Market Review 2016

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Introduction

TenneT publishes this yearly Market Review for the public interested in the electricity markets. We describe the developments in the Western European electricity market, particularly in the Netherlands and Germany, where, as the transmission system operator (TSO), TenneT has a central role in facilitating the market. This publication gives you a brief description of the different topics, the past year's highlights for the European electricity markets and puts the most important developments into perspective.

During the first eight months of 2016, electricity prices generally converged within the Central Western Europe[1] (CWE) region. Afterwards, prices diverged into two zones. One price region contained Germany, aside from Austria and Luxembourg with which Germany forms a common price zone[2], and the Netherlands and the other zone included Belgium and France.

At the beginning of 2016, prices for hard coal and natural gas decreased, but in May hard coal prices started to increase sharply, as did natural gas prices in September. Therefore, during the last third of the year generation costs in the Netherlands and Germany converged and accordingly constituted one price region most of the time.

The electricity consumption in the CWE region in 2016 was comparable to previous years. The generation stack in the Netherlands and Germany further evolved to a less conventional and increasingly renewable generation system.

Net positions (delta between exports and imports) in the European market areas changed slightly in 2016. In the monthly net positions in the CWE region there was a change in direction in the last third of 2016. With the French market area having a negative net position and the Dutch market area having a positive net position, the respective net positions of the two countries reverted at the end of 2016.

In the balancing regime, several European cooperation initiatives took place like the International Grid Control Cooperation (IGCC), which the French TSO RTE joined in 2016. Simultaneously, the German Frequency Containment Reserve tendering developed further, due to the international cooperation between Switzerland, Austria, Denmark and the Netherlands.

Redispatch volumes in Germany showed a downward trend in 2016 for the first time since 2013. The decrease in redispatch volumes can be traced back to deviating feed-in by renewables due to different weather conditions as well as grid infrastructure projects.

The German feed-in tariff for renewables decreased again, with renewable generation becoming more competitive. The German feed-in tariff was updated in 2016, linking grid infrastructure to the new capacities and introducing auctions for the installation of new renewable generation.

This TenneT Market Review was created in close cooperation with IAEW from RWTH Aachen. We hope that you will enjoy reading it as much as we enjoyed creating it. Any remarks or comments on the report can be shared with the TenneT Customer Care Center.

[1] The Central Western European (CWE) market region formed by Austria, Belgium, France, Germany, Luxembourg and the Netherlands.
[2] Germany is currently part of a single bidding zone consisting of Germany, Austria and Luxembourg in which one single price is formed on the forward and spot markets. To increase readability of this report, the bidding zone Germany-Austria-Luxembourg is abrevated as Germany for all price related statements.

Electricity market prices

In 2016, the average day-ahead prices for the CWE region dropped to new record lows during the first eight months of the year, whereas the prices started to increase from September 2016. Overall price differences became smaller in the CWE region in 2016.

During the first month, the CWE region had convergent prices. Afterwards, prices diverged into two zones. One price region contained Germany and the Netherlands, and the other included Belgium and France.

At the same time, trading volumes on the intraday markets increased in Germany, especially for 15-minute products, whereas the trading volumes in the Netherlands decreased.

After a brief background explaining the set-up of the electricity markets, the price developments at the day-ahead market, followed by intraday and futures markets are described. Chapter 6 covers balancing markets in more detail.

a. Background

Electricity generators compete in wholesale electricity markets to sell electricity to large industrial consumers and electricity suppliers. Suppliers compete in the retail electricity market to sell electricity to the final consumer. This TenneT market review focuses on wholesale electricity markets.

Electricity is a commodity with the property that generation has to equal consumption (plus grid losses) on an instantaneous basis. The design of electricity markets is adapted to deal with this particular property.

Different types of electricity markets are arranged in a sequential order, starting years before the actual physical delivery and ending after the actual delivery, see Figure 1.

Market timeframes and balancing

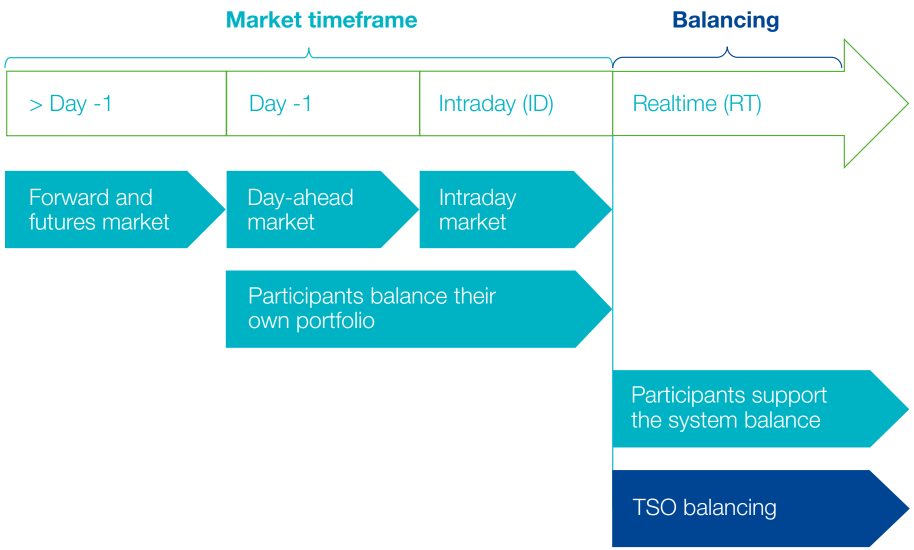

Figure 1: Market timeframes and balancing

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Electricity market prices

Apart from the organized markets for electricity at power exchanges, market participants are able to trade bilaterally or "over-the-counter"[3] (OTC) as well. Since these transactions are non-transparent, they are not taken into account in this market review.

The forward and futures markets span the time intervals from years before up to the day before delivery. Forwards and futures are contracts to deliver/ consume a certain amount of electricity at a certain time in the future for a price agreed upon today. Futures are standardized contracts on power exchanges, forwards are traded bilaterally over-the-counter and are not standardized. Market participants use these markets to reduce their risks, also known as hedging. Electricity generators use forward and futures markets to ensure future sales and reduce their vulnerability to possible electricity price decreases; large (industrial) electricity consumers use these markets to secure their future electricity consumption at upfront known costs and reduce their vulnerability to possible price increases.

In the day-ahead market, electricity is traded one day before actual delivery. The day-ahead market is of major importance and also the market with the highest trading volumes and number of participants. The price from the day-ahead market is most often referred to as 'the electricity price' and the day-ahead market is seen as the market in which most welfare is gained. Interconnector capacity between different bidding zones is optimized in day-ahead, maximally anticipating expected demand and supply in each bidding zone, dependent on the market and weather circumstances. The product resolution is one hour, denying load serving participants the opportunity to buy their desired load profiles on these most liquid, international markets at a suitable resolution.

In the intraday market, electricity is traded on the delivery day itself. The intraday market enables market participants to correct for shifts in their day-ahead nominations due to better renewable feed-in forecasts, demand changes, unexpected power plant outages, etc.

The principles of the balancing market are covered in detail in chapter 6.

b. Day-ahead price developments

In 2016, the average prices for the CWE region dropped further during the first eight months of the year and as of September 2016 the prices started to increase again. Price differences became on average smaller in the CWE region in 2016.

i. Average prices in CWE

Figure 2 shows the development of wholesale prices for the CWE region.

Over the first eight months of 2016, the average price level was lower than the year before for all market areas in the CWE region. The average monthly price in Germany dropped to a record low of 22 €/MWh in February 2016. The low prices in the first two thirds of 2016 are mainly the result of low generation costs due to low prices for fuels and CO_2 emission allowances. Chapter 3 describes the impact of fuel price developments in more detail.

[3] OTC stand for over-the-counter, meaning that these trades are made bilaterally between market parties without using a power exchange to make the trade.

Electricity market prices

Further, in the first eight months of 2016, price differences between market areas of the CWE region were rather small. Afterwards, in the last third of the year, prices started to diverge, splitting CWE into two separate price regions. Especially in Belgium and France, prices started to rise. In France the day-ahead price went up from 25.52 €/MWh in February to 65.14 €/MWh in November. In the last four months of 2016 the average price was around 54 €/MWh in Belgium and France, and at 37 €/MWh in the Netherlands and Germany.

This significant price increase was mainly caused by a limited amount of available generation capacity due to the unavailability of the nuclear fleet in France and Belgium, which chapter 8 analyzes in more detail. Furthermore, low reservoir levels in the alpine region and period's low temperature contributed to this situation. The German and Dutch prices also rose as these countries started to produce more electricity to supply Belgium and France. However, the price increase was relatively small compared to the one in Belgium and France.

Monthly Average Day-ahead Wholesale Prices in CWE countries

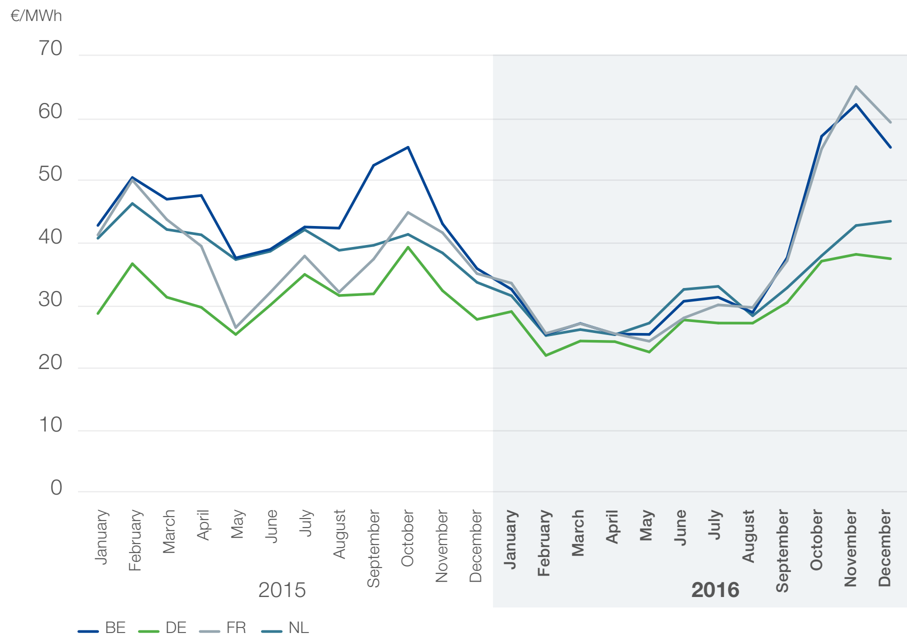

Figure 2: Monthly average of hourly day-ahead wholesale prices in CWE countries.

Source: EPEX Spot, energate

Electricity market prices

ii. Wholesale prices and price convergence

The average day-ahead prices in 2015 and 2016 as well as the price convergence related to the Netherlands and Germany are illustrated in Figure 3.

The different colors reflect the day-ahead price levels. The market areas with the lowest average prices are colored in bright green, high price levels are marked in bright red. The numbers in the boxes show the percentage of hours in which a country had the same wholesale price as the Dutch and the German market area respectively (NL|DE).

The average prices decreased all over Europe from 2015 to 2016, due to lower fuel and CO_2 allowances prices in 2016, shown in more detail in chapter 3. Since Germany and Austria constitute one market area, there is full price convergence.

The increase in hours of price convergence between many market areas in 2016 indicates a positive development for the integration of national electricity markets to a European electricity market.

European Wholesale Prices and Price Convergence

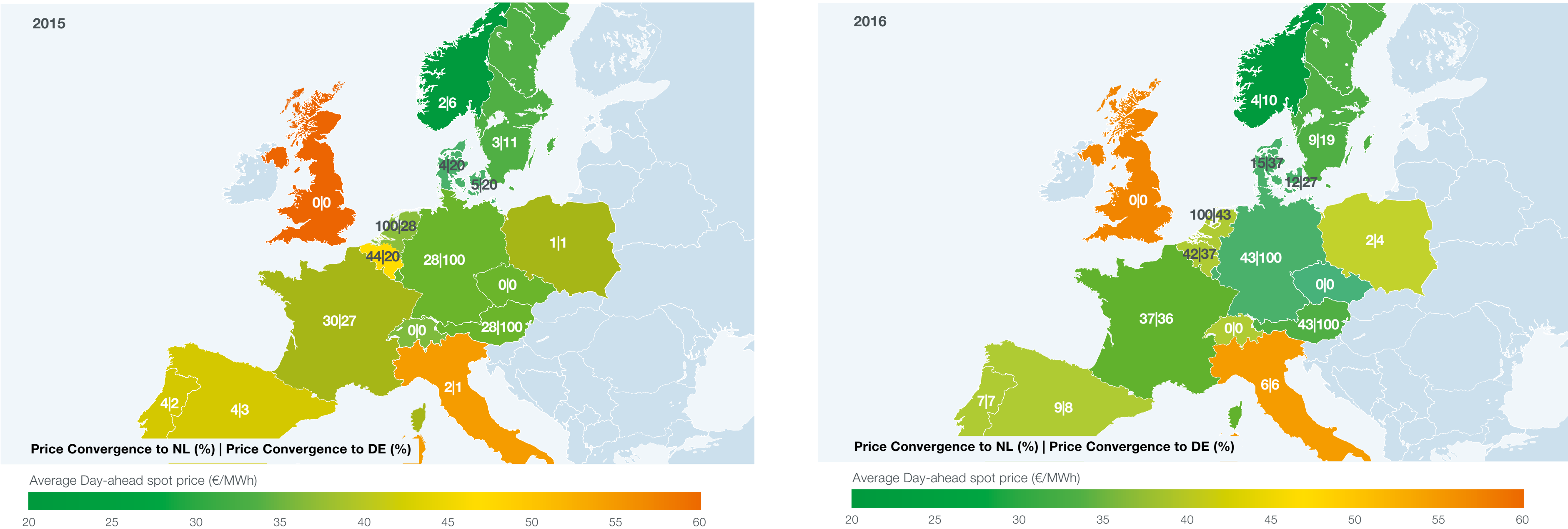

Figure 3: Yearly average of hourly day-ahead prices and % hours with full price convergence (in relation to the Dutch and German market area) of different market areas[4] in Europe. Source: energate, APX, EEX, Nordpool Spot, POLPX, OTE, GME, OMIP

[4] For countries with multiple market areas, the market area directly bordering the neighboring country is used for the visualization: Italy: North, Norway: NO_2 and Great Britain: GB2.

Electricity market prices

Figure 4 shows the development of the full price convergence in the CWE region per month. The monthly price convergences between Germany and the Netherlands as well as between Germany and France were higher in the first eight months and lower in the last three months of 2016 compared to 2015. This development results directly from the price decoupling of CWE into two price regions during the last third of the year as shown previously.

During the summer months, there was a strong price convergence between Belgium and France. The price level in the Dutch and the Belgian market areas were nearly identical in the first three quarters of 2016, but deviated significantly in the last third of 2016. The same situation occurred between France and Germany.

Monthly Price Convergence

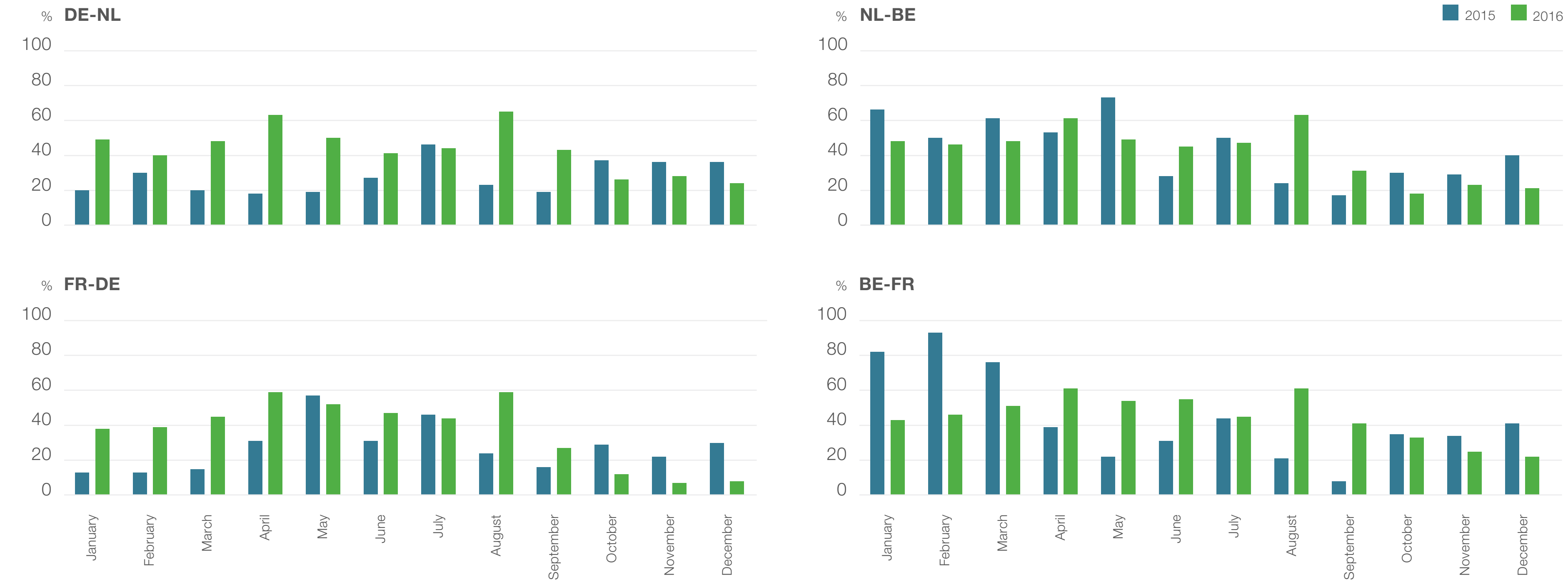

Figure 4: Monthly price convergence between CWE countries (2015-2016). Source: EPEX Spot, energate

Electricity market prices

iii. Development of price differences in CWE Region

In Figure 5 the hourly day-ahead price differences between market areas in the CWE Region are illustrated by showing the frequency of occurrence of price differences between two areas.

The price difference between Germany and the Netherlands decreased in 2016 compared to 2015. In 2016, the price was equal[5] for almost 4000 hours per year, which means an increase of about 33% compared to 2015. This convergence resulted mainly through lower prices in the Netherlands caused by a more competitive natural gas generation in 2016, shown in detail in chapter 3.

The price difference of Belgium and the Netherlands was similar to 2015, even though there were more hours with higher prices in Belgium at the end of the year (reflected by negative price differences). The high average price visible in Figure 2 is influenced by high price peaks in Belgium, which are represented in the two left categories in Figure 5 with an increasing amount of hours. As can be seen there were higher prices in the Netherlands compared to Belgium in summer 2016. This can be found in Figure 5 as well by more hours with positive price differences in 2016.

Price differences between Germany and France in general became smaller in 2016 with the unchanged observation of higher prices in France. However, the number of hours with large price differences of more than 20 €/MWh increased also. This can be traced back to price peaks in France in the last third of 2016.

Although price differences between France and Belgium occur in both directions, the dominant direction has changed. In 2015, prices in Belgium were often higher than prices in France. In 2016, this development was inverted and prices in France were often higher than those in Belgium. The cause for this can be found in the unavailability of nuclear power plants in Belgium in 2015, and the unavailability of nuclear powers plants in France in 2016, shown in more detail in Chapter 8.

[5] A price difference between -0.001 €/MWh and 0.001 €/MWh is considered as equal. Please note that due to readability and understandability reasons, the price difference cluster include different price ranges.

