Bundesnetzagentur Bundeskartellamt

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Report
Monitoring report 2019

Monitoring report 2019

in accordance with section 63(3) in conjunction with section 35
of the Energy Industry Act (EnWG)
and section 48(3) in conjunction with section 53(3) of the Competition Act (GWB)
Editorial deadline: 27 November 2019

Bundesnetzagentur für Elektrizität, Gas, Telekommunikation, Post und Eisenbahnen

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German Energy Industry 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 and monitoring reports

(3) At least every two years, as part of its monitoring activities pursuant to section 48(3) sentence 1, the Bundeskartellamt shall prepare a report on the competitive conditions in the electricity generation market.

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 annually by the Bundesnetzagentur and the Bundeskartellamt. Undertakings 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 2019, some 6,500 undertakings overall 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 transition and climate targets continue to shape developments in the electricity and gas markets in Germany. These developments are documented and analysed in this Monitoring Report. Consumers remain in the spotlight this year. The monitoring carried out by the Bundesnetzagentur and the Bundeskartellamt aims to inform consumers, create transparency in the market and provide an analysis of developments in competition.

The market share of the five biggest electricity producers – and thus the concentration on the conventional electricity generation market – continued to decline overall. However, power within the group has shifted in recent years, particularly due to Vattenfall's sale of its lignite activities to LEAG and the takeover of E.ON subsidiary Uniper by Finnish company Fortum. While RWE is the market leader by some distance, its share does not suggest that it has a dominant position. As part of its examination of the plans to merge RWE and E.ON, the Bundeskartellamt carried out a pivotal analysis, which revealed that RWE was indeed pivotal – that is to say, indispensable – for meeting electricity demand for a fairly significant number of hours over the year, but not to an extent that would lead to a presumption of market dominance. The Bundeskartellamt will further pursue its analysis in its forthcoming report on the competitive conditions in the field of electricity generation (market power report).

The energy transition continues to make progress. As in previous years, conventionally generated electricity is losing ground to electricity from renewable sources. The increase in electricity from renewables was smaller in 2018, particularly because of the decline in new build projects, but even so, 37% of domestic gross electricity consumption was generated from renewable energy – a record high. New solar photovoltaic installations helped achieve this level, while fewer new wind turbines were added both onshore and offshore.

Despite the increase in electricity generated by installations receiving payments under the Renewable Energy Sources Act (EEG), the total amount of EEG payments fell for the first time in 2018 compared to previous years. The decrease was due in particular to the comparatively high electricity prices. These affect the level of the statutory payments for installations marketed directly by the producers, which make up the overwhelming majority of this generation.

The far-reaching changes in electricity generation have a direct impact on the grid and require significant adjustments to it. The expansion of the grid continues to lag behind where it needs to be. Apart from the rollout of new infrastructure, the implementation of specific measures to optimise and increase the utilisation of the existing electricity networks is becoming more and more important. These measures are already taken into account when sizing long-term grid expansion plans.

The reorganisation of electricity production, coupled with the delays in the rollout of grid infrastructure, is making it necessary for transmission system operators to intervene regularly in generation in order to maintain system security. The volume of these electricity-related and voltage-related redispatching measures, which are used to adjust electricity feed-in from conventional generating installations to relieve overloading of power lines, remained at a high level in 2018, although it was down on the previous year. The volume of renewable energy installations curtailed by feed-in management measures was almost unchanged in comparison to the previous year, with the proportion of electricity from renewables that was able to be transported remaining constant at 97%.

Electricity network charges rose in 2019 despite some cost components being transferred to the offshore network surcharge. The increase was due to the rising costs for the electricity grid expansion at all levels and the high projected costs for system security measures.

Average wholesale electricity prices were again considerably higher in 2018, this time by about 22%. By contrast, liquidity on the wholesale electricity trading markets developed in different directions, with day-ahead trading falling while intraday trading showed significant growth. The volume of futures trading registered growth too following the de facto split in the German-Austrian market area from 1 October 2018, which had a significant effect on the structure of the relevant trading products. There was also a clear increase in gas wholesale prices in 2018, while liquidity in wholesale gas trading declined overall.

As in previous years, the combined market shares of the largest electricity and gas suppliers for standard load profile and interval-metered customers in the respective retail markets were clearly below the statutory thresholds for presuming market dominance. Nevertheless, the positive developments on the retail electricity and gas markets stalled in many areas. Supplier switching rates, for example, remained more or less unchanged in 2018. The number of providers available to consumers stabilised at its already high level.

On the reference date of 1 April 2019, the average electricity price for household customers was over 30 ct/kWh for the first time. Gas prices for household customers, meanwhile, recorded a year-on-year increase after several years of decline. Electricity and gas prices for commercial and industrial customers rose as well, but rather less steeply. The price rises that occurred during the reporting year were primarily accounted for by the price components controlled by the supplier, as the higher prices that had already been seen on the wholesale markets in the previous year were passed on to end customers. There was good news regarding electricity and gas disconnections. The number of connections, which are carried out when customers do not pay their bills, dropped in both sectors in 2018.

Germany's position as a natural gas transit country for Europe is strengthening, with a rise in natural gas imports and exports from the previous year. Germany remains dependent on natural gas imports owing to the continued decline in domestic production. The country's storage levels from existing gas storage facilities reached a new high at the beginning of the withdrawal period in early November 2019, giving a boost to supply security in the natural gas sector. The low average interruption duration per connected final consumer – less than a minute in the year – also indicates the high supply quality of the German gas network.

The conversion of the German L-gas networks to H-gas supply, which is affecting a lot of private consumers in particular, is going ahead as planned. The highest annual figure of around half a million converted appliances will be reached in the coming years.

The rollout of smart metering systems is also under starter's orders. The first smart metering system was certified by the Federal Office for Information Security (BSI) in December 2018, followed by the second in September 2019, so the rollout is now planned for the end of 2019.

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

Jochen Homann
President of the
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Telekommunikation, Post und Eisenbahnen

Andreas Mundt
President of the Bundeskartellamtes

Key findings

Generation

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. In 2018, the aggregate market share of the five largest undertakings in the market for the first-time sale of electricity based on the German market area was 73.9%, compared to 75.5% in the previous year.

With respect to the German conventional generating capacity generally available for use in the market for the first-time sale of electricity, the share of the five largest suppliers was 60.8% and thus also significantly below the previous year's level of 64.9%.

Germany's total net electricity generation declined from 601.4 TWh in 2017 to 592.3 TWh in 2018 due to a decrease in gross electricity consumption. After a substantial rise of 24.6 TWh in generation from renewable energy sources in 2017, there was a smaller increase of 6.0 TWh in 2018 to a total of 210.8 TWh. Electricity generation from renewable energy sources accounted for 37% of gross electricity consumption.

The year 2018 saw a further expansion of renewable energy capacity, although growth was slightly smaller than in the previous year. At the end of 2018, installed renewable capacity had increased year-on-year by approximately 6.6 GW. The total generating capacity was at 221.6 GW in 2018, compared to 215.6 GW in 2017, with 103.3 GW of non-renewable and 118.2 GW of renewable capacity.

The growth in renewable energy capacity of 6.6 GW (sum of renewable energy installations with and without payments under the EEG) is due in particular to the greater increase in solar installations (+2.9%) compared to the previous years. Onshore and offshore wind power capacity also continued to grow. However, at 2.3 GW the net expansion of onshore wind power capacity more than halved compared to 4.9 GW a year earlier.

Total renewable electricity generation increased year-on-year by 6.0 TWh or 2.9% to 210.8 TWh, mainly accounted for by a 15.2% year-on-year increase in the amount of electricity generated through solar. Compared to 2017, onshore wind generation increased by 2.4 TWh or 2.8% in 2018. Offshore wind generation was also up, showing an increase of 1.8 TWh or 10.1%. The warm temperatures in 2018 led to a drop in electricity generated from run-of-river hydroelectric plants by 2.0 TWh or 11.7% and from hydro storage plants by 0.8 TWh or 37.3%. Payments to renewable installation operators under the EEG averaged 13.2 ct/kWh in 2018.

Despite the increase in electricity generation from installations receiving EEG payments, the total amount of payments under the EEG decreased for the first time in 2018 compared to previous years falling by 1.3% to €25.7bn. The decrease is due in particular to the comparatively high electricity prices in 2018, which affect the level of the payments. Directly marketed installations do not receive the full amount via the EEG surcharge, but only the difference, if any, to the market price.

Redispatching and feed-in management

The need for redispatching measures continued to be at a high level in 2018, but the volume decreased compared to 2017. In 2018, total reductions in feed-in amounted to 7,919 GWh, increases in feed-in from operational plants totalled 6,956 GWh and the use of reserve power plants accounted for 654 GWh. Overall, a total of 15,529 GWh of reductions and increases in feed-in was requested. Redispatching measures were taken on 354 days. The reductions in feed-in from power plants as a result of redispatching measures thus corresponded to 2.1% of the total non-renewable generation fed into the grid. Costs for redispatching measures with operational and grid reserve power plants amounted to approximately €803m in 2018.

At around 5,403 GWh, feed-in management measures in 2018 almost remained at the 2017 level. Compared with 2017, when feed-in management measures totalled 5.518 GWh, this corresponds to a decrease in the amount of energy curtailed of approximately 115 GWh. The total estimated compensation payments claimed by installation operators and notified to the Bundesnetzagentur amounted to approximately €635.4m in 2018, slightly up on the previous year's level of €609.9m.

Electricity network charges

After average network charges for household customers had fallen for the first time again in 2018, there was an increase of 0.4% to 7.22 ct/kWh in 2019. As from 2019, cost components from the network charges are part of the offshore network surcharge. The costs for network users nationwide based on the sum of the network charges and the offshore network surcharge increased by just under 6% from 7.23 ct/kWh (7.19 ct/kWh plus 0.037 ct/kWh offshore liability surcharge) in 2018 to 7.64 ct/kWh (7.22 ct/kWh plus 0.416 ct/kWh offshore network surcharge) in 2019.

Wholesale electricity markets

The spot market was characterised by various developments. The volumes of day-ahead trading on EPEX SPOT and on EXAA showed a year-on-year decrease, while the volume of intraday trading rose by some 12.5% compared to the previous year.

Volumes in futures trading recorded a growth of approximately 11% year-on-year. Moreover, in 2018 the Phelix-DE future almost entirely replaced the Phelix-DE/AT future. Phelix-DE trading volumes were at 1,058 TWh and Phelix-DE/AT at 27 TWh, compared to 196 TWh and 786 TWh in 2017 respectively. Volumes traded via broker platforms also increased. The volume of OTC clearing of Phelix-DE futures on EEX rose significantly to 1,053 TWh in 2018, now equalling the volume traded on the exchange.

Wholesale electricity prices averaged across 2018 were again considerably higher. Spot market prices (for the combined German-Austrian market area until 30 September 2018) were up about 22% year-on-year, and futures (for the market area Germany/Luxembourg) were quoted approximately 33% higher for the following year.

Retail electricity markets

Retail market developments in 2018 stagnated in many areas. Rising prices on the wholesale markets are now also affecting final customers.

As in previous years, 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 showed a further year-on-year decrease, down to around 24.4% in the national market for supplying interval-metered customers, and down to 31.3% in the national market for non-interval-metered customers on special contracts.

The supplier switching rate for non-household customers has been fairly constant since 2009. The volume-based switching rate for customers with an annual consumption of more than 10 MWh stood at 12.3% in 2018, compared to 13.0% in 2017. The share of electricity consumed by household customers served by a supplier other than their local default supplier is stable at 31%. At 4.7m, the number of household customers who switched their electricity supplier also remained unchanged. The number of undertakings operating in the market largely remained the same, giving household customers a choice between an average of 124 different suppliers.

The average total price (excluding VAT and possible reductions) for industrial customers with an annual consumption of 24 GWh was 15.98 ct/kWh on 1 April 2019, up 0.68 ct/kWh on the previous year. The average total price (excluding VAT) for commercial customers with an annual consumption of 50 MWh was 22.22 ct/kWh in April 2019, representing an increase on the previous year of 0.66 ct/kWh. This increase in prices for industrial as well as commercial customers is mainly accounted for by the price components controlled by the supplier.

The average price for household customers as at 1 April 2019 was 30.85 ct/kWh, and thus for the first time exceeded 30 ct/kWh. This average value is calculated by weighting the individual prices across all contract models according to consumption for an annual consumption of between 2,500 kWh and 5,000 kWh, producing a reliable average for the electricity price for household customers. As at 1 April 2019, the price component controlled by the supplier (energy procurement, supply and margin) accounted for about 7.6 ct/kWh or 25% of the total price, thus showing a further year-on-year increase. The average network charge and the meter operation charges add up to 7.22 ct/kWh in 2019, which is just under 24% of the total price. At 6.41 ct/kWh, the EEG surcharge fell again, now accounting for about 21% of the total price.

Electric heating

Electric heating prices were higher than in 2018. The arithmetic mean of the gross total price for night storage heating as at 1 April 2019 was 21.92 ct/kWh, up on the previous year's level of 21.08 ct/kWh. The arithmetic mean of the total price for heat pump electricity was 22.50 ct/kWh, up on the previous year’s figure of 21.71 ct/kWh. In general, prices for heat pump electricity are higher than for night storage heating.

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. This increase in the switching rate indicates a higher degree of competition. Yet at the same time, the switching rates are still far below those for household electricity and non-household customers. The volume-based supplier switching rate for 2018 was around 4%. There is a steady increase in the share of electricity provided for heating purposes and in the number of electric heating meter points served by a supplier other than the local default supplier, now standing at around 13%. This figure was still at around 9% in 2016.

Electricity imports and exports

Germany's electricity exports decreased slightly for the first time in 2018 compared to the previous year. Cross-border trade volumes for electricity amounted to 85.3 TWh in 2018, down from 90 TWh in 2017. With an export balance of 51.3 TWh, Germany is one of Europe's large exporters of electricity. The export surplus corresponded to €2,099m. Despite a decrease in the volume, there was an increase in the export surplus in monetary terms, up from €1,725m in 2017.

Gas imports and exports

The volume of gas imported into Germany rose by some 83 TWh or around 5% from 1,676 TWh in 2017 to 1,760 TWh in 2018. The year 2018 also saw an increase in gas exports, from 770.4 TWh in 2017 to 849.1 TWh in 2018, up approximately 105.6 TWh or 14% on the previous year.

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

Gas supply interruptions

In 2018, the average interruption in supply per connected final consumer was 0.48 minutes per year, which is a value that clearly reflects the high level of supply quality of the German gas network.

Market area conversion

The conversion of German L-gas networks to H-gas began in 2015 with the smaller network operators and has since been in progress as planned with the larger network operators such as Westnetz, EWE Netz and wesernetz Bremen. The highest annual figure of around 550,000 converted appliances will be reached in the coming years.

Gas storage facilities

The market for the operation of underground natural gas storage facilities is still relatively highly concentrated, although concentration has eased over the past few years. The aggregate market share of the three largest storage facility operators stood at around 67.1% at the end of 2018, representing a slight decrease on the previous year.

On 31 December 2018, the total maximum usable volume of working gas in underground storage facilities was 280.02 TWh. Of this, 134.12 TWh was accounted for by cavern storage, 123.89 TWh by pore storage and 22.01 TWh by other storage facilities. As at 1 November 2019 the storage level of gas storage facilities was at over 99%.

Wholesale natural gas markets

Overall, the liquidity of the wholesale natural gas markets declined in 2018. Although the volume traded on the stock exchange increased by a total of around 13% (spot market: +26%, futures market: -33%), bilateral wholesale trading via broker platforms, which accounts for a much larger share, experienced a decrease in volume of around 14%.

As in the previous year, wholesale gas prices in 2018 showed some considerable increases. The various price indices (EGIX, cross-border prices, as calculated by the Federal Office for Economic Affairs and Export Control (BAFA)) show a year-on-year increase of between 13% and 28%. A fully reliable year-on-year comparison for the European Gas Spot Index (EGSI) introduced in September 2017 will be available next year.

Retail gas markets

The level of concentration in the two largest gas retail markets continues to be well below the statutory thresholds for presuming market dominance. In 2018, cumulative sales for the four largest companies to customers with a standard load profile (SLP) were about 86 TWh and around 138 TWh for interval-metered customers. The aggregate market share of the four largest companies (CR4) in 2018 was around 23% for SLP customers, and thus the same as in the previous year, and about 31% for interval-metered customers, compared to 30% in 2017.

The retail gas markets are continuing to develop positively. Over 1.5m household customers switched gas supplier in 2018; yet the overall number of customers switching gas supplier recorded a slight decline. What is noticeable though is that a growing number of household customers immediately choose an alternative supplier rather than the default supplier when moving home or moving into new builds.

The total consumption affected by supplier switches in 2018 was 89.5 TWh, corresponding to a year-on-year increase of 1.5 TWh or about 2%. The switching rate for non-household customers was 9.0%, representing an increase of around 0.9 percentage points compared to the previous year.

At approximately 0.6m, the total number of customers changing contract continued to develop positively in 2018. Overall, the percentage of household customers supplied by the local default supplier on a default contract continues to decline, standing at 18% in 2018. In addition, there was another significant increase in the number of undertakings operating in the market. Today, household customers can choose between an average of more than 100 different suppliers. At the same time, the number of gas disconnections has again fallen. In 2018, a total of nearly 33,000 customers were disconnected, representing a year-on-year decrease of just over 17%.

The gas prices for non-household (industrial and commercial) customers as at 1 April 2019 showed year-on-year increases. The arithmetic mean of the overall price (excluding VAT) for an annual consumption of 116 GWh ("industrial customer") was 2.86 ct/kWh, and thus 0.04 ct/kWh or around 1.4% higher than the previous year's figure. The arithmetic mean of the overall price (excluding VAT) for an annual consumption of 116 MWh ("commercial customer") was 4.55 ct/kWh, and thus 0.15 ct/kWh or around 3.4% higher than a year earlier.

After several years of decreases the gas prices for household customers again recorded a year-on-year increase as at 1 April 2019. The volume-weighted average across all groups of household customers with an average consumption of 23,250 kWh was up 4.4% or 0.27 ct/kWh at 6.34 ct/kWh (including VAT). The main reasons for the rise in gas prices are the increases in gas procurement costs (6%) and network charges (4%).

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A Developments in the electricity markets

1. Summary

1.1 Generation and security of supply

At 592.3 TWh, Germany's net electricity generation in 2018 was lower than the 2017 level (601.4 TWh). One particular reason for the reduction in the level of net electricity generation is the decrease in gross electricity consumption. The decline in the overall level of net electricity generation was accompanied by a decrease in generation from non-renewable energy sources (-15.1 TWh or -3.8%). The largest decrease here was in net electricity generation from natural gas power plants at -8.3 TWh (-11.4%). There was a reduction of 3.1 TWh (-3.7%) in electricity generation from black coal plants. Lignite power plants generated 1.6 TWh less electricity (-1.2%).

After a large rise in generation from renewable energy sources in 2017, there was a smaller increase of 2.9% in 2018 to a total of 210.8 TWh (2017: 204.8 TWh). Electricity generated from renewables accounted for 37% of gross electricity consumption in 2018.[1]

Installed generating capacity was characterised in 2018 by a further increase in renewable capacity. Overall, renewable capacity increased by 6.6 GW, compared to an increase of 7.4 GW between 2016 and 2017.[2] The largest increases here in 2018 were in solar photovoltaic (+2.9 GW), onshore wind (+2.3 GW) and offshore wind (+1.0 GW). Non-renewable generating capacity (nuclear, lignite, black coal, natural gas, mineral oil products, pumped storage and other non-renewable energy sources) decreased by 0.7 GW in 2018. Total (net) installed generating capacity increased to 221.6 GW at the end of 2018, with 103.3 GW of non-renewable and 118.2 GW of renewable capacity. The non-renewable generating capacity includes power stations operational in the market and power stations outside the market (eg standby lignite and grid reserve power stations).

The installed capacity of systems eligible for payments under the Renewable Energy Sources Act (EEG) in Germany stood at 114.1 GW at the end of 2018 (2017: 107.5 GW). This represents an increase of around 6.6 GW (6.1%). A total of 195.4 TWh of electricity from renewable energy installations received payments under the EEG in 2018. Electricity generation from installations eligible for EEG payments thus increased by 4.2%. Despite the increase in the amount of electricity generated by installations receiving EEG payments, payments in 2018 fell for the first time compared to previous years. The total amount of payments decreased by 1.3% to €25.7bn. The decrease is due in particular to the comparatively high electricity prices in 2018, which affect the level of the payments. Directly marketed installations do not receive the full amount via the EEG surcharge, but only the difference, if any, to the market price. In 2018, renewable installation operators received an average of 13.2 ct/kWh under the EEG.[3]

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[1] If the share of renewables in generation is taken to be more than 40%, it usually relates to the definition of consumption as "grid load" (for example on the SMARD website).

[2] The 2017 figure from the 2018 monitoring has been updated.

[3] The average EEG payment is calculated by dividing the total sum paid under the EEG in a year by the total amount of renewable electricity fed in during that year.

1.2 Cross-border trading

Electricity exports again exceeded imports in 2018. The volume of cross-border trading increased slightly by 2%.

Germany's electricity exports decreased slightly for the first time in 2018 compared to the previous year. Cross-border trade volumes for electricity amounted to 91.57 TWh in 2018 (2017: 90 TWh). With an export balance of 52.46 TWh Germany is one of Europe’s large exporters of electricity. The export surplus corresponded to €2,125m. Despite a decrease in the volume, there was an increase in the export surplus in monetary terms (2017: €1,725m).

1.3 Networks

1.3.1 Network expansion

The projects currently listed in the Power Grid Expansion Act (EnLAG) (as at the first quarter of 2019) comprise lines with a total length of about 1,800 km. A further 20 km are in the spatial planning procedure and around 550 km are in or about to start the planning approval procedure (as at the first quarter of 2019). Overall, around 1,200 km have been approved, of which approximately 800 km – or about 45% of the total – have been completed. 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.

The projects listed in the Federal Requirements Plan Act (BBPlG) comprise lines with a total length of about 5,900 km (as at the first quarter of 2019). 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 be largely determined by the route of the north-south corridors and will become apparent in the course of the procedure. Approximately 3,600 km fall under the responsibility of the Bundesnetzagentur. As at the first quarter of 2019, approximately 2,700 km of these lines are in the federal sectoral planning procedure, around 200 km are about to start the planning approval procedure and about 30 km are in the planning approval procedure. Approximately 2,200 km of the total fall under the responsibility of the federal state authorities. As at the first quarter of 2019, around 50 km of these lines are in the spatial planning procedure and 1,100 km are in or about to start the planning approval procedure. A further 100 km or so have already been approved in the procedures carried out by the Federal Maritime and Hydrographic Agency (BSH).

1.3.2 Investments

In 2018, investments in and expenditure on network infrastructure by the network operators amounted to around €9,830m (2017: €9,727m) (both values under commercial law).[4] This comprised €6,464m of investments and expenditure by the distribution system operators (DSOs) and €3,366m by the four transmission system operators (TSOs). The TSOs' investments increased slightly from €2,707m in 2017 to

[4] 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.

€2,954m in 2018. The DSOs' investments also increased slightly from €3,501m in 2017 to €3,938m in 2018. The investment figures back to 2008 have been corrected to include the TSOs' offshore investments.

1.3.3 Network and system security

Redispatching measures serve to maintain network and system security. In 2018, total reductions in feed-in amounted to 7,919 GWh and increases in feed-in from operational power plants amounted to 6,956 GWh. The need for redispatching was thus still at a high level but was 24% lower compared to 2017 (2017: 20,439 GWh).

In 2017, in particular the unusual load flows in the first quarter that were due to various factors had led to a high need for redispatching measures. In the fourth quarter of 2017, the strain on the networks was already beginning to ease due to the commissioning of the "Thuringia power bridge". From the third quarter of 2018, however, there was another increase in redispatched volumes; one particular reason was the introduction at the end of April 2018 of the MinRAM process for flow-based capacity calculation in the CWE region. This methodology involves taking account of a standard minimum capacity of 20% per line in the capacity calculation. This increases the need for redispatching measures and is only partly compensated by the congestion management scheme (bidding zone split) introduced at the border with Austria as from 1 October 2018.

There was a correspondingly small decrease in the costs. An initial estimate by the TSOs puts the costs for the operational power stations at around €351.5m plus about €36.0m for countertrading measures (in total €387.5m). These costs are around 8% lower than the total costs in 2017 (2017: €420.6m).

In 2018, the grid reserve was used on 166 days to provide a total of around 904 GWh of energy. The initial estimate by the TSOs put the costs of using the grid reserve at €85.2m, representing a decrease of 54% (2017: €183.9m). The main reason for this is that no plants outside Germany were contracted for the grid reserve for winter 2018/2019. The costs for reserving the plant capacity plus other costs not dependent on the use of the grid reserve amounted to around €330.3m.

The amount of energy curtailed as a result of feed-in management measures, that is the curtailing of installations receiving payments under the EEG or the Combined Heat and Power Act (KWKG), was again high in 2018, totalling 5,403 GWh. This represents a slight decrease of 2% compared to the previous year (2017: 5,518 GWh). The amount of energy curtailed thus corresponded to 2.8% of the total amount of energy generated by renewable energy installations eligible for payments under the EEG (including direct marketing) (2017: 2.9%). The amount of compensation paid to installation operators in 2018 was about €719m, up around €145m on 2017 (2017: €574m). The total estimated claims from installation operators, however, increased slightly in 2018 to €635m. The discrepancy between the figures is due to the fact that the compensation paid in 2018 does not reflect the amounts payable for the curtailments actually made in 2018. The compensation paid in 2018 may include amounts for curtailments in previous years, and claims from 2018 may not be reflected properly, as the billing period does not correspond to the period when the curtailments were made.

In 2018, as in previous years, feed-in management measures primarily involved onshore wind power plants, which accounted for 72% of the total amount of curtailed energy (2017: 81%). Offshore wind power plants, which were first affected by feed-in management measures in 2015, accounted for around 25% (about 1,356 GW) of the total amount of curtailed energy in 2018, representing another increase (2017: 15% or around 826 GW).

