STOCHASTIC WIND-THERMAL GENERATION COORDINATION FOR TURKISH DAY-AHEAD ELECTRICITY MARKET

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ABSTRACT

STOCHASTIC WIND-THERMAL GENERATION COORDINATION FOR TURKISH DAY-AHEAD ELECTRICITY MARKET

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Uncertainties in wind power forecast, day-ahead and imbalance prices for the next day possess a great deal of risk to the profit of generation companies (GENCOs) participating in a day-ahead electricity market. GENCOs are exposed to imbalance penalties in the balancing market for any mismatch between their day-ahead power bids and real-time generations. Proper coordination of wind generation with thermal generation reduces this risk associated with wind uncertainty. This thesis proposes an optimal bidding and generation coordination strategy for GENCOs having wind and thermal generation units in the Turkish day-ahead electricity market. The objective is to find an optimal trade-off between expected profit and risk under wind uncertainty, depending on the risk preference of GENCO. Coordination problem is formulated as a mixed-integer two-stage stochastic programming problem. Scenario based wind power approach is used to handle the stochasticity of wind power. Solution algorithm makes use of dynamic programming in finding the unit commitment status of thermal units. For risk measurement, conditional value at risk (CVaR) term is introduced to the objective function. Sample case studies are investigated in order to assess the impact of the market, wind and thermal data on the day-ahead bidding and wind-thermal coordination. In addition to this, profitability of the coordination and different day-ahead bidding strategies as well

as trade-off between expected profit and CVaR are examined with comparative case studies.

Keywords: wind-thermal coordination, Turkish day-ahead electricity market, balancing market, CVaR

ÖZ

TÜRKİYE GÜN ÖNCESİ ELEKTRİK PİYASASI İÇİN
STOKASTİK RÜZGÂR-TERMİK ENERJİ ÜRETİMİ KOORDİNASYONU

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Üretim şirketlerinin gün öncesi elektrik piyasalarından elde ettiği kâr; ertesi günkü rüzgâr tahmini, piyasa takas fiyatı ve sistem dengesizlik fiyatlarındaki belirsizlikler yüzünden büyük risk altındadır. Gün öncesi taahhüt edilen üretim ile gerçek zamanlı üretim arasındaki fark, üretim şirketlerini dengeleme güç piyasasında cezaya maruz bırakmaktadır. Rüzgâr üretiminin termik üretim ile koordinasyonu belirsizliklere bağlı riskleri azaltmaktadır. Bu tez, Türkiye gün öncesi elektrik piyasasına katılan; rüzgar ve termik enerji üretimi ünitelerine sahip üretim şirketleri için optimum teklif verme ve üretim koordinasyonu stratejisi önermektedir. Amaç üretim şirketinin risk tercihine en uygun beklenen kâr ve risk dengesini bulmaktır. Koordinasyon problemi iki aşamalı rassal programlama problemi olarak formüle edilmiştir. Senaryo tabanlı yaklaşım ile rüzgârın rassallığı ele alınmıştır. Çözüm algoritması termik ünite atamalarını bulmak için dinamik programlama metodundan yararlanmaktadır. Risk ölçümü için koşullu riske maruz değer (CVaR) terimi hedef fonksiyona eklenmiştir. Piyasada oluşan değerler ile rüzgâr ve termik verilerinin gün öncesi teklif ve rüzgâr-termik enerji üretimi koordinasyonu üzerindeki etkisi örnek çalışmalar ile incelenmiştir. Buna ek olarak, koordinasyonun kârlılığı ve farklı gün öncesi teklif stratejileri ile birlikte beklenen kâr ve CVaR dengesi karşılaştırmalı çalışmalarla irdelenmiştir.

Anahtar Kelimeler: rüzgâr-termik enerji üretimi koordinasyonu, Türkiye gün öncesi elektrik piyasası, dengeleme güç piyasası, koşullu riske maruz değer

in memory of my grandmother

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LIST OF ABBREVIATIONS

TEAŞ	Turkish Electricity Generation and Transmission Company
EÜAŞ	Electricity Generation Company
TEDAŞ	Turkish Electricity Distribution Company
TEİAŞ	Turkish Electricity Transmission Company
TETAŞ	Turkish Electricity Trading and Contracting Company
TEK	Turkish Electricity Authority
EPDK	Energy Market Regulatory Authority
EPİAŞ	The Energy Markets Operation Company
ENTSO-E	European Network of Transmission System Operators for Electricity
MYTM	National Load Dispatch Center
PMUM	Market Financial Settlement Center
BSR	Balancing and settlement regulation
PDF	Probability density function
PMF	Probability mass function
UC	Unit commitment
PBUC	Price-based unit commitment
ED	Economic dispatch
MCP	Market clearing price
SMP	System marginal price
MO	Market operator
ISO	Independent system operator

RTO	Regional transmission organization
SAA	Sample average approximation
SMIP	Stochastic mixed-integer program
OECD	Organisation for Economic Co-operation and Development
BO	Build-operate
BOT	Build-operate-transfer
TOR	Transfer-of-operational-rights
GDP	Gross domestic product
CVaR	Conditional value at risk
VaR	Value at risk

NOMENCLATURE

Indices

t	Bidding period
s	Scenario
w	Wind plant
g	Thermal unit

Decision Variables

P_{tgw}^{bid}	Optimum amount of day-ahead power bid at time t for coordinated wind-thermal generation (MW)
P_{tg}^{bid}	Optimum amount of day-ahead power bid at time t for uncoordinated thermal generation (MW)
P_{tw}^{bid}	Optimum amount of day-ahead power bid at time t for uncoordinated wind generation (MW)
Δ_{ts}	Net imbalance power at time t for scenario s (MW)
Δ_{ts}^{+}	Imbalance-up power at time t for scenario s (MW)
Δ_{ts}^{-}	Imbalance-down power at time t for scenario s (MW)
P_{tsg}	Power produced by thermal unit g at time t for scenario s (MW)
u_{tg}	UC status of thermal unit g at time t; 1 means ON; 0 means OFF
ζ and η	Auxiliary variables for computing CVaR_{α}

Stochastic Variables

P_{tsw}	Wind power generation at time t for scenario s (MW)

Parameters and Constants

ρ_t^{da}	Day-ahead market price at time t (\$/MWh)
ρ_t^{smp}	System marginal price at time t (\$/MWh)
ρ_t^{+}	Imbalance-up price at time t (\$/MWh)
ρ_t^{-}	Imbalance-down price at time t (\$/MWh)
$RBID_{tgw}$	Revenue from coordinated wind-thermal generation day-ahead bid (\$)
$RBID_{tg}$	Revenue from uncoordinated thermal generation day-ahead bid (\$)
$RBID_{tw}$	Revenue from uncoordinated wind generation day-ahead bid (\$)
$PIMB_{ts}$	Imbalance penalty at time t for scenario s (\$)
$\overline{P}_g$	Maximum thermal power output limit of thermal unit g (MW)
$\underline{P}_g$	Minimum thermal power output limit of thermal unit g (MW)
P_{tg}^{opt}	Optimum thermal power output found by PBUC of thermal unit g at time t (MW)
P_{tsg}^{max}	Maximum power output of thermal unit g at time t for scenario s (MW)
P_{tsg}^{min}	Minimum power output of thermal unit g at time t for scenario s (MW)
P_{tw}^{exp}	Expected wind power generation at time t (MW)
u_g^{ini}	Initial ON/OFF duration of thermal unit g at the beginning of scheduling horizon (hour)
$MinUp_g$	Minimum-up time of thermal unit g (hour)
$MinDn_g$	Minimum-down time of thermal unit g (hour)
T_{tg}^{up}	Time that thermal unit g has been up at time t (hour)

T_{tg}^{dn}	Time that thermal unit g has been down at time t (hour)
$\overline{RU}_g$	Maximum ramp-up rate limit of thermal unit g (MW/h)
$\overline{RD}_g$	Maximum ramp-down limit of thermal unit g (MW/h)
RU_{tsg}^{max}	Maximum thermal ramp-up time of unit g at time t for scenario s (MW/h)
RD_{tsg}^{max}	Maximum thermal ramp-down time of unit g at time for scenario s (MW/h)
FC_g	Fuel cost of thermal unit g ($/MBtu)
a_g, b_g, c_g	Heat rate curve parameters of thermal unit g (MBtu/MW^2, MBtu/MW, MBtu)
$StUp_g$	Start-up cost of thermal unit g ($)
C_{tsg}	Thermal generation cost of thermal unit g at time t for scenario s ($)
β	Risk aversion parameter
α	Confidence level
$CVaR_\alpha$	Conditional value at risk at the α confidence level
π	Probability of a scenario
N_S	Number of scenarios
N_T	Duration of period (hour)
N_G	Number of thermal units

CHAPTER 1

INTRODUCTION

In recent years, share of wind power in electricity generation portfolios worldwide has increased with dramatic pace. Regulations on greenhouse emissions, increasing price of fossil fuels, government incentive price tariffs for renewable energy and technological developments have led the wind power to have competitive advantages over conventional sources of energy. Total installed capacity of the wind power throughout the world has been doubled in the last four years and reached about 318 GW as of 2013 [1]. Target of European Union is to obtain 20% of its electricity generation from renewable energy sources by 2020 most of which is scheduled to be generated from the wind power [2]. The U.S. aims at an adoption level of 20% by the year 2030 [3]. According to the strategic plan of Ministry of Energy and National Resources, Turkey has a goal of 20 GW of wind power installed in the whole country by 2023, which is the 100th anniversary of the country [4].

Trading of the wind power in electricity markets is still a relatively new problem. Most wind power producers prefer trading electricity with grant-in-aid fixed feed-in tariff or long term agreements in order to prevent their profits from price fluctuations in short term electricity markets [5, 6]. Such risk-free long term contracts usually have lower selling prices compared to those in short term electricity markets. Participation in short term markets such as day-ahead electricity markets may increase profits but also brings its risk along. Wind producers face three main sources of risk caused by uncertainties in day-ahead markets; which are namely, wind power generation, day-ahead price and balancing market price [7].

The objective of a power producer in such markets is to maximize the expected value of profit under certain level of risk associated with these uncertainties. Thus, generation companies (GENCOs) must hedge their profits against these risk factors to participate in a day-ahead electricity market.

Day-ahead markets mandate participants to declare their generation schedules for the next day several hours before the start of the operational day. Time difference between submission of bids and real-time operation ranges from 14 to 38 hours. For example, in Spanish day-ahead market, bids are submitted a day before at 10:00 am [9]. It is 11:30 am for Turkish day-ahead market case [10]. On the other hand, hourly wind power generation can be forecasted with a mean absolute error in the range of 15%-20% for a single plant from day before; thus, deviations from day-ahead schedule inevitably occur in actual generation [8]. For this reason, wind producers are exposed to high imbalance penalties in the balancing markets because of the uncertain wind forecasts. Imbalance prices are highly volatile and unpredictable. One of the reasons for this is that the amount of energy traded and number of participants in balancing markets is relatively low compared to day-ahead markets. Secondly, dual pricing mechanism, which Turkish balancing market has been practicing, makes imbalance prices even more difficult to estimate due to almost random nature of sign of overall imbalances of the producer and the system.

Contrary to the wind power generation, thermal generation is highly controllable and dispatchable. Nuclear and coal-fired thermal units, which are considered as baseload units, have lower operating costs relative to other fossil-fueled units; however, they have slower ramp rates, higher minimum generation levels and require long start-up and shut-down time to operate. On the other hand, natural gas or oil-fired thermal units, which are known as intermediate and peaking units, have faster ramp rates, relatively lower minimum generation levels and fast start-up and shut down capabilities which make them suitable for balancing wind generation. In despite of high flexibility, these units usually have expensive operating costs [11]. Due to uncertainty and variability in market prices, thermal units are also subjected to risk of low profits or loss in day-ahead markets. Coordination facilitates thermal units to contribute to the revenue of a GENCO by balancing wind generation at periods of low thermal profitability. Wind generation; on the other hand, utilizes thermal units to avoid high imbalance penalties in balancing market with coordination. Consequently, wind-thermal coordination has been found beneficial for both wind and thermal units under wind and price uncertainty [9]. Independent system operator (ISO), which is responsible for the system balance, also benefits from coordination since it reduces the system imbalance caused by uncertainty in wind generation.

Not only coordination but also the strategy of GENCO for bidding in the wholesale markets influences revenue, imbalance cost, and consequently the overall profit of a GENCO. In order to make optimal decisions in the presence of uncertainties, two-stage programming method has been widely used [5, 9, 12, 13, 14, 15]. In two-stage stochastic programming, there are first and second stage decisions which are made before and after uncertainties are resolved, respectively. First stage decisions, which are known as "here and now decisions", are determined based on the possible realizations of uncertainties belonging to the second stage. Second stage decisions, which are also known as “wait and see decisions” are given after the uncertain event occurs. In wind-thermal coordination problem, first stage decisions may include thermal unit commitment (UC) schedule, day-ahead bid; while second stage decisions may cover economic dispatch (ED) of thermal unit with realization of uncertainties. Moreover, attitude towards risk plays an important role on the first and second stage decisions of GENCO. This thesis utilizes conditional value at risk (CVaR) concept, which is exercised to represent the risk preference of GENCOs in various studies [5, 7, 9, 13, 16], as a risk measurement tool.

Much of the previous research studied the wind-thermal coordination from an independent system operator (ISO) perspective [17, 18]. This study approaches to wind-thermal coordination problem from point of view a GENCO which participates in Turkish day-ahead electricity market. The organization of this thesis is as follows. In Chapter 2, background information is given about the general electricity market structure, Turkish balancing and settlement market, wind-thermal coordination and CVaR. Deregulation of electricity markets, market entities and their roles are mentioned briefly. Emphasis is put on the wholesale and retail electricity trade, especially on the types of wholesale markets. Development of Turkish electricity market is discussed with comparison of its past and today. Turkish balancing and settlement market, specifically day-ahead and balancing market stages are introduced with their auction mechanism. Generation scheduling, UC and ED concepts are explained. A short review of literature for trading wind generation in spot markets is given.

Chapter 3 is dedicated to the problem formulation and methodology. Application of two-stage stochastic programming to the wind-thermal coordination problem is explained in detail. Assumptions made in the problem formulation are revealed in this section. Objective functions for both coordinated and uncoordinated wind-thermal generation are defined in order to perform comparative case studies. Bidding constraints for different bidding strategies as well as market and thermal constraints are introduced to the problem. Lastly, solution algorithm to the problem is studied step by step.

In Chapter 4, various case studies are carried out in order to prove the validity of solution algorithm. Cases for hourly, multi-stage and 24 hour wind-thermal coordination are presented in order to assess different aspects of coordination. Impact of market data, wind power forecast, bidding strategy, risk attitude and thermal constraints on day-ahead power bid, thermal UC, thermal ED and profit of GENCO is investigated. Trade-off analysis of expected profit and CVaR is also practiced in this section.

Finally, this study finishes with Chapter 5, which is the conclusion and future work part. Introduced methodology and results obtained in the thesis are discussed.

Contributions to literature and future study that can be made on the scope of this thesis are also given.

CHAPTER 2

GENERAL BACKGROUND

2.1 ELECTRICITY MARKET

Electric power industry consists of four main components; generation, transmission, distribution and supply/retail as illustrated in Figure 2.1. For the last decades, these functions were used to operate under monopolies throughout the world; such as vertically integrated companies and state-owned entities. Deregulation of the electric power industry, which is also known as restructuring, resulted in vertically integrated power industry transforming into vertically separated entities. This led to the privatization and liberalization of electric power industry functions [19]. Deregulation does not dictate a unique structure; extent of it in different countries may vary. In most countries, transmission and distribution networks are still owned by monopolies [20]. Figure 2.2 illustrates the examples of regulated and deregulated electric power industries [22].

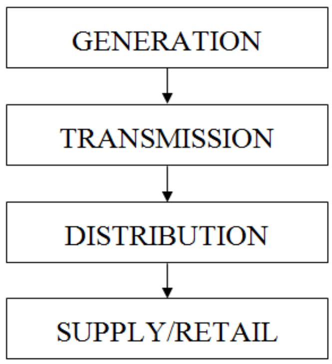

Figure 2.1 Vertical chain of electric power industry [19]

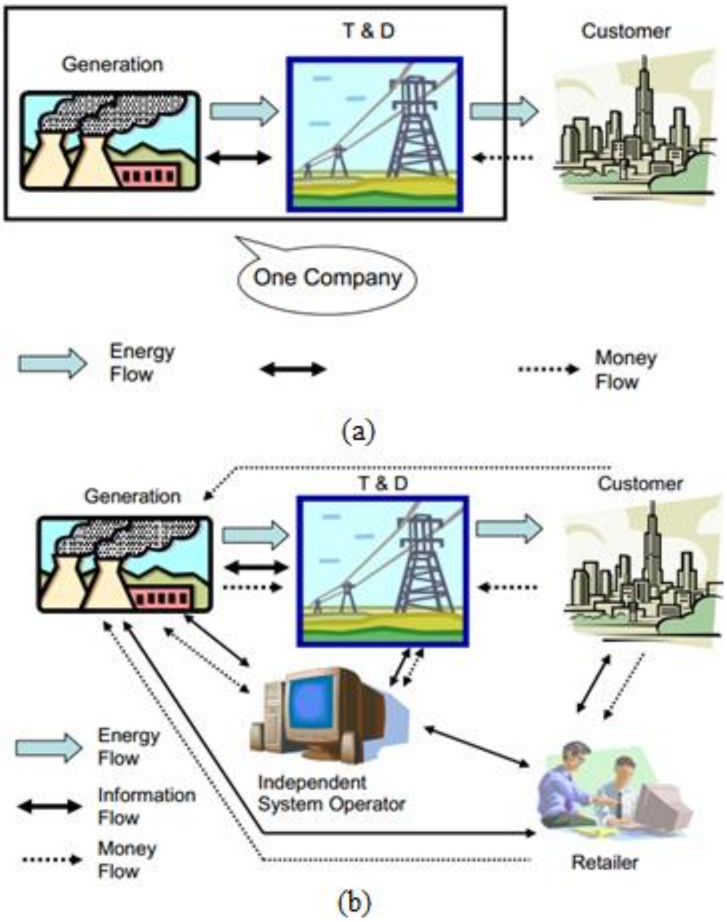

Figure 2.2 (a) Regulated electricity market example, (b) Deregulated electricity market example [22]

Major challenge in the new electric power industry structure is to form a competitive market environment on the generation and supply side while infrastructure (transmission and distribution) is managed by monopoly and open to all other market players [21]. A competitive power market created various ways of electricity trading between generation and retail services. Electricity generated by a GENCO is not always directly delivered to end-customer; it is bought and re-sold a number of times. All these transactions take place in the wholesale electricity market. Retailers buy the power in the wholesale market, then re-price and deliver it to end-consumers. End-consumers may range from households to large manufacturing facilities. Wholesale power is usually generated at high-voltage level, quantities in the scale of megawatt (MW) and then sold to retail companies. Retail electricity market starts at lower voltage levels and involves the distribution and deliver of power to end-consumers. Small and medium consumers purchase power from retailers, while large consumers may prefer to buy power from wholesale markets as illustrated in Figure 2.3 [23]. In addition to that, there are other market players such as aggregators, brokers and marketers who do not own any generator but facilitate energy transactions [24]. Since the generation of electricity is no longer a local monopoly and end-consumers can change their wholesaler and retailer, the market price does not have to be regulated any longer in sufficiently competitive markets [23].

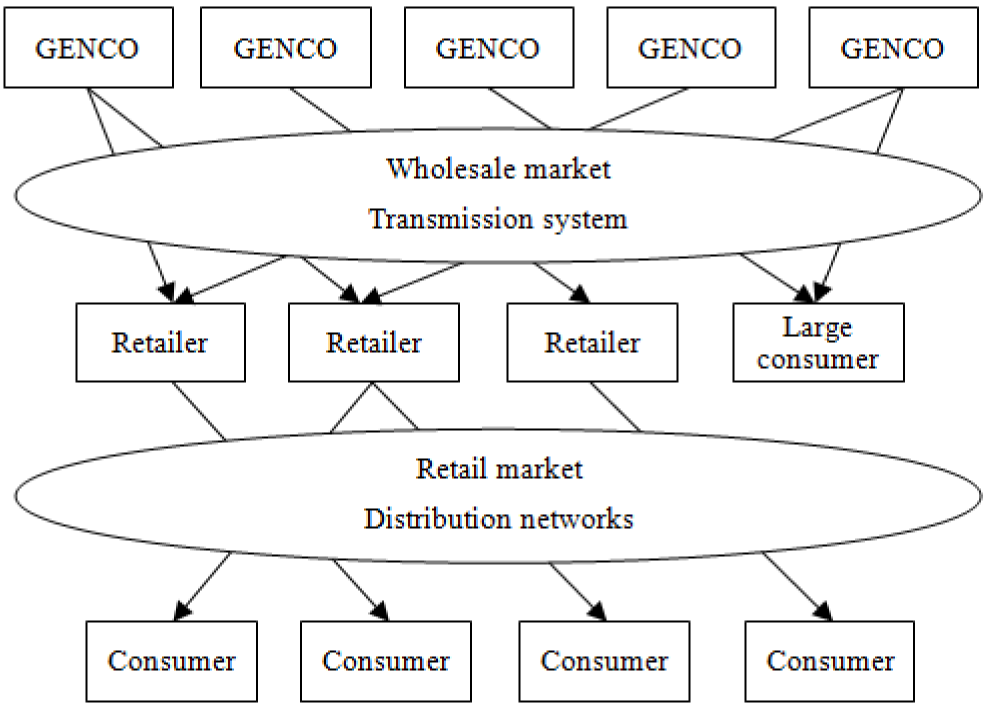

Figure 2.3 Wholesale and retail competition [23]

Wholesale electricity markets are mainly composed of energy markets, ancillary services and transmission market. Energy markets can be examined in three typical models, namely, pool model, bilateral contracts model and hybrid model. Pool market, also known as centralized markets, is an electricity market where demand and supply price-quantity pairs are matched through a market clearing process [24]. Such markets are also known as short-term (spot) markets [25]. On the supply side, GENCO can bid any price to sell its power; however, bidding too high or too low brings its risk of not being able to sell any power or less profitable trade. Likewise, buyers must balance its bid in order to be able to purchase power for a reasonable price [24]. An independent entity, which is called independent system operator (ISO) or regional transmission organization (RTO) depending on the market structure, is responsible for bid-based security-constrained economic dispatch in pool market. Duty of ISO may expand into transmission security, maintenance scheduling and power exchange in some market structures. The ISO must be equipped with powerful computational tools, involving market monitoring, ancillary services auctions, and congestion management in order to fulfill its responsibility.

