Bundesnetzagentur Bundeskartellamt

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Report
Monitoring report 2016

Monitoring report 2016

in accordance with section 63(3) i. c. w. section 35 EnWG
and section 48(3) i. c. w. section 53(3) GWB
Data cut-off date: 30. November 2016

Bundesnetzagentur für Elektrizität, Gas, Telekommunikation, Post und Eisenbahnen

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German Energy Act section 63(3)
Reporting

(3) Once a year, the Bundesnetzagentur shall publish a report on its activities and in agreement with the Bundeskartellamt, to the extent that aspects of competition are concerned, on the results of its monitoring activities, and shall submit the report to the European Commission and the Agency for the Cooperation of Energy Regulators (ACER). The report shall include the report by the Bundeskartellamt on the results of its monitoring activities under section 48(3) in conjunction with section 53(3) of the Competition Act as prepared in agreement with the Bundesnetzagentur to the extent that aspects of regulation of the distribution networks are concerned. The report shall include general instructions issued by the Federal Ministry of Economic Affairs and Energy in accordance with section 61.

German Competition Act section 53(3)
Activity report

(3) The Bundeskartellamt shall prepare a report on its monitoring activities under section 48(3) in agreement with the Bundesnetzagentur to the extent that aspects of regulation of the distribution networks are concerned, and shall transmit the report to the Bundesnetzagentur.

Foreword

The energy transition and how it is taking shape continues to be the dominant factor for the energy market in Germany. As in the past, this transition is leading to a noticeable decline in conventionally produced electricity to the benefit of electricity supplied from renewable energy sources. In fact, in 2015 electricity from renewable energy sources already accounted for more than 31% of gross domestic electricity consumption.

In collecting the annual data and in preparing this report, the Bundeskartellamt (Federal Cartel Authority) and the Bundesnetzagentur (Federal Network Agency for Electricity, Gas, Telecommunications, Post and Railway) have continued to work closely together. The Bundeskartellamt focuses on the competitive aspects of the electricity and gas value added chains, whilst the Bundesnetzagentur directs its attention towards the networks, security of supply and delivery to household customers.

Thanks to the commitment of the companies taking part, it has once more been possible to increase market coverage and the validity of the data collected. Thus the degree of coverage, as reflected by the level of response, was well over 90% and in many areas it very nearly reached 100%. An analysis of this data provides a comprehensive, extensive and detailed view of market developments.

Despite economic growth, domestic electricity consumption has fallen slightly. One possible reason for this could be that consumers are achieving greater energy efficiency.

Domestic electricity generation has risen again as a result of increased dispatch of electricity from renewable energy sources. Although power generation from conventional plants has decreased in recent years, an increase in conventional power plant capacity can still be noted. This increase is no doubt due to the long-term nature of the power plant construction projects that had been agreed upon before the energy transition policy. In future, however, a reduction can be expected in the current overcapacity at conventional power plants.

On balance, competition in electricity generation has improved in the period under review. Despite another slight increase last year in the combined market shares of the largest electricity producers in conventional electricity generation, their competitive room to manoeuvre is still limited. One of the causes of this is that a greater proportion of demand is now met by electricity from renewables.

In addition, there is a lot of liquidity on the electricity wholesale markets, which is facilitating market entry.

Consequently, there is no longer any single dominant supplier in either of the two largest electricity retail markets in Germany and the number and variety of suppliers for the consumer to choose from has never been so high. More and more household customers are taking advantage of the opportunity to change their supply contract or their supplier in order to save costs. There has even been a sudden growth in electric heating customers changing their supplier after years of hardly any supplier change whatsoever.

The increase in electricity prices as of 1 April 2016 resulted in a slight rise in prices for household customers compared with the previous year and a slight reduction for industrial and commercial customers.

A fall in gas wholesale prices could be noted in 2015. As a result of this downwards trend, as of 1 April 2016 prices for gas consumers also fell on average compared with the previous year, although essentially non-household customers benefited the most from this trend. In the meantime a liquid wholesale market in natural gas has become established throughout Germany. At the national level there is competition between suppliers in the major retail markets.

The Bundesnetzagentur and the Bundeskartellamt will continue to follow the development of the electricity and gas markets in Germany closely and will play a role in shaping this process within their areas of activity.

Jochen Homann

President
Bundesnetzagentur

Andreas Mundt

President
Bundeskartellamt

Key findings

Electricity generation and security of supply

Total net electricity generation increased by 11.1 TWh from 583.6 TWh in 2014 to 594.7 TWh in 2015. In 2015, electricity generation was characterised by an increase in generation from renewable sources. Generation from conventional sources declined as in the previous years.

The market power of the largest electricity producers has decreased significantly over the last few years. In 2015, the cumulative market share of the four largest electricity producers in the market for the first-time sale of electricity was 69.2%, up 2.2 percentage points on a year earlier but still lower than the share of 72.8% in 2010.

In 2015, the average interruption in supply per connected final consumer was 12.70 minutes and thus below the ten-year average from 2006 to 2015 of 15.87 minutes. The quality of supply thus maintained a consistently high level in 2015.

Development of renewable energy generation

Generation from renewable energy sources accounted for 31.4% of gross electricity consumption in 2015. The net amount of electricity generated from renewable energy sources increased by 26 TWh to 181.1 TWh. The largest growth was in electricity generation from wind, with the amount generated in 2015 totalling 79.1 TWh.

Redispatch and feed-in management

Redispatched energy amounted to around 16,000 GWh in 2015, more than three times as much as in 2014. The transmission system operators (TSOs) put the costs for redispatch actions in 2015 at around €412m.

The curtailment quantity as a result of feed-in management measures almost trebled from 1,581 GWh in 2014 to 4,722 GWh. Compensation payments in 2015 amounted to around €315m. Claims for compensation for 2015 are estimated at €478m.

Electricity network tariffs

There was a slight increase in the network tariffs for household customers. The average charge for household customers on default tariffs was 6.71 ct/kWh, up 0.2 ct/kWh on a year earlier. The charges for non-household customers remained broadly unchanged on the previous year's levels. The network charge, including billing, metering and meter operation charges, for "commercial customers" with an annual consumption of 50 MWh rose by around 0.08 ct/kWh while that for "industrial customers" with an annual consumption of 24 GWh fell by 0.06 ct/kWh.

Wholesale electricity markets

In 2015, the wholesale electricity markets were marked once again by high liquidity. While there were further significant increases in the volumes traded in both spot and futures markets, trading via broker platforms did not show such growth.

There was another decrease in the average wholesale prices in 2015. Base prices on the spot markets averaged €31.63/MWh, down 3% on the previous year. The average base year future price was €30.97/MWh and thus 12% lower.

Retail electricity markets

The Bundeskartellamt assumes that there is no longer any single dominant supplier in either of the two largest electricity retail markets. The cumulative market share of the four largest undertakings in the national market for supplying interval metered customers was 31% and in the market for supplying non-interval metered customers (above all household customers) on non-default tariffs was 36%.

The volume-based switching rate for non-household customers in 2015 was 12.6%, up 1.6 percentage points on the previous year. There was a further increase in the switching rate for household customers. Four million household customers switched electricity supplier in 2015, which is around 231,000 more than a year earlier.

Electricity prices for non-household customers as of 1 April 2016 again showed a slight year-on-year decrease. This is primarily due to a reduction in the price component that can be controlled by the supplier, against an increase in surcharges. Electricity prices for household customers as of 1 April 2016 showed a small increase compared to the previous year. As of 1 April 2016, the average price for household customers with an annual consumption of between 2,500 kWh and 5,000 kWh was 2% up on 2015 at 29.80 ct/kWh (including VAT). Taxes, levies, network tariffs and surcharges account for around 75% of the total price in Germany. According to Eurostat, German household customers continue to pay the second highest electricity prices in Europe. In Germany, taxes, levies and surcharges account for more than 50% of the prices, which is considerably higher than the European average of 33%.

Since 2014 there has been a significant increase in the number of electric heating customers who have switched supplier, following many years with hardly any customers switching. The percentage of electric heating customers served by a supplier other than the local default supplier increased from 4.3% in 2014 to around 6.6% in 2015. The last few years have seen an increase in transparency for end customers and in the services offered by national electric heating suppliers. The consequent switching activity is helping to stimulate competition in the electric heating sector.

Electricity imports and exports

In 2015, as in the previous years, the volume of Germany's electricity exports was considerably higher than that of its imports. Exports increased again from 59.2 TWh in 2014 to 68.0 TWh. Overall, the German export balance rose from 34.5 TWh in 2014 to 51.0 TWh in 2015. Electricity was principally exported to Austria and the Netherlands. The total balance also reflects a decline in imports from 24.7 TWh to 17.0 TWh.

Gas imports and exports

Gas imports and exports decreased slightly compared to the previous year. The volume of gas imported into Germany decreased by some 8.4 TWh from 1,542 TWh to 1,534 TWh. There was also a decrease in exports. The volume of gas exported decreased from 810.1 TWh in 2014 to 746.3 TWh in 2015.

The main sources of imports to Germany remain Russia, Norway and the Netherlands. The main recipients of Germany's exports were Czechia, Switzerland and the Netherlands.

Gas supply interruptions

In 2015, the average interruption in supply per connected final consumer was 1.7 minutes per year. The level of gas supply reliability remained at 99.999%.

Gas storage facilities

The market for the operation of underground natural gas storage facilities is relatively highly concentrated. The aggregate market share at the end of 2015 of the three largest storage facility operators was down slightly at 73.3%. The current storage level at natural gas storage facilities in Germany is high compared to past years. On 1 October 2016, at the beginning of the 2016/2017 gas year, the total storage level of German storage facilities was around 95%.

Wholesale natural gas markets

Varying developments were recorded in the liquidity of the wholesale markets in 2015. While the bilateral wholesale trading volume was down on the previous year, the on-exchange trading volume increased by 38% after even more than doubling in the previous year.

2015 was again marked by lower wholesale gas prices. The various price indices showed a year-on-year decrease of between 6% and 13%.

Retail gas markets

The levels of concentration in the two largest gas retail markets are well below the statutory thresholds for presuming market dominance. The cumulative market share of the three largest undertakings in the market for supplying interval metered customers was 29%, and 22% in the market for supplying non-interval metered gas customers (in particular household customers) under a contract outside the scope of default supply.

The number of customers switching supplier rose again in 2015. More than 1.1m household customers switched gas supplier in 2015. The volume-based supplier switching rate for non-household customers in 2015 was again around 12%, and around 10% for household customers.

The noticeable downward trend in gas retail prices continued. There was a particularly sharp decrease in the prices paid by industrial customers. The average price (excluding VAT) as of 1 April 2016 for "industrial" customers with an annual consumption of 116 GWh was 2.77 ct/kWh (1 April 2015: 3.5 ct/kWh) and thus by far the lowest ever since data on gas prices was first collected for the monitoring reports. There was a considerable decrease in the prices paid by commercial customers.

The average price for household customers across all contract categories (ie default supply contract, non-default contract with the default supplier, and contract with a supplier other than the local default supplier) decreased by about 2.1% to 6.54 ct/kWh (including VAT) as of 1 April 2016 (1 April 2015: 6.68 ct/kWh). For an average level of consumption, default tariffs are about 0.6 ct/kWh more expensive than non-default contracts with the default supplier and about 0.5 ct/kWh more expensive than contracts with a supplier other than the local default supplier.

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1. Summary

1.1 Generation and security of supply

Net electricity generation in Germany in 2015 amounted to 594.7 TWh compared to 583.6 TWh in 2014. Electricity generation from non-renewable energy sources decreased by 15 TWh or 3.5% on the previous year. Nuclear and hard coal power plants recorded the largest decreases in electricity generation. The closure of Grafenrheinfeld nuclear power station led to a reduction in nuclear electricity generation of 6.7 TWh or 7.3%. Generation from hard coal in 2015 was down 5.5 TWh or 4.9% on 2014. Generation from brown coal was 2 TWh or 1.4% lower than a year earlier.

In 2015 generation was characterised by a further increase in capacity from renewables. Altogether, growth in renewables capacity amounted to 7.6 GW, compared to 6.8 GW in 2014. Onshore and offshore wind recorded the highest increases in generation capacity of 3.6 GW and 2.4 GW respectively. Total (net) installed generation capacity thus reached 204.6 GW at the end of December 2015, of which 106.7 GW was non-renewable and 97.9 GW renewable energy capacity.

The market power of the largest electricity producers had decreased significantly in the period after 2010. The market for the first-time sale of electricity (excluding electricity supported under the Renewable Energy Sources Act – EEG) remains highly concentrated, however, with the four largest electricity producers having a cumulative market share of 69.2% relating to the Germany/Austria market area. This represents an increase of 2.2 percentage points on the previous year's share of 67.0%, mainly due to growth recorded by Vattenfall. However, the market share of the four largest producers is still around 3.5 percentage points lower than in 2010. In addition, the closure of the remaining nuclear power plants by 2022 will lead to future changes in the market structure.

The room for manoeuvre in the market for the first-time sale of electricity is limited amongst other things by the fact that since 2009 more electricity generation capacity has been available in Germany and Europe than is required to meet demand. An increasing proportion of the demand is being covered by electricity generated from renewable sources. Better options for importing electricity as a result of progressive market coupling can also help to limit the room for manoeuvre in the market for the first-time sale of electricity, whereas a reduction in cross-border transmission capacity would have the opposite effect.

Generation from renewable energy sources accounted for 31.4% of gross electricity consumption in 2015. The net amount of electricity generated from renewable energy sources increased by 26.0 TWh from 155.1 TWh in 2014 to 181.1 TWh in 2015. This represents a year-on-year increase of 16.8%. The largest growth in absolute terms was in electricity generation from wind, with the amount generated rising by 21.7 TWh to 79.1 TWh. Onshore and offshore wind generation increased year on year by 15 TWh and 6.7 TWh respectively. The amount of electricity generated by solar power was 35.2 TWh, up 2.2 TWh on the previous year.

The total installed capacity of installations in Germany entitled to financial support under the Renewable Energy Sources Act was 93.0 GW as at 31 December 2015, compared to around 85.4 GW a year earlier. This represents an increase in 2015 of around 7.6 GW or 8.2%. A total of 161.8 TWh of electricity from renewable energy installations received support under the Renewable Energy Sources Act. This was 25.8 TWh or 19% more than in the previous year. The total sum paid to the renewable energy installation operators by the operators to whose networks the installations are connected was €24.2bn, a year-on-year increase of 13.4%. As in the past few years, about half of the payments in 2015 – around 52% – again went to installations with fixed feed-in tariffs. The share of the payments made for direct selling was up by 8 percentage points on the previous year.

In 2015 the average interruption in supply per connected final consumer was 12.70 minutes and thus below the ten-year average from 2006 to 2015 of 15.87 minutes. The quality of supply thus maintained a consistently high level in 2015.

1.2 Cross-border trading

The year 2015 was characterised by new record high levels of electricity exports. As the hub for electricity exchange in Europe, Germany continues to play a key role within the central interconnected system. There were changes in 2015 in the average available transmission capacity to and from neighbouring countries. Import and export capacity decreased by about 7% on 2014 to around 19.7 GW. The previous year had seen an increase of about 0.3% on 2013.

There was still an increase in the trade balance, however, with a rise in exports compared to imports and higher usage of the reduced transmission capacity. Total cross-border traded volumes rose from 83.9 TWh in 2014 to 85.0 TWh in 2015, an increase of 1.3%. This reflects a massive decline of 31.3% in imports from 24.7 TWh in 2014 to 17.0 TWh against an increase of 14.9% in exports from 59.2 TWh in 2014 to 68.0 TWh. Electricity was principally exported to Austria and the Netherlands, with an export balance of 28.7 TWh and 16.2 TWh respectively. Overall, there was a substantial increase of 47.8% in the German export balance from 34.5 TWh in 2014 to 51.0 TWh in 2015.

1.3 Networks

1.3.1 Grid expansion

Taking into account the second quarterly report for 2016, 650 km – or around 35% – of the total of about 1,800 km of power lines planned under the Power Grid Expansion Act (EnLAG) have been completed and around 900 km approved. The transmission system operators (TSOs) anticipate that some 45% of the planned lines will be completed by 2017. So far, none of the underground cable pilot lines have been put into operation. The TSO Amprion is currently preparing tests under operating conditions for the first 380 kV underground cable pilot project in Raesfeld.

The Bundesnetzagentur approved the scenario framework for 2017 to 2030 on 30 June 2016. The framework provides the basis for the forthcoming network development plan for 2017 to 2030. The TSOs are to publish a draft electricity network development plan for 2017 to 2030 based on the approved scenario framework by 10 December 2016 in accordance with section 12b(3) third sentence of the Energy Act (EnWG).

Alongside monitoring the Power Grid Expansion Act projects, the Bundesnetzagentur publishes quarterly updates on the status of the expansion projects under the Federal Requirements Plan Act (BBPlG). These projects currently comprise lines with a total length of around 6,100 km. At the third quarter of 2016 around 350 km had been approved and about 80 km completed. Eight of the 43 projects have been designated as pilot projects for low-loss transmission over long distances (high-voltage direct current transmission). Five direct current projects have been earmarked for priority underground cabling and five alternating current projects for partial underground cabling. In addition, one project is a pilot project using high-temperature conductors and two are submarine cable projects.

1.3.2 Investments

In 2015 investments in and expenditure on network infrastructure by the four German TSOs amounted to €2,361m compared to €1,796m in 2014. Investments in new builds, upgrades and expansion projects increased from €1,248m in 2014 to €1,673m in 2015. The investments and expenditure incurred by the distribution system operators (DSOs) rose from €6,193m in 2014 to €6,845m in 2015. There was an increase in the number of DSOs carrying out measures to enhance, reinforce or expand their networks as at 1 April 2016.

1.3.3 Network and system security and system stability

The TSOs' redispatch actions serve to maintain network and system security. In 2015, redispatch actions amounted to 15,811 hours, representing a significant increase from 8,453 hours in 2014. Redispatch actions were taken by the operators on a total of 331 days in 2015 and comprised a total volume of 16,000 GWh compared to 5,197 GWh in 2014. Reductions through redispatch actions corresponded to 1.9% of total generation from non-renewable energy installations, up from 0.6% in the previous year. The TSOs put the costs of system services for redispatch actions in 2015 at around €412m. As in the previous years, the actions primarily concerned the TenneT and 50Hertz control areas, with the line between Remptendorf and Redwitz, the Brunsbüttel area (north of Hamburg) and the line from Vierraden to Krajnik in Poland the most affected.

In 2015 a total of six DSOs and one TSO took adjustment measures for conventional installations without compensation. The measures taken to adjust electricity feed-in and offtake comprised a total of around 26.5 GWh.

The curtailment quantity as a result of feed-in management measures increased substantially from 1,581 GWh in 2014 to 4,722 GWh in 2015, and was thus almost three times higher than in the previous year. This corresponds to 2.6% of the total amount of energy generated by renewable energy installations, compared to 1% in 2014. The sum total of compensation payments also increased significantly from €83m in 2014 to €315m in 2015. In total, claims for compensation from installation operators for 2015 are estimated at €478m.

In 2015, as in the previous years, feed-in management measures primarily involved wind power stations, accounting for 87.3% of the total amount of unused energy, up from 77.3% in 2014. For the first time, offshore wind installations were also affected by feed-in management measures in 2015, accounting for around 16 GWh or 0.3% of the total amount of unused energy. Biomass replaced solar as the second leading energy type affected in 2015 by curtailments, with a share of almost 8%.

In total, the costs for network and system security[1] increased substantially by about €696m from €436m in 2014 to around €1,133m in 2015. This is primarily due to the large increase in the number of network and system security measures taken in 2015.

The TSOs were required to maintain 7,515 MW of reserve capacity to ensure network stability in the winter of 2015/2016. The reserve procured comprised just under 3,000 MW from Germany and around 4,500 MW from foreign power stations.

Compared to the previous years the TSOs used the reserve power plants very frequently during the winter half-year of 2015/2016, with the plants providing power on a total of 93 days. The reason here is that as of November 2015 deployment decisions also take into account which plants are most efficient to alleviate the predicted shortages.

1.3.4 Network tariffs

The network tariffs for household customers increased slightly. The charges for non-household customers remained broadly unchanged on the previous year's levels. The charges as of 1 April 2016 for the three consumption groups were as follows:

- household customers (default tariff), annual consumption 2,500-5,000 kWh: 6.71 ct/kWh;
- "commercial customers", annual consumption 50 MWh: 5.85 ct/kWh;
- "industrial customers", annual consumption 24 GWh, without a reduction under section 19(2) of the Electricity Network tariffs Ordinance (StromNEV): 2.06 ct/kWh.

1.4 Ancillary services

The net costs of ancillary services increased by €284m from €1,029m in 2014 to €1,313m in 2015. A large part of the costs is accounted for by the costs of national and cross-border redispatch – up from €185m in 2014 to almost €412m, procuring primary, secondary and tertiary control reserves – down from €437m in 2014 to just under €316m, and energy to compensate for losses – at around €277m compared to €288m in 2014. The structure of the system service costs changed considerably in 2015 from 2014. There was a further decrease – of €121m – in the total net costs for balancing, as a result in particular of the lower costs for secondary and tertiary reserves, down €73m and €56m respectively. By contrast, there was a small increase of €8m in the costs for primary reserve. The costs for energy to compensate for losses in 2015 were down by around €10m on 2014.

1.5 Wholesale

Well-functioning wholesale markets are fundamental to competition in the electricity sector. Spot and futures markets are crucial for meeting suppliers' short and longer term electricity requirements. Power exchanges play a key role alongside bilateral, over-the-counter (OTC) wholesale trading. They create a reliable trading

[1] The operators use feed-in management, redispatch, reserve power plants and countertrading to maintain network and system security.

forum and at the same time provide important price signals for market participants in other electricity sectors.

Adequate liquidity with sufficient volume on both the supply and the demand side improves opportunities for new suppliers to enter the market. In 2015 the wholesale electricity markets were marked once again by high liquidity, with a further increase in the liquidity of the spot and future markets compared to the previous year. The volume of day-ahead trading on EPEX SPOT and EXAA increased slightly whilst the volume of intraday trading on EPEX SPOT grew by 45%. The volume of electricity futures contracts traded on EEX rose by 15% from 812 TWh to 937 TWh. While futures trading via broker platforms did not show such growth, OTC clearing of futures contracts on EEX increased year on year by more than half from 557 TWh in 2014 to 877 TWh in 2015, a rise of around 57%.

There was a further decrease in the average wholesale prices in 2015. Average prices on the spot markets fell year on year, with Phelix Day Base and Phelix Day Peak prices down by 3% and 5% respectively. Despite lower peak prices, the average daily price dispersion was greater than in the previous year. Prices for electricity futures also fell further in 2015. At €30.97/MWh, the average Phelix Base Year Future price in 2015 was €4.12/MWh or around 12% lower than the average for 2014 of €35.09/MWh. The average Phelix Peak Year Future price in 2015 was €39.06/MWh. This was €5.34/MWh and also 12% lower than the average for 2014 of €44.40/MWh. Compared to the all-time peak reached in 2008, the downward trend in base and peak year prices continues. In addition to the changes introduced since the end of 2014 (separate intraday auctions for 15-minute contracts; shorter minimum lead time for intraday trading on EPEX SPOT; trading of electricity contracts for German/Austrian control areas possible up to 30 minutes before delivery since July 2015), trading of Cap Futures (weekly contracts) was introduced in September 2015 as a hedge against price peaks in light of the increasing share of renewables in the market.

The sales volumes of the TSOs using the power exchanges primarily to market electricity from renewables decreased again year on year. The percentage of electricity sold by the TSOs on EPEX SPOT fell from 38% in 2011 to 18% in 2015. This is a result of the increase in the amount of renewable electricity sold directly.

1.6 Retail

There was a further increase in the number of electricity suppliers available to retail customers. In 2015 final consumers could choose between an average of 115 suppliers in each network area (not taking account of corporate groups). The average number of suppliers for household customers was 99.

The number of household customers switching supplier has increased significantly since 2006, with around 4m switching in 2015. In addition, almost 1.7m household customers have switched energy tariff with their supplier. In 2015 a relative majority of household customers – 43.1% compared to 43.2% in 2014 – were on tariffs other than the default tariff with their regional default supplier. The percentage of household customers on default tariffs was 32.1%, representing another year-on-year decrease from 32.8% in 2014. 24.9% of all household customers are now served by a supplier other than their regional default supplier, compared to 24% in 2014. There was a corresponding increase again in the percentage of customers who no longer have a contract with their default supplier. Overall, around 75% of all households are served by their default supplier (on either default or other tariffs). Thus the strong position that default suppliers still have in their respective service areas weakened further in the year under review.

By contrast, default suppliers play a relatively small role in serving non-household customers. Around 68% of the total amount of electricity delivered to interval metered customers in 2015 was supplied by a legal entity other than the regional default supplier, while only about 32% was supplied on contracts with the default supplier outside of default supply contracts. Less than 1% of all interval metered customers are on standard tariffs with their default supplier. The supplier switching rate for non-household customers in 2015 was about 13%, the highest since monitoring started in 2006. The switching rates show that since then between around 10.5% and 12.5% – and thus a significant proportion – of non-household customers have switched supplier every year.

The Bundeskartellamt assumes that there is no longer any single dominant supplier in either of the two largest electricity retail markets. The cumulative market share of the four largest undertakings in the national market for supplying interval metered customers was 31%, down two percentage points on 2014. The cumulative share in the national market for supplying non-interval metered customers (above all household customers, excluding electric heating customers) on non-default tariffs remained unchanged from 2014 at 36%. These figures are considerably lower than the statutory thresholds for presuming market dominance.

The number of household customers whose supply was disconnected by the network operator at the regional default supplier's request fell in 2015 by 20,000 to 331,273. For the first time, the suppliers were also asked to provide data on disconnections for household customers on non-default tariffs. In total, about 359,000 customers across all tariffs were disconnected in 2015. In addition, suppliers issued around 6.3m disconnection notices to household customers. Of these, about 1.6m were subsequently passed on to the relevant network operator for disconnection. These figures are based on data provided by 768 DSOs and 998 suppliers. Data was again collected on the use – at the default suppliers' request – of prepay systems such as pay-as-you-go meters using cash or smart cards. In total, around 19,400 prepay systems were installed in 2015.

Electricity prices for non-household customers as of 1 April 2016 showed a slight year-on-year decrease. This is most probably due to the drop in wholesale electricity prices. The individual price for industrial customers depends to a large extent on special statutory regulations enabling certain price components to be reduced. These regulations aim primarily to reduce prices for electricity-intensive undertakings. The average price as of 1 April 2016 for customers with an annual consumption of 24 GWh and not entitled to reductions was around 14.21 ct/kWh (excluding VAT), of which 10.72 ct/kWh was accounted for by surcharges, taxes, network tariffs and levies. This would be higher than the European average. The state-controlled surcharges, taxes, network tariffs and levies for industrial customers entitled to reductions could fall from 10.72 ct/kWh to below 1 ct/kWh, depending on the individual circumstances. This would then result in electricity prices for industrial customers that are lower than the European average. The average electricity price as of 1 April 2016 for non-household customers with an annual consumption of 50 MWh was around 21.20 ct/kWh (excluding VAT).

For the first time data was collected in 2016 on the prices for household customers in four different consumption bands. Following a slight fall in the previous year, the prices again showed a small increase in the year under review. As of 1 April 2016, the average price for household customers on default tariffs with an annual consumption of between 2,500 kWh and 5,000 kWh (comparable to the previous year's 3,500 kWh consumption band) had risen year on year by 1.8% to 30.63 ct/kWh (including VAT). Prices for the two other customer groups – those on other tariffs with their default supplier and those with another supplier – also increased slightly. Electricity prices for customers on other tariffs with their default supplier and with an annual consumption of between 2,500 kWh and 5,000 kWh averaged 29.01 ct/kWh and for customers with another supplier were an average 28.17 ct/kWh. The volume-weighted average across all three groups for an annual consumption of between 2,500 kWh and 5,000 kWh was 29.80 ct/kWh (including VAT). In a European comparison only Denmark has higher electricity prices than Germany. Germany's high prices are due to a heavy burden of surcharges, taxes and levies. There was a further increase in the state-determined price components of the offshore liability surcharge and the surcharges payable under the Renewable Energy Sources Act, the Combined Heat and Power Act (KWKG) and section 19 of the Electricity Network tariffs Ordinance. The renewable energy surcharge is used to balance out the renewable energy costs incurred by the TSOs and the income generated from selling renewable energy on the spot market, and alone accounts for more than 21% of the prices. Network tariffs also rose. The price components not controlled by the supplier (taxes, levies, surcharges and network tariffs) amount in total to about 75%. The competitive component of the electricity price found in "energy procurement, supply, other costs and the margin" accounts for around 25% of average total prices.

As of 1 April 2016, there was another decrease – of around 3% – in the "energy procurement, supply, other costs and the margin" component of the price, leading to a dampening effect on overall prices. This component has again fallen in all household customer tariff categories. The decrease could be related in particular to the drop in wholesale prices.

As a rule, customers on default tariffs can make savings by switching tariff and even more by switching supplier. Special bonuses offered by suppliers are an added incentive for customers to switch supplier.

Since 2014 there has been a significant increase in the number of electric heating customers who have switched supplier, following many years with hardly any customers switching. The last two years have seen an increase in transparency for end customers and in the services offered by national electric heating suppliers. The percentage of electric heating customers (meter points) served in 2015 by a supplier other than the regional default supplier was more than 6%, up two percentage points on a year earlier. Electric heating prices were broadly unchanged compared to the previous year. The average price as of 1 April 2016 for electric storage heating customers with an annual consumption of 7,500 kWh was around 20.59 ct/kWh, and 21.33 ct/kWh for heat pump customers.

2. Network overview

Network structure figures 2015

	TSOs	DSOs	Total
Network operators (number)	4	817	821
Total circuit length (km)	36,001	1,780,856	1,816,857
Extra high voltage	35,610	360	35,970
High voltage	391	96,267	96,658
Medium voltage	0	511,164	511,164
Low voltage	0	1,173,065	1,173,065
Total final consumers (meter points)	535	50,298,514	50,299,049
Industrial, commercial and other non-household customers		3,015,426	3,015,426
Household customers		47,283,088	47,283,088

Table 1: Network structure figures 2015

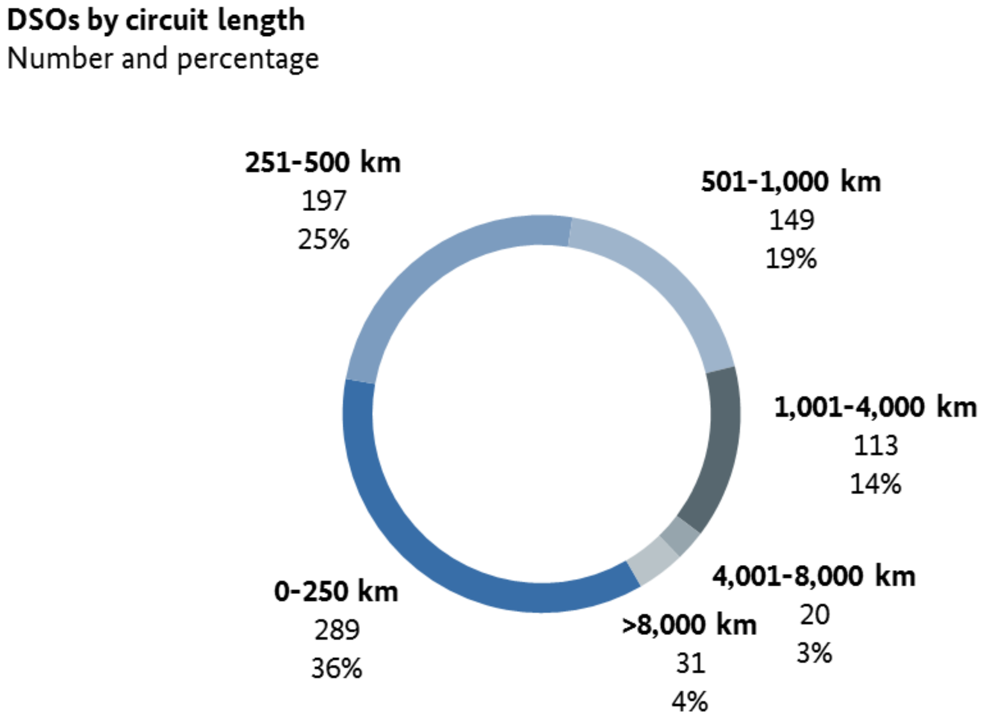

Figure 1: Distribution system operators by circuit length

Network balance 2015

	TSOs	DSOs	Total
Total net nominal generation capacity as of 31 December 2015 (GW)			204.6
Facilities using non-renewable energy sources			106.7
Facilities using renewable energy sources			97.9
Generation facilities eligible for support under the Renewable Energy Sources Act			93.0
Total net generation 2015 (including electricity not fed into general supply networks) (TWh)			594.7
Facilities using non-renewable energy sources			413.6
Facilities using renewable energy sources			181.1
Generation facilities eligible for support under the Renewable Energy Sources Act			161.8
Net amount of electricity not fed into general supply networks 2015 (TWh)[1]			34.9
Losses (TWh)	8.1	17.7	25.8
Extra high voltage	6.4	0.0	6.4
High voltage (including EHV/HV)	1.7	3.2	4.9
Medium voltage (including HV/MV)	0.0	5.8	5.8
Low voltage (including MV/LV)	0.0	8.7	8.7
Cross-border flows (physical flows) (TWh)			111.2
Imports			32.1
Exports			79.1
Consumption (TWh)[2]	38.3	449.7	488.0
Industrial, commercial and other non-household customers	27.4	327.8	355.2
Household customers	0.0	120.7	120.7
Pumped storage	10.9	1.2	12.1

[1] Own use by industrial, commercial and domestic users, excluding consumption by Deutsche Bahn AG for traction purposes
[2] Including consumption by Deutsche Bahn AG for traction purposes

Table 2: Network balance 2015

The network balance 2015 provides an overview of supply and demand in the German electricity grid in 2015. Total electricity supply was 626.8 TWh, comprising a net total of electricity generated of 594.7 TWh (including 10.1 TWh from pumped storage) and imports through physical flows amounting to 32.1 TWh. Total electricity consumption from general supply networks was 488 TWh, comprising 475.9 TWh for final consumers and 12.1 TWh for pumped storage stations. Pumped storage stations generally consume more than they generate because of the electricity used for generation. The net total of electricity generated but not fed into general supply networks (industrial, commercial and domestic own use) was 34.9 TWh. Distribution and transmission losses amounted to 25.8 TWh and exports through physical flows 79.1 TWh. The sum of the individual entries for demand is 627.8 TWh. The statistical difference between this and the total supply of 626.8 TWh is 1 TWh or 0.16%.

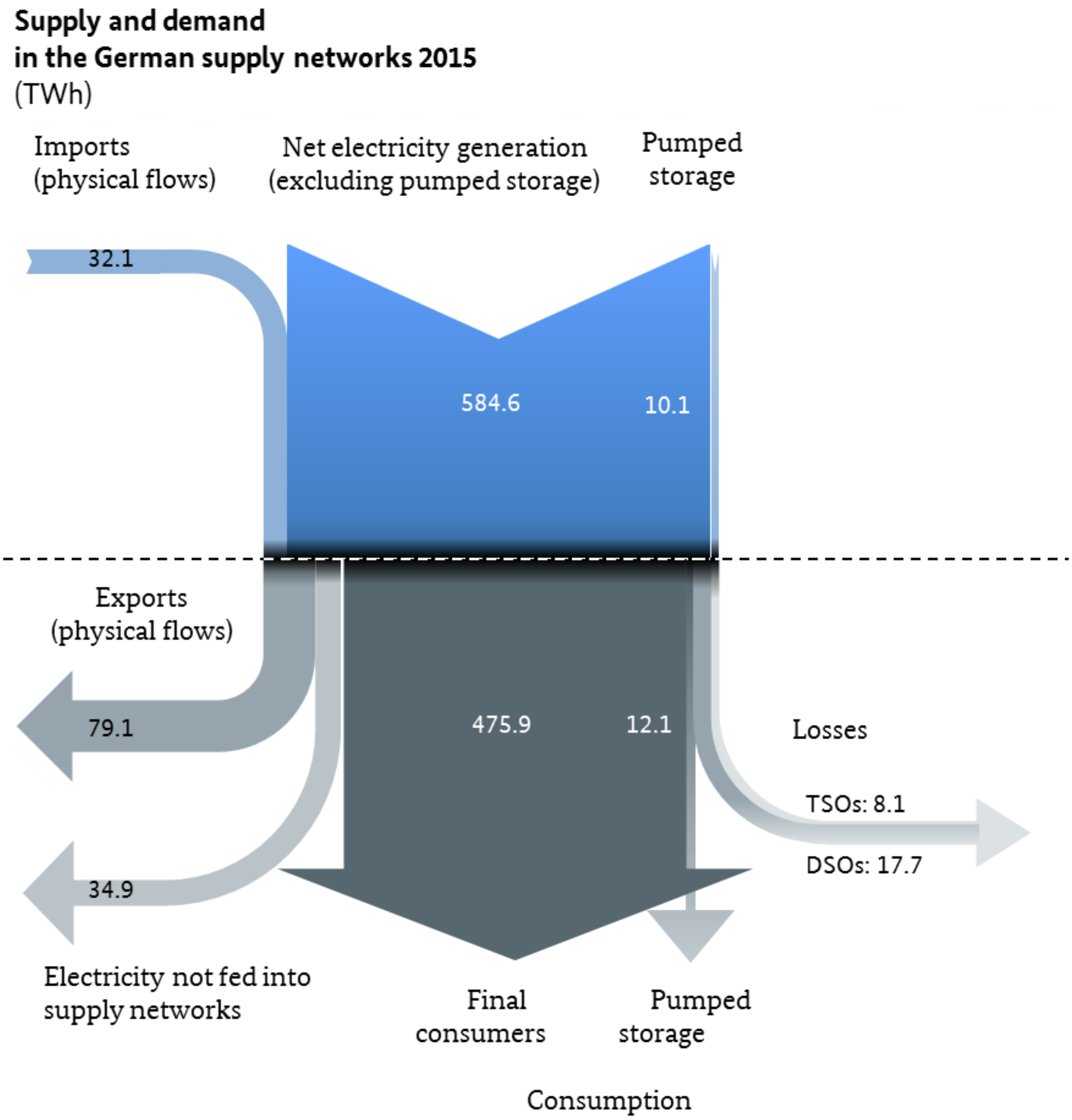

Figure 2: Supply and demand in the German supply networks 2015[2]

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[2] On account of the methodology used, exports and imports were determined on the basis of the physical flows instead of the exchange schedules as in the 2015 monitoring report.

The four German TSOs took part in the 2016 monitoring survey. The TSOs' total circuit length (overhead lines and underground cables) was 36,001 km as of 31 December 2015 (see Table 1 on page 26). This represents an increase of 1,389 km on 2014. The total number of meter points in the four TSOs' network areas was 535, all of which were interval metered, ie average consumption was recorded at least quarter hourly. The offtake of the 153 final consumers connected to the TSOs' networks totalled 27.4 TWh as of 31 December 2015, representing a year-on-year decrease of around 1 TWh.

As of 17 August 2016 a total of 879 electricity DSOs were registered with the Bundesnetzagentur, 817 of whom took part in the 2016 survey. According to these 817 DSOs, the offtake of the 48,597,340 final consumers connected to the DSOs' networks totalled 448.5 TWh in 2015, a decrease of about 10 TWh on the previous year.

The DSOs' total circuit length (overhead lines and underground cables) at all network levels was 1,780,856 km as of 31 December 2015. The total number of meter points supplied in the DSOs' network areas was 50,298,514, including 368,794 interval meters and 47,283,088 meter points for household customers as defined in section 3 para 22 of the Energy Act.

Number of TSOs and DSOs in Germany

	2008	2009	2010	2011	2012	2013	2014	2015	2016
Total TSOs	4	4	4	4	4	4	4	4	4
Total DSOs	855	862	866	869	883	883	884	880	875
DSOs with fewer than 100,000 connected customers	779	787	790	793	807	812	812	803	798

Table 3: Number of TSOs and DSOs in Germany 2008 to 2016

The majority of DSOs (627 or 79%) have networks with a short to medium circuit length (lines and cables) of up to 1,000 km, supplying 7.2m or 14% of all meter points in Germany. 171 DSOs have networks with a total circuit length of more than 1,000 km, supplying 43m or about 85% of the total number of meter points. Figure 1 on page 26 shows a breakdown of DSOs by circuit length.

The following table shows the consumption of electricity in 2015 by final consumers in the network areas of the TSOs and DSOs participating in the survey.

Final consumption by customer category

Category	TSOs (TWh)	DSOs (TWh)	TSOs + DSOs (TWh)	Percentage of total (%)
≤10 MWh/year	0	120.7	120.7	25.4
10 MWh/year - 2 GWh/year	0.1	123.7	123.8	26.0
>2 GWh/year	27.3	204.1	231.4	48.7
Total	27.4	448.5	475.9	100.0

Table 4: Final consumption by customer category based on data from DSOs and TSOs[3]

Overall, final electricity consumption in Germany, based on consumption at meter points in general supply networks, was around 11.6 TWh or 2.4% down on a year earlier.

Although the number of non-household customers with an annual consumption of more than 2 GWh is relatively small, these customers account for nearly half of the total electricity consumption in Germany. Consumption by these large consumers was down nearly 5% from the previous year. Smaller non-household customers (annual consumption >10 MWh and ≤2 GWh) accounted for 26% of total consumption in 2015, nearly 1% down on a year earlier. The largest customer group in terms of numbers comprises final consumers with an annual consumption of ≤10 MWh and almost entirely household customers. This group accounted for about 25.4% of total consumption in 2015, broadly the same as in 2014.

There were hardly any changes in the DSOs' structure, which continues to be primarily regional. As in the previous year, more than three quarters of the DSOs surveyed supply up to 30,000 meter points, while around 10% of all DSOs supply more than 100,000 meter points. The latter supply about 77% (38.6m) of all meter points. The following chart shows a breakdown of DSOs by the number of meter points supplied.

[3] Figures may not sum exactly owing to rounding.

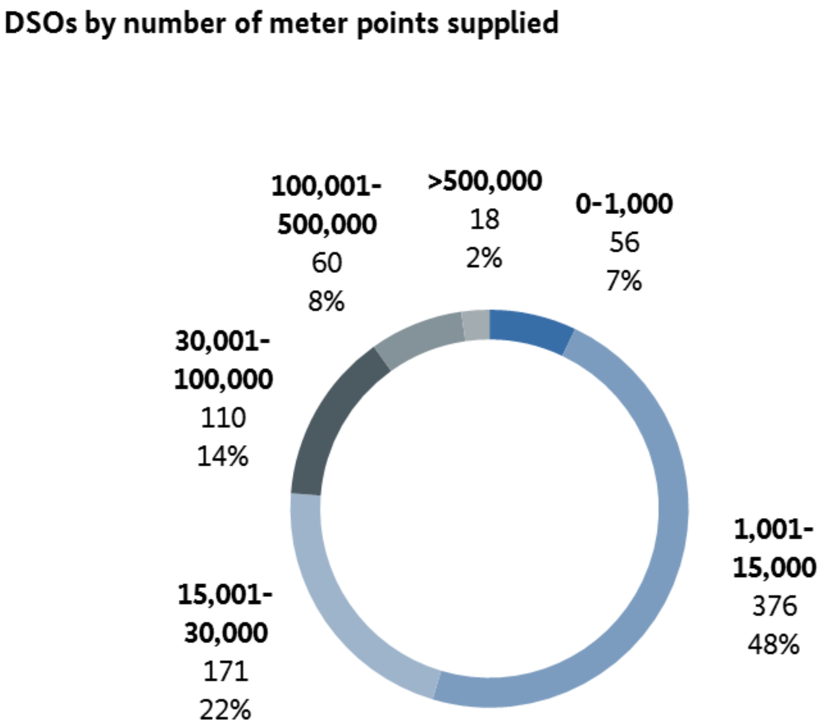

Figure 3: Distribution system operators by number of meter points supplied

3. Market concentration

The degree of market concentration is a good indicator of the intensity of competition. Market shares are a useful reference point for estimating market power because they represent (for the period of reference) the extent to which demand in the relevant market was actually satisfied by one company[4]. For the purpose of energy monitoring, however, an extensive analysis of market power is not required[5]. Such an analysis would include a residual supply analysis with regard to electricity generation.[6]

The following methods are typically used to represent the market share distribution: The Herfindahl-Hirschman Index or the sum of the market shares of the three, four or five competitors with the largest market shares (so-called "concentration ratios", CR3 - CR4 - CR5). The larger the market share covered by only a few competitors, the higher the market concentration. In view of the (historically evolved) structure of the electricity markets, the following analysis uses the market shares of the four strongest suppliers (CR 4) as a point of reference to measure market concentration.

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[4] Cf. Bundeskartellamt, Guidance on substantive merger control, para. 25.

[5] In July 2016 the Act on the Further Development of the Electricity Market (Electricity Market Act) was passed. In accordance with the new Act the Bundeskartellamt will prepare a biennial report on the competitive conditions in the electricity generation market. This report can be published independently of the Monitoring Report.

[6] Cf. Bundeskartellamt, Sector Inquiry into the Electricity Generation and Wholesale Markets, 2011, p.96 ff.

Calculation of (group) market shares under competition law vs. calculation of market shares with the "dominance method"

For the calculation of market shares one first has to define which companies (legal persons) are to be considered as affiliated companies and consequently as a corporate group. This step is necessary because it has to be assumed that there is no (substantial) competition between the individual companies of a group.

German Competition law uses the concept of "affiliated companies" (Section 36 (2) German Competition Act, GWB). The concept focuses on whether there is a control relationship between companies. The turnover or sales quantities of each controlled company are fully attributed to the company group, the sales quantities of a company that is not controlled are not added to the company group's sales quantities (not even in parts). A typical example of a control relationship is a scenario in which the majority of the voting rights in an affiliated company are held by another company. There are also other, less typical forms of control, for example through personal links between the companies or an agreement to confer control. If several companies act together in such a way that they can jointly exercise a controlling influence over another company (e.g. because of a shareholder agreement or consortium agreement), each of them is regarded as controlling. Investigating and assessing which companies belong to a certain group under these principles can sometimes be rather time-consuming.

For this reason, in energy monitoring group membership is predominantly assessed by applying the considerably simpler "dominance method". This method exclusively focuses on whether one shareholder holds at least 50 % of the shares in a company. If a shareholder holds more than 50 % of the shares in a company, that company's sales quantities are fully attributed to the shareholder. If two shareholders each hold 50 % of the shares in a company, they each are attributed 50 % of the sales quantities. Where there is only one shareholder holding 50 % of the shares while all other shareholders hold shares of under 50 %, half of the sales quantities are attributed to the largest shareholder; the other half is not attributed to any of the remaining shareholders. If all the shareholders hold shares of below 50 %, the sales quantities of the company are not attributed to any of them (in this case the company is a "controlling company" itself).

In the case of majority participations, both calculation methods usually render the same results. However, a controlling relationship can also occur under a minority participation. Such a case would not be covered by the dominance method. A calculation of market shares under the dominance method therefore tends to render results where the market shares of the strongest company groups are too low. This applies in particular if there are strong joint ventures active in the market.

The report examines the market concentration on the economically significant market for the first-time sale of electricity (generation of electricity for further resale) and on the two largest retail markets for electricity (sales to end consumers). The market shares on the retail markets are estimated with the help of the so-called "dominance method". By contrast, the market shares on the market for the first-time sale of electricity are calculated on the basis of competition law principles, which renders more accurate results (see box explaining the differences between the two calculation methods).

3.1 Electricity generation and first-time sale of electricity

The Bundeskartellamt defines one relevant product market for the first-time sale of electricity (first level of supply). In its case practice the Bundeskartellamt has recently applied the following criteria for the calculation of market shares:[7]

The market shares are assessed according to feed-in quantities (not capacities). Electricity which is remunerated according to the fixed remuneration system under the Renewable Energy Sources Act (EEG) or optional direct marketing was recently included in the residual supply analysis but not in the calculation of the market shares on the market for the first-time sale of electricity.[8] Electricity from renewable energy resources is generated and fed in independently of the demand situation and electricity wholesale prices. Renewable electricity plant operators are not exposed to competition from the other ("conventional") electricity suppliers. In the case of drawing rights, the corresponding amounts or capacities are attributed not to the power plant owner but to the owner of the drawing rights, provided he decides on the use of the power plant and bears the risks and rewards of marketing the electricity.[9] Only those volumes of electricity will be considered that are fed into the general supply grid. In other words electricity fed into closed distribution networks, traction current and electricity for own consumption do not belong to the market for the first-time sale of electricity. The Bundeskartellamt defines the geographic market as a joint market for Germany and Austria. The main reasons for this are that there are no network bottlenecks at the interconnections between the two countries and that there is a common price zone for German-Austrian electricity wholesale trading. These conditions do not exist in any other neighbouring country of Germany.[10]

As in the previous year, data on the electricity capacities and volumes generated by the four strongest companies (E.ON, EnBW, RWE and Vattenfall) was additionally collected for this year's Monitoring Report based on these definitions. Data on the overall market was derived from a survey of producers and network operators undertaken as part of the energy monitoring activities. In addition, the Austrian energy regulator E-Control has provided aggregate data for Austria.

The results of the survey are illustrated in the following table, which also includes data from the previous year collected on the same basis for comparison:

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[7] Cf. Bundeskartellamt, decision of 8 December 2011, ref. B8-94/11, RWE/Stadtwerke Unna, para. 22 ff.

[8] Cf. Bundeskartellamt, Sector Inquiry into Electricity Generation and Wholesale Markets, p.73 f. (available only in German).

[9] Cf. Bundeskartellamt, Sector Inquiry into Electricity Generation and Wholesale Markets, p.93 f. (available only in German).

[10] Cf. Bundeskartellamt, Sector Inquiry into Electricity Generation and Wholesale Markets, p.81 ff (available only in German).

Electricity volumes generated by the four largest German electricity producers based on the definition of the market for the first-time sale of electricity (i.e. without electricity from renewable energies, traction current)

	Germany + Austria 2014		Germany + Austria 2015		Germany 2014		Germany 2015	
	TWh	Market Share	TWh	Market Share	TWh	Market Share	TWh	Market Share
RWE	135.5	30.0%	127.5	29.6%	131.9	32.0%	125.1	32.2%
Vattenfall	74.1	16.0%	83.1	19.3%	74.1	18.0%	83.1	21.4%
EnBW[1]	49.8	11.0%	49.0	11.4%	49.8	12.0%	49.0	12.6%
E.ON	43.9	10.0%	38.9	9.0%	43.6	11.0%	38.6	9.9%
CR 4		**67.0%**		**69.2%**		**73.0%**		**76.2%**
Other companies		33.0%		30.8%		27.0%		23.8%
Total net electricity generation	452.7	100%	431.1	100%	408.4	100%	388.2	100%

[1] Data on EnBW includes directly marketed EEG electricity

Table 5: Electricity volumes generated by the four largest German electricity producers based on the definition of the market for the first-time sale of electricity (i.e. without EEG electricity, traction current, electricity for own consumption)

The aggregate market share of the four strongest companies (CR 4) on the market for the first-time sale of electricity amounted to 69.2 % in 2015 in the German/Austrian market area. This represents an increase of 2.2 % compared to the previous year and is due to a large extent to an increase in the market share of Vattenfall[11]. In line with a general fall in market volume (total net electricity generation on the market for the first-time sale of electricity fell in 2015 by around 24 TWh), there was a significant decrease in E.ON's market shares and a slight decrease in RWE's market shares. There was only a minimal increase in EnBW's market shares. In comparison with 2010 the aggregate market share of the four largest producers (CR 4) is still approx. 3.5 % lower despite the increase in the reporting year. The long-term decrease in market concentration is largely a consequence of the loss of market shares of E.ON and RWE. Of the four strongest companies only Vattenfall was able to achieve market share increases in comparison to 2010.

[11] Start of operation of Moorburg power plant in 2015.

There has been no considerable change in overall German-Austrian electricity consumption and electricity generation volumes (including electricity from renewable sources) in the last ten years. Since the volume of energy fed in from renewable sources also rose constantly, production from other energy sources (and consequently the volume of the market for the first-time sale of electricity, see definition above) decreased. In 2015 the volume of the market for the first-time sale of electricity fell significantly - by 4.8 % – (from 452.7 TWh to 431.1 TWh) compared to the previous year. The reason for this, apart from a further increase in the feed-in of electricity under the EEG, is a decline in electricity consumption in 2015 (cf. section I.A.2 from page 26). By comparison, electricity volumes generated by the four largest electricity producers on the market for the first-sale of electricity have only fallen by about 0.3 % compared to the previous year, i.e. to a much lesser extent than the market volume.

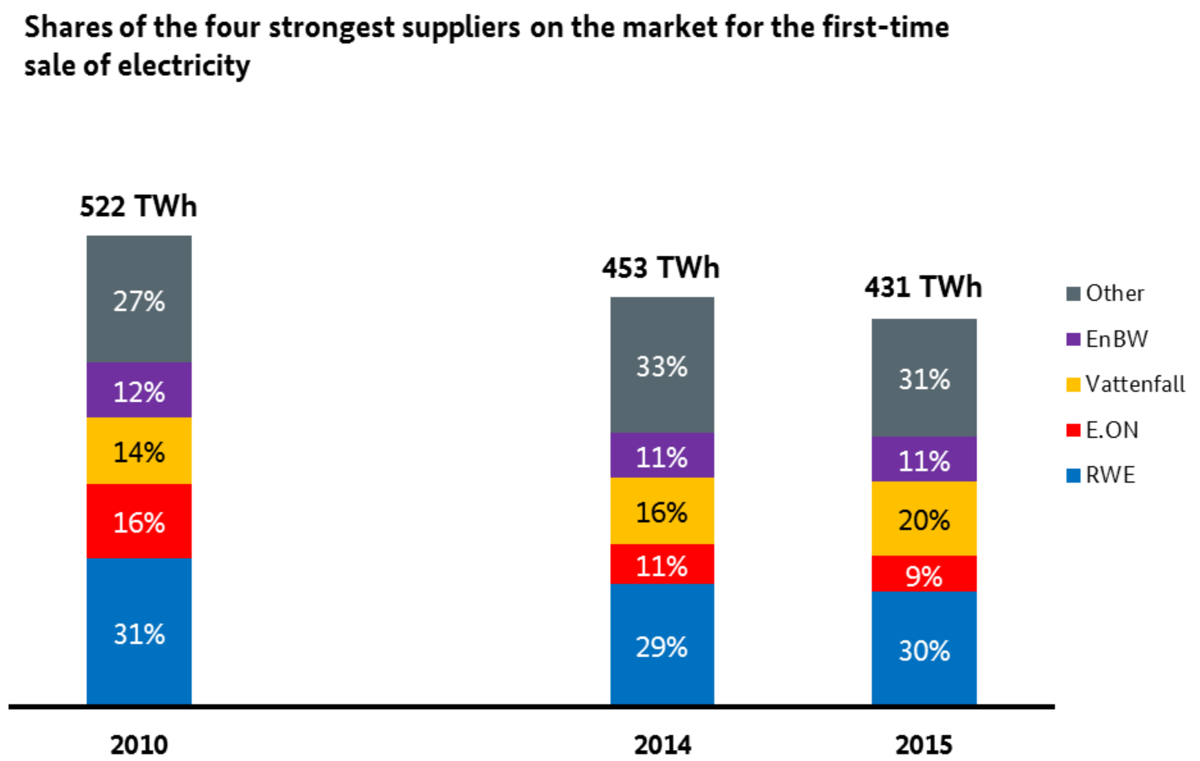

Figure 4: Shares of the four strongest suppliers on the market for the first-time sale of electricity

The four companies' share of Germany-wide generation capacities available for use on the market for the first-time sale of electricity (i.e. without EEG capacities, tract current capacity, closed power plants or from plants not fed into the general supply grid) fell from 61.6 % in 2015 to 58.2 %. The total amount of capacity available in Germany and Austria fell by 2 GW in comparison to the previous year. The capacities attributable to RWE and E.ON declined by 2.3 GW and 2.4 GW. By contrast, capacities attributable to Vattenfall rose by 0.8 GW. In comparison to 2010 there was a decline in the capacity shares of the four largest electricity producers. As is the case with the generation volumes, the reduction in shares is principally due to E.ON's and RWE's sunk capacities.

Generation capacities of the four largest German electricity producers based on the definition of the market for the first-time sale of electricity (without EEG electricity, tract current)

	Germany + Austria 31 December 2014		Germany + Austria 31 December 2015		Germany 31 December 2014		Germany 31 December 2015	
	GW	Share	GW	Share	GW	Share	GW	Share
RWE	29.5	25.7%	27.2	24.2%	28.3	29.2%	26.0	27.4%
Vattenfall	15.9	13.9%	16.7	14.8%	15.9	16.4%	16.7	17.5%
EnBW[1]	12.4	10.8%	11.9	10.6%	12.4	12.8%	11.9	12.6%
E.ON	12.1	10.6%	9.7	8.6%	12.0	12.4%	9.6	10.1%
CR 4		**61.6%**		**58.2%**		**70.8%**		**67.6%**
Other companies		38.4%		41.8%		29.2%		32.4%
Total capacity	114.7	100%	112.7	100%	97.0	100%	95.1	100%

Data rounded up. [1] The data of EnBW include EEG capacities.

Table 6: Generation capacities of the four largest German electricity producers based on the definition of the market for the first-time sale of electricity (without EEG electricity, tract current).

The market for the first-time sale of electricity thus remains highly concentrated with a CR 4 of 69.2 % (share of electricity generation volume). However, the level of concentration has decreased compared to 2010. Apart from the decline in market concentration, other factors have led to a downward trend in market power. Since 2009 there have been more generation capacities Germany-wide and Europe-wide than are required to cover demand. In addition, an increased share of the demand for electricity is covered with the feed-in of renewable energy. The improved use of transmission capacity for electricity imports as a consequence of increased market coupling can help to limit the companies' scope of action on the market for the first-time sale of electricity whereas a reduction in cross-border transmission capacity would have the opposite effect. These additional aspects are not reflected in the market shares illustrated but would be taken into consideration in an extensive analysis of market power - in particular in a residual supply analysis. With regard to the future, it should also be borne in mind that the decommissioning of existing German nuclear power plants envisaged for 2022 at the latest, will bring about changes in the market structure.

3.2 Electricity retail markets

In the electricity retail markets the Bundeskartellamt differentiates between customers with metered load profiles and customers with standard load profiles. Metered load profile customers are customers whose electricity consumption is determined on the basis of a recording load profile measurement. These are generally industrial or commercial customers. Standard load profile customers are consumers with relatively low levels of consumption. These are usually household customers and smaller commercial customers. In the case of these customers a standard load profile is assumed for the distribution of their electricity consumption over specific time intervals.

In recent cases the Bundeskartellamt has defined a Germany-wide market for the supply of metered load profile customers with electricity. As regards the supply of standard load profile customers, the Bundeskartellamt has so far differentiated between three product markets: (i) Supply with electric heating (network-based definition), (ii) default supply (network-based definition), (iii) supply on the basis of special contracts (without electric heating, Germany-wide definition).[12]

In energy monitoring the sales volumes of the individual suppliers (legal persons) are collected as national total values. In the case of standard load profile customers, a differentiation is made between electric heating, default supply and supply on the basis of a special contract. The following analysis is based on data of around 1,150 electricity providers (legal persons) (previous year: 1,100). In last year's monitoring activities the survey on sales quantities was improved to allow for a market share assessment which mirrors the Bundeskartellamt's market definition also for the Germany-wide market for the supply of standard load profile customers with special contracts without electric heating. This form of survey was continued in this year's monitoring activities.

In the reporting year 2015 the approx. 1,150 companies companies sold a total of approx. 266 TWh of electricity to metered load profile customers in Germany (previous year: 268 TWh) and approx. 161 TWh of electricity to standard load profile customers (previous year: 160 TWh). Of the total sales to standard load profile customers, 14 TWh were accounted for by electric heating, 106 TWh by standard load profile customers with special contracts and 41 TWh by standard load profile customers with default supply contracts.

Based on the data provided by the individual companies it was determined which sales volumes were attributed to the four strongest companies. The aggregate sales volumes were attributed to the four strongest companies with the help of the "dominance method" according to the rules illustrated above. This provides sufficiently accurate results for the purpose of this analysis. In interpreting the percentage shares it should be borne in mind that the monitoring survey of the electricity suppliers does not cover the entire market. The percentage shares indicated therefore only approximately correspond to the actual market shares.

In 2015 the four strongest companies sold a total of approx. 82 TWh on the market for the supply of electricity to metered load profile customers. The aggregate market share of the four companies (CR 4) on the Germany-wide metered load profile customer market accordingly amounts to around 31 % (in 2014: 33 %) This value is

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[12] Cf. Bundeskartellamt, decision of 30 November 2009, file reference, B8-107/09; Integra/Thüga, para. 32 ff.

clearly below the statutory thresholds for the presumption of a dominant position (Section 18 (4) and (6) GWB).

The Bundeskartellamt assumes that there is no longer a dominant supplier on the market for the supply of metered load profile customers.

In 2015 the cumulative sales of the four strongest companies on the Germany-wide market for the supply of standard load profile customers with special contracts (without electric heating) amounted to approx. 38 TWh. The aggregated market share of the four companies (CR 4) on this market therefore amounts, as in the previous year, to around 36 %. This value is also clearly below the statutory thresholds for the presumption of a dominant position (Section 18 (4) and (6) GWB). The Bundeskartellamt assumes that there is no longer a dominant supplier on the Germany-wide market for the supply of standard load profile customers with special contracts without electric heating.

On the basis of the monitoring data the shares of sales to all standard load profile customers, i.e. including electric heating and default supply customers, can also be calculated. However, the total values thus determined do not correspond with the Bundeskartellamt's market definition. They only represent the size of the shares of the strongest companies in the Germany-wide sale of electricity to all standard load profile customers. The volume of electricity supplied by the four strongest companies to all standard load profile customers amounts to approx. 66 TWh, which corresponds to an aggregate market share of the four strongest companies (CR 4) of around 41 % (previous year: also 41 %). The share in relation to all standard load profile customers is higher than in the analysis purely on the basis of standard load profile customers with special contracts (without electric heating). The reason for this is that in the areas of electric heating and default supply the four strongest companies account for higher shares of the Germany-wide sales volumes than in the area of special contracts for standard load profile customers with special contracts without electric heating.

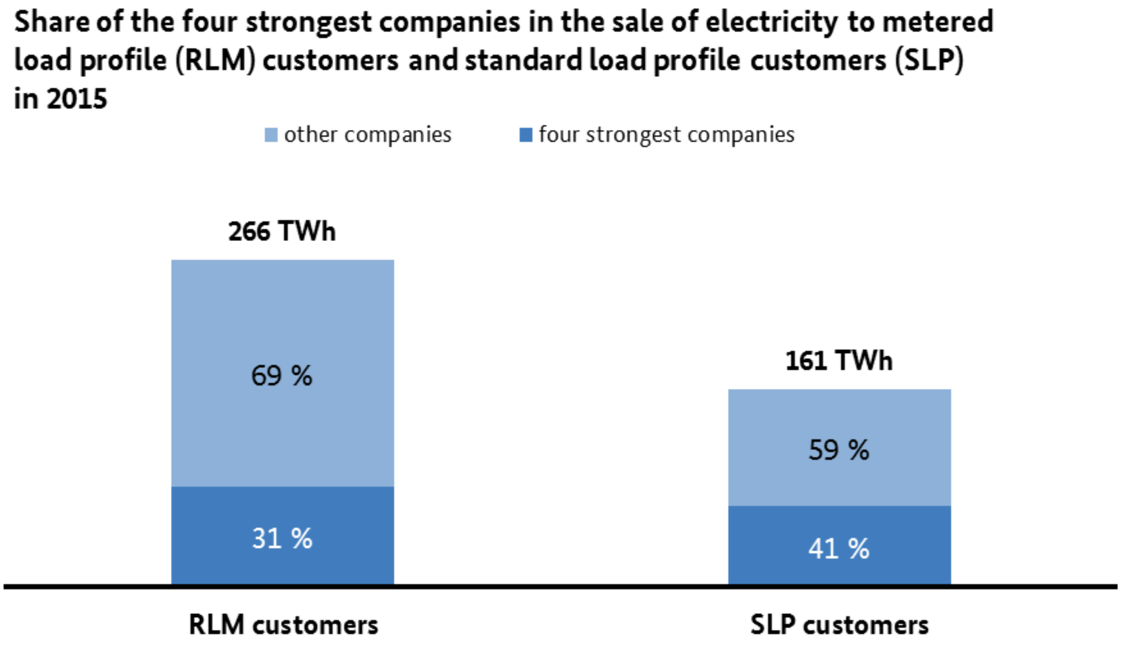

Figure 5: Share of the four strongest companies in the sale of electricity to metered load profile (RLM) and standard load profile (SLP) customers in 2015

B Generation

1. Existing capacity and development of the generation sector

1.1 Power plant capacity in Germany

In 2015, as in prior years, electricity generation was marked by a further increase in capacity from renewables. Capacity from all renewable sources increased by 7.6 GW, compared with the increase of 6.8 GW in 2014. As at the end of 2015 the share of installed capacity from renewables in the total installed energy capacity was at around 47.8% (Figure 6). A detailed breakdown of the installed capacity of individual renewable energy sources entitled to financial support under the EEG as well as their development can be found in I.B.2.2 as of page 53.

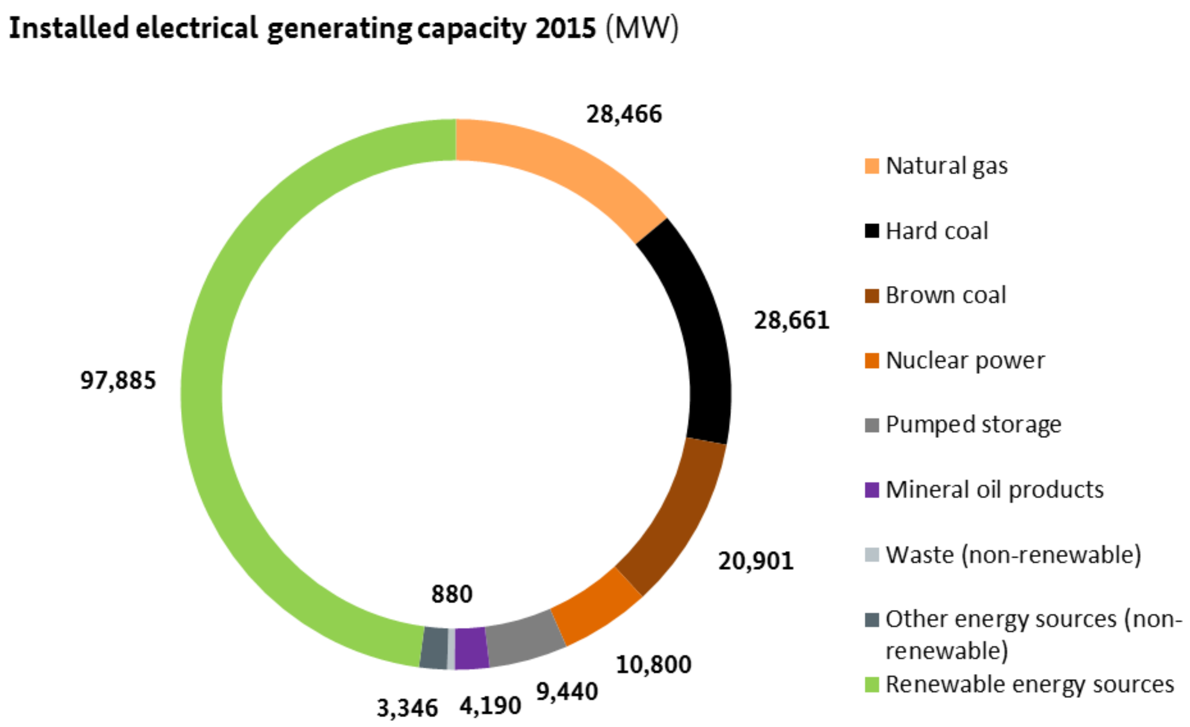

Figure 6: Installed electrical generating capacity (net nominal capacity) as at 31 December 2015

Capacity from the non-renewable sources covered in the monitoring survey increased in 2015 by 0.6 GW, as is shown in Figure 7. The total (net) installed generating capacity thus rose by 8.3 GW from 196.3 GW (31 December 2014) to 204.6 GW as at 31 December 2015.[13] This comprises 106.7 GW from non-renewables and 97.9 GW from renewables. This capacity growth in non-renewables is mainly due to the use of hard coal

[13] The total installed generating capacity figures include (pumped storage and hydro) capacity in Luxembourg, Switzerland and Austria feeding into the German grid.

(including the commissioning of the power plants Moorburg A and B, GKM in Mannheim and the Wilhelmshaven power plant), which has increased by 2.5 GW. The capacity decline in the area of nuclear power is due to the legally required closure of the Grafenrheinfeld power plant.

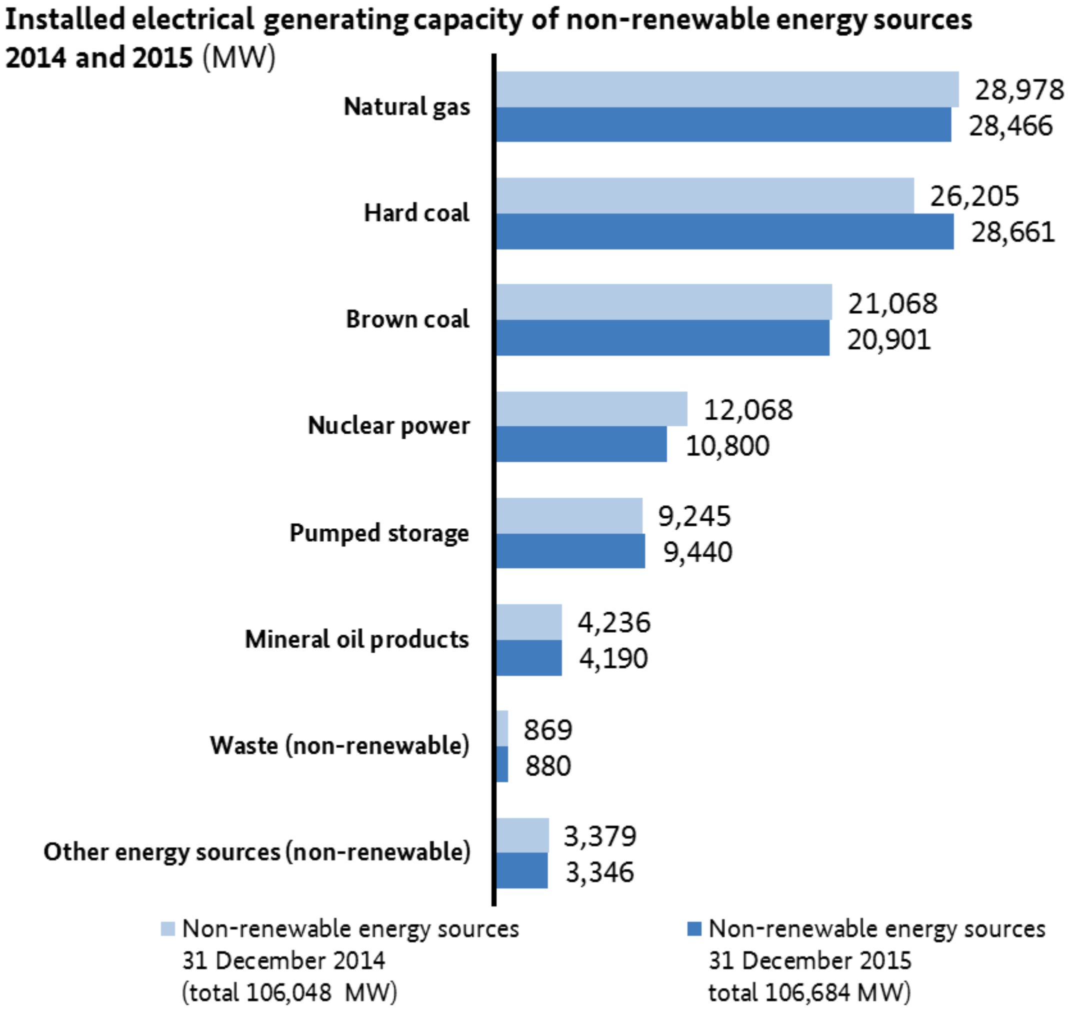

Figure 7: Installed electrical generating capacity of non-renewable energy sources 2014 and 2015

Due to a slight decline in non-renewable capacity (-0.5 GW), the share of renewables has further increased since the beginning of the year (see in Figure 8 on page page 41). In the area of renewable energy sources there is no more current monthly or quarterly data available. Since the beginning of the year, further growth can also be expected in this area in particular. Of the total installed generating capacity, 106.2 GW are accounted for by non-renewables and 97.9 GW by renewables (as at November 2016, EEG 31 December 2015). Chapter I.B.2.2 provides a detailed breakdown of the development of the individual renewable energy sources.

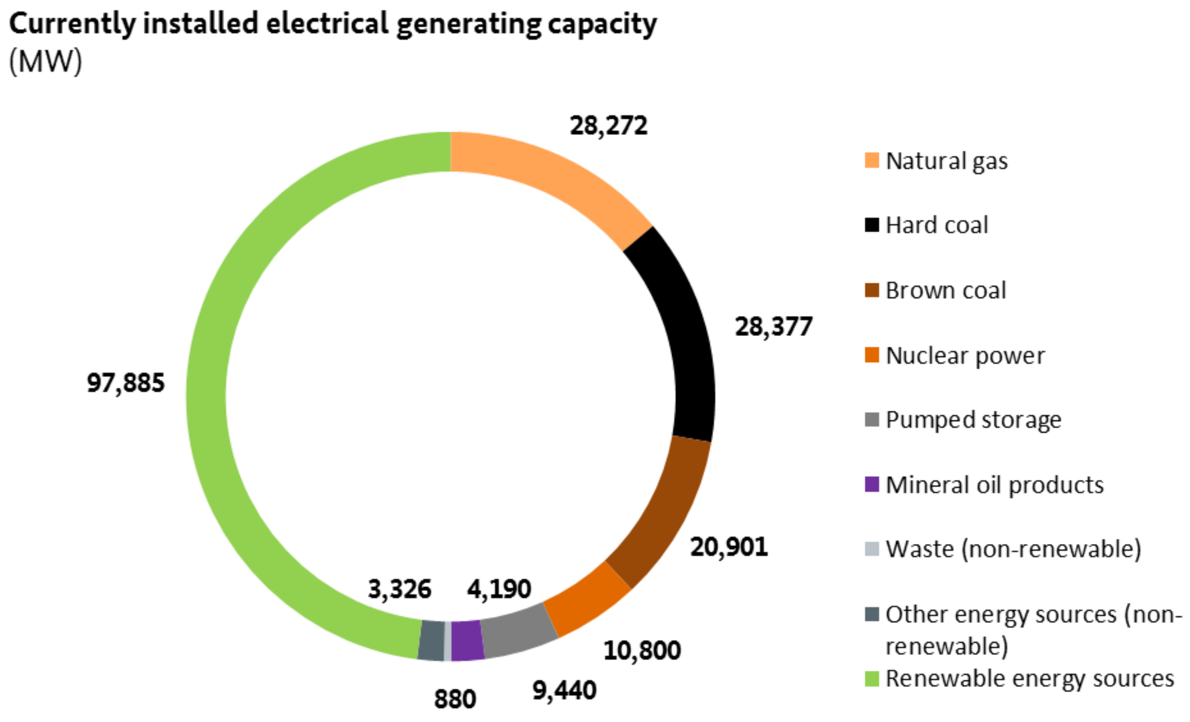

Figure 8: Currently installed electrical generating capacity (net nominal capacity as of November 2016, EEG 31 December 2015)

1.2 Power plant capacity by federal state

The following Figure 9 shows the location of installed generating capacity, broken down by renewable and non-renewable energy sources, in each of the federal states. The Figure does not include generating capacity in Luxembourg, Switzerland and Austria feeding into the German grid. With regard to non-renewable energy sources, only plants with a capacity of 10 MW or more are shown. The Bundesnetzagentur does not have any detailed data on smaller installations with a capacity of less than 10 MW not entitled to financial support under the EEG and therefore cannot allocate this capacity (totalling 4.3 GW) to specific states.

Generating capacity by energy source in each federal state

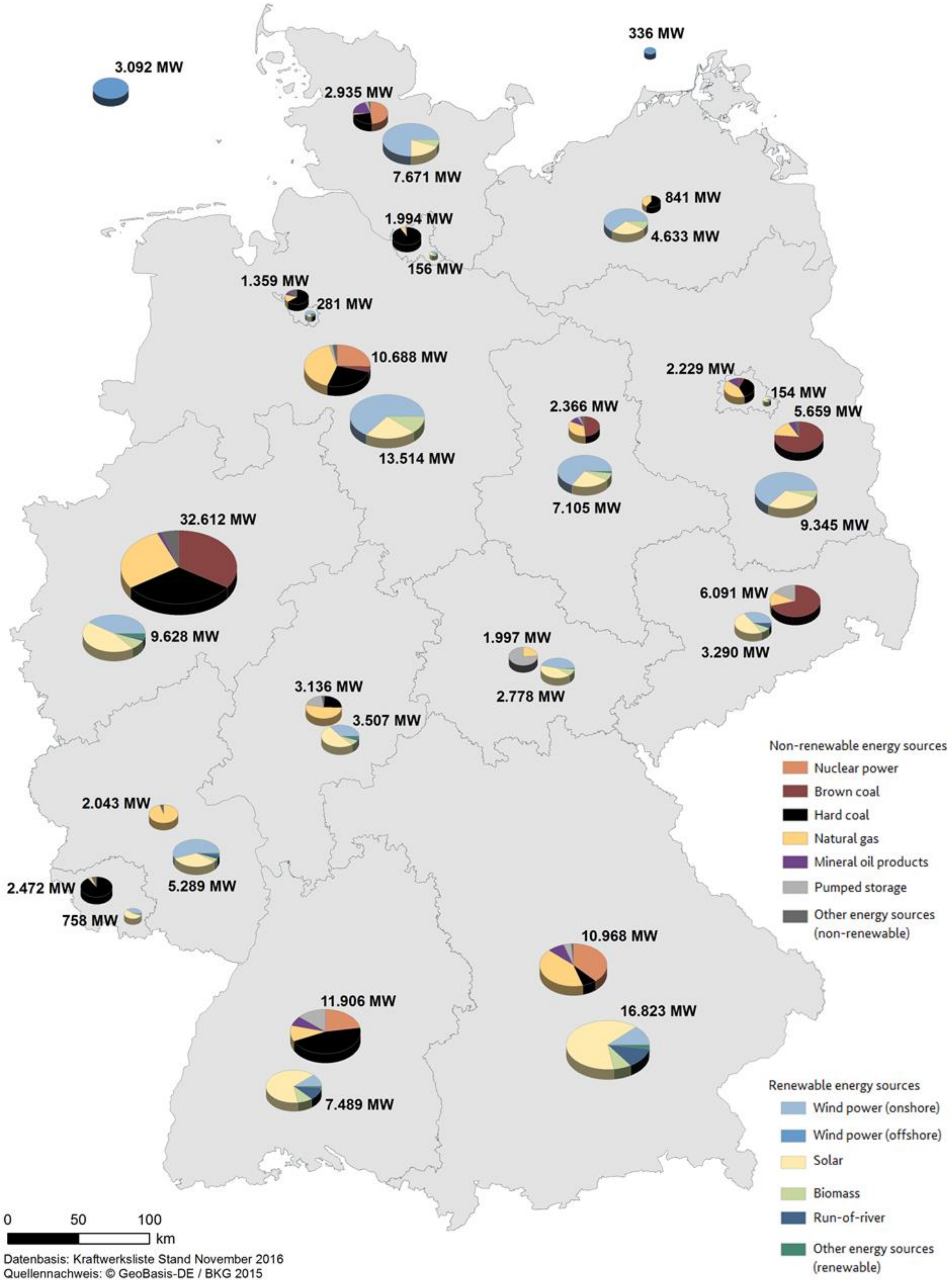

Figure 9: Generating capacity by energy source in each federal state (net nominal capacities as of November 2016, EEG 31 December 2015)

Generating capacity by energy source in each federal state
in MW

Federal state	Non-renewable energy sources							Renewable energy sources						
	Brown coal	Hard coal	Natural gas	Nuclear Power	Pumped storage	Mineral oil products	Other renewable sources	Biomass	Run-of-river hydro	Offshore wind	Onshore wind	Solar	Other renewable sources	Total
BW	0	5,526	1,045	2,712	1,873	700	49	778	780	0	735	5,117	79	**19,394**
BY	0	847	4,491	3,982	543	969	136	1,439	1,922	0	1,821	11,309	332	**27,791**
BE	164	777	943	0	0	327	18	43	0	0	9	84	18	**2,383**
BB	4,409	0	733	0	0	334	183	437	5	0	5,831	2,982	91	**15,004**
HB	0	896	170	0	0	88	206	7	10	0	174	41	48	**1,640**
HH	0	1,794	150	0	0	38	12	44	0	0	63	37	12	**2,150**
HE	34	753	1,620	0	623	25	82	243	63	0	1,280	1,811	110	**6,643**
MV	0	514	318	0	0	0	9	353	3	0	2,843	1,414	20	**5,474**
NI	352	2,933	4,102	2,696	220	59	326	1,355	59	0	8,457	3,580	62	**24,201**
NW	10,442	11,371	7,972	0	303	504	2,021	742	146	0	4,046	4,364	330	**42,241**
RP	0	13	1,922	0	0	0	107	168	223	0	2,908	1,920	69	**7,331**
SL	0	2,206	114	0	0	0	154	19	11	0	298	416	14	**3,231**
SN	4,325	0	657	0	1,085	17	8	291	211	0	1,161	1,608	19	**9,381**
ST	1,148	0	772	0	80	231	135	418	26	0	4,590	1,963	109	**9,472**
SH	0	730	31	1,410	119	575	70	411	5	0	5,728	1,498	30	**10,606**
TH	0	0	482	0	1,509	0	6	250	32	0	1,297	1,187	12	**4,774**
North Sea	0	0	0	0	0	0	0	0	0	3,092	0	0	0	**3,092**
Baltic Sea	0	0	0	0	0	0	0	0	0	336	0	0	0	**336**
Total	**20,873**	**28,360**	**25,521**	**10,800**	**6,355**	**3,866**	**3,522**	**6,999**	**3,495**	**3,428**	**41,241**	**39,332**	**1,354**	**195,145**

No detailed data is avaialble for installations with a capacity of less than 10 MW; the total capacity of these installations (4,297 MW) is therefore not included in the table.

Table 7: Generating capacity by energy source in each federal state (net nominal capacities as at November 2016, EEG 31 December 2015)

1.3 Power plants outside of the electricity market

The total generating capacity from non-renewables (as of November 2016) can be divided into power plants operating within the electricity market (97.8 GW) and power plants operating outside of the electricity market (8.4 GW). Within these two categories, the following subsets can be classified with regard to power plant status:

Power plants operating in the electricity market:

- 96.4 GW: plants in operation;

- 1.4 GW: plants temporarily not in operation (eg owing to repairs following damage) or with restricted operation.

Plants operating outside of the electricity market:

- 4.8 GW: backup power stations (power stations rated as systematically relevant under sections 13b(4) and 13b(5) EnWG and now only operated when requested by the TSOs);

- 0.4 GW: power plants on security standby

- 3.2 GW: plants temporarily closed.

The backup power plants are plants which were notified as scheduled for temporary or final closure but which may not be closed for supply security reasons (see I.C.6 as of page 108 for more information). These plants currently comprise power stations using natural gas (3.1 GW), mineral oil products (1.2 GW) and hard coal (0.5 GW).

Under section 13g EnWG, as from 1 October 2016 the brown coal power plants Buschhaus, Neurath C, Niederaußem E and F, Frimmersdorf P and Q as well as Jänschwalde E and F are to be gradually transferred to so-called security standby status (transfer of brown coal plant Buschhaus Block D to security standby status by 1 October 2016, 352 MW). In addition to ensuring security of supply, security standby serves primarily to reduce carbon dioxide emissions in the electricity sector. The power plant units remain on security standby for four years. During this period, these power stations are not permitted to produce electricity other than for security standby purposes. After four years, the plants must be permanently closed. A return to the electricity markets is not permitted.

The plants temporarily closed are power stations using natural gas (2.6 GW), brown coal (0.3 GW), mineral oil products (0.2 GW) and hard coal (0.1 GW).

An additional 0.4 GW of plant capacity was mothballed in summer 2015. These plants are closed during the summer season and fired up again afterwards. The majority of the plants mothballed in the summer used hard coal (0.3 GW).

The following Figure shows the location of power plants operating outside of the electricity market. The map shows power plants which have been notified as scheduled either for temporary ("reserve power plants") or final closure but which may not be closed for supply security reasons. These plants can be made operational again within a period of one year, in contrast to plants which have been permanently closed.

Power plants outside of the electricity market

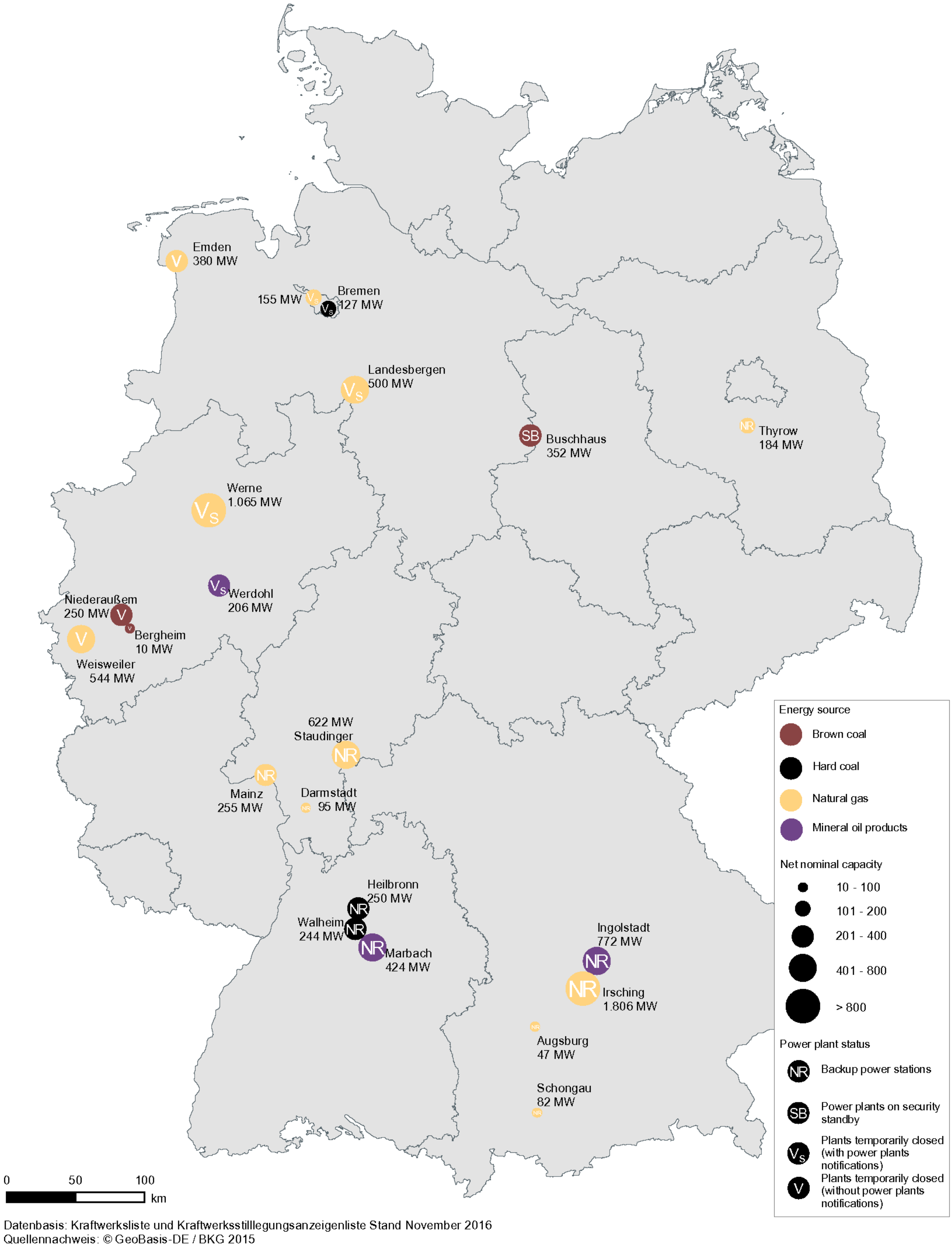

Figure 10: Power plants outside of the electricity market (net nominal capacity as of November 2016)

1.4 Net electricity generation 2015

In 2015, electricity generation was marked by a sharp increase in generation from renewable energy sources. At the same time there was a further decrease in generation from non-renewable sources. As in prior years, the increased generation from renewables was the result of the continuing expansion of these still relatively new technologies. Overall, the net amount of electricity generated increased by 11.1 TWh or 1.9%, from 583.6 TWh in 2014 to 594.7 TWh in 2015. Electricity generation from renewable energy sources increased by 26 TWh (16.8%), from 155.1 TWh in 2014 to 181.1 TWh in 2015. Renewables' share of net electricity generation thus rose to 30.4% in 2015; the share of renewables in the gross electricity consumption in 2015 was 31.4%. Chapter I.B.2.2.3 contains a detailed analysis of the volumes generated from installations entitled to financial support under the EEG.

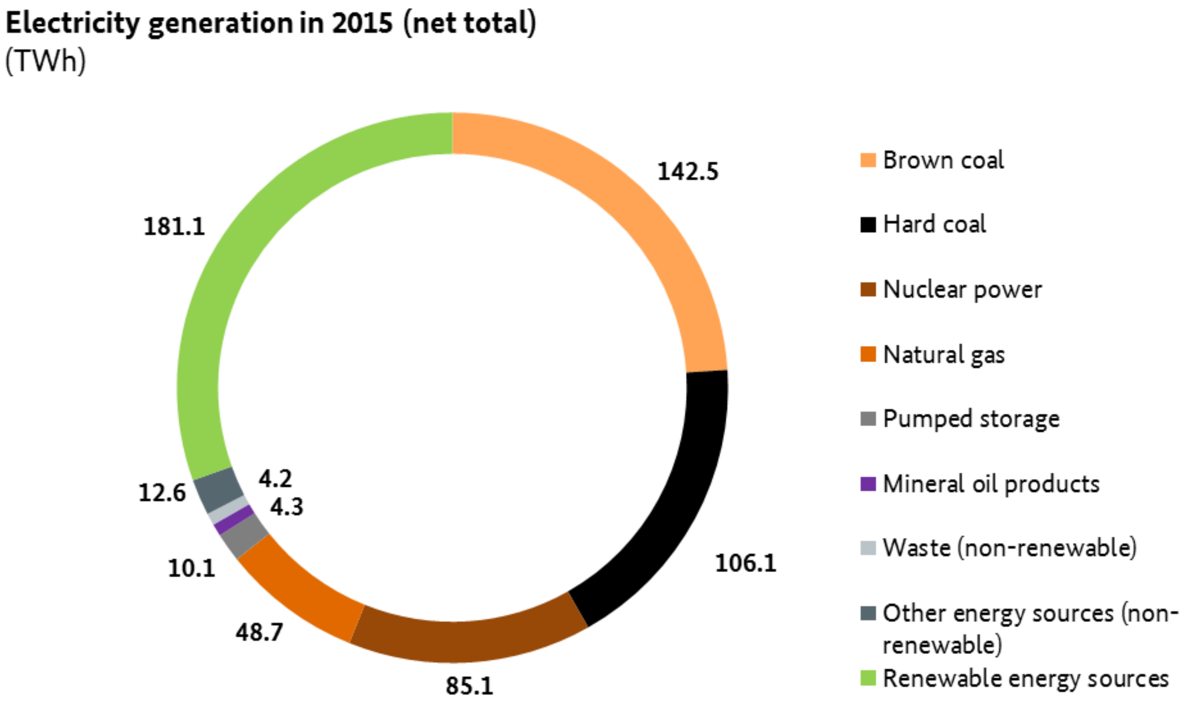

Figure 11: Net electricity generation 2015

Overall, generation from non-renewable sources fell by 15 TWh in 2015 (-3.5%) to 413.6 TWh (see Figure 12). Nuclear and hard coal power plants showed the largest decreases. As a result of the closure of the Grafenrheinfeld nuclear power plant, electricity generation from nuclear plants declined by 6.7 TWh, or 7.3%. Generation from hard coal power plants fell by 5.5 TWh (-4.9%). As in the prior year, generation from brown coal power plants decreased again in 2015; here, generation fell by 2 TWh or -1.4% to 142.5 TWh. The decline in the electricity feed-in from hard coal power plants in particular is due primarily to the increased feed-in from renewables. As has been the case in previous years, the increased feed-in from renewables is leading to lower wholesale prices and in turn to a decrease in generation by plants with relatively high operating costs. At the same time, the loss of power plant capacity in the baseload area (in particular nuclear power plants) must be substituted, at least temporarily, by capacity from other power plants in Germany or abroad.

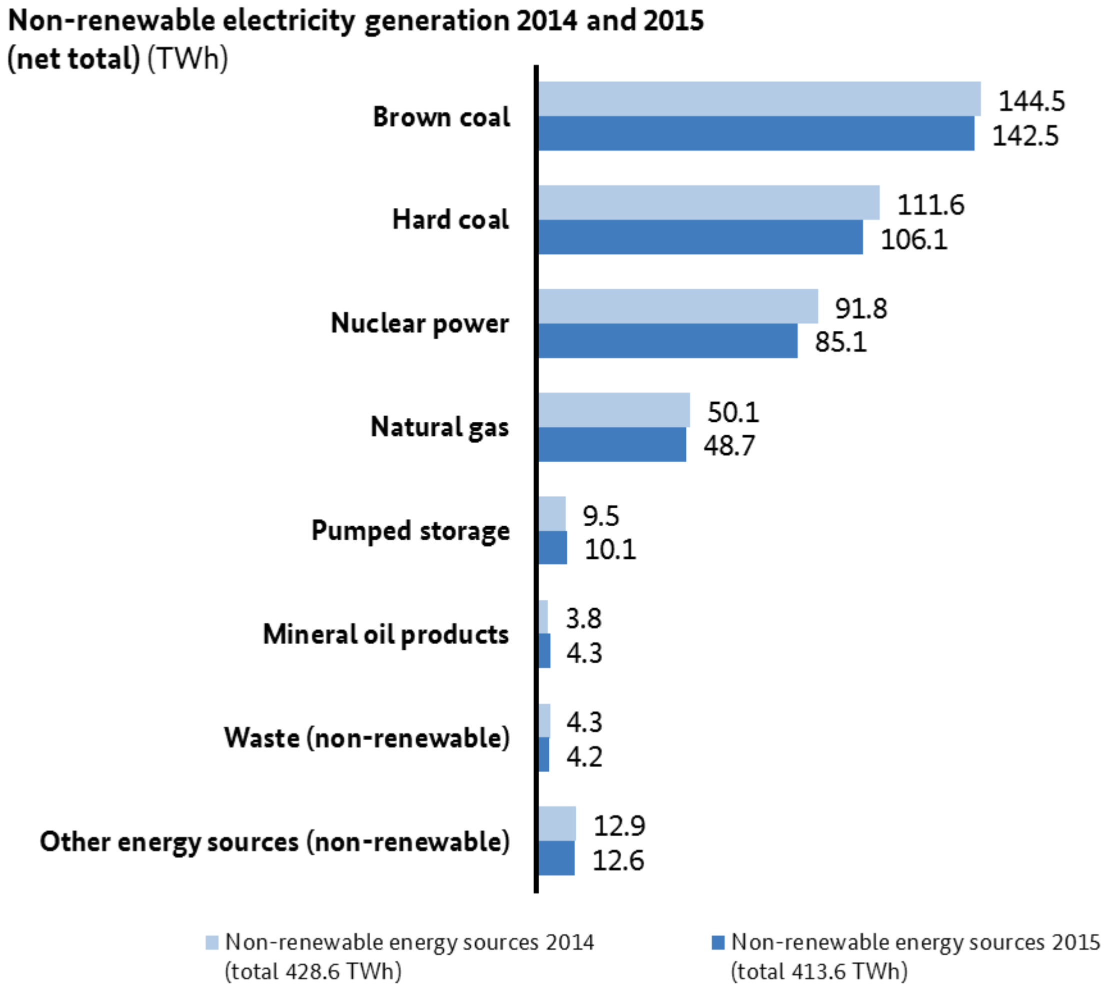

Figure 12: Electricity generation (net total) from non-renewable sources 2014 and 2015

1.5 CO_2 emissions from electricity generation in 2015

For the first time, the Bundesnetzagentur asked operators of power plants with a net nominal capacity of at least 10 MW to supply data on CO2 emissions from electricity generation. For CHP plants, operators only had to supply data on the share of CO_2 emissions attributable to electricity generation. Because this information was collected for the first time, the results of the survey cannot be verified using historical figures. In order to evaluate the findings, we therefore draw upon the publication by the German Environment Agency "Development of specific carbon dioxide emissions in the German electricity mix 1990 to 2015". In that publication, the Environment Agency calculates carbon dioxide emissions by multiplying fuel inputs with the fuel-specific carbon dioxide emission factors. The data basis for the fuel inputs is the Federal Republic of Germany’s energy balance, published by the Federal Statistical Office. The direct carbon dioxide emissions from electricity generation for 2015 are shown as estimates in the publication of the German Environment Agency.

For the purpose of evaluating the findings Table 8 compares the findings of the Bundesnetzagentur’s new survey on CO_2 emissions with those of the Environment Agency.

CO2 emissions from electricity generation 2015

	As reported to Bundesnetzagentur t million	As estimated by Federal Environment Ministry t million	Delta t million
Brown coal	163	159	4
Hard coal	97	95	2
Natural gas	18	20	-2
Mineral oil products	2	5	-3
Waste	7	13	-6
Other energy sources[1]	14	19	-5
Total	301	312	-11

[1] Other energy sources (non-renewable), mine gas

Table 8: CO2 emissions from electricity generation 2015

According to data supplied by the power plant operators, brown coal fired power plants emitted 163m tonnes of CO_2 emissions, which made up over half of all CO_2 emissions from electricity generation in 2015 (54.9%). Hard coal fired power plants emitted 97m tonnes of CO_2, while natural gas-fired power plants emitted 18m tonnes. The remaining 23m tonnes of CO_2 are distributed across mineral oil-fired power plants (2m tonnes), waste to energy power plants (7m tonnes) and other energy sources (14m tonnes).

A comparison of the Bundesnetzagentur's survey results with the figures of the Environment Agency shows that the figures for all energy sources are in the same order of magnitude. Possible reasons for smaller deviations could be the systematic differences between survey and estimate, as well as differing minimum capacity limits. The data submissions from power plant operators, for example, do not include CO_2 emissions from generating facilities with under 10 MW of net nominal capacity. A relatively heterogeneous reporting behaviour was evident for the energy source waste; this may be due to difficulties in correlating the CO_2 emissions to the non-biogenic share of generation, among other factors.

1.6 Development of conventional generating capacity

1.6.1 Expansion of conventional power plants

In addition to information on existing power plants, the Bundesnetzagentur also requests information on the future development of power plant capacity. In the section below we first look at power plant expansion. Chapter I.B.1.6.2 then examines the impact which the closure of plants is expected to have on the future development of the power plant fleet. The analysis of the future power plant fleet focuses exclusively on non-renewable energy sources. The analysis of expected growth only takes into account generating facilities currently in trial operation or under construction with a minimum net nominal capacity of 10 MW. In such cases, the probability of projects being implemented is considered to be sufficiently high.

Generation capacity totalling 3,469 MW is currently in trial operation or under construction and will likely be completed by 2019 (see Figure 13). The capacity expansion projects underway in Germany relate to natural gas (1,922 MW), hard coal (1,055 MW) and other energy sources (120 MW). The 1,055 MW of hard coal capacity is attributable to the hard coal-fired plant Datteln 4, the completion date of which is still unknown. Most of the capacity from other energy sources is accounted for by battery storage systems (100 MW in total). Pumped storage plants with a total capacity of 372 MW are also currently under construction in Austria; energy from these plants will be fed into the German grid. There are currently no projects underway for pumped storage plants in Germany.

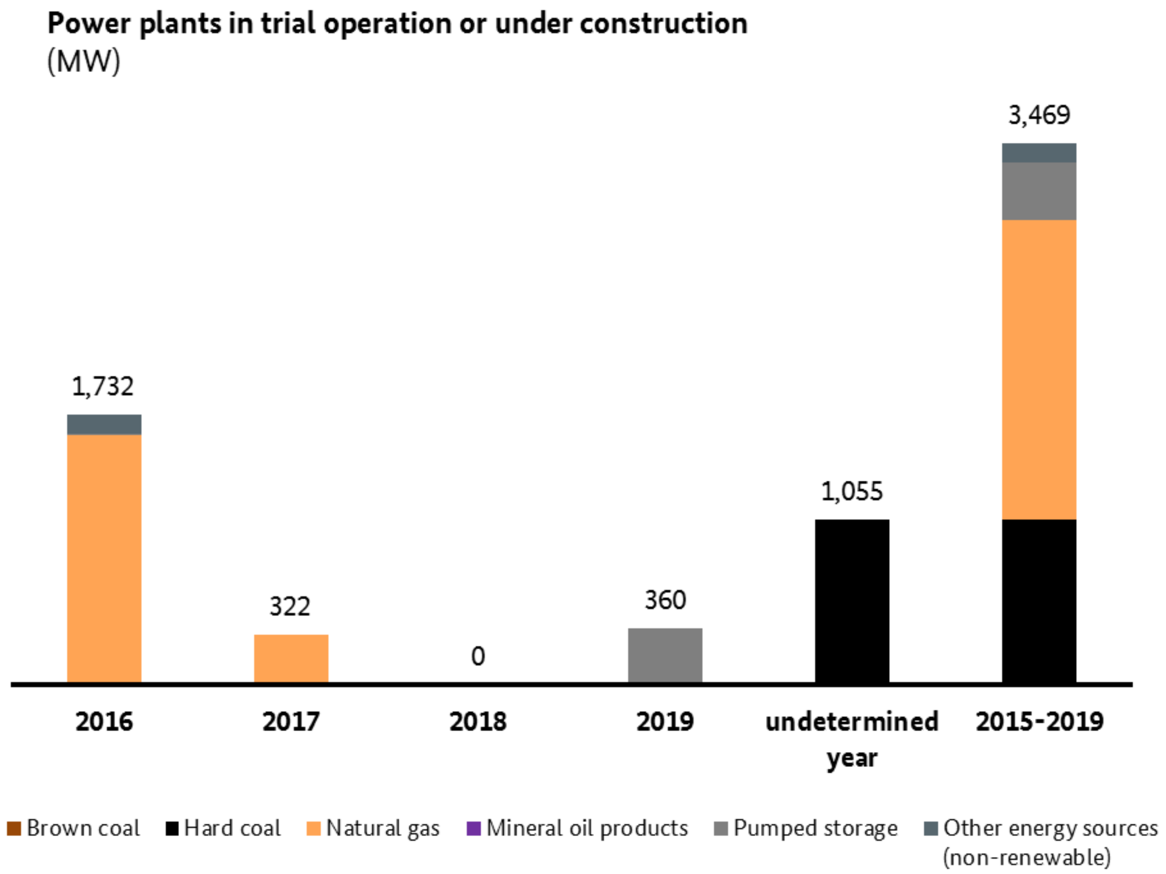

Figure 13: Power plants in trial operation or under construction from 2016 to 2019 (national planning data for net nominal capacity 2016 to 2019, as of November 2016)

1.6.2 Power plant closures

The future development of the power plant fleet can be described on the basis of power plant expansion and the planned closures of power plants. Just as with expansion of power plants, the analysis of power plant closures takes into account only those power plants for which there is a sufficiently high probability of closure. These include power plants which have been notified to the Bundesnetzagentur as scheduled for final plant closure. It also takes into account the decommissioning of nuclear power plants required by law. Figure 14 shows the regional distribution of expected new power plant units or units to be closed with a minimum capacity of 10 MW for the period up to 2019. The total number of plants which have been notified as scheduled for final closure does not include systemically relevant power plants, as the closure of such plants is prohibited. Also not included is the planned decommissioning of the nuclear power plants Brokdorf, Gundremmingen Block C, Grohnde, Neckarwestheim 2, Lingen and Isar 2, with a total capacity of 8,107 MW. In addition, the figure does not take into account brown coal fired power plants on security standby, as final closure of these plants does not take place until after they have been on security standby for four years, ie in the year 2020 at the earliest. Finally, planned temporary plant closures are also not included as, unlike final closures, these can be brought back online within one year for purposes of supply security.

In Germany as a whole, the capacity of planned closures – consisting of plants notified as scheduled for final closure and nuclear power plants scheduled for statutory decommissioning by the year 2019 (6,255 MW) – exceeds the capacity expansion of power generation units (3,469 MW) by 2,786 MW. A reduction of existing surplus capacities is therefore expected. For purposes of supply security, a differentiated analysis of northern and southern Germany is also of interest. The analysis uses the Main river line as an approximate dividing line between northern and southern Germany. South of the Main, 478 MW of power plant capacity is currently under construction. By contrast, a capacity of 2,742 MW is marked for final closure in southern Germany by 2019. Some 2,686 MW of this is attributable to the Gundremmingen B (scheduled for decommissioning in 2017) and Philippsburg (scheduled for decommissioning in 2019) nuclear power plants alone. This equates to a deficit of -2,264 MW in southern Germany by 2019. North of the Main river as well, capacity from planned plant closures exceeds the planned expansion of power plants. The planned closure of power plants with a total capacity of 3,513 MW stands in contrast to power generation units in trial operation or under construction (including Datteln 4) with a total capacity of 2,991 MW. This corresponds to a deficit of -522 MW by 2019. Based on this outlook for non-renewable power plants, the existing north-south divide will be further compounded by 2019.

Locations with an expected increase or decrease in power generation capacity to 2019

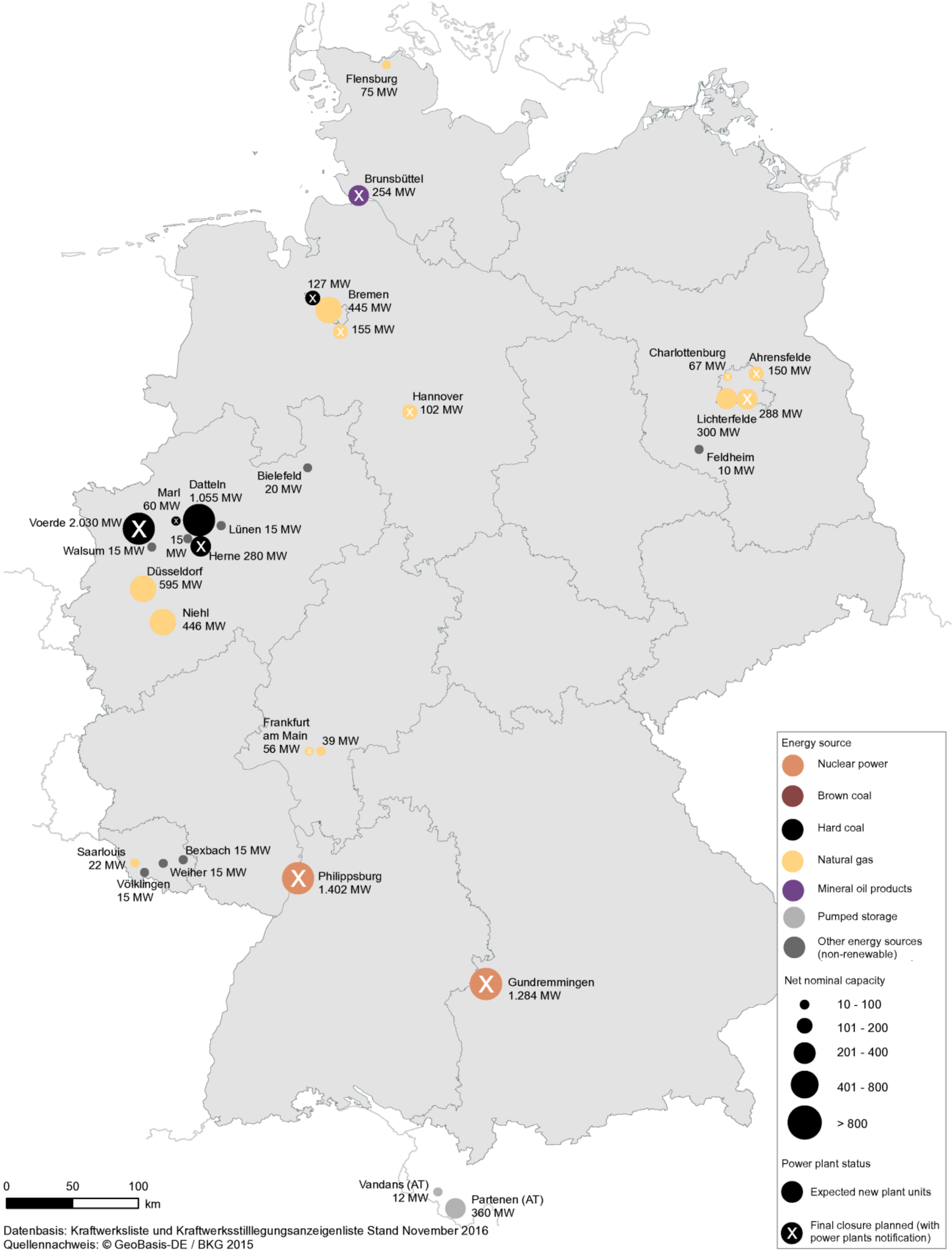

Figure 14: Locations with an expected increase or decrease in power generation units (as of November 2016)

In addition to the above-mentioned formal notifications of planned final closures, the Bundesnetzagentur was also informed of plans for the final closure of additional power generation units during the course of its monitoring activities. The final closure of a total additional capacity of 330 MW is thus expected by 2019.[14] This relates specifically to hard coal power plants with a capacity of 238 MW, other energy sources with a capacity of 34 MW, natural gas power plants with a capacity of 34 MW and brown coal power plants with a capacity of 24 MW. The majority of this power plant capacity (306 MW) is located north of the Main line.

This puts the total capacity from scheduled final closures of power plants by 2019 at 6,585 MW. Some 2,766 MW of this is located in southern Germany. In Germany as a whole, the overall balance of the expansion and reduction of power plant capacity by 2019, including the pumped storage plants under construction in Luxembourg and Austria, is therefore -3,116 MW. This balance of power plant expansion and closures is calculated on the basis of power generation units in trial operation or under construction minus formal notifications of final plant closures pursuant to section 13b(1) EnWG, nuclear power plant closures and final closures identified through the monitoring process. The overall balance for southern Germany in the same period is -2,288 MW.

2. Development of renewable energies

2.1 Differentiation between renewable energies entitled to financial support and those not entitled to financial support

Not all renewable energy generating facilities are entitled to financial support under the EEG. A distinction must be made between renewable energies with and without entitlement to financial support. The majority of installed renewable energy capacity falls under the EEG support regime. 93.0 GW of the 97.9 GW of capacity installed at the end of 2015 is eligible for EEG support. Chapter I.B.2.2 examines the renewable energies entitled to financial support in more detail.

The 4.9 GW of renewable energy capacity not entitled to financial support under the EEG is primarily accounted for by the energy sources run-of-river power (2.5 GW), dammed water (1.5 GW) and waste (0.9 GW). For the energy source waste, only the biogenic share of the waste generation is considered a non-eligible renewable energy source. The remaining 0.9 GW of energy capacity for the energy source waste is assigned to the conventional energy sector. In 2015, the total electricity generation from renewable energies not entitled to support under the EEG amounted to 18.3 TWh. The majority of that energy was generated in run-of-river and dammed water power plants (14.1 TWh in total) and in waste-fired power plants (3.9 TWh).

2.2 Development of renewable energies entitled to financial support

The key figures presented in this section are collected by the Bundesnetzagentur to fulfil its monitoring function in the nationwide equalisation scheme process. To this end, selected data is provided on an annual basis from the year-end accounts of TSOs (by 31 July), energy utilities and DSOs (by 31 May). Since August 2014, the Bundesnetzagentur's installations register is used as an additional source of information to evaluate the installed capacity of EEG installations.

[14] This does not include the new replacement power plant at the Kiel power plant location, where a hard coal power plant with a capacity of 323 MW is to be replaced by a natural gas power plant with a capacity of 190 MW; this new power plant is still under construction.

In the publication "EEG in Numbers 2015", the Bundesnetzagentur provides market stakeholders with evaluations that go beyond the key figures presented here. In particular, this publication contains evaluations for specific energy sources, federal states and access levels.

2.2.1 Installations register/ market master data register

With the EEG 2014, development paths were introduced for the four key renewable energy sources. Thus, statutory target corridors were established for the growth of onshore wind energy, offshore wind energy, solar power and biomass. A new register, the installations register, was created to monitor expansion, calculate funding rates on the basis of expansion and provide data to facilitate the integration of renewable energy sources into the existing electricity supply system.

All installations commissioned since August 2014 must be recorded in this register. For installations commissioned before 1 August 2014, data must be registered if a reportable event occurs – notably, capacity changes or closures. Reporting requirements also exist for new installation licences issued from this date onwards. Data on registered installations must be kept up to date by the operators of these installations. This makes it possible to map the entire life cycle of an installation. Beginning with the construction licence, reporting requirements range from the commissioning and any changes, to the final closure of an installation. Some 7,448 reports were registered in 2015.

All data recorded in the installations register is published online at https://www.bnetza.de/anlagenregister. This provides an overview of the renewable power generation landscape for all interested parties. Transparency helps to increase acceptance of Germany's *Energiewende*.

With the aim to record not only the expansion of renewable energies, but also to provide an overview of the entire power generation landscape in Germany, consideration is being given to expanding this register to include all generating facilities – renewable and conventional, new and existing facilities, electricity and gas. For this reason, an authorization has been included in the EnWG within the framework of the Electricity Market Act for the so-called market master data register. The market master data register, which is to be operated by the Bundesnetzagentur, will register not only all electricity generating facilities, but also the master data on electricity consumption facilities, storage systems, gas consumption and generating facilities, as well as the master data of all market stakeholders of significance to the energy industry. Access to the master data found in this register will achieve a significant improvement in data quality and simplify many processes in the energy sector. In the future, the central registration will help to standardise, simplify or eliminate altogether many of the official reporting obligations in place. In due time, this market master data register is to replace the installations register. The statutory instrument (based on authorisation contained in the EnWG) that will form the legal basis for establishing and operating the market master data register is currently being developed. The implementation of this register will require further legislative work, as the Federal Ministry for Economic Affairs and Energy must issue a special ordinance for this purpose.

2.2.2 Installed capacity

The total installed capacity of installations entitled to financial support under the EEG was approximately 93.0 GW on 31 December 2015 (31 December 2014: around 85.4 GW). This represents an increase in the total installed capacity of such installations of around 7.6 GW in 2015, or around 8.9%.

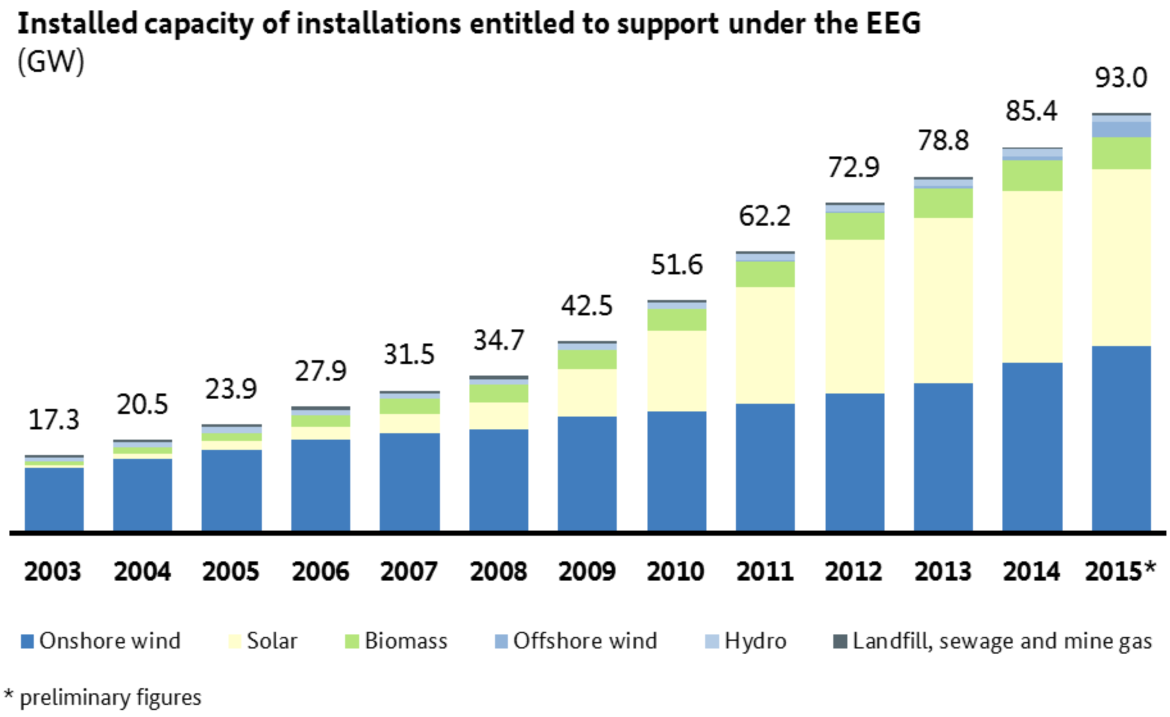

Figure 15: Installed capacity of installations entitled to financial support under the EEG to 2015

Installed capacity of installations entitled to financial support under the EEG by energy source

	Total 31 December 2014 in MW	Total 31 December 2015* in MW	Increase / decrease in 2015 in MW	Increase / decrease compared with 2014 (%)
Hydro	1,541	1,549	8	0.5
Gases[1]	515	510	-5	-1.0
Biomass	6,799	6,900	101	1.5
Geothermal	33	33	0	0.0
Onshore wind	37,620	41,242	3,621	9.6
Offshore wind	994	3,428	2,434	245.0
Solar	37,900	39,332	1,433	3.8
Total	85,402	92,995	7,593	8.9

[1] Landfill, sewage and mine gas

* preliminary figures

Table 9: Installed capacity of installations entitled to financial support under the EEG by energy source (as of 31 December 2014/31 December 2015)

A particularly sharp rise in the capacity of offshore wind plants was recorded in 2015. Facilities with a capacity of approximately 2.4 GW were newly installed (2014: approximately 0.4 GW), which represents an increase of 245%. The capacity of onshore wind plants (3.6 GW) also continued to rise sharply in comparison to the other energy sources, although the increase was less than in the prior year (2014: 4.3 GW). While the deployment of solar installations also rose by a further 1.4 GW, this increase was lower than the average growth rate of the last 10 years (3.7 GW). The deployment of biomass installations also slowed (2015: 0.1 GW; 2014: 0.31 GW).

For onshore wind plants as well as for solar power, an annual growth corridor of 2.4 to 2.6 GW is planned. With an overall increase of 3.6 GW (gross total), onshore wind significantly exceeded the planned growth corridor, while the increase of 1.4 GW for solar power (net total) fell well below of the planned growth corridor. In the case of biomass, an increase of installed capacity of 0.1 GW (gross total) is planned; this increase, however, applies only to the commissioning of new plants rather than the expansion of existing facilities. While there was an increased deployment of 0.1 GW of biomass capacity, newly commissioned plants accounted for only 0.36 GW of that increase.[15] The installed capacity of offshore wind plants is set to rise to a total of 6.5 GW by 2020 and 15 GW by 2030. In the year 2015, installations with an installed capacity of 2.4 GW had been commissioned, so that by 31 December 2015 a total of 3.4 GW had been installed, which already accounts for half of the expansion target for 2020.

Number of new installations

Some 49,201 new facilities were installed in 2015. This is significantly below the average of the last five years of 178,032 new installations per year. Solar installations accounted for 97% of new installations, onshore wind plants for 1.6% and biomass installations for 0.9%.

Number of installations entitled to financial support

	2009	2010	2011	2012	2013	2014	2015*
Hydro	6,324	6,571	6,825	6,974	7,095	7,130	7,169
Gases[1]	668	672	680	684	689	683	686
Biomass	8,347	9,943	12,697	13,371	13,997	14,366	14,482
Geothermal	4	4	4	6	9	10	10
Onshore wind	18,503	19,264	20,204	21,339	22,569	23,846	25,118
Offshore wind	7	16	49	65	143	241	811
Solar	636,756	894,756	1,154,968	1,328,293	1,448,641	1,514,493	1,561,694
Total	670,609	931,226	1,195,427	1,370,732	1,493,143	1,560,769	1,609,970

[1] Landfill, sewage and mine gas

*preliminary figures

Table 10: Number of installations entitled to financial support

[15] Source: Publication of biomass deployment in the installations register of the Bundesnetzagentur

When considering the development of individual energy sources, special mention must be made of the substantial capacity growth of new offshore wind plants of 263.5%.

Growth rates of EEG installations entitled to financial support, by energy source

	Total number as of 31 December 2014	Total number as of 31 December 2015*	Increase / decrease in 2015 %	Increase / decrease compared with 2014 %
Hydro	7,130	7,169	39	0.5
Gases[1]	683	686	3	0.4
Biomass	14,366	14,482	116	0.8
Geothermal	10	10	0	0.0
Onshore wind	23,846	25,118	1,272	5.3
Offshore wind	241	811	570	236.5
Solar	1,514,493	1,561,694	47,201	3.1
Total	1,560,769	1,609,970	49,201	3.2

[1] Landfill, sewage and mine gas

*preliminary figures

Table 11: Growth rates of EEG installations entitled to financial support by energy source (as of 31 December 2014/31 December 2015)

2.2.3 Annual energy feed-in

Annual energy feed-in by energy source

In 2015 the total annual energy feed-in from installations entitled to financial support under the EEG was 161.8 TWh. This represents a year-on-year increase of 25.8 TWh, or 19%.

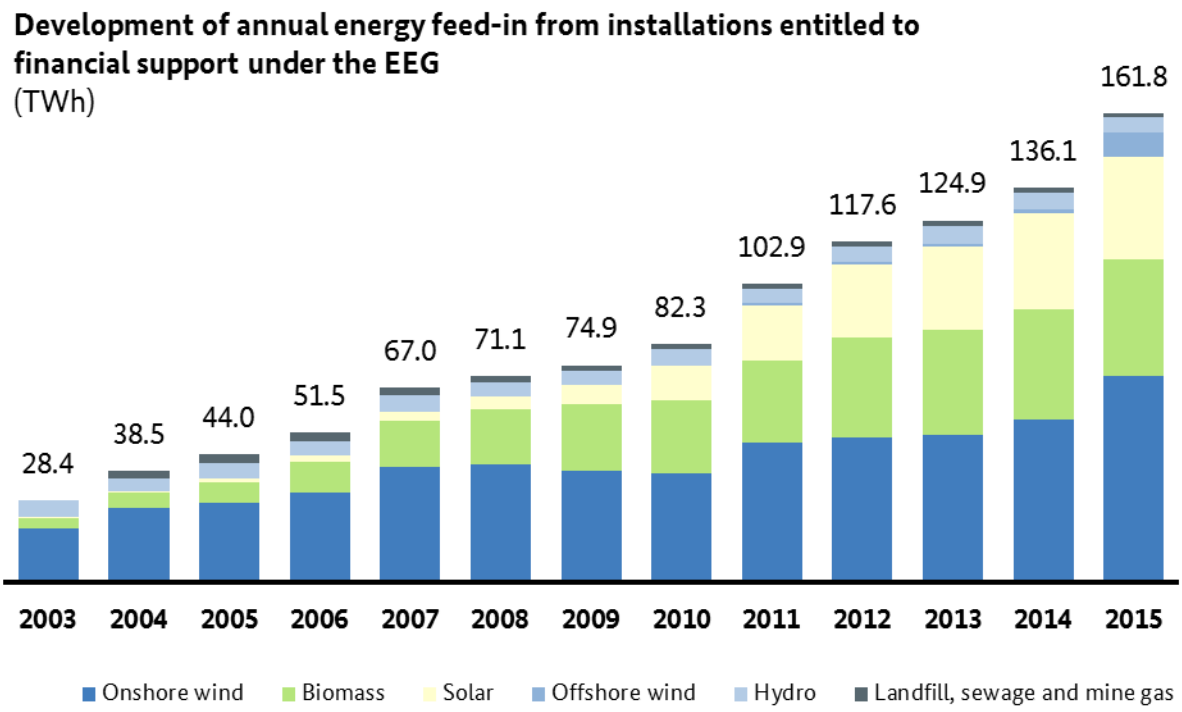

Figure 16: Development of annual energy feed-in from installations entitled to support under the EEG

The largest share of annual energy feed-in of 70.9 TWh (44%) was generated by onshore wind plants, followed by biomass installations with a share of 40.6 TWh (25%) and solar installations with a share of 35.2 TWh (22%).

Annual energy feed-in from installations entitled to support under the EEG by energy source

	Total as of 31 December 2014	Total as of 31 December 2015	Increase / decrease compared with 2014
	in GWh	in GWh	%
Hydro	5,646	5,347	-5.3
Gases[1]	1,646	1,438	-12.7
Biomass	38,313	40,628	6.0
Geothermal	98	133	35.7
Onshore wind	55,908	70,922	26.9
Offshore wind	1,449	8,162	463.1
Solar	33,002	35,212	6.7
Total	136,063	161,842	18.9

[1] Landfill, sewage and mine gas

Table 12: Annual energy feed-in from installations entitled to support under the EEG by energy source (as of 31 December 2015/31 December 2014)

As was the case in the prior year, the annual energy feed-in from hydropower and from landfill, sewage and mine gas fell in 2015, while the annual energy feed-in generated by offshore wind plants continued to increase. This increase in annual energy feed-in from offshore wind plants is proportionate to the rise in installed capacity.

There was also a sharp increase of 27% in annual energy feed-in from onshore wind energy in 2015, which was attributable in particular to the high-yield wind year.

Compared with the previous years, there were high annual average wind speeds all across Germany, in particular in the northern regions where a majority of the onshore wind power plants are installed.

