早稲田大学大学院環境・エネルギー研究科
博士学位論文

Strategic Bidding and Transmission Congestion Management in Deregulated Electricity Market

競争環境における入札戦略並びに送電線混雑管理に関する研究

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Chapter 1 Introduction

The rapid deregulation of the electricity industry in the last two decades has produced the formation of several markets around the world. Following the example of other commodities, the electricity market is commonly managed by an exchange that publishes daily the traded quantities and the market prices. Unfortunately, electricity cannot be exchange freely but has to be traded subject to the physical constraints of the transmission network. In addition, electricity cannot be stored as any other commodity but it is necessary to consume it at the same time of productions. These peculiar characteristics of the electricity market have been deeply investigated in the last decades and new technologies developed. The research included in this thesis started with the first steps of the deregulation in Japan. The necessities for new tools both in the market management side and in the market participant side were the impulse to develop the new theories summarized in this work.

1.1 The deregulation process

The earliest introduction of market concepts and privatization to electric power systems took place in Chile in the late 70s. The Chilean model was generally perceived as successful in bringing rationality and transparency to power pricing, but it contemplated the continuing dominance of several large incumbents and suffered from the attendant structural problems. Argentina improved the Chilean model by imposing strict limits on market concentration and by improving the structure of payments to units held in reserve to assure system reliability. One of the principal purposes of the introduction of market concepts in Argentina was to privatize existing generation assets (which had fallen into disrepair under the government-owned monopoly, resulting in frequent service interruptions) and to attract capital needed for rehabilitation of those assets and for system expansion. The World Bank was active in introducing a variety of hybrid markets in other Latin American nations, including Peru, Brazil and Colombia, during the 90s, with limited success.

In the late 80s, the English Prime Minister Margaret Thatcher developed a policy based on minimum state intervention, free markets, and entrepreneurialism. After the election in 1983, the Government sold off most of the large utilities including the electricity generation sector in 1990. With the privatization of the generation sector, the creation of an independent company that owns and operates the transmission grid and the market, the UK

model was a key event in the electricity market development.
Following the UK example, several other countries approached the same process either if in different ways.
The most famous examples include:
Norway: 1991
Sweden: 1996
USA: 1996 (Order 888,889)
Australia: 1995
The European Union deliberated the first directive about the deregulation of the electricity market in the member countries in the 1996; the directive was revised in 2003.
The objective of deregulation and privatization is to increase the efficiency and sustainability of the energy sector through the competition. Increasing the number of entities competing in the energy industry, governments aim to develop an environment that dynamically adjusts to the customers needs and increases the total welfare.

1.2 Electricity pricing

In the past, it was commonly thought that electricity could not be managed properly under market forces. High costs for infrastructures and complexity of real time operation were considered the barriers to a complete electricity market; a single monopolistic company that operates under regulated condition was considered the most efficient way to manage the electricity industries. The introduction of deregulations in the bank, telecommunication and other political strategic sectors, shows that it was feasible to privatize and operate markets either in sectors that were classically considered natural monopolies.
The macroeconomic theory of the intersection between the offers and demand was applied to the electricity and it was shown that efficiency in the electricity market could be obtained with the introduction of the market.
In the late '80s Schweppy formalized the theory of the spot pricing of electricity, showing that it is feasible to price electricity in real time, in opposition to the classical theories, that claim that the electricity price have to be decided on a long term cost base calculation. Schweppy demonstrated that the marginal cost of the generation production is applicable for electricity pricing inducing efficient macro behavior in both the supplying and the demand side of the industry. The possibility to price electricity on spot base was a fundamental condition for the development of the market, and Schweppy's work gave an important impulse to the deregulation policy of United States.
It was demonstrated that the benefit that may be earned from the marginal pricing could ensure a profit rate sufficient to justify investments in the generation sector. The marginal

pricing theory substitutes the average price theory for electricity pricing.

1.3 New entities and players in the power industry

Changing from a monopolistic schema, in which the public or private utility is in charge to follow all the chain process from generation, to transmission, until the deliver to the final customers of electricity, to a competitive environment took in place several organization problems and structural discussions.
It is generally recognized that the electricity business can be divided in 4 main parts:

- Generation
- Transmission
- Distribution
- Retail

Customers are the final entities in the value chain.
Generation sector has the role to produce electricity from other energy fonts such as nuclear, thermal and hydro. Once the electricity is produced, it has to be transmitted via the high voltage transmission lines from the production location to the consumption location. To distribute the electricity to final customers a low voltage network (the distribution network) is normally employed. The retail sector role includes contracts management, customers care billing and settlement functions.
Either after the deregulation, the transmission and distribution businesses (also defined as the wire business) are recognized as natural monopolies. In other words, it can be said that it is necessary to have a single company owning the network for a fixed area. The network can be operated by an entity that does not own it. Since the network is utilized by the companies that are operating in the generation and the retail business, it is fundamental that the network operator is an independent entity capable of ensuring fairness and clearness of the utilization of the network itself.
The necessity to have a monopolistic transmission company is a consequence of the importance to optimize the network configuration and avoid inefficient constructions. Transmission and distribution entities are in general regulated companies with a pre-negotiated return on equity. Recently, the phenomenon of merchant transmission companies is increasing for special projects such as DC interconnection between control areas. These projects are not subject to regulation and can be very profitable in condition of highly congested areas.
The generation and the retail sector are the parts of the electricity industry that are generally privatized and deregulated. The introduction of the competition and the consequent possibility of profit for new entries are the incentive for the creation of new companies and

to attract new capitals from investors.
The generation market, also defined as the wholesale market, is normally the first sector of the electricity industry to be deregulated. IPPs (independent power producers), merchant generators or generation companies are the new players that enter in the wholesale market.
IPPs are generating units built after the stipulation of long-term contracts: PPA (power purchase agreement). The IPP owner reduces the investment risk with a contract that insure the recovery of the monetary exposure; merchant generators are projects that relies on the market or short term contract for the recover of the investments. IPPs were strongly encouraged by governments and politicians in the late 80s. The objective was the development of an environment that may be easily adapted to the competition schema.
The retail side of the market is in general deregulated by steps and in a second time respect the wholesale market. The main reason is the protection of small electricity customers from the risks of the market. In the first step large customers are enable to choose the supplier and enter directly in the wholesale market. In this stage, local distribution companies or other regulated entities such a ‘single buyer’ are responsible for supplying the electricity service to not-eligible customers. In a second stage, when the wholesale market is mature, all the retail market is open to competition. At this point several entities such as retail companies, aggregators, and energy service providers enter in the market.
The wholesale market can be operated on a bilateral way or on central way. The advantage to have a central market is the possibility to have a clear price signal to the market participants.
The introduction of the market is also an incentive for brokers or traders to enter in the electricity business. Traders and brokers have an important role in the development of a mature market: they ensure liquidity and information availability for other players.
Figure 1 is a schematic description of the relation among players and entities in a deregulated electric industry. The dot lines represents the contracts and the money flow; the continuous lines show the flow of electricity. Generation sector utilizes the transmission and distribution network to deliver electricity to the final customers. The monetary transactions may occur among generation sector, retail sector, traders and market structures. The transmission system operator collects the market information (the orange line) to ensure the physical delivery of the electricity.

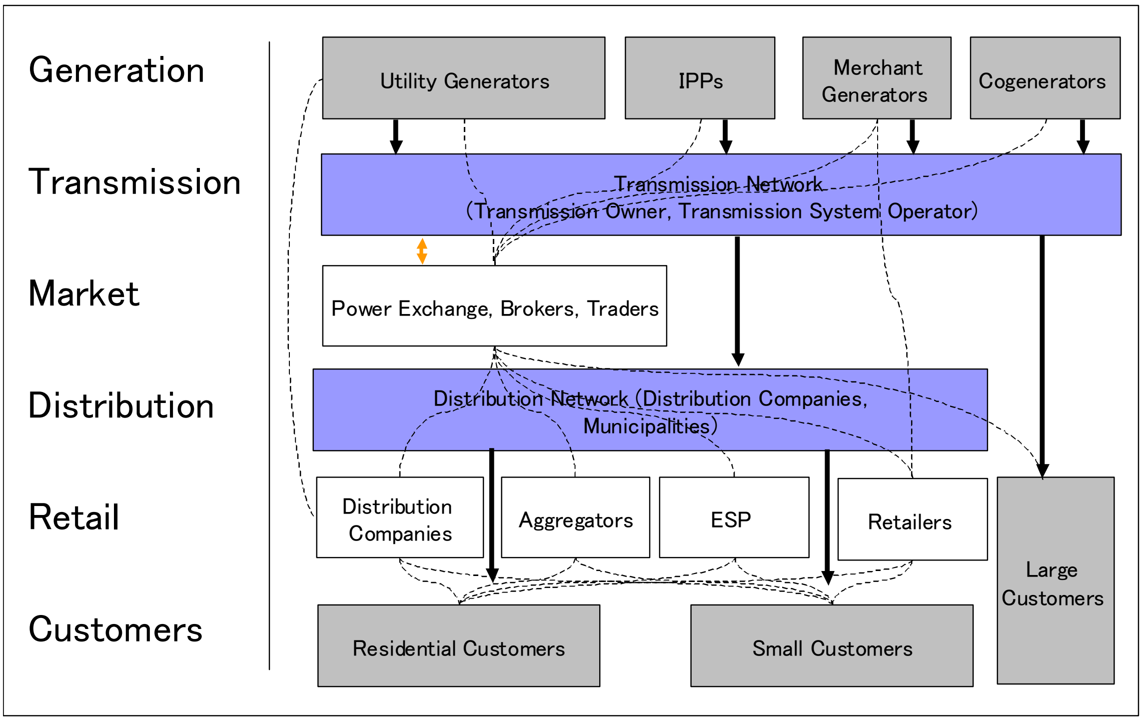


Figure 1: Entities in the deregulated market

1.4 Information technologies applied to the power system

The improvement of information technologies and communication networks needs a special mention. It has to be recognized that the development of efficient electricity markets was strongly supported by IT infrastructure. The increase of entities involved in the electricity business is the cause of an increase of information exchange among them and an enormous quantity of data that have to be processed daily. Production and consumption have to be monitored on a very short-term period (from one hour to fifteen minutes depending on the country) for settlement proposes. This big amount of data have to be acquired trough an information network, validated and processed in relative short time.
Power exchanges have to acquire a large amount of bids and offers and to process them trough complex calculation to obtain market solutions in few minutes.
Power system operators have to collect plans and schedules of all the generators to forecast the power flow on the transmission lines and to ensure a safe and efficient transmission network operation.
In the last three decades, computer and communication costs decreased constantly and at the same time performance increased. The progress in computer science permitted to utilized high performance computer equipment to store and process data, Internet is the basic infrastructure for electricity trading and information exchange, and the improvement

of software development had allowed market players and system operators to acquire sophisticated calculation tools at reasonable prices.
This thesis proposes solutions for the deregulated market assuming that the IT and communication infrastructures are available and efficiently operating; the algorithms developed were translated in computer programs and tested.

1.5 The Japanese situation

The Japanese electricity industry was operated by 10 regional private monopolistic utilities. Japan approaches the deregulation of the electricity industry at the end of the 90s. The first step was the introduction of IPPs: several companies offer to build and operate power plants and to sell the power production to the regional utilities for a pre-determinate price. IPPs contracts vary between 10 to 15 years. The introduction of IPPs became the bases for the development of a competitive framework for the wholesale market. In 2000, the retail market was partially open. New entities called PPS (Power Producer and Supplier) could supply electricity to large customers (2000 kW or above) such as factories or commercial buildings. In general, the PPSs buy electricity from independent generators or co-generators and use the utility transmission network to transmit it to their customers. PPSs pay a transmission fee to the utilities for accessing the network.
In 2004 the eligibility criteria to be supplied by PPS was enlarged to medium-large size customers (500 kW), and subsequently, in 2005 to medium size customers (50kW) allowing retail competition in the 63% of the total market. The full deregulation of the retail market, including the residential customers, is now under discussion and may be implemented in the future.
In addition of the reconstructing of the retail market, several other reforms, including the introduction of a power exchange and the development of an organization that coordinate the transmission access, were done.
In December 2007, the Japanese electricity industry is characterized by the presence of 10 monopolistic utilities still vertical integrated, more than 25 PPSs that supply the 3% of the retail market, several IPPs that supply electricity to the utilities, one large generation company, J-power, that operates around 10% of the total generation capacity of Japan, a power exchange (JEPX) that operate a forward and a day-ahead market, and an independent transmission access coordinator (ESCJ). Figure 2 shows a schematic representation of the entities operating in the Japanese electricity industry and their relation. Japanese utilities transmission networks are interconnected by inter-tie line, for this reason it is possible to have a single Japanese electricity market.
This research and algorithms developed in this thesis are based on the Japanese market

model and the needs of Japanese market participants.

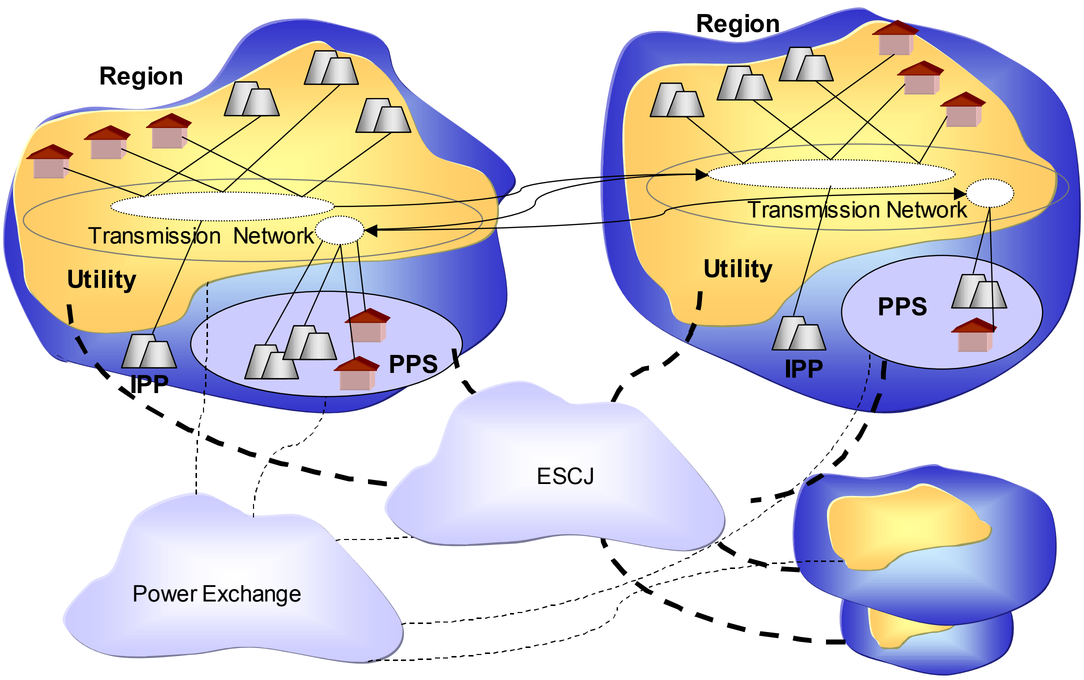


Figure 2: Entities in the Japanese electricity industry

1.6 Research objective

The changes in the electric industry are the cause of several problems and challenges for both the new market players and the utilities. The increasing of entities operating in the market implicates a distributed decision making process and, as consequences, the necessity of coordination or to take decision under impartial or imperfect information conditions.

In this thesis, after a deep investigation of the market models and rules, I shall focus on three main problems that are particularly relevant for the Japanese players.

The first subject is the development of strategic bidding decision for generation companies. The complexity of the market rules and the operation constraints of power plants make the bidding development process non-trivial. Market price forecasting method and unit commitment optimization techniques are developed and integrated to find the strategic bid that maximize the generation company profit.

To support PPS decision making, a day-ahead scheduling method for generation and demand portfolio that consider the possibility to supply electricity in several control areas is

proposed.
Another fundamental problem of the Japanese market is the management of the transmission congestion. Interconnections among utilities are limited in capacity; for this reason it may happen that the all the transactions among players cannot be accommodated. Algorithms, to decide who should have the right to use transmission capacity and how the transmission capacity limitation should influence the electricity price, are developed and tested. The basic concept implemented for the transmission congestion management is the market splitting model.
This thesis is organized as follow.

In the second chapter of the dissertation, the market rules are analyzed. Since, the particularity of electricity as commodity is the impossibility of storage and the need to be consumed in the same instant of production, the importance of sequential markets (from forward market to real time market) and the link between them is analyzed in the chapter. Furthermore, the delivery of electricity is subject to several other services that can be compared to the logistics for other goods. These services are commonly known as ancillary services. Since the market volume related to ancillary services is an important part of the total electricity market (it may vary between 5 to 15% of the total market volume), the ancillary service market and the rules associated with them are also analyzed.

In the third chapter, the market from the viewpoint of players in general and of generation companies in particular is analyzed and methods to improve the market price forecasting and optimize the bid strategy are explained. The market price forecasting is a fundamental task for market participants. A player with a good knowledge of the possible market price for the following day is able to develop an optimal bid that will increase the daily profit. As a consequence of the high volatility of the market price, it is important to employ a flexible method to be able to catch all the elements that influence the price. A neural network algorithm is implemented and tested on the Japan Electric Power Exchange data proving the performance. Since, short-term generation planning objective function change from a cost minimization to a revenue maximization problem under deregulation, a method to approach the new unit commitment problem is developed. Several operational constraints such as ramp-rate, minimum time-up and time-down, transmission limits, are considered with the intent to find an operational schedule and a market bid that are at the same time profitable and operationally feasible. To solve the complex unit commitment problem, i.e. a mixed-integer non-linear problem, an optimization method is developed. The method is a combination of quadratic and dynamic programming integrated together to produce an optimal operational schedule. Furthermore, techniques to individuate possible speculation between electricity and ancillary services markets are developed.

The fourth chapter describes an optimal portfolio approach for PPS. In Japan, differently from the utility companies, PPS may supply electricity to customers disperse in several control areas. The supply source can be dislocated in any region and the PPS have to apply for a special wheeling contract (furikae) to send electricity across control areas. Losses, contract constraints and wheeling fees have to be evaluated together to develop the optimal schedule that maximizes PPS profit. This thesis proposes an optimization algorithm for multi-area scheduling. The algorithm is a modification of the unit commitment approach proposed for strategic bid development.

In the fifth chapter, one of the main problems related to the deregulated market, the transmission congestion problem is presented and solution methods proposed.
The transmission congestion problem is caused by the conflict of interests among the market players: limited transmission resources have to be allocated to several independent players, all of them operating with the intent to improve their own profit. Since it is not possible to improve the transmission capacity in a short time frame and in several cases the economical benefit of new transmission line does not justify the investment costs, methods that allocate in a fair and efficient way the available capacity and allowed the participants to understand the congestion are fundamental for a good market behavior. This dissertation defines a framework to identify the congested paths and methodologies to relive congestion based on the market split approach. The market prices produced by the method are clear signal to market participants to identify congested areas and new business opportunity. In particular areas that are strongly congested have a high price due to the import electricity, on the contrary, areas that are not congested or that have excess of electricity see a low price. The framework is implemented with the intent to support both the forward and the spot electricity markets. The forward market is normally managed with a continuous auction mechanism. Transmission constraints are integrated in the auction algorithm, and the market price, for each area, changes according to the constraints. For the spot market, a single price auction approach is proposed. An iterative algorithm to individuate the possible congested transmission line and to find the submarkets in which it is necessary to split the market to relief congestion is developed. The proposed methods to manage and relief congestion are simple, based on an algebraic algorithm that ensures reproducibility and always-feasible solution. Complex radial and loop network can be modeled and solved. An algorithm to solve complex network constraints such as band or minimum flow constraints (particularly important in the Japanese transmission network where DC interconnection are in operation) is also developed and applied to the spot market congestion management.

The sixth chapter summarizes the contents of the dissertations and strengths on the practical importance of the new approaches developed during the research periods. In this chapter the open problems and research theme that still need to be investigated are also introduced with the intent to propose future improvement of the deregulated electricity market.

Chapter 2 Analysis of Market Rules

Before to develop the bidding strategies and the transmission management, this thesis wants to explain the kind of markets and the rules already implemented around the world. A clear understanding of the markets rules is indispensable for the market participants in order to develop of a consistent bid strategy. The market rules include: the market structured, the participants constraints, the clearing rules, and the transmission network access rules.
The market structure can be classified in three main types:

- the central market model
- the decentralized model
- the hybrid model

In addition to the main market structures, it is necessary to look at which kind of products can be exchanged in the market and how the transactions are processed.
Auction mechanisms and congestion management methodologies are also classified in this chapter.

2.1 Market structures

In a central market, a single market operator purchases all the electricity and the related products. Generators cannot select freely the counter-party, and they are forced to sell trough an auction mechanism to the central market. Examples of this kind of market structure are the Korean market model or the English market until 2001. The central market, also known as compulsory market, has the advantage to concentrate the operating power in the hand of the market/transmission operator; in this way it is possible to avoid problems of coordination. Nevertheless, the high level of "regulation" do not permit to the market to grow properly, this may cause negative effect to the customers. In the English example, it was possible recognized events of market power, gaming and unfair market pricing.
In a decentralized or bilateral model all the electricity is sold through bilateral contracts. This kind of model gives to the generator companies a high level of freedom but it can create coordination problems among the players in the market. Examples of this kind of market are the NETA model (UK) and the Japanese market. Several power exchanges or brokerage services can be implemented also in this market structure but they are not mandatory and in general, they do not have any responsibility in the power delivery.
In the hybrid model a generator is free to sell electricity to a counter party on a bilateral base, but it may also decide to sell through a market operator that coordinate the transaction and ensure more stability and less risk.
In some cases, generators and retailers can stipulate bilateral transaction until several hours before the delivery, after this term they are forced to sell in the market as it happens in PJM

(Pennsylvania, new Jersey, Maryland).
The company that operates the market can operate the transmission system (for example on PJM) or the transmission system can be operated independently from the market (the previous California model, the Nord Pool).
Figure 3 schematizes the market models developed in the world until now. ISO is the acronyms of independent system operator, SC schedule coordinator (there are several other definitions such as balance group or balancing entity, the Japanese PPS can be recognized as a kind of SC) and PX power exchange.

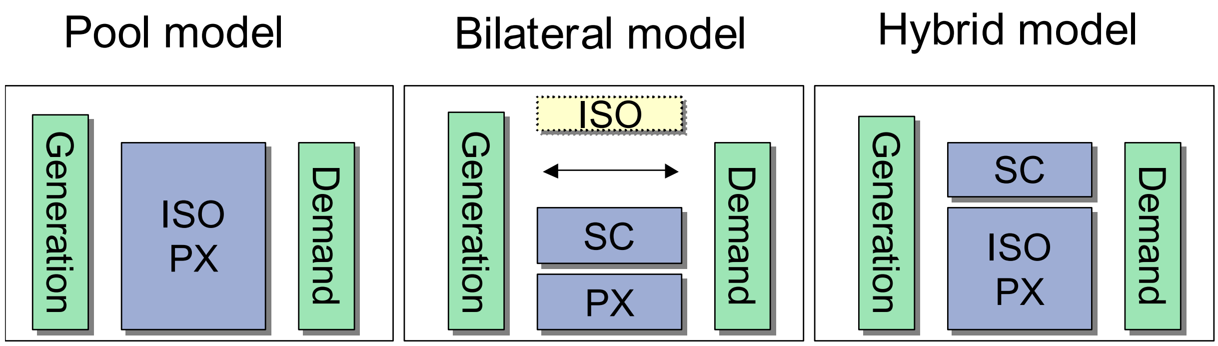


Figure 3: Market structures

Another way to classify the market structure is based on the rules adopted for the transmission access. A bilateral model is also defined as third party access model because companies that are not utilities access to the transmission network.

2.2 Products related with electricity and time schedule

Electricity is a complex commodity. The main difference between electricity and other commodities is that electricity cannot be stored but it has to be used at the same time that it is produced. For this reason it becomes difficult to create a market. From a theoretical point of view it is necessary to have a real time market in which the electricity is priced at the time it is produced and consumed. Since it is impossible to operate a market second by second, the common approach is to create products in the futures and adjust the exchanged quantity sequentially based on the changes in the consumption forecast.
It is possible to distinguish two main categories of products: energy products (the unit is kWh) and products related with the capacity (the unit is kW). The energy products are the main part of the market; products related with capacity may be seen as the essential additional services indispensable to deliver electricity that are not the electricity itself. In Figure 4 the time frame and the relation between products is represented.

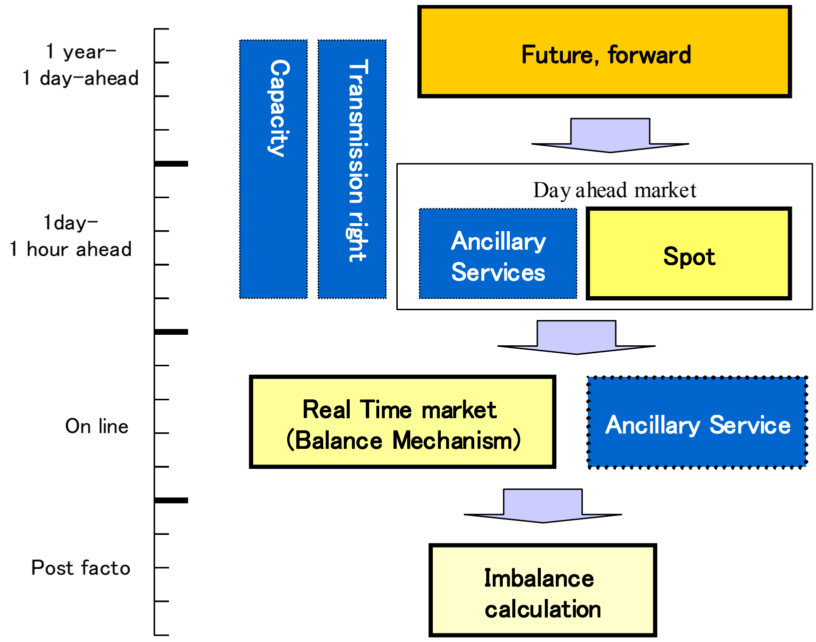


Figure 4: Electricity related products and time schedule

2.2.1 Energy products

The energy products are generally classified based on the time differences between the transaction time and the delivery time. Future and forward are products in the late future. The common time frame is between 3 years to a week ahead to the delivery time. Future and forward are contracts in the future for the delivery of a certain quantity of electricity at a predetermined price. The difference between future and forward is in the type of contract. Futures are contracts exchanged only in an official exchange, they are in general anonymous (the buyer does not know the name of the seller) and can be delivered or settled only financially based on the spot price. Forwards are bilateral contracts between a buyer and a seller, the seller has obligation to deliver it. In Japan a forward market was created in 2005 and it is still in operation. In the spot market, players trade electricity for the near future (normally between 24 hours to 1 hour ahead). The price is set for each hour or part of it. In the Japanese spot market 30 minutes products for the next day are traded. Either if the electricity traded in the spot market will be delivered just few hours after the stipulation of the contract, in the real time, it may still happen that several conditions change, and, as consequence, the market position of the players. An unexpected high temperature may cause an increase of demand and, as consequence, the market position of retails company may become short (the purchase electricity is not enough to cover the demand), a generator can fail to produce electricity, or a sudden increase of wind can be the cause of an unexpected power production by wind generation. To adjust the changes in demand and generation and to keep the energy balance, a real time market or a balance mechanism is introduced. In general, the real time market is run few minutes before the delivery time by

the power system operator (10-20 minutes).
After the delivery of the electricity, it is necessary to measure the real production and consumption of each player and to settle the imbalance to avoid subsidization or unfair operations.
In the Japanese schema the real time market is not yet implemented. Eventual imbalance produced by PPS are absorbed by the utilities and charged at a fix rate.