Bilateral contract is a private agreement on the exchange of power between a buyer and seller. Terms and conditions of the agreement are decided by the trading parties. Those parties may have a sole aim of avoiding risks coming from uncertain market prices in the pool. In pool markets, generators are not only sellers but also could be buyers in order to fulfill their bilateral contract obligations in case of a generation shortage. Besides that, buyers can also be sellers in the case of a broker. Depending on time of trade and amount of power, bilateral trading may have different forms through physical and financial contracts [23]. The hybrid model combines unites both pool and bilateral contracts model. In the hybrid model, participating in the pool is not compulsory for buyers and sellers [24].

With regard to time of trade; there exist forward and real-time markets in wholesale electricity markets. The day-ahead electricity market is a common example of forward markets. Both energy and ancillary services can be traded in such market [24]. Ancillary services market include all the transactions for system frequency control such as primary, secondary and tertiary reserve; reactive power for voltage regulation and black-start capabilities [23]. Intra-day markets are opportunity for producers to offset their day-ahead bids in case of a change in scheduled generation due to uncertainty of wind or generator outage. Thus, producers minimize their imbalance penalties for any discrepancy between day-ahead bid and real-time generation. Balancing market is where producers can trade some of its high ramp generation capacity for system operator to level the system supply and demand balance [25]. Buyers and sellers may participate in futures market for exchange of electricity generation at a particular price, time and place in order to hedge financial risks. Figure 2.4 summarizes trade possibilities in wholesale electricity markets.

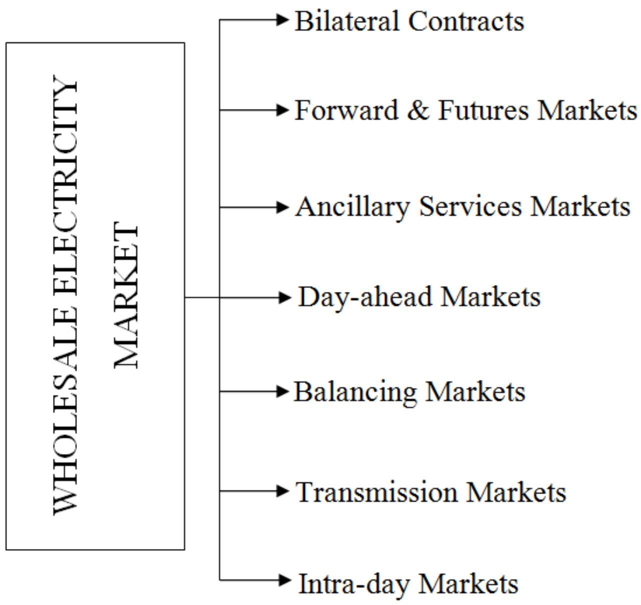

Figure 2.4 Trade possibilities in wholesale electricity market

2.1.1 Past and Today in Turkish Electricity Market

Turkey, having the sixth largest electricity generation installed capacity in Europe, has a fast growth rate in electricity consumption which surpasses gross domestic product (GDP) per capita growth as a result of population growth, industrialization and economic growth over the past two decades [26]. However, Turkey is still behind the electricity consumption per capita compared to average of Organisation for Economic Co-operation and Development (OECD) countries as given in Figure 2.5. This is considered to be an indication of further growth in electricity consumption per capita along with increasing GDP per capita in future. Table 2.1 highlights the dramatic increase in electricity consumption of Turkey according to TEİAŞ data.

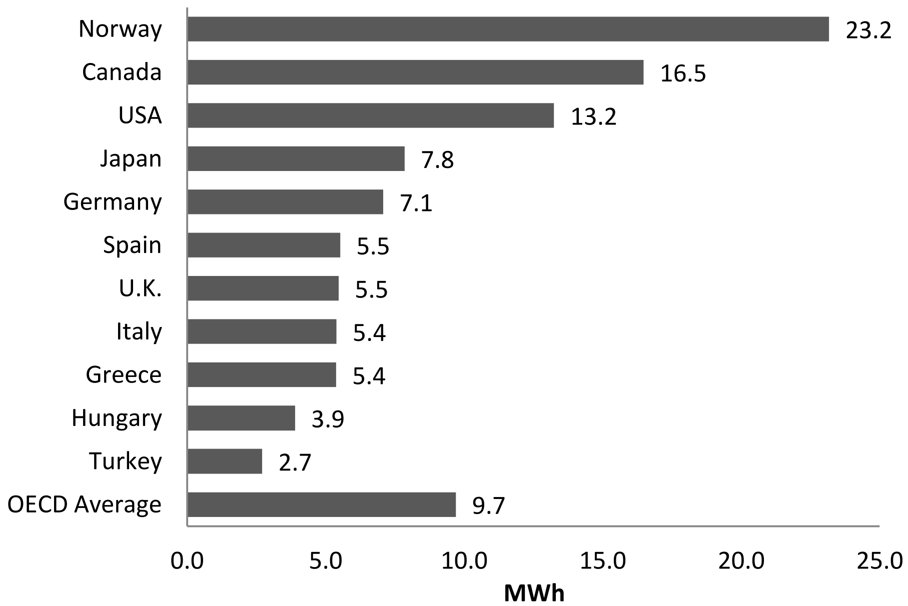

Figure 2.5 Countries electricity consumption per capita in 2011 [28]

Table 2.1 Peak demand and energy consumption in Turkey between 2003-2012 [27]

Year	Peak Demand (MW)	Growth (%)	Consumption (GWh)	Growth (%)	Minimum Load (MW)	Min. Load / Peak Demand (%)
2003	21729	3.4	141151	6.5	9270	43
2004	23485	8.1	150018	6.3	8888	38
2005	25174	7.2	160794	7.2	10120	40
2006	27594	9.6	174637	8.6	10545	38
2007	29249	6.0	190000	8.8	11100	38
2008	30517	4.3	198085	4.3	10409	34
2009	29870	-2.1	194079	-2.0	11123	37
2010	33392	11.8	210434	8.4	13513	40
2011	36122	8.2	230306	9.4	14822	41
2012	39045	8.1	242370	5.2	13922	36

History of Turkish electricity market can be examined in three main eras; monopoly, deregulation and liberalization. With the establishment of Turkish Electricity Authority (TEK) in 1970, electricity market was ruled as a state-owned monopoly until the start of liberalization progress. First law that regulates transfer of operational rights to native and foreign investors in generation, transmission, distribution and trade of electricity issued in 1984. In 1994, TEK was decomposed into two public owned organizations Turkish Electricity Generation and Transmission Company, TEAŞ (for generation and transmission) and Turkish Electricity Distribution Company, TEDAŞ (for distribution). TEAŞ was further vertically unbundled into three public owned organizations; Turkish Electricity Transmission Company, TEİAŞ (for transmission), Electricity Generation Company, EÜAŞ (for generation) and Turkish Electricity Trading and Contracting

Company, TETAŞ (for trade and contract) in 2001 in accordance with Turkish Electricity Market Law number 4628 issued that year. Figure 2.6 illustrates vertical unbundling in Turkish electricity market history.

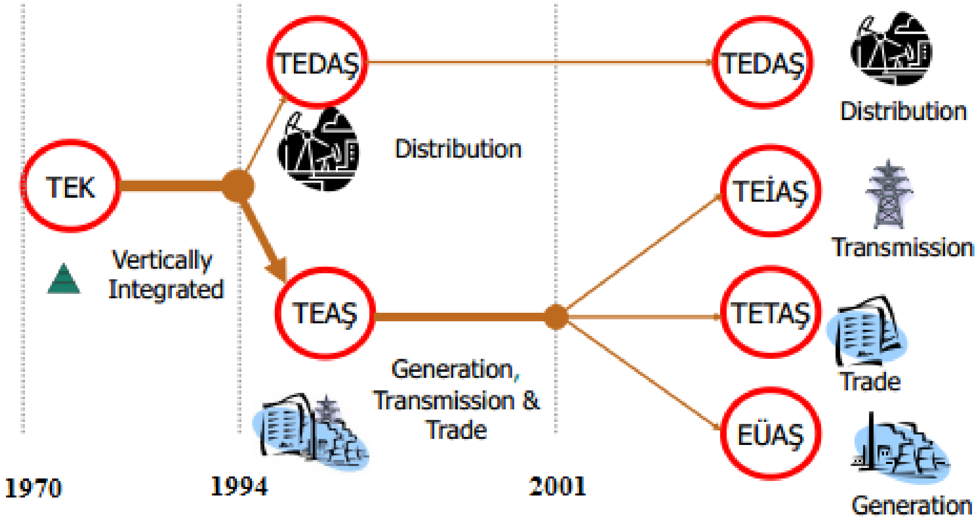

Figure 2.6 Vertical unbundling in Turkish electricity market history [29]

The market has been experiencing rapid pace of regulation and privatization process since unbundling of TEAŞ with electricity market law. In transmission and wholesale TEİAŞ and TETAŞ operate as state-owned entities, while TEDAŞ and EÜAŞ are gradually privatized under the control of Turkish Privatization Administration. In 2001, EPDK (Energy Market Regulatory Authority) was established in order to perform the regulatory and supervisory functions in the energy market. Integration into European Network of Transmission System Operators for Electricity (ENTSO-E), balancing and settlement regulations (BSR), laws issued on natural gas, nuclear energy and renewable are other milestones of Turkish Electricity market. For fully competitive market, intra-day market, nuclear investments, establishment of the Turkish Energy Markets Operation Company, EPİAŞ are on the horizon. Figure 2.7 depicts milestones in Turkish electricity market.

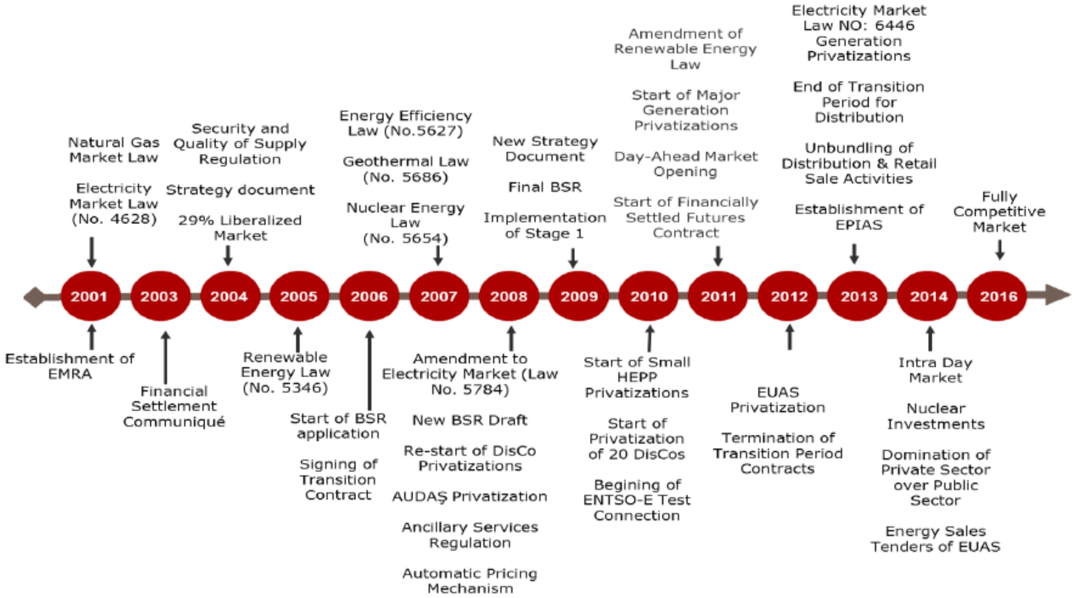

Figure 2.7 Milestones in Turkish electricity market [30]

With the recent liberalization, the appearance of Turkish electricity market has been changing significantly, the level of competition has been increasing and more and more players have been entering into the market every day. Objective of Turkish Electricity Market Law issued under number 6446, which was formerly issued under law number 4628, is to facilitate a stable and transparent market that provides consumers adequate, secure, quality, continual, cheap and environmental friendly electricity in competitive environment in accordance with provisions and to ensure independent regulation and supervision on the market. Turkish electricity market covers whole generation, transmission, distribution, wholesale, and retail, import and export trade activities managed by legal entities complying with the law. Private companies can play a role in generation, distribution and trading of electricity.

Participants in Turkish electricity market and energy flow are illustrated in Figure 2.8. In this figure, generation side is represented by the state entity private GENCOs, EÜAŞ and TETAŞ with its build-operate (BO), build-operate-transfer (BOT) and transfer-of-operational-rights (TOR) generators. EÜAŞ is entitled to build, lease and operate generation facilities in accordance with EPDK approved generation capacity projection. Total market share of a private GENCO in generation, including BO, BOT, TOR generation, cannot exceed 20% of the total installed capacity in the preceding year. GENCOs can sell their power to wholesale and retail companies or directly to eligible customers, while non-eligible customers are obliged to deliver electricity from distribution and retail companies. Eligible customers are those whose electricity consumption is more than 4500 kWh in a year. This consumption limit was set in 2014 and future target is to set the limit to zero in order to increase participation and competition in the demand side of the market.

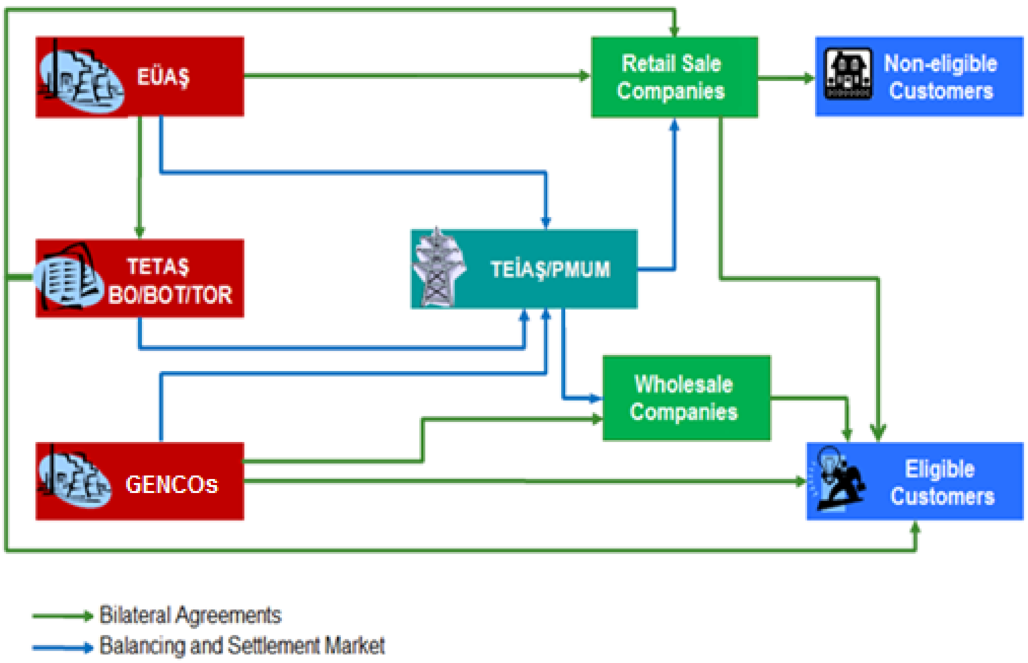

Figure 2.8 Participants in Turkish Electricity Market and energy flow [45]

The state-owned entity TEİAŞ is responsible for all transmission, market and system activities including transmission network planning construction and operation, preparation of the transmission, connection and use of system tariffs and grid code, international interconnection activities and preparation of generation capacity projection. Power system control and operation; and market balancing and settlement are managed via National Load Dispatch Center (MYTM) and Market Financial Settlement Center (PMUM), respectively under TEİAŞ [29]. Main responsibility of TETAŞ is to take over and manage electricity sale and purchase contracts. TETAŞ principally purchases electricity from EÜAŞ and can make annual sales to distribution companies under the authorization of EPDK. Total market share of a private wholesale company and its affiliates cannot exceed 10% of the total electricity consumed during the preceding year. Duties of distribution companies include distribution network planning construction and operation. Distribution companies may engage in generation and in retail sale activities with separate license. Retail sale companies trade electricity at distribution voltage level without any limitation on regional basis.

State share of electricity power plants is declining with growing privatization of power plants owned by EÜAŞ. Contribution of private companies in generation sector is three times that of the state in total generation capacity of 21365 MW installed in Turkey between 2003 and 2012 according to EPDK. Dominance of private sector in generation has become obvious recently, with 98% of the 2944 MW new installed capacity is set up by private companies in 2009. By 2012, more than half of the electricity generation capacity was owned by private companies. Regarding electricity distribution, all of the 21 distribution regions have been either sold or in privatization process [30]. Figure 2.9 summarizes share of private companies in generation, transmission and distribution.

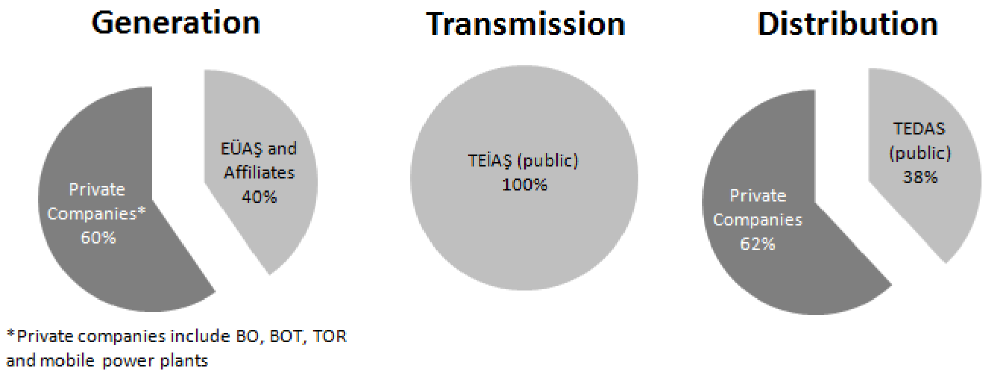

Figure 2.9 Market share in generation, transmission and distribution in 2012 [30]

2.1.1 Turkish Balancing and Settlement Electricity Market

Attendants of Turkish electricity market can participate in the balancing and settlement market which is regulated by law number 4628. Aim of the balancing and settlement market is to complement bilateral agreements to ensure daily electricity supply and demand balance of the system. This is achieved by the day-ahead and balancing markets coordinated by PMUM and MYTM in Turkish balancing and settlement market. Participation in day-ahead and balancing markets is not mandatory for supply and demand side. Balancing market manages tertiary reserves of attendants which preserve system supply/demand balance and security. Settlement, which is also known as financial conciliation, regulates transactions regarding the market.

At first, there was only balancing mechanism which was operated on hourly basis while transactions were taken place on monthly basis in the market in 2006. Settlement has been performed on hourly basis since day-ahead planning and real-time balancing market were introduced in 2009. It was obligatory for participants to submit available capacity to the day-ahead planning. In 2011, day-ahead market was adopted to replace day-ahead planning. Different from day-ahead planning, day-ahead market includes a collateral mechanism and creates a possibility for demand side to bid into market. Thus, participation of demand side helps power system to gain flexibility in supply and demand balance. Future target of balancing and settlement market is to introduce intra-day markets where supply side can trade electricity by updating their day-ahead generation schedules before real-time operation. With this market mechanism, imbalance power caused by uncertain generation types such as wind and solar is aimed to be reduced. Hence, producers will be able to avoid imbalance penalties in balancing market. Timeline of Turkish balancing and settlement market is given in Figure 2.10.

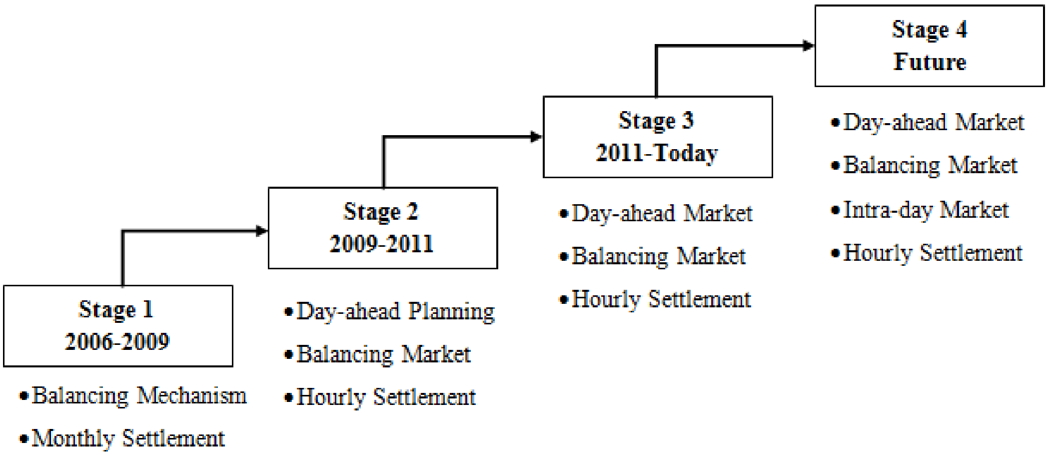

Figure 2.10 Timeline of Turkish balancing and settlement market

In the current stage of balancing and settlement market, there exist day-ahead and balancing markets. However, due to the fact that these relatively new markets are not adequately known and understood by GENCOs and wholesale suppliers; about 80-85% of the energy trade is still made through bilateral contracts. These contracts are agreed on the scale of months or years. Long term contracts still attract the attention of generation companies and large consumers as the risk is low compared to the spot market which has fluctuating prices. Day-ahead market, which covers about 10-15% of the energy trade in Turkish electricity market, is closed down ten hours before the start of operational day. On the contrary, balancing market does not have a certain schedule in advance. Deviations from the estimated demand or supply are compensated in real-time from balancing sources in accordance with balancing auction results from day-ahead. About 0-5% of electricity is traded in the balancing market in which decisions are given hourly [18]. Generators, wholesale suppliers and consumers are allowed to submit bids to the day-ahead or balancing market. Generators can bid to balancing market with the remaining capacity from bilateral contracts and day-ahead market. While it is PMUM which holds the auction for day-ahead market, MYTM is responsible for auction in balancing market. Each participant is to be paid based on day-ahead price, imbalance price, which is also known as real-time price, and amount of power supplied or consumed in settlement phase. Financial transactions are usually due to finalization in weeks or months after the operational day. Time horizon, volume of transactions and relations of market participants with market and system operator, PMUM and MYTM respectively; are summarized in Figure 2.11.

