ELECTRICITY MARKET PROBE

E-CONTROL

Short-Term Physical Electricity Trading in Austria

Marketing Opportunities, Market Concentration and Market Functioning

Sample period: 2012–2013

Based on data available on: 1 July 2014

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The content of this working paper reflects the opinion of the authors and does not necessarily represent the official position of E-Control.

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1. Introduction

Energie-Control Austria, the regulatory authority for the electricity and natural gas markets in Austria (E-Control), is responsible for drawing up analyses and expert reports and opinions on the market and competition conditions in the Austrian electricity and natural gas markets in accordance with section 21(2) *Energie-Control-Gesetz* (E-Control Act). Furthermore, section 24(1) E-Control Act entrusts E-Control with comprehensive regulatory and monitoring tasks in terms of competition supervision and trading with wholesale energy products. In the framework of section 88(3)(6) *Elektrizitätswirtschafts- und -organisationsgesetz* (Electricity Act), E-Control is in charge of monitoring the procurement of balancing services[1]. In complying with these tasks, E-Control continuously carries out monitoring activities, complementing them with relevant analyses, such as the present working paper that takes a closer look at short-term physical electricity trading in Austria.

Short-term electricity trading in the wholesale market has gained significance in the past few years. In this context, increased volatile electricity generation from renewable energy sources can be cited as an important factor which requires more flexible marketing strategies or, in other words, enables even shorter procurement periods due to increased liquidity. The product range offered on power exchanges reflects this trend: in 2012, for example, intraday exchange trading on the EPEX Spot was expanded to include Austria as well, and auctions of quarter hour trading products were introduced. Due to the ambitious European and national renewable energy targets, it can be expected that short-term electricity trading will become even more relevant in the coming years. On that account, E-Control addresses this topic in detail in this analysis.

The first chapter of the paper presents the research questions to be answered and explains the methods applied. The second chapter identifies the main marketing opportunities for short-term electricity trading in Austria, including the respective timeframes and sequences. The aim is to give an overview of alternative marketing opportunities, to determine their time-related dependencies and to identify possible trading constraints. The third chapter of this working paper takes a closer look at competition in short-term markets. To this end, various methods for determining market concentration are applied to selected markets and the results compared with each other to reach a consistent overview of the competitive situation. The last chapter of this paper determines and quantifies potential interdependencies between short-term markets as well as the impact of fundamental data, such as the volume of wind or photovoltaic power fed into the grid, on price and volume evolutions in these market segments. The purpose of the analysis is to secure a comprehensive understanding of the trading activities in the short-term physical electricity markets in Austria and to identify the major drivers for the price and volume evolutions in these markets. A further aim is to determine and analyse possible undesirable developments or inefficiencies in the market. As a result, it will become easier to classify short-term electricity trading problems, to derive necessary measures and to take them into account in the future organisation of the market.

1.1. Research questions

This working paper intends to investigate four research questions in connection with short-term physical electricity trading. These research questions are as follows:

Research question 1: What are the marketing opportunities in short-term physical electricity trading in Austria?

[1] The term balancing, aka control reserve, as used in this paper, comprises both the availability of power generation capacity for control purposes (balancing capacity) and the energy fed in or received (positive or negative balancing energy) from such available capacity. Balancing markets, aka control reserve markets, therefore serve to procure balancing capacity and balancing energy.

The aim of the first research question is to identify the short-term marketing opportunities available to market participants in Austria. In the process, in addition to the macro structure of electricity trading and the short-term market segments contained therein, the specific features of the individual marketing opportunities, such as bid formats or technical prerequisites and their relevance for electricity trading in Austria, will also be presented in terms of volumes traded on these markets.

Research question 2: What is the timeframe for these marketing opportunities?

Research question 2 is closely linked to research question 1, which is why they are evaluated together. The aim of research question 2 is to determine the time-related interdependencies between the individual marketing opportunities in order to identify possible alternative markets. These findings will present a vital prerequisite for forming theses and for analysing research question 4.

Research question 3: What is the competitive situation in short-term physical electricity trading in Austria?

Research question 3 examines the competitive situation of short-term electricity trading. Market concentration and liquidity present key parameters for efficient competition and will be analysed and calculated using various evaluation methods for the short-term markets determined in research question 1. The aim is to arrive at a well-founded conclusion on the “maturity” of the short-term markets in Austria. Due to data availability constraints, the analysis period will be limited to the years 2012 and 2013.

Research question 4: How do fundamental data and price trends in alternative markets affect the price and volume evolutions in Austrian short-term physical electricity trading?

Research question 4 takes a look at how fundamental influencing factors such as wind and photovoltaic power fed into the grid or price trends in alternative markets affect price and volume evolutions in the individual short-term markets. The aim of the analysis is to determine whether significant price and volume drivers exist, to identify them and to quantify their effects.

1.2. Overview of the methodological approach

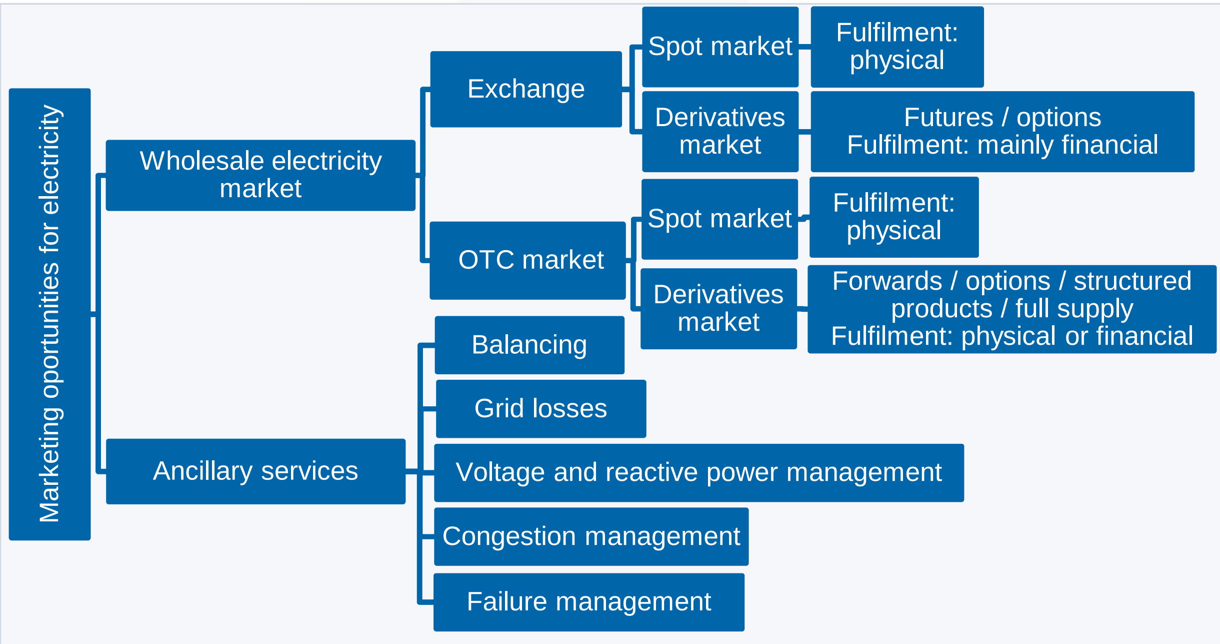
The evaluation of the research questions is carried out through both qualitative and quantitative methods. We use predominantly qualitative methods to discuss research questions 1 and 2. In a comprehensive research process, we identify and present the short-term marketing opportunities available as well as their timeframe and relevance for the Austrian electricity market. As part of the evaluation of research question 3, we conduct a quantitative analysis of the competitive situation in short-term trading. Here, the individual short-term markets are considered and evaluated using various key figures such as the market concentration ratio (CR) or the Herfindahl-Hirschman Index (HHI). Research question 4 carries out a quantitative analysis of the interdependencies between the various marketing opportunities and the influences of various fundamental data by means of statistical considerations and econometric analyses. Based on the findings in connection with research questions 1 and 2, we define theses for possible interdependencies and influencing factors in short-term trading and examine them with regard to their relevance using historical time series analyses. Detailed information on the methods applied in this working paper and conclusions reached are provided in the relevant chapters.

2. Marketing opportunities in short-term physical electricity trading in Austria

Marketing of electrical energy before physical fulfilment can take place on various platforms and by using different products. Short-term physical trading presents the last opportunity for sales and procurement, and is gaining significance due to the developments in renewable energy. The following section therefore analyses these marketing opportunities as well as their timeframe, and serves to clarify research questions 1 and 2. First, we give an overview of all trading opportunities on the electricity market and the embedding of short-term markets. Then, the individual short-term markets are described and their characteristics explained. Finally, we present the trading timeframes and evaluate the interdependencies between the individual short-term markets.

2.1. Overview and delimitation of short-term trading

A look into electricity marketing reveals that companies can choose from two options. They can market their portfolio via the wholesale market or offer ancillary services to the transmission system operator (see Figure 1).



Sources: (EFET, 2008), (APG, 2013)

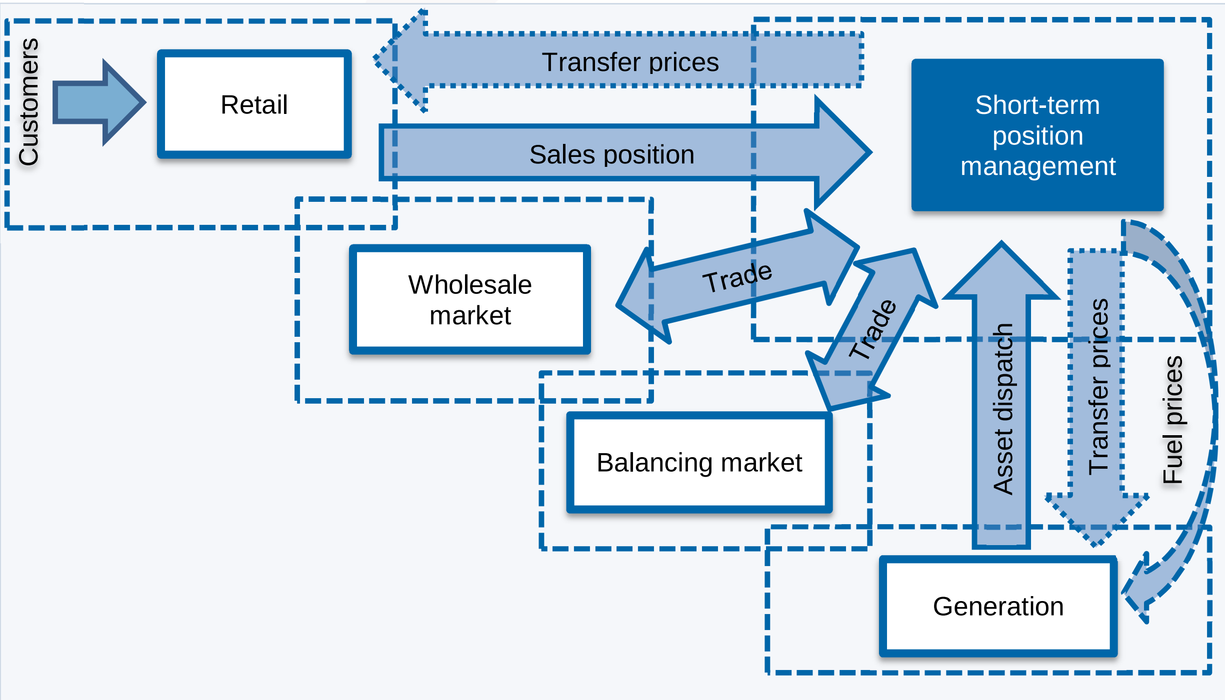
Figure 1: Overview of electricity marketing opportunities in Austria

While both electricity generating companies with physical assets and those that are pure electricity traders have access to the wholesale market, the provision of ancillary services is reserved for market participants that own generating facilities which comply with certain technical prerequisites. These prerequisites usually differ depending on the service procured by the transmission system operator, which is why the number of competitors and the trading volume in this market segment are significantly lower than in the wholesale electricity market. In Austria, the transmission system operator contracts facilities for the provision of balancing services, grid losses, voltage and reactive power as well as congestion and failure management. Electricity wholesale trading ideally serves to cover consumption at a minimum cost and to provide optimum marketing of company portfolios. Since the wholesale market comprises not only purely physical trading but also financial trading, wholesale trading has significantly higher trading volumes. Wholesale marketing can take place via power exchanges or over the counter (OTC). Both options enable long-term procurement and marketing via derivatives as well as short-term optimisation of the contract and generating portfolios via the spot market. Spot trading can be subdivided into a day-ahead market and an intraday market, and is fulfilled largely physically. Trading in derivatives hedges margins for generators in the long term and minimises the risks for suppliers, and can be fulfilled physically or financially. In exchange trading, fulfilment is predominantly financial.

This working paper focuses on short-term marketing opportunities. In the wholesale electricity market, they comprise both exchange trading and OTC trading. As regards ancillary services, the paper also includes considerations related to the auctions of balancing services because they are conducted on a weekly and daily basis and present an important alternative marketing opportunity for generators with physical assets. Trading portfolios are optimised by allocating trading positions to the individual market segments. This process is carried out by a company's position management, which will be explained briefly in the following.

2.2. Position management

Power plant operators secure the production of their generating systems up to three years in advance through so-called long-term position management. Each quarter, one twelfth of the total capacity[2] is passed from long-term position management to short-term position management. There, the trading positions are optimised up to one day before fulfilment in due consideration of the various marketing opportunities in short-term trading (see Figure 2).



Source: (EFET, 2008a)

Figure 2: Optimisation of marketing opportunities in short-term physical electricity trading by short-term position management

Depending on price expectations, electricity will either be self-generated (positive spreads expectation) or purchased at a more favourable price from the wholesale market (negative spreads expectation). Open trading positions are passed among the company divisions generation, trade and retail, largely at internally set transfer prices. The risk of an open position is borne by the division on whose books it is recorded. If a position is not closed, it will enter physical fulfilment (VSE, 2012). Asset dispatch usually plays a key role in the

[2] These are the trading positions of the next three months.

optimisation of short-term trading. It must ensure that the assets are used in accordance with the trading positions; at the same time, asset dispatch can further optimise the use of power plants before actual physical delivery and therefore achieve additional gross margins, e.g. by taking into account portfolio effects. Dispatching closely works with the trading division, which positions the bids on the wholesale market and the balancing market. In addition, trading can be used to exploit short-term market developments and realise further revenue potential (RWE, 2013). The various marketing opportunities and their timeframes are described in detail in the following.

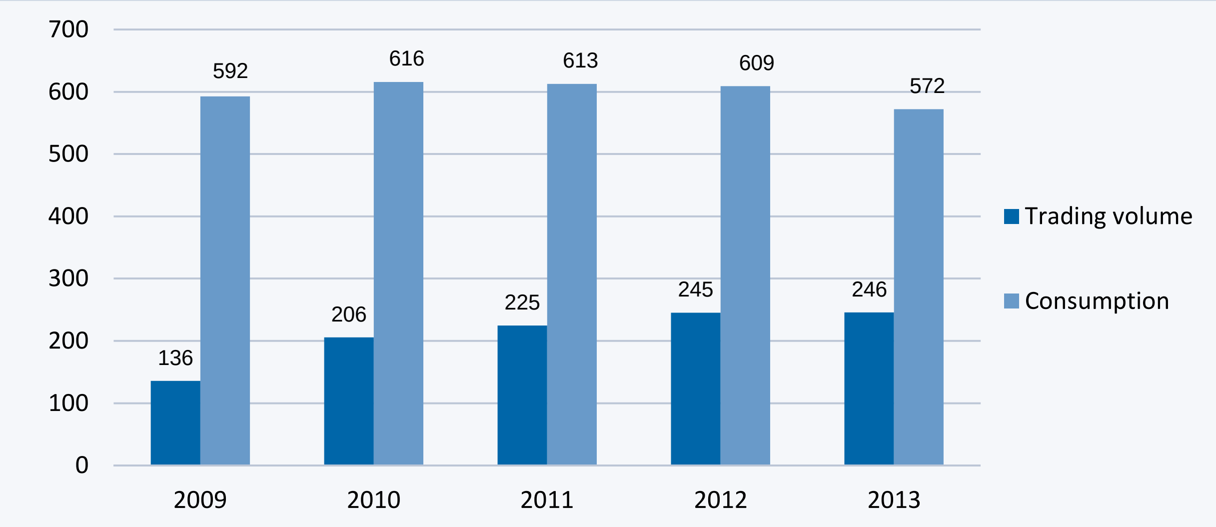
2.3. Day-ahead exchange marketing

The day-ahead market enables trading of electricity products for the following day. It is an essential part of exchange trading and at the same time provides an important reference price signal for OTC trade, which will be further discussed in section 2.6.1. Day-ahead market participants can adjust their portfolio based on current generation and consumption forecasts for the next day and as a result optimise marketing of their generation and consumption quantities. Due to the high capacity of cross-border lines, the Austrian day-ahead market is closely tied to the German market area, forming a joint German-Austrian price zone. Exchange trading of day-ahead products can be conducted on two different platforms: European Power Exchange EPEX Spot based in Paris and Energy Exchange Austria EXAA Abwicklungsstelle für Energieprodukte AG headquartered in Vienna. Both platforms use auctions[3] to determine the price for delivery on the following day, and both allow for trades with physical fulfilment within the control areas APG, Amprion, TenneT, TransnetBW and 50Hertz. They will be described in detail in the following.

2.3.1. EPEX Spot

European power exchange EPEX Spot SE was founded in September 2008 as a joint venture between the power exchanges EEX AG and Powernext SA. Since 2009, EPEX Spot has been the major hub for spot trading for the bidding zones Germany-Austria, France and Switzerland. In the past few years, EPEX Spot has managed to establish itself as a major European power exchange that has been recording a steady growth in trading volumes ever since its launch. In the years 2012 and 2013, the day-ahead trading volume already reached more than 40% of the overall electricity consumption in Germany and Austria (see Figure 3).

Day-ahead trading volume on EPEX Spot and electricity consumption in Austria and Germany (TWh)



Sources: (EPEX Spot, 2014), (EPEX Spot, 2014a), (ENTSO-E, 2014)

Figure 3: Trading volume on EPEX Spot day-ahead market (bidding zone Germany-Austria) as compared to annual electricity consumption in Germany and Austria

[3] As compared to continuous trading on the OTC market and the short-term intraday market.

Possible day-ahead market order formats

The power exchange EPEX Spot offers its members extensive marketing opportunities via day-ahead auctions. It is possible to place single hour orders for the following day or block orders. In addition to a total of 17 standard block orders, market participants can also submit user-defined blocks linking several hours of their choice. Block orders are executed on an all-or-none basis, which means that either the order is matched on all hours or it is entirely rejected. The minimum volume per single hour or block order in the day-ahead market is 0.1 MW, the minimum price increment is 0.1 €/MWh. The price limit for limited single hour or block orders (limit orders) must be chosen between −500 €/MWh and +3,000 €/MWh. Matched orders are executed at a price determined by the limit or at a better price. Alternatively, market participants may also enter unlimited bids (market orders). These have no price limits and are executed at any price determined by the trading system (market clearing price).

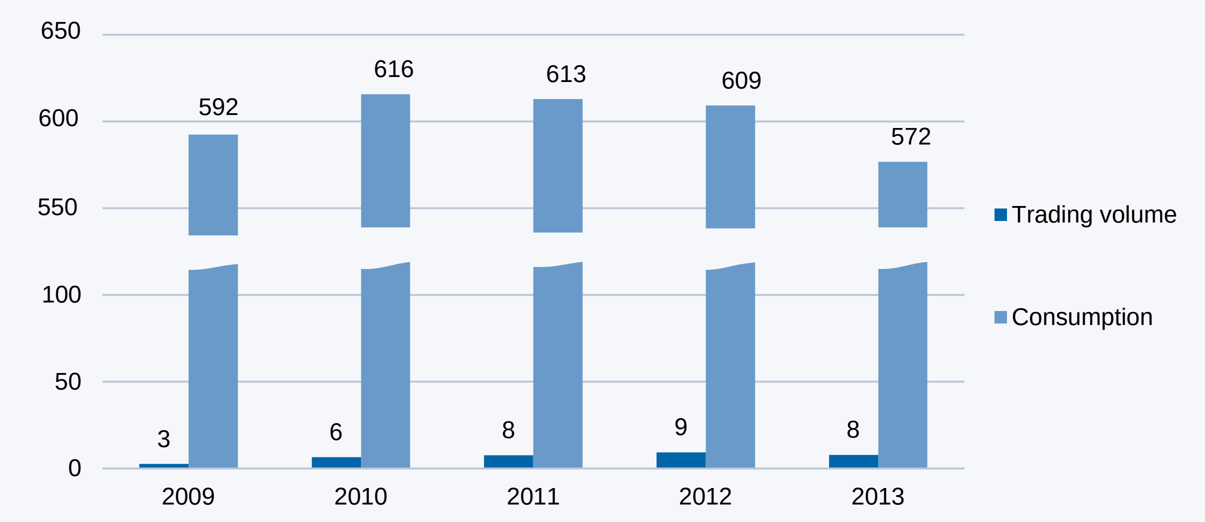
Day-ahead market timeframe

The auctions at EPEX Spot take place year-round, seven days a week. The order book for an auction is opened 45 days before physical delivery. Orders can be placed until noon one day before delivery. After the order books are closed, the price is determined by the EPEX Spot matching process. A combinatorial optimisation algorithm accepts only those single-hour and block orders that result in the maximisation of the total welfare in the market area, considering current network constraints (EPEX Spot, 2014b). The resulting hourly day-ahead prices are published from 12.42 the day before delivery on the EPEX Spot website.