2.2.2 Other electricity related products

To ensure the deliver of electricity other related products are indispensable.
One important parameter in power system is the available capacity. The available capacity is defined as the quantity of power (kW) that can be on line at in certain day. Power plant maintenance or lack of power plant can be the causes of shortage of available capacity. To avoid this situation, North America organizations such as PJM (Pennsylvania, New Jersey Maryland regional transmission organization) and New York ISO introduced a capacity market. The objective is to incentive the construction of new power plant in case of lack of capacity, and to indirectly guide the maintenance schedule of power plants in period of low demand. The capacity market is run on a long-term base, from 6 month to one year ahead the delivery day.
In addition of the products described until now, just few words about transmission rights. An owner of a transmission right has the possibility to send electricity between two areas without warring about congestions. At the starting, the transmission owners are in possession of the transmission rights. They sell it on an auction based to transmission users. PJM, New York ISO and other North American organizations implemented a transmission right market. In Europe a similar mechanism is utilize to allocate the transmission capacity among countries.

2.2.3 Ancillary services

A special mention about ancillary services shell be done. Ancillary services definition is still not standardized among countries. In general an ancillary service is defined as a service that is indispensable to deliver the electricity in a safety and stable manner but is not the energy itself. Ancillary services include planning, transmission operation, reserve, regulation, frequency control, black start, voltage control and reactive power.
In a vertical integrated power industry, ancillary services were naturally performed by the power company and the associated costs were included in the electricity tariff. With the deregulation, the transmission operator does not own any generator and for this reason he has to procure ancillary services on a competitive base.
The problem related with ancillary services is fundamental since it affects the generation companies' profit directly. There is no incentive for a generation to produce reactive power or to reduce the output to keep a certain margin of system reserve if these services are not properly rewarded.

In USA, FERC recognized six ancillary services: scheduling, system control and dispatch; reactive power supply and voltage control; regulation and frequency response; energy imbalance; spinning reserve; supplemental reserve.
The European transmission operators association (UCTE) recognized three man ancillary services: primary control, secondary control, minutes reserve. The primary control is defined as power that can be activated in less than 15 seconds; secondary control has to be activated in less than 5 minutes, minutes reserve in less than 15 minutes. Each European member country is required to supply an amount of reserve proportionally to the peak demand.
Figure 5 shows the reserve quantity and the time-scale utilization in France.

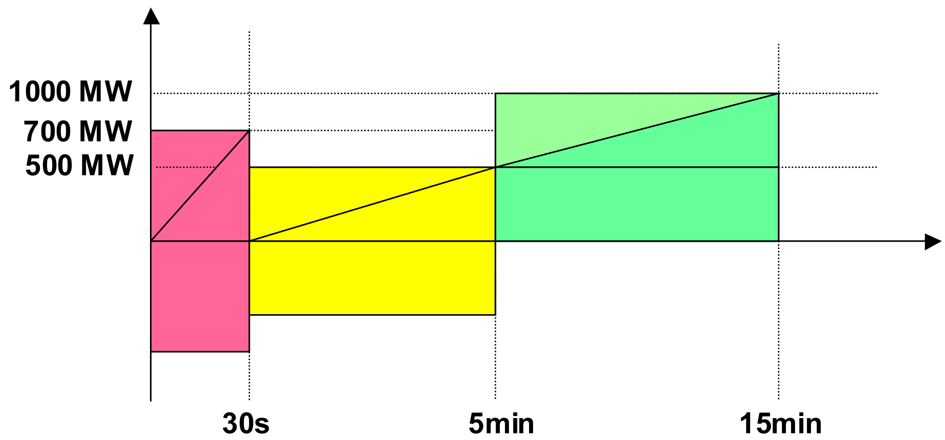


Figure 5: Reserve definition in France

The transmission operator has the responsibility to calculate and to procure the quantity of ancillary services necessary to ensure safe power system operation.
The way to procure ancillary services is different depending on countries. In PJM regulation and reserve are acquired by the ISO from the power plants daily. Generators submit bids and the PJM selects the bids with an auction mechanism.
In Germany primary and secondary reserve are auctioned twice a year. A generator, that wins the auction, is committed to supply the service for six month.
France adopted a negotiation schema: the French power system operator purchases primary and secondary reserve from selected generators at fix price with a yearly contract.

2.3 Auction and clearing mechanisms

Auction is recognized as the most efficient mechanism to price electricity and to decide the transaction among players. Auction has a long history; it has been used from the past in several markets or to price goods that the value cannot be easily estimated such as paint or large proprieties.

Electricity can be classified as a multi-unit good since it is produced by several power plants and used by several customers at the same time.

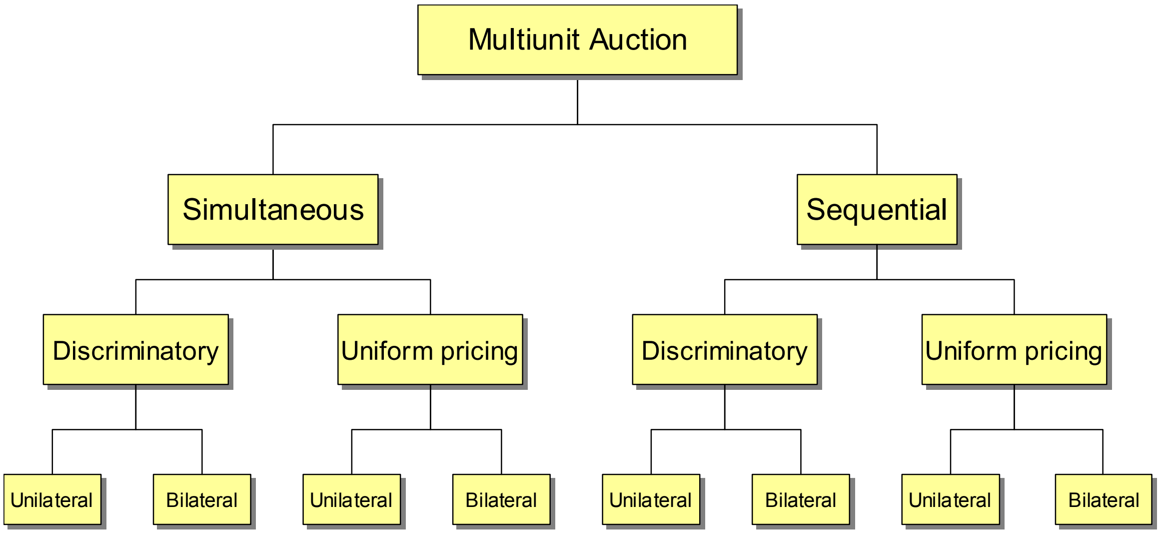


Figure 6: Auction Mechanism Classification

Figure 6 is a classification of the possible auction mechanisms for electricity.
First of all the auction mechanisms can be classified based on the timing. In a simultaneous auction, all the players are asked to bid before a prefix time (the gate close) and the bids are kept secret. The auction operator clears the market in a single calculation and informs the participants of the results (accepted quantity and transaction price). Simultaneous auction is adopted for day-ahead market because it is fast and does not require iterations.
In the sequential or continues auction players are informed of the current available bids (quantities and prices), players can decide to submit a bid themselves or wait until the price changes. Sequential auctions are implemented for commodities or stock. In the electricity market sequential or continues auctions are utilized in forward markets.
Auctions can be classified based on the price setting rules. Two kind of pricing can be recognized: the uniform pricing and the discriminatory.
In the uniform pricing all the participants of the auction see the same price. In general for power generation bidding the highest accepted bid set the price. This method is adopted by several power exchanges including EEX in German and Nord Pool.
In a discriminatory auction (also called pay as bid auction), the accepted bids are settled at the bid price. The disadvantage of the discriminatory auction is that it dose not produce a clear market price. The UK market NETA adopted a pay as bid auction.
In Figure 7 the concept of uniform price and discriminatory auction for electricity market is described. In the example three independent generation companies bid a certain amount of power in the market. The demand is represented by the vertical line. The cross between the demand and the bids aggregation curve determines the winner of the auction.

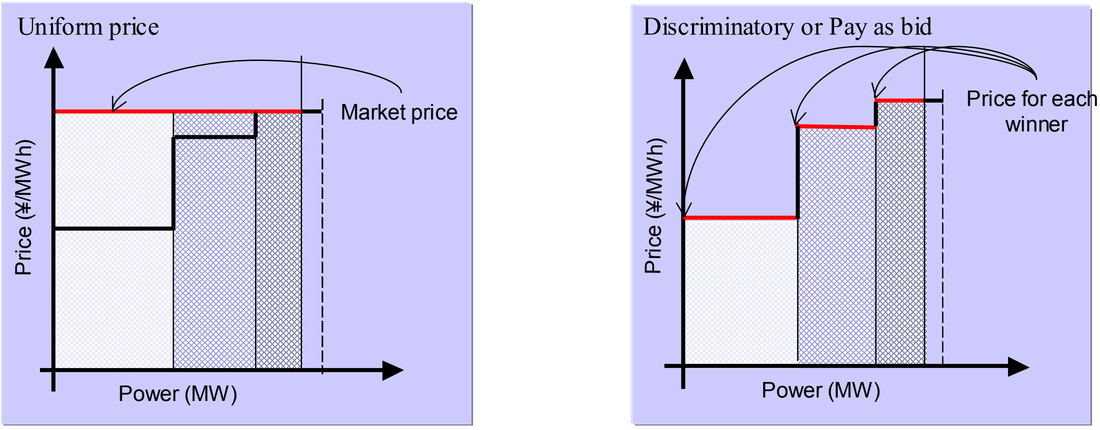


Figure 7: Uniform Price and Discriminatory Auction for power

The third type of classification regards the players in the market. If both the selling side and the buying side are allowed to bid, the auction is defined bilateral auction. In the case in which only the generation side bids and a single buyer that set only the quantity needed in the market buys the electricity, the auction is called unilateral. In case of market concentration (it is common that the generation sector is owned by few strong companies), it is recognized that bilateral auction is an effective instrument to control the market price and to avoid price spike; nevertheless it is complex to develop a demand side bidding process due to the importance of the electricity in the daily life and the consequent inelasticity of the demand.

2.4 Congestion management

Another important aspect of electricity as commodity is that electricity has to be delivered using the transmission network that is subject to the Maxwell laws. Since the transmission network has not an infinite capacity it may happen that is necessary to select expensive bid to avoid transmission overloading. The problem of possible transmission overloading in a deregulated market is approached with the congestion management.
In the past, the vertical integrated utility managed the transmission constraints with an optimal power flow approach: all the information about generation costs, constraints and transmission limits were evaluated at the same time to find the cheapest generation dispatch. With the unbundling of the electricity company and the increase of the entities that access the transmission network it is indispensable to develop a clear and efficient mechanism that ensure the respect of the transmission limits and, at the same time, a fair access at the transmission services.

2.4.1 Nodal pricing

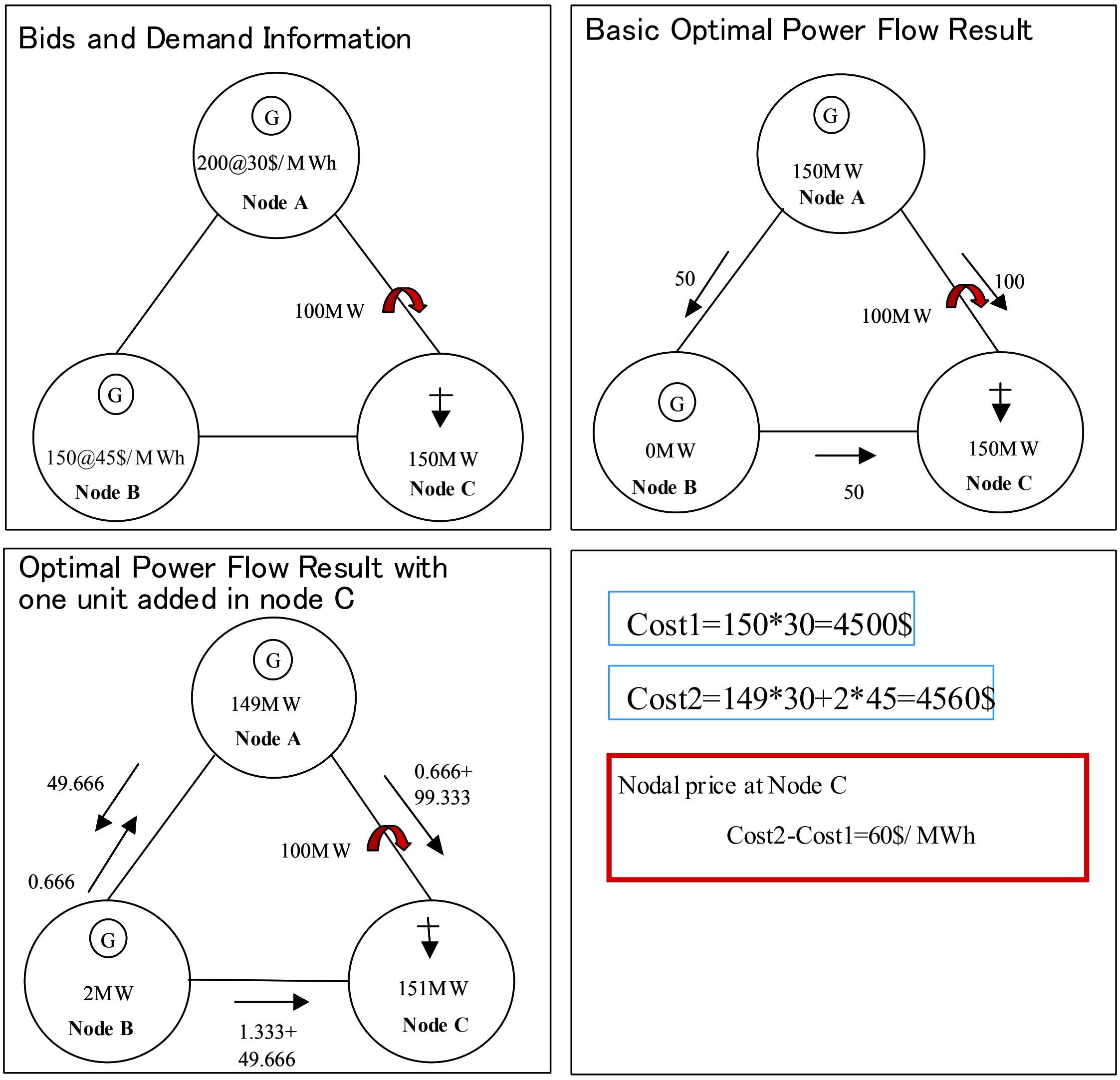
The most famous congestion management technique is the nodal pricing. This method is adopted by several North America markets include New York ISO and PJM. The nodal pricing is an optimal power flow based calculation that produces as results the accepted bid quantity for each generator and the market price at each network node. In general, a marginal incremental approach is adopted to calculate the nodal price. At first the power flow calculation is performed and the total generation costs calculated. Next, a unit of demand (in general 1 MW) is added to one node and the OPF calculation performed again. The cost difference between the two solutions is the nodal price of the node itself.

Figure 8 is a simple example of a system with 3 nodes. In node A there is a cheap generator (30\$/MWh), in node B an expensive one (45\$/MWh), and, in node C, a demand. For simplicity, the impedance of the lines is considered to be the same for each line. The transmission line between node A and B is constrained at 100 MW. From the OPF calculation, due to the constrain on line A-B, it happens that the price in node C go up to 60\$/MWh

From the example is evident that the nodal price can be higher than the most expensive bid (in same case it may happen that the nodal price in some nodes is lower than the cheapest bid).

The nodal price is an efficient and fair congestion management technique, nevertheless it presents some disadvantage: it requires the calculation of several optimal power flow iterations. If the system is very large (thousands of nodes) it can take long time before to get the solution. In addition it is not so transparent: players can have difficulties to understand the price and to develop their bids. In PJM, it was demonstrated that some companies could take advantage of the method creating intentional congestion and increasing the price in some nodes.

The method is very effective in a mesh network where it is difficult to individuate the influence of the generation output on each transmission line.



※The impedance of each transmission line is considered to be the same

Figure 8: Nodal price calculation

2.4.2 Zonal price

The zonal price is an approach similar to the nodal price but with the introduction of several approximations. To avoid complex calculation and to produce a clear market price signal the total network is divided in few areas (in general from three to ten). The main objective is to ensure that the market participants clearly understand the congestion areas and, as consequence, invests in new generation properly. The disadvantage of the zonal price is that eventually intra-area congestions have to relief with other methods to ensure proper transmission network operation. The method was adopted in California and Texas.

2.4.3 Market split

Particularly important for this thesis is the market split method. In chapter 5, a new methodology for solving a congested market with a market split method is introduced. The market split is useful in situation were the market is involving more than one control area. It is evident that the interconnections among control areas are in general week. The cause of this is that they were constructed not for market propose but with the intent to support frequency control and power system operation among control centers. For this reason it is common to have congestion problem among control areas, the market split method divides the control areas in submarket in case of congestion.

The market split mechanism was first introduced in Nord Pool in 1995. Nord Pool is a market that involves four countries (Norway, Sweden, Finland and Denmark). Each country is a control area. Following the Nord Pool example, Germany, which has a network composed by four control areas, adopted the same model. Japan decided to adopt the market split mechanism in the spot market to manage the transmission congestion among power utilities.

The market split concept is very simple: at first an auction between buyers and sellers is performed. In this stage the transmission constraints are not considered. Once the market solution is available, the transmission constraints are checked. If there is an overload on some interconnections the market is divided in two submarkets and the market solution for each of them recalculated. The results consist in different prices for each submarket.

In the recent years, the European countries are adopting the concept of market-coupling. It is a methodology that allowed optimizing the utilization of the interconnection line among countries. The market-coupling concept is the opposite of the market split. Starting from 2 or more independent markets, a certain amount of electricity is exchanged among markets. France, Belgium and Holland had start a market coupling mechanism in 2006.

2.4.4 Counter flow re-dispatch

To manage the possible local congestions that may occur inside areas due to the approximation introduced by the zonal pricing or market split, several countries adopted a counter flow re-dispatching approach. On the real time the transmission system operator may ask to two or more generating units to modified the output in order to produce a counter flow that may relief the overloading of one or more lines. The system operator refunds the generators of the costs that may incur as consequence of the re-dispatch.

2.5 Conclusions

An analysis of the market structures, rules and congestion management was described in this chapter.
This thesis considers a bilateral model with an independent power exchange.
Transmission access is possible for generation companies and schedule coordinators on a contract base and under the payment of the appropriated fees. Schedule coordinators (PPS) submit the wheeling schedule to the transmission operator daily to ensure safe and efficient operation of the power system.
The power exchange is a voluntary exchange that operates spot and forward market. The spot market is operated with a simultaneous, uniform pricing, bilateral auction model (single price auction), market players are allowed to submit multiple bids including buying and selling orders; the forward market implements a sequential continuous bilateral model (zaraba) in which the price change continuously depending of the market players behavior.
The transmission congestion is managed with a market split approach that ensures an optimal utilization of the available capacity and a clear congestion signal to the market participants.

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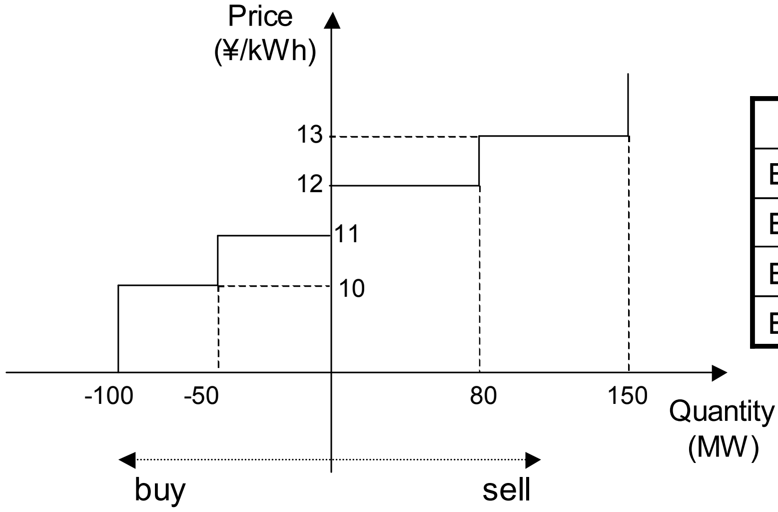
Chapter 3 Strategic bidding for generation companies

Generation companies compete in the wholesale market to supply electricity at the best price. The objective of these companies is to run the business in the most profitable way. To support the generation companies in the bidding task, this thesis developed a strategic bidding formulation. A strategic biding is based on two main factors. The first is a good knowledge on the market situation; a clear understating of the market and a precise price forecast are the keys. This thesis propose a neural network based price forecasting method that do not include only the historical price data but utilize also the forecast demand to determine the price in the future.
The second factor is a good knowledge of the generation costs and the possibility to minimize them. This thesis proposed an optimization method that, considering the forecasted market price and the operational cost, produces the optimal strategic bid for the day-ahead market.
The profit function for the generation company can be expressed as the difference of the revenue and the costs.

$$Profit = \sum_t P_t \cdot Q_t - \sum_t C(Q_t)$$

,where
t = time interval
P_t= market price is a function of the market rules and the players bids
$C(Q_t)$ = generation cost is a function of generating unit characteristics and the fuel price
Q_t = production quantity is a function of the bid price, bid quantity and market conditions.

In the following section each term of the equation will be formalized to develop the objective function, which has be solved to calculate the optimal bid.
A bid is defined as the series of price/quantity couples that a player submits to the market; it can be composed by either will to sell and will to buy electricity. In this dissertation it is assumed that a sell bid is represented by a positive quantity, on the other side, a buy bid is represented by a negative quantity. In several market, including Japan, each player can develop a multiple bid for each product, the quantity that is win is a function of the bid price and the market price. One common condition is that the bid quantity have to increase with the increasing of the price.



	Price	Quantity
Block1	10	-100
Block2	11	-50
Block3	12	80
Block4	13	150

Figure 9: Example of multiple block bid

Figure 9 is and example of a multiple block bid. The player expresses the will to buy 100 MW if the price is lower than 10 yen/kWh, 50 MW if the price is between 10 and 11 yen/kWh; if the market price is between 12 yen/kWh and 13 yen/kWh, the player wish to sell 80MW and for price higher than 13yen/kWh the selling quantity become 150MW.

3.1 Price forecasting

Electricity price is an essential economic factor, which has a large impact on industry and consumers. Electric industry has been deregulated and restructured worldwide for reducing electricity prices. Trading in electricity market has the advantage to sell electricity at a high price. On the other hands, it may happen to incur in the risk of low electricity price when demand is low. Therefore, high accuracy forecasting methods are required for decreasing the risk and developing an optimal strategic bid.
In the proposed method, firstly, neural networks are applied to forecast total maximum power demand for the next day of the mainland in Japan. Secondly, electricity price at peak time on the next day is predicted based on the previously forecasted demand. Because of the strong correlation of power demands and electricity prices, it was possible to improve the accuracy of electricity price prediction.

3.1.1 Price analysis

Power demand is one of the factors that strongly influence the electricity price. For this reason, to perform a correct price forecasting it is indispensable to have very high quality demand forecasting.
The electric power supply system is indispensable for lifeline systems and industrial activities. However, electric power is not storable, so it is necessary for system operators to keep adequacy of electric power against continuously varying power demands, and at the same time, it is necessary to forecast daily power demands accurately for stable and efficient power system operations.
Forecasting of power demands is classified into to categories; one is the long term forecasting and the other is the short term that may vary from a week, to few hours depending on the purpose and the targeted period of prediction. In this thesis, I focus on the prediction of demand for the next day, because these data mainly determined the bid in the day-ahead market. Figure 10 shows changes of the electricity price in the spot market and the peak electric demands from April 2005 to March 2006 in Japan. The large fluctuations are seasonal changes, it may be recognized that electric demands in summer and winter are very large. Compared with them, electric demands in spring and autumn are relatively small. The small fluctuations are weekly changes. The electric demands on weekdays are larger than those on weekends and holidays. It can be said that the electric power demand is influenced by various kinds of nonlinear data such as wheatear related variables. Moreover, electric power price is also influenced by various kinds of nonlinear data such as the type of power supply and the price of the fuel, and so on. Therefore, for predicting electricity price, I applied neural networks that hold high performances to extract dynamic features, to learn unstudied data and to represent nonlinear correlations.

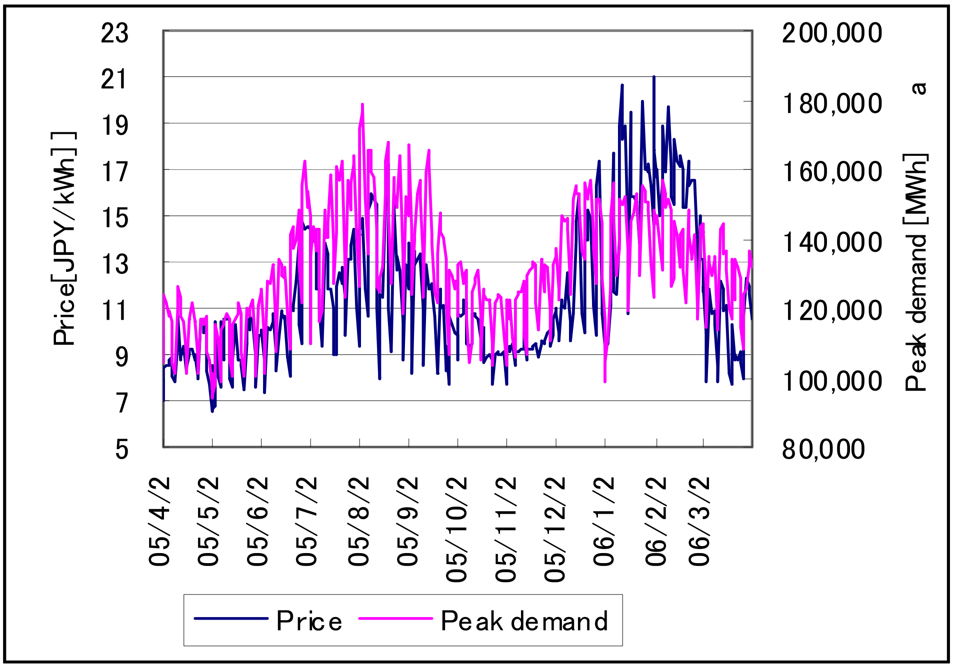


Figure 10: JEPX spot price and Japanese peak demand trend

Since it is important to select the input variables for forecasting electricity spot price, the correlation between the electricity price and various nonlinear data is analyzed. Figure 11 shows the correlation between electricity price and nonlinear data including, temperature, demand and market price in the previous day from October 2005 to March 2006. Correlation coefficients are in the range from -1 to +1. Here, +1 is a direct correlation: an increase of the variable implicates an increase of the market price, and -1 represents an inverse correlation: an increase of a certain variable has as consequence a decrease of the spot price. In addition, 0 means that changes in demand or other parameters do not influence the price. Analysis of the historical data shows that there is strong correlation between electric power price and power demand of both the day-ahead and the same day (Figure 11).