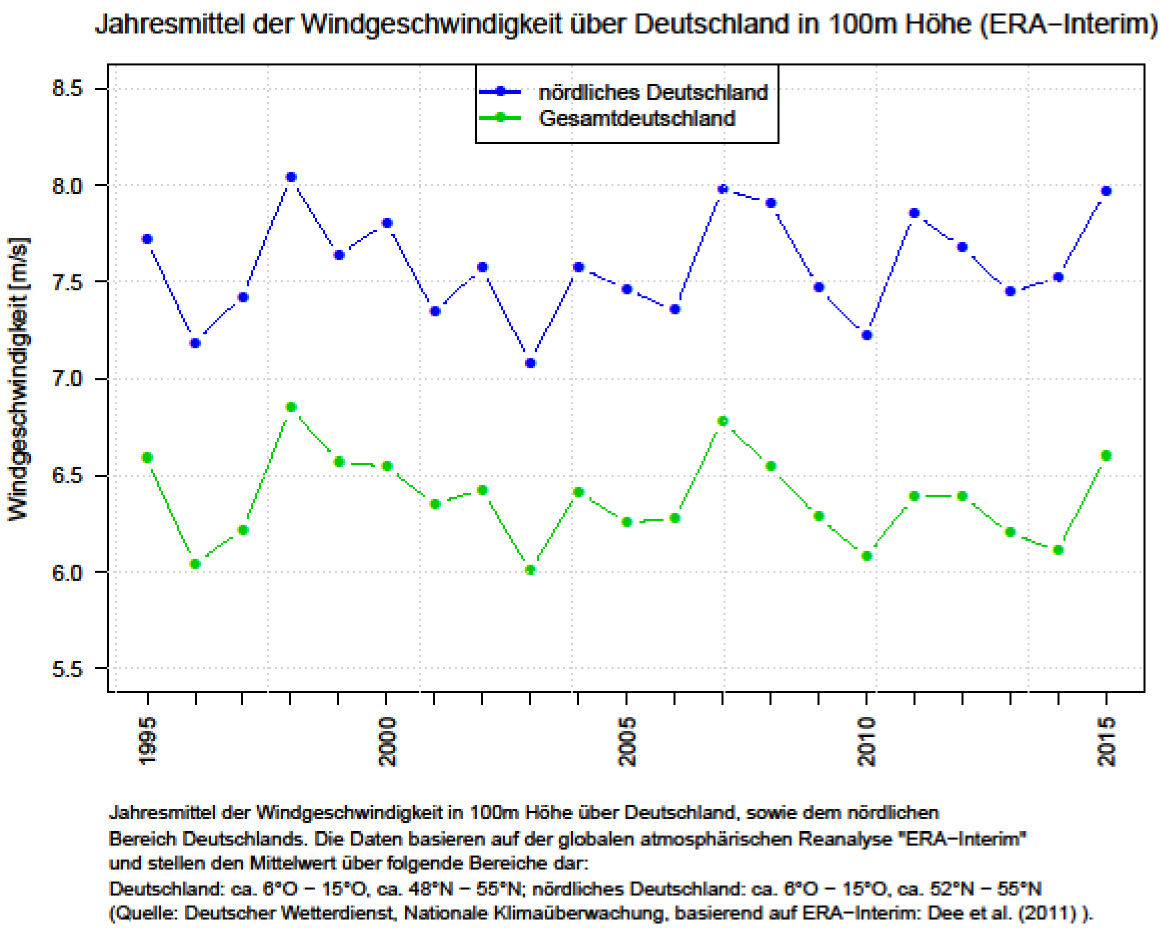

Figure 17: Annual average wind speed at 100 m elevation for all of Germany as well as for northern Germany

Maximum feed-in from wind power plants and photovoltaic installations

The maximum feed-in from wind power plants and photovoltaic installations increased sharply compared with previous years. In 2015, the maximum feed-in from wind power plants and photovoltaic installations of 47.6 GW was recorded on 30 March 2015. This peak feed-in was due mainly to the rise in the capacity of wind power plants and photovoltaic installations, but can also be attributed to the particular weather conditions on that day. On 30 March, wind power plants fed up to 34.7 GW into the grid, caused by the spring storm NIKLAS. This coincided with a comparatively high level of feed-in of 13.0 GW from photovoltaic installations. NIKLAS was among the most powerful March storms recorded during the reference period from 1981 to 2010. Locally, in particular in northern Germany, the maximum 10-minute mean wind speed exceeded that of the low-pressure storm system KYRILL.[16]

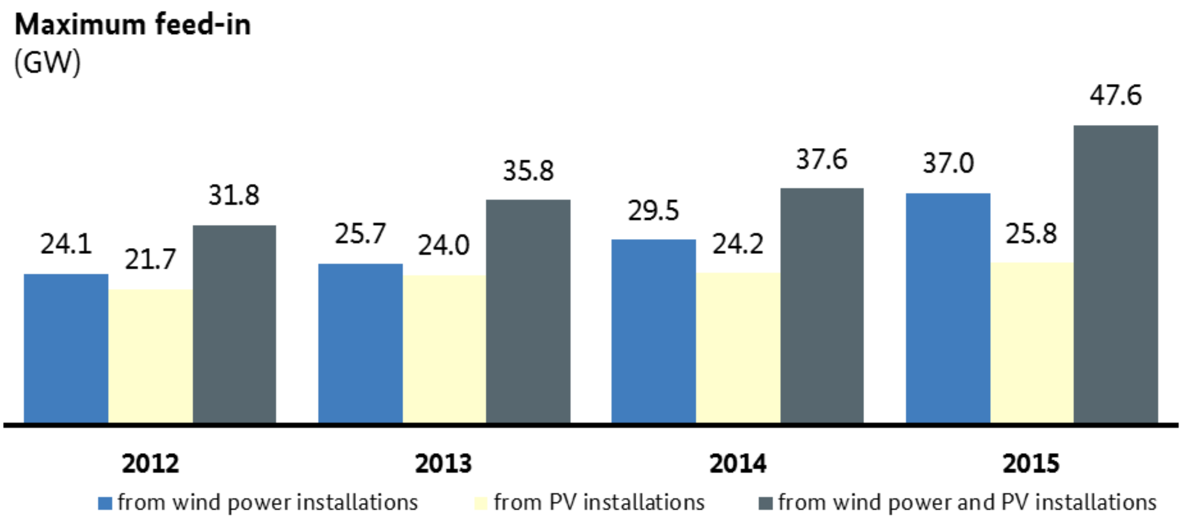

Figure 18: Maximum feed-in

In 2015 the maximum feed-in from photovoltaic installations of 25.8 GW was recorded on 21 April 2015. By far the year's highest feed-in values for wind power plants (onshore and offshore) were recorded in December 2015. The peak capacity of 37 GW achieved on 18 November 2015 was due primarily to the gale force winds of storm BILLIE. Several peak values were also observed in the first half of the year as a result of various storm systems.

[16] Deutscher Wetterdienst: Hintergrundpapier Orkantief NIKLAS (information paper on storm NIKLAS), p. 4

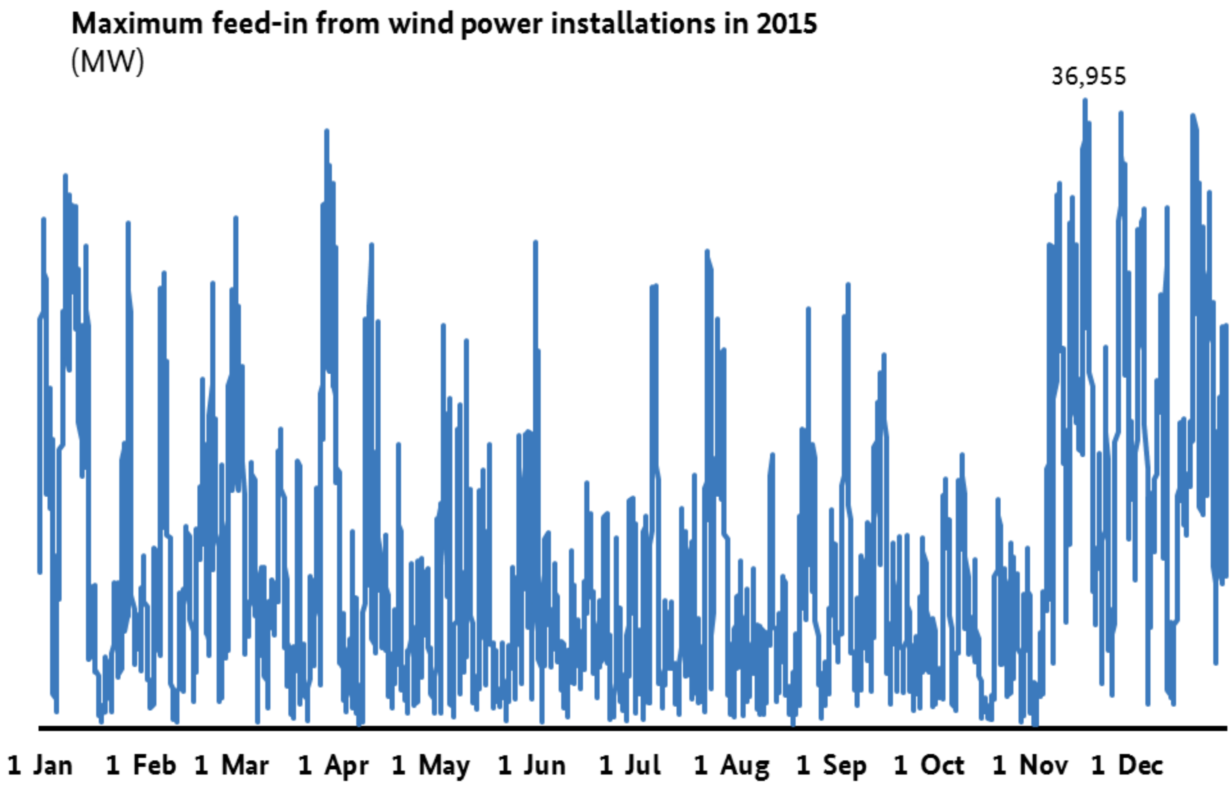

Figure 19: Maximum feed-in from wind power plants in 2015

Breakdown by fixed feed-in tariffs and direct selling

As an alternative to fixed feed-in tariffs under the EEG 2012, installation operators were able to choose between three different forms of direct selling, as provided for by section 33b EEG 2012: claiming a market premium, reducing the EEG surcharge through energy utilities (green electricity privilege), or other forms of direct selling. Under the EEG 2014, direct selling is now the standard form of selling. Only new installations with a capacity of up to 100 kW[17] can still opt for fixed feed-in tariffs. Other forms of direct selling, ie selling without claiming financial support, also remain possible.

Despite having had the option of selling renewable energy directly for some time, only a few installation operators made use of the option of direct selling in 2009. Since the 2012 revision of the EEG, there has been a clear shift towards this form of selling. In 2013 more than half of annual energy feed-in was sold directly, and in 2014 a total of 62.8% of annual feed-in was sold through direct channels. With the introduction of direct selling as the standard for new installations, a fixed feed-in tariff was paid for only 30.6% of annual energy feed-in in 2015.

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[17] Until December 2015, the threshold was temporarily at 500 kW. As so 1 January, all new installations with a capacity of more than 100 kW must participate in direct selling.

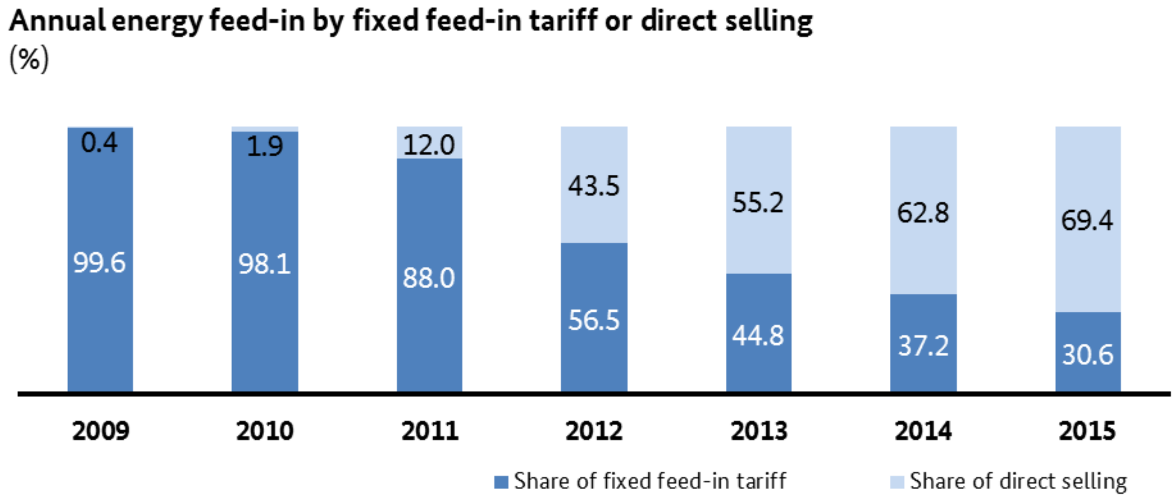

Figure 20: Annual energy feed-in from installations entitled to financial support by fixed feed-in tariff and direct selling

Table 13 shows that, for most energy sources, far more than half of all energy feed-in is sold directly. In the case of offshore wind power plants, direct selling accounts for nearly 100% (2014: 90%) of annual feed-in, while for onshore wind power the share is over 90%. The proportion of electricity sold directly from photovoltaic installations (18.6%) continues to be relatively low (2014: 16.5%).

Annual energy feed-in from installations with a fixed feed-in tariff and installations with direct selling

	All installations GWh	Installations with feed-in tariff GWh	Installations with direct selling GWh	Share of installations with direct selling in total annual feed-in %
Hydro	5,347	2,445	2,903	54.3%
Gases[1]	1,438	532	906	63.0%
Biomass	40,628	11,154	29,475	72.5%
Geothermal	133	80	53	39.9%
Onshore wind	70,922	6,680	64,242	90.6%
Offshore wind	8,162	22	8,140	99.7%
Solar	35,212	28,652	6,560	18.6%
Total	161,842	49,564	112,278	69.4%

[1] Landfill, sewage and mine gas

Table 13: Annual energy feed-in from installations with a fixed feed-in tariff and installations with direct selling

In 2015 the main energy source for direct selling was onshore wind power, which accounted for a share of 57.2% (2014: 57.3%). The share of energy feed-in from offshore wind power installations also increased sharply to 7.3% (2014: 1.5%).

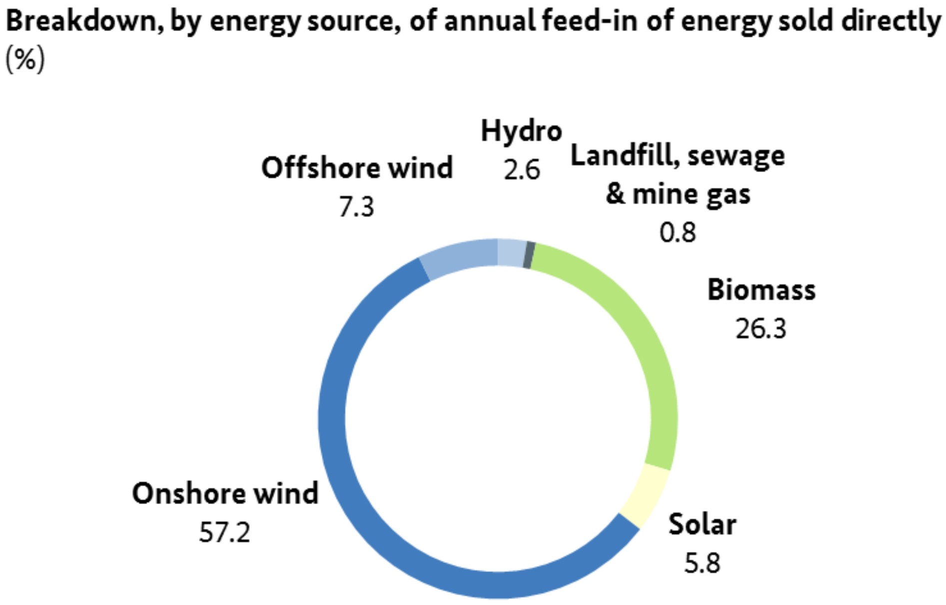

Figure 21: Breakdown, by energy source, of annual energy feed-in sold directly

2.2.4 Financial support

Financial support for the renewable energy fed into the public electricity network is paid by the operators to whose networks the generating installations are connected in accordance with the technology-specific reference values (rates) as defined in the EEG. The financial support is paid for the year in which the installation is commissioned and for a subsequent period of 20 years.

In 2015 a total of €24.2bn was paid to installation operators by the operators to whose networks the installations are connected. This includes, on the one hand, the remuneration payments to installation operators who sell their electricity through transmission system operators (fixed feed-in tariff). On the other hand, this amount also includes premium payments to installation operators who market their electricity themselves ("market premium"). In contrast to previous years, the majority of financial support in 2015 no longer went to installations with fixed feed-in tariffs; instead, funding is distributed more or less equally between installations with fixed feed-in tariffs and those with direct selling (fixed feed-in tariffs: 52%, direct selling: 48%).

Photovoltaic installations (€10.6bn), biomass installations (€6.8bn) and onshore wind power installations (€5.1bn) accounted for significant shares of this financial support.

Financial support by energy source

	Total as of 31 December 2014 € million	Total as of 31 December 2015 € million	Increase / decrease compared with 2014 %
Hydro	401	407	1.5%
Gases[1]	83	73	-11.8%
Biomass[2]	6,379	6,754	5.9%
Geothermal	23	29	26.9%
Onshore wind	4,046	5,083	25.6%
Offshore wind	213	1,262	492.7%
Solar	10,230	10,640	4.0%
Total	21,374	24,248	13.4%

[1] Landfill, sewage and mine gas

[2] including support for flexibility

Table 14: Financial support by energy source (as of 31 December 2015/31 December 2014)

Table 14 shows that compared with previous years, there was a greater increase in financial support in 2015, in particular in the area of offshore and onshore wind power. This increase is attributable to two effects: the sharp increase in annual energy feed-in from these installations that received remuneration payments (see Chapter I.B.2.2.3) and declining wholesale prices for electricity, which have diminished market revenues and thus increased premium payments.

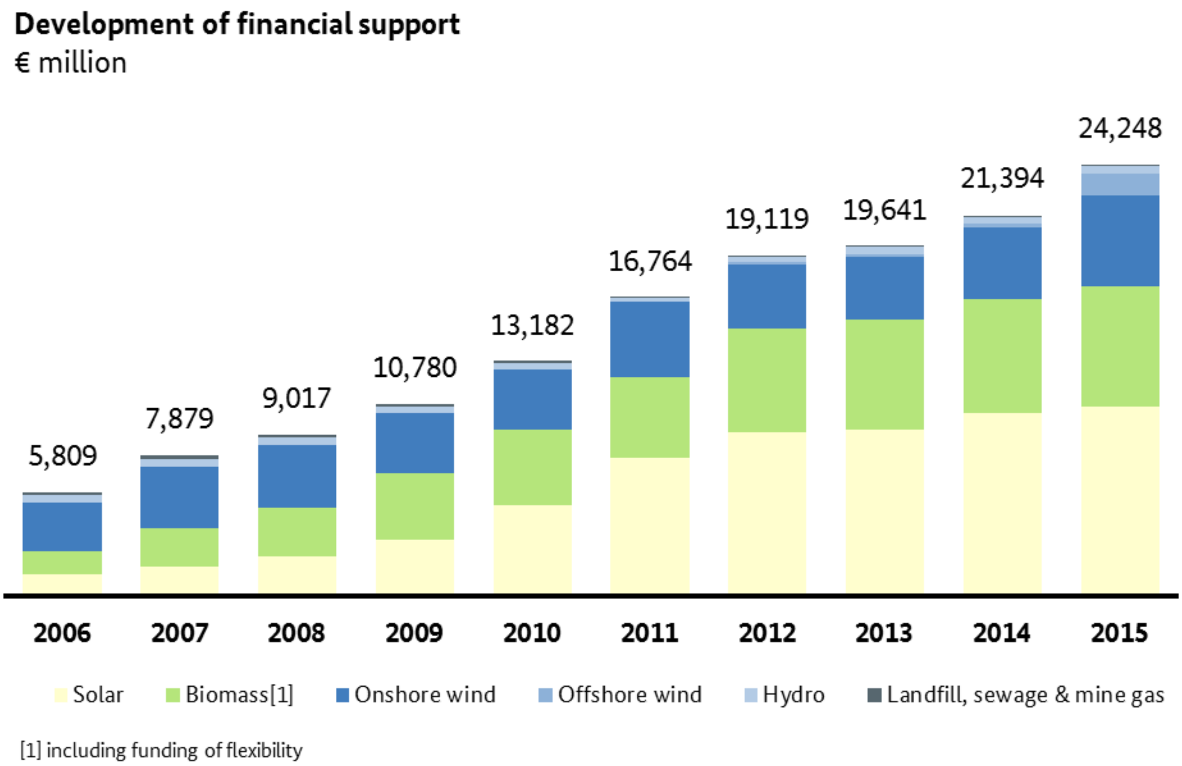

Figure 22: Trends in financial support by energy source

The financial support for EEG installations is for the most part refinanced through the EEG surcharge. Accordingly, the increase in support payments leads to an increase in the EEG surcharge over time. A portion of this increase is attributable to the decline in wholesale prices for electricity and market profits for renewable electricity. Figure 23 shows this development.

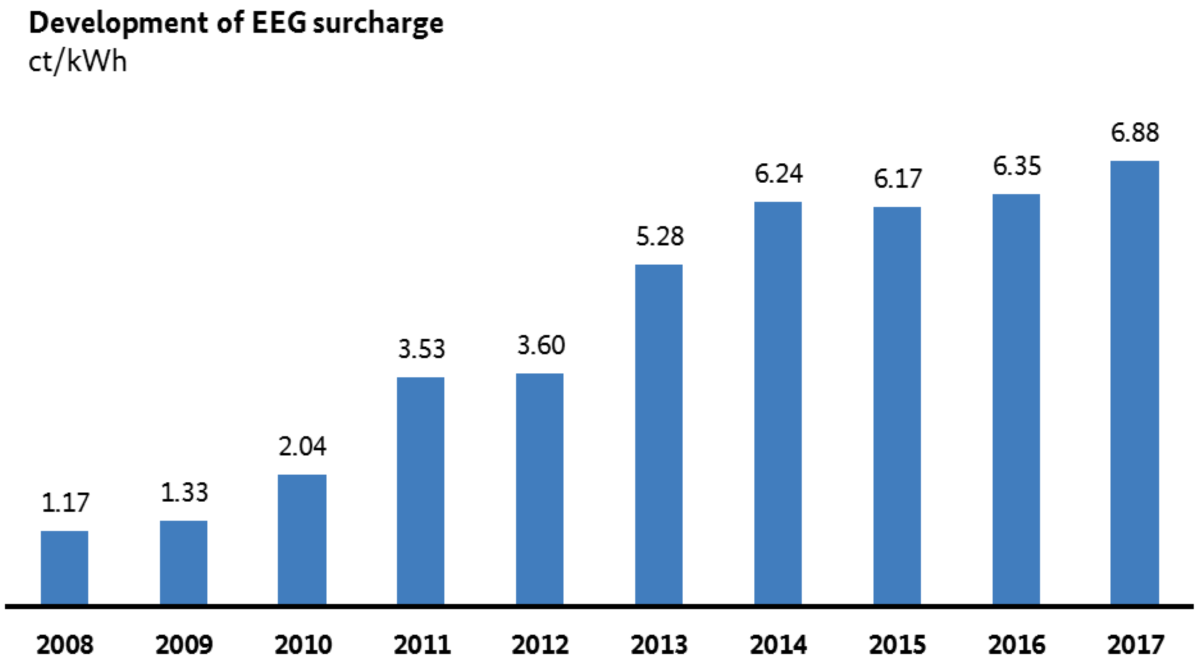

Figure 23: Changes in the EEG surcharge

Lowering of funding rates

Funding rates for the individual technologies have been redefined in the EEG 2014. Various rewards have also been eliminated, thus simplifying the funding system. To reflect the cost reductions brought about by technological advancements, automatic cost reduction mechanisms have been introduced to address these developments. Thus, as of September 2014, the funding rates for solar power are reduced by a set percentage each month. For onshore wind power and biomass, funding rates are reduced on a quarterly basis as of January 2016. There is an additional adjustment (reduction or increase) of funding rates that depends on the actual capacity expansion in a pre-defined reference period. If the planned expansion corridor is exceeded, the degression rate used for calculating financial support is automatically increased, thus lowering funding rates. If, by contrast, expansion fails to meet the statutory expectations, funding rates remain the same or even rise. Calculations are based on the data recorded in the installations register and in the photovoltaic registration portal.

Because the actual expansion of photovoltaic installations during the respective reference period[18] was as much as 900 MW below the target corridor (2.4 to 2.6 GW gross total per year), funding rates for the first three quarters of 2015 were reduced by 0.25% (instead of the planned reduction of 0.5% if expansion had met the corridor). In the fourth quarter of 2015, as well as in the first three quarters of 2016, expansion during the relevant reference period was more than 900 MW below the defined corridor, so that there was no further decline in funding rates in these quarters.

[18] The relevant reference period extends 12 months into the past, beginning 14 months before the adjustment of the funding rate. For example, the actual new expansion of solar capacity in the months June 2015 to May 2015 is taken into account for the calculation of the adjustment in the calendar months July 2016 to September 2016.

Funding rates for onshore wind power were reduced by 1.2% at the beginning of every quarter of 2016 (instead of the planned reduction of 0.4% if expansion had met the corridor), because expansion in the respective reference periods exceeded the defined corridor (2.4 to 2.6 GW net per year) by more than 800 MW.

Funding rates for biomass were reduced by 0.5% at the beginning of each quarter of 2016; this is the standard reduction pursuant to section 28(2) EEG, applicable because the defined corridor of 100 MW gross expansion was not exceeded.

Reduction of funding rates

Energy source	Relevant reference period for calculating actual reduction	Growth corridor in MW	Actual growth in reference period in MW	Applied reduction %	Reduction cycle	Period of validity of reduction
Solar	Sep. 13 - Aug.14	2,400 - 2,600 (gross)	2,398	0.25	monthly	Q3 2014
	Dec. 13 - Nov. 14		1,953	0.25		Q1 2015
	Mar. 14 - Feb. 15		1,811	0.25		Q2 2015
	Jun.14 - May15		1,581	0.25		Q3 2015
	Sep. 14 - Aug. 15		1,437	0		Q4 2015
	Dec. 14 - Nov. 15		1,419	0		Q1 2016
	Mar. 15 - Feb. 16		1,367	0		Q2 2016
	Jun. 15 - May 16		1,336	0		Q3 2016
Onshore wind	Aug. 14 - Jul. 15	2,400 - 2,600 (net)	3,666	1.2	quarterly	Q1 2016
	Nov. 14 - Oct. 15		3,712	1.2		Q2 2016
	Feb. 15 - Jan. 16		3,564	1.2		Q3 2016
	May 15 - Apr. 16		3,941	1.2		Q4 2016
Biomass	Aug. 14 - Jul. 15	< 100 (gross)	71	0.5	quarterly	Q1 2016
	Nov. 14 - Oct. 15		67	0.5		Q2 2016
	Feb.15 - Jan. 16		25	0.5		Q3 2016
	May 15 - Apr. 16		25	0.5		Q4 2016

Table 15: Reduction of funding rates

2.2.5 Auctions for solar farm funding

Financial support for ground-mounted photovoltaic (PV) installations was switched to an auction system in 2015. The operators of new ground-mounted PV installations commissioned after September 2015 are only granted financial support if their bid has previously been accepted within the framework of an auction. The legal basis for these auctions is the Ground-mounted PV Auction Ordinance ("Freiflächenausschreibungsverordnung" or FFAV), which came into effect on 12 February 2015.

The auctions for ground-mounted PV installations are so-called pilot auctions, in which the instrument of auctions for renewable energies was tested for the first time. The Bundesnetzagentur was responsible for conducting the pilot auctions and carries out three rounds of bidding each year on 1 April, 1 August and 1 December. For 2015 and 2016, bids can be placed for a total volume of 900 MW (2015: 500 MW, 2016: 400 MW). As of 2017, the instrument of auctions will be used to determine the financial support not only for ground-mounted PV installations, but it will be expanded to all large-scale solar power systems (rooftop and ground-mounted systems) with an installed capacity of over 750 kW. As a result, bids can then be placed for a total of 600 MW each year. Small and medium sized PV systems with a capacity of under 750 kW will continue to be eligible for financial support according to statutory funding rates.

In the auctioning process so far, the level of support for ground-mounted PV systems is determined on the basis of bids. The bids must specify a price in cents per kilowatt hour (bid rate) for the electricity generated in the installations and an installation capacity in kilowatts (bid volume). Support is granted to the bidders with the lowest bid rates until the total volume put out to auction has been reached.

Within the framework of the five auction rounds, two different pricing procedures were used: uniform pricing and pay-as-bid pricing. In a uniform price auction, the last highest successful bid determines the price for the other bids. In the pay-as-bid model, by contrast, successful bids are granted support on the basis of the rate specified in the respective bid. In the bidding rounds conducted thus far, the average support level has declined from round to round (see Table 16).

Once the successful bidder has set up and commissioned a solar farm, he can apply to the Bundesnetzagentur for an entitlement to financial support. He is entitled to financial support for his installation if the installation is located in an area which is eligible for such support and is not bigger than 10 megawatts. Thus far (as of September 2016), 21 installations with a total capacity of 121 MW have been built.

Support awards lapse two years after notification if no application for an entitlement to support has been submitted by the deadline. In this case, the bidder must pay a fine.

Installations are generally remunerated as provided for in the EEG, ie via supported direct selling. Support is allocated to the bidders' installations, whereby several allocations can be made to one installation. In addition, the location specified in the bid need not necessarily correspond to the actual location. The Bundesnetzagentur calculates a level of support for each installation. Financial support is provided for a period of 20 years from the year the installation was commissioned (not 20 years including the year the installation was commissioned, as applicable elsewhere in the EEG).

The bidding rounds conducted thus far have been successful: most bids met the formal requirements. Unfortunately, there are occasionally still cases of bids being disqualified due to individual errors that can be avoided, although this is occurring less frequently.

Competition in the auctions was intense: all rounds were significantly oversubscribed. The following table provides an overview of the five bidding rounds conducted thus far.

Results of five auction rounds for ground-mounted PV systems

	April 2015	August 2015	Dez 15	April 2016	August 2016
Volume put up for auction	150 MW	150 MW	200 MW	125 MW	125 MW
Submitted bids	170 (715 MW)	136 (558 MW)	127 (562 MW)	108 (539 MW)	62 (311 MW)
Winning bids	25 (157 MW)	33 (159 MW)	43 (204 MW)	21 (128MW)	22 (118MW)
Excluded bids	37 (144 MW)	15 (33 MW)	13 (33 MW)	16 (57 MW)	9 (46 MW)
Average support rate	9.17 ct/kWh	8.49 ct/kWh	8.00 ct/kWh	7.41 ct/kwh	7.25 ct/kwh
Highest support rate	11.29 ct/kWh	11.18 ct/kWh	11.09 ct/kWh	11.09 ct/kWh	11.09 ct/kWh
Applicable support rate[1]	9.02 ct/kWh	8.93 ct/kWh	No longer possi-ble under EEG	No longer possi-ble under EEG	No longer possi-ble under EEG
Price mechanism	Pay-as-bid	Uniform pricing	Uniform pricing	Pay-as-bid	Pay-as-bid

[1] at the time of auction

Table 16: Results of the five auction rounds for ground-mounted PV systems

In the five auction rounds, support was granted for projects in all federal states, with the exception of the city-states, with a concentration in Germany's eastern states as well as in Bavaria. However, bidders are not required to realise successful projects in the location specified in the bid.

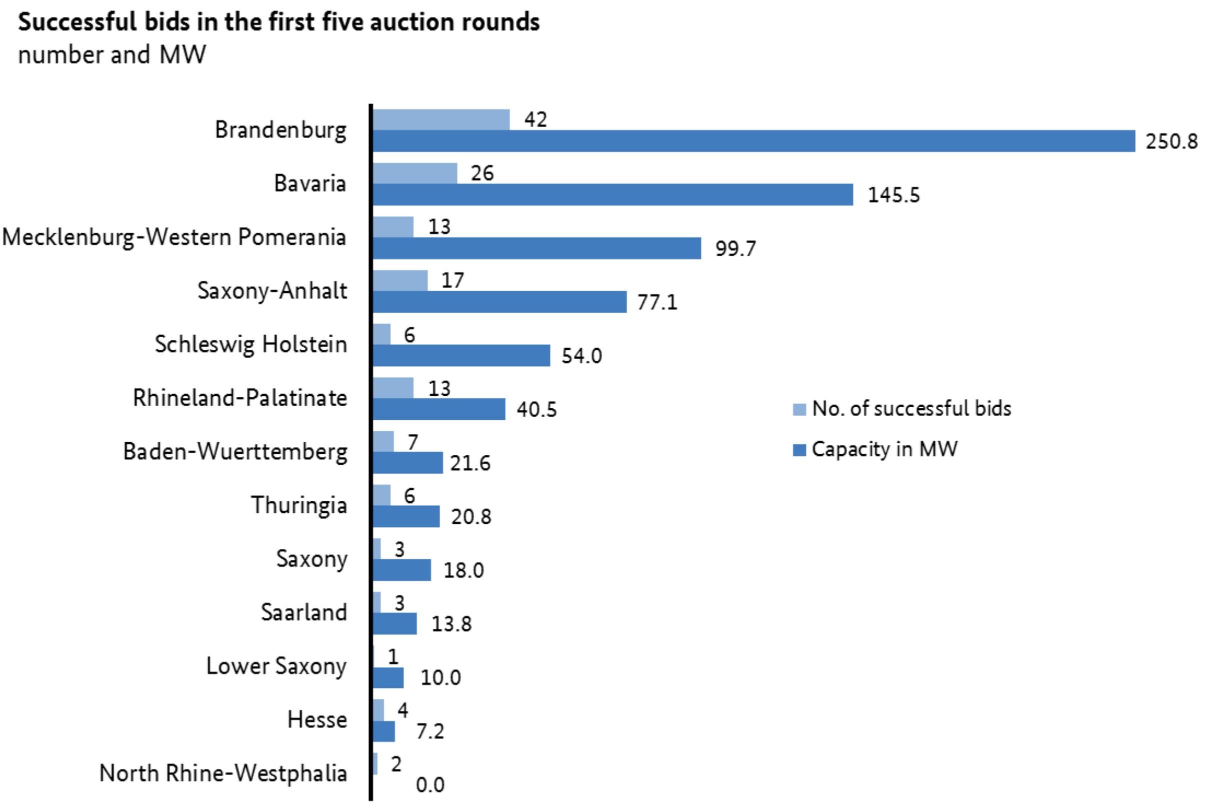

Figure 24: Successful bids in the first five auction rounds

Outlook

In the EEG 2017, auctions are planned for onshore and offshore wind power and for biomass. Here too, the Bundesnetzagentur will be responsible for carrying out the auctions.

C Networks

1. Status of network expansion

1.1 Monitoring of projects under the Power Grid Expansion Act (EnLAG)

Attention was focused on speeding up the installation of extra-high voltage electricity lines back in 2009 with the passing of the Power Grid Expansion Act (EnLAG).

The current amendment to this legislation specifies 22 projects which require urgent implementation in order to meet energy requirements. A review preceding production of the 2022 network development plan resulted in the cancellation of project no. 22 and, following production of the 2024 network development plan, of project no. 24 from the most recently amended EnLAG. Six of the 22 projects are underground cable pilot lines.

The four German transmission system operators (TSOs), TenneT, 50Hertz, Amprion and TransnetBW, are responsible for planning, establishing and operating these projects. The relevant federal state authorities are responsible for conducting the applicable spatial planning and planning approval procedures for construction of a total of around 1,800 new path kilometres. The Bundesnetzagentur regularly documents the status of approval procedures for specific projects on its website at http://www.netzausbau.de. This is based on the current state of construction and planning work, as detailed in quarterly reports produced by the four TSOs.

Current status

Of the total 1,800 kilometres of lines which are required, approximately 650 kilometres (or around 35%) have so far been constructed based on the third quarterly report for 2016 and around 900 kilometres have been approved. The TSOs expect around 45% of the kilometres of line provided for by the Power Grid Expansion Act (EnLAG) to be completed by 2017. To date, none of the projects with pilot routes for underground cables has gone into operation. TSO Amprion is currently preparing pilot operation of the first 380-kV underground cable pilot project in Raesfeld.

The following map shows the current expansion status of EnLAG procedures up to the third quarter of 2016:

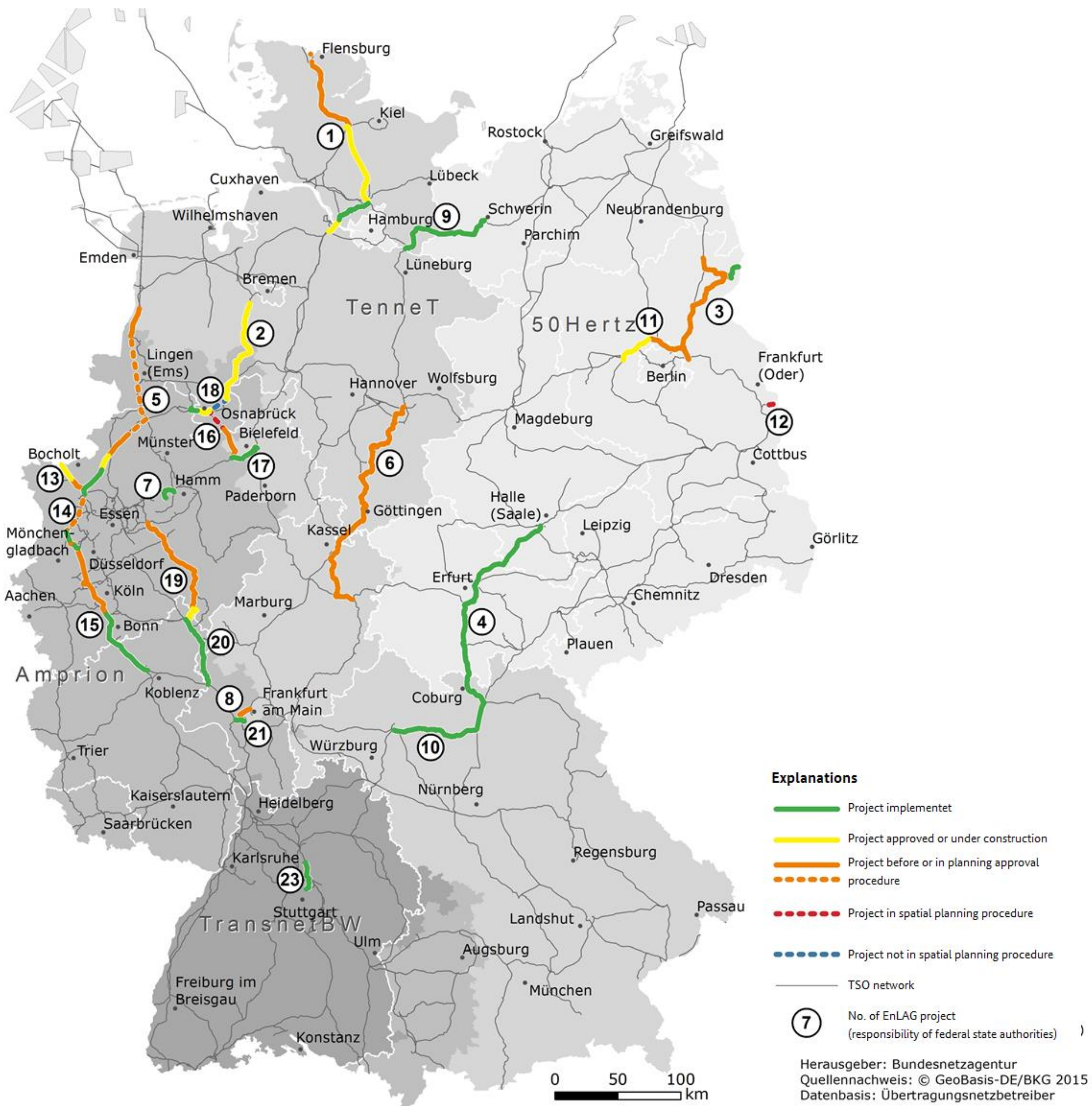

Figure 25: Progress on expanding power lines under the Power Grid Expansion Act (EnLAG) by the third quarter of 2016

1.2 Monitoring the federal requirements plan

Alongside EnLAG project monitoring, the Bundesnetzagentur also issues quarterly reports on the procedural status of expansion projects under the Federal Requirements Plan Act (BBPlG) on its website at www.netzausbau.de/vorhaben.

Of a total of 43 projects nationwide, 16 cross state or national borders within the meaning of the Grid Expansion Acceleration Act (NABEG). The Bundesnetzagentur is responsible for the federal sectoral planning of these 16 projects as well as the subsequent planning approval procedure.
The lines detailed in the Federal Requirements Plant Act currently have a total length of around 6,100 km. The total length of power lines will be largely determined by the route of the new direct current project linking the

north and south of Germany. The route this project takes will become apparent in the course of the procedure. By the third quarter of 2016 approximately 400 km of the total route of around 6,100 km had been approved and 80 km completed.

Eight of the 43 projects have been singled out as pilot projects for low-loss transmission over large distances (high-voltage direct current transmission). Underground cabling has been prioritised for five direct current projects and for sections of five alternating current projects. In addition, one pilot project has been designated for high temperature low sag transmission and two others for submarine cabling.

The following map shows the current expansion status of Federal Requirements Plan Act procedures up to the third quarter of 2016:

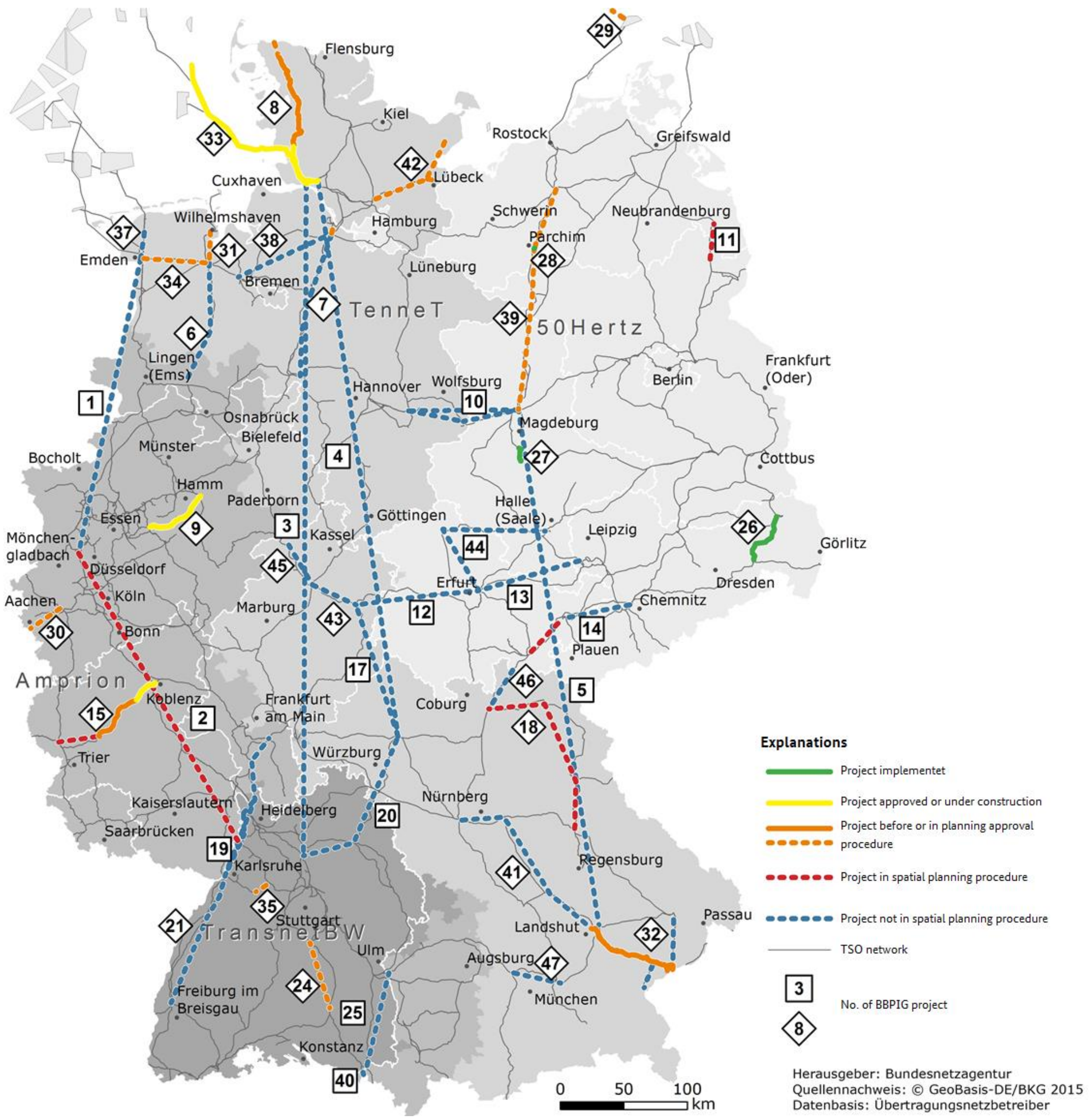

Figure 26: Progress on expanding power lines under the Federal Requirements Plan Act (BBPlG) by the third quarter of 2016

1.3 Network development plan 2025 and 2017 to 2030

The NEP 2025 was discontinued in compliance with section 118(16) second sentence EnWG. The procedure, which was already at an advanced stage, would not have been capable of taking adequate account without delay of the amendment of the EEG adopted in the summer. This is because the developments arising from the amendment depart from the forecasts in the 2025 scenario framework. Amongst other things these developments involve changes to development corridors and the spatial distribution of renewable energies. This particularly applies to onshore wind energy and to biomass.

The NDP 2025 would have needed to be modified accordingly. This procedure would then have overlapped with the procedure for the next NDP (for the target year 2030). This would have meant that two network development plans, each with its own target years, would have had to be discussed and consulted on simultaneously at the end of 2016: the second draft of the NDP 2025 by the Bundesnetzagentur and, at the same time, the second draft of the NDP 2017 to 2030 by the transmission system operators. This would have been counterproductive for transparent public participation and discussion.

The Bundesnetzagentur took the significant changes to the amendment of the EEG into account when it approved the scenario framework 2017 to 2030 as the basis for the current NDP 2017 to 2030.

1.4 Status of offshore network development plan 2025

The transmission system operators published the revised draft version of the Offshore NDP 2025 on 29 February 2016. It was only possible to take into account the introduction of a transitional and tendering system for the existing offshore wind farm from the year 2021 after the procedure had started. The Bundesnetzagentur published its preliminary evaluation findings on the O-NDP 2025 on 14 June 2016 and engaged in consultations with the public through to 9 August 2016. At the time this monitoring report went to press the O-NDP 2025 had still not been confirmed.

The offshore network development plan (O-NDP) defines requirements for grid connection lines and concerns grid connection systems for the offshore wind farms in the North Sea and Baltic Sea. The offshore network development plan distinguishes between "starting grid" and "grid extension" connection lines. The starting grid includes all the commissioned, planned and operational grid connection systems for wind farms for which a grid connection commitment had been made before the offshore network development plan was drawn up or which have been commissioned on the basis of an offshore network development plan. The grid extension includes all the power lines which have been confirmed in the current offshore network development plan.

1.5 Grid connection of offshore wind farms

On 24 November 2015 the Bundesnetzagentur's Ruling Chamber 6 concluded the second proceedings for the allocation of connection capacity on grid connection lines for offshore wind farms with the allocation of connection capacity to the applicants. The auction was held on 3 November 2015. The bids submitted by Trianel Windkraftwerk Borkum GmbH & Co.KG (50 MW), British Wind Energy GmbH (42 MW), EnBW Hohe See GmbH (50 MW) and ESG Edelstahl und Umwelttechnik Stralsund GmbH (2.3 MW) were awarded in full and the offer made by EnBW Albatros GmbH with 66.8 MW as a marginal offer was partially met. Total transmission capacity of 211.1 MW was allocated.

Upon application from Trianel Windkraftwerk Borkum GmbH & Co.KG the capacity allocation of 50 MW in respect of the wind farm Trianel Windkraftwerk Borkum GmbH & Co. KG was withdrawn on 13 June 2016.

On 28 January 2016 the Ruling Chamber concluded two administrative cases on capacity relocation under section 17d(5) EnWG. Both capacity relocations were designed to support the orderly and efficient use and exploitation of grid connection lines.

The first case concerned the reciprocal relocation of the connection capacity of the offshore wind farms in Cluster 8 of the Hohe See and Albatros I test field offshore wind farms in the North Sea. This ruling resulted in the relocation of the offshore Hohe See wind farm's connection capacity of 50 MW from the NOR-6-2 to the NOR-8-1 grid connection line. At the same time, the connection capacity of the Albatros I test field offshore wind farm of 50 MW was also relocated from the NOR-8-1 to the NOR-6-2 grid connection line. In a second case the Ruling

Chamber decided to relocate the connection capacity of the Borkum Riffgrund 1, Merkur Offshore and Trianel Windpark Borkum offshore wind farms in Cluster 2 in the North Sea so that all of these wind farms are connected to just one of the NOR-2-2 or NOR-2-3 grid connection lines.

The Offshore Wind Energy Act which was passed on 8 July 2016 and which enters into force on 1 January 2017 entails a major reform of the funding regime for offshore wind farms. Statutory feed-in tariffs will be replaced by competitive pricing. Offshore wind farms which are commissioned between 2021 and 2025 can compete in two rounds of tenders for a total of 3,100 MW. Existing projects which have already progressed to a defined planning stage are eligible to participate in auctions during this transitional phase. Projects in the exclusive economic zone must also be located within certain clusters.

Tenders for offshore wind farms commissioned between 2026 and 2030 will be based on area planning. Under the "central model" tenders are held on 1 September each year for 700 MW to 900 MW as stipulated in the land development plan. One of the functions of the land development plan is to specify areas in which offshore wind farms should be erected in the future.

By 1 August 2016 a total of 31 applications had been submitted to the Bundesnetzagentur for the approval of investments in the connection of OWFs with a total volume of €21.6bn, of which 26 applications with a volume of €19.3bn have already been approved.

1.6 Network development planning 2017 to 2030

The first step in network development planning is consultation with and approval by the Bundesnetzagentur of a scenario framework produced by transmission system operators (TSOs) under section 12a EnWG. The 2017 to 2030 scenario framework is the first scenario framework in the new two-year cycle. The legally-defined reference period has been treated flexibly and 2030 used as the target year.

The scenario framework 2017 to 2030 was approved by the Bundesnetzagentur on 30 June 2016 and lays the foundations for the coming NDP 2017 to 2030.

Installed generating capacity in the 2030 scenario framework
in GW

Energy source	Reference 2015	Scenario A 2030	Scenario B 2030	Scenario B 2035	Scenario C 2030
Nuclear	10.8	0.0	0.0	0.0	0.0
Brown coal	21.1	11.5	9.5	9.3	9.3
Hard coal	28.6	21.7	14.8	10.8	10.8
Natural gas	30.3	30.5	37.8	41.5	37.8
Oil	4.2	1.2	1.2	0.9	0.9
Pumped storage	9.4	11.9	11.9	13.0	11.9
Other non-renew. sources	2.3	1.8	1.8	1.8	1.8
Total non-renew. sources	**106.9**[1]	**80.6**	**79.0**	**79.3**	**74.5**
Onshore wind	41.2	54.2	58.5	61.6	62.1
Offshore wind	3.4	14.3	15.0	19.0	15.0
Solar photovoltaics	39.3	58.7	66.3	75.3	76.8
Biomass	7.0	5.5	6.2	6.0	7.0
Hydro	5.6	4.8	5.6	5.6	6.2
Other renewable sources	1.3	1.3	1.3	1.3	1.3
Total generation renew. sources	**97.8**	**138.8**	**152.9**	**168.8**	**168.4**
Total generation	**204.7**	**219.4**	**231.9**	**248.1**	**242.9**

[1] Figures may not sum exactly owing to rounding

Table 17: Installed generating capacity in the 2030 scenario framework

Scenario framework 2030

Net electricity consumption (TWh)	**Reference 2015**	**Scenario A 2030**	**Scenario B 2030**	**Scenario B 2035**	**Scenario C 2030**
Net electricity consumption[2]	532.0	517.0	547.0	547.0	577.0
Drivers of sector coupling in millions					
Heat pumps	0.6	1.1	2.6	2.9	4.1
Electric vehicles	0.0	1.0	3.0	4.5	6.0
Annual peak load (GW)					
Annual peak load[3]	83.7	84.0	84.0	84.0	84.0
Flexibility options and storage (GW)					
Power-to-gas		1.0	1.5	2.0	2.0
PV battery-storage system		3.0	4.5	5.0	6.0
DSM (industry, crafts, trades and services)		2.0	4.0	5.0	6.0

Market modelling

			Max. carbon emissions of		
Requirements for market modelling			165m tonnes	137m tonnes	165m tonnes

[2] Including aggregate network losses in distribution system.
[3] Including aggregate power loss in distribution system.

Table 18: Other 2030 scenario framework figures

On the basis of the approved scenario framework the TSOs are required, under section 12b(3) sentence 3 EnWG, to produce the first draft of the electricity network development plan 2017 to 2030 by 10 December 2016. The approval of the scenario framework includes certain stipulations:

– Scenarios B 2030 and C 2030 state that the power plant pool in Germany will emit a maximum of 165 million t CO_2 by the year 2030. In Scenario B 2035 the upper limit is 137 million t CO_2.

– In order to reduce grid expansion requirements, all scenarios are based on a reduction of up to 3% in the volume of electricity fed in by all onshore wind farms and photovoltaic systems (existing and new). A reduction in feed-in from renewable energy- installations connected to the distribution networks will be made to optimise costs for the distribution systems.

– In all scenarios the total quantity of electricity which combined heat and power (CHP) can be reasonably expected to generate must be broken down according to energy source. This should make it possible to assess whether the statutory objective of increasing the net amount of electricity generated by CHP plants to 120 TWh by the year 2030 is met.

- An assessment must be made in all scenarios to determine whether the EEG objectives of increasing the share of gross electricity consumed which comes from renewable energies is met by 2030 or 2035.

- All the scenarios must also examine the contribution made by the electricity sector towards reducing greenhouse gas emissions and primary energy consumption.

2. Expansion in the distribution system, including measures for the optimisation, reinforcement and expansion of the distribution system

2.1 Measures for the optimisation, reinforcement and expansion of the distribution system

Distribution system operators (DSOs) are required to optimise, reinforce and expand their networks to reflect the state of the art without undue delay, in order to ensure the uptake, transmission, and distribution of electricity. The strong expansion in renewable energy installations, coupled with the legal obligation to connect and purchase regardless of network capacity, represents a considerable challenge for DSOs. Alongside conventional expansion measures, network operators are primarily responding to these challenges by developing increasingly smart grids which will allow them to adapt to changing requirements over time. The way forward and the measures adopted may differ considerably from one network operator to the next. Given the highly heterogeneous nature of grids in Germany, future energy developments mean that all DSOs need to develop and implement their own strategies for achieving efficient grid operations. It is actually quite useful in this context that so many networks are in any case due for modernisation. In many cases it will therefore be possible to convert grids by investing the financial returns from existing systems (intelligent restructuring) without any associated increases in network costs.

A total of 817 (previous year: 807) DSOs had provided information about the extent to which they had taken action to optimise and expand their networks. Compared with the previous year the number of companies has increased for all measures. Growth has been strongest in the optimisation of grids. A total of 34 companies report that they have implemented grid optimisation measures. This corresponds to an increase of almost 7% in the number of companies in this field. The following diagram shows the development of measures since 2009.

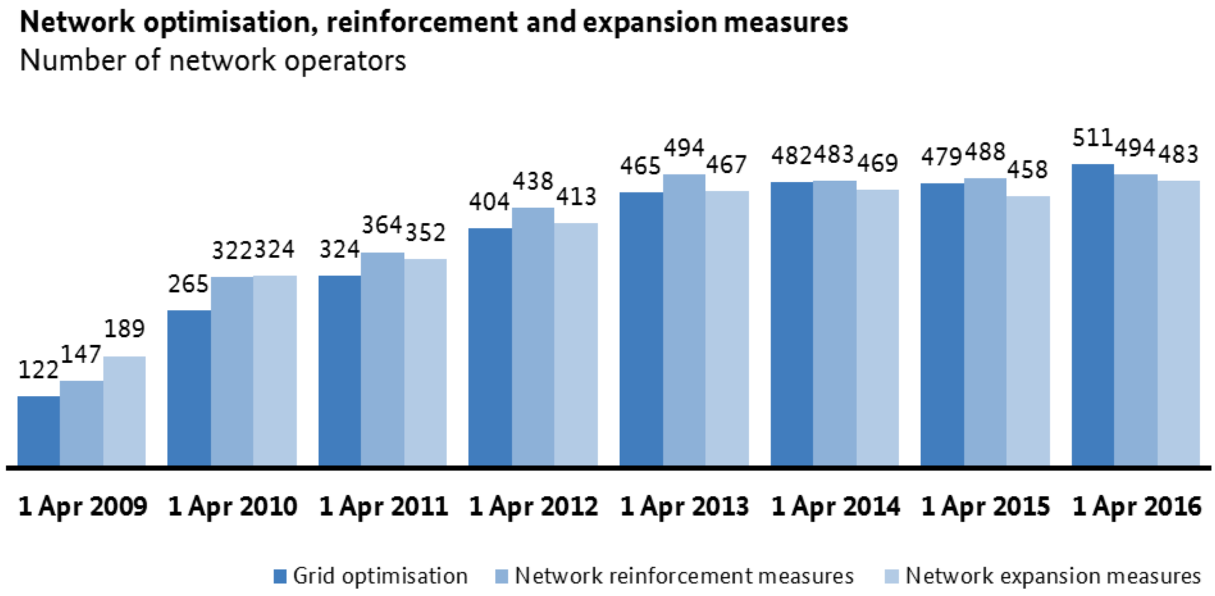

Figure 27: Measures for the optimisation, reinforcement and expansion of the distribution system

The following network optimisation and reinforcement measures are being implemented by DSOs.

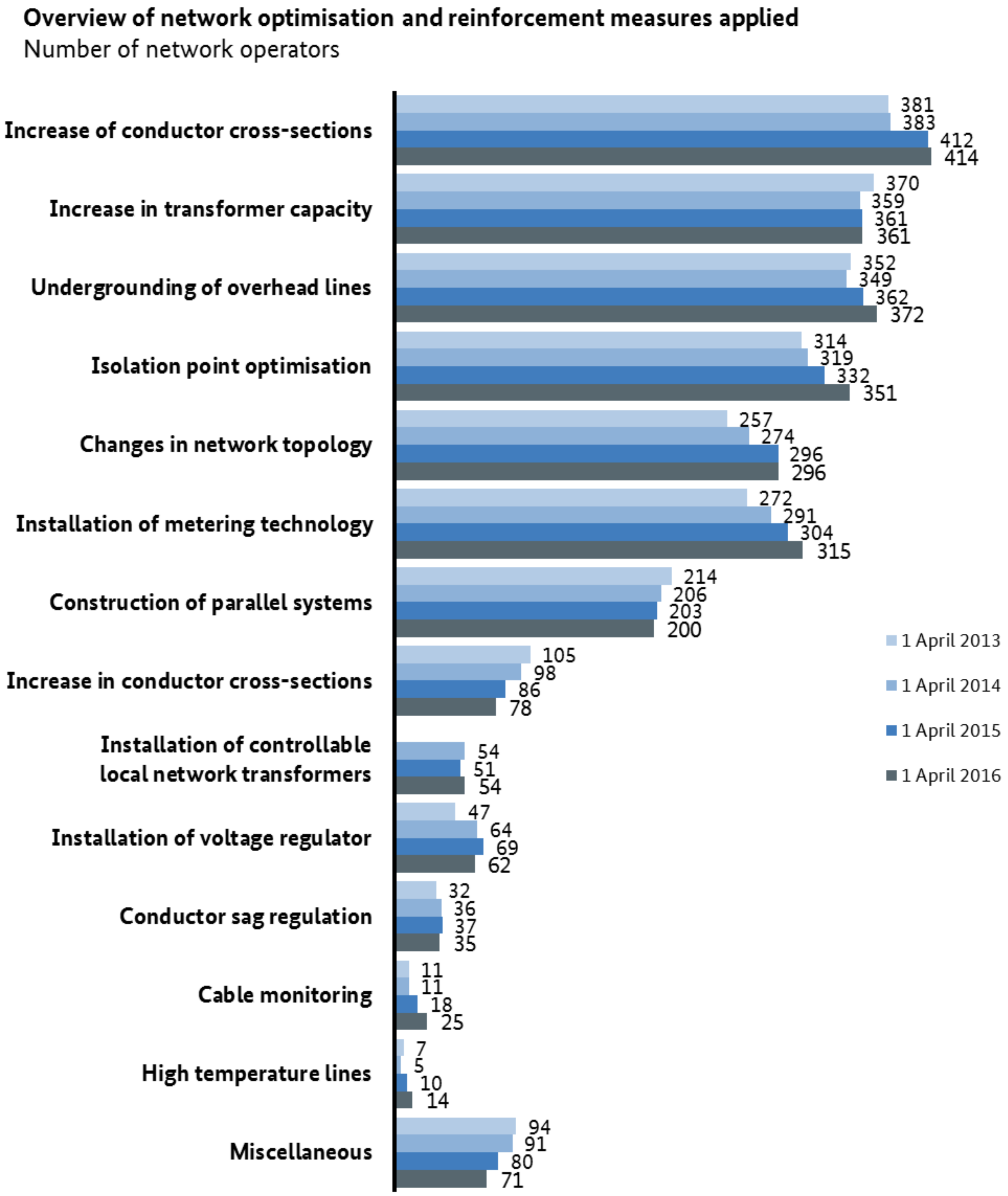

Figure 28: Overview of network optimisation and reinforcement measures applied

Compared to the previous year there was, in particular, an increase in the number of isolation point optimisation measures, in the installation of metering technology and the undergrounding of overhead lines. In contrast, slightly fewer measures were implemented to increase conductor cross-sections or install voltage regulators.

2.2 Grid expansion requirements of high-voltage network operators

Operators of high voltage networks with a rated voltage of 110 kilovolts are required by section 14(1b) EnWG to report annually on the grid status of their networks and the impact of the anticipated expansion in feed-in installations - including production of electricity from renewable energy sources – on their network in the following ten years.

The grid expansion requirements of high-voltage network operators were again calculated in this year's monitoring report. The questionnaire excluded DSOs whose 110-kV networks consist solely of short stub lines with a small total power line length, and DSOs which function solely as utilities for an industrial or chemicals park or similar. The questionnaire for the year under review 2015 was sent to a total of 57 DSOs.

The Bundesnetzagentur has also requested a network status and network expansion planning report in compliance with section 14(1a) EnWG from these 57 DSOs for the additionally operated low-voltage levels.

The reports submitted by the surveyed DSOs cover 98% of the circuit lengths at the high-voltage level, 74% at the medium-voltage level and 71% at the low-voltage level.

2.3 Total expansion requirements (all voltage levels)

On the reporting date 31 December 2015, total expansion requirements of €9.3bn in the next ten years (2016 – 2026) were reported to the Bundesnetzagentur. The projections of the large DSOs compared to the previous year are as follows (on 31 December 2014: €6.6bn / 56 DSOs); on 31 December 2013: €6bn / 53 DSOs) have gone up dramatically. The DSOs have not provided any reasons for this sudden increase. The recent changes made to the Incentive Regulation Ordinance mean that reasons need no longer be given. In this respect, the appropriateness of grid expansion at the DSO level is no longer assessed.

The following diagram shows the grid expansion requirements forecast by DSOs at all voltage levels.

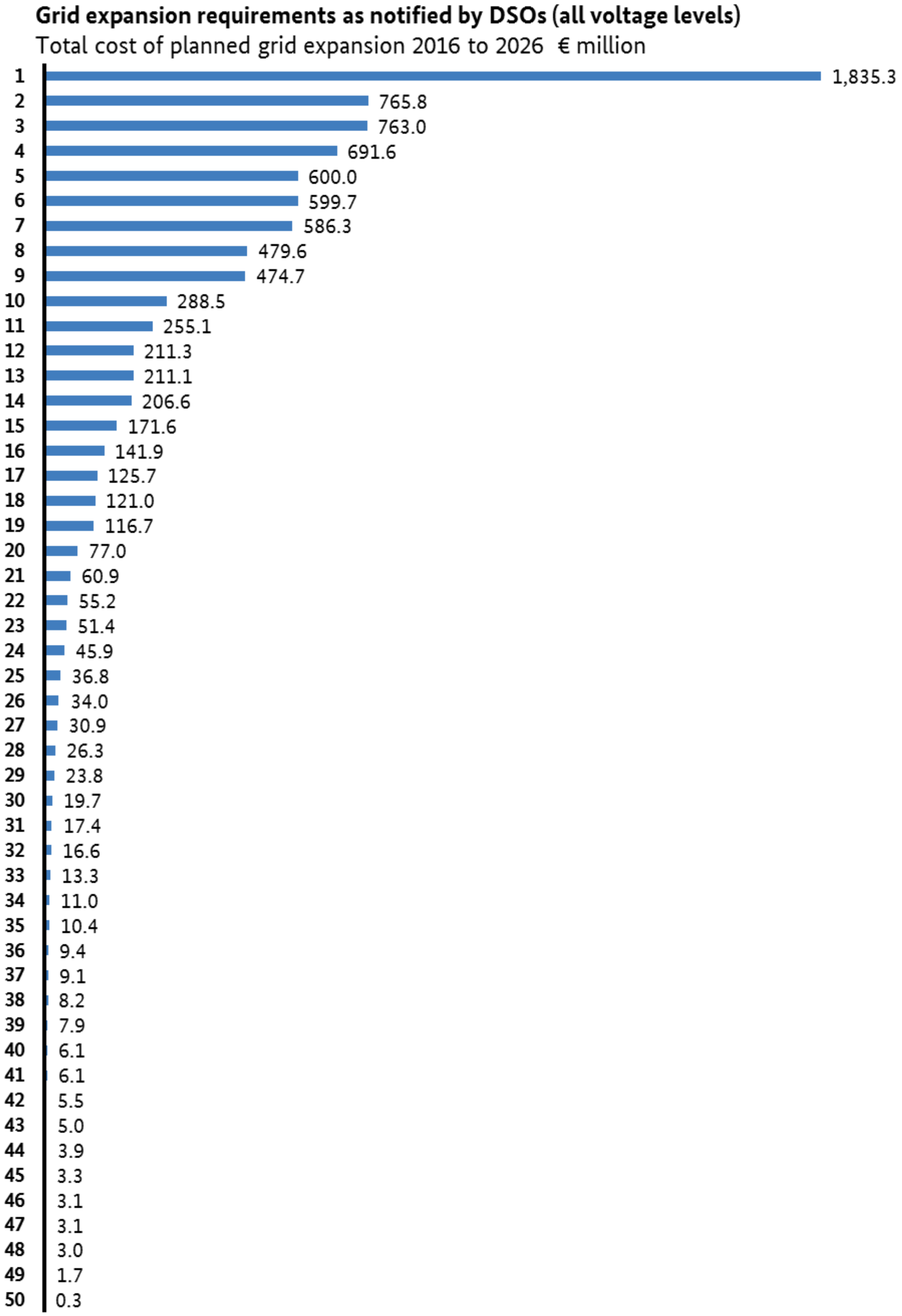

Figure 29: Grid expansion requirement per DSO (all voltage levels)

This shows highly heterogeneous grid expansion requirements:
22 DSOs project grid expansion requirements of between zero and €10m in the next ten years (of these 7 DSOs have not specified any investment projects), a further 16 DSOs remain below the €100m limit and 19 DSOs forecast grid expansion requirements of over €100m. The 17 DSOs with the greatest grid expansion requirements account for 90% of total requirements.

The forecast grid expansion requirements are not only due to growing renewable energy capacities and embedded generation, but also to a large extent to restructuring and in part age-related replacement investments.

The evaluations also show that many DSOs continue to find it difficult to plan the expansion of grids for periods of time of longer than 10 years. Not only are new measures added every year, measures which have not yet been implemented also cease to be relevant. Planning uncertainties arise in particular from the difficulty in predicting the specific locations of renewable energy installations which is even more important in the distribution system than it is in transmission systems. Other reasons include the protracted procedures for obtaining official permits, objections raised by public agencies or land owners and modifications to the expansion of the high-voltage system to accommodate grid expansion in the transmission network.

A total of 1,984 measures (31 December 2014: 1,318; 31 December 2013: 1,263) were submitted to the Bundesnetzagentur for the period up to 2026. Of these 55% were still at the planning stage at the time of the survey, 25% of the measures were under construction and 20% had been completed by early 2016. Compared to the previous year 666 new expansion measures have been added, but only 366 measures completed. This represents an increase in the absolute number of planned grid expansion measures in particular.

Project status, total expansion requirements (all voltage levels)
Numbers and breakdown

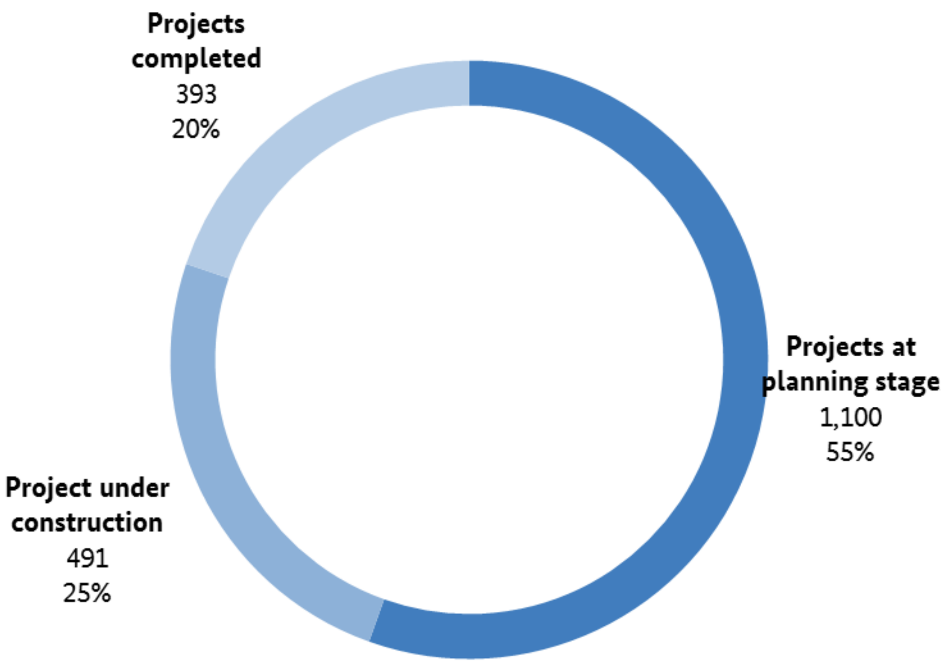

Figure 30: Project status, total expansion requirements (all voltage levels)

2.4 Expansion requirements based on the anticipated expansion in feed-in installations at the high-voltage level

If the measures submitted for the high voltage level under section 14(1b) EnWG are considered separately, the expansion requirements from the perspective of the network operators amount to €2.6bn over the next ten years (2016 to 2026). 24 of the 57 surveyed DSOs have submitted measures for this purpose. The measures were identified on the basis of all forms of expansion of feed-in installations – not just those producing electricity from renewable energy. In larger cities, for example, combined cycle gas turbine plants were given as reasons for expansion.

The following diagram shows the grid expansion requirements forecast by DSOs at the high-voltage level.

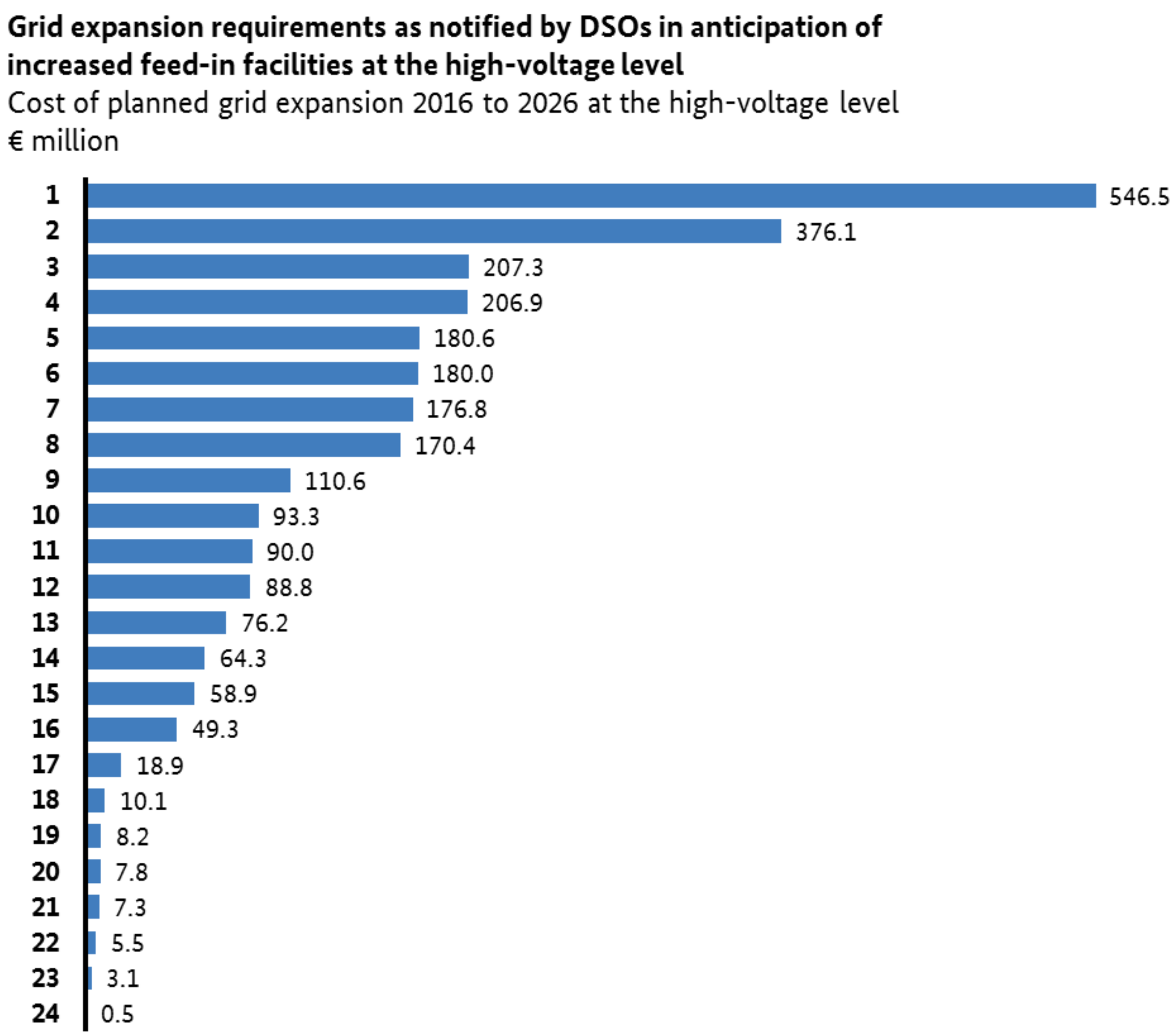

Figure 31: Grid expansion requirements according to DSO based on anticipated expansion in feed-in installations at the high-voltage level

The distribution is highly heterogeneous here as well; this is due to the different network structures and, in particular, the level of previously installed capacity and projected increase in output from renewable energy systems.

A total of 348 measures were submitted to the Bundesnetzagentur for the period up to 2026. Of these 65% were still at the planning stage at the time of the survey, 25% of the measures were under construction and 10% had been completed by early 2016.

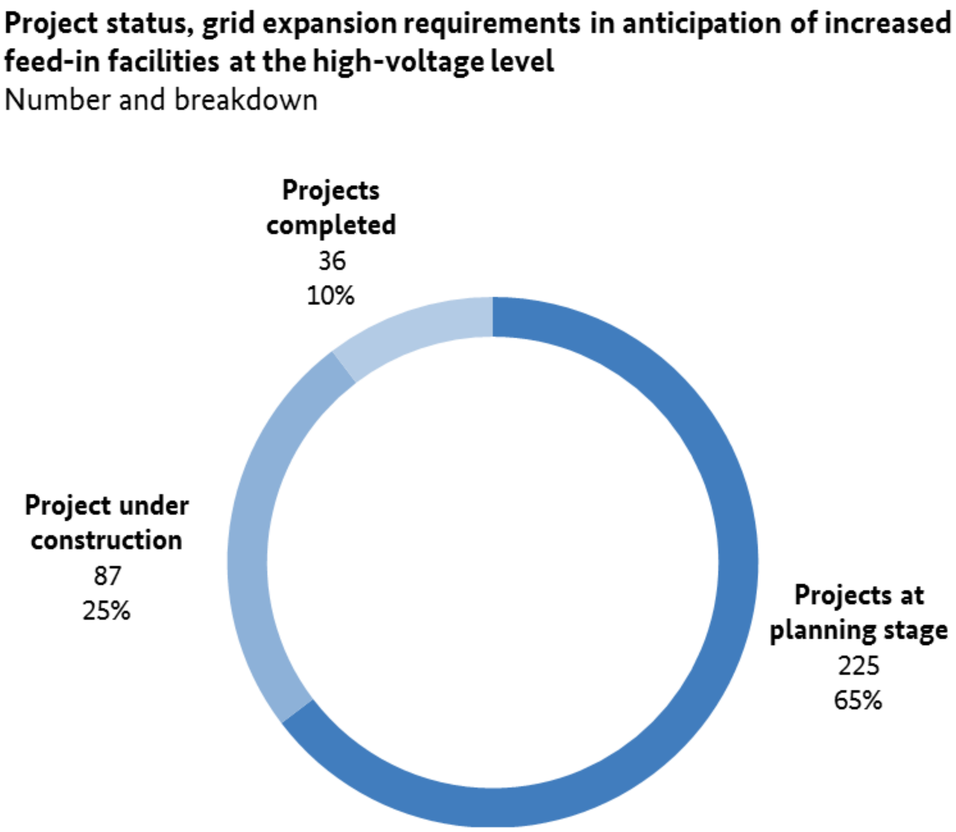

Figure 32: Project status, grid expansion requirements based on the anticipated expansion in feed-in installations at the high-voltage level

It is also apparent and positive that all high-voltage network operators which have notified feed-in management measures to the Bundesnetzagentur as a result of network congestion problems in their own distribution systems have also notified the need to expand high-voltage grids in response to the existing network congestion to cope with the anticipated expansion in feed-in installations, especially for the generation of electricity from renewable energy sources.

3. Investments

Investments are the capitalised gross additions to fixed assets made during the year under review as well as the value of new fixed assets newly rented and hired during the year under review. Expenditure arises from the combination of all technical and administrative measures as well as management measures adopted during the life cycle of an asset to preserve it in or return it to a functioning state so that it can perform its required function.

The following are the results for transmission and distribution system operators under commercial law. A link cannot be derived to the implicit values for the revenue caps.

3.1 Investments in transmission networks (incl. cross-border connections)

In 2015 the four German TSOs together spent approximately €2,361m (2014: €1,769m) on investment in and expenditure on network infrastructure. This figure includes investments in and expenditure on metering/control devices and communication infrastructure amounting to approximately €3m. Included in this spending are investments in and expenditure on cross-border connections amounting to approximately €174m (2014: €74m). Actual expenditure on network infrastructure deviated by €283m from the planning values reported in 2014 (planning values for 2015: approximately €2,644m). The transmission system operators have thus met 89% of their planned investment and expenditure costs. Investments in new builds, upgrades and expansion projects other than cross-border connections fell below planned spending of €1,673m by around 12% (planned: €1,890m). Investments in maintenance and renewal and expenditure excluding cross-border connections remained at €217m and €297m, approximately 9% and 6% below the planned values (planned €238m and €315m). The investments planned for cross-border connections in particular have again increased significantly for new build, upgrades and expansion at €172m (previous year: €71m) while remaining approximately 13% below the planned value for the year 2015 (planned: €199m). 86% or around €2m of planned expenditure on cross-border connections was carried out. Total investments of around €2,355m and total expenditure of €347m are planned for the year 2016. This amounts to total planned investments and expenditure of around €2,701m for the year 2016 or a planned increase of almost 14 percent. The following diagram shows the investments and expenditure, including cross-border connections, both separately and in aggregate since the year 2008 as well as the values planned for the year 2016.

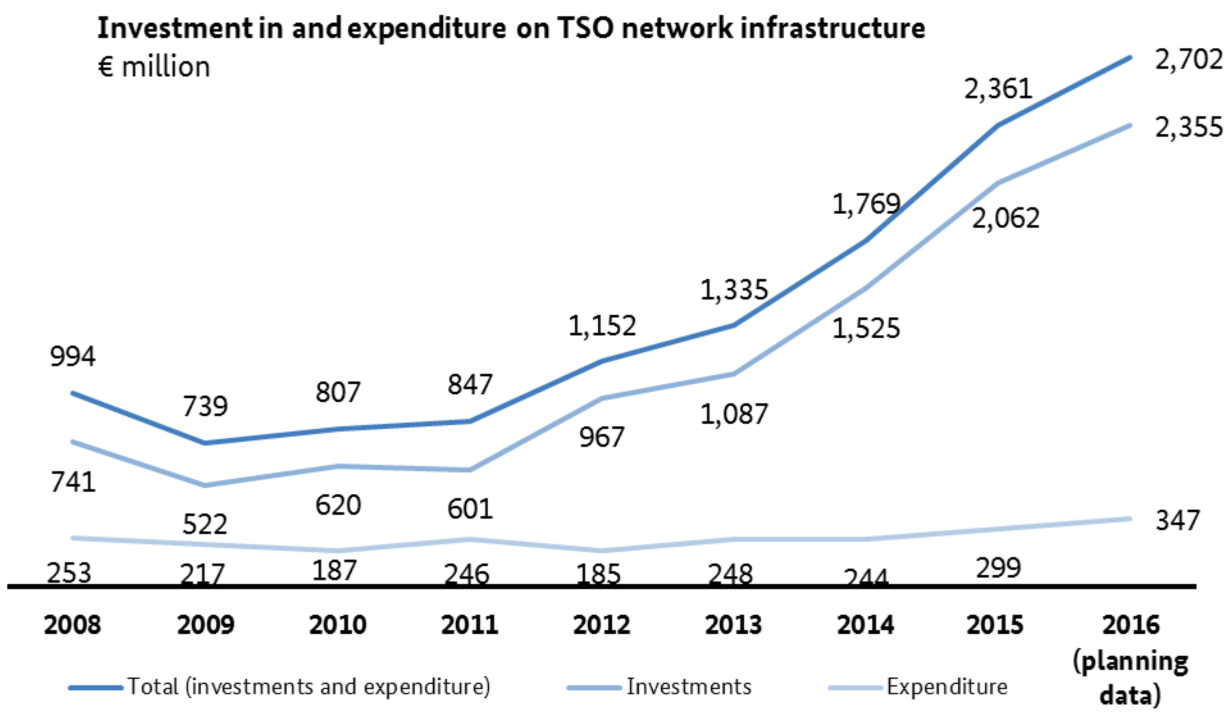

Figure 33: Investment in and expenditure on TSO network infrastructure since 2008 (including cross-border connections)

3.2 Investments and expenditure by electricity distribution system operators

Investments in and expenditure on network infrastructure by 817 DSOs which provided data for the 2016 monitoring questionnaire totalled approximately €6,845m in 2015 (2014: €6,193m). This figure includes investments in and expenditure on metering/control devices and communication infrastructure amounting to approximately €482m (2014: €478m). The target volume of investment in distribution networks of €3,646m planned by DSOs for 2015 was significantly exceeded by €1,755m with actual investment amounting to €5,401m. Expenditure in 2015 amounted to €3,045m and was thus, at plus €43m, slightly higher than the planned volume of €3,002m for the year 2015. Overall, with a delta of €197m, total DSO spending on the network infrastructure exceeded the planning values for 2015 of €6,648m. For the coming year of 2016, the DSOs plan a somewhat lower volume of investment in the distribution networks for new installations, upgrades, expansion, maintenance and renewal of €3,571m and higher spending costs of €3,307m.

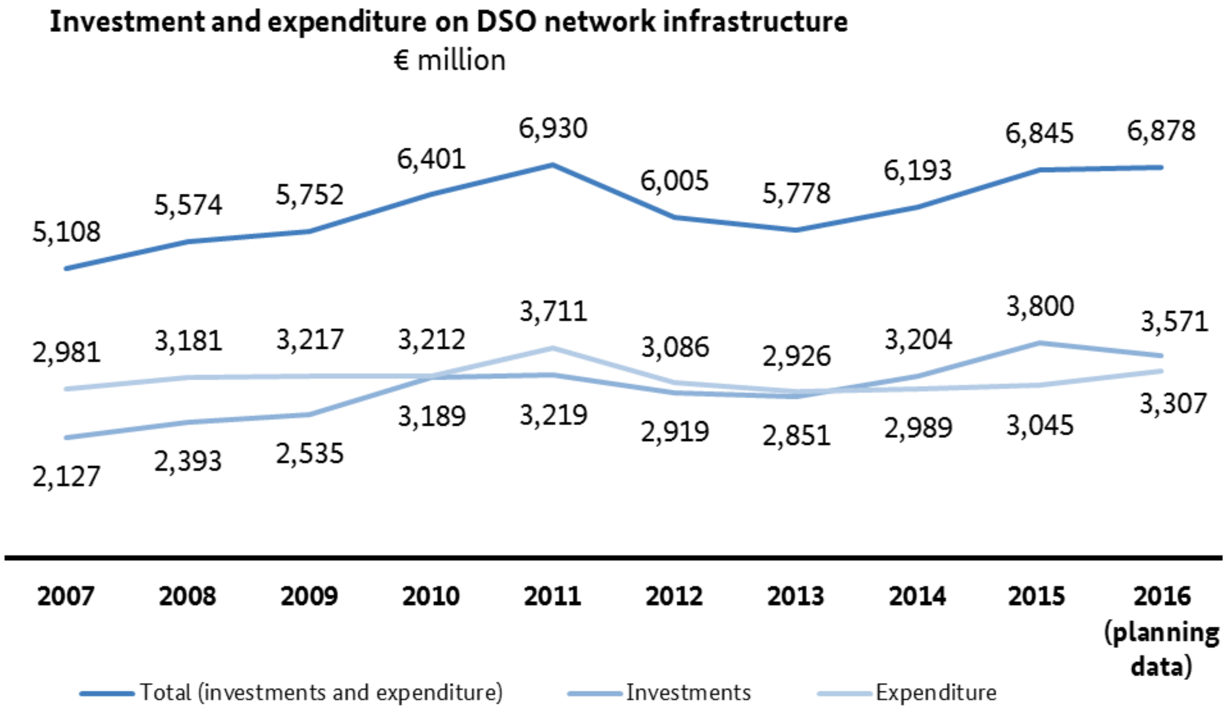

Figure 34: Investments in and expenditure on network infrastructure (including metering/control devices and communication infrastructure) by DSOs

The level of DSO investment depends on circuit lengths, the number of meter points served as well as other individual structure parameters, including geographical circumstances. As a rule, DSOs' investments tend to be higher the longer their circuits are. Almost one quarter of DSOs (198) are in the €0 to €100,000 investment category. Around 10% of companies (83) have peak investments of over €5m per network area. The following diagram shows the various categories of investment as percentages of the total number of network operators:

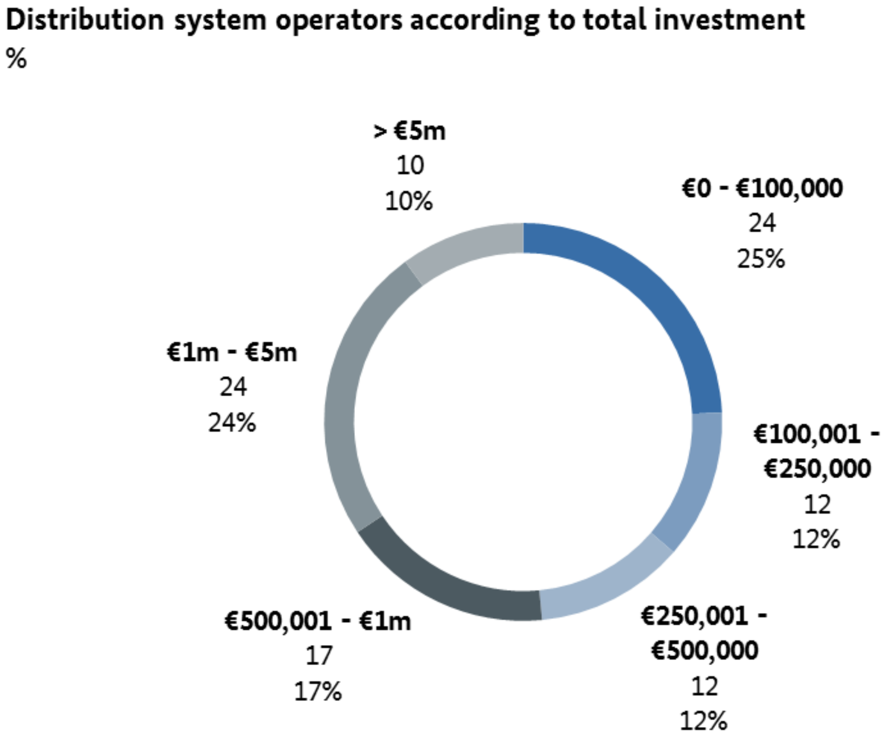

Figure 35: DSOs according to total investment

The data notified for the monitoring report on the distribution of expenditure by DSOs shows that 29% (204) of companies report expenditure of up to €100,000. 67 companies, accounting for nine percent of the total, report expenditure of over €5m. In the year under review 2015, more than half of the DSOs (54 percent) posted expenditure exceeding €250,000 for their networks:

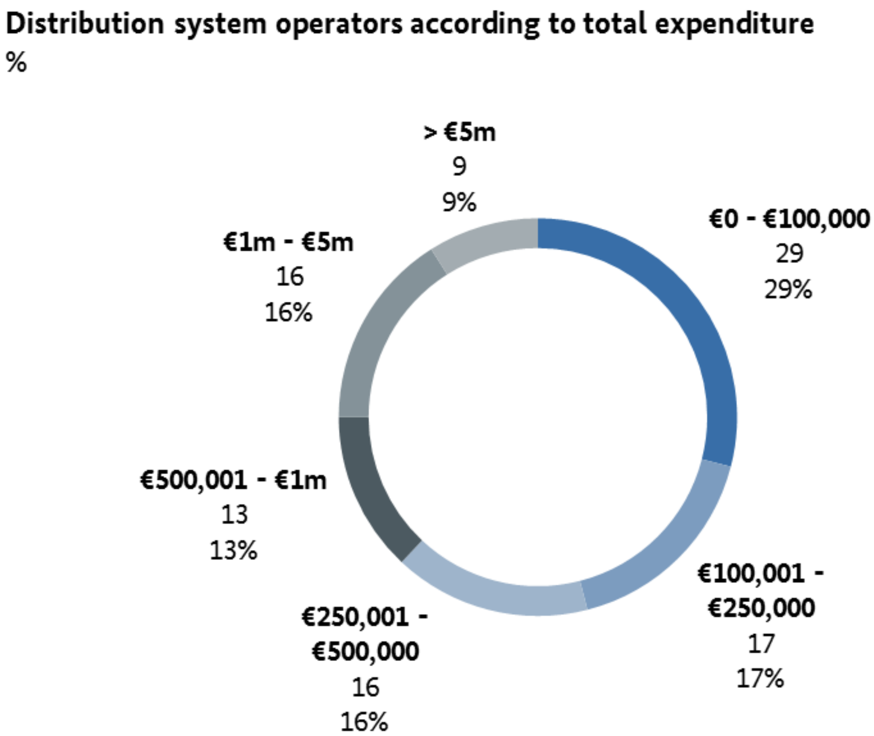

Figure 36: DSOs according to total expenditure

3.3 Investment and incentive regulation

The Incentive Regulation Ordinance (ARegV) provides network operators the opportunity of including the costs of expansion and restructuring investment in network tariffs over and above the approved revenue caps. Based on section 23 ARegV the Bundesnetzagentur can respond to applications by issuing approvals for individual projects which meet the stated requirements.

Since the amendment of section 23 ARegV in early 2012 projects are subject to approval on their merits. After approval has been issued the network operator can adjust its revenue cap in line with the operating and capital costs associated with the project directly in the year in which such costs are incurred. The stated costs are then subject to ex-post checks by the Bundesnetzagentur.

158 new applications for investment measures in the fields of electricity and gas had been submitted to the competent Ruling Chamber by 31 March 2016. Across all segments, these measures are associated with acquisition and production costs of approximately €8.87bn. 97 applications relating to electricity were made for a volume of approximately €4.19bn. 47 of these applications, corresponding to a volume of approximately €3.79bn, were made by TSOs and 50, for a volume of approximately €0.4bn, by DSOs.

4. Supply disruptions in the electricity network

Operators of energy supply networks are required under section 52 EnWG to submit to the Bundesnetzagentur by 30 April of each year a report detailing all interruptions in supply that occurred in their networks in the previous calendar year. This report must state the time, duration, extent and cause of each supply interruption lasting longer than three minutes. Furthermore, the network operator must provide information on the measures required to avoid supply interruptions in the future.

850 network operators reported some 177,751 interruptions in supply for 860 networks in 2015 for the calculation of the system average interruption duration index (SAIDI) for end customers. The figure of 12.70 minutes calculated for the low and medium voltage levels is much lower than the average figure for the last ten years (average for 2006 to 2015: 15.87 minutes). The quality of supply thus maintained a constant high level throughout 2015.

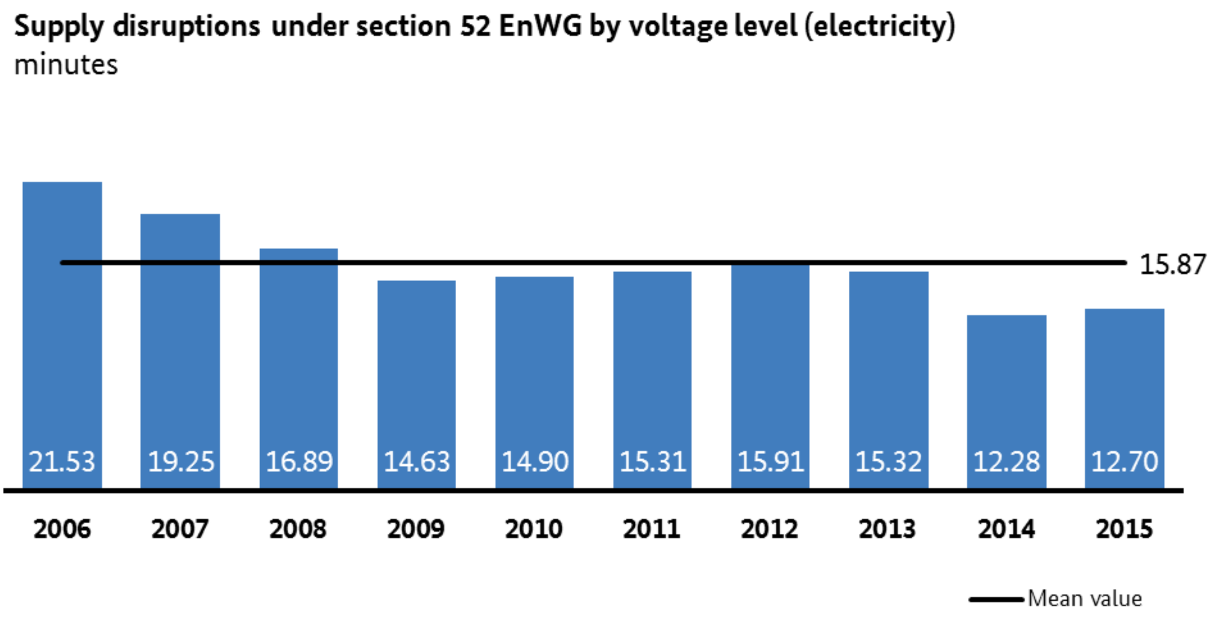

Figure 37: Development of the SAIDI, 2006 to 2015

The modest increase in average interruption duration is due mainly to an increase of 0.36 minutes to 10.45 minutes at the medium voltage level. The average interruption duration at the low voltage level also increased by 0.06 minutes to 2.25 min.

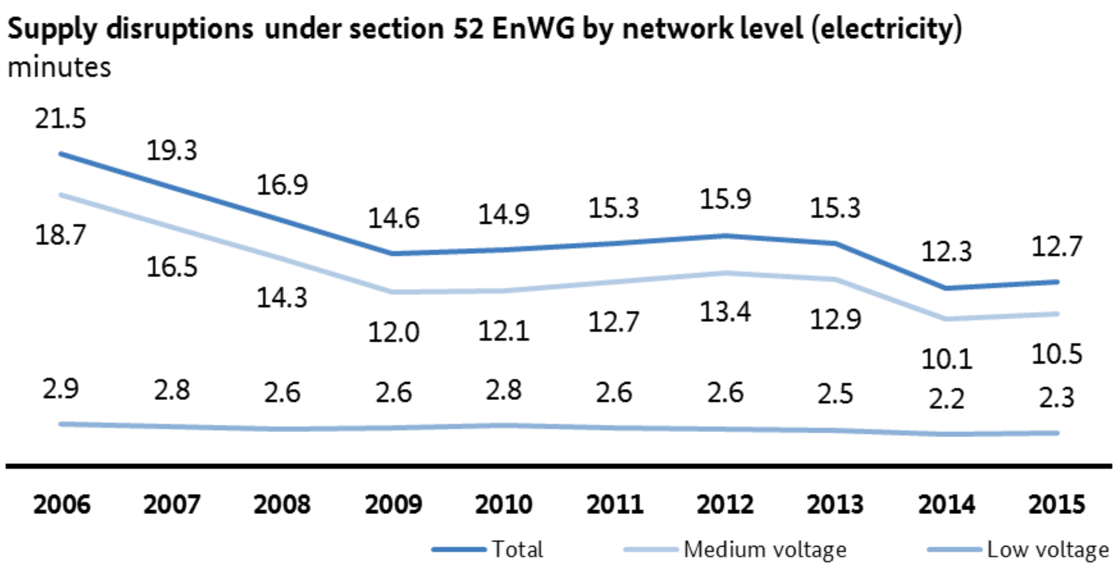

Figure 38: Development of the SAIDI at LV and MV from 2006 to 2015

Compared to the previous year there was a substantial increase in the number of disruptions caused by atmospheric effects. These include supply disruptions caused, e.g., by thunderstorms, storms, ice, sleet, snow, hoar frost, fog, condensation (including in connection with pollution), moisture, penetration from rainfall, thaw, flooding, cold, heat and conductor gallop. The increase in this type of disruption can be attributed to several extreme weather events in 2015. As well as various storms these also included the heat waves in the summer of 2015. High temperatures were responsible, for example, for short circuits or flashover arcing at power substations.

The energy transition and the associated increase in embedded generation does not appear to have had a discernible impact on the quality of supply in 2015 either.

The number of supply disruptions also increased in 2015. While there were 173,825 supply disruptions in 2014, this number rose to 177,751 supply disruptions in 2015.

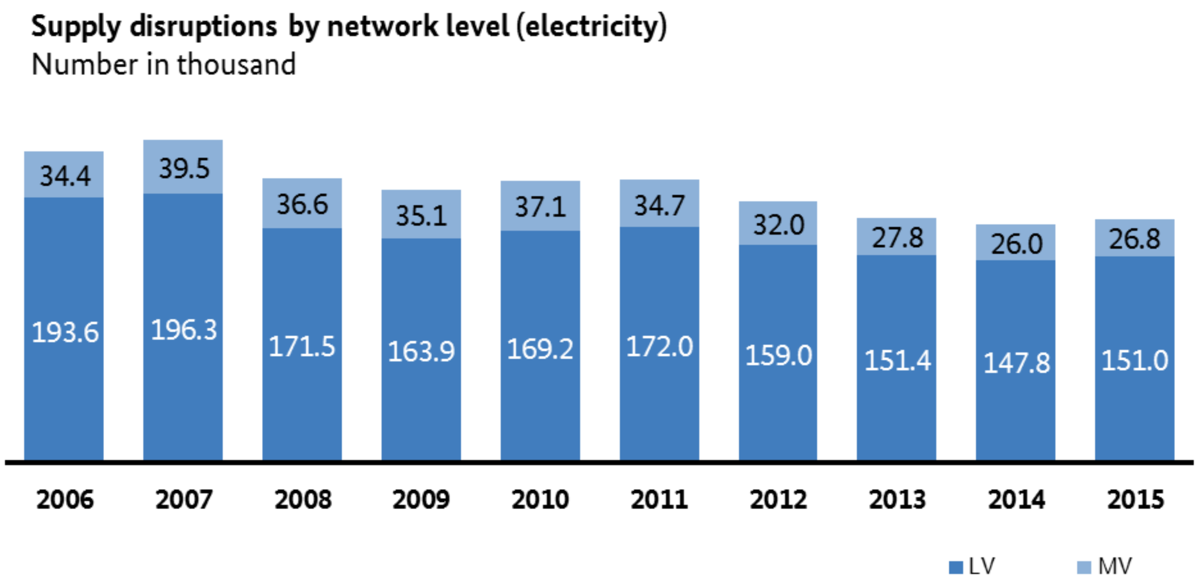

Figure 39: Supply disruptions by network level (LV, MV) from 2006 to 2015

The SAIDI value does not take account of planned interruptions or those which occur owing to force majeure, such as natural disasters. Only unplanned interruptions caused by atmospheric effects, third-party intervention, ripple effects from other networks or other disturbances in the network operator's area are included in the calculations.

5. Network and system security measures

System operators are legally entitled and obliged to take certain measures to maintain the security and reliability of the electricity supply system. A distinction is made between three types of measure:

– Measures under section 13(1) EnWG (redispatching)

– Measures under section 13(2) EnWG in conjunction with section 14 of the Renewable Energy Sources Act (EEG) (feed-in management)

– Adjustment measures under section 13(2) EnWG

The following table summarises the regulatory contents and key instruments and scope of measures in 2015:

Network and system security measures under section 13 of the Energy Act in 2015

	Redispatching	Feed-in management	Adjustment measures
Legal basis	Energy Act section 13(1) Network-related and market-related measures: topological measures, such as balancing energy, reduced and increased loads, redispatching and countertrading	Renewable Energy Sources Act section 14(1) in conjunction with Energy Act section 13(2): Feed-in management: reduction of feed-in from renewable energy, mine gas and combined heat and power (CHP) installations	Energy Act section 13(2) Adjustment of electricity feed-in, transit and offtake
Rules for affected installation operators	Measures contractually agreed with the installation operator including compensation for costs under section 13(1, 1a) of the Energy Act	Measures at request of the installation operator including compensation for costs under section 14(1) Renewable Energy Sources Act in conjunction with section 2 of the Energy Act	Measures at request of installation operators without compensation for costs under section 13(2) of the Energy Act
Scope in reporting period	Total redispatch (TSOs): **16,000 GWh).**	Unused energy (TSOs and DSOs): **4,722 GWh**	Unused energy (TSOs and DSOs): **26.5 GWh**
Estimated cost in reporting period	Redispatching through TSOs' system services[1]: **411.9 billion euros***	Estimated compensation[2] claimed by installation operators under section 15 Renewable Energy Sources Act (TSOs and DSOs): **478 million euros** Compensation payments to installation operators under section 15 Renewable Energy Sources Act: **314.8 billion euros***	No compensation payments to installation operators under section 13(2) Energy Act

All redispatching data excluding backup power station.

[1] Net redispatching costs (see Chapter D System services).

[2] Preliminary assessment of compensation payments claimed by installation operators from feed-in management measures according to data supplied by TSOs and DSOs to the Bundesnetzagentur.

Table 19: Network and system security measures under section 13 EnWG

The following subsections provide a detailed view of the deployment of the different network and system security measures.

5.1 Redispatching

TSOs are entitled and obliged to remove threats or disruptions to the electricity supply system by taking network-related and market-related measures. Where DSOs are responsible for the security and reliability of the electricity supply in their networks, they too are entitled and obliged to take such measures.

Network-related measures, most notably topological measures, are taken by the TSOs practically every day of the year. Market-related measures primarily take the form of congestion management measures. A distinction can basically be made between redispatching and countertrading.

Redispatching means measures to intervene in the market-based operating schedule of generating units to change feed-in, prevent overloading of power lines (preventive redispatching) or relieve overloading (curative redispatching). Electricity-related redispatching is used to avoid or relieve sudden congestion on lines or in substations, while voltage-related redispatching is used to maintain the voltage in the network area affected by providing reactive power. Redispatching can be an internal measure applicable to one control area only or a wider measure applicable to more than one control area. Overall feed-in is maintained at a constant level by reducing feed-in from one or more generating units while increasing feed-in from one or more other units (in the areas to be balanced).

Countertrading is also used to avoid or relieve congestion by changing the planned operating schedule of generating units. In contrast to redispatching, however, countertrading involves commercial transactions, and there is no obligation for the plant operators to enter into such transactions. Countertrading has little practical significance compared to redispatching.

The German TSOs submit detailed data on redispatching to the Bundesnetzagentur on a monthly basis. The following evaluation is based on the data notified in 2015.

5.1.1 Calendar year 2015

A very high level of redispatching was required in 2015. This was in part due to the shutdown of the Grafenrheinfeld nuclear power station ahead of schedule, a high level of additional installed wind capacity, relatively windy weather, delays in implementing grid expansion measures under the Power Grid Expansion Act (EnLAG) and Federal Requirements Plan Act (BBPlG) as well as the temporary decommissioning of network elements to enable grid expansion construction to proceed, and high levels of electricity exports to Austria in particular. The Bundesnetzagentur received reports of electricity-related and voltage-related redispatching totalling 15,811 hours (2014: 8,453 hours). As all measures, including those taken in parallel to counteract congestion, are recorded, the total number of hours applies to all measures. Overall, interventions of this kind were required on 331 days. This means that redispatching occured almost daily. Feed-in was reduced by a total of 7,994 GWh (2014: 2,600 GWh). The compensatory increases in feed-ins totalled 8,006 GWh (2014: 2,597 GWh). Thus the total amount of energy required for redispatching in 2015 (reductions and increases in feed-ins) was about 16,000 GWh, compared to 5,197 GWh in 2014. The volume of redispatching in 2015 was thus more than three times higher than in 2015. Reductions in feed-ins through redispatching corresponded to 1.9% (2014: 0.6%)

of total generation from installations not eligible for payments under the Renewable Energy Sources Act (EEG). In all, increases and reductions in feed-in through redispatching amounted to around 3.9% (2014: 1.2%) of total generation from installations not eligible for financial support. Estimated net redispatching costs[19] (excluding countertrading) in 2015 were reported at €411.9m (refer also to chapter I.D from page 116). Costs in 2014 still amounted to around €185.4m. Redispatching occurred in all control areas, including those of TenneT and 50Hertz in particular. Details are shown in the following table:

Redispatching 2015

Control area	Duration (hours)	Volume (GWh)[1]	Total volume (energy redispatched plus balancing countertrades) (GWh)	Net costs[2] for redispatching (€m)
TenneT	9,095	4,030	8,072	411.9
50Hertz	6,512	3,930	7,862	
Transnet BW	126	16	31	
Amprion	78	18	35	

[1]If a joint request for redispatching is made by two neighbouring TSOs, the assessment by the the Bundesnetzagentur the total duration and volume of these measures is split half-half between the two requesting TSOs.
[2]Refer to Chapter D System services.

Table 20: Redispatch measures in 2015

The net costs stated here for redispatching in 2015 reflect the information available to the TSOs in April 2016. More up-to-date information and data for previous years will be taken into account in cost reviews undertaken by the Bundesnetzagentur.

Redispatching in 2015 was mainly electricity-related, with measures totalling 13,660 hours and 7,553 GWh. The feed-in increase corresponds in most cases to the amount of reduction. 13,459 hours (99%) of this amount related to the following network elements:

[19] Redispatching can also generate revenues, such as from lower fuel costs for ramped down power plants. Redispatching costs are reported net in the Monitoring Report (costs set equal to expenses minus cost-reducing revenues). Any revenues are therefore already included in the total costs.

Electricity-related redispatching on the most heavily affected network elements in 2015

No	Affected network element	Control area[1]	Duration (hours)	Volume (GWh)	Volume countertrade (GWh)
1	Remptendorf - Redwitz	50Hertz/ TenneT	4,115	3,704	3,704
2	Area Vierraden - Krajnik (PL) (Vierraden, Krajnik, Pasewalk, Neuenhagen)	50Hertz	2,833	1,498	1,498
3	Brunsbüttel-50Hertz-Zone (Hamburg Nord)	TenneT/ 50Hertz	2,039	763	768
4	Area Hamburg (Hamburg Nord, 50Hertz-Zone)	TenneT/ 50Hertz	898	221	221
5	Area Conneforde (UW Conneforde)	TenneT	875	313	313
6	Area Lehrte (Lehrte-Mehrum, -Godenau, -Göttingen)	TenneT	654	132	132
7	Area St. Peter (Altheim-Simbach-St. Peter, Pirach-St. Peter, Pleitning-St. Peter (AT))	TenneT	334	177	177
8	Area Borken-Gießen (Borken-Gießen-Bergshausen-Karben)	TenneT	270	75	75
9	Area Mecklar (Mecklar, Borken)	TenneT	268	210	210
10	Dollern-Wilster	TenneT	259	70	70
11	Area Mecklar-Dipperz (Mecklar-Borken, Mecklar-Dipperz, Dipperz-Aschaffenburg)	TenneT	231	94	94
12	Area Großkrotzenburg (Großkrotzenburg, Großkrotzenburg-Dipperz, Großkrotzenburg-Karben)	TenneT	174	81	81
13	Röhrsdorf - Hradec (CZ)	50Hertz	141	86	86
14	Altbach	TransnetBW	118	12	12
15	Ovenstädt-Eickum	TenneT	86	30	30
16	Area Hamburg-Flensburg - Kassö (Hamburg, Flensburg, Audorf, Kassö (DK))	TenneT	49	9	13
17	Landesbergen - Wechold - Sottrum	Tennet	38	9	10
18	Area Donau West/Ost (Vöhringen-Hoheneck-Dellmensingen)	Amprion	34	7	7
19	Walberberg West (Knapsack-Sechtem)	Amprion	23	5	5
20	Grohnde-Vörden-Bergshausen	TenneT	20	6	6

[1] The first mentioned control area names the TSO which has carried out the data announcement of the redispatching measure to the *Bundesnetzagentur* .

Table 21: Electricity-related redispatching on the most heavily affected network elements in 2015 as reported by the TSOs

Redispatching was required in particular for the line between Remptendorf and Redwitz, the Brunsbüttel area (Hamburg Nord) and the Vierraden to Krajnik line in Poland. These three net elements accounted for 30, 21 and 15 percent of all electricity-related redispatching. It is not yet wholly apparent whether completion of the Thuringia power bridge will relieve serious congestion. As part of the South-West Interconnector, this project is intended to close the gap which exists for historical reasons between the grids in the old and new federal states. Three of the five sections of the Thuringia power bridge are currently in operation. The other two sections, from Altenfeld to the border between Thuringia and Bavaria and from there to Redwitz are currently being operated on a trial basis.

The line between the 50 Hertz control area, Hamburg Nord and the Conneforde area also came under considerable strain. In total the Central Hessen region, including the Borken, Borken-Gießen, Mecklar, Mecklar-Dipperz and Großkrotzenburg areas, are also heavily affected by electricity-related redispatching. The above table does not show redispatching totalling 201 hours on other network elements of less than 12 hours per line in 2015.

The following map shows the location of the particularly critical network elements (number of hours per line > 12) listed in the above table:

Electricity-related redispatching on the most heavily affected network elements in 2015

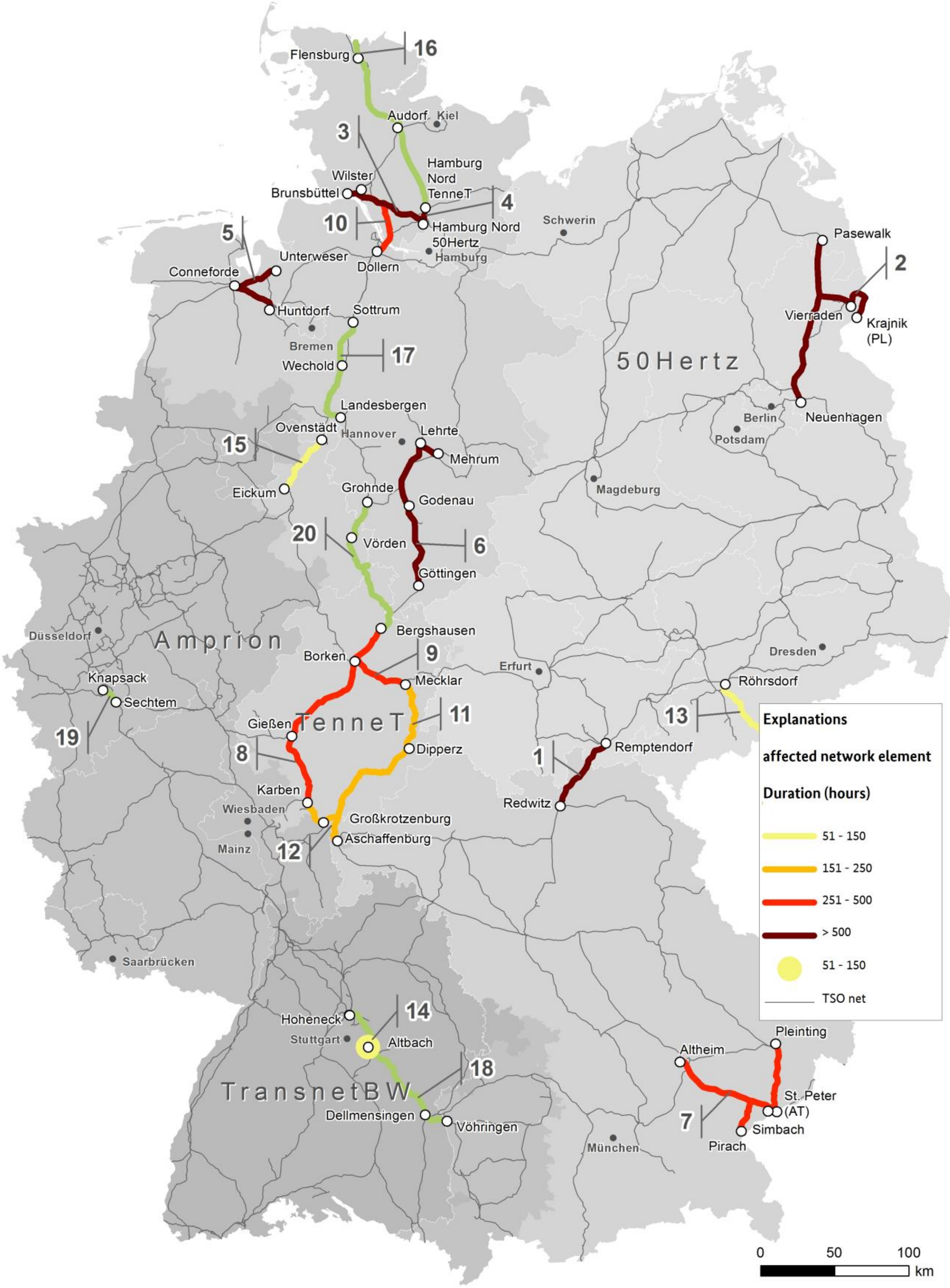

Figure 40: Electricity-related redispatching on the most heavily affected network elements in 2015 as reported by the TSOs

In addition to electricity-related redispatching, voltage-related redispatching totalling 2,151 hours occurred in 2015. The total amount of energy redispatched was 440 GWh. TenneT reported the majority of measures, accounting for 2,146 hours The network area most heavily affected was between Ovenstädt, Bechterdissen and Borken and the network area around the Conneforde substation. The following table details the network elements and network areas affected.

Voltage-related redispatching on the most heavily affected network elements in 2015[1]

Network area	Duration (hours)	Volume (GWh)
Control area TenneT: southern network area	**422**	**108**
network area Oberbayern	190	57
network area Nordostbayern	221	49
network area Unterfranken	11	2
Control area TenneT: central network area	**1,165**	**225**
Ovenstädt-Bechterdissen-Borken	689	136
network area Mehrum-Grohnde-Lehrte-Krümmel	41	6
network area Borken (Borken-Dipperz-Großkrotzenburg, Gießen, Karben)	435	83
Control area TenneT: northernnetwork area	**559**	**105**
network area Conneforde	549	103
network area Landesbergen	2	< 0,1
network area Schleswig-Holstein und Hamburg	8	2
Control area Amprion	**5**	**2**

[1] Because voltage-related redispatching refer to spatially bigger net regions (and not on single transmission lines or transformer stations), it is renounced for representation reasons a general map.

Table 22: Voltage-related redispatch measures on the most strongly affected network elements in 2015 as notified by TSOs.

5.1.2 Development from 2014 to 2015

As there was a high level of redispatching overall in 2015 there was an increase in redispatching on many network elements previously subject to overloading. There was a significant reduction in redispatching compared to the previous year on the Bärwalde-Schmölln network element in particular, which was subject to less than 12 hours overloading, and the line from Hamburg to Kassö in Denmark where the volume of redispatching around the Hamburg Nord area has increased substantially overall. While the Lehrte area was also subject to significantly less overloading in 2015, more measures were taken on the network elements further south in the Central Hessen region around the areas of Borken, Borken-Gießen, Mecklar, Mecklar-Dipperz and Großkrotzenburg.

The duration and scope of voltage-related redispatch measures increased in the calendar year 2015. All in all, the overall duration of measures increased by 687 hours. In 2014 most measures still affected TenneT's network area to the north. The TenneT central network area, which accounted for over 54% of hours, was most heavily affected in 2015.

The table clearly shows that in the calendar year 2015 it was primarily the 50Hertz and TenneT control areas which came under particularly strong pressure at certain times. Despite this, the German TSOs were in a position at all times to deal with the situation appropriately. Neither the TSOs nor the Bundesnetzagentur expect the need for redispatching to decline in the near future.

In view of the ruling issued by the Higher Regional Court in Düsseldorf on 28 April 2015 revoking the Bundesnetzagentur's rulings on redispatching (BK6-11-098 and BK8-12-019) and the accompanying statement that not only expenses but also further costs incurred and potential revenues lost in the event of redispatching are reimbursable, there may be a subsequent change in the costs for redispatching over the past few years.

5.2 Feed-in management measures and compensation

Feed-in management is a special measure regulated by law to increase network security relating to renewable energy, mine gas and combined heat and power (CHP) installations. The climate friendly electricity generated by these installations has to be fed in and transported with priority. Under specific conditions, however, the network operators responsible may also temporarily curtail priority feed-in from these installations if network capacities are not sufficient to transport the total amount of electricity generated. Importantly, such feed-in management is only permitted once the priority measures for conventional installations have been exhausted. The expansion obligations of the operator answerable for the congestion remain in parallel to these measures.

The operator of the installation with curtailed feed-in is entitled to compensation for the energy and heat not fed in as provided for by section 15(1) of the Renewable Energy Sources Act. The costs of compensation must be borne by the operator in whose network the cause for the feed-in management measure is located. The operator to whose network the installation with curtailed feed-in is connected is obliged to pay the compensation to the installation operator. If the cause lay with another operator, the operator responsible is required to reimburse the costs of compensation to the operator to whose network the installation is connected.

5.2.1 Development of curtailment quantity

The following diagram shows the curtailment quantity resulting from feed-in management measures since 2009 for the most heavily affected energy sources.

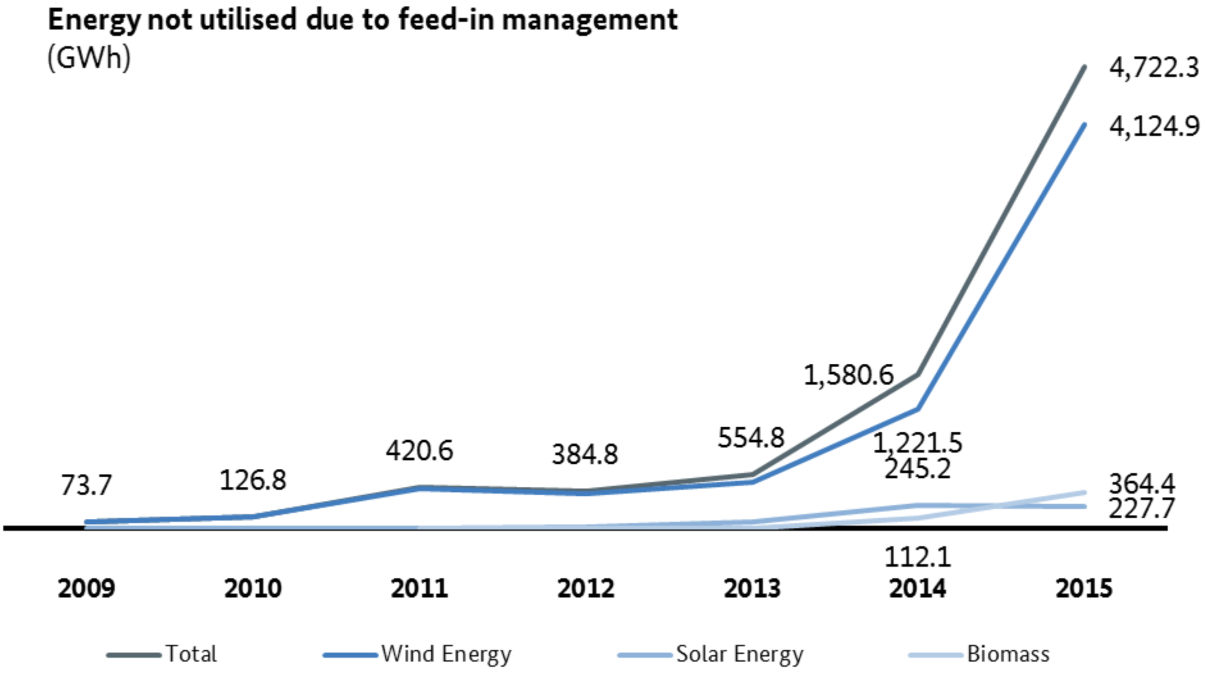

Figure 41: Curtailment quantity resulting from feed-in management measures

Compared to 2014 (1,580 GWh), the amount of energy not fed in as a result of feed-in management measures rose almost threefold to 4,722 GWh. This is 2.8% of the total net volume of electricity generated in 2015 by installations eligible for financial support under the Renewable Energy Sources Act (including direct selling), up from 1.35% in 2014.

The increase in feed-in management measures is due to various factors, such as the continued increase in the amount of energy from renewable sources and the work still required to optimise, reinforce and expand the networks. Another factor is the continuing lack of substations to feed renewable electricity back into the upstream extra high voltage network. To a lesser extent, grid expansion measures taken by network operators can also lead to increased congestion and consequently to the need for feed-in management measures during their construction phase. In the process, parts of the network are taken out of operation, for instance, or operation is restricted. Another factor relating to the use of feed-in management measures is the weather. In 2015 there were strong peaks in feed-in from wind farms (see chapter I.B.2.2.3 on page 57).

As in previous years wind power plants again accounted for 87.3% of total curtailment quantity in 2015 and were thus again most affected by FMM (2014: 77.3%). Offshore wind power plants were also affected by FMM for the first time in 2015. These accounted for 0.3% (around 16 GWh) of total curtailment quantity. The amount of energy curtailed from biomass plants exceeded that from photovoltaic installations (the second most frequently curtailed source of energy) by almost 8%. The amount of curtailment quantity from photovoltaic installations fell year on year to around 228 GWh (2014: around 245 GWh) to make up around 5%of total curtailment quantity (2014: around 16%). The remaining curtailment quantity (around 0.1%) was distributed amongst four other energy sources as shown in the following table.

Breakdown of curtailment quantity resulting from FMM according to sources of energy

Energy source	Unused energy (incl. heat) in kWh	Share in per cent
Wind power	4.124.872.607	87,3
Biomass, including biogas	364.371.926	7,7
Solar Energy	227.648.202	4,8
Run-of-river hydro	3.013.468	0,1
Installation under KWKG	1.499.546	< 0.1
Landfill, sewage and mine gas	888.088	< 0.1
Dammed water (excluding pumped storage)	2.191	< 0.1
Total	**4.722.296.028**	**100,0**

Table 23: Curtailment quantityas a result of feed-in management measures by energy source

According to reports on network and system security provided by network operators, feed-in management measures were used in 2015 as follows.

Curtailment quantity under section 14 EEG in 2015

	Curtailment quantity under section 14 EEG (kWh)	Percentage of total unused energy
Implementation by the TSO	**341.383.641**	**7%**
Implementation by the DSO	**4.380.912.359**	**93%**
Own measures	526.648.626	11%
Support measures by the DSOs (cause in transmission system)	3.854.263.733	82%
Total feed-in management measures	**4.722.296.000**	**100%**

Table 24: Curtailment quantityunder section 14 EEG in 2015

In 2015 the TSOs were the main causes of feed-in management measures. This is apparent from the evaluation of daily and quarterly reports made by transmission and distribution system operators to the Bundesnetzagentur. A total of around 89% of unused energy was the result of congestion in the transmission system and 7% of unused energy was curtailed directly and compensated by the TSOs. Most - 82% - interventions were supporting measures which were ordered by TSOs but implemented by DSOs (cf. Table 24). The compensation payments for supporting measures by DSOs must be reimbursed by the TSOs.

Even if the causes of feed-in management measures are mainly situated in transmission systems, only 7% of the unused energy from installations connected to transmission networks is curtailed. The remaining 93% is curtailed at installations which are connected to distribution networks.

The following diagram shows volumes of unused energy per quarter. More energy needed to be curtailed from wind power plants in the winter months than in the summer months. In the summer months the volume of unused energy from photovoltaic installations rose only minimally, however. It is particularly noticeable that in the fourth quarter of 2015, which was heavily affected by storms (see I.B.2.2.3 on page 57), large volumes of wind energy had to be curtailed.