Electricity market prices

Hourly Price Difference between CWE countries

Figure 5: Hourly price difference between the CWE countries divided over clusters of price differences for 2015 and 2016. Source: EPEX Spot, energate

Electricity market prices

iv. Development of price volatility for European wholesale prices

Figure 6 depicts the standard deviation (volatility) of hourly day-ahead prices for various European countries. For most market areas, including Belgium, the Netherlands and Germany, the volatility remained comparable to 2015. However, for France and Great Britain the volatility increased significantly and nearly doubled.

The higher volatility in Belgium and France can be traced back to high price peaks in these market areas in the second half of 2016 and overall higher prices during this time. The higher volatility in Great Britain can be explained by a combination of heavy infrastructure maintenance, security of supply concerns because of unplanned power plant shutdowns, and political turmoil due to Brexit and the related decrease in value of the British pound.

Standard Deviation of European Day-ahead Wholesale Prices

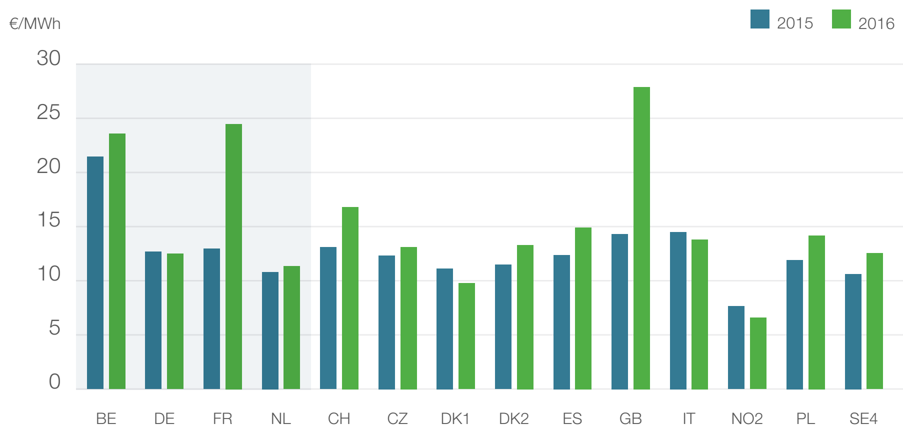

Figure 6: Standard deviation of European day-ahead wholesale prices in 2015 and 2016. Source: OPSCOM, PXE, OMIP, EPEX Spot

Figure 7 shows therefore the day-ahead prices for France, Belgium, the Netherlands, Germany and Great Britain on four days in November 2016. On two days, high spikes above 800 €/MWh were reached in France and Belgium whereas the German and Dutch day-ahead price remained on a low level. This leads to the high standard deviation in France and Belgium and shows why the German and Dutch standard deviation is limited compared to the others. The price spikes were caused by the coinciding of huge residual loads, a limited generation capacity use to unusually low availabilities of nuclear power plants and limited import capacities.

Day-ahead Prices in November 2016

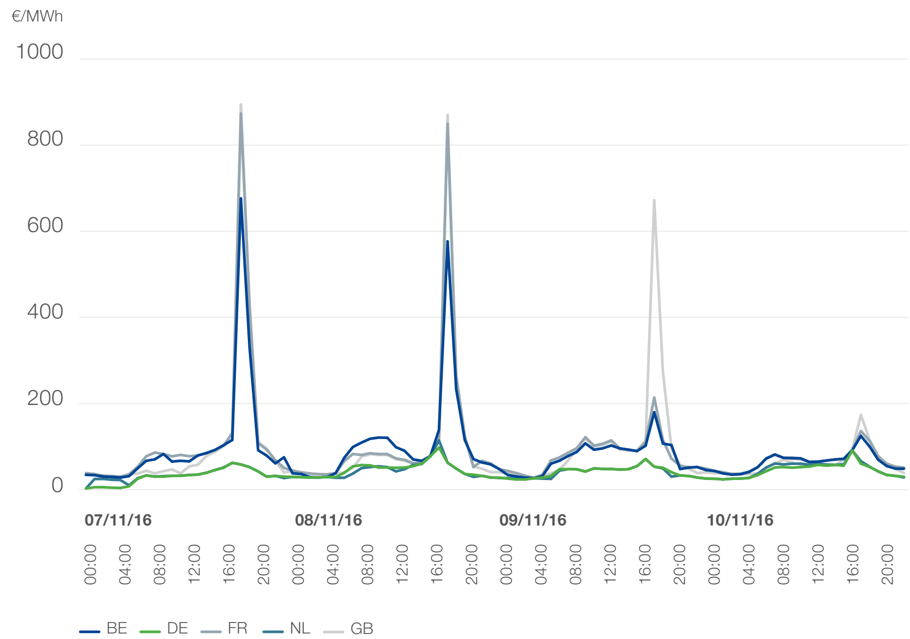

Figure 7: Day-ahead wholesale prices on four typical days in November 2016. Source: EPEX Spot

Electricity market prices

v. Price duration curve

Figure 8 shows the price duration curves for 2015 and 2016 for the Netherlands and Germany. The curve shows the number of hours in a certain year where the market price is above a particular price level. For Germany, the difference between 2015 and 2016 is modest. For the Netherlands on the other hand, the curve of 2016 is significantly below the curve of 2015 and much closer to the curve of Germany than it was in 2015. This convergence resulted mainly from cheaper natural gas generation in 2016 in the Netherlands, shown in detail in chapter 3.

In other words, the Dutch prices were much closer to the German prices in 2016 than in 2015. This is not only the case for the average price but also for the peak price section. For the low price section, a difference between the countries can still be observed: the Germany day-ahead price even went negative for 97 hours in 2017, while the lowest day-ahead price in the Netherlands was above zero with 2.79 €/MWh. The main reason for this is that Germany has a higher share of renewables and 'must run' plants which need to produce even when renewables are able to (largely) cover electricity demand within Germany and exports to neighboring market areas.

Duration Curve of Wholesale Prices

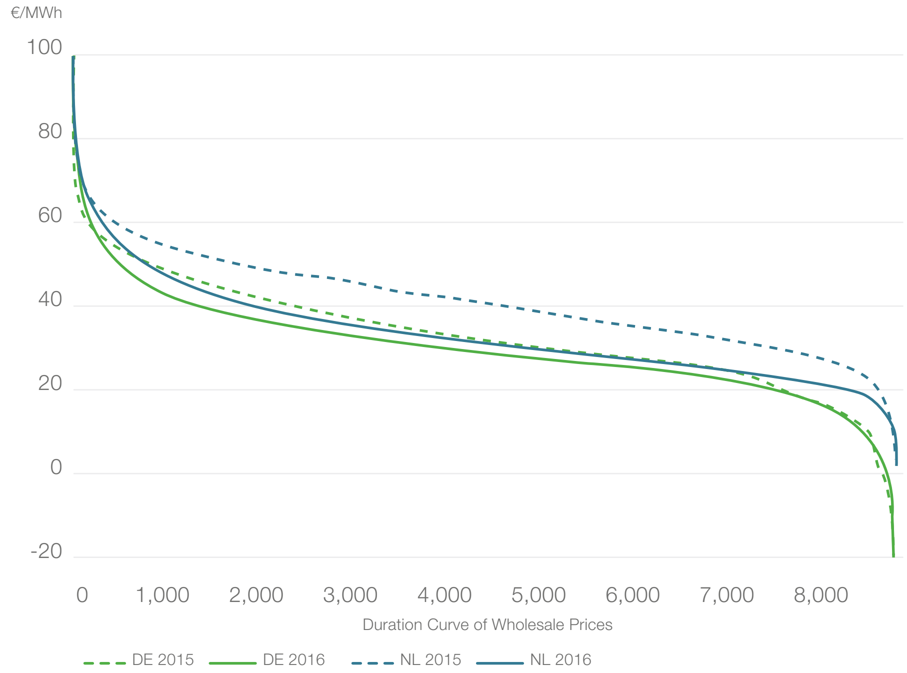

Figure 8[6]: Duration curve of wholesale prices in Germany and the Netherlands in 2015 and 2016.
Source: EPEX Spot

[6] Remark: There is a small amount of hours with exceptional high and low prices, which Figure 8 does not show due to presentation reasons. Furthermore, since 2016 was a leap year, the figure shows 24 more hours in 2016.

Electricity market prices

c. Intraday developments

Market participants trade at the day-ahead market based on their expectations for the next day. Due to information becoming available after closure of the day-ahead market, like new forecasts for renewables, plant outages or changed demand situations, the participants trade at the intraday market to optimize their positions.

For example, the accuracy of renewable generation forecasts increases as the moment of delivery approaches, as shown in the top graph of Figure 9. The intraday market enables market participants to better reflect these forecasts in their positions.

Furthermore, quarter-hourly products are traded in the intraday market which enable a better approximation of the real demand ramps and generation variability (e.g. from solar or wind power generation) than the hourly products at the more liquid day-ahead market. This is especially important since imbalance settlement periods are on a quarter-hourly basis. The bottom graph of Figure 9 shows the difference between hourly and quarter-hourly products and their accuracy of representing actual feed-ins.

Approximation of the realized load and forecast errors on intraday markets

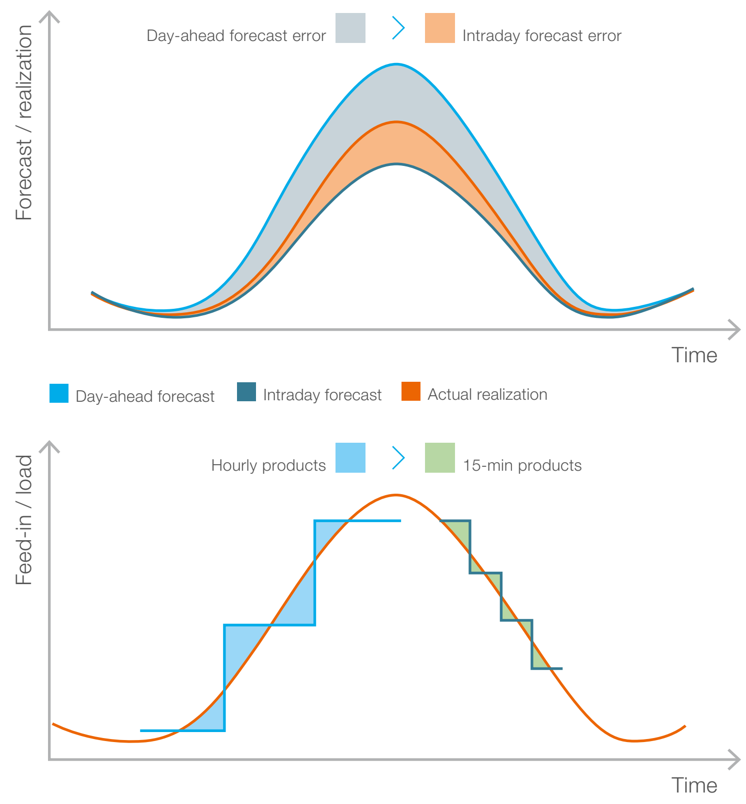

Figure 9: Approximation of the realized load and forecast errors on intraday markets

With the increase of renewable generation, there is an increase in trading volumes on the intraday markets. As Germany has the largest intraday market, the report examines this market in more detail than the Dutch intraday market.

Electricity market prices

i. Intraday trading volumes in Germany

The German intraday market, besides the possibility for OTC trades, consists of two parts. Firstly, there is a daily intraday auction at 15.00 on the previous day, which functions similar to the day-ahead market except that in this auction quarter-hourly products instead of hourly products are traded. Secondly, there are two continuous intraday markets: one operated by EPEX Spot with quarter-hourly and hourly products, which closes 30 minutes before delivery, and one operated by Nord Pool Spot, which closes, since September 2016, 20 minutes before delivery. Note that in Germany the TSO is balance responsible for some of the renewables that are not directly sold on the market. Therefore, the German TSOs also trade intraday to balance the renewable electricity they already sold on the day-ahead market.

Figure 10 shows the volumes traded in the intraday auction and the continuous intraday market. The volume traded in the intraday auction increased from 3.9 TWh/a in 2015 to 6.22 TWh/a in 2016, i.e. by 59%. The trading volume of hourly products in the German intraday market rose from about 26 TWh/a in 2015 to 28 TWh/a in 2016, and the volume of the quarter-hourly products increased by 0.8 TWh/a to 4.7 TWh/a. The volume of all products has thus increased, with the main increase in the intraday auction. The aggregated volumes of all EPEX intraday markets represent 17.3% of the traded day-ahead volumes at EPEX Spot.

Intraday Trading Volumes in Germany

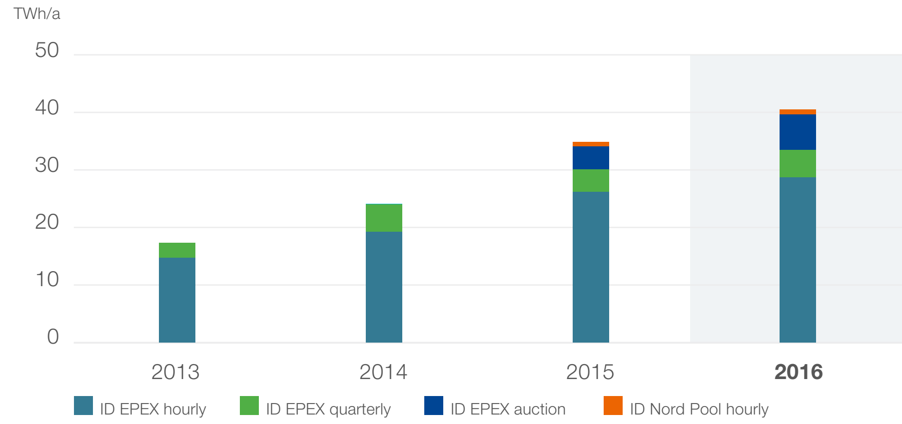

Figure 10: Intraday trading volumes in Germany traded at EPEX Spot and Nord Pool.
Source: EPEX Spot, Nord Pool

Electricity market prices

ii. Intraday trading volumes in the Netherlands

The intraday markets of Germany and the Netherlands are organized differently. First the Dutch intraday market does not have an intraday auction. Second, the Dutch continuous intraday market contains only hourly products. In the Netherlands, it is possible to trade intraday hourly products on both Nord Pool as well as EPEX Spot (which was formerly known as APX before merging into EPEX Spot in 2015). Thirdly, in the Dutch market, imbalance is regarded as a competitive market opportunity rather than a cost recovery mechanism, thus filling a niche otherwise occupied by intraday trades.

As shown in Figure 11, the volumes on the intraday (OTC excluded) in the Netherlands are much smaller than those in Germany. This is due to: a) the smaller size of the market in the Netherlands; b) a lower amount of intermittent renewable capacities; c) a different balancing market which allows to trade; and d) ex-post trading capabilities. Especially comparing day-ahead and intraday volumes shows that the volumes on intraday markets are only about 1.8% of the day-ahead volumes for EPEX Spot. However, there was an increase in traded volumes from 2013 to 2014 but a decrease in both 2015 and 2016. This change is mainly due to the decreasing trading volume at Nord Pool, where the traded volume in 2016 was only 25% of the volume in 2014. Main reason for the decreasing intraday volume on Nord Pool is because in September 2015 APX Power NL and Belpex migrated their intraday markets from the trading platform Elbas to Eurolight, while intraday trading between Norway and the Netherlands continued on the Elbas platform. This led to a split in liquidity over these platforms, with mainly strongly decreasing liquidity for intraday trade between the Netherlands and Norway.

Intraday Trading Volumes in the Netherlands

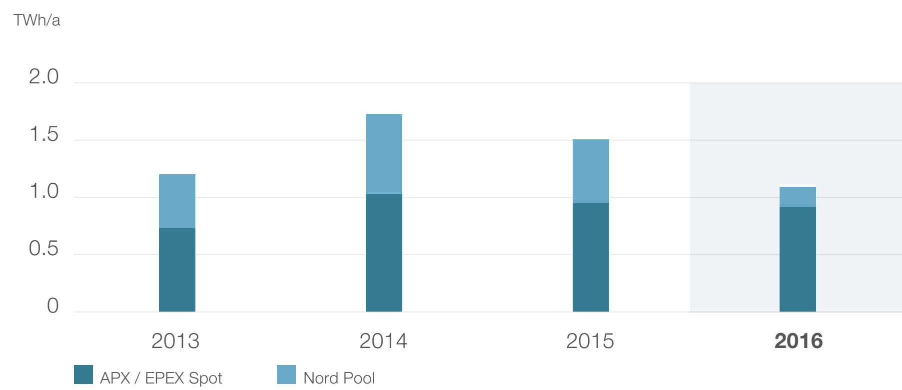

Figure 11: Intraday trading volumes in the Netherlands traded at APX/EPEX Spot and Nord Pool.
Source: EPEX Spot, APX, Nord Pool

Electricity market prices

d. Futures markets

In the futures market participants trade long-term contracts. The purpose of this market is the reduction of financial risk by hedging, selling or buying a certain amount of electricity for delivery in the future.

A future is a standardized contract, where the buyer agrees to purchase a certain volume of electricity at a certain price at a specified date or period in the future and the seller agrees to deliver this electricity through a financial settlement. One of the most commonly traded electricity products is the baseload future for one year, which represents a delivery in each hour of the corresponding year. In general, the futures prices mostly depend on the futures for fuel prices, since those are the most important factors for the cost of electricity generation. The correlation between futures prices for electricity and for fuel prices is dicussed in chapter 3.

Figure 12 shows the price development of the German baseload futures for the years 2017, 2018 and 2019. From January 2015 to halfway through 2016, the futures prices for the different years were close together. Starting in August 2016, the price for the baseload futures for 2017 rose significantly above the price for futures for 2018 and later. This price increase was caused by an increasing demand for 2017 futures, as market participants wanted to hedge against possible events in 2017. One reason for the increased hedging at the end of 2016 is the higher unavailability of nuclear power plants in France and Belgium at that time, which was expected by market participants to continue in 2017.

German Futures Prices

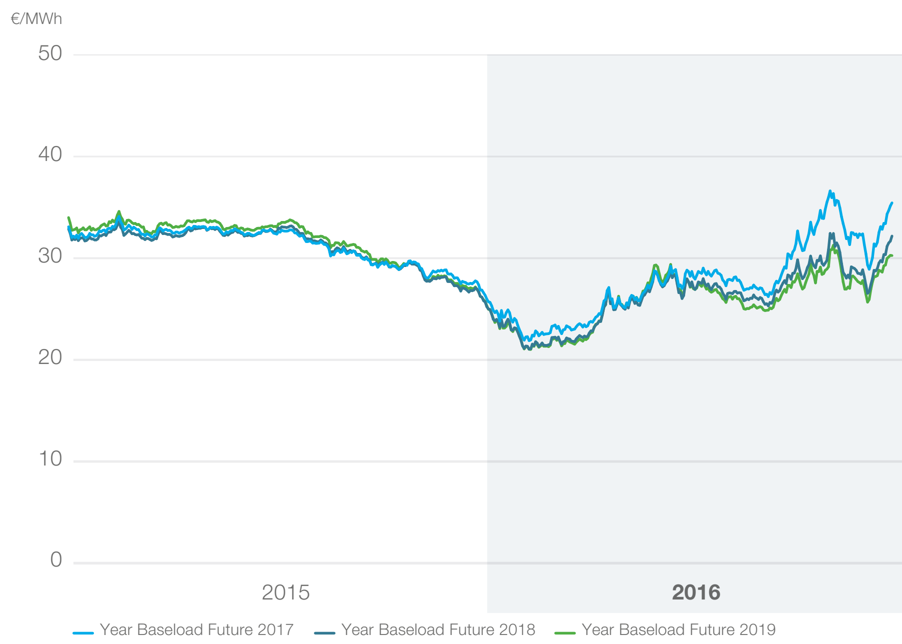

Figure 12: Prices of baseload year futures for 2017, 2018, 2019 and 2020 for Germany.
Source: energate

Fuel & CO_2 allowance prices

The fuel and CO_2 emission allowance prices showed a high volatility in 2016. The year 2016 began with decreasing prices for hard coal and natural gas, but in May hard coal prices started to increase significantly, as did natural gas prices in September. On average, the natural gas price was below the price level of 2015, whereas the price for hard coal was on average similar to 2015. Prices for CO_2 emission allowances deteriorated in January 2016 and levelled off at prices below 6 €/tCO_2 , which was significantly below the average price in 2015.

a. Background

Fossil power plant operators require fuel to generate electricity. Costs for these fuels are a major driver for the costs of generating electricity with these power plants. Furthermore, European power plant operators also need to purchase CO_2 emission allowances equal to the amount of CO_2 their plants emit. The price of these emission allowances also influences the costs of generating electricity and makes the costs of electricity based on CO_2 intensive fuels higher compared to less CO_2 intensive fuels.

