Bundesnetzagentur Bundeskartellamt

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Report

Monitoring report 2017

Monitoring Report 2017

in accordance with section 63(3) in conjunction with section 35 of the Energy Act (EnWG)
and section 48(3) in conjunction with section 53(3) of the Competition Act (GWB)
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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.

Monitoring Report data origin

Unless otherwise indicated, the figures in this report have been taken from the data collected during the monitoring survey carried out by the Bundesnetzagentur and the Bundeskartellamt. Companies that are active on the electricity or gas market in Germany provide data for the survey on all aspects of the value-added chain (generation, network operation, metering operations, trade, marketing etc.). Further data on trade is supplied by the electricity and gas stock exchanges, and by energy brokers. All the data is checked for plausibility and validated by the Bundesnetzagentur and the Bundeskartellamt. In 2017, overall some 6,500 undertakings supplied data to the two authorities. Thus the degree of coverage in each market segment, as reflected by the level of response, was well over 95% and in many areas it reached 100%. Any discrepancies between this and other data are the result of different data sources, definitions and survey periods.

Foreword

The energy markets in Germany are still going through profound change. Although this trend continued throughout 2016, the main focus shifted somewhat. For instance, electricity generation from onshore wind energy fell unexpectedly due to relatively low winds in 2016. In contrast, following years of declining generation, natural gas-fired power plants produced considerably more electricity than they did in 2015. In particular the retail markets for gas and electricity reflected a positive trend towards even more competition and thus to a greater range of choices and price advantages for final customers.

The Bundeskartellamt and the Bundesnetzagentur have continued their close collaboration on this report. The Bundeskartellamt has focused on the competitive aspects of the electricity and gas value added chains, including delivery to non-household customers whilst the Bundesnetzagentur has directed its attention towards the networks, security of supply and delivery to household customers.

Thanks to the commitment of the companies surveyed, 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 95% and in many areas it very nearly reached 100%.

Domestic electricity generation has increased again, particularly due to a rise in feed-in from natural gas-fired power plants, whereas generation from lignite and black coal has fallen. In addition, the generation sector has been further marked by capacity growth in renewable energy sources while conventional power plant capacity remained virtually constant in 2016. In future the recently introduced auctions for new renewable energy capacity will determine the development of generating capacity in the field of renewables and may lead to lower levels of payment.

Compared with the previous year, in 2016 electricity consumption remained more or less consistent. Likewise, the proportion of electricity in domestic gross electricity consumption originating from renewable energy sources changed only minimally and remained at just over 31%. At the same time, cross-border trade in electricity decreased slightly in volume, although proceeds from the net trade surplus remained practically the same at €1.45bn.

On the whole, there have been further improvements in competitive conditions on the electricity markets. In recent years the market-dominating position of the largest companies for conventional electricity generation has shrunk considerably. In 2016, the degree of market concentration fell even lower, most especially because the ownership of parts of lignite-fired power plants in Germany has changed fundamentally and this has brought about a shift in market shares. Liquidity in the wholesale electricity markets is at its highest level since monitoring began. Average wholesale prices for electricity were still decreasing significantly in 2016, although there were signs of a rise in prices for futures trading at year-end.

Retail markets are still developing very positively. The cumulative market share of the four largest undertakings was again down on the previous year, and it can be assumed that there is no longer any single dominant supplier in the national retail markets for standard load profile and interval metered customers.

The electricity prices collected at the reporting date of 1 April 2017 show that prices for household customers have for the most part remained steady compared with the previous year, and prices for industrial and commercial customers have risen slightly. This rise can largely be attributed to a rise both in surcharges and in network charges. The network charges to be paid by household customers rose on average nearly 9% from 2016 to 2017, with strongly diverging upwards and downwards trends in some networks. The ongoing upwards trend in network charges is likely to be brought to an end by the Network Charges Modernisation Act, or at least temporarily.

Continuous improvement in competitive conditions on the gas markets could also be noted. In 2016, liquidity in wholesale trading in natural gas rose considerably overall, moreover, compared with the previous year; significantly lower wholesale prices were once again reported. The degree of market concentration on the two largest retail gas markets was considerably below the statutory threshold for the presumption of a dominant position in the market and, when compared with the previous year, has decreased markedly. Gas prices for the final user, both household customers and non-household customers, have again, on average, fallen slightly as at 1 April 2017 when compared with the previous year, so the downwards trend in gas prices for final consumers is continuing.

The number of household customers that have switched electricity or gas supplier has risen sharply and has reached the highest number since the start of liberalisation. The supplier switching rate for non-household customers is likewise at an all-time high for electricity. This is also a result of a renewed increase in the number of suppliers.

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. The data in this report show that our efforts are bearing success and that the markets are on the right path as regards competition.

Jochen Homann
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Andreas Mundt
President of the Bundeskartellamt

Key findings

Electricity generation

Germany's net electricity generation increased in 2016 to 600.3 TWh, up 6.0 TWh on the 2015 level of 594.3 TWh. There was a marked year-on-year increase of 37.7% in the amount of electricity generated by natural gas-fired power plants, following several years of declining production, with generation at more or less the same level as in 2012. Generation from virtually all the other non-renewable sources was down on 2015.

The generation landscape was characterised in 2016 by further growth in installed renewable energy capacity. At the end of 2016, renewable capacity had increased year-on-year by 6.7 GW. Altogether, total generating capacity rose from 204.9 GW in 2015 to 212.0 GW in 2016, with 107.5 GW of non-renewable and 104.5 GW of renewable capacity.

The market power of the largest conventional electricity producers (electricity not eligible for payments under the Renewable Energy Sources Act – EEG) has decreased significantly over the last few years. There was a further decline in market concentration in 2016, with the cumulative market share of the then four largest electricity producers in the German-Austrian market having already decreased in the period between 2010 and 2015 from 72.8% to 69.2%. The most recent decline is mainly due to the sale of Vattenfall's lignite activities to LEAG and the associated shifts in market shares: the cumulative market share of 69.4% for 2016 is now spread between five large, independent undertakings. The cumulative market share of the five largest undertakings in only the German market for the first-time sale of electricity – to be considered in light of the plan to split the joint bidding zone – is 76.5%, compared to the four largest undertakings' share of 76.2% in 2015. This indicates a decline in market concentration in this market area as well.

Electricity supply interruptions

In 2016, the average interruption in supply per connected final consumer was 12.80 minutes and thus below the ten-year average from 2006 to 2015 of 15.87 minutes. The quality of supply thus remained at a consistently high level in 2016.

Development of renewable energy generation

The growth in renewable energy capacity of 6.7 GW is due in particular to the continued expansion of onshore wind capacity. Onshore wind recorded a year-on-year increase of 4.2 GW, solar energy 1.5 GW, and offshore wind 0.8 GW.

Onshore wind generation was down by 6.5% on 2015 despite the continued increase in capacity, on account of the relatively low wind levels in 2016. The amount of electricity generated through solar also fell slightly, down 2.1% on a year earlier. There was an increase in offshore wind generation of 3.9 TWh or 48.1%. Total renewable electricity generation thus remained broadly unchanged for the first time ever, up by just 0.2%. Renewable electricity generation was equivalent to 31.2% of gross electricity consumption in 2016. Payments to renewable installation operators under the Renewable Energy Sources Act averaged in 2016 at 15.1 ct/kWh.

Competitive auctions have now been introduced to determine the level of payments for new renewable capacity, and a total of 13 auctions have been held (nine for solar photovoltaic installations, two for onshore wind energy, one for offshore wind projects, and one for biomass plants).

Redispatch and feed-in management

In 2016, reductions in feed-in comprised 6,256 GWh and increases 5,219 GWh, amounting to a total volume of 11,475 GWh, compared to 15,436 GWh in 2015. The reductions in feed-in as a result of redispatch measures corresponded to 1.5% of total non-renewable generation, down from 1.9% in the previous year.

The amount of renewable energy curtailed as a result of feed-in management measures also decreased, down from 4,722 GWh in 2015 to 3,743 GWh in 2016. The sum total of compensation payments made in 2016 – for curtailments in 2016 and previous years – was around €643m, compared to €315m in 2015. Claims for compensation for 2016 are estimated at €373m, compared to €478m a year earlier.

A main factor for the decrease in redispatch and feed-in management measures was the relatively low wind levels in 2016. Overall, an analysis of the annual figures does not indicate any general trend in these measures.

Electricity network charges

The charges for household customers showed an increase, having been broadly stable in the period between 2013 and 2015. The average network charges rose from 1 April 2016 to 1 April 2017 by around 9% to 7.30 ct/kWh. There was also an increase in the network charges for non-household customers: the charges for commercial customers rose by almost 6% to 6.19 ct/kWh, while those for industrial customers with an annual energy consumption of 24 GWh increased by a good 10% to 2.26 ct/kWh.

Wholesale electricity markets

The liquidity of the wholesale electricity markets in 2016 reached its highest level since monitoring began. Volumes in on-exchange futures trading and volumes traded via broker platforms increased significantly, while spot market trading volumes declined.

Average wholesale prices declined further in 2016. The average base price on EPEX SPOT fell by about 8% to €28.98/MWh and thus to its lowest level since 2007. With an average of €26.58/MWh, the Phelix base year future was down by around 14% on the previous year, with a marked low in mid-February 2016 and an increase in the price at year-end. In response to the planned split of the German-Austrian price zone, EEX launched trading in separate power futures for the two countries.

Retail electricity markets

The Bundeskartellamt assumes that there is no longer any single dominant undertaking in either of the two largest electricity retail markets. The cumulative market shares of the four largest undertakings showed a further year-on-year decrease, down to around 28% in the national market for supplying interval-metered customers and 34% in the national market for non-interval-metered customers on special contracts.

The retail markets are continuing to develop very positively. More than 4.6m household customers switched supplier in 2016. This is the highest figure since the start of liberalisation. In addition, almost 2.4m household customers switched tariffs with the same supplier. There was also another increase in the number of undertakings operating in the market. Household customers can choose between an average of 112 different suppliers. At the same time, there was a decrease in the number of customers whose electricity supply was disconnected. In 2016, a total of about 328,000 customers were disconnected, representing a year-on-year decrease of around 31,000.

The supplier switching rate for non-household customers has been fairly constant since 2009. The rate for non-household customers with an annual consumption of more than 10 MWh stood at 12.7% in 2016, compared to 12.6% in 2015.

The average total price (excluding VAT and possible reductions) for industrial customers with an annual consumption of 24 GWh was 14.90 ct/kWh, up 0.69 ct/kWh on the previous year; the increase is mainly accounted for by the network charges and statutory surcharges. The average total price (excluding VAT) for commercial customers with an annual consumption of 50 MWh in April 2017 was 21.70 ct/kWh, representing an increase on the previous year of 0.50 ct/kWh. This rise is largely due to the increase in both the surcharges and the network charges.

The average electricity price for household customers as at 1 April 2017 was broadly unchanged from the previous year. Despite a rise in the network charges and renewable energy surcharge, a decrease of almost 13% in the energy price components prevented a further increase in the overall price. This can be explained by, amongst other things, the increase in the number of customers switching supplier and the continued fall in wholesale prices since 2011. The volume-weighted average across all groups of household customers with an annual consumption of between 2,500 kWh and 5,000 kWh was broadly unchanged from 2016, up only very slightly by 0.06 ct/kWh to 29.86 ct/kWh (including VAT). Taxes, levies, network charges and surcharges make up around 78% of the total price in Germany.

Electric heating

Electric heating prices were slightly higher than in 2016. The arithmetic mean of the gross total price for night storage heating customers as at 1 April 2017 was 20.94 ct/kWh (including VAT), slightly up on the previous year's level of 20.59 ct/kWh. The arithmetic mean of the total price for heat pump customers was 21.65 ct/kWh (including VAT), around 0.7 ct/kWh higher than the price for night storage heating customers and broadly unchanged from the previous year.

There has been a steady increase in switching activity among electric heating customers, albeit at a low level, following many years with hardly any customers switching. The increase in the switching rate indicates a higher degree of competition. Yet at the same time, the switching rates for electric heating customers are still far below those for household electricity and non-household customers. The supplier switching rate for 2016 was around 4%.

Electricity imports and exports

Germany's electricity exports again exceeded its imports in 2016. Whilst total cross-border traded volumes fell from 84.9 TWh in 2015 to 78.1 TWh, there was another small increase in the German export balance from 51.0 TWh in 2015 to 51.9 TWh in 2016.

Gas imports and exports

Gas imports and exports were higher than in 2015. The volume of gas imported into Germany rose by some 89 TWh or around 6% to 1,626 TWh from 1,537 TWh. Gas exports also increased, from 746.3 TWh in 2015 to 770 TWh in 2016, equivalent to a rise of about 24 TWh or 3%.

The main sources of gas imports for Germany remain Russia (Nord Stream, 28%), Norway (19%) and the Netherlands (16%). Exports primarily went to Czechia (46%), the Netherlands (18%) and Switzerland (12%).

Gas supply interruptions

In 2016, the average interruption in supply per connected final consumer was 1.03 minutes per year. The level of gas supply reliability remained at 99.999%.

Market area conversion

The conversion of German L-gas networks to supply H-gas started well in 2015 with the Schneverdingen conversion. This success continued in 2016 in the networks of Stadtwerke Böhmetal, Hilter, Rees, Nienburg/Weser, Gasversorgung Grafschaft Hoya, Gelsenwasser Energienetze (Isselburg, Landesbergen-Brokeloh), Stadtnetze Neustadt am Rübenberge, Achim and some parts of the wesernetz in Bremen. Approximately 114,000 appliances will have been adapted by the end of 2017.

The probable, planned costs of market area conversion were €5.5m for the NetConnect Germany market area in 2016. For the GASPOOL market area, the planned costs amounted to about €18m for 2016.

Gas storage facilities

The market for the operation of underground natural gas storage facilities is still relatively highly concentrated, although less so than in the previous year. The cumulative market share at the end of 2016 of the three largest storage facility operators was down considerably to 68.2% (2015: 73.3%).

The storage year started with rather subdued levels of injections, with one reason being natural gas prices during the period. On 1 October 2017, at the beginning of the 2017/2018 gas year, the total storage level of German storage facilities was around 85% (2016: 95%). The high storage level of the previous year, which had been driven by prices, was not repeated, with a level of over 92% on 1 November 2017.

Wholesale natural gas markets

Overall, the liquidity of the wholesale natural gas markets increased significantly in 2016. There was once again a rise, of about 17%, in volumes of bilateral wholesale trading via broker platforms. On-exchange gas trading volumes were actually up 69%.

2016, the year under review, was again marked by significantly lower wholesale gas prices. The various price indices showed a year-on-year decrease of between 25% and 31%.

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 Monitoring Report 2017 deals with the market concentration of the four largest companies in the retail gas market for the first time, rather than the three largest as in the year before, because there is now another provider with a notable market share. The cumulative market share of the four largest companies in 2016 was around 25% for standard load profile (SLP) customers and about 28% for interval-metered customers. A decline in market concentration may therefore be identified in both areas, since the four largest companies now have a slightly higher market share of SLP customers than the three largest companies had the year before and around the same share of interval-metered customers.

The retail gas market continues to develop very positively. Over 1.5m household customers changed their gas supplier in 2016, equivalent to a notable increase of about 34% over 2015. This is the highest level since the gas market was liberalised. The volume-based switching rate among non-household customers was just over 11% in 2016 (2015: nearly 12%). There were also around 780,000 changes of contract in the year. The diversity of suppliers on the market increased again as well, with household customers being able to choose between an average of 90 different suppliers. At the same time, the number of gas disconnections reduced. In 2016, a total of about 40,000 disconnections were reported, which was down about 5,000 on the figure from 2015.

The noticeable downward trend in consumer gas prices continued. There was a further decrease in the prices paid by industrial customers. The average overall price (excluding VAT) was 0.08 ct/kWh lower at 2.69 ct/kWh, slightly lower (around 3%) than the previous year's figure of 2.77 ct/kWh. The average gas price for an annual consumption of 116 GWh was therefore the lowest ever since the first data on gas prices (as at 1 April 2008) was collected for monitoring reports.

There was also a considerable decrease in the prices paid by commercial customers. The arithmetic mean of the overall price (excluding VAT) of 4.50 ct/kWh is 0.27 ct/kWh or around 5% lower than last year's average price.

Gas prices for household customers as at 1 April 2017 showed a year-on-year decrease. The main reason for this was the significant drop in procurement costs, reflected in the price component "energy procurement, supply and margin". The volume-weighted average across all groups of household customers with average consumption was up 6% or 0.40 ct/kWh to 6.15 ct/kWh (including VAT). Taxes, levies and network charges make up around 50% of the total gas price in Germany.

I Electricity market

A Developments in the electricity markets

1. Summary

1.1 Generation and security of supply

Germany's net electricity generation in 2016 was up 6.0 TWh on 2015 to 600.3 TWh. Generation from non-renewable energy sources increased by 5.6 TWh. There was a significant year-on-year change in generation by natural gas-fired power plants: the amount of electricity generated increased considerably by 18.2 TWh or 37.7% for the first time following several years of declining production and reached the level recorded in 2012. By contrast, generation from virtually all the other non-renewable sources decreased. Nuclear generation was down 6.8 TWh or 8.0% on 2015. Generation by hard coal-fired power plants was down 2.7 TWh or 2.6%. Generation by lignite-fired plants was 2.1 TWh or 1.5% lower.

The market power of the largest electricity producers has decreased significantly over the last few years. In 2010, the cumulative market share of the then four largest electricity producers in the market for the first-time sale of electricity (electricity not eligible for payments under the Renewable Energy Sources Act) in the German-Austrian market area stood at 72.8%, while in 2015 it was just 69.2%. Against the backdrop of the changes among the undertakings in 2016 and the associated shifts in market shares, due in particular to the sale of Vattenfall's lignite activities to LEAG, an analysis of electricity generation and the first-time sale of electricity must now include five – instead of previously four – electricity producers. The cumulative market share of these five largest producers in the market for the first-time sale of electricity in 2016 amounted to 69.4%. Overall, the degree of market concentration is lower since the cumulative market share is now spread between five large, independent undertakings. The cumulative market share of the five largest undertakings in only the German market for the first-time sale of electricity – to be considered in light of the plan to split the joint bidding zone – is 76.5%, compared to the four largest undertakings' share of 76.2% in 2015. This indicates a decline in market concentration in this market area as well.

Several factors besides lower market concentration are leading to a downward trend in market power. In particular, more of the demand for electricity is now covered by renewable energy sources, and the cumulative market share of the largest renewable electricity producers is considerably smaller than that of conventional producers. In addition, the closure of the remaining nuclear power plants by 2022 will lead to changes in the market structure.

Renewable electricity generation was equivalent to 31.2% of gross electricity consumption in 2016, around the same as the 2015 level of 31.4%. Unlike in previous years, net generation from renewables showed only a slight increase of 0.4 TWh or 0.2%. Onshore wind generation fell by 4.6 TWh or 6.5% despite the continued increase in wind generation capacity, on account of the relatively low wind levels in 2016. The amount of electricity generated through solar also fell slightly, down 0.7 TWh on 2015. The largest increase was offshore wind at 3.9 TWh or 48.1%. This is mainly due to the fact that numerous installations were put into operation during 2015, and 2016 was their first whole year of generation, with approximately 2,930 hours.

The generation landscape was characterised in 2016 by a further increase in installed renewable energy capacity. Altogether, growth in renewable capacity amounted to 6.7 GW, compared to 7.5 GW in 2015. Onshore wind and solar energy recorded the highest increases in generating capacity with 4.2 GW and 1.5 GW respectively. Non-renewable generating capacity (nuclear, lignite, hard coal, natural gas, mineral oil products, pumped storage and other non-renewable energy sources) increased slightly in 2016 by 0.4 GW. This is largely due to new natural gas-fired power stations being put into operation. Total (net) installed generating capacity thus increased to 212.0 GW at the end of 2016, with 107.5 GW of non-renewable and 104.5 GW of renewable capacity.

The total installed capacity of installations eligible for payments under the Renewable Energy Sources Act in Germany stood at 99.7 GW at the end of 2016, compared to 92.9 GW a year earlier. This represents an increase of around 6.7 GW or 7.2%. A total of 161.5 TWh of electricity from renewable energy installations received payments in 2016, compared to 161.8 TWh in 2015. Despite the small decrease, payments under the Renewable Energy Sources Act were broadly stable at €24.3bn, up 0.4% on 2015. This can be explained by the fact that the level of payment varies for the different sources of energy. Energy sources eligible on average for lower payments fed in less in 2016 than in 2015, while energy sources eligible on average for higher payments fed in more than in the previous year. In 2016, the average paid to installation operators under the Renewable Energy Sources Act was 15.1 ct/kWh.[1] Unlike previous years, 2016 was the first year in which the majority of the payments – 52% – were made to installation operators eligible for market premiums.

Following the amendment to the Renewable Energy Sources Act at the end of 2016/beginning of 2017, the level of payment for around 80% of new renewable capacity is now determined through competitive auctions for the different sources of energy. Installations must bid successfully in the auctions to receive payments under the Act.

The auctions for solar photovoltaic installations have so far been marked by a high level of competition. The average volume-weighted award price fell in each successive auction from 9.17 ct/kWh to under 5 ct/kWh. The two auctions held for onshore wind energy (together comprising a total volume of 1,800 MW) were also significantly oversubscribed. Citizens' energy companies showed a strong presence in these first two auctions, accounting for more than 90% of the successful bids in each case. The average volume-weighted award price fell from 5.71 ct/kWh in the first auction to 4.28 ct/kWh in the second. In the auction held in April 2017 for offshore wind farm projects, four bids for projects with a total capacity of 1,490 MW were accepted. The prices awarded ranged from 0.00 ct/kWh to 6.00 ct/kWh. In the auction for biomass plants, all the bids submitted together comprised a volume of 40,912 kW, which was considerably lower than the volume available of 122,446 kW. The average volume-weighted award price was 14.30 ct/kWh. In the first joint auction for ground-mounted solar photovoltaic systems in Germany and Denmark, all of the successful bids were for Danish projects.

In 2016, the average interruption in supply per connected final consumer was 12.80 minutes and thus below the ten-year average from 2006 to 2015 of 15.87 minutes. The quality of supply thus remained at a consistently high level in 2016.

1.2 Cross-border trading

Electricity exports again exceeded imports in 2016. Despite the overall decrease in trading volumes, Germany forms the hub for electricity exchange in Europe and plays a key role within the central interconnected system. The average available transmission capacity to and from Germany's neighbouring countries was largely stable in 2016.

[1] The average is calculated by dividing the total sum paid under the Renewable Energy Sources Act in a year by the total amount of renewable electricity fed in during that year.

Total cross-border traded volumes fell from 84.9 TWh in 2015 to 78.1 TWh in 2016, a decrease of 8%. This reflects a decline of 22.6% in imports from 16.9 TWh in 2015 to 13.1 TWh, while exports also fell 4.4% from 68 TWh in 2015 to 65 TWh. Overall, there was a small increase of 1.6% in the German export balance from 51.0 TWh in 2015 to 51.9 TWh in 2016.

1.3 Networks

1.3.1 Grid expansion

Based on the third quarterly report for 2017, 1,000 km of the total of about 1,800 km of power lines listed in the Power Grid Expansion Act (EnLAG) have been approved, with around 750 km of these – about 40% of the total – completed. A further 600 km or so of lines are at the regional planning and planning approval stage. The transmission system operators (TSOs) anticipate that some 80% of the line kilometres listed in the Act will be completed by 2020. So far, none of the underground cable pilot lines have been put into full operation. Operational testing is in progress for the first 380 kV underground cable pilot project in Raesfeld.

Alongside monitoring the projects in the Power Grid Expansion Act, the Bundesnetzagentur publishes quarterly updates on the status of the expansion projects listed in the Federal Requirements Plan Act (BBPlG). These projects currently comprise lines with a total length of some 5,900 km. At the third quarter of 2017, around 450 km had been approved and about 150 km of these completed. A further 2,400 km or so of lines are at the federal sectoral planning stage with the Bundesnetzagentur and around 600 km are at the regional planning and planning approval stage with the federal state authorities.

1.3.2 Investments

In 2016, investments in and expenditure on network infrastructure by the four German TSOs amounted to €2,439m, compared to €2,358m in 2015 (both values under commercial law).[2] Investments in new builds, upgrades and expansion projects fell slightly from €1,672m in 2015 to €1,636m in 2016. The investments and expenditure incurred by the distribution system operators (DSOs) rose from €6,845m in 2015 to €7,157m in 2016. There was a further increase in the number of DSOs carrying out measures to enhance, reinforce or expand their networks as at 1 April 2017.

1.3.3 Network and system security and system stability

The redispatching measures taken by the TSOs serve to maintain network and system security. A measure can be any action taken to ease restrictions on a network element. The reductions in feed-in as a result of redispatching measures corresponded to 1.5% of total non-renewable generation, down from 1.9% in the previous year. In 2016, reductions in feed-in comprised 6,256 GWh and increases 5,219 GWh, amounting to a total volume of 11,475 GWh, compared to 15,436 GWh in 2015.

Overall, redispatching measures amounted to 13,339 hours, representing a decrease from 15,811 hours in 2015. Since all measures taken to ease restrictions in the network and thus measures taken in parallel are recorded, the

[2] Investments and expenditure are defined in the glossary. The values under commercial law do not correspond to the implicit values included in the system operators' revenue cap in accordance with the provisions of the Incentive Regulation Ordinance (ARegV). A comparative calculation of the values under commercial law with the values from incentive regulation will be able to be made following the introduction of an index-based investment monitoring pursuant to section 33(5) ARegV. Medium to long-term trends can be derived from the evaluations on the basis of the survey of commercial values. The introduction of an index-based investment monitoring pursuant to section 33(5) ARegV is currently being prepared by the Bundesnetzagentur taking account of the effort required for companies to transmit data.

sum of the hours in which measures were taken cannot be put in relation to the total number of 8,760 hours in a year. In 2016, redispatching measures were taken by the operators on a total of 329 days.

This represents a decrease of around a quarter compared to 2015, although the volume remains high compared to the years preceding 2015. The TSOs put the costs of system services for redispatching measures in 2016 at around €220m. As in the previous years, the measures primarily concerned the TenneT and 50Hertz control areas, with the line between Remptendorf and Redwitz, the area around the line from Vierraden to Krajnik in Poland, and the Brunsbüttel area (north of Hamburg) the most affected.

The amount of renewable energy curtailed as a result of feed-in management measures also decreased from 4,722 GWh in 2015 to 3,743 GWh in 2016. This corresponds to 2.3% of the total amount of renewable energy generated, compared to 2.9% in 2015. The sum total of compensation payments increased significantly from €315m in 2015 to €643m in 2016. In total, claims for compensation from installation operators for 2016 are estimated at €373m. The discrepancy between the figures is due to the fact that the compensation paid in 2016 does not reflect the compensation for energy curtailments in 2016 but includes compensation paid for curtailments in previous years.

In 2016, as in the previous years, feed-in management measures primarily involved wind power plants, accounting for 94.4% of the total amount of curtailed energy, up from 87.3% in 2015. Solar was the second leading energy type affected in 2016 by curtailments, with a share of almost 5%.

In 2016, a total of four DSOs and one TSO took non-renewable energy adjustment measures for which no compensation is paid. The measures taken to adjust electricity feed-in and offtake totalled around 14.4 GWh.

In total, the costs for network and system security[3] fell by about €243m from €1,133m in 2015 to around €890m in 2016. This is primarily due to the reduction in the number of network and system security measures taken in 2016, which was in turn due to the weather.

In 2016, the grid reserve was used on 108 days to provide an average capacity of 552 MW and a total of around 1,209 GWh of energy.

1.3.4 Network charges

There was a significant increase in the network charges (including billing, metering and meter operation charges) for household customers. The charges for non-household customers were also up on a year earlier. The network charges (including billing, metering and meter operation charges) for commercial customers increased by almost 6% or 0.34 ct/kWh and those for industrial customers by a good 10% or 0.20 ct/kWh. The charges as at 1 April 2017 for the three consumption groups were as follows:

- household customers (default supply), annual consumption 2,500-5,000 kWh: 7.30 ct/kWh;

- commercial customers, annual consumption 50 MWh: 6.19 ct/kWh;

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

– industrial customers, annual consumption 24 GWh, without a reduction under section 19(2) of the Electricity Network Charges Ordinance (StromNEV): 2.26 ct/kWh.

There are large regional differences in the network charges. A comparison of the network charges in Germany for the three consumption groups, based on all the TSOs' published price lists (charges including billing but excluding metering and meter operation), shows the following: the network charges for household customers range from just over 3 ct/kWh to 11.7 ct/kWh; the range of network charges for commercial customers is similar to that for household customers, with charges ranging from 2.8 ct/kWh to 10.4 ct/kWh; and the network charges for industrial customers range from around 1 ct/kWh to 6.6 ct/kWh.

1.4 System services

The net costs for system services in a broader sense[4] fell by €339m from €1,800m in 2015[5] to €1,461m in 2016. These figures for the first time also include the estimated claims from installation operators for compensation for feed-in management measures as costs for system services in a broader sense. A large part of the total costs is accounted for by the costs of reserving and using grid reserve power plants at around €285m (2015: €219m), national and cross-border redispatching at just under €220m (2015: €412m), reserving primary, secondary and tertiary balancing capacity at €198m (2015: €316m), energy to compensate for losses at about €305m (2015: €277m), and the estimated claims from installation operators for compensation for feed-in management measures in 2016 at around €373m (2015: €478m).

The structure of the system service costs changed in 2016 from 2015. The total net costs for balancing fell again, this time by €118m. One reason for this fall is the further slight decrease in the volume of the three types of balancing reserve. The costs for energy to compensate for losses in 2016 were up around €27m on 2015. One of the reasons for this increase was that additional energy was needed at short notice to compensate for energy lost in transport.

1.5 Wholesale

Well-functioning wholesale markets are vital to competition in the electricity sector. Spot and futures markets are crucial for meeting suppliers' short and longer term electricity requirements. Electricity exchanges play a key role alongside bilateral wholesale trading (over-the-counter trading, or OTC). They create a reliable trading forum and at the same time provide key price signals for market players in other areas of the electricity industry.

Overall, the liquidity of the wholesale electricity markets in 2016 reached its highest level since monitoring began. Volumes in on-exchange futures trading and volumes traded via broker platforms increased significantly, while spot market trading volumes declined. The volume of day-ahead trading on EPEX SPOT in 2016 was around 235 TWh, significantly down on the previous year's volume of 264 TWh. By contrast, the volume of intraday trading rose, with a substantial increase of around 3 TWh or 9% to 41 TWh. The volume of day-ahead trading on EXAA remained stable at around 8 TWh in 2016. The on-exchange trading volumes of Phelix futures increased significantly again, following considerable growth in the previous years: volumes rose in 2016 by 56% from 937 TWh to over 1,466 TWh.

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[4] TSOs' system services and TSOs' and DSOs' feed-in management measures.

[5] This figure has been adjusted to include the estimated claims from installation operators for compensation for feed-in management measures taken by the TSOs and DSOs.

Average spot market prices declined further in 2016. The Phelix day base average on EPEX SPOT fell by about 8% from €31.63/MWh in 2015 to €28.98/MWh and thus to its lowest level since 2007. At €32.01/MWh, the Phelix day peak was also nearly 9% below the previous year's level of €35.06/MWh. The gap between the Phelix day base and the Phelix day peak was €3.03/MWh in 2016 and thus again down on the previous year. As a result, the average Phelix day peak in 2016 was just 10% higher than the Phelix day base (compared to 21% in 2008).

The annual averages of the Phelix future prices fell again compared to a year earlier, despite an increase in the price at the end of the year. With an average of €26.58/MWh in 2016, the Phelix base year future was down by €4.40/MWh or around 14% on the previous year's average of €30.97/MWh, with a marked low in mid-February 2016 and an increase in the price at year-end. The price of the Phelix peak front year future averaged €33.51/MWh over the year. This was €5.55/MWh or around 14% down on the previous year's average of €39.06/MWh. Compared to the historic high of 2008, the base and peak front year future prices have continued their downward trend.

In response to the planned split of the German-Austrian price zone, EEX launched trading in separate power futures for the two countries. EEX launched Phelix-DE futures for the German market area in April 2017 and separate Phelix-AT futures for the Austrian market area on 26 June 2017. It also introduced trading in options on Phelix-DE futures.

1.6 Retail

There was another increase in the number of electricity suppliers available to retail customers. In 2016, final consumers could choose between an average of 130 suppliers in each network area (not taking account of corporate groups). The average number of suppliers for household customers was 112.

The number of household customers switching supplier has increased significantly since 2006. The number of switches reached a new high of about 4.6m in 2016, up by around 595,000 on the previous year's figure of 4m. In addition, almost 2.4m household customers switched contracts with the same supplier. In 2016, a relative majority of household customers – 40.9% compared to 43.1% in 2015 – were on non-default contracts with their regional default supplier. The percentage of household customers on default contracts stood at 30.6%, representing another year-on-year decrease from 32.1% in 2015. 28.6% of all household customers are now served by a supplier other than their regional default supplier, compared to 24.9% in 2015. There was a corresponding increase in the percentage of customers who no longer have a contract with their default supplier. Overall, around 71.5% of all households are served by their default supplier (under either default or other contracts). Thus the strong position held by default suppliers in their respective service areas weakened again in 2016.

By contrast, default suppliers play a relatively small role in serving non-household customers. Around 70% of the total amount of electricity delivered to interval-metered customers in 2016 was supplied by a legal entity other than the regional default supplier, while only about 30% was supplied under non-default contracts by the default supplier. Less than 1% of all interval-metered customers are on standard contracts with their default supplier. The supplier switching rate for non-household customers in 2016 was about 13%, the highest since monitoring began in 2006.

The Bundeskartellamt assumes that there is no longer any single dominant undertaking 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 decreased further, down three percentage points on 2015 to 28%. The cumulative share in the national market for supplying non-interval-metered customers on special contracts[6] (above all household customers, excluding electric heating customers) stood at 34%, down two percentage points on a year earlier. These figures are clearly below the statutory thresholds for the presumption of market dominance (section 18(4) and (6) of the Competition Act – GWB).

There was a slight decrease in 2016 in the number of electricity customers whose supply was disconnected. The number of household customers whose supply was disconnected by the network operator at the regional default supplier's request fell by 13,000 to 318,469. For the first time, the DSOs were also asked to provide the number of customers not with their regional default supplier whose supply they had disconnected, and reported around 12,000 disconnections. According to the suppliers, a total of about 328,000 customers across all types of contract (default and non-default) were disconnected in 2016, representing a decrease of some 31,000. Suppliers issued around 6.6m disconnection notices to household customers. Of these, about 1.2m were subsequently passed on to the relevant network operator with a request for disconnection. These figures are based on data provided by 770 DSOs and 962 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 20,200 prepay systems were installed in 2016.

Electricity prices for non-household customers as at 1 April 2017 showed a year-on-year increase. 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 lower prices for electricity-intensive undertakings. There was a minimal decrease in the arithmetic mean of the price component that is controlled by the supplier for customers with an annual consumption of 24 GWh ("industrial customers") and not eligible for any statutory reductions, falling from 3.48 ct/kWh to 3.41 ct/kWh, down by 0.07 ct/kWh compared to the previous year's decrease of 0.71 ct/kWh. By contrast, there was an increase in the surcharges. These totalled 7.08 ct/kWh – with the renewable energy surcharge alone at 6.88 ct/kWh – and were thus 0.58 ct/kWh up on a year earlier. The average net network charge was 2.23 ct/kWh, up by around 10% on the previous year's level of 2.03 ct/kWh. The average total price (excluding VAT and possible reductions) was 14.90 ct/kWh, up 0.69 ct/kWh on the previous year; the increase is mainly accounted for by the network charges and statutory surcharges.

The average total price (excluding VAT) for non-household customers with an annual consumption of 50 MWh ("commercial customers") in April 2017 was 21.70 ct/kWh, representing an increase on the previous year of 0.50 ct/kWh. This rise is largely due to the increase in both the renewable energy surcharge and the network charges. This is also reflected in the shares of these price components in the total price. The renewable energy surcharge now accounts for 32% of the total price, compared to 30% a year earlier, while the net network charge accounts for 27% compared to 26% in the previous year. As a result, the price components not controlled by the supplier (network charges, metering, surcharges, electricity tax and concession fees) now amount to around 78% of the total price for commercial customers, compared to 76% a year earlier.

In 2017, data was collected from the suppliers operating in Germany on the prices for household customers. As in the previous year, there was a small increase in the prices. As at 1 April 2017, the average price for household customers on default contracts with an annual consumption of between 2,500 kWh and 5,000 kWh had risen

[6] The term "special contract" appears in section 1(4) of the Electricity and Gas Concession Fees Ordinance (KAV). The term continues to be of importance in calculating concession fees and has already been the subject of abuse proceedings and sector inquiries (electric heating). The terms default (and fallback) supply and "special contract" are relevant to market definition under competition law and will continue to be used because they are defined in law.

slightly by around 1% from 30.63 ct/kWh in 2016 to 30.94 ct/kWh (including VAT). Prices for the other two customer groups – those on other contracts with their default supplier and those with another supplier – also increased slightly. Electricity prices for customers on other contracts with their default supplier and with an annual consumption of between 2,500 kWh and 5,000 kWh averaged 29.61 ct/kWh and for customers with another supplier 29.12 ct/kWh. The volume-weighted average across all three groups for an annual consumption of between 2,500 kWh and 5,000 kWh was 29.86 ct/kWh (including VAT). This figure is calculated by weighting the individual prices for the three groups according to their consumption, producing a reliable average for the electricity price for household customers. There were further increases in particular in the renewable energy surcharge and the net network charge. The price components not controlled by the supplier (taxes, levies, surcharges and network charges) amount to about 78%. The competitive component of the electricity price found in "energy procurement, supply and margin" accounts for around 22% of the average total price.

As at 1 April 2017, there was another decrease in this price component, falling by around 13% or 0.93 ct/kWh from 7.35 ct/kWh to 6.42 ct/kWh and leading to a dampening effect on overall prices. This further decrease across all types of contract for household customers could be related in particular to the continued low level of wholesale prices and the increase in the number of customers switching supplier.

As a rule, customers on default contracts can make savings by switching contract and even more by switching supplier, saving up to 1.34 ct/kWh and 1.82 ct/kWh respectively.[7] Household customers with an annual consumption of 3,500 kWh could consequently cut their energy costs by around €47 or €64 per year. Special bonuses offered by suppliers, including one-off bonus payments, are an added incentive for customers to switch. One-off bonus payments for customers switching to special contracts with their regional default supplier average at €50, and those for customers switching to a non-default supplier at €62.

According to Eurostat, there are large differences throughout Europe in the price of electricity for household customers. At 29.77 ct/kWh, Germany has the second highest price after Denmark of the 28 EU Member States.[8] German prices are about 45% higher than the European average of 20.54 ct/kWh. Germany's comparatively high price is due according to Eurostat to its higher proportion of surcharges, taxes and levies.

Eurostat publishes price data for non-household customers in seven different consumption bands. The statistics show that the price of electricity for instance for industrial customers with an annual consumption of between 20 GWh and 70 GWh varies considerably between the different European countries. The net price in Germany excluding taxes and levies is 5.28 ct/kWh, nearly 1 ct/kWh below the European average of 6.25 ct/kWh; non-recoverable surcharges, taxes and levies average at 4.37 ct/kWh, nearly twice the European average of 2.25 ct/kWh. The total net price for Germany of 9.65 ct/kWh is higher than the average in Europe of 8.50 ct/kWh.

There has been a continued increase in the low-level switching activity of electric heating customers, following many years with hardly any customers switching. The DSOs have reported a steady increase in the number of customers switching supplier. In the reporting year, around 91,350 electric heating meter points with a total electricity consumption of around 583 GWh changed supplier. This was the equivalent of 4.4% of meter points and 4.2% of consumption, compared to 2.8% and 2.7% a year earlier. The increase in the switching rate indicates a

[7] Savings based on an annual consumption of between 2,500 kWh and 5,000 kWh.

[8] The European comparison is based on prices calculated by Eurostat. The price for household customers therefore differs from the volume-weighted price given in this report.

higher degree of competition. The last two years have seen an increase in transparency for end customers and in the services offered by national electric heating suppliers. Consumers can now find locally available suppliers more easily, for instance by using internet portals, looking in consumer magazines or obtaining information from the consumer advice centres. Yet at the same time, the switching rates for electric heating customers are still far below those for household electricity and non-household customers.

Electric heating prices were broadly unchanged from the previous year. The arithmetic mean of the gross total price for night storage heating customers as at 1 April 2017 was 20.94 ct/kWh (including VAT), slightly up on the previous year's level of 20.59 ct/kWh. The arithmetic mean of the total price for heat pump customers was 21.65 ct/kWh (including VAT), around 0.7 ct/kWh higher than the price for night storage heating customers and broadly unchanged from the previous year.

1.7 Digital metering

The Metering Act (MsbG), a key element of the Energy Transition Digitisation Act, sets out new rules for meters and metering in Germany, making the rollout of modern metering equipment and smart metering systems mandatory throughout the country. The monitoring survey was adapted to take account of the introduction of the new technology. In 2016, there were no smart metering systems available in the market, thus the condition for the Federal Office for Information Security (BSI) to determine technical availability – market availability of systems from at least three independent manufacturers – was not met. Nor was any modern metering equipment available in the market in 2016. Whilst the beginning of 2017 saw the first modern metering equipment being installed by various network and meter operators, the rollout of smart metering systems is no longer expected to begin before year-end, since no BSI-certified smart meter gateways are yet available in the market. The BSI has therefore not yet been able to determine technical availability in accordance with section 30 of the Metering Act; this first requires the availability of systems from at least three independent manufacturers and would then mark the start of the mandatory rollout of smart metering systems.

However, in light of the statutory requirements set out in the Metering Act and advances in metering technology, a large-scale rollout of modern metering equipment and smart metering systems is expected in the coming years.

2. Network overview

The network balance provides an overview of supply and demand in the German electricity grid in 2016. Total electricity supply was 625.9 TWh, comprising a net total of electricity generated of 600.3 TWh (including 9.9 TWh from pumped storage) and imports through physical flows amounting to 25.6 TWh. Total electricity consumption from the general supply networks was 488.1 TWh, comprising 475.6 TWh for final consumers and 12.5 TWh for pumped storage stations. The amount of energy consumed by pumped storage stations is higher than the amount generated because of the electricity needed for the pumping process (energy industry use). The net total of electricity generated but not fed into the general supply networks (industrial, commercial and domestic own use) was 36.9 TWh. Distribution and transmission losses amounted to 26 TWh and exports through physical flows 74.5 TWh. The sum of the individual entries for demand is 625.5 TWh. The difference between this and the total supply of 625.9 TWh is 0.4 TWh or 0.06%. Supply and demand are therefore almost completely balanced. The minimal difference of 0.4 TWh is due to the complex structure of the data survey involving a large number of different market players.

Network balance: 2016

	TSOs	DSOs	Total
Total net nominal generating capacity as at 31 December 2016 (GW)			212,0
Facilities using non-renewable energy sources			107,5
Facilities using renewable energy sources			104,5
Generation facilities eligible for payments under the Renewable Energy Sources Act			99,7
Total net generation 2016 (including electricity not fed into general supply networks) (TWh)			600,3
Facilities using non-renewable energy sources			420,0
Facilities using renewable energy sources			180,3
Generation facilities eligible for payments under the Renewable Energy Sources Act			161,5
Net amount of electricity not fed into general supply networks 2016 (TWh)[1]			36,9
Losses (TWh)	8,4	17,6	26,0
Extra high voltage	6,7	0,0	6,7
High voltage (including EHV/HV)	1,7	2,9	4,6
Medium voltage (including HV/MV)	0,0	5,9	5,9
Low voltage (including MV/LV)	0,0	8,8	8,8
Cross-border flows (physical flows) (TWh)			100,1
Imports			25,6
Exports			74,5
Consumption (TWh)[2]	38,2	449,9	488,1
Industrial, commercial and other non-household customers	26,5	329,4	355,9
Household customers	0,0	119,7	119,7
Pumped storage	11,7	0,8	12,5

[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 1: 2016 Network balance based on data from TSOs and DSOs

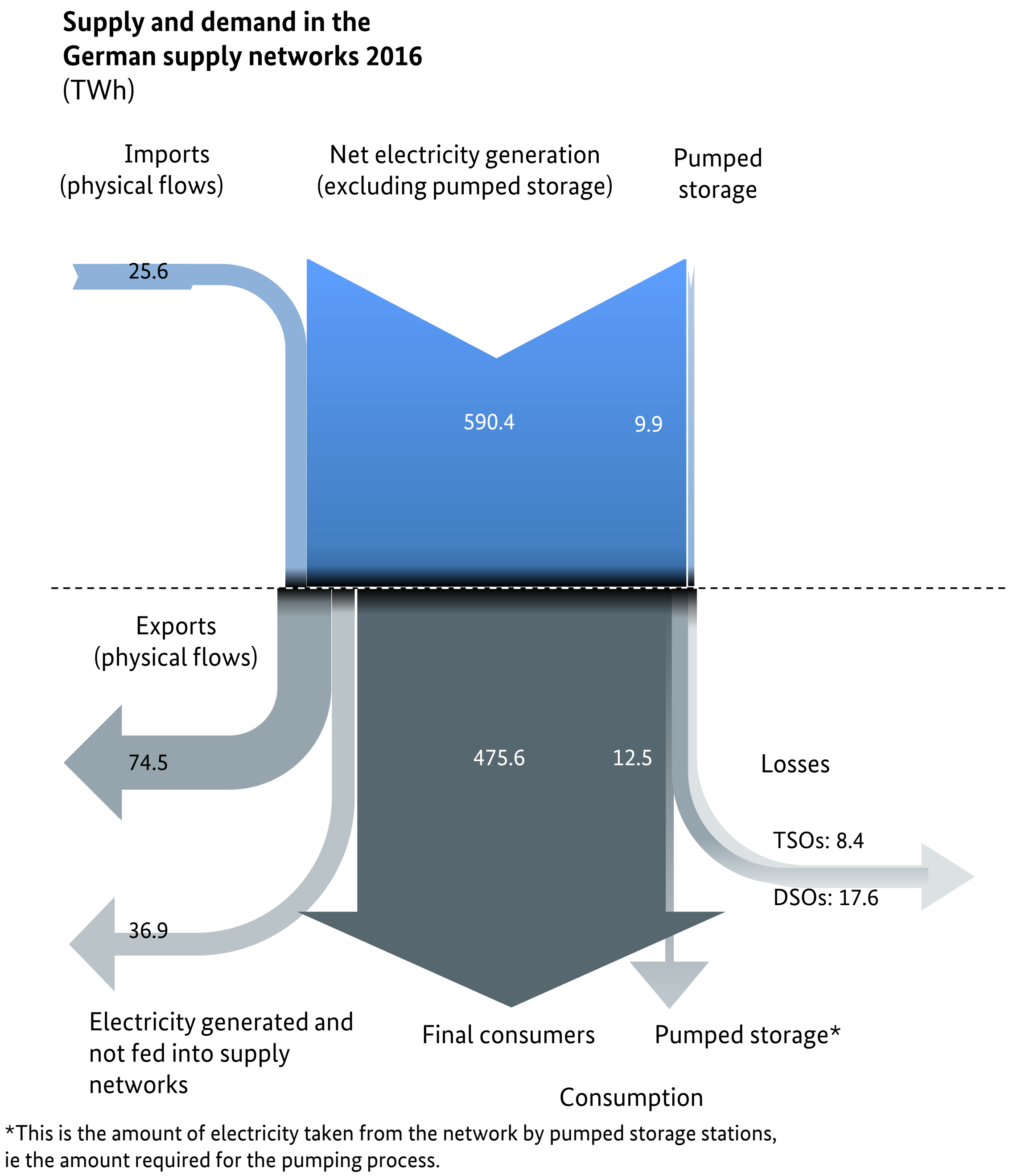

Figure 1: Supply and demand in the German supply networks: 2016

The four German TSOs took part in the 2017 monitoring survey. The TSOs' total circuit length (overhead lines and underground cables) as at 31 December 2016 was 36,597 km (see Table 2).

This represents an increase of 596 km on 2015. The total number of meter points in the four TSOs' network areas was 537, all of which were interval-metered, i.e. average consumption was recorded at least quarter hourly. The offtake of the 146 final consumers connected to the TSOs' networks totalled 26.5 TWh as at 31 December 2016, representing a year-on-year decrease of around 1 TWh.

Network structure figures 2016

	TSOs	DSOs	Total
Network operators (number)	4	829	833
Total circuit length (km)	36,597	1,807,575	1,844,172
Extra high voltage	36,214	179	36,393
High voltage	383	96,366	96,749
Medium voltage		520,326	520,326
Low voltage		1,190,704	1,190,704
Total final consumers (meter points)	537	50,714,468	50,715,005
Industrial, commercial and other non-household customers		3,107,959	3,107,959
Household customers		47,606,509	47,606,509

Table 2: 2016 network structure figures based on data from TSOs and DSOs

As at 10 November 2017, a total of 879 electricity DSOs were registered with the Bundesnetzagentur, 829 of whom were included up to 31 July 2017 in the data analysis for the Bundesnetzagentur's 2017 monitoring report.[9] According to these 829 DSOs, the offtake of the 49,961,844 final consumers connected to the DSOs' networks totaled 448 TWh in 2016, a decrease of about 0.5 TWh on the previous year.

The DSOs' total circuit length (overhead lines and underground cables) at all network levels as at 31 December 2016 was 1,807,575 km. The total number of meter points supplied in the DSOs' network areas was 50,714,468, including 368,226 interval meters and 47,606,509 meter points for household customers as defined in section 3 para 22 of the Energy Industry Act (EnWG).

The majority of the DSOs included in the data analysis (628 or 78%) have networks with a short to medium circuit length (lines and cables) of up to 1,000 km. These DSOs serve 7.4m or 15% of all meter points in Germany. 178 DSOs have networks with a total circuit length of more than 1,000 km, supplying 43.1m or about 85% of the total number of meter points. Figure 2 shows a breakdown of DSOs by circuit length.

[9] The figures for total circuit length and final consumers are not directly comparable with the figures from previous years because of the steady increase in the number of DSOs participating in the monitoring survey over the years.

DSOs by circuit length
(number and percentage)

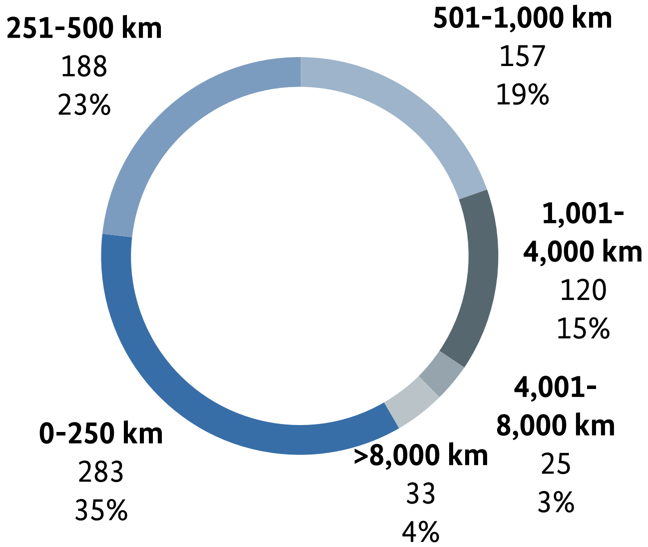

Figure 2: Number and percentage of DSOs by circuit length based on data from DSOs

TSOs and DSOs in Germany

	2009	2010	2011	2012	2013	2014	2015	2016	2017
Total TSOs	4	4	4	4	4	4	4	4	4
Total DSOs	862	866	869	883	883	884	880	875	878
DSOs with fewer than 100,000 connected customers	787	790	793	807	812	812	803	798	797

Table 3: Number of TSOs and DSOs in Germany: 2009-2017

Table 4 shows the consumption of electricity in 2016 by final consumers in the network areas of the TSOs and DSOs participating in the survey. Overall, final electricity consumption in Germany in 2016, based on consumption at meter points in the general supply networks, was virtually unchanged from the previous year at 475.6 TWh compared to 475.9 TWh in 2015.

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 1.4% on a year earlier. Smaller non-household customers (annual consumption >10 MWh and ≤2 GWh) accounted for almost 27% of total consumption in 2016, up by a good 3% on the previous year. 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 25.2% of total consumption in 2016, representing a slight year-on-year decrease of 0.8%. 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 76% or 38.6m of all meter points. Figure 3 shows a breakdown of DSOs by the number of meter points supplied.

Final consumption by customer category

Category	TSOs (TWh)	DSOs (TWh)	TSOs + DSOs (TWh)	Percentage of total (%)
≤10 MWh/year	0	119.7	119.7	25.2
10 MWh/year - 2 GWh/year	0.1	127.8	127.9	26.9
>2 GWh/year	26.4	201.6	228.0	47.9
Total	26,5	449.1	475.6	100.0

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

DSOs by number of meter points supplied

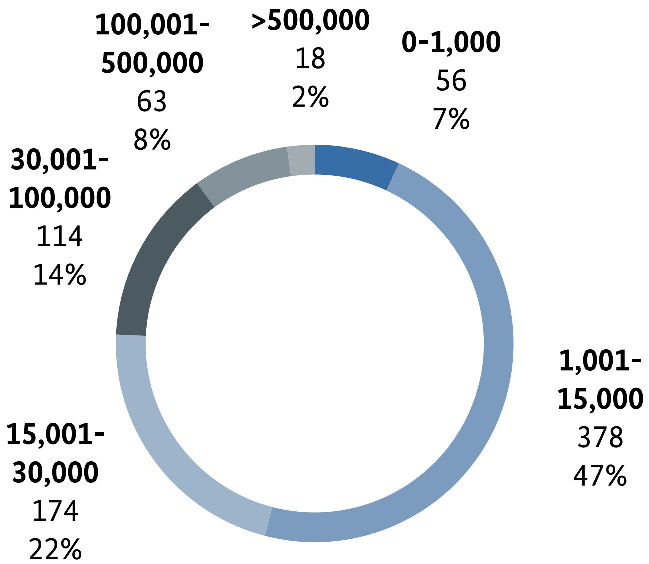

Figure 3: DSOs by number of meter points supplied based on data from DSOs

3. Market concentration

The degree of market concentration is determined by the market share distribution of the players on the market concerned. Market shares are a useful reference point for estimating market power because they represent the extent to which demand in the relevant market was actually satisfied by one company during the reference period. [10]

However, an extensive analysis of market power is currently not being carried out in the course of energy monitoring. According to the practice of the Bundeskartellamt, such an analysis would include a residual supply analysis with regard to electricity generation.[11] In future, the Bundeskartellamt will compile a report on competitive conditions in the electricity generation sector in accordance with Section 53 GWB as amended by the Electricity Market Act.[12] This report will build on the data collected by the Market Transparency Body for Electricity/Gas and will be published at least every two years independently of the annual Monitoring Report, if necessary.

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 (known as "concentration ratios", CR3 – CR4 – CR5). The larger the market share covered by only a few competitors, the higher the market concentration.

In previous reporting years – and as a result of the historically evolved structure of the power markets – the points of reference for the analysis of power generation, first-time sales of electricity and end customer supply were the four strongest power producers RWE AG, E.ON SE, EnBW AG and Vattenfall GmbH, which far surpassed other producers with regard to power generation capacities and electricity volumes fed into the grid (CR 4).

However, power generation underwent significant changes on the supplier side in 2016.

- RWE outsourced network operations, renewable energies and electricity and gas sales to its new subsidiary innogy SE on 1 April 2016. The subsidiary was listed on 7 October 2016 with RWE continuing to hold around 77 per cent of the shares (the remaining shares are in a free float with a single-digit percentage range). In view of the majority participation, it is currently safe to assume that this constitutes a company group (RWE has sole control of innogy); innogy is also fully consolidated in RWE's consolidated balance sheet for 2016. This internal process was not subject to merger control.

- E.ON outsourced large parts of its former core business – conventional power generation (excluding nuclear power plants), energy wholesale trading and gas production – to its new subsidiary Uniper AG, which was listed on the exchange on 12 September 2016. E.ON is the largest direct shareholder of Uniper with a share of around 47 per cent; the remaining 53 per cent of Uniper shares are in a free float (institutional investors, private investors). In 2016, the calculation of the market shares was still based on the rules applying to company groups because E.ON was the sole shareholder of Uniper for the bigger part of the year and the

[10] Cf. Bundeskartellamt, Guidance on Substantive Merger Control, para. 25.

[11] Cf. Bundeskartellamt, Sector Inquiry Electricity Generation and Wholesale Markets, 2011, p. 96 ff. (in German)

[12] Section 2 of the Act on the Further Development of the Electricity Market, Federal Law Gazette. I 2016, 1786, 1811. Cf. the legislative intent, Bundestag Printed Paper 18/7317, 134.

largest shareholder for the remaining part of the year.[13] There is also likely to be a high level of agreement among shareholders because E.ON shareholders became Uniper shareholders with the same proportion of shares on 12 September 2016.[14] This deconcentrating process was not subject to merger control.

– Vattenfall completely divested itself of its lignite business in Lusatia, which accounted for almost half of its conventional power generation capacities in Germany, on 1 October 2016. The business was purchased by the Czech energy supplier Energetický a Průmyslový Holding (EPH) and PPF Investments, which each hold 50 per cent of the shares and therefore have joint control of Vattenfall Europe Mining AG (lignite extraction, renamed as Lausitz Energie Bergbau AG) and Vattenfall Europe Generation AG (power generation, renamed as Lausitz Energie Kraftwerke AG).[15] The whole lignite business in Lusatia will operate under the name LEAG in future.[16]

In light of the changes on the supplier side in 2016, especially the sale of Vattenfall's lignite operations to LEAG, the current CR 4 analysis of power generation and first-time sales of electricity is no longer appropriate. As a result of the transaction, Vattenfall's market shares almost halved in terms of capacities to the benefit of LEAG and consequently market shares on the supply side shifted to such an extent that the market leader RWE has now been joined by four other major power producers with almost the same market shares. These four producers are far ahead of their nearest competitors on the market. Since there is no longer a basis for the current CR 4 analysis or a CR 3 analysis, the analysis of power generation and first-time sales of electricity for 2016 will be based on the five largest power producers RWE, E.ON/Uniper, EnBW, Vattenfall and LEAG (CR 5).

This report examines the market concentration on the economically significant market for the first-time sale of electricity (power generation) and on the two largest retail markets for electricity. The market shares on the retail markets are estimated using the "dominance method". The market shares on the market for the first-time sale of electricity are calculated on the basis of competition law principles, which produces more accurate results (for details of the differences between the two calculation methods see the box below).

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[13] Although E.ON has no longer held a majority stake with 47 per cent of the shares since then, it can be expected to exercise over 50 per cent of Uniper voting rights in light of the actual presence at shareholder meetings. This is due to the fact that around 11 per cent of the shares are held by private investors who, as past experience has shown, are less likely to attend shareholder meetings.

[14] E.ON shareholders were issued with Uniper shares at a ratio of 10:1 on this date.

[15] Cf. COMP/M.8056 – Vattenfall/EPH of 22 September 2016.

[16] Cf. https://www.leag.de/de/geschaeftsfelder/, retrieved on 12 September 2017

Calculation of group market shares under competition law vs. calculation of market shares using the “dominance method”

For the calculation of market shares one first has to define which companies (legal entities) are to be considered as affiliated companies and consequently as a corporate group. This implies 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) of the German Competition Act, GWB). The concept aims to establish whether a dependent or controlling relationship exists between companies. The turnover or sales of each controlled company are fully attributed to the company group; the sales of a company that is not controlled are not added to the company group’s sales (not even on a pro-rata basis). A typical example of a controlling relationship is a scenario where the majority of the voting rights in an affiliated company are held by another company. Controlling relationships may also arise for other reasons, for example, personal ties or a controlling agreement. 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 a consortium agreement), each of them is considered a controlling company. Investigating and assessing which companies belong to a certain group under these principles can sometimes be rather time-consuming.

For this reason, group membership is predominantly assessed in the course of energy monitoring by applying the considerably simpler “dominance method”. The sole aim of this method is to establish whether one shareholder holds at least 50 per cent of the shares in a company. If a single shareholder holds more than 50 per cent of a company’s shares, that company’s sales will be fully attributed to this shareholder. If two shareholders each hold 50 per cent of a company’s shares, they will each be attributed 50 per cent of the sales. If there is only one shareholder holding 50 per cent of the shares with all other shareholders holding shares of less than 50 per cent, half of the sales will be attributed to the largest shareholder; the remaining shares will not be attributed to any of the remaining shareholders. If no shareholder holds a share of 50 per cent or more, the company’s sales will not be attributed to any shareholder (in this case, the company will be the parent company).

In the case of majority shareholding, the two calculation methods usually produce the same results. However, a controlling relationship can also occur under a minority shareholding and would not be identified as such through the dominance method. A calculation of market shares using the dominance method therefore tends to underestimate the market shares of the strongest company groups, particularly, when there are strong joint ventures active in the market.

3.1 Power generation and first-time sale of electricity

The Bundeskartellamt defines a relevant product market for the first-time sale of electricity. In its case practice, the Bundeskartellamt has most recently applied the following criteria for the calculation of market shares[17]:

The market shares are assessed according to feed-in quantities (not capacities). Electricity remunerated according to the fixed remuneration system under the Renewable Energy Sources Act (EEG) or according to historically sometimes optional direct marketing was most 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.[18] Electricity from renewable energy resources is generated and fed into the grid regardless of the demand situation and electricity wholesale prices. Renewable power plant operators are not subject to competition from the other ("conventional") electricity suppliers. In case of purchase rights, the corresponding volumes or capacities are attributed not to the power plant owner but to the owner of the purchase rights, provided the owner has control over the use of the power plant and bears the risks and rewards of marketing the electricity.[19] Only electricity volumes that are fed into the general supply grid will be taken into consideration. In other words, electricity fed into closed distribution networks, electricity for own consumption and traction current are not included in the market for the first-time sale of electricity. In geographical terms, the Bundeskartellamt defines the market for Germany and Austria as a single market.[20] The main reasons for this are that no NTC value is currently being recorded at the interconnections between the two countries and, in particular, that there is a common price zone – with inevitably uniform prices – for the German-Austrian electricity wholesale trade at present. Such conditions currently do not exist in other neighbouring countries.[21]

As described above, data on the electricity capacities and volumes generated by the five – instead of last year's four – strongest companies (RWE, E.ON/Uniper, EnBW, Vattenfall and LEAG) was additionally collected on the basis of these definitions in the course of this year's energy monitoring. Data on the overall market was extracted from monitoring questionnaires completed by producers and network operators. In addition, the Austrian energy regulator E Control has provided aggregate data for Austria.

The results of the survey on power generation volumes are shown in the table below, which also includes data from the previous year collected on the same basis for comparison. It should be noted that the figures from 2015 and 2016 are not directly comparable because the analysis now includes five instead of four suppliers.

[17] Cf. Bundeskartellamt, Decision of 8 December 2011, B8-94/11, RWE/Stadtwerke Unna, para. 22 ff. (in German)

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

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

[20] The consequences of potential congestion management at the German-Austrian border for the geographical market definition should be examined on the basis of its impact on the market.

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

Electricity volumes generated by the four or five largest electricity producers based on the definition of the market for the first-time sale of electricity

	Germany + Austria 2015		Germany + Austria 2016		Germany 2015		Germany 2016	
	TWh	**Market share**	**TWh**	**Market share**	**TWh**	**Market share**	**TWh**	**Market share**
RWE	127.5	29.6%	134.0	31.7%	125.1	32.2%	130.8	33.5%
Vattenfall[1]	83.1	19.3%	66.8	15.3%	83.1	21.4%	66.8	17.7%
EnBW[2]	49.0	11.4%	47.3	10.8%	49.0	12.6%	47.3	12.1%
E.ON/Uniper	38.9	9.0%	37.2	8.5%	38.6	9.9%	36.9	9.4%
LEAG[3]	-	-	17.3	4.0%	-	-	17.3	4.4%
CR 4 (2015) CR 5 (2016)	298.5	69.2%	302.6	69.4%	295.8	76.2%	299.1	76.5%
Other companies	132.6	30.8%	133.5	30.6%	92.4	23.8%	92.0	23.5%
Total net electricity generation	431.1	100%	436.1	100%	388.2	100%	391.1	100%

[1] Vattenfall transferred its lignite business in Lusatia to LEAG on 1 October

[2] EnBW data includes EEG electricity for direct marketing

[3] LEAG data includes lignite operation in Lusatia between 1 October and 31 December only

Table 5: Electricity volumes generated by the four or five largest German power producers based on the definition of the market for the first-time sale of electricity (i.e. excluding EEG electricity, traction current, electricity for own consumption)

The aggregate market share of the five strongest companies (CR 5) on the market for the first-time sale of electricity in the German/Austrian market area was around 69.4 per cent in 2016 (69.2 per cent for the CR 4 in 2015). With an increased market volume of around 5 TWh, the market shares of E.ON/Uniper and EnBW fell slightly while RWE's market share rose by 1.1 percentage points. Vattenfall's market share declined significantly from 19.3 per cent to 15.3 per cent. The analysis of this change in market share has to take account of the transfer of the Lusatia lignite business on 1 October 2016. The feed-in volumes of the lignite business were included in the calculation of Vattenfall's market share only until 1 October 2016. The calculation of LEAG's market share, in turn, included only the feed-in volumes from 1 October 2016 until the end of 2016. LEAG's market share is therefore underrepresented in terms of capacities while Vattenfall's market share is overstated.

While the feed-in volumes from renewable energy resources rose steadily over the last six years, other power generation volumes and the volume of the market for the first-time sale of electricity as defined above decreased over the same period.

The total volume of the market for the first-time sale of electricity in the German/Austrian market area increased slightly by 5 TWh year-on-year to 436.1 TWh in 2016. The share of this volume generated in Germany rose by 2.8 TWh to 391.1 TWh. At the same time, the total Austrian volume for 2016 increased by 2.2 TWh to 45 TWh. The generation volumes of the now five largest suppliers on the market for the first-time sale of electricity grew by around 4.1 TWh or 0.5 percentage points overall.

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

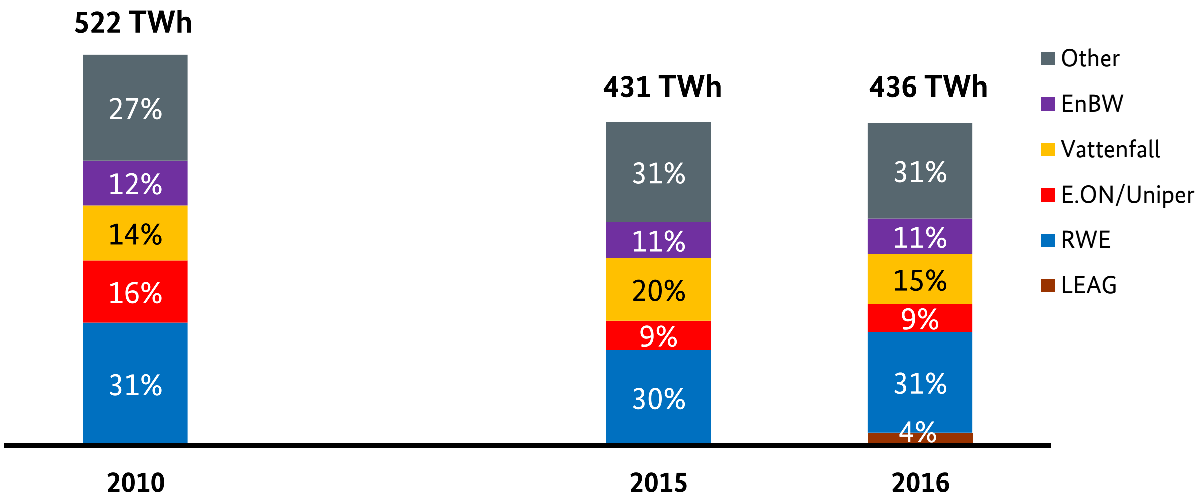


Figure 4: Share of the five strongest companies on the market for the first-time sale of electricity

The five companies' shares of the German/Austrian generation capacities available for use on the market for the first-time sale of electricity (i.e. excluding EEG capacities, traction current, closed power plants or plants not feeding into the general supply grid) was 56.6 per cent, down slightly from 58.2 per cent in the previous year. In 2015, the analysis was still based on four power producers, the current – and smaller – capacity share of 56.6 per cent is now spread across five power producers. The degree of market concentration has consequently decreased.

The total amount of power generation capacity available in Germany and Austria grew by 2 GW year-on-year. One notable factor is that the capacities attributable to RWE increased by 0.4 GW while those attributable to EnBW and E.ON/Uniper declined by 0.2 GW. Vattenfall's shares were reduced by half due to the sale of its lignite business in Lusatia – and hence its power plants – to LEAG.

Generation capacities of the four or five largest German electricity producers based on the definition of the market for the first-time sale of electricity (excluding EEG electricity, traction current)

	Germany + Austria 31 Dec 2015		Germany + Austria 31 Dec 2016		Germany 31 Dec 2015		Germany 31 Dec 2016	
	GW	Market share	GW	Market share	GW	Market share	GW	Market share
RWE	27.2	24.2%	27.6	24.1%	26.0	27.4%	26.2	27.0%
Vattenfall	16.7	14.8%	8.3	7.3%	16.7	17.5%	8.3	8.6%
EnBW[1]	11.9	10.6%	11.7	10.2%	11.9	12.6%	11.7	12.1%
E.ON/Uniper	9.7	8.6%	9.5	8.2%	9.6	10.1%	9.3	9.6%
LEAG	-	-	7.8	6.8%	-	-	7.8	8.0%
CR 4 (2015) CR 5 (2016)	65.5	**58.2%**	64.9	**56.6%**	64.2	**67.6%**	63.4	**65.3%**
Other companies	47.2	41.8%	49.8	43.4%	30.9	32.4%	33.7	34.7%
Total capacity	112.7	100%	114.7	100%	95.1	100%	97.1	100%

[1] EnBW data includes EEG capacities

Table 6: Generation capacities of the four or five largest German power producers based on the definition of the market for the first-time sale of electricity

To sum up, it can be said that, in terms of generation volume, the market for the first-time sale of electricity continues to be concentrated with a CR 5 of 69.4 per cent (69.2 per cent for the CR 4 in 2015). However, the cumulative market shares are now spread across five – instead of four – large, mutually independent suppliers. As a result, the degree of market concentration has decreased overall. Besides the decline in market concentration, there are a number of other factors that have led to a downward trend in market power. Power generation capacities in Germany and Europe have invariably exceeded the demand for electricity for years. In addition, an increased share of the demand for electricity is covered by the feed-in of renewable energy.

The degree of market concentration is further qualified by the generation and first-time sale of electricity from plants that are eligible for payments under the Renewable Energy Sources Act ("EEG electricity"), which suppresses demand on the market for the first-time sale of electricity described above because of the priority feed-in and the pricing structure. However, electricity remunerated according to the fixed remuneration system under the Renewable Energy Sources Act (EEG) or according to historically sometimes optional direct marketing is still not included in the calculation of the market shares on the market for the first-time sale of electricity. The reason is that the generation and feed-in of electricity from renewable energy resources is not subject to competition on the market for the generation and sale of other, largely conventional electricity.

This Monitoring Report for the first time contains surveys on the five producers' market shares in EEG power generation in order to provide a rough estimate of the effects on the degree of market concentration. In line with the survey on the generation and first-time sale of conventional electricity, the producers were this time also asked about their generation volumes and capacities of EEG electricity, which were then put in relation to the overall market data. The five large suppliers' market shares in the generation of EEG electricity are substantially below those of conventional power generation. Their share of the German/Austrian market area amounted to around 6 per cent of the generation volume in 2016. They also accounted for around 3 per cent of capacities in 2016.

The improved use of transmission capacities for electricity imports as a consequence of increased market coupling can help limit the scope of action on the market for the first-time sale of electricity. These additional aspects are not reflected in the market shares illustrated but would be taken into consideration in an extensive analysis of market power, particularly, in a residual supply analysis. With regard to the future, it should ultimately also be borne in mind that the decommissioning of existing German nuclear power plants envisaged for 2022 at the latest, is one of the factors that will bring about further 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. They are generally industrial or commercial customers. Standard load profile customers are consumers with relatively low levels of consumption. They are usually household customers and smaller commercial customers. The distribution of these customers' electricity consumption over specific time intervals is based on a standard load profile.

The Bundeskartellamt most recently defined a Germany-wide market for the supply of electricity to metered load profile customers. The Bundeskartellamt has until now differentiated between three product markets for the supply of standard load profile customers: (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, definition as a national market).[22] Since the EnWG no longer uses the term "special contract customers" in this sense, the relevant contracts are referred to as "special contracts" only in the context of market definition under competition law. For the purpose of the Monitoring Report, these contracts will otherwise be referred to as "contract with the default supplier outside the default supply" or as "contract with a supplier who is not the local default supplier".[23]

In energy monitoring, the sales volumes of individual suppliers (legal entities) are collected as national total values. In the case of standard load profile customers, a differentiation is made between electric heating, default

[22] Cf. Bundeskartellamt, Decision of 30 November 2009, file reference, B8-107/09; Integra/Thüga, para. 32 ff. (in German)

[23] The term "special contract" is used in Section 1 (4) of the Electricity and Gas Concession Fees Ordinance (KAV). The term continues to be important for the calculation of the concession fee and has also been the subject of abuse proceedings and sector inquiries (electric heating). The terms "default (and auxiliary) supply" and "special contract" are appropriate for the purpose of market definition in terms of competition law and will continue to be used because they are legally defined.

supply and supply under a special contract. The following analysis is based on data from around 1,150 electricity providers (legal entities). The same number of providers responded in 2015.

In 2016, around 266 TWh of electricity were sold to metered load profile customers and around 161 TWh of electricity to standard load profile customers, almost the same volumes as in the previous year. 14 TWh of the total sales to standard load profile customers consisted of electric heating, 38 TWh went to standard load profile customers with default supply contracts and 108 TWh to standard load profile customers with special contracts.

In contrast to the generation and first-time sale of electricity, the changes among the large suppliers did not have a significant effect on the market shares relating to the supply of final consumers of electricity so that the current CR 4 analysis continues to be appropriate. Based on the data provided by the individual companies, it was determined which sales volumes were attributed to the four strongest companies. The sales volumes were aggregated using the "dominance method" according to the calculation method described above. This provides sufficiently accurate results for the purpose of this analysis. With regard to data on percentages, it should be borne in mind that the monitoring survey of the electricity suppliers does not cover the entire market. The quoted percentages therefore merely approximate the actual market shares.

In 2015, the four strongest companies sold a total of around 75 TWh on the German market for the supply of electricity to metered load profile customers. The aggregated market share of the four companies (CR 4) is therefore around 28 per cent in this sector. In the previous year, the CR 4 still sold as much as 82 TWh, which was equivalent to a share of 31 per cent. There has been another decline in the market shares of the CR 4 on the metered load profile customer market. This figure is 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 2016, the cumulative sales of the four strongest companies on the German market for the supply of standard load profile customers with special contracts (outside the default supply and excluding electric heating) amounted to around 36 TWh – down from 38 TWh in the previous year. The aggregated market share of the four companies (CR 4) therefore amounts to around 34 per cent on this market, down from 36 per cent in 2015. This figure 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 German market for the supply of standard load profile customers with special contracts (excluding electric heating).

In the default supply sector, the cumulative domestic sales of the CR 4 was around 15.8 TWh of the total default supply volume of standard load profile customers, which amounted to around 38.4 TWh. The share of the CR 4 was therefore around 41 per cent. With regard to the supply of standard load profile customers with electric heating, the CR 4 maintained their relatively strong position. The cumulative sales of the CR 4 are around 8.9 TWh of the total 14.4 TWh of electric heating (night storage heaters and heat pumps). As a result, the CR 4 account for around 62 per cent. The shares of sales to all standard load profile customers, i.e. including electric heating customers and default supply customers, can also be calculated on the basis of the monitoring data. The total values thus determined do not correspond to the Bundeskartellamt's definition of a product market but are merely meant to indicate the size of the shares of the strongest companies in a national analysis involving all standard load profile customers. The volume of electricity supplied by the four strongest companies to all standard load profile customers was around 62 TWh, which is equivalent to an aggregate share of around 38 per cent. The volume of electricity supplied by the CR 4 was still 41 per cent in 2015. The share in relation to all standard load profile customers is higher than in the analysis based solely on 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 – as illustrated above – tend to account for higher shares of the German sales volumes than in the area of special contracts for standard load profile customers with special contracts, excluding electric heating.

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

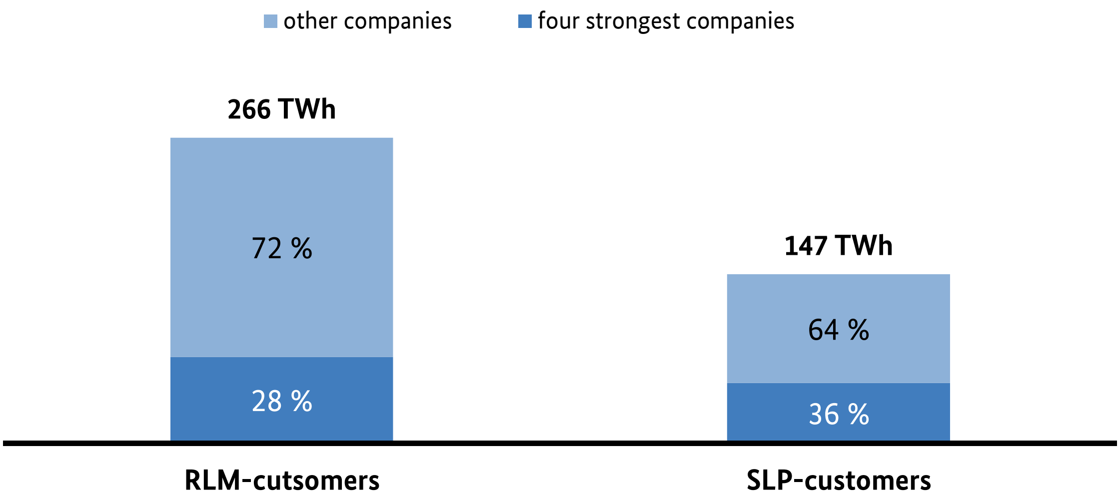


Figure 5: Share of the four strongest companies in the sale of electricity to metered load profile (RLM) and standard load profile (SLP) customers in 2016

B Generation

1. Existing capacity and development of the generation sector

1.1 Net electricity generation 2016

Net electricity generation increased in 2016 by 6.0 TWh to 600.3 TWh. In contrast with previous years, in 2016 for the first time capacity from renewables rose only slightly despite the continuing expansion of generation from renewable energy sources (see "Development of renewable energies" on page 64 onwards). With regard to non-renewable energy sources, generation increased in 2016, after falling in the previous two years, by 5.6 TWh to 420.0 TWh. Electricity generation from renewable energy sources increased by 0.4 TWh (0.2%) from 180.0 TWh in 2015 to 180.3 TWh in 2016. Renewables' share of net electricity generation was 30.0% in 2016. The share of renewables in the gross electricity consumption in 2016 was 31.2%. The "Development of renewable energies" chapter on page 68 onwards contains a detailed analysis of the annual energy feed-in entitled to payments under the EEG and its development.

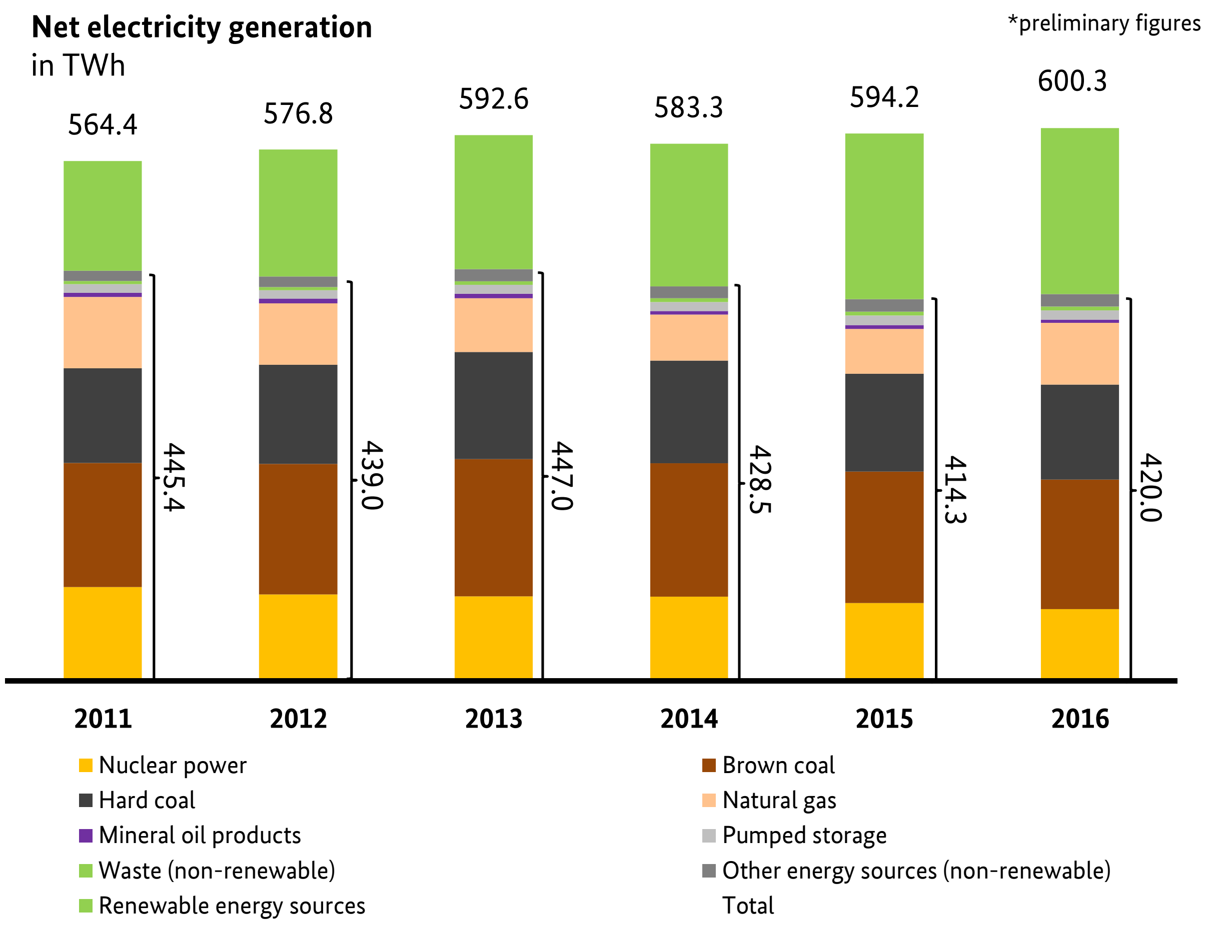


Figure 6: Development of net electricity generation

Electricity generation from non-renewable energy sources increased by 5.7 TWh on the previous year (+1.4%) from 414.3 TWh to 420.0 TWh (cf Figure 6). Feed-in from natural gas power plants increased sharply for the first time after years of declining generation with 37.7% more electricity being generated than in 2015. At 66.9 TWh, electricity generation from natural gas power plants was at much the same level as in 2012 (66.6 TWh). In contrast, with the exception of the energy source waste, generation from all other non-renewable energy sources declined. Generation from black coal power plants fell by 2.7 TWh (-2.6%) to 103.3 TWh. The Grafenrheinfeld nuclear power plant ceased producing electricity in 2016. Until its closure in 2015 it had continued generating electricity through to the middle of the year. For this reason, generation from nuclear power plants fell by 6.8 TWh or 8.0% to 78.3 TWh in 2016. As in the two previous years, generation from lignite-fired power plants decreased again in 2016. This decline was due primarily to the transfer of the lignite-fired plant Buschhaus to security standby status on 1 October 2016. Generation fell by 2.1 TWh (-1.5%) to 140.3 TWh.

Net electricity generation 2011 - 2016
in TWh

	2011	2012	2013	2014	2015	2016
Nuclear	102.4	94.2	92.1	91.8	85.1	78.3
Lignite	134.2	141.5	148.7	144.5	142.5	140.3
Black coal	103.1	107.7	116.4	111.6	106.1	103.3
Natural gas	77.1	66.6	58.4	50.0	48.6	66.9
Mineral oil products	4.7	5.0	4.6	3.8	4.3	3.6
Pumped storage	9.1	8.9	9.7	9.5	10.1	9.9
Waste (non-renewable)	3.7	3.8	3.9	4.3	4.2	4.3
Other energy sources (non-renewable)	11.1	11.2	13.1	12.9	13.4	13.5
Total of non-renewable energy sources	445.4	439.0	447.0	428.5	414.3	420.0
Renewable energy sources	119.0	137.8	145.6	154.8	180.0	180.3
Total	564.4	576.8	592.6	583.3	594.2	600.3
Renewables' share of net electricity generation	**21%**	**24%**	**25%**	**27%**	**30%**	**30%**

*preliminary figures

Table 7: Net electricity generation

There were several reasons for the sharp increase compared to previous years in feed-in from natural gas power plants. One cause is the change in prices of black coal and natural gas. Falling gas prices on future and spot markets contrasted with rising black coal prices. These differences in fuel prices make at least modern gas fired power stations increasingly competitive with inefficient black coal power plants. In addition, increasing fluctuation in the feed-in of renewable energies tends to result in higher load gradients. Flexible, non-volatile power plants, such as gas fired power stations, are ideal for covering such peak demand.

1.2 CO2 emissions from electricity generation in 2016

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 in 2016. For CHP plants, operators only had to supply data on the share of CO2 attributable to electricity generation. Table 8 contains the results of the survey of power plant operators.

CO_2 emissions from electricity generation in 2016

	CO_2 emissions in 2015 t million	CO_2 emissions in 2016 t million	Change in t million
Lignite	163.0	158.6	-4.4
Black coal	97.2	89.6	-7.6
Natural gas	17.9	24.9	7.0
Mineral oil products	2.3	1.9	-0.4
Waste	6.9	7.6	0.7
Other energy sources[1]	13.8	17.3	3.5
Total	301.1	299.9	-1.2

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

Table 8: CO2 emissions from electricity generation in 2016

According to the data provided by operators of power plants, total CO_2 emissions in 2016 were in the same range as in 2015 (-1.2m tonnes of CO_2). Compared to the first survey in 2015, an improvement in reporting behaviour could be observed. Companies' return rate, particularly for waste and other energy sources, has risen again compared to 2015 when the survey was first performed. According to the data provided by the power plant operators, lignite-fired plants emitted 158.6m tonnes of CO_2 emissions, which made up over half of all CO_2 emissions from electricity generation in 2016 (52.9 %). This means that a smaller volume of CO_2 was emitted from lignite-fired plants than in 2015 (163.0m tonnes). Black coal-fired power plants emitted 97m tonnes of CO2, or 7.6m tonnes less than in 2015. In contrast, CO_2 emissions from natural gas-fired power plants rose by 17.9m tonnes of CO_2 in 2015 to 24.9m tonnes of CO_2 in 2016. The combination of lower CO_2 emissions from black coal-fired power plants and higher emissions from gas-fired power plants is the result of less electricity being generated by black coal-fired power plants and more by gas-fired power plants (see the "Net electricity generation 2016" chapter on page 48). The remaining 26.8m tonnes of CO_2 are distributed across mineral oil-fired power plants (1.9m tonnes), waste to energy power plants (7.6m tonnes) and other energy sources (17.3m tonnes).

It should be noted that the data submissions from power plant operators do not include CO_2 emissions from generating facilities with under 10 MW of net nominal capacity. Reporting behaviour for the energy source waste was better than in 2015 but still relatively heterogeneous; this may be due in part to difficulties in correlating the CO_2 emissions to the non-biogenic share of generation, among other factors.

1.3 Generating capacity in Germany

In 2016, as in previous years, electricity generation was marked by an increase in capacity from renewables. Total (net) installed generation capacity[24] rose by 7.2 GW from 204.9 GW (at the end of 2015) to 212.0 GW at the end of 2016.[25] Of this 107.5 GW was non-renewable and 104.5 GW renewable energy capacity.

Renewables grew by 6.7 GW compared to 7.5 GW in 2015. As at the end of 2016 the share of installed capacity from renewables in the total installed energy capacity was around 49.3%. Compared to 2011 (the year in which figures were first recorded for comparison purposes) installed capacity increased by 38.0 GW; this is equal to an increase in installed capacity of renewable energy sources in the total installed energy capacity of around 10 percentage points. The "Development of renewable energies" chapter on page 65 onwards contains a detailed analysis of the installed capacity of installations entitled to payments under the EEG and its development.

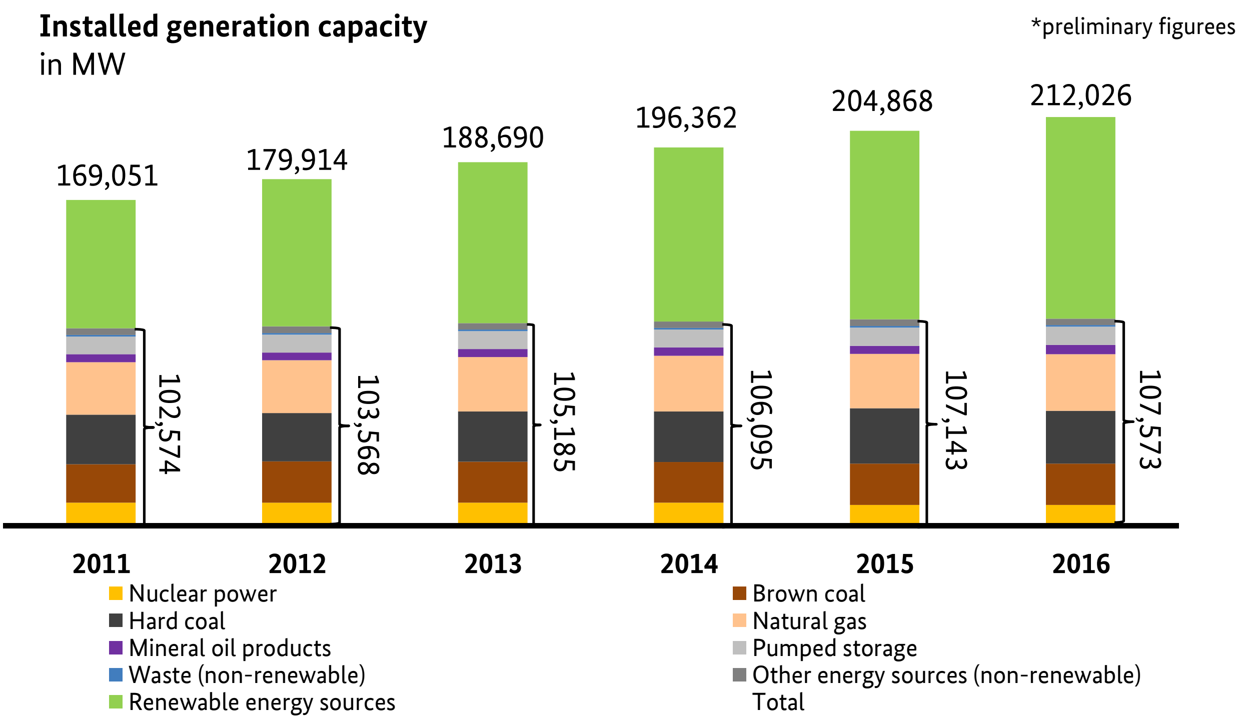


Figure 7: Development of installed electrical generating capacity (nominal net capacity) as at 31 December 2016

Capacity from non-renewable sources increased in 2015 by 0.4 GW, as is shown in Table 9. This capacity growth in non-renewables is mainly due to the use of natural gas (including the commissioning of the power plants GuD in Düsseldorf and Niehl 3 in Mittelsbüren), which has increased by 2.5 GW. Black coal generating capacity fell for the first time since 2012. This competitive decline was due in particular to the closures of the Westfalen C and Hafen power plants in Bremen. The electrical generating capacity of black coal increased between 2012 and 2016, largely due to the commissioning of power plants planned prior to the phasing out of nuclear energy.

[24] Total installed generation capacity figures include power plants which are not currently operating in the electricity market (power plants which cannot be closed by law and temporarily closed plants).

[25] The total installed generating capacity figures include (pumped storage and hydro) capacity of 4.6 GW in Luxembourg, Switzerland and Austria feeding into the German grid.

Installed generation capacity, 2011 - 2016
in MW

	2011	2012	2013	2014	2015	2016
Nuclear	12,068	12,068	12,068	12,068	10,800	10,800
Lignite	19,847	21,266	21,206	21,068	21,419	21,359
Black coal	25,724	25,177	25,964	26,210	28,654	27,419
Natural gas	27,249	27,378	28,389	29,019	28,359	29,614
Mineral oil products	4,166	4,136	4,136	4,236	4,196	4,691
Pumped storage	9,229	9,234	9,234	9,245	9,442	9,440
Waste (non-renewable)	831	852	861	869	883	885
Other energy sources (non-renewable)	3,460	3,457	3,327	3,380	3,390	3,372
Renewable energy sources*	66,477	76,346	83,533	90,267	97,725	104,453
Total of non-renewable energy sources	102,574	103,568	105,185	106,095	107,143	107,580
Total	169,051	179,914	188,718	196,362	204,868	212,033
Renewables' share of total electricity generation	**39%**	**42%**	**44%**	**46%**	**48%**	**49%**

* preliminary figures for 2016

Table 9: Installed electrical generating capacity (net nominal capacity)

Capacity from non-renewable sources fell in 2017 by 2.8 GW due to the closure of black coal power plants in Voerde, Herne and in Marl, as well as of the power station using mineral oil in Brunsbüttel. There are no more current monthly or quarterly data available for installations using renewable energy sources which are entitled to payments under the EEG; Figure 8 consequently shows the figures for these installations on 31 December 2016. This share is correspondingly underrepresented despite the fact that further growth can also be expected in this field, in particular since the beginning of the year. A total of 104.8 GW are currently accounted for by non-renewables (as at November 2017) A detailed breakdown of the development of the individual renewable energy sources can be found in the section on the "Development of renewable energies" on page 65 onwards.

Current installed generation capacity
in MW

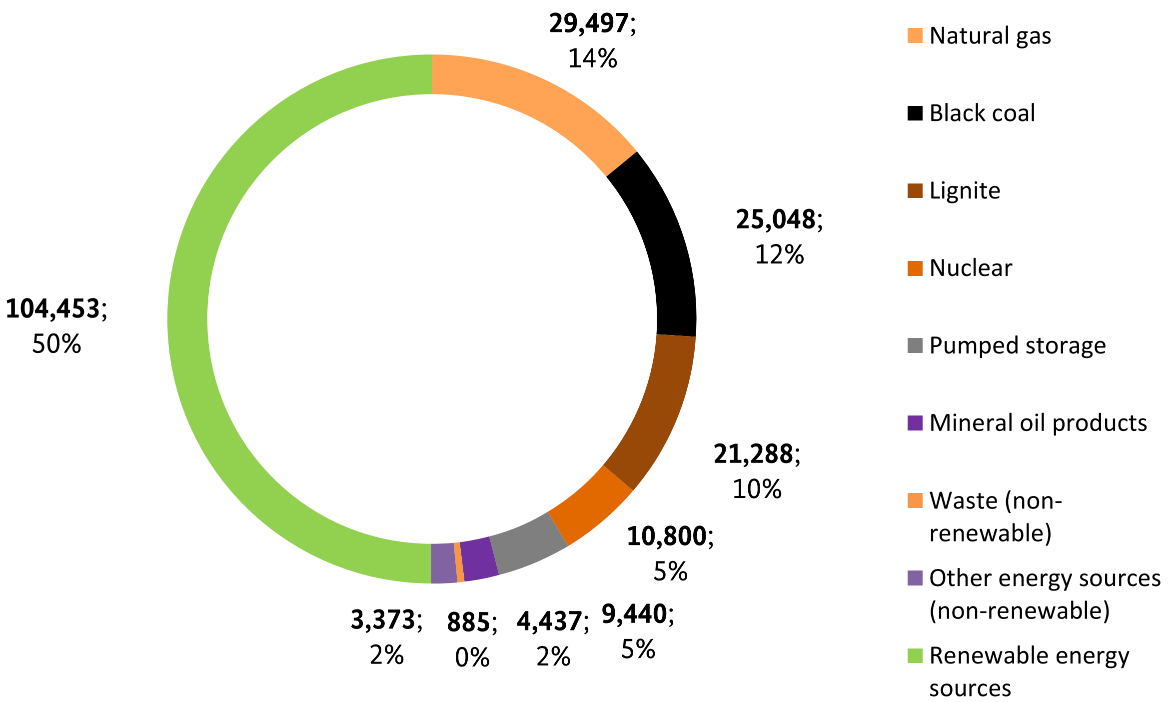


Figure 8: Currently installed electrical generating capacity (net nominal capacity as of November 2017; EEG 31 December 2016)

1.4 Power plant capacity by federal state

The following Figure 9 shows the location of installed generation 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 payments under the EEG and therefore cannot allocate this capacity (totalling 4.6 GW) to specific states.

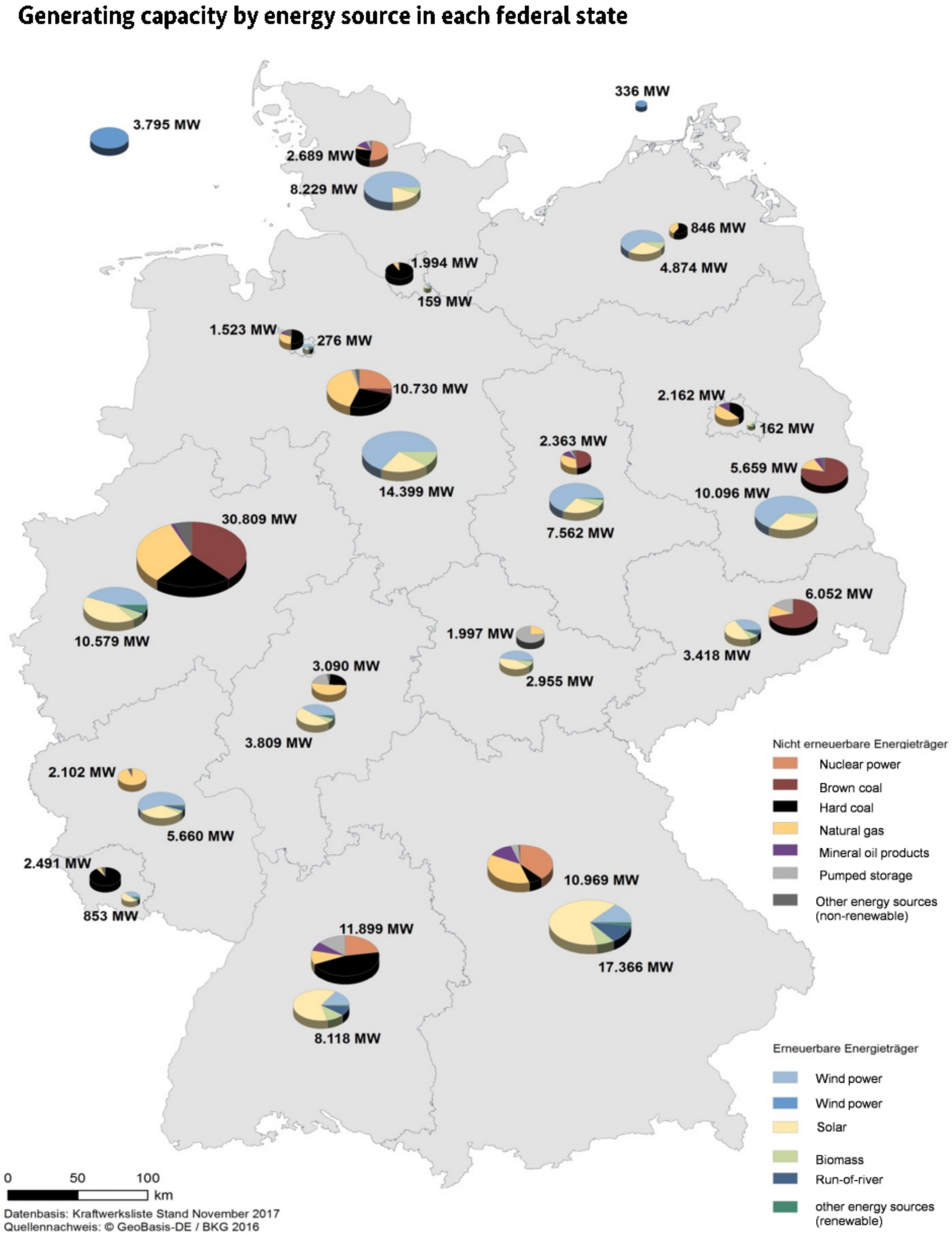


Figure 9: Generating capacity by energy source in each federal state (net nominal capacity as of November 2017; EEG 31 December 2016)

Generating capacity by energy source and federal state
in MW

Federal state	Non-renewable energy sources							Renewable energy sources						
	Lignite	**Black coal**	**Natural gas**	**Nuclear**	**Pumped storage**	**Mineral oil products**	**Other**	**Biomass**	**Run-of-river hydro**	**Offshore wind**	**Onshore wind**	**Solar power**	**Other**	**Total**
BW	0	5,529	1,034	2,712	1,873	702	49	912	655	0	1,156	5,311	84	**20,017**
BY	0	847	4,077	3,982	543	1,384	136	1,500	1,918	0	2,122	11,489	337	**28,335**
BE	0	777	1,040	0	0	327	18	45	0	0	12	87	18	**2,324**
BB	4,409	0	733	0	0	334	183	440	5	0	6,358	3,206	87	**15,755**
HB	0	772	459	0	0	86	206	12	10	0	165	41	48	**1,798**
HH	0	1,794	150	0	0	38	12	44	0	0	64	39	12	**2,153**
HE	34	753	1,570	0	625	25	84	246	62	0	1,526	1,870	105	**6,899**
MV	0	514	318	0	0	0	14	345	3	0	2,989	1,518	20	**5,721**
NI	352	2,933	4,144	2,696	220	59	326	1,418	58	0	9,239	3,623	61	**25,129**
NW	10,995	8,218	8,886	0	303	504	1,903	749	152	0	4,702	4,465	511	**41,388**
RP	0	13	1,953	0	0	0	136	173	233	0	3,161	2,024	69	**7,763**
SL	0	2,211	136	0	0	0	144	20	11	0	327	426	69	**3,344**
SN	4,325	0	618	0	1,085	17	8	297	213	0	1,176	1,680	52	**9,470**
ST	1,153	0	759	0	80	236	135	424	27	0	4,869	2,133	109	**9,925**
SH	0	672	97	1,410	119	321	70	458	5	0	6,205	1,533	28	**10,918**
TH	0	0	482	0	1,509	0	6	252	32	0	1,389	1,270	12	**4,952**
North Sea	0	0	0	0	0	0	0	0	0	3,795	0	0	0	**3,795**
Baltic Sea	0	0	0	0	0	0	0	0	0	336	0	0	0	**336**
Total	**21,267**	**25,034**	**26,455**	**10,800**	**6,357**	**4,032**	**3,431**	**7,335**	**3,384**	**4,132**	**45,460**	**40,715**	**1,621**	**200,022**

No detailed data is available for installations with a capacity of less than 10 MW; the total capacity of these installations (4,573 MW) is therefore not inclued in the table

Table 10: Generating capacity by energy source in each federal state

1.5 Power plants outside of the electricity market

The total generating capacity of 104.8 GW from non-renewables (as of November 2016) can be divided into power plants operating within the electricity market (93.9 GW) and power plants operating outside of the electricity market (10.9 GW). Within these two categories, the following subsets can be classified with regard to power plant status:

Power plants operating in the electricity market:

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

Plants operating outside of the electricity market:

- 6.9 GW: backup power stations (power stations raided and systematically relevant under sections 13b(4) and 13b(5) EnWG and now only operated when requested by the TSOs)
- 0.9 GW: power plants on security standby
- 3.1 GW: plants temporarily closed.

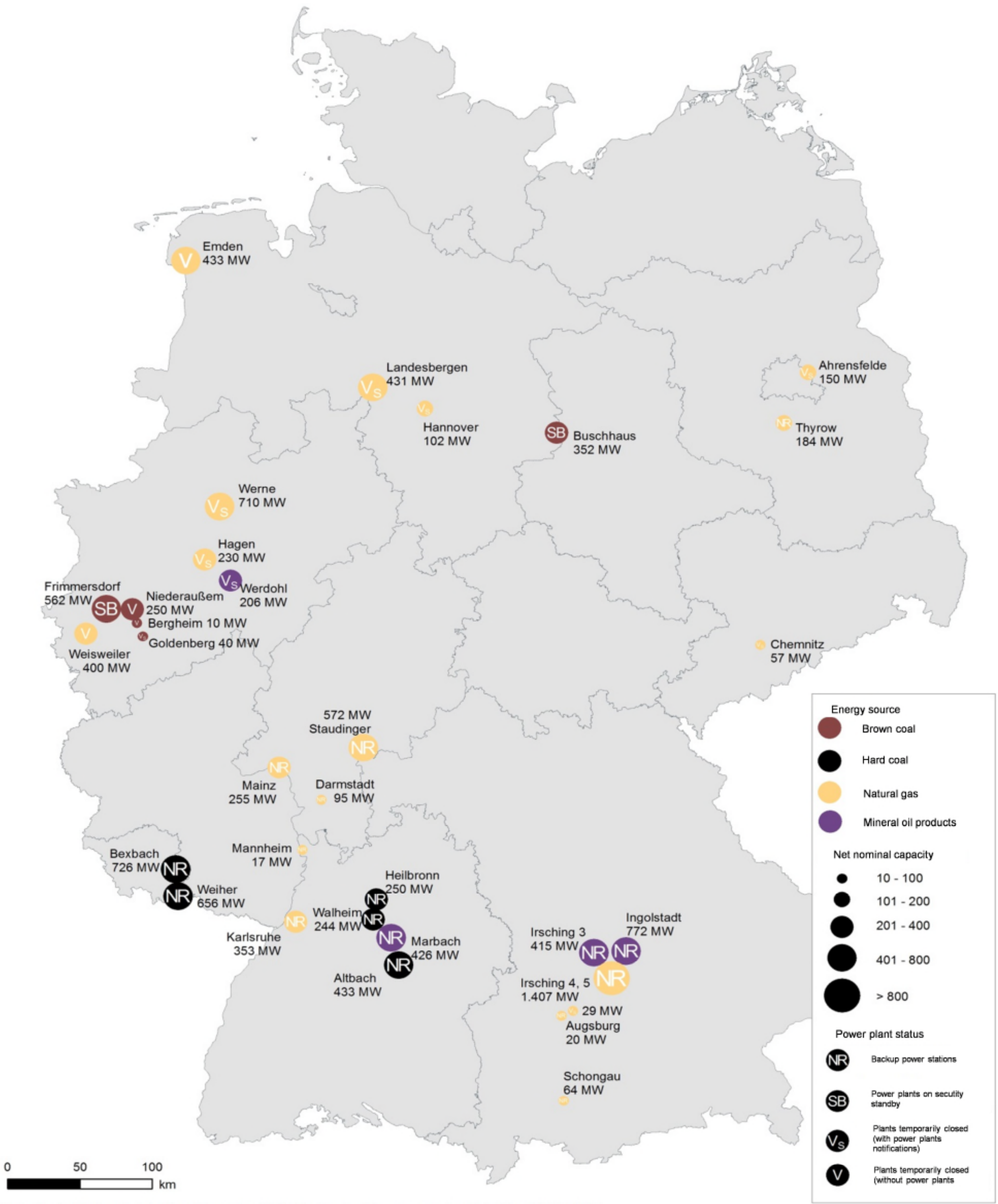
The backup power plants referred to above are plants which were notified as scheduled for temporary or final closure but which may not be closed for supply security reasons (see "Operation of reserve power plants" as of page 113 for more information). These plants currently comprise power stations using natural gas (3.0 GW), black coal (2.3 GW) and mineral oil products (1.6 GW).

Under section 13g EnWG, as from 1 October 2016 the lignite-fired 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 lignite-fired plant Buschhaus Block D to security standby status by 1 October 2016, 352 MW, and the lignite-fired plants Frimmersdorf P and Q by 1 October 2017, 562 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 market is not permitted.

The plants temporarily closed are power stations using natural gas (2.6 GW), lignite (0.3 GW), mineral oil products (0.2 GW).

Figure 10 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. The EnWG distinguishes between temporary and final closure as follows: In contrast to final closures, temporary closures can be reversed within a period of one year.

Power plants outside of the electricity market (net nominal capacity)



Datenbasis: Kraftwerksliste Stand November 2017, Kraftwerksstilllegungsanzeigenliste Stand 18.07.2017
Quellennachweis: © GeoBasis-DE / BKG 2016

Figure 10: Power plants outside the electricity market (net nominal capacity, as of November 2017)

1.6 Changes in the generation capacities of non-renewable energy sources

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. The "Power plant closures" chapter on page 61 onwards 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 2,345 MW is currently in trial operation or under construction and will likely be completed by 2020 (see Figure 11). The capacity expansion projects underway in Germany relate to black coal (1,055 MW), natural gas (883 MW) and other energy sources (35 MW). 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 for pumped storage plants in trial operation or under construction in Germany.

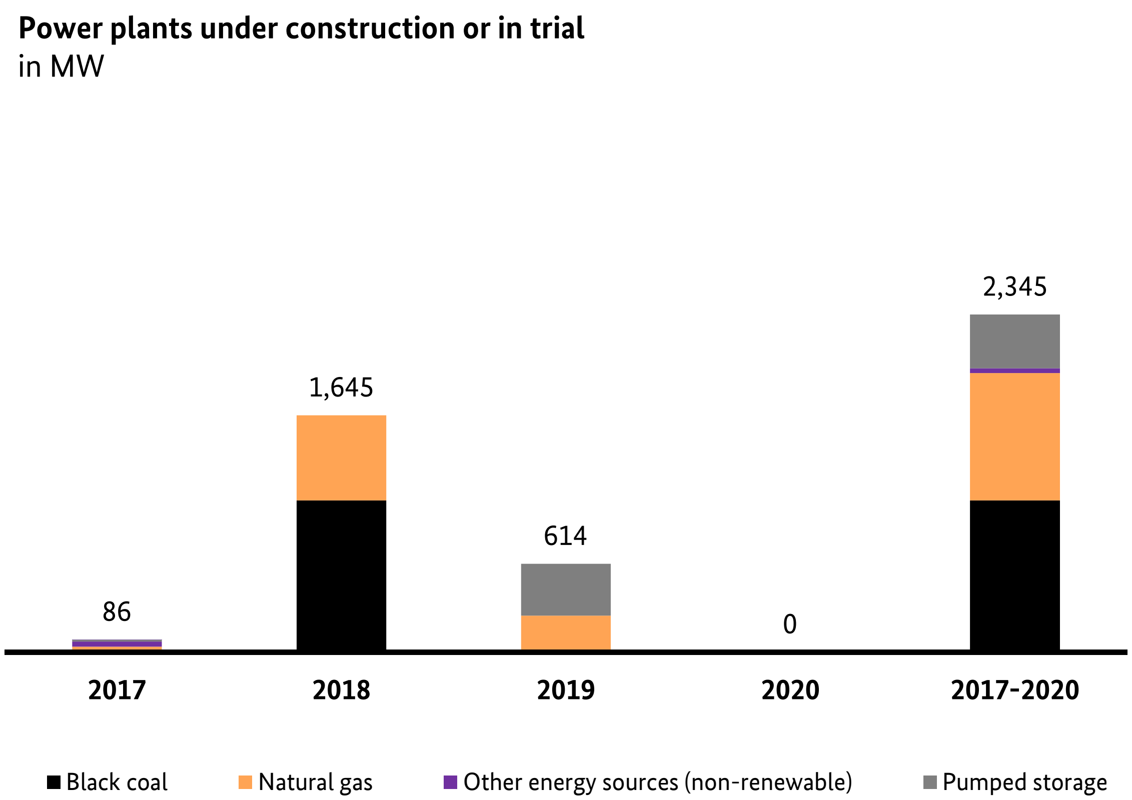


Figure 11: Power plants in trial operation or under construction from 2017 to 2020 (national planning data for net nominal capacity 2017 to 2020, as of November 2017)

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 or temporary plant closure. It also takes into account the statutory decommissioning of nuclear power plants.

Figure 12 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 2020. The total number of plants which have been notified as scheduled for closure does not include systemically relevant power plants, as the closure of such plants is prohibited. Also excluded is the decommissioning, planned for the period after 2020, 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 Germany as a whole, the capacity of planned closures – consisting of plants notified as scheduled for final closure (1,788 MW) and nuclear power plants scheduled for statutory decommissioning by the year 2020 (2,686 MW) – exceeds the capacity expansion of power generation units (2,345 MW) by 2,129 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, 526 MW of power plant capacity is currently under construction (including pumped storage plants in Austria with a total capacity of 372 MW). By contrast, a capacity of 3,131 MW is marked for final closure in southern Germany by 2020. 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 -2,605 MW in southern Germany by 2020. North of the Main river, the planned expansion of power plants exceeds capacity from planned plant closures. The planned closure of power plants with a total capacity of 1,343 MW stands in contrast to power generation units in trial operation or under construction (including Datteln 4) with a total capacity of 1,819 MW. This corresponds to a deficit of 476 MW by 2020. Based on this outlook for non-renewable power plants, the existing north-south divide will be further compounded by 2020.

In addition to the final closures, the Bundesnetzagentur was also informed of the final closure of a total capacity of 910 MW.

In addition, the lignite-fired plants Niederaußem E and F, Jänschwalde E and F and Neurath C, with a total capacity of 1,816 MW, will be transferred to security standby status. After four years these plants must be put on security standby.

In addition to the above-mentioned formal notifications of planned final or temporary closures, the Bundesnetzagentur was also informed of plans for the closure of additional power generation units during the course of its monitoring activities. The final closure of a total additional capacity of 190 MW is thus expected by 2020. This relates specifically to black coal power plants with a capacity of 124 MW, natural gas power plants with a capacity of 10 MW and other energy sources with a capacity of 56 MW. The majority of this power plant capacity (168 MW) is located north of the Main line. A gas power plant (55 MW) north of the Main is the only plant to be closed temporarily.

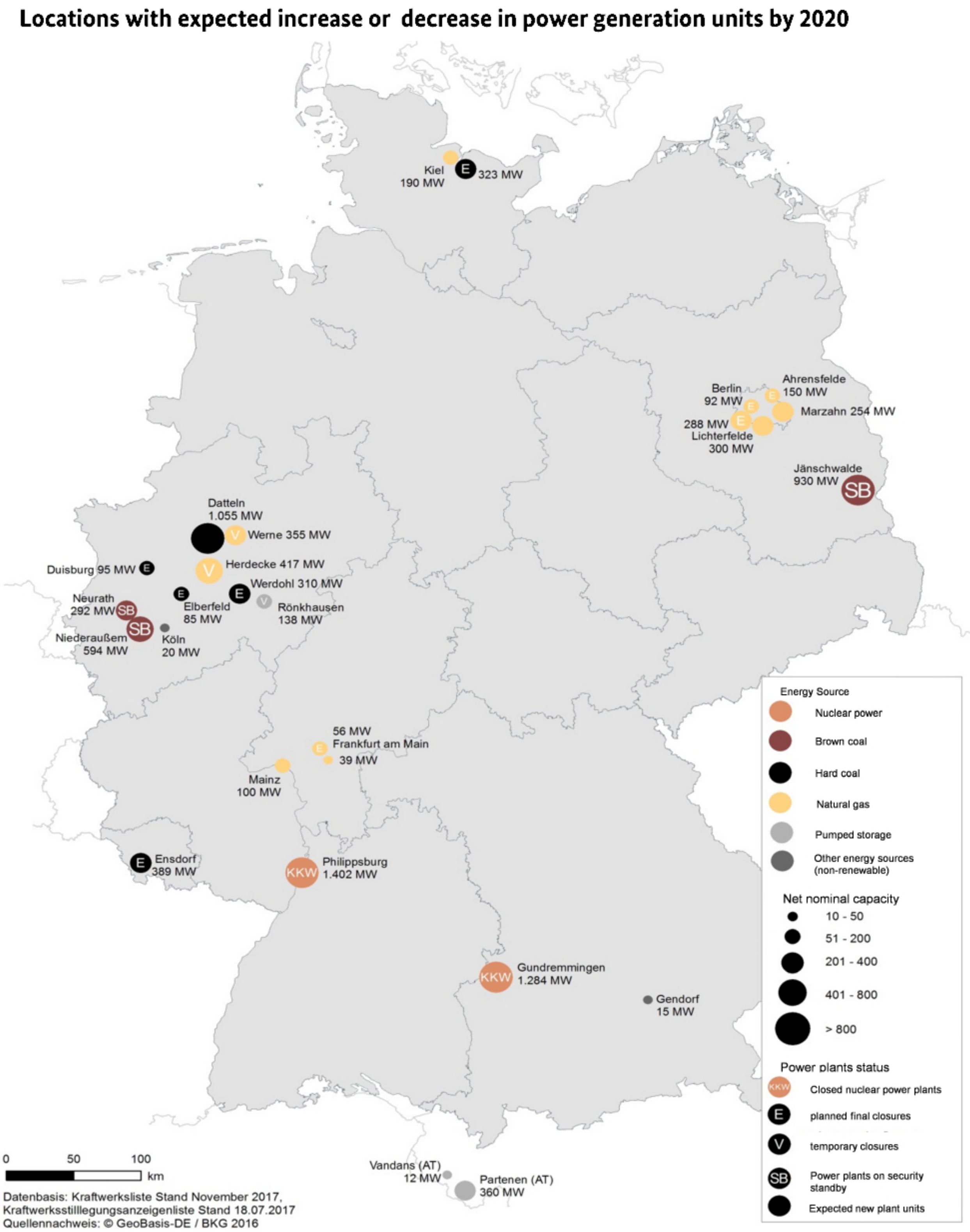


Figure 12: Locations with an expected increase or decrease in power generation capacity to 2020

This puts the notified total capacity from scheduled final closures of power plants by 2020 at 4,664 MW. Some 3,153 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 2020, including the pumped storage plants under construction in Luxembourg and Austria, is therefore 2,319 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 2,627 MW.

2. Development of renewable energies

2.1 Development of renewable energies (entitled to payments under the EEG)

Not all renewable energy generating facilities are entitled to payments under the EEG. A distinction must be made between renewable energies with and without entitlement to payments. The majority of installed renewable energy capacity falls under the EEG payment regime (market premium or feed-in tariff). 99.7 GW of the 104.5 GW of capacity installed at the end of 2016 is eligible for EEG payments. This chapter consequently examines the renewable energies entitled to payments in more detail.

The 4.8 GW of renewable energy capacity not entitled to payments is primarily accounted for by the energy sources run-of-river power (2.4 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 non-renewable energy sector. A total of 19.9 TWh of electricity was generated from renewable energies in 2016. The majority of that energy was generated in run-of-river and dammed water power plants (15.0 TWh in total) and in waste-fired power plants (4.2 TWh).

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 has been used as an additional source of information to evaluate the installed capacity of EEG installations.

In the publication "EEG in Numbers 2016", 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.

2.1.1 Installed capacity

As of 31 December 2016, the total installed capacity of installations receiving payment in accordance with the EEG was approximately 99.7 GW (31 December 2015 approximately 92.9 GW). Around 6.7 GW of total additional plant capacity entitled to payments was installed in 2016. This represents an increase of around 7.2 percent.

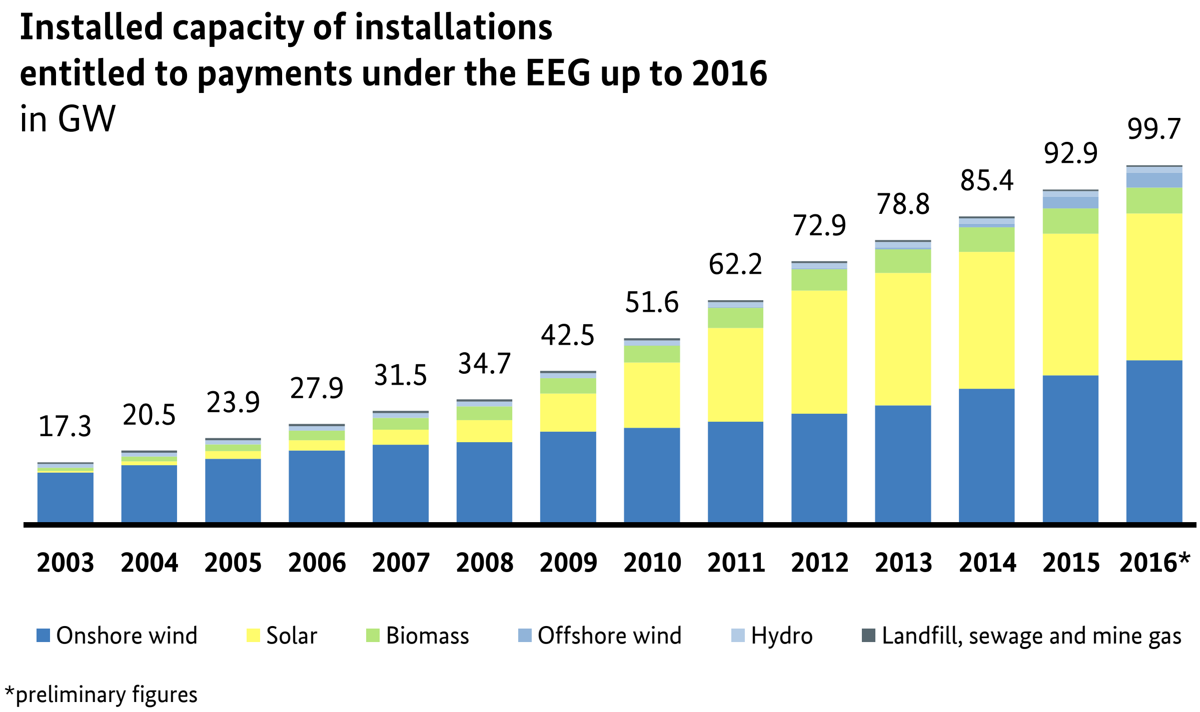


Figure 13: Installed capacity of installations entitled to payments under the EEG to 2016

A sharp rise in the net capacity of offshore and onshore wind power plants was again recorded in 2016. Offshore wind power plants with a capacity of approximately 0.8 GW were newly installed (2015: approximately 2.3 GW), which represents an increase of 25.8%. The net new build of onshore wind plant capacity (4.2 GW) was greater than in the prior year (2015: 3.6 GW). Expansion of photovoltaic installations by 1.5 GW was greater than in the previous two years but less than the development path defined in the EEG (2.5 GW). The deployment of biomass installations remained stable at 0.2 GW (2015: 0.2 GW). It is striking in this respect that very few new installations went on line and that most expansion took place as part of the flexibilisation of existing facilities.

For onshore wind plants an annual development path of 2.8 GW is planned and for solar power a growth corridor of 2.5 GW. With an overall increase of 4.4 GW (gross total), onshore wind significantly exceeded the planned development path, while the increase of 1.5 GW for solar power (gross total) fell well below the planned development path. In the case of biomass, an increase of installed capacity of 0.15 GW (gross total) is planned; this increase, however, applies only to the commissioning of new plants rather than the expansion of existing facilities 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 2016, installations with an installed capacity of 0.8 GW had been commissioned, so that by 31 December 2016 a total of 4.1 GW had been installed, which already accounts for 64% of the expansion target.

Number of installations entitled to payments under the EEG by energy source

	Total 31 December 2015	Total 31 December 2016*	Increase / Decrease in 2016	Increase / Decrease compared to 2015
	in MW	in MW	in MW	in percent
Hydro	1,576.1	1,584.7	8.6	0.5%
Gases[1]	500.9	508.7	7.8	1.6%
Biomass	7,033.8	7,236.2	202.3	2.9%
Geothermal	34.0	39.5	5.5	16.2%
Onshore wind	41,296.6	45,459.9	4,163.3	10.1%
Offshore wind	3,283.3	4,132.0	848.7	25.8%
Solar	39,224.1	40,715.6	1,491.5	3.8%
Total	92,948.7	99,676.5	6,727.7	7.2%

[1] Landfill, sewage and mine gas

*preliminary figures

Table 11: Number of installations entitled to payments (on 31 December)

Some 52,907 new facilities were installed in 2016. This is significantly lower than the average of the last five years of 95,543 new installations per year. Photovoltaic installations accounted for 97% of new installations, onshore wind plants for 1.6% and biomass installations for 0.9%. The growth rates of EEG installations entitled to payments are shown in Table 12.

When considering the development of individual energy sources, special mention must be made of the substantial capacity growth of new offshore wind plants of 19.9% and the commissioning of one big geothermal power plant. Table 13 shows the growth rates of EEG installations entitled to payments by energy source.

Number of installations entitled to payments under the EEG

	2010	2011	2012	2013	2014	2015	2016*
Hydro	6,571	6,825	6,974	6,864	6,947	7,078	7,130
Gases[1]	672	680	684	622	627	630	651
Biomass	9,943	12,697	13,371	13,485	14,024	14,113	14,367
Geothermal	4	4	6	7	8	9	10
Onshore wind	19,264	20,204	21,339	21,819	23,593	24,696	26,573
Offshore wind	16	49	65	113	241	789	946
Solar	894,756	1,154,968	1,328,293	1,449,413	1,521,365	1,572,922	1,623,467
Total	931,226	1,195,427	1,370,732	1,492,323	1,566,805	1,620,237	1,673,144

[1] Landfill, sewage and mine gas

*preliminary figures

Table 12: Development of annual energy feed-in from installations entitled to payments under the EEG

Growth rates of installations by energy source

	Total 31 December 2015	Total 31 December 2016*	Increase / Decrease in 2016	Increase / Decrease compared to 2015
	Number	Number	Number	in percent
Hydro	7,078	7,130	52	0.7%
Gases[1]	630	651	21	3.3%
Biomass	14,113	14,367	254	1.8%
Geothermal	9	10	1	11.1%
Onshore wind	24,696	26,573	1,877	7.6%
Offshore wind	789	946	157	19.9%
Solar	1,572,922	1,623,467	50,545	3.2%
Total	1,620,237	1,673,144	52,907	3.3%

[1] Landfill, sewage and mine gas

*preliminary figures

Table 13: Growth rates of EEG installations entitled to payments by energy source (on 31 December)

2.1.2 Annual energy feed-in

In 2016 the total annual energy feed-in from installations entitled to payments under the EEG was 161.5 TWh. This represents a year-on-year decrease of 0.2 TWh and has therefore hardly changed. The largest share of annual energy feed-in of 66.3 TWh (41%) was generated by onshore wind plants, followed by biomass installations with a share of 41.0 TWh (25%) and photovoltaic installations with a share of 34.5 TWh (21%).

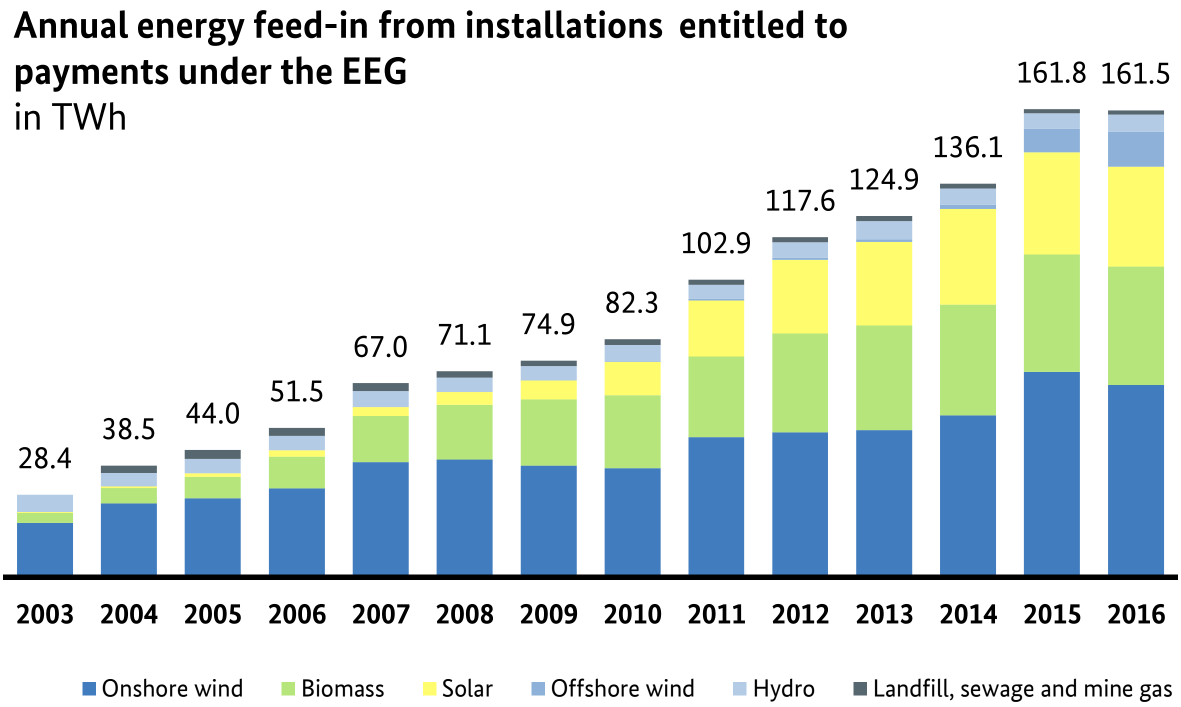


Figure 14: Development of annual energy feed-in from installations entitled to payments under the EEG

The fact that annual energy feed-in has not increased, despite continuing expansion, is mainly due to weather conditions in 2016. The decline in energy generated from the supply-dependent energy sources of onshore solar and wind was relatively greater than for hydropower, which had declined in recent years but which increased again in 2016.