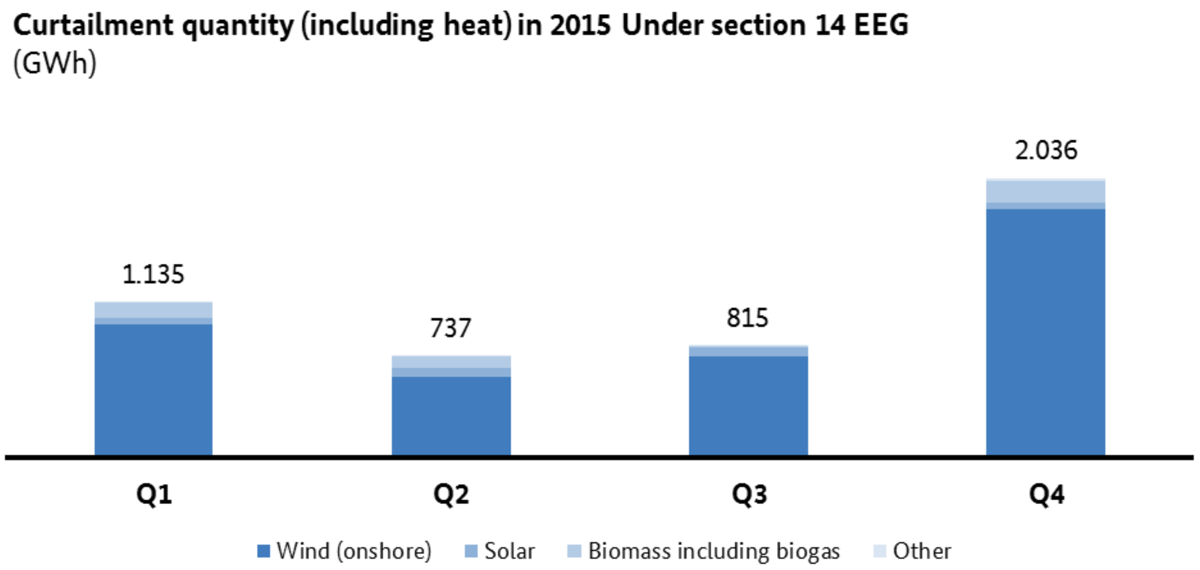

Figure 42: Curtailment quantity (including unused heat) due to section 14 of the EEG

All the regions of Germany are now affected by feed-in management measures. Nonetheless, 97% of unused energy is the result of FMM in the northern federal states, where Schleswig-Holstein is particularly affected.

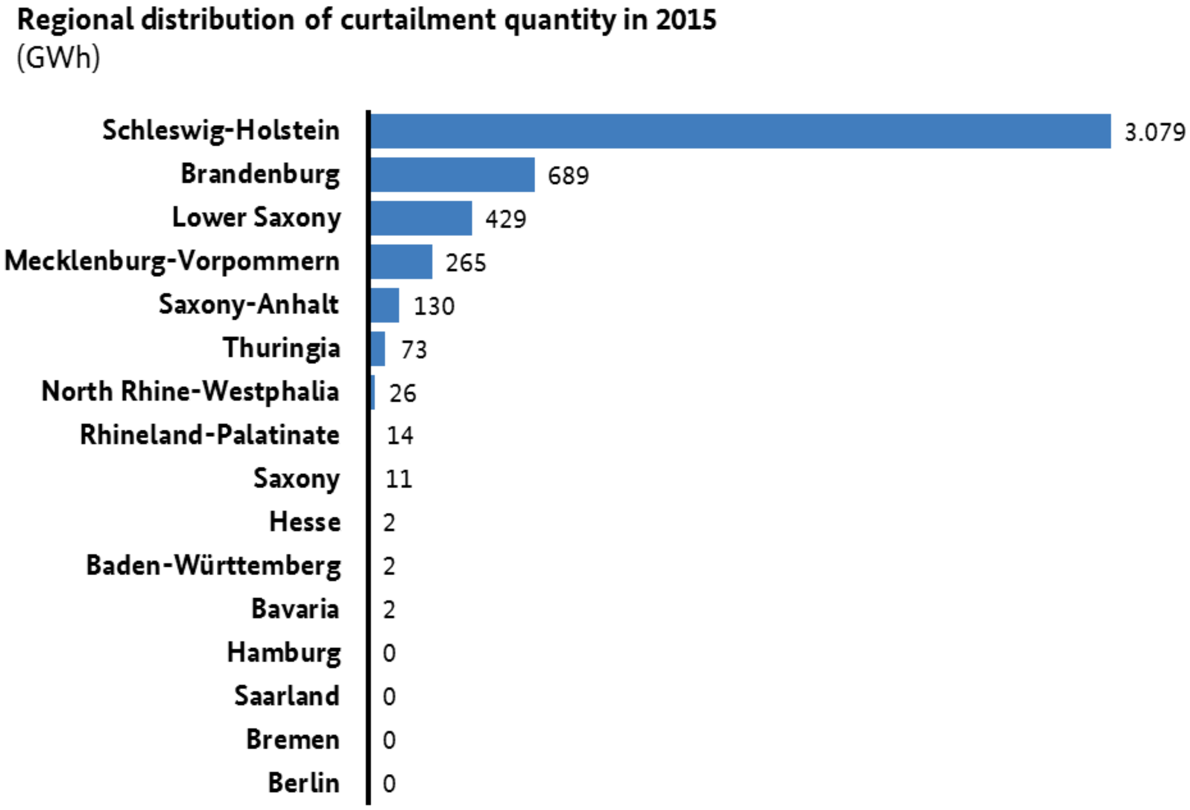

Figure 43: Regional distribution of curtailment quantity in 2015

5.2.2 Compensation claims and payments

With regard to the costs of feed-in management a distinction can be made between installation operators' estimated compensation claims for the year and the actual compensation paid. Estimated compensation claims are projected by network operators on the basis of the unused energy produced by renewable energy installations and reported to the Bundesnetzagentur every quarter. The actual compensation paid is the compensation paid by network operators to installation operators during the year under review. These are reported once a year in the Monitoring Report. Actual compensation paid includes the costs from previous years which can be asserted for three years. This means, for instance, that costs from the years 2012, 2013 and 2014 can also be included for the year 2015. This procedure means that the compensation paid in one year is not identical with the amounts incurred for unused energy in the relevant year. A restructured questionnaire now makes it possible to estimate the compensation payments made for unused energy in previous years. The compensation paid to the operators of the renewable and CHP installations affected by feed-in management measures – in economic terms similar to conventional plants whose feed-in has been curtailed through redispatching – is such that the operators are in more or less the same position as if feed-in from their installations had not been prevented by congestion.[20]

[20] Feed-in management measures carry considerably fewer residual risks for the renewable and CHP installation operators through, for instance, the cost-sharing arrangement under section 15 of the Renewable Energy Sources Act. Plants whose feed-in has been curtailed

Total compensation paid in 2015 almost quadrupled to around €315m. The costs of compensation are borne by the network tariffs paid by the final consumers, adding an average of around €6.26 per final consumer per year, up from €1.65 in the previous year. The additional cost will be higher for consumers in regions particularly affected by feed-in management measures. These higher costs are offset by lower surcharges payable by the consumers under the Renewable Energy Sources Act, since no financial support has to be paid for the electricity generated but not fed in from the renewable and CHP installations. The following graph shows the compensation paid from year to year for feed-in management measures from the year 2009.

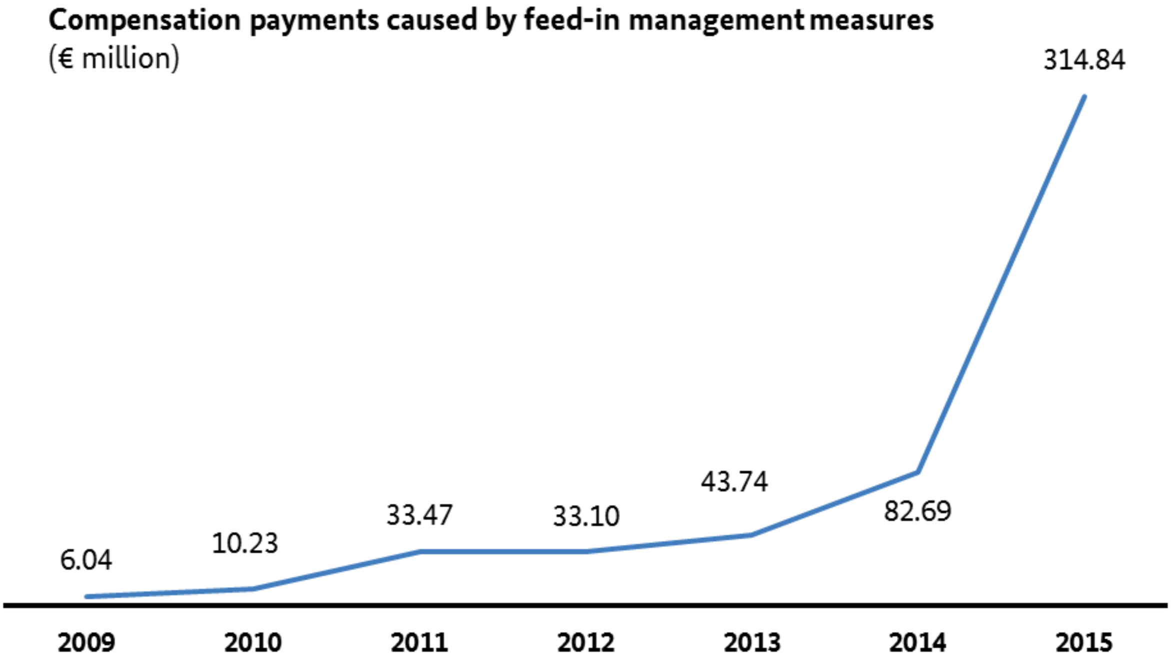

Figure 44: Compensation payments resulting from feed-in management measures

The compensation payments are generally settled through bills from the installation operators, although a number of network operators also offer credits (without bills from the installation operators). The compensation paid in 2015 therefore does not reflect the actual amounts payable for the volume of unused energy in 2015. The compensation payments for 2015 also include payments for unused energy in previous years.

On the basis of the quarterly estimates made by network operators, installation operators held claims for compensation in 2015 amounting to around €478m.[21] Network operators paid compensation of around €315m to installation operators for the year 2015. Of this amount around €222m is also for unused energy in 2015. The approximate €93m remaining covers compensation payments for unused energy in previous years. This means

receive equivalent amounts of electricity from the network operator through redispatching; this eliminates marketing risks created by congestion.

[21] Cf. Quarterly reports of the Bundesnetzagentur at: http://www.bundesnetzagentur.de/cln_1421/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/Versorgungssicherheit/Stromnetze/Netz_Systemsicherheit/Berichte/Berichte_node.html

that around 46% of network operators' estimated claims for compensation for unused energy in 2015 have already been settled. At the time of the survey, 54% (€256m) of estimated compensation claims had not yet been settled; this in turn will have an effect on the amount of compensation paid in the coming years. The detailed figures for the compensation claims estimated by network operators and the actual amounts of compensation paid are shown in the following table.

Compensation payments reported by network operators under section 15 EEG in 2015

	Estimated compensation claimed by installation operators (€)		Compensation payments under section 15 EEG (€)		Of which compensation claimed in previous years (€)
Implementation and payment of compensation by the TSO	**35,727,836**	**7%**	**27,494,822**	**9%**	**4,314,329**
Implementation and payment of compensation by the DSO	**442,295,075**	**93%**	**287,342,093**	**91%**	**88,844,734**
Own measures	52,234,395	11%	51,696,341	16%	29,260,918
Support measures by the DSOs (cause in transmission system)	390,060,680	82%	235,645,752	75%	59,583,816
Total feed-in management measures	**478,022,911**	**100%**	**314,836,916**	**100%**	**93,159,063**

Table 25: Compensation payments reported by network operators under section 15 of the Renewable Energy Sources Act in 2015

Apart from the estimated compensation payments reported to the Bundesnetzagentur by network operators, the Bundesnetzagentur extrapolated the compensation payments for network operators for the year 2014 in last year's Monitoring Report. These amounted to around €183m and have been basically confirmed by the current figures, i.e. from the total of compensation paid in the previous year of approximately €83m and the figures reported this year for compensation paid in previous years of approximately €93m.

5.3 Adjustment measures

The TSOs are legally entitled and obliged to adjust all electricity feed-in, transit and offtake or to demand such adjustment (adjustment measures) where a threat or disruption to the security or reliability of the electricity supply system cannot be removed or cannot be removed in a timely manner by network-related or market-related measures.

Where DSOs are responsible for the security and reliability of the electricity supply in their networks, they too are legally entitled and obliged to take adjustment measures. Furthermore, DSOs are also required to support the measures taken by the transmission system operators by implementing their own measures as instructed by the latter (supporting measures).

Curtailing feed-in from renewable energy, mine gas and combined heat and power (CHP) installations may also be necessary, regardless of feed-in management provisions, if the threat to the system is caused not by congestion but by another security problem. The measures to be taken in these cases do not affect grid expansion measures that may be required in the particular network area concerned.

In 2015, six DSOs and one TSO carried out adjustment measures involving feed-in adjustments equal to 26.5 GWh. The most frequently curtailed source of energy at 90.9% is waste (non-biodegradable share) followed by natural gas (3.3%) and hard coal (3.1%). Feed-in was also curtailed from installations powered by brown coal and mineral oil (0.5 or 0.1%).

In 2015 one TSO implemented four adjustment measures over the course of three days for a total period of six hours affecting feed-in of 826 MWh. On one day offtake by a pumped storage installation was prohibited for over two hours. As a result an offtake volume of 551 MWh from the grid was avoided. Other measures involve reductions in feed-in.

Six DSOs took adjustment measures over 2,128 hours. In the process energy from conventional installations was reduced by 15,702 MWh.

At the instigation of a TSO two DSOs carried out 629 hours of supporting measures to reduce electricity feed-in from conventional plants by 9,436 MWh.

Distribution of adjustments of electricity feed-in and offtake according to energy sources in 2015

Energy source	Adjustments under section 13(2) Energy Act	Percentage
Waste (non-renewable)	24.11	90.9%
Natural gas	0.88	3.3%
Hard coal	0.82	3.1%
Pumped storage	0.55	2.1%
Brown coal	0.13	0.5%
Mineral oil products	0.02	0.1%
Total	**26.52**	**100.0%**

Table 26: Distribution of adjustments of electricity feed-in and offtake according to energy sources in 2015

6. Reserve capacity

6.1 Reserve power plants

The TSOs were required to maintain 7,515 MW of reserve capacity to ensure network stability in the winter of 2015/2016. The reserve procured comprised just under 3,000 MW from Germany and around 4,500 MW from foreign power stations.

Compared to the previous years the TSOs used the reserve power plants very frequently during the winter half-year of 2015/2016, with the plants providing power on a total of 93 days compared to only 7 days in the winter half-year of 2014/2015. The reason here is that as of November 2015 deployment decisions also take into account which plants are most efficient to alleviate the predicted shortages. In the context of redispatch actions, foreign reserve power plants regularly proved to be more efficient in terms of having a better network-related effect on the shortage than domestic reserve or operational plants.[22] In other words, the TSOs required less capacity to fire up the foreign reserve plants than if they had used positive redispatch from domestic reserve or operational plants. The redispatch volume required by the TSOs to alleviate the shortage can thus be reduced, in turn reducing the risk of errors in taking redispatch actions. This ultimately means that the level of system security can be improved by primarily using foreign plants which have a more efficient effect on the shortages for redispatch actions.

On average, 80% of the reserve capacity for winter 2015/2016 was provided by foreign plants. It has been shown that because of their location, Austrian plants in particular can best alleviate the critical situations in the transmission networks, especially in Czechia and Poland, which are mainly caused by the large amounts of wind electricity exported from northern Germany to Austria.

In November 2015, reserve plants provided power on a total of 15 days, with an average of 1,131 MW and a maximum of 2,210 MW. The month saw four depressions with strong winds over northern Germany which more or less coincided with the times when the largest amounts of reserve capacity were required.

In December 2015, reserve plants provided power on 16 days, with an average of just 850 MW. At the same time, however, the highest amount of reserve capacity required in winter 2015/2016 – 3,499 MW – was needed on 4 December when Storm Philipp struck.

In January 2016, reserve plants provided power on 14 days, with an average of 1,079 MW. The highest amount required during the month – 2,727 MW – was on 29 January 2016, when there were very strong winds in northern Germany.

In February 2016, reserve plants provided power on 16 days, with an average of 1,045 MW. In March 2016, reserve plants provided power on 17 days, with an average of just 584 MW. Here, with the exception of one day when the TSOs requested power from a plant in Italy, all the plants providing reserve capacity were in Austria.

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[22] See the Bundesnetzagentur's report "Identifying the reserve capacity required for winter 2016/2017 and winter 2018/2019" (only in German): http://www.bundesnetzagentur.de/SharedDocs/Downloads/DE/Sachgebiete/Energie/Unternehmen_Institutionen/Versorgungssicherheit/Berichte_Fallanalysen/Feststellung_Reservekraftwerksbedarf_1617_1819.pdf?__blob=publicationFile&v=2

In mid-April 2016, the TSOs – following approval by the Bundesnetzagentur – extended some of the reserve capacity contracts with foreign plant operators that were due to expire on 15 April to 22 April 2016. The decision was made in view of restrictions in the network and the very small effect of the German reserve plants available throughout the year on the shortages in the network.

Reserve capacity deployment

	Number of days	Average (MW)	Total (MWh)
October	3	190	4,295
November	15	1,190	154,718
December	16	850	243,673
January	14	1,079	265,213
February	16	1,045	266,573
March	17	560	163,702
April	12	719	122,038
Total	93	796	1,220,212

Source: TSOs' status reports with initial instruction

Table 27: Reserve capacity deployment

The Bundesnetzagentur examined the TSOs' system analysis and subsequently confirmed the need for 5,400 MW of reserve capacity for winter 2016/2017. This can be met by the current pool of reserve power plants, comprising the reserve plants in Germany and the foreign plants contracted in the previous year. A call for expressions of interest to procure additional reserve capacity is therefore not necessary.

6.2 6.2 Hard coal stocks at south German power plants

The dry weather that lasted until mid-November 2015 led to lower river levels across the country. This resulted in considerable restrictions on shipping on the Rhine – a key transport route for hard coal from international ports in the Netherlands – and thus also to restrictions on the transport of coal to power stations in southern Germany. As far as possible, efforts were made while river levels were low to transport more hard coal to the coal-fired stations by train. One plant operator notified a short-term non-availability of capacity for redispatch actions under section 13(1) of the Energy Act. During the low water period in November 2015, TransnetBW, as the TSO affected by the potential non-availability of coal-fired stations and in agreement with the Bundesnetzagentur, required the plant operators concerned for a limited period of time to keep sufficient coal stocks for 160 full load hours of generation for redispatch purposes.

7. Network tariffs

Network tariffs are used to recover, inter alia, the costs for the use of network infrastructure, services to guarantee secure and reliable network operation, and distribution losses. Network tariffs are to be calculated by the network operators on the basis of the permissible revenue caps. The caps are derived from the costs for network operation, maintenance and expansion as verified by the regulatory authorities plus the regulatory profit (or the rate of return on equity) and annual adjustments.

7.1 Changes in network tariffs

The following graph shows the changes in the average volume-weighted[23] network tariffs (ct/kWh) for three consumption levels from 1 April 2006 to 1 April 2016, whereby the year 2006 was marked by special effects arising from the introduction of regulation. The charges for billing, metering and meter operation are included in the figures. The electricity suppliers' data on which the figures are based was highly diversified. Furthermore, several changes were made to the system of data collection over the years. The network tariffs are based on the following consumption levels:

- household customers on default tariffs: annual consumption 3,500 kWh, low voltage supply, no interval metering; as from 2016 the network tariffs are based on an annual consumption of between 2,500 kWh and 5,000 kWh (Eurostat Band DC);

- commercial customers: annual consumption 50 MWh, annual peak load 50 kW, annual usage period 1,000 hours, low voltage supply (0.4 kV), interval metering (figures for non-interval metered customers were to be given on the basis of supply without interval metering);

- industrial customers: annual consumption 24 GWh, annual peak load 4,000 kW, annual usage period 6,000 hours, medium voltage supply (10 kV/20 kV), interval metering; no account is taken here of the surcharges and reductions under section 19 of the Electricity Network tariffs Ordinance.

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[23] The network charges for non-household customers (industrial and commercial customers) as from 2014 are determined arithmetically.

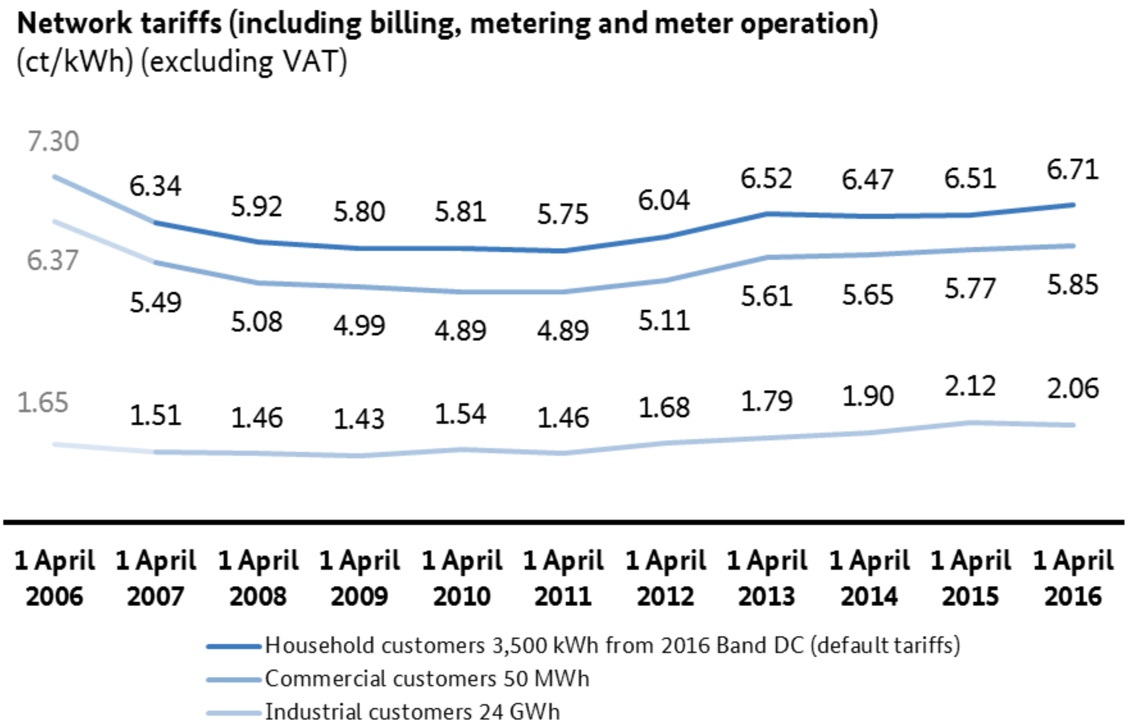

Figure 45: Network tariffs 2006[24] to 2016[25]

The charges for household and commercial customers showed a slight increase, having been broadly stable over the previous three years. There was a small decrease of around 3% in the network tariffs for industrial customers for the first time in four years. The average volume-weighted network tariffs for household customers (low voltage) increased by 0.2 ct/kWh in the period from 1 April 2015 to 1 April 2016. The charges for non-household customers remained broadly unchanged on the previous year's levels. The network tariffs for commercial customers increased slightly by 0.08 ct/kWh while those for industrial customers with an annual energy consumption of 24 GWh fell by 0.06 ct/kWh.

Various new factors have had an additional influence on the network tariffs since 2006. The energy transition brought with it a significant increase in embedded generation. The increase in electricity generation led to more network expansion and a greater need for system services among the network operators. Over the last few years various costs such as compensation for feed-in management measures or measures under the System Stability Ordinance (SysStabV) have also been fed into the calculation of the network tariffs. These, together with inflation, have the effect of raising costs.

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[24] The year 2006 was marked by special effects arising from the introduction of regulation, which initially resulted in excessive network charges being reported by companies. It was only once regulation began to take effect and network charges were reduced that costs that had been erroneously allocated to network charges could be assigned to the price components that they belonged to under the principle of causation. The increases in price components other than network charges that took effect after regulation began, particularly in "supply", were thus only partly a result of reductions in network charges. The year 2006 is therefore only of limited use as a reference year for a comparison over time.

[25] The figures for industrial and commercial customers as from 2014 are determined arithmetically.

While these factors influence the level of the costs, the increase in self-generation of electricity has an effect on the offtake of electricity from the general supply network.

The fact that the network tariffs for the various consumption groups have developed differently is due to the varied effect of the factors described at the individual network and substation levels. The increase in self-generation, for instance, is found more often at the low voltage level.

7.2 Expansion factor for electricity

The idea behind the expansion factor is to ensure that the costs of expansion investments resulting from a lasting change in a DSO's supply services during a particular regulatory period are taken into account with as little delay as possible when setting the revenue cap. Costs for replacement investments are not covered by the expansion factor. Claims for expansion investments at high voltage level can only be made in connection with investment measures.

Under section 4(4) para 1 in conjunction with section 10 of the Incentive Regulation Ordinance, DSOs can apply – once a year by 30 June of the calendar year – for an adjustment to the revenue cap based on an expansion factor. The adjustment made takes effect on 1 January of the following year. Any adjustments to the revenue cap are granted up to the end of the particular regulatory period. Under the revised Incentive Regulation Ordinance adjustments to revenue caps based on expansion factors can be applied for up until 30 June 2017.

Overall, the adjustments made to revenue caps for 2015 on the basis of expansion factors from 117 applications amounted to €255.2m.

7.3 Transfer of electricity networks ownerships

Around 300 network transfer notifications/applications were submitted to the Bundesnetzagentur in the period from 2012 to 2016. The following graph shows the number of notifications/applications made in each year.

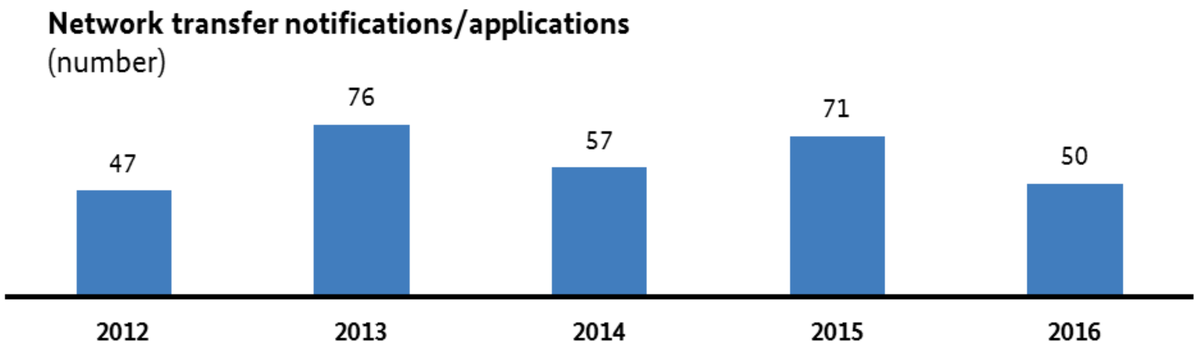

Figure 46: Network transfer notifications/applications

7.4 Costs of retrofitting renewable energy installations in accordance with the System Stability Ordinance

The significant increase in the number of embedded generation facilities over the last few years has long meant that it is fundamentally important to the stability of the network for these facilities to operate correctly in the event of frequency changes. As a solution to the "50.2 hertz problem", which concerns the frequency protection trip settings for solar PV installations, the System Stability Ordinance entered into force on 26 June 2012, requiring PV inverters to be retrofitted. Section 10 of the Ordinance in conjunction with section 57(2) of the Renewable Energy Sources Act provides for the costs to be divided between the network tariffs and the renewable energy surcharge.

The 2015 amendment to the Ordinance extended the retrofitting requirements to apply to operators of other renewable energy facilities, namely CHP, wind, biomass and hydro power installations. The operators must bear a certain proportion of the costs themselves as specified in section 21 of the Ordinance; the excess costs are financed through the network tariffs as provided for by section 22 of the Ordinance.

Most of the retrofitting work on PV installations was carried out by the network operators in 2013 and 2014, leading to corresponding increases in the revenue caps based on the predicted costs. The costs actually incurred were, however, significantly lower than forecast. The resulting differences are balanced out in the network operators' incentive regulation accounts. Retrofitting work on CHP, wind and hydro power installations began in 2015, also leading to increases in the revenue caps from 2016 onwards. There was a significant decrease in the costs incurred in retrofitting PV installations in 2015 compared to the previous years. One of the reasons may be that claims were made for retrofitting on only a few individual installations.

Retrofitting costs in the revenue caps
(€m)

	2013	2014	2015	2016
Forecast	48.5	73.1	4.9	22,6 (22,4)
Actual	12.2	35.3	6,8 (1,3)	

Figures in brackets in accordance with section 22 of the System Stability Ordinance

Table 28: Retrofitting costs in the revenue caps

Based on the cost forecasts, retrofitting work has directly added around €149m to the network tariffs. Owing to the fact that the actual costs in 2013 and 2014 were significantly lower than forecast, the comparison between forecast and actual costs will lead to a considerable sum being reimbursed to the network users. This will not happen, however, until the incentive regulation account is balanced in the third regulatory period.

7.5 Avoided network tariffs

Under section 18(1) of the Electricity Network tariffs Ordinance, operators of embedded generation facilities are entitled to payment from the operator of the distribution network into which they feed electricity. The sum paid must correspond to the network charge avoided by feeding in electricity at an upstream distribution network or substation level. The concept of avoided upstream network tariffs must not be confused with avoided costs. As a rule network costs are not avoided by facilities at lower voltage levels.

The concept of avoided network tariffs originated in the Associations' Agreement II/II+ when fully integrated utilities were still the norm and no unbundled network operators existed. Facilities connected downstream were generally smaller and – according to the municipal utility companies in particular – thus generated electricity at higher costs than large-scale plants at extra high voltage level. The smaller and larger plants compete with each other on the power exchange through the electricity prices. No account is taken of the supposed advantage over larger scale plants from generating closer to demand. The aim of paying the avoided network tariffs to the downstream facilities was to acknowledge generation close to demand and help the facilities become competitive.[26]

The avoided network tariffs within the meaning of section 18(1) of the Electricity Network tariffs Ordinance have experienced a highly dynamic development over recent years, as a result in particular of the changes in the generation structure.

The assumption that connecting facilities downstream would reduce network expansion has not proven to be true. Furthermore, basing the charges on the reduced offtake of energy from the upstream network level leads to self-perpetuating effects that make the instrument increasingly expensive for the networks concerned. Avoided network tariffs lead to partly questionable network connection requests. They are believed to be one of the factors behind the phenomenon that conventional generation plants are still in operation and connected to the grid despite negative electricity prices.

The following table shows a breakdown of the avoided network tariffs for each network and substation level. The figures comprise the sum of the avoided network tariffs for the network operators under the Bundesnetzagentur's own or delegated responsibility.[27]

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[26] See VKU (2015):http://www.vku.de/energie/netzzugang-netzanschluss-elektrizitaet/vermiedene-netznutzungsentgelte/historie.html (accessed March 2015).

[27] In 2014 Lower Saxony assumed responsibility for the network operators previously delegated to the Bundesnetzagentur. The Bundesnetzagentur does not have figures for the avoided network charges for 2013 (reported in 2014). In 2015 Mecklenburg-Western Pomerania assumed responsibility for the network operators previously delegated to the Bundesnetzagentur, hence the figures for 2016 do not include these network operators.

Avoided network charges by network and substation level
(€m)

Level	2011 (actual figures)	2012 (actual figures)	2013 (actual figures)	2014 (actual figures)	2015 (forecast figures)	2016 (forecast figures)
EHV/HV	79	65	67	64	11	23
HV	464	484	478	594	659	753
HV/MV	65	77	88	84	107	119
MV	345	494	463	550	554	619
MV/LV	16	30	36	37	42	33
LV	94	144	142	160	185	186
Total	1,063	1,294	1,274	1,489	1,558	1,733

Table 29: Avoided network tariffs (section 18(1) of the Electricity Network tariffs Ordinance) by network and substation level

The figures show a continuous increase in the total amount of avoided network tariffs. The rise in costs is due to various factors, including the following:

The growth in embedded generation means the existing capacity of the upstream network is used to a lesser extent. The infrastructure costs which stay the same are spread over a smaller marketed volume. This leads to an increase in the network tariffs at the upstream network level. This in turn results in an increase in the avoided network tariffs since they are calculated on the basis of the network tariffs at the upstream network or substation level.

The investments required for line expansion and the associated operational costs mean that the infrastructure costs for the upstream network will continue to rise. On account of the economic life of these investments, line expansion in the upstream network – made necessary in particular by renewable energy installations – will lead to an increase in the avoided network tariffs in the long term.

The increasing offshore expansion costs at the transport network level result in higher upstream network costs and thus higher network tariffs in the distribution networks. There is therefore a need for changes to the system of avoided network tariffs to dampen the rise in prices.

D System services

Guaranteeing system stability is one of the TSOs' core tasks and is performed using system services. System services comprise procuring and using the three types of balancing reserve:

- primary,
- secondary and
- tertiary control reserve.

They also include procuring energy to cover losses, reactive power and black start capability, and national and cross-border redispatch and countertrading, as well as contracting and using reserve power plants and interruptible loads under the Interruptible Loads Ordinance (AbLaV)[28].

[28] The costs for interruptible loads under the Interruptible Loads Ordinance are derived from the capacity-based prices.

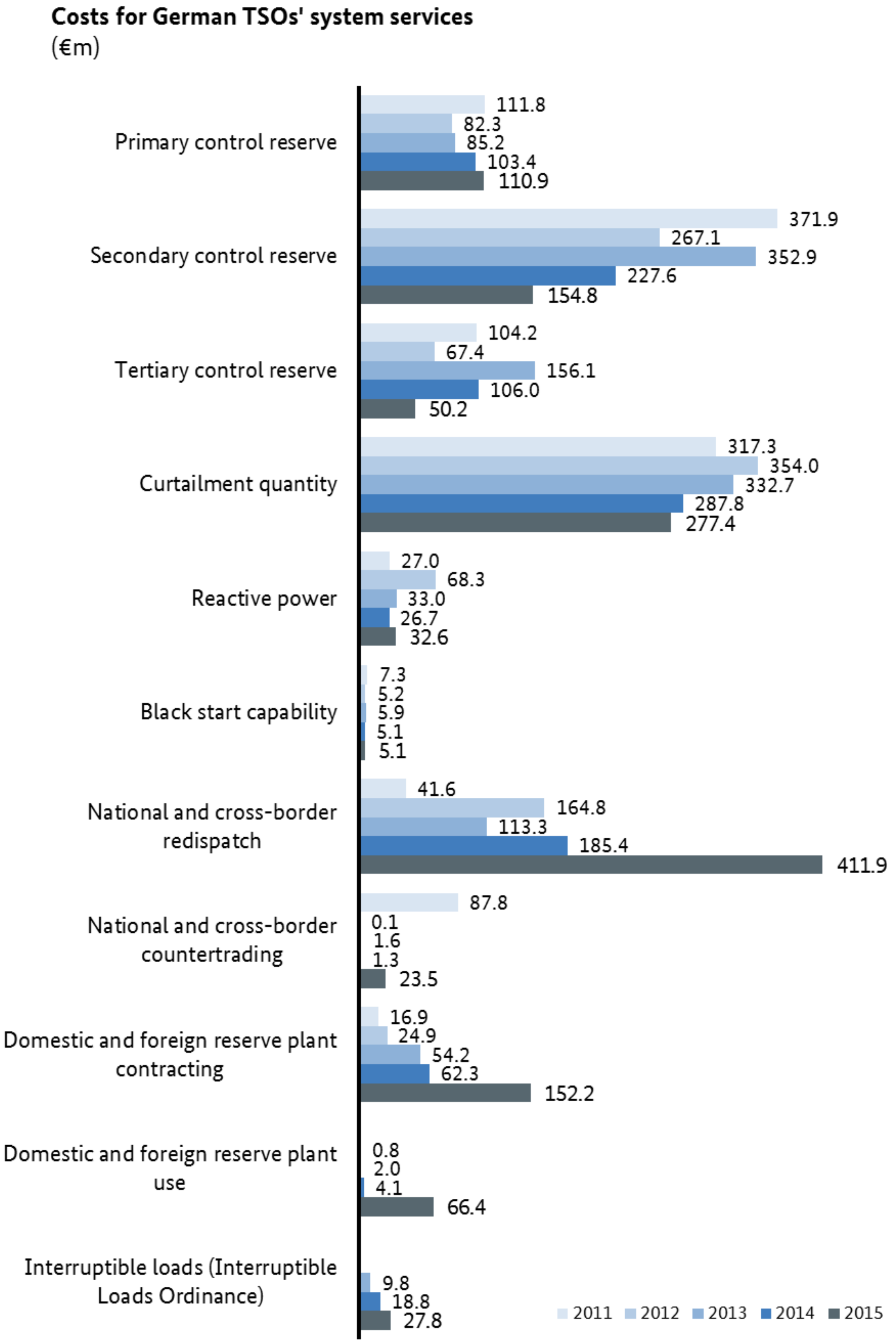

Figure 47: Costs for German TSOs' system services 2011 to 2015

The total costs for system services recovered through the network tariffs increased markedly from €1,088m in 2014 to €1,453m in 2015. The cost-reducing revenues totalled €140m, compared to €59m in 2014. As a result, there was an increase in the net costs for system services[29] from €1,029m in 2014 to a total of €1,313. A large part of the costs is accounted for by the costs of national and cross-border redispatch – up from €185m in 2014 to almost €412m, procuring primary, secondary and tertiary control reserves – down from €437m in 2014 to just under €316m, and energy to compensate for losses – at around €277m compared to €288m in 2014.

The structure of the system service costs changed considerably in 2015 from 2014. There was a further decrease – of €121m – in the total net costs for balancing, as a result in particular of the lower costs for secondary and tertiary reserves, down again by €73m and €56m respectively. One reason for this is the further slight decrease in the volume procured of these two types of reserve (see below). By contrast, there was a small increase of €8m in the costs for primary reserve. The costs for energy to compensate for losses in 2015 were down by around €10m on 2014.

There was a significant increase, however, in the costs for redispatch, countertrading and reserve power plants. There were increases in the costs for both national and cross-border redispatch, up around €130m and €97m respectively. The costs for contracting reserve power plants were up €90m on 2014. The more frequent use of the reserve plants in 2015 resulted in a provisionally estimated increase of about €62m in deployment costs. There was also a rise – of €22m – in the costs for countertrading.

Together with the TSOs' and DSOs' estimated costs for compensation claimed by installation operators for feed-in management measures, the costs for reserve power plants and countertrading represent a significant proportion of the costs incurred by the operators to maintain network and system security. In total, the costs for network and system security increased substantially by around €696m from €436m in 2014 to about €1,133m in 2015. This is mainly due to the large increase in the number of network and system security measures taken in 2015.[30]

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[29] Net costs (outlay costs minus cost-reducing revenues) and costs for reserve power plants and interruptible loads under the Interruptible Loads Ordinance.

[30] Cross-reference: Network and system security measures

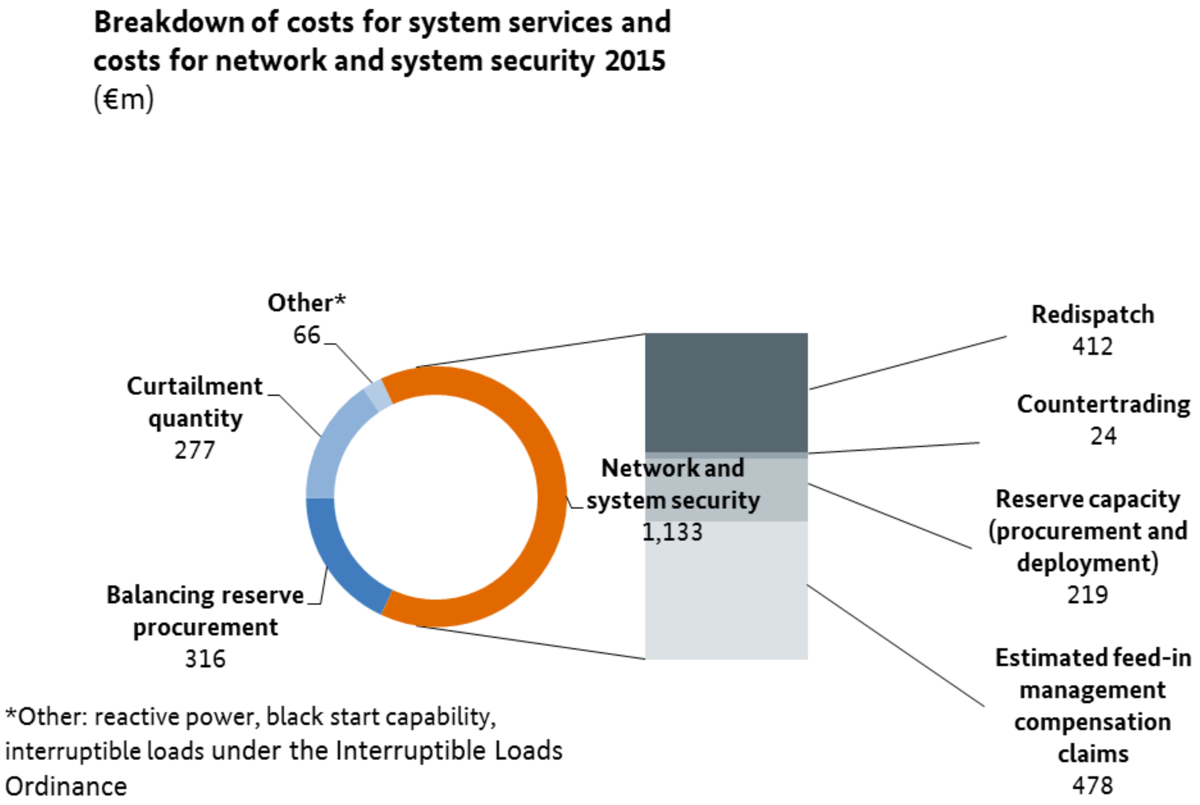


Figure 48: Breakdown of costs for German TSOs' system services and costs[31] for network and system security 2015

1. Balancing services

The TSOs procure and activate balancing reserves and energy to balance demand and generation in the electricity supply system and thus maintain the stability and frequency of the system. The reserves are procured by the TSOs in national tendering processes in accordance with the Bundesnetzagentur's determinations issued in 2011 (BK6-10-097/098/099). While the costs of procuring balancing reserves are covered by the network tariffs, the actual energy activated is settled in the form of balancing energy with the balancing group managers (dealers, suppliers) causing the imbalances.

A grid control cooperation scheme covering the control areas of all four German TSOs (50Hertz, Amprion, TenneT and TransnetBW) was completed when Amprion joined in 2010 as instructed by the Bundesnetzagentur. The scheme, with a modular structure, prevents inefficient use of secondary control reserves and dimensions the balancing reserve requirements for all four control areas together. The scheme also creates a nationally uniform, integrated market mechanism for secondary and tertiary reserves and optimises the costs of using balancing reserves for the whole of Germany. The imbalances in the individual control areas are netted so that only what remains has to be compensated for by activating reserves. Inefficient use is almost completely eliminated and the

[31] The figures shown here may differ from the individual entries in figure 47 owing to rounding.

volume of balancing capacity required is reduced, as reflected by the lower levels of secondary and tertiary reserves tendered and energy activated.

In 2011 the Bundesnetzagentur issued determinations within this context on

- reducing minimum bid volumes,
- shortening tendering periods,
- pooling and
- providing collateral for investments in the primary, secondary and tertiary reserve markets.

One of the aims of the determinations is to encourage new suppliers to enter the market and to further open up the balancing markets for other technologies, for example for interruptible consumption or storage facilities.

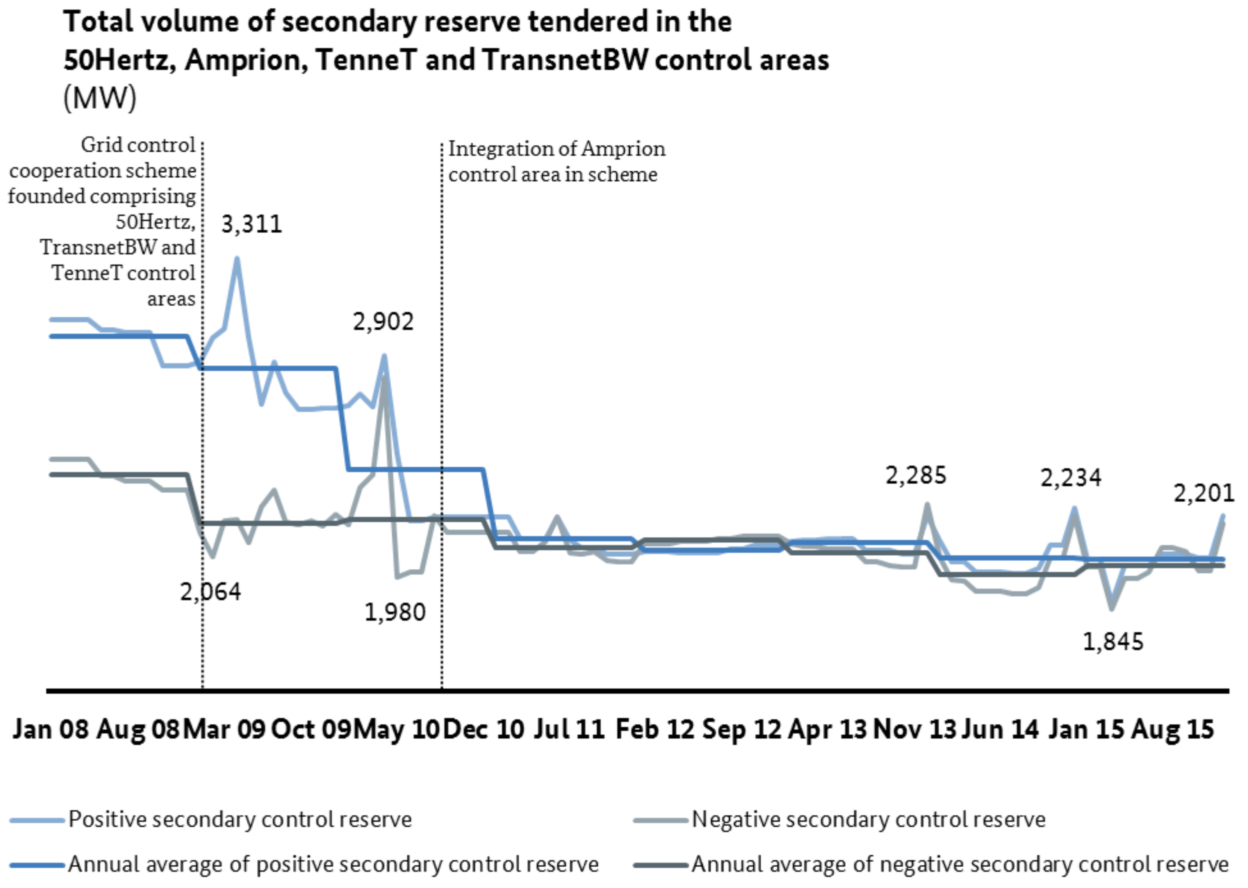


Figure 49: Total volume of secondary reserve tendered in the control areas of 50Hertz, Amprion, TenneT and TransnetBW

The average volume of positive secondary reserve tendered in 2015 was broadly unchanged on the previous year at 2,053 MW compared to 2,058 MW in 2014. The average volume of negative secondary reserve tendered increased from 1,987 MW in 2014 to 2,027 MW. Overall, there were only small fluctuations in the volumes tendered over the course of the year.

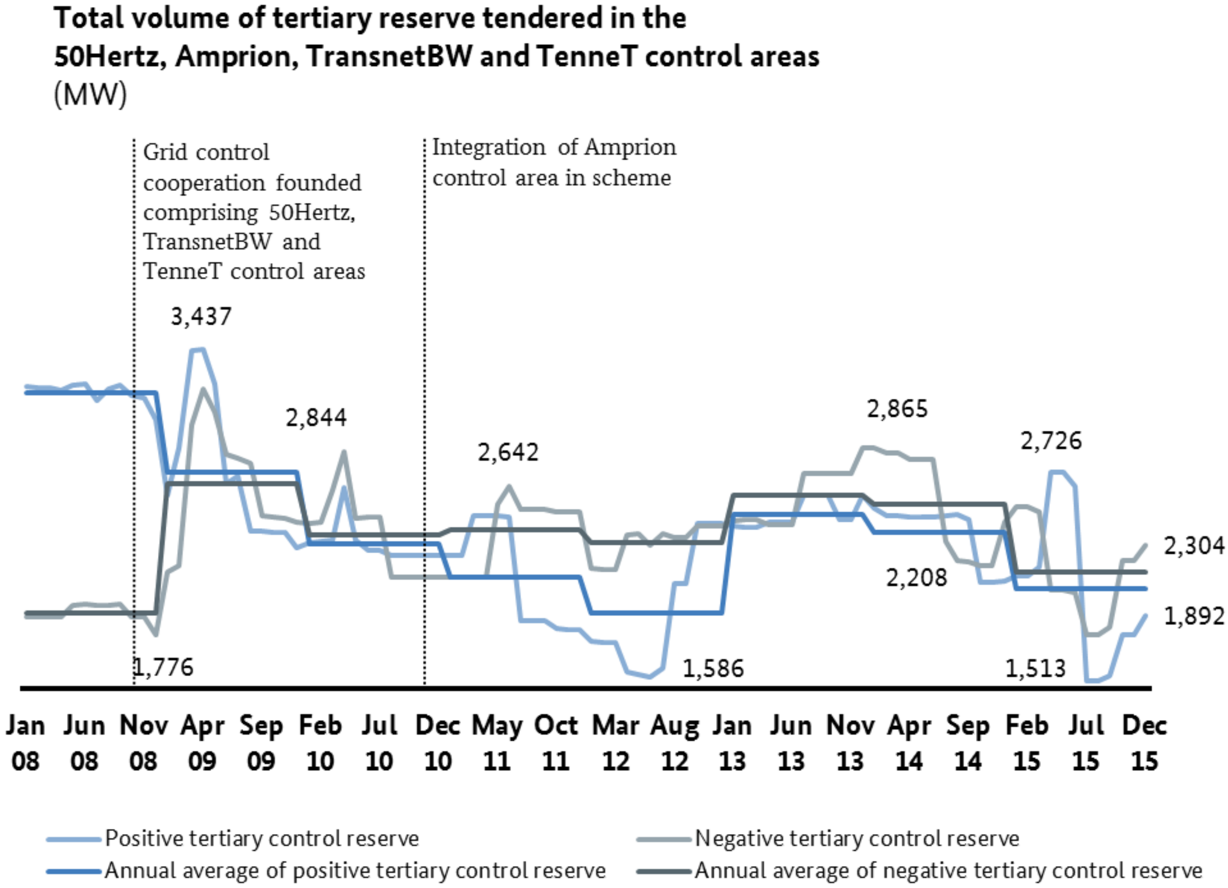


Figure 50: Total volume of tertiary reserve tendered in the control areas of 50Hertz, Amprion, TenneT and TransnetBW

The picture is less uniform when it comes to tertiary reserve. While there was a continued decline in the average volume of positive tertiary reserve tendered from 2,309 MW to 1,907 MW between 2010 and 2012, the average volume in 2014 was 2,376 MW. In 2015, the average volume tendered fell to 2,044 MW. Following an increase in the demand for positive tertiary reserve from 2,123 MW in January 2015 to 2,726 MW in May 2015, there was a marked decline in July 2015 to 1,513 MW, a new record low level. Demand for positive tertiary reserve rose again to 1,892 MW by the end of 2015.

There was a year-on-year decrease in the annual average volume of negative tertiary reserve procured. The average volume of negative tertiary reserve tendered in 2015 was 2,146 MW. As with positive tertiary reserve, however, volumes fluctuated considerably during the course of the year. In January 2015 the average volume of negative tertiary reserve tendered stood at 2,522 MW; this decreased in the period up to August to 1,782 MW before increasing to reach 2,304 MW in December.

Overall, therefore, the changes in the volumes of positive and negative tertiary reserve tendered within the twelve-month period are considerably more volatile than for secondary reserve. This is due in part to changes in generating patterns and the continued increase in the number of renewable energy installations in Germany.

The range of the volumes of primary, secondary and tertiary control reserves tendered in the period from 2012 to 2015 are shown in the following table:

Balancing reserves (minimum and maximum volumes) tendered by the TSOs

	Year	Capacity tendered (MW)	
		Min	Max
Primary control reserve	2012	567	592
	2013	576	593
	2014	568	578
	2015	568	578
Secondary control reserve (positive)	2012	2,081	2,109
	2013	2,073	2,473
	2014	1,992	2,500
	2015	1,868	2,234
Secondary control reserve (negative)	2012	2,114	2,149
	2013	2,118	2,418
	2014	1,906	2,500
	2015	1,845	2,201
Tertiary control reserve (positive)	2012	1,536	2,149
	2013	2,406	2,947
	2014	2,083	2,947
	2015	1,513	2,726
Tertiary control reserve (negative)	2012	2,158	2,413
	2013	2,413	3,220
	2014	2,184	3,220
	2015	1,782	2,522

Table 30: Balancing reserves (minimum and maximum volumes) tendered by the TSOs 2012 to 2015

There was a year-on-year decrease in the maximum volumes of positive and negative secondary and tertiary reserve tendered. At the same time there was a decrease in the minimum volumes of secondary and tertiary reserve tendered. The range between the minimum and maximum levels for positive and negative secondary reserve and for negative tertiary reserve narrowed. By contrast, the range between the minimum and maximum levels for positive tertiary reserve widened. The demand for primary control reserve increased slightly year on year from 568 MW in 2014 to 578 MW. This is broadly the same as the level in 2012. Overall, the volume tendered for Germany has decreased slightly since 2009.

The German TSOs are seeking to harmonise the primary reserve markets across the borders in cooperation with the Bundesnetzagentur and other European TSOs and regulators. The Swiss network operator Swissgrid joined the German TSOs' joint primary reserve tendering scheme in March 2012 and procures 25 MW of Switzerland's primary reserve requirements through the scheme. TenneT TSO BV in the Netherlands joined in January 2014. An initial volume of 35 MW and currently 71 MW and thus a good 70% of the Netherlands' primary reserve requirements is tendered through the joint tendering scheme. On 7 April 2015 the primary reserve tendering partnership scheme between Germany, the Netherlands and Switzerland was coupled with Austria and Switzerland's joint scheme, creating the largest primary reserve market in Europe with requirements currently amounting to 793 MW. The joint tendering procedure is open to all pre-qualified providers in the participating countries; the procedure follows the German regulations and uses the existing tendering systems. The next step will be in August 2016 when the Belgian network operator ELIA is scheduled to join the scheme. The French TSO RTE has also already expressed interest in participating, probably from 2017.

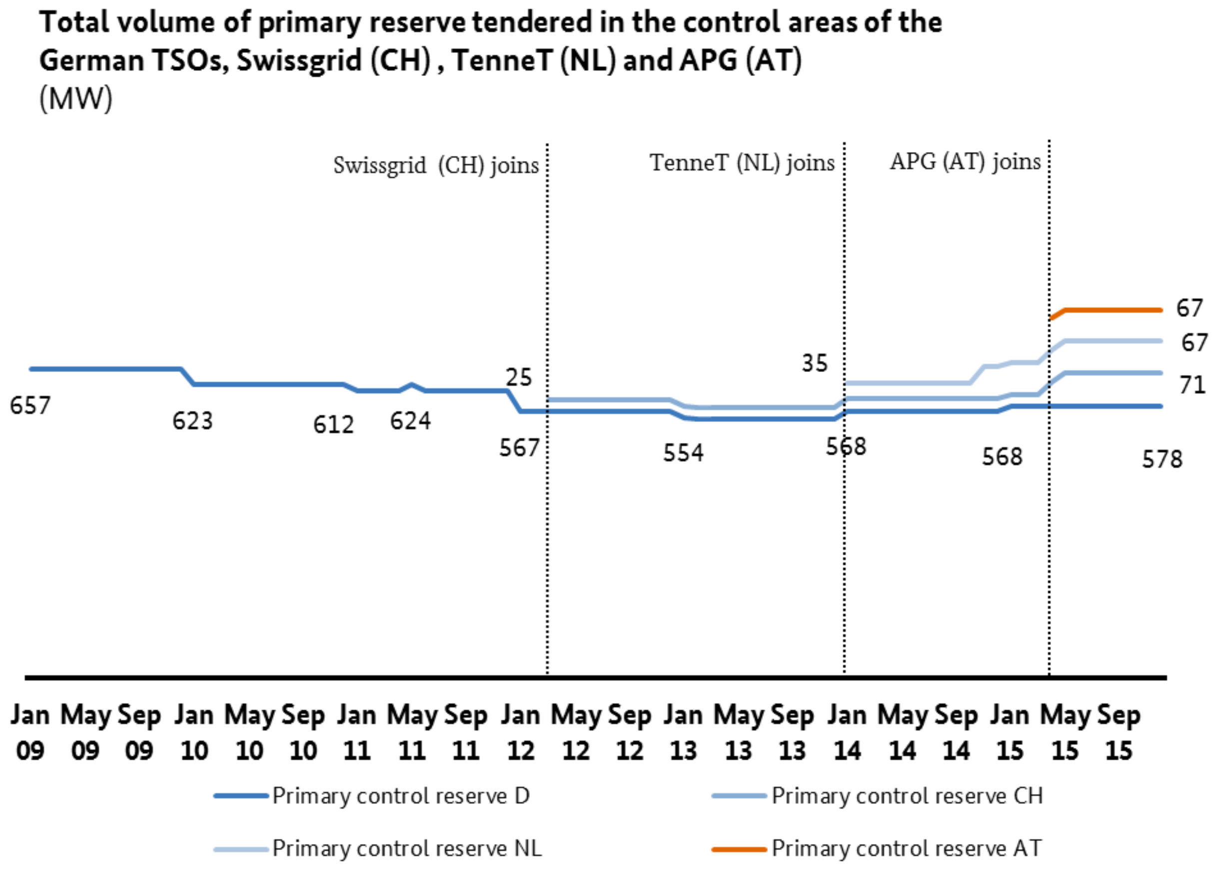


Figure 51: Total volume of primary reserve tendered in the control areas of the German TSOs, Swissgrid (CH) and TenneT (NL)

The German TSOs have also intensified their cooperation with the Austrian TSO APG relating to secondary reserve. As of 14 July 2016 a common merit order list is used to activate secondary reserve. This ensures that only the economically most advantageous offer for secondary reserve is taken in each country, enabling the costs for balancing energy to be reduced. This form of cooperation between the TSOs paves the way with regard to the European guideline on electricity balancing, which also provides for cross-border activation of balancing reserves based on a common merit order list with a view to further integrating balancing markets in the future.

The grid control cooperation scheme and the determinations issued by the Bundesnetzagentur contribute to increasing the potential for competition by enlarging the market area, creating a national market for secondary and tertiary reserves and aligning the conditions for tendering. By 28 October 2016 the number of pre-qualified secondary reserve providers had risen to 35 (compared to 15 in 2010 and 20 in 2013) and that of tertiary reserve providers to 47 (compared to 35 in 2010 and 36 in 2013). The number of primary reserve providers was 23, compared to 14 in 2013. In particular the possibility to pool several small installations into one virtual power plant has contributed to the increase in the number of providers. The strong growth in the number of balancing service providers over the last few years shows how attractive this market is.

2. Use of secondary control reserve

As Figure 49 shows, the total volume of secondary control reserve tendered and procured between 2011 and 2015 remained at a similar, comparatively low level. There was a slight decrease in the volume of secondary reserve actually used in 2015 compared to 2014.

The total amount of energy activated for positive secondary control in 2015 was some 1.4 TWh (compared to 1.2 TWh in 2014) and that for negative secondary control 1.1 TWh (compared to 1.6 TWh in 2014). The total amount of energy activated for secondary control hence decreased from 2.8 TWh in 2014 to 2.5 TWh in 2015, with another slight shift towards positive secondary control. Hence on average in 2015 around 7.8% of the average volume of positive secondary reserve tendered and about 6% of the average volume of negative secondary reserve tendered was used. It should be noted, however, that in a total of 24 quarter hours in the year at least 80% of the average secondary reserve capacity was required; overall this confirms the necessity of the volumes tendered.

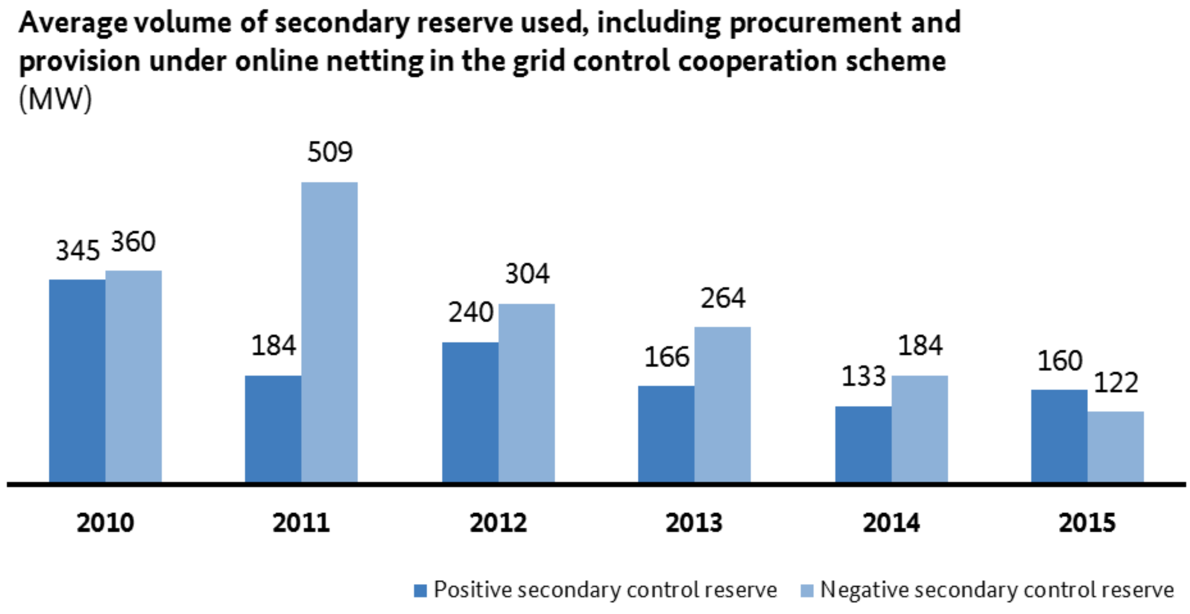


Figure 52: Average volume of secondary reserve used, including procurement and provision under online netting in the grid control cooperation scheme

3. Use of tertiary control reserve

The frequency of use of tertiary control reserve remained broadly unchanged in 2015 following a decrease of a good 40% in 2014. The total number of dispatch requests was 7,561, just 1.5% up on the previous year. Overall, there were 2,788 requests for negative tertiary reserve in 2015, compared to 3,769 in 2014, and 4,773 requests for positive tertiary reserve, compared to 3,682 in 2014.

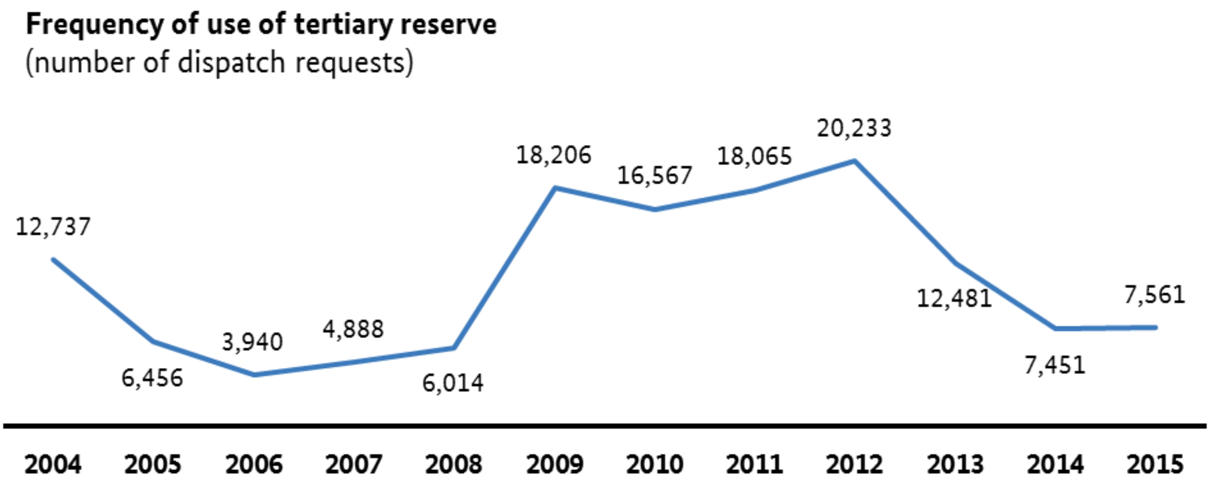


Figure 53: Frequency of use of tertiary reserve

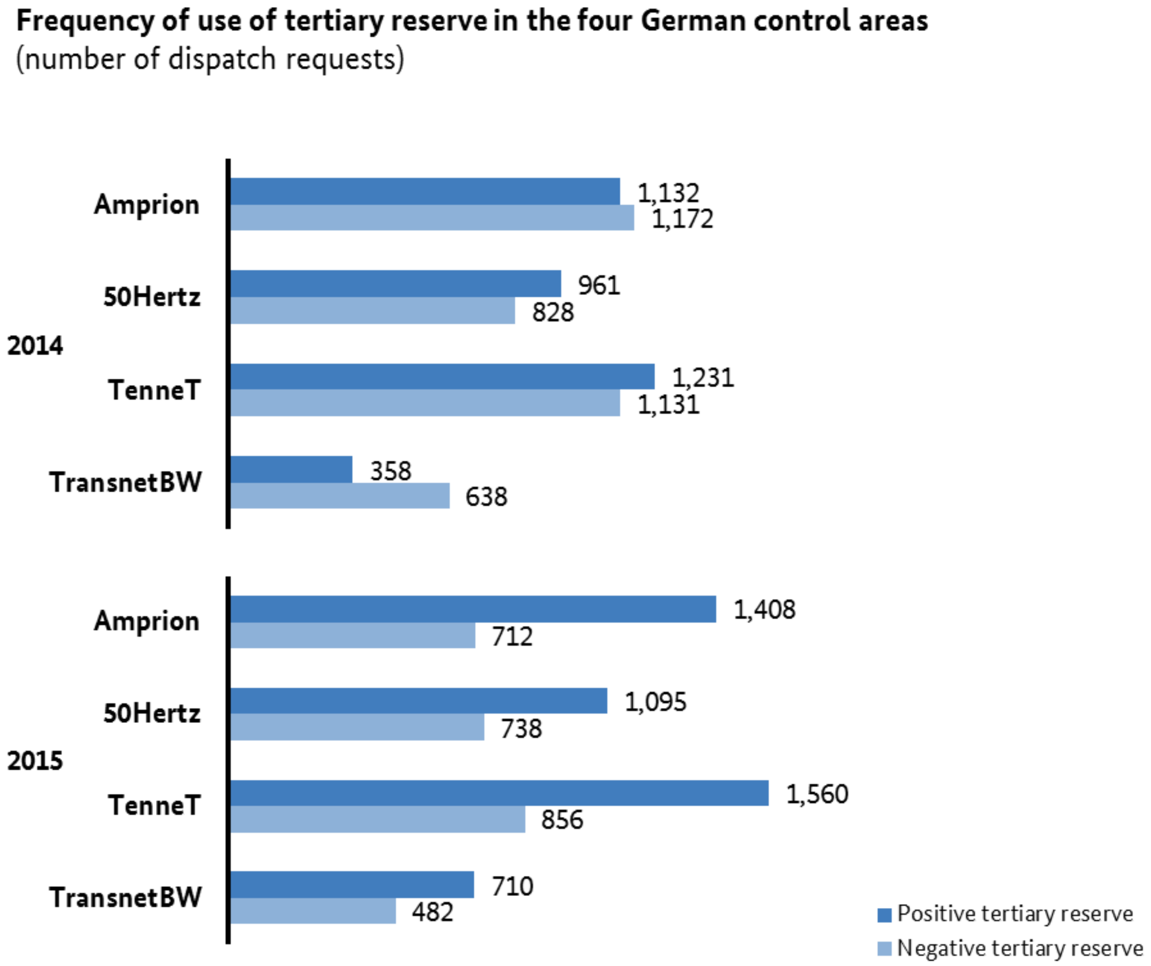


Figure 54: Frequency of use of tertiary reserve in the four German control areas 2014 and 2015

There was only a small decrease in the average volume of positive tertiary reserve requested from 176 MW in 2014 to 172 MW in 2015. Likewise, there was a decrease in the average negative minute reserve dispatched from 184 MW in 2014 to around 167 MW in 2015. On average in 2015 around 8% of the average volume of both positive and negative tertiary reserve tendered was used. As with secondary reserve, however, it must be noted that in several quarter hours almost all of the tertiary reserve capacity was required. In 16 cases at least 80% of the average capacity was required; overall this again confirms the necessity of the volumes tendered.

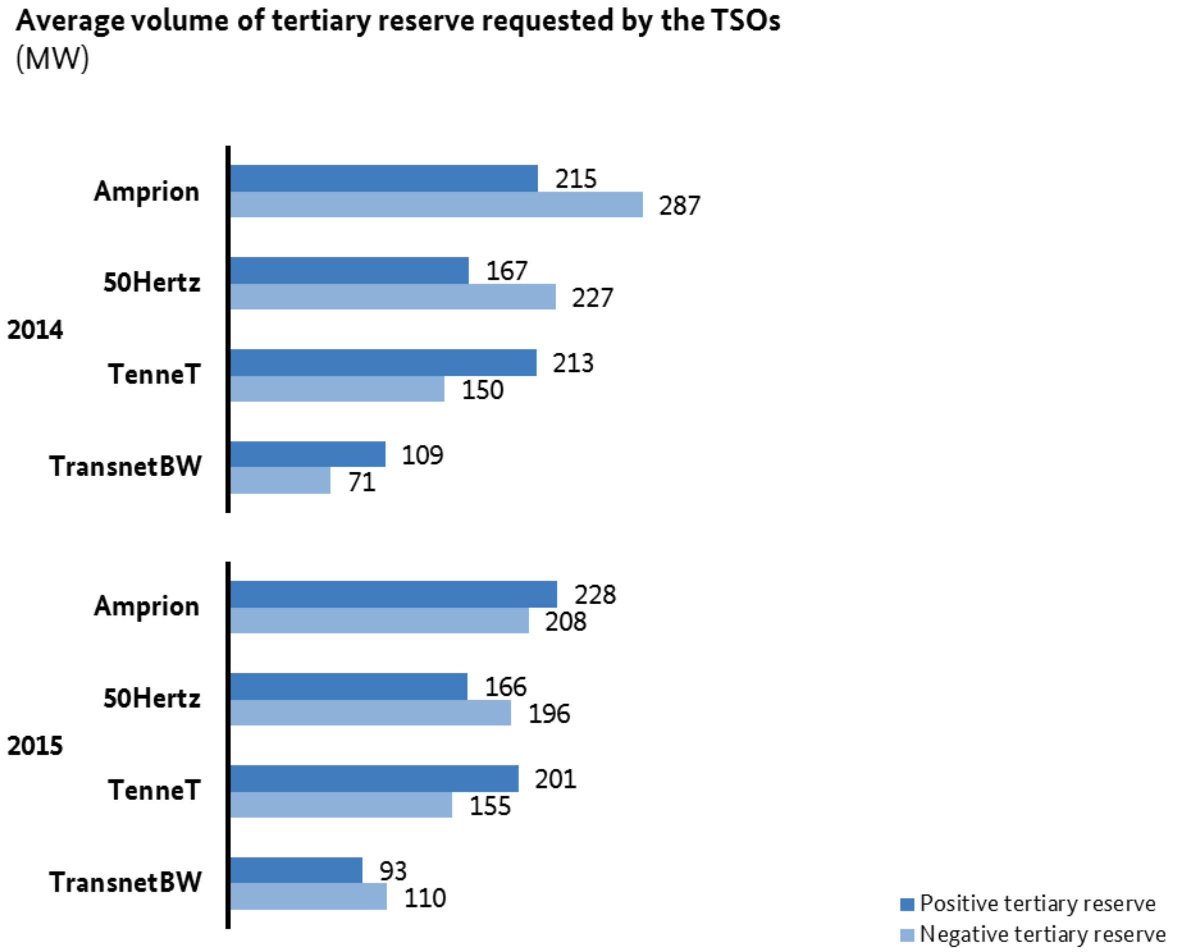


Figure 55: Average volume of tertiary reserve requested by the TSOs 2014 and 2015

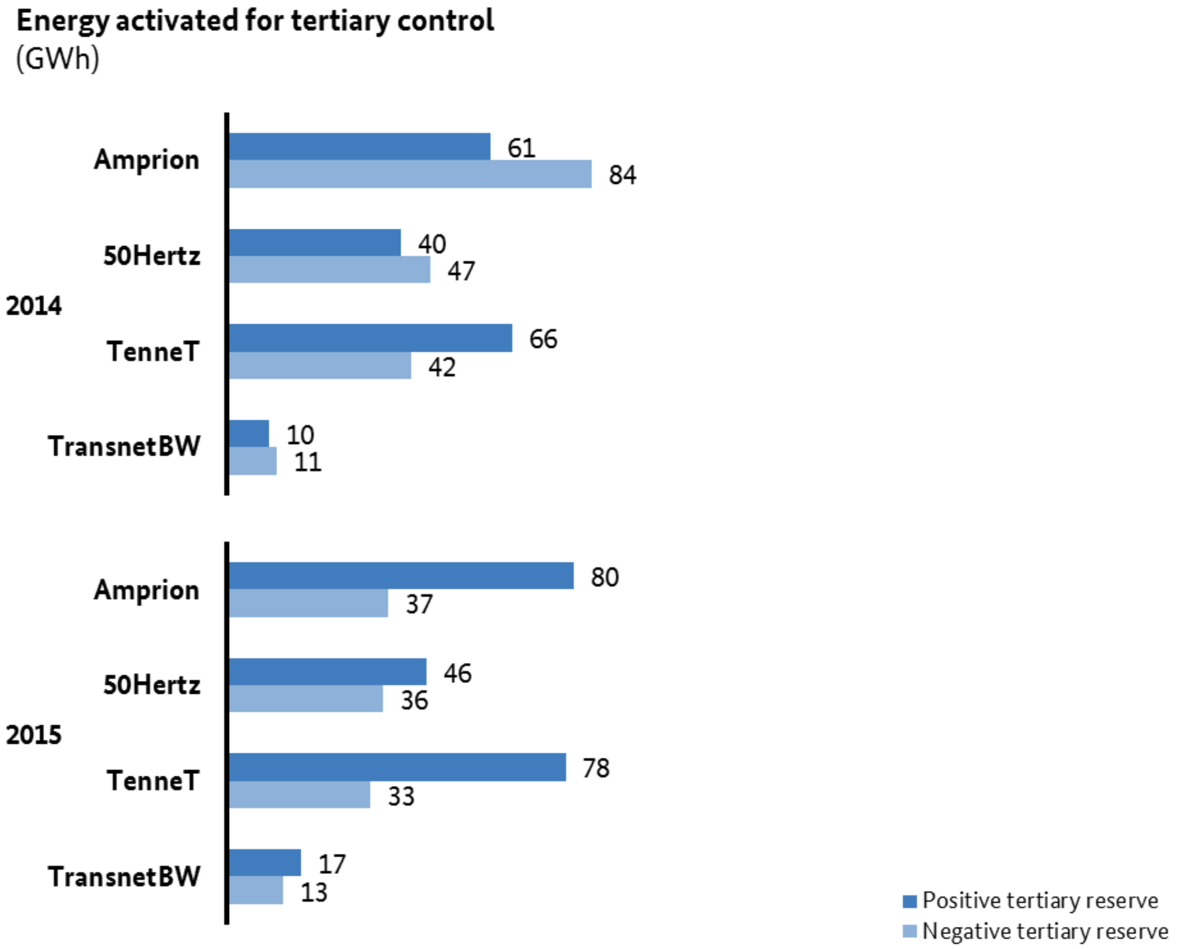
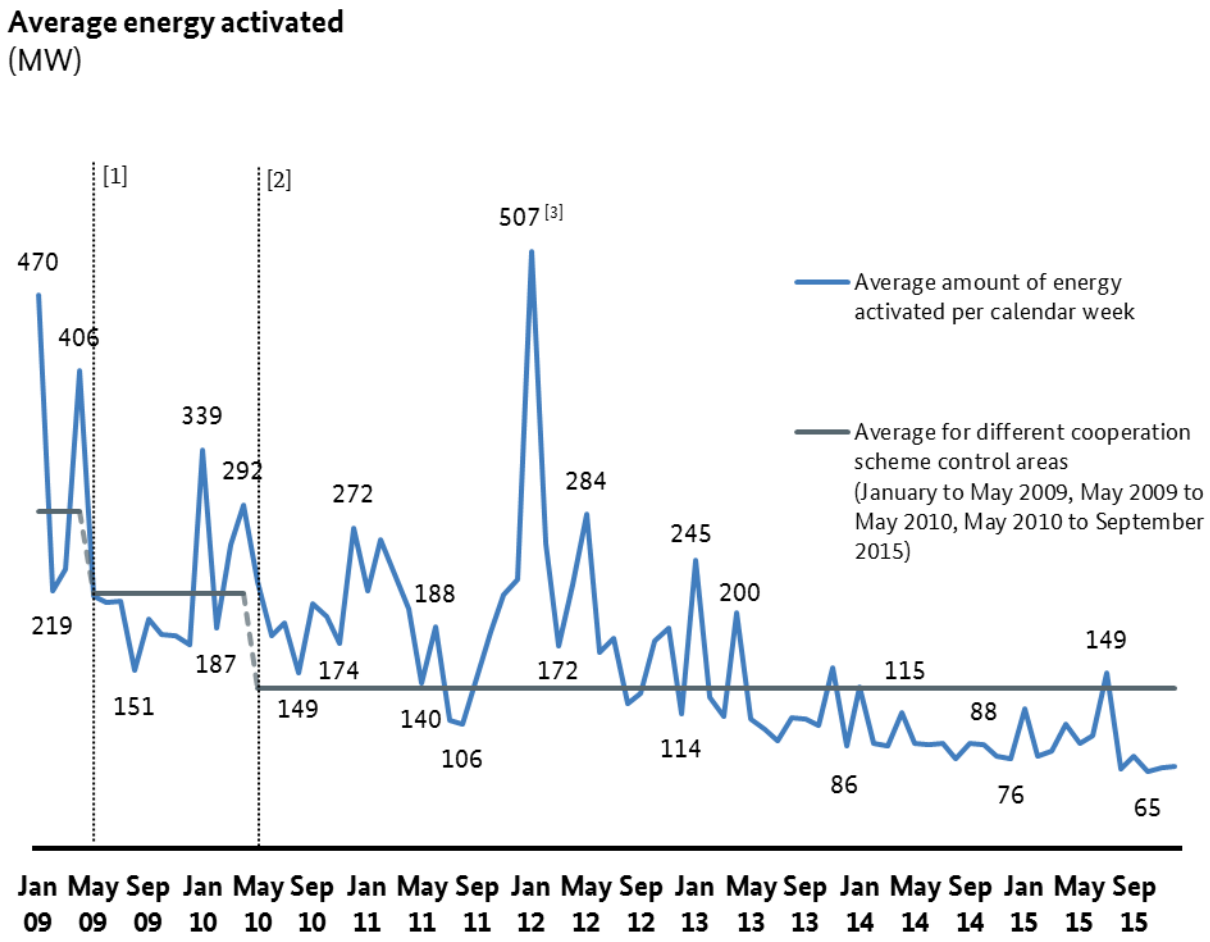


Figure 56: Energy activated for tertiary control 2014 and 2015

The total amount of energy activated for positive tertiary control in 2015 was 221 GWh, compared to 176 GWh in 2014, and that for negative tertiary control 119 GWh, compared to 185 GWh in 2014. This is the first time since 2013 that there is a shift away from negative to positive tertiary control, following a gradual convergence between the amounts of energy activated for positive and negative tertiary control since 2014.

The following line graph shows the average use of energy for secondary and tertiary control in each calendar month from 2009 to 2015. It also shows an average for each period. A change in the grid control cooperation scheme (eg setting up, Amprion joining) marks the beginning of a period. The graph illustrates the scheme's savings potential in terms of activated energy since January 2011. It also shows the decrease in the total average amount of energy activated for secondary and tertiary control and a reduction in volatility over time.



[1] Grid control cooperation scheme founded comprising 50Hertz, TransnetBW and TenneT control areas
[2] Integration of Amprion control area in scheme
[3] This figure reflects the critical network situation in February 2012 when all the available capacity was required.

Figure 57: Average amount of energy activated

4. Balancing energy

The regulations laid down by the Bundesnetzagentur reforming the balancing energy price system came into effect on 1 December 2012. The aim is to provide better incentives for the proper management of balancing groups with a view to preventing system-relevant imbalances such as occurred in February 2012.

The maximum portfolio balancing energy price within the grid control cooperation scheme rose again in 2015 to €6,343.59/MWh. Overall, the maximum price exceeded €2,000/MWh on eighteen occasions in 2015.

Maximum balancing energy prices

Year	Grid control cooperation scheme (€/MWh)
2010	600.90
2011	551.60
2012	1,501.20
2013	1,608.20
2014	5,998.41
2015	6,343.59

Table 31: Maximum balancing energy prices 2010 to 2015

In cases where the balance of energy activated for control within the grid cooperation scheme is close to zero (known as "zero crossings"), extreme balancing energy prices may occur uniformly across the control area owing to the calculation formula used. Up to April 2016 the balancing energy price was limited in these cases to the maximum price of a control energy bid activated in the particular quarter hour. However, if the prices bid by the suppliers were high, then the balancing energy prices were also high despite being capped. In May 2016 an updated method to calculate balancing energy prices was introduced; the linearised multi-step model was developed by the market players as an industry compromise and was accepted by the Bundesnetzagentur to supplement the existing regulations laid down in its determination (BK6-12-024).[32] In cases where the balance within the grid control cooperation scheme is between -500 MW and +500 MW, an additional cap is placed on the balancing energy price in the particular quarter hour in a new step in the calculations.

The average 15-minute price for balancing energy within the grid control cooperation scheme in 2015 in the case of a positive control area balance (short portfolio) was broadly unchanged on the previous year at around €75.99/MWh. There was another significant year-on-year decrease in the price in the case of a negative control area balance (long portfolio) to around -€42.66/MWh. The average balancing energy price was thus around 95%[33] above the average (peak) intraday trading price in 2015.

[32] Bundesnetzagentur communication on using the linearised multi-step model (in German): http://www.bundesnetzagentur.de/cln_1421/DE/Service-Funktionen/Beschlusskammern/1BK-Geschaeftszeichen-Datenbank/BK6-GZ/2012/2012_0001bis0999/2012_001bis099/BK6-12-024/BK6-12-024_Mitteilung_vom_20_04_2016.html?nn=269594

[33] Based on the EPEX SPOT average (peak) intraday trading price of €39.03/MWh for 2015.

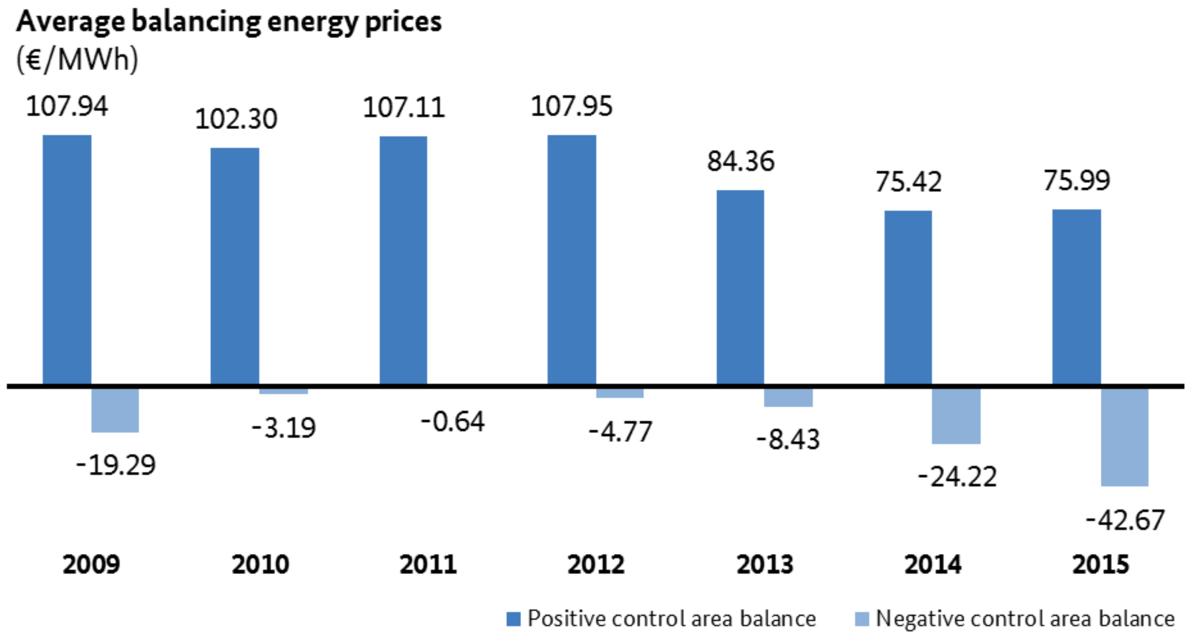


Figure 58: Average balancing energy prices 2009 to 2015

The following graph shows the frequency distribution of balancing energy prices in the grid control cooperation scheme in 2014 and 2015. As in previous years, in 2015 there was an accumulation of prices around €0/MWh in the case of a negative control area balance. In addition, in 2015 there was again a greater frequency of prices between €40/MWh and €90/MWh in the case of a positive control area balance.

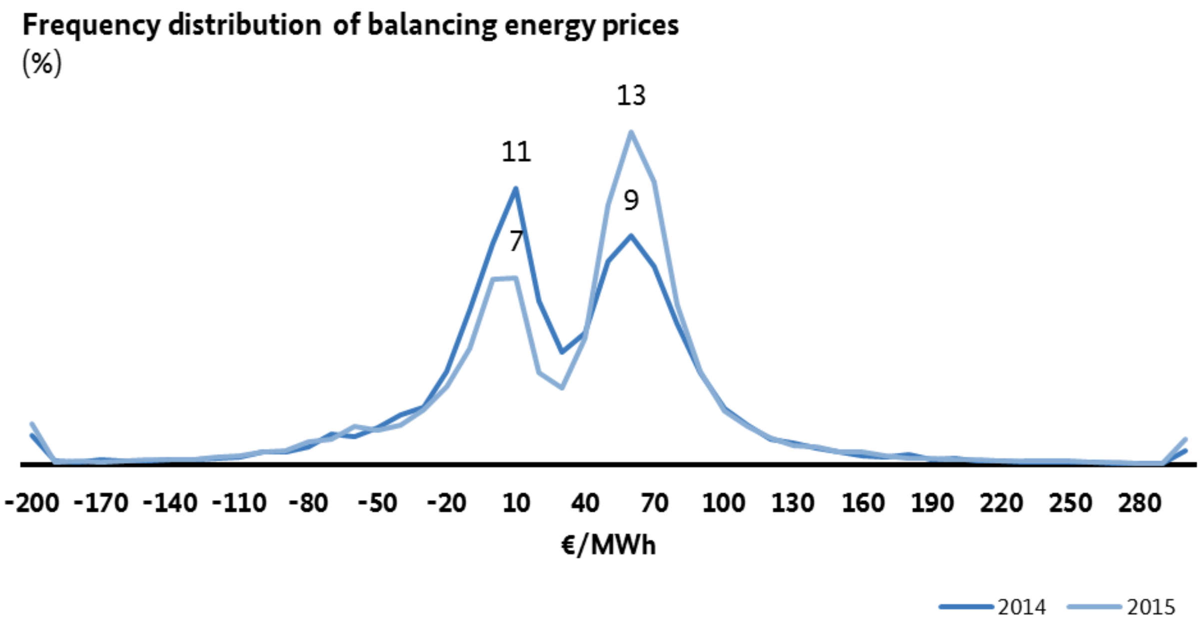


Figure 59: Frequency distribution of balancing energy prices 2014 and 2015

5. Intraday trading

Section 5(1) of the Electricity Network Access Ordinance (StromNZV) allows schedule notifications – in which balancing group managers notify TSOs about planned electricity supply and commercial transactions in the period from the day following submission until the next working day (based on quarter-hour figures) – to be submitted up to 14:30 on a given day. Schedules can also be modified during the day, enabling balancing group managers to respond to short-term changes in supply and demand. The following graph shows the number and volume of intraday changes to schedules in 2015:

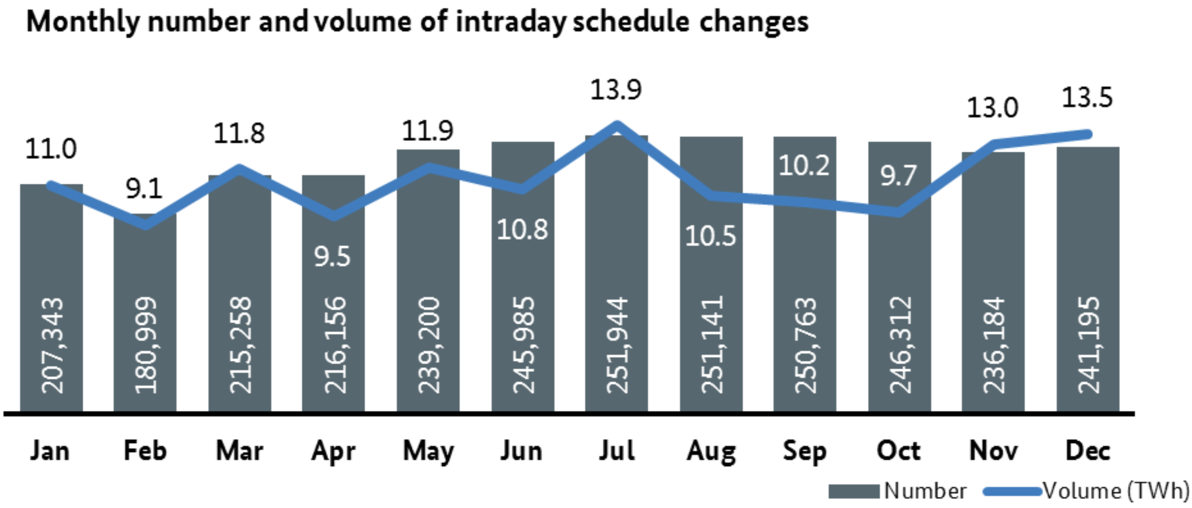


Figure 60: Monthly number and volume of intraday schedule changes 2015

In 2015, a total number of 2,782,480 schedule changes accounted for a total volume of 134.9 TWh, compared to 2,106,419 changes and 96.5 TWh in 2014. On average, nearly 232,000 schedule changes were made each month in 2015, the highest monthly number being 251,944 in July and the lowest 180,999 in February. One reason for the repeated steep increase in both the number and volume of intraday schedule changes is the increase in intermittent feed-in from renewables, which frequently needs to be balanced out during the day through intraday trading.

6. International expansion of grid control cooperation

Over the last few years the German TSOs have been pushing forward the expansion of module 1 of their joint grid control cooperation scheme, which aims to prevent the inefficient use of secondary reserve across different control areas. Under the International Grid Control Cooperation (IGCC) scheme, Germany and the following countries cooperate to avoid inefficient use of secondary control reserve: Denmark (since October 2011), the Netherlands (since February 2012), Switzerland (since March 2012), Czechia (since June 2012), Belgium (since October 2012) and Austria (since April 2014). Most recently the scheme expanded significantly when France joined in February 2016.

The IGCC enables the imbalances and hence the demand for secondary reserve in the participating control areas to be automatically registered and physically netted. This imbalance netting means that TSOs with a surplus of energy in their control areas provide power to those with a shortage. No cross-border transmission capacity needs to be reserved for this exchange of energy: the maximum amount of energy that can be exchanged across the border corresponds to the remaining capacity available after the close of trading in the intraday market.

The imbalances netted within the international cooperation scheme currently amount to around €4m to €6m per month. Overall, the international scheme has already achieved cost savings of over €240m through avoiding inefficient use of reserves. The concept of physically netting imbalances also promises high welfare gains for the whole of Europe. The guideline on electricity balancing hence requires all European TSOs using secondary control reserve to implement imbalance netting in the future. The IGCC has been designated by ENSTO-E as a European pilot project to provide technical and organisational experience at an early stage; the project is under the watch of the regulators, with the Bundesnetzagentur in a leading function.

E Cross-border trading and European integration

The year 2015 was characterised by new record high levels of electricity exports. As the hub for electricity exchange in Europe, Germany continues to play a key role within the central interconnected system. There were changes in 2015 in the average available transmission capacity to and from neighbouring countries. Import and export capacity decreased by 7.3% on 2014 to 19,652 MW. The previous year had seen an increase of 0.3% on 2013.

Total cross-border traded volumes rose from 83.8 TWh in 2014 to 84.9 TWh in 2015, an increase of 1.3%. This reflects a massive decline of 31.3% in imports from 24.7 TWh in 2014 to 17 TWh against an increase of 14.8% in exports from 59.2 TWh in 2014 to 68 TWh. Overall, there was a substantial increase of 47.8% in the German export balance from 34.5 TWh in 2014 to 51 TWh in 2015.

1. Average available transmission capacity

Of key importance to the European internal electricity market is the availability of transmission capacity between the countries in Europe. The average available transmission capacity was determined using the TSOs' annual average hourly net transfer capacity (NTC) values, where available. Gaps were filled using average NTC values taking the ENTSO-E formulae[34] as the basis of calculation.

[34] Care was taken to ensure that the values for individual borders were determined using data from the same source. Only a limited comparison can be made of the capacity of individual countries, however, as the NTC values transmitted on an hourly basis by the TSOs may deviate from the average values calculated using ENTSO-E formulae owing to the use of different calculation methods. Details of the NTC calculation methods used by ENTSO-E and the German TSOs can be found at https://www.entsoe.eu/publications/market-reports/ntc-values/Pages/default.aspx.

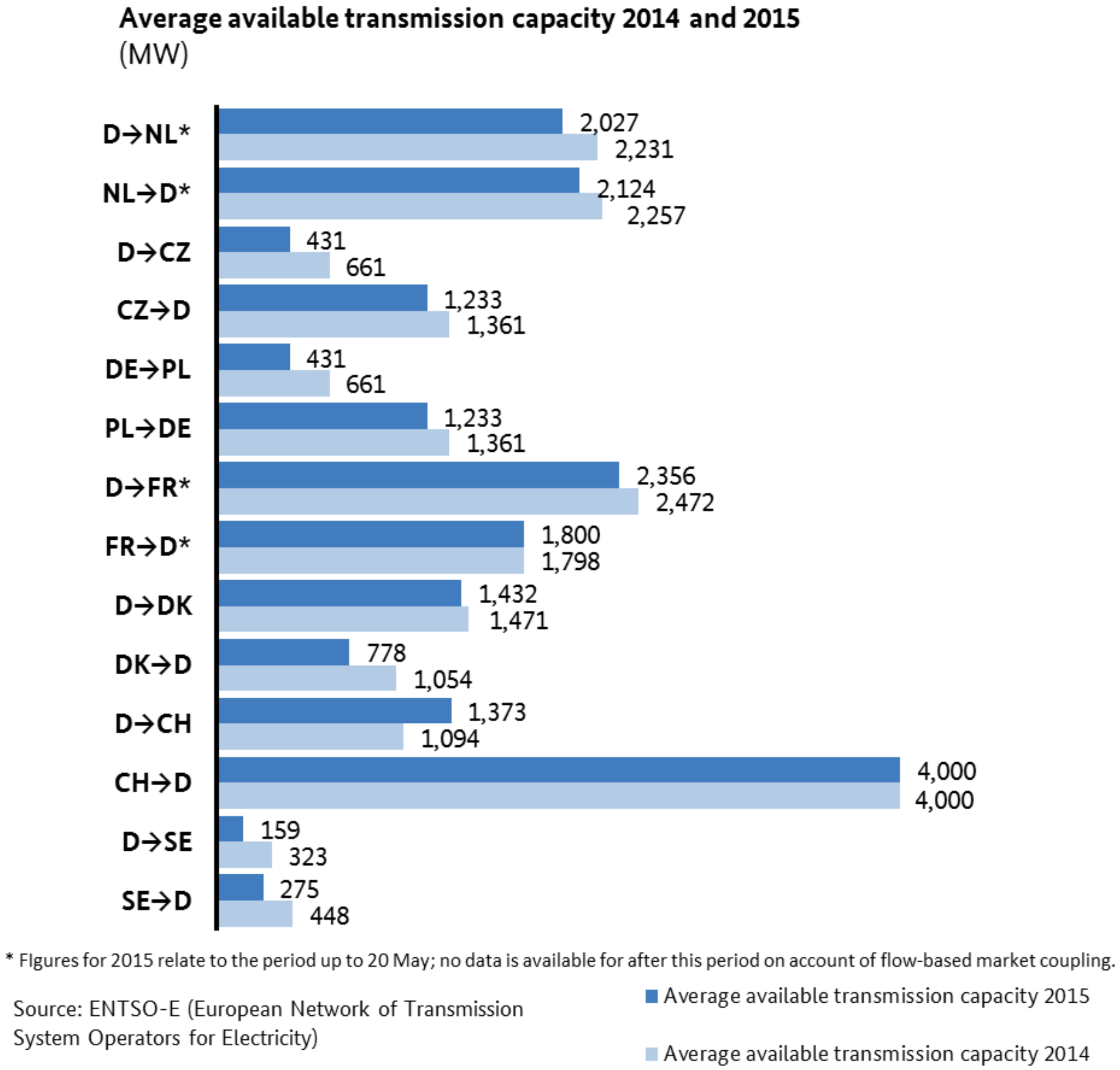


Figure 61: Average available transmission capacity

Import capacity showed some significant changes, with the exception of the borders with France and Switzerland. The most noticeable decreases were recorded at the Swedish and Danish borders where import capacity fell by 38.5% and 26.2% respectively. The only increase recorded was at the French border, with capacity rising by 0.1%.

Export capacity also showed changes, with above-average decreases at all borders with the exception of the Swiss border. The greatest decrease was recorded at the Swedish border, with capacity falling by 50.9%. There were also large decreases at the Czech and Polish borders where export capacity fell in both cases by 34.8%. The only increase recorded was at the Swiss border, with capacity rising by 25.5%.

Amongst the reasons for the changes in capacity are technical breakdowns and maintenance work on transmission system lines and line expansion. Of particular note is the Hamburg area, with numerous transmission lines running in and around Hamburg. Construction work on a new Elbe crossing north-west of Hamburg began in 2015 and has added to the tense situation in the north. To guarantee security of supply a temporary line running more or less parallel to the north of the existing line has been needed during the construction phase. This temporary line has less capacity than the old line. The network situation in the north will remain tense until the new line is completed. Germany's neighbouring countries are also increasingly feeling the effects of the situation. The German TSOs are required to carry out maintenance and repairs to transmission lines as quickly and efficiently as possible to guarantee a smooth exchange of electricity with other countries.

The expansion of wind energy on the coasts has led to increased network congestion in Germany in the last few years. Germany's wind electricity has been supplemented by cheap electricity from Denmark traded on the European energy exchange, adding to the congestion. To guarantee system security, import capacity at the Danish border (DK1) has been adjusted to accommodate the new situation. The following graph shows the total number of hours in each year during which certain amounts of import capacity were available at the Danish border (DK1).

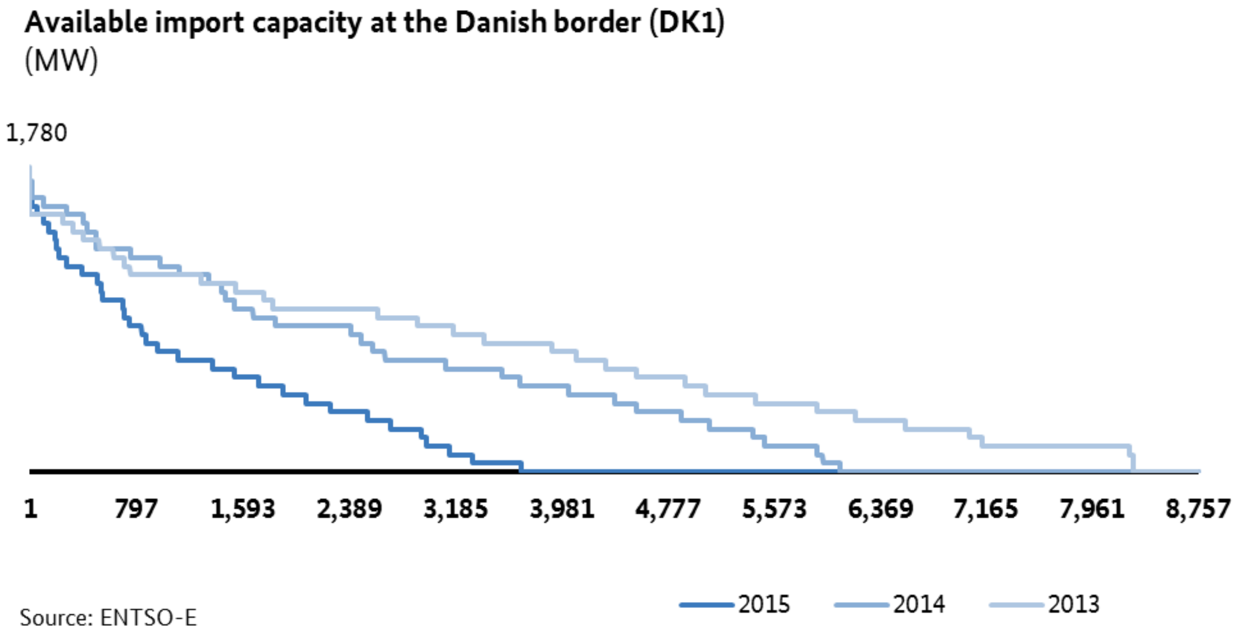


Figure 62: Available import capacity at the Danish border (DK1)

The restriction on trading capacity is due to the European legal requirement to give priority to renewable energy. It has, however, caused increasing dissatisfaction among the Danish market players since it has not been possible to sell cheap Danish electricity to the more expensive German market area. Solutions are currently being developed to enable Scandinavian market players to take a larger part in the German market even before network expansion has been completed.

Average available transmission capacity (import and export capacity) over all German cross-border interconnectors decreased by 7.3% from a total of 21,193 MW in 2014 to 19,652 MW in 2015.

The following tables show the individual figures.[35]

Import capacity trend

	(Net) average available transmission capacity 2014 (MW)	(Net) average available transmission capacity 2015 (MW)	Change (%)
NL → D	2,257.2	2,123.8	-5.9
PL → D	1,361.2	1,233.1	-9.4
CZ → D	1,361.2	1,233.1	-9.4
FR → D	1,798.5	1,800.0	0.1
DK → D	1,054.2	778.0	-26.2
CH → D	4,000.0	4,000.0	0.0
SE → D	447.6	275.2	-38.5
Total	12,279.7	11,443.1	-6.8

Table 32: Import capacity 2014 to 2015

Export capacity trend

	(Net) average available transmission capacity 2014 (MW)	(Net) average available transmission capacity 2015 (MW)	Change (%)
D → NL	2,231.2	2,026.6	-9.2
D → PL	660.6	430.9	-34.8
D → CZ	660.6	430.9	-34.8
D → FR	2,472.2	2,356.3	-4.7
D → DK	1,471.5	1,432.4	-2.7
D → CH	1,094.2	1,373.4	25.5
D → SE	323.3	158.8	-50.9
Total	8,913.5	8,209.3	-7.9

Table 33: Export capacity 2014 to 2015

[35] The data used was provided by the German TSOs and checked for plausibility by the Bundesnetzagentur.

2. Cross-border flows and implemented exchange schedules

The exchange schedules implemented are decisive in assessing the net balance of electricity imports and exports (balance of trade) at each external border and at all of Germany's borders as a whole.

These exchange schedules reflect excess generation, or demand shortage, and hence follow the rules of the market[36]. The following diagrams show the exchange schedules implemented and the physical flows at Germany's borders in 2014 and 2015.

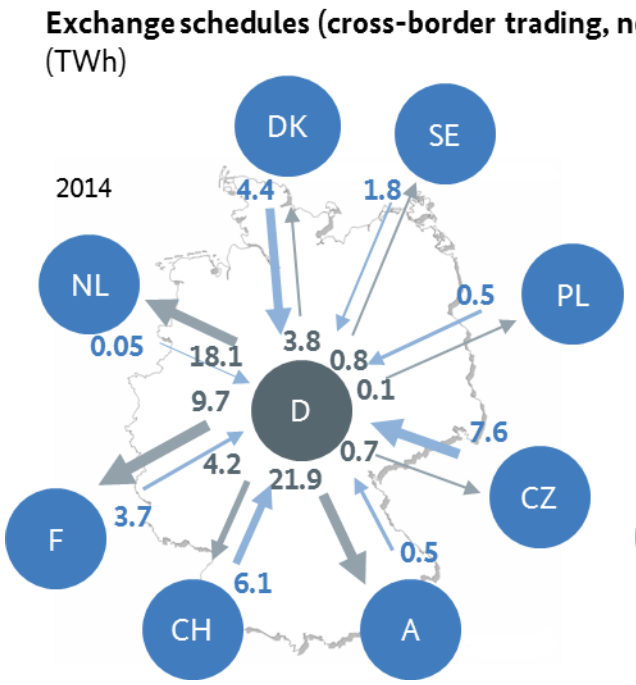


Figure 63: Exchange schedules (cross-border electricity trading)

[36] The aim is for electricity to be traded from low-price to high-price countries via the cross-border interconnectors.

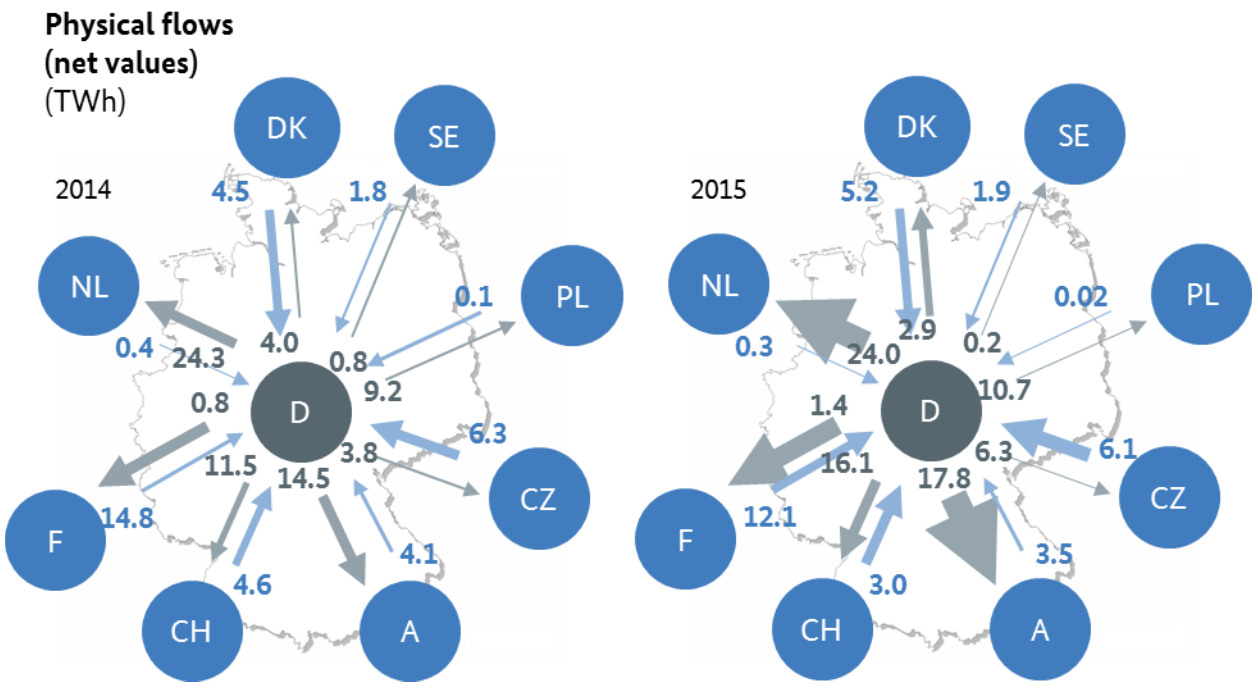


Figure 64: Physical flows

The increase in exports in 2015 is linked to the decrease in prices on the German energy exchange. There was a further decrease – of 1.1% – in the average EPEX day-ahead spot price from €32.76/MWh in 2014 to €31.63/MWh in 2015. The following graph shows the day-ahead spot prices over the last few years.

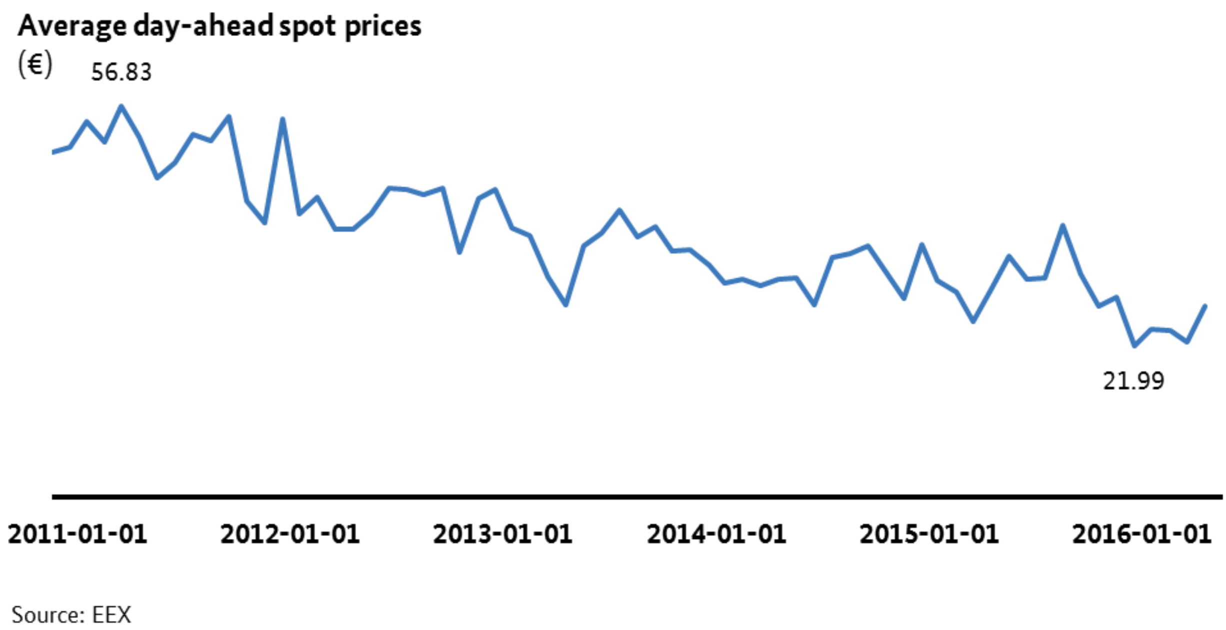


Figure 65: Average day-ahead spot prices 2011 to 2016

The following tables show the individual figures.[37]

Comparison of imports from cross-border flows
(TWh)

	Actual physical flows 2014	Binding exchange schedules 2014	Actual physical flows 2015	Binding exchange schedules 2015
NL → D	0.4	0.1	0.3	0.1
PL → D	0.1	0.5	0.0	0.4
CZ → D	6.3	7.6	6.1	4.8
FR → D	14.8	3.7	12.1	2.1
DK → D	4.5	4.4	5.2	5.1
CH → D	4.6	6.1	3.0	2.5
AT → D	4.1	0.5	3.5	0.2
SE → D	1.8	1.8	1.9	1.9

Table 34: Comparison of imports from cross-border flows

Comparison of exports from cross-border flows
(TWh)

	Actual physical flows 2014	Binding exchange schedules 2014	Actual physical flows 2015	Binding exchange schedules 2015
D → NL	24.3	18.1	24.0	16.3
D → PL	9.2	0.1	10.7	0.1
D → CZ	3.8	0.7	6.3	1.2
D → FR	0.8	9.7	1.4	11.5
D → DK	4.0	3.8	2.9	2.5
D → CH	11.5	4.2	16.1	7.3
D → AT	14.5	21.9	17.8	28.9
D → SE	0.8	0.8	0.2	0.2

Table 35: Comparison of exports from cross-border flows

[37] The data used was provided by the German TSOs and checked for plausibility by the Bundesnetzagentur.

Comparison of the balance of cross-border flows
(TWh)

	Actual physical flows 2014	Binding exchange schedules 2014	Actual physical flows 2015	Binding exchange schedules 2015
Imports	36.4	24.7	32.1	17.0
Exports	68.9	59.2	79.1	68.0
Balance	32.5	34.5	47.0	51.0

Table 36: Comparison of the balance of cross-border flows[38]

The actual physical flows[39] shown in the following graph deviate from the exchange schedules at the borders.[40]

[38] The physical flows balance and the exchange schedules (trade flows) balance should theoretically be identical. Deviations arise because cross-border redispatch actions can lead to a decrease in the physical flows. In 2015 cross-border redispatch actions amounted to 3.2 TWh. The remaining 0.8 TWh is presumably due to measurement errors.

[39] Physical flows represent the actual flow of electricity through the individual electricity networks.

[40] The total net export balance for the exchange schedules implemented and actual physical flows – excluding transmission losses – is identical across all German cross-border interconnectors. However, the values at each border generally differ as actual physical flows follow the purely physical path of least resistance and, on account of the interconnected transmission systems, can deviate from the exchange schedules implemented and flow indirectly from regions with high generation capacity via third countries (eg from France via Germany/Switzerland to Italy).

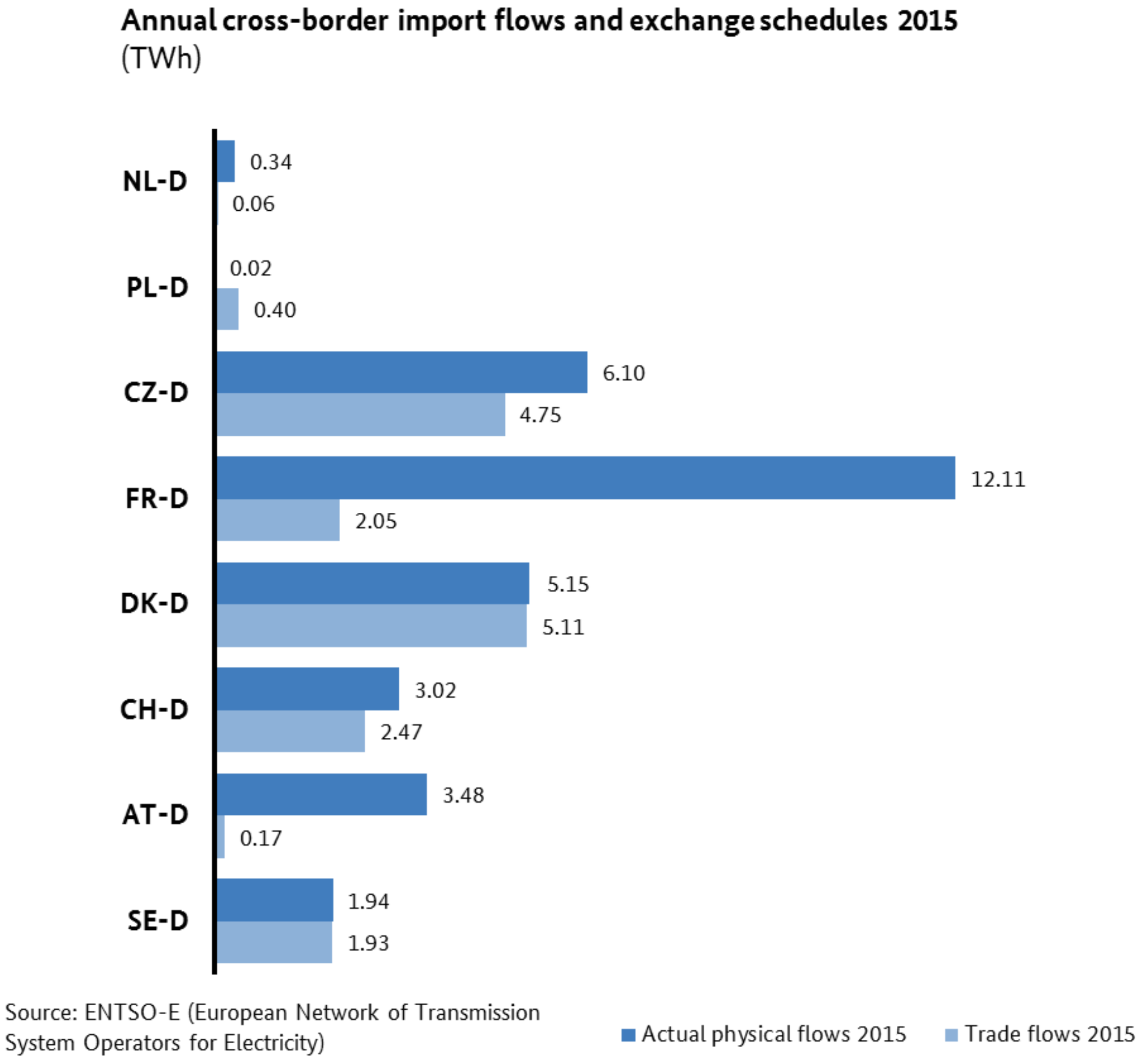


Figure 66: Annual cross-border import flows and exchange schedules

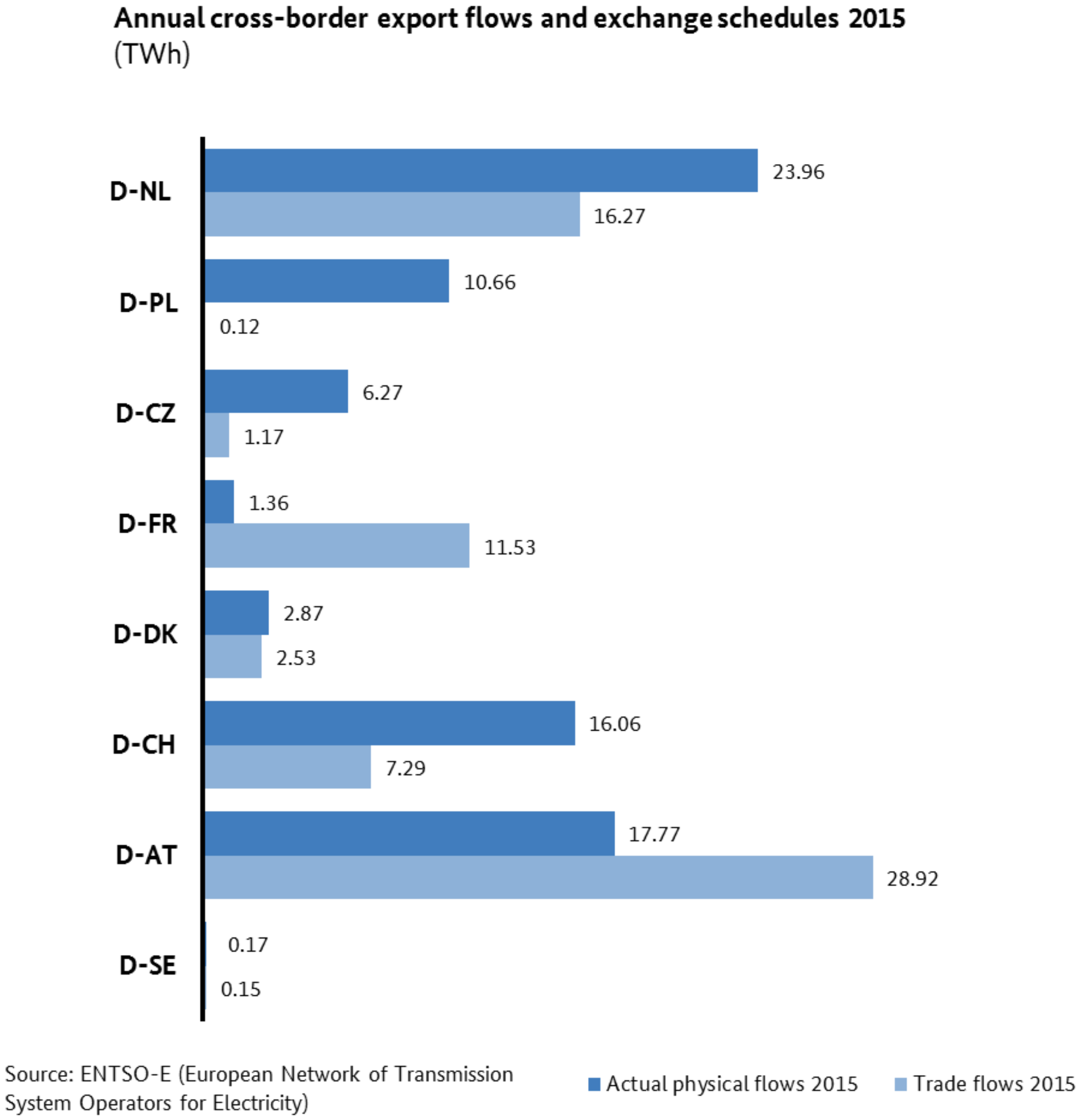


Figure 67: Annual cross-border export flows and exchange schedules

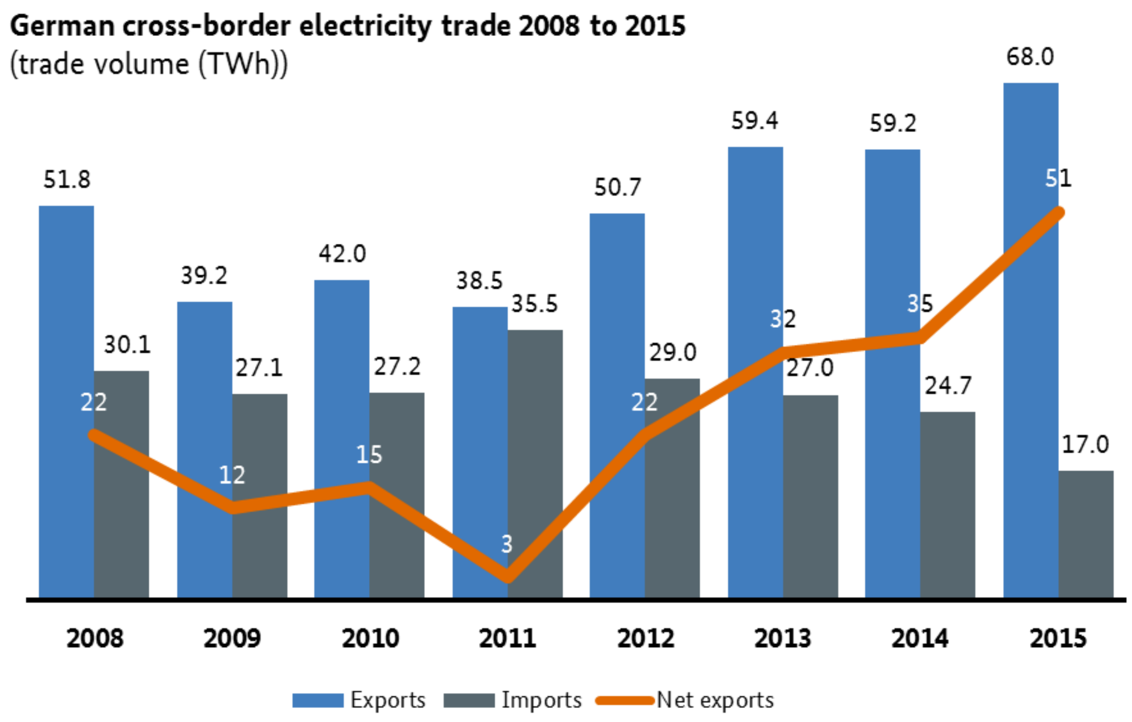


Figure 68: German cross-border electricity trade

Monetary trends in cross-border electricity trade

	2014		2015	
	TWh	**Trade volume (€)**	**TWh**	**Trade volume (€)**
Exports	59.17	1,900,557,809.92	67.96	2,062,614,362.74
Imports	24.66	839,647,858.29	16.95	588,323,933.24
Balance	34.52	1,060,909,951.63	51.01	1,474,290,429.50
Export revenues (€/MWh)		32.12		30.35
Import costs (€/MWh)		34.05		34.71

Table 37: Monetary trends in cross-border electricity trade[41]

[41] The Bundesnetzagentur bases the evaluation of exports and imports on the applicable hourly day-ahead spot market prices on the EPEX SPOT exchange. The hourly spot market prices are multiplied by the hourly imports and exports to and from the individual countries to show the monetary trend. We assume that electricity will only be imported if Germany's prices are higher than those of other countries and that electricity will only be exported if it is cheaper than in other countries. In this respect we are assuming rational market behaviour to be such that even longer-term contracts will only be fulfilled by actual exports or imports if the effective price level provides an appropriate reason to do so.