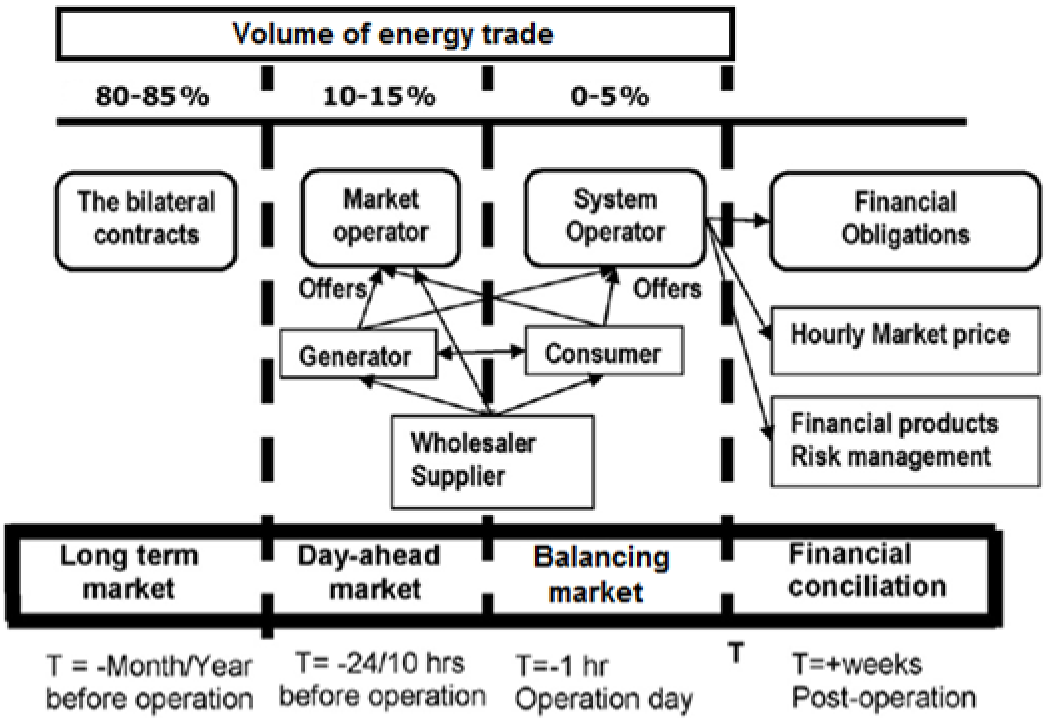

Figure 2.11 Activities on Turkish balancing and settlement market [31]

2.1.1.1 Auction in Turkish Day-Ahead Electricity Market

There are four main goals of Turkish day-ahead electricity market. First is to facilitate market participants to balance their generation and/or consumption portfolio by trading electricity for the next day. Second goal is to provide a balanced system for the system operator, MYTM by the market operator, PMUM. Next is to set a reference price for electricity and final goal is to make the congestion management possible for MYTM by creating bidding zones. Supply and demand side can adjust their generation and consumption with respect to price. Day-ahead prices are determined on hourly basis [10].

Turkish day-ahead market is an example of the pool model mentioned in Section 2.1. Among the day-ahead market participants, there are wholesale suppliers, private and state-owned generation units. There are two kinds of pricing mechanism in day-ahead market markets, which are namely uniform and pay-as-bid pricing. In uniform pricing, buyers and sellers trade electricity at the same price, which is called market clearing price (MCP). On the other hand, participants buy or sell energy according to their submitted price in pay-as-bid pricing. Turkish day-ahead electricity market executes uniform pricing in the day-ahead market auction. In the auction, market participants submit their supply and demand volumes remaining from bilateral transactions to the day-ahead market. Participants bid power quantities (MW) and their corresponding prices ($/MWh) that they are willing to sell or buy. At the end of the auction period, PMUM puts these quantity-price offers in order starting from the least-cost for generator bids and highest price for buying bids. The highest demand bids are matched with the lowest supply bids in terms of price. While PMUM constructs the supply and demand curve, it makes use of interpolation for empty values between two successive price/quantity offers. MCP, which is equal to day-ahead price in this case, is found at where ordered demand and supply offers are met as in the example illustrated in Figure 2.12. Generators who bid lower than MCP is accepted into day-ahead market and rewarded with

MCP, while buying offers which are higher than MCP can purchase power from market at MCP [31].

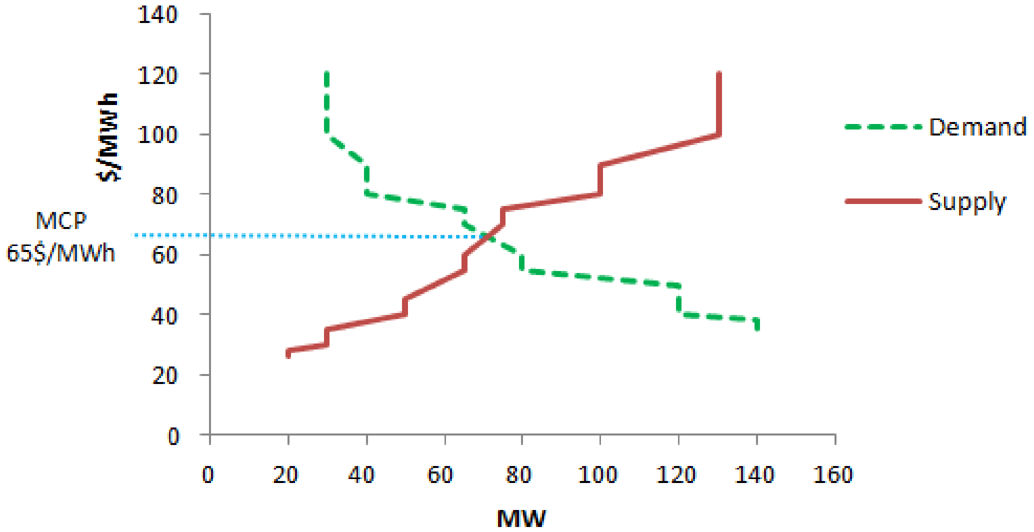

Figure 2.12 MCP settlement

Market participants can submit hourly, block and flexible bids in the day-ahead market. Amount and price of bids can vary for different hours. Maximum and minimum amount of power and price which can be traded is determined by the PMUM. A participant can submit both buying and selling offers for the same hour. In hourly bidding, there can be at most 32 buying and selling bids for each hour. Bids should be made in increasing price order. Different from hourly bidding, block bidding can be made for 4 to 24 successive hours of the day-ahead market. Block biddings are not evaluated hourly by PMUM; but they are accepted or rejected for the whole period of time that the block bidding is valid. Price of the block bid is compared with the average MCP of the time period that offer is valid. Block bidding is suitable for thermal units which have high minimum-up and minimum-down hour constraints and start-up and -down costs. Flexible bidding contains price and quantity information for one hour; however, the bid does not target a specific hour. In other words, PMUM can accept these bids at any hour in day-ahead. Hourly and block biddings have priority with respect to flexible bids for evaluation in day-ahead market auction. Examples of hourly and block biddings of a supplier are illustrated in Figure 2.13.

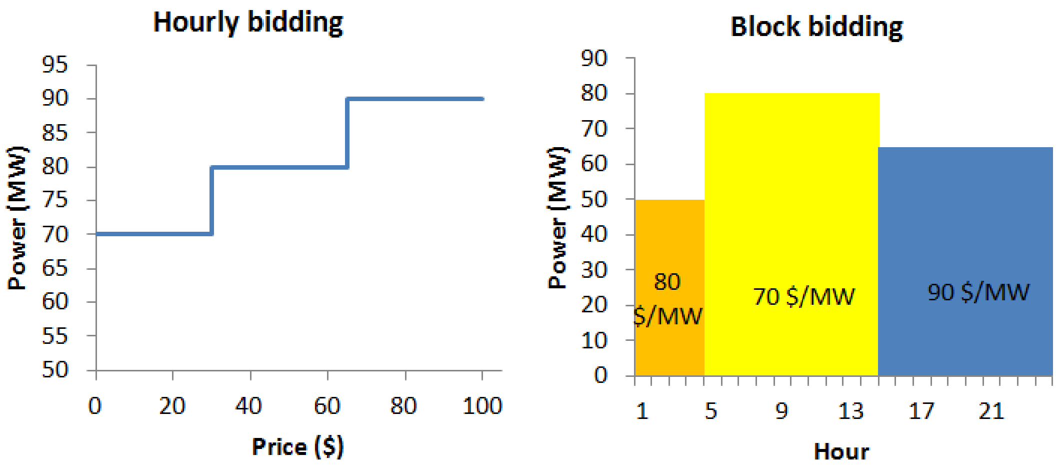

Figure 2.13 Hourly and block bidding for supply side

The bilateral contracts should be submitted until 16:00 to PMUM on the day before the day-ahead. The MYTM forecasts hourly demand for the next day depending on the temperature, bilateral contracts, and historical data and submit to PMUM and market participants together with transmission capacity and system constraints. Amount of power that should be supplied from the balancing and settlement market for each hour is found by subtracting the amount of power provided by the bilateral contracts from forecasted demand for the next day. Each market participant submits buy and sell bids to the market until 11:30 and PMUM evaluates the validity of bids by 12:00. Day-ahead market price and accepted bids for each hour of the next day are announced at 13:00. Each market participant may submit an objection before the final day-ahead market results are determined. The final results are published at 14:00 after objections are resolved. Table 2.2 summarizes the process of day-ahead market settlement.

Table 2.2 Day-ahead market settlement timeline

Day	Time	Activity
-2	16:00	Participants submit the bilateral contracts (before day-ahead) to PMUM
-1	09:30	MYTM submits the available transmission capacity, forecasted day-ahead demand and system constraints to PMUM and participants
-1	11:30	Participants submit buy/sell bids to PMUM
-1	13:00	Announcement of hourly day-ahead market prices and accepted bids by PMUM
-1	13:30	Objections
-1	14:00	PMUM announces the final day-ahead market results
0	00:00	The operational day begins

2.1.1.2 Auction in Turkish Balancing Electricity Market

Despite the fact that PMUM provides MYTM a balanced system with the day-ahead market, there can still be deviations in system balance due to uncertainties in generation and demand side caused by the changes in weather conditions, generator outages, etc. Balancing electricity market is the wholesale electricity market where demand and supply reserve capacity is sold or purchased in order to preserve the system balance in real-time. Participants are required to be able to change their generation or load at least 10 MW in 15 minutes in order to participate in the balancing market. Supply and demand side can submit both up-regulation and down-regulation bids into the market. Up-regulation bids are evaluated when the system is short of generation. Up-regulation can be provided either from increasing generator outputs or decreasing demand. Likewise, down-regulation is needed when there is excess generation in the system balance. Down-regulation is served by decreasing generator outputs. One should note that, primary, secondary and tertiary reserves that are used for system frequency control is managed by ancillary service.

Tertiary reserves which are utilized for system supply and demand balance operate under the balancing market. Figure 2.14 summarizes system reserves with their operational time scale, purpose and market mechanism.

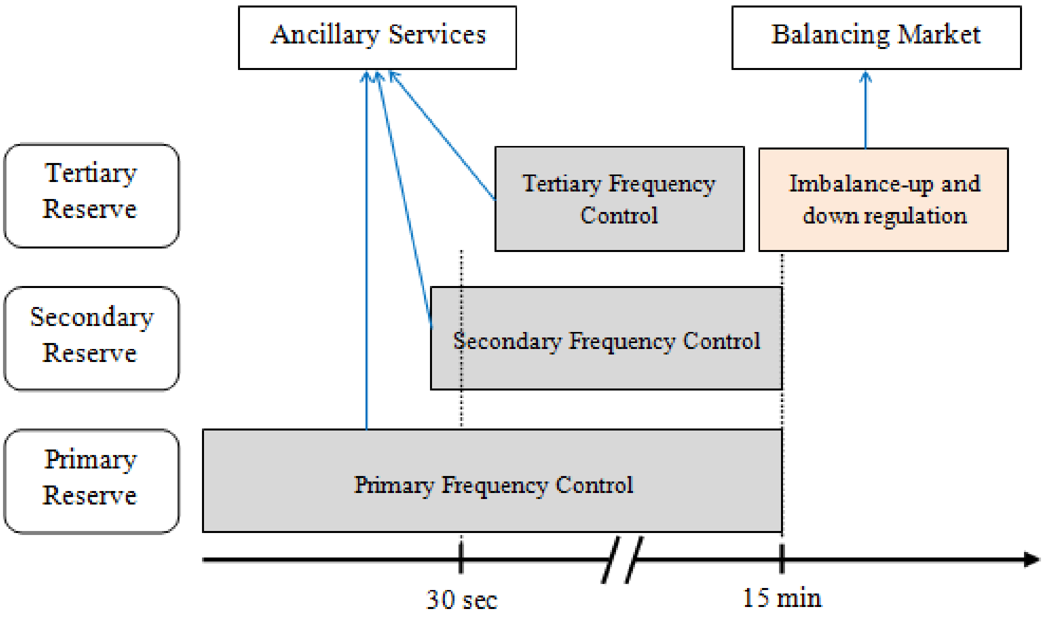

Figure 2.14 System reserves for supply and demand balance

Balancing market is not a suitable environment for participants to trade energy because of its highly variable pricing mechanism which depends on the direction of the system imbalance. There are mainly two balancing market pricing mechanism in balancing electricity markets; single imbalance pricing and dual imbalance pricing. In single imbalance pricing, same price is applied for positive and negative imbalance power; whereas, different prices are imposed on positive and negative imbalance power in dual pricing. In markets, where dual imbalance price is implemented such as in Turkish balancing electricity market, imbalance price depends on the sign of imbalance of the GENCO with respect to the sign of the overall system imbalance. Therefore, when the system is running *short* ($\lambda < 0$), then those GENCOs who are running *short* are penalized, while those who are running *long* ($\lambda > 0$) are not penalized. The opposite holds true when the system is running *long*. These rules are set up such that the GENCOs that degrade the system balance are penalized, while those that maintain the system balance are not affected.

There are certain rules in up-regulation and down-regulation bidding. Price for up-regulation bid of an hour must be equal or more than the day-ahead price of that hour. On the contrary, down-regulation price of an hour must be equal or lower than day-ahead price of that hour. Price of up and down-regulation bids must be submitted in increasing and decreasing order in terms of price for particular hour respectively. Amount of up and down-regulation power bids cannot be less than 10 MW. Up-regulation and down-regulation bids of qualified participants are arranged in increasing and decreasing order based on their price by MYTM respectively. The hourly price determined by the system direction and amount of deficit is called system marginal price (SMP). An illustration of up-regulation and down-regulation bids as well as SMP is given in Figure 2.15. Note that SMP cannot be determined in advance, it can only be known after the operational day.

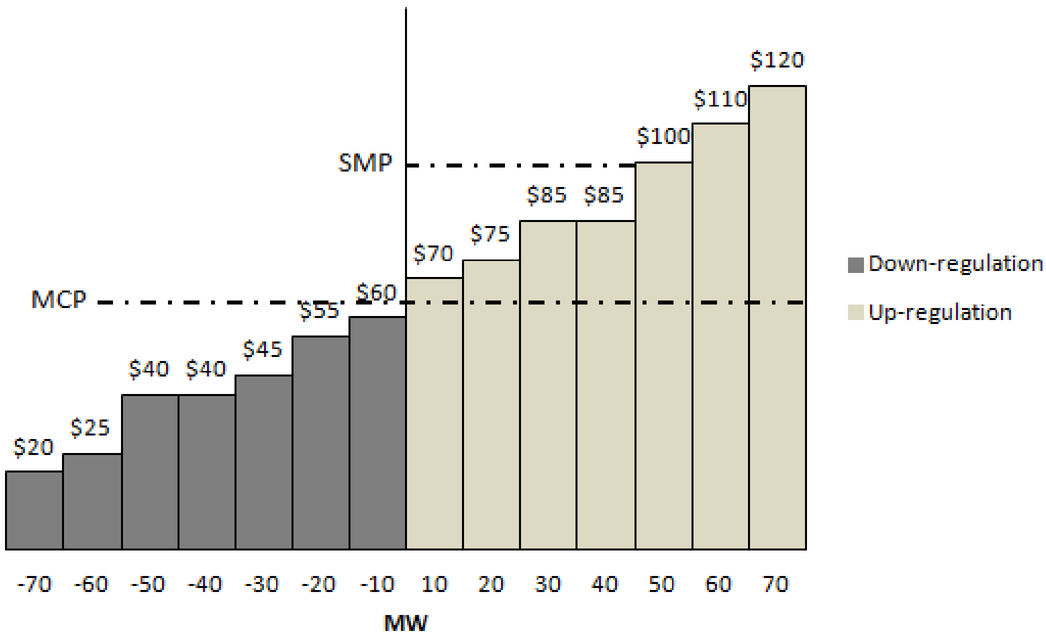

Figure 2.15 SMP settlement

In Turkish balancing market, up and down-regulation prices had been determined by single price mechanism till 2011. Volume of energy traded in the balancing market could not be decreased but increased due to attractive SMP prices for buying and selling electricity in balancing market [32]. Along with the start of double price mechanism in 2011, participants have been forced to manage the balance of their portfolios against deterrent SMP prices. Double price mechanism practiced in Turkish balancing market is investigated from the supplier side in detail in the following:

Given that

$$\begin{matrix} \rho_t^{smp} \leq \rho_t^{da}, & if\ \lambda > 0 \\ \rho_t^{smp} \geq \rho_t^{da}, & if\ \lambda < 0 \end{matrix}, \forall t \tag{2.1}$$

- If GENCO's real-time generation is more than the amount of day-ahead power bid, price of excess generation ρ_t^+, which is called imbalance-up price in the context of the thesis, sold to balancing market from GENCO is subjected to imbalance price mechanism given in Equation (2.2) with respect to system direction λ.

$$\rho_t^+ = \begin{cases} min\{\rho_t^{da}, \rho_t^{smp}\} = \rho_t^{smp}, if\ \lambda > 0 \\ max\{\rho_t^{da}, \rho_t^{smp}\} = \rho_t^{da}, if\ \lambda < 0 \end{cases}, \forall t \tag{2.2}$$

- If GENCO's real-time generation is less than the amount of day-ahead power bid, price of lack of generation ρ_t^-, which is called imbalance-down price in the context of the thesis, bought from balancing market by GENCO is subjected to imbalance price mechanism given in Equation (2.3) with respect to system direction λ.

$$\rho_t^- = \begin{cases} min\{\rho_t^{da}, \rho_t^{smp}\} = \rho_t^{da}, if\ \lambda > 0 \\ max\{\rho_t^{da}, \rho_t^{smp}\} = \rho_t^{smp}, if\ \lambda < 0 \end{cases}, \forall t \tag{2.3}$$

Balancing market settlement starts after the day-ahead market settlement closure. Until 16:00, participants submit their final generation or consumption schedule and; up and down-regulation bids to MYTM. MYTM evaluates and verifies the validity of regulation bids to be used in the next day at 17:00. MYTM sorts up and down-regulation bids with respect to their prices to be used in real-time in case of an imbalance in the system. Table 2.3 summarizes balancing market settlement process.

Table 2.3 Balancing market settlement timeline

Day	Time	Activity
-1	16:00	Participants submit their final generation/consumption schedules to MYTM
		Participants submit up and down-regulation bids to MYTM
-1	17:00	Verification of bids by MYTM
0	00:00	Utilization of regulation bids with regard to system imbalance by MYTM

2.2 WIND-THERMAL GENERATION COORDINATION

In the literature, there are various studies on generation scheduling, bidding strategies in day-ahead markets, stochasticity of wind generation and risk management that can be related to wind-thermal coordination in day-ahead electricity markets.

There are three main sets of decisions in power planning problem regarding the length of the planning time horizon, namely, long-term, medium term and short-term. Long-term planning decisions, which are on the scale of years, include determining the capacity, type and number of generator units to own for a GENCO.

For the daily or weekly medium term decisions, commitment of the available units is to be decided. Ultimately, short term power planning objective is to meet the real-time electricity demand or the amount of power bid to short term markets with the committed units in seconds or hours. In general, one can say that long-term planning is a power expansion problem, medium term planning is identified as a UC problem, and the short term problem is classified as an ED problem [33].

In the regulated industry, UC is related to meet the load demand at the minimum cost. This type of UC is generally known as cost-based unit commitment. UC problem turns into security-constrained unit commitment (SCUC) problem if maintaining sufficient spinning reserve to satisfy load deviations is introduced into the UC problem. Deregulation brought a new objective for GENCOs in the new electricity market structure. Satisfying the load is no longer a constraint and security is unbundled from energy and priced as an ancillary service. In this new concept, unit's ON/OFF status is imposed by price, including fuel price, energy sale price, bilateral agreement, ancillary sale price, etc. This UC is referred as price-based unit commitment (PBUC) [24]. ED problem is defined as meeting electricity demand with available generation units at minimum cost for non-profit system operators. In deregulated markets, ED problem of a GENCO is evolved into determining optimum generation for maximum profit before bidding in spot markets.

Market prices and wind power for next day cannot be precisely known prior to bidding and scheduling in day-ahead markets. Hence, a GENCO benefits from stochastic models for forecasting wind power and market prices [34]. Risk-constrained stochastic unit commitment and self-scheduling method for bidding strategies under uncertainty of MCP is offered for thermal generation units in [34, 36]. In [36, 37], a methodology to find the optimal bidding of wind power generation into day-ahead market in the United States is offered. In [15], bidding strategy for each day-ahead, intra-day and balancing markets for wind power producers are investigated with case studies. A three-stage stochastic programming is introduced for designing offers for day-ahead market, adjustment market and balancing market for wind power producers in [7].

GENCO is penalized from deviations in the day-ahead schedule and real-time dispatch in balancing markets. To handle the risk of loss or low profitability in wind power generation caused by imbalance penalties, three main methods have been introduced in the literature. First is the coordination of wind power and energy storage technologies such as pumped-storage [12, 36]. Another approach is to formulate stochastic models to produce optimal offering strategies [5, 6, 14, 34]. The final approach is the coordination of wind power with dispatchable generation types such as thermal and hydro power [9, 14, 38].

Wind-thermal generation coordination has been found beneficial for both wind and thermal unit profits in the day-ahead market. Coordination improves the expected profits while contributes to reduction in both wind and thermal bidding risks [9]. In this thesis, risk management is conducted through CVaR measure which is studied in the next section in detail.

2.3 CONDITIONAL VALUE AT RISK (CVaR)

Short-term volatility of electric power prices and uncertainty of wind power have paved the way for risk assessment when trading energy in day-ahead electricity markets for GENCOs. While GENCO tries to maximize its expected profit with day-ahead decisions; it also faces the risks of having low profits or losses when uncertainties are resolved in real-time. CVaR optimization technique offers reshaping one tail of the profit distribution, which corresponds to losses or low profits and discards the opposite tail that represents high profits [16]. In other words, CVaR aims to maximize the expected profits of the least profitable scenarios.

There are various methods of risk management that have been previously exercised for electricity markets in the literature other than CVaR such as mean-variance, value at risk (VaR), and hedging. CVaR is frequently used for optimization under uncertainties in electricity markets due to its linearity and other superior mathematical properties [5, 7, 9, 16]. CVaR is correlated to VaR which provides information about the low profits or large losses that GENCO may incur. VaR measures the potential minimum profit for a given confidence level α. On the other hand, CVaR, which is also known as mean excess loss, mean shortfall, or tail VaR, is measured as the weighted average of expected profits lower than VaR as illustrated in the example given in Figure 2.16. In comparison with VaR, CVaR calculates the risk beyond VaR by looking at the tail of distribution. Mathematically speaking, at a confidence level α, CVaR is the expected value of conditional profits that does not exceed VaR with probability of 1-α. For example, if VaR and CVaR of day-ahead profit are \$10 000 and \$6000 at confidence level of α respectively, it can be interpreted as there is α chance that day-ahead profit and expected profit are at least \$10 000 and \$6000 respectively.