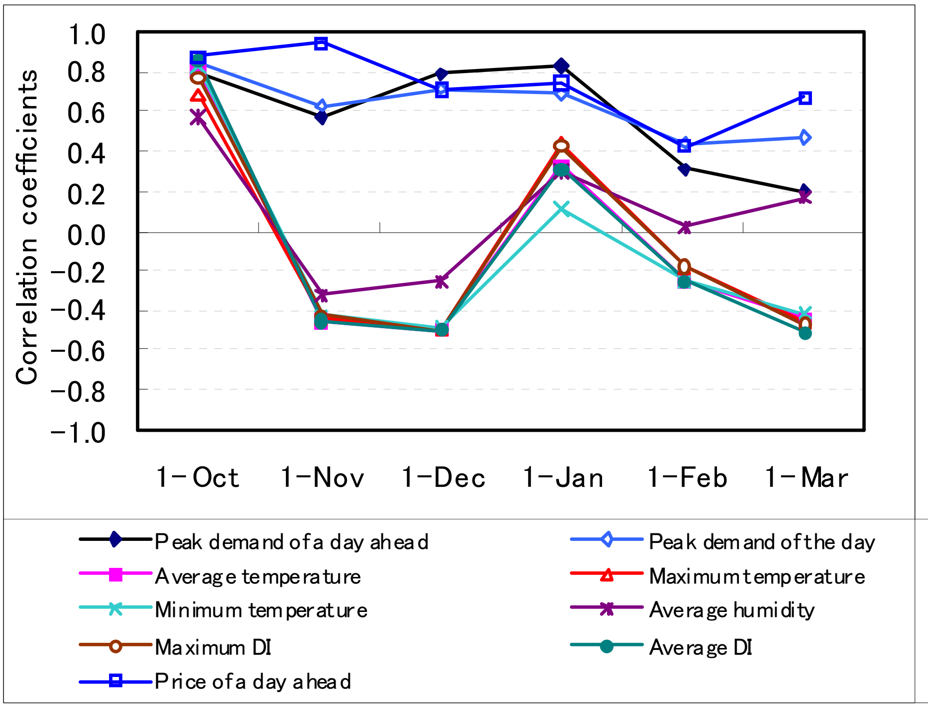


Figure 11: The correlation between electricity price and nonlinear data

Coefficients of the correlation show that electricity price has the time series characteristic. From this analysis, it has shown that the peak electricity price has three characteristics;

- Electricity price is influenced by the power demand.
- Electricity price has the time series characteristic.
- Features of electricity price differ on weekdays, weekend and holidays.

Moreover, it can be said that the correlation of the power demand of the same day is stronger than the power demand of a day ahead, and to utilize the power demand of the same day the spot price can be forecasted with more accuracy. Therefore, this proposed method forecasts the peak power demand of the day firstly, and secondly the electricity price is forecasted by using the forecasted peak power demand and the electricity price of a day ahead.

3.1.2 The neural network model

The multilayer perceptron (MLP) neural network is applied to determine parameters for an autoregressive (AR) model considering n discrete time periods as below.

$$\hat{y}(k+1) = a_1\, y(k) + a_2\, y(k-1) + \cdots + a_n\, y(k-n+1)$$

where *y(k)* is a time series datum observed.

A three layer MLP neural network, as shown in Figure 12, is introduced to obtain the AR model. All activation functions in hidden layer are tanh(x) (described as f_j in Figure 12), and the activation function in the output layer is $x(F_0(\Sigma) = \sum_{j=1}^{n_h}(x) + w_0)$.

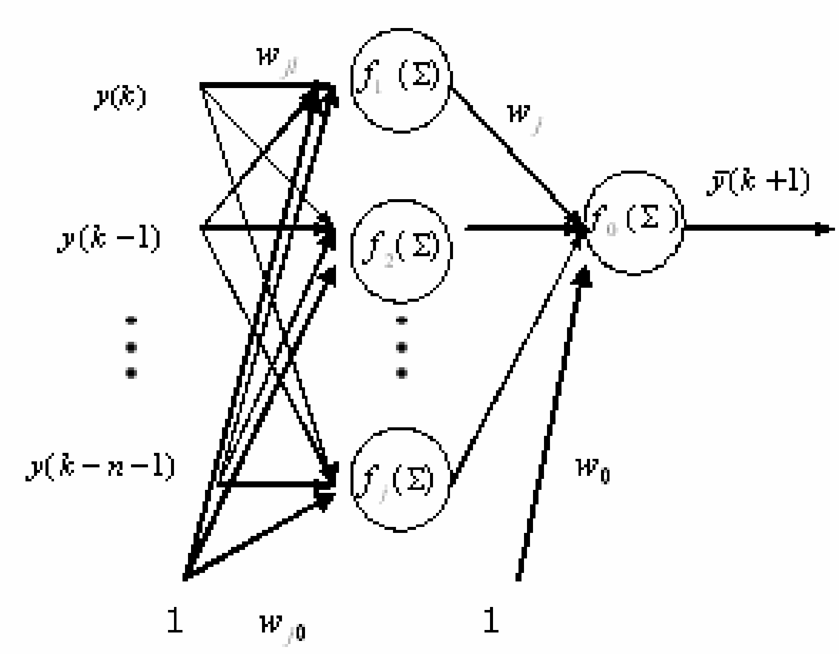


Figure 12: A fully connected three-layer feedforward network

The output of the MLP is

$$\hat{y}(k+1) = \sum_{j=1}^{n_h} w_j \tanh\left[\sum_{l=1}^{n} w_{jl}\varphi(l) + w_{j0}\right] + w_0$$

where

$\varphi(l) = y(k-l+1),\ \ l = 1, 2, \ldots, n$

w_{jl} : weight which connects input and hidden layer

w_j : weight which connects output and hidden layer

n_h : number of hidden neurons

w_{j0} : weight which connects hidden layer and bias

w_0 : weight which connects output layer and bias

W^0 : vector form of w_j , $[w_1, w_2, \ldots, w_{n_h}]$

W_l^I : vector form of w_{jl} , $[w_{1l}, w_{2l}, \ldots, w_{n_h l}]^{\mathrm{T}}$

The derivative of the output with respect to the input φ_l is

$$\frac{\partial \hat{y}(k+1)}{\partial \varphi(l)} = \sum_{j=1}^{n_h} w_j w_{jl} \left(1 - \tanh^2 \left[\sum_{l=1}^{n} w_{jl} \cdot \varphi(l) + w_{j0} \right] \right)$$

Now, to make the model much simpler, linear activation function for f_j and F_{o} is applied to the MLP in Figure 12, and the linear output can be represented as follows:

$$\hat{y}(k+1) = \sum_{j=1}^{n_h} w_j \left[\sum_{l=1}^{n} w_{jl} \cdot \varphi(l) + w_{j0} \right] + w_0$$

and the derivative of the output with respect to the input $\varphi(l)$ is

$$\frac{\partial \hat{y}(k+1)}{\partial \varphi(l)} = \sum_{j=1}^{n_h} w_j w_{jl} = W^0 W_l^I$$

From Taylor series expansion, parameter a_1 is obtained by

$$a_1 = \frac{\partial \hat{y}(k+1)}{\partial y(k)} = \frac{\partial \hat{y}(k+1)}{\partial \varphi(1)} = W^0 W_1^I$$

In general, the parameters of the AR model can be obtained as follows:

$$\left[a_1, a_2, \ldots, a_n \right] = \left[W^0 W_1^I, W^0 W_2^I, \ldots, W^0 W_n^I \right]$$

From the above equations, the vector of the most likely demand (crisp value) can be obtained.

For the linear activation function in the neural network the inputs are scaled between 0.1 and 0.9 by the maximum and minimum inputs of the time window considered as below

$$y'(k-l+1) = s \cdot y(k-l+1) + b$$

where

$$s = \frac{0.8}{y^{\max} - y^{\min}}$$

and

$$b = \frac{0.1 y^{\max} - 0.9 y^{\min}}{y^{\max} - y^{\min}}$$

Here

$$y^{\max} = \underset{l}{Max}[y(k-l+1)]$$

$$y^{\min} = \underset{l}{Min}[y(k-l+1)]$$

and

$l = 1, 2, \ldots, n$

Because the time window for the training moves step by step, $y^{\max}$ and $y^{\min}$ are subsequently updated for a correct scaling. Outside of this window there is no need of assuming normal distribution of errors, which can give rise to the difficulty of stationary in regular regression-based time series modeling. This scaling is also consistent with the fuzzy model introduced below which observes the possible data ranges within an interval determined by the past data.

3.1.3 The demand forecast model

A three-layer neural network has been used to forecast the power demand; the number of input neurons is three and that of output neurons is one. As input variables, the maximum temperature, the average DI (discomfort index), and the day-ahead peak electric demand are selected out of the factors of the correlation analysis. The previous month demand data are used for the learning process of the three-layer neural networks to forecast the peak demands of the next month. Figure 13 shows the neural network model for the proposed forecasting.

In this thesis, it is necessary to integrate each input variable of the nine Japanese regions into the national input variables. The national power demand is the sum of the peak demands in each region; and a weighted sum of the other input variables at each region is used as an input datum to neural networks. The weight coefficients are determined by demand ratios in different regions.

$D_{national} = D_1 + D_2 + \ldots + D_9$

$D_{national}$: Forecasted total peak demand of whole mainland.

D_1= demand in Hokkaido region

D_2= demand in Tohoku region

:

D_n= demand in Kyushu region

$$T_{ave} = w_1 T_1 + w_2 T_2 + \ldots + w_9 T_9$$

$$w_n = \frac{D_n}{D_{whole}}$$

D_n : Peak demand at each region.
T_{ave} : Average weather factor at for the entire country.
T_n : Weather factor at each region.
w_n : Wight of various places in demand.

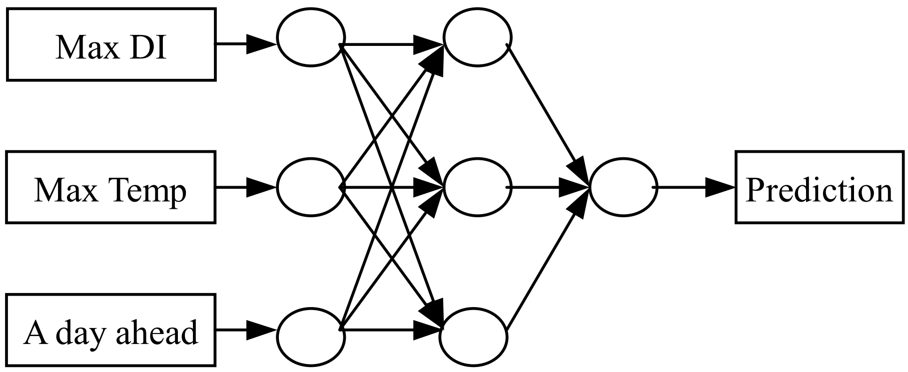


Figure 13: Neural network model for demand forecasting

3.1.4 Numerical application

The proposed approach was applied to a set of real data covering the winter period from January to March 2006. Since the first week of January is a peculiar week because of a long-term holiday, this period is removed from applied data. To prove the influence of the peak demand on the spot price I forecast the price in 3 different cases and the results are compared with the real market prices published by JEPX. In the first case the peak demand data is ignored and the forecasted price is calculated using only the previous days prices.

In the second case in addition to the previous days prices, I introduced the forecasted peak demand as input.

In the third case, the electricity price is forecasted from the real power demand. Either if, for practical forecasting propose it is not possible to know in advance the real power demand of the next day, this case was introduced with the intent to confirm the assumption of correlation between price and peak demand.

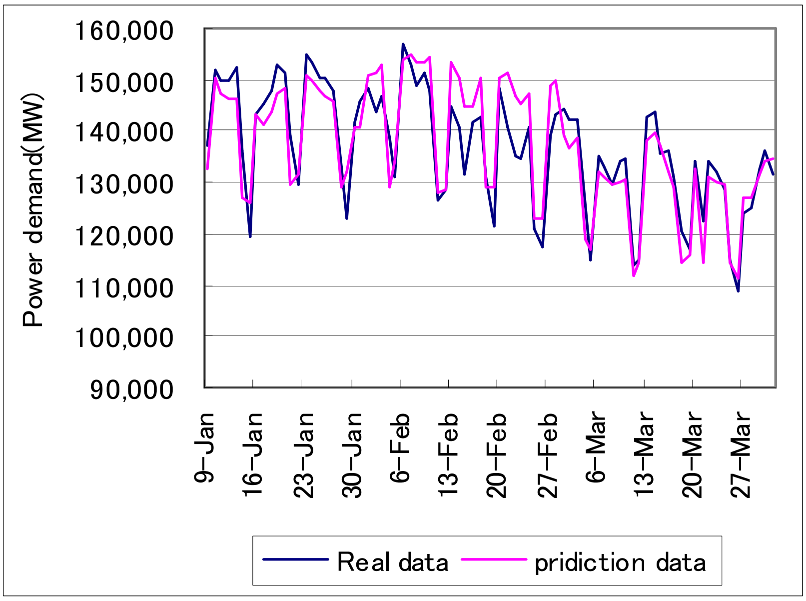


Figure 14: Result of next day maximum demand forecast from January to March 2006

Figure 14 shows the result of forecasting peak power demand of the next day. It is evident that the neural network performs accurately in the prediction of the demand fluctuation. Figure 15 shows the result of the forecasted electricity prices at peak time.

Table 1 shows the comparison of the average error ratio of each case. From Figure 15 and Table 1, it can be understood that case3 has the highest accuracy. It can be said that the correlation between price and demand is very high and reproducible trough neural network. From Figure 15 it may be said that it is still difficult to predict spike in prices using neural network. It is evident that the error is larger in January, period in which the Japanese Power Exchange experienced several price spikes.

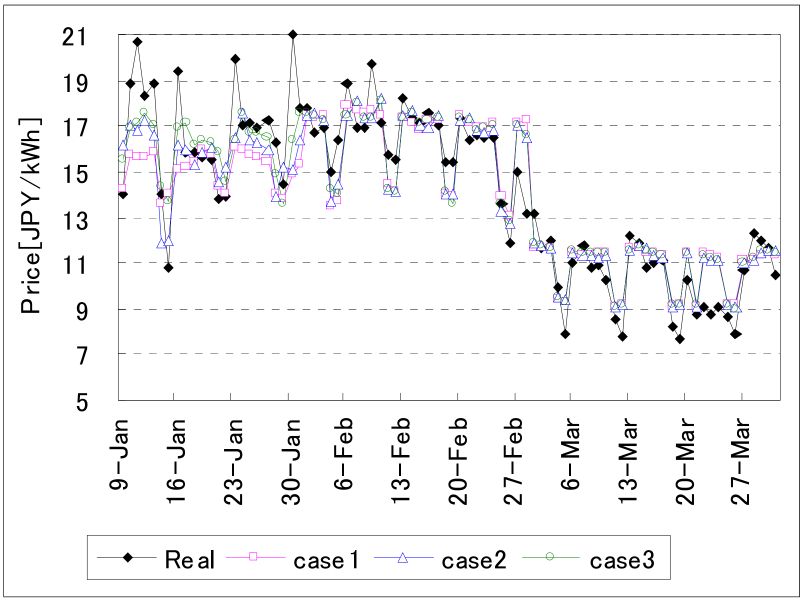


Figure 15: Result of next day electricity price forecast from January to March 2006

As a result, it has been shown that the amount of the electricity demands is closely related to the electricity price and moreover that the proposed method can follow the price fluctuation which changes on Saturday and Sunday and Monday when the volatility of price from a day ahead is large.

By those applications, it is verified that the method is able to cope with the large price fluctuation in such as in the electric power exchange in Japan.

Since the number of transaction is still small and the price is not stable in the Japanese electric power exchange that have just started to operate from April, 2005, it is expected that more accurate forecast of the system becomes possible when the amount of the electric power dealings will increase in the future and the electric power price will become stable.

Table 1: Comparison of average error of each case

Average error [%]	Case 1	**Case2**	Case3
January	11.20	**9.65**	8.81
February	6.39	**6.17**	6.03
March	9.02	**8.80**	8.74
Total average	8.74	**8.10**	7.87

3.2 Generation bidding development

The strategic bidding is the most important task of a company who owns power plants. The bid has to be decided based on the market price, the power plants constraints and the costs. In a vertical integrated utility generators were dispatched with the objective to supply the total load at the minimum costs. The tools to calculate the optimal operation point for each generator are the unit commitment and the economic load dispatch. For generation companies the same tools can be utilized but the objective function changes. In this thesis, two strategic bid methods are developed: the cost base and the price base bid.

3.2.1 Generation costs determination

To formulate a consistent bid in case of an auction or an offer in case of counter party, it is fundamental to understand clearly the costs of a generator. In this section a model to determine the generation cost is described.
The generation costs can be divided in 3 groups:

- Investments costs
- Operation and Maintenance costs
- Fuel costs

The investment costs include the capital that has to be invested for buying and constructing the generation unit. Several studies, available in literature, report about the average investments costs for kind of fuel or dimension of the generating units. Investments have to be deeply understood and analyzed in the decision process of constructing a new power plant but are not fundamental in the daily bidding process.
These kinds of costs do not influence directly the daily bid strategy, and for this reason are not analyze more in deep.
Operation and maintenance costs may be divided in fixed O&M costs that have to be analyzed and evaluated in the long term planning (yearly based) and variable O&M that influence the total cost in the short term planning and may be evaluated also during the bidding process. O&M are also not considered since I will focus on the short term bidding problem.
The fuel costs are a function of the operation level. Generally, the fuel consumption for hour is modeled as a quadratic function of the power output level of the generating unit. In formula:

$$C(p) = a \cdot p^2 + b \cdot p + c$$

,where
C is the consumption function (MJ/h), p is the generation output level, a is the quadratic term (MJ/kW²h), b is the linear term (MJ/kWh) and c is the fix term (MJ/h) also known as no load consumption.

In a graph the function looks like Figure 16

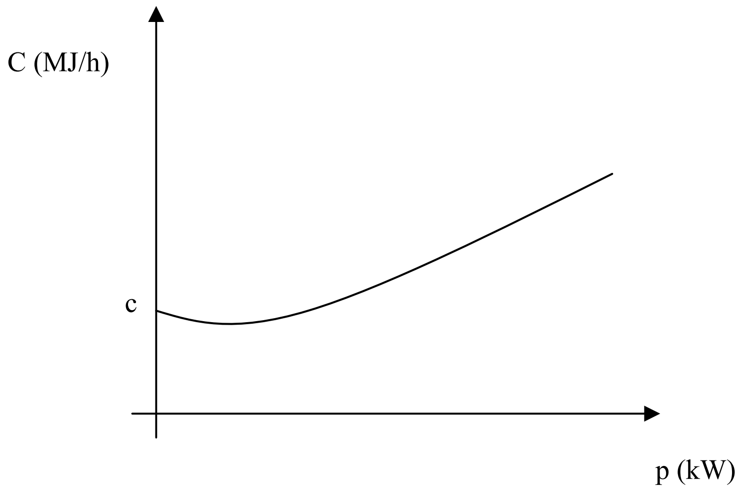


Figure 16: Fuel cost function

The marginal consumption is defined as the increment of consumption of fuel for an increment of power in output in formula:

$$MC = \frac{dC(p)}{dp} = 2a \cdot p + b$$

In addition to the hourly consumption function, the start-up consumption is also another important element that has to be modeled. The start up fuel consumption can be modeled as the inverse of an exponential function of the number of hours that the unit is off before the starting time. In formula:

$$C1(t_{off}) = d - \frac{1}{e^{t_{off}}}$$

,where

C1 is the consumption function (MJ), t_{off} is the number of hours from the last shut down and d (MJ) is the total consumption of fuel in case of completely cold start-up.

A graphical representation is plotted in Figure 17.

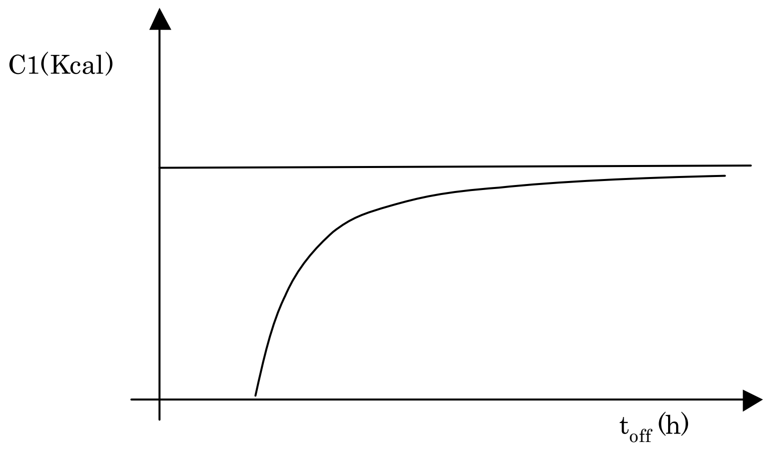


Figure 17: Start-up cost function

The functions *C* and *C1* have to be multiplied for the price of the utilized fuel to get the costs.
From the described model is evident that, once that the cost parameter are fixed, it is possible to calculate the total costs as function of the output *p* and the number of hours that the unit was off in case of start-up.

3.2.2 The unit commitment problem

Unit commitment is the problem of determining the schedule of generating units subject to the equipment and operating constraints. The generation schedule includes the ON/OFF decision and the operation target level. Since the ON/OFF is an integer variable and the operation target is a continuous variable, the unit commitment is a mixed integer nonlinear problem.
The operating constraints are classified in two groups:
1) Constraints on the output:
   - Operating range (maximum and minimum output of a unit)
   - Up and down ramp rate
   - Fuel constraints

2) Time constraints:
   - Minimum time-up
   - Minimum time down
   - Starting time range

The optimization consists in minimizing the operational costs or maximizing the profit, subject to the above-described constraints.
This thesis approach the problem with an iterative algorithm that treat the constraints on the output with a quadratic programming approach and the time constraints with a dynamic programming approach.

At the first step the unit commitment variable ON/OFF is set equal ON for all the calculation time range (24 or 168 hours depending if it is one day or one week unit commitment). The quadratic programming is performed to calculate the optimal dispatch level subject to the constraints on the output. The optimal output, operational costs and the time constraints are then integrated in a dynamic programming problem. Figure 18 is a graphical representation of the dynamic programming algorithm for a unit with minimum time up equal three hours, minimum time down equal two hours and no constraints on the starting time range.

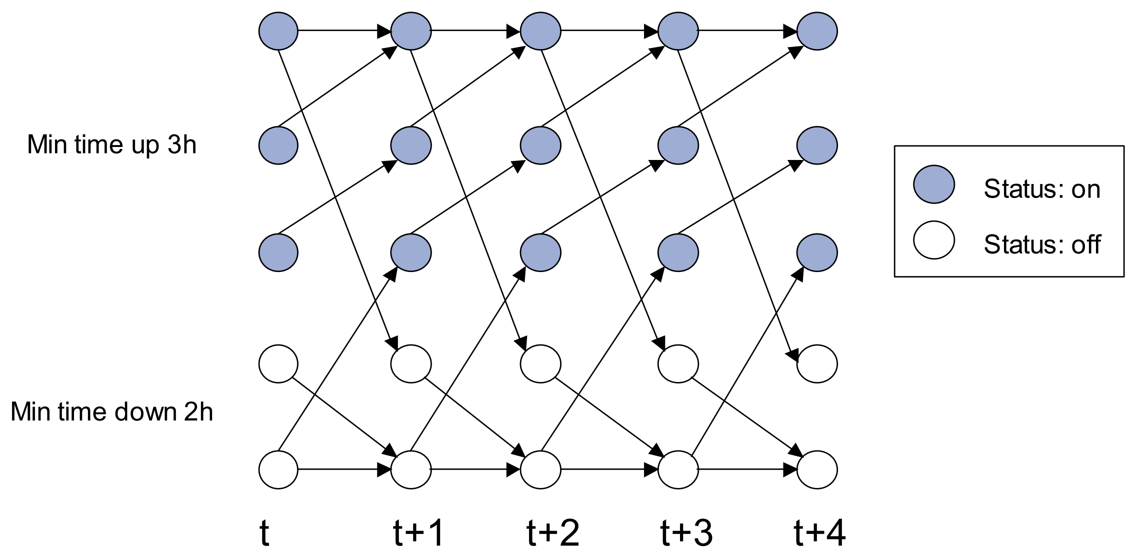


Figure 18: Dynamic Programming

The solution of the dynamic programming is the optimal ON/OFF sequence. The sequence is utilized as the base of a new quadratic programming in which the generation dispatch has to be adjusted. The process has to be iterated until there is a decrease in the total fuel costs or an increase in the profit (the objective function). Figure 19 shows the flow chart of the unit algorithm developed in this research.