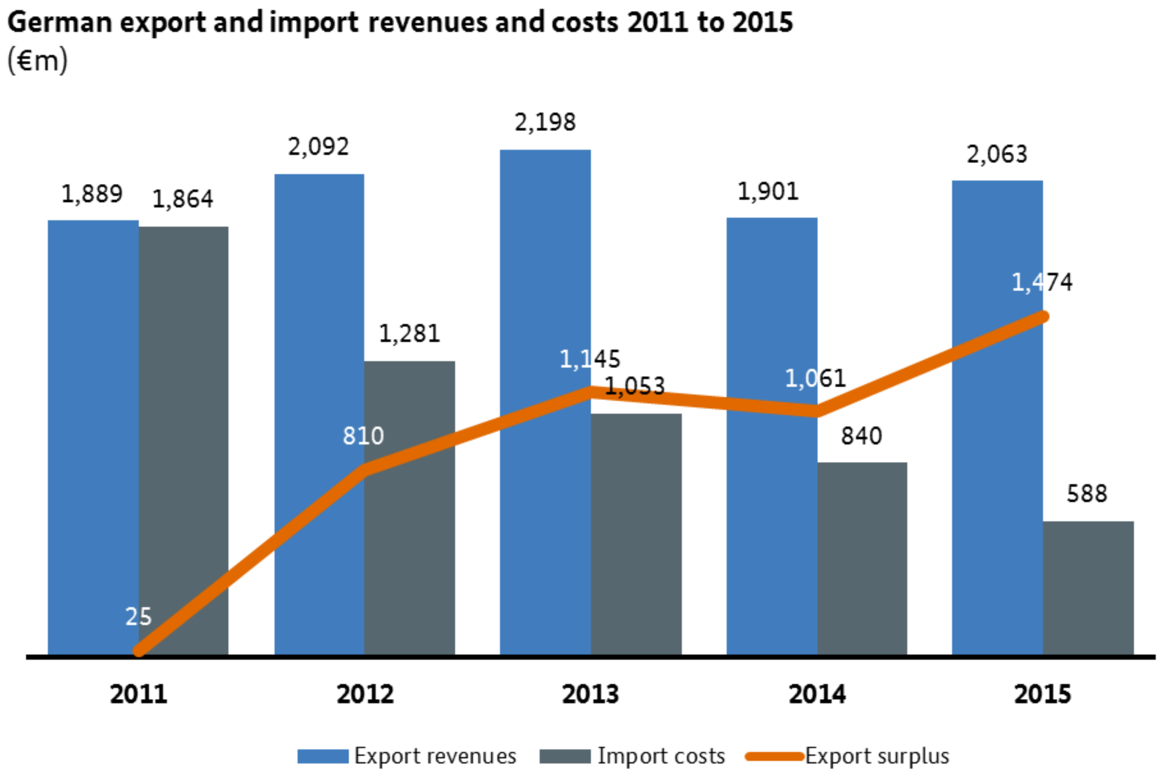


Figure 69: German export and import revenues and costs

Changes in cross-border trading volumes between Germany and its neighbouring countries reflect changes in the price differences. The reasons for these differences depend on a wide range of factors that have a direct influence on the merit order and therefore especially on wholesale prices in the individual countries. This means that changes in trading volumes are not determined solely by the German market, but also reflect shifts in supply and demand in each neighbouring country.

3. Unplanned flows

In principle, any examination of imports and exports should only involve the amounts of electricity traded between the countries. There is a distinction between this and examining which transmission lines the traded amounts of electricity actually (physically) flow along and whether the electricity flows as a loop or transit flow, possibly through third countries.[42] The following diagrams show the unplanned flows from Germany to neighbouring countries and back again.

[42] The Bundesnetzagentur only uses the TSOs' exchange schedules (trade flows) to determine the figures. It is more feasible to use the exchange schedule figures in any related public discussion as these figures reflect trading activity. In contrast, the physical flows are based on a number of factors, including loop flows from German-German trades that are physically transported via foreign networks.

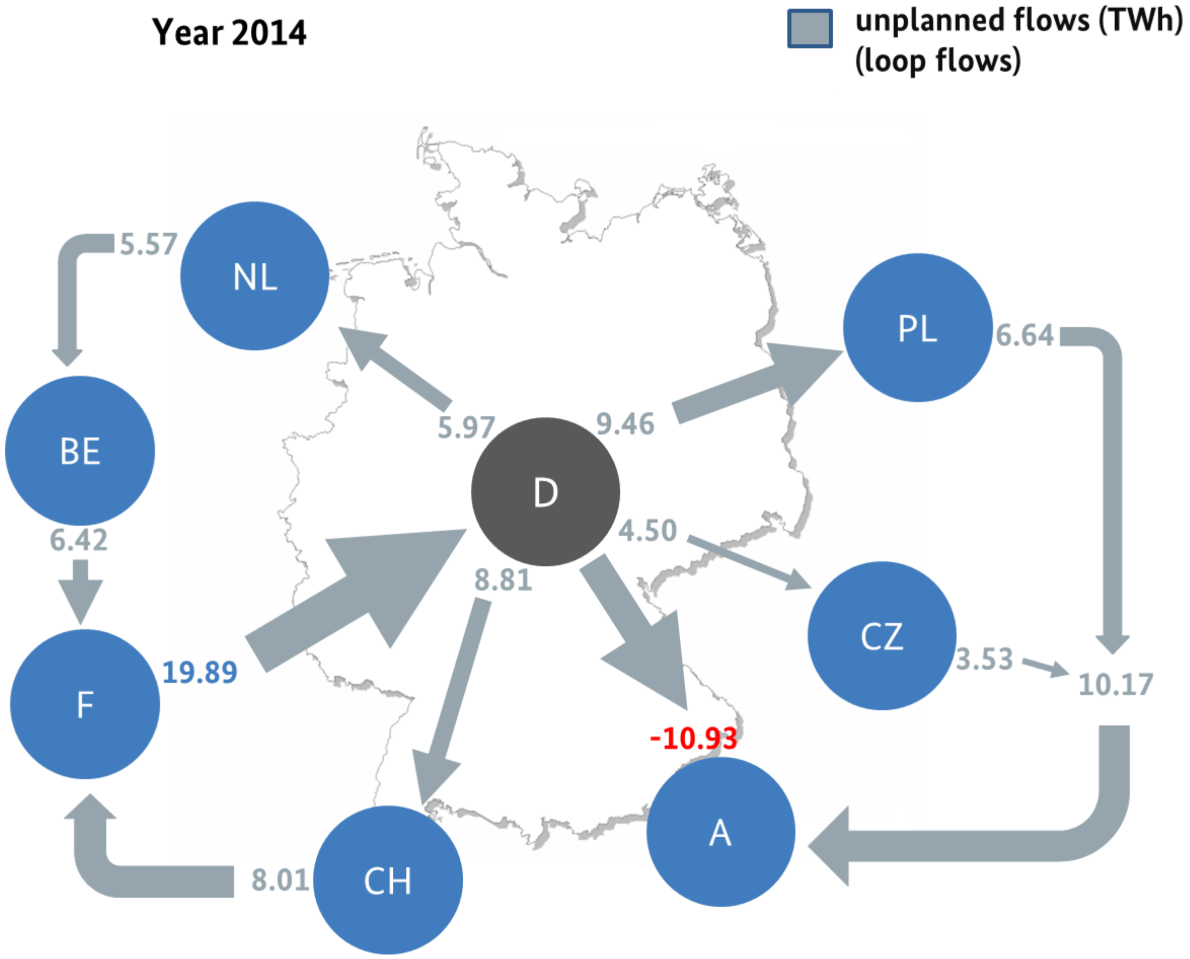


Figure 70: Unplanned flows 2014

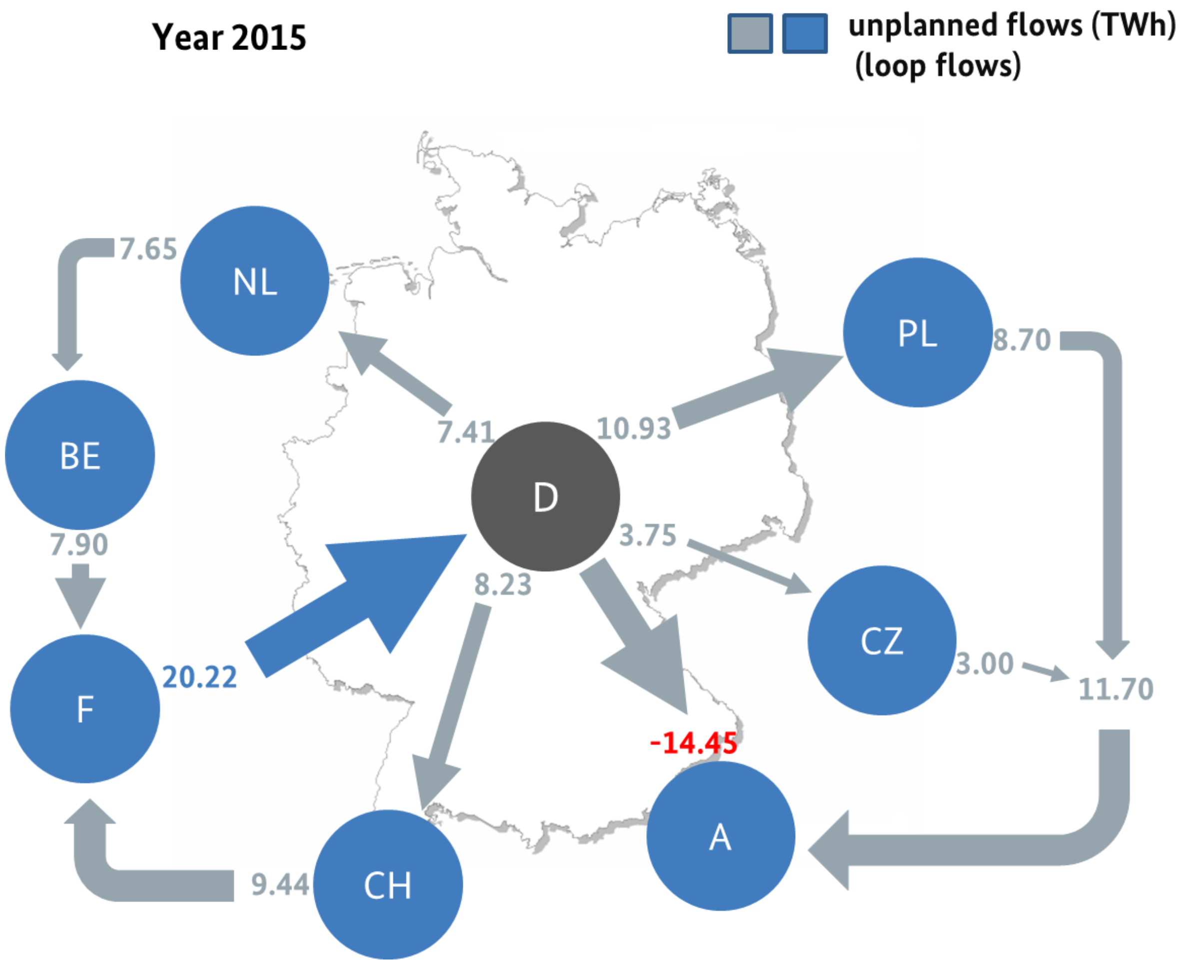


Figure 71: Unplanned flows 2015

As shown in the diagrams, electricity follows the law of physics and always takes the path of least resistance. A look at Germany's western and eastern borders makes the need for rapid network expansion even clearer. The shortage of transport capacity within Germany means that electricity flows across the western border to the Netherlands, through Belgium and France and then back to Germany. In the east, electricity also follows an indirect path through Poland and Czechia to Austria. In contrast to the west, however, the electricity does not flow back to Germany but is consumed in Austria or transported further. This physical "deficit" amounted in 2015 to -14.45 TWh. The deficit at this border contrasts with the physical surplus at the other borders.

This makes clear the shortage of physical capacity between Germany and Austria.[43]

Irrespective of all expansion measures, trade in electricity between different market areas inevitably results in unplanned flows. The high volumes transported, alongside comparatively little progress in network expansion, mean that Germany's neighbouring countries are particularly affected by the German energy transition. To avoid

[43] The balance of unplanned flows is 4.4 TWh. Trade flows and actual flows should theoretically be identical. The difference of 4.4 TWh is due to the increase in cross-border redispatch actions in 2015. Cross-border redispatch actions can lead to a decrease in physical flows. In 2015 cross-border redispatch actions amounted to 3.2 TWh. The remaining 1.2 TWh is presumably due to measurement errors.

the problem of unplanned flows causing network instability in other countries, Germany is actively taking part in various measures. A cross-border redispatch regime was established using a virtual phase-shifting transformer at the German-Polish border, reducing unplanned flows and increasing network stability in Germany and Poland. The virtual phase-shifting transformer has now been replaced by a physical phase-shifting transformer at the border with Poland. The next step is to operate phase-shifting transformers at the border with Czechia.

4. Revenue from compensation payments for cross-border load flows

Under Article 1 of Commission Regulation (EU) No 838/2010, the TSOs receive inter-TSO compensation (ITC) for the costs incurred from hosting cross-border flows of electricity (transit flows) on their networks. ENTSO-E established an ITC fund for the purpose of compensating the TSOs. The fund is to cover the cost of losses incurred on national transmission systems as a result of hosting cross-border flows of electricity and the costs of making infrastructure available to host these cross-border flows.

Every year ACER publishes a report for the European Commission on the implementation of the ITC mechanism as required in point 1.4 of Part A of the Annex to Commission Regulation (EU) No 838/2010. The latest figures for the 2015 ITC year[44] are as follows. The four German TSOs received compensation for losses and the provision of infrastructure totalling €3.65m and paid contributions of €9.75m. This means that on balance the German TSOs contributed a net amount of €6.1m to the ITC fund. Thus the 2015 ITC year was the first time that Germany was a net contributor to the ITC fund, having been a net recipient since the introduction of the mechanism (€7.65m in 2014, €13.21m in 2013, €26.8m in 2012). The previous few years had seen signs of this development, which is mainly due to the large increase in Germany's electricity exports and the related changes in cross-border flows. Transit flows through Germany fell by 6.7% while the decrease in the costs of losses in Germany was larger than in other EU countries. These two factors resulted in a decrease in the amount of compensation received by the TSOs. There was another significant increase – of nearly one third – in electricity exports, leading to an increase in the contributions made by the German TSOs to the ITC fund. Altogether this meant that for the first time the German TSOs were net contributors.

ITC mechanism (net) compensation payments for German TSOs
(€m)

2011	2012	2013	2014	2015
21.0	26.8	13.2	7.7	-6.1

Table 38: ITC compensation

[44] Compensation and contributions for an ITC year are calculated by the TSOs at the end of each calendar year (settlement period), resulting in a delay of about six months between the end of a settlement period and the time when compensation and contributions are actually paid.

5. Market coupling of European electricity wholesale markets

The creation of a European internal market in electricity is a declared aim of the EU. Under point 3.2. of Annex I to Regulation (EC) No 714/2009 this aim is to be implemented progressively in individual European regions.

In February 2014 the day-ahead markets in the coupled regions of Central Western Europe (CWE – Austria, Belgium, France, Germany, Luxembourg and the Netherlands) and North-West Europe (NWE – Denmark, Finland, Norway and Sweden) and in Estonia, Latvia, Lithuania, Poland and the United Kingdom were interconnected via the SwePol link. Spain and Portugal then became connected in May 2014. This meant that three quarters of the European electricity market were successfully coupled. The next significant step in creating the European internal electricity market was attained with the coupling of the Italian borders with Austria, France and Slovenia in February 2015. In July 2016 the common border between Austria and Slovenia was then also connected.

The aim of market coupling is the efficient use of day-ahead available transmission capacity between the participating countries. This reduces the loss of social welfare that may result from congestion between the countries. As a result, the process therefore leads to an alignment of prices on the national day-ahead markets involved. Indeed, price convergence, which serves as an indicator of the efficient use of interconnector capacity, is significantly higher in coupled regions than in uncoupled regions.

At the European level, the Bundesnetzagentur is coordinating the implementation of market coupling throughout the whole of Europe as part of regulatory authority cooperation within ACER.

6. Flow-based capacity allocation

The Commission Regulation establishing a guideline on capacity allocation and congestion management (known as the CACM guideline) defines flow-based market coupling as the target model for short-term capacity management in central Europe. The essential basis of this is provided by flow-based capacity calculation. This involves taking account of the physical flows that specific commercial transactions are expected to generate at the capacity calculation stage and then determining the remaining available transmission capacity according to efficiency criteria and system security aspects. This guarantees greater system security and the improved use of transmission capacity.

Following the successful introduction of market coupling in the CWE region in autumn 2010, implementation of the flow-based capacity calculation began. The project partners continued with this work in 2014. The flow-based capacity calculation method was successfully launched in the CWE region on 20 May 2015. As was expected from the tests, the results have confirmed an increase in transmission capacity and, consequently, greater price convergence between the participating countries.

In early 2016, the TSOs in the Central Eastern Europe (CEE) and CWE regions signed a memorandum of understanding on the development of a common flow-based capacity calculation methodology. The methodology is currently expected to be introduced in early 2019. The two regions will then be directly linked and cross-border capacity will be calculated using the same methodology.

Work in both regions is being coordinated by a special joint working group with the participation of all the regulatory authorities and TSOs. The first step is for the TSOs to develop a common capacity calculation methodology in line with the CACM guideline for approval by the regulatory authorities.

7. Current status regarding European Regulations for the electricity sector

Article 8 of Regulation (EC) No 714/2009 on conditions for access to the network for cross-border exchanges in electricity sets out the areas in which network codes or guidelines are to be developed with a view to harmonising European electricity trading and creating a European internal market in electricity. Significant progress was made in this context in 2015.

The CACM guideline, which establishes rules for congestion management and capacity allocation in day-ahead and intraday trading, entered into force on 14 August 2015 as the first binding regulatory instrument passed on the basis of the Regulation.

Since then, the TSOs, the entities designated as nominated electricity market operators (NEMOs) and the national regulatory authorities and ACER have been working on implementing the rules set out in the Regulation. Two proposals put forward to the national regulatory authorities and ACER for approval are currently under discussion: a proposal from the European TSOs regarding the determination of capacity calculation regions, and a proposal from the designated NEMOs on how the market coupling operator (MCO) functions are to be performed.

With a view to achieving a European internal market in electricity and to secure network stability, the grid connection codes create the most harmonised framework possible for market participants connecting their facilities to the electricity grid. These market participants include operators of generation plants, HVDC cables and major electricity consumption units (such as energy-intensive industrial enterprises), demand side management providers and distribution system operators. The adoption of the three EU Regulations laying down rules in this area has provided a uniform framework. The three network codes set out harmonised requirements for frequency control and fault ride-through capability, as well as requirements for system restoration, reactive power and demand side response, to give just a few examples.

Against this background, the three grid connection codes were unanimously adopted by the EU Member States in comitology in 2015. At the same time it was possible to remove a number of doubts regarding the regulatory provisions in respect of all grid connection codes. This paved the way for the Regulation establishing a network code on requirements for grid connection of generators to be adopted on 26 June 2015. Following scrutiny by the European Parliament and the Council of the EU, the network code entered into force on 17 May 2016. On 11 September 2015 the Regulation establishing a network code on requirements for grid connection of high voltage direct current systems and direct current-connected power park modules was adopted. On 16 October 2015 the Commission's draft Regulation establishing a network code on demand connection was also submitted to comitology and was adopted by the Member States.

Each of the three grid connection codes provides considerable scope for action at national level. Germany's legislature used the scope provided and, in connection with the amendment of the Renewable Energy Sources Act (EEG), assigned in section 19 of the Energy Act (EnWG) the responsibility for defining the technical connection requirements – taking into account the framework conditions of the three network codes – to VDE, the German Association for Electrical, Electronic & Information Technologies. The Bundesnetzagentur is responsible above all for defining the threshold values on which the generator requirements are based, setting the criteria for applications for exemption from the technical connection requirements, and dealing with appeals from parties seeking connection.

The guideline on forward capacity allocation lays down rules on cross-border forward capacity allocation on interconnectors and was adopted by the Member States in comitology on 30 October 2015.

The guideline on electricity balancing sets out requirements aimed at integrating the European balancing markets, which are still largely organised on a national basis, and is currently being discussed by the Member States in the committee procedure. The European Commission aims to adopt the guideline by the end of 2016, thus the guideline is expected to enter into force as a European Regulation with general applicability and direct effect in the Member States in mid-2017.

The System Operation Guideline is composed of three network codes and was adopted in comitology on 4 May 2016. The guideline provides for harmonised operational security requirements and the definition of security limits. It harmonises the procedure for the internal and cross-border notification of schedules as well as the minimum technical requirements for balancing energy and the relevant limits for cross-border exchange. It also establishes binding rules for load frequency control in the form of technical minimum requirements and defined procedures.

The network code on emergency and restoration is expected to be adopted in comitology by the end of this year. The network code sets the requirements for measures to be undertaken in a state of emergency and the procedures to be implemented to restore the network after a blackout state. In a state of emergency, all market activities may be suspended should system security otherwise be at risk. The network code provides for harmonised rules and conditions for the suspension of market activities in such cases.

7.1 Early implementation of the cross-border intraday project

The cross-border intraday project (XBID) was launched back in February 2007 as a project for the CWE region. The project is no longer restricted to this region but now covers the entire "NWE plus" region comprising the following EU and EEA Member States: Austria, Belgium, Denmark, Finland, France, Germany, Italy, Luxembourg, the Netherlands, Norway, Spain, Sweden and the United Kingdom. Switzerland is also participating in the project as an observer. According to the CACM guideline, Switzerland's active participation depends on it adopting the most important provisions in the EU's acquis unionaire legislation relating to electricity and on concluding an intergovernmental agreement with the EU. This agreement is to clearly set out cooperation in the electricity sector between Switzerland and the EU, and especially the institutional issues.

Significant progress was made on the project in 2015, with the parties to the project – the TSOs from the "NWE plus" Member States and the APX/BelPex, EPEX SPOT, GME, Nord Pool Spot and OMIE power exchanges – agreeing to conclude a contract with the IT provider, Deutsche Börse AG (DBAG). DBAG was given the responsibility for designing and developing the XBID platform. The platform, which will comprise a capacity management module and a joint order book, is to be used to bundle and then link the power exchanges' local electricity trading systems with the TSOs' available cross-border transmission capacity. This will facilitate the continuous and implicit matching of trading in electricity supply in one bidding zone with demand in another region's bidding zone, always provided that sufficient cross-border transmission capacity is available to process the trades. To enable the bundling of the order books and the capacity calculations, the parties to the project will also work on developing local implementation projects at the same time as developing the main XBID platform. As part of its collaboration within the ACER working groups and decision-making bodies, the Bundesnetzagentur has played a role in the project parties reaching agreement and finalising the contractual basis for the project. The platform is expected to be put into operation in 2017 following the test phase.

7.2 Early implementation of the bidding zone review process

The CACM guideline provides for a review of the existing bidding zone configuration at European level. The review process – which is already being followed on a voluntary basis by the participating TSOs and national regulatory authorities as part of the early implementation of the CACM guideline – is becoming increasingly important, also in light of discussions at European level about the future design of the electricity market.

In the first step, a report on the situation in the transmission networks and a report on the distribution of market power and liquidity are drawn up every three years following a request by ACER. If one of the reports reveals inefficiencies, a review of the bidding zone configuration is initiated in which the TSOs assess possible alternative bidding zone configurations. The review gives priority to criteria relating to network security, market efficiency and the stability of the bidding zones.

The results of the review are to be presented within 15 months of the decision to launch the process and may comprise a proposal to maintain or amend the bidding zone configuration. The Member States, or the national regulatory authorities, are to reach an agreement within six months on the proposal to maintain or amend the bidding zone configuration based on the results of the review.

In the second half of 2015 the participating European TSOs began the process of coordinating with the participating regulatory authorities the methodology to be used in calculating alternative bidding zone configurations and the input parameters to be considered. The first calculation results are expected at the beginning of 2017. The Bundesnetzagentur expects the European review of the bidding zone configuration to confirm the results of its own analyses regarding the German-Austrian border.

The Bundesnetzagentur welcomes this process as it enables the much-discussed issue of amending bidding zones, particularly with respect to the German-Austrian bidding zone, to be examined for the first time in a structured procedure at European level.

F Wholesale market

Functioning wholesale markets are vital to competition in the electricity industry. Spot markets where electricity volumes that are needed or not needed in the near future can be bought or sold, and futures markets that permit the hedging of price risks in the medium and long term play an equally important role. Sufficient liquidity, that is, an adequate volume on the supply and demand sides, increases the scope for new suppliers to enter the market. Market players are given opportunities to diversify their choice of trading partners and products as well as their trading forms and procedures. Besides bilateral wholesale trading (referred to as over-the-counter trading or OTC), electricity exchanges also create reliable trading places and provide major price signals for market players in other areas of the electricity industry.

Overall liquidity of the electricity wholesale markets remained stable and at a high level in 2015. While volumes in on-exchange futures trading grew significantly again, volumes traded via broker platforms were more likely to decline. Average electricity wholesale prices continued to fall in 2015. Average spot market prices fell by about 3 per cent year-on-year and futures contracts for the following year were about 12 per cent lower on average.

1. On-exchange wholesale trading

As in previous reporting years, the review of on-exchange electricity trading covers the German/Austrian market area and the exchanges in Leipzig (European Energy Exchange AG – EEX), Paris (EPEX SPOT SE)[45] and Vienna (Abwicklungsstelle für Energieprodukte AG – EXAA). The exchanges took part in collecting energy monitoring data again this year.[46] Since Germany and Austria constitute a common supply area, the specific electricity contracts ("products") are traded on all three exchanges at exchange prices that are the same for both countries ("single price zone"). EEX offers electricity products in futures trading; EPEX SPOT SE and EXAA supply electricity products on the spot markets.

The exchanges have become established as major trading places. The total number of participants authorised at the electricity exchanges in the German/Austrian market area has grown for years and new highs were reached on the EEX and EPEX SPOT exchanges on 31 December 2015; only EXAA recorded a marginal reduction in participants.

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[45] EEX and EPEX SPOT are affiliated under corporate law; the EEX Group is the indirect majority shareholder of EPEX SPOT SE.

[46] In addition, Nord Pool Spot AG, which did not take part in collecting monitoring data, also provides facilities for the trading of electricity destined for Germany. It offers intraday trading to Germany as the supply area (trading volume in 2015: 1 TWh) and the trading of market coupling products for Germany (from and to Sweden or Denmark)

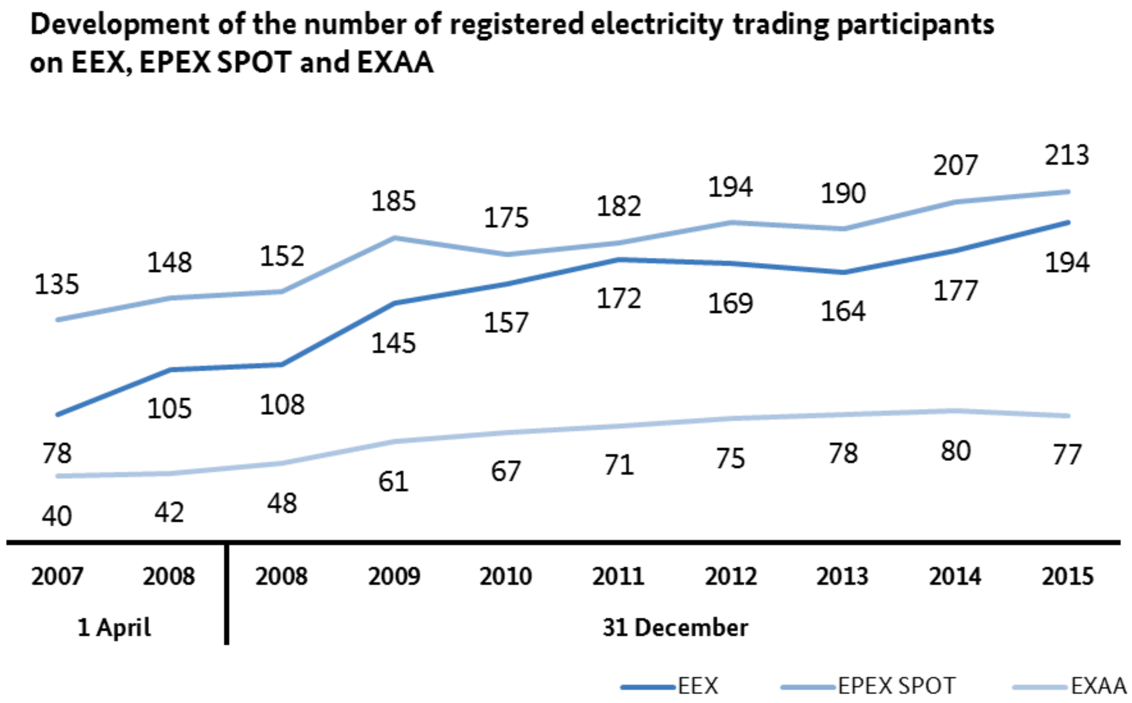

Figure 72: Development in the number of registered electricity trading participants on EEX, EPEX SPOT and EXAA

Companies operating at wholesale level do not necessarily have to have their own access to the exchange in order to take advantage of the opportunities it offers. As an alternative, companies can use the services offered by brokers that are registered with the exchanges. Large corporations often combine their trading activities in an affiliate with relevant exchange registration. EPEX SPOT and EEX classify their exchange participants according to the following categories.[47]

[47] EXAA does not classify its exchange participants.

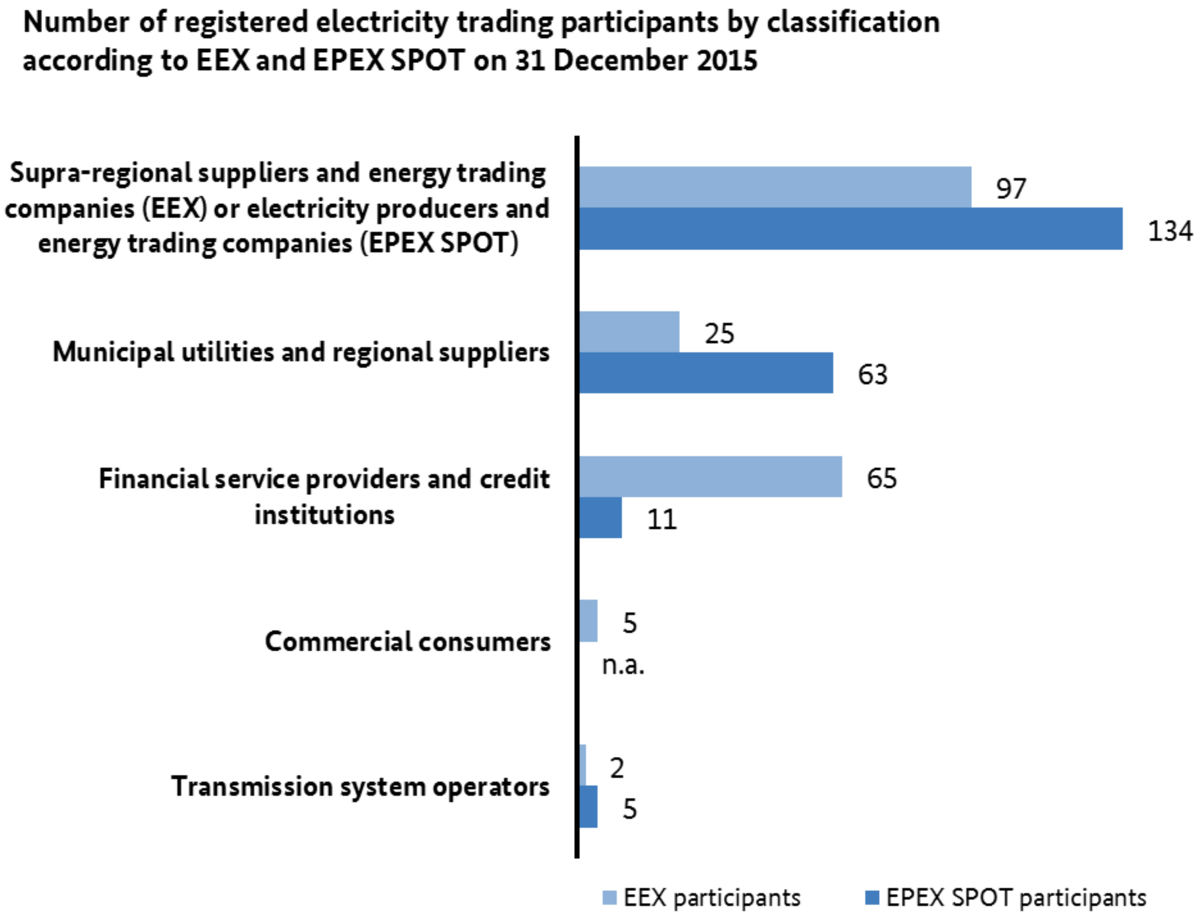

Figure 73: Number of registered electricity trading participants by EEX and EPEX SPOT classification as of 31 December 2015[48]

Futures trading and spot trading perform different but largely complementary functions. While the spot market focuses on the physical fulfilment of the electricity supply contract (supply to a balancing group), futures contracts are largely fulfilled financially. Financial fulfilment means that ultimately no electricity is supplied between the contracting parties by the agreed due date; instead the difference between the pre-agreed futures price and the spot market price is compensated in cash. The bids that can be placed on EPEX SPOT for Phelix futures originating from futures trading on EEX for physical fulfilment provide the relevant link. The on-exchange spot markets (section I.F.1.1) and the futures markets (section I.F.1.2) are dealt with separately below.

1.1 Spot markets

Electricity is traded on the on-exchange spot markets a day ahead and with shorter lead times (intraday). The two spot markets examined here, EPEX SPOT and EXAA, offer day-ahead trading and continuous intraday trading.

[48] The current participants in EPEX Spot can only be compared as a whole with the participants from 2014 because the categories were reorganised in 2015. The “commercial customer” category was added to the “municipal utilities and regional suppliers” category. In addition, exchange members were now expected to choose their category themselves, which could cause further differences.

Contracts can be physically fulfilled (supply of electricity) on the two on-exchange spot markets for the Austrian control area (APG) and for the German control areas (50Hertz, Amprion, TenneT, TransnetBW).

The day-ahead auction on EPEX SPOT takes place at 12 noon every day (the final result is published after 12:40 p.m.). Auctions on EXAA are held on five days a week at an earlier time than those on EPEX SPOT (trading closes at 10:12 a.m. and the final result is announced at 10:20 a.m.). In addition to single hours and standardised blocks, a combination of single hours chosen by the exchange participant (user-defined blocks) can also be traded in the day-ahead auction on EPEX SPOT. Bids for the complete or partial physical fulfilment of futures traded on EEX (futures positions) may also be submitted.

Auctions for quarter-hour contracts are held on both EXAA and EPEX SPOT. Quarter hours have been traded in day-ahead auctions on EXAA alongside single hours and blocks since September 2014. EPEX SPOT introduced an auction for quarter-hour contracts (known as intraday auctions) for the German control areas in December 2014. The auction is held at a different time than the auction for single hours and takes place at 3 p.m. each day (results available from 3:10 p.m.). These three auction formats are all uniform price auctions.

Continuous intraday trading on EPEX SPOT involves single hours, 15-minute periods and standardised or user-defined blocks. Intraday trading begins at 3 p.m. for next-day supplies and at 4 p.m. for 15-minute periods. EPEX SPOT has reduced the minimum lead time in intraday trading. Since July 2015, it has been possible to trade electricity contracts for the German control areas and within the Austrian control area up to 30 minutes before the commencement of supply.[49] Continuous intraday trading of fifteen-minute periods was extended to Austria (control area APG) on 1 October 2015.[50]

The expansion of trading opportunities to include quarter-hour contracts and the reduction in the minimum lead time take particular account of the increased input of electricity from supply-dependent (renewable) sources. Another product that promotes the market integration of renewable energies in the spot market sector is green electricity, which is tradable on EXAA and combines renewable energy certificates with physical electricity.[51]

1.1.1 Trading volumes

The volume of day-ahead trading on EPEX SPOT was 264 TWh in the reporting year 2015, a slight increase compared to the previous year (263 TWh). The volume of intraday trading rose to 38 TWh, a substantial increase of about 12 TWh or approximately 45 per cent. The volume of the day-ahead market on EXAA grew slightly to 8.3 TWh (approximately 65 per cent of which was generated by the German control areas) in 2015.

[49] Cf. EPEX SPOT press release from 16 July 2015.

[50] EPEX SPOT press release from 2 October 2015.

[51] The trading volume of the GreenPower product increased from 24 GWh in 2014 to approximately 32 GWh in 2015.

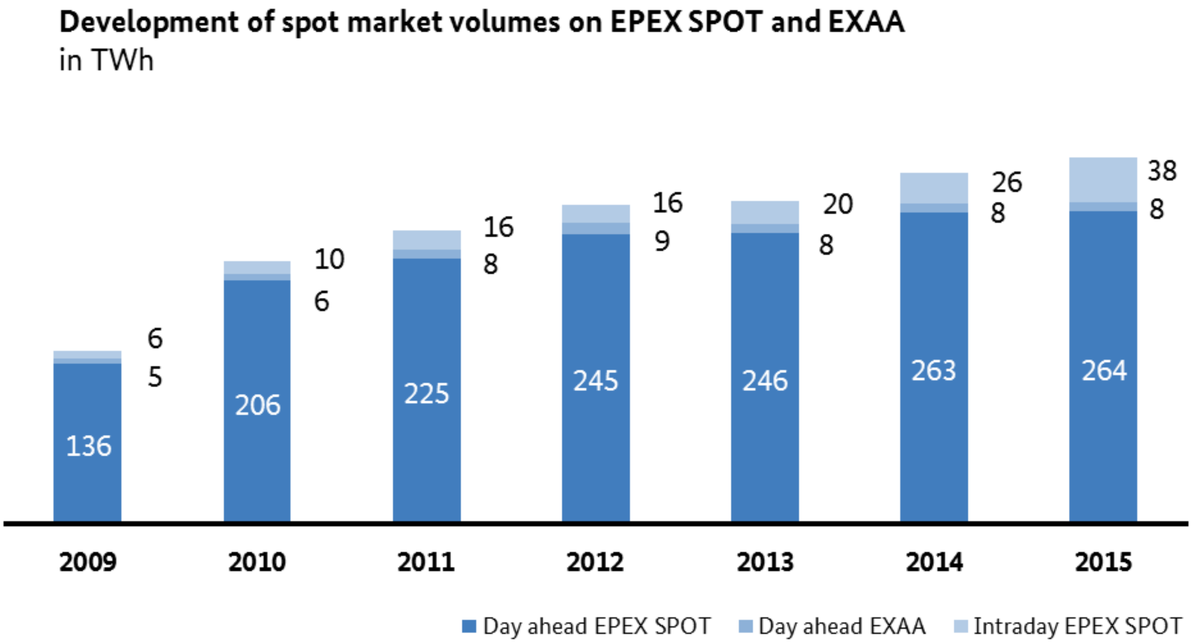

Figure 74: Development of spot market volumes on EPEX SPOT and EXAA

1.1.2 Number of active participants

There were no major changes to the number of participants that were active on both exchanges.

A participant registered on EPEX SPOT is regarded as "active" on the trading day if at least one bid has been submitted by the participant (purchase or sale). The average number of active buyers in the reporting year was 127 (125 in 2014); the average number of sellers was 123 (121 in 2014), another slight increase. As in the previous year, an average of 163 participants, or about 77 per cent of all registered participants (compared to 79 per cent in 2014), were active per trading day.[52] The number of net buyers per trading day (balance in favour of "purchase") is roughly at the same level as the previous year with 84 participants in 2015 (83 in 2014 and 81 in 2013). The number of net sellers (balance in favour of "sale") fell very slightly to 79 following the growth over the last few years (most recently from 75 in 2013 to 80 in 2014). A participant registered on EXAA is regarded as "active" if at least one bid (purchase or sale) has been submitted for each supply day.[53] In the reporting year, about 45 participants (40 in the previous year), or just over half of all registered participants, were active per supply day. Some 73 per cent of all participants in EXAA (71 per cent in 2014) have trading accounts in the German control areas. An average of 31 participants (25 in 2014) per supply day submitted bids for supplies into the German control areas.

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[52] Although the number of active participants stayed the same as in the previous year, the quote is lower because of an increase in the total number of trading participants on EEX.

[53] A different approach – supply day instead of trading day – is applied to provide a uniform basis for a review of the figures from the two spot market places despite different trading conditions (auction days, auction times). However, this is possible to only a limited extent because of further differences between EPEX SPOT and EXAA.

1.1.3 Price dependence of bids

Bids in day-ahead auctions on EPEX SPOT and EXAA can be submitted on a price-dependent or price-independent basis. In contrast to price-dependent bids (limit orders), participants do not set fixed price-volume combinations for price-independent bids (market orders). Price independence means that a volume is to be bought or sold regardless of price.

Compared to the previous year, the relatively high proportion of price-independent bids on EPEX SPOT fell slightly in the reporting year. 76 per cent of the purchase bids that were submitted in 2015 were price-independent (compared to 77 in 2014). The proportion of price-independent bids among submitted selling bids was 69 per cent and fell year-on-year (73 per cent in 2014).

Price dependence of bids submitted in hour auctions on EPEX SPOT

	Sales bids submitted in 2015		**Purchase bids submitted in 2015**	
	Volume in TWh	Percentage	Volume in TWh	Percentage
Price-independent bids	181.0	68.5%	200.2	75.8%
of which via TSOs	47.7		0.4	
of which physically fulfilled Phelix futures	46.0		73.0	
other	87.3		126.8	
Price-dependent bids (in a broader sense)	44.3	31.5%	48.4	24.2%
of which blocks	13.3		6.3	
of which market coupling contracts	25.6		9.2	
of which price-dependent bids (in a narrower sense)	83.1		63.9	
Total	264.1	100%	264.1	100%

Table 39: Price dependence of bids submitted in hour auctions on EPEX SPOT in 2015

The marketing of renewable energy (EEG) volumes by the transmission system operators plays a major role on the seller side and it was carried out on an almost completely price-independent basis again (99.8 per cent).[54] However, the volume marketed by the transmission system operators continued to fall to approximately 48 TWh (51 TWh in 2014 and 55 TWh in 2013). On the seller side, the volume of bids on EPEX SPOT for the physical fulfilment of Phelix futures fell from 48 TWh in 2014 to 46 TWh in 2015. On the buyer side, the volume rose from 70 TWh in 2014 to 73 TWh in 2015.

The bids submitted on EXAA are broken down by price dependence as follows: on EXAA, 69 per cent (5.7 TWh) of purchase bids and 73 per cent of sales bids (6.1 TWh) are contingent on price conditions. According to EXAA, its proportion of price-limited bids is higher than that of EPEX SPOT because EXAA auctions take place approximately two hours earlier.[55]

1.1.4 Price level

The most commonly used price index on the spot market for the German/Austrian market area is the Phelix (Physical Electricity Index), which is published by EEX/ EPEX SPOT. The Phelix day base is the arithmetic mean of the 24 single-hour prices of a full day and the Phelix day peak is the arithmetic mean of hours 9 to 20 (i.e. 8 a.m. to 8 p.m.). EXAA publishes the bEXAbase and the bEXApeak, which relate to the corresponding single hours (for the same market area).

Average spot market prices declined again in 2015. The Phelix day base average fell from €32.76/MWh in 2014 to €31.63/MWh, or by about 3 per cent, to the lowest level since 2007. At €35.06/MWh the Phelix day peak was also nearly 5 per cent below the previous year's level of €36.80/MWh. The gap between the Phelix day base and the Phelix day peak has steadily narrowed since 2008 and was €3.43/MWh in 2015. As a result, the average Phelix day peak in 2015 was only 11 per cent higher than the Phelix day base (compared to 21 per cent in 2008).

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[54] Section 1 (1) of the Equalisation Scheme Execution Ordinance (Verordnung zur Ausführung der Verordnung zur Weiterentwicklung des bundesweiten Ausgleichsmechanismus – AusglMechAV) requires transmission system operators to market the hourly inputs of renewable energies forecast for the following day for which there is an entitlement to feed-in tariffs (section 19 (1) (2) of the German Renewable Energy Sources Act – Gesetz für den Ausbau erneuerbarer Energien - EEG) on a spot market exchange and offer them on a price-independent basis.

[55] This also explains the closer correlation between EXAA price results and OTC prices. Cf. EXAA Annual Report 2014, p. 23.

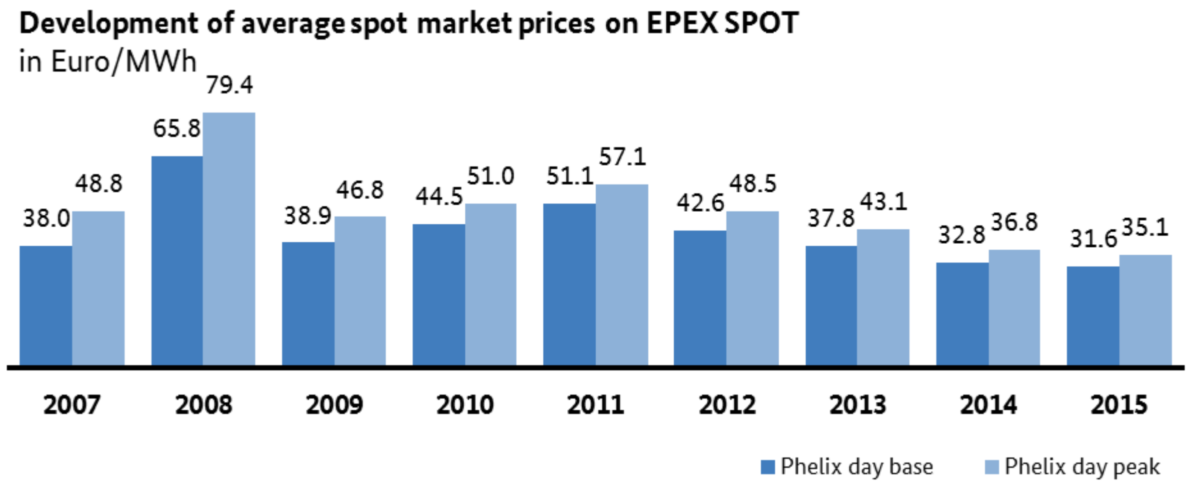

Figure 75: Development of average spot market prices on EPEX SPOT

As in previous years, the bEXA and Phelix indices for 2015 are very close to each other. In the reporting year 2015, the annual average electricity prices in day-ahead auctions were lower on EPEX SPOT than on EXAA – this applies both to the Phelix day base when compared to the bEXAbase and to the Phelix day peak when compared to the bEXApeak.

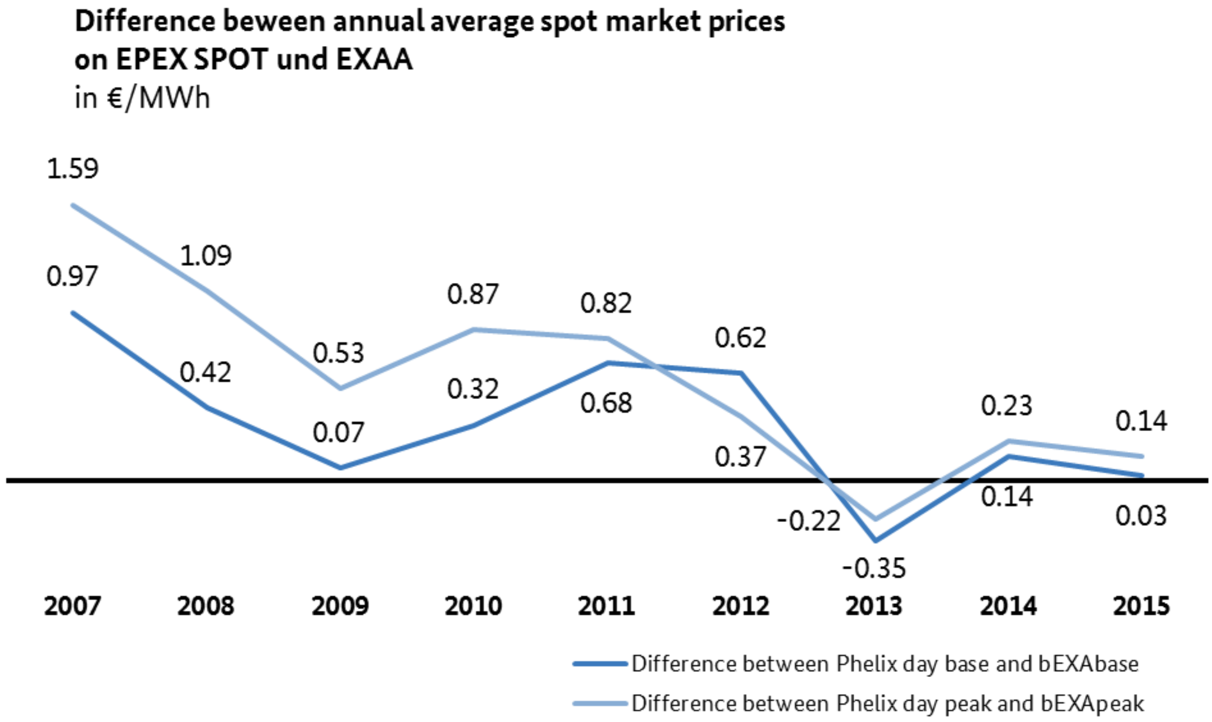

Figure 76: Difference between base and peak spot market prices on EPEX SPOT and EXAA

1.1.5 Price dispersion

As in previous years, daily average spot market prices exhibit considerable dispersion. The following figure shows the development of spot market prices over the year, using the Phelix day base as an example. Daily average prices typically have a weekly profile with lower prices at the weekend. The bEXAbase, which is not shown in the figure, follows the same pattern. Overall, this indicates that spot market prices have become much more volatile since the previous year and increasingly tend to be lower.

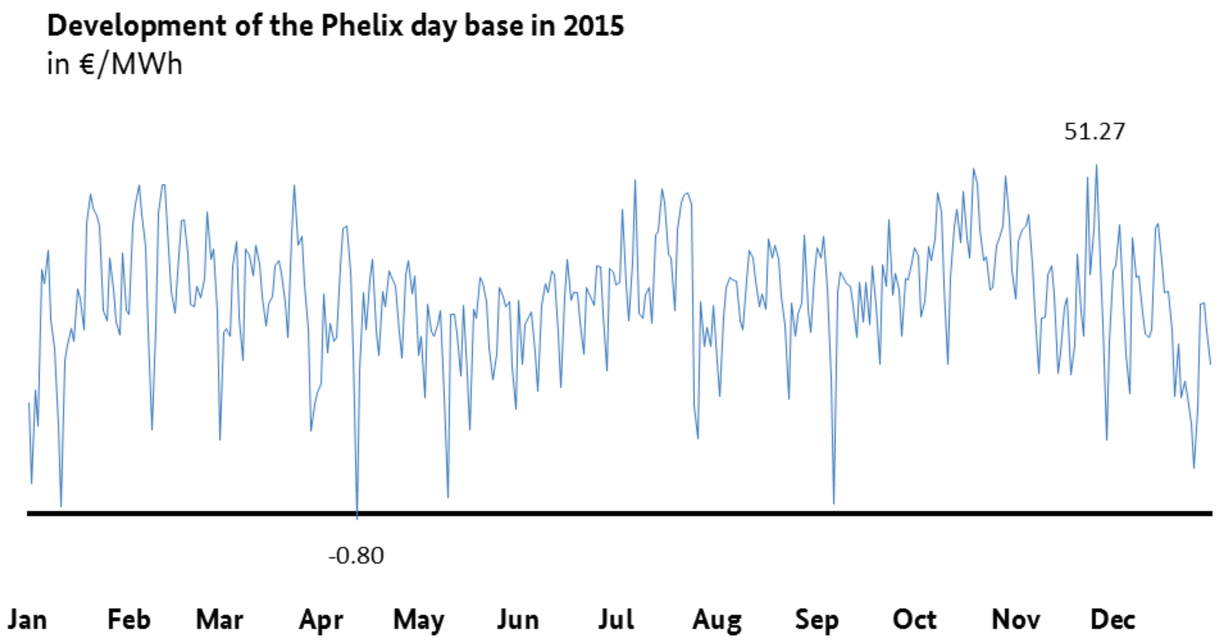

Figure 77: Development of the Phelix day base in 2015

The base and peak prices on EPEX SPOT exhibited slightly increased dispersion in 2015. The range of the middle 50 per cent of the graded Phelix day base values was €10.42/MWh in 2015 and grew by 8 per cent compared to 2014.[56] The corresponding peak range of the middle 50 per cent rose by 14 per cent. The ranges of the middle 80 per cent of the graded values increased by 8 per cent (base) and decreased by 2 per cent (peak). There was one negative value[57] in the Phelix day base in 2015 (on 12 April) and two negative values in the Phelix day peak (also on 12 April and on 6 September).

Overall, daily average spot market prices for 2015 were found to be at a lower average level than in the previous year. The lowest of the reported quantiles each have a lower value and the range of the reported quantiles has been reduced at the same time. The highest Phelix day base value was €51.27/MWh (€55.48/MWh in 2014) or 13 per cent below the previous year's value. The maximum Phelix day peak value was €65.12/MWh in the reporting year (€69.39/MWh in 2014), equivalent to 12 per cent lower.

[56] 2015: upper limit €37.29/MWh – lower limit €26.87/MWh = range €10.42/MWh
2014: upper limit €38.00/MWh – lower limit €28.31/MWh = range €9.70/MWh.
2013: upper limit €46.88/MWh – lower limit €31.23/MWh = range €15.65/MWh.

[57] Negative prices are price signals on the electricity market and occur when high and inflexible power generation meets weak demand. Inflexible power sources cannot be quickly shut down and started up again without major expense. This includes renewable energies because their generation depends on external factors (e.g. wind and sun).

Price ranges of Phelix day base and Phelix day peak

	Middle 50 per cent 25 to 75 per cent range of the graded figures in €/MWh	Middle 80 per cent 10 to 90 per cent range of the graded figures in €/MWh	Extreme values lowest and highest figures in €/MWh
Phelix day base 2013	31.23 – 46.88	23.66 – 52.81	-6.28 – 62.89
Phelix day base 2014	28.31 – 38.00	22.29 – 42.71	-4.13 – 55.48
Phelix day base 2015	26.87 - 37.29	20.30 - 42.38	-0.80 - 51.27
Phelix day peak 2013	34.44 – 54.42	24.76 – 62.28	-18.99 – 80.50
Phelix day peak 2014	30.98 – 42.51	22.82 – 51.69	-17.59 – 69.39
Phelix day peak 2015	28.66 - 41.83	20.82 - 49.09	-11.38 - 65.12

Table 40: Price ranges of Phelix day base and the Phelix day peak between 2013 and 2015

EXAA shows a similar pattern. The upper and lower limits of the ranges for bEXAbase and bEXApeak have, for the most part, increased year-on-year and the ranges have grown slightly. The percentage changes of the ranges follow the same trend as the changes in the Phelix day base and the Phelix day peak (with the exception of the middle 80 per cent range, which is just 2 per cent higher).

Price ranges of bEXAbase and bEXApeak

	Middle 50 per cent 25 to 75 per cent range of the graded figures in €/MWh	Middle 80 per cent 10 to 90 per cent range of the graded figures in €/MWh	Extreme values lowest and highest figures in €/MWh
bEXAbase 2013	30.75 – 46.56	23.80 – 51.33	1.10 – 60.62
bEXAbase 2014	28.52 – 37.92	23.27 – 42.56	4.15 – 55.86
bEXAbase 2015	26.62 - 37.34	20.41 - 42.48	-0.79 - 49.27
bEXApeak 2013	34.25 – 54.51	23.14 – 61.73	4.80 – 76.40
bEXApeak 2014	30.61 – 42.76	23.69 – 51.51	-1.75 – 69.17
bEXApeak 2015	28.61 - 42.11	20.74 - 49.09	0.40 - 59.10

Table 41: Price ranges of bEXAbase and bEXApeak between 2013 and 2015

1.2 Future markets

Futures with standardised maturities can be traded on EEX for the German/Austrian market area if the Phelix (base value) is the subject matter of the contract. Options for specific Phelix futures can generally also be traded, however, as in the last few years, there were no such transactions on EEX. Trading in cap futures (for week contracts) was launched on the futures market in September 2015 to hedge price peaks in light of the growing share of renewable energy on the market.[58]

The next section is based solely on on-exchange transaction volumes, not including OTC clearing (see section I.F.2.2 on OTC clearing).

1.2.1 Trading volumes

The on-exchange trading volumes of Phelix futures increased again in the reporting year 2015, this time by 15 per cent to 937 TWh following considerable growth in the previous years (50 per cent between 2012 and 2013 and 21 per cent between 2013 and 2014). The number of active participants on the EEX futures market (not including OTC clearing) averaged 65 per trading day in 2015 (compared to 53 in 2014).

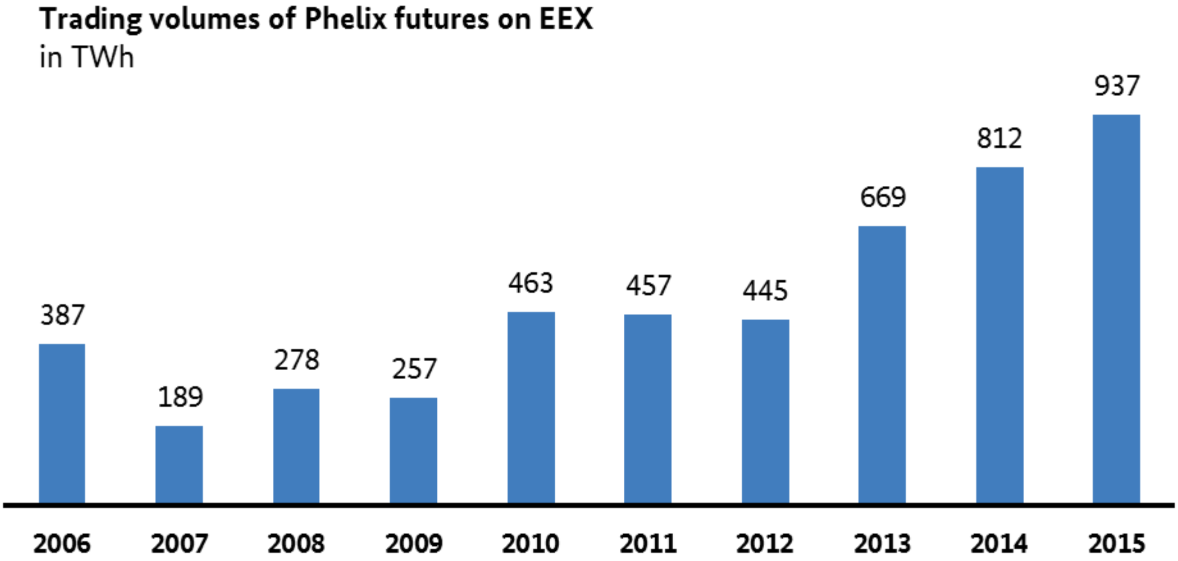

Figure 78: Trading volumes of Phelix futures on EEX

Futures trading in 2015 again predominantly focussed on contracts for the year ahead (2016) as the fulfilment year with some 51 per cent of the total trading volume, i.e. approximately 479 TWh. Trading for the reporting year 2015 made up the second largest share with approximately 24 per cent. Here, the volume increased from 149 TWh in 2014 to 223 TWh in the reporting year, i.e. by approximately 50 per cent, compared to the previous year. Trading for 2017 accounted for about 16 per cent of the contract volume. However, there was a decline in trading for 2018 (8 per cent) and for the next few years beyond (2 per cent).

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[58] Cf. EEX press release from 14 September 2015.

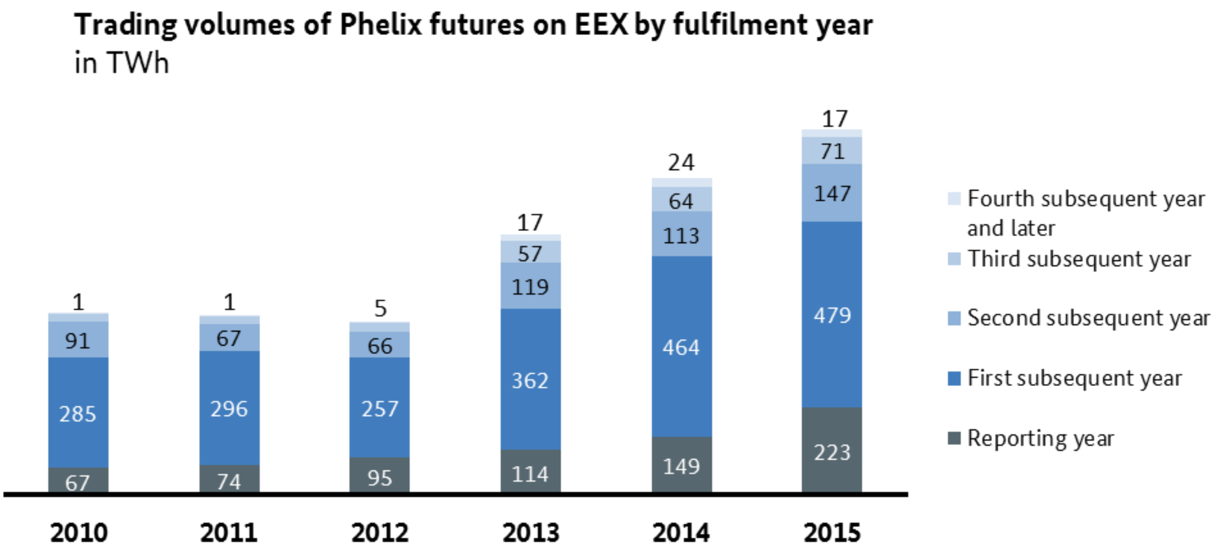

Figure 79: Trading volumes of Phelix futures on EEX by fulfilment year

1.2.2 Price level

The Phelix year futures base and peak are the two most important futures traded on EEX for the German/Austrian market area in terms of volume. The baseload future relates to a constant and continuous supply rate (every hour, every day) while the peakload future covers the hours from 8:00 a.m. to 8:00 p.m. from Monday to Friday

The prices for the year futures continued to fall over the reporting year 2015. The figures for the baseload future and the peakload future were always below the prices on the corresponding trading days in the previous year. The peak price declined more than the base price.

Accordingly, the price difference between Phelix base year future 2015 and Phelix peak year future 2015 narrowed from €9.05/MWh to €6.73/MWh during the course of the year.

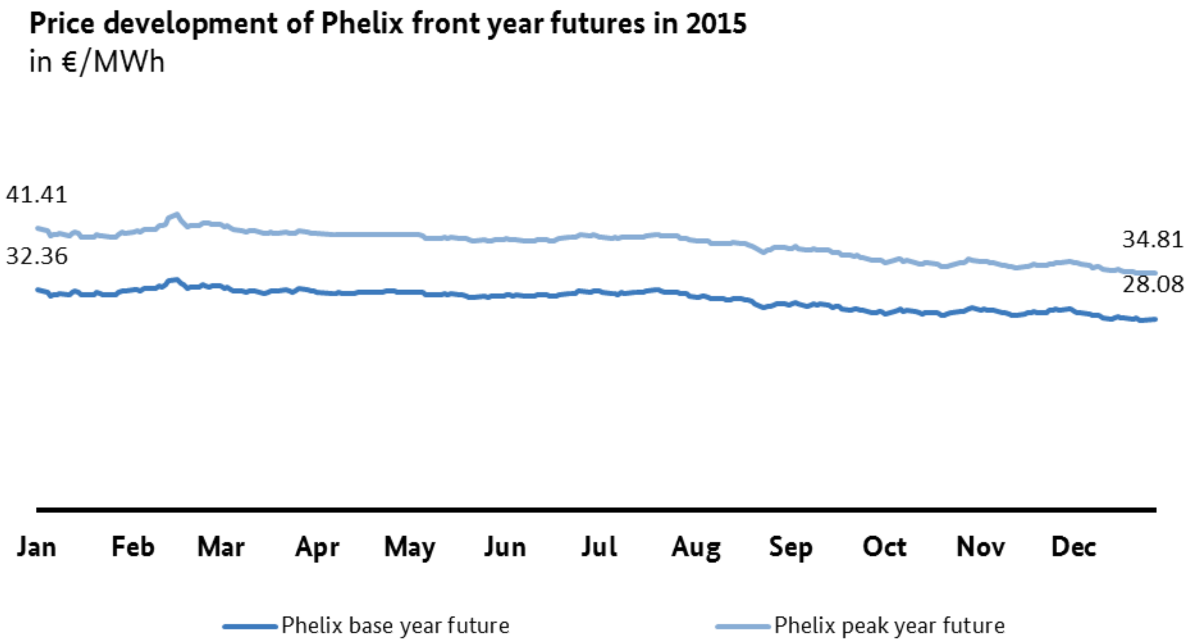

Figure 80: Price development of Phelix front year futures in 2015

An annual average can be calculated on the basis of the Phelix front year futures prices recorded on EEX on individual trading days. This average would correspond to the average electricity purchase price (or electricity sales price) of a market player if the latter buys (or sells) the electricity not at short notice but pro rata in the preceding year.

The annual averages of the Phelix front year future prices fell again compared to the previous year. With an average of €30.97/MWh in 2015, the Phelix base year future fell by €4.12/MWh year-on-year (€35.09/MWh in 2014), a drop of approximately 12 per cent. The price of the Phelix peak front year future averaged €39.06/MWh over the year (€44.40/MWh in 2014). The year-on-year decline is €5.34/MWh or approximately 12 per cent. Compared to the historic high of 2008, the front year base prices and front year peak prices have continued their downward trend.

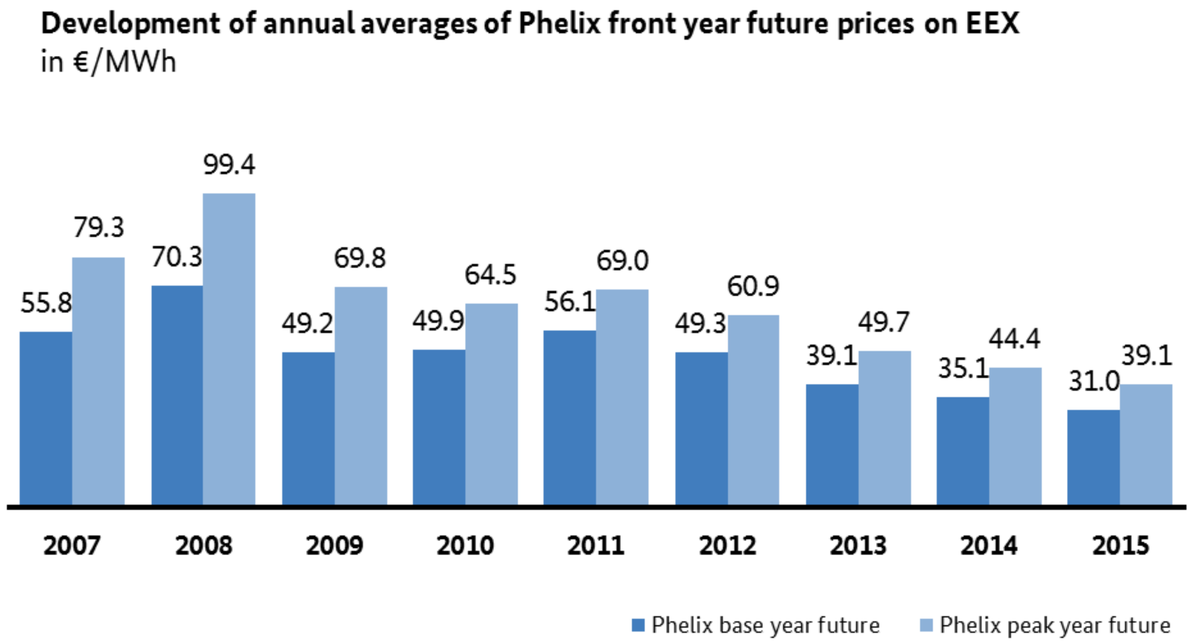

Figure 81: Development of annual averages of Phelix front year prices on EEX

The annual average price difference between base and peak products was approximately 26 per cent (27 per cent in 2014). While the peak price was more than 40 per cent higher than the base price in the period from 2007 to 2009, this difference has been reduced to only 23 to 29 per cent since 2010. Year-on-year, the total price difference fell from €9.31/MWh (2014) to €8.09/MWh (2015).

1.3 Trading volumes by exchange participants

1.3.1 Share of market makers

Exchange participants committed to publishing binding purchase and sales prices (quotations) at the same time are referred to as market makers. The role of market makers is to increase the liquidity of the market place. The specific conditions are agreed between the market makers and the exchange in market maker agreements, which include provisions on quotation times, the quotation period, the minimum number of contracts and maximum spread. The companies involved are not prevented from engaging in additional transactions (that are not part of their role as market maker) as exchange participants.

The same four companies as in previous years acted as market makers on the EEX futures market for Phelix futures during the reporting period: E.ON SE (now Uniper Global Commodities SE)[59], EDF Trading Limited, RWE Supply & Trading GmbH[60] and Vattenfall Energy Trading GmbH. The market makers' share in the purchase and

[59] After the separation of the operational business on 1 January 2016, Uniper Global Commodities SE became the successor company of E.ON SE and responsible for energy trade. Cf. E.ON press release from 4 January 2016.

[60] RWE Supply & Trading GmbH is to continue to act as the energy trading company of the RWE Group. Cf. RWE AG press release from 2 May 2016.

sales volumes of Phelix futures was about 33 per cent in each case. This is equivalent to the previous year's level. The figure refers to the turnover the companies generated when acting as market makers, i.e. it does not include the volumes the four companies may have traded outside their role as market makers.

In addition to agreements with market makers, EEX maintains contracts with exchange participants who are committed to strengthening liquidity to an individually agreed extent. The total trading volume generated by these companies in 2015 was approximately 8 per cent in sales and 9 per cent in purchases.

Three market makers (five market makers since 1 December 2015) were active on the day-ahead market of EXAA in the reporting period. In 2015, the cumulative share of transactions carried out by companies in their role as market makers was 2.4 per cent of the purchase volume of the day-ahead auction (1.8 per cent in 2014) and 7.6 per cent (7.8 per cent in 2014) of the sales volume.

1.3.2 Share of transmission system operators

In accordance with the Equalisation Mechanism Ordinance (AusglMechV), the transmission system operators (TSOs) are obliged to sell renewable energy volumes passed on to them in accordance with the fixed feed-in electricity tariffs under the Renewable Energy Sources Act on the spot market of an electricity exchange. For this reason, the TSOs account for a large but steadily declining share of the spot market volume on the seller side.

The share of TSOs in the day-ahead sales volumes of EPEX SPOT continues to fall. It was 18 per cent in the reporting year 2015 compared to 19 per cent in 2014[61] (23 per cent in 2013; 28 per cent in 2012). The volumes marketed by TSOs also declined in absolute terms. The on-exchange day-ahead sales volume marketed by TSOs was approximately 47.8 TWh in 2015, 50.6 TWh in 2014 and 69.3 TWh in 2013.

This decline is caused by the fact that an increasing number of renewable energy plant operators opted for direct marketing so that the volume to be marketed by TSOs was reduced accordingly.[62] TSOs generated a very small spot market volume on the buyer side and carried out only a small number of transactions on the futures markets.

1.3.3 Share of participants with the highest turnover

An analysis of the trading volume generated by the participants with the highest turnover gives an insight into the extent to which exchange trading is concentrated. The participants with the highest turnover include the large electricity producers, financial institutions and – on the spot market – the TSOs. In order to compare the figures over time, it is important to note that the group of the (e.g. five) participants with the highest turnover can change over the years, so that the cumulative share of turnover does not necessarily relate to the same companies. This is not a group view, i.e. the turnover of a group is not aggregated if a group has several participant registrations.[63]

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[61] The figure relating to the transmission operators' share of the day-ahead sales volume for 2014, which was originally published in the Monitoring Report 2015, has since been corrected from 21 per cent to 19 per cent.

[62] For additional details see section I.B.2.4

[63] Generally speaking, groups only have one participant registration.

The share of the five purchasers with the highest turnover in the day-ahead trading volume on EPEX SPOT declined significantly from 46 per cent in 2014 to 40 per cent in the reporting year. The corresponding share on the seller side also decreased compared to the previous year. The cumulative share of the five sellers with the highest turnover was approximately 35 per cent in 2015 (39 per cent in 2014). The previously higher shares on the seller side are primarily due to the TSOs' higher sales volumes at that time.

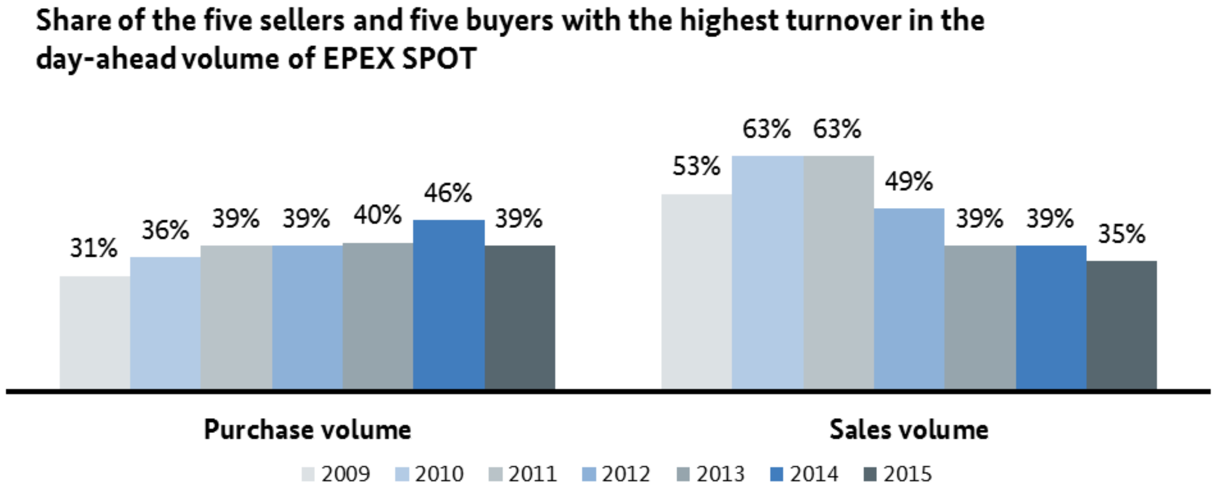

Figure 82: Share of the five sellers and five buyers with the highest turnover in the day-ahead volume of EPEX SPOT

EXAA as another exchange for day-ahead auctions follows a similar trend. The share of the five participating purchasers with the highest turnover fell from 38 per cent in 2014 to 33 per cent in the reporting year. The share of the five sellers with the highest turnover was 28 per cent in the reporting year (31 per cent in 2014)[64].

The share of the five buyers of Phelix futures with the highest turnover on EEX (excluding OTC clearing) was approximately 41 per cent, and the share of the five sellers with the highest turnover was approximately 43 per cent. This represents a small reduction of 3 percentage points on the buyer side and 1 percentage point on the seller side compared to 2014.

[64] In the current reporting year, purchase and sale shares have been reviewed separately unlike the Monitoring Report 2015, which provided an average figure for sale and purchase shares.

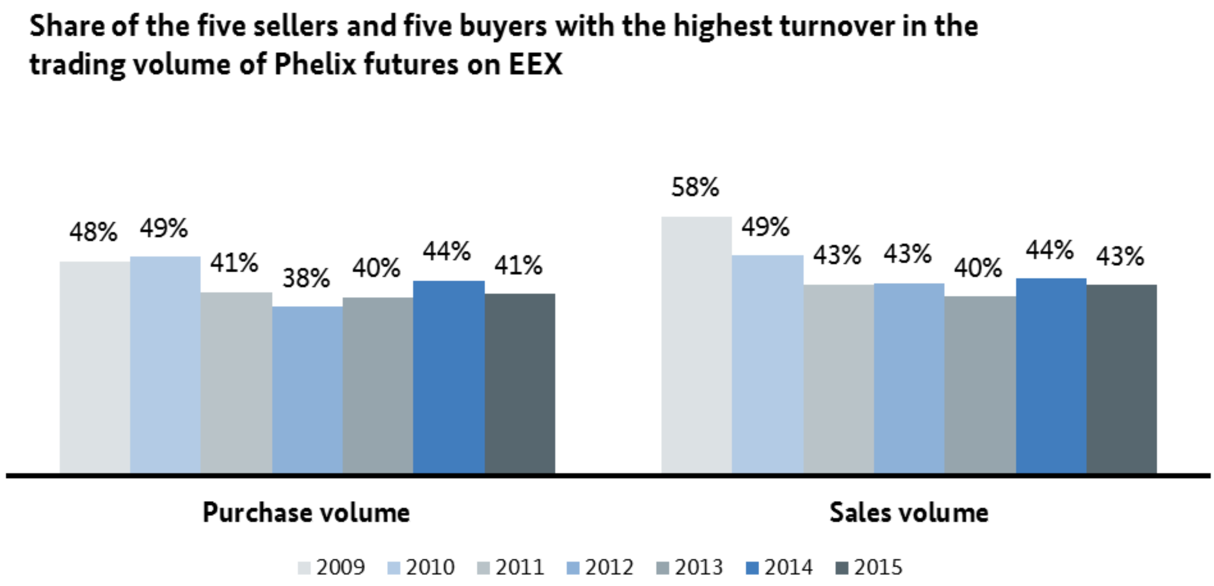

Figure 83: Share of the five buyers and five sellers with the highest turnover in the trading volume of Phelix futures on EEX

1.3.4 Distribution of trading volumes by exchange participant classification

The electricity exchanges assign each of the participants registered with them to a specific participant group. The figure below does not show the transaction volume generated by these participant groups divided into purchase and sale but only the averaged shares for purchase and sale. The shares in the spot market volume relate to the transaction volume reduced by market coupling contracts (imports and exports).

Averaged shares of EPEX SPOT or EEX participant groups in sales or purchase volumes in 2015

	EPEX SPOT	EEX
Supra-regional suppliers and energy trading companies (EEX) or electricity producers and energy trading companies (EPEX SPOT)	74%	60%
Financial service providers and credit institutions	5%	36%
Transmission system operators	10%	<1%
Municipal utilities and regional suppliers	10%	3%
Commercial consumers	-	1%

Table 42: Averaged shares of EPEX SPOT and EEX participant groups in sales and purchase volumes in 2015

2. Bilateral wholesale trading

Bilateral wholesale trading (“OTC trading”, “over the counter”) is characterised by the fact that the contracting parties are known to each other (or become known to each other no later than on conclusion of the transaction) and that the parties can make flexible and individual arrangements regarding the details of the contract. The surveys carried out for energy monitoring of OTC trading aim to record the amount, structure and development of bilateral trading volumes. Unlike exchange trading, however, it is impossible to provide a complete picture of bilateral wholesale trading since there are no clearly definable market places outside the exchanges or a standard set of contract types.

Brokers play a major role in bilateral wholesale trading. They act as intermediaries between buyers and sellers and pool information on the supply and demand of electricity transactions. Electronic broker platforms are used to bring interested parties on the supply and demand sides together and so increase the chances of the two parties reaching an agreement.

On-exchange OTC clearing plays a special role. OTC trading activities can be registered on the exchange to hedge the parties’ trading risk.65 OTC clearing provides an interface between on-exchange and off-exchange electricity wholesale trading.

In the reporting year, different broker platforms were once again surveyed with regard to bilateral wholesale trade (cf. section I.F.2.1). Data was also collected on OTC clearing on EEX (cf. section I.F.2.2). The surveys revealed a stable high level of liquidity in bilateral electricity wholesale trading in the reporting year 2015.

2.1 Broker platforms

During monitoring, operators of broker platforms were also asked to answer questions on the contracts they brokered. Many brokers provide an electronic platform to support their intermediary business.

A total of eleven brokers who brokered electricity trading transactions with Germany as a supply area took part in this year’s collection of wholesale trading data (12 in the previous year). The volume brokered by them was approximately 4,847 TWh in 2015 compared to 4,946 TWh in 2014. However, the figures are not directly comparable so that the resulting decline has no informative value because two broker platforms from the previous year (whose volume accounted for approximately 100 TWh) no longer took part in the reporting year 2015, and a new broker platform (whose volume accounts for approximately 10 TWh) took part for the first time. According to information from the London Energy Brokers’ Association (LEBA), which, however, does not include all broker platforms, the trading volume for German power brokered by LEBA members rose by approximately 3 per cent year-on-year.66 The figures therefore indicate that the volume traded via broker platforms has remained stable following a significant decline in the previous year.

[65] EEX no longer refers to this service as “OTC clearing”, but as “trade registration”.

[66] See https://www.leba.org.uk/assets/monthly_vol_reports/LEBA%20Energy%20Volume%20Report%20December%202015.pdf (retrieved on 18 April 2016).

Contracts for the year ahead continue to make up the majority of electricity transactions brokered on broker platforms with 52 per cent, followed by the activities for the current year with 26 per cent. Short-term transactions with a fulfilment period of less than one week generated only small volumes. The distribution of the fulfilment periods corresponds to that of the previous year.

Volume of electricity traded via broker platforms in 2015 by fulfilment period

Fulfilment period	Volume traded in TWh	Percentage
Intraday	0	0%
Day ahead	109	2%
2-6 days	83	2%
2015, at least 7 days	1,280	26%
First subsequent year	2,528	52%
Second subsequent year	620	13%
Third subsequent year	204	4%
Fourth subsequent year and later	22	0%
Total	**4,847**	**100%**

Table 43: Volume of electricity traded via broker platforms in 2015 by fulfilment period

2.2 OTC clearing

Alongside the on-exchange EEX order book trade, on-exchange OTC clearing played a special role in bilateral wholesale trading. The exchange, or its clearing house, is the contracting party of the trading participants in on-exchange trading so that the exchange bears the counterparty default risk. While the default risk in bilateral trading can be reduced or hedged by various means, it cannot be eliminated altogether. Another factor is that OTC transactions can be included in the provision of collateral for exchange trading, e.g. with futures.

By registering on the exchanges, the contracting parties ensure that their contract is subsequently traded as a transaction originating on the exchange, i.e. both parties act as though they had each bought or sold a corresponding futures market product on the exchange. OTC clearing therefore represents an interface between on-exchange and off-exchange electricity wholesale trading.

EEX, or its clearing house European Commodity Clearing AG (ECC), provides OTC clearing (or trade registration, s.a.) for all futures market products that are also approved for exchange trading on EEX.

The volume of OTC clearing of Phelix futures on EEX was 877 TWh in 2015 (557 TWh in 2014), that is, 57 per cent higher than in the previous year. Since OTC clearing is used to (retrospectively) offset futures concluded on the exchange, the development of the OTC clearing volume should be considered in the context of the on-exchange futures market volume. The total volumes of on-exchange futures trading and OTC clearing remained relatively stable for a long time (from 2006 to 2011). The volume has been increasing since 2012 and the total volume has almost doubled since then. As in the previous year, the total volume reached a new all time high in the reporting year 2015. The OTC clearing volume grew by 57 per cent, and exchange trading grew by 15 per cent year-on-year. OTC clearing recorded the strongest growth but did not achieve the peak of 2007.

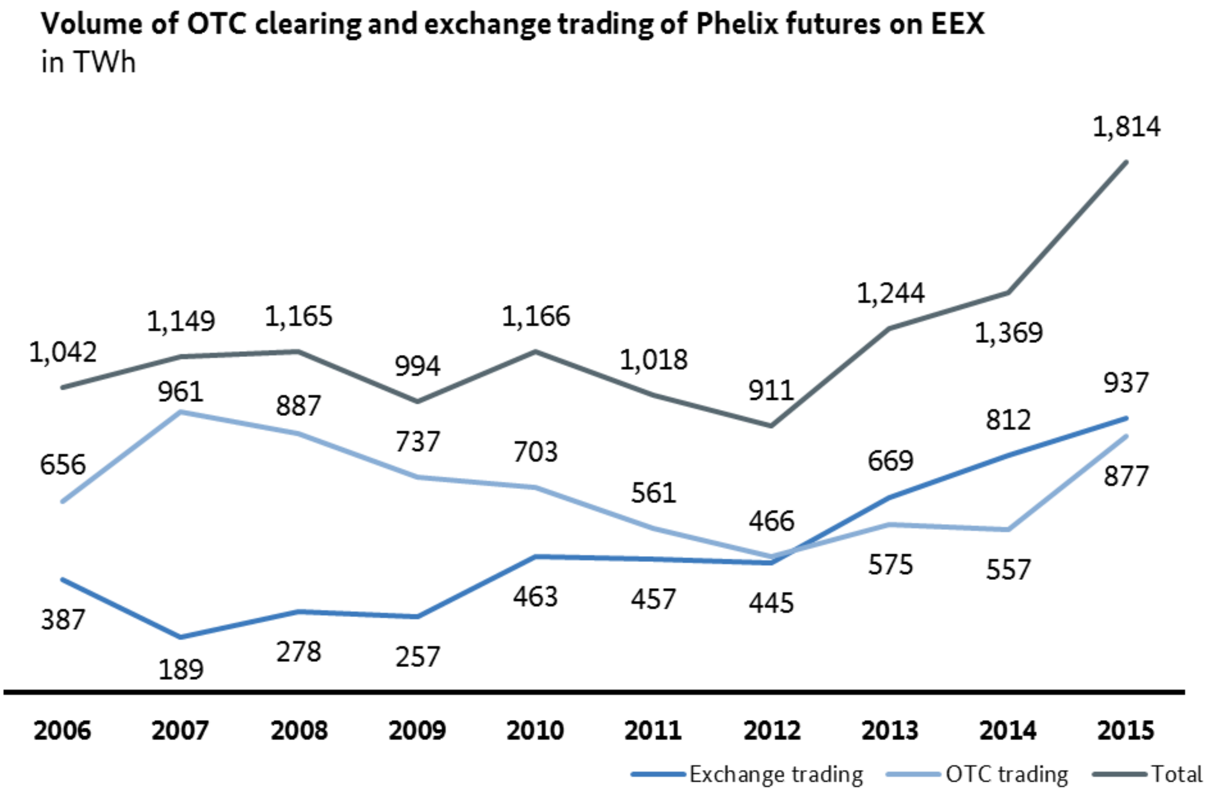

Figure 84: Volume of OTC clearing and exchange trading of Phelix futures on EEX

According to the London Energy Brokers' Association (LEBA), the share of cleared contracts has steadily increased over time. The volume for German power registered by LEBA members for clearing (not only on EEX) was 802 TWh in 2015 as reported by LEBA, which is equivalent to a share of about 18 per cent of the total OTC contracts brokered by LEBA members. By contrast, the corresponding figures were approximately 13 per cent (557 TWh) in 2014, approximately 10 per cent (534 TWh) in 2013 and approximately 7 per cent (377 TWh) in 2012.[67]

Phelix options had no bearing on exchange trading on EEX. As in the previous year, there were no such transactions in the reporting year. By contrast, OTC clearing of Phelix options agreed off the exchange has practical significance: Phelix options accounted for a share of 67 TWh or 8 per cent of OTC clearing in the reporting year 2015, while 810 TWh or 92 per cent of OTC clearing was made up of Phelix futures. The OTC clearing volume for options doubled compared to the previous year (33 TWh or 6 per cent in 2014).

[67] Cf. http://www.leba.org.uk/pages/index.cfm?page_id=59 (retrieved on 11 November 2016). The total volume of German power brokered by LEBA members was 5,395 TWh in 2012; 5,302 TWh in 2013; 4,367 TWh in 2014 and 4,518 TWh in 2015.

The distribution of the volumes registered on EEX for OTC clearing across the various fulfilment periods in 2015 has a similar structure as that in previous years. Contracts for the year ahead (2016) made up almost half of the volume (49 per cent). Approximately 35 per cent related to the reporting year 2015 and about 13 per cent related to the year after next (trading for 2017). Later fulfilment periods accounted for only a small share of 4 per cent.

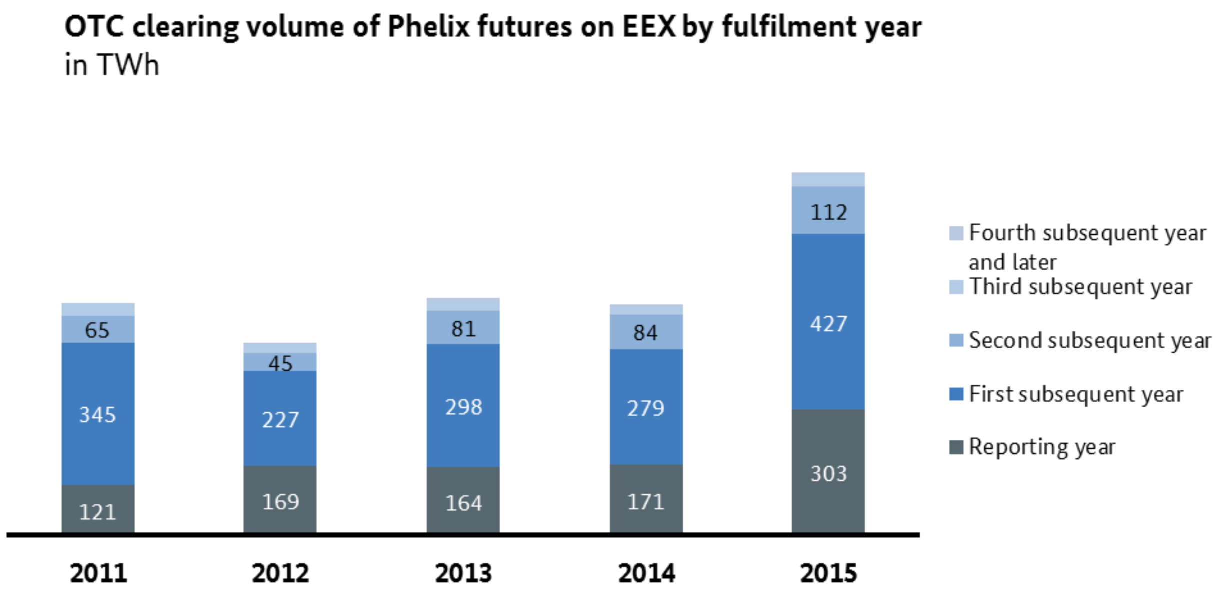

Figure 85: OTC clearing volume for Phelix futures on EEX by fulfilment year

The majority of the OTC clearing volume of Phelix futures on EEX is generated by just a few broker platforms. The five companies that registered the largest volumes for OTC clearing in 2015 accounted for about 66 per cent of all purchases and 67 per cent of all sales (the figures for 2014 were 72 per cent of all purchases and 70 per cent of all sales). Purchases and sales were both conducted via broker platforms.

EPEX SPOT offers OTC clearing for intraday contracts. However, the practical significance of this supply continues to be quite small. The volume attributed to this in 2015 was again only 0.02 TWh (in 2014 it was also 0.02 TWh).

G Retail

1. Supplier structure and number of providers

When looking at the retail market in the electricity sector it is worth noting how the supplier market is structured and how many suppliers are active in the market. The analysis covers data from 1,238 suppliers on the meter points served by them and clearly shows that in absolute terms most suppliers serve only a small number of meter points. For the data analysis the information provided by the suppliers was considered to be submitted from individual legal entities without taking company affiliations or links into consideration. Approximately 83% of all the suppliers taking part in the monitoring belong to the group of suppliers that serve less than 30,000 meter points. At just 7.2 million meter points in total, this amounts to only 14% of all registered meters[68]. Some 7% of all suppliers serve over 100,000 meter points each. This group covers some 36.6 million meter points and therefore about 73% of all the meter points registered by suppliers. Hence the majority of companies operating as suppliers have a customer base made up of a relatively small number of meter points, whereas 86 large suppliers (individual legal entities) serve the largest number of meters in absolute terms.

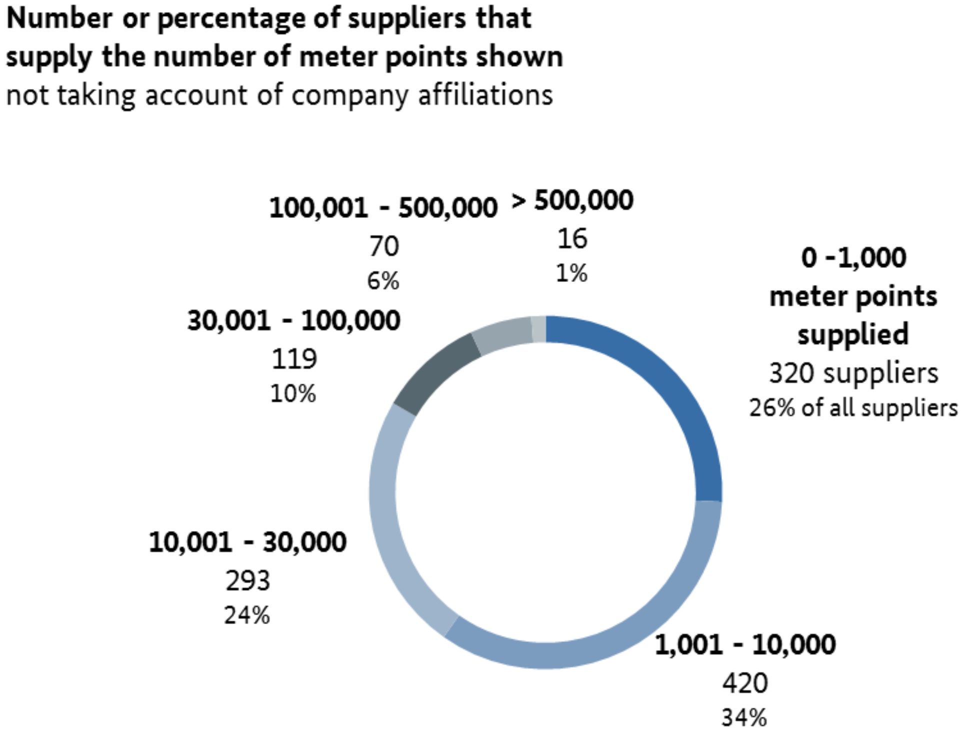

Figure 86: Number of suppliers by number of meter points supplied[69]

[68] Suppliers reported a total of 50.1m meter points of final consumers supplied.

[69] Figures may not sum exactly owing to rounding.

Electricity customers had the choice of an even larger number of suppliers than in 2014. An evaluation of the data supplied by 801 distribution network operators on the number of suppliers that supply the consumers in each network area produced the following results: In 2015 more than 50 operated in nearly 83% of all network areas (664 network areas). In the year 2007 this number barely covered one quarter of the network areas (165 network areas). Today more than 100 suppliers operate in well over half the network areas, whereas three years ago it was only 33% (259 network areas). On average, final consumers in Germany can choose between 115 suppliers in their network area (2014: 106); household customers can choose between 99 suppliers (2014: 91). Despite the large number of suppliers, this does not automatically translate into a high level of competition. Many suppliers offer tariffs in several network areas, yet do not acquire a significant number of customers outside of their own default supply area.

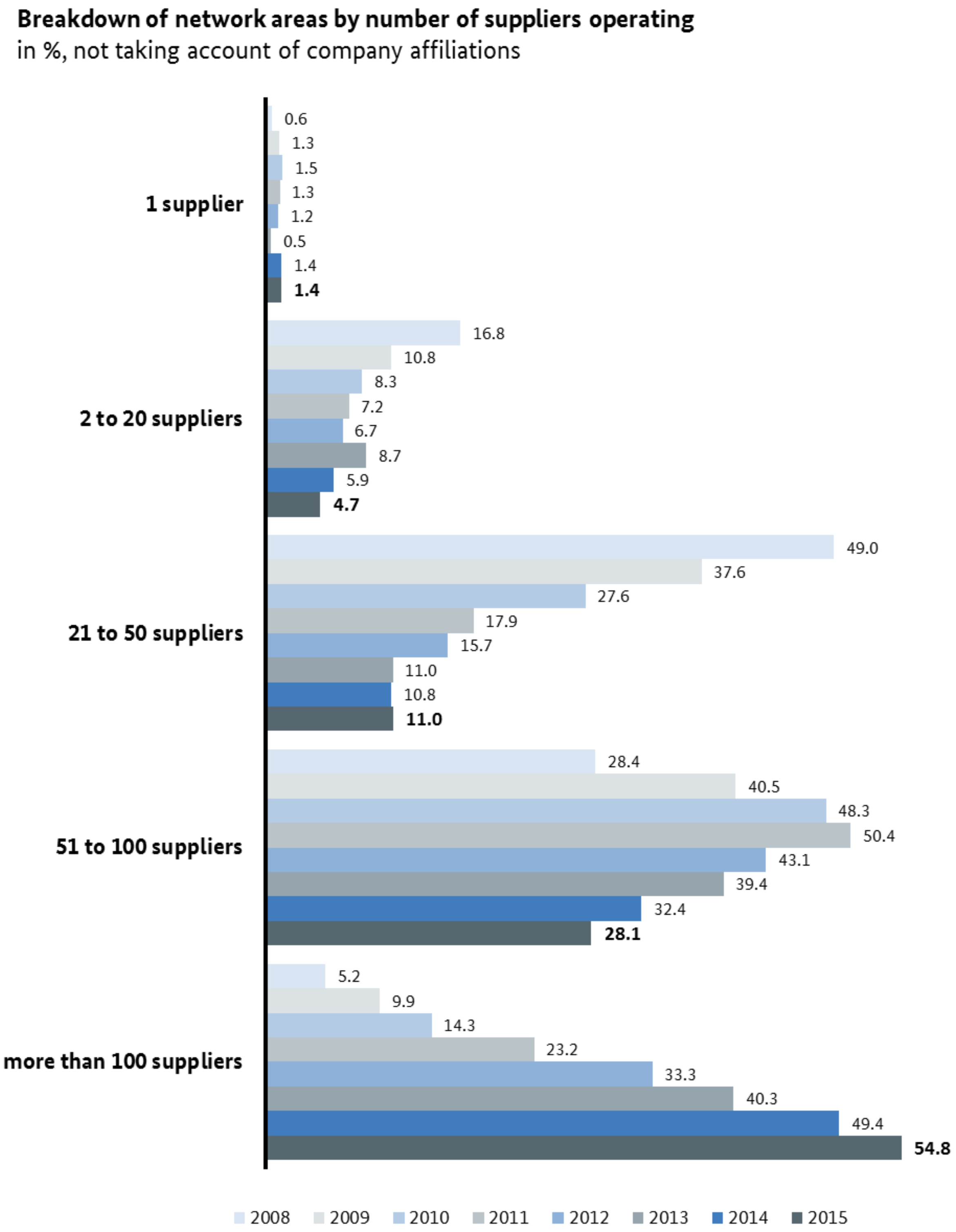

Figure 87: Breakdown of network areas by number of suppliers operating

Suppliers were also asked about the number of network areas in which they supply final consumers with electricity. The analysis of the data submitted by 1,099 suppliers shows that the absolute majority only operate regionally. 55% of suppliers serve a maximum of 10 network areas, while 16% serve only one network area. 22% of companies operate in 11-50 network areas, with 12% operating in 51-250 network areas and 5% operating in 251-500 network areas. 63 suppliers, or around 6%, supply customers in more than 500 network areas. This figure can be taken as the approximate number of suppliers that operate throughout the whole of Germany. On a national average, a supplier has customers in 79 network areas (2014: 75).

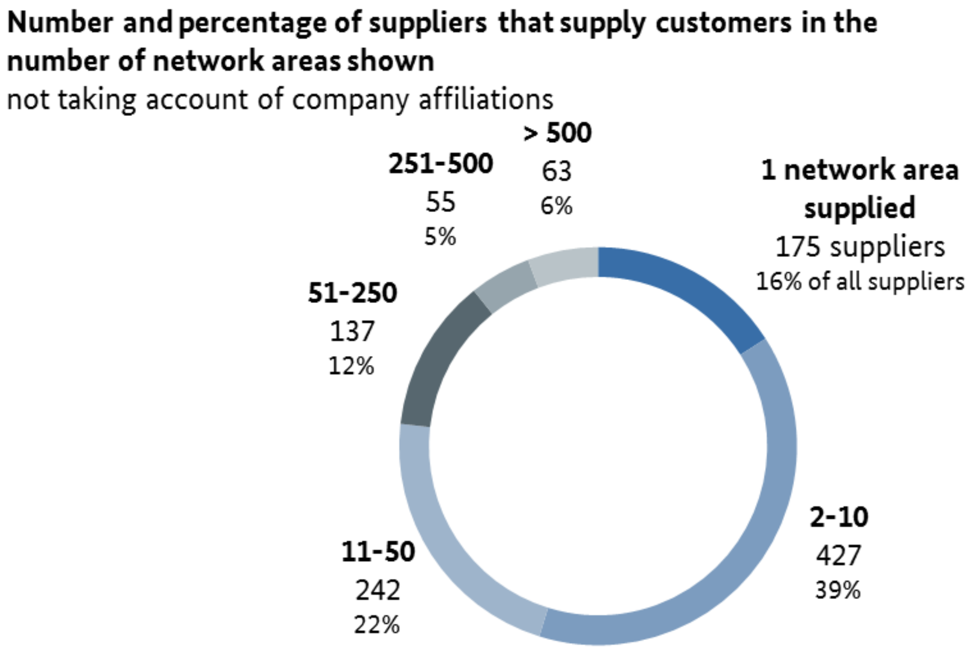

Figure 88: Breakdown of suppliers by number of network areas supplied[70]

2. Contract structure and supplier switching

Switching rates and processes are important indicators of growing competition. The annual switching rates in the electricity retail sector continue to be at a high level. In summary, the rate of supplier switches is at 10.4% and for household customers and at 12.4% for non-household customers (previous year: 11%). Collecting such key figures, however, is bound up with various difficulties and, as a result, the relevant data collection must be limited to the data that best reflects the actual switching behaviour.

As part of the monitoring, data on contract structures and supplier switches relating to each specific customer group is collected through questionnaires for network operators (TSOs and DSOs) and suppliers.

Electricity consumers can be grouped according to their metering profile into customers with and without interval metering. For the latter, consumption over a set period of time is estimated using a standard load profile (SLP).

[70] Figures may not sum exactly owing to rounding.

Final consumers can also be divided into household, commercial and industrial customers. Household customers are defined in the German Energy Act EnWG primarily according to qualitative characteristics[71]. Non-household customers are referred to in the monitoring report as commercial and industrial customers. There is so far no recognised definition of commercial customers[72] on the one hand and industrial customers on the other. For monitoring purposes as well, a strict separation of these two customer groups is not undertaken.

According to supplier questionnaires, the volume of electricity sold to all final consumers in 2015 reached approximately 427 TWh. Of this, around 266 TWh was supplied to interval metered customers and 161 TWh to SLP customers (including 14 TWh night storage and heat pump electricity). The majority of SLP customers are household customers. In 2015, household customers were supplied with around 121 TWh, including night storage and heat pump electricity.

As part of the monitoring, data is collected on the volume of electricity sold to various final consumer groups, broken down into the following three contract categories:

- default supply contract,
- contract with the default supplier outside of default supply contracts and
- contract with a supplier who is not the local default supplier.

For the purposes of this analysis, the default supply contract category also includes fallback energy supply (section 38 EnWG) and doubtful cases[73]. Delivery outside the default supply contract is a referred to either as a special contract with an outside supplier or is defined specifically ("Contract with a default supplier outside of default supply contracts" or "Contract with a supplier who is not the local default supplier"). An analysis on the basis of these three categories makes it possible to draw conclusions as to the extent of the decline in the importance of default supply and the role of default suppliers since the liberalisation of the energy market. The corresponding figures, however, should not be directly interpreted as "cumulative net switching figures since liberalisation". It must be noted that for monitoring purposes the legal entity is taken to be the contracting party; thus a contract with a company affiliated with the default supplier falls under the category "contract with a supplier who is not the local default supplier"[74].

For the first time, electricity suppliers supplied information as to how many household customers switched their electricity supply contract in 2015.

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[71] Section 3 para 22 EnWG defines household customers as final consumers who purchase energy primarily for their own household consumption or for their own consumption for professional, agricultural or commercial purposes not exceeding an annual consumption of 10,000 kilowatt hours.

[72] The category "commercial customers" usually also includes customers from the liberal professions, agriculture, services and public administration.

[73] In addition to household customers, final consumers served by fallback supply are usually included under the default supply tariff, section 38 EnWG. For monitoring purposes, suppliers were asked to allocate cases that could not be clearly categorised to default supply".

[74] It is also possible that further ambiguities may arise, for example if the local default supplier changes. In these cases, no automatic switch of contract takes place (section 36(3) EnWG).

Furthermore, data was collected in the TSO and DSO questionnaires on the number of "supplier switches" in 2015, according to the different customer groups. In the monitoring report, the term "supplier switch" refers to the process by which a final consumer's meter point is assigned to a new supplier. As a rule, moving into or out of premises is not considered a supplier switch[75]. In this analysis, too, it must be noted that the change of supplier refers to a change in the supplying legal entity. According to this definition, a "change of supplier" can thus be brought about by an internal reallocation of supply to another group company, the insolvency of the former supplier or in the event that the supplier terminates the contract ("involuntary supplier switch"). The actual scope of supplier switches can therefore deviate from the figures registered. In addition to supplier switches, the monitoring report also analysed household customers' choice of supplier.

2.1 Non-household customers

2.1.1 Contract structure

Electricity volumes for non-household customers are predominantly supplied to interval-metered customers whose electricity consumption is recorded at short intervals ("load profile"). Interval-metered customers are characterised by high consumption[76]; the majority are industrial or other high-consumption non-household customers.

In the reporting year 2015, approximately 1,050 electricity suppliers (individual legal entities) provided data on the metering points supplied and on the consumption of interval-metered customers in Germany (985 in the previous year). The 1,050 electricity suppliers include many affiliated companies so that the number of suppliers does not equal the number of competitors.

The companies supplied just under 266 TWh of electricity to the approximately 361,000 metering points of interval-metered customers in 2015 (268 TWh was supplied to 359,000 metering points in the previous year). 99.7 per cent of this was supplied under contracts outside the default supply. It is unusual, but not impossible, for interval-metered customers to be supplied under default or auxiliary supply contracts.

A total of 0.8 TWh of electricity was supplied to interval-metered customers with a default or auxiliary supply, which is 0.3 per cent of the total volume supplied to interval-metered customers (divided between 1.9 per cent of all metering points). 31.6 per cent of the total electricity for interval-metered customers was supplied under a special contract with the default supplier (divided between 46.6 per cent of all metering points) and 68.1 per cent was supplied under a contract with a legal entity other than the local default supplier (divided between 51.5 per cent of all metering points). In the previous year, 34.0 per cent of the volume sold was supplied under special contracts with the default supplier and 66.5 per cent under special contracts with other suppliers. These figures again show that with regard to the volume sold, the default supply is of secondary importance for the acquisition of interval- metered electricity customers.

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[75] If the supplier upon moving house is not the local default supplier, this is considered a "switch of supplier". Transfers of supply contracts as a result of concession switch are not considered to be a supplier switch.

[76] In accordance with section 12 of the Electricity Network Access Ordinance (StromNZV), interval metering is generally required if annual consumption exceeds 100 MWh.

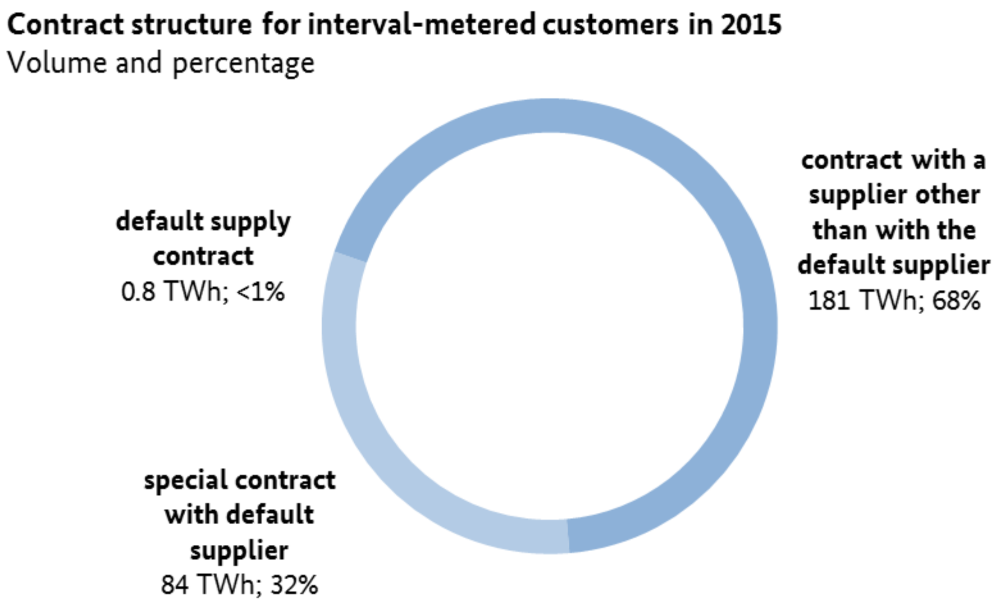

Figure 89: Contract structure for interval-metered customers in 2015

2.1.2 Supplier switching

Data on the supplier switching rates (as defined in monitoring, s.a.) among different customer groups in 2015 and the consumption volumes attributed to these customers was collected in the TSO and DSO surveys. The surveys differentiated between three consumption categories: industrial customers typically fall into the >2 GWh/year category, a wide range of non-household customers fall into the 10 MWh/year to 2 GWh/year category and household customers as defined by section 3, paragraph 22 of the Energy Industry Act (EnWG) fall into the <10 MWh/year category. The survey produced the following results.

Supplier switches by consumer category in 2015

Final consumer category	Number of meter points where the supplying legal entity changed in 2015	Percentage of all meter points in this category	Consumption at meter points where the supplier changed	Percentage of total consumption by consumer category
< 10 MWh/year	3,100,746	6.6 %	8.9 TWh	7.5 %
10 MWh/year – 2 GWh/year	205,653	10.3 %	15.5 TWh	12.8 %
> 2 GWh/year	2,878	15.4 %	28.5 TWh	12.5 %

Table 44: Supplier switching rates by consumption category in 2015

The consumption band of over 10 MWh/year consists almost entirely of non-household customers.[77] The volume-based switching rate for the two categories with a consumption exceeding 10 MWh/year was 12.6 per cent in 2015. Compared to the previous year's figure this represents an increase of 1.6 percentage points. The difference is within the range of previous years. Switching rates in the non-household customer category have remained more or less constant since 2006. The survey does not examine what percentage of non-household customers have switched supplier once, more than once or not at all over a period of several years. Switching rates among non-household customers continue to be higher than switching rates among household customers.

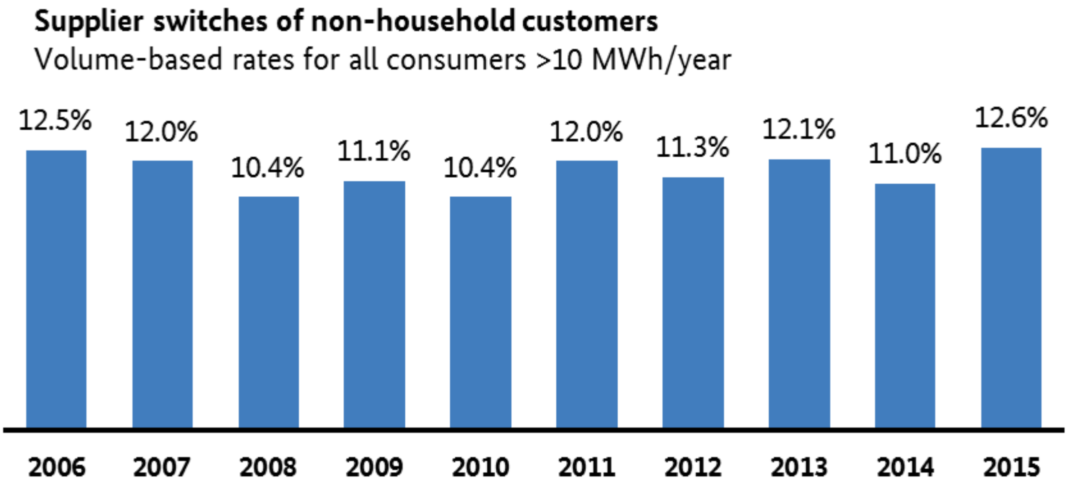

Figure 90: Development of supplier switching among non-household customers

2.2 Household customers

2.2.1 Contract structure

The data from the monitoring report shows that in 2015 a relative majority of 43.1% of household customers concluded a special contract with the local default supplier (2014: 43.2%). The percentage of household customers with a standard default supply contract is 32.1%. Thus the percentage of default supply customers has fallen only slightly when compared with the prior year (2014: 32.8%). Meanwhile, 25% of all household customers are served by a company other than the default supplier (2014: 24%). Consequently, there has been a further increase, if only slightly, in the percentage of customers who no longer have a contract with their default supplier; overall, about 75% of all households are still served by the default supplier (by way of default supply or a special contract). Thus the strong position that default suppliers have in their respective service areas has weakened only slightly.

[77] Where consumption is predominantly household-based, end customers are considered to be household customers even if their consumption exceeds 10 MWh per year (section 33, paragraph 22 of the EnWG). This primarily applies to heating electricity customers.

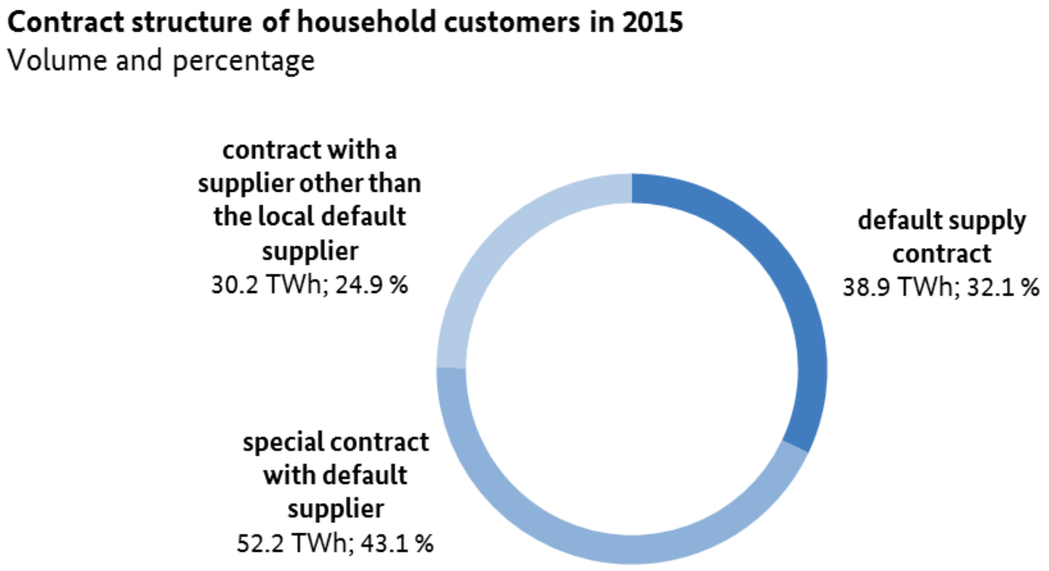

Figure 91: Contract structure of household customers

2.2.2 Switch of contract

For the first time, this year's monitoring report collected data from suppliers on household customers who changed their existing supply contract within a company (switch of contract). Suppliers were only required to register contract switches that were initiated by the customer[78]. The total number of contract switches was around 1.7 million; the volume of electricity involved in the contract switches amounted to approximately 4.6 TWh. This results in a switching rate based on number and volume of switches of 3.7% and 3.8%.

Contract switches by household customers

Category	2015: contract switches in TWh	Percentage of total consumption (121.2 TWh)	2015: number of contract switches	Share of total number of household customers
Household customers who switched their existing energy supply contract with their supplier	4.6	3.8	1,681,610	3.7

Table 45: Contract switches by household customers

[78] Adjustments to the contract that result from changes to the general terms and conditions, expiring tariffs or customers moving to an affiliated company within the group do not apply here.

2.2.3 Supplier switch

To determine the number of supplier switches by household customers, the DSOs were questioned as to the number of supplier switches at the meter points, as well as the choice of supplier when moving home in their network area. The total number of household customers switching supplier (including switches made due to moving home), has risen from 3.8 million in 2014 to around 4 million in 2015. This development is primarily the result of a significantly greater number of switches not related to moving home (+319,367). For the first time, there was a decline in the number of switches due to moving home (88,456).

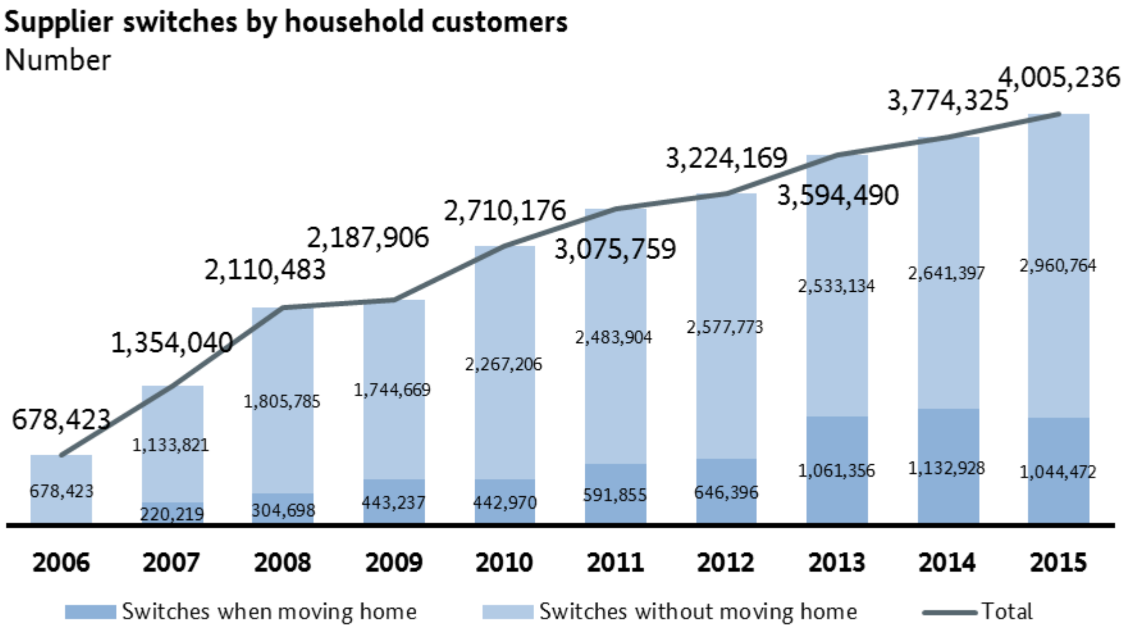

Figure 92: Number of supplier switches by household customers

When viewing the trend in supplier switches from 2006 to 2015, one-off effects have to be taken into account for the years 2011 and 2013 as a consequence of the insolvency of two large cut-price electricity suppliers. The customers affected were initially switched to fallback supply and subsequently, insofar as they had not switched to another supplier themselves, were transferred to the default supply of the local default supplier. An estimated 500,000 customers were affected (also when taking the monitoring figures into account). By definition, such an atypical procedure is recorded as a switch, despite the fact that it is not based on a customer deciding to make the switch. It is therefore appropriate to remove the estimated portion of "switches brought on" by the insolvency. An adjustment of the figures from 2011 and 2013 by removing the 500,000 switches brought on by insolvency thus provides a more accurate picture of the rise in the number of switches, not including switches made for moving home. This is shown in the figure above, already in adjusted form.

A total of 2,960,764 switches were determined for 2015, excluding for moving home. This amounts to around 6.4% of household customers and corresponds to an increase by about 320,000 relative to the prior year. These switches entail an electricity volume of about 9.5 TWh, which in absolute terms is an increase when compared to the prior year’s figure of 8.2 TWh. The percentage switching rate of total electricity supplied to household customers (not including night storage and heat pump electricity) in 2015 was at around 8.4%.

In addition to the switching figures shown for household customers that excluded switches when moving home, the number of household customers that immediately chose an alternative supplier over the default supplier when moving into new premises declined by around 90,000, to 1,044,472. At 2.3 TWh, the electricity amount registered for supplier switches is also just under the prior year's amount.

Supplier switches by household customers, including switches when moving home

Category	2015: Supplier switches in TWh	Percentage of total consumption[1] (112.7 TWh)	2015: Number of supplier switches	Percentage of total household customers
Household customers switching supplier without moving home	9.5	8.4	2,960,764	6.4
Household customers who switched to a supplier other than the default supplier when moving home	2.3	2	1,044,472	2.3
Total	11.7	10.4	4,005,236	8.7

[1] Not including heating electricity

Table 46: Supplier switches by household customer, adjusted for insolvency, including switches when moving home

A joint view of household customer supplier switches that includes switches when moving home shows a total of 4 million switches for 2015 with a total electricity volume of 11.7 TWh. This corresponds to a switching rate based on volume and number of switches of 10.4% and 8.7% respectively. The volume-based rate was again above the quantity-based rate. This suggests that a household customer's high level of electricity consumption has a positive influence on his/her decision to switch supplier. The average volume of electricity consumed by a household customer that made a switch was approximately 2,900 kWh in 2015. In contrast to this, household customers who were supplied by a default supplier consumed only about 2,200 kWh on average.

A joint view of the contract and supplier switches in 2015 makes it possible to calculate the number of household customers who undertook a change in their energy supply contract in the 2015 year under review. A total of nearly 5.7 million switches were made, with the volume of electricity involved in contract and supplier switches totalling 13.4 TWh.

3. Disconnections, cash or smart card meters, tariffs and terminations

3.1 Disconnections of supply

In 2015, the Bundesnetzagentur once again carried out surveys of the tariffs offered and questioned network operators and electricity suppliers about disconnection notices threatening to cut of supply and requests made to

DSOs for disconnection, as well as the number of actual disconnections carried out, along with the associated costs.

In the 2011 to 2014 monitoring reports, the survey on disconnections focused solely on threatened disconnections and notices for disconnection under default supply, as well as disconnections carried out on behalf of the local default supplier.

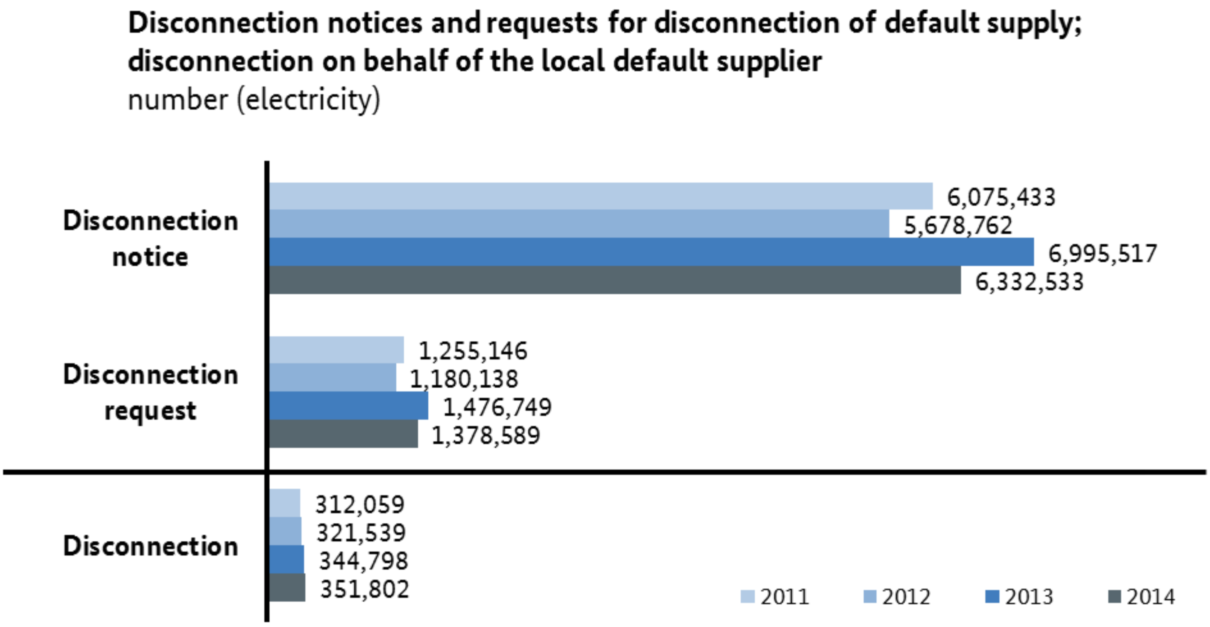

Figure 93: Disconnection notices and requests for disconnection of default supply; disconnection on behalf of the local default supplier (electricity); 2011 to 2014[79]

For the year 2015, the survey of electricity suppliers was further differentiated. The survey of disconnection notices and requests is now directed at all suppliers rather than only at default suppliers. At the same time, the suppliers were asked about disconnections of default supply as well as about disconnections of contracts of household customers outside of default supply contracts.

The background of the modified survey is on the one hand the practice of some suppliers of regulating the contractual terms of disconnections and requesting disconnections with the DSO outside of the default supply system as well. Distribution system operators, however, had in many cases not offered disconnections in their supplier contracts at all, or had only offered them for the default supplier. For this reason, the Federal Court of Justice in 2015 established that a network operator is in violation of his obligation to grant non-discriminatory network access if he rejects an electricity supplier's request for disconnection of electricity supply solely on the grounds that the delivery does not fall under a default supply contract[80]. Since 1 January 2016, the rights and

[79] It is important to note with regard to the data for 2011 that some suppliers could only provide estimates of the number of disconnection notices and requests.

[80] Federal Court of Justice, EnZR 13/14, 14 April 2015

obligations that are in effect between network operator and network user are now regulated in the network usage contract/supplier framework agreement for electricity, which is specified by the Bundesnetzagentur and regulates the possibility to discontinue supply at the request of any supplier.

On the other hand, network operators had until now already been unable to tell whether a disconnection request by the default supplier was occurring within the framework of a default supply contract or in a contract with a default supplier outside of a default supply contract. To request a disconnection under section 24(3) NAV, the supplier must only credibly show that the contractual prerequisites for a disconnection between supplier and connection user are met. He is not, however, required to disclose the contractual terms. Neither is a supplier obligated to effect a modification of his network registration with the network operator if the operator changes the contractual terms with the customer. Network operators therefore have no way of knowing whether a customer who was originally supplied under a default supply contract with the default supplier is actually still under default supply or has switched to a household contract with the default supplier.

The analysis for 2015 is based on data provided by 768 DSOs and 998 suppliers. Under the StromGVV, default suppliers have the right to disconnect supplies to customers, in particular upon failure to fulfil payment obligations of at least €100 and after appropriate notice has been given.

Compared with the prior year, the number of disconnections carried out on behalf of the local default supplier has declined to 331,272. Overall, there were roughly 20,000 fewer disconnections at meter points than in the prior year. This figure is based on information from the DSOs, who ultimately carry out the disconnections on behalf of the suppliers. Based on the total number of meter points at the distribution system level in Germany that were included in the monitoring data collection, the market coverage rate for this question was about 99.2%.

In 2015, DSOs reinstated electricity supply for around 300,000 meter points that were disconnected on behalf of the default supplier, compared to 318,000 in the prior year.

The network operators charged their customers an average fee of €49 for disconnecting a supply, with the actual costs charged ranging between €8 and €210. The average fee to household customers for reinstating supplied to a meter point was €52, although the fees charged varied from €7 to €154.