Annual energy feed-in from installations entitled to EEG payments by energy source

	Total 31 December 2015 in GWh	Total 31 December 2016 in GWh	Increase / Decrease compared to 2015 in percent
Hydro	5,347	5,949	11.2%
Gases[1]	1,438	1,434	-0.3%
Biomass	40,628	41,016	1.0%
Geothermal	133	175	31.2%
Onshore wind	70,922	66,324	-6.5%
Offshore wind	8,162	12,092	48.2%
Solar	35,212	34,490	-2.1%
Total	161,842	161,479	-0.2%

[1] Landfill, sewage and mine gas

Table 14: Annual energy feed-in from EEG installations entitled to payments by energy source (on 31 December)

Annual energy feed-in from onshore wind energy fell by 6.5% (4.6 TWh) in 2016, which is largely due to the fact that 2016 was a relatively low wind year.

Annual average wind speeds were comparatively low all across Germany, and in the northern regions in particular, where a majority of the onshore wind power plants are installed (cf Figure 15, next page).

Maximum feed-in from wind power plants and photovoltaic installations

The maximum feed-in from wind power plants and photovoltaic installations only increased slightly compared with previous years. In 2016, the maximum feed-in from wind power plants and photovoltaic installations of 48.3 GW was recorded on 8 May 2016. In contrast to the previous year, this peak feed-in was due not to a storm front, but to sunny weather conditions. On 8 March, photovoltaic installations fed up to 26.1 GW into the grid. This coincided with a medium level of feed-in of 22.2 GW from wind power plants. Figure 16 shows the maximum feed-in from wind power plants and photovoltaic installations between 2012 and 2016.

In 2016 the maximum feed-in from photovoltaic installations of 26.2 GW was recorded on 6 May 2016. The year’s highest feed-in values for wind power plants (onshore and offshore) were recorded in February 2016. The peak capacity of 36.4 GW achieved on 1 February 2016 was due primarily to the gale force winds of storm NORKYS. Several peak values were also observed at the end of the year as a result of various storm systems. Figure 17 shows the development of feed-in from wind power plants in 2016.

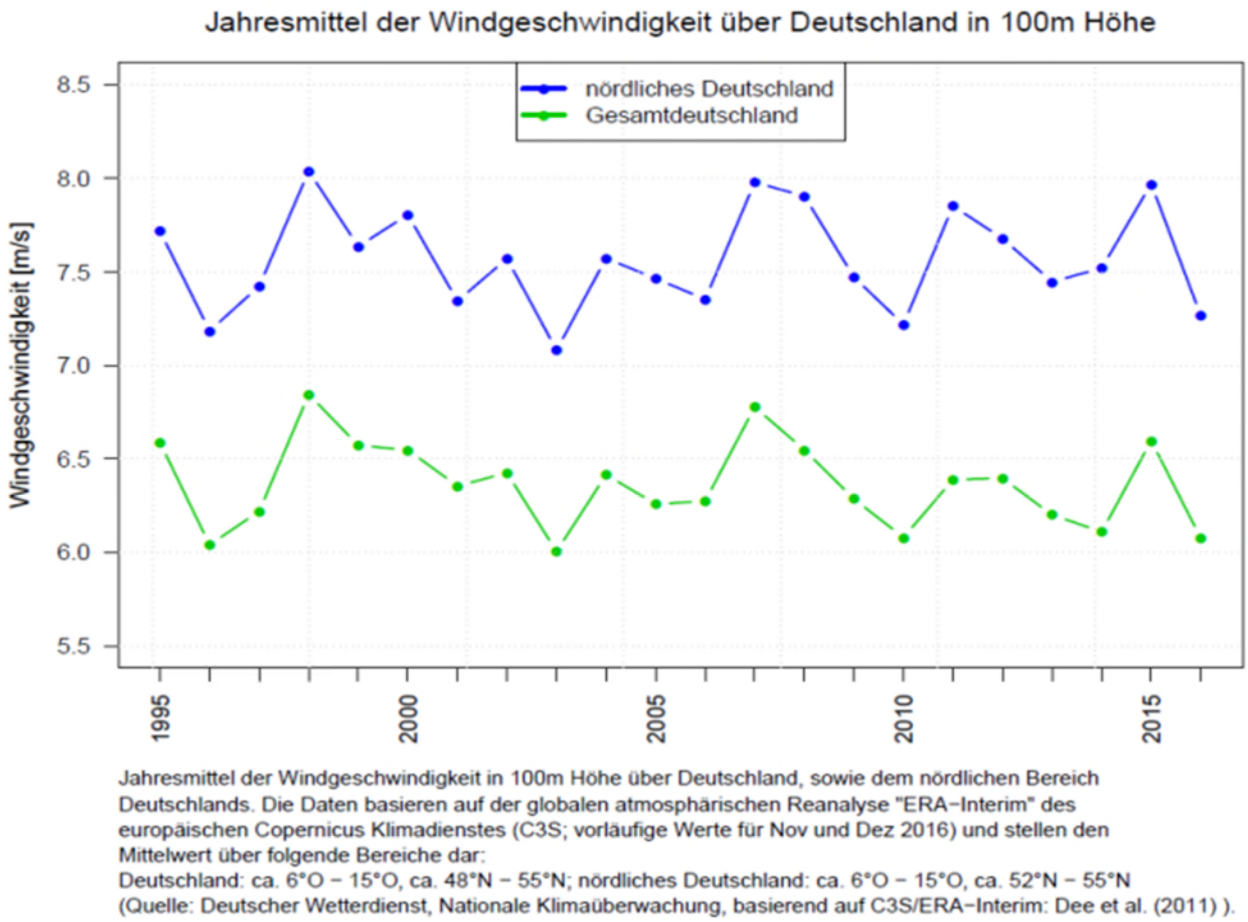


Figure 15: Annual average wind speed at 100m elevation for all of Germany as well as for northern Germany

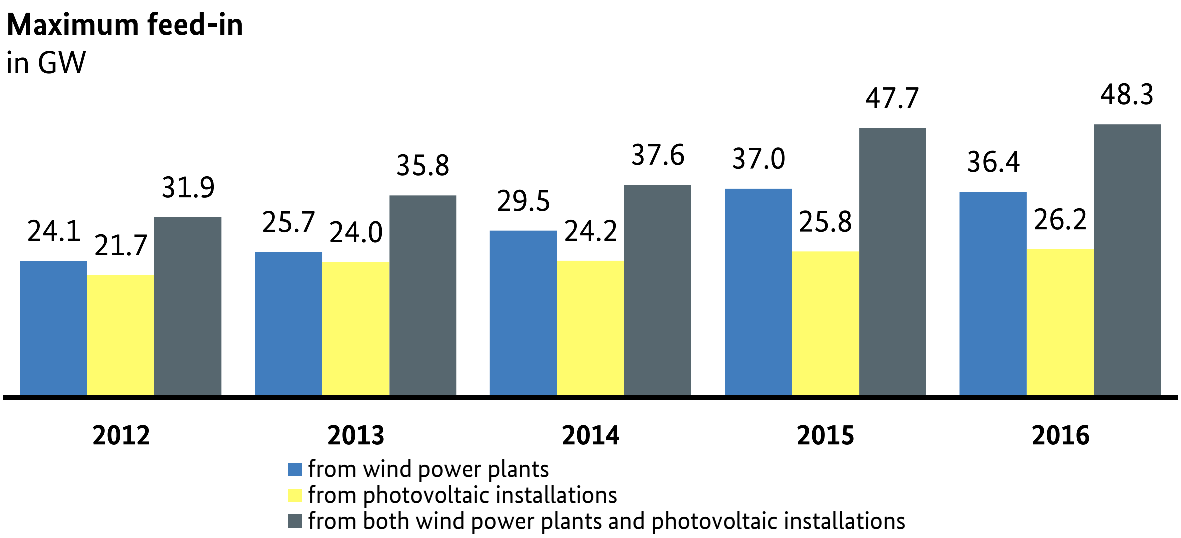


Figure 16: Maximum feed-in

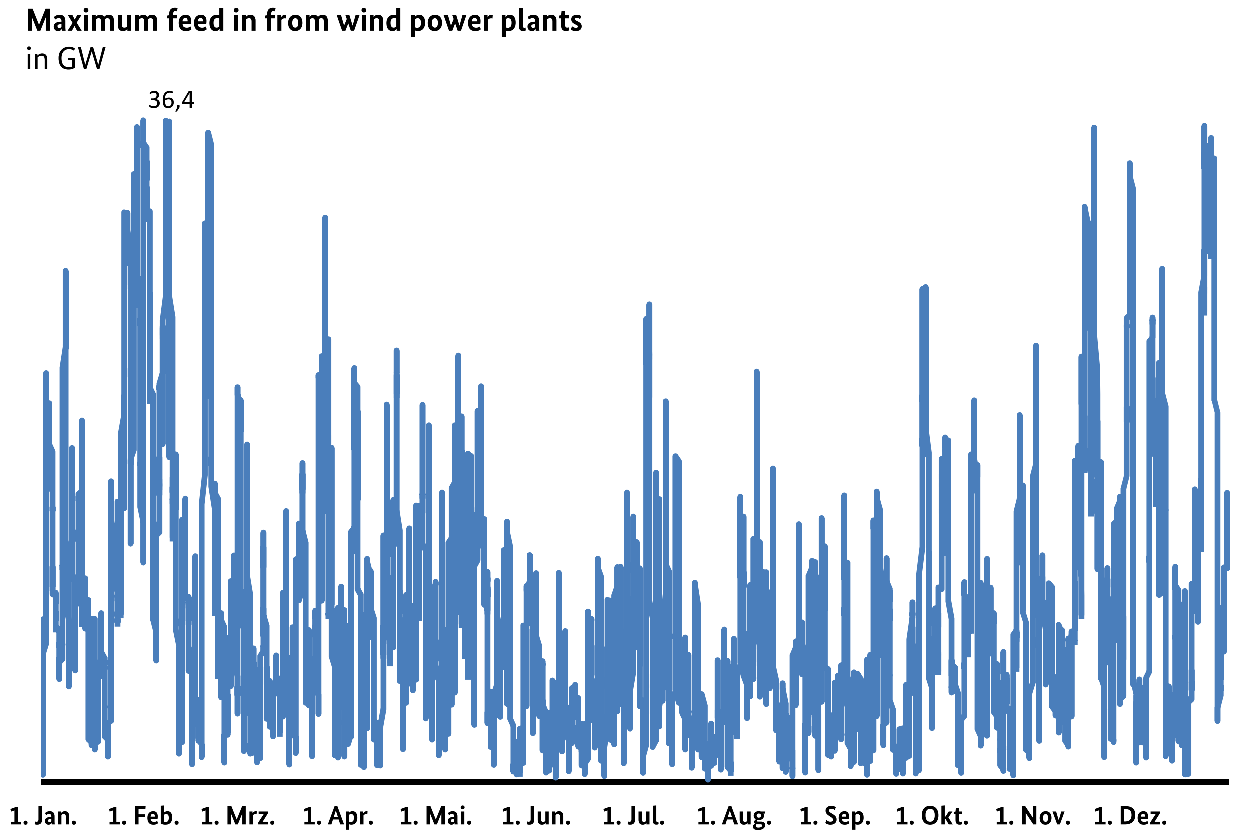


Figure 17: Maximum feed-in from wind power plants in 2016

2.1.3 Form of 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 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. Subsequent amendments to the EEG all stipulate direct selling or the market premium as standard forms of selling. Only existing or new installations with a capacity of up to 100 kW can still opt for fixed feed-in tariffs. Other forms of direct selling, ie selling without payment under the EEG, also remain possible.

In 2013 more than half of annual energy feed-in was sold directly, and in 2015 a total of 69.4% of annual feed-in was sold through direct channels. In 2016 only 27.2% of annual energy feed-in was paid a fixed feed-in tariff (cf Figure 18).

Table 15 shows that almost three quarters of annual energy feed-in was remunerated under the EEG in the form of the market premium. This is already the case for 100% of offshore wind power plants (and at 93.5%, the number of onshore wind power plants receiving market premiums is also approaching the 100% mark. In 2015 the figure was still 90.6%). At 22.6%, the proportion of annual energy feed-in from photovoltaic installations paid a market premium (2015: 18.65%) is still relatively low but growing continually.

In 2016 the main energy source for direct selling was onshore wind power, which accounted for a share of 52.8% (2015: 57.2%). The share of energy feed-in from offshore wind power installations also increased to 10.3% (2015: 7.3%).

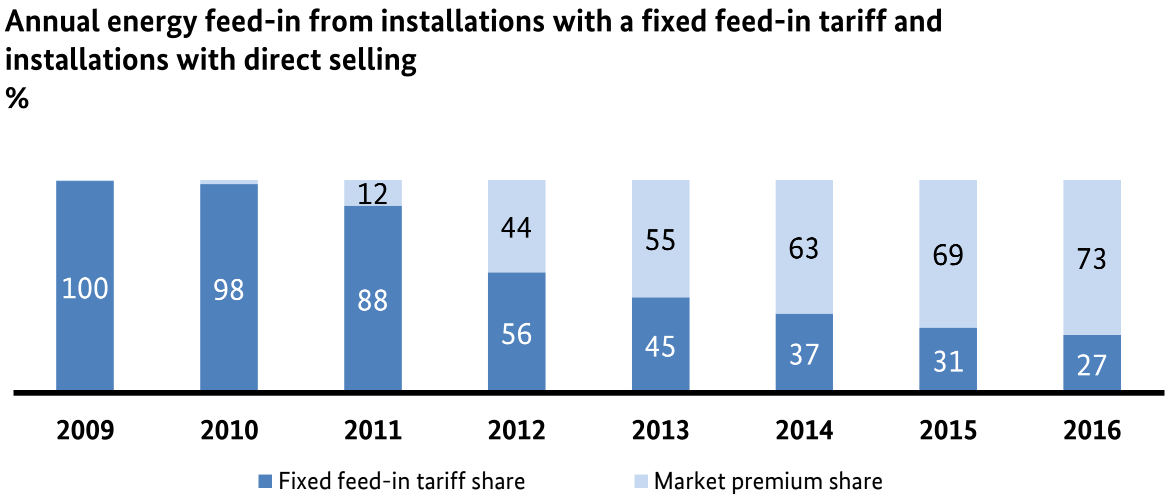


Figure 18: Annual energy feed-in from installations entitled to payments by fixed feed-in tariff or market premium

Annual energy feed-in from installations with a fixed feed-in tariff and market premium

	All installations GWh	Installations with feed-in tariff GWh	Installations with market premium GWh	Share of installations with market premium in total annual feed-in %
Hydro	5,949	2,669	3,248	54.6%
Gases[1]	1,434	396	1,026	71.5%
Biomass	41,016	9,819	31,197	76.1%
Geothermal	175	18	157	90.0%
Onshore wind	66,324	4,279	62,031	93.5%
Offshore wind	12,092	0	12,092	100.0%
Solar	34,490	26,699	7,784	22.6%
Total	161,479	43,880	117,536	72.8%

[1] Landfill, sewage and mine gas

Table 15: Annual energy feed-in from installations with a fixed feed-in tariff and market premium

Breakdown, by energy source, of annual feed-in from installations with market premium
in %

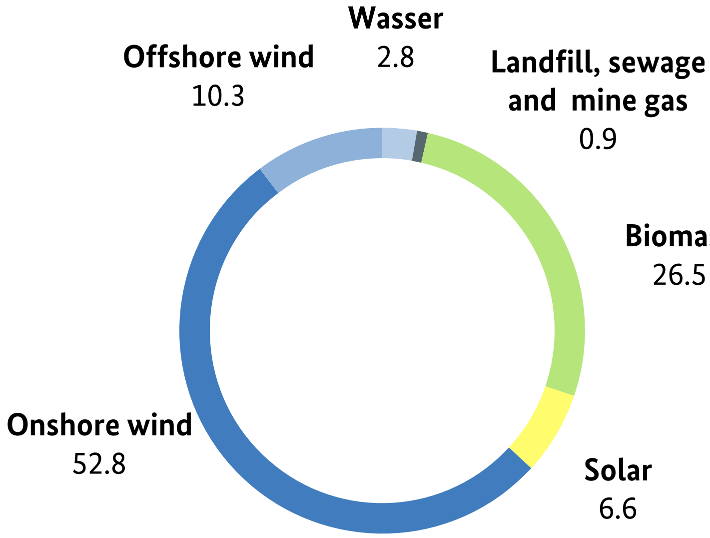


Figure 19: Breakdown, by energy source, of annual feed-in from installations with market premium

2.2 Changes in payments under the EEG

2.2.1 Overall changes in payments under the EEG

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

In 2016 a total of €24.3bn was paid to installation operators by the operators to whose networks the installations are connected. This includes, on the one hand, payments to installation operators who sell their electricity through transmission system operators (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 payments in 2016 went to installations entitled to the market premium (feed-in tariffs: 48%, market premium: 52%).

Photovoltaic installations (€10.2bn), biomass installations (€6.9bn) and onshore wind power installations (€4.7bn) accounted for significant shares of these payments.

Payments by energy source

	Total 31 December 2015 € million	Total 31 December 2016 € million	Increase / Decrease compared to 2015 %
Hydro	407	467	14.8%
Gases[1]	73	72	-1.6%
Biomass[2]	6,754	6,902	2.2%
Geothermal	29	39	34.9%
Onshore wind	5,083	4,693	-7.7%
Offshore wind	1,262	1,948	54.3%
Solar	10,640	10,226	-3.9%
Total	24,248	24,346	0.4%

[1] Landfill, sewage and mine gas

[2] including support for flexibility

Table 16: Payments under the EEG by energy source (as of 31 December)

Table 16 shows that compared with previous years overall payments in 2015 increased only slightly. This is in particular due to the constant annual feed-in from these installations (cf Table 14). Payments only increased significantly for offshore wind and geothermal, largely owing to the significant expansion of these energy sources.

Operators of renewable energy installations received an average of 15.1 ct/kWh in payments from the EEG[26] in 2016. Payments for the different energy sources varied significantly, however. For example, operators of photovoltaic installations received an average of 29,6 ct/kWh in 2016 while operators of onshore wind plants received an average of 7.1 ct/kWh. These average values include both existing installations, which receive high payments under the EEG, and new installations which receive much lower payments under the EEG. Installation operators have also received additional revenue since 2012 from direct marketing on power exchanges. The revenues are not included in the payments shown. Figure 21 shows that, compared with previous years, the average payments under the EEG have only risen minimally since the previous year.

[26] Average payments under the EEG are arrived at by dividing total payments under the EEG by the total annual feed-in for the relevant year.

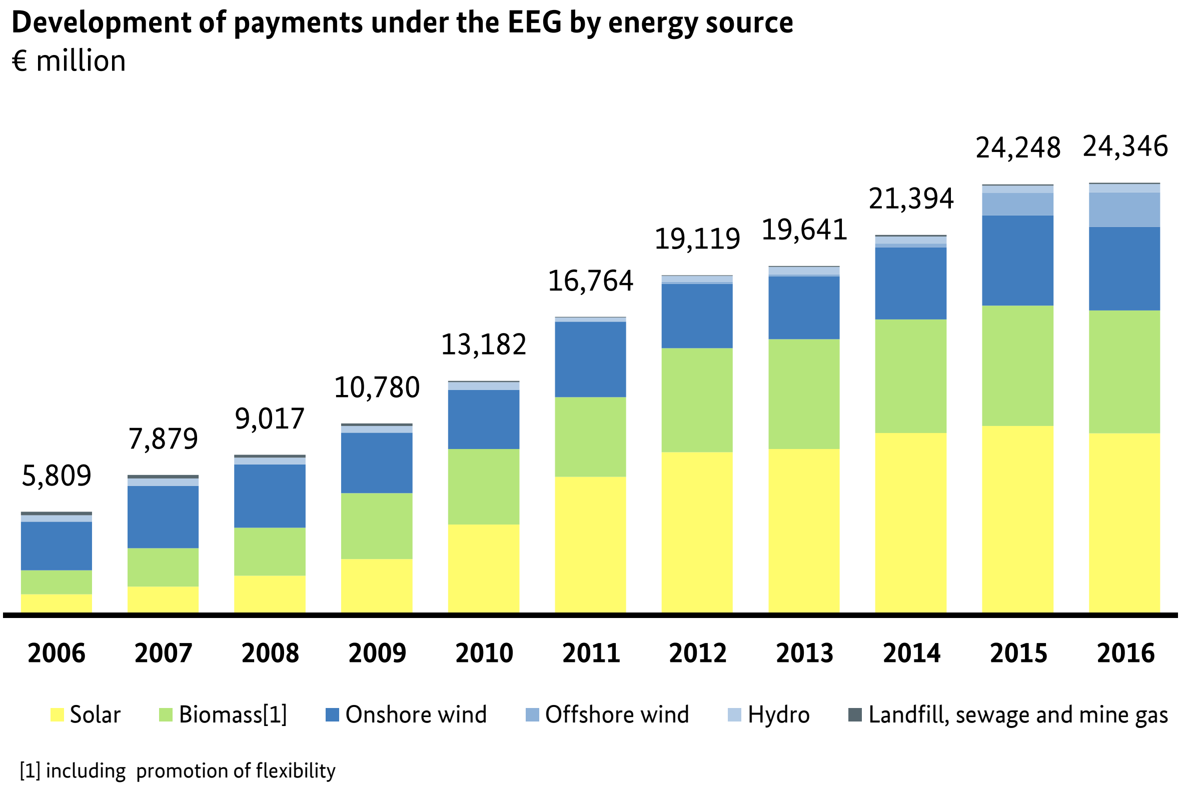


Figure 20: Changes in payments under the EEG according to energy source

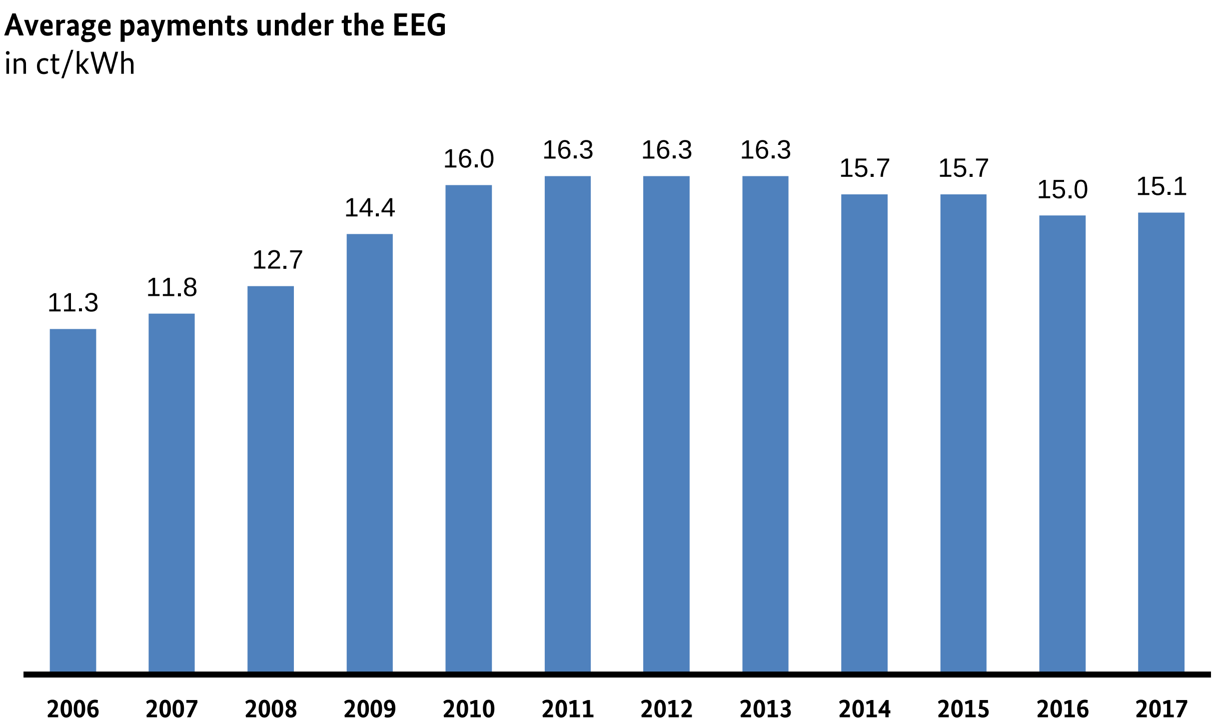


Figure 21: Changes in average payments under the EEG

2.2.2 Changes in the EEG surcharge

Payments under the EEG are for the most part refinanced through the EEG surcharge. Accordingly, the increase in payments under the EEG leads to an increase in the EEG surcharge over time. In previous years a portion of this increase has been attributable to the decline in wholesale prices for electricity and market profits for renewable electricity. Figure 22 shows that the EEG surcharge has been comparatively stable at between 6.2 and 6.9 ct/kWh since 2014. In the two previous years it rose much more steeply from 3.6 to 6.24 ct/kWh. The falling payments for new installations in particular has slowed the rate of increase substantially in recent years. The recovery in wholesale prices for electricity in 2017 will even result in a slight reduction in the EEG surcharge in 2018.

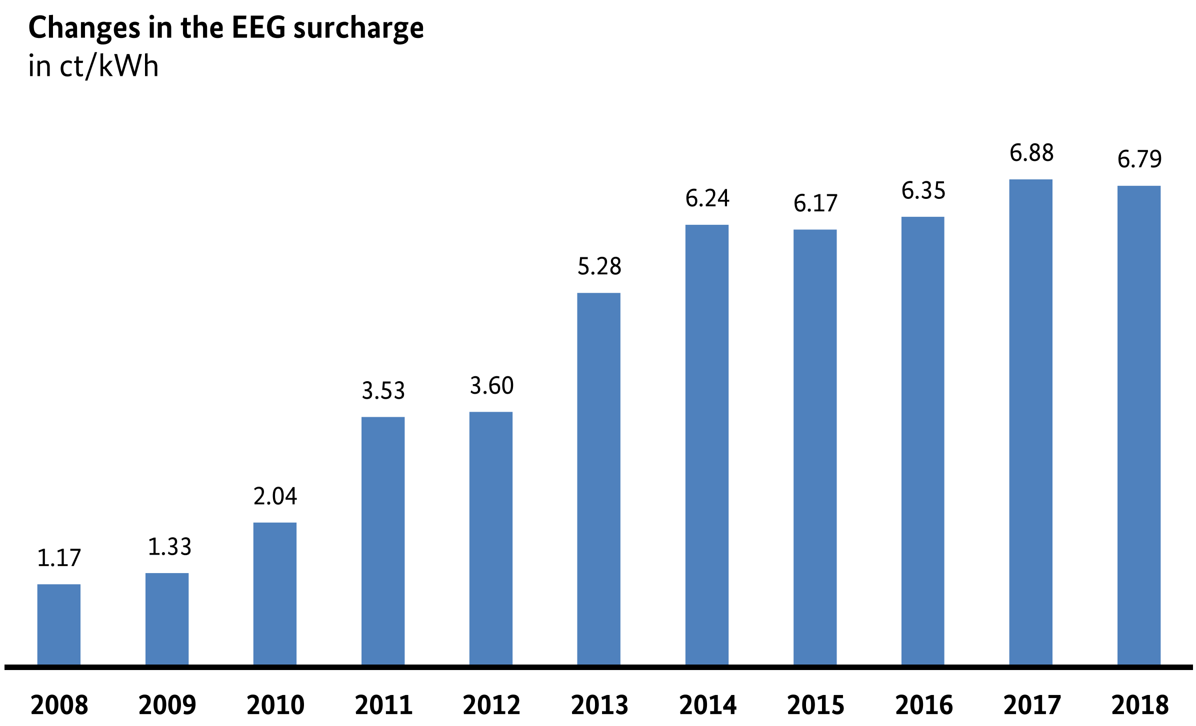


Figure 22: Changes in the EEG surcharge

2.2.3 Lowering of the values to be applied

Automatic cost reduction mechanisms were introduced in the EEG 2014 to reflect the cost reductions brought about by technological advancements. Thus, as of September 2014, the values to be applied for solar power are reduced by a set percentage each month. For onshore wind power and biomass, the values to be applied are reduced on a quarterly basis as of January 2016. There is an additional adjustment (reduction or increase) of the values to be applied 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 calculation purposes is automatically increased, thus lowering the value to be applied. If, by contrast, expansion fails to meet the statutory expectations, the values to be applied remain the same or even rise. Calculations are based on the data recorded in the installations register and in the photovoltaic registration portal.

Lowering of the values to be applied

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	May 2013 - Aug. 2014	2,400 - 2,600 (gross)	2,398	0.25%	monthly	Q3 2014
	Dec. 2013 - Nov. 2014		1,953	0.25%		Q1 2015
	Mar. 2014 - Feb. 2015		1,811	0.25%		Q2 2015
	Jun. 2014 - May 2015		1,581	0.25%		Q3 2015
	Sep. 2014 - Aug. 2015		1,437	0.0%		Q4 2015
	Dec. 2014 - Nov. 2015		1,419	0.0%		Q1 2016
	Mar. 2015 - Feb. 2016		1,367	0.0%		Q2 2016
	Jun. 2015 - May 2016		1,336	0.0%		Q3 2016
	Sep. 2015 - Aug. 2016		1,096	0.0%		Q4 2016
	Fixed in EEG 2017	2.500 (gross)	-	0.0%		Jan 17
	(Jul. 2016 - Dec. 2016) x2		2,025	0.0%		Feb. 17 - Apr. 17
	(Oct. 2016 - Mar. 2017) x2		2,149	0.25%		May 17 - Jul. 17
	(Jan. 2017 - Jun. 2017) x2		1,802	0.0%		Aug. 17 - Oct. 17
	(Apr. 2017 -Sep. 2017) x2					Nov. 17 - Jan. 18
Onshore wind	Aug. 2014 - Jul. 2015	2,400 - 2,600 (net)	3,666	1.2%	quarterly	Q1 2016
	Nov. 2014 - Oct. 2015		3,712	1.2%		Q2 2016
	Feb. 2015 - Jan. 2016		3,564	1.2%		Q3 2016
	May 2015 - Apr. 2016		3,941	1.2%		Q4 2016
	Fixed in EEG 2017	2,400 - 2,500 (gross)	-	1.2%	one-off	Jan 17
	Fixed in EEG 2017		-	1.05%	monthly	Mar.17 - Aug. 17
	May 2016 - Apr. 2017		4,676	2.4%	quarterly	Q4 2017
	Aug. 2016 - Jul. 2017					Q1 2018
Biomass	Aug. 2014 - Jul. 2015	< 100 (gross)	71	0.5%	quarterly	Q1 2016
	Nov. 2014 - Oct. 2015		67	0.5%		Q2 2016
	Feb. 2015 - Jan. 2016		25	0.5%		Q3 2016
	May 2015 - Apr. 2016		25	0.5%		Q4 2016

Table 17: Lowering of the values to be applied

Because the actual expansion of photovoltaic installations during the respective reference period[27] was as much as 900 MW below the target corridor (2.4 to 2.6 GW gross total per year), the values to be applied 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 the values to be applied in these quarters.

The values to be applied 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.

The values to be applied 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.

2.3 Auctions

With the revision of the EEG at the turn of the year 2016/17 the payments under the EEG switched from approximately 80% of the expansion of renewable energies to determination of payments by auction. This means that payments are now only granted to operators if their bid has previously been accepted within the framework of an auction; the only exceptions are for

- onshore wind plants and PV installations with an installed capacity of up to 750 kW,
- newly commissioned biomass installations with an installed capacity of over 150 kW, and
- hydropower and geothermal installations.

The KWKG was also amended as the basis of the KWK Auction Ordinance. Combined heat and power (CHP) installations bigger than one megawatt now also only receive payments if they have taken part successfully in an auction.

Bids are accepted on the basis of the rate specified in the respective bid ("pay as bid"). Exceptions only apply to bids made by citizens' energy companies for auctions for onshore wind power and existing biomass installations with an installed capacity of less than 150 kW: Rates are fixed in a uniform pricing system with the last highest successful bid determines the price for the other bids in both rounds.

Successful awards lapse after defined periods of time, the duration of which differs according to energy source. Bidders pay penalties if installations are not commissioned within the defined period.

2.3.1 Auctions for photovoltaic installations

The Bundesnetzagentur initially determined the payments made for renewable energy installations in a pilot procedure in 2015 and 2016. The statutory basis for these auctions was the Ground-mounted PV Auction

[27] The relevant reference period extends 12 months into the past, beginning 14 months before the adjustment of the values to be applied. 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.

Ordinance ("Freiflächenausschreibungsverordnung" or FFAV). Auctions were open only to bids for ground-mounted PV installations set up in specific areas. A total of six rounds of bidding were held.

Results of six auction rounds for ground-mounted PV systems

	April 2015	August 2015	December 2015	April 2016	August 2016	December 2016
Price mechanism	Pay-as-bid	Uniform pricing	Uniform pricing	Pay-as-bid	Pay-as-bid	Pay-as-bid
Volume put up for auction	150 MW	150 MW	200 MW	125 MW	125 MW	160 MW
Submitted bids	170 (715 MW)	136 (558 MW)	127 (562 MW)	108 (539 MW)	62 (311 MW)	7600.0%
Submitted bid volume	715 MW	558 MW	562 MW	539 MW	311 MW	423 MW
Winning bids	25	33	43	21	22	27
Volume of winning bids	157 MW	159 MW	204 MW	128 MW	118 MW	163 MW
Excluded bids	37	15	13	16	9	5
Volume of excluded bids	144 MW	33 MW	33 MW	57 MW	46 MW	19 MW
Average rate	9.17 ct/kWh	8.49 ct/kWh	8.00 ct/kWh	7.41 ct/kwh	7.25 ct/kwh	6.9 ct/kWh
Maximum rate	11.29 ct/kWh	11.18 ct/kWh	11.09 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 possible under EEG		
Commissioning period (exclusion deadline)	6. Mai. 17	20. Aug. 17	18. Dez. 17	18. Apr. 17	12. Aug. 17	15. Dez. 17
Implementation rate	99.4%	89.9%				

[1] at the time of auction

Table 18: Results of six auction rounds for ground-mounted PV systems

The bid volumes for all the auctions were significantly oversubscribed. Progressively fewer bids needed to be excluded owing to formal errors, demonstrating that bidders have accepted the procedure.

Competitive pressure is reflected in falling winning bids. The value of the highest successful bid fell from round to round. Bids were received from all around Germany: Awards for projects were made in all Germany's territorial states; most of these were awarded in the eastern and southern German Länder.

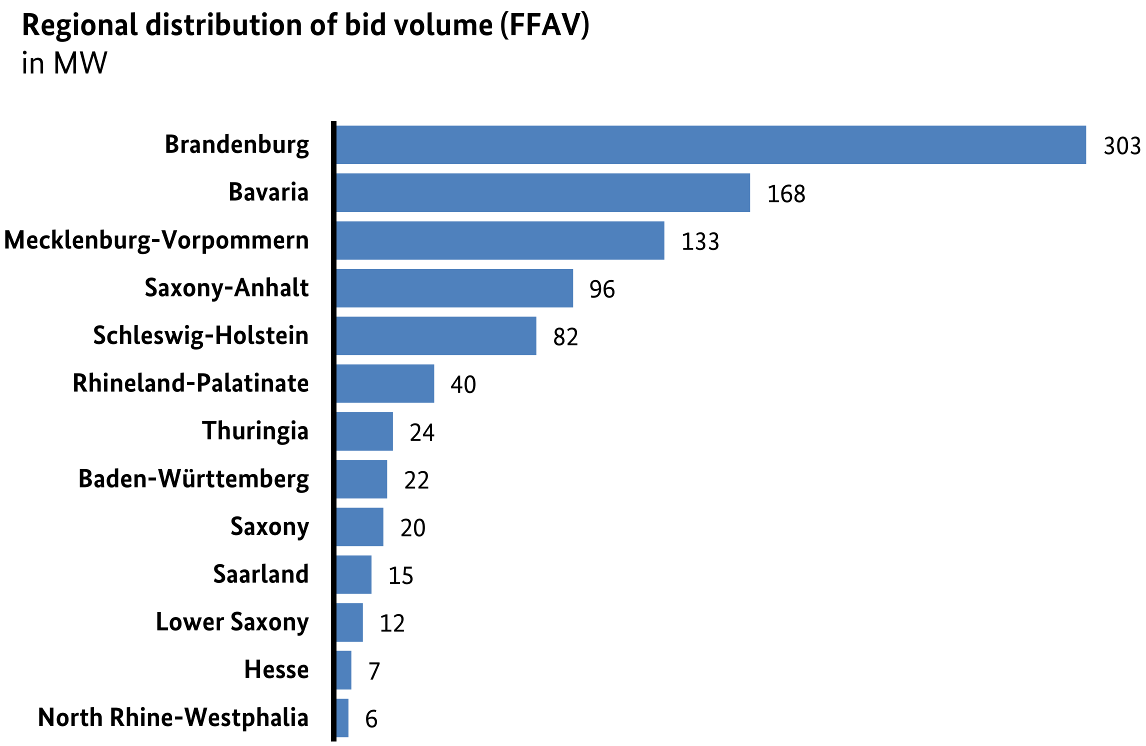


Figure 23: Regional distribution of bid volume (FFAV)

The periods of time within which the awards must be implemented have lapsed under the FFAV for the first two rounds. The procedure was successful with implementation rates of 99.38% and 89.9%.

Since 2017, auctions for photovoltaic installations have been held in accordance with the slightly modified rules of the Renewable Energy Sources Act (EEG): All photovoltaic installations which generate more than 750 kW must now have placed successful bids in order to qualify for payments. Bids for projects on grassland or arable land in neighbouring areas are acceptable if permitted by ordinance by the individual federal states; to date this has only happened in Baden-Württemberg and Bavaria. Three auctions, each for 200 megawatts, are held every year.

The trend continued in each of these three rounds in 2017. Despite being higher, the bid volume was significantly oversubscribed; the volume weighted winning bids have continued to fall - down to a volume weighted winning bid of below 5 ct/kWh.

Bids were received from all around Germany, as shown in Figure 24 (page 82). Bavaria joined Baden-Württemberg in opening up auctions for bids for arable and grasslands, in designated disadvantaged areas.

The period of time within which awarded projects must be implemented under the FFAV is two years from announcement of the award decision and it is therefore not yet possible to provide reliable figures for all rounds of auction bidding.

Auctions for photovoltaic installations in 2017

	February 2017	June 2017	October 2017
Volume put up for auction (MW)	200	200	200
Submitted bids	97	133	110
Submitted bid volume (MW)	488	646	754
Winning bids	38	32	20
Volume of winning bids (kW)	200,079	200,646	222,203
Excluded bids	9	17	6
Volume of excluded bids (MW)	27	56	20
Maximum rate (ct/kWh)	8.91	8.91	8.84
Average, volume weighted winning bid (ct/kWh)	6.58	5.66	4.91
Lowest bid (awarded) (ct/kWh)	6.00	5.34	4.29
Highest bid (awarded) (ct/kWh)	6.75	5.90	5.06

Table 19: Auctions for photovoltaic installations in 2017

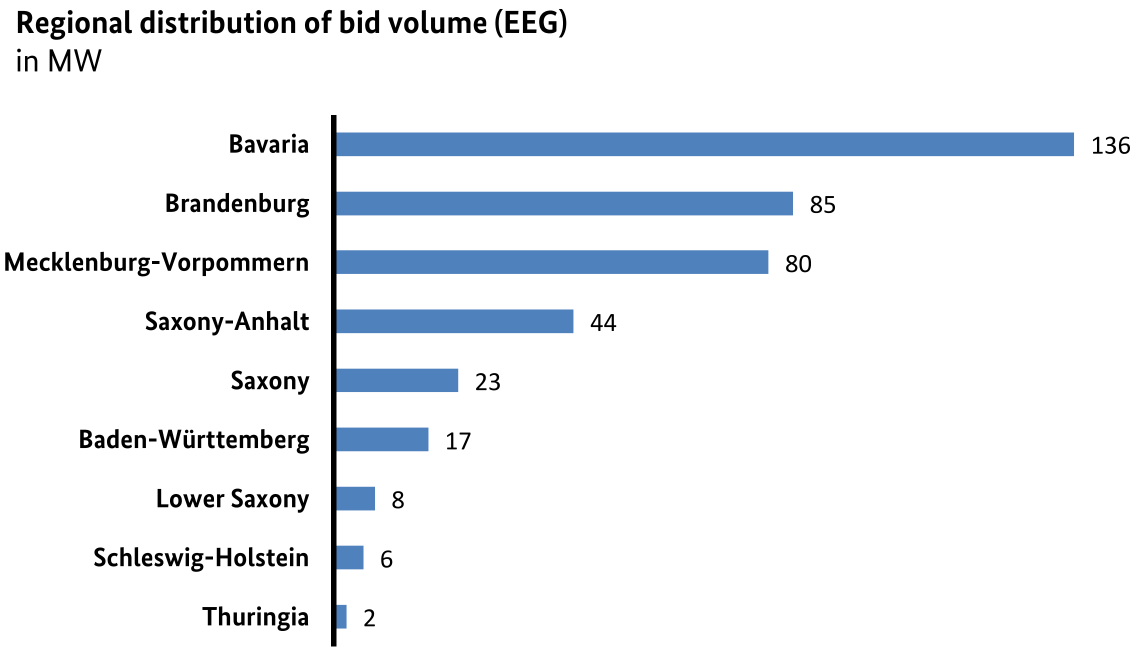


Figure 24: Regional distribution of bid volume (EEG)

2.3.2 Auctions for onshore wind plants

Since the beginning of 2017 payments for wind plants have also been determined by auction. All onshore wind plants with an installed capacity of more than 750 kW must participate in such auctions. The procedure involves three to four annual rounds of bidding with for a tender of between 2,800 and 2,900 megawatts per year. Permits under federal emission law must be submitted for the plants. Bids are made for rates for a plant at a 100% reference location; the actual payments may, however, diverge from these.

There are two special features of auctions for onshore wind plants: The grid expansion area and citizens' energy companies.

- The grid expansion area is an area in northern Germany which includes the states of Schleswig-Holstein, Mecklenburg-Vorpommern, Bremen, Hamburg and parts of Lower Saxony. As there have been delays in the construction of electricity lines in this area, awards may only be made there for a limited volume.

- Citizens' energy companies are companies of at least ten people of whom at least six must be resident in the district in which the plant for which a bid is made will be built. These companies receive two bonuses under the EEG. Firstly, they only have to include an expert report on wind conditions with their bid and do not have to obtain permits under federal emission law. Secondly, they are awarded the uniform price for the last highest successful bid in a round.

Acutions for onshore wind plants

	01.05.2017	01.08.2017	Total
Volume put up for auction (MW)	800	1,000	1,800
Submitted bids	256	281	537
Submitted bid volume (MW)	2,137	2,927	5,064
Submitted bid volume (MW) in the NAG	477	632	1,109
Winning bids	70	67	137
Volume of winning bids (MW)	807	1,013	1,820
Volume of winning bids in the NAG (MW)	28	213	241
Excluded bids	12	14	26
Excluded bids in MW	60	103	163
Maximum rate (ct/kWh)	7	7	
Average, volume weighted winning bid (ct/kWh)	5.71	4.28	
Lowest bid (awarded) (ct/kWh)	4.20	3.50	
Highest bid (awarded) (ct/kWh)	5.78	4.29	
Highest bid in the NAG (awarded) (ct/kWh)	5.58	Upper threshold not applicable	

Table 20: Auctions for onshore wind plants in 2017

The Bundesnetzagentur received a total of 537 bids for the first two tender deadlines in 2017. Both auction rounds were oversubscribed. Citizens' energy companies were well represented in both rounds. The quality of bids for wind auctions is very high: only around 5% of bids had to be excluded.

The value of winning bids fell between the first and second rounds. In total, over 90% of winning bids were made by citizens' energy companies.

There was an overall north-south discrepancy in successful bids in the first round and a concentration of winning bids in the east of Germany in the second round.

Distribution of bids and awards per federal state

Federal state	Number of bids	Capacity in kW	Of which citizens' energy companies	Number of awards	Capacity in kW	Of which citizens' energy companies
Baden-Württemberg	20	156,100	36%	0		
Bavaria	12	90,820	50%	3	26,200	100%
Brandenburg	72	857,720	87%	36	540,360	99%
Hesse	26	326,580	64%	6	80,930	100%
Mecklenburg-Vorpommern	34	436,980	91%	13	202,600	98%
Lower Saxony	94	976,610	80%	35	485,510	91%
North Rhine-Westphalia	120	1,053,210	91%	9	96,600	98%
Rhineland-Palatinate	40	298,010	33%	3	36,900	100%
Saxony	5	42,000	84%	3	35,100	100%
Saxony-Anhalt	8	118,800	53%	4	66,000	67%
Schleswig-Holstein	78	481,590	96%	19	155,900	96%
Thuringia	26	213,400	58%	6	93,450	96%
No location data provided	2	11,850	100%	0	0	
Total	537	5,063,670	79%	137	1,819,550	95%

Table 21: Distribution of bids and awards according to federal state in the first two auction rounds

The reference yield model merely takes account of differences in wind conditions prevailing at locations; the main explanations for the auction results is therefore the differences in available space and grid connection costs. The sites which are most economic are always successful in auctions and a complete levelling of conditions is neither intended nor possible.

2.3.3 Other auctions [opened auction, offshore wind, biomass, CHP]

As the European electricity market becomes increasingly integrated, the European Commission is requiring Member States to hold auctions with other Member States. International treaties will need to be made for this purpose. The Federal Republic of Germany has already concluded a cooperation treaty with the Kingdom of Denmark. Based on this treaty, the Bundesnetzagentur held an auction in November 2016 in which projects with a location in Denmark and Germany were able to participate. The tender was for 50 megawatts. Awards were all made to projects in Denmark for winning bids of 5.38 ct/kWh.

The auctions for determining payments for offshore wind plants started in 2017. Awards were made for four bids in the first round in April 2017. These bids for a total of 1,490 megawatts were awarded at rates of between zero and six cents per kilowatt-hour. The average volume weighted winning bid was 0.44 ct/kWh. This was much lower than expected and reflects the high level of competition in the first auction round. All the successful projects are in the North Sea.

The Bundesnetzagentur held the first auction in Germany for biomass installations on 1 September 2017. This procedure differed in one respect, namely that installations which were already in operation were also able to take part in the auction if they were only entitled to a further eight years of payments under the EEG as a maximum. In contrast to photovoltaic and wind, participation in the first auction round for biomass was low. The bid volume of 40,912 kW (33 bids) was significantly lower than the tender for 122,446 kW. There was a notably low participation rate and high rate of exclusion (almost 3%) owing to formal errors in the bid documentation submitted (5 bids) as well as a failure to meet the participation conditions (four bids). The average volume weighted value for all winning bids was 14.30 ct/kWh. The medium winning bids for new installations was for 14.81 ct/kWh. On average, bids for existing installations were awarded at 14.16 ct/kWh. Most of the successful 24 successful projects (27,551 kW) were therefore awarded the maximum payment allowed under the dem EEG. Regardless of the actual price at which awards were made, the rate for existing installations is limited to the average in the three years preceding the auction. The next auction for biomass installations is scheduled for 1 September 2018 and it remains to be seen whether interest will grow in obtaining payments for existing installations as they approach the end of their entitlement periods.

The Bundesnetzagentur will hold a first auction round for combined heat and power (CHP) installations and innovative CHP systems in December 2017. All installations with an installed capacity of over one megawatt must take part. Innovative CHP systems generate part of the heat they provide from renewable energies.

3. Minimum generation

For some time now the long-term goal of producing CO2 free and non-nuclear electricity generation has called for substantial structural changes in Germany's energy generation system. This will continue to be the case into the foreseeable future. There are currently periods in which large volumes of renewable energy are fed into the grid when demand is low. Conventional plant cannot be ramped down as required and the electricity market must deal with surplus supply for a few hours every year. This issue is often referred to in the media as "phantom electricity". The Bundesnetzagentur has examined this phenomenon in its report on minimum generation. This first report was published by the Bundesnetzagentur on 11 April 2017 in response to a request under the new electricity market law (Strommarktgesetz).

Minimum generation is the feed-in which the grid requires for technical reasons or which is provided to provide system services. This power is required for network and system security and cannot therefore be taken from the grid. Minimum generation is not the same as the so-called conventional generation base. This includes power plant capacity which also does not respond, or only weakly, to price signals and which is produced even when electricity prices at the exchange are negative. This power is not, however, explicitly produced for network and system security. Conventional generation base may be produced as a result of technical power plant restrictions or income opportunities outside the power market (such as cogeneration, self supply, avoided grid fees). Figure 25 shows the difference between minimum generation and conventional generation base.

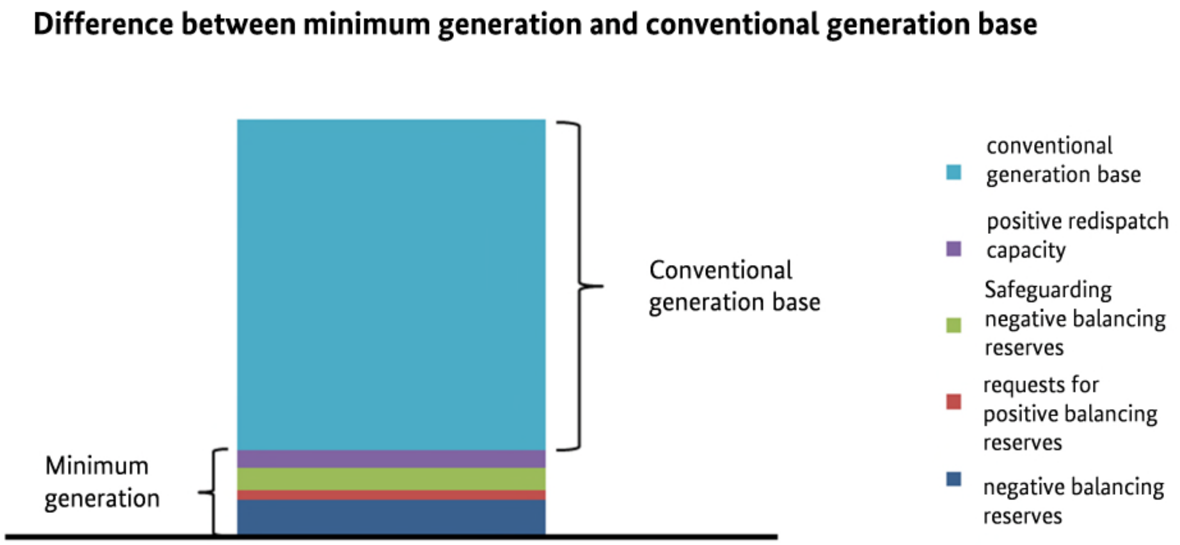


Figure 25: Difference between minimum generation and conventional generation base

The report finds that, at a total of 23 GW to 28 GW, around one quarter of the peak power fed into the German grid does not respond or responds only weakly to prices at the electricity exchange. However, only a very small part of this generation is required for technical network-related reasons. In the hours analysed in 2015 the minimum generation was thus 3 GW to 4.5 GW (excluding the shares for reactive power and short circuit power).

Most conventional electricity generation in the analysed hours is "conventional generation base". This is between around 19 and 24 GW (80% to 86% of the electricity generated by conventional power plants in the hours analysed). Figure 26 shows the results of the report on minimum generation.

Overview of minimum generation and the conventional generation base in all the hours studied
in MW

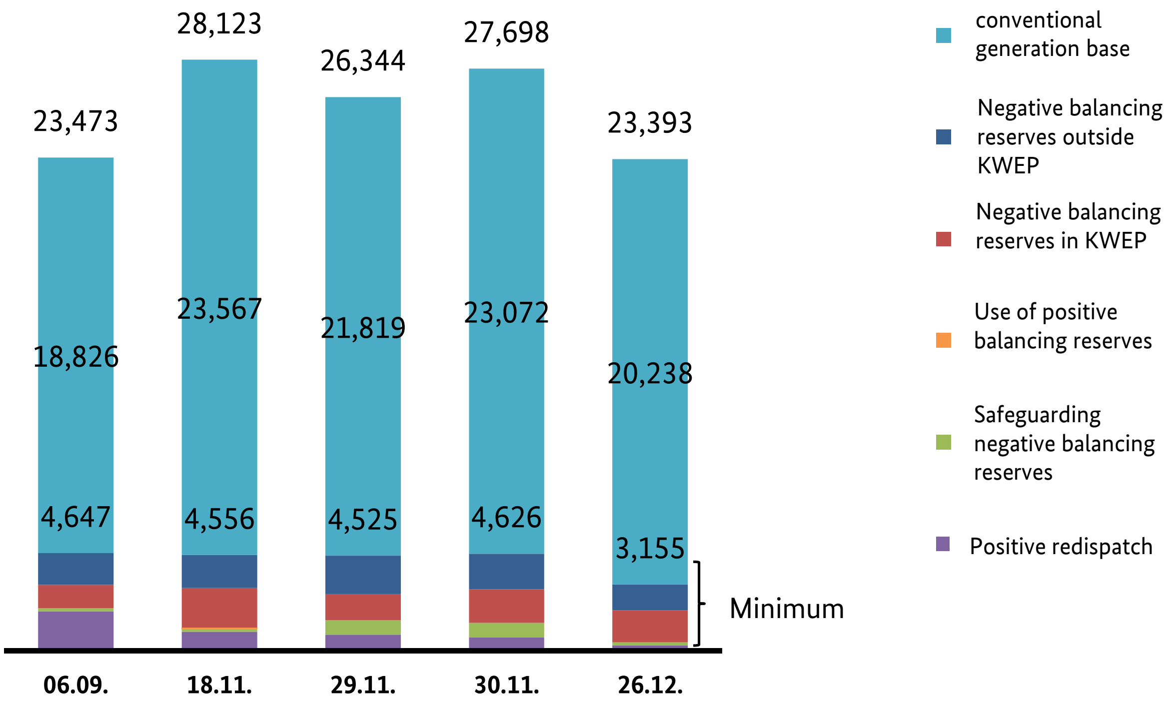


Figure 26: Overview of minimum generation and the conventional generation base in all the hours studied

At first sight this generation appears to be uneconomic as costs are incurred for production of electricity in the power plants without any revenue being generated from sales. In fact, producers actually have to pay to have electricity taken off their hands. The obvious reason for this generation is that the plants are technically inflexible. They cannot be ramped down and up again fast enough for the few hours during which wholesale prices are negative. The hours during which wholesale prices are negative are both symptomatic of inflexibility and an important incentive for investment in flexibility to the extent that such flexibility is technically feasible. In recent years some operators have invested heavily in making their installations more flexible; further investments by power plant operators could reduce the conventional generation base further.

Other reasons for the production of electricity even when wholesale prices are negative are economic incentives which are stronger than electricity market prices. These include commitments to supply heat from installations promoted under the Combined Heat and Power Act (Kraft-Wärme-Kopplungsgesetz), incentives arising from rules on own consumption and entitlement to payment of so-called avoided grid fees.

More needs to be known about the actual situation and technical aspects of minimum generation and the conventional generation base for better integration of renewable generation and to achieve the goal of reducing the share of conventional generation. This will entail gradually and continually reducing the conventional generation base and generating the minimum power the grid needs for technical reasons in some other way, such as from renewable energy sources.

In its follow-up report for 2019, the Bundesnetzagentur will base its analyses on a broader range of data and will look at the reasons for the insensitivity to price signals of feed-in from the conventional generation base in greater detail.

C. Networks

1. Status of network expansion

1.1 Monitoring of projects in the Power Grid Expansion Act

Attention was already being focused on speeding up grid expansion at the extra-high voltage level back in 2009 with the passing of the Power Grid Expansion Act (EnLAG).

The current version of the Act lists 22 projects that require urgent implementation in order to meet energy requirements. Project no 22 was deleted following a review preceding production of the network development plan 2022 and project no 24 during the production of the network development plan 2024. Six of the 22 projects are designated as underground cable pilot projects.

The four German transmission system operators (TSOs) – TenneT, 50Hertz, Amprion and TransnetBW – are responsible for planning, establishing and operating these projects. The individual federal state authorities are responsible for conducting the spatial planning and planning approval procedures for the projects. The Bundesnetzagentur regularly updates the information on the status of the approval procedures for the individual projects on its website at http://www.netzausbau.de/vorhaben. The information is based on the quarterly reports produced by the four TSOs on the current state of construction and planning work.

Current status

The projects currently listed in the Power Grid Expansion Act comprise lines with a total length of some 1,800 km. At the third quarter of 2017, about 1,000 km of the lines had been approved; around 750 km of these – or about 40% of the total – had been completed. A further 600 km or so of lines are at the spatial planning and planning approval stage. The TSOs anticipate that some 80% of the line kilometres listed in the Act will be completed by 2020. So far, none of the underground cable pilot lines have been put into full operation. Operational testing is in progress for the first 380 kV underground cable pilot project in Raesfeld.

Figure 27 shows the status of the projects listed in the Power Grid Expansion Act as at the third quarter of 2017.

1.2 Monitoring of projects in the Federal Requirements Plan

Alongside monitoring the projects in the Power Grid Expansion Act, the Bundesnetzagentur publishes quarterly updates on the status of the expansion projects listed in the Federal Requirements Plan Act (BBPlG) on its website at www.netzausbau.de/vorhaben.

Of a total of 43 projects nationwide, 17 are designated as crossing federal state or national borders within the meaning of the Grid Expansion Acceleration Act (NABEG). The Bundesnetzagentur is responsible for the federal sectoral planning and the subsequent planning approval procedure for 16 of these projects.

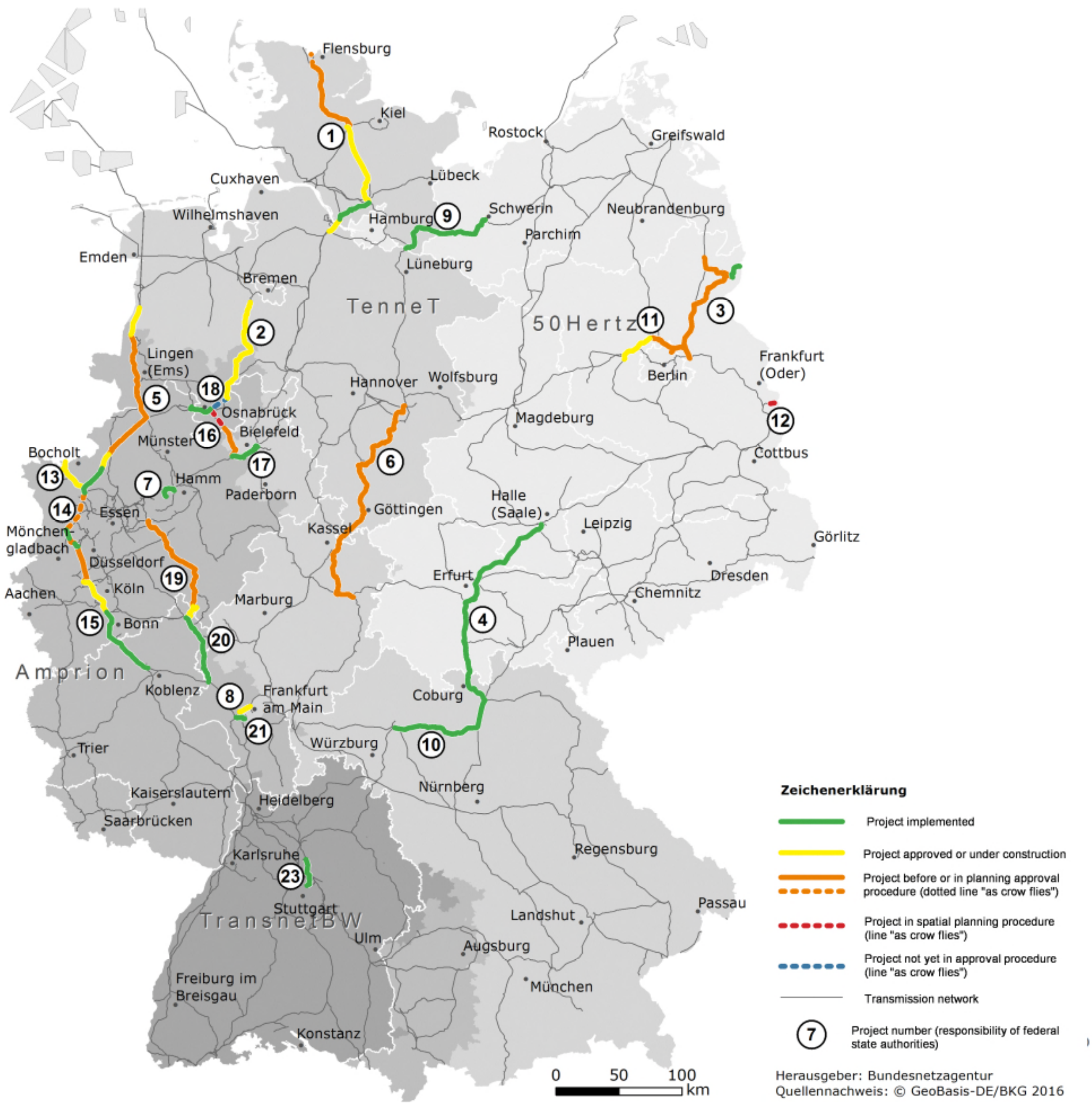


Figure 27: Status of line expansion projects in the Power Grid Expansion Act: 3rd quarter 2017

Eight of the 43 projects have been designated as pilot projects for low-loss transmission over long distances (high voltage direct current (HVDC) transmission). Five direct current (DC) projects have been earmarked for priority underground cabling and five alternating current (AC) projects for partial underground cabling. In addition, one project is designated as a pilot project using high-temperature conductors and two are designated as submarine cable projects.

Current status

The projects currently listed in the Federal Requirements Plan Act comprise lines with a total length of some 5,900 km. According to the network development plan, around 3,050 km of these lines will serve to reinforce the system. The total length of the lines in Germany will largely depend on the route of the north-south corridors and will become apparent in the course of the procedure. At the third quarter of 2017, around 450 km had been approved and about 150 km of these completed. A further 2,400 km or so of lines are at the federal sectoral planning stage with the Bundesnetzagentur and around 600 km are at the spatial planning and planning approval stage with the federal state authorities.

The following map shows the status of the projects listed in the Federal Requirements Plan Act as at the third quarter of 2017.

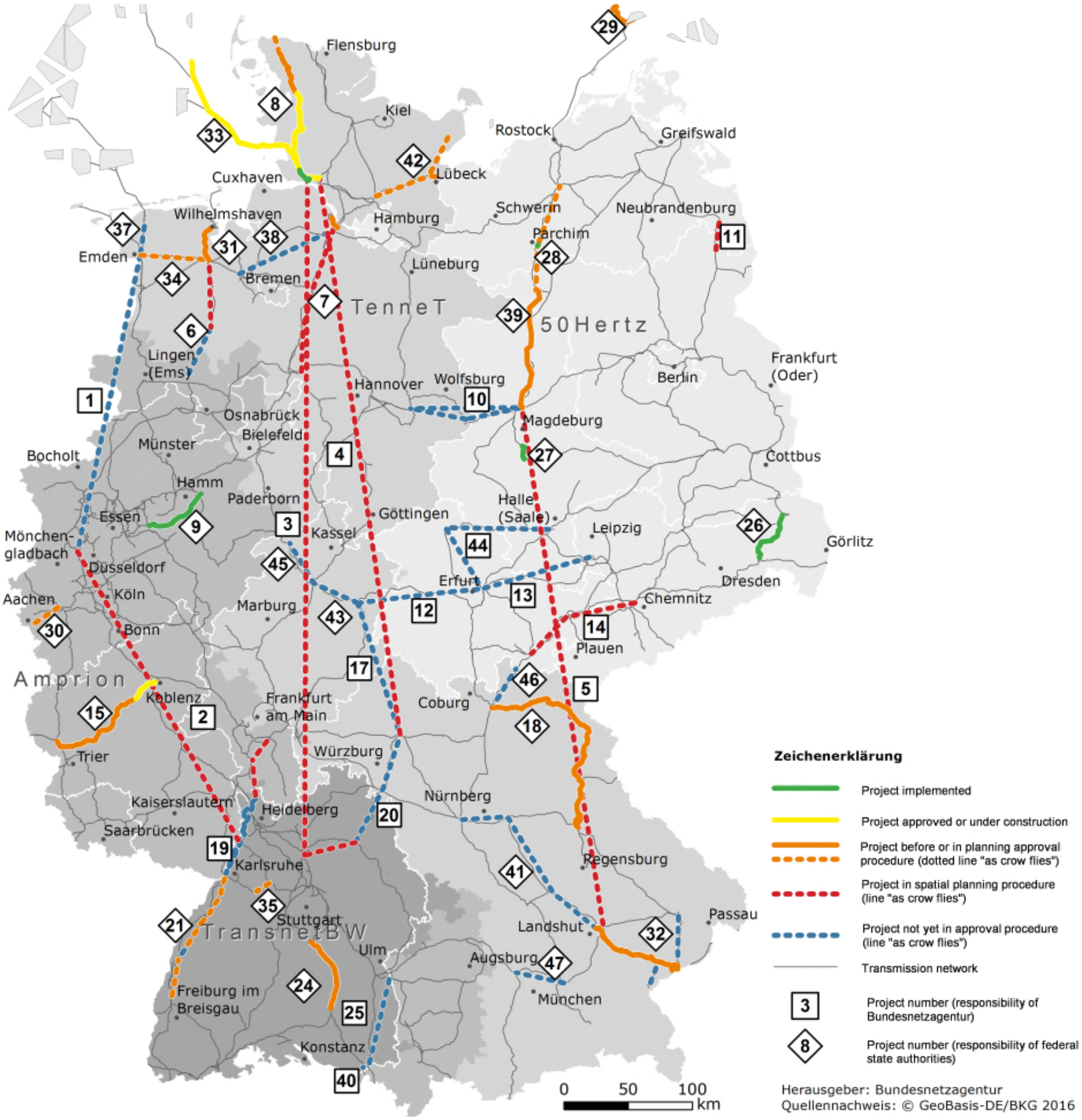


Figure 28: Status of expansion projects in the Federal Requirements Plan Act: 3rd quarter 2017

1.3 Network development plan status

The TSOs published their first draft of the network development plan 2017 2030 on 31 January 2017, giving the public, public agencies and federal state energy supervisory authorities the opportunity to comment. On 2 May 2017, they submitted their revised draft to the Bundesnetzagentur. On 4 August 2017, the Bundesnetzagentur published its preliminary assessment findings and draft environmental report. This marked the start of the second consultation round, giving authorities and the general public the opportunity to respond by 16 October 2017. Confirmation of the network development plan 2017 2030 is anticipated for the end of 2017 following evaluation of the responses.

The network development plan 2017 2030 looks at whether the projects in the Federal Requirements Plan still prove necessary and which additional measures are required in light of the progress of the energy transition. It is based on the assumption that the projects in the Power Grid Expansion Act have been implemented. The TSOs have not proposed any additional projects for the period up to 2030 for HVDC lines running from the north to the south of Germany to supplement those listed in the Federal Requirements Plan. Instead, any further demand is to be met in the first instance largely by reinforcing existing extra-high voltage AC lines, and use of the transmission system is to be made more efficient with network elements that control the flow of electricity.

The question in the medium to long term will be whether and where further large-scale HVDC connections can serve as an appropriate and proportionate means of expanding the grid. Expansion of the AC grid is dependent on this. Potential technological progress in the period up to 2030 could reduce the need for further grid expansion. This need is nevertheless expected to exceed current expansion requirements since it is linked to the continued growth in renewable energy and consequently to the success of Germany's energy transition.

The network development plan 2017 2030 takes account of the climate targets and addresses the central issues of the 2016 reform of the Renewable Energy Sources Act (EEG). This concerns various aspects including changes to the development corridors and the spatial distribution of onshore wind energy and biomass electricity generation. Future developments, for instance in storage, coupling between the electricity, heating and transport sectors, and the flexible use and provision of electricity feed into the planning process.

1.4 Offshore network development plan status

The offshore network development plan defines the requirements for the transmission links connecting the offshore wind farms in the North and Baltic Seas to the onshore grid. The introduction of an auction scheme for renewable electricity generation also marked a systemic change for offshore wind energy. From 2026 onwards, auctions will be held for sites in the North and Baltic Seas that have been pre-assessed by the state (known as the "target model"). Transitional arrangements for the period from 2021 to 2025 provide for existing projects to bid in two auctions for a volume in each case of 1,550 MW. The transmission capacity available in the auctions is based on the confirmed offshore network development plan 2025. The first of these two auctions was held in spring 2017. The requirements for offshore transmission links will in future be determined in the target model by the onshore network development plan, which in turn is based on the provisions of the site development plan. In this sense, the offshore network development plan for the period 2017 2030 is therefore the last of its kind.

The offshore network development plan 2025 was confirmed on 25 November 2016. According to the plan, three transmission links will be needed in the Baltic Sea in the period from 2021 to 2022 and four in the North Sea in the period from 2023 to 2025.

On 31 January 2017, the TSOs published their first draft of the offshore network development plan 2017 2030 for public consultation. On 2 May 2017, they submitted their revised draft to the Bundesnetzagentur. This draft proposes two additional transmission links in the North Sea and two in the Baltic Sea for the period from 2026 to 2030 in addition to those already confirmed in the offshore network development plan 2025. On 4

August 2017, the Bundesnetzagentur published its preliminary assessment findings on the second draft. This marked the start of the second consultation round, giving authorities and the general public the opportunity to respond by 16 October 2017. Confirmation of the offshore network development plan 2017 2030 is anticipated for the end of 2017 following evaluation of the responses.

By 1 August 2017, the Bundesnetzagentur had received 32 applications for the approval of investment measures for offshore transmission links totalling €21.4bn; 26 of these applications totalling €18.8bn have already been approved.

2. Distribution network expansion

2.1 Optimisation, reinforcement and expansion in the distribution networks

The distribution system operators (DSOs) are required to optimise, reinforce and expand their networks in line with the state of the art so as to ensure the uptake, transmission and distribution of electricity. The substantial expansion in renewable energy installations and the legal obligation to integrate the installations and the energy generated regardless of network capacity represent considerable challenges for the DSOs. Alongside conventional expansion measures, system operators are responding to these challenges primarily by developing increasingly smart grids that will allow them to adapt to the changing requirements. The way forward and the measures adopted may differ considerably from one operator to the next. Given the highly heterogeneous nature of the networks in Germany, DSOs need to work out their own individual strategies for accommodating future energy developments and achieving efficient network operation. The fact that many networks are in any case due for modernisation is an advantage, as it will frequently be possible to adapt grids by investing the financial returns from existing systems (intelligent restructuring), without any associated increases in network costs.

A total of 829 DSOs (817 in the previous year) provided information about the extent to which they had taken action to optimise, reinforce or expand their networks. There was a year-on-year increase in the number of companies for each of these three categories. The largest increase was in the number of operators optimising their networks. A total of 530 companies reported network optimisation measures, almost 4% more than in the previous year. The following diagram shows the number of operators taking action in the period since 2009.

Network optimisation, reinforcement and expansion measures
(number of DSOs)

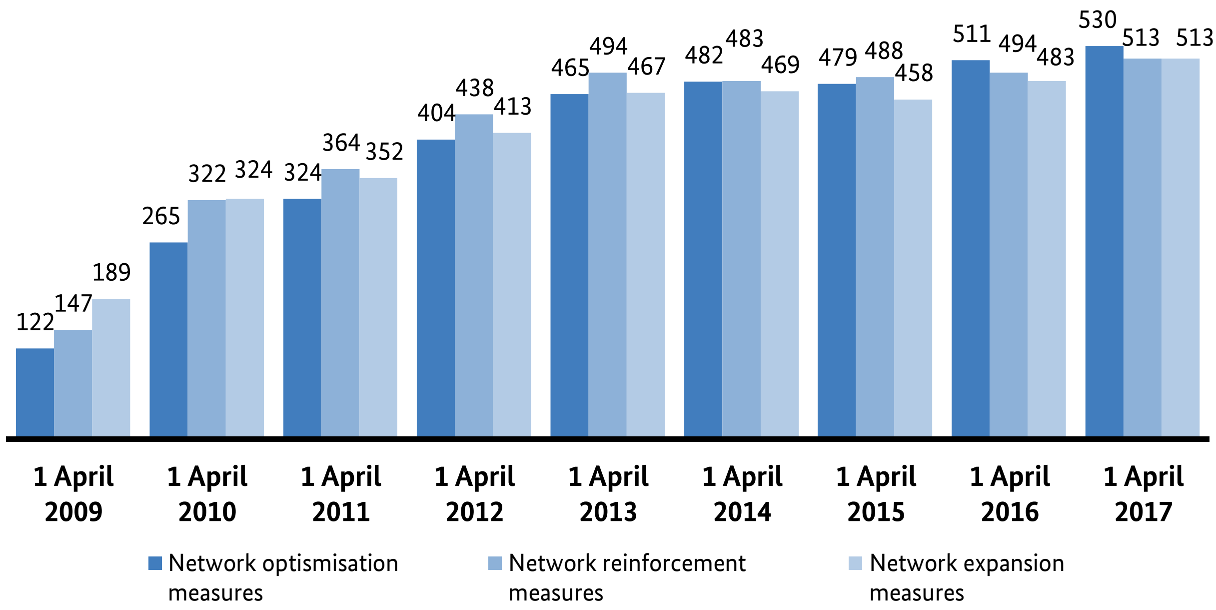


Figure 29: DSOs' network optimisation, reinforcement and expansion measures

Overview of network optimisation and reinforcement measures
(number of DSOs)

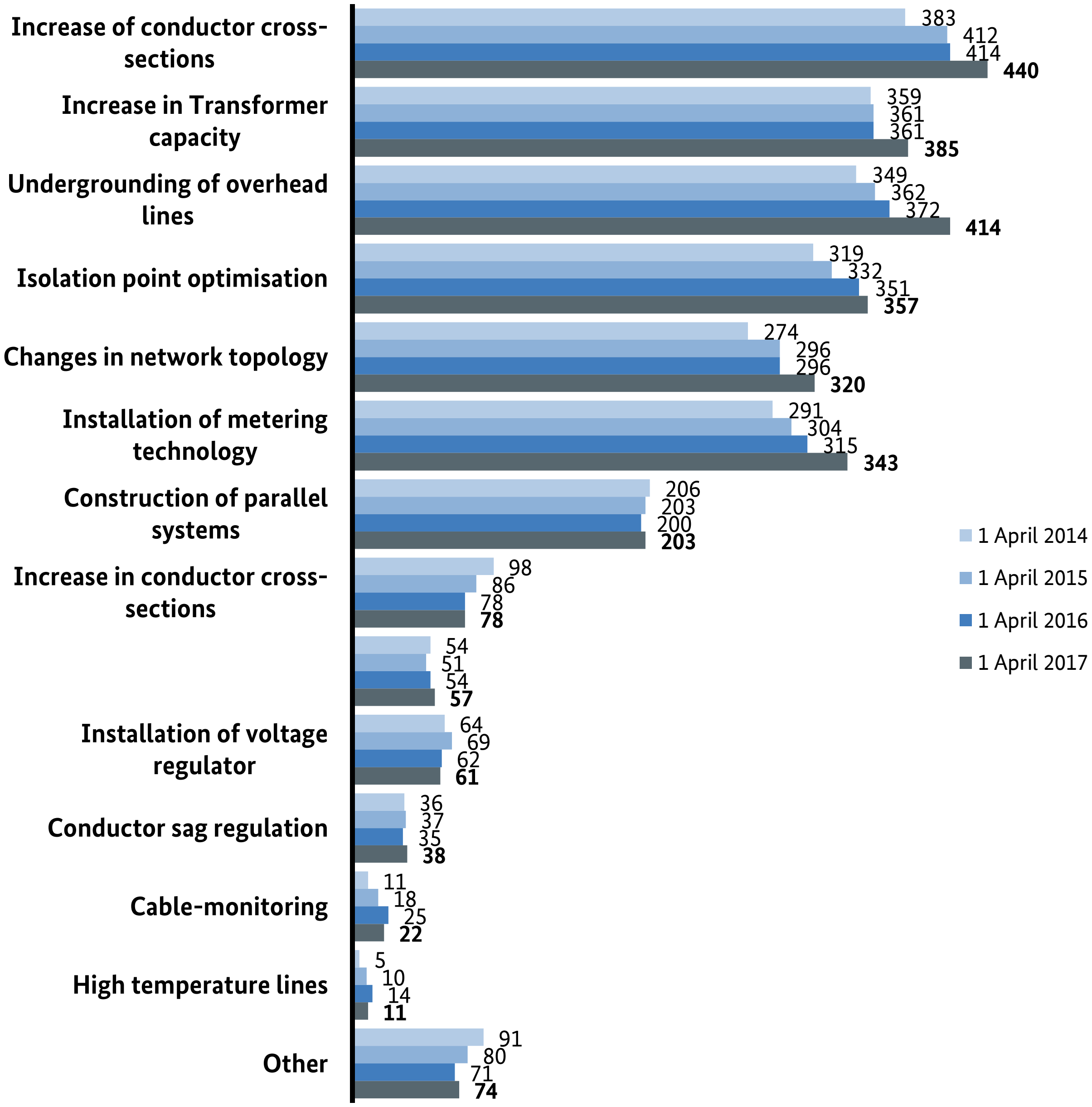


Figure 30: Overview of network optimisation and reinforcement measures taken

Figure 30 shows the measures implemented by the DSOs to optimise and reinforce their networks. There were year-on-year increases in particular in the number of measures for replacing overhead lines with underground cables (+42 DSOs), installing metering technology (+28 DSOs), and changing network topology (+24 DSOs). There was a slight decrease in measures for conductor monitoring and high temperature conductors.

2.2 Network expansion requirements

2.2.1 High-voltage network operators' expansion requirements

Operators of electricity distribution networks are required by section 14(1a) of the Energy Industry Act (EnWG) to draw up and submit to the regulatory authority a report on the status of their networks and their network expansion plans within two months of a request from the authority.

In the 2017 monitoring survey, 57 DSOs operating high-voltage networks were asked to submit reports so as to identify their expected network expansion requirements for the next ten years. The reports submitted by the DSOs cover 98% of the total circuit length at high-voltage level, 70% at medium-voltage level and 67% at low-voltage level.

2.2.2 Total expansion requirements (all voltage levels)

The planned and ongoing network expansion measures reported to the Bundesnetzagentur as at 31 December 2016 comprise a total investment volume of €10bn in the next ten years (2017 2027).

This represents another increase compared to the previous years (€9.3bn and 57 DSOs at the end of 2015, €6.6bn and 56 DSOs at the end of 2014, and €6bn and 53 DSOs at the end of 2013).

The following diagram shows the investment volume forecast by the DSOs for network expansion at all voltage levels.

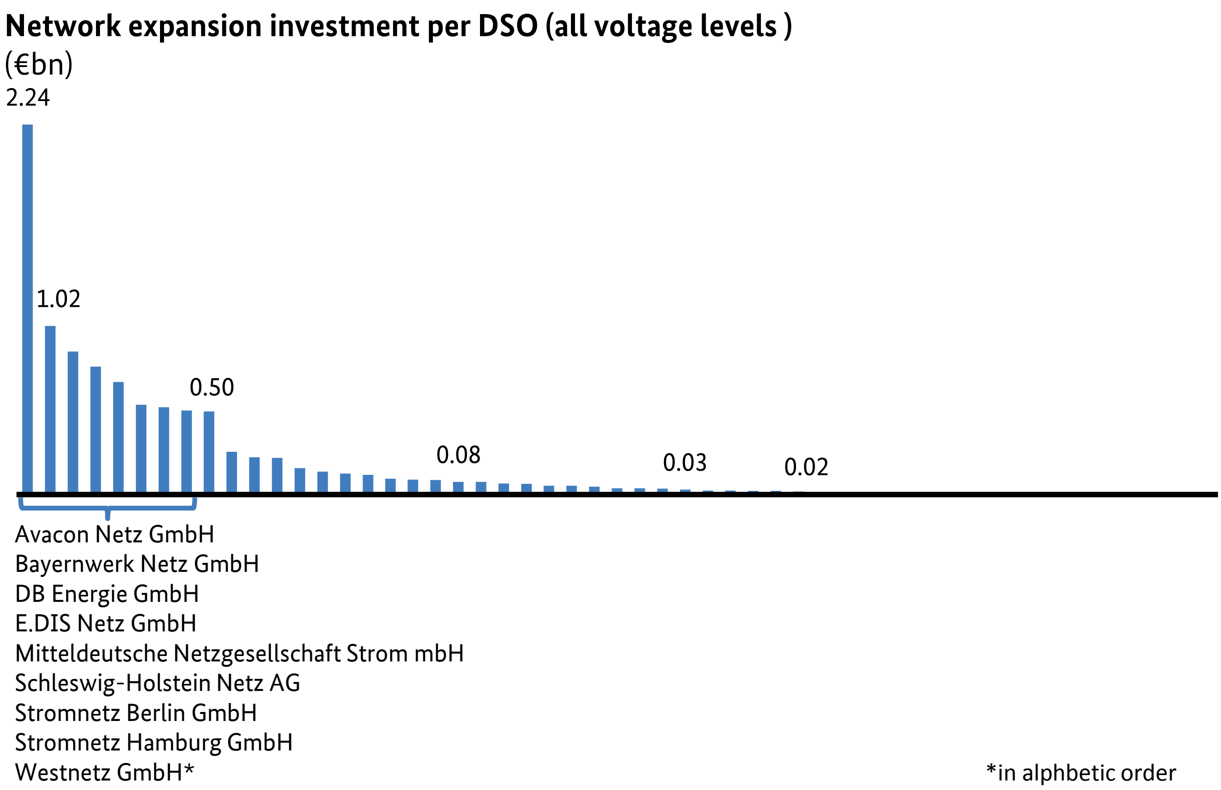


Figure 31: Network expansion investment per DSO (all voltage levels)

There is a very heterogeneous distribution: 19 DSOs forecast expansion measures comprising a volume of up to €10m in the next ten years, a further 22 DSOs forecast measures of up to €100m, and the remaining 16 DSOs forecast a high volume exceeding €100m and accounting for nearly 90% of the total forecast by all the DSOs. The nine DSOs with the highest planned and ongoing investment volumes are Avacon Netz GmbH, Bayernwerk Netz GmbH, DB Energie GmbH, E.DIS Netz GmbH, Mitteldeutsche Netzgesellschaft Strom mbH, Schleswig Holstein Netz AG, Stromnetz Berlin GmbH, Stromnetz Hamburg GmbH and Westnetz GmbH.

The forecasted network expansion measures are necessary not only because of the growth in renewable energy and embedded generation, but to a large extent also because of restructuring and – in some cases age-related – replacement investments. Only 398 of the 1,758 planned or ongoing investment measures reported are due in technical terms to the expansion in renewable energy installations. The growth in renewable energy thus accounts for around €1.84bn of the total planned investment volume of €10bn across all distribution network and voltage levels. The reasons for the DSOs' network expansion measures vary considerably. While Stromnetz Berlin GmbH, with the highest investment requirements, is planning virtually no investment measures to connect and integrate embedded generation, more than three quarters of E.DIS Netz GmbH's planned or ongoing investments are linked to the growth in embedded generation.

The DSOs' reports also show that many DSOs continue to find it difficult to plan network expansion over a period of ten years: not only are new measures added every year, decisions are also taken not to implement some of the planned measures. Planning uncertainties arise in particular from the fact that it is difficult to make long-term predictions about the exact siting of renewable energy generating facilities, a factor that is even more important at distribution than at transmission level. Other reasons include lengthy procedures for obtaining official permits, objections from public agencies or land owners, and modifications to high-voltage network expansion plans to accommodate expansion in the transmission network. The planning uncertainties concern not only details such as the chance of realising the planned investment measures and the timetable for the planned investments, however, but also – to a considerable extent – the estimated investment volume, with planned investments for projects sometimes varying up or down by more than 50%. DSOs cite the approval process and coordination with upstream operators, the public and other stakeholders as the most common reasons for changing their plans.

The Bundesnetzagentur was notified of a total of 2,089 measures for the period up to 2027 (compared to 1,984 at the end of 2015, 1,318 at the end of 2014, and 1,263 at the end of 2013).

At the time of the survey, 1,282 or 61% of these measures were still at the planning stage and 476 or 23% were in progress, while 331 or 16% had been completed by the beginning of 2017.

This represents an increase in absolute terms in particular in the number of planned network expansion measures.

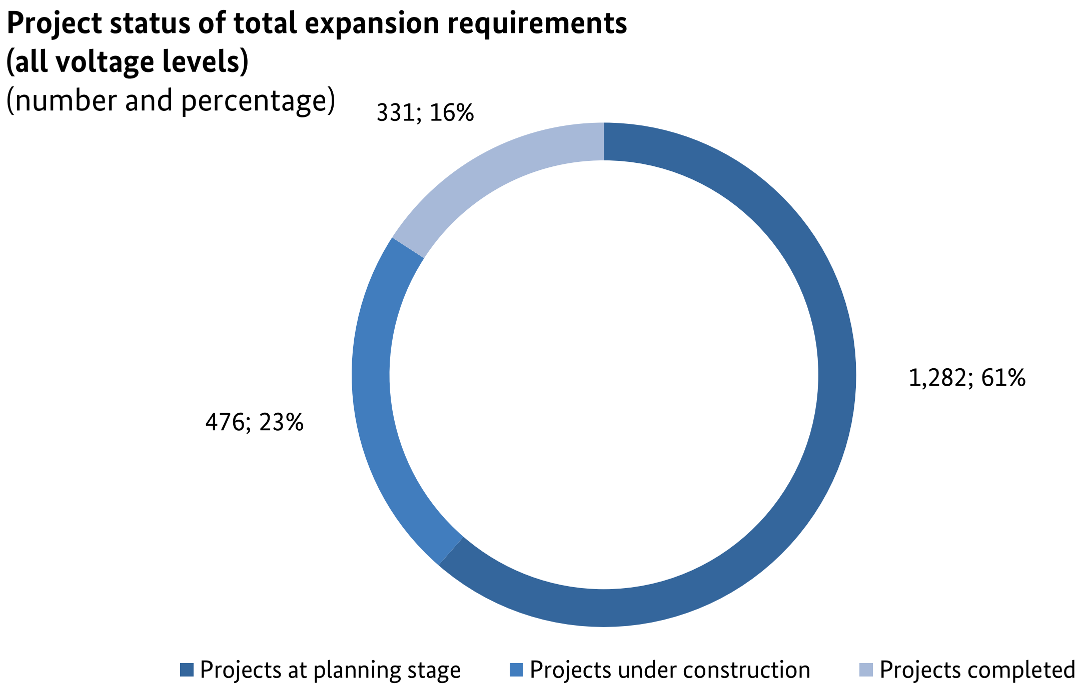


Figure 32: Project status of total expansion requirements (all voltage levels)

3. Investments

For the purposes of the monitoring survey, investments are defined as the gross additions to fixed assets capitalised in 2016 and the value of new fixed assets newly rented and hired in 2016. Expenditure arises from the combination of all technical or administrative measures taken during the life cycle of an asset to maintain or restore working order so that the asset can perform the function required.

The following figures are the values under commercial law derived from the TSOs' and DSOs' balance sheets. The values under commercial law do not correspond to the implicit values included in the operators' revenue caps in accordance with the provisions of the Incentive Regulation Ordinance (ARegV). A comparative calculation of the values under commercial law with the values from incentive regulation will be able to be made following the introduction of index-based investment monitoring pursuant to section 33(5) of the Ordinance. Medium to long-term trends can be derived from the evaluations on the basis of the survey of commercial values. The introduction of index-based investment monitoring pursuant to section 33(5) of the Ordinance is currently being prepared by the Bundesnetzagentur taking account of the effort required for companies to transmit data.

3.1 Transmission system operators' investments and expenditure

In 2016, investments in and expenditure on network infrastructure by the four German TSOs amounted to around €2,439m, up 3% on the previous year's figure of €2,358m. The difference between actual investments and expenditure in 2016 and the figure of €2,698m forecast in last year's monitoring survey is about €260m. The TSOs thus realised 90% of their planned investments and expenditure.

The individual categories for network infrastructure investments and expenditure are shown in Table 22:

TSOs' network infrastructure investments and expenditure

	2016	2015
Investments (€m)	**2,073**	**2,060**
New build, upgrade and expansion projects other than for cross-border connections	1,636	1,672
New build, upgrade and expansion projects for cross-border connections	234	172
Maintenance and renewal excluding cross-border connections	203	216
Maintenance and renewal of cross-border connections	0	0
Expenditure (€m)	**366**	**298**
Expenditure excluding cross-border connections	363	296
Expenditure on cross-border connections	3	2
Total	**2,439**	**2,358**

Table 22: TSOs' network infrastructure investments and expenditure

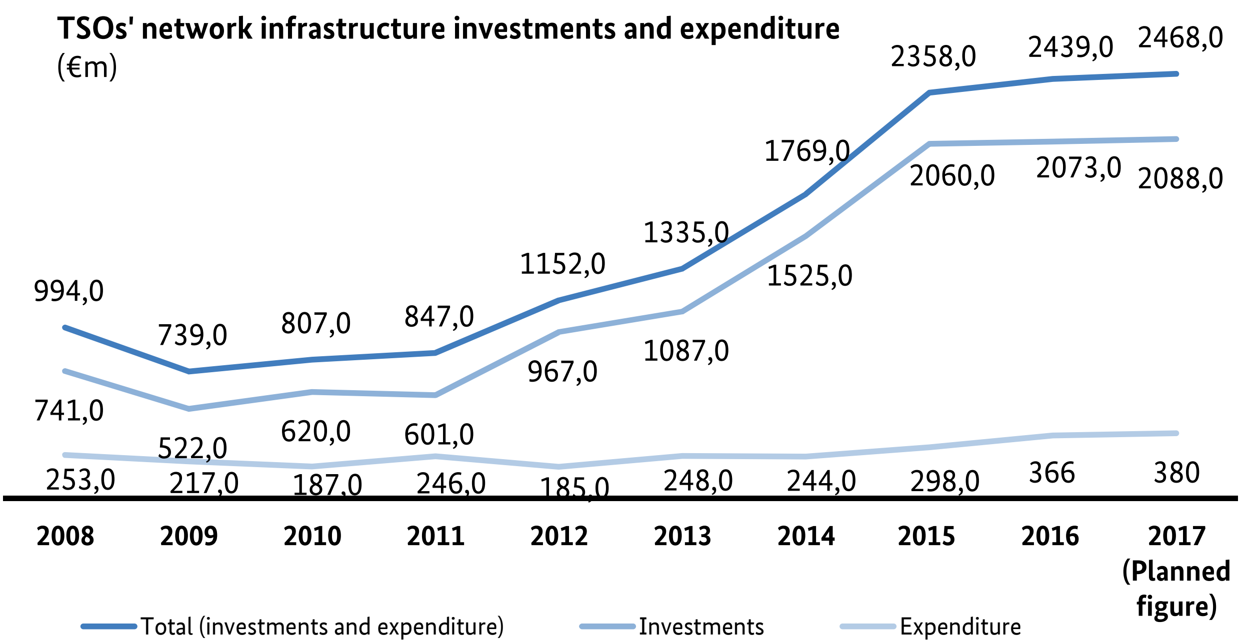


Figure 33: TSOs' network infrastructure investments and expenditure since 2008 (including cross-border connections)

Total investments of around €2,088m and total expenditure of €380m are currently planned for 2017. The planned total for investments and expenditure of about €2,468m is around 1% higher than the total amount realised in 2016.

Figure 33 shows the figures for investments, expenditure and combined investments and expenditure (including cross-border connections) since 2008 and the planned figures for 2017.

3.2 Distribution system operators' investments and expenditure

In 2016, investments in and expenditure on network infrastructure by the 828 DSOs amounted to around €7,157m, up 5% on the previous year's figure of €6,845. Investments and expenditure for metering systems amounted in 2016 to around €506m, compared to €482m in 2015. The planned total for investments and expenditure in 2017 is €6,772m. Figure 34 shows the figures for investments, expenditure and combined investments and expenditure since 2008 and the planned figures for 2017.

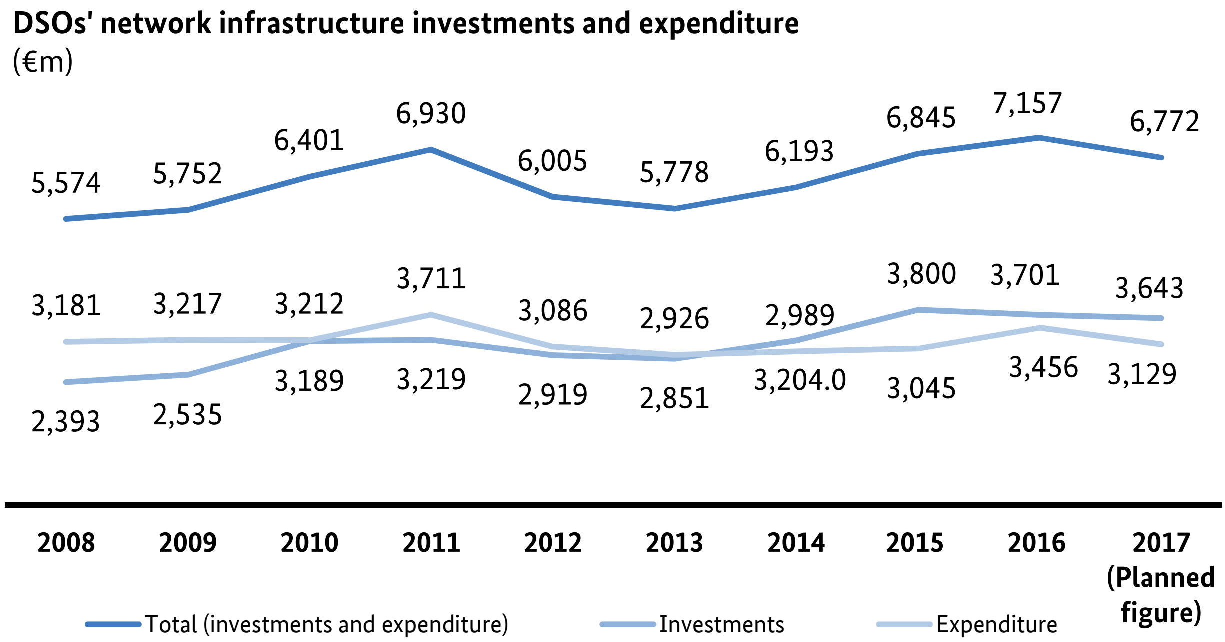


Figure 34: DSOs' network infrastructure investments and expenditure

The level of investment by DSOs depends on circuit lengths, the number of meter points served, and other individual structural parameters, including in particular geographical factors. DSOs with longer circuits tend to have higher investments. 172 or 21% of the DSOs are in the €0 €100,000 investment category. 78 or around 9% of the DSOs are in the top category with investments exceeding €5m per network area. Figure 35 shows the percentage of DSOs in each investment category:

DSOs by investment
(%)

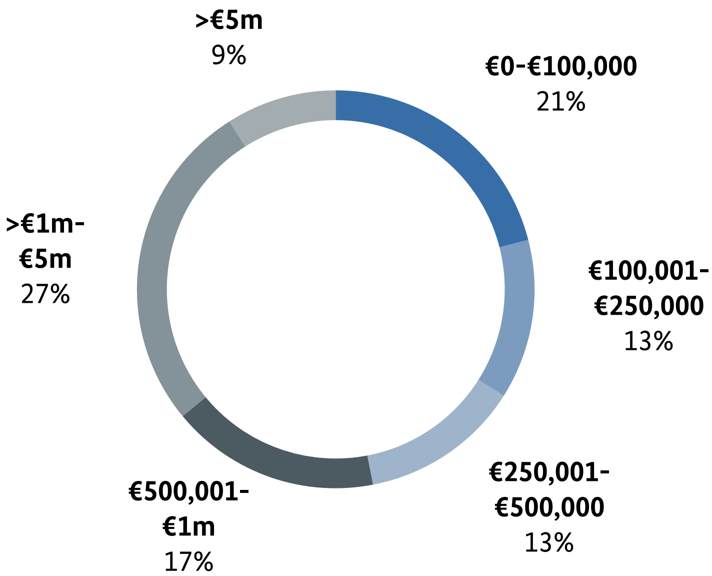


Figure35: DSOs by investment

DSOs by expenditure
(%)

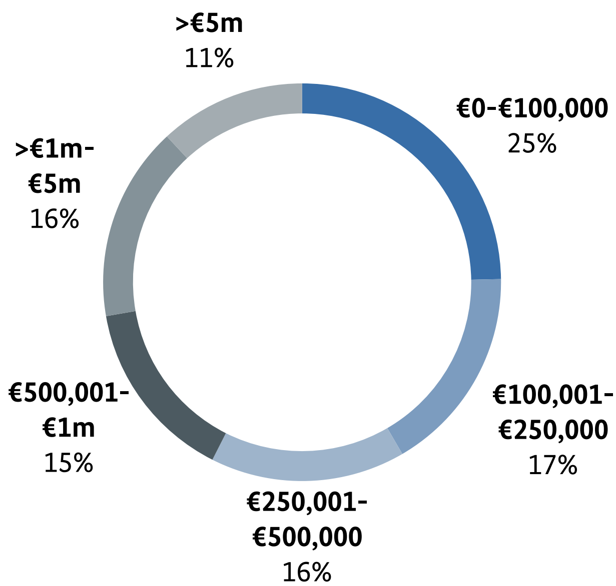


Figure 36: DSOs by expenditure

178 or 25% of the DSOs are in the €0 €100,000 expenditure category. 83 or 12% of the DSOs are in the category with expenditure exceeding €5m. In 2016, more than half of the DSOs – 58% – recorded network expenditure exceeding €250,000.

3.3 Investments and incentive regulation

The Incentive Regulation Ordinance gives network operators the opportunity to budget for expansion and restructuring investment costs in the network charges over and above the level approved in the revenue caps. Under section 23 of the Ordinance, the Bundesnetzagentur grants approval upon application for individual projects that meet the stated requirements.

Since the amendment to section 23 of the Ordinance in spring 2012, investment projects are subject to approval on their merits. Once approval has been given, network operators may adjust their revenue caps by the operating and capital costs associated with their project immediately in the year in which the costs are incurred. The operators' costs are then subject to ex post checks by the Bundesnetzagentur.

As at 31 March 2017, 85 new applications for electricity and gas investment projects had been submitted to the competent ruling chamber. The acquisition and production costs associated with the projects across all segments amount to around €8.8bn. 71 applications totalling approximately €8.4bn were submitted for the electricity sector; 51 applications comprising a volume of around €8.3bn were from TSOs and 20 applications comprising about €0.1bn from DSOs.

4. Electricity supply interruptions

Operators of energy supply networks are required under section 52 of the Energy Industry Act 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. The report must state the time, duration, extent and cause of each supply interruption lasting longer than three minutes. Network operators must also provide information on the measures required to avoid supply interruptions in the future.

For the year 2016, 860 operators reported 172,504 interruptions in supply for 868 networks for the calculation of the average supply interruption ($SAIDI_{EnWG}$[28]) for final consumers. The figure of 12.80 minutes calculated for the low-voltage and medium-voltage levels is below the ten-year average from 2006 to 2015 of 15.87 minutes. The quality of supply thus remained at a consistently high level in 2016.

[28] The system average interruption duration index $SAIDI_{EnWG}$ (referred to in the last report simply as SAIDI) differs from the index $SAIDI_{ARegV}$ calculated for each individual company for the quality factor in the incentive regulation scheme.

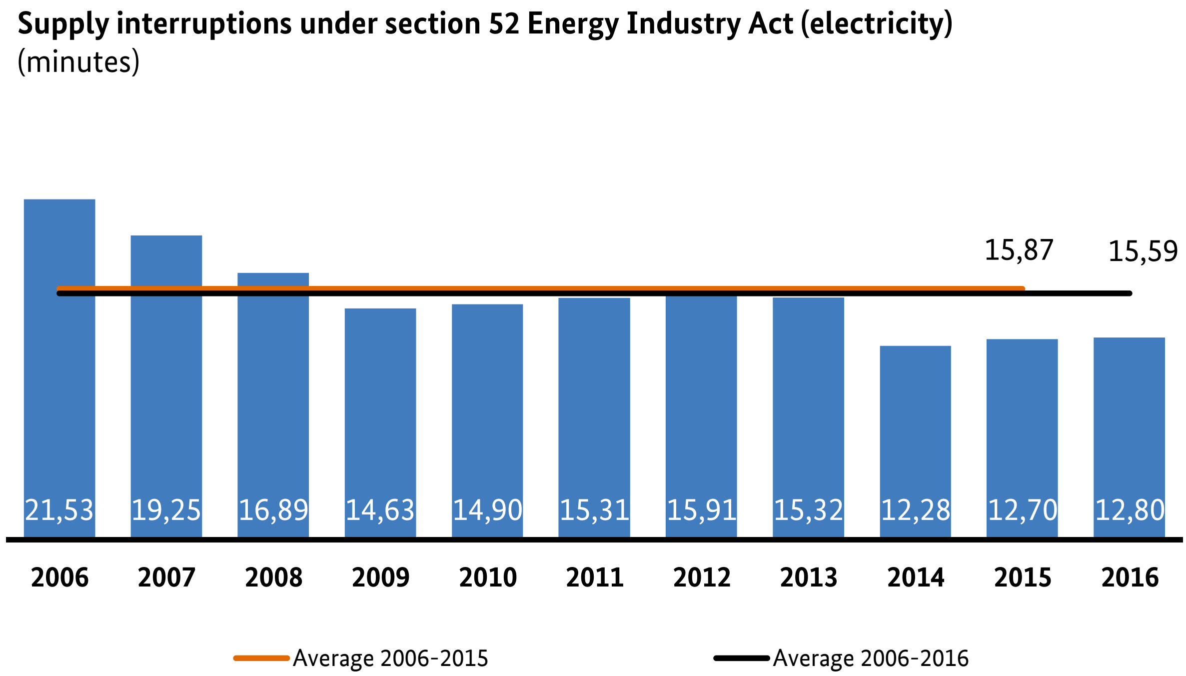


Figure 37: SAIDI: 2006-2016

The slight increase in the average supply interruption in 2016 is solely due to the increase of 0.25 minutes to 10.70 minutes for the medium-voltage level. The average for the low-voltage level, by contrast, decreased year on year by 0.15 minutes.

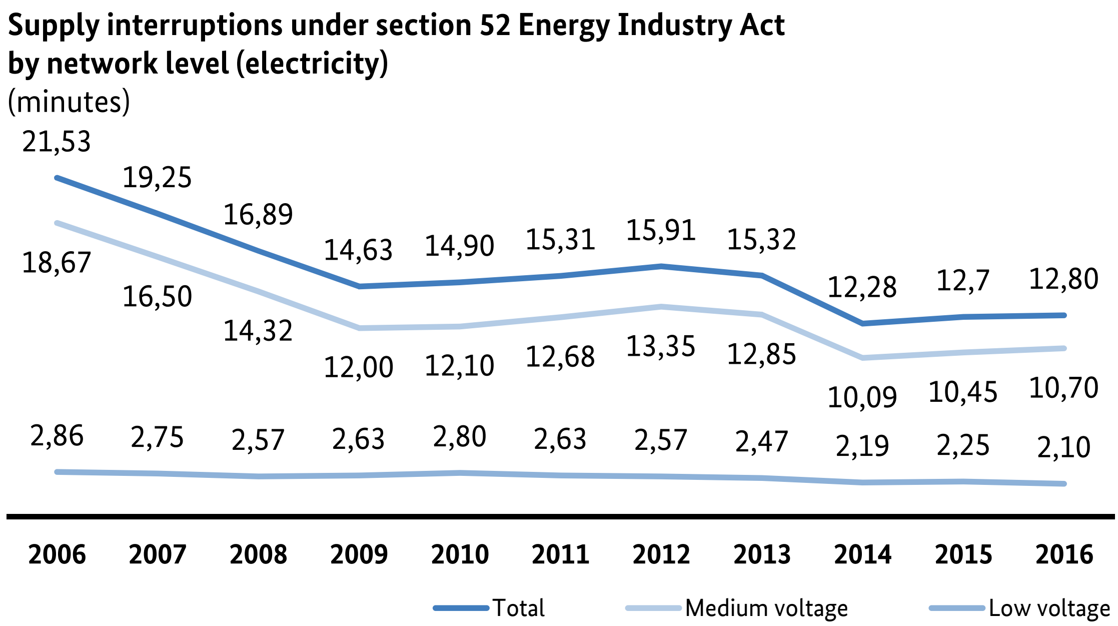


Figure 38: SAIDI at low-voltage and medium-voltage level: 2006-2016

There was an increase in particular in the number of supply interruptions caused by ripple effects. These are interruptions that are caused in a network by a disturbance in an upstream or downstream network or at the final consumer's facility or by an interruption in supply at a power plant feeding in to the grid.

There was a year-on-year decrease in the number of supply interruptions caused by atmospheric effects. These effects include in particular thunderstorms, gales and storms, ice, sleet, snow, hoar frost, fog, dew, condensation (including in connection with pollution), rain penetration, snowmelt, flooding, cold, heat, and conductor gallop (oscillation of conductors). Since there were hardly any weather extremes (such as winds of up to force 10 on the Beaufort scale) in 2016 compared to the previous year, a decrease is plausible.

The energy transition and the associated growth in embedded generation again does not appear to have had a significant impact on the quality of supply in 2016.

5. Network and system security measures

Network operators are legally entitled and obliged to take certain measures to maintain the security and reliability of the electricity supply system. There are various possible measures:

- **Redispatching:** Reducing and increasing electricity feed-in from power plants according to a contractual arrangement with a network operator or with a statutory obligation towards the network operator with costs being reimbursed.
- **Grid reserve power plants:** Deploying grid reserve plant capacity to compensate for a deficit of redispatch capacity according to a contractual arrangement with costs being reimbursed.
- **Feed-in management:** Curtailing feed-in from renewable energy and combined heat and power (CHP) installations at the network operator's request with compensation being paid.
- **Adjustment measures:** Adjusting electricity feed-in and/or offtake at the network operator's request without compensation, where other measures are insufficient.

The network operators report the network and system security measures taken to the Bundesnetzagentur.

The following table summarises the legal basis and rules for redispatching, feed-in management and adjustment measures together with the volume and costs of the measures taken in 2016. The table contains updated costs for redispatching that differ from the figures for 2016 published in the quarterly report on network and system security measures. The table also contains updated figures for the feed-in management compensation payments. The other figures correspond to those published for 2016 in the quarterly report.

Network and system security measures under section 13 of the Energy Industry Act: 2016

	Redispatching	Feed-in management	Adjustment measures
Legal basis and regulatory content	Energy Industry Act sections 13(1) and 13a(1) Network-related and market-related measures: topological measures such as balancing energy, interruptible loads, redispatching, countertrading	Energy Industry Act section 13(2) and (3) sentence 3 in conjunction with RES Act sections 14 and 15, for CHP installations in conjunction with CHP Act section 3(1) sentence 3 Feed-in management: reduction in feed-in from renewable energy, mine gas and CHP installations	Energy Industry Act section 13(2): Adjustment of electricity feed-in, transit and offtake
Rules for affected installation operators	Measures according to contractual arrangement with network operator with reimbursement of costs: Energy Industry Act sections 13(1) and 13a(1)	Measures at network operator's request with reimbursement of costs: Energy Industry Act section 13(2) and (3) sentence 3 in conjunction with RES Act sections 14 and 15, for CHP installations in conjunction with CHP Act section 3(1) sentence 3	Measures at network operator's request without reimbursement of costs: Energy Industry Act section 13(2)
Scope in reporting period	Total redispatching volume (TSOs): **11,475 GWh**	Curtailed energy (TSOs and DSOs): **3,743 GWh**	Adjustment measures (TSOs and DSOs): **14.4 GWh**
Estimated costs in reporting period	Redispatching as part of the TSOs' system services[1]: **€220.0m**	Estimated claims for compensation[2] from installation operators under RES Act section 15 (TSOs and DSOs): **€372.7m** Compensation paid to installation operators under RES Act section 15: **€643.0m**	No entitlement to compensation for installation operators for adjustment measures under Energy Industry Act section 13(2)

The figures for redispatching do not include reserve power plants.
[1] Net redispatching costs (see Chapter D "System services")
[2] Provisional estimate of claims from installation operators for compensation for feed-in management measures according to the TSOs' and DSOs' reports to the Bundesnetzagentur

Table 23: Network and system security measures under section 13 of the Energy Industry Act: 2016

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

5.1 Redispatching

Section 13(1) of the Energy Industry Act entitles and obliges TSOs 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 under section 14(1) of the Energy Industry Act 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 include in particular contractually agreed arrangements to maintain the security of the electricity supply system.

Redispatching means measures to intervene in the market-based operating schedules of generating units to shift feed-in. In this context, power plants are instructed by TSOs, either under a contractual arrangement or a statutory obligation, to reduce/increase their feed-in while, at the same time, other power plants are instructed to increase/reduce their feed-in accordingly.[29] These interventions have no impact on the overall balance between generation and load since action is taken to ensure that the reductions in feed-in are balanced physically and economically by increases elsewhere. Redispatching is undertaken by network operators to ensure the safe and reliable operation of the electricity supply networks. The aim is either to prevent overloading of power lines or to relieve overloading. Network operators reimburse the plant operators involved in the redispatching measures for the costs incurred. A distinction is made between electricity-related and voltage-related redispatching. Electricity-related redispatching is used to avoid or relieve sudden overloading affecting power lines and transformer stations. Voltage-related redispatching, by contrast, is used to maintain the voltage in the affected network area, for instance by adjusting reactive power. This involves adjusting the active power feed-in from power plants to enable them to provide the reactive power needed to maintain voltage stability. This can be done by firing idle power plants up to their minimum active power feed-in level or by reducing feed-in from power plants operating at full capacity down to their minimum level. As with electricity-related redispatching, this form of reactive power provision only involves conventional power plants on account of the priority dispatch rules. In the case of voltage-related redispatching, system balancing measures may take the form of market transactions. Redispatching can be an internal measure applicable to one control area only or a wider measure applicable to more than one control area.

The German TSOs provide the Bundesnetzagentur with detailed data on the redispatching measures taken on a monthly basis. The following analysis is based on the data reported in 2016. It does not include any measures taken under the TSOs' cross-area pre-optimisation procedures, which primarily aim to achieve more efficient use of the grid reserve.

5.1.1 Total redispatching in the calendar year 2016

In 2016, the Bundesnetzagentur received reports of electricity-related and voltage-related redispatching totalling 13,339 hours. Since all measures taken to ease restrictions in the network and thus measures taken in parallel are recorded, the sum of the hours in which measures were taken cannot be put in relation to the total number of 8,760 hours in a year. In 2016, redispatching measures were taken on a total of 329 days.

Reductions in feed-in amounted to around 6,256 GWh. The reductions in feed-in as a result of redispatching corresponded to 1.5% of total non-renewable generation, down from 1.9% in the previous year. Increases in feed-in for balancing amounted to around 5,219 GWh. In 2016, reductions and increases in feed-in thus comprised a total volume of about 11,475 GWh. The fact that the increases in feed-in were lower than the reductions in feed-in is mainly due to the additional use of grid reserve plant capacity to balance the adjustments made. The figures for redispatching primarily reflect measures using operational plants. The capacity provided in 2016 by grid reserve power plants amounted to around 1,209 GWh. Details of the deployment of grid reserve plant capacity are set out in section 5.2 below.

The volume of redispatching in 2016 was thus around a quarter lower than in 2015. There was a year-on-year decrease both in the total number of hours, down 2,472 from 15,811, and in the sum of reductions and

[29] All redispatching information and data in this report relate to measures under contractual arrangements or statutory obligations in line with sections 13(1) and 13a(1) of the Energy Industry Act.

increases in feed-in, down 3,961 GWh from 15,436 GWh. While there was a decrease in the volume and duration of the redispatching measures taken in the TenneT and 50Hertz control areas, there was an increase in the TransnetBW and Amprion areas. However, redispatching still primarily affected the TenneT and 50Hertz control areas. The TSOs' preliminary estimates put the costs of redispatching in 2016 at around €220m. This also represents a considerable decrease of about €192m on the previous year's figure of €412m.

Redispatching measures: 2016

Control area	Duration (hours)	Volume of reductions in feed-in (GWh)[1]	Total volume (energy redispatched plus balancing countertrades) (GWh)	Net costs[2] for redispatching (€m)
TenneT	7,609	3,126	6,271	220
50Hertz	4,746	2,859	4,663	
TransnetBW	430	80	158	
Amprion	554	191	383	

[1]If a joint request for redispatching is made by two neighbouring TSOs, the total duration and total volume is halved between the two TSOs for the purpose of the Bundesnetzagentur's analysis.
[2]See Chapter D "System services".

Table 24: Redispatching measures: 2016

The net costs given here for redispatching in 2016 reflect the TSOs' data from April 2017. Updated figures for 2016 and any previous years will be taken into account in the Bundesnetzagentur's cost reviews.

5.1.2 Electricity-related redispatching in the calendar year 2016

Redispatching in 2016 was mainly electricity-related. The electricity-related measures comprised a total of 10,260 hours and reductions in feed-in amounting to 5,721 GWh. Network elements requiring measures lasting at least 12 hours accounted for 93% or 9,870 hours of the total. In addition, the TSOs took further measures totalling 702 hours on other network elements. These measures lasted less than 12 hours for each line.

Figure 39 shows the location of the particularly critical network elements (number of hours per line ≥12) as listed in Table 25 (pages 110 and 111).

Duration of electricity-related redispatching measures on the most heavily affected network elements: 2016

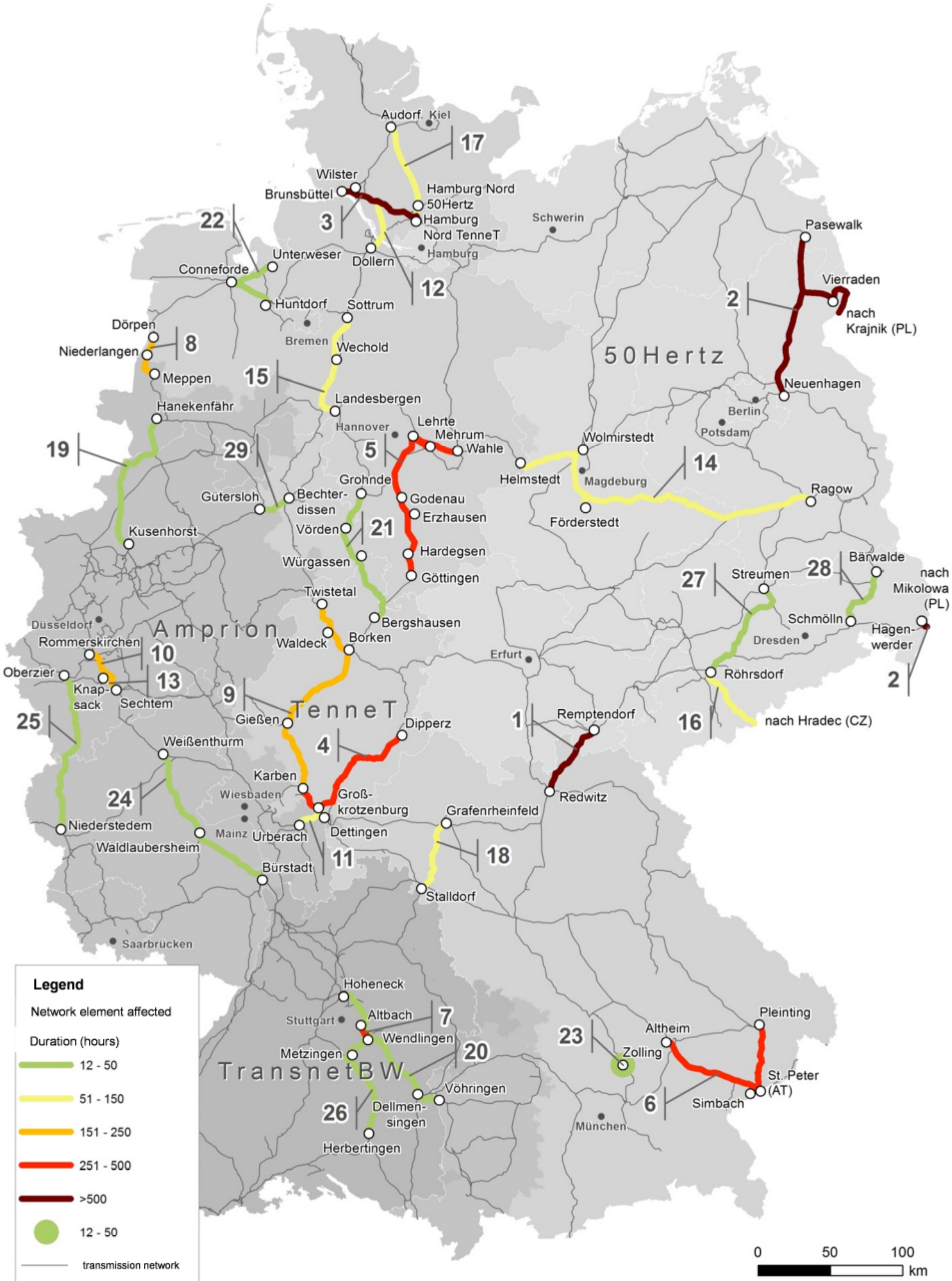


Figure 39: Electricity-related redispatching on the most heavily affected network elements according to TSO reports: 2016

Electricity-related redispatching on the most heavily affected network elements: 2016

No	Network element	Control area[1]	Duration (hours)	Volume of feed-in reductions (GWh)	Volume of feed-in increases (GWh)[2]
1	Remptendorf-Redwitz area	50Hertz/ TenneT	3,499	2,907	2,907
2	Vierraden-Krajnik (PL)-Mikulowa (PL) area (50Hertz control area-PSE network (PL), Hagenwerder-Mikulowa, Pasewalk-Vierraden, Vierraden-Neuenhagen, Mikulowa-Czarna, Mikulowa-Swiebodzice)	50Hertz	1,754	889	889
3	Brunsbüttel-Brunsbüttel 50Hertz area	TenneT/ 50Hertz	1,739	645	645
4	Großkrotzenburg area (Großkrotzenburg, Großkrotzenburg-Dipperz, Großkrotzenburg-Karben)	TenneT	461	273	280
5	Lehrte area (Lehrte-Godenau, Lehrte-Mehrum, Lehrte Wahle, Lehrte-Erzhausen-Hardegsen-Göttingen)	TenneT	451	121	121
6	Simbach-St. Peter (AT) area (Pleinting-St. Peter, Altheim-Simbach-St. Peter)	TenneT	293	127	127
7	Altbach area (Altbach, Altbach-Wendlingen)	TransnetBW	253	35	35
8	Dörpen-Niederlangen-Meppen (Amprion control area)	TenneT/ Amprion	203	78	79
9	Borken area (Borken-Waldeck-Twistetal, Borken-Gießen-Karben, Gießen-Karben)	TenneT	165	69	69
10	Ville Ost line (Rommerskirchen-Sechtem)	Amprion	153	73	70
11	Großkrotzenburg-Amprion control area (Großkrotzenburg-Urberach/Amprion area, Großkrotzenburg-Dettingen/Amprion area)	TenneT/ Amprion	102	35	35
12	Dollern-Wilster	TenneT	84	26	26
13	Walberberg West (Knapsack-Sechtem)	Amprion	75	22	23

[1] The first control area denotes the TSO reporting the redispatching measure to the Bundesnetzagentur.
[2] These counterbalancing volumes may include capacity provided by reserve power plants.

Electricity-related redispatching on the most heavily affected network elements: 2016

No	Network element	Control area[1]	Duration (hours)	Volume of feed-in reductions (GWh)	Volume of feed-in increases (GWh)[2]
14	Wolmirstedt area (Helmstedt - Wolmirstedt, Wolmirstedt-Förserstedt-Ragow)	50Hertz	73	71	71
15	Landesbergen area (Landesbergen-Sottrum, Landesberg-Wechold-Sottrum)	TenneT	66	20	20
16	Röhrsdorf-Hradec (CZ)	50Hertz	65	28	28
17	Hamburg area (Audorf-Hamburg Nord, Hamburg Nord-50Hertz area)	TenneT	57	11	11
18	Grafenrheinfeld-Stalldorf	TransnetBW	56	30	30
19	Grafschaft West line (Kusenhorst-Haneckenfähr)	Amprion	47	1	1
20	Donau Ost/West (Vöhringen-Hoheneck-Dellmensingen)	Amprion	43	9	9
21	Grohnde area (Grohnde-Vörden-Bergshausen, Grohnde Würgassen)	TenneT	37	9	9
22	Conneforde area (Conneforde transformer station, Conneforde-Huntorf, Conneforde-Unterweser)	TenneT	35	8	8
23	Zolling transformer	TenneT	32	2	2
24	Soonwald Ost line (Weissenthurm-Waldlaubersheim-Bürstadt)	Amprion	27	1	1
25	Selhausen West line (Oberzier-Niederstedem)	Amprion	24	20	23
26	Herberting-Hoheneck-Metzingen	TransnetBW	22	4	4
27	Streumen-Röhrsdorf	50Hertz	20	11	11
28	Bärwalde-Schmölln	50Hertz	19	28	28
29	Bechterdissen-Gütersloh/Amprion	TenneT/ Amprion	15	7	7

[1] The first control area denotes the TSO reporting the redispatching measure to the Bundesnetzagentur.
[2] These counterbalancing volumes may include capacity provided by reserve power plants.

Table 25: Electricity-related redispatching on the most heavily affected network elements: 2016

5.1.3 Voltage-related redispatching in 2016

In addition to electricity-related redispatching, the TSOs reported voltage-related redispatching measures totalling 3,077 hours and a volume of around 534 GWh in 2016. This was supplemented by counter trades also amounting to 534 GWh. The volume of voltage-related redispatching measures in 2016 was broadly unchanged from the previous year: while the total number of hours was up 926 on the 2015 figure of 2,151 hours, the volume was only 94 GWh higher than the previous year's 440 GWh. Table 26 shows the duration and volume of the measures required in the individual control and network areas:

Voltage-related redispatching measures: 2016[1]

Network area	Duration (hours)	Volume (GWh)
TenneT control area: southern network area	**128**	**11**
Oberbayern network area	91	9
Nordostbayern network area	37	2
TenneT control area: central network area	**2,352**	**411**
Ovenstädt-Bechterdissen-Borken	970	176
Mehrum-Grohnde-Lehrte-Krümmel network area	127	1
Borken (Borken-Dipperz-Großkrotzenburg, Gießen, Karben) network a	1,255	234
TenneT control area: northern network area	**352**	**65**
Conneforde network area	263	47
Landesbergen network area	89	18
TransnetBW control area: Altbach, Buenzwangen, Endersbach, Muehlhausen, Wendlingen	**97**	**10**
50Hertz control area	**148**	**37**

[1] Since these measures relate to larger network regions (and not individual lines or transformer stations), the measures
Source: Bundesnetzagentur's monitoring section

Table 26: Voltage-related redispatching on the most heavily affected network elements according to TSO reports: 2016

5.2 Deployment of grid reserve plant capacity

The TSOs' decisions on which plants to deploy for redispatching include consideration of the grid reserve. The TSOs consider which grid reserve plants would be most efficient to eliminate the expected network restrictions. Foreign grid reserve plants have regularly proved to be more efficient in terms of having a better network-related effect on restrictions than domestic grid reserve plants. The TSOs require less capacity to fire up foreign grid reserve plants than if they use positive redispatch capacity from the plants in Germany. As a result, smaller volumes are needed by the TSOs to ease the restrictions; this reduces the risk of error in carrying out redispatching measures, which in turn improves the level of system security.

In 2016, the grid reserve was used on 108 days to provide an average capacity of 552 MW and a total of around 1,209 GWh of energy. The available grid reserve capacity totalled 7,515 MW in the first quarter of 2016 and

8,383 MW in the fourth quarter. This shows that although frequent use was made of grid reserve capacity, the volumes needed were generally low and thus the situations in the networks far from critical.

There was an increase in the use of the grid reserve compared to 2015: the number of days was up 69 on the 2015 figure of 39 days and the amount of energy provided was around 658 GWh higher than the previous year's figure of 551 GWh. One of the reasons for this is the TSOs' improved redispatching scheme.

In 2016, the costs for reserving the grid reserve plants in Germany and other countries amounted to €177.4m, while the deployment costs were put by the TSOs at €107.4m. This amounts to total costs of around €285m (see "Costs for system services" starting on page 146).

In the first quarter of 2017, the grid reserve was used on 60 days to provide an average capacity of 1,299 MW and a total of around 1,484 GWh of energy. This means that during the winter half-year of 2016/2017, the grid reserve was used by the TSOs on a total of 108 days. The reasons for this were a shortage of redispatch capacity in southern Germany, particular demand from other western European countries, and large flows of electricity within Germany to the south-west of the country.

Summary of grid reserve deployment: 2016 and 1st quarter 2017

2016	Number of days	Average capacity (MW)	Total energy (MWh)
January	15	1,079	265,213
February	16	1,052	266,573
March	17	655	163,702
April	12	759	120,332
May[1]	4	420	15,100
June[2]	1	595	10,945
July	1	375	1,500
August	0	0	0
September	0	0	0
October	10	389	49,676
November	14	714	151,782
December	18	584	163,974
Total: 2016	**108**	**552**	**1,208,797**
1st quarter 2017	**Number of days**	**Average capacity (MW)**	**Total energy (MWh)**
January	24	1,866	871,150
February	21	1,334	469,234
March	15	698	143,945
Total: 1st quarter 2017	**60**	**1,299**	**1,484,329**

1) One of the four days for operational testing only

2) Operational testing only

Source: TSOs' status reports

Table 27: Summary of grid reserve deployment: 2016 and 1st quarter 2017

5.3 Feed-in management measures and compensation

Feed-in management is a special measure regulated by law to increase network security and relating to renewable energy, mine gas and CHP installations. Priority is to be given to feeding in and transporting the climate-friendly electricity generated by these installations. Under specific conditions, however, the network operators responsible may also temporarily curtail such priority feed-in 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 non-renewable and non-CHP installations have been exhausted. The expansion obligations of the operator answerable for the network restrictions 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 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.

5.3.1 Curtailed energy

The following graph shows the amount of energy curtailed as a result of feed-in management measures since 2009 for the most heavily affected energy sources.

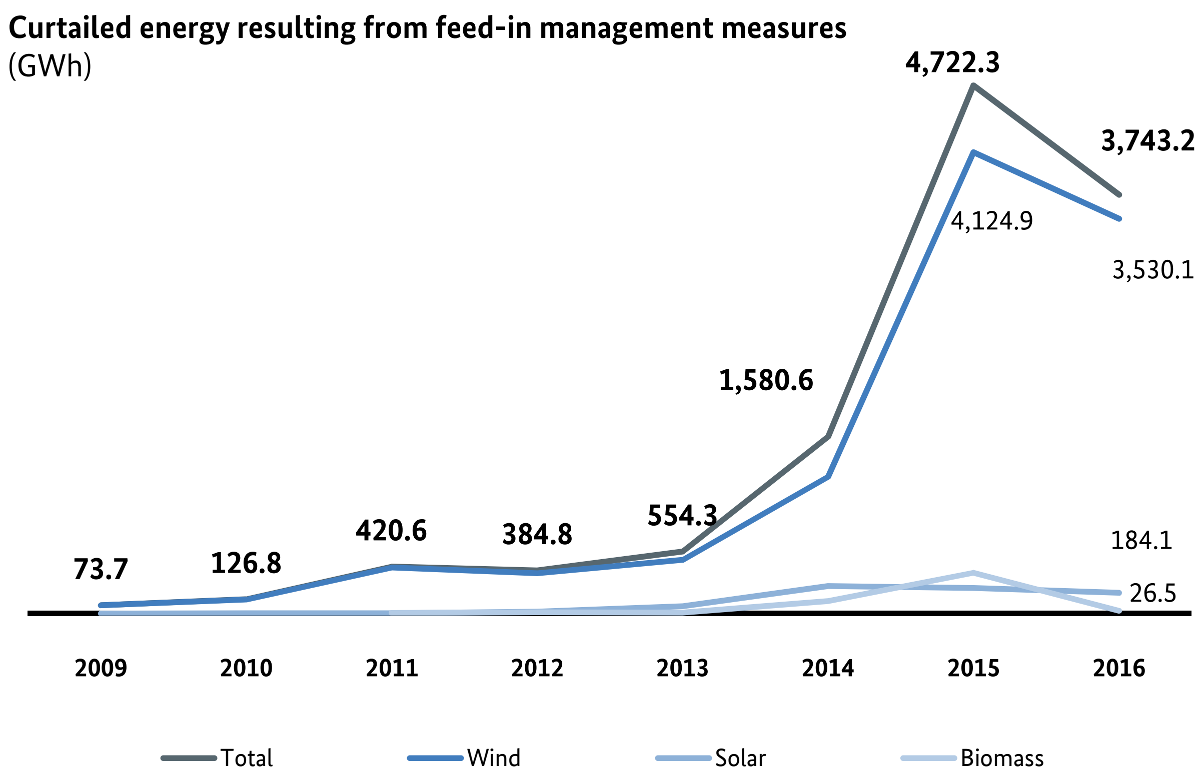


Figure 40: Curtailed energy resulting from feed-in management measures

The amount of energy curtailed as a result of feed-in management measures decreased by a good 20% from 4,722 GWh in 2015 to 3,743 GWh. This corresponds to 2.3% of the total amount of electricity generated in 2016 by installations eligible for payments under the Renewable Energy Sources Act (including direct selling), down from 2.9% in 2015.