For some fuels, liquid global and European markets exist, while other fuels are not traded on global markets. Hard coal, natural gas and crude oil are traded on global markets and therefore have a transparent price. Lignite or uranium on the other hand are not traded on global markets, which makes their prices nontransparent. This is because the transportation costs of lignite are too high in relation to its low specific energy density, so the lignite power plants are usually in close proximity to the lignite pits. For uranium, legal conditions restrict mining and trading. CO_2 emission allowances are also traded on international exchanges.

b. Development of European fuel prices

Figure 13 shows the development of European fuel prices in 2015 and 2016. The graph on the left shows the natural gas price, based on the day-ahead natural gas prices at the Dutch virtual trading point Title Transfer Facility (TTF). The central graph illustrates the development of the hard coal price in 2016 referencing the API#2 price index. On the right, the futures prices for CO_2 emission allowances are depicted.

The natural gas price decreased from an average price of about 20 €/MWh$_{th}$[7] in 2015 to below 15 €/MWh$_{th}$ in 2016. After staying between 10 to 15 €/MWh$_{th}$ for the first part of 2016, in September an upward price rally started and the natural gas price reached a maximum price of close to 20 €/MWh$_{th}$ at the end of the year. This price increase can mainly be attributed to rising crude oil prices caused by the decision of OPEC to cut oil output. Since natural gas constitutes a substitute for crude oil in many applications like heating, the liquid worldwide market for crude oil implicitly affects the natural gas price.

The price for hard coal slightly declined in the first four months of the year 2016, but then sharply increased by 96% towards a four-year record high of 9.5 €/MWh$_{th}$ in November 2016. The commonly acknowledged cause of this price rally was the decision of China in March 2016 to limit coal mines' annual operating days from 330 to 276 or even less as it seeks to restructure its coal industry. Safety closures and weather related supply curbs in China and Australia reduced further the output of coal resulting in the depicted price increase of coal on the global market as supply of coal became tight. As coal is still China's top energy source, this led to a significant cost increase, forcing China's top planning body to reverse some of the restrictions in November. After this decision, the price dropped back to 6.7 €/ MWh$_{th}$ in December 2016.

[7] Fuel prices are expressed in €/MWhth, where MWhth is the amount of heat released during the combustion of the fuel (heating value).

Fuel & CO_2 allowance prices

The futures prices for CO_2 emission allowances in 2016 showed a price decrease in January. The price for CO_2 emission allowance futures fell from about 8.2 €/tCO_2 to below 6 €/tCO_2. The main reason for this drop is believed to be the low oil price at this time dragging down the price for natural gas. With this, the price difference between natural gas and hard coal declined and made it more attractive to use natural gas in comparison to coal for power generation. This reduced the need for CO_2 emission allowances and thereby led to a price drop for emission allowances.

In 2016 the price for CO_2 emission allowances was more volatile than in 2015, which is largely attributed to uncertainty regarding European political decisions on the future of the Emissions Trading System (ETS) in the light of the Paris agreement.

Development of Natural Gas Price **Hard Coal Price API#2 ASK** **Development of CO_2 prices**

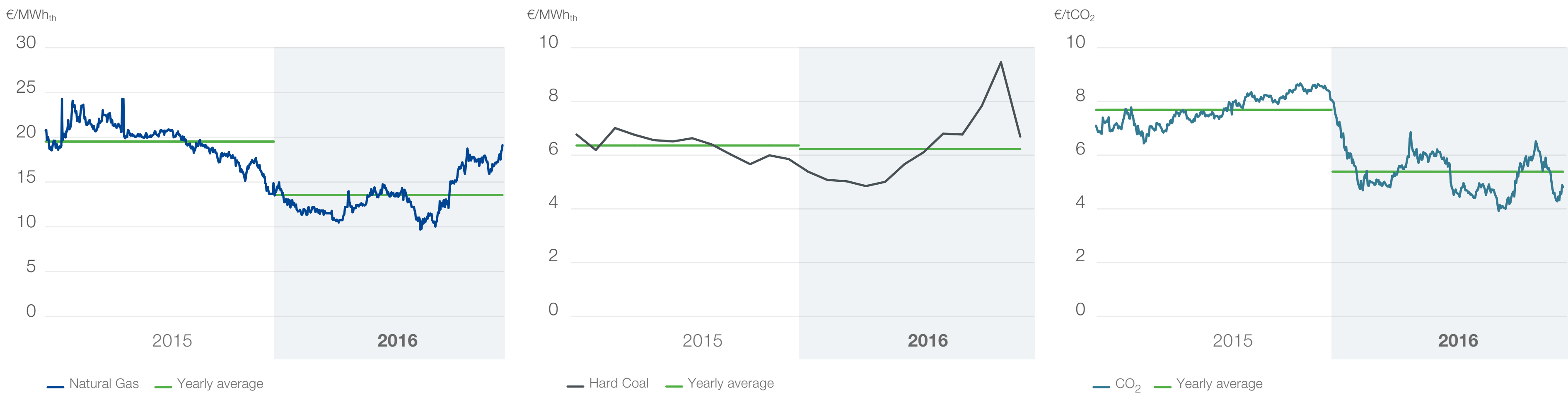

Figure 13: Daily day-ahead gas prices from EEX TTF index, monthly hard coal prices from API#2 ASK(CIF ARA) and daily CO_2 futures prices for years 2015/2016 traded through 2015/2016.
Source: energate[8]

[8] Assumptions: Gas EEX TTF daily day-ahead Index (energate), API#2 hard coal monthly (CIF ARA) (energate). CO2 futures price daily for years 2015/2016 through 2015/2016 (EEX, energate), API#2 index published in $ and converted here to €, in order to be comparable to the other fuel prices.

Fuel & CO_2 allowance prices

c. Clean dark spread and clean spark spread

The clean dark spread (CDS) and clean spark spread (CSS) are indicators for revenues per unit of generating electricity with a conventional coal or gas plant respectively, taking into account fuel and CO_2 emission allowances costs. All other additional costs must be covered via the spreads. Based on clean dark spreads and clean spark spreads, the profitability of the different technologies can be compared.

The clean dark spread is calculated on the average day-ahead base price, as coal plants usually act as base load power plants. The clean spark spread is calculated with day-ahead base prices as well as with the day-ahead peak prices[9], to show the difference in profitability of running a natural gas plant in baseload or in start-stop operation during peak hours.

Figure 14 shows the resulting monthly average clean dark spread base as well as the clean spark spread base and peak for Germany for 2015 and 2016. In 2016 natural gas-fired generation becomes competitive in peak hours and from August 2016 also in off-peak hours, although still less competitive than generating baseload electricity with coal.

German Monthly Average Clean Dark Spread Base and Clean Spark Spread Base/Peak

Figure 14: Monthly average clean dark spread base and clean spark spread base/peak in Germany. Calculations based on different assumptions[10]. Source: EPEX Spot, energate

[9] Peak hours are the hours between 8:00 and 20:00 on working days.
[10] Assumptions for calculating spreads: Efficiency of coal-fired power plants: 40%, efficiency of gas-fired power plants: 55%, emission factors coal: 0.0917 tCO_2/GJ_{th}, emission factor gas: 0.0556 tCO_2/GJ_{th}, heating value of 1 kg coal amounts 25.1 MJ.

Fuel & CO_2 allowance prices

Figure 15 shows the spreads for the Netherlands. The spreads for the Netherlands are higher than the spreads for Germany, as the average day-ahead price in the Netherlands is higher than the one in Germany while the fuel costs are nearly the same. The clean spark spread peak increased from approximately 5 €/MWh in the first half of 2016 to around 20 €/MWh by the end of 2016. Also, the clean spark spread base achieved relatively high positive values of above 5 €/MWh. These strong spreads were a major driver for the increase in generation from gas plants in the Netherlands in the second half of 2016, as shown in Figure 23.

Dutch Monthly Average Clean Dark Spread Base and Clean Spark Spread Base/Peak

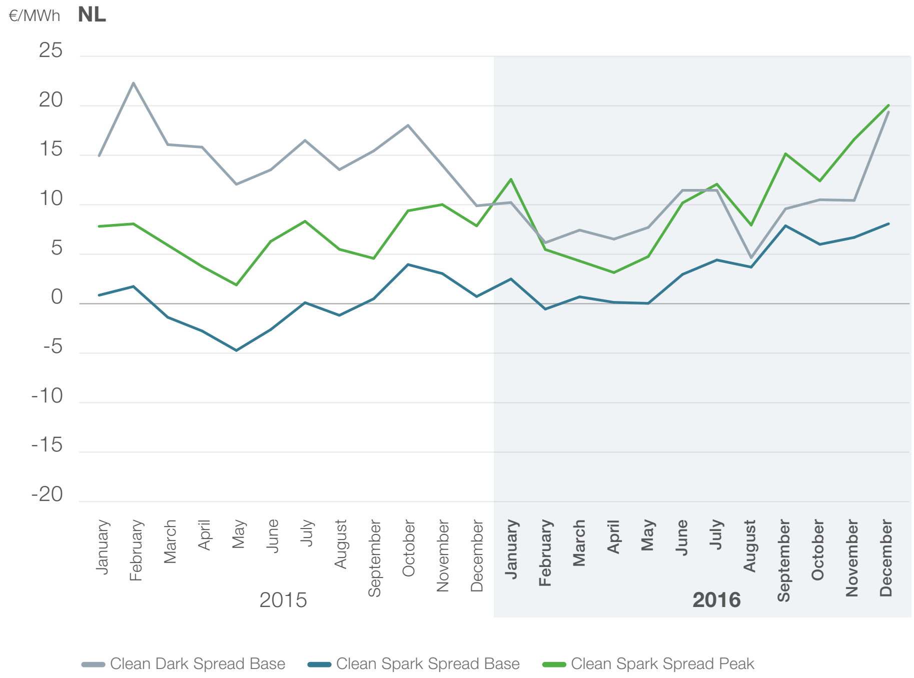

Figure 15: Monthly average clean dark spread base and clean spark spread base/peak in the Netherlands. Calculations based on different assumptions[11], like in the previous figure.
Source: EPEX Spot, energate

[11] Assumptions for calculating spreads: Efficiency of coal fired power plants: 40%, efficiency of gas fired power plants: 55%, emission factors coal: 0.0917 tCO_2/GJ_{th}, emission factor gas: 0.0556 tCO_2/GJ_{th}, heating value of 1 kg coal amounts 25.1 MJ.

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Power consumption and generation

Electricity consumption in the CWE region in 2016 was comparable to previous years. The slightly lower demand in France in January and February can be explained by a reduced electricity demand for electric heating due to the mild winter of 2015/2016.

The generation stack in the Netherlands and Germany continuously evolves to a system with a lower amount of conventional generation capacity and increasing renewable generation capacity. However, although the renewable generation capacity increased, the share of renewable generation in 2016 remained similar to 2015 in Germany. In the Netherlands, the generation with hard coal plants decreased because of the closure and decommissioning of several coal plants due to agreement on Energy for Sustainable Growth. The generation of gas-fired power plants increased significantly, partly to replace the generation from the decommissioned coal plants as well as to supply electricity to Belgium and France.

a. Background

All consumers need electricity for their specific applications, which can include household appliances as well as industrial processes. The generation stack, meaning the combination of all generation units, must be able to meet the consumption at all times and should therefore be designed to cover the maximum non-flexible consumption. The consumption itself depends on various factors, with time and weather being major influences. In cold weather, the demand for electric heating and therefore the electricity consumption to be covered increases.

Generation units transform primary energy into electricity, which is called production or generation. Different types of generation units are mainly conventional units and renewable energy systems (RES). The generation of these types differs in terms of controllability. The intermittent generation of RES highly depends on weather conditions, whereas the conventional generation mainly depend on the supply of fuel and emission allowances as well as their respective cost.

b. Consumption

i. Monthly consumption CWE compared to average of 2010 – 2015

Figure 16 shows the monthly aggregated consumption in the CWE region in 2016 compared to the average monthly consumption from 2010 to 2015. The graph shows that the monthly consumption in all CWE regions is very similar to the average consumption from 2010 to 2015. The slightly lower demand in France in January and February can be explained by a reduced electricity demand for electric heating due to the mild winter of 2015/2016.

Power consumption and generation

Development of Monthly Electricity Consumption in CWE Region

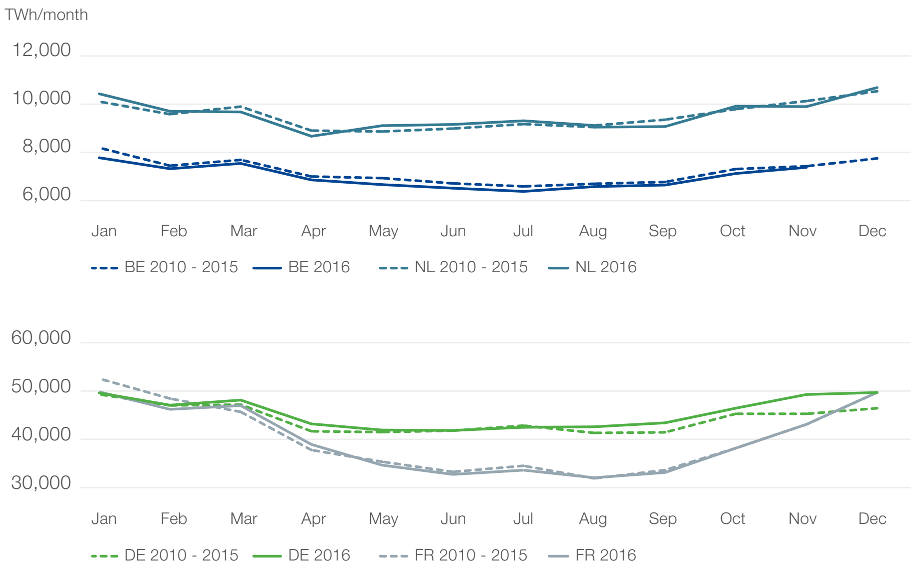

Figure 16: Monthly electricity consumption in CWE region. Source: ENTSO-E monthly values from country packages (2010-2015), ENTSO-E monthly values from power statistics (2016) for Germany, Belgium and the Netherlands, daily values from RTE for France (2016)

c. Conventional and RES capacity

i. Generation capacity developments in Germany

In Germany, currently three different types of reserve power plants exist. The first reserve was the so-called “Netzreserve”. It was introduced for the first time in 2013. In every winter, German TSOs contract generation capacities to hold back capacities to ensure a secure system operation. These capacities TSOs refund the necessary operating costs. This reserve is activated if the needed redispatch capacity exceeds the capacity available on the market. The reserve supply is set up with units currently not participating in the market as well as with units registered for closure by the plant operator, but declared as system-relevant by the Bundesnetzagentur in close cooperation with the German TSOs.

The second type of reserve is the “Kapazitätsreserve”. The Kapazitätsreserve will be built up starting in winter 2018/2019. The allocation of units to the Kapazitätsreserve will commence in 2017. The contracted units are not allowed to participate in the markets anymore.

The last reserve type, called “Sicherheitsbereitschaft”, “Klimareserve” or “Braunkohlereserve”, is going to be built up on lignite fired units with an overall capacity of 2.7 GW started in October 2016. The units in this reserve will be shut down completely after four years. Those stand-by plants are started up in case of insufficient supply on the electricity market as a last resort in order to avoid load shedding.

Power consumption and generation

The trend of increasing renewable generation capacities continued in Germany in 2016, as shown in Figure 17. In total about 4 GW of renewable capacity was installed in 2016, the majority of which being onshore wind.
On conventional capacity, there was not such a clear trend. On the one hand 1.5 GW of hard coal capacity was commissioned[12], while on the other hand 0.6 GW of lignite was taken offline and the total operational gas capacities reduced by 1.4 GW. The capacities in the reserves increased to 5.1 GW, as 1.7 GW of natural gas-fired power plants were added to the "Netzreserve". 0.35 GW of the closed lignite capacity was included in the "Sicherheits-bereitschaft". Besides these reserves, as in the previous year, about 3 GW of capacities were mothballed. The owners of these plants have taken these capacities offline, but with the option to make them operational again if market circumstances improve.

German Operational Generation Capacities **Changes** **German Reserve and Mothballed Capacities**

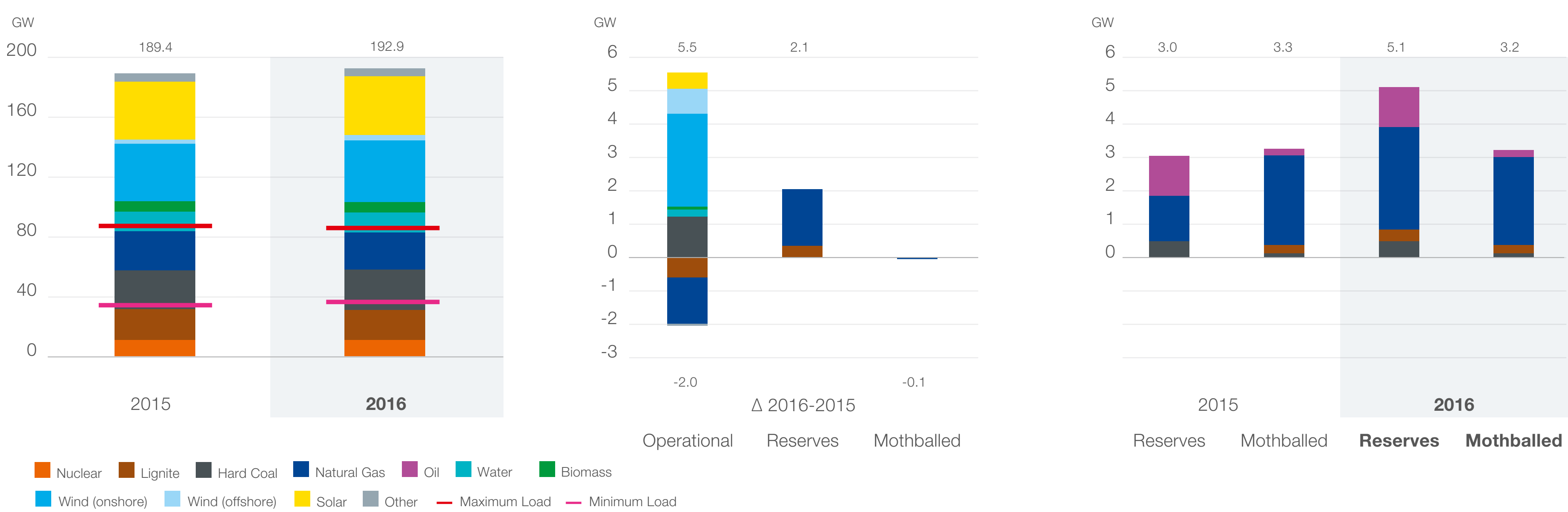

Figure 17: German generation capacities per fuel type in 2015 and 2016. Source: Kraftwerkslisten Bundesnetzagentur, Load: ENTSO-E Generation

[12] These hard coal plants started operation at the end of the year 2015. Due to the date of the referred publication at the beginning of November for the last review, these plants were not included in the 2015 overview (in TenneT Market Review 2015). In this review, the concerned plants are included in the 2016 numbers in Figure 17.
Moorburg A: 800MW; officially commissioned in November 2015.
Wilhelmshaven ENGIE: 731MW; officially commissioned in November 2015.