2.3.2. EXAA

The energy exchange EXAA is the second trading platform of relevance to short-term physical electricity trading in Austria. Founded as a commodity exchange in 2001, EXAA has since 2002 been offering its members the possibility of concluding physical trades of day-ahead products for Germany and Austria. In December 2012, EXAA also launched trading of electricity from renewable energy sources[4]. With the exception of the year 2013, the EXAA day-ahead market managed to record a continuous increase in trading volume. Compared to overall electricity consumption in Germany and Austria, however, only a small portion of 1 to 2% is traded via EXAA (see Figure 4).

Day-ahead trading volume on EXAA and electricity consumption in Austria and Germany (TWh)



Sources: (EXAA, 2014) (ENTSO-E, 2014)

Figure 4: Trading volume on EXAA day-ahead market (bidding zone Germany-Austria) as compared to annual electricity consumption in Germany and Austria

[4] GreenPower@EXAA.

Possible day-ahead market order formats

Similar to EPEX Spot, EXAA offers its exchange members extensive marketing opportunities via day-ahead auctions. Members can place single hour orders for the next day or choose from 14 different block orders. Block orders, by default, are handled in the same way as single hour orders and partial execution is possible. Alternatively, members can submit block orders with a “fill-or-kill” option, which corresponds to the EPEX Spot “all-or-none” principle. The minimum trading volume on the EXAA day-ahead market is 0.1 MWh/h, the minimum price increment is 0.01 €/MWh. Single hour orders and block orders can be submitted as limit orders with a price limit or as price-inelastic market orders. The possible price limits for limited orders range from −150 €/MWh[5] to +3,000 €/MWh.

Day-ahead market timeframe

EXAA enables year-round trading of day-ahead products. Orders for Saturday, Sunday and Monday, however, must be placed on Friday. In addition, prior to statutory holidays, orders must be submitted for all statutory holidays including the first working day that follows. The order book is opened six days before the day-ahead auction. From this moment, traders can place their orders for the auction every day between noon and 4.00 pm. On the day of the auction it is possible to submit orders between 08.00 and 10.12. After the order books are closed, the hourly market price is determined by the EXAA matching algorithm. Single hour and block orders are auctioned together. At 10.15 the results of the auction and the tentatively accepted orders are announced. Subsequently, at 10.16 a three-minute post-trading period begins, during which surplus orders which were not or not fully accepted by the matching algorithm can be traded at the determined market price.

2.4. Intraday exchange marketing

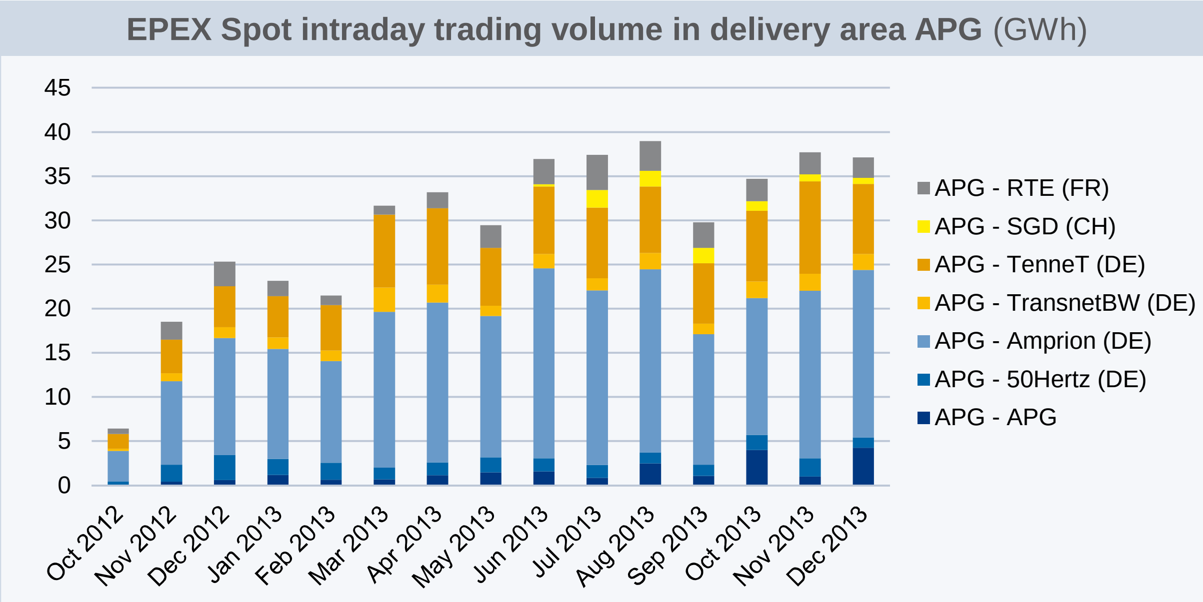
The intraday market is the second important segment of short-term physical electricity trading. It is downstream of the day-ahead market and enables electricity generators, traders and suppliers to adjust their portfolios immediately before physical fulfilment. Intraday trading has gained significance in the past few years, especially due to the growing portion of intermittent renewable energies and the resulting volume uncertainties. Via the intraday market it is possible for market participants to buy or sell e.g. when they need to compensate for forecast errors or when there are unplanned failures. Owing to the short lead time between trading and physical fulfilment of the contracts, unlike in the day-ahead market, the price is not determined via a single auction process but by continuous trading. The buy and sell orders are constantly compared and matched as soon as they can be executed. Intraday products can be traded via power exchanges or via broker platforms or bilateral agreements. The focus of the next section is on intraday exchange trading for the Austrian market area.

2.4.1. EPEX Spot

Since October 2012, EPEX Spot has enabled its market participants to trade intraday products in the Austrian control area APG. Thanks to the flexible intraday trading schemes (FITS)[6] also cross-border intraday trade with Germany, France and Switzerland is possible. In 2012, the year of its introduction, the trading volume in the Austrian delivery area APG amounted to 50 GWh, and to 391 GWh in the first full trading year 2013, each of which was significantly lower than the trading volume on the EPEX Spot and EXAA day-ahead markets. Trading took place largely in the form of cross-border trades with German control areas, and only a small amount was conducted regionally in the control area APG (see Figure 5). Therefore, cross-border trade with Germany holds major significance for the Austrian intraday market. In the following, the trading opportunities as well as trading timeframes in

[5] See (CISMO, 2013).
[6] FITS enables the implicit use of cross-border transmission capacities.

the Austrian delivery area APG and the four German delivery areas Amprion, TenneT, 50Hertz and TransnetBW are discussed in detail.



Source: EPEX Spot

Note: The trading volume comprises single hour contract trading, but not block contracts.

Figure 5: Trading volume on the EPEX Spot intraday market in delivery area APG as well as between delivery area APG and neighbouring control areas

Possible intraday market order formats (delivery area APG)

In the delivery area APG of the EPEX Spot intraday market, single hour and block orders[7] can be traded for delivery on the same or the following day. Furthermore, it is possible for market participants to submit user-defined block orders. Additionally, two different order types are offered: limit orders, which are executed at an agreed price or a better price, and market sweep orders, matching continuous single hour orders with other single hour orders. Apart from that, four execution conditions can be defined: “all-or-none” (AON) orders are executed for their full quantity or cancelled. “Immediate-or-cancel” (IOC) orders are either executed immediately or cancelled automatically and can also be executed partially. The unexecuted quantities are cancelled. “Fill-or-kill” (FOK) orders are either executed immediately and for their full quantity or cancelled. “Iceberg orders” (ICB) are large orders split into several small partial orders. The trader determines the total quantity and an initial (i.e. partial order) quantity. The total quantity is not revealed to the market and is submitted as a series of partial orders having equal quantity until the total quantity is covered[8]. All orders placed on the Austrian intraday market must have a minimum contract size of 0.1 MW. The minimum price increment for intraday contracts is 0.01 €/MWh. The technical price range within which orders can be placed comprises –9,999.99 €/MWh to +9,999.99 €/MWh.

Intraday market timeframe (delivery area APG)

Trading on the intraday market for the delivery area APG is conducted year-round, 24 hours a day. The order books open at 15.00 one day prior to delivery and close 75 minutes before physical fulfilment. The intraday market is organised by continuous trading, enabling the continuous matching of the best orders in the order books. The orders are prioritised based on the order type (buy or sale), the determined price limit and the time each limit is entered. If

[7] EPEX Spot provides trading of base load contracts (daily, hours 1 to 24) and peak load contracts (Monday to Friday, hours 9 to 20) on the Austrian intraday market.
[8] In the event of an odd lot, the quantity of the last order is smaller than the partial order quantity.

sufficient intraday capacity is available and a cross-border nomination is possible, cross-border trading can take place in the market areas France and Germany as well. For this purpose, the order books of the delivery area APG are consolidated with the order books for the delivery areas Germany and France and compatible orders are executed. Regional and cross-border orders are handled with equal priority. However, they are explicitly identified as such to traders. If congestion in the transmission network appears after a trade has been executed and cross-border trade becomes impossible, even cross-border trades that have already been executed will no longer appear in the order book.

Possible intraday market order formats (delivery areas Amprion, TenneT, 50Hertz, TransnetBW)

The EPEX Spot intraday market for the German delivery area enables market participants to trade quarter-hour contracts in addition to single hours and block orders. The possible order types and execution conditions for orders in the German delivery areas do not differ from those of the delivery area APG. The same applies to the minimum contract size, the minimum price increment and the technical price limits within which orders can be placed.

Intraday market timeframe (delivery areas Amprion, TenneT, 50Hertz, TransnetBW)

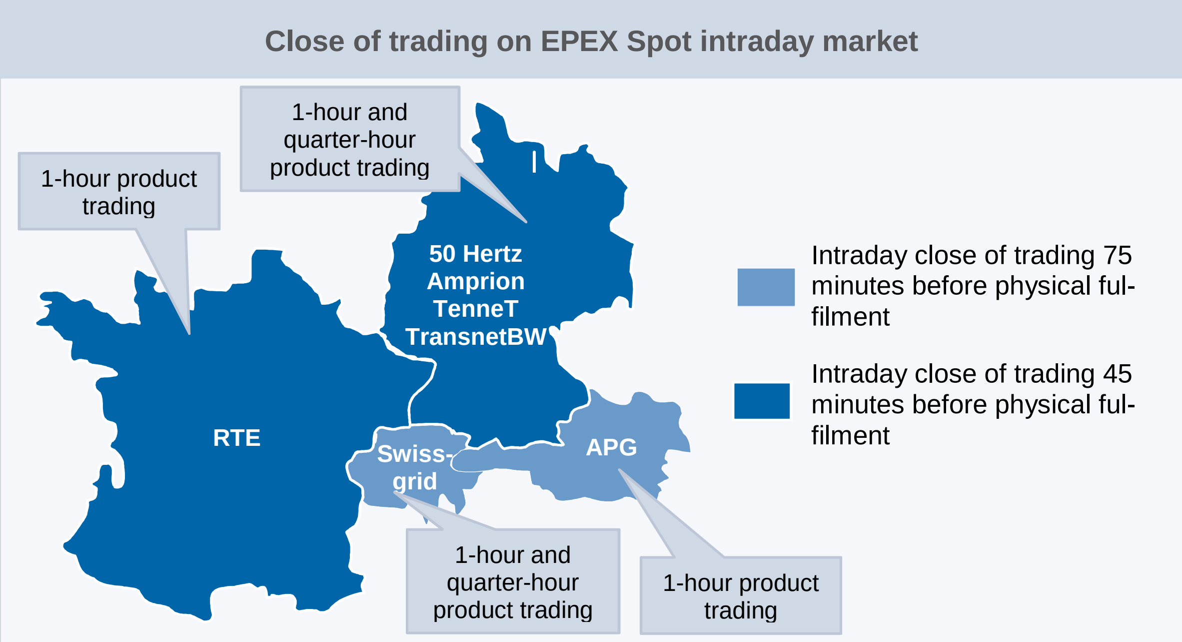
Intraday trading on EPEX Spot can be conducted year-round, 24 hours a day. The order books for single hours and block contracts in the German control areas are opened at the same time as intraday trade for the delivery area APG, at 15.00 the day before delivery. Trading for quarter-hour products starts at 16.00 the day before delivery. Trading is only possible for delivery into the German control block and ends 45 minutes before physical fulfilment.

In order to be able to cover the liquidity for quarter-hour product trades and minor schedule deviations at an early stage, EPEX Spot[9] is currently considering launching a day-ahead auction for quarter-hour products. Austrian power exchange EXAA[10] has been contemplating this as well. EXAA intends to implement the plans as early as summer 2014[11]. This way, quarter-hour product trades for Saturday, Sunday and Monday could be conducted already on Friday, which would simplify matters for smaller market participants that usually do not operate their trading floor on weekends (E&M, 2014).

Indirect intraday trading on EPEX Spot

EPEX Spot trading for the delivery area APG closes 75 minutes before the hour of physical fulfilment. After that, market participants are no longer able to conclude trades directly in Austria via the power exchange. Close of trading was determined based on an agreement in line with ENTSO-E (2004), according to which changes of schedules for exchanges between control blocks must be submitted no later than 45 minutes before physical fulfilment, and on top there is a 30-minute lead time for schedule nominations on the part of European Commodity Clearing (ECC), the EPEX Spot clearing house. Since close of trading in the delivery areas of Germany and France does not happen until 45 minutes before physical fulfilment, the market participants in those countries can trade 30 minutes longer directly via the EPEX Spot intraday market (see Figure 6).

[9] See (EPEX Spot, 2014c).
[10] See (ZfK, 2014).
[11] Quarter-hour product trading on EXAA was launched on 3 September 2014, which was after the editorial dead-line for this paper. Therefore, this market segment is not included in the considerations.



Source: Own research

Figure 6: Close of trading in the different delivery areas of the EPEX Spot intraday market

Currently, Austrian market participants can trade on the EPEX Spot intraday market only indirectly up to 45 minutes before physical fulfilment: they can submit buy or sale orders in a German or French delivery area, and once an order is accepted they can register an intraday schedule change across control blocks with the transmission system operator. Since such schedule changes are not carried out by the ECC, the 30-minute lead time for nominations is obsolete. However, such an exchange trade is handled like an OTC agreement, which means that the schedule must be registered with APG over the phone[12]. Twenty minutes after the registration of the intraday schedule change, the market participant receives a response from the transmission system operator, informing on whether or not there is sufficient capacity in the network to carry out the cross-control block transaction.

If a schedule change causes problems it is rejected and the previously agreed schedule is delivered. Market participants in Austria therefore face the risk that trades concluded in other control blocks may not be fulfilled. Indirect exchange trading in or from the Austrian delivery area therefore has a potentially higher risk compared to direct exchange trading in the German and French delivery areas. In view of an increased portion of volatile generation from intermittent renewable energy sources and growing significance of short-term trade, this could result in serious disadvantages for market participants in the delivery area APG. Therefore, efforts should be made to align the close of trading in the different EPEX Spot delivery areas.

2.5. Balancing market

In the area of ancillary services, the balancing market[13] is the most important short-term marketing option. In its function as control area manager, the transmission system operator APG procures sufficient quantities of available capacity in the form of tenders to be able to compensate for unexpected deviations in generation and consumption. The equilibrium of generation and consumption at all times is necessary to guarantee stable grid frequency.

[12] See (E-Control, 2012). Since schedule changes over the phone could potentially lead to restrictions in short-term trade, they should be reviewed for their usefulness.
[13] The term balancing, aka control reserve, as used in this paper, comprises both the availability of power generation capacity for control purposes (balancing capacity) and the energy fed in or received (positive or negative balancing energy) from such available capacity. Balancing markets, aka control reserve markets, therefore serve to procure balancing capacity and balancing energy.

Load frequency control occurs through the use of positive and negative balancing energy. Positive balancing energy refers to either additional energy being fed into the grid or a reduction of consumption. Negative balancing energy is produced by reducing the energy fed into the grid or by increasing consumption. At present, balancing services are provided largely by generation units. In the future, greater participation of consumption units in tenders for balancing services is expected. In the following section, the various types of balancing services are discussed first, followed by a presentation of the procurement process and timeframe in the balancing market.

2.5.1. Types of control

In the area of load frequency control, a distinction is made between the three types of control, i.e. primary, secondary and tertiary[14]. They differ particularly in regard to their speed of activation and change. This classification, which is also referred to in the Austrian Electricity Act 2010[15], originates from the Continental Europe Operation Handbook (ENTSO-E, 2004). There is a different classification in the network codes on electricity balancing and load frequency control and reserves, which will play a significant role in the future[16].

Primary control

Primary control is needed to restore the grid balance within seconds following a sudden change in load. This takes place automatically through relevant controllers in the event of frequency deviations. The amount of the primary control reserve (PCR) is set for the entire Continental European Grid and distributed to the individual control areas (ENTSO-E, 2004). For the APG control area, ±71 MW were to be reserved in 2012, ±66 MW for 2013 and ±71 MW again for 2014.

Secondary control

Secondary control is designed to relieve primary control and is activated no later than 30 seconds following a disruption. This is to restore the grid balance, eliminate the deviation in frequency and free up primary control. The ENTSO-E Operation Handbook[17] cites various methods for setting the amount of the secondary control reserve (SCR). Since 2012, the secondary control reserve has been ±200 MW. It is meant to cover the deviations that are to be expected in normal operation as well as major disruptions[18]. In Austria, in addition to secondary control reserve in the narrower sense, a so-called incident reserve in the amount of 280 MW is available. This is procured as part of the tender for tertiary control, but compensates for a block failure and is consequently a part of secondary control[19].

Tertiary control

Tertiary control is deployed to relieve secondary control. It is manually activated by the control area manager and subject to more moderate time requirements. It must be fully activated after 15 minutes. Activation currently takes place by telephone. However, in the course of 2014, a conversion to electronic communication has started. The available positive capacity amounts to 280 MW (from incident reserve), the negative capacity to 125 MW. In the event of a power plant failure, energy purchased from incident reserve[20] is charged in accordance with the rules for secondary control, otherwise it is considered procurement of tertiary control energy.

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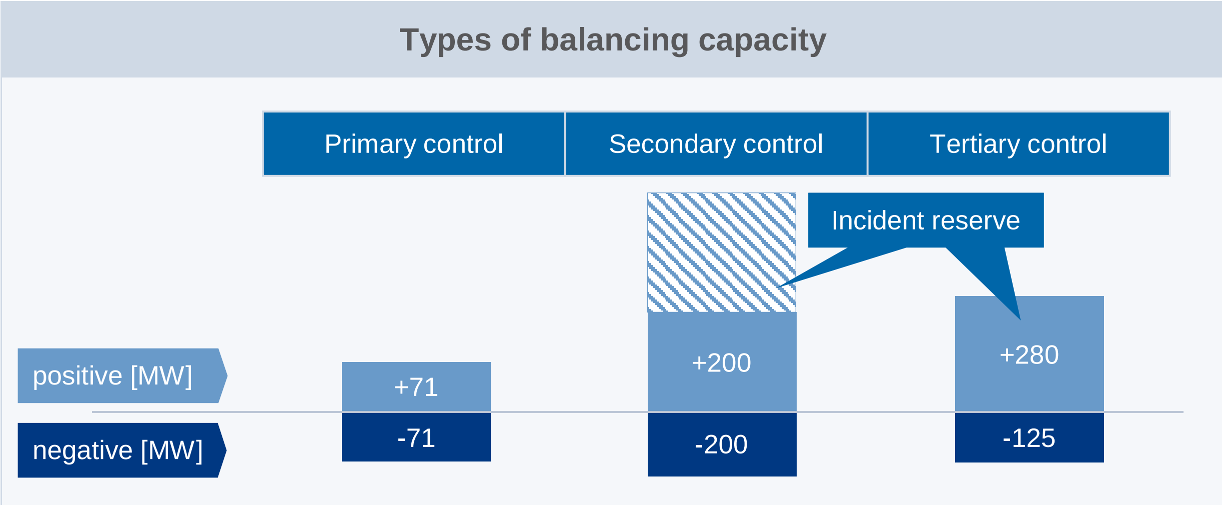
[14] The latter is also referred to as minute reserve.
[15] See the definitions in section 7 (1)(58, 62, 67) Electricity Act 2010.
[16] For the current status of proceedings as well as for the draft texts of the network codes, see (ENTSO-E, 2014).
[17] See (ENTSO-E, 2004).
[18] Such as the failure of the biggest generation unit.
[19] See Section 7(1)(62) Electricity Act 2010.
[20] Incident reserve is the reserve that is necessary to compensate for the largest possible generation incident in a control area. The size of the total reserve must match the size of the incident (ENTSO-E, 2004).



Source: Own research

Note: The amount procured for primary control is redetermined annually and in 2014 is ±71 MW.

Figure 7: Overview of the procured volume for the various capacity products on the Austrian balancing market.

2.5.2. Conditions for participating in the tenders for balancing services

To participate in the balancing market, for every type of control there is, first, a technical prequalification and, second, a framework agreement to be signed which defines the relationship between the control area manager and the balancing service provider. The prequalification conditions define the technical characteristics which the units of a supplier pool must have, particularly with regard to the available control range, control dynamic and data exchange. The prequalification conditions for primary, secondary and tertiary control as well as the current tendering conditions are published by the control area manager (APG, 2014).

To strengthen the market by opening it up to new market participants and to lay the groundwork for further international cooperation, both the prequalification conditions and the framework documentation were revised in 2014. The amendments involve, among other things, easier participation of consumption units particularly for the provision of negative balancing capacity, a reduction of minimum order volumes, facilitated combination of technical units into pools, and an adjustment of individual products. These measures are set out in greater detail in a second working paper.

