,100
Extra Income created by joint bidding (1000 USD)	NA	315	620	690	840	1,220	1,570	1,940
Percentage Increase in income (%)	NA	0.39	0.65	0.53	0.36	0.44	0.44	0.31
Extra Income created by joint bidding per MW of installed Power (1000 USD)	NA	1.21	1.62	1.26	0.83	1.02	1.01	0.69
Extra Income created by joint bidding per million m^3 of water inflow (1000 USD)	NA	0.13	0.26	0.29	0.35	0.51	0.65	0.81

*4 WPPs (305 MW of installed capacity) in the data set with the largest percentage of loss of income due to imbalance
** 10 WPPs (470 MW of installed capacity) in the data set with the largest percentage of loss of income due to imbalance
***All values of SPP in data set are multiplied by 3
****All values of SPP in data set are multiplied by 10

The findings in the Table 4.15 is mostly in compliance with the findings of the Table 4.14. As was also the case in CTC regime, amount of water inflow to the turbine for power generation is the same whether the HPP bids in day ahead market independently or bids jointly with different collaboration groups stated in the Table. Therefore, water resource is again scarce within the boundaries of given constraints.

Despite the existence of same amount of annual water inflow to the turbine for all collaboration groups, total income increases as the total installed capacity of the collaboration group of HPP, WPP and SPP increases, however, the rate of increase decreases as was the case in CTC regime.

The main difference with constant tolerance coefficient and differentiated tolerance coefficient regimes is that the rate of income increase via joint bidding is higher under CTC regime compared to DTC regime since less tolerance is given for hydro power plants under differentiated tolerance coefficient regime.

Monthly breakdown of the annual amount of extra income created by the joint bidding of the HPP with the SPP is shown in Table 4.16 with comparison of the 2 different tolerance coefficient regimes.

Table 4. 16. Monthly Breakdown of Total Extra Income Created by the Joint Bidding of HPP With SPP

Month	**Total Extra Income due to JB of HPP with SPP under CTC Regime (1000 USD)**	**Total Extra Income due to JB of HPP with SPP under DTC Regime (1000 USD)**
January	-73.5	-58.7
February	4.4	-4.7
March	60.9	208.4
April	-14.6	432.5
May	-59.1	10.1
June	-60.4	-88.2
July	-77.3	-85.1
August	180.0	-83.0
September	81.5	54.0
October	-172.5	30.7
November	30.8	-187.1
December	414.8	86.4
Total	**315.1**	**315.3**

Monthly breakdown of extra income for the joint bidding of the SPP with the HPP also shown in Figure 4.4.

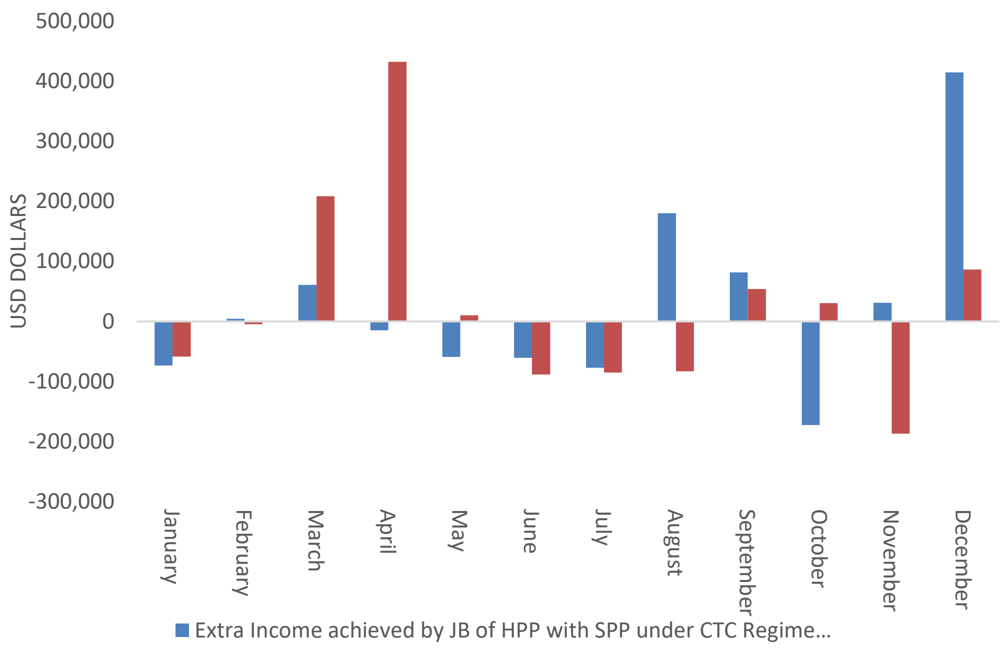

Figure 4. 4. Monthly Breakdown of Extra Income Achieved by JB of HPP with SPP

There are substantial differences among the monthly breakdown of extra incomes in CTC regime and DTC regime. Extra income created by joint bidding of the HPP with the SPP under CTC regime is higher during the period starting with August except for October and peaks in December. However, the distribution is totally different under DTC regime. Extra income peaks in March and April during which the incoming water to reservoir also peaks. Under DTC regime, tolerance coefficient of the HPP is equal to 1. This means no tolerance has been given to HPPs for imbalances, therefore joint bidding creates higher incomes during the months with higher amounts of incoming water to the reservoir since the HPP can benefit from the tolerance given to WPPs. These results are based on the available data in data set for the year 2017. Distribution of extra income with respect to different months may change for different years. However, it can concluded that when less tolerance for imbalance is given to hydro power plants, which is the case under DTC regime, joint bidding of solar power plant with hydropower plant creates highest values in spring during which the reservoir volume is highest for hydropower plants.

Extra annual income created by joint bidding of the HPP with 15 WPPs in data set is 912,377 USD under CTC regime and it is equal to 843,067 USD under DTC regime. The monthly breakdown of this annual incomes is shown in Table 4.17.

Table 4. 17. The Monthly Breakdown of the Annual Extra Income by Joint Bidding of HPP With WPP Group

Month	**Total Extra Income achieved by JB of H with W Group owner under CTC regime (USD)**	**Total Extra Income achieved by JB of H with W Group owner under DTC regime (USD)**
January	-28,261	-156,097
February	-89,306	-98,375
March	-30,923	270,927
April	-73,983	861,252
May	-104,073	-86,573
June	-360,868	-99,407
July	-23,580	-1,926
August	190,948	-359,255
September	439,977	-60,565
October	-76,510	328,274
November	311,034	-122,622
December	757,923	367,434
Total	912,377	843,066

Monthly breakdown in the Table 4.17 above is also shown in Figure 4.5.