The decrease in feed-in management measures is essentially due to various factors. One of these factors is the weather. In 2016, for instance, there were around 25% fewer peaks in feed-in from wind farms than in 2015. The level of curtailed energy remains high despite the decrease in feed-in management measures. Owing to the continued growth in renewables and the work still required to optimise, reinforce and expand the networks, the tense situation in the grid is not likely to improve in the course of next year. Detailed and up-to-date information on feed-in management measures is included in the Bundesnetzagentur's quarterly reports on network and system security.

In 2016, as in previous years, feed-in management measures primarily involved wind power plants, accounting for 93.5% of the total amount of curtailed energy, up from 87.3% in 2015. Offshore wind power plants, which were first affected by feed-in management measures in 2015, accounted for about 32 GW or 0.9% of the total amount of curtailed energy in 2016, up from around 16 GW and 0.3% in 2015. The following table shows the individual amounts of curtailed energy and the percentages of the total amount for the energy sources affected by feed-in management measures:

Curtailed energy resulting from feed-in management measures by energy source

Energy source	Curtailed energy (GWh)	Share
Wind (onshore)	3,498.02	93.5%
Solar	184.08	4.9%
Wind (offshore)	32.03	0.9%
Biomass, including biogas	26.47	0.7%
CHP	1.80	<0.1
Run-of-river	0.50	<0.1
Landfill, sewage and mine gas	0.29	<0.1
Total	**3,743.19**	**100.0%**

Table 28: Curtailed energy resulting from feed-in management measures by energy source: 2016

The network operators' reports on system and network security measures provided the following details of the use of feed-in management: The operators' daily and quarterly reports to the Bundesnetzagentur show that the TSOs were responsible for the majority of the feed-in management measures taken in 2016. Overall, restrictions in the transmission networks accounted for around 89% of the energy curtailed, although installations connected to transmission networks accounted for only 4% of the energy curtailed and compensated. The remaining 96% was accounted for by installations connected to distribution networks. Support measures requested by the TSOs but taken by the DSOs accounted for the majority – 85% – of the curtailed energy (see Table 29). Compensation for the support measures taken by the DSOs must be paid by the TSOs.

Many regions in Germany are now affected by feed-in management measures. Nonetheless, 97% of the curtailed energy is the result of feed-in management measures in the northern federal states, with Schleswig-Holstein particularly affected (see Figure 41).

Curtailed energy under section 14 of the Renewable Energy Sources Act: 2016

	Curtailed energy under RES Act section 14 (GWh)	Percentage of total curtailed energy
Measures taken by TSOs (cause in transmission network)	**149.33**	**0.039894341**
Measures taken by DSOs	**3,593.86**	**0.960105659**
DSOs' own measures (cause in distribution network)	395.65	11%
DSOs' support measures (cause in transmission network)	3,198.21	85%
Total feed-in management measures	**3,743.19**	**1**

Table 29: Curtailed energy under section 14 of the Renewable Energy Sources Act: 2016

Curtailed energy by federal state: 2016
(GWh)

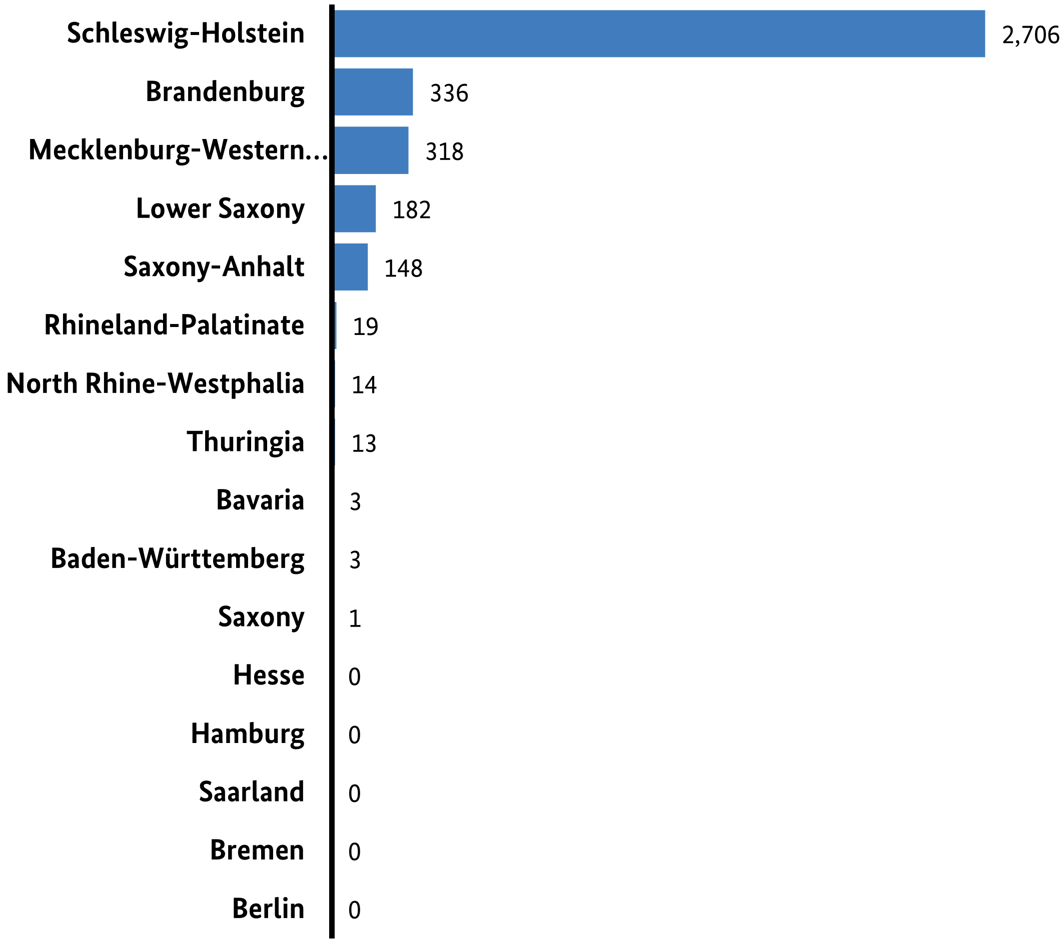


Figure 41: Curtailed energy by federal state: 2016

5.3.2 Compensation claims and payments

A distinction must be made between the network operators' estimates of the claims for compensation for feed-in management measures in a specific year and the actual compensation paid in that year. The estimates are based on the amount of curtailed energy from renewable energy installations and reported to the Bundesnetzagentur on a quarterly basis. The actual compensation paid is the amount of compensation paid by network operators to installation operators during the year under review and reported on an annual basis in the monitoring survey. This includes the costs of compensation for measures taken up to three years previously. This means, for example, that the figure for 2016 may include costs arising from measures taken in 2013, 2014 and 2015. Consequently, the compensation paid in one year does not reflect the actual costs incurred for curtailments in that year. A revised questionnaire now makes it possible to determine the amount of compensation paid for curtailments in previous years. The compensation paid to operators of the renewable and CHP installations affected – 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.[30]

The sum total of compensation payments more or less doubled in 2016 to around €643m. The costs of the compensation paid to the installation operators are borne by the network charges paid by the final consumers, adding an average of around €12.68 per final consumer in 2016, compared to €6.26 in 2015 and €1.65 in 2014. The additional costs are 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 payments have to be paid for the electricity generated but not fed in from the renewable and CHP installations. Figure 42 below shows the compensation paid each year since 2009 as a result of feed-in management measures.

The compensation is generally settled through bills from the installation operators. A number of network operators also offer credits (without bills from the installation operators). The compensation paid in 2016 therefore does not reflect the actual amounts payable for the curtailments in 2016. The compensation paid in 2016 also includes amounts payable for curtailments in previous years.

The claims for compensation from installation operators in 2016, based on the network operators' quarterly estimates, amounted to around €373m, down some €105m on 2015.[31]

[30] 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 receive equivalent amounts of electricity from the system operator through redispatching; this eliminates marketing risks created by network restrictions.

[31] See the Bundesnetzagentur's quarterly reports available at: https://www.bundesnetzagentur.de/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/Versorgungssicherheit/Netz_Systemsicherheit/Netz_Systemsicherheit_node.html

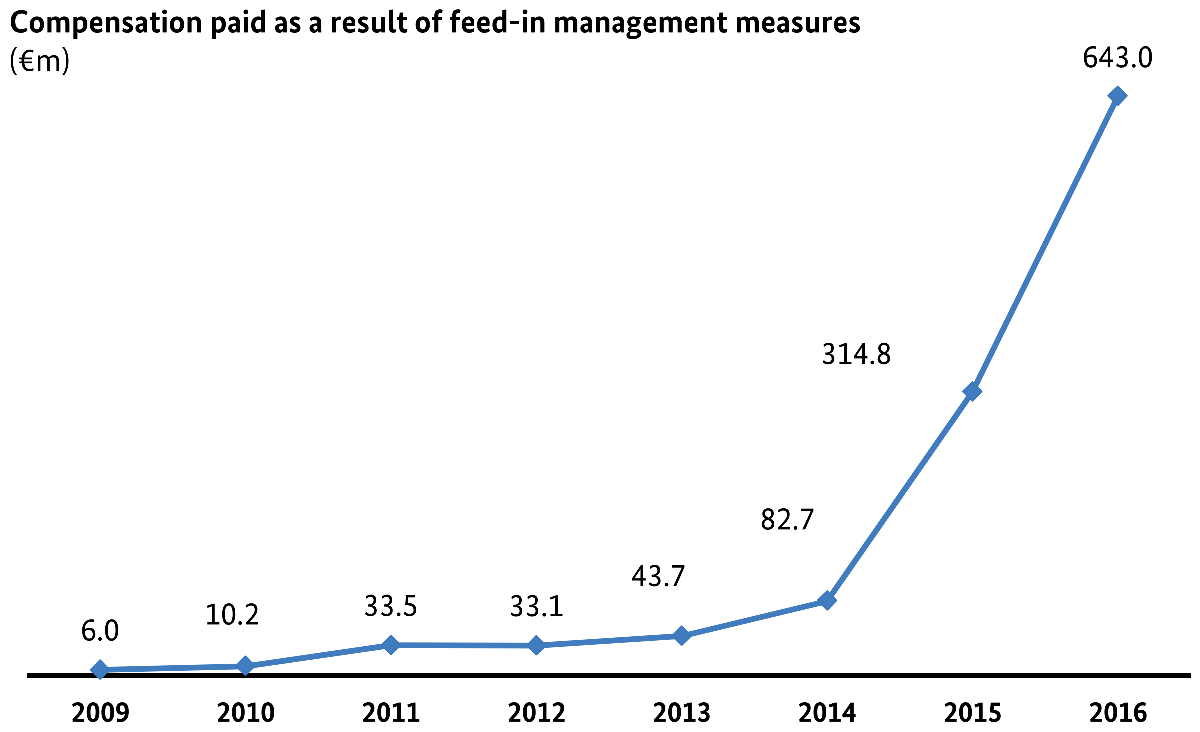


Figure 42: Compensation paid as a result of feed-in management measures

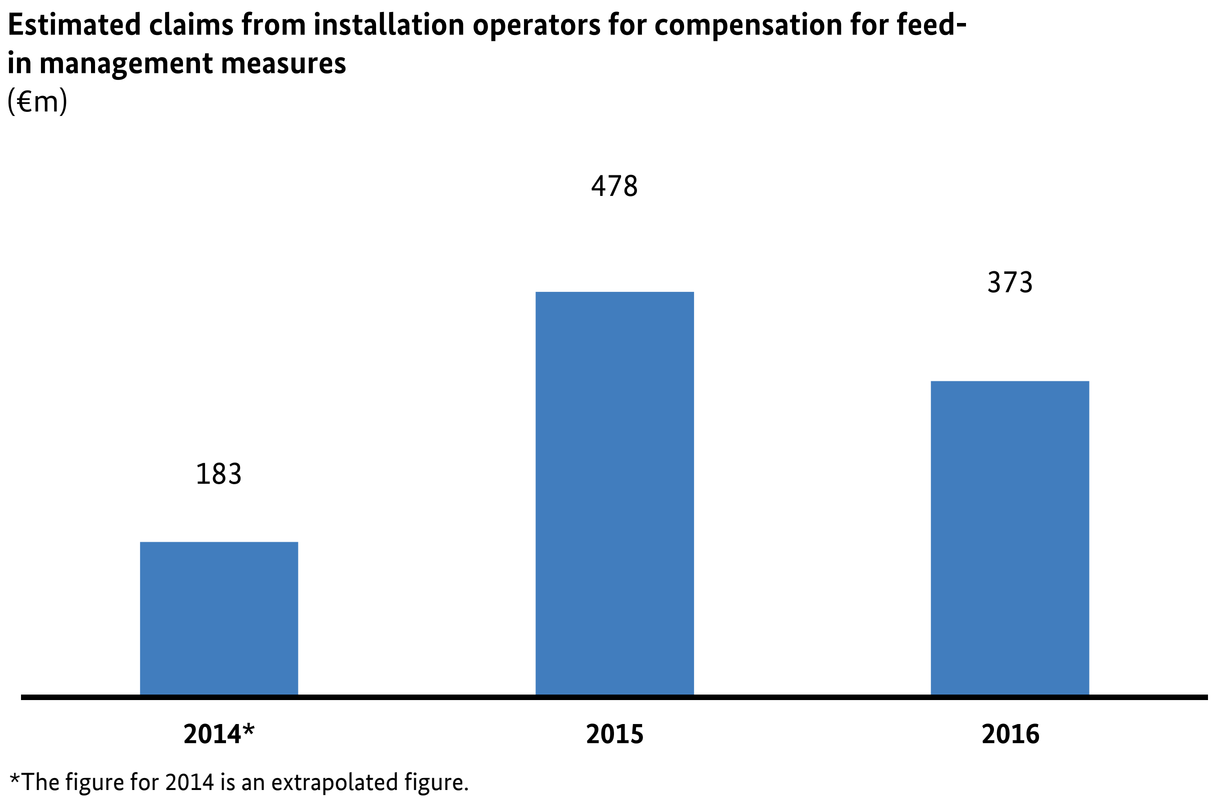


Figure 43: Estimated claims from installation operators for compensation for feed-in management measures

In 2016, the network operators paid a total of around €643m in compensation to the installation operators. Approximately €238m was compensation for curtailments in 2016, while the remaining amount of around €405m was compensation for curtailments in previous years. This means that some 63% of the claims from installation operators for compensation for curtailments in 2016, as estimated by the network operators, have already been settled. At the time of the survey, around 37% or €134m of the estimated compensation claims had not yet been settled; this will have a knock-on effect on the amount of compensation paid in subsequent years. Table 30 shows the detailed figures for the network operators' estimates of compensation claims and the actual compensation paid:

Compensation payments under section 15 of the Renewable Energy Sources Act according to network operator data: 2016

	Estimated claims for compensation from installation operators (€)		Total compensation paid under RES Act section 15 (€)		Compensation for measures in previous years (€)
Measures taken and compensation paid by TSOs (cause in transmission network)	**17,368,347**	**0.047**	**19,212,855**	**0.0299**	**8,968,979**
Measures taken and compensation paid by DSOs	**355,367,241**	**0.95**	**623,812,383**	**0.97**	**395,759,610**
DSOs' own measures (cause in distribution network)	37,668,928	0.1	196,203,870	0.31	162,778,562
DSOs' support measures (cause in transmission network)	317,698,314	0.85	427,608,513	0.66	232,981,048
Total feed-in management measures	**372,735,588**	**1**	**643,025,239**	**1**	**404,728,589**

Table 30: Compensation payments under section 15 of the Renewable Energy Sources Act according to network operators' reports: 2016

5.4 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 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 required to take their own measures to support measures implemented by the TSOs, as instructed by the TSOs (support measures).

Curtailing feed-in from renewable energy, mine gas and CHP installations 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 network restrictions but by another security problem. The measures to be taken in such cases do not affect grid expansion measures that may also be required in the particular network area concerned.

In 2016, a total of four DSOs and one TSO took adjustment measures. The measures taken to adjust electricity feed-in and offtake totalled around 14.4 GWh. Non-biodegradable waste was by far the most frequently adjusted source of energy, accounting for around 87%. Saxony-Anhalt accounted for the majority of the adjustment measures with 56%, followed by Saxony with 23% and Hesse with 12%.

Feed-in and offtake adjustments by energy source: 2016

Energy source	Adjustments under section 13(2) (GWh)	Share
Waste (non-biodegradable)	11.34	86.9%
Pumped storage	1.41	10.8%
Black coal	0.20	1.5%
Natural gas	0.10	0.8%
Total	**14.35[1]**	**100.0%**

[1] This figure includes 1.3 GWh from the 1st quarter of 2016 that cannot be attributed to a specific energy source.

Table 31: Feed-in and offtake adjustments by energy source: 2016

5.5 Black coal stocks at south German power plants

The prolonged low-water period in winter 2016/2017 resulted in considerable restrictions on and also interruptions to shipping transportation for black coal deliveries to coal-fired power plants in the TransnetBW control area.

These restrictions were exacerbated by low temperatures and consequent ice on the Neckar river. The cold temperatures also halted rail deliveries to sites without thawing facilities that enable frozen coal to be unloaded from the wagons even when outside temperatures are low.

The cold period in January 2017, higher electricity prices and extensive redispatching meant that there was a high level of generation from black coal-fired plants, leading to a depletion in stocks. This resulted in low stock levels at a number of sites in the TransnetBW control area as well as generally very low levels at sites in Saarland within the Amprion control area. The south German plants in the TenneT control area, by contrast, had sufficient stocks.

The stocks of coal are regularly documented by the TSOs responsible – TransnetBW, Amprion and TenneT TSO – in cooperation with the power plant operators. TransnetBW and Amprion had taken measures together with the plant operators to conserve and expand the stocks.

These measures included changes in the use of power plants with low stock levels for redispatching in order to conserve the stocks of coal at these plants. The TSOs also instructed individual plants to increase their stocks to a minimum level.

The plant operators endeavoured to optimise and expand delivery options, but there was often limited scope for alternative deliveries by train or ship.

The measures taken by the TSOs and the plant operators made it possible to mostly stabilise stocks during the cold and low-water period, albeit at a generally low level.

It was not until the second half of February 2017, when milder temperatures and considerable rainfall led to significant increases in river levels, that a longer-term improvement to the situation could be achieved through increased ship deliveries. This made it possible for stocks at all the plants in southern Germany and Saarland to be replenished up to a sufficient or good level by the end of February.

The findings from the low-water period 2016/2017 will be used to elaborate the low-water action plan drawn up by TransnetBW following the previous low-water period in November 2015. In this context, TransnetBW is also in dialogue with the plant operators to enable their past experience and proposals for possible action in future low-water situations to be taken into account. TransnetBW and the plant operators will also discuss the options for additional stocks of coal to be maintained at individual sites.

A repeat of last winter's shortage in Saarland is not expected in the future since the two largest plants – Bexbach and Weiher III – are due to become part of the grid reserve in winter 2017/2018. Grid reserve power plants are required to maintain a minimum level of stock as set by the TSO responsible, which in this case is Amprion.

6. Network charges

6.1 Setting network charges

Network charges are levied by the TSOs and DSOs and make up part of the retail price for electricity (see also G "Retail" section 4 "Price level" starting on page 223). Network charges are based on the costs incurred by the network operators for the operation, maintenance and expansion of their networks. These regulated costs are the basis for the prices that network operators are allowed to charge network users for transporting and distributing energy. Under the legislative provisions in Germany, network charges are only payable when electricity is drawn from a network; generators feeding in electricity into a network, who are also "network users", do not have to pay network charges. There are three steps in the process of setting network charges:

Determining the network costs

The regulatory regime is divided into five-year regulatory periods. The base level of costs is set before the beginning of each regulatory period by means of a cost examination in accordance with section 6 of the Incentive Regulation Ordinance. The competent regulatory authorities examine each operator's network operation costs as set out in the certified annual accounts in accordance with the principles laid down in the Electricity Network Charges Ordinance (StromNEV). The last cost examination was carried out on the basis of the costs of the base year 2011. The next cost examination will be carried out beginning in the second half of 2017 on the basis of the costs of the year 2016. This step results in determining the networks costs recognised as necessary for network operation, which in turn form the basis for setting the revenue caps under the incentive-based regime.

Setting the revenue caps

In the second step, the recognised network costs are used to set a revenue cap in accordance with the provisions of the Incentive Regulation Ordinance. Each revenue cap generally applies for the whole of a regulatory period. The operators' network costs are subject to an efficiency benchmarking exercise to compare the costs (input) with the scope of the services supplied (output). The recognised costs and the efficiency benchmarking results are used to set the revenue cap. Any inefficiencies need to be remedied in the course of the regulatory period. The revenue cap stipulates the revenue each operator is allowed to generate within a regulatory period to be able to operate and maintain the network.

The revenue cap can be adjusted and reviewed once a year within a regulatory period under certain conditions only[32]. The factors leading to such adjustments include:

- changes to what are known as the permanently non-controllable costs; these costs include, for example, avoided network costs (see 6.5), upstream operator costs, costs of retrofitting renewable energy installations in accordance with the System Stability Ordinance (SysStabV) (see 6.6), investment costs as provided for by section 23 of the Incentive Regulation Ordinance (see 3.3), grid reserve costs (see 5.2), costs of procuring balancing reserves (see D "System services"), redispatching costs (see 5.1), feed-in management costs (see 5.3), and offshore transmission link costs (see 1.4);
- the retail price index, which reflects general inflation;

[32] A new cost examination is not carried out. A review is made of, for instance, the annual capital expenditure (capex) true-up and adjustments to the permanently non-controllable costs.

- the expansion factor, which covers the costs of network expansion within a regulatory period (but which will no longer be used after the end of 2018);
- the quality element;
- the incentive regulation account balance: differences between forecast and actual figures are entered into the account and then added to or deducted from the revenue cap; differences between forecast and actual consumption quantities are also recorded in the account.

Deriving the network charges

The network charges are derived by the network operators on the basis of the principles laid down in the Electricity Network Charges Ordinance. The allowed revenues (revenue cap) are allocated to the network or substation levels as cost-reflectively as possible.

The specific annual costs for each network or substation level (in euros per kilowatt per year) are then calculated by dividing the total costs for the level by the simultaneous maximum load at that level in the year, beginning with the highest level operated. Unlike in gas networks, network charges are payable solely by network users drawing electricity from a network; no network charges are payable by network users feeding in electricity. The "coincidence function" (section 16 of the Electricity Network Charges Ordinance) is applied to derive four charges from the specific annual costs: a capacity charge and a unit charge for <2,500 hours and for >2,500 hours of network usage. The basic idea is to make a plausible assumption about a network user's contribution to the network costs: a network user whose individual annual maximum load very probably contributes to the annual maximum load of the network pays a higher capacity charge. The probability is derived from a network user's hours of usage and is reflected in the charging scheme by the different charges for <2,500 hours and >2,500 hours of network usage. A unit charge and, in some cases, a standing charge is to be set for non-interval-metered network users (those with an annual offtake of less than 100,000 kWh – mainly household customers and smaller commercial customers at low-voltage level). In this case, there is no general rule that the two charges must be "in reasonable proportion" to each other, which allows for a certain margin.

The charges calculated and the forecast sales cover the network or substation level costs. Offtake at the next lower network or substation level is treated as consumption, with the costs being passed on.

This principle is applied at all further levels; however, as the low-voltage network is the lowest level, no costs are passed on and all the network costs need to be covered at that level. In light of the significant changes in generation and usage structures as a result of the energy transition, there has been increasing discussion in 2016 and 2017 about the actual meaning of "cost-reflective" in terms of the key cost drivers contributing to network costs. This discussion may – but will not necessarily – lead to changes in the structure of network charges.

The network operators publish their provisional network charges on their websites on 15 October each year for the following calendar year and then publish their final charges on 1 January of the year in which the charges take effect. They are not allowed to make any changes to the published network charges in the course of the year. Operators must demonstrate to the regulatory authority that their published network charges as validated in accordance with section 20(1) of the Electricity Network Charges Ordinance cover the network costs (revenue cap) as determined in the first step of the process and do not exceed the costs.

6.2 Average network charges in Germany

The analysis of average network charges in Germany is based on data submitted in the monitoring survey by electricity suppliers. The suppliers provide data on their average network charges for customers in specific consumption groups and different contract categories. The consumption groups are as follows:

- "household customers" on default contracts: as from 2016, the network charges relate to an annual consumption of between 2,500 kWh and 5,000 kWh (Eurostat Band DC) and low-voltage supply; prior to this, the charges related to households with an annual consumption of 3,500 kWh;

- "commercial customers": annual consumption 50 MWh, annual peak load 50 kW, annual usage period 1,000 hours, low-voltage supply (0.4 kV);

- "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 pursuant to section 19 of the Electricity Network Charges Ordinance.

The electricity suppliers' data is used to calculate the national average volume-weighted[33] network charge for each consumption group. Figure 44 shows the changes in the network charges (in cents per kilowatt hour) from 1 April 2006 to 1 April 2017, whereby the year 2006 was marked by special effects arising from the introduction of regulation. As from 1 January 2017, the network charges include the charges for billing, while the charges for metering are included under "meter operations". The figures shown incorporate these charges that were previously itemised separately.

The charges for household customers show an increase, having been broadly stable in the period between 2013 and 2015. In the period from 1 April 2016 to 1 April 2017, the charges rose by 0.59 ct/kWh or almost 9% to 7.30 ct/kWh. The charges for non-household customers are also up on a year earlier: the charges for commercial customers rose by 0.34 ct/kWh or almost 6% to 6.19 ct/kWh, while those for industrial customers with an annual energy consumption of 24 GWh increased by 0.20 ct/kWh or a good 10% to 2.26 ct/kWh.

Various new factors have had an additional influence on the network charges since 2006. The energy transition has been accompanied by a significant increase in embedded generation. The increase in electricity generation has 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 have also been integrated into the calculation of the network charges.

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

The fact that the network charges 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 frequently at the low-voltage level.

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

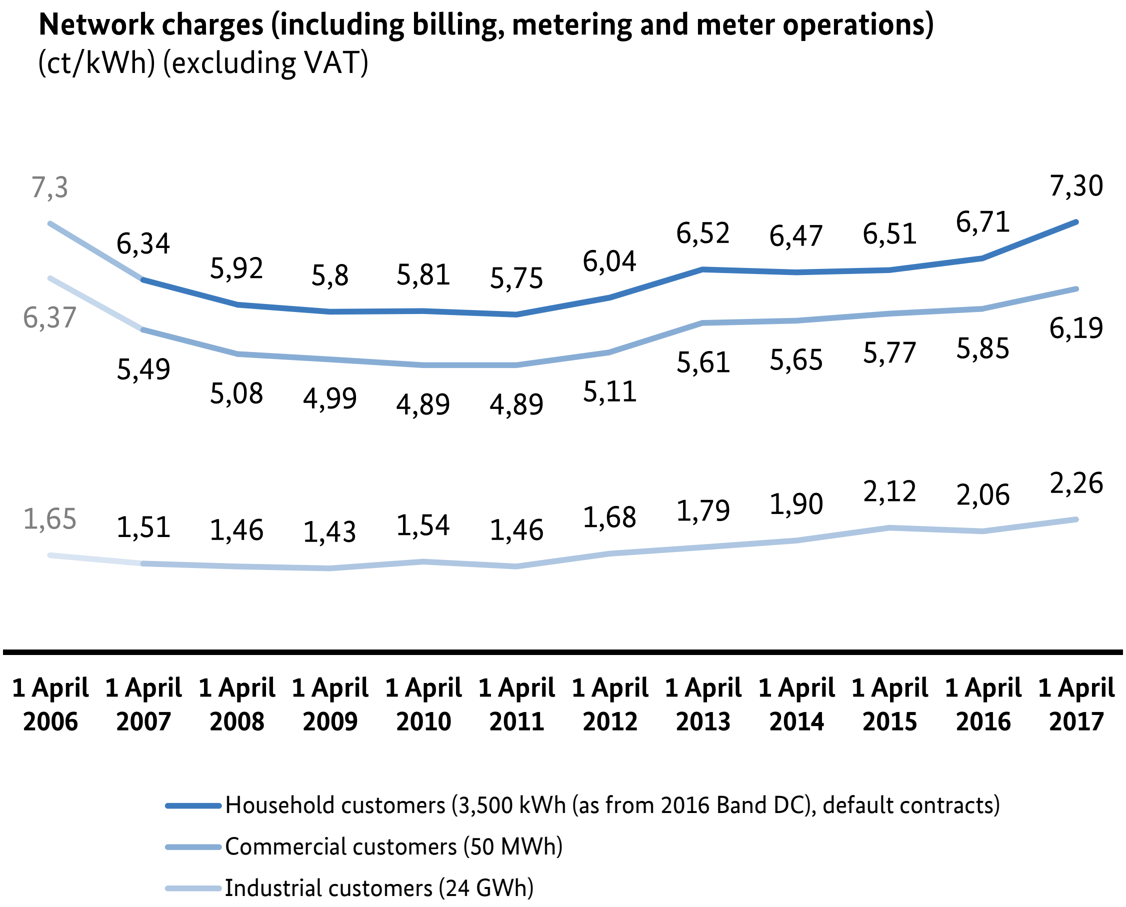

Figure 44: Network charges: 2006 -2017

6.3 Regional differences in network charges

There are large regional differences in the network charges. In the monitoring survey, network charges across Germany have been compared using the information in the DSOs' published price lists relating to the three consumption groups (household, commercial and industrial customers – see 6.2 "Average network charges in Germany"). Section 27(1) of the Electricity Network Charges Ordinance requires all network operators to publish the network charges applicable in their networks on their websites. The information relating to each DSO's unit and capacity charges was used to calculate the network charges (in cents per kilowatt hour) applicable for 2017. The information does not include either the charges for metering and meter operations or VAT; the billing charges are included in the network charge. Seven categories from <5 ct/kWh to >10 ct/kWh have been used to illustrate the differences in network charges more clearly. The network charges were calculated regardless of whether or not the DSOs actually have customers in a specific consumption group. This is relevant in particular in the case of industrial customers. An overview of the network charges in each federal state was also created: the individual network charges were weighted with the relevant number of meter points to obtain the average network charge in each federal state.

The network charges for household customers range from just over 3.1 ct/kWh to 13.6 ct/kWh. This represents a difference by a factor of up to four. The map illustrating the spread of network charges shows that charges in the north-east and east are generally higher than in the south-west. There are also differences between urban and rural areas. The overview of average charges in the different federal states shows that Schleswig-Holstein has the highest charges and Bremen the lowest.

Net network charges for household customers in Germany: 2017

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks included
Schleswig-Holstein	8.64	5.24	11.01	43
Saxony-Anhalt	8.23	4.40	8.92	29
Mecklenburg-Western Pomerania	7.82	5.35	11.36	18
Thuringia	7.70	5.29	9.56	30
Saxony	7.54	5.57	9.60	36
Brandenburg	7.25	3.44	9.24	27
Lower Saxony	7.19	3.96	10.21	71
Bavaria	7.16	3.12	11.71	232
Hesse	6.78	4.32	8.65	48
Hamburg	6.76	6.76	6.76	1
Saarland	6.63	5.04	13.63	19
Baden-Württemberg	6.49	3.86	11.55	122
Rhineland-Palatinate	6.41	4.28	9.31	55
Berlin	6.30	6.25	6.30	2
North Rhine-Westphalia	6.20	4.05	9.75	102
Bremen	5.39	5.25	8.67	4

*The weighting was based on the number of the operators' meter points in each network area.

Table 32: Net network charges for household customers in Germany: 2017

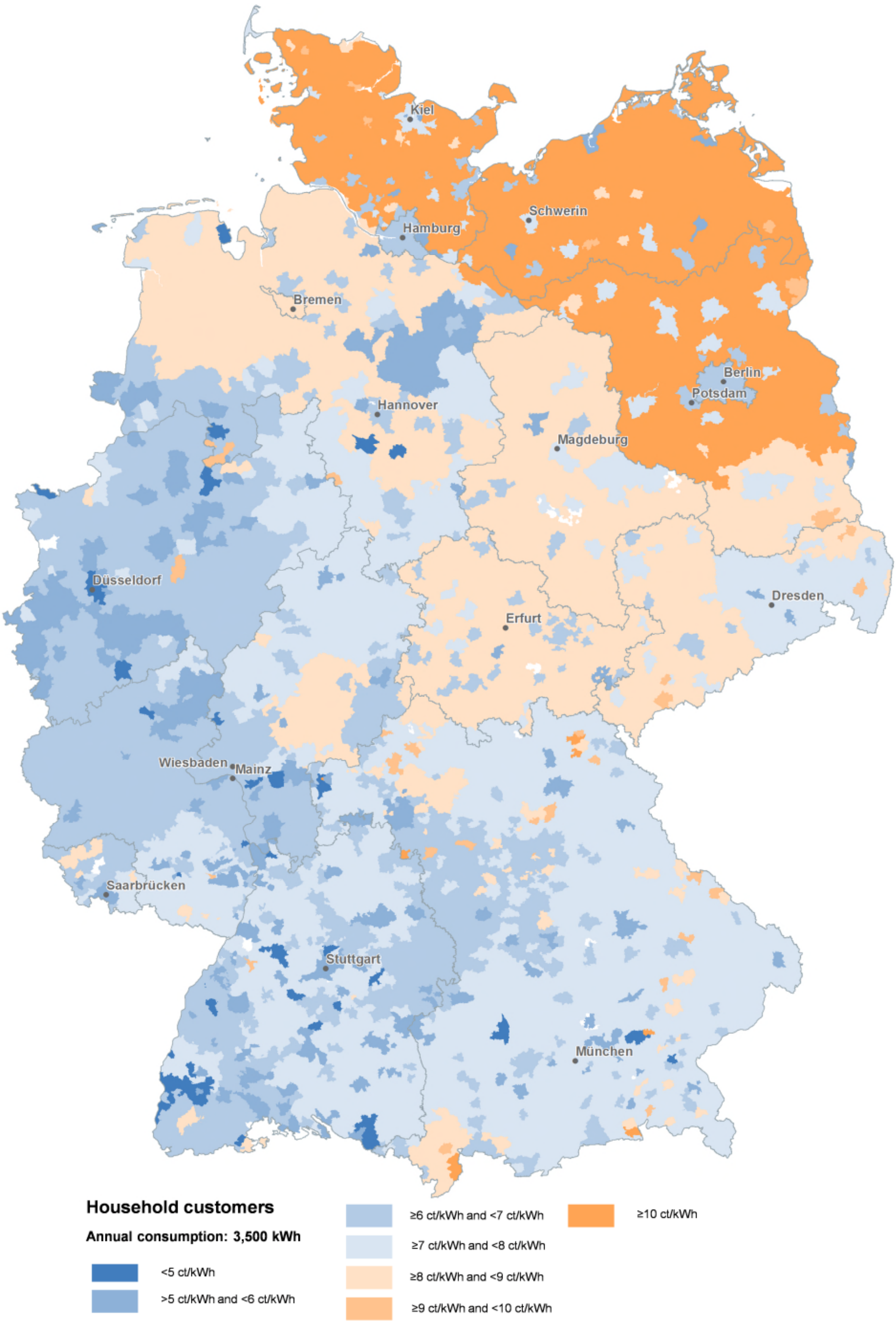

Figure 45: Spread of network charges for household customers

The spread of network charges for the 50 MWh annual consumption group (commercial customers) is similar to that for household customers, with charges ranging from 2.8 ct/kWh to 10.4 ct/kWh. Overall, however, charges are lower than for household customers. Schleswig-Holstein has the highest average charges and Bremen the lowest compared to the other federal states.

Net network charges for commercial customers in Germany: 2017

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks included
Schleswig-Holstein	7.11	4.04	9.38	43
Thuringia	6.79	4.55	8.13	30
Saxony	6.78	4.73	8.61	36
Brandenburg	6.62	3.17	8.44	27
Saxony-Anhalt	6.62	3.84	7.92	29
Mecklenburg-Western Pomerar	6.60	4.57	9.32	18
Baden-Württemberg	6.11	3.25	10.00	122
Bavaria	5.91	3.12	10.38	232
Lower Saxony	5.89	3.54	9.81	71
Rhineland-Palatinate	5.84	2.83	8.84	55
Hamburg	5.80	5.80	5.80	1
Hesse	5.56	3.39	7.75	48
Saarland	5.51	4.26	7.49	19
Berlin	5.42	5.42	5.78	2
North Rhine-Westphalia	5.12	3.36	9.54	102
Bremen	3.86	3.71	8.03	4

*The weighting was based on the number of the operators' meter points in each network area.

Table 33: Net network charges for commercial customers (annual consumption 50 MWh) in Germany: 2017

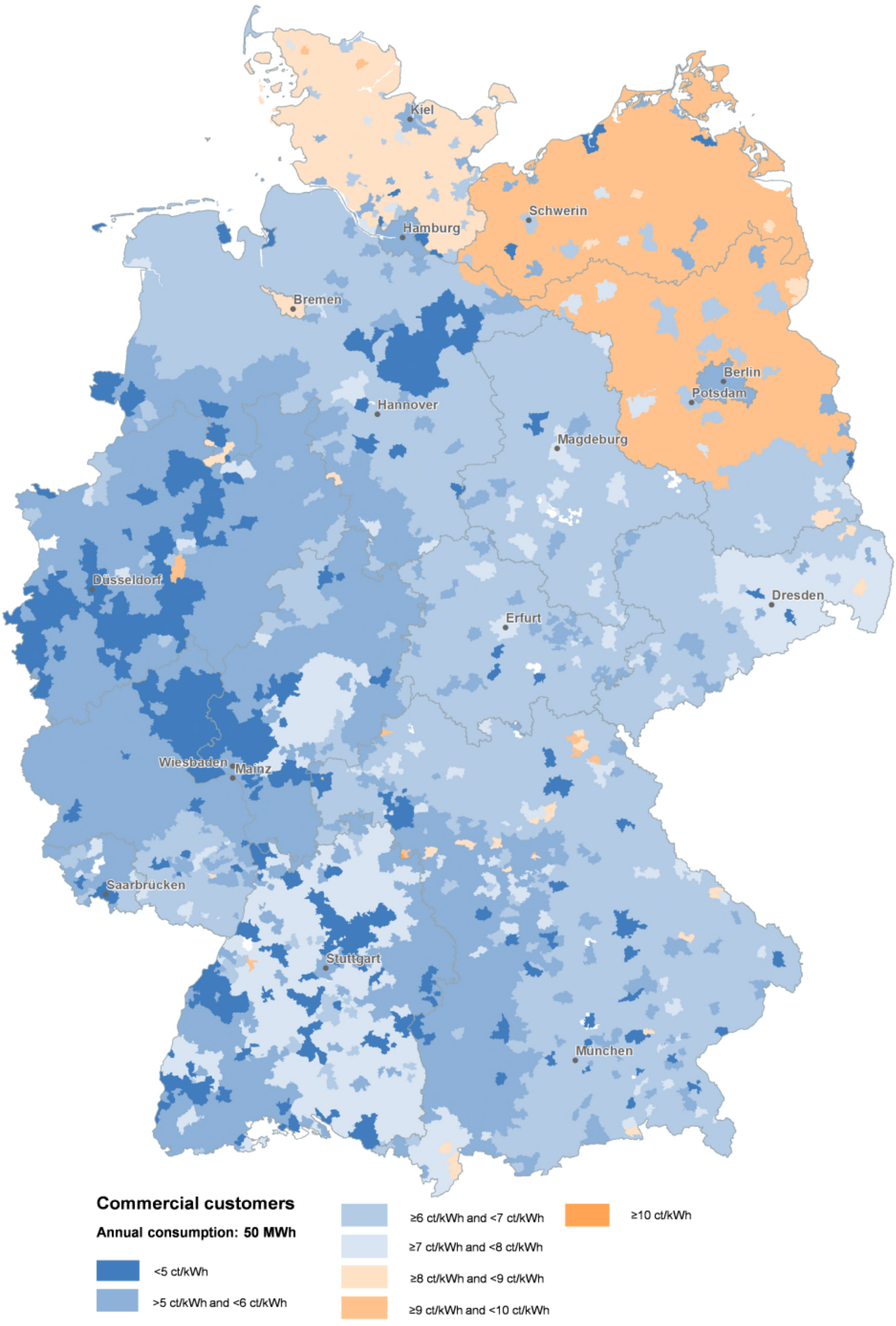

Figure 46: Spread of network charges for commercial customers

The spread of network charges for the 24 GWh annual consumption group (industrial customers) is slightly different. Although charges in the north-east, in particular, are generally higher than in other areas, charges in the centre of the country are also higher. Saxony-Anhalt has the highest average charges and North Rhine-Westphalia the lowest compared to the other federal states. The network charges for industrial customers range from around 1 ct/kWh to 6.6 ct/kWh. These charges do not take account of possible reductions through individual network charges pursuant to section 19(2) of the Electricity Network Charges Ordinance. In some cases, the charges for industrial customers entitled to individual network charges may therefore be lower.

Net network charges for industrial customers in Germany: 2017

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks included
Saxony-Anhalt	3.25	1.84	3.70	30
Mecklenburg-Western Pomerar	3.19	1.73	4.42	18
Schleswig-Holstein	3.17	1.43	4.26	42
Saxony	3.01	1.68	3.73	36
Brandenburg	2.89	2.36	3.93	27
Thuringia	2.82	1.71	3.55	28
Berlin	2.75	2.75	2.78	2
Lower Saxony	2.69	1.47	4.01	68
Bremen	2.53	2.52	2.90	4
Bavaria	2.50	1.11	6.65	223
Hamburg	2.41	2.41	2.41	1
Hesse	2.22	1.34	4.58	51
Baden-Württemberg	2.16	1.14	5.20	122
Saarland	2.13	1.51	3.03	19
Rhineland-Palatinate	2.07	1.51	3.30	55
North Rhine-Westphalia	1.99	1.01	3.98	101

*The weighting was based on the number of the operators' meter points in each network area.

Table 34: Net network charges for industrial customers (annual consumption 24 GWh) in Germany: 2017

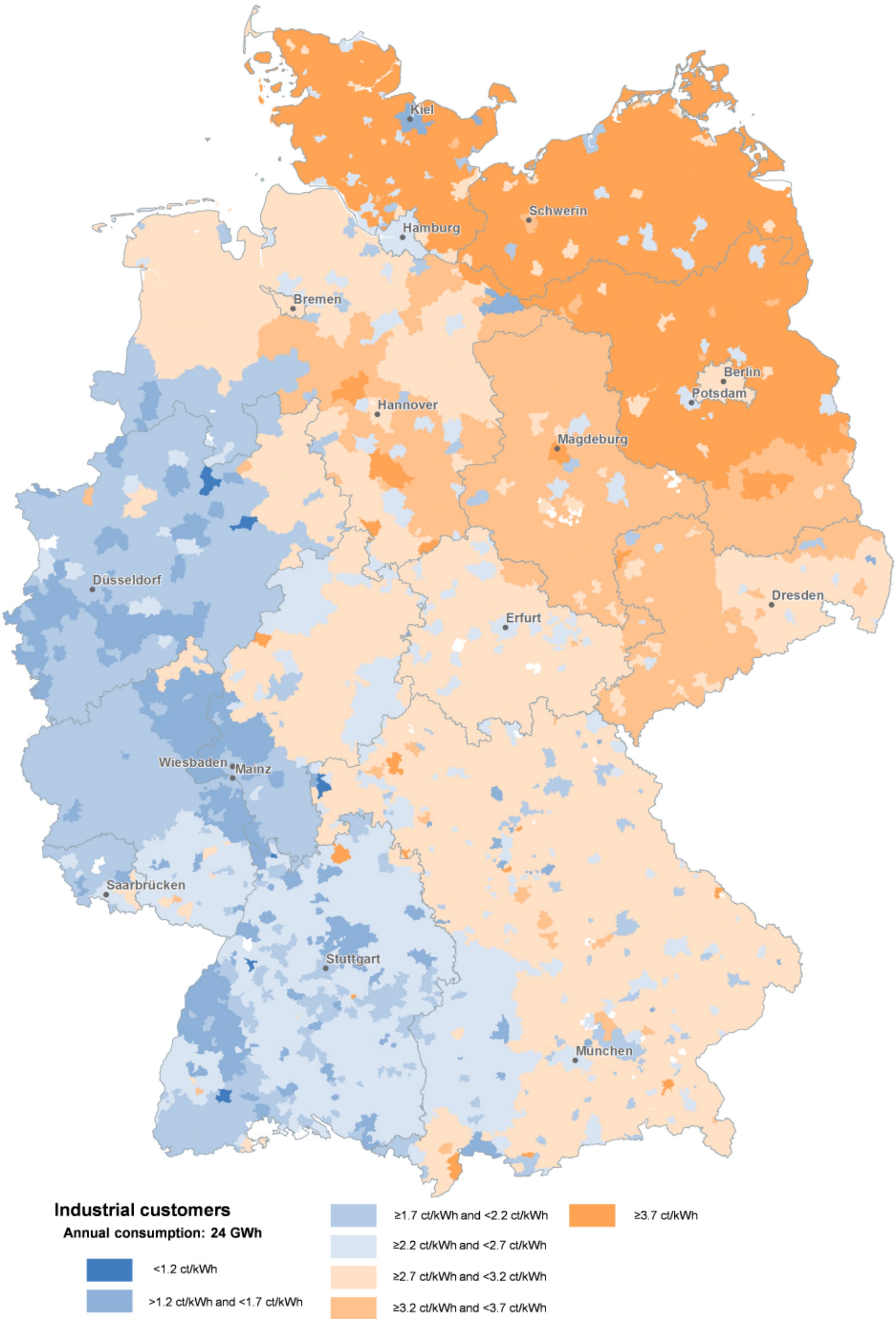

Figure 47: Spread of network charges for industrial customers

The regional differences in network charges are due to a complex range of factors[34]. One of the main factors is a decrease in network utilisation. Many of the networks modernised in the east following Germany's reunification are now seen as oversized. Although some of these networks are under-utilised, the network charges are still based on the networks' size. Another key factor is the population density. In less densely populated areas, the network costs have to be shared out between a small number of network users, while in more densely populated areas the costs are shared among a high number. In recent years, the costs of integrating renewables, including the costs of feed-in management, have become a further factor contributing to the differences in network charges. Renewable energy installations are being installed primarily in rural areas, resulting in costs in these areas. The age of the networks also plays a role. Older networks with a lower residual value are cheaper than new networks for the network users. The quality of the networks is also relevant, since it has a direct influence on the network operators' revenue caps. In addition to these factors relating to the DSOs' own networks, the upstream transmission networks also have an influence on the network charges. Increases in the TSOs' charges – for instance as a result of an increase in network and system security measures such as redispatching and the use of grid reserve plant capacity – lead to higher costs that have varied between control areas. The legislature has responded to this with the Network Charges Modernisation Act (NEMOG): the charges at transmission network level are to be harmonised as from 2019, and uniform national charges are to apply as from 1 January 2023. This will ensure that in particular the network and system security costs, which are all essentially incurred at transmission network level, are also shared fairly between all network users.

6.4 Expansion factor for electricity

Under section 4(4) para 1 in conjunction with section 10 of the Incentive Regulation Ordinance, electricity DSOs can apply for an adjustment to their revenue caps for networks below high-voltage (110 kV) level based on what is known as an "expansion factor"; this rule applies until the end of the second regulatory period in 2018. DSOs can apply for an adjustment once a year by 30 June of a year, and the adjustment made takes effect on 1 January of the following year. As a result of the 2016 revision of the Incentive Regulation Ordinance, the expansion factor will no longer be used as from the third regulatory period and will be replaced by the capital expenditure (capex) true-up.

The expansion factor ensures that the costs of expansion investments resulting from a sustainable change in the scope of the services provided by a DSO during a particular regulatory period are taken into account with as little delay as possible when setting the revenue cap. To include investments directly resulting from the energy transition, the expansion factor was modified by a determination issued by Ruling Chamber 8 (BK8 10/004): with effect from 30 June 2010, a new parameter – number of feed-in points for embedded generators – can be used in addition to the parameters listed in section 10(2) of the Ordinance when determining the expansion factor. Connecting embedded generation plants to an electricity distribution network can bring about sustainable changes in the services provided by a DSO.

With its budget approach and resulting efficiency incentives, the expansion factor contributes to achieving an intelligent and technology-neutral implementation of the energy transition. It is a universal mechanism that is not designed to compensate every operator for the specific investment costs of each expansion measure year for year, but rather acts as a technology-neutral bridge between the base years with incentives for optimisation.

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[34] See also the Bundesnetzagentur's report on the system of electricity network charges in Germany.

Overall, the adjustments made to revenue caps for 2016 on the basis of expansion factors amounted to €296.5m. The adjustments resulted from 120 applications relating to the revenue caps for 2016, 103 of which were submitted by the deadline of 30 June 2015 and 17 in previous years.

6.5 Avoided network charges

Under section 18(1) of the Electricity Network Charges Ordinance, embedded generation plant operators 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 network or substation level. The concept of avoided upstream network charges must not be confused with avoided costs. As a rule, network costs are not avoided by plants at lower voltage levels.

The concept of avoided network charges originated in the Associations' Agreement II/II+: plants connected downstream are generally smaller and thus generate 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. It was said that the advantage over larger scale plants from generating closer to demand was not taken into account. The aim of paying the avoided network charges to the downstream plants was to acknowledge generation close to demand and make downstream plants competitive.[35]

The avoided network charges within the meaning of section 18(1) of the Electricity Network Charges Ordinance have increased significantly in recent years, as a result in particular of the changes in the generation structure and the TSOs' increasing network costs.

Table 35 shows a breakdown of the avoided network charges for each network and substation level. The figures comprise the sum of the avoided network charges for the network operators under the Bundesnetzagentur's responsibility through its own or an official delegation of powers.[36]

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

[36] 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 operators.

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

Level	2012 (actual figures)	2013 (actual figures)	2014 (actual figures)	2015 (actual figures)	2016 (actual figures)	2017 (forecast figures)
EHV/HV	65	67	64	11	23	6
HV	484	478	594	659	753	1,148
HV/MV	77	88	84	107	119	119
MV	494	463	550	554	619	823
MV/LV	30	36	37	42	33	41
LV	144	142	160	185	186	232
Total	1,294	1,274	1,489	1,558	1,733	2,369

Table 35: Avoided network charges (section 18(2) of the Electricity Network Charges Ordinance) by network and substation level (€m)

The figures show a continual increase in the total amount of avoided network charges. 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 still remain, are spread over a smaller marketed volume. This leads to an increase in the network charges at the upstream level. This in turn results in an increase in the avoided network charges since they are calculated on the basis of the network charges at the upstream network or substation level. This mechanism creates incentives to connect plants at lower rather than higher voltage levels and is therefore taking increasing effect.

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 charges in the long term.

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

Under the Network Charges Modernisation Act adopted by the German Bundestag on 30 June 2017, there will be a gradual reduction in the payments for intermittent generators. The framework conditions will be adapted step by step in light of the successive developments in the market. The most important changes in the phasing out of avoided network charges are as follows:

- abolition of avoided network charges for new conventional plants as from 1 January 2023 and for new intermittent plants as from 1 January 2018;

- abolition of avoided network charges for existing intermittent plants as from 1 January 2020, with an annual reduction of one third in the original base figure as from 1 January 2018;

- as from 2018: the remaining avoided network charges will be calculated on the basis of the price list for 2016, with

- offshore connection costs and underground cabling costs being excluded from the transmission network costs in the price list for 2016.

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

The significant increase in the number of embedded generators over the last few years has long meant that it is fundamentally important to the stability of the network for these generators to operate correctly in the event of frequency changes. As a solution to the "50.2 Hz problem", which relates to the frequency protection parameters for solar photovoltaic (PV) installations, the System Stability Ordinance was enacted with effect from 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 charges and the renewable energy surcharge.

The 2015 amendment to the Ordinance extended the retrofitting requirements to apply to operators of CHP and other renewable energy installations, namely 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, while the additional annual costs incurred are financed through the network charges in accordance with section 22 of the Ordinance.

Most of the retrofitting work on PV installations was carried out by the network operators in the period from 2013 to 2015, leading to corresponding increases in the revenue caps based on the predicted costs. The costs actually incurred[37] 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.

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[37] The figures for the costs actually incurred apply subject to examination of the network operators' incentive regulation accounts.

Retrofitting costs in the revenue caps
(€m)

	2013	2014	2015	2016	2017
Forecast	48.5	73.1	4.9	22.6 (22.4)	6.1
Actual	12.2	35.3	6.8 (1.3)		

Figures in brackets in accordance with System Stability Ordinance section 22

Table 36: Retrofitting costs in the revenue caps

Retrofitting work is estimated to have directly added €155m to the network charges. A full set of figures for the actual costs, in particular for 2016, is not yet available. It is worth noting that the forecast costs are considerably higher than the actual costs. This does not result in any disadvantages for the network users, however, since the differences, together with interest, are reimbursed to the network users under the incentive regulation account scheme provided for by section 5 of the Incentive Regulation Ordinance.[38]

6.7 Transfer of electricity networks

Section 26 of the Incentive Regulation Ordinance states that when part of an energy supply network is transferred to another operator, the regulatory authority will decide how the revenue cap for the network is to be split between the operators concerned. Partial network transfers occur in particular when a local authority grants rights of way for the purpose of operating energy supply networks to a different operator (section 46 of the Energy Industry Act). Decisions by the Federal Court of Justice together with the 2016 amendment to the Incentive Regulation Ordinance have led to substantial changes in the procedure for splitting the revenue caps. Section 26 subsections (2) to (6) of the revised Ordinance, in force since September 2016, state that when part of an energy supply network is transferred, the regulatory authority will decide ex officio which part of the revenue cap is to be allocated to the part to be transferred should the network operators concerned not reach agreement themselves. The decision is taken by either the Bundesnetzagentur or a federal state regulatory authority, depending on which authority is responsible for the operator transferring part of a network.

As at the end of December 2016, the Bundesnetzagentur had received around 365 applications for electricity network transfers between 2012 and 2016. Figure 48 shows the number of notifications/applications for each year.

[38] All figures solely relate to the network operators under the Bundesnetzagentur's own or delegated responsibility.

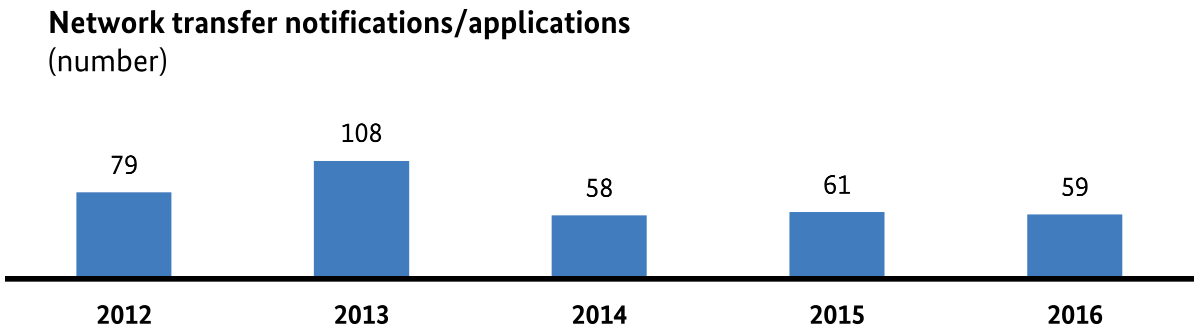

Figure 48: Network transfer notifications/applications

It should be noted that follow-up notifications and applications for the network transfers in 2012 and 2013 had to be made for the second regulatory period since the network transfers had not been taken into account in the base year (2011).

In 2016, Ruling Chamber 8 took decisions on 133 network transfers.

6.8 Individual network charges – Electricity Network Charges Ordinance section 19(2)

Individual network charges are granted as a reduction on the general network charge to network users meeting certain defined criteria. Section 19(2) of the Electricity Network Charges Ordinance therefore essentially grants privileges to final consumers whose specific consumption behaviour makes an individual contribution to lowering and/or avoiding network costs. A distinction is currently made between atypical network users as per section 19(2) first sentence of the Ordinance and electricity-intensive network users as per section 19(2) second sentence. While atypical network users shift their peak load to outside the network's peak load period, electricity-intensive network users have both even and permanent consumption patterns. The criteria for determining these individual network charges were last clarified and defined in the Bundesnetzagentur's decision of 11 December 2013 (BK4 13 739).

The approval procedure to be followed when agreeing individual network charges was replaced by a notification procedure as a result of the provisions effective from 1 January 2014 on appropriate arrangements for setting individual network charges under section 19(2) of the Ordinance. Individual network charges are no longer verified in an approval procedure before they take effect, but are notified to the regulatory authority responsible and may then be subject to ex post checks.

Final consumers are able to notify agreements with network operators for individual network charges as provided for by section 19(2) of the Ordinance by 30 September of each year. After the end of each billing period, the final consumers are required to provide the regulatory authority responsible with proof of compliance with the criteria for appropriately setting individual network charges.

The first notifications for individual network charges under the Bundesnetzagentur's responsibility were registered and settled for 2014. The number of final consumers actually granted individual network charges rose continually up to 2016. In 2016, a total of 3,375 notifications for individual network charges for atypical network users were registered with the Bundesnetzagentur (see Table 37).

Notifications for individual network charges for atypical network users in accordance with Electricity Network Charges Ordinance section 19(2) first sentence

	2014	2015	2016	+2017	2017
Total number of offtake points granted reductions	1,500	2,987	3,375	749	4,124
Total energy (TWh)	8.6	25.3	25.8	3.6	29.5
Total reductions (€m)	85.6	292.2	310.8	30.7	341.5

Table 37: Notifications for individual network charges for atypical network users

The total amount of reductions in network charges granted to these final consumers, following provisional assessment, was around €310m.

The total amount of reductions in network charges granted to electricity-intensive network users in 2016 was considerably higher at €388m (see Table 38), although the number of notifications for reductions for these users was significantly lower. In 2016, reductions were granted for a total of 317 offtake points for final consumers such as large businesses or industrial enterprises with particularly energy-intensive production processes. According to the current schedule, the Bundesnetzagentur has not yet completed its ex post checks on the billing documents submitted for 2015 and 2016.

In 2017, the Bundesnetzagentur received more than 800 further notifications for individual network charges. Based on a preliminary estimate, the total amount of reductions in network charges granted for atypical users is set to increase again to some €340m, with a total of 4,124 offtake points. The total amount of reductions for electricity-intensive network users is also expected to increase significantly to around €450m. The final figures for 2017 will not be available until completion of the checks on notifications and receipt of the actual billing data as required from the final consumers concerned.

Notifications for individual network charges for electricity-intensive network users in accordance with Electricity Network Charges Ordinance section 19(2) second sentence

	2014	2015	2016	+2017	2017
Total number of offtake points granted reductions	255	275	317	72	389
Total energy (TWh)	40.0	42.6	45.2	4.8	50.0
Total reductions (€m)	272.4	324.5	388.4	57.7	446.0

Table 38: Notifications for individual network charges for electricity-intensive network users

6.9 Special forms of network usage for electricity storage systems

The Electricity Market Act added a new subsection (4) to section 19 of the Electricity Network Charges Ordinance. The new subsection requires electricity supply network operators to offer an individual network charge to final consumers taking electricity from the grid solely for storage and returning electricity from the storage system to the grid. The individual network charge consists solely of an annual capacity charge (in euros per kilowatt) that is payable only for the amount of electricity taken and not returned to the grid.

This arrangement is designed to bring economic relief to storage system operators. So far, however, none of the planning figures put forward for the revenue caps for 2017 by the network operators within the Bundesnetzagentur's responsibility have included revenue relating to this individual network charge. One reason may be that the new arrangement was only introduced at the end of 2016. In addition, most new storage systems are already fully exempt from network charges for a period of 20 years under the transitional arrangement in section 118(6) first sentence of the Energy Industry Act. Also, many pumped storage stations have undergone expansion in recent years so as to become eligible for full exemption from network charges for a period of 10 years as provided for by section 118(6) second sentence of the Act. The scope for individual network charges for storage system operators is, for the time being, therefore extremely limited within the current framework.

6.10 Load control

DSOs already have an option available at low-voltage level for controlling loads. According to section 14a of the Energy Industry Act, DSOs are able to conclude contracts for load control (previously load interruption). The DSOs can control consumption from loads such as night storage heating systems, heat pumps and electric vehicles as and when required, in return for a reduction in the network charge. This enables them to prevent the consumption of a large amount of electricity from the low-voltage network at the same time, in turn preventing the network from becoming overloaded.

627 out of the 829 DSOs surveyed stated that they levied reduced network charges for a total of 1,416,586 meter points with load control. Figure 49 shows a breakdown by federal state. The chart shows a high

concentration in Bavaria and Baden-Württemberg, with around half of all the meter points with load control in these two southern federal states.

Almost all of the meter points are for heating systems (see Figure 50 on page 144), and direct electric heating also accounts for most of the "Other" loads. Electric vehicle charging stations currently make up just 0.1% of all meter points with load control, corresponding to only 1,012 charging stations. The reasons behind this may be that consumers are not aware of the options under section 14a of the Energy Industry Act or consider the possible loss of comfort to be too high in relation to the potential earnings.

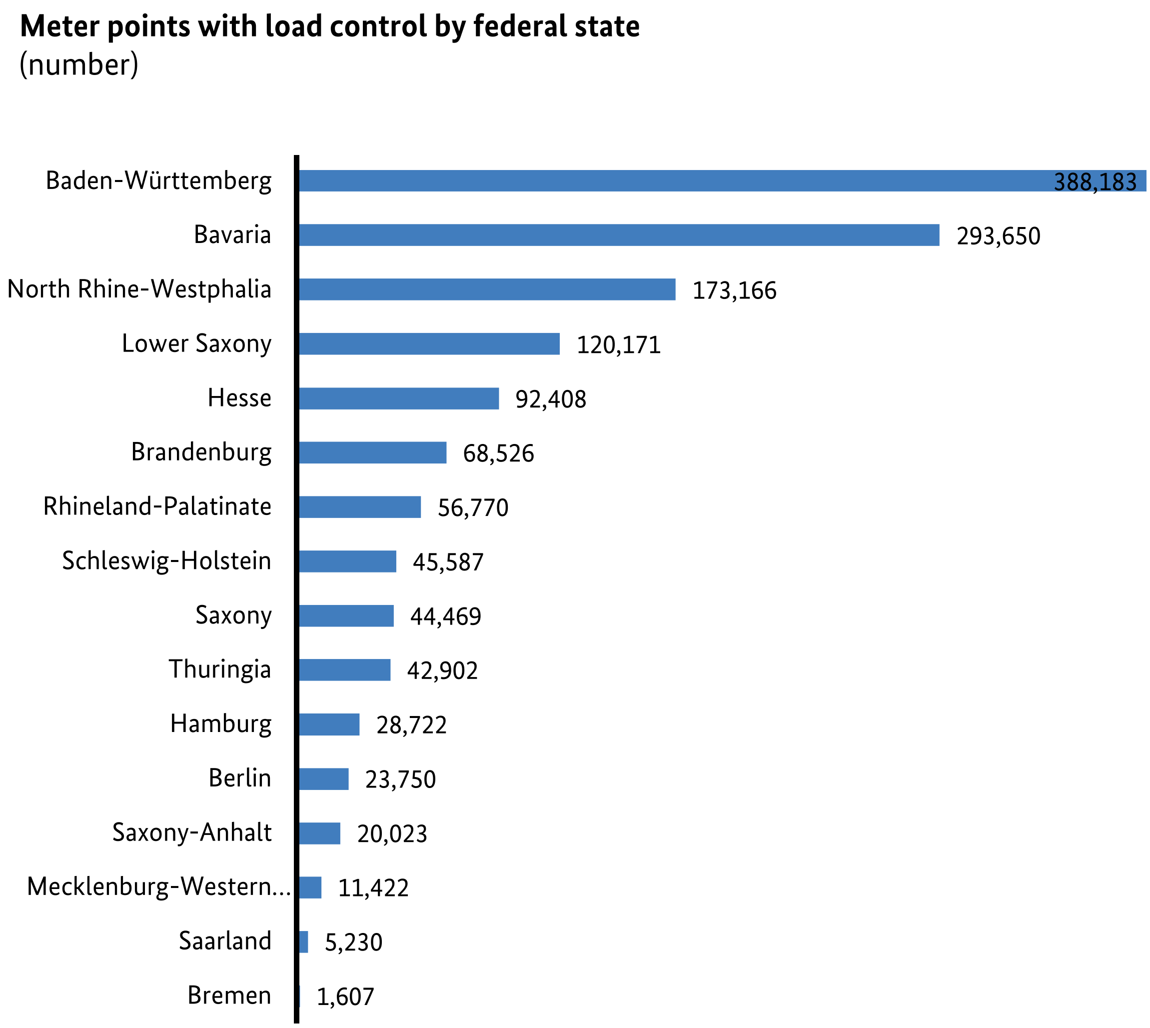

Figure 49: Meter points with load control by federal state

The average reduction in the network charge given by DSOs in return for load control is 55%, which corresponds to a discount of 3.30 ct/kWh. The reductions vary slightly for the different types of load: night storage heating systems receive the largest reduction in the unit charge at more than 55%, heat pumps and electric vehicle charging stations are given a reduction of just under 50% each, while the reduction for "Other" loads is slightly lower at 41%. In a small number of network areas, a capacity charge is also payable at the low-voltage level. The reduction on the capacity charge for night storage heating systems, heat pumps and electric vehicle charging stations is as high as 90%, while "Other" loads receive a discount of just 30%.

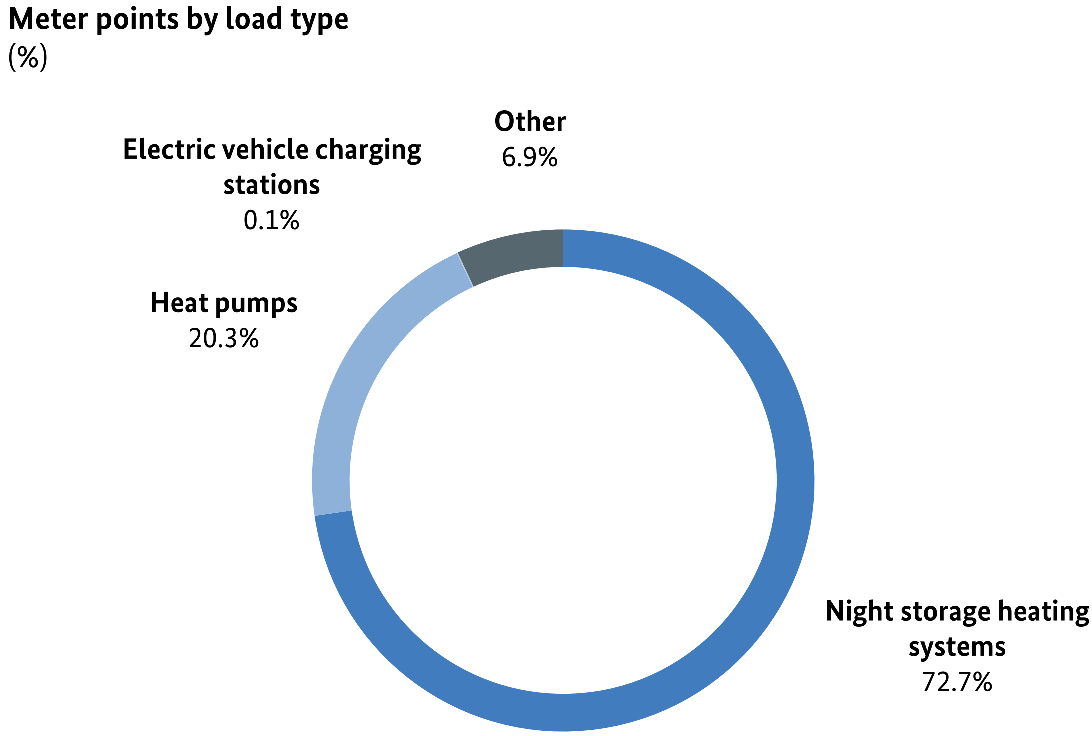

Figure 50: Breakdown of meter points by load type

It is also clear that in very few cases does the "control" of consumption behaviour really mean "smart" intervention based on the current status of the network. The use of the different load control technologies for night storage heating systems and for heat pumps is very similar: nearly 60% of the DSOs use ripple control and more than 30% use time switching, while only around 3% use the slightly more modern remote control technology and over 5% do not use any control technology at all. The picture is different for electric vehicle charging stations: the majority of DSOs – over 71% – do not actively control these loads at all. Figure 51 shows a more detailed breakdown of the control technologies used.

In future, any loads wishing to benefit from the arrangements in section 14a of the Energy Industry Act must be fitted with smart meters. The advantage of smart metering systems compared to time switches and ripple control, which are mainly used at present, is that they support bidirectional communication. In future, therefore, network operators will be able to retrieve data on the current status of the load and on the status following control actions. Another advantage of smart metering systems not generally offered by time switches is that it is possible to easily change a pre-set control profile and carry out ad hoc control actions not within a profile.

Load control technology
(%)

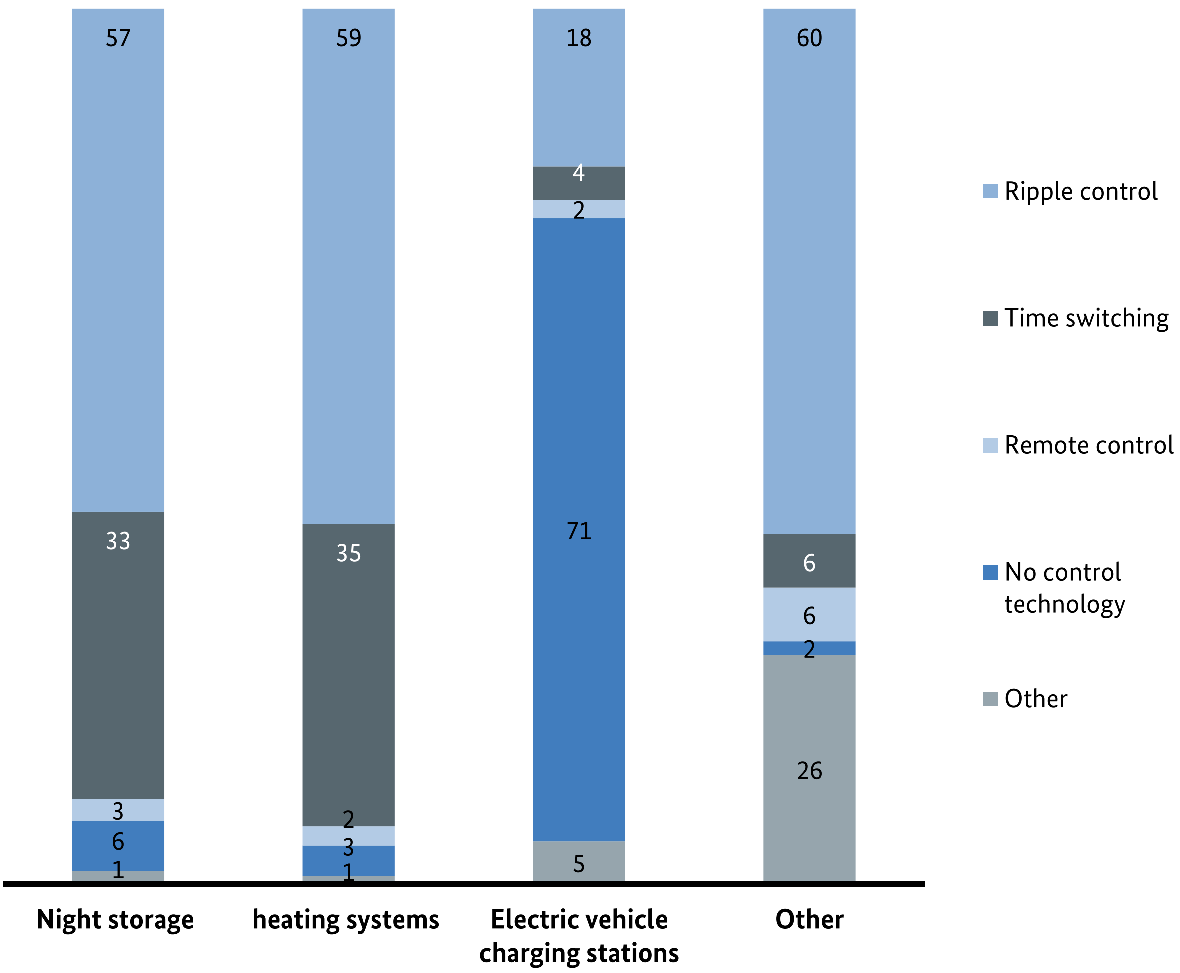

Figure 51: Load control technology

D System services

Guaranteeing system stability is one of the core tasks of the transmission system operators (TSOs) and is performed using system services. System services include maintaining the grid frequency by reserving and using the three types of balancing capacity: primary, secondary and tertiary control reserve.

They also include procuring energy to cover losses, reactive power and black start capability and, for the purposes of the monitoring survey, national and cross-border redispatching, countertrading [39] and feed-in management measures taken by the TSOs and the distribution system operators (DSOs). Contracting and using grid reserve plant capacity and interruptible loads under the Interruptible Loads Ordinance (AbLaV)[40] are also part of the range of system services.

1. Costs for system services

The total costs for these system services recovered through the network charges decreased from €1,940m in 2015[41] to €1,597m in 2016. The cost-reducing revenues totalled €135m, compared to €140m in 2015. As a result, there was a decrease in the net costs for system services [42] from €1,800m in 2015 [43] to a total of €1,461m. These figures for the first time also include the estimated claims from installation operators for compensation for feed-in management measures taken by the TSOs and DSOs as costs for system services in a broader sense. These claims have been estimated by the network operators at around €373m, compared to €478m in 2015. Another large part of the total costs is accounted for by the costs of reserving and using grid reserve power plants at around €285m (2015: €228m), national and cross-border redispatching at just under €220m (2015: €412m), procuring primary, secondary and tertiary control reserves at €198m (2015: €316m), and energy to compensate for losses at about €305m (2015: €277m).

The structure of the costs for system services changed again in 2016 from 2015. The total net costs for balancing energy fell again, this time by €118m. One reason for this fall is the further slight decrease in the volumes of the three types of balancing reserve procured. The costs for energy to compensate for losses in 2016 were up around €27m on 2015. One of the reasons for this increase was that additional energy was needed at short notice to compensate for energy lost in transport.

By contrast, there was a clear decrease in the costs for national redispatching and countertrading. The costs for national redispatching were down by some €203m and the costs for countertrading by €12m. There was a slight increase of around €11m, however, in the costs for cross-border redispatching. Overall, the total costs for redispatching (national and cross-border) in 2016 were around €192m down on 2015. There was a further increase in the costs for grid reserve power plants. The costs for reserving the grid reserve plant capacity were

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[39] Countertrading is a measure used by the TSOs to avoid overloading in the electricity grid. Countertrading is used when the agreed minimum trading capacity exceeds the capacity that can be transported in the networks. In this case, a countertrade is organised. This enables a minimum level of trading to be guaranteed at all times without the networks being overloaded.

[40] The costs for interruptible loads under the Interruptible Loads Ordinance are based on the capacity prices.

[41] This figure has been adjusted to include the estimated claims from installation operators for compensation for feed-in management measures taken by the TSOs and DSOs.

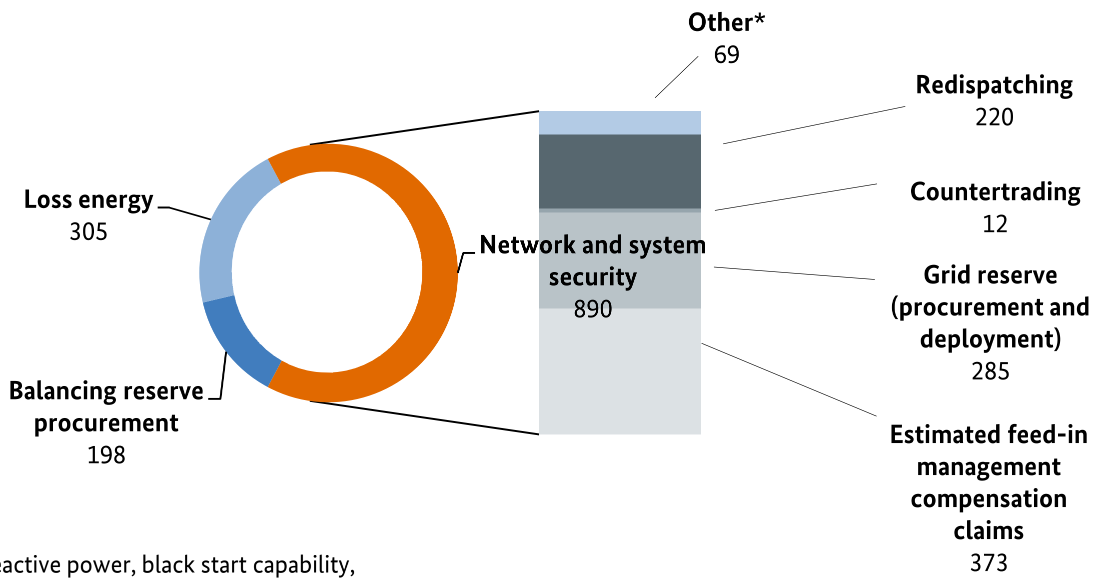
[42] Net costs (outlay costs minus cost-reducing revenues) and costs for grid reserve power plants and interruptible loads under the Interruptible Loads Ordinance.

[43] This figure has been adjusted to include the estimated claims from installation operators for compensation for feed-in management measures taken by the TSOs and DSOs.

up €25m on 2015. The frequent use of the grid reserve power plants in 2016 resulted in a provisionally estimated increase of about €41m in deployment costs. The claims from installation operators for compensation for feed-in management measures, as estimated by the network operators, were down around €105m on 2015, as a result of the decrease in the amount of curtailed energy from renewable energy and combined heat and power (CHP) installations. Figure 53 shows the development in the costs for system services from 2011 to 2016.

Together with the TSOs' and DSOs' estimates of the claims from installation operators for compensation for feed-in management measures, the costs for redispatching, grid reserve power plants and countertrading represent a significant proportion of the costs incurred by the network operators in maintaining network and system security.

Costs for system services and costs for network and system security: 2016
(€m)



*Other: reactive power, black start capability, interruptible loads under the Interruptible Loads Ordinance

Figure 52: Costs for German TSOs' system services and costs for network and system security: 2016

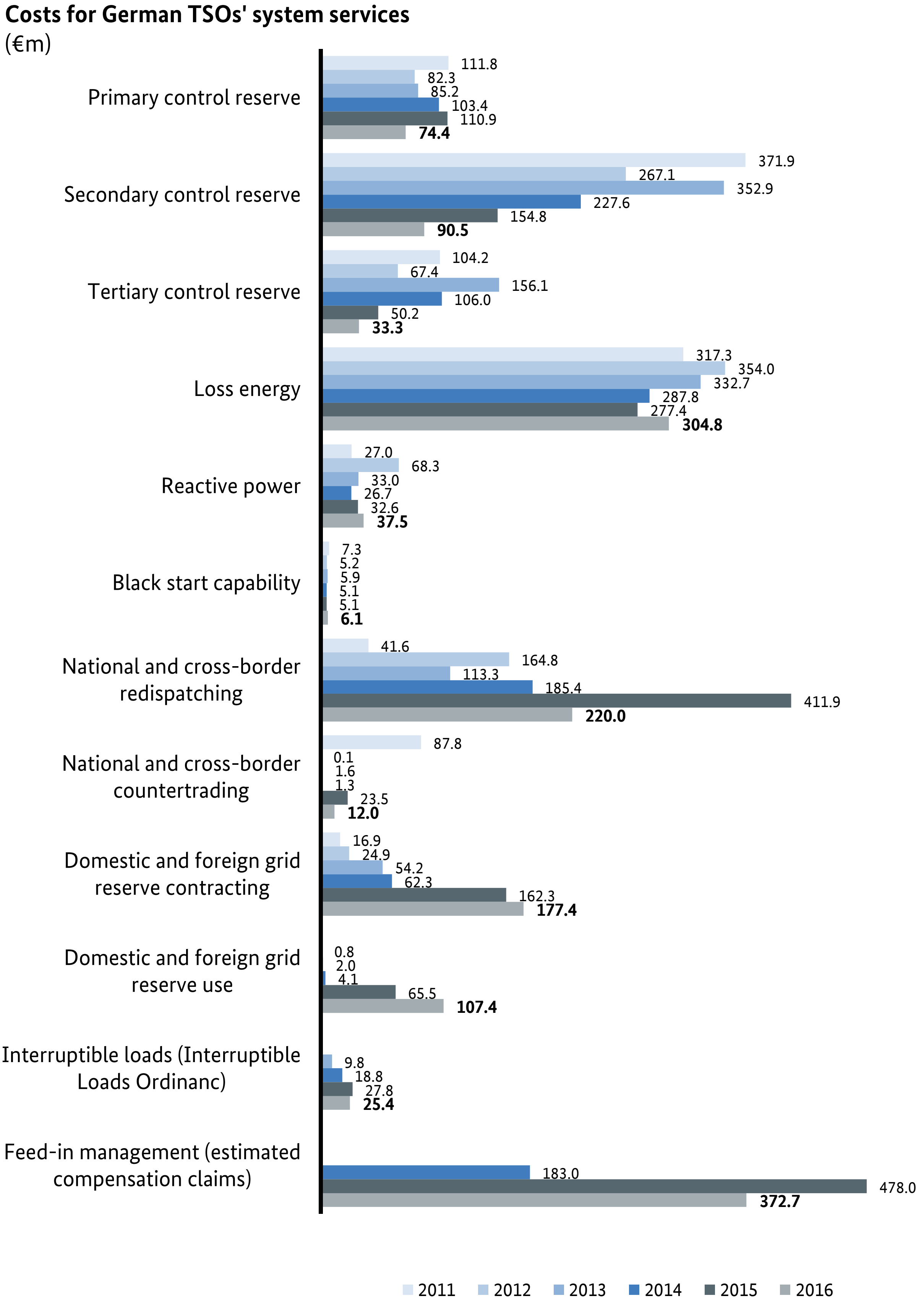


Figure 53: Costs for German TSOs' system services: 2011-2016

In total, the costs for network and system security decreased by around €243m from €1,133m in 2015 to about €890m in 2016. This is mainly due to the decrease in the number of network and system security measures taken in 2016 (see "Network and system security measures" in the "Networks" chapter starting on page 104).

2. 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. Balancing reserves are procured by the TSOs in national tendering processes in accordance with the Bundesnetzagentur determinations issued in 2011 (BK6 10 097/098/099). While the costs of procuring balancing reserves are covered by the network charges, the actual energy activated is settled in the form of economic balancing energy with the balance responsible parties (dealers, suppliers) causing the imbalances.

A grid control cooperation scheme covering the control areas of the four responsible TSOs (50Hertz, Amprion, TenneT, TransnetBW) has been in place since 2010. The scheme, with a modular structure, prevents inefficient use of secondary control reserve 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 volume of balancing capacity required is reduced, as reflected by the lower levels of secondary and tertiary reserves tendered and energy activated.

Balancing reserves are still currently procured in accordance with the determinations on primary, secondary and tertiary reserves issued by the Bundesnetzagentur in 2011. One of the aims of the determinations was to encourage new suppliers to enter the market and to open up the balancing energy markets further for other technologies, for example for load control or storage facilities.

In the past, balancing reserve was mainly provided by conventional power plants. It is now also increasingly being offered by battery storage systems. Renewable generators supplying balancing reserve include hydro power and in particular biogas. The continual increase in the share of renewable energy in electricity generation means that renewables will need to take on greater responsibility for the stability of electricity supply in the future. To make it easier for flexible generators such as wind power plants to participate in the balancing energy markets, the Bundesnetzagentur in June 2017 issued new tendering conditions and publication requirements for secondary and tertiary reserves (BK6 15 158/159).[44] As a result, the auctioning period for secondary reserve has been shortened from one week to one calendar day, and the blocks for the individual products are considerably shorter at four hours. These shorter periods are essential in particular for wind and photovoltaic generators to be able to forecast capacity and decide on deployment. The changes to the conditions for tertiary reserve include shortening the auctioning period from one working day to one calendar day. In addition, there are new rules on the minimum bid volumes and safeguards for both secondary and tertiary reserves.

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[44] A pilot project initiated by the TSOs responsible for the control areas and running until the end of 2017 already gives wind generators the opportunity to pre-qualify as tertiary reserve providers and to provide reserve.

2.1 Tendering for balancing reserves

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 14 July 2017, the number of pre-qualified secondary reserve providers had risen to 37 (compared to 15 in 2010 and 20 in 2013) and that of tertiary reserve providers to 52 (compared to 35 in 2010 and 36 in 2013).[45] The number of primary reserve providers was 24, 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.

Table 39 shows the range of the volumes of primary, secondary and tertiary control reserves tendered in the period from 2012 to 2016. There was a slight year-on-year decrease in the maximum volumes of positive and negative secondary reserve tendered. At the same time, there was a slight increase in the minimum volumes of secondary reserve tendered. There was a minimal increase in the maximum volume of positive tertiary reserve tendered and a decrease in the maximum volume of negative tertiary reserve tendered. There were also slight decreases in the minimum volumes of tertiary reserve tendered. The range between the minimum and maximum volumes for positive and negative secondary reserve and for negative tertiary reserve narrowed. By contrast, the range between the minimum and maximum volumes for positive tertiary reserve widened slightly. The demand for primary control reserve was at a similar level to the previous year at 583 MW, compared to 578 MW in 2015, and was broadly unchanged over the year.

The average volume of positive secondary reserve tendered in 2016 showed a slight year-on-year change at 2,009 MW compared to 2,053 MW in 2015. The average volume of negative secondary reserve tendered also decreased slightly from 2,027 MW in 2015 to 1,945 MW in 2016. An analysis of the period since 2010 shows that there have only been small fluctuations in the volumes tendered over the course of each year (see Figure 54 on page 152).

[45] Although the first wind generators have successfully pre-qualified to provide negative tertiary reserve, they have yet to take part in the tendering for economic reasons, amongst others.

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
	2016	583	583
Secondary control reserve (positive)	2012	2,081	2,109
	2013	2,073	2,473
	2014	1,992	2,500
	2015	1,868	2,234
	2016	1,973	2,054
Secondary control reserve (negative)	2012	2,114	2,149
	2013	2,118	2,418
	2014	1,906	2,500
	2015	1,845	2,201
	2016	1,904	1,993
Tertiary control reserve (positive)	2012	1,536	2,149
	2013	2,406	2,947
	2014	2,083	2,947
	2015	1,513	2,726
	2016	1,504	2,779
Tertiary control reserve (negative)	2012	2,158	2,413
	2013	2,413	3,220
	2014	2,184	3,220
	2015	1,782	2,522
	2016	1,654	2,353

Table 39: Balancing reserves (minimum and maximum volumes) tendered by the TSOs: 2012-2016

Total volume of secondary reserve tendered in the 50Hertz, Amprion, TenneT and TransnetBW control areas
(MW)

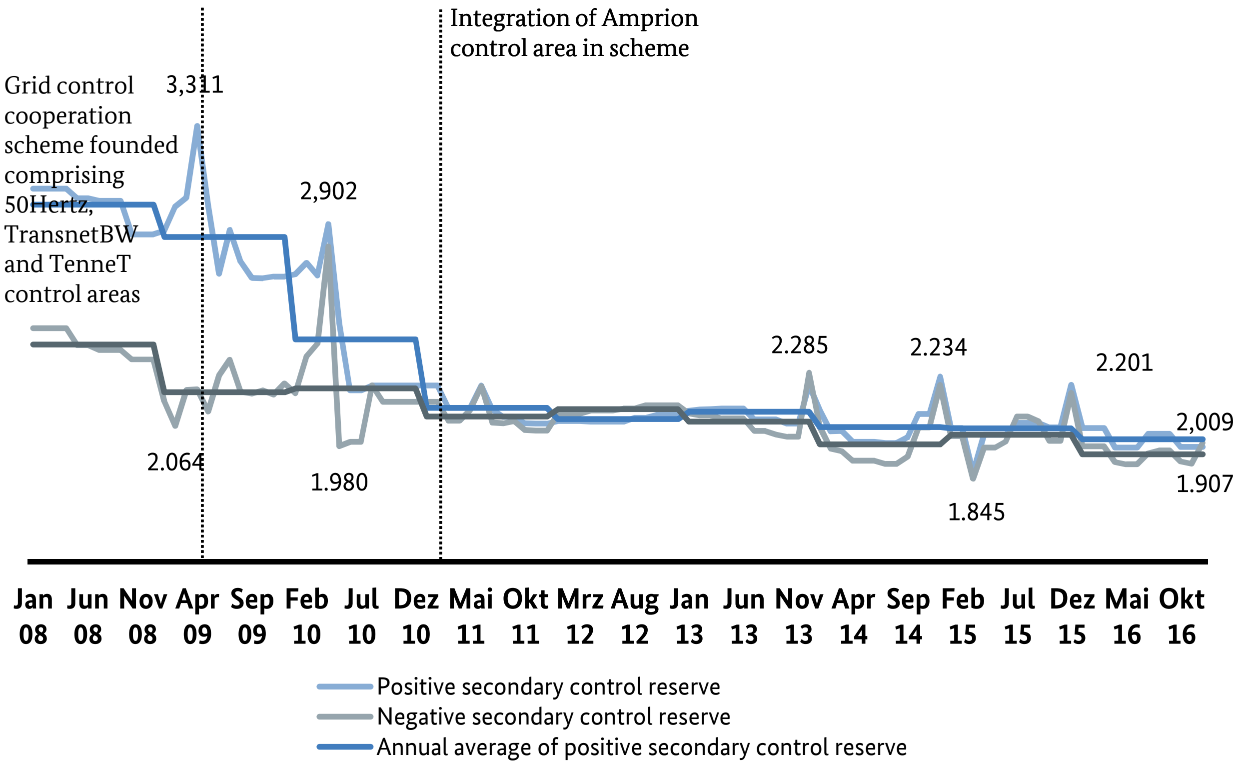


Figure 54: Total volume of secondary reserve tendered in the control areas of 50Hertz, Amprion, TenneT and TransnetBW

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 2016, the average volume was virtually unchanged from the previous year at 2,059 MW, compared to 2,044 MW in 2015. Following an increase in the demand for positive tertiary reserve from 2,101 MW in January 2016 to 2,779 MW in June 2016, there was a marked decline in August 2016 to 1,504 MW, a new record low level. Demand for positive tertiary reserve rose again to 1,850 MW by the end of 2016.

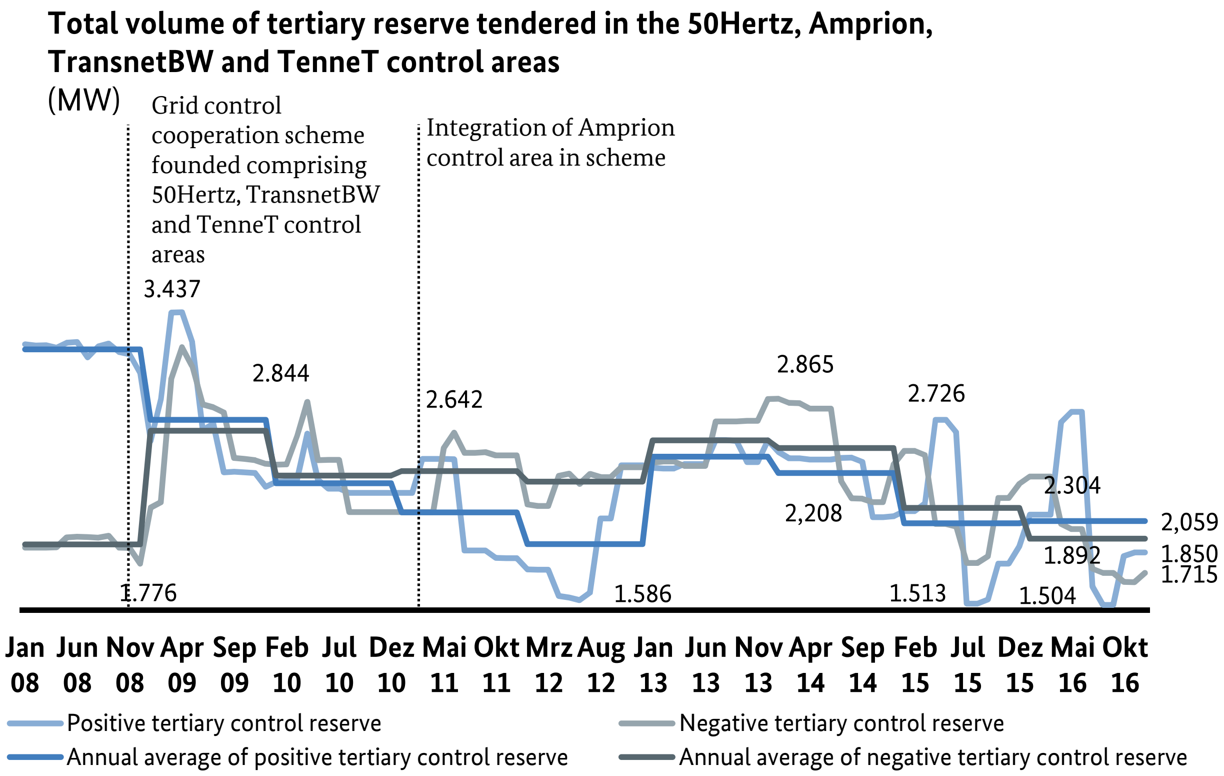


Figure 55: Total volume of tertiary reserve tendered in the control areas of 50Hertz, Amprion, TenneT and TransnetBW

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 2016 was 1,941 MW, compared to 2,146 MW in 2015. As with positive tertiary reserve, however, volumes fluctuated considerably during the course of the year. In January 2016, the average volume of negative tertiary reserve tendered stood at 2,353 MW; this decreased in the period up to November 2016 to 1,654 MW, a new record low, and increased only slightly in December to 1,715 MW.

Overall, 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.

Total volume of primary reserve tendered in the control areas of the German TSOs, Swissgrid (CH), TenneT (NL), APG (AT) and ELIA (BE)
(MW)

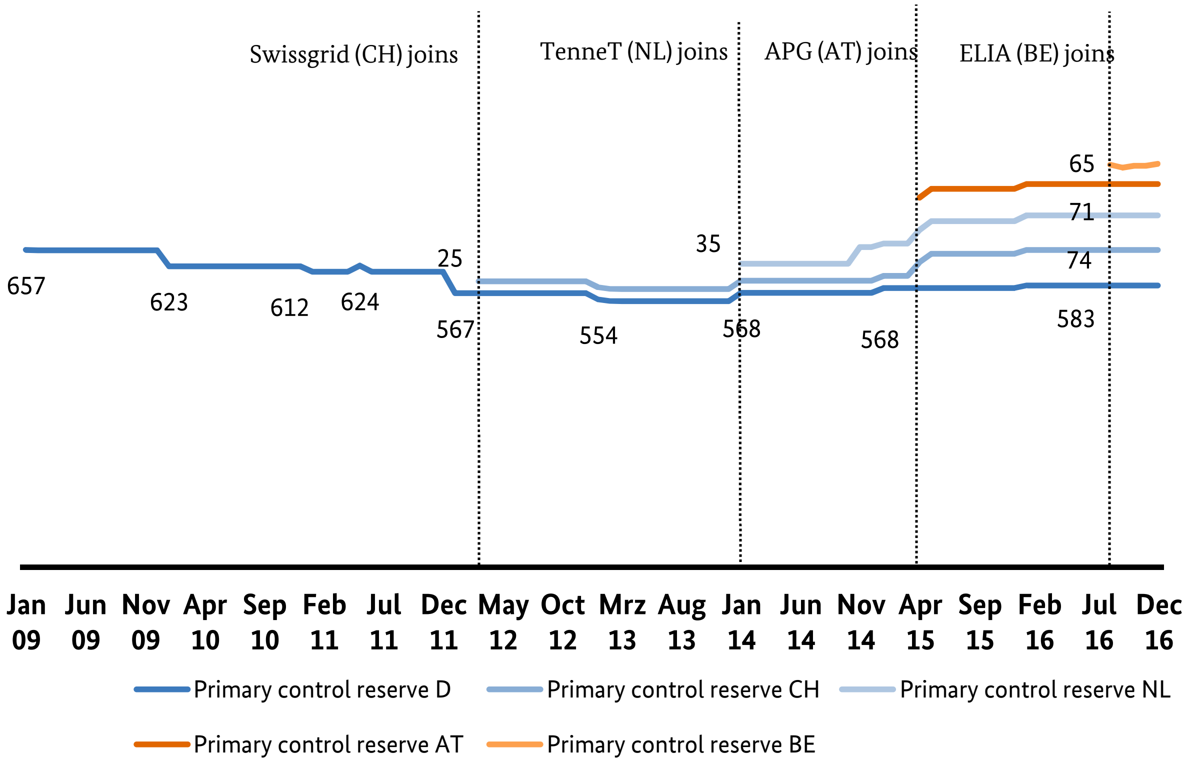


Figure 56: Total volume of primary reserve tendered in the control areas of the German TSOs, Swissgrid (CH), TenneT (NL), APG (AT) and ELIA (BE)

Figure 56 shows that the volume of primary reserve tendered has also remained stable over the long term. 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; the volume of primary reserve procured for Switzerland through the scheme has risen from an initial 25 MW to the current 74 MW. TenneT TSO BV in the Netherlands joined in January 2014. Following an initial volume of 35 MW, currently 71 MW and thus a good 70% of the Netherlands' primary reserve requirements are tendered through the joint tendering scheme. In April 2015, the primary reserve tendering partnership scheme between Germany, the Netherlands and Switzerland was coupled with Austria and Switzerland's joint scheme. The average volume procured for Austria through the scheme in 2016 was 65 MW. The Belgian network operator ELIA joined the joint tendering scheme in August 2016 and the French TSO RTE in January 2017. The scheme has created the largest primary reserve market in Europe, comprising a total volume of some 1,400 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.

2.2 Use of balancing reserves

As Figure 54 (page 152) shows, the total volume of secondary control reserve tendered and procured between 2011 and 2016 remained at a stable, comparatively low level. There was a slight year-on-year decrease in the overall volume of secondary reserve actually used.

In 2016, the total amount of energy activated for positive secondary control was some 1.4 TWh, the same as in 2015, and that for negative secondary control 0.7 TWh, compared to 1.1 TWh in 2015. The total amount of energy activated for secondary control hence decreased from 2.5 TWh in 2015 to 2.1 TWh in 2016, with again a slight shift towards positive secondary control.

On average in 2016, around 8% of the average volume of positive secondary reserve tendered and about 4.2% of the average volume of negative secondary reserve tendered was used. It should be noted, however, that in a total of 11 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.

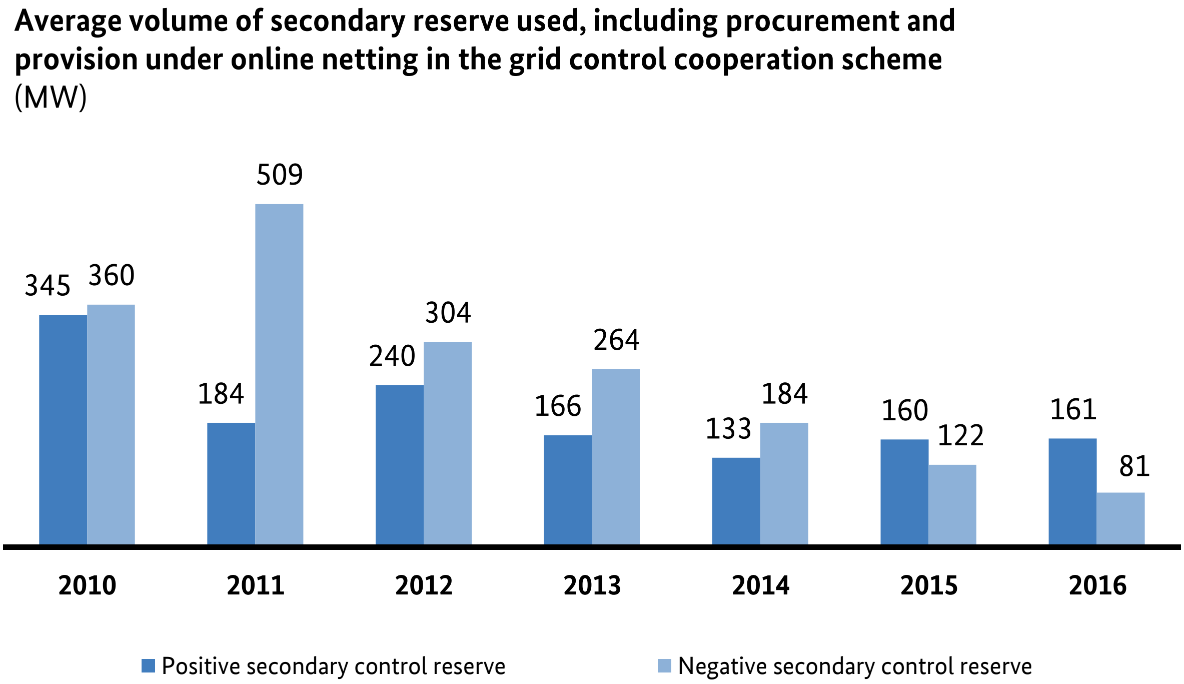


Figure 57: Average volume of secondary reserve used, including procurement and provision under online netting in the grid control cooperation scheme

There was another decrease in 2016 in the frequency of use of tertiary control reserve; in 2014, the number of dispatch requests had dropped by a good 40% to around 7,450 and had remained broadly unchanged in 2015. At 5,324, the total number of dispatch requests in 2016 was 30% lower than in the previous year. Overall, there were 1,216 requests for negative tertiary reserve in 2016, compared to 2,788 in 2015, and 4,108 requests for positive tertiary reserve, compared to 4,773 in 2015.

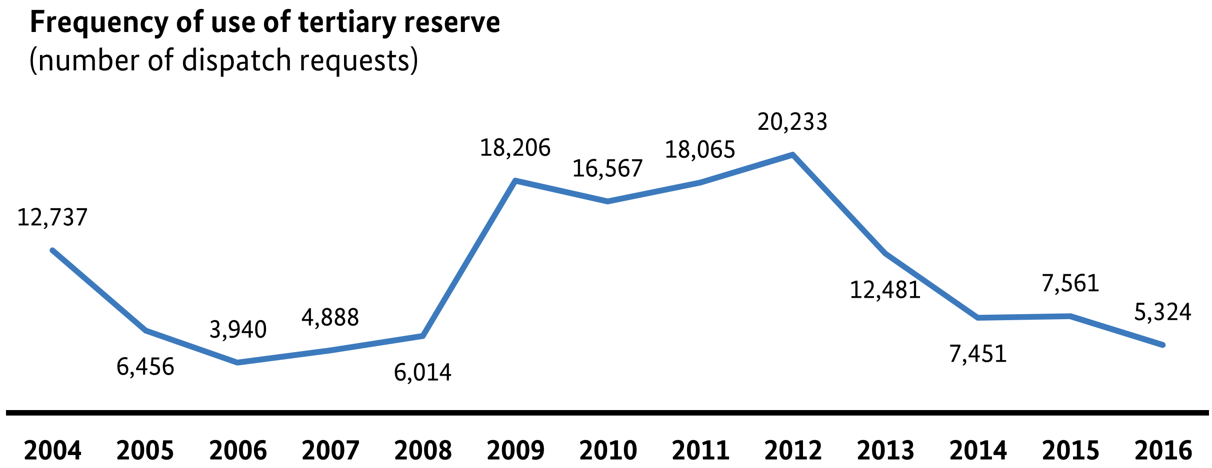


Figure 58: Frequency of use of tertiary reserve

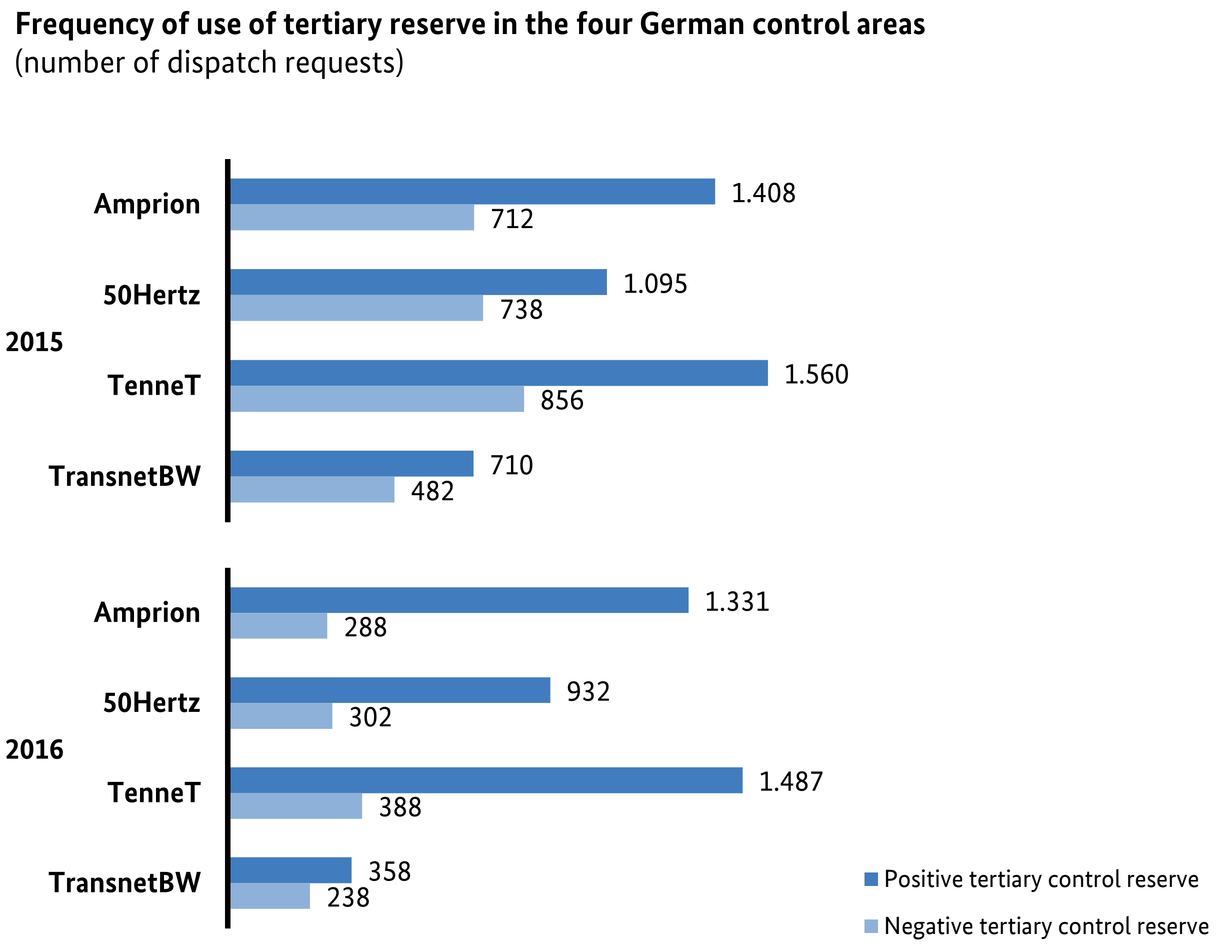


Figure 59: Frequency of use of tertiary reserve in the four German control areas: 2015 and 2016

There was a small decrease in the average volume of positive tertiary reserve requested from 172 MW in 2015 to 149 MW in 2016. There was a slight increase in the average volume of negative tertiary reserve requested from 167 MW in 2015 to 175 MW in 2016. On average in 2016, around 7% of the average volume of positive tertiary reserve tendered and just under 9% of the average volume of 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 eight cases, at least 80% of the average capacity reserved was required; overall this again confirms the necessity of the volumes tendered.

Average volume of tertiary reserve requested by the TSOs
(MW)

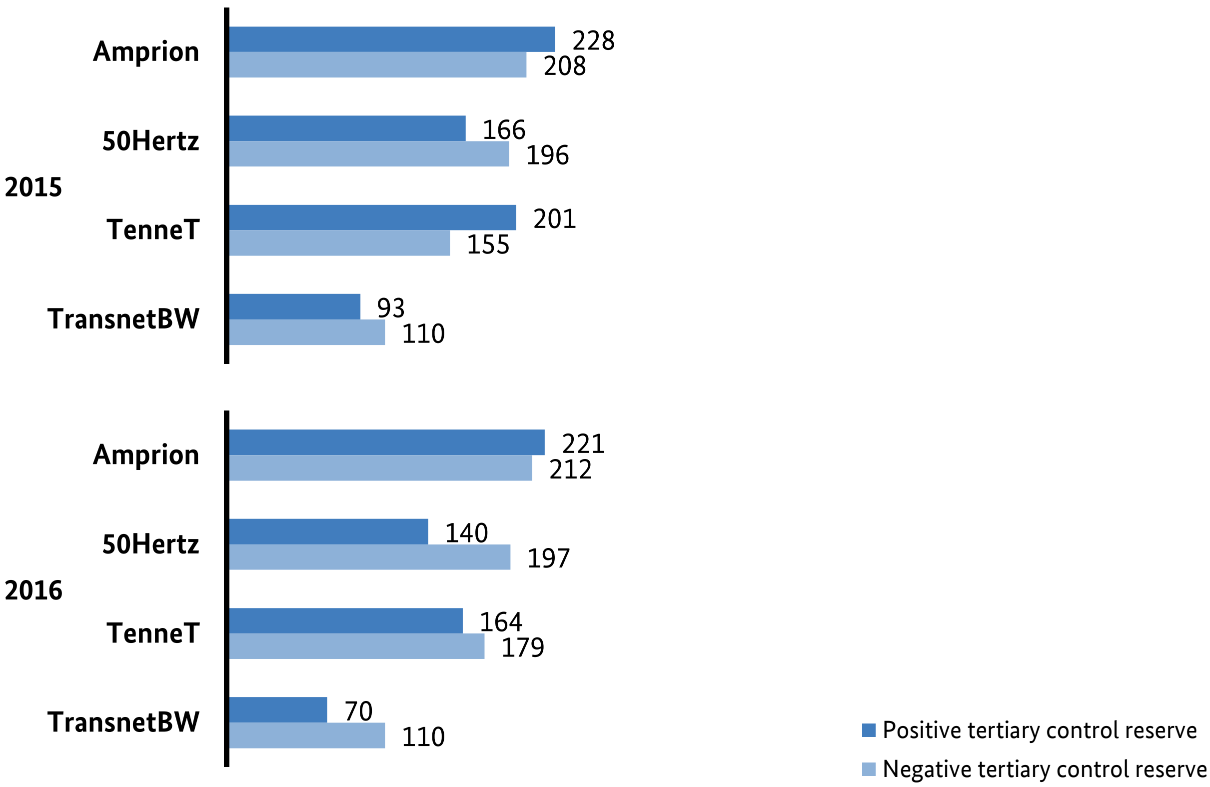


Figure 60: Average volume of tertiary reserve requested by the TSOs: 2015 and 2016

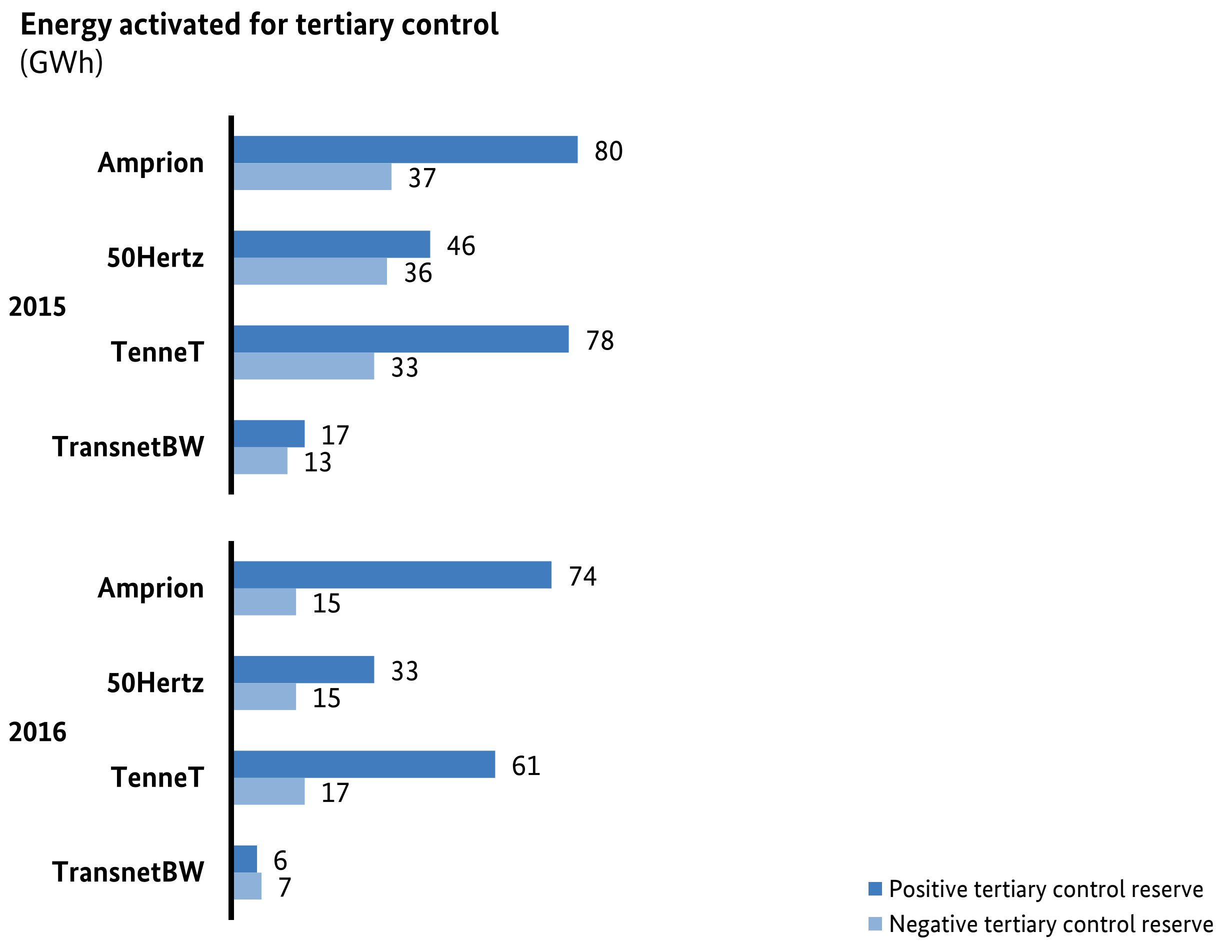
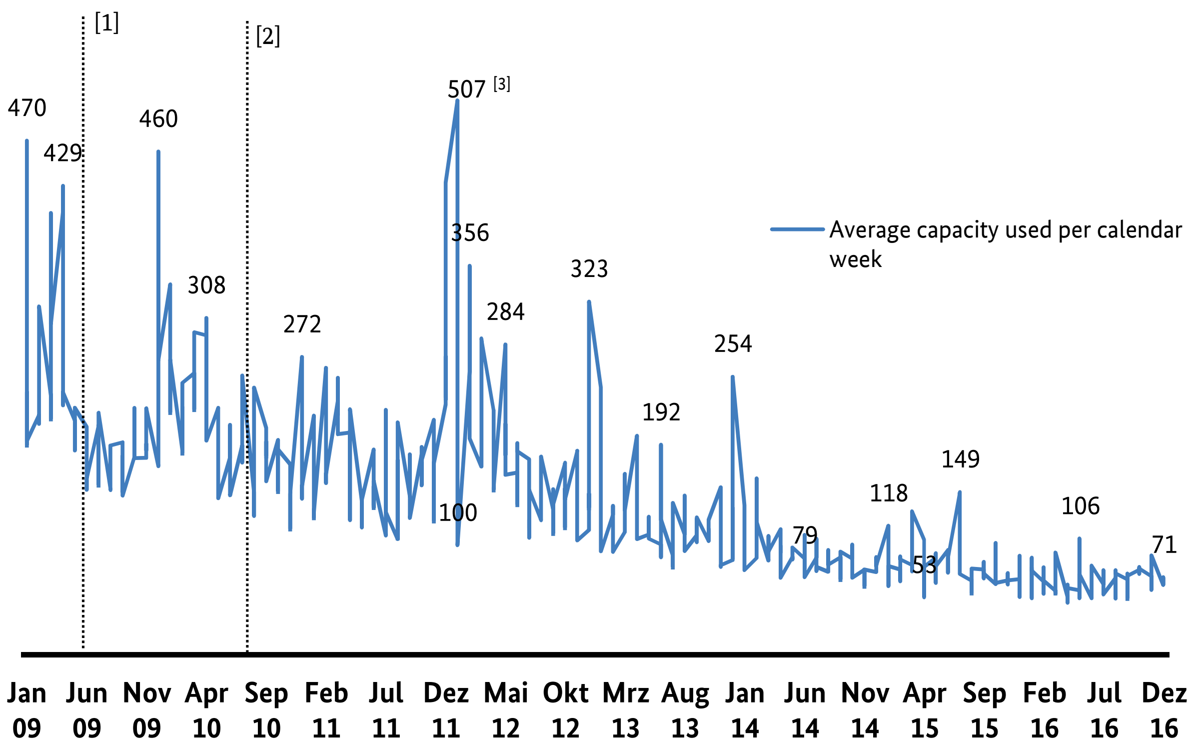


Figure 61: Energy activated for tertiary control: 2015 and 2016

The total amount of energy activated for positive tertiary control in 2016 was around 174 GWh, compared to 221 GWh in 2015, and that for negative tertiary control 54 GWh, compared to 119 GWh in 2015. Once again, there has been a shift away from negative to positive tertiary control.

Figure 62 illustrates the average use of secondary and tertiary control reserves in each calendar week from 2009 to 2016. It shows a decrease in the total average volume of secondary and tertiary reserves used and a reduction in volatility over time.

Average energy activated
(MW)



[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 Spring 2012 when all the available capacity was required.

Figure 62: Average volume of secondary and tertiary control reserves used

2.3 Imbalance prices

The Bundesnetzagentur's determination reforming the imbalance price system has been in effect since December 2012. The aim of the reform was to provide better incentives for the proper management of balancing groups with a view to preventing system-relevant imbalances.

The maximum imbalance price within the grid control cooperation scheme in 2016 was €1,212.80/MWh. The maximum price exceeded €500/MWh on a total of nine occasions in 2016.

In cases where the balance of energy activated for control within the grid cooperation scheme is close to zero (known as "zero crossings"), extreme imbalance prices may occur uniformly throughout the control area owing to the calculation formula used. In the period up to April 2016, the imbalance price was limited in such cases to the maximum price of a balancing energy bid activated in the particular quarter hour. However, if the prices bid by the suppliers were high, then the imbalance prices were also high despite being capped. In May 2016, an updated method to calculate imbalance 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)[46]. In cases where the balance within the grid control cooperation scheme is between 500 MW and +500 MW, an additional cap is now placed on the imbalance price in the particular quarter hour in a new step in the calculations.

Maximum imbalance 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
2016	1,212.80

Table 40: Maximum imbalance prices: 2010-2016

The average 15 minute price for balancing energy within the grid control cooperation scheme in 2016 in the case of a positive control area balance (short portfolio) showed a significant year-on-year decrease of 33% to €50.17/MWh. The price in the case of a negative control area balance (long portfolio) showed a substantial year-on-year increase of 66% to €14.12/MWh. The average imbalance price in the case of a positive control area balance was thus around 57%[47] above the average (peak) intraday trading price in 2016.

46 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

47 Based on the EPEX SPOT average (peak) intraday trading price of €32.01/MWh for 2016.

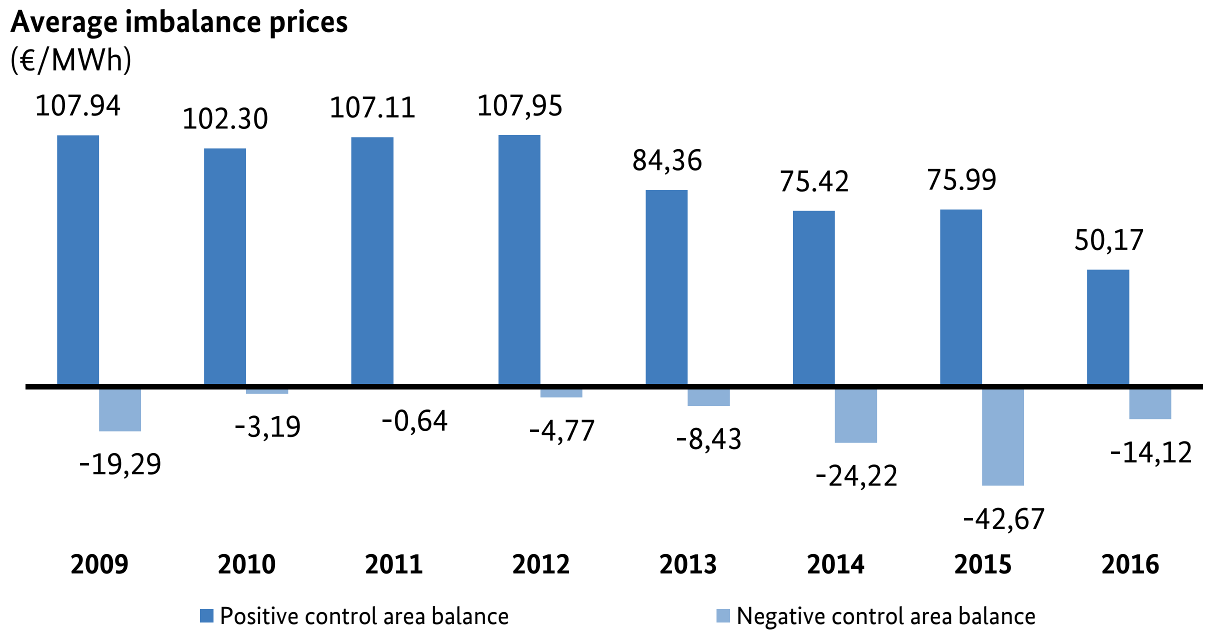


Figure 63: Average imbalance prices: 2009-2016

The following graph shows the frequency distribution of imbalance prices in the grid control cooperation scheme in 2015 and 2016. As in previous years, in 2016 there was an accumulation of prices around €0/MWh in the case of a negative control area balance. In addition, in 2016 there was again a greater frequency of prices around €40/MWh in the case of a positive control area balance.

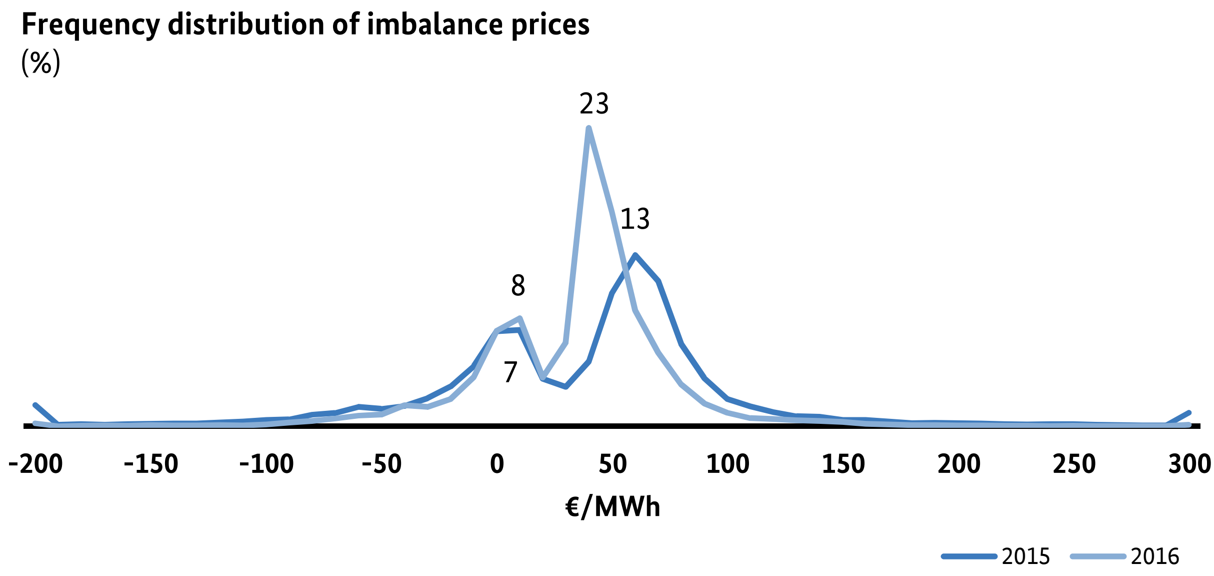


Figure 64: Frequency distribution of imbalance prices: 2015 and 2016

3. Intraday schedule changes

Section 5(1) of the Electricity Network Access Ordinance (StromNZV) allows schedule notifications – in which balance responsible parties 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 balance responsible parties to respond to short-term changes in supply and demand. The following graph shows the number and volume of intraday changes to schedules in 2016.

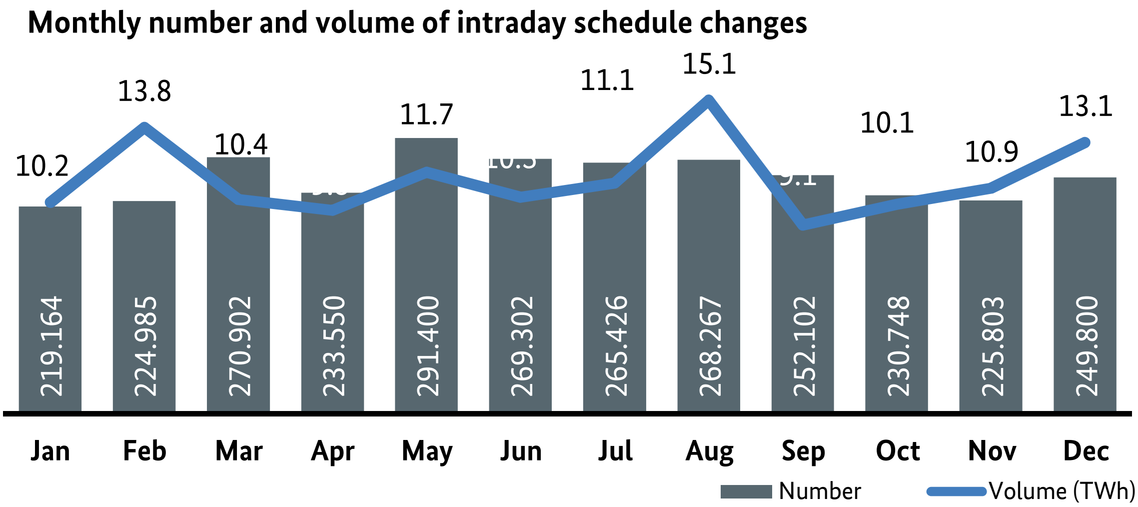


Figure 65: Monthly number and volume of intraday schedule changes: 2016

In 2016, a total number of 3,001,449 schedule changes accounted for a total volume of around 135.9 TWh, compared to 2,782,480 changes and 134.9 TWh in 2015. On average, some 250,121 schedule changes were made each month in 2016; the highest monthly number was 291,400 in May and the lowest 219,164 in January. These figures represent only slight year-on-year increases in the number and volume of intraday schedule changes, compared to the steep increases in previous years. One reason for the high level is the feed-in from renewables, which increasingly needs to be balanced out during the day through intraday trading.

4. European developments in the field of electricity balancing

4.1 International expansion of grid control cooperation

Over the last few years, module 1 of the German joint grid control cooperation scheme, which aims to prevent the inefficient use of secondary reserve across different control areas, has been successfully expanded to include other European TSOs' control areas. Under the International Grid Control Cooperation (IGCC) scheme, Germany and the following countries cooperate to avoid the 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). The scheme expanded significantly when France joined in February 2016, and Spain and Portugal are due to join next.

The IGCC scheme 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 IGCC scheme currently total around €3m to €7m per month. Overall, the international scheme has already achieved cost savings of over €320m through avoiding inefficient use of reserves, with Germany accounting for some €140m. The concept of physically netting imbalances promises high welfare gains for the whole of Europe as well. The guideline on electricity balancing, which enters into force at the end of 2017, therefore requires all TSOs in the Continental Europe synchronous area using secondary reserve to in future implement the imbalance netting process. The IGCC scheme has been designated by the European Network of Transmission System Operators for Electricity (ENSTO E) as a European pilot project to provide technical and organisational experience at an early stage; the project is being accompanied by the regulators, led by the Bundesnetzagentur.

4.2 Secondary reserve cooperation scheme between Germany and Austria

The German TSOs have 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 – provided that there are no network restrictions – only the economically most advantageous offer for secondary reserve is taken in each country, enabling the costs for balancing energy to be reduced. If cooperation is not possible, for instance because of operative network restrictions, the German and Austria TSOs activate secondary reserve at a national level as before. This form of cooperation between the TSOs has paved the way with regard to the European guideline on electricity balancing in force from the end of 2017; the guideline provides for cross-border activation of balancing energy based on a common merit order list, with a view to further integrating balancing energy markets in the future.

5. Interruptible loads

5.1 TSOs' tendering for interruptible loads

The legal basis for tendering for interruptible loads is the Interruptible Loads Ordinance. The original ordinance that entered into force in January 2013 was replaced by a revised version with effect from 1 October 2016.

The new ordinance changed the rules for the auctions to be carried out by the TSOs. Before the new ordinance came into force, the TSOs collectively held a national auction once a month for delivery periods that ran from 00:00 on the first day of a month until 24:00 on the last day of the month; tendering was for up to 1,500 MW each of immediate and fast interruption. Under the new rules, the TSOs hold weekly auctions for delivery periods from 00:00 on a Monday to 24:00 on a Sunday for up to 750 MW each of immediate and fast interruption.

The following graph shows the capacity tendered and contracted for immediate and for fast interruption. The graph shows that the total capacity contracted has increased over the whole period, although the monthly volumes have remained relatively constant. There is a clear trend in terms of the ratio between immediate and fast interruption, with a steady increase in the proportion of immediately interruptible loads.