The main reason for the continuing high level of feed-in management measures in 2018 was the curtailment of offshore wind power plants in addition to the wind situation and the growth of renewable capacity. Given the increased need for feed-in management measures and assuming that there will be a further steady increase in renewables, the measures required for network optimisation, reinforcement and expansion must be implemented without delay. This applies to the networks in and around Dörpen in the Emsland region and, in the case of feed-in management measures, in particular to the substation level between high voltage and extra-high voltage in Schleswig-Holstein.

In 2018, a total of five DSOs took adjustment measures. The measures to adjust electricity feed-in totalled around 8.3 GWh.

In total, the costs for network and system security amounted to about €1,438.4m in 2018. This represents a decrease of around €72.3m (-4.8%) compared to the previous year (2017: €1,510.7m).

1.3.4 Network charges

The volume-weighted network charges (including meter operation charges) for household customers for 2019 rose by 0.4% (+3 ct/kWh).

- Household customers, annual consumption 2,500 kWh to 5,000 kWh: volume-weighted 7.22 ct/kWh

As from 2019, the offshore liability surcharge and cost components from the network charges are part of the offshore network surcharge. The costs for network users nationwide based on the sum of the network charges and the offshore network surcharge increased by just under 6% from 7.23 ct/kWh (7.19 ct/kWh plus 0.037 ct/kWh offshore liability surcharge) in 2018 to 7.64 ct/kWh (7.22 ct/kWh plus 0.416 ct/kWh offshore network surcharge) in 2019.

With respect to non-household customers, the arithmetic mean charges for commercial customers are slightly higher than the previous year's level.[5] The network charges (including meter operation charges) for commercial customers increased by 1% to around 6.31 ct/kWh (2017: 6.27 ct/kWh). By contrast, the network charges (including meter operation charges) for industrial customers fell by approximately 1% to around 2.33 ct/kWh (2017: 2.36 ct/kWh). The charges as at 1 April 2019 for the selected consumption groups were as follows:

- Commercial customers, annual consumption 50 MWh: arithmetic mean 6.31 ct/kWh

- Industrial customers, annual consumption 24 GWh, without a reduction under section 19(2) of the Electricity Network Charges Ordinance (StromNEV): arithmetic mean 2.33 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 DSOs' published price lists (charges excluding meter operation), shows the following: the network charges for household customers range from 1.78 ct/kWh to 25.38 ct/kWh; the range of network charges for commercial customers is similar to that for household

[5] It should be noted that the arithmetic mean reflects neither the wide spread of the network charges nor the heterogeneity of the network operators for these consumption groups.

customers, with charges ranging from 0.19 ct/kWh to 24.63 ct/kWh; the network charges for industrial customers (without possible reductions) range from around 1.16 ct/kWh to 7.77 ct/kWh.

1.4 System services

The net costs for system services decreased in 2018 to around €1,881.39m (2017: €1,983.1m). A large part of the costs were accounted for by the costs of reserving and using grid reserve power plants at around €415.5m (2017: €480.0m), national and cross-border redispatching at just under €351.5m (2017: €391.6m) and the estimated claims for compensation for feed-in management measures at €635.4m (2017: €609.9m). Other large costs incurred were for procuring primary, secondary and tertiary control reserves at €123.3m (2017: €145.5m) and for energy to compensate for losses at about €273.2m (2017: €280.4m). The structure of the costs for system services in 2018 was only slightly different to that in 2017.

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.

The liquidity of the wholesale electricity markets was characterised by various developments in 2018. There was a slight decrease in the overall volume of trading in the spot market. Trading volumes in the day-ahead market decreased, while those in the intraday market increased. Another key development in wholesale electricity trading was the introduction of congestion management at the border between Germany and Austria on 1 October 2018, which effectively divided the combined German-Austrian market area (bidding zone split).[6]

Various developments were seen on the spot market. The volume of day-ahead trading on EPEX SPOT in 2018 was 224.6 TWh, around 3.7% lower compared to the previous year (233.2 TWh). The volume of day-ahead trading on EXAA was also lower, with a decrease of about 13.9% to around 7.2 TWh. By contrast, the volume of intraday trading rose to 52.8 TWh, corresponding to an increase of around 5.8 TWh or about 12.5% compared to the previous year.

Futures trading recorded small increases in volumes. The Phelix-DE future almost entirely replaced the Phelix-DE/AT future in 2018. Volumes traded via broker platforms also recorded increases.[7] The volume of OTC clearing of Phelix-DE futures on EEX rose considerably to 1,053 TWh in 2018, now equalling the volume traded on the exchange.

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[6] This bidding zone was dissolved on 1 October 2018, as agreed between the Bundesnetzagentur and the Austrian regulatory authority E-Control on 15 May 2017, so that there is now a bidding zone for Austria and a separate bidding zone for Germany and Luxembourg. See https://www.bmwi.de/Redaktion/DE/Pressemitteilungen/2017/20170515-bnetza-e-control-einigen-sich.html (accessed on 13 September 2018).

[7] The volume reported to the Bundeskartellamt is smaller compared to the previous year, but one large broker did not report data; taking the broker's volume in the previous year, there are also slight increases.

Alongside trading on the exchange, OTC clearing on the exchange has a special function in bilateral wholesale trading. The volume of OTC clearing of Phelix futures on EEX in 2018 was 1,053 TWh, compared to 905 TWh in the previous year. As OTC clearing has the effect of (subsequent) equalisation with futures traded on the exchange, it makes sense to also look at the development of the OTC clearing volume in the context of the on-exchange futures trading volume.

Wholesale electricity prices averaged across 2018 were again considerably higher. Spot market prices (for the combined German-Austrian market area up until 30 September 2018) were up about 22% year-on-year, and futures (for the market area Germany/Luxembourg) were quoted approximately 33% higher for the following year.

Futures prices rose considerably during the course of 2018. One reason was the closure or removal from the market of power stations. On 27 December 2018, the Phelix-DE peak year-ahead future stood at €66.26/MWh, representing an increase of around 43% compared to the beginning of the year. The Phelix-DE base year future also rose to €54.44/MWh, corresponding to an increase of around 48% compared to the start of the year.

1.6 Retail

1.6.1 Contract structure and competition

In the retail market, there was no further increase in the number of electricity suppliers available to consumers. In 2018, final consumers could choose on average between 143 suppliers in each network area (not taking account of corporate groups). The average number of suppliers for household customers was 132.

The number of household customers switching supplier has increased steadily since 2006. The number stagnated for the first time in 2017 and remained at the same high level of around 4.7m in 2018 (2017: 4.7m). The supplier switching rate – based on the total number of household customers – is thus again 10.2% (2017: 10.2%).[8] In addition, around 2.6m household customers switched energy supply contracts with the same supplier. The switching rate for non-household customers – with an annual consumption of more than 10 MWh – based on consumption volumes was 12.3% (2017: 13.0%).

In 2018, a relative majority of 42% of household customers' consumption was supplied under non-default contracts with local default suppliers (2017: 41%). The percentage of household customers' consumption supplied under default contracts stood at 27% (2017: 28%). This represents only a slight decrease in the percentage of consumption supplied under default contracts, unlike in previous years. The percentage of household customers' consumption provided by a supplier other than the local default supplier is stable at around 31% (2017: 31%), having previously increased continuously. Overall, around 69% of household customers' consumption is still supplied by default suppliers (under either default or other contracts). Thus the strong position that default suppliers have in their respective service areas remains broadly unchanged.

[8] The supplier switching rate for 2017 has been corrected.

1.6.2 Disconnections

There was a decrease in 2018 in the number of electricity customers whose supply was disconnected. The number of disconnections actually carried out by the network operators in 2018 was 296,370, representing a decrease of 10% compared to the previous year (2017: 330,098). The number of disconnection notices issued by suppliers to household customers is very much higher. The number of notices issued in 2018 was approximately 4.9m, of which about 1m were passed on to the relevant network operator with a request for disconnection (2017: 4.8m notices and 1.1m requests).

1.6.3 Price level

Varying developments were recorded for electricity prices for non-household customers as at 1 April 2019 compared to the previous year. The average total price (excluding VAT and possible reductions) for industrial customers with an annual consumption of 24 GWh was 15.98 ct/kWh, up 0.68 ct/kWh on the previous year; the increase is mainly accounted for by the price components controlled by the supplier. There was also a year-on-year increase in the total price (excluding VAT) for commercial customers with an annual consumption of 50 MWh, up around 0.66 ct/kWh to 22.22 ct/kWh. This rise is mainly due to the increase in the price component controlled by the supplier. Overall, this price component makes up around 26% (2017: 24%) of the total price; on average about 74% of the total price comprises costs that the supplier cannot control, with in particular the EEG surcharge and the network charge accounting for a large part of these costs.

Data was collected from the suppliers operating in Germany on the prices for household customers as at 1 April 2019. The average price (including VAT) increased to 30.85 ct/kWh (2018: 29.88 ct/kWh). This average is calculated by weighting the individual prices across all contract models for an annual consumption of 2,500 kWh to 5,000 kWh according to consumption volumes to obtain a reliable average for the electricity price for household customers.

In 2019, the price component controlled by the supplier (energy procurement, supply and margin) accounts for around 24.7% of the total electricity price and has thus increased as in the previous year. This increase can be related in particular to the increasing wholesale prices in 2018. These higher prices are slowly being passed on to the household customers. The network charge in 2019 remains broadly unchanged on the previous year and thus still at a high level. The EEG surcharge has decreased by 6% but still makes up around 21% of the total price. Together with the reduction in the KWKG surcharge and the section 19 StromNEV surcharge, this is dampening increases in prices in 2019.

Compared to 2018, the average price for household customers on default contracts with an annual consumption of 2,500 kWh to 5,000 kWh increased by around 1.5% to 31.94 ct/kWh (2018: 31.47 ct/kWh). The average price for customers on a non-default contract with their default supplier is 30.46 ct/kWh (2018: 29.63 ct/kWh). The price for customers on a contract with a supplier other than their local default supplier has increased by around 5.8% and is now also 30.46 ct/kWh (2018: 28.80 ct/kWh).

As a rule, customers on default contracts can make savings by switching contract (-1.48 ct/kWh) and switching supplier (-1.48 ct/kWh).[9] Household customers with an annual consumption of 3,500 kWh could consequently

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

cut their energy costs by around €52 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 non-default contracts with their local default supplier average €55, and those for customers switching to a non-default supplier €64.

1.6.4 Surcharges

The network operators estimated that they would pass on nearly €26.14bn in surcharges to network users in 2019. In order of volume, this total comprises the EEG surcharge (€22.59bn), the section 19 StromNEV surcharge (€0.91bn), the KWKG surcharge (€1.05bn), the new offshore network surcharge (€1.56bn) and the interruptible loads surcharge (€0.02bn). The EEG charge thus continues to make up the largest part (over 86%) of total surcharges.

1.6.5 Electric heating

According to the suppliers' data, the arithmetic mean of the total gross price (including VAT) for night storage heating as at 1 April 2019 was 21.92 ct/kWh and thus higher than the previous year's level of 21.08 ct/kWh. The arithmetic mean of the total gross price for heat pump electricity was 22.50 ct/kWh and thus also higher than the previous year's level of 21.71 ct/kWh. Here, too, the rise is mainly due to the increase in the price component controlled by the supplier.

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. This increase in the switching rate indicates a higher degree of competition. Yet at the same time, the switching rates are still far below those for household electricity and non-household customers. The volume-related supplier switching rate for 2018 was again around 4%. However, there is a steady increase in the share of electricity provided for heating purposes and electric heating meter points provided by a supplier other than the local default supplier, now standing at around 13%.

1.7 Digitisation of metering

The entry into force of the Metering Act (MsbG) in September 2016 triggered significant changes in metering. The MsbG requires the comprehensive rollout of modern metering equipment and smart metering systems. Whereas in the past household customers were mainly equipped with analogue Ferraris meters, modern metering systems consist of digital meters that are connected to a communication unit (smart meter gateway) via an interface. Modern metering systems do not transmit any data. They are referred to as smart metering systems when they are connected to a smart meter gateway, enabling them to transmit the data recorded by the meter.

Since the beginning of 2017, the first modern metering systems have been available in the market and have been installed by the first metering operators on a large scale. It was still not possible to start the rollout of smart metering systems in 2018, since only one smart meter gateway certified by the Federal Office for Information Security (BSI) was available in the market at the end of 2018. However, in light of the statutory requirements set out in the MsbG 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

With its determinations on the electricity and gas market communication interim model of 20 December 2016 (BK6-16-200/BK7-16-142) the Bundesnetzagentur required all energy market players to introduce and exclusively use a new identification code to identify market locations and meter locations as from 1 February 2018. In the Monitoring Report 2019 the term "meter point" has therefore been replaced by the terms "market location" and "meter location", as applicable.

Energy is generated or consumed in a market location. The market location is connected to the network by means of at least one line. The market location is a connecting point for supply and balancing.

A meter location is a location at which energy is measured and that includes all technical equipment required to collect and, if necessary, transmit the meter data. All relevant physical quantities at a point in time are collected no more than once at a meter location. The term "meter location" corresponds to the term "meter" within the meaning of section 2 para 11 of the Metering Act (MsbG).

2.1 Network balance

The network balance provides an overview of supply and demand in the German electricity grid in 2018. Total electricity supply was 622.6 TWh, comprising a net total of electricity generated of 592.3 TWh (including 9.2 TWh from pumped storage) and cross-border flows from abroad amounting to 30.3 TWh.[10] Total electricity consumption was 621.2 TWh, including 467.8 TWh for final consumers and 13.1 TWh for pumped storage stations from the general supply networks. 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 39.1 TWh. It may be assumed that the actual value for self-generation is higher, because only data for plants of 10 MW or more are reported to the Bundesnetzagentur. Distribution and transmission losses amounted to 24.6 TWh and physical flows to other countries 76.8 TWh. The sum of the individual entries for demand is around 621.2 TWh. The difference between this and the total supply of 622.6 TWh is 1.4 TWh or 0.22%. Supply and demand are therefore almost completely balanced. The difference of 1.4 TWh is due to the complex structure of the data survey involving a large number of different market players.

[10] The physical flows, and not the trade flows, are decisive for the network balance. Trade flows (72.0 TWh of exports and 19.6 TWh of imports) are different from physical flows in the interconnected alternating current system.

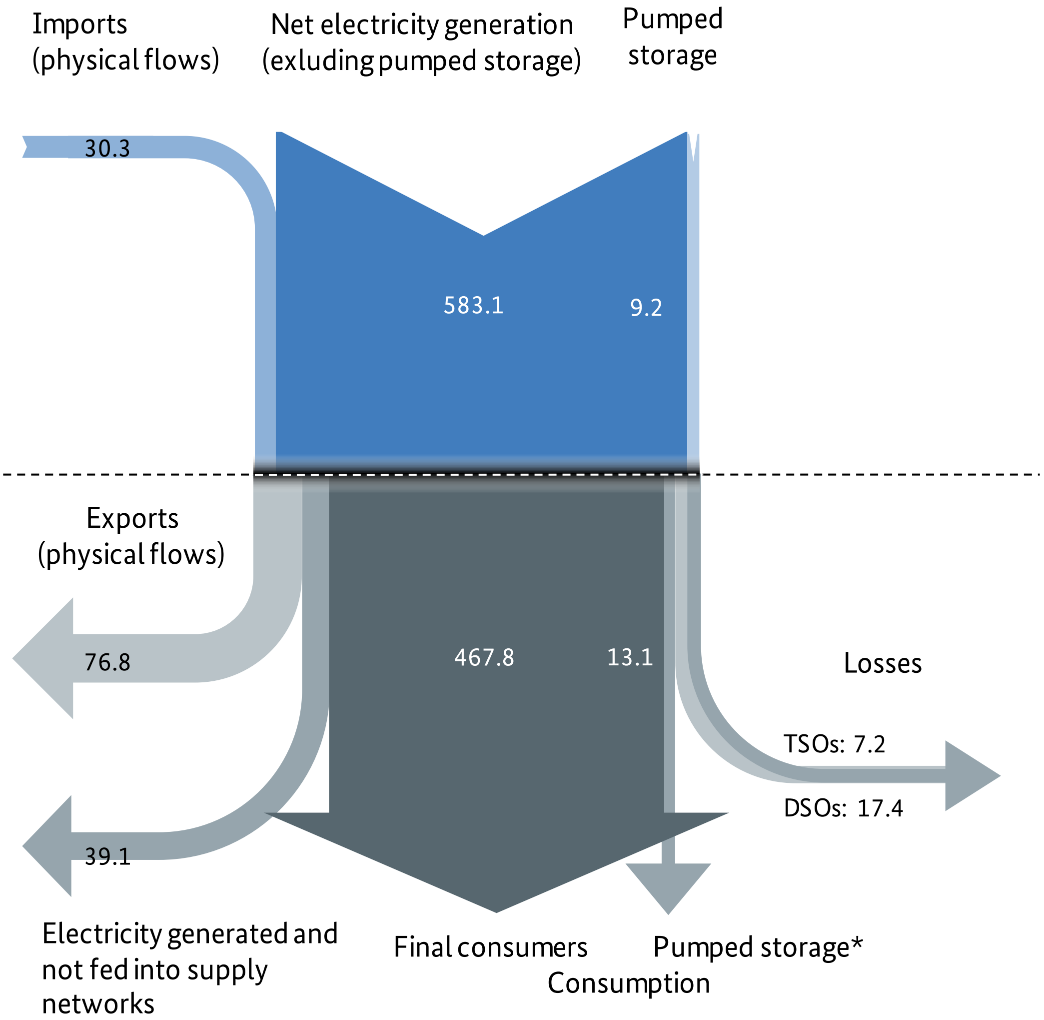
Electricity: network balance 2018

	TSOs	DSOs	Total
Total net nominal generating capacity as at 31 December 2018 (GW)			**221.6**
Facilities using non-renewable energy sources			103.3
Facilities using renewable energy sources			118.3
Generation facilities eligible for payments under the Renewable Energy Sources Act			114.1
Total net generation (including electricity not fed into general supply networks) (TWh)			**592.3**
Facilities using non-renewable energy sources			381.5
Pumped storage			9.2
Facilities using renewable energy sources			210.8
Generation facilities eligible for payments under the Renewable Energy Sources Act			195.4
Net amount of electricity not fed into general supply networks (TWh)[1]			39.1
Losses (TWh)	**7.2**	**17.4**	**24.6**
Extra-high voltage	5.8	< 0,1	5.8
High voltage (including EHV/HV)	1.3	3.3	4.6
Medium voltage (including HV/MV)		5.7	5.7
Low voltage (including MV/LV)		8.5	8.5
Cross-border flows (physical flows) (TWh)			
Imports			76.8
Exports			30.3
Consumption (TWh)[2]	**24.8**	**443.0**	**480.9**
Industrial, commercial and other non-household customers	24.8	318.4	343.2
Household customers		124.6	124.6
Pumped storage			13.1

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

Table 1: 2018 network balance based on data from TSOs, DSOs and power plant operators

Electricity: supply and demand in the electricity supply system in 2018
(TWh)



*This is the amount of electricity taken from the network by pumped storage stations, ie the amount required for the pumping process.

Figure 1: Supply and demand in the electricity supply system in 2018

2.2 Electricity consumption

A gross electricity consumption reported for the monitoring survey of 574.3 TWh can be derived from the network balance presented in I.A.2.1. This gross consumption comprises the sum of gross electricity generation from renewable (211.6 TWh) and non-renewable (409.2 TWh) energy sources (620.8 TWh) and cross-border flows into Germany (30.3 TWh) less the cross-border flows out of Germany (76.8 TWh).[11] Gross generation is higher than net generation because it includes energy industry own use. Generation from renewable energy sources thus accounted for 37% of gross electricity consumption in 2018.

[11] The actual figure is higher, because only energy industry own use and electricity volumes from self-generation plants with an installed capacity of 10 MW or higher are included in the monitoring.

Electricity: share of renewable energy sources in gross electricity consumption (%)

2014	2015	2016	2017	2018
27	31	31	36	37

Table 2: Share of renewable energy sources in gross electricity consumption

It is also possible to calculate the electricity consumption of final customers in Germany. At 506.9 TWh, this figure is well below the gross value, because it does not include energy industry own use, electricity taken from the grid into pumped storage or network losses. The majority of this figure is made up of consumption by final consumers, which fell again to about 467.8 TWh from 472.6 TWh in 2017. Then there is the net electricity generation that is not fed into the grid and is used directly by final consumers, which according to the monitoring is 39.1 TWh.[12]

Table 3 shows the consumption of electricity in 2018 by final consumers in the network areas of the transmission system operators (TSOs) and distribution system operators (DSOs) participating in the survey. Total consumption from the DSOs' networks was around 443.0 TWh and from the TSOs' networks 24.8 TWh.

The figures show that although the number of customers with an annual consumption of more than 2 GWh is relatively small, these customers account for nearly half of the total consumption in Germany. At 225.9 TWh, consumption by these large consumers decreased compared with the previous year (2017: 227.5 TWh). Customers with an annual consumption between 10 MWh and 2 GWh accounted for about one quarter of the total consumption in 2018. Consumption by these customers also decreased compared with the previous year (2018: 123.3 TWh; 2017: 124.9 TWh). The largest customer group in terms of numbers comprises final consumers with an annual consumption of up to 10 MWh. This group comprises almost exclusively household customers, but also smaller commercial customers. These customers also accounted for around one quarter of the total consumption in 2018 and their consumption also decreased compared with the previous year (2018: 118.6 TWh; 2017: 120.1 TWh).

[12] Here, too, the actual value will be higher because this figure only includes electricity from self-generation plants with an installed capacity of 10 MW or higher.

Electricity: final consumption by customer category

Category	TSOs (TWh)	DSOs (TWh)	TSOs + DSOs (TWh)	Percentage of total (%)
≤ 10 MWh/year	< 0,1	118.6	118.6	25.4
10 MWh/year - 2 GWh/year	1.1	122.2	123.3	26.4
> 2 GWh/year	23.7	202.1	225.9	48.3
Total	24.8	443.0	467.8	100.0

Table 3: Final consumption (excluding pumped storage) by customer category based on data from TSOs and DSOs

Electricity: final consumption by load profile

Category	TSOs (TWh)	DSOs (TWh)	TSOs + DSOs (TWh)	Percentage of total (%)
Interval-metered customers	24.8	283.8	308.6	66
Standard load profile customers		159.2	159.2	34
Household customers within the meaning of section 3 para 22 EnWG		124.6	124.6	27
Total	24.8	443.0	467.8	

Table 4: Final consumption (excluding pumped storage) by load profile based on data from TSOs and DSOs

The average household customer consumed about 2,575 kWh in 2018, according to data from DSOs.[13] The highest household customer consumption was in the band between 2,500 kWh and 5,000 kWh and totalled about 43.2 TWh, according to data from electricity suppliers. The average consumption for this representative case was about 3,300 kWh, and the total number of market locations around 13.1m. The largest number of household customers with around 15.1m market locations are in the band between 1,000 kWh and 2,500 kWh. The total amount of energy consumed by this group was around 26.2 TWh and the average 1,730 kWh.

[13] Household customers as defined in section 3 para 22 EnWG

2.3 Network structure data

The TSOs and 846 DSOs took part in the 2019 Monitoring Report data survey.[14] As at 5 November 2019, a total of 883 DSOs were registered with the Bundesnetzagentur.

Electricity: TSOs and DSOs in Germany

	2014	2015	2016	2017	2018	2019
TSOs with responsibility for control areas	4	4	4	4	4	4
Total DSOs	884	880	875	878	890	883
DSOs with fewer than 100,000 connected customers	812	803	798	797	809	803
DSOs with fewer than 30,000 connected customers	620	605	607	625	614	645

Table 5: Number of TSOs and DSOs in Germany from 2014 to 2019

The following table shows the network structure figures "circuit length" and "market locations" for these companies.

[14] Data reported for TenneT GmbH's offshore holding companies are included in the monitoring under TenneT.

