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The Swiss Wholesale Electricity Market

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1 Introduction

In 2014, Switzerland had a total electricity consumption of 59.3 TWh or 7.3 MWh per capita (SFOE, 2015). The main demand comes from households (31.8%), industrial production (31.4%), and services (27.0%). Due to high electrification and dense network of public transport, transport accounts for 8.1% of demand; the remaining part is consumed by agriculture and others.

On the supply side, Swiss electricity generation is characterized by a high share of hydro (56%) and nuclear power (38%). The remaining 6% are mainly produced by renewable sources (4%) and conventional thermal generation (2%). Due to its central location within Europe, Switzerland is a transit country, i.e., in 2014 around 25 TWh (out of 78 TWh in total) of the flows on the Swiss transmission grid have been caused by transit flows between neighboring countries mainly from the north down to Italy (Swissgrid, Swissgrid, 2015a).[1]

Electricity demand and supply need to be balanced in every instance in time avoiding failures of the electricity system. This requirement lead to some particularities of electricity markets which are special compared to other commodity markets. The first part of this article introduces these particularities in general terms and their consequences on the design of electricity markets. In the second part, we describe the Swiss wholesale electricity

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[1]This document is based on many resources and data available online. These sources are not provided in the references but directly inserted as links in the electronic version of this document.

market. The description starts by summarizing the institutional design of the Swiss market. This is followed by an empirical characterization of the markets based on descriptive statistics of prices and quantities. As, to our best knowledge, a detailed description and empirical description of the Swiss market is missing in the literature so far, our main goal is provide it as a basis for future research on the enhancement of the Swiss electricity market design.

Section 2 provides a general introduction into electricity markets and their different sub-markets. The structure presented in this section then guides the description of the Swiss market afterwards. Section 3 explains the organization of demand and supply parties in balancing groups in the Swiss market. The Swiss energy only market is described in Section 4. Section 5 outlines the redispatching process. The imbalance market including reserve procurement and imbalance settlement is described in Section 6. Section 7 summarizes and provides some thoughts on improvements of the current market design.

2 A Primer on Electricity Markets

The commodity electricity has some special characteristics. First, it can only be stored in a limited amount. Second, electricity needs to be transported from producers to consumers using the electricity grid. Due to physical laws this transmission requires that demand and supply balance at each instance in time; if a consumer increases demand a supplier has to increase its production in the same moment. Third, electricity can not be disposed, i.e., excess supply is not possible. If excess supply (or excess demand) occurs, the frequency in the transmission grid changes leading to a disruption of supply. Forth, electricity is hardly substitutable in particular in a short time period; most appliances and production processes require electricity as an input and cannot switch away to other sources. Therefore, a disruption of electricity supply causes high cost and high level of reliability, i.e., maintaining the supply and demand balance, is required

2.1 Market Participants

Four different classes of actors interact on an electricity market:[2] Suppliers, final demand, the transmission system operator, and the regulatory authority.

Suppliers, often called *generators*, own generation assets used to supply electricity. Generation assets are power plants as well as storage facilities. While plants are only able to generate electricity, storage facilities can trans-

[2] We focus on the description of liberalized electricity markets, i.e., generation assets and the transmission grid are owned and operated by different parties.

fer limited amounts of electricity from one point in time to another. Power plants are differentiated by the used primary fuel as well as their technological characteristics. Technological characteristics determine the *flexibility* of a generator, i.e., the ability to change output in a given time span. Flexibility plays an important role in maintaining the reliability of electricity supply as it determines the ability to handle given imbalances in the demand-supply equality in a short amount of time.

Households and industries form the group of final demand which is usually called *load*. Industries may be able to change their demand in a short timespan, e.g. by using own generation assets or altering the production cycle, i.e., they might react price elastic in the short run. In contrast, households are rather inelastic in the short term.[3]

The *transmission system operator* (TSO) is responsible for operating the transmission system and, thus, for maintaining reliability of the electricity system.[4] Finally, the regulatory authority provides and monitors the market environment.

For billing and measurement purposes, generators and consumers are organized in *balancing groups* (BG). A BG is group of various generators and consumers which is represented by a single *balancing responsible party* (BRP). Measurement of energy used or supplied takes place at the BG level and the BRP is responsible for communication between the TSO and the BG.

2.2 Energy-only and Imbalance Markets

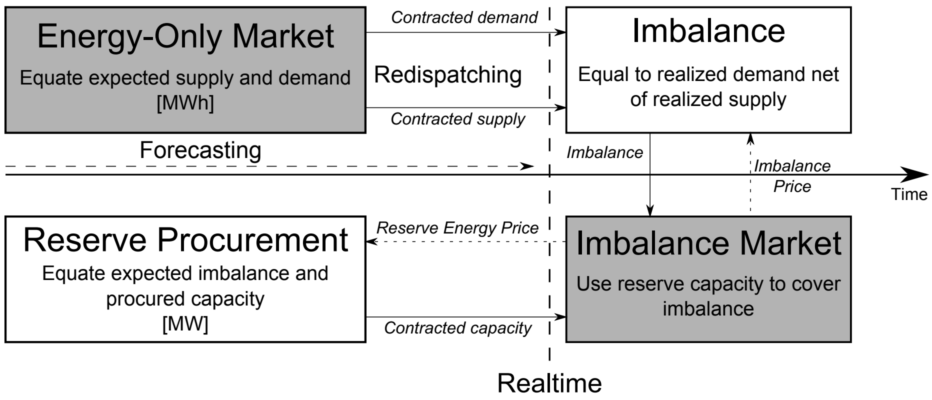
Figure 1 provides an overview of a generic electricity market. The vertical dashed line denotes *realtime/delivery time*, i.e., the time when demand and supply are known for certain. In order to address the reliability requirement electricity markets are organized in two different sub-markets shown by the shaded boxes. Based on demand and supply forecasts the *energy-only market* (EOM) balances expected demand and supply. The TSO needs to take control over the electricity system at some point in time in order to maintain stability of the transmission grid. The TSO analyzes whether the proposed demand and supply schedules are feasible from a transmission point of view. If overloading of lines in the grid can be foreseen, the TSO is allowed to adjust demand and supply schedules; a process called *redispatching*.

At realtime demand and supply become known. As they most likely deviate from their expected value, an *imbalance* occurs and reliability requires

[3]Technologies such as smart metering and storage facilities on the household side can improve short-term price reaction. However, these are still at an early stage of deployment.