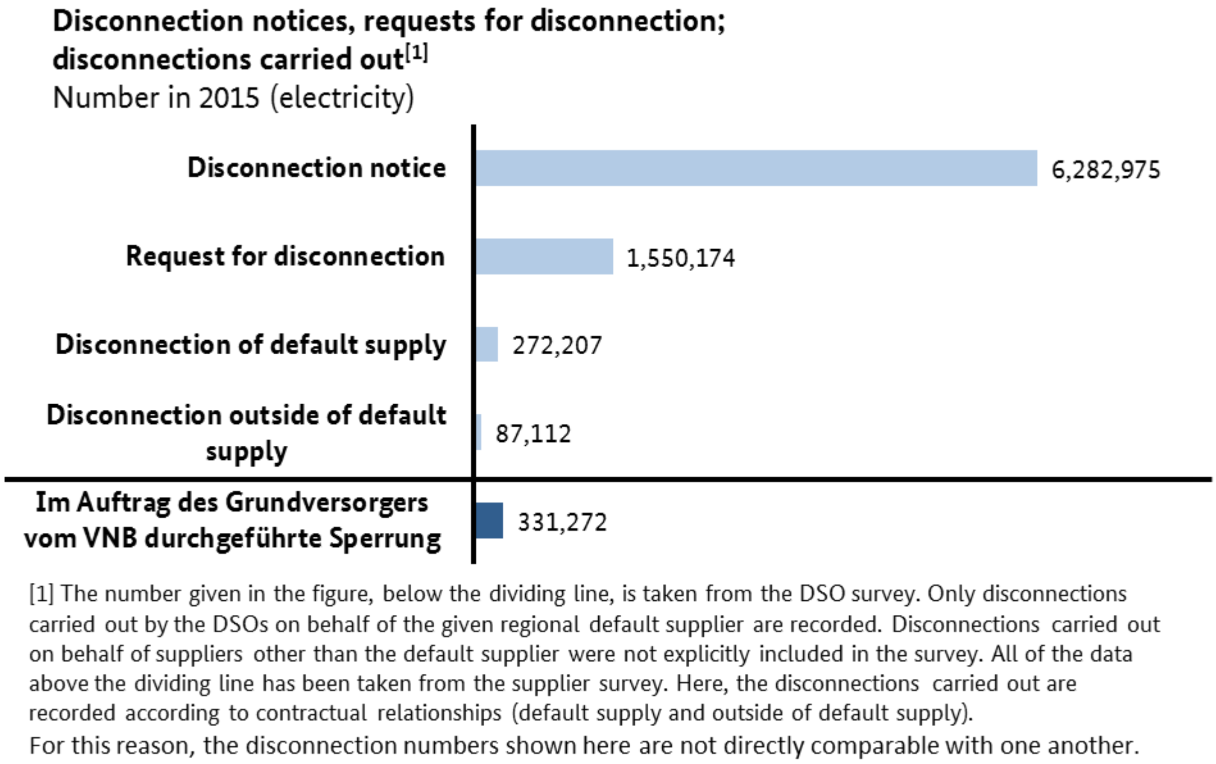

Figure 94: Disconnection notices and requests, actual disconnections

At the same time the suppliers were asked how often in 2015 they had issued disconnection notices to customers who had failed to meet payment obligations, and how often they had requested the network operator responsible to disconnect supplies. The survey is now no longer directed only at default suppliers, but rather at all suppliers. The companies responded that they had issued almost 6.3 million disconnection notices to household customers. According to the data provided by the companies, disconnection notices threatening to cut customers off are sent when the statutory requirements of section 19 StromGVV are met and when, on average, a customer is €119 in arrears. Of the nearly 6.3 million disconnection notices issued, approximately 1.6 million resulted in electricity being disconnected by the pertinent network operator. The suppliers also responded that there were around 272,000 cases of disconnections carried out within the framework of a default supply contract. The average percentage of actual disconnections relative to the respective overall number of customers under default supply was 2.1%. Disconnection outside of a default supply contract was carried out in approximately 87,000 cases. Ultimately, network operators thus carried out 359,000 actual disconnections (within and outside of default supply contractual terms). Of the nearly 6.3 million disconnection notices issued by suppliers, around 25% lead to a disconnection request. In just under 6% of the nearly 6.3 million cases of disconnection notices did the respective network operator actually cut off the supply. This corresponds to a rate of 0.8% of all meter points of household customers in Germany.

According to information provided by the suppliers, in 2015 the ratio between total disconnections and the number of household customers affected was 1 to 0.9. This means that an estimated 10% of disconnections involved repeat disconnections of the same customers.

3.2 Cash meters and smart card meters

In the 2016 monitoring, distribution system operators and suppliers were surveyed for the second time on prepayment systems in accordance with section 14 StromGVV, such as cash meters or smart card meters. Over the course of 2015, prepayment systems were installed on behalf of default suppliers at about 19,400 offtake points in 362 network areas (2014: around 17,300). In about 4,700 cases (2014: around 4,800), a chip or smart card meter was newly installed in the 2015 calendar year, with about 3,000 such meters being taken out again. This corresponds to figures from the previous year.

3.3 Tariffs, billing and terminations of contract

Section 40(5) EnWG requires suppliers to offer load-based tariffs or time of use tariffs to final consumers of electricity insofar as this is technically feasible and economically reasonable. In the 2015 year under review, nearly 12% of suppliers offered load-based tariffs; this represents a slight increase relative to the prior year 2014, in which approximately 10% of suppliers offered such tariffs. Some 70% of suppliers offered time of use tariffs[81] in 2015 (2014: 74%), with about 13%, as in 2014, offering other tariffs as well.

Section 40(3) EnWG also requires suppliers to offer final consumers monthly, quarterly or half yearly bills. Customer demand for such billing cycles has increased significantly in the 2015 year under review. However, with a total of around 23,000 customer enquiries for billing cycles of less than one year (2014: around 14,000), customer demand for such billing cycles remains low.

Moreover, in 2015, 140 suppliers stated that they carry out other forms of billing for household customers. In approximately 31,000 cases in total, suppliers carried out monthly, quarterly or semi-annual billing. The average fee (including VAT) for each additional billing was around €9 with customer reading and €11 without customer reading.

Despite the number of disconnection notices and supplier requests for disconnection, very few suppliers actually terminate service with their customers. Termination of a default supply contract is only permitted under stringent conditions: there must be no obligation to provide basic services or the requirement for disconnection must have been met repeatedly; also, the termination notice must have been issued due to arrears in payment. In 2015, suppliers terminated about 154,000 contracts with their customers overall (2014: approximately 150,000). The average customer arrears upon a termination of the energy supply contract in 2015 was roughly €175.

4. Price level

For monitoring purposes, suppliers that provide final consumers with electricity in Germany were asked about the retail prices their companies charged on 1 April 2016 for various consumption levels. For the first time, the consumption level for household customers was divided according to the following consumption levels:

- Range I (DA[82]): annual electricity consumption under 1,000 kWh

[81] In particular these included special tariffs for heating electricity and heat pump electricity.

[82] "DA", "DB" and "DC" refer to the consumption bands defined by EUROSTAT.

- Range II (DB): annual electricity consumption between 1,000 and 2,500 kWh
- Range III (DC): annual electricity consumption between 2,500 and 5,000 kWh
- Range IV: annual electricity consumption between 5,000 and 10,000 kWh

Furthermore, as in previous years, two different consumption levels for non-household customers with an annual consumption of 50 MWh and 24 MWh were analysed.

Suppliers were asked to give the overall price in cents per kilowatt hour (ct/kWh) to include the non-variable price components such as the service price, base price and transfer or internal price. The suppliers were asked to break down the final price into individual price components. This includes components that the suppliers cannot control but may vary from one network area to another, including network tariffs, concession fees and charges for billing, metering and meter operations. Ultimately the state-controlled surcharges and taxes were taken into account in the total price, i.e. value added and electricity taxes, surcharges under the EEG, KWKG and section 19(2) StromNEV, and for offshore liability and interruptible loads. After deducting these transitory items from the overall price, the amount remaining is the amount controlled by the supplier, which includes the costs of electricity procurement and distribution, other costs and the supplier's margin.

Both with regard to the overall price and the individual price components, the suppliers were asked to provide their "average" overall prices for the four consumption levels of household consumers for each of the three different contract types. Some of the companies questioned once again drew attention to the fact that they were unable to provide average figures on account of their inter-regional activity and/or customer-specific pricing. Some individual companies separately pointed out that due to the large number of tariffs and/or large number of networks involved, they have selected a specific tariff as being representative.

For household customers, companies were asked to provide data on the price components of four consumption ranges for three different contract types (see page 195):

- default supply contract,
- contract with the default supplier outside of default supply contracts (after switch of contract) and
- contract with a supplier who is not the local default supplier (after the switch of supplier).

The findings are presented separately in the following by contract type or consumption level. To better illustrate any long-term trends, a comparison is made in each case with the prior year's figures – provided they correspond with the consumption level. When comparing the figures as at 1 April 2016 and 1 April 2015, it should be noted that differences in the calculated averages partially fall within the margin of error.

As in the prior year (although not included in earlier price data), non-default suppliers were also included in the companies questioned about prices. With regards to the prices for the 50 MWh per year and 24 GWh per year consumption levels, for the third consecutive year only those suppliers were asked to provide data that served at least one customer whose electricity demand fell below the relevant level of consumption.

4.1 Non-household customers

24 GWh/year consumption category ("industrial customers")

The customer group with an annual consumption in the 24 GWh range consists entirely of interval-metered customers, i.e. generally industrial customers. The wide range of options with regard to contractual arrangements is very important to this customer group. Suppliers generally do not use specific tariff groups for consumers who fall into the 24 GWh/year category but offer customer-specific deals. Their customers include those with a full supply and those whose negotiated consumption (in the amount relevant to this category) represents only part of their procurement portfolio. Supply prices are often indexed against wholesale prices. In some cases, customers themselves are responsible for settling network tariffs with the network operator. In extreme cases, these types of contracts even go so far as to require suppliers to merely provide balancing group management services for customers in terms of the economic result. For high-consumption customers the distinction between retail and wholesale trading can be quite fluid.

Special statutory regulations on the potential reduction of specific price components have a significant impact on individual prices for industrial customers. The main aim of these regulations is to reduce prices for businesses with high electricity consumption. The scale of the charges resulting from price components outside the supplier's control and the corresponding impact on individual prices depend on the maximum possible reduction available to companies in the 24 GWh/year consumption category. However, the price query was based on the assumption that none of the possible reductions applied to the customers concerned (section 63ff. of the EEG, section 19(2) of the StromNEV, section 9(7), paragraph 3 of the KWKG, section 17f of the EnWG).

The 24 GWh/year consumption category was defined as an annual usage period of 6,000 hours (annual peak load of 4,000 kW; medium voltage supply of 10 or 20 kV). Data was collected only from suppliers with at least one customer with an annual consumption between 10 GWh and 50 GWh. This customer profile essentially applied to only a limited group of suppliers. The following price analysis of the consumption category is based on data from 212 suppliers (there were also 212 suppliers in the previous year). Over half of the 212 suppliers had fewer than ten customers with an annual consumption exceeding 24 GWh.

This data was used to calculate the (arithmetic) mean of the total price and the individual price components. The data spread for each price component was also analysed in terms of ranges. The 10th percentile represents the lower limit and the 90th percentile the upper limit of each reported range. This means that the middle 80 per cent of the figures provided by the suppliers are within the stated range. The analysis produced the following results.

Price level for the 24 GWh/year consumption category without reductions on 1 April 2016

	Spread in the 10 to 90 percentile range of the supplier data sorted by size in ct/kWh	Average (arithmetic) in ct/kWh
Price components outside the supplier's control		
Net network charge	1.32 – 2.81	2.03
Metering, billing, meter operation	0.00 – 0.02	0.03[1]
Concession fee	0.11 – 0.11	0.11[2]
EEG surcharge	6.35	6.35
Other surcharges[1]	0.15	0.15
Electricity tax	2.05	2.05
Price component controlled by the supplier (remaining balance)	2.46 – 4.51	**3.48**
Total price (excluding VAT)	12.91 – 15.69	14.21

[1] Some 90 per cent of suppliers quoted a figure of 0.024 ct/kWh or less. Since a small number of suppliers quoted a much higher figure, the arithmetic mean is over 0.024 ct/kWh.
[2] Over 90 per cent of suppliers quoted a concession fee of 0.11 ct/kWh. Fewer than 20 suppliers quoted a lower figure and fewer than five suppliers quoted a higher figure.
[3] KWKG (0.06 ct/kWh), section 19(2) of the StromNEV (0.06 ct/kWh), offshore liability (0.03 ct/kWh)

Table 47: Price level on 1 April 2016 for the 24 GWh/year consumption category without reductions

The arithmetic mean of the price component controlled by the supplier has declined again, falling by 0.71 ct/KWh from 4.19 ct/kWh to 3.48 ct/kWh (down by 0.42 ct/kWh year-on-year).[83] By contrast, surcharges increased to 6.50 ct/kWh in total (including an EEG surcharge of 6.35 ct/kWh), making them 0.17 ct/kWh higher than the previous year. The average net network tariff was 2.03 ct/KWh and lower than in the previous year (2.06 ct/kWh in 2015). The average overall price (excluding VAT and excluding possible reductions) of 14.21 ct/kWh is 0.59 ct/kWh below the arithmetic mean of the figures collected in the previous year.

[83] A comparison of these averages has to take account of the data spread mentioned above.

By definition, these prices were based on the assumption that (industrial) customers with an annual consumption of 24 GWh were not eligible for any of the statutory reductions available. In the consumption category thus defined, cost items outside the supplier's control accounted for a total of 10.72 ct/kWh, or about 75 per cent, of the overall price. However, electricity consumers who meet the requirements of the applicable laws and regulations can take advantage of reductions in network tariffs, concession fees, electricity tax and the surcharges under the EEG, KWKG, section 19 of the StromNEV and section 17f. of the EnWG. If all of these possible reductions are applied, the price component outside the supplier's control could be reduced from over 10 ct/kWh to below 1 ct/kWh.[84]

The EEG surcharge offers the greatest scope for possible reductions. It can be reduced by up to 95% for customers with an annual consumption of 24 GWh depending on the specific case; the actual level of possible reduction depends on several factors in accordance with section 64 of the EEG. Under section 19, paragraph 2, sentence 1 of the StromNEV, the net network charge may be reduced by up to 80%.[85] The electricity tax may be waived, refunded or reimbursed in full in accordance with section 9a of the StromStG. The concession fees under section 2, paragraph 4, sentence 1 of the KAV and the surcharges under section 9 of the KWKG and section 17f. of the EnWG offer significantly less scope for a reduction of the overall price in quantitative terms. No monitoring data was collected on the actual extent to which industrial customers make use of each of the possible reductions. As a result, the monitoring data cannot be used to draw conclusions on the average price for industrial customers.

Possible reductions for the 24 GWh/year consumption category on 1 April 2016

	Anticipated or collected figure in the price query in ct/kWh	**Amount of possible reduction in ct/kWh**	Remaining balance in ct/kWh
EEG surcharge	6.35	-6.04	0.31
Electricity tax	2.05	-2.05	0.00
Net network charge	2.03	1.63	0.41
Other surcharges	0.15	-0.06	0.09
Concession fee	0.11	-0.11	0.00
Total	**10.69**	**-9.88**	**0.81**

Table 48: Possible reductions for the 24 GWh/year consumption category on 1 April 2016

[84] There are different eligibility requirements for the various possible reductions. During monitoring, no data was collected on whether there are any cases in practice where all the possible maximum reductions are, or can be, fully exploited.

[85] The even greater reductions possible under section 19, paragraph 2, sentence 2 of the StromNEV are not relevant to the 24 GWh/year consumption category since it has been defined as comprising 6,000 hours of use.

50 MWh/year consumption category ("commercial customers")

The 50 MWh/year category described below was defined as an annual usage period of 1,000 hours (annual peak load of 50 kW; low voltage supply of 0.4 kV). An annual consumption of 50 MWh is 14 times higher than the 3,500 kWh category ("household customers") and is also two thousandths of the 24 GWh/year consumption category. Given the moderate level of consumption, individual contractual arrangements play a significantly smaller role than in the 24 GWh/year consumption category. Suppliers were asked to make a plausible estimate of the charges for customers whose consumption profile is similar to that of the consumption category based on the terms and conditions that applied on 1 April 2016. Data was requested from suppliers that had at least one customer with an annual consumption between 10 MWh and 100 MWh. Since this consumption level is below the 100 MWh threshold above which network operators are required to use interval metering, it is safe to assume that in this category consumption is measured using a standard load profile.

The following price analysis of the consumption category was based on data from 871 suppliers (827 in the previous year). The data was used to calculate the (arithmetic) means of the overall price and of the individual price components. The data spread for each price component was also analysed in terms of ranges that included the middle 80% of the figures provided by the suppliers. The analysis produced the following results.

Price level for the 50 MWh/year consumption category on 1 April 2016

	Spread in the 10 to 90 percentile range of the supplier data sorted by size in ct/kWh	Average (arithmetic) in ct/kWh	Percentage of total price
Price components outside the supplier's control			
Net network charge	4.02 - 7.18	5.50	26%
Metering, billing, meter operation	0.03 - 1.31	0.35	2%
Concession fee	0.11 – 1.59	0.93	4%
EEG surcharge	6.35	6.35	30%
Other surcharges[1]	0.86	0.86	4%
Electricity tax	2.05	2.05	10%
Price component controlled by the supplier (remaining balance)	3.03 - 7.28	5.15	24%
Total price (excluding VAT)	18.45 - 23.45	21.2	

[1] KWKG (0,44 ct/kWh), section 19(2) of the StromNEV (0.38 ct/kWh), offshore liability (0.04 ct/kWh)

Table 49: Price level for the 50 MWh/year consumption category on 1 April 2016

The remaining balance controlled by the supplier decreased again, this time by 0.93 ct/kWh (0.31 ct/kWh in the previous year) from an average 6.08 ct/kWh to 5.15 ct/kWh.[86] The total of other surcharges alone (excluding the renewable energy surcharge) rose by 0.41 ct/kWh to 0.86 ct/kWh; the renewable energy surcharge increased by 0.17 ct/kWh to 6.35 ct/kWh. The net network charge also increased by 0.06 ct/kWh to 5.50 ct/kWh. The average overall price (excluding VAT) of 21.20 ct/kWh, however, is 0.26 ct/kWh below the arithmetic mean of the previous year's figure (21.47 ct/kWh). Therefore, an average of about 76 per cent (72 per cent in the previous year) of the overall price in this consumption category relates to cost items outside the supplier's control (network tariffs, metering, surcharges, electricity tax and concession fee). Only about 24 per cent (28 per cent in the previous year) refers to price elements that provide scope for commercial decisions.

[86] A comparison of these averages has to take account of the data spread mentioned above.

4.2 Household customers

In this section, retail prices and price components for household customers are examined and set out in tabular form as the volume weighted averages for different types of tariff in four consumption bands. The suppliers of electricity to final consumers in Germany provided data for the following consumption bands for low voltage supply (0.4 kV):

- band I (DA[87]): annual consumption below 1,000 kWh;
- band II (DB): annual consumption between 1,000 kWh and 2,500 kWh;
- band III (DC): annual consumption between 2,500 kWh and 5,000 kWh;
- band IV: annual consumption between 5,000 kWh and 10,000 kWh.

Prices were looked at for customers on default tariffs, customers on contracts with the default supplier outside of default supply contracts (having switched tariff), and customers served by a supplier other than their regional default supplier (having switched supplier). In addition, the volume weighted price across all types of tariff for band III was calculated to provide continuity and enable a comparison with previous years. It is important to note that the average network tariffs listed for each type of tariff are calculated using the figures provided by the suppliers, which in turn are the charges averaged over all the networks supplied. This results in a different network charge for each tariff.

In addition, the arithmetic mean of the total prices and the range of the prices for the different tariffs in each consumption band are given in a separate table following each table of volume weighted prices. These figures relate to the range between 10% and 90% of the prices quoted by the suppliers when arranged in order of size.

The use of new consumption bands is due to a change in the methodology used by Eurostat to collect price data.

The following tables show the results of the data analysis for band I:

[87] "DA", "DB" and "DC" refer to the consumption bands defined by EUROSTAT.

Average volume weighted price per tariff for household customers with an annual consumption below 1,000 kWh (band I; Eurostat band DA) as of 1 April 2016 (ct/kWh)

Price component	Default tariff	Contract with the default supplier outside of default supply contracts	Special tariff with other supplier
Energy procurement, supply, other costs and margin	11.74	6.34	7.89
Net network charge	9.52	8.42	10.68
Billing charge	2.16	1.83	1.70
Metering charge	0.60	0.61	0.51
Meter operation charge	1.71	1.48	1.38
Concession fee	1.78	1.77	1.52
Renewable energy surcharge	6.35	6.35	6.35
CHP surcharge	0.45	0.45	0.45
Section 19 surcharge	0.38	0.38	0.38
Offshore liability surcharge	0.04	0.04	0.04
Electricity tax	2.05	2.05	2.05
Value added tax	6.98	10.06	6.26
Total	**43.73**	**39.77**	**39.21**

Table 50: Average volume weighted price per tariff for household customers in consumption band I as of 1 April 2016

Arithmetic mean and range of prices per tariff for household customers with an annual consumption below 1,000 kWh (band I; Eurostat band DA)

Household customers (range between 10% and 90% of suppliers' quoted prices arranged in order of size) **1 April 2016 (ct/kWh)**	**Default tariff**	**Contract with the default supplier outside of default supply contracts**	**Special tariff with other supplier**
Arithmetic mean	39.23	36.11	35.09
Range	29.09 - 50.38	27.31 - 44.82	25.85 - 44.43

Table 51: Arithmetic mean and range of prices per tariff for household customers in consumption band I as of 1 April 2016

It is important to note that suppliers are asked to give the prices to include the fixed price components such as the service, base and internal prices. The higher per kilowatt hour prices calculated for customers with a relatively low consumption are due to the combination of the lower consumption levels and the fixed price components such as the base price.

The volume weighted prices were calculated using the consumption volumes for 2015 and the prices as of 1 April 2016.

The following tables show the results of the data analysis for band II:

Average volume weighted price per tariff for household customers with an annual consumption between 1,000 kWh and 2,500 kWh (band I; Eurostat band DB) as of 1 April 2016 (ct/kWh)

Price component	Default tariff	Contract with the default supplier outside of default supply contracts	Special tariff with other supplier
Energy procurement, supply, other costs and margin	8.60	7.17	6.35
Net network charge	6.62	6.24	7.31
Billing charge	0.67	0.61	0.56
Metering charge	0.19	0.20	0.16
Meter operation charge	0.54	0.50	0.46
Concession fee	1.78	1.76	1.55
Renewable energy surcharge	6.35	6.35	6.35
CHP surcharge	0.45	0.45	0.45
Section 19 surcharge	0.38	0.38	0.38
Offshore liability surcharge	0.04	0.04	0.04
Electricity tax	2.05	2.05	2.05
Value added tax	5.25	4.89	4.88
Total	**32.91**	**30.62**	**30.52**

Table 52: Average volume weighted price per tariff for household customers in consumption band II as of 1 April 2016

Arithmetic mean and range of prices per tariff for household customers with an annual consumption between 1,000 kWh and 2,500 kWh (band II; Eurostat band DB)

Household customers (range between 10% and 90% of suppliers' quoted prices arranged in order of size) **1 April 2016** **(ct/kWh)**	**Default tariff**	**Contract with the default supplier outside of default supply contracts**	**Special tariff with other supplier**
Arithmetic mean	31.71	30.03	29.06
Range	27.36 - 34.87	26.05 - 32.86	24.12 - 32.74

Table 53: Arithmetic mean and range of prices per tariff for household customers in consumption band II as of 1 April 2016

The use of different consumption bands instead of an annual consumption of 3,500 kWh makes it difficult to compare the prices with previous years. Band III is more or less comparable to the 3,500 kWh annual consumption band used in previous years. The following tables show the results of the data analysis for band III:

Average volume weighted price per tariff for household customers with an annual consumption between 2,500 kWh and 5,000 kWh (band III; Eurostat band DC) as of 1 April 2016 (ct/kWh)

Price component	Default tariff	Contract with the default supplier outside of default supply contracts	Special tariff with other supplier
Energy procurement, supply, other costs and margin	8.06	6.74	5.90
Net network charge	6.00	6.13	6.40
Billing charge	0.35	0.31	0.31
Metering charge	0.09	0.08	0.08
Meter operation charge	0.27	0.24	0.22
Concession fee	1.72	1.62	1.49
Renewable energy surcharge	6.35	6.35	6.35
CHP surcharge	0.45	0.45	0.45
Section 19 surcharge	0.38	0.38	0.38
Offshore liability surcharge	0.04	0.04	0.04
Electricity tax	2.05	2.05	2.05
Value added tax	4.89	4.63	4.50
Total	**30.63**	**29.01**	**28.17**

Table 54: Average volume weighted price per tariff for household customers in consumption band III as of 1 April 2016

Arithmetic mean and range of prices per tariff for household customers with an annual consumption between 2,500 kWh and 5,000 kWh (band III; Eurostat band DC)

Household customers (range between 10% and 90% of suppliers' quoted prices arranged in order of size) **1 April 2016** **(ct/kWh)**	**Default tariff**	**Contract with the default supplier outside of default supply contracts**	**Special tariff with other supplier**
Arithmetic mean	29.85	28.16	27.78
Range	26.99 - 32.46	25.87 - 30.30	24.24 - 30.31

Table 55: Arithmetic mean and range of prices per tariff for household customers in consumption band III as of 1 April 2016

A direct comparison of the three types of tariff – default tariff, contract with the default supplier outside of default supply contracts, and tariff with a supplier other than the regional default supplier – makes it clear that default tariffs are still the most expensive option for customers with an annual consumption of between 2,500 kWh and 5,000 kWh. At the same time, a comparison is only possible to a limited extent. While the average consumption in 2015 for customers on default tariffs was around 2,202 kWh, the average for customers on contracts with the default supplier outside of default supply contracts and customers who had switched from their default supplier was about 40% higher at around 3,089 kWh.

Household customers can still make savings by switching tariff and, as a rule, even more by switching supplier. A comparison of the average prices for the three types of tariff shows that throughout the period since 2008 default tariffs were the most expensive option for household customers. Prices for customers on contracts with the default supplier outside of default supply contracts were consistently cheaper over the same period than for those on default tariffs. On average, prices for customers who have switched from their regional default supplier to a new supplier are the cheapest. In eight of the nine years in the period since 2008, average prices for customers who had switched from their regional default supplier were – to a greater or lesser extent – lower than those for customers who had switched tariff with their existing default supplier.

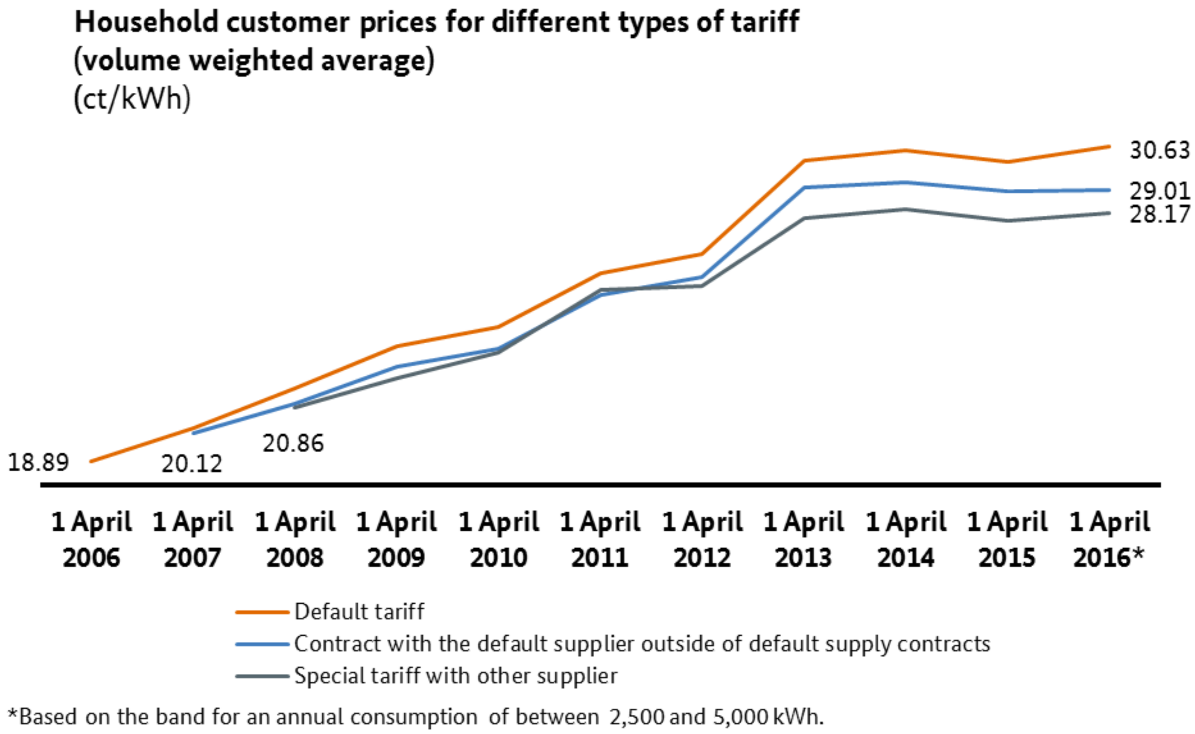

Figure 95: Household customer prices for different types of tariff

The volume weighted average price component that can be controlled by the supplier, including energy procurement and supply costs, as of 1 April 2016 was 8.06 ct/kWh for customers on default tariffs and thus nearly 37% higher than that for customers who had switched from their regional default supplier at 5.90 ct/kWh (as calculated from the data provided). In 2015, the difference between the two groups was only 30%. The average price component for energy procurement, supply, other costs and the margin for customers on contracts with the default supplier outside of default supply contracts was 6.74 ct/kWh, compared to 7.43 ct/kWh in the previous year, and thus around 16% lower than that for customers on default tariffs. Any direct comparison of these figures must take into account further differences between the three customer groups other than their different consumption levels. For instance, default contracts have shorter notice periods and on average a higher risk of non-payment. These risk costs are also included in the price component controlled by the supplier. Lastly, a degree of inaccuracy owing to the system of data collection and analysis also has to be taken into account. The following graph provides a detailed overview of the trend.

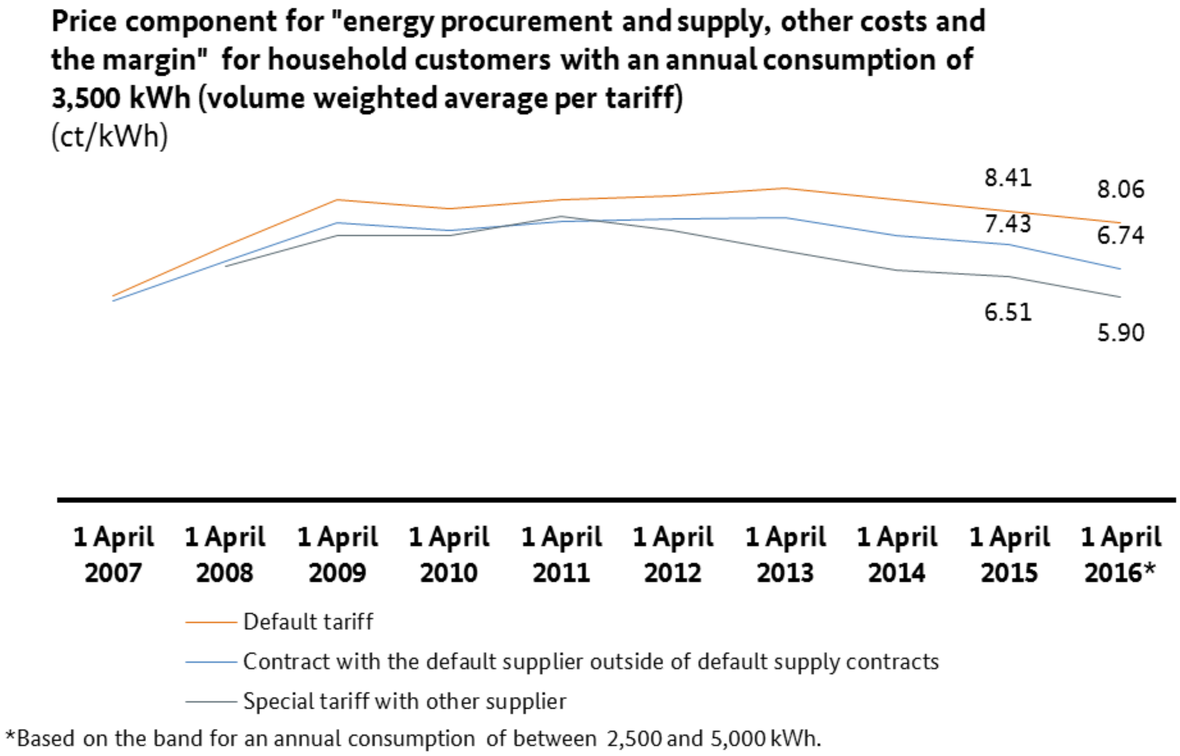

Figure 96: Price component for "energy procurement and supply, other costs and the margin" for household customers with an annual consumption of 3,500 kWh 2007 to 2016 (volume weighted average per tariff)

Band IV as used in the survey represents household customers with an above-average annual consumption of between 5,000 kWh and 10,000 kWh. The following tables show the results of the data analysis for band IV:

Average volume weighted price per tariff for household customers with an annual consumption between 5,000 kWh and 10,000 kWh (band IV) as of 1 April 2016 (ct/kWh)

Price component	Default tariff	Contract with the default supplier outside of default supply contracts	Special tariff with other supplier
Energy procurement, supply, other costs and margin	7.52	5.78	5.55
Net network charge	5.58	5.43	6.02
Billing charge	0.17	0.17	0.16
Metering charge	0.05	0.06	0.05
Meter operation charge	0.15	0.16	0.13
Concession fee	1.75	1.72	1.49
Renewable energy surcharge	6.35	6.35	6.35
CHP surcharge	0.45	0.45	0.45
Section 19 surcharge	0.38	0.38	0.38
Offshore liability surcharge	0.04	0.04	0.04
Electricity tax	2.05	2.05	2.05
Value added tax	4.65	4.29	4.30
Total	**29.12**	**26.87**	**26.96**

Table 56: Average volume weighted price per tariff for household customers in consumption band IV as of 1 April 2016

Arithmetic mean and range of prices per tariff for household customers with an annual consumption between 5,000 kWh and 10,000 kWh (band IV)

Household customers (range between 10% and 90% of suppliers' quoted prices arranged in order of size) 1 April 2016 **(ct/kWh)**	**Default tariff**	**Contract with the default supplier outside of default supply contracts**	**Special tariff with other supplier**
Arithmetic mean	28.63	26.89	26.58
Range	25.73 - 30.99	24.44 - 28.93	23.61 - 29.04

Table 57: Arithmetic mean and range of prices per tariff for household customers in consumption band IV as of 1 April 2016

Band IV, with its high consumption level of between 5,000 kWh and 10,000 kWh, has the lowest per kilowatt hour prices of all four bands for all three types of tariff. Of particular note is the fact that on average customers who have switched tariff with their existing default supplier have the lowest prices and not customers who have switched from their regional default supplier to a new supplier.

Non-default tariffs can have a range of features other than the total price that suppliers use to compete for customers. These features may offer greater security to the customer (eg guaranteed prices) or to the supplier (eg payment in advance, minimum contract period), which is then compensated for between the parties elsewhere (total price).

The suppliers were questioned specifically about any such features. Minimum contract periods and fixed prices were found to be especially common. Average minimum contract periods for special tariffs are 10 months while fixed prices are offered for an average period of 14 months.

The following table provides an overview of the various special bonuses and schemes that are offered by electricity suppliers:

Special bonuses and schemes for household customers

As of 1 April 2016	Household customers			
	Contract with the default supplier outside of default supply contracts		Special tariff with other supplier	
	No of tariffs	Average scope	No of tariffs	Average scope
Minimum contract period	357	10 months	403	10 months
Price stability	304	14 months	375	14 months
Advance payment	59	11 months	38	10 months
One-off bonus payment	94	€58	161	€61
Free kilowatt hours	4	250 kWh	9	189 kWh
Deposit	7	-	3	-
Other bonuses and special arrangements	93	-	105	-

Table 58: Special bonuses and schemes for household customers

The number and various possible combinations of the elements that form the prices make it difficult to compare the wide range of competitive tariffs. The average price for all household customers in consumption band III is taken as an indicator. A volume weighted average across all the tariffs was calculated by weighting the individual prices for the three types of tariff using the relevant consumption volumes. The average price calculated as of 1 April 2016 was 29.80 ct/kWh. The following table provides a detailed breakdown of the individual price components.

Average volume weighted price across all tariffs for household customers with an annual consumption between 2,500 kWh and 5,000 kWh (band III; Eurostat band DC) as of 1 April 2016 (ct/kWh)

Price component	Volume weighted average across all tariffs (ct/kWh)	Percentage of total price (%)
Energy procurement, supply, other costs and margin	7.35	24.7
Net network charge	6.11	20.5
Billing charge	0.34	1.1
Metering charge	0.09	0.3
Meter operation charge	0.25	0.8
Concession fee	1.65	5.5
Renewable energy surcharge	6.35	21.3
CHP surcharge	0.45	1.5
Section 19 surcharge	0.38	1.3
Offshore liability surcharge	0.04	0.1
Electricity tax	2.05	6.9
Value added tax	4.76	16.0
Total	**29.80**	**100**

Table 59: Average volume weighted price across all tariffs for household customers in consumption band III as of 1 April 2016

The following diagram shows the percentage distribution of the individual price components.

Breakdown of the retail price for household customers with an annual consumption between 2,500 and 5,000 kWh as of 1 April 2016 (volume weighted average across all tariffs)
(%)

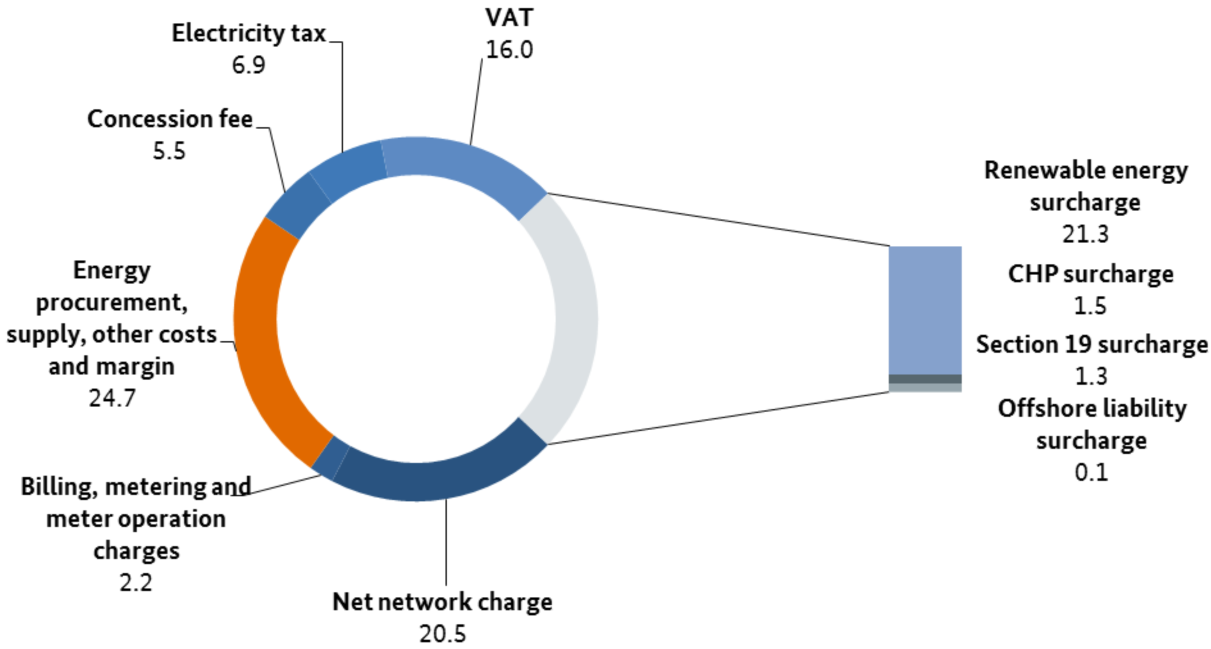

Figure 97: Breakdown of the price for household customers in consumption band III as of 1 April 2016 (volume weighted average across all tariffs)

The net network charge accounts for 20.5% of the total electricity price for household customers. The charges for billing, metering and meter operation account for around 2.2% of the total price, while energy procurement and supply costs account for 24.7%. Taxes (electricity and VAT) account for 22.9% of the price. Surcharges and levies (surcharges payable under the Renewable Energy Sources Act, the Combined Heat and Power Act and section 19 of the Electricity Network tariffs Ordinance, the offshore liability surcharge and concession fees) together amount to approximately 30%, with the renewable energy surcharge having by far the largest share at 21.3%. In total, surcharges, taxes and levies account for more than 52% of the average electricity price for household customers.

The following table shows the change in the volume weighted electricity price across all tariffs from 1 April 2015 to 1 April 2016. In 2016, the electricity price increased slightly by 0.69 ct/kWh or about 2%. This year's price survey was different in that no surcharges payable under section 18 of the Interruptible Loads Ordinance (AbLaV) were published. According to section 19 second sentence of the Ordinance, the Ordinance was due to expire with effect from 1 January 2016. Since no extension of the existing Ordinance was planned and no new Ordinance with effect from 1 January 2016 was anticipated when the interruptible loads surcharges for 2016 were due to be published (on 15 October 2015), the TSOs did not publish any surcharges and therefore no data will be collected for the time being.

This will not initially be affected by the decision taken by the German Bundestag on 17 December 2015 to extend the (then) existing Ordinance until 30 June 2016; however, any costs incurred under the Ordinance may need to be priced into a subsequent surcharge.

Change in volume weighted price for household customers across all tariffs from 1 April 2015 (annual consumption 3,500 kWh) to 1 April 2016 (annual consumption 2,500-5,000 kWh)

	Volume weighted average across all tariffs (ct/kWh)	Change relative to the level of the price component	
		(ct/kWh)	(%)
Energy procurement, supply, other costs and margin	7.35	-0.22	-3
Net network charge	6.11	0.17	3
Billing charge	0.34	0.01	2
Metering charge	0.09	0.00	0
Meter operation charge	0.25	0.02	9
Concession fee	1.65	0.02	1
Renewable energy surcharge	6.35	0.18	3
CHP surcharge	0.45	0.20	44
Section 19 surcharge	0.38	0.14	37
Offshore liability surcharge	0.04	0.09	225
Interruptible loads surcharge	0.00	-0.01	-100
Electricity tax	2.05	0.00	0
Value added tax	4.76	0.11	2
Total	29.80	0.69	2

Table 60: Change in volume weighted price for household customers across all tariffs from 1 April 2015 (annual consumption 3,500 kWh) to 1 April 2016 (annual consumption 2,500-5,000 kWh)

The changes in the essential price components of the volume weighted electricity price for household customers are presented below. First, a look at the network tariffs shows another increase in 2016[88] – up 0.20 ct/kWh or just over 3% on 2015 – following successive decreases in the period up to 2011. Network tariffs have risen by 0.99 ct/kWh or about 17% over the eight-year period since 2006. In 2013, network tariffs rose above the level in the reference year (2007) and have continued to rise since. This analysis relates to the network tariffs excluding the surcharge under section 19 of the Electricity Network tariffs Ordinance of 0.38 ct/kWh.[89]

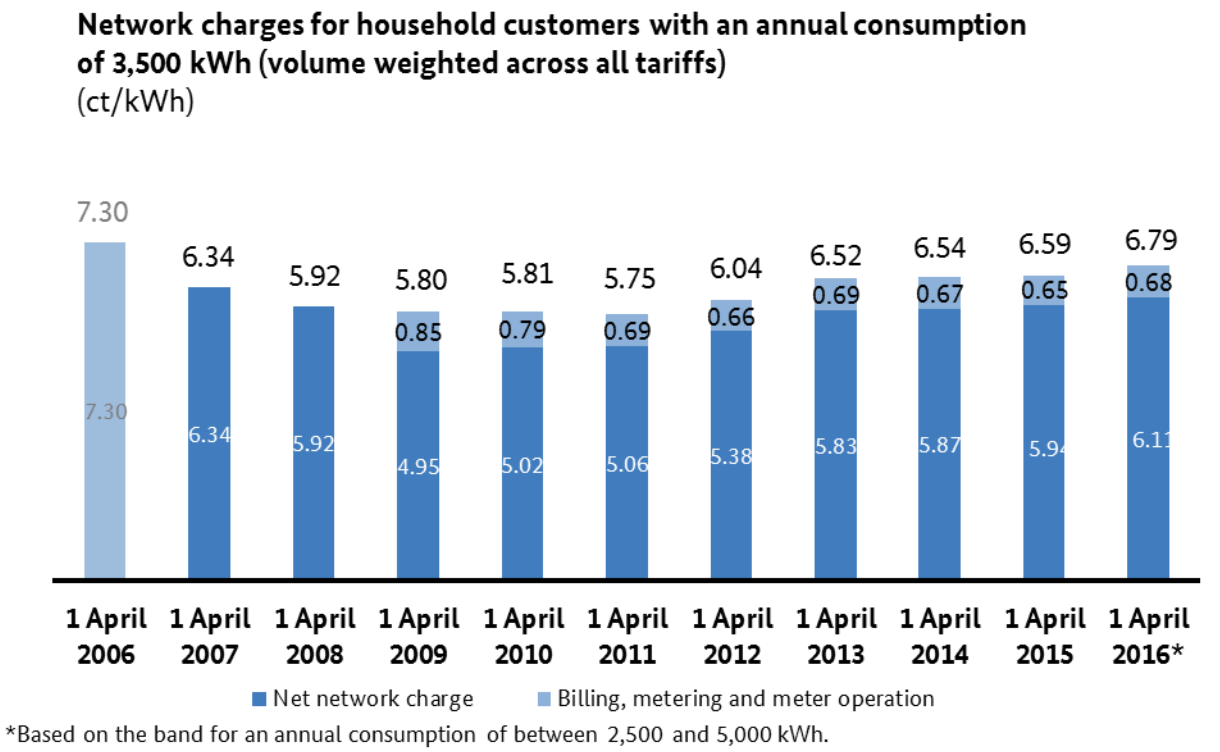

Figure 98: Network tariffs for household customers, including charges for billing, metering and meter operation

Next, an overview is given of the changes in the remaining price components of the volume weighted price for household customers across all tariffs. There has been a continued increase since 2011 in the percentage of the electricity price accounted for by network tariffs (including billing, metering and meter operation). There has also been a noticeable increase in taxes and levies over the past four years. The price component for energy procurement, supply, other costs and the margin remained more or less stable in the period from 2009 to 2013, while there was a rise in the period from 2007 to 2009. There was another decrease as of 1 April 2016 in the price components controlled by the supplier, down 0.22 ct/kWh or nearly 3% on a year earlier. This decrease could be related in particular to the continued drop in wholesale prices (see I.F on page 153). It appears that these low prices are slowly being passed on to household customers on all three types of tariff.

[88] Net network charges include charges for billing, metering and meter operation.

[89] The surcharge under section 19 of the Electricity Network Charges Ordinance was included in the network charges up to 2011 but since 2012 has been reported separately.

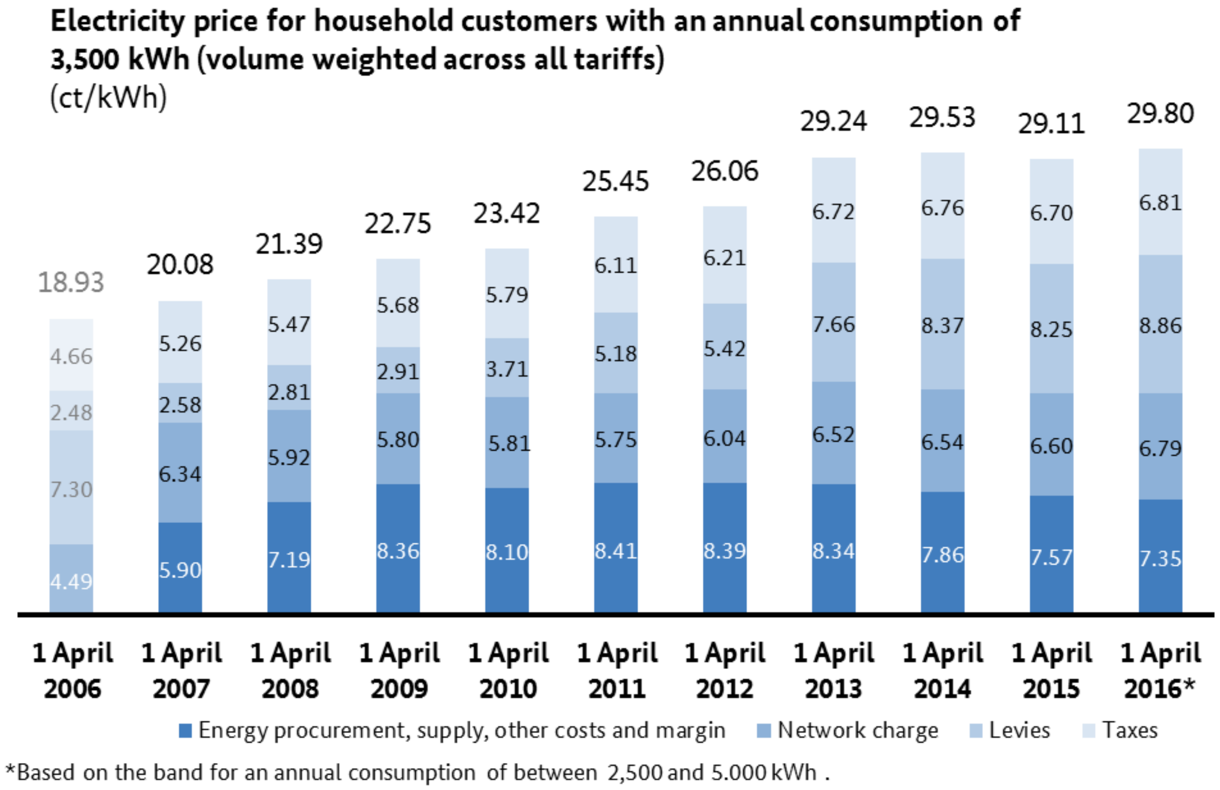

Figure 99: Volume weighted electricity price for household customers across all tariffs

A particular contributing factor to the increase in levies is the renewable energy surcharge. This surcharge is used to balance out the renewable energy costs incurred by the TSOs (in particular the feed-in payments to installation operators) and the income generated from selling renewable energy on the spot market. The surcharge is announced by the TSOs on 15 October each year for the following calendar year. The Bundesnetzagentur ensures that the surcharge has been determined properly. The renewable energy surcharge for 2016 rose to 6.35 ct/kWh.[90] However, the increase in the overall price means that the percentage of the total electricity price accounted for by the surcharge remains at around 21%. In 2010, the renewable energy surcharge was only 2.05 ct/kWh and accounted for around 9% of the total price. The following graph shows the changes in the surcharge in more detail.

[90] The renewable energy surcharge for 2017 has been set at 6.88 ct/kWh.

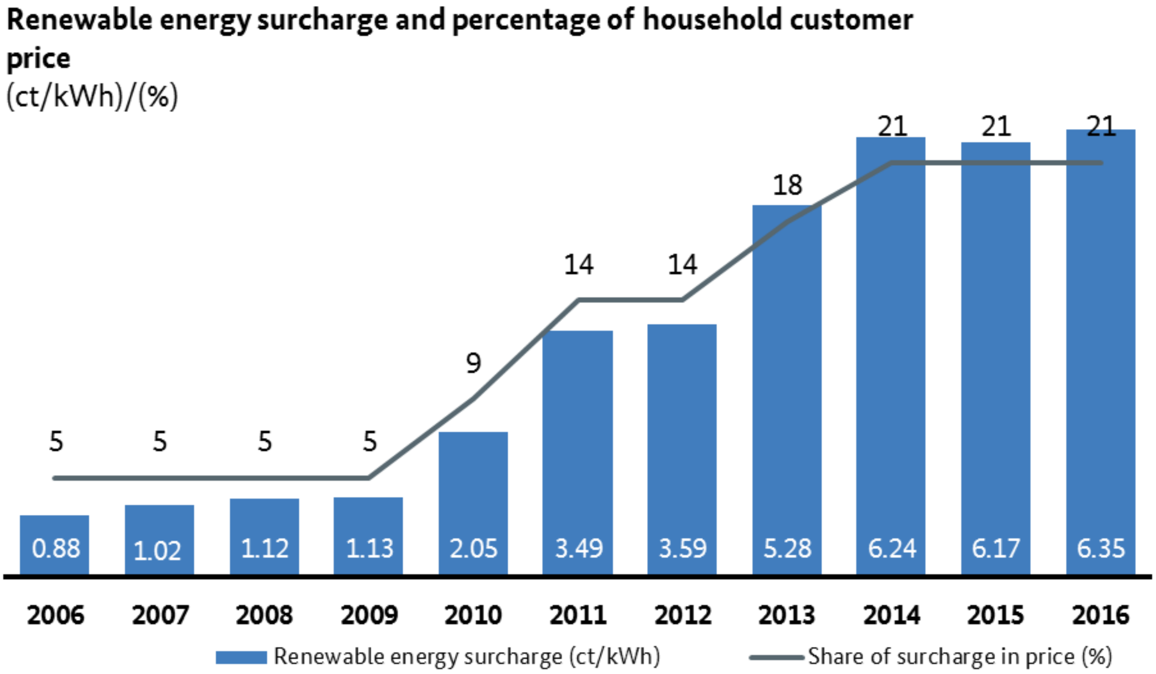

Figure 100: Renewable energy surcharge and percentage of household customer price

Finally, the changes in the energy procurement, supply, other costs and margin price component in the period from 2006 to 2016 are presented.[91] There was a year-on-year decrease of 0.22 ct/kWh in the price component controlled by the supplier from 7.57 ct/kWh to 7.35 ct/kWh; the percentage of the volume weighted total price for electricity across all tariffs accounted for by the price component also decreased from 26% to just under 25%. Hence the percentage of the overall price that can be influenced by a supplier's business decisions has decreased once again. The following graph shows the price component for energy procurement, supply, other costs and the margin in each of the years from 2006 to 2016.

[91] A change to the data collected from the suppliers means that since 2014 the individual price components for energy procurement and supply have not been reported separately.

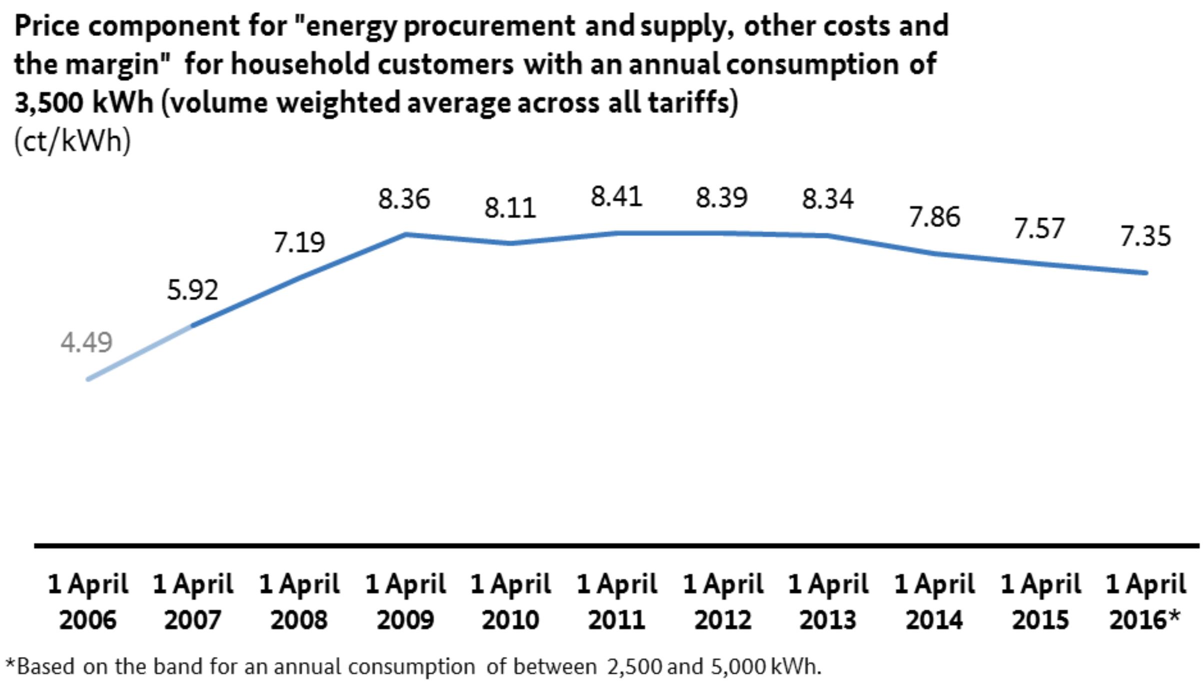

Figure 101: "Energy procurement and supply, other costs and the margin" price component for household customers

5. Electricity for heating

During this year's monitoring, data on contract arrangements, supplier switching and price levels for heating electricity (night storage heating and heat pumps) was once again collected from suppliers and distribution system operators.

Compared to the previous year, heating electricity consumption increased slightly in the reporting year 2015. According to the volumes reported by a total of 876 suppliers, about 14.4 TWh of heating electricity was supplied to just under 2.1 million metering points during the reporting period. This corresponds to an average supply of just under 7,050 kWh per metering point in 2015. The previous year's figure was just over 6,600 kWh per metering point (13.6 TWh at 2.1 million metering points). These figures have to be seen in the light of the particularly mild weather in 2014.

According to the data provided by the suppliers, just under 12.1 TWh of electricity was supplied for night storage heating. On average, about 7,200 kWh per year were supplied to 1.6 million night storage metering points. The volume of electricity supplied to the approximately 377,000 metering points for heat pumps was just over 2.3 TWh, resulting in an average of about 6,200 kWh per year. Night storage heating accounts for the largest share of consumption (84 per cent in terms of volume and 82 per cent of metering points). Heat pumps continue to play a minor role (16 per cent in terms of volume and 18 per cent of metering points). Almost all heating electricity suppliers serve both night storage customers and heat pump customers. Several suppliers explained that they were not able to provide an accurate breakdown of the volumes and metering points by night storage heating or heat pumps[92] and therefore gave an estimate of the breakdown or entered the total in one of the two categories. 758 of the 876 electric heating suppliers provided data on volume and metering points for both night storage heating and heat pumps.

The data on consumption volumes and the number of metering points collected from the distribution system operators during monitoring roughly corresponds to the results of the supplier surveys. According to the data provided by 724 distribution system operators, a total of 13.5 TWh was supplied to just under 2.1 million metering points (night storage heating and heat pumps) in 2015.

5.1 Contract structure and supplier switching

As in previous years, suppliers were asked how their heating electricity supply was distributed across network areas where they were the default supplier and network areas where they were not the default supplier. The survey refers to the default supplier status of the legal entity supplying the electricity, which excludes company affiliations (for more detail see section I.G.2). In contrast to section I.G.2, the evaluation of the heating electricity supplied by the local default supplier does not differentiate between “default supply contracts” and “contracts with default supplier outside the default supply” because in the Bundeskartellamt's view heating electricity is always supplied under special contracts.[93]

The percentage of heating electricity supplied in 2015 by a legal entity other than the local default supplier is at a similar level as in the previous year. About 885 GWh, or 6.2 per cent, of the entire heating electricity supply in 2015 came from suppliers other than the default supplier. However, the number of heating electricity metering points not served by the default supplier increased dramatically. About 6.6 per cent of heating electricity metering points (104,000 night storage heaters and 30,000 heat pumps) were not, or no longer, supplied by the local default supplier in 2015. This figure was still about 4.3 per cent (metering points) and 5.7 per cent (volume) in the previous year.

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[92] One of the reasons given for this was that there was no (price) difference between night storage heaters and heat pumps in terms of sales.

[93] Cf. Bundeskartellamt, Heizstrom – Überblick und Verfahren, (Electric heating - overview and proceedings), September 2010, pp. 9-10.

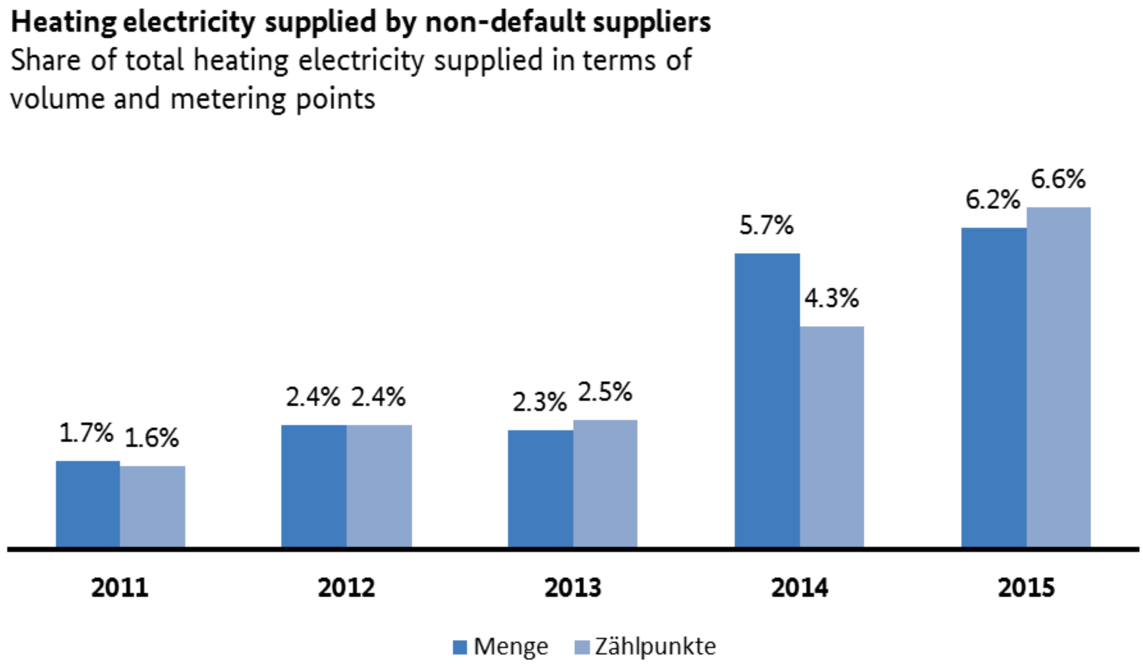


Figure 102: Percentage of heating electricity volume and metering points supplied by a supplier other than the local default supplier

According to the data provided by the distribution system operators, supplier switching rates have risen steadily in the heating electricity sector. The data shows that there was a change of supplier at about 58,000 heating electricity metering points (just under 43,000 in the previous year); these metering points accounted for about 364 GWh in 2015. This represents a switching rate of 2.7 per cent of the consumption volume and 2.8 per cent of metering points. The trend over the years shows that switching rates for heating electricity have risen slightly. The switching rate by metering points was 2.2 per cent in 2014, 1.5 per cent in 2013 and 0.5 per cent in 2009. The survey of distribution system operators revealed that switching rates differed by network area. 452 of the 724 distribution system operators (of a total of 778) that provided data on heating electricity volumes also reported figures on supplier switching[94]. These 452 distribution system operators represent about 96 per cent of the heating electricity volume and metering points of all 724 distribution system operators that provided data on heating electricity (13 TWh or 2 million metering points).

The switching rates varied depending on the network area. The middle 80 per cent of the graded figures for the quantitative switching rate per distribution system operator were between 0.3 per cent and 6.3 per cent (the evaluation relates to the 452 distribution system operators that provided supplier switching figures).

[94] Several distribution system operators also pointed out that they had no data, or only individual data, in the electric heating sector for analysis.

After many years of hardly any supplier switching, there has been a steady increase in switching activity at a low level. This is evidence of a boost in competition. The level of transparency for end customers has improved and the range of services provided by national suppliers of heating electricity has been expanded over the last two years. Consumers are now able to find local suppliers more easily, e.g. through websites, consumer magazines or information from consumer advice centres. However, switching rates in the heating electricity sector are still far below the switching rates of household and of non-household electricity customers.

5.2 Price level

As in the previous year, price data was collected on night storage tariffs and heat pump tariffs. The survey was carried out on 1 April 2016. Suppliers were asked to base their figures on an annual consumption of 7,500 KWh/year. The following analysis is based on the price data for night storage heating provided by 773 suppliers (751 in the previous year) and the price data for heat pumps provided by 750 suppliers (719 in the previous year).

According to the results of the survey, the arithmetic mean of the total gross price for night storage heating was 20.59ct/kWh (incl. VAT) on 1 April 2016, which approximates the previous year's level (20.42 ct/kWh). The arithmetic mean of the total price for heat pump electricity was 21.33 ct/kWh (incl. VAT), which puts it at the same level as the previous year and just under 0.9 ct/kWh higher than the price for night storage heating.

Price level on 1 April 2016 for night storage heating with a consumption of 7,500 kWh/year

	Spread in the 10 to 90 percentile range of the supplier data sorted by size in ct/kWh	Average (arithmetic) in ct/kWh	Percentage of total price
Price components outside the supplier's control			
Net network charge	1.50 - 3.65	2.49	12%
Metering, billing, meter operation	0.24 - 0.64	0.43	2%
Concession fee	0.11 - 1.02	0.43	2%
EEG surcharge	6.35	6.35	31%
Other surcharges[1]	0.86	0.86	4%
Electricity tax	2.05	2.05	10%
VAT	2.89 - 3.72	3.29	16%
Price component controlled by the supplier (remaining balance)	2.84 - 6.64	4.68	23%
Total price (excluding VAT)	18.11 - 23.31	20.59	100%

[1] KWKG (0.45 ct/kWh), section 19(2) of the StromNEV (0.38 ct/kWh), offshore liability (0.04 ct/kWh)

Table 61: Price level on 1 April 2016 for night storage heating with an annual consumption of 7,500 kWh

The remaining balance controlled by the supplier, which includes procurement costs, distribution costs, other costs and the margin, was 4.68 ct/kWh for night storage heating and lower than in the previous year (5.19 ct/kWh). The price component controlled by the supplier still averaged 5.72 ct/kWh on 1 April 2012 and 5.8 ct/kWh on 1 April 2013. The trend over the years shows that this price component has been falling steadily in the heating electricity sector. The remaining balance controlled by the supplier as of 1 April 2016, which includes procurement costs, distribution costs, other costs and the margin, also fell dramatically in the heat pump sector and was 5.04 ct/kWh compared to 5.63 ct/kWh in the previous year. In the reporting year, the average balance for heat pumps is slightly higher than that for night storage heating. The price component controlled by the supplier is only about 23 per cent of the total price, including VAT, for night storage heating (25 per cent in the previous year), and about 24 per cent of the total price, including VAT, for heat pumps (26 per cent in the previous year).

About 63 per cent of the price for night storage heating consists of taxes, surcharges and concession fees. Compared to last year, the total of all fixed surcharges rose by 0.6 ct/kWh. The Bundeskartellamt has set the concession fee at 0.11 ct/kWh because heating electricity is supplied under special contracts.[95] Nevertheless, some suppliers quoted figures of more than 0.11 ct/kWh in this year's survey. This may be the result of summary invoices where heating electricity and household electricity are not metered separately or the result of incorrect data entries or incorrect assessments. The average figure obtained in the survey for network tariffs and metering was 2.92 ct/kWh in the night storage heating category and was roughly the same as the previous year's figure of 2.87 ct/kWh.

[95] Cf. Bundeskartellamt, Heizstrom – Überblick und Verfahren, (Electric heating - overview and proceedings), September 2010, pp. 9-10.

Price level on 1 April 2016 for heat pumps with a consumption of 7,500 kWh/year

	Spread in the 10 to 90 percentile range of the supplier data sorted by size in ct/kWh	Average (arithmetic) in ct/kWh	Percentage of total price
Price components outside the supplier's control			
Net network charge	1.50 - 4.42	2.68	13%
Metering, billing, meter operation	0.23 - 0.64	0.43	2%
Concession fee	0.11 - 1.32	0.51	2%
EEG surcharge	6.35	6.35	30%
Other surcharges[1]	0.86	0.86	4%
Electricity tax	2.05	2.05	10%
VAT	2.98 - 3.84	3.41	16%
Price component controlled by the supplier (remaining balance)	2.86 - 7.05	5.04	24%
Total price (excluding VAT)	18.69 - 24.03	21.33	100%

[1] KWKG (0.45 ct/kWh), section 19(2) of the StromNEV (0.38 ct/kWh), offshore liability (0.04 ct/kWh)

Table 62: Price level on 1 April 2015 for heat pumps with an annual consumption of 7,500 GWh

6. Green electricity segment

In the 2016 survey, information was collected from suppliers on the volume of green electricity delivered to final consumers. Following an error in the survey for 2014, the volumes of green electricity supplied to household customers in 2014 and 2015 and the share of green electricity in the total volume of electricity supplied in both years are presented together below.

Green electricity supplied to household customers 2014 and 2015

	Category	Total green electricity supplied 2014	Share of green electricity in total volume and meter points (%) 2014	Total green electricity supplied 2015	Share of green electricity in total volume and meter points (%) 2015
Household customers	Volume (TWh)	21.5	17.4%	24.0	19.8%
	Number of meter points	7,790,382	17.2%	8,617,808	19.1%
Other final consumers	Volume (TWh)	25	8.4%	25.8	8.7%
	Number of meter points	711,837	18.2%	913,473	17.9%
Total	Volume (TWh)	46.5	11.0%	49.8	11.9%
	Number of meter points	8,502,219	17.3%	9,531,281	19.0%

Table 63: Green electricity supplied to household customers 2014 and 2015

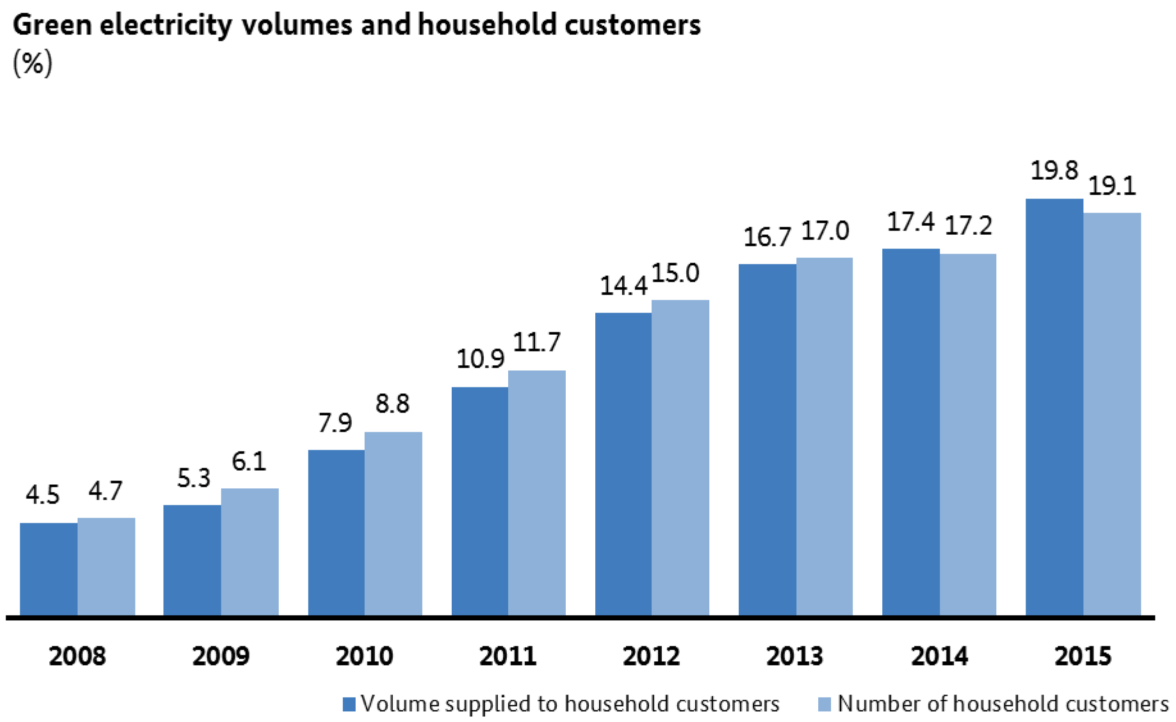


Figure 103: Green electricity volumes and household customers

There was a further increase in 2014 and 2015 in the share of green electricity in the total volume supplied to household customers and in the percentage of households supplied with green electricity. There was a particular increase of 2.4% in the share of green electricity in total consumption in 2015. The percentage of household customers supplied with green electricity also rose by almost two percentage points.

Average volume weighted price for green electricity for household customers with an annual consumption between 2,500 kWh and 5,000 kWh (band III; Eurostat band DC) as of 1 April 2016 (ct/kWh)

Price component	Volume weighted average (ct/kWh)	Percentage of total price (%)
Energy procurement, supply, other costs and margin	5.80	20.5
Net network charge	6.34	22.4
Billing charge	0.38	1.4
Metering charge	0.13	0.5
Meter operation charge	0.29	1.0
Concession fee	1.60	5.7
Renewable energy surcharge	6.35	22.4
CHP surcharge	0.45	1.6
Section 19 surcharge	0.38	1.3
Offshore liability surcharge	0.04	0.1
Electricity tax	2.05	7.2
Value added tax	4.53	16.0
Total	**28.35**	**100**

Table 64: Average volume weighted price for green electricity for household customers in consumption band III as of 1 April 2016

Arithmetic mean and range of prices for green electricity for household customers with an annual consumption between 2,500 kWh and 5,000 kWh (band III; Eurostat band DC)

Household customers (range between 10% and 90% of suppliers' quoted prices arranged in order of size) **1 April 2016** **(ct/kWh)**	**Total price**
Arithmetic mean	28.65
Range	25.42 - 31.14

Table 65: Arithmetic mean and range of prices for green electricity for household customers in consumption band III as of 1 April 2016

The average volume weighted retail price for green electricity for household customers with an annual consumption between 2,500 kWh and 5,000 kWh increased slightly to 28.35 ct/kWh as of 1 April 2016. The price for green electricity in 2015 calculated subsequently using volume weighting was 27.75 ct/kWh as at 1 April 2015.

The following diagram shows the percentage distribution of the individual price components.

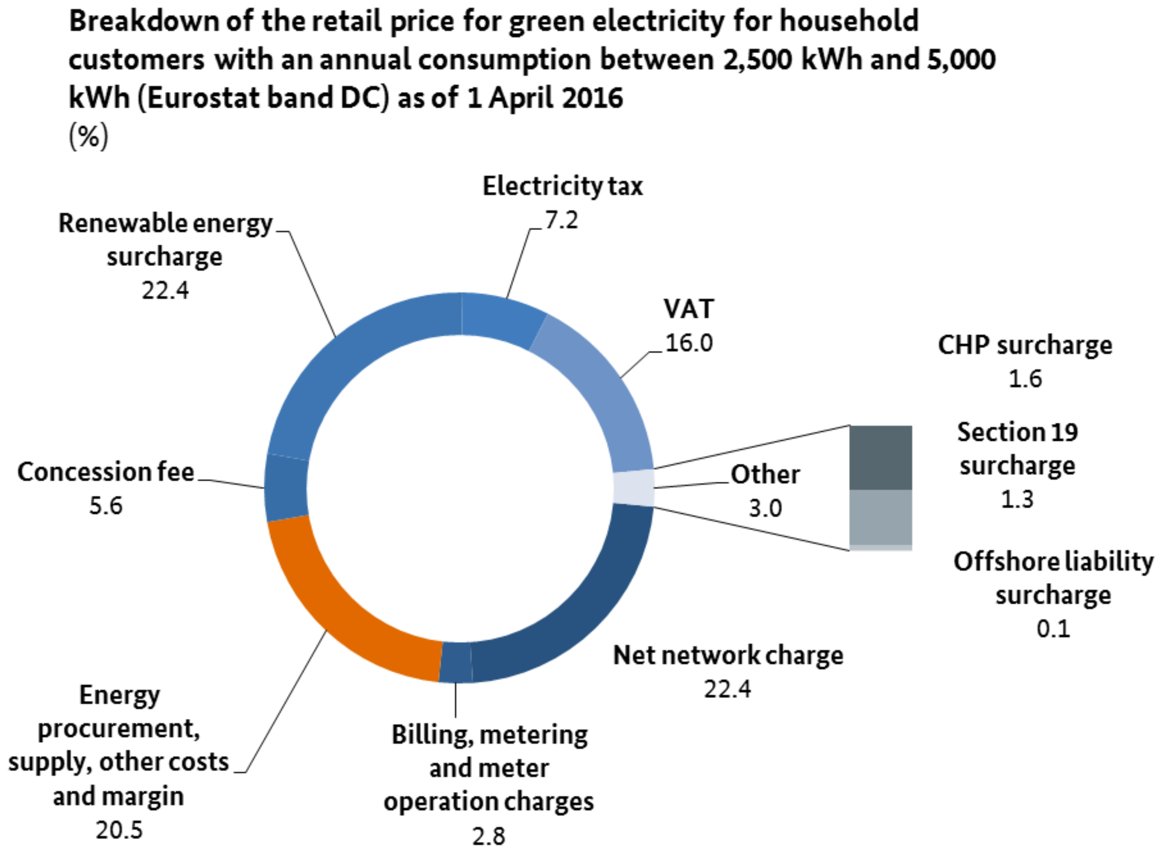


Figure 104: Breakdown of the retail price for green electricity for household customers in consumption band III as of 1 April 2016 (volume weighted average across all tariffs)

As with conventional electricity, many suppliers offer their customers a range of special bonuses and schemes that can have a further effect on the prices under the various tariffs. The number and various possible combinations of the elements that form the prices make it difficult to compare the wide range of competitive tariffs. The following table provides an overview of the various special bonuses and schemes that are offered by electricity suppliers to customers on green electricity tariffs:

Special bonuses and schemes (1 April 2016)

	Household customers on green electricity tariffs	
	Number of tariffs	Average scope
Minimum contract period	411	10 months
Price stability	342	14 months
Advance payment	44	11 months
One-off bonus payment	118	€60
Free kilowatt hours	8	194 kWh
Deposit	4	-
Other bonuses and special arrangements	97	-

Table 66: Special bonuses and schemes for household customers on green electricity tariffs

7. Comparison of European electricity prices

Eurostat, the statistical office of the European Union, publishes end consumer electricity prices for each six-month period that show the average payments made by household customers and non-household customers in EU Member States. The figures published for each consumer group include (i) the price including all taxes, levies and surcharges, (ii) the price excluding recoverable taxes, levies and surcharges ("net price") and (iii) the price excluding taxes, levies and surcharges ("adjusted price"). Eurostat also publishes a breakdown of the adjusted price into network tariffs and the remaining balance controlled by the supplier ("energy and supply"), which includes electricity procurement costs, distribution costs, other costs and the margin. Eurostat does not collect the data itself but relies on data from national bodies. Rules on the classification, analysis and presentation of the price data aim to ensure European-wide comparability.[96] However, the survey method is set by the member state (cf. Directive 2008/91/EC, Annex I h), which leads to national differences.

7.1 Non-household customers

Eurostat publishes price statistics for seven different consumer groups in the non-household sector that differ according to annual consumption ("consumption bands"). The following describes the 20 to 70 GWh/year consumption category as an example of one of these consumption bands. The 24 GWh/year category ("industrial

[96] For details see http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2008:298:0009:0019:DE:PDF (retrieved on 11 November 2016).

customers"), for which specific price data is collected during monitoring (see section I.G.4.1), falls into this consumption range.

The customer group with an annual consumption of 20 to 70 GWh consists mainly of industrial customers, who can deduct national VAT on a regular basis. As a result, the total price has been adjusted for VAT for the purpose of European-wide comparison. Besides VAT, there are various other taxes, levies and surcharges resulting from specific national factors. These costs can be recovered by this customer group and – like the VAT – have also been deducted from the gross price in accordance with the Eurostat classification. These possible reductions are a very important factor for individual net electricity prices, especially for industrial customers in Germany (for more details see section I.G.4.1).

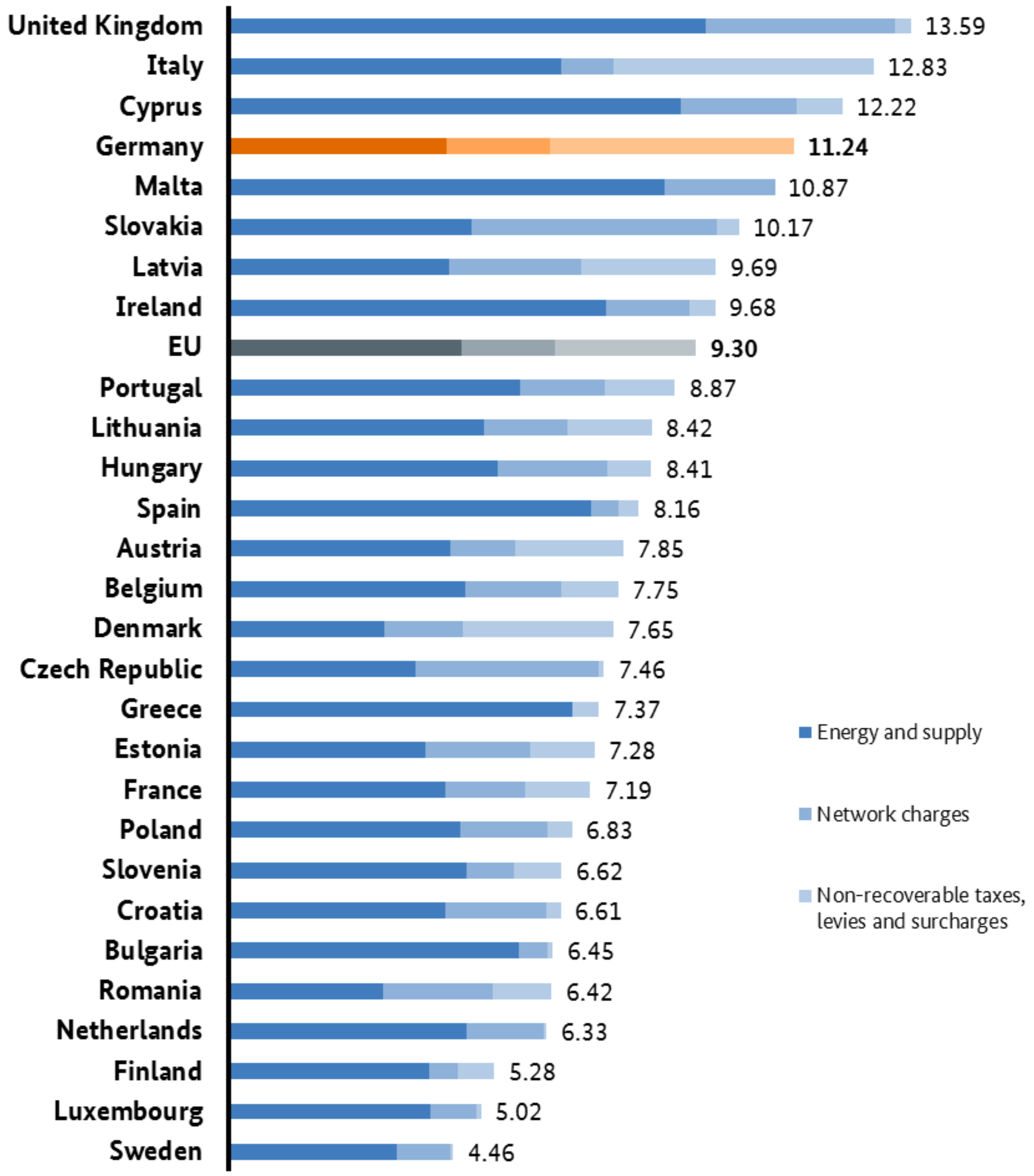
According to Eurostat data, there are significant differences in the price of electricity for industrial customers. The United Kingdom has the highest net price with 13.59 ct/kWh, while Sweden has the lowest with 4.46 ct/kWh. The European average is 9.30 ct/kWh, of which 2.81 ct/kWh consists of non-recoverable taxes, levies and surcharges and 6.49 ct/kWh is made up of network tariffs and the remaining balance controlled by the supplier ("energy and supply").

At 6.39 ct/kWh, the adjusted net price in Germany is just 1 ct/kWh below the European average of 7.12 ct/kWh. The adjusted net price of 13.26 ct/kWh in the United Kingdom is almost twice as high as that in Germany. The German figure of 6.39 ct/kWh comprises 2.05 ct/kWh network tariffs and 4.34 ct/kWh "energy and supply". The "energy and supply" price component is almost exactly the same as the figure of 4.19 ct/kWh recorded during monitoring for the 24 GWh consumption category on 1 April 2015 (see Monitoring Report 2015, p. 196).

The answer to the question as to whether the net price paid by German industrial customers in the 20-70 GWh/year consumption band is higher or lower than the European average essentially depends on the specific amount of the non-recoverable surcharges, taxes and levies. In the relevant consumption band, this amount can vary between 0.40 ct/kWh and 8.66 ct/kWh (see Monitoring Report 2015, p. 198). In order to determine the average of the net prices actually paid in the relevant consumption band on the basis of a sample survey, numerous assumptions have to be made regarding the amount of possible reductions claimed on average. The documentation published by Eurostat, however, does not list the relevant assumptions concerning the price paid by industrial customers in Germany.[97] The figure relating to the average amount of non-recoverable surcharges, taxes and levies in the 20 to 70 GWh/year consumption band is 4.85 ct/kWh in Germany or more than twice as much as the European average of 2.18 ct/kWh. The resulting net price for Germany is 11.24 ct/kWh, which is higher than the European average of 9.30 kWh.

[97] Cf. Eurostat, Electricity Prices – Price Systems 2014, 2015 Edition: http://ec.europa.eu/eurostat/documents/38154/42201/Electricity-prices-Price-systems-2014.pdf/7291df5a-dff1-40fb-bd49-544117dd1c10 (retrieved on 11 November 2016).

Comparison of European electricity prices in the second half of 2015 for non-household customers with an annual consumption between 20 GWh and 70 GWh
in ct/kWh, excl. recoverable taxes, levies and surcharges



Source: Eurostat
Remark: For Greece there is no differentiation of network charges and energy and supply.

Figure 105: Comparison of European electricity prices in the second half of 2015 for non-household customers with an annual consumption between 20 and 70 GWh

7.2 Household customers

Eurostat takes five different consumption bands into consideration when comparing household customer prices. The volumes consumed by household customers in Germany are mostly in the middle category with an annual consumption between 2,500 kWh and 5,000 kWh. The 3,500 kWh/year consumption level, for which specific price data is collected during monitoring (see section I.G.4.2), falls into this consumption band. This year, this consumption level was assigned to the category of the above-mentioned consumption bands (categorised as “Band III” here, cf. section I.G.4.2).

The following shows a European comparison of the medium consumption band. Household customers generally cannot have surcharges, taxes and levies refunded, which is why the total price including VAT is relevant to these customers.

Electricity prices for household customers vary greatly in Europe. Germany has the second highest price among the 28 EU Member States with 29.46 ct/kWh. Prices in Germany are about 40 per cent higher than the EU average of 21.05 ct/kWh. Only Denmark has higher prices for household customers than Germany. The figure for Germany roughly corresponds to the weighted average price of 29.11 ct/kWh across all contract categories, which was determined during monitoring on 1 April 2015 (see Monitoring Report 2015, p. 209).

The high price paid in Germany compared to other Member States is due to a higher proportion of surcharges, taxes and levies. In the EU, 6.86 ct/kWh on average consists of surcharges, taxes and levies, whereas these account for more than twice as much in Germany with 15.19 ct/kWh. By contrast, at 14.27 ct/kWh the net price adjusted for all taxes, surcharges and levies is close to the EU average of 14.19 ct/kWh.

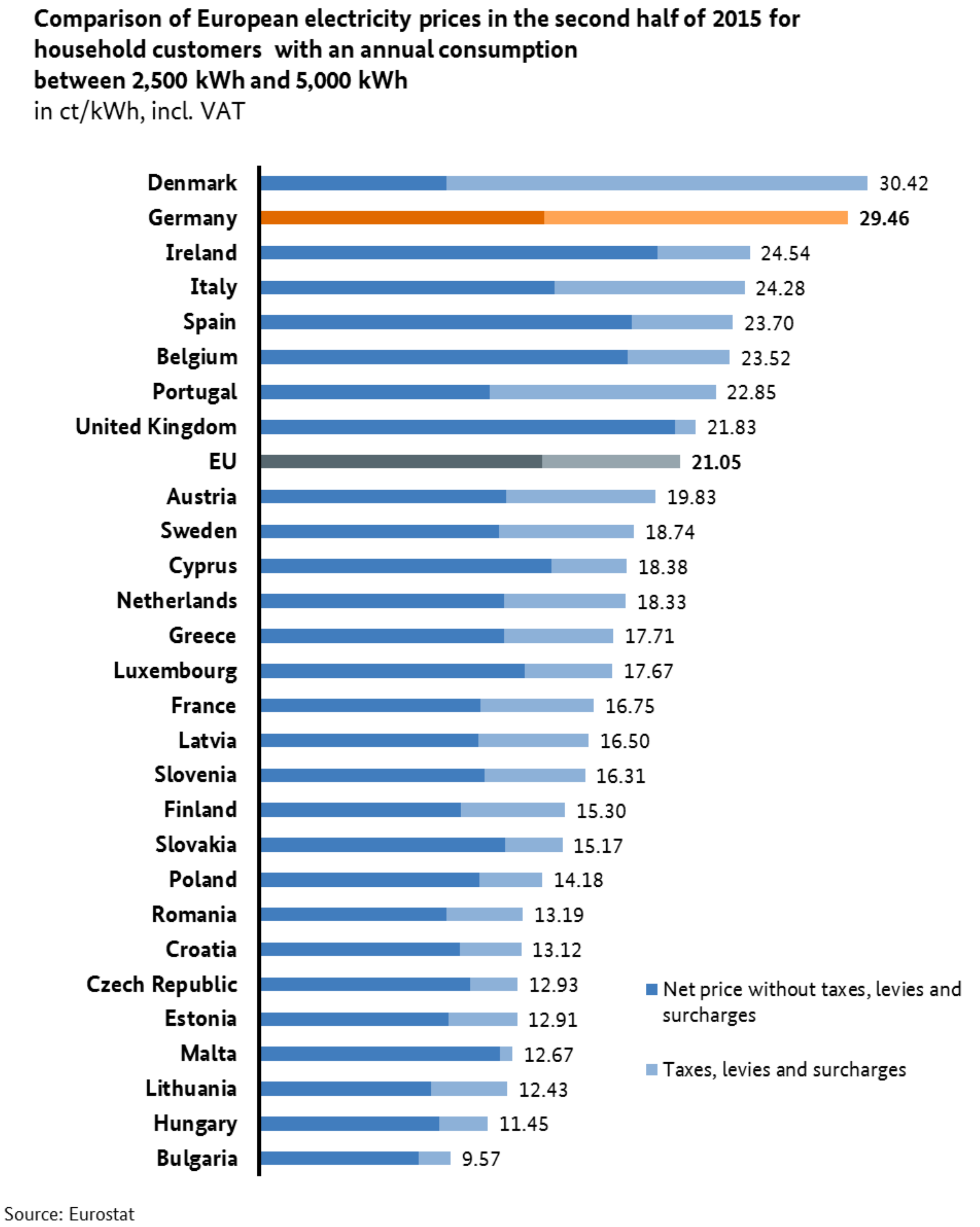


Figure 106: Comparison of European electricity prices in the second half of 2015 for household customers with an annual consumption between 2,500 and 5,000 kWh

H Metering

1. The network operator as the default meter operator and independent meter operators

811 companies responded to the 2016 monitoring questionnaire for 50,856,171 electricity meter points. In 2015, these companies can be categorised as follows:

Meter operators

	Number	
	2014	**2015**
Default DSO	680	775
Non-default DSO	34	23
Of which exclusively	10	5
Suppliers	40	19
Of which suppliers that are also independent meter operators	4	6
Meter operators independent of DSOs and suppliers	14	13

Table 67: Meter operators

The Electricity and Gas Metering Liberalisation Act and the Metering Framework Conditions Ordinance allow connection users to freely choose the company which is responsible for the installation, operation and maintenance of metering equipment and -systems as well as actual metering. This can be done by third parties alongside network operators. Independent meter operators also provide metering services in the network areas of some 784 distribution network operators, which leads to the following distribution breakdown irrespective of the network size:

Distribution networks by number of independent meter operators

	Number of independent meter operators					
	up to 5	**up to 10**	**up to 20**	**up to 30**	**up to 40**	**More than 40**
Number of networks	291	227	190	54	13	9
Breakdown in %	37	29	24	7	2	1

Table 68: Distribution networks by numbers of independent meter operators

Irrespective of the network size, the average number of independent meter operators working in the distribution network is around ten per distribution network area. The highest number is 132 independent meter operators.

Independent meter operators cover 220,000 meter points in the distribution networks, which equates to a share of less than one percent of the total number of meter points in these networks. This low share is illustrated in the following graph. The meter points at which independent meter operators are active are determined in relation to all the meter points in a network area. There are only very few networks (around three percent) in which more than one percent of meter points are serviced by independent meter operators.

Share of independent meter operators in the distribution network areas

	Percentage of meter points with independent meter operators in relation to all meter points in the network area					
	Up to 1%	**Up to 5%**	**Up to 10%**	**Up to 15%**	**Up to 20%**	**More than 20%**
Number of networks	766	21	4	1	0	1
Breakdown in %	97	3	<1	<1	0	<1

Table 69: Share of independent meter operators in the distribution network areas

2. Requirements under section 21 b ff. EnWG

The EnWG provides for the obligatory installation of intelligent metering systems if specific requirements have been met and it is technically feasible. The number of meter points for buildings that have been newly connected to the energy supply network has risen by 73,000. Final customers with annual consumption of more than 6,000 kWh have 175,000 more meter points than in the previous year. The number of meter points of operators of new installations with installed capacity exceeding seven kW as regulated under the EEG or KWKG has risen compared to the previous year by around 240,000. The following table shows the meter points which meet the requirements:

Metering points requiring smart meters under section 21c EnWG

Requirement	Meters
a) Buildings that have been newly connected to the energy supply networks or have undergone major refurbishment	458,465
b) Final customers with annual consumption of more than 6,000 kWh	4,330,915
c) Operators of new installations with installed capacity exceeding 7 kW as regulated under the EEG or KWKG	408,174

Table 70: Meter points requiring smart meters under section 21c EnWG

3. Meter technology for household customers

Meter technology employed for SLP customers

Requirement	Meters 2014	Meters 2015
a) Electro-mechanical meters (AC and DC meters following the Ferraris principle)	45,064,524	44,030,251
of which twin tariff or multiple tariff meters (Ferraris principle)	2,986,830	2,944,190
b) Electronic meter (basic meter not connected to communications network)	4,219,719	5,029,241
c) Electronic metering system (whose basic meter can communicate remotely but does not meet the criteria of section section 21i ff. EnWG)	507,349	1,041,867
d) Metering system corresponding to sections 21d, 21e EnWG	79,206	90,244

Table 71: Meter technology employed for SLP customers[98]

In the household customer segment (SLP customers) there has been a significant shift towards electronic metering systems. Overall the number of electronic metering systems rose by 1.3 million meter points. Despite the fall in the number of Ferraris meters in use by around 1 million meter points, these are still found at about 44 million meter points. The use of two-tariff and multiple-tariff meters has remained practically unchanged from the prior year's level at approximately 3 million meter points. The technical requirement for remote communication connection to allow remote meter readings has been complied with at over 1 million meter

[98] The value for meter technology which complied with sections 21d and 21e EnWG in 2014 has been subsequently corrected.

points with electronic metering systems that do not meet the criteria of section 21i ff EnWG and at approximately 90,000 meter points where the metering systems do meet the criteria of sections 21d and 21e EnWG. The following diagram shows the number and breakdown of transmission technologies used for the 400,000 meter points that are read remotely.

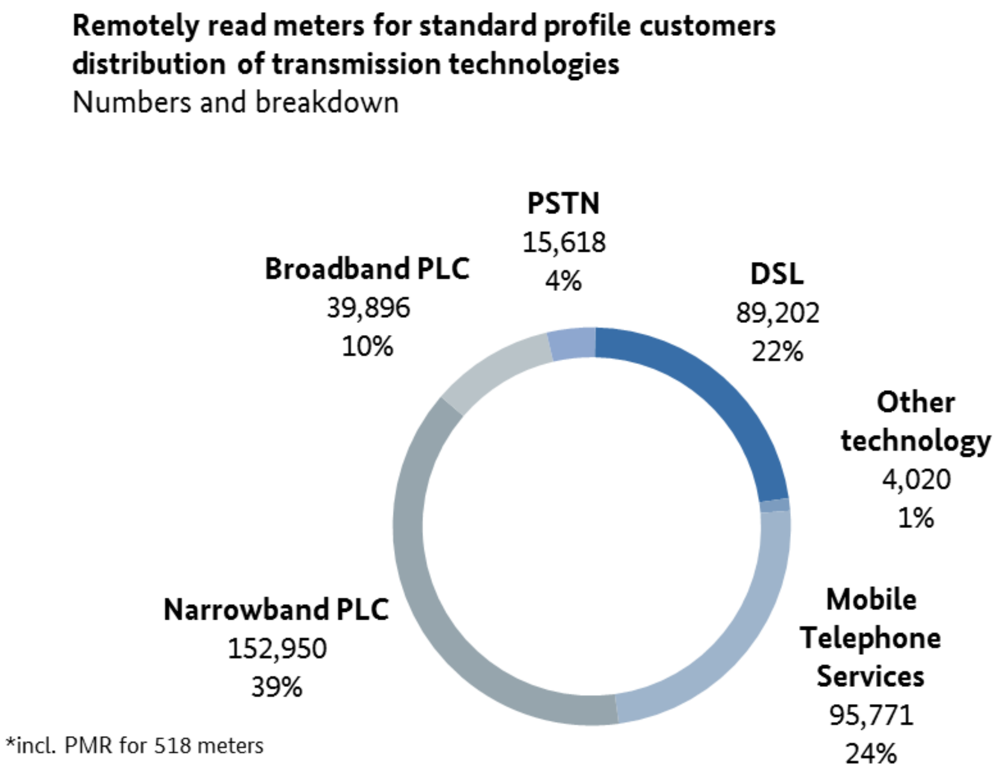


Figure 107: Transmission technologies for remotely read meters for SLP customers (numbers and breakdown)

The percentage of transmissions via power line communication (PLC) has fallen by approximately 6% since the prior year. This is mainly attributable to the rise in mobile and DSL/broadband (cable) transmissions as the number of connections for narrowband and broadband PLC remain relatively constant. PLC transmission technology is now used in less than one of two cases. The number of connections via telephone lines (PSTN) is practically unchanged since the previous year, whereas the share (4%) has fallen slightly. The number of meter points for which DSL and broadband transmission is used has risen by almost 50,000 and mobile transmission (GSM, GPRS, UMTS, LTE) is used at a total of 33,000 more meter points than in the previous year.

This is shown in the following diagram.

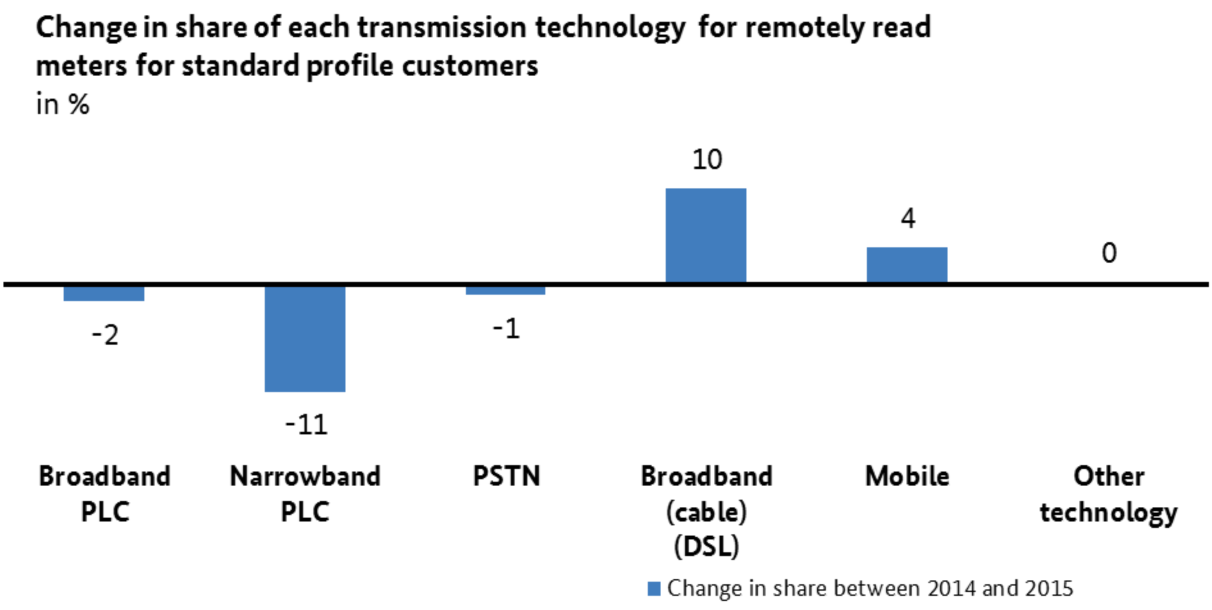


Figure 108: Change in the percentage of transmission technology used for remotely read metering systems for SLP customers compared with the prior year

The share of PLC and PSTN technology used for transmission is falling while more and more SLP meter points are being read using DSL and mobile transmission.

4. Meter technology used for interval-metered customers

The number of meter points for interval-metered industrial and business customers has reached 408,000 and is thus at roughly the same level as last year.

Meter technology employed for interval-metered customers

Requirement	Meters 2015
Meter installations for interval-metered customers	408,325
Metering systems complying with sections 21d, 21e EnWG	60,792
Other	36,556

Table 72: Meter technology employed for interval-metered customers

The following diagram shows the number and breakdown of transmission technologies.

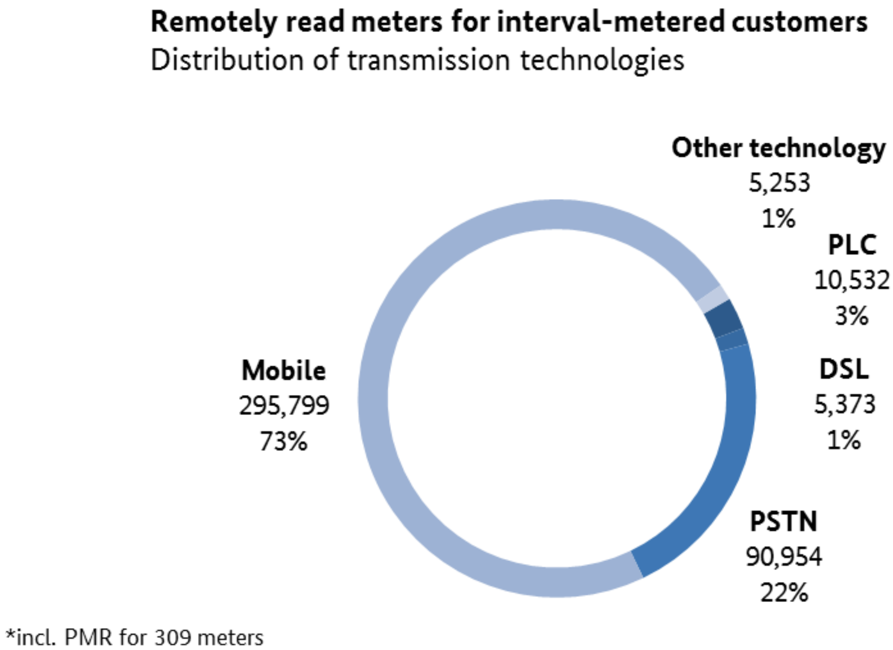


Figure 109: Number and breakdown of transmission technologies employed for interval-metered customers

There are very few changes in the interval-metered field from the prior year. There was a significant increase in the number of remote meter readings transmitted via mobile communication of around 15,000 meter points more than in the prior year. In contrast, data from around 5,000 fewer meter points were transmitted by telephone line. Similar to the previous year, the above diagram shows that in the interval-metered segment, transmission technologies other than by radio (GSM, GPRS, UMTS, LTE) and telephone line (PSTN) are rarely used.

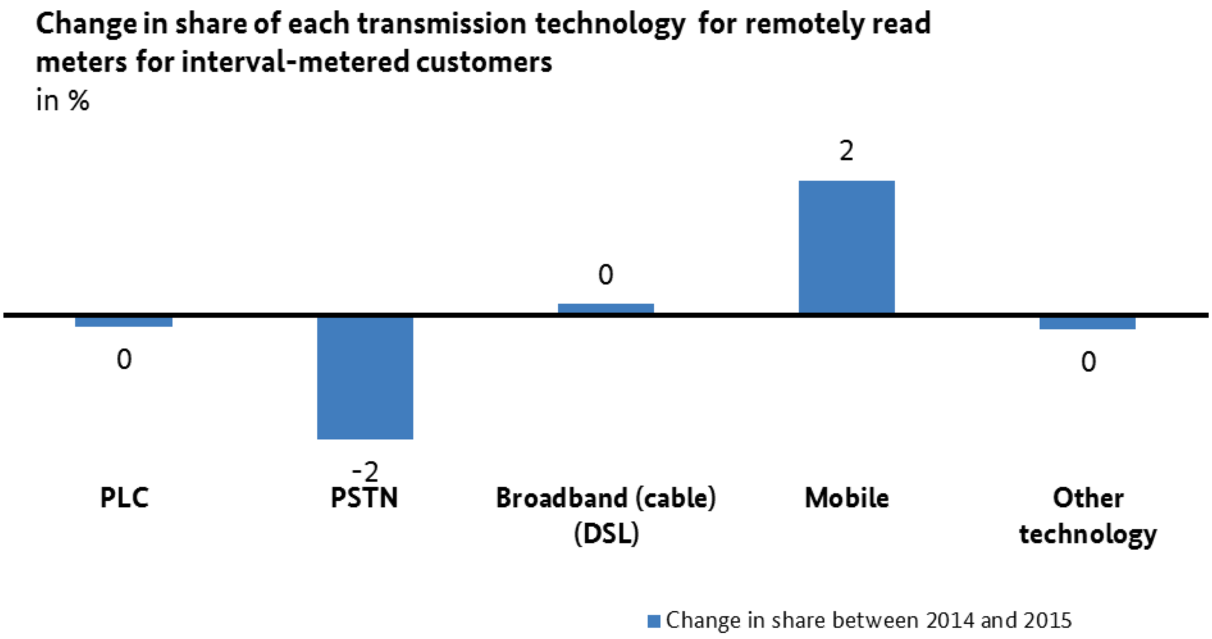


Figure 110: Change in the share of each transmission technology for remotely read metering systems for interval-metered customers compared with the prior year

Other than for the SLP segment, the interval-metered segment shows the main change to be transmission via mobile communication. At the same time as telephone line transmission is falling, mobile transmission of meter data is growing at a similar rate. Nearly three-quarters of remote read meters now communicate by mobile transmission.

This difference may be explained primarily by the typical voltage level at which the meter is connected to the network. Whilst a low-voltage supply is common for SLP customers, commercial and industrial interval-metered customers are usually connected to a medium-voltage system or higher. However, less effort is needed for data transmission at a low voltage level than for a higher voltage level. In addition, very little data is transmitted without a repeater, meaning that a dense network with many meters (that can also work as repeaters) is a pre-condition for PLC use. This is more a given in the network area for household customers rather than for industrial or commercial customers.

A second reason for the difference between SLP and interval-metered customers is the cost aspect. Data transfer via power lines incurs fewer costs by far than wireless data transmission, which means that this can create a barrier to using the latter for household customers.

5. Metering investment and expenditure

Total investment[99] in metering was noticeably lower in 2015 than in 2014 (-€11 million) and was distributed in a completely different way. In 2014, around half of total investment was made in new installations, upgrades and expansion, on the one hand, and maintenance and replacement on the other. In 2015, in contrast, only around one third of total investment was made in new installations, upgrades and expansion and two thirds in maintenance and replacement.

Investments made in new installations, upgrades and expansion in 2015 were around 35% lower than the planning values reported in 2015. In contrast, around 10% more was invested in maintenance and replacement than originally planned.

The volume of expenditure, in contrast, remained relatively constant. Compared to 2014 total spending fell somewhat whilst remaining at the same level as the previous year and within the range of planning values for the previous year.

The forecast for 2016 is for an increase of less than 10%, although spending as a whole will remain significantly more constant than the volume of investments.

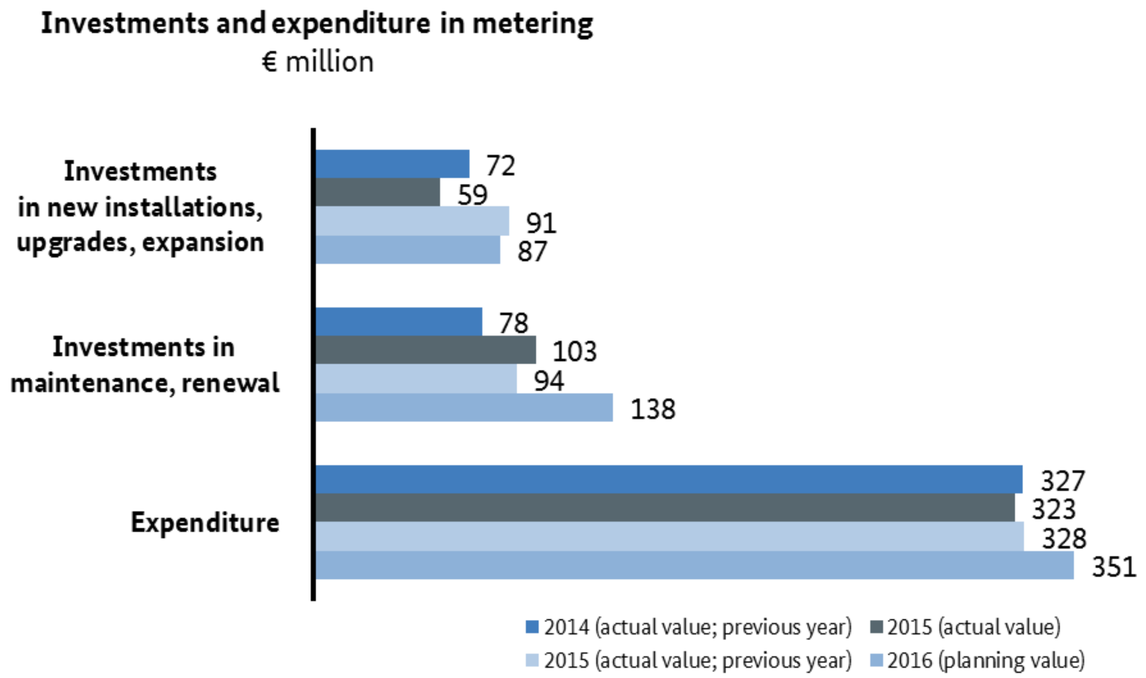


Figure 111: Investment and expenditure for metering

When compared with the DSOs' total investment volume, expenditure behaviour is revealed as the opposite of that of investment behaviour. Actual investments in metering in 2015 were far below the figures planned for

[99] Definitions are provided in the chapter on Investment I.C on page 72.

2015, whereas the total investments planned for network infrastructures by DSOs for 2015 have been met comfortably. With respect to expenditure, too, there is a distinct difference between expenditure for metering and the DSOs' total expenditure.

Also when comparing the change in the planning data there are differences both in investments and in expenditure. Whereas overall the DSOs plan a lower volume of investment for 2016, the figures for metering are expected to be significantly higher. In contrast, metering operators plan rising spending on a similar level to that of DSOs in 2016.

II Gas market

A Developments in the gas markets

1. Summary

1.1 Production, imports and exports, and storage

In 2015, natural gas production in Germany fell by 0.6bn m^3 to 8.5bn m^3 of gas (with calorific adjustment).[100] This corresponds to a decline of 6.9% compared to the previous year. The decline in natural gas production is chiefly due to the increasing exhaustion of the large deposits and the resulting natural decline in output. The reserves-to-production ratio of proven and probable natural gas reserves was 8 years as of 1 January 2016 (2015: 8.8 years).

In 2015, the total volume of natural gas imported into Germany was 1,534 TWh. Based on the previous year's figure of 1,542 TWh, imports to Germany decreased slightly by 8.4 TWh, a drop of 0.5%. Imports from the Netherlands decreased significantly (-10.6%) while imports from Russia through the Nord Stream pipeline rose by 11%.

In 2015, the total volume of natural gas exported by Germany was 746.3 TWh. Based on the previous year's figure of 810.1 TWh, exports from Germany decreased significantly by 63.8 TWh or just under 8%. Exports to the Netherlands rose sharply (+27.5%), while there was a large decrease in exports to Austria (-36.7%) and Switzerland (-19.4%).

The total maximum usable volume of working gas in underground storage facilities as of 31 December 2015 was 27.6bn Nm^3.[101] About half of this was accounted for by cavern storage facilities and the other half by pore storage facilities. There was another slight decrease in the volume of short-term (up to 1 October 2017) freely bookable working gas; the capacity bookable from 2016/2017 also decreased slightly. The volume of working gas available for longer-term booking increased again compared to previous years.

The current storage level at natural gas storage facilities in Germany is high compared to past years. On 1 October 2016, at the beginning of the 2016/2017 gas year, the total storage level of German storage facilities was around 95%.

The market for the operation of underground natural gas storage facilities is still highly concentrated but less concentrated than in the previous year. The aggregate market share of the three largest storage facility operators on 31 December 2015 was some 73%, representing a year-on-year decrease of nearly two percentage points.

[100] Gas volumes with calorific adjustment are amounts measured in a manner that is commercially relevant. Calorific adjustment is used because natural gas is not sold according to its volume, but according to its energy content (9.7692 kWh/m^3). In contrast, gas without calorific adjustment has a natural calorific value that may vary depending on the location of the deposit (in Germany this figure varies between 2 and 12 kWh/m^3).

[101] The 7Fields and Haidach storage facilities in Austria are fully accounted for in this figure.

1.2 Networks

The gas network development plan (NDP) 2015 was presented to the Bundesnetzagentur by the TSOs on time on 1 April 2015. The Bundesnetzagentur then published the document for full consultation. Taking the results of the consultation into account, the Bundesnetzagentur issued a request for modification to the TSOs on 1 September 2015.

The need for the total of 37 new measures included in the gas NDP 2015 is in particular due to the market area conversion from L-gas to H-gas and the ensuing increased demand for H-gas. From a security of supply perspective, market area conversion plays a significant role in the draft gas NDP 2015. The result is a specific proposal for the gradual transformation of these areas that goes beyond 2025 to cover the period until 2030.

On 1 April 2016, the TSOs submitted their draft gas NDP 2016-2026 to the Bundesnetzagentur. Essentially, the measures in the gas NDP 2015 are confirmed by the results of the gas NDP 2016-2026. Moreover, the gas TSOs are proposing a further 39 expansion measures up to 2026, largely on the basis of the need for market area conversion as a result of the decline in L-gas imports from the Netherlands over the next few years, the need to take account of increased H-gas demand, and the increase in demand for capacity with regard to planned reserve gas fired power plants. Furthermore, individual measures can be attributed to the increased capacity required in the distribution network, particularly in southern Germany.

In 2015, investments in and expenditure on network infrastructure by the 16 German TSOs amounted to €495.9m (2014: €527.4m). Of this, €340.7m (2014: €383.6m) was accounted for by investments in new builds, upgrades and expansion projects and €155.2m (2014: €143.8m) by investments in network infrastructure maintenance and renewal. Expenditure on network infrastructure maintenance amounted to €365.5m in 2015 for all TSOs (2014: €266.6m).

The investment volume for new builds, upgrades and expansion projects (€681.5m) as well as network infrastructure maintenance and renewal (€430.5m) amounted to €1,112m according to the data provided by the gas DSOs. This was a decrease of 3.7% compared to the prior year's investment volume (€1,155m). The €1,079m in investments for distribution networks originally planned by gas DSOs for 2015 was therefore exceeded by €33m.

According to the data provided by the gas DSOs, maintenance expenses amounted to €1,203m in 2015. This was an increase of almost 12% compared to the previous year (€1,075m). The €1,158m in expenses for the distribution network originally planned by the gas DSOs for 2015 was therefore exceeded by €45m.

The Bundesnetzagentur again conducted a comprehensive survey of all gas supply interruptions throughout the Federal Republic of Germany. The average value for all final consumers determined from the results of this survey – the System Average Interruption Duration Index or SAIDI – reflects the average duration of supply disruptions experienced by a customer over a period of one year and was 1.699 minutes in 2015 (2014: 1.257 minutes).

The average volume-weighted network charge, including billing, metering and meter operation charges, for household customers on default tariffs in consumption band II was 1.50 ct/kWh on 1 April 2016, representing a year-on-year increase of 0.1 ct/kWh or 7.1%.

Compared to the previous year, the total quantity of gas supplied by general supply networks in Germany increased in 2015 by 64.3 TWh or 8% to 865.7 TWh. The quantity of gas supplied to household customers (as defined in section 3 para 22 EnWG) rose by just over 13.5% to 254.5 TWh. There was a further decrease in the gas supplied to gas fired power stations with a nominal capacity of at least 10 MW. 38.8 TWh of gas was supplied to such gas fired power stations in 2015, a drop of over 10% compared to the previous year.

With regard to gas transmission networks, the quantity of gas procured directly on the market by large final consumers (industrial customers and gas fired power stations) amounted to 57.2 TWh, equivalent to just under 36% of the total quantity of gas supplied by the TSOs. With regard to gas distribution networks, the amount of gas procured without a conventional supplier contract amounted to 31.4 TWh, corresponding to a share of approximately 4.5% of the total supplied by the DSO.

The conversion of German L-gas networks to H-gas began in 2015. Overall the conversion, which is expected to be completed by 2030, will affect more than four million gas customers with around 4.9m gas appliances.

1.3 Wholesale

Liquid wholesale markets are vital to ensure well-functioning markets along the entire value-added chain in the natural gas sector, from the procurement of natural gas all the way to supplying final customers. Liquid wholesale markets facilitate market entry and foster competition for final consumers.

Varying developments were recorded in the liquidity of the wholesale natural gas markets in Germany in 2015. In 2015, natural gas transactions brokered by broker platforms with Germany as the place of delivery amounted to some 2,652 TWh, representing a decrease of around 11% compared to the previous year. A further increase of 38% in on-exchange gas trading volumes was, however, recorded, having already more than doubled in the previous year. The Bundeskartellamt now defines the wholesale market for natural gas as a national market and no longer defines markets based on their respective network area.

2015, much like the previous year, was marked by falling wholesale gas prices.[102] The annual average daily reference prices calculated by EEX fell by around 6% (2014: 22%), while the cross-border price, as calculated by the Federal Office for Economic Affairs and Export Control (BAFA), decreased on average by 13% (2014: 15%). The changes in the BAFA cross-border price over the course of 2015 clearly show a correlation with exchange prices for natural gas.

1.4 Retail

The majority of household customers (54%) were supplied by the local default supplier under a non-default contract (2014: 57%) and were delivered 122.4 TWh of gas (2014: 116 TWh). Just under one quarter of household customers (23.5%, compared to 24% in 2014) with a default supply contract were supplied with 53.3 TWh of gas (2014: 49.8 TWh). The percentage of household customers who have a contract with a supplier other than the local default supplier once again increased and now stands at 22.4% (2014: 19%) for 50.8 TWh of gas (2014: 38.3 TWh). Default supply is of only minor significance for non-household customers. Around 71% of the total volume of gas delivered to interval metered customers in 2015 was supplied on the basis of a contract with a legal entity other than the local default supplier.

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[102] Influencing factors include the world market prices for oil and LNG, weather and temperatures, the renegotiation of long-term supply contracts on the European gas market, increasing trade at European gas trading points and gas storage capacities.

The volume-based supplier switching rate for non-household customers was still around 12% in 2015. There was a strong rise in the switching rates among non-household customers between 2006 and 2010. Since then the switching rate has remained more or less constant. The number of household customers who switched supplier rose by around 15% (+120,171 supplier switches) to 925,195. By contrast, the number of household customers who immediately chose an alternative supplier rather than the default supplier when moving home decreased by 13.5% (-33,011 household customers). In addition, almost half a million household customers have changed their gas tariff with their supplier.

The total volume of gas supplied to household customers who switched supplier (including those switching when moving home) increased in 2015 by 3 TWh or 13.3% to 25.6 TWh. Considering the significant increase in gas supplied to household customers by network operators, the volume-based switching rate remained stable at 10.1%.

The Bundeskartellamt assumes that there is no longer any single dominant supplier in either of the two largest gas retail markets. The cumulative market share of the three largest undertakings in the national market for supplying interval metered customers was 29%, and 22% in the national market for supplying non-interval metered gas customers (in particular household customers) under a contract outside the scope of default supply. These figures are considerably lower than the statutory thresholds for presuming market dominance.

Since market liberalisation and the creation of a legal basis for a well-functioning supplier switch, there has been a steady positive development in the number of active gas suppliers for all final consumers in the different network areas. In 2015, there was a choice of more than 50 gas suppliers in nearly 83% of the network areas. Final consumers in almost 31% of the network areas had a choice of more than 100 suppliers. On average, final consumers in Germany can choose between 90 suppliers in their network area; household customers can, on average, choose between 75 suppliers (these figures do not take account of company affiliations).

As of 1 April 2016 retail prices for gas fell again compared to a year earlier (1 April 2015).

Gas prices for non-household (industrial/commercial) customers fell considerably. The levies/taxes and network tariffs have remained unchanged, meaning that the falling prices are solely due to a further reduction in the price component that can be controlled by the supplier (energy procurement, supply, other costs and margin). The average price (excluding VAT) as of 1 April 2016 for "industrial" customers with an annual consumption of 116 GWh was 2.77 ct/kWh (1 April 2015: 3.5 ct/kWh) and thus by far the lowest ever since data on gas prices was first collected for the monitoring reports.

Gas prices for household customers also fell, although to a considerably lesser extent. This decrease was also due to a further reduction in the price component that can be controlled by the supplier (energy procurement, supply, other costs and margin). The average price for household customers across all contract categories (ie default supply contract, non-default contract with the default supplier, and contract with a supplier other than the local default supplier) decreased by about 2.1% to 6.54 ct/kWh (including VAT) as of 1 April 2016 (1 April 2015: 6.68 ct/kWh). On 1 April 2016, the volume-weighted price for default supply in consumption band II was 6.99 ct/kWh, a slight decrease of 1.7% compared to the previous year. The price for customers in consumption band II supplied under a non-default contract by their default supplier was 6.37 ct/kWh, a considerable drop of 4.6% compared to the previous year. The price for customers in consumption band II with a supplier other than the local default supplier was 6.49 ct/kWh, a clear increase of 6% compared to the previous year.

A look at the household customer prices over the past ten years (2006-2016) shows that default supply constitutes the most expensive tariff for gas customers. Overall, the price paid by default supply customers has increased by just under 14% over the past ten years. Customers with a non-default contract with their default supplier and customers with a supplier other than the local default supplier have been able to rely on very stable gas prices. The price increase for these customers over the last eight years remained below 2%.

The number of household customers whose supply was disconnected by the network operator at the local default supplier's request fell in 2015 by just under 3,000 to 43,626. For the first time, the suppliers were also asked to provide data on disconnections for household customers on non-default tariffs. In total, about 43,126 customers across all tariffs were disconnected in 2015.

Compared to the previous year, the number of disconnection notices issued (1,284,670) remained more or less steady (-0.3%). Compared to 2014, the number of requests for disconnection fell by 4.1% to 261,260. A comparison of the number of disconnection notices issued with the number of disconnections actually carried out shows that about 3.4% of the notices issued actually led to gas supply disconnection.

Data was again collected on the use – at the default suppliers' request – of prepay systems such as pay-as-you-go meters using cash or smart cards. In total, 1,178 prepay systems were installed in 2015.

A comparison with the gas prices across Europe shows that household customers in Germany pay slightly below average prices and non-household customers in Germany pay slightly above average prices.

2. Network overview

All 16 TSOs took part in the 2016 Monitoring Report data survey. The total length of the gas transmission network was 37,809 km on 31 December 2015 and included 3,495 offtake points for delivery to final consumers, redistributors or downstream networks including the points at which gas can be taken off for delivery to storage facilities, hubs and conditioning or conversion plants. The number of final consumer meter points in the transmission network was 567. Some 159.4 TWh of gas was delivered to final consumers from the DSO network, which is 5.7 TWh or 3.4% less than the previous year.

As of 4 July 2016, a total of 715 DSOs were registered with the Bundesnetzagentur, 669 of whom took part in the 2016 monitoring survey. As of 31 December 2015, the total length of pipelines in the gas distribution network was 489,585 km and included 10.7m offtake points for delivery to final consumers, redistributors or downstream networks including the points at which gas can be taken off for delivery to storage facilities, hubs and conditioning or conversion plants. As of 31 December 2015, there were 14.1m final customer meter points in the gas distribution network of the DSOs participating in the monitoring survey. The number of meter points for household customers as defined in section 3 para 22 of the EnWG was 12.4m. Total gas supplies from the network of these DSOs amounted to 706.3 TWh in 2015, up by 70 TWh or just around 11% compared to the previous year. The quantity of gas supplied to household customers as defined in section 3 para 22 EnWG rose by 30 TWh or 13.5% to 254.5 TWh.

A simplified comparison between the supply and demand of natural gas in 2016 in Germany is shown below. It must be pointed out, however, that this is based on gas flows meaning that self-supply and statistical differences have not been accounted for. The amount of gas entering the German network was 1,617.6 TWh in 2015. Around 5% came from domestic sources (83.6 TWh), the rest (1,534 TWh) was imported. Around 46% (746.3 TWh) of available gas volumes in Germany was transported to neighbouring countries in Europe. Final consumers used 865.7 TWh of gas in Germany. The balance of gas that entered and exited storage was positive and amounted to 6.7 TWh. Thus more gas was injected into storage facilities than taken off.