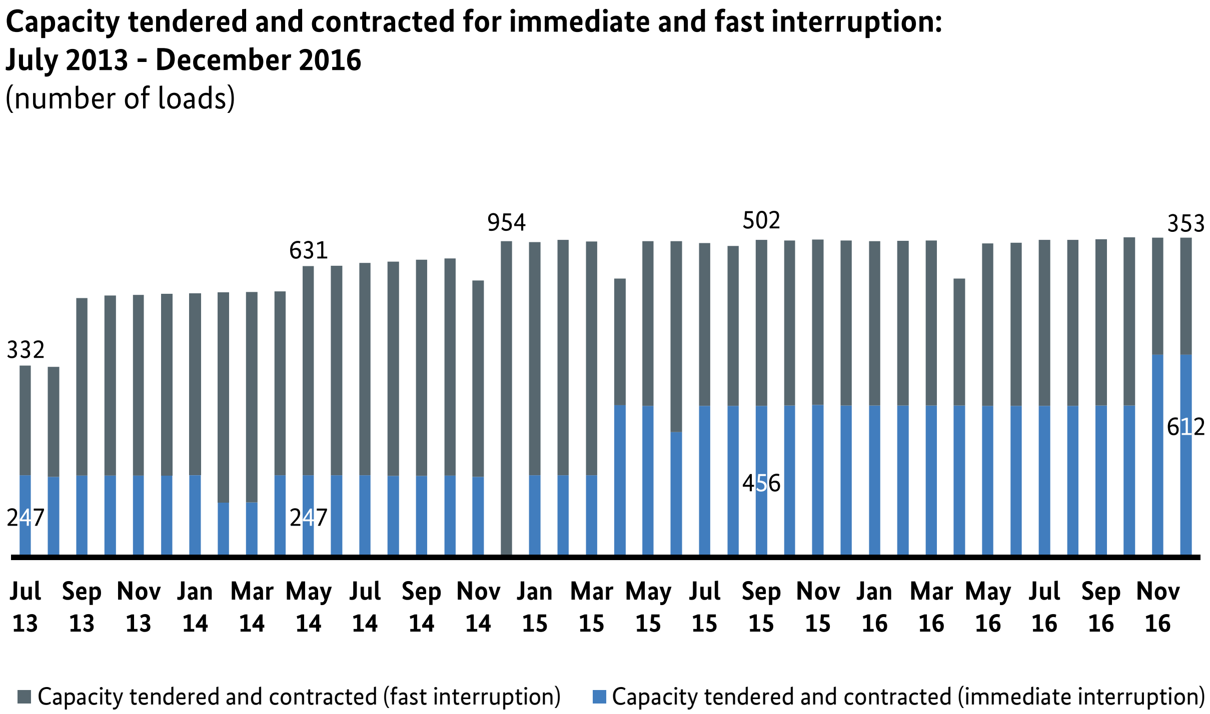


Figure 66: Capacity tendered and contracted for immediate and fast interruption: July 2013   December 2016

5.2 Pre-qualified capacity

In 2016, ten interruptible loads at six locations with a total interruptible capacity of 987 MW were pre-qualified. This represents another slight increase in pre-qualified capacity, which rose from an initial 925 MW in 2014 to 979 MW in 2015. The majority of the loads are connected to Amprion GmbH's control area. Other loads are located within the 50Hertz Transmission GmbH and TenneT TSO GmbH control areas. The contracted capacity is therefore concentrated in the west and north of Germany, with the exception of one interruptible load in the south.

5.3 Use of interruptible loads

In 2016, interruptible loads were used to balance the system on two days, ie use was comparable with the use of balancing capacity. Reductions in consumption of 373 MW and 394 MW were activated almost simultaneously for between 18 and 44 minutes. The interruptible loads were used instead of secondary reserve at the same time as positive tertiary reserve. Neither the full positive tertiary reserve capacity nor the full interruptible capacity had to be used.

Interruptible loads were not used in 2016 for redispatching purposes.

5.4 Costs for interruptible loads

The energy-based costs for the actual reductions in consumption are relatively low at €168,100, reflecting the comparatively low use of interruptible loads in 2016. By comparison, the capacity-based costs for contracting the interruptible loads in 2016 amounted to €25,406,700. The average interruptible capacity available in the period under review was 948 MW. The costs for contracting interruptible loads averaged at €2,233 per month per MW.[48] In comparison, the costs for tertiary reserve amounted to €2.78m[49] per month for an average capacity of 4,000 MW, which corresponds to an average of €695 per month per MW.[50] In 2016, all but one of the providers complied with the non-availability requirements. The TSOs' requests for capacity were fulfilled by the providers.

48 This figure differs from the capacity price of €2,500 per month per MW as set in the old ordinance and applicable until the new ordinance entered into force on 1 October 2016. The new ordinance sets a maximum capacity price of €400 per week per MW.

49 These costs comprise the costs for both negative and positive tertiary reserve and cannot be broken down using the data available.

50 The response time requirements for fast interruptions are comparable to those for tertiary reserve, while immediate interruptions can be activated significantly faster. In addition, there are further differences in quality between interruptible loads and balancing energy, for example with respect to availability.

E. Cross-border trading and European integration

As in previous years, Germany again exported considerably more electricity than it imported in 2016. As the hub for electricity exchange in Europe, Germany continues to play a key role within the central interconnected system. Transmission capacity in 2016 remained largely stable compared to the previous year.

Total cross-border traded volumes fell from 84.9 TWh in 2015 to 78.1 TWh in 2016, a decline of 8%. This reflects a decline of 22.6% in imports from 16.9 TWh in 2015) to 13.1 TWh against a fall of 4.4% in exports from 68 TWh in 2015 to 65 TWh. Overall, there was a slight increase of 1.6% in the German export balance from 51.0 TWh in 2015 to 51.9 TWh in 2016.

1. Average available transmission capacity

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 as the basis of calculation.[51]

Average available transmission capacity (import and export capacity) over all German cross-border interconnectors decreased by 0.81% from a total of 24,323 MW in 2015 to 24,125 MW in 2016. Tables 41 and 42 show the the figures for all import and export capacities[52].

Import capacity changed at all borders. At the Swedish border, import capacity rose by 49.5%. At the Danish border, import capacity fell by 6%. There were slight increases of 5% at the Polish border and of 2.2% at the Czech border. Import capacity fell by 20.5% at the Dutch border against an increase of 6.5% at the French border.

Export capacity also showed changes, with above-average decreases of 67.6% at the Polish border and 67.4% at the Czech border. Export capacity also fell by 5.6% at the Dutch border. At the French border, export capacity increased by 1% and also slightly at the Swiss border by 7%. Large increases of 27.8% were also observed at the Danish border and of 120.8% at the Swedish border.

The "maximum available capacity" at each border was taken from the available data, which in the first calculation step represented a theoretical corridor, to make a comparison in Flow-Based Market Coupling (FBMC)[53]. These maximum capacities can only be theoretically achieved at a single border if all the other flows and power plant feed-in optimally support this border, i.e. no further loads are placed on critical network elements in the same flow direction. This distinguishes the FBMC data from the NTC data. For this reason comparisons are very difficult to make.

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[51] 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.

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

[53] In the framework of the CWE FBMC a distinction must be made between the 'maximum capacities' entered in the algorithm by the TSOs and the actual trading capacities determined as the result of the FBMC. (Physical flows must also be distinguished as overlaying allocated, planned and unplanned flows).

Import capacity

	(Net) average available transmission capacity 2012 (MW)	Change compared to previous year (%)	(Net) average available transmission capacity 2013 (MW)	Change compared to previous year (%)	(Net) average available transmission capacity 2014 (MW)	Change compared to previous year (%)	(Net) average available transmission capacity 2015 (MW)	Change in transition NTC to Flow-Based	(Net) average available transmission capacity 2015 (MW)	Change compared to previous year (%)	(Net) average available transmission capacity 2016 (MW)
						NTC					
PL → D	1,301.12		1,260.63		1,361.16		1,233.11				1,260.41
		-3.11%		7.98%		-9.41%				2.21%	
CZ→ D	1,380.14		1,260.63		1,361.16		1,233.11				1,295.00
		-8.66%		7.98%		-9.41%				5.02%	
DK→ D	1,334.16		1,192.55		1,054.16		777.95				731.03
		-10.61%		-11.60%		-26.20%				-6.03%	
CH→ D	4,000.00		4,000.00		4,000.00		4,000.00				4,000.00
		0.00%		0.00%		0.00%				0.00%	
SE→ D	457.00		481.65		447.60		275.15				411.41
		5.39%		-7.07%		-38.53%				49.52%	
			NTC						**Flow-Based**		
NL -> D*	2,314.83		2,291.11		2,257.17		2,123.76		2,799.57		2,225.46
		-1.02%		-1.48%		-5.91%		31.82%		-20.51%	
FR -> D*	1,800.00		1,790.46		1,798.45		1,800.00		3,765.66		4,011.40
Total		-0.53%		0.45%		0.09%		109.20%		6.53%	

Change in transition NTC to Flow-Based*

Table 41: Import capacity trend from 2012 to 2016

Export capacity

	(Net) average available transmission capacity 2012 (MW)	Change compared to previous year (%)	(Net) average available transmission capacity 2013 (MW)	Change compared to previous year (%)	(Net) average available transmission capacity 2014 (MW)	Change compared to previous year (%)	(Net) average available transmission capacity 2015 (MW)	Change in transition NTC to Flow-Based	(Net) average available transmission capacity 2015 (MW)	Change compared to previous year (%)	(Net) average available transmission capacity 2016 (MW)
						NTC					
D → PL	600.66		665.67		660.59		430.92				140.53
		10.82%		-0.76%		-34.77%				-67.39%	
D → CZ	997.21		665.65		660.59		430.92				139.44
		-33.25%		-0.76%		-34.77%				-67.64%	
D → DK	1422.47		1468.68		1471.46		1432.42				1830.73
		3.25%		0.19%		-2.65%				27.81%	
D → CH	895.63		964.72		1094.23		1373.39				1469.64
		7.71%		13.42%		25.51%				7.01%	
D → SE	375.72		312.45		323.25		158.83				350.61
		-16.84%		3.46%		-50.87%				120.75%	
			NTC						**Flow-Based**		
D → NL*	2276.65		2220.70		2231.18		2026.58		3264.45		3080.11
		-2.46%		0.47%		-9.17%		61.08%		-5.65%	
D → FR*	2603.07		2562.95		2472.18		2356.27		3147.91		3179.63
Total		-1.54%		-3.54%		-4.69%		33.60%		1.01%	

Change in transition NTC to Flow-Based*

Table 42: Export capacity trend from 2012 to 2016

Capacities to Austria are not shown as Austria forms a single market area with Germany until October 2018. Capacities to Belgium are not shown as there is currently no interconnection at the TSO level between Belgium and Germany. Reasons for the changes in capacity include work on transmission system lines, technical breakdowns and maintenance work on transmission system lines and the installation of phase-shifting transformers. German transmission system operators are required to carry out maintenance and repairs on power lines as quickly and effectively as possible to guarantee a smooth exchange of electricity with other countries.

In the summer of 2017, an agreement was reached between Germany and Denmark to increase the electricity-trading capacity on the border between western Denmark and Germany. The agreement provides for minimum trading capacities for the border between west Denmark and Germany as well as collaboration on countertrading measures between transmission system operators[54]. From July 2017, minimum trading capacities will be gradually increased to 1,100 MW by 2021 on the basis of this agreement.

Available capacities at the Danish border (DK1) to Germany
in MW

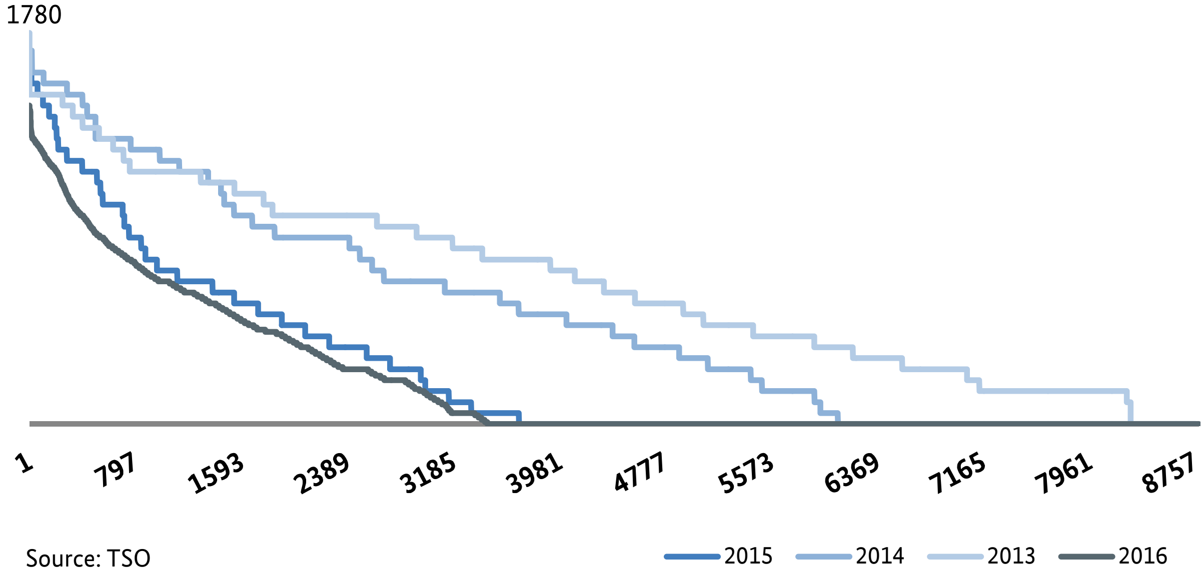

Figure 67: Available capacities at the Danish border (DK1) to Germany in MW

[54] Countertrading is a measure taken by transmission system operators to avoid or remove congestion. It is used when the agreed minimum trading capacities exceed the transport capacity of the grid. In this case a reciprocal commercial transaction is organised. This guarantees minimum trading at any time without the grids being congested.

2. Cross-border load flows and implemented exchange schedules

The implemented exchange schedules are decisive in assessing the net balance of electricity imports and exports 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[55]. Figures 68 and 69 show the exchange schedules implemented and the physical flows at Germany's borders in 2015 and 2016.

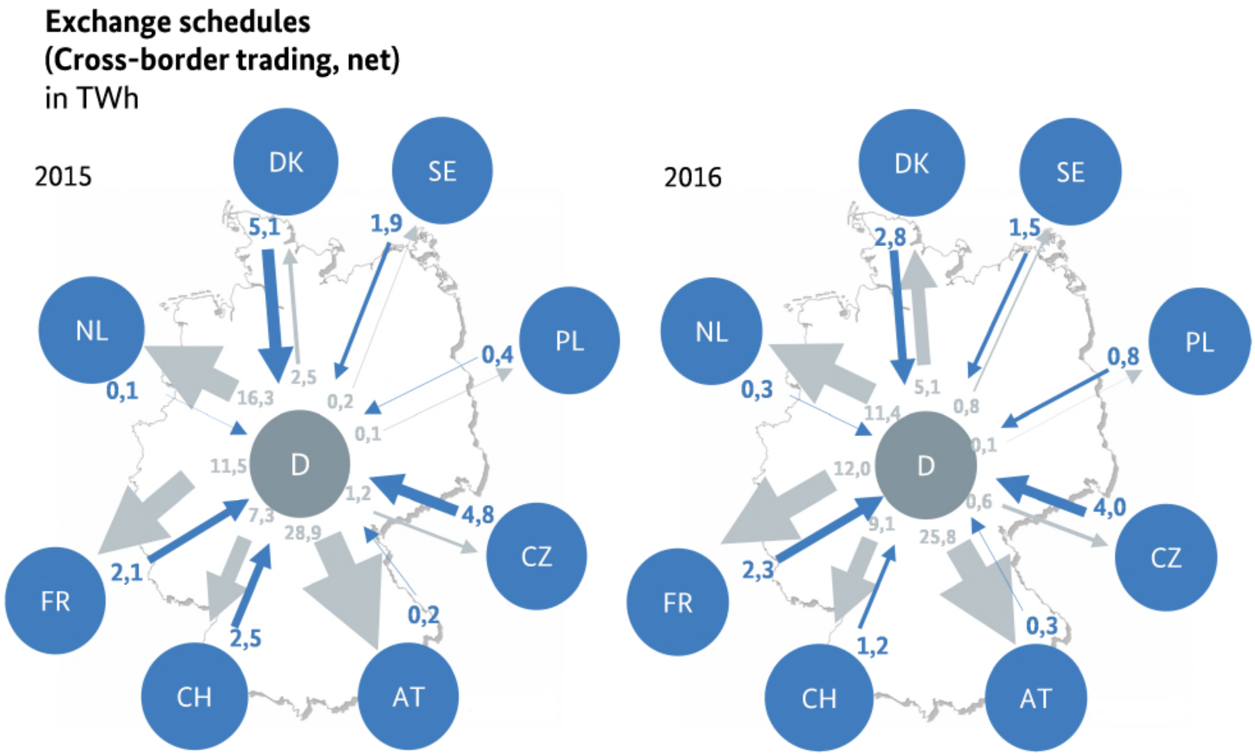

Figure 68: Exchange schedules (cross-border electricity trading)

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

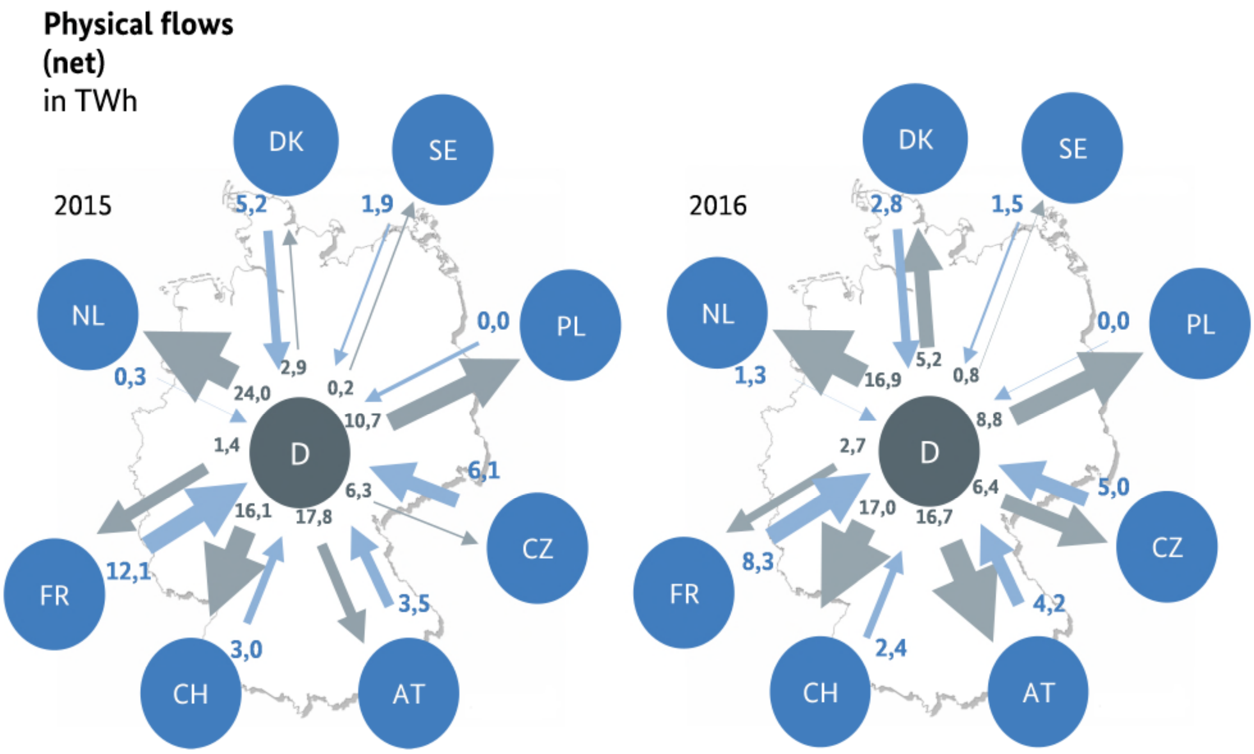

Figure 69: Physical flows

Tables 43 and 45 show the figures for all import and export capacities[56].

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

	Actual physical flows 2015	Binding exchange schedules 2015	Actual physical flows 2016	Binding exchange schedules 2016
Import	32.16	16.94	25.62	13.11
Export	79.12	67.98	74.51	64.98
Balance	46.96	51.04	48.89	51.87

Table 43: Comparison of the balance of cross-border electricity flows[57]

[56] The data used was provided by the German TSOs and checked for plausibility by the Bundesnetzagentur.
[57] Theoretically, the physical flows balance and the exchange schedules (trade flows) balance should be identical. Deviations arise because cross-border redispatch actions can lead to a decrease in the physical flows. In 2016 cross-border redispatch actions amounted to 2 TWh. The remaining 1 TWh is presumably due to measurement errors.

Comparison of imports from cross-border flows (TWh)

	Actual physical flows 2015	Binding exchange schedules 2015	Actual physical flows 2016	Binding exchange schedules 2016
NL → D	0.34	0.06	1.34	0.27
PL → D	0.02	0.4	0.01	0.75
CZ → D	6.1	4.75	5.04	4
FR → D	12.11	2.05	8.32	2.32
DK → D	5.15	5.11	2.78	2.75
CH → D	3.02	2.47	2.44	1.24
AT → D	3.48	0.17	4.2	0.32
SE → D	1.94	1.93	1.48	1.46

Table 44: Comparison of imports from cross-border electricity flows

Comparison of exports from cross-border flows (TWh)

	Actual physical flows 2015	Binding exchange schedules 2015	Actual physical flows 2016	Binding exchange schedules 2016
D → NL	23.96	16.27	16.89	11.4
D → PL	10.66	0.12	8.75	0.11
D → CZ	6.27	1.17	6.39	0.58
D → FR	1.36	11.53	2.73	12.05
D → DK	2.87	2.53	5.23	5.06
D → CH	16.06	7.29	17.02	9.12
D → AT	17.77	28.92	16.66	25.85
D → SE	0.17	0.15	0.84	0.82

Table 45: Comparison of exports from cross-border electricity flows

The actual physical load flows shown in Figures 70 and 71[58] deviate from the exchange schedules at each frontier[59].

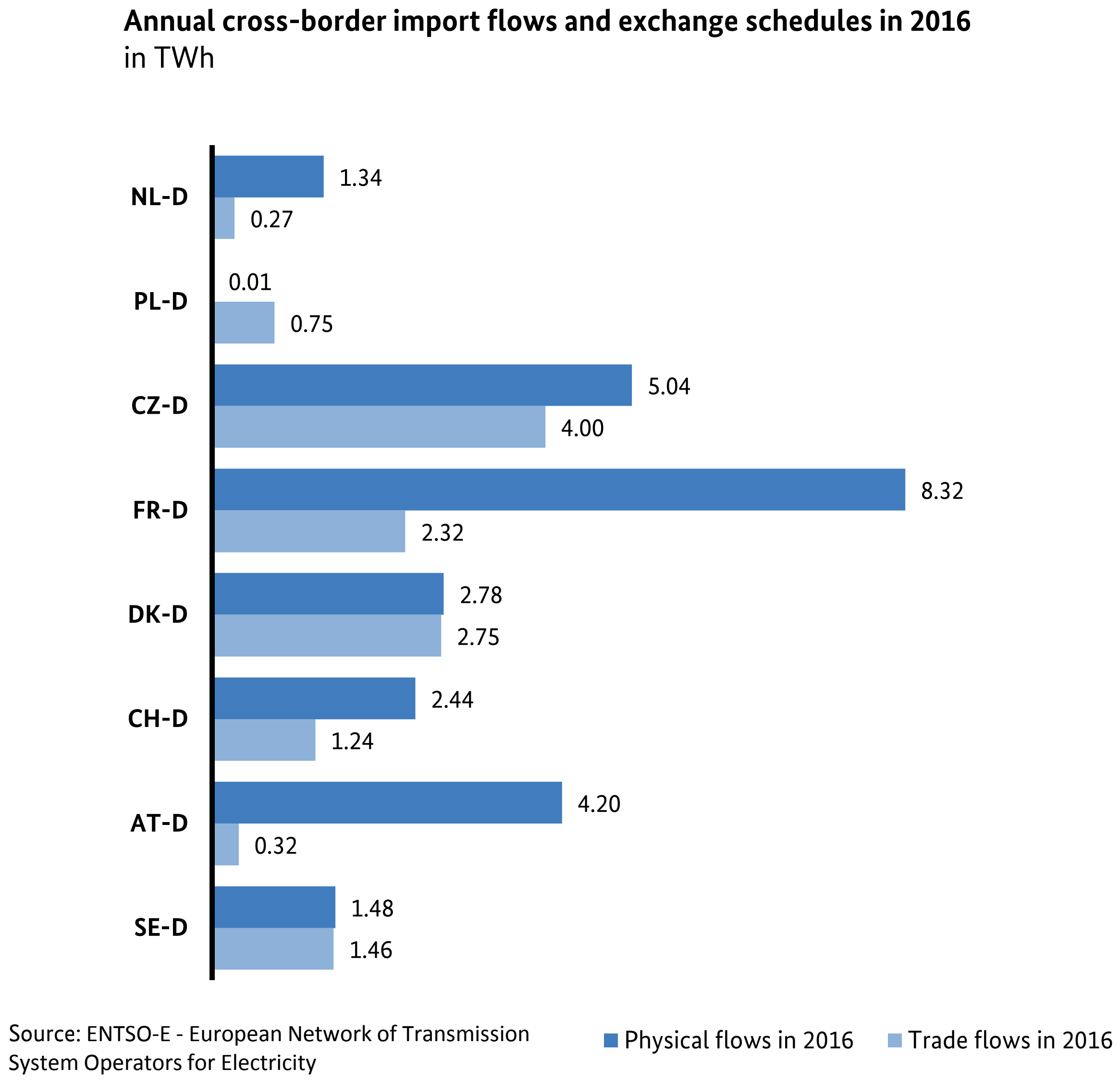

Figure 70: Annual cross-border import flows and exchange schedules 2016

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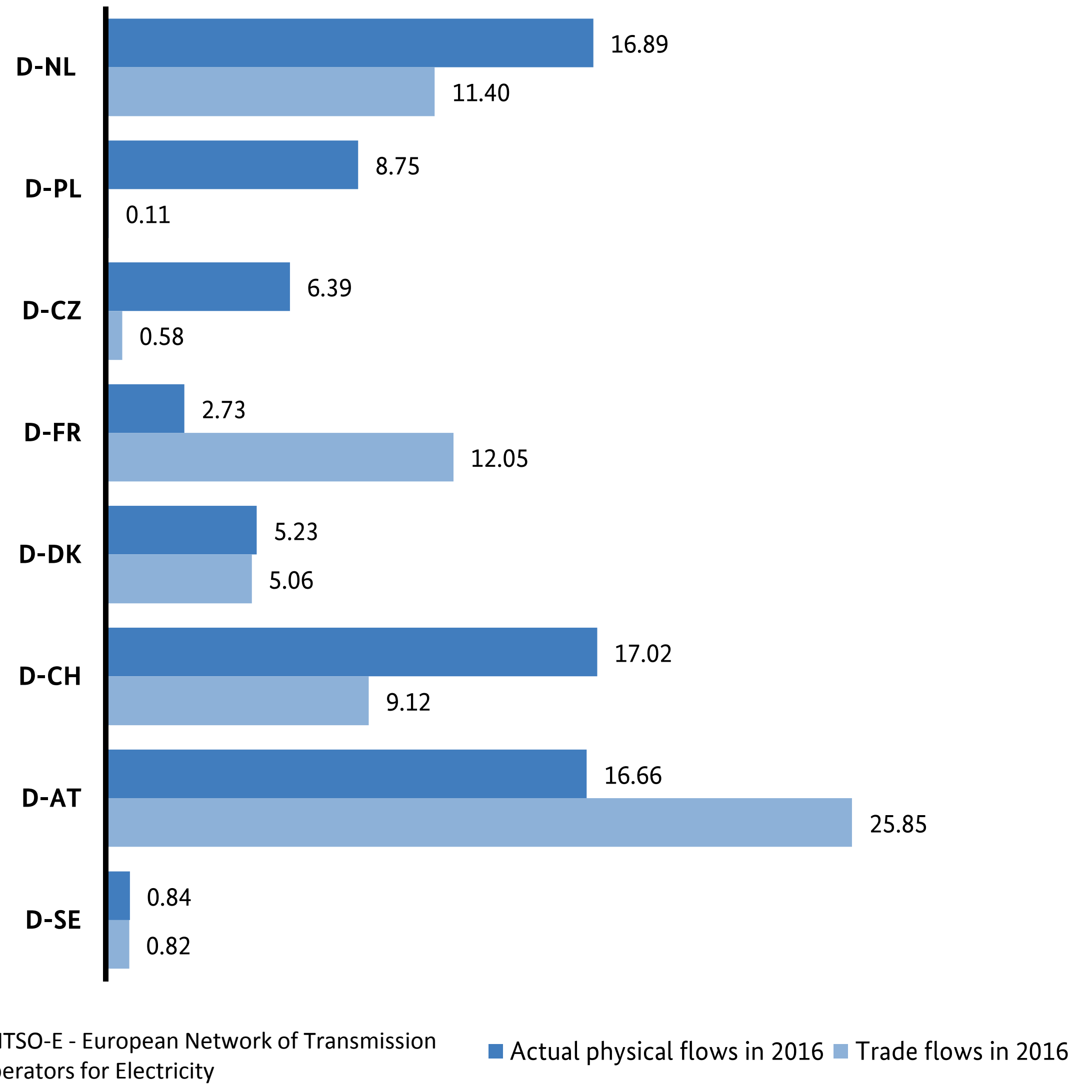
[58] Physical flows represent the actual flow of electricity through the individual electricity networks.

[59] 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 via third countries (eg from France via Germany/Switzerland to Italy).

Annual cross-border export flows and exchange schedules in 2016
in TWh



Source: ENTSO-E - European Network of Transmission System Operators for Electricity

Figure 71: Annual cross-border export flows and exchange schedules 2016

Electricity trading in Germany has been characterised by years of falling imports. Net exports, on the other hand, have risen continuously since 2011, stabilising at a high level in 2016 as shown in Figure 72.

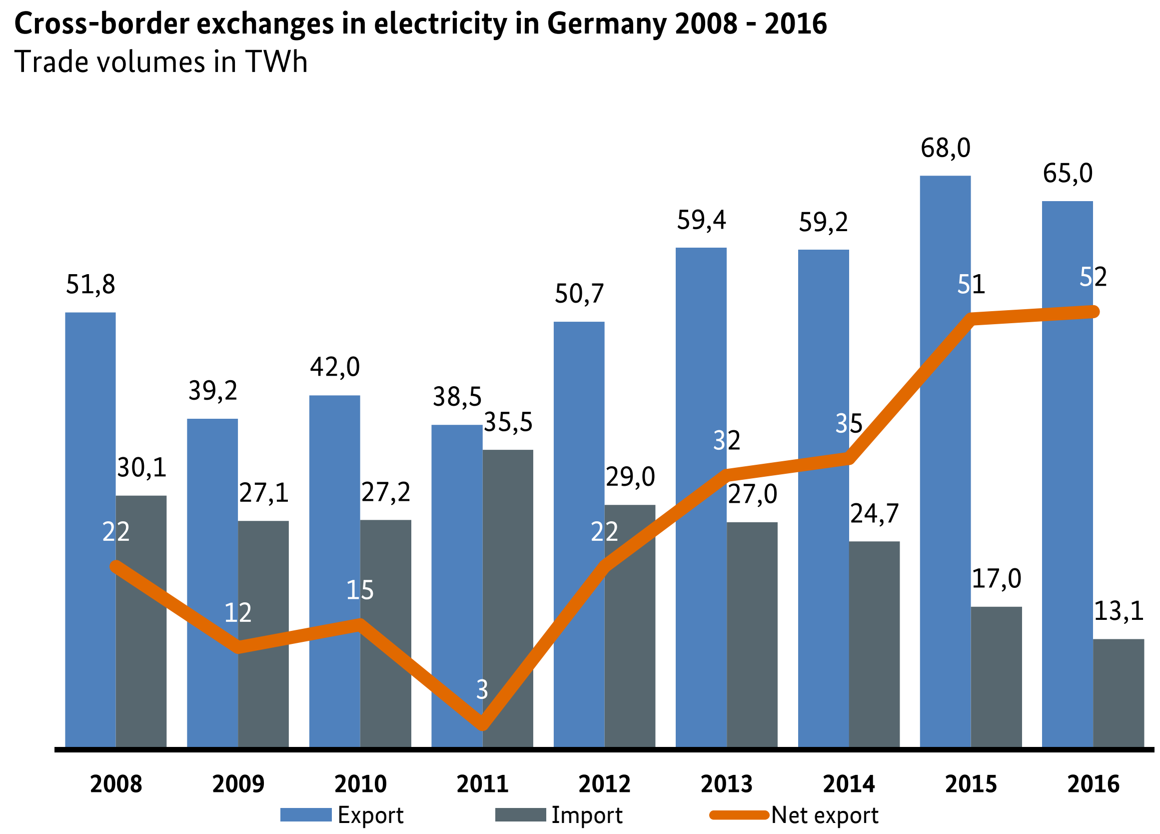


Figure 72: German cross-border electricity trade

Monetary trends in cross-border electricity trade

	2015		2016	
	TWh	**Trade Volume (€)**	**TWh**	**Trade Volume (€)**
Exports	67.96	2,062,614,362.74	64.98	1,843,064,660.05
Imports	16.95	588,323,933.24	13.11	395,607,565.04
Balance	51.01	1,474,290,429.50	51.87	1,447,457,095.01
Export revenues (€/MWh)		30.35		28.36
Import costs (€/MWh)		34.71		30.18

Table 46: Monetary trends in cross-border electricity trade[60]

[60] 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 incentive to do so.

German export and import revenues and costs 2011-2016
in € millions

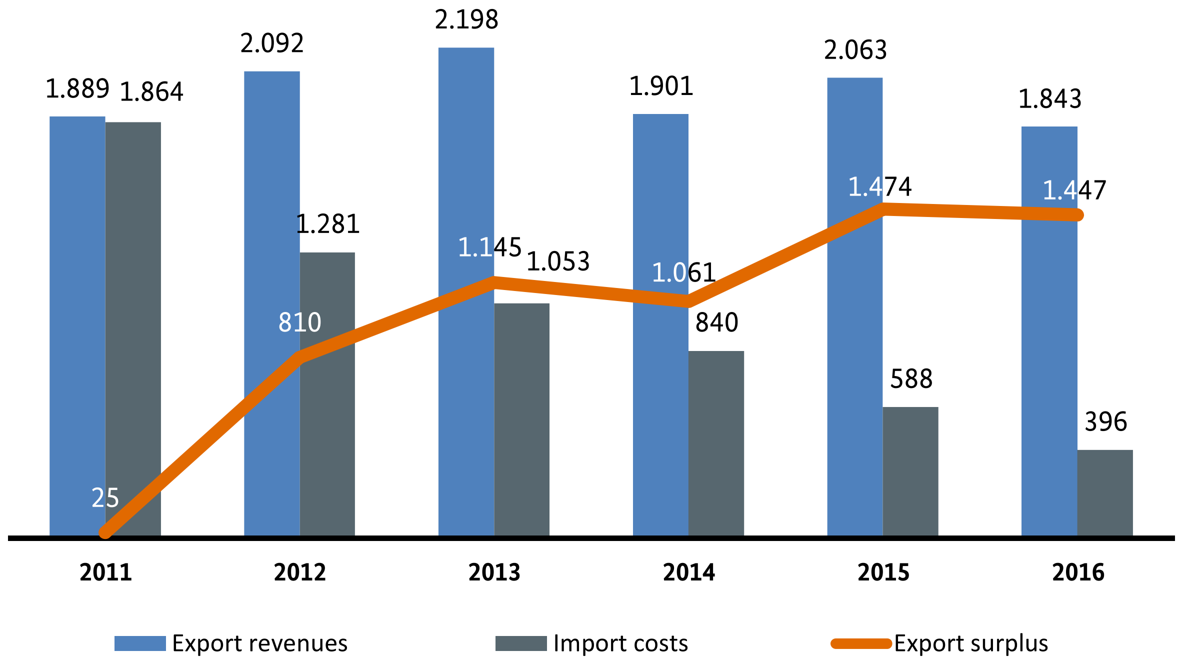


Figure 73: German export and import revenues and costs 2011 to 2016

Changes in cross-border trading volumes between Germany and its neighbouring countries reflect changes in 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

The amounts of electricity traded between the countries must be examined separately from the transmission lines along which the traded amounts of electricity actually (physically) flow and whether the electricity flows as a loop or transit flow, possibly through third countries.[61] The following example demonstrates how unplanned flows are calculated: In 2015, Germany imported (trade) 0.06 TWh from and exported 16.27 TWh to the Netherlands. This is equal to an export surplus (trade) of 16.21 TWh. At the same, 0.34 TWh flowed physically from the Netherlands to Germany. In contrast, 23.96 TWh flowed from Germany to the Netherlands. This is equal to an export surplus (physical) of 23.62 TWh. This means that on balance (trade minus physical) 7.41 TWh of electricity flowed from Germany to the Netherlands which had not been traded between the two countries. This is is known as unplanned flow.

The following diagrams show the unplanned flows, arising from the difference between net physical and trade flows, from Germany and to its neighbouring countries and back again.

[61] The Bundesnetzagentur uses the TSO's exchange schedules (trade flows) and the physical flows to determine the figures. The physical flows are based on a number of factors, including loop flows from German-German trades that are physically transported via foreign networks.

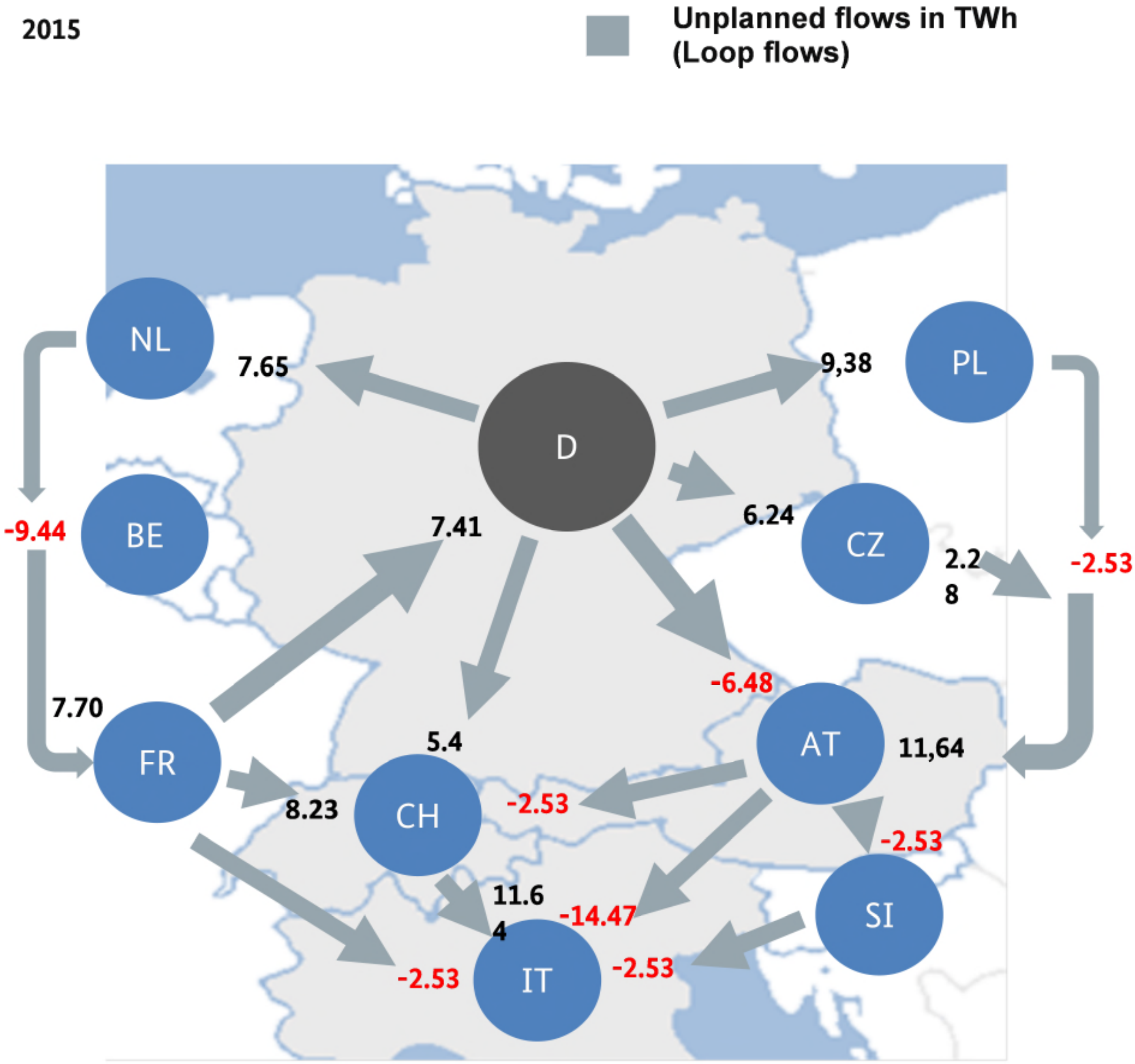


Figure 74: Unplanned flows 2015

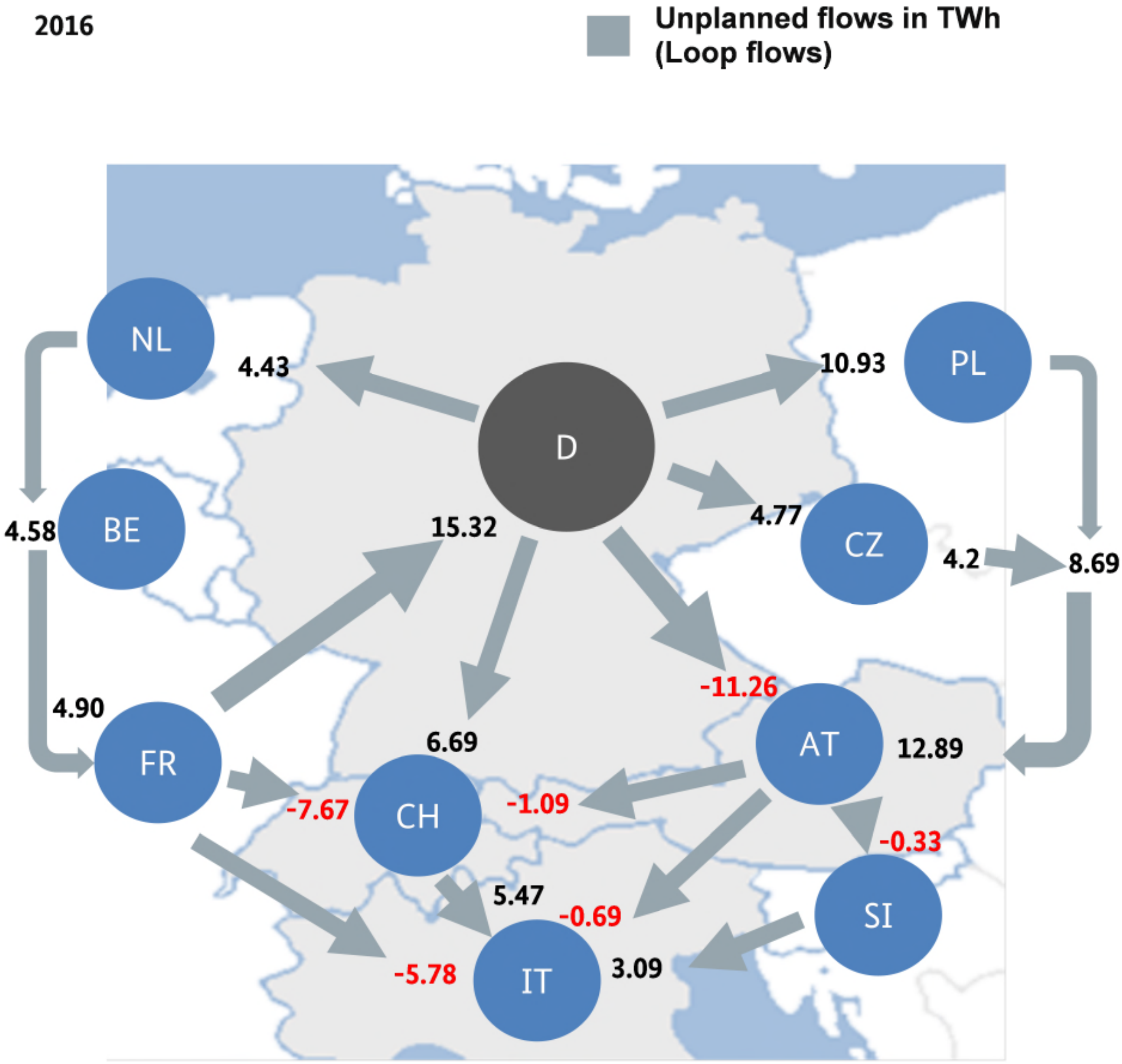


Figure 75: Unplanned flows 2016

The red figures in the diagrams reflect the physical deficit (trade > physics), while the black figures illustrate the trade deficit (physics > trade).

Loop flows and transit flows are physical phenomena which occur in a zonally organised electricity trading system. As shown in the diagrams, electricity follows the law of physics and always takes the path of least resistance. Some of the electricity trade within or between two countries consequently flows through grids in neighbouring countries. The figures show that some electricity flows across the western border of Germany to the Netherlands, through Belgium and France and then back to Germany. In the other direction, loop flows from France also spill over into the power grids of southern Germany in particular. When this happens, the electricity which is traded in France does not flow directly from France to Switzerland, to Italy or to its destinations on French territory, but takes a detour through Germany. On Germany's eastern border, some power likewise overflows into the Czech and Polish grid systems on its way to Austria. The power is either consumed in Austria or transported further. This amounted to −11.26 TWh in 2016. Unscheduled power flows stemming from the German transmission network also loop through the Czech grid before returning to the German transmission network and being consumed there.

Irrespective of all expansion measures, trade in electricity between different market areas inevitably results in unplanned flows. These unplanned flows are the result, in particular, of the high volumes of power which are transported as a result of trading within Germany and Europe. Germany is taking active part in various measures to prevent the problem of unplanned flows putting the security of power supply in other countries at risk. A cross-border redispatch regime was first established by installing a virtual phase-shifting transformer at the German-Polish border which reduced unplanned flows and increased network stability in Germany and Poland. The virtual phase-shifting transformer has now been replaced by a physical phase-shifting transformer at the cross-border interconnections. The partial installation and operation of physical phase shifting transformers and closure of the Vierraden-Krajnik line has already successfully reduced load flows between Germany and Poland to safe levels. Two physical phase-shifting transformers also started operating at the northern cross-border interconnection towards the Czech Republic in January 2017. Four more will follow in the course of 2017.

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 will 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.

ACER reports to the European Commission each year 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 ITC year[62] 2016 are as follows: The four German TSOs received compensation for losses and the provision of infrastructure totalling €4.97m and paid contributions of €17.45m. This means that on balance the German TSOs contributed a net amount of €12.48m to the ITC fund.[63] As a result, Germany was again a net contributor to the ITC fund in 2016 as it had been for the first time in 2015 when the mechanism was first introduced (–€6.1m in 2015, €7.65m in 2014, €13.21m in 2013, €26.8m in 2012). This trend has emerged over a period of several years and is mainly due to the large increase in Germany's electricity exports and the related cross-border flows.

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 certain 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 means that three quarters of the European electricity market are 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.

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[62] 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.

[63] Owing to the need for recalculations to be made at short notice the figures for 2016 are provisional. The final figures are expected to be available by the end of 2017.

The aim of market coupling is the efficient use of day-ahead available transmission capacity between the participating countries. This reduces the welfare losses that may result from network restrictions 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. Capacity allocations based on load flows

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.

The flow-based capacity calculation method was successfully launched in the CWE region in 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.

The decision taken in September 2016 on the determination of capacity calculation regions merged the previous regions of Central East Europe (CEE region) and Central West Europe into a common region. This means that the flow-based capacity calculation method must be implemented in the entire CORE region. This is currently expected to begin in the first six months of 2019.

Work in the region will be 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 proposal for a capacity calculation methodology in line with the CACM guideline for approval by the regulatory authorities in mid-September 2017.

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 the three fields of electricity trading, grid system connection and grid operations in 2016.

Commission Regulation (EU) 2015/1222 establishing a guideline on capacity allocation and congestion management (CACM GL), which entered into force in 2015, details the form which congestion management methods for day-ahead and intraday capacity allocation should take. These are currently being implemented by the nominated electricity market operators (NEMO), national regulatory authorities and ACER. One of the proposals tabled in 2016 by the European TSOs was for the determination of capacity calculation regions; this proposal was approved by ACER.

Commission Regulation (EU) 2016/1719 establishing a guideline on forward capacity allocation (FCA GL), which entered into force on 17 October 2016, details the allocation of cross-border forward capacity to the interconnectors. This must now be implemented by the TSOs, the national regulatory authorities and ACER.

The Commission Regulation establishing a guideline on electricity balancing (EB GL), which determines mechanisms for the integration of what are still predominantly nationally organised balancing energy markets and on the allocation of cross-zonal transmission capacity for balancing purposes was in comitology in 2016. The regulation is expected to come into force in late 2017/early 2018.

Commission Regulation (EU) 2016/631 establishing a network code on requirements for grid connection of generators (NC RfG), Commission Regulation (EU) 2016/1388 establishing a network code on demand connection (DCC) and Commission Regulation (EU) 2016/1447 establishing a network code on requirements for grid connection of high voltage direct current systems and direct current-connected power park modules (NCHVDC) all came into force in 2016. They create the most harmonised grid connection conditions for market players with aim of establishing the single European market for electricity and to achieve network stability.

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 Industry 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, for and dealing with appeals from parties seeking connection.

Commission Regulation (EU) 2017/1485 establishing a guideline on electricity transmission system operation (SO GL) came into force on 14 September 2017. The Regulation provides for harmonised operational security requirements and the definition of security limits. It also 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.

System operation is also affected by the Regulation establishing a network code on emergency and restoration (NC E&R), which was also submitted to comitology in 2016 and which is expected to be adopted by the fourth quarter of 2017. The regulation details procedures for emergencies and restoration.

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 has expanded ever since and now covers a region comprising the following EU and EEA Member States: Germany, France, the Netherlands, Belgium, Luxembourg, Austria, the United Kingdom, Denmark, Sweden, Finland, Norway, Spain, Italy, Portugal, Greece, Estonia, Latvia, Lithuania. Switzerland, which originally participated as an observer, has now left the project as the intergovernmental agreement with the EU required by Article 1(4) and (5) of the CACM guideline, relating to cooperation in the electricity sector had not been reached by the end of 2016.

Following the focus in 2015 on the agreement between the parties to the project – including the TSOs from the above Member States and the EPEX SPOT, GME, Nord Pool Spot and OMIE power exchanges – to conclude a contract with the IT provider, Deutsche Börse AG (DBAG), work continued in 2016 on implementation of the XBID platform. The platform, which will comprise a capacity management module and a joint order book, will 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. The platform is expected to be put into operation by the project parties in 2018 following the test phase.

7.2 Early implementation of the bidding zone review process

Amendment of current bidding zones is increasingly coming to the fore in the context of discussion in Europe of the future shape of the electricity market.

In this respect, the CACM guideline provides for an assessment every three years, beginning with the coming into force of the regulation, of the efficient configuration of the existing bidding zones by the participating TSOs, national regulatory authorities and ACER.

The assessment process consists of four steps. In the first step, the TSOs produce a technical report within nine months following a request by ACER. This report will review the bidding zone configuration from a network perspective. At the same time, ACER will cooperate with national regulatory authorities to write the market report which includes aspects such as the distribution of market power and market liquidity in the existing bidding zones. ACER will draw on the findings of both reports to decide whether a review of the bidding zone configuration should be performed. If one of the reports reveals inefficiencies, a review of the bidding zone configuration is initiated in which the TSOs assess possible amendments to the configuration of bidding zones. The review gives priority to criteria relating to network security, market efficiency and the stability of the bidding zones.

As part of this review, the TSOs may make proposals for alternative bidding zone configurations to which market players may respond in a public consultation. The results of the review are to be presented by the TSOs within 15 months of the decision to launch the process and may comprise a proposal to maintain or amend the bidding zone configuration. The regulation stipulates that, after transferring decision-taking competence to the national regulatory authorities, the Member States must reach an agreement within six months on the proposal to maintain or amend the bidding zone configuration based on the results of the review. The Federal Government has conferred this task on the Bundesnetzagentur.

The Bundesnetzagentur has worked within the process to ensure that appropriate account is taken of criteria such as planned grid expansion. When the grid has been expanded, it will be sufficiently free of congestion which means that the single German bidding zone can be maintained.

The review is expected to be completed by early 2018.

F Wholesale market

Functioning wholesale markets are vital to competition in the electricity industry. Spot markets, where electricity volumes that are required or offered at short notice can be bought or sold, and futures markets, which permit the hedging of price risks and speculation 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 important price signals for market players in other areas of the electricity industry.

In 2016, liquidity on the electricity wholesale markets rose to its highest level since records began. On-exchange futures trading volumes and trading volumes brokered via broker platforms both increased significantly. The volume of OTC clearing of Phelix futures on EEX grew substantially again in 2016. The spot market, however, experienced a decline.

Average electricity wholesale prices continued to fall in 2016. Average spot market prices fell by about 4 per cent year-on-year and futures contracts for the subsequent year were about 14 per cent lower on average with a marked low point in the middle of February 2016.

1. On-exchange wholesale trading

As in previous years, the review of on-exchange electricity trading relates to the market area covering Germany, Austria and Luxembourg and to the exchanges in Leipzig (European Energy Exchange AG – EEX), Paris (EPEX SPOT SE)[64] and Vienna (Abwicklungsstelle für Energieprodukte AG – EXAA). These exchanges took part in collecting energy monitoring data again this year[65]. Since Germany, Austria and Luxembourg constitute a common bidding zone in 2016, the specific electricity contracts ("products") are traded on all three exchanges at exchange prices that are the same for the three countries ("single price zone"). EEX offers electricity products in futures trading; EPEX SPOT SE and EXAA supply electricity products on the spot markets

The total number of participants authorised at the electricity exchanges in the market area covering Germany, Austria and Luxembourg has grown for years and reached a new all-time high on the EEX exchange on 31 December 2016; the number of participants authorised at EXAA remained stable; only EPEX SPOT saw a decline in participants.

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

[65] 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 2016: around 1.5 TWh) and the trading of market coupling products for Germany (from and to Sweden or Denmark)

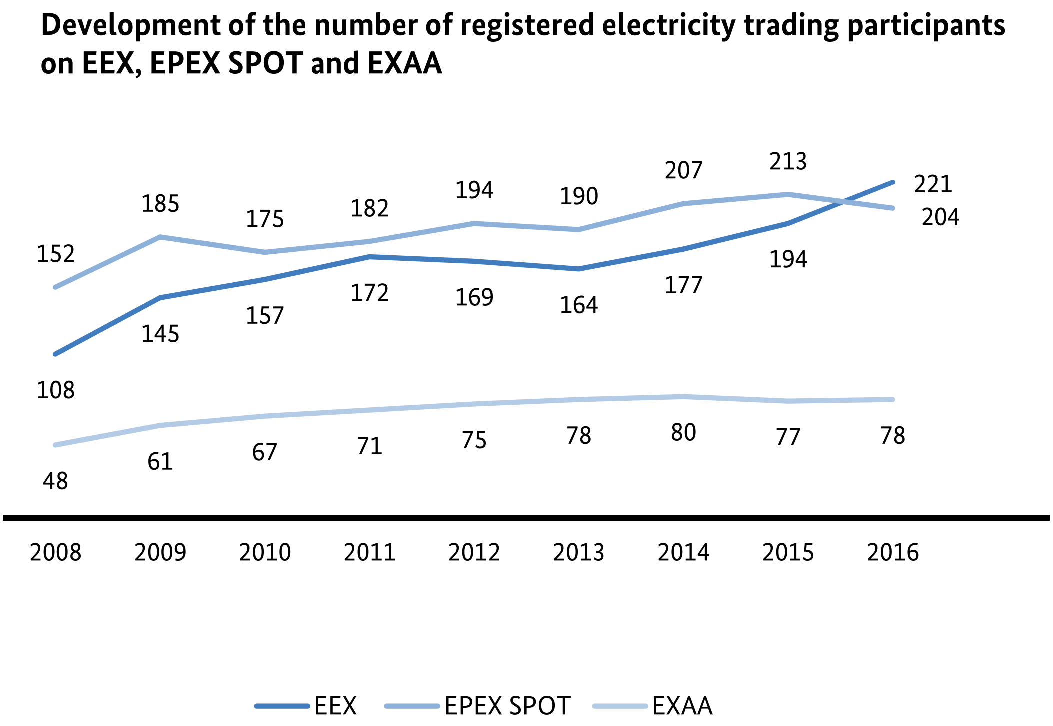


Figure 76: Development of the number of registered electricity trading participants on EEX, EPEX SPOT and EXAA

Not every company requires its own access to the exchange. Alternatively, 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. In the categories according to which EPEX SPOT and EEX classify their exchange participants[66], the range of participants for 2016 is as follows.

[66] EXAA does not classify its exchange participants.

Number of registered electricity trading participants by EEX and EPEX SPOT classification on 31 December 2016

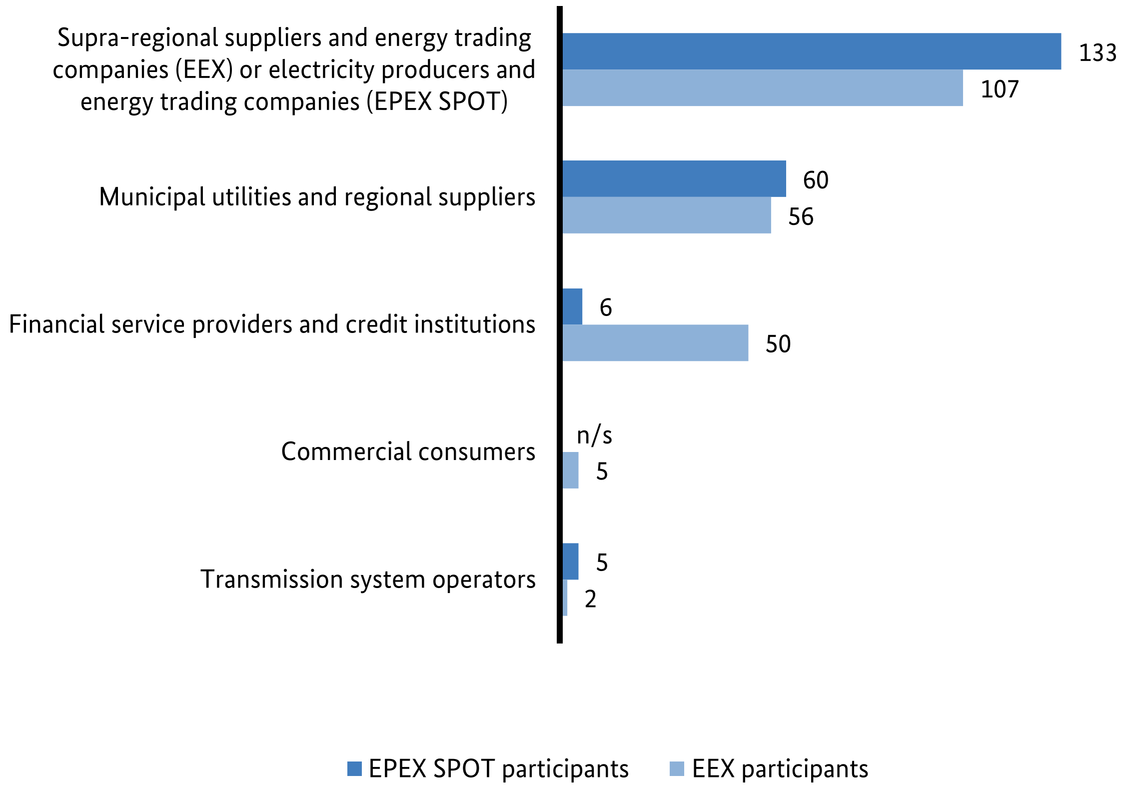


Figure 77: Number of registered electricity trading participants by EEX and EPEX SPOT classification on 31 December 2016

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 1.1) and the futures markets (section 1.2) are dealt with separately below.

1.1 Spot markets

Electricity is traded on the on-exchange spot markets a day ahead and for the following or current day (intraday). The two spot markets examined here, EPEX SPOT and EXAA, offer day-ahead trading and continuous intraday trading. Contracts can be physically fulfilled (supply of electricity) on the two on-exchange spot markets for the Austrian control area (APG), for Luxembourg (Creos) and for the four 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 at 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. The results are available from 3:10 p.m. All three auction formats are 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 single-hour 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.[67] Continuous intraday trading of fifteen-minute periods was extended to Austria (control area APG) on 1 October 2015.[68]

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.[69]

1.1.1 Trading volumes

The volume of day-ahead trading on EPEX SPOT was 235 TWh in 2016, a significant decline compared to the previous year (264 TWh). However, the volume of intraday trading rose to 41 TWh, a substantial increase of around 3 TWh or around 9 per cent.[70] The volume of the day-ahead market on EXAA remained stable and was once again around 8 TWh in 2016. Around 71 per cent of this volume was supplied to the German control areas.

[67] Cf. EPEX SPOT press release of 16 July 2015.

[68] Cf. EPEX SPOT press release of 2 October 2015.

[69] The trading volume of "Green Power" was 32 GWh in 2015 and fell to 11 GWh in 2016, a decline of approximately 65 per cent.

[70] Cf. EPEX Spot press release of 11 January 2017.

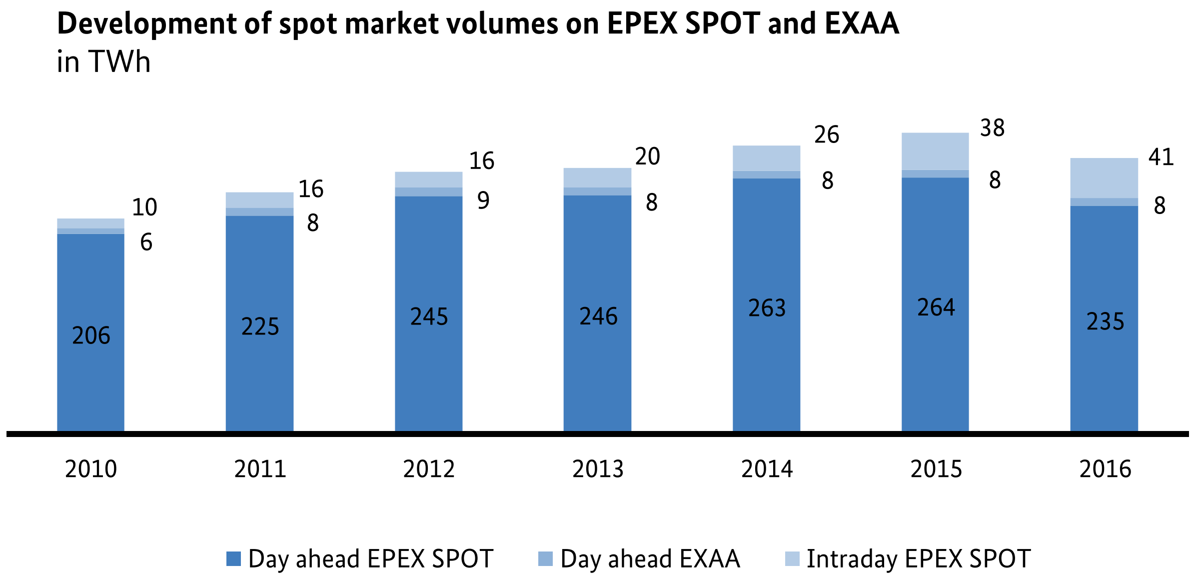


Figure 78: Development of spot market volumes on EPEX SPOT and EXAA

1.1.2 Number of active participants

There were some minor changes to the number of participants 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 2016 was 122 (compared to 127 buyers in 2015) and the average number of sellers was 117 (compared to 123 in 2015), a slight decline on both counts. An average of 156 participants (compared to 163 participants in the previous year), or about 76 per cent of all registered participants, were active per trading day. The number of net buyers per trading day (balance in favour of “purchase”) is roughly at the same level as the previous year with 81 participants in 2016. The number of net sellers (balance in favour of “sale”) fell to 75 following the growth over the last few years.

A participant registered on EXAA is regarded as “active” if at least one purchase or sale bid has been submitted for each supply day.[71] In 2016, around 43 participants (45 in the previous year), or just over half of all registered participants, were active per supply day. Some 74 per cent of all participants on EXAA (73 per cent in 2015) have trading accounts in the German control areas. An average of 29 participants per supply day (31 in 2015) submitted bids for supplies to the German control areas.

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.

[71] A different approach – supply day instead of trading day – is meant 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.

The relatively high proportion of price-independent bids on EPEX SPOT fell slightly in 2016 compared to the previous year. 69 per cent of purchase bids submitted were price-independent compared to 76 per cent in 2015. The proportion of price-independent bids among selling bids submitted was 62 per cent, down from 69 per cent in the previous year.

Price dependence of bids submitted in hour auctions on EPEX SPOT

	Sales bids submitted in 2016		Purchase bids submitted in 2016	
	Volume in TWh	Percentage	Volume in TWh	Percentage
Price-independent bids	146.4	62.3%	162.2	69.0%
by TSOs	41.6		0.4	
physically fulfilled Phelix futures	28.2		56.6	
other	76.7		105.1	
Price-dependent bids (in a broader sense)	88.5	37.7%	72.8	31.0%
blocks	17.1		7.1	
market coupling contracts	30.1		6.7	
price-dependent bids (in a narrower sense)	41.4		59.0	
Total	234.9	100%	234.9	100%

Table 47: Price dependence of bids submitted in hour auctions on EPEX SPOT in 2016

The marketing of renewable energy (EEG) volumes by the transmission system operators plays a major role on the seller side and was again almost completely price-independent at 99.8 per cent.[72] However, according to the power exchanges, the volume marketed by the transmission system operators continued to fall to around 42 TWh (48 TWh in 2015 and 51 TWh in 2014).

[72] 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.

The installed capacity of installations that sell electricity via direct marketing increased at the same time. In January 2016, the market premium was drawn on by operators of installations with a capacity of approximately 53 GW; in December 2016 it was already drawn on by operators of installations with a capacity of just under 60 GW. The installed capacity of installations with other direct marketing also rose from around 77 MW to over 165 MW in the same period.[73]

On the seller side, the volume of bids on EPEX SPOT for the physical fulfilment of Phelix futures fell from 46 TWh in 2015 to 28 TWh in 2016. On the buyer side, the volume also fell from 73 TWh in 2015 to 57 TWh in 2016.

The bids submitted on EXAA are broken down by price dependence as follows: on EXAA, 69 per cent of purchase bids and 73 per cent of sales bids 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.[74]

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 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 2016. The Phelix day base average on EPEX SPOT fell from €31.63/MWh in 2015 to €28.98/MWh, or by about 8 per cent, to the lowest level since 2007. At €32.01/MWh the Phelix day peak was also nearly 9 per cent below the previous year's level of €35.06/MWh. The difference between the Phelix day base and the Phelix day peak was €3.03/MWh in 2016, which again was lower than in 2015. As a result, the average Phelix day peak in 2016 was only 10 per cent higher than the Phelix day base (it was 21 per cent higher in 2008).

[73] For information provided by the TSOs on direct marketing see https://www.netztransparenz.de/EEG/Monatliche-Direktvermarktung
[74] This was also the reason behind the closer correlation between EXAA price results and OTC prices. Cf. EXAA annual report 2015, p. 24 f.

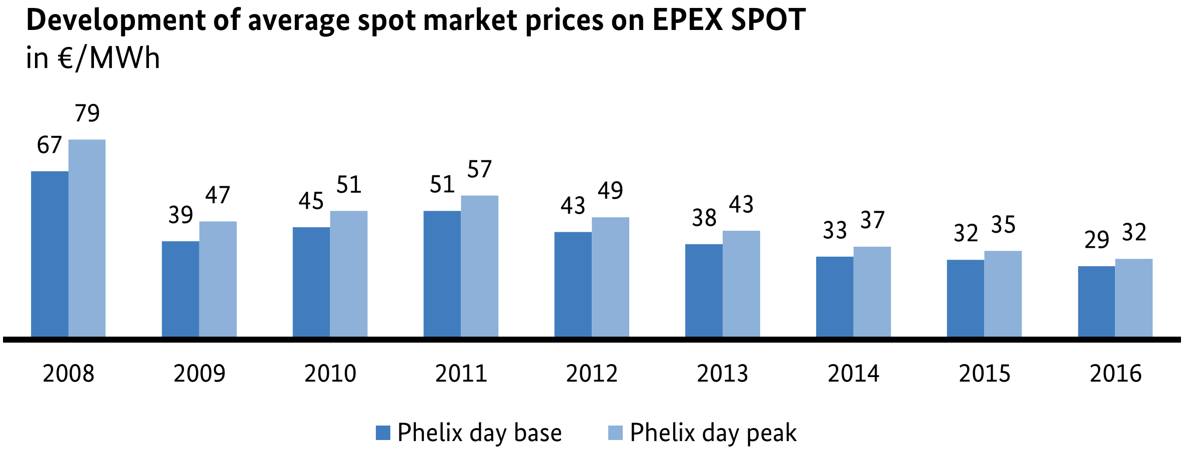


Figure 79: Development of average spot market prices on EPEX SPOT

The bEXA and Phelix indices for 2016 are very close to each other. Compared to previous years, during which the difference steadily decreased, the difference has now slightly increased. Furthermore, 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.

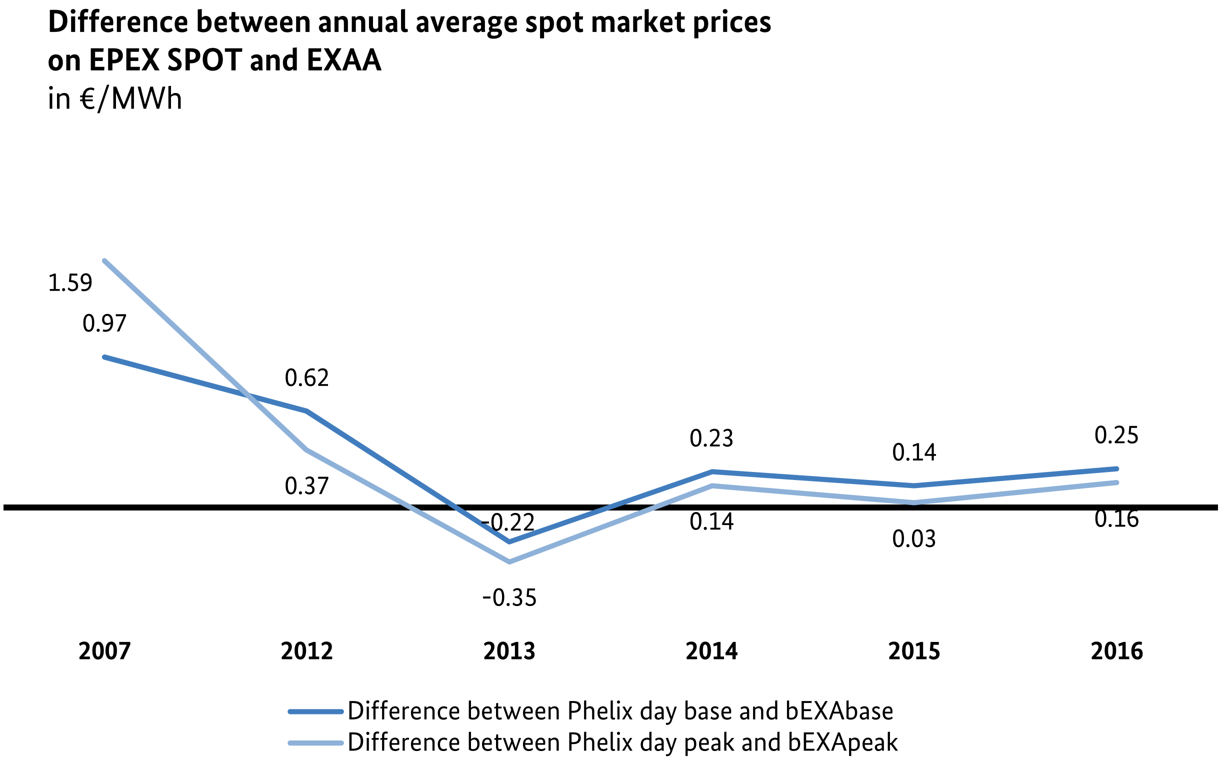


Figure 80: Difference between base and peak spot market prices on EPEX SPOT and EXAA in €/MWh[75]

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. As in the previous year, there were some occasional peaks and troughs in 2016 that went far beyond the usual fluctuations. These extreme values showed even greater variation than the previous year's figures (between +€60.06/MWh and -€12.89/MWh compared to +€51.27/MWh and -€0.80/MWh in the previous year).

[75] The difference is calculated on the basis of the relevant EXAA value minus the relevant EPEX value.

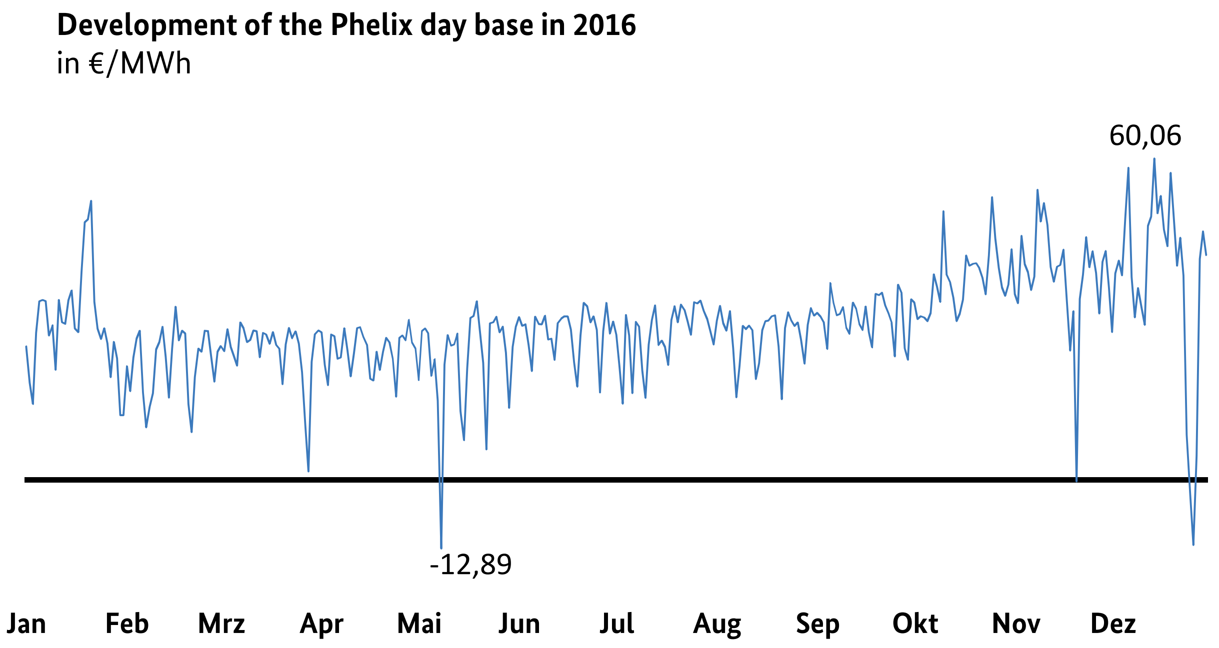


Figure 81: Development of the Phelix day base in 2016 in €/MWh

The base and peak prices on EPEX SPOT exhibited slightly decreased dispersion in 2016. The range of the middle 80 per cent of the graded Phelix day base values was €21.81/MWh in 2016 and fell by only 1 per cent compared to 2015. The corresponding peak range of the middle 80 per cent rose by 1 per cent. There were four negative values[76] in the Phelix day base in 2016 and as many as five negative values in the Phelix day peak. The highest negative Phelix day base price of -€12.89/MWh was recorded on 8 May 2016 and the Phelix day peak reached its lowest value on the same day with -€36.46/MWh[77]. Overall, daily average spot market prices for 2016 were found to be at a lower average level throughout compared to the previous year. However, the extreme values increased. The highest value was €51.27/MWh in 2015. In 2016, the highest Phelix day base value was €60.06/MWh or 17 per cent higher than the previous year's value. The Phelix day peak also increased. It rose from €65.12/MWh in 2015 to €76.84/MWh in 2016, which is equivalent to an increase of 18 per cent.

[76] Negative prices are price signals on the electricity market that 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.

[77] Other days with negative Phelix day base prices included 20 November, 25 December and 26 December 2016. There were negative Phelix day peak prices on two other days, which were 20 November and 26 December 2016.

Price ranges of Phelix day base and Phelix day peak in €/MWh

	Middle 80 per cent	*Range of the middle 80 per cent*	Extreme values	*Range of extreme values*
Phelix day base 2014	22.29 – 42.71	20.42	-4.13 – 55.48	59.61
Phelix day base 2015	20.30 – 42.38	22.08	-0.80 – 51.27	52.07
Phelix day base 2016	18.57 – 40.38	21.81	-12.89 – 60.06	72.95
Phelix day peak 2014	22.82 – 51.69	28.87	-17.59 – 69.39	86.98
Phelix day peak 2015	20.82 – 49.09	28.27	-11.38 – 65.12	76.5
Phelix day peak 2016	18.38 – 46.94	28.56	-36.46 – 76.84	113.3

Table 48: Price ranges of Phelix day base and the Phelix day peak between 2014 and 2016

EXAA shows a similar pattern. Both the maximum and minimum values for bEXAbase and bEXApeak and the resulting range between these values increased significantly year-on-year. The percentage changes of the ranges follow the same trend as the changes in the Phelix day base and the Phelix day peak.

Price ranges of bEXAbase and bEXApeak in €/MWh

	Middle 80 per cent	*Range of the middle 80 per cent*	Extreme values	*Range of extreme values*
bEXAbase 2014	23.27 – 42.56	19.29	4.15 – 55.86	51.71
bEXAbase 2015	20.41 – 42.48	22.07	-0.79 – 49.27	50.06
bEXAbase 2016	18.62 – 40.92	22.30	-4.50 – 59.12	63.62
bEXApeak 2014	23.69 – 51.51	27.82	-1.75 – 69.17	70.92
bEXApeak 2015	20.74 – 49.09	28.35	0.40 – 59.10	58.70
bEXApeak 2016	19.43 – 46.89	27.46	-12.60 – 74.90	87.50

Table 49: Price ranges of bEXAbase and bEXApeak between 2014 and 2016 in €/MWh

1.2 Futures 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) has been possible since September 2015 to hedge price peaks in light of the growing share of renewable energy on the market.[78] EEX started trading separate electricity futures for Germany/Luxembourg and for Austria with a view to splitting the German/Austrian bidding zone. Phelix-DE have been tradeable in the German Phelix-AT bidding zone since April 2017 and in the Austrian bidding zone since 26 June. There are also options for trading solely on the Phelix-DE.[79] The new Phelix-DE and Phelix-AT futures will initially be settled against the existing German/Austrian day-ahead auction price. Following the separation, Phelix-DE

[78] Cf. EEX press release of 14 September 2015.

[79] Cf. EEX press release of 11 April 2017 - https://www.eex.com/en/about/newsroom/news-detail/eex-to-launch-power-futures-for-germany/66308; EEX press release of 16 May 2017 https://www.eex.com/en/about/newsroom/news-detail/eex-to-launch-austrian-power-future-and-extend-phelix-de-future-products/67020

futures will be settled against a German day-ahead auction price and Phelix-AT futures will be settled against an Austrian day-ahead auction price.[80]

The following section deals solely with on-exchange transaction volumes, excluding OTC clearing (cf. section on OTC clearing, page 204 ff.).

1.2.1 Trading volumes

Following substantial growth in the previous years, the on-exchange trading volumes of Phelix futures increased significantly again in 2016 and were up 56 per cent from 937 TWh to over 1,466 TWh. The number of active participants on the EEX futures market (excluding OTC clearing) also grew and averaged 75 per trading day in 2016 compared to 65 in 2015.

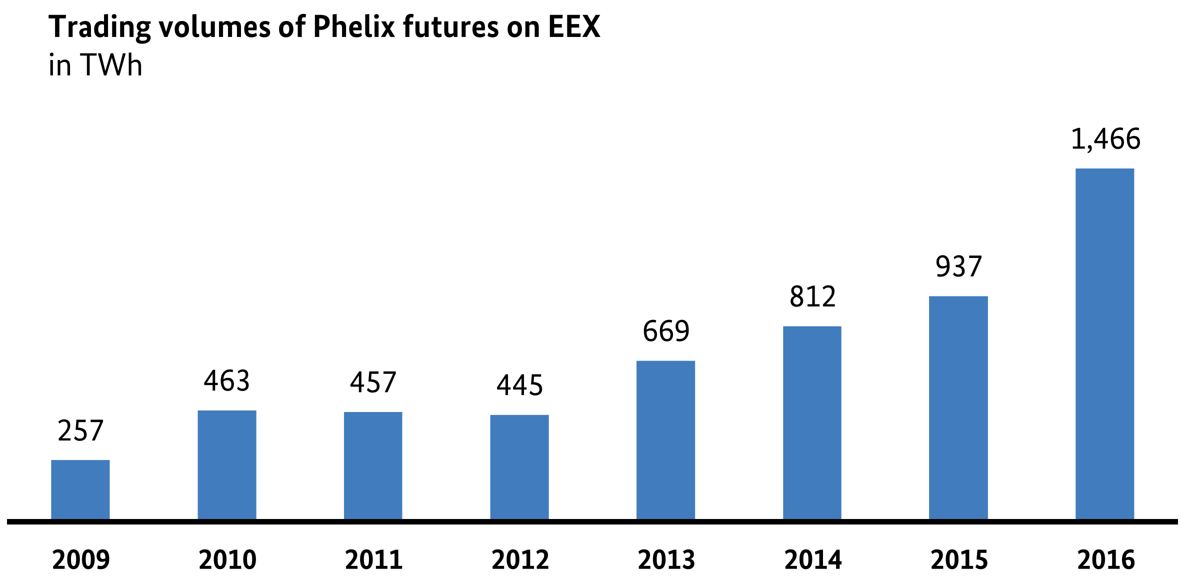


Figure 82: Trading volumes of Phelix futures on EEX in TWh

Futures trading in 2016 predominantly focussed on contracts for the year ahead (2017) as the fulfilment year with some 66 per cent of the total trading volume, i.e. around 975 TWh. Trading for 2018 made up the second largest share with approximately 15 per cent. Compared to the previous year, the volume increased here from 147 TWh in 2015 to 222 TWh for the fulfilment year 2018, i.e. long-term procurement rose by around 51 per cent. Trading for 2016 accounted for only around 12 per cent of the contract volume and at 182 TWh was 18 per cent below the previous year's figure of 223 TWh. Trading for 2019 and for the next few years was 17 TWh and accounted for 6 per cent of the total volume, the same level as the previous year.

[80] Cf. EEX press release of 16 May 2017. https://www.eex.com/de/about/newsroom/news-detail/eex-fuehrt-stromfutures-fuer-oesterreich-ein-und-ergaenzt-phelix-de-produktpalette/67016

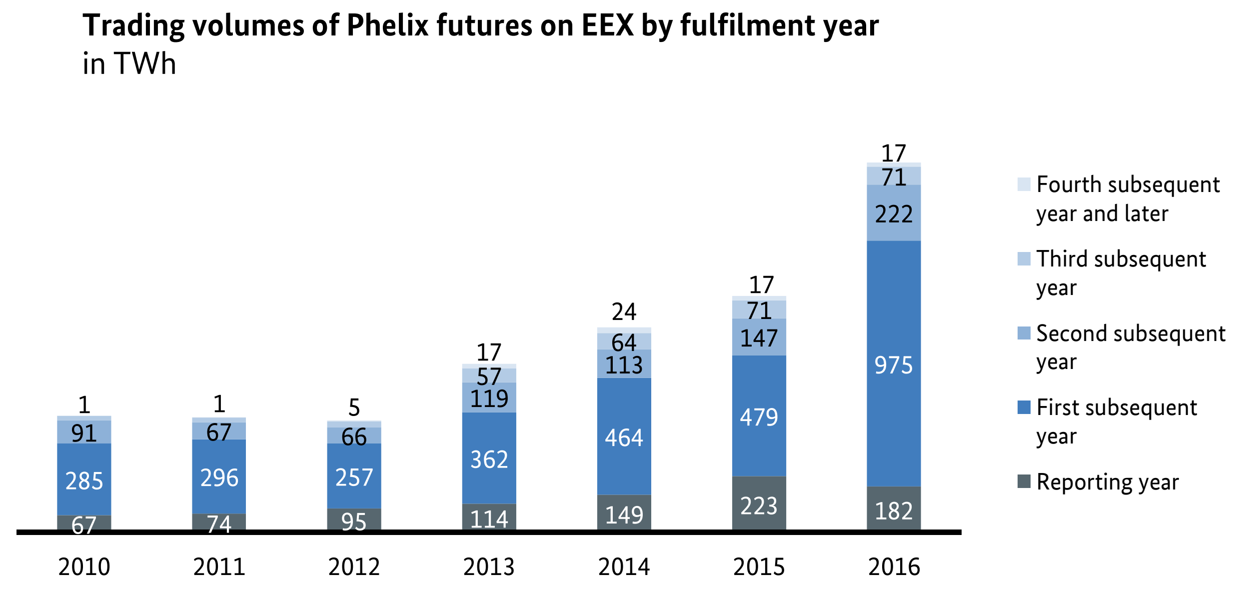


Figure 83: Trading volumes of Phelix futures on EEX by fulfilment year in TWh

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. Baseload futures relate to a constant and continuous supply rate (every hour, every day) while peakload futures cover the hours from 8:00 a.m. to 8:00 p.m. from Monday to Friday.

In the course of 2016, futures prices increased for the first time in years. Prices fell only in the first quarter of 2016 and then rose again, especially in the last quarter of 2016. Among the reasons were increased demand for electricity in Western Europe due to a cold spell and the, sometimes unexpected, decommissioning and maintenance of nuclear power plants in France and Germany.

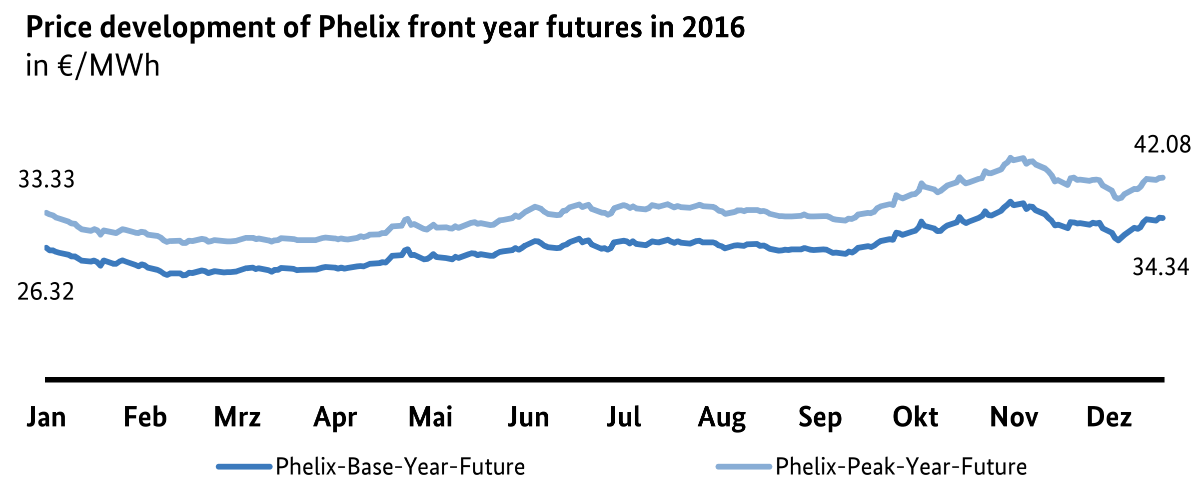


Figure 84: Price development of Phelix front year futures in 2016 in €/MWh

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 bought (or sold) the electricity not at short notice but pro rata in the preceding year.

The annual averages of the Phelix futures prices fell again year-on-year despite a price increase at the end of the year. With an annual average of €26.58/MWh, the Phelix base year futures fell by €4.40/MWh from €30.97/MWh in 2015, a drop of approximately 14 per cent. The price of the Phelix peak front year futures averaged €33.51/MWh over the year. The price declined by €5.55/MWh, or around 14 per cent, from the previous year's figure of €39.06/MWh. The annual average values for the base and peak futures continued their downward trend from the historic high in 2008.

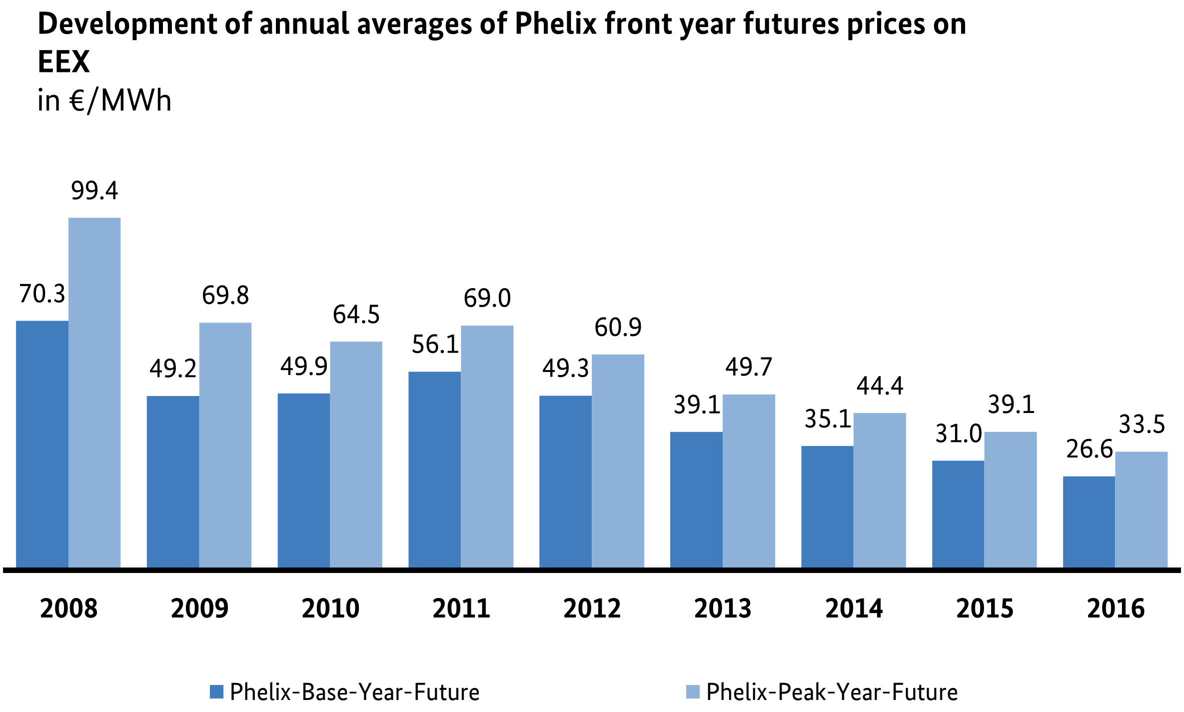


Figure 85: Development of annual averages of Phelix front year futures prices on EEX in €/MWh

The annual average price difference between base and peak products was €6.93/MWh. It was still as much as €8.09/MWh in 2015. While the peak price was more than 40 per cent higher than the base price between 2007 and 2009, the difference has been reduced to only 23 to 29 per cent since 2010 and averaged 26 per cent as in the previous year.

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 the previous years acted as market makers on the EEX futures market for Phelix futures during the reporting period: Uniper Global Commodities SE (trading as E.ON SE until 31 December 2015), EDF Trading Limited, RWE Supply & Trading GmbH and Vattenfall Energy Trading GmbH. The market makers' share in the purchase volume was 20 per cent, down from 33 per cent in the previous year. On the sales side, the volume fell to 20 per cent from 34 per cent in the previous year. 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. These companies generated approximately 7 per cent of the total trading volume (sales and purchases) in 2016, a slight decline compared to the previous year.

Five market makers were active on the day-ahead market of EXAA in the reporting period. In 2016, the cumulative share of transactions carried out by companies in their role as market makers was 3.3 per cent of the purchase volume of the day-ahead auction (2.4 per cent in 2015) and 9.4 per cent of the sales volume (7.6 per cent in 2015).

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 has been declining for a number of years and, as in the previous year, was only around 18 per cent in 2016. By comparison, their share was still 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 41.7 TWh in 2016; in 2015, this value was still around 47.8 TWh and in 2012 around 69.5 TWh. TSOs generated a very small spot market volume of about 0.3 per cent 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. Also, this report does not provide group values, i.e. the turnover of a group of companies is not aggregated if that group has several participant registrations.[81]

[81] 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 grew slightly to 41 per cent from 40 per cent in 2015. The corresponding share on the seller side declined significantly compared to the previous year. The cumulative share of the five sellers with the highest turnover was approximately 32 per cent in 2016 compared to 35 per cent in 2015. The previously higher shares on the seller side are primarily due to the TSOs' higher sales volumes at that time.

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

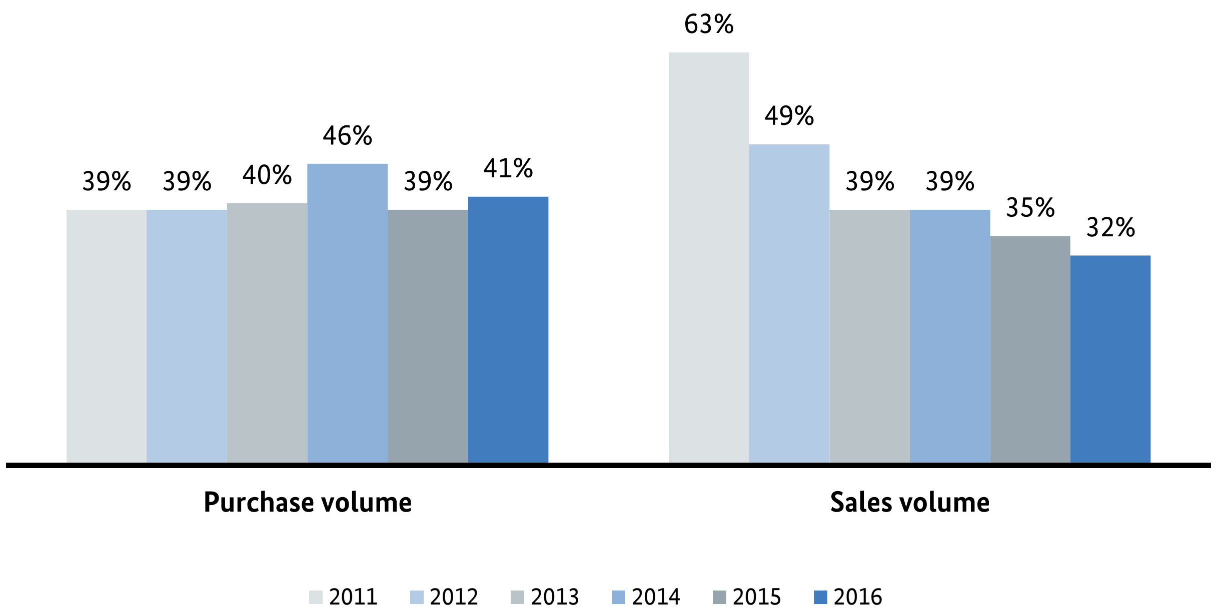


Figure 86: Share of the five sellers and five buyers with the highest turnover in the day-ahead volume of EPEX SPOT

EXAA as another exchange for day-ahead auctions experienced a slight increase in concentration at a low level. The share of the five participating purchasers with the highest turnover grew from 33 per cent in 2015 to 37 per cent in 2016. The share of the five sellers with the highest turnover was around 28 per cent in 2015 and rose to 35 per cent in 2016.

The share of the five buyers of Phelix futures with the highest turnover on EEX (excluding OTC clearing) declined substantially from around 41 per cent in 2015 to 30 per cent in 2016. The share of the five sellers with the highest turnover also fell sharply from 43 per cent in 2015 to 30 per cent in 2016. This represents a substantial reduction of 11 percentage points on the buyer side and 13 percentage points on the seller side compared to 2015.

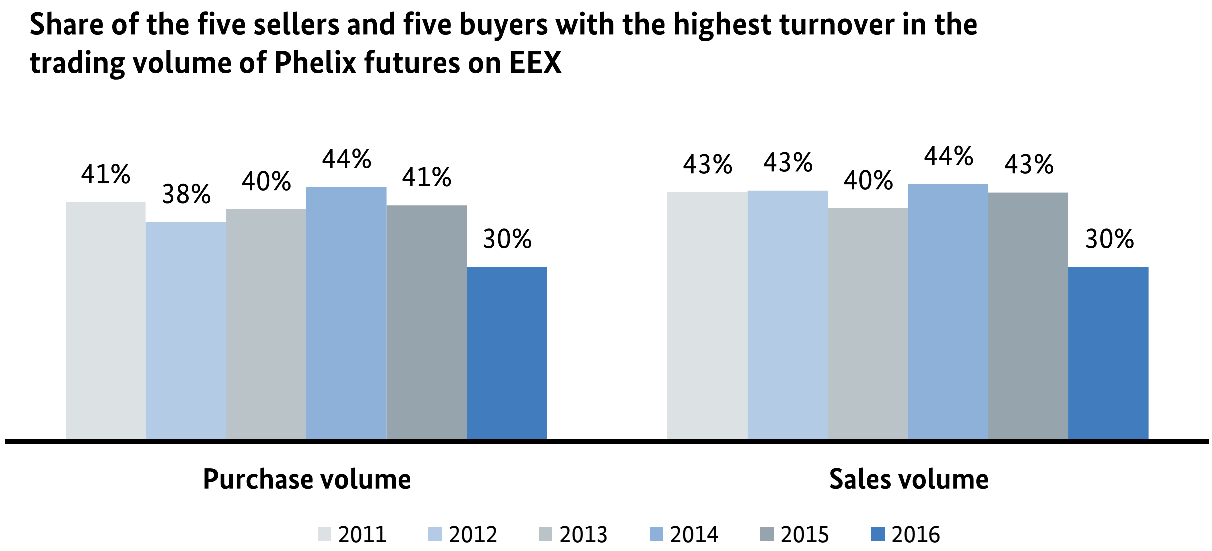


Figure 87: Share of the five buyers and five sellers with the highest turnover in the trading volume of Phelix futures on EEX

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 separately for purchases and sales but only the weighted average shares for purchases and sales. The shares in the spot market volume indicate the transaction volume reduced by market coupling contracts (imports and exports).

Averaged shares of EPEX SPOT and EEX participant groups in sales and purchase volumes in 2016

	EPEX SPOT	EEX
Supra-regional suppliers and energy trading companies (EEX) and electricity producers and energy trading companies (EPEX SPOT)	74%	56%
Financial service providers and credit institutions	4%	35%
Transmission system operators	10%	< 1%
Municipal utilities and regional suppliers	11%	8%
Commercial consumers	-	< 1%

Table 50: Averaged shares of EPEX SPOT and EEX participant groups in sales and purchase volumes in 2016

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 the 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 off-exchange there are no clearly definable market places nor is there 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.[82] OTC clearing provides an interface between on-exchange and off-exchange electricity wholesale trading.

In 2016, different broker platforms were once again surveyed with regard to bilateral wholesale trade (cf. section 2.1 below). Data on OTC clearing on EEX was also collected (cf. section 2.2 below). The surveys revealed a stable high level of liquidity in bilateral electricity wholesale trading in 2016.

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 conduct their brokerage services.

The same 11 brokers as in the previous year who brokered electricity trading transactions with Germany as a supply area took part in this year's collection of wholesale trading data. The total volume brokered by them was around 5,759 TWh in 2016 compared to 4,837 TWh in 2015, an increase of around 19 per cent. Data from the London Energy Brokers' Association (LEBA), which, however, does not include all broker platforms, also showed that the volume had grown. The trading volume for German power brokered by LEBA members rose from 4,517 TWh to 5,518 TWh, or by around 20 per cent year-on-year.[83]

Contracts for the year ahead continue to make up the majority of electricity transactions brokered on broker platforms with 63 per cent (52 per cent in the previous year), followed by the activities for the current year with 18 per cent (26 per cent in the previous year). Short-term transactions with a fulfilment period of less than one week generated only small volumes. Compared to the previous year, the distribution of the fulfilment periods has shifted slightly from short-term activities to contracts for the year ahead (2017).

[82] EEX no longer refers to this service as "OTC clearing", but as "trade registration". The original designation has been retained in this Monitoring Report.

[83] See https://www.leba.org.uk/assets/monthly_vol_reports/LEBA%20Energy%20Volume%20Report%20December%202015.pdf (retrieved on 2 June 2017).

Volume of electricity traded via eleven broker platforms in 2016 by fulfilment period

Fulfilment period	Volume traded in TWh	Percentage
Intraday	0	0%
Day ahead	77	1%
Less than one week	51	1%
More than one week	1,062	18%
2017	3,625	63%
2018	782	14%
2019	143	2%
2020 and beyond	19	<1%
Total	**5,759**	**100%**

Table 51: Volume of electricity traded via broker platforms in 2016 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. In OTC clearing, 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 without applying this method, it cannot be eliminated altogether. Another factor is that the inclusion of OTC transactions can in some cases reduce the amount of the collateral necessary for exchange trading, e.g. futures, that has to be deposited with the clearing bank.

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 1,367 TWh in 2016. The volume was only 877 TWh in 2015. 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 until 2011). The volume has been increasing since 2012. Compared to 2016, the volume has more than tripled since 2012 and reached new all-time highs in OTC trading and in exchange trading. There was significant year-on-year growth in the OTC clearing volume (56 per cent) and in exchange trading (57 per cent).

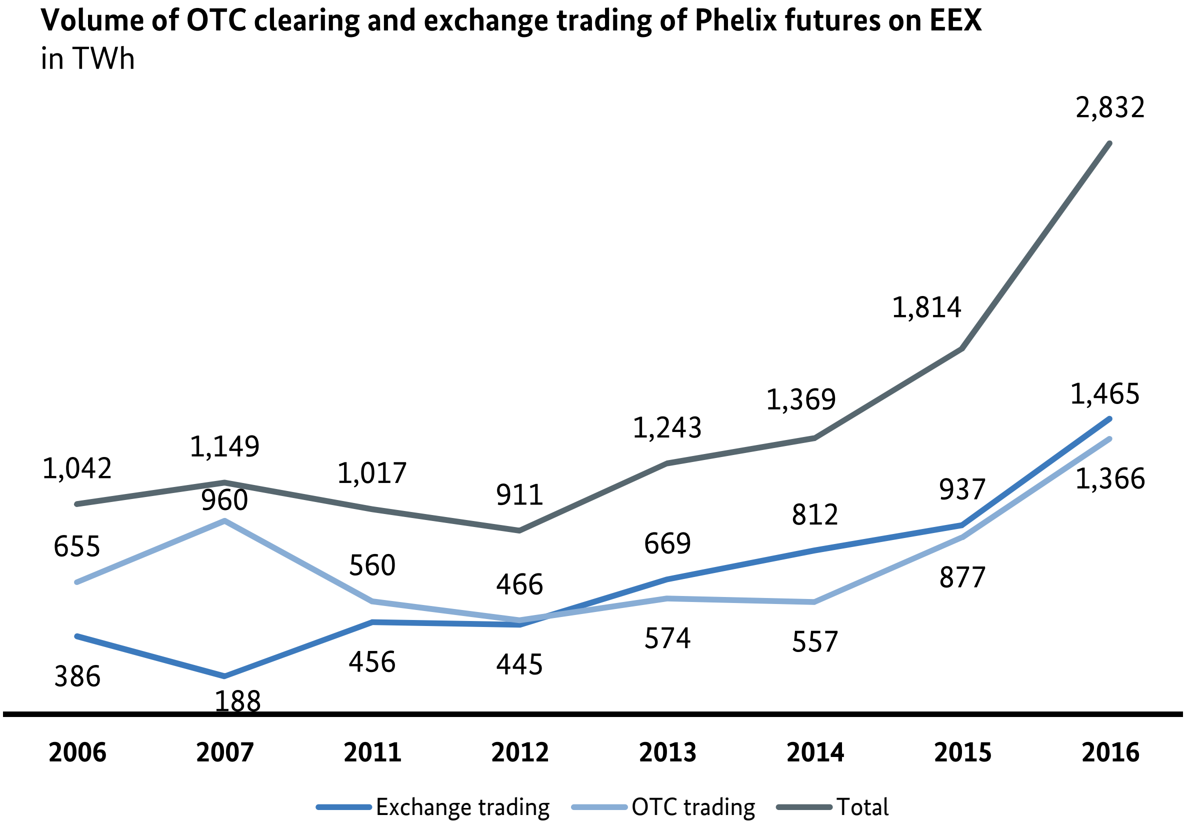


Figure 88: Volume of OTC clearing and exchange trading of Phelix futures on EEX

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 1,183 TWh in 2016, as reported by LEBA, which is equivalent to a share of about 22 per cent of the total OTC contracts brokered by LEBA members. By contrast, the corresponding figures were around 18 per cent with a volume of 802 TWh in 2015 and around 19 per cent with a volume of 557 TWh in 2014.[84]

Phelix options had no bearing on exchange trading on EEX. As in the previous year, there were no such transactions in 2016. By contrast, OTC clearing of Phelix options agreed off the exchange has practical significance: Phelix options accounted for a share of 189 TWh or 14 per cent of OTC clearing in 2016 while the remaining 1,178 TWh or 86 per cent of OTC clearing consisted of Phelix futures. The OTC clearing volume for options almost tripled compared to the previous year. The distribution of the volumes registered on EEX for OTC clearing across the various fulfilment periods in 2016 shifted slightly compared to the previous year. While in 2015 about half the volume (49 per cent) consisted of contracts for the year ahead, the figure had risen to 59 per cent (800 TWh) in 2016. Only around 20 per cent (275 TWh), compared to 35 per cent in the previous year, related to 2016. Around 18 per cent related to the year after next (trading for 2018). Later fulfilment periods made up only a small share of 4 per cent.

[84] Cf. http://www.leba.org.uk/pages/index.cfm?page_id=59 (retrieved on 2 June 2017). The total volume of German power brokered by LEBA members was 5,518 TWh for the whole of 2016, 4,518 TWh in 2015 and 4,367 TWh in 2014.

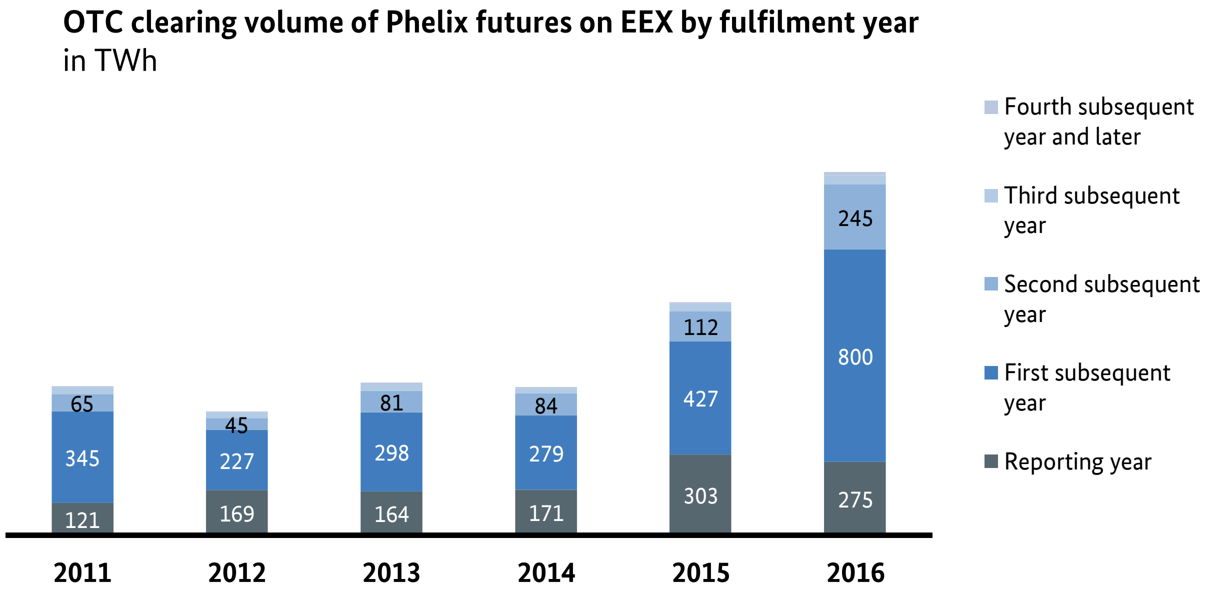


Figure 89: OTC clearing volume for Phelix futures on EEX by fulfilment year in TWh

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 2016 accounted for about 62 per cent of all purchases and 62 per cent of all sales (the figures for 2015 were 66 per cent of all purchases and 67 per cent of all sales). 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 2016 was again only 0.03 TWh. In the previous year, it was also a mere 0.02 TWh.

G. Retail

1. Supplier structure and number of providers

A look at the retail market in the electricity sector enables an analysis of the structure and the number of suppliers active in the market. The analysis covers data from 1,404 suppliers for the year 2016 on the meter points served by them. For the data analysis the information provided by the suppliers was considered to be submitted by individual legal entities without taking company affiliations or links into consideration. The data shows that approximately 85% of all suppliers taking part in the monitoring belong to the group of suppliers that serve less than 30,000 meter points. This group serves just under 7.6m meter points, or 15% of all registered meters. Suppliers registered a total of 50.2m meter points of final consumers supplied. Some 7% of all suppliers serve over 100,000 meter points each. This group, however, covers some 35.9m meter points and therefore about 72% 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.

Number or percentage of suppliers that supply the number of meter points shown
not taking account of company affiliations

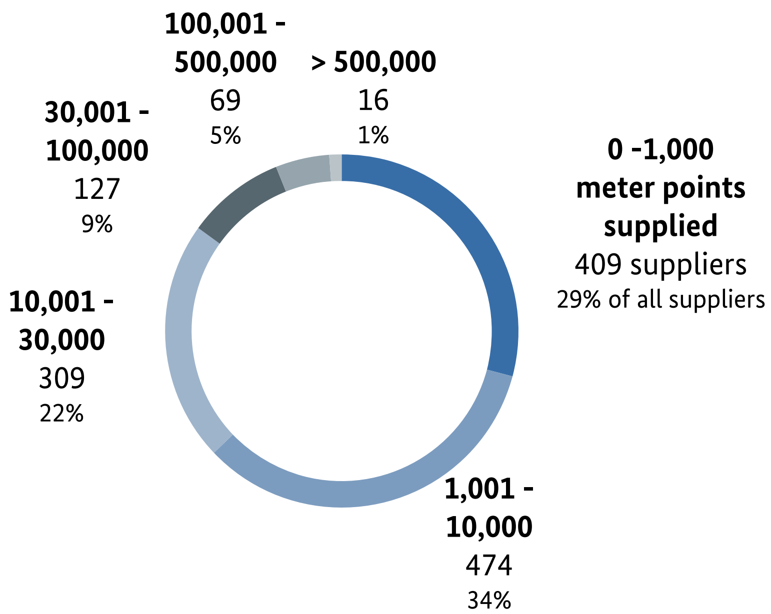


Figure 90: Number of suppliers by number of meter points supplied

Electricity customers had the choice of an even larger number of suppliers than in 2015. An evaluation of the data supplied by 816 DSOs on the number of suppliers that supply the consumers in each network area produced the following results: In 2016 more than 50 suppliers operated in over 86% of all network areas (703 network areas). In the year 2007 this number was barely 25% (165 network areas). Today more than 100 suppliers operate in well over half of the network areas, whereas four years ago it was only 33% (259 network areas). On average, final consumers in Germany were able to choose between 130 suppliers in their network area in 2016 (2015: 115); household customers were able to choose between 112 suppliers (2015: 99). Despite the large number of suppliers, this does not automatically translate into a high level of competition. Many suppliers that are also default suppliers offer tariffs in several network areas, yet do not acquire a significant number of customers outside of their own default supply area.

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 1,231 suppliers shows that the absolute majority only operate regionally. 54% of suppliers serve a maximum of 10 network areas, while 17% serve only one network area. 24% of companies operate in 11-50 network areas, with 12% operating in 51-250 network areas and 5% in 251-500 network areas. 74 suppliers, or around 6%, supply customers in more than 500 network areas (see Figure 90). 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 80 network areas (2015: 79).

Number and percentage of suppliers that supply customers in the number of network areas shown
not taking account of company affiliations

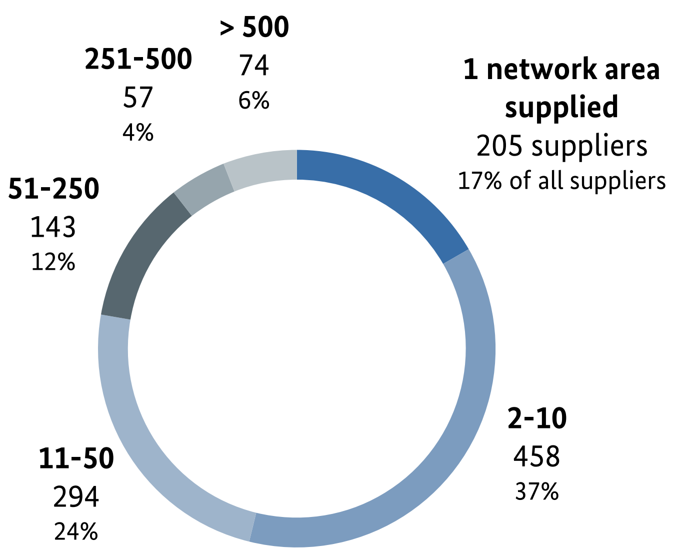


Figure 91: Breakdown of suppliers by number of network areas supplied

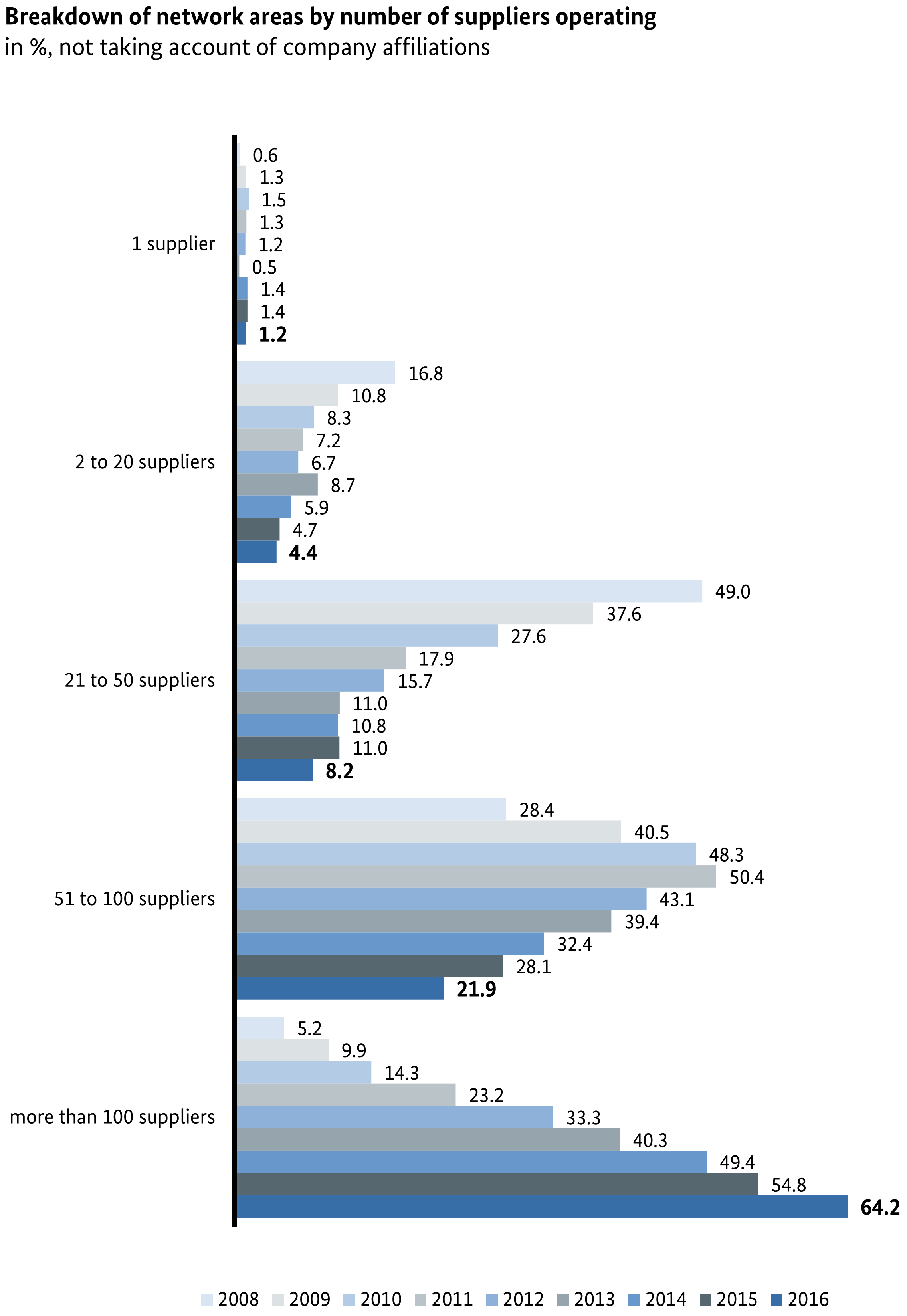


Figure 92: Breakdown of network areas by number of suppliers operating

2. Contract structure and supplier switching

Switching rates and processes are important indicators of the level of competition. The annual switching rates in the electricity retail sector are at a high level, and have increased again in 2016. In summary, the rate of supplier switches is at 11.4% for household customers (2015: 10.4%) and at 12.7% (2015: 12.6%) for non-household customers with over 10 MWh of annual consumption. 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).

Final consumers can also be grouped into household, commercial and industrial customers. Household customers are defined in the German Energy Industry Act (EnWG) primarily according to qualitative characteristics.[85] Non-household customers are also referred to in the monitoring report as commercial and industrial customers. There is so far no recognised definition of commercial customers[86] 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 2016 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 heating electricity). The majority of SLP customers are household customers. In 2016, household customers were supplied with around 121 TWh, including night storage and heating 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 purpose of this analysis, the default supply contract category also includes fallback supply (section 38 EnWG) and doubtful cases.[87] Delivery outside the default supply contract is referred to either as a

[85] 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.

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

[87] 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 also asked to allocate cases that could not be clearly categorised to default supply.

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".[88] This year again, electricity suppliers supplied information as to how many household customers switched their electricity supply contract in 2016.

Furthermore, data was collected in the TSO and DSO questionnaires on the number of "supplier switches" in 2016, 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.[89] 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. The actual scope of supplier switches can therefore deviate from the figures reported. In addition to supplier switches, the monitoring report also analysed household customers' choice of supplier upon moving house.

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 ("consumption profile"). Interval-metered customers are characterised by high consumption;[90] the majority are industrial or other high-consumption non-household customers.

In the reporting year 2016, approximately 1,150 electricity suppliers (individual legal entities) provided data on the meter points supplied and on the consumption of interval-metered customers (1,050 in the previous year). The 1,150 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 370,600 meter points of interval-metered customers in 2016 (266 TWH was supplied to 361,000 meter points in the previous year). 99.7% of this was supplied under contracts outside of default supply.[91] It is unusual, but not impossible, for interval-metered customers to be supplied under default or fallback supply contracts. A total of 0.8 TWh of

[88] 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).

[89] 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.

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

[91] Under section 36 EnWG, default supply only applies to household customers. Any mention in the following to default supply of non-household customers refers to fallback supply.

electricity was supplied to interval-metered customers with a default or fallback supply, which is 0.3% of the total electricity supplied to interval-metered customers.

30% of the total electricity for interval-metered customers was supplied under a special contract with the default supplier (divided between 45.1% of all interval meter points). Approximately 70% of the total electricity was supplied under a contract with a legal entity other than the local default supplier (divided between approximately 53.4% of all meter points). In the previous year, 31.6% of the volume was sold under special contracts with the default supplier and 68.1% 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.

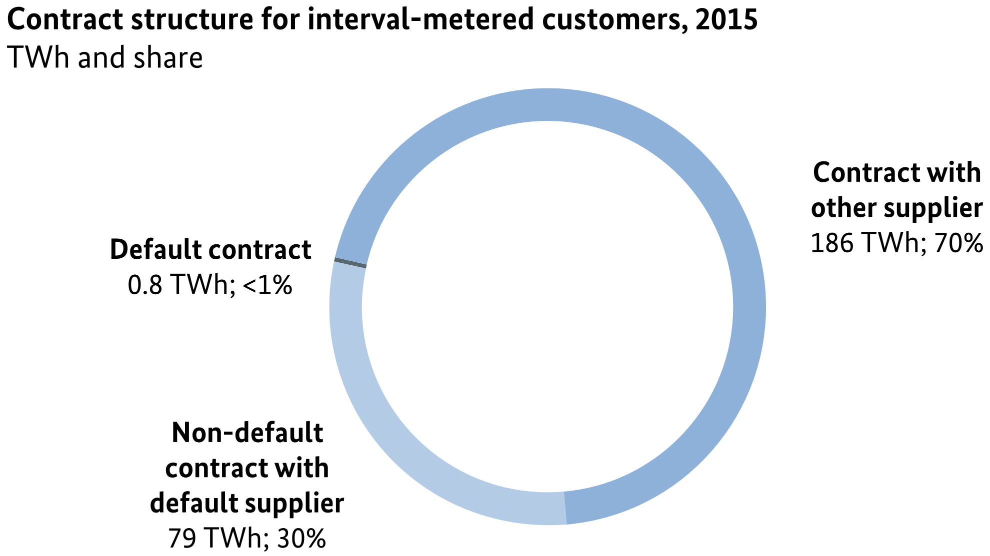


Figure 93: Contract structure for interval-metered customers in 2016

2.1.2 Supplier switching

Data on the supplier switching rates (as defined in monitoring) among different customer groups in 2016 and the consumption volumes attributed to these customers was collected in the TSO and DSO surveys. The surveys differentiated between the following consumption categories: industrial customers typically fall into the >2 GWh/year category, and a wide range of non-household customers fall into the 10 MWh/year to 2 GWh/year category.[92] The survey produced the following results:

[92] Where consumption is predominantly household-based, end customers are considered to be household customers even if their consumption exceeds 10 MWH per year (section 3 para 22 EnWG). This primarily applies for heating electricity customers.

Supplier switches by consumer category in 2016

Final consumer category	Number of meter points where the supplier changed	Share in all meter points of the consumption category	Consumption at meter points where the supplier changed	Percentage of total consumption by consumer category
>10 MWh/year – 2 GWh/year	255,326	11.5%	18.7	14.6
> 2 GWh/year	2,760	14.5%	26.3	11.5
Total non-household consumers	**258,086**	**11.5%**	**45,0 TWh**	**12.7**

Table 52: Supplier switching rates by consumption category in 2016

The volume-based switching rate for the categories with a consumption exceeding 10 MWh/year was 12.7% in 2016. The switching rate in the previous year was 12.6%. Switching rates in the non-household customer category have remained more or less constant since 2009. The survey does not examine what percentage of non-household customers have switched supplier once, more than once or not at all during a period of several years.

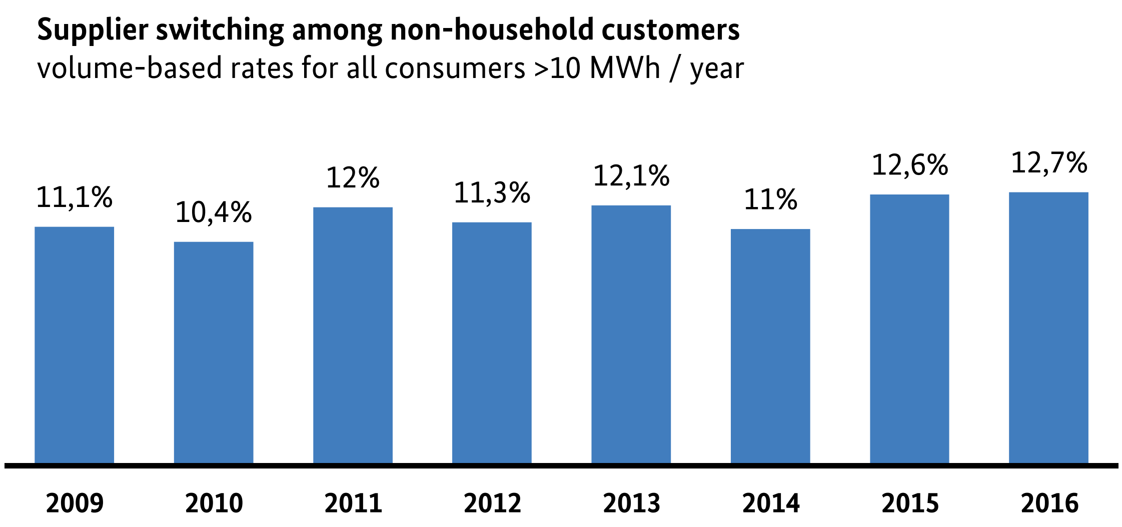


Figure 94: Development of supplier switching among non-household customers

2.2 Household customers

2.2.1 Contract structure

The data from the monitoring survey shows that in 2016 a relative majority of 40.9% of household customers had a special contract with the local default supplier (2015: 43.1%). The percentage of household customers with a standard default supply contract is 30.6% (2015: 32.1%). Thus both the percentage of default supply customers and the percentage of customers who concluded a special contract with the local default supplier have fallen when compared to the previous year. Meanwhile, 28.6% of all household customers are served by a company other than the default supplier (2015: 24.9%). Consequently, there has been a further increase in the percentage of customers who no longer have a contract with their default supplier. Overall, about 71% 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 slightly when compared to the previous year.

Contract structure of household customers in 2016
Volume and percentage

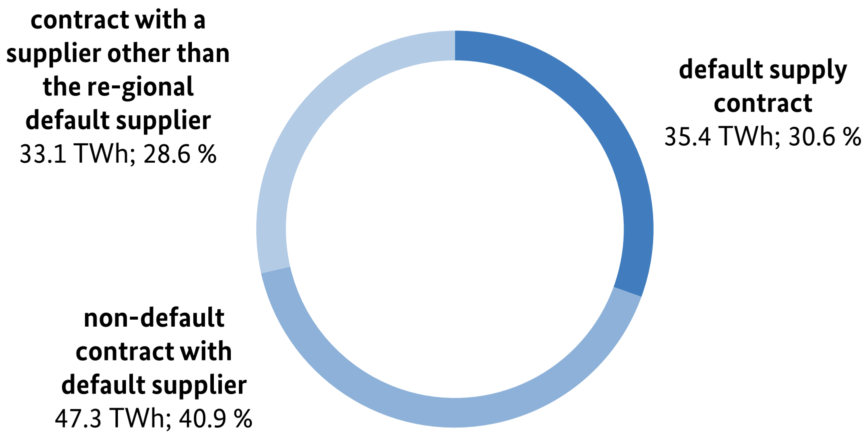


Figure 95: Contract structure of household customers

2.2.2 Switch of contract

Contract switches by household customers

Category	2016: contract switches in TWh	Percentage of total consumption (11.8 TWh)	Number of contract switches	Share of total number of household customers
Household customers who switched their existing energy supply contracts with their supplier	6	5.2	2405022	5.3

Table 53: Contract switches by household customers in 2016

For the second 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 report contract switches that were initiated by the customer.[93] The total number of contract switches was around 2.4 million, which is significantly higher than the previous year's figure (2015: 1.7m contract switches). The volume of electricity involved in the contract switches also increased accordingly, to approximately 6.0 TWh (2015: 4.6 TWh). This results in a switching rate based on number and volume of switches of 5.3% and 5.2%.

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 around 4m in 2015 to approximately 4.6m in 2016. This development is primarily the result of a significantly greater number of switches not related to moving home (+622,312). There was also a slight increase in supplier switches due to moving home (+11,719); that figure, however, has remained relatively constant since 2013.