Electricity: network structure figures 2018

	TSOs*	DSOs	Total
Network operators (number)	7	883	890
Total circuit length (thousand km)	36.8	1,814.2	1,851.0
Extra-high voltage	36.4	0.3	36.7
High voltage	0.4	94.2	94.6
Medium voltage		519.2	519.2
Low voltage		1,200.5	1,200.5
Total final consumers (market locations) (thousand)	0.5	51,405.9	51,406.3
Industrial, commercial and other non-household customers	0.5	3,011.3	3,011.3
Household customers		48,394.5	48,394.5

*Figures include offshore holding companies

Table 6: 2018 network structure figures based on data from TSOs and DSOs

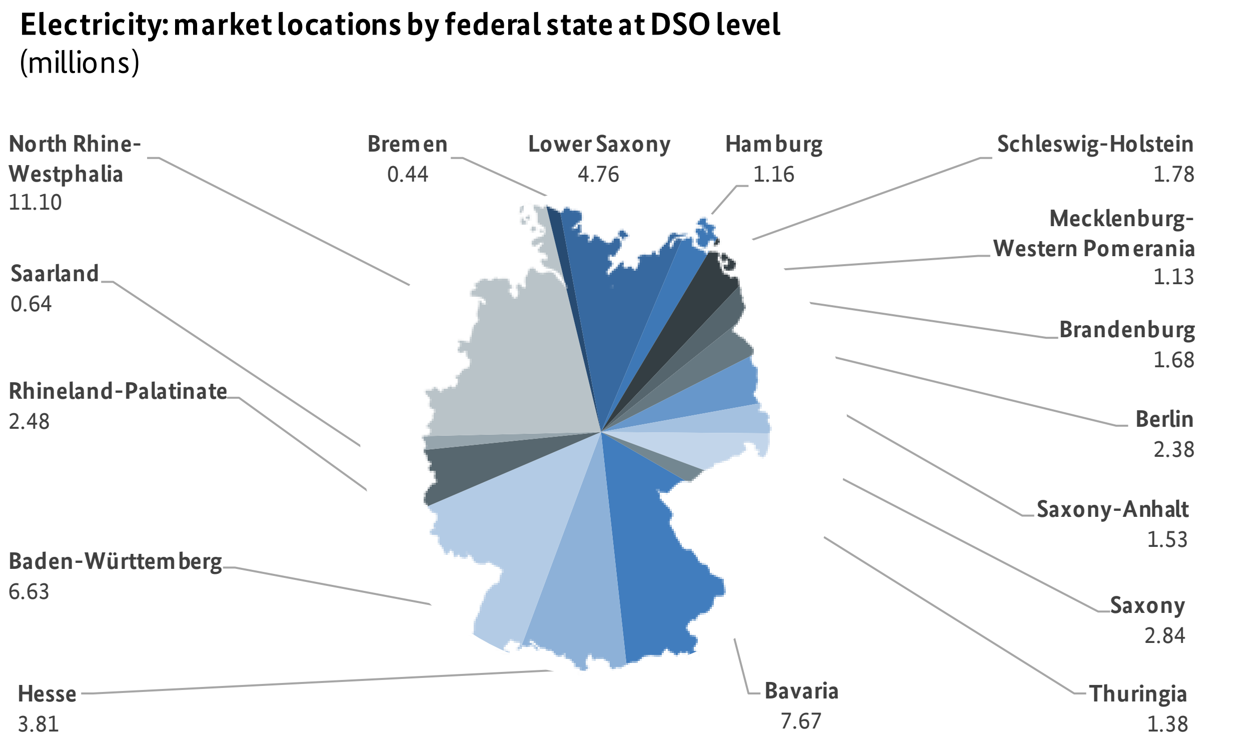


Figure 2: Market locations by federal state at DSO level based on data from DSOs

Electricity: market locations by federal state at TSO level

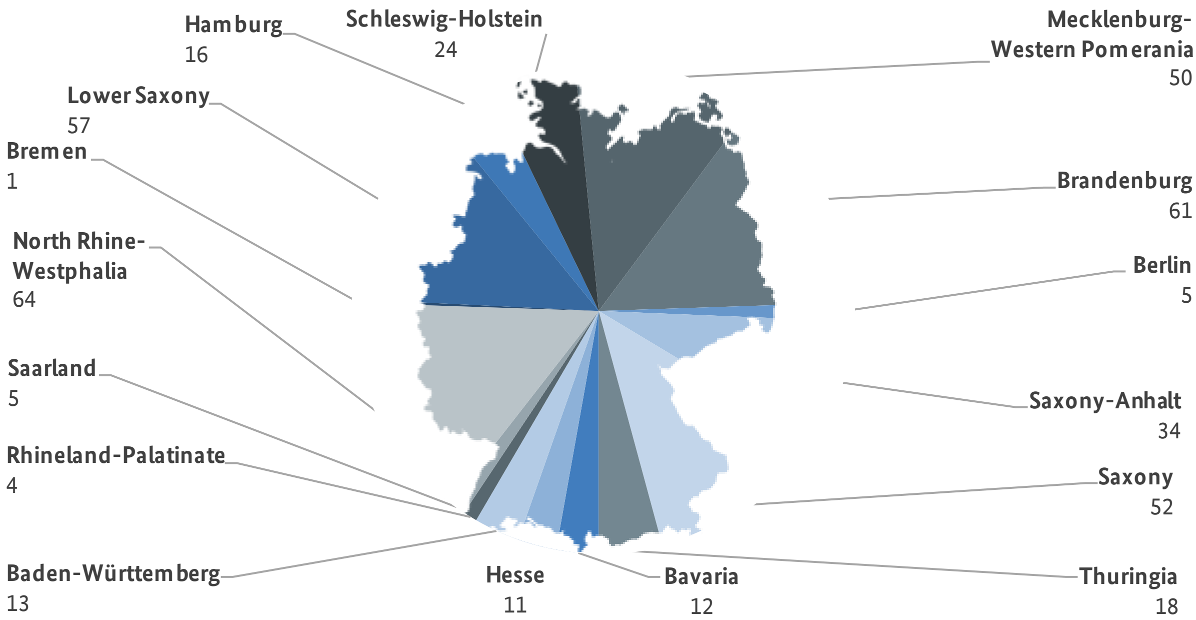


Figure 3: Market locations by federal state at TSO level based on data from TSOs

The circuit length at TSO level increased by around 135 km compared to 2017. The total number of market locations of final consumers in the TSOs' networks was 427. Almost all of these market locations were interval-metered, in other words average consumption was recorded at least every quarter of an hour.

The DSOs' total circuit length at all network levels as at 31 December 2018 was around 1.8m km. As shown in the following figure, the majority of the DSOs included in the data analysis (652 or 77%) have networks with a short to medium circuit length (lines and cables) of up to 1,000 km. These DSOs serve 10.2m or 20% of all market locations in Germany. A total of 182 DSOs have networks with a total circuit length of more than 1,000 km. These network operators supply 41.2m market locations, about 80% of the total.

Electricity: DSOs by circuit length
(number and percentage)

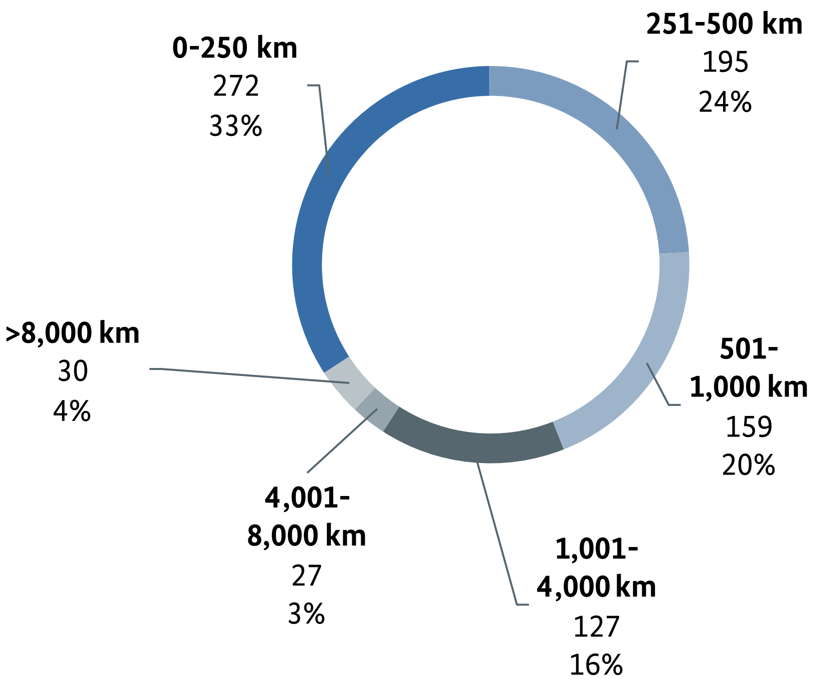


Figure 4: Number and percentage of DSOs by circuit length based on data from DSOs

The number of market locations of final consumers in the DSOs' network areas was around 51.4m, of which about 48.4m were for household customers as defined in section 3 para 22 of the Energy Industry Act (EnWG). Around 374,000 meter locations were interval-metered.

As in the previous year, more than three quarters of the DSOs supply 30,000 or fewer market locations, while 10% of the companies supply more than 100,000 market locations. These 10% supply about 75% (38.6m) of all market locations.

Electricity: DSOs by number of market locations supplied
(number and percentage)

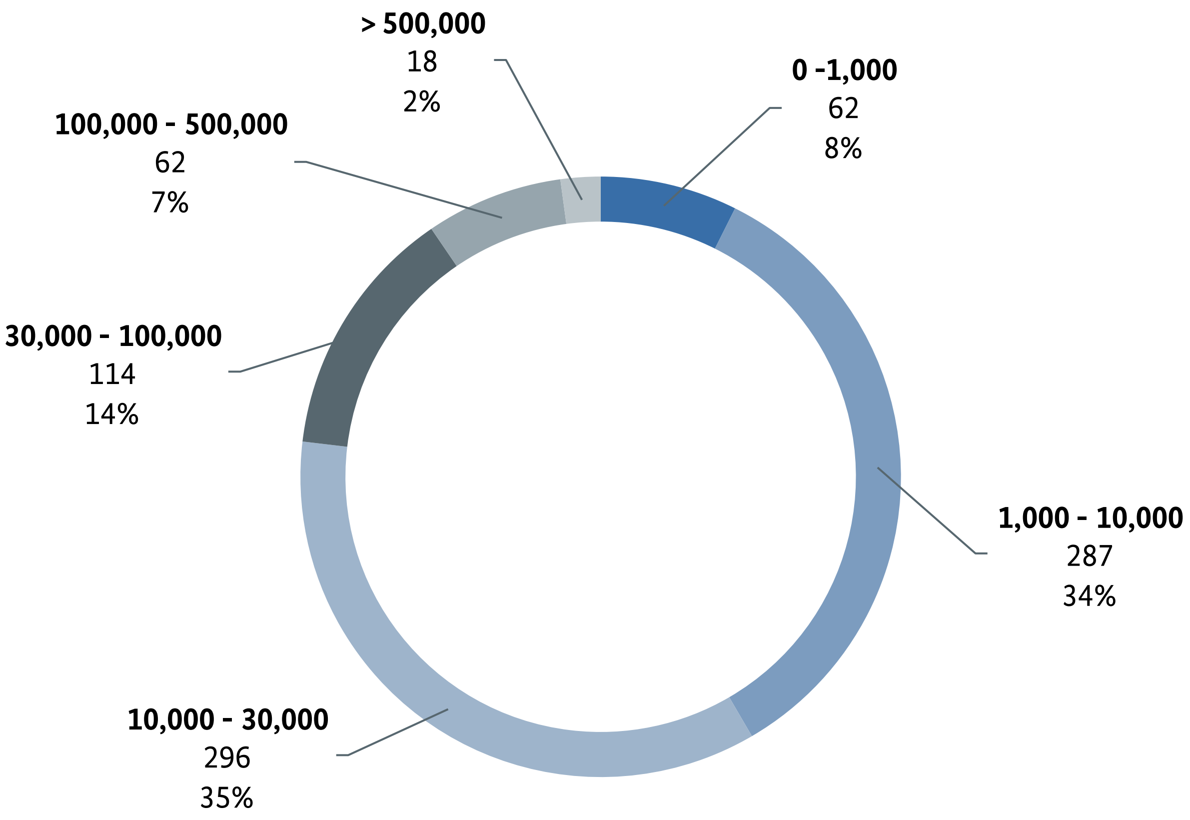


Figure 5: DSOs by number of market locations supplied based on data from DSOs

3. Market concentration

As in previous years, an extensive analysis of market power was not carried out because this would not fit in the scope of the current Monitoring Report. A residual supply analysis , which is of essential importance in the Bundeskartellamt's practice for assessing market power in the electricity generation sector, is therefore not included in the report.[15] Instead this report will be based on indicators which are less complex to identify.

An extensive market power analysis will be provided in an upcoming first report on competitive conditions in the electricity generation sector (Market Power Report), which the Bundeskartellamt will publish in accordance with Section 53 of the German Competition Act, GWB[16]. The analysis will be largely based on data held by the Energy Information Network on the use of power plants over the year and publicly available data. This is used to determine the so-called Residual Supply Index (RSI). This index shows to what extent a company's power plant fleet is indispensable for meeting the demand for electricity. It takes account of the fact that at every given period the amount of electricity produced has to match the amount required and that

[15] Cf. Bundeskartellamt, Sector inquiry into Electricity Generation and Wholesale Markets, 2011, p. 96 ff.

[16] As amended by the Electricity Market Act – Section 2 of the Act on the Further Development of the Electricity Market, Federal Law Gazette I 2016 p. 1786, 1811. Cf. also legislative intent, Bundestag printed paper 18/7317, 134.

storage facilities are only very limited. This index can thus be used to measure the extent of market power held by a company as the latter can significantly influence the amount of electricity available by the way it operates its power plants and - e.g. by strategically withholding capacity - can also significantly influence the electricity price.

As already explained in detail on p. 501 of the section "Selected activities of the Bundeskartellamt", the results of the analysis carried out in the assessment of the RWE/E.ON merger show that RWE's power plants are already pivotal during a significant number of hours in the year, i.e. are indispensable for meeting the demand for electricity. However, the number of pivotal hours has not yet reached the level necessary to presume a dominant position. It cannot be ruled out that, irrespective of the merger project already examined by the Bundeskartellamt, the extent of the indispensability of RWE's conventional power plant fleet will increase in future due to the general market shortages resulting from the nuclear phase-out and RWE's prospective market power could expand to a degree in excess of the threshold above which market dominance is presumed.

In the coming market power report this residual supply analysis will be conducted with more recent data which will provide an updated overview of market power situation in the electricity generation sector in Germany.

For the purposes of this report the identification of possible market power will be based on the degree of market concentration, which in turn will be determined by the market share distribution of the players on the respective market. Market shares are generally a good reference point for estimating market power because they represent (for the period of reference) the extent to which demand in the relevant market was actually satisfied by a company.[17]

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) are typically used to represent the market share distribution. The larger the market share covered by only a few competitors, the higher the market concentration.

In the previous reporting year - and as a result of the historically evolved structure of the power markets - the points of reference for the analysis of power generation and first-time sale of electricity were the five strongest power producers RWE AG, E.ON SE or Uniper [18], EnBW AG, Vattenfall GmbH and LEAG GmbH. At the same time these far surpassed other producers with regard to power generation capacities and electricity volumes fed into the grid (CR 5).

However, there are also major differences among the five largest electricity producers. With a clear lead the market leader RWE is now followed by four other power producers with market shares between 6.8 and 16.6%

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

[18] After the implementation of E.ON's divestment of Uniper to Fortum, the two companies are no longer regarded as a company group as in the previous year. As a result Uniper is no longer considered as part of the CR5 in terms of the first-time sale of electricity and E.ON is no longer considered in terms of power generation capacities.

of the volume sold and between 6.2% and 12.3% of generation capacity, which themselves have a significant market share lead over the other power producers.

As in the previous year, the points of reference for the analysis of end customer supply in the reporting year were the four strongest suppliers, which, with the exception of LEAG, were identical with the largest market players in the first-time sale of electricity.

The 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 on the other hand 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).

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.

Competition law uses the concept of "affiliated companies" (Section 36 (2) 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 quantities (not even on a pro-rata basis). A typical example of a controlling relationship is a scenario in which the majority of the voting rights in an affiliated company are held by another company. There are also other, less typical forms of dominance, for example through personal links between the companies or a dominance 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 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% of the shares in a company. If a single shareholder holds more than 50% of a company's shares, that company's sales will be fully attributed to this shareholder. If two shareholders each hold 50 % of a company's shares, they will each be attributed 50 % of the sales. If only one shareholder holds 50 % of the shares with all other shareholders holding shares of less than 50 %, 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 % 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 by 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 generation of electricity which is not remunerated under the Renewable Energy Sources Act (EEG) (hereinafter also "conventional power") and the first-time sale of electricity (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[19]:

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 (see above) but not in the calculation of the market shares on the market for the first-time sale of electricity.[20] Electricity from renewable energy resources is generated and fed into the grid regardless of the demand situation and electricity wholesale prices. Renewable electricity plant operators are not exposed to competition from the other "conventional" electricity suppliers. In the case of drawing rights, the corresponding amounts or capacities are attributed not to the power plant owner but to the owner of the drawing rights, provided he decides on the use of the power plant and bears the risks and rewards of marketing the electricity.[21] 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 defined the market for Germany/Luxembourg and Austria as a single market, at least until the bidding zones were split on 1 October 2018. However, data from the whole calendar year 2018 were collected for this monitoring report. In the merger control proceeding regarding RWE's acquisition of a minority shareholding in E.ON (see above) the Decision Division left open the effect of the bidding zone splitting on the market definition but pre-emptively based its decision on the possible narrower market definition according to the Germany/Luxembourg market area. This approach is taken in the monitoring report; in the following sections the German market area is considered as the basis for market definition.

Data was collected on electricity generation (volume of first-time sale of electricity and capacities) provided by the five largest companies based on the above definitions. In terms of the first-time sale of electricity these were RWE, E.ON, EnBW, Vattenfall and LEAG, and in terms of electricity generating capacities from their own power plants including drawing rights to other power plants, RWE, Uniper, EnBW, LEAG and Vattenfall. As in the previous year, the points of reference for the analysis of end customer supply were the four strongest suppliers, including their majority holdings. Data on the overall market was extracted from monitoring questionnaires completed by producers and network operators.

The results of the survey on volumes of electricity generated in 2018 are shown in the table below. Data from the previous year is shown for comparison.

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

[20] Cf. Bundeskartellamt, Sector Inquiry Electricity Generation and Wholesale Markets, p. 73 f.

[21] Cf. Bundeskartellamt, Sector Inquiry Electricity Generation and Wholesale Markets, p. 93 f.

Electricity volumes generated by the five largest German electricity producers

Germany 2017			Germany 2018		
Company	**TWh**	**Share**	**Company**	**TWh**	**Share**
RWE	117.0	32.2%	RWE	105.9	30.2%
LEAG	58.2	16.0%	LEAG	58.0	16.5%
EnBW	43.6	12.0%	EnBW	45.8	13.1%
E.ON / Uniper[1]	31.5	8.7%	E.ON[1]	23.9	6.8%
Vattenfall	24.1	6.6%	Vattenfall	25.7	7.3%
CR 5	274.4	**75.5%**	**CR 5**	259.3	**73.9%**
Other companies	89.1	24.5%	Other companies	91.5	26.1%
Total net electricity generation	363.5	100%	Total net electricity generation	350.8	100%

[1] In 2017 E.ON and Uniper were regarded as a company group. After the sale of Uniper to Fortum and the clearance by EU COM, E.ON und Uniper were regarded as two separate companies in 2018.

Table 7: Electricity volumes generated by the five largest German electricity 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 on the market for the first-time sale of electricity in the German market area was 73.9 per cent in 2018. The market share was still 75.5% in 2017. Based on the above definition the total net electricity generation which was not entitled to payments under the EEG fell by 12.7 TWh to 350.8 TWh. The reason for this is that further conventional capacities were withdrawn from the market. At the same time electricity generation from renewable energies entitled to payments under the EEG reached a new record level of around 195 TWh, consequently replacing conventional electricity. This represents a decrease of around 4% of conventional electricity compared with the previous year.

RWE's market share fell by 2% compared to the previous year. The transfer of coal-fired power plants to security standby status had a considerable impact on this (Section 13g EnWG) Here LEAG, EnBW and Vattenfall were able to secure market share gains of between 0.5 and 1.1%. It has to be remembered that in 2017 E.ON/Uniper were regarded as a company group. After the sale of Uniper to the Finnish energy company Fortum and the clearance by the EU Commission, E.ON and Uniper were regarded as two separate companies in 2018. The reduction in CR5's capacity is exclusively attributable to the sale of Uniper to Fortum.

Share of the five largest companies on the market for the first-time sale of electricity in the German market area

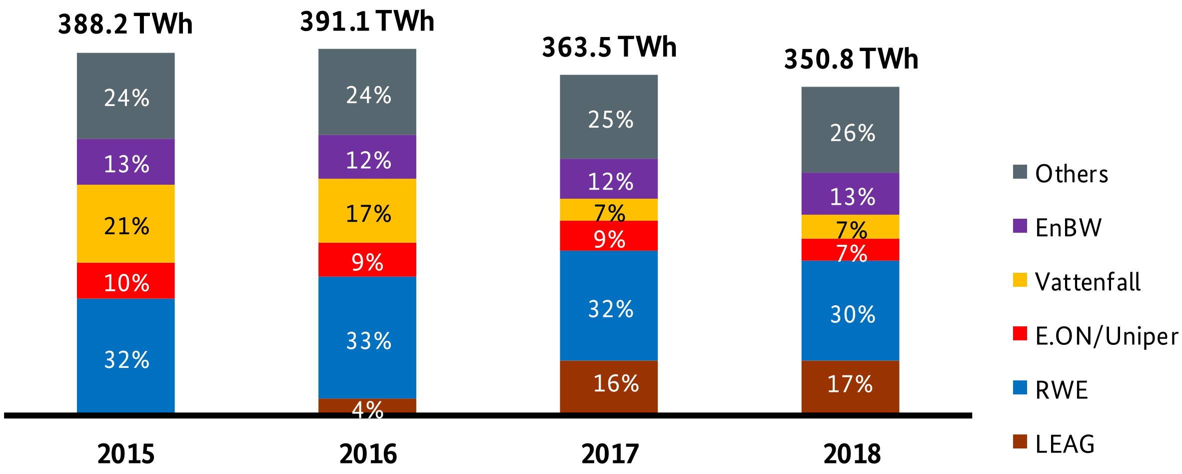

Figure 6: Share of the five largest companies on the market for the first-time sale of electricity in the German market area[22]

The five largest suppliers' share of the German conventional **generation capacities** available for use on the market for the first-time sale of electricity was 60.8%, down from 64.9% in the previous year. The total amount of power generation capacity available fell by 1.4 GW year-on-year to 91.2 GW. The reduction in the capacity of the CR5 amounts to 4.6 GW, whilst the share of the other suppliers of the generation capacity rose. As regards the gain in share of the other suppliers, account has to be taken of the fact that now that E.ON and Uniper are meanwhile treated as separate entities, the former is not included among the five largest suppliers. E.ON's remaining shareholdings in nuclear power plants via its subsidiary PreussenElektra were therefore not included in the CR5 share of German conventional **generating capacity**. RWE's reduction in capacity is attributable to the transfer of the lignite-fired plants Niederaußen E and F to security standby status. Consequently, the degree of market concentration has significantly decreased due to the sale of Uniper to Fortum. The degree of market concentration is likely to decrease further as far as capacity is concerned as a result of the planned shut-down and decommissioning of further nuclear power plants and coal-fired power stations.

[22] In the first three quarters of 2016 the feed-in volume of Lusatia's lignite business was included in the volume attributed to Vattenfall. The calculation of LEAG's market share included the Lusatia lignite feed-in-volumes of the last quarter. In 2017 E.ON and Uniper were still treated as a company group. For this reason the respective market shares of the companies need to be assessed accordingly.

Generation capacities of the five largest electricity producers

Germany 31.12.2017			Germany 31.12.2017		
Company	**GW**	**Share**	**Company**	**GW**	**Share**
RWE	23.9	25.8%	RWE	22.9	25.1%
EnBW	11.1	12.0%	EnBW	11.2	12.3%
E.ON / Uniper[1]	9.3	10.0%	Uniper[1]	5.6	6.2%
Vattenfall	8.1	8.7%	Vattenfall	8.0	8.7%
LEAG	7.8	8.4%	LEAG	7.8	8.5%
CR 5	60.1	**64.9%**	**CR 5**	55.5	**60.8%**
Other companies	32.5	35.1%	Other companies	35.7	39.2%
Total capacity	92.6	100%	Total capacity	91.2	100%

[1] In 2017 E.ON and Uniper were regarded as a company group. After the sale of Uniper to Fortum and the clearance by EU COM, E.ON and Uniper were regarded as two separate companies in 2018.

Table 8: Generation capacities of the five largest electricity producers

To sum up, it can be said that, in terms of generation volume, the market for the first-time sale of electricity in the German market area continued to be concentrated in 2018 with a CR 5 of 73.9% (cf. Table 8 above). In 2017 the CR 5 still amounted to 75.5%. The degree of market concentration is based on the German market area.

Apart from 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 with 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 EEG 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 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.

However, this Monitoring Report 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 also asked about their generation volumes and capacities of EEG electricity, which were then put in relation to the overall market data. The share of the five largest companies mentioned of the German market area alone accounted for around 5% of the EEG generation volume in 2018 compared to around 6% in the previous year. They also accounted for around 4% of EEG capacities in 2018. In the previous year it was a mere 3.2%.

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 (see above). With regard to the future, it should ultimately also be borne in mind that the decommissioning of existing German nuclear power plants, envisaged for the end of 2022 at the latest, is one of the factors that will bring about further changes in the market structure. The recommendations for action of the so-called Commission on Coal ("Growth, Structural Change and Employment") provide for further decommissioning of lignite and black coal-fired power stations in the medium term.

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 generally industrial or commercial customers. Standard load profile customers are generally consumers with relatively low levels of consumption such as 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)[23].

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

[23] Cf. Bundeskartellamt, Decision of 30 November 2009, B8-107/09, Integra/Thüga, para. 32 ff.

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".[24] 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 supply and supply under a special contract. The following analysis is based on data from around 1,175 electricity providers (legal entities) (2017: round 1,070).

Based on information supplied by suppliers, in 2018 around 260.6 TWh of electricity were sold to metered load profile customers and around 158.2 TWh of electricity to standard load profile customers. 13.3 TWh of the total sales to standard load profile customers consisted of electric heating, i.e. around 8.4%. Of the 144.8 TWh sales to standard load profile customers without electric heating, 34.6 TWh went to standard load profile customers with default supply contracts, i.e. around 24% and 110.2 TWh went to other standard load profile customers with special contracts, i.e. around 76%. In 2017, 261 TWh of electricity were sold to metered load profile customers and 162 TWh to standard load profile customers. Approx. 14.5 TWh of the total sales to standard load profile customers consisted of electric heating and 35.2 TWh went to standard load profile customers with default supply contracts and 113 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 or that some suppliers could not provide data on quantities. The quoted percentages therefore merely approximate the actual market shares.

In 2018 the four strongest companies sold a total of around 63.6 TWh on the **German market for the supply of electricity to metered load profile customers**. The aggregated market share of the four companies was therefore only around 24.4% in this sector. In the previous year, the CR 4 still sold as much as 65 Tw, which was equivalent to a share of 25 per cent. There has been another slight 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 2018 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 34.4 TWh – down from 37 TWh in the previous year. The aggregated market share of the CR 4 in this market was therefore around 31.3% – 33% in 2017. This value is also clearly below the statutory thresholds for the presumption of a dominant position. The Bundeskartellamt assumes that there is

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[24] The term "special contract" appears 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 fallback) supply" and "special contract" are appropriate for the purpose of market definition under competition law and will continue to be used because they are legally defined.