Gas resources and consumption in Germany in 2015

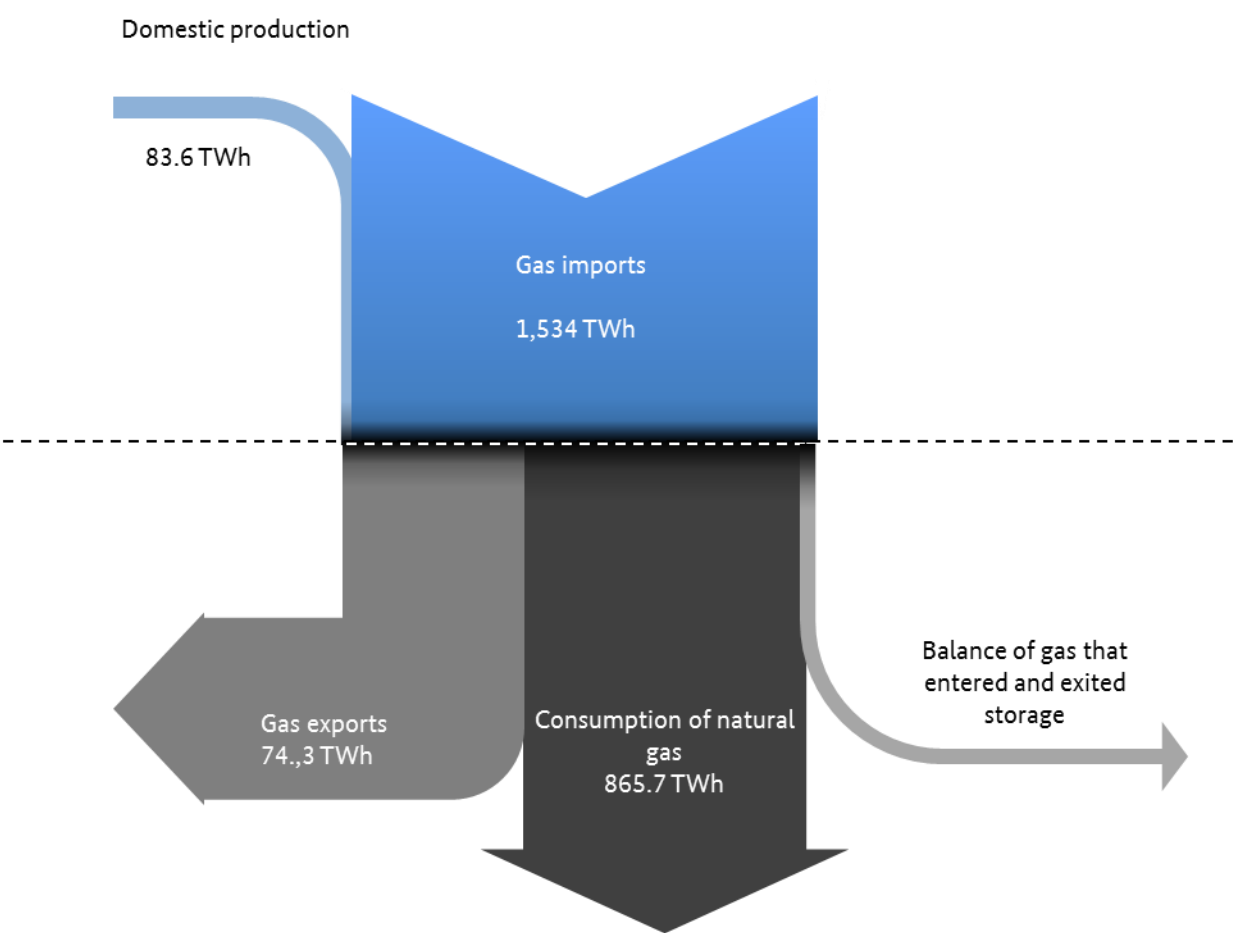

Figure 112: Gas resources and consumption in Germany in 2015

Number of gas network operators in Germany registered with the Bundesnetzagentur

	2008	2009	2010	2011	2012	2013	2014	2015	2016
Transmission system operators (TSOs)	18	18	18	14	17	17	17	17	16
Distribution system operators (DSOs)	686	712	712	711	739	724	714	714	715
DSOs with fewer than 100,000 connected customers	659	667	671	678	683	686	689	689	690

Table 73: Number of gas network operators in Germany registered with the Bundesnetzagentur

Gas DSOs were asked about the total length of their networks as well as the length subdivided according to pressure ranges (nominal test pressure in bar). The findings from the operators surveyed are as follows:

2015 network structure figures

	TSOs	DSOs	DSOs with > 100,000 customers	DSOs with < 100,000 customers	Total amount of TSO and DSO
Network operators	16	669	25	644	685
Pressure range (km)	37,809	481,103	168,107	312,996	518,912
≤ 0.1 bar	0	157,287	51,488	105,799	157,287
> 0.1 – 1 bar	1	231,602	86,588	145,014	231,603
> 1 bar	37,808	92,214	30,030	62,184	130,022
Number of offtake points	3,495	10,731,120	3,584,674	7,146,446	10,734,615
≤ 0.1 bar	0	5,793,596	1,709,008	4,084,588	5,793,596
> 0.1 – 1 bar	7	4,350,224	1,747,848	2,602,376	4,350,231
> 1 bar	3,488	587,300	127,818	459,482	590,788
Final customers (meter points)	567	14,123,577	6,195,762	7,927,815	14,124,144
Industrial and commercial customers and other non-household customers	500	1,736,107	13,174	1,722,933	1,736,607
Household customers	0	12,387,301	5,564,176	6,823,125	12,387,301
Gas fired power plants with a net electricity capacity of at least 10 MW	67	169	39	130	236

Table 74: 2015 network structure figures according to the TSO and DSO survey

The majority of gas DSOs (586 operators) have short to medium length networks up to 1,000 km. Of the remainder, 77 DSOs have gas networks with a total length of more than 1,000 km. The following figure shows a breakdown of DSOs according to network length:

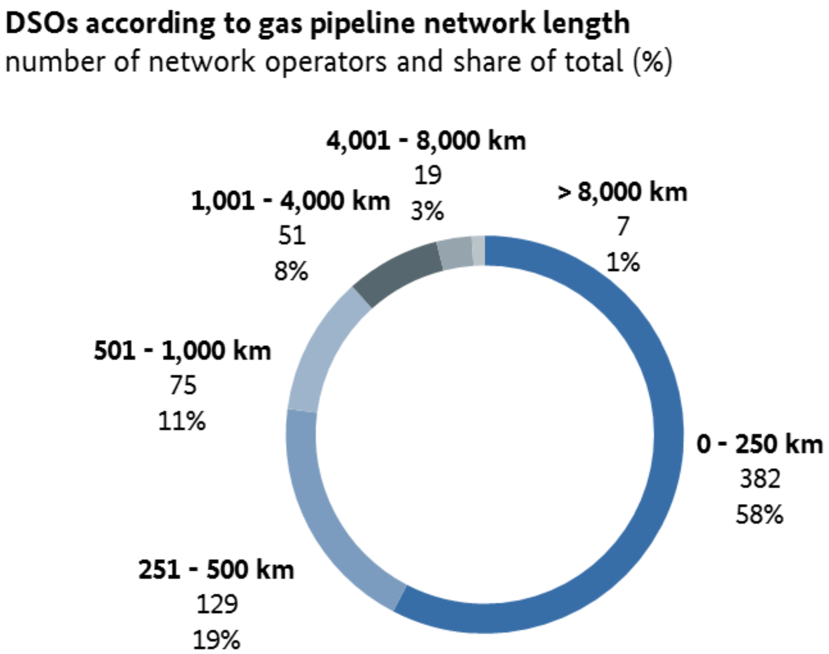

Figure 113: DSOs according to gas pipeline network length as stated in the DSO survey

The table below shows a breakdown of the quantity of gas provided to final customers in the network areas of the TSOs and DSOs surveyed in 2015.

Gas offtake volumes in 2015 broken down by final consumer category, according to the survey of gas TSOs and DSOs

	TSO offtake volume (TWh)	Share of total amount	DSO offtake volume (TWh)	Share of total amount
≤ 278 MWh/year	0.002	0.001%	311.6	44.1%
> 278 MWh/year ≤ 2,780 MWh/year	0.1	0.1%	81.9	11.6%
> 2,780 MWh/year ≤ 27,800 MWh/year	1.7	1.1%	86.6	12.3%
> 27,800 MWh/Jahr ≤ 278,000 MWh/Jahr	15.9	10.0%	104.3	14.8%
> 278,000 MWh/year ≤ 1,112,000 MWh/year	30.3	19.0%	60.3	8.5%
> 1,112,000 MWh/year	82.9	52.0%	22.9	3.2%
Gas fired power plants with ≥ 10 MW net nominal capacity	28.5	17.9%	38.7	5.5%
Total	159.4	100%	706.3	100.0%

Table 75: Gas offtake volumes in 2015 broken down by final consumer category, according to the survey of gas TSOs and DSOs

The following consolidated overview includes the total offtake of the gas TSOs and DSOs and that of suppliers to final consumers. For the first time, gas TSOs and DSOs were asked in the 2016 monitoring survey to provide figures on the volumes that mostly large final consumers (industrial customers and gas fired power plants) procure directly on the market themselves, ie not using the classic route via a supplier, and instead approach the network operator as a shipper (paying the transport charges themselves). The quantity of gas procured directly on the market amounted here to 57.2 TWh, equivalent to just under 36% of the total quantity of gas delivered by TSOs. With regard to gas distribution networks, the amount of gas procured without a conventional supplier contract amounted to 31.4 TWh, corresponding to a share of approximately 4.5% of the total supplied by the DSO. The total sum of gas procured directly on the market, amounting to almost 89 TWh, considerably reduces the deviation between the ascertained amount of gas taken off and the ascertained amount of gas delivered. The remaining difference can be attributed to incomplete answers to individual questions from the initial survey.

Total gas offtake volumes in 2015, according to the survey of gas TSOs and DSOs and total volumes of gas delivered according to gas supplier survey, broken down by final consumer category

	TSO and DSO offtake volume (TWh)	Share of total amount	Total volume of gas delivered by shippers (TWh)	Share of total amount
≤ 278 MWh/year	311.6	36.0%	296.5	39.4%
> 278 MWh/year ≤ 2,780 MWh/year	82.0	9.5%	74.5	9.9%
> 2.780 MWh/year ≤ 27,800 MWh/year	88.3	10.2%	77.5	10.3%
> 27,800 MWh/year ≤ 278,000 MWh/year	120.2	13.9%	100.6	13.4%
> 278,000 MWh/year ≤ 1,112,000 MWh/year	90.6	10.5%	73.9	9.8%
> 1,112,000 MWh/year	105.8	12.2%	87.9	11.7%
Gas fired power plants with ≥ 10 MW net nominal capacity	67.2	7.8%	42.5	5.6%
Total	865.7	100.0%	753.4	100.0%

Table 76: Total gas offtake volumes in 2015, according to the survey of gas TSOs and DSOs and total volumes of gas delivered according to gas supplier survey

Compared to the previous year, the total quantity of gas supplied by general supply networks in Germany increased in 2015 by 64.3 TWh or 8% to 865.7 TWh. The quantity of gas supplied to household customers (as defined in section 3 para 22 EnWG) rose by just over 13.5% to 254.5 TWh. There was a further decrease in the gas supplied to gas fired power stations with a nominal capacity of at least 10 MW. Some 38.8 TWh of gas was supplied to such gas fired power stations in 2015, a drop of over 10% compared to the previous year.

The structure of the gas retail market remained for the most part unchanged. There is a total of 5,625 entry points to the gas distribution networks, of which 212 entry points are for emergency entry only. A look at the number of meter points served by the DSOs shows that only 25 DSOs supply more than 100,000 meter points each. Out of a total of 14.1m meter points supplied by the DSOs in Germany, some 44% (6.2m), accounting for 43% (300 TWh) of the total gas supplies, are served by DSOs that supply more than 100,000 meter points. The majority (58%) of DSOs active in Germany supply between 1,000 and 10,000 gas customers.

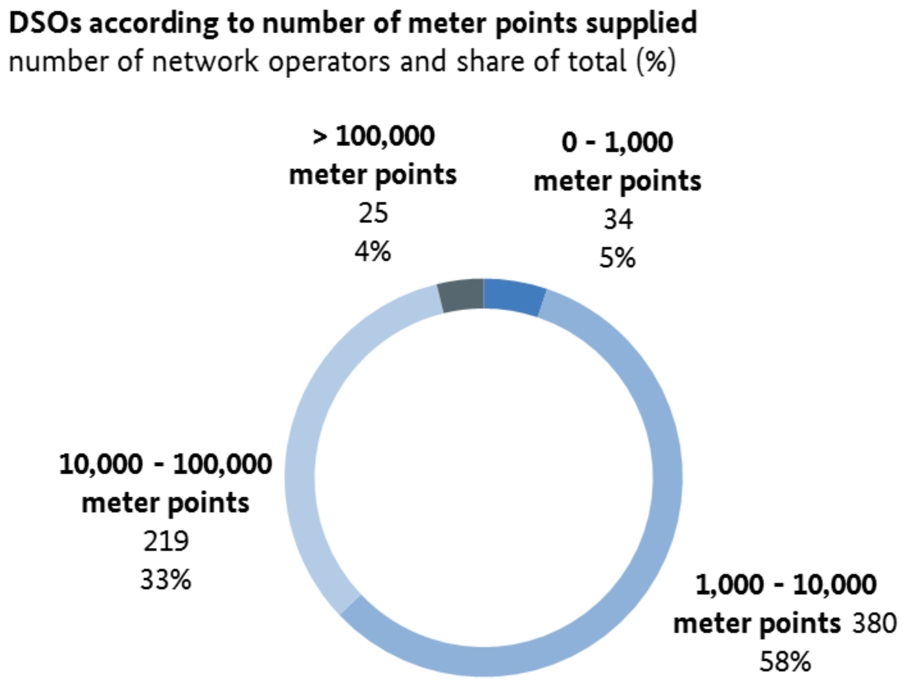

Figure 114: DSOs according to number of meter points supplied (data from the gas DSO survey)

3. Market concentration

The degree of market concentration is a good indicator of the intensity of competition. Market shares are a useful reference point for estimating market power because they represent (for the period of reference) the extent to which demand in the relevant market was actually satisfied by one company103. To represent the market share distribution, i.e. the market concentration, this report uses CR3 values (so-called "concentration ratio" which indicates the sum of the market shares of the three strongest suppliers). The larger the market share covered by only a few competitors, the higher the market concentration.

3.1 Natural gas storage facilities

In its decision-making practice the Bundeskartellamt defines a relevant product market for the operation of underground gas storage facilities which includes both porous rock and cavern storage facilities. In geographic terms the Bundeskartellamt has defined this market as a national market. It has also considered including the "Haidach" and "7Fields" storage facilities in Austria.[104] These two storage facilities are located near the Austrian-German border and are connected directly or indirectly to the German gas networks.

[103] Cf. Bundeskartellamt, Guidance on substantive merger control, para. 25.

[104] Cf. Bundeskartellamt, decision of 23 October 2014, B8-69/14 – EWE/VNG, para. 215 ff., Bundeskartellamt, decision of 31 January 2012, B8-116/11 - Gazprom/VNG para. 208 ff.

The European Commission also recently considered this alternative market definition, as well as some further alternatives, and ultimately left open the exact market definition.105 For the purposes of illustrating the concentration in the market for the operation of underground natural gas storage facilities, the Haidach and 7Fields storage facilities in Austria will be included in the following assessment. The Bundeskartellamt calculates the market shares in this market on the basis of storage capacities (maximum working gas volume).106

This year's survey, based on the questionnaire "Underground natural gas storage facility operators", again focused on all storage facilities and requested, among other data, information on working gas volumes at the reference date 31.12.2015. The storage facility operators are a total of 25 legal persons. The attribution of companies to a group was carried out according to the dominance method (cf. the methodological notes in section I.A.3 p. 31).

The market for the operation of underground natural gas storage facilities is characterised by a high level of concentration. However, there has been a decline in concentration compared to the previous year. On 31 December 2015, the maximum working gas volume of the underground natural gas storage facilities connected to the German gas network (i.e. including Haidach and 7Fields) amounted to approx. 27.6 billion Nm³. (previous year: 27.4 billion Nm³). On 31 December 2015, the aggregate working gas volume of the three companies with the largest storage capacities amounted to approx. 20.2 billion Nm³ (2014: 20.5 billion Nm³): The CR3 value thus decreased from approx. 74.9 % to approx. 73.3 %.

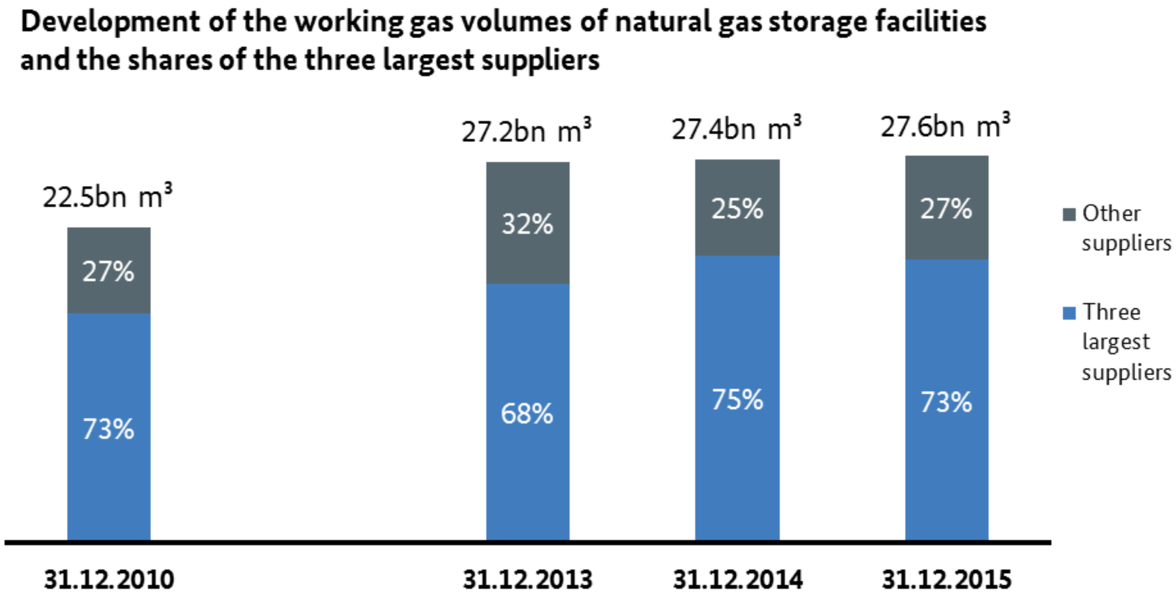

Figure 115: Development of the working gas volumes of natural gas storage facilities and the shares of the three largest suppliers

[105] Cf. COMP/M.6910 – Gazprom/Wintershall of 3.12.2013. para. 30 ff.

[106] Cf. Bundeskartellamt, decision of 23.10.2014, B8-69/14 – EWE/VNG, para. 236 ff.

3.2 Gas retail markets

On the gas retail markets the Bundeskartellamt differentiates between customers with metered load profiles and those with standard load profiles. Metered load profile customers are customers whose gas consumption is determined on the basis of a recording load profile measurement. These are generally industrial or large-scale commercial customers and gas power stations. Standard load profile customers are consumers with relatively low levels of consumption. These are usually household customers and smaller commercial customers. A standard load profile is assumed for the distribution of their gas consumption over specific time intervals. The Bundeskartellamt currently defines the market for the supply of gas to customers with metered load profiles and the market for the supply of gas to customers with standard load profiles on the basis of special contracts as national markets. The supply of gas to standard load profile customers in the default supply sector is a separate product market which is still defined according to the respective network area.107

In energy monitoring the sales volumes of the individual suppliers (legal persons) are collected as national total values. In the case of sales to standard load profile customers, a differentiation is made between default supply and supply on the basis of special contracts. The following analysis is based on the data of approx. 930 gas suppliers (legal persons) (2014: 800). In 2015, these companies sold a total of approx. 348 TWh of gas to standard load profile customers in Germany (2014: 321 TWh) and approx. 411 TWh of gas to customers with metered load profiles (2014: 391 TWh). In accordance with the Bundeskartellamt's practice of market definition, sales to customers with metered load profiles also include sales to gas power stations. Of the total volume of sales to standard load profile customers, special contracts accounted for approx. 284 TWh (2014: 261 TWh) and default supply contracts accounted for 64 TWh. (2014: 60 TWh). The increase in sales volume is generally attributed to the fact that temperatures were less mild than in 2014.

The attribution of sales volumes to the company groups was again carried out on the basis of the dominance method which provides sufficiently accurate results for the purposes of this report (cf. methodological notes in section I.A.3, p. 31).

In the case of customers with standard load profiles, the total cumulative sales of the three strongest companies amounted to approx. 76 TWh in 2015, approx. 64 TWh of which were accounted for by special contracts. In the case of customers with metered load profiles, sales amounted to at least 120 TWh. In 2015, the aggregated market share of the three strongest companies (CR3) thus amounts to about 22 % for standard load profile customers with special contracts (2014: 23 %) and about 29 % for customers with metered load profiles (2014: 32 %). These market shares continue to be clearly below the statutory thresholds for the presumption of market dominance (Section 18 GWB). Compared to the previous year, there was no change in market concentration in any of the two markets. For the standard load profile sector an additional calculation was made to determine the CR3 value for the supply of gas to all standard load profile customers throughout Germany (i.e. including default supply customers). As in the previous year, this resulted in a CR3 value of about 22 %.

With regard to the percentage shares provided, it should be noted that in the gas supply sector the monitoring survey has been significantly improved compared to the previous year but does not cover the whole market. The percentage shares are thus merely approximate to the actual values.

[107] Cf. Bundeskartellamt, decision of 23 December 2014, B8-69/14 – EWE/VNG, para. 129-214.

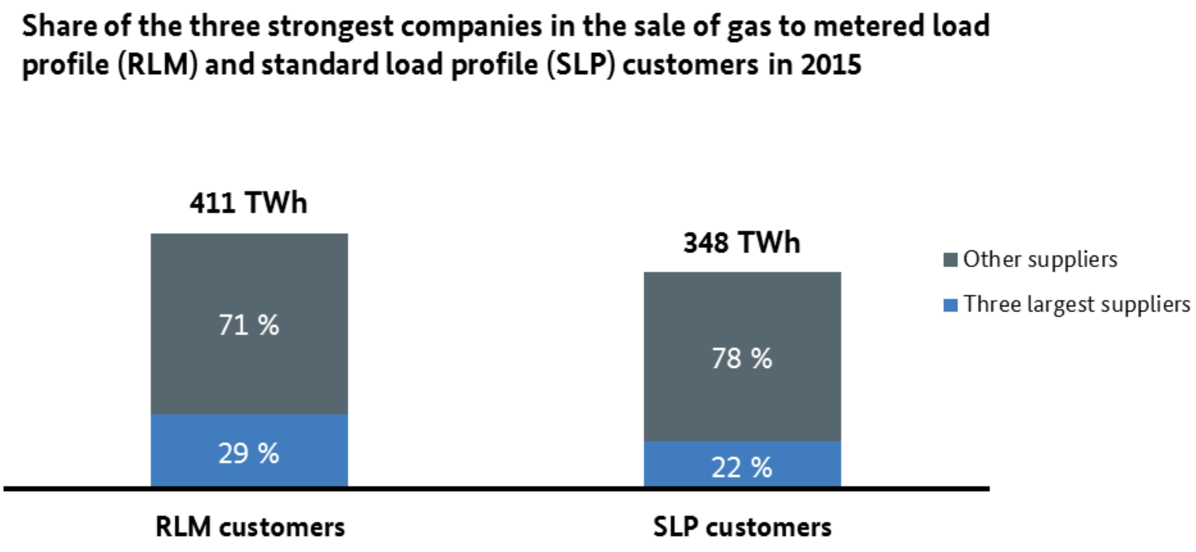

Figure 116: Share of the three strongest companies in the sale of gas to metered load profile (RLM) customers and standard load profile (SLP) customers in 2015

B Gas supplies

1. Production of natural gas in Germany

In 2015, natural gas production in Germany fell by 0.6bn m^3 to 8.5bn m^3 of gas (with calorific adjustment).[108] This corresponds to a decline of 6.9% compared to the previous year. The decline in natural gas production is chiefly due to the increasing exhaustion of the large deposits and the resulting natural decline in output.[109] Thus, Germany could only cover 9.7% of its own consumption through domestic gas production in 2015 (Working Group on Energy Balances (AGEB) 2016).

The reserves-to-production ratio of proven and probable natural gas reserves, calculated on the basis of the previous year's production and reserves, was 8 years as of 1 January 2016, compared to 8.8 years as of 1 January 2015. The reserves-to-production ratio does not take the natural decline in output from the deposits into account and therefore should not be seen as a forecast, but rather as a snapshot and guideline figure.[109]

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[108] Gas volumes with calorific adjustment are amounts measured in a manner that is commercially relevant. Calorific adjustment is used because natural gas is not sold according to its volume but according to its energy content (9.7692 kWh/m^3). In contrast, gas without calorific adjustment has a natural calorific value that may vary depending on the location of the deposit (in Germany this figure varies between 2 and 12 kWh/m^3).

[109] The results of the consultation have been published on the Bundesnetzagentur's website. http://www.bundesnetzagentur.de/cln_1412/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/NetzentwicklungundSmartGrid/Gas/NEP2012-2015/NEP_Gas2015/Netzentwicklungsplan_Gas_2015_node.html.

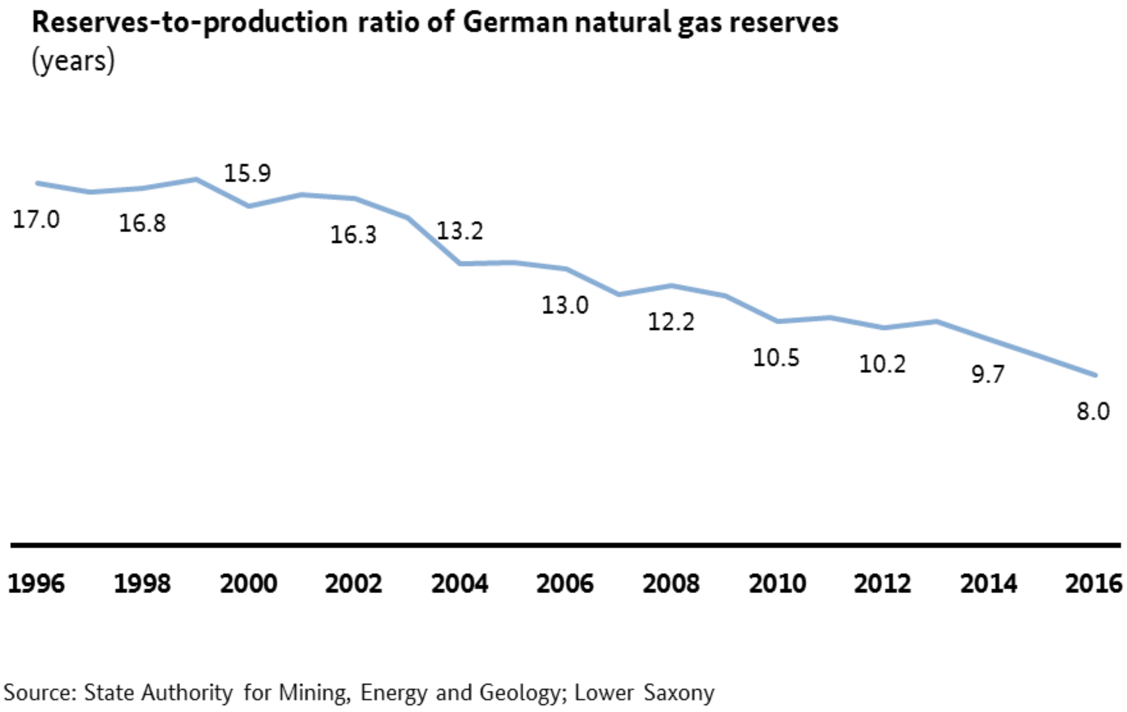

Figure 117: Reserves-to-production ratio of German oil and gas reserves since 1996

2. Natural gas imports and exports

A new database forms the basis for the 2016 Monitoring Report's analysis of gas volumes exported by and imported to Germany. The monitoring report now bases its assessment of imports and exports on the physical gas flows that enter and exit Germany at cross-border transfer points, reported daily by the TSOs to the Bundesnetzagentur. Because of the infrastructure in place, recorded import and export volumes may also include transit flows or loop-flows (eg volumes of gas that leave Germany at the Olbernhau cross-border transfer point using the GAZELLE gas pipeline and then re-enter the German network at the Waidhaus cross-border transfer point).

In 2015, the total volume of natural gas imported into Germany was 1,534 TWh. Based on the previous year's figure of 1,542 TWh, imports to Germany decreased slightly by 8.4 TWh, a drop of 0.5%. When looking at the countries of origin, the focus here is on the countries that Germany imports from at their given cross-border transfer point. Imports from the Netherlands decreased significantly (-10.6%) while imports from Russia through the Nord Stream pipeline rose by 11%.

The main sources of gas imports to Germany remain Russia and Norway. However, the Netherlands, as an established and liquid European producer, trading hub and point of arrival for LNG shipments with connections to natural gas fields in Norway and the United Kingdom, is also a significant source of imports for Germany. Improved integration of national markets and more efficient management of cross-border capacities has eased trading and provided further alternatives for gas traders.

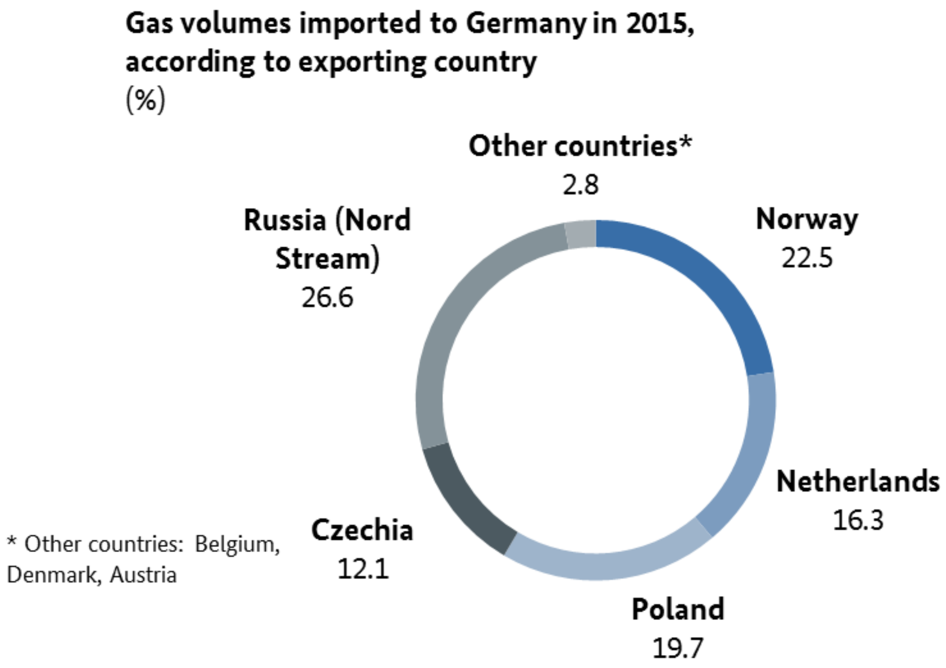

Figure 118: Gas volumes imported to Germany in 2015, according to exporting country

In 2015, the total volume of natural gas exported by Germany was 746.3 TWh. Based on the previous year's figure of 810.1 TWh, exports from Germany decreased significantly by 63.8 TWh or just under 8%. When looking at the destination countries, the focus here is on the countries that Germany exports to at their given cross-border transfer point. Just over half of Germany's gas exports go to Czechia. Exports to the Netherlands rose sharply (+27.5%), while there was a large decrease in exports to Austria (-36.7%) and Switzerland (-19.4%).

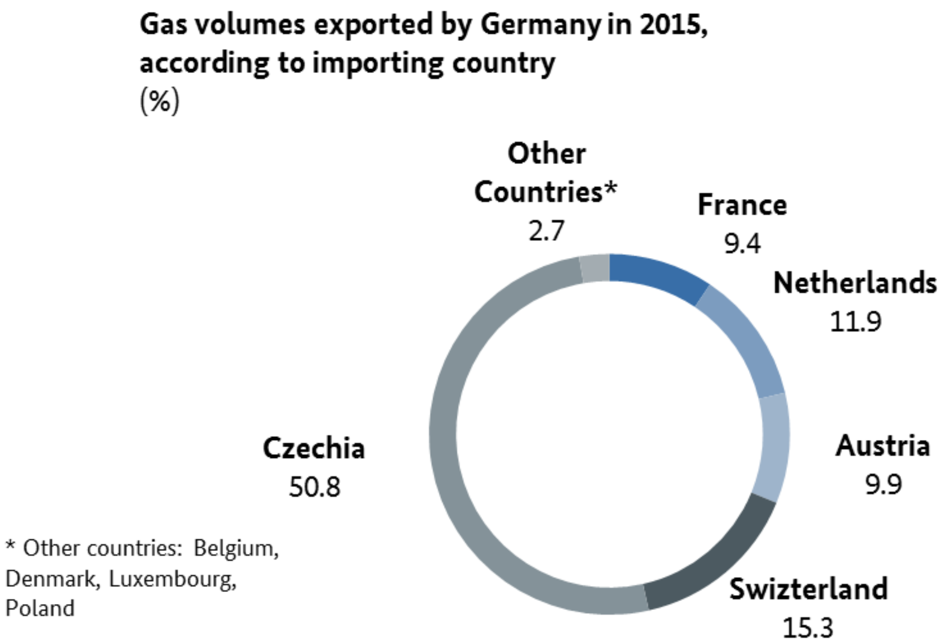

Figure 119: Gas volumes exported by Germany in 2015, according to importing country

The tables below are a consolidated look at the volumes of gas that were imported and exported, divided into countries exporting from and importing to Germany, giving a picture of the changes that took place between 2014 and 2015.

Change in gas imports

Exporting country	Imports in 2014 (TWh)	Imports in 2015 (TWh)	Year on year change (TWh)	Year on year change (%)
Belgium	21.3	20.7	-0.6	-2.8
Denmark	7.2	6.6	-0.6	-8.3
Netherands	280.1	250.5	-29.6	-10.6
Norway	337.3	345.1	7.8	2.3
Austria	13.3	14.9	1.6	12.0
Polen	304.9	302.6	-2.3	-0.8
Russia (Nord Stream)	367.6	408.1	40.5	11.0
Czechia	210.7	185.5	-25.2	-12.0
Total	1,542.4	1,534.0	-8.4	-0.5

Table 77: Change in gas imports between 2014 and 2015

Change in gas exports

Importing country	Exports in 2014 (TWh)	Exports in 2015 (TWh)	Year on year change (TWh)	Year on year change (%)
Belgium	8.4	6.4	-2.0	-23.8
Denmark	1.6	1.2	-0.4	-25.0
France	75.6	70.2	-5.4	-7.1
Luxembourg	5.6	3.7	-1.9	-33.9
Netherlands	69.5	88.6	19.1	27.5
Austria	116.3	73.6	-42.7	-36.7
Poland	12.3	8.1	-4.2	-34.1
Switzerland	142.1	114.6	-27.5	-19.4
Czechia	378.7	379.9	1.2	0.3
Total	810.1	746.3	-63.8	-7.9

Table 78: Change in gas exports between 2014 and 2015

According to the survey of gas suppliers and wholesalers there are 24 companies importing gas into Germany.

3. Biogas

Key biogas injection figures as of 31 December 2015 are as follows.

Biogas injection key figures

	Unit	2011	2012	2013	2014	2015
Number of facilities injecting biogas (including facilities injecting hydrogen)		77	108	144	185	190
Volume of biogas injected	m Ncm	275	413	520	688	774
Volume of biogas injected	m kWh	2,674	4,393	5,471	7,489	8,364
Ancillary costs of the gas network operators passed down to all network users	€m	78	107	131	154	178
Ancillary costs per kWh of biogas injected	ct/kWh	2.917	2.436	2.394	2.056	2.124

Table 79: Biogas injection, key figures for 2011-2012

C Networks

1. Network expansion and investments

1.1 Gas Network Development Plan

The gas network development plan includes measures for needs-oriented optimisation, reinforcement and expansion of the network, as well as for maintaining security of supply; these will be necessary in the next decade to ensure secure and reliable network operations. As required by law it has been published annually until 2016 but from now on will be published every two years. The content of the gas network development plan focuses firstly on expansion issues arising due to the connection of new gas power plants – there is an interconnection here with the electricity market – and of gas storage facilities and industrial customers. Secondly it looks at connections between the German gas transmission network and those in neighbouring European countries and at capacity needs in the downstream networks. Finally, the conversion of numerous network areas from low-calorific gas (L-gas) to high-calorific gas (H-gas) is an important element of the gas network development plan.

The gas network development plan 2015 was presented to the Bundesnetzagentur by the TSOs within the specified period on 1 April 2015. The document was then submitted for comprehensive consultation by the Bundesnetzagentur.[110] Taking the results of the consultation into account, the Bundesnetzagentur formulated a modification request addressed to the TSOs on 1 September 2015.

The necessity for the altogether 37 new measures contained in the gas network development plan 2015 is derived in particular from the market area conversion from L-gas to H-gas and, associated with that, the need to take account of higher consumption of H-gas. This topic plays an important role in the draft gas network development plan 2015 under the aspect of security of supply. The result is a concrete proposal for the gradual conversion of the areas over a period beyond 2025 to the year 2030.

In its modification request, the Bundesnetzagentur instructed the TSOs to remove two of the 56 proposed network expansion measures from the gas network development plan 2015 because they did not yet have the degree of specification required for approval. The Bundesnetzagentur instructed the TSOs to modify one additional measure. The gas network development plan 2015 became binding on the TSOs with the announcement of the modification request. The TSOs have now implemented the modification request and published the modified gas network development plan 2015.[111]

[110] The results of the consultation have been published on the Bundesnetzagentur website: http://www.bundesnetzagentur.de/cln_1412/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/NetzentwicklungundSmartGrid/Gas/NEP2012-2015/NEP_Gas2015/Netzentwicklungsplan_Gas_2015_node.html.

[111] http://www.fnb-gas.de/de/netzentwicklungsplan/nep-2015/nep-2015.html.

On 1 April 2016, the TSOs presented the Bundesnetzagentur with a draft version of the gas network development plan 2016 to 2026.[112] For the most part, the measures included in the gas network development plan 2015 are confirmed by the outcomes of the gas network development plan 2016 to 2016. In addition, looking ahead until 2026 the TSOs propose a further 39 expansion measures that result primarily from the market area conversion made necessary by falling L-gas imports from the Netherlands over the coming years, consideration of an increased need for H-gas and increased capacity requirements for planned reserve gas power plants. Another reason for individual measures is the increased need for capacity in the distribution network, especially in southern Germany.

The draft gas network development plan 2016 to 2026 contains two different modelling variants, which reflect the differences in distribution of the origin of the additional H-gas needed in Germany. One of the modelling variants assumes that the extension of the Nord Stream pipeline will take place. The two variants differ considerably in terms of their network expansion measures and expansion costs: the variant without the Nord Stream extension results in an investment volume of €3.9bn by 2026, while the variant including the Nord Stream extension entails six further measures with an additional investment volume of roughly €500m.

The TSOs' NDP proposal that was selected from these two variants includes the Nord Stream extension, and all in all translates into line construction of 802km, increased compressor capacity of 526 MW and an investment volume of around €4.4bn for the period up to 2026.

[112] The draft gas network development plan 2016–2026 is available on the internet at: http://www.fnb-gas.de/de/netzentwicklungsplan/nep-2016/nep-2016.html.

Network expansion measures Gas NDP 2015 and Gas NDP 2016

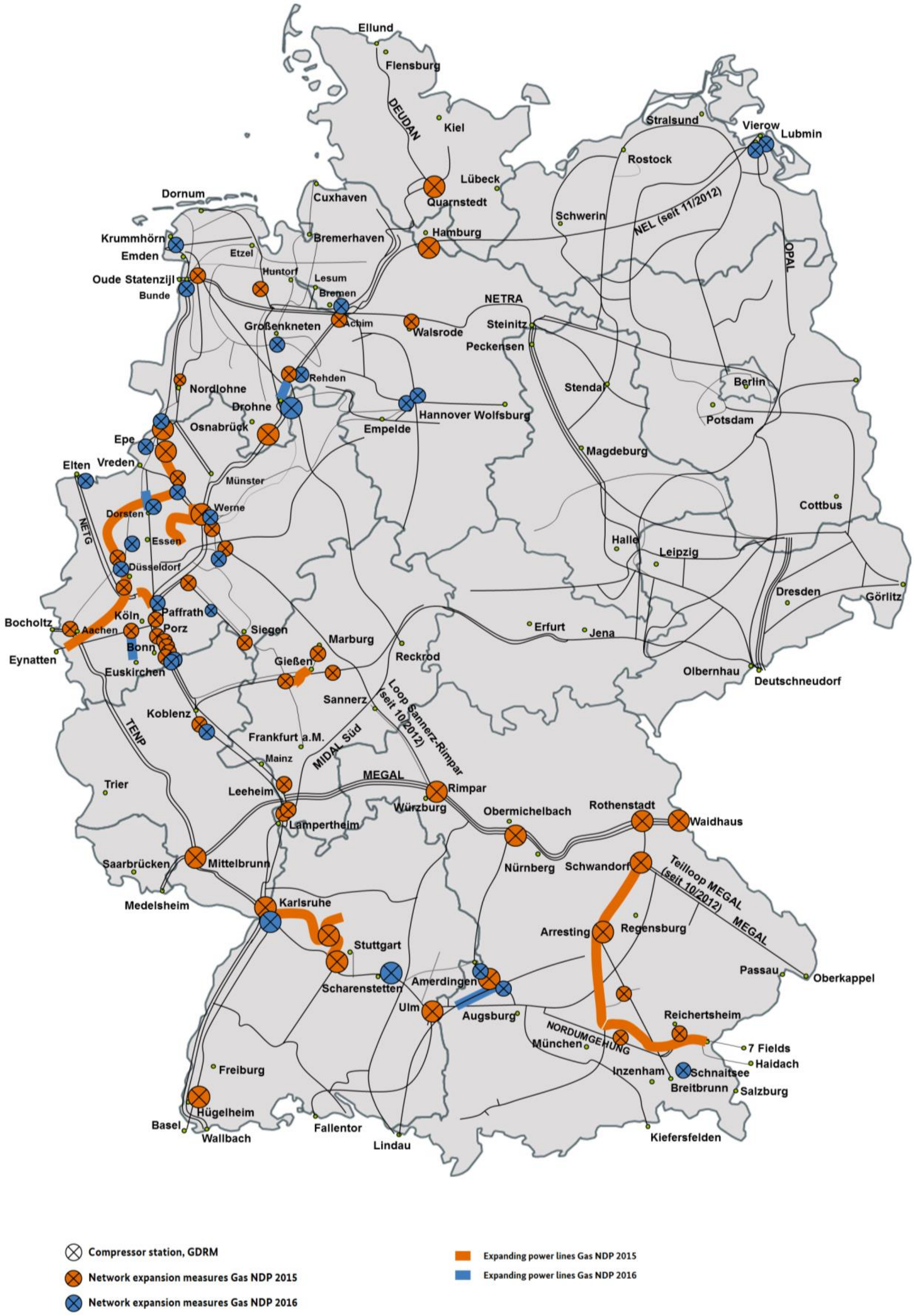

Figure 120: Confirmed network expansion measures Gas NDP

1.2 Investments in and expenditure on network infrastructure

Investments are considered to be gross additions to fixed assets capitalised in the year under review and the value of new fixed assets newly rented in the year under review. Expenditures consist of the combination of any technical, administrative or management measures taken to maintain or restore working order to an asset during its life cycle so that it can perform the function required. The results shown below are the figures supplied by the TSOs and DSOs under commercial law. No correlation with the imputed values in the revenue cap can be deduced from these figures.

In 2015 the 16 German TSOs invested a total of €495.9m (2014: €527.4m) in network infrastructure. Of this total, €340.7m (2014: €383.6m) was investment in new installations/expansion/extension and €155.2m (2014: €143.8m) in maintenance/renewal of network infrastructure. Of the total investments in 2015, 48% can be attributed to the transmission systems in the GASPOOL market area and 52% to the NCG market area (2014: 58.6% GASPOOL, 41.4% NCG). The investments planned for 2016 amount to a total of €644.4m, which would equate to an increase of 30% compared to 2015. This relatively large fluctuation is a result of investments in a few individual large-scale projects.

Across all TSOs, expenditure on maintenance and repair of network infrastructure amounted to €365.5m in 2015 (2014: €266.6m), of which 51.8% was applicable to the GASPOOL market area and 48.2% the NCG market area (2014: 48.1% GASPOOL, 51.9% NCG). The overall total for investments and expenditure across all TSOs is thus approximately €861.4m. The chart below shows investments and expenditure both separately and as a sum total since 2013, as well as the planned figures for 2016.

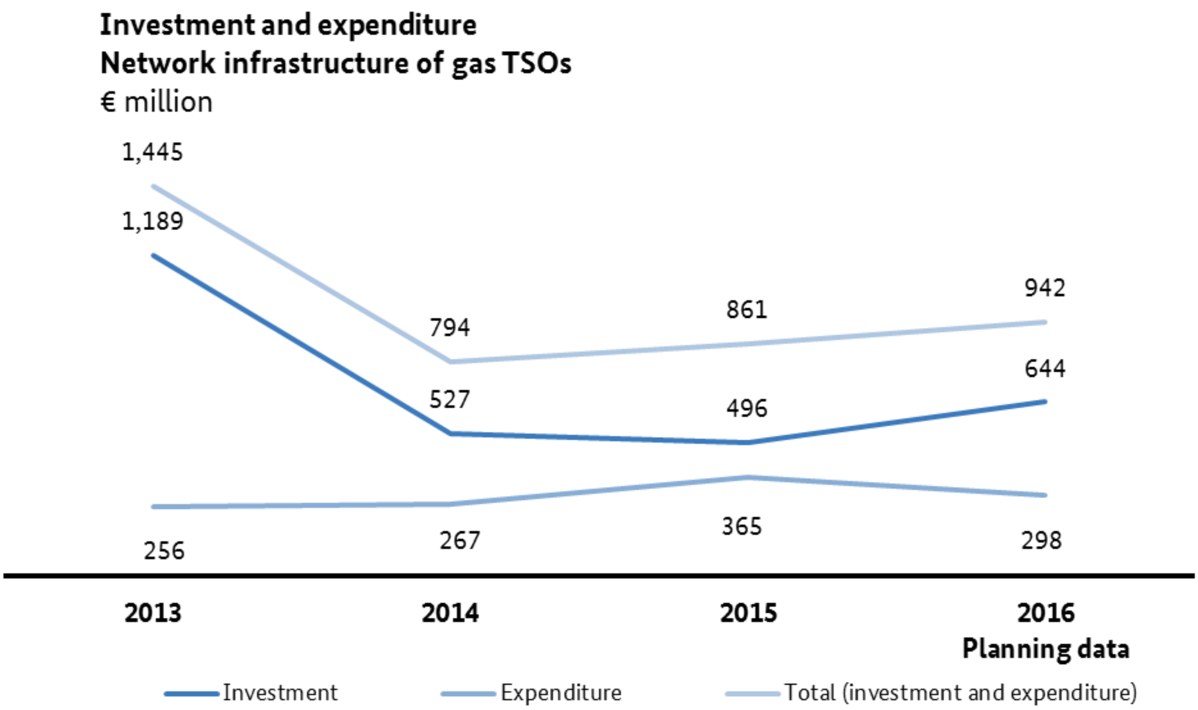

Figure 121: Investments in and expenditure on network infrastructure by TSOs

In the course of data collection for the 2016 Monitoring Report, around 600 DSOs declared investment in new installations, expansions and extensions (€681.5m) and maintenance and repair (€430.5m) of network infrastructure totalling €1,112m for 2015, a slightly lower amount compared with the previous year (€1,155m) (-3.7%). This means that the DSOs invested €33m more in distribution networks in 2015 than originally planned (€1,079m).

According to the DSOs' reports, expenditure on maintenance and repair in 2015 was €1,203m, amounting to an increase of almost 12% compared with the previous year's figure (€1,075m). Expenditure on distribution networks was therefore €45m higher than the amount originally planned by the DSOs for 2015, namely €1,158m.

The DSOs' plans for 2016 include a decreasing volume of investment, totalling around €1,007m, and falling expenditure on network infrastructure, amounting to €1,042m.

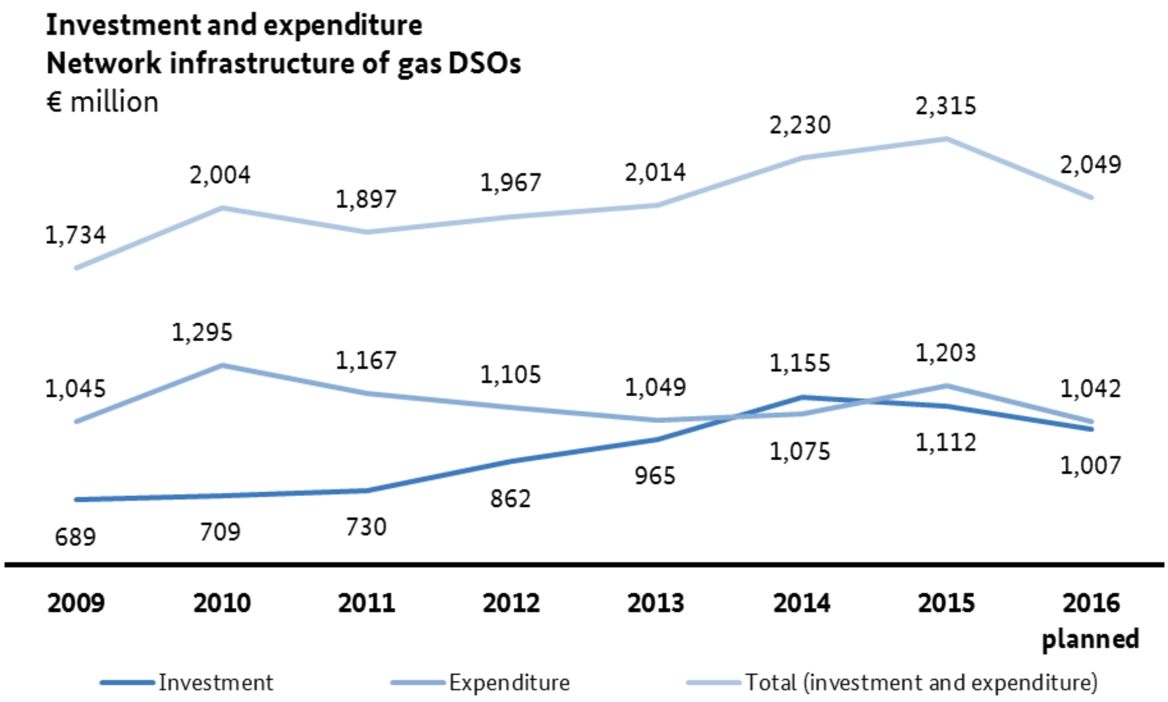

Figure 122: Investments in and expenditure on network infrastructure by gas DSOs

The level of DSO investment depends on the length of their gas pipeline network, the number of meter points served as well as other individual structure parameters, including, in particular, geographical circumstances. As a rule, DSOs tend to invest more the longer their pipeline networks are. While 133 of the surveyed gas DSOs reported investments of between €500,001 and €1m, only 49 gas DSOs made investments totalling more than €5m.

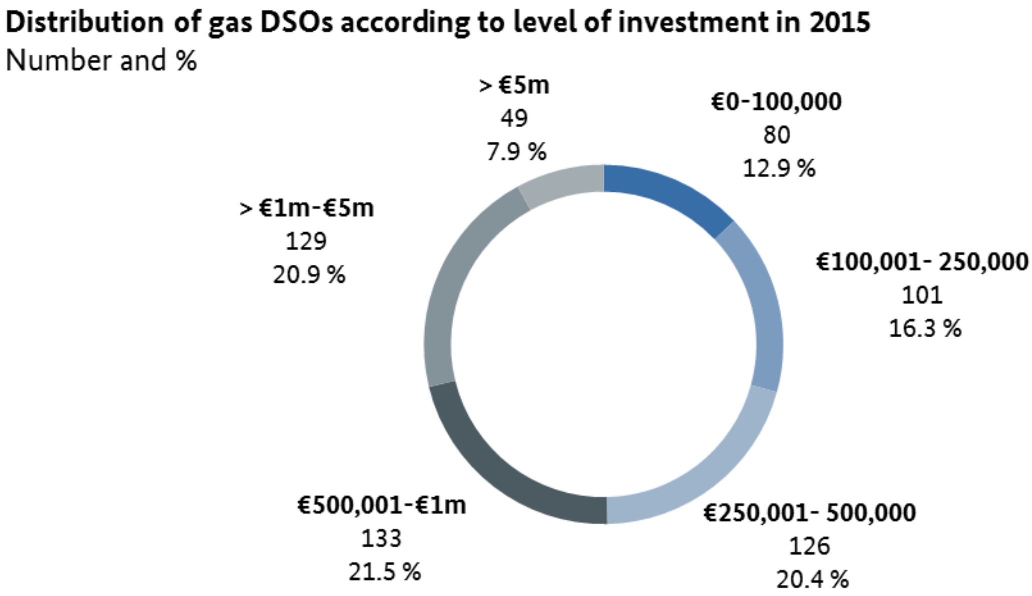

Figure 123: Distribution of gas DSOs according to level of investment in 2015

Of the surveyed gas DSOs, 129 reported total expenditures in the bracket between €100,001 and €250,000, while only 55 gas DSOs reported expenditures totalling more than €5m.

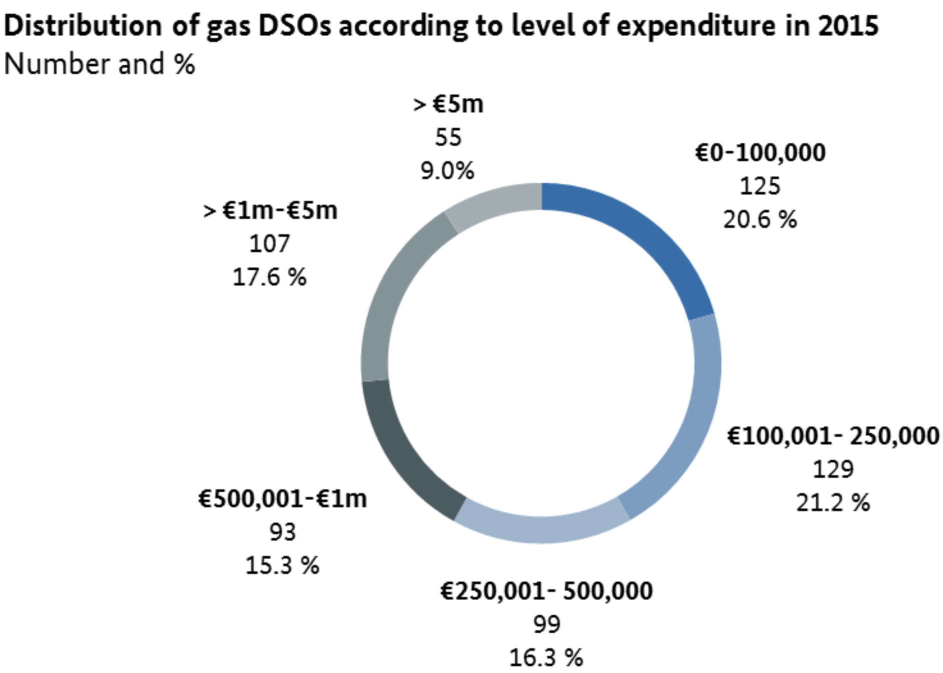

Figure 124: Distribution of gas DSOs according to level of expenditure in 2015

1.3 Investment measures and incentive-based regulation

The Ordinance concerning Incentive Regulation for the Energy Supply Networks (ARegV) offers network operators an opportunity to budget for costs for expansion and restructuring investment beyond the authorised revenue cap of network tariffs. Based on section 23 ARegV, upon application the Bundesnetzagentur grants approval for individual projects insofar as the prerequisites stated in the Ordinance have been met.

Since the amendment to section 23 ARegV in spring 2012, approval of a project is granted on the merits of the investment. Once the approval has been given, the network operator may adjust his revenue cap by the costs of capital and of operation connected to the project immediately in the year the costs are incurred. The costs budgeted are checked by the Bundesnetzagentur in an ex-post control.

As of 31 March 2016, 158 applications for investment projects in the electricity and gas markets had been submitted to the competent Ruling Chamber. Costs of acquisition and production of about €8.87bn are linked to these investment measures across these sectors. Compared to 2015, the number of applications across the sectors fell slightly (2015: 164 applications), whereas the total investment volume covered by the applications rose considerably (2015: €5.53bn). Gas network operators submitted 61 applications in total with an investment volume of about €4.8bn.

2. Capacity offer and marketing

2.1 Available entry and exit capacities

In 2015, as before, the questions asked dealt with the booking, use, availability and booking preference for transport capacity. Distinctions were again made between the various capacity products offered on the market. The questions concerned the median offer of firm capacity at cross-border and market area interconnection points and also at points of interconnection with storage facilities, power stations and final consumers. This survey does not include the reserve capacity agreed with the downstream network operators within the internal booking process since the network interconnection points with distribution networks are not marketed directly to shippers (see section II.C.2.4).

Across all firm capacity products the total entry capacity of all TSOs increased by 22.1m kWh/h to 512m kWh/h. There is a notable decline in firm and freely allocable capacity (FZK). Although this capacity product still constitutes the largest proportion of firm products offered in both market areas, the total shows a decrease of 3.2% compared to the previous year. The increase in firm entry capacities is primarily the result of increased availability of capacity with conditional firmness and allocability (bFZK) and of dynamically allocable capacities (DZK). As the survey did not include detailed questions on the capacity offer it is not possible to assume that FZK offers were substituted by products with allocation restrictions.

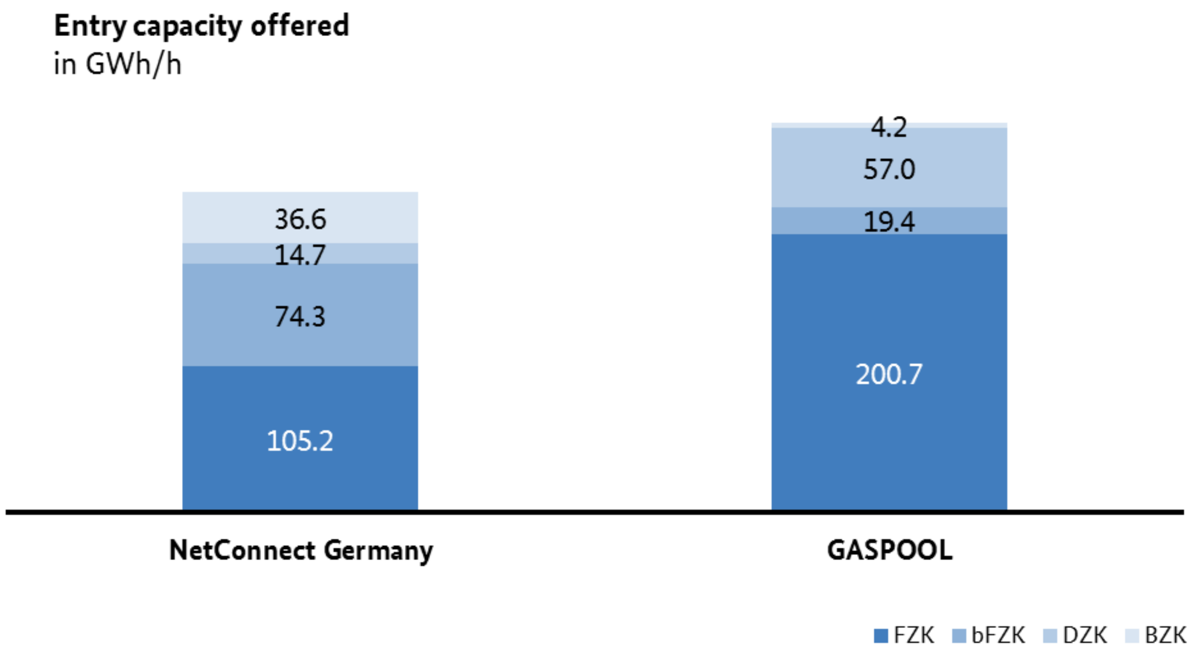

Figure 125: Entry capacity offered

In contrast, the exit capacity decreased by 7.2m kWh/h to 310.9m kWh/h compared to the previous year. One reason for this development is the shifting of unbooked capacities at the marketable points in order to be able to consolidate or remove the time limit on a higher degree of internal booking. In this case, too, the offer of FZK capacities in particular declined. It should be noted that not every TSO offers all capacity products. The aggregated developments therefore cannot be projected onto each individual TSO.

The greater overall availability of entry capacities compared with exit capacities can be explained first and foremost by the fact that Germany is an import country. Because network planning is geared to this, more entry capacities than exit capacities are marketed at cross-border interconnection points. As described above, the capacities for distribution networks and therefore the majority of final consumers are not included in this list because they are not marketed directly to the shippers by the transmission system operators. These marketing levels should therefore not lead to the drawing of incorrect conclusions. Overall, the German gas networks have more exit capacity than entry capacity across all network levels.

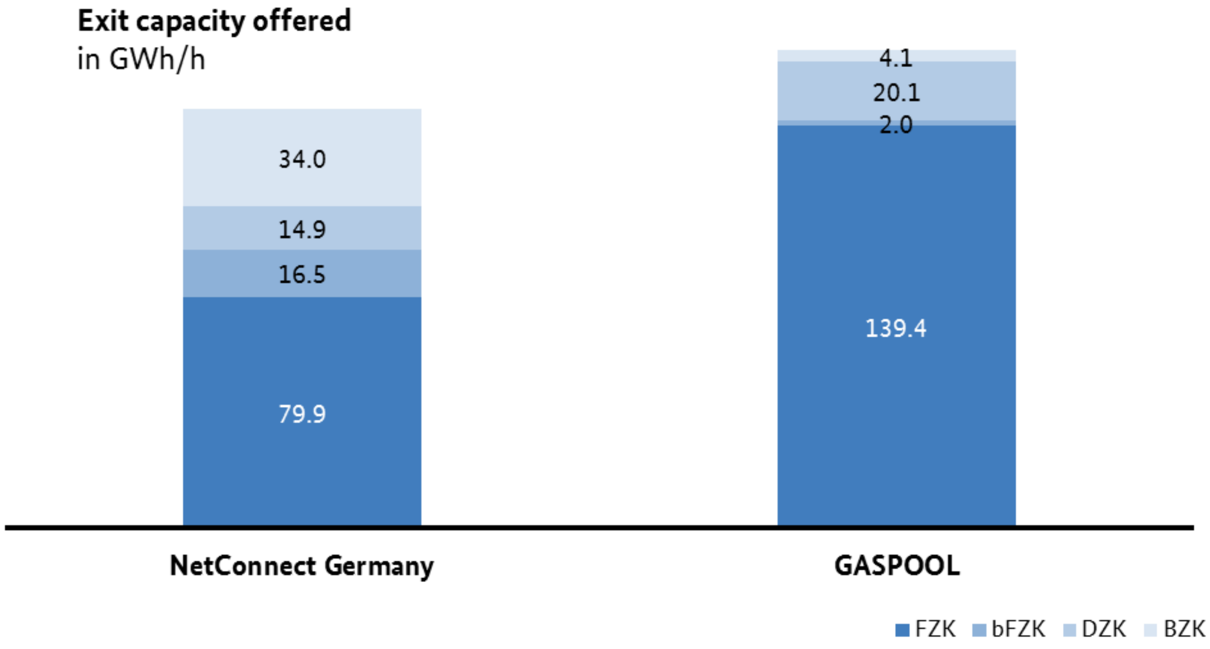

Figure 126: Exit capacity offered

According to section 12 para 3 of the cooperation agreement (KoV) VIII annex 1, renominations at market area and cross-border interconnection points are subject to a restriction. The renomination is permitted if it does not exceed 90% of the total (firm) capacity booked by shippers at the booking point and does not fall below 10% of the booked (firm) capacity. In the case of initial nominations of a minimum of 80% of booked (firm) capacity, half of the unnominated capacity is allowed for upward renomination. In the case of initial nominations of a maximum of 20% of booked (firm) capacity, half of the unnominated capacity is allowed for downward renomination. Renomination beyond these restrictions remains possible but is equated to the nomination of interruptible capacity. The restrictions allow TSOs to offer more capacity than is the case in a base case without a renomination restriction. Once again, this instrument enabled a large amount of additional capacity to be offered. In the year 2015, the offer of entry capacity through TSOs' renomination restrictions amounted to 2m kWh/h in the NCG market area, which corresponds to an increase of 38.2% compared with the year 2014. The offer of corresponding exit capacity increased by 83% to 2.7m kWh/h. In 2015, TSOs in the GASPOOL market area were able to increase the offer of entry capacities based on renomination restrictions by 55.2% to 2.2m kWh/h. The exit capacities offered in 2015 increased by 169.1% to 35m kWh/h compared to 2014.

2.2 Termination of capacity contracts

During the reporting period, a total of 81 long-term capacity contracts were terminated, of which 68 were at cross-border points, nine at storage facility connection points and five at market area interconnection points. The following kinds of capacity were affected: 61x FZK, 10x interruptible, 9x DZK and 1x BZK. The terminated contracts had a median contract term of 3.6 years and comprised capacity rights averaging 1.9m kWh/h. The reasons for the termination of capacity contracts are varied and may include the dissipation of further contractual congestion situations as well as the secured procurement of short-term capacity.

The changing booking situation offers the TSOs both opportunities and risks. On the one hand the fact that the capacity bookings by the shippers are tied more closely to physical transport requirements enables them to align their offer of capacity more precisely to market needs. Capacity can be shifted from points of low demand to points where it is high, provided this is hydraulically possible. On the other hand there is the challenge posed by the TSOs' liquidity planning and network charge calculation. When it is more difficult to forecast booking patterns it becomes harder to set specific charges and plan revenue flows.

2.3 Interruptible capacity

Interruptible gas capacity is, as a rule, less expensive than firm capacity. It does however involve the risk that the desired gas transport may not be possible. Key elements for calculating the tariffs for interruptible capacity were defined in the Determination for Pricing Entry and Exit Capacity ("BEATE") (see section II.C.3).

A total of 16 gas wholesalers and suppliers with contracts involving interruptible capacity stated that they had in fact experienced interruptions in the 2014/15 gas year. As in recent reporting years, there was a very uneven distribution of both the number and the length of the interruptions among the various wholesalers and suppliers. Apart from the duration of interruption in hours, the diagram below also shows the absolute number of interruptions experienced by the wholesalers and suppliers in the particular gas year. Compared with the previous year, both the number of interruptions and the average interruption duration rose, with an average interruption duration of 14.3 hours, up from13.7 hours in the year before. Overall, the duration of interruption for all affected companies again increased compared with the previous year (gas year 2014/15: 1,515 h; gas year 2013/14: 946 h; gas year 2012/13: 1,975 h; gas year 2011/12: 6,753 h). There was also a slight increase in the absolute number of affected wholesalers and suppliers whose contracts were interrupted at least once, compared with previous years (gas year 2014/15: 16; gas year 2013/14: 10; gas year 2012/13: 11; gas year 2011/12: 14).

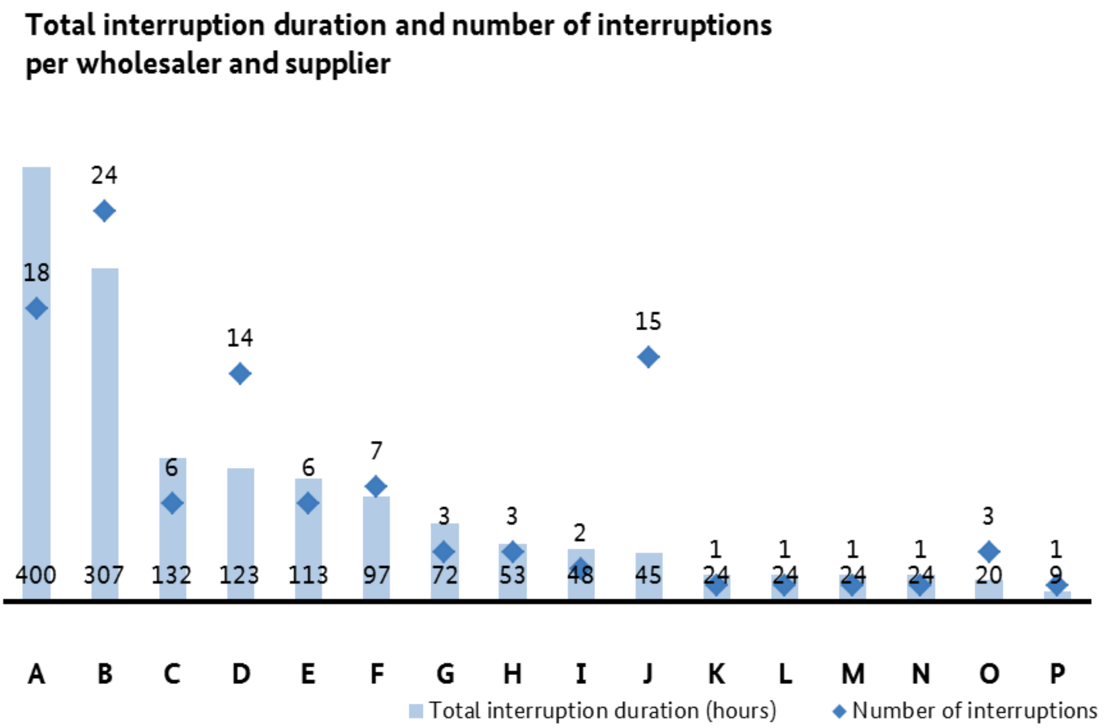

Figure 127: Total interruption duration in hours and number of interruptions per wholesaler and supplier

The diagram can be elucidated by a brief explanation of a single example: The diagram includes the 16 wholesalers and suppliers who experienced at least one interruption in the period under review and reported this in the survey, specifying the respective pair of values of interruption duration and frequency. The company with the highest interruption duration (column 1) experienced a total of 18 interruptions lasting a total of 400 hours.

Both shippers and transmission system operators were surveyed on the duration of interruption and interrupted volume of both interruptible and firm capacity products in relation to the initial nomination or alternatively the last figure renominated by the shipper before the interruption was made known.

In 2015, the volume of initially (re-)nominated gas that was not transported through all entry and exit points into or out of the market area was 2.6bn kWh (2014: 6.6bn kWh). Of this, the interruption of interruptible capacity made up the majority (92.1%). Through the interruption of interruptible capacity, a total of 2.4bn kWh of the nominated volume was not transported. The majority of interrupted volume (65.3%) is attributed to interruptions at cross-border interconnection points. The share of interruptions at storage facility connection points was 33.8%; the remainder of the interruptions were attributed to inter-market-area transports.

With regard to firm capacity contracts (which include FZK, bFZK, DZK and BZK), interruptions at cross-border interconnection points made up the majority (99.8%) of interrupted volume, with interconnection points to storage facilities accounting for 11.7%. In addition, two cases of interruptions at final consumer connection points were reported. There was no nomination obligation at these connection points, so in these cases no data is available on interrupted volumes according to the above definition.

The following diagram depicts the regional distribution of interruptions. The interrupted volumes depicted relate to the share of the nominated volume that was not transported due to an interruption issued by the TSO. In relation to the total nomination volume accepted, there were interruptions to 0.05% of the volume nominated by shippers at entry points and 0.14% at exit points. As mentioned above, however, a majority of interruptions were attributed to volume from interruptible transport contracts.

The direction of the arrow shows in which direction transmission was interrupted. In this context it is important to note that the width of each arrow grows in proportion to the share of the volume interrupted in relation to total interruption.

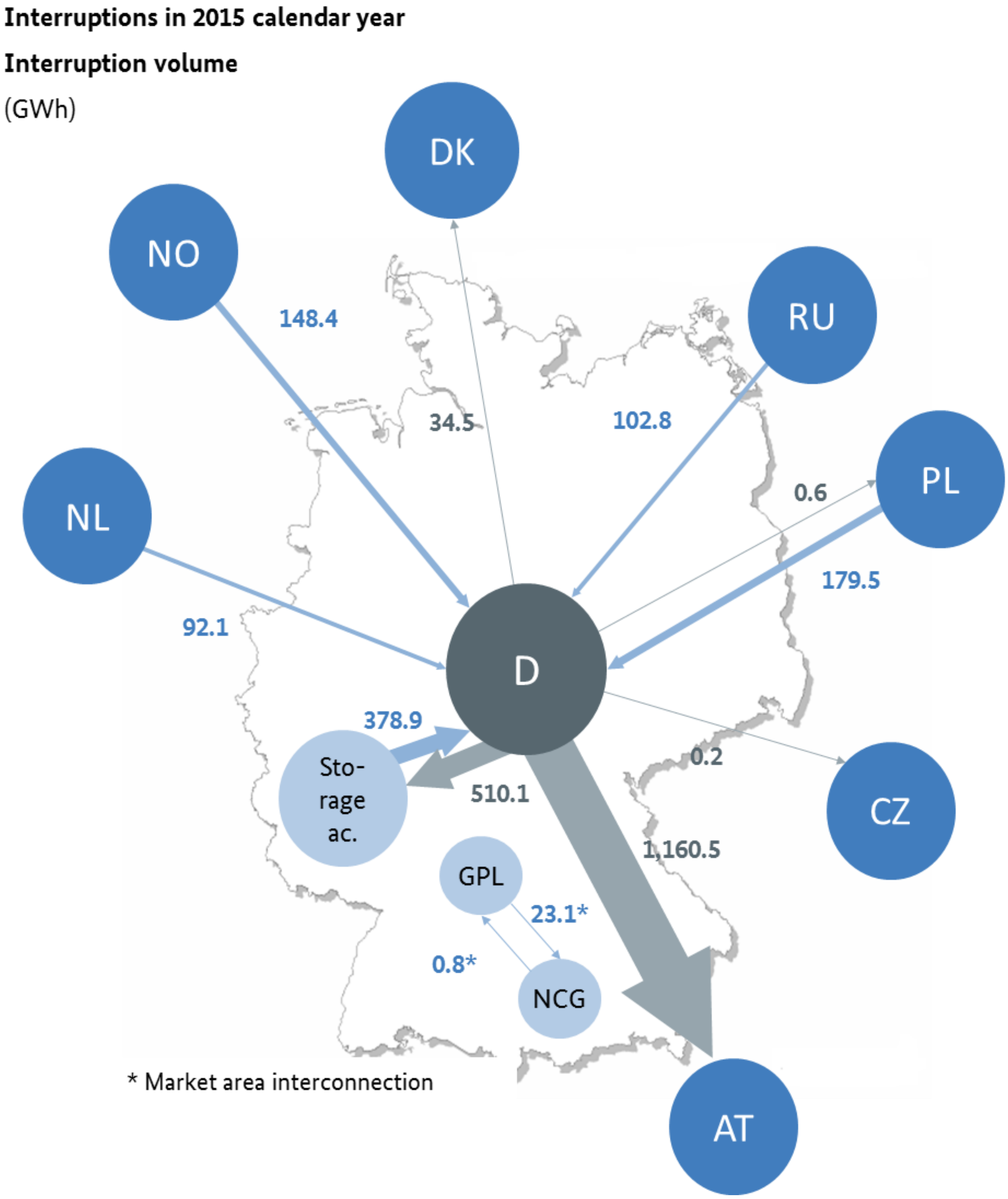

Figure 128: Interruption volumes according to region

2.4 Internal booking

A fundamental element of the TSOs' capacity model is the firm exit capacity (internal booking) agreed with the downstream network operators. Although this reserve capacity is not booked by shippers, it still has a significant influence on the level of firm capacity offered at marketable entry and exit points. In 2015, internal booking by the downstream network operators in the NetConnect Germany market area amounted to a total of 157.4 GWh/h. Altogether the TSOs were able to make firm commitments, either with or without a time limit, to 99.8% of this total.

In the GASPOOL market area a reserve capacity totalling 101.7 GWh/h was booked, with the proportion of firm commitments with or without a time limit amounting to 99.5%.

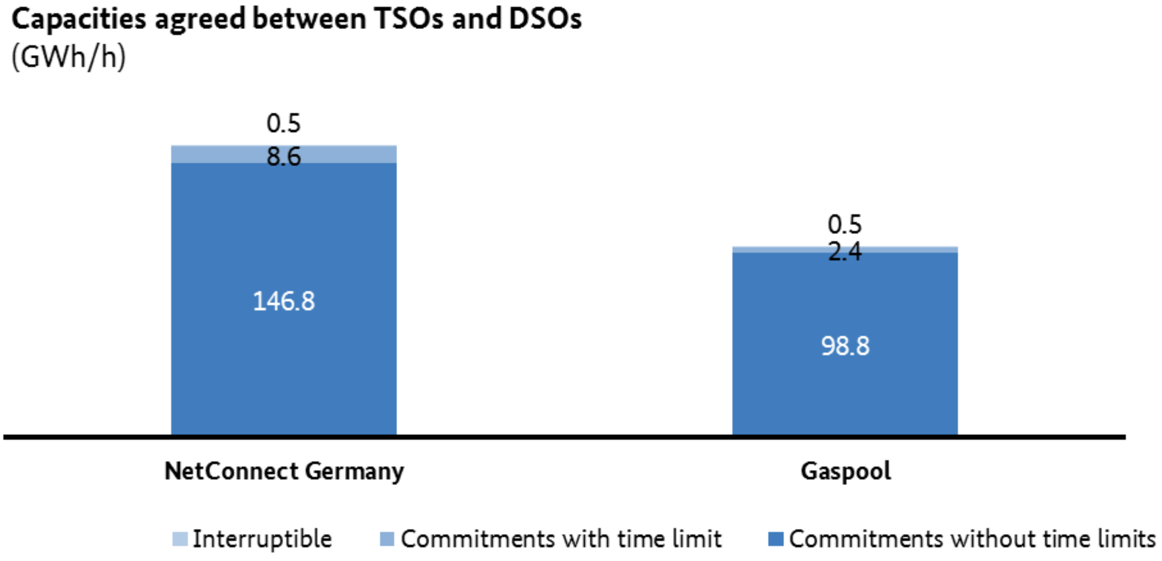

Figure 129: Capacities agreed between TSOs and DSOs

3. Gas supply disruptions

As in the previous years, the Bundesnetzagentur again conducted a comprehensive survey of all gas supply interruptions throughout the Federal Republic of Germany. Section 52 of the Energy Act (EnWG) requires gas network operators to report all interruptions in supply during the previous year to the Bundesnetzagentur by 30 April of each year. The Bundesnetzagentur uses the information to calculate the system average interruption duration index (SAIDI). This indicates the average interruption duration per final customer over the course of one year. The SAIDI does not take into account scheduled interruptions, nor those caused by force majeure, for example by natural disasters. Only unplanned interruptions caused by third-party intervention, ripple effects from other networks or other disturbances in the network operator's area are included in the calculations.

The 2015 results of the comprehensive survey of supply disruptions in all existing gas networks in the Federal Republic of Germany that are registered in the Bundesnetzagentur's energy database (approximately 730) were as follows:

SAIDI results for 2015

Pressure range	Specific SAIDI	Comments
≤ 100mbar	0.94 min/a	Household and small consumers
> 100mbar	0.76 min/a	High-volume customers, gas-fired power plants
> 100mbar	0.03 min/a	Downstream network operators
All pressure ranges	1.7 min/a	SAIDI value for all final customers

Table 80: SAIDI results for 2015

The SAIDI figures for gas networks in Germany have been calculated by the Bundesnetzagentur since 2006. The figures have been as follows over the years[113]:

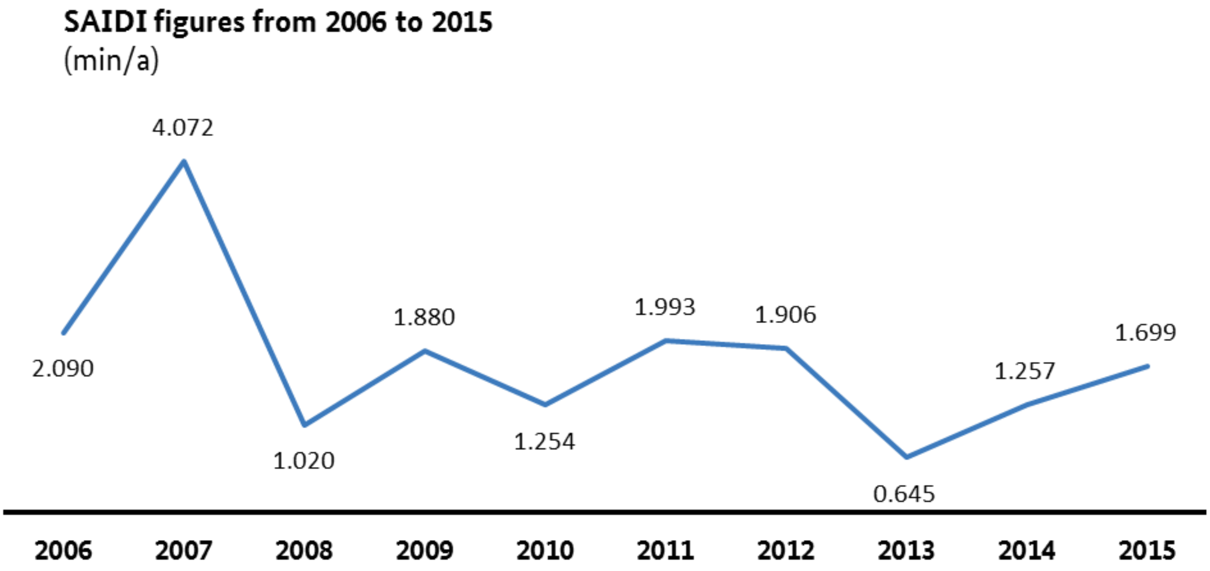

Figure 130: SAIDI figures from 2006 to 2015

4. Network tariffs

The network charge is a fee every network user utilising the network must pay to the network operator. This fee is usually part of the gas charge that gas customers pay to their gas supply company. The level of the network charge cannot be determined on the basis of free competition because gas networks are natural monopolies. Consequently, network tariffs are regulated by the regulatory authorities, which set the network charge on the basis of an individual efficiency-based revenue cap for each network operator within the framework of incentive-

[113] The 2014 figures were compiled without taking the Rhine-Main natural gas pipeline (ERM) accident into account. If this accident is included in the calculations the SAIDI for 2014 is about 16.8 minutes.

based regulation. The revenue cap itself is set by the regulatory authorities for one regulatory period, a period of five years. This is based on a cost examination for the respective regulatory period. The network charge is made up of several elements. In most cases users pay a basic charge or a capacity price for the service provided and also a commodity price for the volume of gas supplied. Additional charges include metering and accounting fees. It is mandatory for network operators to publish their network tariffs online.

4.1 Development of network tariffs in overall gas price between 2007 and 2016

The following figure shows the development of the average volume-weighted net gas network tariffs for three consumption categories in ct/kWh from 1 April 2007 to 1 April 2016. The charges include upstream network costs as well as charges for billing, metering and metering operations. The values shown are based on data provided by gas suppliers, which shows considerable spread. The data collection systems used have also been adjusted on numerous occasions over the course of time. The network tariffs shown are based on the following three consumption categories:

– Household customers with a standard default supply contract: As of the reporting date 1 April 2016, differentiation according to consumption band II is at an annual consumption of between 20 GJ (5,556 kWh) and 200 GJ (55,556 kWh). Before this date – as in previous years – the network tariffs were determined with respect to the average consumption of 23.269 kWh.

– Business customers: Consumers with an annual consumption of 116 MWh and without a fixed annual usage time.

– Industrial customers: Consumers with an annual consumption of 116 GWh and an annual usage time of 250 days (4,000 hours).

As of 1 April 2016, the average volume-weighted network charge, including accounting, metering and meter operation charges, for household customers on default tariffs in consumption band II was 1.50 ct/kWh, representing an increase of 0.1 ct/kWh or 7.1% since 1 April 2015.

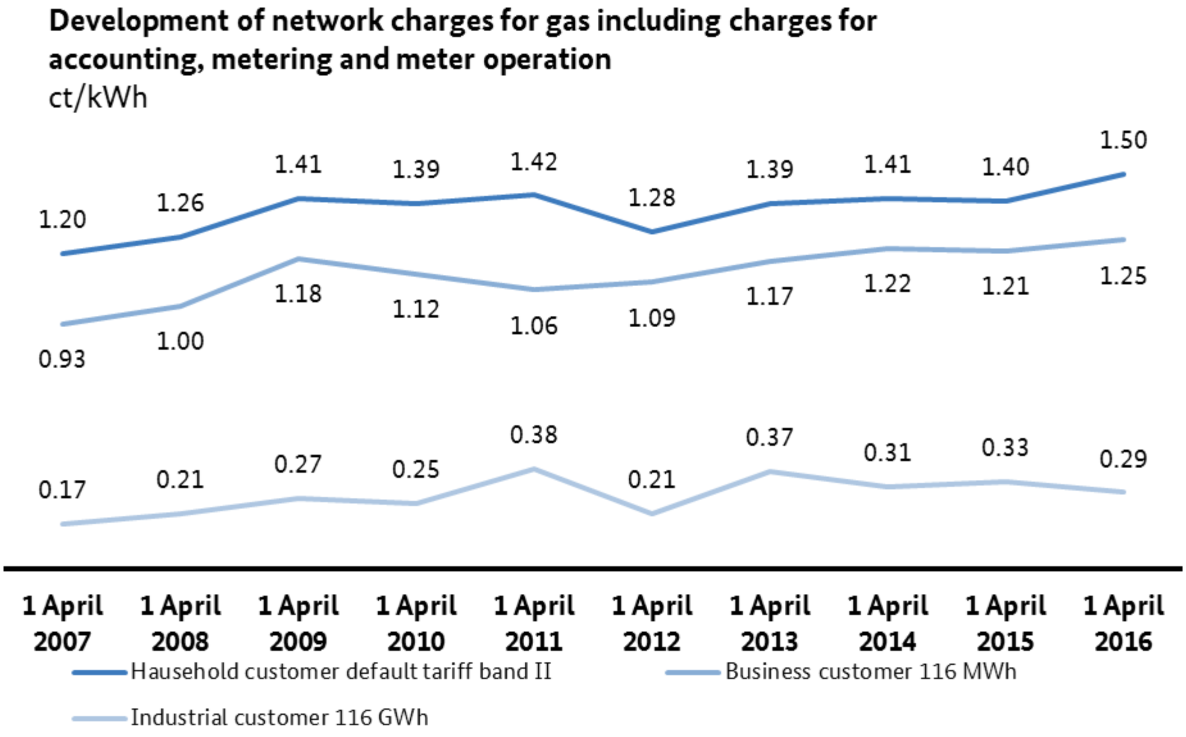

Figure 131: Development of network tariffs for gas (including charges for accounting, metering and meter operation) according to the survey of gas suppliers

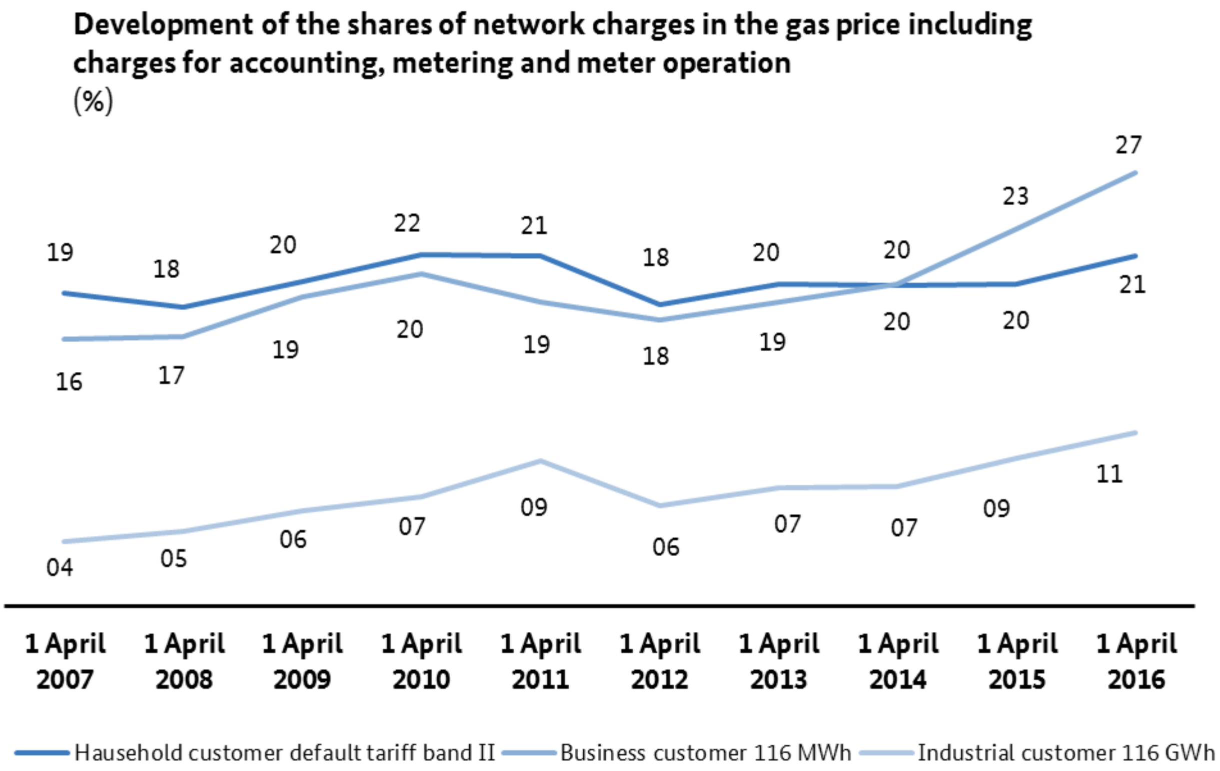

Figure 132: Development of the shares of network tariffs for gas (including charges for accounting, metering and meter operation) according to the survey of gas suppliers

4.2 Expansion factor as per section 10 ARegV

A lasting change in supply services allowed DSOs to apply this year again for an expansion factor for their investments in network expansion. This factor ensures that costs for these investments resulting from a lasting change in the operator's supply services during the regulatory period are also taken into account when determining the revenue cap. A lasting change in supply services is deemed to have occurred if the parameters cited in section 10(2), second sentence, of the Incentive Regulation Ordinance (ARegV) change on a permanent basis and to a significant extent. In the 2015 reporting year, 85 applications for expansion factors were made.

4.3 Incentive regulation account as per section 5 ARegV

The difference between revenue allowed under section 4 ARegV and revenue potentially generated by operators in light of the development of actual consumption volumes is entered annually in an incentive regulation account. Section 28 para 2 ARegV requires operators to submit the data needed to keep the incentive regulation account to the regulatory authority in each instance by 30 June of the following calendar year. The regulatory authorities use the data to determine the differences to be entered in the incentive regulation account. In the final year of the regulatory period, the balance of the account is established for the past calendar years in accordance with section 5(4) ARegV. The balance in the account is cleared by additions or deductions spread evenly over the following regulatory period; these carry interest as stated in section 5(2), third sentence, ARegV.

4.4 Network interconnection points under section 26(2) ARegV

In 2015, a total of 35 applications to redefine revenue caps according to network interconnection points were submitted to the Bundesnetzagentur under section 26(2) ARegV. The network operators must state in their applications what percentage of the revenues is to be assigned to the part of the network being transferred and what percentage to the remaining part, and give reasons for this. In many cases there is a time lag in processing the applications; concession changes in particular can bring about delays as a result of differences of opinion between the two network operators involved with regard to the purchase price, the tangible assets to be transferred and/or the revenue cap to be transferred. The Bundesnetzagentur as well as any regulatory authorities of the federal states must ensure that the total of both parts of the revenue does not exceed the revenue cap already set as a whole.

4.5 Horizontal cost allocation

In June 2016, the Ruling Chamber issued a determination regarding specifications for implementing appropriate horizontal cost allocation between TSOs and appropriate division of costs between entry and exit charges. The determination comes into effect on 1 January 2018 with binding force. The methodology that has now been defined prescribes a capacity-weighted entry-exit split which must be adhered to, including within the framework of validation. Subsequently, the costs assigned to the entry side must be allocated to all entry points in the respective market area. This results in a consistent, specific entry charge for a firm, freely allocable annual capacity in a market area. When deciding on this method of cost allocation, the Ruling Chamber took care to ensure that the method reflects the principles standardised in section 20(1b) EnWG, promotes non-discriminatory calculation of tariffs and conforms to the principle of causation in the structuring of tariffs. One particular consideration leading to the decision was that the Ruling Chamber had found that in recent years the TSOs had increasingly transferred costs to captive customers on the exit side, which as of a certain level contradicts the principle of non-discrimination. As a result of the entry-exit split that has now been defined and of the resulting cost allocation process, the costs of transport across networks of multiple TSOs will be borne appropriately and proportionately by customers on both the entry and exit sides.

D Balancing

1. Balancing gas and imbalance gas

Balancing gas is used to ensure network stability and security of supply within the market areas and is procured by the market area managers. A distinction is to be made here between internal balancing gas that is free of charge (network buffer within the market area) and chargeable external balancing gas (procurement through exchanges and/or balancing platforms). As a rule, the share of internal balancing gas is higher, as the market area managers are obligated to use this energy first. Because in winter months there are more frequent fluctuations regarding short and long portfolios, there is an increase in the share of external balancing gas during this period.

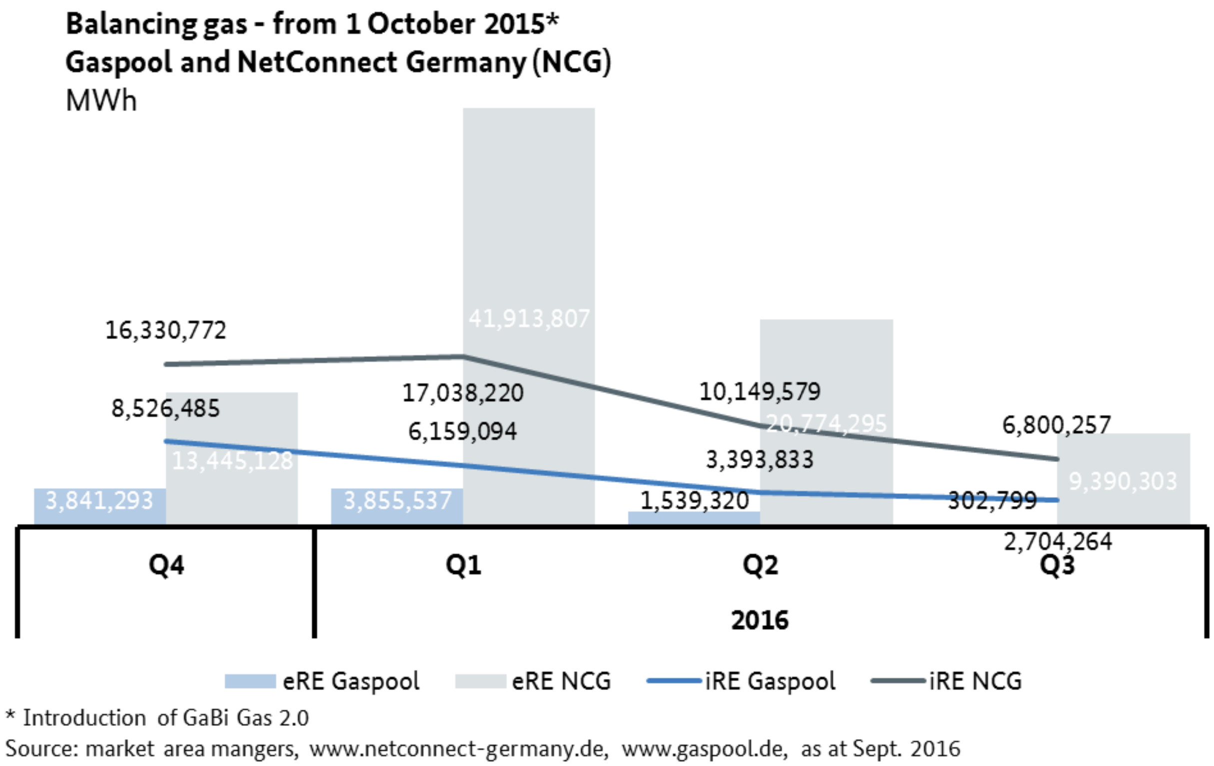

Figure 133: Balancing gas use from 1 October 2015, as at September 2016

The purchase price depicted for balancing gas is calculated as a volume-weighted average of the daily balancing gas purchase prices of MOL1 to MOL3 per MWh and thus enables a comparison to be drawn between market areas.

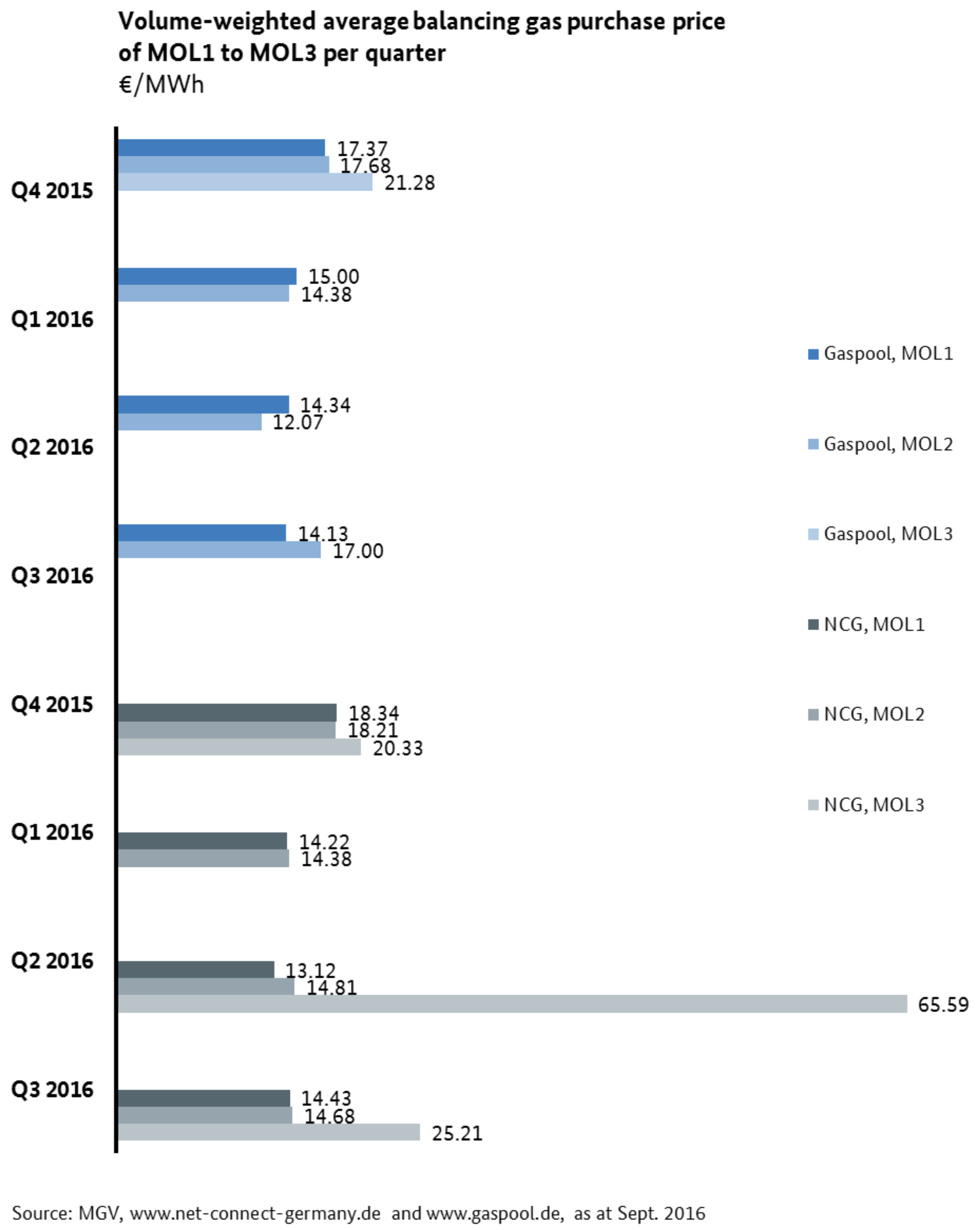

Figure 134: Balancing gas purchase price from Q4 2015, as at September 2016

The different product types in the two market areas must be taken into account in the procurement of long-term products. In the case of Gaspool, only contracts based on capacity prices and not those based on commodity prices were taken into account in the figure below – overview of MOL4 costs for the Gaspool market area.

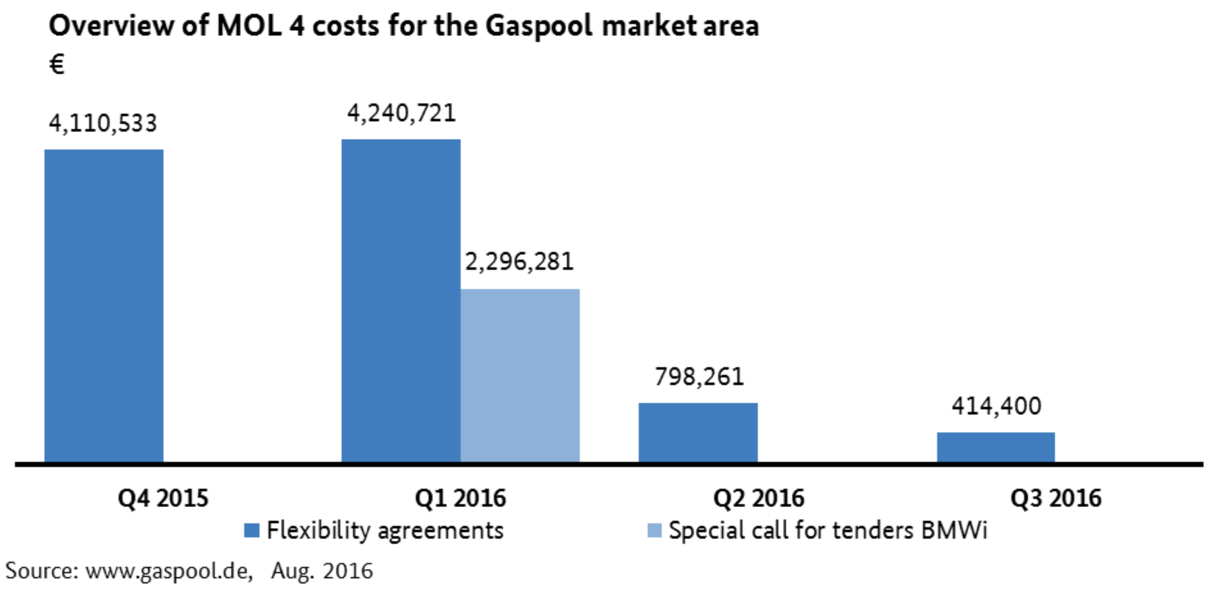

Figure 135: Overview of MOL 4 costs for the Gaspool market area, as at August 2016

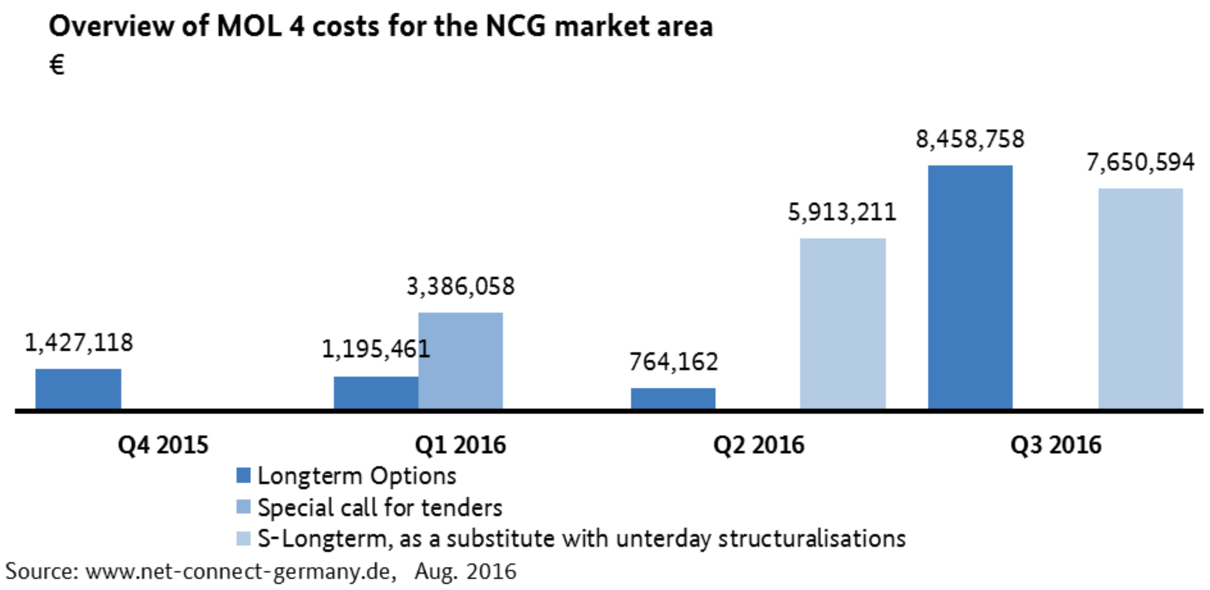

Figure 136: Overview of MOL 4 costs for the NCG market area, as at August 2016

The term imbalance gas refers to the difference between entry and exit quantities within a balancing group at the end of the balancing period. It comes about through deviations between the amount of gas actually consumed and the forecast consumption volume. For this quantity of gas the balancing group manager is charged a positive imbalance price in the case of short supply and a negative imbalance price in the case of surplus supply; this price is oriented to the prices at the various trading places. Additions and deductions serve as incentives for the balancing group manager to avoid imbalances in his balancing group.

The introduction of GABi Gas 2.0 on 1 October 2015 led to fundamental changes in the way imbalance gas prices are calculated. The previous calculation model used a price pool involving various exchanges to calculate imbalance prices, whereas now the balancing gas prices and the volume-weighted average price for gas including a 2% addition/deduction are used to calculate the positive and negative imbalance price. As a result, the two market areas have different imbalance prices. The figure below shows the development of the imbalance price according to the new calculation method since 1 October 2015.

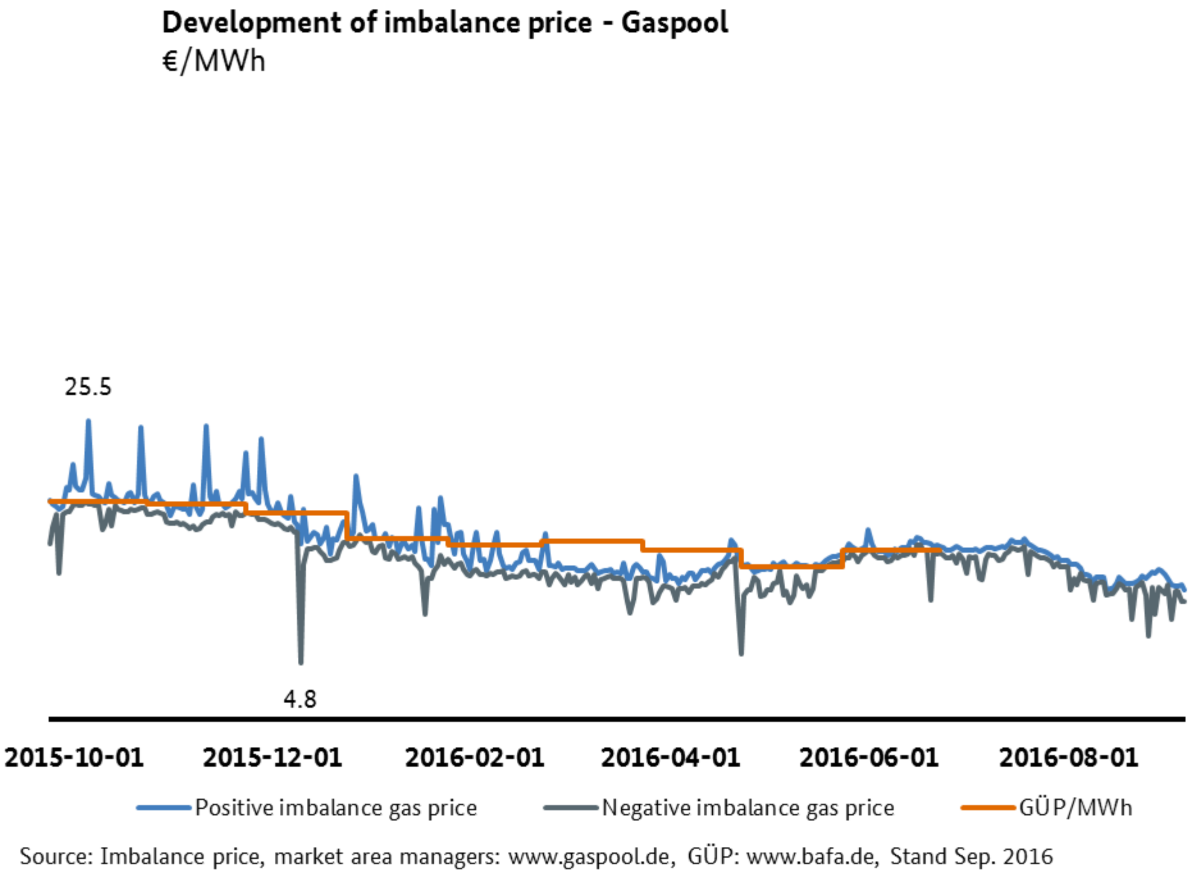

Figure 137: Development of Gaspool imbalance price since 1 October 2015, as at September 2016

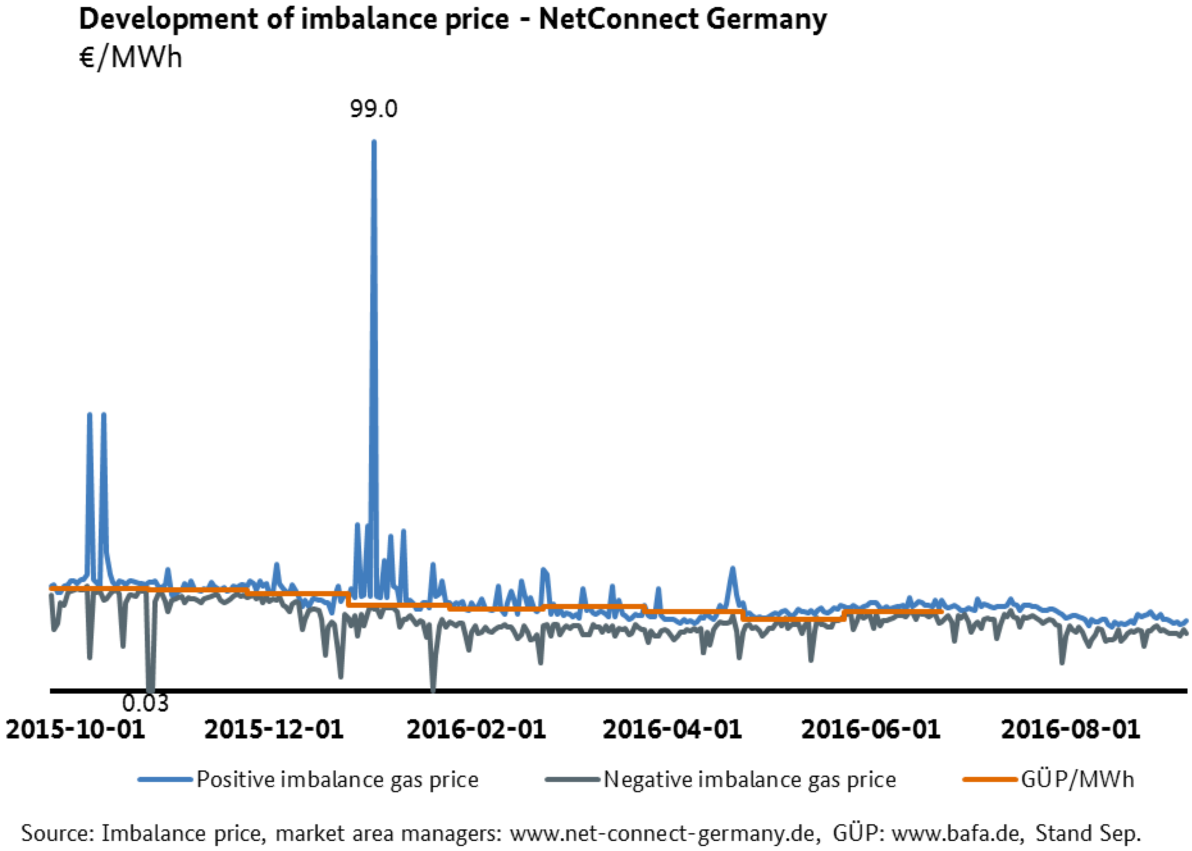

Figure 138: Development of NetConnect imbalance price since 1 October 2015, as at September 2016

2. Development of the balancing neutrality charge (since 1 October 2015)

The costs and revenues incurred by the market area manager from the gas balancing regime must be allocated to the balancing group managers. In the process, the market area manager forecasts the future costs and revenues for his neutrality charge account. If the forecasted costs exceed forecasted revenues, the market area manager levies a balancing neutrality charge from the respective balancing group managers.

The increasing procurement of balancing gas at the exchanges and a well-functioning balancing system, among other factors, have allowed both of the market area managers to temporarily lower the balancing neutrality charges to €0/MWh for several periods.

The forecasted demand for balancing gas and the associated costs have led GASPOOL and NCG to reintroduce a neutrality charge.

The introduction of GaBi Gas 2.0 on 1 October 2015 made it mandatory for the market area managers to set up two separate neutrality charge accounts, one for SLP exit points and another for RLM exit points. If the costs are forecast to exceed revenues, the market area manager levies a neutrality charge from the respective balancing group managers. As of 1 October 2016, the neutrality charges (SLP and RLM) each apply for one year.

For the period from 1 October 2016, only a neutrality charge of €0.80/MWh for SLP will be levied in the NCG market area. For the same period, a neutrality charge of €0.75/MWh will be levied for SLP and €0.25/MWh for RLM in the Gaspool market area.

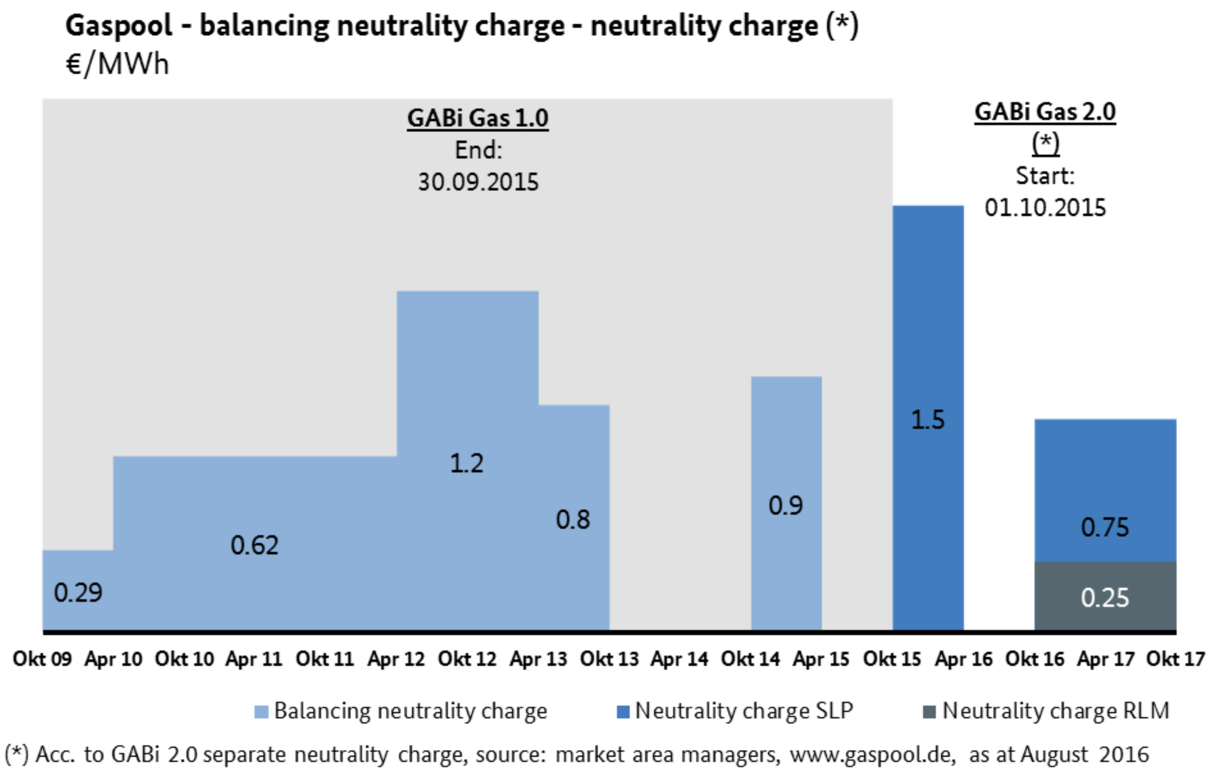

Figure 139: Balancing neutrality charge – neutrality charge in GASPOOL market area, as at August 2016

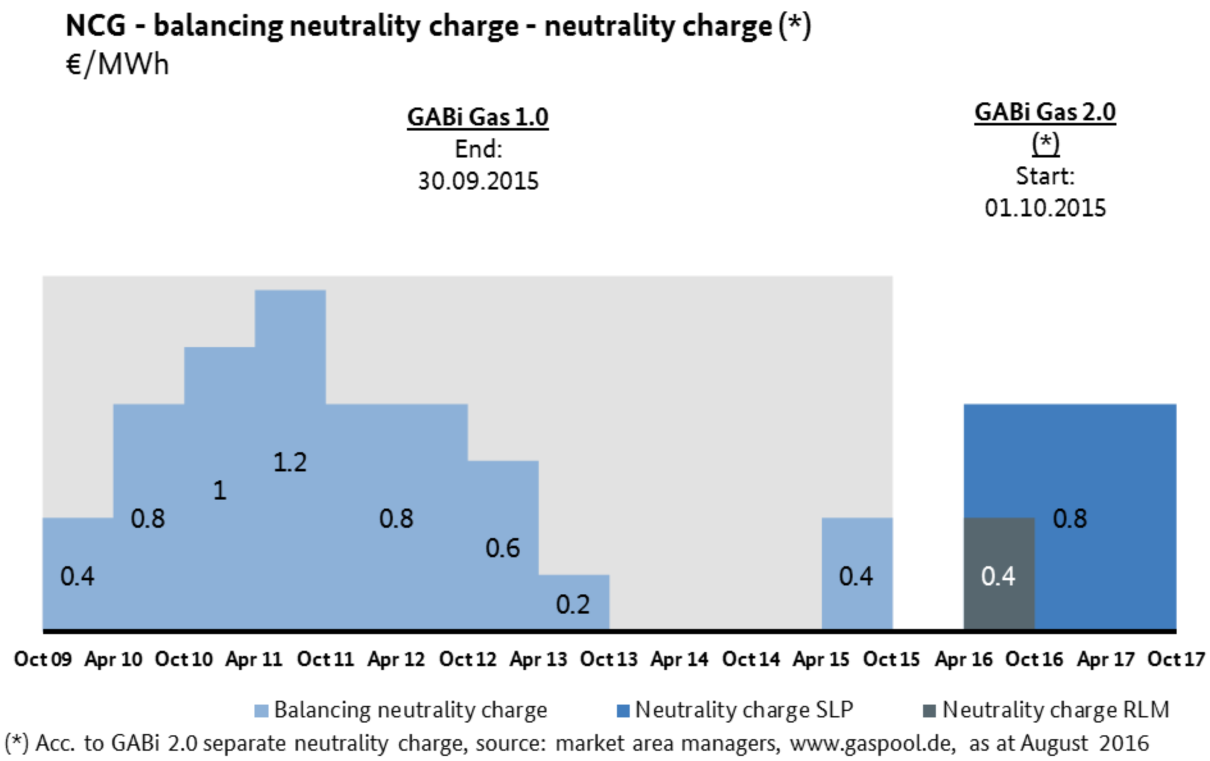

Figure 140: Balancing neutrality charge – neutrality charge in NCG market area, as at August 2016

3. Standard load profiles

Network operators can use two types of standard load profile (SLP). Analytical profiles, in general terms, are based on the previous day's consumption at the time of estimation. Synthetic profiles rely on statistically calculated values. In 2015, the synthetic SLP profiles were used by 81.6% of operators; analytical profiles were used by 14.8% of operators, compared with 14.2% in 2014.

The significance of SLP profiles is evident in the fact that nearly all exit network operators (97.3%) used them when delivering to household or small business customers. The synthetic profiles of the Technical University of Munich (TU München), used in the versions 2002 and 2005, dominate with a market coverage of 95.8%. This figure also remains virtually unchanged compared with the previous year (95.6%).

The TU München offers a range of different profiles which reflect the offtake behaviour of various customer groups. 45.7% of network operators stated that all available profiles were applied, compared with 48.9% in 2014. As in the previous year, 2.5 profiles were used on average for household customers, whereas eight profiles were used on average for business customers.

As forecasts, SLP profiles by their very nature contain inaccuracies. The average deviation between allocation and the actual offtake on a daily basis was 4.9%, which is higher than in 2014 (3.8%). The average maximum deviation on any one day was 58%, which is a slight increase compared with the previous year's level (56.1%). These extreme fluctuations are a cause for concern as they can each result in increased balancing gas. It must be borne in mind, however, that these figures may not be representative as only 62.6% of the network operators provided relevant data regarding deviations at all, although it could be assumed that the operators who responded tended to be those with a comparatively high forecast quality. In the previous year, too, only 62.6% of network operators provided relevant data.

9.1% of operators made adjustments to the load profiles owing to the deviations, compared to 14.6% in 2014.

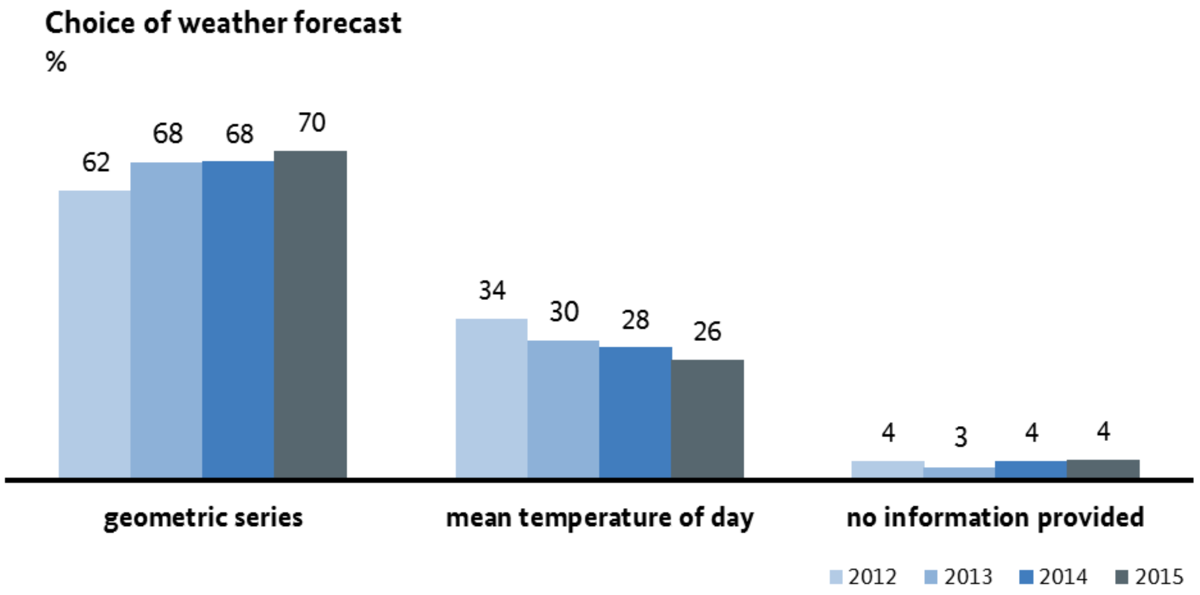

Figure 141: Choice of weather forecast

Due to the strong temperature dependence of SLP profiles, there is a continuing strong trend toward using a differentiated forecast temperature ("geometric series"). In this procedure, the actual temperatures of the days before the day of delivery are taken into account to decrease the deviation risk.

Various procedures are available to the operators for the settlement of the SLP reconciliation quantities. As can be seen in Figure 142, a trend towards fixed-date procedures was already observed in previous years.

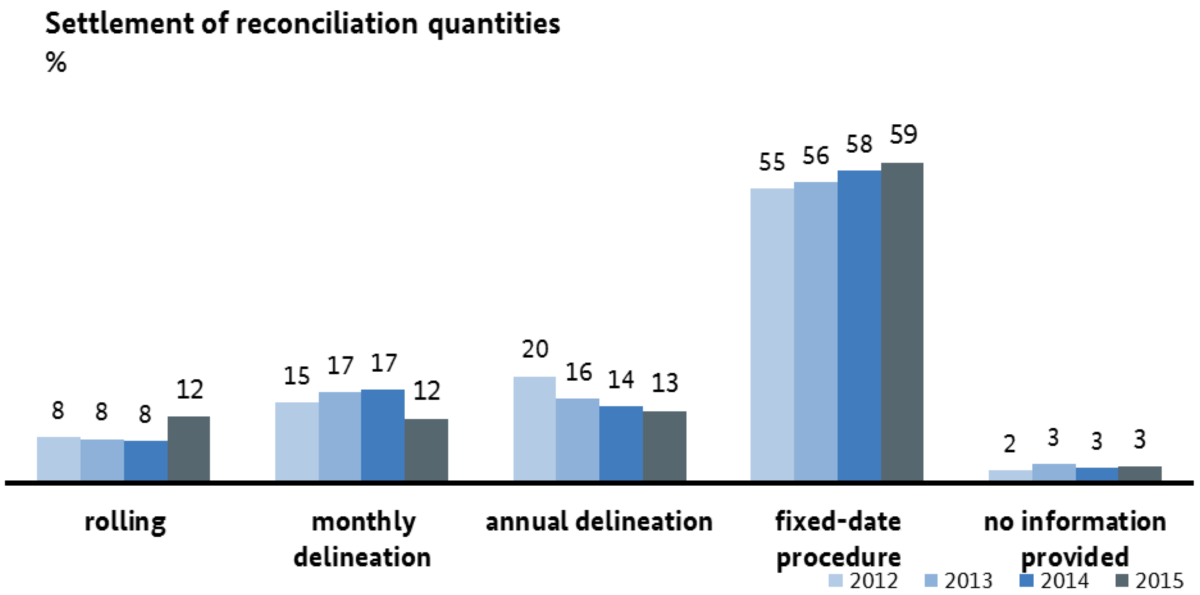

Figure 142: Procedures for the settlement of reconciliation quantities

4. Interval metering and case group switching

The German gas sector balancing system categorises final consumers according to their offtake behaviour and maximum supply capacity and allocates them into different case groups. These include, on the one hand, standard load profile customers who are, for the most part, household and small business customers. On the other hand, there is the group of high-volume interval-metered industrial customers, which includes final consumers with an hourly offtake capacity of at least 500 kW or an annual offtake of at least 1.5 GWh. These are in turn divided into high-volume customers with and without a daily flat supply (RLMmT and RLMoT). The balancing group manager can decide, at the request of the shipper, to switch groups, provided that the market area manager does not see the risk of an unacceptable degradation of system stability and does not reject the request of a planned switch. The advantage of the RLMmT group, in addition to the ex-post allocation of offtake volumes to a daily flat supply, also lies in the higher hourly balancing group deviation tolerance of 15% (compared to a 2% tolerance for the RLMoT group).