CVaR can be used for analytical and simulation-based methods where uncertainty is modeled by finite number of scenarios. Common values used for α is 0.90, 0.95 and 0.98 [16]. Maximization CVaR value of profit in optimization problems is formulated as follows:

$$Maximize\ CVaR_{\alpha} = \zeta - \frac{1}{1-\alpha}\sum_{s}^{N_s} \pi_s . \eta_s \tag{2.4}$$

subject to

$$-PROFIT_s + \zeta - \eta_s \leq 0, \forall s \tag{2.5}$$

$$\eta_s \geq 0, \forall s \tag{2.6}$$

In Equation (2.4), $PROFIT_s$ is equal to the profit of scenario s with the corresponding probability of π_s. ζ is an auxiliary variable whose optimal value is equal to VaR. η_s is the difference between VaR and $PROFIT_s$. Looking at the constraints given in Equations (2.5) and (2.6), optimization problem of CVaR tends to minimize the value of η_s for each s, at the same time tries to set the value of η_s to the highest possible value between 0 and $\zeta - PROFIT_s$. Summation of η_s is divided by the sum of probabilities of these scenarios, which is $1 - \alpha$. Difference between VaR and this summation is equal to CVaR. Value of α is proportional to risk aversion of the GENCO. Risk neutral behavior is represented by setting $\alpha = 0$ and its corresponding value is equal to expected value of profit. GENCO can make decisions based on worst-case scenario by setting $\alpha = 1$.

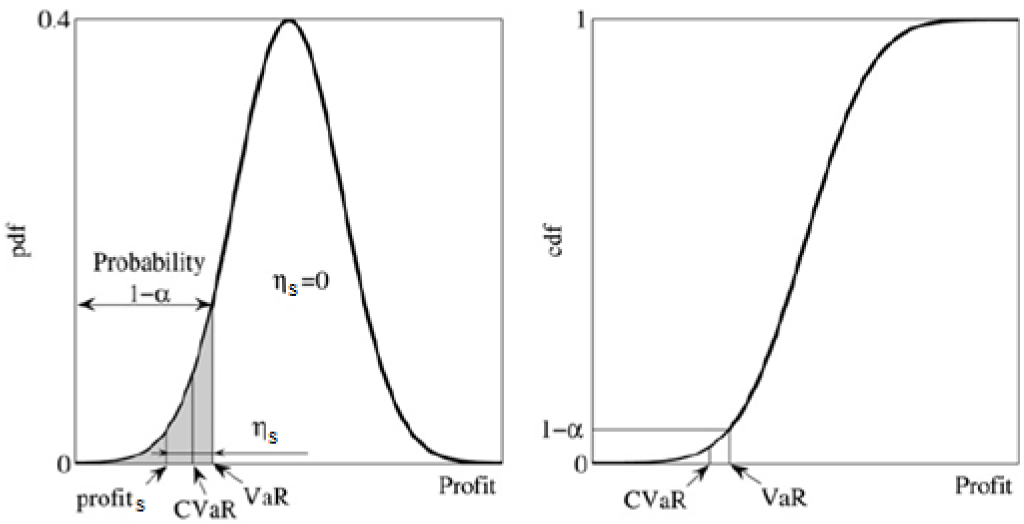

Figure 2.16 VaR and CVaR illustration on profit distribution [13]

CHAPTER 3

PROBLEM FORMULATION AND METHODOLOGY

In this chapter, problem formulation and methodology for stochastic wind-thermal generation coordination for Turkish day-ahead market are discussed in detail. First, two-stage stochastic programming approach to the optimization problem is investigated. Then, objective functions for coordinated and uncoordinated wind-thermal generation strategies are introduced separately in order to assess the performance of the coordination. Stochastic, deterministic and risk averse approaches to day-ahead power bidding are given with other market and thermal unit constraints in the problem formulation. Finally, the solution algorithm is presented to solve the wind-thermal generation coordination problem at the end of this chapter.

3.1 TWO-STAGE STOCHASTIC PROGRAMMING

There are two main challenges for a GENCO which participates in the day-ahead market with its thermal and wind units. First is to determine the optimal day-ahead bid under wind power uncertainty; while second is to find the optimal generation dispatch of thermal units when the wind generation is realized as real-time operation approaches. In order to overcome these challenges caused by uncertainty, two-stage stochastic programming approach is used as a solution method. Stochastic programming (SP) approach has been practiced for managing uncertainties in optimization problems in generation planning [9, 12, 36].

In a standard two-stage stochastic programming, there are two groups of decision variables; namely, first stage and second stage variables. First stage decision variables should be set before the actual realization of uncertainties. Once the uncertainties are resolved, second stage decision variables, which are also known as recourse variables, are determined. A recourse action is taken in the second stage with regard to outcome of uncertain event that affects optimality of problem in the second stage. The general formulation of a two-stage stochastic integer programming is written in the following:

$$Decide\ x(\tilde{w})\ \rightarrow Observe\ \tilde{w}\ \rightarrow Decide\ y(w)$$

First stage:

$$\underset{(x)}{Maximize}\ px + \ E[f(x,\tilde{w})]$$

subject to

$$Ax = b, x \geq 0, x\ integer \tag{3.1}$$

Second stage:

$$\underset{(y)}{Maximize}\ f(x,w) = g(w)y$$

subject to

$$T(w)x + W(w)y = h(w), y \geq 0, y\ integer$$

In the above formulation, x and y are first and second stage decision variables, respectively. $\tilde{w}$ denotes all possible outcomes and their associated probability distributions of uncertain variables. In the first stage, profit px of the first stage decision plus the expected profit $E[f(x,\tilde{w})]$ of the second stage, which is found by the utilization of probability distribution of uncertainty $\tilde{w}$, are maximized. Second stage problem is an optimization problem where the uncertainty $\tilde{w}$ is unfolded and recourse action is taken where the term Wy compensates a possible inconsistency such as $Tx \leq h$ in the problem. Term gy is the profit of this recourse action.

Uncertainty represented with $\widetilde{w}$ in above formulation can be derived in two different ways. The first way is by the continuous probability function where numerical integration is held within the random probability space. Probability function can be obtained from historical data or forecast tools. This approach causes nonlinearities and computation difficulties to the problem. The other approach, which is the most common, is the scenario-based approach where uncertainty represented with discrete events [5, 6, 7, 9, 12, 14, 15, 34, 36, 38]. Each possible outcome of the uncertain parameters represents a particular scenario. In order to solve the two-stage stochastic programming numerically, uncertain parameters are dicretized in a finite set of scenarios and deterministic equivalent of the stochastic problem is formulated [36, 40, 57]. The main setback of this approach is the increase in computational effort and uncertain parameters. In the above formulation expectation function $E[f(x,\widetilde{w})]$ can be modeled with a finite number of scenarios whose probability corresponds toπ_s. The realizations of $g(w), T(w), W(w)$ and $h(w)$ are correspondingly denoted as g_s, T_s, W_s and h_s for each scenario represented with s. Hence, the deterministic equivalent of formulation which covers the first and the second stages can be written as in Equation (3.2).

$$
\begin{gathered}
\underset{(x, y_1 \ldots . y_s)}{Maximize} \quad px + \sum_{s \epsilon S} \pi_s g_s y_s \\
\text{subject to } Ax = b \\
T_s x + W_s y_s = h_s, \qquad \forall s \in S \\
x \geq 0, y_s \geq 0, \qquad \forall s \in S \\
x \text{ and } y \text{ integers}
\end{gathered}
\tag{3.2}
$$

When there is infinite or very large number of possible realizations, size of the optimization problem dramatically increases. Approximation methods have been developed to overcome this difficulty with reducing number of scenarios and obtain a solution close to optimal [17, 39, 40]. SAA approximates the expectation of the stochastic formulation and facilitates the problem to be solved by deterministic algorithms. Realizations of the random vector $\widetilde{w}$ are generated as $w^1, \ldots \ldots, w^S$ where $s \in S$. Expected value function $E[f(x, \widetilde{w})]$ in Equation (3.1) is approximated as the sum of the realized values of the function divided by the number of scenarios N. The resulting objective function obtained by SAA can be written as in Equation (3.3).

$$\underset{(x)}{Maximize} \; px + \frac{1}{N}\sum_{s \in S} f(x, w^s) \tag{3.3}$$

In this thesis, the wind-thermal coordination problem is solved with the two-stage optimization framework. The objective is to determine first-stage variables such that expected profit in the first-stage and realized profit in the second-stage are maximized.

- First-stage decisions, which are also known as "here and now decisions", are made before the only uncertain parameter in this thesis, which is the wind power, is realized. Scenarios that represent the probability distribution of the wind power forecast are generated in the first stage for realization of plausible wind power scenarios in the second stage. First stage decisions are the day-ahead power bid and thermal UC. Deterministic inputs are day-ahead price, imbalance-up and imbalance-down price and risk preference of GENCO in the first stage. Objective is to maximize the expected profit in the first stage.
- Second-stage decisions, which are also known as "wait and see decisions", are made after the uncertain event, which is the wind power generation, occurs and affected by decisions given in the first stage. Second stage decisions involve ED of thermal units under realized wind power. Decisions of the first stage, day-ahead power bid and thermal commitment decision are deterministic inputs to the second stage. Objective is to maximize the realized profit in the second stage.

The timeline of two-stage stochastic programming for wind-thermal coordination is shown in Figure 3.1.

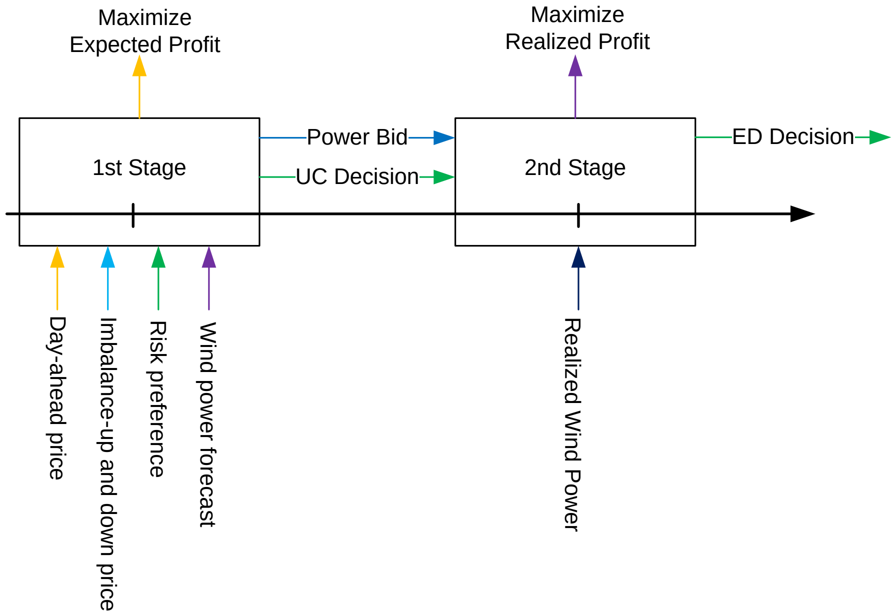

Figure 3.1 Two-stage stochastic programming model for wind-thermal coordination

3.2 PROBLEM FORMULATION

Wind-thermal coordination problem formulated in this thesis is a two-stage stochastic mixed integer problem (SMIP). The only integer variables are UC statuses of thermal units. Before introducing the objective function and constraints for the problem formulation, assumptions made in the formulation are given explicitly. Assumptions include the following:

- GENCO is assumed to have no bilateral agreement and trade energy only in the day-ahead market.

- GENCO does not participate in the balancing market by bidding up and down-regulation power; however, sells or purchases power from balancing market in case of a deviation from its scheduled day-ahead generation.
- GENCO is assumed to have a small share of generation capacity in the market; therefore, GENCO is a price-taker, i.e., it has no capability of altering market prices by bidding strategically.
- GENCO is assumed to forecast day-ahead and imbalance prices precisely and uses them as direct inputs into its profit maximization problem. Therefore, day-ahead and imbalance prices for each hour are assumed to be known by GENCO before bidding in the day-ahead market.
- Knowing the market prices for each hour, GENCO is assumed to ensure acceptance of its bids to the day-ahead market for each hour by bidding low price. Thus, GENCO is only concerned about the amount of power in day-ahead market bidding, not the price.
- Wind power is the only uncertain variable in the problem formulation. Wind power scenarios have finite values with certain probability of occurrence and sum of probabilities of these different scenarios is equal to 1.
- UC statuses of all thermal units are locked at the first stage and do not change in the second stage where wind uncertainty is realized. In other words, UC statuses are not scenario dependent, i.e., same for each scenario for certain hour.
- Day-ahead wind power forecast for each hour is assumed to have a normal distribution. Expected value and standard deviation of wind power forecast are assumed to be available to GENCO.
- GENCO is assumed to degrade the system balance for all hours in case of a deviation, i.e., when GENCO is *short*, the system is *long* or vice-versa. Hence, GENCO is paid with imbalance-up price for its excess generation sold to balancing market and buys lack of power with imbalance-down price from balancing market.

- System constraints such as spinning and non-spinning reserves for primary and secondary frequency control are not considered in the formulation.
- Operating cost of wind power is assumed to be zero.
- Outputs of wind power units are aggregated and represented as if there is single wind unit in the problem formulation.
- There is no shut-down cost of thermal units. Also, start-up ramp is assumed to be equal to ramp-up limit of the thermal unit.

3.2.1 Objective Function

Different objective functions for coordinated and uncoordinated wind-thermal generation are introduced in order to assess the benefit of coordination. Also, risk averse behavior of GENCO is formulated with the inclusion of CVaR in the objective function for the coordinated generation. Objective functions for those two cases are given in the following part of the thesis.

3.2.1.1 Coordinated Wind-Thermal Generation

The main objective of GENCO's wind-thermal generation coordination problem is to maximize its total expected profit in Turkish day-ahead market. Revenue of a GENCO comes from the total energy sold to day-ahead market and excess energy sold to balancing market. Fuel costs of thermal units and imbalance energy purchased from balancing market incur expenses to GENCO. Equation (3.4) is the objective function of coordinated wind-thermal generation. The first and the second stage decision variables of the objective function are given in parenthesis. Note that the first-stage decision variables which are the day-ahead power bid P_{tgw}^{bid} and thermal unit status u_{tg} are independent of wind power scenarios, while second-stage decision variables thermal unit dispatch P_{tsg} and imbalance power Δ_{ts} are dependent on the realization of wind power scenario.

$$\underset{\left(P_{tgw}^{bid}, P_{tsg}, u_{tg}, \Delta_{ts}\right)}{Maximize} \quad E[PROFIT]$$

$$E[PROFIT] = \sum_{t=1}^{N_T} \sum_{s=1}^{N_S} \pi_s . \left[RBID_{tgw} - \sum_{g=1}^{N_G} C_{tsg} + PIMB_{ts} \right] \tag{3.4}$$

The three terms between the brackets of Equation (3.4) refer to per scenario revenue of the day-ahead bid, total cost of thermal generation and imbalance penalty, respectively. These three terms can be expressed as follows:

$$RBID_{tgw} = \rho_t^{da} . P_{tgw}^{bid}, \forall t \tag{3.5}$$

$$\begin{aligned} C_{tsg} = FC_g . u_{tg} . \left[a_g . P_{tsg}{}^2 + b_g . P_{tsg} + c_g \right] \\ + max\left\{0, StUp_{tg} . \left(u_{tg} - u_{t-1,g}\right)\right\}, \forall t, s, g \end{aligned} \tag{3.6}$$

$$PIMB_{ts} = \begin{cases} (\rho_t^{+} . \varDelta_{ts}) . M, & \varDelta_{ts} \geq 0, M = 1 \\ (\rho_t^{-} . \varDelta_{ts.}) . (1 - M), & \varDelta_{ts} < 0, M = 0 \end{cases}, \forall t, s \tag{3.7}$$

As it can be seen in Equation (3.5), day-ahead revenue is dependent on the power bid P_{tgw}^{bid} and the day-ahead price ρ_t^{da}. Total cost function of the thermal generation in Equation (3.6) contains fuel cost of generation type, generation cost function and start-up cost of the unit. Note that integer variable of commitment status u_{tg} is multiplied with total cost of thermal generation making the formulation mixed-integer problem. Thermal generation cost function is a quadratic function which causes nonlinearity in the objective function. Imbalance penalty function $PIMB_{ts}$, which is derived from the Turkish imbalance price mechanism explained in Section 2.1.1.2, is modeled with a binary variable *M* in Equation (3.7) due to dual nature of imbalance pricing mechanism. In this thesis, an equivalent linear formulation proposed in [7] is used to eliminate the binary variable in order to obtain computational simplicity and efficiency in the solution. This linear formulation which is presented in Equation (3.8) is descended from the decomposition of energy imbalance $\varDelta_{ts}$ into summation of positive and negative imbalances, $\varDelta_{ts}^{-}$ and $\varDelta_{ts}^{+}$, respectively. Since the imbalance penalty, regardless of positive or negative, opposes to the maximization of profit, optimization problem tends to minimize the imbalance penalty function. Therefore, without a necessity of a binary variable M, the optimal solution is guaranteed with one of the variables Δ_{ts}^{-} or Δ_{ts}^{+} equals to zero due to the fact that $\rho_t^{+} \leq \rho_{da}$ and $\rho_t^{-} \geq \rho_{da}$.

$$PIMB_{ts} = \rho_{ts}^{+}.\Delta_{ts}^{+} - \rho_{ts}^{-}.\Delta_{ts}^{-}, \forall t, s \tag{3.8}$$

The coordinated objective function introduced so far aims to maximize the expected profits without consideration of risk. Risk assessment is crucial for the evaluation of trade-off between profit and risk in stochastic problems. CVaR is included as a risk measurement term in the objective function given in Equation (3.9). CVaR term which is explained in detail in Section 2.3 of the thesis is multiplied by a weighting factor $\beta \in [0, \infty)$ in order to simulate the effect of risk averse behavior on the expected profit and CVaR.

$$\underset{\left(P_{tgw}^{bid}, P_{tsg}, u_{tg}, \Delta_{ts}^{+}, \Delta_{ts}^{-}\right)}{Maximize} \quad E[PROFIT] + \beta.CVaR_{\alpha} \tag{3.9}$$

3.2.1.2 Uncoordinated Wind-Thermal Generation

In uncoordinated wind-thermal generation, GENCO maximizes its expected profit by bidding wind and thermal generation in the day-ahead market separately. Uncoordinated thermal generation is formulated by setting wind power scenarios P_{tsw} to zero for all t and s in Equation (3.4). Profit from uncoordinated thermal generation is not stochastic but deterministic since there is no uncertain variable in the objective function. As it can be seen in Equation (3.10), decision variables in parenthesis of the objective function are independent of scenarios.

$$\underset{\left(P_{tg}^{bid}, u_{tg}\right)}{Maximize} \quad PROFIT$$

$$PROFIT = \sum_{t=1}^{N_T} \left[RBID_{tg} - \sum_{g=1}^{N_G} C_{tg} \right] \tag{3.10}$$

First term in the brackets of Equation (3.10) is the day-ahead revenue obtained from thermal generation. Second term is the cost of thermal generation formulated in Equation (3.6). Note that the imbalance penalty term is not included in the objective function since there is no uncertainty related to thermal generation and market prices. Uncoordinated thermal generation is a straightforward price based unit commitment (PBUC) problem.

Objective function of uncoordinated wind generation contains terms of the day-ahead revenue and imbalance penalty due to uncertainty in the wind power. It is formulated in Equation (3.11) by setting all thermal unit status u_{tg} to zero for all t and g in Equation (3.4).

$$\underset{\left(P_{tw}^{bid}, \Delta_{ts}^{+}, \Delta_{ts}^{-}\right)}{Maximize} \quad E[PROFIT]$$

$$E[PROFIT] = \sum_{t=1}^{N_T} \sum_{s=1}^{N_S} \pi_s . \left[RBID_{tw} + PIMB_{ts} \right] \tag{3.11}$$

3.2.2 Constraints

There are various types of constraints that can be added to the wind-thermal generation coordination problem which arise from day-ahead bidding strategy, market mechanism, system constraints, emission constraints, crew constraints, thermal unit constraints and so on. Detailed description on system constraints, emission constraints, crew and other constraints are given in [42], [43] and [44]. In this thesis, bidding, market and thermal constraints are the interest of problem formulation.