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 were around 14.4 TWh of the total default supply volume of standard load profile customers, which amounted to around 34.6 TWh. The share of the CR 4 was therefore around 41.5%. In the previous year this had been around 41.2% of the cumulative sales of the CR 4 of 15.8 TWh and a total default supply volume of 38.4 TWh.

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 in the German area were around 7.8 TWh of the total 13.3 TWh of electric heating. As a result, the CR 4 account for around 59.2%. This was still 59.2% in the previous year.

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 56.7 TWh of a total of 158.2 TWh; which is equivalent to an aggregate share of around 35.8 per cent. In 2017 the volume supplied by the CR 4 was still 61.6 TWh and their market share was 38.2%. The share in relation to all standard load profile customers is thus higher than in the analysis based solely on standard load profile customers with special contracts. 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 standard load profile customers with special contracts, excluding electric heating.

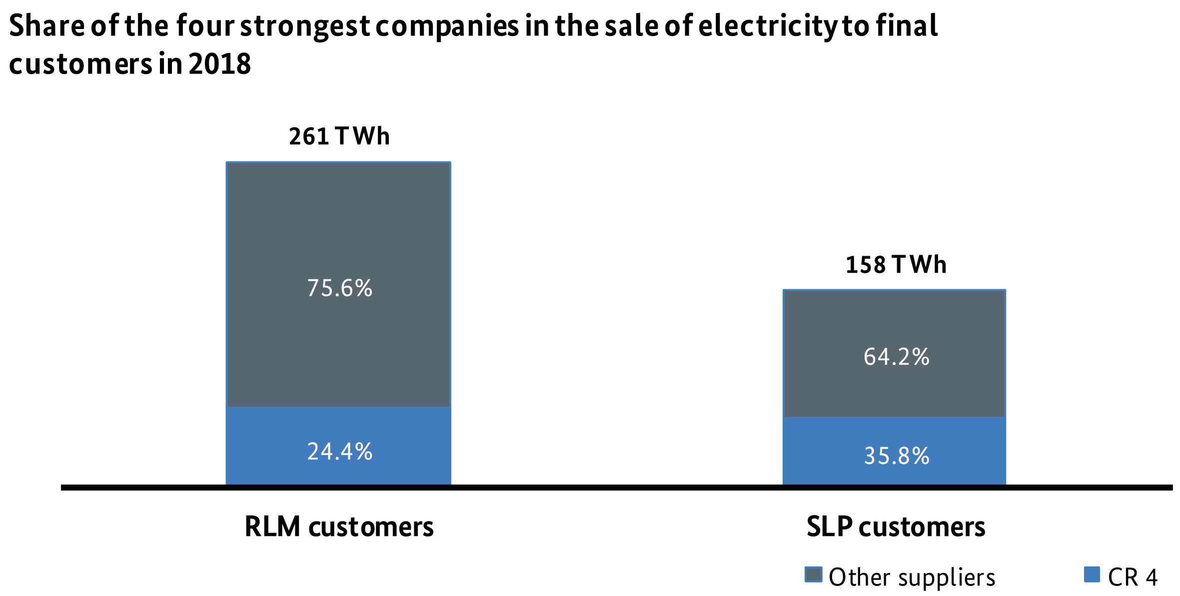

Figure 7: Shares of the four strongest companies in the sale of electricity to final customers in 2018

4. Consumer advice and protection

The Bundesnetzagentur's task as the central information point for energy consumers is to provide private household customers with independent information about their rights, the dispute resolution process and market events. The energy consumer advice service 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.

In May 2019, an online form was set up as a further contact option, providing consumers with a direct way to send their queries to the consumer advice service: www.bnetza.de/energie-kontakt.

Overview of customer queries

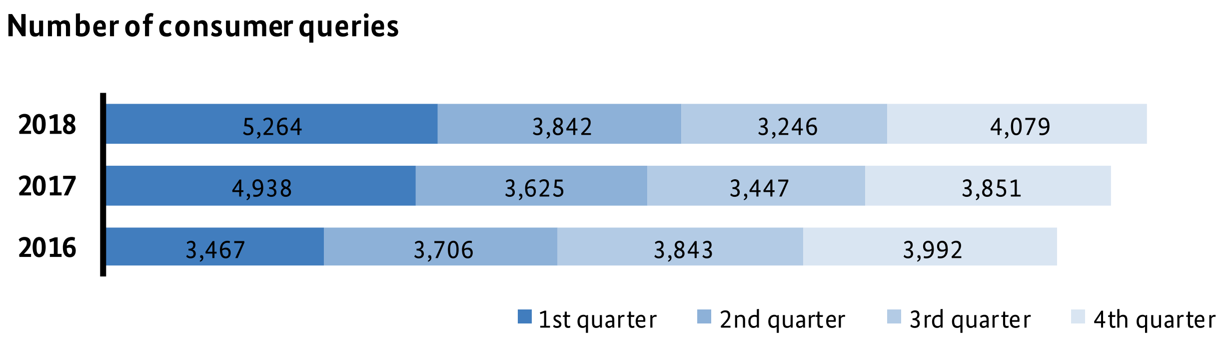

Figure 8: Number of consumer queries

In 2018, 16,431 queries and complaints were sent to and dealt with by the consumer advice service, a slight increase on the previous year. A total of 8,474 queries were received by telephone, 7,462 by e-mail and 495 by post.

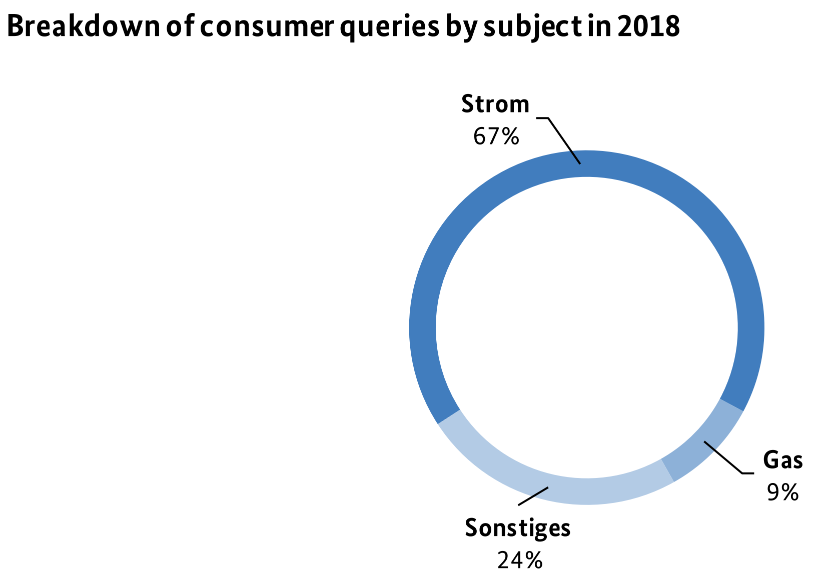

Figure 9: Breakdown of consumer queries by subject in 2018

Most of the queries related to the electricity sector. "Other" includes research-related questions, queries from consultancies and correspondence on matters not falling within the Bundesnetzagentur's remit.

In the past year, the energy consumer advice service dealt with questions from consumers on all aspects of the energy market and responded by explaining possible actions and pointing out legal remedies. Consumers were concerned about issues such as grid connection and billing problems as well as recent developments in metering. Of particular interest to consumers were general contractual questions like contract length, cancelling and bonuses, questions about fallback supply, problems when switching supplier, and payment in instalments and the size of such instalments.

The changeover from L-gas to H-gas in the northern and western parts of the country has not yet led to a rise in the number of queries sent to the energy consumer advice service. However, since the changeover in the densely populated areas to be converted is due to take place in the coming years, the Bundesnetzagentur has posted comprehensive information on this topic on its website (www.bnetza.de/marktraumumstellung).

In the reporting period, there were again insolvencies affecting a few energy suppliers – e:veen Energie eG (July 2018), DEG Deutsche Energie GmbH (for the first time in December 2018) and BEV Bayerische Energieversorgungsgesellschaft mbH (January 2019) – and a number of consumers nationwide. The consumers were immediately transferred to the fallback supplier, thus guaranteeing a seamless energy supply. Customers affected received general information about the procedure from the consumer advice service and were referred to the relevant insolvency administrator.

Alongside the information and advice provided by the Bundesnetzagentur's energy consumer advice service, the energy dispute resolution panel (Schlichtungsstelle Energie e.V.) in Berlin acts in disputes between consumers and energy suppliers, meter operators and metering service providers with the aim of finding mutually acceptable solutions in formal, out-of-court proceedings. This service is free of charge for consumers.

In 2018, the dispute resolution panel received just over 7,500 applications, with over half relating to suppliers affected by insolvency. Only approximately 300 out of the more than 1,400 electricity suppliers and just over 1,000 gas suppliers taking part in the monitoring were involved in a dispute resolution procedure. In 2018, the majority of the applications for dispute resolution again related to just a few companies or groups of companies. In around 80% of the cases, the dispute between the consumer and the energy utility was successfully resolved. The dispute resolution panel assumes in its activity report that, despite the rise in the number of applications for dispute resolution compared to 2017, the quality of the companies' complaints management is improving.[25]

The interplay between the Bundesnetzagentur and the dispute resolution panel, consumer organisations and private lawyers guarantees effective consumer protection in the energy market.

Considering the total number of household customers served (electricity 46.1m; gas 11.7m) and the number of customers switching in 2018 (electricity approx 4.6m; gas approx 0.6m), the number of complaints received by

[25] Activity Report 2018, Schlichtungsstelle Energie e.V., 1 February 2018, https://www.schlichtungsstelle-energie.de/presse/presseartikel/taetigkeitsbericht-der-schlichtungsstelle-energie-kopie.html

the Bundesnetzagentur is low and insolvencies affect only a very small group of customers. The Bundesnetzagentur therefore does not consider it necessary to publish a list of the companies to which the complaints related.

In this report, the information particularly relevant for consumers is set out in special boxes in the following sections:

- Development of the generation sector – electricity
- Development of renewable energies – electricity
- Status of grid expansion – electricity
- Supply interruptions – electricity and gas
- Network charges – electricity and gas
- Electric vehicles/charging stations – electricity
- Contract structure and supplier switching – electricity and gas
- Disconnections, cash/smart card meters, tariffs and contract terminations/non-annual billing – electricity and gas
- Price level – electricity and gas
- Metering – electricity and gas
- Development of natural gas imports and exports
- Market area conversion – gas
- Core energy market data register – general topics
- Sector inquiry: comparison sites and consumer protection – general topics

5. Sector coupling

Sector coupling refers to an approach with the primary aim of interconnecting the electricity, heating, transport and industrial sectors. The technologies that can be usefully applied to implement sector coupling mainly serve to make electricity usable in the other sectors as well and thus also to promote the defossilisation of the energy system as a whole.[26] Defossilisation can occur directly through electrification, as in the case of

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[26] The term "defossilisation", in contrast to the more common term "decarbonisation", makes a clearer distinction between the use of carbon compounds and their origin. A large number of (for example industrial) processes depend on the use of carbon. Defossilisation still "allows" this use, provided that no fossil carbon is used.

electric vehicles. Applications that cannot be directly electrified, for example because of technical restrictions, can be defossilised through the use of synthetically produced gas (power-to-gas). One key application of sector coupling is the generation of heat from electricity (power-to-heat), for example to heat private households.

The concept of sector coupling means that the applications lead to an increase in load or consumption for the electricity system. Sector coupling is not to be seen as an end in itself, however, because the effects on carbon emissions need to be viewed across the whole energy system. Depending on the technology-specific efficiency and the level of the carbon emissions associated with meeting the additional electricity demand, the overall carbon effects may be positive.

The following are some of the applications that fall under sector coupling:

Electrical heat generation

Almost all of today's so-called controllable consumer equipment is for electrical heat generation, in particular using heat pumps or night storage heating systems. The network operators surveyed levy a reduced network charge for 1.45m items of controllable consumer equipment. This represents a year-on-year increase of about 46,000 items of equipment (see I.C.7.2).

Charging stations for (part) electric vehicles

Following the entry into force of the Charging Station Ordinance (LSV) in March 2016, the Bundesnetzagentur records the notifications from recharging point operators with details of the charging infrastructure provided by the operators. All recharging points accessible to the public that have been taken into operation since the LSV entered into force are subject to the notification obligation. Recharging points not subject to the notification obligation may also be notified.

By 16 July 2019, the Bundesnetzagentur had been notified of a total of 10,797 charging stations with 21,181 recharging points; 17,958 recharging points had a power less than or equal to 22 kW (normal-power recharging points) and 3,223 were high-power recharging points (see I.C.7.1).

According to the Kraftfahrt-Bundesamt (KBA – Federal Motor Transport Authority), 150,172 externally rechargeable passenger vehicles were registered in Germany as at 1 January 2019, of which 83,175 were fully electric vehicles and 66,997 plug-in hybrids.[27]

Synthetic gas injection

Section 3 para 10c EnWG defines the term biogas as "biomethane, gas from biomass, landfill gas, sewage treatment plant gas and mine gas as well as hydrogen produced by water electrolysis and synthetically produced methane if the electricity used to perform electrolysis and the carbon dioxide or carbon monoxide used for methanation are mainly and verifiably derived from renewable energy sources within the meaning of Directive 2009/28/EC (OJ L 140, 5 June 2009, p 16)".

The biogas injection overview in II.B.4 includes separate figures for the injection of hydrogen and synthetically produced methane corresponding to this definition. In 2018, three facilities injected hydrogen

[27] https://www.kba.de/DE/Statistik/Fahrzeuge/Bestand/Umwelt/2019_b_umwelt_dusl.html.

and two facilities injected synthetically produced methane (both figures as at 31 December 2018). With 1.4m kWh of hydrogen and 1.1m kWh of synthetically produced methane, however, these forms of injection accounted for only 0.024% of the total amount of biogas injected in 2018. The facilities injecting hydrogen have a total installed electric capacity of 8.3 MW and those injecting synthetic methane a total installed electric capacity of 8 MW.

In addition to these facilities, there are a number of other facilities which, however, do not inject the gas produced into the natural gas network. The majority of these facilities are demonstration and research facilities. The current total installed electric capacity of these facilities, as far as the technical specifications are known, is 25.4 MW.[28]

The scenarios on which the Network Development Plan (NDP) 2019-2030 is based take account of power-to-gas capacities of 1.0 GW (A 2030), 2.0 GW (B 2030) and 3.0 GW (C 2030) and power-to-gas capacities of 0.5 GW (B 2025) and 3.0 GW (B 2035), comprising one fifth power-to-methane and four fifths power-to-hydrogen in each case. The 2017 reference figure does not include power-to-gas capacity.

[28] Source: Bundesnetzagentur's own research.

B Generation

1. Installed electricity generation capacity and development of the generation sector

Renewable energies are being expanded as nuclear power is phased out and they will reduce CO_2 emissions in Germany. New conventional generation capacity has been created in recent years, primarily from the new build of flexible natural gas power plants.

The change in the electricity mix calls for further grid expansion, in particular to transport electricity generated in the north of the country to the south of Germany.

In order to secure the supply of electricity in Germany, the Bundesnetzagentur assesses in advance which power plants can be closed or must continue to operate to stabilise the grid.

1.1 Net electricity generation in 2018

Net electricity of 592.3 TWh was generated in 2018; this was around 9.1 TWh less than the 601.4 TWh generated in 2017. The overall reduction in net electricity generation is primarily due to a fall in gross electricity consumption. Generation from non-renewable energy sources fell in 2018 by 15.1 TWh to 381.5 TWh. In contrast, more electricity was again generated from renewable energy sources than in the previous year (see " I.B.2 Development of renewable energies"). This increase was, however, less pronounced than in the previous year. Electricity generated from renewable energy sources increased by 6.0 TWh (2.9%), from 204.8 TWh in 2017 to 210.8 TWh in 2018. Renewables accounted for 37.0% of gross electricity consumption[29], which totalled 574.3 TWh. The chapter "I.B.2 Development of renewable energies " contains a detailed analysis of the annual amount of electricity supplied by installations eligible for payments under the EEG and its development.

[29] Gross electricity consumption is calculated from gross electricity generation plus cross-border import load flows and minus cross-border export load flows. Gross electricity generation also includes the energy consumed by power plants for their own use and is thus higher than net electricity generation. See also "I.A.2.2 Electricity consumption".

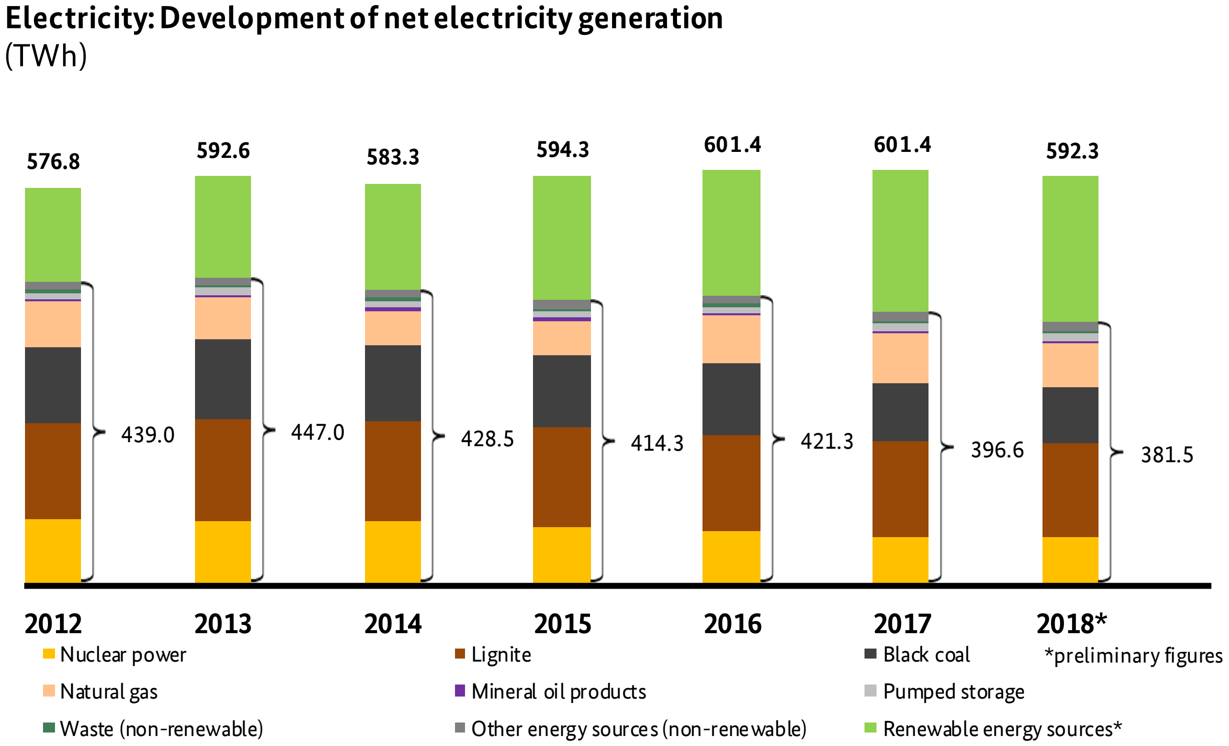

Figure 10: Development of net electricity generation (as at October 2019)

Net electricity generation from non-renewable energy sources fell by a total of 15.1 TWh (-3.8%) to 381.5 TWh, down from 396.6 TWh in 2017 (cf Figure 10).

This continues the decline reported in 2017. Following two years of increased generation, feed-in from natural gas-fired power plants fell from 72.7 TWh in 2017 to 64.4 TWh in 2018 (-11.4%). There were several reasons for the decline in generation from natural gas-fired power plants: One was that the warm year in 2018 meant that less heat needed to be generated. This affected smaller natural gas-fired power plants (smaller than 10 MW) in particular. At the same time, increased feed-in of electricity from renewable energy sources and a rise in prices for natural gas in 2018 both contributed to a reduction in generation from natural gas-fired power plants.

Generation from black coal power plants fell by 3.1 TWh (-3.7%) to 80.4 TWh. This can be attributed in particular to the closure of black coal-fired power plants and the decline in heat generation.

As in the previous years, generation from lignite-fired power plants decreased again slightly from 137.5 TWh in 2017 to 135.9 TWh in 2018 (-1.2%). This decline was due to the transfer of more lignite-fired plants to security standby status. The lignite-fired power plant units Niederaußem F and E and Jänschwalde F were transferred to security standby status on 1 October 2018. Only 70.4 TWh of electricity was generated from nuclear power plants in 2018, which is close to the level of 70.5 TWh in 2017. This is mainly due to two opposite effects. The first was the closure of the Gundremmingen B nuclear power plant on 31 December 2017, which resulted in less electricity being generated in 2018. The second was that relatively little electricity was generated in individual power plants in 2017. Their generation output was back at the same level as in previous years in 2018. Mineral oil-fired power plants generated 3.5 TWh, equivalent to their 2017 level.

Electricity: Development of net electricity generation
(TWh)

	2013	2014	2015	2016	2017	2018
Nuclear power	92.1	91.8	85.1	78.3	70.5	70.4
Lignite	148.7	144.5	142.5	139.9	137.5	135.9
Black coal	116.4	111.6	106.1	103.3	83.5	80.4
Natural gas	58.4	50.0	48.7	68.0	72.7	64.4
Mineral oil products	4.6	3.8	4.3	3.9	3.5	3.5
Pumped storage	9.7	9.5	10.1	9.9	10.2	9.2
Waste (non-renewable)	3.9	4.3	4.2	4.3	4.3	4.2
Other energy sources (non-renewable)	13.1	12.9	13.4	13.6	14.3	13.6
Total of non-renewable energy sources	447.0	428.5	414.3	421.3	396.6	381.5
Renewable energy sources*	145.6	154.8	180.0	180.2	204.8	210.8
Total	592.6	583.3	594.3	601.4	601.4	592.3

*preliminary figures

Table 9: Net electricity generation

1.2 CO_2 emissions from electricity generation in 2018

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 2018. For CHP plants, operators only had to supply data on the share of CO2 attributable to electricity generation. The results of the survey of power plant operators are provided in Table 10.

Electricity: CO_2 emissions from electricity generation
(million tonnes)

	CO_2 emissions million			Change on
	2016	2017	2018	2017
Lignite	157.9	155.7	152.8	-2.9
Black coal	90.1	74.6	72.4	-2.2
Natural gas	26.2	27.2	22.5	-4.6
Mineral oil products	2.1	2.0	2.3	0.4
Waste	7.7	7.6	7.5	-0.1
Other energy sources[1]	17.6	18.4	17.2	-1.2
Total	301.7	285.4	274.8	-10.7

[1] Other energy sources (non-renewable). Mine gas

Table 10: CO_2 emissions from electricity generation

According to the data provided by operators of power plants, total CO_2 emissions from electricity generation in 2018 fell by 10.7m tonnes compared to 2017. This is in particular due to a reduction in the net generation of electricity from black coal, lignite and natural gas-fired power plants. Lignite-fired power plants again emitted less CO_2 in 2018 owing to the gradual transfer of some of these power plants to security standby status (see "I.B.1.1 Net electricity generation in 2018"). Power plant operators reported that lignite-fired power plants emitted 152.8m tonnes of CO_2 emissions in 2018 which accounted for over half of all CO_2 emissions from electricity generation (55.6%). Owing to the decline in electricity generation from natural gas the associated emissions fell by 4.6m tonnes of CO_2 to 22.5m tonnes in 2018. Black coal-fired power plants emitted 72.4m tonnes of CO_2 or 2.2m tonnes less than in the previous year. The remaining 27.0m tonnes of CO_2 are emitted by mineral oil-fired plants (2.3m tonnes), waste to energy power plants (7.5m tonnes) and other energy sources (17.2m tonnes).

It should be noted that the data submitted by power plant operators do not include CO2 emissions from generating facilities with under 10 MW of net nominal capacity.

1.3 Installed electricity generation capacity in Germany in 2018

In 2018, as in previous years, electricity generation was marked by growth in renewables, albeit less pronounced than in previous years. This is largely due to the slower expansion of onshore wind energy, which grew by 2.3 GW compared to 4.9 GW in 2017. Total (net) installed generation capacity, which includes power stations not currently operating in the electricity market but which are grid reserve power stations or are in lignite-fired power plant security standby, rose by 6.0 GW from 215.6 GW (at the end of 2017) to 221.6 GW at the end of 2018.[30] Of this, 103.3 GW was non-renewable and 118.2 GW renewable energy capacity.

Renewables grew by 6.6 GW compared to 7.4 GW[31] year on year in 2017. As at the end of 2018 the share of renewable energy generation capacity in Germany's total installed generation capacity was around 53%. Compared to 2011 (the year in which figures were first recorded for comparison purposes) renewable energy generation capacity has increased by 51.8 GW; this is equal to an increase of the renewables' share in the total installed generation capacity of around 14%. The chapter "I.B.2 Development of renewable energies" contains a detailed analysis of the installed capacity of installations eligible for payments under the EEG and its development.