Power consumption and generation

ii. Generation capacity developments in the Netherlands

Figure 18 shows the development of operational generation capacity in the Netherlands. Despite a significant increase of renewable capacity, the total operating capacity in the Netherlands decreased by 0.2 GW to 29.3 GW because of an even higher decrease in conventional capacity.
The decrease in conventional capacity is mainly caused by the closure of three coal-fired power plants (Amer 8, Borssele 12 and Gelderland 13), as result of the agreement on Energy for Sustainable Growth from 2013. The volume of mothballed capacity stayed roughly the same.

Renewable capacity increased by 1.5 GW, almost equally divided over offshore wind, onshore wind and PV capacity. The commissioning of offshore wind park Gemini in 2016 resulted in an increase of 0.6 GW of offshore wind. The generation capacities of onshore wind showed an estimated growth of 0.4 GW, resulting in a total installed capacity of 3.5 GW on 1 January 2017. The installed capacity of solar panels showed an estimated growth of 0.5 GW resulting in a projected total installed capacity of 2.0 GW at January 1st 2017.

Dutch Operational Generation Capacities | Changes | Mothballed

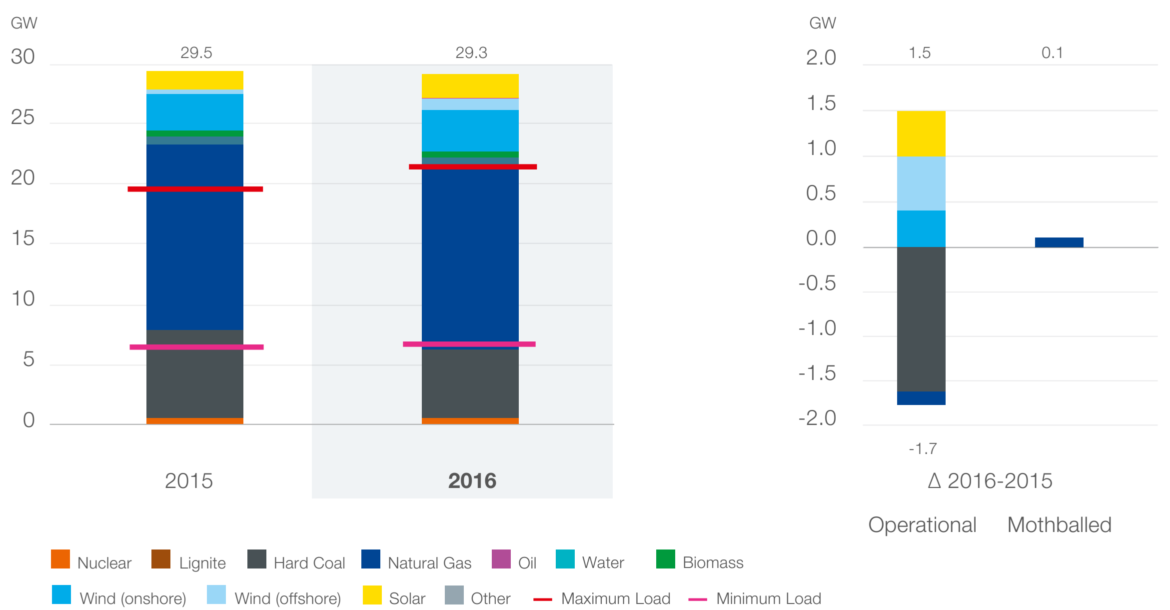

Figure 18: Dutch operational and mothballed generation capacities per fuel type in 2015 (at 1 January 2016) and 2016 (1 January 2017), and the changes in 2016[13].
Source: Capacities: TenneT[14]; Load: ENTSO-E

[13] Two manual adjustments are made for changes happening at January 1 to better reflect capacity installed at the end of 2015 and 2016, being, a) inclusion of 1.6 GW coal capacity for 2015 which close 1-1-2016 and b) inclusion of 0.7 GW gas for 2016 which close 1-1-2017.

[14] Figures for 2016 are preliminary. Renewable capacities for 2017 are estimated based on data from Nationale Energieverkenning 2016.

Power consumption and generation

d. Generation

i. Shares of gross electricity generation in Germany

The change of the generation stack in Germany towards more renewables is not reflected in the shares of the gross electricity generation. As shown in Figure 19 the shares of gross electricity generation per technology of 2016 remained close to the shares of 2015. The main reason that the share of renewable generation did not increase was the lower absolute generation of RES of -2 TWh/a compared to 2015 due to less beneficial weather circumstances. This is further explained in paragraph 4.d.ii.

Major changes can be seen on the generation of the gas-fired plants which generated 44% (= 13.3 TWh) more electricity in 2016 than in 2015. This increase can mainly be attributed to the improved clean spark spreads in the second half of 2016, as shown in paragraph 3.c. Electricity generation from biomass dropped significantly to 8 TWh/a (14.2%).

The overall total generation in Germany was about 2.8% lower in 2016 compared to 2015, as a result of the nearly unchanged demand, the lower RES feed-in and the reduced competitiveness of the German hard-coal generation due to the fuel price developments described in the previous chapter (see paragraph 3.b).

German Shares of Gross Electricity Generation

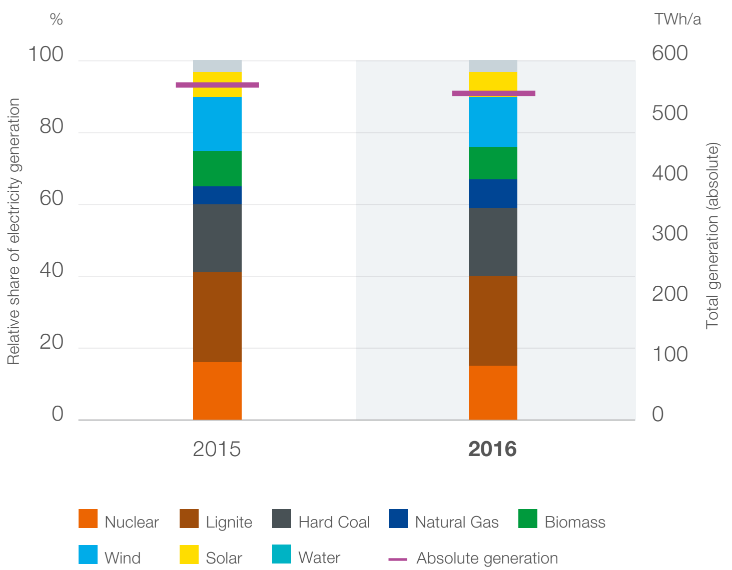

Figure 19: Shares of gross electricity generation in Germany (left axis) and total generation in TWh/a (right axis). Source: Fraunhofer ISE

Power consumption and generation

ii. Zooming in on German RES feed-in

Figure 20 shows a slight decline of feed-in by solar panels as well as wind turbines in Germany, even though in 2016 the installed capacity increased. The feed-in of RES decreased by about 1 TWh/a due to poor weather conditions for both. After the exceptionally windy year 2015, the wheather conditions in 2016 remained within the long term average conditions.

Feed-in of RES in Germany

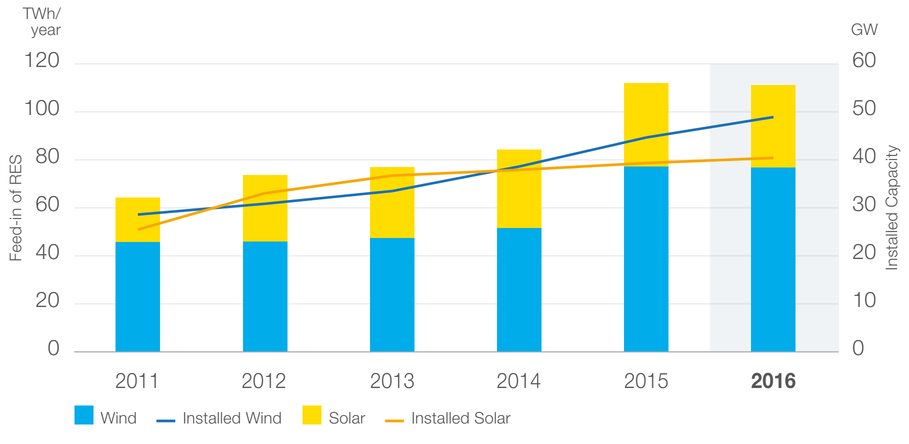

Figure 20: Feed-in and installed capacities of wind turbines and solar panels in Germany.
Source: EEX, Fraunhofer ISE

Power consumption and generation

Figure 21 shows the development of the monthly average solar and wind feed-in for Germany for the last two years. The graph shows the volatile behavior of the feed-in and the differences of RES feed-in energy. During 2016, the average RES feed-in peaked in February because of the all-year peak of wind feed-in, while the highest average feed-in of solar panels was in July 2016 with an amount of 6.6 GW.

Note also the seasonal pattern for solar and wind feed in Figure 21. While solar generation is highest during summer, wind generation is highest during winter. Together, they lead to a relatively stable average RES generation per month, with the lowest feed-in in October or November over the last four years.

German Monthly Average Renewable Feed-in

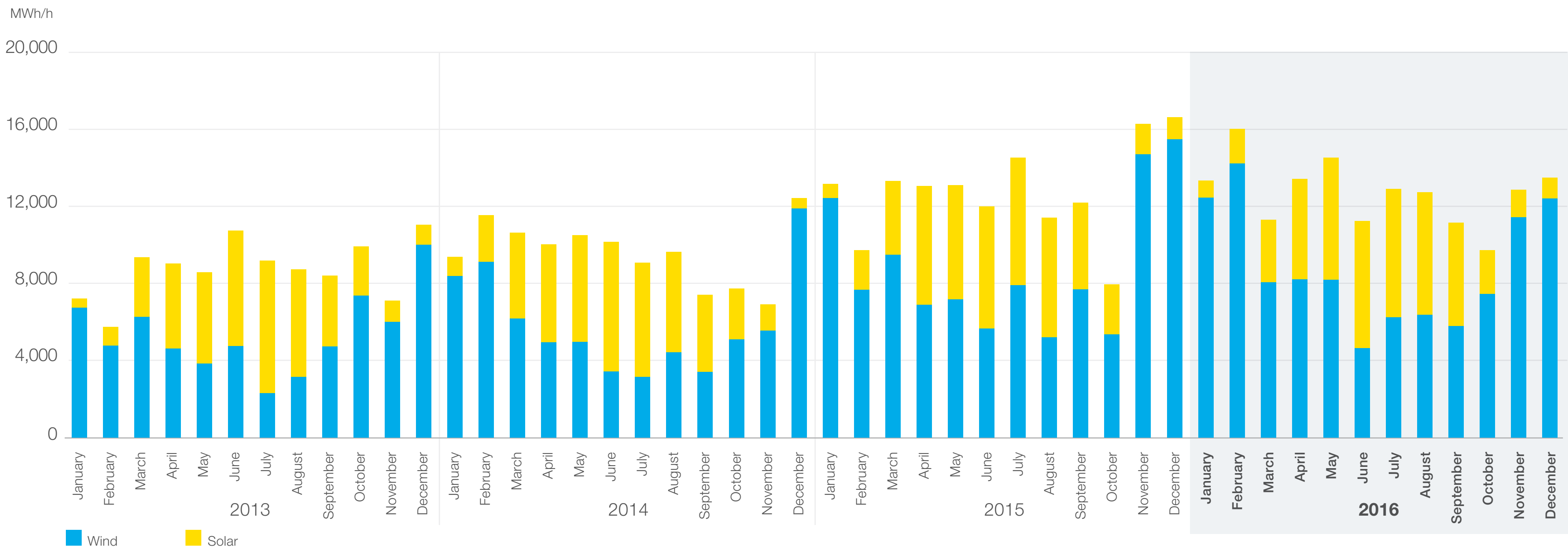

Figure 21: Monthly average RES feed-in in Germany. Source: EPEX Spot

Power consumption and generation

iii. Shares of gross electricity generation in the Netherlands

Overall, the generation in the Netherlands increased from 91 TWh in 2015 to 97 TWh in 2016. Figure 22 shows the share of the gross electricity generation per fuel type in the Netherlands. The share of generation from wind turbines increased by about 30% from 2015 to 2016 to 4.6% of gross electricity generation, largely caused by the commissioning of the 0.6 GW wind park Gemini.

Dutch Shares of Gross Electricity Generation

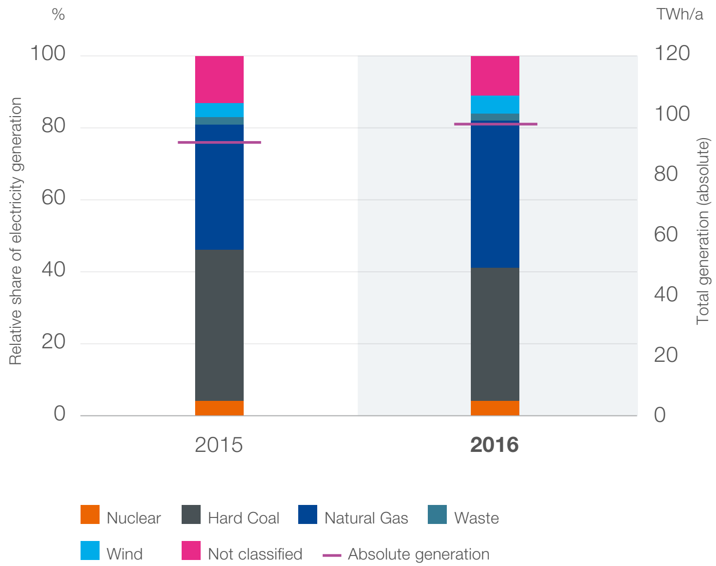

Figure 22: Shares of gross electricity generation per fuel type in the Netherlands (left axis) and total generation in TWh/a[15] (right axis). Preliminary values for 2016. Source: TenneT

[15] Not classified generation includes units smaller than 10 MW and is therefore not traceable to specific fuel type.

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Power consumption and generation

In 2016, the share of electricity generation by coal-fired plants decreased by 12 %, mainly because of the decommissioning of three coal-fired power plants. The share of natural gas in the annual domestic generation increased by about 24 % compared to 2015. One reason for this is that generation from the decommissioned coal plants is replaced by gas-fired plants, but a more important reason is that the margins for electricity generation with gas-fired power plants significantly increased in 2016, see paragraph 3.c. The impact of the improved clean spark spread is shown in Figure 23, where the generation of gas-fired power plants significantly increased in the last months of the year while the generation of coal-fired plants remained around the same level, as they were already generating at full capacity.

Dutch Generation from Coal and Gas Plants

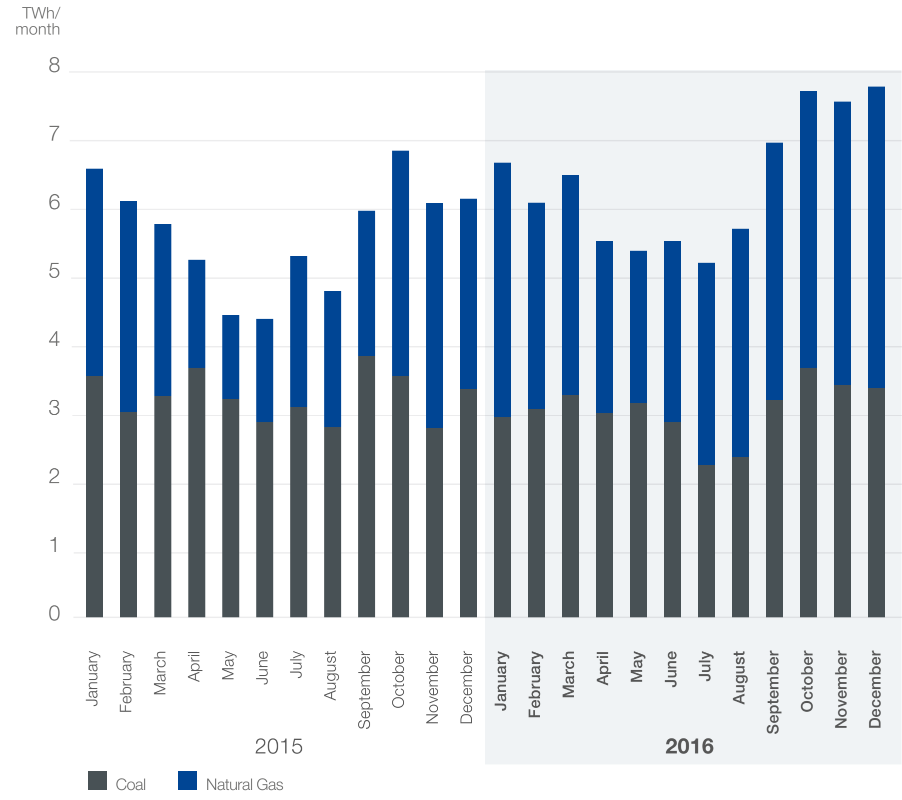


Figure 23: Dutch gross electricity generation[16] from coal and gas plants. Source: TenneT

[16] Hard coal power generation includes all plants, but natural gas power generation includes only plants above 10 MW, due to data availability reasons.

Market integration & interconnection flows

Net positions in the European market areas changed slightly in 2016. With higher exports in the German-Austrian market area and unchanged imports, the German-Austrian net position increased. More exports were possible due to a lower electricity demand in 2016 compared to 2015 in Germany.

The monthly net positions in the CWE region changed their direction in the last third of 2016. With the French market area having a negative net position and the Dutch market area having a positive net position, the respective net positions of the two countries inverted end of 2016.

a. Background

The European transmission network provides the physical backbone for the further integration of the European electricity market. Market integration enables the transport of electricity across national borders and makes the buying and selling of electricity more efficient and more effective, and increases overall welfare for society.

The European electricity market consists of a number of interconnected markets, called bidding zones or market areas[17]. Typically, bidding zones correspond with Member States, such as is the case for the Netherlands, Belgium and France. On the other hand, there are countries which constitute a single bidding zone together, such as Germany, Luxemburg and Austria, and countries which contain multiple bidding zones, such as Norway and Sweden.

Within each bidding zone, electricity can be traded freely without taking into account network constraints. In contrast, trading between bidding zones is limited because of the physical limitations of the transmission networks and limited interconnection capacity. For this trade, most often referred to as cross-border trade, the available interconnection capacity needs to be taken into account in the trading process.

Coordination across bidding zones is essential since electricity flows cannot be restricted by commercial arrangements but follow the law of physics. For example, when Germany exports to France, part of the electric power will flow through the Netherlands and Belgium instead of following the direct path between the two countries. Therefore, the impact of this transaction needs to be taken into account on the available capacity at the Dutch and Belgium borders. This is also the reason why TSOs distinguish electricity flows in commercial and physical flows.

European TSOs make use of coordinated capacity calculation and congestion management methodologies to determine the amount of capacity for cross-border trading which can be offered to the market, while ensuring a reliable operation of the power system. TSOs either use a coordinated net transmission capacity (CNTC) or a Flow-Based (FB) method to calculate the available interconnection capacities. Accoring to the guideline on capacity allocation and congestion management, the Flow-Based method should be used as a primary approach for day-ahead and intraday capacity calculation where cross-zonal capacity between bidding zones is highly interdependent. Therefore, the countries in the CWE region implemented Flow-Based market coupling in 2015. More information on Flow-Based market coupling can be found on the TenneT homepage[18].