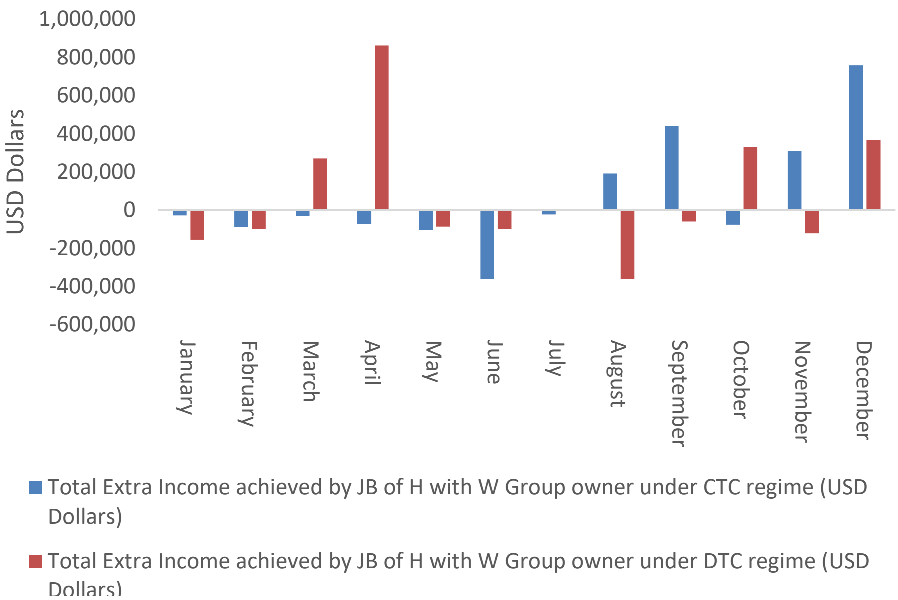

Figure 4. 5. Monthly Breakdown of Extra Income Achieved by JB of HPP with SPP

As was the case for the JB of the HPP with SPP, there are substantial differences between extra income distribution in CTC regime and DTC regime. As can be seen from the Figure 4.5, the extra income created by joint bidding is achieved during the second half of the year starting with August and it peaks in December under CTC regime. However, March and April are the months when the extra incomes by JB peaks under DTC regime. However, as was the case for Figure 4.4, these results are based on the available data in data set for the year 2017. Distribution of extra income with respect to different months may change for different years. However, it is again clear that tolerance coefficient is one of the main factors behind the monthly distribution of extra income achieved via joint bidding. Joint bidding of hydro power plant with wind power plants creates highest extra income during the spring when the reservoir volume is highest when no tolerance is given for hydropower plants.

The results of the mixed-integer linear optimization model in terms of total income in day ahead market for different collaboration groups with CTC regime and DTC regime are summarized in Table 4.18.

Table 4. 18. The Results of Optimization Model for Different Collaboration Groups and Different TC Regimes

Collaboration Group	Total Installed Capacity	Income with optimized generation of the HPP under CTC Regime (1000 USD)	Income with optimized generation of the HPP under DTC Regime (1000 USD)	Percentage Change (%)
HPP	80	42,791	42,311	-1.12
HPP with SPP	260	82,638	82,158	-0.58
HPP with 4 WPPs*	385	96,329	96,171	-0.16
HPP with 10 WPPs**	550	131,303	131,355	0.04
HPP with 15 WPPs***	1,017	236,961	237,650	0.29
HPP, 15 WPPs and SPP	1,197	276,873	277,561	0.25
HPP, 15 WPPs and (3 SPP**)**	1,557	356,285	356,974	0.19
HPP, 15 WPPs and (10 SPP***)**	2,817	633,371,918	634,060,254	0.11

*4 WPPs with highest rates of loss of income in data set (305 MW installed capacity)

**10 WPPs with highest rates of loss of income in data set (470 MW installed capacity)

*** 15 WPPs in the whole data set with 937 MW installed capacity

**** The values of the SPP in the data set are multiplied by three

***** The values of the SPP in the data set are multiplied by ten

Table 4.18 includes different collaboration groups with increasing installed capacity to be able to understand the impact of joint bidding for different cases. As mentioned before there are 15 WPPs in the data set. Different groups of

WPPs are also included in the table to be able to analyze the impact of installed capacity on the income achieved by joint bidding. In the last collaboration groups, the installed capacity has been increased with 3 SPPs and 10 SPPs (by multiplying the values of the SPP in data set by 3 and 10) to see the counterbalancing capability of the HPP for different installed capacities of collaboration groups.

Income of the HPP decreases 1% as a result of the change in tolerance coefficient regime (less tolerance for imbalance has been given for HPPs with the new DTC regime). As the installed power of WPPs increases in the collaboration group, the total income of the collaboration has also the tendency to increase since more tolerance for imbalance has been given for WPPs in the new differentiated tolerance coefficient regime.

4.2.3. Sharing of the Extra Income Achieved by Collaboration:

As explained in detail, both in the JBMHM and JBSHM, extra incomes are achieved due to the joint bidding with collaboration

How the extra incomes achieved by the collaboration can be shared is also a challenging issue. Especially, there should be enough incentive for hydropower plants to adjust their generation for an objective of maximization of income of the collaboration group. In practice, there are balancing groups with considerably high installed capacities. The more the installed capacity of the collaboration group, the greater the income gain through joint bidding. Responsible entity for the balancing group makes agreements for each of the participant of the balancing group. Since the extra incomes are guaranteed by collaboration, some portion of the expected income gain is shared with the participants of the balancing group via mutual agreements. In these agreements, participants are guaranteed to earn more than the expected income when they bid individually. For example, as explained before the maximum possible income from the day-ahead market can be achieved if realized generation is equal to the day-ahead planned generation (if there is no imbalance). In this case based on the formulas explained before:

Total income = Guaranteed price . Realized generation + (1-Tolerance Coefficient). Market Clearing Price

Tolerance coefficient for wind power plants is 0.97 currently. Therefore, maximum achievable income (which happens when there is no imbalance) = Guaranteed Price. Realized Generation + 0.03. Realized Generation.

Extra income margin over the guaranteed price is equal to 3% of the market clearing price. This extra income margin is provided by the Energy Market Regulatory Authority to compensate the losses due to imbalance.