[4]As we do not investigate the incentives to maintain and invest into the electricity grid, we use the term *transmission system operator*. Generally, this term is used in order to reflect the fact that the grid operator owns the transmission assets (opposed to the *Independent Transmission Operator* which does not own but operates the assets).

Figure 1: Overview Electricity Markets



its elimination which is handled in the *imbalance market* (IBM). In order to address these imbalances, generation capacity is needed. To guarantee that capacity is available and not contracted for energy sales, the capacity needs to be procured at the same time or before the EOM is cleared. Thus, the IBM equates the (expected) imbalance with the procured *reserve capacity.*

It has to be pointed out, that balancing and redispatching are traditionally two separate processes. Redispatching occurs due to network problems and the TSO is often not allowed to use reserve capacity for this purpose. Moreover, redispatching takes place before delivery time. In contrast, balancing is necessary due to (expected) deviations in the demand-supply equation and occurs independently of the transmission grid after delivery time.

2.2.1 Energy-only markets

Based on forecasts the *energy-only market* (EOM) aims to equate expected demand and supply. Generators and demand actors bid energy into the market and the market maker equates these bids until the market is cleared.[5] EOM are often organized in further sub-markets distinguished by their *gate closure*, i.e., the point in time when the market is cleared relative to real-time; year-, month-, and day-ahead market (DAM) which are cleared a year, month, or day before delivery time.[6] In the intra-day market (IDM), energy is traded within the last 24 hours before delivery date.

Beside the sequence of sub-markets, three main aspects are important in designing EOM markets (see Table 1). First, the product specification: while it is clear that the product traded is electricity delivered, the market

[5]The market maker can, for example, be an independent authority or the TSO.

[6]Apparently, derivative products such as futures and options also exist which we here do not aim to analyze further.

maker has to decide about the temporal and locational differentiation of the product. Second, the gate-closure of the IDM which specifies at which point in time the market is cleared. Third, the trading mechanism, e.g. whether the market is cleared at a certain point in time or continuously. Moreover, the trading mechanism determines the auction format and the types of bids used (e.g., simple or complex bids).

Table 1: Market Design Aspects of Energy-Only Markets

Design Criterion	**Description**
Sub-markets	Organization of successive markets distinguished by their gate closure.
Temporal product specification	Duration of the delivery time period
Locational product specification	Indexing of products by the node or zone in which they are produced/demanded
Trading mechanism	Market clearing at a certain point in time or continuously. Auction mechanism (e.g., simple vs. complex bids)

The product traded on the EOM market is electricity delivered, i.e. MW over a certain time period; thus, MWh. In setting up the market, the market maker or participants need to decide about the time span of delivery. As demand and supply vary instantaneously in time, a shorter contract duration helps to avoid so-called *schedule leaps* which arise as pre-defined contracts length prohibits an instantaneous matching of demand and supply (Hirth & Ziegenhagen, 2015). On the other hand, a very short contract length, e.g. minute contracts, lead to a high variation of production and, as altering the output of an power plant is costly, the cost of production. Moreover, decreasing contract length leads to an increasing number of products traded.

Spatial differentiation of electricity is another concern in designing energy-only markets. In a *nodal price* approach commodities are indexed to the node in the transmission network at which they are produced or consumed. While this approach helps to transfer information about the status of the transmission grid to the EOM, it increases the number of products traded in the market. More importantly, it requires that the TSO participates in the EOM.

As trading in the EOM is based on forecasts of demand and supply and as forecast errors decline in time, moving the gate closure closer to real time helps decreasing expected deviations of demand and supply and, thus, increasing reliability of the system. However, gate closure cannot coincide with realtime as the TSO needs to take control over the electricity system in order to maintain system stability (redispatching). Thus, IDM gate closure addresses the issue of minimizing expected deviations of demand and supply and meeting the technical ability of the TSO to organize transmission flows in a short time frame.

2.2.2 Imbalance markets

Imbalance markets eliminate the imbalance between demand and supply at realtime; thus, imbalance markets are cleared after the realization of supply and demand are known. Two general types of imbalances can occur: First, *deterministic imbalances* are known before the revelation of uncertainty. Scheduled leaps belong to this class as they arise when it is not possible to match the contract length in the EOM market with instantaneous changes in demand and supply. Second, *uncertain imbalances* are caused by the fact that demand and supply cannot be forecasted with certainty and include, e.g, unforeseen plant shut downs and errors in the forecast of intermittent renewable energies. In the IBM, consumers and generators are demand and supply parties at the same time. On the one hand, they demand energy in-/decreases in order to equate the imbalance they caused. On the other, this in-/decrease is provided, i.e., supplied, by the generators.[7] As the TSO is responsible for system stability, it usually serves as the market-maker in the sense of clearing demand and supply.

It is important to emphasize some particularities of balancing markets. First, imbalances, that is the demand for balancing energy, are inherently stochastic. Uncovered demand leads to a failure of the electricity system. Thus, demand needs to be covered entirely by balancing facilities in every point in time. Therefore, demand is completely inelastic during the balance management.

Second, demand can be positive or negative. A positive balancing demand is a situation in which consumer demand unexpectedly exceeds electricity generation causing a need for additional supply. In contrast, a negative demand situation requires a decrease in generation.

Third, supply of reserve energy, i.e., additional generation, needs to be procured before or simultaneously with the EOM. This is necessary to ensure that the capacity is available and not blocked by the contracts of the EOM. We call this stage of the market *reserve procurement* or *reserve market*.[8] Conversely, negative reserve – the decrease in generation – requires that the supplier is generating, i.e., has a contract on the EOM. Thus, supply needs to be procured before demand is known and is, therefore, inelastic during

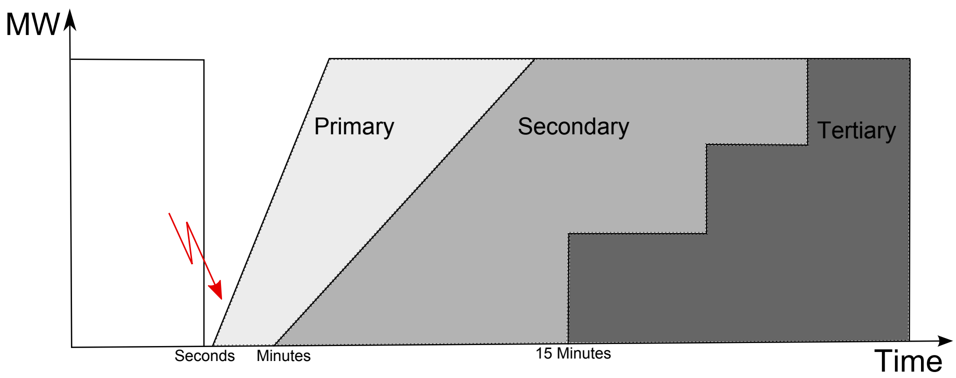
[7] In principle, demand parties are also able to provide reserve "capacity" by de-/increasing load. This possibility existed, e.g., in Germany until the end of 2015. To not further complicate the exposition, we abstract from this fact.

