

Chapter 2

Electricity Markets

This chapter presents the main properties of electricity, the microstructures of the electricity market and introduces the derivatives which are specific to this market. Regarding electricity's properties, I focus only on those that have a direct consequence on pricing and trading. The fact that electricity cannot be stored cannot be understated. In the same line, the constraints on its transport make electricity a local commodity. There is no such thing as an international homogeneous electricity market or even a regional electricity market on the scales of Europe or the United States as is the case for gas markets. There are at least as many electricity markets as there are countries in the world. It is thus not possible to enter into the details of each country's specific electricity market. Here, I deal only with the most common features of their structure. Further, I introduce some of the most specific derivatives of electricity markets by presenting the context, objective, and constraints of the electricity utilities whether they are large or small, or whether they hold generation assets or are purely retailers.

2.1 Electricity Features

All commodities exhibit technical features that make them unique. For example, trading live cattle on the Chicago Board of Trade (CBOT) might be as technical as trading electricity. But, electricity presents two main characteristics that raise both theoretical and practical problems:

1. electricity cannot be stored,
2. the transport of electricity satisfies specific laws.

2.1.1 Storage

The fact that electricity cannot be stored is sometimes tempered by using the expression that it cannot be stored at reasonable cost. In fact, because electricity

consumption is a continuous phenomenon, they exist both an energy problem and a capacity problem, that is, the pace at which energy can be released.

Regarding energy, the most economical way to store a large amount of energy for electricity generation is still hydroelectric reservoirs. Nevertheless, this is not a universal solution because it relies on the hydroelectric potential of a country. For instance, in a country like France where the hydroelectric potential was developed over the 1950s to the 1970s, it now represents 25 GW of installed capacity of a total installed capacity of 110 GW. Hydroelectric generation represents 15 % of the total generation, and its energy storage capacity is around 10 TWh as compared to an annual consumption of 500 TWh. Moreover, its availability depends on inflows coming from precipitation. Contrary to a thermal power plant whose fuel can be bought, a hydroelectric plant might be unavailable because its reservoir is empty—and rain cannot be bought (even now). This point can be illustrated by the Norwegian electricity system. In this country, more than 95 % of the generation is based on hydroelectric. The total consumption is around 130 TWh, and the hydroelectric generation is about 124 TWh. But, due to the dependence on hydrology, the energy capacity can vary from 160 TWh during wet years to 100 TWh during dry years which in this last case leads to a lack of energy. Further, the cost of building a hydroelectric power plant varies a lot according to the place where it is built. Nevertheless, the investment cost varies from 1.5 to 2.7 billion euros per GW (source: Report on the development of hydroelectric generation, French Ministry of Industry, 2006). To make a comparison, the investment cost for a combined cycle gas turbine is around 450 million euros per GW.

Regarding capacity, there has to be enough capacity to continuously satisfy the power demand. However, the energy required to satisfy the power demand over a certain period of time might exist, but not at the right capacity. To give an order of magnitude, the total installed capacity of France is around 110 GW while the annual maximum power demand has reached 100 GW in the last several decades. In the case of Norway, the installed capacity is around 30 GW with 29 GW of it hydroelectric. But, the annual maximum power demand has reached 30 GW in the last several decades too. To overcome the capacity problem, installing enough capacity to satisfy demand in any situation might be a solution. But, this method requires too many power plants that would be used for only a few hours in their lifetime. The cost of this system would be prohibitively expensive.

The fact that power cannot be stored has drastic effects on the way electricity systems have to be managed. A too long excess of demand compared to generation might first be resolved by a decrease in frequency and if not properly corrected, in dramatic blackouts. Thus, this risk has two major implications in terms of generation management. First, it implies a minute by minute real-time assessment of the equilibrium between consumption and generation because 15 min of disequilibrium can result in a major blackout. Second, the transport system operator (TSO) who is responsible for the electricity system's security and reliability needs to have at its disposal *operating reserves* to be able to cope with the uncertainties which affect generation and consumption.

Operating reserves are generation capacities that can be mobilised within a given notification time. They are sorted according to their response time. Because frequency is immediately affected by any discrepancy between consumption and generation, a first reserve consists in the capacities that can be automatically increased or decreased without any human intervention. This reserve is composed by the primary and the secondary reserves. They can be mobilized within less than 15 min. Beyond 15 min, the reserve is manually mobilised through a direct order by the system operator to the generation plant's management. This is the tertiary reserve. It consists in two parts. First, the rapid tertiary reserve provides the generation capacities that can be mobilised in 15 min for a guaranteed period of at least one hour. It offers a complement to the secondary reserve. Second, the additional tertiary reserve provides capacities that can be mobilised in 15–30 min for a guaranteed generation of 6 h. A deferred reserve is made of power that can be brought in line in more than half an hour. The volume of each reserve can vary depending on the nature of the uncertainties on a particular electricity system. To give orders of magnitude, the following minimum values hold in France where consumption on a given hour varies from 50 GW in off-peak hours of the summer to 100 GW in the peak hours of winter:

primary reserve ≈ 700 MW

secondary reserve ≈ 500 MW

tertiary reserve ≈ 1.500 MW.

Thus, at any given time t , the system operator can compute his or her *operating margin* for the maturity $t + h$ that represents the difference between the demand forecast at time $t + h$ and the sum of the secondary, tertiary, and deferred reserves. The margin required for a maturity of 15 min is set by the event of losing the group with the highest generation capacity. For a longer maturity, it is set by the probability of using exceptional measures (e.g., load shedding). For instance, in France, this risk is defined to be lower than a 1 % chance during peak hours. This risk level requires a margin of 2.3 GW to be available for the next two hours.

The reader with a greater interest in the fields of power system reliability can consult the Power System Reliability Memento [150] of the French system operator, which is available on the RTE website.