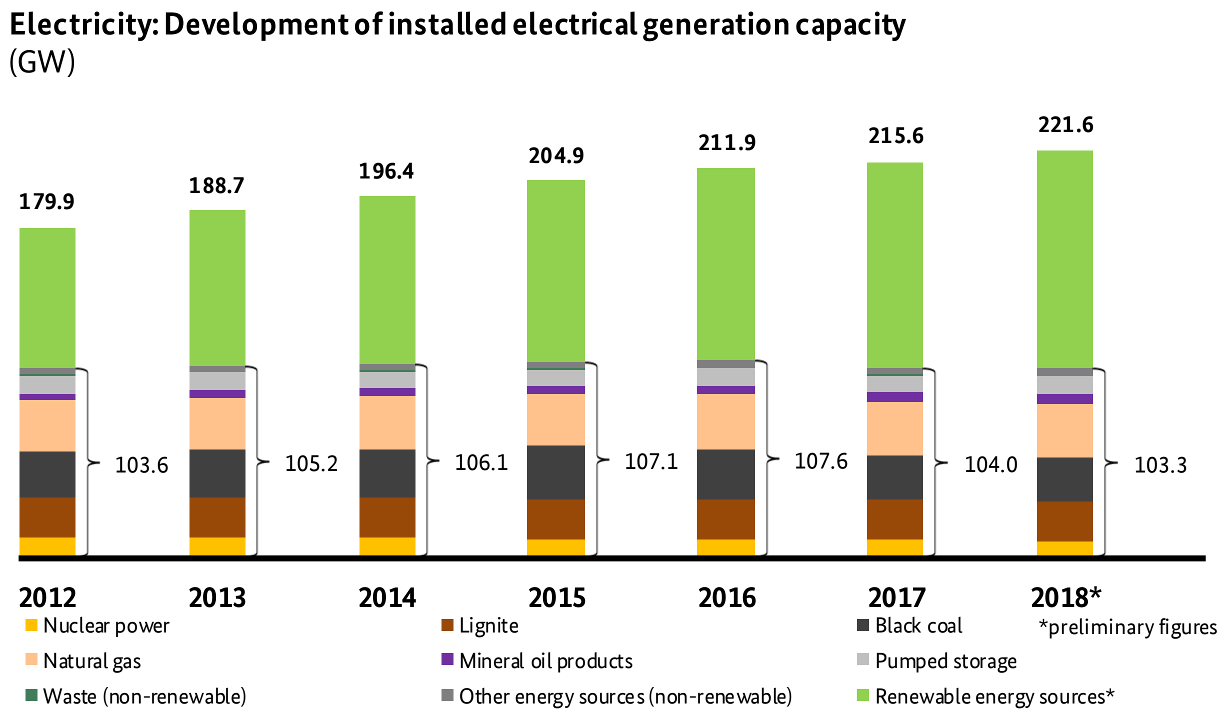

Figure 11: Development of installed generation capacity

Installed capacity from non-renewable sources decreased in 2018 by 0.7 GW, as shown in Table 11. This decrease is explained in particular by the reduction in black coal power plant capacities due to final closures. In contrast, the capacity of pumped storage stations grew slightly.

[30] The total generation capacity figures include (solar, pumped storage and hydro) generation capacity of 4.3 GW in Denmark, Luxembourg, Switzerland and Austria which feeds into the German grid.

[31] The figures taken from Monitoring 2018 have been updated for 2017.

Electricity: Change in installed electrical generating capacity
(GW)

	2013	2014	2015	2016	2017	2018
Nuclear power	12.1	12.1	10.8	10.8	10.8	9.5
Lignite	21.2	21.1	21.4	21.3	21.1	21.1
Black coal	26.0	26.2	28.7	27.4	24.0	23.8
Natural gas	28.4	29.0	28.4	29.7	29.8	30.2
Mineral oil products	4.1	4.2	4.2	4.6	4.4	4.4
Pumped storage	9.2	9.2	9.4	9.5	9.5	9.8
Waste (non-renewable)	0.9	0.9	0.9	0.9	0.9	0.9
Other energy sources (non-renewable)	3.3	3.4	3.4	3.5	3.5	3.6
Total of non-renewable energy sources	105.2	106.1	107.1	107.6	104.0	103.3
Renewable energy sources*	83.5	90.3	97.7	104.2	111.6	118.2
Total	188.7	196.4	204.9	211.9	215.6	221.6
Renewables' share of total electricity generation	**44%**	**46%**	**48%**	**49%**	**52%**	**53%**

*preliminary figures

Table 11: Development of installed electrical generation capacity

1.4 Current power plant capacity in Germany

Total (net) installed generation capacity is currently 223.0 GW. Of this amount, 102.0 GW was sourced from non-renewables (October 2019) and 121.0 GW from renewables (30 June 2019). Closures and commissioning of black coal and natural gas-fired power plants within the twelve month period reduced non-renewable capacities compared to 2018 by 1.3 GW. A detailed breakdown of the development of the installed capacity by each renewable energy source can be found in the section “I.B.2 Development of renewable energies“.

Electricity: Current installed electrical generation capacity
(GW)

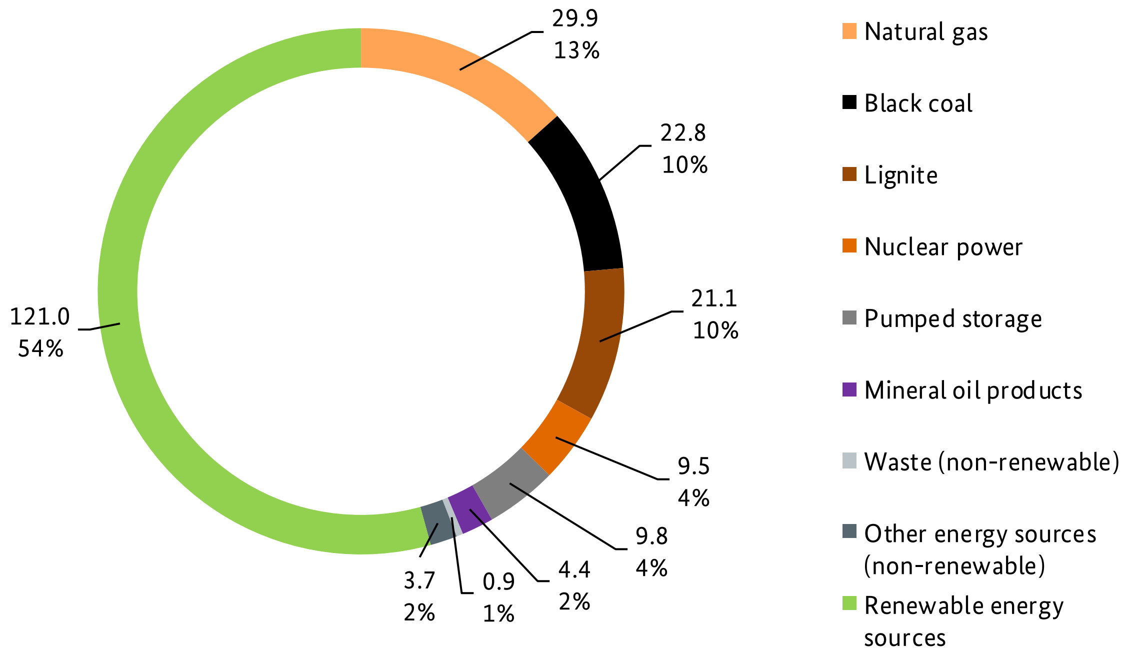

Figure 12: Current installed electrical generation capacity

Table 12 shows closures of power plant capacity since 2013. The table shows the additional capacity in each year and the average age of the power plants at the time of closure. The table shows that from 2013 and up to 1 October 2019 a total capacity of 24,923 MW has been closed. With 14,916 MW, the larger part has been finally closed (finally closed capacity of 12,357 MW and 2,559 MW from previous decommissioning of nuclear power plants; the Philippsburg 2 nuclear power plant will be decommissioned on 31 December 2019 and is therefore not included in the table below). Total closures of power plant capacity can be broken down into decommissioned nuclear power stations, closures of other power stations, lignite-fired power stations in security standby status and grid reserve power stations.

Electricity: Closures of power plant capacity

Year		2013	2014	2015	2016	2017	2018	2019*	Total on 1 Oct 2019
Further closures during the year (MW)		1,266	4,494	3,563	4,026	6,919	2,826	2,185	24,923
of which final closure**	Capacity (MW)	911	2,423	1,377	1,688	2,763	1,767	1,428	12,357
	Average age in years at time	43	43	38	36	41	34	32	38
of which temporarily closed**	Capacity (MW)	355	214	661	301	78			1,253
	Average age in years at time	40	41	39	33	26			35
of which grid reserve	Capacity (MW)		1,857	250	1,685	2,232			6,024
	Average age in years at time		42	50	29	38			37
New capacity on security standby***	Capacity (MW)				352	562	1,059	757	2,730
	Average age in years at time				31	49	41	39	41
Closures under the Nuclear Phase-Out Amendment Act	Capacity (MW)			1,275		1,284			2,559
	Average age in years at time			33		33			33

* preliminary values

** includes all closed plants, with and without notification

*** The power plants on security standby will be finally closed after four years and are currently outside of the electricity market.

Table 12: Power plant capacity which exited the market since 2013

1.5 Current power plant capacity by federal state

Figure 13 shows the location of installed generation capacity in each federal state broken down by renewable and non-renewable energy sources, including power plants which are not currently operating in the electricity market. The Figure does not include generation capacity in Luxembourg, Denmark, Switzerland and Austria which feeds into the German grid (total of 4.3 GW). Only power plants using non-renewable energy sources with a capacity of 10 MW or more are shown. The Bundesnetzagentur records detailed data on smaller installations with a capacity of less than 10 MW which are not eligible for payments under the EEG in aggregated form for each energy source and cannot therefore allocate this capacity (totalling 5.4 GW) to specific federal states.

Electricity: Generation capacity by energy source in each federal state

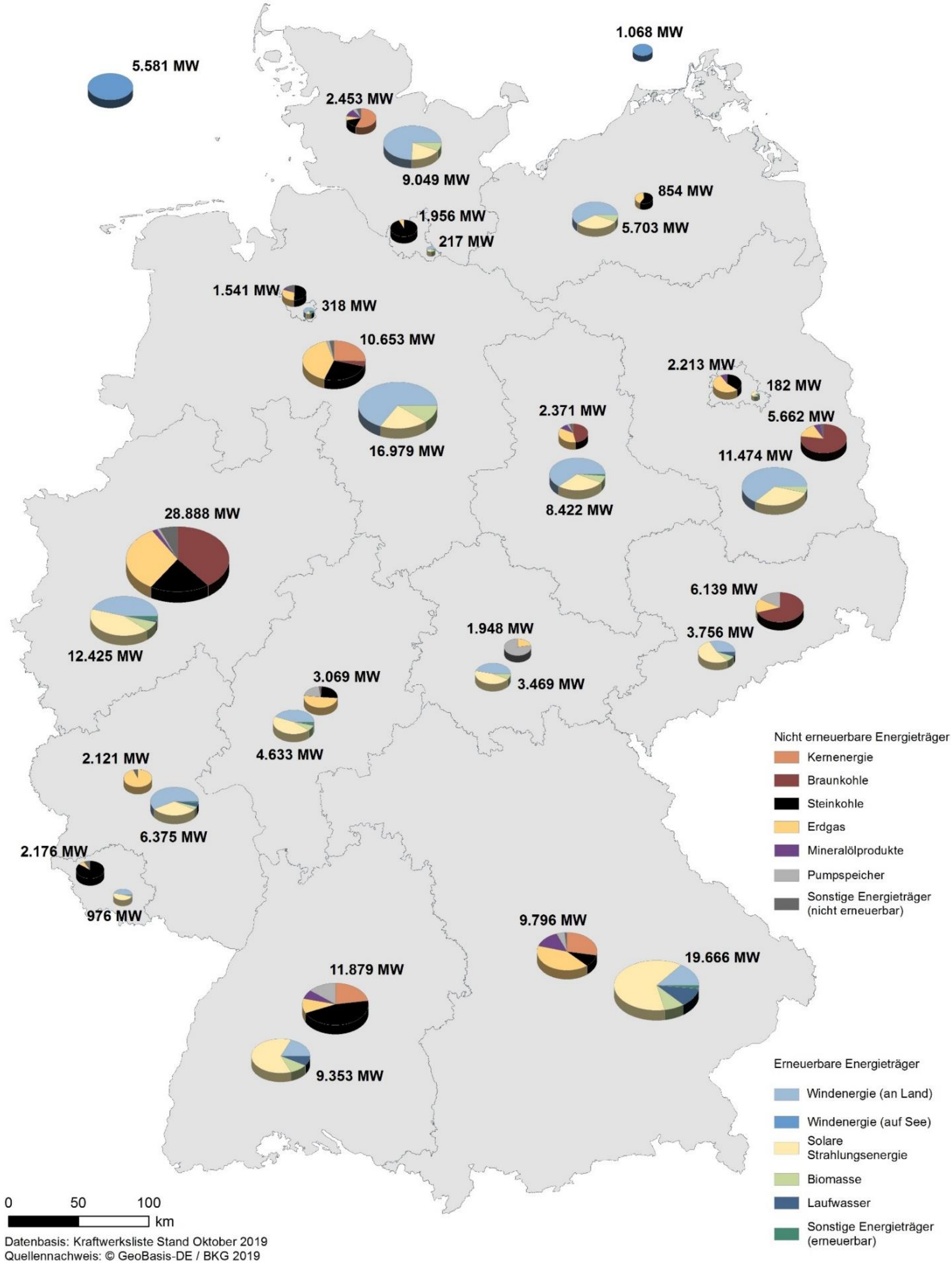

Figure 13: Generation capacity by energy source in each federal state

Electricity: Generating capacity by energy source and federal state, including plants temporarily closed, grid reserve power plants and plants on security standby*
(MW)

Federal state	Non-renewable energy sources							Renewable energy sources						
	Lignite	**Black coal**	**Natural gas**	**Nuclear power**	**Pumped storage**	**Mineral oil products**	**Others**	**Biomass**	**Run-of-river hydro**	**Offshore wind**	**Onshore wind**	**Solar**	**Others**	**Total**
BW	0	5,506	1,029	2,712	1,873	702	57	961	656	0	1,625	6,030	81	**21,232**
BY	0	847	4,155	2,698	543	1,388	165	1,810	1,973	0	2,546	13,000	336	**29,462**
BE	0	777	1,200	0	0	218	18	43	0	0	12	108	18	**2,395**
BB	4,364	0	781	0	0	334	183	451	5	0	7,104	3,830	84	**17,137**
HB	0	772	459	0	0	86	224	12	10	0	203	45	48	**1,859**
HH	0	1,794	150	0	0	0	12	40	0	0	119	46	12	**2,172**
HE	34	753	1,548	0	625	25	84	275	62	0	2,062	2,129	105	**7,702**
MV	0	514	319	0	0	0	21	352	3	0	3,323	2,005	20	**6,556**
NI	352	2,933	4,051	2,696	220	56	344	1,696	55	0	11,063	4,108	58	**27,632**
NW	10,908	6,650	8,367	0	303	545	2,115	871	156	0	5,839	5,229	330	**41,313**
RP	0	13	1,959	0	0	0	149	177	232	0	3,631	2,268	67	**8,496**
SL	0	1,822	155	0	0	0	200	20	11	0	457	473	14	**3,152**
SN	4,325	0	705	0	1,085	17	8	270	210	0	1,250	2,010	15	**9,895**
ST	1,104	0	841	0	80	213	134	465	28	0	5,117	2,708	104	**10,793**
SH	0	357	129	1,410	119	276	163	553	5	0	6,719	1,745	27	**11,502**
TH	0	0	432	0	1,509	0	6	251	32	0	1,608	1,567	11	**5,417**
North Sea	0	0	0	0	0	0	0	0	0	5,581	0	0	0	**5,581**
Baltic Sea	0	0	0	0	0	0	0	0	0	1,068	0	0	0	**1,068**
Total	**21,087**	**22,738**	**26,280**	**9,516**	**6,357**	**3,859**	**3,882**	**8,245**	**3,438**	**6,648**	**52,681**	**47,302**	**1,330**	**213,362**

No detailed data is available for non-EEG installations with a capacity of less than 10 MW; the total capacity of these installations (5,356 MW) is therefore not included in the table

The figures do not include generating capacity in Luxembourg, Denmark, Switzerland and Austria feeding into the German grid. (4,296 MW)

* This table includes the following plant statuses: operational, seasonal mothballing, special cases, temporarily shut down, reserve capacity, security mode for backup purposes

Table 13: Generation capacity by energy source in each federal state

1.6 Storage and pumped storage

The term electricity storage applies to all technical facilities used to take electrical energy from transmission or distribution networks, to store it electrically, chemically, mechanically or physically and to release the electrical energy recovered back to the grid for later offtake. The most common electricity storage technologies are battery-storage systems, compressed air energy storage or pumped storage.

Electricity storage facilities play a dual function in the energy industry. Firstly, they are the final consumers of stored electricity. The electricity fed into an electricity storage facility is used up by converting it into a different form of energy. As a rule, storage facilities are considered final consumers of the electrical energy they receive from the grid (Decision of BGH EnVR 56/08 marginal note 9). At the same time, storage facility operators are also producers of the electricity which is returned to the grid from storage.

In accordance with this classification, storage facility operators are subject to regulations and obligations. This means that, in principle, network charges and levies are payable for the use of all electricity withdrawn from the grid, supplied or last consumed by electricity storage facilities. For various reasons, however, electricity storage facilities are subject to numerous special rules which drastically reduce the payment of charges and levies. These are highly diverse and range from the reimbursement of doubly-paid EEG surcharges through to reduction or total exemption. Exemptions from the EEG surcharge cover conversion losses which may differ depending on the type of storage and state-of-the-art technology used.

In addition, many pumped storage stations are covered by exemption provisions under section 118 of the Energy Industry Act (EnWG) which, if certain statutory requirements are met, exempt these stations completely for a temporary period from network charges. In 2018, exemptions for storage facilities or pumped storage stations under section 118 EnWG amounted to around €260m. In addition, pumped storage stations that are not completely exempt from network charges under section 118 EnWG may agree an individual network charge under section 19(4) of the Electricity Network Charges Ordinance (StromNEV) as well as a discount for grid flexibility.

Section 18 StromNEV also requires distribution system operators to distribute so-called "avoided network charges" to storage facility operators. As with other electricity producers, these payments are made based on the amount of electricity generated and fed into the distribution network. The amounts paid are of the same order of magnitude as the network charges paid for electricity withdrawn from the grid. Pumped storage stations connected to distribution systems in Germany which are in receipt of “avoided network charges” account for 20% of the gross electricity consumed by all pumped storage stations in Germany.

The Bundesnetzagentur has monitoring information on storage facilities with a capacity of at least 10 MW. This currently covers pumped storage stations and battery-storage systems.

Notification of a total of 11 battery-storage systems with a net nominal capacity of at least 10 MW was made for the Monitoring Report 2019. These 11 systems have a total net nominal capacity of 197 MW. 78 MW are currently under construction and are scheduled to go into operation by 2022.

There are currently also over 25 pumped storage stations[32] in the Federal Republic of Germany with a net nominal capacity of over 10 MW. In total, these power plants have an installed capacity of 6,357 MW. One of these plants ceased operating in 2011. The remaining plants generated a total of 6.7 TWh of electric power in 2018.

A further pumped storage station with a planned net nominal capacity of 16 MW is currently under construction and is due to go into operation in 2020. Nine other pumped storage stations in Luxembourg and Austria with a total capacity of 3,455 MW fed an additional 2.5 TWh of electricity into the public supply network in 2018.

Pumped storage stations therefore generated a total of 9.2 TWh of electricity. The amount removed from the grid by pumping operations totalled 13.1 TWh.

1.7 Power plants outside of the electricity market

The total generation capacity of 102.0 GW from non-renewables (as at October 2019) can be divided into power plants operating within the electricity market (90.1 GW) and power plants operating outside of the electricity market (11.9 GW). Within these two categories, the following subsets can be classified with regard to power plant status:

Power plants operating in the electricity market:

- 89.6 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: grid reserve power plant capacity (power stations systemically relevant under sections 13b(4) and 13b(5) EnWG and now only operated when requested by the TSOs)

[32] The electricity produced by pumped storage stations is classified as conventionally generated in the monitoring report and in the energy forecasts used in the scenario framework and the network development plan. This electricity is considered to be generated conventionally because the electricity mix used by the storage system is mainly based on conventional energy sources.

- 2.7 GW: power plant capacity on security standby[33]

- 2.3 GW: plants temporarily closed.

The grid reserve power stations referred to above are stations which were notified as scheduled for temporary or final closure but which may not be closed for supply security reasons (see "Use of grid reserve power plants" for more information). These plants currently comprise power stations using natural gas (2.9 GW), black coal (2.3 GW) and mineral oil products (1.6 GW).

In accordance with section 13g EnWG, the lignite-fired power plants Buschhaus, Neurath C, Niederaußem E and F, Frimmersdorf P and Q as well as Jänschwalde E and F have been gradually transferred to so-called security standby status as from 1 October 2016 (transfer of lignite-fired plant Buschhaus Block D to security standby status by 1 October 2016, 352 MW; the lignite-fired plants Frimmersdorf P and Q by 1 October 2017, 562 MW; and the lignite-fired plants Neideraußem E and F and Jänschwalde F by 1 October 2018, 757 MW). The Neurath C and Jänschwalde E plants were transferred in 2019 as the last power plants to go into security standby. 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 (1.8 GW), lignite (0.3 GW) and mineral oil products (0.2 GW).

The following figure shows the location of power plants operating outside of the electricity market. The map shows power plants which have been notified as scheduled either for temporary ("grid reserve power stations") or final closure but which may not be closed for supply security reasons. The EnWG distinguishes between temporary and final closure: In contrast to final closures, temporary closures can be reversed within a period of one year.

[33] The costs for these power plants were between €100m and €200m in 2018. More detailed information is unobtainable as the operators of these facilities classify this information as operating and business secrets.

Electricity: Power plants outside of the electricity market

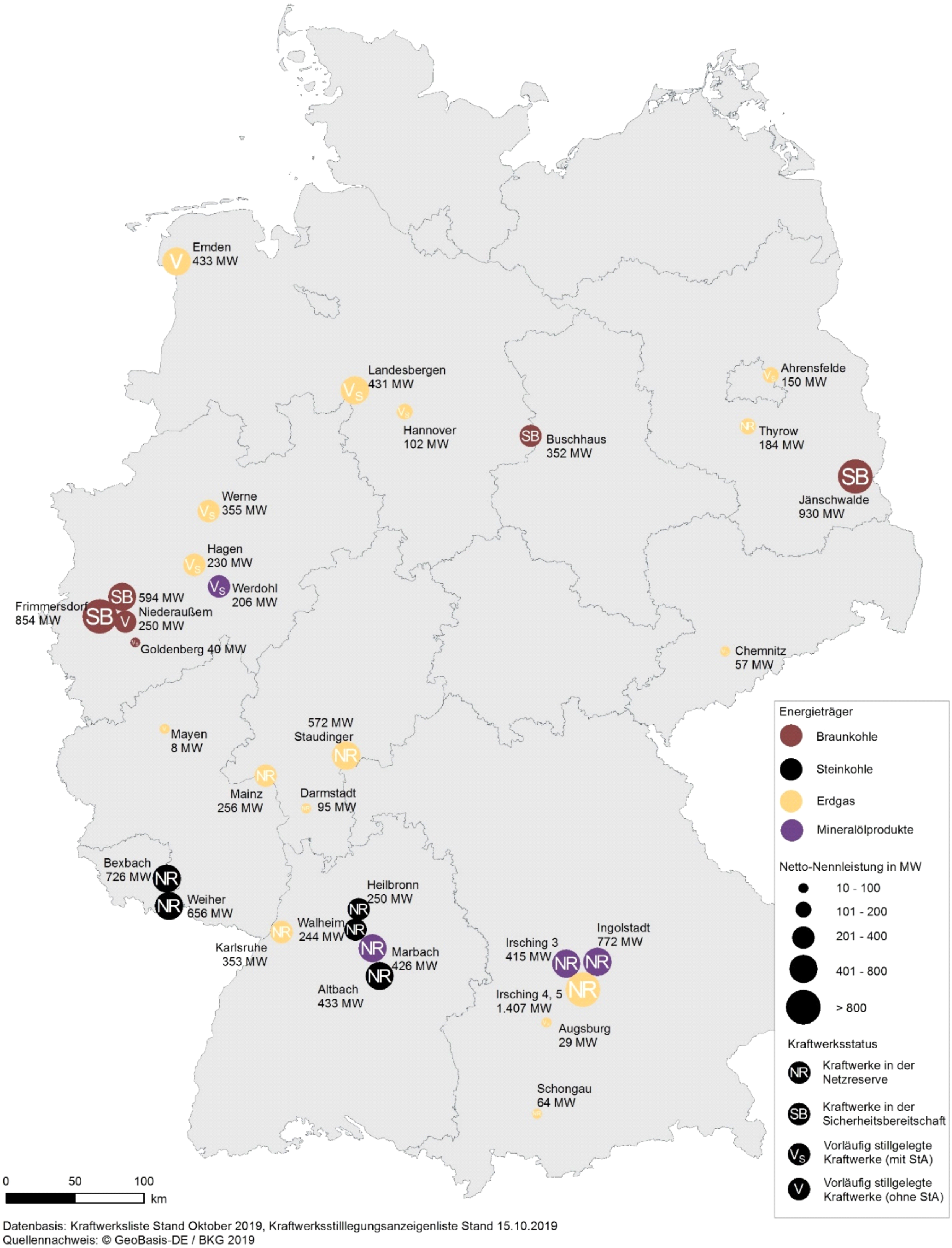

Figure 14: Power plants outside of the electricity market

1.8 Future development of non-renewable energy sources

1.8.1 Projected power plant construction

In addition to information on existing power plants, the Bundesnetzagentur also requests information on the future development of power plant capacity. The following section first examines the construction of new power plants. Section I.B.1.8.2

complements the assessment of the future development of the generation system by including power plant closures. The analysis of the future generation system focuses exclusively on non-renewable energy sources. The analysis of newly constructed power plant capacity is restricted to power generating facilities currently in trial operation or under construction with a minimum net nominal capacity of 10 MW up to the year 2022. In such cases, the probability of projects being implemented is considered to be sufficiently high.

Generation capacity totalling 2,325 MW is currently in trial operation or under construction and will likely be completed by 2022 (see Figure 15). The power plants projects in Germany relate to black coal (1,052 MW), natural gas (1,120 MW), other energy sources (16 MW) and pumped storage (16 MW).