[8] 'Procurement' is the more neutral term as it also includes mandatory provision of reserve capacity. However, the term 'market' is more common in the literature.

the market clearing stage of the IBM.

At the stage of market clearing the IBM therefore constitutes a system of inelastic supply and demand. Moreover, as reserve should be able to always restore the demand and supply balance, supply usually exceeds demand. Thus, a situation of permanent excess supply results at the time of balance management ruling out the existence of scarcity price signals.

Figure 2: Balancing Types



Notes: Adapted from http://www.e-control.at/industrie/strom/strommarkt/ausgleichsenergie.

Besides the differentiation of positive and negative reserve power, products are differentiated by their flexibility, i.e., by their ability to deliver energy within a pre-defined amount of time. Figure 2 shows an overview over the different types of reserve. The red arrow indicates an unforeseen drop in the power supply. The imbalance is recognized by a drop in the frequency of the grid and *primary reserve* is immediately and automatically activated.[9] Primary reserve has not to be activated in the area in which the imbalance occurs but can be activated anywhere in the synchronized grid (*solidarity principle*). Primary control is replaced by *secondary reserve* which has to be available within 30 seconds and fully activated within 5 minutes.[10] Secondary reserve is usually half-automatically activated, i.e., the TSO sends a signal to the plant which automatically changes output. However, in contrast to primary reserve, it is usually activated at a location close to the point of disruption. *Tertiary reserve* which is also called *minute reserve* both complements and replaces secondary control.[11] This reserve

[9]'Primary reserve' is also referred to as 'primary control' or'frequency containment reserve'

[10]'Secondary reserve' is also referred to as 'secondary control', 'frequency restoration reserve', or 'spinning reserve'.

[11]'Tertiary reserve' is also referred to as'tertiary control', 'replacement reserve', or 'non-spinning reserve'.

has to be able to be completely activated within 15 minutes and to last for at least one hour up to a maximum of four hours (see Consentec, 2014; ENTSO-E, 2016, for further technical details).[12]

Whether or not a plant is allowed to contribute to the different kinds of reserve power depends on the technical characteristic, i.e., whether a plant fulfills the *pre-qualification* criteria set by the TSO. Depending on whether a plants has to produce when offering balancing capacity, reserves are sometimes called *(non-)spinning reserve.*

Table 2: Design criteria for reserve procurement

Design Criterion	**Description**
Temporal product specification	Duration of the delivery time period
Locational product specification	Indexing of products by the node or zone in which they are provided
Trading mechanism	Auction design or mandatory provision
Cost reimbursement	Cost coverage in the case of energy delivery
Demand	Method to determine demand for reserve capacity

The TSO procures reserve capacity in order to ensure against imbalances leading to system blackouts. In contrast to the EOM, the product in the balancing market is capacity which in the case of an imbalance can be used to produce more or less energy. Thus, besides designing the capacity procurement, the market maker also needs to specify a mechanism how to reimburse cost caused by energy delivery. While the product differentiation based on the flexibility of the reserve providers is fixed based on technical grounds, the capacity product needs to be further detailed along the time and spatial dimension, i.e., the contract length and possible nodal differentiation need to be determined (Table 2). Concerning the market clearing mechanism, the regulator has to decide whether the procurement should be market-based or whether delivery of reserve capacity is mandatory. In the case of market-based procurement, the trading or auctioning mechanism as well as the gate closure need to be set. Finally, the TSO needs to decide about the demand for reserve capacity which is based on a reliability criterion, e.g., the probability that load is not served. Depending on whether the TSO uses a static or dynamic approach, i.e., determines capacity demand only once or updates demand, that is called *static* or *dynamic sizing* (see

[12] We do not further analyze the *forth* or *time control* which is used to eliminate differences between the *synchronous* time measured using the frequency of the grid and real time.

e.g. Khatir et al., 2010).

Balancing causes two type of cost: the cost of reserving the capacity and, the cost of generating energy in the case of an imbalance. T two processes are necessary in order to allocate these cost. First, imbalance need to be measured for each generator and consumer which is called *imbalance settlement*. Second, the cost need to be allocated. As system stability is a service to the final consumers, one can argue that cost should be refinanced via a uniform surcharge on the final electricity price. On the other hand, allocating cost to parties that cause the imbalance avoids strategic behavior. The process of allocating cost to market actors that caused the imbalance is called *imbalance pricing*.

In economic terms, imbalance pricing aims to solve an adverse selection/ hidden-information problem: BRPs have private information about their demand and supply possibilities which can be enhanced by using costly forecast technologies. Therefore, the *imbalance spread*, i.e., the deviation between prices in the EOM and balancing prices, determines the incentive to reveal the true ability of BRPs and also to increase the forecast technology.

Besides determining a mechanism to allocate capacity and energy cost, the regulator needs to specify the contract length, i.e., for which time intervals imbalance prices are determined. Moreover, the gate closure determines the point in time when cost allocation is carried out. A particularly important question is whether market participants are allowed to trade imbalances before the cost allocation takes place. In so-called *day-after markets* a party with a positive and one with an negative imbalance are allowed to net their positions and, thus, avoid paying the imbalance cost.

2.2.3 Cross-border Trade

Due to the central role of the transmission grid for system stability, international trade in electricity is more complicated than in other markets. This is mainly caused by the fact that international trade requires coordination of two or more TSOs. For managing the grid, each TSO has to know the amount injected or withdrawn at the cross-border connections. A mechanism is therefore needed to allocate the cross-border transmission capacities to parties that have internationally traded in the EOM or balancing market. One possibility is an explicit auction of the capacities which is run in parallel to the EOM and reserve capacity procurement. Another option is *market coupling*. In such a system traders provide their bids to the market and TSOs analyze these bids. The market maker clears the market over all regions under the transmission constraints provided by the TSOs. Thus, transfer capacities are auctioned implicitly in the market clearing procedure.