2.1.2 Transport

Electricity is transported according to Kirchhoff's laws. Basically, these laws state that the intensity at each node should be zero and the tension in each loop should also be zero. An important consequence of these laws is that, in a meshed electricity network, power goes from one point to another through *all* available paths. Figure 2.1 presents a three-node electricity network where each line is supposed to have the same technical properties and the same lengths. Line A–C can handle 180 MW while line A–B and B–C can handle 90 MW. These limitations hold in both directions. Suppose that a power operator G1 has a customer in node C whose consumption is 180 MW,

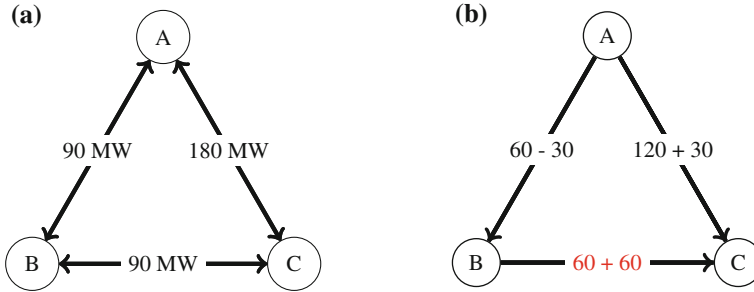


Fig. 2.1 The effect of Kirchhoff's law on electricity exchange. **a** Constraints on capacities, **b** actual flows

while a power operator G2 also has a customer in node C whose consumption is 90 MW. Suppose each operator holds enough generation capacity and that there is no generation cost advantage. If the power flows in lines A–C and B–C like trucks, there is no conflict. Operator G1 generates 180 MW and transmits it through line A–C while operator G2 generates 90 MW and transmits it transit through line B–C. But, because electricity flows through all of the available paths between points, 2/3 of the 180 MW transmitted by G1 will spread from A to C and 1/3 from A to B, and then from B to C. The same holds for the 90 MW transmitted by operator G2. These transmissions then lead to the violation of the transit capacity of line B–C by carrying 120 MW while the line is limited to 90 MW.

It is the main reason why the transfer capacities which are available for trading between countries require some electricity generation hypothesis before they can be computed. In Europe, the available net transfer capacities (NTC) are managed and published by the ENTSOE (European Network System Operator for Electricity) and are made publicly available on its website (www.entsoe.net). To handle these constraints, TSOs and the electricity markets use different methods. In the first years of the European electricity markets, continental Europe chose an explicit auction mechanism. Those who wanted to sell power from one country and have it delivered to another country had to buy the transfer capacity between the countries at an auction that was organised by the TSOs. This method has the benefit of being simple. But, it induces inefficiencies and often adverse flows (flows going from a high price country to a low price country) because of the coordination problems between the market timing of both the power and the transmission capacities.

At the same time, since its early beginning in the 1990s, the NordPool has implemented an implicit auction mechanism between its member countries. In this mechanism, the buyers and sellers post their bids without worrying about transport constraints. Their bids are assigned to their areas. Then, the market operator performs a clearing which takes into account the possibilities of exchange between the zones. While more complex than the former, this method has the benefit of avoiding adverse flows and simplifying the business of traders. This method was chosen by the different actors of the electricity market in continental Europe under the name of *market coupling*. From 2006 to now, the coupling of markets has been achieved between

(in alphabetic order) Belgium, Denmark, Estonia, Finland, France, Germany and Austria, Great Britain, Latvia, Lithuania, Luxembourg, the Netherlands, Norway, Poland, Portugal, Spain, and Sweden.

For an introduction on the auction mechanism for electricity transport, I refer the reader to Stoft's book on power system economics [154, part 5].

Remark 2.1 The topic of this book is mostly about what happens at the transport level of electricity because this is the level at which the wholesale markets operate. Nevertheless, the change that occurs at the distribution level of electricity because of the introduction of renewable energies cannot be ignored. The distribution network was historically designed to transfer power from the transport level to the consumers. Electricity would flow downward from the transport level to the distribution level. With the connection of renewable sources such as solar panels and wind farms at the distribution level, now power sometimes flows upward from the distribution network to the transport network.

This phenomenon requires an adaptation of the way distribution networks are monitored and operated. The concept of *smart grids* applies to this adaptation. Smart Grids correspond to the development of the information technology infrastructure which allows the control of the distribution network to adapt to the massive introduction of intermittent sources of energy. In this regard, the smart counter is one key element of the infrastructure. It is the ability to have a fine measure of household consumption but also the capacity to communicate with the customer to send him or her price signals. But it is not the only key element. Flexibilities in consumption (the capacity to defer consumption in time even for a few hours) as well as short-term storage capacities which are able to cope with important variations in wind generation become an issue. I will come back to this point in Sect. 2.3.

2.2 Market Microstructure

The design of electricity wholesale markets differs from one country to the next. However, the properties of electricity have led to common features in the markets' microstructures. I focus here only on those common factors. In each country, the electricity market is composed of a series of markets with different time scales and different scopes. Generally, three different gross markets can be distinguished:

1. the intraday market and/or the balancing mechanism: the balancing mechanism consists of exchanges between the TSO and the market players to ensure the real-time assessment of the grid while the intraday market allows the exchanges between the market players themselves to ensure the equilibrium between their generation and the consumption of their customers.
2. the day-ahead market: quantities are exchanged one day before delivery for the next 24 h or 48 half-hours of the next day.
3. the forward market: market players can buy or sell electricity for future delivery.

To illustrate these three markets, I use France and Germany as examples.

2.2.1 Intraday Market and Balancing Mechanism

In a very short time frame (say the next 12 hours), the actors in the electricity market are most concerned with the precise equilibrium between generation and consumption of their portfolio. Each actor is made financially accountable for all of the discrepancies between the consumption of its customers and its generation. The TSO is also most concerned about a precise equilibrium between the overall generation and consumption in the system. For this reason, two systems coexist. The first one is designed by the TSO and is called the balancing mechanism which adjusts the generation and consumption. The other one is a market where the actors can exchange generation to reduce their imbalances.

The first purpose of the balancing mechanism is to ensure the security of the system. In particular, it aims at maintaining constant the frequency and the voltage to all points in the networks. To achieve this purpose, France requires some obligations from all of the market players who own generation assets which can contribute to the reserves. For instance, coal-fired plants, nuclear power plants, and hydroelectric power plants can contribute while wind farms cannot because of the way they are presently connected to the grid. Market players have the obligation to offer all of their available generation to the TSO so that he or she is able to increase or decrease generation if needed. These bids can involve a non-negligible level of complexity because they tend to reproduce precisely the dynamical constraints of the groups. At this time frame and for the purpose followed by the TSO, it is not possible to neglect the notification time, ramp constraints, and so on. But, basically, the power plant owners submit a quantity together with a price and a maturity, and the system operator selects them according to their economic efficiency.

A second objective of this mechanism is to provide a transparent market price for the cost of the imbalances in the system. If the TSO has to adjust generation, then it is because at least one actor is not generating as much power as its customers are consuming or is generating too much power. Thus, this actor has to incur the costs of the adjustments made by the TSO. It is done at a price referred to as the *imbalanced price*.