2.5.3. Procurement of balancing services

The procurement of balancing services has taken place in weekly auctions for all three types of control since 2012[21]. Tertiary control had already been procured via market-based tendering since 2001, primary control since 2010. Only approved providers with prequalified plants can participate in the tenders for balancing services. Subject of the auctions is the availability of balancing capacity for a certain period of time, which can be called on to deliver if necessary. A capacity price is paid for balancing capacity. The bids with the lowest capacity prices are accepted until the quantity tendered is reached. The accepted bids are remunerated using a pay-as-bid pricing mechanism, i.e. the providers receive the capacity price that they bid.

In addition to the capacity price, for secondary and tertiary control there is also an energy price[22]. This price is paid to the respective provider when it is called on to provide positive

[21] The procurement of secondary control was also carried out in 4-week auctions in the period from calendar week 1 of 2012 to calendar week 12 of 2013.
[22] Also referred to as unit price.

balancing energy. When negative balancing energy is requested, i.e. when the balancing service provider actually increases consumption, this price is paid by the provider. However, as the price for negative balancing energy regularly turns out to be negative itself, in the end there are payments to the provider in this case as well. Like the capacity price and the volume bid, the energy price is part of a market participant's bid, but with regard to the scoring rule the energy price is only considered as a differentiating factor if the capacity prices are identical.

All of the accepted bids are ranked in a merit order list (MOL) according to their energy price. This ranking is followed when balancing energy is needed. The energy price for the accepted bids can be adjusted day-ahead[23], which results in a new MOL for each day. The adjustment cannot result in higher prices for positive balancing energy or lower prices for negative balancing energy than are bid in the weekly auctions. Only for tertiary balancing energy is there an additional option outside the weekly auctions: providers can make daily bids for the following day for which only the balancing energy is remunerated but not the capacity. These are then included in the MOL in accordance with the bid on the energy price and called if needed.

If the required amounts cannot be procured in the first auction round, an additional “second call” tender is carried out or, if necessary, another “last call” tender. If the required capacity cannot be procured in either of these tenders, suitable power plants are obliged to provide it in accordance with section 69(4) Electricity Act 2010.

Auction schedule for primary control

The necessary primary control is procured in weekly auctions, on each Wednesday prior to the start of the delivery period. Bids can be submitted from 09.00 until 14.00. Participants can change their bids as often as they want before the end of the auction. Only the capacity price for the availability of capacity during the delivery period is bid and remunerated. Balancing energy is not separately remunerated.

Auction schedule for secondary control

The provision of secondary control takes place across six products: peak, off-peak and weekends, each for positive and negative capacity. These products are currently procured in weekly auctions. Bids can be submitted on Tuesday prior to the start of the delivery period from 09.00 to 15.00. As in the auction for primary control, the bids in this time slot can be changed at any point during the auction window. Bids must specify a volume, a capacity price and an energy price. Again, they are awarded on the basis of the capacity prices. If these are identical for two or more bids, the bid energy price is used as the differentiating factor. Actual calls for secondary control energy are placed following the energy price ranking in the MOL. All accepted bidders have the opportunity to adapt their energy price from 09.00-15.00 on the day prior to delivery[24]. This means the final MOL is re-determined every day.

Auction schedule for tertiary control

Tertiary control auctions, aka market maker auctions, are held weekly. Market participants can submit their bids on the Wednesday prior to the start of the delivery period, between 09.00 and 15.00. The process is similar to the auction for secondary control. Six time slots per day are tendered, each for positive and negative control. The auctions for the period from Monday to Friday and the weekend are carried out separately. Altogether, there are 24 product time slot combinations within a week. The energy prices can be adapted from the end of a weekly auction until 15.00 of the day before delivery[25]. Authorised bidders can submit additional bids during this period, but these bids only contain a volume and energy

[23] On the last business day (except Saturday) before the start of the delivery period.
[24] On the last business day (except Saturday) before the start of the delivery period.
[25] On the last business day (except Saturday) before the start of the delivery period.

price (capacity is not remunerated) and are only valid for one day. All bids (market maker and energy only) are included in the MOL for the relevant day and called on this basis.

Overview of balancing products in Austria			
	Primary control	**Secondary control**	**Tertiary control**
Equivalence in network codes[26]	FCR	Automatic FRR	Manual FRR
Activation time	< 30 seconds	< 5 minutes	< 10 minutes
Reserve capacity	2012: ±71 MW 2013: ±66 MW 2014: ±71 MW	200 MW plus 280 MW incident reserve (procured together with tertiary control)	+280 MW (incident reserve) -125 MW
Bidding volumes	At least 2 MW, after that increments of 1 MW	At least 5 MW, after that increments of 5 MW	10 MW to 50 MW for a supplier's first bid, afterward 25 MW to 50 MW, only full MW can be offered
Delivery period	1 week	1 week / (4 weeks)[21]	Mon-Fri Sat+Sun
Tendered products	Weekly product (Mon-Sun: 00.00-24.00), capacity only	Peak (Mon-Fri: 08.00-20.00) Off-Peak (Mon-Fri: 00.00-08.00 and 20.00-24.00) Weekends (Sat-Sun: 00.00-24.00) Each for positive and negative control	6 time slots for every 4 hours, each separated for positive and negative control
Timeframe for submitting bids	Wednesday the previous week, 09.00-14.00	Tuesday the previous week, 09-00-15.00 Adjustment of energy prices possible the day before delivery 09.00-15.00 Energy price cannot exceed (pos. control) or fall short of (neg. control) the price bid in the weekly auction	Wednesday the previous week, 09.00-15.00 (market maker) Adjustment of energy prices for accepted market maker bids from the end of the weekly auction through 15.00 the day prior to delivery Energy price cannot exceed (pos. control) or fall short of (neg. control) the price bid in the weekly auction Submission of additional tertiary control energy bids possible (compensation only for balancing energy / no market maker compensation).

Table 1: Overview of balancing products in Austria[27]

[26] The network codes use the terms frequency containment reserves (FCR), frequency restoration reserves (FRR), which can be automatically or manually activated, and replacement reserves (RR). The reservation of RR is not obligatory; tertiary control can be considered manual FRR in Austria.
[27] The information displayed refers to the period between 2012 and 2013, as discussed in this report. There will be amendments due to the changes in the prequalification and tendering conditions in 2014 (APG, 2014).

Trading balancing services across control areas – status quo and outlook

Against the backdrop of the European Internal Electricity Market[28] there is cross-border cooperation for individual balancing products, or plans for such. Since July 2013, APG and the Swiss control area manager Swissgrid have jointly procured primary control. Within the scope of this cooperation, any surplus in bids at an auction in one control area is included in the procurement process of the other control area[29]. The development of a similar cooperation for secondary and tertiary control is planned with German transmission system operators[30].

In addition to the measures concerning the joint procurement of balancing services, non-market-based measures for optimising the deployment of balancing energy are also developed through cooperation across control areas. Within the scope of "imbalance netting", before the deployment of secondary control energy, there is a review of whether existing deviations in the participating control areas can be offset against one another. If so, the control area managers do not purchase balancing energy but instead exchange energy between their control areas. The cost savings that result from not having to request balancing energy are distributed between the participating control area managers. There are currently such agreements with the Slovenian transmission system operator ELES[31] and with transmission system operators in Germany, Denmark, the Netherlands, Belgium, the Czech Republic and Switzerland in the scope of the International Grid Control Cooperation (IGCC)[32].

2.6. Additional marketing opportunities

In addition to the aforementioned marketing opportunities on the electricity exchanges EPEX Spot and EXAA, and on the balancing market, participants in the Austrian market can optimise their portfolio by way of short-term OTC trading or deploy their generation capacities to counter imbalances within their balance groups. These marketing opportunities are now outlined in brief.

2.6.1. Short-term OTC trading

OTC trading denotes a form of off-exchange, non-standardised trading which takes place between trading partners and is frequently carried out with intermediaries such as brokers (Bundeskartellamt, 2011). In contrast to exchange trading, trading in the OTC segment is not anonymous. The identity of the counterparties is either known in advance or, if an intermediary is involved, is announced upon conclusion of a trade. As in exchange markets, a distinction can be made between trade in long-term and trade in short-term contracts. While long-term contracts cover periods of quarters or years and are physically or financially fulfilled, short-term trading occurs to optimise the portfolio for the next or current day and is generally fulfilled physically. In wholesale markets, OTC trading assumes an important role. For example, in 2013 for the delivery area Germany, which represents a major sales market for Austrian traders, approximately 5,000 TWh[33] were traded on the OTC market and a comparatively small share of 1,600 TWh[34] on the electricity exchanges. Moreover, the trend in OTC trading volumes has shown a considerable rise in the last few years. In short-term physical electricity trading in Austria, OTC trading is primarily concentrated in the day-ahead segment. Intraday trading takes place largely on exchanges and only to a limited extent off-

[28] See network code balancing specifically on the balancing services segment (ENTSO-E, 2014).
[29] For more information, see http://www.apg.at/de/markt/netzregelung/primaerregelung/kooperation.
[30] For scheduling and details, see (APG, 2014).
[31] The cooperation between ELES and APG in the scope of the INC project has existed since May 2013. For more information, see http://www.apg.at/de/markt/netzregelung/sekundaerregelung/inc.
[32] APG has participated in the IGCC project since 24 April 2014.
[33] See (LEBA, 2014).
[34] See (Statista, 2014).

exchange[35]. In general, however, short-term OTC trading offers the advantage of a very brief lead time ahead of physical fulfilment. While intraday trading on the EPEX Spot for the APG control area closes 75 minutes prior to physical delivery, OTC transactions can be traded up to 15 minutes prior to the quarter hour of delivery inside the control area. By this time any short-term schedule changes must be reported to the control area manager. Even so, the OTC market shows a very low level of liquidity for this timeframe[35].

Previously, the general problem was that OTC trading exhibited only very limited transparency and information on price and quantity developments could only be estimated indirectly by surveying market participants. The enactment of the European Market Infrastructure Regulation (EMIR) in August 2012, which introduces mandatory clearing of all off-exchange standard derivatives transactions via a central counterparty and reporting of these OTC transactions to a transaction register, will make OTC trading much more transparent in the future. In the area of energy wholesale markets, the Regulation on Energy Market Integrity and Transparency (REMIT) plays an important role also. It enables the Agency for the Cooperation of Energy Regulators (ACER) to gather information about all on-exchange and off-exchange energy wholesale contracts for the purposes of market monitoring, and to publish parts of this information in order to increase transparency on the energy wholesale markets[36]. REMIT came into effect on 28 December 2012. The scope of data collection by ACER is defined by the European Commission by means of implementing acts. The specific collection of data starts nine months after these implementing acts become effective. E-Control also has the authority to enact ordinances that enable it to stipulate in detail the energy wholesale products which are to be reported, including frequency, scope and format of the reports[37]. The combined effect of these measures should substantially increase the transparency of OTC trading in the future and result in an even better understanding of trading activities and their reciprocal effects.

2.6.2. Offsetting short-term imbalances in balance groups

Another short-term marketing opportunity is the deployment of power plant capacities to compensate for imbalances within balance groups. This serves to minimise imbalance charges for the balance group or, when providing support to a control area, to potentially generate additional revenue. Imbalance charges are incurred when actual generation or actual consumption inside a balance group deviate from the submitted schedule. They are determined for every quarter of an hour. The individual balance groups are charged on a monthly basis. In order to minimise the imbalance charges for their balance groups, generation companies can try to balance their group's net position by deploying available power plants. As in Austria only the aggregated schedule of generation and consumption is communicated to the control area manager and drawn upon for calculating imbalances, there is no need to balance consumption and generation separately.

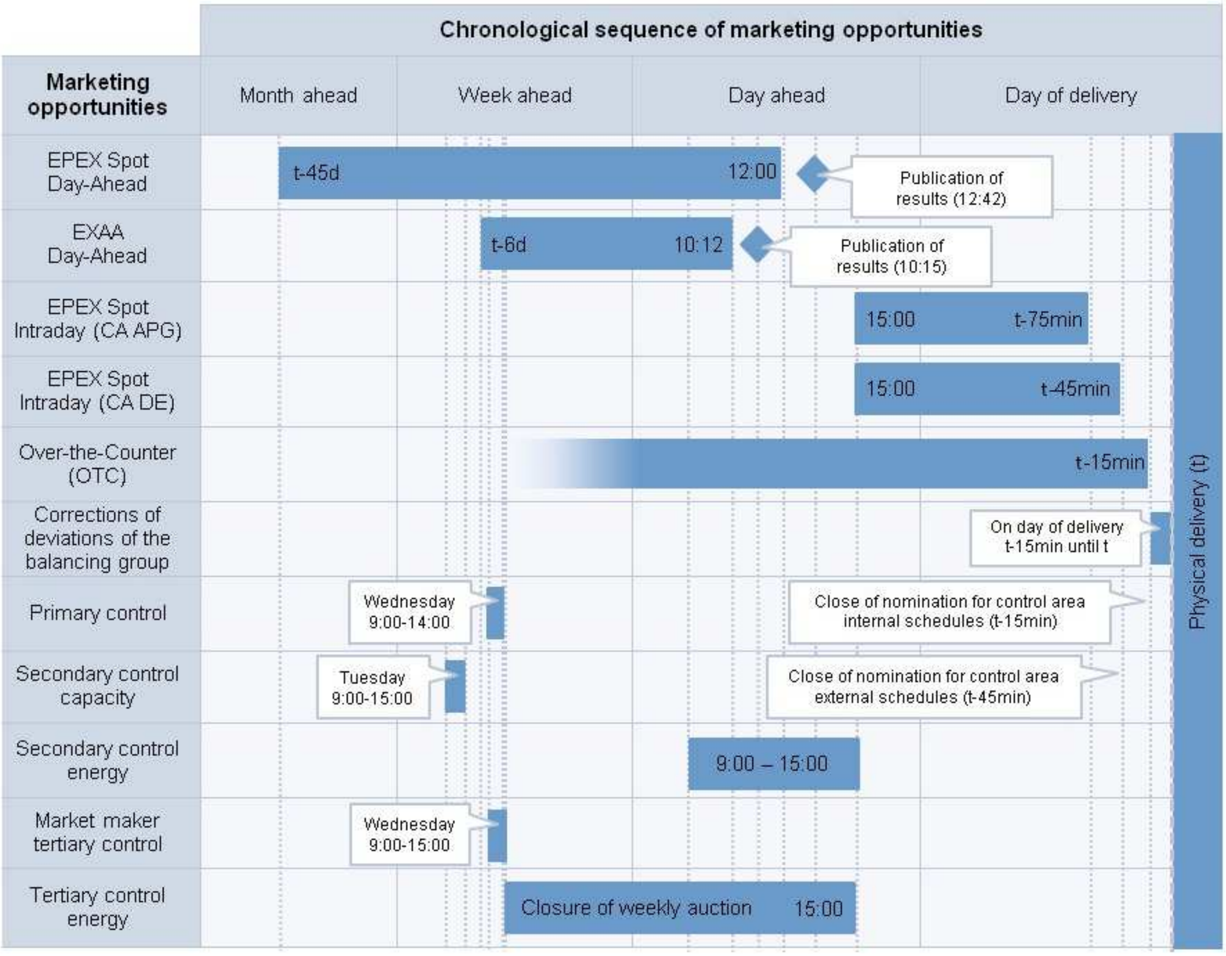
Austria's balancing regime incentivises market participants both to keep their own balance group's position in check and, if possible, to support the TSO in maintaining network stability. In this regime, instead of aiming for a balanced position, a balance group could on purpose create an imbalance in its own group that runs counter to the deviation in the overall control area; this would enable it to provide balancing energy to the control area and thereby reap additional revenues. However, given that the situation in control areas can fluctuate significantly and can at short notice change back and forth between load surpluses and shortages, this type of marketing is associated with considerable risk. That is, if a balance group creates an imbalance in the same direction as the control area as a whole, it receives no remuneration for balancing energy but rather has to pay imbalance charges to the clearing and settlement agent. Sound knowledge of the current control area position and its potential development is consequently an important prerequisite for taking advantage of this

[35] According to Austrian market participants.
[36] The condition for publishing is that the information does not disclose any commercially sensitive data concerning individual market participants, transactions or market places and that no conclusions may be inferred on the basis of it (see Regulation (EU) No. 1227/2011, Article 12(2)).
[37] See section 25a(2) E-Control Act.

marketing option. For greater understanding, the Austrian mechanism for pricing imbalances is presented once again in detail in section 6.1.1.

2.7. Timeframe of marketing possibilities

In the previous chapters, we gave a detailed description of the individual market segments that allow electricity trading portfolios to be marketed in the short term or to be optimised. Now we present the individual segments according to their timeframe and highlight their interactions (see Figure 8).



Source: Own research

Note: Over-the-counter (OTC) trading that takes place days, weeks or months prior to physical delivery is not regarded as a short-term marketing possibility by this paper, but rather as forward trading. This is expressed in the above illustration by the faded left end of the OTC time bar.

Figure 8: Timeframe of marketing possibilities in short-term physical electricity trading in Austria

In theory, the earliest marketing possibility for short-term power trading is the over-the-counter market. Bilateral supply contracts can be closed long before physical delivery[38]. However, sufficient liquidity generally forms only shortly before delivery, say three or four days before fulfilment[39]. The liquidity in the OTC intraday market is small compared to exchange trading. Most of the intraday volume is traded on the power exchange EPEX Spot[39]. Trading in the OTC market for transactions with other control blocks closes 45 minutes prior to delivery, and for transactions within a control area, trading ends 15 minutes before delivery; at both deadlines, corresponding schedules must be submitted to the proper transmission system operator or clearing and settlement agent, as appropriate.

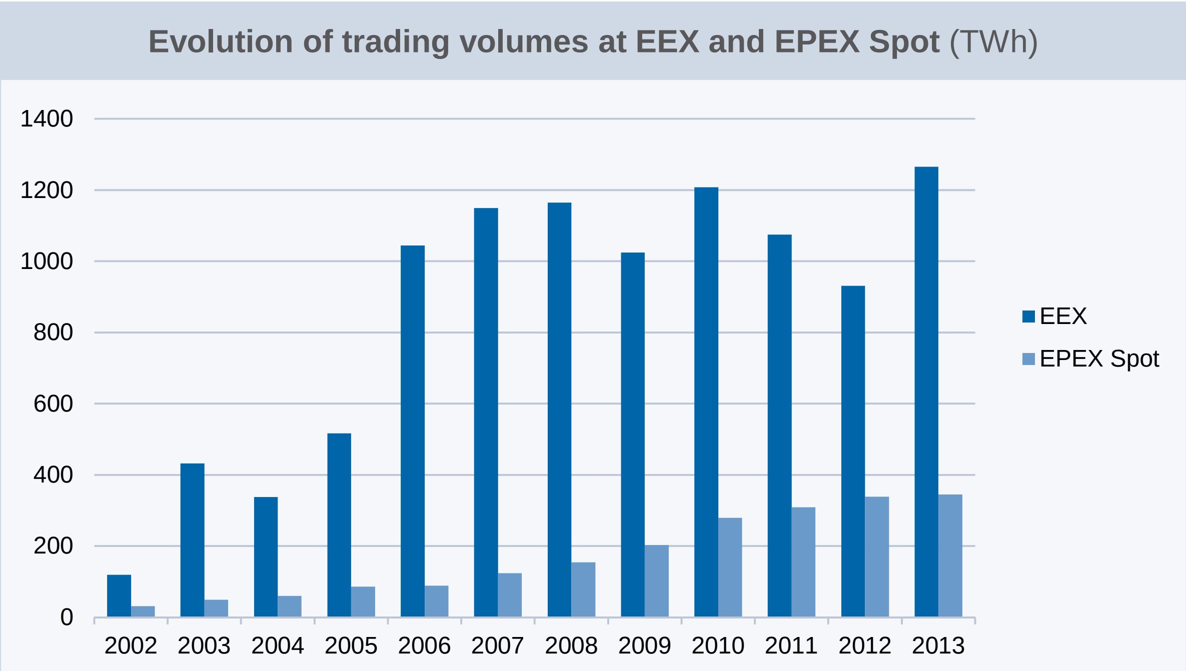
[38] In this context, supply contracts that are closed several days, weeks or months before physical delivery are not regarded by this paper as short-term marketing possibilities, but as forward contracts.
[39] According to Austrian market participants.

The first exchange market that enables bids and offers for short-term trading in Austria is EPEX Spot. Day-ahead trading opens 45 days before physical fulfilment and ends with the auction at noon the day before delivery. The second power exchange relevant for the Austrian market, EXAA, permits traders to enter bids for the day-ahead auction starting six days before delivery. Similar to EPEX Spot, EXAA holds an auction the day before fulfilment, but a bit earlier – at 10.12 rather than at noon. Trading on EXAA therefore represents an opportunity for a first optimisation round for market participants' portfolios. Due to the earlier closure time, bids typically have tighter price limits, or fewer bids without price limits are entered. As a result, EXAA prices tend to exhibit lower volatility than EPEX Spot prices, allowing market participants to reduce their price risk. Owing to the early time of auctioning and the narrow price limits, EXAA prices have very accurately reflected traders' assessment of the market and thus have had a high correlation with OTC prices (EXAA, 2014). Nonetheless, most day-ahead exchange trading, including bids with broader limits or no limits at all, is carried out on EPEX Spot.