After this general introduction we now turn to the example of the Swiss wholesale electricity market. After describing the organization of demand

and supply actors in balancing groups, we present the different sub-markets.

3 Swiss Balancing Groups

Balancing groups (BG) are used for three major purposes. First, measurement of energy delivered; second, coordination between the TSO and market participants; third, accounting between the TSO and market participants, i.e., reserve and imbalance billing. Each balancing group is represented by a Balancing Responsible Party (BRP).

In Switzerland, three different types of BG exist. The standard BG is the major unit for measurement and billing. For scheduling and accounting two further types of BGs exist: CH-15 and reserve balancing groups which both have shorter lead-times; schedules have to be submitted until 15 minutes before delivery time. The group of CH-15 balancing groups is allowed to only trade within Switzerland in the day-ahead and intra-day market. Reserve balancing groups are used for balancing procedures and billing and are allowed to trade internationally. Both, reserve and CH-15 BGs have to be associated with a standard group and all three together form the accounting unit used for imbalance settlement. A list of BG is provided by Swissgrid.

Note that information about generation and demand plans is submitted4d to Swissgrid by each balancing group. Thus, the Swiss grid does not receive any a-priory information about the production schedules of single units or generators. This information becomes only now at real-time when it becomes measurable.

4 Swiss Energy-Only Markets

The Swiss energy-only market is organized around two major markets: An day-ahead auction and continuous intra-day trade. Both markets are organized by the European Power Exchange (EPEX) in Paris.

4.1 Day-ahead Market

The day-ahead market is organized as a uniform auction with hourly contracts. It opens 45 days before delivery time and is cleared the day before at 11:00 determining contracts for hourly delivery for each hour of the following day. Beside hourly products, block contracts for base and peak load as well as contracts covering several hours are offered (see EPEX). The minimum bid size and step is 0.1 MW. Prices have to lie between -500 and 3000 €/MWh with increments of 0.1 MW.

Given the day-ahead results as well as future and over-the-counter contracts, the balancing responsible parties (BRP) of buyer and seller, have to submit their schedules to the TSO (Swissgrid) until 14:30 the day before delivery. Swissgrid verifies that the schedules match and allows for rescheduling in the case of mismatches. In the case of cross-border trade, schedules have to be submitted until 14:45 to the domestic as well as foreign TSO which both check the schedules. For both cases the re-scheduling phase ends at 15:30. Between 15:30 and 16:30 Swissgrid and foreign control block responsible parties (usually the TSO) coordinate their respective control area schedules. At 16:30 final day-ahead schedules are fixed (Swissgrid, 2011).

Table 3: Day-ahead volumes, prices, and revenues

	2010	2011	2012	2013	2014	2015
Volume [TWh]	9.32	12.06	16.68	18.74	20.47	22.91
Avg. Price [€/MWh]	51.65	57.01	49.43	44.82	36.67	40.29
Base Price [€/MWh]	51.06	56.49	48.86	44.41	36.35	39.97
Peak Price [€/MWh]	57.93	62.28	55.04	49.81	40.24	43.21
Revenues [Million €]	481.60	687.60	824.45	840.02	750.49	923.19
Consumption [TWh]	58.52	57.55	57.68	58.03	56.41	56.84
Market Value [Million €]	3022.22	3281.10	2851.18	2600.76	2068.64	2290.08

Notes: Author's own calculation based on EPEX data. Consumption based on data provided by Swissgrid. Average prices are calculated as weighted average using traded volumes as weights. Market value is defined as the product of the average hourly price and consumption.

Table 3 shows the development of average prices and traded volumes for hourly contract as well as average prices for base and peak-load contracts. Trade volumes in the day-ahead market steadily increased over the last years.[13] Average hourly prices decreased by 11 € (22%) in between 2010 and 2015. As a consequence, the value of the Swiss electricity market — defined as the product of final consumption (around 60 TWh) and the average hourly price — decreased by more than 730 Million € (24%). Remarkably, the spread between the base and peak price index dropped by over 50% from 6.8 € to 3.2€.

Summarizing, the day-ahead market gained in importance as a trading platform for electricity over the last years. However, prices and, thus, the value of the electricity market steadily decreased. Moreover, the base-peak price spread also strongly declined indicating problems for short-run storage suppliers.

[13] As total demand is rather constant, the share of final demand traded in the day-ahead market increased up to 40% in 2015. The remaining part is traded either over-the-counter, in long-term contracts, in the future market, or in the intra-day market.

4.2 Intra-day Market

The intra-day market started operating in June 2013. Electricity is continuously traded after the market opens at 15:00 at the day before delivery time.[14] Hourly, quarter-hourly, and base and peak contracts are traded. The minimum bid size and increment is set to 0.1 MW. Prices have to be in the range from -9999.99 to 9999.99 €/MWh. Thus, the price range for intra-day bids is higher than in the day-ahead market.[15] The Swiss intra-day market closes one hour before delivery time.

The BRP of buyer and seller have to update their day-ahead schedules and report them to Swissgrid which continuously verifies them. The final schedule has to be submitted until 45 minutes before delivery time, i.e, a quarter hour after the intra-day market closes.[16] After finally verifying these schedules with foreign control areas, final schedules are fixed half an hour before realtime.

Table 4: Intra-day prices, volumes, and revenues

	2014	2015
Volume [TWh]	1.10	1.44
Avg. Price [€/MWh]	44.32	46.33
Base Price [€/MWh]	36.71	40.35
Peak Price [€/MWh]	40.97	43.86
Revenues [Million €]	48.60	66.81

Notes: Author's own calculations based on EPEX data. Average prices calculated as weighted average using traded volumes as weights. For base and peak prices the unweighted mean is reported. Numbers are based on hourly contracts. As quarter-hourly only constitute a minor part of intra-day trade they are neglected (see Epex)

Table 4 shows average hourly, base, and peak prices as well as traded volumes and revenues gained on the intra-day market. Between 2014 and 2015 the traded volume increased but remains to be only a small fraction of the day-ahead volume. However, prices are slightly higher than in the day-ahead market. The base-peak price spread also declined but the series is to short to extract a reliable trend.

[14]For quarter-hourly contracts the market opens at 16:00.

[15]As the Swiss day-ahead price never reached the upper price bound, intra-day prices might be essentially regarded as unbounded.