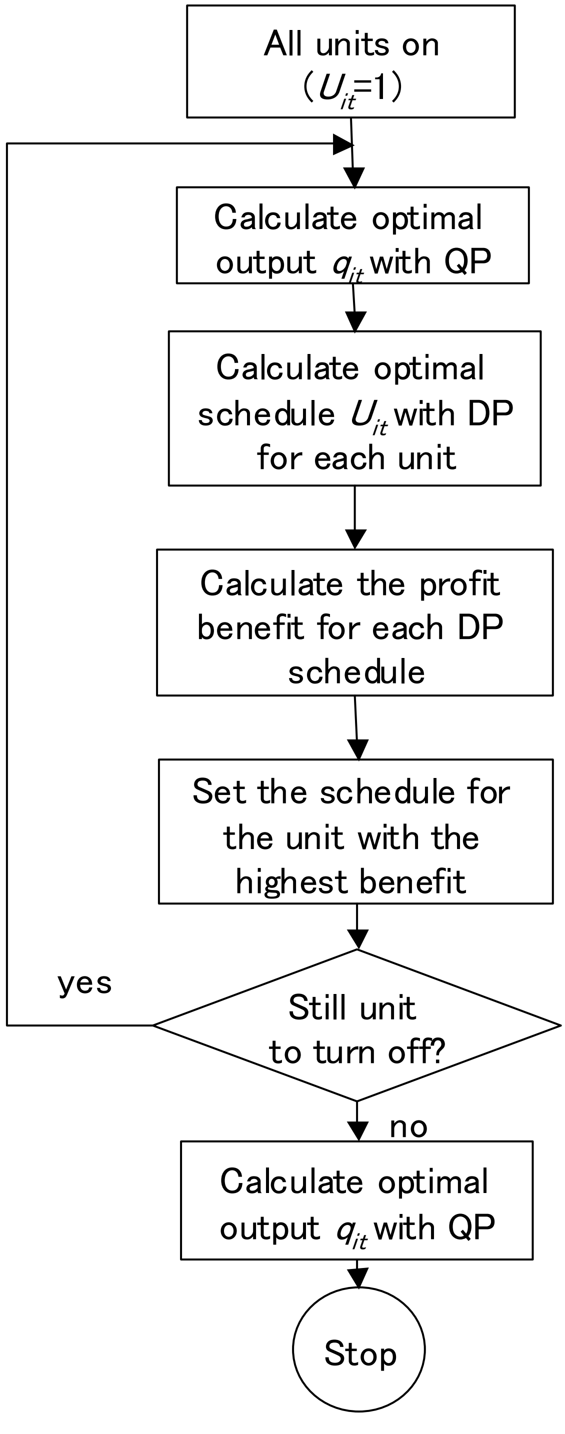


Figure 19: Flow chart of the unit commitment algorithm

3.2.3 Player strategies

After analyzing the type of players that competes in the market, it was clear that it is necessary to distinguish two groups based on the generation portfolio and the market share. The first group of generation companies includes small players with a market share of 10% or less. These players are not able to influence the market price, for the reason they can be

defined as price takers. For a price taker, this thesis proposes a price based bidding strategy; the player maximizes his profit under the consideration that his bid will not influence the price. The main variables include the operation schedule for generators and the quantity that the player has to bid in the market.
A large player, with several generating units and a large market share, has to consider the influence of his bid on the market price. It is possible to affirm that players with a share of 20 or 30% are able to change the price due to the market power that they have. This thesis defines these players as price makers. For a price maker I propose a cost base bidding. The objective is the minimization of the total cost to produce a certain quantity of electricity that can be bid in the market. The bidding price has to be developed based on the actual costs and of the reasonable profit that the company intends to produce.

3.2.4 Price based bidding

Small players with only little generation capacity are not able to influence the market price. Those players are known as price takers. For price taker players, this thesis proposes a price bidding strategy.
The price base bid is build by a unit commitment approach. The objective function of the optimization problem is the maximization of the profit:

$$\max_{p_t, U_{i,t}} \sum_t \left(P_t \cdot Q_t - \sum_i \left(C_i(p_{i,t}) \cdot U_{i,t} + C1_i \cdot \min\left(0, \left(U_{i,t} - U_{i,t-1}\right)\right)\right)\right)$$

where

- P_t : forecasted price for time t
- Q_t: bid quantity for time t
- p_t: generator unit i output at time t
- C_i: generator i cost function
- $C1_i$: generator i start-up cost function
- $U_{i,t}$: generator i schedule status at time t (U=1 generator ON, U=0 generator OFF)

The first term of the equation is the revenue from selling in the spot market (it is the payment in case of buying from the market: negative Q_t); the second term is the summation of the fuel cost for each unit including the start-up cost.

The objective function is subject to several constraints:

1) Energy balance constrain

$$\sum_i p_{i,t} = Q_t + D_t \qquad \forall t$$

where

- D_t : eventual demand or supply obligation at time t

2) Operation constraints

$$\overline{Q_i} \le p_{i,t} \le \underline{Q_i} \quad \forall t, \forall i$$

$$p_{i,t} \le p_{i,t-1} + rampup_i \quad \forall t, \forall i$$

$$p_{i,t} \ge p_{i,t-1} + rampdn_i \quad \forall t, \forall i$$

where

$\underline{Q_i}$: minimum output of unit *i*

$\overline{Q_i}$: maximum output of unit *i*

$rampup_i$ output increasing ramp rate of unit *i*

$rampdn_i$ output decreasing ramp rate of unit *I*

3) Time constraints

Time constraints

$$\left(X_{i,t}^{on} - T_i^{minpu}\right) \cdot \left(U_{i,t-1} - U_t\right) \ge 0 \quad \forall t$$

$$\left(X_{i,t}^{off} - T_i^{mindn}\right) \cdot \left(U_{i,t-1} - U_t\right) \ge 0 \quad \forall t$$

where

$X_{i,t}^{on}$: on status of unit *i*

X,t_i^{off} : off status of unit *i*

T_i^{minup}: minimum time up of unit *i*

T_i^{mindn}: minimum time down of unit *i*

The optimization problem is solved with the decommissioning method described in 3.2.3. Once the output level is calculated for each generating unit, the bid quantity for each time interval Q_t is computed from the energy balance equation.

Figure 20 is an example of calculation for a generation company with 8 small units and a supply obligation (the blue line over the 24 hours). The red line is the forecasted market price plot. The difference between the supply obligation and the sum of the generation output represent the optimal bid quantity Q_t. A negative Q_t means a buy order; a positive Q_t is a sell order. The price associated with the bid quantity is the forecasted price.

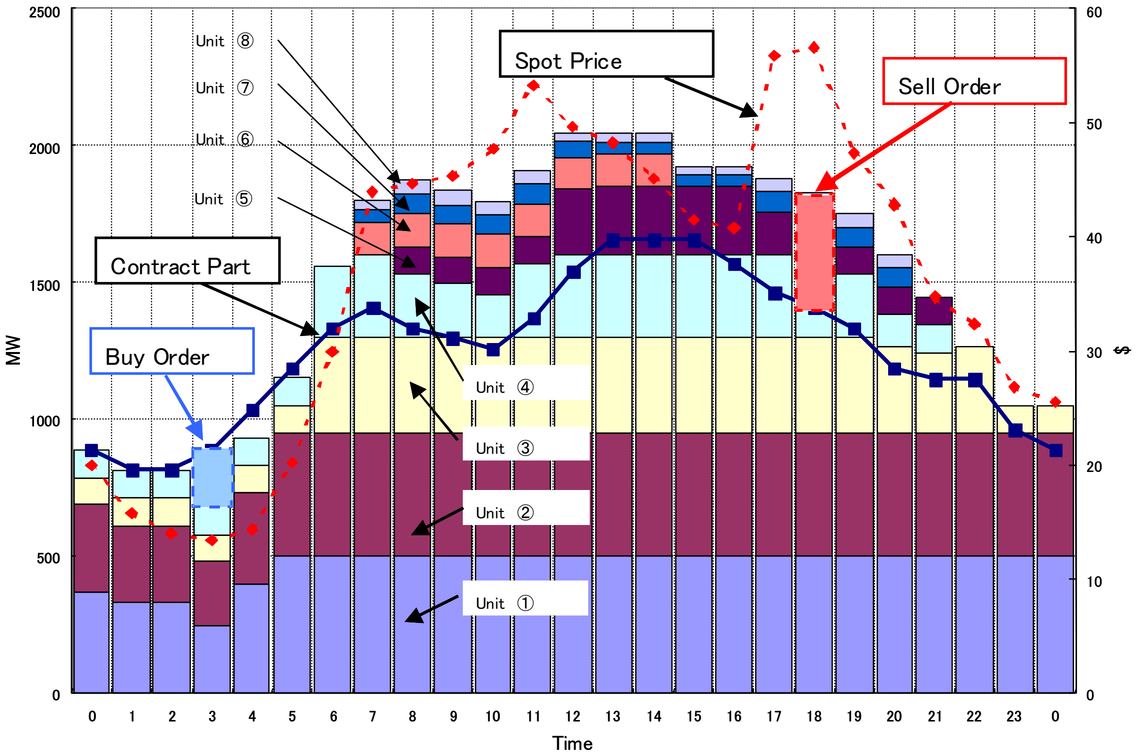


Figure 20: Generation schedule

The Japanese power exchange allows each player to make a multiple bid. A multiple bid is a combination of several price-quantity couples. The only condition in a multiple-bid is that it has to be crescent (the bid quantity increase with the price).

The possibility to make a multiple bid can be used to hedge the risk associated with errors in the price forecasting. It was shown in the previous section, that either in case of a good quality forecasting an average error of 8-9% is still present.

The multiple-bid is created generating several price scenarios. I propose to create each price curve from the original forecasted spot price introducing a percentage variation as described in Figure 21.

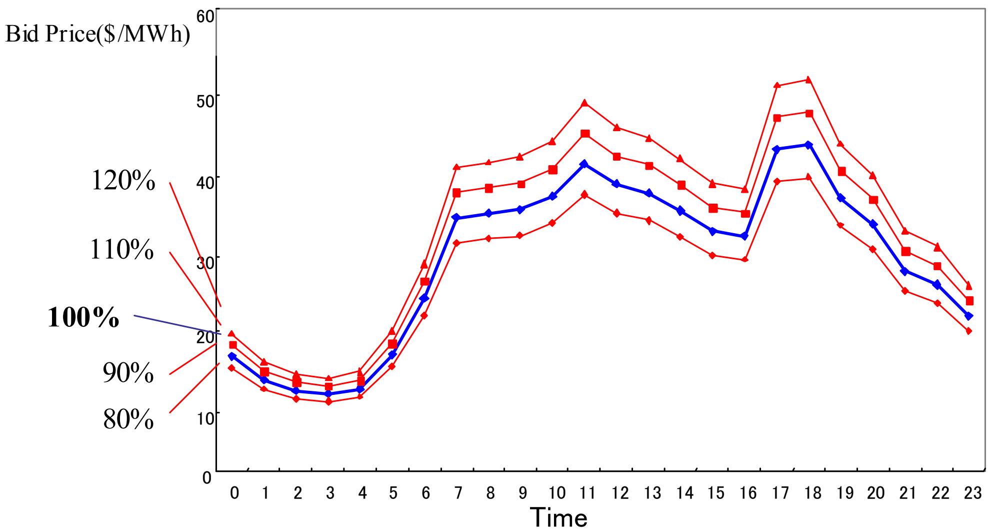


Figure 21: Price scenarios

The proposed optimization method is then applied for each price scenario creating a generating units dispatch for each price condition. The optimal bid curve for the generation company is composed by prices for each scenario and the associated bid quantity. Figure 22 is an example of multiple blocks bid for one time period.

It may be possible that for two different prices, the algorithm produces the same optimal bid quantity. In this case, the multiple-bid has to be reduced to create a monotonically increasing bid.

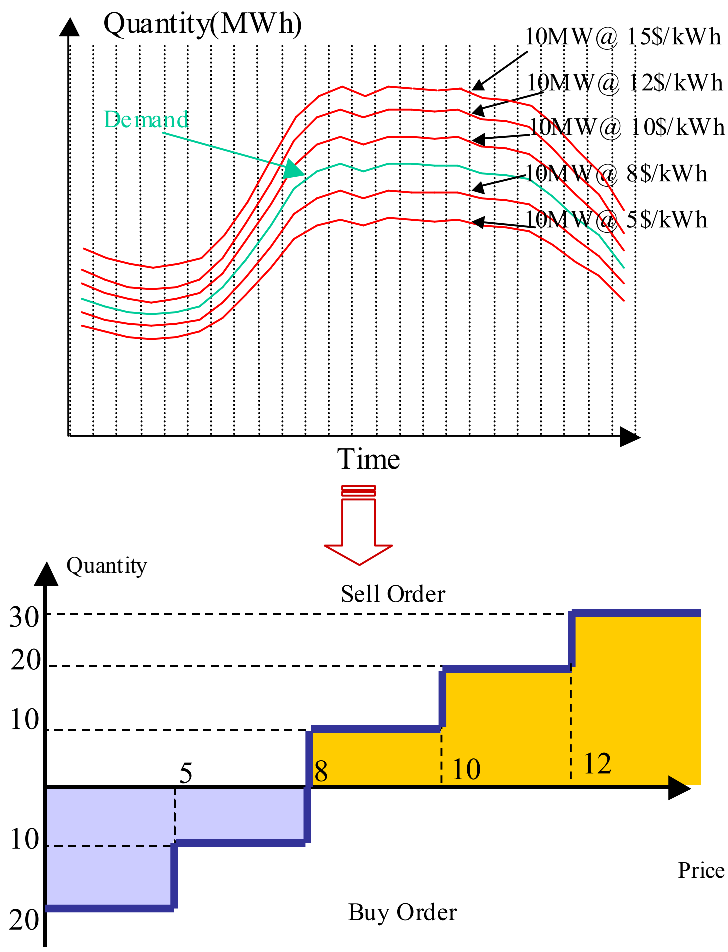


Figure 22: Multiple blocks bid

3.2.5 Cost based bidding

A market player prefers to adopt a cost base bid strategy if the bid of the player can influence the market price. This kind of player is known as price maker.
To develop a cost base bidding the total selling quantity has to be given and the bid price is calculated from the generation cost in each time period.
The objective function changes from profit maximization to cost minimization. In formula:

$$\min_{p_t, U_{i,t}} \sum_t \left(\sum_i \left(C_i(p_{i,t}) \cdot U_{i,t} + C1_i \cdot \min\left(0, \left(U_{i,t} - U_{i,t-1}\right)\right)\right)\right)$$

where the symbols have the same meaning of the previous section.
In this case the quantity to bid Q_t is given for each bid interval.
The objective function is subject to the energy balance constrain and the operational constraints for each generating unit as described in 3.2.4.
The optimization problem is solved with the same method utilize for the price based bid

approach.
Once the target output for each unit is determinate, it is necessary to calculate the bid price. Generation companies have two alternatives: set the bid price as the marginal cost of the most expensive unit committed in the time interval, or utilize the average cost of all the unit committed in the interval. From a theoretical point of view the marginal cost is the most correct bid price but some companies prefer to add fix costs and calculate the bid price as average of the operational costs.
To create a multiple bid, as previous described, it is necessary to build several scenarios and to calculate the costs for each of these. In the cost base bid, the scenarios are determined by the quantity of electricity that the player wants to buy or sell in the market.
Figure 23 is an example of scenarios setting.

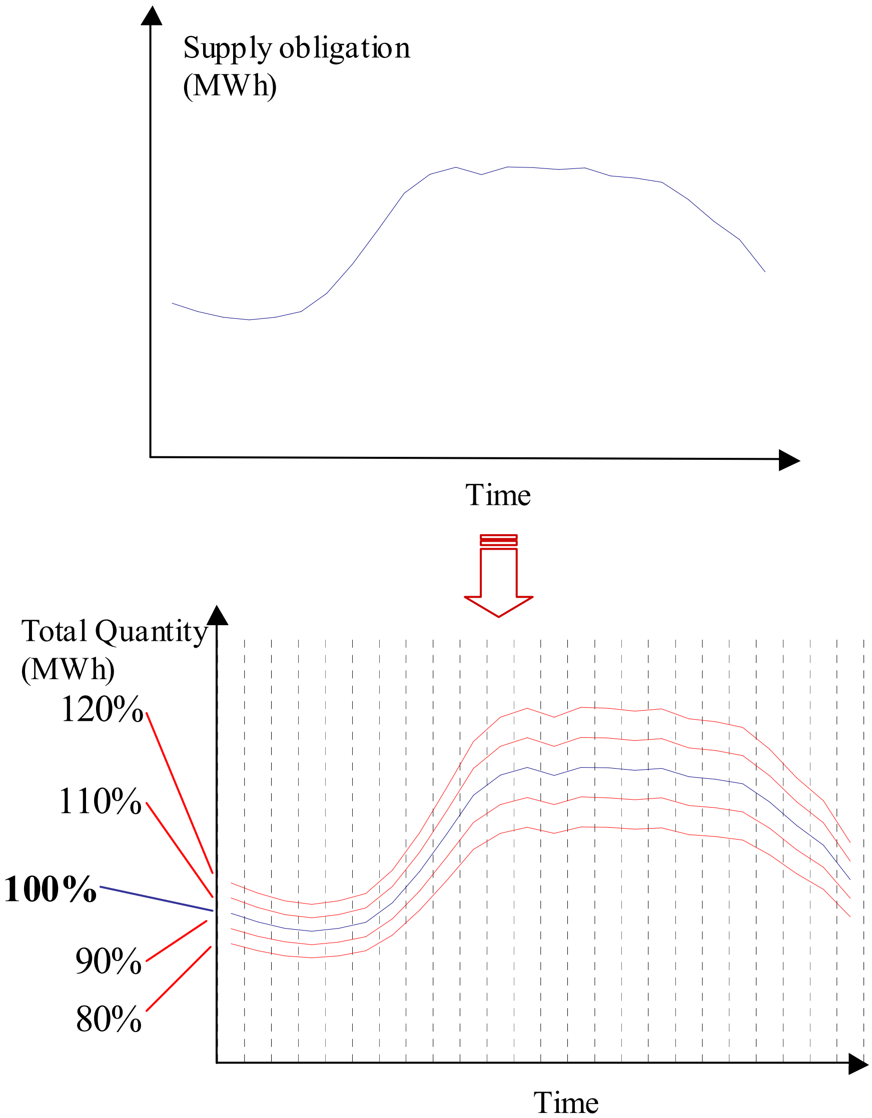


Figure 23: Scenarios for cost base bid

3.2.6 Multi-product bidding

In the previous two sections, the optimal bidding strategy for selling electricity in a spot market is developed. In the real market, a generator can decide to sell also other product in addition of electricity. As described in the second chapter of this thesis, the transmission operator may acquire ancillary services such as regulation and reserve from generators with an auction base mechanism.

Even though electricity, regulation and reserve services are transacted in a market, they are strongly related among themselves because the generation capacity is utilized to produce ancillary services as well as electricity at the same time. Especially the mechanical unit characteristics, such as ramp-rate and the mechanical capacity of the unit, have a strong effect on these transactions. Figure 24 illustrates the inter-operational relation among the previously mentioned commodities. A generator, operating at the maximum level, cannot trade neither regulation and reserve services. Further, the shut down unit cannot trade regulation and spinning type of reserve.

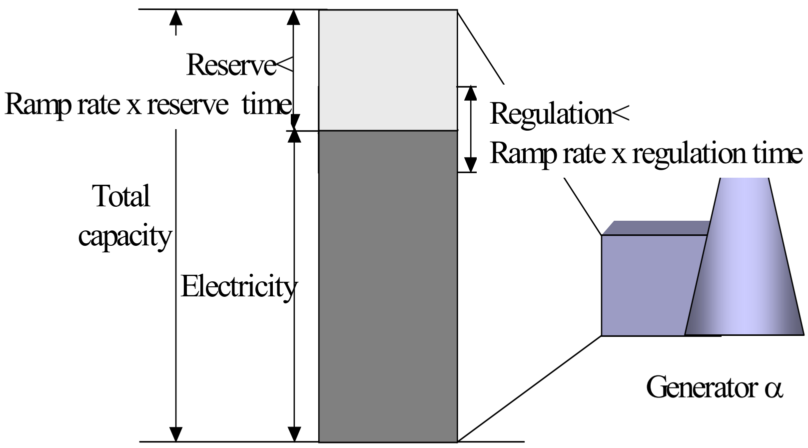


Figure 24: Capacity utilization

Electricity and ancillary services are paid to each generator at the market clearing prices.

Based on the market information such as forecasted market clearing prices and transmission charge, the generation company calculates the production of each commodity and the associated price that each unit has to bid in each market in order to maximize the profit.

The problem is formulated using a constrained optimization approach. The objective is the maximization of the profit for the generating units owned by the company, subject to the unit operational constraints such as ramp-rate, minimum time up, minimum time up, and mechanical constraints on the production. As in the previous section, it is supposed that the generation company is a price taker, the forecasted prices are taken as parameters for the problem and the quantities to bid in each market as the variables that have to be calculated.

The generator may be able to supply electricity and ancillary services in several markets. For example a generator can sell in the New York market or in the Ontario market

depending on the economical conditions.
The problem is formulated as below:

$$\max_{Q}\sum_{t}\left(\sum_{i,m}\left(P_m^e\cdot Q_{im}^e+P_m^{reg}\cdot Q_{im}^{reg}+P_m^{res}\cdot Q_{im}^{res}\right)\cdot U_i(t)-\quad\sum_i C_i\left(\ \sum_m Q_{im}^e\ \right)\cdot U_i(t)\right)$$

The following list summarized the symbols in the above formula.

$P_m{}^e$: forecasted price for electricity market *m*
$P_m{}^{reg}$: forecasted price for regulation market *m*
$P_m{}^{res}$: forecasted price for reserve market *m*
C_i: cost function for generator *i*
$Q_{im}{}^e$: bid quantity in electricity market *m* by generator *i*
$Q_{im}{}^{reg}$: bid quantity in regulation market *m* by generator *i*
$Q_{im}{}^{res}$: bid quantity in reserve market *m* by generator *i*
U_i: status variable for generator *i* (0=off, 1=on)

, where the first and second term in the equation represent the possible revenue from the market and the production costs, respectively. The objective function is subject to the following constraints:

Capacity constraints

$$\sum_m Q_{im}^e+0.5\cdot\sum_m Q_{im}^{reg}+\sum_m Q_{im}^{res}\le\overline{Q_i}\cdot U_i(t)\qquad\forall i$$

$$\sum_m Q_{im}^e-0.5\cdot\sum_m Q_{im}^{reg}\ge\underline{Q_i}\cdot U_i(t)\qquad\forall i$$

where

$\underline{Q_i}$: minimum output of unit i
$\overline{Q_i}$: maximum output of unit i

Time constraints

$$\left(X_i^{on}(t-1)-T_i^{minup}\right)\cdot\left(U_i(t-1)-U_i(t)\right)\ge 0$$
$$\left(X_i^{off}(t-1)-T_i^{mindn}\right)\cdot\left(U_i(t-1)-U_i(t)\right)\ge 0$$

where

X_i^{on} : on status of unit i
X_i^{off} : off status of unit i
T_i^{minup}: minimum running time of unit i
T_i^{mindn}: minimum shutting down time of unit i

Ramp-rate constraints

$$\sum_m Q_{im}^e(t)\le\sum_m Q_{im}^e(t-1)+Ramp_i\cdot time\_intrval$$

$$\sum_m Q_{im}^{reg}(t) \le Ramp_i \cdot time\_regulation$$

$$\sum_m Q_{im}^{e}(t) \le Ramp_i \cdot time\_reserve$$

where $Ramp_i$ is the ramp rate of unit i.
Since the problem to be solved is characterized as a mixed integer-continuous one, the unit commitment algorithm, described in 3.2.2 that integrates quadratic programming and dynamic programming is applied to deal with both the continuous and the integer variables, respectively. Firstly, the problem is solved with respect to the continuous variables *Q*s utilizing quadratic programming, and then with respect to the integer variables *U*s utilizing dynamic programming.

In the following example, the quantities that have to be bid in each market and the associated prices are determined utilizing the proposing method. In addition, the probable profit and revenue are calculated and compare with the case in which the generation company will not consider the possibility to bid in several markets utilizing the proposed optimal decision making methodology.
It is supposed that the generation company owns one generating unit and it has the possibility to bid in two markets the three products: electricity regulation and reserve.
The hourly production cost for each unit (\$/h) is supposed to be quadratic with the production level, in formula:

$$C_i\left(Q_i^e\right) = a_i \cdot Q_i^{e^2} + b_i \cdot Q_i^e + c_i$$

For simplicity the fuel cost is already integrated in the cost function.
The regulation supplying time is set at 3 minutes and the reserve time is set at 10 minutes.
In Figure 25, the forecasted prices for electricity regulation and reserve are plotted.

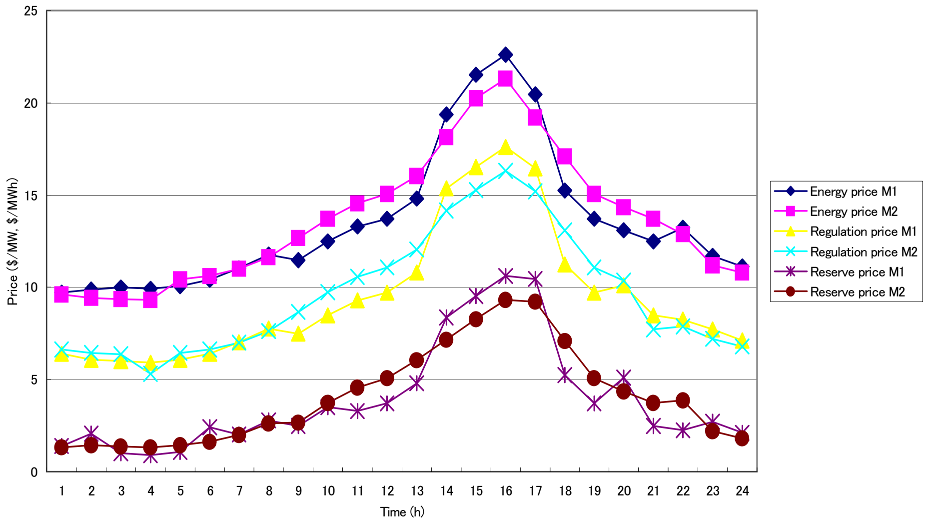


Figure 25: Prices in the 2 markets

Table 2 contains the cost data and the operational characteristic of each unit. It is supposed that the generator has the obligation to sell all the 3 services in the same market during a time interval.

Table 2: Unit characteristics

	A ($/MWh²)	b ($/MWh)	c ($/h)	Ramp (MW/m)	min time up (h)	min time down (h)	min (MW)	max (MW)
Unit 1	0.005	8.41	503	8	4	4	500	150

From the calculation the follow optimal quantity for each unit for each market for each products is calculated and shown in Table 3.

Table 3: Optimal bid quantity

Time	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00
Q^e	0	0	0	0	0	198	261	336	408	408	408	408
Q^{reg}	0	0	0	0	0	24	24	24	24	24	24	24
Q^{res}	0	0	0	0	0	80	80	80	80	80	80	80
m	-	-	-	-	-	1	1	1	2	2	2	2
Time	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	24:00
Q^e	408	408	408	408	408	408	408	408	408	408	330	270
Q^{reg}	24	24	24	24	24	24	24	24	24	24	24	24
Q^{res}	80	80	80	80	80	80	80	80	80	80	80	80
m	2	1	1	1	1	2	2	2	2	1	1	1

The price that should be bid is the minimum between the forecasted price and the marginal cost for energy and any price below the forecasted for ancillary services. In this way the generator will increase the possibility to win the bid reducing the risk to run the unit under its production costs.

The forecasted profit for this bid is: 38949 $

On the contrary, Table 4 considers the case in which the generation company optimizes the quantity to bid in the market considering only the energy bidding. Once that the electricity quantity is set the generator bid the residual capacity in the ancillary service market. For this calculation it is also considered that the generation choose to bid in one market only. The bid prices are set in the same way of the previous example.