[17] The contents of this background information are largely based on: EI Fact sheet: Cross-border electricity trading: towards flow-based market coupling, of KU Leuven Energy Institute.
[18] Flow-based market coupling.

Market integration & interconnection flows

b. Net positions

Figure 24 shows the yearly aggregated net positions for 2015 and 2016 for the different market areas throughout Europe. The numbers show the total electricity imports (negative) and exports (positive) of each market area, the color indicates the net position of the corresponding market areas.

Yearly Aggregated Net Positions

From 2015 to 2016, the net positions in the CWE region changed slightly. With the exception of Portugal and Denmark, all countries shown in Figure 24 kept their positive respectively negative net position as in 2015. Focusing on the CWE region, we see that the Belgian imports decreased whereas Dutch exports increased. Furthermore, the exports in the German-Austrian market area increased in 2016, leading to a higher net position, since the imports remained similar to 2015.

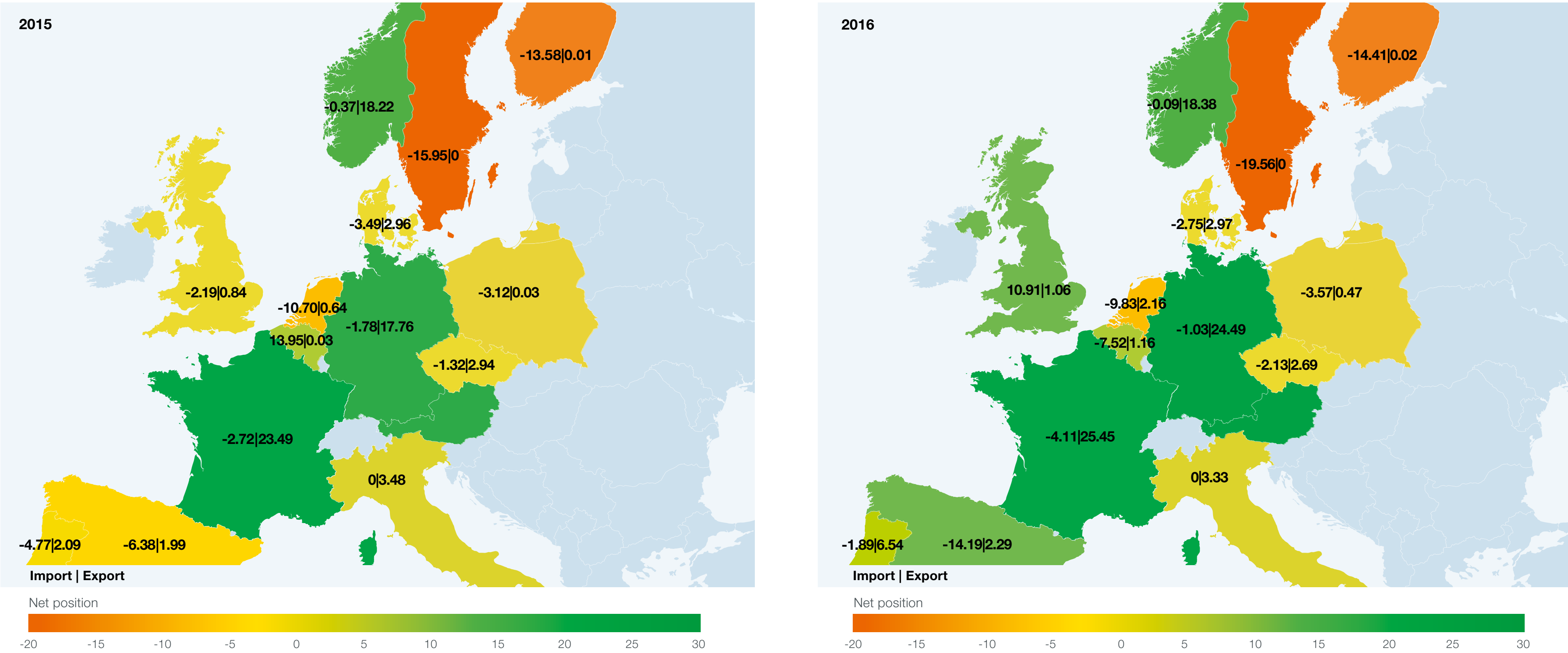


Figure 24: Yearly aggregated net positions, imports and exports. Source ENTSO-E[19]

[19] Data from ENTSO-E Transparency. Data for 2015 are incomplete since the first five days of the year are missing.

Market integration & interconnection flows

Monthly net positions of the CWE regions for 2015 and 2016 are depicted in Figure 25. Most months Belgium and the Netherlands have a net importing position while Germany and France have a net exporting position. In October 2016, an interesting switch took place between the Netherlands and France; France became a net importer and the Netherlands a net exporter. The switch concerning France was the result of temperature sensitive power demand related to electrical heating, in combination with a high unavailability of French nuclear power plants. The rising electricity prices and improved spreads led to more generation in the Netherlands, which exported electricity to other countries within Europe including France.

Monthly Net Positions in CWE Countries

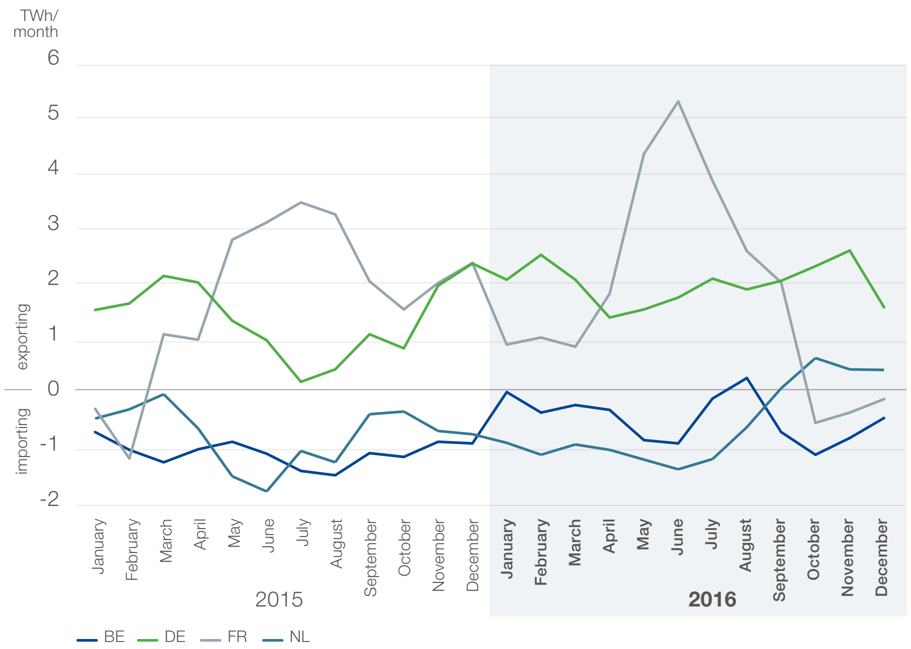


Figure 25: Monthly net positions in CWE countries. Source: ENTSO-E

With the introduction of the Flow-Based capacity calculation methodology within CWE, the net positions per country which optimize social welfare across the CWE region are calculated. To get a better view on which market areas are providing electricity when the Netherlands and Germany are importing, the import relations are analyzed in more detail. Figure 26 shows the accumulated positive net position for each market area in hours where the Netherlands or Germany have a negative net position, divided by the accumulated positive net position of all market areas. Therefore, only exporting exporting market areas are taken into account in hours where imports to the Dutch respectively German market occur. Afterwards the average share of these hourly values is calculated, so that all columns sum up to 100%. This calculation does not take congestions and physical limitations of the grid into account, but assumes a copper plate throughout Europe.

Market integration & interconnection flows

The figure shows that in situations where the Dutch market area imports, the net position of Germany, France and Norway have the highest share of all positive net positions. For Germany, shares are spread more across markets with higher shares of France and Norway. Therefore, France and Norway are the countries which provide most of the electricity when the Netherlands and Germany are importing, and the Netherlands import a significant share of electricity from Germany, whereas Germany imports only a very limited share of the Netherlands.

In contrast to the previous analysis, the following figure shows which countries are importing most while Germany respectively the Netherlands are exporting. Exporting can be interpreted as helping other countries to cover their demand at the lowest possible price. Figure 27 shows that Italy is mostly importing when Germany and the Netherlands export. This can be traced back to the high generation costs of the Italian generation stack. The difference in importing by the Netherlands and Germany if the corresponding other is exporting can be explained by the different size of the two market areas.

Import Relations

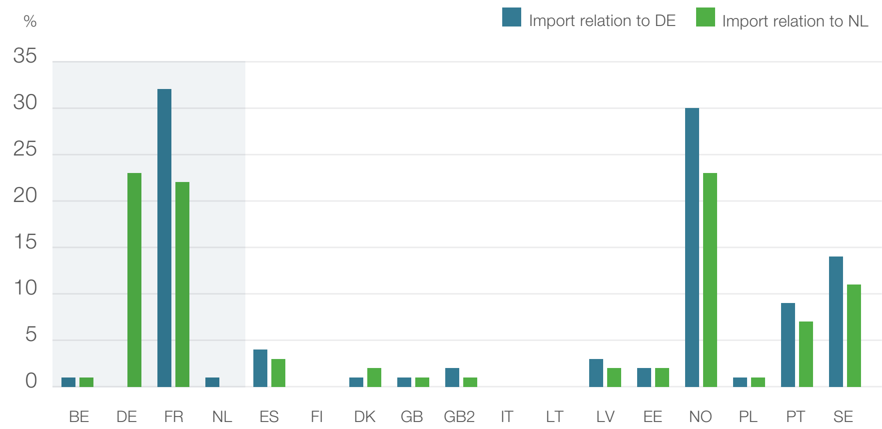


Figure 26: Import relations to the Netherlands and Germany 2016. Source: ENTSO-E

Export Relations

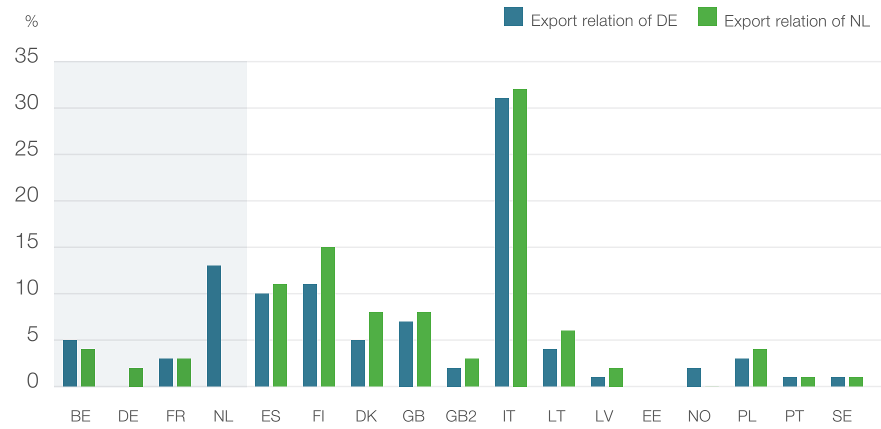


Figure 27: Export relations of the Netherlands and Germany 2016. Source: ENTSO-E

Market integration & interconnection flows

i. Special case: Germany – Austria

Germany, Austria and Luxembourg currently form a common market area (bidding zone) in the electricity market, which is a unique situation in Europe. The German-Austrian bidding zone is part of Central Western Europe (CWE) Flow Based market coupling, but since there is no bidding zone border between these two countries, trading volumes within the bidding zone are basically unlimited. For a number of years, increasing day-ahead and intraday volumes of German and Austrian traders have been observed. These result in higher physical flows, leading to overload of numerous grid elements connecting both countries. Therefore, remedial actions are needed more frequently, which is costly, and their ability to cope with the overload is limited.

In November 2016, the Agency for the Cooperation of Energy Regulators (ACER) decided on the configuration of future Capacity Calculation Regions (CCR). This decision stated, inter alia, that Germany and Austria will be split up into two separate bidding zones, with a bidding zone border between these two new market areas as part of CCR Core. In addition, the German Federal Network Agency (Bundesnetzagentur) requested German transmission system operators to prepare the introduction of capacity management on the German-Austrian border until July 2018.

The reconfiguration of the existing and well-established German-Austrian bidding zone is a highly complex project. Capacity calculation must be coordinated between transmission system operators on both sides of the border and in neighboring countries. Furthermore, capacity allocation must be implemented in trading systems of different electricity market operators. Experts from the TSOs and NEMOs are currently working on a timely implementation of an advanced capacity management on the German-Austrian border.

c. Development physical flows

With the previous chapters analyzing market integration and market results for 2016, this chapter focuses on the actual physical cross-border flows in the CWE region.

Figure 28 illustrates the yearly aggregated actual physical cross-border flows in the CWE region and at the German borders in TWh/a in 2015 and 2016. Physical cross-border flows only follow the laws of physics and depend mainly on the location where in the grid consumption and generation takes place as well as on the transmission grids' configuration and state.

As Figure 28 shows, the actual physical flows changed from 2015 to 2016. Most notable are the decreasing physical flows from France to Belgium, France to Germany, the Netherlands to Belgium, and Germany to the Netherlands, and the increasing flows of Belgium to France, Germany to Czech Republic and vice versa. The changes in these physical flows are in line with what can be expected from the market situation of 2016.

Market integration & interconnection flows

European Physical Cross-Border Flows

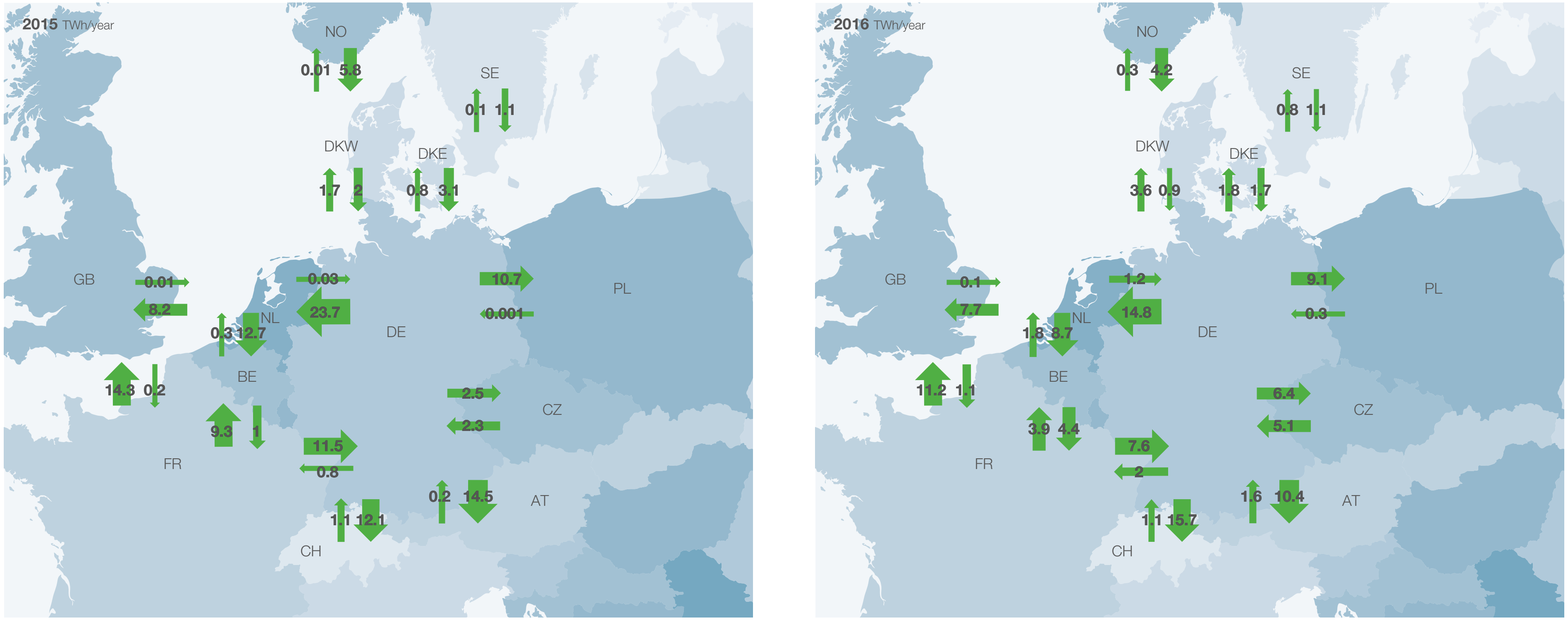


Figure 28: Annual total of physical cross-border flows in the CWE region and at the German borders in TWh. Source: TenneT, ENTSO-E, Swissgrid

Balancing

Various voluntary implementation initiatives related to market integration aim to lower costs for balancing. With the French TSO RTE joining the International Grid Control Cooperation, the netted volumes increased significantly in 2016.

The traded volumes in the common frequency containment reserve (FCR) tender process increased, with other international system operators joining the process. In 2016 Belgium joined the tender process increasing the volumes by about 40MW.
Due to the higher liquidity of the FCR tender process, the prices for FCR are decreasing and the maximum contracted prices are converging towards the average contracted prices.

After a brief background explaining the set-up of balancing structures, a chapter on the developments on international balancing markets follows. As examples of this, the International Grid Control Cooperation and the German tender process for FCR is presented.

a. Background

In self-dispatching systems it is the responsibility of market participants to match the energy supply and demand. Unlike most commodities, electrical energy needs to be balanced at every point in time, due to the limited possibilities to store this electricity. Through balance responsibility, in principle every market participant is financially responsible for its energy balance, which is measured over specific time periods: the imbalance settlement period (ISP). In Germany and the Netherlands the ISP is equal to fifteen minutes.

All power deviations during the ISP in the balance between generation and consumption are the responsibility of the TSO. In order to resolve those power imbalances, TSOs such as TenneT are responsible for several processes: jointly for the frequency containment process (FCR), and individually for the frequency restoration process (FRR), with both automatic (aFRR) and manual (mFRR) activation, and in cooperation for the imbalance netting process. Some TSOs also make use of the reserve replacement process, which is not further addressed in this publication.

In the case of an imbalance between generation and consumption, the difference is instantly covered by the kinetic energy of rotating masses synchronously coupled to the network. Consequently, these rotating masses either speed up or slow down and cause a deviation from the nominal system frequency, i.e. 50 Hz.

In order to stabilize the frequency, the deviation causes the frequency containment reserve (FCR) to be activated automatically and proportionally to the deviation in every Load Frequency Control Block (LFC Block).
The TSOs of continental Europe ensure that a jointly dimensioned total amount of +/- 3000 MW of FCR capacity is available. Much of this capacity is procured through auctions.

After the frequency has been stabilized, the main priority lies in freeing the used FCR capacity in case it is required to be activated again. The frequency restoration process is a process in which each TSO ensures its local responsibilities are met. When a power deviation is caused by an imbalance in one specific country, the frequency containment process is activated in the whole of continental Europe. During the frequency restoration process the activated FCR is replaced by FRR, which is activated locally where the imbalance has occurred. For the frequency restoration process, products with both automatic and manual activation are used.

Balancing

Balancing capacity is procured in order to ensure sufficient availability of these products when needed. Providers of balancing capacity have the obligation to provide balancing energy when instructed by the TSO. Upon activation of the products, the resulting balancing energy is bought or sold to the balancing service provider (BSP).

Finally, TSOs use the imbalance netting process to avoid that positive and negative imbalances occurring simultaneously are countered by the activation. The upward demand of one TSO is reduced by the downward demand of another, and vice versa. This process increases the efficiency of the TSOs[19] balancing efforts.

b. International balancing market developments

On a European level, the different balancing markets and systems are subject to significant developments. TSOs undertake voluntary initiatives for improvement of balancing market functioning and integration, also in light of the upcoming guidelines on Electricity Balancing (EBGL), which have been accepted by member states in the Electricity Cross-border Committee on 16 March this year. Along with the System Operations Guidelines (SOGL), expected to enter into force later this year, the EBGL provides the framework and minimum requirements for the harmonization and integration of the balancing markets, specifically focusing on the exchange of balancing energy through a common merit order list.