[16]CH-15 balancing groups are restricted to trade within Switzerland, only. These BGs have to submit their final schedule until 15 minutes before delivery time. Swissgrid verifies and fixes these schedules until 5 minutes before realtime.

4.3 Cross-border Trade

The North Western Europe (NWE) market coupling couples all European electricity markets except Switzerland and Ireland. Under this regime, market participants trade electricity in the day-ahead market and the market makers perform market clearing across all regions taking into account cross-border transmission capacities calculated by the respective TSOs. Thus, cross-border capacities are implicitly allocated to the market participants and congestion rents are distributed afterwards to the TSOs.[17]

Due to the current lack of an institutional agreement between Switzerland and the European Union, Switzerland does not participate in this market coupling although Swissgrid has implemented the technical prerequisites. Thus, Swiss cross-border capacities are allocated based on an explicit auction, i.e., market participants have to trade energy and to procure the necessary capacities for international trade. Auctions for net-transfer capacities (NTC) are organized by Joint Allocation Office (JAO) and auctions capacities for January 2016 are shown in Table 5. As NTCs values depend on the situation within the countries and, thus, vary by time of the year and day, the values have to be taken as indicative number provided to inform about the rough magnitude of NTC trade.

Table 5: Cross-border capacities [MW]

	From Switzerland	To Switzerland
Austria	1200	314
Germany	4000	586
France	1100	3200
Italy	3510	1910

Notes: Indicative values for January 2016 month-ahead auctions are shown (Swissgrid).

For intra-day trades Swissgrid has an agreement with the Austrian (APG), French (RTE), and German (Amprion, TransNetBW) TSOs allowing the implicit allocation of NTC capacities.

4.4 Summary

The daily market procedure of the Swiss EOM is summarized in Figure 3. An overview over products traded is provided in Table 6.

[17] Explicit auctions still exist to procure capacities for OTC trade.

Table 6: Products energy-only market

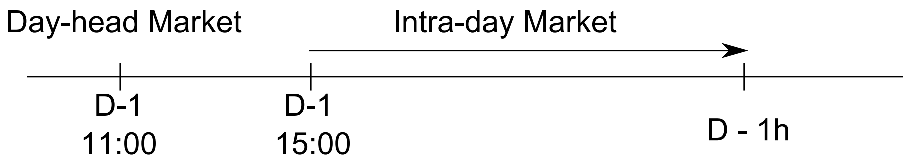
	Day-ahead	Intra-day	
Contract length	1 hour	1 hour	15 minutes
Gate closure	D-1 11:00	D - 60 min	D - 60 min
Auction type	uniform	continuous	continous

Table 7: Products on reserve markets

	Primary Reserve	Secondary Reserve	Tertiary Reserve		Tertiary energy
			Weekly auction	Daily auction	
Product type	symmetric	symmetric	positive/negative	positive/negative	positive/negative
Average demand	75 MW	390 MW	200/120 MW	250/130 MW	n.a.
Contract length	1 week	1 week	1 week	4 hours	n.a.
Gate closure	week-ahead Tuesday 15:00	week-ahead Tuesday 13:00	week-ahead Tuesday 13:00	2 days-ahead 14:30	intra-day D - 1h
Capacity payments	pay-as-bid	pay-as-bid	pay-as-bid	pay-as-bid	n.a.
Energy payments	-	day-ahead price +- 20 %	have to bid in energy auction	have to bid in energy auction	n.a.

Notes: We were not able to find information on the tertiary energy auction.

Figure 3: Time-line Swiss Energy-only market



5 Redispatch

As the operator of the electricity grid, Swissgrid is responsible for maintaining the stability of the transmission grid. Preventive and operative measures are used to fulfill this task.

5.1 Preventive Measures

Swissgrid predicts the network status on a year, month, and week ahead basis. In case of possible grid problems, it publishes likely constraints on production located at certain nodes as maximum percentage of capacity to be used at that node. Two days before realtime, congestion warnings for certain regions in the form of maximum production are released to generators in that region. Based on the day-ahead production schedules of domestic as well as scheduled injection patterns at cross-border nodes (i.e., at 16:00), Swissgrid checks the network status. If a N-1 criterion[18] is violated, they impose a maximum generation constraint for suppliers in respective regions (Swissgrid, 2014a). When preventive production constraints are violated, all power plants have to pay a penalty of 10% of the day-ahead price for the excessive energy in case redispatching becomes necessary.

5.2 Operative Measures

Operative measures are used when preventive measures are not able to stabilize the congestion situation. Two general measures are used: first, topological measures (e.g., alternative line configurations); second, redispatching of either domestic or foreign power plants. In order to guarantee an efficient redispatch, Swissgrid uses primarily topological measures.

In order to procure redispatch capacity, generators do not only submit their scheduled supply but also a minimum and maximum amount of generation possible to Swissgrid. Plant redispatch can be activated immediately but usually a lead-time of a quarter-hour is recommended. The redispatch measure can last for three hours. Plants to be redispatched are chosen based

[18] A N-1 criterion dictates that an electricity system has to be able to manage a given demand/supply situation even if one of the assets in the system, e.g. a power plant or transmission line, suddenly becomes unavailable (see ENTSOE).

on simulation of the grid status such that congestion is released in an efficient manner.

Re-dispatched plants with an increase in generation receive the average day-ahead price over the ten most expensive hours of the preceding week. In case of a downward redispatch, storage plants have to pay 70% of the day-ahead price of the respective hour. In the case of a negative price, they receive 130% of the hourly price. Non-storage hydro and nuclear plants do not have to pay for a downward redispatch; however, in the case of negative price they receive the hourly price with a premium of 30%.

In the case of an international redispatch, payments between the foreign TSO and Swissgrid is based on an individual contract. Billing between Swissgrid and domestic plants is regulated as in the case of national redispatch.

Table 8: Re-dispatch statistics

		2012		2013		2014		2015	
		Pos	Neg	Pos	Neg	Pos	Neg	Pos	Neg
Nat.	Count	20	28	34	46	27	43	6	33
Re-disp.	Avg. Duration [h]	1.37	1.33	1.92	2.25	1.43	1.32	1.78	1.63
(N-1)	Avg. Energy [MWh]	4.56	4.61	13.35	13.35	8.53	7.17	3.95	6.25
	Count					91	699	678	466
Internat.	Avg. Duration [h]					1.54	1.33	1.53	1.41
Re-disp.	Avg. Energy [MWh]					6.07	87.65	81.87	80.46

Notes: Author's own calculations based on data provided by Swissgrid.