Table 4: Optimal bid quantity without consideration about the multi-market multi product possibility

Time	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00
Q^e	0	0	0	0	0	0	336	306	408	488	500	500
Q^{reg}	0	0	0	0	0	0	24	24	24	24	0	0
Q^{res}	0	0	0	0	0	0	80	80	80	0	0	0
m	-	-	-	-	-	-	1	1	1	1	1	1
Time	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	24:00
Q^e	500	500	500	500	500	500	500	469	408	483	329	0
Q^{reg}	0	0	0	0	0	0	0	24	24	24	24	0
Q^{res}	0	0	0	0	0	0	0	29	80	5	80	0
m	1	1	1	1	1	1	1	1	1	1	1	-

The forecasted profit for this bid is: 28471 $

It is clear from the results that the profit can be strongly increased with a multi products multi market bidding strategy.

3.3 Conclusions

In a deregulated market generation companies are looking for tools to build strategic bids. To answer to this needs, this thesis analyzed the parameters that differenced a profitable bid from a non-profitable one. Since one of key parameters is the market price, at first, a neural network algorithm for price forecasting is proposed. After a detailed analysis of the historical Japanese spot price, the correlation between peak demand and market price was individuated. The proposed method integrates a peak demand forecasting with price forecasting.

Once the price forecast is available the generation company has to proceed to develop the bids. Generation costs and operation constraints are integrated together in a decommissioning algorithm to produce the optimal bids.

Since players have different characteristics and needs depending on the size of the company and the impact on the market, this thesis proposes two approach to the strategic bidding: the price-base bid for price takers and the cost-base bid for price maker.

In addition to the bid strategy for electricity, a multi-product bid optimization algorithm is proposed. Generator companies try to increase their profit selling not only electricity but also ancillary service such as regulation and reserve. Numerical results show the possible increment of profit that a generation company may obtain following the proposed methodology.

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Chapter 4 Generation scheduling for multi-area market

The Japanese electricity market was open to new players for thirty percent of whole demand from April 2000. The new rules incentive the instauration of competitive multi bilateral trading for electricity. In order to give a wide range of retail choices for final customers, bilateral trading was recognized as a suitable model from the point of view of dynamic incentive to competition and short-term and long-term stability in the supply. In the on-going deregulation of electricity market in Japan, even if utility companies are still responsible for transmission operation under their ownership, no one plays a role of mandatory type of market operation except than short-term adjustment and ancillary services operation. In a certain sense, it is a kind of free market under minimum supply regulation conditions.

Because not only to meet energy balancing requirement for physical trading, but also to consider the network logistics such as transmission constraints, losses, and usage price, all the market participants owning or operating generators should execute self-scheduling and self-dispatch calculation on a long and short term horizon.

In this thesis, it is proposed a calculation method that helps the supplier companies or retailers to obtain the maximum profit from the purchase and sell portfolio in a short term prospective.

4.1 Market model

The market that is considered is modeled on the market structure applied in Japan until 2005.

A certificated PPS (Power Producer and Supplier) can utilize the transmission lines owned by the vertical integrated utility to supply electricity to eligible customers. A PPS can produce the electricity by itself or purchase it on a contract base from merchant power plants.

A PPS has the duty to maintain the imbalance between the production and the supply to demand in each control area within +/-3% on a 30 minutes interval. To fulfill the balance requirement, PPS can control demand or generation in the real time.

The PPS is allowed to trade the electricity in the same control area or among several control areas. Japan is divided in 9 control areas that are connected by tie lines. A PPS can produce electricity in a control area and supply it to a customer located in another control area.

The electricity that is produced in a different area from the demand is subject to the wheeling fees and losses based on the MWh that flow. In addition a PPS has to purchase the transmission service to have the right to utilize the inter-area transmission lines.

The advantages of a multi-area environment include the possibility to have a demand curve

with a high power factor and the possibility to optimize the utilization of the generation fleet.
Nevertheless there are strict rules that have to be respected: the quantity of electricity flowing among areas has to be schedule by the PPS the day before of the real flowing and cannot be adjusted in the real time to supply eventual imbalance. As consequence of this condition, the day-ahead schedule for PPS becomes of fundamental importance.
In addition, PPS has to schedule a certain amount of reserve in each area to be able to follow the natural fluctuation of the demand in the real time and to supply any discrepancy between the forecasted load and the real demand. For this reason it is necessary to keep, in each area, a generating unit that can supply regulation, in other words it is necessary to have a unit that can be re-dispatched in the real time to ensure the balance between demand and supplying.

4.2 Objective function: profit maximization

A PPS is an independent company with the objective to run a profitable and sociable useful business. For this reason, this thesis recognized that the main objective of the PPS is the maximization of the profit under the constraints that the market rules impose and the requests that generation companies and customers can add to the contracts.
I want to focus on the short-term profit maximization and, in particular, on the formulation of the model and on the solution approach of the consumption/power plant production schedule and dispatch under the assumption that contracts with generation and demand are already stipulated and fixed; in other words the I do not intend to evaluate contracts, but I want to study the profit maximization under the contracts constraints.
The same model can be extended to a long-term scenario and contracts in both the purchase side and selling side of the business evaluated together.
Regarding the short term prospective, it is possible to write the objective function as the maximization of the difference between the total income and the total costs.

$$\max\left(\sum R(D) - \sum C(Q) - \sum T(D,Q)\right)$$

,where
D = demand of a customer
Q = output level of a generator

The first term R represents the revenue from the sale of electricity to the demand, the second term C represents the costs that the PPS has to effort to purchase electricity from generators (or to produce electricity if the power plants are owned) and the third T is the total expenses for transmission use. The above equation represents the net profit of the PPS.
The variables in the objective function are the output level for each generator or purchase contract Q and the customers demand D in case that the contract with customers allowed

energy dispatch.

4.3 Multi area modeling for generation

As it was explain in the previous section, a PPS can utilize a single generating unit to supply electricity in several control areas; nevertheless the costs to supply electricity in each area is a function of the generation production and of the quantity that is wheeled.
To evaluate properly the weight of costs such as wheeling fess, the generation output is decomposed in the sum of the quantity that the generator supply in each area; in Figure 26, this concept is schematically described.

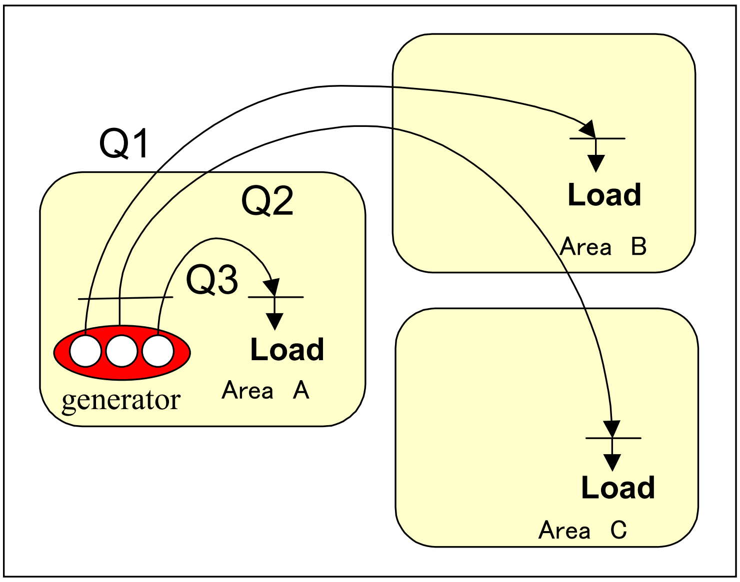


Figure 26: Generation modeling for multi-area

In other words, I proposed to approach the optimization problem, decomposing the generator or purchase contract quantity in a number of sub-quantities equal to the number of areas in which the PPS is operating.
The generator produces the total quantity $Q=Q_1+Q_2+Q_3$ but the costs, meant as summation of production costs and transmission costs for each individual sub-quantity, are different since subject to wheeling fee and losses.
The quantities Q_1,Q_2 and Q_3 are subject to the constraints of the contracted transmission services.
This model for generation permits to evaluate all the costs and constraints in the optimization process and, at the same time, to track the quantities that flow from each generating unit in each control area.
In addition, at least a generator for each control area has to be able to supply a certain quantity of regulation to adjust the possible fluctuation of the load in the real time.

Each unit is informed about the schedule that has to be performed in the operating day; the wheeling schedule has to be supplied to the system operator and it is utilized to set the power flow level P0 for each interconnection line. The system operator of each control area needs to know the P0 of each interconnection to perform the frequency control in the real time. In the Japanese market, PPSs are asked to submit the wheeling schedule for each generator or contract at least at 12:00 of one day before the delivery day.

4.4 Generation scheduling problem

This thesis focus on the generation scheduling for the day-ahead, but easily, the problem can be extended to the load scheduling and dispatching as well.

4.4.1 Objective function

The objective function is the maximization of the profit; it is possible to rewrite the profit equation as function of the quantities *Q* output of the generating units, described in the previous section. Assuming that the costs for production are a linear function of the output level *Q* and it may change in the time and that the price is different from customer to customer and in the time, the objective function is expressed as follow.

$$\max \sum_t \sum_j P_{j,t} \cdot D_{j,t} \quad -$$

$$\sum_i \sum_t \left(C1_{i,t} \cdot \sum_a Q_{i,t,a} + \sum_a C2_{i,t,a} \cdot Q_{i,t,a} + sp_i \cdot U_{i,t} \cdot (1 - U_{i,t-1}) + C3_{i,t} \cdot Reg_{i,t} \right)$$

,where
$D_{j,t}$: demand j at time t
$P_{i,t}$: price of selling to demand j at time t
$C1_{i,t}$: the generation cost of generation i at time t
$Q_{i,t,a}$: the production of generation i for control area a at time t
$C2_{i,t,a}$: the wheeling fee to send the production of generation i to control area a at time t
Sp_i: start up cost of generator i
$U_{i,t}$: the status of generator i at time t (1=generator on, 0=generator off)
$C3_{i,t}$: the price of generator i to support regulation at time t
$Reg_{i,t}$: regulation quantity of generator i at time t

The output of each generating unit $Q_{i,t}$ is calculated as the summation of the $Q_{i,t,a}$.
For simplicity, it is assumed that the cost function is a linear one. The assumption is consistent with the fact that almost all the contracts between generation companies and PPS include only a price for kWh. The model can be easily modified to consider other type of

cost function such as quadratic.

4.4.2 Virtual generator

If the PPS cannot supply the customers with its own generation capacity and contracts or if the production exceed the demand because of contract condition in same time interval, the PPS schedule operator can decide to purchase electricity or regulation from the utility operating in the control area or, in case of excess production, to sell electricity to the utility. To take in account this possibility, in the proposed approach, the utilities are modeled as virtual generating units with infinite capacity of production or absorption and without any kind of constraints. A virtual generator and a virtual demand are set for each area in which the PPS is operating. The price for the virtual generators is set as the value published in the tariff of each utility company and the virtual demand-selling price is set equal 0. The production of the virtual generator is constrained to be consumed in the same control area and cannot be wheeled in another area since the Japanese utilities required that the balance has to be kept in each area.

4.4.3 Constraints

The total generation production has to be in balance with the total demand and total losses in each time period

$$\sum_{a} \sum_{i} \left(Q_{i,t,a} \cdot \left(1 - loss_{i,a} \right) \right) = \sum_{j} D_{j,t} \qquad \forall t$$

,where

$loss_{i,a}$: percentage of losses for generator *i* to send electricity to area *a*.

In each area the minimum regulation requirement has to be supply by the generators located in that area

$$\sum_{i \in a} Reg_{i,t} = Reg_{t,a} \qquad \forall a, t$$

,where

$Reg_{t,a}$: regulation requirement for area a at time t

When a unit is start-up, it is constrained to run for a minimum number of hours, in addition when a unit is shut down, it will not be able to start-up again immediately but it will require a minimum number of hours of non-operation.

$$\left(X_i^{on}(t-1) - T_i^{minup} \right) \cdot \left(U_i(t-1) - U_i(t) \right) \geq 0$$
$$\left(X_i^{off}(t-1) - T_i^{mindn} \right) \cdot \left(U_i(t-1) - U_i(t) \right) \geq 0$$

,where

X_i^{on}: the number of time periods that the unit *i* was on until time *t-1*
X_i^{off}: number of time periods that the unit *i* was off until time *t-1*
T_i^{minup}: the minimum number of time periods that the unit *i* has to run
T_i^{mindn}: the minimum number of time periods that the unit *i* has to be off.

A unit or a demand can set a maximum level and a minimum level of operation:

$$Q_i^{min} \le Q_{i,t} \le Q_i^{max} \qquad \forall i,t$$
$$D_j^{min} \le D_{j,t} \le D_i^{max} \qquad \forall j,t$$

,where
Q_i^{min}: minimum output of generator *i*
Q_i^{max}: maximum output of generator *I*
D_j^{min}: minimum consumption of demand *j*
D_j^{max}: maximum consumption of demand *j*

The operator may force a generator to be on line to follow the must-run requirement of a contract introducing a must-run condition.
The total electricity flowing from an area to another can be subject to transmission capacity constraints due to physical limits or contract limitation. For simplicity I assumed that the transmission constraints are individual for each generator or contract. It is possible to extend the concept constrains for a group of contract or generators if needed.

$$Q_{i,t,a} \le \overline{Q_{i,t,a}} \qquad \forall i,a,t$$

,where

$\overline{Q_{i,t,a}}$: contract limit of wheeling of generation *i* to area *a* at time *t*

In addition, each unit has to respect the ramp rate constraints both for electricity and regulation

$$\sum_a Q_{i,t,a} \le \sum_a Q_{i,t-1,a} + Rampup_i \cdot 60 \qquad \forall i,t$$
$$Reg_{i,t} \le Rampup_i \cdot \Delta t \qquad \forall i,t$$

where,
$Rumpup_i$: maximum output change of generator *i* in one minute
Δt: interval in which the generator *i* have to supply the regulation

4.5 Solution approach

The problem can be recognized as a mixed integer/continues ones. The PPS has to decide which unit to use and at which level to dispatch the units and the demands.
The decision variables related to the dispatch of each generating unit and each consumer are continues, and on the other hand, the decision variables to use or not a unit or to supply or not a demand are integer.
The solution for the continuous variables is approached by linear programming method and the integer variables are searched using a dynamic programming approach. The two calculation techniques are integrated in an iteration process to obtain the optimal solution through the so-called decommissioning approach. At the initial points all the generating units are set as running and all the demands as to be supplied. Units and demands will be stopped or not supplied one by one if they will be evaluated as not profitable for the PPS.
The liner program calculation and the dynamic programming algorithm are linked with the economical parameter λ, which is the langrangian multiplier of the balance constrains.

4.6 Numerical simulation

The proposed model is applied to a company that is trading in 3 areas. It is supposed that the company is contracting with 3 generators and own 2 generators. The company is contracting with 20 demands for supplying the electricity at a fix price. Let's supposed that the selling price is 9¥/kWh.

Table 5 Generating unit data

	Q^{min} (MW)	Q^{max} (MW)	*Rampup* (kW/min)	T^{mindn} (h)	T^{minup} (h)	*C1* (¥/kWh)	*Sp* (¥)
Unit 1	1	15	1	3	4	4	0
Unit 2	1	15	1	2	3	7.1	0
Unit 3	1	15	1	3	4	6.2	0
Unit 4	1	15	1	2	2	6.9	0
Unit 5	1	15	1	1	1	8.5	0

Table 5 lists the characteristics of each generator and the production costs that the PPS has to effort. For simplicity it is assumed that the generation cost is independent of time and that there are not start-up costs.
In Figure 27, the location of the units, the wheeling fees and the losses are illustrated.

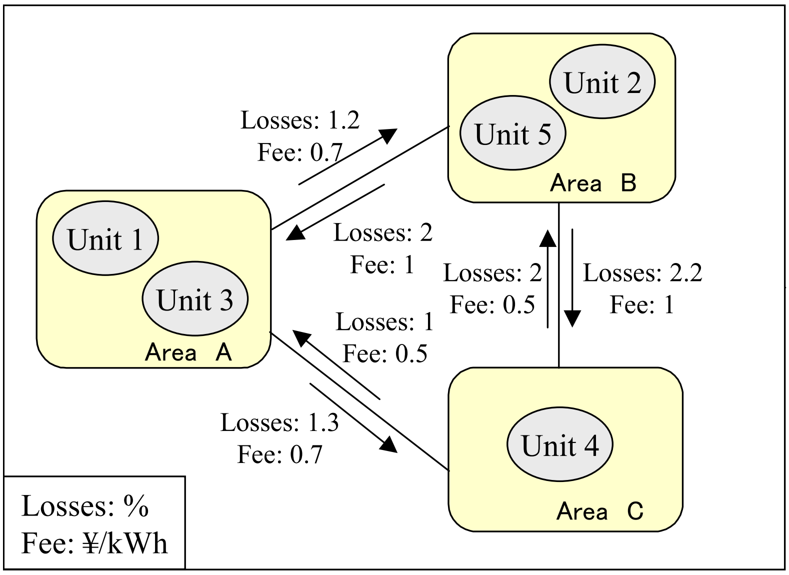


Figure 27: Generation units' distribution, fees and losses

Losses are set between 1 and 2.2% and wheeling fee between 0.5 and 1 ¥/kWh. Looking at the data in Table 5 and at the information in Figure 27, it is possible to see that the cheapest electricity is in area A and area B has the most expensive one.

It is supposed that the PPS has already reserve 10MW of transmission capacity between area 1 and area 2, 10MW between area 2 and area 3 and 10 MW between area 3 and area 1.

From the simulation, I wanted to calculate the total profit on 24 hours, and compare it with the profit that the same PPS will get under the same condition but without the multi-area optimization, in other words, considering that the PPS has not reserved any transmission capacity.

The minimum time interval that it is considered is 30 minutes.

Since it is assumed that the demand price is fixed and that demand cannot be curtailed, the PPS has to forecast the consumption of each demand contract to solve the multi-area dispatching and scheduling problem.

Figure 28 plots the forecasted load for the 3 areas; the demand is high in area A and low in area B and C.

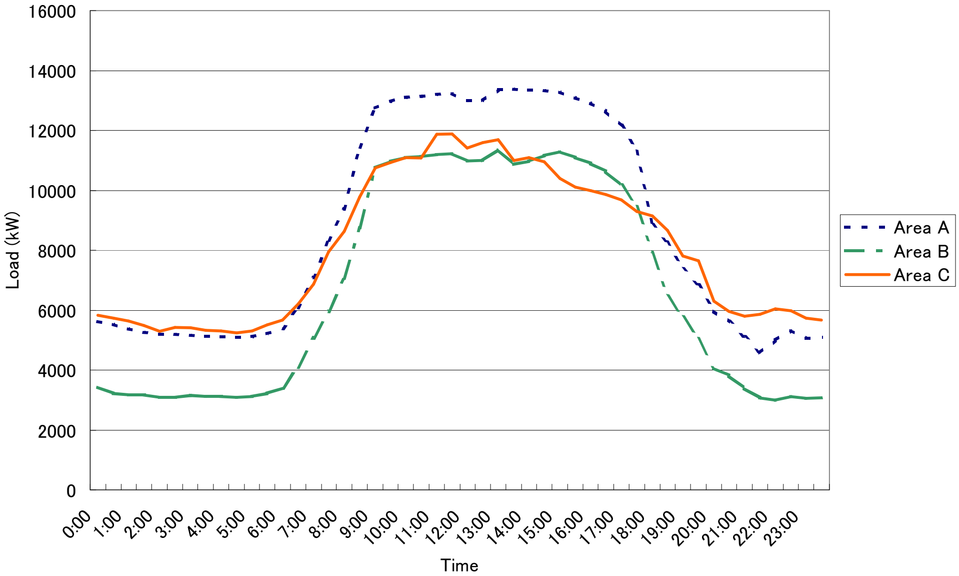


Figure 28: Load for each area.

The regulation requirement is set at 1% of the load for each area.

Figure 29 shows the output of each generation in each 30 minutes interval; it is clear that unit 5 is shut down all the time since too expensive. Unit 4 and unit 2 are requested to run to supply the required regulation in their area, but the output is very closed to the minimum output level. Unit 1 supply the most of electricity during all the day. Unit 3 is started up in the morning to follow the load increasing and shut down in the evening when the load decrease.

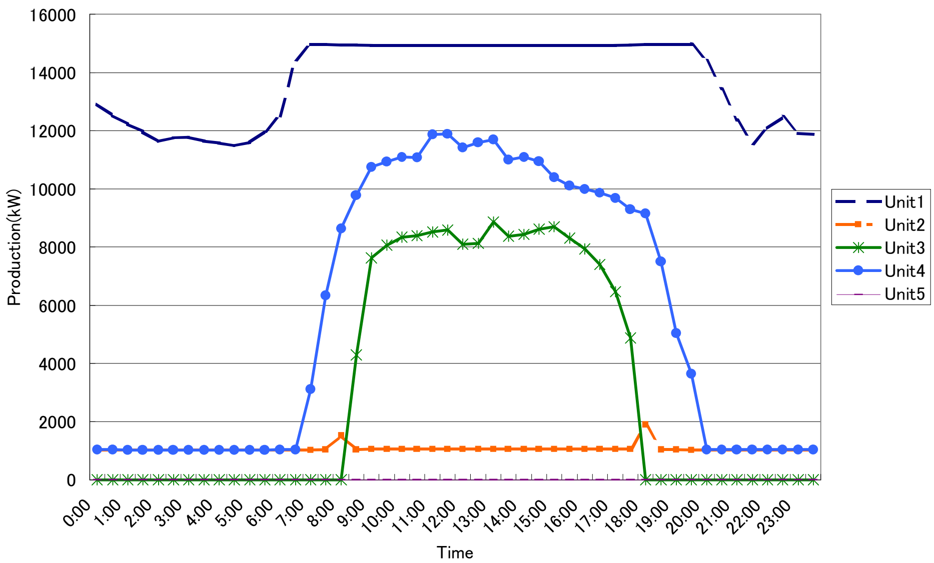
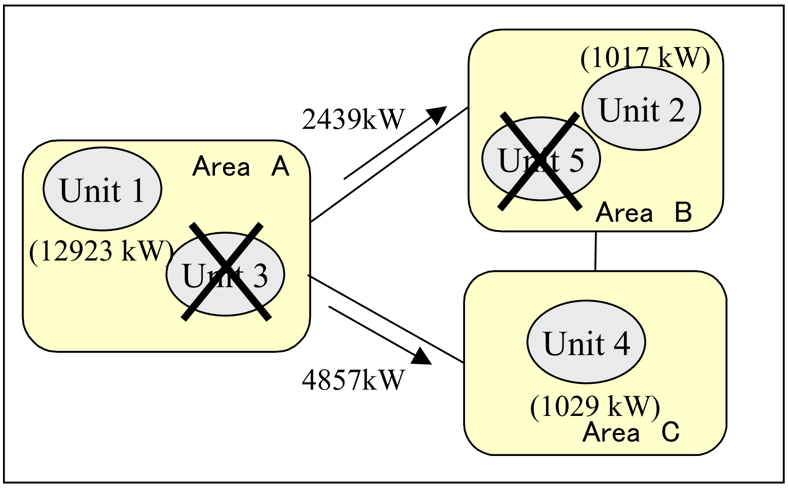
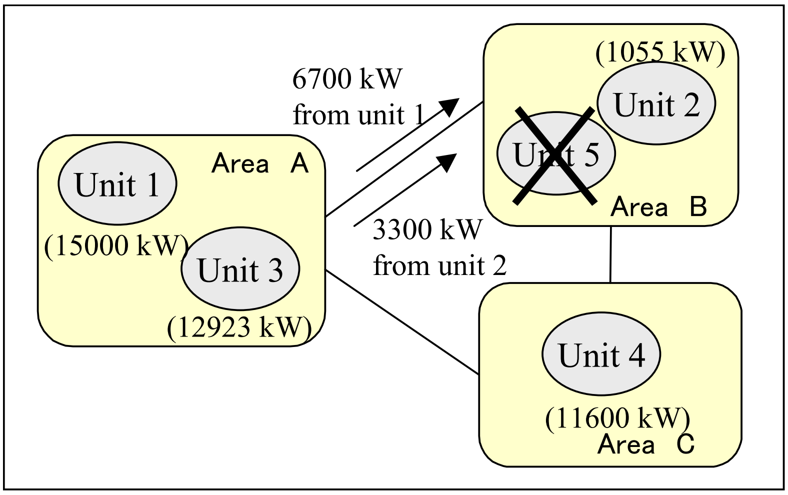


Figure 29: Generation output

In Figure 30, the production for each generator and the track of the flow is represented for an off-peak time interval and peak time interval; 0:00 and 12:00 were selected. It is evident that the tendency is to export electricity from area A to area B and C. During the off-peak period unit 1 is wheeling electricity to areas A and B, in the peak time interval, both the unit 1 and 3 supply electricity to area B were only expensive generators are available.



A: Time period 0:00



B: Time period 12:00

Figure 30: Unit output tracking in 2 snap shots

The total profit for the PPS for the 24 hours simulation is: 2,026,055 ¥. The same simulation was performed under the assumption that the PPS has not reserved any transmission capacity, in other words without applying the multi-area optimization approach. In this case the total profit was estimated to be 1,750,088 ¥.

Utilizing the opportunity to wheel electricity among control areas through the proposed multi-area approach it is possible to increases the profit for the PPS of more than 15%.

4.7 Conclusion

An approach to the generation and wheeling schedule for PPS was proposed. To evaluate properly the costs associated with the wheeling fees and the transmission losses, the generation output variable was decomposed in its wheeling component for each area.
The proposed method was recognized to be efficient and profitable. A PPS can increase the total profit evaluating in the proper way all the constraints and the profit possibility; for this reason, this method is deployed in computer software and delivered to PPSs that utilize it in the daily scheduling process.

4.8 Reference

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Chapter 5 The congestion management problem

The rapid deregulation of the electricity industry in the last two decades has produced the formation of several markets around the world. Following the example of other commodities, the electricity market is commonly managed by an exchange that publishes daily the traded quantities and the market prices. Unfortunately, electricity cannot be exchange freely because it has to be traded subject to the physical constraints of the transmission network. These constraints can cause congestions.

The problem of transmission congestion is particularly relevant to interconnections among power system control areas. It is a matter of fact that interconnections among control areas were developed with the objective to increase the stability of the power system. Interconnected networks have the advantage to support frequency control and emergency procedures. The capacity of the interconnection was designed for the previous described scope and not for trading. However, due to deregulation of the market and the increase of the number of transmission users, the utilization of the interconnections has changed from frequency support to trading support: transmission lines are the highways of electricity. Market players dispatch generating resources with the objective to increment their own economic benefit. For this reason, it is common that the transfer capacity requested to transfer electricity from a control area to another control area exceeds the transfer capability of the interconnection line between the two areas.

In other words, it can be said that the transmission congestion problem is caused by the conflict of interests among the market players: limited transmission resources have to be allocated to several independent players, all of them operating with the intent to improve their own profit.

In case of insufficient transfer capacity among control areas, it is then necessary to introduce rules to manage the congestion on the transmission lines. A congestion management method has to be able to relief the overflow on the transmission lines and, at the same time, to give a strong economical signal to the transmission user. This economic signal is worldwide recognized as the difference of the electricity price between congested areas.