Intraday trading at EPEX Spot starts after day-ahead trading has been concluded and the results have been published. From 15.00 on the day before delivery until 75 minutes before fulfilment, market participants can close deals for the supply of electricity into or out of the delivery area APG. After this period and up to 45 minutes before fulfilment, they can still trade indirectly for deliveries into or out of the German-French delivery area. This way, intraday trading enables market participants to adjust their portfolios at very short notice. Because of its short bidding period compared to the day-ahead market, the intraday market sees a very low trading volume and in general more volatile prices, which can have a range of up to ±9.999,99 €/MWh. In addition to block contracts and single hour contracts, market participants are also able to indirectly trade 15-minute products in the intraday market via the German delivery areas. Trading in these products starts on the day before delivery at 16.00 and ends 45 minutes prior to fulfilment, like trading in block and single hour contracts. Intraday trading is normally used to obtain electricity to compensate for unplanned outages, or to sell or buy when there are wind, solar PV or load forecast errors. Given that liquidity in intraday trading only reaches a sufficient level four to five hours prior to delivery[39], only highly flexible generating plants are in a position to respond to price signals in this market segment. As a consequence, the intraday market competes with the balancing market, which has strict flexibility requirements for participating generating plants also.

Contracting in the balancing market starts in the week prior to delivery. Potential assets need to be prequalified by the transmission system operator to be allowed to bid into the balancing market, therefore this marketing opportunity is not available to all market participants. Procurement of individual products starts with the auction for secondary control between 09.00 and 15.00 on Tuesday in the week prior to delivery. At this point, market participants already have to decide which of the following makes better business sense: keeping a power station available in the following week for balancing services, or marketing it through the subsequent day-ahead, intraday or OTC markets. Considering the very attractive level of prices in this market segment at the moment, prequalified generating plants are expected to be marketed primarily on the balancing market, other short-term markets being less profitable. Auctioning for secondary control is followed by auctioning for primary control between 09.00 and 14.00 on Wednesday in the week prior to delivery, and by the market maker's auction for tertiary control between 09.00 and 15.00. Generators that win one of the auctions contractually agree to keep their plants on call in the following week, so as to supply balancing energy at the request of the transmission system operator. The probability of the transmission system operator activating the generating plants hinges on their energy prices. In order to maximise the utilisation of their power stations, market participants are given the option to temporarily adjust the energy price of their plants towards nil and thus increase the probability of being called. For secondary control energy this is possible between 09.00 and 15.00 on the day before delivery, and for tertiary control energy between the end of the weekly auction and 15.00 on the day before delivery. Market participants whose bids were not accepted in the market maker auction still have the chance to explicitly offer their prequalified generating plants in tertiary control energy tenders. In providing tertiary control energy, prequalified power stations thus have an alternative to the day-ahead market and the intraday market. As bids for tertiary control energy are already selected at 15.00 on the day prior to delivery, generators can participate in the call for tenders without losing possible intraday marketing options. As far as secondary control is concerned, such explicit participation in energy-only tenders is not possible; all secondary control is auctioned off in the capacity auction.

Depending on revenue expectations and power station portfolios, market participants offer available capacities in individual market segments or optimise marketing strategies. On account of the very high revenue expectations, highly flexible plants are offered predominantly on the balancing market these days[40]. In most cases, baseload and load-following power stations are brought on the market through longer-term derivatives contracts, while peaking plants are offered in shorter-term trading. Owing to the increasing volatility of power generation and decreasing prices on the futures market, short-term power trading is gaining in importance. This is reflected by the rise in traded volumes over the past few years (see Figure 9)[41]. Hence it is essential to gain profound insight into the functioning of these markets and their interactions, and to ensure their efficiency.



Source: (Statista, 2014)

Figure 9: Evolution of volumes in derivative trading at EEX and in spot trading at EPEX Spot from 2002 to 2012.

3. Market concentration and liquidity

Market concentration and liquidity in the wholesale market are key measures to determine whether competition in this market is effective. The first far-reaching studies in the electricity sector were conducted within the scope of the European Commission's Energy Sector Inquiry[42] (SEC(2006)1724), which found that wholesale competition in most market areas was insufficient. Different measures, including the 3rd Energy Package[43] and other

[40] According to Austrian market participants.
[41] The rise in traded volumes is due to the higher liquidity in existing market areas, and to the expansion of intra-day trading to new market areas.
[42] See http://ec.europa.eu/competition/sectors/energy/inquiry.
[43] See e.g. http://www.e-control.at/de/industrie/news/monats-archiv/oktober-2009/3-energiemarkt-liberalisierungspaket.

regulatory and market-based measures have been taken in order to encourage competition in the wholesale sector. This chapter will mainly look at the liquidity and concentration of short-term electricity markets. Special focus will be put on the intraday and balancing markets. Even though these markets are of increasing importance in the light of rising generation levels from volatile sources, very few studies in Austria have so far looked at them.

The level of market concentration can be determined by means of different key figures like the concentration rate (CR) or the Herfindahl-Hirschman Index (HHI). In individual cases, the different calculation methods can lead to different results as they pursue – to some extent – diverging approaches and have different requirements regarding the quantity and quality of the data used. However, we can assume that a market which seems to be concentrated as measured by several different methods can actually be considered a concentrated market[44].

Irrespective of the calculation method, the relevant product and geographic market must be defined before any indicators are determined since market definition can have a major impact on the result. If the markets were defined too broadly, e.g. as energy markets in Europe, the calculated concentration level would be low because of the high number of market participants and no sound conclusions could be drawn concerning competition and market power. The latest study on the German-Austrian electricity generation and wholesale markets conducted by the German Federal Cartel Office[45] defines the product market with reference to generation units, i.e. as the first-time sales market. Amongst other things, this is justified with the fact that there are only limited possibilities to store electricity:

“Concerning the product market definition in electricity, mere trade activities must thus be excluded. In order to maintain network stability, the electricity generated at the production level must – with the exception of system-related losses – at any time be identical to the overall demand at the end-customer level. The possibilities to store electrical energy, e.g. by means of pumped-storage power stations, are currently rather limited. The electricity amount supplied to end customers is therefore mainly managed via the control of generation volumes, i.e. power stations at production level going online or offline. The first-time sales market for electricity thus reflects the actually active competitive forces at production level.” (Bundeskartellamt, 2011, p. 70) [own translation]

As regards the geographic market definition, the Federal Cartel Office assumes that the requirements for a German-Austrian market are met. The study eventually concludes that the wholesale market in the period under review was highly concentrated and that all four major German power generation companies (EnBW, E.ON, RWE and Vattenfall) were indispensable suppliers in a significant number of hours based on the Pivotal Supplier Index (PSI) and the Residual Supply Index (RSI). However, the study does not directly look at the interaction between different market segments with physical delivery, like the intraday or the balancing markets.

The following section of this paper focuses on the concentration and liquidity of the short-term markets in Austria. Due to data constraints, no conclusive market definition, as would be required for an investigation into market power in the narrower sense, is made. Even though the concentration values determined are indicative of the competitive level and the liquidity of individual trading platforms like the EXAA day-ahead market, they cannot be seen as indicative of all trade activities in this market segment. The sole exception here is the balancing market. Because of the extensive data available for the balancing market, it is possible for this market to conduct an investigation into market concentration in the narrower sense.

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[44] Amongst other sources, part 1 of (DG Comp, 2007) gives an overview of the relevant indicators for electricity wholesale markets.

[45] See (Bundeskartellamt, 2011, S. 87ff).

3.1. Data and methodology

A measure with which market concentration can be determined is the market concentration ratio (CR). The concentration ratio places the market share of the biggest company (monopoly) or biggest companies (oligopoly) into relation to the entire market. This occurs, first, by measuring the market shares of the individual companies. Here it should be noted that various reference values, such as volumes or turnover, are possible.

$$a_i = \frac{x_i}{\sum_{j=1}^{n} x_j} \qquad \textbf{(1)}$$

a_i	market share of company i
x	reference value for market share
j	total number of companies

Apart from determining the market share of a company, the total market share of several companies can be determined by adding the individual market shares (e.g. for CR(3)). The number of companies drawn upon to measure the market share of an oligopoly depends on the market and situation.

$$CR_j = \sum_{i=1}^{j} a_i \qquad \textbf{(2)}$$

CR_j	joint market share of j companies
a_i	market share of company i
j	number of companies considered

The Herfindahl-Hirschman Index (HHI) represents a measure of concentration for the entire distribution of market shares. It is calculated by summing up the squares of the market shares of all market participants. The percentage determined is generally multiplied by a factor of 10,000.

$$HHI = \sum_{i=1}^{n} a_i^2 * 10000 \qquad \textbf{(3)}$$

HHI	Herfindahl-Hirschman Index
a_i	market share of company i
n	total number of companies

The HHI can accept values between 0 and 10,000, with an HHI of 0 equivalent to minimal concentration or equal distribution and an HHI of 10,000 equivalent to maximum concentration or a monopoly. From an HHI of 1,000 a market is considered moderately concentrated, and from 1,800 highly concentrated.

3.2. Results for the day-ahead market

For day-ahead trading in Austria the two exchanges EPEX Spot and EXAA are of particular importance. Liquidity and commercial concentration on EPEX Spot have already been considered in a number of papers and studies. For example, in their annual monitoring reports the German Federal Network Agency and Federal Cartel Office[46] analyse commercial concentration across all day-ahead volumes. The combined turnover share of the five most profitable companies, or the CR(5), was 39 percent on the buy side and 49 percent on the sell side for 2012. The aggregation of the sell and buy sides results in a CR(5) of 42 percent. Although the concentration has increased on the buy side and decreased on the sell side

[46] See (Bundesnetzagentur, 2014, S. 119).

since 2009, the latter was still higher than the former in 2012. This may be attributed to an at least moderate market concentration in electricity generation, as found in the previous section.

E-Control's Market Statistics[47] and the EXAA Market Analysis[48] report monthly CR and HHI figures for the Austrian electricity exchange EXAA, separated for the buy and sell sides. As is shown in the market statistics data in Table 2, concentration on the basis of CR(5) is above the annual average of EPEX Spot over several months. In principle, however, both trading venues report a similar level of concentration. The HHI varies between values of nearly 400 and 1000 over the year, but is generally below the 1000 benchmark that denotes a moderately concentrated market. The analysis also shows that market concentration is declining.

	"Buy" according to volume traded				"Sell" according to volume traded			
	HHI	CR(3)	CR(4)	CR(5)	HHI	CR(3)	CR(4)	CR(5)
Jan 2013	472	26%	32%	38%	590	32%	37%	41%
Feb 2013	1013	47%	51%	55%	700	36%	42%	47%
Mar 2013	404	22%	29%	35%	549	30%	36%	41%
Apr 2013	488	28%	33%	39%	558	31%	37%	43%
May 2013	663	35%	42%	48%	506	28%	33%	38%
Jun 2013	460	26%	31%	37%	588	34%	38%	42%
Jul 2013	514	30%	36%	39%	657	35%	39%	43%
Aug 2013	498	30%	36%	40%	477	26%	33%	39%
Sep 2013	579	34%	41%	45%	501	30%	35%	40%
Oct 2013	681	35%	40%	45%	388	21%	26%	31%
Nov 2013	398	22%	28%	33%	413	23%	28%	33%
Dec 2013	447	25%	31%	36%	396	22%	28%	33%

Source: E-Control Market Statistics

Table 2: Concentration figures for the EXXA day-ahead market

3.3. Results for the intraday market

The data of EPEX Spot are used to determine the concentration on the intraday market in Austria. During the observation period, no information was available for intraday OTC trading. The data of the EPEX Spot exchange refer to intraday trading including the delivery area APG. This accounts for the fact that Austria's intraday trading takes place on EPEX Spot via a separate order book. The delivery area APG thus represents at least a separate bidding zone on the power exchange EPEX Spot. Due to the usually high volume of cross-border trading in this market segment, the delivery area APG does, however, not necessarily represent a separate market segment in terms of economics and competition law.

The first method used to evaluate market liquidity is the concentration ratio. Measuring oligopoly power on the intraday electricity market, the market share of the three largest companies (CR(3)) is calculated. Table 3 shows the concentration ratio of the intraday products traded on the EPEX Spot market in 2012 and 2013. The table is divided into the submarkets "buy" and "sell", each of which lists the aggregate market share of the top three companies in terms of their bid or offer volumes, and the total number of market participants. The individual lines represent the various hourly products for the individual submarkets. In general, the concentration ratio in all submarkets and of all products is above 50%. In all categories, however, the CR(3) is noticeably higher during off-peak hours than during peak hours, which is due to the lower number of market participants during off-peak hours. Comparing the buy and sell sides, it becomes apparent that the concentration ratio varies

[47] See http://www.e-control.at/de/statistik/strom/marktstatistik/stromboersen
[48] See http://www.exaa.at/de/marktdaten/market-analysis

more strongly among “buy” products than among “sell” products. However, neither of the two submarkets has a CR(3) that is generally higher than the other’s.

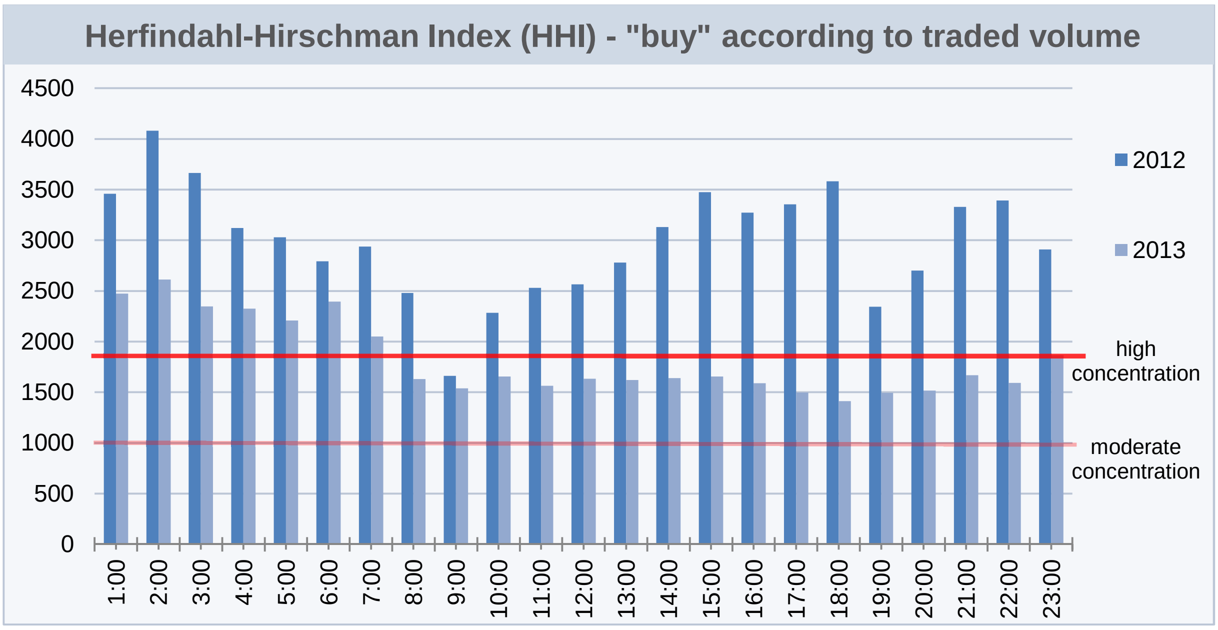
Market concentration ratio CR(3) on the EPEX Spot intraday market (delivery area APG)								
	Buy				Sell			
	2012		2013		2012		2013	
Product	CR(3)	no. of buyers	CR(3)	no. of buyers	CR(3)	no. of sellers	CR(3)	no. of sellers
1.00	89%	7	89%	13	87%	7	77%	15
2.00	75%	8	89%	13	92%	5	79%	16
3.00	71%	10	86%	13	91%	6	75%	16
4.00	80%	8	81%	16	84%	7	77%	15
5.00	80%	8	81%	13	83%	8	74%	16
6.00	82%	8	79%	11	84%	7	78%	13
7.00	68%	8	73%	14	85%	5	67%	14
8.00	70%	7	65%	17	77%	6	60%	14
9.00	67%	8	68%	15	60%	9	58%	18
10.00	69%	9	57%	19	77%	8	63%	17
11.00	75%	9	59%	17	83%	11	60%	20
12.00	66%	11	57%	18	83%	11	63%	20
13.00	70%	11	58%	21	84%	10	62%	21
14.00	60%	11	58%	23	88%	10	62%	22
15.00	69%	10	56%	23	87%	9	62%	22
16.00	64%	10	57%	22	87%	11	60%	22
17.00	64%	11	50%	21	88%	10	56%	22
18.00	65%	11	51%	20	89%	9	57%	22
19.00	71%	11	54%	22	74%	11	60%	21
20.00	66%	11	53%	21	81%	11	60%	22
21.00	74%	11	52%	23	85%	10	64%	21
22.00	78%	9	61%	20	87%	11	58%	22
23.00	77%	10	68%	20	86%	11	65%	21
24.00	72%	11	69%	21	78%	11	66%	22

Note: 2012 data were only available from 16 October 2012; data not including weekends and holidays

Source: EPEX Spot, own calculations

Table 3: Market concentration ratio (CR 3) on the EPEX Spot intraday market for the delivery area APG

The second concentration measure with which market concentration on the EPEX Spot intraday market is evaluated is the HHI. Figure 10 shows the HHI of the traded “buy” volume. Similar to the concentration ratio, the HHI is also indicative of higher market concentration during off-peak hours. Between 1.00 a.m. and 7.00 a.m., the HHI is above 1,800 for both years. For 2012, the HHI indicates high concentration with the exception of the 9.00 a.m. product. For 2013, the HHI indicates moderate concentration regarding the remaining products.

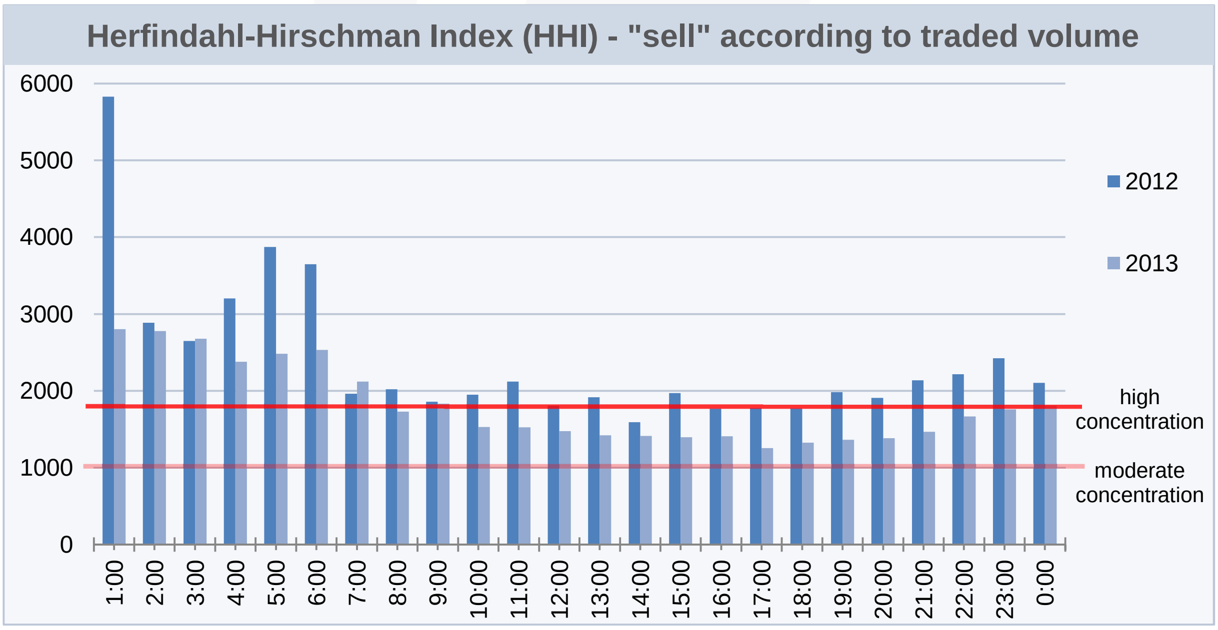


Note: 2012 data were only available from 16 October 2012; data not including weekends and holidays

Source: EPEX Spot, own calculations

Figure 10: Herfindahl-Hischman Index (HHI) for traded volume of "buy" orders on EPEX Spot for delivery area APG

The HHI for the traded volume of "sell" orders indicates high concentration during off-peak hours and moderate concentration during peak hours. As with the previous analyses, the HHI for 2012 is above the level for 2013.



Note: 2012 data were only available from 16 October 2012; data not including weekends and holidays

Source: EPEX Spot, own calculations

Figure 11: Herfindahl-Hischman Index (HHI) for traded volume of "sell" orders on EPEX Spot for delivery area APG

In summary, we can say that the EPEX Spot intraday market is a concentrated market. The analysis of the concentration ratio CR(3) and the HHI leads to the conclusion that concentration during off-peak hours is higher than during peak hours due to the lower number of market participants. During peak hours concentration is only moderate.

3.4. Results for the balancing markets

Due its special structure, the balancing market cannot be compared to other wholesale electricity markets. Demand is fixed by the control area manager, which requests a certain volume of balancing capacity on a weekly basis. Pre-qualified sellers can participate in the auction. There are different products for each type of control.

Geographically, the market is limited to the Austrian control area, with the exception of primary control, which has been procured in cooperation with Switzerland since July 2013. Product market definition in this case is given by the balancing capacity products of primary, secondary and tertiary control purchased via auctions. In the following, the period of 2012 and 2013 is examined. Mentions of products with pre-qualification requirements refer to the situation at the end of 2013.

Below, the aggregated market share of the three largest suppliers CR(3) and the HHI are calculated to give a general overview of market concentration. When measuring the concentration ratio, different reference values are considered. They include the volume bid, the volume of accepted bids, the turnover[49] and the pre-qualified capacity for each type of control. Regarding pre-qualified capacities, references are to the entire pre-qualified balancing capacity range (positive and negative).

3.4.1. Primary control market

The primary control market is the most densely concentrated balancing market (see Table 4). This is due to the stringent technical requirements for power plants providing primary control; only few power plants are able to meet them. Moreover, there is high concentration of pre-qualified capacity among certain providers.