Table 8 shows descriptive statistics of operative redispatch measures at the plant level. National redispatch due to N-1 grid violation does not occur often and is quite constant over time. However, international redispatch measures, i.e., actions asked for by a foreign TSO, do occur more often and also show a higher energy demand. Average duration of redispatching tends to be around 1.5 hour in both cases.

6 Swiss Imbalance Market

6.1 Reserve Procurement

6.1.1 Primary Reserve

Primary reserve capacity has to be fully available within 30 seconds and last for maximum 15 minutes. It is activated automatically using frequency controllers at the plant level (Swissgrid, 2013, 2015b). Moreover, primary reserve is activated under the *solidarity principle*, i.e., independent of the location of the event causing frequency deviations. Thus, TSOs can procure primary reserve in regions outside of the own grid.

Within the electricity grid of continental Europe (UCTE) 3000 MW are procured for primary reserve. Each regional grid operator has to procure a share of this amount equal to its load in total UCTE load (ENTSO-E, 2016). Thus, Switzerland has to procure a yearly amount of about 75 MW (Swissgrid, 2015b).

Swiss primary reserve is procured as a symmetric product. That is the procured capacity can be used to decrease or increase generation. Moreover, it is a one price product in the sense that only the provision of capacity is paid while energy delivery is not. The capacity has to be reserved for a full week starting at Monday. A week-ahead pay-as-bid auction closing at Tuesdays at 13:00 determines prices. The minimum bid and mid steps are 1 MW and the maximum bid is set to 25 MW.[19] Since 2010, Swissgrid can procure primary reserve in France. Since 2012, part of the primary reserve requirement is auctioned in the German system.[20] Starting in 2013, Swissgrid has an agreement with the Austrian TSO APG (Austrian Power Grid) allowing to pool the Swiss and Austrian primary reserve market.

6.1.2 Secondary Reserve

Secondary reserve capacity has to be available within 30 seconds and fully dispatched after 5 minutes for a period up to 15 minutes. It is activated in a semi-automatically manner using an actuating signal from Swissgrid to the supplier.

Swissgrid uses a deterministic as well probabilistic criterion to determine secondary and tertiary reserve capacity demand. The deterministic criterion is a N-1 measure requiring that the outage of largest plant in the Swiss market can be balanced. The probabilistic criterion is based on the so-called deficit curve which describes the statistical distribution of imbalances taking into account possible plants failures and forecast errors (Abbaspourtorbati & Zima, 2016).

Swissgrid procures secondary reserve capacity as a symmetric product which has to be available for a whole week starting on Monday. A week-ahead pay-as-bid determines capacity prices. The minimum bid size is 5 MW with increments of 1 MW up to a maximum of 50 MW (Swissgrid, 2015b). Reserve activation is proportional to the contracted capacity of a

[19] Suppliers are allowed to pool their bids for all reserve types.

[20] Due to the historical background, Germany is divided into four control areas which started to form the Grid Control Cooperation (GCC) in 2010 in order to net out imbalances before using reserve energy. The GCC has expanded to the International Grid Control Cooperation (IGCC) covering Austria, Czech Republic, Denmark, The Netherlands, Sweden, and Switzerland. In February 2016 the French TSO RTE started the test phase of joining the IGCC. The IGCC uses the remaining NTC capcities to net imbalances across regions avoiding inefficient secondary reserve activation. While the reserve capacity procurement is not affected, the IGCC helps to reduce the cost of balancing by reducing the need for reserve energy (see 50Hertz).

supplier. Energy is compensated according to respective day-ahead energy (SwissIX) price in the hour of activation. Positive (negative) reserve energy receives an additional margin of 20% (-20%) but at least the weekly base index price.[21]

Table 9: Secondary reserve capacity and energy

	2014	**2015**
Capacity [MW*wk]	398.33	378.23
Positive energy		
Total [GWh]	158.82	242.31
Mean [MW]	18.13	27.66
Standard deviation [MW]	27.80	35.82
Maximum [MW]	216.70	283.30
Negative energy		
Total [GWh]	221.72	183.12
Mean [MW]	25.31	20.90
Standard deviation [MW]	32.88	30.88
Maximum [MW]	306.00	277.70

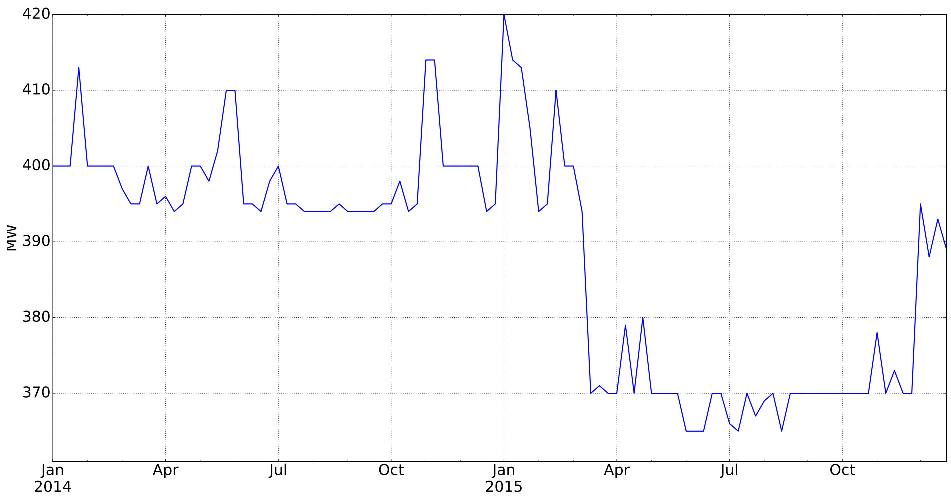
Notes: Author's own calculations based on tender and energy data provided by Swissgrid. We use * in units to identify durations of reservation in contrast to energy units. Thus, MW*wk denotes one reserved MW of capacity over the duration of one week.

Table 9 shows the average weekly capacity procured as well as descriptive statistics for capacity usage, i.e., secondary reserve energy. On average Swissgrid procured around 390 MW of secondary reserve capacity per week. Figure 4 shows that capacity procurement shows only small variations over the year. However, there is a notable drop in the amount of capacity in March 2015. On average, secondary reserve energy is only a small fraction of the procured capacity. However, the standard deviation is rather high compared to the mean and in some hours around 74% of the reserved capacity is used.