5.1 The forward market

In a continuous auction type of market it is impossible to use a pure market split approach for the congestion management because the transactions are sequential in the time and the contracts are bilateral, and further market split evaluation cannot be performed. Nevertheless several forward markets around the world have adopted a continuous auction (zaraba) mechanism to manage the market itself. The congestion management is

approached in several ways. A common approach is to create a financial market. Nord Pool and the German Power exchange EEX adopted this kind of approach. The electricity is traded only as a financial good and not delivered. The objective to trade in the financial market is to hedge the risk associated with the spot market.
Other approaches to the transmission congestion problem include flow gate and transmission right trading. In these approaches, a parallel market for flow gate or transmission rights, have to be managed with the electricity market. It may create complexity and difficulties in the market monitoring and in the trading itself.
To avoid the demerit associated with the already implemented methods, I proposed a new methodology based on a power flow calculation that allowed managing the electricity market and the transmission congestion at the same time.

5.1.1 Concept of hub

The basic concept is the introduction of several exchanges hubs connected by physical transmission lines. The concept fit particularly with the Japanese network and with the areas defined in the Japanese spot market. Each control area can be seen as a hub in the forward market and as a zone in the spot market. Any player can sell or buy electricity in each hub subject to the condition of available transfer capability.
The available transfer capability for each inter-tie may be supplied to the power exchange by ESCJ every morning before starting the trading day. After the closing of the trading day, the power exchange may inform ESCJ about the transactions that were fixed during the day. The available transfer capability can be updated, thought the trading day, by JEPX instantly at the moment that a transaction is finalized.
The method will automatically drive the price of congested hubs at a higher level compared with the price of no-congested hubs.
The market operator may reconfigure the hubs and the interconnection, following the moves in the market. If power system operators individuate new congested areas, new hubs can be created.
Followings are descriptions of the concept of the hub configuration with an example. Figure 31 is a simple representation of a possible structure. A board, as represented in Table 6 is available for each hub. Players can post bid in any hub but the bid has to include in addition to the price and the quantity, information about the delivery or withdraw location (hub).

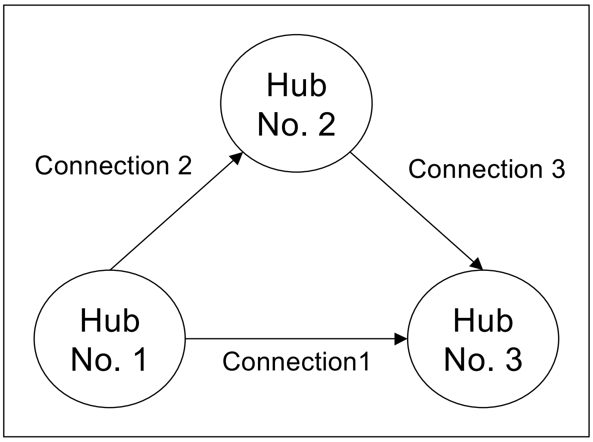


Figure 31: Hubs and connections

Firstly, it is assumed that at the current trading time, the orders listed in Table 6 are posted in Hub No. 3 and the location of the orders is the same Hub No. 3.

Table 6: Example of posted orders

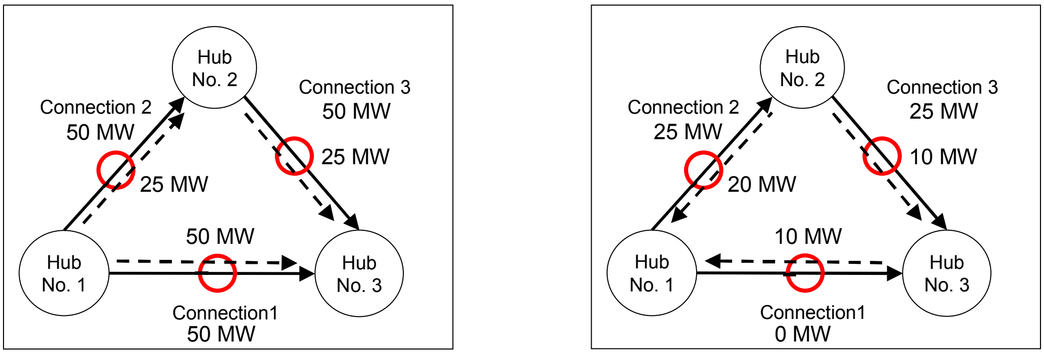
Buy MWh	Price ¥/kWh	Sell MWh
	30	180
	28	100
	25	155
100	20	
170	18	

Secondly, it is assumed the available transfer capability to be 50 MW for all the three interconnections and that the impedance for each interconnection is the same, through a simple power flow calculation it can be examined that a player is able to sell from Hub No. 1 a maximum of 75 MWh at 20¥/kWh: 50 MW flow from Hub No. 1 to Hub No. 3 on connection 1, 25 MW flow from Hub No.1 to Hub No. 3 through Hub No.2 on connection 2 and 3 as shown in Figure 32-a. Once the transaction is fixed, the available transfer capability for each interconnection has to be updated. The available transfer capability has to be set to 0 MW for the connection 1 and to 25 MW for the connection 2 and 3.

Since the continues auction is a sequential process, it may happen that another transaction of 30 MW is scheduled from Hub 2 to Hub 1 after the previous transaction is processed. Because this transaction is in counter flow on connection 1 with respect to the previous transaction and transfers the same flow of the previous transaction on connection 2, the available transfer capability can be upgraded as: 10 MW from Hub No. 1 to 3 on connection 1, 45 MW from Hub No 2 to 3 on connection 2 and 15 MW from Hub No.2 to 3 on connection 3.

At this time it is possible to trade more 15 MW from Hub No. 3 to Hub No. 1 for 20¥/kWh

(Figure 32-b).
In case the available capacity on the connection 1 persists to be 0 MW, players that try to buy electricity in Hub 3 automatically have to purchase from high price offers (in the example 25¥/kWh or more) and, on the other hand, players who are located in Hub No. 1 and Hub No. 2, that intend to sell electricity are forced to sell it in their own hub.



(a) Transaction for player A (b) Supplementary transaction

Figure 32: The available transfer capability before and after the transactions

Since the number of transaction may be very high and for each hub it is possible to have many products (weekly forward, monthly forward and so on) that all utilize the same connection schema, it is fundamental that the update process of the available capability is fast. For this reason and for keeping the market liquidity higher it is important to have a small number of hubs.

5.1.2 Match quantity calculation

The fundamental concept in the calculation process is that all the transactions are processed sequentially. This assumption is consistent with the continuous auction rules adopted by JEPX, since, in the continuous auction, each transaction is decided independently and sequentially following the price merit priority and the posting time priority.
Each order is defined by 6 parameters:
- kind of product (in the same market several product may be traded, in the Japanese forward market monthly peak and base products are available)
- player name
- location (it will be considered as source for an ask and as sink for a bid)
- order type (bid for buying and ask for selling)
- price for unit (¥/kWh)
- quantity (MW)

- Determination of the transaction quantity
When two orders can be matched in a transaction a simple power flow calculation is

performed for each time period that composes the product.
The ask order location is recognized as the source and the bid order location is recognized as the sink. All the transactions already processed are ignored.
The power flowing on each connection is individuated and compared with the available transfer capability between hubs. The transaction quantity is then fixed at the minimum quantity that satisfies all the transmission constraints and the order quantities. In formula:

$$Q_t = \max\left(Q_{bid}, Q_{ask}, Q_{i\to j}^{t_1} \ldots\ldots, Q_{i\to j}^{t_n}\right)$$

where,

Q_{bid} = quantity to purchase by the bid order

Q_{ask} = quantity to sell by the ask order

$Q_{i\to j}^{t_i}$ = maximum quantity that can be transferred from location of the source i to location of the sink j at time period t_i
n = total number of time periods

$Q_{i\to j}$ is calculated for each time period using a power flow calculation as follow:

$$Q_{i\to j} \max Q_i$$

$$s.t$$
$$Q_i = -Q_j$$
$$\underline{H} \cdot \overline{Q} \le \overline{ATC}$$

, where Q_i is the quantity from the source hub i, Q_j is the quantity at the sink hub j, H is the transfer admittance matrix that transforms the power at each hub in the flow on each line, $\overline{Q}$ is the vector of the hubs injection (the only 2 elements are at hub i and hub j), and ATC is the vector of the transfer available capability for each interconnection line.

- Upgrade of the ATC values
Once the transaction quantity is decided, the opposite process is performed to find the real flow on each interconnection and to upgrade the ATC values:

$$\overline{ATC}_{new} = \overline{ATC} - \underline{H} \cdot \overline{Q}_t$$

,where $\overline{Q_t}$ is the vector of the power injection at each hub ($+Q_t$ at hub *i*, and $-Q_t$ at hub *j*)

In case of simple networks, the calculation may be performed in a few milliseconds.

- Upgrade of the posted order

Once that the ATC are upgraded, it may happen that some of the posted orders become non-deliverable or non-transmittable. A calculation similar to the one described in the determination of the transaction quantity is then performed on each order to determine the availability of the transmission capacity. In this calculation the counter party location is set as the hub location.

All the ask order that cannot be delivered and all the bid order that cannot be satisfied transmission capacity limitation have to be temporary deleted from the posted information in order to avoid the possibility to give a wrong signal to the participants. The orders may be reposted in case of congestion relief or the players may cancel them.

Speediness in the upgrade of the ATC process and in the upgrade of the posted order process is a fundamental issue. Players may follow inappropriate behaviors if the information about both transfer capabilities and orders are not correct or delay in the time. For this reason, I concentrated on a method that can manage the transmission capability and can be performed in a short time span.

5.1.3 Operation constraints

In the previous session, the base case in which all the inter-ties are in alternating current was described.

The Japanese inter-ties have a minimum flow to be respected, and in some case, they can be operated only in a discrete way (for example the FC interconnection between Tokyo Electric and Chubu Electric must be operated as multiple of 20 MW). The DC interconnections can be operated at a fix flow independently from the network configuration. For this reason, the kinds of constraints, previously described, can be easily integrated in the method adding the following constraints:

$$Q_t = \begin{cases} Q_t & if \quad Q_t \geq \overline{\overline{Q}}_k \qquad \forall k \\ 0 & otherwise \end{cases}$$

,where $\overline{\overline{Q_k}}$ is the minimum flow constraint on each DC connection *k*.

5.1.4 Tests result

The described model was utilized in a simulation game to testify the efficiency of it. Ten players were involved in the simulation. They were selected among professionals with back ground on the energy market.

To each player, a role was assigned in the market. The players were divided in:

- retailers (4 players)
- generation companies (4 players)
- traders (2 players)

The resources were divided in two hubs linked by an interconnection with a capacity of 100 MW.

The hub 1 was characterized as an area with cheap generation capacity and small demand. On the contrary, hub 2 had large demand and expensive generation capacity. The simulation intent was to verify that after a few transactions the interconnection between hub 1 and hub 2 would be congested and the prices in the 2 hubs would diverge.

The players were trading hourly MW for the following day. Figure 33 is a simple representation of the simulated market.

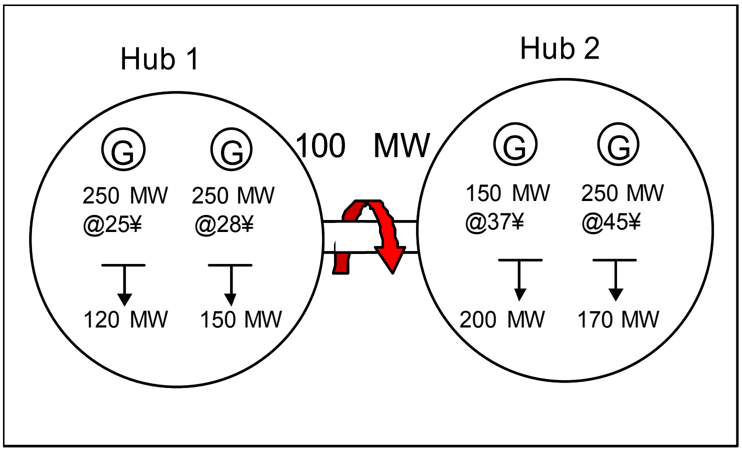


Figure 33: Market model

The players were informed about the total demand for each hub, the available transfer capability of the interconnection between the two hubs and the range of costs of generation (25-45 ¥/kWh).

The simulation session was ranging over 6 hours. During the session the retailers were asked to buy a quantity of electricity equal to the contracted demand.

Figure 34 represents the plotting of the price during the simulation.

It is evident from the graph that during the first 2 hours of the simulation the price in the two hubs is almost the same. Basically the electricity is sold from players located in hub 1 in both hubs. Once the interconnection is full the market is suddenly split and the prices in the two hubs change drastically.

In hub 1 the price decreases due to a strong competition of the generation companies; on the contrary, in hub 2 the price increase since the only generation capacity available has high cost.

The market mechanism gives a right signal of the physical situation. Players can easily understand looking at the price trend in each hub that the price difference between the two hubs is caused by congestion.

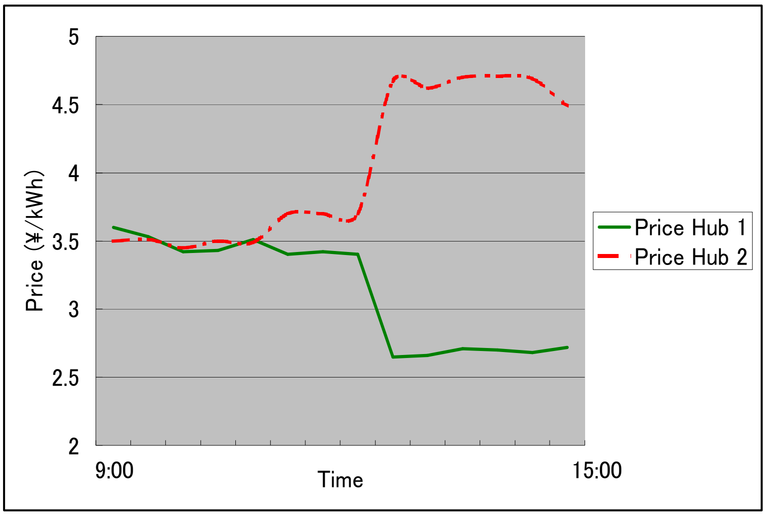


Figure 34: Comparison of the price trend in the two hubs

5.2 The spot market

For the spot market a pure market split approach is proposed. The technique developed in this thesis assures an optimal market solution and at the same time reduce drastically the calculation time.

5.2.1 Auction rules in markets

The single price auction mechanism is often utilized to set the market price in an electricity day-ahead market. The objective is to find the single market price that maximizes the quantity of electricity exchanged in the market and the consequent quantity that may be contracted by each player. The price is built using the market participants' order prices.
An order is defined by the price-quantity pair and the position (offer or bid). An offer order is a will to sell a certain quantity of electricity at a price equal or higher than the offer price. On the contrary, a bid order is a will to buy a certain amount of electricity at a price equal or lower than the bid price.
Market participants' orders are collected until a predetermined time called gate close. After the gate close, the market operators process all the order to find the market price and the contract quantity for each order.
In a single price auction, the market price and the contract quantity for each order have to be set respecting the following conditions described in the following equations.
The conditions for an offer order are:

$$\begin{array}{ll} price_{offer} < price_{market} & quantity_{contract} = quantity_{offer} \\ price_{offer} > price_{market} & quantity_{contract} = 0 \\ price_{offer} = price_{market} & 0 \le quantity_{contract} \le quantity_{offer} \end{array}$$

,where $price_{offer}$ and $quantity_{offer}$ are the price-quantity pair of the offer order, $price_{market}$ is the price for the market and $quantity_{contract}$ is the quantity that the player sell.
In a similar way, the conditions for a bid are:

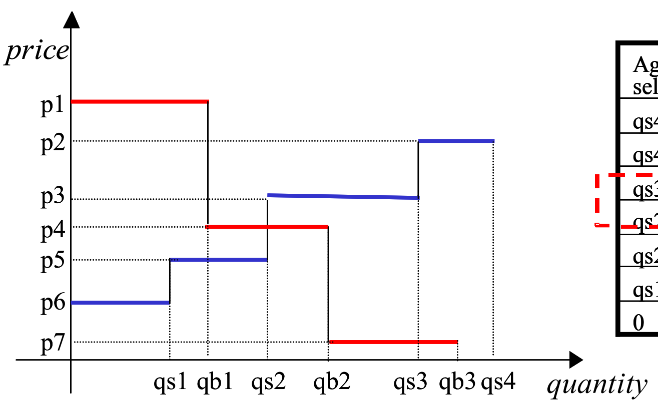
$$\begin{array}{ll} price_{bid} > price_{market} & quantity_{contract} = quantity_{bid} \\ price_{bid} < price_{market} & quantity_{contract} = 0 \\ price_{bid} = price_{market} & 0 \le quantity_{contract} \le quantity_{bid} \end{array}$$

In other words, the formula expresses the concept that any seller will not sell at a price that is lower than his offer price, and any buyer will not buy at a price higher than his bid price.
The objective of maximization of the exchange quantity does not ensure the uniqueness of

the solution. For this reason it is necessary to introduce additional rules to set the final market solution. In this thesis, it will be assumed that in case of multi-solution the lowest price that satisfies the previous described constraints is selected as the market price.
In some cases, at the market price, the total offer quantity may not be equal to the bid one. The excess of quantity in the offer or bid side is defined as a surplus. The surplus is distributed among orders with the price equal to the market price in a proportional way.
This thesis implemented a sequential approach to calculate the market price and the contract quantity for each order. The method can be described in 4 steps as bellows:

1) sort all the bid and offer prices from the highest to the lowest.
2) calculate the aggregated sell and buy quantity for each price.
3) calculate the tradable quantity for each price as the minimum between the aggregated sell and buy quantity
4) select the price that correspond the maximum tradable quantity. If two or more prices have the same maximum tradable quantity, the price with the smallest surplus (aggregated sell/buy quantity) is selected.

Once the price and the total trade are individuated, the contract quantity for each player is calculated using the condition expressed by the winning conditions.
Figure 35 is a graphical representation of the sequential process results. The market price, which is a solution of the described algorithm, satisfies the condition to be the cross point between bids and offers curves.
The proposed method is a practical algorithm that can be easily implemented on a computer system.
Similar algorithms are implemented and performed daily in commodities and stocks exchanges.



Aggregated sell quantity	Price	Aggregated buy quantity	Tradable quantity
qs4	p1	qb1	min(qs4,qb1)
qs4	p2	qb1	min(qs4,qb1)
qs3	p3	qb1	min(qs3,qb1)
qs2	p4	qb2	min(qs2,qb2)
qs2	p5	qb2	min(qs2,qb2)
qs1	p6	qb2	min(qs2,qb2)
0	p7	qb3	min(0,qb3)

Figure 35: Market price calculation

5.2.2 Market splitting

One of the main differences between electricity and the other commodities is that electricity has to be transferred through transmission lines. The auction algorithm, described in the previous section, does not consider any constraints related with the transmission network. In reality, an order, in addition to the quantity, the price, includes also another important information: the location. From a power system point of view, the location of an order can be considered as:

the source point in case of a sell order
the sink point in case of a buy order.

It may happen that, the solution produced by the previous described algorithm may not respect some of the constraints on the transmission lines. In this case it is necessary to split the market in two sub-markets with different prices to ensure that the constraints are respected and the transmission lines are utilized optimally.
Figure 36 represents a simple example with 2 areas connected by a transmission line. In Area 1, a player offers a quantity of electricity equal to Q_{offer} at P_{offer} (offer price), in Area 2 a player bids a quantity of electricity equal to Q_{bid} at P_{bid}. The trade quantity is the minimum between Q_{offer} and Q_{bid} if the bid price is higher than the offer price, 0 otherwise. In this example the trade quantity between offer and bid corresponds to the power flowing between Area 1 and 2.
In formula:

$$Q_{trade} = Q_{flow} = \begin{cases} \min(Q_{bid}, Q_{offer}) & if \quad P_{bid} > P_{offer} \\ 0 \quad otherwise \end{cases}$$

If the trade quantity Q_{flow} is bigger than the transmission line capacity Q_{limit}, the solution is not acceptable from a transmission network point of view. In this case, the market has to be split in two sub-markets and the auction calculation performed again for each of them. As consequence of the market split the price in the area that is the exporting electricity (Area 1 in this case) has to be lower or equal to the market price without transmission constraint consideration, in a similar way the price in the area that is importing electricity will see a price higher or equal to the unconstrained market price.

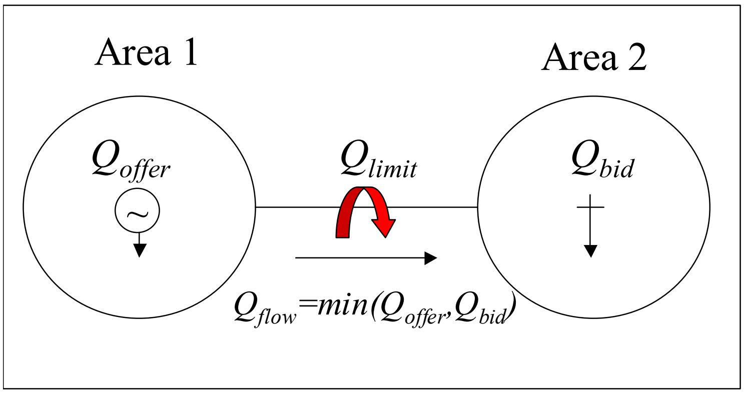


Figure 36: Congested market example

To ensure the best utilization of the transmission line, the concept of virtual offer and virtual bid is introduced.

A virtual offer is an offer at low price (lowest offer price in the auction – 0.1) and quantity equal to the Q_{limit}, located in the area that is importing electricity. A virtual bid is a bid at high price (highest bid price in the auction + 0.1) and quantity equal to Q_{limit}, located in the area that is exporting electricity. Figure 37 shows how the market may be split introducing virtual bid and offer.

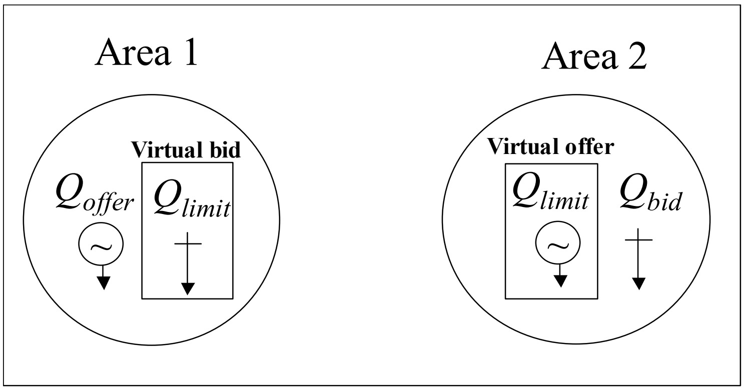


Figure 37: Market split

After the introduction of the virtual bid and the virtual offer, the two sub-markets, Area 1 and Area 2, are completely independent and the auction algorithm can be performed to calculate the market price and the total trade quantity for each of them.

As it is represented in Figure 38, since Q_{limit} is smaller than Q_{flow}, the price in Area 1 P_{area1} becomes lower than the market price before the market splitting P_{market}, on the contrary the price in Area 2 P_{area2} becomes higher.

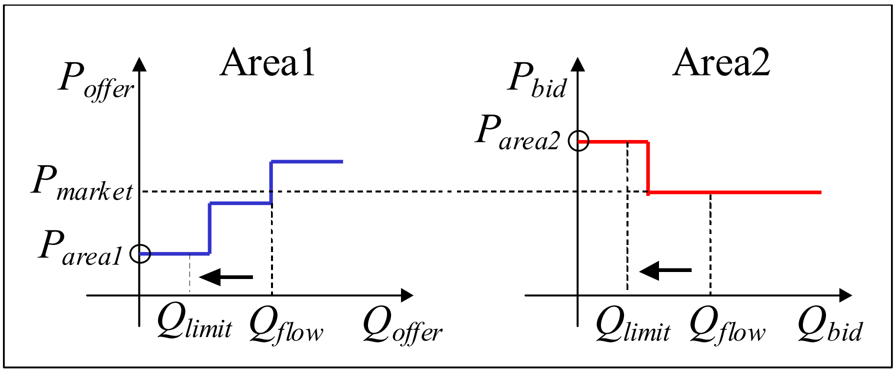


Figure 38: Prices in the areas

Once the auction algorithm described in the previous section is performed and the potential transaction quantity for each order is calculated, it is possible to calculate the net difference between satisfied sell orders and satisfied buy orders inside each area (net import or net export) with the following equation:

$$p_i = \sum_{sell} Q_{sell}^{satisfied} - \sum_{buy} Q_{buy}^{satisfied}$$

In case of radial networks, the flow on each transmission line can be easily calculated using the topology information and the quantities p_i.

5.2.3 Congested submarket identification

In the previous section, the market split concept was described for a market composed by two areas. In this case, it is easy to recognize the congested path and the location of the market split. The problem becomes more complex in case of 3 or more areas. Figure 39 is an example of market with 4 areas. It is not trivial to find the location of the market split that maximizes the trading quantity under the rules described in 5.2.1.

It seems that the interconnection between Area 2 and Area 3 is the most congested interconnection with an overflow of 115MW. In reality, solving the congestion on interconnections 1-2 and 4-2 will automatically relief the connection on interconnection 2-3 without any needs to split the market between Area 2 and Area 3.

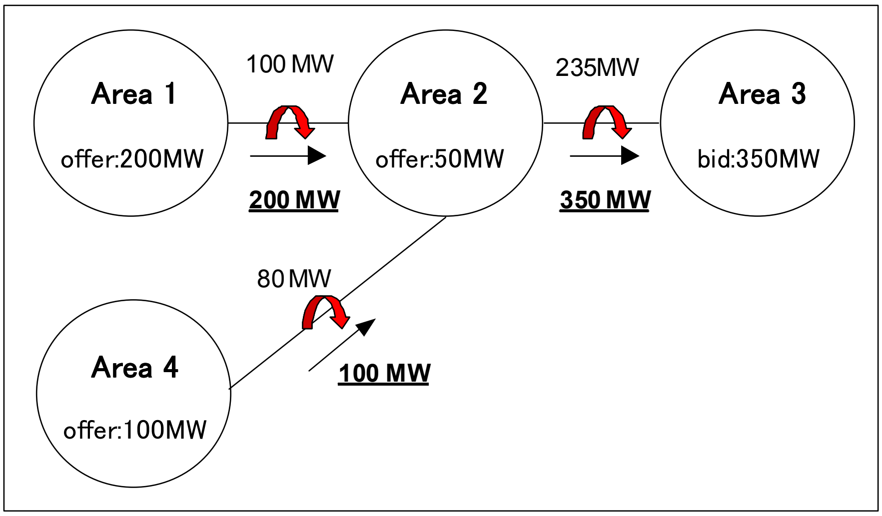


Figure 39: Market with 4 areas and 3 congested interconnections

To individuate the position of the splits, this research proposes an algorithm that is described in the next sections.