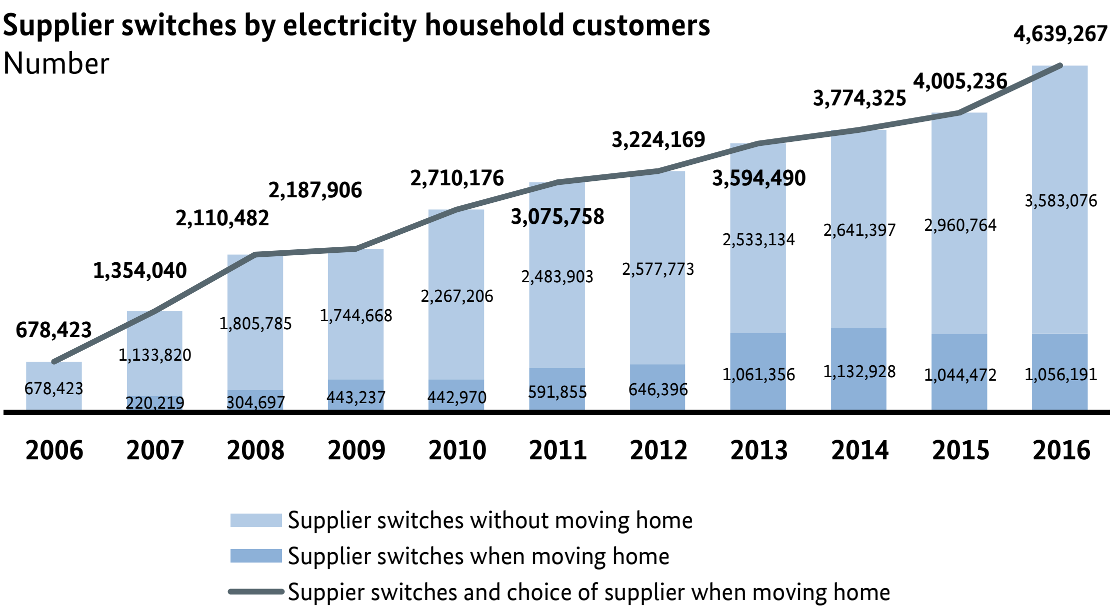


Figure 96: Number of supplier switches by household customers

When viewing the trend in supplier switches from 2006 to 2016, 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, provided 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 figures from the monitoring survey 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

[93] 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.

switches, not including switches made for moving home. This is shown in the figure above, already in adjusted form.

A total of 3,583,076 switches were determined for 2016, excluding for moving home. This amounts to around 7.4% of household customers and corresponds to an increase by about 620,000 relative to the previous year. These switches entail an electricity volume of about 11.1 TWh, which in absolute terms is an increase when compared to the previous year's figure of 9.5 TWh. The switching rate based on total electricity consumed by household customers (excluding heating electricity) in 2016 was at around 9.3%.

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 increased slightly by around 12,000, to 1,056,191. At 2.5 TWh, the electricity amount registered for supplier switches is also slightly above the previous year's amount.

Supplier switches by household customers, including switches when moving home

Category	2016: Supplier switches in TWh	Percentage of total consumption[1] (118.9 TWh)	2016: Number of supplier switches	Percentage of total household customers
Household customers switching supplier without moving home	11.1	9.3	3583076	7.4
Household customers who switched to a supplier other than a default supplier when moving home	2.5	2.1	1056191	2.2
Total	13.6	11.4	4639267	9.6

[1] Not including heating electricity

Table 54: 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 around 4.6m switches for 2016, with a total electricity volume of 13.6 TWh. This corresponds to a switching rate based on volume and number of switches of 11.4% and 9.6% respectively. Thus 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 2016. In contrast to this, household customers who were supplied by a default supplier consumed only about 2,100 kWh on average.

A joint view of the contract and supplier switches in 2016 makes it possible to calculate the number of household customers who undertook a change in their energy supply contract. A total of around 7.0m switches were made, with the volume of electricity involved in contract and supplier switches totalling 19.6 TWh.

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

3.1 Disconnections of supply

In 2016, the Bundesnetzagentur once again carried out surveys of the tariffs offered and questioned network operators and electricity suppliers about disconnection notices and disconnection orders, 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 disconnection notices and orders relating to default supply customers, as well as on disconnections carried out on behalf of the local default supplier.

Disconnection notices and requests for disconnection of default supply; disconnection on behalf of local default supplier
number (electricity)

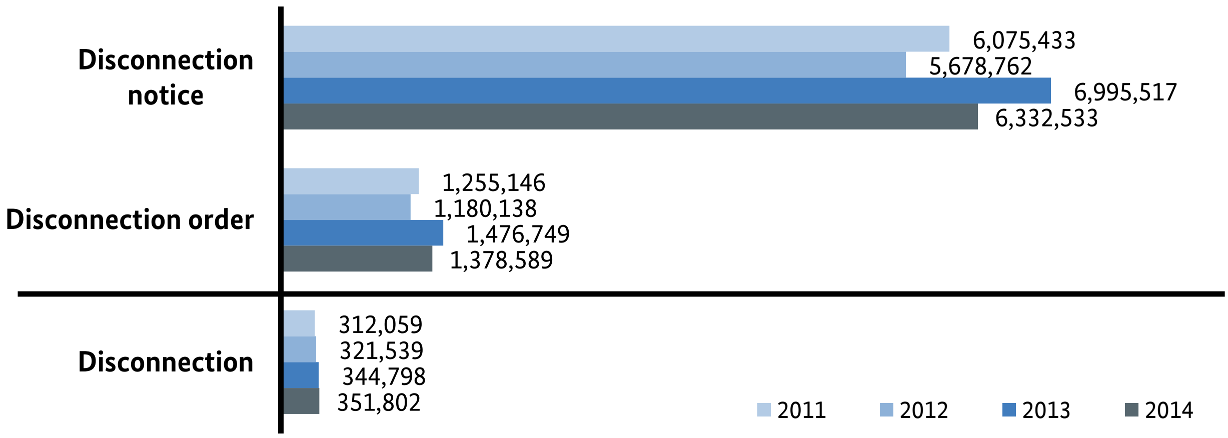


Figure 97: Disconnection notices and requests for disconnection of default supply; disconnection on behalf of the local default supplier (electricity); 2011 to 2014[94]

Starting in 2015, the survey of electricity suppliers was further differentiated. The survey of disconnection notices and orders 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 household customers with non-default supply contracts. For the 2016 monitoring, the survey was expanded to include DSOs. The survey now also includes disconnections carried out by DSOs on behalf of a supplier other than the local default supplier.

The background of the modified survey is, on the one hand, the practice of some suppliers of regulating disconnections in non-default supply contracts and requesting the DSO to disconnect non-default supply customers as well. DSOs, however, had in many cases not offered disconnections in their supplier framework

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

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.[95] Since 1 January 2016, the rights and 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 order by the default supplier was occurring within the framework of a default supply contract or in a non-default supply contract. To request a disconnection under section 24(3) of the Low Voltage Network Connection Ordinance (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. Nor 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 is actually still under default supply or has switched to a household customer contract with the default supplier.

The analysis for 2016 is based on the data provided by 770 DSOs and 962 suppliers. Under the Electricity Default Supply Ordinance (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. The figures provided by DSOs and suppliers show a slight decline in the overall number of disconnections in 2016.

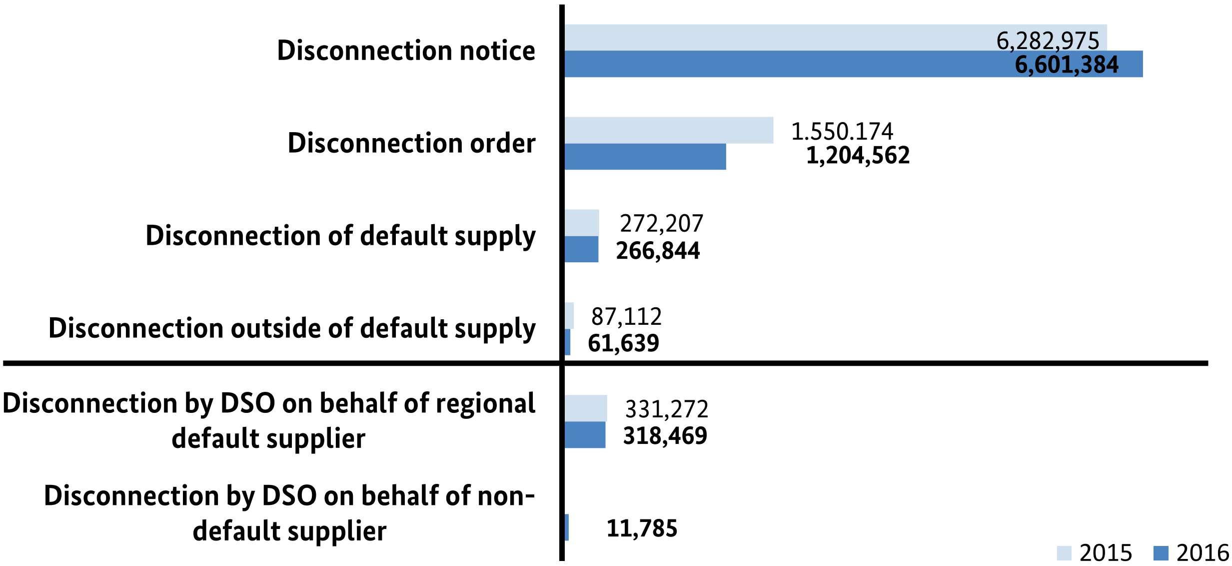
Compared with the previous year, the number of disconnections carried out on behalf of the local default supplier has declined to 318,469, with roughly 13,000 fewer disconnections carried out at meter points than in 2015. In addition, there were nearly 12,000 disconnections carried out on behalf of a supplier other than the local default supplier. 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 98.9%.

In 2016, DSOs reinstated electricity supply for around 293,000 meter points that had been disconnected on behalf of the default supplier, compared to 300,000 meter points in the previous year. In addition, electricity supply was reinstated for approximately 12,500 meter points on behalf of a supplier other than the local default supplier.

The network operators charged the electricity suppliers an average fee of €46 (excluding VAT) for disconnecting a supply, with the actual costs charged ranging between €13 and €176. The average fee to household customers for reinstating supply to a meter point was €49 (excluding VAT), with the actual fees charged varying from €10 to €151.

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

Disconnection notices, requests for disconnection, disconnections carried out[1]
Number in 2015 and 2016 (electricity)



[1] The number given in the figure below the dividing line is taken from the DSO survey. For 2015, only disconnections carried out by the DSOs on behalf of the local default supplier were recorded. Disconnections carried out on behalf of suppliers other than default suppliers are explicitly included in the survey as of 2016. The DSOs do not have information regarding the contractual relationships of the individual disconnections. All of the data above the dividing line has been taken from the supplier survey. Here, the disconnections carried out are recorded according to contractual relationships (default supply and outside of default supply). For this reason, the disconnection numbers shown here are not directly comparable.

Figure 98: Disconnection notices and disconnection orders, actual disconnections

At the same time, the suppliers were asked how often in 2016 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 supply. The survey is now no longer directed only at default suppliers, but rather at all suppliers. The companies responded that they had issued almost 6.6m 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 (the same level as in 2015). Of the nearly 6.6m disconnection notices issued, approximately 1.2m resulted in electricity being disconnected by the pertinent network operator. The suppliers also responded that there were around 267,000 cases of disconnections carried out within the framework of a default supply contract, which is around 5,000 fewer disconnections than in the previous year. The average percentage of actual disconnections relative to the respective overall number of customers under default supply was 1.6%. Disconnection outside of a default supply contract was carried out in approximately 61,000 cases (a decline of 25,000 relative to the previous year). Ultimately, network operators thus carried out a total of 328,000 disconnections (of customers with default and non-default supply contracts), which is 31,000 fewer disconnections than were carried out in 2015.

Of the nearly 6.6m disconnection notices issued by suppliers, around 18% led to a disconnection order. In just under 5% of the 6.6m cases of disconnection notices did the respective network operator actually cut off the supply. This corresponds to a rate of 0.7% of all meter points of household customers in Germany.

There are various reasons why this figure is so low compared to the number of disconnection notices. One assumption is that in many cases a disconnection notice leads to a payment. In other cases, customers might not allow the persons charged with carrying out the disconnection onto their premises. In order to ultimately disconnect the electricity supply, judicial enforcement is required, which in turn costs time and money.

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

While some suppliers pass on only the costs charged by the network operator commissioned with carrying out the disconnection or reinstatement of supply, a number of electricity suppliers charged their customers an additional average fee of €47 (including VAT) for disconnecting a supply,[96] with the actual costs charged ranging between €2 and €199. Electricity suppliers charged their customers an average fee of €51 (including VAT) for reinstating supply to a meter point, with the fees charged varying from €2 to €197.

3.2 Cash meters and smart card meters

In the 2017 monitoring survey, DSOs and suppliers were again surveyed on prepayment systems in accordance with section 14 StromGVV, such as cash meters or smart card meters. Over the course of 2016, prepayment systems were installed on behalf of default suppliers at about 20,200 points of consumption in 388 network areas (2015: around 19,400). This corresponds to 0.04% of all meter points of household customers in Germany. In just under 4,600 cases (2015: around 4,700), a cash or smart card meter was newly installed in the 2016 calendar year, with about 3,100 such meters being taken out again (2015: 3,000).

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 2016, nearly 10% of suppliers offered load-based tariffs; this represents a slight decrease relative to the previous year 2015, in which approximately 12% of suppliers offered load-based tariffs. Some 63% of suppliers offered time-of-use tariffs[97] in 2016 (2015: 70%), with about 11% offering other tariffs as well (2015: 13%).

Section 40(5) EnWG also requires suppliers to offer final consumers monthly, quarterly or semi-annual bills. Customer demand for such billing cycles decreased significantly in 2016. With a total of around 14,000 customer enquiries for billing cycles of less than one year (2015: around 23,000), customer demand for such billing cycles remains very low.

Moreover, in 2016, 139 suppliers stated that they carry out other forms of billing for household customers. In approximately 27,000 cases in total, suppliers carried out monthly, quarterly or semi-annual billing (2015: 31,000). The average fee (including VAT) for each additional billing was around €9 with customer reading and €11 without customer reading.

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[96] Supplier's own costs, not including the costs incurred with the commissioned network operator

[97] In particular these include special tariffs for heating electricity and heat pump electricity.

Despite the number of disconnection notices and disconnection orders, very few suppliers actually terminate services 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 customer must have been warned of contract termination because of arrears in payment. In 2016, suppliers terminated about 171,600 contracts with their customers overall (2015: approximately 154,000). The average customer arrears upon a termination of the energy supply contract in 2016 was €162.

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 2017 for various consumption levels. The consumption level for household customers was divided according to the following consumption bands:

– band I (DA[98]): annual electricity consumption under 1,000 kWh

– band II (DB): annual electricity consumption between 1,000 kWh and 2,500 kWh

– band III (DC): annual electricity consumption between 2,500 kWh and 5,000 kWh

– band IV: annual electricity consumption between 5,000 kWh 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 GWh 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 in the overall price. The suppliers were asked to break down the final price into individual price components. This includes components that the suppliers cannot control but that may vary from one network area to another, including network charges, concession fees and charges for billing, metering and meter operations. Furthermore, the state-controlled surcharges and taxes were to be taken into account, i.e. value added and electricity taxes, surcharges under the EEG, KWKG and section 19(2) StromNEV, and surcharges 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 energy and supply costs and the 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 (see below). 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 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 bands for three different contract types:

[98] “DA”, “DB” and “DC” refer to the consumption bands defined by EUROSTAT.

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

The findings of the supplier survey are presented 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 previous year's figures – insofar as they correspond to the consumption level. When comparing the figures as at 1 April 2017 and 1 April 2016, it should be noted that differences in the calculated averages partially fall within the margin of error.

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 charges 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 (sections 63 ff. EEG, section 19(2) StromNEV, section 36 KWKG, section 17f. 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 number of suppliers. The following price analysis of the consumption category was based on data from 212 suppliers (there were also 212 suppliers in the previous year). Over half of the 212 suppliers had fewer than 10 customers with an annual consumption exceeding 24 GWh.

This data was used to calculate the (arithmetic) mean of the total price and of the individual price components. Furthermore, the data spread for each price component was 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% 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 2017

	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]	1,37 - 3,10	2.23
Metering, billing, meter operation	0,00 - 0,03	0.03
Concession fee	0,11 - 0,11	0,10 [2]
EEG surcharge	6.88	6.88
Other surcharges[3]	0.20	0.20
Electricity tax	2.05	2.05
Price component controlled by the supplier (remaining balance)	2,65 - 4,20	**3.41**
Total price (excluding VAT)	13,74 - 16,23	14.90

[1] Due to legislative changes, as of 1 January 2017 the price component "billing" is included in the net network surcharge and is no longer part of the category "Metering, billing, meter operation"; for the next Monitoring Report, the survey will therefore be adjusted to reflect the respective price components.
[2] Over 90% of suppliers quoted a concession fee of 0.11 ct/kWh. Fewer than 20 suppliers quoted a lower figure.
[3] KWKG (0.095 ct/kWh), StromNEV (0.064 ct/kWh), section 18 AbLaV surcharge (0.006 ct/kWh), offshore liability (0.035 ct/kWh)

Table 55: Price level on 1 April 2017 for the 24 GWh/year consumption category without reductions

The arithmetic mean of the price component controllable by the supplier declined slightly, falling by 0.07 ct/kWh from 3.48 ct/kWh to 3.41 ct/kWh (down by 0,71 ct/kWh from the previous year)[99]. By contrast, surcharges increased to 7.08 ct/kWh in total (including an EEG surcharge of 6.88 ct/kWh), making them 0.58 ct/kWh higher than in the previous year. The average net network charge was 2.23 ct/kWh and thus around 10% higher than in the previous year (2.03 ct/kWh in 2016). The average overall price (excluding VAT

[99] A comparison of these averages has to take into account the above-mentioned data spread.

and excluding possible reductions) of 14.90 ct/kWh is 0.69 ct/kWh above the arithmetic mean of the figures collected in the previous year; the increase is largely due to both network charges and statutory surcharges.

By definition, these prices were based on the assumption that (industrial) customers with an annual consumption of 24 GWh/year 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 11.46 ct/kWh, or about 77%, of the overall price. However, electricity consumers who meet the requirements of applicable laws and regulations can take advantage of reductions in network charges, 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.[100]

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(2) first sentence of the StromNEV, the net network charge may be reduced by up to 80%.[101] Electricity tax may be waived, refunded or reimbursed in full in accordance with section 9a of the StromStG. The concession fees under section 2(4) first sentence of the KAV and the surcharges under section 36 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 2017

	Anticipated figure in the price query in ct/kWh	**Amount of possible reduction** in ct/kWh	**Remaining balance** in ct/kWh
EEG surcharge	6.88	-6.55	0.33
Electricity tax	2.05	-2.05	0.00
Net network charge	2.23	-1.78	0.45
Other surcharges	0.20	-0.06	0.14
Concession fee	0.1	-0.10	0.00
Total	**11.48**	**-10.54**	**0.94**

Table 56: Possible reductions for the 24 GWh/year consumption category on 1 April 2017

[100] 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.

[101] The even greater reductions possible under section 19(2) line 2 of the StromNEV are not relevant to the 24 GWh/year consumption category since this has been defined as comprising 6,000 hours of use.

50 MWh/year consumption category ("commercial customers")

The 50 MWh/year consumption 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), which corresponds to the consumption profile of a commercial customer. 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 contract 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 2017. 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 959 suppliers (871 in the previous year). This data was used to calculate the (arithmetic) mean of the total 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 2017

	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			76
Net network charge[1]	4.18 - 7.75	5.91	27
Metering, billing, meter operation	0.02 - 0.98	0.28	1
Concession fee	0.11 - 1.59	0.95	4
EEG surcharge	6.88	6.88	32
Other surcharges[2]	0.80	0.80	4
Electricity tax	2.05	2.05	9
Price component controlled by the supplier (remaining balance)	3.07 - 6.81	4.82	22
Total price (excluding VAT)	19.38 - 23.88	21.70	

[1] Due to legislative changes, as of 1 January 2017 the price component "billing" is included in the net network surcharge and is no longer part of the category "Metering, billing, meter operation"; for the next Monitoring Report, the survey will therefore be adjusted to reflect the respective price components.
[2] KWKG (0.438 ct/kWh), StromNEV (0.388 ct/kWh), section 18 AbLaV surcharge (0.006 ct/kWh), offshore liability (-0.028 ct/kWh)

Table 57: Price level for the 50 MWh/year consumption category on 1 April 2017

The remaining balance that can be controlled by the supplier decreased again. Whereas in April 2016 this value was at 5.15 ct/kWh, by April 2017 it had fallen to 4.82 ct/kWh – a decrease by 0.33 ct/kWh (compared to a decrease by 0.93 ct/kWh in the previous year).[102]

The renewable energy surcharge increased by 0.53 ct/kWh to 6.88 ct/kWh relative to the previous year's level of 6.35 ct/kWh. The other surcharges fell from 0.86 ct/kWh to 0.80 ct/kWh – a decrease of 0.06 ct/kWh. The average net network charge rose by 0.41 ct/kWh to 5.59 ct/kWh.

The average overall price (excluding VAT) of 21.70 ct/kWh in April 2017 rose 0.50 ct/kWh relative to the previous year's figure. This increase is in large part due to both the higher renewable energy surcharge and the

[102] A comparison of these averages has to take into account the above-mentioned data spread.

increased network charges. This is also reflected in the percentage of these price components in the overall price. The renewable energy surcharge, on the one hand, now makes up 32% of the overall price (2016: 30%), while the net network charge on the other hand makes up 27% of the overall price (compared to 26% in the previous year). Therefore, an average of about 78% (compared to 76% in the previous year) of the overall price in this consumption category relates to cost items outside of the supplier's control (network charges, metering,[103] surcharges, electricity tax and concession fee). Only about 22% (24% in the previous year) relates to price elements that provide scope for commercial decisions.

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 tariffs 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[104]): 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

First the volume-weighted average price across all types of contract for household customers was looked at in the consumption band between 2,500 kWh and 5,000 kWh per year (band III). In section 4.2.2, individual consumption bands are subsequently analysed, with the focus on the consumption band of a typical household customer in band III.

4.2.1 Volume-weighted price across all contract categories for household customers (Band III)

In the following tables and figures, a volume-weighted overall price across all contract categories for band III was calculated in order to provide continuity and enable a comparison with previous years. The average price for all household customers in consumption band III is taken as an indicator, which is calculated by weighing the individual prices for the three types of contract (default supply, non-default supply, contract with a supplier other than the local default supplier) using the relevant consumption volumes. The average price calculated as at 1 April 2017 was 29.86 ct/kWh (2015: 29.80 ct). Table 58 provides the detailed breakdown of the individual price components.

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[103] The charge for billing is now part of the net network charge, in accordance with section 7(2) of the Metering Operations Act (MsbG) and section 17(7) third sentence of the StromNEV. With regard to the other price components, section 17(7) first sentence of the Strom NEV specifies that as at 1 January 2017 the charge for meter operation must also include the charge for billing. This year's Monitoring Report does not yet make this differentiation [see BNetzA section on metering operation].

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

Average volume-weighted price per type of contract for household customers with an annual consumption between 2,500 kWh and 5,000 kWh (band III; Eurostat band DC) as at 1 April 2017 (ct/kWh)

Price component	Volume-weighted average across all types of contract (ct/kWh)	Percentage of total price
Energy and supply, margin	6.42	21.5
Net network charge incl. billing	6.99	23.4
Metering, meter operation	0.32	1.1
Concession fee	1.62	5.4
EEG surcharge	6.88	23.0
CHP surcharge	0.44	1.5
Section 19 StromNEV surcharge	0.39	1.3
Section 18 AbLaV surcharge	0.01	0.0
Offshore liability surcharge*	-0.03	n.a.
Electricity tax	2.05	6.9
VAT	4.77	16.0
Total	**29.86**	**100**

* Since in previous years household customers paid too much into the offshore surcharge account, in 2017 they will receive a credit of 0.03 ct/kWh.

Table 58: Average volume-weighted price across all types of contract for household customers in consumption band III as at 1 April 2017

Because household customers paid too much into the offshore surcharge account, in 2017 they receive a credit of 0.03 ct/kWh, which is factored into customers' electricity bills.

The following figure shows the percentage distribution of individual price components, whereby the negative price component of the offshore liability surcharge is not included.

Breakdown of the retail price for household customers with annual consumption between 2,500 and 5,000 kWh as at 1 April 2017 (volume-weighted average across all types of contract, band III, Eurostat: DC)
(%)

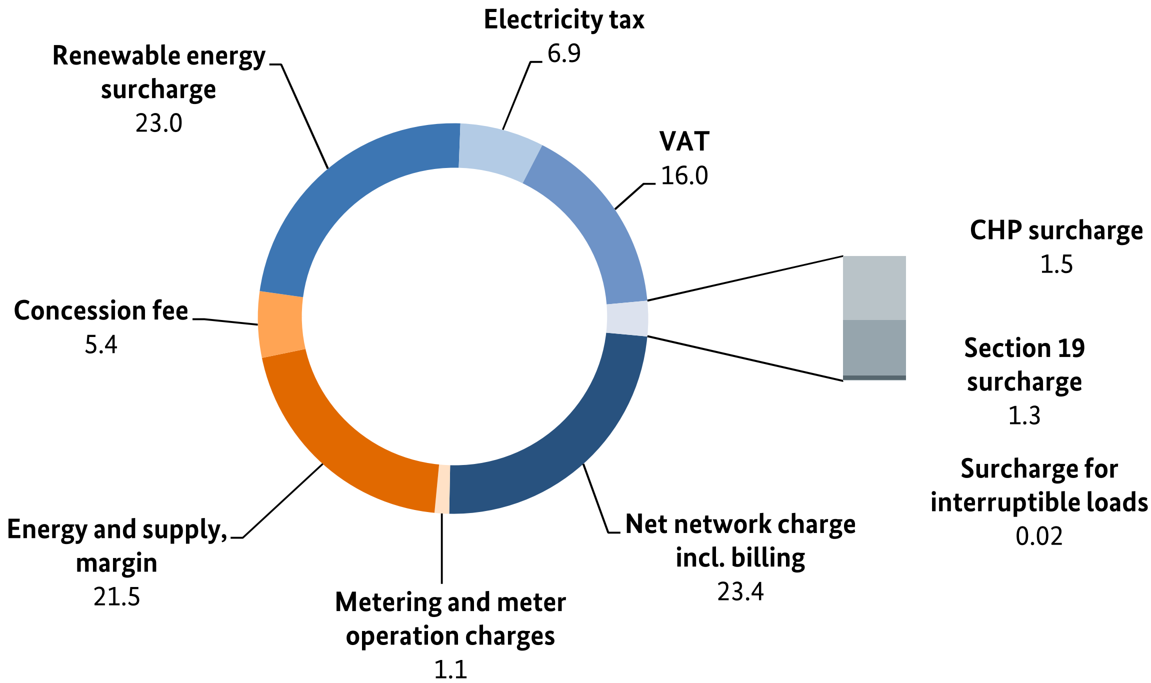


Figure 99: Breakdown of price for household customers in consumption band III as at 1 April 2017 (volume-weighted average across all types of contract)[105]

Figure 99 shows that surcharges, taxes and levies account for over 54% of the average electricity price for household customers. The net network charge including billing, metering and meter operations accounts for a share of around 24.6%. The share of the electricity price that the supplier can control (energy and supply costs and the margin) thus accounts for only around 21.5% in 2017 (previous year: 24.7%).

The following table shows the change in the volume-weighted electricity price across all tariffs from 1 April 2016 to 1 April 2017. In 2017, the electricity price remained stable (+0.08 ct/kWh).

[105]The value added tax makes up 16% of the total gross price, since the statutory 19% VAT is charged on and added to the net price (100%). Thus the VAT at 19% is the dividend and the total price at 119% is the divisor.

Change in volume-weighted price level across all types of contract from 1 April 2016 to 1 April 2017 for household customers with an annual consumption between 2,500 kWh and 5,000 kWh (band III; Eurostat band DC)

	Volume-weighted average across all types of contract (ct/kWh)	Change in level of price component	
		(ct/kWh)	(%)
Energy and supply, margin	6.42	-0.92	-14
Net network charge incl. billing	6.99	0.54	8
Metering, meter operation	0.32	-0.02	-7
Concession fee	1.62	-0.04	-2
EEG surcharge	6.88	0.53	8
CHP surcharge	0.44	-0.01	-2
Section 19 StromNEV surcharge	0.39	0.01	3
Section 18 AbLaV surcharge	0.01	0.01	60
Offshore liability surcharge*	-0.03	-0.07	k.A.
Electricity tax	2.05	0.00	0
VAT	4.77	0.01	0
Total	**29.86**	**0.06**	**0**

* Since in previous years household customers paid too much into the offshore surcharge account, in 2017 they will receive a credit of 0.03 ct/kWh.

Table 59: Change in volume-weighted price for household customers across all types of contract from 1 April 2016 to 1 April 2017 (annual consumption 2,500-5,000 kWh)

Subsequently, the changes in the essential price components of the volume-weighted electricity price for household customers are presented. First, a look at the network charges shows a sharp increase in 2017,[106] following successive decreases in the period up to 2011. The increase amounts to nearly 8% (+0,52 ct/kWh) relative to 2016. Seen over a nine-year period, network charges have risen by 1.51 ct/kWh or about 26%. In

[106] Net network charge includes charges for billing, metering and meter operation.

2013, network charges rose above the level in the reference year (2007) and have continued to rise since then. This analysis relates to the network charges excluding the surcharge under section 19 of the StromNEV of 0.39 ct/kWh.[107]

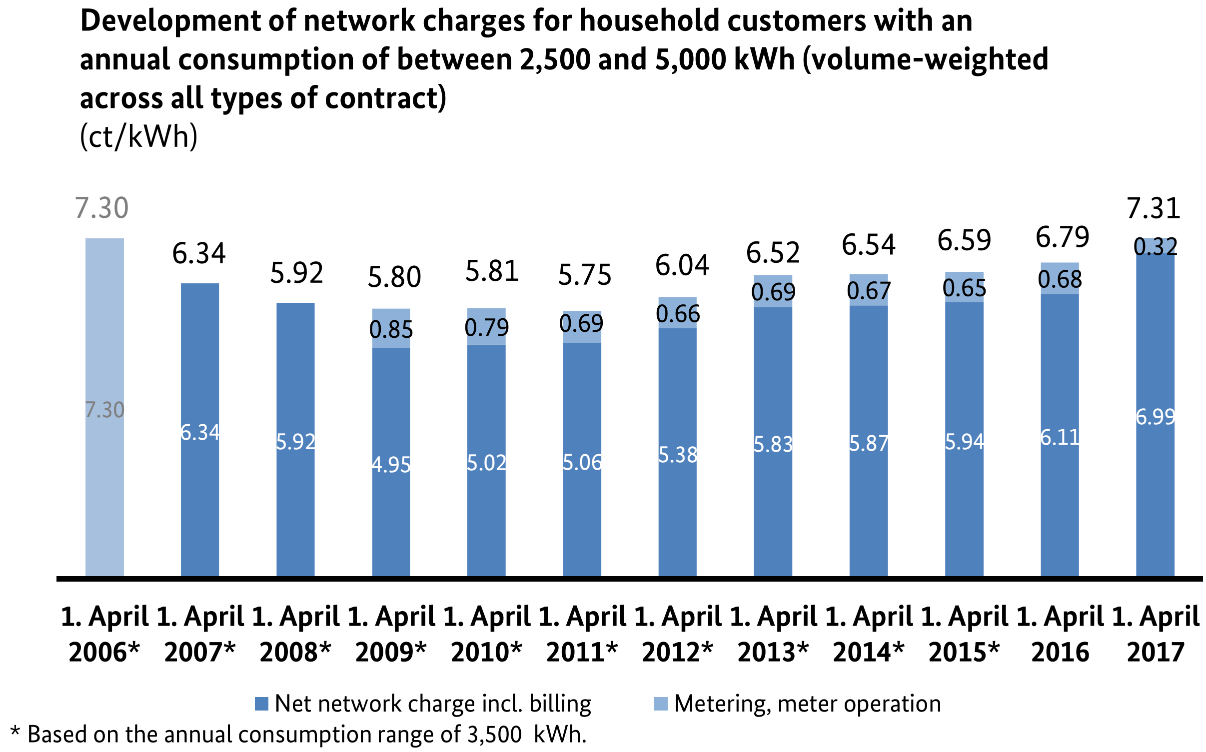


Figure 100: Network charges for household customers, including charges for billing, metering and meter operation (2006-2017)

Next, an overview is given of the changes in the remaining price components of the volume-weighted price for household customers across all types of contract. There has been a continued increase since 2011 in the percentage of the electricity price accounted for by network charges (including billing, metering and meter operation). There has also been a noticeable increase in taxes and levies, in particular over the past four years. The price component for energy, supply and the margin remained more or less stable in the period from 2009 to 2013, while since 2014 there has been a decrease in the price component controlled by the supplier, down 0.93 ct/kWh or nearly 13% from 1 April 2016 and 1 April 2017. This decrease could be related in particular to the continuing low wholesale prices in 2016 (see chapter "Wholesale market", p. 185 ff.). It appears that these low prices are slowly being passed on to household customers.

[107] The surcharge under section 19 of the Electricity Network Charges Ordinance (Strom NEV) was included in the network charges up to 2011 but since 2012 has been reported separately.

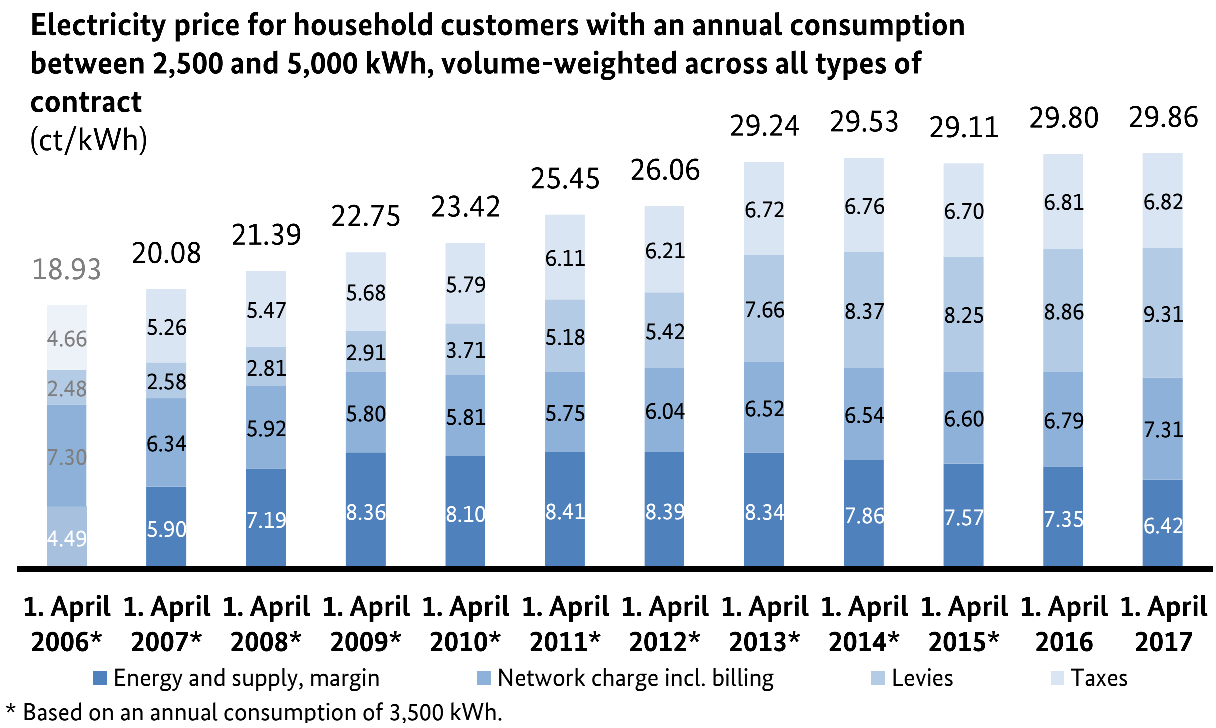


Figure 101: Volume-weighted electricity price for household customers across all types of contract

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 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 2017 rose to 6.88 ct/kWh, thus accounting for around 23% of the total electricity price. Figure 102 shows the changes in the surcharge in more detail.

For 2018, the levels of the various surcharges have already been published. The renewable energy surcharge has fallen and in 2018 will amount to 6.79 ct/kWh. The surcharge as regulated under KWKG will also decrease, to 0.345 ct/kWh in 2018 (2017: 0.438 ct/kWh). The surcharge under section 18 of the Ordinance on Interruptible Load Agreements (AbLaV) will amount to 0.011 ct/kWh (2017: 0.006 ct/kWh). The new surcharge under section 19 of the StromNEV will be 0.37 ct/kWh (2017: 0.388 ct/kWh).

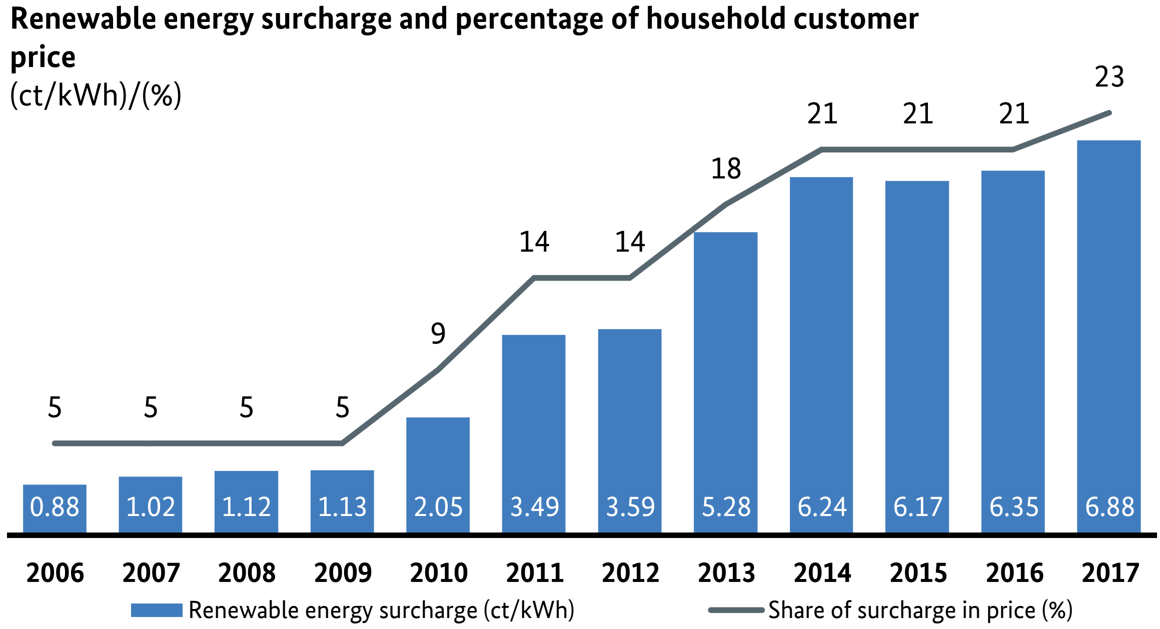


Figure 102: Renewable energy surcharge and percentage of household customer price (2006-2017)

Finally, the changes in the price component for energy and supply costs and the margin in the period from 2006 to 2017 are presented.[108] While in the previous year the price component controlled by the supplier was at 7.35 ct/kWh, or 25% of the volume-weighted total price, this year it fell by 0.93 ct/kWh to 6.42 ct/kWh, thus accounting for a share of 21.5% of the volume-weighted total price for electricity across all types of contract. Hence the percentage of the overall price that can be influenced by a supplier's business decisions has fallen sharply. The following graph shows the price component for energy and supply costs and the margin in each of the years from 2006 to 2017:

[108] A change to the data collected from the suppliers means that since 2014 the individual price components for energy and supply have not been reported separately.

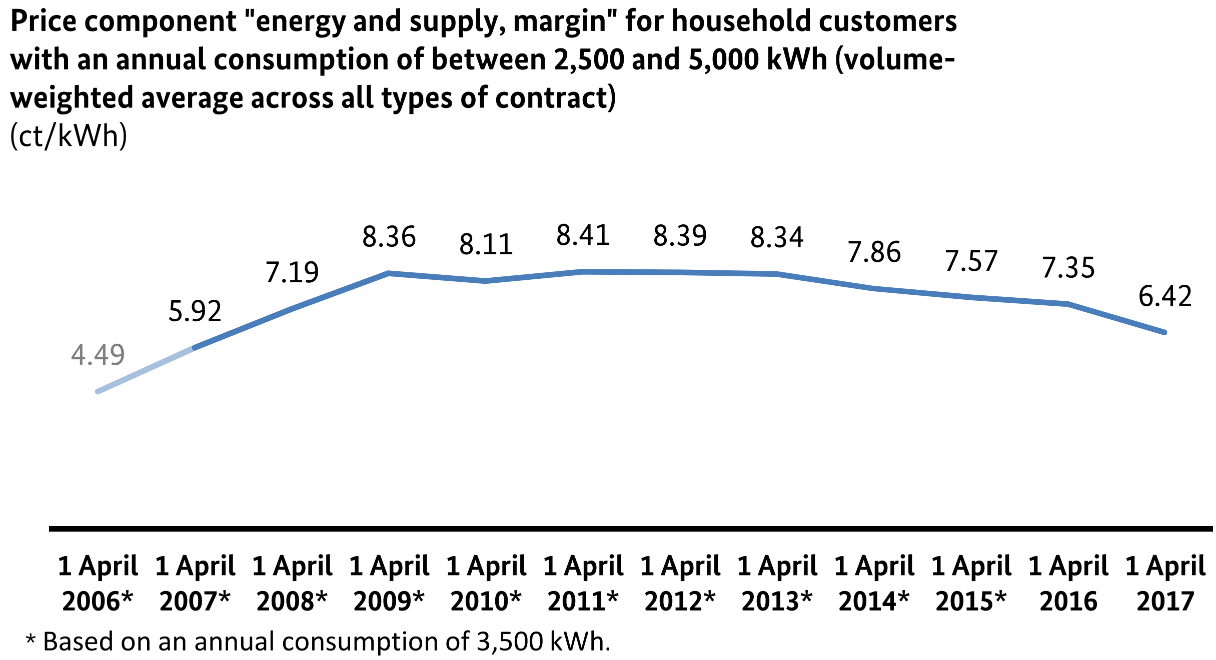


Figure 103: Change in the price component “energy and supply costs and margin” for household customers

Household customer prices by consumption band

Using the figures provided by the suppliers, average prices are calculated for default supply contracts, for non-default contracts with the default supplier (having switched tariff) and for contracts with a supplier other than the local supplier (having switched supplier). The following section examines the prices for the four consumption bands of household customers. It is important to note that the average network charges 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, legislative changes have led to a merging of the price components net network charge and billing, metering and meter operation, which in this report are now shown as a single component.

The use of new consumption bands since 2016 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:

Average volume-weighted price per contract category for household customers with an annual consumption below 1,000 kWh (band I; Eurostat band DA) as at 1 April 2017 (ct/kWh)

Price component	Default supply contract	Non-default contract with the default supplier	Contract with supplier other than the default supplier
Energy and supply, margin	10.42	8.93	7.71
Net network charge incl. billing	14.18	11.97	11.79
Metering, meter operation	2.37	1.85	1.38
Concession fee	1.65	1.76	1.38
EEG surcharge	6.88	6.88	6.88
CHP surcharge	0.44	0.44	0.44
Section 19 StromNEV surcharge	0.39	0.39	0.39
Section 18 AbLaV surcharge	0.01	0.01	0.01
Offshore liability surcharge*	-0.03	-0.03	-0.03
Electricity tax	2.05	2.05	2.05
VAT	7.22	6.50	5.87
Total	**45.58**	**40.75**	**37.87**

*Since in previous years household customers paid too much into the offshore surcharge account, in 2017 they will receive a credit of 0.03 ct/kWh.

Table 60: Average volume-weighted price per type of contract for household customers in consumption band I as at 1 April 2017

It is important to note that for customers with a relatively low consumption, suppliers are asked to give prices including non-variable price components such as the service, base and internal prices. The combination of lower consumption levels with the non-variable price components such as the base price results in a higher kilowatt-hour rate.

Since in previous years household customers paid too much into the offshore surcharge account, in 2017 they will receive a credit of 0.03 ct/kWh, which will be factored into customers' electricity bills.

The volume-weighted prices were calculated using the consumption volumes for 2016 and the prices as at 1 April 2017. The following tables show the results of the data analysis for band II:

Average volume-weighted price per contract category for household customers with an annual consumption between 1,000 kWh and 2.500 kWh (band II; Eurostat band DB) as at 1 April 2017 (ct/kWh)

Price component	Default supply contract	Non-default contract with the default supplier	Contract with supplier other than the default supplier
Energy and supply, margin	7.55	6.47	5.94
Net network charge incl. billing	8.37	7.62	8.53
Metering, meter operation	0.62	0.62	0.56
Concession fee	1.65	1.60	1.62
EEG surcharge	6.88	6.88	6.88
CHP surcharge	0.44	0.44	0.44
Section 19 StromNEV surcharge	0.39	0.39	0.39
Section 18 AbLaV surcharge	0.01	0.01	0.01
Offshore liability surcharge*	-0.03	-0.03	-0.03
Electricity tax	2.05	2.05	2.05
VAT	5.31	4.93	5.01
Total	**33.23**	**30.97**	**31.38**

*Since in previous years household customers paid too much into the offshore surcharge account, in 2017 they will receive a credit of 0.03 ct/kWh.

Table 61: Average volume-weighted price per type of contract for household customers in consumption band II as at 1 April 2017

Band III covers the majority of typical household customers in Germany and is comparable to the 3,500 kWh annual consumption band used until 2015. The following tables show the results of the data analysis for band III, with individual price components analysed in more detail and shown in time series:

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 2017 (ct/kWh)

Price component	Default supply contract	Non-default contract with the default supplier	Contract with supplier other than the default supplier
Energy and supply, margin	7.32	6.34	5.68
Net network charge incl. billing	6.97	6.88	7.15
Metering, meter operation	0.33	0.31	0.32
Concession fee	1.65	1.62	1.58
EEG surcharge	6.88	6.88	6.88
CHP surcharge	0.44	0.44	0.44
Section 19 StromNEV surcharge	0.39	0.39	0.39
Section 18 AbLaV surcharge	0.01	0.01	0.01
Offshore liability surcharge*	-0.03	-0.03	-0.03
Electricity tax	2.05	2.05	2.05
VAT	4.95	4.73	4.65
Total	**30.94**	**29.61**	**29.12**

*Since in previous years household customers paid too much into the offshore surcharge account, in 2017 they will receive a credit of 0.03 ct/kWh.

Table 62: Average volume-weighted price per type of contract for household customers in consumption band III as at 1 April 2017

A direct comparison of the three types of contract – default, non-default with the regional supplier (usually after switching tariff), and contract with a supplier other than the regional default supplier (usually after switching 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 2016 for customers on default tariffs was around 2,101 kWh, the average for customers on non-default contracts with the default supplier and customers who had switched from their default supplier was about 33% higher, at around 2,785 kWh.

Household customers can achieve additional savings compared to a default supply contract by switching the tariff with the default supplier (-1.34 ct/kWh) and, to an even greater extent, by switching supplier (-1,82 ct/kWh).[109] For a household customer with an annual consumption of 3,500 kWh/year, this amounts to savings in energy costs of around €47 and €64 per year respectively.

A comparison of the average prices for the three types of contract shows that throughout the period since 2008, default tariffs were the most expensive option for household customers. Prices for customers on non-default contracts with the default supplier were consistently cheaper over the same period of time than for those on default tariffs. On average, prices for customers who have switched from the regional default supplier to a new supplier are the cheapest. In nine out of the ten 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 default supplier.

At 7.32 ct/kWh, the price component that can be controlled by the supplier, including energy and supply costs, was nearly 29% higher for customers on default tariffs than for customers who had switched from their default supplier; the volume-weighted average price component for the latter group was 5.68 ct/kWh as at 1 April 2017. In 2016, the difference between the two groups was 37%. The average price component for energy and supply costs and the margin for customers on non-default contracts with the default supplier was 6.34 ct/kWh, compared to 6.74 ct/kWh in the previous year, and thus around 13% 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 has to be taken into account. The following graph provides a detailed overview of the trend:

[109] The cost savings apply to the consumption band between 2,500 and 5,000 kWh/year.

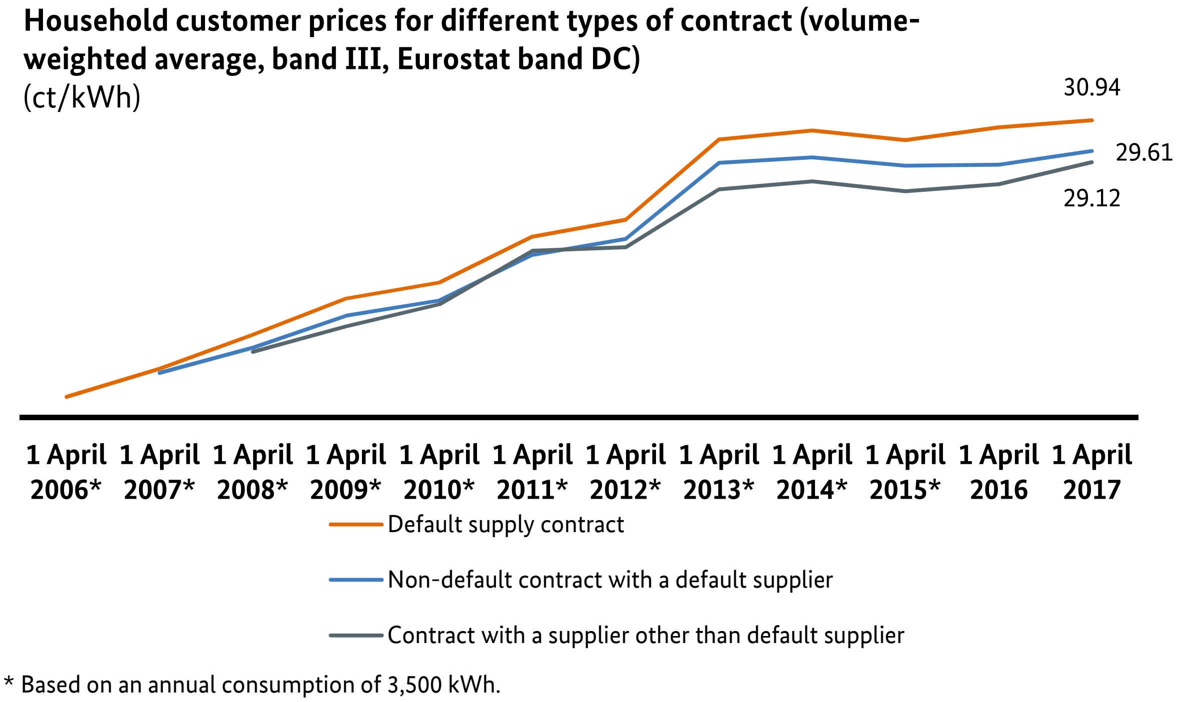


Figure 104: Household customer prices for the different types of contract (2006-2017)

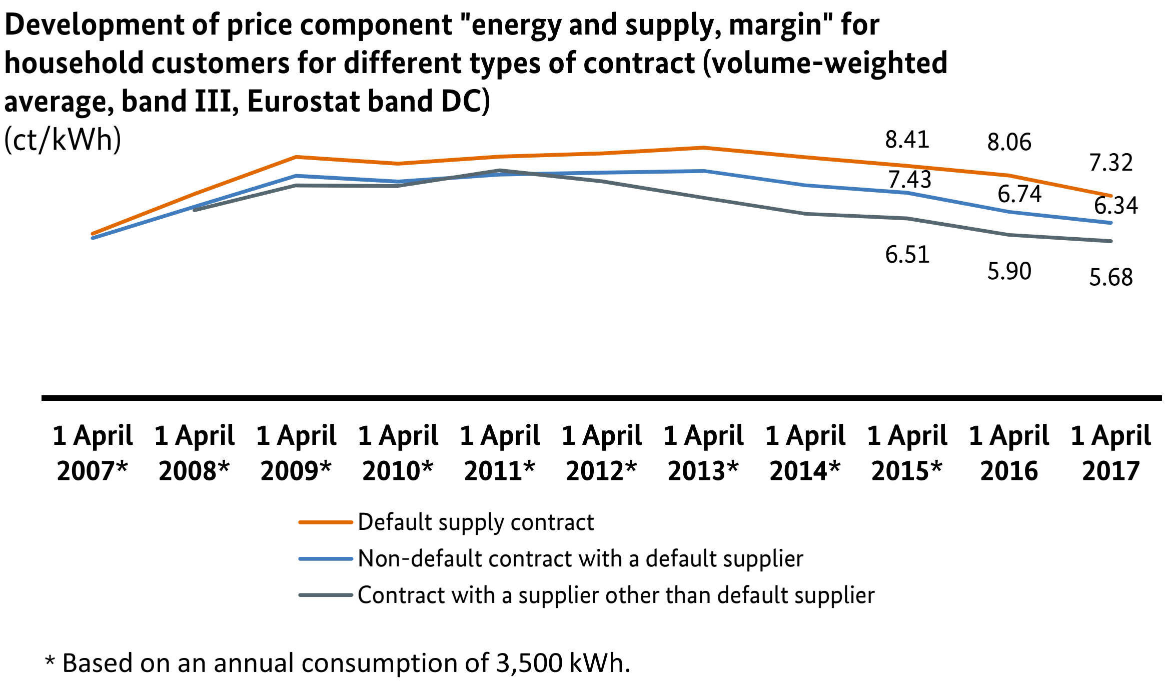


Figure 105: Development of the price component “energy and supply costs and margin” for household customers

Special bonuses and schemes

Non-default supply contracts can have a range of further features that suppliers use to compete for customers. These features may offer greater security to the customer (e.g. price stability) or to the supplier (e.g. 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 price stability were found to be especially common. Minimum contract periods for special tariffs with the local default supplier are 15 months on average, while price stability with a supplier other than the regional default supplier is offered for an average period of 14 months.

One-off bonus payments offered in conjunction with non-default contracts with the default supplier range between €5 and €175, with an average payment of €50, whereas contracts with a supplier other than the default supplier offer one-off payments ranging from €5 to €260, with an average payment of €62.

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 at 1 April 2017	Household customers			
	Non-default contract with the default supplier		Contract with supplier other than the default supplier	
	No of tariffs	Average scope	No of tariffs	Average scope
Minimum contract period	457	11 months	403	10 months
Price stability	325	15 months	410	14 months
Advance payment	55	10 months	38	10 months
One-off bonus payment	110	€ 50	191	€ 62
Free kilowatt hours	7	172 kWh	11	264 kWh
Deposit	9	-	5	-
Other bonuses and special arrangements	104	-	117	-

Table 63: Special bonuses and schemes for household customers

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 type of contract for household customers with an annual consumption between 5,000 kWh and 10,000 kWh (band IV) as at 1 April 2017 (ct/kWh)

Price component	Default supply contract	Non-default contract with the default supplier	Contract with supplier other than the default supplier
Energy and supply, margin	6.45	5.42	4.42
Net network charge incl. billing	6.79	6.00	6.72
Metering, meter operation	0.16	0.17	0.17
Concession fee	1.54	1.63	1.51
EEG surcharge	6.88	6.88	6.88
CHP surcharge	0.44	0.44	0.44
Section 19 StromNEV surcharge	0.39	0.39	0.39
Section 18 AbLaV surcharge	0.01	0.01	0.01
Offshore liability surcharge*	-0.03	-0.03	-0.03
Electricity tax	2.05	2.05	2.05
VAT	4.69	4.36	4.28
Total	**29.36**	**27.32**	**26.83**

*Since in previous years household customers paid too much into the offshore surcharge account, in 2017 they will receive a credit of 0.03 ct/kWh.

Table 64: Average volume-weighted price per type of contract for household customers in consumption band IV as at 1 April 2017

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 contract.

5. Electricity for heating

In this year's monitoring, data on contract arrangements, supplier switching and price levels for heating electricity – here the distinction is made between 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 2016. According to the volumes reported by a total of 939 heating electricity suppliers, about 14.48 TWh of heating electricity was supplied to just under 2.07m meter points during the reporting period. This corresponds to an average supply of just under 7,000 kWh per meter point in 2016. The previous year's figure was just under 7,050 kWh per meter point, with a total volume of 14.39 TWh at 2.05m meter points.

According to the data provided by the suppliers, just under 11.94 TWh of electricity was supplied for night storage heating at 1.6m night storage meter points, resulting in an average of about 7,250 kWh per meter point in 2016. The volume of electricity supplied to the approximately 426,700 meter points for heat pumps amounted to just over 2.53 TWh, or an average of about 5,950 kWh/year. Night storage heating accounts for the largest share of consumption (82% in terms of volume and 79% of meter points). The share of heat pumps is increasing steadily, accounting for 18% in terms of volume and 21% of meter points in 2016. This corresponds to an increase of about 2% relative to the previous year, when heat pumps accounted for only 16% in terms of volume and 18% of meter 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 meter points by night storage heating or heat pumps,[110] and therefore gave an estimate of the breakdown or entered the total in only one of the two categories. 834 of the 939 electric heating suppliers provided data on volume and meter points for both night storage heating and heat pumps.

The data on consumption volumes and the number of meter points collected from the DSOs on questionnaire 3 of the monitoring survey roughly corresponds to the results of the supplier surveys from questionnaire 4. According to the data provided by 754 DSOs, a total of 13.9 TWh of heating electricity was supplied to just under 2.09m meter points (night storage heating and heat pumps) in 2016. The DSOs, however, are not asked to differentiate between night storage heating and heat pumps.

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 electricity, which excludes company affiliations (for more detail see section "Contract structure and supplier switching"). The evaluation of the heating electricity supplied by the regional default supplier does not differentiate between "default supply contracts" and "non-default supply contracts with the default supplier" because in the Bundeskartellamt's view, heating electricity is sui generis always supplied under special contracts.[111] The percentage of heating electricity supplied in 2016 by a legal entity other than the regional default supplier has increased by around 45%, to over 1,282 GWh (2015: 885 GWh). About 8.8% of the entire heating electricity supply in 2016 came

[110] 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.

[111] Cf. Bundeskartellamt, Heizstrom – Überblick und Verfahren (Electric Heating – overview and proceedings), September 2010, pp. 9-10.

from suppliers other than the default supplier. The number of heating electricity meter points not served by the default supplier also increased, from 6.6% to 8.6%. The decisive factor in this increase is the fact that the number of heat pumps not supplied by the regional default supplier rose from around 30,000 meter points in 2015 to over 48,100 in 2016. Altogether, 11% of heat pump meter points were supplied by a legal entity other than the default supplier.

Heating electricity supply by non-default suppliers
Share of total heating electricity supplied in terms of volume and meter points

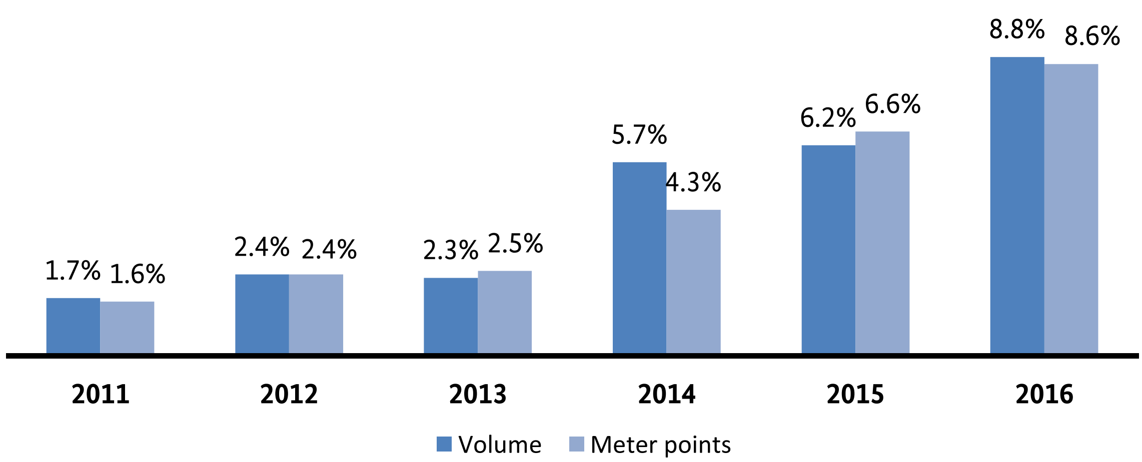


Figure 106: Percentage of heating electricity volume and meter points supplied by a supplier other than the regional default supplier

According to the data provided by the DSOs, supplier switching rates have risen steadily in the heating electricity sector. The data shows that there was a change of supplier at about 91,350 heating electricity meter points. These meter points accounted for about 583 GWh of heating electricity in 2016, which represents a switching rate of 4.2% in terms of consumption volume and 4.4% of meter points.

In the previous year, there was a change of supplier at just under 58,000 meter points, accounting for a volume of around 367 GWh. This corresponds to a switching rate of 2.7% in terms of consumption volume and 2.8% of meter points. The trend over the years shows that switching rates for heating electricity have risen slightly.

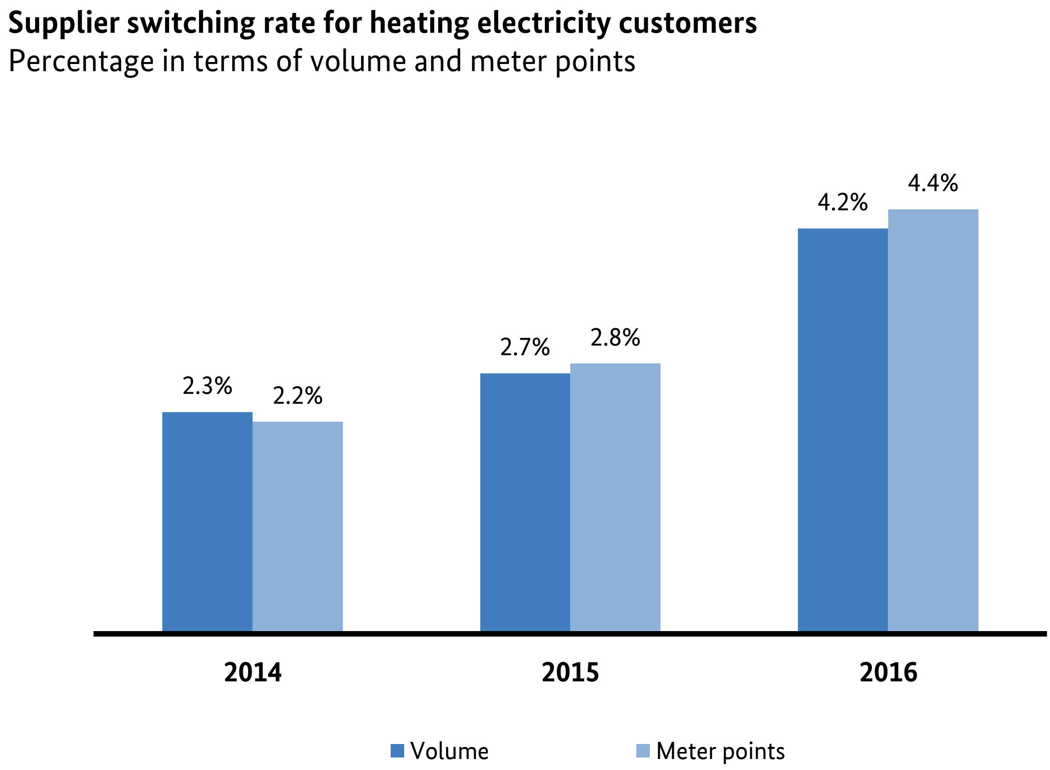


Figure 107: Supplier switching rates for heating electricity customers (2014-2016)

519 of the 754 DSOs that provided data on heating electricity volumes also reported figures on supplier switching.[112] These 519 DSOs represent around 96% of the heating electricity volume and meter points of all 754 DSOs that provided data on heating electricity.

The switching rates varied depending on the network area. The middle 80% of the graded figures for the quantitative switching rate per DSO that reported supplier switches were between 0.6% and 9.8%.

After many years of hardly any supplier switching, there has now 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 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 as at 1 April 2017. 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 843 suppliers (773 in the previous year) and the price data for heat pumps provided by 816 suppliers (750 in the previous year).

[112] Several DSOs also pointed out that they had no data, or only individual data, in the electric heating sector for analysis.

According to the results of the survey, the arithmetic mean of the total gross price for night storage heating was 20.94 ct/kWh (including VAT) on 1 April 2017, which is slightly above the previous year's level (20.59 ct/kWh). The arithmetic mean of the total price for heat pump electricity was 21.65 ct/kWh (including VAT), which puts it at the same level as the previous year and around 0.7 ct/kWh higher than the price for night storage heating.

Price level on 1 April 2017 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]	1,50 - 3,92	2.66	13
Metering, billing, meter operation	0,11 - 0,48	0.30	1
Concession fee	0,11 - 1,17	0.44	2
EEG surcharge	6.88	6.88	33
Other surcharges[2]	0.80	0.80	4
Electricity tax	2.05	2.05	10
VAT	2,97 - 3,77	3.34	16
Price component controlled by the supplier (remaining balance)	2,79 - 6,37	4.45	21
Total price (excluding VAT)	18,58 - 23,62	20.94	100

[1] Due to legislative changes, as of 1 January 2017 the price component "billing" is included in the net network charge and is no longer part of the category "Metering, billing, meter operation"; for the next Monitoring Report, the survey will therefore be adjusted to reflect the respective price components.
[2] KWKG (0.438 ct/kWh), section 19(2) StromNEV surcharge (0.388 ct/kWh), surcharge for interruptible loads under section 18 AbLaV (0.006 ct/kWh), offshore liability surcharge (-0.028 ct/kWh)

Table 65: Price level on 1 April 2017 for night storage heating with an annual consumption of 7,500 kWh

The amount that can be controlled by the supplier, which includes energy and supply costs and the margin, was 4.45 ct/kWh for night storage heating, which again represented a slight year-on-year decline (2016: 4.68 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 share controlled by the supplier, which includes energy and supply costs and the margin, also fell in the heat pump sector, to 4.81 ct/kWh as at 1 April 2017, compared to 5.04 ct/kWh in the previous year. In the reporting year, the average balance for heat pumps was slightly higher than that for night storage heating. The price component controlled by the supplier makes up only about 21% of the total price, including VAT, for night storage heating (23% in the previous year), and about 22% of the total price, including VAT, for heat pumps (24% in the previous year). About 65% 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 0.5 ct/kWh. The Bundeskartellamt has set the concession fee at 0.11 ct/kWh because heating electricity is supplied under special contracts.[113] 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 due to incorrect data entries or incorrect assessments. The average figure obtained in the survey for network charges and metering was 2.96 ct/kWh in the night storage heating category, a slight increase compared to the previous year's figure of 2.92 ct/kWh.

[113] Cf. Bundeskartellamt, Heizstrom – Überblick und Verfahren (Electric Heating – overview and proceedings), September 2010, pp. 9-10.

Price level on 1 April 2017 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]	1,50 - 4,43	2.85	13
Metering, billing, meter operation	0,11 - 0,50	0.30	1
Concession fee	0,11 - 1,32	0.51	2
EEG surcharge	6.88	6.88	32
Other surcharges[2]	0.80	0.80	4
Electricity tax	2.05	2.05	9
VAT	3,08 - 3,90	3.46	16
Price component controlled by the supplier (remaining balance)	2,88 - 6,84	4.81	22
Total price (excluding VAT)	19,28 - 24,41	21.65	100

[1] Due to legislative changes, as of 1 January 2017 the price component "billing" is included in the net network charge and is no longer part of the category "Metering, billing, meter operation"; for the next Monitoring Report, the survey will therefore be adjusted to reflect the respective price components.
[2] KWKG (0.438 ct/kWh), section 19(2) StromNEV surcharge (0.388 ct/kWh), surcharge for interruptible loads under section 18 AbLaV (0.006 ct/kWh), offshore liability surcharge (-0.028 ct/kWh)

Table 66: Price level on 1 April 2017 for heat pumps with an annual consumption of 7,500 kWh/year

6. Green electricity segment

In the 2017 survey, information was collected from suppliers on the volume of green electricity delivered to final consumers. The volumes of green electricity supplied to household customers and other final consumers in 2016 and the share of green electricity in the total volume of electricity supplied in 2016 are presented below.

Green electricity supplied to household customers in 2016

Category		Total electricity supplied	Total green electricity supplied	Share of green electricity in total volume and meter points
Household consumers	TWh	114.62	26.5	23.1%
	Number of meter points	45,274,217	9,950,687	22.0%
Other final consumers	TWh	304.68	31.2	10.2%
	Number of meter points	4,911,142	725,215	14.8%
Total	TWh	419.3	57.7	13.8%
	Number of meter points	50,185,359	10,675,902	21.3%

Table 67: Green electricity supplied to household customers in 2016

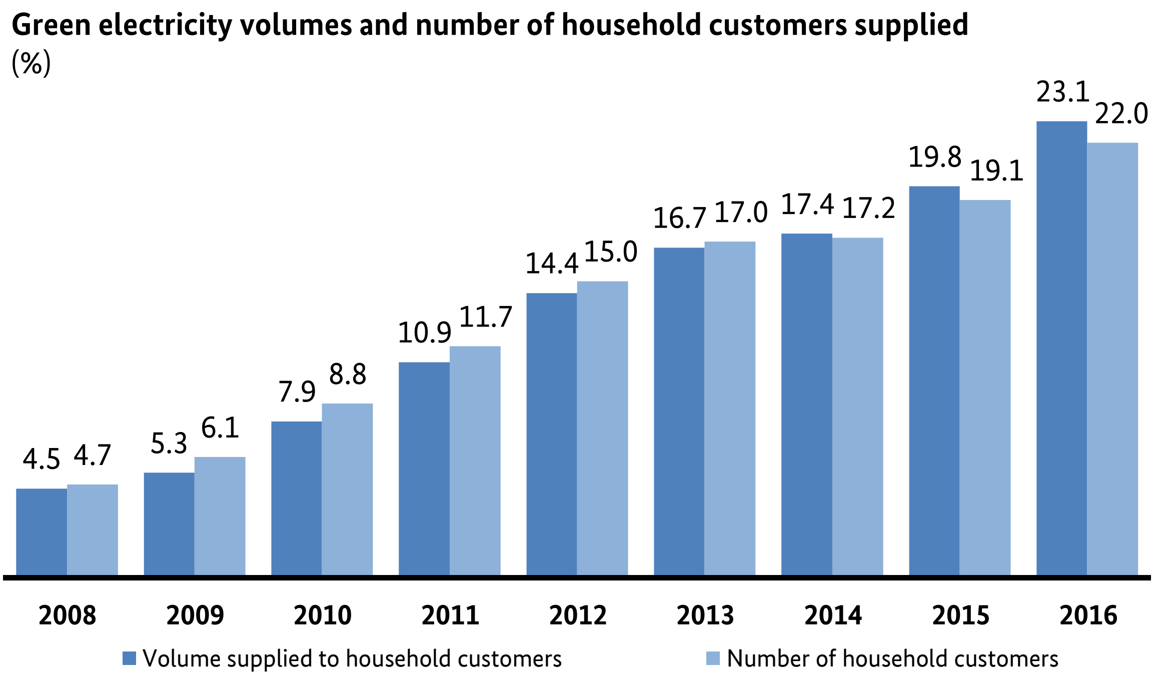


Figure 108: Green electricity volumes and number of household customers supplied

There was a further increase in 2016 in the share of green electricity in the total volume supplied to household customers and in the percentage of households supplied with green electricity. In 2016 the share of green electricity in total consumption increased by 3.3%. The percentage of household customers supplied with green electricity also rose by almost 3%, to about 10m meter points.

The following table shows the average volume-weighted prices and the individual price components for green electricity supplied to household customers, as well as their percentage of the total price:

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 at 1 April 2017 (ct/kWh)

Price component	Volume-weighted average (ct/kWh)	Percentage of total price
Energy, supply and other costs, margin	5.97	20.3
Net network charge incl. billing	7.04	23.9
Metering, meter operation	0.36	1.2
Concession fee	1.62	5.5
EEG surcharge	6.88	23.4
CHP surcharge	0.44	1.5
Section 19 StromNEV surcharge	0.39	1.3
Section 18 AbLaV surcharge	0.01	0.0
Offshore liability surcharge*	-0.03	n.a.
Electricity tax	2.05	7.0
VAT	4.69	16.0
Total	**29.42**	**100.00**

*Since in previous years household customers paid too much into the offshore surcharge account, in 2017 they will receive a credit of 0.03 ct/kWh.

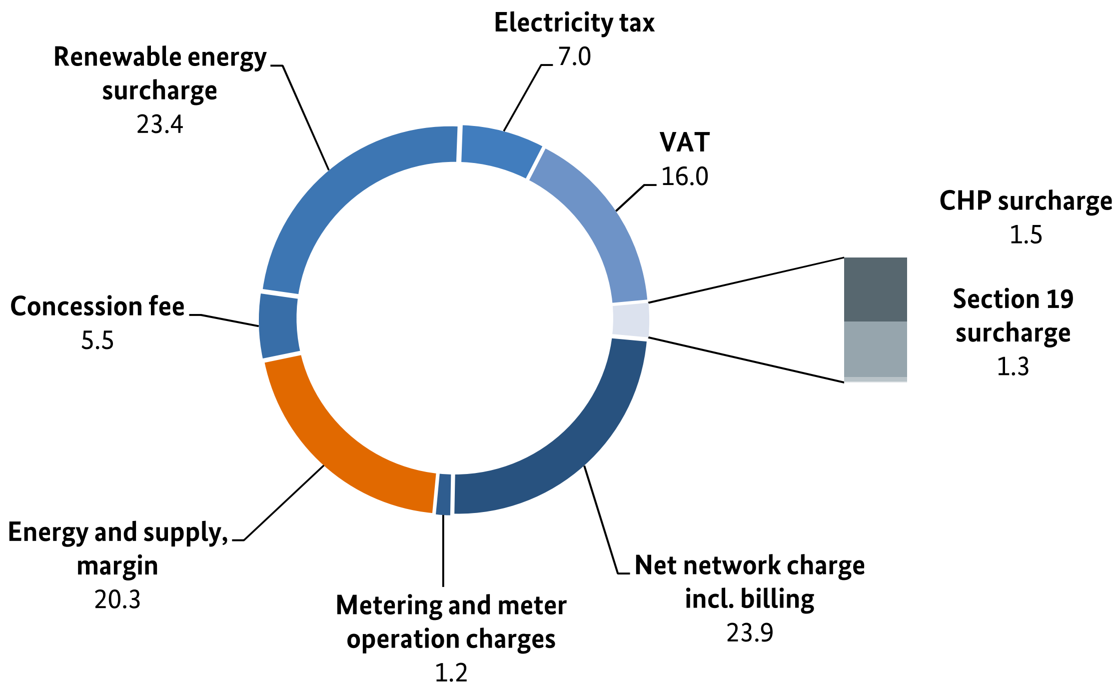
Table 68: Average volume-weighted price for green electricity for household customers in consumption band III as at 1 April 2017

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 to 29.42 ct/kWh as at 1 April 2017 (previous year:

28.35ct/kWh). Household customers thus pay around 3.8% more for green electricity than they did in the previous year.

The following diagram shows the percentage distribution of the individual price components for green electricity:

Breakdown of the retail price for household customers with annual consumption between 2,500 and 5,000 kWh (DC) for green electricity, as at 1 April 2017
(%)



Figures109: Breakdown of the retail price for green electricity for household customers in consumption band III as at 1 April 2017[114]

As with conventional electricity, many suppliers offer their customers a range of special bonuses and schemes that can have a further effect on 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. One-off bonus payments for household customers for green electricity range from €5 to €200, with an average payment of €60. 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:

[114] The value added tax makes up 16% of the total gross price, since the statutory 19% VAT is charged on and added to the net price (100%). Thus the VAT at 19% is the dividend and the total price at 119% is the divisor.

Special bonuses and schemes for household customers (green electricity)

1 April 2017	Household customers (green electricity)	
	No of tariffs	Average scope
Minimum contract period	466	11 months
Price stability	389	14 months
Advance payment	53	10 months
One-off bonus payment	156	€ 60
Free kilowatt hours	9	194 kWh
Deposit	7	-
Other bonuses and special arrangements	112	-

Table 69: Special bonuses and schemes for household customers on green electricity tariffs

As is the case with conventional electricity tariffs, the most common bonuses and schemes offered with green electricity tariffs pertain to minimum contract term, price stability and one-off payments.

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 all taxes, levies and surcharges ("adjusted price"). Eurostat also publishes a breakdown of the adjusted price into network costs and the remaining balance controlled by the supplier ("energy and supply"), which includes electricity procurement costs, supply costs and the margin. Eurostat does not collect the data itself, but relies on data from national bodies; until now it has used data supplied by the Federal Statistical Office that is based on figures provided by the German Association of Energy and Water Industries. Rules on the classification, analysis and presentation of the price data aim to ensure European-wide comparability.[115] However, the survey method is set by the individual Member State (cf. Directive 2008/92/EC, Annex I h), which leads to national differences.

7.1 Non-household consumers

Eurostat publishes price statistics for seven different consumer groups in the non-household sector that differ according to annual consumption ("consumption bands"). The following section describes the 20 to

[115] For details see: http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2008:298:0009:0019:DE:PDF (accessed on 26 July 2017).

70 GWh/year consumption band as an example. The 24 GWh/year category ("industrial customers"), for which specific price data is collected (see section "Price level" 4.1, p. 224), falls into this consumption band.

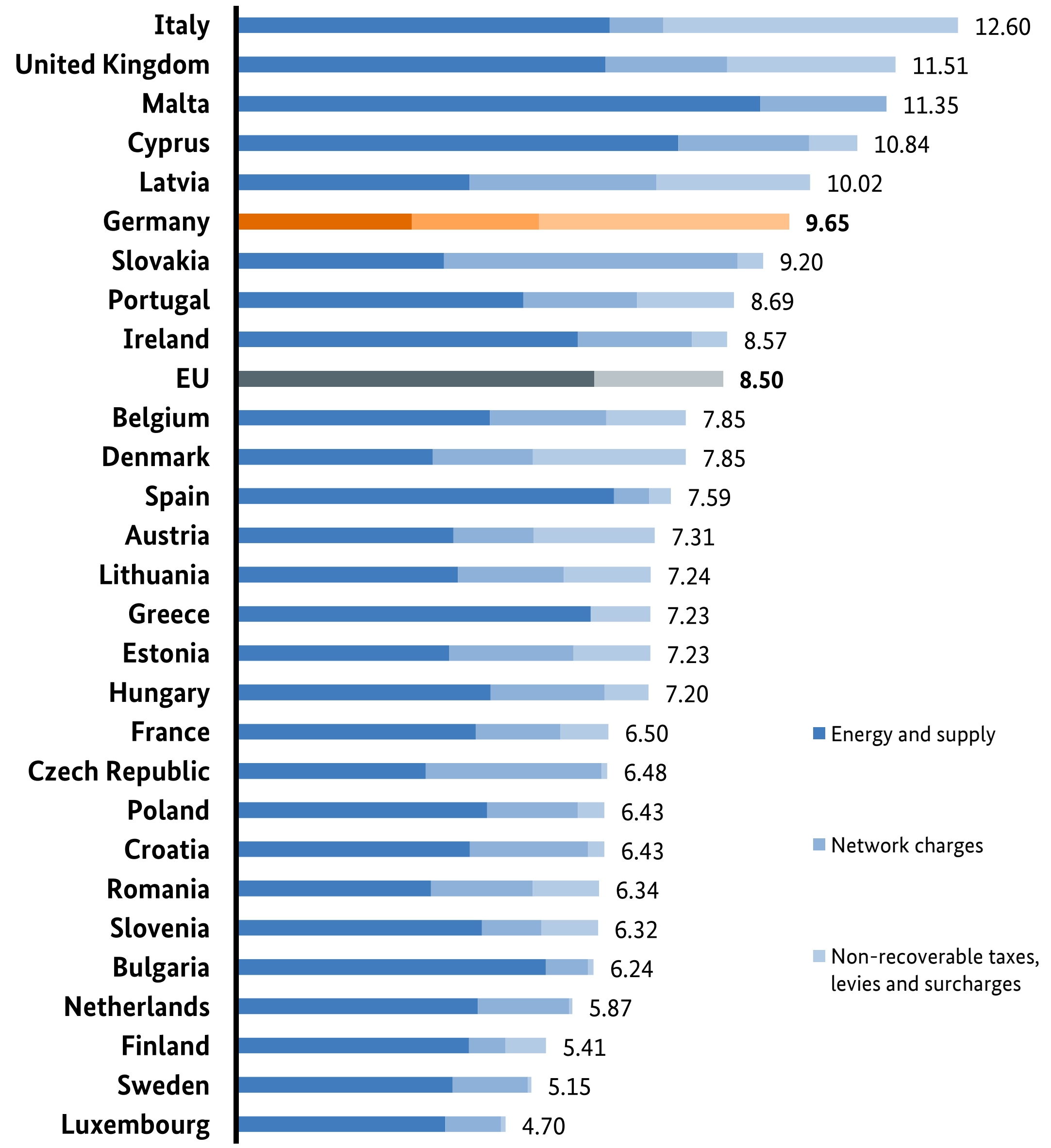
The customer group with an annual consumption of 20 to 70 GWh consists mainly of industrial customers, who can deduct national VAT on a regular basis. As a result, the total price has been adjusted for VAT for the purpose of European-wide comparison. Besides VAT, there are various other taxes, levies 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. These possible reductions are a very important factor for individual net electricity prices, especially for industrial customers in Germany (for more details see section "Price level" 4.1, p. 224).

According to Eurostat data, there are significant differences in the price of electricity for industrial customers across Europe. Italy has the highest net price with 12.60 ct/kWh, while Luxembourg has the lowest, with 4.70 ct/kWh. The European average is 8.50 ct/kWh, of which 2.25 ct/kWh consists of non-recoverable taxes, levies and surcharges and 6.25 ct/kWh is made up of network charges and the remaining balance controlled by the supplier ("energy and supply"). At 5.28 ct/kWh, the adjusted net price in Germany is just under 1 ct/kWh below the European average of 5.28 ct/kWh. The German net price is comprised of 2.21 ct/kWh network charges and 3.07 ct/kWh "energy and supply". The "energy and supply" price component is almost exactly the same as the figure of 3.48 ct/kWh recorded for the 24 GWh/year consumption category on 1 April 2016 (see Monitoring Report 2016, p. 200).

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 0.47 ct/kWh and 9.25 ct/kWh (see section "Price level" 4.1, p. 224). 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.[116] The figure relating to the average amount of non-recoverable surcharges, taxes and levies in the 20 to 70 GWh/year consumption band in Germany is 4.37 ct/kWh, or more than twice as much as the European average of 2.25 ct/kWh. The resulting net price for Germany is 9.65 ct/kWh, which is higher than the European average of 8.50 ct/kWh.

[116] 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 (accessed on 26 July 2017).

Comparison of European electricity prices in the second half of 2016 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 110: Comparison of European electricity prices in the second half of 2016 for non-household consumers with an annual consumption between 20 GWh and 70 GWh

7.2 Household consumers

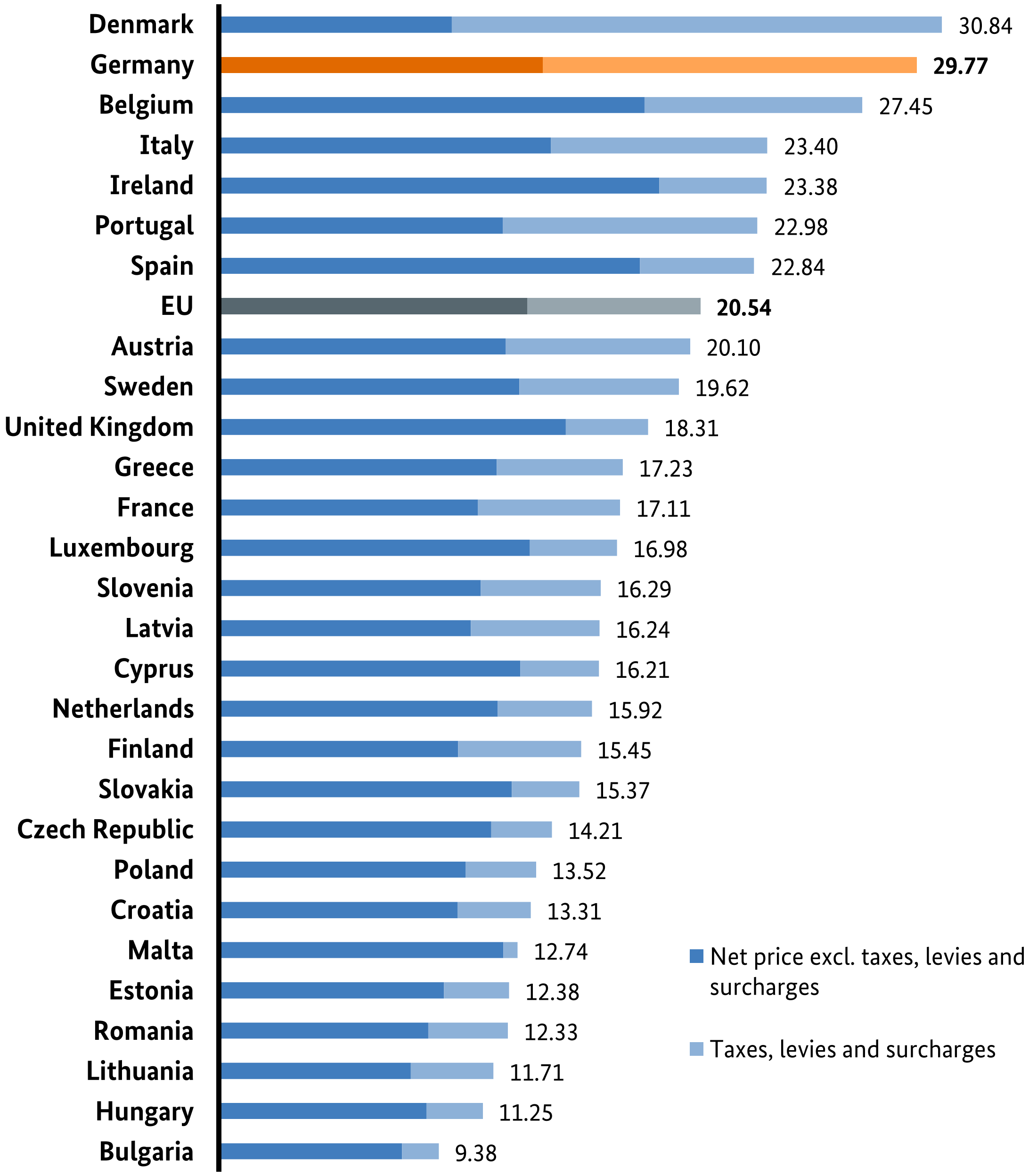
Eurostat takes five different consumption bands into consideration when comparing household customer prices. The volumes consumed by household customers in Germany are mostly in the middle category, with an annual consumption between 2,500 kWh and 5,000 kWh. In the monitoring survey, this consumption level is also categorised as consumption band III (see section „Price level“, p. 229).

The following shows a European comparison of the medium consumption band. Household consumers 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 consumers vary greatly in Europe. Germany has the second-highest price among the 28 EU Member States, with 29.77 ct/kWh. Prices in Germany are about 45% higher than the EU average of 20.54 ct/kWh. Only Denmark has higher prices for household consumers than Germany. The figure for Germany roughly corresponds to the volume-weighted average price of 29.80 ct/kWh across all contract categories which applied on 1 April 2016 (see Monitoring Report 2016, p. 216).

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, 7.39 ct/kWh on average consist of surcharges, taxes and levies, whereas in Germany these components account for more than twice as much, with 15.95 ct/kWh. By contrast, at 13.82 ct/kWh, the net price adjusted for all taxes, surcharges and levies in Germany is close to the EU average of 13.15 ct/kWh.

Comparison of European electricity prices in the second half of 2016 for household consumers with an annual consumption of 2,500 kWh to 5,000 kWh
in ct/kWh ; incl. VAT



Source: Eurostat

Figure 111: Comparison of European electricity prices in the second half of 2016 for household customers with an annual consumption between 2,500 kWh and 5,000 kWh

H Metering

1 Digitisation of metering

Metering was completely revamped in Germany with the adoption of the Metering Act (MsbG), which is an integral part of the Energy Transition Digitisation Act. The new law prescribes a comprehensive roll-out of modern metering devices and smart metering systems in Germany. This Act, which entered into force on 2 September 2016, has replaced sections 21b et seq. of the Energy Industry Act (EnWG) and the Metering Framework Conditions Ordinance (MessZV).

The "basic responsibility for meter operations" has hence been legally defined for the first time and a distinction has been made between the basic responsibility for conventional metering systems and the basic responsibility for modern metering devices and smart meters. The basic responsibility for both categories of equipment lies with network operators, but whereas the basic responsibility for conventional metering systems will remain permanently with network operators, the basic responsibility for modern metering devices and smart meters can be transferred to a third party service provider from 1 October 2017 onwards.

In addition to these general provisions governing the implementation of electricity and gas metering, the Act contains above all provisions relating to the roll-out of smart metering systems and modern metering devices. From 2017, meter operators are obliged to provide final consumers who have an annual electricity consumption exceeding 10.000 kWh and new installations with an installed capacity of between 7 and 100 kW with a smart metering system, provided the Federal Office for Information Security (BSI) has established technical feasibility. From 2020 onwards, it will be compulsory to provide final consumers with an annual electricity consumption exceeding 6,000 kWh and new installations with installed capacity in excess of 100 kW with smart meters. If the Metering Act does not stipulate that the installation of smart meters is compulsory, meter operators will be obliged to install modern metering devices.

Since the statutory framework was amended in the middle of the period under review, the market survey has been divided into two parts. As such, it is worth noting that there were no smart metering systems available on the market in 2016, meaning that the Federal Office for Information Security was unable to establish technical feasibility, which requires that at least three smart meters of independent manufacturers are available on the market. There were no modern metering devices available on the market in 2016 either. The information provided in the following therefore only applies to the old legal regime. However, a number of network operators and meter operators have been installing the first modern metering devices since early 2017. Notwithstanding this, it is unlikely that a roll-out of smart metering devices will occur before the end of 2017 since no smart meter gateway available on the market has been certified by the Federal Office for Information Security. This explains why the technical feasibility pursuant to section 30 of the Metering Act has not yet been established. This will not happen until at least three metering devices of independent manufacturers are available on the market, marking the launch of the compulsory roll-out of smart metering systems. However, the statutory requirements set forth in the Metering Act and the further development of technologies in this area suggest that the large-scale roll-out of modern metering devices and smart metering systems can be expected in the next few years.

2. The network operator as the default meter operator and independent meter operators

816 companies responded to the 2016 monitoring survey, reporting a total of 51,987,882 electricity meter points. In 2016, meter operators can be categorised as follows:

Role of meter operators within the meaning of the Metering Act

	Share	
	Conventional meter operators	Meter operation of modern metering devices or smart metering systems
Default network operator	779	442
Other network operators	34	23
of whom are exclusively not default network operators	20	0
Suppliers	40	21
Meter operators independent of network operators and suppliers	27	9

Table 70: Role of meter operators within the meaning of the Metering Act

Pursuant to section 5 of the Metering Act, customers can freely choose the company which is responsible for the installation, operation and maintenance of metering equipment and systems as well as actual metering. These tasks can be performed by third parties alongside network operators. The data submitted in the monitoring survey indicates that independent meter operators are providing metering services in network areas of some 804 DSOs, which leads to the following distribution irrespective of network size:

Distribution networks by number of independent meter operators

	Number of independent meter operators					
	up to 5	6 bis 10	11 to 20	21 to 30	31 to 40	over 40
Number of networks	219	234	259	65	16	11
Distribution in percent	27	29	32	8	2	1

Table 71: Breakdown of distribution networks by number of independent meter operators

Irrespective of the network size, the average number of independent meter operators working in a distribution network is around eleven. The highest number is 119 independent meter operators in a network area.

Independent meter operators cover around 239,000 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 Table 72. 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 4% of all networks) in which more than 1% of meter points are serviced by independent meter operators.

Share of independent meter operators in the distribution network areas

	Number of meter points with meter operation by independent meter operators in the distribution network area					
	up to 1%	**>1% to 5%**	**>5% to10%**	**>10% to 15%**	**>15% to 20%**	**>20%**
Number of networks	799	27	7	0	1	1
Distribution in percent	101	3	<1	0	<1	<1

Table 72: Share of independent meter operators in the distribution network areas

3. Requirements under section 29 ff. of the Metering Act

The Metering Act provides for the obligatory installation of smart metering systems if specific requirements have been met and it is technically feasible. The following tables show the number of meter points subject to the obligatory installation of smart metering systems based on consumer groups defined in the Metering Act. The columns with a grey background refer to the future roll-out of smart metering systems as defined in the Metering Act, for which the companies have not yet been able to provide relevant information.

Meter points requiring smart meters under section 29 in conj. with sections 31 and 32 of the Metering Act	**Number of meter points**			
	Total	of which have been equipped with metering systems in acc. with section 19 (5) of the Metering Act	of which have been equipped with modern metering devices as defined in the Metering Act	of which have been equipped with smart metering systems as defined in the Metering Act
Final consumers with annual power consumption				
> 6,000 kWh & ≤ 10,000 kWh	1,850,906	268,829	4,602	
> 10,000 kWh & ≤ 20,000 kWh	864,686	121,550	1,489	
> 20.000 kWh & ≤ 50.000 kWh	433,797	72,374	758	
> 50,000 kWh & ≤ 100,000 kWh	122,832	32,751	310	
> 100,000 kWh	235,914	125,680	513	
Consumer facilities in accordance with section 14a EnWG	979,144	104,026	1,989	
of which meter points at loading stations for electric vehicles	1,337	209	31	
Installed capacity at plant operators in accordance with section 2 para 1 of the Metering Act				
> 7 kW & ≤ 15 kW	379,471	59,158	1,147	
> 15 kW & ≤ 30 kW	211,893	25,677	545	
> 30 kW & ≤ 100 kW	130,321	14,364	251	
> 100 kW	77,556	21,190	158	

Table 73: Meter points requiring smart meters under section 29 in conjunction with sections 31 and 32 of the Metering Act

Approx. 4.5m final consumers in a range of consumption categories will be affected by the obligatory installation of smart meters under section 29 in conjunction with sections 31 and 32 of the Metering Act, with almost 1.9m final consumers who have an annual consumption of between 6,000 and 10,000 kWh accounting for the vast majority. Meter operators reported that around 34m final consumers were eligible for voluntary installation under section 29 in conjunction with section 31 of the Metering Act. Final consumers with an annual electricity consumption of 2,000 kWh represent the largest group.

	Number of meter points			
Optional installation within the meaning of section 29 in conj. with section 31 of the Metering Act	Total	of which have been equipped with metering systems in accordance with section 19(5) of the Smart Meters Operation Act	of which have been equipped with modern metering devices as defined in the MeteringAct	of which have been equipped with smart metering systems as defined in the Metering Act
Final consumers with annual power consumption of:				
≤ 2,000 kWh	17,952,430	2,531,521	12,510	
> 2,000 kWh &≤ 3,000 kWh	7,427,381	1,000,835	5,155	
> 3,000 kWh &≤ 4,000 kWh	4,782,221	616,570	3,384	
> 4,000 kWh &≤ 6,000 kWh	4,176,488	546,560	3,360	
Installed capacity at plant operators in accordance with section 2 para 1 of the Metering Act				
> 1 kW & ≤ 7 kW	327,070	52,804	1,005	

Table 74: Voluntary installation under section 29 in conjunction with section 31 of the Metering Act

In response to the question in the monitoring survey whether the default meter operator is planning on equipping final consumers with annual consumption below 6,000 kWh with a smart metering system, 72 companies said "Yes" and 244 companies said "No". 334 companies remain undecided. 141 meter operators refrained from answering the question.

4. Organisation of meter operations

With regard to meter operations, companies need to ask themselves whether they wish to fulfil all the functions of meter operations themselves or whether they should transfer some of these functions to third party service providers (external or within the group). In addition to the installation of metering devices, this also applies to the operation, maintenance and billing of meter points and smart meter gateway administration. The answers to the questions in the monitoring survey indicate that the majority of meter operators perform these tasks themselves. However, smart meter gateway administration where there is a growing trend to employ independent service providers forms a clear exception. Figure 112 contains a breakdown of the individual remits.

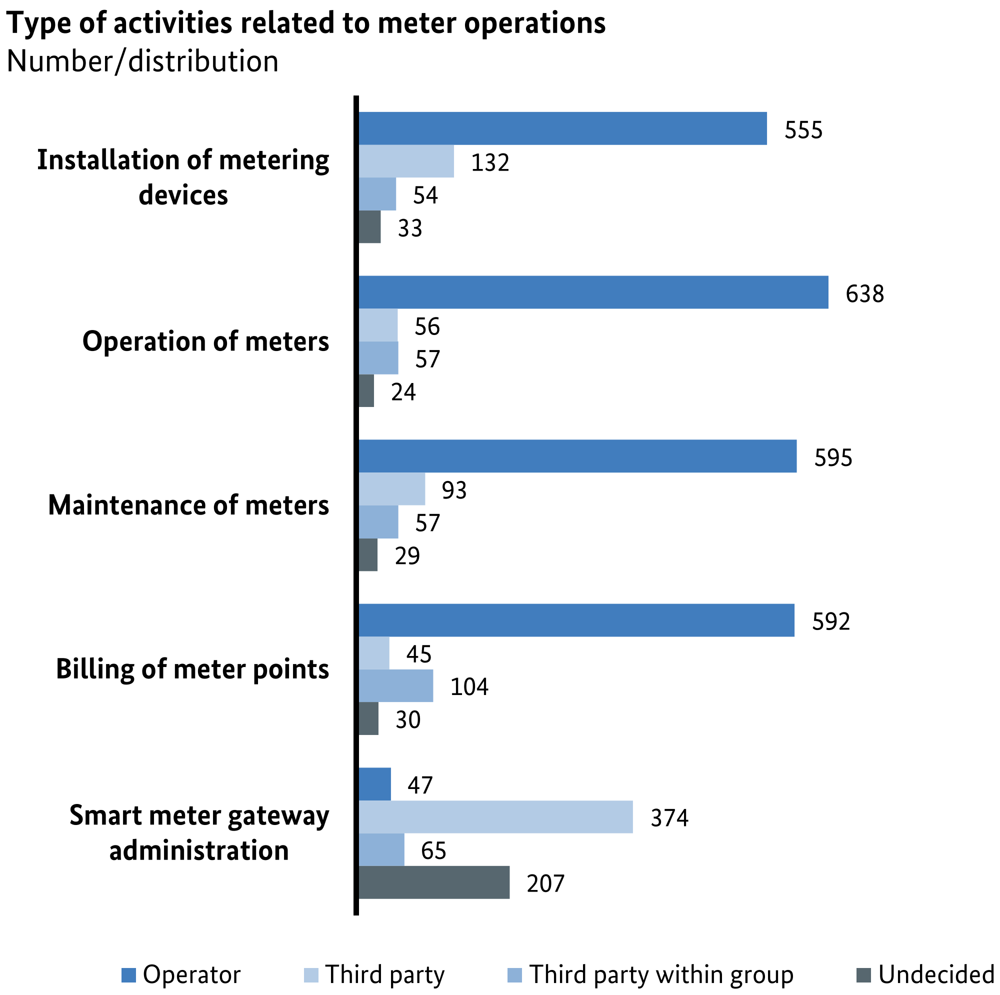


Figure 112: Performance of the activities related to meter operations

In future, the companies will also be able to decide whether they would like to transfer their basic responsibility for the operation of modern metering devices and smart metering systems to another company. The vast majority of almost 93% of the companies surveyed said this was not an option for them. They intend to continue performing this task themselves (cf. Figure 113).

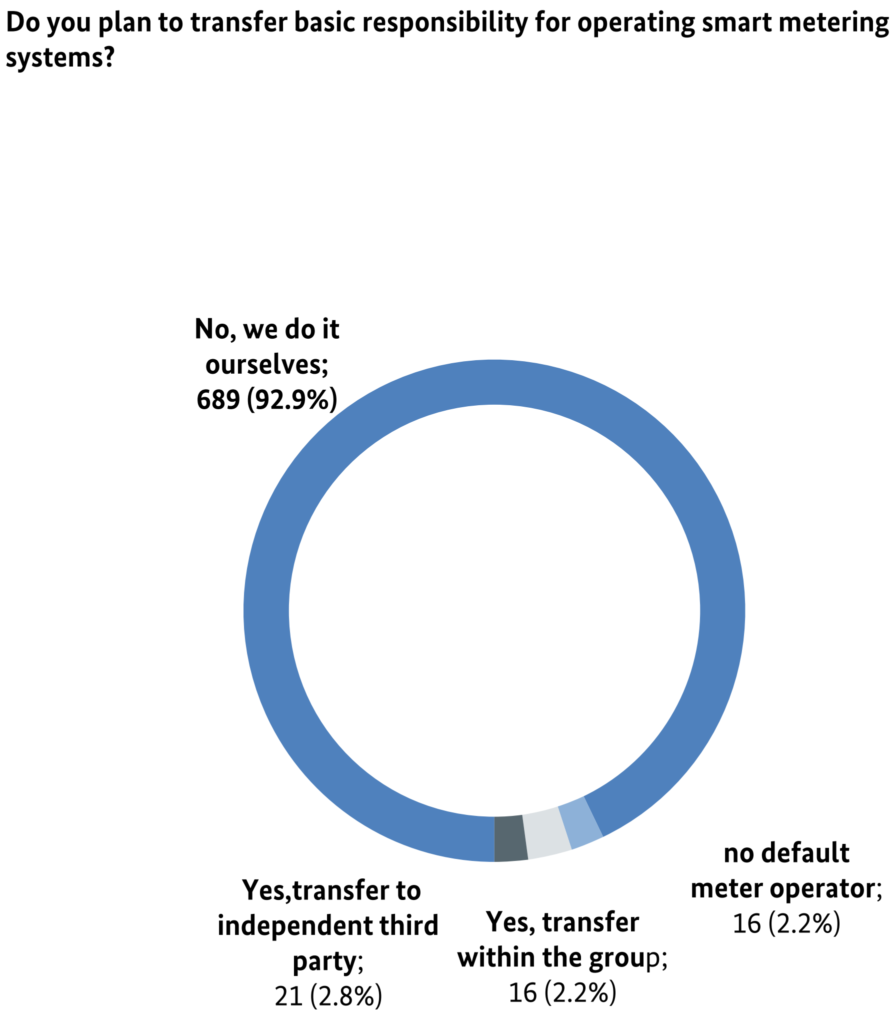


Figure 113: Transfer of basic responsibility for smart metering systems

The majority of companies only provide meter operation services for the electricity segment and do not use the smart meter gateway to operate meters for gas, district heating, heating energy or water as well. Of the companies offering meter operation services in the other segments, between 5% and 16% also operate meters for other utilities. This figure is slightly higher for the gas segment in which over 100 companies provide meter operation services (cf. Figure 114).

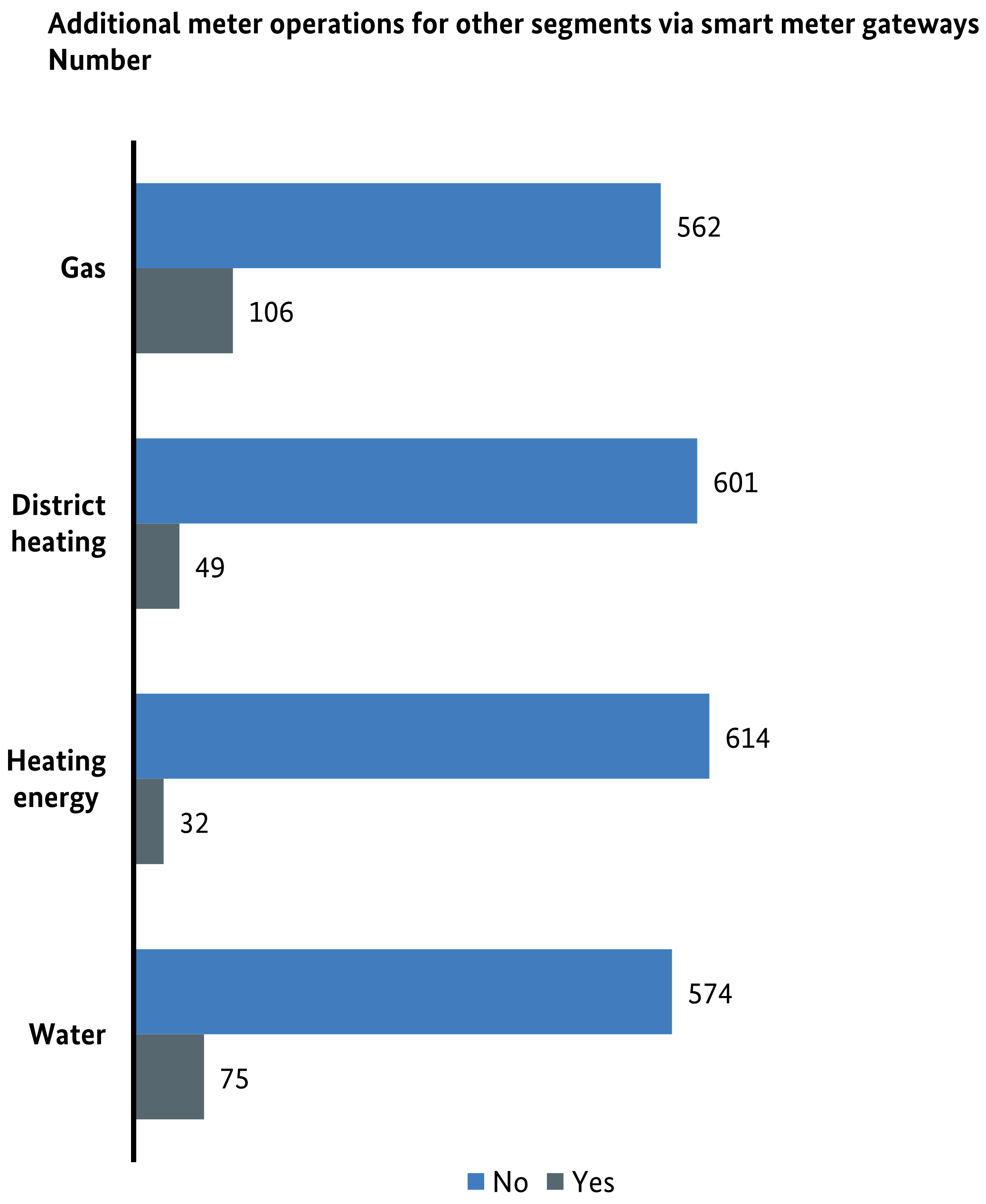


Figure 114: Additional meter operations for other segments via smart meter gateways

The provision of additional meter operation services for smart metering systems as defined in section 35(2) of Metering Act varies. Whereas the majority of companies also provide current transformers and voltage converters, very few companies offer smart metering systems in the form of prepayment meters. A large number of companies have decided not to offer additional services such as enabling or performing control of consumption via smart metering systems or the provision and technical operation of smart meter gateways for value-added services. At the same time, the number of meter operators who are undecided is high in all categories. Figure 115 illustrates the relevant evaluation.

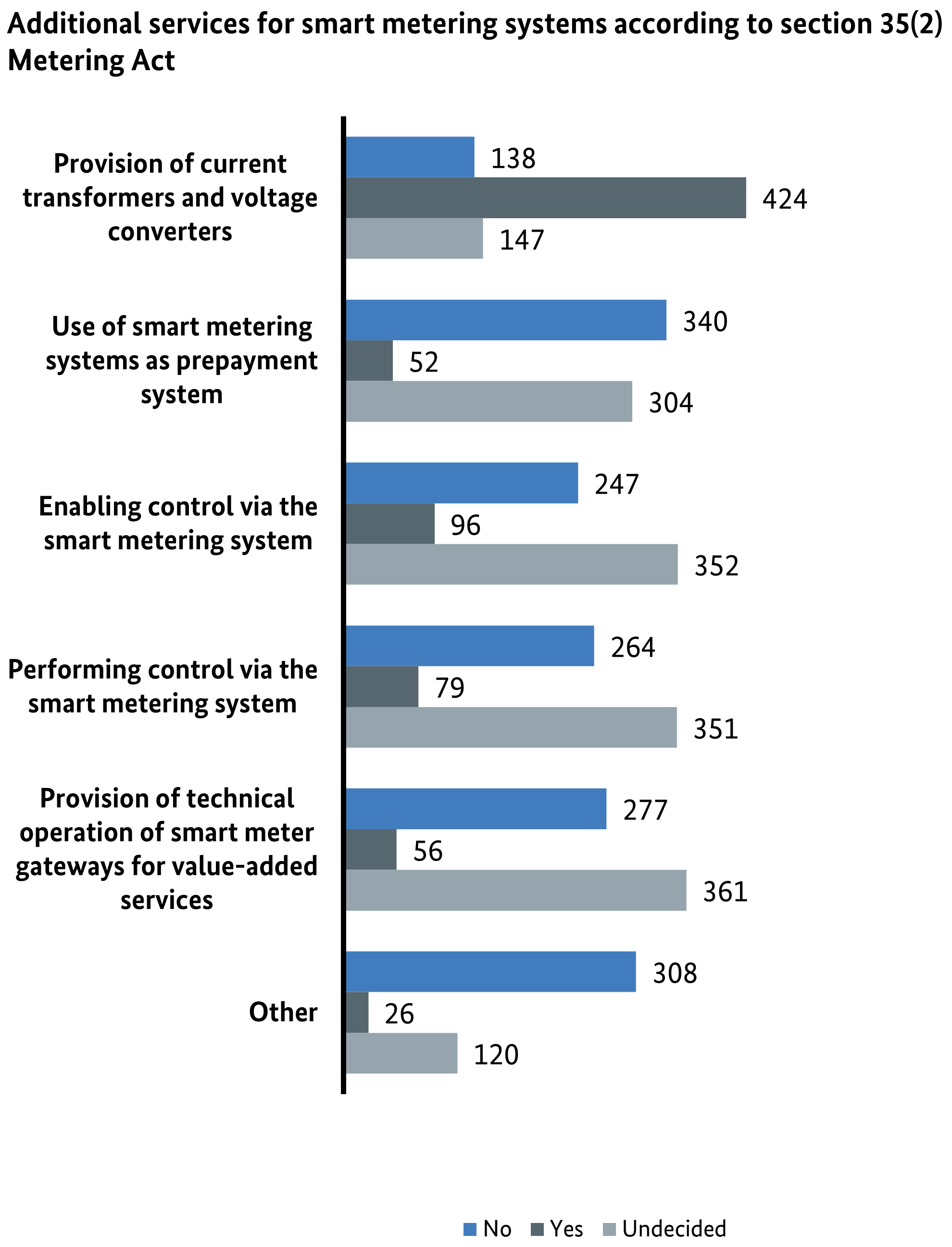


Figure 115: Additional services for smart metering systems

The vast majority of meter operators, 82% to be precise, do not offer combined electricity supply and meter operation services (see Figure 116).

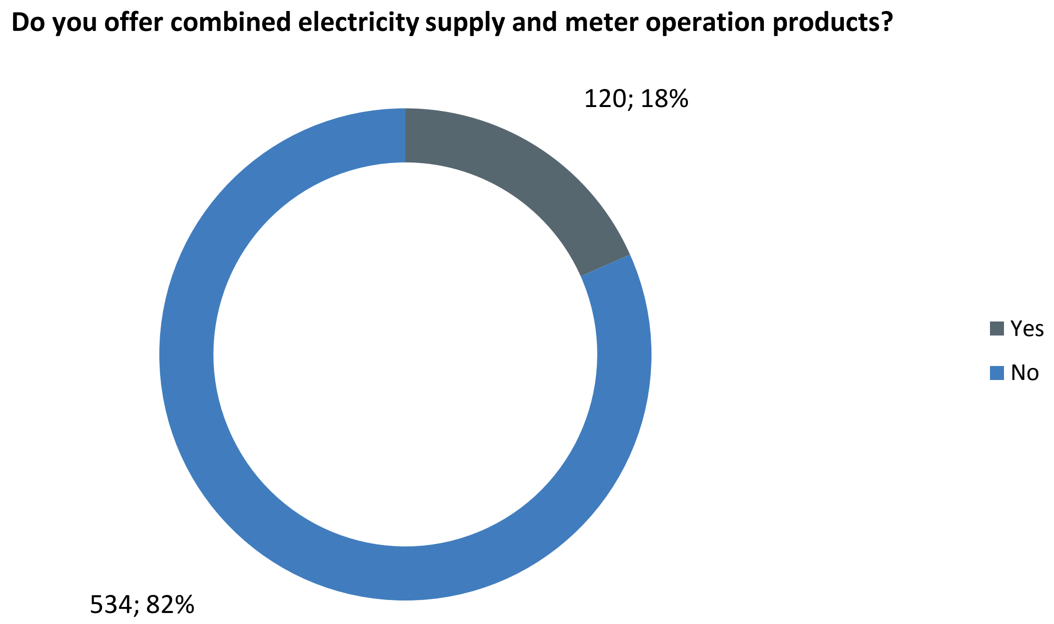


Figure 116: Combined electricity supply and meter operation products

By and large, it is the suppliers who bill the customers for meter operation services. In just 41 cases, a separate bill is issued for meter operation services. Although hybrid billing models, namely billing partly by separate invoice and partly by the supplier, are used a bit more frequently, they are far less common than billing by the supplier (see the following Figure 117).

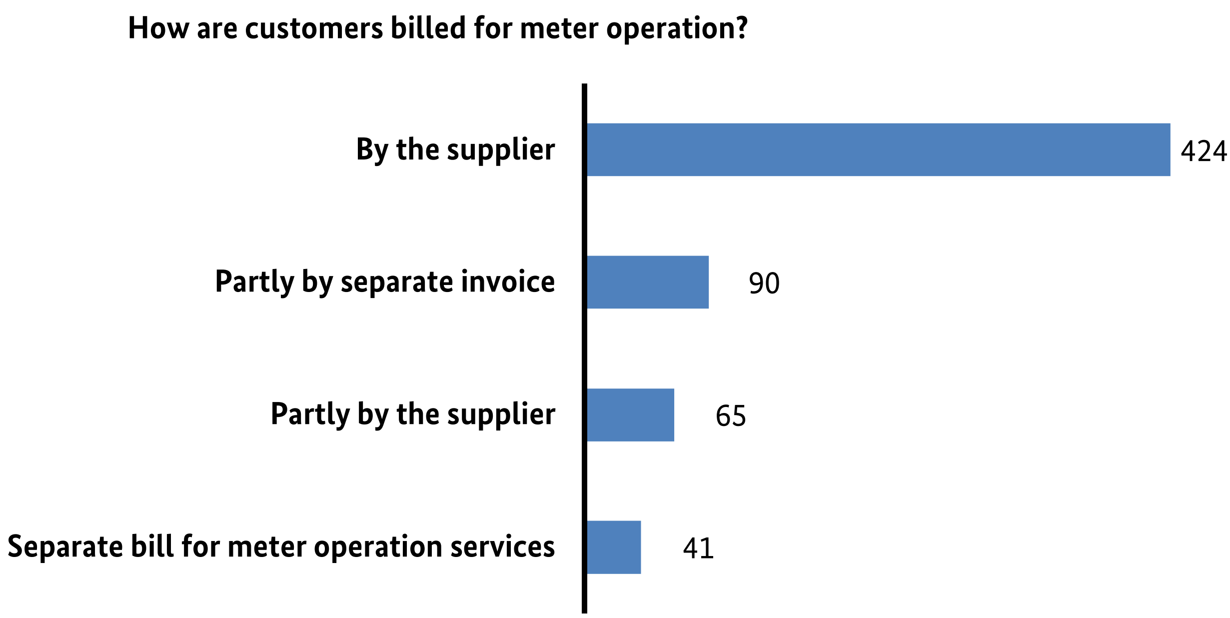


Figure 117: Billing of customers for meter operation

5. Meter technology for household customers

The following picture emerges in relation to the current metering landscape in Germany based on the information provided by meter operators on the meter technology and the metering systems used in the SLP customer segment:

Meter technology used in the SLP customer segment

Requirement	Meter points 2015	Meter points 2016
Electromechanical metering systems (with current transformers and three-phase meters based on the Ferraris principle)	44,030,251	43,413,117
of which two-tariff and multiple-tariff meters (Ferraris principle)	2,944,190	2,794,792
Electronic meter device (basic meter not connected to a communication network) in accordance with section 2 para 15 of the Metering Act	5,029,241	6,945,610
Modern measuring device (not connected to a communication network in accordance with section 2 para 15 of the Metering Act	-	50,251
Metering systems in accordance with section 2 para 13 of the Metering Act that are not smart metering systems pursuant to section 2 para 7 of the Metering Act (e.g. EDL40)	-	453,797
Snart metering systems in accordance with section 2 para 7 of the Metering Act		

Table 75: Meter technology used in the SLP customer segment[117]

In the household customer segment (SLP customers), the significant shift towards electronic metering systems continued once again in 2016. All in all, the number of electronic metering systems rose by approx. 1.9 million year-on-year. Despite the fall in the number of Ferraris meters in use by around 600,000 meter points, these are still found at about 43 million meter points. There has been a slight decline in the use of two-tariff and multiple-tariff meters from the previous year's level to approximately 2.8m modern meter points. These meters which comply with section 2 para 15 of the Metering Act and are not connected to a communication network have meanwhile been installed at approx. 50,000 meter points. Metering systems that comply with section 2 para 3 of the Metering Act but are not smart metering systems have been installed at almost 500,000 SLP customer meter points.

[117] The figure for metering systems complying with sections 21d and 21e of the EnWG was corrected retroactively.

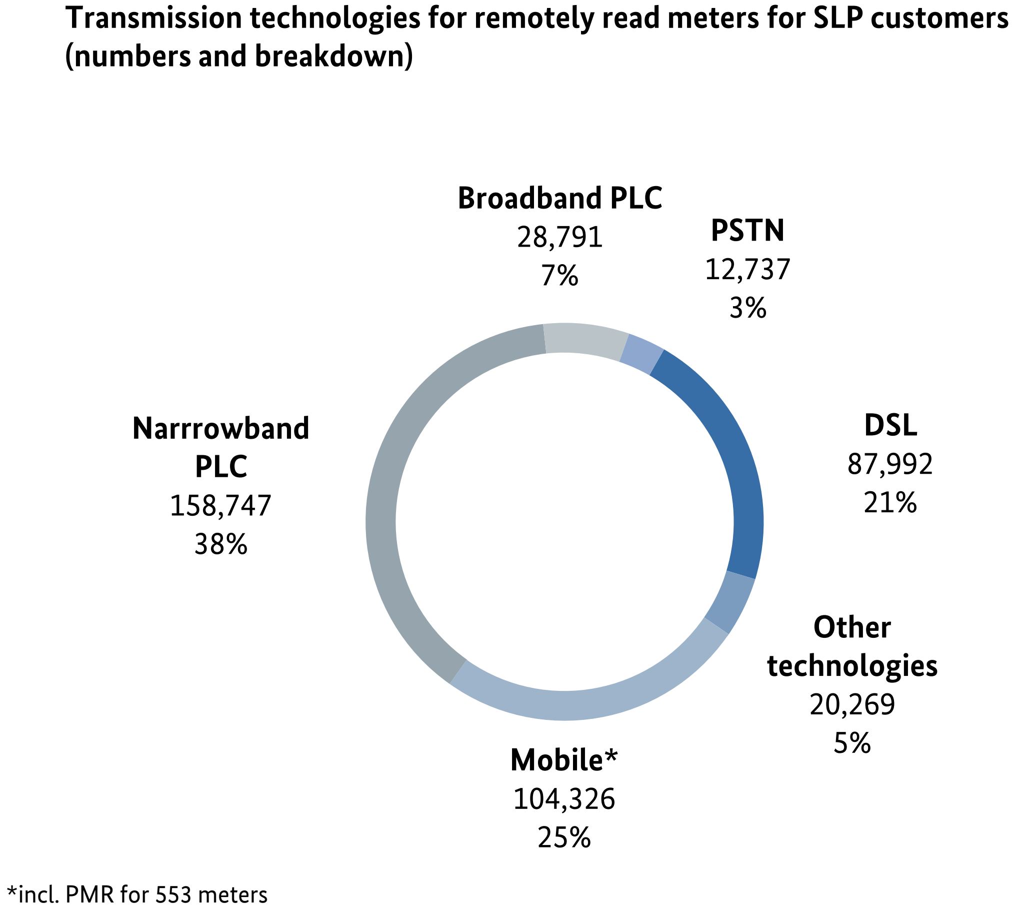


Figure 118: Transmission technologies for remotely read meters for SLP customers (numbers and breakdown)

The percentage of data transmissions via power line communication (PLC) has fallen by approximately 6,000 meter points since the previous year. This is mainly attributable to the rise in mobile transmissions and transmissions via other technologies. This means PLC transmission technology is now being used in less than 45% of cases. There has been a slight decline in the number of connections via telephone lines (PSTN) and broadband (DSL).

This is shown in the following Figure 119.

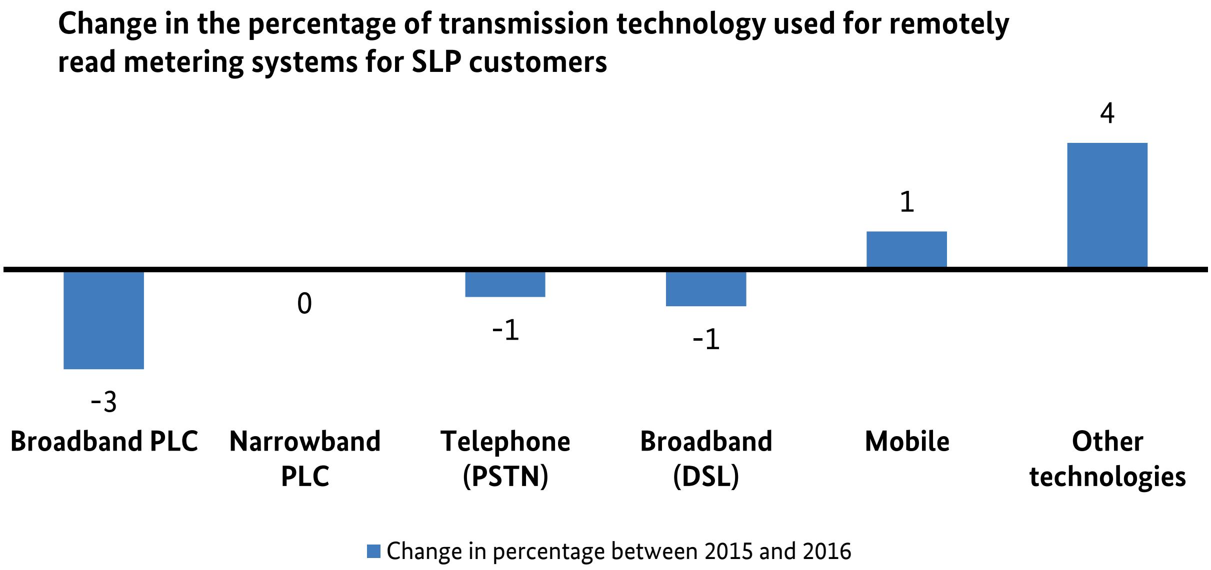


Figure 119: Change in the percentage of transmission technology used for remotely read metering systems for SLP customers compared with the previous year

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 wireless transmission.

6. Meter technology used for interval-metered customers

According to the information provided by meter operators, the number of meter points of interval-metered final consumers reached 385,000, with non-household customers from the industrial and commercial segment accounting exclusively for all interval-metered customers.

Meter technology employed for interval-metered customers

Requirement	Meter points 2016
Metering equipment in the interval-metered segment (>100,000 kWh/year)	385,154
Metering systems in accordance with section 2 para 13 of the Metering Act that are not smart metering systems pursuant to section 2 para 7 of the Metering Act (≤ 100,000 kWh/year)	177,104
Other	49,596

Table 76: Meter technology employed for interval-metered customers

The following diagram shows the number and breakdown of transmission technologies used

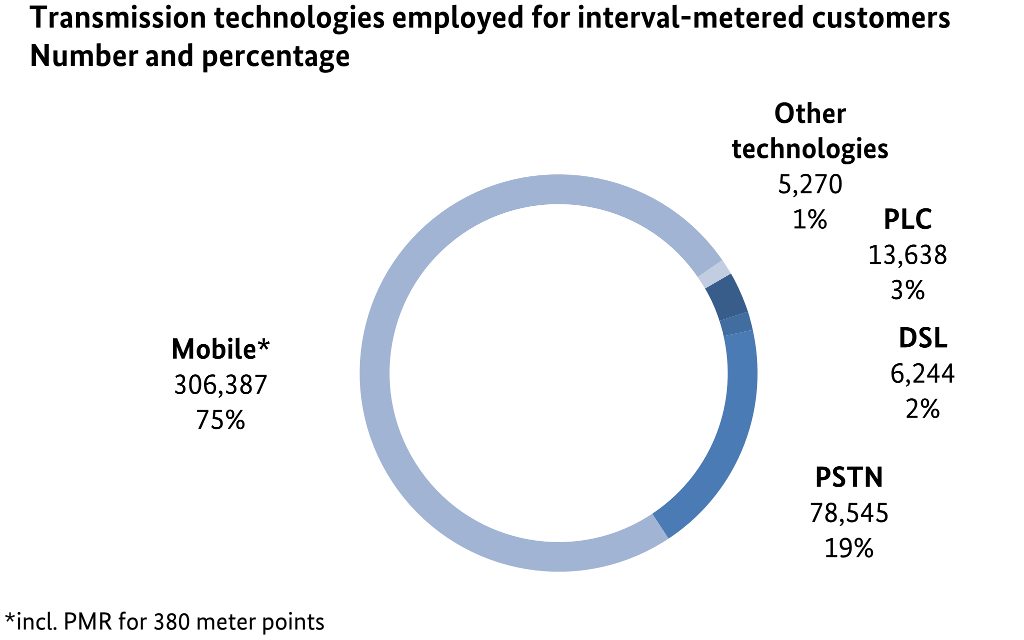


Figure 120: Number and percentage of transmission technologies employed for interval-metered customers

There were very few changes in transmission technology used in the interval-metered field compared to the previous year. There was a significant increase of around 3 percent in the number of remote meter readings transmitted via mobile communication compared to the previous year. By contrast, data from 3 percent fewer meter points was transmitted by telephone line. Similar to the previous year, the diagram above shows that in the interval-metered segment, transmission technologies other than by radio (GSM, GPRS, UMTS, LTE) and telephone line (PSTN) are rarely used.

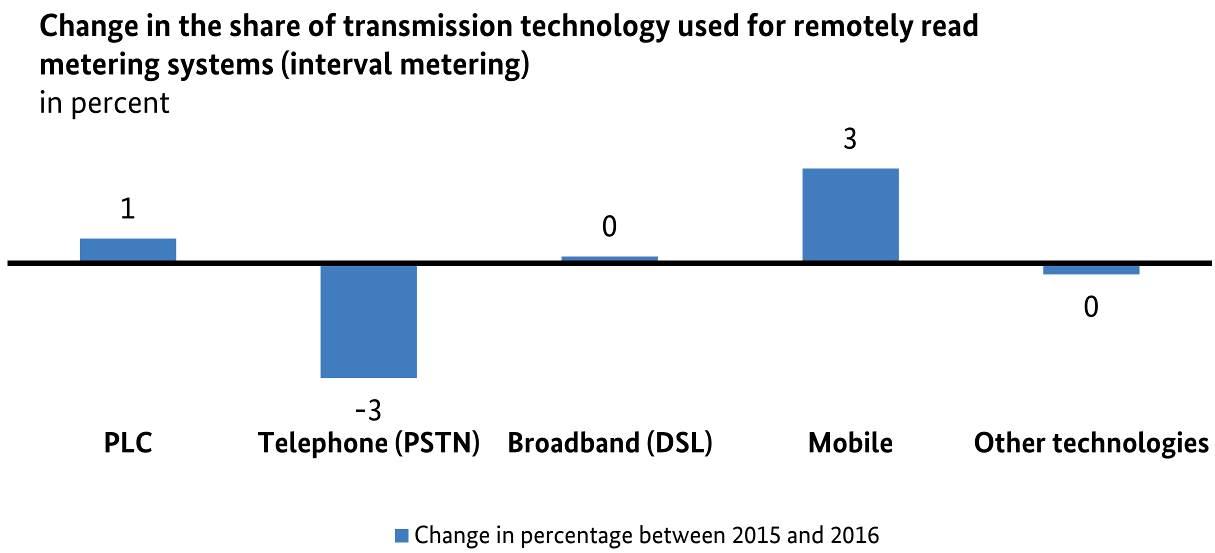


Figure 121: Change in the share of each transmission technology for remotely read metering systems for interval- metered customers compared to the previous year

Unlike the SLP segment, the interval-metered segment shows transmission to mainly take place 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 remotely read meters now communicate by mobile transmission.

This difference may be explained primarily by the typical voltage level. 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. 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 of a given in the network area for household customers 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 far fewer costs than wireless data transmission, which means that this can create a barrier to using the latter for household customers.

7. Metering investment and expenditure

Total investment and expenditure [118] in metering noticeably rose by a total of around €24m to €509m in 2016, with investment once again being distributed in a completely different way. Whereas investment in maintenance and renewal declined slightly in 2016, both investment in new installations, upgrades and expansion and expenditure increased vis-à-vis 2015.

Investment in new installations, upgrades and expansion made in 2016 lagged around 31% behind the planned values for 2016.Investment made in maintenance and renewal was around 42% below the investment predicted the previous year. The volume of expenditure, by contrast, was only around 4% less than the predicted values. The planned values for 2017 suggest there will be a sharp increase in investment and expenditure.

Only around €8m out of total investment of €509m in 2016 accounted for investment in smart metering systems and modern metering devices. The forecast for 2017 is for a sharp increase of this share to around €124m as illustrated in Figure 122 below.

[118] Definitions are provided in the section on Investment in the Networks Chapter (page 98 et. seq.).