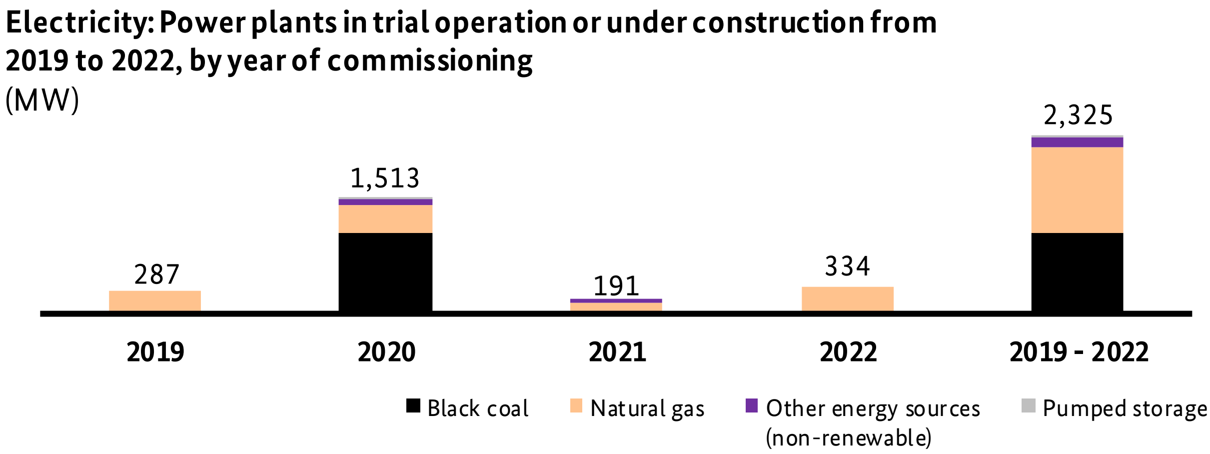

Figure 15: Power plants in trial operation or under construction

1.8.2 Expected power plant closures

The future development of the generation system can be described in terms of the new build and planned closures of power plants. Just as with power plant construction, the analysis of power plant closures only considers those power plants with a sufficiently high probability of closure. These include power plants that have been notified to the Bundesnetzagentur as scheduled for final or temporary closure and nuclear power plants, whose closure is required by law.

Figure 16 shows the locations of the expected new power generating units or units to be closed with a minimum capacity of 10 MW for the period up to 2022. 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.

In Germany as a whole, the capacity of planned closures – consisting of plants notified as scheduled for final closure (1,009 MW) and the statutorily required closure of nuclear power plants (9,509 MW) – will exceed the capacity of newly constructed power generating units (2,325 MW) by 8,193 MW up to the year 2022. A reduction of the existing surplus capacities is therefore expected.

The Bundesnetzagentur was not notified of any temporary closures in addition to the final closures.

In addition, pursuant to section 13g EnWG, lignite-fired power plants with a total capacity of 1,973 MW will be transferred to security standby status by 1 October 2022. The Jänschwalde E and Neurath C blocks, with a total capacity of 757 MW, were transferred to security standby status on 1 October 2019 and will therefore only be finally closed on 1 October 2023.

In addition to the above-mentioned formal notifications of planned final closures, the Bundesnetzagentur was also informed of further planned closures of power generating units through its monitoring activities. The planned closures of which the Bundesnetzagentur has been informed during the monitoring process are not included in Figure 16. The final closure of a total additional capacity of 1,312 MW is thus expected by 2022. This concerns specifically black coal power plants with a capacity of 1,187 MW, natural gas-fired power plants with a capacity of 57 MW and other energy sources with a capacity of 68 MW.

Electricity: Locations with an expected increase or decrease in power generation capacity to 2022

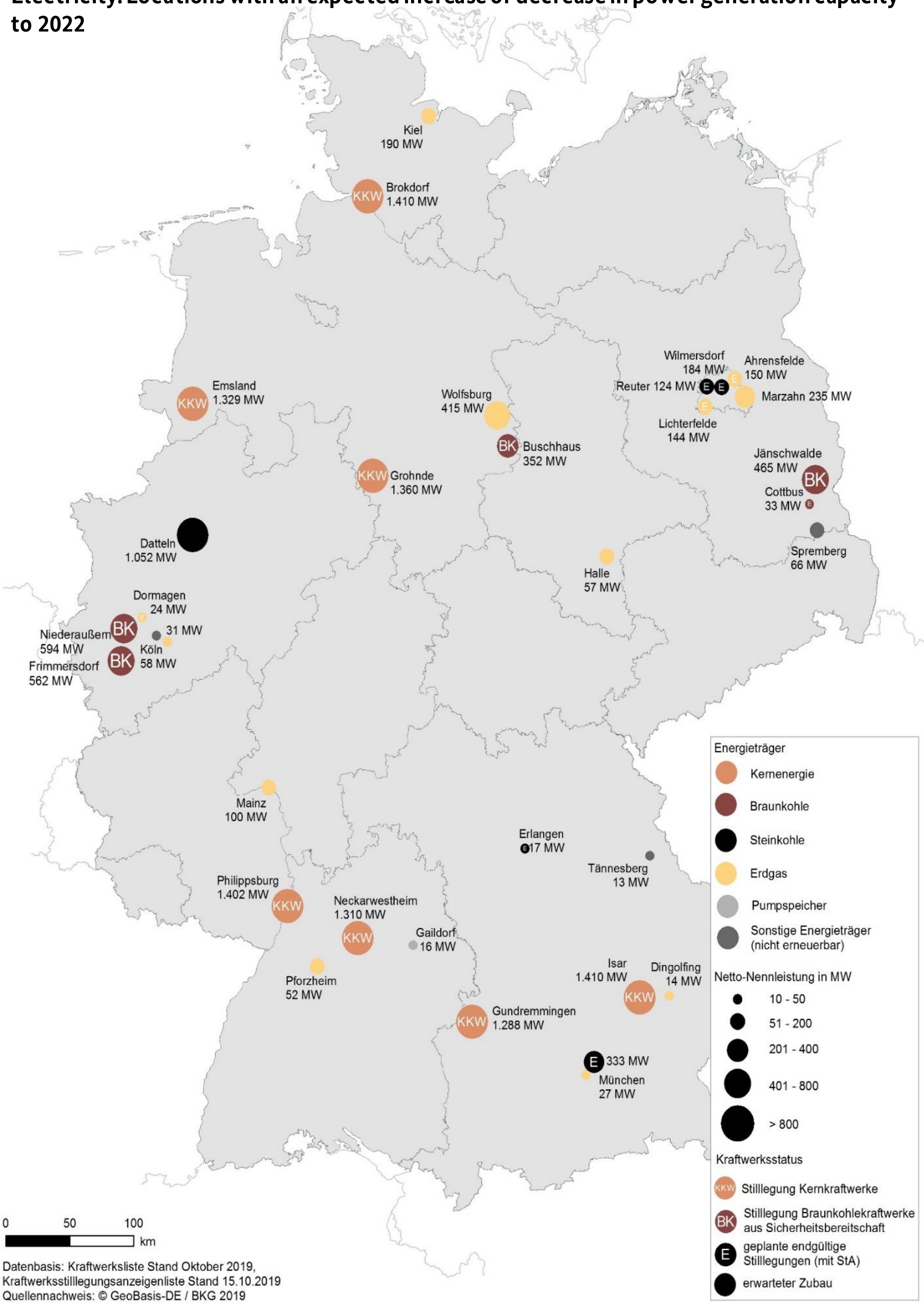

Figure 16: Locations with an expected increase or decrease in power generation capacity up to 2022

The capacity of power plants scheduled for closure by the year 2022 thus totals 13,803 MW.

The overall national balance of the increase and decrease of power generation capacity by 2020 is thus -11,478 MW. This balance of power plant construction and closure is calculated on the basis of power generation units in trial operation or under construction (2,325 Mw) minus formal notifications of final plant closures pursuant to section 13b(1) EnWG (1,009 MW), nuclear power plant closures (9,509 MW), lignite-fired power plants scheduled for final closure by 1 October 2022 (1,973 MW) and scheduled final closures identified through the monitoring process (1,312 MW).

1.9 Combined heat and power (CHP)

Combined heat and power (CHP) is the simultaneous conversion of primary fuels into mechanical or electrical energy and useful heat in a single thermodynamic process.

CHP plants with an electrical capacity of more than 1 MW and up to and including 50 MW may participate in auctions provided they meet the requirements stated in section 5(1) No. 2 Combined Heat and Power Act (KWKG). CHP payments are only made on electricity fed into the general supply grid to plant operators who have taken part successfully in a CHP auction. The same applies to innovative CHP systems under section 5(2) KWKG. The first auction for CHP plants was held on 1 December 2017 and for innovative CHP systems on 1 June 2018. Two auctions will be held every year for both types up to the year 2021.

The Bundesnetzagentur's list of power plants includes all CHP plants with an electrical net nominal capacity of at least 10 MW broken down precisely by plant unit. Since 1 July 2017, all CHP plants must be registered in the Bundesnetzagentur's core energy market data register regardless of size.

1.9.1 Operating CHP plants with a minimum capacity of 10 MW

TThe evaluations presented in this chapter include all CHP-capable German power generation units with a net nominal electrical capacity of at least 10 MW. In 2018, 485 power generation units capable of extracting heat and/or steam were on the market. Of these, 257 are bigger than 10 MW and smaller than 50 MW. Since December 2017, upgraded or new CHP plants of this size are required to participate in CHP auctions in order to benefit from payments under the KWKG (see chapter “I.B.1.9.3 CHP auctions“). Figure 17 shows the number of CHP-capable power generation units per federal state. North Rhine-Westphalia is the federal state with the most installed CHP-capable power generation units, both in terms of the number of power generation units and installed useful heat and electrical capacity.

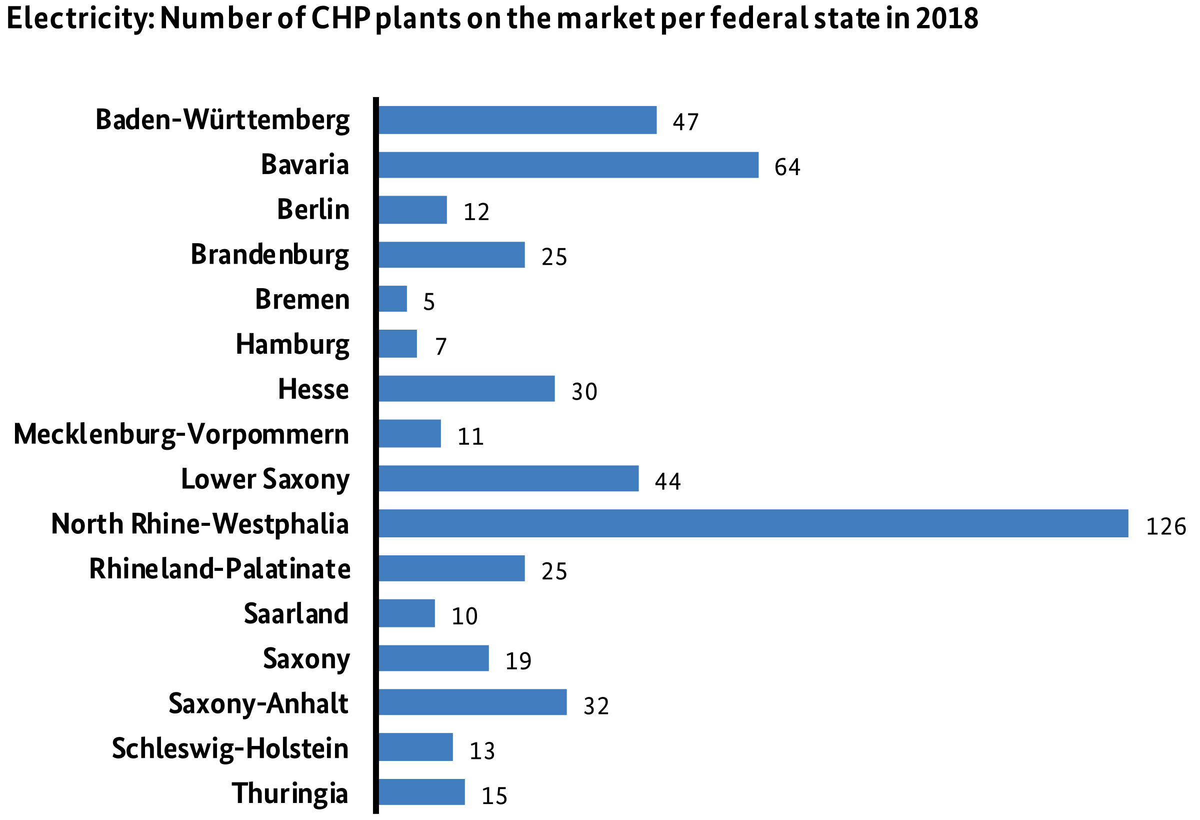

Figure 17: Number of CHP plants on the market per federal state in 2018

The installed electrical and useful heat capacity of CHP plants in MW are shown separately in Figure 18. While the installed electrical capacity of CHP plants is 20.6 GW, the useful heat capacity installed in these plants amounts to 45.2 GW. The biggest plants of each kind provide 728 MW of electrical capacity and 680 MW of useful heat capacity. These two biggest plants are not part of the same power plant and use different energy fuel sources.

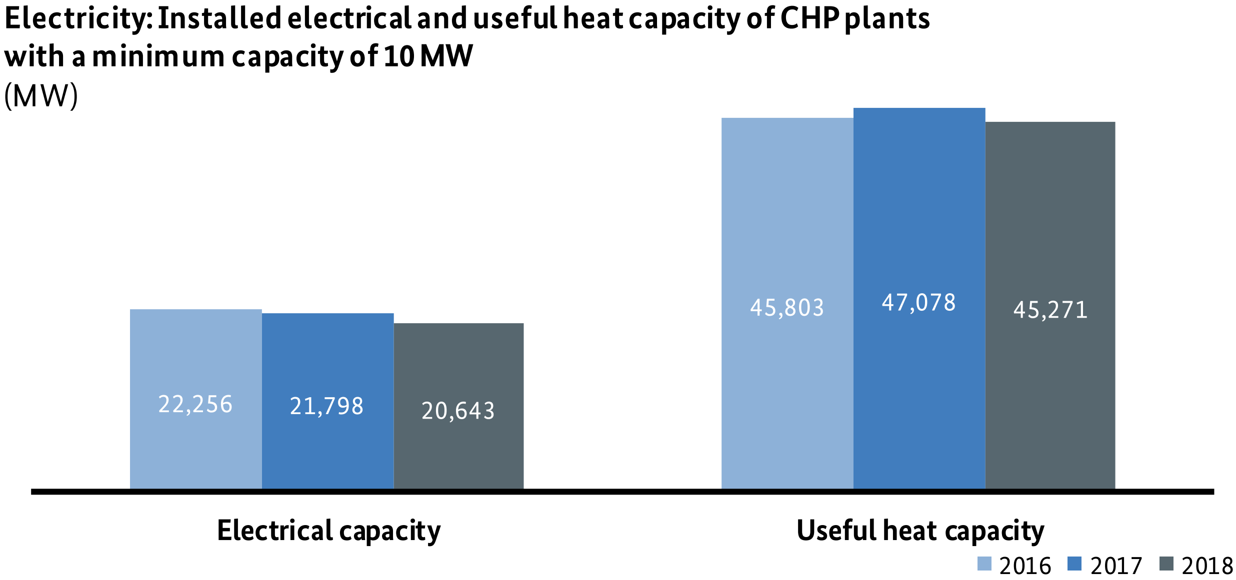

Figure 18: Installed electrical and useful heat capacity of CHP plants with a minimum capacity of 10 MW

The installed (electrical and useful heat) capacity is sourced as follows (Table 14). The table clearly shows that natural gas and black coal in particular are used in CHP power plants. The share of these energy sources in CHP plants has remained unchanged since 2016. Numerous smaller CHP power plants in Germany have an installed electrical capacity of less than 10 MW and are not captured by the monitoring survey performed by the Bundesnetzagentur and are therefore not included in the capacities shown in the following table.

Electricity: Installed electrical and useful heat capacity of CHP plants with a minimum capacity of 10 MW by energy source (MW)

	Electrical capacity		Effective thermal capacity	
	2017	**2018**	**2017**	**2018**
Waste	750	749	3,621	3,541
Biomass	449	461	1,866	1,862
Lignite	1,227	1,077	5,210	4,887
Natural gas	11,430	11,026	20,699	19,792
Others	1,305	1,171	3,446	3,743
Black coal	6,638	6,159	12,236	11,446
Total	21,799	20,643	47,078	45,271

Table 14: Installed electrical and useful heat capacity of CHP plants with a minimum capacity of 10 MW by energy source

The CHP-capable power generation units on which this evaluation is based produced 139.4 TWh useful heat and 65.8 TWh of electricity in 2018. The amount of electricity produced by CHP plants decreased by around 5

TWh in 2018. The amount of useful heat generated also fell by around 5.8 TWh between 2017 and 2018. For the first time, this year's monitoring report surveyed the share of non-CHP electricity generated by CHP plants. The informative value of this data is as yet limited as there are no figures for previous years with which to compare it. In 2018, 154.0 TWh of non-CHP electricity was generated. Non-CHP electricity is one element of the net electricity generated by CHP plants. It is generated using the steam produced in the power plant without heat recovery. Non-CHP electricity can be used for redispatching, whereas the electricity generated on the basis of heat by highly efficient CHP plants is given feed-in priority under section 13(2) and (3) sentence 3 EnWG in conjunction with sections 14 and 15 EEG in conjunction with section 3(1) sentence 3 KWKG and can therefore only be used for redispatching once priority measures have been exhausted.

Electricity: Amount of electricity and useful heat produced by CHP plants
(TWh)

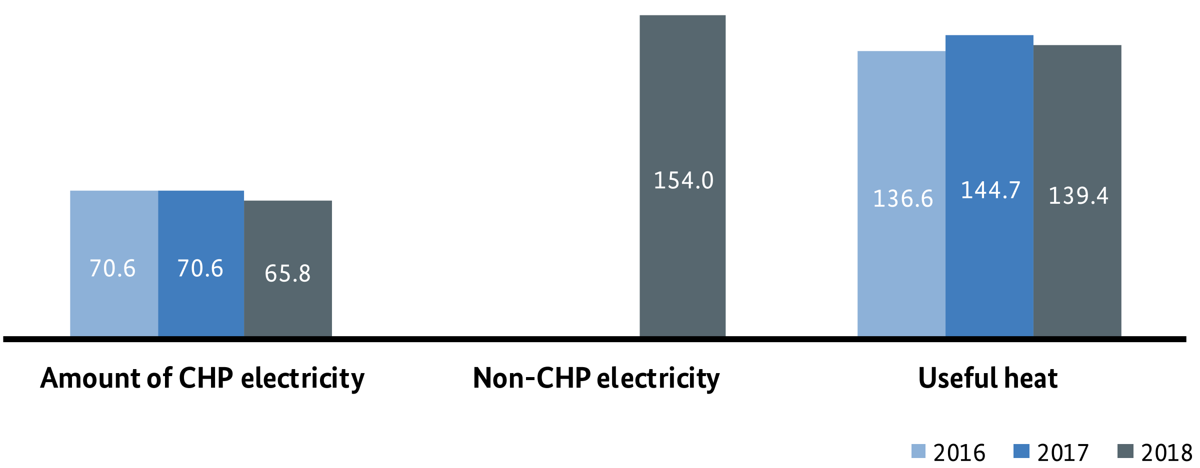

Figure 19: Amount of electricity and useful heat produced by CHP installations with a minimum capacity of 10 MW

The amount of useful heat and CHP electricity produced through heat extraction results from an energy mix which corresponds to the installed capacity. The most important energy sources for the generation of CHP electricity and useful heat are natural gas and black coal (see Table 15). Natural gas is a particularly important energy source for electricity generated by CHP plants through heat extraction and accounts for 65% of total generation. 43% of useful heat is generated from natural gas and 21% from black coal. It is interesting that the amount of non-CHP electricity is several times higher than the amount of CHP electricity if the energy sources of lignite and black coal are used. The amount of non-CHP electricity is significantly lower than that of CHP electricity if natural gas is used.

Electricity: Amount of electricity and useful heat produced by CHP plants with a minimum capacity of 10 MW by energy source (TWh)

	CHP electricity generated		Condensing electricity	Useful thermal power generated	
	2017	2018	2018	2017	2018
Waste	3.1	2.8	2.7	11.1	11.2
Biomass	2.3	2.0	1.2	8.8	9.3
Lignite	3.7	3.6	86.6	15.5	14.2
Natural gas	44.5	42.5	12.1	59.6	59.6
Others	4.3	4.1	4.6	15.3	15.9
Black coal	12.8	10.9	46.8	34.4	29.2
Total	70.7	65.9	154.0	144.7	139.4

Table 15: Amount of electricity and useful heat produced by CHP plants with a minimum capacity of 10 MW per energy source

1.9.2 CHP plants newly registered in the core energy market data register from July 2018 onwards

Since 1 July 2017, under the Core Energy Market Data Register Ordinance (MaStRV) CHP plants must be registered with the Bundesnetzagentur. Approval information and technical core energy data for the plant – such as main fuel and capacity – must be provided as well as plant operator and plant location data. The date on which the plant was put into operation, the operator to whose grid the plant is connected, the voltage level and information about the ability to control the plant remotely must also be provided.

Electricity: Commissioning of CHP plants by months in 2018

Month	Net nominal capacity in MW	Number
January	8	196
February	11	206
March	30	243
April	9	220
May	8	204
June	24	266
July	46	283
August	56	293
September	36	335
October	59	418
November	113	486
December	125	438
Total	**525**	**3,588**

Source: Bundesnetzagentur's core energy market data register

Table 16: Commissioning of CHP plants by months in 2018

In the calendar year 2018, 3,588 plants with a total net nominal capacity of 525 MW were registered. More than half of the new capacity was commissioned in the months October to December 2018 (297 MW).

Electricity: Commissioning of CHP plants by capacity classes in 2018

Capacity class	Net nominal capacity in MW	Number
≤ 50 kW	34	3,262
50 kW - 250 kW	20	144
250 kW - 1 MW	56	103
1 MW - 10 MW	369	75
> 10 MW	46	4
Total	**525**	**3,588**

Source: Bundesnetzagentur's core energy market data register (MaStR)

Table 17: Commissioning of CHP plants by capacity classes in 2018

Most (3,262) of the commissioned CHP plants produced up to 50 kW. This accounts for over 90% of all newly registered plants. The largest net nominal capacity is attributable to the 1 to 10 MW plant class, which accounts for over 70% of new capacity (369 MW).

Electricity: Commissioning of CHP plants by federal state in 2018

Federal state	Net nominal capacity	Number
Baden-Württemberg	44	716
Bavaria	38	521
Berlin	7	80
Brandenburg	12	107
Bremen	< 1	19
Hamburg	6	73
Hesse	18	314
Mecklenburg-Vorpommern	7	39
Lower Saxony	12	392
North Rhine-Westphalia	28	578
Rhineland-Palatinate	15	183
Saarland	< 1	38
Saxony	22	156
Saxony-Anhalt	34	99
Schleswig-Holstein	198	184
Thuringia	84	89
Total	**525**	**3,588**

Source: Bundesnetzagentur's core energy market data register

Table 18: Commissioning of CHP plants by federal state in 2018

Most plants were commissioned in Baden-Württemberg (716), North Rhine-Westphalia (578) and Bavaria (521). In terms of net nominal capacity, the highest share was installed in Schleswig-Holstein. This is due to one large CHP plant with a capacity of 192 MW which comprises 20 generators.

1.9.3 CHP auctions

Under the revised Combined Heat and Power Act (KWKG), which came into force at the turn of the year 2016/2017, and the related CHP Auction Ordinance, the funding of CHP plants with a capacity of more than 1 MW and up to and including 50 MW is subject to their successful participation in an auction. Separate auctions are held for conventional CHP systems and for innovative systems. Innovative CHP systems include a CHP plant, an innovative renewable heat source and an electric heat generator. The innovative renewable heat source may be solar energy, geothermal energy or a heat pump.

Bids are accepted on the basis of the rate specified in the respective bid ("pay as bid"). Awards expire after 54 months. Bidders pay penalties if plants are not commissioned within 48 months. The highest amount for bids is 7 ct/kWh for CHP plants and 12 ct/kWh for innovative CHP systems (iCHP systems). The following tables show the outcomes of previous auctions:

Electricity: CHP auctions

	Auction 1 Dec 2017	Auction 1 June 2018	Auction 3 Dec 2018	Auction 3 June 2019
CHP plants				
Auction volume	100 MW	93 MW	77 MW	51 MW
Number of bids	20 (225 MW)	15 (96 MW)	18 (126 MW)	13 (87 MW)
Number of awards	7 (82 MW)	14 (91 MW)	12 (100 MW)	4 (46 MW)
Disqualifications	0	1 (4 MW)	3 (8 MW)	0
Average award price (volume weighted)	4.05 ct/kWh	4.31 ct/kWh	4.77 ct/kWh	3.95 ct/kWh
Innovative CHP systems				
Auction volume		25 MW	29 MW	30 MW
Number of bids		7 (23 MW)	3 (13 MW)	5 (22 MW)
Number of awards		5 (21 MW)	3 (13 MW)	5 (22 MW)
Disqualifications		2 (2 MW)	0	0
Average award price (volume weighted)		10.27 ct/kWh	11.31 ct/kWh	11.17 ct/kWh

Table 19: CHP auctions

2. Development of renewable energies

An essential cornerstone of the clean-energy transition is the continuous expansion of renewable energies. For this purpose, ambitious annual development corridors for the renewable technologies of onshore wind, offshore wind, solar and biomass technologies have been legally anchored in the EEG.