Table 10 shows the cost associated with secondary reserve for the capacity and energy provision. The average price for reserve capacity in 2014 and 2015 has been around 3950 € /MW*wk (23.50 € /MW*h). The secondary reserve market has a total size of around 100 Mill. € with the main revenue stream from capacity reservation. Positive energy has been more costly than negative. The increase in positive secondary energy cost is caused by the increase in energy provision (Table 9) as well as an increase in the average price from 35 to 41 € /MWh. While negative energy activation has decreased (Table 9) the increase in cost is caused by a sharp increase in the

[21]In the case of negative day-ahead prices the margins are reversed, i.e., positive (negative) energy delivery receives the SwissIX price with a margin of -20% (20%).

Figure 4: Weekly procured secondary reserve



Based on tender data provided by Swissgrid.

Table 10: Cost of secondary reserve [Mill. €]

	2014	**2015**
Capacity	80.27	77.71
Energy Positive	8.30	13.00
Energy Negative	6.15	5.71
Total Cost	94.71	96.39

Notes: Author's own calculations based on tender and energy data provided by Swissgrid.

average price from around 13 to 24 € /MWh.

6.1.3 Tertiary/Minute Reserve

Tertiary reserve is activated manually with a notification from Swissgrid to the supplier (e-mail or phone call). The supplier has to be fully available 15 minutes after the notification and up to an interval of four hours.

Minute reserve is procured as asymmetric product, i.e., positive and negative reserve are separately commissioned. Two different auctions are used: First, a week-ahead auction closing at Tuesday 13:00 procures negative and positive minute reserve capacity to be available for the whole week after starting from Monday. Second, four-hour time slices (starting at 0:00) are auctioned two days before the delivery date with a gate closure at 14:30.[22]

[22]No auctions are held on weekends. Thus, there are two auctions on Thursdays (Fri-

Both auctions are pay-as-bid with minimum bid of 5 MW, increments of 1 MW and a maximum bid size of 100 MW (Swissgrid, 2015b).

Given that the bid of a generator is accepted in the capacity auction, it is required to provide a bid in tertiary energy auction. However, even if a generator is not contracted in the capacity auction, it is allowed to bid into the tertiary energy auction. Tertiary energy is procured in a separate pay-as-bid auction which closes one hour before the delivery period starts, i.e., the gate closure coincides with intra-day market closure (see Swissgrid).

Table 11: Tertiary reserve capacity and energy

	2014		2015	
	Positive	Negative	Positive	Negative
	Capacity		Capacity	
Weekly auction [MW*wk]	197.90	135.35	232.58	108.62
Daily time slices [MW*4h]				
00:00 - 04:00	277.19	148.70	250.48	123.90
04:00 - 08:00	278.81	149.35	226.19	127.43
08:00 - 12:00	269.91	149.99	214.52	129.80
12:00 - 16:00	269.78	149.92	219.06	128.75
16:00 - 20:00	273.45	150.09	216.60	129.38
20:00 - 00:00	270.61	150.05	217.37	129.28
	Energy		Energy	
Total [GWh]	74.93	178.93	129.43	133.18
Mean [MW]	2.14	5.11	3.69	3.80
Standard deviation [MW]	7.80	11.61	9.93	10.00
Maximum [MW]	100.00	97.50	113.75	81.75

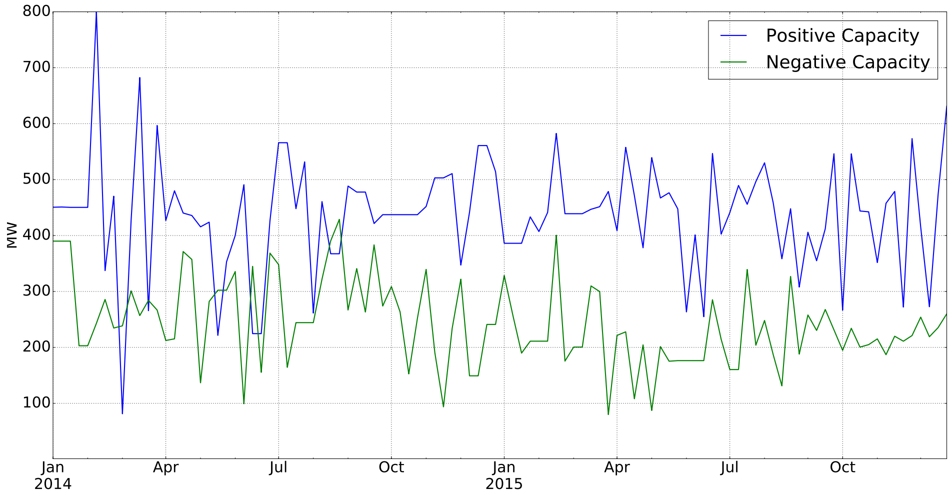
Notes: Author's own calculations based on tender and energy data provided by Swissgrid. The data include aggregated reserve activation on a quarter-hourly basis. As positive and negative reserve are often simultaneously activated, the numbers are only indicative.

Table 11 shows average capacity procured in the weekly and daily auctions for tertiary reserve. On average around 450 (250) MW of positive (negative) reserve are procured; negative capacity has decreased in the year 2015. The weekly variation shown in Figure 5 shows that tertiary reserve demand is much more volatile than secondary capacity demand.

Table 12 shows total cost of tertiary reserve decomposed by capacity and energy cost as well as positive and negative reserve. Total cost of around 24 Mill. € are mainly caused by positive reserve which shows higher capacity and energy cost. Energy cost of negative reserve are negative which is caused by negative tertiary energy prices in hours with high demand. Average

days) at 14:30 and 15:30 determining deliveries for Saturday and Sunday (Monday and Tuesday).

Figure 5: Weekly procured tertiary reserve



Based on tender data provided by Swissgrid.

prices for positive four-hour contracts range from 0.5 in the night times to 6.3 €/MW*h during peak hours.[23] Negative 4-hour prices are on average higher ranging from 2 to 6.7 €/MW*h and show an opposite patter, i.e., highest price occur in off-peak times. The average weekly price for positive (negative) tertiary reserve has been 4.7 (2.7) €/MW*h in 2014 and 5.16 (3.31) €/MW*h in 2015. Average positive (negative) tertiary energy price amount to 64 (-7) €/MWh in 2014 and 67 (-50) €/MWh.