Responsible entity from the balancing group guarantees the income (Guaranteed Price . Realized Generation) to the participants and accept the balancing responsibility and the responsibility of all transactions in return of the extra income margin (or mutually agreed portion of this extra income margin) provided by the regulatory authority.

4.3. Analysis of Outputs of Battery Deployment Model:

In the first and second model, effect of collaborative joint bidding on income in day ahead market is analyzed for different collaboration groups and different tolerance coefficient regimes set by regulatory authority.

In the third model vanadium redox flow batteries are deployed to counterbalance the deviations and maximize the total income for WPPs and SPP. Different battery sizes for different collaboration groups have been deployed in the model to be able to analyze the impact of size of power of battery on income for each collaboration group.

4.3.1. Analysis of Outputs for Wind Power Plants

Table 3.19 summarizes the result of the model for collaboration of all WPPs (15 WPPs with a total installed capacity of 937 MW) in the data set. Income without the battery deployment is the income achieved when these 15 WPPs bids jointly in day ahead market with no use of storage technology. Therefore, extra income defined in the table is calculated by the subtraction of “total Income in case of Joint Bidding with the Deployment of Battery” from “total income in case of joint bidding without the use of battery.”

The income values given in the Table 4.19 are annual incomes since the model is run for the whole calendar year.

The model is run for the collaboration group of 15 WPPs with an installed capacity of 937 MW for different battery sizes from 1MW to 200 MW in Table 4.19.

Table 4. 19. Annual Extra Income With the Deployment of Battery for 15 WPPs

Power of Battery (MW)	Annual Income with Battery Deployment (1000 USD)	Annual Income without Battery Deployment (1000 USD)	Annual Extra Income with Battery (1000 USD)	Percentage Increase in Income (%)	Annual Extra Income per MW of Battery (1000 USD)	Sum of Absolute Value of Imbalance Amounts with Battery (MWh)
1	193,332	193,325	7	0.004	6.8	386,770
10	193,388	193,325	63	0.032	6.2	382,474
30	193,493	193,325	168	0.087	5.6	374,632
50	193,576	193,325	251	0.130	5	368,437
100	193,703	193,325	378	0.196	3.8	357,424
200	193,817	193,325	492	0.255	2.5	343,531

It is apparent from Table 4.19 that extra income increases as the power of the battery increases. However, the rate of increase of extra income is decreasing as the power of battery rises. This is shown in Figure 4.6.

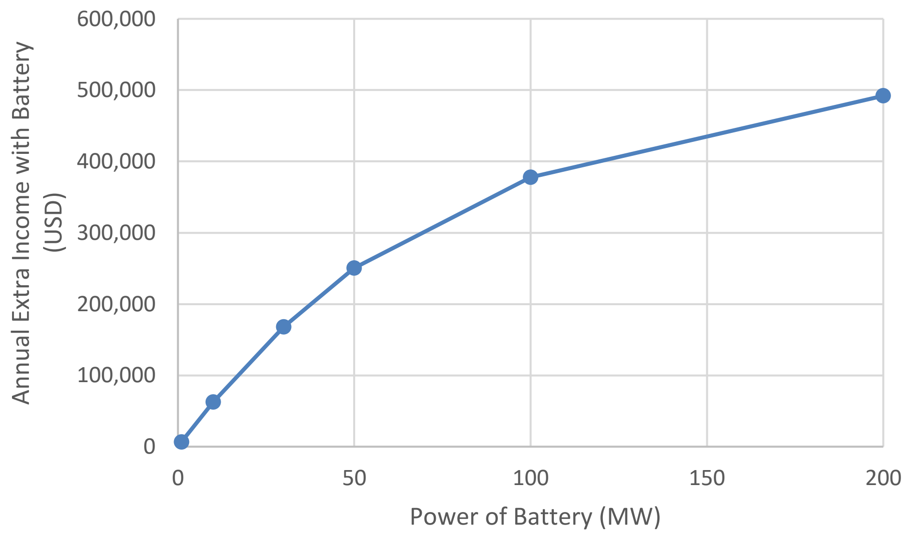

Figure 4. 6. Extra Income Achieved with Respect to Battery Size for 15 WPPs

The slope of the curve in Figure 3.6 can be considered as the marginal efficiency of battery ($/MW) in terms of income gains. The marginal efficiency of the battery declines with a decreasing rate as the size of power capacity of battery rises. The decline in marginal efficiency of battery is shown in Figure 4.7.

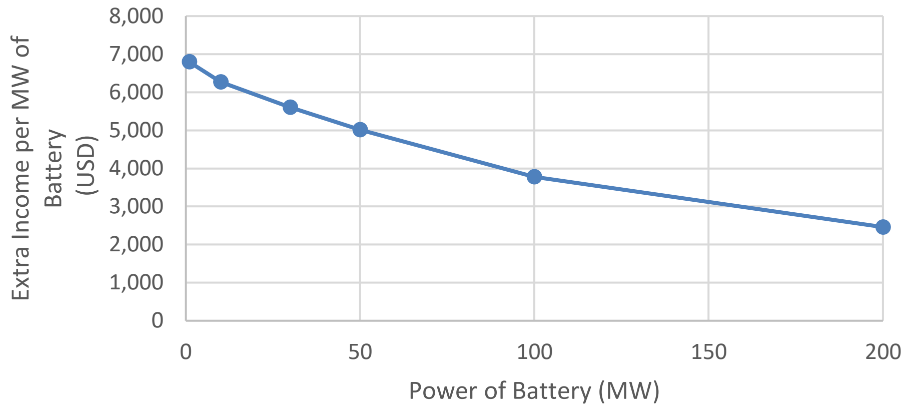

Figure 4. 7. Marginal Efficiency of Battery With Respect to the Battery Size for WPPs

Area under the Marginal efficiency curve in Figure 4.7 is equal to the total extra income. In parallel to the findings in Figure 4.6, total extra income increases but in a decreasing rate. To find out the optimum battery size, cost function of battery with respect to its power capacity is needed. The intersection point of the cost function with extra income function can be considered as the optimum battery size. However, there is a wide range of different estimations for VRFB cost in literature especially due to the continuous improvements in VRFB and continuous and dynamic changes in the cost structure. In addition, these estimations are based on different assumptions in different years [43, 44]. Since extra income achieved per MW of VRFB is already presented in Figure 3.7, levelized cost of storage with VRFB can be compared with the extra incomes achieved per MW of the battery. Levelized cost of storage is defined as the ratio of the discounted costs to the discounted energy stored over a project lifetime [45]. The unsubsidized levelized cost of storage for utility scale flow batteries is between \$289 and \$536 /kw-year[46]. This values are equal to \$289,000 and \$536,000 /MW-year. If these levelized costs are compared with the annual extra income values achieved per MW of battery shown in Figure 4.7 which are between approximately $2,460-$6,795/MW-year, deployment of VRFB for WPPs to counterbalance the deviations and reduce the imbalances in day ahead market is not financially viable and feasible with current cost structure of VRFB and in the absence of any subsidization.