3.2.2.1 Bidding Constraints

GENCO should determine the amount of power to bid to market with precise forecast of market prices and wind power uncertainty in day-ahead. Bidding constraints are separately defined for stochastic and deterministic bidding approach for coordinated generation as well as uncoordinated generation in the following:

i. Stochastic Wind-Thermal Bidding for Coordinated Generation

Amount of power bid to day-ahead market for each hour cannot be *more* than maximum possible wind power scenario plus maximum possible generation limit of thermal generators which are available (ON) at that hour. Likewise, amount of power bid to day-ahead market for each hour cannot be *less* than minimum possible wind power scenario plus minimum possible generation limit of thermal generators available at that hour. Equation (3.12) presents constraints on P_t^{bid} for stochastic coordinated bidding.

$$min(P_{tsw}) + \sum_{g=1}^{N_G} P_{tsg}^{min}.u_{tg} \leq P_{tgw}^{bid} \leq max(P_{tsw}) + \sum_{g=1}^{N_G} P_{tsg}^{max}.u_{tg}\,, \forall t \qquad (3.12)$$

ii. Deterministic Wind-Thermal Bidding For Coordinated Generation

In deterministic bidding, power bid is within the limits between the expected wind power plus the minimum possible generation limit of thermal generators available at that hour and expected wind power plus the maximum possible generation limit of thermal generators available at that hour. Expected wind power is equal to value that has the highest probability in the distribution. For normally distributed wind power forecast, mean value is the expected wind power. Equation (3.13) illustrates the deterministic wind-thermal bidding constraint:

$$P_{tw}^{exp} + \sum_{g=1}^{N_G} P_{tsg}^{min}.u_{tg} \leq P_{tgw}^{bid} \leq P_{tw}^{exp} + \sum_{g=1}^{N_G} P_{tsg}^{max}.u_{tg}\,, \forall t \tag{3.13}$$

iii. Stochastic Wind-Thermal Bidding for Uncoordinated Generation

In uncoordinated wind-thermal generation, power bid of thermal and wind units are determined separately. For uncoordinated thermal generation, power bid of thermal unit is between sum generation limits of available thermal units at that hour as illustrated in Equation (3.14).

$$\sum_{g=1}^{N_G} P_{tg}^{max} \leq P_{tg}^{bid} \leq \sum_{g=1}^{N_G} P_{tg}^{max}\,, \forall t \tag{3.14}$$

For uncoordinated wind generation, power bid is constrained to be between lowest and highest wind power scenario as given in Equation (3.15).

$$min(P_{tsw}) \leq P_{tw}^{bid} \leq max(P_{tsw})\,, \forall t \tag{3.15}$$

3.2.2.2 Imbalance Price Constraints

Dual imbalance price mechanism practiced by Turkish balancing market is explained in detail in Section 2.1.1.2. By complying with this price mechanism, it is assumed that GENCO degrades the system balance for all hours in case of any deviation from day-ahead bid in the problem formulation. Therefore, negative and positive imbalance prices are always opposed to GENCO's profit. When GENCO is running short, it is penalized by paying to market operator with negative imbalance price which is more than day-ahead price, $\rho^{-} > \rho^{da}$. When GENCO is running long, it is penalized by being paid by market operator with positive imbalance price which is less than day-ahead price, where $\rho^{da} > \rho^{+}$. Constraint on imbalance prices is given in Equation (3.16).

$$\rho_t^{+} \leq \rho_t^{da} \leq \rho_t^{-}, \forall t \tag{3.16}$$

3.2.2.3 Imbalance Power Constraint

Imbalance power is equal to difference between day-ahead bid and real-time generation of GENCO. Either Δ_{ts}^{+} or Δ_{ts}^{-} is equal to zero for all t and s due to nature of the optimization problem as explained in Section 3.2.1.1. Equation (3.17) presents the imbalance power constraint.

$$\Delta_{ts} = \left(P_{tsw} + \sum_{g=1}^{N_G} P_{tsg} \right) - P_{tgw}^{bid} = \Delta_{ts}^{+} - \Delta_{ts}^{-}, \forall t, s \tag{3.17}$$

3.2.2.4 Thermal Unit Constraints

Thermal unit constraints considered in thesis are namely generation, ramp-up and ramp-down power and minimum-up and minimum-down time limits. They are described and formulated in the following:

i. Unit's ramp-up and ramp-down capacity constraints:

Due to machinery limits, electrical output of a thermal unit cannot change more than a certain amount over a period of time. In Equation (3.18), generation of thermal unit for successive hours is bounded by ramp-up and ramp-down constraints.

$$-\overline{RD}_g \leq P_{tsg} - P_{t-1,sg} \leq \overline{RU}_g, \forall t, s, g \tag{3.18}$$

ii. Generation constraints:

Generation constraint is defined as the minimum and maximum feasible generation capacity of an operating thermal unit. Generation level of a unit should be in the range between the maximum and minimum possible generation for all times. Maximum and minimum generation levels are limited by minimum and maximum generation capacity of the unit as well as ramp-up and ramp-down constraints as given in Equation (3.19), (3.20) and (3.21).

$$P_{tsg}^{min}.u_{tg} \leq P_{tsg} \leq P_{tsg}^{max}.u_{tg}, \forall t, s, g \tag{3.19}$$

where

$$P_{tsg}^{max} = \begin{Bmatrix} min\{P_{t-1,sg} + \overline{RU}_g, \overline{P}_g\}, & if\ u_{tg} = u_{t-1,g} = 1 \\ min\{\underline{P}_g + \overline{RU}_g, \overline{P}_g\} & if\ u_{tg} = 1, u_{t-1,g} = 0 \end{Bmatrix}, \forall t, s, g \tag{3.20}$$

$$P_{tsg}^{min} = \begin{Bmatrix} max\{P_{t-1,sg} - \overline{RD}_g, \underline{P}_g\} & if\ u_{tg} = u_{t-1,g} = 1 \\ \underline{P}_g, & if\ u_{tg} = 1, u_{t-1,g} = 0 \end{Bmatrix}, \forall t, s, g \tag{3.21}$$

iii. Minimum up and down time constraints:

A thermal unit can have limited temperature changes which result in some time to bring the unit on-line or off-line. Once a generation unit is running, it cannot be shut down immediately. Likewise, off units cannot be started immediately. Time required to for a thermal unit to turn off and turn on is defined as minimum-up and minimum-down time as given in Equation (3.22) and (3.23) respectively.

$$\left[T_{t-1,g}^{up} - MinUp_g\right] \times \left[u_{t-1,g} - u_{tg}\right] \geq 0, \forall t, g \tag{3.22}$$

$$\left[T_{t-1,g}^{dn} - MinDn_g\right] \times \left[u_{tg} - u_{t-1,g}\right] \geq 0, \forall t, g \tag{3.23}$$

3.3 SOLUTION ALGORITHM

Solution algorithm for the wind-thermal coordination, which is developed in MATLAB environment, is given with a flowchart in Figure 3.2. Each step in the figure is numbered and will be explained in this section. Dynamic programming is used in order to eliminate the mixed-integer nature of the problem formulation and find the optimum UC of thermal units. MATLAB's fmincon function is used as a solver for each dynamic programming stage.

In the first step of the solution algorithm; t and k, which denote time and number of feasible previous transitions, are initialized. t is initialized as 1 since it is the beginning of scheduling period and k is initialized as 1 due to the fact that there is only one feasible previous state at t=1. Also, at this step of the algorithm, problem is fed with market, wind and thermal unit data. These include the following:

- Market data
    - Day-ahead price
    - Imbalance-up and imbalance-down price
- Wind power forecast data
    - Expected wind power
    - Standard deviation
- Thermal unit data
    - Number of units
    - Generation capacity of each unit
    - Ramp-up and ramp-down limits of each unit
    - Start-up cost of each unit
    - Initial ON/OFF duration of each unit
    - Minimum-up and minimum-down time limits of each unit
    - Fuel price of each unit
    - Cost coefficients of each unit

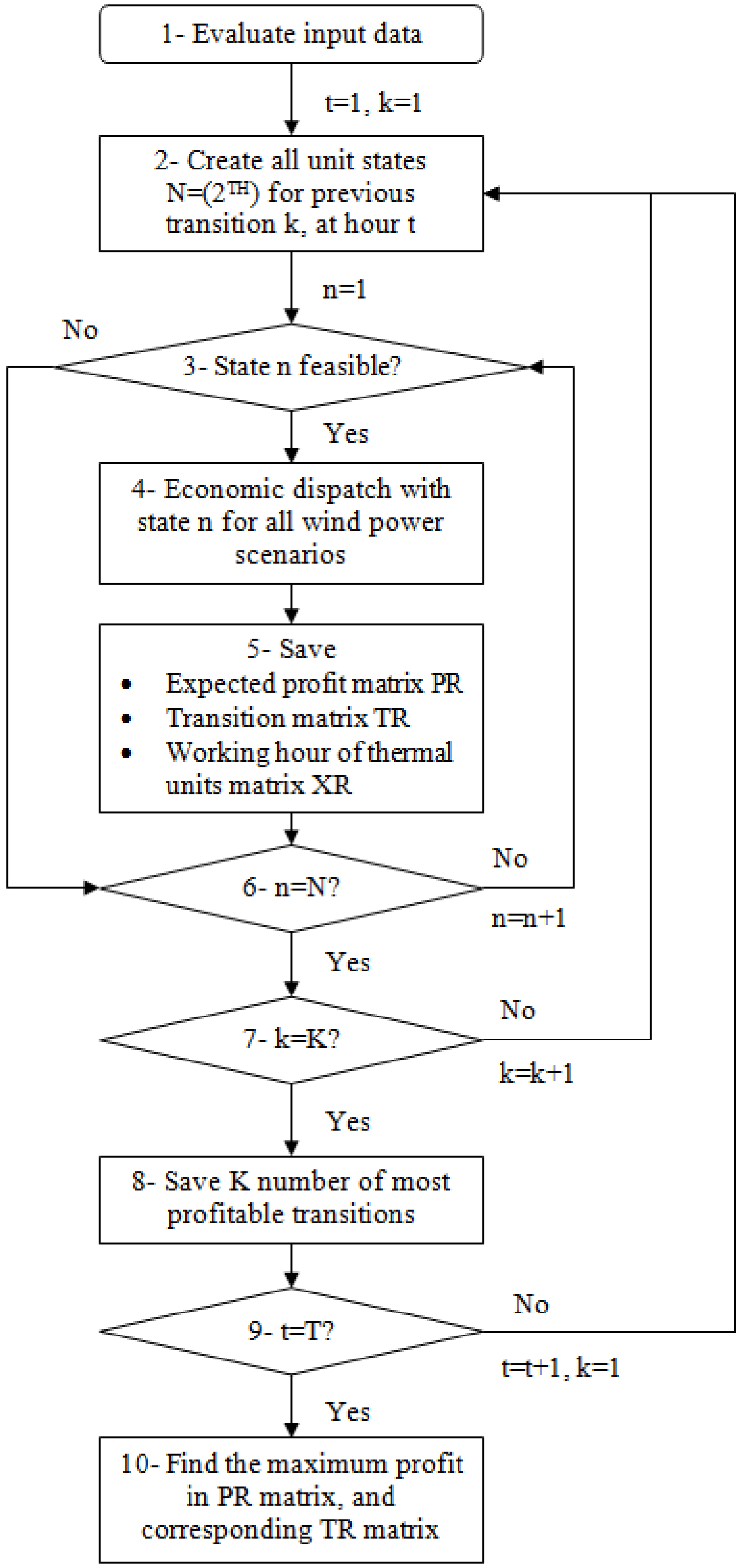

Figure 3.2 Solution algorithm for wind-thermal coordination

In the second step of the algorithm, all possible $N=2^G$ thermal UC statuses for each previous transition k and hour t, where G denotes the total number of thermal units, are created with complete enumeration. For example, for G=3 there are $N=2^3=8$ possible states as illustrated in Table 3.1.

Table 3.1 Thermal UC status combinations

State No (n)	**Unit 1**	**Unit 2**	**Unit 3**
1	OFF	OFF	OFF
2	OFF	OFF	ON
3	OFF	ON	OFF
4	OFF	ON	ON
5	ON	OFF	OFF
6	ON	OFF	ON
7	ON	ON	OFF
8	ON	ON	ON

Whether transition k from previous hour to current hour for state n is feasible or not is checked with minimum-up and minimum-down constraints in the third step of the algorithm. For this purpose, ON/OFF data of thermal units in current state n are compared to data stored in XR matrix which is the duration that thermal units have been ON or OFF until that hour. Then, XR is updated for the next hour if transition to current state is feasible. Unfeasible transitions are not stored in the memory. Following example illustrates the case: Let's assume that Unit 1 has been OFF for one hour, while Unit 2 and Unit 3 has been ON for two and four hours, respectively at hour t=3 for previous transition k. XR matrix can be constructed as XR=[-1; 2; 4] with given information, where negative sign denotes the hours that unit has been OFF. Also, assume that minimum-down and up constraints for each unit is 3 hours.

Now let's check the feasibility of all possible states built in Table 3.1 for the next hour t=4.

Table 3.2 Feasibility check of transition k from t=3 to t=4

t=3	**t=4**			
XR	**State No**	**Updated XR**	**Feasibility**	**Explanation**
[-1; 2; 4]	1	-	NO	Unit 2 cannot be turned OFF due to minimum-up constraint
[-1; 2; 4]	2	-	NO	Unit 2 cannot be turned OFF due to minimum-up constraint
[-1; 2; 4]	3	[-2; 3; -1]	YES	No violation on minimum-up and minimum-down constraints
[-1; 2; 4]	4	[-2; 3; 5]	YES	No violation on minimum-up and minimum-down constraints
[-1; 2; 4]	5	-	NO	Unit 1 cannot be turned ON due to minimum-down constraint Unit 2 cannot be turned OFF due to minimum-up constraint
[-1; 2; 4]	6	-	NO	Unit 1 cannot be turned ON due to minimum-down constraint Unit 2 cannot be turned OFF due to minimum-up constraint
[-1; 2; 4]	7	-	NO	Unit 1 cannot be turned ON due to minimum-down constraint
[-1; 2; 4]	8	-	NO	Unit 1 cannot be turned ON due to minimum-down constraint

In the fourth stage of the algorithm, ED with thermal units which are ON is conducted with each wind power scenario with the objective function and constraints given in Section 3.2. Expected profits and their corresponding optimum transition sub-paths are saved in PR and TR matrices, respectively. To illustrate this stage, let's consider the example given in Figure 3.3. At t=3, number of previous transitions are given as K=3. For each previous hour transition k at t=3 to next hour $N=2^G=2^3=8$ thermal UC combinations are created for three thermal units. Assuming that all transitions from t=3 to t=4 are feasible, there are total of K(t=4)=K(t=3)xN=3x8=24 sub-paths obtained for t=4. Accumulated profit of each transition at t=4 is calculated as sum of three parameters. First is the accumulated profit PR(t, k) at t=3 for given transition path k. Second is the transition cost TC(k, n), which is defined as the cost for getting to next state at t=4 from the previous state at t=3. Final parameter is the profit for the current state SP(t, n) at t=4. PR and TR matrices, which are formed by the loops in the sixth and seventh stages for each t, are saved in the fifth stage for the next hour. Same process is followed until whole scheduling period is covered.

The size of the transition matrix TR increases with t through the scheduling horizon. As mentioned before, for G number of thermal units there are 2^G possible states. Assuming that all state transitions are feasible, for T hours of scheduling horizon, size of TR matrix, K, becomes $(2^G)^T$. In order to reduce the computational effort, time and program memory, at each hour not all but K number of most profitable states are saved in PR, TR and XR matrices. This may result in not finding the optimum transition path of the problem; hence, suboptimum profit. In the eight stage of the problem, algorithm decides how many number of transitions K is saved for the next hour. In the final stage, optimum transition path; thus, UC schedule is found by the transition path saved in TR that corresponds to maximum profit in PR.

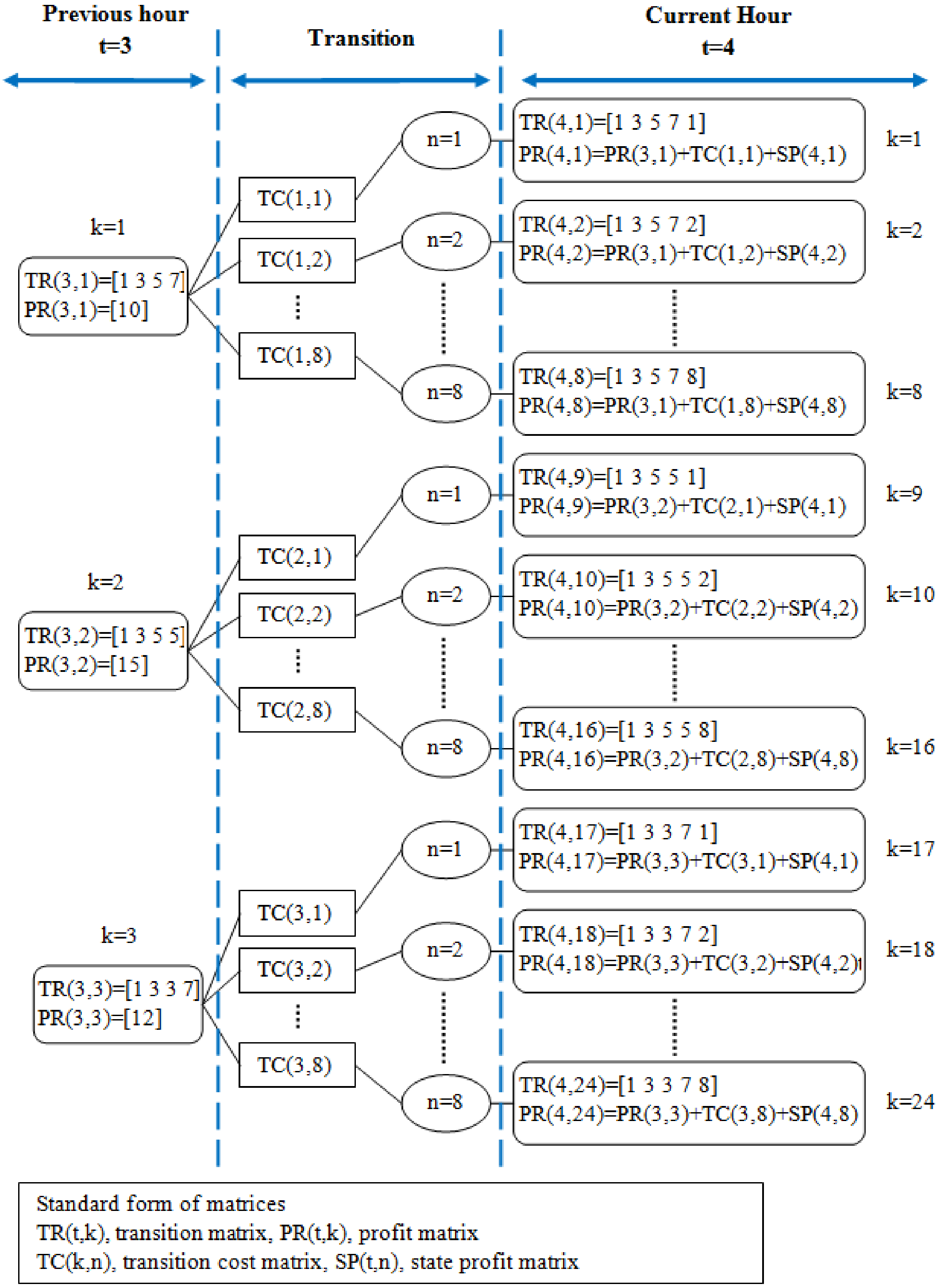

Figure 3.3 Fourth stage of the solution algorithm

CHAPTER 4

CASE STUDIES

In this chapter, variety of numerical case studies are carried out in order to demonstrate the impact of wind-thermal coordination on thermal unit scheduling, benefits of wind-thermal coordination on profits and the validity of the algorithm developed in Chapter 3. Moreover, examples for risk measurement with CVaR are presented in case studies. Influence of GENCO's risk attitude in day-ahead bidding, generation scheduling, expected profit and CVaR is also observed.

The GENCO which is considered in the case studies is assumed to own two thermal units and a wind farm. The capacity of the wind farm is 180 MW, while the total installed capacity of thermal plants is 90 MW. Hypothetical market prices and wind power forecast are inputs to the proposed model. Day-ahead and imbalance prices are generated in compliance with Turkish day-ahead and balancing market pricing rules. In order to create wind power scenarios, simplistic assumption made in [44] is used for Case 1 and Case 2. Wind power scenarios are represented by high, medium or expected and low wind power and assigned with their respective probabilities as shown in Figure 4.1. For Case 3, probability mass function (PMF) is used to determine the wind power scenarios with given PDF of the wind power forecast.

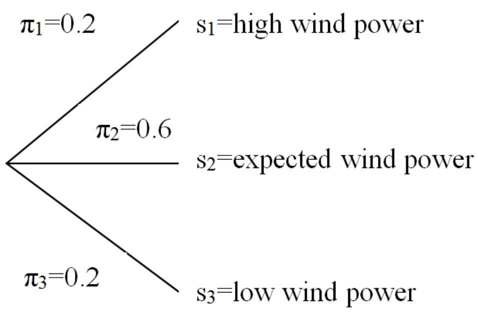

Figure 4.1 An example for simplistic wind power scenarios

Methodology developed in Chapter 3 is employed with related objective functions and constraints to the case studies in this section. In the following sections, the results of case studies are provided. Studies on wind-thermal generation coordination are divided into three main case studies. Each case study has sub-case studies to illustrate the following:

- **Case 1:** Hourly coordination of a single thermal unit with wind power generation is tested in order to show the effects of wind power forecast distribution, imbalance-up and imbalance-down price and wind power forecast certainty on ED of thermal unit, day-ahead power bid and expected profit.
- **Case 2:** Multi-hour analysis of wind-thermal coordination is examined for evaluating the impact of coordination, bidding strategy and wind power forecast on thermal UC.
- **Case 3:** 24 hour wind-thermal generation coordination is executed considering all thermal unit constraints including start-up cost, ramp-up and ramp-down limits and minimum-up and minimum-down time for more realistic problem. Uncoordinated and coordinated wind-thermal generation approaches of a GENCO are compared with different bidding strategies separately. Also, trade-off between expected profit and CVaR is analyzed through cases.

MATLAB R2012b is chosen as the programming tool in the thesis. Problems are solved in a computer that has Intel Core i5 processor with 2.60GHz and 8GB memory. For multi-hour analysis, K=8 states are saved in each stage of the dynamic programming in order to reduce computational size and time. With this configuration, MATLAB solves 24 hour wind-thermal coordination problem defined in this thesis in less than six minutes.

4.1 CASE 1: HOURLY ANALYSIS OF WIND-THERMAL COORDINATION

Let's consider the coordination of a single thermal unit with wind generation for one hour. Effect of wind power forecast distribution, balancing market prices and wind forecast certainty on hourly thermal unit ED, day-ahead power bid and expected profit are examined in detail with the help of this case. Through this case, inter-hour constraints such as minimum-up and minimum-down time, ramp-up and ramp-down and start-up cost do not have any impact on the results since the analysis is carried out for a single hour. Thermal unit is assumed to be ON regardless of market price. Thermal unit data for Case 1 is given in Table 4.1. Marginal cost of generation of the thermal unit is given in 5 MW intervals in Table 4.2 with the overall generation cost in order to give an idea to the reader about whether the cost of the imbalance penalty or the compensation of forecast errors with thermal generation is preferable.

Table 4.1 Thermal unit data for Case 1

$\underline{P}$ (MW)	$\overline{P}$ (MW)	FC (\$/MBtu)	a (MBtu)	b (MBtu/MW)	c (MBtu/MW^2)
5	45	1.0	85.509	70.85831	0.18819

Table 4.2 Marginal and generation costs of thermal unit for Case 1

Power (MW)	Marginal Cost ($/MWh)	Generation Cost ($)
5	88.90	444.51
10	8129	812.91
15	79.38	1190.73
20	78.90	1577.95
25	78.98	1974.59
30	79.35	2380.63
35	79.89	2796.08
40	80.52	3220.94
45	81.23	3655.21

4.1.1 Case 1.1: Effect of Wind Power Forecast Distribution

Effect of the wind power forecast distribution on thermal dispatch and day-ahead power bid is investigated in this case study. For this purpose, three wind power forecasts with the same expected wind power value of 120 MW but different probability distributions are created at first. Also, as a fourth case, wind power forecast with the same error in magnitude as in Case 1.1.3 but different expected value is included for comparison in order to show the effect of expected value of the forecast on ED of thermal unit. Market data and wind power forecast data for Case 1.1 are given in Table 4.3 and Table 4.4, respectively. Note that wind power forecast distribution ranges are chosen to be lower, equal and higher than thermal unit range in the first three cases, respectively.