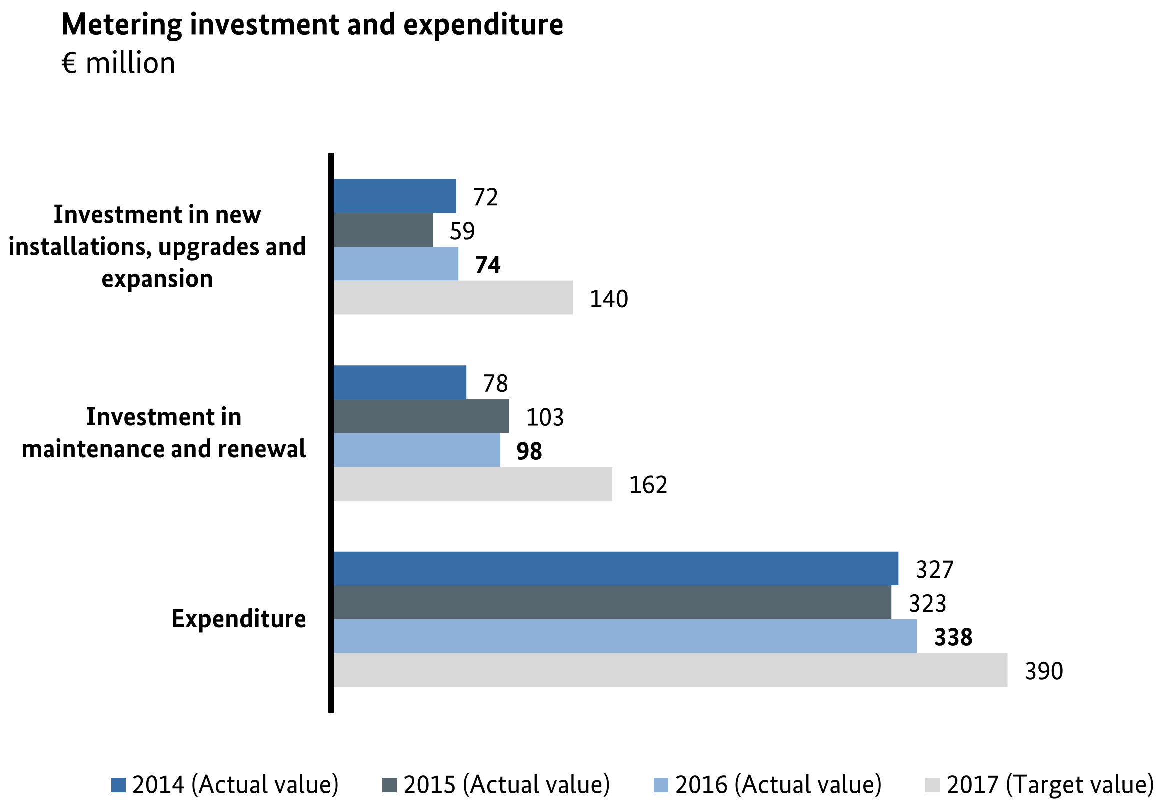


Figure 122: Metering investment and expenditure

8. Final consumer prices for metering systems

For the first time, meter operators were asked about the prices final consumers were charged for metering systems. The arithmetic average values of the prices indicated are outlined in Table 77. The prices for standard services as defined in section 35(1) of the Metering Act range on average between €78.39 and €374.25 per year depending on the final consumer group and capacity installed by meter operators.

The prices for voluntary installation within the meaning of section 29 in conjunction with section 31 of the Metering Act are illustrated in Table 78. Depending on the final consumer group, they vary, on average, between €23.62 and €49.73 per year.

Table 79 shows that final consumers are charged on average €20.12 per year for modern metering devices within the meaning of section 29 in conjunction with section 32 of the Metering Act.

Prices for standard services within the meaning of section 35 (1) of the Metering Act for the implementation of metering operation

Final consumers with annual power consumption	Price in €/year
> 6,000 kWh	78.39
> 10,000 kWh & ≤ 20,000 kWh	101.35
> 20,000 kWh & ≤ 50,000 kWh	134.19
> 50,000 kWh & ≤ 10,.000 kWh	165.96
> 100,000 kWh	374.25
Consumer devices within the meaning of section 14a EnW(	86.44
Installed capacity at plant operators in accordance with section 2 para 1 of the Metering Ac	**Price in €/year**
> 7 kW & ≤ 15 kW	82.28
> 15 kW & ≤ 30 kW	104.82
> 30 kW & ≤ 100 kW	172.25
> 100 kW	345.87

Table 77: Prices for standard services within the meaning of section 35(1) of the Metering Act for the implementation of metering operation

Prices for voluntary installation within the meaning of section 29 in conjunction with section 31 of the Metering Act

Final consumers with annual power consumption	Price in €/year
> 4,000 kWh ≤ 6,000 kWh	49.73
> 3,000 kWh ≤ 4,000 kWh	35.06
> 2,000 kWh ≤ 3,000 kWh	27.94
≤ 2,000 kWh	23.62

Table 78: Prices for voluntary installation within the meaning of section 29 in conjunction with section 31 of the Metering Act

Prices for voluntary installation of modern metering devices within the meaning of the Metering Act	Price in €/year
Modern metering device as defined in the Metering Act	20.12

Table 79: Prices for voluntary installation of modern metering devices within the meaning of the Metering Act

II. Gas market

A Developments in the gas markets

1. Summary

1.1 Production, imports and exports, and storage

In 2016, natural gas production in Germany fell by 0.7bn m^3 to 7.8bn m^3 of gas (with calorific adjustment).[119] This corresponds to a decline of 8.1% compared to the previous year. The decline in 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, calculated on the basis of the previous year's production and reserves, was 8.1 years as at 1 January 2017 (2016: 8 years).

The total volume of natural gas imported into Germany in 2016 was 1,626 TWh. Compared to the previous year's figure of 1,537 TWh, imports to Germany rose significantly by 89 TWh or about 6%. Imports from Norway dropped around 9%, while imports from Russia through the Nord Stream pipeline rose by 12.5%.

In 2016, the total volume of natural gas exported by Germany was 770.4 TWh. Compared to the previous year's figure of 746.3 TWh, exports from Germany rose by 3.2% to 24.2 TWh. About 46% of the natural gas exported by Germany went to Czechia although exports to the country were down 7.4% on the previous year. Exports to the Netherlands (+58.2%) and France (+24.7%) rose sharply, while there was a clear decrease in exports to Switzerland (-6.8%) and Austria (-10.9%).

The total maximum usable volume of working gas in underground storage facilities as at 31 December 2016 was 25.3bn Nm^3. About half of this was accounted for by cavern storage facilities and the other half by pore storage facilities. The volume of short-term (up to 1 October 2017) freely bookable working gas declined slightly, as did the capacities bookable for 2018. The volume of long-term bookable working gas from 2019 remained stable. Compared to previous years, the volume of long-term working gas that can be booked five years in advance increased again.

The storage year started with rather subdued levels of injections, with one reason certainly being natural gas prices during the period. Prices for supply in winter 2017/18 were in some cases lower than spot market prices, so many traders preferred futures over buying and injecting gas.

On 1 October 2017, at the beginning of the 2017/2018 gas year, the total storage level of German storage facilities was around 85% (2016: 95%). The high storage level of the previous year, which had been driven by prices, was not repeated, with a level of over 92% on 1 November 2017.

The market for the operation of underground natural gas storage facilities is relatively highly concentrated but less so than in the previous year. The cumulative market share at the end of 2016 of the three largest storage facility operators dropped markedly to 68.2% (previous year: 73.3%). This decline is largely due to the

[119] 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).

deconcentration in the storage market resulting from the takeover of VNG AG by EnBW AG during 2016. In the previous year, VNG AG had still been owned by EWE AG.

1.2 Networks

The first draft of the gas network development plan (NDP) 2016-2026 was presented to the Bundesnetzagentur by the transmission system operators (TSOs) on time on 1 April 2016. The TSOs submitted the second draft of the gas NDP 2016-2026 to the Bundesnetzagentur on 5 April 2017. It became necessary to draw up a second draft following a complaint procedure concerning the scenario framework underlying the gas NDP 2016-2016, which had been confirmed by the Bundesnetzagentur on 11 December 2015.

Taking the results of the consultation into account, the Bundesnetzagentur issued a request for modification to the TSOs on 26 July 2017 and as a result, 42 new measures have been added compared to the gas NDP 2015. These new measures mostly involve the market area conversion from low-calorific L-gas to high-calorific H-gas, the connection of new gas power stations and the diversion of gas from the planned Nord Stream expansion. With the request for modification, the Bundesnetzagentur confirmed 112 of the measures submitted by the TSOs, with an investment volume of approximately €3.9bn. The confirmed measures include an 822.6 km pipeline extension and a compressor expansion of 429 MW.

Five measures related to the Nord Stream expansion will not be included in the gas NDP 2016-2026 until the approvals for its construction have been obtained. The inclusion of these measures would bring the investment volume for the gas NDP 2016-2026 to €4.4bn. In addition, three measures had to be taken out of the gas NDP 2016-2026 as they were not yet detailed enough for the Bundesnetzagentur to assess and approve them. Two further measures are no longer necessary since the planning they are based on has been updated, according to the TSOs.

In 2016, investments in and expenditure on network infrastructure by the 16 German TSOs amounted to €753.2m (2015: €861.4m) (both values under commercial law).[120]

Total investments of €1.132bn are planned for 2017, corresponding to a year-on-year increase of 76%. This relatively high fluctuation is due to investments in large-scale, one-off projects. Investments and expenditure of distribution system operators (DSOs) amounted to €2,131m in 2016 (2015: €2,315m).

As in previous years, the Bundesnetzagentur conducted a comprehensive survey of all gas supply interruptions throughout the Federal Republic of Germany. The System Average Interruption Duration Index (SAIDI) determined from the results of this survey reflects the average duration of supply disruptions experienced by a customer over a period of one year and was 1.03 minutes in 2016 (2015. 1.699 minutes per year).

[120] Investments and expenditure are defined in the glossary. The values under commercial law do not correspond to the implicit values included in the system operators' revenue cap in accordance with the provisions of the Incentive Regulation Ordinance (ARegV). A comparative calculation of the values under commercial law with the values from incentive regulation will be able to be made following the introduction of an index-based investment monitoring pursuant to section 33(5) ARegV. Medium to long-term trends can be derived from the evaluations on the basis of the survey of commercial values. The introduction of an index-based investment monitoring pursuant to section 33(5) ARegV is currently being prepared by the Bundesnetzagentur taking account of the effort required for companies to transmit data.

The average volume-weighted network charge, including metering and meter operation charges, for household customers on default tariffs in consumption band II was 1.50 ct/kWh on 1 April 2017, remaining stable from the previous year.

Compared to 2015, the total quantity of gas supplied by general supply networks in Germany increased in 2016 by 75.6 TWh or nearly 9% to 941.3 TWh. The quantity of gas supplied to household customers (as defined in section 3 para 22 of the Energy Industry Act (EnWG)) rose by about 8% to 275.6 TWh. Reversing the trend of recent years, gas supplied to gas-fired power stations with a nominal capacity of at least 10 MW rose sharply to 94 TWh in 2016, 38% higher than in 2015 (68.2 TWh).

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) – ie not using the classic route via a supplier, and instead approaching the network operator as a shipper (paying the transport charges themselves) – amounted to 87.5 TWh, equivalent to nearly 48% 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 58.1 TWh, corresponding to a share of approximately 7.7% of the total supplied by the DSOs.

The conversion of German L-gas networks to supply H-gas started well in 2015 with the Schneverdingen conversion. This success continued in 2016 in the networks of Stadtwerke Böhmetal, Hilter, Rees, Nienburg/Weser, Gasversorgung Grafschaft Hoya, Gelsenwasser Energienetze (Isselburg, Landesbergen-Brokeloh), Stadtnetze Neustadt am Rübenberge, Achim and some parts of the wesernetz in Bremen. Approximately 114,000 appliances will have been adapted by the end of 2017.

The probable, planned costs of market area conversion were €5.5m for the NetConnect Germany (NCG) market area in 2016. For the GASPOOL market area, the planned costs amounted to about €18m for 2016. Both figures are purely projected costs from the network operators, without differences from previous years being included.

1.3 Wholesale

Liquid wholesale markets are vital to ensure well-functioning markets along the entire added-value chain in the natural gas sector, from the procurement of natural gas through to supplying end customers. The greater the variety of options for companies to procure gas for both the short and long term at the wholesale level, the less they are tied to a single supplier long-term. 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.

The volume traded on the spot market rose again in 2016 to about 295 TWh (2015: about 195 TWh). As in previous years, the focus of spot trading for both market areas in 2016 was on day-ahead contracts (NCG: 128.5 TWh, 2015: 76.8 TWh; GASPOOL: 51.1 TWh, 2015: 42.6 TWh). The futures trading volume rose from about 97 TWh in 2015 to about 130 TWh in 2016, corresponding to an around 34% increase. In 2016, natural gas transactions brokered by the broker platforms surveyed with Germany as the place of delivery amounted to a total of 3,120 TWh (2015: 2,652 TWh), of which 1,252 TWh was for contracts with delivery in 2016 (delivery time of at least one week).

The year 2016, much like the previous year, was marked by falling wholesale gas prices.[121] The annual average daily reference prices calculated by EEX fell by around 29% (2015: 6%), while the cross-border price, as calculated by the Federal Office for Economic Affairs and Export Control (BAFA), decreased on average by 25% (2015: 13%). The changes in the BAFA cross-border price over the course of 2016 indicates a correlation with exchange prices for natural gas.

1.4 Retail

An overall analysis of how household customers were supplied in 2016 in terms of volume shows that the majority of them (53%) were supplied by the local default supplier under a non-default contract (2015: 54%) and were delivered 128.3 TWh of gas (2015: 122.4 TWh). Nearly 22% of household customers had a default supply contract (2015: 24%) and were supplied with 52.8 TWh of gas (2015: 53.3 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 25.6% (2015: 22%) for 62.4 TWh of gas (2015: 50.8 TWh), making supply by the local default supplier under a default contract the least popular form of supply.

The gas sold to non-household customers is mainly to interval-metered customers. About 29% of the total volume delivered to these customers was supplied under a contract with the default supplier on non-default terms and some 71% under a contract with a legal entity other than the default supplier, which is the same distribution as in the previous year. The figures show that default supply is of only minor significance in the acquisition of non-household customers in the gas sector.

The total number of household customers changing contract was 780,000. The volume of gas these customers were delivered was approximately 16 TWh. The resulting numbers-based and volume-based switching rates are 6.5% and 6.6% respectively. The slightly higher volume-based switching rate is an indication that it is high-consumption household customers who tend to change contracts in order to gain cost advantages.

The number of household customers who switched supplier rose significantly yet again, by around 36% (+333,117 supplier switches) to 1,258,312 (2015: 925,195). There was also a clear rise of about 25% to 264,954 in the number of household customers who immediately chose an alternative supplier rather than the default supplier when moving home (+52,655 household customers). When looking at 12.4m household customers (according to DSO figures) the resulting number-based household customer switching rate comes out to 12.3% (2015: 9.2%).

The total volume of gas supplied to customers who switched supplier (including those switching when moving home) increased in 2016 by 11.6 TWh or 45% to 37.2 TWh. Considering the increase in gas supplied to household customers by network operators in 2016, the volume-based switching rate rose to 13.5% (2015: 10.1%). The volume-based supplier switching rate (13.5%) is still above the numbers-based rate (12.3%) because high-consumption household customers exhibit more intensive switching behaviour. At around 24,500 kWh, the calculated annual consumption of an average gas customer that switched supplier is above the national average of approx 20,000 kWh.

[121] 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.

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. A total of 103 TWh of gas consumed was affected by supplier switches, a rise of 11 TWh or 12% over the previous year.

The Monitoring Report 2017 deals with the concentration ratio (CR) of the four largest companies in the retail gas market for the first time, rather than the three largest as in the year before, because there is now another provider with a notable market share. The cumulative sales for the four largest companies to customers with standard load profile (SLP) was about 94 TWh in 2016, of which about 79 TWh was supplied under special contracts. Cumulative sales to interval-metered customers were about 126 TWh. The cumulative market share of the four largest companies in 2016 was around 25% for SLP customers (2015 CR3: 22%) and about 28% for interval-metered customers (2015 CR3: 29%). These two market shares remain well below the statutory thresholds for presuming market dominance. A decline in market concentration may therefore be identified in both areas, since the four largest companies now have a slightly higher market share of SLP customers than the three largest companies had the year before and around the same share of interval-metered customers.

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. This positive trend continued in 2016 as well. Consumers had more than 50 gas suppliers to choose from in nearly 90% of network areas. Final consumers in over 46% of network areas had a choice of more than 100 suppliers. It is clear that developments are similarly positive when focusing particularly on household customers. In 79% of network areas, household customers had a choice of 50 or more suppliers. In 30% of network areas, customers had a choice of more than 100 gas suppliers. On average, final consumers in Germany can choose between 105 suppliers in their network area; household customers can, on average, choose between 90 suppliers (these figures do not take account of corporate groups).

As at 1 April 2017 retail prices for gas fell again compared to a year earlier (1 April 2016).

The average price for household customers across all three 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 6% to 6.15 ct/kWh (including VAT) as at 1 April 2017 (1 April 2016: 6.54 ct/kWh).

The gas price for default supply dropped 3.7% to 6.73 ct/kWh (including VAT) as at 1 April 2017. The gas price for special contracts with the default supplier fell by 4.7% and was 6.07 ct/kWh (including VAT) on 1 April 2017. Gas prices under a contract with a supplier other than the regional default supplier decreased markedly, by 11% to 5.78 ct/kWh (inc VAT) as at 1 April 2017, reaching the lowest level since the first survey as at 1 April 2008.

A look at the household customer gas prices over the past eleven years (2006-2017) 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. The price paid by default supply customers has increased by just under 10% over the past ten years up to 1 April 2017.

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 6.07 ct/kWh between 2007 and 2017. Overall, the gas price for customers with a special contract with the default supplier (after change of contract) has fallen by almost 3% over the last ten 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 5.78 ct/kWh between 2008 and 2017. Overall, the gas price for customers in this category has fallen significantly over the past nine years, by nearly 10%, and reached a historic low as at 1 April 2017. This type of contract is the most affordable supply contract for customers with average consumption (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 stable gas prices that have seen further clear drops this year. The difference between the most expensive and the most affordable contract for an average customer (band II) was 0.49 ct/kWh in 2008. By contrast, it was 0.95 ct/kWh in 2017. The incentive to switch from default supply to a more affordable contract therefore increased in the review period.

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 and margin", it is notable that this price component for customers with a supplier other than the regional default supplier hit the lowest point since the survey was started at 2.7 ct/kWh. Moreover, the price component "energy procurement, supply and margin" for default supply customers was 3.35 ct/kWh on 1 April 2017, 6.4% lower than in the first survey in 2007. There was an even greater drop in this component for customers with a non-default contract with their default supplier (3.01 ct/kWh as at 1 April 2017).

Customers on default tariffs can make savings by switching tariff or supplier. The average household customer with gas consumption of 23,250 kWh could save an average of €153 a year as at 1 April 2017 by changing contract. The average potential saving for the year from changing supplier was €221.

In addition, special bonuses offered by gas suppliers, including one-off bonus payments, are an added incentive for customers to switch supplier. Such one-off bonuses average €65 for customers on non-default terms in a contract with the default supplier and €75 for customers under contract with a supplier other than the local default supplier.

Gas prices for non-household (industrial/commercial) customers fell again. The average overall price (excluding VAT) for an annual consumption of 116 GW/h ("industrial customer") was 0.08 ct/kWh lower at 2.69 ct/kWh, slightly lower (around 3%) than the previous year's figure of 2.77 ct/kWh. The average gas price was therefore the lowest ever since the first data on gas prices (as at 1 April 2008) was collected for monitoring reports. The arithmetic mean of the overall price (excluding VAT) for an annual consumption of 116 MW/h ("commercial customer") of 4.50 ct/kWh is 0.27 ct/kWh or around 5% lower than last year's price. Components of the overall price that are not under the control of the supplier (in particular, network charges and levies) both remained more or less stable compared to the previous year.

The number of disconnections carried out by DSOs on behalf of the regional default supplier fell to 38,576, which represents a drop of nearly 12% year-on-year or around 5,000 disconnections. Additionally, 1,260 gas disconnections were carried out on behalf of suppliers other than the regional default supplier.

In 2016, gas DSOs restored supply to around 30,633 customers whom they had previously disconnected on behalf of the default supplier. The decline in restored meter points, of about 5,300 meter points compared to the year before, is largely due to the general decrease in gas disconnections. Supply was also restored to about 1,486 meter points on behalf of gas suppliers other than the regional default supplier.

Compared to the previous year, the number of disconnection notices issued by all gas suppliers (1,845,550) remained almost steady (-0.1%). Compared to 2015, the number of disconnection orders fell by 4.3% to 272,135. Around 14% of the 1.8m disconnection notices issued by gas suppliers (both default and non-default) resulted in a disconnection subsequently being ordered from the DSO in 2016.

According to the gas suppliers, 39,004 disconnection orders (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, equivalent to a decline of around 4,000 disconnections on the year before. A comparison of the number of disconnection notices issued with the number of disconnections actually carried out makes it clear that about 2.1% of the notices issued actually resulted in a disconnection being carried out by the DSO. Additionally, gas suppliers indicated that they disconnected customers with a default contract 26,707 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 12,297 times. The disconnection rate for non-default customers was 0.2%.

German household customers paid slightly more than the European average for gas, while non-household customers paid significantly more. The net gas price in the consumption range 27.8 to 278 GWh/year ("industrial customer") is 2.64 ct/kWh, which is at the upper end of the scale. The EU average is 2.40 ct/kWh. On average, approximately 10% of the net price in Europe (0.24 ct/kWh) is made up of non-recoverable taxes and levies, whereas in Germany it is higher at about 15% (0.40 ct/kWh). Unlike in the industrial customer sector, there are major differences in gas prices for household customers across Europe. The gas price level for household customers in Germany (6.42 ct/kWh) is only slightly above the EU average (6.36 ct/kWh).

2 Network overview

All 16 TSOs took part in the 2017 Monitoring Report data survey. The total length of the gas transmission network was 38,759 km on 31 December 2016 and included 3,499 exit 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 customer meter points in the transmission network was 568. 183 TWh of gas was delivered to final consumers from the DSO network, which is 23.6 TWh or 14.8% less than the previous year.

As of 10 November 2017, a total of 717 gas DSOs were registered with the Bundesnetzagentur, 696 of whom took part in the 2017 monitoring survey as of 31 July 2017. As of 31 December 2016, the total length of pipelines in the gas distribution network was 497,429 km and included 10.8m exit 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 2016, 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 758.3 TWh in 2016, up by 52 TWh or just around 7% compared to the previous year. The quantity of gas supplied to household customers as defined in section 3 para 22 EnWG rose by 21 TWh or 8% to 275.6 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 total amount of gas entering the German network was 1,712 TWh in 2016. Around 4.5% came from domestic sources (76.5 TWh), the rest (1,626 TWh) was imported. The balance of gas that entered and exited storage in 2016 amounted to 1.6 TWh, with more gas being withdrawn from the storage facilities than injected into them. Moreover, 9.4 TWh of biogas upgraded to natural gas quality was fed into the German natural gas network in the year.

Around 45% (770.4 TWh) of available gas volumes in Germany was transported to neighbouring countries in Europe. Final consumers used 941.3 TWh of gas in Germany.

Gas available and gas use in Germany in 2016

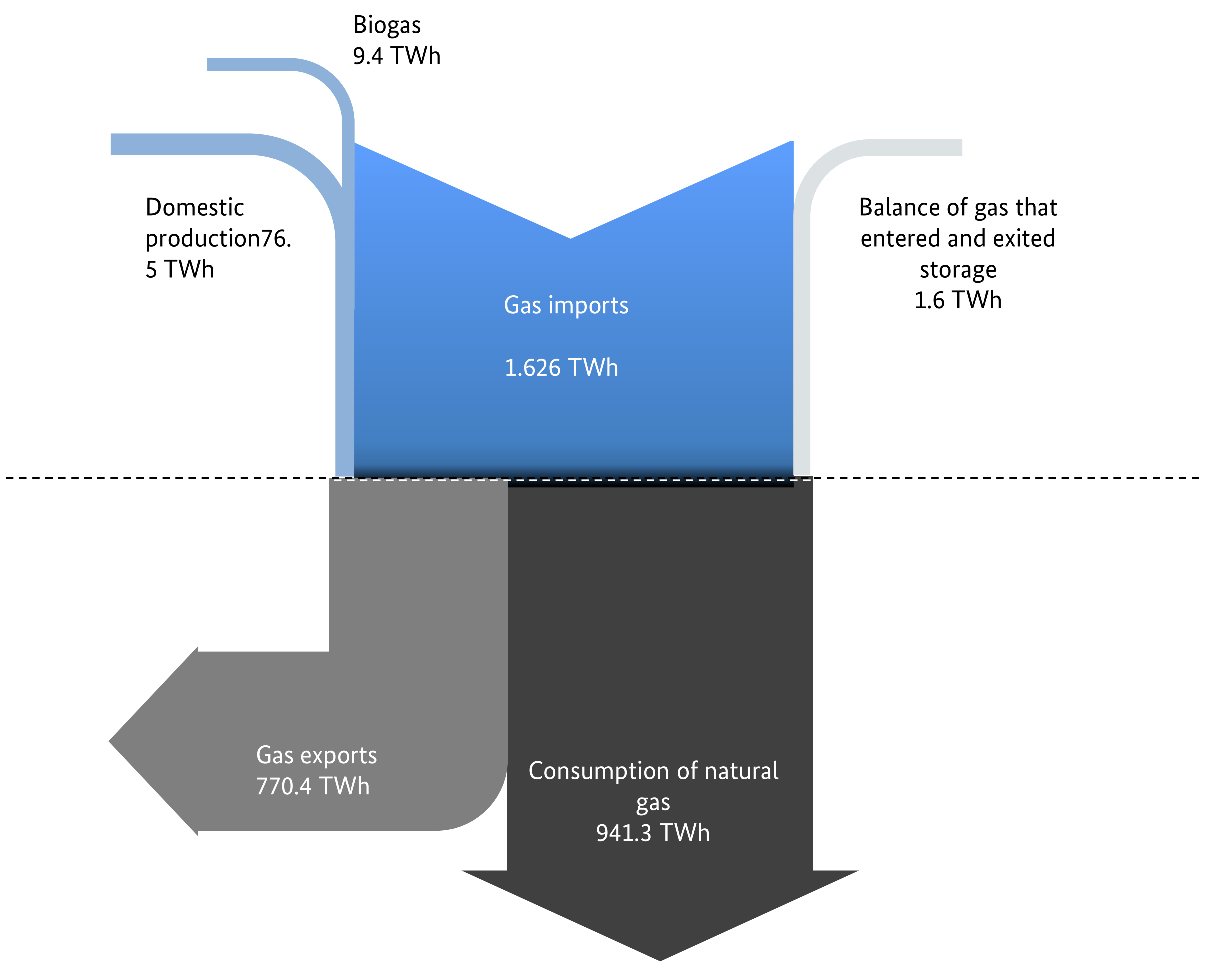


Figure 123: Gas available and gas use in Germany in 2016

Number of gas network operators in Germany registered with the Bundesnetzagentur

	2009	2010	2011	2012	2013	2014	2015	2016	2017
Transmission system operators (TSOs)	18	18	14	17	17	17	17	16	16
Distribution system operators (DSOs)	712	712	711	739	724	714	714	715	717
DSOs with fewer than 100,000 connected customers	667	671	678	683	686	689	689	690	692

Table 80: Number of gas network operators in Germany registered with the Bundesnetzagentur as at 7 November 2017

Gas network operators were asked about the total length of their networks, as well as the length subdivided according to pressure ranges (nominal pressure in bar). The findings from the operators surveyed are shown in Table 81.

The majority of gas DSOs (605 operators) have short to medium length networks of up to 1,000 km. Of the remainder, 78 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:

DSOs according to gas pipeline network length
number of network operators and share of total

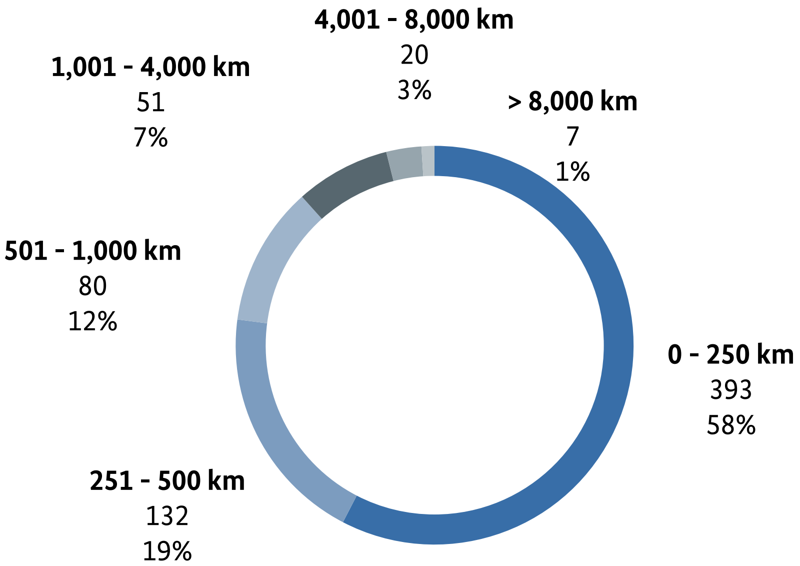


Figure 124: DSOs according to gas pipeline network length as stated in the DSO survey – as at 31 December 2016

2016 network structure figures

	TSOs	DSOs	DSOs with > 100,000 customers	DSOs with < 100,000 customers	Total no of TSOs and DSOs
Network operators	16	696	25	671	712
Network length (in km)	38,759	497,429	229,169	268,260	536,188
≤ 0.1 bar	0	156,053	50,302	105,751	156,053
> 0.1 – 1 bar	1	240,527	142,974	97,553	240,528
> 1 bar	38,758	100,850	35,893	64,957	139,608
Number of offtake points	3,499	10,812,254	4,483,802	6,328,452	10,815,753
≤ 0.1 bar	0	5,758,221	1,668,429	4,089,792	5,758,221
> 0.1 – 1 bar	13	4,412,595	2,597,124	1,815,471	4,412,608
> 1 bar	3,486	641,438	218,249	423,189	644,924
Final consumers (meter points)	568	14,486,778	6,228,633	8,258,145	14,487,346
Industrial and commercial customers and other non-household customers	509	2,070,407	631,051	1,439,356	2,070,916
Household customers	0	12,416,171	5,597,525	6,818,646	12,416,171
Gas-fired power plants with a net electricity capacity of at least 10 MW	59	201	57	144	260

Table 81: 2016 network structure figures according to the TSO and DSO survey – as at 31 December 2016

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 2016.

Gas exit volumes in 2016 broken down by final consumer category, according to the survey of gas TSOs and DSOs

	TSO exit volume (TWh)	Share of total amount	DSO exit volume (TWh)	Share of total amount
≤ 300 MWh/year	0.002	0.001%	340.0	44.8%
> 300 MWh/year ≤ 10,000 MWh/year	0.6	0.3%	129.5	17.1%
> 10,000 MWh/year ≤ 100,000 MWh/year	6.7	3.7%	104.9	13.8%
> 100,000 MWh/year	130.8	71.5%	134.9	17.8%
Gas-fired power plants with ≥ 10 MW net nominal capacity	44.9	24.5%	49.0	6.5%
Total	183.0	100%	758.3	100.0%

Table 82: Gas exit volumes in 2016 broken down by final consumer category, according to the survey of gas TSOs and DSOs

The following consolidated overview includes the total quantity of gas provided to final consumers by TSOs, DSOs and suppliers for 2016. Once again, gas TSOs and DSOs were asked in the 2017 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 87.5 TWh, equivalent to just under 48% 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 58.1 TWh, corresponding to a share of approximately 7.7% of the total supplied by the DSOs.

Total gas exit volumes in 2016, 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 exit volume (TWh)	Share of total amount	Total volume of gas delivered by suppliers in TWh	Share of total amount
≤ 300 MWh/year	340.0	36.1%	318.8	38.5%
> 300 MWh/year ≤ 10,000 MWh/year	130.1	13.8%	117.5	14.2%
> 10,000 MWh/year ≤ 100,000 MWh/year	111.6	11.9%	105.5	12.7%
> 100,000 MWh/year	265.7	28.2%	218.2	26.4%
Gas-fired power plants with ≥ 10 MW net nominal capacity	93.9	10.0%	67.7	8.2%
Total	941.3	100.0%	827.7	100.0%

Table 83: Total gas exit volumes in 2016, according to the survey of gas TSOs and DSOs and total volumes of gas delivered according to gas supplier survey

Compared to 2015, the total quantity of gas supplied by general supply networks in Germany increased in 2016 by 75.6 TWh or nearly 9% to 941.3 TWh. The quantity of gas supplied to household customers (as defined in section 3 para 22 EnWG) rose by about 8% to 275.6 TWh. Reversing the trend of recent years, gas supplied to gas-fired power stations with a nominal capacity of at least 10 MW rose sharply to 94 TWh in 2016, 38% higher than in 2015 (68.2 TWh).

The structure of the gas retail market remained for the most part unchanged. There is a total of 6,255 entry points to the gas distribution networks, of which 217 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 14.3m meter points supplied by the DSOs in Germany, some 43% (6.2m), accounting for 43% (323 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.

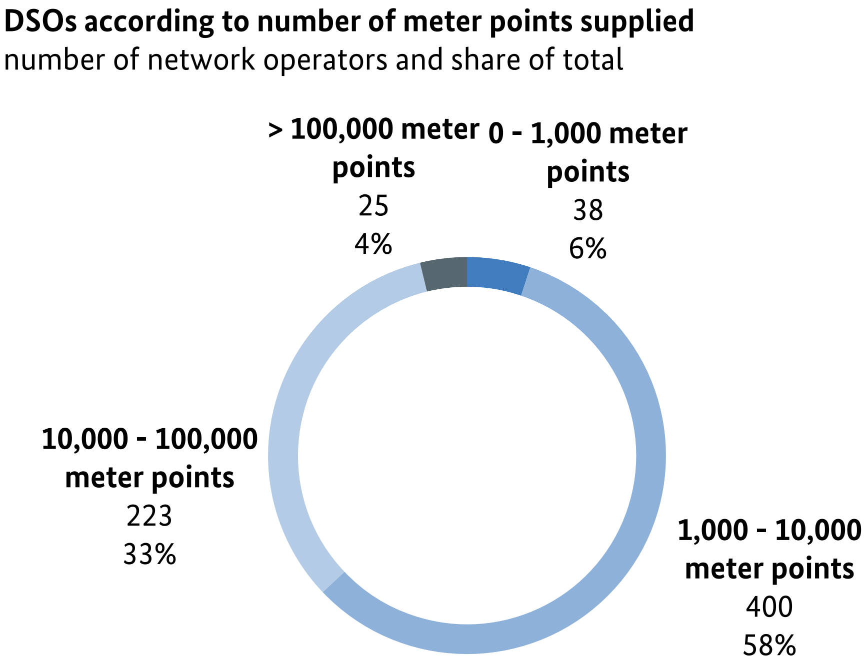


Figure 125: DSOs according to number of meter points supplied (data from the gas DSO survey) – as at 31 December 2016

3. Market concentration

The degree of market concentration is an important indicator of the intensity of competition. Market shares are a useful reference point for estimating market power. They represent the extent to which demand in the relevant market was actually satisfied by one company during the reference period.[122] To represent the market share distribution, i.e. the market concentration, this report uses CR3 values or CR4 values (known as "concentration ratio", i.e. the sum of the market shares of the three or four 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 that includes both porous rock and cavern storage facilities. In geographical terms, the Bundeskartellamt has defined this market as a national market and in the process also considered including the "Haidach" and "7Fields" storage facilities in Austria.[123] These two storage facilities are located near the German border in Austria and are connected directly or indirectly to the German gas networks. The European Commission also recently considered this alternative market definition – and a number of other alternatives – and ultimately left open the exact market definition.[124] The Haidach and 7Fields storage facilities in Austria will be fully included in the following assessment to illustrate the concentration in the

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

[123] Cf. Bundeskartellamt, Decision of 23 October 2014, B8-69/14 – EWE/VNG, para. 215 ff. (in German), Bundeskartellamt, Decision of 31 January 2012, B8-116/11 – Gazprom/VNG, para. 208 ff. (in German)

[124] Cf. COMP/M.6910 – Gazprom/Wintershall of 3 December 2013, para. 30 ff.

market for the operation of underground natural gas storage facilities. The Bundeskartellamt calculates the market shares in this market on the basis of storage capacities (maximum usable working gas volume).[125]

This year's survey, which isbased on a questionnaire sent out to 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 of 31 December 2016. The storage facility operators comprise a total of 24 legal entities. Companies were attributed to a group according to the dominance method (cf. the methodological notes in section I Electricity market, A 3. Market concentration, p. 40).

The market for the operation of underground natural gas storage facilities is characterised by a high level of concentration. However, this concentration declined compared to the previous year. The maximum usable working gas volume of the underground natural gas storage facilities connected to the German gas network and analysed in the course of monitoring, which included Haidach and 7Fields, was around 26.9bn Nm³ on 31 December 2016 compared to 27.6bn Nm³ in the previous year. One of the reasons behind the reduction in the working gas volume was the decommissioning process affecting two pore storage facilities (-0.15bn Nm³) in Lower Saxony and Brandenburg. The 'Epe NL' cavern facility in the Netherlands was excluded from market monitoring because it is connected only to the Dutch network and is consequently no longer of any significance to the German market (-0.31bn Nm³).

The aggregate working gas volume of the three companies with the largest storage capacities was around 18.4bn Nm³ on 31 December 2016 compared to 20.2bn Nm³ in the previous year. The CR3 value therefore fell from around 73.3 per cent to around 68.2 per cent. The decline is largely due to the takeover of VNG AG by EnBW AG in the reporting year, which had a deconcentrating effect on the storage sector.[126] In the previous reporting year, VNG AG was still owned by EWE AG.

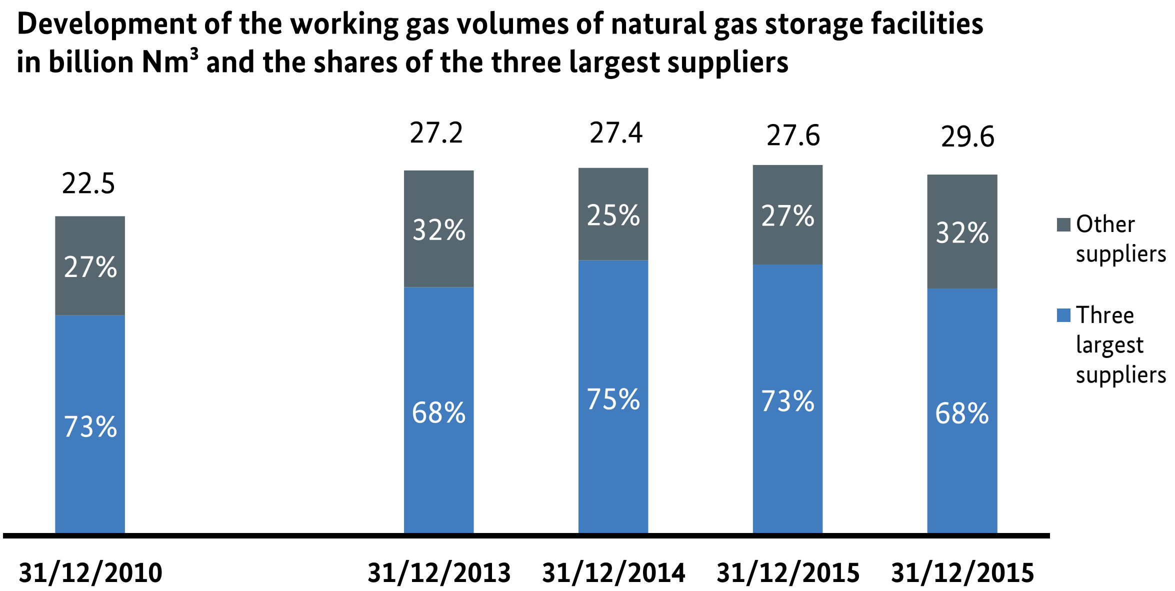


Figure 126: Development of the working gas volumes of natural gas storage facilities in billion Nm³ and the shares of the three largest suppliers

[125] Cf. Bundeskartellamt, Decision of 23 October 2014, B8-69/14 – EWE/VNG, para. 236 ff. (in German)

[126] Cf. Bundeskartellamt, Proceedings B8-137/15

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 those whose gas consumption is determined on the basis of a recording load profile measurement. They are generally industrial or large-scale commercial customers and gas-fired power plants. Standard load profile customers are those with relatively low levels of gas consumption and usually include household customers and smaller commercial customers. The distribution of their gas consumption over specific time intervals is based on a standard load profile. 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 under special contracts as national markets (cf. section I Electricity market, A 3.2 Electricity retail markets, p. 45 ff.). The supply of gas to standard load profile customers under a default supply contract is a separate product market which continues to be defined according to the relevant network area[127].

In energy monitoring, the sales volumes of the individual suppliers (legal entities) 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 under special contracts. The following analysis is based on the data provided by around 995 gas suppliers (legal entities) (930 in the previous year). In 2016, these companies sold around 371 TWh of gas to standard load profile customers (348 TWh in the previous year) and around 453 TWh of gas to customers with metered load profiles (411 TWh in the previous year) across Germany. In accordance with the Bundeskartellamt's approach to market definition, sales to customers with metered load profiles also include sales to gas-fired power plants. Of the total volume of sales to standard load profile customers, special contracts accounted for around 309 TWh (284 TWh in the previous year) and default supply contracts for 62 TWh (64 TWh in the previous year).

Sales volumes were attributed to company groups on the basis of the dominance method which provides sufficiently accurate results for the purposes of this report (cf. methodological notes in section I Electricity market, A 3. Market concentration, p. 40).

The Monitoring Report for 2017 for the first time analysed the market concentration (CR) of the four (three in the previous year) strongest companies on the gas retail market because another supplier with a significant market share has entered the market. The total cumulative sales of the four strongest companies to customers with standard load profiles amounted to around 94 TWh in 2016, of which some 79 TWh consisted of special contracts. Cumulative sales to customers with metered load profiles were around 126 TWh. In 2016, the aggregated market share of the now four strongest companies therefore amounts to about 25 per cent for customers with a standard load profile contract (22 per cent for the previous year's CR3) and about 28 per cent for customers with metered load profiles (29 per cent for the previous year's CR3). Both market shares continue to be significantly below the statutory thresholds for the presumption of market dominance (Section 18(6) GWB). Against this background, market concentration was found to decline in both areas because the now four (instead of previously three) strongest companies account for a slightly higher (standard load profile customers) or roughly the same (metered load profile customers) cumulative market share compared to the previous year. With regard to the data on percentages, it should be noted that the monitoring survey among gas suppliers improved again because of the higher number of suppliers taking part, but does not cover the whole market. The percentages consequently merely approximate the actual values.

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[127] Cf. Bundeskartellamt, Decision of 23 December 2014, B8-69/14 – EWE/VNG, para. 129-214 (in German).

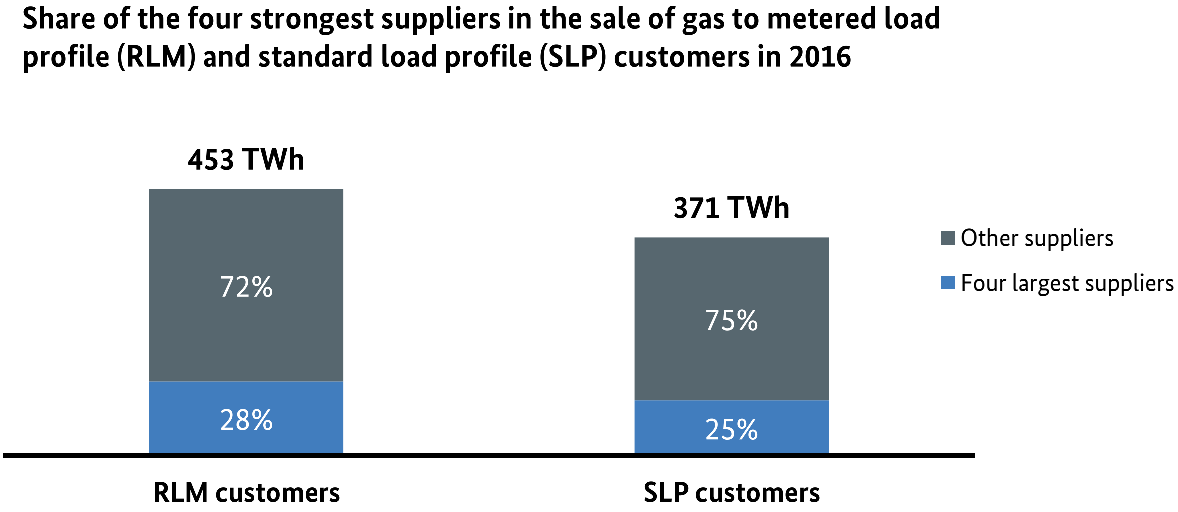


Figure 127: Share of the four strongest suppliers in the sale of gas to metered load profile (RLM) and standard load profile (SLP) customers in 2016

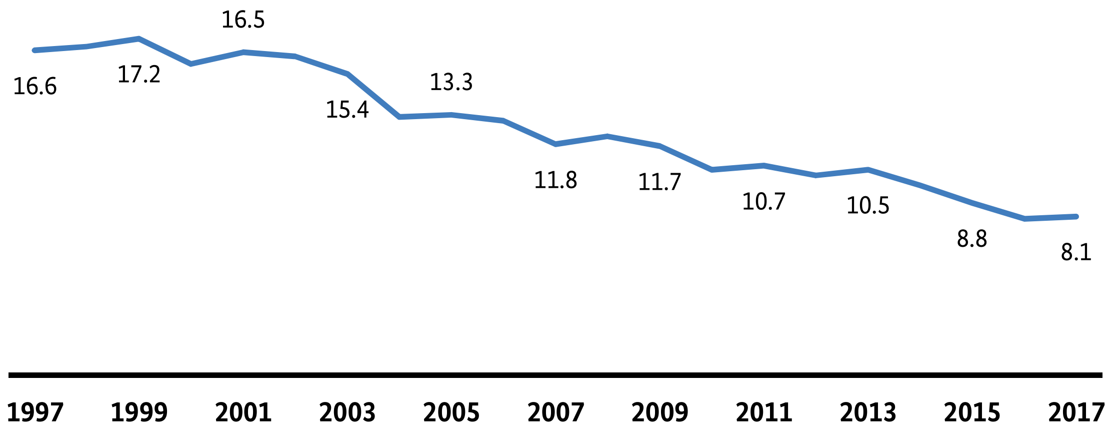
B. Gas supplies

1. Production of natural gas in Germany

In 2016, natural gas production in Germany fell by 0.7bn m^3 to 7.8bn m^3 of gas (with calorific adjustment).[128] This corresponds to a decline of 8.1% 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.[129] Another factor is the lack of major new gas finds. Consequently, Germany was able to cover only 8.3% of its own consumption through domestic gas production in 2016 (Working Group on Energy Balances (AGEB) 2017).

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 8.1 years as of 1 January 2017, compared to 8 years as of 1 January 2016. 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.[130]

Reserves-to-production ratio of German natural gas reserves
(years)



Source: State Authority for Mining, Energy and Geology (LBEG), Lower Saxony

Figure 128: Reserves-to-production ratio of German natural gas reserves (since 1997)

[128] 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).

[129] Source: Annual report "Erdöl- und Erdgasreserven in der Bundesrepublik Deutschland am 1. Januar 2017" [Crude Oil and Natural Gas Reserves in the Federal Republic of Germany as at 1 January 2017]; State Authority for Mining, Energy and Geology (LBEG), Lower Saxony.

[130] Ibid.

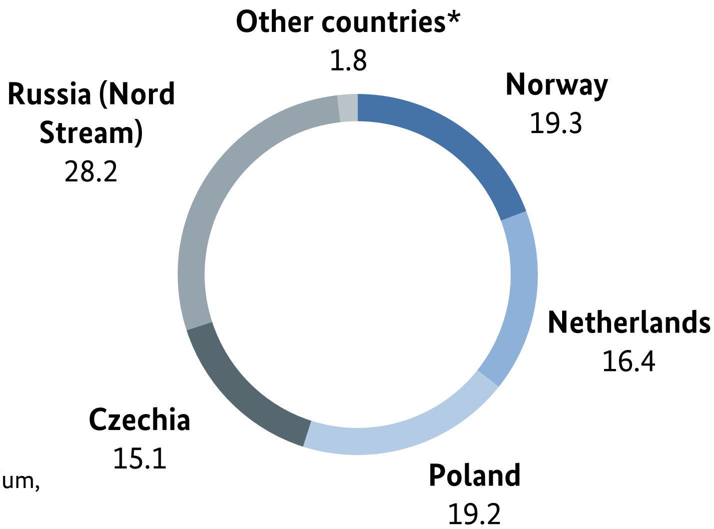
2. Natural gas imports and exports

The monitoring report 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 2016, the total volume of natural gas imported into Germany was 1,626 TWh. Based on the previous year's figure of 1,537[131] TWh, imports to Germany increased by 89 TWh, a rise of slightly more than 6%. 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 Norway decreased by just over 9%, while imports from Russia through the Nord Stream pipeline rose by 12.5%.

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.

Gas volumes imported to Germany in 2016, according to exporting country
(%)



* Other countries: Belgium, Denmark, Austria

Figure 129: Gas volumes imported to Germany in 2016, according to exporting country

In 2016, the total volume of natural gas exported by Germany was 770.4 TWh. Compared with the previous year's figure of 746.3 TWh, exports from Germany rose by 24.2 TWh (3.2%). When looking at the destination countries, the focus here is on the countries that Germany exports to at their given cross-border transfer point. Around 46% of German natural gas exports went to Czechia, a decrease of 7.4% compared to the

[131] The figure shown in the 2015 monitoring report (1,534 TWh) had to be corrected retrospectively to 1,537 TWh because of a late addition to the data.

previous year's figures. Exports to the Netherlands and France rose sharply (+58.2% and +24.7% respectively), while there was a large decrease in exports to Switzerland (-16.8%) and Austria (-10.9%).

Gas volumes exported by Germany in 2016, according to importing country (%)

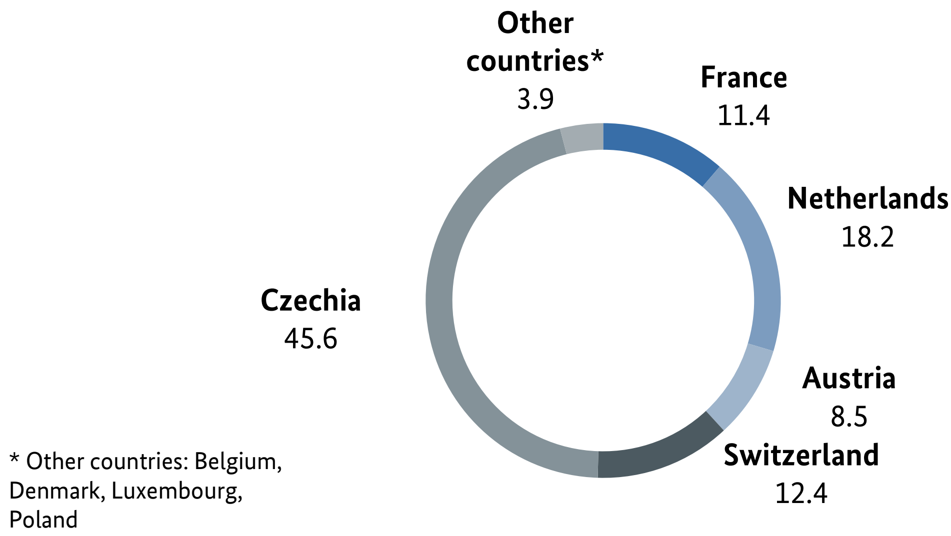


Figure 130: Gas volumes exported by Germany in 2016, according to importing country

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 2016 and 2015.

Change in gas imports

Exporting country	Imports in 2016 (TWh)	Imports in 2015 (TWh)	Year on year change (TWh)	Year on year change (%)
Russia (Nord Stream)	458.9	408.1	50.8	12.5
Norway	314.3	345.1	-30.9	-8.9
Poland	312.7	302.6	10.1	3.3
Netherlands	266.1	253.5	12.6	5.0
Czechia	245.3	185.5	59.8	32.2
Austria	11.9	14.8	-2.9	-19.6
Belgium	10.1	20.7	-10.7	-51.5
Denmark	6.7	6.6	0.1	1.4
Total	1,626.0	1,537.0	89.0	5.8

Table 84: Change in gas imports between 2016 and 2015

Change in gas exports

Importing country	Exports in 2016 (TWh)	Exports in 2015 (TWh)	Year on year change (TWh)	Year on year change (%)
Czechia	351.5	379.8	-28.3	-7.4
Netherlands	140.2	88.6	51.6	58.2
Switzerland	95.3	114.5	-19.2	-16.8
France	87.6	70.2	17.3	24.7
Austria	65.6	73.6	-8.0	-10.9
Belgium	20.4	6.4	13.9	216.3
Poland	5.1	8.1	-3.0	-37.3
Luxembourg	2.7	3.7	-1.0	-27.5
Denmark	2.1	1.2	0.9	74.8
Total	770.4	746.3	24.2	3.2

Table 85: Change in gas exports between 2016 and 2015

According to the survey of gas suppliers and wholesalers there are 26 companies importing gas into Germany.

3. Biogas

Key biogas injection figures as of 31 December 2016 are as follows:

Biogas injection key figures

	Unit	2012	2013	2014	2015	2016
Number of facilities injecting biogas (of which facilities injecting hydrogen or synthesis gas)		108	144	185	190	210 (6)
Volume of biogas injected (of which hydrogen or synthesis gas injected)	m Ncm	413	520	688	774	856 (1.0)
Volume of biogas injected (of which hydrogen or synthesis gas injected)	m kWh	4,393	5,471	7,489	8,364	9,222 (4.8)
Ancillary costs of the gas network operators passed down to all network users	€m	107	131	154	178	172
Ancillary costs per kWh biogas injected	ct/kWh	2.436	2.394	2.056	2.124	1.865

Table 86: Biogas injection, key figures for 2012-2016

C. Networks

1. Network expansion

1.1 Gas Network Development Plan

The gas network development plan (Gas NDP) 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 (in even-numbered years).

The content of the Gas NDP 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 first draft of the Gas NDP 2016-2026 was presented to the Bundesnetzagentur by the TSOs within the specified period on 1 April 2016. The TSOs submitted the second draft of the Gas NDP 2016-2026 to the Bundesnetzagentur on 5 April 2017. This second draft had to be prepared following a complaints procedure, which was directed against the Bundesnetzagentur's official confirmation (from 11 December 2015) of the scenario framework that formed the basis of the Gas NDP 2016-2026. The complaints procedure had been launched because two gas-fired power plant projects, one in Altbach and one in Heilbronn, had not been taken into account; both are now included in the Gas NDP 2016-2026. The second draft of the Gas NDP 2016-2026 is based on the partial new decision on the scenario framework adopted by the Bundesnetzagentur on 3 January 2017. Like the first draft, the second draft of the Gas NDP 2016-2026 was submitted for consultation by the Bundesnetzagentur.[132]

Taking the results of the consultation into account, the Bundesnetzagentur formulated a modification request addressed to the TSOs on 26 July 2017.

Compared with the Gas NDP 2015, 42 new measures have been added. The new measures primarily concern the market area conversion from low-calorific L-gas to high-calorific H-gas, the connection of new gas-fired power plants and the delivery of gas from the planned Nord Stream extension.

In the modification request, the Bundesnetzagentur confirms 112 of the measures submitted by the TSOs, with an investment volume of around €3.9bn. The confirmed measures include line extension totalling 822.6 km and increased compressor capacity amounting to 429 MW.

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[132] The results of the consultations are available on the Bundesnetzagentur website (in German): https://www.bundesnetzagentur.de/SharedDocs/Downloads/DE/Sachgebiete/Energie/Unternehmen_Institutionen/NetzentwicklungUndSmartGrid/Gas/NEP_2016/NEP_Gas_2016_Konsultationsergebnisse.pdf?__blob=publicationFile&v=2

Five measures connected to Nord Stream 2 will not be incorporated into the Gas NDP 2016-2026 until after approval for the construction of Nord Stream 2 has been granted. These measures would increase the Gas NDP 2016-2026 investment volume to a total of €4.4bn.

In addition, three measures do not yet have the degree of specification required for examination and approval by the Bundesnetzagentur and must therefore be removed from the Gas NDP 2016-2026. According to the TSOs, a further two measures are no longer necessary on the basis of plans that have since been updated.

Furthermore, the Bundesnetzagentur instructs the TSOs to include an additional investment project in the Gas NDP 2016-2026. In the Bundesnetzagentur's view this project fulfils the criteria for an NDP measure, and should therefore have been included in the TSOs' expansion proposal.

In order to prepare the next Gas NDP 2018-2028, the German TSOs published the scenario framework for the Gas NDP 2018-2028 on 19 June 2017 and consulted on it until 14 July 2017.[133] The TSOs revised the draft and submitted the revised version to the Bundesnetzagentur for approval on 11 August 2017.

1.2 2017 Implementation Report

On 31 March 2017 the TSOs published the first gas network development plan (Gas NDP) implementation report. As of 2017, the implementation report must be drawn up in every year that ends in an odd number. In accordance with section 15b Energy Industry Act (EnWG) the report must contain information on the implementation status of the most recently published network development plan and, in the event of delayed implementation, the main reasons for such delays. The document presented on 31 March 2017 was submitted for comprehensive consultation by the Bundesnetzagentur.[134] The comments suggest that the market would like future reports to include a more detailed description containing more information on the respective implementation status of the expansion measures, such as milestones in the planning of individual projects, information on reasons for delays and, above all, information on the timing of the provision of capacity.

The implementation report produced by the TSOs lists the confirmed measures in the gas NDP 2015 and also measures in the second consultation document on the Gas NDP 2016-2026, in total 132 measures. The TSOs have updated an overview of the implementation status of the individual measures which had previously been included in the Gas NDP.

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[133] https://www.bundesnetzagentur.de/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/NetzentwicklungundSmartGrid/Gas/NEP_Gas2018/Szenariorahmen2018/NEPGas_Szenario2018_node.html

[134] Consultation results: https://www.bundesnetzagentur.de/EN/Areas/Energy/Companies/GridExpansion/Gas/ImplementationReport/ImplementationReport_node.html

Confirmed network expansion measures Gas NDP 2016-2026

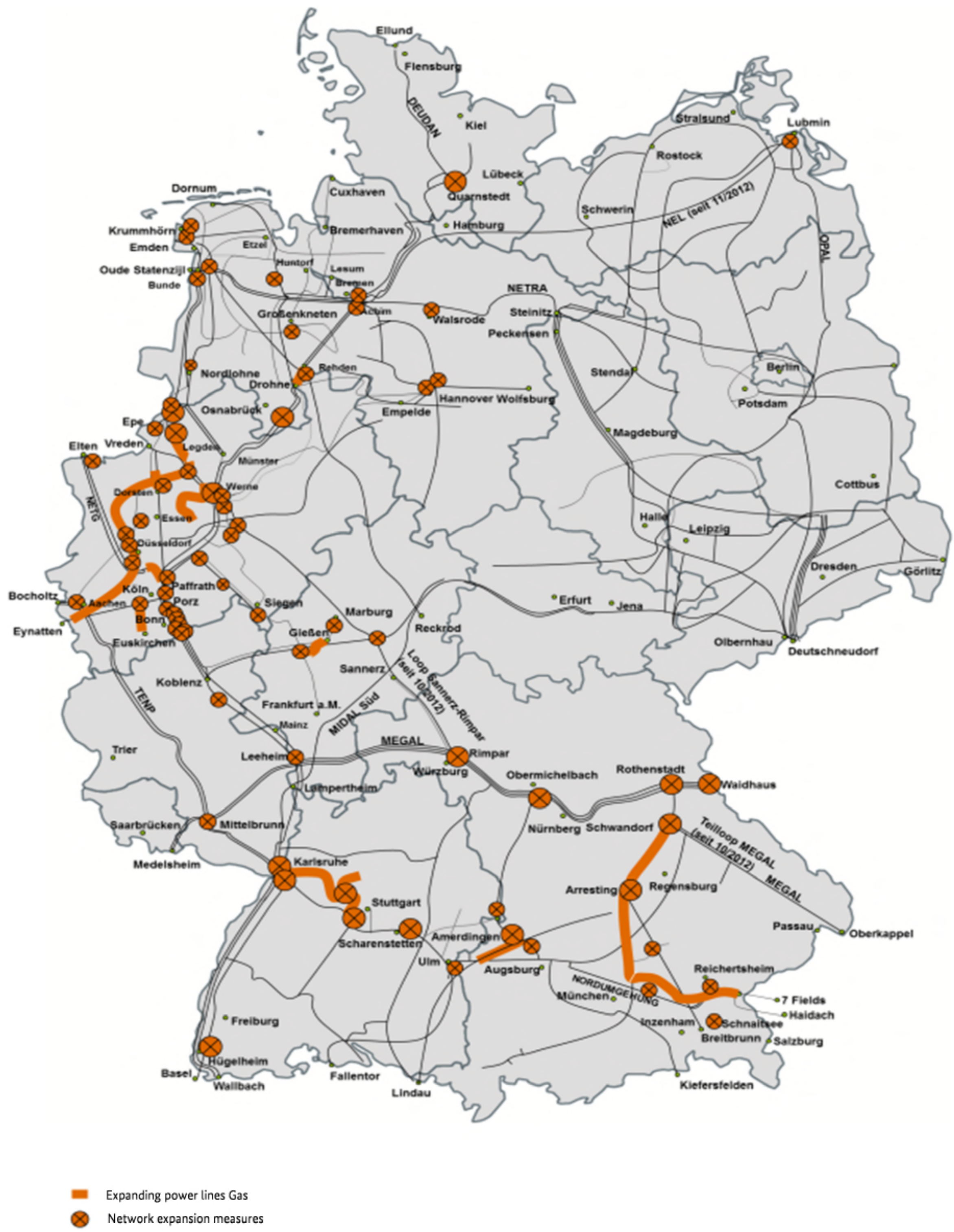


Figure 131: Confirmed network expansion measures Gas NDP 2016-2026

2. Investments

Investments as defined in the monitoring survey are considered to be gross additions to fixed assets capitalised in 2016 and the value of new fixed assets newly rented in 2016. 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 as listed in the respective company balance sheets. The figures supplied under commercial law do not correspond to the imputed values included in the calculation of the TSOs' revenue caps using the system prescribed in the Incentive Regulation Ordinance (ARegV). Introducing indicator-based investment monitoring according to section 33(5) ARegV will make it possible to carry out comparative calculations using the figures supplied under commercial law and those derived from the incentive-based regulation. The figures supplied under commercial law can also be used to extrapolate medium- to long-term trends. The Bundesnetzagentur is currently making preparations to introduce indicator-based investment monitoring according to section 33(5) ARegV while considering, among other issues, the cost of data transmission for companies.

2.1 Investments in and expenditure on network infrastructure by TSOs

In 2016 the 16 German TSOs invested a total of €469.9m (2015: €495.9m) in network infrastructure. Of this total, €422.4m (2015: €340.7m) was investment in new installations/expansion/extension and €47.5m (2015: €155.2m) investment in maintenance/renewal of network infrastructure. Of the total investments in 2016, 22% can be attributed to the transmission systems in the GASPOOL market area and 78% to the NCG market area (2015: 48% GASPOOL, 52% NCG). The investments planned for 2017 amount to a total of €1.132bn, which would equate to an increase of 76% compared to 2016. 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 €283.3m in 2016 (2015: €365.5m), of which 48% was applicable to the GASPOOL market area and 52% to the NCG market area (2015: 51.8% GASPOOL, 48.2% NCG). The overall total for investments and expenditure across all TSOs is thus approximately €753.2m. The chart below shows investments and expenditure both separately and as a sum total since 2013, as well as the planned figures for 2017.

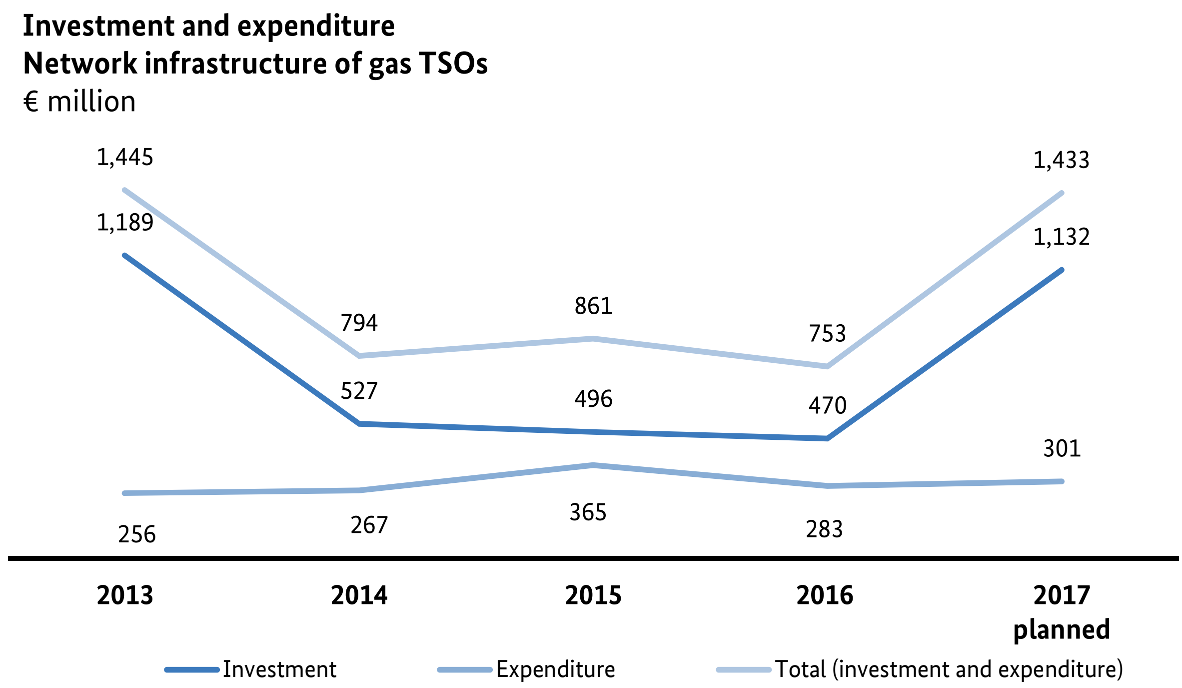


Figure 132: Investments in and expenditure on network infrastructure by TSOs

2.2 Investments in and expenditure on network infrastructure by gas DSOs

In the course of data collection for the 2017 Monitoring Report, around 650 gas DSOs declared investment in new installations, expansions and extensions (€631m) and maintenance and repair (€389m) of network infrastructure totalling €1,020m for 2016. The projected total investment for 2017 is €1,058m.

According to the gas DSOs' reports, expenditure on maintenance and repair in 2016 was €1,111m. The projected expenditure on maintenance and repair for 2017 is €1,095m.

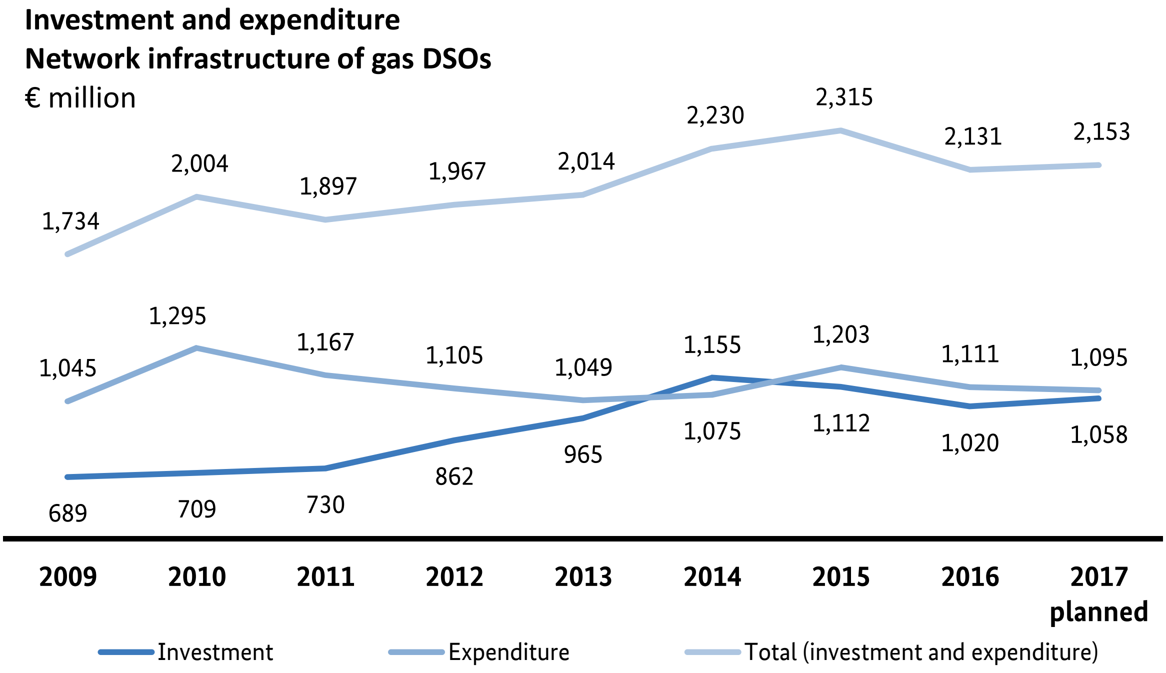


Figure 133: Investments in and expenditure on network infrastructure by gas DSOs

The level of DSO investment depends on the length of their gas pipeline network and 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 130 of the surveyed gas DSOs reported investments of between €100,001 and €250,000, only 46 gas DSOs made investments totalling more than €5m.

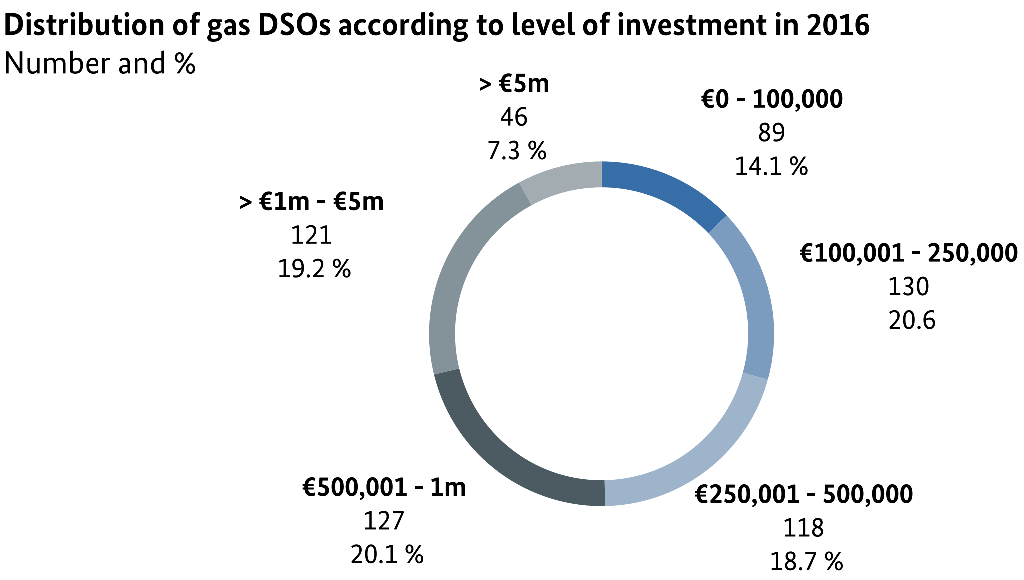


Figure 134: Distribution of gas DSOs according to level of investment in 2016

Of the surveyed gas DSOs, 144 reported total expenditures in the bracket between €0 and €100,000, while only 51 gas DSOs reported expenditures totalling more than €5m.

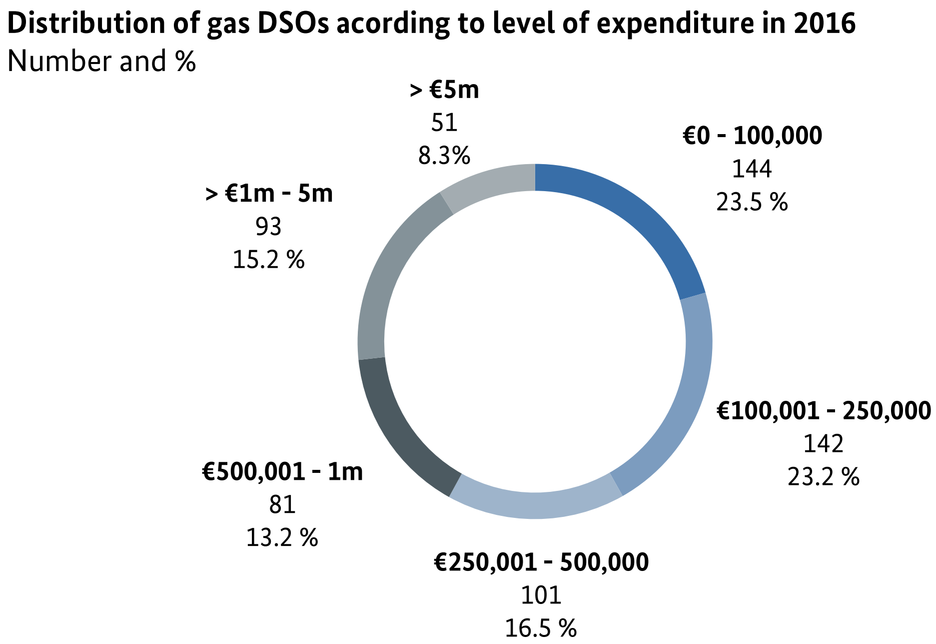


Figure 135: Distribution of gas DSOs according to level of expenditure in 2016

2.3 Investments 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 2017, 85 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 €8.8bn are linked to these investment measures across these sectors. Fourteen applications with a total investment volume of about €350m related to the gas market. All of these applications were submitted by TSOs; no applications were received from DSOs.

3. Capacity offer and marketing

3.1 Available entry and exit capacities

In 2016, as before, the questions asked in the monitoring survey related to 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.

In contrast to last year's decrease[135], the total entry capacity of all TSOs increased by 5.2m kWh/h to 480m kWh across all firm capacity products. Like last year, 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 marked decrease of 3.9% compared to the previous year. For the other capacity products (bFZK, DZK and BZK), however, there was an increase in entry capacities. As the survey did not include detailed questions on the capacity offer it cannot be concluded that FZK offers were substituted by products with allocation restrictions.

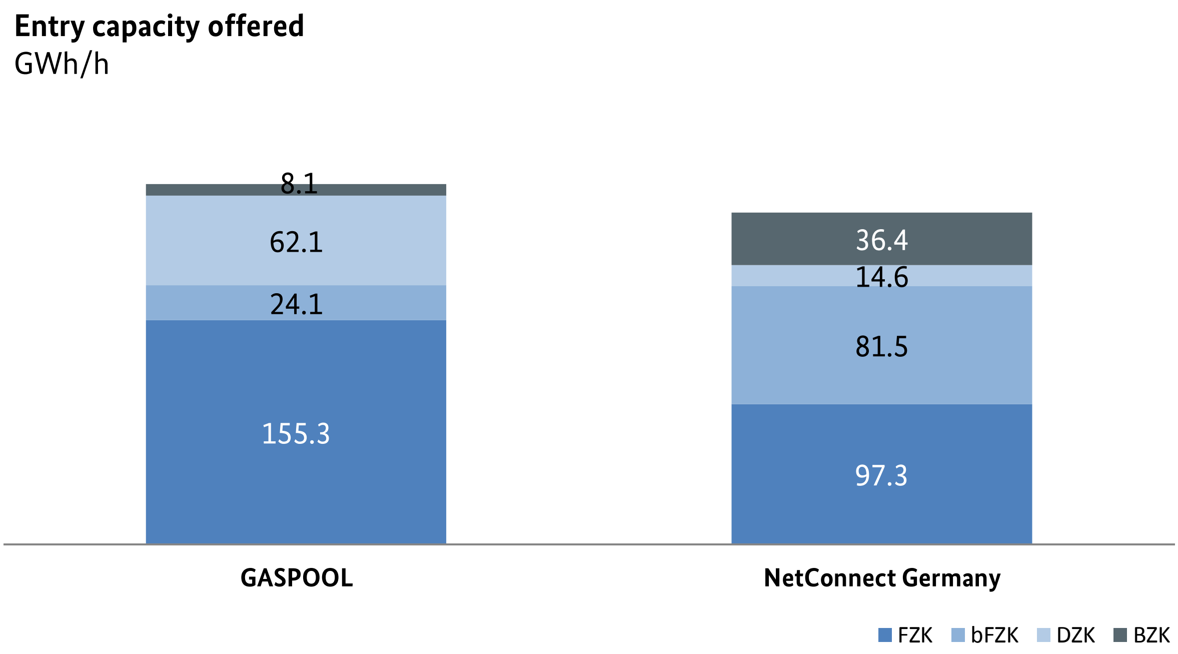


Figure 136: Entry capacity offered

In contrast, the exit capacity increased by 20.2m kWh/h to 331.1m kWh/h compared to the previous year. 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

[135] The figures for entry capacities for 2015 were updated retrospectively.

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.

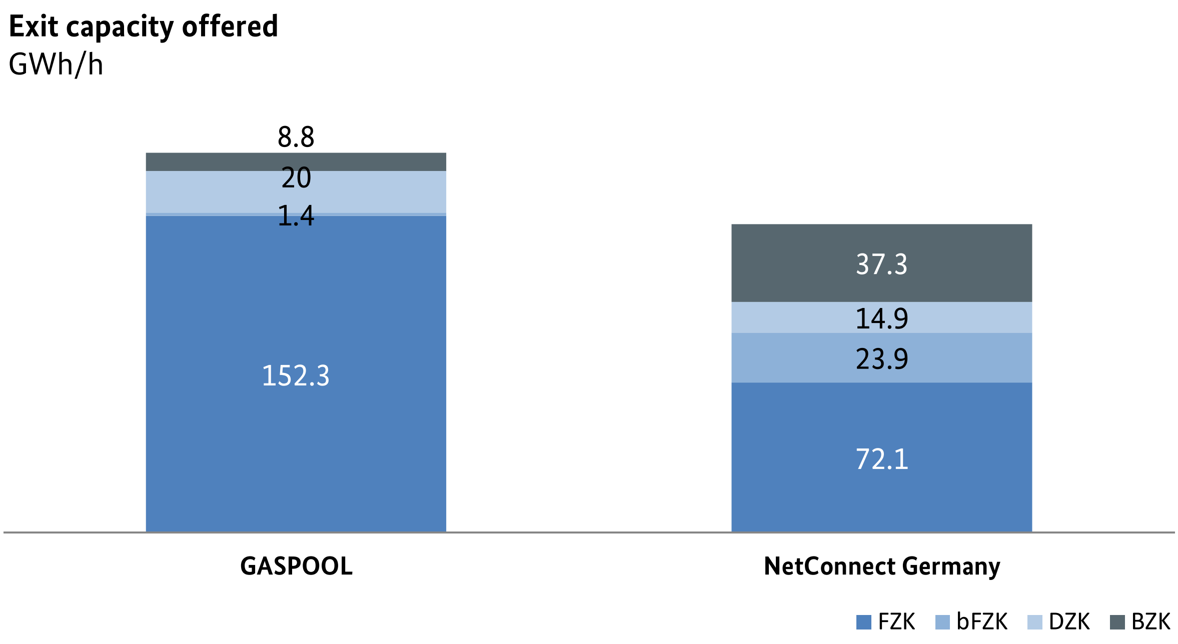


Figure 137: Exit capacity offered

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 2016, the offer of entry capacity through TSOs' renomination restrictions amounted to 2.4m kWh/h in the NCG market area, which corresponds to an increase of 15.2% compared with the year 2015. The offer of corresponding exit capacity increased by 17% to 3.3m kWh/h. In 2016, TSOs in the GASPOOL market area were able to increase the offer of entry capacities based on renomination restrictions by 21.3% to 2.9m kWh/h. The exit capacities offered in 2016 increased by 5.7% to 3.7m kWh/h compared to 2015.

3.2 Termination of capacity contracts

During the reporting period, a total of 177 long-term capacity contracts were terminated, of which 136 were at storage facility connection points, 30 at cross-border points, six at market area interconnection points and five at end users. The following kinds of capacity were affected: 159x FZK, 17x interruptible and 1x DZK. The terminated contracts had a median contract term of 259 days and comprised capacity rights averaging 4.2m 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, tending towards ever shorter-term booking, 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.

3.3 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").

A total of 13 gas wholesalers and suppliers with contracts involving interruptible capacity stated that they had in fact experienced interruptions in the 2015/16 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 18.9 hours, up from 14.3 hours in the year before. Overall, the duration of interruption for all affected companies again increased compared with the previous year (gas year 2015/2016: 4,625 h; 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 a slight decrease in the absolute number of affected wholesalers and suppliers whose contracts were interrupted at least once, compared with the previous year (gas year 2015/2016: 13; gas year 2014/15: 16; gas year 2013/14: 10; gas year 2012/13: 11; gas year 2011/12: 14).

Total interruption duration and number of interruptions per wholesaler and supplier

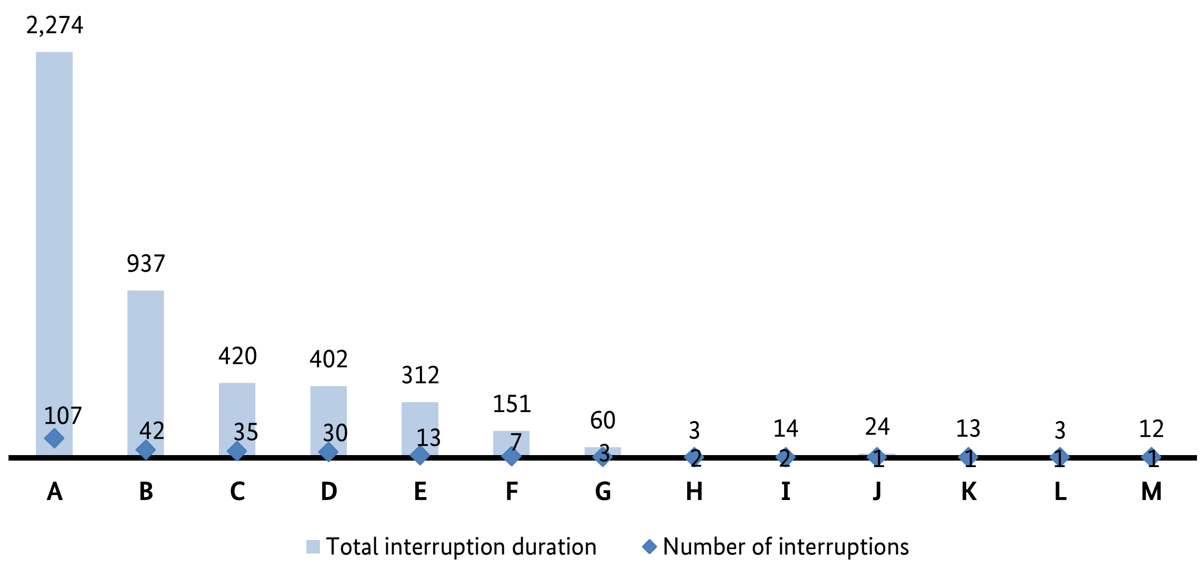


Figure 138: Total interruption duration in hours and number of interruptions per wholesaler and supplier

The diagram can be elucidated by a brief explanation of a single example: The diagram includes the 13 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 107 interruptions lasting a total of 2,274 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 2016, 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 2.8bn kWh (2015: 3bn kWh). Of this, the interruption of interruptible capacity made up the majority (96%). Through the interruption of interruptible capacity, a total of 2.8bn kWh of the nominated volume was not transported. The majority of interrupted volume (54.3%) is attributed to interruptions at storage facility connection points. The share of interruptions at cross-border interconnection points was 44.2%; 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), the interrupted volume was made up entirely of interruptions at cross-border interconnection points.

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 0.16% 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.

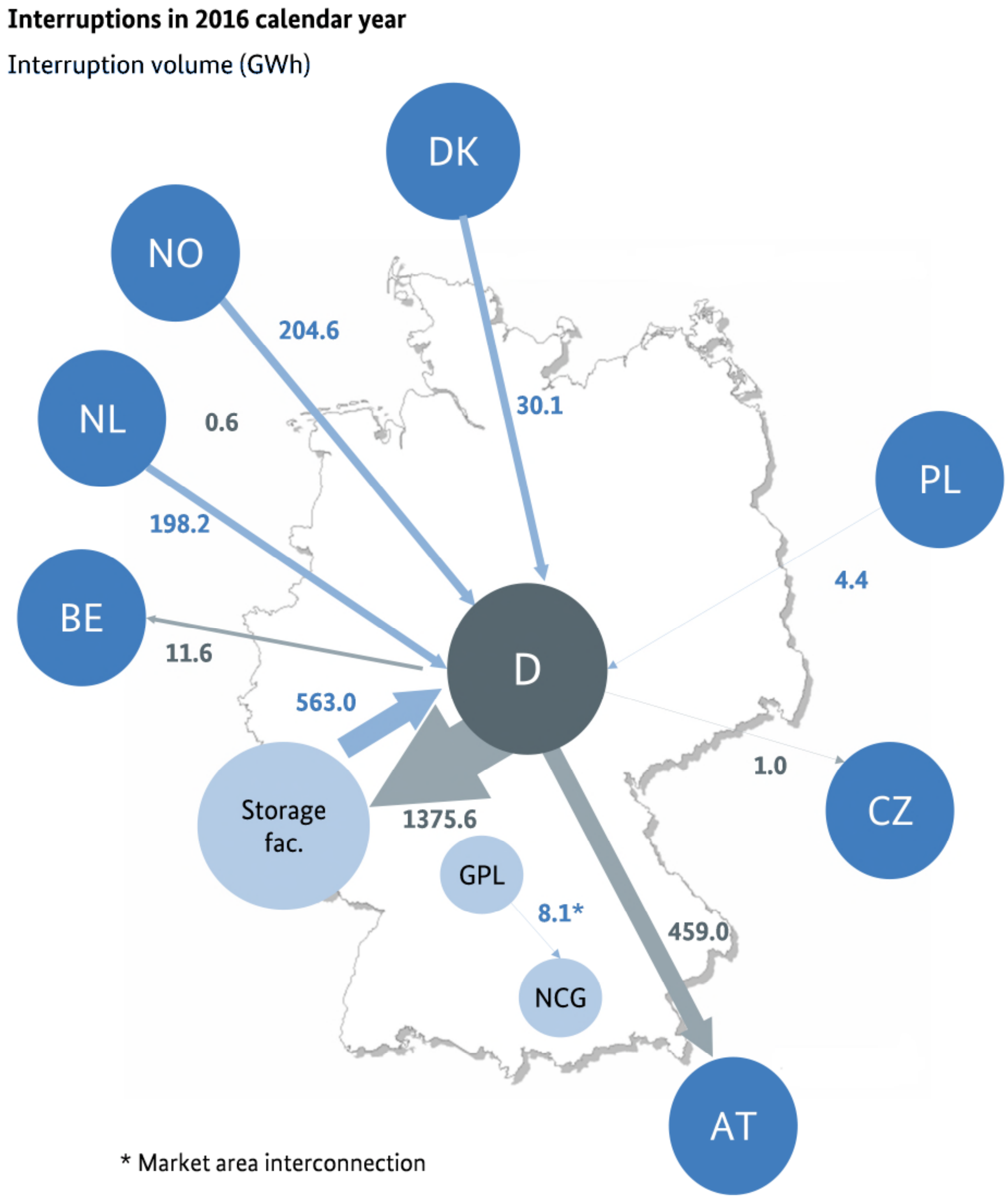


Figure 139: Interruption volumes according to region

3.4 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 2016, internal booking by the downstream network operators in the NetConnect Germany market area amounted to a total of 153.7 GWh/h. Altogether the TSOs were able to make firm commitments, either with or without a time limit, to 98.9% of this total.

In the GASPOOL market area a reserve capacity totalling 102.2 GWh/h was booked, with the proportion of firm commitments with or without a time limit amounting to 99.5%.

Capacities agreed between TSOs and DSOs
(GWh/h)

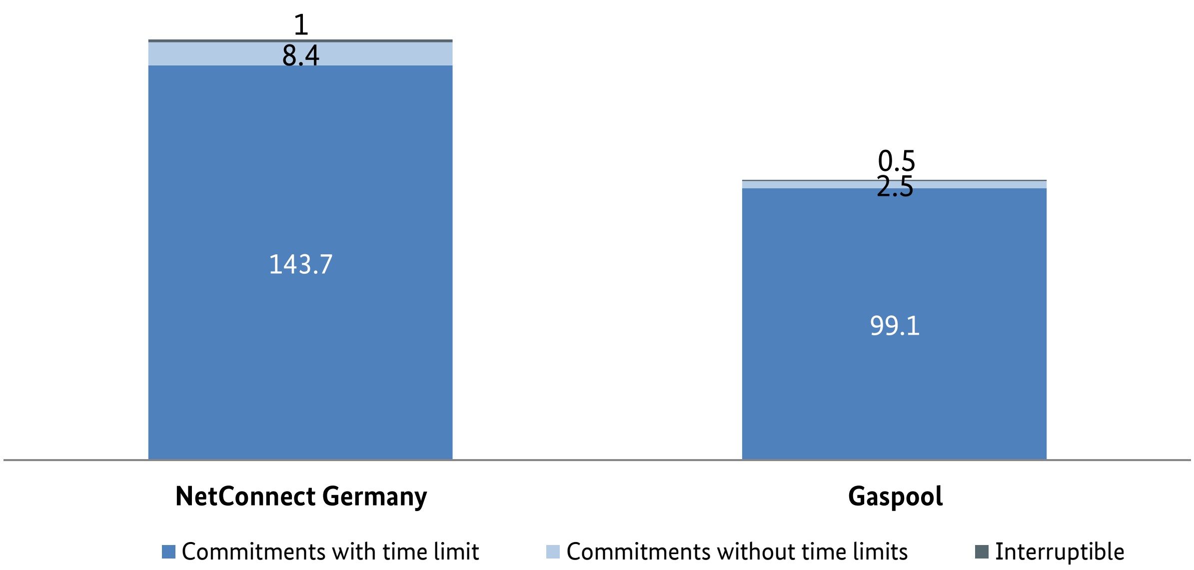


Figure 140: Capacities agreed between TSOs and DSOs in GWh/hour.

4. 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 Industry 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 2016 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 networks) were as follows:

SAIDI results for 2016

Pressure range	Specific SAIDI	Comments
≤ 100mbar	0.84 min/a	Household and small-volume consumers
> 100mbar	0.18 min/a	High-volume consumers, gas-fired power plants
> 100mbar	0.01 min/a	Downstream network operators
All pressure ranges	1.03 min/a	SAIDI figure for all final customers

Table 87: SAIDI results for 2016

The Bundesnetzagentur has calculated the SAIDI figures for gas network operators in Germany since 2006. The figures have been as follows over the years:[136]

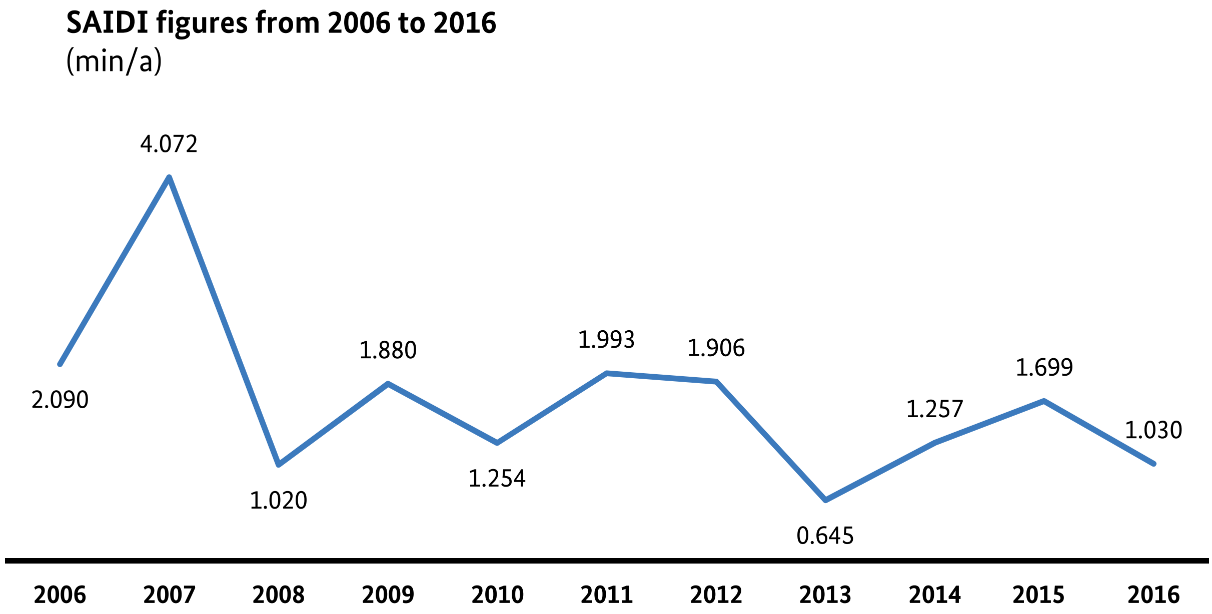


Figure 141: SAIDI figures from 2006 to 2016

[136] 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.

5. Network charges

5.1 Calculation of network charges for gas

Network charges are fees charged by the TSOs and DSOs and form part of the retail price (see also "Price level" in Chapter G Retail, beginning on page 381). The network charges are the means of spreading the costs of operation, maintenance and expansion of networks among all network users. The calculation of the network charges is based on a system prescribed by the Gas Network Charges Ordinance (GasNEV), which is binding for all network operators. The network operator's charges must be non-discriminatory and as cost-reflective as possible, taking due account of a revenue cap. The revenue cap for each network operator is calculated for each year of a regulatory period using the rules laid down in the Incentive Regulation Ordinance (ARegV). The network charges are therefore a regulated part of the final price.

The revenue cap is calculated using the instruments of the incentive regulation on the basis of a previously conducted cost examination, during which the responsible regulatory authority ascertains and examines the costs of network operation. The cost examination is carried out before the start of a regulatory period, i.e. every five years, on the basis of the audited annual accounts for the financial year completed two years previously. The network costs are obtained from this as the total of current outlay costs, imputed depreciation allowances, expected return on equity and imputed taxes less cost-reducing revenues and income. The 2010 costs were used to set the base level for calculating the revenue caps for the second regulatory period. The current cost examination has been ongoing since the second half of 2016 based on the 2015 cost data.

The values calculated for the base year are used to determine the revenue caps with the application of various adjustment factors (eg sectoral productivity development, efficiency requirements, capital cost deduction because of assets written down in the meantime and capex mark-up for new investments etc).

To this end, the network costs are divided into different cost components. Particular mention should be made of the permanently non-controllable costs, which are not subject to the instruments of the incentive regulation. Significant cost components in this regard include, at the transmission network level, costs for investment measures in accordance with section 23 ARegV. Key permanently non-controllable costs for the DSOs include upstream network costs. The revenue cap is adjusted annually with respect to certain cost components. The forecast and actual figures are compared using the network operator's incentive regulation account. The network charge system is used to share the revenues allowed for the respective network operators among the network users.

In principle, section 3 GasNEV allows for two different tariff systems to be used for cost unit accounting. Of those two systems, entry and exit capacity charges prescribed by section 13 GasNEV are the norm, and are calculated using the entry-exit access model. By contrast, section 18 GasNEV stipulates that commodity and capacity prices or commodity and base prices are set on the exit side for local distribution networks. No entry tariffs are charged in this case. A few regional distribution networks use the entry-exit tariff system. The network charge system for gas networks thus differs significantly from the system for electricity networks, which has neither entry tariffs nor capacity charges.

The exit tariffs charged by all other DSOs comprise two components, a capacity price and a commodity price. The so-called network participation model is used very often to form these prices. This entails dividing the distribution network and its associated costs into two parts, a local transport network and a local distribution network. A mathematical function is used to determine the share of the local distribution network apportionable to a customer with given consumption. Customers with lower consumption require a larger share of the local distribution network, while it is more probable that customers with higher consumption are connected to local transport capacity. This results in a degression of the specific network charge at higher levels of consumption. The procedure is carried out separately for the capacity price and the commodity price. For non-interval-metered customers (all household customers and many small commercial customers) an average reserve capacity is used, so the capacity component is represented by a base price.

Other systems apart from the network participation model are also used to calculate tariffs. In the main, these systems yield comparable results with respect to tariff degression and likewise do not depend on an individual customer's specific connection situation.

On 1 January each year the network operators must demonstrate to the regulatory authority that the established tariff system does not exceed the revenue cap. In the event of a downward adjustment of the revenue cap according to the rules of the Incentive Regulation Ordinance, the network operators are obliged to adjust their tariffs, whereas in the event of an upward adjustment they have the right to do so but it is not mandatory.

5.2 Development of average network tariffs in Germany

Figure 142 below 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 2017. The charges for metering and meter operation have been added to the network tariffs shown in the figure below. Since 1 January 2017 the charge for accounting forms part of the network tariffs and is no longer shown separately. 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 2017, the average volume-weighted network charge, including metering and meter operation charges, for household customers on default tariffs in consumption band II was 1.50 ct/kWh, therefore unchanged from the previous year. During the period under review (10 years), network tariffs for household customers on default tariffs have increased from 1.20 ct/kWh to 1.50 ct/kWh.

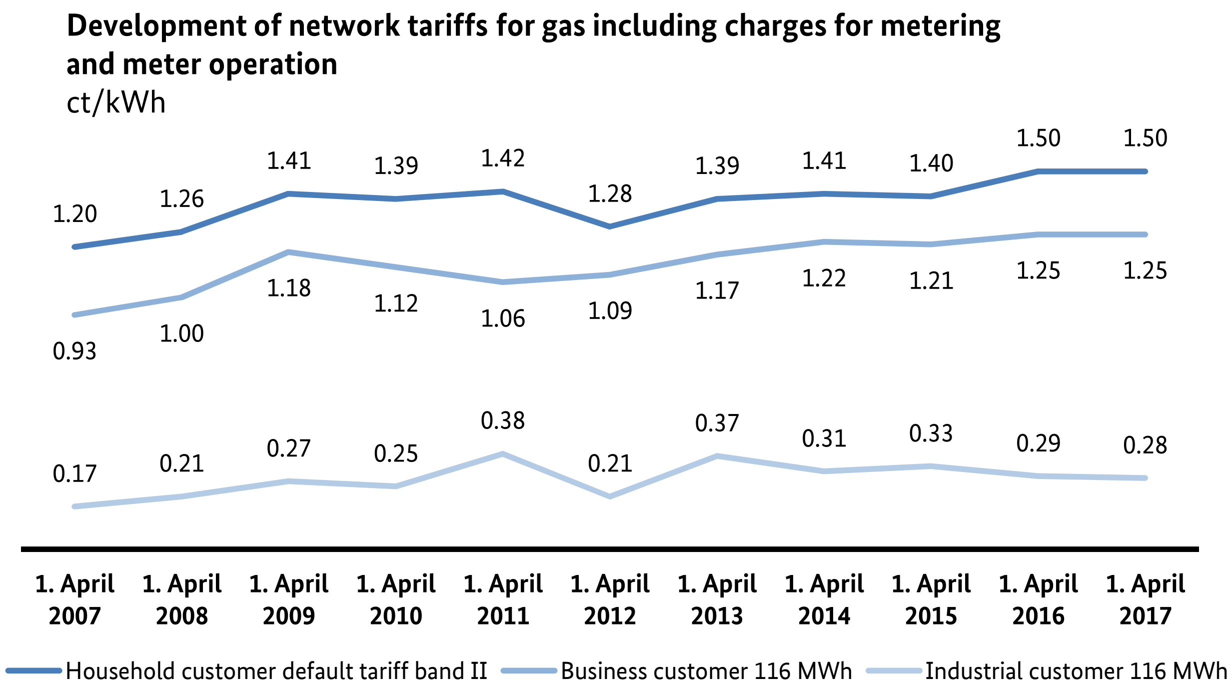


Figure 142: Development of network tariffs for gas (including charges for metering and meter operation) according to the survey of gas suppliers

5.3 Regional distribution of network tariffs

There is wide regional variation in the level of network tariffs. The price sheets published by all DSOs are used as the basis for compiling the relevant information on the three consumption categories (household, business and industrial customers, see above) in order to compare network tariffs in Germany. According to section 27(1) GasNEV all network operators are obliged to publish the network tariffs applicable in their networks on their website. The information on the respective base, capacity and commodity prices provided by each DSO is then used to determine the 2017 network tariffs in ct/kWh. The figures do not include the metering and meter operation charges or value added tax; from 1 January 2017 charges for accounting are included in the network tariffs. For the sake of clarity, network tariffs are divided into six (household and business customers) or five (industrial customers) categories.[137] 705 gas networks were analysed to determine the level of network tariffs for household customers, and 701 networks were analysed for business customers. This corresponds to market coverage of 98% in both areas. The network tariffs were also entered in a chart broken down by federal state, in which the individual network tariffs are weighted by the number of meter points in each case, to obtain information on the average network tariff level in each state.

The lowest network tariffs for household customers across Germany are set at 0.7 ct/kWh, and the highest 3.8 ct/kWh. With the exception of Saarland, there is an East to West gradient with regard to the distribution of network tariffs. The average network tariff for household customers in the new federal states (not including Berlin) is 1.71 ct/kWh, while the average in the old states (including Berlin) is 1.39 ct/kWh. Looking at the averages by federal state, the highest network tariffs for household customers are found in Mecklenburg-Western Pomerania and Saarland, the lowest in Bavaria and Bremen.

[137] Only regions with an existing gas distribution network are shown in colour on the maps. Accordingly, regions without an existing gas distribution network are shown in white.

Net network tariffs for household customers in Germany for 2017

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks considered
Mecklenburg-Western Pomerania	2.00	0.90	2.80	24
Saarland	1.82	1.29	2.59	19
Saxony-Anhalt	1.81	0.89	2.86	28
Thuringia	1.63	1.00	2.32	30
Saxony	1.62	0.96	2.25	37
North Rhine-Westphalia	1.50	0.82	3.85	126
Brandenburg	1.47	0.85	3.23	28
Baden-Württemberg	1.47	0.96	2.52	106
Rhineland-Palatinate	1.41	0.85	2.38	36
Schleswig-Holstein	1.40	0.70	2.02	43
Hesse	1.36	0.96	1.73	47
Lower Saxony	1.32	0.77	1.91	64
Hamburg	1.29	1.29	1.29	1
Berlin	1.25	1.25	1.25	1
Bavaria	1.25	0.79	3.85	109
Bremen	1.24	1.20	1.44	2

* The number of meter points belonging to the operators in the respective network areas was used as the basis for weighting.

Table 88: Distribution of network tariffs for household customers in Germany, as at 1 January 2017

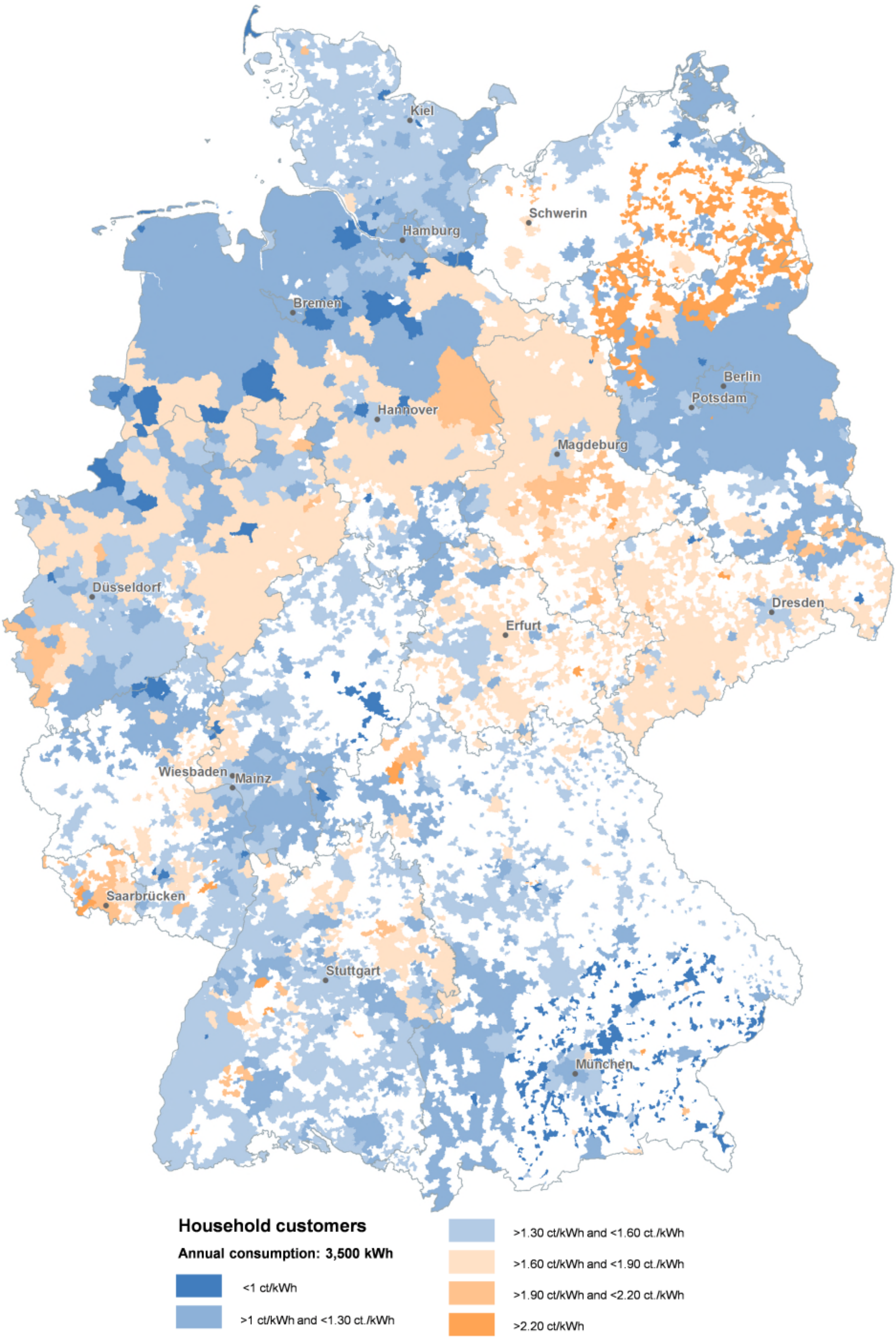


Figure 143: Distribution of network tariffs for household customers

The distribution of network tariffs for business customers is similar to that for household customers. Across Germany, the spread between the lowest and highest network tariffs extends from 0.5 ct/kWh to 3.4 ct/kWh. The East to West gradient in the distribution of network tariffs is less marked than for household customers. The average network tariff for business customers in the new federal states (not including Berlin) is 1.45 ct/kWh, while the average in the old states (including Berlin) is 1.17 ct/kWh. Looking at the averages by federal state, the highest network tariffs for business customers are found in Mecklenburg-Western Pomerania and Saxony-Anhalt, the lowest in Berlin and Bremen.

Net network tariffs for business customers in Germany for 2017

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks considered
Mecklenburg-Western Pomerania	1.93	0.94	2.36	24
Saxony-Anhalt	1.57	0.83	2.32	28
Saarland	1.50	1.06	2.17	19
Saxony	1.33	0.74	1.97	37
Baden-Württemberg	1.25	0.64	2.46	106
Rhineland-Palatinate	1.23	0.65	2.06	36
Brandenburg	1.22	0.75	3.13	28
Thuringia	1.21	0.71	1.89	30
Lower Saxony	1.19	0.65	1.64	43
North Rhine-Westphalia	1.18	0.14	2.21	47
Bavaria	1.14	0.68	3.36	126
Hesse	1.14	0.81	1.84	109
Hamburg	1.09	1.09	1.09	2
Schleswig-Holstein	1.09	0.60	1.79	1
Berlin	1.08	1.08	1.08	1
Bremen	0.93	0.90	1.03	64

* The number of meter points belonging to the operators in the respective network areas was used as the basis for weighting.

Table 89: Distribution of network tariffs for business customers in Germany, as at 1 January 2017

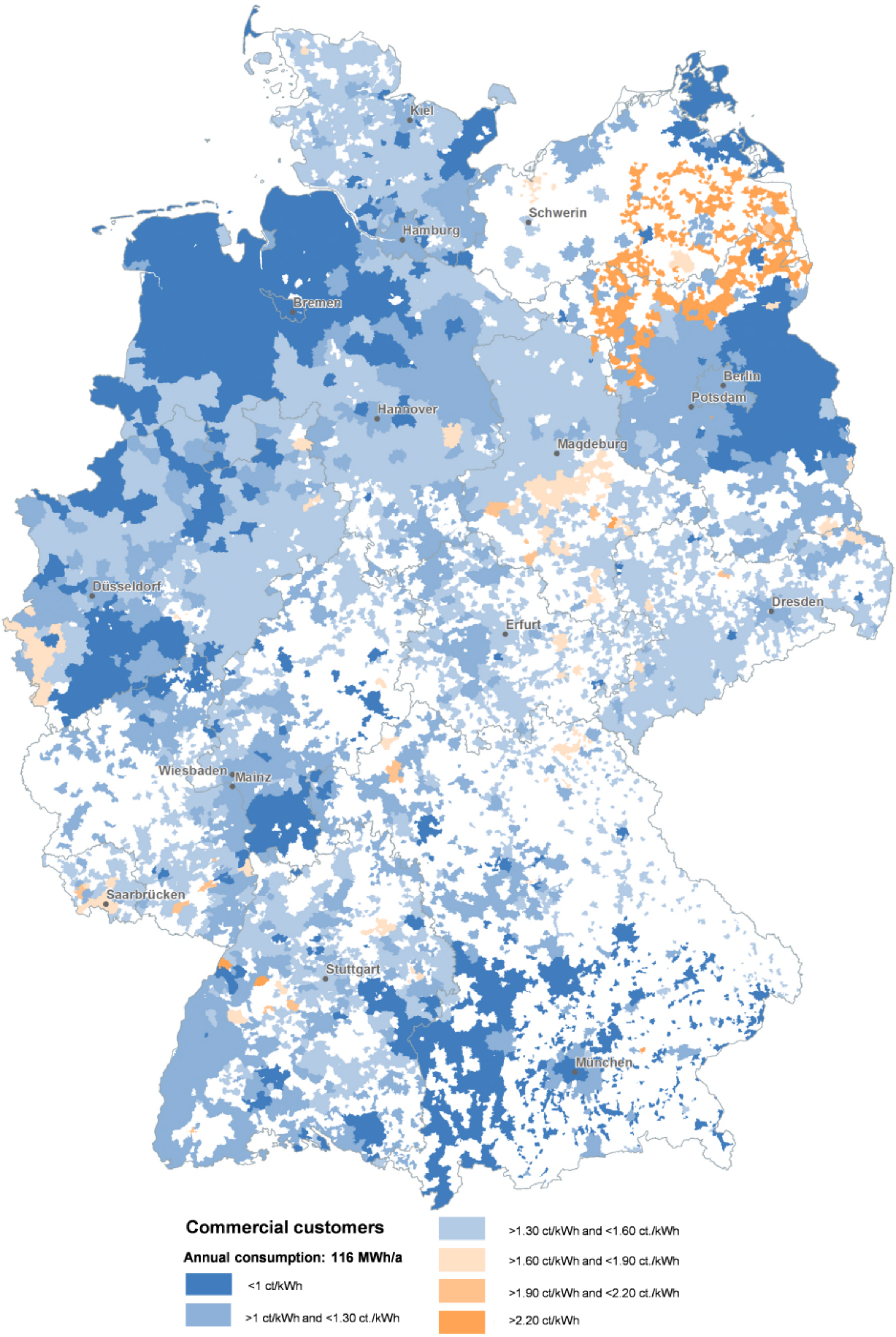


Figure 144: Distribution of network tariffs for business customers

Only those gas networks that have at least one customer withdrawing 116 GWh were taken into account when determining the average network tariffs for industrial customers. Figures from 127 network operators were thus included in the analysis of network tariffs for industrial customers. Across Germany, the spread between the lowest and highest network tariffs extends from 0.1 ct/kWh to 0.9 ct/kWh. The average network tariff for industrial customers in the new federal states (not including Berlin) is 0.37 ct/kWh, while the average in the old states (including Berlin) is 0.29 ct/kWh. Looking at the averages by federal state, the highest network tariffs for industrial customers are found in Thuringia and Saxony-Anhalt, the lowest in Mecklenburg-Western Pomerania and Bremen.

Net network tariffs for industrial customers in Germany for 2017

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks considered
Thuringia	0.45	0.31	0.55	6
Saxony-Anhalt	0.44	0.21	0.99	8
Saarland	0.43	0.35	0.56	4
Saxony	0.39	0.11	0.62	7
Rhineland-Palatinate	0.33	0.27	0.73	7
Brandenburg	0.32	0.20	0.47	4
Baden-Württemberg	0.32	0.19	0.44	16
Berlin	0.30	0.30	0.30	1
Hesse	0.29	0.16	0.41	13
North Rhine-Westphalia	0.29	0.17	0.36	19
Hamburg	0.29	0.29	0.29	1
Schleswig-Holstein	0.28	0.24	0.40	6
Bavaria	0.28	0.12	0.66	21
Lower Saxony	0.26	0.20	0.48	10
Mecklenburg-Western Pomerania	0.26	0.25	0.27	2
Bremen	0.17	0.16	0.24	2

* The number of meter points belonging to the operators in the respective network areas was used as the basis for weighting.

Table 90: Distribution of network tariffs for industrial customers in Germany, as at 1 January 2017

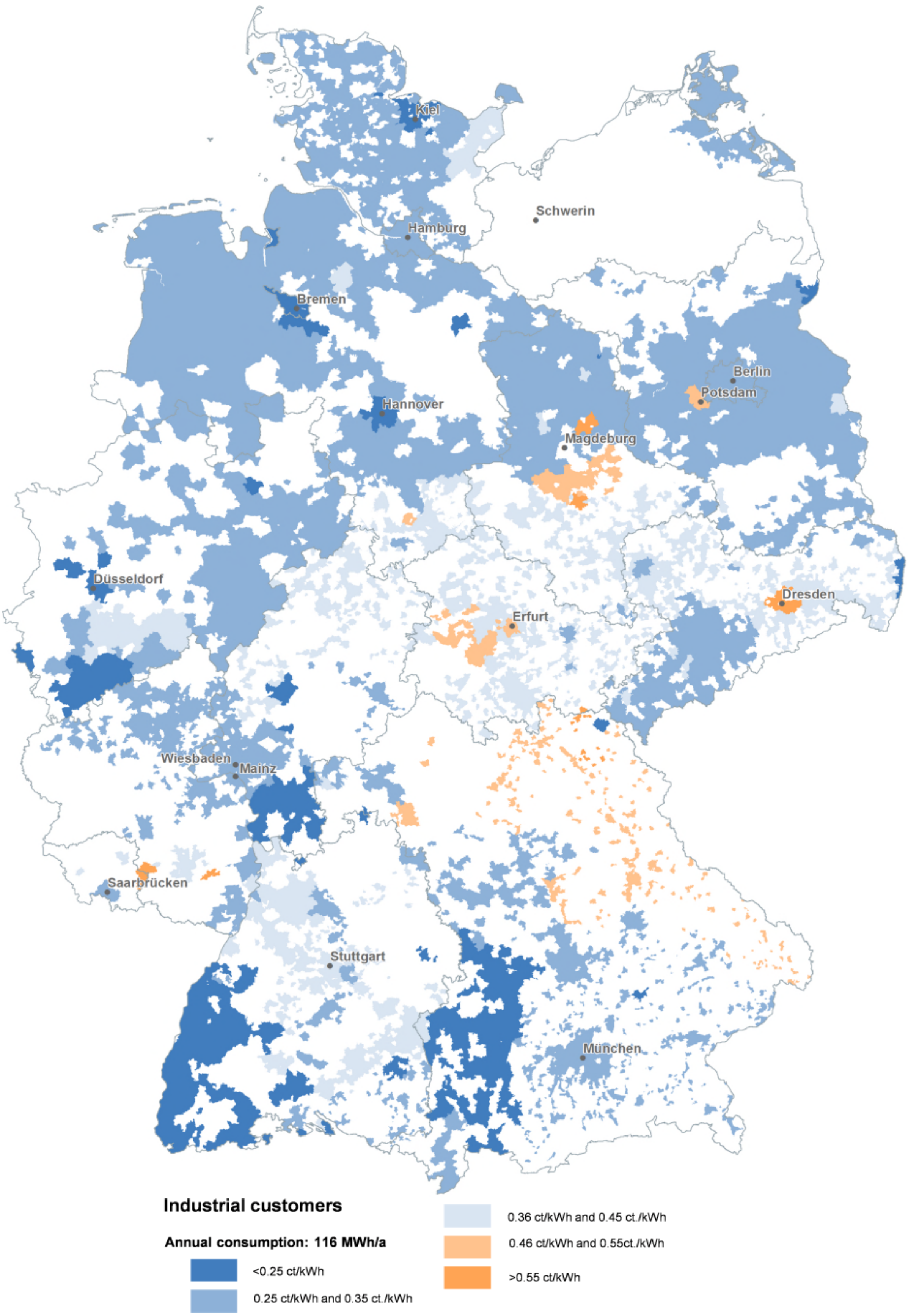


Figure 145: Distribution of network tariffs for industrial customers

The reasons for the regional differences in network tariffs are manifold. One key factor is lower levels of utilisation of the networks, and another the average age of the networks in the respective regions. The modernisation of networks in the new federal states following German reunification often resulted in networks which, from today's perspective, are oversized. In some cases these networks are now insufficiently utilised, while still incurring costs in line with their size. Another driver of difference is population density. In sparsely populated regions the network costs have to be spread over a small number of network users, whereas the opposite is the case in densely populated regions. The age structure of individual networks also has an impact on tariffs. More recently built networks have higher residual values, which increases specific capital costs and in turn leads to higher tariffs. As a result of their greater depreciation, older networks have lower residual values and therefore lower capital costs, thus in turn leading to lower tariffs. However, with advancing age, networks incur higher costs for maintenance and repair, which have a corrective effect that tends to equalise the tariffs.

5.4 Expansion factor as per section 10 ARegV

In 2016, for the last time, the gas DSOs were able to apply for an expansion factor for their investments in network expansion in the case of a lasting change in supply services. 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 2016, 68 applications for expansion factors were made.

5.5 Incentive regulation account as per section 5 ARegV

In 2016 the rules governing the incentive regulation account underwent a fundamental change. The incentive regulation account is now no longer held by the regulatory authority but by the network operator. Each year, the network operator determines the differences described in section 5(1) and (1a) ARegV, which as stated in section 5(2) ARegV carry interest and which constitute the balance of the incentive regulation account as at 31 December of the respective year. The balance is allocated to the revenue cap on an annuity basis, by additions and deductions, over the three calendar years following the year in which the balance was determined. These additions and deductions result in the respective adjustment amounts set out in section 4(4) first sentence para 1a in conjunction with section 5(3) ARegV. The network operator must apply to the regulatory authority for approval of the incentive regulation account balance and the ensuing adjustment amounts as at 30 June every year.

The transitional arrangement in section 34(4) ARegV stipulates that network operators shall apply to settle the incentive regulation account balance for the first time on 30 June 2017. The first settlement covers all outstanding calendar years. It thus relates to the calendar years 2012 to 2016. The differences determined for these years according to section 5(1) ARegV carry interest and must be included in the calculation of the incentive regulation account balance as at 31 December 2016. The incentive regulation account balance as at 31 December 2016 must be allocated to five annuities, which are taken into account as adjustment amounts for the calendar year revenue caps in the third regulatory period (2018 to 2022).

5.6 Network transfers under section 26(2) ARegV

In the event of a partial transfer of an energy supply network to a different network operator, in accordance with section 26 ARegV the regulatory authority specifies what effect the transfer has on the revenue caps of the network operators concerned. The amendment to ARegV which came into effect in 2016 brought significant changes to this procedure. According to section 26(2-6) ARegV as applicable since September 2016, when an energy supply network is partly transferred to a different network operator the affected network operators must apply to the regulatory authority to define the shares of the revenue caps assigned to the part of the network that is transferred. If no corresponding application from the two network operators is received within six months of the commencement of network operation, the regulatory authority shall allocate the revenue caps ex officio on the basis of a defined distribution key.

In 2016 the Bundesnetzagentur received 17 applications for network transfers in the gas sector, and took decisions on five of them.

5.7 Horizontal cost allocation

In June 2016, the Ruling Chamber responsible for gas network charges 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 was scheduled to come into effect on 1 January 2018 with binding force. The defined methodology in this determination prescribed a capacity-weighted entry-exit split, which results in a consistent, specific entry charge for a firm, freely allocable annual capacity in a market area.

During the hearing on 11 October 2017, the 3rd Antitrust Panel of the Higher Regional Court of Düsseldorf indicated that in its view no appropriate enabling provision was in place at the time of the HoKoWä (horizontal cost allocation mechanism) determination. This prompted the decision by the Bundesnetzagentur to revoke the HoKoWä determination with immediate effect, stating that, pending final clarification of this legal issue, implementation of the HoKoWä determination on 1 January 2018 would carry unacceptable risks for the affected companies and their customers.

In the meantime, the network code on harmonised transmission tariff structures (Regulation (EU) No 2017/460) was approved. This code stipulates that, in principle, from 1 January 2020 a reference price methodology (such as the postage stamp method) must be jointly applied for each market area, in other words uniform entry-exit tariffs for each market area.

5.8 Preparation for cost examination and efficiency comparisons

In spring 2016, the Bundesnetzagentur adopted determinations on conducting the cost examination to determine the base level for the third regulatory period and on the survey of structural data for efficiency comparisons relating to DSOs and TSOs.

To enable the cost examination to take place, the Bundesnetzagentur obliged 170 gas supply network operators to submit the documents required to determine the base level in accordance with section 6(1) ARegV by 1 July 2016. Notwithstanding this provision, 90 gas supply network operators who fulfil the requirements for participation in the simplified procedure according to section 24 ARegV and who had submitted an application to this end by 30 June 2016 were obliged to submit all documents required for determining the base level by 1 September 2016.

For the survey of structural data for the purpose of efficiency comparisons, the determinations obliged the gas supply network operators not participating in the simplified procedure to submit data on loads, structure and sales relating to the 2015 financial year which the Bundesnetzagentur needs to conduct the efficiency comparisons for the third regulatory period. The information provided in the survey had to be submitted by the 16 TSOs by 1 April 2016 and by the 185 DSOs (under federal responsibility and the responsibility of the federal states) by 15 September 2016.

In 2016, the Bundesnetzagentur used this data as the initial basis for determining the base level for gas supply network operators and to conduct efficiency comparisons.

5.9 Misuse proceedings according to section 30 Energy Industry Act (EnWG)

In 2016, as part of misuse proceedings under section 30 EnWG, the Bundesnetzagentur obliged a DSO to establish network tariffs using only one price sheet from 1 January 2018 when converting the set revenue cap into tariffs for accessing its energy supply network and to do this without identifying separate tariffs for individual areas of its network. This amounted to binding implementation of the "one network operator - one network tariff" principle after a transitional phase to harmonise the tariffs in the individual areas of the network. Legal proceedings against the decision are pending.

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 a balancing platform). 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.

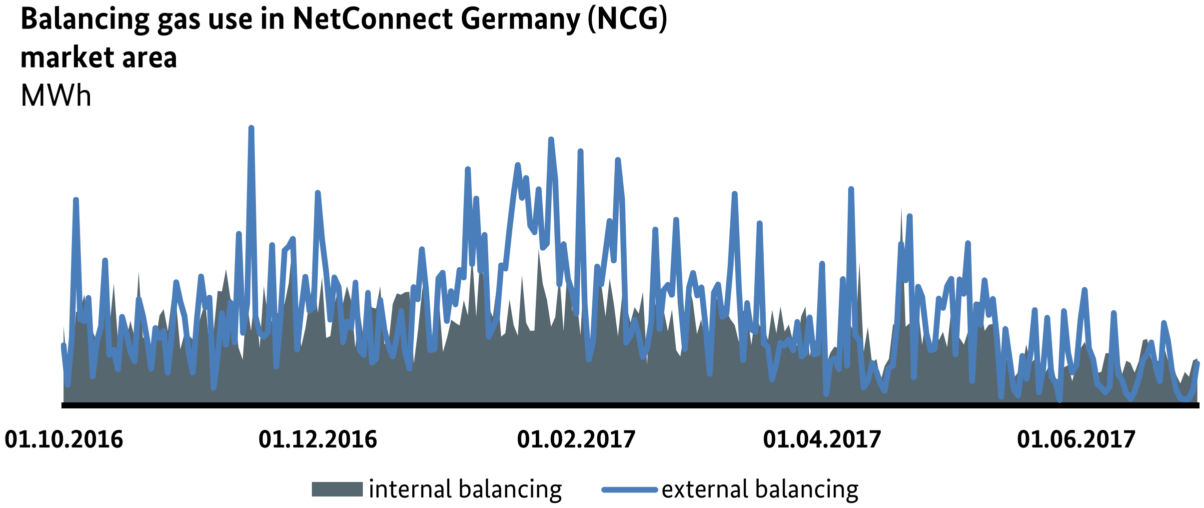


Figure 146: Balancing gas use from 1 October 2016 in the NetConnect Germany market area, as at June 2017 (source: www.net-connect-germany.de)

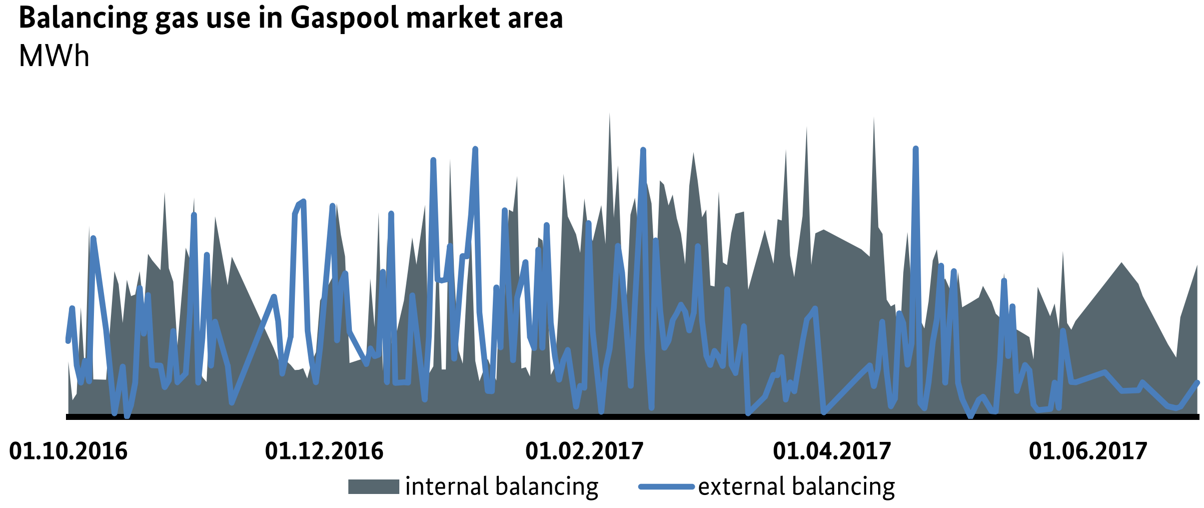


Figure 147: Balancing gas use from 1 October 2016 in the Gaspool market area, as at June 2017 (source: www.gaspool.de/)

The purchase prices and volumes depicted for balancing gas are calculated as an average of the daily balancing gas purchase prices and volumes. In the period under review, the balancing product MOL3 was not purchased at all in the Gaspool market area and only once, on 9 May 2017, in the NetConnect Germany market area. The average daily price was €18.80/MWh for an average volume of 3,636 MWh.