Ahead of the legislation, voluntary implementation initiatives related to market integration can roughly be divided on the basis of four distinct aims:

- Netting and reducing activated volumes of balancing energy;
- Sharing of reserves (joint reduction of balancing capacity required to cover dimension incidents);
- Integrating markets for balancing energy; and
- Integrating markets for balancing capacity.

The reduction of activated volumes of balancing energy through imbalance netting is steadily increasing, specifically through the International Grid Control Cooperation (IGCC). This leads to large efficiency gains on the side of the TSOs.

Several European initiatives focus on the exchange of balancing energy from FRR. In 2016 the EXPLORE TSOs of Austria, Belgium, Germany and the Netherlands published a report[20] on a target model for exchange of balancing energy from FRR, in which a specific focus was placed on the necessity to reach a consistent market model. In August 2016 the exchange of balancing energy from aFRR started between the relatively similar markets of Austria and Germany: a significant step towards the future further integration of balancing energy markets.

Finally, the balancing capacity used for FCR is increasingly procured through the German FCR tender process, integrating the FCR market further and further and thereby creating commercial opportunities for new providers of FCR, including battery operators, see chapter 8.b.

c. International Grid Control Cooperation

The International Grid Control Cooperation (IGCC) currently consists of 11 TSOs, the largest imbalance netting cooperation in Continental Europe. The European network of transmission system operators for electricity (ENTSO-E) is following this project as taking the lead in the bottom-up implementation of the EBGL.

On 2 February 2016, the French TSO RTE joined the IGCC. As shown in Figure 29, inclusion of this large LFC block has resulted in a significant increase of the netted volumes. In particular, the German LFC block has benefitted from RTE's participation; in certain months of 2016 the netted volumes were doubled in comparison to the previous year. Future integration of European Balancing Platforms will further optimize a proper balancing market. This is performed under the umbrella of the EBGL.

[20] Target model for exchange of frequency restoration reserves.

Balancing

Amount of Netted Imbalances (Short+Long) – Monthly Values

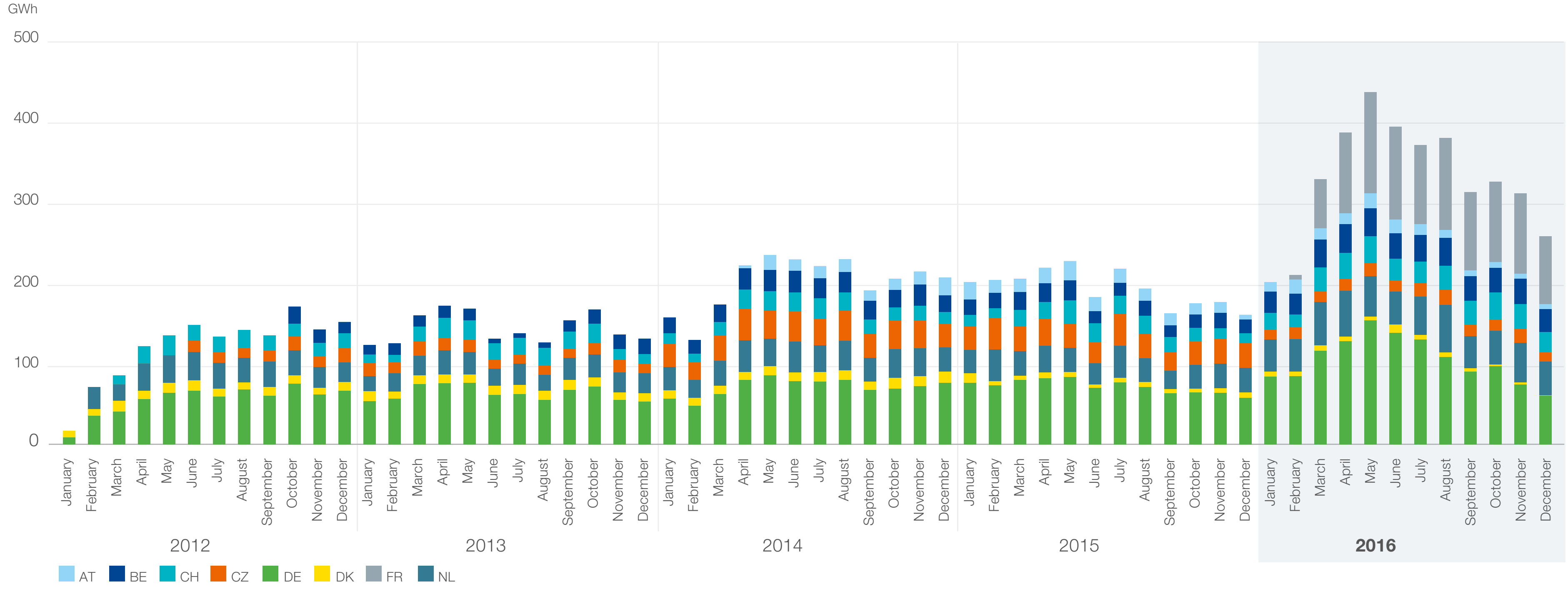


Figure 29: Monthly volumes of netted imbalances for all IGCC members for the imbalance netting process. Source: IGCC

Balancing

d. German FCR tender process

The jointly dimensioned total amount of +/- 3000 MW of FCR capacity in the synchronous area Continental Europe is distributed between all TSOs proportionally. For every TSO, the respective amount of control power is based on the sum of the net generation and consumption of its control area divided by the sum of net generation and consumption of the synchronous area over a period of one year. Although neither the total FCR in the synchronous area nor the proportion of the German share has changed significantly, the FCR market established in Germany increased due to international cooperation between adjacent LFC-Areas from Switzerland, the Netherlands, Austria, Denmark and Germany.

The joint call for tenders is organized by the German TSOs via an internet platform. As shown in Figure 30 the demand for FCR in the auction organized by the four TSOs in Germany increased between 2014 and 2017.

Starting in 2014, TenneT NL joined the call for tenders, increasing the demand from 583 MW (German demand) to 628 MW. In 2015, APG (the Austrian TSO) and Swissgrid (the Swiss TSO) joined the call for tenders, resulting in an auctioned demand of about 793 MW. On 1st of August 2016, Belgian TSO Elia joined the above-mentioned cooperation, making the procured amount in the joint tender process around 830 MW. Belgium procures dynamic amounts based on Elias calculations for the Belgian FCR demand. At the beginning of 2017, the French TSO RTE joined the coordinated tender, increasing the volume further to 1400 MW.

Capacity Volume of FCR Auctioned on Regelleistung

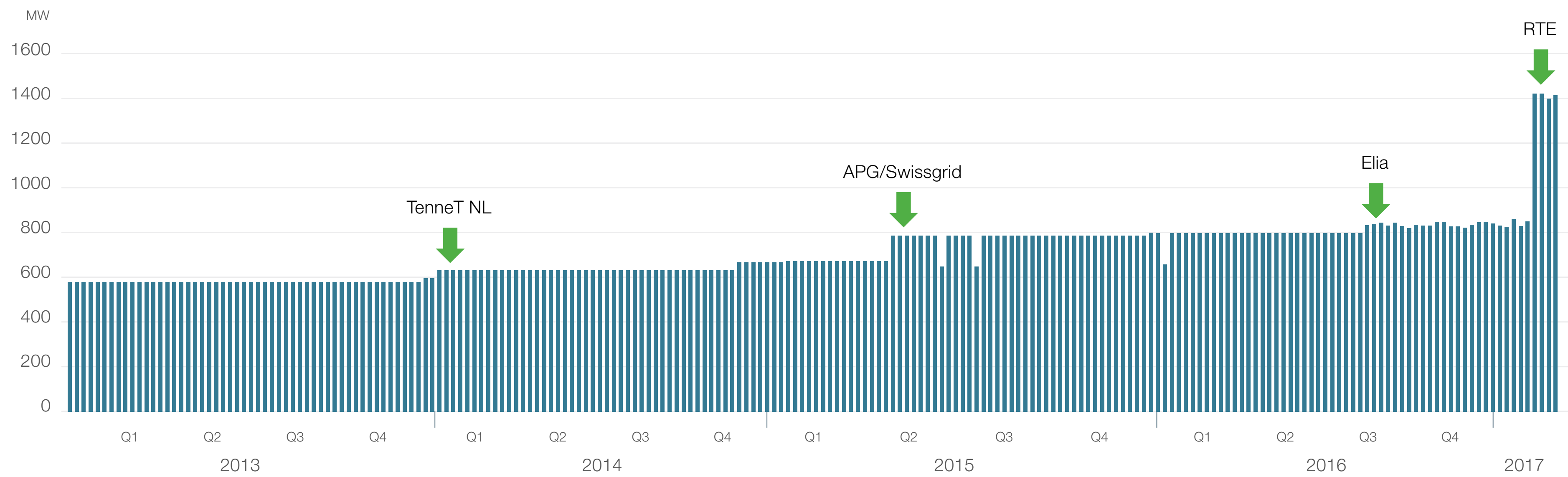


Figure 30: Capacity volume of automatic Frequency Containment Reserve auctioned on Regelleistung. Source: regelleistung.net

Balancing

e. FCR Price developments

Figure 31 shows the course of the price for FCR capacity compared to the average price of the allocated bids. The price curve displays repeating peaks, which result from low price situations at the day-ahead market during Christmas and Easter. Furthermore, there is a remarkable difference in the behavior of the average price compared to the maximum price. In 2013 and in previous years, the average price did not show regular price peaks. This was also true at times of exceptionally high maximum prices. However, starting in 2014, the average price started to follow the maximum price curve more closely and developed high prices at times when maximum prices showed peaks. Consequently, in 2016, the average price was close to the maximum price. This convergence might be a sign of a more competitive market, where all market players bid similar prices. The assumption of a growingly competitive market is also backed by the fact that over the course of the past six years, a decrease in prices for FCR can clearly be observed. Especially from 2015 to 2016, the prices for FCR decreased significantly.

Prices for Frequency Containment Reserve in Germany

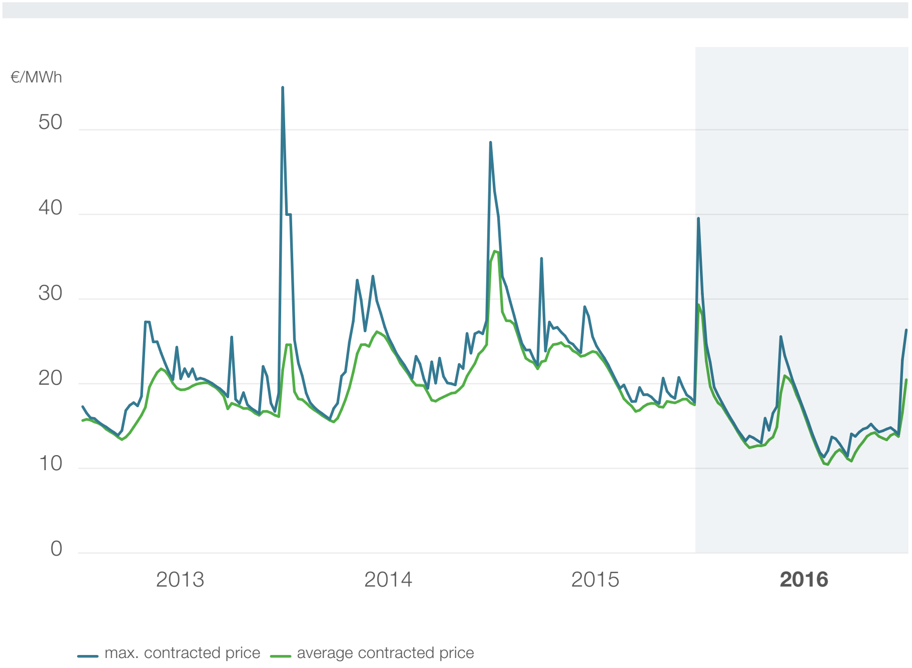


Figure 31: Development of prices for Frequency Containment Reserve in Germany. Source: regelleistung.net

Redispatch in Germany and grid tariffs

TSOs can request redispatch measures to relieve possible congestions originating from an physically infeasible market result. With redispatch volumes falling for the first time since 2013, the costs for redispatch in Germany are decreasing as well. The decrease in redispatch volumes can be traced back to variations in feed-in by RES due to different weather conditions and grid infrastructure projects. Nonetheless, the system operators in Germany and the Netherlands had to increase their grid tariffs in 2016.

a. Background

After the closure of the day-ahead market, the TSO reviews the resulting dispatch schedules and the resulting loading of the grid. Since transmission lines can only transport a limited amount of power, the market result can be incompatible with the network. If necessary, the TSO requests redispatch measures to relieve possible congestions, where by advising some power plants to increase or decrease generation and therewith change their production schedules accordingly. In addition to conventional redispatch, congestion measures with renewables ("Einspeisemanagement") are often necessary in Germany. Due to the rising share of renewables, especially in northern Germany, an increase of such additional measures has occurred since 2013. A further costly remedial action is the activation of the one of the reserves described in chapter 4.c.i. This report focuses on the developments of redispatch as main cost driver of costly remedial actions, leaving the cost for other supplementary measures out of scope. Nevertheless, all the resulting costs are borne by the electricity consumers through the so-called grid tariffs.

Redispatch in Germany and grid tariffs

b. Volumes and costs

The volumes of redispatch measures with participation of the four German TSOs for the last four years are depicted in Figure 32.

The graph shows, that the yearly redispatch volumes have grown from 2013 to 2015 while the volumes in 2016 are generally lower than in 2015. The main reason for the reduction is the weak wind year. Another reason for the reduction could be the commissioning of a new line.

Redispatch Volume in Germany

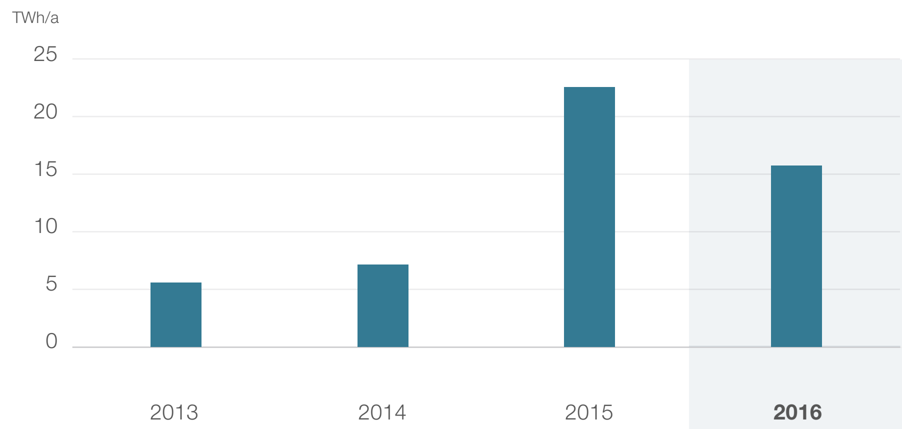


Figure 32: Redispatch volume in Germany from 2013 to 2016 for all requested German TSOs and others with significant volumes[21]. Source: netztransparenz.de

[21] Only volumes higher than 0.1 TWh/a are taken into account.

Figure 33 illustrates the quarterly redispatch costs in Germany for the years 2015 and 2016. In 2015 redispatch costs amounted to about 402.5 million € in Germany. Costs for 2016 are only available for the first three quarters, amounting to 101.7 million €. This is only 25% of the total redispatch costs of 2015.

Redispatch Costs in Germany

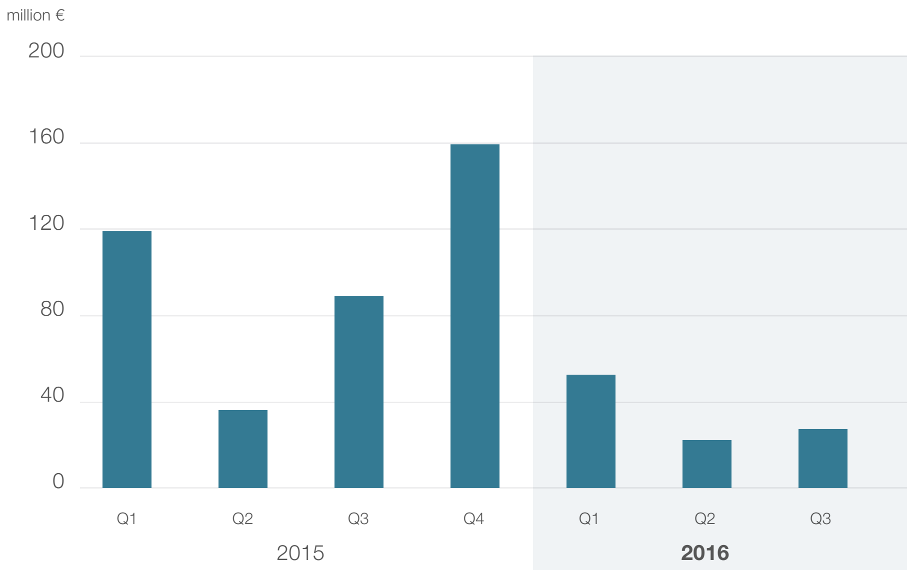


Figure 33: German redispatch costs per quarter in 2015 and 2016. Source: Bundesnetzagentur

Regardless of the developments, the redispatch volumes in Germany remained on a still quite high level in 2016. The network expansions that are needed to reduce the number of measures are progressing. But there is still a mismatch between the pace at which generation locations change as a result of the energy transition and the pace at which the necessary infrastructure can be realized.

Redispatch in Germany and grid tariffs

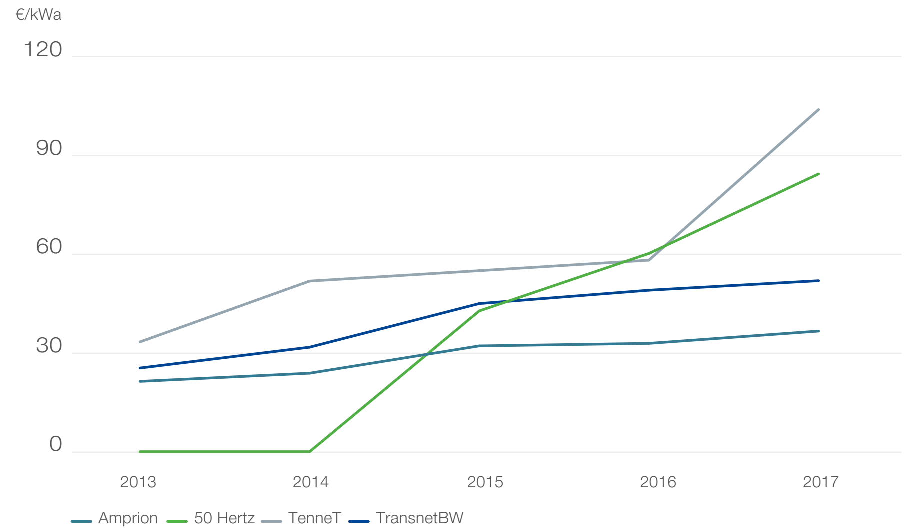
c. Grid tariffs

i. Germany

The grid tariffs in Germany were increasing from 2013 to 2017, as Figure 34 illustrates. The graphs show the costs for consumers with more than 2500 full load hours per year using the high-voltage transmission grid[22]. The German grid tariff includes an annual capacity tariff (peak demand rate) and a tariff for electricity consumed (energy rate).