To give a concrete example of this mechanism, Table 2.1 shows the way the imbalance price is settled by the RTE, the French TSO, for a given hour h of the day. In this table, S represents the day-ahead price settled the day before for the hour h , P^d is the weighted average price of the offers used by the TSO to decrease the generation (or increase the consumption), P^u is the average price of the offers used by the TSO to increase the generation (or decrease the consumption). The table reads in the following way.

When the network needs to be adjusted upward (lack of generation, first column) and the actor is itself generating too much (first row), then the actor is paid at the spot price established the day before for each MWh. In the opposite, if the actor is itself not producing enough (second row), it pays each MWh of its imbalance at a price that is always higher than the spot price and the average cost incurred by the TSO to compensate for its generation deficit.

Table 2.1 French TSO imbalance price settlement mechanism as of April 2013

	Network adjustment trend positive	Network adjustment trend negative
Actor imbalance positive: actor is paid	S	$\min\left(S, \frac{P^d}{1+k}\right)$
Actor imbalance negative: actor pays	$\max(S, P^u \times (1+k))$	S

When the network needs to be adjusted downward (excess of generation, second column), and the actor is producing too much (first row), the actor is paid, but at a price that is less than the average cost incurred by the TSO to decrease the generation (P^d), and less than the day-ahead spot price.

Although apparently complex, those rules are basic. It is natural to pay those who produce energy even if the system has too much of it and to make pay those who do not produce enough even though the system has too much electricity. Moreover, the system is designed to avoid any arbitrage opportunity between the spot market and the balancing mechanism. If the payment for having a negative imbalance in the case where the system is lacking power (first column, second row) is not floored by the spot price, then the temptation exists to sell power on the spot market at price S and to not deliver it. This action leads to a negative imbalance position that would be penalised in some cases at a lower price, leading to a profit.

Moreover, the factor k ensures that the TSO does not have a negative balance sheet at the end of the year because the TSO always pays those who contribute to correct the imbalance less than what the TSO pays to correct them.

Besides this mechanism where the TSO is the only buyer or seller, a market exists where players can adjust their own positions between their generation and the consumption of their customers. In this market, players are constantly exchanging power to adjust their own perimeter over the next few hours. There is growing interest by market players in this market because of the increase in short-term uncertainties. This increase in uncertainty is mainly due to renewable energies. For instance, in France, these exchanges can be done over-the-counter on the EPEX platform. Electricity can be bought or sold as much as 32 hours in advance before delivery. The exchanges performed there are not marginal. For certain hours, the exchanged volumes can be as large as 5 GW. Moreover, this market is not limited to France. It includes Germany, Austria, and Switzerland. This market shares some features with forward markets. The actors can take a commitment for delivery on a future day but reverse it in the next minute. Figure 2.2 shows the index price of the intraday market on EpexSpot (weighted average of the intraday transactions) as a function of the day-ahead price in 2012. The figure shows that there was a spike on the day-ahead market while nothing happened on the intraday, and, more interesting maybe, there was no spike on the day-ahead market but one occurred on the intraday. Price caps might differ on the day-ahead and on the intraday markets. For instance, on EPEX, the prices on the

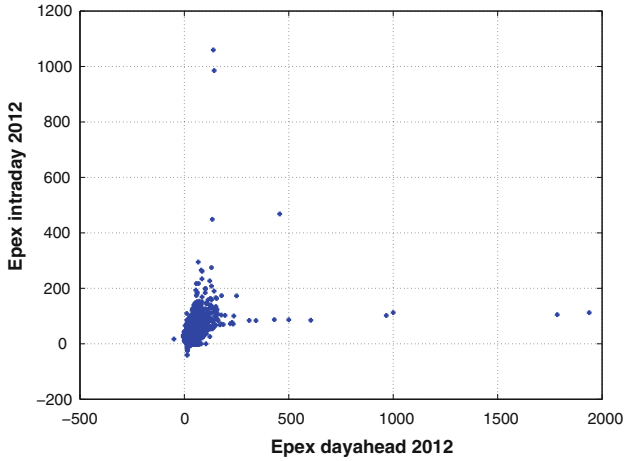


Fig. 2.2 Relation between the average intraday price for delivery at a given hour and the day-ahead spot price for the same hour in 2012. *Source* EpexSpot

day-ahead market range from -500 to $+3.000$ €/MWh while on the intraday market they move between -10.000 and $+10.000$ €/MWh.

Figure 2.3 shows an example of the evolution of the transaction price for the delivery of a given hour on the German intraday market in December 2010. The price moves from 70 €/MWh (close to the reference provided by the spot) to 120 €/MWh before going back to 80.

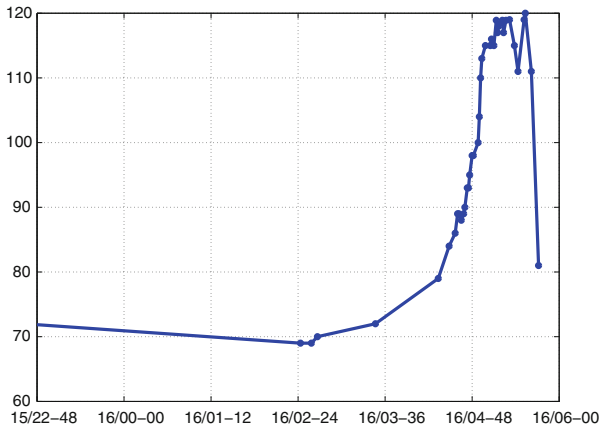


Fig. 2.3 Intraday transaction price for delivery at 7 a.m. on 16 December, 2010, on the German intraday market. X-axis reads: day/hour-minutes. *Source* EpexSpot

2.2.2 Day-Ahead Market

The day-ahead market is based on a fixed trading auction. Each day the market participants submit bids before a certain time (around 10:00 a.m.). They can bid (sales or purchases) for a particular hour of the next day or for a set of hours (order block). The bids of the market participants for a particular hour form two curves as Fig. 2.4 shows. One represents the sales curve and one the purchases. Then, around 12:00 p.m., the market organiser clears the market: the organiser fixes a price for each hour of delivery and determines the sellers and the buyers. The market players then have enough time to send the generation orders to their power plants and send their schedule to the TSO.

Moreover, Fig. 2.4 illustrates the fact that it is possible to submit negative prices for buying and selling. A negative sale price indicates that the seller is ready to pay to sell, and a negative purchase price indicates that the buyer is ready to be paid to buy. This phenomenon is the consequence of the lack of flexibility in some thermal power plants. It can be less expensive to let a coal-fired plant run during hours of the day when the spot price is below its fuel cost than shutting it down and starting it up again later. On the demand side, some customers also have the flexibility to increase their consumption if they are compensated for the cost of changing the schedule of their production process. The figure shows that Sunday the 16th of June, 2010, had particularly low demand during the night, the price settled at -154 €/MWh , but some actors were ready to pay as much as 500 €/MWh with a volume of 4 GWh.