The sum of absolute value of imbalances (RG-DAP) reduces as the power of the battery increases.

4.3.2. Analysis of Outputs for Solar Power Plant

The model outputs for the solar plant is summarized in Table 4.20.

Table 4. 20. Outputs of Battery Model for the Solar Power Plant

Power of Battery (MW)	Income with Battery Deploymen t(USD Dollars)	Income without Battery Deploymen t (USD Dollars)	Extra Income with Battery (USD Dollars)	Extra Income per MW of Battery (USD Dollars)	Sum of Absolute Value of Imbalance Amounts with Battery(M Wh)
1	39,532,883	39,531,724	1,160	1,160	82,297
5	39,537,269	39,531,724	5,545	1,109	82,057
10	39,542,284	39,531,724	10,561	1,056	81,801
20	39,551,403	39,531,724	19,679	984	81,390
30	39,559,627	39,531,724	27,903	930	81,036
40	39,567,291	39,531,724	35,567	889	80,716
50	39,574,713	39,531,724	42,989	860	80,407
100	39,608,452	39,531,724	76,728	767	79,369
200	39,670,335	39,531,724	138,611	693	78,613

Sum of absolute value of imbalances also reduces as the power capacity of the battery increases. Extra income for SPP also increases as the power capacity of the battery increases but the rate of increase in extra income is declining as shown in Figure 4.8.

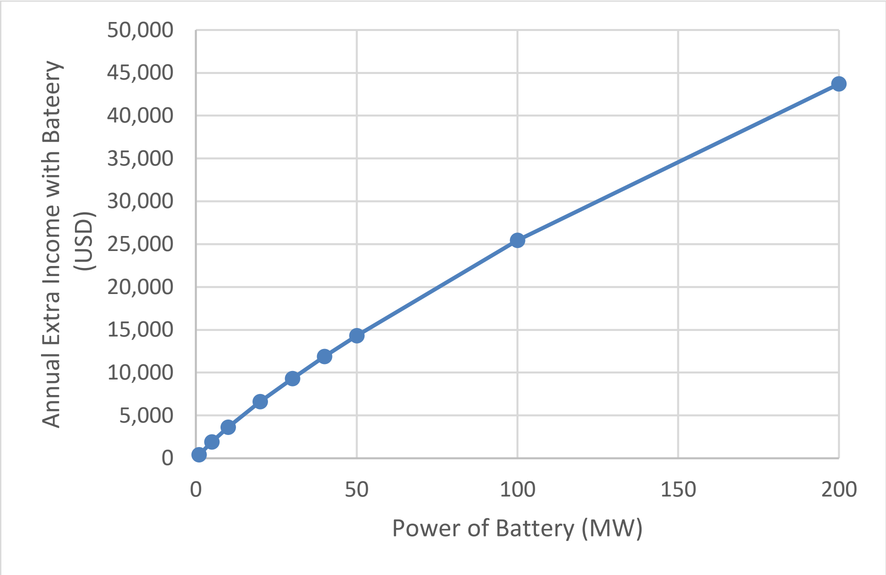

Figure 4. 8. Extra Income Achieved with Respect to Battery Size for SPP

The rate of increase in extra income declines as the size of power capacity of battery rises. However, as shown in Figure 4.9, the overall rate of decline in efficiency in terms of income gains is much less than that of WPPs. However, extra income values per MW of battery for SPP is between $218 and $400 /MW-year, while these values are $2,460-$6,795/MW-year for the group of 15 WPPs. Therefore, deployment of VRFB for WPPs created extra income more than 10 fold of that of for SPP. Deployment of VRFB for SPP is also financially not feasible and viable.

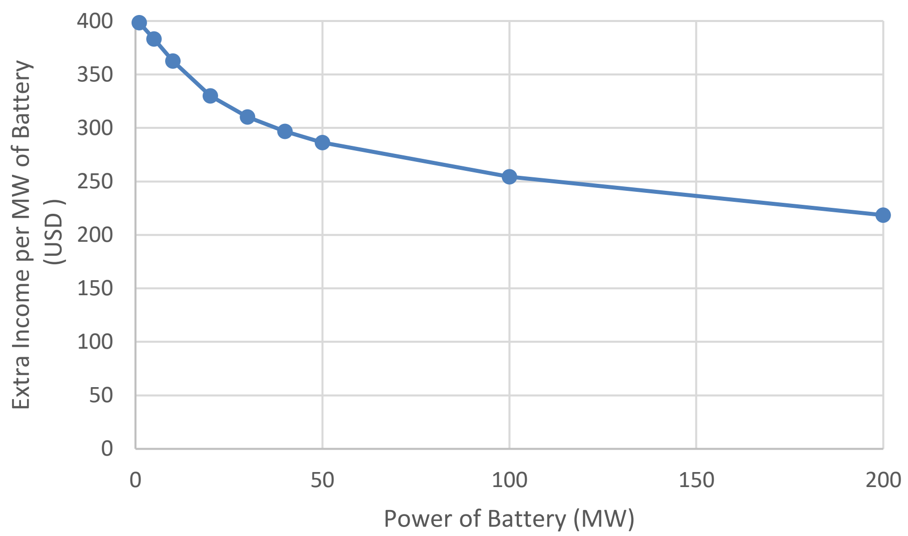

Figure 4. 9. Efficiency of Battery With Respect to the Battery Size for SPP

4.3.3. Feasibility of VRFB for Wind and Solar Power Plants

It can be viable if the extra income becomes sufficient to cover the levelized cost of VRFB, which is between 289.000 and 536.000 USD/MW-year. This is summarized in Table 4.21.

Table 4. 21. Feasibility of VRFB in Day-Ahead Market

	Levelized Cost of VRFB (USD/MW-year)	Annual Extra Income with the Deployment of VRFB (USD/MW-year)
Solar Power Plant	289,000-536,000	218-400
Wind Power Plants	289,000-536,000	2,460-6,795

Deployment of VRFB can be feasible if the annual extra income values become sufficient to cover the levelized cost of VRFB which is between 289 and 536 USD/kw-year. Levelized cost of VRFB is already declining based on the technological improvements in addition to the experiences gained. 29% drop in the cost of VRFB is forecasted till 2025 compared to 2018 prices [43].