Table 4.3 Market data for Case 1.1

ρ^{da} (\$/MWh)	ρ^{+} (\$/MWh)	ρ^{-} (\$/MWh)
81	60	100

Table 4.4 Wind power forecast data for Case 1.1

	Scenario s	**1**	**2**	**3**
	Probability π	0.2	0.6	0.2
Case 1.1.1	P_{tsw} **(MW)**	110	120	130
Case 1.1.2	P_{tsw} **(MW)**	100	120	140
Case 1.1.3	P_{tsw} **(MW)**	90	120	150
Case 1.1.4	P_{tsw} **(MW)**	80	110	140

For uncoordinated thermal generation, optimum power that would be generated by the thermal unit with given market data is found as 26.95 MW according to Equation (3.10). This information will be used to assess the impact of coordination on ED of thermal unit in the following evaluation.

Imbalance-down power penalty price given in Table 4.3, which is $100/MWh, is always larger than marginal cost of increasing generation with thermal unit, which is maximum of $88.90/MWh according to Table 4.2. Likewise, the imbalance up-price of $60/MWh, is less profitable than reducing the thermal unit output for as low as $78.90/MW. Therefore, it can be concluded that coordination with the thermal unit is always more profitable than buying or selling power from real-time market with imbalance prices. Results given in Table 4.5 prove this claim.

Table 4.5 Results for Case 1.1

	Scenario s / Prob. π	P_{tsw} (MW)	P_{tsg} (MW)	Δ_{ts}^{+} (MW)	Δ_{ts}^{-} (MW)	P_{tgw}^{bid} (MW)	$E[PROFIT]$ ($)
Case 1.1.1	**1 / 0.2**	110.00	36.95	0.00	0.00	146.95	9763.60
	2 / 0.6	120.00	26.95	0.00	0.00		
	3 / 0.2	130.00	16.95	0.00	0.00		
Case 1.1.2	**1 / 0.2**	100.00	45.00	0.00	0.00	145.00	9740.30
	2 / 0.6	120.00	25.00	0.00	0.00		
	3 / 0.2	140.00	5.00	0.00	0.00		
Case 1.1.3	**1 / 0.2**	90.00	45.00	0.00	13.72	148.72	9661.86
	2 / 0.6	120.00	28.72	0.00	0.00		
	3 / 0.2	150.00	5.00	6.28	0.00		
Case 1.1.4	**1 / 0.2**	80.00	45.00	0.00	13.72	138.72	8851.86
	2 / 0.6	110.00	28.72	0.00	0.00		
	3 / 0.2	140.00	5.00	6.28	0.00		

When the wind power forecast distribution range is lower than the thermal unit output power range as in Case 1.1.1, GENCO would give such a bid that, there would be no imbalance power in each scenario. As it can be seen from Table 4.5, GENCO can compensate the wind deviations from expected forecast value with increasing or decreasing thermal unit output and thus, avoid imbalance penalty. In such a case, GENCO can adjust its thermal unit output to 26.95 MW, which is equal to value of the uncoordinated thermal generation, for the most probable scenario knowing that compensation is possible in case of a deviation for other scenarios. Therefore, power bid given in Case 1.1.1 is the sum of expected wind power of 120 MW and uncoordinated thermal generation with given market data, which is 26.95 MW. Note that, this is the case when wind power range is narrower than thermal unit output range.

In Case 1.1.2, thermal unit output power range is equal to wind power forecast distribution range which is 40 MW. Solution algorithm adjusts thermal output limits to the lowest possible output in high wind scenario and the highest possible output in low wind scenario not to have imbalance power. In order to do so, GENCO bids such an amount of power that is equal to the sum of lowest possible output of thermal unit and high wind scenario or vice-versa. Therefore, in the most expected scenario thermal unit does not operate at its most profitable output, instead; it operates at 25 MW not to have imbalance power for the given bid of 145 MW in case of a low wind scenario.

Wind power forecast distribution range is 20 MW wider than thermal unit output power range in Case 1.1.3. In order to reduce imbalance penalty for inevitable imbalance power, thermal unit output is again set to maximum and minimum for low and high wind scenarios respectively. Note that difference between imbalance-up price with respect to day-ahead price is \$2/MWh more compared to that of imbalance-down price. GENCO earns \$81/MWh - \$60/MWh = \$21/MWh less for any positive deviation for 1 MW deviation while it loses \$100/MWh - \$81/MWh = \$19/MWh more for any negative deviation from day-ahead bid. Therefore, GENCO prefers risking being short due to low value of imbalance- down penalty compared to imbalance-up penalty and bids larger amount of power 148.72 MW compared to Case 1.1.2.

Comparing Case 1.1.3 and Case 1.1.4, it can be seen that ED of thermal unit is the same for each wind scenario. It is because of the fact that the magnitude of the wind power forecast error is the same for these cases. Day-ahead power bid difference between these two cases is equal to difference between expected wind forecast. Therefore, one can conclude that it is not the expected value of wind but the forecast distribution which determines thermal unit dispatch. Taking Case 1.1.1, 1.1.2 and 1.1.3 into consideration, one can see that expected profit decreases as wind forecast range increases. This is because of the fact that an increase in wind power range results in an imbalance power that cannot be compensated by thermal unit; as a result, imbalance penalty.

4.1.2 Case 1.2: Effect of Imbalance-up Penalty Price

Imbalance-up price is the price that GENCO would be paid for its excess generation of day-ahead power bid. Since it is always less than the day-ahead price, GENCO makes less profit in case of a positive deviation in wind power forecast than it could have with precise forecast. Effect of imbalance-up price on hourly wind-thermal coordination is examined in two main cases; where wind power forecast range is wider than thermal generation units or vice-versa. Wind data used in these case studies is given with their respective probabilities in Table 4.6.

Table 4.6 Wind data for Case 1.2

	Scenario s	**1**	**2**	**3**
	Probability π	0.2	0.6	0.2
Case 1.2.1	**P_{tsw} (MW)**	90	120	150
Case 1.2.2	**P_{tsw} (MW)**	110	120	130

In order to study the effect of imbalance up-price, imbalance-down price is kept constant as \$100/MWh for different day-ahead prices given in Table 4.7. Day-ahead price is selected in a manner that uncoordinated thermal unit operates at its minimum for \$75/MWh, between lower and upper generation bounds for \$80/MWh and \$85/MWh and its maximum for \$90/MWh which is found by PBUC with Equation (3.10). By this way, the impact of imbalance-up price with different day-ahead price is aimed to be investigated. Imbalance price is gradually decreased for each case until wind-thermal coordination reaches such a point that day-ahead power bid does not increase anymore due to dominance of the imbalance-down price.

Table 4.7 Market data for Case 1.2

$\boldsymbol{\rho^{da}}$ **(\$/MWh)**	$\boldsymbol{\rho^{+}}$ **(\$/MWh)**	$\boldsymbol{\rho^{-}}$ **(\$/MWh)**
75	$< \boldsymbol{\rho^{da}}$	**100**
80		
85		
90		

Figure 4.2 depicts the sensitivity analysis of day-ahead power bid to the imbalance-up price with \$1/MWh decrement for different day-ahead prices with the given wind data. Imbalance power is inevitable in Case 1.2.1 due to the wind power forecast range. At high imbalance-up prices, bidding low and selling imbalance-up power is profitable. As imbalance-up price decreases, day-ahead power bid increases in a non-linear fashion due to non-linear nature of the expected profit function. At certain imbalance-up price, GENCO quits increasing its bid and prefers

not to sell imbalance-up power which is not profitable anymore. This price is found at optimum day-ahead power bid where GENCO cannot have any imbalance-up power for any scenario. For day-ahead prices that do not trigger thermal unit to operate at maximum, GENCO bids as much as 155 MW of power and limit imbalance-down power at 20 MW for the low wind scenario. On the other hand, for a day-ahead price of $90/MWh, GENCO can risk of having 30 MW of imbalance-down power for low wind scenario by bidding 165 MW of day-ahead power with operating thermal unit at its maximum output due to the fact that profit comes from day-ahead bid in case of a expected wind power scenario surpasses imbalance-down power penalty in case of a low wind scenario at high day-ahead price. Also note that, at higher day-ahead price, day-ahead power bid is less sensible to imbalance-up price changes. When day-ahead price is $90/MWh, GENCO does not change its day-ahead power bid for imbalance-up prices lower than $86/MWh. This value is $22/MWh when day-ahead price is $75/MWh. One can conclude that as day-ahead price decreases, sensitivity to imbalance-up price increases and decision making for day-ahead power bid plays a critical role for GENCO's expected profit.

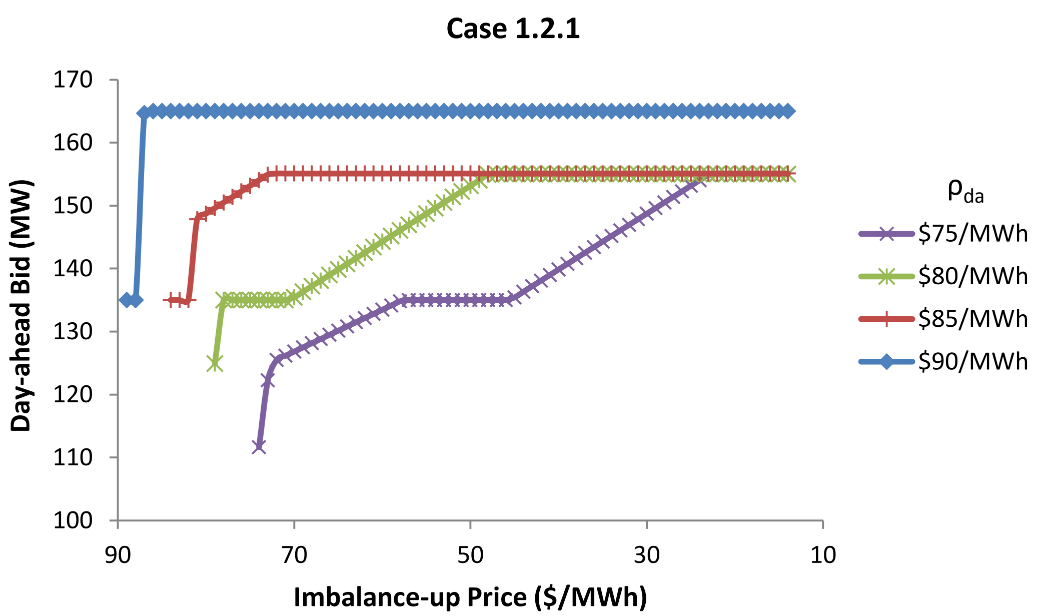

Figure 4.2 Day-ahead bid vs. imbalance-up price for Case 1.2.1

In Case 1.2.2, wind power range is between thermal generation limits. Figure 4.3 illustrates the sensitivity analysis of day-ahead power bid for case 1.2.2. At high imbalance-up prices, it is more profitable for GENCO to bid relatively low and have excess power production in case of a high wind scenario as in Case 1.2.1. For day-ahead price of \$85/MWh and \$90/MWh, GENCO bids the same amount of power for low imbalance-up prices as in Case 1.2.1; however, it bids higher at high imbalance-up prices since thermal unit is capable of compensating wind power deviations. For the other day-ahead prices, GENCO bids lower compared to Case 1.2.1 due to the fact that impact of imbalance-up and imbalance-down price on day-ahead power bid is negligible since thermal unit is capable of correcting wind power deviations. For all day-ahead prices considered, GENCO bids such amount of power that there is no possibility of imbalance power for each scenario above a certain imbalance-up price. It is the day-ahead price which determines the day-ahead power bid for lower imbalance-up price. A higher day-ahead price leads to a higher amount of day-ahead power bid. Different from Case 1.2.1, sensitivity of the day-ahead power bid with regard to the imbalance-up price is very low in this case.

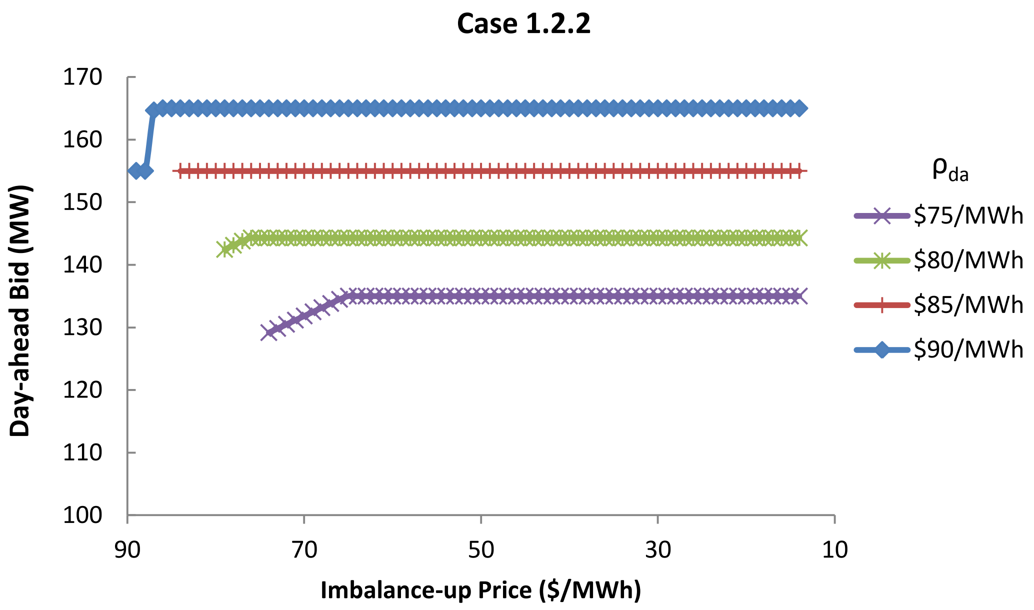

Figure 4.3 Day-ahead bid vs. imbalance-up price for Case 1.2.2

In both Case 1.2.1 and Case 1.2.2, the expected profit is observed to be constantly decreasing until a certain imbalance-up price. This imbalance-up price is found at where the day-ahead power bid does not increase anymore. Figure 4.4 illustrates the comparison of Case 1.2.1 and Case 1.2.2 at the same day-ahead price of $80/MWh. It can be seen that the expected profit of Case 1.2.1 is more prone to changes in the imbalance-up price since the imbalance power is inevitable in this case.

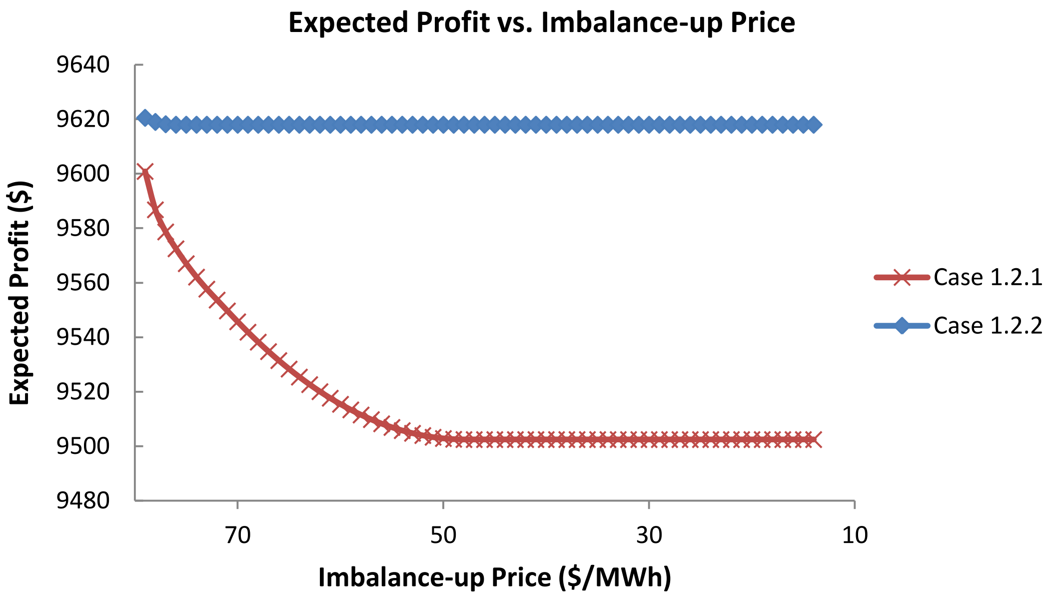

Figure 4.4 Expected profit vs. imbalance-up price for a day-ahead price of $80/MWh

4.1.3 Case 1.3: Effect of Imbalance-down Penalty Price

Effect of imbalance-down price is examined in the same fashion as in Case 1.2. For this purpose, the same wind data in Case 1.2 is used to distinguish the impact of the wind power forecast range which is given in Table 4.8.

Table 4.8 Wind data for Case 1.3

	Scenario s	**1**	**2**	**3**
	Probability π	0.2	0.6	0.2
Case 1.3.1	P_{tsw} **(MW)**	90	120	150
Case 1.3.2	P_{tsw} **(MW)**	110	120	130

This time imbalance-up price which is chosen as \$60/MWh is kept constant and imbalance-down price is gradually increased for different day-ahead prices. Day-ahead prices are also the same prices that are used in Case 1.2. Market data are given in Table 4.9.

As the imbalance-down price gets to a higher value, the day-ahead power bid of GENCO decreases. This is due to the fact that GENCO avoids being short in case of a low wind power scenario. For Case 1.3.1 which has unavoidable imbalance power due to a wider wind power range, GENCO bids as low as 133 MW and allows only imbalance-up power, which is more preferable than the imbalance-down penalty for high imbalance-down prices. As it is shown in Figure 4.5, at lower day-ahead price, day-ahead power bid is more fragile to changes in the imbalance-down price. Lower the day-ahead price, sooner the day-ahead power bid reaches its minimum. The reason why the day-ahead price of \$75/MWh has slightly lower day-ahead bid for high imbalance-down prices compared to other day-ahead prices is that imbalance-up profit is more than day-ahead profit obtained by thermal unit. This is consistent with the fact that at a low day-ahead price, thermal unit operates at minimum possible output.

Table 4.9 Market data for Case 1.3

ρ^{da} ($/MWh)	ρ^{+} ($/MWh)	ρ^{-} ($/MWh)
75	60	$> \rho^{da}$
80		
85		
90		

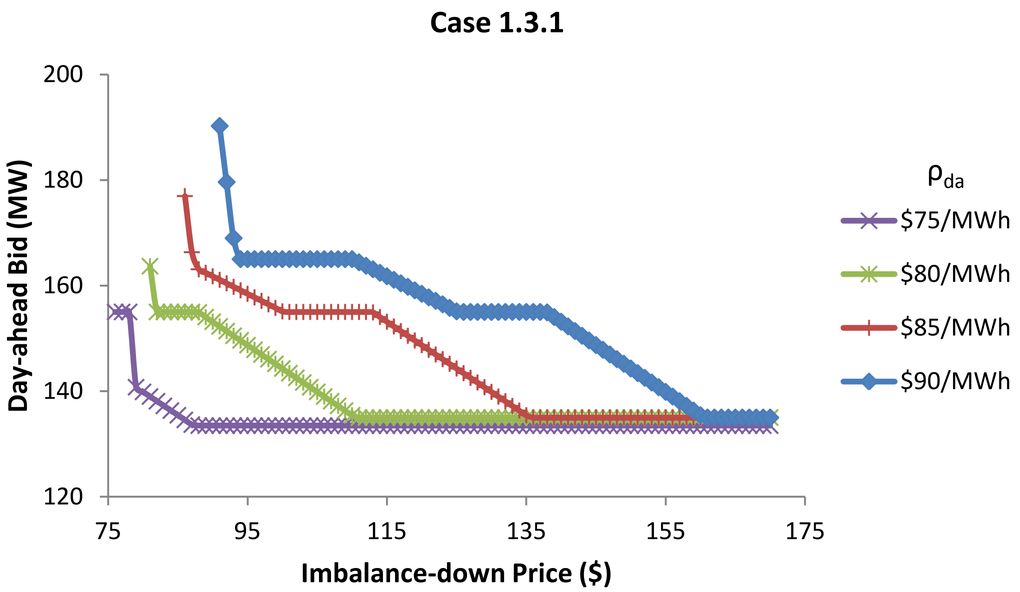

Figure 4.5 Day-ahead bid vs. imbalance-down price for Case 1.3.1

For Case 1.3.2, the thermal unit has the capability of compensating deviations in wind power for each scenario. Except for low imbalance-down prices, GENCO offers a day-ahead bid that cannot have imbalance power for any scenario. At a low imbalance-down price, GENCO may intentionally bid higher and risk being short for low wind power scenarios. As it can be seen in Figure 4.6, in Case 1.3.2, the day-ahead power bid is less prone to changes in the imbalance-down price compared to Case 1.3.1.

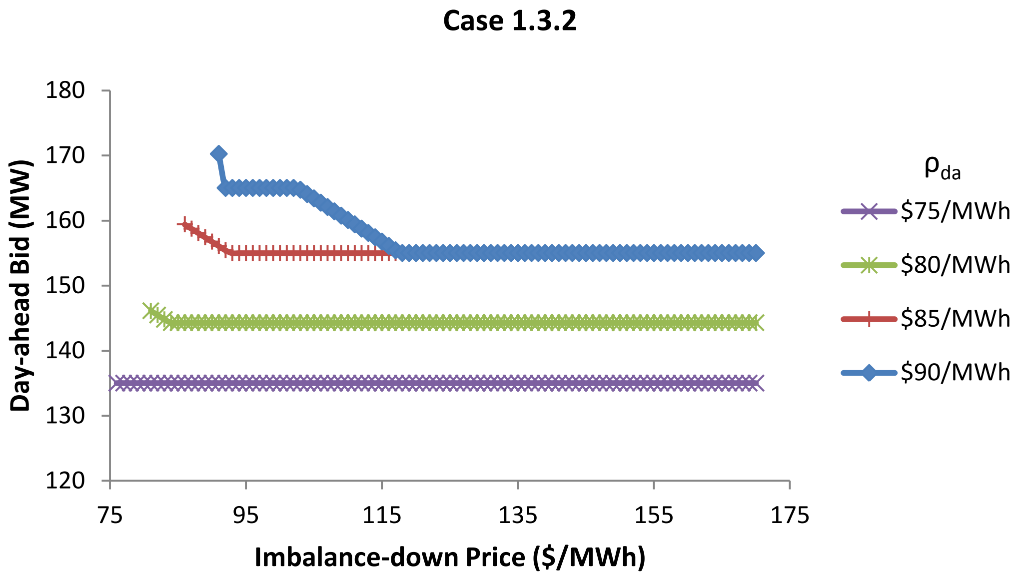

Figure 4.6 Day-ahead bid vs. imbalance-down price for Case 1.3.2

Expected profit decreases with the higher imbalance-down price as illustrated in Figure 4.7 for a day-ahead price of $80/MWh. In Case 1.3.1, thermal unit can compensate wind power forecast range not to have imbalance power. However, in Case 1.3.1, the expected bid gradually decreases to establish an equilibrium between imbalance-down and imbalance-up powers as the imbalance-down price changes. At a certain imbalance-down price, which is $111/MWh for a day-ahead price of $80/MWh, expected profit does not change anymore since GENCO reduces its bid not to become short in low wind scenario.