The peak demand rate was rising for all four TSOs from 2013 to 2017, with high increases from 2016 to 2017 especially for TenneT and 50Hertz, since for these two TSOs the redispatch costs are highest. The energy rate was increasing for all four TSOs as well, even though Amprion decreased their energy rate from 2014 to 2015. As for the peak demand rate, three of the four TSOs have increased the rate from 2016 to 2017.

Peak Demand Rate



Energy Rate

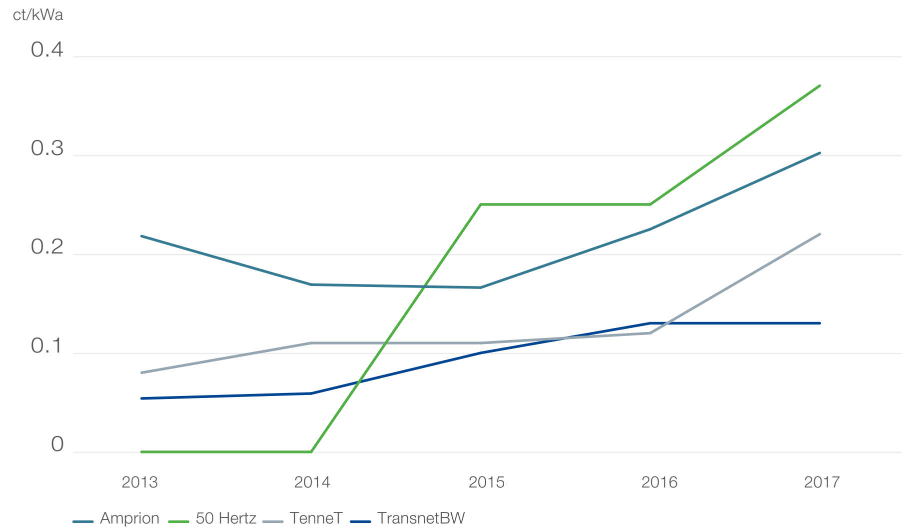


Figure 34: Grid tariff (peak demand rate and energy rate) for German TSOs. Source: German TSOs

[22] "Jahresleistungspreissystem" with quarter-hourly measurement of the requested power

Redispatch in Germany and grid tariffs

The grid tariffs in Germany have risen over the last 10 years. As depicted in Figure 35, the grid tariffs had a major impact on the average consumer price for electricity. For this calculation a consumer with a yearly demand of 3500 kWh was assumed. 2016 was the first year in which the grid tariffs had a higher share of the average consumer price than the share of the price for the actual electricity. The grid tariffs amounted to 7.07 ct/kWh whereas the cost of electricity was only 6.11 ct/kWh.

Average Consumer Price for Electricity

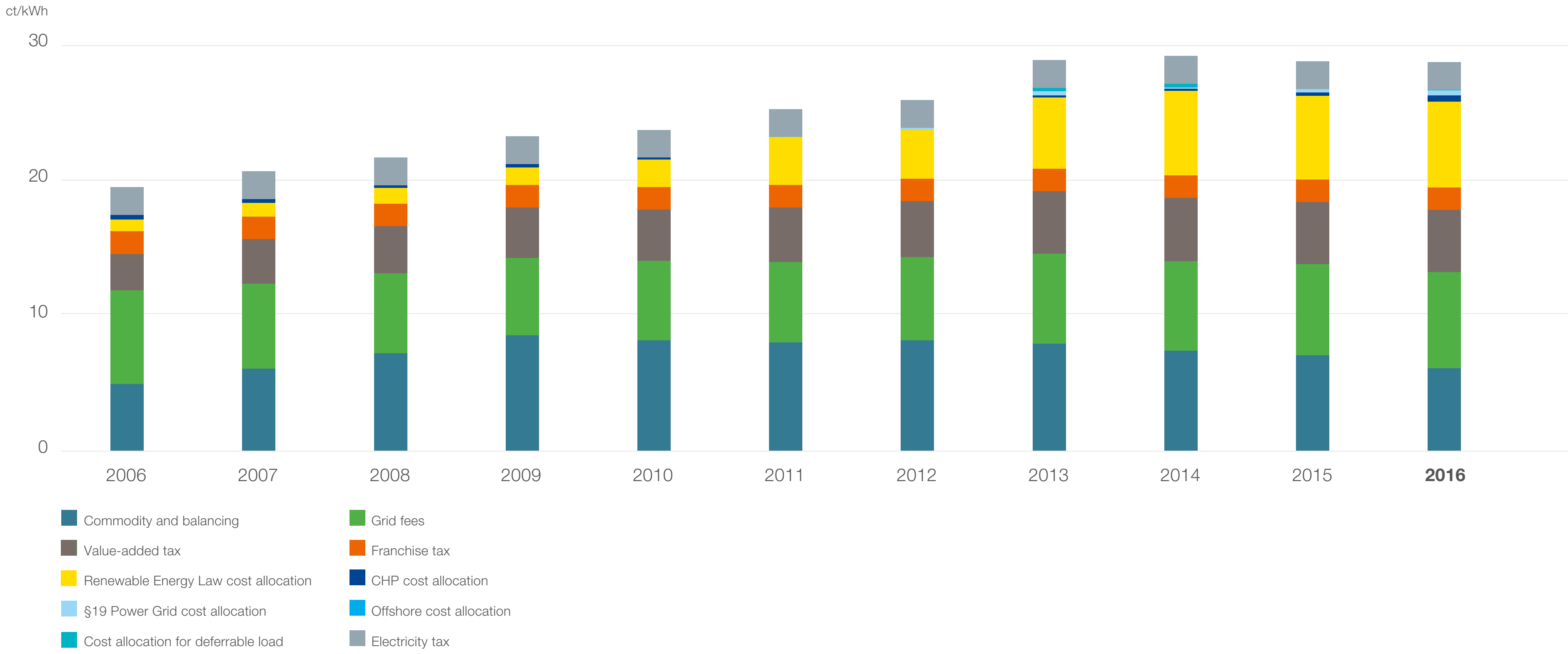


Figure 35: Average end consumer price for electricity in Germany. Source: BDEW

Redispatch in Germany and grid tariffs

ii. Netherlands

TenneT has four sets of grid tariffs in the Netherlands based on voltage level and full load hours. The different voltage levels are extra high voltage (380 and 220 kV) and high voltage (150 and 110 kV). The tariffs depend on the full load hours with a difference between more and less than 600 full load hours per year[23].

The tariff structure consist of a fixed service fee per connection for each year and a usage service fee with two components. The first component is the contracted peak load capacity (kWcontract) whereas the second part represents the fee for the measured peak load during a month or a week[24] (kWmax).

The fixed service fee is used to cover the periodic connection costs as well as the costs for non-usage related transmission services. The kWcontract and kWmax components are used to cover usage related transmission services as well as system services costs. In the Netherlands the transmission tariff is 100% charged to consumption, there are no charges applied to generation (i.e. G-charge/producententarief).

The fixed service fee per connection is 12.479 €/year for extra high voltage (EHV) and €2.760 €/year for high voltage (HV) connections. Figure 36 shows the components of the usage fee, being the tariffs for contracted peak load capacity (kWcontract) and the peak load (kWmax).

Grid Tariff in the Netherlands

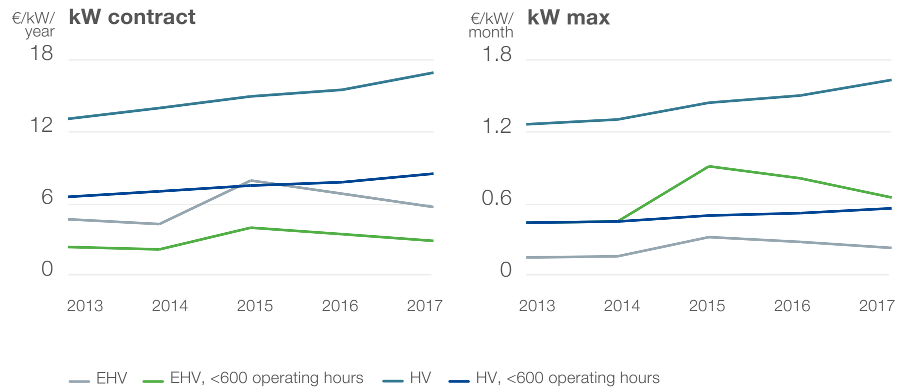


Figure 36: Grid tariff (kWcontract and kWmax) in the Netherlands. Source: TenneT

For the Netherlands, the grid tariffs for EHV connections increased drastically in 2015 because of the abolishment of the system services tariff. Costs for system services from 2015 on are covered via kWcontract and kWmax instead of a separate €/MWh tariff. In 2016 and 2017 tariffs decreased to a level comparable to 2014. An important reason for this decrease is that TenneT used part of the revenues of congestion rents and cross-border capacity auctions to cover costs and investments in its grids, consequently averting tariff increases.

Although part of the revenues of congestion rents and cross-border capacity auctions are used to limit costs for HV connections, they were not enough to offset the rising costs for these parts of the grid.

23 Calculated as total consumed electricity per year divided by contracted capacity (kWh/kWcontract).
24 For connections with more than 600 full load hours, the kWmax fee is per month; for connections with less than 600 full load hours, the kWmax fee is per week.

Special events in 2016

Besides the general trends in the Dutch and the German electricity markets, this report puts special focus on two events in 2016. One of them was the long unavailability periodsperiods of nuclear power plants in France and Belgium with resulting high prices on the spot markets. Another special event in 2016 was the entering of different new players into the balancing markets.

a. Unavailability of nuclear plants in France and Belgium

Figure 37 depicts the daily unavailability of Belgian power plants in 2016. That year, there were long periods of high unavailability of nuclear power plants. Comparing the daily unavailability in 2016 and 2015, the unavailability in 2015 was higher at the beginning of the year, whereas in 2016, especially from October till December, the unavailability was higher. Due to the large share of unavailable generation capacities in Belgium and due to high residual loads, price peaks occurred in some hours in October and December.

Daily Unavailability of Belgium Power Plants 2016

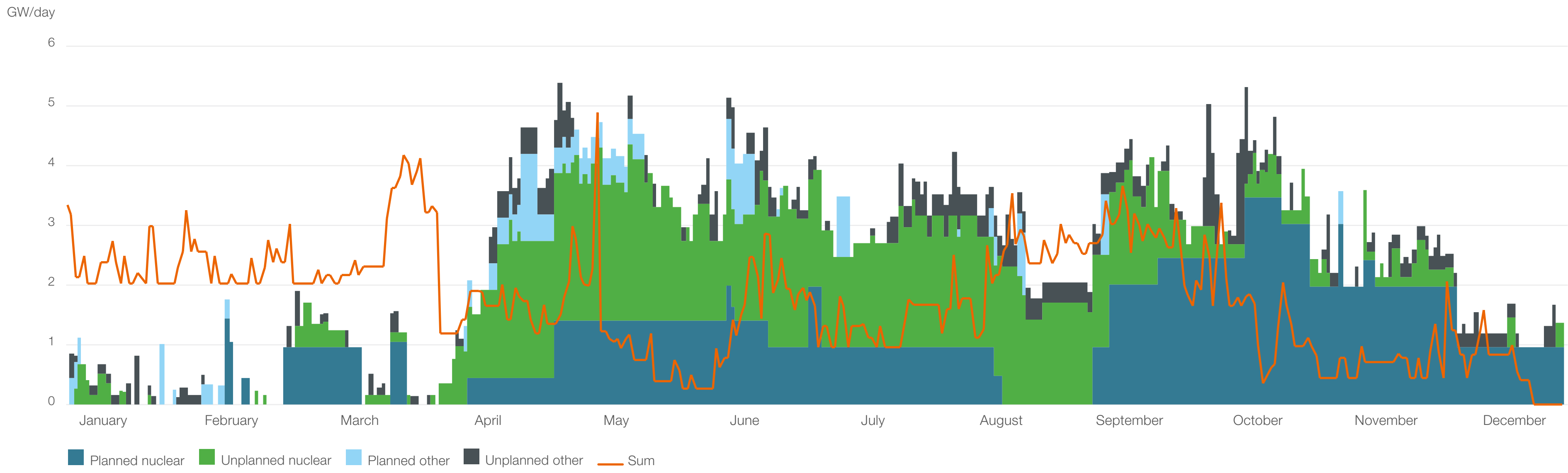


Figure 37: Daily unavailability of Belgian power plants. Source: Elia

Special events in 2016

In Figure 38, higher unavailability in the summer can be observed due to many planned inspections in summer months, when the consumption – and subsequently the electricity prices – are low. Comparing the nuclear availabilities of 2015 and 2016, the figure shows that especially starting in September, the unavailability in 2016 was higher compared to 2015.

Additional compulsory checks and additional controls on steam-powered turbines, which were necessary during operational checks of nuclear power plants of Areva for many units in France, technical irregularities were witnessed, resulting in extended down-times.

In November and December, the availability was still below 70% and indicated a decade-low generation of nuclear electricity generation of 378 to 385 TWh/a[25]. The unavailability and the uncertainty about resuming normal operation increased prices at spot and futures markets, especially in France and Belgium, as we showed in the second chapter of our market review.

Availability of French Nuclear Power Plants

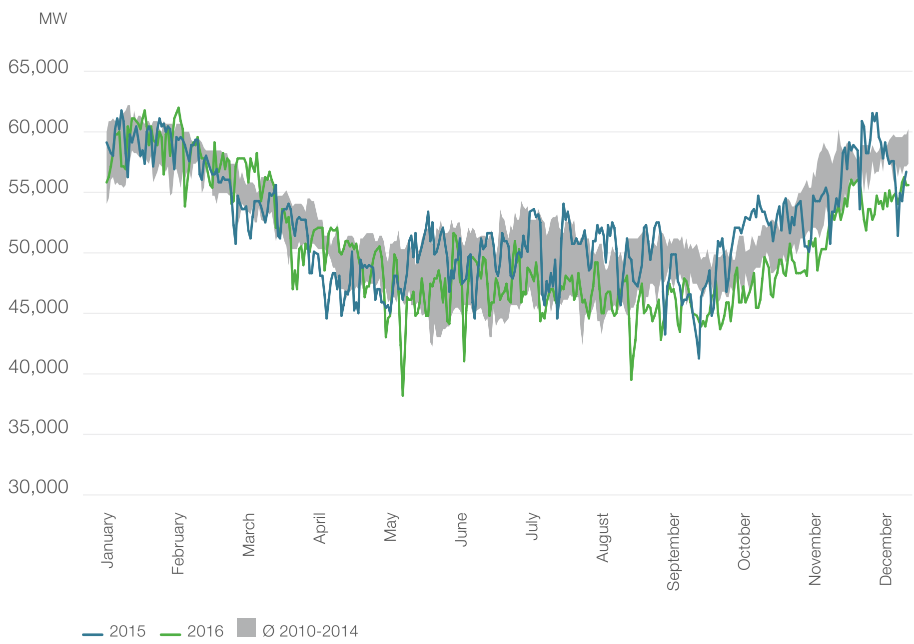


Figure 38: Daily availability of French nuclear power plants. Source: RTE

[25] Source: ICIS.

Special events in 2016

The high unavailability in Belgium and France also had consequences for the intraday markets. In the first two weeks of November 2016, price peaks of almost 1,000 €/MWh were observable in the French intraday market, as Figure 39 illustrates. These peaks mainly occured due to the high load in winter and the simultaneously low availability of nuclear power plants that produced more than 70% of the electricity in France in the last years.

Prices on the French Intraday market

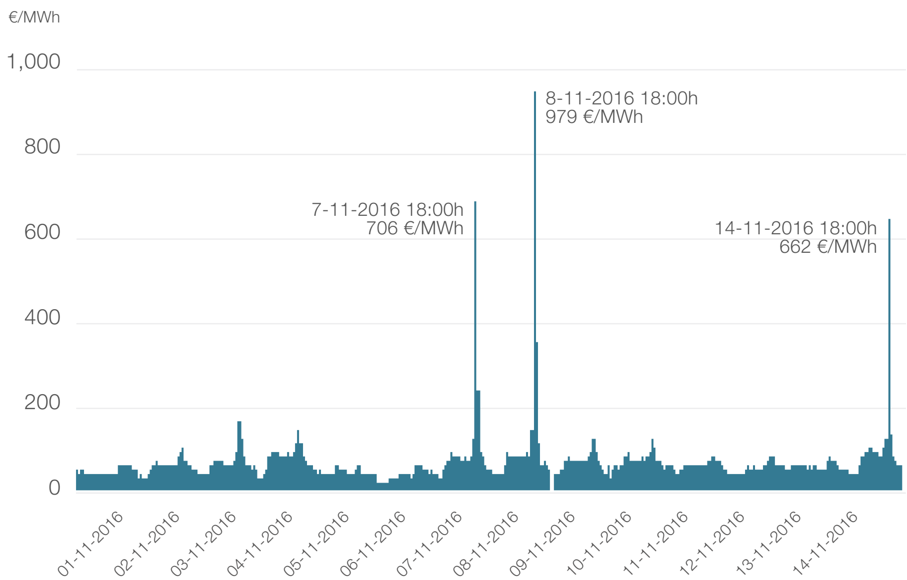


Figure 39: French intraday market in the first two weeks of November 2016. Source: EPEX Spot

b. New players in balancing markets

Besides the unavailability of nuclear power plants in France and Belgium, another special event was the market entry of many new players in the balancing markets. Some examples from Germany and the Netherlands are presented in the following sections.

i. New types of prequalified units

Within the TenneT German LFC Area, many new small scale technologies are nowadays prequalified to participate in balancing markets. Examples are power-to-gas and power-to-heat technologies providing negative automatic FRR (aFRR). Furthermore, wind farms may be prequalified for negative manual FRR (mFRR) products and large scale batteries can be prequalified for the FCR market. Due to aggregation possibilities, the e-mobility sector is capable of participating in the negative FRR markets as well. The total availability of small scale technology (units smaller than 100 MW) within the TenneT German LFC Area is potentially capable of covering the total balancing demand.

ii. Introduction of ‘pq prequalification portal’

In 2016, TenneT implemented a new prequalification portal in Germany, together with the other three German TSOs. Since the German “Energiewende”, more small scale flexibility has been incentivized to participate in balancing markets. The large number of new Balance Service Providers increased the necessary effort of prequalification in the ‘old’ prequalification process because the TSOs have to check each technical unit separately. To increase the simplicity and transparency of the prequalification process, the new prequalification portal was implemented. The new portal has been operational since Q3 2016, since Q4 2016 all new prequalifications have been conducted on the platform.

Special events in 2016

iii. STEAG batteries in Germany and AES in the Netherlands

A couple of new players entered the market for FCR in Germany and the Netherlands. With STEAG, the first company in Germany started investing in battery systems explicitly for FCR. STEAG brought six large-scale battery systems totaling 90 MW[26] online in 2016. Germany's share of providing FCR amounts to about 583 MW. Comparing this to the new installed capacities from batteries shows that the STEAG batteries can provide about 16% of the allocated demand for FCR in Germany. In the Netherlands, AES Corp. installed a 10 MW Lithium-ion battery system providing FCR from the Zeeland Province[27]. Since batteries have very low operating costs, the new installed systems are likely to have an impact on this market.

iv. Wind power plants providing mFRR

As on the FCR market, there are new players on the markets for FRR. In Germany, a pilot project was started in 2016 testing the contribution of wind turbines for mFRR. On average, the four German TSOs procure a total of about 4000 MW (upward as well as downward) of frequency restoration reserves (both aFRR and mFRR). With the increased share of RES, these technologies are intended to provide mFRR as well. As the first company in Germany, Statkraft has participated in the German balancing market with a pool of wind turbines since February 2016.

v. EV charging station (The New Motion)

Another new player on the balancing market in the Netherlands are EV charging stations. A company called *The New Motion* has aggregated more than 19,000 electric vehicle charging stations starting from January 2016 to provide FCR by adjusting the charging behavior of the individual electric vehicles[28]. Each charging point can deliver frequency support and has an integrated vehicle-to-grid technology enabling the discharging of the vehicle's battery as well.