On the other hand, tolerance coefficient set by the regulatory authority is currently 0.97 (3% tolerance for imbalances) for wind power plans and 0.98 (2% tolerance for imbalances) for solar power plants in Turkey. However, less tolerance might be given to WPPs by the regulatory authority. In addition, coefficient of imbalance is also set by the regulatory authority. Higher coefficient of imbalance means higher imbalance cost. Therefore, higher imbalance cost can also be a driver for the feasibility of VRFB. Another possible driver for the feasibility of the use of VRFB to maximize the income in day-ahead markets is the increasing trend of market clearing prices.

In summary, declining trend of the cost of VRFB together with increasing trend of market clearing prices will make the deployment of VRFB feasible in coming future, if these trends continue. When VRFB will be feasible depends on the rate of decline in VRFB cost and the rate of increase in market clearing prices in addition to the regulatory coefficients set by regulatory authority.

On the other hand, VRFB can also be deployed in balancing market. The energy stored in low-price period can be sold at high-price period.

4.4. Summary of Model Results:

Till the end of April 2016, the entire generation counted by the meters of the power plants in the renewable energy support mechanism (RESM) was purchased by the system operator according to the feed-in tariffs, leaving the plants without price, volume and currency risks. These plants were also exempt from balancing responsibility so were not obliged to forecast their future generation as well. In other words, there was no cost for imbalance between planned generation and realized generation. Balancing responsibility came into force on 29 th of April in 2016 in Turkey.

To meet this obligation with maximum possible income while reducing the loss of income (LOSSI), which happens such a DAP is declared that planned amount of generation is equal to the realized amount of generation without any imbalance; there are 2 possible strategies for WPPs and SPPs to reduce their imbalances and maximize their income in day ahead market.

1. Joint Bidding in day ahead market via collaboration by participating to balancing groups (JBMHM and JBSHM)
2. Deployment of storage technologies (BM)

The data set covers the 27 different power plants (15 WPPs, 1 SPP, 10 HPPs with limited reservoir capacity and 1 HPP with large reservoir capacity).

3 different models are developed for WPPs and SPPs:

JBMHM (JB with HPPs with Limited Reservoir Capacity): Linear Optimization Model for Joint Bidding via different collaboration groups including 10 HPPs with limited reservoir capacity

JBSHM (JB with HPP with Large Reservoir Capacity): Mixed Integer Linear Optimization Model for Joint Bidding via different collaboration groups including the HPP with large reservoir capacity

BM (Battery Deployment Model): Linear Optimization Model with the deployment of storage technologies.

The results of these optimization models has been achieved via The General Algebraic Modeling System (GAMs) software program.

The results of the model are achieved for different collaboration groups and for different tolerance coefficient regimes (constant tolerance coefficient (CTC) regime and differentiated tolerance coefficient (DTC) regime set by the regulatory authority. In CTC regime which was in force before 2018, tolerance coefficients were fixed and equal to 0.98 for all power plants. As of 2018, DTC regime has been adopted by EMRA. Tolerance coefficients set in the new regime are 0.98 (implies a 2% tolerance for the imbalances), 1 (no tolerance for imbalances) and 0.97 (implies a 3% tolerance for the imbalances) for solar power plants, hydropower plants and wind power plants respectively.

In JBMHM, collaboration of WPPs and the SPP with 10 HPPs which have limited reservoir capacity (mostly dependent on the seasonal variations in river flow) are analyzed. In JBSHM, a hydro power plant with 80 MWs of installed capacity which has large reservoir capacity is included in the model excluding 10 HPPs with limited reservoir capacity in JBMHM.

According to the results of JBMHM, total income is increased and the loss of income (LOSSI) due to the difference between RG and DAP (imperfect forecasting) is reduced for all collaboration groups. This is summarized in Table 4.22.

Table 4. 22. Loss of Income for Different Collaboration Groups

Collaboration Group	Reduction Rate in LOSSI with Joint Bidding (%)	Increase in Total Income with Joint Bidding (%)	
		CTC Regime	DTC Regime
15 WPPs	50	1.35	1.38
10 HPPs, 15 WPPs and 1 SPP	60	1.33	1.23

Therefore, as can be seen from Table 4.22, collaboration leads to higher income and WPPs benefits from an even higher income with DTC regime. In addition, as the installed power of the collaboration group increases, LOSSI per MW of installed power of the corresponding collaboration group decreases.

In Case-2 of JBMHM, HPPs' generation amount is decided and optimized by the optimization program within the constraints specified in JBMHM.

In Case-2, Optimized (decided) amount of generation by HPPs with limited reservoir capacity creates extra annual income gains up to 0,4%.

The imbalances are comparatively higher in the months March, April and May for the SPP and WPPs. These are also the periods with highest amount of generation and least amount of imbalances for HPPs; since these 10 HPPs have limited reservoir capacity and river flow is mostly dependent on the seasonal variations. Therefore, there is a perfect match for both WPPs and the SPP for the collaboration with HPP especially in spring period under CTC regime. March, April and May are the months during which the collaboration of both WPPs and the SPP with HPPs yields higher rates of increase in income (almost one third of the annual increased income). However, monthly breakdown of the increased income are totally different under DTC regime. There is no seasonal tendency in terms of distribution of increased incomes via collaboration. The main reason for this situation is due to the fact that no tolerance is given for HPPs under DTC regime.

In JBSHM, even the HPP bids independently in day ahead market, the amount of water inflow to the turbine needed for the maximization of total income is 3.4 billion m^3. However, due to the existence of limitations for minimum and maximum amount of water volume in reservoir (its minimum allowed reservoir capacity is 1.67 billion m^3 and its maximum allowed reservoir capacity is 2.55 billion m^3), the HPP could utilize 2.4 billion m^3 of water inflow to the turbine which leads to a less income (20.3 million dollars) compared to the case with no water reservoir volume limitation. Therefore, the water scarcity exists for the

HPP even in the case of independent bidding despite its 3 billion m^3 of total reservoir volume.