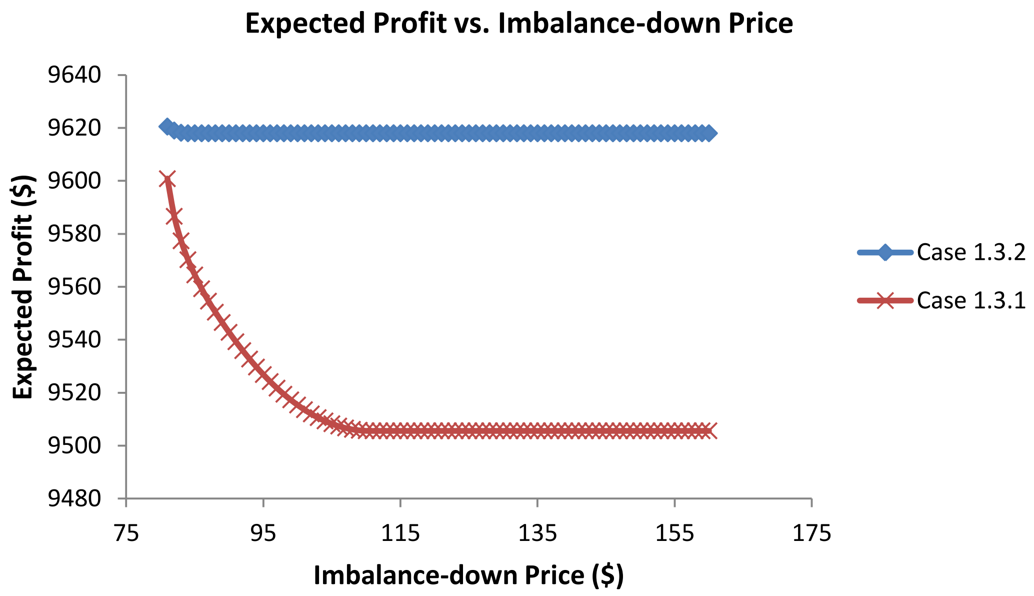

Figure 4.7 Expected profit vs. imbalance-down price for a day-ahead price of $80/MWh

4.1.4 Case 1.4: Effect of Wind Power Forecast Certainty

In this case, the effect of wind power forecast certainty on hourly thermal dispatch and the day-ahead power bid is examined. For this purpose, four different scenarios with the same expected value of wind power but with different probabilities are created as given in Table 4.10. Market price data are given in Table 4.11. According to market data, note that for every imbalance-up power of 1 MW, GENCO earns $21/MWh less while for every imbalance-down power of 1 MW, it pays back to the market $19/MWh more. From this finding, one can conclude that imbalance-up price is prominent to GENCO's day-ahead power bid decision.

Table 4.10 Wind power forecast with different certainties

	Scenario s	**1**	**2**	**3**
	P_{tsw} (MW)	90	120	150
Case 1.4.1	**Probability π**	0.2	0.6	0.2
Case 1.4.2	**Probability π**	0.1	0.8	0.1
Case 1.4.3	**Probability π**	0.05	0.9	0.05
Case 1.4.4	**Probability π**	0.01	0.98	0.01

Table 4.11 Market price data for Case 1.4

ρ^{da} (\$/MWh)	**ρ^{+} (\$/MWh)**	**ρ^{-} (\$/MWh)**
81	60	100

As the certainty in wind power forecast increases, the day-ahead bid decreases as given in Table 4.12. This is because of the fact that GENCO avoids being long due to the dominance of imbalance-up price over the imbalance-down price. In addition to this, as certainty increases, stochasticity of the wind-thermal coordination problem decreases. Thus, GENCO bids the sum of expected value of wind power, 120 MW and optimum thermal generation, 26.95 MW to the day-ahead market. Moreover, as the wind certainty increases, the expected profit also increases due to the low probability of imbalance power.

Table 4.12 Results for Case 1.4

	Scenario s / Prob. π	P_{tsw} (MW)	P_{tsg} (MW)	Δ_{ts}^{+} (MW)	Δ_{ts}^{-} (MW)	P_{tgw}^{bid} (MW)	$E[PROFIT]$ ($)
Case 1.4.1	**1 / 0.20**	90	45.00	0.00	13.72	148.71	9661.86
	2 / 0.60	120	28.71	0.00	0.00		
	3 / 0.20	150	5.00	6.29	0.00		
Case 1.4.2	**1 / 0.10**	90	45.00	0.00	12.61	147.61	9716.38
	2 / 0.80	120	27.61	0.00	0.00		
	3 / 0.10	150	5.00	7.39	0.00		
Case 1.4.3	**1 / 0.05**	90	45.00	0.00	12.24	147.24	9743.74
	2 / 0.90	120	27.24	0.00	0.00		
	3 / 0.05	150	5.00	7.76	0.00		
Case 1.4.4	**1 / 0.01**	90	45.00	0.00	12.00	147.00	9765.65
	2 / 0.98	120	27.00	0.00	0.00		
	3 / 0.01	150	5.00	8.00	0.00		

4.2 CASE 2: MULTI-HOUR ANALYSIS OF WIND-THERMAL COORDINATION

Throughout this section; the impact of coordination, thermal unit constraints, the bidding strategy and the wind power forecast on thermal UC are investigated for ten hours of scheduling horizon. For that purpose, in addition to thermal unit in Case 1, relatively more expensive second thermal unit is coordinated with wind power. Thermal unit data are given in Table 4.13. Marginal and overall generation costs of thermal units are given with 5 MW intervals in Table 4.14.

Table 4.13 Thermal unit data for Case 2

Unit No	$\underline{P}$ (MW)	$\overline{P}$ (MW)	$MinUp$ (hour)	$MinDn$ (hour)	u_{ini} (hour)	FC ($/MBtu)
1	5	45	1	1	-1	1.0
2	5	45	1	1	-1	1.0
Unit No	RU **(MW)**	RD **(MW)**	a **(MBtu)**	b **(MBtu/MW)**	c **(MBtu/MW^2)**	$StUp$ **($)**
1	40	40	85.51	70.86	0.19	0
2	40	40	89.34	78.23	0.23	0

Table 4.14 Marginal and generation cost of thermal units for Case 2

	Unit 1		Unit 2	
Power (MW)	**Marginal Cost ($/MWh)**	**Generation Cost ($/MWh)**	**Marginal Cost ($/MWh)**	**Generation Cost ($/MWh)**
5	88.90	444.51	97.26	486.29
10	81.29	812.91	89.48	894.80
15	79.38	1190.73	87.66	1314.88
20	78.90	1577.95	87.36	1746.51
25	78.98	1974.59	87.59	2189.70
30	79.35	2380.63	88.15	2644.46
35	79.89	2796.08	88.88	3110.77
40	80.52	3220.95	89.72	3588.65
45	81.23	3655.28	90.62	4078.09

Throughout Case 2, the wind power forecast is divided into seven scenarios with an expected value of 110 MW for all hours between t=1-10. Data are given in Table 4.15.

Table 4.15 Wind power forecast data for t=1-10

Scenario s	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Probability π	0.05	0.12	0.20	0.26	0.20	0.12	0.05
P_{tsw} (MW)	80	95	105	110	115	125	140

4.2.1 Case 2.1: Uncoordinated Thermal Generation

As mentioned before, the uncoordinated thermal UC is a straightforward PBUC problem. The thermal unit turns ON when the day-ahead price is high enough to make a profit. Unit responses to different day-ahead prices are given in Table 4.16. ON unit is represented by 1, while OFF unit is by 0. As it can be seen from the results, Unit 2, which is the more expensive unit, turns ON later than Unit 1 at a day-ahead price of $94/MWh. Both thermal units contribute to the power bid of 79.09 MW at this price.

4.2.2 Case 2.2: Wind-Thermal Coordination with Deterministic Bidding

In the deterministic bidding case, the day-ahead power bid is found as the sum of expected wind power and optimum thermal power for uncoordinated generation as found in Case 1.1. For each day-ahead price, there are two imbalance price sets that have higher and lower imbalance prices generated in order to reflect the impact of value of the imbalance price. Results are given in Table 4.17. Note that thermal UC statuses are the same as in Case 2.1.

Table 4.16 Thermal UC for Case 2.1

ρ^{da} (\$/MWh)	P_{tg}^{bid} (MW)	Unit 1 UC Status	Unit 2 UC Status
75	0	0	0
78	0	0	0
84	34.92	1	0
87	42.88	1	0
94	79.09	1	1

Table 4.17 Day-ahead power bid and thermal UC for Case 2.2

t (hour)	ρ^{da} (\$/MWh)	ρ^{+} (\$/MWh)	ρ^{-} (\$/MWh)	P_{tgw}^{bid} (MW)	Unit 1 UC Status	Unit 2 UC Status
1	75	70	76	110.00	0	0
2	75	40	130	110.00	0	0
3	78	75	85	110.00	0	0
4	78	65	95	110.00	0	0
5	84	83	88	144.92	1	0
6	84	60	110	144.92	1	0
7	87	80	90	152.89	1	0
8	87	60	105	152.89	1	0
9	94	90	100	189.09	1	1
10	94	70	125	189.09	1	1

4.2.3 Case 2.3: Wind-Thermal Coordination with Stochastic Bidding

In the stochastic bidding case, thermal and wind power bids are superposed in the day-ahead power bidding constraint in Equation (3.12). Different thermal unit statuses obtained in stochastic bidding compared to Case 2.2 are shown bold in Table 4.18.

Cheaper Unit 1 is ON for GENCO to avoid the imbalance penalty for the periods t=2, t=3 and t=4, where the day-ahead price is lower than the marginal cost of the unit. At t=1 and t=2, day-ahead price is the same; however, GENCO prefers to commit Unit 1 at t=2 where imbalance prices are higher than those of t=1 in order to avoid high imbalance penalty cost. Higher day-ahead price does not necessarily mean a higher power bid. At t=3, the day-ahead price is higher than that of t=2 but imbalance-down price is dominating the imbalance-up price. In order to avoid low profit from excess generation, GENCO bids more power at a lower day-ahead price at t=2. At t=5 and t=6, market data do not force to turn Unit 2 ON. Coordination with the cheaper thermal, which is Unit 1, is still more profitable. At t=7 and t=8, the day-ahead price is lower than the marginal cost of Unit 2, however; Unit 2 is forced to be ON in order to reduce the imbalance power for those times. At t=9 and t=10, thermal units are not only ON for coordination but also their generation is profitable at this day-ahead price.

4.2.4 Case 2.4: Wind-Thermal Coordination with Risk-Averse Bidding

In this case, the risk-averse behavior of GENCO is included into the problem. β =1 for risk averse parameter and α=0.95 for CVaR are chosen for risk assessment. Status of thermal unit 1 changed with respect to Case 2.3 is shown in bold in Table 4.19.

Day-ahead power bid decreases for all hours with respect to Case 2.3 in order to increase the profit in low wind scenarios. Note that at hour t=3, GENCO reduces its bid such that Unit 1 turns OFF and bids the value of lowest wind scenario, 80 MW. The CVAR criteria add more weight to the lowest profit outcomes as given in Equation (3.9). This results in much less bidding in the day-ahead market for all hours in order to avoid imbalance-down penalties.

Table 4.18 Day-ahead power bid and thermal UC for Case 2.3

t (hour)	$\boldsymbol{\rho^{da}}$ **(\$/MWh)**	$\boldsymbol{\rho^{+}}$ **(\$/MWh)**	$\boldsymbol{\rho^{-}}$ **(\$/MWh)**	$\boldsymbol{P_{tgw}^{bid}}$ **(MW)**	**Unit 1 UC Status**	**Unit 2 UC Status**
1	75	70	76	125.00	0	0
2	75	40	130	130.00	<u>**1**</u>	0
3	78	75	85	127.21	<u>**1**</u>	0
4	78	65	95	130.00	<u>**1**</u>	0
5	84	83	88	139.74	1	0
6	84	60	110	140.00	1	0
7	87	80	90	172.36	1	<u>**1**</u>
8	87	60	105	169.20	1	<u>**1**</u>
9	94	90	100	187.98	1	1
10	94	70	125	185.00	1	1

Table 4.19 Day-ahead power bid and thermal UC for Case 2.4

t (hour)	$\boldsymbol{\rho^{da}}$ **($/MWh)**	$\boldsymbol{\rho^{+}}$ **($/MWh)**	$\boldsymbol{\rho^{-}}$ **($/MWh)**	$\boldsymbol{P_{tgw}^{bid}}$ **(MW)**	**Unit 1 UC Status**	**Unit 2 UC Status**
1	75	70	76	115.00	0	0
2	75	40	130	120.00	1	0
3	78	75	85	80.00	**0**	0
4	78	65	95	115.77	1	0
5	84	83	88	117.32	1	0
6	84	60	110	125.00	1	0
7	87	80	90	156.85	1	1
8	87	60	105	152.77	1	1
9	94	90	100	166.77	1	1
10	94	70	125	170.00	1	1

4.2.5 Case 2.5: Wind-Thermal Coordination with Thermal Ramp Limits

Now it is assumed that Unit 1, which is the cheaper unit, has a ramp-up and ramp-down capacity of 10 MW/h. In order to see the effect of ramp-limit, order of the price set with respect to hours has been changed. Bold digits show the thermal unit status changed with respect to Case 2.4 for the same price set in Table 4.20.

Low ramp capacity of cheaper Unit 1 resulted in committing expensive Unit 2 more often compared to Case 2.4. The reason is that Unit 1 is not capable of compensating the imbalance power alone with the limited ramp range. Therefore, different from Case 2.4, Unit 2 is turned ON for price set t=2 and t=3. At t=1, t=5, t=7 and t=8 imbalance-up and imbalance-down prices are not so high, hence Unit 1 is capable of compensating the imbalance power even with its limited ramp. Also, Unit 1 is turned on at hour t=1 in order to reach a higher level of production in the following hours which is limited by ramp.

Table 4.20 Day-ahead power bid and thermal UC for Case 2.5

t (hour)	$\boldsymbol{\rho^{da}}$ **($/MWh)**	$\boldsymbol{\rho^{+}}$ **($/MWh)**	$\boldsymbol{\rho^{-}}$ **($/MWh)**	$\boldsymbol{P_{tgw}^{bid}}$ **(MW)**	**Unit 1 UC Status**	**Unit 2 UC Status**
1	78	75	85	120.00	**1**	0
2	84	60	110	148.55	1	**1**
3	75	40	130	139.60	1	**1**
4	87	60	105	164.44	1	1
5	75	70	76	150.00	1	0
6	94	90	100	187.98	1	1
7	87	80	90	165.20	1	1
8	78	65	95	130.00	1	0
9	84	83	88	139.25	1	0
10	94	70	125	185.00	1	1

4.2.6 Case 2.6: Effect of Wind Power Forecast on Thermal Unit Status

The effect of wind forecast distribution on thermal unit scheduling is investigated in this case. For this purpose, wind data in Table 4.21 are used for respective hours.

Table 4.21 Wind power forecast data for Case 2.6

Scenario s		**1**	**2**	**3**	**4**	**5**	**6**	**7**
Probability π		0.05	0.12	0.20	0.26	0.20	0.12	0.05
P_{tsw} (MW)	**t=1**	80	95	105	110	115	125	140
	t=2	70	85	95	110	125	135	150
	t=3	60	75	85	110	135	145	160
	t=4	50	65	75	110	145	155	170

Larger wind power forecast range; i.e., wider wind power forecast distribution causes Unit 2 to be committed in order to avoid imbalance power as given in Table 4.22. As the wind power forecast range gets wider, power bid increases to minimize imbalance-up power which is less preferable than imbalance-down power due to dominance of imbalance-up price.

Table 4.22 Day-ahead power bid and thermal UC for Case 2.6

t (hour)	**ρ^{da} (\$/MWh)**	**ρ^{+} (\$/MWh)**	**ρ^{-} (\$/MWh)**	**P_{tgw}^{bid} (MW)**	**Unit 1 UC Status**	**Unit 2 UC Status**
1	80	55	100	135.03	1	0
2	80	55	100	137.71	1	0
3	80	55	100	152.65	1	1
4	80	55	100	155.00	1	1

4.3 CASE 3: 24 HOUR WIND-THERMAL COORDINATION

24 hour analysis of wind-thermal coordination is investigated in this case analysis. Effect of coordination on the expected profit and CVaR is evaluated in a more realistic problem by adding minimum-up and minimum-down constraints; ramp-up and ramp-down constraints and start-up costs to problem. Furthermore, CVaR with different confidence intervals are compared with regard to impact on realized profits. Revised thermal unit data are given in Table 4.23.

Table 4.23 Thermal unit data for Case 3

Unit No	$\underline{P}$ **(MW)**	$\overline{P}$ **(MW)**	$MinUp$ **(hour)**	$MinDn$ **(hour)**	u_{ini} **(hour)**	FC **($/MBtu)**
1	5	45	4	2	-2	1.0
2	5	45	1	1	-2	1.0
Unit No	RU **(MW)**	RD **(MW)**	a **(MBtu)**	b **(MBtu/MW)**	c **(MBtu/MW^2)**	$StUp$ **($)**
1	10	10	85.51	70.86	0.19	100
2	40	40	89.34	78.23	0.23	0

Market data, expected wind power and standard deviation for Case 3 are given in Appendix. It is assumed that hourly wind power forecast has a normal distribution and increasing standard deviation in the later hours of the day. In order to find a discrete approximation for the wind power forecast, PDF is integrated over certain intervals to obtain PMF. PMF is a function that gives the probability of a discrete random variable; in our case wind power scenarios. To have a good approximation of PDF, large number of scenarios is needed to cover the probability space. On the other hand, there is a trade-off between number of sample scenarios and the computational complexity. In this case study, wind power forecast PDF for each hour is divided into six confidence intervals with the standard deviation of σ between [-3σ, +3σ] so as to find these representative samples as seen in Figure 4.8. The interval [-3σ, +3σ] spans the 99.74% of total area in PDF. This can be interpreted as the probability of the wind power outcome in the next day lies within this interval with 99.74% of chance. The interval outside [-3σ,+3σ] has only 0.26% of probability and it has a very small effect on the problem solution. Therefore, values which deviate more than 3σ from expected wind power forecast value is ignored to reduce computational effort and time. Equation (3.24) is solved to find wind power scenarios for each σ interval. $Q(x)$ is the PDF of wind power forecast and x is the wind power as illustrated in Figure 4.8. PMF of wind power scenarios for all hours are given in Appendix. Their probabilities are assigned as the normalized cumulative probability of corresponding confidence intervals given in Table 4.24.

$$
\begin{aligned}
W(1) &= \frac{1}{\sigma}\int_{-3\sigma}^{-2\sigma} x.Q(x).dx \\
W(2) &= \frac{1}{\sigma}\int_{-2\sigma}^{-1\sigma} x.Q(x).dx \\
W(3) &= \frac{1}{\sigma}\int_{-1\sigma}^{0} x.Q(x).dx \\
W(4) &= \frac{1}{\sigma}\int_{0}^{1\sigma} x.Q(x).dx \\
W(5) &= \frac{1}{\sigma}\int_{1\sigma}^{2\sigma} x.Q(x).dx \\
W(6) &= \frac{1}{\sigma}\int_{2\sigma}^{3\sigma} x.Q(x).dx
\end{aligned}
\tag{3.24}
$$

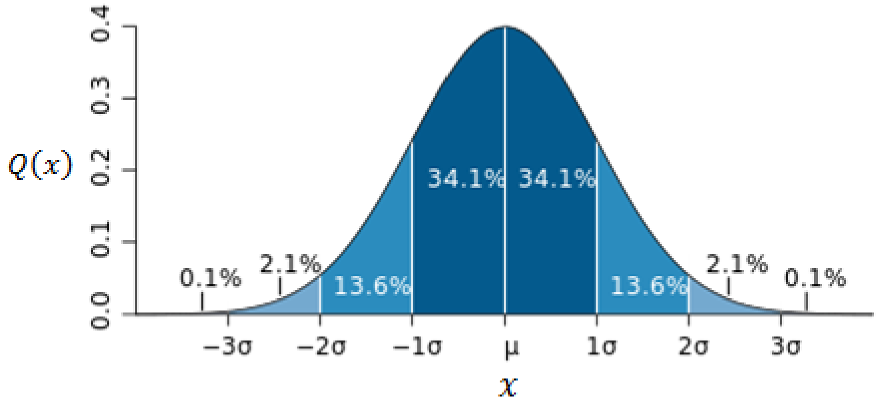

Figure 4.8 Normal PDF of wind power forecast and confidence intervals with respect to σ

Table 4.24 Wind power forecast probabilities

Scenario No	Distribution Interval	Normalized Probability
1	[-3σ, -2σ]	0.021
2	[-2σ, -1σ]	0.136
3	[-1σ, 0]	0.342
4	[0, +1σ]	0.342
5	[+1σ, +2σ]	0.136
6	[+2σ, +3σ]	0.021

In Figure 4.9, six wind scenarios found with the above method for each differently colored σ interval is shown with black lines. The expected wind power is shown with red line. Numerical wind data for all six wind scenarios for 24 hour is given in Appendix.

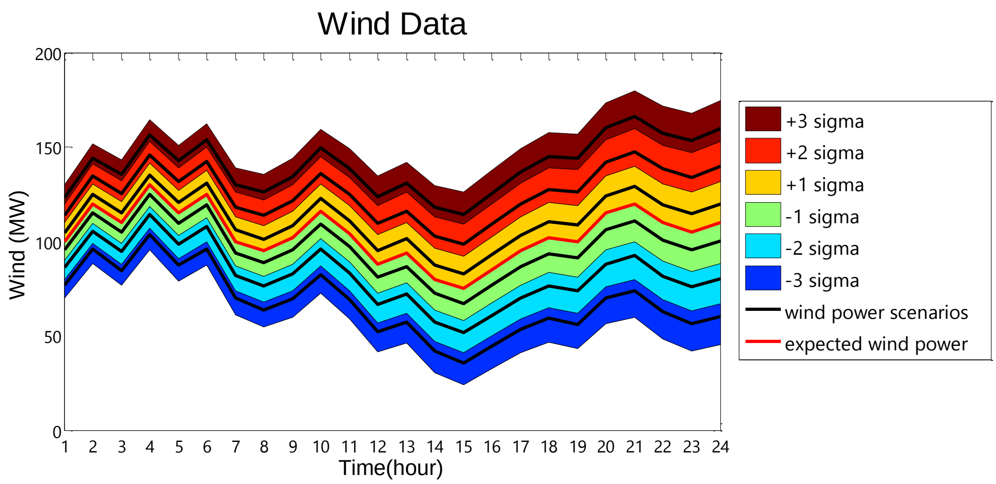

Figure 4.9 Wind power scenarios for every σ interval

There are six different sub-cases considered in Case 3, which are namely uncoordinated wind-thermal generation, coordinated wind-thermal generation with risk attitude parameters β=0, β=0.1, β=0.5 and β=1; and coordinated wind-thermal generation with deterministic bidding. In Table 4.25, profit and CVaR analysis are performed for these cases. CVaR is calculated for α=0.98 ($CVaR_{98}$) which equals to the value of lowest profitable scenario in the problem. In terms of expected profit and CVaR, coordinated wind-thermal generation with stochastic bidding is prominent to uncoordinated generation and coordinated generation with deterministic bidding. Expected profit of coordinated generation is 1.25% and 0.5% higher than that of uncoordinated generation and coordinated deterministic bidding. Situation in CVaR is even more distinct for coordinated generation with %4.6 and 2.4% larger CVaR compared to uncoordinated generation and coordinated deterministic bidding, respectively. Note that CVaR of uncoordinated thermal generation is equal to its expected profit because of the fact that there is no stochasticity in thermal only generation.