Moreover, because the market participants are allowed to submit block orders, the clearing process results in a non-convex optimisation problem for which defining a market price requires caution. For details, see the documentation regarding the market coupling algorithm named Cosmos available on EpexSpot's website [78].

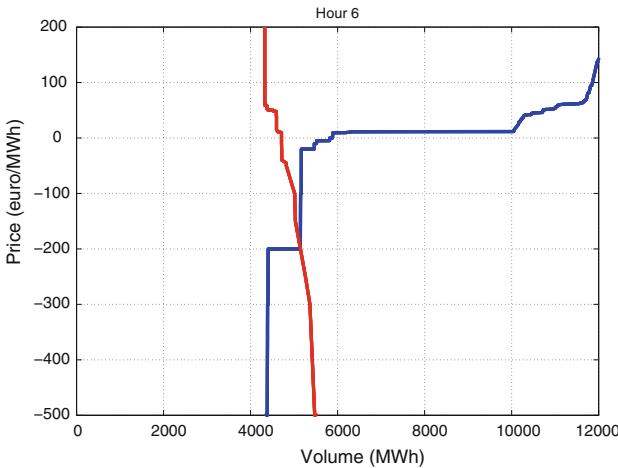
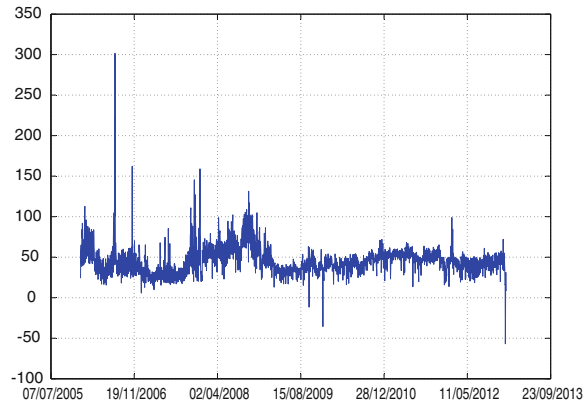


Fig. 2.4 Day-ahead market volume of sales and purchases on 16 June, 2013. *Source* EpexSpot

Fig. 2.5 German daily day-ahead electricity price from 2006 to June 2012.

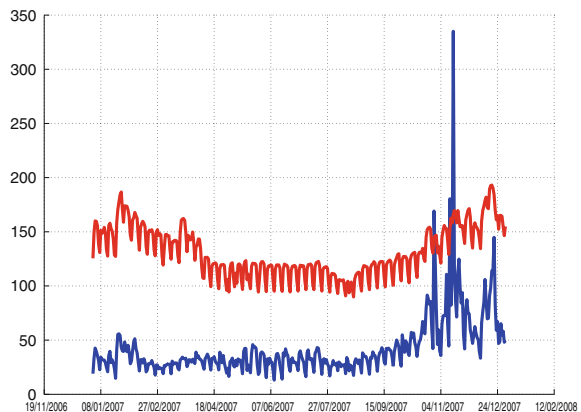
Source EpexSpot



A direct consequence of the fact that electricity cannot be stored is the occurrence of extreme *spikes* in the day-ahead market. This phenomenon is illustrated in Fig. 2.5 with the daily average of the German spot price during the years 2006 to 2012. The figure shows that the daily average price reaches values as high as 300 €/MWh, but it reaches values as high as 2,400 €/MWh during one hour. The figure also shows occurrences of negative price spikes and their disappearance since 2009 with the development of solar energy.

As Fig. 2.6 shows, electricity day-ahead prices exhibit all of the seasonal patterns of the economic activity of a country: daily, weekly, and annual seasonality such as the moment people wake up to go to work, the moment they get back home and switch on their home appliances, the moment they go to sleep, and the moment when offices and some factories close for the weekend. Electricity day-ahead prices also show fat tails and long memory. They also exhibit correlation with the temperatures in countries with electric heating or air conditioning.

Fig. 2.6 French daily electricity consumption in relation to the daily spot prices during the year 2007. Consumption is scaled to fit the picture. Source EpexSpot and RTE



In the European Union, each country has its own electricity day-ahead market cleared by its own market operator. Without coordination, the resulting quoted prices might provide the wrong signals when compared to the transit flow between countries. Indeed, an inquiry performed in October 2004 by the French Ministry of Finance on electricity prices showed that there was barely no relation between the French-German price spread and the transit on the French-German interconnection [147, Sect. I.4.1.1].

Because the quoted day-ahead prices by the market operator have a transparency function, a mechanism has been developed to ensure a consistent relation between cross-border transactions and local day-ahead prices. This mechanism consists in a *market coupling* process which implements a *decentralised implicit auction* mechanism. It is the same mechanism as in the NordPool market. In each country, the market participants do not have to care about finding a counterparty in neighbouring countries. The participant just has to submit its bid in its country (sell or buy). Then, the market organisers perform a clearing process *with* transport constraints implied by the available transfer capacity. If there are no binding transit capacity constraints, then there is a single price for the clearing area. If there is at least one binding transit capacity constraint, then two prices emerge. The debate in the literature on the congestion management mechanisms for cross-border trading is important. For an introduction to this debate, one can begin with Ehrenmann and Neuhoff's [82].

Due to the importance of the relation between the spot and futures prices in the pricing theory, it is important to know what the spot price for power is. Sometimes, the intraday market is referred to as the spot market. Because the intraday price is the shortest time to maturity, it might appear as the *real* spot market, in a sense where the spot refers to a price for instantaneous delivery. But, the reference price for delivery in the futures market is the day-ahead market price. For this reason, I refer to the day-ahead market as the electricity spot market.

2.2.3 Forward Market

Electricity forward markets share many aspects with those of storable commodities such as oil, coal, or metals. In all of the countries where an electricity market exists, the organised markets have developed and proposed standardised contracts for future delivery as well as a margin call mechanism to reduce the counterparty's risk. As in any other commodity contract, the standardised contracts for future delivery specify the currency, the underlying volume, the location of delivery, the trading period, and the tick size. Because electricity is the same in all of the parts of the network grid, the question of quality is not relevant. Physical delivery is often preferred. However, a financial settlement is getting more frequent as markets become more mature. Moreover, because they are doing it for other commodities or financial products, organised markets report the prices and quantities of the OTC contracts.