Amount of water inflow to the turbine for power generation is the same whether the HPP bids in day ahead market independently or bids jointly with different collaboration groups as shown in the Table 3.15. According to the model outputs of the mixed integer linear optimization model, despite the existence of same amount of annual water inflow to the turbine for all collaboration groups, total income increases as the total installed capacity of the collaboration group of HPP, WPP and SPP increases, however, the rate of increase decreases. The main reason for the decreasing rate of increase in income is due to the higher rate of power generation with less marginal efficiency as the total installed capacity of the group increases. This is also clearly visible from the total annual amount of electricity generation of HPP for different collaboration groups. As the total installed capacity of the group increases, the power generation of the HPP decreases despite the use of same amount of water inflow to the turbine.

The impact of reservoir capacity is clearly visible from the outputs of JBSHM. In JBSHM, the collaboration of the HPP with the SPP yields an income increase of 0.38% for CTC regime and 0.39% for DTC regime. These percentages are 0.39% for CTC regime and 0.40% for DTC regime in Case-2 of JBMHM. Even though the installed power of the HPP in JBSHM is almost 1/4 of the installed capacity of 10 HPPs in JBMHM, percentages of income increase are almost the same. This is also the case for the collaboration of the HPP with 15 WPPs (the rate of increase in income is 0.37% in Case-2 of JBMHM for both tolerance coefficient regimes while they are 0.39% for CTC regime and 0.36% for DTC regime in JBSHM). This findings shows the income-increasing impact of the reservoir capacity of the HPP in JBSHM. In addition, extra incomes achieved by joint bidding with the HPP are less in case of DTC regime compared to the CTC regime for the all collaboration groups including WPPs.

How the extra incomes achieved by the collaboration via the deployment of joint bidding strategy will be shared is also a challenging issue. In practice, there are balancing groups registered to EPIAS for spot market operations with considerably high installed capacities. The more the installed capacity of the collaboration group, the greater the income gain through joint bidding. Responsible entity for the balancing group makes agreements for each of the participant of the balancing group. Since the extra incomes are guaranteed by collaboration, some portion of the expected income gain is shared with the participants of the balancing group via mutual agreements. In these agreements, participants are guaranteed to earn more than the expected income when they bid individually. However, if these balancing groups start to be dominant in the market in a way to be able to change the market clearing prices and the quantities sold in the market then inquiry might be conducted by Competition Authority and Energy Market Regulatory Authority to assess whether there is a case of abuse of dominant position. Abuse of dominant position is legally forbidden.

Responsible entity from the balancing group guarantees the income (Guaranteed Price. Realized Generation) to the participants and accept the balancing responsibility and the responsibility of all transactions in return of the extra income margin (or mutually agreed portion of this extra income margin).

Battery deployment model includes the deployment of VRFB, which is defined as the one of the most promising energy storage system option especially for utility scale applications in the literature, for WPPs and the SPP. The model is run for different collaboration groups and the extra income achievements with respect to the size of battery is analyzed. According to the findings based on the model outputs, extra income values per MW of battery for SPP is between $218 and $400 /MW-year, while these values are between $2,460-$6,795/MW-year for the group of 15 WPPs. Therefore, deployment of VRFB for WPPs created extra income more than 10 fold of that of for SPP. If the levelized costs are compared with the annual extra income values achieved per MW of battery for

WPPs and the SPP, deployment of VRFB for WPPs and the SPP to counterbalance the deviations and increase the total income in day ahead market is not a financially viable and feasible option with current cost structure of VRFB in the absence of any subsidization.

According to the model outputs based on the available data set, joint Bidding in day ahead market via collaboration by participating to balancing groups (1 st strategy) ensures extra income achievements for both WPPs and the SPP. Regarding the 1 st strategy, if the WPPs and SPP set balancing groups even in the absence of any dispatchable energy source, they can benefit from the extra income achievements mainly due to the savings from the imbalance cost. If this balancing groups also includes the dispatchable energy source, even higher extra incomes are possible. Joint bidding with HPPs yields extra incomes which is highly related to the size of the reservoir capacity. The income-increasing impact of the HPP, which has large reservoir capacity and 80 MWs of installed capacity, is equal to the 10 HPPs which have limited reservoir capacity and 311 MWs of installed capacity. Deployment of storage technologies (2nd strategy), is not financially feasible and viable according to the current cost structure of VRFB. It can be viable if the extra income becomes sufficient to cover the levelized cost of VRFB, which is between $289,000 and $536,000 /MW-year. However, the income-increasing impact of VRFB, which is another dispatchable source of energy, is not enough to cover its cost under current cost structure. Declining trend of the cost of VRFB together with increasing trend of market clearing prices will make the deployment of VRFB feasible in coming future, if these trends continue. When VRFB will be feasible depends on the rate of decline in VRFB cost and the rate of increase in market clearing prices in addition to the regulatory coefficients set by regulatory authority.

CHAPTER 5

CONCLUSION

2 possible strategies are proposed for WPPs and SPPs to reduce their imbalances and maximize their income in day ahead market.

Strategy 1. Joint Bidding in day ahead market via collaboration by participating to balancing groups. Joint Bidding Multi-Hydro Model (Joint bidding with hydropower plants with limited reservoir capacity) and Joint Bidding Single-Hydro Model (Joint Bidding with HPP with large reservoir capacity) are developed to assess the impact of 1st strategy.

Strategy 2. Deployment of storage technologies. Battery Deployment Model is developed to assess the impact of deployment vanadium redox flow batteries.

Main outcomes derived from the assessment of these strategies are:

- Joint Bidding in day ahead market via collaboration by participating to balancing groups (1st strategy) even in the absence of any dispatchable energy source ensures extra income achievements for both WPPs and the SPP up to 1.38% annually. Therefore, joining a balancing group is attractive for renewable energy-based power plants. Moreover, day ahead offered generation by individual power plants is used as an input in the models even in case of joint biddings. It should be noted that in case of joint bidding, the power plants could offer higher amount of generation and take higher risks in day ahead market due to the balancing impact of the balancing groups.