Table 4.25 Profit analysis of Cases

Case	$CVAR_{98}$ (\$)	$E[PROFIT]$ (\$)
Uncoordinated Thermal	3731.21	3731.21
Uncoordinated Wind	115481.59	197705.77
3.1 Sum of Uncoordinated Generation	119212.81	201436.98
3. 2 Coordinated Wind-Thermal β=0	124641.41	203945.83
3.3 Coordinated Wind-Thermal β=0.1	125893.38	203824.79
3.4 Coordinated Wind-Thermal β=0.5	130151.08	202669.44
3.5 Coordinated Wind-Thermal β=1	132088.57	201288.32
3.6 Coordinated Wind-Thermal with Deterministic bidding	121738.92	202895.95

Expected profit vs. CVaR plot is given for Case 3 in Figure 4.10. Uncoordinated bidding has the lowest expected profit and CVaR among all cases. For coordinated generation, as the risk averse behavior increases with β; $CVaR_{98}$ too increases but the expected profit decreases. The performance of coordinated deterministic bidding in values of expected profit and CVaR is better than that of uncoordinated generation. Comparing Case 3.1 to Case 3.5, one can note that 4.6% increase in CVaR results in only 1.3% reduction in expected profit. According to this trade-off between expected profit and CVaR, GENCO can choose its preference of risk before bidding in the day-ahead market.

The risk on profit variability can be controlled at the cost of a small reduction in expected profit. Figure 4.11 illustrates this case for the coordinated wind-thermal generation with GENCO's attitude towards risk β. As the risk averse behavior increases with β, standard deviation of realized profits decreases. In Figure 4.12, realized profits for risk averse coordinated wind-thermal generation are presented.

Given that coordinated wind-thermal generation with β=1 has the lowest profit standard deviation, it has the tightest U shape distribution, i.e., difference between realized profits are narrower. Numerical values for Figure 4.12 are given in Appendix together with thermal UC and hourly day-ahead power bid for each case.

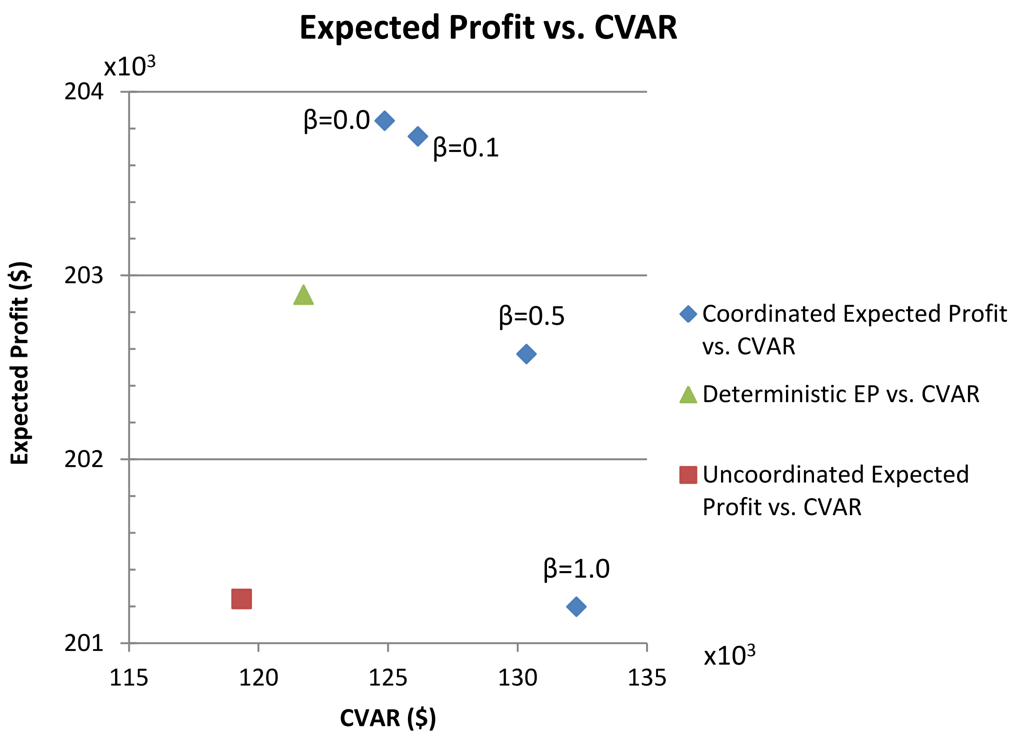

Figure 4.10 Expected profit vs. CVaR

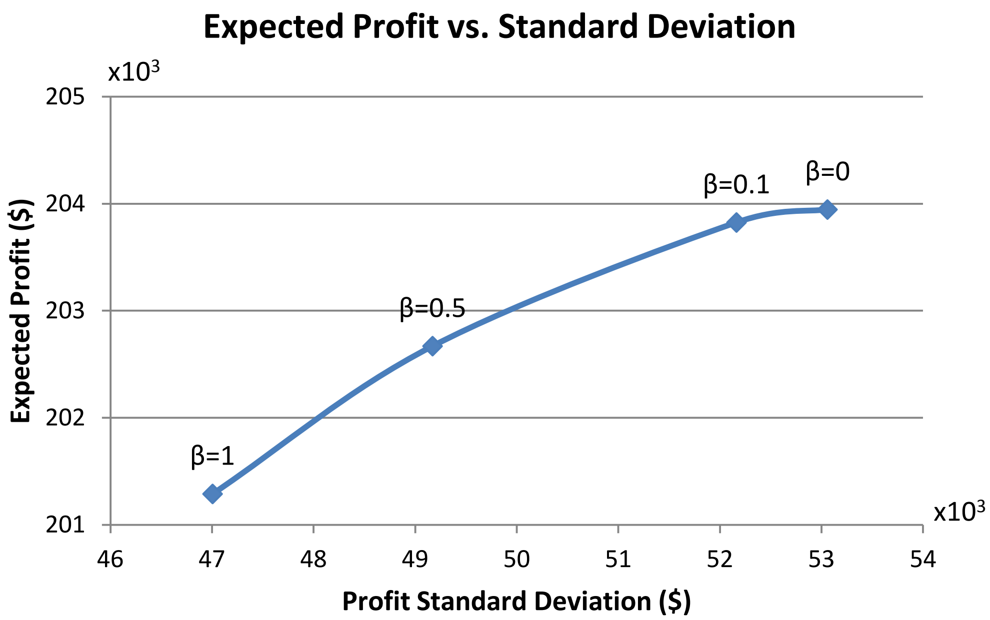

Figure 4.11 Expected profit vs. standard deviation

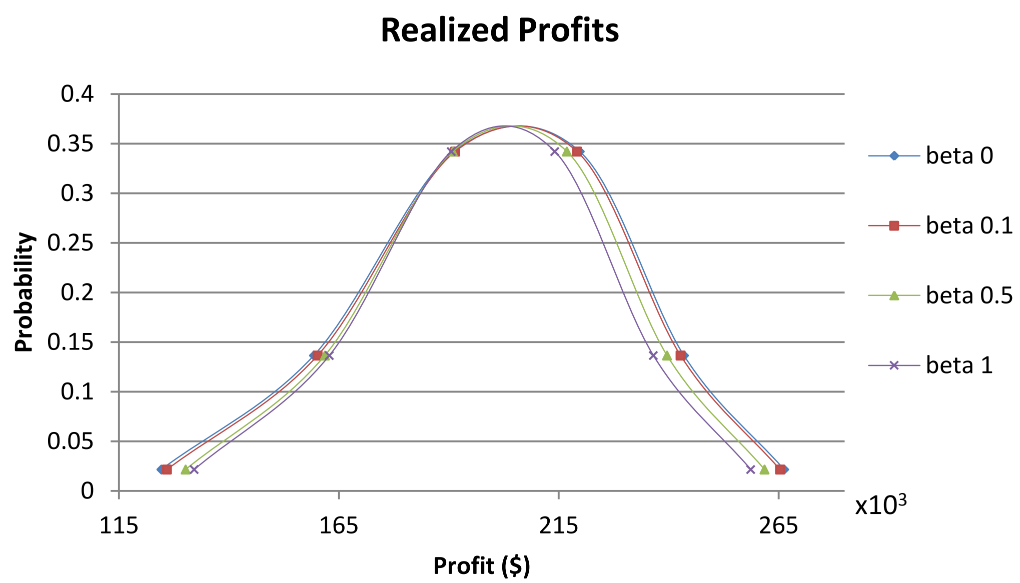

Figure 4.12 Realized profits for Case 3

Last observation in this section is the impact of choosing value of the confidence interval α for CVaR measurement. For this purpose, confidence level α=0.85 that covers the probability of the four most profitable scenarios is chosen. For $CVaR_{85}$, same calculations are made for the coordinated wind-thermal generation for β=1. Profits for each of six scenarios are compared in Table 4.26. Results prove that, the confidence level α of CVaR puts more emphasis on the profits lower than (1-α)th quantile of the distribution. It can be seen that the only scenario at which $CVaR_{98}$ overcomes $CVaR_{85}$ is the first scenario. It is because of the fact that $CVaR_{98}$ only puts weight to the first scenario according to the formula in Equation (3.9). On the other hand, $CVaR_{85}$ focuses on the expected profit of the least two profitable scenarios, first and second scenarios. As a result, day-ahead power bid of $CVaR_{85}$ are higher than those of $CVaR_{98}$ for all hours since it aims to maximize not only the least profitable first scenario but also the second scenario which has more probability of occurrence than the first scenario. Higher day-ahead power bid results in higher profits for the rest of wind scenarios for $CVaR_{85}$ compared to $CVaR_{98}$.

Table 4.26 Realized profit analysis for $CVaR_{98}$ and $CVAR_{85}$ with β=1

Scenario	**Realized Profit ($) for $CVaR_{98}$, β=1**	**Realized Profit ($) for $CVaR_{85}$, β=1**
1	132088.57	129952.15
2	162821.16	162986.61
3	190544.72	191316.60
4	214079.14	215383.25
5	236494.26	238395.00
6	258639.60	260822.41

CHAPTER 5

CONCLUSION

In this thesis, a two-stage stochastic programming model for wind-thermal coordination is proposed for a GENCO participating in Turkish day-ahead electricity market with its thermal and wind generation units. Aim of the GENCO is to determine the optimum power to be submitted to the day-ahead market that maximizes its expected profit in the first stage while controlling risks associated with possible realizations of wind power output in the second stage. Based on this objective, GENCO finds the most suitable hourly generation schedule and optimal bids subjected to market and thermal constraints. Risk-averse attitude of GENCO is reflected on the problem formulation with the CVaR criterion. MATLAB environment and its solvers are utilized to solve the coordination problem. Comparative case studies are used to illustrate the performance of bidding strategies and benefits of the coordination.

Before bidding in the day-ahead market, in order to maximize the expected profit, GENCO decides on thermal UC and amount of power that will be submitted to the market based on the market prices and available wind power forecast. In the operational day, wind power generation is realized and hourly ED of thermal unit is carried out to minimize imbalance penalties imposed by the balancing market arising from the discrepancy between the day-ahead power bid and the real-time generation. Results indicate that the wind-thermal generation coordination significantly contributes to the profit of GENCO by reducing the imbalance penalty charged by the balancing market compared to the uncoordinated generation.

Coordination leads thermal units to commit more often to balance real-time generation deviations from the day-ahead bid caused by the wind uncertainty. Thus, ramp limits, start-up cost, minimum-up and minimum-down time and generation capacity of thermal units can greatly affect the benefit of coordination.

Case studies indicate that the optimal day-ahead power bid and expected profit are highly dependent on the variability of the wind power forecast, the day-ahead and imbalance prices, and the risk preference of the GENCO. Stochastic bidding is proved to perform better than deterministic bidding in terms of expected profit. In addition to this, stochastic solution lowers the chance of getting low profits, i.e., CVaR. Risk preference of GENCO also plays a decisive role on the day-ahead power bid. Risk averse attitude results in a lower amount of power bid to the day-ahead market compared to risk neutral attitude. The reason for this is due to the fact that GENCO reduces its bid to avoid being short and imbalance down penalty in case of a low wind generation. Consequently, risk averse bidding may result in decommitment of thermal units to reduce the bidding volume.

Wind-thermal coordination does not only improve expected profits but also substantially increases the CVaR. The imbalance penalty for any discrepancy between the day-ahead bid and the real-time delivery may force GENCO to give more risk averse decisions to increase CVAR. CVaR criterion maximizes the expected profits of the lowest possible wind power scenarios; hence, lessens the chance of having low profits. GENCO can effectively control the trade-off between CVaR and expected profit with the proposed formulation in this thesis. Different levels of risk result in different actual profits. Small reduction in the expected profit can result in high growth in CVaR; hence, GENCO determines its generation scheduling and day-ahead bidding according to its risk preference.

The case studies presented in this thesis are built on several assumptions. More realism can be added to the wind-thermal coordination problem by converting deterministic day-ahead and balancing market prices into stochastic prices. Hence, price-quantity offers can be constituted for the day-ahead market bidding. More developed scenario generation and reduction techniques, which are out of the scope of this thesis, can be developed for better representation of uncertainty and more accurate results in coordination problems. Analysis can be further scaled up with other types of generation such as hydro pumped-storage. Impact of greenhouse emission caps on electricity generation facilities which are likely to be imposed in near future by governments aiming to comply with international agreements can be added to the coordination problem with different objective function and constraints.

Alternative market environments and rules for pricing mechanisms can be introduced to the coordination problem to assess the influence of market design on bidding strategies, expected profits and scheduling of generation. There exist adjustment markets where producers can update their amount of scheduled generation between closure of the day-ahead market and the beginning of the operation period. Thus, it is possible for GENCOs to take corrective actions to reduce the differences between scheduled and expected generation so as not to be exposed to imbalance penalties. PMUM has a target of establishing an adjustment market in the near future as mentioned before. This will help GENCOs having wind generation units in their portfolio to compensate day-ahead power bids with certainty gained between the day-ahead market closure and opening of the adjustment market by updating wind power forecasts; hence, decreasing the imbalance penalty and the risk.

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APPENDIX A

RESULTS FOR CASE 3

Market and wind power forecast data used in Case 3 is given in this section. Also, wind power scenarios obtained by PMF are explicitly written for each hour. Moreover, numerical results such as day-ahead power bid, thermal UC statuses and realized profits for each analysis in Case 3 are tabulated in the following.

Table A-1 Market data for Case 3

Hour	ρ^{da} **($/MWh)**	ρ^{+} **($/MWh)**	ρ^{-} **($/MWh)**	**Hour**	ρ^{da} **($/MWh)**	ρ^{+} **($/MWh)**	ρ^{-} **($/MWh)**
1	74	40	100	**13**	82	68	94
2	86	55	120	**14**	88	83	101
3	75	65	112	**15**	92	78	104
4	95	50	101	**16**	95	91	124
5	70	35	88	**17**	77	58	93
6	95	50	118	**18**	75	71	87
7	77	72	80	**19**	70	50	81
8	85	46	128	**20**	75	48	84
9	75	64	114	**21**	82	72	88
10	72	36	102	**22**	88	75	114
11	76	56	90	**23**	94	62	120
12	70	62	82	**24**	80	60	102

Table A-2 Wind power forecast data for Case 3

Hour	P_{tw}^{exp} **(MW)**	**Standard Deviation σ (MW)**	**Hour**	P_{tw}^{exp} **(MW)**	**Standard Deviation σ (MW)**
1	100	10.00	**13**	94	16.00
2	120	10.50	**14**	80	16.50
3	110	11.00	**15**	75	17.00
4	130	11.50	**16**	85	17.50
5	115	12.00	**17**	95	18.00
6	125	12.50	**18**	102	18.50
7	100	13.00	**19**	100	19.00
8	95	13.50	**20**	115	19.50
9	102	14.00	**21**	120	20.00
10	116	14.50	**22**	110	20.50
11	104	15.00	**23**	105	21.00
12	88	15.50	**24**	110	21.50

Table A-3 Wind power scenarios for Case 3

	Hour / Scenario	1	2	3	4	5	6
Wind Power Data (MW)	**1**	76.92	86.22	95.42	104.58	113.78	123.08
	2	95.77	105.53	115.19	124.81	134.47	144.23
	3	84.61	94.84	104.96	115.04	125.16	135.39
	4	103.45	114.15	124.73	135.27	145.85	156.55
	5	87.29	98.46	109.50	120.50	131.54	142.71
	6	96.13	107.76	119.27	130.73	142.24	153.87
	7	69.98	82.07	94.04	105.96	117.93	130.02
	8	63.82	76.38	88.81	101.19	113.62	126.18
	9	69.66	82.69	95.58	108.42	121.31	134.34
	10	82.50	96.00	109.35	122.65	136.00	149.50
	11	69.34	83.31	97.12	110.88	124.69	138.66
	12	52.19	66.62	80.89	95.11	109.38	123.81
	13	57.03	71.92	86.66	101.34	116.08	130.97
	14	41.87	57.23	72.43	87.57	102.77	118.13
	15	35.71	51.54	67.20	82.80	98.46	114.29
	16	44.55	60.85	76.97	93.03	109.15	125.45
	17	53.40	70.16	86.74	103.26	119.84	136.60
	18	59.24	76.47	93.51	110.49	127.53	144.76
	19	56.08	73.77	91.28	108.72	126.23	143.92
	20	69.92	88.08	106.05	123.95	141.92	160.08
	21	73.77	92.39	110.82	129.18	147.61	166.23
	22	62.61	81.70	100.59	119.41	138.30	157.39
	23	56.45	76.01	95.36	114.64	133.99	153.55
	24	60.29	80.32	100.13	119.87	139.68	159.71

Table A-4 Amount of day-ahead power bid for Case 3

	Hour	Case 3.1	Case 3.2	Case 3.3	Case 3.4	Case 3.5	Case 3.6
Day-ahead power bid (MW)	**1**	112.93	110.42	109,58	102.94	100.42	108.35
	2	140.19	162.78	160,38	154.47	153.08	145.00
	3	119.96	129.96	129,84	119.61	119.61	125.00
	4	217.11	211.92	210,24	204.14	196.55	201.26
	5	135.50	145.50	145,50	144.50	134.50	130.00
	6	201.98	199.44	197,76	186.13	186.13	196.26
	7	122.28	130.96	130,96	119.04	119.04	116.32
	8	123.81	143.62	143,62	139.21	131.19	130.00
	9	110.58	110.58	107,69	94.66	94.66	117.00
	10	127.65	127.65	125,33	132.65	119.35	121.00
	11	110.88	115.88	115,88	112.12	102.12	104.00
	12	80.89	94.96	85,89	73.64	67.19	88.00
	13	116.34	116.34	111,66	118.95	108.15	109.00
	14	118.55	133.25	128,37	115.01	107.66	126.12
	15	147.57	147.82	143,50	130.54	125.71	139.77
	16	142.10	150.85	139,62	134.55	134.02	166.26
	17	128.26	128.26	121,74	111.74	95.16	120.00
	18	108.51	108.51	108,51	84.24	80.42	117.00
	19	113.72	113.72	113,72	106.28	96.28	105.00
	20	138.95	138.95	128,95	128.95	121.06	130.00
	21	158.78	154.18	144,18	135.82	125.82	149.60
	22	166.71	171.70	155,98	142.61	137.11	176.12
	23	193.73	177.63	173,99	154.64	146.45	184.09
	24	125.13	149.87	149,87	134.64	130.13	135.00

Table A-5 UC Statuses for Case 3

		Case 3.1		Case 3.2		Case 3.3		Case 3.4		Case 3.5		Case 3.6	
	Hour / Unit	**1**	**2**	**1**	**2**	**1**	**2**	**1**	**2**	**1**	**2**	**1**	**2**
Thermal UC Status	**1**	1	0	1	0	1	0	1	0	1	0	1	0
	2	1	0	1	1	1	1	1	1	1	1	1	0
	3	1	0	1	0	1	0	1	0	1	0	1	0
	4	1	1	1	1	1	1	1	1	1	1	1	1
	5	1	0	1	0	1	0	1	0	1	0	1	0
	6	1	1	1	1	1	1	1	1	1	1	1	1
	7	1	0	1	0	1	0	1	0	1	0	1	0
	8	1	0	1	1	1	1	1	1	1	1	1	0
	9	1	0	1	0	1	0	1	0	1	0	1	0
	10	0	0	1	0	1	0	1	1	1	1	1	0
	11	0	0	1	0	1	0	1	0	1	0	0	0
	12	0	0	1	0	1	0	1	0	1	0	0	0
	13	1	0	1	0	1	0	1	1	1	1	1	0
	14	1	0	1	1	1	1	1	1	1	1	1	1
	15	1	1	1	1	1	1	1	1	1	1	1	1
	16	1	1	1	1	1	1	1	1	1	1	1	1
	17	1	0	1	0	1	0	1	0	1	0	1	0
	18	1	0	1	0	1	0	1	0	1	0	1	0
	19	1	0	1	0	1	0	1	0	1	0	1	0
	20	1	0	1	0	1	0	1	0	1	0	1	0
	21	1	0	1	0	1	0	1	0	1	0	1	0
	22	1	1	1	1	1	1	1	1	1	1	1	1
	23	1	1	1	1	1	1	1	1	1	1	1	1
	24	1	0	1	1	1	1	1	1	1	1	1	0

Table A-6 Realized profits for Case 3

	Scenario	1	2	3	4	5	6
Realized profits ($)	**Case 3.1**	119212.80	154613.74	189107.24	218311.60	240292.62	261963.37
	Case 3.2	124641.41	159333.09	191220.06	219770.18	243475.16	266249.71
	Case 3.3	125893.38	160147.63	191457.25	219143.27	242700.73	265312.94
	Case 3.4	130151.08	161817.45	190904.02	216838.43	239612.71	261782.14
	Case 3.5	132088.57	162821.16	190544.72	214079.14	236494.26	258639.60
	Case 3.6	121738.92	157137.40	191142.53	218571.15	241895.08	264596.57