The most important difference in the electricity forward contracts from the storable commodities comes from their term structure. Because electricity cannot be stored

and because the spot market is a day-ahead market with an hourly time-step, a power operator who wants to hedge its generation for the next year needs to have at its disposal the forward contracts for all of the hours in the year. For a non-leap year, the quantity corresponds to 8,760 hourly forward contracts. Such a forward structure would result in a huge dispersion of liquidity because the market participants would spread their needs to all of those contracts. For this reason, electricity forward contracts aggregate hours during a *delivery period*. The delivery period specifies all of the hours during which the electricity should be delivered. The choice is not left to the seller to pick the time for delivery during the delivery period as, for instance, is the case for crude oil futures contracts on the New York Mercantile Exchange (Nymex). The delivery period refers to a month, a quarter, a year, or even a week or a day. The contract also is precise on the schedule of the delivery: the base-load if the electricity is to be delivered during all of the hours of the period and the peak hours or off-peak hours if the electricity is to be delivered only during a special period which reflects large or low demand.

This aggregation mechanism results in a sparse structure of the electricity forward curve. The further the maturity, the longer the delivery period. For instance, the European Energy Market (EEX) offers forward contracts with the following term structure for delivery in the German market: 6 Calendars, 11 Quarters, 9 Months, 4 Weeks, 2 Weekends and 8 Days.

These contracts can come in three different delivery forms: base-load (every hour of the delivery period), peak-load (7:00–20:00 Monday to Friday), and off-peak (base-load minus peak-load). The calendars, quarters, and months come in those three forms while weeks, weekends, and days come only in base and peak forms. So, each day, 106 contracts are available, which represents only a very small fraction of the 525,584 h of the next six years. Nevertheless, despite this concentration of trades on a small number of contracts, liquidity remains an issue in the electricity forward market. It is not uncommon to report no more than 20 MW available per day for two-month-ahead contracts—to be compared with the generation capacity of a standard coal power plant of 400 MW.

Figure 2.7 gives the evolution of the German month-ahead and year-ahead base-load contracts from 2006 to mid-2012. The behaviour of their prices is similar to standard financial products. They do not exhibit strong seasonal patterns with spikes. The jumps in the month-ahead prices come from the seasonality effect of changing contracts. Further, the month-ahead contracts present a much higher volatility than the year-ahead ones. The figure also shows that the effect of the boom on commodities during the years 2005 to 2008 and the financial crisis of August 2008 are reflected in the year-ahead price. It rose from 50 €/MWh to 100 in 2 years and went back to 45 in less than 6 months.

Figure 2.8 shows the different possible shapes of the German forward curve. The figure shows the relative position of the daily spot price in normal backwardation (left: the spot is slightly above the futures price) as well as in contango (right: the spot is clearly lower than the futures prices). If the month-ahead and year-ahead contracts tend to be aligned to form a nice configuration, then the spot price does not fit the plan and tends to exist independently of the remaining forward curve. The

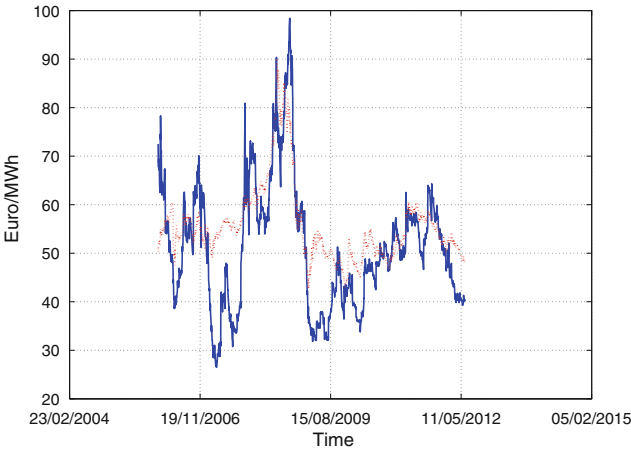


Fig. 2.7 Daily quotation of German month-ahead (*blue solid line*) and year-ahead (*red dotted line*) futures contracts from 2006 to June 2012. Time in French format dd/mm/yyyy Source EpexSpot

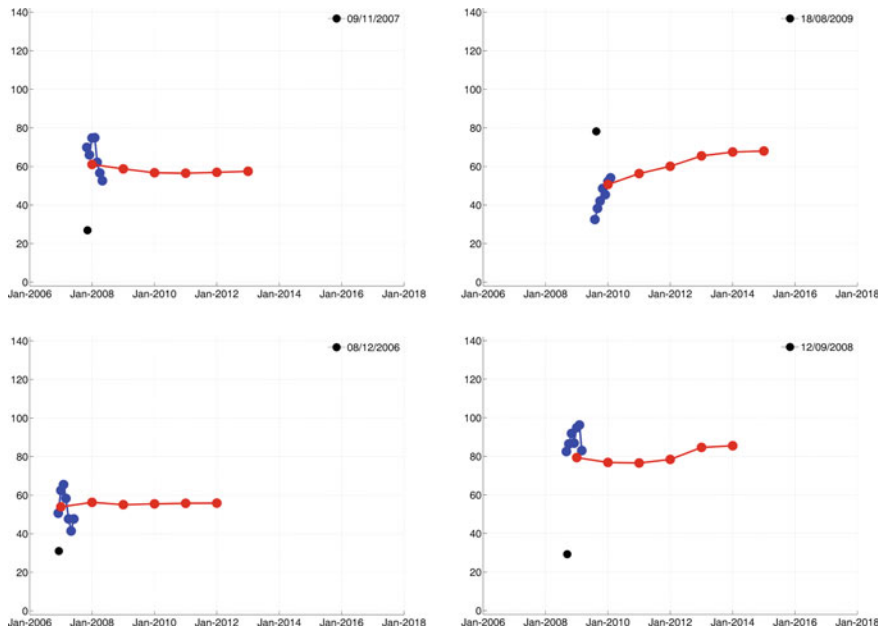


Fig. 2.8 Illustrations of four different dates of the German electricity forward curve with only year-ahead (*red dots*) and month-ahead (*blue dots*) base-load contracts. The *black dot* corresponds to the average spot price on the dates. The X-axes are the delivery date, and the Y-axes are the price in €/MWh

figure at the bottom also shows that the shapes of the term structure can be much more complex. It gives an illustration of the strong seasonal pattern that can affect the month-ahead contracts while the year-ahead part of the curve remains perfectly flat.