CR(3) and HHI for the primary control market				
	Volume offered	**Volume accepted**	**Turnover**	**Pre-qualified capacity**
CR(3)	93%	91%	91%	95%
HHI	5,352	5,582	5,217	7,111

Source: Own calculations

Table 4: Market concentration ratio CR(3) and Herfindahl-Hirschman Index (HHI) in the primary control market based on volumes offered and accepted, turnover and pre-qualified capacity

3.4.2. Secondary control market

As 4-week auctions were carried out for secondary control until March 2013, the bids of the 4-week auctions and the respective 1-week auctions are merged to ensure uniform evaluation. Also bids that were placed only in the second or third tender (second and last call) are taken into account. The evaluation is carried out for individual products and for the overall result of the tender, in which the various products are weighted according to their delivery period.

As can be seen from the market concentration ratio, also the secondary control market is highly concentrated (see Table 5). The CR(3) for all products, calculated with the various reference values, is above 90%. The HHI also indicates high concentration. The graphic representation in Figure 12 shows that the HHI of both positive and negative products is considerably above 1,800.

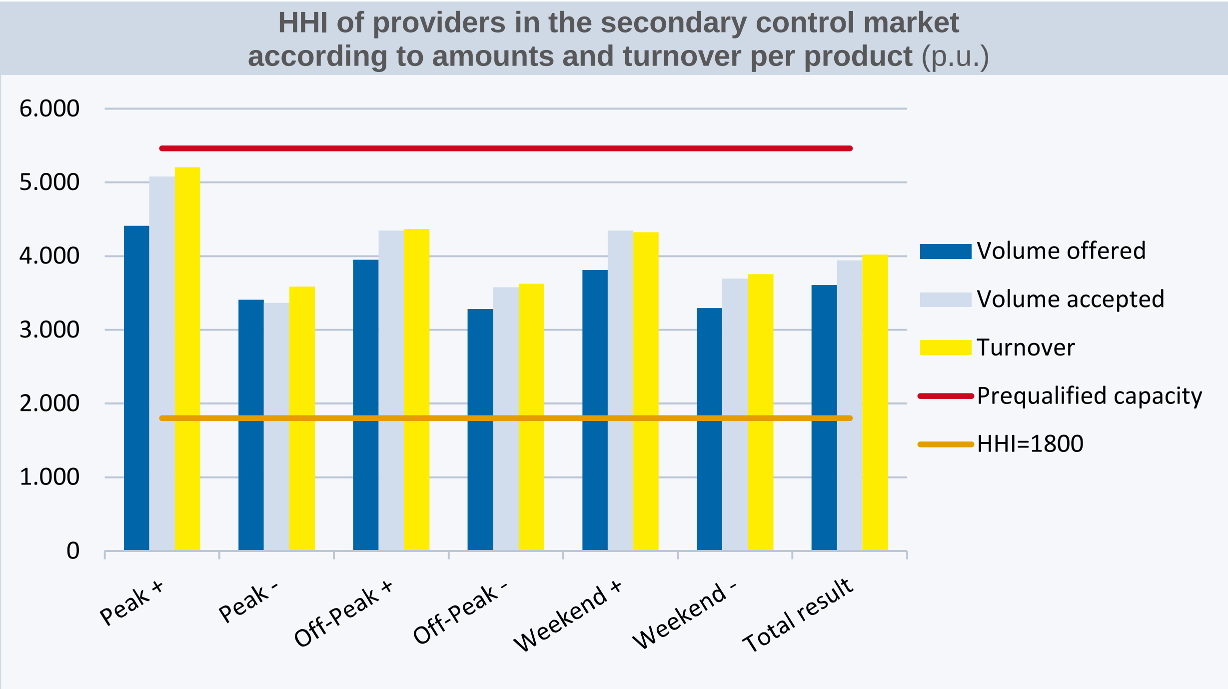
[49] Calculated from the amounts of accepted bids and the capacity price.

CR(3) in the secondary control market				
Product alias	**Volume offered**	**Volume accepted**	**Turnover**	**Pre-qualified capacity**
SRL_Peak_+	94%	94%	94%	-
SRL_Peak_-	93%	92%	93%	-
SRL_OffPeak_+	94%	93%	93%	-
SRL_OffPeak_-	92%	91%	92%	-
SRL_Weekend_+	94%	94%	94%	-
SRL_Weekend_-	93%	92%	93%	-
Total	93%	93%	93%	90%

Source: Own calculations

Note: Turnover is calculated from revenues from balancing capacity auctions but excludes revenues from balancing energy requested. The volumes referenced also correspond to those from auctions.

Table 5: Market concentration ratio (CR(3)) in the secondary control market based on volumes offered and accepted and turnover

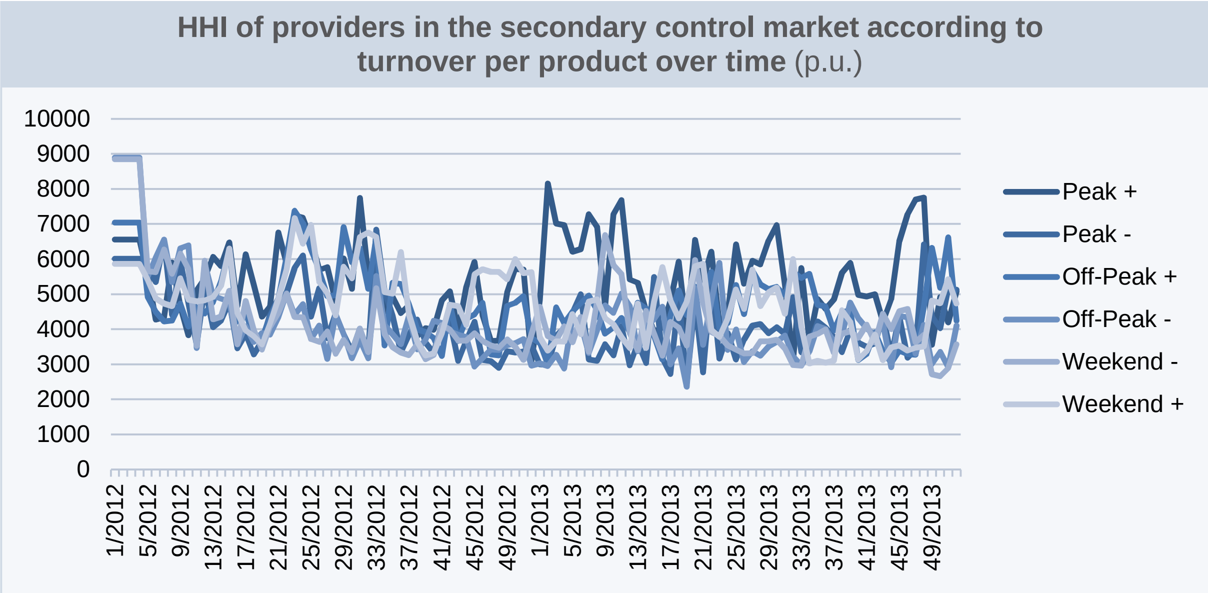


Source: Own calculations

Note: Turnover is calculated from revenues from balancing capacity auctions but excludes revenues from balancing energy requested. The volumes referenced also correspond to those from auctions.

Figure 12: Herfindahl-Hirschmann Index (HHI) in the secondary control market

The market shares of individual providers and the HHI vary quite a bit for the different weeks. Nevertheless, the HHI hardly falls below the 3,000 even for the weeks and products with the lowest concentration levels. Thus, the market must be considered highly concentrated during the entire observation period (see Figure 13).



Source: Own calculations

Note: Turnover is calculated from revenues from balancing capacity auctions but excludes revenues from balancing energy requested.

Figure 13: Trend over time of the Herfindahl-Hirschman Index (HHI) in the secondary control market

3.4.3. Tertiary control market

In this market concentration analysis, tertiary control capacity was, for purposes of clarity, subdivided into four groups: incident reserve weekdays, incident reserve weekends, negative tertiary control capacity weekdays and negative tertiary control capacity weekends.

As the analysis shows, the market for incident reserve (IR) and tertiary control capacity (TCC) is noticeably less concentrated than the other balancing markets in Austria. This is due to the considerably lower technical requirements, which can also be met by many smaller providers. Even so, the HHI is consistently at a level of 3,000 or above, which means that the market for incident reserve and tertiary control capacity must also be considered highly concentrated.

CR(3) and HHI in incident reserve and tertiary control capacity markets													
	Mon-Fri						Sat+Sun						
	IR+			TCC-			IR+			TCC-			
	Volume offered (MW)	Volume accepted (MW)	Turnover (€)	Volume offered (MW)	Volume accepted (MW)	Turnover (€)	Volume offered (MW)	Volume accepted (MW)	Turnover (€)	Volume offered (MW)	Volume accepted (MW)	Turnover (€)	Pre-qualified capacity
CR(3)	79%	79%	78%	88%	89%	85%	83%	84%	86%	85%	86%	82%	83%
HHI	3,337	3,746	3,824	3,562	3,935	3,560	3,563	4,259	4,560	3,318	3,194	2,991	3,627

Source: Own calculations

Note: Turnover is calculated from revenues from balancing capacity auctions but excludes revenues from balancing energy requested. The volumes referenced also correspond to those from auctions.

Table 6: Market concentration ratio (CR(3)) and Herfindahl-Hirschman Index (HHI) in incident reserve and tertiary control capacity markets according to volumes offered and accepted and turnover per product

3.4.4. Summary

As described in detail in the sections above, the balancing market is highly concentrated across all control types and products. In terms of HHI, the highest concentration is found in the primary control market and the lowest concentration in the market for incident reserve and tertiary control capacity.

Table 7 sums up the market concentration ratio (CR(3)) and HHI for turnover in the individual submarkets (not including breakdown by product). This is a suitable type of concise representation as the turnover includes both volume and price aspects.

CR(3) and HHI for all control types			
	Primary control	**Secondary control**	**Tertiary control**
CR(3)	91%	93%	79%
HHI	5,217	4,020	3,490

Source: Own research

Table 7: Market concentration ratio (CR(3)) and Herfindahl-Hirschman Index (HHI) in the various balancing markets according to turnover

Market concentration and liquidity are indicators for efficient pricing in a market and make it possible to better classify price developments in a certain market segment. In the following chapter, we consider which other factors influence prices and liquidity in the individual short-term markets or which interdependencies exist. This should provide an even more comprehensive understanding of the developments in these market segments.

4. Interdependencies in physical electricity trading

4.1. Introduction

In collaboration with Frontier Economics, we conducted a study to examine the interdependencies in short-term physical electricity trading in Austria. It intended to offer greater insight into the factors determining price and volume evolutions in day-ahead, intraday and balancing markets. With an increasing volume of weather-dependent renewable energies being fed into the system, a greater part of trading can be expected to shift to real-time or close-to-real-time markets. It will therefore become increasingly important to observe these markets as well as the interrelations of price developments and liquidity at the various trading venues. On the basis of econometric considerations and having regard to the distinct characteristics of the energy sector, the study developed price and volume models for the day-ahead, intraday and balancing markets. These models are presented in greater detail below.

4.2. Aims and methodology

The study's central aim was to identify interrelations between fundamental data or price developments in alternative markets and price and volume evolutions in the day-ahead, intraday and balancing markets. In addition to analysing fundamental data, the study also aimed to investigate how alternative marketing options may affect price developments and, possibly to a lesser extent, volume evolutions in the individual short-term markets.

The analysis is based on a one-step Error Correction Model (ECM)[50], which is highly suitable to the requirements of the fundamental data analysis envisaged. While risk analysts and traders tend to choose models and mathematical approaches that are also used in the financial industry, such as GARCH, Monte Carlo simulations, etc., an ECM offers the advantage of allowing for a direct interpretation of the results as interrelations between exogenous and explained variables (the latter are in this case prices and volumes). From an econometric point of view, another advantage of an ECM is that it can be applied to stationary as well as integrated time series, circumventing potential difficulties in the application of the Ordinary Least Squares (OLS) estimator on integrated time series.

As with most econometric models, the assessment and refinement of the ECM are key problems in its application. As the present regression analysis attempts to explain prices or volumes, on the left side of the regression equation, through a number of independent variables, on the right side of the equation, an ad hoc approach bears the risk that the selection of the independent variables results in a final specification of the equation that is non-traceable or arbitrary. It is therefore essential to avoid, as far as possible, results that are obtained merely by an arbitrary selection of explanatory variables, which would cause a strong distortion of quantitative effects. Such an approach might create (spurious) relationships between variables that would not be seen in another model, or it could lead to effects being underestimated or possibly even overlooked, even though said effects might play an important role in the “true” model. For these reasons, the present analysis relies on theoretical considerations while simultaneously attempting to take into account the specific characteristics of the energy industry in selecting potential explanatory variables, using the robustness and fit of the model as the final decisive criterion.

The goodness of fit can be assessed according to various principles. It is generally presumed that the algebraic signs of the coefficients ($\beta_0, \beta_1, \ldots$) match the fundamental considerations in a suitable model; otherwise, it would seem likely that the model was incorrectly specified, variables were omitted or there was a problem of multicollinearity[51]. Furthermore, the EC term (β_1) in an ECM has to be between -1 and 0. Other criteria include the adjusted R^2, the root mean squared error (RMSE) as well as the Akaike and Bayesian information criteria (AIC and BIC) for the selection of lags[52]. After the estimation, the necessary post-estimation tests[53] are carried out to determine the econometric suitability of the model, especially with regard to the residuals e_t. Special importance is given to the robustness of the model, by focusing on path independence when selecting variables to ensure that statistically insignificant explanatory variables are not in- or excluded mechanistically.

The remainder of this paper distinguishes between final and preliminary models. The final model meets the econometric criteria mentioned above and contains only explanatory variables with economically correct algebraic signs and statistically significant coefficients. The latter requirement may be justifiably suspended in individual cases if this concerns small samples or if an elimination of insignificant coefficients would result in poorer statistical properties of the model. The criteria mentioned above were also used in the specification of the functional form of the regression equation, such as logs, semi-logs or polynomials. Meanwhile, the preliminary model as reported below is neither reduced in form nor does it necessarily meet all of the goodness of fit criteria specified above. Rather, loosely following a general-to-specific methodology, it is a first-step model which encompasses all potential explanatory variables that are derived from energy economic principles.

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[50] In a model with only one independent or explanatory variable x, the regression equation with the formula $\Delta y_t = \beta_0 + \beta_1 y_{t-1} + \beta_2 x_{t-1} + \beta_3 \Delta x_t + e_t$ relies on the following interpretation of the coefficients, which is also valid for the tables below: β_1 describes the speed at which the model returns to a balanced state; β_3 describes the short-term influence of x on y; β_2/β_1 describes the long-term effect.

[51] A direct linear correlation between two or more independent variables.

[52] Lags for the time *t* describe the observations of the preceding period, i.e. the number of lags i in the terms $t-i,\ i = 1, \ldots,$. The AIC and BIC information criteria are used to determine the relevant number of lags *i* for the model. The criteria compare the complexity and significance of potential models. AIC and BIC differ in their calculation methods and the latter penalizes model complexity more strongly than the former.

[53] Econometric models are based on assumptions that must hold for the results to be valid. This is checked by so-called post-estimation tests.

Thus, the final specification of each model relies on the individually relevant econometric considerations and energy industry principles, which may vary slightly from one market segment to another. For balancing products, in particular, the different geographical market area (Austria, not Austria/Germany) suggests another approach. Details are given in the relevant sections below. Further, it should be noted that the discussion in chapter 2 of this paper on the functioning of the individual market segments had a large influence on the selection of potential explanatory variables as presented below.

4.3. Data and descriptive statistics

Relying on considerations about merit order, electricity demand and the opportunity cost of balancing products, various possible explanatory variables are identified for the individual submarkets. Moreover, hypotheses are proposed on the individual, possible alternative markets. A summary is given below in Table 8. Following the evaluation of the descriptive statistics, and in line with econometric considerations, a short list is compiled from the possible explanatory variables and is discussed below for the individual market segments.

Market segment (explained variable)	Fundamental data	Data on alternative markets
Day-ahead (EPEX Spot prices/volumes)	(i) System load (ii) Wind power infeed (iii) Solar PV infeed (iv) Primary energy prices (v) River levels / flow rates (vi) Levels of pumped storage reservoirs (vii) Planned and unplanned unavailability of generating units	(i) Price spreads to day-ahead markets in France, Switzerland, the Czech Republic and Nord Pool
Intraday (EPEX Spot Intraday DE prices/volumes)	(i) Wind power forecast error (between day-ahead and intraday) (ii) Solar PV forecast error (between day-ahead and intraday) (iii) Run of river hydro forecast error (between day-ahead and intraday) (iv) Load forecast error (between day-ahead and intraday) (v) Unplanned unavailability of generating units (between day-ahead and intraday)	(i) Price spreads to intraday markets in France, the Czech Republic and Nord Pool (ii) Price spreads to day-ahead markets in Germany/Austria, France, Switzerland, the Czech Republic and Nord Pool (iii) Prices for balancing energy in the previous period (iv) Prices in the day-ahead market of EXAA (absolute value)
Primary control (capacity prices, excess supply)	(i) River levels / flow rates (ii) Planned and unplanned unavailability of prequalified generating units	(i) Prices for Phelix Baseload Week Futures (ii) Prices for Phelix Peakload Week Futures (iii) Prices for market maker‘s tertiary control in the previous week
Secondary control (capacity prices, energy prices, excess supply)	(i) River levels / flow rates (ii) Levels of pumped storage reservoirs (iii) Planned and unplanned unavailability of prequalified generating units	(i) Prices for Phelix Baseload Week Futures (ii) Prices for Phelix Peakload Week Futures (iii) Prices for primary control in the previous week (iv) Prices for market makers’ tertiary control in the previous week (v) Prices in the day-ahead market of Austria/Germany (EPEX Spot, EXAA), France, Switzerland, the Czech Republic and Nord Pool
Tertiary control (capacity prices, energy	(i) River levels / flow rates (ii) Levels of pumped storage	(i) Prices for Phelix Baseload Week

prices, excess supply)	reservoirs (iii) Planned and unplanned unavailability of prequalified generating units	Futures (ii) Prices for Phelix Peakload Week Futures (iii) Prices for primary control in the previous week, prices in day-ahead markets Austria/Germany (EPEX Spot, EXAA), France, Switzerland, the Czech Republic and Nord Pool (iv) Intraday market prices in the previous period

Table 8: Alternative marketing possibilities in short-term physical electricity trading in Austria, and possible explanatory variables of price and volume (long list).

4.3.1. Day-ahead market

As laid out in section 2.3, both EPEX Spot (EPEX) and EXAA enable day-ahead trading for the physical delivery area of Germany and Austria. This means that both EPEX and EXXA prices, or their volume-weighted average, could be used for an analysis. As EXAA does not organise intraday trading yet, and in an effort to maximise consistency, only EPEX Spot hourly prices are used as a dependent variable. This has the added advantage of focusing the observation on the market with the higher trading volume. A Pearson's correlation analysis of time-series data for prices on the two exchanges resulted in a value of 0.8966, confirming that an econometric analysis of EXAA prices is not expected to hold any additional insight. For the same reason, other marketing options such as OTC prices are not analysed either.

As far as the day-ahead market is concerned, the selection of fundamental data is based on the merit order, which sets the market clearing price in uniform price auctions for hourly products (see Figure 14). On the demand side, load is expected to have a positive influence on price, as higher demand with given supply moves the intersection of the two curves to the right. It should be noted, however, that this effect might not be linear, as the merit order curve is steeper during peak hours and a small increase in demand can lead to more pronounced price changes than in periods of low load.

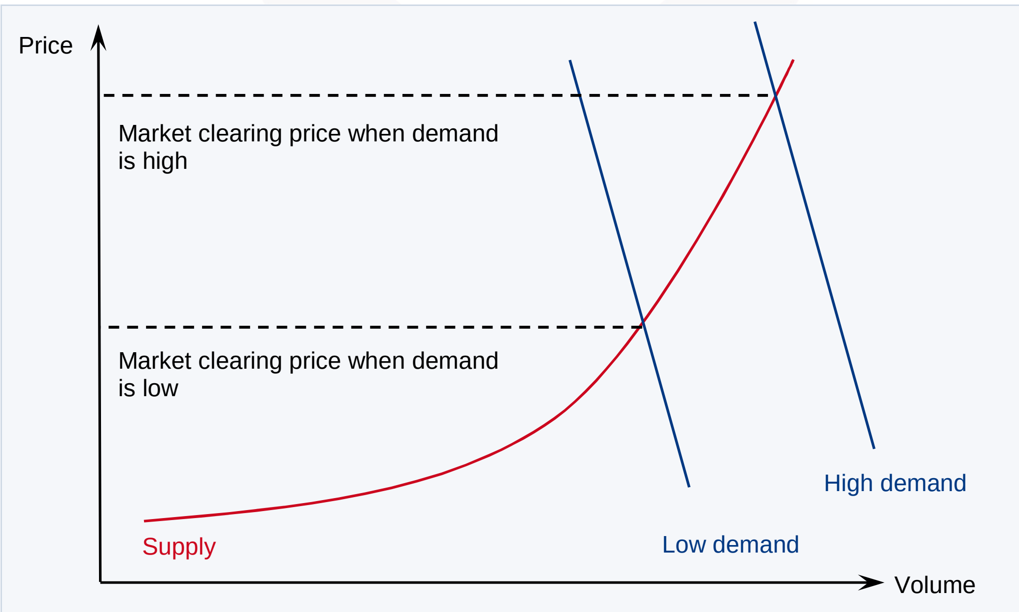


Figure 14: Price formation in the context of a uniform price auction

This can be particularly observed in the load profile of the data set in question, as illustrated by a scatter plot (Figure 15).