In the survey on the gas year 2014/2015, 288 traders and suppliers provided information about the groups to which their interval-metered customers were allocated.

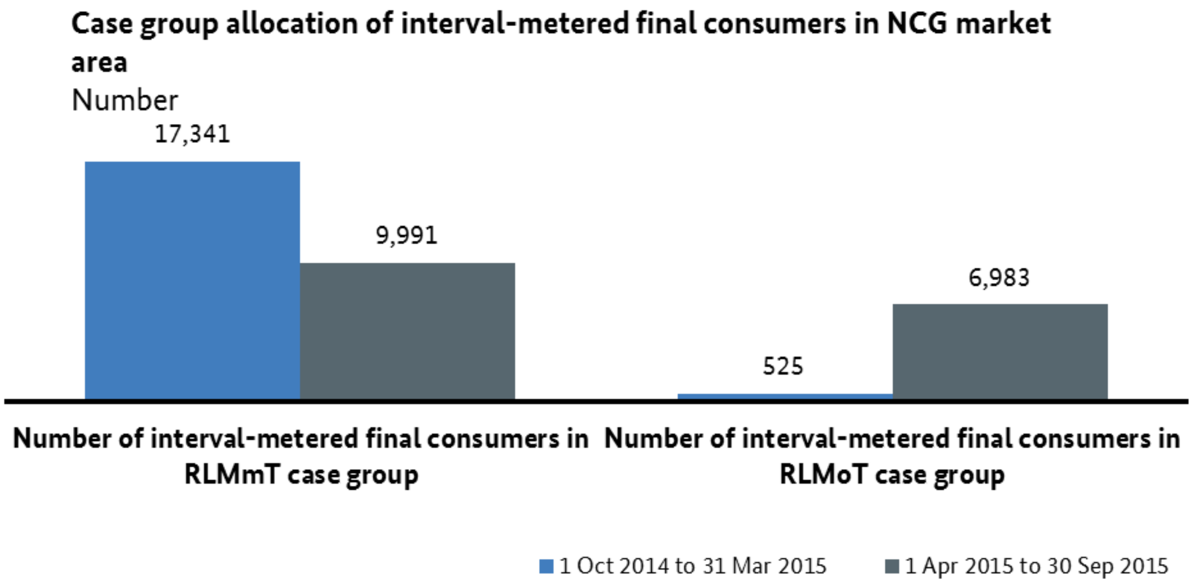

Figure 143: Case group allocation of interval-metered final consumers in the NCG market area

In the NCG market area, almost all of the interval-metered customers were allocated to the RLMmT case group in the winter half-year of the relevant gas year. The increase in the balancing neutrality charge on 1 April 2015 to 0.04 ct/kWh resulted in an increase in the number of interval-metered high-volume consumers without a daily flat supply (up from 525 to 6,983) as reported by the traders and suppliers responding to the survey.

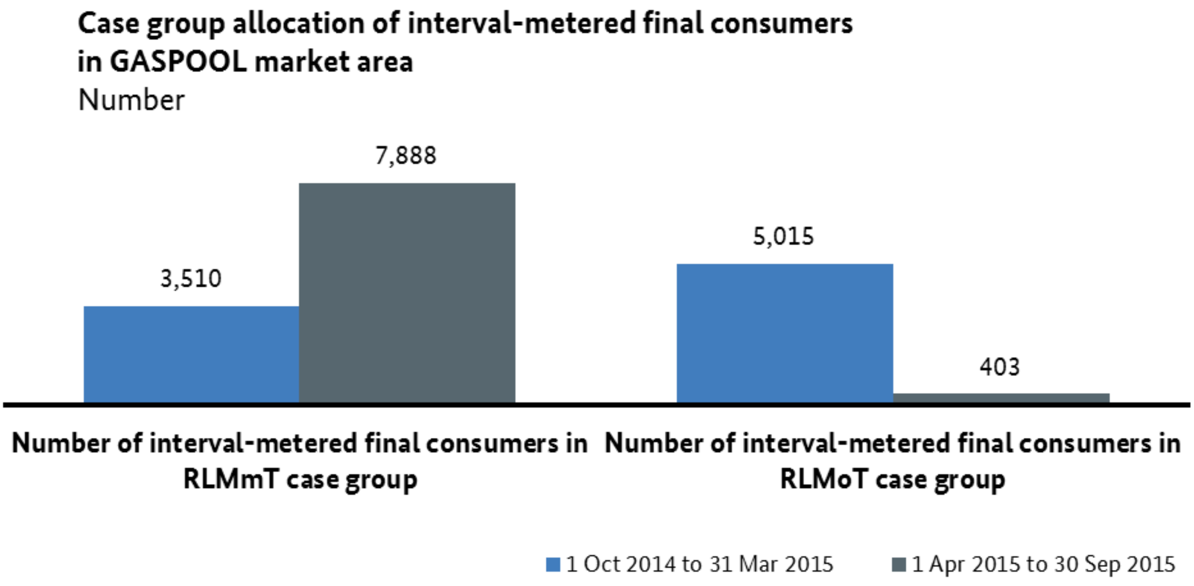

Figure 144: Case group allocation of interval-metered final consumers in the GASPOOL market area

The reverse is true for the GASPOOL market area, where a balancing neutrality charge of 0.09 ct/kWh was levied only in the winter half-year of the 2014/15 gas year. Accordingly, the number of interval-metered high-volume customers without a daily flat supply as reported by the traders and suppliers responding to the survey fell from 5,015 to 403, with the reduction of the charge to zero in the summer half-year.

Both diagrams show that the level of the balancing neutrality charge levied during the respective periods influences the decision on the allocation of interval-metered customers to a specific case group.

In general, the balancing group manager or shipper can choose their case group independently of the maximum supply capacity, as long as the market area manager does not see an associated risk to the safe and efficient operation of the gas network. In this case, the market area manager is authorised to reject the request. Across all market areas, two out of a total of 17,840 notices were rejected on technical grounds in the 2014/15 gas year. Compared to the previous year, when there were 7,204 notices and three rejections on technical grounds, the number of case group switches increased significantly, which can be explained first and foremost by the balancing neutrality charge levied at times in the two market areas.

In accordance with the GeLi Gas business processes for change of gas supplier, shippers can receive hourly data of their RLM customers from their network operators. Balancing group managers were asked within the context of monitoring how many interval-metered final consumers this hourly data transmission was used for in order to carry out intraday adjustments to the nominations. During the period from 1 October 2014 to 31 March 2015 such an adjustment was undertaken for 2,392 customers, and from 1 April to 30 September 2015 2,387 customers. This corresponds to around 11% and 13% respectively of the high-volume customers with daily flat supply served by the balancing group managers providing data.

In addition to the case groups mentioned above, there are also RLM exit points with the possibility of a substitute nomination procedure, for example in the form of an online flow control system (RLMNEV). The balancing group managers who provided data put the number of high-volume customers with substitute nomination procedures in their balancing groups at a total of 155 for the first half of the gas year and 154 for the second half.

The case-group allocation system described above was applicable for the last time during the 2014/2015 reporting period. With its decision as part of the determination proceedings for gas balancing ("GaBi Gas 2.0"), Ruling Chamber 7 implemented the European Network Code on Gas Balancing on 19 December 2014 under file reference BK7-14-020. According to this balancing system, which came into effect on 1 October 2015, as a general principle RLM exit points are allocated to the RLMmT case group. In this case, too, balancing group managers and shippers have the alternative of allocating the exit point to the RLMoT case group. What is new is that an RLM neutrality charge is levied for both case groups.

After the introduction of within day obligations from 1 October 2016, both case groups are granted a uniform tolerance of ±7.5% of the daily offtake quantity for every hour.

E Market area conversion

The market area conversion, ie work coordinated by TSOs to convert the supply of gas from low-calorific L-gas to high-calorific H-gas will become increasingly important in the coming years. L-gas regions in the northern and western parts of Germany will have to be converted because of continually falling domestic production and lower import volumes of L-gas from the Netherlands. According to current estimates, natural gas imports from the Netherlands will no longer be delivered to Germany beginning 1 October 2029. The resulting scarcity of L-gas means that it will virtually disappear from the German gas market by the year 2030. This is why the companies responsible, in particular the TSOs and affected DSOs, have already taken the necessary measures in order to prevent the falling availability of L-gas from affecting the security of supply in any negative way. The new structure of natural gas supply will affect more than four million household, commercial and industrial gas customers that have an estimated 4.9m appliances burning gaseous fuels. All of these appliances must gradually be converted from L-gas to H-gas. The conversion of German L-gas networks to H-gas began successfully in 2015 with the conversion of the network operated by Heidjers Stadtwerke in Schneverdingen. In this region, 7,055 appliances had to be converted for H-gas use. Gastransport Nord, Gasunie Germany Transport Services, Nowega, Open Grid Europe and Thyssengas are TSOs directly affected by the market area conversion. In total, these five TSOs cover 1,022 L-gas interconnection points. With 582 L-gas interconnection points, Open Grid Europe covers the lion's share (around 57%) of interconnection points to downstream network operators and industrial customers for L-gas.

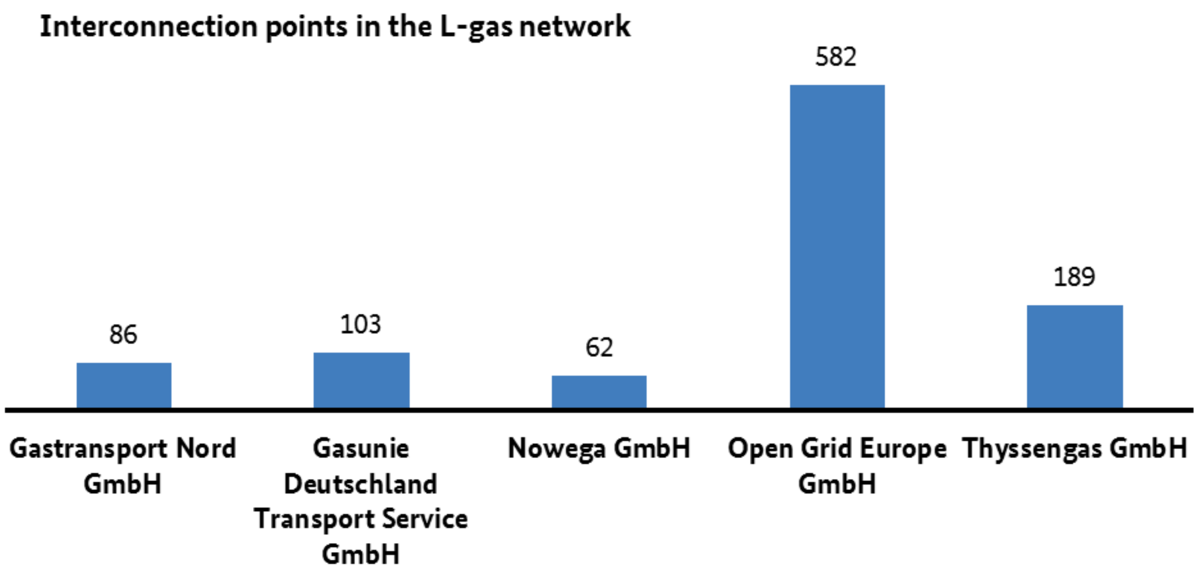

Figure 145: Interconnection points in the L-gas network as of 2015

Gasunie Deutschland Transportservice, Open Grid Europe and Thyssengas intend to gradually convert L-gas subareas to H-gas by 2020. Altogether, of the 108 L-gas areas that need to be converted, 21 subareas will be converted over the next five years.

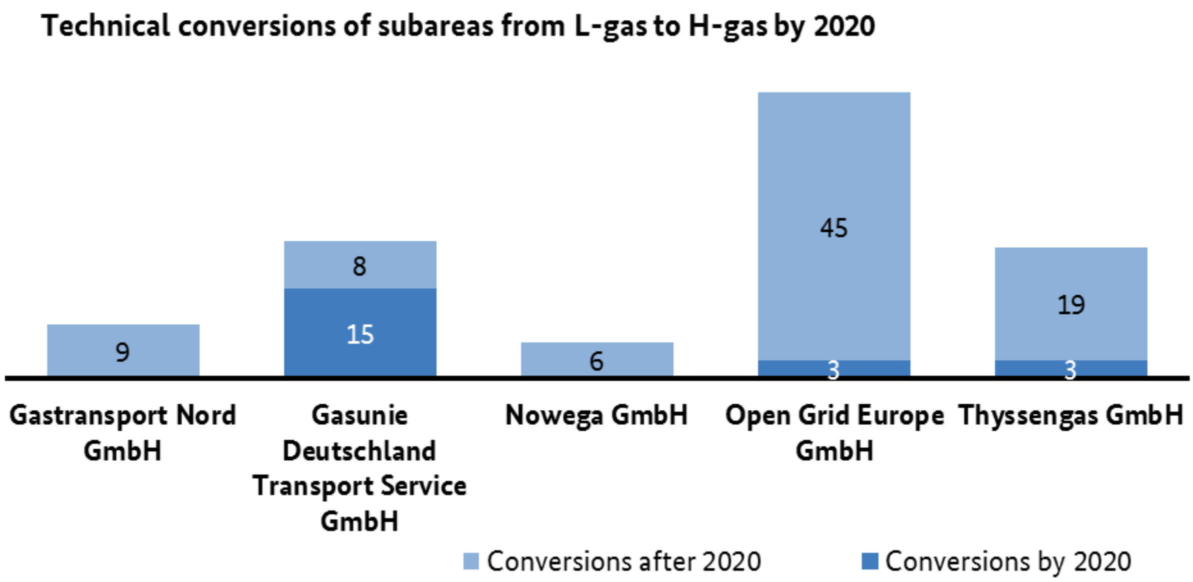

Figure 146: Technical conversions of subareas from L-gas to H-gas

The planned conversions by individual network operators tend to take place in months when less gas is consumed, from April to October. By 2020, some 1,139 conversions will be carried out for interval-metered customers and 542,086 for standard load profile (SLP) customers.

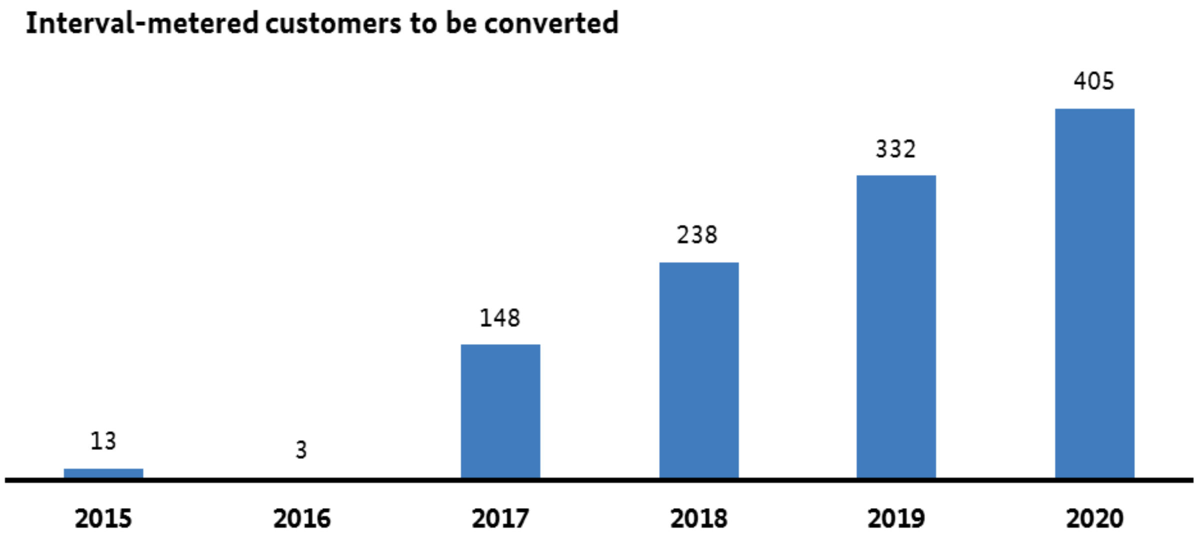

Figure 147: Interval-metered customers to be converted by 2020

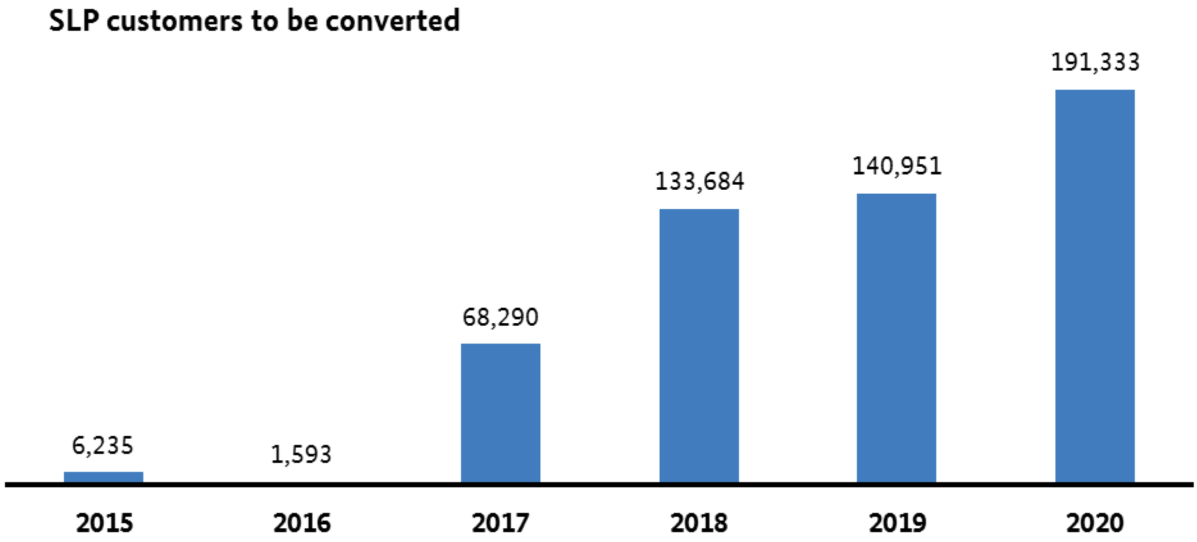

Figure 148: SLP customers to be converted by 2020

Faced with a such a large number of adjustments to appliances, network operators are utilising technical skills provided by specialist companies (with DVGW G676-B1 certification). The adjustments are carried out in three steps. At first, all appliances burning gaseous fuels are registered in a comprehensive list. On the basis of data from this list, the project management team plans the adjustments to gas appliances. All adjustments necessary must be implemented over the course of the next step. This generally requires the appliance's nozzles to be replaced. In the final step of the conversion process, 10% of the appliances are inspected one more time to monitor quality. Just a few years ago, only one or two companies provided such services. After the market area conversion became official, an increasingly competitive market began developing that currently counts 18 active companies. Accordingly, there was also a high response rate to the calls for bids from the twelve network operators that have already set up competitive bidding for services. Some of the task packages up for bidding were tailored in diverse ways and, in some cases, it was foreseen that several companies would share one package.

On average, 5.7 service providers bid for the "registration of appliances" package, of which, on average, 2.5 bids were successful. On average, 3.7 companies submitted bids for the "monitoring the registration of appliances" package, of which, on average, 1.3 companies were successful. On average, 5.4 bidders bid for the "conversions and appliance adjustments" package, which was assigned to, on average, 2.4 companies. On average, 3.8 bids were submitted for the "inspection of conversions and appliance adjustments" package, of which, on average, 1.3 companies were successful. On average, 4.4 companies were interested in taking on the important tasks of the project management team. In this case, on average, 1.3 companies were successful in their bids.

Bids and awards for individual task packages for the market area conversion

Task package	Bids	Awards
Appliance registration	5.7	2.5
Monitoring the registration process	3.7	1.3
conversions and appliance adjustments	5.4	2.4
inspection of conversions and appliance adjustments	3.8	1.3
Tasks of the project management team	4.4	1.3

Table 81: Bids and awards for individual task packages for the market area conversion

In the first half of 2016 it was noted that many gas customers made an effort to inform themselves about the conversion from L- to H-gas, which had just begun in Lower Saxony and Bremen. So far, the FAQ site of the Bundesnetzagentur's website recorded over 10,000 visits, up from last year's figure of 4,000. The Bundesnetzagentur is now offering more information on its FAQ site, especially in the context of current changes to legislation.

Reports on initial progress came in after Heidjers Stadtwerke in Schneverdingen-Neuenkirchen (a part of the Soltau municipality in Lower Saxony) successfully converted their L-gas supply area to H-gas in October 2015. In this network area, around 6,000 exit points and almost 7,000 gas appliances had to be adjusted.

Since condensing boilers made up 80% of the appliances, early conversions could only be carried out sporadically and the four companies commissioned to list and adjust the appliances were therefore forced to work within a tight time frame.

Problems arose in individual cases when customers refused access - both during the registration phase and the actual technical conversion phase. Appliances which, due to their age or lack of approval, could not be converted by simply replacing their nozzles also constituted a problem. The share of these non-adjustable devices was below 0.3%. In addition, there was a larger number of devices that had to be converted manually by a technician or could only be adjusted by the manufacturer.

The number of appliance malfunctions that happened after gas supply was converted is estimated at less than 100. A gas device switching off because emissions are not within the normal range is one example of a typical malfunction. In this case, a technician needs only to readjust the appliance for it to start working properly again.

Meanwhile, manufacturers of large gas appliances have announced that replacement nozzles will remain available for devices that are up to 30 years old.

The number of companies and technicians who carry out the conversions on behalf of the network operator and additionally have been certified for this task has been sufficient.

Already converted in May 2016 was the network area operated by Stadtwerke Böhmetal (Walsrode / Bad Fallingbostel) with approximately 10,000 customers and the municipality of Bomlitz, which belongs to the network area operated by Avacon AG.

Preparatory work for the conversion process begins with the registration of appliances at least one year before H-gas is actually injected into the network instead of L-gas.

The registration of appliances has begun in the following locations in Lower Saxony as of spring 2016:

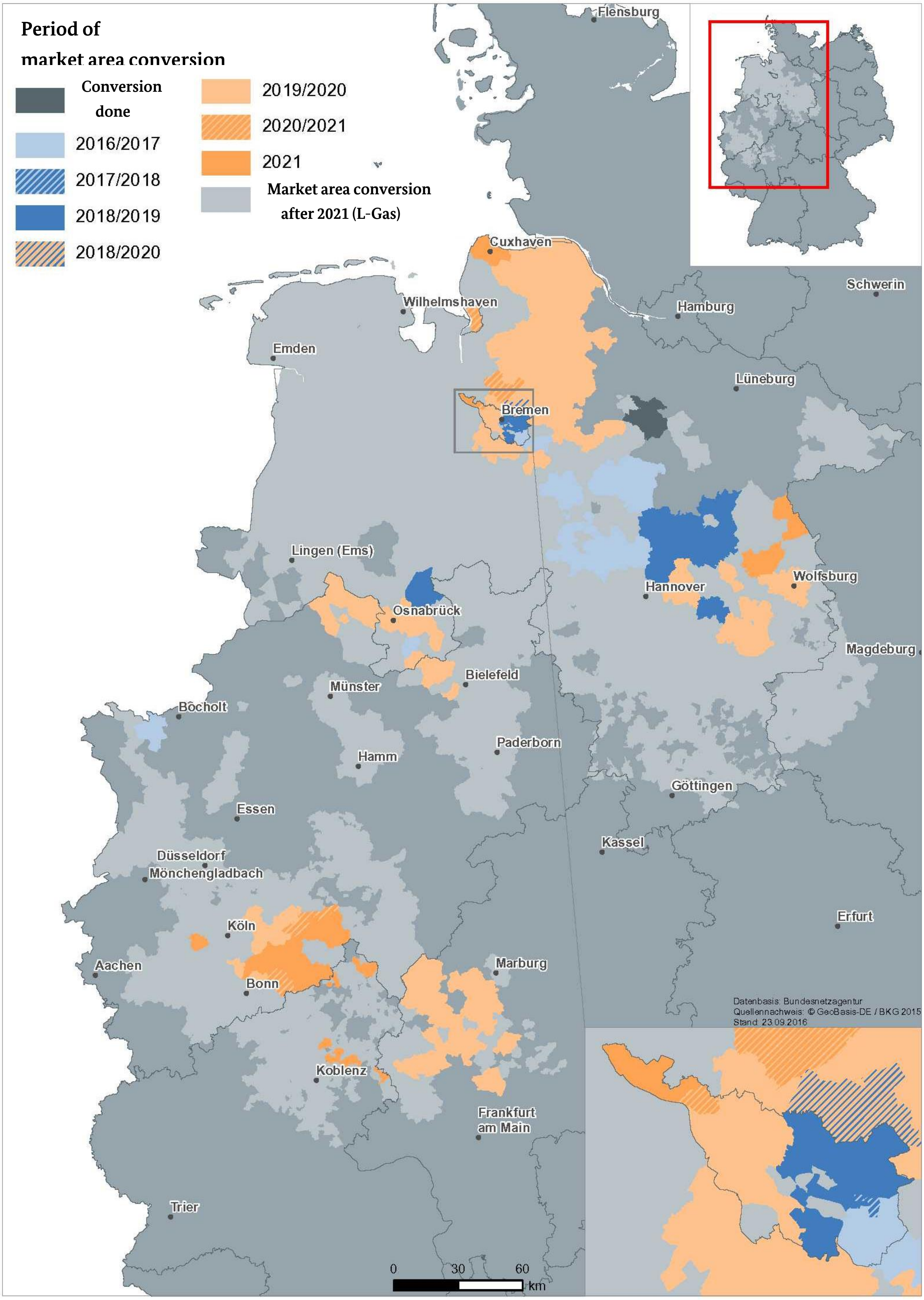

Figure 149: Market area conversion time line

F Wholesale market

Liquid wholesale markets are vital to market development along the entire value chain in the natural gas sector, from the procurement of natural gas to the supply to end customers. More scope for short-term and long-term natural gas procurement at wholesale level makes companies less dependent on a single supplier in the long term. This increases the opportunities for market players to choose from a variety of trading partners and hold a diversified portfolio of short-term and long-term trading contracts. Liquid wholesale markets make it easier to enter the market and ultimately also promote competition for end customers.

The Bundeskartellamt (Federal Cartel Office) assumes that the natural gas wholesale market operates at national level and therefore no longer defines it within the limits of networks or market areas. Liquidity in the natural gas wholesale market developed in different ways in 2015. The volume of brokered gas trading declined at bilateral wholesale level while the volume of on-exchange gas trading rose by 38 per cent.

The reporting year 2015 was once again characterised by significantly lower gas wholesale prices. The various price indices show a year-on-year decline of 6 to 13 per cent.[114]

1. On-exchange wholesale trading

The exchange relevant to natural gas trading in Germany is operated by the European Energy Exchange AG and its subsidiaries (referred to collectively as EEX below). As in previous years, EEX took part in this year's data collection in the course of monitoring. EEX carries out short-term and long-term trading transactions (spot market and futures market) and spread products. All types of contracts are equally tradable for the two German market areas NetConnect Germany (NCG) and GASPOOL.

On the spot market, natural gas can be traded for the current gas supply day with a lead time of three hours (within-day contract/intraday product), for one or two days in advance (day contract) and for the following weekend (weekend contract) on a continuous basis (24/7 trading). The minimum trading unit is 1 MW so that even small volumes of natural gas can be procured or sold at short notice. Quality-specific contracts (for high calorific gas or low calorific gas) are also tradable. The main purpose of the futures market is to hedge against price risks, optimise portfolios and, to a much lesser degree, ensure long-term gas procurement. Futures can be traded on EEX for specific months, quarters, seasons (summer/winter) or years.

Launched as a cooperation between EEX and the French Powernext SA in 2013, PEGAS has consolidated gas trading activities on a joint platform, which makes cross-border trading easier. Following antitrust clearance by the authorities, including the Bundeskartellamt, EEX acquired the majority of shares in Powernext SA on 1 January 2015 and incorporated it into the EEX Group. PEGAS allows its members to trade spot and futures market products for the German, French, Dutch, Belgian, British and Italian market areas. As a result of the full

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[114] The daily reference prices NCG and GASPOOL fell year-on-year by an annual average of around 6 per cent, the arithmetic mean of the European Gas Index Germany (EGIX) fell by around 7 per cent and the (unweighted) average of monthly cross-border prices (BAFA) fell by around 13 per cent.

consolidation of Powernext, additional trading volumes have been included in the consolidated companies of EEX since 1 January 2015. Trading volumes rose by 52 per cent on the spot market for gas and by 110 per cent on the futures market for gas in all PEGAS market areas.[115] EEX itself also witnessed a shift from non-exchange trading to the exchange, which provides central clearing functions that simplify the traders' risk management. EEX attributes this development to the reduction in the credit lines customarily applied to the OTC trade, which was caused by a decline in the creditworthiness of the market players.[116]

The entire trading volume on EEX relating to the German market areas GASPOOL and NCG was around 292 TWh in 2015, an increase of around 80 TWh, or 38 per cent, on the previous year's figure of 212 TWh. While trading volumes for the GASPOOL market area increased by approximately 29 TWh or around 42 per cent, the volume for the NCG market area increased by 50 TWh or around 35 per cent.

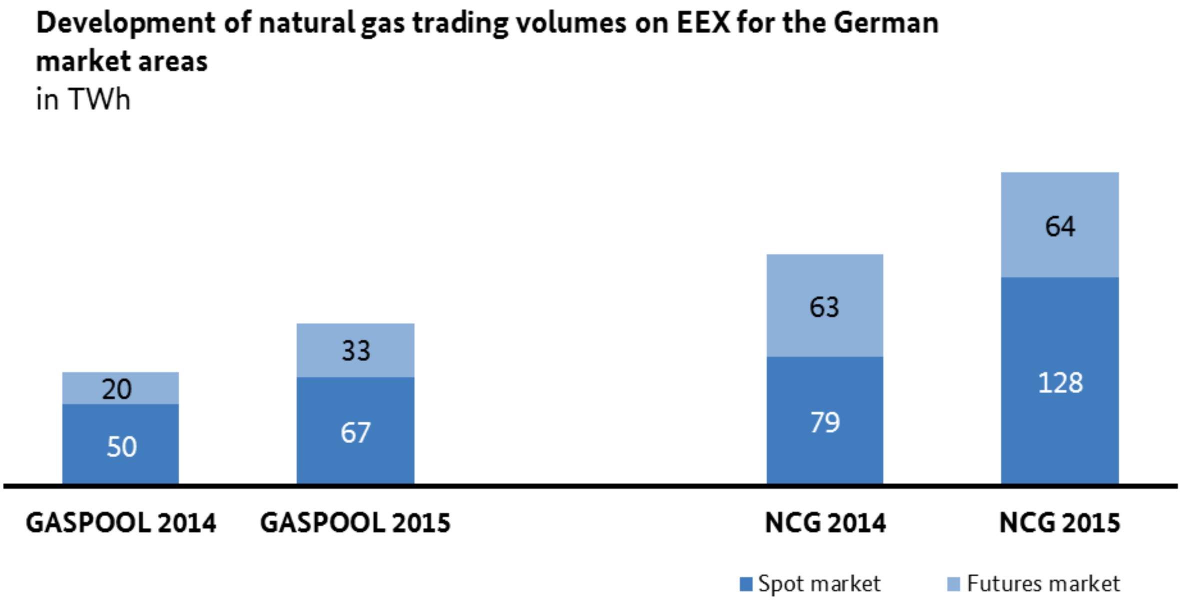

Figure 150: Development of natural gas trading volumes on EEX for the German market areas

The volume traded on the spot market increased again in 2015 and was around 195 TWh (around 129 TWh in 2014). As in the previous years, the majority of spot market transactions for both market areas was focused on day-ahead contracts (NCG: 76.8 TWh; GASPOOL: 42.6 TWh) in 2015. The trading volume of futures contracts rose from 83 TWh in 2014 to around 97 TWh in the reporting year, an increase of about 17 per cent.

The annual average number of active participants on the spot market per trading day was around 71 (around 35 in the previous year) for NCG contracts and around 59 (around 26 in the previous year) for GASPOOL contracts. By contrast, the average number of active[117] participants on the futures market per trading day was 9.8 (NCG; 7.7

[115] EEX Annual Report 2015, p. 67ff.

[116] EEX Annual Report 2015, p. 58.

[117] Participants are considered to be active on a trading day if at least one of their bids has been submitted.

in the previous year) and 5.9 (GASPOOL; 3.6 in the previous year) for the two market areas. The comparison of these figures has to take account of the fact that, owing to their term, futures contracts are geared towards higher volumes than spot contracts. In light of the lower growth rates on the futures market, an important role is played by the fact that due to daily margining (the daily adjustment of the pledged collateral) exchange-traded and thus cleared contracts represent a liquidity risk to the market player for the entire long period until maturity and can also entail a considerable amount of effort.

There were two market makers[118] operating on the EEX gas futures market in 2015 to ensure liquidity and continuous trade: E.ON and RWE (there were four companies in the previous year). As market makers, the two companies' share of turnover in all gas futures contracts concluded via EEX in 2015 was about 12 per cent on the sales side and about 16 per cent on the purchase side. Besides agreements with market makers, EEX also maintains contracts with trading participants who are committed to strengthening liquidity to an individually agreed extent. In terms of trading volume, these companies accounted for about 42 per cent of purchases and about 46 per cent of sales in 2015.

2. Bilateral wholesale trading

By far the largest share of wholesale trading in natural gas is carried out on a bilateral basis, i.e. off the exchange ("over the counter" – OTC). Bilateral trading offers the advantage of flexible transactions, which, in particular, do not rely on a limited set of contracts. Brokerage via broker platforms forms an important part of OTC trading.

2.1 Broker platforms

Brokers act as intermediaries between buyers and sellers and pool information on the demand and supply of short-term and long-term natural gas trading products. The services of a broker can reduce search costs and make it easier to effect large transactions while at the same time allowing greater risk diversification. Brokers also offer services to register trading transaction brokered by them for clearing on the exchange to hedge the counterparty default risk of the parties.[119] Electronic broker platforms are used to formalise the bringing together of interested parties on the supply and demand sides and so increase the chances of the two parties reaching an agreement.

As in the previous year, a total of eleven broker platforms took part in this year's collection of wholesale trading data. Ten of these platforms brokered natural gas trading transactions with Germany as the supply area (NCG and/or GASPOOL) in 2015.

The natural gas trading transactions brokered by these ten broker platforms in 2015 with Germany as the supply area comprise a total volume of 2,652 TWh (2,966 TWh in the previous year), of which 1,179 TWh were contracts to be fulfilled in 2015 (fulfilment period of one week or more).

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[118] Trading participants who have both a buy and a sell quote in their order book for a minimum period of time on the trading day. Market makers ensure basic liquidity.

[119] OTC clearing on EEX in the natural gas sector has so far been of only little practical significance. In 2015, OTC clearing comprised contracts with a volume of around 0.5 TWh (2.5 TWh in the previous year).

The decline in volume is confirmed by the figures relating to brokered natural gas trading for the market areas NCG and GASPOOL published by the London Energy Brokers' Association (LEBA).[120] Seven of the eleven broker platforms that provided data on which the above evaluation was based are members of LEBA. The affiliated broker platforms accounted for a total of 2,452 TWh for the two German market areas in 2015. This represents an increase of 6 per cent on the previous year's volume of 2,613 TWh.

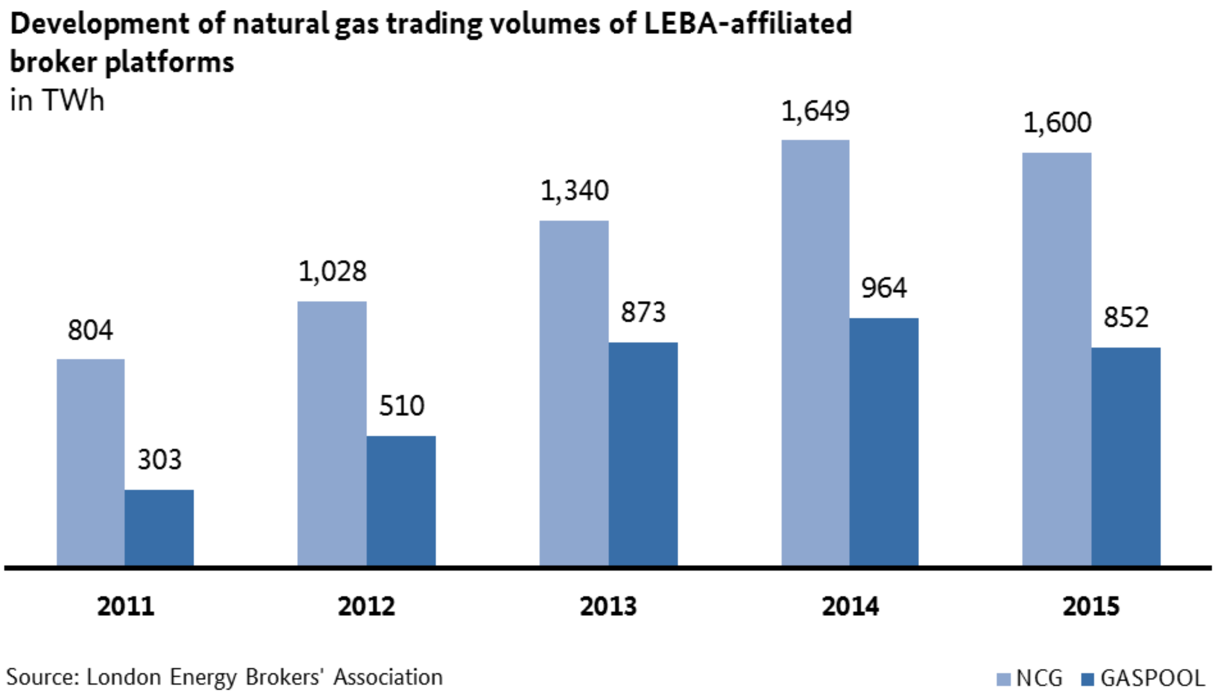

Figure 151: Development of natural gas trading volumes of LEBA-affiliated broker platforms for German market areas

Short-term transactions with a fulfilment period of less than one week amount to about 18 per cent of the trade brokered by these eleven broker platforms. Transaction in the current year account for the majority of natural gas trading followed by the activities for the subsequent year. While natural gas traded in and for 2015 (including spot trading) constitutes as much as 62 per cent of the total volume and still as much as 29 per cent for the subsequent year (2016), the share of transactions with supply dates in 2017 and beyond is 9 per cent. This structure largely corresponds to the previous year's result.

[120] See http://www.leba.org.uk/pages/index.cfm?page_id=59&title=leba_data_notifications (retrieved on 25 April 2016)

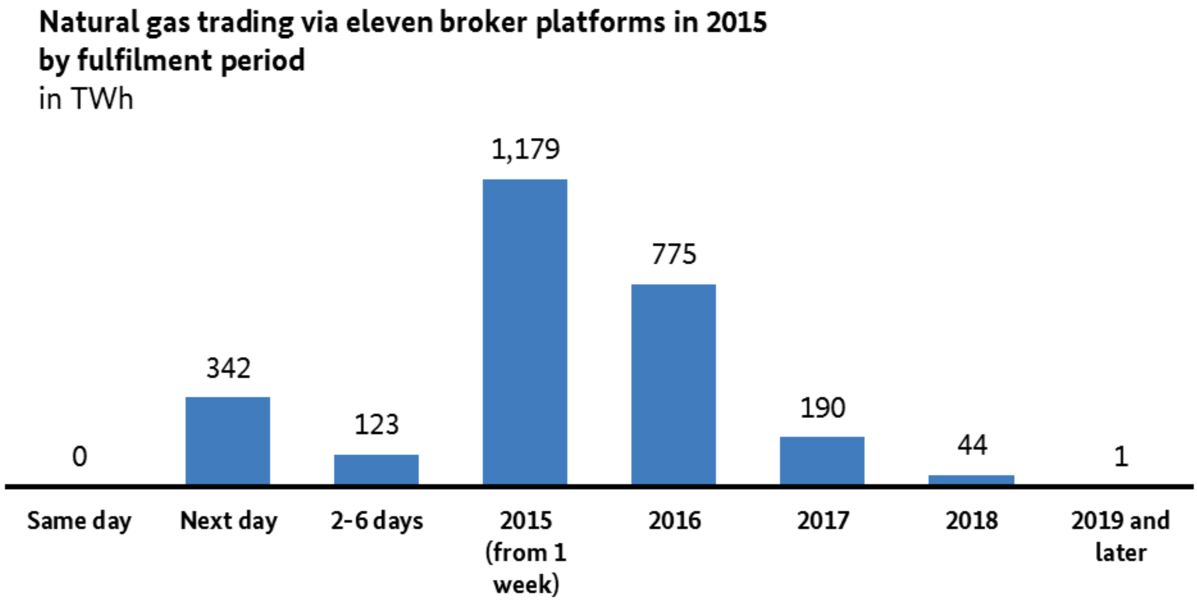

Figure 152: Natural gas trading for the German market areas via eleven broker platforms in 2015 by fulfilment period

2.2 Nomination volumes at virtual trading points

The nomination volumes at the two German virtual trading points (VTPs) of NCG and GASPOOL are key indicators of the liquidity on the wholesale natural gas markets. Balancing group managers can transfer gas volumes between balancing groups via the VTPs through nominations (physical fulfilment).

Wholesale transactions with physical fulfilment are generally reflected in the relevant balancing group transfers so that an increase in wholesale transactions on the spot market leads to a corresponding increase in nomination volumes.[121]

There has been an increase in nomination volumes at virtual trading points since the consolidation of the German market areas. This trend continued in the reporting year.

The two parties responsible for the market area, NCG and GASPOOL, once again took part in this year's collection of gas wholesale trading data. The gas volumes nominated on the two VTPs increased from a total of 3,074 TWh to 3,452 TWh, a rise of about 12 per cent. The GASPOOL VTP accounted for about 43 per cent of the nomination volume, and the NCG VTP for 57 per cent. Almost 90 per cent of the nomination volume consisted of high calorific gas.

[121] On the other hand, not all nomination volumes are automatically associated with a transaction on the wholesale markets because nominations can also relate to intragroup balancing group transfers.

There has been a year-on-year increase in the nominated volumes of high calorific gas, both at the NCG VTP and at the GASPOOL VTP. The same applies to low calorific gas.

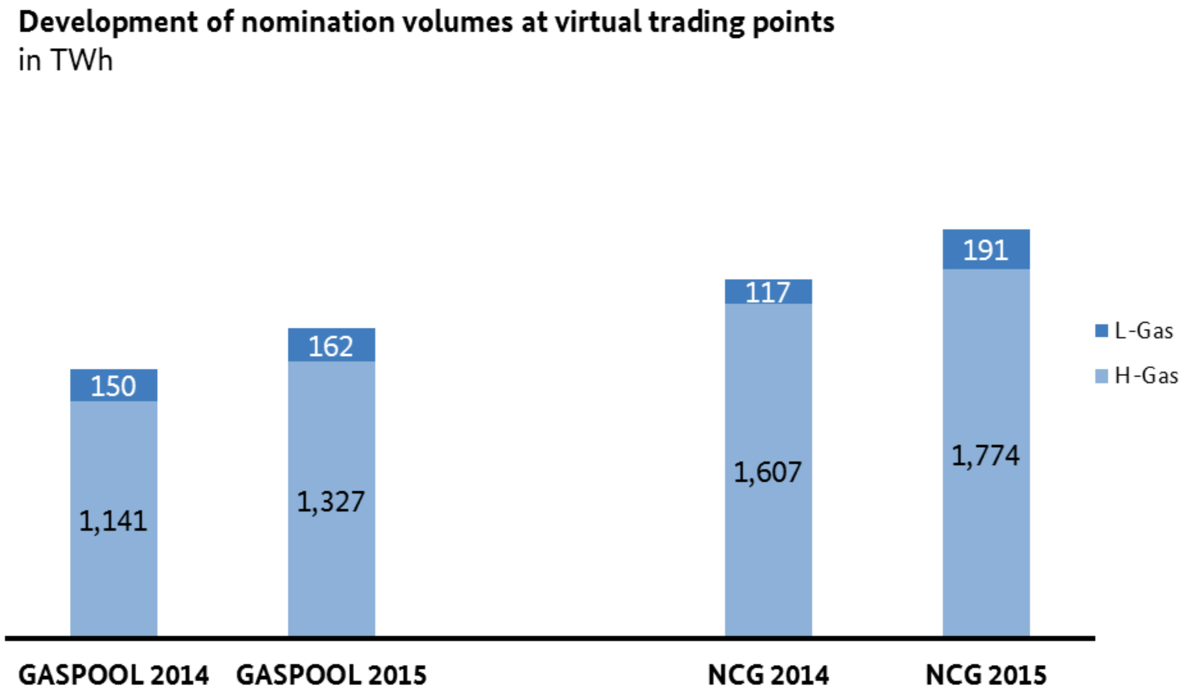

Figure 153: Development of nomination volumes at virtual trading points

As in previous years, the monthly nomination volumes reflect seasonal differences. The (aggregated) monthly nomination volumes of both VTPs peaked at 241 TWh between May and August 2015. The lowest nomination volume was 228 TWh in June 2015; the annual high of about 346 TWh was reached in January 2015.

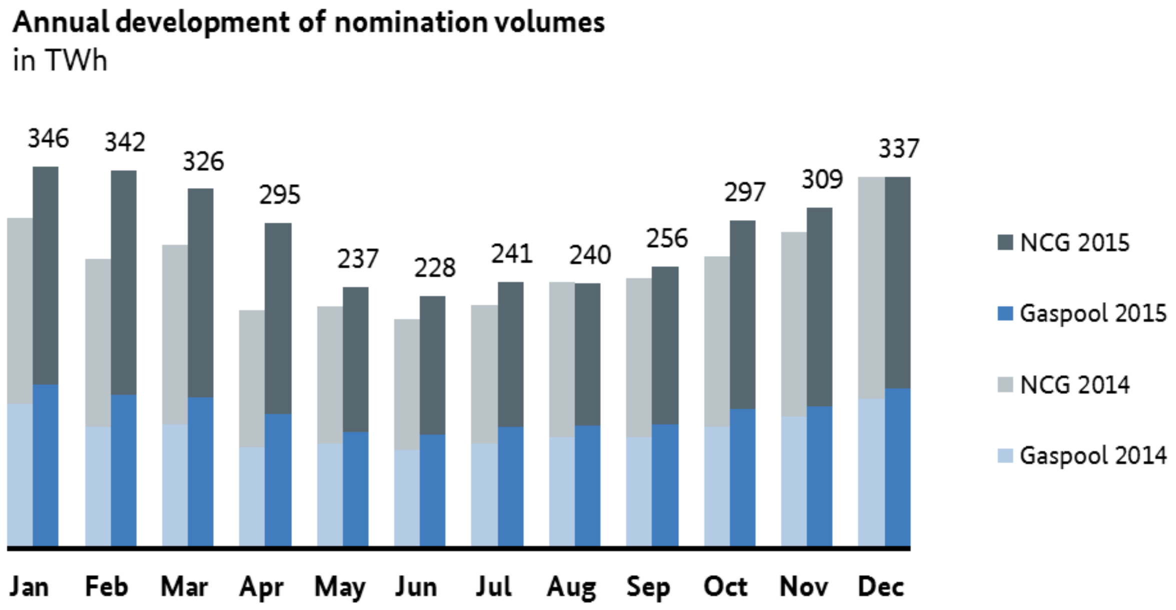

Figure 154: Annual development of nomination volumes at virtual trading points in 2014 and 2015

The number of active trading participants, i.e. of companies that carried out at least one nomination a month, continued to increase in both market areas in 2015. The number of active trading participants in the NCG market area increased from 303 to 317 (by about 5 per cent) for high calorific gas and from 159 to 162 (by about 2 per cent) for low calorific gas. The average annual number of active participants in the GASPOOL market area increased year-on-year from 255 to 271 (by about 6 per cent) for high calorific gas and from 134 to 145 (by about 8 per cent) for low calorific gas.

3. Wholesale prices

The daily reference price published by EEX shows the price level on the on-exchange spot market and therefore the average costs of short-term natural gas procurement. In addition, the European Gas Index Germany (EGIX) provides a reference price for procurement within a timeframe of approximately one month. The BAFA cross-border price for natural gas gives an approximate indication of the price of natural gas procurement on the basis of long-term supply contracts.

EEX determines daily reference prices on the on-exchange spot market for the GASPOOL and NCG market areas by calculating the volume-weighted average of the prices across all trading transactions for gas supply days on the last day before physical fulfilment.[122] The daily reference prices are published by EEX at 10:00 a.m. CET on the relevant supply day and are an indicator of the price level of spot market transactions.

The (unweighted) annual average of the daily reference price was €20.01/MWh for the NCG market area and €19.91/MWh for GASPOOL in 2015. The previous year's figures were €21.21/MWh for NCG and €21.08/MWh for

[122] For details on the calculation method see http://cdn.eex.com/document/150893/2013-11- 28_Beschreibung_Tagesreferenzpreis.pdf (retrieved on 11 November 2016).

GASPOOL, which means that the annual average of the daily average reference prices fell by about 6 per cent. The daily reference prices fluctuated between €13.71/MWh (on 25 December) and €24.12/MWh (on 16 February) over the course of 2015.

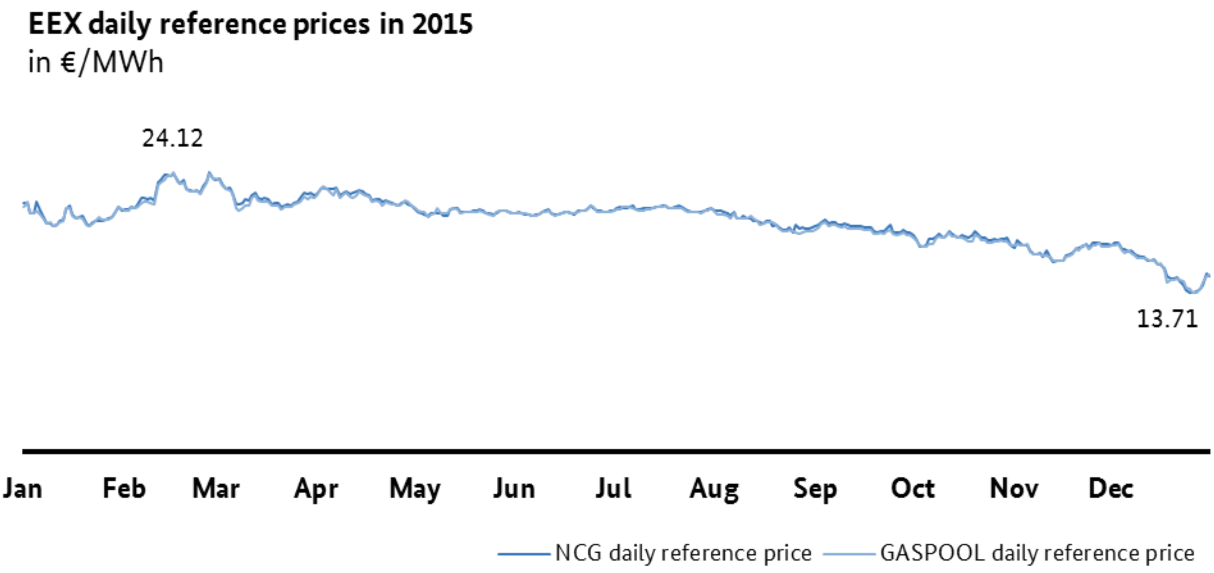

Figure 155: EEX daily reference prices in 2015

The difference between the daily reference prices of NCG and GASPOOL was again quite small in 2015 with a maximum of 2 per cent on 359 out of 365 days. The difference reached a higher level of 3 to 4 per cent only on six days.

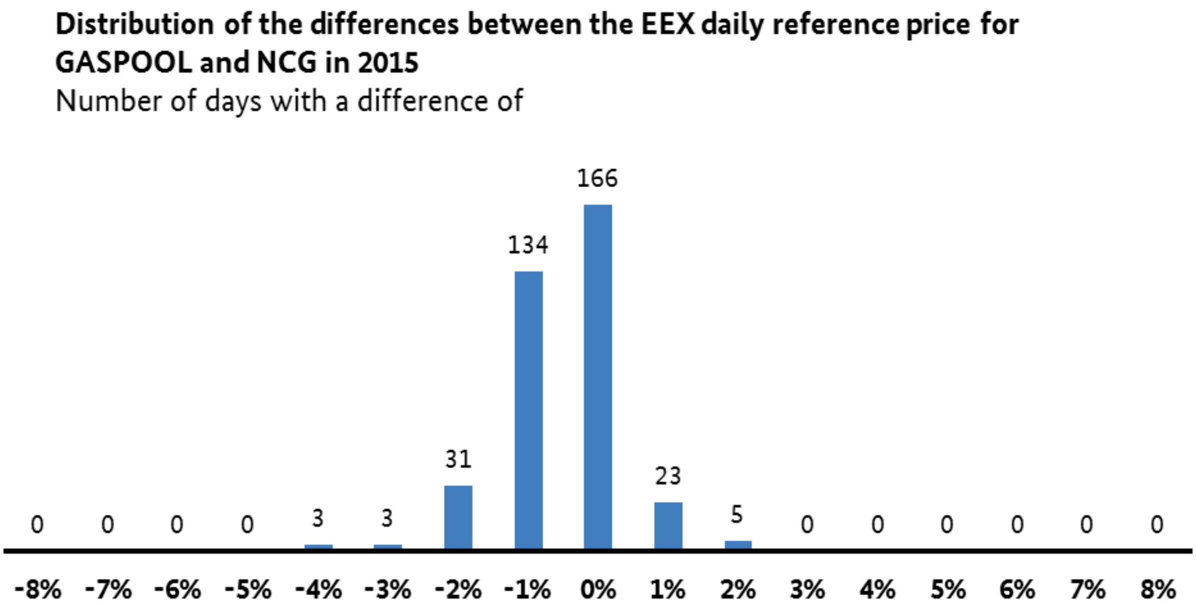

Figure 156: Distribution of the differences between the EEX daily reference prices for GASPOOL and NCG in 2015

The EGIX Germany is a monthly reference price for the futures market. It is based on transactions on the on-exchange futures market that are concluded in the latest month-ahead contracts for the NCG and GASPOOL market areas.[123] In 2015, the EGIX Germany ranged from €17.70/MWh in December to €22.91/MWh in January. The arithmetic mean of the 12 monthly figures was €20.46/MWh, a fall of approximately 7 per cent compared to the previous year's figure of €22.04/MWh.

The cross-border price for each month is calculated by the Federal Office for Economic Affairs and Export Control (Bundesamt für Wirtschaft und Ausfuhrkontrolle – BAFA) as a reference price for long-term natural gas procurement. For this purpose, BAFA evaluates documents relating to natural gas procured from Russian, Dutch, Norwegian, Danish and British gas extraction areas. The calculations are mainly based on import quantities and prices agreed in import agreements; spot volumes and prices are largely disregarded.[124]

The monthly BAFA cross-border prices for natural gas ranged from €17.61/MWh to €28.50/MWh between 2013 and 2015. The (unweighted) average of the monthly cross-border prices was €20.30/MWh in 2015; the figure was still as high as €23.39/MWh (down 13 per cent) in 2014.

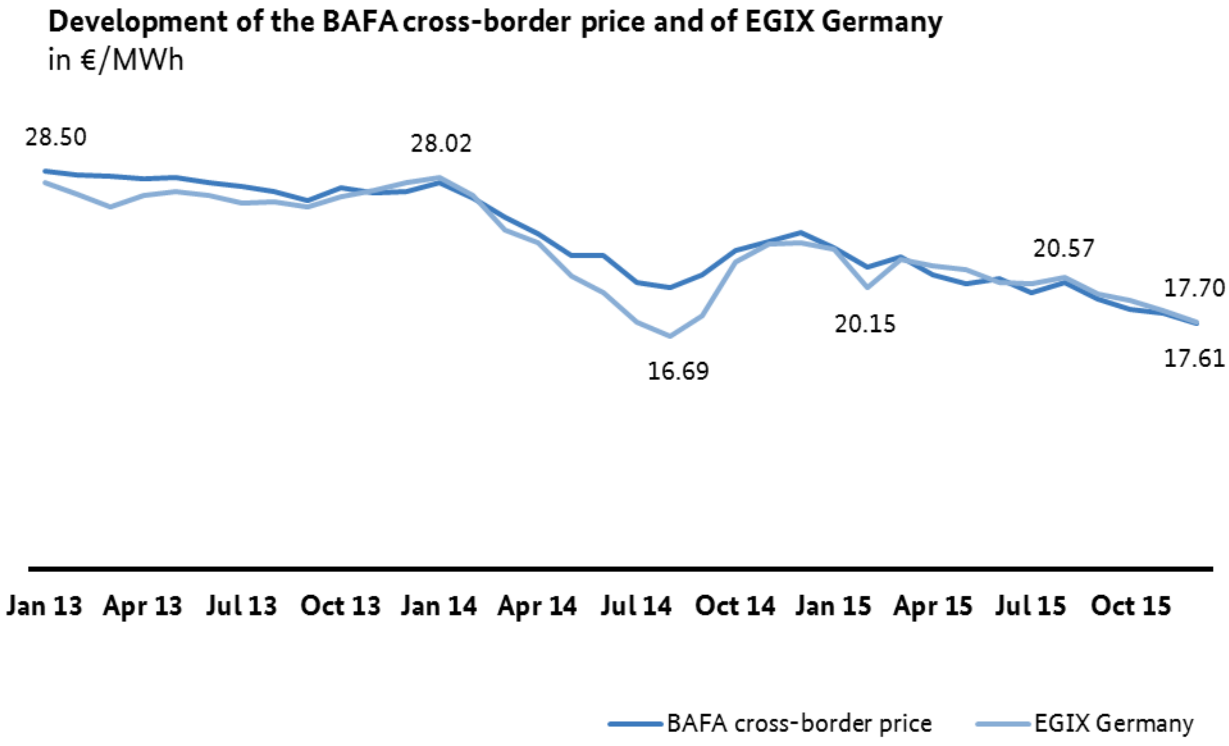

Figure 157: Development of the BAFA cross-border price and the EGIX Germany between 2013 and 2015

[123] For a detailed calculation of the values see https://www.eex.com/blob/9272/836d03126059d5115fb61134fe8f9993/2014-02-06---beschreibung-egix-pdf-data.pdf (retrieved on 25 October 2016).

[124] For details see http://www.bafa.de/bafa/de/energie/erdgas/ (retrieved on 25 October 2016)

Older gas import contracts were usually based on price agreements linked to oil prices. In recent years, this link has been increasingly disregarded for new contracts and contract amendments.[125] Price indices, such as the EEX daily reference price or the EGIX, allow long-term contracts to be indexed according to exchange prices. The development of the BAFA cross-border price in 2015 clearly shows that it is aligned with natural gas exchange prices.

[125] Cf. RWE AG, Annual Report 2015, p. 81.

G Retail

1. Supplier structure and number of providers

A total of 946 gas suppliers were surveyed for the 2016 Monitoring Report. The increase in the group of suppliers surveyed was, above all, the result of extensive market research conducted by the Bundesnetzagentur. In the evaluation of the data provided by gas suppliers, each gas supplier is considered as an individual legal entity without taking possible company affiliations or links into account. This evaluation came to the conclusion that the majority of the gas suppliers (442 companies or 49%) supplied between 1,000 and 10,000 meter points each. These 442 suppliers delivered gas to 1.9m or 14% of the total number of meter points[126]. The amount of gas that these suppliers delivered to final consumers amounted 78 TWh. Based on the total reported volume of gas delivered of 753.4 TWh, this corresponds to a share of 10.4%.

The smallest group of gas suppliers (comprising 26 companies or 3%), in which each company supplies more than 100,000 meter points, supplies 5.8m or 42% of the consumer meter points. The amount of gas that these suppliers delivered to final consumers amounted 211 TWh. Based on the total reported volume of gas delivered of 753.4 TWh, this corresponds to a share of 28%. Most gas suppliers in Germany therefore have a relatively small number of customers, whereas in absolute terms the few large gas suppliers serve the majority of meter points.

[126] The number of final consumer meter points reported by the gas suppliers, standing at 13,734,067, deviates slightly from the figure reported by the network operators, which stands at 14,124,144. This difference is due to the greater market coverage of gas TSOs and DSOs.

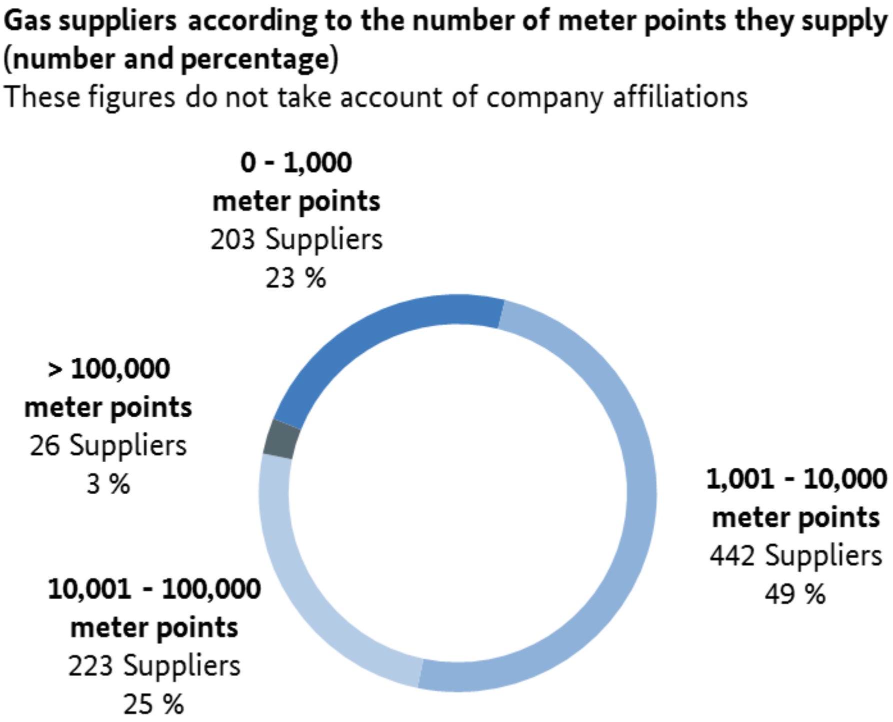

Figure 158: Number of gas suppliers and the share they make up of the total (%), according to the number of meter points they supply

One indicator of the degree of choice for gas customers is the number of suppliers in each network area. In the survey for the 2016 Monitoring Report, the gas network operators were asked to report on the number of suppliers serving at least one final consumer in their networks. This refers to the number of supplying legal entities, meaning that any company affiliations or links among the suppliers are not taken account of. Given that many suppliers are offering rates in many networks in which they do not have a considerable customer base, the reported high number of suppliers does not automatically assume a high level of competitive intensity.

Since market liberalisation and the creation of a legal basis for a well-functioning supplier switch, there has been a steady positive development in the number of active gas suppliers for all final consumers in the different network areas. In 2015, there was a choice of more than 50 gas suppliers in nearly 83% of the network areas. Final consumers in almost 31% of the network areas had a choice of more than 100 suppliers. It is clear that developments are similarly positive when taking a particular look at household customers. In 69% of the network areas, household customers have a choice of 50 or more suppliers. In nearly 20% of the network areas customers had a choice of more than 100 gas suppliers.

On average, final consumers in Germany can choose between 90 suppliers in their network area; household customers can, on average, choose between 75 suppliers (these figures do not take account of company affiliations).

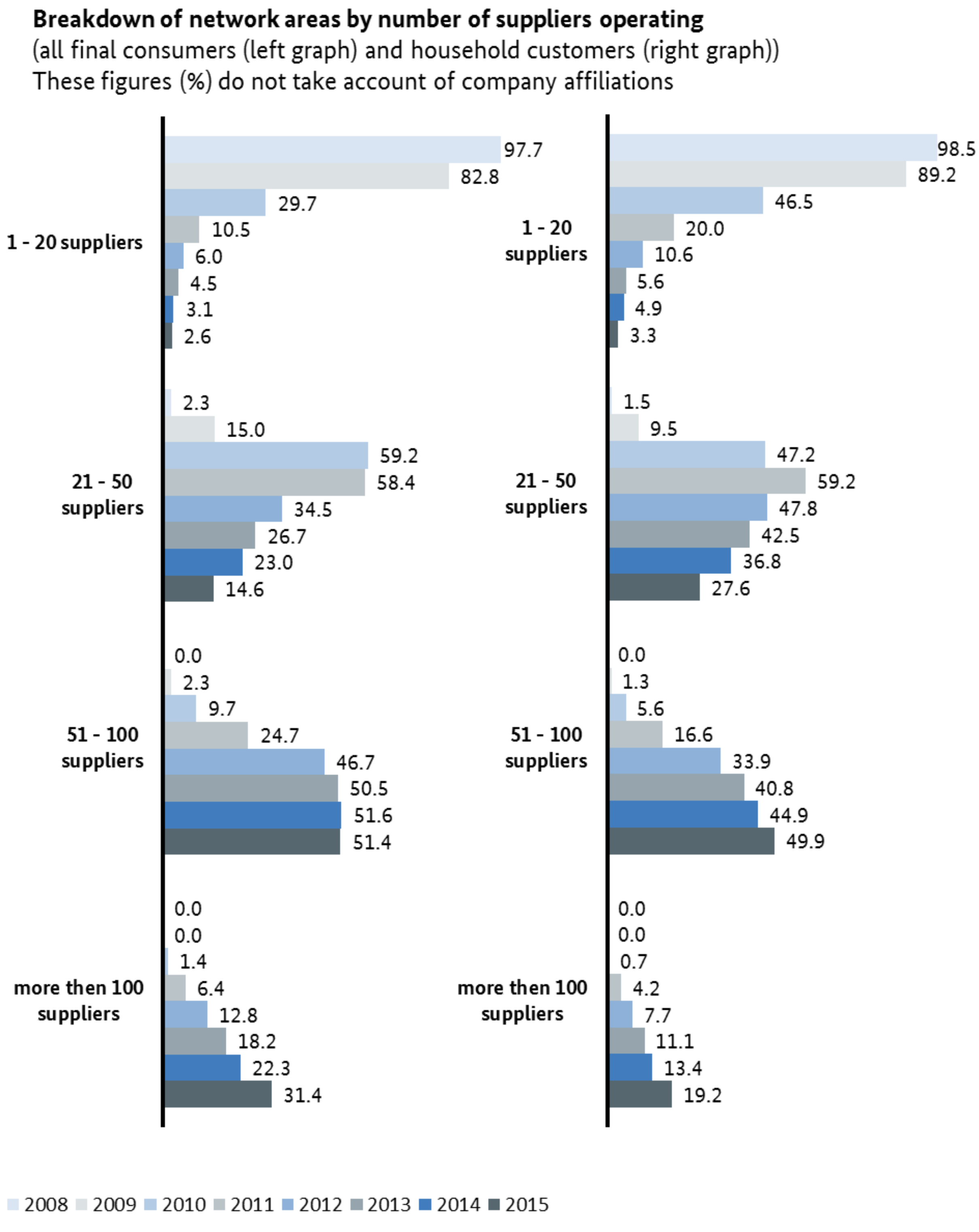

Figure 159: Breakdown of network areas by number of suppliers operating

Suppliers were also asked about the number of network areas in which they supply final consumers with gas. Only 17% of the gas suppliers only operate in one established network area. Most of the gas suppliers (57%) supply at most 10 network areas with gas and are therefore only active regionally. In order to determine the number of gas suppliers active nationwide, it was established that if a supplier is active in more than 500 network areas they are virtually active across all of Germany. A total of 29 gas suppliers (4%) fulfil this criterion and are regarded as suppliers that are active nationwide. On a national average, gas suppliers are active in around 60 network areas.

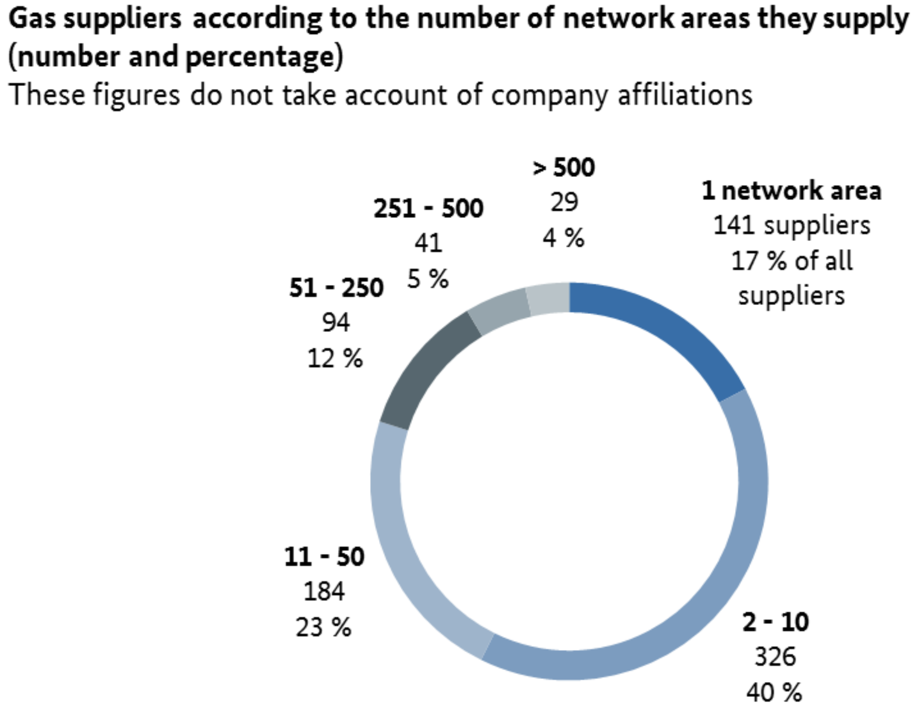

Figure 160: Number and percentage of gas suppliers (and the share they make up of the total (%)), according to the number of network areas they supply

2. Contract structure and supplier switching

Changes in switching rates and processes are important indicators of the level of competition. Collecting such key figures, however, is bound up with many difficulties and, as a result, the relevant data collection has to be limited to data that best reflects the actual switching behaviour.

In the survey, data on contract structures and supplier switching is collected through questionnaires relating to each specific customer group to be completed by the TSOs, DSOs and suppliers.

Final consumers can be grouped according to their meter profile into customers with and without interval metering. For customers without interval metering, consumption over a set period of time is estimated using a standard load profile (SLP).

Final consumers can also be divided into household and non-household customers. Household customers are defined in the German Energy Act (EnWG) according to qualitative characteristics.[127] All other customers are non-household customers, which includes customers in the industrial, commercial, service and agricultural sectors as well as public administration.

According to the questionnaires filled out by gas retailers and suppliers, the total quantity of gas supplied by suppliers to all final consumers in 2015 reached approximately 758 TWh (2014: 712 TWh). Of this, 410 TWh was supplied to interval metered customers (2014: 391 TWh) and 348 TWh to SLP customers. The majority of non-interval metered customers are household customers. In 2015 household customers were supplied with around 226.5 TWh.

In the monitoring survey, data is collected from the gas suppliers on the volumes of gas sold to various final consumer groups broken down into the following three contract categories:

- default contract,
- customers with a non-default contract with their default supplier and
- customers with a supplier other than the local default supplier.

For the purposes of this analysis, the default contract category also includes fallback energy supply (section 38 EnWG) and doubtful cases.[128] Supply outside the framework of a default contract is either designated as a non-default contract or is defined specifically ("non-default contract with the default supplier" or "contract with a supplier other than the local default supplier"). An analysis on the basis of these three categories makes it possible to draw conclusions as to the extent of the decline in the importance of default supply and the role of default suppliers since the liberalisation of the energy market.

The corresponding figures, however, should not be directly interpreted as "cumulative net switching figures since liberalisation". It must be noted that for monitoring purposes the legal entity is taken to be the contracting party, thus a contract with a company affiliated with the default supplier falls under the category "contract with a supplier other than the local default supplier".[129]

For the first time, gas suppliers were asked how many household customers have switched or changed their energy supply contract in the 2015 calendar year (change of contract).

Data was also collected from the TSOs and DSOs on the number of customers in different groups switching supplier in 2015. A supplier switch, as defined in the monitoring survey, means the process by which a final

[127] Section 3 para 22 EnWG defines household customers as final consumers who purchase energy primarily for their own household consumption or for their own consumption for professional, agricultural or commercial purposes not exceeding an annual consumption of 10,000 kilowatt hours.

[128] In addition to household customers, final consumers served by fallback supply are usually included under the default supply tariff, section 38 EnWG. For monitoring purposes, suppliers were asked to allocate cases that could not be clearly categorised to "default supply".

[129] It is also possible that further ambiguities may arise, for example if the local default supplier changes.

consumer's meter point is assigned to a new supplier. In this analysis, too, it must be noted that the change of supplier question refers to a change in the supplying legal entity. A network operator cannot distinguish between an internal reallocation of supply contracts to another group company and a change of supplier initiated by a customer – or only at considerable time and expense – and therefore both fall under supplier switching. The same applies to any insolvency of the former supplier or in the event that the supplier terminates the contract ("involuntary supplier switch"). This is why the actual extent to which customers switched suppliers may slightly deviate from the figures established in the survey. In addition to supplier switches, the choice of supplier made by household customers upon moving home was also analysed.

2.1 Non-household customers

2.1.1 Contract structure

Gas sold to non-household customers is mainly supplied to interval-metered customers where consumption is recorded at short intervals ("load profile"). Interval-metered customers are characterised by high consumption and/or high energy requirements.[130] All interval-metered customers are non-household customers with a high level of consumption, such as industrial customers or gas power plants.

In the reporting year 2015, around 740 gas suppliers (separate legal entities) provided information on metering points and on the volumes supplied to interval-metered customers (730 suppliers responded in the previous year). The 740 gas suppliers include a number of affiliated companies so that the number of suppliers is not equal to the number of actual competitors.

Overall, these suppliers sold over 410 TWh of gas to interval-metered customers via more than 38,500 metering points in 2015. Over 99 per cent of this volume was supplied under contracts with the default supplier outside the default supply and under contracts with suppliers other than the local default supplier. In other words, over 99 per cent was supplied under special contracts. It is unusual, but not impossible, for interval-metered customers to be supplied under a default or auxiliary supply contract. Around 0.9 TWh of gas was supplied to interval-metered customers with a default or auxiliary supply contract. This corresponds to about 0.2 per cent of the total volume supplied to interval-metered customers. About 29 per cent of the total volume supplied to interval-metered customers was sold under contracts with the default supplier outside the default supply and about 71 per cent under supply contracts with a legal entity other than the default supplier. This largely corresponds to last year's distribution (33 per cent and 67 per cent). The figures show that default supplier status is only of secondary importance for the acquisition of interval-metered gas customers.

[130] In accordance with section 24 of the Gas Network Access Ordinance (GasNZV), interval metering is generally required for customers with a maximum hourly consumption rate exceeding 500 KW or maximum annual consumption of 1.5 GWh.

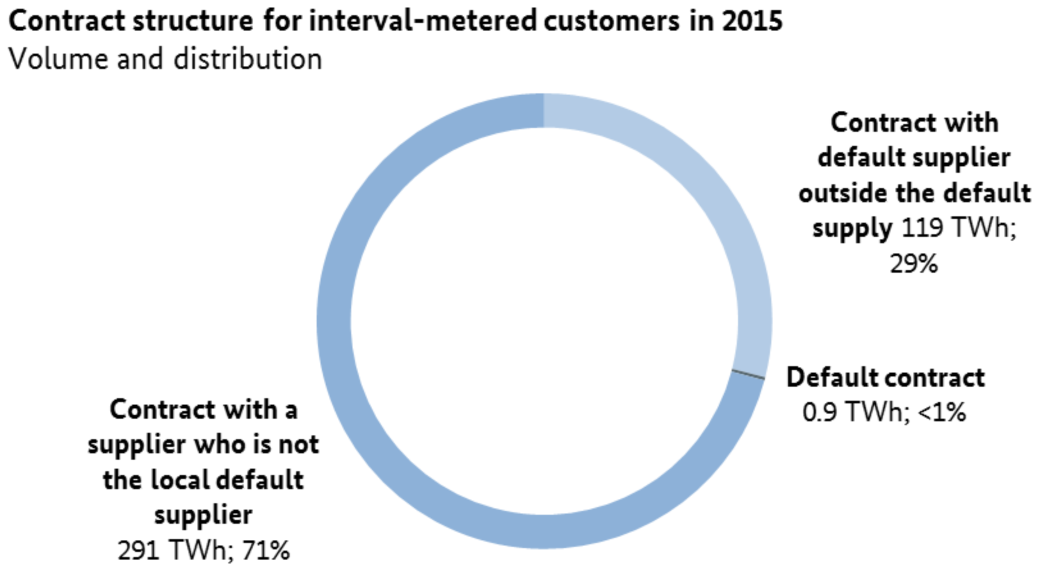

Figure 161: Contract structure for interval-metered customers in 2015

2.1.2 Supplier switching

Data on the supplier switching rates (as defined for monitoring, s.a.) of different customer groups in 2015 was collected in the TSO and DSO surveys. This did not include the percentage of industrial and commercial customers who have changed supplier once, more than once or not at all over a period of several years. The supplier switching figures were retrieved and differentiated by reference to five different consumption categories. The survey produced the following results.

Supplier switching by consumption category in 2015

End consumer category	Number of metering points with change of supplier	Share of all metering points in the consumption category	Volume consumed at metering points with change of supplier	Share of total volume consumed in the consumption category
<0.3 GWh/year	1,102,783	8.1%	28.3 TWh	9.3%
0.3 GWh/year – 10 GWh/year	14,566	12.8%	16.3 TWh	13.8%
>10 GWh/year – 100 GWh/year	1,019	13.1%	15.9 TWh	15.6%
>100 GWh/year	97	5.8%	27.2 TWh	10.8%
Gas power plants	12	5.1%	4.4 TWh	6.6%

Table 82: Supplier switching by consumption category in 2015

The total number of metering points with a change of supplier fell slightly by 32,903 (-2.6 per cent). In light of the colder winter compared to the previous year, the gas volume affected by supplier switching rose from 87.4 TWh in 2014 to 92.1 TWh in 2015, an increase of 4.7 TWh (5.4 per cent).

The four categories with consumption exceeding 0.3 GWh/year (including gas-fired power plants) consist entirely of non-household customers. The volume-based switching rate across these four categories was 11.8 per cent in 2015, the same figure as in the previous year. Switching rates among industrial and commercial customers increased sharply between 2006 and 2010. The switching rate has remained more or less constant at around 12 to 13 per cent since 2010.

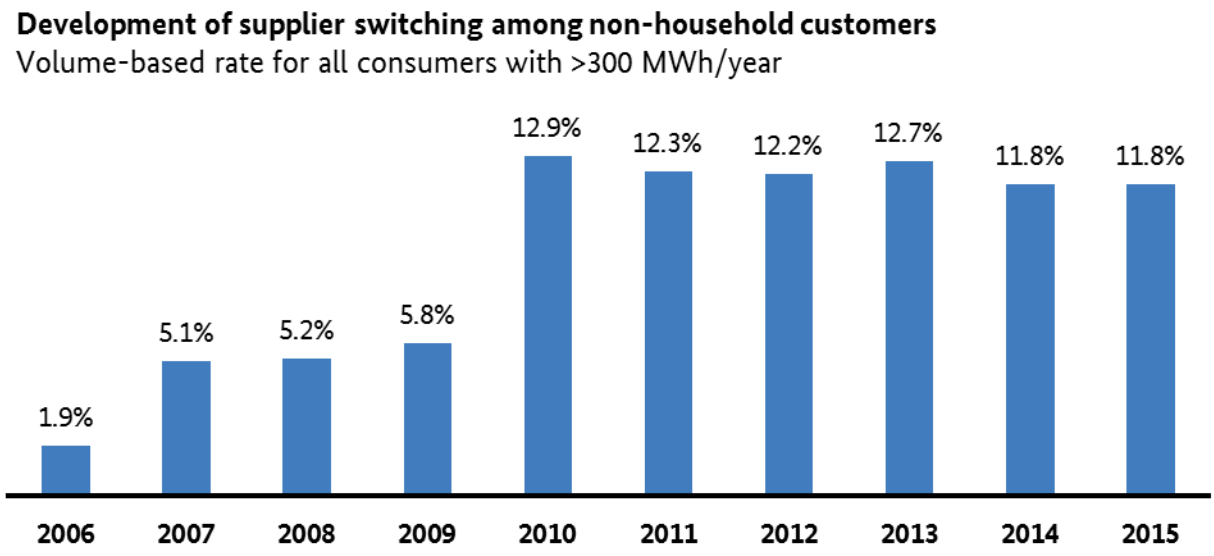

Figure 162: Development of supplier switching among non-household customers

2.2 Household customers

2.2.1 Contract structure

An analysis of how household customers were supplied in 2015 in terms of volume shows that the majority of household customers (54%) were supplied by the local default supplier under a non-default contract (2014: 57%) and were delivered 122.4 TWh of gas (2014: 116 TWh). Just under one quarter of household customers (23.5%, compared to 24% in 2014) with a default supply contract were supplied with 53.3 TWh of gas (2014: 49.8 TWh). The percentage of household customers who have a contract with a supplier other than the local default supplier once again increased and now stands at 22.4% (2014: 19%) for 50.8 TWh of gas (2014: 38.3 TWh).[131]

[131] The total volume of gas supplied to household customers reported by gas suppliers of 226.5 TWh differs from the amount reported by gas DSOs (254.5 TWh) because the market coverage of the network operator survey is higher.

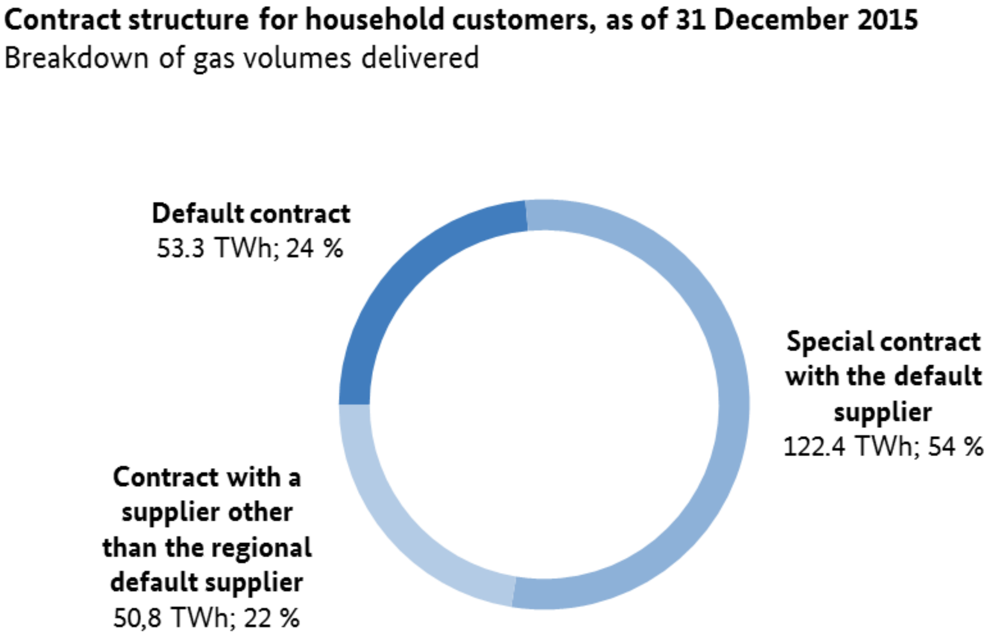

Figure 163: Contract structure for household customers (volume of gas delivered) according to survey of gas suppliers

When taking a particular look at the number of household customers supplied in 2015 it becomes clear that a relative majority of 45.9% of them signed a non-default contract with the local default supplier. In terms of both the volume of gas delivered and number of customers supplied, a total of 78% of household customers are supplied by the default supplier under a default contract or through a contract outside of default supply.[132] The differences between the share of customers supplied on default terms and those on non-default terms in a contract with the default supplier (23.5% compared with 32.3% and 54% compared with 45.9%) result from the fact that default supply customers with a higher consumption of gas switch to a more affordable contract on non-default terms.

[132] The total number of household customers reported by gas suppliers of 11,757,753 differs from the number of household customers reported by DSOs (12,387,301) because the market coverage of the network operator survey is higher.

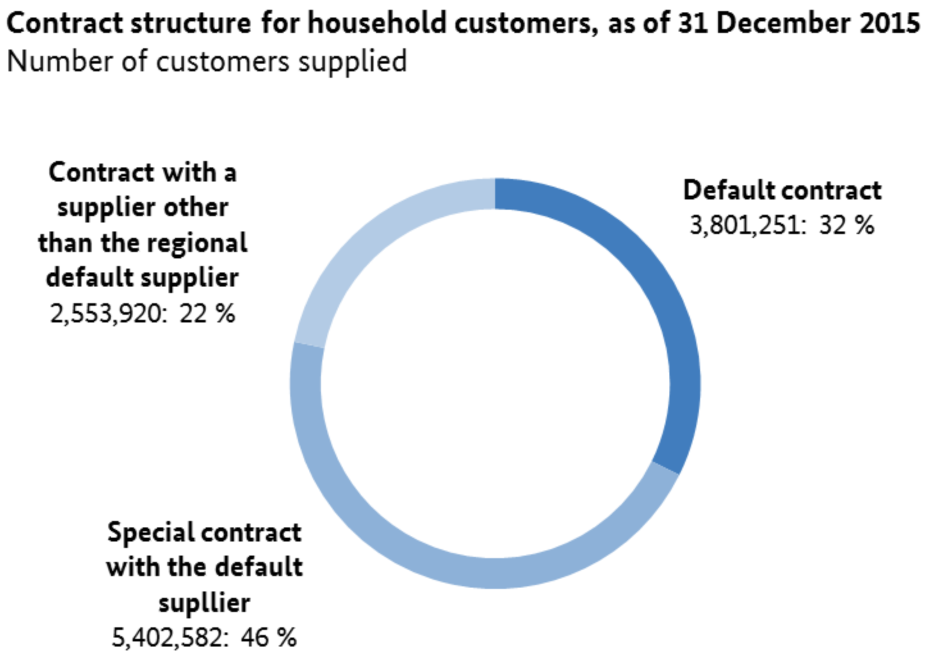

Figure 164: Contract structure for household customers (number of customers supplied) according to survey of gas suppliers

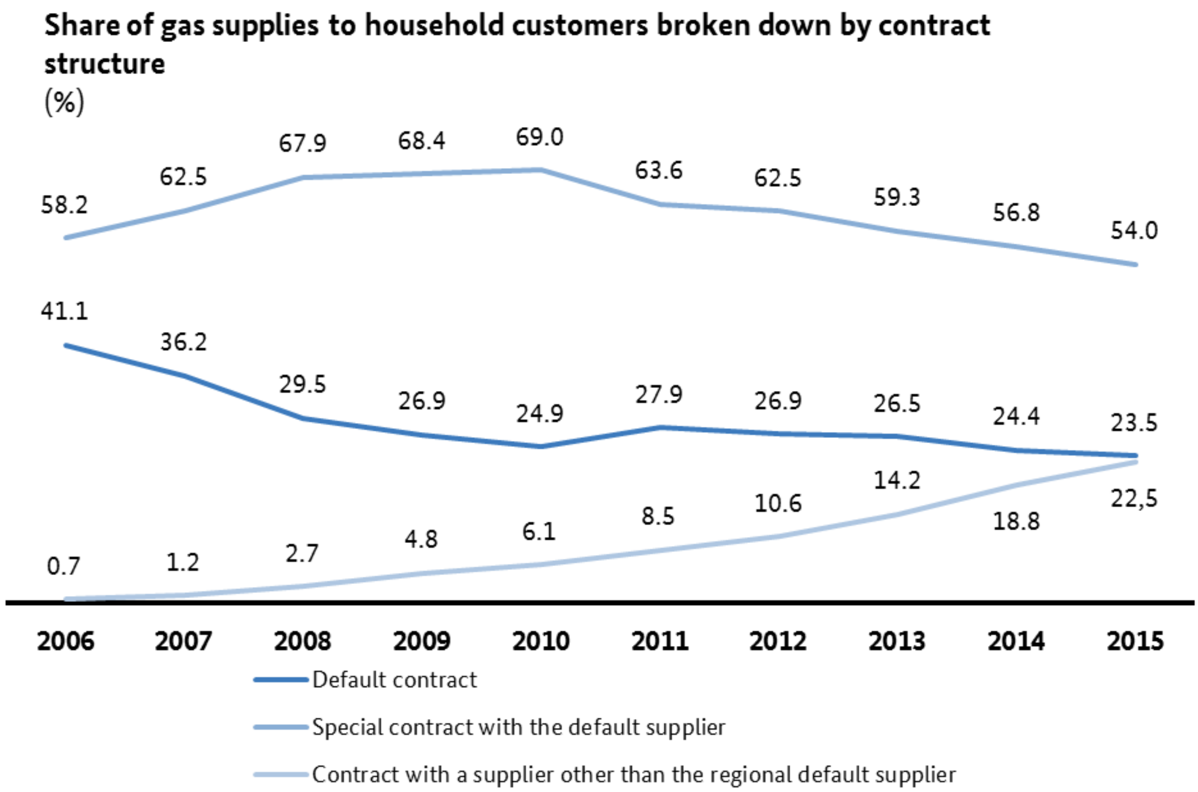

Figure 165: Share of gas supplies to household customers broken down by contract structure according to survey of gas suppliers

2.2.2 Change of contract

For the first time, data for the monitoring survey was collected from gas suppliers on household customers that carried out a change of contract. Only contract changes carried out at the customer's request applied in the survey.[133] The total number of customers changing contract was 480,815. The volume of gas these customers were delivered was approx 12.03 TWh. The resulting number-based and volume-based switching rates are 4.09% and 5.31% respectively.

Household customers that changed their contracts

Category	Subsequent consumption in 2015 (TWh)	Share (%) of total consumption (226.5 TWh)	Number of contracts changed in 2015	Share (%) of all household customers
Household customers that had changed their contract by their existing supplier	12.03	5.31	480,815	4.09

Table 83: Household customers that changed their contracts according to survey of gas suppliers

2.2.3 Supplier switches

To determine the number of supplier switches by household customers, the DSOs were asked to provide information on the number of customers switching and volumes involved at meter points as well as information concerning customers choosing a supplier other than the default supplier within the meaning of section 36(2) EnWG immediately when moving home. The number of household customers who switched supplier rose by around 15% (+120,171 supplier switches) to 925,195. By contrast, the number of household customers who immediately chose an alternative supplier rather than the default supplier when moving home decreased by 13.5% (-33,011 household customers).

[133] Adjustments to the contract that result from changes to the general terms and conditions, expiring tariffs or customers moving to an affiliated company within the group do not apply here.

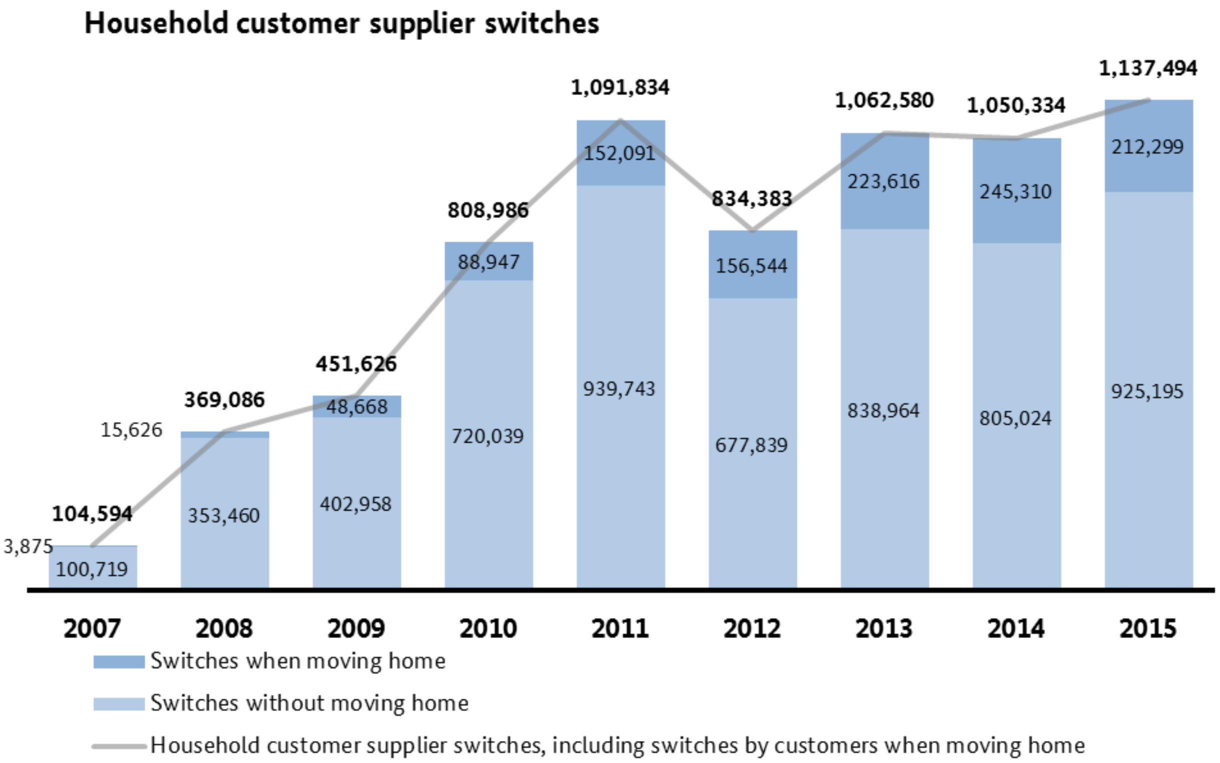

Figure 166: Household customer supplier switches according to the DSO survey

The overall trend continues to be positive and when looking at 12.4m household customers (according to DSO figures) the resulting number-based household customer switching rate comes out to 9.2% (2014: 8.4%).

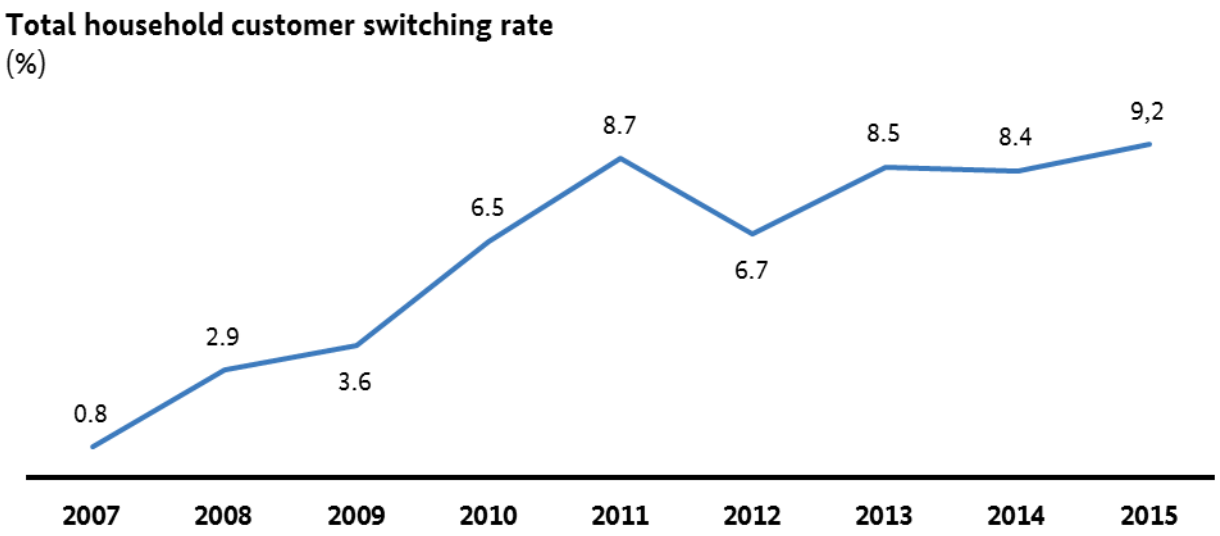

Figure 167: Total household customer switching rate based on DSO data survey

The DSOs were also asked to provide information on the volumes of gas recorded at the meter points of households that switched supplier or selected a new supplier in the process of moving home. The total volume of gas supplied to customers who switched supplier (including those switching when moving home) increased in 2015 by 3 TWh or 13.3% to 25.6 TWh. Considering the significant increase in gas supplied to household customers by network operators in 2015, the volume-based switching rate remained stable at 10.1%. The volume-based supplier switching rate (10.1%) is still above the numbers-based rate (9.2%) because high-consumption household customers exhibit more intensive switching behaviour. At around 22,000 kWh, the calculated annual consumption of an average gas customer that switched supplier is above the national average of approx 20,000 kWh.

Household customer supplier switches, including switches by customers when moving home

Category	Subsequent consumption in 2015 (TWh)	Share (%) of total consumption (254.5 TWh)	Number of supplier switches in 2015	Share (%) of all (12,387,301) household customers
Household customer supplier switches without moving home	21.4	8.4%	925,195	7.5%
Household customers that choose a different supplier after moving home	4.2	1.7%	212,299	1.7%
Total	25.6	10.1%	1,137,494	9.2%

Table 84: Household customer supplier switches, including switches by customers when moving home

3. Gas supply disconnections and contract terminations, cash/smart card meters and non-annual billing

3.1 Disconnections and terminations

In the data survey for the 2016 Monitoring Report, DSOs and gas suppliers were asked several questions about disconnection notices, disconnection orders, disconnections that were actually carried out and the costs each action incurred.

Between 2011 and 2014, the survey on disconnections concerned only the notices and orders issued to disconnect a default supply customer and the disconnections carried out on behalf of the local default supplier.

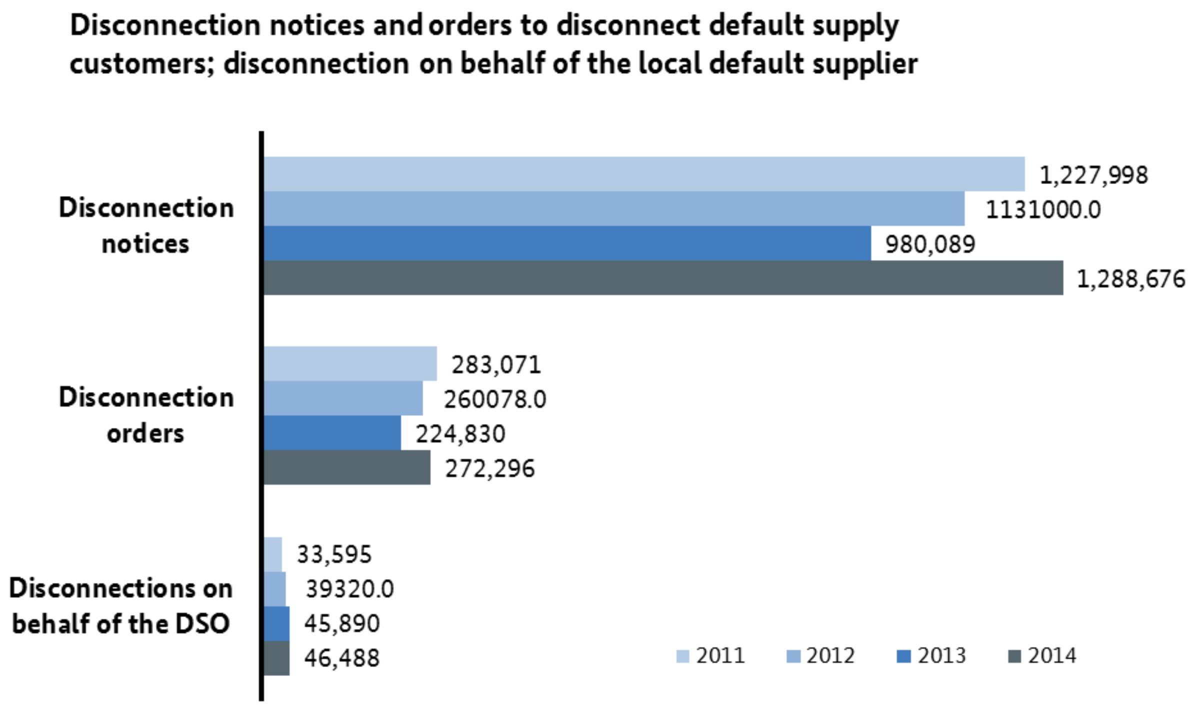

Figure 168: Disconnection notices and orders to disconnect default supply customers; disconnection on behalf of the local default supplier (gas) for the years 2011 - 2014

The gas supplier survey was further differentiated for the 2015 year. The survey of disconnection notices and orders now addresses all gas suppliers and not just default suppliers. Moreover, the suppliers answer questions both about disconnections in default supply and disconnections for household customers with non-default contracts.

The reason why the survey was changed is the fact that, up to now, network operators have not been able to differentiate whether a disconnection that was ordered by the default supplier related to a default contract or to a non-default household customer contract with the default supplier. For when an order is issued to disconnect a customer, in accordance with section 24(3) of the Low Pressure Network Connection Ordinance (NDAV), the supplier must only credibly claim that the contractual requirements for an interruption of supply between the supplier and the customer are met. The supplier does not, however, have to disclose the conditions of the contract. Moreover, a gas supplier does not have to change his network registration with the network operator if he changes the conditions of the customer's contract. Network operators therefore generally have no knowledge as to whether a customer who originally received default supply service from their default supplier actually still is on default terms or has switched to a non-default contract with the default supplier.

Compared to the previous year, the number of disconnections carried out by DSOs on behalf of the default supplier fell to 43,626, which represents a drop of 6%. This figure is based on information from the DSOs that ultimately carry out the disconnections on behalf of the suppliers. In 2015, the DSOs restored supply to around 36,000 customers which they had previously disconnected on behalf of the default supplier.

The average charge paid by suppliers to DSOs for disconnecting customers was around €55, with the actual costs charged ranging from €10 to €210. The average charge paid by suppliers to DSOs for restoring supply to customers was around €62, with the actual costs charged ranging from €10 to €203.

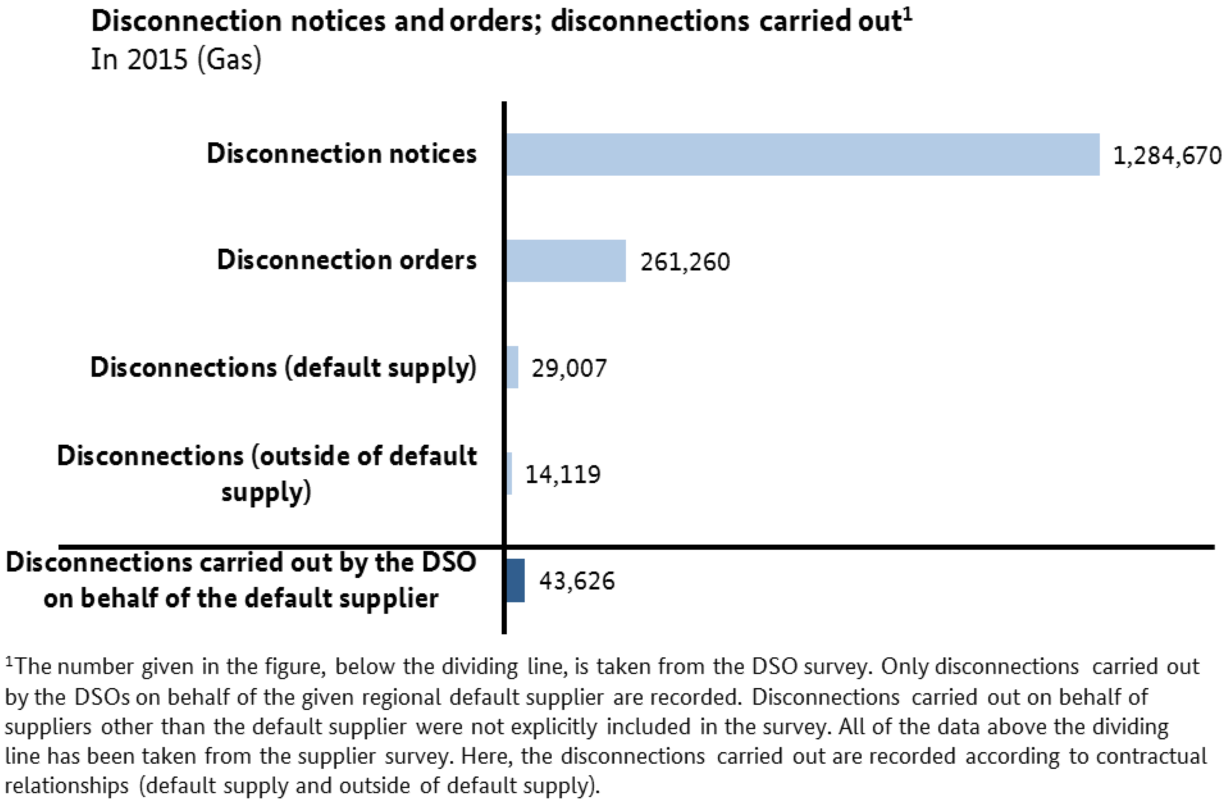

Figure 169: Disconnection notices and orders; disconnections carried out

At the same time the suppliers were asked how often in 2015 they had issued disconnection notices to customers that had failed to meet payment obligations and how often they had ordered the network operator responsible to disconnect supplies. This survey is now addressed to all gas suppliers and is no longer limited only to default suppliers. Compared to the previous year, the number of disconnection notices issued (1,284,670)[134] remained more or less steady (-0.3%). Compared to 2014, the number of disconnection orders fell by 4.1% to 261,260. Only some 20% of the 1.3m disconnection notices resulted in a disconnection subsequently being ordered.

According to the gas suppliers, 43,126 disconnection notices (for customers on a default contract or a non-default contract with the default supplier) ended with a disconnection carried out by the network operator responsible. A comparison of the number of disconnection notices issued with the number of disconnections actually carried out makes it clear that about 3.4% of the notices issued actually resulted in a disconnection carried out. Additionally, gas suppliers indicated that they disconnected customers with a default contract 29,007 times. The disconnection rate with respect to the total number of customers under a default contract was on average less than one percent (0.8%). Customers outside of default supply (non-default customers) were disconnected 14,119 times. The disconnection rate for non-default customers was 0.2%.

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[134] Some of the energy suppliers do not make a distinction between gas, electricity, water and heating when issuing disconnection notices. Therefore, this number may also include disconnections that were not directly linked to gas supply.

According to the information provided by gas suppliers, 67.3% of the disconnections affected household customers that were supplied by a default supplier. 32.7% of all disconnected customer were supplied under a non-default contract. When considering the number of disconnections and the number of disconnected household customers, it becomes clear that approximately 6% of household customers under a default contract were disconnected multiple times. Some 15% of household customers under a non-default contract were disconnected multiple times. The GasGVV does not specify a minimum level of arrears for supply disconnection. The average level of arrears was about €123. Another common criterion for disconnection was the number of days a customer was behind in settling their accounts or making a partial payment.

The DSOs charged their customers an average fee of €46 for disconnecting supply, with the actual costs charged ranging from €2 to €190. Customers were charged an average reconnection fee of €55, with the lowest fee at €2 and the highest at €170 for reconnection.

Despite issuing disconnection notices and orders, only a small number of gas suppliers actually terminate supply contracts with their customers. Moreover, the termination of a default supply contract is only permitted under stringent conditions. There must be no obligation to provide basic services or the requirements to disconnect gas supply must have been met repeatedly and the customer must have been warned of contract termination because of late payment. In 2015, gas suppliers had to terminate their contractual relationship with a total of 47,935 gas customers due to their failure to fulfil a payment obligation. Criteria frequently cited for terminating contracts included reaching the final dunning level and missing two or three partial payments without any prospect of fulfilling the claim.

3.2 Cash/smart card meters

In the 2016 monitoring survey, DSOs and gas suppliers answered several questions on prepayment systems, as per section 14 GasGVV, such as cash meters or smart card meters. According to the data provided by DSOs, 45 DSOs had set up a total of 1,178 cash/smart card meters or other comparable prepayment systems, as per section 14 GasGVV, in the context of default supply in 2015. Some 223 prepayment systems were newly installed and 179 existing prepayment systems were removed in 2015. On average, DSOs charged gas suppliers €36 annually for a prepayment system. This charge is divided into costs for meter operation (on average approx €21), metering (on average approx €4) as well as billing (on average approx €11). The average annual base price that the gas supplier charged customers was €122, with the costs charged ranging from €14 to €211. The kilowatt-hour rate for gas billed using a prepayment meter averaged 6.5 ct/kWh and ranged between 4.2 ct/kWh and 9.2 ct/kWh.

3.3 Non-annual billing

Section 40(3) EnWG requires gas suppliers to offer final consumers monthly, quarterly or half yearly bills. According to the survey of gas suppliers, demand for non-annual billing cycles is still low.

Non-annual billing in 2015

	Requests	Non-annual bills issued	Average charge for each additional bill for customers reading their own meters (Range)	Average charge for each additional bill for customers not reading their own meters (Range)
Other forms of billing for household customers	6,733	6,511	€13.6 Euro (€2 - €50)	€17.1 Euro (€2.5 - €62)
monthly	449	451		
quarterly	87	166		
semi-annual	998	1,059		
period missing	5,199	4,835		

Table 85: Non-annual billing according to gas supplier survey

4. Price level

In the monitoring survey, suppliers that supply gas to final consumers in Germany were asked about the retail prices their companies charged on 1 April 2016 for various consumption levels. The category of household customers, which were defined (see Monitoring Report 2015, pg 300) as having an average consumption of 23 MWh/year (= 82.8 giga joules or GJ)[135], was broken down for the first time according to the following consumption bands:

– Band I (D1[136]): annual consumption below 20 GJ (5,556 kWh)

– Band II (D2): annual consumption between 20 GJ (5,556 kWh) and 200 GJ (55,556 kWh)

– Band III (D3): annual consumption above 20 GJ (55,556 kWh).

Furthermore, as in previous years, the consumption levels of 116 MWh (= 417.6 GJ for "commercial customers") and 116 GWh (= 417,600 GJ for "industrial customers") were analysed.

Suppliers were asked to give the overall price in cents per kilowatt hour (ct/kWh) and to include the non-variable price components such as the service price, base price and transfer or internal price. Suppliers were also asked to provide a breakdown of the price components that they cannot control, including, in particular, network tariffs, concession fees and charges for billing, metering and meter operations. After deducting these components from

[135] 1 MWh = 3.6 GJ.

[136] "D1", "D2" and "D3" refer to the consumption bands defined by EUROSTAT.

the overall price, the amount remaining is the amount controlled by the supplier which comprises above all gas procurement, supply, other costs and the supplier's margin.

The suppliers were asked to provide their "average" overall prices and price components for each of the consumption levels.

In respect of the consumption of household customers (bands I, II and III), suppliers were asked to provide data on the price components for three different contract types:

- default contract,
- special contract with the default supplier, and
- contract with a supplier other than the local default supplier.

The findings are set out below, broken down by customer category and consumption level. To better illustrate any long-term trends, a comparison is made in each case with the previous year's figures. When comparing the figures as they stood on 1 April 2016 and 1 April 2015, it should be noted that differences in the calculated averages are lower in some cases than the range of error for the data collection method.

The survey was addressed to all suppliers operating in Germany. With regard to the prices for the 116 GWh/year and 116 MWh/year consumption levels, only those suppliers were asked to provide data that served at least one customer whose gas demand fell within the range of the relevant level of consumption (this applied to 97 and 642 suppliers respectively).

4.1 Non-household customers

116 GWh/year consumption category ("industrial customers")

The customer group with an annual consumption in the 116 GWh range consists entirely of interval-metered customers, i.e. generally industrial customers. The wide range of options with regard to contractual arrangements is very important to this customer group. Suppliers generally do not use specific tariff groups for consumers who fall into the 116 GWh/year category but offer customer-specific deals. Their customers include those with a full supply and those whose negotiated consumption (in the amount relevant to this category) represents only part of their procurement portfolio. For high-consumption customers the distinction between retail and wholesale trading is inherently fluid. Supply prices are often indexed against wholesale prices. There are types of contracts where customers themselves are responsible for settling network tariffs with the network operator. In extreme cases, these types of contracts even go so far as to require suppliers to merely provide balancing group management services for customers in terms of the economic result.

The 116 GWh/year consumption category was defined as an annual usage period of 250 days (4,000 hours). Data was collected only from suppliers with at least one customer with an annual consumption between 50 GWh and 200 GWh. This customer profile applied to only a small group of suppliers. The following price analysis of the consumption category is based on data from 97 suppliers (98 suppliers in the previous year).

This data was used to calculate the arithmetic mean of the total price and the individual price components. The data spread for each price component was also analysed in terms of ranges. The 10th percentile represents the lower limit and the 90th percentile the upper limit of each reported range. This means that the middle 80 per cent of the figures provided by the suppliers are within the stated range. The analysis produced the following results.

Price level for the 116 GWh/year consumption category on 1 April 2016

	Spread in the 10 to 90 percentile range of the supplier data sorted by size in ct/kWh	Average (arithmetic) in ct/kWh	Percentage of total price
Price components outside the supplier's control			
Net network charge	0.16-0.41	0.29	11%
Metering, billing, meter operation	0.00-0.01	0.002	0%
Concession fee	0.00	0.00 [1]	0%
Gas tax	0.55	0.55	20%
Price component controlled by the supplier (remaining balance)	1.38-2.52	1.92	70%
Total price (excluding VAT)	2.14-3.38	2.77	

[1] Under section 2, paragraph 5, no. 1 of the Electricity and Gas Concession Fees Ordinance (KAV), concession fees for special contract customers apply only to the first 5 GWh (0.03 ct/kWh). Allocating this price component to the total volume consumed results in a very small average, i.e. an average of 0.00 ct/kWh (rounded) in the 116 GWh/year consumption category.

Table 86: Price level for the 116 GWh/year consumption category on 1 April 2016

Network tariffs, metering and concession fees account for an average of 10.5 per cent of the overall price in the 116 GWh/year consumption category (industrial customers). This percentage is considerably lower than that applying to household customers or non-household customers with low consumption (see below).

The share of the components that can be controlled by the supplier (gas procurement and supply, other costs and the margin) is accordingly much larger at 69.5 per cent than that applying to household customers.

The average overall price (excluding VAT) of 2.77 ct/kWh is 0.69 ct/kWh and significantly lower (by about 20 per cent) than last year's figure. The average gas price in the 116 GWh/year category has therefore been by far at the lowest level since the first data on gas prices was collected for energy monitoring (1 April 2008). Retail prices in the 116 GWh/year category fell even more sharply than wholesale prices. Since the components of the overall price outside the supplier’s control (especially network tariffs and levies) remained the same, the decline in the overall price reduces the price component that can be controlled by the supplier.

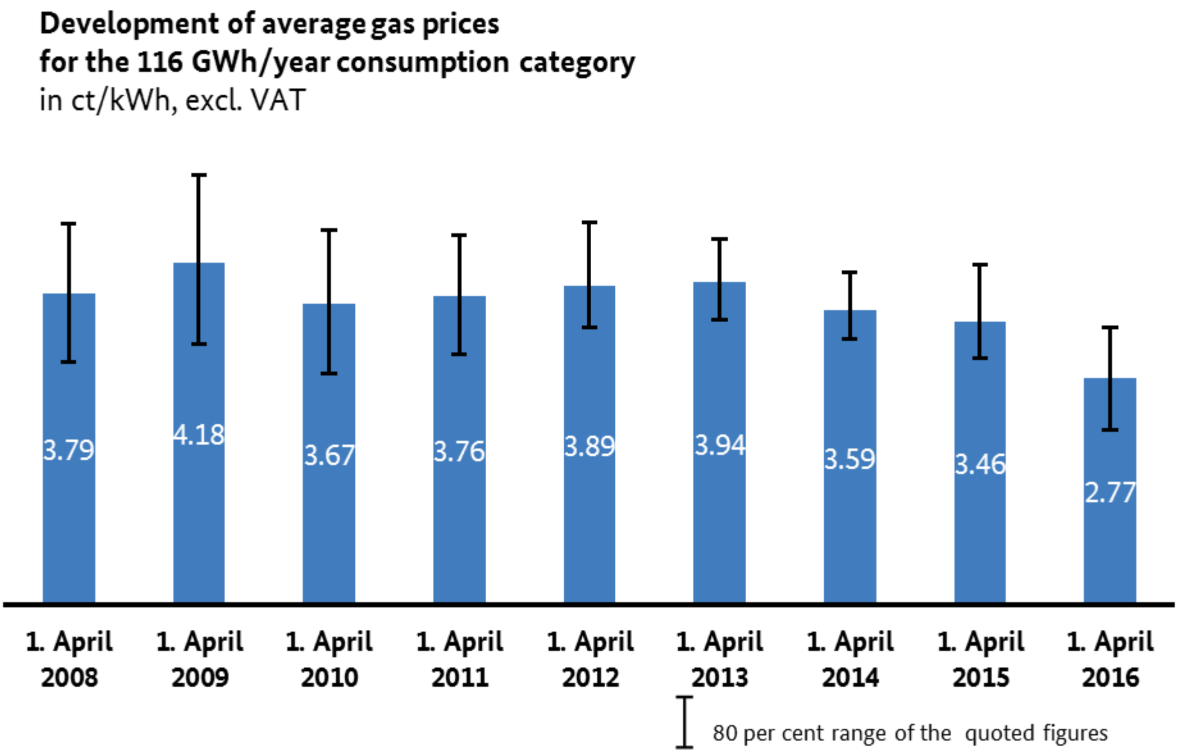

Figure 170: Average gas prices for the 116 GWh/year consumption category

116 MWh/year consumption category ("commercial customers")

The non-household customer category based on an annual consumption of 116 MWh includes commercial customers with a relatively low level of consumption. No annual usage period was defined for this customer category. This amount of annual consumption is one thousandth of the amount consumed by industrial customers in the 116 GWh/year category and five times higher than the amount consumed by household customers in the 23 MWh/year category. Given the moderate level of consumption, individual contractual arrangements play a significantly smaller role than in the 116 GWh/year consumption category. Since this consumption level is below the 1.5 GWh above which network operators are required to use interval metering, it is safe to assume that consumption in this category is measured using a standard load profile. Suppliers were asked to make a plausible estimate of the charges for customers whose consumption profile is similar to that of the consumption category based on the terms and conditions that applied on 1 April 2016. Data was collected from suppliers that had customers with a consumption profile of roughly comparable magnitude, i.e. with an annual consumption between 50 MWh and 200 MWh.

The following price analysis of the consumption category was based on data from 642 suppliers (630 in the previous year). The data was used to calculate the (arithmetic) means of the overall price and of the individual price components. The data spread for each price component was also analysed in terms of ranges that included the 80 per cent of the figures provided by the suppliers. The analysis produced the following results.

Price level for the 116 MWh/year consumption category on 1 April 2016

	Spread in the 10 to 90 percentile range of the supplier data sorted by size in ct/kWh	Average (arithmetic) in ct/kWh	Percentage of total price
Price components outside the supplier's control			
Net network charge	0.84-1.56	1.20	25%
Metering, billing, meter operation	0.02-0.10	0.05	1%
Concession fee	0.03-0.03	0.04 [1]	1%
Gas tax	0.55	0.55	12%
Price component controlled by the supplier (remaining balance)	2.21-3.52	2.88	61%
Total price (excluding VAT)	3.98-5.44	4.72	

[1] 55 of the 642 suppliers quoted a figure above 0.03 ct/kW. These suppliers sold only small volumes. A concession fee in excess of 0.03 ct/kWh could apply to non-household customers if the gas is supplied under a default supply contract (cf. section 2, paragraph 2, no. 2 b of the Electricity and Gas Concession Fees Ordinance (KAV)).

Table 87: Price level for the 116 MWh/year consumption category on 1 April 2016

This year, an average 39 per cent of the overall price in the commercial customer category (116 MWh) consists of cost items outside the supplier’s control (network tariffs, gas tax and concession fee). 61 per cent concerns price elements that provide scope for commercial decisions.

The arithmetic mean of the overall price of 4.72 ct/kWh (excluding VAT) is 0.37 ct/kWh or around 7 per cent lower than last year's figure. The absolute amount of the price components outside the supplier’s control rose from 1.80 ct/kWh to 1.84 ct/kWh year-on-year. The remaining balance that can be controlled by the supplier fell by 0.41 ct/kWh (from 3.29 ct/kWh in 2014 to 2.88 ct/kWh in 2015) or by about 12.5 per cent.

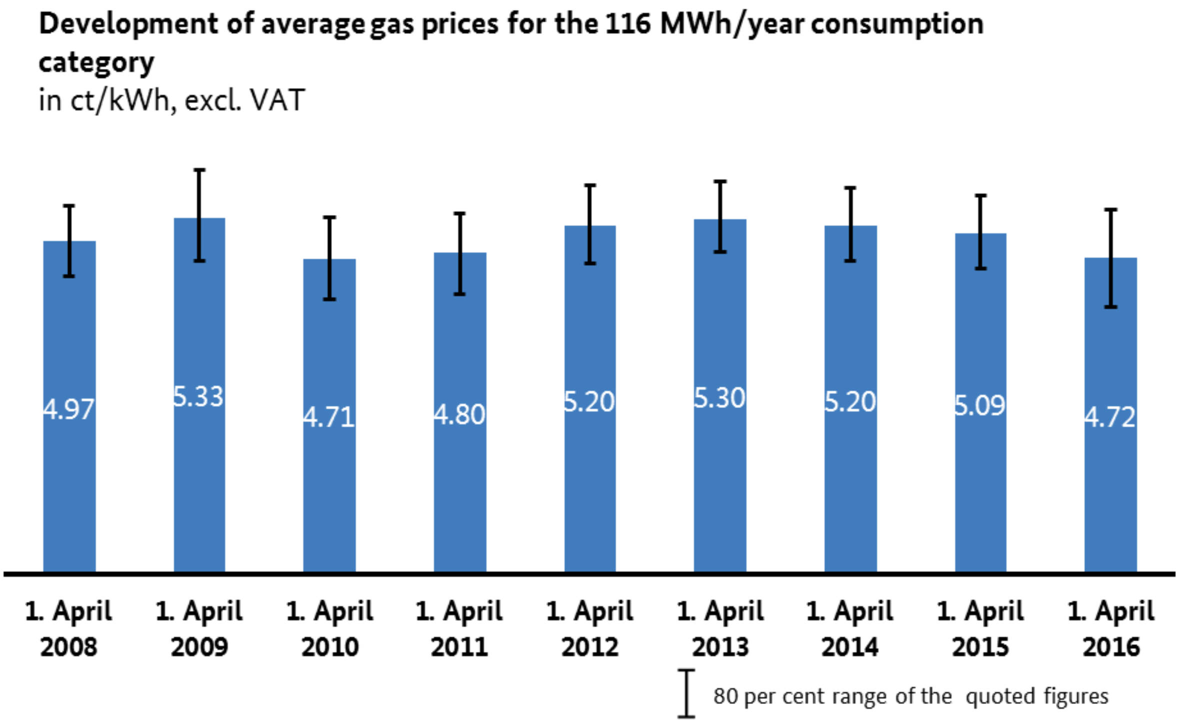

Figure 171: Development of average gas prices for the 116 MWh/year consumption category

4.2 Household customers

In the data survey for the 2016 Monitoring Report, the survey of prices for household customers was broken down into three different bands:

- Band I (D1[137]): annual consumption below 20 GJ (5,556 kWh)
- Band II (D2): annual consumption between 20 GJ (5,556 kWh) and 200 GJ (55,556 kWh)
- Band III (D3): annual consumption above 20 GJ (55,556 kWh).

The process of adapting the survey to the consumption bands took consideration of the development of the European survey of prices carried out by Eurostat. In order to draw a comparison with the previous years, band II was shown in the figure for the weighted price in default supply on 1 April 2016, as it represents an annual consumption between 20 GJ (5,556 kWh) and 200 GJ (55,556 kWh). For the preceding years, an annual consumption of 23,269 kWh was used, which corresponds to the mean value of consumption band II. The total quantities of gas that were delivered by each respective supplier in the previous year were used to weight the gas price. It is important to note that the average network tariffs listed for each type of contract category are calculated using the figures provided by the suppliers, which in turn are the charges averaged over all the networks supplied. This results in a different network charge for each tariff.

[137] "D1", "D2" and "D3" refer to the consumption bands defined by EUROSTAT

In addition, the arithmetic mean of the total prices and the range of the prices for the different tariffs in each consumption band were given in a separate table following each table of volume weighted prices. These figures relate to the range between 10% and 90% of the prices quoted by the suppliers when arranged in order of size.

The large variety of the different components that form the prices make it especially difficult to compare the tariffs. Therefore, a separate synthetic average price is calculated as the key figure on the basis of the available data for the three types of supply contract – default contract, special contract with the default supplier (after change of contract), and contract with a supplier other than the regional default supplier (after change of contract) – taking into account all supply contracts with the correct proportions. For this purpose, the individual prices of the three types of supply contracts are weighted with the given volume of gas delivered. Band II, with an annual consumption between 20 GJ (5,556 kWh) and 200 GJ (55,556 kWh), which best reflects the the average consumption in Germany of 20,000 kWh, was selected for the diagram presenting the total synthetic price across all contract categories on 1 April 2016.