Convergence: Another important issue regarding the electricity forward contracts concerns the settlement mechanism of the delivery period. The electricity futures contracts are settled against the average day-ahead price of the delivery period. This mechanism ensures that the electricity futures contracts provide the hedge required by the market participants.

For example, on 1 March, a power operator owns a power plant of 1 MW. The April base-load futures price is 40 €/MWh. That price suits the operator's objectives and so, he or she immediately sells one contract. On the last business day of March, the April contract settlement price is 45 €/MWh. Thus, the operator has lost 5 €/MWh on the futures value but still holds the futures contract during the delivery period. During the month of April, independently of what is happening in the futures market, the operator operates the plant on a base-load schedule each hour with full power. Then, the operator receives exactly the average April day-ahead market price. In this example, the average April day-ahead price is 30 €/MWh. From the April futures contract the operator holds, he or she receives for each hour of April, $(45 - 30) = 15$ €/MWh. In the end, the operator receives $-5 + 45 - 30 + 30 = 40$ €/MWh, which was the selling price objective.

This example shows that, contrary to other commodity markets, the operator cannot rely on the convergence of the futures to the spot price to reverse the operator's position in the financial market on the last days of the contract quotation.

In this example, if the operator buys back the April contract on the last business day of March, believing that the average day-ahead price will settle exactly at 45 €/MWh, then the result will be completely different. First, the operator still incurs the loss of 5 €/MWh from the margin call. But, now the operator receives 30 €/MWh on the spot market with no hedge. With the 5 €/MWh loss on the futures market, the operator's selling price is 25 €/MWh. The 15 € difference comes from the basis risk between the last quotation of the April base-load and the resulting average day-ahead price.

However, the actors on the market do not hold a year-ahead contract during its whole delivery period. Instead, as soon as the contracts with shorter maturities appear, such as quarters-ahead and months-ahead, they sell their longer maturities and buy the shorter ones. This procedure is automatically implemented in the EEX calendars and quarters contracts in a mechanism called *cascading*. A few days before the delivery period, every open position on a year-ahead futures contract is replaced by an equal position in the three months from January to March and the three quarters of April, July, and October.

Options market: There are quotations available for vanilla options on the futures contracts on the organised markets like the EEX or the NordPool. European calls and puts are open on the futures contracts with different strike prices and three different maturities. For example, on the last trading day of 2012, there were three calls and three puts with the expiration dates of 13 April, 13 July, 13 October and four calls

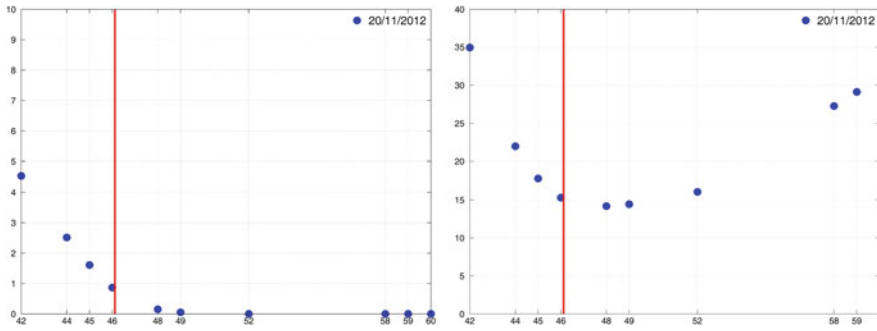


Fig. 2.9 Prices of call options on year-ahead futures base-load contract with expiry on January 2013 as of 20 November, 2012, (*left*) and their implied volatility (*right*) as a function of the strike price. The *solid red line* indicates the options in the money

and puts with the expiration date 14 January for the year-ahead contracts in 2014. The same year-ahead contracts were available for 2015 and 2016 with the slight difference that more calls and puts were available for the last expiration dates. Also, only the base-load contract was available. Thus, these contracts resulted in only 82 options available for the trade of the year-ahead contracts. The calls and puts were also available for base-load months and quarters. The prices for those contracts were provided even though there were no transactions and no open interests. Some contracts were barely traded while the options with an expiry on N January with the underlying year N grabbed all of the liquidity. Thus, in 2012, the options on year-2013 with expiry on 13 January represented all of the open interest for options. They represented an average of 58 contracts with a maximum of 300, and calls and puts were equally traded.

Figure 2.9 provides an example of the prices quoted on 20 November, 2012, for call options on the year-ahead base-load futures contracts for 2013 with expiry in January 2013. I also provide an estimation of their implied volatility. This figure depicts a situation where there is some open interest in most of the options with an available price. It shows that the implied volatility can produce a nice smile with a volatility of around 30 %.

2.2.4 The Diversity of Electricity Markets

The general presentation above hides a great deal of heterogeneity in the development of the electricity markets around the globe. Sioshansi and Pfaffenberger's book [153] on the reform implementations in the worldwide electricity market shows that these markets have followed very different paths. The markets in some countries have important growth both in terms of volume and in the complexity of their products.

An example of such developments is the Pennsylvania, New Jersey, and Maryland market (PJM) in the United States. The PJM market has existed since 1997 and

now serves more than 60 million customers in the Mid-Atlantic and the District of Columbia. Its total annual consumption is approximately 800 TWh with more than 180 GW of installed capacity of which 60% are gas-fired plants. The spot market is a bid-based mechanism with security constraints which deliver prices for each node of its operating network (more than 10,000). In addition to offering prices for energy, PJM also provides its operators financial transmission rights to hedge the locational risk spread. Since 2007, it has launched a capacity market to ensure long-term reliability of the system and to provide its investors with a market signal on the value of the capacity. Its futures and options are also available on the Nymex. The contracts come in different delivery time schedules (off-peak, peak, day-ahead, month-ahead) but also in different locations of the PJM network.

In Europe, a similar development has occurred in Scandinavia with the NordPool, in continental Europe with the EEX, and the market coupling mechanism progressively developed across Western countries.

The NordPool was launched in 1996 and covered only Sweden and Norway. It now connects Norway, Sweden, Finland, Denmark, Lithuania, Latvia, and Estonia for an annual generation of approximately 480 TWh generated by 370 companies. Its hydroelectric generation accounts for 100 TWh and its nuclear for another 100. The remaining generation comes from coal- and oil-fired plants. The NordPool's day-ahead spot price is operated by ElSpot and consists of an implicit auction mechanism between all of the countries covered by the market. An intraday market also exists which allows the NordPool to secure the imbalances. The intraday market has seen important growth thanks to the introduction of wind energy and the increasing need for intraday rescheduling. The financial market for Scandinavian electricity formerly known as Eltermin is now operated by Nasdaq OMX Commodities. It offers futures and options that cover the daily, weekly, monthly, quarterly, and the annual horizons. Each underlying is given by the hourly day-ahead spot price fixed by ElSpot.