[26] Source: STEAG.
[27] Source: AES energy storage.
[28] Source: The New Motion.

RES and subsidies

New developments regarding regulation, subsidies and costs of RES were able to be observed in 2016. The German EEG[29]-levy continued its upward trend and reached new record high values. Similar to the German EEG-levy the SDE+ budget in the Netherlands also increased significantly in 2016.

The average EEG-feed-in tariff ("EEG-Einspeisevergütung") decreased again, with RES becoming more competitive compared to conventional power plants. The German EEG was updated in 2016, linking grid infrastructure to the expansion of RES and introducing auctions for the installation of new RES. The competitive bidding for RES in a pilot project showed decreasing investment costs in 2016 for offshore wind turbines.

a. Background

The electricity produced by RES must be subsidized in order to incentivize and guarantee a reliable investment in most cases.

In Germany, two main subsidy schemes are being applied. One possibility is a feed-in tariff, called "EEG-Einspeisevergütung". Here, the TSO buys the electricity from his DSO and the DSO buys it from the connected producers for a fixed price, which is determined in Germany by a feed-in tariff for each unit. To earn the money for the "EEG-Einspeisevergütung", the system operator is obligated to sell the RES generation on the day-ahead and intraday market. The difference between the market price he gets for the electricity and the feed-in tariff he has to pay for buying the electricity is one basis for calculating the EEG-levy.

Another possibility exists through direct commercialization ("Direktvermarktung"), where RES operators sell their energy on the spot markets and additionally receive a market premium ("Marktprämie") covering basically the difference between feed-in tariff and market price and an additional premium ("Managementprämie") for their expenditures in management. "Marktprämie" and "Managementprämie" are also funded by the EEG-levy. This promotional instrument puts RES closer to the markets.

With decreasing costs for new RES systems, the subsidization is lowered, since RES become more competitive.

b. Development of German and Dutch levies

With the increasing generation of RES and low spot market prices, the German EEG-levy rises. As Figure 40 depicts, the price for the EEG-levy started at 2 cent/kWh in 2010. By 2016, the EEG-levy reached 6.3 cent/kWh. For 2017, the EEG-levy is set to be 6.8 cent/kWh. Each end consumer of electricity pays the EEG-levy as part of the price of every consumed kWh.

[29] EEG: Erneuerbare-Energien-Gesetz: The Renewable Energy Sources Act is a series of German laws that originally provided a feed-in tariff scheme to encourage the generation of renewable electricity.

RES and subsidies

EEG Umlage

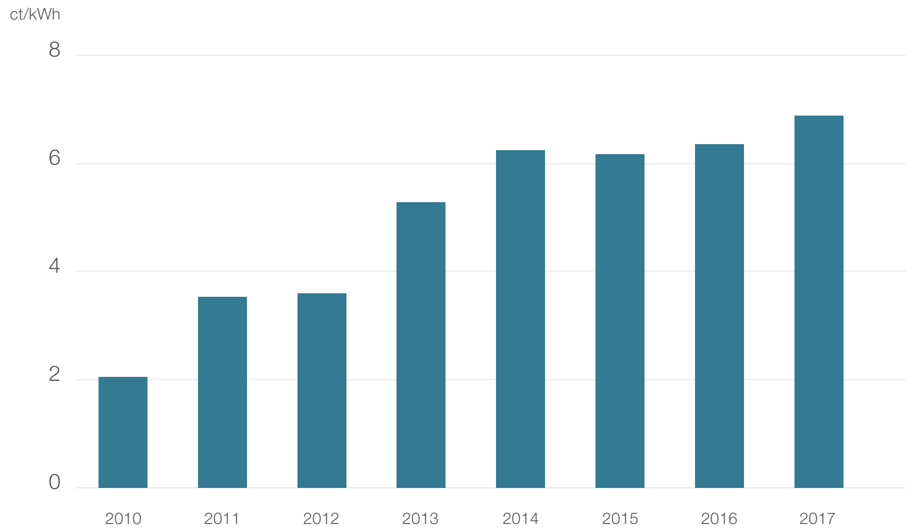


Figure 40: Development of German EEG-Umlage 2010 to 2017. Source: Bundesnetzagentur

Budget of SDE+

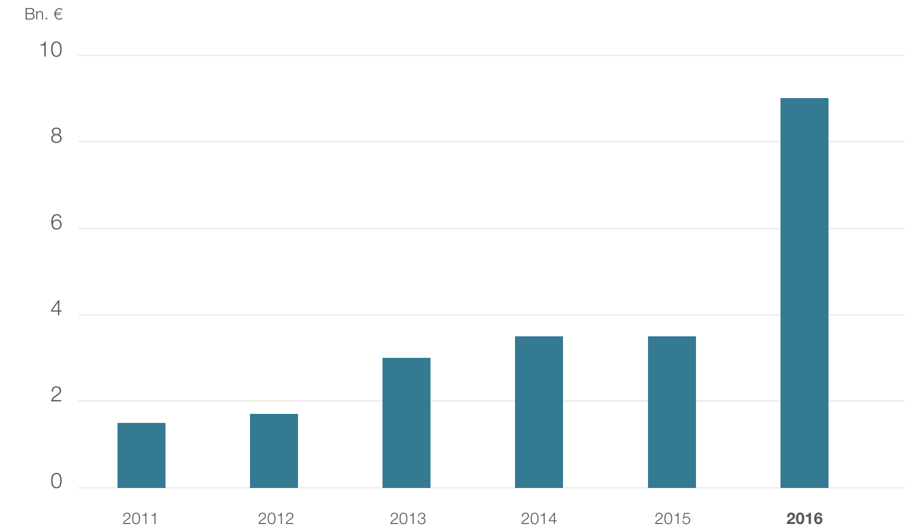


Figure 41: Development of SDE+ from 2011 to 2016. Source: IEA

A similar principle is in place in the Netherlands, called "Stimulering Duurzame Energieproductie" (SDE+). In this system, there is a fixed budget for every year for paying an operating subsidy. Producers receive a guaranteed payment for the electricity they generate from renewable sources. The generation of renewable energy is not always competitive and it can cost more than fossil energy. The SDE+ compensates for the difference in price between fossil and renewable energy over a period of eight, twelve or 15 years, depending on the RES technology. Figure 41 shows the budget for SDE+ that has increased since 2011. There was a major increase from 2015 to 2016 to reach the goals for RES in the Netherlands.

RES and subsidies

i. German subsidies for Wind, Solar and Biomass

The average subsidies for renewable energy systems from 2004 to 2016 are depicted in Figure 42. The graph shows that the average subsidy from wind onshore systems is almost constant at about 9.1 cent/kWh, whereas the average subsidy for biomass started with an average subsidy of 9 cent/kWh in 2004 and increased to 20.6 cent/kWh in 2016. The subsidy for solar systems decreased from about 53 cent/kWh in 2005 to 30.6 cent/kWh in 2016, which equals a drop of about 40%. For offshore wind turbines, there was the regular "EEG-Einspeisevergütung" from 2009 to 2012. After this, offshore wind turbines were backed by another form of subsidy. Starting in 2017, new subsidy regulations will also be available.

Average "EEG-Einspeisevergütung" *

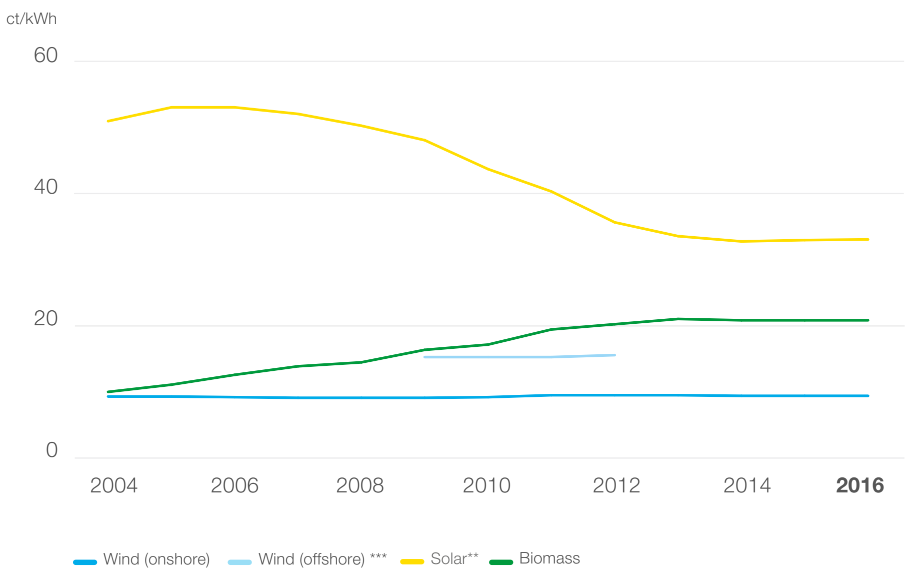


Figure 42: German average "EEG-Einspeisevergütung" in cent/kWh. Source: BDEW

* Average subsidy of the assured "Einspeisevergütung" for all units and the corresponding year.
** "Selbstverbrauchungsregelung" is taken into account.
*** For wind offshore after 2013 only "Direktvermarktung".

RES and subsidies

c. Updated EEG

In 2016, the German government updated the law for RES – the EEG. The major changes resulted from a new mechanism for identifying remunerated projects. In order to lower the overall costs for RES by introducing competition among investors, investors have to win auctions for funding.

In order to test the new auction design, a pilot project for the auction of ground-mounted solar panels was started and showed lower prices than in other market designs. In the coming years, there will also be auctions for onshore wind, offshore wind, solar and biomass. The amount of auctioned RES capacity will be set to the expansion path determined by the German government.

Further major changes resulted from the coupling of the network development and installation of RES. Its aim is to narrow the number of RES installations in areas where the grid is too weak to integrate many RES. In the new EEG this region is called "Netzausbaugebiet". The exact area of the "Netzausbaugebiet" will be determined in a separate process.

From 2017, in the regions with network development delays, the subsidized amount of expansion of RES will be reduced to 58% of the average amount of yearly installed capacity from 2013 to 2015. In November 2016, a first draft of the location for the "Netzausbaugebiet" was published. The suggested distribution is illustrated in Figure 43. As Figure 43 shows, the drafted "Netzausbaugebiet" is located in northern Germany, where most of the German wind turbines are installed today.

Proposed "Netzausbaugebiet"

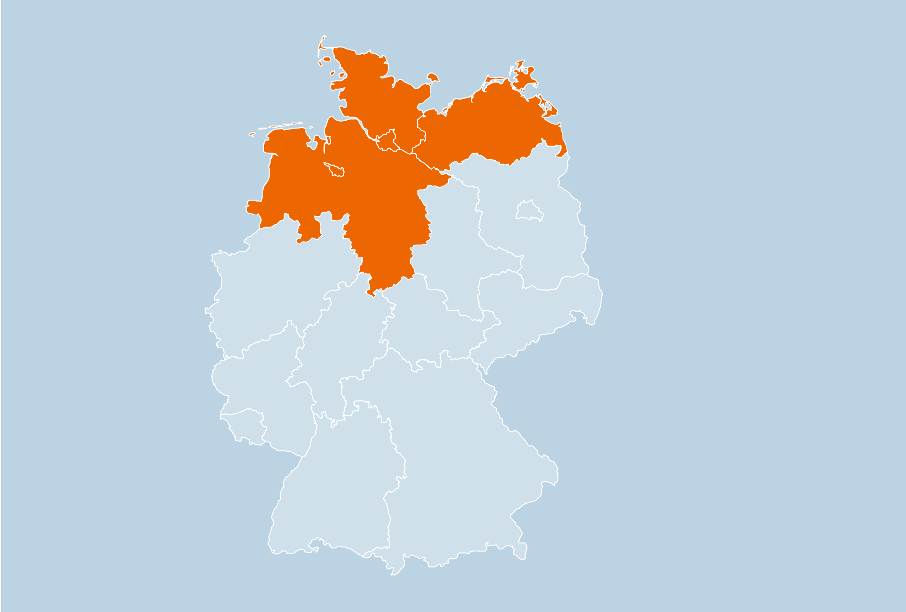


Figure 43: „Proposed Netzausbaugebiet". Source: Bundesnetzagentur, Entwurf Netzausbaugebietsverordnung

RES and subsidies

d. Competitive bidding for new RES

Since April 2015, there is a pilot project for auctions regarding new RES capacity in Germany. This pilot project introduces competitive bidding for new ground-mounted solar capacity to evaluate the effect of competition on the price for new RES capacity. Since April 2015, there have been five auctions.

As Figure 44 illustrates, the price for new solar capacity fell from above 9 cent/kWh in 2015 to about 7 cent/kWh in 2016. These prices are below the average "EEG-Einspeisevergütung" for ground-mounted solar capacity. This result indicates that introducing a bidding system makes energy supply by solar cheaper compared to a system with fixed compensation of the "EEG-Einspeisevergütung". Therefore, auctions for all RES have been introduced in the new EEG, to benefit from competition for lower subsidies.

Average Subsidies

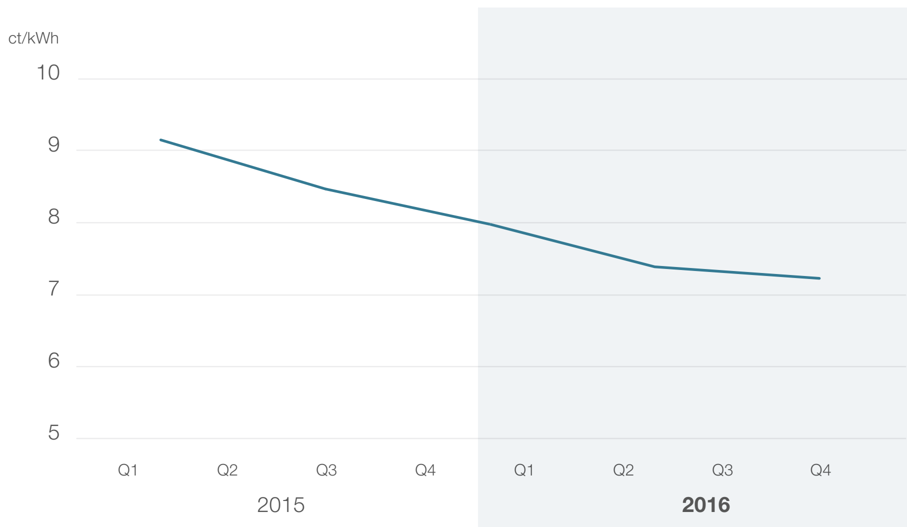


Figure 44: Average subsidies for new solar capacity in pilot project. Source: Bundesnetzagentur Report on solar pilot project

RES and subsidies

e. Costs of offshore wind turbines

Another example of the development of RES costs is the development of levelized costs of electricity (LCOE) and strike prices for offshore wind turbines. In 2011, an industry target was set in order to lower the LCOE of new offshore wind capacity.

Figure 45 illustrates clearly that this industry target (green dots) was already undercut in 2016. There was a surprisingly low price result of the tender process for Borssele I and II wind farms. Borssele I and II achieved a strike price of 73 €/MWh without grid connection, which is expected to be about 15 €/MWh. This is about 25% below the industry's target, including grid connection, for 2020. Another project with very low prices was Vesterhav North and South with prices of only 64 €/MWh. Later in 2016 there were even lower prices for Borssele III (Netherlands) and IV of only 54.5 €/MWh and for Kriegers Flag (Denmark), even below 50 €/MWh. This development shows that offshore wind is becoming increasingly economical and needs less subsidies.

LCOE Development and Strike Prices

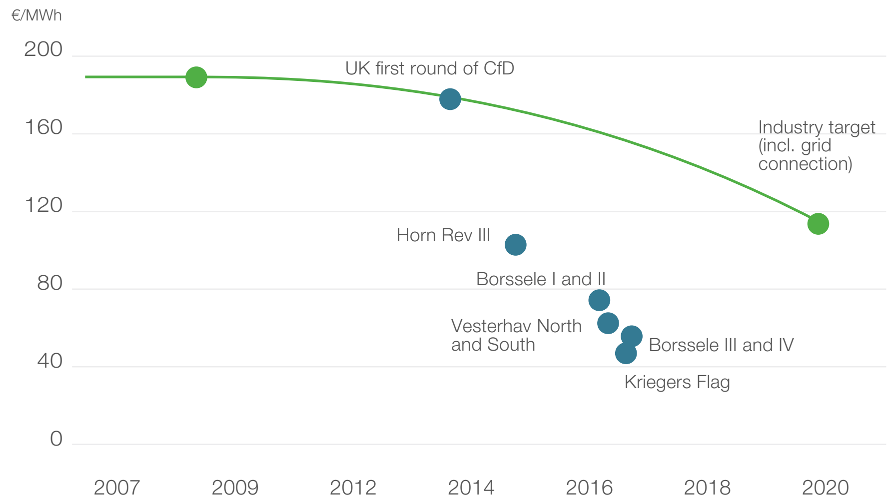


Figure 45: CLOE development and strike prices offshore wind energy.
Source: Roland Berger, energate

Main findings

At the beginning of 2016, electricity prices generally converged within the CWE region. Afterwards, prices diverged into two zones. One price region contained Germany and the Netherlands, and the other included Belgium and France.

The generation costs in the Netherlands and Germany came closer together and therefore they constituted one price region most of the time. Thus, especially Dutch natural gas plants were more competitive in 2016. The higher prices in Belgium and France resulted from low availabilities of nuclear plants. The availability was below 70% at the end of the year and resulted in a decade-low of nuclear electricity generation in France.

This development caused unusual price spikes on the Belgian and French day-ahead and intraday markets. Furthermore, due to these increased generation uncertainties, market participants witnessed higher prices in 2016 at the futures market for 2017.

The electricity consumption in the CWE region was comparable to previous years. The demand in France in January and February of 2016 was slightly lower, mainly due to a reduced usage of electric heating in the mild winter. In the Netherlands and Germany, the generation stack gained RES generation capacities, but the renewable feed-in remained virtually unchanged in 2016.

The monthly net positions in the CWE region changed their direction in the last third of 2016. With the French market area having a negative net position and the Dutch market area having a positive net position, the respective net positions of the two countries inverted. This analysis demonstrates the advantageous flexibility provision through the integrated pan-European electricity market.

In the balancing regime, several European cooperation initiatives took place like the International Grid Control Cooperation (IGCC), which the French TSO RTE joined in 2016. Simultaneously, the common Frequency Containment Reserve tendering process developed further, due to the international cooperation between Switzerland, Austria, Denmark and the Netherlands.

Redispatch volumes in Germany fell in 2016 for the first time since 2013. The decrease in redispatch volumes can be traced back to changed feed-in by renewables due to different weather conditions and grid infrastructure projects.

The German feed-in tariff decreased again, with renewable generation becoming more competitive. The German feed-in tariff was updated in 2016, linking grid infrastructure to the new capacities and introducing auctions for the installation of new renewable generation.

Finally, the current overall wind turbine costs turned out to be lower than expected by the industry, indicating that wind turbines are becoming more competitive.

Colophon

This Market Review is a publication of TenneT

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TenneT Taking power further

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TenneT is a leading European electricity transmission system operator (TSO) with its main activities in the Netherlands and Germany. With 22,500 kilometers of high-voltage connections we ensure a secure supply of electricity to 41 million end-users. We employ approximately 3,000 people, have a turnover of EUR 3.2 billion and an asset value totalling EUR 19 billion. TenneT is one of Europe's major investors in national and cross-border grid connections on land and at sea, bringing together the Northwest European energy markets and enabling the energy transition. We take every effort to meet the needs of society by being responsible, engaged and connected.

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