- *Area type identification*

First of all, I want to introduce the concept of import, export and neutral constrained area. For each area a parameter t_i (congestion index) is calculated.

$$t_i = p_i + \sum_j \min(Q_j^{limit}, Q_j^{flow}) - \sum_k \min(Q_k^{limit}, Q_k^{flow})$$

Where i is the index of the area, p_i is the net quantity of the area i previously described, j is the index for interconnection with flow with the direction to the area i and k is the index for interconnection with the flow from the area i, Q^{limit} is the maximum capacity of the interconnection in the direction of the flow and Q^{flow} is the quantity that will flow on the transmission line as result of the auction calculation without any constraint on the network.

An area is defined congested in export (E) if the congestion index t is bigger than 0, congested in import (I) if t is lower than 0 and neutral to the congestion (N) in case of t equal 0.

From the equation, it is easy to understand that an area defined as congested in export is an area for which the quantity of electricity that can import plus the net quantity of the area itself is bigger than the quantity that it can transfer or export to others area. Similarly for an import area, the net quantity of the area itself p_i summed to the quantity that may be transferred to other areas is lower than the quantity that it is able to import due to the transmission constraints. In Figure 40, examples of each kind of areas are described.

It can be demonstrated as consequence of the balance condition of the power system that if in a system, one or more areas are export area, then it exists at least one area that is an import one and vice versa (Appendix 2).

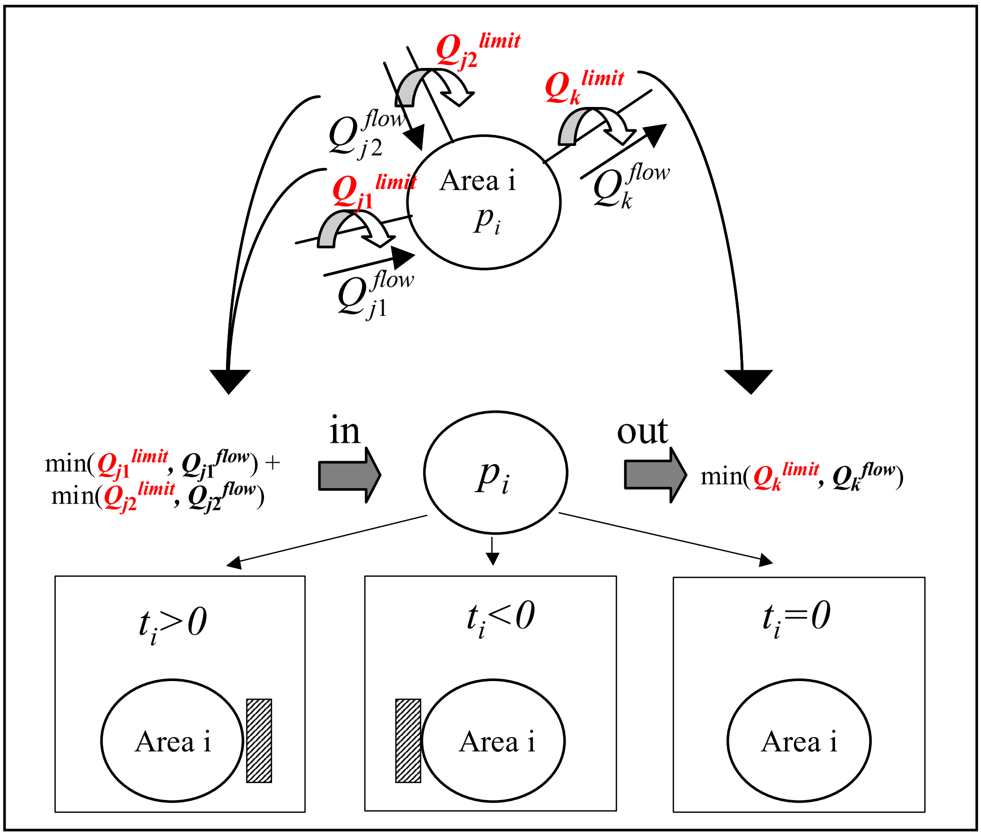


Figure 40: Representation of export, import and neutral areas

-System reduction and splitting rules

In the previous section, it was described the definition of areas as import, export and neutral. In this section the rules for splitting are introduced. Two area interconnected by the same line should be split in two separated markets if and only if the area which is transferring electricity to the other area is an export constrained area and the area which is receiving electricity is an import area.

The rule can be explained intuitively with the help of a graphical support. In Figure 41, all the possible combination of areas as node of the same interconnection is described. An import area is represented with a round mark and a barrier on the left that means the impossibility to get all the electricity required, an export area by a round mark and barrier on the right that means the impossibility to transfer all electricity that is required. A neutral area does not have any barrier. The arrow between the areas represents the direction of the power flow on the interconnection line. From the figure it can be said that in the case of Export-Import combination, the split of the two areas in two market will has as consequence a reduction of the power flowing between the two areas. The export area will then export less power and the import area, import less power reducing, in this way the congestion condition of both the two areas; in any other case in Figure 41, the split of the two areas will not be of benefit for both or neither for one of the area (for example in the import-export combination).

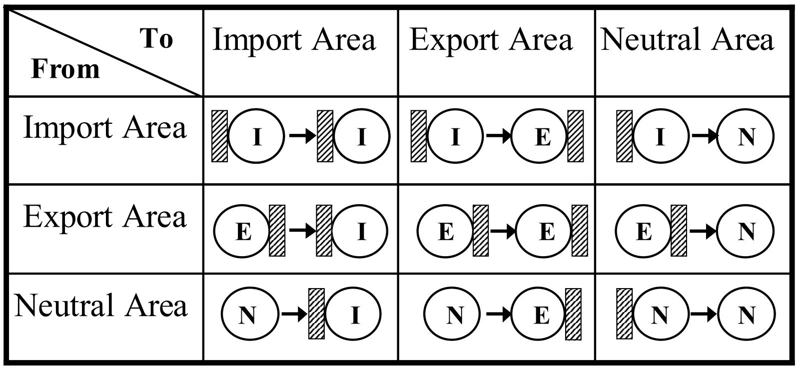


Figure 41: The matrix of the splitting rules

It is possible to demonstrate mathematical that splitting combination of import-export, import-import or export-export may cause an increase of system congestion and an inversion of prices (an area exporting electricity may have a market price higher than an area importing electricity) in case of radial network (Appendix 2).

A system reduction algorithm is introduced with the objective to recognize easily the location of the export-import interconnection that has to be split.

For each interconnection in the system, if the areas that delimitated the interconnection are of the same kind, they will be merged in one area. A neutral area has to be merged with an export area if it is connected with one export area, otherwise it can be merged with an import area.

In Figure 42, the example of Figure 39 is reduced to a simple system. The connected areas 2 and 3, both import areas, are merged in a new area 2+3. After the merging the system is reduced in a 3 areas one with 2 interconnection of type export-import.

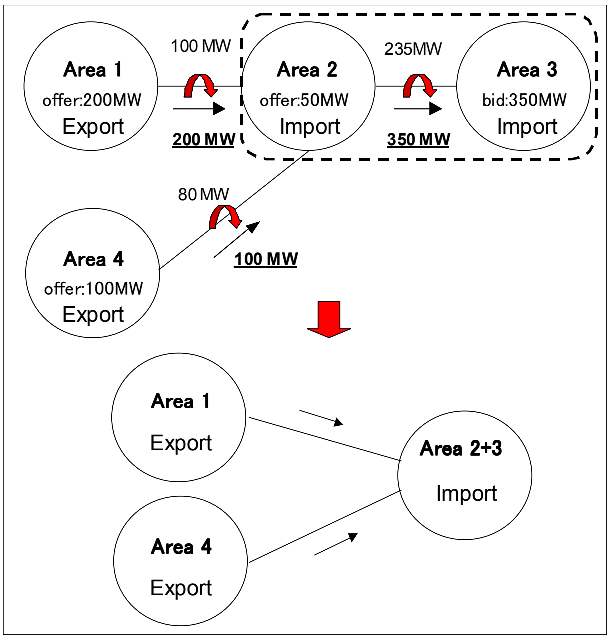


Figure 42: Example of system reduction

-Loops Transformation

In the previous section the identification of the congested area was described. The method is applicable only for radial network. In case of loops it is necessary to transform the topology in an equivalent radial network. For loops composed by 3 areas and at least one DC interconnection it is possible to utilize a delta-star transformation with the introduction of a virtual area in the center of the star. Figure 43 is an example of transformation. The capacity of each interconnection line in the star configuration is equal to the sum of capacity of the line of the area itself. Similarly, the power flow can be calculated as the sum of the power flow on each line.

The virtual area is an area with net power production equal 0. Since it is assumed that at least on of the interconnection is a DC connection, the power flow of the loop can be solved without the introduction of the induction matrix but introducing a standard rule. In this thesis, we assume that the DC connection has a priority respect to the other interconnections in the loop.

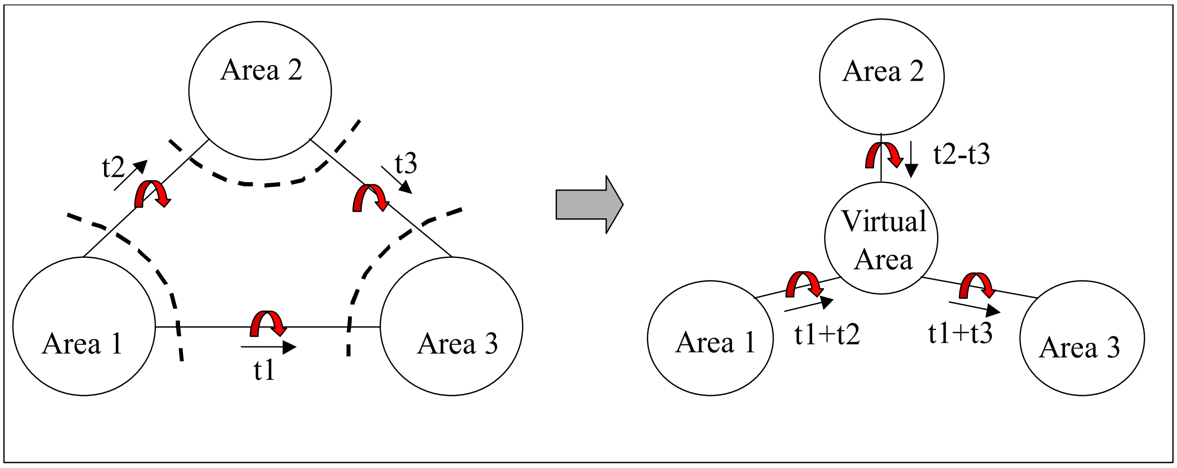


Figure 43: Delta-Star transformation

In other world, the loop power flow is calculated maximizing the power flow on the DC transmission line.

The assumption to have only loops with at least one DC transmission is consistent with the Japanese network topology.

5.2.4 Application to a small system

In this section an example of application to a system with 5 areas, 5 interconnections and 9 players is presented.

The network configuration and the player orders are shown in Figure 44. An order with a positive quantity is an offer (sell order); a negative quantity is associated to a bid (buy order).

Cheap electricity is offered from area 1 and 2, and the buyers are mainly located in area 4 and 5. The line between area 3 and 4 is a DC interconnection.

In Table 7, the sort of the order based on the price and the system solution without network constraints is presented. The tradable quantity is maximized for a system price of 8.5 and the associated total tradable quantity is 650 MW.

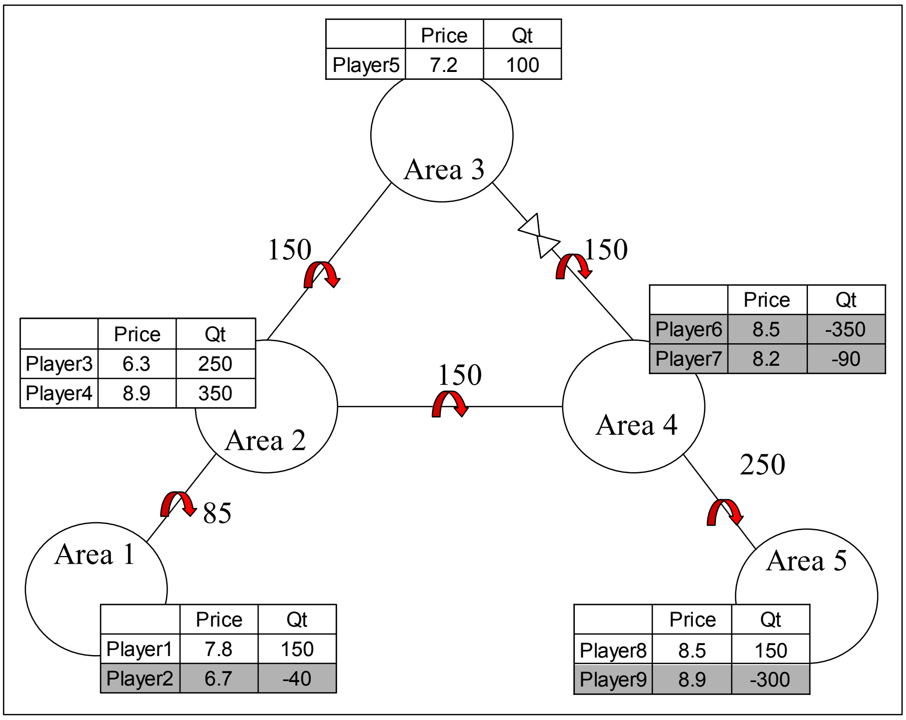


Figure 44: Example system

Table 7: Market solution without network constraints

Aggregated sell	Sell	Price	Buy	Aggregated buy	Tradable quantity
1000	350	8.9	300	300	300
650	150	8.5	350	650	650
500		8.2	90	740	400
500		8		740	400
500	150	7.8		740	400
350	100	7.2		740	150
250		6.7	40	780	150
250	250	6.3		780	150

Based on the system price of 8.5 it is possible to calculate the trading quantity for each player. Players 1, 3, 5 and 8 offered electricity at a price lower than the market price, for this reason, they are able to sell electricity, player 4 offered at 8.9 a price higher than the market price, for this reason the tradable quantity is 0.

The solution of the power flow calculation associated with the market price equal 8.5 and the total tradable quantity of 650 MW is graphically described in Figure 45. A large quantity of electricity is exported by area 1 and 2 to area 4 and 5. In addition of the power flow data, Figure 45 shows the tradable quantity for each player.

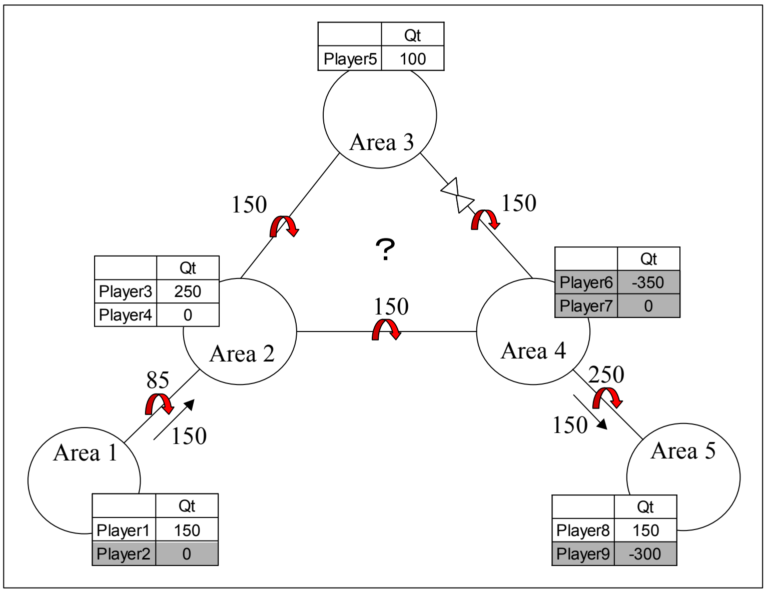


Figure 45: Power Flow

The power flowing on lines 2-3, 3-4 and 2-4 cannot be determinate. Utilizing the delta-star transformation the system can be modeled as in Figure 46. As consequence of the transformation a new area, the virtual area V is introduced.

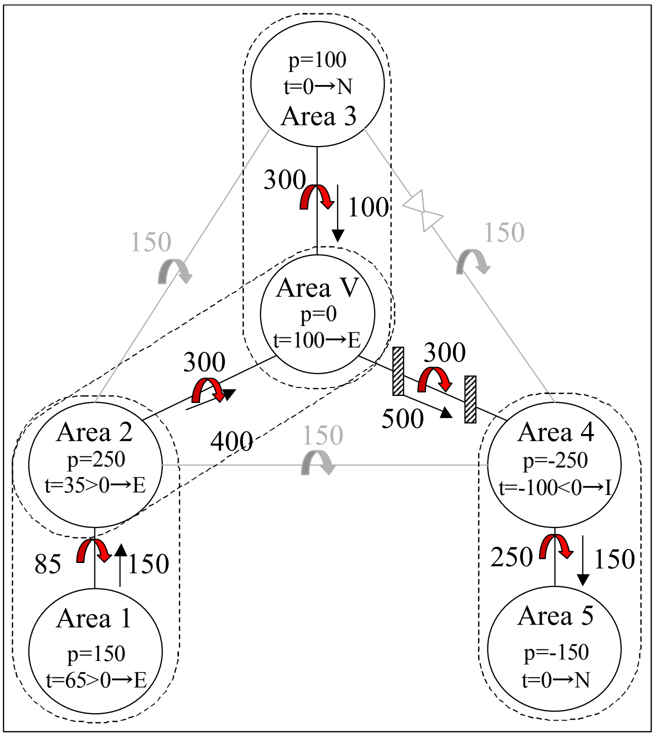


Figure 46: Area types and system reduction

After calculating the area type and reducing the system it is evident that Area 1, 2, 3 and the virtual area can be reduced in an export congested area and area 4 and 5 in an import congested area. The system can be then divided in 2 submarkets, the first composed by area 1, 2 and 3, the second by area 4 and 5. To divide the submarket is necessary to introduce the virtual offers and bids. In area 2 a virtual bid of 150 MW and price of 9 is introduced, similarly in area 3 a virtual bid of 150 MW and the price of 9 is build. A virtual offer of 300 MW is introduced in area 4. The 2 submarkets can now be solved independently using the algorithm described in 5.2.1. The final market solution with the price for each area and the trade quantity for each player is described in Figure 47.

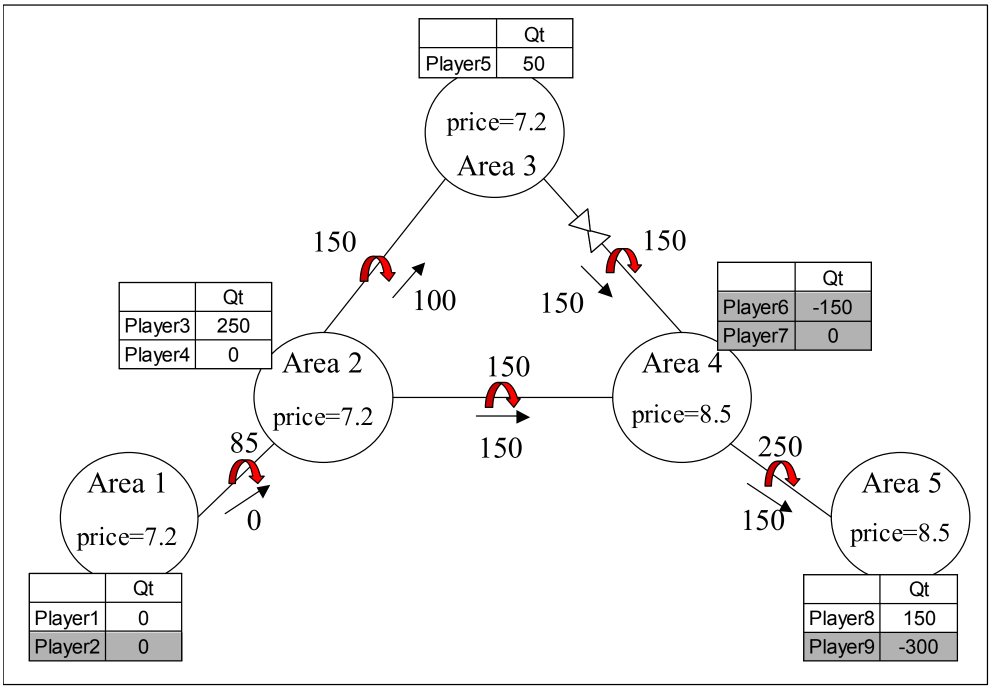


Figure 47: Final solution

As consequence on the congestion area 1, 2 and 3 have a low price of 7.2, all the players in those areas buy and sell electricity at the same price 7.2. Area 4 and 5 sow a higher price 8.5. Because of the congestion on the loop player 6 is not able to buy all the quantity that he was asking, and player 1 is not selling electricity. The transmission capacity of lines 2-4 and 3-4 is utilized completely, other lines only partially. In particular I would like to point out how the congestion on line 1-2 that was present in the first solution without constraints is automatically relieved by the split of the 2 submarkets.

In this example with few areas only one split was enough to solve the market; in general, depending from the complexity of the system, it may happen that in the submarkets created after the split, some lines are still congested. In these cases it is necessary to apply the same algorithm to the submarket and to divide it in other submarket until when all the transmission congestion are not cleared.

5.2.5 Application to the Japanese market

The proposed congestion management algorithm was tested on a full-scale model for the Japanese market. It was assume that 50 players compete in the market. This assumption is quite closed to the actual players of the Japanese Exchange; at the current moment 36 players are active in JEPX. The network model is developed based on the information available on the ESCJ site. The nine control areas, in which Japan is divided, are connected with ten transmission lines. East and west Japan are connected with a frequency change asset. Three inter-ties are direct current transmission lines.

The available capacity of each interconnection is sized based on the total size on the interconnection. The bids are create randomly and do not contain any strategies or players information. Figure 48 is a graphic representation of the assumed model.

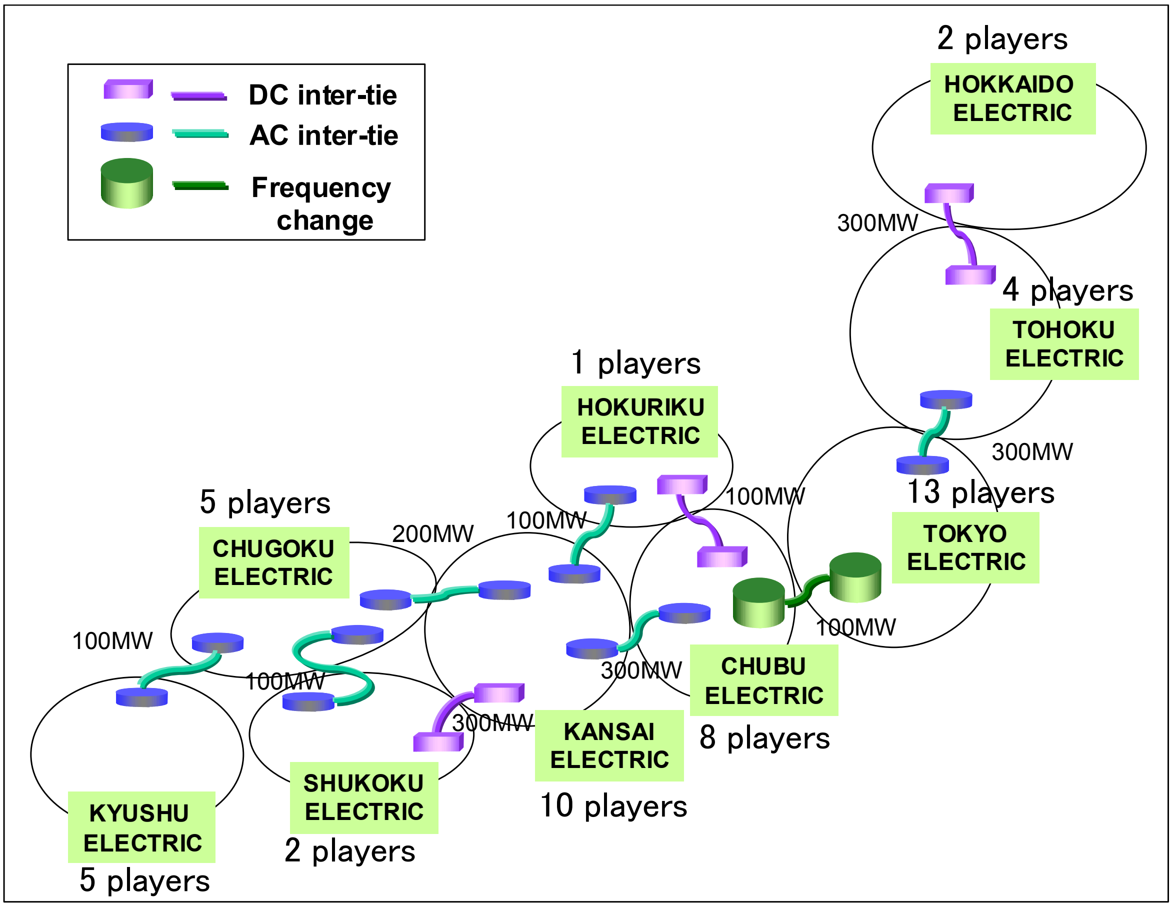


Figure 48: Japanese Market Model

Following the process previously described, first the market is cleared without considering the transmission network constraints. The solution of this first step produce the system marginal price, the trading quantity for each player and the power flow on each transmission line. In Figure 49 the solution of the first step is presented. Loops with three nodes are modified in radial network with the delta-start transformation.

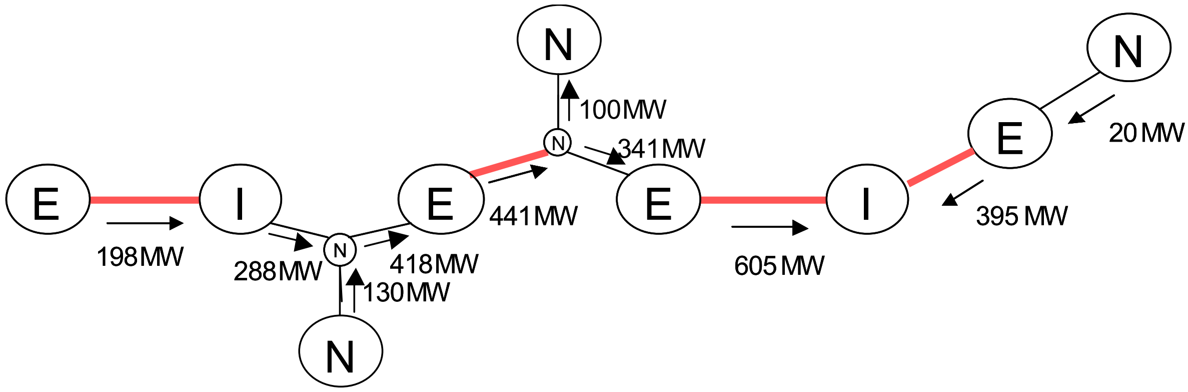


Figure 49: Solution without transmission constraints

The system marginal price if 10¥/kWh and it produce a large flow from west and north to Tokyo causing congestion on almost all the interconnections. Congested transmission interconnections are represented with a red line in Figure 49.