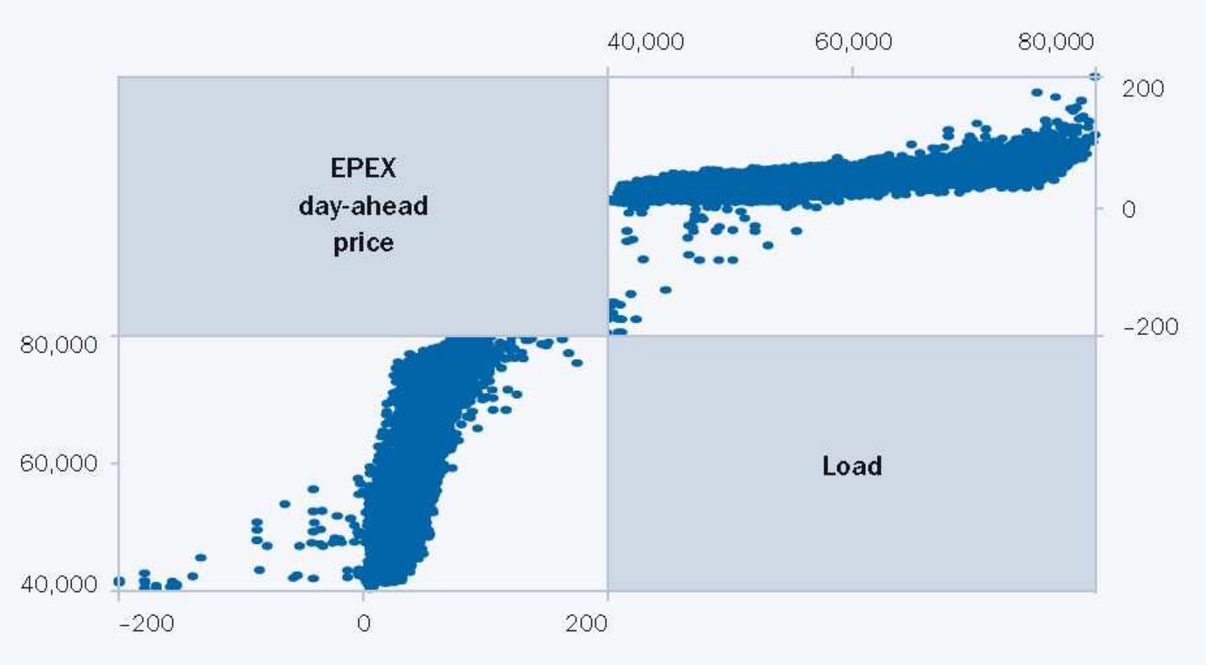


Figure 15: Scatter plot of EPEX day-ahead price and load profile

On the supply side, wind and solar PV power are fed into the grid at a marginal cost of zero, pushing the merit order to the right and dampening prices. In this case, too, the influence depends on the steepness of the merit order curve at a given time. Wind and solar PV should have a greater influence on prices during peak hours with high load. Moreover, the effect of solar PV is highly seasonal, as the December-February period accounts for only 6-7% of solar power infeed. In addition, the effect of solar PV on prices is limited to hours of useful sunshine, usually around noon. If the solar PV supply were directly used as an explanatory variable, its influence would be underestimated, as periods in which the influence is low reduce the effect. An alternative avenue is to look at the residual load, i.e. the total load minus generation by wind and solar PV. Table 9 shows an evaluation of the most common descriptive statistics of a sample for the day-ahead market.

Descriptive statistics					
Variable	**Observations**	**Mean**	**Standard deviation**	**Minimum**	**Maximum**
EPEX Spot price (h)	4,386	43	16	-100	134
Load	4,386	67,547	8,784	42,232	84,286
Wind infeed	4,386	5,749	4,991	135	26,084
Solar PV infeed	4,386	9,259	5,751	144	23,952
Residual load (load minus wind power and solar PV)	4,386	52,538	11,887	18,049	78,859
Flow rate Rhine	4,386	161	243	44	2,848
Flow rate Danube	4,386	391	196	147	1,955
Planned unavailability	4,386	13,942	6,297	1,423	26,831
Unplanned unavailability	4,386	2,277	1,105	212	7,593

Sources: Energate, ENTSO-E / TSOs, www.eeg-kwk.net, BfG, EEX Transparency Platform

Table 9: Descriptive statistics of possible explanatory variables for an analysis of the day-ahead market

Prices for primary energy sources, especially gas and coal, and prices for carbon dioxide emission allowances could theoretically have an influence on price formation, too, as they influence the costs of fossil-fuel marginal power stations in the merit order. However, an evaluation of the correlation matrix shows that the linear relationship on an hourly basis is very low. At 0.036 for NCG natural gas and up to 0.17 for ARA coal prices, the Pearson's coefficient is well below the level on which a positive linear correlation can generally be postulated. An aggregation of the time series on a daily or even weekly basis significantly increases this correlation. But as the goal of the analysis is to explain hourly price formation, primary energy prices are not examined any further.

When considering alternative day-ahead markets, econometric considerations come into play. It is generally assumed that neighbouring geographical markets such as Italy, Switzerland and France are relevant for pricing at EPEX as long as market access is technically feasible and complies with national market regulations. But unlike with other alternative markets such as the intraday market, the direction of the effect with neighbouring markets is not controlled by the chronological trading process (i.e. day-ahead influences the intraday market and not the other way round). Regarding prices in neighbouring day-ahead markets, it is not at all clear which price determines others; for example, whether Nordpool prices affect EPEX prices or conversely is unknown, and so is the direction of the effect. This contradicts a central econometric assumption – the exogeneity of all explanatory variables – and may distort the regression analysis. Further, the high correlation of prices in European day-ahead markets brings about the issue of multicollinearity, which no longer allows the equation to be identified, or at least distorts the interpretation of the coefficients. Finally, there is the risk of a spurious regression – the risk of identifying a relationship that only seems to exist because prices merely respond to the same underlying drivers (oil prices, for instance). For these reasons, alternative neighbouring markets are not analysed for the day-ahead market.

4.3.2. Intraday market

The examination of the intraday market is based on similar considerations as that of the day-ahead market. The first challenge is the method of selecting dependent variables, since EPEX Spot maintains separate order books for trades with hourly and quarter-hourly products, as shown in section 2.4. Due to the different trading closing times for deliveries in Germany and Austria, the delivery area indicated along with an order also plays a role. Seeing that intraday trading is relatively new to the delivery area Austria and has less liquidity, it appears reasonable to focus the analysis on German intraday prices[54]. Moreover, potential explanatory variables for prices and volumes are only rarely available in quarter hour intervals, so it seems more practical to focus on hourly products. Because of the large number of data points, relying on hourly values does not compromise the statistical properties of the estimates. Thanks to its high liquidity and the brisk participation of Austrian electricity traders, the hourly German intraday price forms the most important reference for Austria's intraday marketplace. The following EPEX intraday prices and volumes therefore always refer to hourly products for the delivery area Germany, though, as described in section 2.4, trading for the delivery area Austria is by all means possible under certain conditions.

When selecting possible explanatory variables, it is important to note that the intraday market takes place after the day-ahead market in that certain events that require further action from the market participants may occur after gate closure of the day-ahead market, and especially following the schedule nomination deadline at D-1 14:30. Such events may include: unexpected power station outages, new forecasts for wind and solar PV generation, and new results in the quarter-hourly load forecast. Hence it is postulated that as far as the intraday

[54] Until October 2012, the German delivery area of EPEX Spot provided the only way for Austrian market participants to conduct intraday trades on an exchange. Owing to this historical development and its relatively high liquidity compared to other intraday markets, the German delivery area continues to be a major price indicator for the Austrian intraday market to this day.

market is concerned, not the absolute forecast levels or traders' expectations are decisive, but the deviations from the forecasts or expectations that were factored into bids in the day-ahead market. These forecast errors – the difference between predicted and actual values – are thus identified as possible explanatory variables. In the case of wind and solar PV, a positive error value means that market participants are "short", which is expected to create additional demand in the intraday market.

Unlike the analysis of the day-ahead market, whose econometric analysis disregarded alternative marketing or alternative markets in neighbouring countries, the analysis of the intraday market does take the day-ahead market into account as an alternative market, the reason being the strict temporal succession of these two markets and thus an expected unambiguous causality. Table 10 confirms that the correlation between intraday and day-ahead prices is very high, standing at 0.88. Other variables in this linear analysis display a rather weak correlation, though at least the signs of their correlations are as expected. Apart from the day-ahead price, the highest correlation is found for the residual load forecast error, which by the way is inversely proportional to the intraday price.

	EPEX intraday price	EPEX day-ahead price	Wind power forecast error	Solar PV forecast error	Load forecast error	Residual load forecast error	Unplanned non-availability of generating units
EPEX intraday price	1						
EPEX day-ahead price	0.8804	1					
Wind power forecast error	0.3284	0.2069	1				
Solar PV forecast error	0.1769	0.0354	0.0269	1			
Load forecast error	-0.3538	-0.3709	0.0198	-0.0500	1		
Residual load forecast error	-0.4817	-0.4116	-0.3641	-0.3341	0.8809	1	
Unplanned unavailability of generating units	0.1672	0.1538	0.0846	-0.0318	-0.0400	-0.0577	1

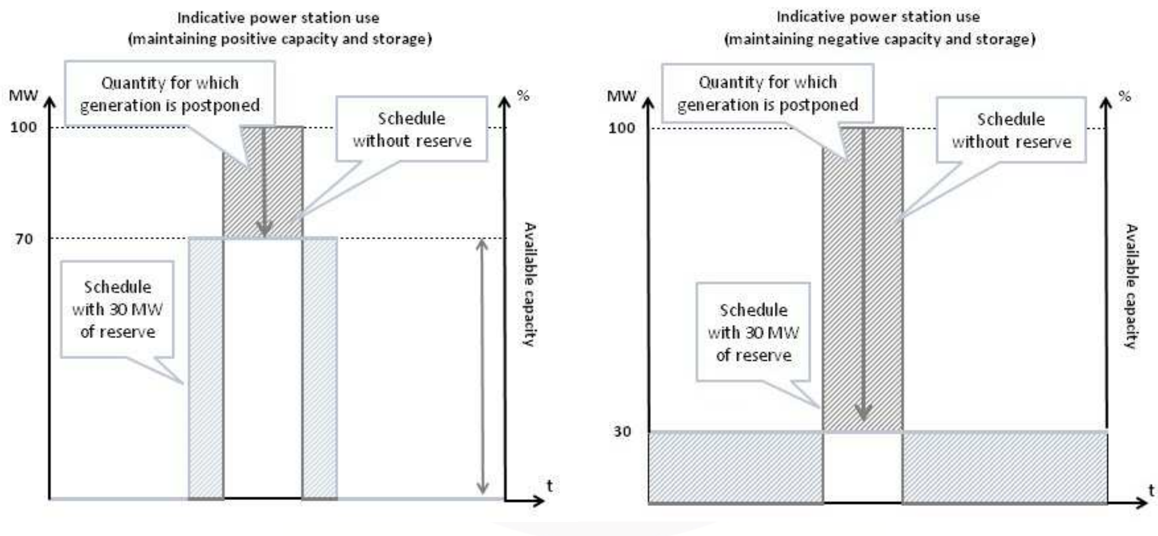
Sources: EPEX Spot, TSOs, Energate, www.eeg-kwk.net, EEX Transparency Platform

Table 10: Correlation matrix for possible explanatory variables of EPEX Spot intraday prices

4.3.3. Balancing markets

From an econometric point of view, the examination of the balancing market gives rise to several challenges. Except in the case of primary control reserve (PCR), several products are auctioned off at once (see section 2.5 for a description of the functioning and the products in these markets), resulting in orders with both capacity prices and energy prices. Thus, there is a considerable number of potential dependent variables and of regression equations to be estimated. Computationally, this does not pose a problem, but the clarity and ease of interpretation of the results is somewhat compromised, which is why an aggregation of products or a focus on individual products seems in order. When considering whether to aggregate, the difficulty is that products such as peak and off-peak, positive or negative secondary control and tertiary control would have to be combined, but the available power stations and resulting merit order functions may vary greatly, depending on the time slot and direction of the delivery. A useful interpretation of the results seems hardly possible in this case, so this option is generally not chosen. However, it is possible to conduct aggregation in the case of secondary control, thanks to a high correlation between prices of the 1-week and 4-week auctions. As far as secondary control is concerned, this leaves six instead of 12 products to be analysed. The 24 products from tertiary control cannot be meaningfully aggregated, which is why, alternatively, the following focuses on two representative products.

The considerations about possible explanatory variables in the balancing market rely on theoretical concepts for determining costs to supply. . When analysing the capacity price, the opportunity cost approach is a useful benchmark, as it adequately reflects the short-term optimisation problem of providers. This approach takes into account the costs of alternative marketing, such as shifting power generation into periods of suboptimal wholesale prices, forgone power generation, generation in periods when costs are not covered and suboptimal purchasing. The opportunity costs of hydropower stations are composed of two factors: the cost of shifting generation as selling it on alternative markets such as the day-ahead market is no longer possible at an ideal time; and unused flowing water, i.e. forgone generation. Additionally, there may be operating costs such as efficiency losses at partial load or costs caused by minimum load conditions. Figure 16 shows this assumed behaviour using the example of a storage power station that maintains availability of positive and negative capacity. If a power station has a maximum capacity of 100 MW and puts aside 30 MW of positive capacity, the energy generated is redistributed over time, as 30 MW has to remain available for the provision of balancing services. By contrast, if negative capacity is to be kept available, the power station must keep operating at no less than 30 MW. Assuming that overall generation remains constant, the power plant in this case is not deployed ideally over time, either[55].



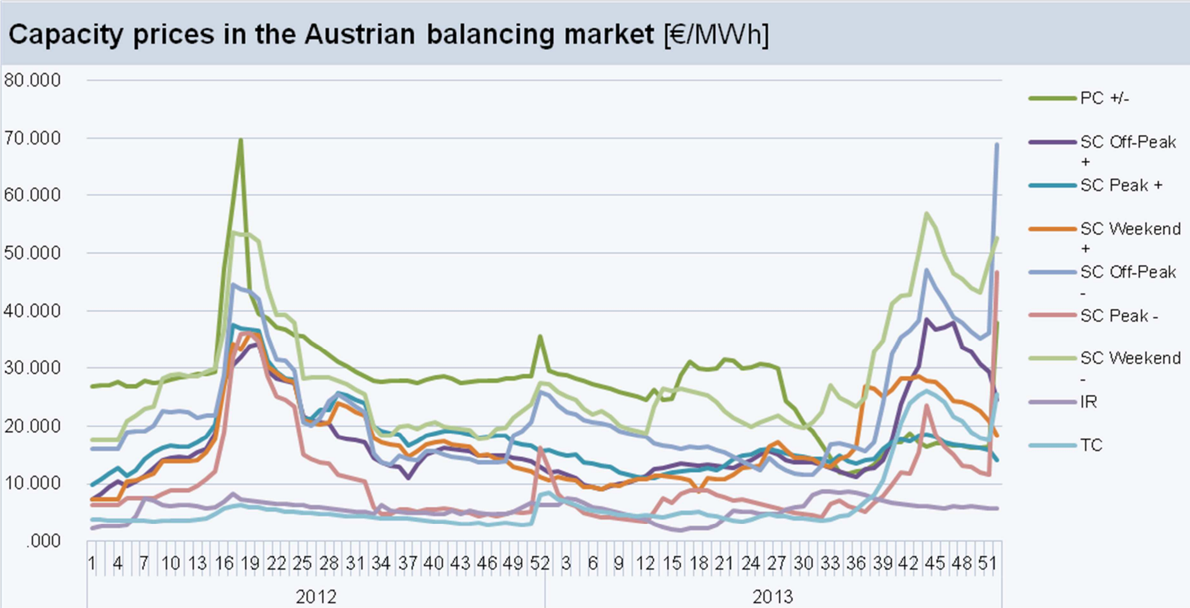
Source: Frontier Economics

Figure 16: Possible deployment of a storage plant for maintaining negative and positive control capacity

Several hypotheses for the regression model used for estimating capacity prices are derived from these considerations. For example, it is to be expected that prices for maintaining negative capacity available tend to be higher than those for positive capacity, as the former incurs must-run costs. The effect of prices on alternative markets also differs depending on the direction of delivery. Maintaining negative capacity at low day-ahead prices and during off-peak hours is more expensive, as the must-run costs are high in this case. When positive capacity is maintained, the effect is reversed, as opportunity costs (i.e. foregone revenues) rise along with increasing day-ahead prices. Excess supply, river flow rates and more generally power station availability are suspected to have a negative influence on capacity prices. The modelling of energy prices, however, follows the modelling of prices for the day-ahead and the intraday market. When interpreting the results, one should bear in mind that power station operators, by means of energy prices, are able to control the probability of their

[55] This is based on the assumption that the schedule without control represents the optimal use of the power station over time regarding other marketing possibilities.

plants being activated. This effect can barely be visualised by an econometric time-series model.



Sources: APG, own calculations

Figure 17: Development of capacity prices in EUR/MWh

One possible problem when modelling capacity prices are multiple price spikes. Above, Figure 17 shows the price development in EUR/MWh of various products. Especially towards the middle of 2012 there is a spike in primary and secondary control prices, while prices appear to generally hike at year's end. When modelling data, this gives rise to a basic question: should these price spikes be interpreted as an endogenous part of the model with the help of fundamental data, or should the spikes be modelled or considered outliers that need to be discarded? Due to the distorting effect of outliers, it is appropriate in most econometric analyses to remove them with clearly defined methods, such as Cook's distance. But since the explanation of price developments, including any price increases, is one of the objectives of this analysis, only those outliers that would very significantly influence the result are removed in the econometric analysis. This represents a restrictive application of Cook's distance. In order to still take the removed price spikes into account, these extreme price situations are studied in a separate single-data point analysis. This analysis is, however, not part of the public version of this paper as it contains confidential data.

4.3.4. Sample period

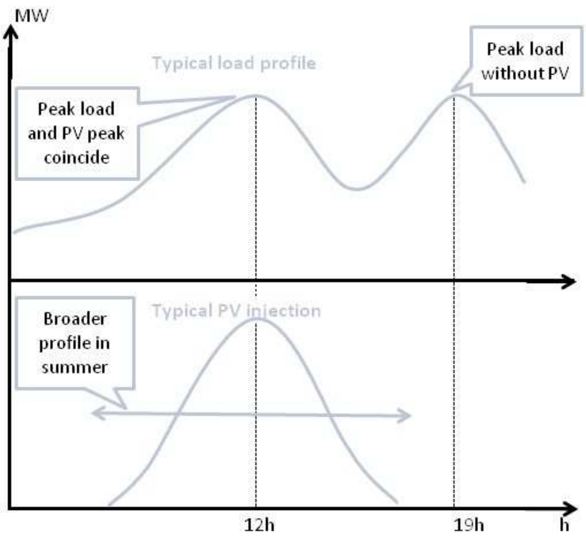
Like the collection of data, the choice of the sample period is of critical importance. In general, larger samples enhance the soundness and quality of results. But when selecting a time frame for data, one should be aware of the fact that dummy variables can only express structural breaks in econometric models to a limited extent. Moreover, a model that relies on the too distant past may reduce the results' validity for the present situation. Given the changes in the installed capacity over the past few years, today's price formation is presumed to differ rather significantly from pre-2010 levels. Likewise, the relevance of solar PV and wind power generation as drivers has increased substantially during this period.

In order to obtain results that are in particular representative of current market events, the analysis is limited to the years 2012 and 2013. Thanks to the hourly intervals in the day-ahead and intraday markets, there is hardly a scarcity in the number of observations available for the estimate. The situation is different for balancing markets, though. Due to the weekly intervals of the auctions, a longer time span would indeed make sense, so as to increase size of the sample[56]. However, these auctions (with the exception of primary control auctions) have only been held in their current form since 2012. This is why balancing markets do not provide consistent data over a longer period of time, preventing the extraction of a larger sample.

4.4. Results for the day-ahead market

Two different approaches are applied for the EPEX day-ahead prices. As mentioned in section 0, the peaks in the daily load profile typically match the peaks of daily solar PV generation, especially during summer. An undifferentiated approach over the entire day would no longer allow an unambiguous interpretation of the coefficients, as effects overlap and the coefficient for solar PV generation would thus be underestimated because part of the actual effect is mathematically reflected in the coefficient for the load profile. Figure 18 is a graphical representation of this problem; a possible approach to solving it was identified in the preliminary model: the use of residual load. In this way, the method laid out in section 0 allows a robust preliminary model to be found. The non-linearities are modelled with polynomial terms for the residual load, which is also the most important explanatory variable in the model. For example, if a residual load of 40 GW increases by 1 GW, the EPEX Spot price rises by 1.42 €/MWh. At a maximum residual load of 80 GW, the same change even causes the price to climb by 5.02 €/MWh. However, this preliminary model does not differentiate between 1 GW of additional load and 1 GW less of wind or solar PV generation, as residual load encompasses both effects simultaneously. The flow rate of the Rhine river holds only limited statistical significance[57]. The flow rate of the Danube and the unplanned unavailability of generating plants do not vary sufficiently from zero to be of statistical significance.

A sizeable part of the examination is devoted to analysing the influence of weather-dependent intermittent renewable energy sources. For this reason, the time series are broken down for the final model so as to directly estimate the influence exerted by load, wind and solar power. The data set is split into individual time series for summer and winter, with a special focus on peak sunlight hours (from 11.00 to 16.00). But since the error correction model contains variables with lags, slicing the data set creates jump discontinuities, which must be absorbed by dummy variables[58]. For instance, a "dummy hour" variable can absorb the jump from hour 16 of the previous day to hour 11 of the following day. This strategy is depicted in Figure 19 for summer/winter discontinuities.