These two markets (PJM and NordPool) disclose not only prices but a large amount of hour data, such as many time series on generation per technology, transit, planned outages, inflows, and the states of the reservoirs, which is all of the information needed by the market participants to precisely assess the equilibrium between offer and demand.

However, some electricity markets have not developed as much as might have been expected in terms of financial derivatives. This is the case for Chile. The Chilean electricity system is basically a one-dimensional network due to the geography of the country. The market is decomposed into three areas, but the main part consists of the central interconnected system which covers around 93% of the Chilean population and 70% of the total installed capacity. The generation is a mix of hydroelectric generation (50%), natural gas (27%), coal (10%), and oil (7%). The main feature of the spot market is that it relies on a cost-based economical dispatch performed by the Economic Load Dispatch Centre. The dispatch minimises the expected discounted value of the generation cost of serving demand in the next 48 half-hours. The system price is the running cost of the most expensive unit of generation used to satisfy the demand. The dispatch is mandatory. A price cap is set by the regulator every six months according to the value of the load lost. Moreover, each power plant receives a

monthly capacity payment based on its availability. Despite the fact that this country was the first to establish a pool market for electricity in the beginning of the 1980s, there is not a developed market of standardised futures and options contracts.

This lack does not mean that the development of a financial market is not possible. New Zealand is an example of the late development of a financial market for electricity. New Zealand is a country composed of two islands with a population of 4 million people. They have an annual electricity consumption of 36 TWh and an installed capacity of 9 GW. Deregulation began in 1987, and the spot market began in 1996. It is similar to the PJM design: bid-based security constraints with nodal prices providing 48 half-hourly prices for each of the 285 nodes in its network. The forward contracts are traded on ASX, New Zealand's electricity futures and options exchange. The exchange launched in December 2013 trades in base-load monthly futures, peak-load quarterly futures, and the average rate options on base-load quarterly futures.

There is no explanation for the diversity of the financial markets' development. Possibly it comes from the generation mix, the network configuration and most of all, the amount of consumption. For instance, Cyprus is a European state where an electricity market should be designed. It has 5 TWh of annual consumption that relies mainly on three fuel power plants for 95 % of its generation. Nevertheless, the evolution of the wholesale market of England and Wales may indicate that the design of the spot market can be a key driver in the development of the financial market. Indeed, the first phase of the English and Wales market in 1992 relied on a mandatory economical dispatch very similar to the Chilean model. During that period, there was not to my knowledge a financial market for futures similar to the one in NordPool. But, now after several changes in the design of the English and Wales power market, the futures and options can be traded on the Nasdaq OMX Commodities board with the standard variety of products available (day, week, month, quarter, year, and base-load and peak-load).

2.3 Real Derivatives

Like any other commodity market, the electricity market has its options markets on quoted futures. But, the most challenging problems do not come from the valuation of these standard products but rather from their pricing, hedging, and structuring into exotic tradable products which are called *real derivatives*. The electricity operators as well as the retailers have these options embedded in their portfolios. A power plant can be seen as a strip of call options. A retail household contract with a curtailment clause which gives the retailer the right to charge the customer an exceptionally high price if the customer does not reduce his or her consumption on a sent signal, is a contract with an embedded put option. Thus, as an analogy with the idea of the real option for investment decision, these rights can be thought of as real derivatives.

Moreover, because electricity cannot be stored, the TSO always needs some flexibilities to be able to cope with uncertainties but also to cope with the dynamic

constraints of the generation system. It is sometimes more economical to be able to reduce consumption or to defer it by a few hours than to satisfy it right away. On the contrary, it might be better sometimes that the electricity consumption is higher to avoid shutting down a power plant which is not flexible. An example of these flexibilities can be illustrated by household water heaters. In France, these home appliances are automatically started up with an electric signal when the consumption is at its lowest during the night. As Remark 2.1 points out, the development of intermittent sources of renewable energies has led to a growing interest from all of the market actors in all of these flexibilities. The flexibilities can be seen as real options bought by the TSO from the users or by any involved actors from the customers.

The following are the three most important real derivatives that are the daily concerns of the operators and their financial representation:

1. Power plant and tolling agreement
2. Energy storage and swing contract
3. Retail contract.

Power plant and tolling agreement: The owner of a power plant creates value by selling power and buying fuel. The owner needs to estimate the value of the generation of a power plant for investment decisions, long-term contract negotiations, and risk management applications. A power plant is an industrial facility and thus, is subject to many technical, environmental, and legal constraints. But, in a first crude approximation, a power plant can be seen as a strip of calls on the spread between its fuel price and the electricity price. For a gas-fired plant, one speaks of a spark spread; while for a coal-fired plant, one speaks of a dark spread. When the carbon emission price is taken into account, then it is called a clean dark spread and a clean spark spread. The payoff per MW of a power plant in a period of time $[0, T]$ is then given by:

$$\int_0^T (S_t - hS_t^f - gS_t^c)^+ dt, \quad (2.1)$$

where S is the spot price of power, S^f is the spot price of its fuel, and h is its heat rate. The variable S^c is the spot price of the emission permit, and g is the emission factor of the plant. The notation x^+ refers to $\max(0, x)$. The payoff (2.1) makes it clear that it is possible to identify the value of a power plant with a strip of call options. Nevertheless, the fact that the instantaneous payoff depends on three assets makes the problem technically difficult. Moreover, the existence of the operational constraints drastically reduces the possibility of capturing the successive positive spreads. The start-up costs, minimum running time, ramp-up and ramp-down constraints, and the limited number of cycles per day, all limit the flexibility of the power plants. Thus, the quantity (2.1) overestimates the profit of the power plant. Valuating power plants with operational constraints gives rise to *optimal control problems*. One way to formulate it is:

$$\sup_{q_t \in \mathcal{A}} \mathbb{E} \left[\int_0^T q_t (S_t - hS_t^f - gS_t^c - \kappa)^+ dt \right], \quad (2.2)$$

where q_t is the generation belonging to an admissible set $\mathcal{A}$, and κ is a start-up cost.