In the next step, it is necessary to reduce the system to individuate the E-I combination that has to be split. Following the rules previously described, Hokkaido and Tohoku area are reduce in a single area of type E, and similarly Shikoku is integrated with Kansai and Hokuriku with Chubu. The group Kansai- Shikoku is then integrated with the group Chubu-Hokuriku forming an area of type E, Chugoku can now be integrated in the group Hokuriku-Kansai-Shikoku-Chubu since an I-E connection is produced. The new area is an E type and can be integrated with Kyushu. As result, the total system is reduced in three main areas: Hokkaido-Tohoku, Tokyo and the West as represented in Figure 50. Following the algorithm proposed in this thesis, it is necessary to split the market in three submarkets: one for the north, one for the west and one for Tokyo.

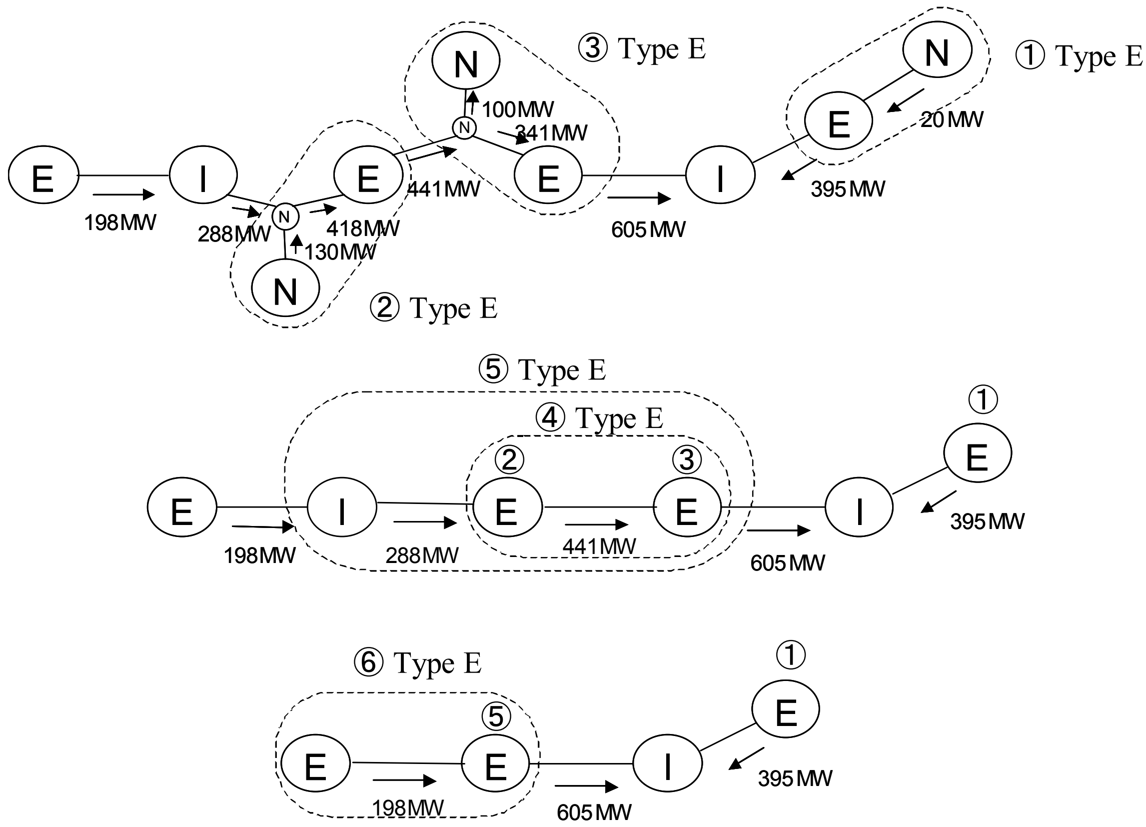


Figure 50: System reduction

At this point, it is possible to solve the auction for each submarket in which the original market was divided after the introduction of the virtual bids. Figure 51 represents the final market solution.

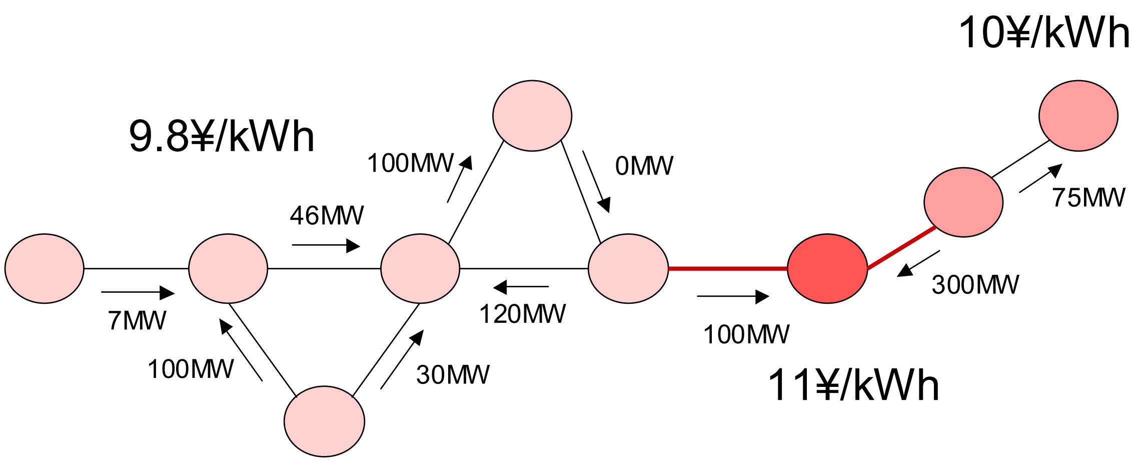


Figure 51: Final solution

Tokyo shows the highest market price at 11¥/kWh, the west part of Japan has the lowest market price at 9.8 ¥/kWh. The congestion is relived in all the transmission lines.

5.2.6 Tests and performance

To describe the algorithm process, simple examples were introduced in the previous section.
In practice, the algorithm has to be utilized for larger systems with several areas and thousands of orders. A test system with 16 areas, 15 interconnection and 80,000 of orders was developed. The algorithm was translated in a Fortran program and the program was performed on the test system to prove the performances. Using an Itanium 1GHz CPU, the calculation terminated in 0.01 sec.

5.3 Conclusions

The transmission congestion problem for forward market and spot market was approached. The objective is to find a method that at the same time inform the participant about the congestion condition with strong price signal and ensure the optimal utilization of the transmission network. Introducing the concept of area and submarkets, the market split is implemented for both forward market and spot market. In the forward market, a sequential auction algorithm is implemented; the spot market is cleared with a single auction mechanism.

To improve the calculation performance, a novel algorithm that determined the congested areas and the necessary submarket is proposed. Tests show the high performances of the proposed method.

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Chapter 6 Conclusions

The research developed in this thesis has proposed practical solutions for the deregulated market. The thesis focused on three main problems, which are consequence of the liberalization of the electricity industry; the first one is the strategic biding of market players, the second one is the scheduling problem for PPS in a multi-area system, the third one is how to manage the transmission congestion in spot and forward market.

After an analysis of the market structures and market rules that are implemented worldwide it was clear that the introduction of deregulation changed the role of players and the relation between them; nevertheless the rules that govern the electricity are the same. For this reason this thesis evaluated the basic planning tools for power system as unit commitment and optimal power flow and applied them with the appropriated variation to the new environment.

The unit commitment problem is a complex mixed-integer non-linear problem in which the schedule of the available generating unit is decided. It has a long history and several techniques were applied in the past. This thesis proposed the decommissioning approach (a combination of dynamic programming and quadratic programming); the proposed method is fast and produces always a feasible solution. Based on the unit-commitment decommissioning algorithm, this thesis approached the bid development problems. With the same algorithm it is possible to build cost base bid, price base bid and multi-products multi-market bids depending of the needs of the market player that utilize it. With the proposed tools, market participants are able to develop an optimal strategy based on their particular needs and position in the market.

This thesis proposes also another application of the unit commitment algorithm. After investigating the position of PPS in the Japanese market, it was clear that the PPS scheduling process was different from the utilities one. PPS had the possibility to send electricity in several control areas from the same generating units, nevertheless different wheeling fees and losses were applied depending on the receiving area. A model to optimize the schedule under these conditions is developed.

To develop a price base bid, it is indispensable to forecast the market price for the biding time frame. For this reason, this thesis proposes a neural network algorithm to forecast the market price. After a deep analysis of the correlation of the market price and other factors such as the power demand, the fuel price and so on, it was clear that the peak demand was the key parameter that influences the market price. The thesis proposes a forecasting method that integrates both the demand forecasting and the price forecasting. For both the calculations, a three layer neural network is implemented.

Several countries adopted an optimal power flow based approach to the transmission congestion problem, PJM and all the other markets that implemented a nodal (or locational

marginal) price, decided to base the market price on the optimal power flow calculation with several simplification. Japan follows another path. Since the Japanese transmission network is particular strong inside the control areas (there is no congestion problems) but week in the interconnections among control areas, it was simpler to use a market split approach to the congestion problem. This thesis develops an algorithm to calculate the market solution based on the market split theory. The algorithm has the advantage to ensure an optimal solution without using linear programming or other time consuming calculation. The algorithm is deployed in the current JEPX and is utilized daily.
Starting from the concept of market split usual implemented for spot markets (single auction market), this thesis extend the concept to the forward market and continuous auction proposing a method to inform market participants about congestion problems not only in the spot market but also in the forward market. To check the efficiency of the method, a simulation platform was developed and several simulations with professionals in the electric field were done.

Future researches should be done to solve problems still open; in particular the environmental problem was not approached in this thesis but it is possible to forecast that in the near future emission constraints will influence the generation business in the long and short term prospective. The green house gas emission constraints have to be integrated in the unit commitment in general and in the bid strategy development in particular to obtain a generation dispatch that minimize not only the production cost but also the environment impact.
In addition, this thesis focuses mainly on the wholesale and the generation side of the market, nevertheless retail and demand side have also a fundamental role in the price driving and transmission congestion. Demand side bid strategies development and demand schedule are subjects that should be investigated in the future.
The proposed approach for strategic bidding is a deterministic one. Nevertheless, a generation company may need to evaluate the risk and, in some case, to minimize the risk associate with a strategic bidding. A stochastic approach to the strategic bidding may be developed in the future.

To conclude I would like to stress once again on the five main points that this thesis propose:

1) A neural network method to forecast the market spot price. The strength of the method comes from the integration of the forecasting of the day-ahead peak electricity demand in the algorithm.

2) A unit commitment base approach to the optimal strategic bid that allowed the player to develop a price base bid or a cost base bid or a multi-products multi markets bid depending of the market condition and the position of the player itself

3) An application of the unit commitment method to the Japanese PPS scheduling problem. To ensure an optimal utilization of the resources a multi-area approach that considers losses, transmission constraints and wheeling fees was developed.

4) A transmission congestion method for electricity forward market, based on the concept of hubs and price difference among hubs, which produces an efficient market signal for market participants.

5) A market split base congestion management algorithm for spot market that ensure an optimal market solution and high calculation time performances. The algorithm is based on an algebraic formulation and can be applied to radial or loops networks.

Appendix 1 The DC power flow

In the congestion management chapter, it was assumed that a simple calculation could be performed to calculate the power flow on each line in the network once that the injection and the extraction quantities at each node are given.
In reality, the situation is more complex and several approximations have to be introduced to obtain a simple algebraic relation between injection and power flow. It was considered that the so-called DC approximation could be considered consistent with the needs of the market: a power flow solution that respects the reality but at the same time can be performed in few milliseconds.

General formulation

The real power flowing from node 1 to node 2 along line *i* is given by:

$$z_{12} = G_i\left(V_1^2 - V_1 \cdot V_2 \cdot \cos(\delta_1 - \delta_2)\right) + \Omega_i \cdot V_1 \cdot V_2 \cdot \sin(\delta_1 - \delta_2)$$

, where

$$G_i = \frac{R_i}{R_i^2 + X_i^2}$$

$$\Omega_i = \frac{X_i}{R_i^2 + X_i^2}$$

R_i = line resistance
X_i = line reactance
V_1 and V_2 = voltage magnitude at node 1 and 2 respectively
δ_1 and δ_2 = voltage phase at node 1 and 2 respectively
If it is assumed that the phase difference between nodes is small and the voltage at each node is close to 1 in a per unit system, it is possible to reduce to a simplified form.

$$z_{12} = \Omega_i \cdot (\delta_1 - \delta_2)$$

since

$$\cos(\delta_1 - \delta_2) \approx 1$$
$$\sin(\delta_1 - \delta_2) \approx (\delta_1 - \delta_2)$$

Lines flow and bus injection function

The power flow has to respect the balance equation of energy. For each node the total injection minus the total extraction has to be equal zero.

$$\underline{y} = \underline{A}^T \cdot \underline{z}$$

,where

$\underline{y}$ = vector of bus injection

$\underline{A}$ = topology matrix that connect node and lines (elements are 0, 1,-1)

$\underline{z}$ = vector of line flow

Appling the approximation introduced in the previous section, it is possible rewrite the balance equation as follow:

$$\underline{y} = \underline{A^T} \cdot \underline{\Omega} \cdot \underline{A} \cdot \underline{\delta}$$

,where

$$\underline{z} = \underline{\Omega} \cdot \underline{A} \cdot \underline{\delta}$$

Solving for δ and rewriting the power flow as function of the system injection y:

$$\underline{z} = \underline{H} \cdot \underline{y}$$

,where

$$\underline{H} = \underline{\Omega} \cdot \underline{A}\left(\underline{A}^T \cdot \underline{\Omega} \cdot \underline{A}\right)^{-1}$$

H is called the transfer admittance matrix.

Some consideration

The assumption of small difference of phases between nodes has a strong impact on the problem formulation. It is evident that as consequence of the formulation the lines are considered as lossless.

Some author propose to approximate the losses as function of the resistance and the square of the power flow:

$$\cos(\delta_1 - \delta_2) \approx 1 - \frac{(\delta_1 - \delta_2)^2}{2}$$

$$\underline{L} = \underline{z}^T \cdot \underline{R} \cdot \underline{z}$$

Integrating this equation in the power flow one it is possible to rewrite H including the losses part.

$$\underline{H} = \underline{R}^{-1} \cdot \underline{A} \cdot \left(\underline{A}^T \cdot \underline{\Omega} \cdot \underline{A}\right)^{-1} \cdot \underline{A}^T \cdot \underline{\Omega} \cdot \underline{R} \cdot \underline{\Omega} \cdot \underline{A}\left(\underline{A}^T \cdot \underline{\Omega} \cdot \underline{A}\right)^{-1}$$

The assumption may still have a strong effect in particular in low voltage network where phase difference is not so small. For this thesis objective, in which we are applying the power flow calculation for a high voltage transmission network with an approximated topology, the assumptions are completely consistent.

Appendix 2 Demonstrations

In section 5.2 it was affirmed that the existence of an export area in system ensures the existence of at least and import area and vice versa. It was also affirmed that split the market between two export areas is not producing a decrees of congestion. In this appendix these two affirmations are demonstrated.

Theorem 1

If in a system there is an export node, in the same system one or more import node exists.

Demonstration:

Let suppose that area *m* is an export one, for the definition of export area:

$$P_m + \sum_{j=1}^{n} \min\left(Q^{limit}{}_{m\to j}, Q^{flow}{}_{m\to j}\right) > 0$$

,where n is the total number of areas in the system.

For the reciprocity of the power flow on a line:

$$\min\left(Q^{limit}{}_{i\to j}, Q^{flow}{}_{i\to j}\right) = -\min\left(Q^{limit}{}_{j\to i}, Q^{flow}{}_{j\to i}\right)$$

The power balance of the system implicate that:

$$\sum_{i=1}^{n} P_i = 0$$

It is possible to integrate the reciprocity equation and the balance equation in:

$$\sum_{i=1}^{n} P_i + \sum_{i=1}^{n}\sum_{j=1}^{n} \min\left(Q^{limit}{}_{i\to j}, Q^{flow}{}_{i\to j}\right) = 0$$

and rewrite it as:

$$\sum_{i=1}^{n}\left(P_i + \sum_{j=1}^{n} \min\left(Q^{limit}{}_{i\to j}, Q^{flow}{}_{i\to j}\right)\right) = 0$$

If one of the terms of the equation is bigger than 0 in value as it was supposed under the condition of the existence of an export area then at least one term has to be lower than 0 to satisfy the equation. This implicates that exist at least a area k for which the flowing equation is respected.

$$P_k + \sum_{j=1}^{n} \min\left(T_{k\to j}, F_{k\to j}\right) < 0$$

Since the equation corresponds to the definition of import area, it was demonstrated that the existence of an export area in a system implicates the existence of one or more import areas.

Theorem 2

If in a system an export node, is connected to another export node the relief of the congestion on the connecting branch will not relief the congestion on the other branch connected to the node.

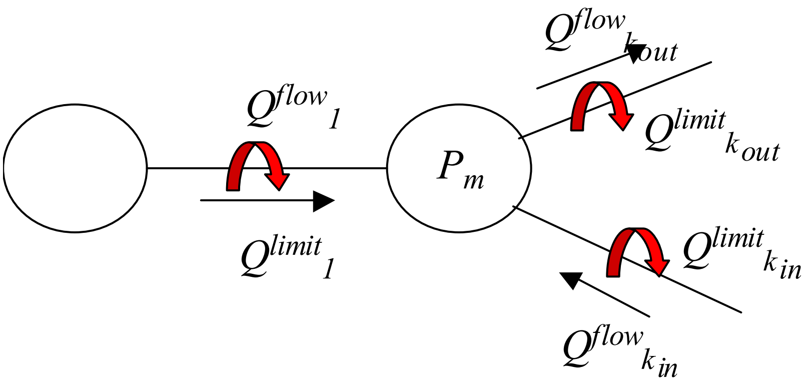

Figure 52: Variable definition

Demonstration:

Let's considered the area *m* to be an export node and line 1 is congested. For the definition it can be affirm that:

$$P_m + Q^{limit}{}_1 + \sum_{k_{in}} Q^{limit}{}_{k_{in}} - \sum_{k_{out}} Q^{limit}{}_{k_{out}} > 0$$

for the balance condition at the area:

$$P_m + Q^{flow}{}_1 + \sum_{k_{in}} Q^{flow}{}_{k_{in}} - \sum_{k_{out}} Q^{flow}{}_{k_{out}} = 0$$

To relief the congestion on line 1 the power flowing on it has to be reduce to the limit capacity, in formula

$$\tilde{Q}^{flow}{}_1 = Q^{limit}{}_1$$

It is possible now to rewrite the balance condition as:

$$\tilde{P}_m + Q^{limit}{}_1 + \sum_{k_{in}} \tilde{Q}^{flow}_{k_{in}} - \sum_{k_{out}} \tilde{Q}^{flow}{}_{k_{out}} = 0 \rightarrow \tilde{P}_m + Q^{limit}{}_1 = \sum_{k_{in}} \tilde{Q}^{flow}_{k_{in}} - \sum_{k_{out}} \tilde{Q}^{flow}{}_{k_{out}}$$

Since the quantity flowing from line 1 in area *m* decrease due to the transmission congestion, the quantity dispatched inside the area increases.

$$\tilde{P}_m \geq P_m$$

As consequence it can be affirmed that

$$\tilde{P}_m + Q^{limit}{}_1 + \sum_{k_{in}} Q^{limit}{}_{k_{in}} - \sum_{k_{out}} Q^{limit}{}_{k_{out}} > 0$$

Integrating the balance condition and the above equation:

$$\sum_{k_{out}} \widetilde{Q}^{flow}{}_{k_{out}} - \sum_{k_{in}} \widetilde{Q}^{flow}_{k_{in}} > \sum_{k_{out}} Q^{limit}{}_{k_{out}} - \sum_{k_{in}} Q^{limit}_{k_{in}}$$

The equation can be rewritten as follow:

$$\sum_{k_{out}} \left(\widetilde{Q}^{flow}{}_{k_{out}} - Q^{limit}{}_{k_{out}} \right) > \sum_{k_{in}} \left(\widetilde{Q}^{flow}{}_{k_{in}} - Q^{limit}{}_{k_{in}} \right)$$

Similarly to the previous assumption about the production in the area, it is possible to affirm that the import is also increase

$$\widetilde{Q}^{flow}_{k_{in}} \geq Q^{flow}_{k_{in}}$$

As consequence

$$\widetilde{Q}^{flow}_{k_{in}} - Q^{limit}_{k_{in}} \geq 0$$

This implicate that

$$\sum_{k_{out}} \left(\widetilde{Q}^{flow}_{k_{out}} - Q^{limt}{}_{k_{out}} \right) > 0$$

but this implicates that there is at least a line *k* that is congested in the direction out of area m.

It was prove that the splitting two export areas in two independent submarkets implicate an increasing of congestion on lines with flow out of the areas itself.

Appendix 3 Data for Market simulation

Bid data utilized in chapter 5 are described in Table 8. Quantities are expressed in MWh/h and price in ¥/kWh. Negative quantities are associated to a buy bid positive to a sell bid.

Table 8: Bid Data

	block 1		block 2		block 3	
	price	quantity	price	quantity	price	quantity
Hokkaido 1	10	100	11.5	124	12	140
Hokkaido 2	9	−130	10	−80	11	50
Tohoku 1	9	100	9.8	115	10.1	140
Tohoku 2	8.6	−100	9	−50	10	−10
Tohoku 3	8.7	50	9	130	9.8	170
Tohoku 4	9.3	85	9.7	95	9.9	100
Tokyo 1	9.5	−200	9.7	−180	10	−150
Tokyo 2	9.9	−200	10.1	−150	10.3	−40
Tokyo 3	11	−200	11.2	−50	11.8	−20
Tokyo 4	10.8	100	11.3	130	12	180
Tokyo 5	10	115	13	170	15	200
Tokyo 6	10	−130	10.8	−100	11.3	−90
Tokyo 7	12	−147	13	−100	15	−90
Tokyo 8	11	200	12	250	12.3	300
Tokyo 9	14	−100	14.2	−80	14.3	−70
Tokyo 10	9.8	−100	10.2	−98	12	130
Tokyo 11	14	100	14.3	140	14.8	180
Tokyo 12	12	−140	13	−100	13.2	−50
Tokyo 13	13	100	13.5	150	13.8	200
Chubu 1	9	100	10	124	11	140
Chubu 2	9	−130	10	−80	11	50
Chubu 3	8	100	8.8	115	9.1	140
Chubu 4	8.6	−100	9	−50	10	−10
Chubu 5	8	50	8.7	130	8.8	170
Chubu 6	9	85	9.2	95	9.5	100
Chubu 7	9.5	−200	9.7	−130	10	−100
Chubu 8	9.9	−100	10.1	−80	10.3	−40
Hokuriku 1	11	−100	11.2	−50	11.8	−20
Kansai 1	9.8	100	10.4	130	10.6	180
Kansai 2	8	115	10	170	11	200
Kansai 3	10	−130	10.8	−100	11.3	−90
Kansai 4	11	−117	12	−100	13	−90
Kansai 5	11	200	12	250	12.3	300
Kansai 6	14	−100	14.2	−80	14.3	−70
Kansai 7	8.8	−100	9.8	80	11	130
Kansai 8	14	100	14.3	140	14.8	180
Kansai 9	9	100	10.5	124	11	140
Kansai 10	9	−130	10	−80	11	50
Shikoku 1	8.5	100	8.8	115	9.1	140
Shikoku 2	8.6	−100	9	−50	10	−10
Chugoku 1	8.7	50	9	130	9.8	170
Chugoku 2	9.3	85	9.7	95	9.9	100
Chugoku 3	9.5	−200	9.7	−130	9.8	−100
Chugoku 4	9.9	−100	10.1	−80	10.3	−40
Chugoku 5	10	−100	10.2	−50	10.8	−20
Kyushu 1	9.8	100	10.5	130	11	180
Kyushu 2	9	115	12	170	13	200
Kyushu 3	9.4	−130	10	−100	11	−90
Kyushu 4	11	−117	12	−100	13	−90
Kyushu 5	9.8	200	11	250	11.3	300

The data are processed as described in chapter 5 and the solution for each player is described in Table 9. It is clear as due to the transmission constraints, the position of several players change drastically from the solution without congestion to the solution with congestion.

Table 9: Trading Result for each player

	Solution without transmission limits		Solution with transmission limits	
	Quantity	Price	Quantity	Price
Hokkaido 1	100	10	5	10
Hokkaido 2	-80	10	-80	10
Tohoku 1	115	10	115	10
Tohoku 2	-10	10	-10	10
Tohoku 3	170	10	170	10
Tohoku 4	100	10	100	10
Tokyo 1	-150	10	0	11
Tokyo 2	-150	10	0	11
Tokyo 3	-200	10	-200	11
Tokyo 4	0	10	100	11
Tokyo 5	115	10	115	11
Tokyo 6	-130	10	-90	11
Tokyo 7	-147	10	-147	11
Tokyo 8	0	10	62	11
Tokyo 9	-100	10	-100	11
Tokyo 10	-98	10	0	11
Tokyo 11	0	10	0	11
Tokyo 12	-140	10	-140	11
Tokyo 13	0	10	0	11
Chubu 1	124	10	100	9.8
Chubu 2	-80	10	-80	9.8
Chubu 3	140	10	140	9.8
Chubu 4	-10	10	-10	9.8
Chubu 5	170	10	170	9.8
Chubu 6	100	10	100	9.8
Chubu 7	-100	10	-100	9.8
Chubu 8	-80	10	-100	9.8
Hokuriku 1	-100	10	-100	9.8
Kansai 1	100	10	65	9.8
Kansai 2	170	10	115	9.8
Kansai 3	-130	10	-130	9.8
Kansai 4	-117	10	-117	9.8
Kansai 5	0	10	0	9.8
Kansai 6	-100	10	-100	9.8
Kansai 7	80	10	51	9.8
Kansai 8	0	10	0	9.8
Kansai 9	100	10	100	9.8
Kansai 10	-80	10	-80	9.8
Shikoku 1	140	10	140	9.8
Shikoku 2	-10	10	-10	9.8
Chugoku 1	170	10	144	9.8
Chugoku 2	100	10	95	9.8
Chugoku 3	0	10	-100	9.8
Chugoku 4	-80	10	-100	9.8
Chugoku 5	-100	10	-100	9.8
Kyushu 1	100	10	36	9.8
Kyushu 2	115	10	115	9.8
Kyushu 3	-100	10	-100	9.8
Kyushu 4	-117	10	-117	9.8
Kyushu 5	200	10	73	9.8

It is possible to see that because of the congestion, the sold quantity in the west part decries and the bought increase.

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