Operators of newly installed renewable energy installations with a capacity of up to 100 kW (ie installations of the kind typically installed on house roofs) are still entitled to statutory feed-in tariffs, i.e. payments under the EEG for the electricity produced without having to sell the electricity themselves. All other operators, ie operators of installations with a capacity of more than 100 kW, must sell the electricity produced by the installation themselves or via a service provider. They also have responsibility for balancing.

The largest share (78%) of renewable electricity generated in Germany in 2018 was sold directly either by the operator or by a service provider.

2.1 Development of renewable energies (eligible for payments under the EEG)

Not all renewable energy generating facilities are eligible for payments under the EEG. A distinction is therefore made between renewable energy generating facilities with and without eligibility for payments. The majority of installed renewable energy capacity falls under the EEG payment regime (market premium or feed-in tariff). Of the 118.2 GW of capacity installed at the end of 2018, 114.1 GW was eligible for EEG payments. This chapter therefore examines renewable energies eligible for payments in more detail.

The 4.1 GW of renewable energy capacity not eligible for payments is primarily accounted for by the energy sources run-of-river power (2.2 GW), dammed water (1.0 GW) and waste (0.9 GW). For the energy source waste, only the biogenic share of the waste is considered a non-eligible renewable energy source. The remaining 0.9 GW of generation capacity for the energy source waste is assigned to the non-renewable energy sources. A total of 15.4 TWh of electricity was generated from non-eligible renewable sources in 2018. The majority of that energy was generated in run-of-river and dammed water power plants (11.1 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 EEG compensation 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). The Bundesnetzagentur's core energy market data register has been used since July 2017 as an additional source of information to evaluate the installed capacity of EEG installations.

In the publication "EEG in Numbers 2018", 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 grid connection levels.[34]

2.1.1 Installed capacity

As at 31 December 2018, the total installed capacity of installations eligible for payments in accordance with the EEG was approximately 114.3 GW. Around 6.6 GW of the total additional capacity eligible for payments was installed in 2018, representing an increase of around 6.1%.

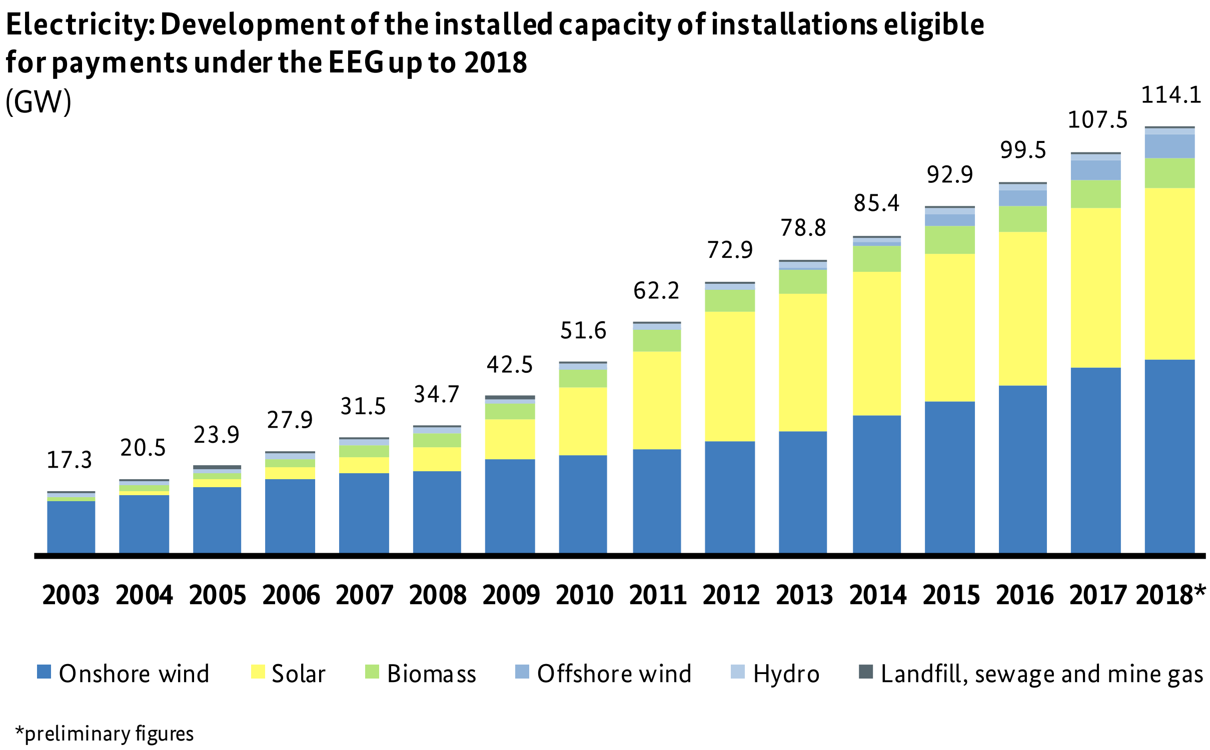

Figure 20: Installed capacity of installations eligible for payments under the EEG up to 2018

Solar capacity rose sharply again in 2018, for the first time in the last five years. In 2018, 2.9 GW of new capacity was installed, compared to an average of 1.6 GW annually over the previous five years. Offshore and onshore wind energy also continued to grow. Nonetheless, net expansion of onshore wind installation capacity (2.3 GW) was less than half the net new build in the previous year (5.0 GW). Offshore wind power plants with a capacity of 1.0 GW were newly installed (2017: approximately 1.3 GW), which represents an

[34] https://www.bundesnetzagentur.de/eeg-daten

increase of 18.3%. The 0.4 GW expansion in biomass installations was slightly higher than in the previous year (2017: 0.3 GW).

Electricity: Installed capacity of installations eligible for payments under the EEG by energy source

	Total 31 December 2017	Total 31 December 2018*	Increase / Decrease in 2018	Increase / Decrease compared to 2017
	in MW	in MW	in MW	in %
Hydro	1,571.6	1,578.4	6.8	0.4%
Gases[1]	460.7	434.0	-26.8	-5.8%
Biomass	7,565.3	7,983.3	418.0	5.5%
Geothermal	37.5	41.6	4.0	10.7%
Onshore wind	50,174.3	52,446.9	2,272.6	4.5%
Offshore wind	5,406.0	6,396.4	990.4	18.3%
Solar	42,292.4	45,230.4	2,937.9	6.9%
Total	107,507.9	114,111.0	6,603.0	6.1%

[1] Landfill, sewage and mine gas

*preliminary figures

Table 20: Installed capacity of installations eligible for payments under the EEG by energy source (as at 31 December)

Some 74,695 new facilities were installed in 2018. Solar installations accounted for 97.2% of new installations, onshore wind installations for 1.5% and biomass installations for 0.8%; the remaining shares were distributed among other technologies. The growth rates of installations eligible for payments under the EEG are shown in Table 21.

Electricity: Development of the number of installations eligible for payments under the EEG

	2012	2013	2014	2015	2016	2017	2018*
Hydro	6,974	6,864	6,947	7,078	7,041	7,138	7,163
Gases[1]	684	622	627	630	612	600	613
Biomass	13,371	13,485	14,024	14,113	14,186	14,271	14,418
Geothermal	6	7	8	9	10	9	10
Onshore wind	21,339	21,819	23,593	24,696	26,057	27,406	28,046
Offshore wind	65	113	241	789	945	1,167	1,308
Solar	1,328,293	1,449,413	1,521,365	1,572,922	1,622,405	1,686,993	1,760,721
Total	1,370,732	1,492,323	1,566,805	1,620,237	1,671,256	1,737,584	1,812,279

[1] Landfill, sewage and mine gas

*preliminary figures

Table 21: Development of the number of installations eligible for payments under the EEG

Table 22 shows the growth rates of EEG installations eligible for payments by energy source.

Electricity: Growth rates of installations by energy source

	Total 31 December 2017	Total 31 December 2018*	Increase / Decrease in 2018	Increase / Decrease compared to 2017
	Number	Number	Number	in %
Hydro	7,138	7,163	25	0.4%
Gases[1]	600	613	13	2.2%
Biomass	14,271	14,418	147	1.0%
Geothermal	9	10	1	11.1%
Onshore wind	27,406	28,046	640	2.3%
Offshore wind	1,167	1,308	141	12.1%
Solar	1,686,993	1,760,721	73,728	4.4%
Total	1,737,584	1,812,279	74,695	4.3%

[1] Landfill, sewage and mine gas

*preliminary figures

Table 22: Growth rates of EEG installations eligible for payments by energy source (on 31 December)

2.1.2 Development corridors

The EEG 2014 introduced capacity-based development corridors for onshore wind, offshore wind, solar and biomass to meet the goals of an increasingly renewable, cost-efficient and grid-compatible energy supply by the years 2025, 2035 and 2050. These goals are summarised in the following table.

Electricity: Development corridors

	Onshore wind	Offshore wind	Solar	Biomass
EEG 2014	2.5 GW net increase per year	6.5 GW increase in 2020;		100 MW gross increase per year
EEG 2017	2.8 GW gross increase for 2017 to 2019	15 GW increase in 2030	2.5 GW gross increase per year	150 MW gross increase for 2017 to 2019
EEG 2019	2.9 GW gross increase as of 2020			200 MW gross increase for 2020 to 2022

Table 23: Development corridors

The following figures show the annual net new build compared to the expansion targets defined in the EEG. The development targets for onshore wind were easily exceeded in the years 2014 to 2017. There was a sharp decline in net increase in 2018 and the development target was not met.

Electricity: Onshore wind development targets
(MW)

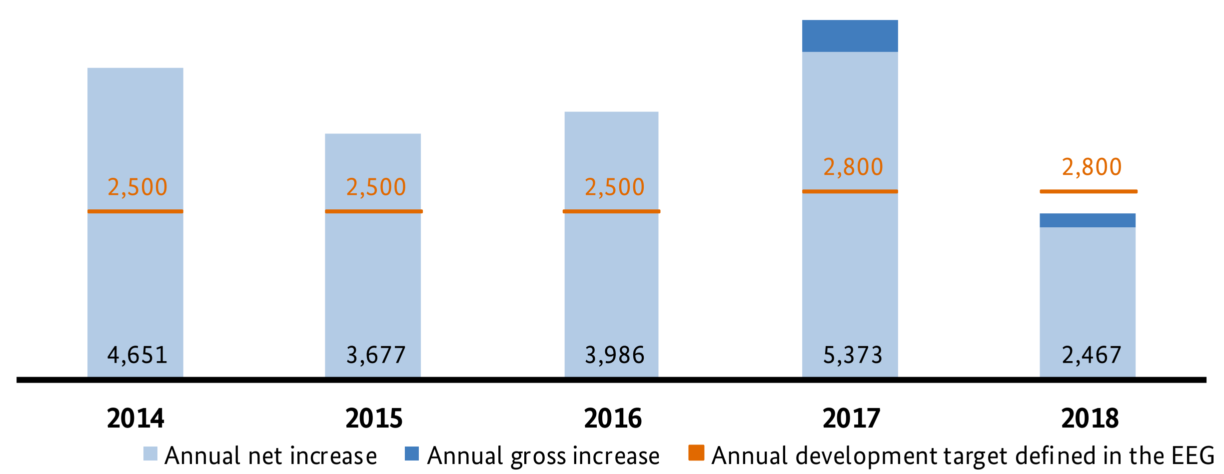

Figure 21: Development targets for onshore wind

Up to 2017, the annual rise in solar capacity was substantially lower than the targets defined in the EEG. The growth target of 2,500 MW was met for the first time and then exceeded by 438 MW in 2018.

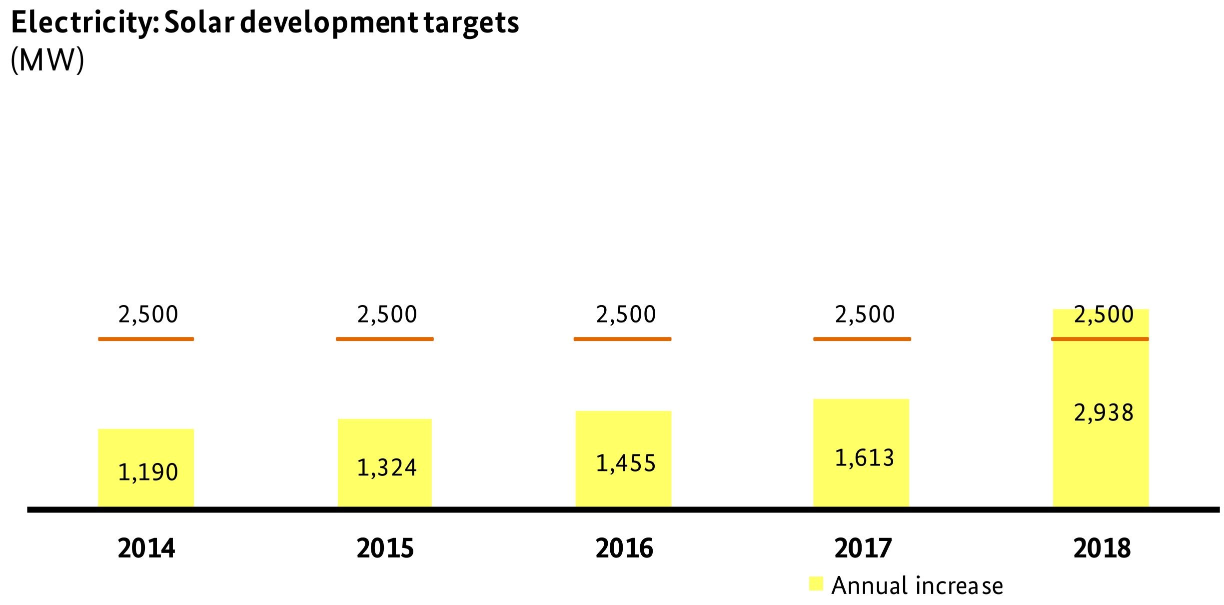

Figure 22: Development targets for solar energy

A payment cap was fixed in the EEG alongside the expansion targets for solar energy. As soon as a total of 52 GWp capacity has been installed, the feed-in tariffs for subsequently commissioned solar installations fall to 0 ct/kWh.

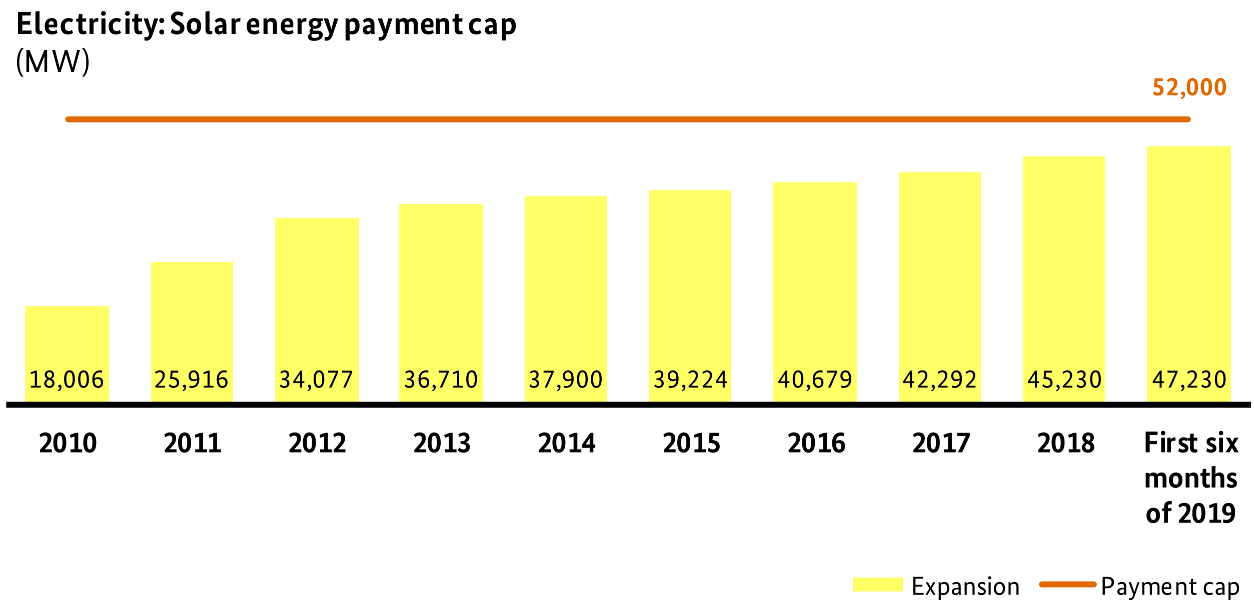

Figure 23: Solar energy payment cap

The following figure shows the annual growth of biomass plants, of which around 90% was due to an increase in capacity. A large part of this increased capacity receives the flexibility premium which was introduced with the EEG 2014. The flexibility premium has been limited to a total of 1,000 MW; this limit was exhausted in July 2019.

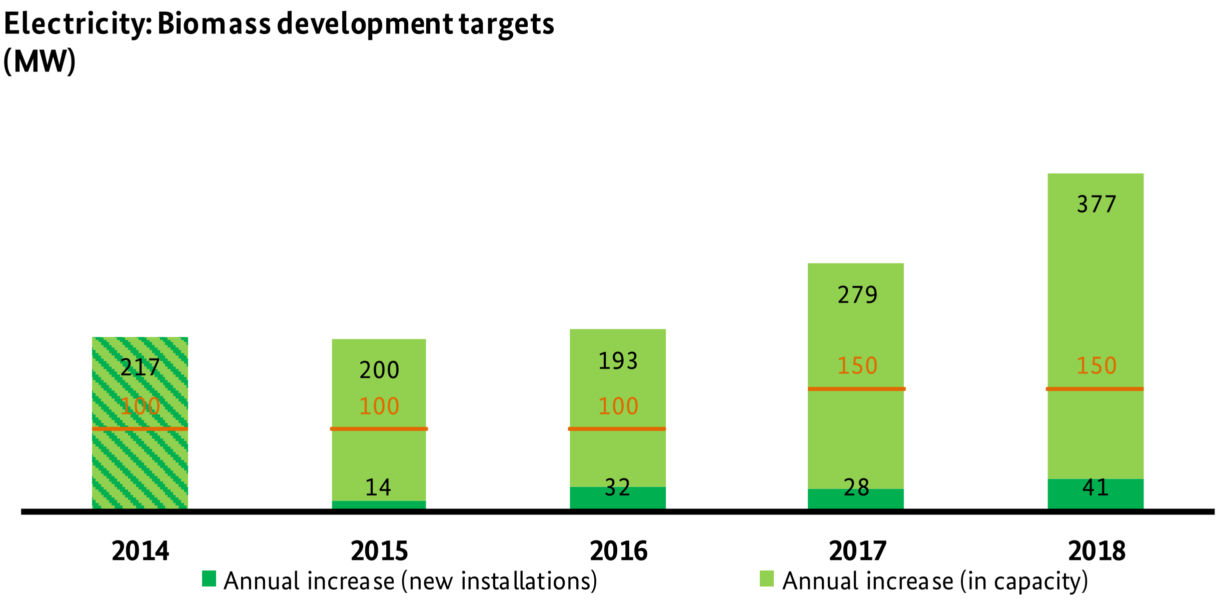

Figure 24: Development targets for biomass

For offshore wind, the first development target of 6,500 MW was met in March 2019 and an average of around 850 MW net new build will be required every year up to 2030 to meet the target for that year.

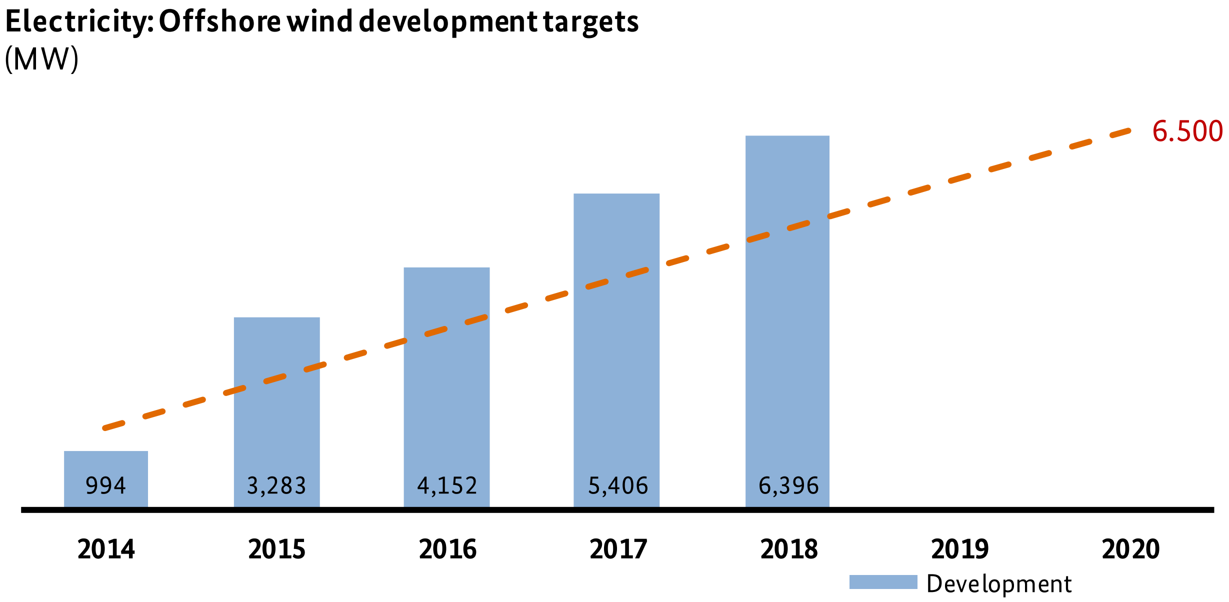

Figure 25: Development targts for offshore wind

In order to achieve the target of 65% gross electricity consumption from renewable energies, which is defined in the Coalition Agreement of 12 March 2018, higher development corridors than those defined in the EEG have been assumed in the 2019 to 2030 scenario framework of the 2019 to 2030 network development plan. All scenarios in the scenario framework are based on the assumption that the 65% target will be met. The development corridor for reaching the target varies however, depending on the different developments of gross electricity consumption assumed in the scenarios. For this reason, the assumed average annual gross rise of 3.6 GW to 4.4 GW for onshore wind and of 2.7 GW to 5.1 GW for solar installations is significantly higher than the EEG targets. The development corridor assumed for biomass plants in all scenarios is 180.0 MW and similar to that in the EEG. At 17.0 GW to 20.0 GW the target value for the year 2030 for offshore wind assumed in the 2019 scenario framework is somewhat higher than the value defined in the EEG or the Offshore Wind Energy Act.

2.1.3 Annual feed-in of electricity

In 2018 the total annual feed-in of electricity from installations eligible for payments under the EEG was 195.4 TWh. Total annual electricity feed-in has increased by 4.2% compared to the previous year (187.4 TWh). At 88.7 TWh or 45%, the largest share of this electricity was generated by onshore wind installations, followed by solar installations with a share of 40.8 TWh (21%) and biomass installations with a share of 40.5 TWh (21%). 2018 was the first year in which more electricity was fed in from solar installations than from biomass installations.

Electricity: Annual feed-in from installations eligible for payments under the EEG (TWh)

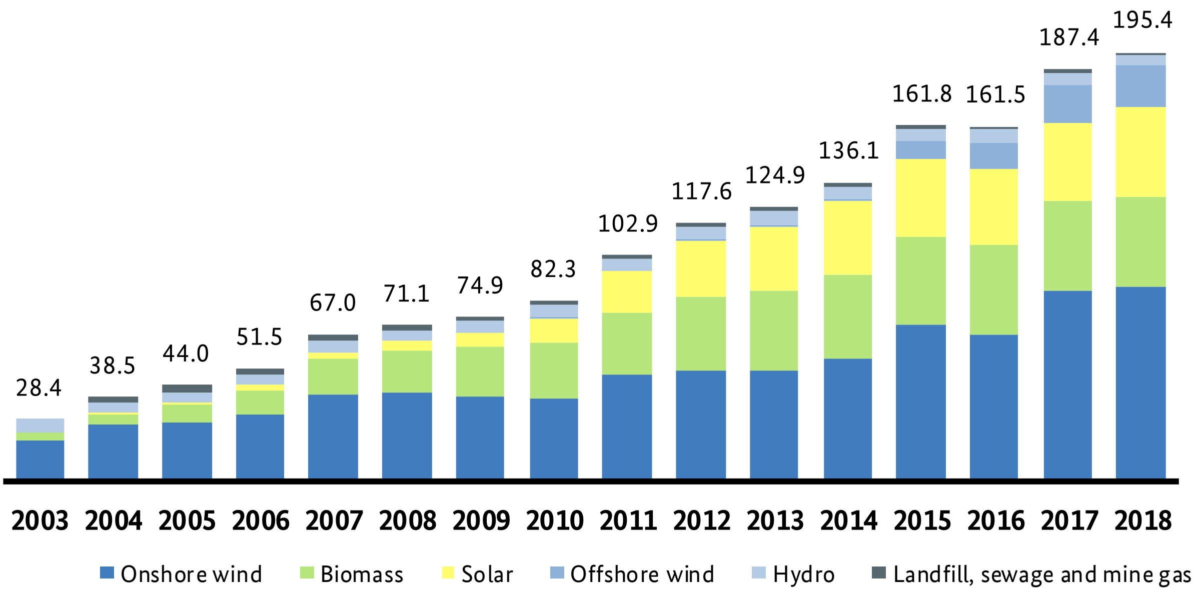

Figure 26: Development of annual feed-in of electricity from installations eligible for payments under the EEG

Annual feed-in of electricity from hydro fell by 15.9% compared to the previous year. This is largely due to the comparatively low levels of precipitation in 2018.[35] The 11.3% fall in the amount of electricity fed in from gas in 2018 correlates with the reduction in gases of 5.8%, see Figure 20.

The annual feed-in of electricity from solar installations rose by 15.2%. This is a sharp increase compared to the five years in which the volume of electricity fed in went up by 7% on average. This increase is partly due to the growth of solar capacity and partly to the record number of sunshine hours and global radiation in 2018.[36]

There has been no noticeable change in annual feed-in of electricity from wind turbines compared with recent years. Figure 27 also shows that the year 2018 was average in terms of wind speeds.