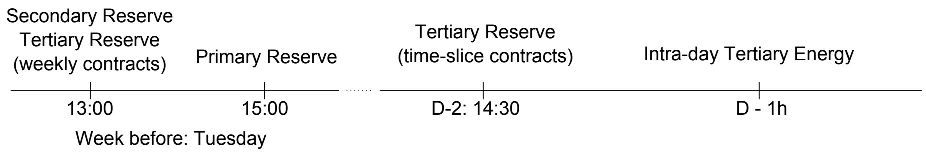
Table 12: Cost tertiary reserve [Mill. €]

	2014		**2015**	
	Positive	Negative	Positive	Negative
Capacity	13.34	7.78	16.23	6.54
Energy	4.63	-1.26	8.84	-6.67
Total	17.97	6.53	25.07	-0.12
Total	24.50		24.95	

Notes: Author's own calculations based on tender and energy data provided by Swissgrid. The data include aggregated reserve activation on a quarter-hourly basis. As positive and negative reserve are often simultaneously activated, the numbers are only indicative.

[23]Price per time-slice are provided in Table 14 in the Appendix.

Figure 6: Time-line Swiss reserve market



6.1.4 Summary

Timing of the reserve markets is shown in Figure 6 and the respective products in Table 7.

6.2 Imbalance Settlement

BRPs are allowed to adjust their intra-Swiss schedules until the day after delivery until 17:00 (Post-Scheduling Adjustment). Swissgrid summarizes and verifies all schedules and uses them as the basis for the imbalance pricing. For each BG of a BRP the difference between scheduled and measured energy deliveries is determined on quarter-hourly basis. By summing the imbalance of each BG the total imbalance for the BRP is determined which forms the basis of imbalance billing (Swissgrid, 2011).

6.2.1 Imbalance pricing

Swissgrid uses a two-price system for imbalance pricing. That is prices for negative and positive imbalances differ. If the BRP produces more (less) energy than scheduled, it is long (short), and the BRP receives (pays) the respective price.

$$P_{long} = \alpha_{long} \left(P_1 + \max\left[P_{spot}, P_{sec+}, P_{ter+}\right]\right) \tag{1}$$

$$P_{short} = \alpha_{short} \left(P_2 + \min\left[P_{spot}, P_{sec-}, P_{ter-}\right]\right) \tag{2}$$

Both prices are constructed as the sum of a base price and the maximum/minimum over the day-ahead price and the respective reserve prices. According to Swissgrid (2011) the base prices is $P_1 = 0.5ct/KWh$ ($P_2 = 1ct/KWh$) for the positive (negative) imbalance price P_{long} (P_{short}). Adjustment factors are $\alpha_{long} = 0.9$ and $\alpha_{short} = 1.1$ for long and short imbalance prices, respectively (Swissgrid, 2014b).

Table 13 shows descriptive statistics for Swiss imbalance prices over the last three years. Imbalance prices are rather low with a low variation. Long prices can show high negative peaks, i.e., BRPs have to pay for excessively produced energy. Vice versa, short price have high positive peaks in which the BRP also has to pay the price.

Table 13: Imbalance prices [€/MWh]

	2013		2014		2015	
	Long	Short	Long	Short	Long	Short
Mean	2.79	6.79	1.87	5.73	1.67	6.32
Std deviation	1.77	2.68	2.46	1.71	4.48	1.84
Minimum	-0.55	1.10	-39.15	-0.33	-39.54	-0.15
Maximum	2.84	43.85	6.98	20.39	9.90	41.90

Notes: Author's own calculations based on data provided by Swissgrid.

7 Summary and Conclusions

The Swiss electricity market is structured around two classes of markets: Energy-only and reserve markets.

Electricity is traded in the energy-only market using a day-ahead and intra-day market. While the day-ahead market offers only hourly products in an uniform price auction, the intra-day market additionally offers quarter-hourly products in a continuous auction. Remarkably, Swiss markets close earlier than those in the neighboring countries: The day-ahead market closes at 11:00, one hour earlier than those of the neighbors; the intra-day market already closes one hour before delivery time while those of the neighbors (except Italy) close only half an hour before. Thus, one might ask whether a shorter lead-time in the intra-day market is (a) possible and (b) meaningful in order to reduce the need for balancing.

Except tertiary reserve all reserve products are symmetric. A differentiation between positive and negative products might be useful in particular in the context of allowing consumers and renewable source to participate in the market as these parties are more suited to deliver negative balancing energy. Secondary energy payments are coupled with the day-ahead price including some margin. While such a system has a tendency to avoid strategic arbitraging between energy-only and balancing energy price, is does not necessarily reflect the true cost of reserve energy delivery. Thus, the question is raised how an incentive compatible and cost based system can be created which also reflects the cost. One possibility would by a system in which suppliers provide bids for capacity and energy (complex bids). Another alternative would be a separate energy auction, as done for tertiary reserve. However, this might prove technically more difficult due to the short lead time of secondary reserve. Secondary reserve is procured in weekly contracts. An shorter contract length or some differentiation for different time period (peak/off-peak) might help to decrease cost of reserve procurement while also allowing more flexible handling of capacity at the generator side. Concerning the amount of reserve procured, we were not able to find any information about the method how reserve demand is calculated. Thus, a first recommendation necessarily has to be to improve the transparency about this method.

Comparing the time-lines of the energy-only and balancing markets, reserve capacities are always procured before the day-ahead market. Whether a harmonization of gate closures of the energy-only and balancing markets, at least for secondary and tertiary reserve, is useful should be subject of further examinations. In particular, the question depends on the method of reserve calculation: in the case of dynamic sizing such a harmonization might be useful while under (long-term) static sizing one would hardly expect an effect.

Swiss imbalance prices are based on the cost of capacity procurement or on the day-ahead price. Thus, reserve energy prices are not reflected in the imbalance prices. A further analysis is necessary to determine whether a reflection of energy prices in the imbalance price is useful or whether these cost should be allocated to consumers.

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Appendix

A Additional Tables

Table 14: Average prices of tertiary reserve four-hour blocks [€ /MW*h]

	2014		2015	
	Positive	Negative	Positive	Negative
00:00 - 04:00	0.56	6.52	0.45	5.25
04:00 - 08:00	2.32	6.75	2.40	5.93
08:00 - 12:00	4.78	2.47	6.31	1.88
12:00 - 16:00	3.31	3.01	3.74	2.56
16:00 - 20:00	5.40	2.38	6.24	2.03
20:00 - 00:00	2.79	3.04	3.23	2.65

Notes: Author's own calculations based on tender data provided by Swissgrid.