- In addition, as the installed power of the collaboration group increases, Loss of income due to imbalance per MW of installed power of the corresponding collaboration group decreases. Annual loss of income due to imbalance is reduced up to 60% with Joint Bidding (%)
- If this balancing groups also includes the dispatchable energy source, even higher extra incomes are possible. Joint bidding with HPPs yields extra incomes which is highly related to the size of the reservoir capacity. The income-increasing impact of the HPP, which has large reservoir capacity and 80 MWs of installed capacity, is equal to the 10 HPPs which have limited reservoir capacity and 311 MWs of installed capacity.
- Tolerance coefficient regimes set by regulatory authority not only impacts the amount of extra income gains but also the collaboration group with highest additional income gains. A collaboration group with highest extra income creation under CTC regime may lose their advantage under DTC regime.
- Since the extra incomes are guaranteed by joint bidding, some portion of the expected income gain is shared with the participants of the balancing group via mutual agreements. In these agreements, participants are guaranteed to earn more than the expected income when they bid individually.
- Responsible entity from the balancing group (registered to EPIAS) basically guarantees the income (Guaranteed Price . Realized Generation) to the participants and accept the balancing responsibility and the responsibility of all transactions in return of the extra income margin (or mutually agreed portion of this extra income margin) provided by the regulatory authority through the deployment of tolerance coefficients.
- The income-increasing impact of VRFB, which is another dispatchable source of energy, is not enough to cover its cost under current cost structure. Declining trend of the cost of VRFB together with increasing

trend of market clearing prices will make the deployment of VRFB feasible in coming future, if these trends continue. When VRFB will be feasible depends on the rate of decline in VRFB cost and the rate of increase in market clearing prices in addition to the regulatory coefficients set by regulatory authority. Less tolerance to imbalances and higher coefficient of imbalance set by the regulatory authority, increasing market clearing prices together with declining battery cost will surely foster the deployment of utility-scale battery technologies. The increase in battery deployment will surely reduce the imbalance amount in day ahead market, contribute considerably to matching supply with demand for electricity and will reduce the burden of TEIAS in balancing market. The investment costs for the upgrade of the grid is likely to be deferred with the deployment of batteries. Batteries may also be deployed in balancing markets for real-time balancing of supply and demand (storing at low prices and selling at high prices).

- Energy Market Regulatory Authority can adjust the regulatory coefficients to attract more attention to the balancing responsibility. Utility scale battery deployment might be incentivized by regulatory authority to foster the penetration of battery technologies to the electricity market.
- Even though the balancing groups are promising in terms of higher incomes for wind and solar power plants, dominant position of balancing groups should be monitored by regulatory authorities in terms of possibility of abuse of dominant position.

The main contribution of this study to the literature is comparative analysis of two different strategies for wind and solar power plants which are considered as the non-dispatchable sources of energy. The deployment of utility-scale battery technologies in electricity markets is a newly emerging market from the viability and feasibility perspective. There are limited studies conducted to assess the impact of deployment of battery technologies in electricity markets. In addition, “Loss of income due to imbalance” is also introduced to the literature. Loss of income represents the clear indication of the opportunity cost of imperfect forecasting. Opportunity cost of imperfect forecasting (LOSSI) is a clear indication for the extent of possible income creation for wind and solar power plants with improved forecasting.

In addition, models developed can be a good basis for further development to cover the intraday market and balancing markets as well as the deployment of battery technologies in these markets. Deployment of utility-scale batteries are likely to be the main game-changer in balancing markets. Storing of energy at low price periods and selling to the market at high price periods seems unavoidable with the declining trend of cost of utility-scale battery technologies.

5.1 Future Line of Work:

As a future line of work, how the achievements in income via collaboration can be shared among the participants of the collaboration groups can be incorporated to the optimization model.

In addition, intraday market and balancing markets can also be incorporated to the scope of this study. Deployment of batteries can be extended to cover the intraday market and balancing market which is an opportunity to store the energy at low prices and sell it at high prices.

REFERENCES

[1] Web page reference: https://www.iea.org/reports/world-energy-outlook 2019/renewables#abstract, January 2020

[2] Peng D., Poudineh R., 2019, Electricity market design under increasing renewable energy penetration: Misalignments observed in the European Union, Utilities policy 61 (2019) 100970

[3] Bianco V., Driha O.M., Jimenez M. S., 2019, Effects of renewables deployment in the Spanish electricity generation sector, Utilities policy 56 (2019) 72-81

[4] Carlini E. M., Schroeder R., Birkebaek J. M., Massaro F., 2018, EU transition in power sector How RES affects the design and operations of transmission power systems, 2019, Electric Power Systems research 169 (2019) 74-91

[5] Vazquez L. C., Carrillo C., Dorado E. D., Lorenzo J.A.M., Alam M.N.E., 2018, Evaluation of a data driven stochastic approach to optimize the participation of a wind and storage power plant in day ahead and reserve markets, Energy 156 (2018) 278-291

[6] Locatelli G., Plerma E., Mancini M., 2015, Assessing the economics of large energy storage plants with an optimization methodology, Energy 83(2015) 15-28

[7] Derinkuyu K., 2015, On the determination of European day ahead electricity prices: The Turkish case, European Journal of Operation Research 244, 980-989.

[8] Gomes I.L.R., Pousinho H.M.I., Melico R., Mendes V.M.F., 2016, Bidding and Optimization Strategies for Wind-PV Systems in Electricity Markets Assisted by CPS, Energy Procedia 106 (2016) 111-121.

[9] Laia R., Pousinho H.M.I., Melico R., Mendes V.M.F., 2016, Bidding Decision of Wind-Thermal GenCO in Day-Ahead Market, Energy Procedia 106 (2016) 87-96.

[10] Gomes I.L.R., Laia R., Pousinho H.M.I., Melicio R., 2018, Aggregation platform for Wind-PV-Thermal Technology in Electricity Market, International Symposium on Power Electronics, Electrical Drives, Automation and Motion

[11] Yin Y., Liu T., He C., 2019, Day-ahead stochastic coordinated scheduling for thermal-hydro-wind-photovoltaic systems, Energy 187 (2019) 115944

[12] Gomes I.L.R. R., Pousinho H.M.I., Melico R., Mendes V.M.F., 2017, stochastic coordination of joint wind and photovoltaic systems with energy storage in day ahead market, Energy 124 (2017) 310-320.

[13] Angarita J.L., Usaola J., Crespo J.M., 2009, Combined hydro-wind generation bids in a pool based electricity market, Electric Power Systems Research, 79 (2009) 1038-1046.