However, the problem above is not new in generation management. It is related to unit commitment problems, that is, scheduling a group of power plants for the next few hours or days. And it is also related to management problems in mid-term generation where the assessment of the generation level of a group of power plants is needed for the next few months. Over the last 40 years, a lot of efforts has been devoted to the development of numerical optimisation algorithms and software to solve those problems. These models are based on a context where monopolies try to satisfy a random demand at the lowest cost. They use mix-integer programming methods or Lagrangian relaxation methods. The introduction of spot markets has changed the problem by introducing new phases like the bidding phase where the power operators have to submit their bids to the market operator. However, the underlying optimisation methods still apply. For a more in depth description of the constraints in power plant scheduling and numerical optimisation methods, the reader can consult Wood et al.'s monograph [169] and the recent survey of Prekopa et al. [146].

The major novelty raised by the development of financial market is the question of the hedge of the payoff (2.2). Typically, the natural hedging instruments are the futures on the fuels, carbon emissions, and the futures on power. But, as we seen in Sect. 2.2.3, the futures contracts available on the electricity market do not have the fine granularity of the spot price. If T is one year, the above payoff is exposed to 8,760 risk factors whereas only a handful of futures are available. In this regard, the electricity market is incomplete. As a consequence, even the notion of the value of the first basic payoff (2.1) is ambiguous. At the present time, it has no consensual answer. This lack of consensus translates immediately into the difficulty of finding exchange prices for tolling contracts. These contracts are financial counterparts of the power plants where the owner concedes an exploitation right in exchange for a fixed premium. Depending on the price models, the constraints taken into account and the hedging capacities, there might be a large discrepancy between the prices.

Energy storage and swing contract: Hydroelectric plants are very flexible. They can provide electricity at very short notice. The valuation problems described for the thermal power plants are still valid for hydroelectric power plants. But, the existence of a limited resource of fuel leads to the problem of storage management. The simplest problem in hydroelectric storage management deals with a single reservoir. The valuation problem is:

$$\sup_{q_t \in [0, \bar{q}], \delta_t} \mathbb{E} \left[\int_0^T q_t S_t dt + g(S_T, X_T) \right], \quad (2.3)$$

where S_t is the electricity spot price, and X_t is the current level of the water in the reservoir. This level satisfies the following dynamic:

$$dX_s^{t,x} = (a_s^{t,a} - q_s - \delta_t) ds, \quad (2.4)$$

where a_s are random inflows. Moreover, X is subject to level constraints and should stay within $[\underline{x}, \bar{x}]$. The control δ_t is the spilling variable. If X_t is at its maximum level and the inflows exceed the generation capacity $\bar{q}$, the operator has no other solution than to spill the excess water. The function g represents a final value for having a certain level of water at a final time.

In a more general form, a whole *network* of hydroelectric plants and reservoirs influence one another. The constraints on the hydroelectric plants become more complex and the dimension of the system drastically increases. Hydroelectric management problems are not new. They were at the origin of the development of dynamic programming [132]. There is important literature on power systems that is devoted to these problems. The main difficulty in these problems is the dimension of the state. The higher the number of reservoirs, the higher the dimension. They are mainly tackled by using stochastic dynamic programming methods, such as the dual dynamic programming method [139], or decomposition methods.

The development of the electricity markets launched a revival of this problem because of the availability of spot prices. Other methods have then been proposed based on the *optimal switching problem* or the *stochastic control problem*.

As was the case for power plants with tolling contracts, the financial representation to storage facilities, named swing options, were developed to offer the ability to store power but without all of the technical constraints involved with a real hydroelectric system. An important class of swing contracts consists of the demand-side management contracts. The customers holding this form of contract enjoy a lower tariff during the year except for a few days when any kWh consumed costs the customer a dissuasive price. What is important here is that the days with the higher price are not known in advance by the customer. The utility warns the customer the day before. Thus, the utility holds an option on the customer's consumption. When the customer is an industrial firm, the result of the signal is deterministic. The firm cancels its consumption. But, when the contracts concern a large amount of households, the resulting total avoided consumption is random.

Retail contract: The retail pricing policy consists in determining the form of the contracts for customers as well as the price to be charged. As in the insurance business, retailers first have to decide on the forms of their contracts and their prices; then, the customers select the contract and consume. When setting the retail pricing policy, a retailer does not know what is going to be its sourcing cost and precisely how much the customers are going to consume.

The consumption of the customer drastically differs from a chemical plant to a household in a building in a big city. The customers are generally sorted into three main classes: industrial, professional, and household. They differ by their number, their consumption volumes and patterns, their economic behaviour, their needs, and by the information the retailers have on their consumption. In a country like France or Germany, industrial customers are much less numerous than households but they represent a significant part of the country's consumption. The industrial customers can benefit from very precise metering of their consumption whereas households are still only measured twice a year in many countries. The industrial customers might not be sensitive to weather whereas households are. The industrial customer

can switch from one retailer to another for 1 cEuro/MWh because each cent can represent thousands of euros on the customer's electricity bill. Household switching is more viscous.

For these reasons, the contracts offered to different classes of customers are very different. The industrial contracts might be tailored to their operational constraints whereas the households are viewed as a mass market that only needs basic standardised contracts. The industrial retail contract often includes embedded options (right to resell to the market the power delivered at a certain price). The household's contracts involve fixed premiums proportional to the subscribed capacity plus a price per kWh. Sometimes they benefit from a two-level tariff depending on the hour of consumption (peak and off-peak). For a case where a detailed description of a retail market is given, the reader is referred to the analysis of the Norwegian household market in von der Fehr and Hansen [161].

This problem has received much less attention in the quantitative energy finance literature than in the economics literature. Indeed, electricity pricing policy was addressed as a problem of long-term pricing during the monopoly period of electricity generation. In that economy, the main concept which dealt with this problem was the marginal cost pricing theory, deeply illustrated in theory and in practice by Boiteux [38]. In a nutshell, the marginal cost pricing of electricity insures a maximisation of the social welfare through a regulated monopoly. With market competition and with the real gross market prices, nothing insures that selling at the marginal generation cost is the right policy to maximise the value of the firm. Indeed, the marginal cost pricing rule requires certain long-term equilibrium conditions on the generation assets to be fulfilled which are unlikely to hold in actual market conditions.

2.4 Conclusion

The structure of electricity markets can be seen as a multi-layered market with successive time horizons going from the forward market of up to six years to the real-time balancing market for the next hour. The electricity forward curve is coarse and presents a cascading structure. The spot prices are defined by the day-ahead market. They present strong seasonality patterns, spiky behavior, and positive as well as negative prices. Further, power plants, tolling contracts, storage and swing contracts and retail contracts are some of the most specific derivatives to electricity markets.

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