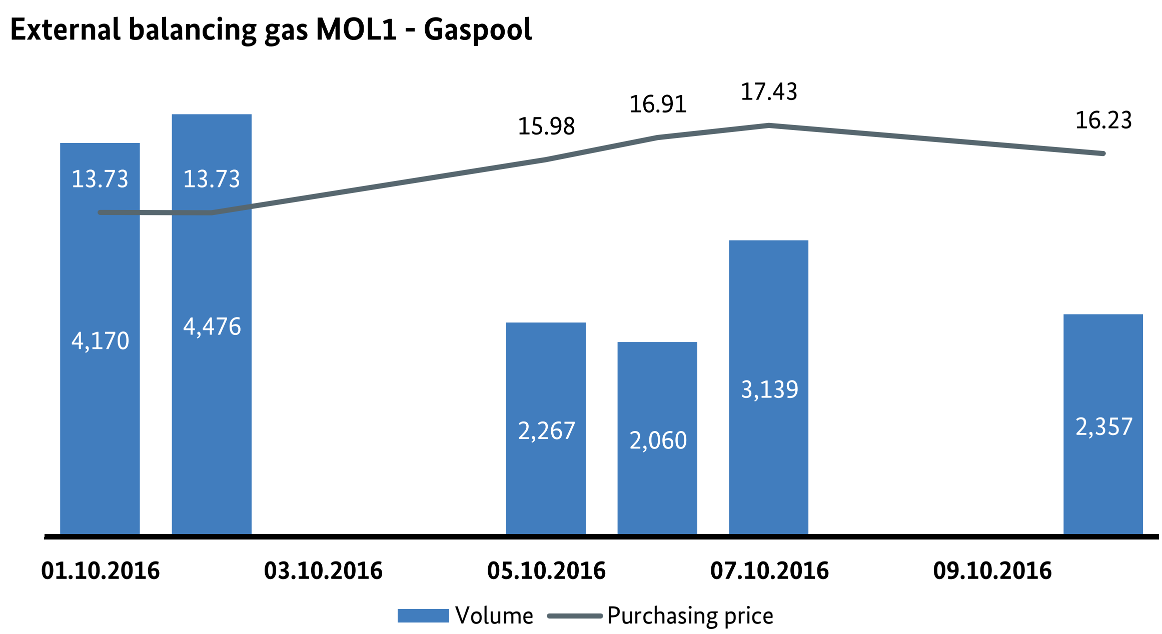


Figure 148: External balancing gas purchase prices and volumes from Q4 2016 for MOL1 in the Gaspool market area, as at June 2017 (source: www.gaspool.de)

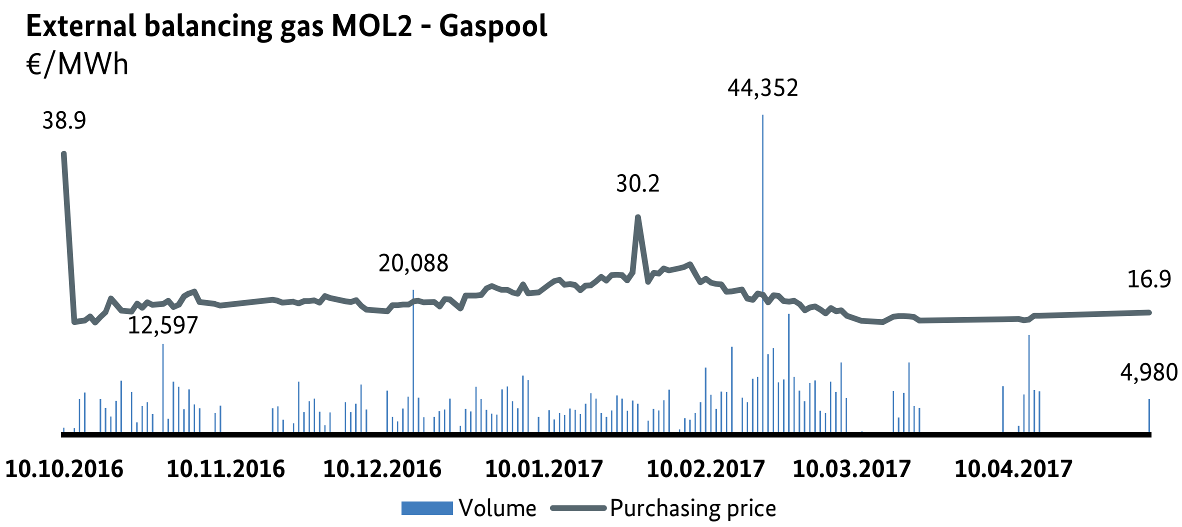


Figure 149: External balancing gas purchase prices and volumes from Q4 2016 for MOL2 in the Gaspool market area, as at June 2017 (source: http://www.gaspool.de)

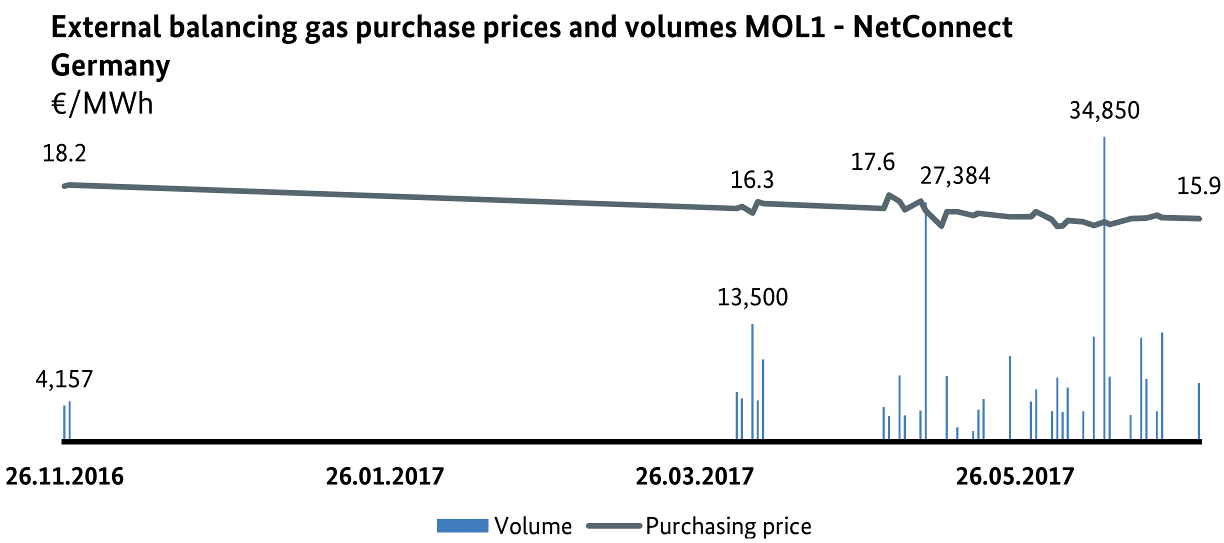


Figure 150: External balancing gas purchase prices and volumes from Q4 2016 for MOL1 in the NetConnect Germany market area, as at June 2017 (source: http://www.net-connect-germany.de)

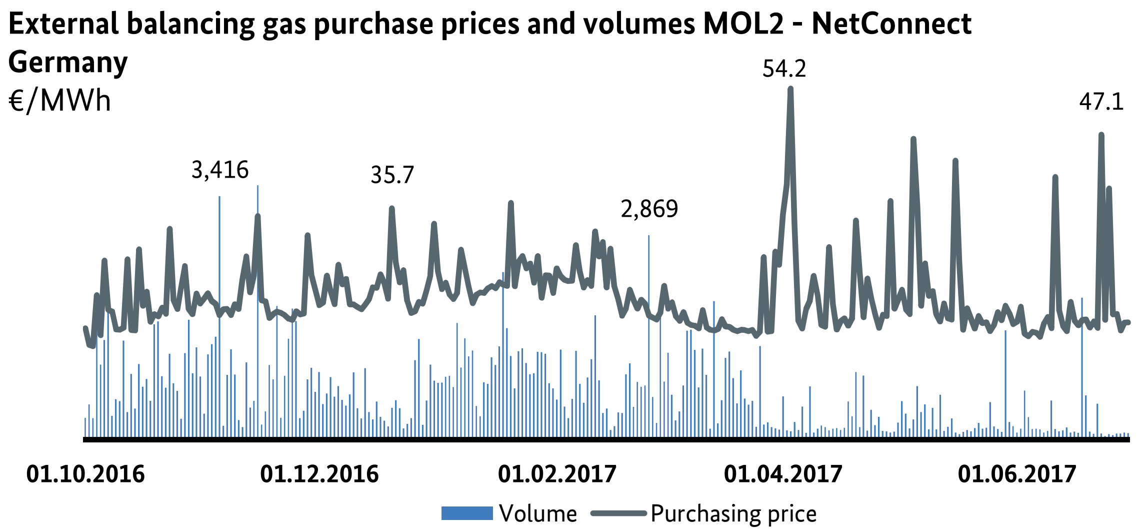


Figure 151: External balancing gas purchase prices and volumes from Q4 2016 for MOL2 in the NetConnect Germany market area, as at June 2017 (source: http://www.net-connect-germany.de)

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. Additions and deductions serve as incentives for the balancing group manager to avoid imbalances in his balancing group.

The implementation of GaBi Gas 2.0 as of 1 October 2015 led to fundamental changes in the way imbalance gas prices are calculated. The previous calculation system used a price pool involving various exchanges to calculate imbalance prices, whereas now the balancing gas prices and the volume-weighted average price of 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 2016.

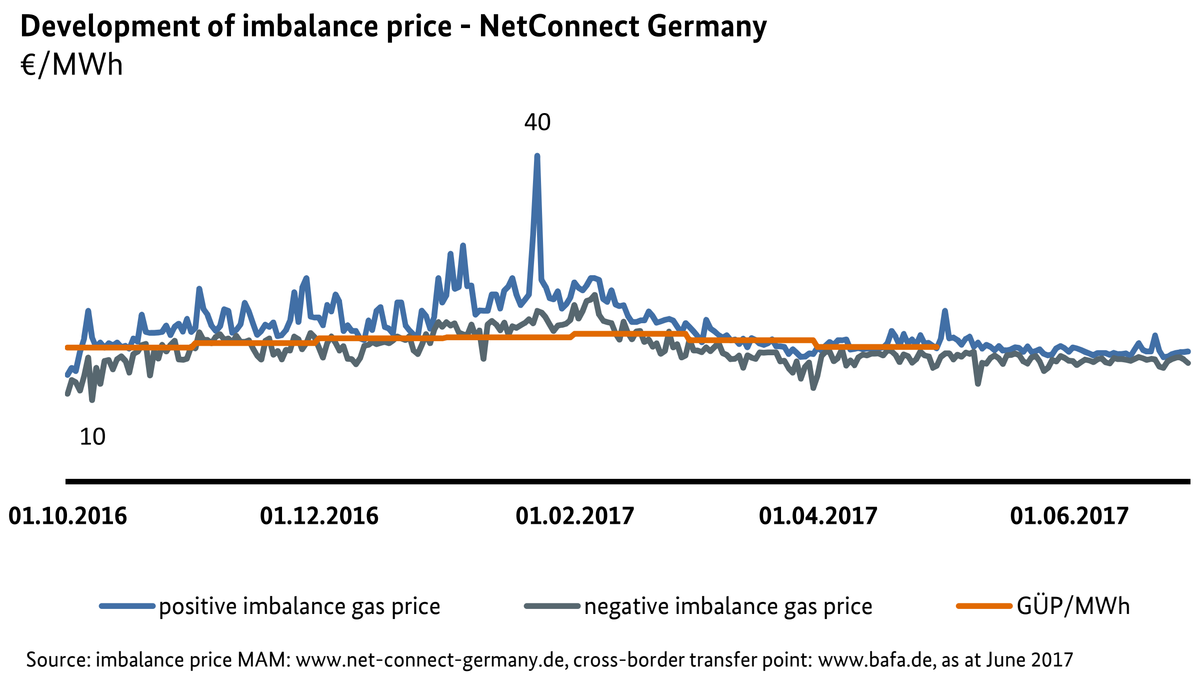


Figure 152: Development of NetConnect Germany imbalance price since 1 October 2016, as at June 2017

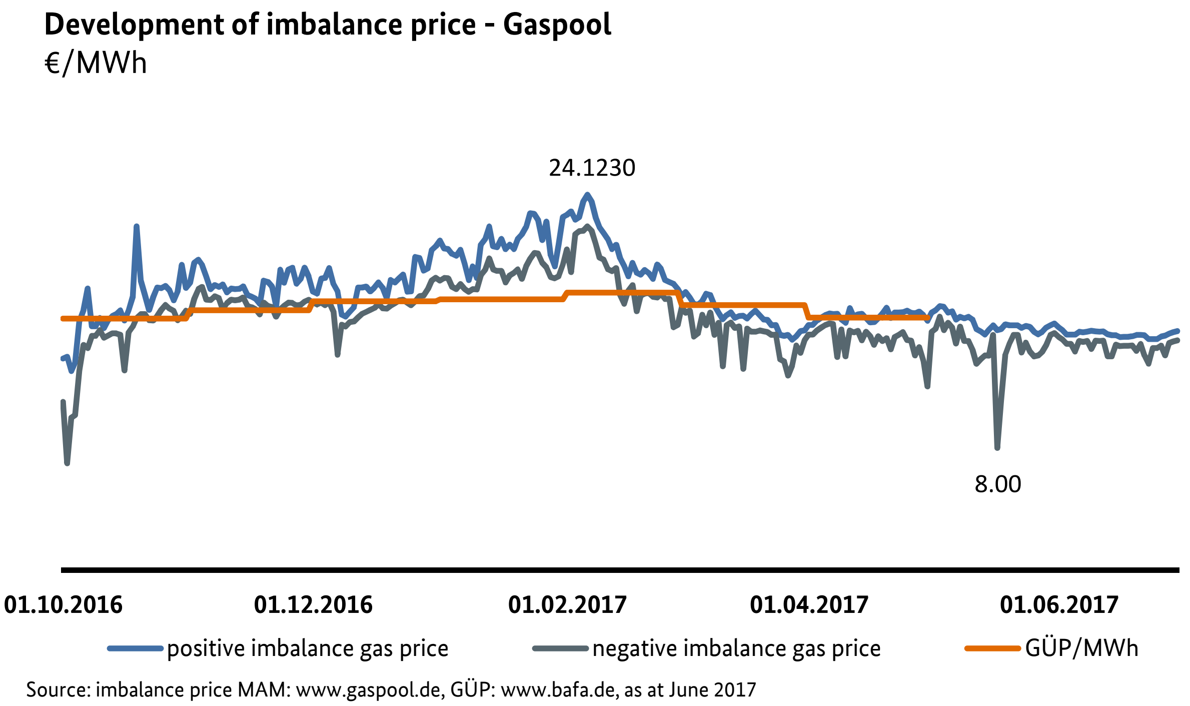


Figure 153: Development of Gaspool imbalance price since 1 October 2016, as at June 2017

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.

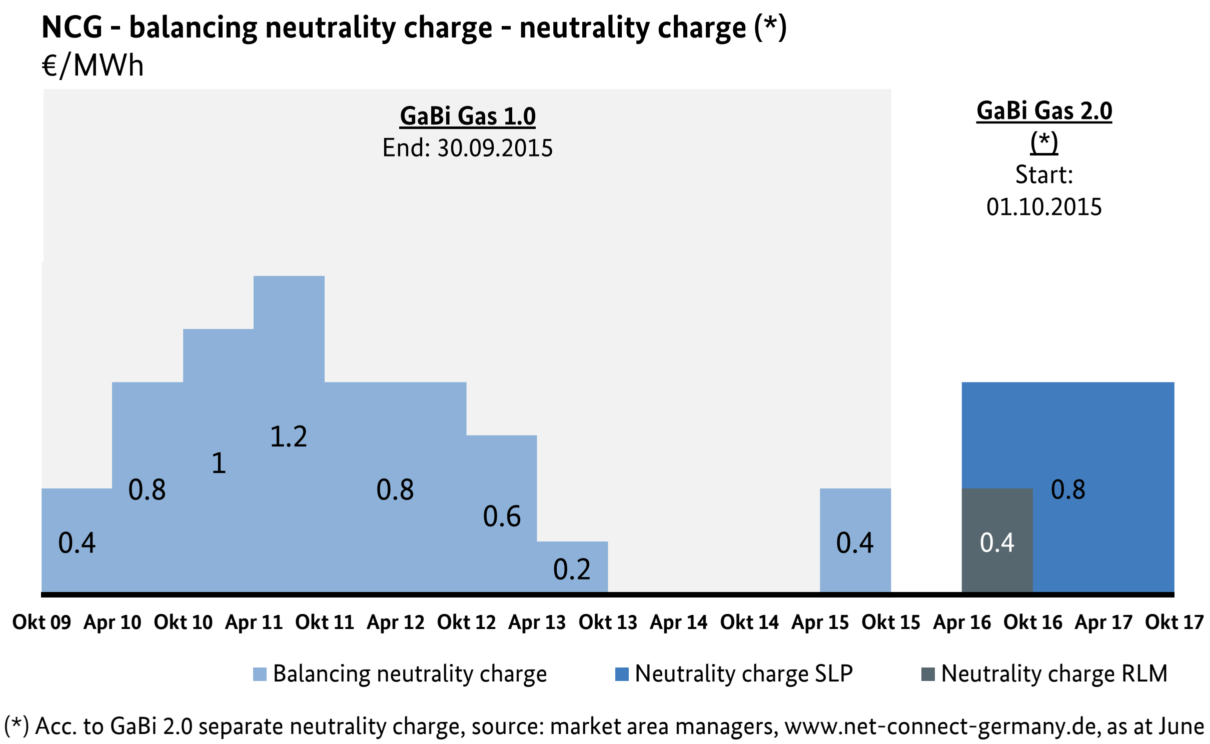


Figure 154: Balancing neutrality charge – neutrality charge in NetConnect Germany market area, as at June 2017

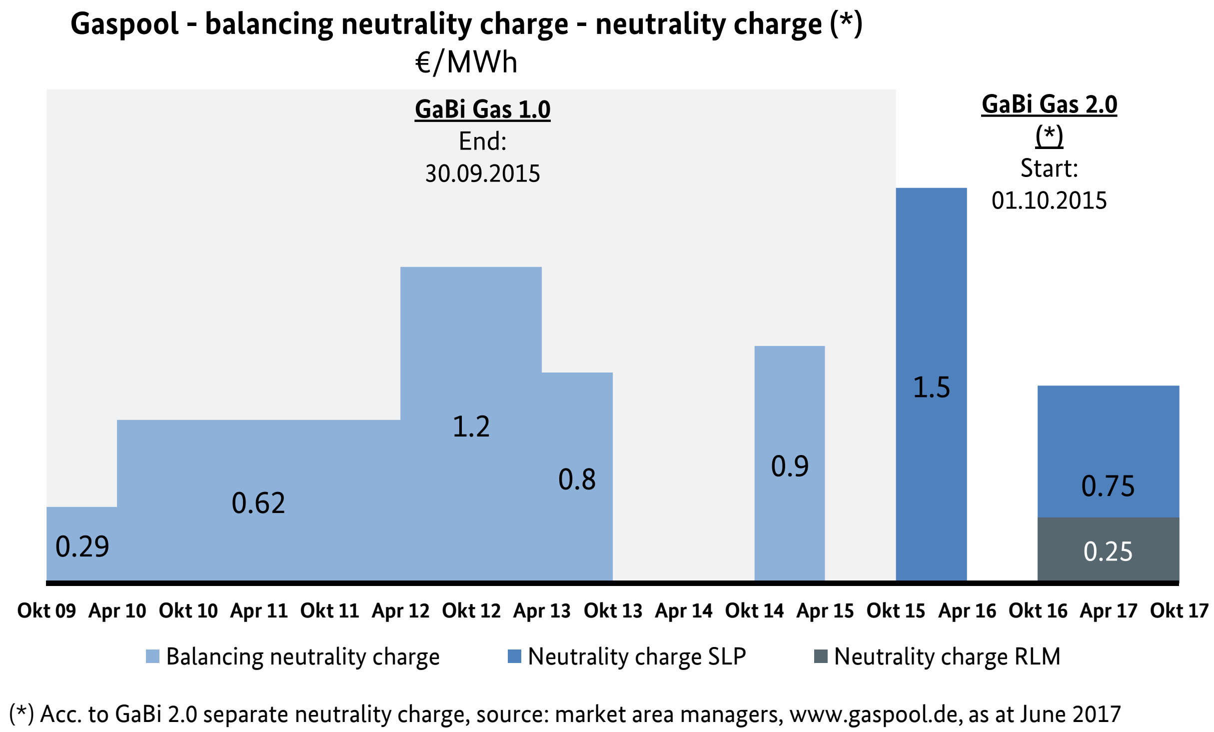


Figure 155: Balancing neutrality charge – neutrality charge in GASPOOL market area, as at June 2017

3. Standard load profiles

Network operators can use two types of standard load profile (SLP): analytical profiles, which, in general terms, are based on the previous day's consumption at the time of estimation, and synthetic profiles, which rely on values derived from statistics. In 2016, the synthetic SLP profiles were used by 79.9% of operators; analytical profiles were used by 14.5% of operators, compared with 14.8% in 2015. Other standard load profile variants used by operators make up the difference to 100%.

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 2002 and 2005 versions, dominate with a market coverage of 94.5%. This figure also remains virtually unchanged compared with the previous year (95.8%).

The TU München offers a range of different profiles which reflect the offtake behaviour of various customer groups. 45.3% of network operators stated that all available profiles were applied, compared with 45.7% in 2015. As in the previous year, two to three profiles were generally used 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 5.8%. The average maximum deviation on any one day was 55%. However, the extent to which these fluctuations result in the use of external balancing gas can only be assessed by looking at the combined effects of all deviations from standard load profile offtakes within a market area. It must also be borne in mind that these figures may not be representative as only 64.2% of the network operators provided relevant data on deviations at all, and it might 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.

9.2% of operators made adjustments to the load profiles owing to the deviations, compared to 9.1% in 2015.

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.

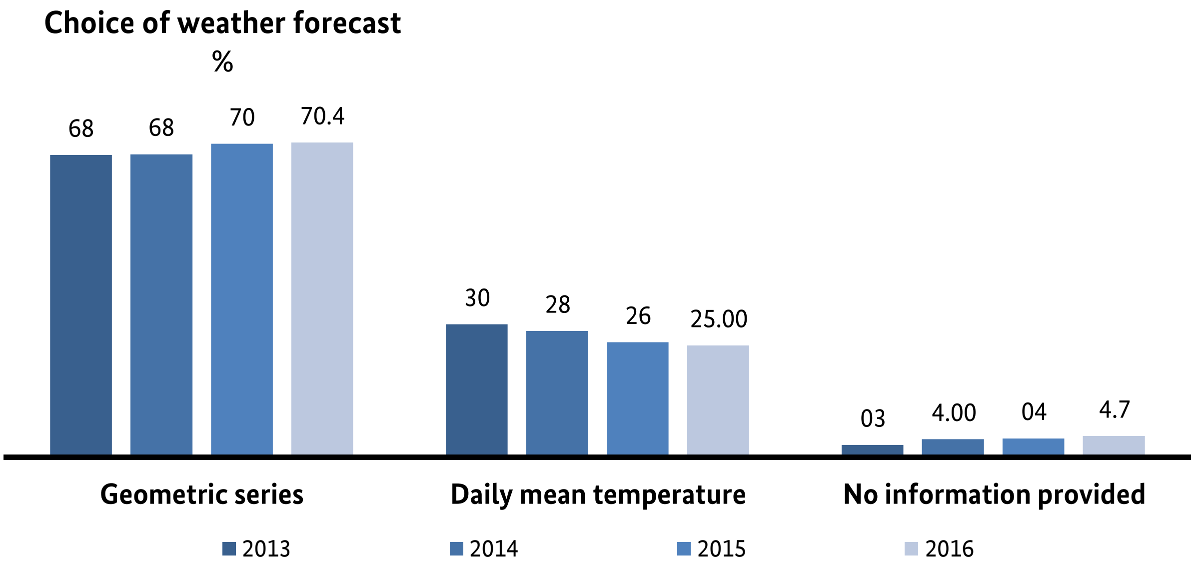


Figure 156: Choice of weather forecast

E. Market area conversion

The market area conversion, i.e. work coordinated by TSOs to convert the supply of gas from low-calorific L-gas to high-calorific H-gas is a central issue relating to gas supply. 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, are taking 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 in the run-up to 2029.

The conversion of German L-gas networks to supply H-gas started well in 2015 with the Schneverdingen conversion. This success continued in the monitoring period in the networks of Stadtwerke Böhmetal, Hilter, Rees, Nienburg/Weser, Gasversorgung Grafschaft Hoya, Gelsenwasser Energienetze (Isselburg, Landesbergen-Brokeloh), Stadtnetze Neustadt am Rübenberge, Achim and some parts of the wesernetz in Bremen. Avacon Hochdrucknetz and Westnetz are distributors between the transmission systems that are important in this context and supply these and other municipal utility companies.

Gastransport Nord GmbH, Gasunie Germany Transport Services GmbH, Nowega GmbH, Open Grid Europe GmbH and Thyssengas GmbH are TSOs directly affected by the market area conversion. In 2015, these five TSOs covered a total of 969 L-gas interconnection points that had to be converted. In 2016, only 950 were left. With 582 L-gas interconnection points, Open Grid Europe covers the lion's share (around 61.5%) of interconnection points to downstream network operators and industrial customers for L-gas.

According to Open Grid Europe and Gasunie Deutschland Transport Services GmbH, a total of 22,000 appliances had been fully converted by April 2017, with a further 92,000 appliances to be converted by the end of the year.

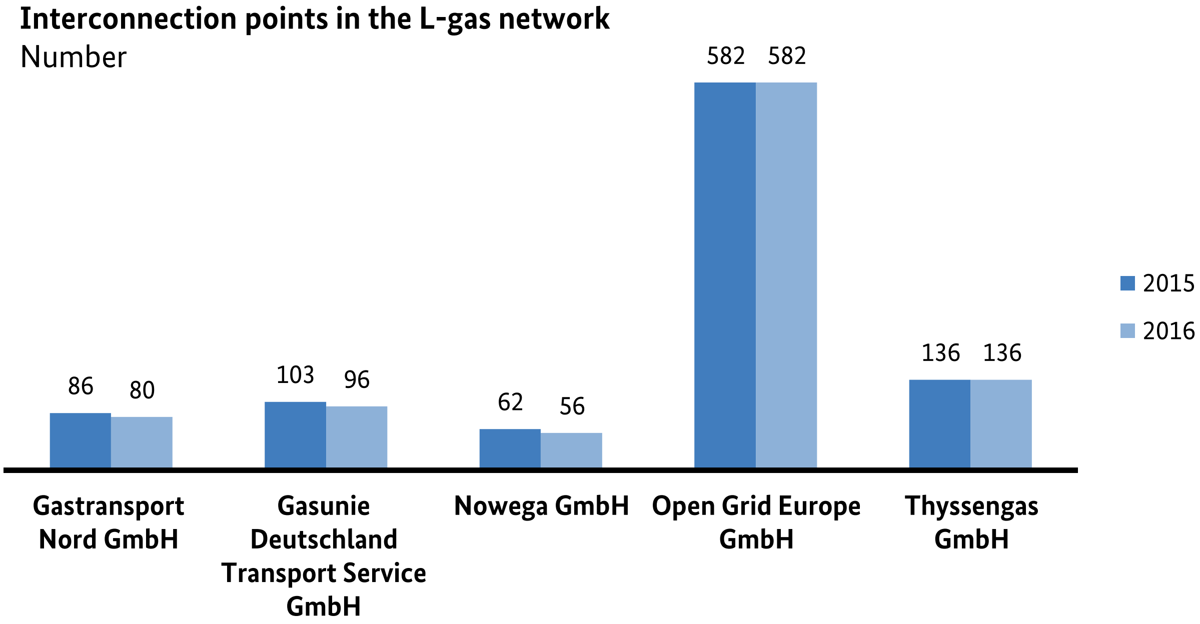


Figure 157: Interconnection points in the L-gas network as at 2015 and 2016

The planned conversions by individual network operators tend to take place in months when less gas is consumed, from April to October. By 2022, some 1,806 conversions will be carried out for interval-metered customers and 904,565 for SLP customers.

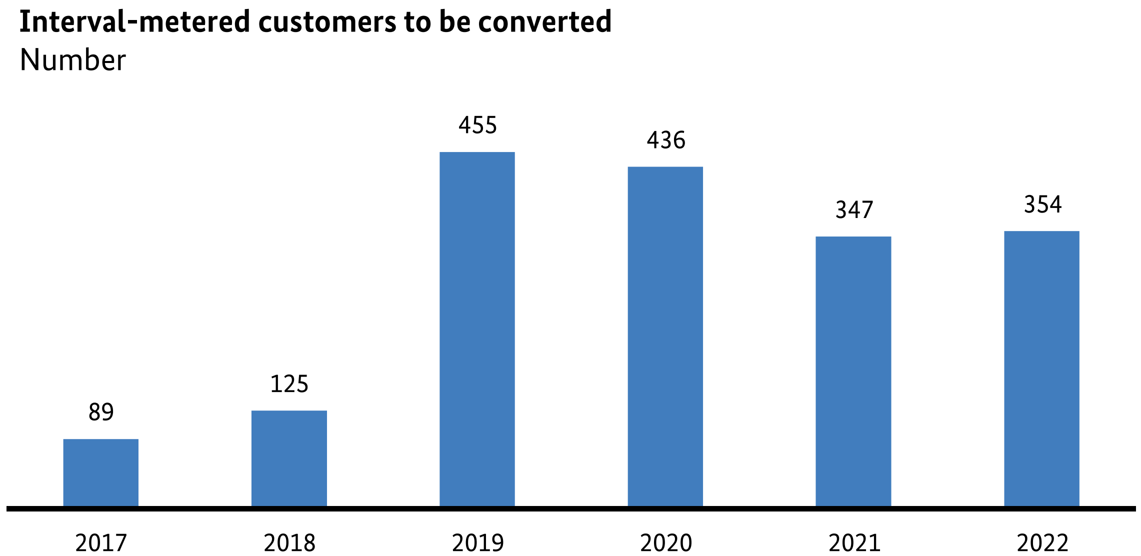


Figure 158: Interval-metered customers to be converted by 2022

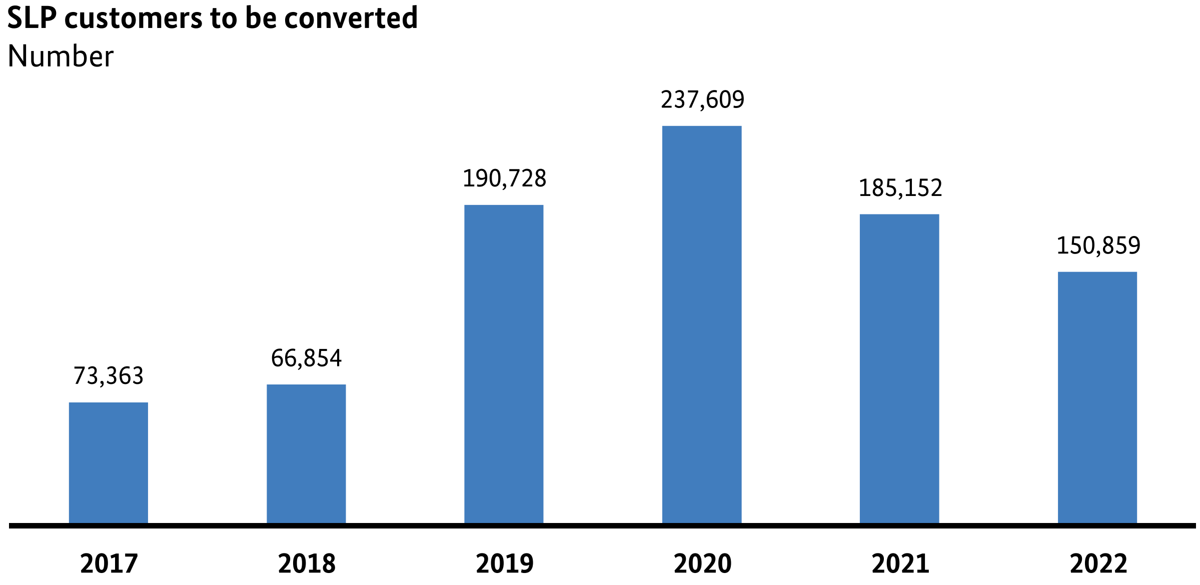


Figure 159: SLP customers to be converted by 2022

Faced with such a large number of adjustments to appliances, network operators are utilising technical skills provided by external specialist companies (with DVGW G676-B1 certification). The adjustments are carried out in three steps. First of all, the service provider compiles a list of all appliances burning gaseous fuels in the network. On the basis of data from this list, the project management team plans the adjustments to gas appliances. In the next step, all appliances have to be converted. 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 28 active companies, up from 18 a year ago.

There continued to be a high response rate to the calls for bids from the 23 network operators. For the services relating to the monitoring of registration and inspection of conversions/adjustments, in particular, there was on average one applicant more than last year. There was no shortage of service providers for the other packages either. The previous survey last year showed that it was planned from the start for several companies to share one package. This time there was a small drop in the number of companies whose bids were successful, because the companies now have more staff and are more often able to provide the services alone.

On average, 5.8 service providers bid for the "registration of appliances" package, of which, on average, 2.1 bids were successful. On average, 4.7 companies submitted bids for the "monitoring registration" package, of which, on average, 1.2 companies were successful. On average, 5.7 bidders bid for the "conversions and appliance adjustments" package, which was assigned to, on average, 2.2 companies. On average, 4.5 bids were submitted for the "inspection of conversions and appliance adjustments" package, of which, on average, 1.1 companies were successful. On average, 4 companies were interested in taking on the important tasks of the project management team. In this case, on average, 1.1 companies were successful in their bids.

Bids and awards for individual task packages for the market area conversion

Task package	Bids		Awards	
	2015	2016	2015	2016
Appliance registration	5.7	5.8	2.5	2.1
Monitoring the registration process	3.7	4.7	1.3	1.2
Conversions and appliance adjustments	5.4	5.7	2.4	2.2
Inspection of conversions and appliance adjustments	3.8	4.5	1.3	1.1
Project management	4.4	4.0	1.3	1.1

Table 91: Bids and awards for individual task packages for the market area conversion

The market area conversion poses a variety of challenges to different groups, including network operators, traders, storage facility operators and heating, plumbing and installation companies as well as those affected such as household or small business final customers and industrial gas users. It is evident that there is a significant need for information on this issue. The Bundesnetzagentur therefore held market area conversion forums in both 2016 and 2017 to allow affected parties the opportunity to obtain information and participate in discussion. Topics such as the TSOs' updated plans, the current decision on the production situation at the Groningen gas field and a practice report were covered. Participants in a discussion brought up, for example, the room for improvement in the availability of spare parts for gas appliances and the composition of conversion kits. Further information about the events can be found on the Bundesnetzagentur website.[138]

The map below shows the market area conversion of the upcoming years by network area.

[138] Events on 27 April 2016 and 26 April 2017
https://www.bundesnetzagentur.de/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/VortraegeVeranstaltungen/VortraegeVeranstaltungen-node.html

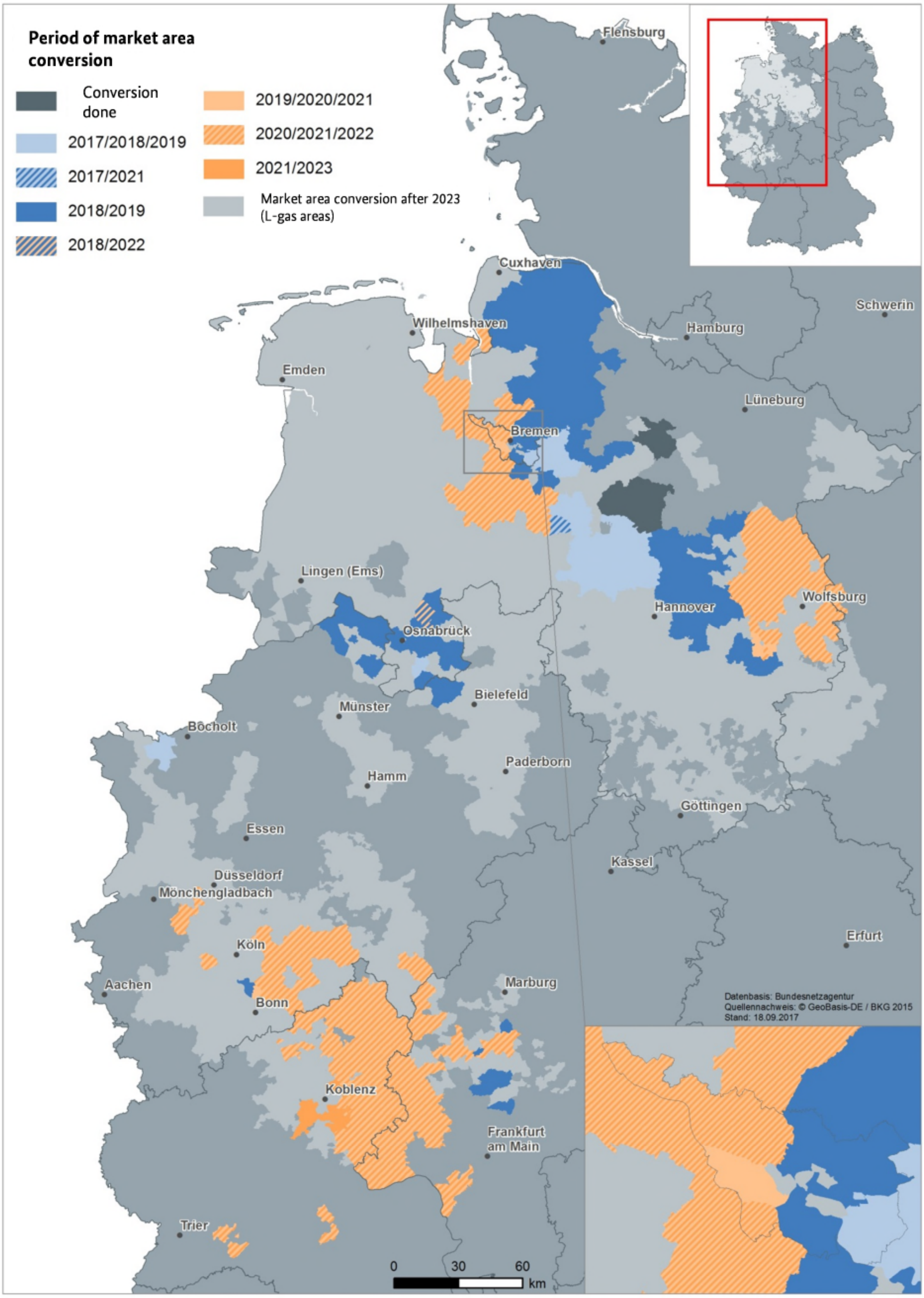


Figure 160: Market area conversion time line

The probable costs of market area conversion were €5.5m for the NetConnect Germany market area in 2016. For the GASPOOL market area, the planned costs amounted to about €18m. Both figures are purely projected costs from the network operators, without differences from previous years being included.

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 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. Overall liquidity in the natural gas wholesale market increased significantly in 2016. The volume of brokered bilateral wholesale trading rose by around 17 per cent in 2016. The volume of on-exchange gas trading increased by as much as 69 per cent.

2016 was once again characterised by significantly lower gas wholesale prices. The various price indices declined between 25 and 31 per cent year-on-year.[139]

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 product trading. 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.

Launched as a partnership 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 merger control 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. Since then, EEX and Powernext have traded on the European gas market under the name PEGAS. PEGAS allows its members to trade spot and futures market products for the German, French, Dutch, Belgian, British and Italian gas market areas. Futures can be traded for specific months, quarters, seasons (summer/winter) or years.

[139] The daily reference prices NCG and GASPOOL fell year-on-year by an unweighted annual average of around 29 per cent, the arithmetic mean of the European Gas Index Germany (EGIX) fell by around 31 per cent and the (unweighted) average of monthly cross-border prices (BAFA) fell by around 25 per cent.

In the second half of 2016, products from the Austrian Central European Gas Hub (CEGH) and Danish Gaspoint Nordic were added to the PEGAS portfolio. A total of 1,756.2 TWh were traded on the EEX Group's gas market in 2016, a year-on-year increase of 69 per cent (1,042.0 TWh in 2015). The spot market accounted for 665.5 TWh (457.7 TWh in 2015) and a total volume of 1,090.7 TWh was traded on the futures market (584.3 TWh in 2015). 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.[140]

The entire trading volume on PEGAS relating to the German market areas GASPOOL and NCG was around 425 TWh in 2016, an increase of around 133 TWh, or 46 per cent, on the previous year's figure of 292 TWh. While trading volumes for the GASPOOL market area increased by approximately 19 TWh or around 19 per cent, the volume for the NCG market area rose by 114 TWh or around 60 per cent.

Development of natural gas trading volumes on EEX for the German market areas
in TWh

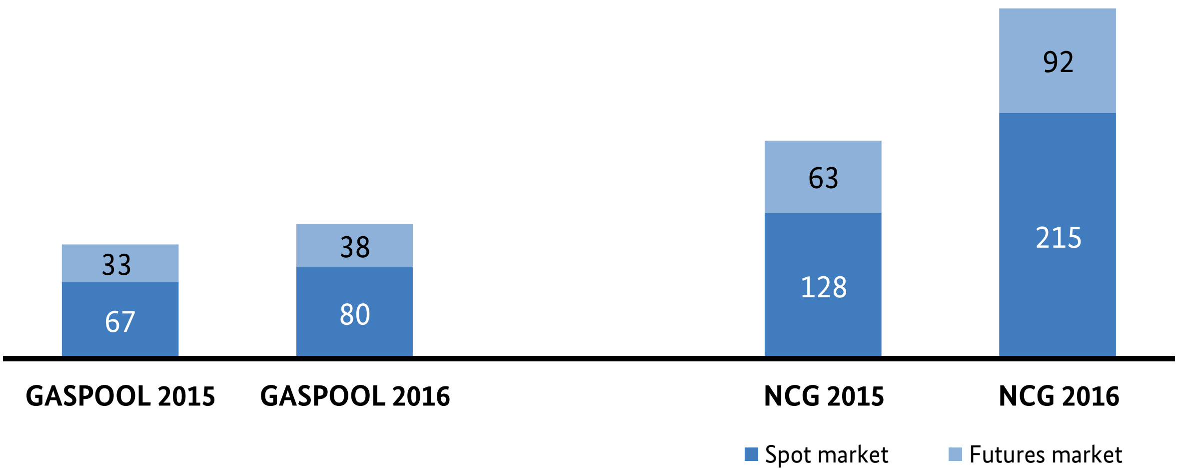


Figure 161: Development of natural gas trading volumes on EEX for the German market areas

The on-exchange volume traded on the spot market increased again in 2016 and was around 295 TWh (around 195 TWh in the previous year). In 2016, as in previous years, the majority of spot market transactions for both market areas focused on day-ahead contracts (NCG: 128.5 TWh, previous year: 76.8 TWh; GASPOOL: 51.1 TWh, previous year: 42.6 TWh). The trading volume of futures contracts rose from around 97 TWh in 2015 to around 130 TWh in the reporting year, an increase of about 34 per cent.

The annual average number of active participants on the spot market per trading day was 79 for NCG contracts (71 in the previous year) and around 68 for GASPOOL contracts (around 59 in the previous year). By contrast, the average number of active[141] participants on the futures market per trading day was 11.2 (NCG; 9.8 in the previous year) and 7.1 (GASPOOL; 5.9 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

[140] EEX Annual Report 2016, p. 84.
[141] Participants are considered to be active on a trading day if at least one of their bids has been submitted.

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.

As in the previous year, there were two market makers[142] operating on the PEGAS gas futures market in 2016 to ensure liquidity and continuous trade: E.ON/Uniper and RWE/innogy.[143] As market makers, the two companies' share of turnover in all gas futures contracts concluded via PEGAS in 2016 was about 18 per cent on the sales side and about 14 per cent on the purchase side. Besides agreements with market makers, PEGAS 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 a total of about 52 per cent of purchases and sales in 2016.

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 is 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. 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.

The natural gas trading transactions brokered by these broker platforms in 2016 with Germany as the supply area comprise a total volume of 3,120 TWh (2,652 TWh in the previous year), of which 1,252 TWh were contracts to be fulfilled in 2016 (fulfilment period of one week or more).

The increase in volume is confirmed by the figures relating to brokered natural gas trading for the NCG and GASPOOL market areas published by the London Energy Brokers' Association (LEBA).[144] Seven of the eleven broker platforms that provided data on which the above evaluation was based are members of LEBA. These affiliated broker platforms accounted for a total of 2,775 TWh for the two German market areas in 2016. This represents an increase of 13 per cent on the previous year's volume of 2,452 TWh.

[142] An exchange participant who has undertaken to publish binding purchase and sales prices (quotations) at the same time is referred to as a market maker. Market makers are meant to increase the liquidity of the market place.
[143] For more information on corporate restructuring see the comments in section I Electricity market, A 3. Market concentration, p. 38 ff.
[144] See http://www.leba.org.uk/pages/index.cfm?page_id=59&title=leba_data_notifications (retrieved on 2 July 2017)

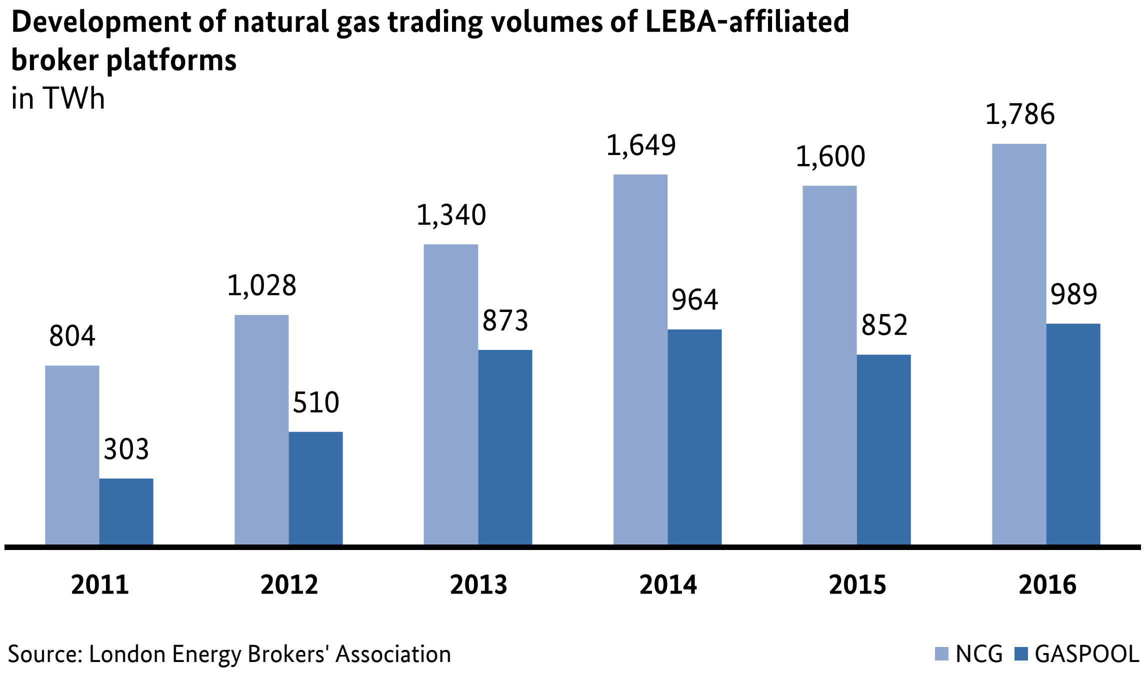


Figure 162: Development of natural gas trading volumes of LEBA-affiliated broker platforms for German market areas

Short-term transactions with a fulfilment period of less than one week account for about 19 per cent of the trade brokered by the eleven broker platforms.

Transactions in the current year make up the majority of brokered natural gas trading followed by the activities for the subsequent year. While natural gas traded during and for 2016 (including spot trading) constitutes as much as 59 per cent of the total volume and still as much as 29 per cent for the subsequent year (2017), the share of transactions with supply dates in 2018 and later is 13 per cent. This structure largely corresponds to the previous year's result (with a slight shift towards later supply dates).

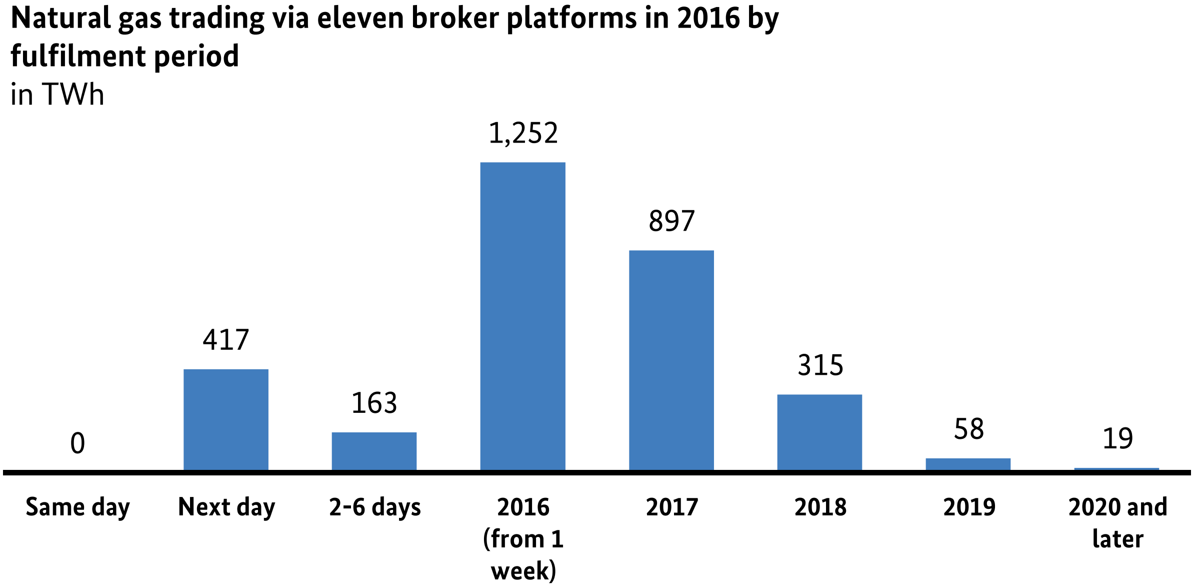


Figure 163: Natural gas trading for the German market areas via eleven broker platforms in 2016 by fulfilment period

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. However, the nomination volume increases more slowly than the trading volume since only the trade balance between parties is nominated, i.e. between market players and the exchange in the course of the exchange transaction. Besides, not all nomination volumes are linked to transactions on the wholesale markets, one example being transfers between balance groups of the same company.

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 at the two VTPs increased from a total of 3,452 TWh to 3,650 TWh, a rise of about 6 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.

The nominated volumes of high calorific gas at the NCG VTP and the GASPOOL VTP increased only marginally (by 0.2 to 6.5 per cent) year-on-year. The growth rates for low calorific gas were between 8.8 and 32.7 per cent, however, this was based on substantially lower trading volumes.

Development of nomination volumes at virtual trading points
in TWh

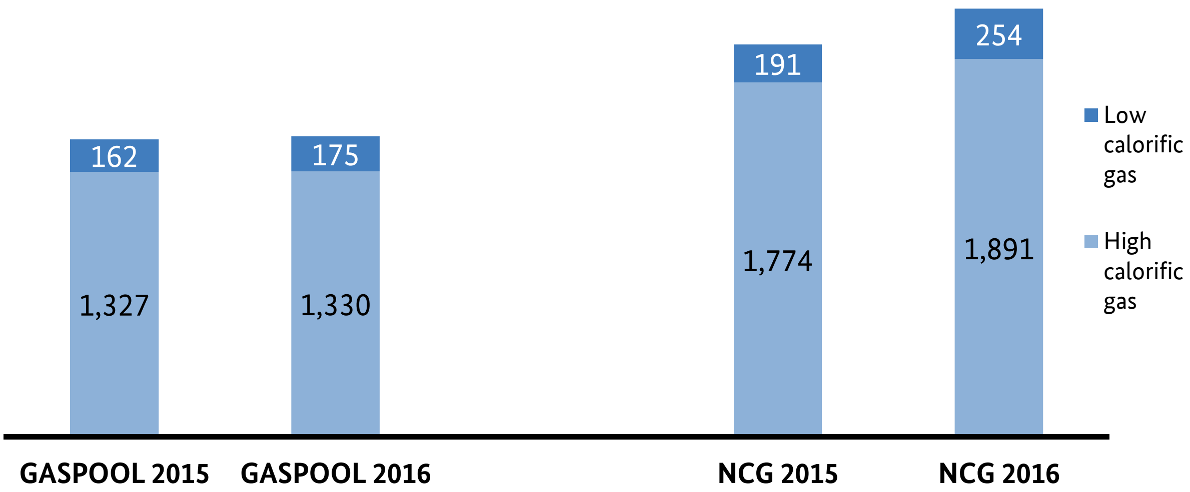


Figure 164: Development of nomination volumes at the German virtual trading points

As in previous years, the monthly nomination volumes reflect seasonal differences. The (aggregated) monthly nomination volumes of both VTPs peaked at 271 TWh between May and August 2016. The lowest nomination volume was 236 TWh in June 2016; the annual peak of about 384 TWh was reached in December 2016.

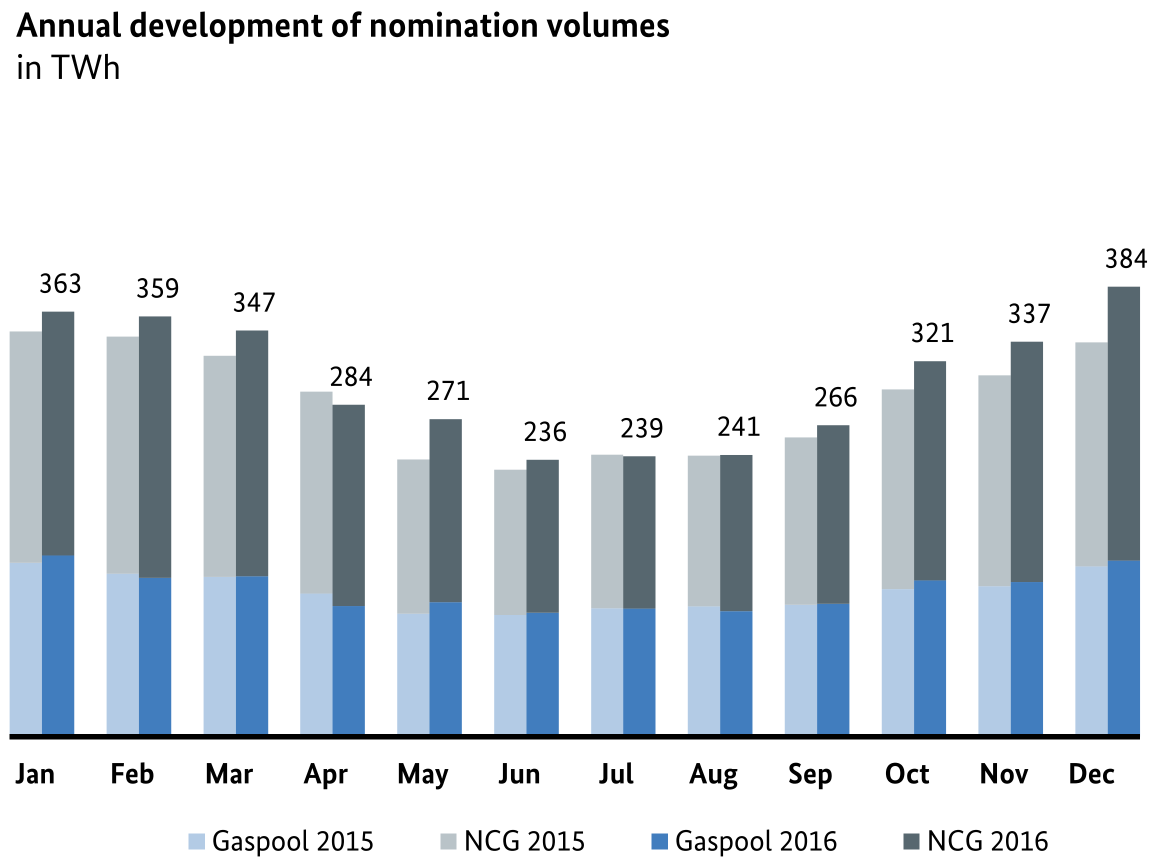


Figure 165: Annual development of nomination volumes at virtual trading points in 2015 and 2016

The number of active trading participants, i.e. companies that carried out at least one nomination in the relevant month, continued to increase in both market areas in 2016. The number of active trading participants in the NCG market area increased from 317 to 319 (by about 1 per cent) for high calorific gas and from 162 to 167 (by about 3 per cent) for low calorific gas. The annual average number of active participants in the GASPOOL market area increased year-on-year from 271 to 288 (by about 6 per cent) for high calorific gas and from 145 to 197 (by about 36 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, which is described in greater detail on page 351 below, 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.[145] 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 €14.14/MWh for the NCG market area and €14.12/MWh for GASPOOL in 2016. The previous year's figures were €20.01/MWh for NCG and €19.92/MWh for GASPOOL, which means that the annual average of the daily reference prices fell by about 29 per cent. The daily reference prices fluctuated between €10.74/MWh on 20 August and €19.56/MWh on 31 December in the course of 2016.

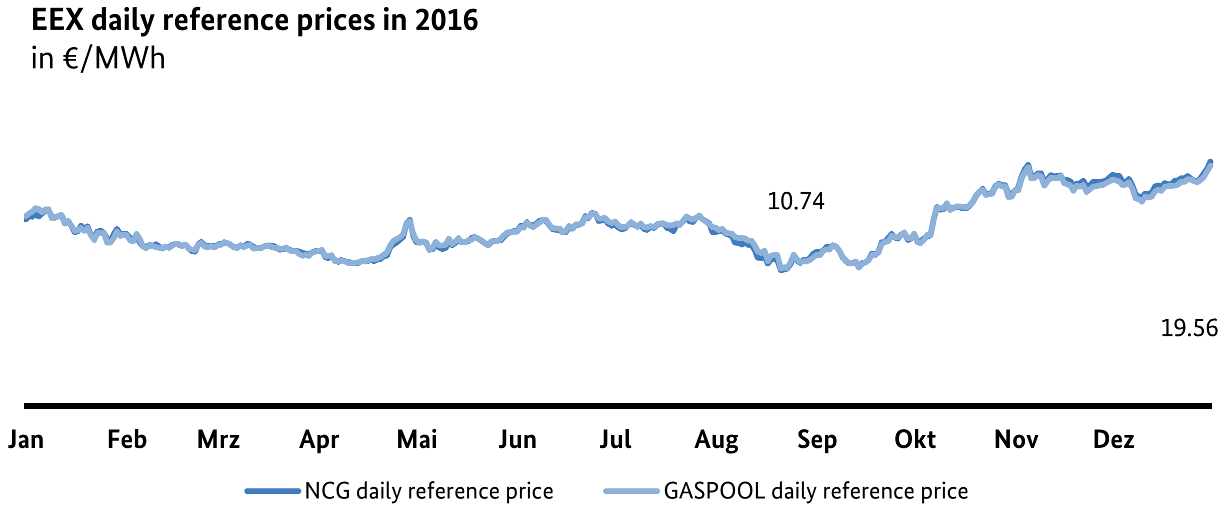


Figure 166: EEX daily reference prices in 2016

The difference between the daily reference prices of NCG and GASPOOL was again quite small in 2016 with a maximum of 2 per cent on 360 out of 366 days. The difference reached a higher level of 3 to 4 per cent on six days only.

[145] For details of the calculation method see http://cdn.eex.com/document/150893/2013-11-28_Beschreibung_Tagesreferenzpreis.pdf (retrieved on 17 July 2017).

Distribution of the differences between the EEX daily reference price for GASPOOL and NCG in 2016
Number of days with a difference of

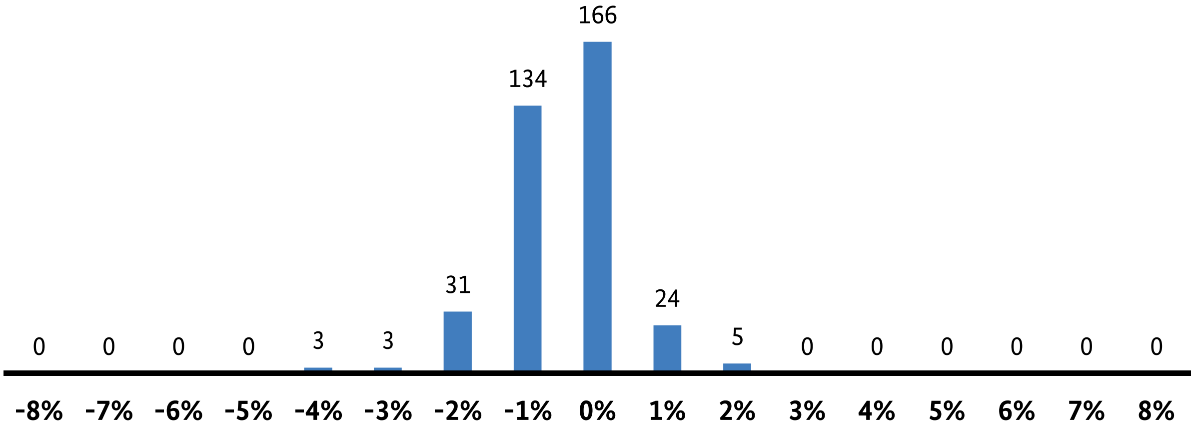


Figure 167: Distribution of the differences between the EEX daily reference prices for GASPOOL and NCG in 2016

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[146]. In 2016, the EGIX Germany ranged from €12.04/MWh in May to €17.78/MWh in December. The arithmetic mean of the twelve monthly figures was €14.15/MWh, a decline of approximately 31 per cent compared to the previous year's figure of €20.46/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. To this end, 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[147] agreed in import contracts; spot volumes and prices are largely disregarded.

The monthly BAFA cross-border prices for natural gas ranged from €13.01/MWh to €28.50/MWh between 2014 and 2016. The (unweighted) average of the monthly cross-border prices was €15.23/MWh in 2016, down by 25 per cent from the 2015 figure of €20.30/MWh.

[146] For a detailed calculation of the values see https://cdn.eex.com/document/86103/EGIX-Informationsblatt_DE.pdf (retrieved on 17 July 2017).

[147] For details see http://www.bafa.de/SharedDocs/Downloads/DE/Energie/egas_aufkommen_export_1991.html (retrieved on 17 July 2017).

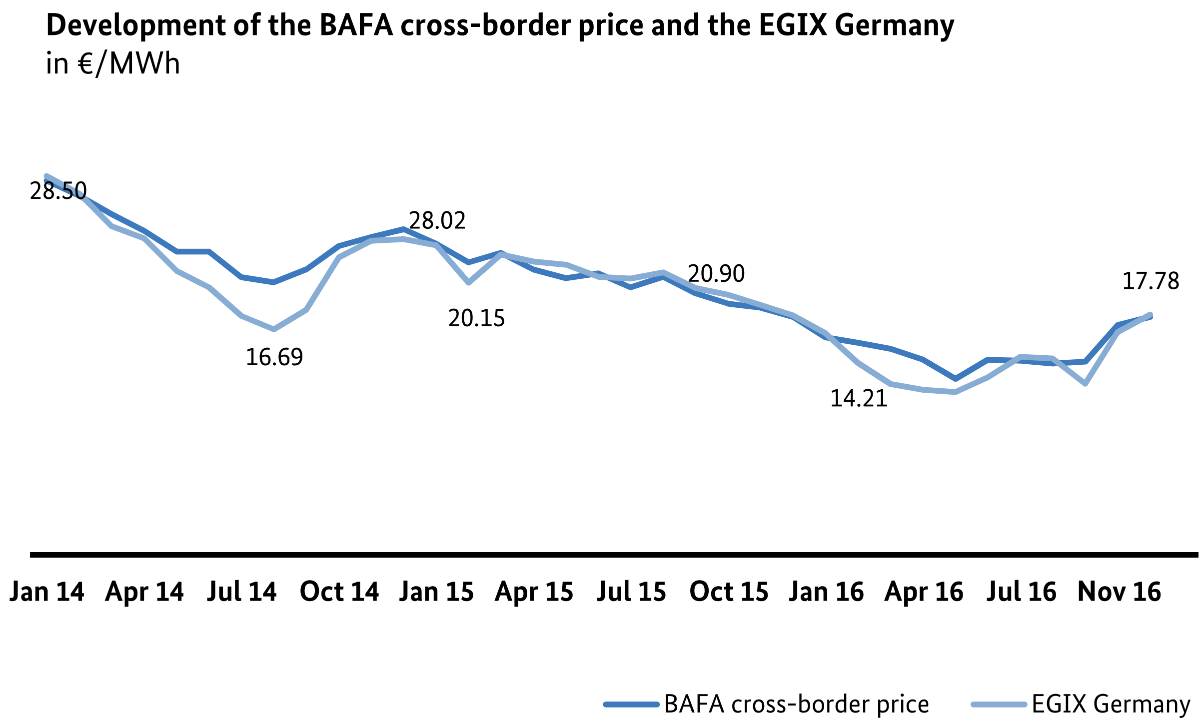


Figure 168: Development of the BAFA cross-border price and the EGIX Germany between 2014 and 2016

Older gas import contracts were usually based on price agreements linked to oil prices. In recent years, this link has been increasingly disregarded in new contracts and contract amendments. 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 2016 clearly shows that it is aligned with natural gas exchange prices.

G. Retail

1. Supplier structure and number of providers

A total of 1,035 gas suppliers were surveyed for the 2017 Monitoring Report. 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 (490 companies or 51%) supplied between 1,001 and 10,000 meter points each.[148] These 490 suppliers delivered gas to 2.1m or 15% of the total number of meter points.[149] The amount of gas that these suppliers delivered to final consumers was 146.4 TWh. Based on the total reported volume of gas delivered of 827.7 TWh, this corresponds to a share of 17.7%.

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 43% of the consumer meter points. The amount of gas that these suppliers delivered to final consumers was 212.7 TWh. Based on the total reported volume of gas delivered of 827.7 TWh, this corresponds to a share of 25.6%. 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.

[148] The analysis is based on the data provided by 965 gas suppliers.

[149] The number of final consumer meter points reported by the gas suppliers, standing at 14.0m, deviates slightly from the figure reported by the network operators, which stands at 14.1m. This difference is due to the greater market coverage of gas TSOs and DSOs.

Gas suppliers according to the number of meter points they supply (number and percentage)
These figures do not take account of company affiliations

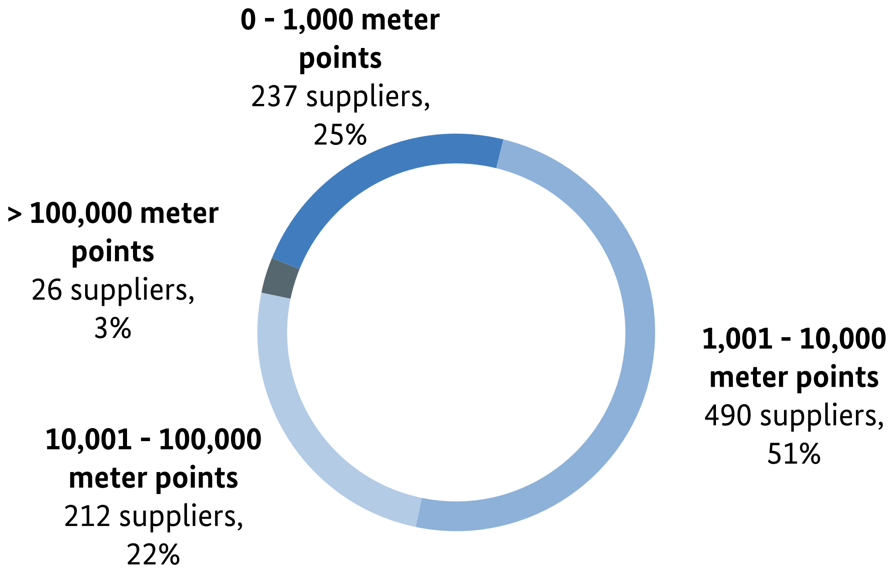


Figure 169: Gas suppliers according to the number of meter points they supply (number and percentage) - as at 31 December 2016

One indicator of the degree of choice for gas customers is the number of suppliers in each network area. In the survey for the 2017 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 competition.

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. This positive trend continued in 2016 as well. Consumers had more than 50 gas suppliers to choose from in nearly 90% of network areas. Final consumers in over 46% of network areas had a choice of more than 100 suppliers. It is clear that developments are similarly positive when focusing particularly on household customers. In 79% of network areas, household customers had a choice of 50 or more suppliers. In 30% of network areas, customers had a choice of more than 100 gas suppliers.

On average, final consumers in Germany can choose between 105 suppliers in their network area; household customers can, on average, choose between 90 suppliers (these figures do not take account of corporate groups).

Breakdown of network areas by number of suppliers operating
(all final consumers (left graph) and household consumers (right graph))
These figures do not take account of company affiliations

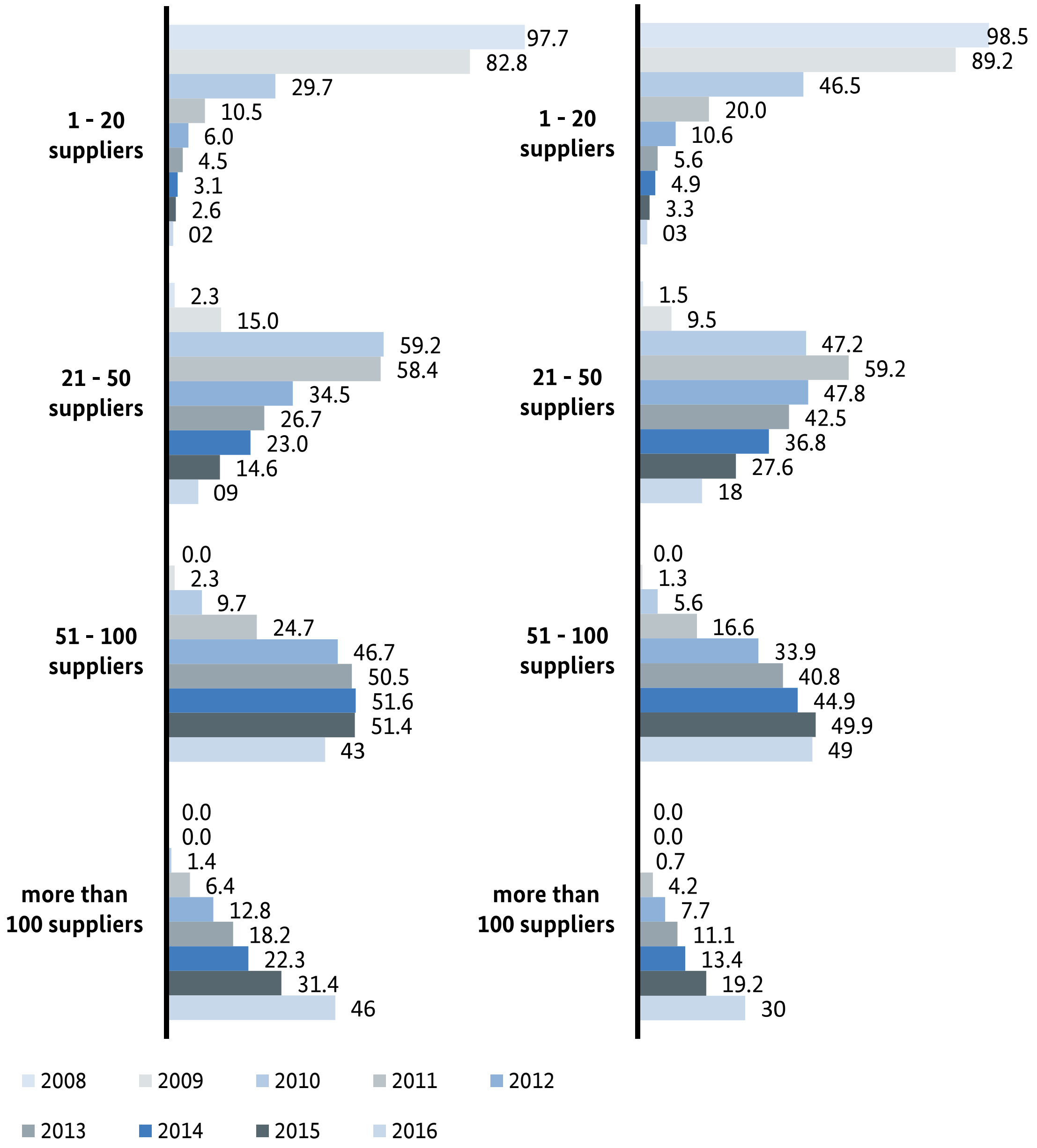


Figure 170: Breakdown of network areas by number of suppliers operating according to the survey of gas DSOs – as at 31 December 2016

Suppliers were also asked about the number of network areas in which they supply final consumers with gas. Only 15% of the gas suppliers operate in one established network area. Most of them (40%) 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 counted as active across all of Germany. A total of 38 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 66 network areas.

Gas suppliers by number of network areas they supply (number and percentage)
These figures do not take account of company affiliations

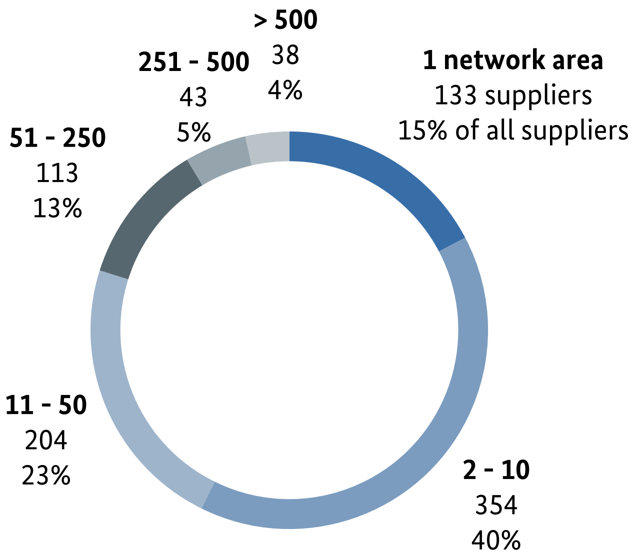


Figure 171: Gas suppliers by number of network areas they supply (number and percentage), according to the survey of gas suppliers – as at 31 December 2016

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.[150] 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 2016 reached 827.7 TWh (2015: 758 TWh). Based on the reported volumes of gas sold to SLP and interval-metered customers, about 453 TWh went to interval-metered customers and

[150] 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.

about 371 TWh to SLP customers, compared to 410 TWh and 348 TWh respectively in the previous year.[151] The majority of SLP customers are household customers. In 2016 the household customers alone were supplied with around 243.5 TWh (2015: 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,
- special contract with the 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.[152] 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"). This is also known as a special contract *sui generis* between the supplier and the customer (cf section 1(4) KAV). An analysis on the basis of these three categories makes it possible to draw conclusions as to the extent to which the importance of default supply and the default suppliers' competitive position have lessened 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".[153]

Once again, gas suppliers were asked how many household customers have switched or changed their energy supply contract in the 2016 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 2016. A supplier switch, as defined in the monitoring survey, means the process by which a final 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.

[151] The difference between the amount of 824 TWh given here and the total volume of 827.7 TWh given in table 72 is due to incomplete data from the suppliers surveyed.

[152] 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".

[153] It is also possible that further ambiguities may arise, for example if the local default supplier changes.

2.1 Non-household customers

2.1.1 Contract structure

Gas sold to non-household customers is mainly supplied to metered load profile customers where consumption is recorded at short intervals ("load profile"). Such customers are characterised by high consumption and/or high energy requirements.[154] All metered load profile customers are non-household customers with a high level of consumption, such as industrial customers or gas power plants.

In the reporting year 2016, around 800 gas suppliers (separate legal entities) provided information on metering points and on the volumes supplied to metered load profile customers (740 suppliers responded in the previous year). The 800 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 453 TWh of gas to metered load profile customers via more than 41,656 metering points in 2016. Over 99 per cent of this volume was supplied under contracts with the default supplier outside the default supply[155] (130 TWh) and under contracts with suppliers other than the local default supplier (323 TWh). It is unusual, but not impossible, for metered load profile customers to be supplied under a default or auxiliary supply contract. Around 0.4 TWh of gas was supplied to metered load profile customers with a default or auxiliary supply contract. This corresponds to about 0.08 per cent of the total volume supplied to such customers.

About 29 per cent of the total volume supplied to metered load profile 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 is the same distribution as in the previous year. The figures show that default supplier status is only of minor importance for the acquisition of gas customers with a metered load profile.

[154] 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.

[155] In accordance with Section 36 of the German Energy Act (EnWG), default supply relates only to household customers. In the following, the term default supply used in connection with non-household customers refers to an auxiliary supply.

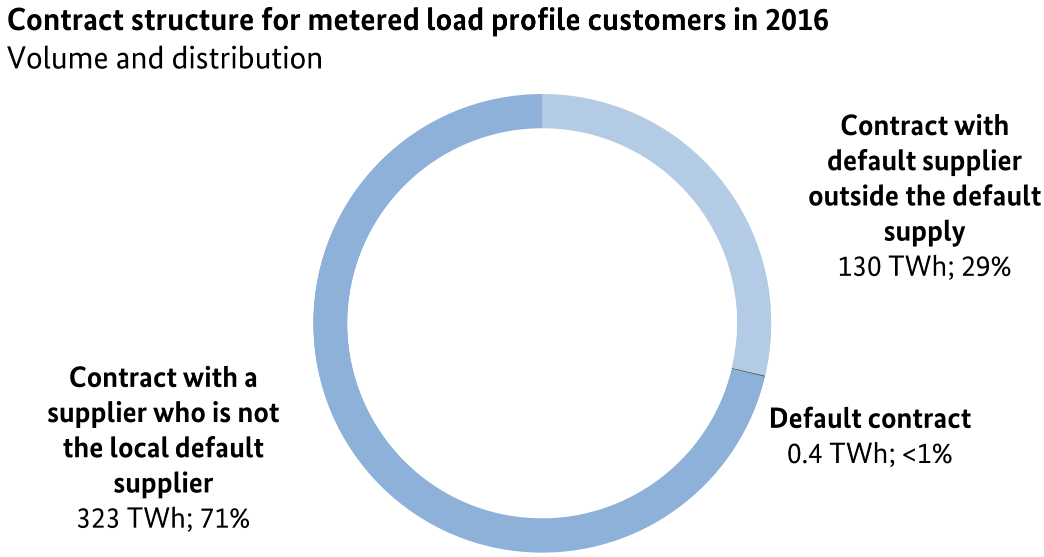


Figure 172: Contract structure for interval-metered customers in 2016

2.1.2 Supplier switching

Data on the supplier switching rates (as defined for monitoring, s.a.) of different customer groups in 2016 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 calculation of the switching rate for non-household customers included only four consumption categories with a final consumption exceeding 0.3 GWh/year, including gas-fired power plants. The survey produced the following results.

Supplier switching by consumption category in 2016

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	1,493,586	11.0%	37.9 TWh	11.5%
0.3 GWh/year – 10 GWh/year	17,430	8.0%	15.5 TWh	12.4%
>10 GWh/year – 100 GWh/year	1,086	14.3%	13.1 TWh	12.1%
>100 GWh/year	120	13.9%	31.5 TWh	12.2%
Gas power plants	6	2.5%	4.7 TWh	5.1%

Table 92: Supplier switching by consumption category in 2016

The total number of metering points with a change of supplier rose by 398,531 (plus 36 per cent) compared to the previous year. This substantial increase predominantly relates to customers with a consumption below 0.3 GWh/year, which also includes household customers. Here, the number of metering points increased by 390,801 (plus 35 per cent).

In 2016, the total gas volume affected by supplier switching was 103 TWh in all five categories. Compared to the previous year, it increased by 11 TWh or 12 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 11.1 per cent in 2016, down from 11.8 per cent in the previous year.

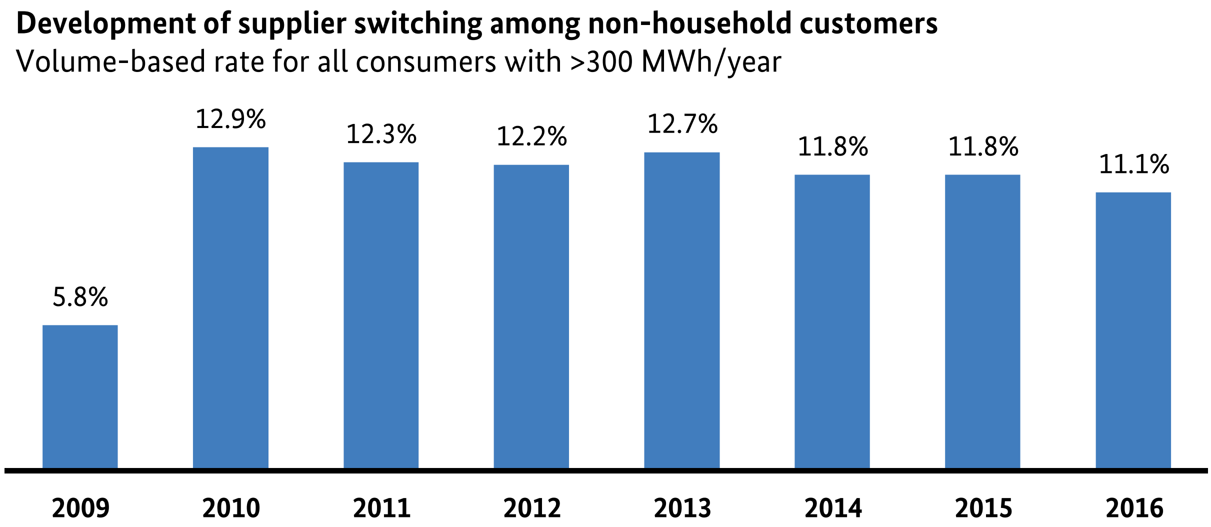


Figure 173: Development of supplier switching among non-household customers

2.2 Household customers

2.2.1 Contract structure

In the data survey for the 2017 Monitoring Report, the survey of quantities of gas supplied to household customers was broken down into three different consumption bands for the first time:

Band I (D1): 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 expansion of the survey to include the bands took consideration of the development of the European survey of prices and gas quantities carried out by Eurostat.

An overall analysis of how household customers were supplied in 2016 in terms of volume shows that the majority of them (53%) were supplied by the local default supplier under a non-default contract (2015: 54%) and were delivered 128.3 TWh of gas (2015: 122.4 TWh). Nearly 22% of household customers had a default supply contract (2015: 24%) and were supplied with 52.8 TWh of gas (2015: 53.3 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 25.6% (2015: 22%) for 62.4 TWh of gas (2015: 50.8 TWh),[156] making supply by the local default supplier under a default contract the least popular form of supply.

[156] The total volume of gas supplied to household customers reported by gas suppliers of 243.5 TWh differs from the amount reported by gas DSOs (275.6 TWh) because the market coverage of the network operator survey is higher.

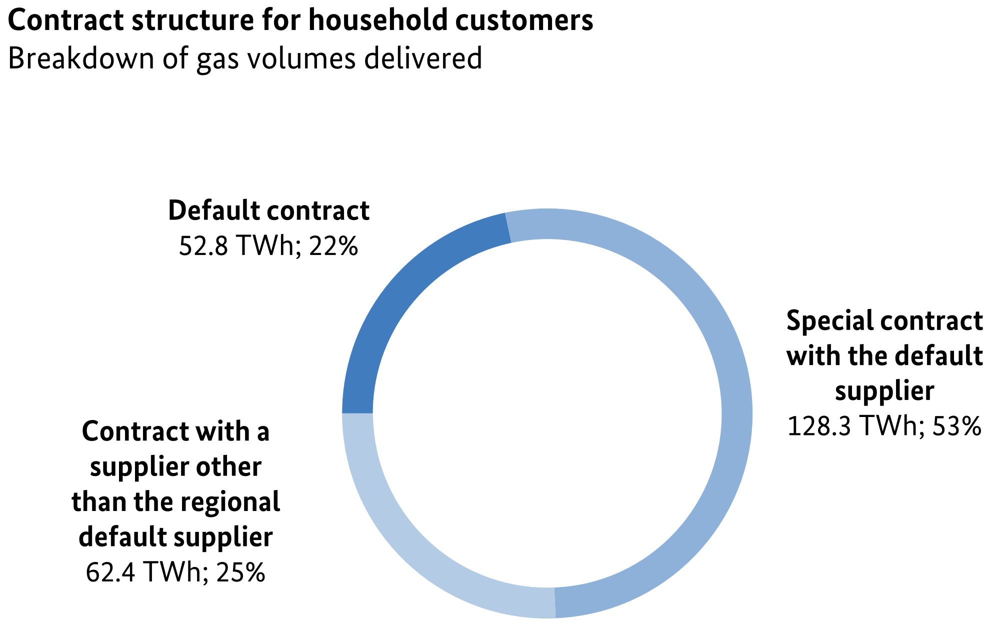


Figure 174: Contract structure for household customers (volume of gas delivered) according to survey of gas suppliers – as at 31 December 2016

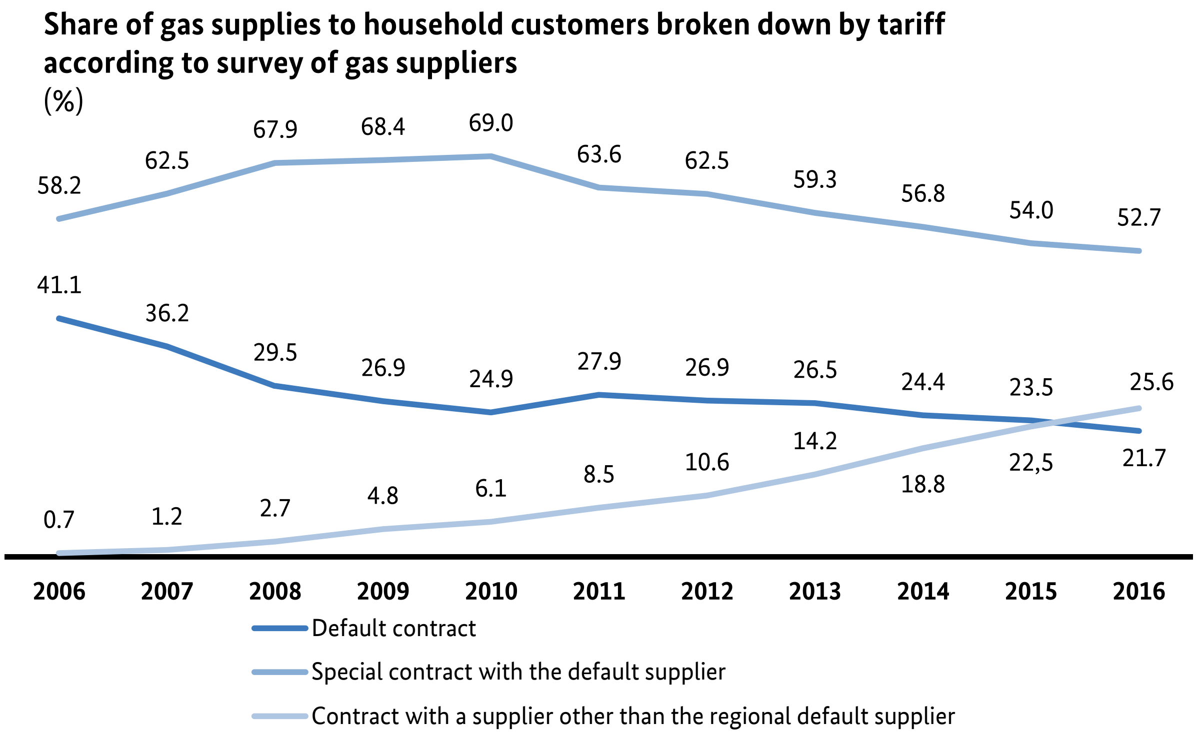


Figure 175: Share of gas supplies to household customers broken down by tariff according to survey of gas suppliers

The volumes of gas supplied to household customers were broken down into three consumption bands, D1, D2 and D3, to enable a more in-depth analysis of how household customers were supplied. This makes clear that the majority of low-consumption household customers (D1) were supplied under a default contract (47.8%). The majority of customers with average (D2) and high (D3) consumption were supplied under a non-default contract with the default supplier. [157]

Contract structure for household customers (volume and distribution) broken down by consumption bands D1, D2 and D3 in TWh

Contract type	Band I with a consumption of < 5,556 kWh (20 GJ)	Share of consumption band I	Band II with a consumption of ≥ 5,556 kWh (20 GJ) < 55,556 kWh (200 GJ)	Share of consumption band II	Band III with a consumption of ≥ 55,556 kWh (200 GJ)	Share of consumption band III
Default contract	3.3	47.8%	38.3	22.7%	8.5	16.1%
Special contract with the default supplier	2.4	34.8%	89.5	53.0%	29.5	56.0%
Contract with a supplier other than the regional default supplier	1.2	17.4%	41.0	24.3%	14.7	27.9%
Total	6.9	100.0%	168.8	100.0%	52.7	100.0%

Table 93: Contract structure for household customers (volume in TWh) broken down into consumption bands in TWh – as at 31 December 2016

When taking a particular look at the number of household customers supplied in 2016 it becomes clear that a relative majority of 45% 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 75% of household customers are supplied by the default supplier under a default contract or through a contract outside of default supply.[158] The differences between the share of customers supplied on default terms and those on non-default terms in a contract with the default supplier (22% compared with 30% and 53% compared with 45%) result from the fact that household customers with a higher consumption of gas tend to switch to a more affordable contract on non-default terms.

[157] The analysis is based on a reported volume of gas supplied to household customers of 228.4 TWh. The difference from the total reported volume of gas supplied to household customers by all gas suppliers of 243.5 TWh is due to a lack of data from some suppliers.

[158] The total number of household customers reported by gas suppliers of 12.1m differs from the number of household customers reported by DSOs (12.4m) because the market coverage of the network operator survey is higher.

Contract structure for household customers
Number of customers supplied

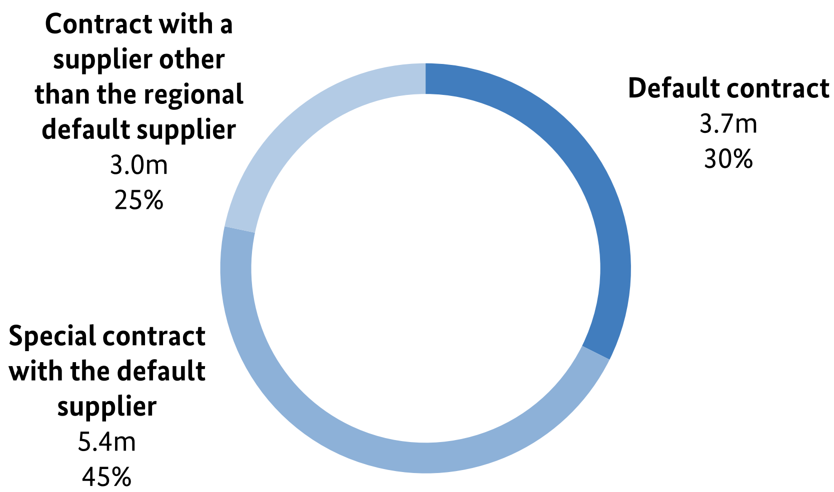


Figure 176: Contract structure for household customers (number of customers supplied) according to survey of gas suppliers – as at 31 December 2016

The number of households supplied was also broken down into three consumption bands, D1, D2 and D3, to enable a more in-depth analysis of how household customers were supplied. This makes clear that the majority of low-consumption household customers (D1) were supplied under a default contract (57.1%). The majority of customers with average (D2) and high (D3) consumption were supplied under a non-default contract with the default supplier.[159]

[159] The analysis is based on a reported total number of household customers of 11.1m. The difference from the total reported number of household customers of all gas suppliers of 12.1m is due to a lack of data from some suppliers.

Contract structure for household customers (number and distribution) broken down by consumption bands D1, D2 and D3 in millions

Contract type	Band I with a consumption of < 5,556 kWh (20 GJ)	Share of consumption band I	Band II with a consumption of ≥ 5,556 kWh (20 GJ) < 55,556 kWh (200 GJ)	Share of consumption band II	Band III with a consumption of ≥ 55,556 kWh (200 GJ)	Share of consumption band III
Default contract	1.2	57.1%	2.1	24.7%	0.09	18.0%
Special contract with the default supplier	0.6	28.6%	4.1	48.2%	0.30	60.0%
Contract with a supplier other than the regional default supplier	0.3	14.3%	2.3	27.1%	0.11	22.0%
Total	2.1	100.0%	8.5	100.0%	0.5	100.0%

Table 94: Contract structure for household customers (number of customers supplied in millions), broken down by consumption bands in TWh – as at 31 December 2016

2.2.2 Change of contract

In 2017, gas suppliers were again asked about household customers that carried out a change of contract in 2016. Only contract changes carried out at the customer's request applied in the survey.[160] The total number of customers changing contract was approximately 780,000. The volume of gas these customers were delivered was approx. 16 TWh. The resulting numbers-based and volume-based switching rates are 6.5% and 6.6% respectively. The slightly higher volume-based switching rate is an indication that it is primarily high-consumption household customers who change contracts in order to gain cost advantages.

Household customers that changed their contracts

Category	Subsequent consumption in 2016 (TWh)	Share (%) of total consumption (243,5 TWh)	Number of contracts changed in 2015	Share (%) of all household customers (12.1m)
Household customers that had changed their contract with their existing supplier	16	6.6	780,000	6.5

Table 95: Household customers that changed their contracts in 2016 according to survey of gas suppliers

[160] 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 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 significantly yet again, by around 36% (333,117 supplier switches) to 1,258,312 (2015: 925,195). There was also a clear rise of about 25% to 264,954 in the number of household customers who immediately chose an alternative supplier rather than the default supplier when moving home (52,655 household customers).

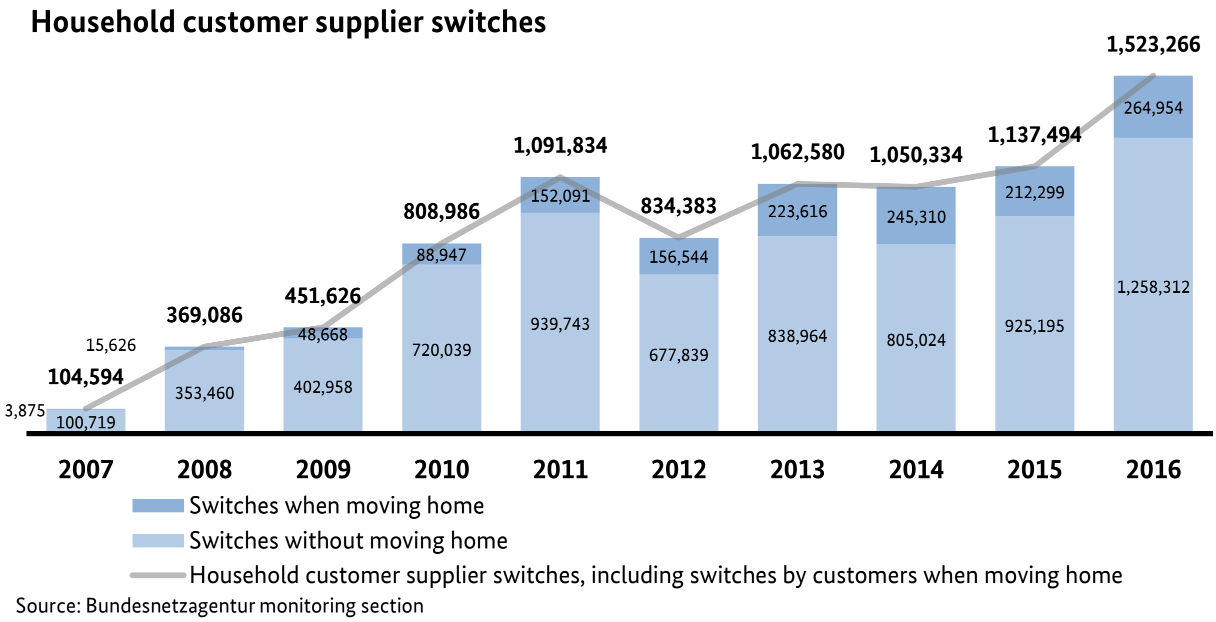


Figure 177: Household customer supplier switches according to the survey of gas DSOs

It is evident that household customers continued to increasingly make use of the cost advantages arising from a switch of supplier in 2016. When looking at 12.4m household customers (according to DSO figures) the resulting number-based household customer switching rate comes out to 12.3% (2015: 9.2%).

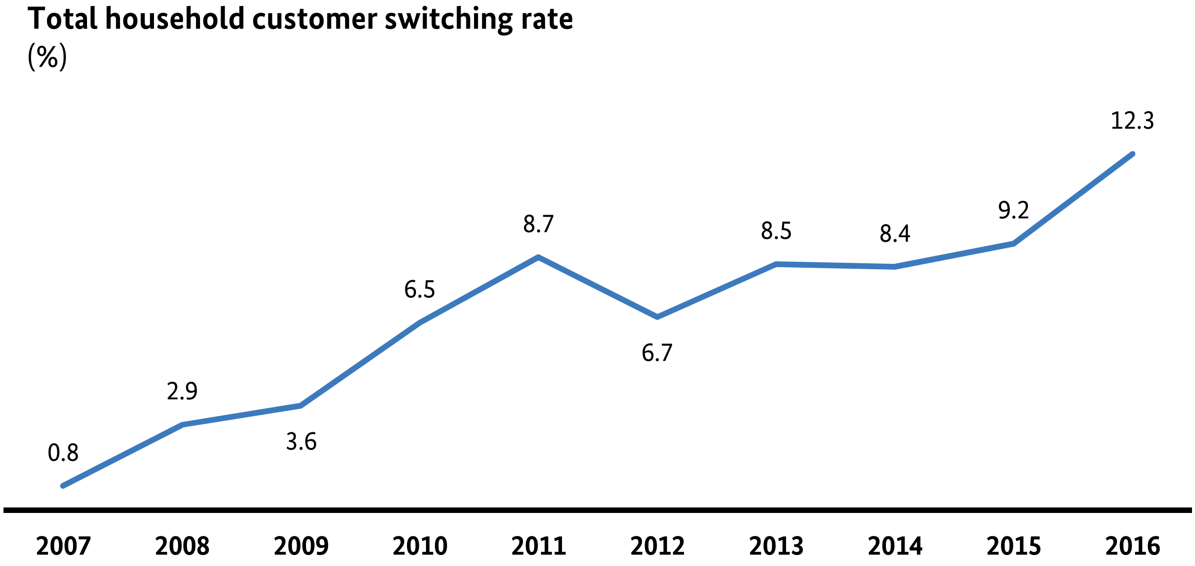


Figure 178: Total household customer switching rate according to the survey of gas DSOs

The gas 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 2016 by 11.6 TWh or 45% to 37.2 TWh. Considering the increase in gas supplied to household customers by network operators in 2016, the volume-based switching rate rose to 13.5% (2015: 10.1%). The volume-based supplier switching rate (13.5%) is still above the numbers-based rate (12.3%) because high-consumption household customers exhibit more intensive switching behaviour. At around 24,500 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 2016 (TWh)	Share (%) of total consumption (275.6 TWh)	Number of supplier switches in 2016	Share of all (12,416,171) household customers
Household customer supplier switches without moving home	32.0	11.6%	1,258,312	10.1%
Household customers who immediately chose an alternative supplier rather than the default supplier when moving home	5.2	1.9%	264,954	2.2%
Total	37.2	13.5%	1,523,266	12.3%

Table 96: Household customer supplier switches in 2016, 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 2017 Monitoring Report, DSOs and gas suppliers were again 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.

Disconnection notices and orders to disconnect default supply customers; disconnection on behalf of the local default supplier

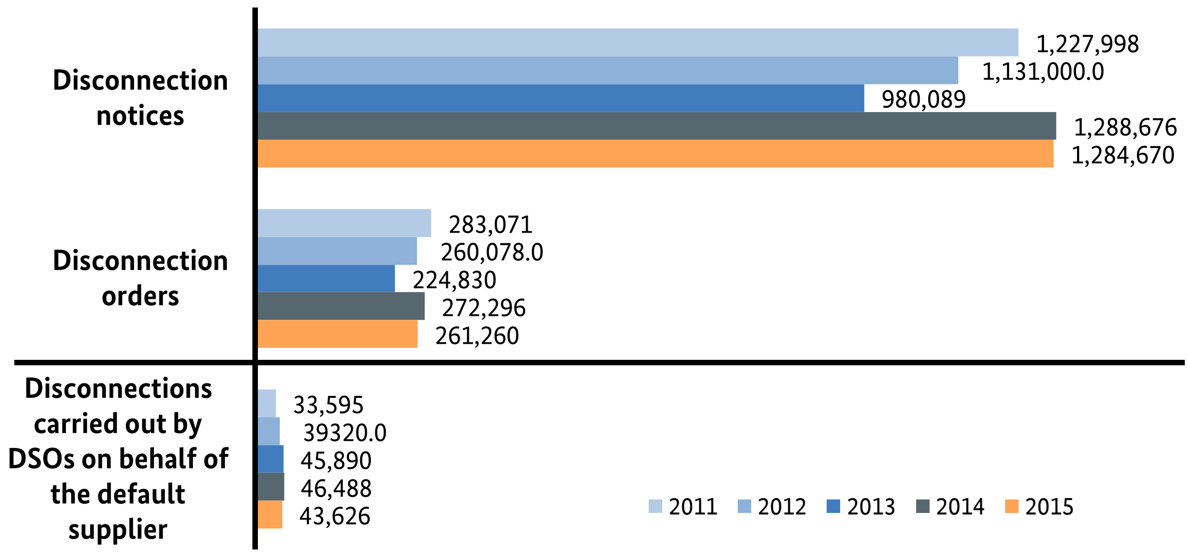


Figure 179: Disconnection notices and orders to disconnect default supply customers; disconnection on behalf of the local default supplier (gas) for the years 2011 - 2015

Starting in 2016, the gas supplier survey was further differentiated. 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 gas supplier survey was also expanded for 2016. Disconnections carried out by the DSOs on behalf of a supplier other than the regional default supplier were also included.

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, since 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 its network registration with the network operator if it 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.

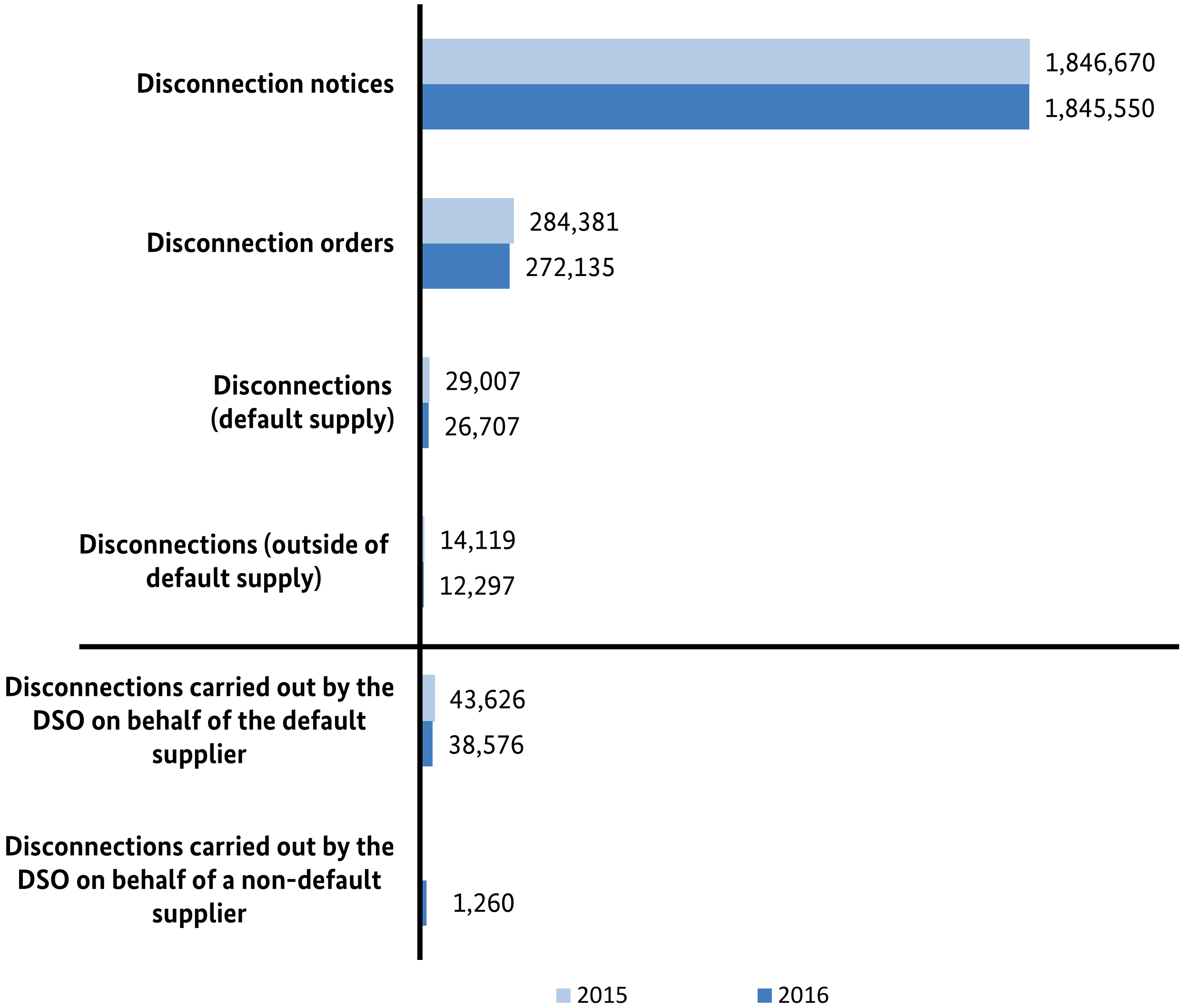
The following analysis for 2016 is based on the data provided by 643 DSOs and 658 gas suppliers. The figures provided by DSOs and gas suppliers show a general decrease in gas disconnections in 2016.

The number of disconnections carried out by DSOs on behalf of the regional default supplier fell to 38,576, which represents a drop of nearly 12% year-on-year or around 5,000 disconnections. Additionally, 1,260 gas disconnections were carried out on behalf of suppliers other than the regional default supplier. This figure is based on information from the DSOs that ultimately carry out the disconnections on behalf of the suppliers.

In 2016, gas DSOs restored supply to around 30,633 customers whom they had previously disconnected on behalf of the default supplier. The decline in restored meter points, of about 5,300 meter points compared to the year before, is largely due to the general decrease in gas disconnections. Supply was also restored to about 1,486 meter points on behalf of gas suppliers other than the regional default supplier.

The average charge paid by suppliers to DSOs for disconnecting customers was around €46 (excluding VAT), with the actual costs charged ranging from €12 to €205 (excluding VAT). The average charge paid by suppliers to DSOs for restoring supply to customers was around €53 (excluding VAT), with the actual costs charged ranging from €10 to €225 (excluding VAT).

Disconnection notices and orders; disconnections carried out [1]
In 2015 and 2016 (gas)



[1]The number given in the figure below the dividing line is taken from the DSO survey. Only disconnections carried out by the DSOs on behalg of the given regional default supplier were recorded for 2015. Disconnections carried out on behalf of suppliers other than the default supplier were added to the survey for 2016. All of the data above the dividing line has been taken from the supplier survey. Here, the disconnections carried out are recorded according to contractual relationships (default supply and non-default supply).. The disconnection figures shown here are not, therefore, directly comparable.

Figure 180: Disconnection notices and orders; disconnections carried out (gas)

At the same time the suppliers were asked how often in 2016 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 (1,845,550) remained more or less steady (-0.1%). Compared to 2015, the number of disconnection orders fell by 4.3% to 272,135. The figures given for disconnection notices and orders in the 2016 Monitoring Report had to be adjusted: the number of disconnection notices in 2015 was 1,846,670 and the number of disconnection orders was 284,381. Around 14% of the 1.8m disconnection notices issues by gas suppliers (both default and non-default) resulted in a disconnection subsequently being ordered from the DSO in 2016.

According to the gas suppliers, 39,004 disconnection orders (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, equivalent to a decline of around 4,000 disconnections on the year before. A comparison of the number of disconnection notices issued with the number of disconnections actually carried out makes it clear that about 2.1% of the notices issued actually resulted in a disconnection being carried out by the DSO. Additionally, gas suppliers indicated that they disconnected customers with a default contract 26,707 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 12,297 times. The disconnection rate for non-default customers was 0.2%.

This ratio has various causes. It is presumed that a disconnection notice often leads to a payment being made. Other customers refuse entry to the persons authorised to carry out the disconnection. A court order is then required to carry out the disconnection, which takes time and leads to a financial outlay.

According to the information provided by gas suppliers, 68% of the disconnections affected household customers that were supplied by a default supplier. 32% of all disconnected customers 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 5% of household customers under a default contract were disconnected multiple times. Some 20% of household customers under a non-default contract were disconnected multiple times. The Gas Default Supply Ordinance (GasGVV) does not specify a minimum level of arrears for supply disconnection. The average level of arrears was about €124. Another common criterion for disconnection was the number of days a customer was behind in settling their accounts or making a partial payment.

While some suppliers only passed on the costs of the network operator which carried out the disconnection/reconnection, some gas suppliers additionally charged their customers an average of about €49 (including VAT)[161] for carrying out a disconnection, with the actual fees charged ranging from €2 to €197 (including VAT). Customers were charged an average reconnection fee of about €58 (including VAT), with the actual fees charged again ranging from €2 to €197 (including VAT).

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 2016, gas suppliers had to terminate their contractual relationship with a total of 47,957 gas customers due to their failure to fulfil a payment obligation. Reasons 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 2017 monitoring survey, DSOs and gas suppliers again 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, 44 DSOs had set up a total of 1,059 cash/smart card meters or other comparable prepayment systems in the context of default supply in 2016. Some 229 prepayment systems were newly installed and 215 existing

[161] The supplier's own costs, not including costs incurred by the network operator carrying out the disconnection.

prepayment systems were removed in 2016. On average, DSOs charged gas suppliers €40 annually for a prepayment system. The average annual base price that the gas supplier charged customers was €129, with the costs charged ranging from €14 to €211. The kilowatt-hour rate for gas billed using a prepayment meter averaged 6.7 ct/kWh and ranged between 3.6 ct/kWh and 10.1 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 2016 according to gas supplier survey

	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	4,852	5,839	€13.80 (€2 - €53)	€17.10 (€2 - €59)
monthly	217	610		
quarterly	140	197		
semi-annual	1169	1,288		
period missing	3,326	3,744		

Table 97: Non-annual billing in 2016 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 2017 for various consumption levels. The category of household customers was broken down according to the following consumption bands:

- Band I (D1[162]): 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).

[162] "D1", "D2" and "D3" refer to the consumption bands defined by EUROSTAT.

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 charges,[163] concession fees and charges for metering and meter operations. After deducting these components from the overall price, the amount remaining is the amount controlled by the supplier, which comprises above all gas procurement, supply 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
- customers 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 2017 and 1 April 2016, 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 99 and 775 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 customers with metered load profiles, 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, such a contract may even require a supplier to merely provide balancing group management services for its customers.

[163] Since 1 January 2017, the component "charge for billing" has been part of the network charges and is no longer reported separately.

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 99 suppliers (97 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 2017

	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]	0.10 - 0.42	0.28	11.0%
Metering, billing, meter operation	0.00 - 0.01	0.003	0%
Concession fee[2]	0.00	0.00[1]	0%
Gas tax	0.55	0.55	20.0%
Price component controlled by the supplier (remaining balance)	1.43 - 2.44	1.86	69%
Total price (excluding VAT)	2.23 - 3.25	2.69	

[1] Following regulatory changes, the "billing" price component has been included in the net network charge since 1 January 2017 and has since no longer been part of the metering, billing, meter operation category. The survey on price components in the next Monitoring Report will be adjusted accordingly.
[2] 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 consumption volume results in a very small average, i.e. an average of 0.00 ct/kWh (rounded) in the 116 GWh/year consumption category.

Table 98: Price level for the 116 GWh/year consumption category on 1 April 2017

Network tariffs, metering and concession fees account for an average of 11 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 costs, supply costs and the margin) is accordingly much larger at 69 per cent than that applying to household customers.

The average overall price (excluding VAT) of 2.69 ct/kWh fell by 0.08 ct/kWh and is only slightly (i.e. around 3 per cent) below the previous year's figure of 2.77 ct/kWh. The average gas price in the 116 GWh/year category has therefore reached the lowest level since the first data on gas prices was collected for energy monitoring (1 April 2008). The components of the overall price outside the supplier's control (especially network tariffs and levies) remained virtually unchanged compared to the previous year.

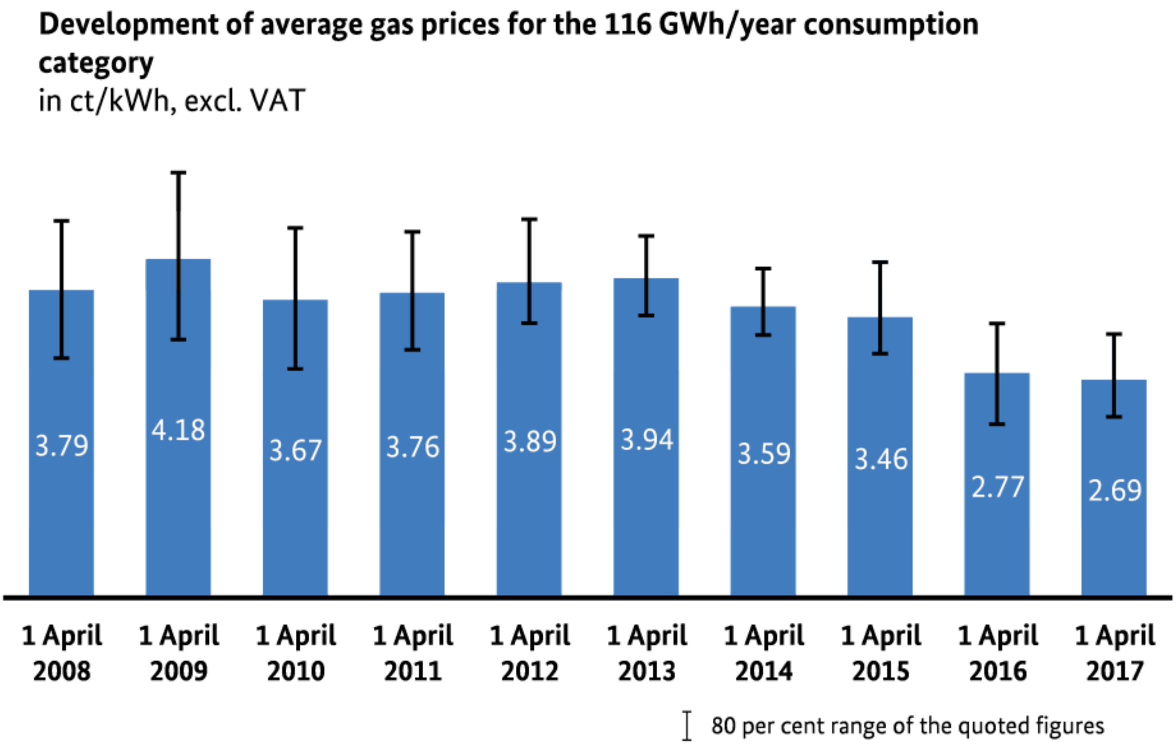


Figure 181: Development of average gas prices for the 116 GWh/year consumption category

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. It is one thousandth of the amount consumed by industrial customers (around 116 GWh) and five times higher than the average annual consumption of household customers (around 23 MWh). 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 2017. 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 775 suppliers (642 suppliers in the previous year). The data was used to calculate the averages 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 GWh/year consumption category on 1 April 2017

	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]	0.87 - 1.55	1.20	27%
Metering, billing, meter operation	0.01 - 0.08	0.05	1%
Concession fee[2]	0.03 - 0.03	0.04[1]	1%
Gas tax	0.55	0.55	12%
Price component controlled by the supplier (remaining balance)	2.09 - 3.28	2.67	59%
Total price (excluding VAT)	3.85 - 5.26	4.50	

[1] Following regulatory changes, the "billing" price component has been included in the net network charge since 1 January 2017 and has since no longer been part of the metering, billing, meter operation category. The survey on price components in the next Monitoring Report will be adjusted accordingly.
[2] 40 of the 702 suppliers quoted a figure above 0.03 ct/kW for the concession fee. 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 was supplied under a default supply contract (cf. Section 2, Paragraph 2, No. 2b of the Electricity and Gas Concession Fees Ordinance (KAV)).

Table 99: Price level for the 116 MWh/year consumption category on 1 April 2017

This year, an average 41 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). 59 per cent relate to price elements that provide scope for commercial decisions.

The arithmetic mean of the overall price of 4.50 ct/kWh (excluding VAT) is 0.27 ct/kWh or around 5 per cent lower than the previous year's figure. The absolute amount of the price components outside the supplier's control was 1.84 ct/kWh, the same as in the previous year. However, the remaining balance that can be controlled by the supplier fell by 0.21 ct/kWh (from 2.88 ct/kWh in 2015 to 2.67 ct/kWh in 2016) or by about 7 per cent.

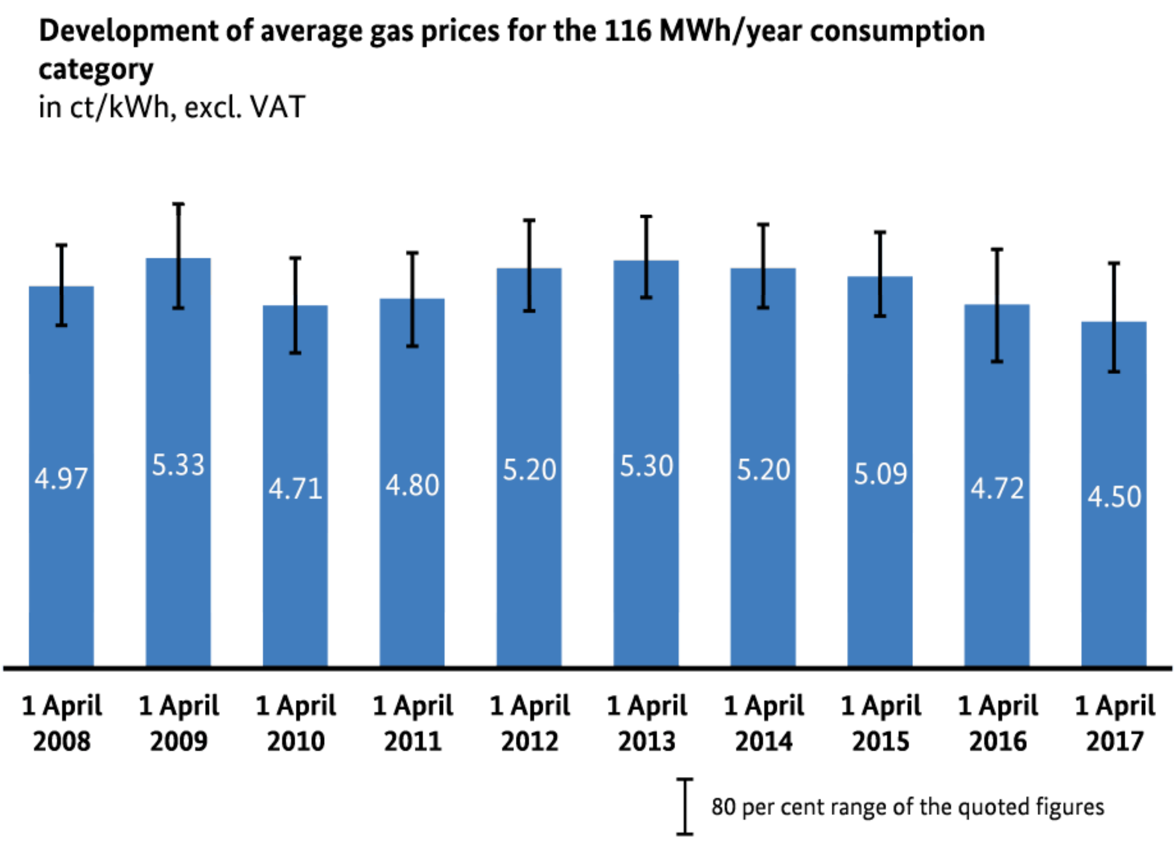


Figure 182: Development of average gas prices for the 116 MWh/year consumption category

4.2 Household customers

In the data survey for the 2017 Monitoring Report, the survey of prices for household customers was broken down into three different bands:

- Band I (D1[164]): 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 200 GJ (55,556 kWh).

The survey of gas prices in consumption bands took consideration of the development of the European survey of prices carried out by Eurostat. The total quantities of gas that were delivered by each respective supplier in the previous year were used to weight the gas price. The prices of each consumption band were weighted with the volume of gas applicable to the band of the responding gas supplier. It is important to note that the average network charges 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

[164] "D1", "D2" and "D3" refer to the consumption bands defined by Eurostat

network charge for each tariff. Since 1 January 2017, the charge for billing has been part of the network charges and is no longer reported separately.

4.2.1 Volume-weighted price across all contract categories for household customers (Band II)

The large variety of the different components that form the prices makes 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 (usually after change of contract), and contract with a supplier other than the regional default supplier (usually 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 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 2017.

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 2017 (ct/kWh)

Price component	Volume-weighted average across all tariffs (ct/kWh)	Share (%) of the total price
Price component for energy procurement, supply and margin	3.02	49.1%
Network charge including upstream network costs	1.44	23.4%
Charge for metering	0.02	0.3%
Charge for meter operations	0.06	0.9%
Concession fees	0.08	1.4%
Current gas tax	0.55	8.9%
VAT	0.98	15.9%
Total	6.15	100.0%

Table 100: Average volume-weighted price across all contract categories for household customers in consumption band II according to the gas supplier survey

Composition of the volume-weighted gas price across all contract categories for household customers - consumption band II
Prices as at 1 April 2017 (%)

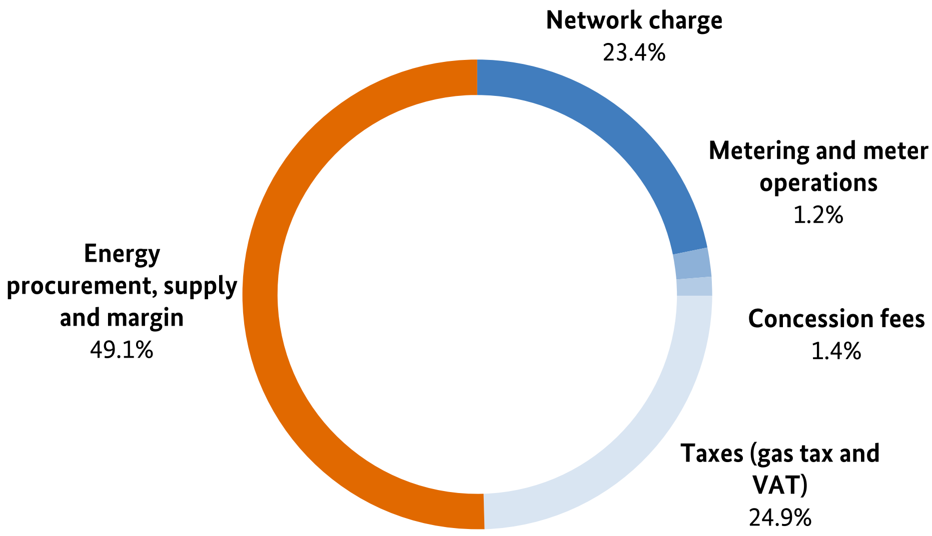


Figure 183: Composition of the volume-weighted gas price across all contract categories for household customers - consumption band II according to the gas supplier survey

Changes in the volume-weighted price across all contract categories for household customers. Consumption band between 20 GJ (5,556 kWh) and 200 GJ (55,556 kWh), (band II; Eurostat: D2)

Price component	Volume-weighted average across all tariffs on 1 April 2016 (ct/kWh)	Volume-weighted average across all tariffs on 1 April 2017 (ct/kWh)	Change in the price component	
			(ct/kWh)	(%)
Price component for energy procurement, supply and margin	3.30	3.02	-0.28	-8.6%
Network charge including upstream network costs	1.43	1.44	0.01	0.8%
Charge for metering	0.02	0.02	0.00	0.0%
Charge for meter operations	0.06	0.06	0.00	-5.3%
Concesson fees	0.08	0.08	0.00	0.0%
Current gas tax	0.55	0.55	0.00	0.0%
VAT	1.05	0.98	-0.07	-6.5%
Total	6.54	6.15	-0.39	-6.0%

Table 101: Changes in the 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)) between 1 April 2016 and 1 April 2017 according to the gas supplier survey

4.2.2 Household customer prices by consumption band

The tables below provide detailed information on the composition of the gas price for household customers, broken down by individual bands 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 at 1 April 2017 (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
Price component for energy procurement, supply and margin	4.47	4.13	4.16
Network chage including upstream network costs	2.50	2.35	2.14
Charge for metering	0.23	0.12	0.12
Charge for meter operations	0.41	0.34	0.30
Concession fees	0.48	0.12	0.04
Current gas tax	0.55	0.55	0.55
VAT	1.64	1.45	1.39
Total	10.28	9.06	8.70

Table 102: 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 at 1 April 2017

Price component	Default contract	Contract with the default supplier outside of default supply contracts	Contract with a supplier other than the regional default supplier
Price component for energy procurement, supply and margin	43.48%	45.58%	47.82%
Network charge including upstream network costs	24.32%	25.94%	24.66%
Charge for metering	2.24%	1.32%	1.38%
Charge for meter operations	3.99%	3.75%	3.45%
Concession fees	4.67%	1.32%	0.40%
Current gas tax	5.35%	6.07%	6.32%
VAT	15.95%	16.00%	15.98%
Total	100%	100%	100%

Table 103: Breakdown of the volume-weighted price components 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 2017 (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
Price component for energy procurement, supply and margin	3.36	3.01	2.70
Network charge including upstream network costs	1.42	1.43	1.48
Charge for metering	0.02	0.02	0.03
Charge for meter operations	0.06	0.05	0.07
Concession fees	0.25	0.04	0.03
Current gas tax	0.55	0.55	0.55
VAT	1.07	0.97	0.92
Total	6.73	6.07	5.78

Table 104: 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 at 1 April 2017

Price component	Default contract	Contract with the default supplier outside of default supply contracts	Contract with a supplier other than the regional default supplier
Price component for energy procurement, supply and margin	49.93%	49.59%	46.71%
Network charge including upstream network costs	21.10%	23.56%	25.61%
Charge for metering	0.30%	0.33%	0.52%
Charge for meter operations	0.89%	0.82%	1.21%
Concession fees	3.71%	0.66%	0.52%
Current gas tax	8.17%	9.08%	9.52%
VAT	15.90%	15.96%	15.92%
Total	100%	100%	100%

Table 105: Breakdown of the volume-weighted price components per contract category for household customers in consumption band II 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 at 1 April 2017 (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
Price component for energy procurement, supply and margin	3.12	2.66	2.40
Network charge including upstream network costs	1.21	1.25	1.25
Charge for metering	0.01	0.01	0.01
Charge for meter operations	0.02	0.02	0.04
Concession fees	0.23	0.06	0.03
Current gas tax	0.55	0.55	0.55
VAT	0.97	0.86	0.81
Total	6.11	5.41	5.08

Table 106: 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 at 1 April 2017

Price component	Default contract	Contract with the default supplier outside of default supply contracts	Contract with a supplier other than the regional default supplier
Price component for energy procurement, supply and margin	51.06%	49.17%	47.24%
Network charge including upstream network costs	19.80%	23.11%	24.61%
Charge for metering	0.13%	0.17%	0.16%
Charge for meter operations	0.28%	0.37%	0.69%
Concession fees	3.76%	1.11%	0.53%
Current gas tax	9.08%	10.18%	10.83%
VAT	15.88%	15.90%	15.94%
Total	100%	100%	100%

Table 107: Breakdown of the volume-weighted price components per contract category for household customers in consumption band III according to the gas supplier survey

Data from 513 gas suppliers was taken into account for the evaluation of prices for customers supplied under a default contract. On 1 April 2017, the volume-weighted price for default supply in consumption band II was 6.73 ct/kWh, a slight decrease of 3.7% compared to the previous year.

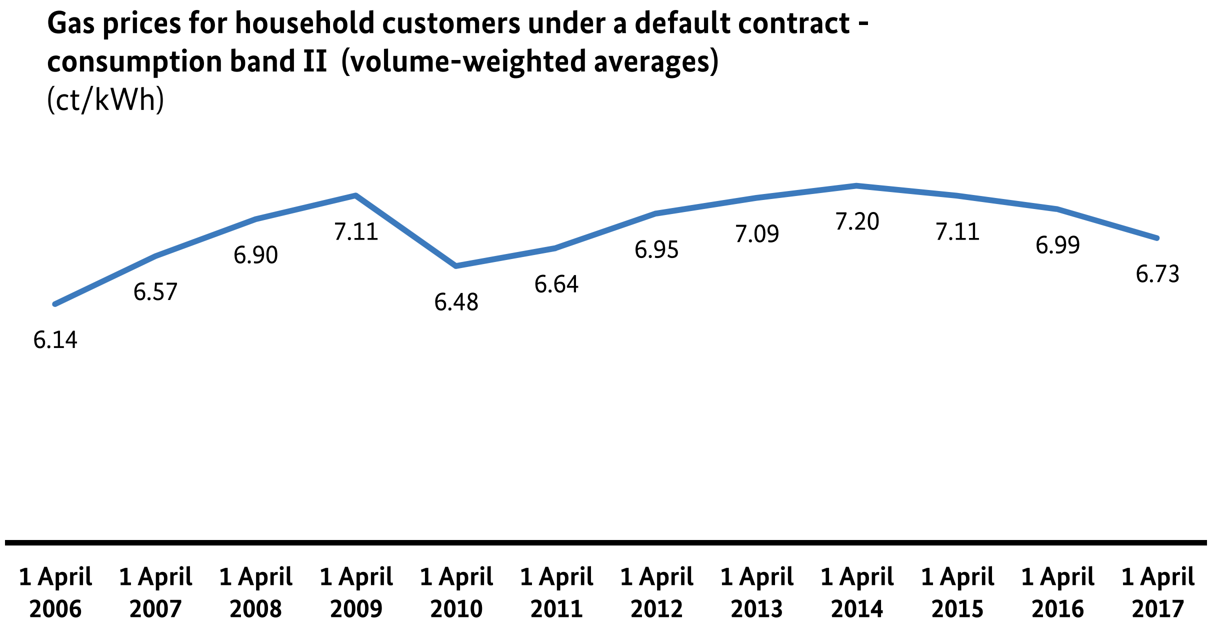


Figure 184: Gas prices for household customers under a default contract (volume-weighted averages) - consumption band II according to the gas supplier survey

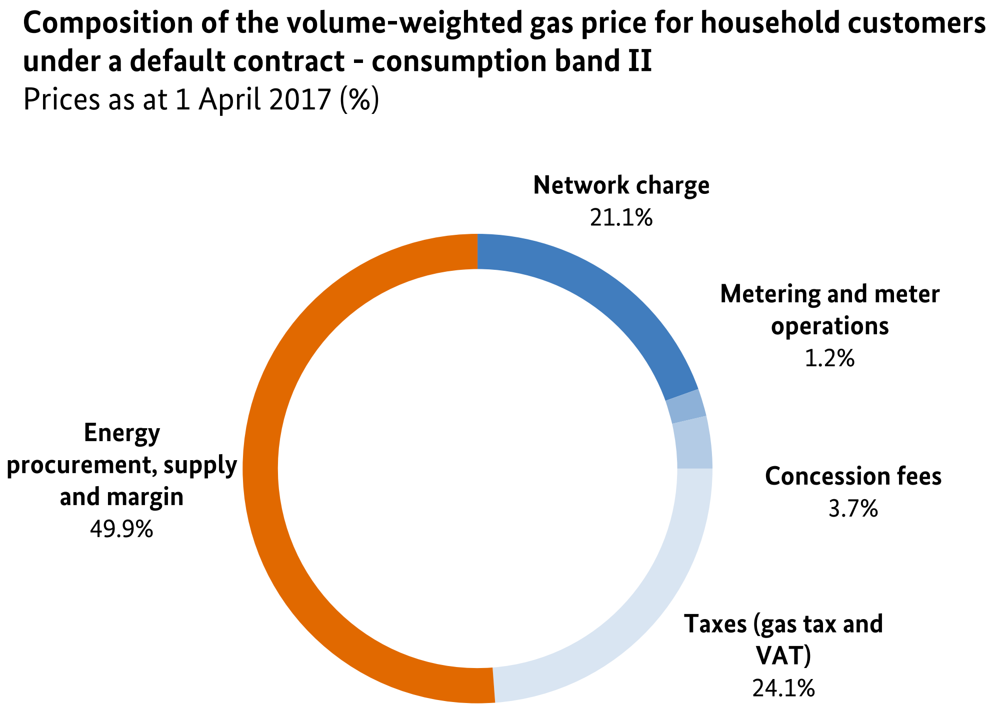


Figure 185: Composition of the volume-weighted gas price for household customers under a default contract. Prices for consumption band II, as at 1 April 2017, according to the gas supplier survey

Data from 499 gas suppliers was taken into account for the evaluation of prices for customers supplied under a special contract with the default supplier. On 1 April 2017, the volume-weighted price for customers under a special contract with the default supplier in consumption band II was 6.07 ct/kWh, a decrease of 4.7% compared to the previous year.