Source: Frontier Economics

Figure 18: Schematics displaying the peaks of solar PV generation and of load

[56] Totalling 104 in the periods of 2012 and 2013.
[57] P-value of 0.068.
[58] Dummy variables can only take the value 0 or 1.

Figure 19: Dummy variables in the new data set

This kind of slicing of the data set is used in the final model. By refraining from the use of polynomial terms, multicollinearity problems are avoided and the coefficients are easier to interpret. No logarithmic transformation is used, either. This eliminates the difficulty in dealing with negative prices, while post-estimation tests show in any case that in a log model residuals are no longer normally distributed. As it turns out, the models for hourly intervals should be favoured over the preliminary model, as measures of the goodness of fit of the model (adj. R-squared, RMSE) are higher and the post-estimation tests yield better results[59]. Table 11 depicts the results for the final day-ahead model for the summer periods.

Goodness of fit	
Number of observations	2,195
F(11, 2183)	552
Prob > F	0.0000
R-squared	0.7357
Adj. R-squared	0.7344
RMSE	4.4730

Final day-ahead model: summer						
d1_EPEX spot price	Coefficient	Std. error	t-value	P>t	95% conf. interval	
l1_EPEX spot price	-0.2034	0.0129	-15.7700	0.0000	-0.2287	-0.1781
l1_load	0.0003	0.0000	12.9700	0.0000	0.0002	0.0003
d1_load	0.0014	0.0000	52.0300	0.0000	0.0013	0.0014
l1_wind	-0.0003	0.0000	-9.1800	0.0000	-0.0004	-0.0002
d1_wind	-0.0013	0.0001	-21.1100	0.0000	-0.0014	-0.0011
l1_PV	-0.0003	0.0000	-8.9000	0.0000	-0.0003	-0.0002
d1_PV	-0.0012	0.0001	-19.5100	0.0000	-0.0013	-0.0011
l1_dummy hour	4.5787	0.4731	9.6800	0.0000	3.6509	5.5066
d1_dummy hour	3.2294	0.3057	10.5600	0.0000	2.6298	3.8290
l1_dummy year	0.9258	0.2029	4.5600	0.0000	0.5280	1.3236
d1_dummy year	14.6310	4.4896	3.2600	0.0010	5.8268	23.4353

[59] For easier reading of this report, the results of the post-estimation tests are not explicitly included. All final models were examined in-depth for the normal distribution of the residuals, autocorrelation, heteroscedasticity, multicollinearity and convergence (ECM), and were found to correspond to the underlying assumptions. Additionally, all models were estimated using the robust Newey-West estimator.

Constant	-5.6184	0.9617	-5.8400	0.0000	-7.5043	-3.7326

Note: d1… first difference, l1… first lag

Source: Frontier Economics

Table 11: Results of the final model for the day-ahead market (summer)

The adjusted R-squared and the F-test generally show that the selected model sufficiently describes the data set in question and is able to explain more than 70% of price variations. By comparison, the preliminary model was able to explain only some 50% of the variations over the entire time series. All coefficients have the expected sign. For example, the influence of load on prices is positive, while the influence of wind and solar PV is negative. In winter (see Table 14 in appendix), the influence of solar PV is significantly stronger, as solar PV generation is expected to be low during this period. As far as load and wind power generation are concerned, however, the difference in coefficients is statistically insignificant.

It can be deduced that 1 GW of additional wind power generated during the observation period decreased the EPEX Spot day-ahead price by 1.3 €/MWh (winter: 1.2 €/MWh), while 1 GW of additionally generated solar PV power lowered the EPEX Spot day-ahead price by 1.2 €/MWh (winter: 1.4 €/MWh). This confirms the expectation that shifts in the merit order make no difference between wind and solar PV power, as both technologies have negligible marginal costs, which places them at the very left of the merit order curve. The difference between the effect of solar PV generation in summer and winter may be explained by the observation that the high level of solar PV generation in summer has a decreasing effect on marginal costs. At the same time, the lower load in summer may be responsible for the weaker effect of solar power. One possible reason is the flatter merit order curve at low load levels and the resulting smaller effect of solar PV on marginal costs. As expected, one 1 GW of additional load causes the price to increase by around 1.4 €/MWh (winter: 1 €/MWh, with the difference between summer and winter regarding the load curve being statistically insignificant, as a Z-test suggests. Unavailability of generating units and river flow rates exhibit no statistically significant influence and are therefore not represented in the final model.

Conspicuously, despite factoring out all other effects included in the model such as wind power, solar PV and load, the price for hour 11 is 3.2-4.4 €/MWh higher than in all other hours of the time slot “Sun-Peak”. This begs the question of which additional factor might systematically have such a great influence on hour 11. One possible explanation is the start-up cost of peaking power plants, which might be priced into this first peak hour.

For the volume model, the same approach as for EPEX Spot day-ahead prices is selected. The resulting estimate shows that the key explanatory variables – load, wind power and solar PV – have plausible +/- signs and values. When 1 MW of load is added, trading volume increases by 0.1 MWh, and when 1 MW of additional solar PV power is generated, trading volume increases by 0.6 MWh. This effect is remarkable in that there are other trading hubs than EPEX Spot, such as broker platforms and the bilateral OTC market. However, the unavailability of generating units has a negative coefficient, which reduces the plausibility of the overall model. With regard to the volume model it is therefore questionable whether a specification of the regression was found that sufficiently reflects the underlying true model.

4.5. Results for the intraday market

For the intraday market, too, four preliminary models are estimated. Similarly to the day-ahead market, three variants are studied for the hourly prices in the delivery areas Austria and Germany, resulting in one full-year observation and two regressions for the summer and winter periods. The fourth preliminary model is derived from an analysis of the hourly averages of the purchase and sales volumes in the delivery areas Austria and Germany[60]. In the specification of the full-year model with the residual load forecast error instead of the separate use of the wind power and solar PV forecast error, the signs of the coefficients are plausible and the model has a good fit (adj. R-squared is 0.579). Thus an increase of the day-ahead price by 1 €/MWh causes the intraday price to rise by 0.78 €/MWh. The residual load forecast error or its polynomial terms have statistical significance, too. A residual load forecast error of 3 GW combined with an additional forecast error of 1 GW leads to a price increase of about 11 €/MWh. The complete results of this analysis are listed in Table 15 in the appendix.

Table 12 shows the results for the model of the winter period, which comprises the months of October through March (see Figure 19). With an adj. R-squared of 0.639, the model presents a good fit and the results are extremely robust. Even if the dummy variables are changed in the estimated equation or if the robust Newey-West estimator is used, the results are equivalent. The coefficients have the positive or negative signs that are to be expected. An increase of the day-ahead price by 1 €/MWh raises the intraday price by 0.83 €/MWh. If the wind power forecast error rises by 1 GW, the resulting higher demand increases the price by 2.5 €/MWh, while the same forecast error for solar PV causes the price to climb by 2.2 €/MWh. As expected, the difference between 1 GW of wind power and solar PV forecast error is not statistically significant, as it makes no difference for traders whether a forecast error stems from wind energy or solar PV generation. As far as unavailable generating units are concerned, 1 GW of unplanned outage leads to a price increase of 1.5 €/MWh.

Additionally, the results of the final model for the summer months of April through September are presented in the appendix (see Table 16). The two seasonal models differ in that the wind power forecast error during winter has a stronger influence than in summer[61] and that in summer the load forecast error is statistically significant. However, the effect is relatively small, as 1 GW of additional forecast error causes a price increase of just 0.3 €/MWh. This may be related to the availability of data, as only two TSOs publish load forecasts in Germany[62].

Goodness of fit	
Number of observations	2,189
F(7, 17535)	259
Prob > F	0.000
R-squared	0.641
Adj. R-squared	0.639
Root MSE	5.602

Final intraday model: winter						
d1_EPEX intraday price	**Coefficient**	**Std. error**	**T**	**P>t**	**95% conf. interval**	
l1_EPEX intraday price	-0.2289	0.0135	-16.92	0.000	-0.2554	-0.2024
l1_EPEX spot price	0.2153	0.0160	13.48	0.000	0.1840	0.2466
d1_EPEX spot price	0.8327	0.0185	44.94	0.000	0.7964	0.8690
l1_wind forecast error	0.0006	0.0001	5.64	0.000	0.0004	0.0008
d1_wind forecast error	0.0025	0.0002	15.02	0.000	0.0022	0.0028
l1_PV forecast error	0.0009	0.0001	9.76	0.000	0.0007	0.0011

[60] The analysis is based on the prices and trade volumes jointly published by EPEX Spot for the Austrian and German intraday markets.
[61] Z-test
[62] In an econometric analysis this poses a problem, especially if the forecast errors of the two TSOs that do not publish forecasts deviate systematically from the two others.

d1_PV forecast error	0.0022	0.0002	12.56	0.000	0.0019	0.0026
l1_non-availabilities (unplanned)	0.0004	0.0001	3.69	0.000	0.0002	0.0007
d1_non-availabilities (unplanned)	0.0015	0.0003	4.83	0.000	0.0009	0.0021
l1_dummy hour	1.3969	0.5316	2.63	0.009	0.3545	2.4393
d1_dummy hour	1.3298	0.3542	3.75	0.000	0.6351	2.0244
l1_dummy block 1	-0.6113	0.3538	-1.73	0.084	-1.3050	0.0825
d1_dummy block1	-0.8116	8.0924	-0.10	0.920	-16.6814	15.0581
l1_dummy block 2	-0.8216	0.3073	-2.67	0.008	-1.4242	-0.2191
d1_dummy block 2	4.2261	5.6702	0.75	0.456	-6.8934	15.3456
Constant	0.0960	0.4811	0.20	0.842	-0.8474	1.0395

Note: d1… first difference, l1… first lag

Source: Frontier Economics

Table 12: Results of the final model for the intraday market (winter)

By contrast, the volume in the intraday market, when modelled over the full year, provides little goodness of fit, as the model can only explain 8% of price fluctuations. Also, the root mean square error (RMSE) of 436 MW is very high when put in relation to the average traded purchase and sales volume of 1,500 MW. Moreover, the coefficients for the wind power and solar PV forecast error are negative and not positive as they should be, given that a higher forecast error should increase demand and thus the price in the intraday market. When estimating traded volumes, the insufficiency of available data may be one of the problems, caused in part by the fact that only two of Germany's four transmission system operators publish their load forecasts. Then again, the wind power and solar PV forecast error based on the day-ahead forecast is factored into the model[63]. Intraday market trading in 2012 and 2013 was continuous, so the information at the time of bidding is relevant with regard to the volumes actually entered into the order book. Due to this time shift, the available forecast errors do not completely mirror the deviations that matter to electricity traders.

4.6. Results for the balancing markets

No satisfying model could be found for balancing products, with the exception of primary control. As explained in the sections on methodology, outliers are eliminated so as to avoid distorting the goodness of fit of the model. Excess supply in the primary control tenders and the launch of the cooperation with Switzerland in July 2013 are identified as the main explanatory variables of primary control prices.

Goodness of fit	
Number of observations	93
F(7, 17535)	11
Prob > F	0.000
R-squared	0.539
Adj. R-squared	0.489
Root MSE	1.056

[63] The forecasts on the EEX Transparency Platform are announced at 18:00 d-1.

Final model primary control						
d1_PCP price	Coefficient	Std. error	T	P>t	95% conf. interval	
l1_PCP price	-0.3298	0.0491	-6.7200	0.0000	-0.4274	-0.2322
l1_Phelix base	0.0728	0.0256	2.8400	0.0060	0.0219	0.1238
d1_Phelix base	-0.0249	0.0284	-0.8800	0.3830	-0.0815	0.0316
l1_excess supply	-0.0798	0.0155	-5.1400	0.0000	-0.1107	-0.0490
d1_excess supply	-0.0364	0.0171	-2.1300	0.0360	-0.0705	-0.0024
l1_levels of pumped storage reservoirs	-5.34E-07	1.95E-07	-2.7400	0.0070	0.0000	0.0000
d1_levels of pumped storage reservoirs	0.00000344	0.00000145	2.3700	0.0200	0.0000	0.0000
l1_dummy GCC	-3.3909	0.6592	-5.1400	0.0000	-4.7021	-2.0798
d1_dummy GCC	-5.8201	1.0994	-5.2900	0.0000	-8.0067	-3.6335
Constant	9.6823	1.8136	5.3400	0.0000	6.0752	13.2894

Note: d1… first difference, l1… first lag

Source: Frontier Economics

Table 13: Final model primary control

The primary control cooperation, i.e. the GCC dummy, significantly decreases prices by about 6 €/MWh. The levels of pumped storage reservoirs in Austria and excess supply, defined as the supply offered minus the volume put out to tender, are statistically significant, at the usual level of 5%, and coefficient signs are in line with expectations. By contrast, the Phelix Base Week Future is not statistically significant. A further reduction of the model leads to poorer post-estimation tests and a lower goodness of fit, as the adjusted R-squared falls below 0.4. The econometric analyses of supply volumes and capacity prices for the other balancing products, however, do not produce robust models with a sufficient fit. In this case, too, the R-squared is well below 40%, while the negative and positive signs of the fundamental explanatory variables are not plausible.

This could be due to the small sample size with a total of 104 observations including outliers, and to the complex and dynamic cost relations and pricing mechanisms. In addition, parameters that probably ought to be factored into the model, such as market power and market concentration, cannot be easily displayed as a time series since markets are highly concentrated over the entire sample period, which is why these factors have to be excluded from the analysis. This is all the more regrettable since – especially in the field of primary control – the expansion of the market and the resulting competition has produced proven empirical effects.

5. Conclusion and outlook

As part of this working paper, we analysed four research questions related to short-term physical electricity trading in Austria, which yielded the following results.

Research questions 1 and 2: Marketing opportunities
The participants in short-term physical electricity trading in Austria have various marketing possibilities at their disposal. Apart from day-ahead and intraday trading on the power exchanges EXAA and EPEX Spot, marketing electricity is also possible via the OTC market, via the balancing market or by adjusting supply and demand inside balance groups. When observing the time sequences of processes at short-term markets, we found that not all options are available in a given time slot. While auctions for balancing products takes place

one week ahead of fulfilment, OTC products can be traded as late as 15 minutes before delivery. Therefore, the desired marketing method has to be selected early on. Revenue expectations, liquidity, the transparency of the market segments and technical restrictions are essential aspects to be considered in decision-making.

In terms of exchange trading, the day-ahead market on EPEX Spot plays a critical role for the Austrian power market. It has the highest volume of trades and provides an important reference price for the entire German-Austrian electricity market. Meanwhile, intraday trading has gained greatly in importance over the past few years. This is mainly due to the rising share of intermittent renewable power fed into the grid and the increased need to market in case of forecast errors. However, certain market deficiencies persist, such as different closing times in neighbouring intraday markets, which impair the efficiency and the concept of equal opportunities in this market segment.

Further short-term marketing opportunities are presented by OTC trading, the balancing market and the possibility for market participants to control their balance group's position. Due to the low level of transparency in OTC trading, we were unable to evaluate the utilisation of this market segment for short-term marketing. According to market participants, however, short-term OTC trading plays only a minor role. By contrast, marketing in the balancing market is considered extremely attractive, thanks to the current level of prices. But given the regulatory volume restrictions and the necessary technical requirements that plants have to fulfil, this market cannot be accessed by all participants. Another marketing possibility is the maintenance of a certain position in the balance group. This does not involve traditional trading as in other market segments; instead, creating a particular position reduces imbalance charges or generates revenue from the support provided to the control area. Market participants are already actively taking advantage of this marketing possibility.

Research question 3: Market concentration

Market concentration is an important indicator of competition and efficient pricing in a market segment. Except for day-ahead exchange trading, concentration is high or very high in all short-term power markets. Strikingly, concentration increases the closer a market segment is to physical fulfilment. On the one hand, this is because the intraday and balancing markets are geographically limited to the delivery area APG; the other reason being the high technical requirements that plants in these markets have to meet, which considerably limits the number of potential participants. This especially applies to the markets for primary and secondary control. That said, the conditions for participation are currently under review so as to facilitate access to the balancing market for interested parties, particularly for smaller electricity generators and consumers[64].

Research question 4: Market functioning

As shown in this working paper, interactions between prices, trade volumes and fundamental data can be identified very accurately, especially in the day-ahead market of EPEX Spot. During the sample period of 2012 through 2013, wind power and solar PV generation as well as load proved to have a significant effect on wholesale electricity prices. As for intraday trading, the price movements of the day-ahead market, wind and solar PV power forecast errors and unplanned outages of generating units significantly impacted prices. The selected models could explain the factors influencing trade volumes only to a limited extent. The examination of the balancing market proved equally challenging. Using the data from the sample period, only the analysis of primary control yielded useful results. From these we infer that excess supply of balancing capacity and the market integration with Switzerland were the two main factors driving down prices.

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[64] For both ongoing and finalised revisions of the framework agreements and prequalification conditions, see: http://www.apg.at/de/markt/netzregelung/konsultationen/konsultationsprozesse

Outlook

The harmonisation of market rules and trading processes is a key prerequisite for ensuring a level playing field and efficiency in cross-border electricity trading. In the future, special attention should be given to removing existing trade barriers, such as the different closing times in the intraday market of EPEX Spot.

Given the rising volume risk in the market, caused primarily by the growing amounts of intermittents, we expect short-term trading to continue to gain importance. Short-term markets should therefore be further developed to enhance flexibility and make them fit for the future. This could include an introduction of trading in 15-minute products or providing market players with immediate information an incentivising them to actively manage their balance group's position. Apart from benefitting the functioning of short-term markets, these measures would also contribute to security of supply.

Regulatory efforts will also focus on developing the balancing market, to implement the binding balancing network code and to counter the high prices currently observed in this market segment. Efficient pricing in a market segment crucially hinges on its liquidity and competition. To improve these, procurement of balancing services should be optimised – for instance, by enabling additional bids on day-ahead basis for secondary control energy, and by opening up the balancing markets, most of which are still operating at a national level. As shown in the example of cross-border procurement of primary control in cooperation with Switzerland, this measure allows those involved to realise considerable efficiency gains. Most future efforts should therefore be focused towards a swift integration of national balancing markets.

6. Appendix

6.1. Marketing opportunities in short-term physical electricity trading in Austria

6.1.1. Balancing energy pricing

In markets for balancing services, a differentiation must be made between the pricing mechanism in the procurement process and the clearing and settlement of costs. Balancing costs are covered via several different mechanisms.

According to section 68(1) Electricity Act, the cost of primary control is borne by all generators with an installed maximum capacity of over 5 MW. The costs are distributed among these generators in proportion to their annual output.

The costs of secondary control are covered via the system services charge on the one hand and via imbalance charges on the other hand (see section 56(1) in conjunction with section 69(1) Electricity Act). In addition to the cost of secondary control capacity and energy, these costs also comprise the cost for the availability and use of the incident reserve[65]. According to the allocation ratio defined by law, 78% of the secondary control cost is covered via the system services charge, while 22% is covered via imbalance charges. The system services charge is a charge per unit of gross energy output payable by injecting parties with a connected capacity of over 5 MW. The system services charge is determined annually in the *Systemnutzungsentgelteverordnung* (System Charges Ordinance). The (negative) tertiary control capacity, the requested tertiary control energy and any unintentional exchanges are fully covered via imbalance charges.

The pricing mechanism for imbalance charges is intended to provide an incentive for balance groups to submit exact schedules and to counter deviations at control area level. The discrepancies between the submitted schedules and the actual values of a balance group are referred to as imbalance. Often, individual balance groups' imbalances offset one another. The aggregated and netted imbalances of all balance groups results in the entire control area's need for balancing energy[66]. The imbalances of the individual balance groups form the basis for the clearing and settlement of imbalance charges. The imbalances are determined as net deviations for each quarter hour period. However, costs also arise when there is a need for immediate balancing at control area level. So it is perfectly possible that a balance group which creates a need for balancing energy because of its load fluctuations is at the same time balanced over the imbalance settlement period.

The settlement mechanism for imbalance charges is set out in the document *Auslgeichsenergiebewirtschaftung* (imbalance pricing and charging), an appendix to the general terms and conditions of the clearing and settlement agent[67]. This document differentiates between the first and the second clearing. The first clearing, which is conducted at a monthly basis, compares the aggregated schedules of the individual balance groups with their aggregated meter readings or standardised load profiles[68]. In the second clearing, which is held 15 months later, the meter readings for customers without continuous metering are taken into account. The same holds true for any corrections.