[14] Akbari E., Hooshmand R. A., Gholipour M., Parastegari M., 2019, Stochastic Programming-based optimal bidding of compressed air energy storage with wind and thermal generation units in energy and reserve markets, Energy 171 (2019) 535-546

[15] Nojavan S., Zare K., Feyzi M. R., 2013, Optimal Bidding strategy of generation station in power market using information gap decision theory (IGDT), Electric Power Systems Research 96 (2013) 56-63

[16] Cruz P., Pousinho H.M.I., Melico R., Mendes V.M.F., 2014, Optimal coordination on wind-pumped-hydro operation, Procedia Technology 17 (2014) 445-451

[17] Knezevic G., Topic D., Juric M., Nicolovski S., 2019, Joint market bid of a hydroelectric system and wind parks, Computers and Electrical engineering 74 (2019) 138-148,

[18] Gomes I.L.R., Melico R., Mendes V.M.F., Pousinho H.M.I, 2019, Decision making for sustainable aggregation of clean energy in day ahead market: Uncertainty and risk, Renewable Energy 133 (2019) 692-702

[19] Vazquez J.L.C., Carrillo C., Dorado E. D., 2017, Evaluation of the uncertainty in the scheduling of a wind and storage power plant participating in day ahead market and reserve markets, Energy Procedia 136 (2017) 73-78

[20] Khaloie H., Abdollahi A., Khah M.S., Siano P., Nojavan S., Moghaddam A.A., Catalao J.P.C., 2020, Co-optimized bidding strategy of an integrated wind-thermal-photovoltaic system in deregulated electricity market under uncertainities, Journal of Cleaner production 242 (2020) 118434

[21] Parastegari M., Hoosmand R., Khodabakhshian A., Zare A., 2015, Joint operation of wind farm, photovoltaic, pump-storage and energy Storage devices in energy and reserve markets, Electrical Power and Energy Systems 64 (2015) 275-284.

[22] Gu Y., Bakke J., McCalley J., 2015, Day Ahead and Real Time Markets Simulation Methodology on Hydro storage, Cahpter 7, Energy Storage for Smart Grids

[23] Angarita J.L., Usaola J. G., 2007, Combining hydro-generation and wind energy Biddings and operation on electricity spot markets, Electric Power Systems Research 77 (2007) 393–400

[24] Braun S., 2016, Hydropower Storage Optimization Considering Spot and Intraday Auction Market, Energy Procedia 87 (2016) 36-44

[25] Shi Y., Eze C., Xiong B., He W., Zhang H., Lim T. M., Ukil A., Zhao J., 2019, Recent Development of Membrane for Vanadium Redox Flow Batteries, Applied Energy 238 (2019) 202-224.

[26]Joerissen L., Garche J., Fabjan C., Tomazic G., 2003, Possible Use of Vanadium Redox-Flow Batteries for Energy Storage in Small Grids and Stand-alone Photovoltaic Systems, Journal of Power Sources 127 (2004) 98-104.

[27] Turker B., Klein S. A., Komsiyska, Trujillo J.J., Bremen L. V., Kühn M., Busse M., 2013, Utilizing a vanadium redox flow battery to avoid wind power deviation penalties in an electricity market", Energy Conversion and Management 76(2013) 1150-1157.

[28] Liaw B., 2019, Large Scale Energy Storage 10 and Battery Safety and Failure Modes, ECS Transactions Vol 89, No 1-2

[29] Mayer K., Trück S., 2018, Electricity markets around the world, Journal of Commodity Markets, 9(2018) 77-100

[30] Aydoğdu A., 2014, Stochastic Wind-Thermal Generation Coordination for Turkish Day-Ahead Electricity Market, Thesis Submitted to The Graduate School Of Natural and Applied Sciences Of Middle East Technical University

[31] Barboros E., 2019, Feasibility of Pumped-Storage Hydraulic Systems based on Hourly Variation of Electricity Prices, Thesis Submitted to The Graduate School Of Natural and Applied Sciences Of Middle East Technical University

[32]Web reference: Turkish electricity Market Report for year 2020, https://www.epdk.gov.tr/Detay/Icerik/3-0-24-3/elektrikyillik-sektor-raporu, July 2021

[33] Üstündağ O., 2019, Utilization of Realistic Pumped Hydroelectric Storage System Model for Various Optimal Short Term Control Strategies Thesis Submitted to The Graduate School Of Natural and Applied Sciences Of Middle East Technical University

[34]Web reference: https://www.epias.com.tr/wp-content/uploads/2020/07/Haziran-2020-Elektrik-Piyasalar%C4%B1-Raporu.pdf, August 2021

[35]Web reference: https://www.mevzuat.gov.tr/mevzuat?MevzuatNo=5346&MevzuatTur=1&MevzuatTertip=5, January 2020

[36]Web reference: https://www.mevzuat.gov.tr/mevzuat?MevzuatNo=18907&MevzuatTur=7&MevzuatTertip=5 ,January 2020

[37] Web reference:
https://seffaflik.epias.com.tr/transparency/piyasalar/gop/ptf.xhtml, August, 2021

[38] Web reference: https://paracevirici.com/doviz-arsiv/merkez-bankasi/gecmis-tarihli-doviz/2017/amerikan-dolari, May,2019

[39] Web reference:
https://www.resmigazete.gov.tr/eskiler/2021/01/20210130-9.pdf, July, 2021

[40] Web reference: https://www.epdk.gov.tr/Detay/Icerik/3-0-72/elektrikyekdem, August 2021

[41] Council of European Energy Regulators, Status Review of Renewable Support Schemes in Europe for 2016 and 2017, Public Report, Ref: C18-SD-63-03 14 December 2018.

[42] Web reference: https://www.epdk.org.tr/Detay/Icerik/1-1270/electricityelektricity-legislation, January 2020

[43] US Department of Energy, Energy Storage Technology and Cost Characterization Report, July 2019

[44] Fayegh A. K., Rosen M.A., A Review of Energy Storage Types, Applications and Recent Developments, Journal of Energy Storage, 2020

[45] Rodby K.E., Carney T. J., Gandomi Y. A., Barton J.L., Darling R.M., Brushett F. R., Assessing Levelized Cost of Vanadium Redox Flow Batteries with Capacity Fade and Rebalancing, Journal of Power Sources, 2020.

[46] Web reference: Lazard’s Levelized Cost of Storage Analysis-version 4.0, https://www.lazard.com/media/450774/lazards-levelized-cost-of-storage-version-40-vfinal.pdf, August, 2019

CURRICULUM VITAE

Surname, Name: Özcan, Mehmet

EDUCATION

Degree	Institution	Year of Graduation
MS	METU Industrial Engineering	2003
BS	METU Environmental Engineering	1999
High School	Alanya High School, Alanya	1993

FOREIGN LANGUAGES

Advanced English

PUBLICATIONS

1. Özcan M., “Deployment of Balanced Scorecard Methodology for Ministry of Environment”, MS Thesis, 2003

2. Özcan M., Keysan O., Satır B., “Optimum Bidding Strategy for Wind and Solar Power Plants in Day-Ahead Electricity Market”; Energy Systems, 12667_2021_441, 2021