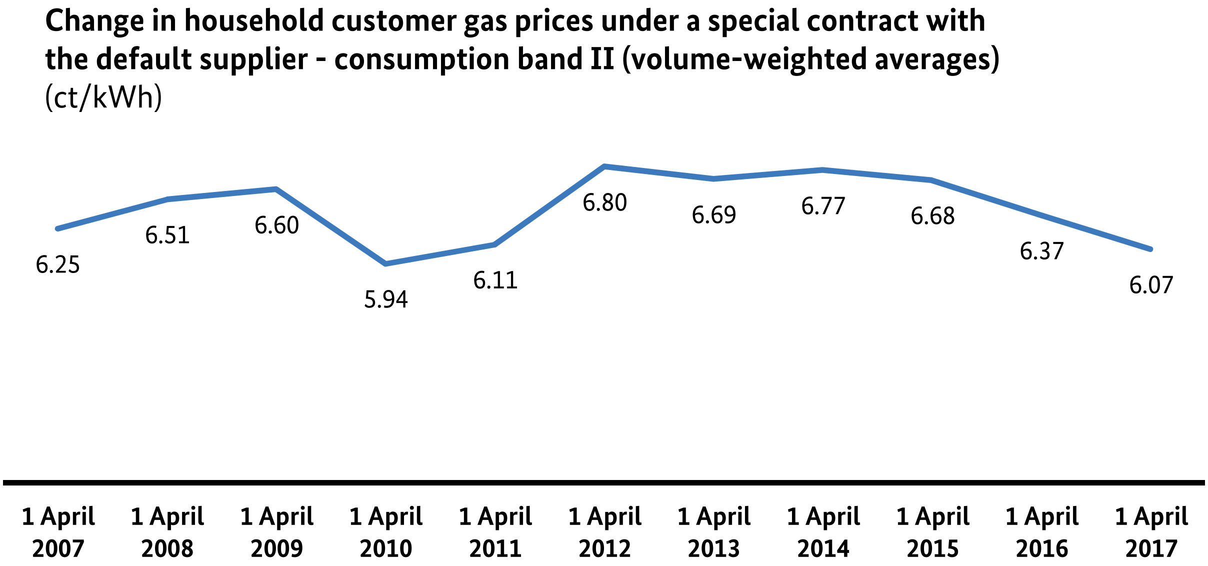


Figure 186: Change in household customer gas prices under a special contract with the default supplier (volume-weighted averages) - consumption band II according to the gas supplier survey

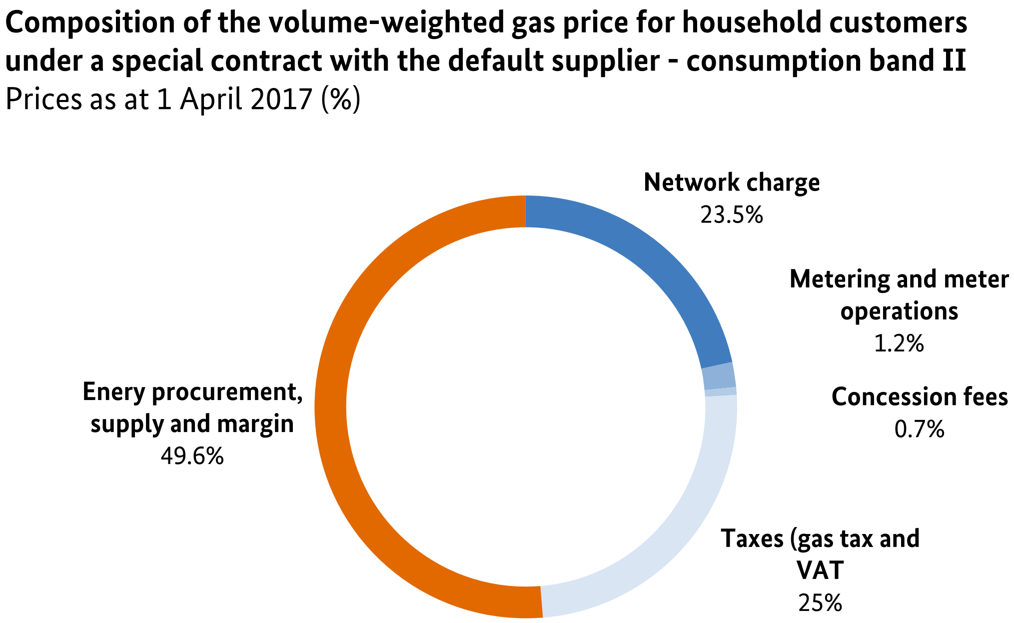


Figure 187: Composition of the volume-weighted gas price for household customers under a special contract with the default supplier. Prices for consumption band II, as at 1 April 2017, according to the gas supplier survey

Data from 561 gas suppliers was taken into account for the evaluation of prices for a contract with a supplier other than the regional default supplier. On 1 April 2017, the volume-weighted price for a contract with a supplier other than the regional default supplier in consumption band II was 5.78 ct/kWh, a clear decrease of

10.9% compared to the previous year. Gas prices for consumers under a contract with a supplier other than the regional default supplier thus reached the lowest level since the first survey on 1 April 2008.

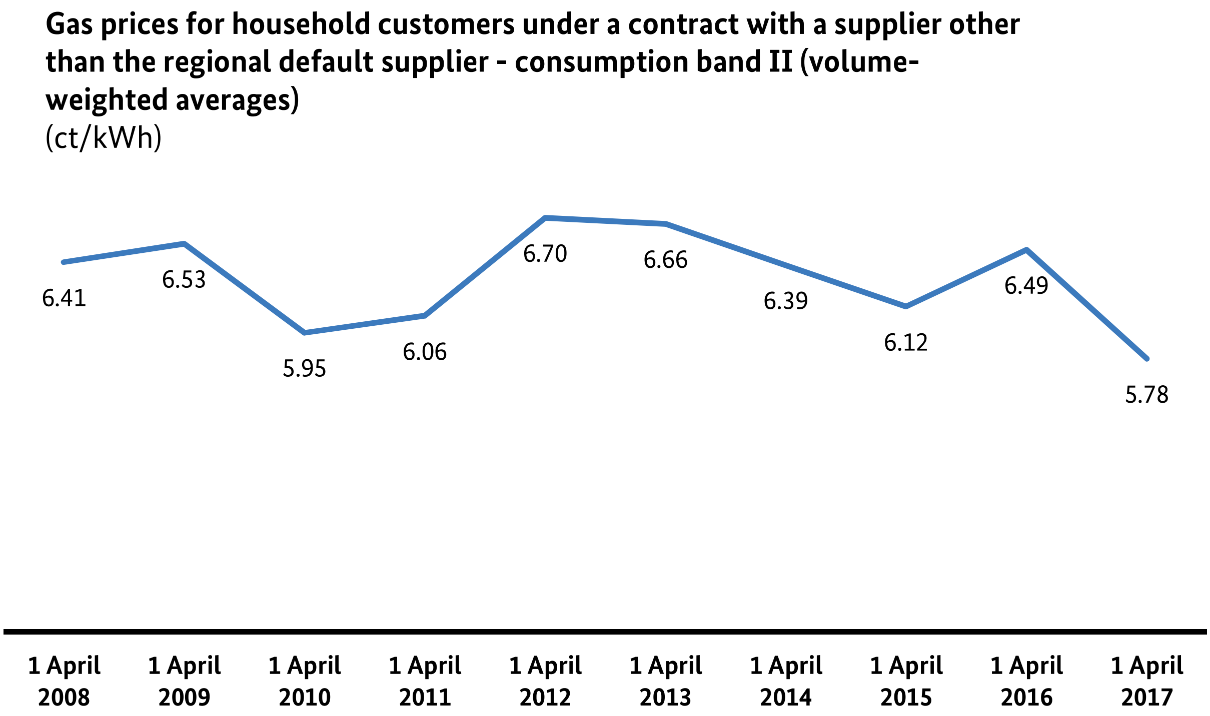


Figure 188: Gas prices for household customers under a contract with a supplier other than the regional default supplier (volume-weighted averages) - consumption band II according to the gas supplier survey

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 at 1 April 2017 (%)

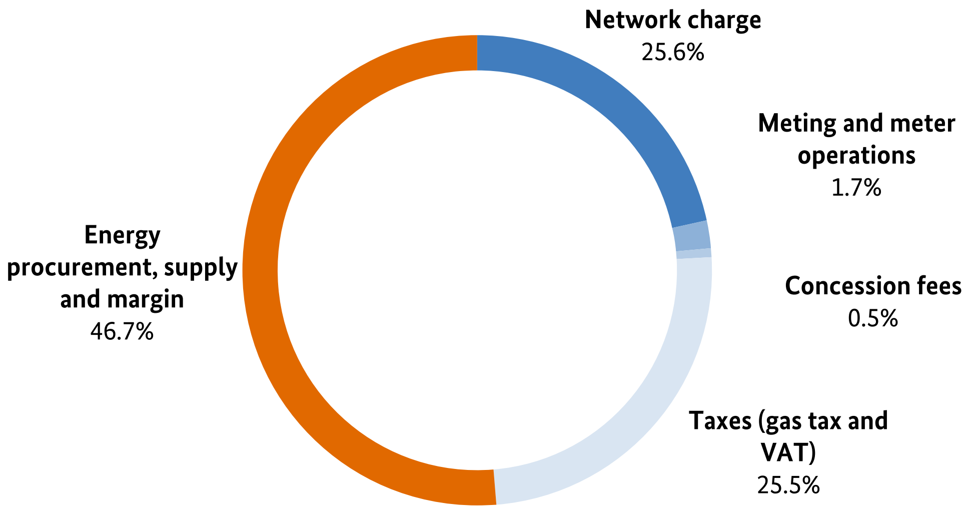


Figure 189: Composition of the volume-weighted gas price for household customers under a contract with a supplier other than the regional default supplier, as at 1 April 2017 - consumption band II according to the gas supplier survey

A look at the household customer gas prices over the past eleven years (2006-2017) shows that default supply, by its nature, 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.

The gas price for customers supplied under a special contract with the default supplier fluctuated between 6.25 ct/kWh and 6.07 ct/kWh between 2007 and 2017.

The price customers paid for gas under a supplier other than the regional default supplier fluctuated between 6.41 ct/kWh and 5.78 ct/kWh between 2008 and 2017. Overall, the gas price for customers in this category has fallen significantly over the past nine years, by nearly 10%, and reached a historic low as at 1 April 2017. This type of contract is the most affordable supply contract for customers with average consumption (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 stable gas prices that have seen further clear drops this year. The difference between the most expensive and the most affordable contract for an average customer (band II) was 0.49 ct/kWh in 2008. By contrast, it was 0.95 ct/kWh in 2017. The incentive to switch from default supply to a more affordable contract therefore increased in the review period.

Customers on default tariffs can make savings by switching tariff or supplier. The average household customer with gas consumption of 23,250 kWh could save an average of €153 a year as at 1 April 2017 by changing contract. The average potential saving for the year from changing supplier was €221.

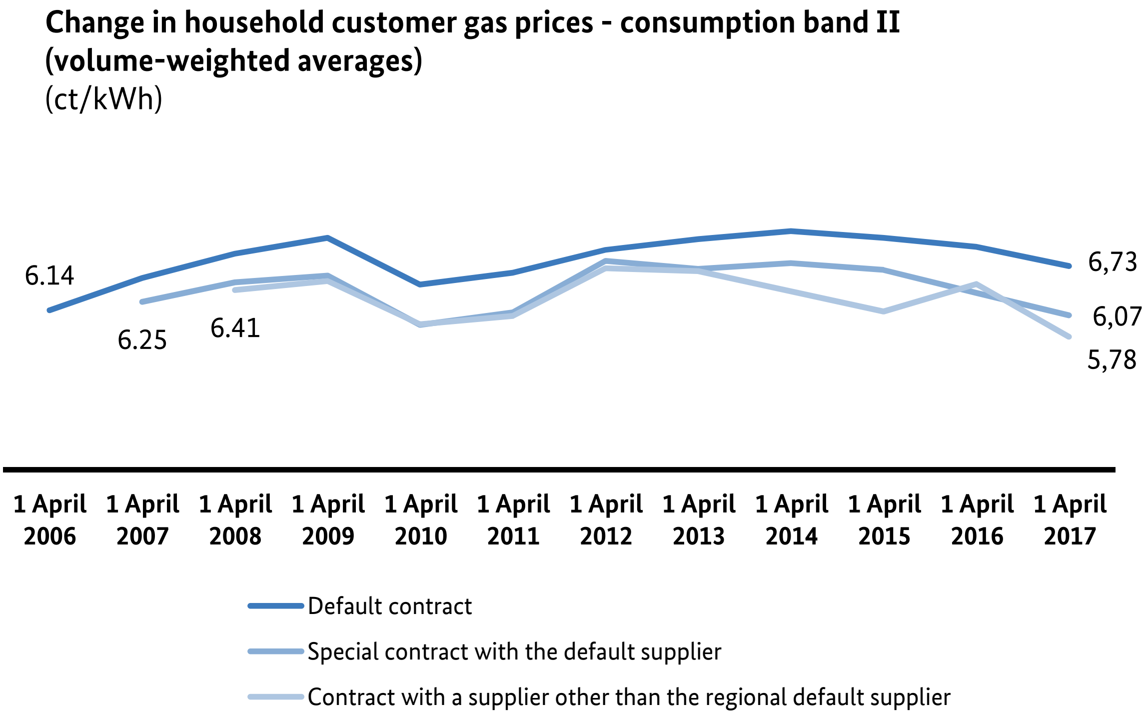


Figure 190: Change in household customer gas prices - consumption band II according to the gas supplier survey

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 and margin", it is notable that this price component for customers with a supplier other than the regional default supplier hit the lowest level in 2017 since the survey was started at 2.7 ct/kWh.

Moreover, the price component "energy procurement, supply and margin" for default supply customers was 3.35 ct/kWh on 1 April 2017, 6.4% lower than in the first survey in 2007. There was an even greater drop in this component for customers with a non-default contract with their default supplier (3.01 ct/kWh as at 1 April 2017).

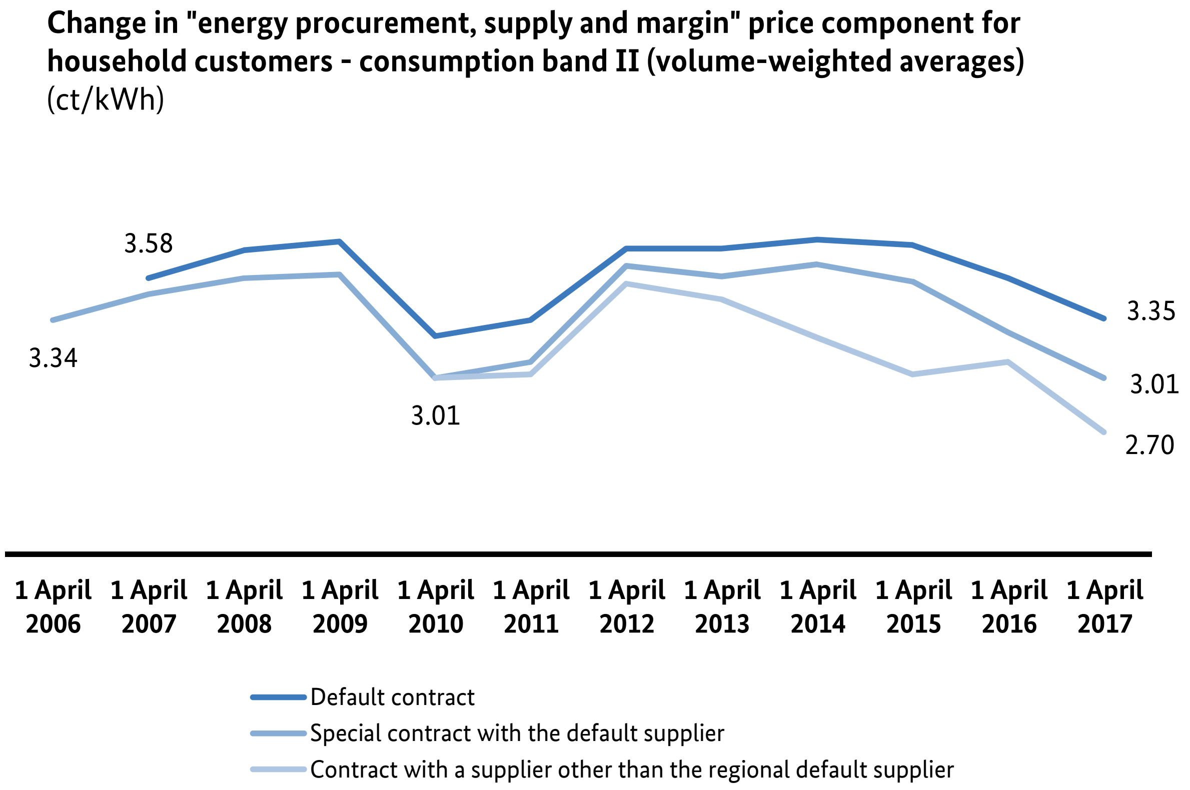


Figure 191: Change in "energy procurement, supply and margin" price component for household customers - consumption band II according to the gas supplier survey

Special bonuses and schemes

Special contracts with the default supplier and contracts with a supplier other than the regional default supplier, show, in addition to differences 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 price stability) or to the supplier (eg payment in advance, minimum contract period). In the data collection for the 2017 Monitoring Report, gas suppliers were asked about their contracts and offers.

The following overview includes various special bonuses and schemes offered to household customers 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 €200 for special contracts with the default supplier. They were considerably higher, between €5 and €400, for contracts with a supplier other than the regional default supplier. One-off bonus payments for customers switching to special tariffs with their regional default supplier average at €65, and those for customers switching to a non-default supplier at €75.

Special bonuses and schemes for household gas customers

As at 1 April 2017	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	354	12 months	394	12 months
Price stability	315	16 months	371	16 months
Advance payment	57	10 months	39	10 months
One-off bonus payment	114	€ 65	171	€ 75
Free kilowatt hours	10	1,400 kWh	6	700 kWh
Deposit	12	-	6	-
Other bonuses	74	-	63	-
Other special arrangements	39	-	35	-

Table 108: Special bonuses and schemes for household customers

5. Comparison of European gas prices

Eurostat, the statistical office of the European Union, publishes average end consumer gas prices for each six-month period paid 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 or, until now, on data provided by the Federal Statistical Office on the basis of a report by the German Association of Energy and Water Industries. Rules on the classification, analysis and presentation of the price data aim to ensure European-wide comparability. However, the survey method is set by the member state (cf. Directive 2008/92/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 100,000 GJ to 1,000,000 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 Non-household customers, p. 376), falls into this consumption range.

The customer group with this level of consumption consists mainly of industrial customers who can usually deduct national VAT. For this reason, 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.[165] Most Member States impose 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 2.64 ct/kWh paid by German customers with an annual consumption between 27.8 and 278 GWh is in the upper range. The EU average is 2.40 ct/kWh. Non-recoverable taxes and levies amount to an average 10 per cent (0.24 ct/kWh) of the net price in Europe. The figure of about 15 per cent (0.40 ct/kWh) for Germany is above average in this respect.

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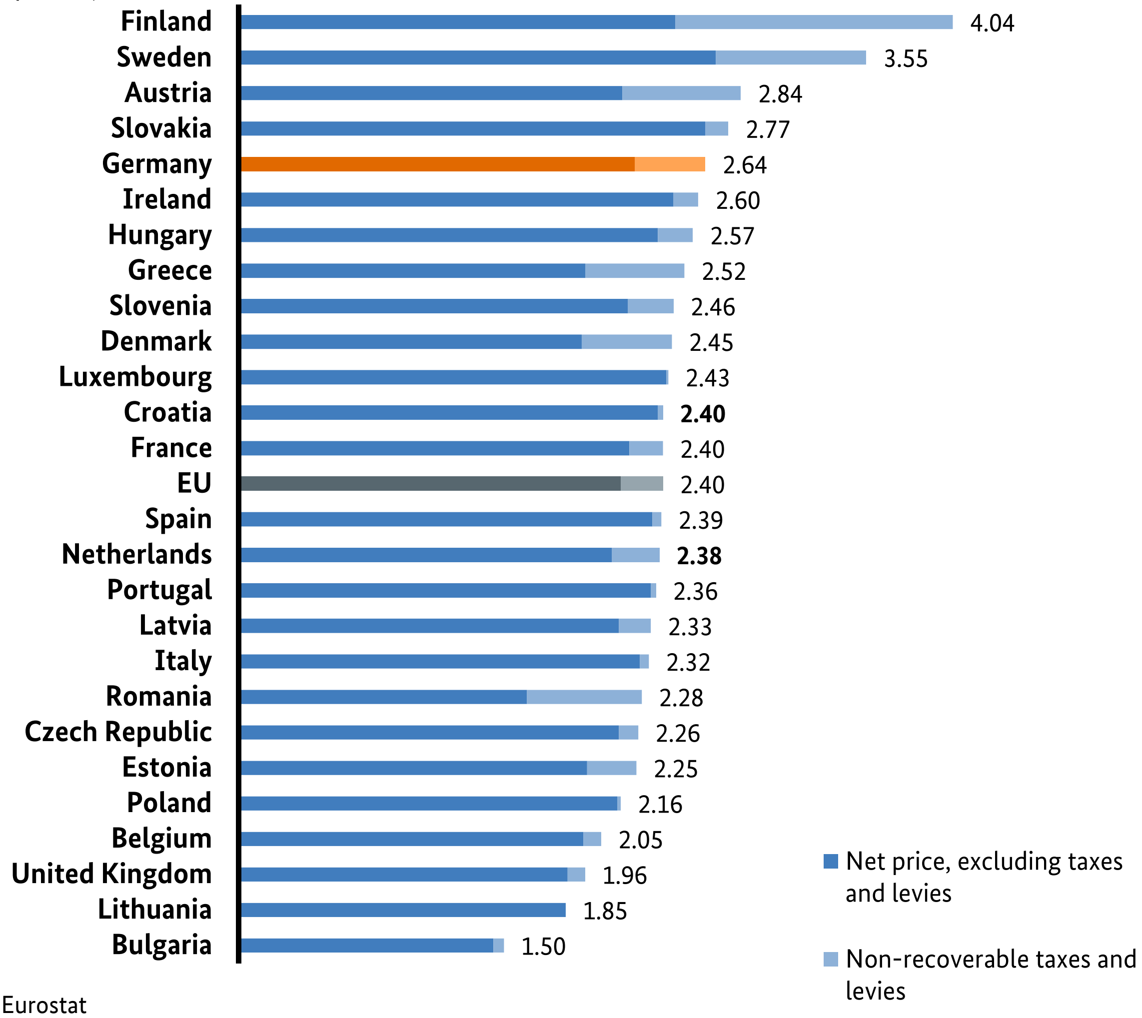
[165] For more information on country-specific deductions see Eurostat, Gas Prices – Price Systems 2014, 2015 Edition: http://ec.europa.eu/eurostat/documents/38154/42201/Gas-prices-Price-systems-2014.pdf/30ac83ad-8daa-438c-b5cf-b52273794f78 (retrieved on 8 August 2017).

Comparison of European gas prices in the second half of 2016 for non-household customers with an annual consumption between 27.8 GWh and 278 GWh

in ct/kWh; excl. recoverable taxes and levies



Quelle: Eurostat

Figure 192: Comparison of European gas prices in the second half of 2016 for non-household customers with an annual consumption between 27.8 GWh and 278 GWh

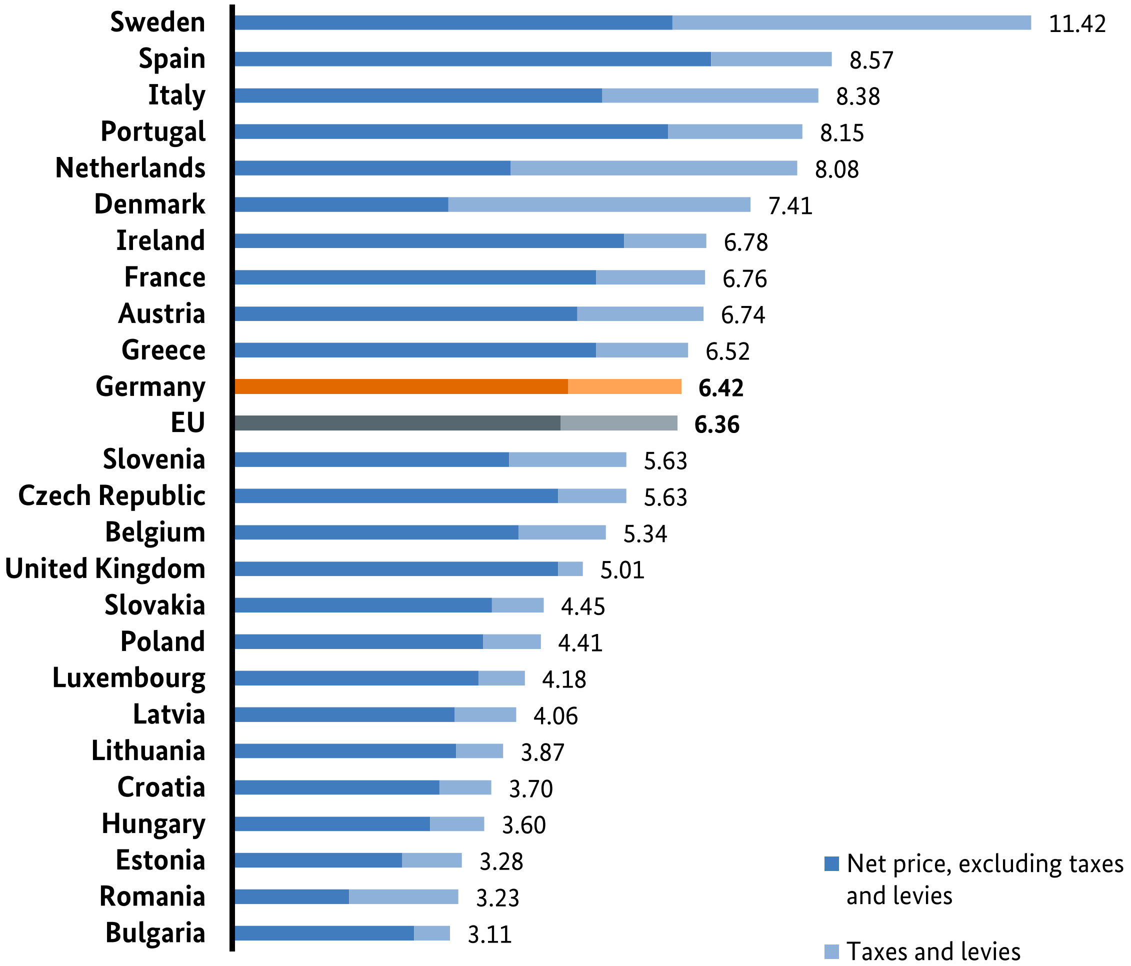
5.2 Household customers

Eurostat takes three different consumption bands into consideration when comparing household customer prices: (i) annual consumption below 5,555 kWh, (ii) between 5,555 kWh and 55,555 kWh and (iii) 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 Household customers, p. 380 ff.), 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 twice as much for natural gas as customers in Belgium and the United Kingdom and more than three times as much as customers in Bulgaria, Romania, Estonia, Hungary and Croatia. The gas price of 6.42 ct/kWh paid by household customers in Germany is close to the EU average price of 6.36 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 7 per cent of the price in the United Kingdom, they make up about 58 per cent of the price in Denmark. Germany's figure of about 25 per cent again matches the European average in this respect. Around 1.62 ct/kWh of the overall price in Germany consists of taxes and levies; the EU average is 1.67 ct/kWh (about 26 per cent).

Comparison of European gas prices in the second half of 2016 for household customers with an annual consumption between 5,555 kWh and 55,555 kWh
in ct/kWh; incl. VAT



Quelle: Eurostat

Figure 193: Comparison of European gas prices in the second half of 2016 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 24 companies operating and marketing a total of 37 underground natural gas storage facilities took part in the 2017 monitoring survey. On 31 December 2016 the total maximum usable volume of working gas in these storage facilities was 25.3bn Ncm.[166] Of this, 11.8bn Ncm was accounted for by cavern storage, 11.5bn Ncm by pore storage facilities and 2bn Ncm 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 (23.2bn Ncm, compared to 2.1bn Ncm for L-gas).

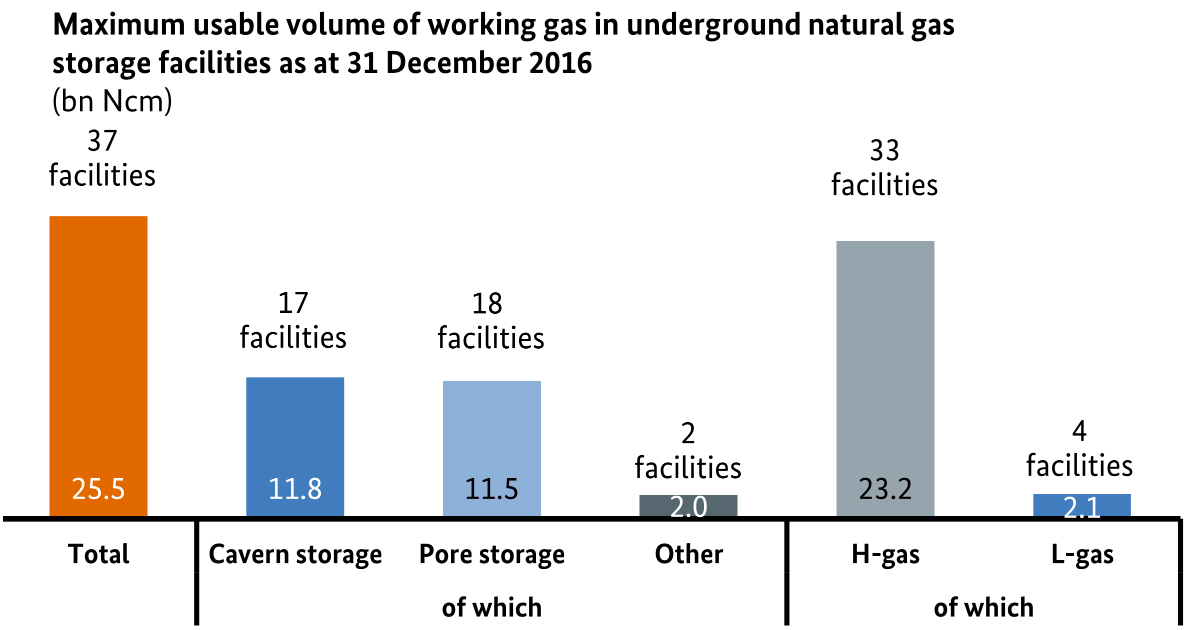


Figure 194: Maximum usable volume of working gas in underground natural gas storage facilities as at 31 December 2016

Figure 195 shows the storage levels of the current storage year compared to the previous years from 2010 onwards. 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.

The storage year started with rather subdued levels of injections, with one reason certainly being natural gas prices during the period. Prices for supply in winter 2017/2018 were in some cases lower than spot market prices, so many traders preferred futures over buying and injecting gas.

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[166] 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.

Changes in storage levels in Germany
Storage year 2017/18 in comparison to previous years
(%)

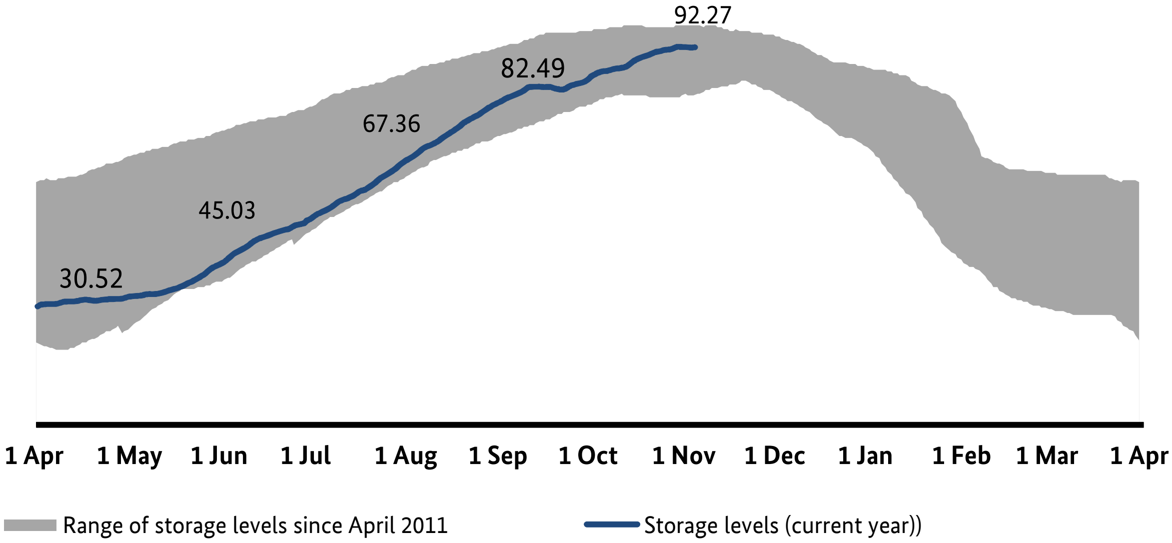

Figure 195: Storage levels compared to previous years (source: AGSI)

The next graph shows the changes in the daily reference price for the NCG and Gaspool market areas plotted over the respective storage levels. It is evident that the large volume of gas withdrawn from storage facilities at the beginning of 2017 was primarily driven by prices, just as the large volume injected into storage in 2016 was principally due to the low spot market prices.

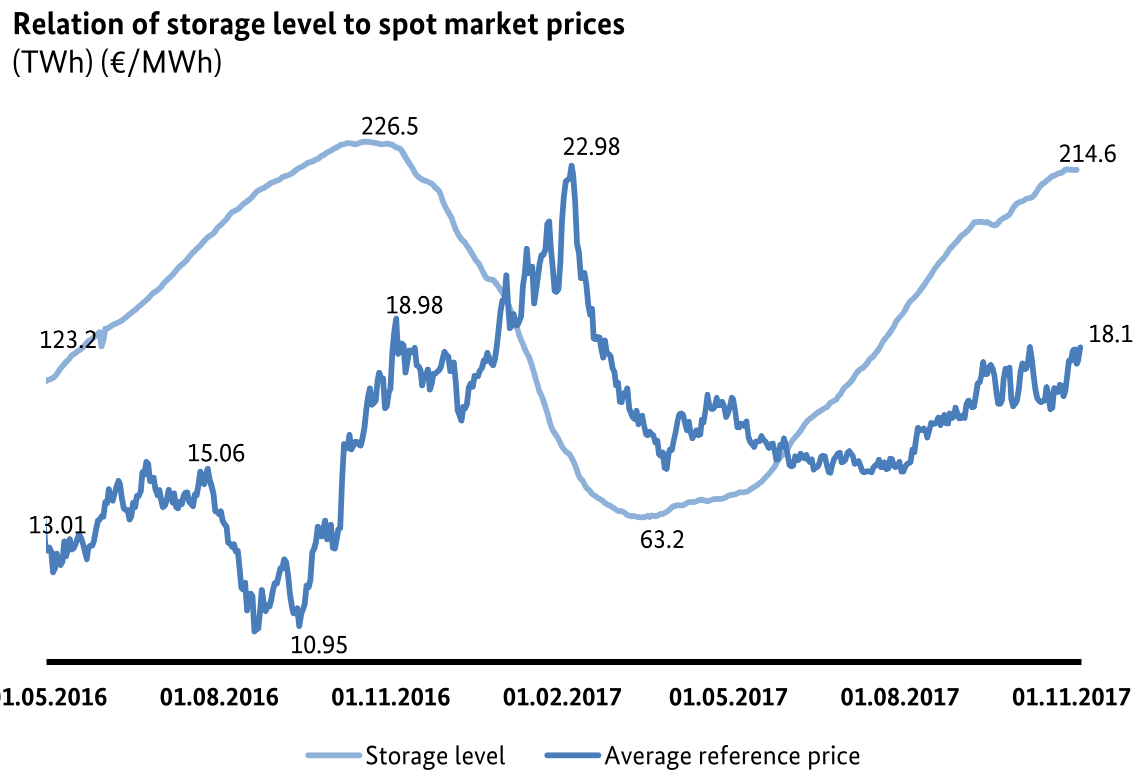

Figure 196: Relation of storage level to spot market prices (source: EEX/AGSI)

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 2016, 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 25.10bn Ncm in 2016 (compared to 25.67bn Ncm in 2015). The total injection capacity was 18.18m Ncm/h and the withdrawal capacity was 30.51m Ncm/h.

3. Use of underground storage facilities – customer trends

According to the data provided by 24 companies, the average number of storage customers in 2016 was 5.8, compared to 5.4 in 2012, 5.3 in 2013, 6.1 in 2014 and 6.1 in 2015. Table 109 shows the trend in the number of customers per storage facility operator.

Changes in the number of customers per storage facility operator over the years

Number of storage customers	2008	2009	2010	2011	2012	2013	2014	2015	2016
1	0.522	0.368	0.4	0.421	0.333	0.375	0.348	0.455	0.458
2	0.13	0.158	0.1	0.105	0.143	0.125	0.174	0.091	0.083
3 - 9	0.261	0.316	0.35	0.316	0.333	0.292	0.217	0.182	0.25
10 - 15	0.087	0.105	0.1	0.053	0.095	0.083	0.13	0.136	0.042
16 - 20	0	0.053	0.05	0.053	0.048	0.083	0.043	0.045	0.083
> 20	0	0	0	0.053	0.048	0.042	0.087	0.091	0.083
Number of storage operators	23	19	20	19	21	24	23	22	24

Table 109: Changes in the number of customers per storage facility operator over the years

There was another slight year-on-year increase 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 bookable, available working gas in underground natural gas storage as at 31 December 2016 compared to the previous years.

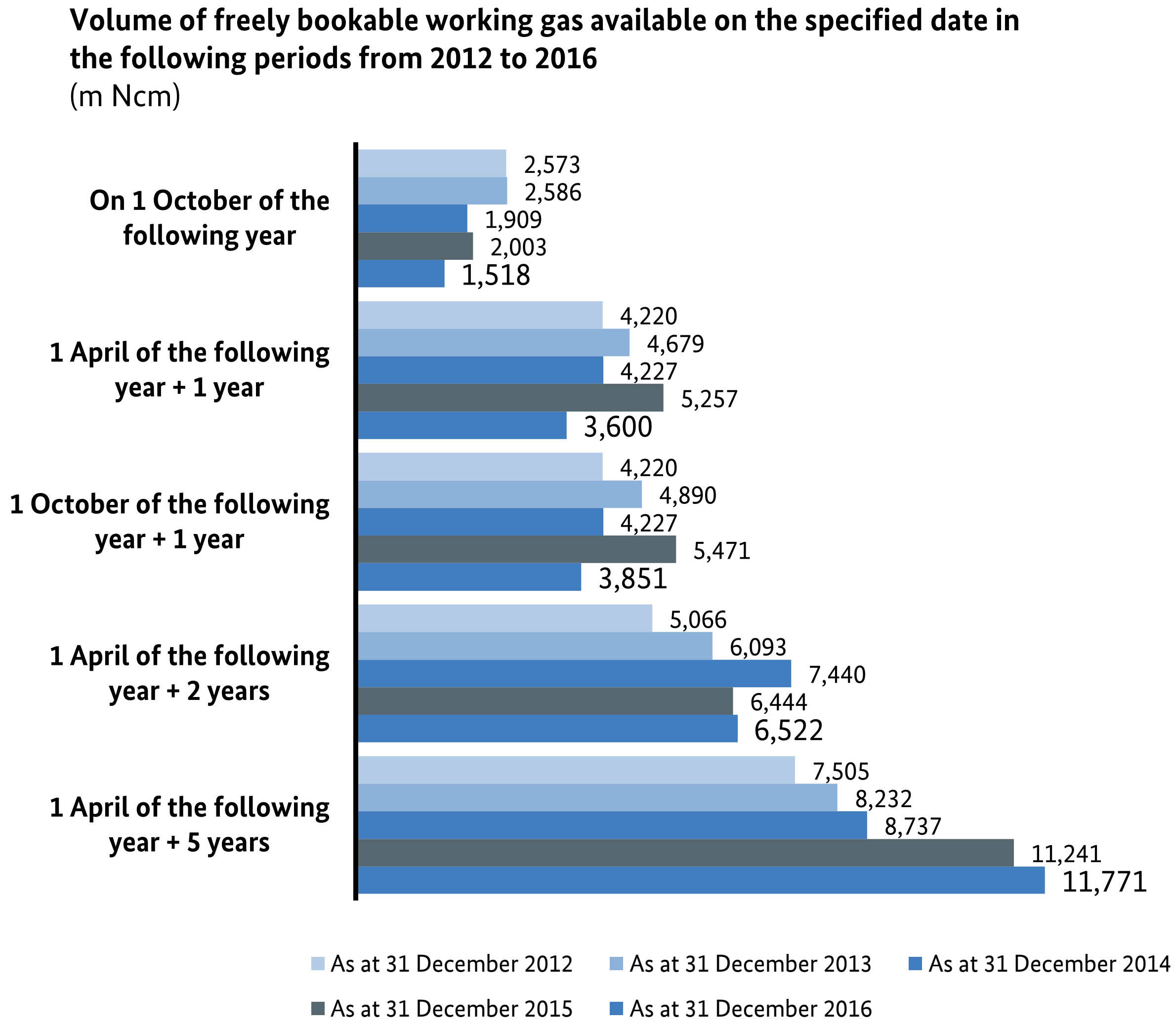

Figure 197: Volume of freely bookable working gas available on the specified date in the following periods from 2012 to 2016

The volume of short-term (up to 1 October 2017) freely bookable working gas declined slightly, as did the capacities bookable for 2018. The volume of long-term bookable working gas from 2019 remained stable. Compared to previous years, the volume of working gas that can be booked five years in advance increased again, showing a further move towards shorter-term booking in the storage market.

I Metering

1. The network operator as the default meter operator and independent meter operators

Metering was completely revamped in Germany with the adoption of the Metering Act (MsbG), which is an integral part of the Energy Transition Digitisation Act. The new law prescribes a comprehensive roll-out of modern metering devices and smart metering systems in Germany. This Act, which entered into force on 2 September 2016, has replaced sections 21b et seq. of the Energy Industry Act (EnWG) and the Metering Framework Conditions Ordinance (MessZV).

The "basic responsibility for meter operations" has hence been legally defined for the first time and a distinction has been made between the basic responsibility for conventional metering systems and the basic responsibility for modern metering devices and smart meters. The basic responsibility for both categories of equipment lies with network operators, but whereas the basic responsibility for conventional metering systems will remain permanently with network operators, the basic responsibility for modern metering devices and smart meters can be transferred to a third party service provider from 1 October 2017 onwards.

Although metering activities have been fully liberalised, it is predominantly the network operators that provide metering services under their "basic responsibility" (in their networks).

The facts presented in this chapter take into account information collected from 668 companies. This paints the following picture for 2016 with regard to the distribution of market roles:

Meter operator roles

Function	2016
Network operator acting as default meter operator within the meaning of section 2(4) MsbG (until 2016: network operator acting as meter operator within the meaning of section 21b(1) EnWG)	668
Network operator acting as meter operator without basic responsibility and providing (metering) services in the market (until 2016: network operator acting as meter operator within the meaning of section 21b(2) of the EnWG, providing (metering) services in the market)	9
Supplier with meter operator activities	6
Independent third party that provides metering services	2

Table 110: Distribution of network operator roles according to data provided by gas meter operators as at 31 December 2016

In 2016, gas DSOs were asked for the first time how many independent meter operators were active in their networks. The average number for the 244 gas DSOs that responded was two independent meter operators. Only one independent meter operator is active in nearly 60% of networks. Two independent meter operators are active in 25% of networks. More than three independent meter operators are active in only 15% of networks.

2. Meter technology for household customers

As at 31 December 2016, approximately 2.6 million meters for standard load profile (SLP) customers were able to be converted so that they could be connected to a smart meter gateway within the meaning of section 2(19) MsbG. About 920,000 meters have already been converted so that they can be connected to a smart meter gateway within the meaning of section 2(19) MsbG.

Metering equipment used by SLP customers

Types of metering equipment used by meter operators for SLP customers	No of meter points by meter size		
	G1.6 to G6	G10 to G25	G40 and higher
Diaphragm gas meters with mechanical counter	7,975,486	259,114	31,123
Diaphragm gas meters with mechanical counter and pulse output	5,580,789	178,867	19,184
Diaphragm gas meters with electronic counter	14,467	763	1,197
Load meters as for load-metered customers	112	187	2,944
Other mechanical gas meters	23,485	3,477	27,006
Other electronic gas meters	6,740	136	429
Number of meters that can be converted so that they can be connected to a smart meter gateway within the meaning of section 2(19) MsbG	2,494,108	79,593	14,685
Number of meters that have actually been converted so that they can be connected to a smart meter gateway within the meaning of section 2(19) MsbG	889,231	26,084	4,915

Table 111: Breakdown of metering equipment used by SLP customers as at 31 December 2016

Where meter operators use remote reading, they predominantly do so via the pulse output. Only 8.3% of the meters are read using M-Bus, the Open Metering System (OMS) standard, telecommunications or other technologies.

Communication link-up systems for SLP customers
Number and breakdown

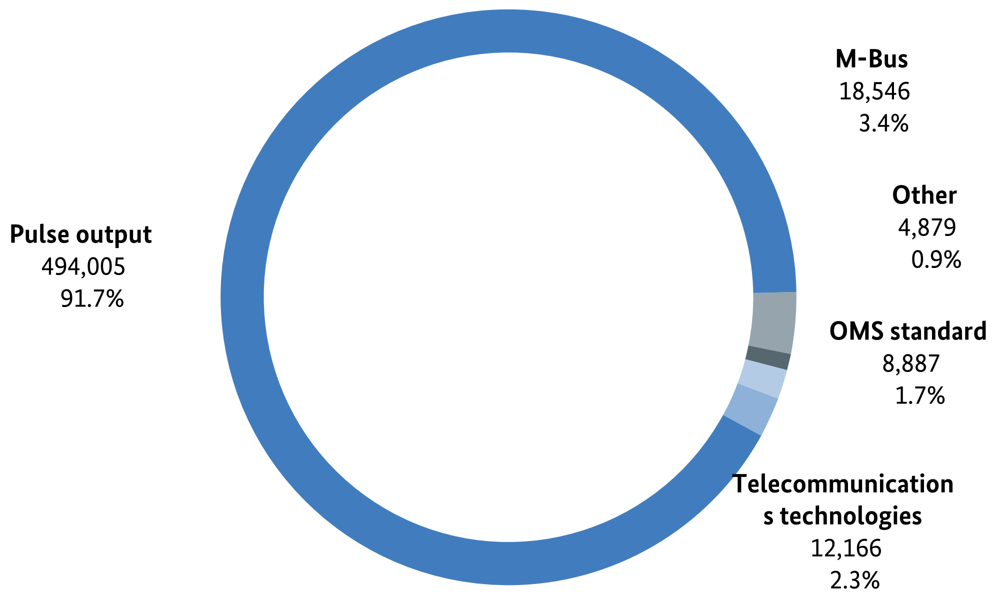

Figure 198: Number and breakdown of communication link-up systems used for SLP customers as at 31 December 2016

3. Metering technology used for interval-metered customers

The distribution of metering technology employed for interval-metered customers in 2016 is as follows:

Metering technologies used for interval-metered customers in 2016

Function	No of meter points
Transmitting meter with a pulse output/encoder meter + a recording device/data storage	15,637
Transmitting meter with a pulse output/encoder meter + volume corrector	9,656
Transmitting meter with a pulse output/encoder meter + volume corrector + recording device/data storage	15,690
Transmitting meter with a pulse output/encoder meter + smart meter gateway	279
Other	300

Table 112: Breakdown of metering technologies used for interval-metered customers as at 31 December 2016

The metering technology used by interval-metered customers transmits data almost exclusively via telecommunication systems. These 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 3.9% of interval-metered customers use this interface.

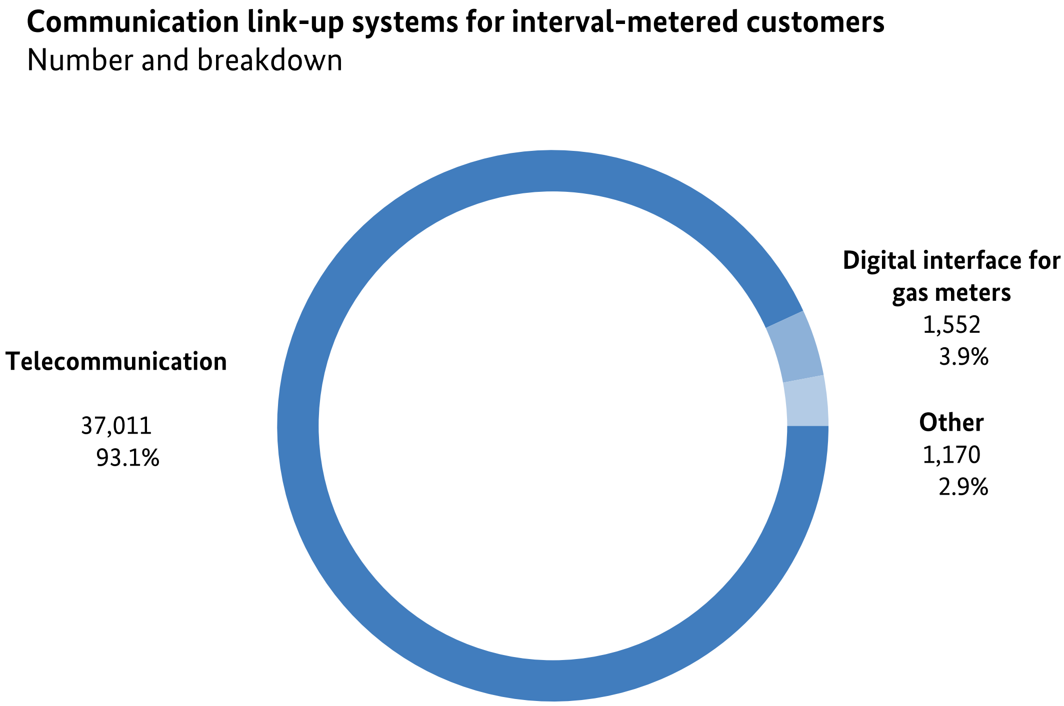

Figure 199: Communication links for load-metered customers

4. Ability of gas metering equipment to be connected to a smart meter gateway within the meaning of section 20(1) MsbG

Meter operators were asked about the number of meter points that they had fitted with metering equipment within the meaning of section 20(1) MsbG in 2016 and that could be connected to a smart meter gateway within the meaning of section 2 para 7 MbsG. 189 meter operators stated that they had fitted a total of 771,833 meter points as at 31 December 2016. The number of meter points fitted with metering equipment able to be connected to a smart meter gateway was around 470,000 as at the end of 2015, according to 191 meter operators.

5. Metering investment and expenditure

Gas meter operators were asked about their investment behaviour in the monitoring survey. The evaluation is based on data from around 550 gas DSOs.

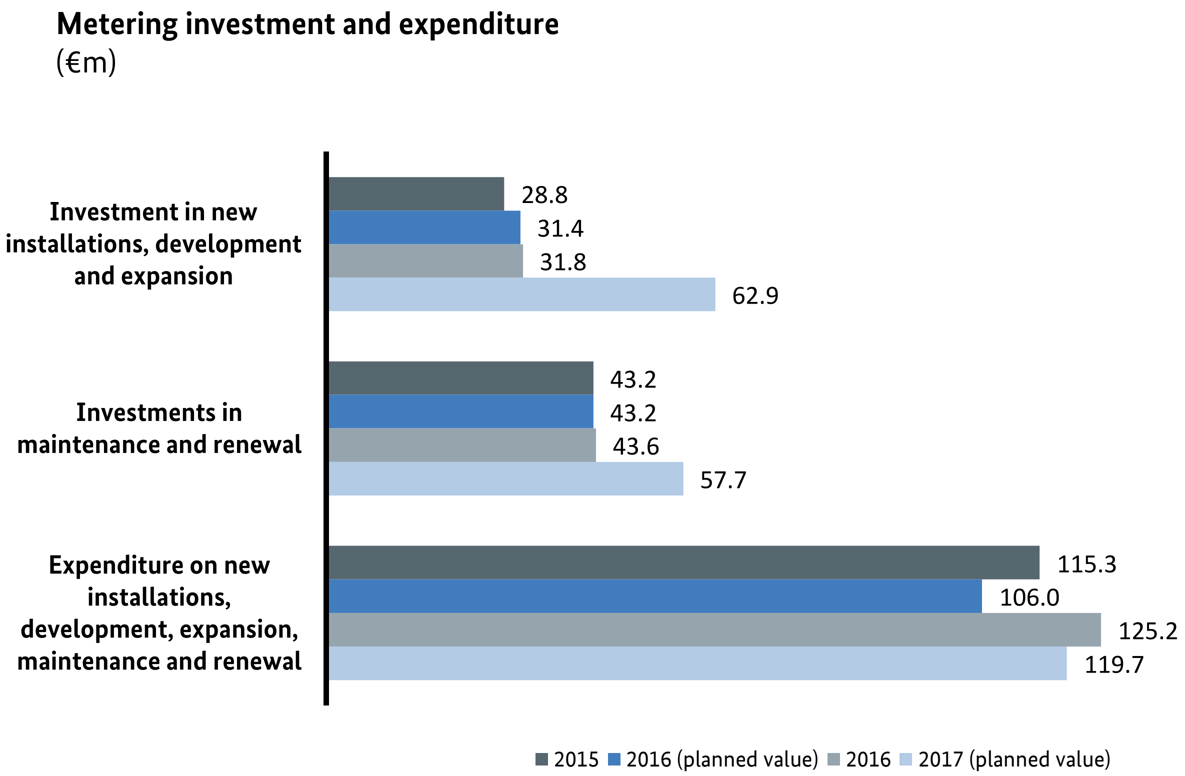

Figure 200: Metering investment and expenditure

II Consumers

1. Consumer advice and protection

The Bundesnetzagentur's task as the central information point for energy consumers is to keep private household customers informed about their rights and the dispute resolution process. The energy consumer advice service at the Bundesnetzagentur has been providing information and support to consumers on general energy issues and questions as well as problems with suppliers and network operators since 2011, developing into an experienced and reliable service and first point of contact. Its staff receive and respond to consumer queries by telephone, e-mail and letter.

Overview of customer queries

About 15,000 queries and complaints were sent to the consumer advice service last year, corresponding to an increase of around 50% year-on-year. Approximately 10,600 queries were received by telephone, 4,100 by e-mail and 315 by post.

The average time needed to process a call was 13.44 minutes, including both the actual conversation and the necessary registration and research time. Queries written digitally, by e-mail or PC fax, required a processing time of 41.07 minutes, while letters and paper faxes required 84.70 minutes. The difference in processing time is largely due to the registration of enquiries and responding by post.

In November 2017 the Bundesnetzagentur set up an online form for consumers as a further contact option. Contract documents and invoices, for example, may be sent securely to the consumer advice service using this form.

Enquiries covered a wide range of gas and electricity issues. The main subjects were billing (eg incorrect bills, problems with meter readings, part payments, payment size, bills not received), supplier switching and registration/deregistration, and contractual disputes (eg contract duration, bonuses, cancellations, credit). In addition, there were isolated queries relating to the grid connection and its costs, network charges and how they are made up, and energy prices in general.

2. Market development of energy 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(1) of the Energy Industry Act (EnWG) to notify their activities to the Bundesnetzagentur. Since 2010, there has been a steady increase in the number of supplier notifications received. As at 31 December 2016, a total of 104 companies supplying electricity, gas or both had notified the Bundesnetzagentur of their activities. A total of 856 energy utilities were registered at the Bundesnetzagentur in 2016.

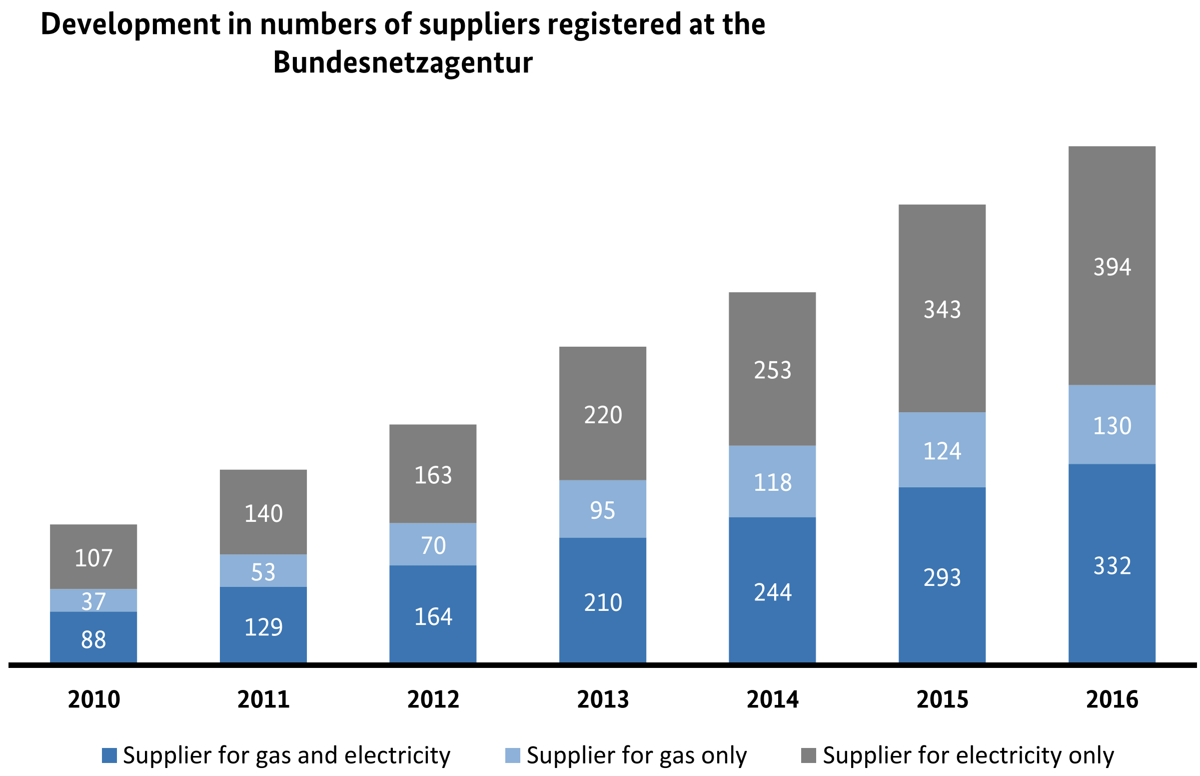

Figure 201: Development in numbers of suppliers registered at the Bundesnetzagentur

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 or business area completely. Eight notifications from companies ceasing activities were received by the Bundesnetzagentur in 2016. The list of gas and electricity suppliers is updated each month and can be found at http://www.bundesnetzagentur.de/lft-energie.

3. Supplier switching process

The numbers-based supplier switching rate in 2016 was 9.6% for electricity and 12.3% for gas. Customers can save money or choose tariffs with particular features, such as green electricity, by switching supplier or just switching tariff.

Household customers on default tariffs with an annual electricity consumption of 3,500 kWh a year could cut their energy costs by around €47 per year by changing contract or €64 per year by changing supplier. Special bonuses offered by suppliers, including one-off bonus payments, provided added incentives for customers to switch. One-off bonus payments for customers switching to special tariffs with their regional default supplier average at €50, and those for customers switching to a non-default supplier at €62.

Household customers with gas consumption of 23,250 kWh could save an average of €153 a year as at 1 April 2017 by changing contract. The average potential saving for the year from changing supplier was €221. Such one-off bonuses, which provide a further incentive to switch, average €65 for customers on non-default terms in a contract with the default supplier and €75 for customers under contract with a supplier other than the local default supplier.

Customers should bear the following advice in mind when switching supplier:

• Tariffs involving prepayment or a deposit should be avoided, because if the supplier were to become insolvent, the payments made in advance could be lost.

• It should be remembered that bonus payments are a one-off and not paid in subsequent years.

• The new contract should not have a duration of more than a year.

• Check if the tariff has a fixed price, but remember that when the fixed price period is over, there could be a significant jump in costs.

• Long notice periods of over three months should be avoided as well.

The key point is that a low price should not be the only factor taken into consideration when choosing a new supplier. It is always a good idea to research tariffs using consumer forums, consumer organisations, search engines and company websites as well.

You can also find more information and advice on switching supplier at www.bundesnetzagentur.de/lieferantenwechsel.

A price comparison tool is a convenient way to compare different suppliers and their offers, but it should be remembered that not all suppliers are necessarily included in every one. It makes sense to do some more research in addition to using a price comparison tool.

4. Consumer price

4.1 Electricity price

Breakdown of the retail price for household customers with a consumption of between 2,500 and 5,000 kWh a year as at 1 April 2017 (volume-weighted average across all contract categories, consumption band III, Eurostat: DC)
(%)

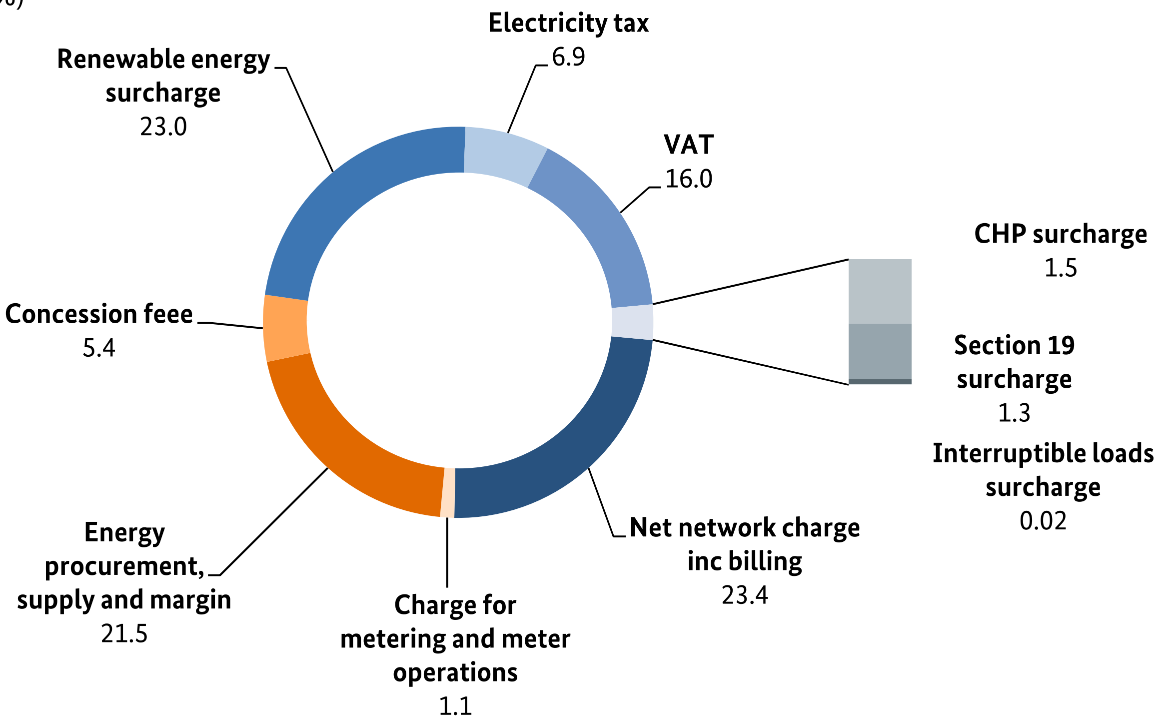

Figure 202: Breakdown of the price for household customers in consumption band III as at 1 April 2017 (volume-weighted average across all contract categories)[167]

The electricity price that customers pay to their supplier is made up of a number of components:

- costs of electricity procurement (generation or purchase), supply and profit margin (21.5% in total),
- metering and meter operations (1.1%),
- net network charge (23.4%),
- concession fees (5.4%),
- surcharge payable under the Renewable Energy Sources Act (EEG) (23%),

[167] VAT makes up 16% of the total (gross) price, as the applicable 19% VAT rate is charged on and added to the net price (corresponding to 100%). The VAT of 19% is therefore the dividend and the total price of 119% the divisor.

- surcharge payable under the Combined Heat and Power Act (KWKG) (1.5%),
- surcharge payable under section 19 of the Electricity Network Charges Ordinance (1.3%),
- surcharge for interruptible loads (0.02%) and
- taxes (22.9%), comprising VAT (16%) and electricity tax (6.9%).

The Bundesnetzagentur does not authorise electricity prices. Regulation merely prescribes the revenue caps allowed for network operators (see also the section "Network charges" in the chapter "Networks" starting on page 124). They calculate their network charges on this basis.

The electricity price agreed with the energy utility usually consists of a monthly base price and a kilowatt-hour rate. The base price is charged monthly, regardless of how much electricity is consumed, whereas the kilowatt-hour rate is calculated for each kWh consumed. The two components vary in suppliers' different tariffs. Generally, the higher one part is, the lower the other. Customers with lower consumption should tend to choose a contract with a low base price and a high kilowatt-hour rate, while those who consume more should look for a low kilowatt-hour rate.

More detailed information on household prices for electricity may be found in the section "Price level" in the "Retail" chapter of the Electricity part, starting on page 375.

4.2 Gas price

Composition of the volume-weighted gas price across all contract categories for household customers - consumption band II
as at 1 April 2017 (%)

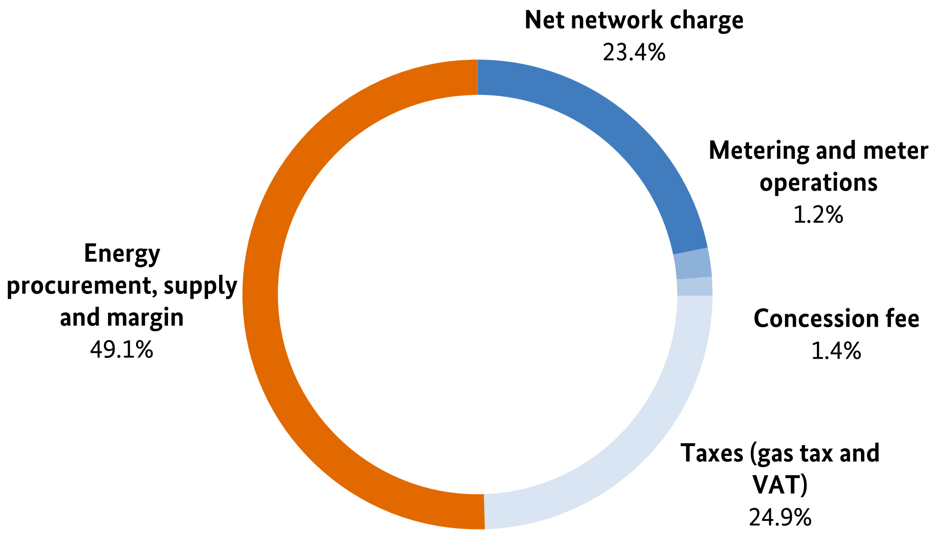

Figure 203: Composition of the volume-weighted gas price across all contract categories for household customers - consumption band II according to the gas supplier survey

The gas price is made up of a number of components:

- costs of gas procurement, supply and profit margin (49.1% in total),
- metering and meter operations (1.2%),
- network charge (23.4%)
- concession fees (1.4%) and
- taxes (gas tax and VAT) (24.9%).

The gas price has been relatively stable for some years. Germany is in the mid-range in Europe for gas prices.

Unlike electricity, natural gas is a product whose energy content depends on multiple factors and can fluctuate. Gas meters do not show the kWh but rather the cubic metres consumed. The kWh consumed are calculated by multiplying the number of cubic meters by the calorific value of the gas and the correction factor. The correction factor stands for the gas properties including temperature and pressure. It depends on the conditions at the supply point. The calorific value is the amount of energy released when the gas is burned and depends in particular on the composition of the gas.

More detailed information on household prices for gas may be found in the section "Price level" in the chapter "Retail" of the Gas part, starting on page 223.

5. New developments for consumers

The legal framework, technical conditions and business strategies that directly affect offers and products for consumers are changing in both the electricity and gas sector. Recent developments are presented here in brief.

5.1 Conversion from L-gas to H-gas

By 2030 about 4.9m gas appliances in private households, commercial and industrial enterprises in the north and west of Germany will have been converted to use H-gas, which largely comes from Russia and Norway, rather than the low-calorific L-gas. Having started in some smaller network areas, the largest infrastructure project in gas supply was also introduced in the first major city, Bremen, in 2016. Around 170,000 households there are affected. Over 34,000 appliances were already registered there in 2016. Clicks on the FAQs on the Bundesnetzagentur website covering this issue quadrupled from 2015 to 2016. Gas customers have been directing their queries about service providers to the energy consumer advice service as well as to the relevant network operators. There were also isolated complaints concerning difficulties making appointments and a lack of technical competence.

The rate of complaints and queries to the network operator is very low, at less than 1% of gas appliances, because the public had been thoroughly and comprehensively informed. It remains to be seen whether this positive trend can be maintained in the coming years as the number of appliances converted each year rises to over 500,000. A detailed map of the network areas that will be affected by the market area conversion in the years to come, as well as more information, can be found in the "Market area conversion" chapter (page 337).

The costs of this expensive but necessary measure have been spread across the whole country since 1 January 2017, so all gas customers are invoiced for them equally. Gas customers not directly affected by the conversion still contribute financially to the project, which helps to ensure the general security of supply. This is one of the provisions introduced by the new section 19a EnWG, which also lays down the right of access of the network operator, disconnection if appliances have not been converted, the information the network operator is obliged to provide and, above all, the right of reimbursement and the conditions for the installation of a new appliance that does not need to be converted (heating or oven, for example – not necessarily another gas appliance). The Gas Appliances Reimbursement Ordinance (GasGKErstV), which was published on 30 June 2017, gives owners of gas appliances an additional right to reimbursement, with retroactive effect from 1 January 2017, if their appliances cannot be converted. Certain conditions, which are detailed in the FAQs on the website, must be met. More information can be found at www.bundesnetzagentur.de/marktraumumstellung.

5.2 Introduction of smart metering systems

Digital electricity meters – smart meters – have up to now been mostly installed in new buildings and for operators of certain renewable energy installations. The Energy Transition Digitisation Act, which entered into force at the beginning of September 2016, made the Metering Act (MsbG) the central law governing metering operations. The MsbG lays the foundations for the introduction of smart metering systems and modern metering equipment as well as setting the framework conditions. Smart metering systems are designed to enable secure and standardised communication in the energy networks and to support the digitisation of the energy transition.

The new legal provisions affect in particular the technical specifications of metering equipment and communication equipment, installation, operation and maintenance. They also govern the security of data communication, especially data readings and the transmission of them to network operators. The billing of meter operation is no longer part of the network charge but is undertaken separately.

Different types of electricity meter

	Ferraris meter	**Modern metering equipment**	**Smart metering system (SMS)**	**Communication unit = smart meter gateway (SMG)**
Meter type	analogue meter	digital meter without communication unit	digital meter with communication unit	communication interface
Meter functions	current meter reading	· current meter reading · saved values by o day o week o month o year going back 2 years can be turned into SMS by retrofitting communication unit	· current meter reading · saved values accessible accurate to 1/4h in: o daily o weekly o monthly o yearly display	· interface between meter and communication network · can connect one or more meters · automatic transmission of data to meter operator
Responsible for installation, metering and technical operation	local network operator as meter operator	default meter operator (usually local network operator) or meter operator chosen by consumer		smart meter gateway administrator **either default meter operator or third-party untertaking**

Table 113: Different types of electricity meter

Advantages for the consumer of having a smart meter installed:

- Greater and more precise transparency of consumption
- Ability to identify devices that consume a lot of power and potential savings
- Introduction of variable electricity tariffs
- No direct meter readings on site necessary
- Metering processes for electricity, gas, heating and district heating can be bundled in future

- Easier implementation of new technologies such as smart home applications, prosumer and tenants' electricity models

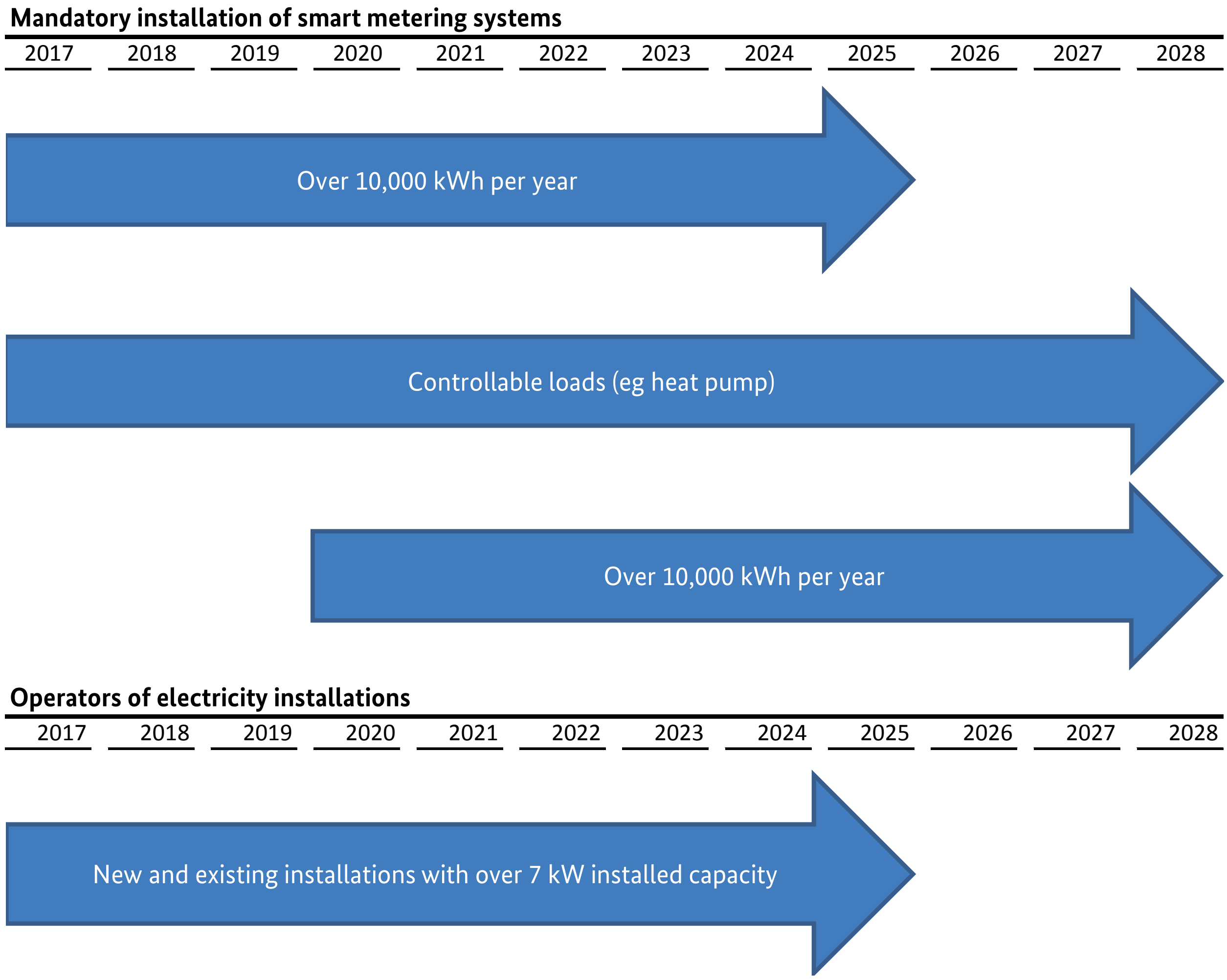

Figure 204: Mandatory installation of smart metering systems

As a basic requirement for the mandatory installation of smart metering systems, the Federal Office for Information Security (BSI) has to ascertain technical availability of the systems. The roll-out of smart metering systems can only start, and the deadlines for their mandatory installation be set, once this ascertainment has taken place, but this is no longer expected to happen in 2017. Technical availability can only be ascertained once there are at least three systems from manufacturers independent of each other available in the market. No BSI-certified smart meter gateways are yet available in the market.

However, various network and meter operators started installing the first modern metering equipment in early 2017 (see also the chapter "Metering" in the Electricity part starting on page 259).

The MsbG also introduces the new market role of the default meter operator, which by law is initially allocated to the network operator. The local network operator can decide whether to continue to fulfil this role or to transfer it to another company. Currently 99% of network operators plan to remain active as default meter operators in the future. There are also competing metering operators that have already entered the market.

You can find more information about the new devices, the exact installation schedule, the newly applicable price caps for metering operations and the data protection provisions that need to be followed at www.bundesnetzagentur.de/smartmeter.

5.3 Electric vehicles/charging stations

The Charging Station Ordinance (LSV) entered into force on 17 March 2016. It specifies minimum technical requirements for the safe and interoperable establishment and operation of publicly accessible recharging points for electric vehicles. Germany is thus the first country to transpose the EU standards for charging plugs from Directive 2014/94/EU on the deployment of this infrastructure into national law. The LSV also contains binding provisions on charging plug standards and an obligation for operators of recharging points accessible to the public to notify the Bundesnetzagentur.

The Bundesnetzagentur has been recording the notifications from operators of normal and high-power recharging points since July 2016 because of the assessment of compliance with the technical safety specifications and interoperability requirements of recharging points pursuant to the LSV.

All recharging points accessible to the public that have been taken into operation since the ordinance entered into force are subject to the notification obligation. In addition, recharging points accessible to the public that are not subject to the notification obligation may be voluntarily notified to the Bundesnetzagentur. Further information can be found at www.bundesnetzagentur.de/ladesaeulen.

The Bundesnetzagentur was notified of a total of 3,561 charging stations with 7,205 recharging points by 18 October 2017, of which 6,397 recharging points had a power less than or equal to 22 kW (normal-power recharging points) and 808 were high-power recharging points.

The recharging points notified are spread across the federal states as follows (as at 18 October 2017):

Distribution of notified charging infrastructure in the federal states

Federal states	Charging stations	Recharging points
Baden-Württemberg	437	825
Bavaria	748	1,645
Berlin	265	526
Brandenburg	26	54
Bremen	32	64
Hamburg	295	597
Hesse	237	458
Mecklenburg-Western Pomerania	25	51
Lower Saxony	296	577
North Rhine-Westphalia	666	1,338
Rhineland-Palatinate	105	201
Saxony	149	316
Saxony-Anhalt	47	96
Schleswig-Holstein	159	316
Thuringia	72	133
Saarland	2	8

Table 114: Distribution of notified charging infrastructure in the federal states (as at October 2017)

In April 2017, the Bundesnetzagentur started publishing an interactive map of charging stations on its website showing all notified normal and high-power recharging points. Key information is shown, such as the location of the charging station, the type of plug with its power and the operator. It is also possible to visualise the regional distribution of charging infrastructure using a heat map. The map may be found at www.bundesnetzagentur.de/ladesaeulenkarte.

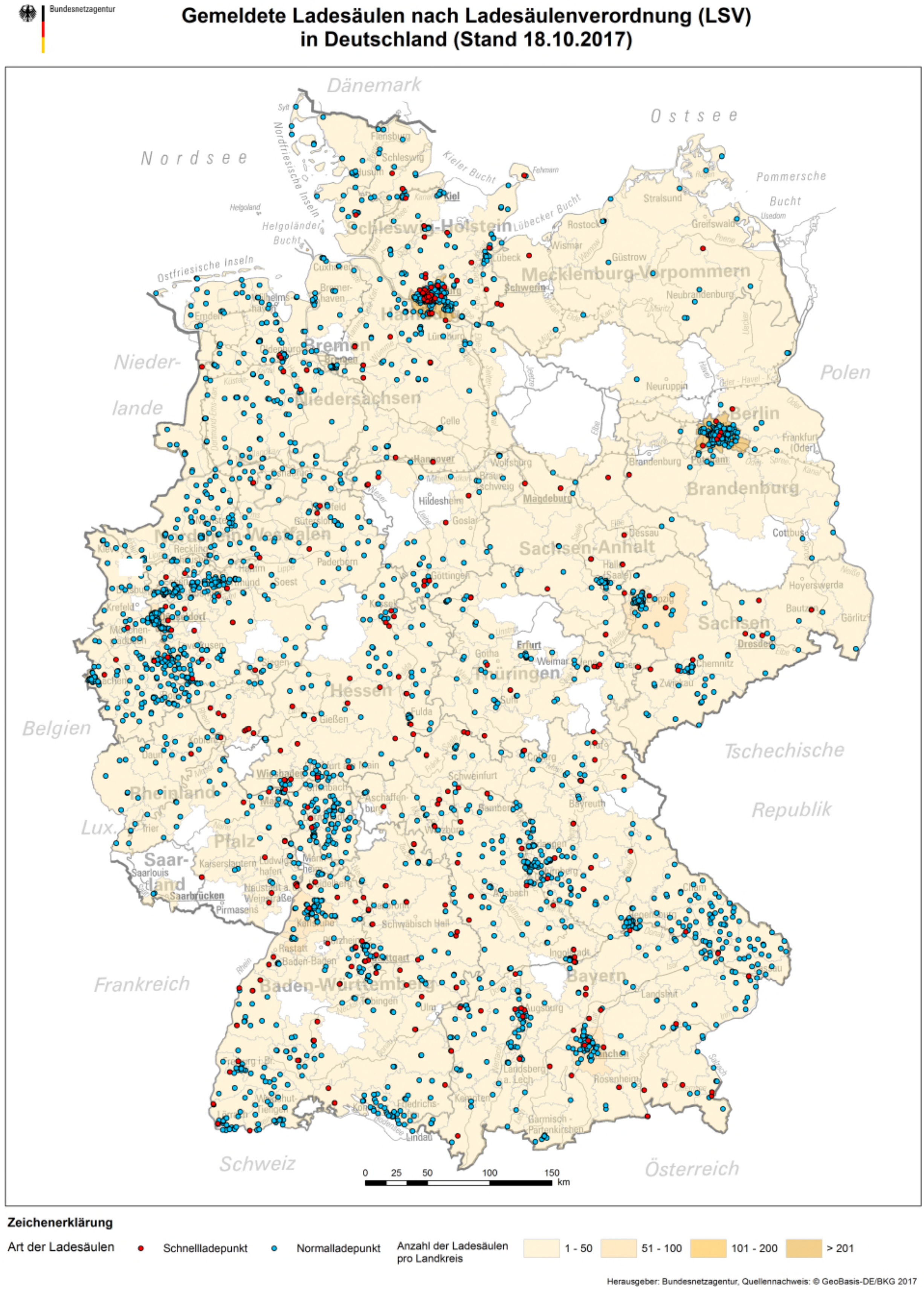

Figure 205: Recharging points in Germany notified pursuant to the LSV, as at 18 October 2017

Publishing the charging station map has caused the number of notifications of charging stations submitted by operators to rise, with the Bundesnetzagentur increasingly receiving notifications about charging stations not subject to the notification obligation, in particular. The number of notified recharging points nearly doubled in the first few months following publication. The development in the number of recharging points notified each month since publication in April 2017 is shown in the following graph.

Development in the number of recharging points notified since publication by the Bundesnetzagentur

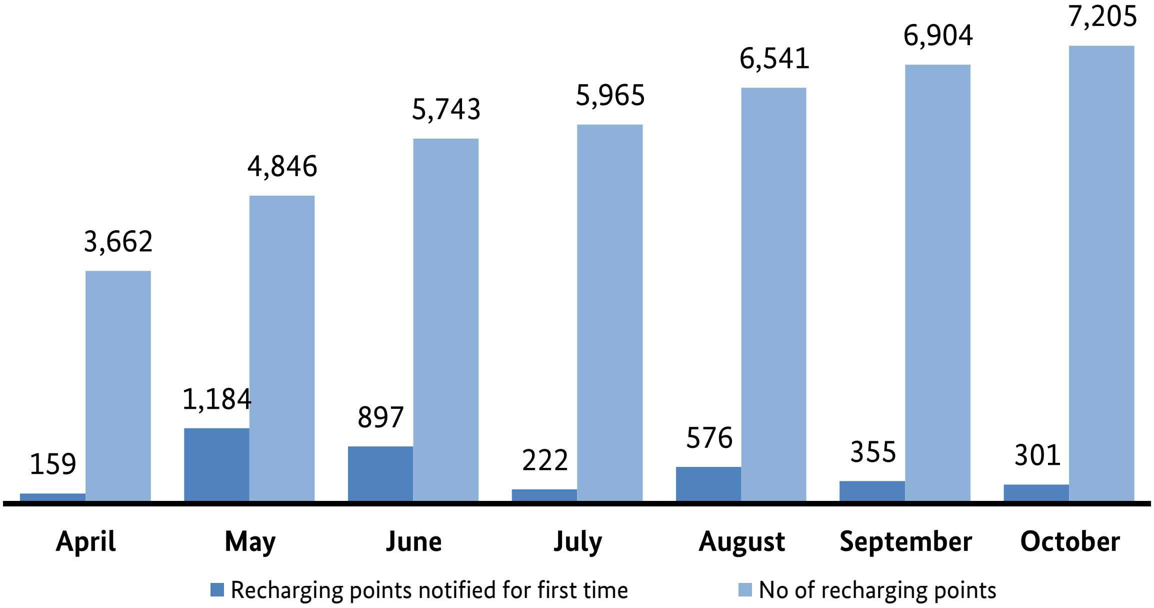

Figure 206: Development in the number of recharging points notified since publication by the Bundesnetzagentur

The LSV prescribes mandatory plug standards for recharging points accessible to the public in order to ensure interoperability. Direct current recharging points must be equipped at least with vehicle connectors of the "Combo 2" charging system. Alternating current recharging points require a "Type 2" plug system and there are differing requirements for normal and high-power recharging points. Normal power recharging points with alternating current must have a "Type 2" socket outlet, while high-power recharging points require a "Type 2" vehicle connector. Any number of additional plugs may be provided at each charging point. The graph below shows the distribution of widely-used plugs at all notified recharging points. It should be remembered that recharging points may have several plug options and there are also older, existing recharging points that are not subject to the plug requirements of the LSV.

The charging capacities of the recharging points are distributed as shown in Figure 208. For recharging points with multiple plug options, the greatest power available is given.

It can be seen that most of the recharging points are normal ones with a power less than or equal to 22 kW. The charging capacities most frequently mentioned in the notifications to the Bundesnetzagentur are 3.7 kW (AC Schuko), 11 kW/22 kW (AC Type 2), 43 kW (DC Combo connector) and 50 kW (DC CHAdeMO).

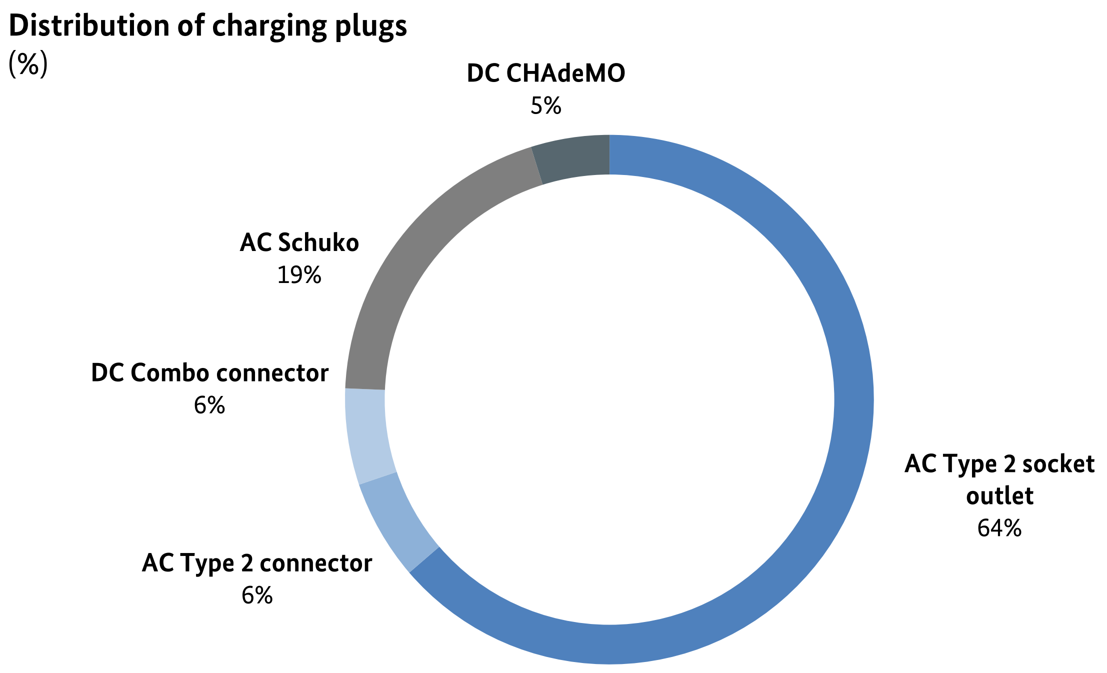

Figure 207: Distribution of charging plugs

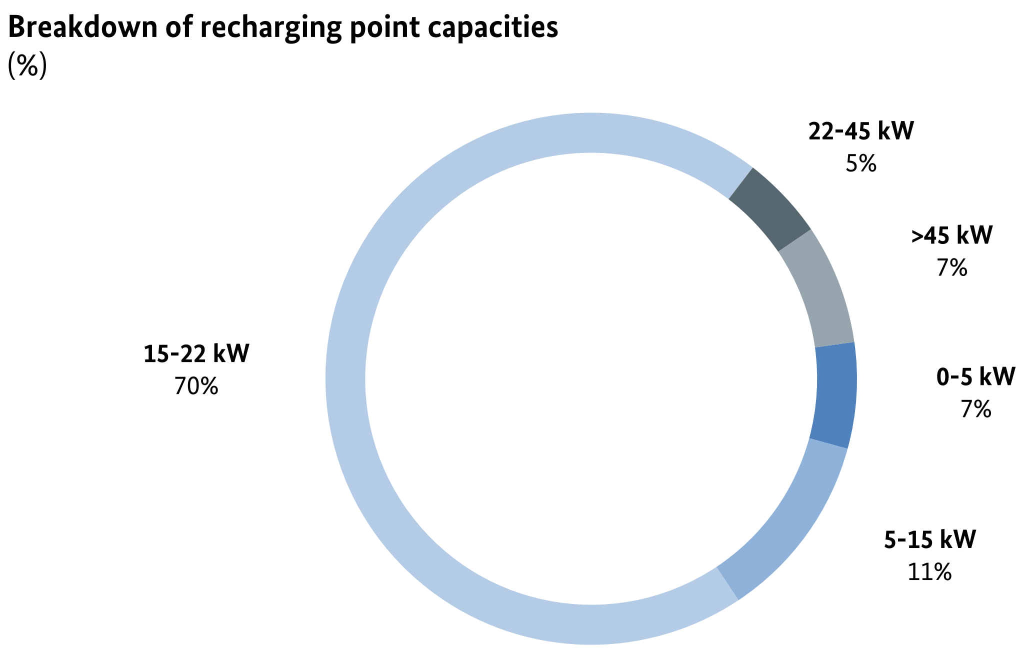

Figure 208: Breakdown of recharging point capacities

5.4 Electricity storage facilities in households

New developments in the field of storage technology and falling prices for storage systems have made it affordable for many people to install and use electricity storage facilities in their own homes. An increasing number of business models is appearing focused on increasing households' own supply from generating installations (eg solar PV installations). Lithium-ion batteries offer household customers various opportunities to participate in the electricity market.

For example, a design with a battery-storage system and solar PV installation on the roof of a residential property means that electricity that is generated and not consumed immediately can be temporarily stored for later use or, if necessary, fed into the grid.

In legal terms, storage facilities are treated as consumers when electricity is taken into them and as generators when it is withdrawn from storage, with the resulting payments and obligations.

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. Their market monitoring activities are based primarily on the trade and fundamental data reported to the Agency for the Cooperation of Energy Regulators (ACER) in accordance with Regulation (EU) No 1227/2011 (REMIT) in conjunction with Implementing Regulation (EU) No 1348/2014. Participants in the wholesale electricity and gas markets must report data to ACER. They need an ACER code to be able to do so, which they receive once they have registered as a market participant with their national regulatory authority. For market participants whose headquarters are in Germany, the national regulatory authority is the Bundesnetzagentur.

The Market Transparency Unit requires access to the data sent to ACER in order to ensure that the market is constantly monitored. As the data is particularly sensitive, ACER has very high data security requirements. It has conducted a thorough assessment of the comprehensive security policy of the Market Transparency Unit and has now confirmed that its security requirements have been met and that the Market Transparency Unit may access data sent to ACER.

In recent months, therefore, the Market Transparency Unit has been focusing on further developing the necessary IT structures to receive, prepare and evaluate the data from ACER and on setting up the market monitoring system.

Until permanent market monitoring for compliance with the REMIT provisions regarding the bans on insider trading and market manipulation can take place, the market is monitored as required when information is received by the Bundesnetzagentur about breaches of REMIT through the ACER Notification Platform.[168] In addition, it is possible to report breaches of REMIT to the Bundesnetzagentur directly; these reports may also be made anonymously.

The Market Transparency Unit may also gather additional data not collected at European level by ACER, following a determination taking account of an ordinance to be issued by the Federal Ministry for Economic Affairs and Energy. Such data may include in particular balancing energy data for electricity, and possibly also gas, and selected data relating to electricity generation plants with a capacity of less than 100 MW.

[168] https://www.acer-remit.eu/np/home

B Selected activities of the Bundesnetzagentur

1. Tasks under REMIT

1.1 Registered market participants

A total of 4,127 market participants pursuant to REMIT have registered in Germany,[169] and are among the 12,726 listed in the European register.[170] While registering, many market participants take the opportunity to ask the Bundesnetzagentur questions by telephone or email. These queries relate to the Centralised European Register of Energy Market Participants (CEREMP) as well as legal issues about the registration and data reporting to ACER. The Bundesnetzagentur responded to 2,634 queries from market participants in 2016. Questions of cross-border relevance were discussed by the Bundesnetzagentur and the other regulatory authorities of the Member States and ACER in the European working group "NRA Questions and Answers on REMIT" with the aim of finding a common interpretation of the European regulations.

1.2 Prosecution of breaches

REMIT contains obligations and prohibitions for participants in the wholesale electricity and gas markets. It is up to Member States to prosecute breaches, which may constitute regulatory or criminal offences depending on their severity. The Bundesnetzagentur is responsible for the prosecution of regulatory offences, while the public prosecutor's office is responsible for the prosecution of criminal offences.

The Bundesnetzagentur receives reports of suspected breaches of REMIT in the first place via ACER's electronic Notification Platform,[171] which is used in particular by persons professionally arranging transactions in wholesale energy products (eg energy brokers or energy exchanges). It is also possible for market participants to send reports of suspected breaches to the Bundesnetzagentur directly.

An overview of reports of suspected breaches received so far is given below:

[169] As at: 7 November 2017

[170] https://www.acer-remit.eu/portal/european-register

[171] https://www.acer-remit.eu/np/home

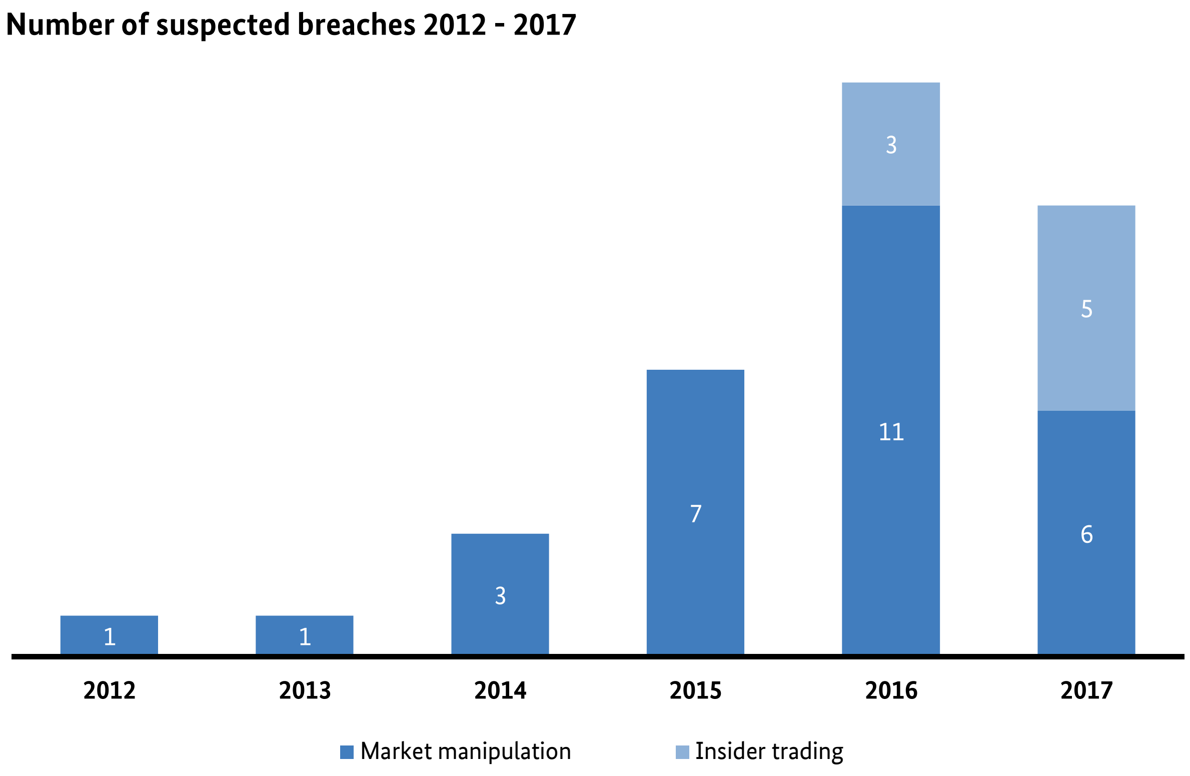

Figure 209: Reports of suspected breaches received by the Bundesnetzagentur 2012 – 2017 (as at 7 November 2017)

The reports are divided into those dealing with suspected market manipulation and those dealing with suspected insider trading. A total of eight cases concerned insider trading, while all others concerned market manipulation. The cases of insider trading received since the beginning of 2016 relate to transactions concluded before the relevant inside information had been published, among other things. The three Bundesnetzagentur fact sheets on the publication of inside information should be taken into account.[172] Cases of suspected market manipulation included "wash trades" – trading with oneself – and placing orders with no intention of executing them. Of the 32 reports of suspected breaches received, 5 are still being investigated, 7 more are under cross-border investigation, and 13 cases were closed following a detailed analysis, as a breach of the ban could not be proven. Cross-border investigations take place when regulatory authorities of other European Member States are involved, for example in cases of blocking the transmission capacity at the border or where the market participants concerned are based or registered in another Member State. To date the Bundesnetzagentur has not imposed any fines or brought charges.

[172] https://remit.bundesnetzagentur.de/REMIT/DE/Informationen/Dokumente/Merkblaetter/start.html

2. SMARD – greater transparency in the electricity market

SMARD is the new Bundesnetzagentur internet platform for electricity market data. It increases transparency in the electricity market and fulfils the mandate to set up a national information platform inserted into the Energy Industry Act (EnWG) by the Electricity Market Act (section 111d EnWG). The data published on the SMARD website, SMARD.de, provide an up-to-date overview of trade, generation, consumption and aspects of system stability. Background articles explain key terms and provide context, while the appealing design, coupled with graphs that are easy to understand, makes it easy for users to access the information on the website.

SMARD is aimed at interested members of the general public as well as professionals from the energy sector, business, science and teaching. SMARD.de provides answers to a wide range of questions using current data: how high is electricity supply and demand? How big is the share of electricity generated from renewable sources? How does electricity consumption change over the course of the day? How much electricity is imported into Germany and exported to its neighbours? Answers to these questions and more can be found in the SMARD data and graphs.

One of the special features of the platform is that users can create individual graphs with different data categories. The topics of electricity generation, electricity consumption, market and system stability are covered by several data categories on the website that include electricity generation broken down by source, wholesale prices and imports and exports. More detailed explanations and current issues relating to the electricity market may be found in the editorial content. There is also a geographic overview of current figures on the electricity market and an overview of the electricity generation landscape in Germany.

SMARD data is largely made available in accordance with the Regulation on the submission and publication of data in electricity markets (Regulation (EU) No 543/2013). This regulation requires German transmission system operators to supply certain data to the European network of transmission system operators (ENTSO-E).

Data quality is of the utmost importance. The Bundesnetzagentur is constantly exchanging information with the transmission system operators (TSOs) in order to continuously improve data quality. As the data is published under a CC BY 4.0 licence, it can be re-used by anyone free of charge.

The SMARD homepage provides quick access to the electricity market data. The objective was to create a platform offering added value on the electricity market to both a professional audience and to interested non-specialists.

Figure 210: Graphs showing data from different categories – for example, electricity generation and consumption – can be created with just a few clicks of the mouse on SMARD.de

Figure 211: SMARD platform homepage

C Selected activities of the Bundeskartellamt

1. Guidelines on the control of the abuse of a dominant position in electricity generation

The Bundeskartellamt is currently preparing guidelines on the control of the abuse of a dominant position in electricity generation.

In the debate about the Electricity Market Act in 2015 and 2016 concerns were frequently expressed that the prohibition of abusive practices under competition law had the effect of an implicit price ceiling and prevented price peaks in situations of scarcity (see Monitoring Report 2016, page 375 f.). 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.

In order to dispel these concerns, the Bundeskartellamt had proposed to publish guidelines on the control of the abuse of a dominant position in electricity generation. This proposal was adopted in the White Paper of the Federal Ministry of Economic Affairs and Energy published in 2015 as one of 20 measures to further develop the electricity market. The guidelines will define the objective, 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. In 2016 the Bundeskartellamt launched a consultation in preparation for the guidelines (the eight comments received are available on the Bundeskartellamt's website).

The Bundeskartellamt is currently drafting the text of the guidelines, which will focus in particular on the positions raised in the comments submitted. Addressing the issues in such a way that the guidelines remain viable in view of the current, foreseeable and possible changes in electricity generation and marketing will pose a particular challenge.

The Bundeskartellamt and the Bundesnetzagentur are currently planning to publish joint guidelines which, in addition to providing clarification on the control of the abuse of a dominant position on the market for the first sale of electricity, will address questions on the interpretation of the REMIT regulation. The guidelines are to be published soon, if possible by the end of this year.

2. Control of the abuse of a dominant position: Award of concessions for electricity networks

The prohibition decision (B8-175/11) which the Bundeskartellamt issued in January 2015 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 the decision of 14 June 2017 of the Düsseldorf Higher Regional Court (Vl-2 Kart 1 /15 (V) in which the court rejected the appeals against the prohibition decision and fully confirmed the Bundeskartellamt's decision. In its decision the Bundeskartellamt had established that the Titisee-Neustadt municipality had acted abusively in its award of rights of way for electricity networks and had ordered it to carry out a new, transparent and non-discriminatory award procedure. The municipality had abused its dominant position by carrying out a discriminatory selection procedure, giving preference to the municipal bidder without any objective justification and applying inadmissible selection criteria. It had also violated the principle of secret competition and the prohibition to agree or grant other benefits than those admissible. The concession contract concluded with the new rights of way holder violated Section 1 GWB.

As the amended version of Section 46 of the Energy Industry Act (EnWG) had come into force during the appeal proceeding, the Düsseldorf Higher Regional Court also expressed its opinion on the new wording of the relevant section. It stated:

"Section 46(4) sentence 2 EnWG states that in the selection of a right of way holder consideration can also be given to the interests of the municipality in addition to the fulfilment of network requirements, especially security of supply and cost efficiency. However, this did not strengthen the position of the municipality in a way which was relevant to this particular case. According to the legislative intent of the EnWG this provision is solely intended to replicate the [...] jurisdiction of the Federal Court of Justice (judgments of 17 December 2013 - KZR 65/12 and KZR 66/12) which state that rights of way must be awarded according to the objectives of Section 1(1) EnWG, but that consideration may also be given to the interests of the local community (cf. Bundestag printed paper 18/8184, p. 14)." (authenticated copy of decision, p. 23 f.)

3. Abuse proceedings in the electric heating sector

In September 2009 the Bundeskartellamt had initiated proceedings against a number of electric heating providers on the suspicion that they had abused their dominant position (Section 19(1) in conjunction with (4) no. 2 GWB and Section 29 sentence 1 no. 1 GWB). The companies were accused of demanding excessive prices for the supply of heating electricity from 2007 to 2009 to household and small commercial customers for the operation of interruptible consumption equipment, i.e. in particular electrical night storage heating and heat pumps.

In October and November 2010 commitment decisions under Section 32b GWB were issued in twelve cases against electric heating suppliers, in which the latter undertook to reimburse consumers or to defer price increases necessitated by increased costs. In addition, all the companies examined during the abuse proceedings made the following structural commitments to the Bundeskartellamt: Electric heating tariffs would have to be published on the Internet in future; the network operators undertook to publish and apply temperature-dependent load profiles for the supply of electric heating and in future only to invoice the concession fee of 0.11 ct/kWh applicable so far to special contracts for all supplies of electric heating. All these commitments were implemented at the latest during the first six months of 2011 and covered approx. 70 % of the volume of electric heating supplied to household and small commercial customers in Germany.

In 2015 the Bundeskartellamt concluded its last remaining proceeding on electric heating prices against Entega Energie GmbH after the company had undertaken in a settlement agreement under public law to reimburse its customers of night storage heating and heat pumps each with 155.72 euros (incl. VAT and interest) for the period 2007 to 2009. According to the agreement Entega was obliged to send the Bundeskartellamt a list of all recipients of the reimbursements along with the amounts reimbursed by 30 April 2017 as proof that the reimbursements had been made to its electric heating customers as provided for in the settlement agreement.

Entega fulfilled this obligation within the specified period. An examination of the list revealed that the fulfilment rate amounted to almost 87% of the reimbursement entitlements. In view of the fact that the entitlement period (2007 to 2009) dated back several years, this was considered to be relatively high. Furthermore, there had been no complaints from the customers affected about non-reimbursement or that the amount reimbursed was too low or too late. The Bundeskartellamt regarded Entega's obligation to reimburse its customers in accordance with the settlement agreement as fulfilled.

4. Sector inquiry: Submetering of heating and water costs

In May 2017 the Bundeskartellamt presented its final report on its sector inquiry into submetering. In the report the authority recommends measures to stimulate competition in the provision of submetering services. 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 allocators or water and heat meters.

The purpose of the sector inquiry was to assess the current market situation and intensity of competition in the metering and billing of heating and water costs and to identify any competition deficits, restraints of competition or abusive practices in this segment.

The Bundeskartellamt's sector inquiry revealed that the supply side is highly concentrated. In 2014 the two market leaders Techem und ista together accounted for more than 50 per cent of the total market volume and the five largest providers together accounted for more than 70 per cent. According to the results of the investigations conducted as part of the inquiry there are strong indications of the existence of an uncompetitive oligopoly consisting of at least the two market leaders and possibly some of the five major providers.

In 2014 the volume of turnover achieved from submetering in Germany amounted to approx. 1.47 billion euros. Disregarding the differences in the scope of services provided, the companies active in the sector achieved an average turnover per housing unit and year of approx. 74 euros. However, the results of the inquiry show large differences between the individual providers. The profits earned by the submetering service providers are relatively high.

The results of the inquiry also indicate that both a number of structural features as well as certain practices of submetering service providers make it difficult for customers to switch provider and are therefore likely to restrict competition between providers.

One of the key structural obstacles to competition are the actual long contract periods which are attributable amongst other things to the different calibration periods for different types of meter.

Price sensitivity on the demand side is weak. This is partly due to the fact that the consumer has to bear most of the costs of submetering without being the contractual partner of the submetering provider. The property owners and landlords are usually the contractual partner who pass on the costs to their tenants. In order to completely remove the resulting obstacles to more competition, this three-way relationship as such would have to be called into question and the costs of submetering imposed on the entity commissioning the submetering provider.

In addition, some submetering costs are non-transparent or difficult for consumers to assess because they only appear in aggregated form in the statement of utility costs.

The lack of interoperability between the meter systems and the low level of comparability of prices and quality of the services offered also make it difficult to switch provider. Legislative intervention has triggered a general development towards more interoperable systems, which could make switching easier in future. The Bundeskartellamt will closely follow the legislative processes.

The authority proposes the following legislative measures to remove the obstacles to competition mentioned above: Improvement of interoperability of meters, a standardisation of calibration periods and service life of meters and greater transparency for tenants through information rights and the obligation to tender.

The complete version of the Final Report (in German) is available for download on the Bundeskartellamt's website.

Lists

List of authorship

Joint texts

Key findings

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Introduction to Retail: Contract structure and supplier switching (I.G.2)

Introduction to Retail: Price level (I.G.4)

Gas markets summary (II.A.1)

Introduction to Retail: Contract structure and supplier switching (II.G.2)

Introduction to Retail: Price level (II.G.4)

Market Transparency Unit for Wholesale Electricity and Gas Markets (IV.A)

(Text passages in these four sections authored as listed below)

Authorship of the Bundesnetzagentur (explanations)

I Electricity market

- A Developments in the electricity markets (in the following sections:)
  - 2. Network overview
- B Generation
- C Networks
- D System services
- E Cross-border trading and European integration
- G Retail (in the following sections:)
  - 1. Supplier structure and number of providers
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I Electricity market

A Developments in the electricity markets (in the following sections:)

3. Market concentration

F Wholesale market

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List of abbreviations

Term	Definition
AbLaV	Interruptible Loads Ordinance
AC	Alternating current
ACER	Agency for the Cooperation of Energy Regulators
ARegV	Incentive Regulation Ordinance
AT	Austria
AusglMechV	Equalisation Scheme Ordinance
BAFA	Federal Office for Economic Affairs and Export Control
BBPlG	Federal Requirements Plan Act
bEXA	Block products traded on the Energy Exchange Austria (EXAA), eg bEXAbase and bEXApeak
bFZK	Capacity with conditional firmness and free allocability
BGH	Federal Court of Justice
BMWi	Federal Ministry for Economic Affairs and Energy
BSI	Federal Office for Information Security
BZK	Capacity with restricted allocability
CEE	Central East Europe
CEREMP	Centralised European Register of Energy Market Participants
CH	Switzerland
CHP	Combined heat and power
CR	Concentration Ratio
CSE	Central South Europe
ct/kWh	Cents per kilowatt hour
CWE	Central West Europe

CZ	Czechia
DC	Direct current
DIN	German Institute for Standardization
DSL	Digital Subscriber Line
DSO	Distribution system operator
DZK	Firm dynamically allocable capacity
EC	European Community
ECC	European Commodity Clearing AG
EEG	Renewable Energy Sources Act
EEX	European Energy Exchange AG
EHV	Extra-high voltage
EnLAG	Power Grid Expansion Act
ENTSO-E	European Network of Transmission System Operators for Electricity
EnWG	Energy Industry Act
EPEX SPOT	European Power Exchange
Eurostat	Statistical Office of the European Communities
EXAA	Energy Exchange Austria Abwicklungsstelle für Energieprodukte AG
FBA	Flow Based Allocation
FZK	Freely allocable capacity
GABi Gas	Basic model of balancing services and balancing rules in the gas sector
GasGVV	Gas Default Supply Ordinance
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	Restraints of Competition Act
GWh	Gigawatt hour
GWJ	Gas year
HVDC	High voltage direct current transmission
HV	High voltage
HVDC	High voltage direct current
IGCC	International Grid control Cooperation
ITC	Inter-TSO compensation
KAV	Electricity and Gas Concession Fees Ordinance
km	kilometre
KoV IV	Cooperation agreement pursuant to section 20(1b) EnWG between the operators of the gas supply networks in Germany, in the third variation of 1 October 2011
kV	kilovolt
kWh	kilowatt hour
KWKG	Combined Heat and Power Act
KraftNAV	Power Plant Grid Connection Ordinance
LNG	Liquefied natural gas
LSV	Charging Station Ordinance
LV	Low voltage
MessZV	Metering Framework Conditions Ordinance
MsbG	Metering Act
MV	Medium voltage

MW	Megawatt
MWh	Megawatt hour
NABEG	Grid Expansion Acceleration Act
NAV	Low Voltage Network Connection Ordinance
NCG	NetConnect Germany
Ncm	Normal cubic metre
Ncm/h	Normal cubic metre per hour
NDAV	Low Pressure Network Connection Ordinance
NDP	Network development plan
NEMOG	Network Charges Modernisation Act
NL	Netherlands
NTC	Net Transfer Capacity
OGE	Open Grid Europe
OMS standard	Open Metering System standard
OTC	Over-the-counter
PL	Poland
PLC	Powerline Carrier/Powerline Communication
PSTN	Public switched telephone network
REMIT	EU Regulation on wholesale energy market integrity and transparency
SAIDI	System Average Interruption Duration Index
SLP	Standard load profile
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
UMTS	Universal Mobile Telecommunications System
VAT	Value added tax
VNG	Verbundnetz Gas AG

Glossary

The definitions pursuant to section 3 of the Energy Industry Act (EnWG), section 2 of the Electricity Network Access Ordinance (StromNZV), section 2 of the Gas Network Access Ordinance (GasNZV), section 2 of the Electricity Network Charges Ordinance (StromNEV), section 2 of the Gas Network Charges Ordinance (GasNEV), section 3 of the Renewable Energy Sources Act (EEG) and section 2 of the Combined Heat and Power Act (KWKG) apply. In addition the following definitions apply:

Term	**Definition**
Adjustment measures	Section 13(2) EnWG 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) EnWG. 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) EnWG to take adjustment measures as referred to in section 13(2) EnWG. Furthermore, section 14(1c) EnWG 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) EnWG 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) EnWG 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 peak load (final consumer)	Peak load, expressed in kilowatt (kW), as metered in 15 minute readings, in the course of a year.
Annual usage time (final consumer)	The annual usage time is the quotient of the energy drawn from the grid in an accounting year and the annual maximum capacity used in that year. It gives the number of days that would be required to withdraw the annual consumption volume by taking off the maximum daily amount (usage time in days = annual consumption divided by maximum daily amount). The 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 = annual consumption divided by maximum hourly amount) (see annex 4 to section 16(2),(3) second sentence StromNEV).
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, 2012).
Balancing capacity	Balancing capacity is maintained to ensure a constant balance between electricity generation and consumption.
Balancing group	As regarding electricity within a control area, the aggregation of feed-in and consumption points that serves the purpose of minimising deviations between feed-in and output by its mix and enabling the conclusion of trading transactions (see section 3 para10a EnWG).
Balancing zone	Within a balancing zone all entry and exit points can be allocated to a specific balancing group. 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 EnWG).
Baseload	Load profile for constant electricity supply or consumption from 00:00 to 24:00 every day.
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 at their own request.
Charge for billing	The charge for billing network use and forecasting annual consumption in accordance with section 13(1) StromNZV has been included in the net network charges since 1 January 2017 and is no longer shown separately (see section 7(2) of the Metering Act).
Charge for meter operations	Charge for meter installation, operation and maintenance. In accordance with section 17(7) first sentence StromNEV, in the electricity sector only a "charge for meter operations" may be shown from 1 January 2017. This includes the charge for metering.
Charge for metering	In the gas sector, the charge for reading the meter, reading out and passing on the meter data to the authorised party (section 15(7) first sentence GasNEV).
CHP net nominal capacity (electrical active power)	For rated thermal capacity, proportion of the net nominal capacity directly linked to heat extraction. The proportion of electrical capacity exclusively related to the generation of electricity is not included here.
Concentration ratio (CR)	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 degree of market concentration.
Consumption	Amounts of electricity delivered by electricity suppliers to final consumers.
Conventional generation base	Proportion of the price-inelastic conventional generation that is not part of the minimum generation.
Countertrading	Countertrading is a measure used by the TSOs to avoid overloading in the electricity grid. It is used when the agreed minimum trading capacity exceeds the capacity that can be transported in the networks. In this case, a countertrade is organised. This enables a minimum level of trading to be guaranteed at all times without the networks being overloaded.

Day-ahead trade	Day-ahead trading on the EPEX Spot (the EEX spot market) is for energy supplied the next day.
Default supplier	The gas and electricity company providing default supply in a network area as provided for by section 36(1) EnWG.
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 EnWG).
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).
Economic balancing energy	*electricity* The activated energy that is settled with the balancing group managers causing the imbalances. Balancing energy is therefore the allocation of call-off costs for balancing capacity and represents the economic settlement of the activated energy. *gas* Difference between entry and exit quantities established by the market area manager for the market area at the end of each balancing period and settled with the balancing group managers (see section 23(2) GasNZV).
EEX/EPEX Spot	European Energy Exchange/European Power Exchange. The EEX, which is indirectly part of the Deutsche Börse Group, operates marketplaces for trading electricity, natural gas, CO_2 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. The electricity futures market is operated by EEX Power Derivates GmbH (a 100% subsidiary of EEX). EEX also holds

	an around 88% stake in Powernext SA, also based in Paris, which operates short-term gas trading (see EEX).
Electric heating	Electricity for heating is the electricity supplied to operate interruptible (= controllable) consumer devices for the purposes of room heating. Interruptible (= controllable) consumer devices essentially comprises overnight storage heaters and electric heat pumps.
Energy price components	The price component that is controlled by the supplier, made up of energy procurement, supply and margin.
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.
Entry-exit system	Gas booking system in which the shipper signs only one entry and exit contract, even if the transport is distributed among several TSOs.
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.
Exit volume	The gas network operators' exit quantities.
Expenditure	Expenditure consists of the combination of all technical or administrative measures taken during the life cycle of an asset to maintain or restore working order so that the asset can perform the function required (expenditure on replacement and maintenance).
Fallback supplier	The default supplier is the fallback supplier (see section 38 EnWG).
Fallback 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 EnWG).
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) EEG and section 4(1) and (4) second sentence KWKG). 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 (section 13(2) and (3) third sentence EnWG in conjunction with sections 14 and 15 EEG and, in the case of CHP installations, section 4(1) second sentence KWKG). 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 network restrictions 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) EEG 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.
Flow Based Allocation (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.
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.
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 that, 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.

Grid connection	*electricity* Pursuant to section 5 of the Low Voltage Network Connection Ordinance (NAV), the grid connection connects the general electricity network to the electrical installation of the customer. It begins at the branching-off point of the low voltage distribution network and ends with the service fuse, unless a different agreement has been made; in any case, the provisions relating to grid connection are applicable to the service fuse. In the case of power plants, the grid connection is the provision of the line that connects the generating installation and the connection point, and its linkage with the connection point (section 2 para 2 of the Power Plant Grid Connection Ordinance (KraftNAV)). *gas* Pursuant to section 5 of the Low Pressure Network Connection Ordinance (NDAV), 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 within the customer's system.
Gross capacity	Delivered power to the terminals of the generator. In turbine operation for hydro power, gross capacity is measured at the generator's terminals. In a pumped storage station, net capacity is measured at the terminals of the generator if the facility is operated as a motor. Gross capacity is equal to net capacity plus the electrical power used by the plant, including power lost by the plant's transformers but not the power consumed in the process of generation and the power required for the phase shifter (VGB, 2012).
Gross electricity consumption	Gross electricity consumption is calculated from the gross electricity generation plus imports and minus exports (both physical flows).
Gross electricity generation	Electrical energy produced by a generating unit, measured at the generator's terminals (see VGB, 2012).
H-gas	A second-family gas with a higher amount of methane (87 to 99 volume percent) and thus a lower volume percentage of nitrogen and carbon dioxide than L-gas. It has a medium calorific value of 11.5 kWh/m^3 and a Wobbe index from 12.8 kWh/m^3 to 15.7 kWh/m^3.
Hub	An important physical node in the gas network where different pipelines, networks and other gas infrastructures come together and where gas is traded.

Interval-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.
Intraday trading	Transactions involving gas and electricity contracts for supply on the same day are traded on the EPEX Spot (the spot market of the EEX), enabling the short-term optimisation of procurement and sale.
Investments	For the purposes of the energy monitoring survey, investments are defined as the gross additions to fixed assets capitalised in the reporting period and the total value of new fixed assets newly rented and hired in the reporting period. 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 holdings 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 (Federal Statistical Office, 2007).
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 than h-gas. 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 control in the low voltage network (formerly load interruption)	Electricity distribution system operators are required to give a reduction in network charges to suppliers and final customers at the low voltage level with whom they have concluded network access agreements, in return for being able to control meter points with load control for the benefit of the network. Electric vehicles are counted as controllable loads within the meaning of sentence 1. The federal government is empowered, by ordinance having the force of law and requiring the consent of the German Bundesrat, to give concrete shape to the obligation pursuant to sentences 1 and 2, in particular by providing a framework for the reduction of network charges and the contractual arrangements, and by defining control actions that are reserved for network operators and control actions that are reserved for third parties, in particular suppliers. It must observe the further requirements of the Metering Act regarding the communicative integration of the controllable loads. (section 14a EnWG)
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	In the gas market, a market area means a grouping of networks at the same, or downstream, level, in which shippers can freely allocate booked capacity, take off gas for final consumers and transfer gas to other balancing groups.
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.
Maximum usable volume of working gas	The total storage volume less the cushion gas required.
Metering point	Point in the grid at which the flow of energy, or the amount of gas transported, is recorded for billing purposes (see section 2(28) of the Metering Act).

Metering service	Metering the energy supplied in accordance with verification regulations and processing the metered data for billing purposes.
Minimum generation	The minimum generation is the feed-in capacity from conventional power plants required for the technical operation of the grid. Specifically, it is the feed-in capacity explicitly intended for the provision of non-transmission services. The non-transmission services must be provided for the purpose of stable network operation, which is why the technical necessity arises. The minimum generation must be fed in because only then can certain non-transmission services be provided (positive redispatching and balancing capacity, short circuit power and reactive power). It must even be fed in when the feed-in only provides the conditions necessary for non-transmission services to be provided, as in the case of negative balancing reserves. The capacity to safeguard the balancing reserves is included as part of the minimum generation because it directly contributes to its secure provision and works in the same way. However, this safeguard is not 1:1, but rather takes account of probabilities.
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 corresponds to the gross capacity less the power consumed by the unit in the process of generation, even if this is not supplied by the generating unit itself but by a different source (VGB, 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 (VGB, 2012).
Net network charges	*electricity* Electricity network charge, from 1 January 2017 including billing charge, not including charges for metering and meter operations, VAT, concession fees, renewable energy surcharge and surcharge payable under the KWKG. *gas* Gas network charge, from 1 January 2017 including billing charge, not including charges for metering and meter operations, VAT and concession fees.
Net Transfer Capacity	Net transfer capacity of two neighbouring countries (calculated as total transfer

(NTC)	capacity minus transmission reliability margin).
Network access	Pursuant to section 20(1) EnWG, operators of energy supply networks must grant non-discriminatory network access to everyone according to objectively justifiable criteria. The standard scenario is that the network is used by suppliers that then pay network charges to network operators. However, it is also permissible for final customers to use the network, in which case, the final customer pays the network charges to the network operator.
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
Nominal 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 nominal conditions and structural alterations at the plant. Until the exact nominal 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 nominal 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 nominal 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 nominal 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 nominal capacity, unlike the maximum capacity, may not be adjusted to a temporary change in capacity. The nominal 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 (VGB, 2012).
Nominal pressure	The nominal pressure specifies a reference designation for pipeline systems. In accordance with DIN EN ISO, nominal pressure is given using the abbreviation PN (pressure nominal) followed by a dimensionless whole number representing the design pressure in bar at room temperature (20°C). EN 1333 specifies the following nominal pressure levels: PN 2.5 - PN 6 - PN 10 - PN 16 - PN 25 - PN 40 - PN 63 - PN 100 - PN 160 - PN 250 - PN 320 - PN 400.
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.
Normal cubic metre (Ncm)	Section 2 subpara 11 GasNZV defines a normal 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.
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.
OTC trading	OTC stands for "over the counter" and refers to financial transactions between market players that are not traded on an exchange. OTC trading is also known as off-exchange trading.
Peak load	Load profile for constant electricity supply or consumption over a period of 12 hours from 8am to 8pm every working day. Peak load electricity has a higher monetary value than baseload.
Phelix (Physical Electricity Index)	The Phelix Day Base is the calculated average of the hourly auction prices for a full day (baseload) for the market area of Germany/Austria. The Phelix Day Peak is the calculated average of the hourly prices from 8am to 8pm (peak load times) for the market area of Germany/Austria (see EEX).
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	Power plants whose closure has been prohibited by law: power plants whose closure has been prohibited by section 13a EnWG. 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".
Redispatching	Redispatching means measures to intervene in the market-based operating schedules of generating units to shift feed-in. In this context, power plants are instructed by TSOs, either under a contractual arrangement or a statutory obligation, to reduce/increase their feed-in while, at the same time, other power plants are instructed to increase/reduce their feed-in accordingly. These interventions have no impact on the overall balance between generation and load since action is taken to ensure that the reductions in feed-in are balanced physically and economically by increases elsewhere. Redispatching is undertaken by network operators to ensure the safe and reliable operation of the electricity supply networks. The aim is either to prevent overloading of power lines or to relieve overloading. Network operators reimburse the plant operators involved in the redispatching measures for the costs incurred. A distinction is made between electricity-related and voltage-related redispatching. Electricity-related redispatching is used to avoid or relieve sudden overloading affecting power lines and transformer stations. Voltage-related redispatching, by contrast, is used to maintain the voltage in the affected network area, for instance by adjusting reactive power. This involves adjusting the active power feed-in from power plants to enable them to provide the reactive power needed to maintain voltage stability. This can be done by firing idle power plants up to their minimum active power feed-in level or by reducing feed-in from power plants operating at full capacity down to their minimum level. As with electricity-related redispatching, this form of reactive power provision only involves conventional power plants on account of the priority dispatch rules. In the case of voltage-related redispatching, system balancing measures may take the form of market transactions. Redispatching can be an internal measure applicable to one control area only or a wider measure applicable to more than one control area.
Renewable energy surcharge	The renewable energy surcharge is a provision of the EEG and laid down in greater detail in sections 60 et seq of the Act. 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 from network operators that has been set under the EEG or determined through auctions. The funds required are passed on to electricity consumers by the renewable energy surcharge. All non-privileged electricity consumers pay the renewable energy surcharge as part of the electricity price. The TSOs calculate the surcharge. They are required to determine and publish the surcharge for the following calendar year by 15 October each year. The network operators publish this online at www.netztransparenz.de. The Bundesnetzagentur ensures that the surcharge has been determined properly.
Self-supply (generating installations)	Self-supply is defined as an energy product that is used on the premises of a production site or a gas generation site to maintain operations eg electrical energy consumed in the auxiliary and ancillary facilities of a generating unit 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 self-supply includes step-up 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 self-supply during the reference period comprises two elements: self-supply for operations during operating hours and self-supply during idle hours. The latter is not taken into account in the net calculation (see VGB, 2012).
Spot market	Market where transactions are handled immediately. (Intraday and day-ahead auctions)
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 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 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.)
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 final customer at a meter point wishes to change supplier from the current one to a

	different one. This does not include cases of final customers first moving into or moving premises.
Supplier switch when moving premises	If, when first moving into premises or moving premises, a final customer decides on a supplier other than the local default supplier within the meaning of section 36(2) EnWG, this is considered distinct from a supplier switch.
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.
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.

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