Average volume weighted price across all contract categories for household customers for an annual consumption between 20 GJ (5,556 kWh) and 200 GJ (55,556 kWh) per year (band II; Eurostat: D2) as of 1 April 2016 (ct/kWh)

Price component	Volume weighted average across all tariffs (ct/kWh)	Share (%) of the total price
Average price component for energy procurement, supply, other costs and the margin	3.30	50.5%
Average network charge including upstream network costs	1.43	21.8%
Average charge for billing	0.05	0.8%
Average charge for metering	0.02	0.3%
Average charge for meter operations	0.06	0.9%
Average concession fees	0.08	1.2%
Current gas tax	0.55	8.4%
Average VAT	1.05	16.0%
Total	6.54	100%

Table 88: Average volume weighted price across all contract categories for household customers in consumption band II according to gas supplier survey

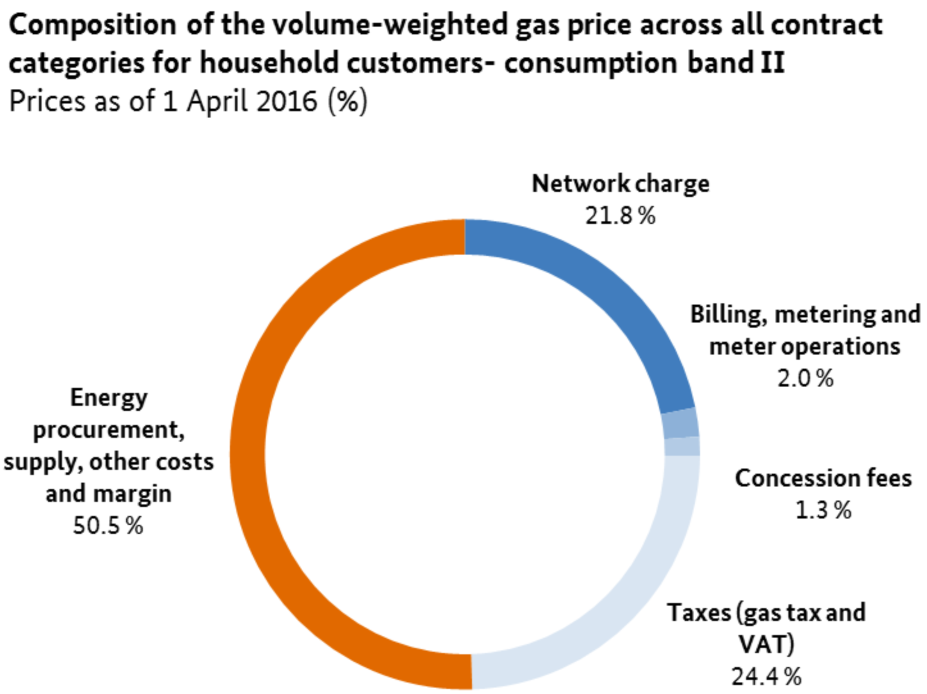

Figure 172: Composition of the volume-weighted gas price across all contract categories for household customers - consumption band II. Prices, as of 1 April 2016, according to gas supplier survey.

Changes in the volume weighted price across all contract categories for household customers; in 2015: for an annual consumption of 23,269 kWh; in 2016: for an annual consumption between 20 GJ (5,556 kWh) and 200 GJ (55,556 kWh), (band II; Eurostat: D2)

Preisbestandteil	Volume weighted average across all tariffs on 1 April 2015 (ct/kWh)	Volume weighted average across all tariffs on 1 April 2016 (ct/kWh)	Change in the price component	
			(ct/kWh)	(%)
Average price component for energy procurement, supply, other costs and the margin	3.51	3.30	-0.21	-5.8%
Average network charge including upstream network costs	1.32	1.43	0.11	8.3%
Average charge for billing	0.05	0.05	0.00	0.0%
Average charge for metering	0.02	0.02	0.00	0.0%
Average charge for meter operations	0.06	0.06	0.00	0.0%
Average concession fees	0.11	0.08	-0.03	-27.8%
Current gas tax	0.55	0.55	0.00	0.0%
Average VAT	1.06	1.05	-0.01	-1.1%
Total	6.68	6.54	-0.14	-2.1%

Table 89: Changes in the volume weighted price across all contract categories for household customers (in 2015: for an annual consumption of 23,269 kWh; in 2016: for an annual consumption between 20 GJ (5,556 kWh) and 200 GJ (55,556 kWh)) between 1 April 2015 and 1 April 2016 according to gas supplier survey

The tables below provide detailed information on the composition of the gas price for household customers, broken down by individual band, I to III, and contract category.

Average volume weighted price per contract category for household customers with a consumption below 20 GJ (5,556 kWh) per year (Band I; Eurostat: D1) as of 1 April 2016 (ct/kWh)

Price component	Default contract	Contract with the default supplier outside of default supply contracts	Contract with a supplier other than the regional default supplier
Average price component for energy procurement, supply, other costs and the margin	4.52	4.21	3.68
Average network charge including upstream network costs	2.03	1.97	2.02
Average charge for billing	0.47	0.35	0.31
Average charge for metering	0.13	0.12	0.09
Average charge for meter operations	0.44	0.37	0.30
Average concession fees	0.42	0.03	0.03
Current gas tax	0.55	0.55	0.55
Average VAT	1.63	1.45	1.33
Total	10.19	9.05	8.31

Table 90: Average volume weighted price per contract category for household customers in consumption band I according to the gas supplier survey

Breakdown of the volume weighted price components per contract category for household customers with a consumption below 20 GJ (5,556 kWh) per year (band I; Eurostat: D1) as of 1 April 2016 (ct/kWh)

Price component	Default contract	Contract with the default supplier outside of default supply contracts	Contract with a supplier other than the regional default supplier
Average price component for energy procurement, supply, other costs and the margin	44.3%	46.5%	44.3%
Average network charge including upstream network costs	19.9%	21.8%	24.2%
Average charge for billing	4.6%	3.8%	3.7%
Average charge for metering	1.3%	1.4%	1.1%
Average charge for meter operations	4.3%	4.0%	3.7%
Average concession fees	4.2%	0.4%	0.4%
Current gas tax	5.4%	6.1%	6.6%
Average VAT	16.0%	16.0%	16.0%
Total	100%	100%	100%

Table 91: Breakdown of the volume weighted price components per contract category for household customers in consumption band I according to the gas supplier survey

**Arithmetic mean and range of prices per contract category for household customers with a consumption below 20 GJ (5,556 kWh)
per year (band I; Eurostat: D1) as of 1 April 2016 (ct/kWh)**

Household customers Range between 10% and 90% of the prices quoted by the suppliers when arranged in order of size	**Default contract**	**Contract with the default supplier outside of default supply contracts**	**Contract with a supplier other than the regional default supplier**
Arithmetic mean	9.40	8.73	8.31
Range	7.45 - 11.91	6.55 - 11.15	5.90 - 10.90

Table 92: Arithmetic mean and range of prices per contract category for household customers in consumption band I according to the gas supplier survey

Average volume weighted price per contract category for household customers with a consumption between 20 GJ (5,556 kWh) and 200 GJ (55,556 kWh) per year (band II; Eurostat: D2) as of 1 April 2016 (ct/kWh)

Price component	Default contract	Contract with the default supplier outside of default supply contracts	Contract with a supplier other than the regional default supplier
Average price component for energy procurement, supply, other costs and the margin	3.58	3.27	3.10
Average network charge including upstream network costs	1.36	1.38	1.62
Average charge for billing	0.06	0.05	0.06
Average charge for metering	0.02	0.02	0.02
Average charge for meter operations	0.06	0.05	0.07
Average concession fees	0.24	0.03	0.03
Current gas tax	0.55	0.55	0.55
Average VAT	1.12	1.02	1.04
Total	6.99	6.37	6.49

Table 93: Average volume weighted price per contract category for household customers in consumption band II according to the gas supplier survey

Breakdown of the volume weighted price components per contract category for household customers with a consumption between 20 GJ (5,556 kWh) and 200 GJ (55,556 kWh) per year (band II; Eurostat: D2) as of 1 April 2016 (ct/kWh)

Price component	Default contract	Contract with the default supplier outside of default supply contracts	Contract with a supplier other than the regional default supplier
Average price component for energy procurement, supply, other costs and the margin	51.18	51.34	47.73
Average network charge including upstream network costs	19.50	21.63	24.98
Average charge for billing	0.80	0.83	1.00
Average charge for metering	0.28	0.28	0.27
Average charge for meter operations	0.81	0.77	1.05
Average concession fees	3.60	0.54	0.53
Current gas tax	7.87	8.63	8.48
Average VAT	15.97	15.97	15.97
Total	100.00	100.00	100.00

Table 94: Breakdown of the volume weighted price components per contract category for household customers in consumption band II according to the gas supplier survey

Arithmetic mean and range of prices per contract category for household customers with a consumption between 20 GJ (5,556 kWh) and 200 GJ (55,556 kWh) per year (band II; Eurostat: D2) as of 1 April 2016 (ct/kWh)

Household customers Range between 10% and 90% of the prices quoted by the suppliers when arranged in order of size	**Default contract**	**Contract with the default supplier outside of default supply contracts**	**Contract with a supplier other than the regional default supplier**
Arithmetic mean	7.10	6.30	6.14
Range	6,19 - 8,20	5,46 - 7,10	5,22 - 6,95

Table 95: Arithmetic mean and range of prices per contract category for household customers in consumption band II as of 1 April 2016 according to the gas supplier survey

Average volume weighted price per contract category for household customers with a consumption above 200 GJ (55,556 kWh) per year (band III; Eurostat: D3) as of 1 April 2016 (ct/kWh)

Price component	Default contract	Contract with the default supplier outside of default supply contracts	Contract with a supplier other than the regional default supplier
Average price component for energy procurement, supply, other costs and the margin	3.40	3.01	2.55
Average network charge including upstream network costs	1.22	1.22	1.25
Average charge for billing	0.02	0.02	0.02
Average charge for metering	0.01	0.01	0.01
Average charge for meter operations	0.02	0.02	0.02
Average concession fees	0.23	0.03	0.03
Current gas tax	0.55	0.55	0.55
Average VAT	1.04	0.93	0.84
Total	6.49	5.79	5.27

Table 96: Average volume weighted price per contract category for household customers in consumption band III according to the gas supplier survey

Breakdown of the volume weighted price components per contract category for household customers with a consumption above 200 GJ (55,556 kWh) per year (band III; Eurostat: D3) as of 1 April 2016 (ct/kWh)

Price component	Default contract	Contract with the default supplier outside of default supply contracts	Contract with a supplier other than the regional default supplier
Average price component for energy procurement, supply, other costs and the margin	52.46	52.07	48.27
Average network charge including upstream network costs	18.84	21.13	23.72
Average charge for billing	0.26	0.27	0.40
Average charge for metering	0.08	0.11	0.15
Average charge for meter operations	0.35	0.35	0.47
Average concession fees	3.57	0.60	0.59
Current gas tax	8.47	9.50	10.43
Average VAT	15.97	15.97	15.97
Total	100.00	100.00	100.00

Table 97: Breakdown of the volume weighted price components per contract category for household customers in consumption band III according to the gas supplier survey

Arithmetic mean and range of prices per contract category for household customers with a consumption above 200 GJ (55,556 kWh) per year (band III; Eurostat: D3) as of 1 April 2016 (ct/kWh)

Household customers Range between 10% and 90% of the prices quoted by the suppliers when arranged in order of size	**Default contract**	**Contract with the default supplier outside of default supply contracts**	**Contract with a supplier other than the regional default supplier**
Arithmetic mean	6.60	5.83	5.64
Range	5,76 - 7,56	5,08 - 6,52	4,81 - 6,41

Table 98: Arithmetic mean and range of prices per contract category for household customers in consumption band III according to gas supplier survey

Data from 538 gas suppliers was taken into account for the evaluation of prices for customers supplied under a default contract. On 1 April 2016, the volume-weighted price for default supply in consumption band II was 6.99 ct/kWh, a slight decrease of 1.7% compared to the previous year.[138]

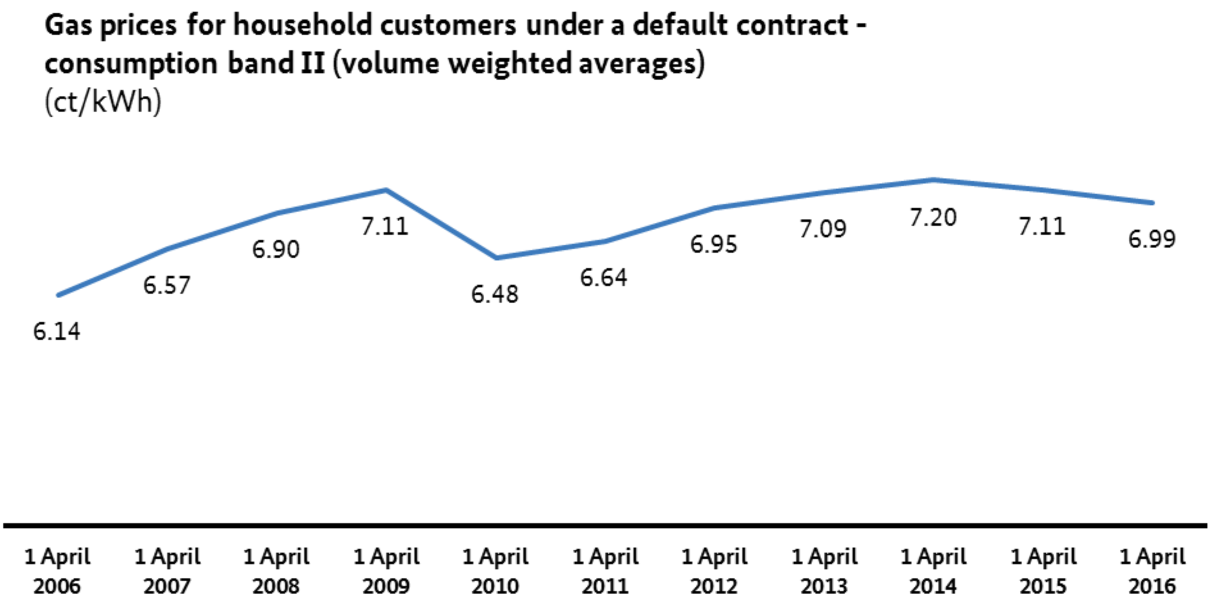

Figure 173: Gas prices for household customers under a default contract (volume weighted averages) - consumption band II according to gas supplier survey

[138] The arithmetic mean of the gas price for household customers under a default contract in consumption band II was 7.16 ct/kWh on 1 April 2016.

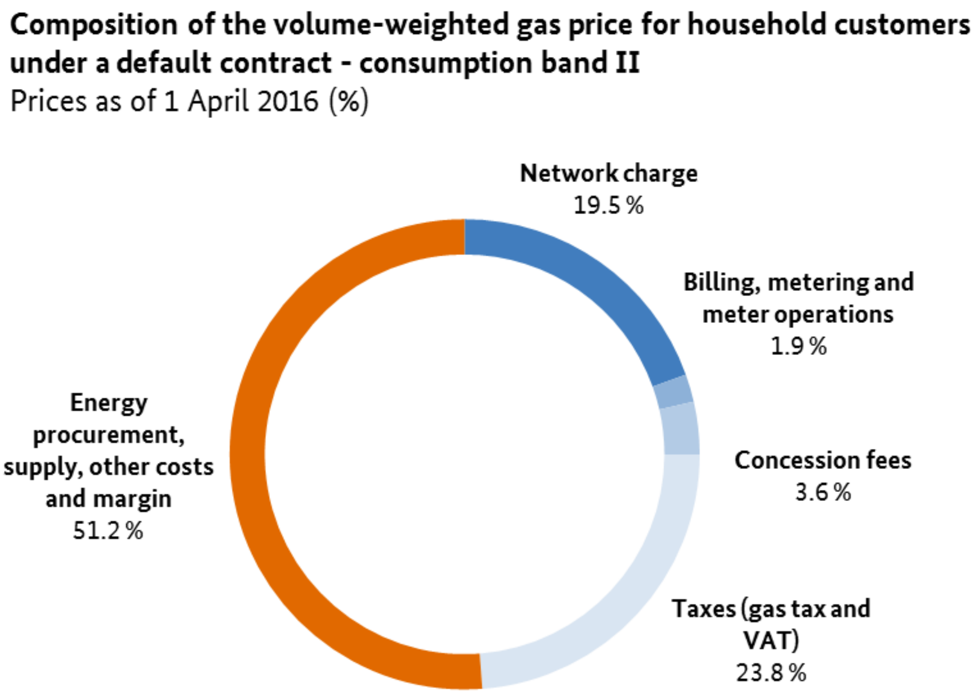

Figure 174: Composition of the volume-weighted gas price for household customers under a default contract. Prices for consumption band II, as of 1 April 2016, according to gas supplier survey

Data from 513 gas suppliers was taken into account for the evaluation of prices for customers supplied under a special contract with the default supplier (after change of contract). On 1 April 2016, the volume-weighted price for customers under a special contract with the default supplier in consumption band II was 6.37 ct/kWh, a clear decrease of 4.6% compared to the previous year.[139]

[139] The arithmetic mean of the gas price for household customers under a special contract with the default supplier in consumption band II was 6.32 ct/kWh on 1 April 2016.

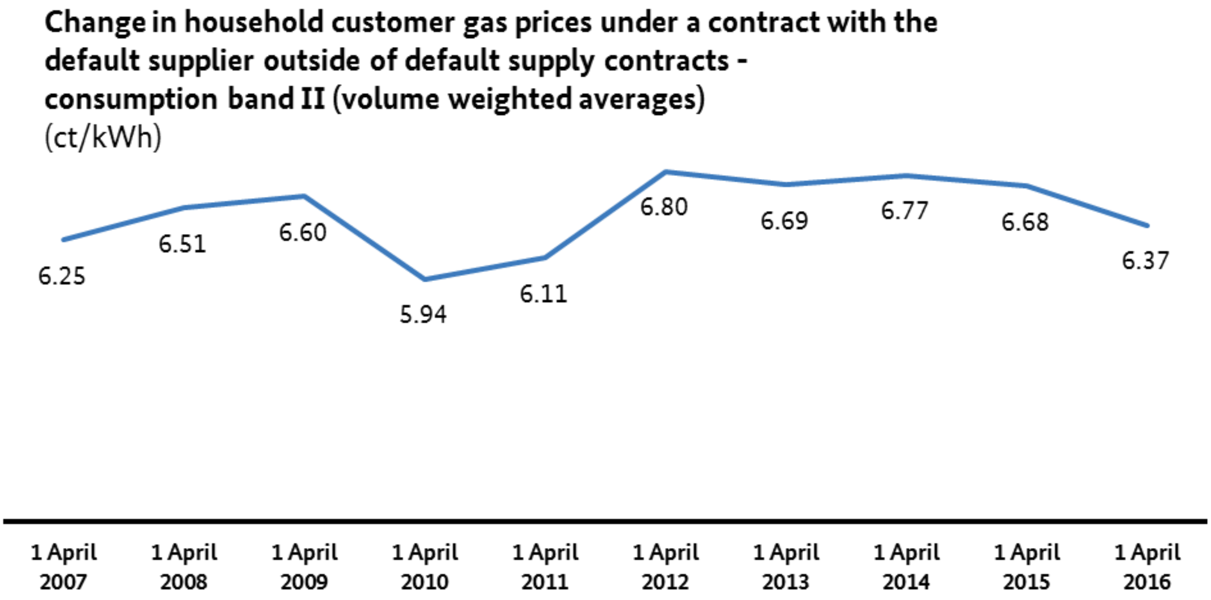

Figure 175: Change in household customer gas prices under a special contract with the default supplier (volume weighted averages) - consumption band II according to gas supplier survey

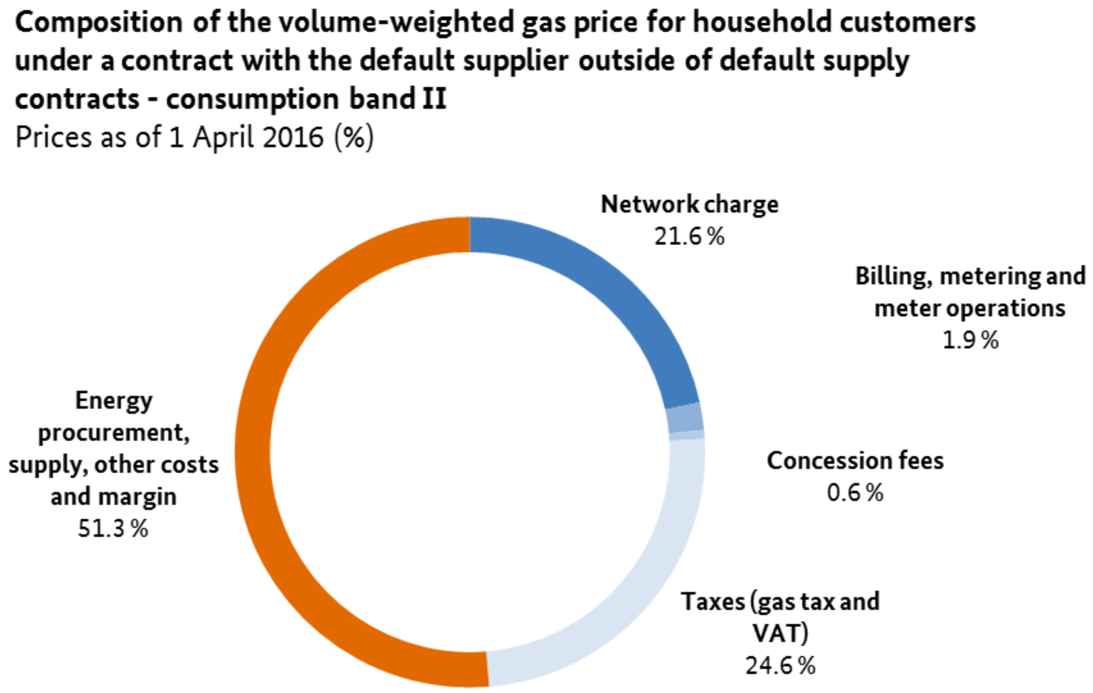

Figure 176: Composition of the volume-weighted gas price for household customers under a special contract with the default supplier. Prices for consumption band II, as of 1 April 2016, according to gas supplier survey.

Data from 385 gas suppliers was taken into account for the evaluation of prices for a contract with a supplier other than the regional default supplier (after change of contract). On 1 April 2016, the volume-weighted price for a contract with a supplier other than the regional default supplier in consumption band II was 6.49 ct/kWh, a clear increase of 6% compared to the previous year.[140]

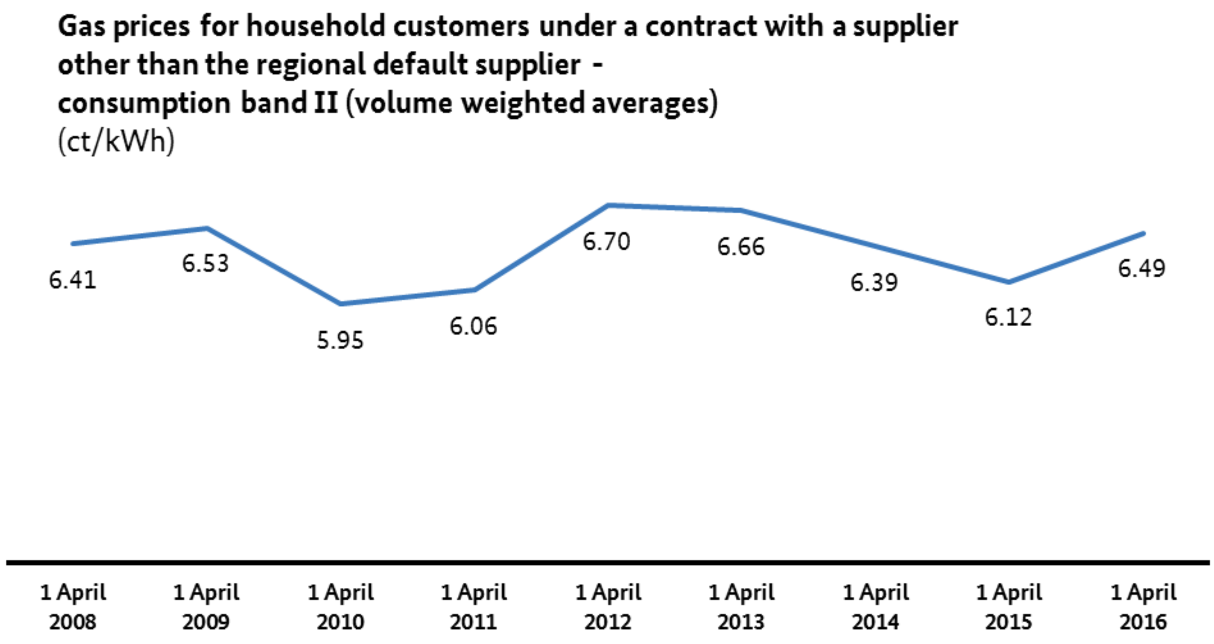

Figure 177: Gas prices for household customers under a contract with a supplier other than the regional default supplier (volume weighted averages) - consumption band II according to gas supplier survey

[140] The arithmetic mean of the gas price for household customers under a contract with a supplier other than the regional default supplier in consumption band II was 6.16 ct/kWh on 1 April 2016.

Composition of the volume-weighted gas price for household customers under a contract with a supplier other than the regional default supplier - consumption band II
Prices as of 1 April 2016 (%)

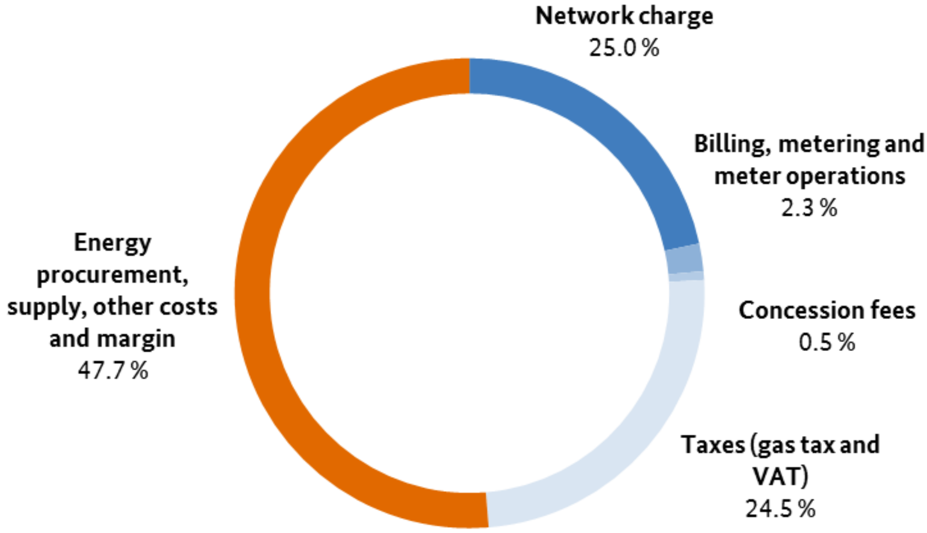

Figure 178: Composition of the volume-weighted gas price for household customers under a contract with a supplier other than the regional default supplier, as of 1 April 2016 - consumption band II according to gas supplier survey

A look at the household customer gas prices over the past ten years (2006-2016) shows that default supply constitutes the most expensive contract category for gas customers. During the period under review, the gas price for customers under a default contract fluctuated between 6.14 ct/kWh in 2006 and 7.20 ct/kWh in 2014. Overall, the price paid by default supply customers has increased by just under 14% over the past ten years.

The gas price for customers supplied under a special contract with the default supplier (after change of contract) fluctuated between 6.25 ct/kWh and 6.37 ct/kWh between 2007 and 2016. Overall, the gas price for customers with a special contract with the default supplier (after change of contract) has risen by almost 2% over the last nine years.

The price customers paid for gas under a supplier other than the regional default supplier (after change of supplier) fluctuated between 6.41 ct/kWh and 6.49 ct/kWh between 2008 and 2016. Overall, the price paid by these customers has increased by 1.2% over the past eight years. For the first time, the volume-weighted average price of gas for household customers supplied under a special contract with the default supplier in band II (after change of contract) (6.37 ct/kWh) was below the gas price for household customers with a supplier other than the regional default supplier in band II (after change of supplier) (6.49 ct/kWh). This type of contract is therefore the most affordable supply contract, at least within band II.

When considering a longer period of time it becomes clear that customers with a special contract with their default supplier and customers with a supplier other than the regional default supplier have been able to rely on very stable gas prices. The difference between the most expensive and the most affordable contract was

0.49 ct/kWh in 2008. By contrast, it was 0.62 ct/kWh in 2016, an increase of 26.5%. The incentive to switch from default supply to a more affordable contract had therefore increased in the review period.

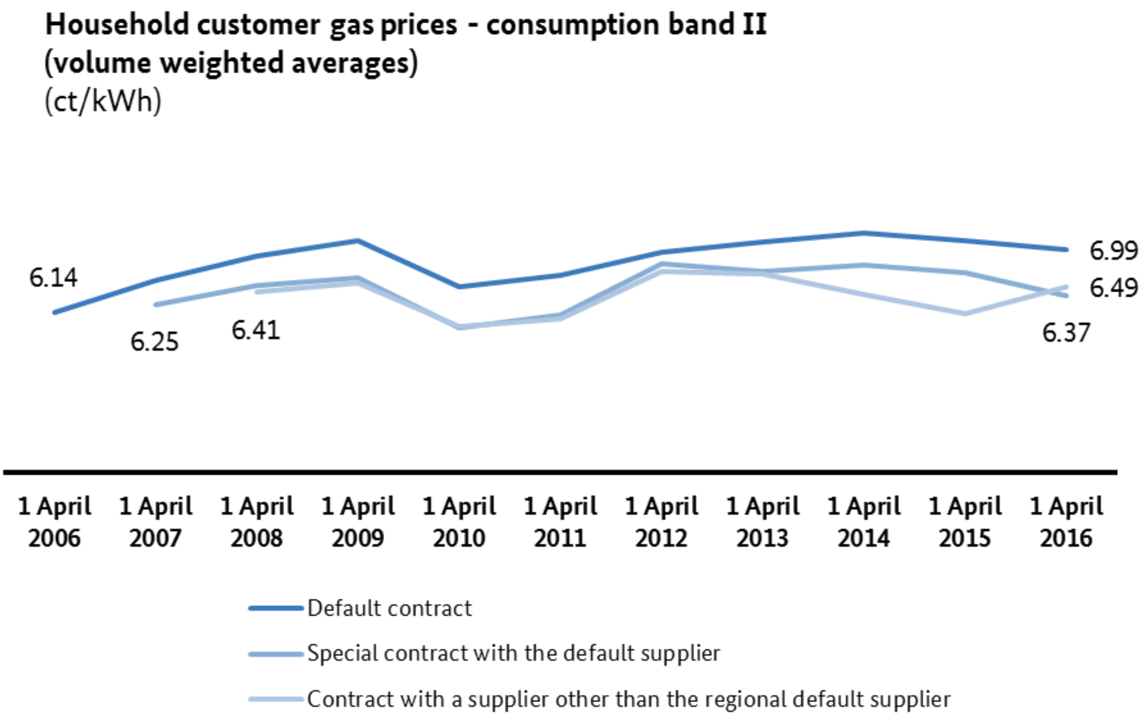

Figure 179: Household customer gas prices - consumption band II according to gas supplier survey

With regard to the main component of the gas price for household customers in band II, which is the price component that can be controlled by the supplier: "energy procurement, supply, other costs and margin", it is striking that this price component stabilised after some significant changes from 2010 to 2012 and reached the level of 2007 in 2016.

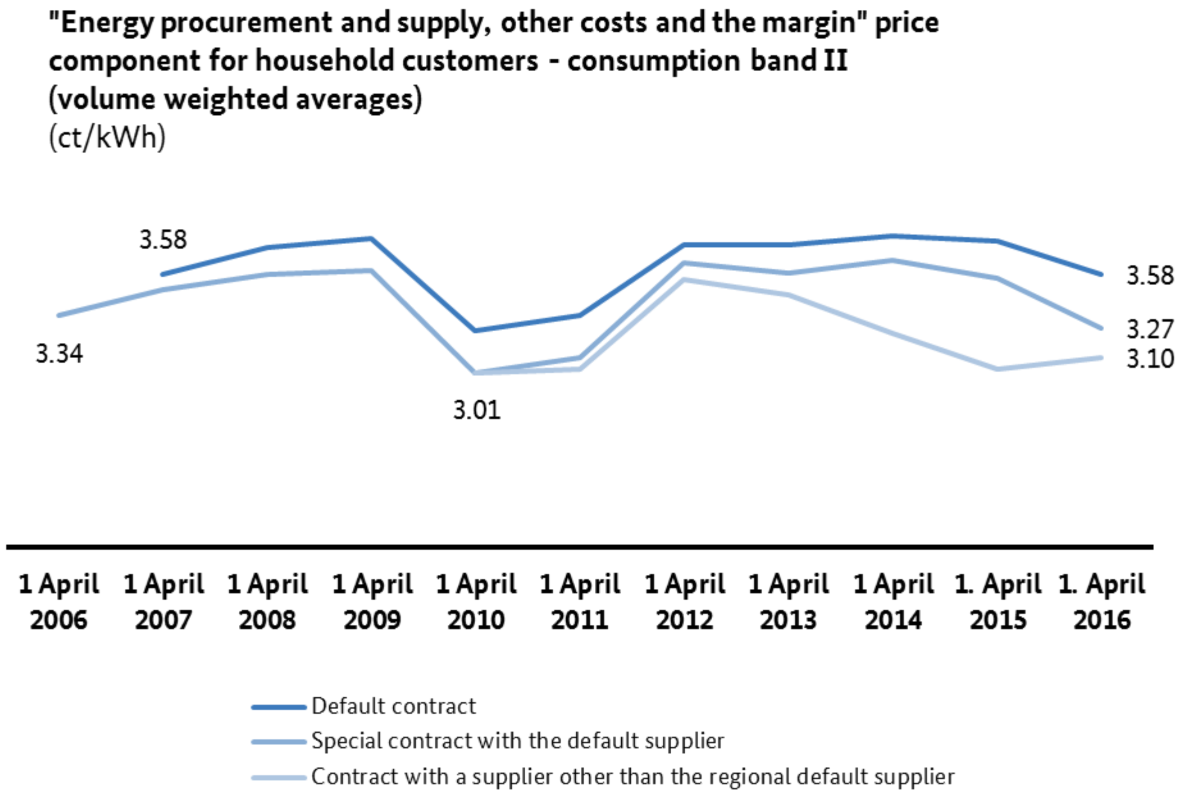

Figure 180: "Energy procurement and supply, other costs and the margin" price component for household customers - consumption band II according to gas supplier survey

Customers supplied under a special contract with the default supplier (after change of contract) and under a contract with a supplier other than the regional default supplier (after change of supplier), show, in addition to differences in in the total price, other differences that gas suppliers use when competing for customers. These features may offer a certain level of security to the customer (eg guaranteed prices) or to the supplier (eg payment in advance, minimum contract period). In the data collection for the 2016 Monitoring Report, gas suppliers were asked about their contracts and offers.

The following overview includes various special bonuses and schemes offered to household customer by gas suppliers. Among the most common features in the offers were minimum contract periods (on average for 12 months) and fixed prices (on average for 16 months). There is, of course, a very large spread among the values of the bonuses paid out. The bonuses awarded were between €5 and €300 for both types of supply contracts.

Special bonuses and schemes for household customers

As of 1 April 2016	Household customers			
	Special contract with the default supplier		Contract with a supplier other than the regional default supplier	
	Number of tariffs reported by surveyed companies	Scope of measure (on average)	Number of tariffs reported by surveyed companies	Scope of measure (on average)
Minimum contract period	331	12 months	353	12 months
Price stability	294	16 months	330	16 months
Advance payment	53	10 months	35	10 months
One-off bonus payment	106	€65	161	€70
Free kilowatt hours	7	1,600 kWh	4	500 kWh
Deposit	9	-	7	-
Other bonuses	74	-	59	-
Other special arrangements	38	-	25	-

Table 99: Special bonuses and schemes for household customers

5. Comparison of European gas prices

Eurostat, the statistical office of the European Union, publishes end consumer gas prices for each six-month period that show the average payments made by household customers and non-household customers in EU Member States. The figures published for each consumer group include (i) the price including all taxes and levies, (ii) the price excluding recoverable taxes and levies (particularly excluding VAT) and (iii) the price excluding taxes and levies. Eurostat does not collect the data itself but relies on data from national bodies. Rules on the classification, analysis and presentation of the price data aim to ensure European-wide comparability.[141] However, the survey method is set by the member state (cf. Directive 2008/91/EC, Annex I h), which leads to national differences.

5.1 Non-household customers

Eurostat publishes price statistics for six different consumer groups in the non-household sector that differ according to annual consumption ("consumption bands"). The following describes the 27.8 to 278 GWh/year consumption category (equivalent to 10,000 to 100,000 GJ) as an example of one of these consumption bands. The 116 GWh/year category ("industrial customers"), for which specific price data is collected during monitoring (see section II.G.4.1), falls into this consumption range.

[141] For details see http://ec.europa.eu/eurostat/web/energy/methodology/prices (retrieved on 25 October 2016)

The customer group with this level of consumption consists mainly of industrial customers who can deduct national VAT. As a result, the European-wide comparison is based on the price without VAT. Besides VAT, there are various other taxes and levies resulting from specific national factors, which can typically be recovered by this customer group and which have also been deducted from the gross price in accordance with the Eurostat classification.[142] Most Member States apply additional taxes and levies that are not recoverable (e.g. gas tax and concession fee in Germany).

Across Europe, prices for industrial customers vary to a much lesser extent than those for household customers. The net gas price of 2.99 ct/kWh paid by German customers with an annual consumption between 27.8 and 278 GWh is close to the EU average of 2.87 ct/kWh. Non-recoverable taxes and levies amount to an average 8 per cent (0.23 ct/kWh) of the net price in Europe. The figure of about 14 per cent (0.41 ct/kWh) for Germany is somewhat above average in this respect.

[142] For more information on country-specific deductions see Eurostat, Gas Prices – Price Systems 2014, 2015 Edition: http://ec.europa.eu/eurostat/documents/38154/42201/Gas-prices-Price-systems-2014.pdf/30ac83ad-8daa-438c-b5cf-b52273794f78 (retrieved on 11 November 2016).

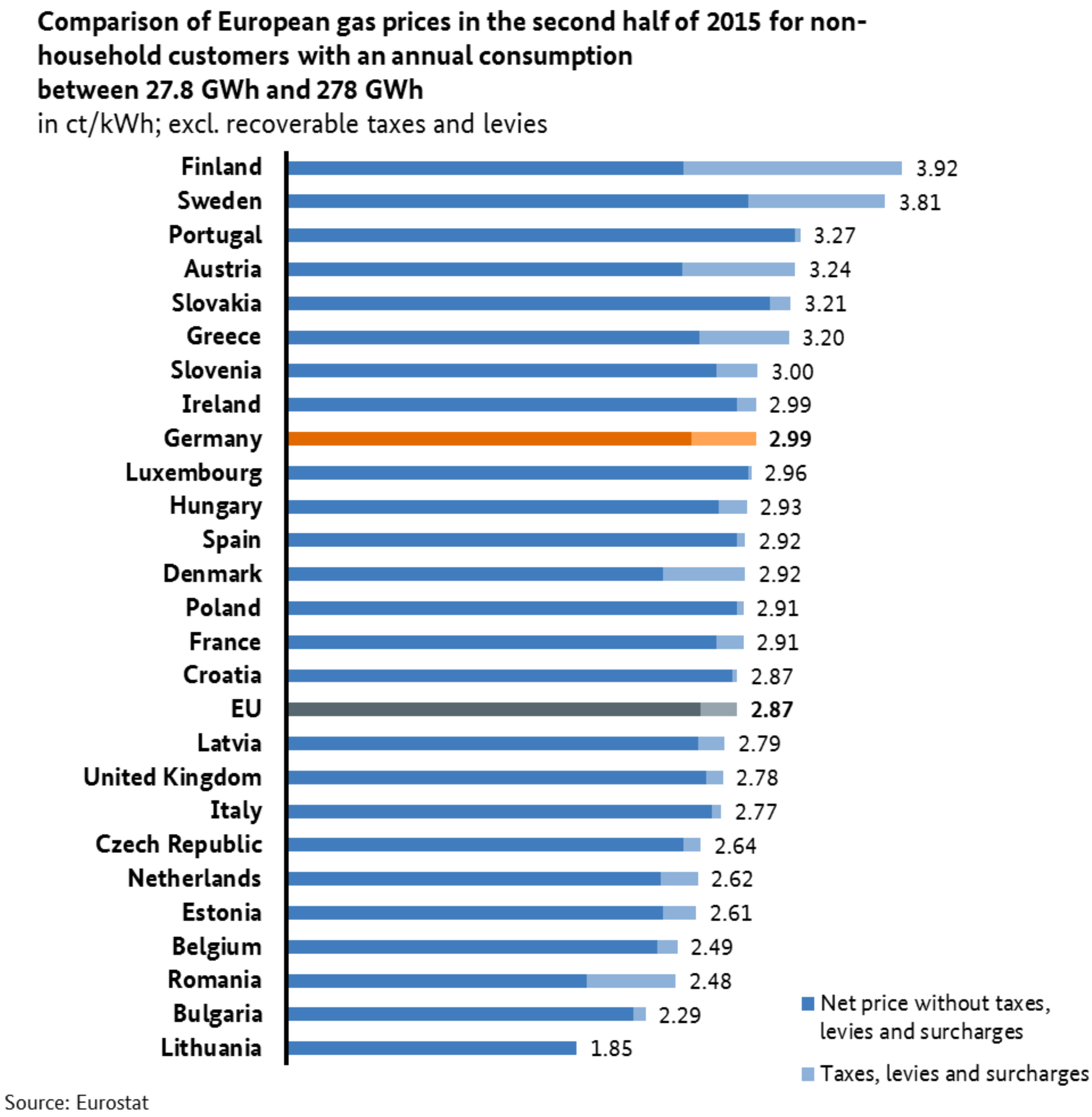

Figure 181: Comparison of European gas prices in the second half of 2015 for non-household customers with an annual consumption between 27.8 GWh and 278 GWh

5.2 Household customers

Eurostat takes three different consumption bands into consideration when comparing household customer prices: annual consumption below 5,555 kWh, between 5,555 kWh and 55,555 kWh and above 55,555 kWh. The 23,269 kWh/year consumption level, for which specific price data is collected during monitoring (see section II.G.4.2, p. 330ff.), falls into the medium Eurostat consumption band. The following therefore shows a European comparison of the medium consumption band. Household customers generally cannot have taxes and levies refunded, which is why the total price including VAT is relevant to these customers.

In contrast to prices in the industrial customer sector, gas prices for household customers vary greatly in Europe. Household customers in Sweden pay more than three times as much for natural gas as customers in Romania.

The gas price of 6.81 ct/kWh paid by household customers in Germany is close to the EU average price of 7.07 ct/kWh.

The percentage of the overall price made up by taxes and levies also varies widely across the EU. While taxes and levies account for only about 5 per cent of the price in the United Kingdom, they make up about 57 per cent of the price in Denmark. Germany's figure of about 25 per cent again matches the European average in this respect. Around 1.68 ct/kWh of the overall price in Germany consists of taxes and levies; the EU average is 1.64 ct/kWh (about 23 per cent).

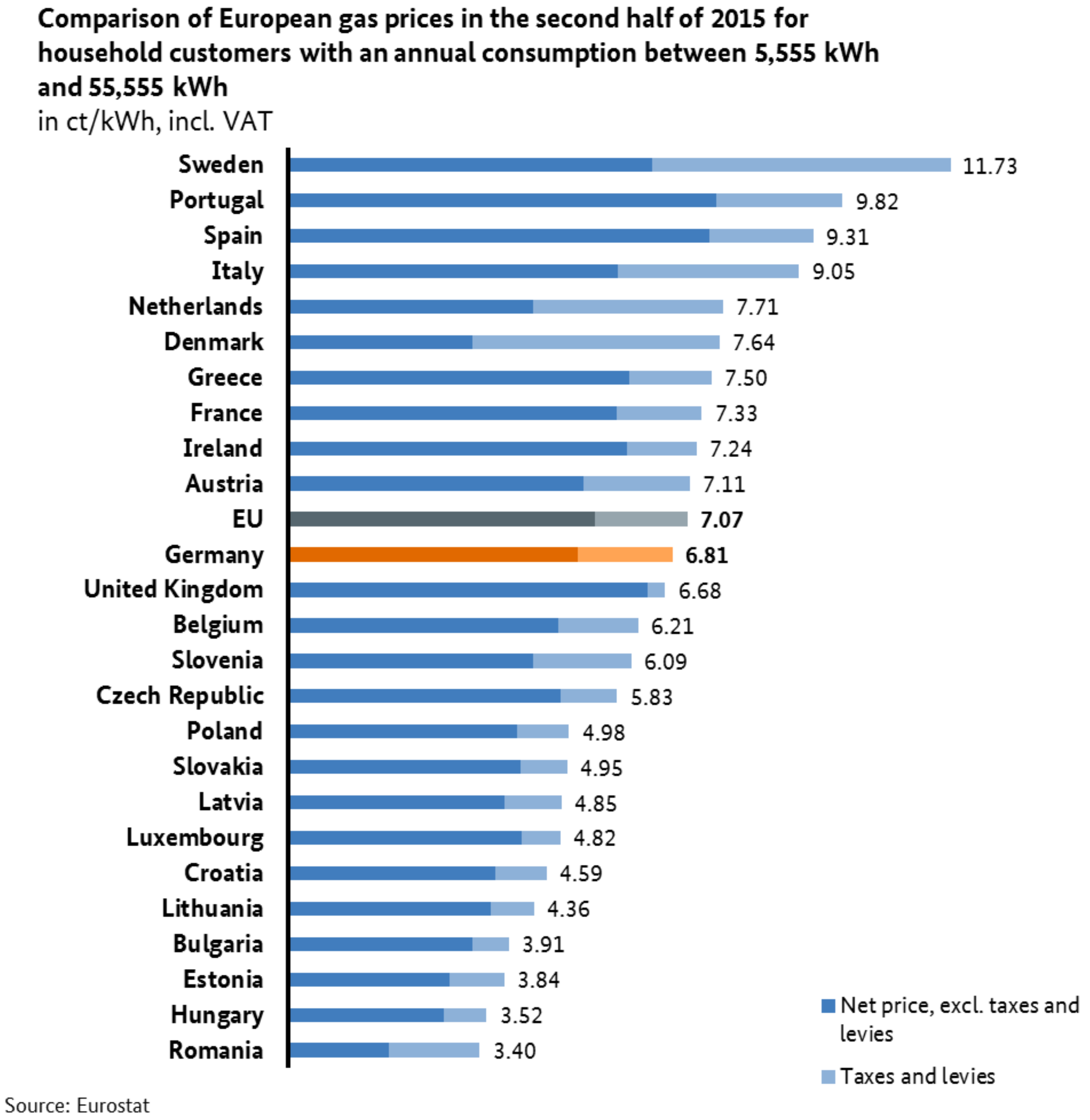

Figure 182: Comparison of European gas prices in the second half of 2015 for household customers with an annual consumption between 5,555 kWh and 55,555 kWh

H Storage facilities

1. Access to underground storage facilities

Some 23 companies operating and marketing a total of 38 underground natural gas storage facilities took part in the 2016 monitoring survey. On 31 December 2015 the total maximum usable volume of working gas in these storage facilities was 25.82bn nm³.[143] Of this, 11.85bn nm³ was accounted for by cavern storage, 11.92bn nm³ by pore storage facilities and 2.05bn nm³ by other storage facilities. Reflecting the structure of the German natural gas market, the largest part of the storage facilities, by far, is designed for the storage of H-gas (23.59bn nm³, compared to 2.23bn nm³ for L-gas).

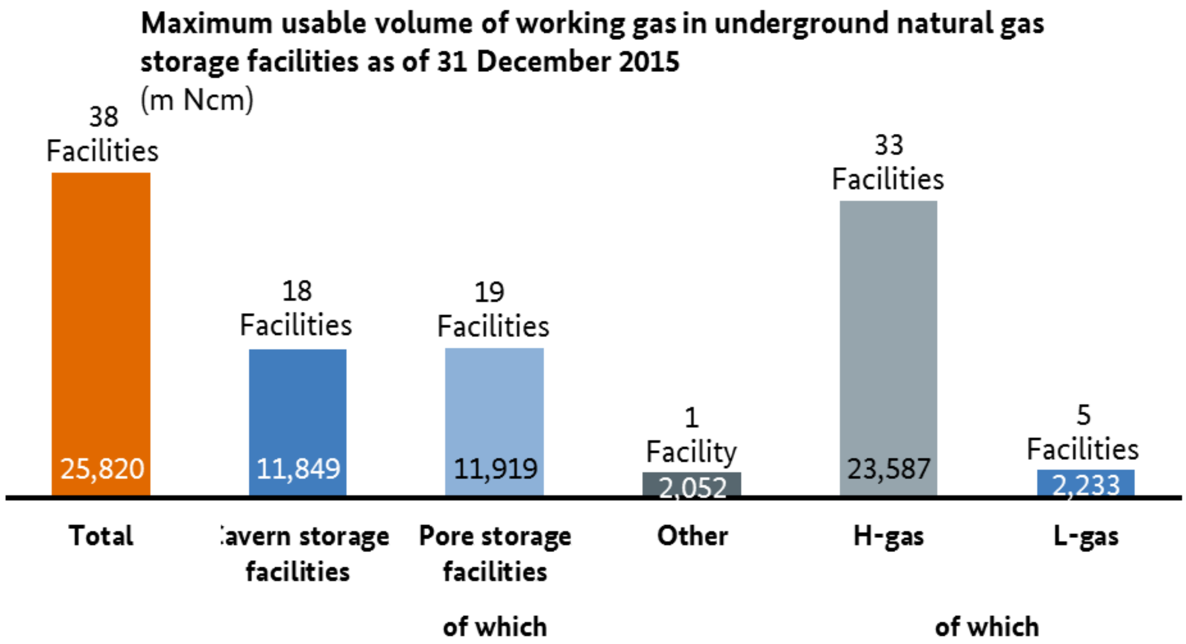

Figure 183: Maximum usable volume of working gas in underground natural gas storage facilities as of 31 December 2015

The next figure shows the changes in storage levels since 2010. Despite considerable differences in the framework conditions under which the gas market operated, the natural gas storage facilities were sufficiently filled each winter in the period monitored. On 1 October 2016, at the beginning of the 2016/2017 gas year, the total storage level of German storage facilities was around 95%.

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[143] This figure includes the 7 Fields storage facility and (a portion of) the Haidach storage facility, both of which are located in Austria. They are included because they are directly connected to the German gas network and thus have an impact on it. Equally, storage facilities that are located in Germany, but only connected to the Dutch network, are not taken into account since they have no direct impact on the German gas network.

The current storage level at natural gas storage facilities in Germany is high compared to past years. One obvious reason for this is the development of gas prices over the past months.

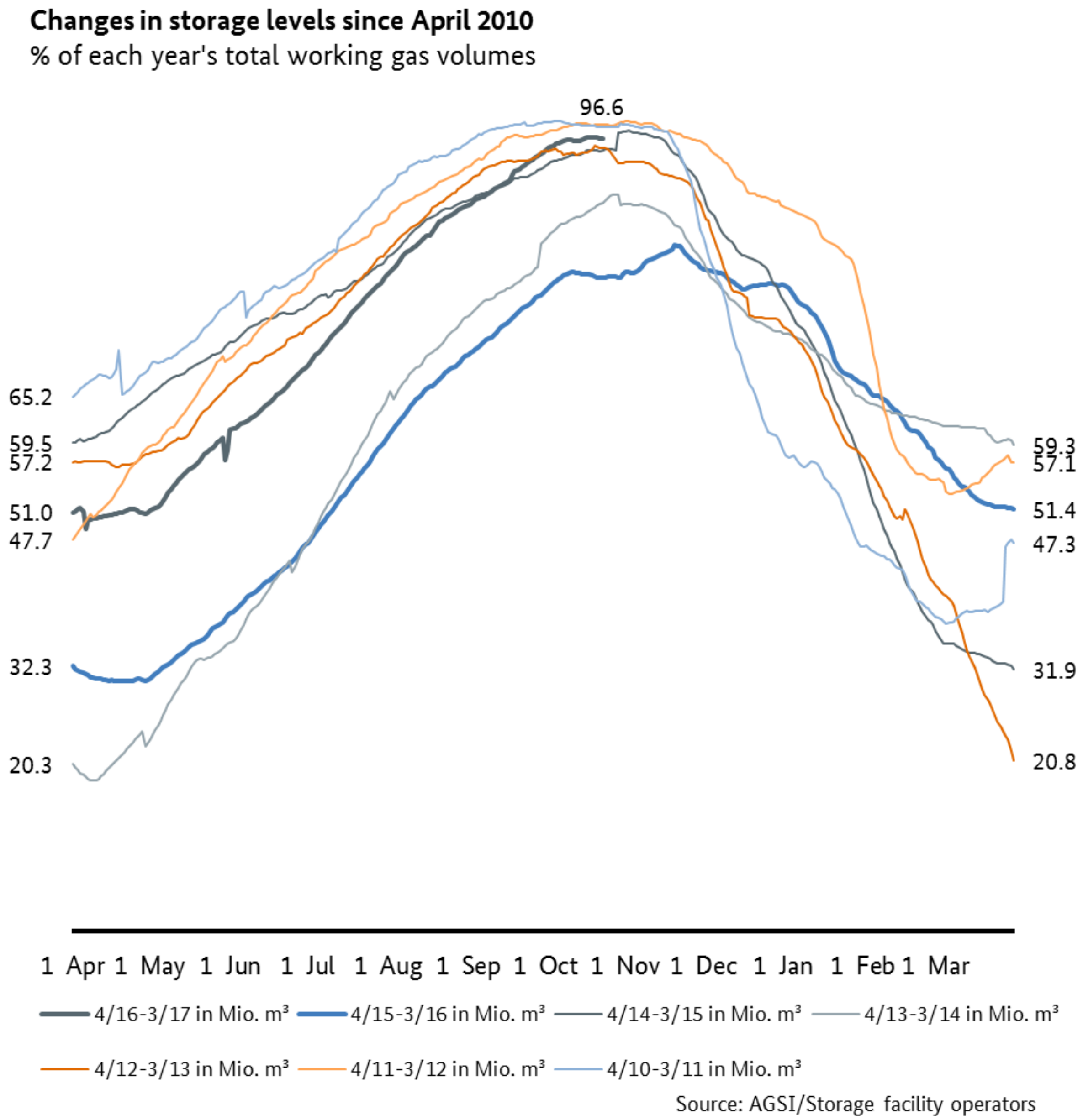

Figure 184: Changes in storage levels: 2010 - today (last update on 23 October 2016)

2. Use of underground storage facilities for production operations

Production operations involve the use of storage facilities by companies that produce gas in Germany. In 2015, around 0.6% of the maximum usable volume of working gas in storage facilities was used for production operations. After deducting the working gas used for production operations, the total working gas volume available to the market in all underground storage facilities was 25.67bn nm^3 in 2015 (compared to 25.43bn nm^3 in 2014). The total injection capacity was 14.66m nm^3/h and the withdrawal capacity was 26.38m nm^3/h.

3. Use of underground storage facilities – customer trends

According to the data provided by 22 companies, the average number of storage customers in 2015 was 6.1 (2011: 5.0; 2012: 5.4, 2013: 5.3, 2014: 6.1). The following chart shows the trend in the number of customers per storage facility operator since 2010:

Changes in the number of customers per storage facility operator over the years

Number of storage customers	2007	2008	2009	2010	2011	2012	2013	2014	2015
1	50%	52%	37%	40%	42%	33%	38%	35%	45%
2	15%	13%	16%	10%	11%	14%	13%	17%	9%
3 - 9	30%	26%	32%	35%	32%	33%	29%	22%	18%
10 - 15	5%	9%	11%	10%	5%	10%	8%	13%	14%
16 - 20	0%	0%	5%	5%	5%	5%	8%	4%	5%
> 20	0%	0%	0%	0%	5%	5%	4%	9%	9%
Number of storage operators	20	23	19	20	19	21	24	23	22

Table 100: Changes in the number of customers per storage facility operator over the years

There was a slight year-on-year decrease in the number of storage customers. The survey again showed, however, that nearly half of the storage operators have only one customer. There were two storage operators with more than 20 customers.

4. Capacity trends

The following chart shows the volume of available working gas in underground natural gas storage as of 31 December 2015 compared to the previous years.

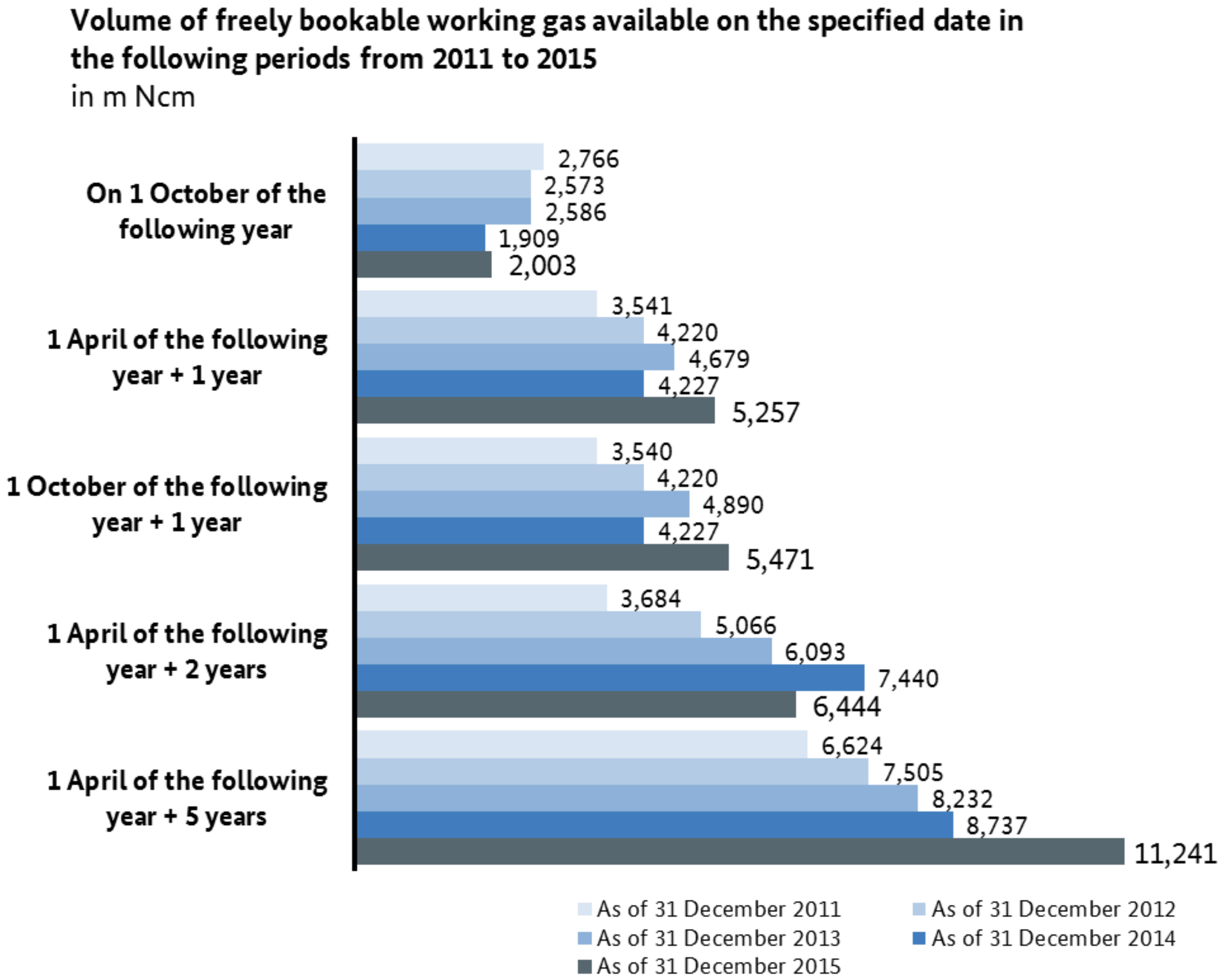

Figure 185: Volume of freely bookable working gas available on the specified date in the following periods from 2011 to 2015

The volume of short-term (up to 1 October 2016) freely bookable working gas remained at approximately the same level, and the capacities bookable from 2017 increased. There was a slight decrease in the volume of long-term bookable working gas from 2018. Compared to previous years, the volume of working gas that can be booked five years in advance increased again.

I Metering

1. The network operator as the default meter operator and independent meter operators

Although metering activities on the energy market have been fully liberalised, it is predominantly the network operators that provide metering services under their "primary responsibility" (in their networks). However, the number of other meter operators, regardless whether they are network operators, suppliers or independent meter operators, is rising, albeit moderately.

The facts presented in this chapter take into account information collected from 668 companies. This paints the following picture with regard to the market distribution of meter operator roles:

Meter operator roles

Funktion	2014	2015
Network operator acting as meter operator within the meaning of section 21b(2) of the EnWG	648	662
Network operator acting as meter operator within the meaning of section 21b(2) of the EnWG, providing (metering) services in the market	8	13
Supplier with meter operator activities	1	2
Indendent third-parties that provide metering services	4	7

Table 101: Market distribution of meter operator roles

2. Meter technology used for domestic customers

With regard to household customers, the biggest change to the previous year was with meters that can be refitted in accordance with section 21f EnWG. Across all sizes of gas meters[144] there was a significant increase - at over 30% - compared to the previous year.

Furthermore, with regard to all sizes of meters, there were shifts from diaphragm gas meters with a mechanical counter to meters that additionally have a pulse output. The exact distribution is shown in the table below.

[144] The total number of meters which can be refitted in accordance with § 21f EnWG was subsequently corrected to 1,105,756 for 2014.

Breakdown of metering equipment/systems used by SLP customers

Types of metering equipment used by the meter operators for standard load profile customers	Number of meter points according to meter size		
	G1.6 to G6	G10 to G25	G40 and higher
Diaphragm gas meter with mechanical counter	8,421,628	276,422	33,037
Diaphragm gas meter with mechanical counter and pulse output	4,933,890	156,282	17,671
Diaphragm gas meter with electronic counter	16,272	624	1,266
Load meters as for load-metered customers	157	189	2,940
Other mechanical gas meters	12,902	2,530	25,246
Other electronic gas meters	2,865	4	1,182
Summe der Zähler i. S. d. § 21f EnWG neue Fassung	25,916	1,218	600
The total number of meters which can be refitted in accordance with § 21f EnWG (revised)	1,441,817	51,985	10,171

Table 102: Breakdown of metering equipment/systems used by SLP customers

Where meter operators use remote reading, they predominantly do so via the pulse output. Only 4.2% of the meters are read using M-Bus, the Open Metering System (OMS) standard, telecommunications or other technologies.

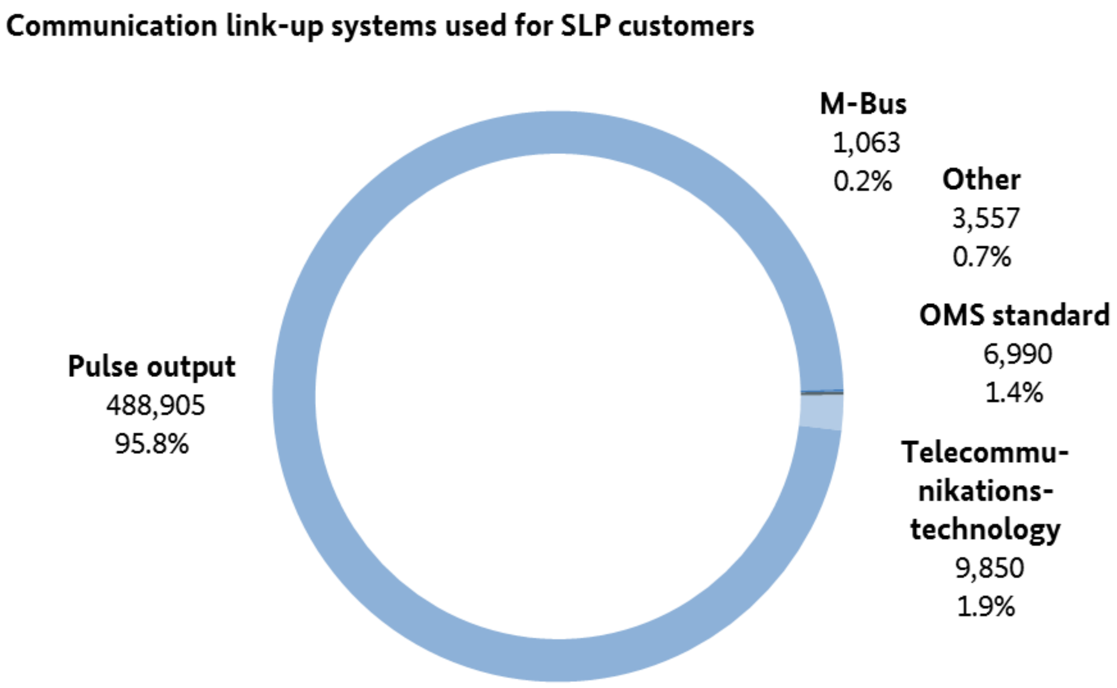

Figure 186: Communication link-up systems used for SLP customers

3. Metering technology used for interval-metered customers

With regard to the metering equipment used for interval-metered customers, only a small number of meter points were modified compared to the previous year[145]. The distribution is as follows:

Metering technologies used for interval-metered customers in 2015

Function	Number of meter points
Number of meter points - transmitting meter with a pulse output/encoder meter and a recording device/data storage	15,750
Transmitting meter with a pulse output/encoder meter + and volume corrector	9,396
Transmitting meter with a pulse output/encoder meter + and volume correctorr + recording device/data storage	14,630
Other	273

Table 103: Breakdown of metering technologies used for interval-metered customers

[145] The number of meter points with a transmitting meter with a pulse output/encoder meter and a recording device/data storage was corrected to 15,471 for 2014.

The meter technology used by interval-metered customers transfers the data almost exclusively over telecommunication systems. The telecommunications systems include mobile communications, telephone lines, DSL, broadband and power lines. The digital interface for gas meters is worth mentioning as an alternative technology used to transfer meter data. Approx 3.7% of interval-metered customers use this interface.

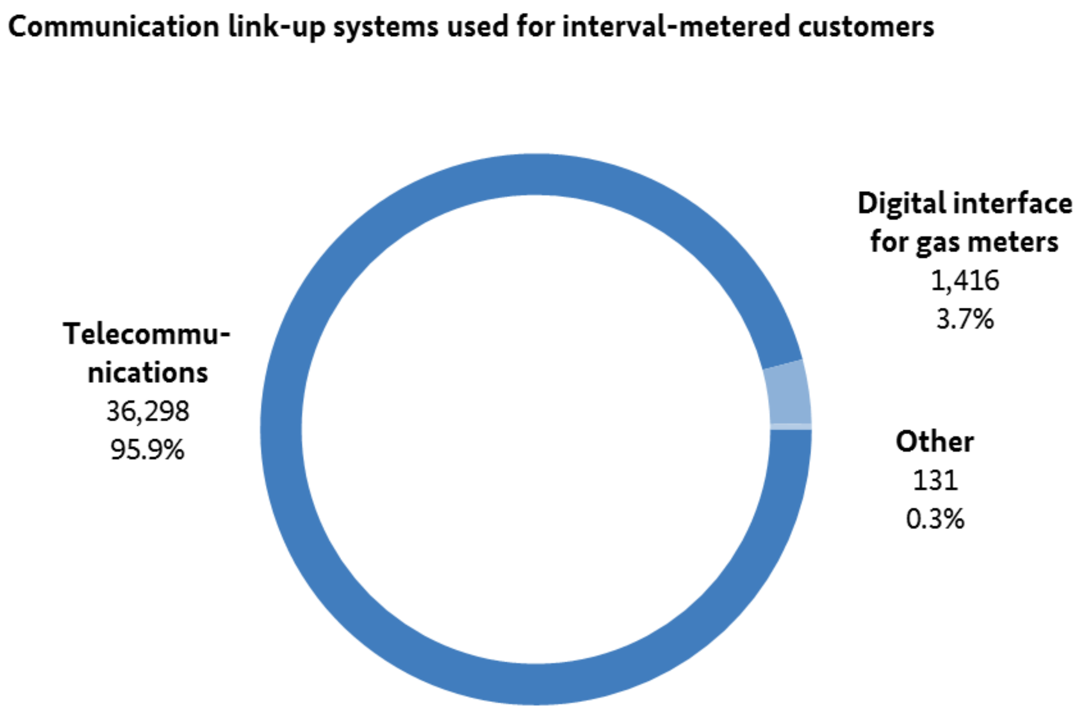

Figure 187: Communication link-up systems used for interval-metered customers

4. Investment and expenditure for metering

For the first time in a monitoring survey, gas meter operators i were asked about their investment behaviour and investment projects.

Some 580 companies provided information on investment activities.

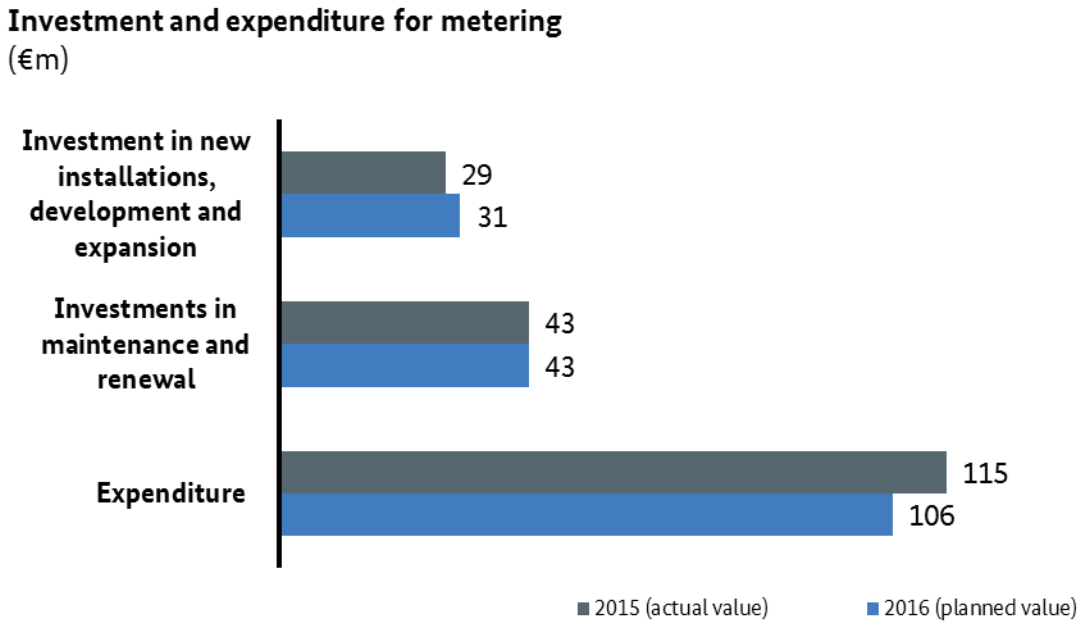

Figure 188: Investment and expenditure for metering

III Consumers

1. Energy consumer advice service

The Bundesnetzagentur's task as the central information point for energy consumers is to keep private energy consumers informed about the current legal situation, their rights as household customers as well as their right to apply for dispute resolution. This task is performed by the Bundesnetzagentur's energy consumer advice service, which consumers can contact by letter, fax or email or by telephone.

In 2015, the energy consumer advice service received around 10,400 queries and complaints. The majority of the queries and complaints – some 5,700 – related to electricity, with just 900 concerning gas and 3,800 about general issues.

The following chart shows a breakdown of all the queries and complaints received during the year up to 31 December 2015:

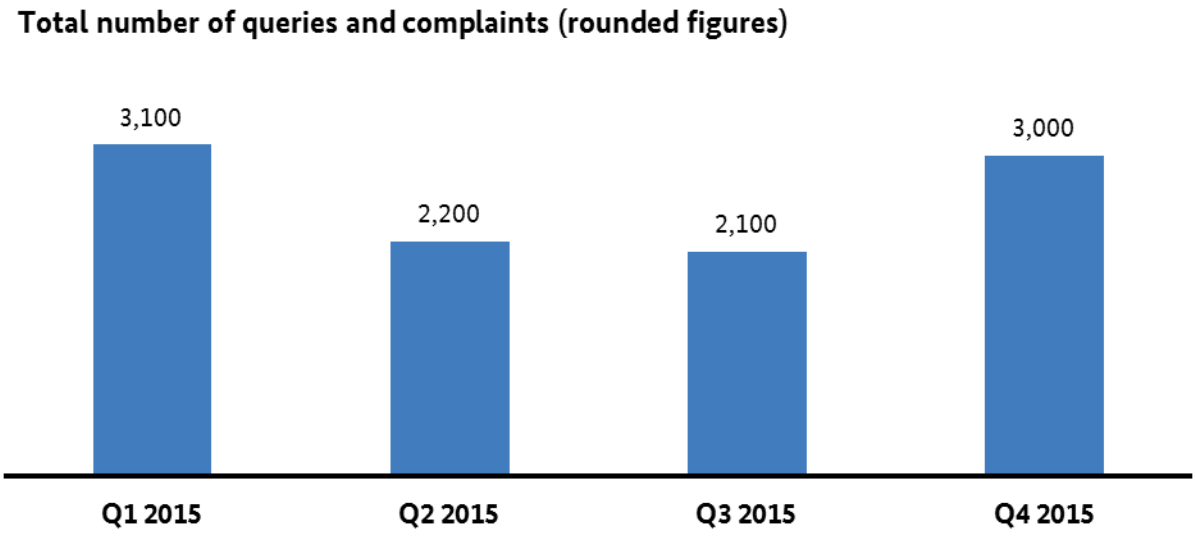

Figure 189: Total queries and complaints up to 31 December 2015

The large number of queries and complaints received from consumers in the first and fourth quarters of the year is most likely due to the fact that price changes made by suppliers as of 1 January lead to an increase in the number of consumers changing supplier and resultant problems with, for instance, switching and/or billing.

As in previous years, the majority of the queries and complaints concerning gas and electricity were questions regarding tariffs and billing and complaints about the quality of service provided by suppliers in particular.

The bulk of the complaints about supply contracts or billing concerned the same few companies. Consumers complained in particular about late or incorrect energy bills, delays in receiving credit balances and bonuses, and differences in interpreting the terms and conditions for bonus payments or contract termination.

Private consumers with contractual or billing problems are entitled to have a complaints procedure carried out with their company instead of taking their case to court. If the company does not provide a remedy within a period of four weeks, energy consumers can then turn to the energy dispute resolution panel – Schlichtungsstelle Energie e.V. – for redress.

Since November 2011 the energy dispute resolution panel has been responsible for mediating between consumers with complaints about contracts or the quality of a company's service and their energy utility, meter operator or metering service provider. In 2015, the panel received 4,875 requests for redress. The panel publishes an annual report of its activities and regular updates of its conciliatory proposals on its website at www.schlichtungsstelle-energie.de.

As a rule, the dispute resolution procedure is free of charge for energy consumers. The conciliatory proposals are not binding, however, so that both consumers and companies still have the option of going to court.

2. Energy issues

The Bundesnetzagentur's electricity and gas web pages provide answers to typical questions from consumers on a wide range of issues.

2.1 Renewable energy

Interest in the self-supply guidelines has remained high since publication of the final version in July 2016. In this connection, there has also been significant interest in the web pages on data collection for the renewables compensation mechanism, on account of the legal reporting obligations to be met by those generating their own electricity.

The Bundesnetzagentur has several dedicated hotlines and contact addresses for various renewable energy issues. In 2015, the Bundesnetzagentur received around 24,000 telephone calls and almost 4,000 emails relating to the installations register, the photovoltaic registration portal and general data collection.

2.2 Market area conversion

The first half of 2016 saw particular interest from consumers in the process that has just begun to switch from L-gas to H-gas in Bremen and Lower Saxony. There have been more than 10,000 visits to the FAQ pages, compared to last year's figure of just under 4,000. The Bundesnetzagentur is extending its range of information available to take account in particular of the current legislative changes.

The Bundesnetzagentur's web pages provide answers to FAQs about market conversion as well as links to the relevant network operators' websites.

2.3 Energy suppliers

There is a clear trend among consumers experiencing problems with their energy suppliers to use the Bundesnetzagentur's information resources. Questions about different tariffs and fallback supply are just some of those that have seen an increase in clicks.

2.4 Grid expansion – participation and dialogue

To increase transparency and gain public acceptance for power line expansion, the Bundesnetzagentur not only offers the opportunities for participation that are prescribed by law but also organises informal events and information opportunities.

On 24 June 2015 the Bundesnetzagentur discussed the opportunities and risks of underground cables and overhead lines with experts in the field and with an interested public. Information was also shared on the latest state-of-the-art technology and on health and environmental issues.

The third science and research dialogue, which took place in Bonn on 17-18 September 2015, provided a platform for an academic exchange on grid expansion. The event's main focus were the challenges associated with grid expansion and these were addressed in two ways: as papers presented by selected authors and in discussions between panels of experts.

The technical dialogue which was held in Cologne on 17 November 2015 dealt with legal consent issues, technical aspects and the search for an appropriate site for a converter station.

In addition to its numerous information and dialogue events, the Bundesnetzagentur provides a wide range of information about grid expansion on its dedicated website at www.netzausbau.de, from leaflets and flyers on specific topics through to short films on YouTube and presentations on SlideShare. The Bundesnetzagentur also posts up-to-date news on grid expansion, including details of upcoming events, on Twitter. The general public can also call or write to the public advice service with their questions.

2.5 Information events for consultation on the 2024 network development plans and for the environmental report

The Bundesnetzagentur's consultation on the network development plans for the period up to 2024 and on the environmental report included four information events. The aim of these events was to promote open dialogue on the network expansion required and its expected impact on the environment.

Governmental bodies, professional associations and the general public were given an opportunity to comment on the draft documents from 27 February 2015 until 15 May 2015. A total of 34,211 submissions were received in response to the consultation and were taken into account in the Bundesnetzagentur's final assessment.

3. New suppliers

All energy utilities that supply electricity or gas to household customers in Germany and that started their activities after 13 July 2005 are required by section 5 of the Energy Act to notify their activities to the Bundesnetzagentur. Since 2010, there has been a steady increase in the number of supplier notifications received. As of 30 June 2016, a total of 794 companies supplying electricity, gas or both had notified the Bundesnetzagentur of their activities. The majority of notifications from companies ceasing activities have been due to restructuring within company groups; only in a few instances have companies actually withdrawn from the market completely.

Supplier notifications

Year	Number of notifications for starting activities	Number of notifications for ceasing activities	Total number of suppliers notified at year end
Total number of suppliers			
2010			232
2011	90	0	322
2012	78	3	397
2013	137	9	525
2014	100	10	615
2015	148	3	760
Suppliers of both gas and electricity			
2010			88
2011	41	0	129
2012	36	1	164
2013	51	5	210
2014	39	5	244
2015	51	2	293
Suppliers of gas only			
2010			37
2011	16	0	53
2012	17	0	70
2013	25	0	95
2014	23	0	118
2015	6	0	124
Suppliers of electricity only			
2010			107
2011	33	0	140
2012	25	2	163
2013	61	4	220
2014	38	5	253
2015	91	1	343

Table 104: Supplier notifications

4. Billing charges

The billing charge is one of the costs passed on by a network operator to the suppliers in the operator's network area. The Electricity and Gas Network tariffs Ordinances specify which costs a network operator may charge. Since 2008 network operators are required to create cost centres for meter operation, metering and billing and to allocate the costs of these activities to the cost centres generating the costs. Billing costs, that is the costs incurred by a network operator in processing metering data for billing purposes or the costs incurred in recovering outstanding network usage charges, were previously included in the general network tariffs and were not a separate cost item.

Network operators must provide the competent regulatory authorities with a breakdown of their costs in order for revenue caps to be set.

In 2015, the billing charge made up on average between 46% and 51% of the meter operation, metering and billing costs reported by the network operators regulated by the Bundesnetzagentur. The Bundesnetzagentur is responsible for regulating network operators serving more than 100,000 connected customers or operating a network covering more than one federal state. It is also responsible for regulating all network operators in Berlin, Brandenburg, Bremen, Schleswig-Holstein and Thuringia, since these states have delegated their regulatory responsibility to the Bundesnetzagentur.

The billing charge is now being abolished with effect from 1 January 2017. There had been some criticism because there were reasons to suspect that network operators were exploiting scope in distributing their costs between the various cost centres. It was also said that the billing charge was too high compared to the costs for meter operation and metering, which hindered competition and innovation in metering.

Abolishing the billing charge as from 2017 does not, however, mean that network operators will not incur any costs; it simply means that the costs will once again be included in the general network tariffs instead of being reported separately.

5. Supervisory proceedings

In June 2015 the Higher Regional Court of Düsseldorf ruled that Care-Energy Energiedienstleistungs GmbH & Co. KG was obliged under section 5 of the Energy Act to notify its supply of energy to household customers. The company responded by stating that it had transferred all of its contractual relationships with energy customers to Care-Energy AG. Care-Energy AG had already notified the Bundesnetzagentur of its activities as a supplier to household customers as required by section 5 of the Energy Act in October 2014 – under its then name EnUp AG.

Following numerous complaints from Care-Energy AG customers in the period between December 2015 and February 2016, in particular about missed or late bills or credit balances not being refunded, the Bundesnetzagentur initiated preliminary investigations under section 5 of the Energy Act in March 2016 and gave the company the opportunity to respond to the complaints. In April 2016, Care-Energy AG sent a one-page reply stating that no customers had been transferred from Care-Energy Energiedienstleistungs GmbH & Co. KG to Care-Energy AG.

Between 30 May and 23 June 2016 all four transmission system operators informed the Bundesnetzagentur that they had warned Care-Energy AG that they would terminate the balancing group contract because the company had not made the advance payments due under the Renewable Energy Sources Act. On 21 June 2016 the Bundesnetzagentur was informed that Care-Energy AG had retrospectively notified operators in numerous network areas in Germany that it had ceased supplying energy to customers on account of the customers moving home. Many of the 19,000 or so customers affected across the country contacted the Bundesnetzagentur to say that their supply contract had been terminated although they had not moved home.

In June 2016, the Federal Court of Justice upheld the ruling issued by the Regional Higher Court of Düsseldorf in June 2015 that Care-Energy Energiedienstleistungs GmbH & Co. KG – which by then was operating under the name Expertos Unternehmens- und Wirtschaftsberatungs GmbH & Co. KG – was obliged under section 5 of the Energy Act to notify its activities as a supplier to household customers.

On 14 June 2016 the Bundesnetzagentur then opened two supervisory proceedings against Care-Energy AG and Expertos Unternehmens- und Wirtschaftsberatungs GmbH & Co. KG for breaching the provisions of section 5 of the Energy Act. The Bundesnetzagentur issued two decisions on 28 and 29 June 2016 requiring Care-Energy AG and Expertos to provide information in response to questions about the reliability of their management, their financial capacity, existing customer contracts and the relationship between the two companies, setting a deadline of 13 and 14 July 2016 and giving warning of a €1m fine. The responses submitted by the two companies are currently being examined.

IV General topics

A Market Transparency Unit for Wholesale Electricity and Gas Markets

The tasks of the Market Transparency Unit for Wholesale Electricity and Gas Markets are carried out jointly by the Bundesnetzagentur and the Bundeskartellamt. The two authorities together monitor the wholesale energy markets from their different viewpoints. While the Bundesnetzagentur monitors compliance with the provisions of the EU Regulation on wholesale energy market integrity and transparency (REMIT) in respect of the prohibition of insider trading and market manipulation, the Bundeskartellamt focuses on breaches of competition law, in particular on determining market power with a view to subsequent investigations into initial indications of an abuse of market power. Circumstances suggesting a breach of the German Security Trading Act or Stock Exchange Act are also reported to the competent authorities.

The joint market monitoring activities are founded on the trade and fundamental data collected at European level by ACER. Data is reported to ACER in accordance with Article 8 of REMIT and Implementing Regulation (EU) No 1348/2014 in two stages. Since 7 October 2015 market participants must report details of all contracts concluded at organised market places. In addition, the fundamental data for electricity and gas are reported to ACER by ENTSO-E and ENTSO-G. Since 7 April 2016 market participants must also report details of all bilateral contracts, known as over-the-counter (OTC) transactions. Transportation contracts and additional fundamental data are also to be reported.

ACER publishes regularly updated lists as well as guidance for market participants reporting data (List of standard contracts, Transaction Reporting User Manual (TRUM), Manual of Procedures (MoP) on data reporting, Questions and Answers (Q&As), Frequently asked questions (FAQs))[146]. These documents are drawn up in consultation with the Market Transparency Unit, which also publishes its own manuals and guidance.[147]

Market participants wishing to report data to ACER must first register with the Bundesnetzagentur in order to obtain a special ACER code. German market participants with queries about data reporting or registration can contact a dedicated team at the Bundesnetzagentur on a special hotline or by email. In the period between January and October 2016 the team dealt with more than 2,300 queries from market participants.

The Market Transparency Unit may stipulate its own requirements in accordance with an ordinance to be issued by the Federal Ministry for Economic Affairs and Energy in order to gather additional data not collected at European level by ACER. Such data may include in particular electricity and, possibly, gas balancing energy data and selected data relating to electricity generation plants with a capacity of less than 100 MW.

One of the Market Transparency Unit's priorities during the last few months has been developing the IT system – and the associated security measures – to process the German market data received from ACER.

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[146] https://www.acer-remit.eu/portal/home

[147] http://www.markttransparenzstelle.de and http://www.remit.bundesnetzagentur.de

B Selected activities of the Bundesnetzagentur

1. Tasks under REMIT

1.1 Registration of market participants

The Bundesnetzagentur started registering market participants under Article 9 of REMIT in March 2015. Once they have registered, market participants receive a special code enabling them to report data to ACER. A total of 3,847 market participants in Germany have registered and are among the 11,647[148] listed in the European register[149]. This makes Germany the European country with the highest number of registered market participants, followed by France, Italy and the United Kingdom, which each have more than 1,100.

1.2 Investigation of breaches

The Bundesnetzagentur is responsible under section 56 para 4 of the Energy Act for monitoring compliance with REMIT and investigating possible breaches. Breaches of REMIT can be divided into three groups:

- breaches of the requirements to register, report data and publish inside information;
- breaches of the prohibition of insider trading; and
- breaches of the prohibition of market manipulation.

One channel through which the Bundesnetzagentur is made aware of suspected breaches is ACER's Notification Platform[150], which is used in particular by persons professionally arranging transactions in wholesale energy products (eg energy brokers or energy exchanges). In addition, it is possible for any market participant to report breaches of REMIT to the Bundesnetzagentur direct; these reports may also be made anonymously.

Since 2012 the Bundesnetzagentur has received 19 reports of suspected breaches.[148] One report related to a breach of the prohibition of insider trading imposed in Article 3 of REMIT, while the remaining reports concerned market manipulation as prohibited in Article 5 of REMIT. Seven allegations were investigated each in 2015 and 2016. A total of 13 cases are still under investigation, including one reported in 2014. The cases include suspicious transactions which may be aimed at setting prices at an artificial level and transactions known as "wash trades", which are aimed at giving false or misleading signals regarding the supply of or demand for wholesale energy products. Eight cases affecting both Germany and other European Member States are being investigated in cooperation with the foreign regulatory authorities concerned. To date the Bundesnetzagentur has not imposed any fines or brought charges.

[148] Both figures are correct as of 3 November 2016.

[149] https://www.acer-remit.eu/portal/european-register

[150] https://www.acer-remit.eu/np/home

C Selected activities of the Bundeskartellamt

1. Prohibition of anti-competitive agreements

In the reporting period the Bundeskartellamt examined whether a proceeding should be initiated under Section 1 GWB and Art. 101 TFEU to examine a possible restriction of competition on account of an agreed reduction of electricity generating capacities and decided initially against this for discretionary reasons.

STEAG GmbH ("STEAG"), Essen, had suggested that the authority initiate an administrative proceeding against RWE Generation SE ("RWE"), Essen. The reason for this was RWE's unilateral and in STEAG's opinion anti-competitive demand to close the hard coal power station at Voerde.

The situation was as follows: The Voerde power station was jointly operated by STEAG and RWE. RWE held the drawing rights to the quantities of electricity generated by the power station; this was laid down in a contract. In 1975 a partnership agreement was signed between STEAG and RWE on the establishment of a plant operating company: The terms and conditions of the establishment, operation, closure and financing of the Voerde power station were set out in a covering agreement of the same date. A clause in the covering agreement states that after a specific period of operation the minority shareholder RWE can unilaterally demand the final closure of the plant.

Accordingly, RWE requested its closure. In turn STEAG offered to take over RWE's share in the operating company, to continue operating the power station by itself and to market the quantities of electricity generated at the power station on its own account. This was followed by negotiations which, however, did not produce any result. Consequently STEAG approached the Bundeskartellamt about the matter.

In examining the case the Bundeskartellamt confirmed that an agreement existed between two independent companies taking into account the complex rules in this individual case. It also did not rule out the anti-competitive character of the agreement. In its previous decision making practice the Bundeskartellamt has regarded capacity shutdown agreements as restrictions of competition by object[151], as they are likely by their very nature to lead to a shortage of supply and thus to price increases to the detriment of consumers. This was all the more true in this particular case because the agreement prevented the economic utilisation of the power station, i.e. either its sale or further operation by STEAG with the company directly marketing all the electricity generated at the Voerde plant. In addition, a shutdown would cause a restriction of competition on the market for the first sale of electricity because

[151] For instance, in the B10-40/09 case involving Evonik (now STEAG) / RWE the Bundeskartellamt objected under Section 1 GWB, Art. 101 TFEU to the shutdown clauses agreed between the companies.

a reduction in electricity generating capacities normally leads to an increase in electricity wholesale prices.[152]

At the time the Bundeskartellamt decided not to initiate a proceeding because the negotiations between the parties on the sale of the plant were still ongoing and the dispute between them mainly concerned legal issues which could also have been addressed by the civil antitrust courts.

STEAG and RWE subsequently agreed on the future of the Voerde plant. The transfer to STEAG of RWE shares in the company operating the Voerde power station was notified to the Bundeskartellamt and cleared within the one-month first phase of merger control (case ref: B8-63/16).

2. Control of abuse of a dominant position: Award of concessions for electricity networks

The immediate enforceability of the Bundeskartellamt's prohibition decision against the Titisee-Neustadt municipality for abusing its dominant position in the selection of a new holder of the rights of way became final following a Federal Court of Justice's decision of 26 January 2016. In the decision the Federal Court of Justice rejected the municipality's appeal against the denial of leave to appeal and appeal on points of law (violation of the right to be heard) lodged against a previous decision of the Düsseldorf Higher Regional Court to uphold the immediate enforceability of the Bundeskartellamt's decision. The court stated that the mere pendency of a municipality's constitutional complaint was not sufficient to affirm a public interest in the suspension of the Bundeskartellamt's decision. Otherwise this would mean that the obligation of the judiciary and public administration to uphold law and justice under Article 20 (3) of the Basic Law would be rendered void. Furthermore, the Federal Court of Justice expressed considerable doubt about the admissibility of the constitutional complaint lodged by the Titisee-Neustadt municipality. On 22 August 2016 the Federal Constitutional Court decided that it would not accept the municipality's constitutional complaint (BVerfG, decision of 22 August 2016 – 2 BvR 2953/14).

In response to several enquiries, the Bundeskartellamt and the Bundesnetzagentur have agreed to further define their guidelines on the award of rights of way for electricity and gas networks. This concerns the legal right of municipalities to information on the multi-annual investment and revenue planning of holders of rights of way under para. 40 h) of their Joint Guidelines. According to their common understanding of para. 40 h), only planning data are to be submitted about the concession network up until the concession contract expires. These are planning data which are compiled on the premise that the former concession holder might not continue as concession holder and give up the network. Applicants can thus estimate the investment situation for the period between the disclosure of data three years before expiry of the concession contract and the end of the concession contract. Investment planning data beyond this period are a major competition parameter in competition for the award of the concession and are therefore not subject to the disclosure obligation of the former concession holder.

[152] The Sector Inquiry "Electricity Generation and Wholesale Markets", on the other hand, dealt with a different case scenario, i.e. a short-term withholding of capacity by a dominant company, which was not based on an agreement, see also p. 118-120 of the sector inquiry.

3. Sector inquiry: Submetering of heating and water costs

In July 2015 the Bundeskartellamt launched a sector inquiry into submetering. Submetering services cover the consumption-based metering and billing of heating and water costs in buildings as well as the provision of the necessary metering equipment such as heating cost distributors or water and heat meters which the service provider usually installs and reads at regular intervals. Submetering is to be defined as a separate product market to metering. Whereas metering covers the consumption-based billing of the supply of energy to a certain property, submetering covers services relating to the allocation of the heating and water costs to the individual consumers at one property.

The purpose of the sector inquiry is to assess the current market situation and intensity of competition in the metering and billing of heating and water costs and identify any competition deficits, restraints of competition or abusive practices in this segment.

The Bundeskartellamt already dealt with a case of submetering in a merger control proceeding in 2002 and found that a non-competitive duopoly existed between ista (then: Viterra) and Techem with a joint market share of over 50 %. The aim of the inquiry is to clarify how market structures have developed since then and if there is still a position of collective dominance. The inquiry takes account of the fact that the actual contractual partners (i.e. the property owner or property management agent) do not usually bear the costs of submetering themselves but pass these on to the tenants. The sector inquiry will also analyse if there are any barriers to market entry, in particular in respect of proprietary systems used in billing and in remote meter-reading via a radio transmitter.

As a first step the Bundeskartellamt sent out online questionnaires to around 90 submetering companies and several large property management companies. The data collected was then sorted and evaluated using statistical methods. In a second step talks were conducted with selected market participants and associations and detailed questions addressed to selected competitors. The results of the analysis will be published in a final report.

4. Competition advocacy

With the introduction of the Electricity Market Act in July 2016 the German legislator launched an "electricity market 2.0". The electricity market 2.0 will build on existing market mechanisms and develop them further by eliminating wrong incentives and distortions of competition. It is essential that undistorted price signals reach the market, which, for instance, adequately reflect scarcities of supply and set the right investment incentives.

In the discussion about the future design of the electricity market it was argued by some that the prohibition of abusive practices under competition law has the effect of an implicit price ceiling on the market for the first sale of electricity. The Bundeskartellamt does not share these concerns. Contrary to what is sometimes claimed, the prohibition of the abuse of a dominant position does not generally prohibit companies from offering capacities with a surcharge on their marginal costs (mark-up). The prohibition of the abuse of a dominant position applies exclusively to dominant companies. These may not use their market power to, for example, drive up prices artificially and to a considerable extent. If, on the other hand, price peaks occur because of actual scarcities which are not market power-related, they are not objectionable under competition law.

Although the Bundeskartellamt does not share the concerns described above, in its comments on the Federal Ministry for Economic Affairs and Energy's discussion paper (Green Book) "An Electricity Market for Germany's

Energy Transition" it proposed to publish guidelines on the control of the abuse of a dominant position in electricity generation."

This proposal was adopted in the Ministry's final document (White Paper): "An Electricity Market for Germany's Energy Transition" (measure no. 2, page 61). The guidelines will clarify "the direction, rules for the application and scope" of the control of the abuse of a dominant position on the market for the first sale of electricity. They are intended to resolve any existing uncertainties.

In preparation for the guidelines the Bundeskartellamt launched a consultation from 1 April 2016 to 31 May 2016. It prepared a questionnaire for interested companies, trade associations and public authorities.[153] Eight statements were submitted, which the Bundeskartellamt is currently analysing.[154]

The Bundeskartellamt and Bundesnetzagentur are currently planning to publish joint guidelines. In addition to providing clarification on the control of the abuse of a dominant position on the market for the first sale of electricity, the guidelines are also intended to address questions on the interpretation of the REMIT regulation. This did not feature in the consultations carried out by the Bundeskartellamt.

The Electricity Market Act also provides for a further measure to make the control of the abuse of a dominant position on the market for the first sale of electricity more transparent. The Bundeskartellamt is also to regularly publish a report in future on the findings of its monitoring of the extent of competition in the electricity generation sector (Section 53 (3) sentence 2 GWB). The report is an integral part of the monitoring activities in accordance with Section 48 (3) sentence 1 and is to be published at least every two years. The report can be published independently of the Monitoring Report which it jointly publishes with the Bundesnetzagentur. In addition to the data it collects itself for this purpose the Bundeskartellamt will also obtain data collected by the Market Transparency Unit for Electricity and Gas Wholesale Trading (Section 47c (1) no. 1 GWB). On the basis of this data the authority can in particular conduct real-time analyses of dominance on the electricity generation markets. This will enable companies to assess more easily in future whether they are dominant and therefore subject to the prohibition of the abuse of a dominant position.

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[153] Cf. http://www.bundeskartellamt.de/SharedDocs/Meldung/DE/AktuelleMeldungen/2016/01_04_2016_Fragebogen_Leitfaden_Stromerzeugung.html

[154] The comments are available for download (only in German) at http://www.bundeskartellamt.de/DE/Missbrauchsaufsicht/Konsultation_Missbrauchsaufsicht_Stromerzeugung/Konsultation_Missbrauchsaufsicht_Stromerzeugung_node.html

Lists

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Intruduction retail contract structure and supplier switching (I.G.2)

Intruduction retail price level (I.G.4)

Summary of the gas market (II.A.1)

Intruduction retail contract structure and supplier switching (II.G.2)

Intruduction retail price level (II.G.4)

Market Transparency Unit for Wholesale Electricity and Gas Markets (IV.A)

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Bundesnetzagentur's authorship (Notes)

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2. Network overview

B Generation

C Networks

D System services

E Cross-border trading and European integration

G Retail (in the following parts:)

1. Supplier structure and number of providers

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List of abbreviations

Term	Definition
ACER	Agency for the Cooperation of Energy Regulators
AGV	working gas volume(s) (of gas storage facilities)
ARegV	Incentive Regulation Ordinance
AusglMechAV	Ordinance implementing the Equalisation Scheme Ordinance
AusglMechV	Equalisation Scheme Ordinance
BAFA	Federal Office of Economics and Export Control
BBPlG	Federal Requirements Plan Act
BFZK	Capacity with conditional firmness and free allocability
BGH	Federal Court of Justice
BKV	Balancing group manager
BlmSchG	Federal Immission Control Act
BMWi	Federal Ministry for Economic Affairs and Energy
CEE	Central East Europe
CR	Concentration ratio
CSE	Central South Europe
CWE	Central West Europe
DIN	German Institute for Standardization
DSL	Digital subscriber line
DSO	Distribution system operator
EC	European Community

ECC	European Commodity Clearing AG
EEG	Renewable Energy Sources Act
EEX	European Energy Exchange AG
EnLAG	Power Grid Expansion Act
ENTSO-E	European Network of Transmission System Operators for Electricity
EnWG	Energy Act
EPEX SPOT	European Power Exchange
Eurostat	Statistical Office of the European Communities
EVU	Energy utility
EXAA	Energy Exchange Austria
FBA	Flow Based Allocation
FNB	Gas transmission system operator
FZK	Freely allocable capacity
GABi Gas	Basic model of balancing services and balancing rules in the gas sector
GasNEV	Gas Network Charges Ordinance
GasNZV	Gas Network Access Ordinance
GeLi Gas	Business processes for change of gas supplier
GPKE	Business processes for supplying customers with electricity
GPRS	General Packet Radio Service
GSM	Global System for Mobile Communications
GW	Gigawatt
GWB	Competition Act
GWh	Gigawatt hour

GWJ	Gas year
HV	High voltage
HVDC	High voltage direct current transmission
HöS	Extra-high voltage
ITC	Inter-TSO compensation
KAV	Concession Fees Ordinance
KoV IV	Concession agreement IV as amended on 1 October 2011
kWh/h	Kilowatt hours per hour
KWK	Combined heat and power
KWKG	Combined Heat and Power Act
LNG	Liquefied natural gas
m^3/h	Cubic metre per hour
MRL	Minute reserve power
MV	Medium voltage
MWh	Megawatt hour
MWh/km^2	Megawatt hour per square kilometre
NABEG	Grid Expansion Acceleration Act
NAV	Low Voltage Connection Ordinance
NCG	Net Connect Germany
NDAV	Low Pressure Connection Ordinance
nm^3	Normalised cubic metre
nm^3/h	Normalised cubic metre per hour
NRV	Grid control cooperation

NS	Low voltage
NTC	Net transfer capacity
OFC	Online flow control
OGE	Open Grid Europe
OLG	Higher regional court
OMS standard	Open Metering System Standard
OTC	Over the counter
PLC	Power line communication
PRL	Primary control power
PSTN	Public switched telephone network
REMIT	Regulation on wholesale Energy Market Integrity and Transparency
RLM	Interval load metering
RLMmT	Load metering with daily flat supply
RLMNEV	Load metering with substitute nomination procedure
RLMoT	Load metering without a daily flat supply
SAIDI	System average interruption duration index
SLP	Standard load profile
SRL	Secondary control power
StromNEV	Electricity Network Charges Ordinance
StromNZV	Electricity Network Access Ordinance
TFEU	Treaty on the Functioning of the European Union
TSO	Transmission System Operator
TWh	Terawatt hour

UGS	Underground storage facillity
UMTS	Universal Mobile Telecommunications Systems
VNG	Verbundnetz Gas AG
V(H)P	Virtual trading point

Glossary

The definitions pursuant to section 3 EnWG, section 2 StromNZV, section 2 GasNZV, section 2 StromNEV, section 2 GasNEV, section 3 EEG and section 3 KWKG apply. In addition the following definitions and the Bundesnetzagentur's guidelines on electricity network operators' internet publication obligations (Leitfaden für die Internet-Veröffentlichungspflichten der Stromnetzbetreiber) apply.

Term	Definition
Access	*Electricity* Includes all the equipment that is the property of the supplier and that is used for one customer only. *Gas* The network connection joins the general supply network with the customer's gas facilities from the supply pipeline to the internal pipes on the premises. It comprises the connecting pipe, any shut-off device outside the building, insulator, main shut-off device and any in-house pressure regulator. The provisions on connection to the network are still applicable to the pressure regulator when it is installed after the end of the network connection but located within the customer's system.
Actual energy consumption	For indicating the actual consumption of gas it would seem appropriate to take kWh as the unit of measurement.
Adjustment measures	Section 13(2) of the Energy Act entitles and obliges TSOs to adjust all electricity feed-in, transit and offtake or to demand such adjustment (adjustment measures) where a threat or disruption to the security or reliability of the electricity supply system cannot be removed or cannot be removed in a timely manner by network-related or market-related measures as referred to in section 13(1) of the Act. Where DSOs are responsible for the security and reliability of the electricity supply in their networks, they too are entitled and obliged under section 14(1) of the Energy Act to take adjustment measures as referred to in section 13(2) of the Act. Furthermore, section 14(1c) of the Act requires DSOs to support the TSOs' measures as required by the TSOs with the DSOs' own measures (support measures). Curtailing feed-in from renewable energy installations under section 13(2) of the Energy Act may also be necessary in situations other than those covered by the feed-in management provisions if the threat to the system is caused not by congestion but by another security problem. Adjustments pursuant to section 13(2) of the Energy Act constitute emergency measures and as such are without compensation.

Affiliated undertakings within the meaning of section 15 Stock Corporation Act	As set out in the German Stock Corporation Act: legally independent companies that in relation to each other are subsidiary and parent company (section 16), controlled and controlling companies (section 17), members of a group (section 18), undertakings with cross-shareholdings (section 19) or parties to a company agreement (sections 291 and 292).
Annual usage time (final consumer)	Annual usage time defines the regularity of the consumer's offtake of electrical energy from the network during a year. The longer the time, the more evenly consumption is distributed over the 8,760 hours of the year (8,784 in a leap year). The time gives the number of hours the consumer needs to reach his annual consumption if he constantly uses the power corresponding to his annual peak load (annual usage time = annual consumption divided by annual peak load). (see Institute for Applied Ecology, Combined heat and power agreement, 2012)
Annual peak load (final consumer)	Peak load, expressed in kilowatt (kW), as metered in 15 minute readings, in the course of a year.
Auxiliary capacity	Electrical power a generating unit requires to operate its auxiliary and ancillary facilities (eg for water treatment, water supply to steam generators, fresh air and fuel supply, flue gas cleaning), plus the power losses of step-up transformers (generator transformers). There are two types of internally used electrical power: the electrical power required to operate a generating unit's auxiliary and ancillary facilities during operating hours and the electrical power required to operate its auxiliary and ancillary facilities outside operating hours. (See VGB PowerTech e.V., Basic Terms of the Electric Utility Industry, 2012)
Balancing energy	Difference between entry and exit quantities established by the balancing group network operator for the market area at the end of each balancing period and settled with the balancing group managers.
Balancing group network operator	A network operator covering the whole market area or a third party enabling a balancing group to be established and with whom a balancing group contract is concluded.
Balancing services	Energy procured by the balancing group manager and used to guarantee the stability of the networks in the particular market area.
Balancing zone	Within a balancing zone all entry and exit points can be allocated to a specific balancing point. In the gas sector a balancing zone corresponds to the market area. This means that all entry and exit points in all networks or network segments that are part of the particular market area belong to a balancing group (see section 3 para 10b Energy Act).

Binding exchange schedules	Unlike physical load flows, which represent the actual cross-border flow of electricity, exchange schedules reflect the commercial cross-border exchange of electricity. Physical load flows and commercial exchange schedules do not necessarily have to match (eg due to loop flows).
Black start capability	Ability of a generating unit (power plant) to start up independently of power supplies from the electricity network. As a first step to restore supply, this is particularly important in the event of a disruption causing the network to break down. Additionally, a "stand-alone capability" is required with a steady supply voltage and capable of bearing loads without any significant voltage and frequency fluctuations.
Cavern storage facility	Artificial hollows in salt domes created by drilling and solution mining. In comparison to pore storage facilities, these often have higher injection and withdrawal capacities and a lower cushion gas requirement, but are also smaller in volume.
Change of contract	A customer's change to a new tariff with the same energy supplier.
Charge for billing	Charge for settling network use and forecasting annual consumption in accordance with section13(1) Electricity Network Access Ordinance.
Charge for metering	Charge for reading the meter, reading out and passing on the meter data to the authorised party.
Charge for meter operations	Charge for meter installation, operation and maintenance.
Concentration ratio	Total market share of the three, four or five competitors with the biggest market shares (Concentration Ratio 3, CR4, CR5) The greater the market share covered by just a few competitors, the higher the market concentration.
Consumption	Amounts of electricity delivered by electricity suppliers to final consumers.
Completion of/Start of operation	The time at which gas supply could begin (gas pipeline under pressure up to the shut-off valve).
Countertrading	Reciprocal commercial transactions across balancing energy zones initiated by TSOs, either preventive or curative, to avoid or remove congestion occurring at short notice.
CO_2 emissions from power generation	The CO_2 released during power generation. For CHP plants the proportion of CO_2 emissions that are to be allocated to power generation according to Working Sheet AGFW FW 309 Part 6 "Energy rating of district heating - Determining the specific CO_2 emission criteria" (December 2014).
Day-ahead trade	Trading market for energy supplied the next day.
Day-ahead capacity	Capacity for the next day

Default supplier	The gas and electricity company providing default supply in a network area as provided for by section 36(1) Energy Act.
Default supply	Energy supply by the default supplier to household customers on the basis of general terms and conditions and general prices (see section 36 Energy Act).
Delivery volumes	Amount of electricity or gas delivered by electricity or gas suppliers to final consumers.
Dominance method	Simplified group accounting method for the purposes of evaluating market concentration. It focuses solely on whether one shareholder holds at least 50% of the shares in a company. If the shares in a company are held as to more than 50% by one shareholder, the company's volume of sales is attributed to the shareholder in full. If two shareholders have a shareholding of 50% each, then the sales are split in half and attributed to each of the shareholders. If there is no shareholding of 50% or more in a company, the volume of sales of this company is not attributed to any shareholder (the company is then itself a "controlling company").
Downstream distributor	Regional and local gas distribution network operator (not an exporter)
EEX / EPEX Spot	European Energy Exchange / European Power Exchange. The EEX operates marketplaces for trading electricity, natural gas, CO2 emission rights and coal. EEX holds a 51% equity investment in the Paris-based EPEX Spot, which operates the power spot markets for Germany, France, Austria and Switzerland (see www.eex.com/de).
Electric heating	Electricity for heating is the electricity supplied to operate interruptible consumer equipment for the purposes of room heating. Interruptible consumer equipment essentially comprises overnight storage heaters and electric heat pumps. (see Eurostat, electricity prices for 2003)
Energy to cover power losses	The energy required for the compensation of technical power losses.
Entry point	A point at which gas can be transferred to the network or subnetwork of a system operator, including transfers from storage, gas production facilities, hubs, or blending and conversion plants.
Exit point	The point at which gas can leave an operator's network for delivery to final customers, downstream networks (own and/or third party) or redistributors, plus the points at which gas can be taken off for delivery to storage facilities, hubs and conditioning or conversion plants.
FBA	Flow Based Allocation of capacity Starting from the planned commercial flows (trades), the capacity available for cross-border electricity trading is determined and allocated on the basis of the actual flows in the network. FBA thus makes it possible to allocate transmission capacity in line with

	the actual market situation as reflected by the bids.
Feed-in management	This is a special measure regulated by law to increase network security relating to renewable energy, mine gas and combined heat and power (CHP) installations. Priority is to be given to feeding in and transporting the electricity generated by these installations (section 11(1) and (5) of the Renewable Energy Sources Act and section 4(1) and (4) second sentence of the Combined Heat and Power Act). Under specific conditions, however, the system operators responsible may also temporarily curtail priority feed-in from these installations if network capacities are not sufficient to transport the total amount of electricity generated (sections 14 and 15 of the Renewable Energy Sources Act in conjunction with section 13(2) and (2a) third sentence of the Energy Act and, in the case of CHP installations, section 4(1) second sentence of the Combined Heat and Power Act). Importantly, such feed-in management is only permitted once the priority measures for conventional installations have been exhausted. The expansion obligations of the operator answerable for the congestion remain in parallel to these measures. The operator of an installation with curtailed feed-in is entitled to compensation for the energy and heat not fed in as provided for in section 15(1) of the Renewable Energy Sources Act. The costs of compensation must be borne by the operator in whose network the cause for the feed-in management measure is located. The operator to whose network the installation with curtailed feed-in is connected is obliged to pay the compensation to the operator of the installation with curtailed feed-in. If the cause lay with another operator, that operator is held responsible and is required to reimburse the costs of compensation to the operator to whose network the installation is connected.
Futures	Contractual obligation to buy (futures buyer) or deliver (futures seller) a specified amount of, for example, electricity, gas or emission rights at a fixed price in a defined future period (period of delivery). Futures contracts are settled either physically or financially (See Eurostat, electricity prices for 2003).
Futures market	Market for trading futures and derivatives. It differs from the spot market in that obligation and settlement do not take place at the same time.
Green electricity tariff	Tariff for electricity which, on account of green electricity labelling or other marking, is shown to have been produced with a high share/high promotion of efficient or regenerative production technologies and which is offered/traded at a separate tariff.
Gross capacity	Delivered power to the terminals of the generator. Hydro power: In turbine operation, gross capacity is measured at the generator's terminals. In a pumped storage station, net capacity is measured at the terminals of the (motor) generator if the facility is operated as a motor. The gross capacity is calculated from net capacity plus own requirements, including

	capacity losses of the machine transformers of the power plant without plant consumption and purchasing for power factor correction. (See VGB PowerTech e.V., Basic Terms of the Electric Utility Industry, 2012)
Gross electricity generation	Electrical energy produced by a generating unit, measured at the generator terminals. (See VGB PowerTech e.V., Basic Terms of the Electric Utility Industry, 2012)
Hub	An important physical node in the gas network where different pipelines, networks and other gas infrastructures come together and where gas is traded.
Intraday trading	On the EEX, transactions involving gas and electricity contracts for supply on the same or following day (see www.eex.com/de).
Investments	Investments are considered to be gross additions to fixed assets capitalised in the year under review and the value of new fixed assets newly rented and leased in the year under review. Gross additions also include leased goods capitalised by the lessee. The gross additions must be notified without deductible input value added tax. The value of internally generated assets as capitalised in the fixed asset account (production costs) is to be included. Notification is also required of assets under construction (work commenced for operational purposes, as far as capitalised). If a special "assets under construction" summary account is kept, notification should be made only of the gross additions without the inventories shown in the account at the beginning of the year under review. Payments on account should be included only if the parts of assets under construction for which they were made have been settled and if they have been capitalised. Not included are the acquisition of holdings, securities etc (financial assets), the acquisition of concessions, patents, licences etc and the acquisition of entire undertakings or businesses and the acquisition of rental equipment formerly used in the undertaking, additions to fixed assets in branch offices or specialist units in other countries and financing charges for investments. (see Institute for Applied Ecology, Combined heat and power agreement, 2012)
Length of circuit	System length (the three phases L1+L2+L3 together) of cables at the network levels LV, MV, HV and EHV (For example: If L1 = 1km, L2 = 1km and L3 = 1km, then the length of the circuit = 1km). In the case of different phase lengths, the average length in kilometres must be determined. The number of cables used per phase is irrelevant for the length of circuit. However, cables leased by, or otherwise made available to the network operator, should be included to the extent they are operated by the network operator. Planned cables, those under construction or leased out and decommissioned cables are not included. Lines in co-ownership should be included with their full number of kilometres to determine the network length. The circuit length at the low voltage network level should include service lines but not the lines of street lighting systems. Lines of more than 36 kV that have a transport function and are subject to a

	high voltage tariff may be considered at the high voltage level.
L-gas (low calorific gas)	A second-family gas with a lower amount of methane (80 to 87 volume percent) and higher volume percentages of nitrogen and carbon dioxide. It has a medium calorific value of 9.77 kWh/m³ and a Wobbe index from 10.5 kWh/m³ to 13.0 kWh/m³.
Load-metered customer	Final customers with an annual electricity offtake exceeding 100,000 kWh, or with a gas offtake exceeding 1.5m kWh per year or more than 500 kWh per hour.
Load-metered final customers	Measurement of the power used by final consumers in a defined period. Load metering is used to establish a load profile showing a final customer's consumption over a defined period. A distinction is made between customers with and customers without load metering.
Market area	Gas A gas market area refers to a consolidation of networks at the same or downstream level in which shippers can freely allocate booked capacity, deliver gas to final consumers and provide gas to other balancing groups.
Market area network operator	The gas transmission system operator operating the top-level pipeline network in a market area. This can also be several network operators jointly covering a market area.
Market coupling	A process for efficient congestion management between different market areas involving several power exchanges. Market coupling improves the use of scarce transmission capacities by taking into account the energy prices in the coupled markets. It involves day-ahead allocation of cross-border transmission capacities and energy auctions on the power exchanges being carried out at the same time based on the prices on the exchanges. For this reason, reference is also made here to implicit capacity auctions.
Market maker	Trading participant who, for a minimum period of time during a trading day, has both a buy and a sell quote in his order book at the same time. Market makers ensure basic liquidity.
Master data	Company data for the successful processing of business transactions. These include contract data such as a customer's name, address and meter number.
Maximum capacity	Capacity at which a generating unit can be operated for a sustained period under normal conditions. It is limited by the weakest part of the plant, determined by measurement and converted to the levels applicable under normal conditions. In the case of a long-term change (eg changes in individual units, changes as a result of ageing), maximum capacity needs to be re-determined. It may deviate from the rated capacity by +/- Δ P. Short downtimes of individual parts of the plant do not result in reduced maximum capacity. (See VGB PowerTech e.V., Basic Terms of the Electric

	Utility Industry, 2012)
Maximum usable volume of working gas	The total storage volume less the cushion gas required.
Metering service	Metering the energy supplied in accordance with verification regulations and processing the metered data for billing purposes.
Natural gas reserves	Secure reserves: in known deposits based on reservoir engineering or geological findings that can be extracted with a high degree of certainty under current economic and technical conditions (90% probability). Probable reserves: a probability level of 50%.
Net capacity	The power a generating unit delivers to the supply system (transmission and distribution networks, consumers) at the high-voltage side of the transformer. It is calculated from the gross capacity less the power consumed by the unit during operation, even if this is not supplied by the generating unit itself but by a different source. (See VGB PowerTech e.V., Basic Terms of the Electric Utility Industry, 2012)
Net electricity generation	A generating unit's gross electricity generation less the energy consumed in the process of generation. Unless otherwise indicated, the net electricity output relates to the reference period. (See VGB PowerTech e.V., Basic Terms of the Electric Utility Industry, 2012)
Net network tariffs	*Electricity* Electricity network tariff excluding billing, metering and meter operation charges. *Gas* Gas network tariff excluding billing, metering and meter operation charges.
Net Transfer Capacity (NTC)	Total transfer capacity less the transmission reliability margin
Netting	Netting (by the TSOs), as far as technically possible, of the capacity requirements of power flows in opposite directions on a congested cross-border interconnection line in order to use this line to its maximum capacity (see Article 6(5) first sentence EC Regulation 1228/2003).
Network area	Entire area over which the network and substation levels of a network operator extend.
Network level	Areas of power supply networks in which electrical energy is transmitted or distributed at extra high, high, medium or low voltage (section 2 para 6 StromNEV) low voltage ≤ 1 kV medium voltage > 1 kV and ≤ 72.5 kV high voltage > 72.5 kV and ≤ 125 kV extra-high voltage > 125 kV

Network losses	The energy lost in the transmission and distribution system is the difference between the electrical energy physically delivered to the system and the energy drawn from the system within the same period. (See VGB PowerTech e.V., Basic Terms of the Electric Utility Industry, 2012)
Nomination	Shippers' duty to notify the network operator, by 2pm at the latest, of their intended use of the latter's entry and exit capacity for each hour of the following day.
Offtake volume	The gas network operators' offtake gas quantities.
OMS standard	Selection of options chosen by the OMS Group from the European Standard 13757-x. This open metering system specification standardises communication in consumption metering.
Operating time	Length of time during which a plant or part thereof converts or transmits energy. Operating time starts when the system is switched on and ends when it or a part of the system is separated from the grid. Start-up and shut-down times with no output of usable energy are not counted as operating time. (See VGB PowerTech e.V., Basic Terms of the Electric Utility Industry, 2012)
OTC trading	Over-the counter or off-exchange trade.
Own consumption	Electrical energy consumed in the auxiliary and ancillary facilities of a generating unit (eg a power generation unit or power plant) for water treatment, water supply to steam generators, fresh air and fuel supply and flue gas cleaning, but excluding the energy consumed in the process of generation. A power plant's own consumption includes step-up transformer (generator transformer) losses, but not, however, the power consumed by auxiliary and ancillary facilities that are not electrically operated; this is covered by the power plant's total heat consumption. A power plant's own consumption during the reference period comprises two elements: own consumption for operations during operating hours and own consumption during idle hours. The latter is not taken into account in the net calculation. (See VGB PowerTech e.V., Basic Terms of the Electric Utility Industry, 2012)
Peak load	Load profile for constant electricity supply or consumption over a period of 12 hours from 8am to 8pm every day of a delivery period. (Eurostat, electricity prices for 2003)
Phelix (Physical Electricity Index)	The Phelix Day Base is the calculated average of the hourly auction prices for hours 1 to 24 every calendar day of the year on the EPEX Spot SE market for the market area of Germany/Austria. The Phelix Peakload Index is based on the hourly prices during peak load hours (8am to 8pm) (see www.eex.com/de).
Physical network congestion	A situation in which demand for supply exceeds the technical capacity at a given point in time.

Pore storage facility	Storage facilities where the natural gas is housed within the pores of suitable rock formations. These are often large in volume but, in comparison to cavern storage, have lower entry and exit capacity and greater cushion gas requirements.
Power plant status	– Reserve capacity power plants: power plants that are operated only at the TSOs' request to ensure security of supply. – Exceptional cases: plants temporarily not in operation (eg owing to repairs following damage) or with restricted operation; – Seasonal mothballing: power plants that are closed during the summer season and fired up again afterwards.
Pulse output	Mechanical counter with a permanent magnet in the counter rotation. May be modified by a synchronising pulse generator (reed contact). Pulse output also includes what is known as a "Cyble meter".
Rated capacity	Maximum capacity at which a plant can be operated for a sustained period under rated conditions at the time of handover. Capacity changes are only permitted in conjunction with major modifications of the rated conditions and structural alterations at the plant. Until the exact rated capacity has been determined, the value ordered in the supply contract should be indicated. If it is unclear whether the value ordered complies with the actual permit and operating conditions expected, a preliminary average rated capacity is to be determined and applied until definitive measurement results are available. The average is to be fixed in such a way that higher or lower production levels, over a normal year, will be offset (eg on account of the cooling water temperature curve). The definitive rated capacity of a power plant unit is determined when the plant has been handed over, usually when the acceptance measurement results are available. It should be noted that the rated conditions apply to an annual average, ie that seasonal changes (for example in the cooling water and air inlet temperature) and internal electrical and steam-side requirements balance out, and that exemplary conditions used in the acceptance test, eg special closed circuit switching, must be converted to normal operating conditions. The rated capacity, unlike the maximum capacity, may not be adjusted to a temporary change in capacity. The rated capacity may not be changed in the case of a reduction in capacity as a result of, or to prevent, damage, nor may it be reduced on account of ageing, deterioration or pollution. Capacity changes require: – additional investment with a view to increasing the plant's capacity, eg retrofitting to enhance efficiency; – the decommissioning or removal of parts of the plant, accepting a loss of capacity; – operation of the plant outside the design range stipulated in the supply contracts

	on a permanent basis, ie for the rest of its life, for external reasons, or – a restriction of capacity, imposed by statutory regulations or orders of public authorities without there being a technical fault in the plant, until the end of its operating life. (See VGB PowerTech e.V., Basic Terms of the Electric Utility Industry, 2012)
Redispatch	The measures to intervene in the market-based operating schedule of generating units to change feed-in. Power plants are instructed by the TSO on the basis of contractual or statutory obligations to reduce/increase their feed-in whilst at the same time other power plants are instructed to increase/reduce their feed-in. These measures have no effect overall on evening out generation and load as it is always ensured that the amounts curtailed are evened out at the physical and balancing level by simultaneous adjustment. Redispatch is to be used by the network operator to ensure the secure and reliable operation of the electricity supply network. This is to prevent overloading of power lines (preventive redispatching) or relieve overloading (curative redispatching). The network operator reimburses the costs incurred by those plant operators involved in redispatch. A distinction is made between electricity-related and voltage-related redispatching. Electricity-related redispatching is used to avoid or relieve sudden overload of lines or substations, whereas voltage-related redispatching is used to maintain the voltage in the network area affected eg by adjusting reactive power. At the same time the active power feed-in from power plants is adjusted so that they can render the necessary reactive power to maintain the voltage. This may involve starting up idle power plants to reach minimum effective power feed-in or reducing feed-in from power plants at full capacity operation to minimum effective power feed-in. The same as for electricity-related redispatch, this provision of reactive power is only used for feed-in priority with respect to conventional power plants For voltage-related redispatching, system balancing measures may even be used with exchange transactions. Redispatching can be an internal measure applicable to one control area only or a wider measure applicable to more than one control area.
Reference period	Total uninterrupted reporting period (calendar period, eg day, month, quarter, year) (see VGB PowerTech e.V., Basic Terms of the Electric Utility Industry, 2012)
Renewable energy surcharge	The surcharge is used to finance the expansion of renewable energies. Renewable energy facility operators that feed electricity into the public grid receive a payment that has been set under the Renewable Energy Sources Act. The TSOs sell the electricity fed in on power exchanges. As the prices obtained on the exchanges are less than the legally set feed-in tariffs, the TSOs are refunded the difference. Alternatively, the electricity produced can be sold directly. The market premium model offsets the difference between the price paid on the exchange and the feed-in tariff by paying a market premium. As an incentive for more facilities to switch from the renewable energy surcharge to directly marketing their electricity, an additional management premium is paid. In other words: Payments to renewable energy facility operators may exceed income from the sale of electricity by up to four times in some cases. The price

	difference is passed on to all electricity consumers by way of the renewable energy surcharge. All electricity consumers pay the renewable energy surcharge as part of the electricity price. The amount of the renewable energy surcharge is set by the TSOs and for 2017 is: 6.88 ct/kWh. The TSOs are required in accordance with section 3(2) of the Ordinance on the Further Development of the Nationwide Equalisation Scheme (AusglMechV) to set and publish the renewable energy surcharge by 15 October each year for the following calendar year. The network operators publish this online at www.eeg-kwk.net.de .
Service and maintenance expense	Expense for any technical, administrative or management measure taken to maintain or restore working order to an asset during its life cycle so that it can perform the function required.
Spot market	Market where transactions are handled immediately.
Standard cubic metre	Section 2 subpara 11 GasNZV defines a standard cubic metre as the quantity of gas which, free of water vapour and at a temperature of 0°Celsius and an absolute pressure of 1.01325 bar, corresponds to the volume of one cubic metre.
Standard load profile customer (SLP)	Electricity Section 12 StromNZV defines standard load profile customers as final customers with an annual offtake of up to 100,000 kWh (electricity) for whom no load profile needs to be recorded by the DSO. (Any deviation to the specific offtake limit may be determined in exceptional cases by the DSOs.) Gas Section 24 GasNZV defines standard load profile customers as final customers with a maximum annual offtake of 1.5m kWh and a maximum hourly offtake of 500 kWh (gas) for whom no load profile needs to be recorded by the DSO. (Any variations above or below these specific withdrawal and offtake capacity limits may be determined by the DSOs.)
Standard supplier	The default supplier (see section 38 Energy Act).
Standard supply	Energy received by final customers from the "general supply" system at low voltage or low pressure and not allocable to a particular delivery or a particular supply contract (see section 38 Energy Act).
Storage facility operator	In this context the term refers to a storage facility operator in the commercial sense. It does not refer to the technical operator, but rather to the company which sells the storage capacities and appears as a market participant.
Supplier switch	This process describes the interaction between market partners when a customer at a metering station wishes to change supplier from the current one to a different one. In principle this does not include cases of first-time moving into premises or moving out of or between premises. This data is compiled and shown separately in the monitoring

	report.
Supplier switch when moving premises	If, when first moving into premises or moving premises, a final consumer (customer) decides on a supplier other than the local default supplier within the meaning of section 36(2) of the Energy Act, this is considered distinct from a supplier switch within the meaning of the GPKE procedures and the GeLi-Gas procedures.
Transformation level	Areas in power supply networks in which electrical energy is transformed from extra high to high voltage, high to medium voltage and medium to low voltage (section 2 para 7 StromNEV). An additional transformation within one of the separate network levels (eg within the medium voltage level) is part of that network level.
Underground storage facilities	These are notably pore, cavern and aquifer storage facilities.
Usage time (final consumers)	Number of days that would be required to withdraw the annual consumption volume by taking off the maximum daily amount (usage time in days equals annual consumption divided by maximum daily amount). Usage time in hours indicates the number of hours required to withdraw the annual consumption volume by taking off the maximum hourly amount (usage time in hours equals annual consumption divided by maximum hourly amount) (see Eurostat's gas prices for 2003)
Virtual point (VP) (also called virtual trading point)	The VP is used as a reference point for settlement in order to represent the gas trading and gas transport transactions within the two-contract model. When gas is injected into a market area, it is available at the VP of that market area and can be traded there as deemed necessary.
Within-day capacity	Capacity of the (current) trading day
Working gas	Gas actually available for withdrawal from a gas storage facility. The formula is: storage volume − cushion gas (volume not available for use) = working gas.

Imprint

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