Decisive for the clearing of imbalances are the clearing price 1 (CP1), payable for the amount of each group's imbalance, and the clearing price 2 (CP2), payable in proportion to

[65] This only refers to the energy requested in cases of power station block failures. In all other cases, these costs are considered positive tertiary control energy and treated accordingly.
[66] Also known as the control area delta.
[67] See (APCS, 2011).
[68] This applies to injecting and withdrawing parties for whom no meter readings are available.

consumption volumes. The aim is to clear 20% of the cost via CP2. The following costs are thus cleared via CP1[69]:

$$K = (1 - s) * K_C \qquad (4)$$

K	monthly cost that needs to be covered by CP1
s	targeted allocation ratio for CP2, currently 20%
K_c	total clearing costs to be covered per month

A CP1 is calculated for every quarter hour of a month. If balance groups create the need for balancing energy, they pay the CP1 for their imbalance while they receive the CP1 if they reduce the need for balancing energy. However, the CP1 can also be negative, as a result of which the payment flows are reversed. To the extent to which balance groups' imbalances offset each other, payments occur between them. Deviations going beyond that, i.e. the total net imbalances across all balance groups, represent the control area's need for balancing energy, i.e. its delta. The following items are thus covered via the CP1:

$$K = \sum_{t \epsilon M} V_t \cdot P_{C,t} \qquad (5)$$

M	amount of all quarter hour periods in a month
V_t	signed balancing energy need in the control area within a quarter hour period
$P_{C,t}$	clearing price 1 per quarter hour

The cost covered via the CP2 is allocated to the individual balance groups based on their monthly consumption. The CP2, which is constant for each month, is therefore calculated as follows:

$$P_S = \frac{K_C - K}{E} \qquad (6)$$

P_S	clearing price 2
E	total consumption of all balance groups

The clearing price 1 ($P_{C,t}$) per imbalance settlement period[70] (t) is a base price ($P_{B,t}$) plus the value of the function for the balancing incentive markup (T). The balancing incentive markup is a function of the control area's delta (V_t), a ceiling calculated for the whole month (U_{Max}), a specified minimum value (U_{Min}) and a specified value at which the maximum markup (V_{Max}) is reached[71].

$$P_{C,t} = P_{B,t} + sgn(V_t) \cdot T(V_t, U_{max}, U_{min}, V_{max}) \qquad (7)$$

The function for the markup comprises the squared delta of the control area in order to make sure that the price in quarter hour periods with major balancing energy needs is higher than in quarter hour periods with smaller balancing energy needs. The base price is predicated on a value called balancing market price (P_t). This price is defined as a volume-weighted average price of all positive and negative balancing energy used within each imbalance settlement period (t).

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[69] The denomination of the variables in the following formulas is identical as in (APCS, 2011).
[70] The imbalance settlement period in the APG control area is 15 minutes.
[71] For the current values at which these parameters are set, see (APCS, 2011).

U_{Min}	minimum value of the function	€ 3.00/MWh
V_{Max}	control area delta value at which the maximum markup is reached	75.00 MWh

$$P_t = \frac{\sum E_{1,i,t} \cdot P_{1,i} + \sum E_{2,j,t} \cdot P_{2,i}}{\sum E_{1,i,t} + \sum E_{2,j,t}} \quad (8)$$

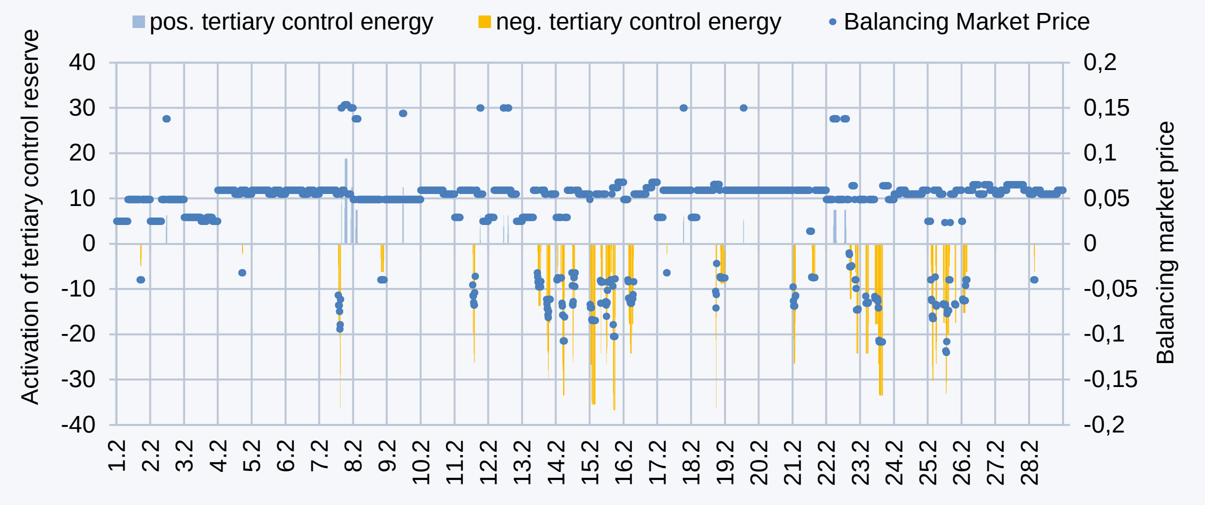
$E_{1,i,t}$ positive balancing energy used in this quarter hour period
$P_{1,i,t}$ corresponding balancing energy price per unit
$E_{2,j,t}$ negative balancing energy used in this quarter hour period
$P_{2,j,t}$ corresponding balancing energy price per unit

The appendices to the imbalance pricing and charging document (APCS, 2011) generally only talk about requested energy. Without this being explicitly mentioned in the appendices, it is, however, clear that this refers exclusively to tertiary control energy. However, in most of the quarter hour periods, no tertiary control energy is called. In this case, the balancing market price is formed as the average of the lowest sales offer ($P_{V,t}$) and the highest purchase offer ($P_{K,t}$) for tertiary control energy according to the MOL valid for each quarter hour period.

$$P_t = \frac{P_{V,t} + P_{K,t}}{2} \quad (9)$$

The result of this calculation algorithm in conjunction with the low frequency of requests for tertiary control energy is that in times without requests, the balancing market price does not change during a full four-hour product-time slot for tertiary control energy. In the event of a request, the balancing market price changes abruptly, however (see Figure 20).

Requests for tertiary control energy (MWh) **and balancing market price** (€/kWh) **in February 2014**



Source: APCS

Figure 20: Requests for tertiary control energy in February 2014

As demonstrated in formula (7), the clearing price 1 ($P_{C,t}$) is not directly derived from the balancing market price (P_t), but rather from the so-called base price ($P_{B,t}$). To do so, the exchange price within the respective quarter hour period ($P_{X,t}$) works as a limit on the balancing market price:

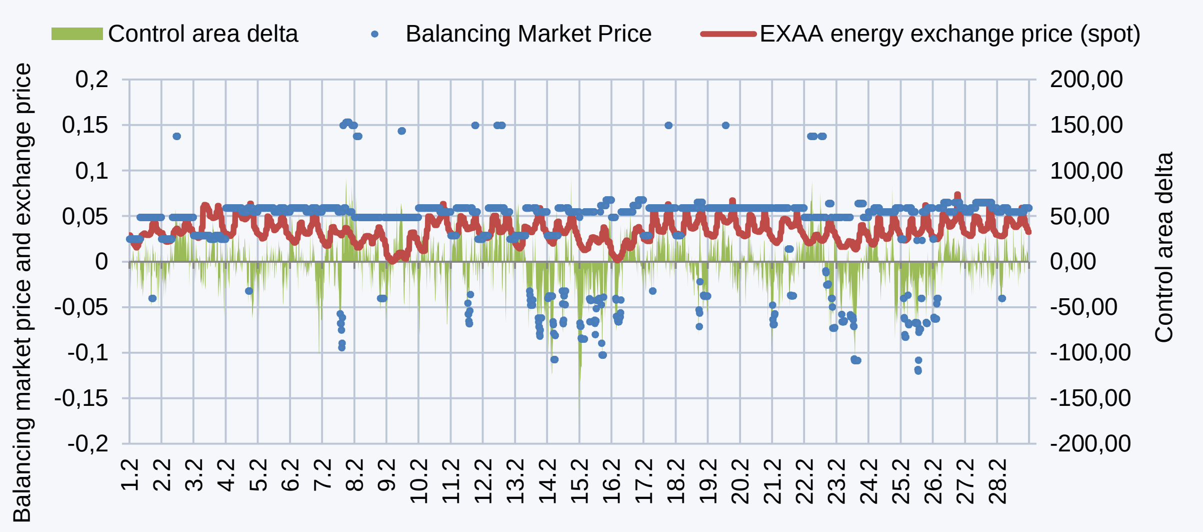
$$P_{B,t} = \begin{cases} \min(P_t, P_{X,t}) & V_t < 0 \\ \max(P_t, P_{X,t}) & V_t > 0 \end{cases} \quad (10)$$

P_t balancing market price
$P_{X,t}$ spot market price at the exchange
V_t control area delta

The spot market price at the exchange used is the EXAA day-ahead price; this is meant to ensure that balance groups do not intentionally incur imbalances if balancing energy is cheaper than energy in the day-ahead market. However, linking the system to the day-ahead market is not unproblematic as potential arbitrage opportunities with respect to the intraday market may arise.

Figure 21 visually illustrates the effects of formula (10). If the delta of the control area has a positive sign, the base price corresponds to the maximum of the balancing market price and the EXAA electricity exchange price. If the delta of the control area has a negative sign, the lower of the two values applies.

Balancing market price, EXAA exchange price (€/MWh) **and delta control area** (MW) **in February 2014**



Source: APCS

Figure 21: Balancing market price, EXAA exchange price and control area delta in February 2014

According to formula (7), the value of the function for the balancing incentive markup (T) is also taken into account in addition to the base price. Depending on whether the control area deviation is positive or negative, the markup function (T) is either added or deducted.

$$T(V_t, U_{Max}, U_{Min}, V_{Max}) = \begin{cases} U_{Min} + \dfrac{U_{Max} - U_{Min}}{V_{Max}^2} \cdot V_t^2 & |V_t| < V_{Max} \\ U_{Max} & |V_t| \geq V_{Max} \end{cases} \qquad \textbf{(11)}$$

The parameters U_{Min} and V_{Max} are fixed parameters[71]. Value U_{Max} represents the maximum value that the function (T) can have in a month and is recalculated every month according to formula (12). For the calculation of the balancing incentive markup function, the balancing energy need in the control area (V_t) is used as V_t squared. As from the value V_{Max}, the function remains constant. The value U_{Max} is calculated in such way that the cost of the first clearing can be covered according to formula (5).

Therefore, the following must apply:

$$U_{Max,S} = \frac{1}{C} \cdot \left[(1-s) \cdot K_C - \sum_{t \in M} V_t \cdot P_{B,t} - U_{Min} \cdot \sum_{\substack{t \in M \\ |V_t| \geq V_{Max}}} \left(|V_t| - \frac{|V_t|^3}{V_{Max}^2} \right) \right] \qquad \textbf{(12)}$$

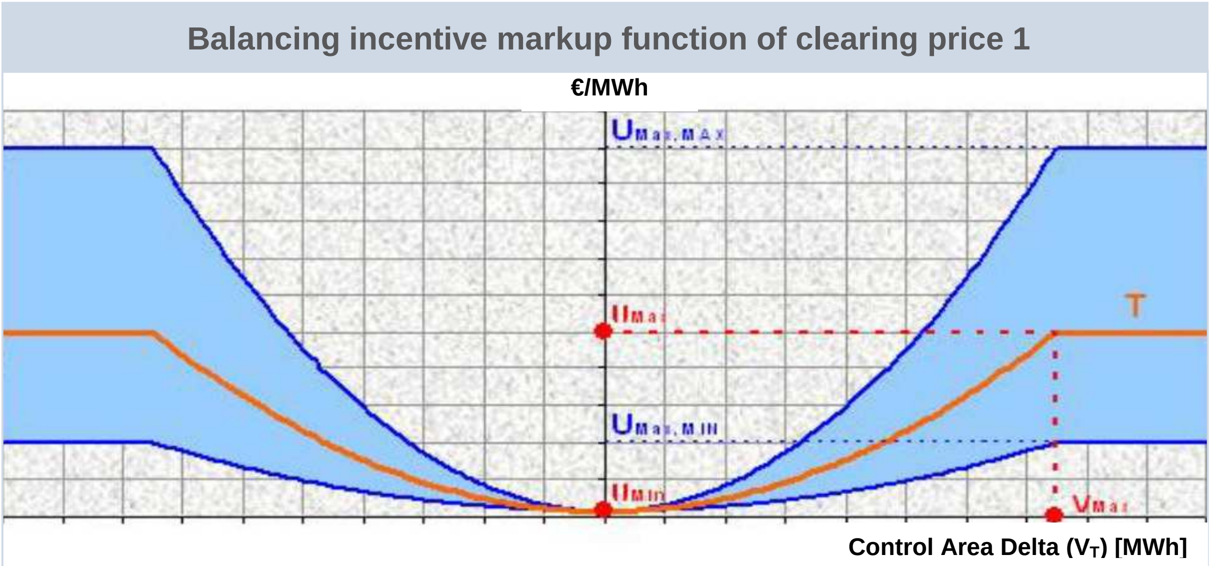
with C being defined as follows:

$$C = \sum_{\substack{t \in M \\ |V_t| < V_{Max}}} \frac{|V_t|^3}{V_{Max}^2} + \sum_{\substack{t \in M \\ |V_t| \geq V_{Max}}} |V_t| \quad (13)$$

Absolute upper and lower limits[72] are furthermore set for U_{Max}. If these are not reached, the allocation ratio (s), which defines the cost-sharing ratio between CP1 and CP2, diverges from the target value of 20%.

$$U_{Max} = \begin{cases} U_{Max,S} & U_{Max,MIN} \leq U_{Max,S} \leq U_{Max,MAX} \quad \Rightarrow \quad s' = s \\ U_{Max,MIN} & U_{Max,S} < U_{Max,MIN} \quad \Rightarrow \quad s' < s \\ U_{Max,MAX} & U_{Max,MAX} < U_{Max,S} \quad \Rightarrow \quad s' > s \end{cases} \quad (14)$$

The function of the balancing incentive markup can be depicted as follows:

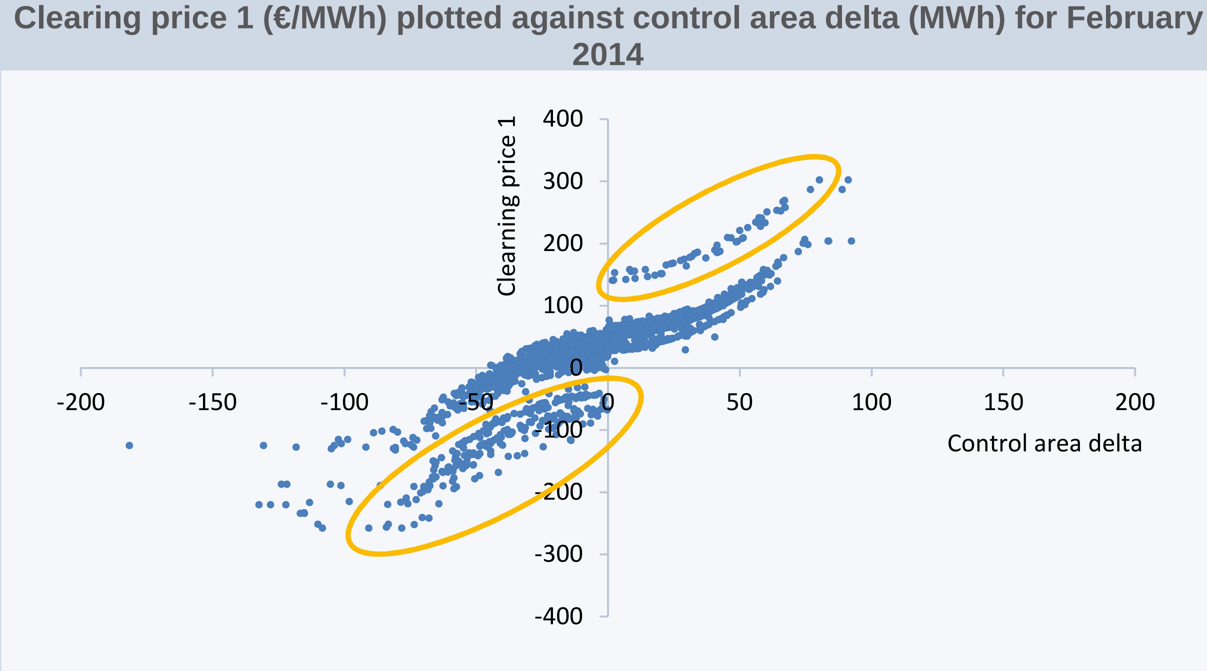


Source: APCS

Figure 22: Markup function of clearing price 1 in the Austrian balancing regime

For every quarter hour period, a clearing price 1 is determined. This price is derived from the base price, which changes significantly in the event of any request of tertiary control energy, and the function of the balancing incentive markup, which is affected by the delta of the control area. Figure 23, in which CP1 is plotted against the delta of the control area, depicts the effects that requests for tertiary control energy have on CP1. These are shown by the additional point clouds over/under the main point cloud. Solely depending on whether there were any requests for tertiary control energy, entirely different clearing prices result for the same delta value of the control area.

[72] $U_{Max, MIN}$	lower limit of the markup function maximum	€40/MWh
$U_{Max, MIN}$	upper limit of the markup function maximum	€200/MWh



Source: APCS

Figure 23: Clearing price 1 plotted against control area delta value for February 2014

6.2. Interdependencies in physical electricity trading

6.2.1. Day-ahead market

Final model – winter

Goodness of fit	
Number of observations	2,189
F(13, 2175)	302
Prob > F	0.0000
R-squared	0.6431
Adj. R-squared	0.6410
RMSE	4.3946

Final day-ahead model – Winter						
d1_EPEX spot price	**Coefficient**	**Std. error**	**t value**	**P>t**	**95 % conf.**	**interval**
l1_EPEX spot price	-0.1855	0.0124	-14.9500	0.0000	-0.2099	-0.1612
l1_Load	0.0002	0.0000	11.1700	0.0000	0.0002	0.0002
d1_Load	0.0010	0.0000	37.7000	0.0000	0.0010	0.0011
l1_Wind	-0.0002	0.0000	-9.4100	0.0000	-0.0003	-0.0002
d1_Wind	-0.0012	0.0000	-27.2100	0.0000	-0.0013	-0.0011

l1_PV	-0.0002	0.0000	-7.7000	0.0000	-0.0003	-0.0002
d1_PV	-0.0014	0.0001	-19.5300	0.0000	-0.0015	-0.0012
l1_dummy hour	5.8371	0.5093	11.4600	0.0000	4.8383	6.8359
d1_dummy hour	4.4442	0.3109	14.2900	0.0000	3.8344	5.0539
l1_dummy block	0.5984	0.2705	2.2100	0.0270	0.0679	1.1289
d1_dummy block	-27.0889	6.3452	-4.2700	0.0000	-39.5322	-14.6455
l1_dummy block2	0.2304	0.2331	0.9900	0.3230	-0.2267	0.6875
d1_dummy block2	-19.6704	4.4465	-4.4200	0.0000	-28.3901	-10.9506
Constant	-3.2650	0.8628	-3.7800	0.0000	-4.9571	-1.5730

Note: d1… first difference, l1… first lag

Source: Frontier Economics

Table 14: Final day-ahead model for the winter season

6.2.2. Intraday

Final intraday model: full-year overview

Goodness of fit	
Number of observations	17,543
F(7, 17535)	2,682
Prob > F	0.000
R-squared	0.579
Adj. R-squared	0.579
Root MSE	5.017

Final intraday model: full-year overview						
d1_EPEX intraday price	Coefficient	Std. error	T	P>t	95% conf. interval	
d1_EPEX intraday price	-0.1814	0.0044	-41.3500	0.0000	-0.1900	-0.1728
l1_EPEX spot price	0.1446	0.0046	31.1900	0.0000	0.1356	0.1537
d1_EPEX spot price	0.7821	0.0056	140.4400	0.0000	0.7712	0.7930
l1_residual load error	-0.0002	0.0000	-14.5800	0.0000	-0.0002	-0.0002
d1_residual load error	-0.0004	0.0000	-12.3100	0.0000	-0.0005	-0.0004

l1_residual load error (squared)	3.02E-09	1.69E-09	1.7900	0.0740	0.0000	0.0000
d1_residual load error (squared)	1.32E-08	4.08E-09	3.2200	0.0010	0.0000	0.0000
l1_non-availabilities (unplanned)	0.0002	0.0000	4.9200	0.0000	0.0001	0.0002
d1_non-availabilities (unplanned)	0.0002	0.0002	1.6200	0.1060	-0.0001	0.0005
Constant	0.7769	0.1173	6.6200	0.0000	0.5468	1.0069

Source: Frontier Economics

Table 15: Final intraday model for the full year

Final intraday model: summer

Goodness of fit	
Number of observations	2,195
F(7, 17535)	355
Prob > F	0.000
R-squared	0.679
Adj. R-squared	0.677
Root MSE	5.603

Final intraday model: summer						
d1_EPEX intraday price	Coefficient	Std. error	T	P>t	95% conf. interval	
l1_EPEX intraday price	-0.2507	0.0139	-18.10	0.000	-0.2778	-0.2235
l1_EPEX spot price	0.2264	0.0155	14.57	0.000	0.1959	0.2568
d1_EPEX spot price	0.8177	0.0174	46.94	0.000	0.7835	0.8518
l1_Wind forecast error	0.0007	0.0001	6.20	0.000	0.0005	0.0009
d1_Wind forecast error	0.0019	0.0002	10.60	0.000	0.0015	0.0022
l1_PV forecast error	0.0010	0.0001	11.29	0.000	0.0008	0.0011
d1_PV forecast error	0.0020	0.0001	14.85	0.000	0.0018	0.0023
l1_Load forecast error	-0.0002	0.0000	-3.25	0.001	-0.0002	-0.0001
d1_Load forecast error	-0.0003	0.0001	-3.67	0.000	-0.0005	-0.0001
l1_dummy hour	1.4964	0.5637	2.65	0.008	0.3909	2.6019
d1_dummy hour	1.5155	0.3855	3.93	0.000	0.7596	2.2714
l1_dummy year	-0.1575	0.2580	-0.61	0.542	-0.6634	0.3484
d1_dummy year	-3.3832	5.6290	-0.60	0.548	-14.4219	7.6555
Constant	0.6815	0.3856	1.77	0.077	-0.0747	1.4377

Source: Frontier Economics

Table 16: Final intraday model for the summer season

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