Electricity: Annual feed-in from installations eligible for payments under the EEG by energy source

	Total 31 December 2017	Total 31 December 2018	Increase / Decrease compared to 2017
	in GWh	in GWh	in %
Hydro	5,777	4,857	-15.9%
Gases[1]	1,319	1,170	-11.3%
Biomass	41,056	40,480	-1.4%
Geothermal	163	165	1.6%
Onshore wind	86,293	88,710	2.8%
Offshore wind	17,414	19,179	10.1%
Solar	35,428	40,807	15.2%
Total	187,448	195,368	4.2%

[1] Landfill, sewage and mine gas

Table 24: Annual feed-in of electricity from EEG installations eligible for payments by energy source (on 31 December)

[35] Source: DWD press release: The weather in Germany in 2018 at https://www.dwd.de/DE/presse/pressemitteilungen/DE/2018/20181228_deutschlandwetter_jahr2018_news.html?nn=16210

[36] Source: DWD press release: The weather in Germany in 2018 at https://www.dwd.de/DE/presse/pressemitteilungen/DE/2018/20181228_deutschlandwetter_jahr2018_news.html?nn=16210

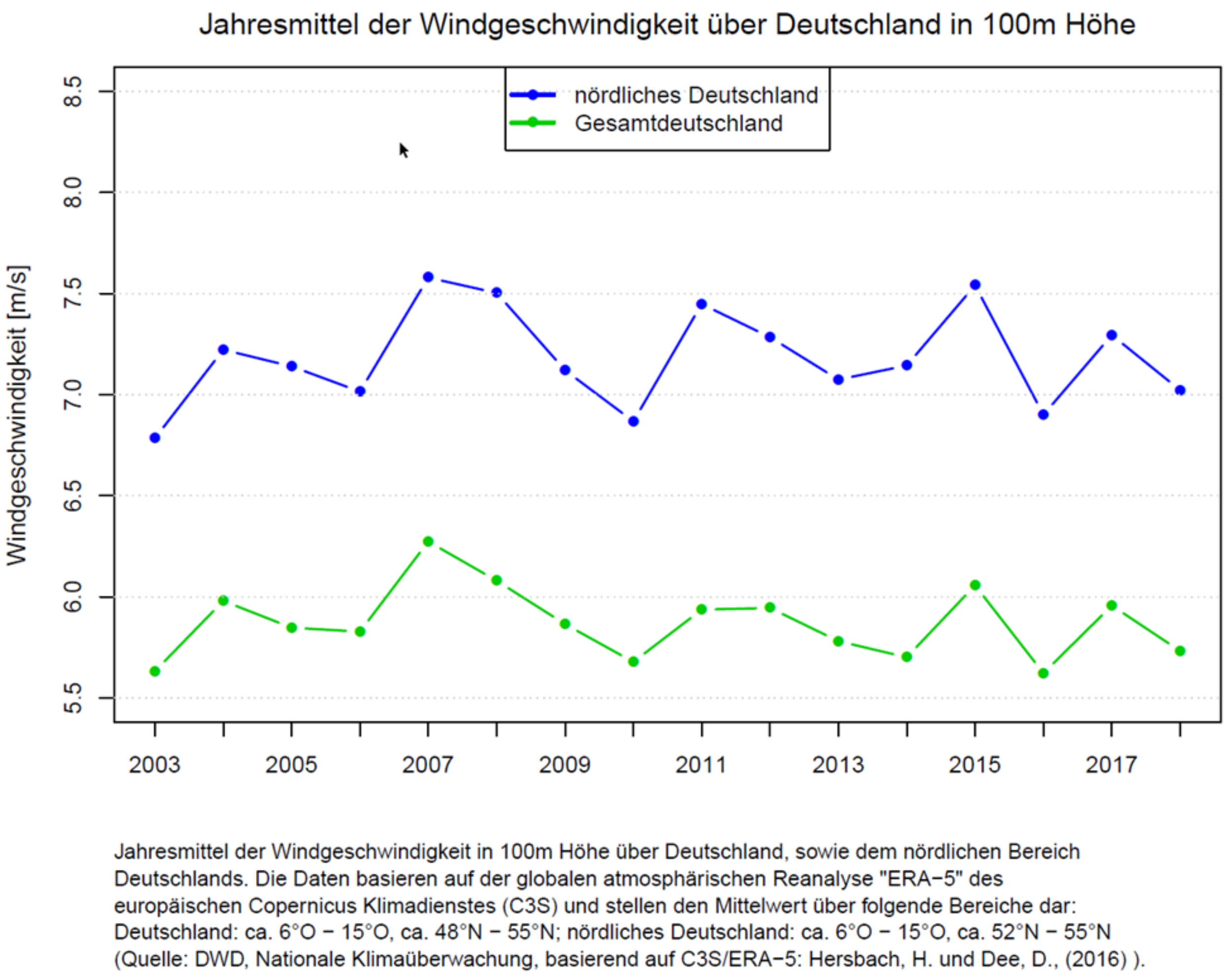

Figure 27: Annual average wind speed at 100 m elevation for all of Germany as well as for northern Germany

Maximum feed-in from wind power and solar installations

The maximum feed-in from wind power and solar installations increased only slightly compared with previous years. In 2018, the maximum feed-in from wind power installations and solar installations of 55.5 GW was recorded on 21 September 2018. Three quarters of this peak feed-in was due to wind power. On this day, solar installations fed up to 13.6 GW into the grid. This coincided with a high level of feed-in from wind power installations (41.9 GW). Figure 28 shows the maximum feed-in from wind power installations and solar installations between 2012 and 2018.

In 2018 the maximum feed-in from solar installations alone of 29 GW was recorded on 2 July 2018. The year's highest feed-in values for wind power (onshore and offshore) were recorded in December 2018. The peak level of 49.9 GW achieved on 8 December 2018 was due primarily to the gale force winds deep low pressure system MARIELOU. Several peak values were also observed in the course of the year as a result of various storm systems. Figure 29 shows the development of feed-in from wind power installations in 2018.

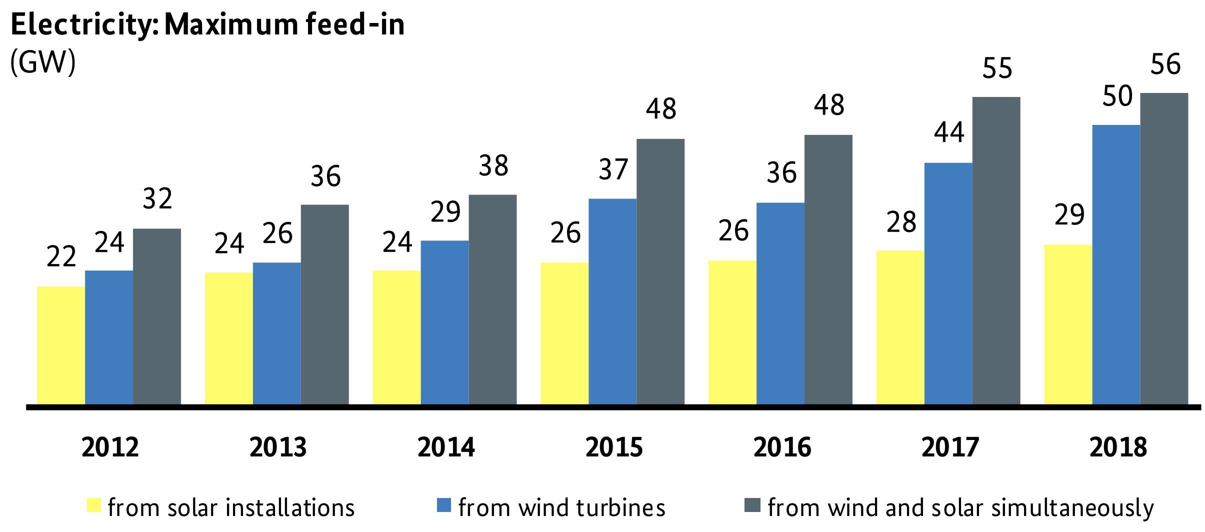

Figure 28: Electricity: Maximum feed-in

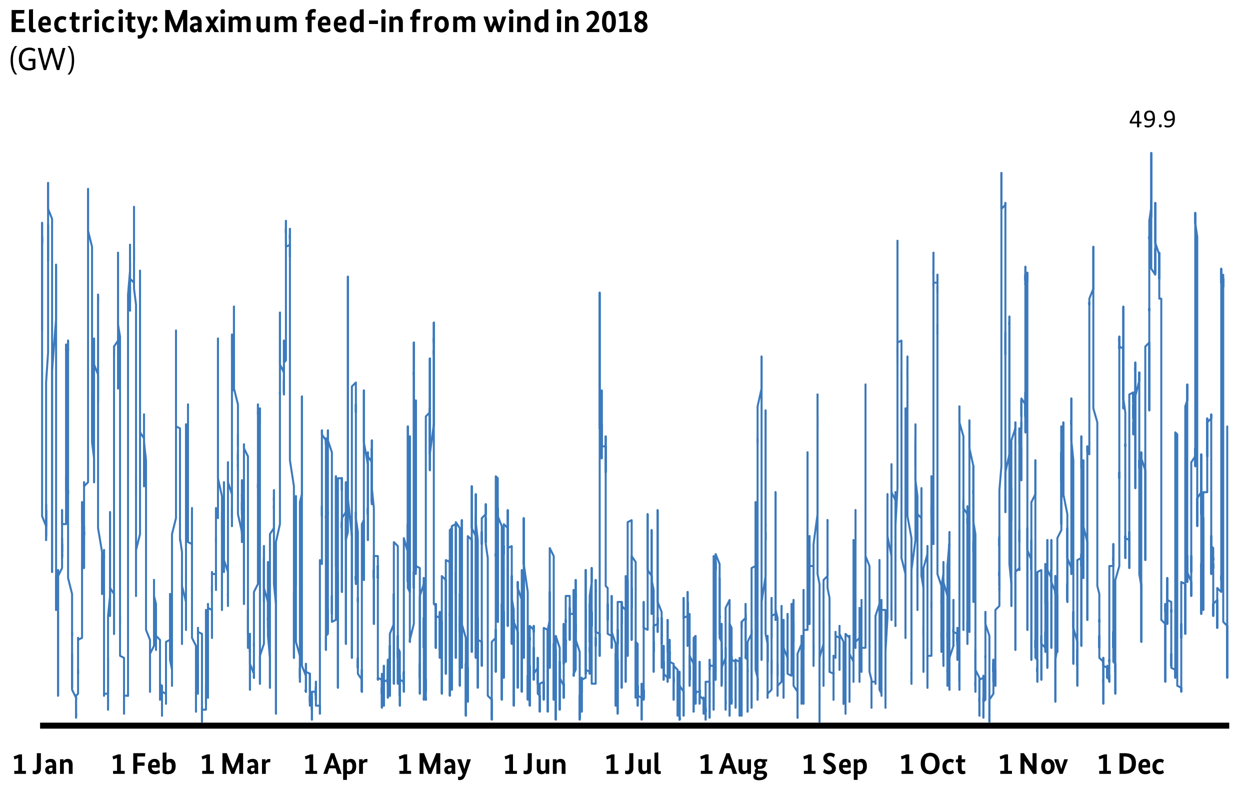

Figure 29: Electricity: Maximum feed-in from wind in 2018

2.1.4 Form of selling

Under the EEG 2012, installation operators were able for the first time to choose between three different forms of direct selling as an alternative to fixed feed-in tariffs: claiming a market premium (as an EEG-based payment in addition to market revenues), a reduction of the EEG surcharge through energy utilities (green electricity privilege), or another form of direct selling (sales of EEG electricity without benefiting from additional payments under the EEG). Subsequent amendments to the EEG all stipulate direct selling and the market premium as standard forms of selling. Only existing installations or new installations with a capacity of up to 100 kW can still opt for fixed feed-in tariffs. Another form of direct selling, i.e. selling without receiving payment under the EEG, also remains possible.

From 2013 more than half of the electricity supplied has been sold directly, and in 2015 a total of 69.4% of the annual feed-in was sold through direct channels. In 2018, fixed feed-in tariffs were only paid for 22% of the electricity supplied (cf Figure 30).

Table 25 shows that just over three quarters of the annual feed-in of electricity was remunerated under the EEG in the form of the market premium. This is already the case for 100% of offshore wind farms (and at 96%, the number of onshore wind turbines receiving market premiums is also approaching the 100% mark (in 2017 the figure was still 95%)). At 29% (2017: 25%), the proportion of electricity from solar installations paid a market premium is still relatively low but growing continually.

In 2018 the main energy source for direct selling was onshore wind, which accounted for a share of 55.8% (2017: 56.5%). The share of biomass and offshore wind also increased to 21.5% and 12.5% respectively.

Electricity: Development of annual feed-in according to fixed feed-in tariff and direct selling (%)

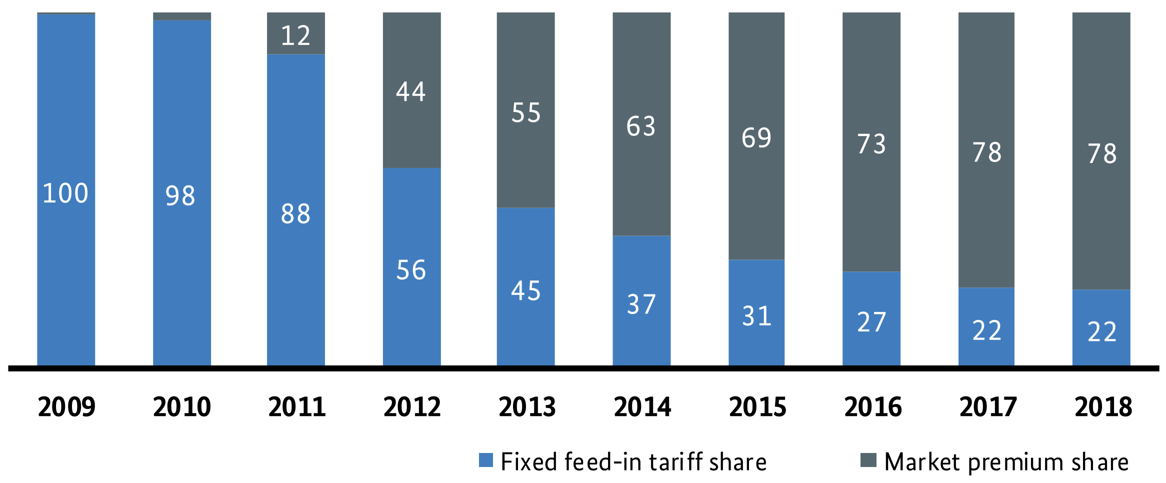

Figure 30: Annual feed-in of electricity from installations eligible for payments under the EEG by feed-in tariff or market premium

Electricity: Annual feed-in from installations with a fixed feed-in tariff or 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	4,857	1,993	2,864	59%
Gases[1]	1,170	272	898	77%
Biomass	40,480	7,670	32,810	81%
Geothermal	165	23	142	86%
Onshore wind	88,710	3,402	85,308	96%
Offshore wind	19,179	0	19,179	100%
Solar	40,807	29,117	11,690	29%
Total	195,368	42,476	152,891	78%

[1] Landfill, sewage and mine gas

Table 25: Annual feed-in of electricity from installations with a fixed feed-in tariff or market premium

Electricity: Breakdown of the annual feed-in from installations with market premium by energy source for 2018 (%)

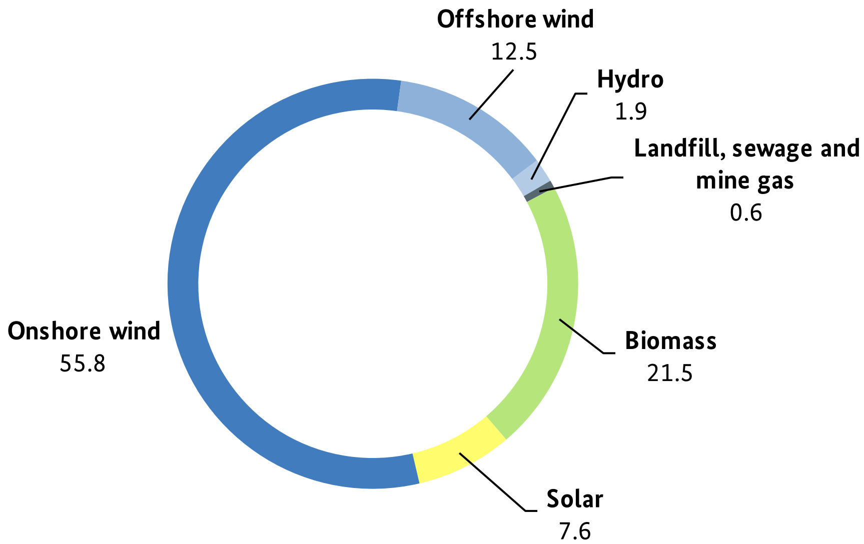

Figure 31: Breakdown of the electricity supplied in 2018 from installations receiving a market premium by energy source

2.2 Changes in payments under the EEG

The EEG surcharge finances green electricity payments to the operators of solar, wind, hydro or biogas and biomass installations. The surcharge is paid for by all electricity customers although certain commercial and industry customers receive a discount. The four transmission system operators determine the surcharge for the following year by 15 October each year on the basis of projected revenue and expenditure.

The payments made to renewable energy operators play a key role in the calculation of the EEG surcharge. All the renewable electricity entitled to a fixed feed-in tariff (approximately 22%), which is mainly produced by small-scale and existing installations, is sold by the transmission system operators on the power exchange. The larger share of renewable electricity (78%) is sold directly by installation operators or via direct sellers on the market, eg the power exchange. In both cases the market revenue is not sufficient to cover the actual payments made or payment entitlements.

This difference is passed on to electricity consumers in the form of the EEG surcharge.

2.2.1 Overall changes in payments under the EEG

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

In 2018 a total of €25.7bn was paid to installation operators by the operators to whose networks the installations are connected. This includes payments to installation operators who sell their electricity through transmission system operators (feed-in tariff) as well as premium payments to installation operators who market their electricity themselves (market premium). In 2018 the majority of payments were made to installation operators entitled to the market premium (feed-in tariff: 45.5%, market premium: 54.5%).

Solar installations (€11.2bn), biomass installations (€6.4bn) and onshore wind installations (€4.9bn) accounted for significant shares of these payments.

Electricity: Payments by energy source

	Total 31 December 2017 (€ million)	Total 31 December 2018 (€ million)	Increase / Decrease compared to 2017 (%)
Hydro	440	348	-20.8%
Gases[1]	60	45	-25.3%
Biomass[2]	6,772	6,393	-5.6%
Geothermal	35	35	-1.2%
Onshore wind	5,720	4,859	-15.1%
Offshore wind	2,770	2,850	2.9%
Solar	10,236	11,176	9.2%
Total	26,033	25,706	-1.3%

[1] Landfill, sewage and mine gas

[2] Including support for flexibility

Table 26: Payments under the EEG by energy source (as at 31 December)

Figure 32 shows that compared with previous years overall payments in 2018 fell slightly for the first time. This is mainly due to the relatively high electricity prices in 2018 (cf chapter "Wholesale market"). The reason is that EEG installations using direct marketing (78%, cf chapter I.B.2.1.4) are remunerated according to the "value to be applied" under the EEG. Installation operators' income is made up of revenue for the electricity they generate and sell on the electricity market plus the market premium. The market premium compensates for the difference between the monthly, average energy source-specific price on the power exchange (the monthly market value) and the value to be applied. This means that the higher the monthly market value, the lower the market premium and total payments under the EEG. The fall in payments is particularly striking for onshore wind energy, and this is due in particular to the fact that 96% of installations receive the market premium.

Electricity: Payments under the EEG by energy source
(€ billion)

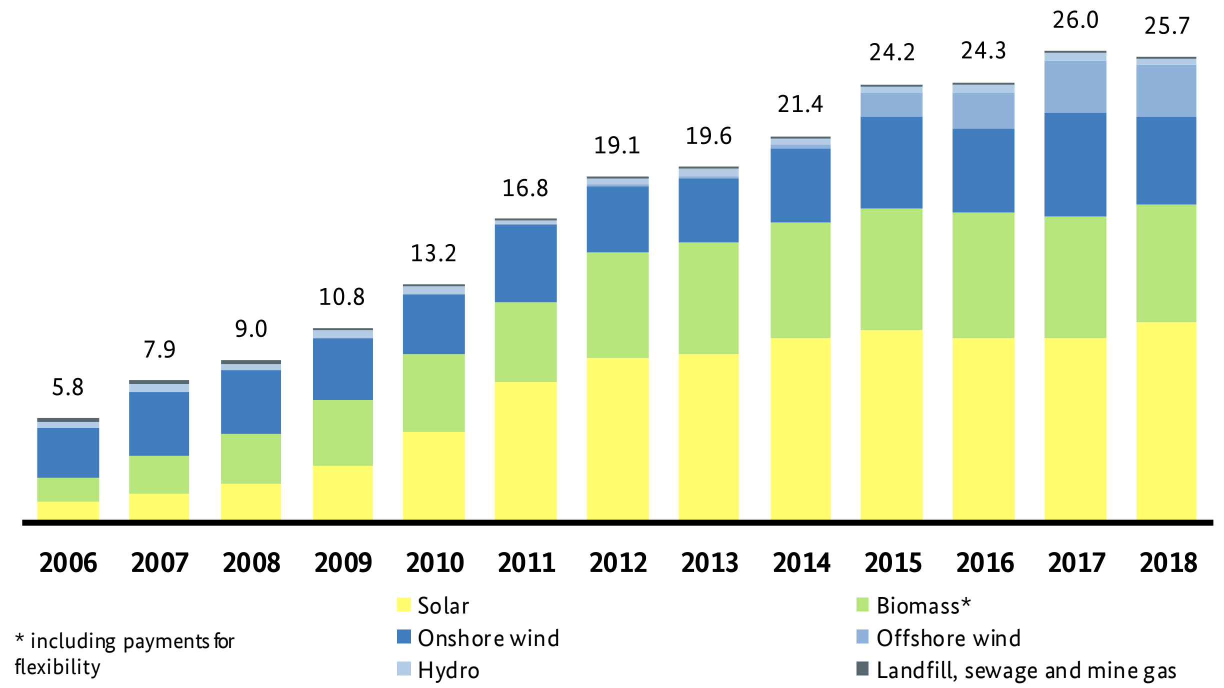

Figure 32: Changes in payments under the EEG by energy source

Renewable energy operators received an average of 13.2 ct/kWh in payments under the EEG[37] in 2018. Payments for the different energy sources varied significantly, however. For example, operators of solar installations received an average of 27.4 ct/kWh in 2018, while operators of onshore wind installations received an average of 5.5 ct/kWh. These average values include both existing installations, which receive very high payments under the EEG, and new installations which receive much lower EEG payments. Installation operators have also received additional revenue since 2012 from direct marketing on power exchanges. These revenues are not included in the payments shown. Figure 33 shows the average payments under the EEG compared with previous years.

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[37] 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.

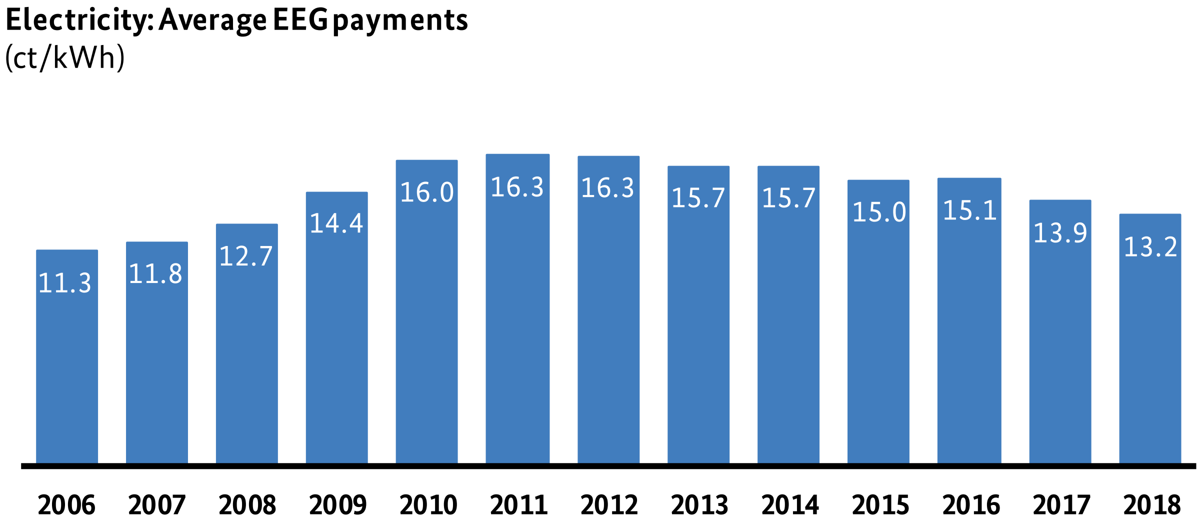

Figure 33: Changes in average payments under the EEG

2.2.2 Changes in the EEG surcharge

Payments under the EEG are for the most part refinanced through the EEG surcharge. Figure 34 shows that the EEG surcharge has been comparatively stable at between 6.2 and 6.9 ct/kWh since 2014, despite the fact that there has been a 40% increase in the capacity for which payments are made under the EEG since 2014. Falling payment entitlements for new installations in particular have slowed the rate of increase of payments to installation operators substantially in recent years. The EEG surcharge peaked at 6.88 ct/kWh in 2017. The additional payments for new installations have since been offset by increasing revenue from higher wholesale prices for renewable electricity. At 6,76 ct/kWh, the EEG surcharge for 2020 is now below its peak. It is, however, slightly higher than in 2019 as the EEG surcharge account balance is lower than it was in the previous year.

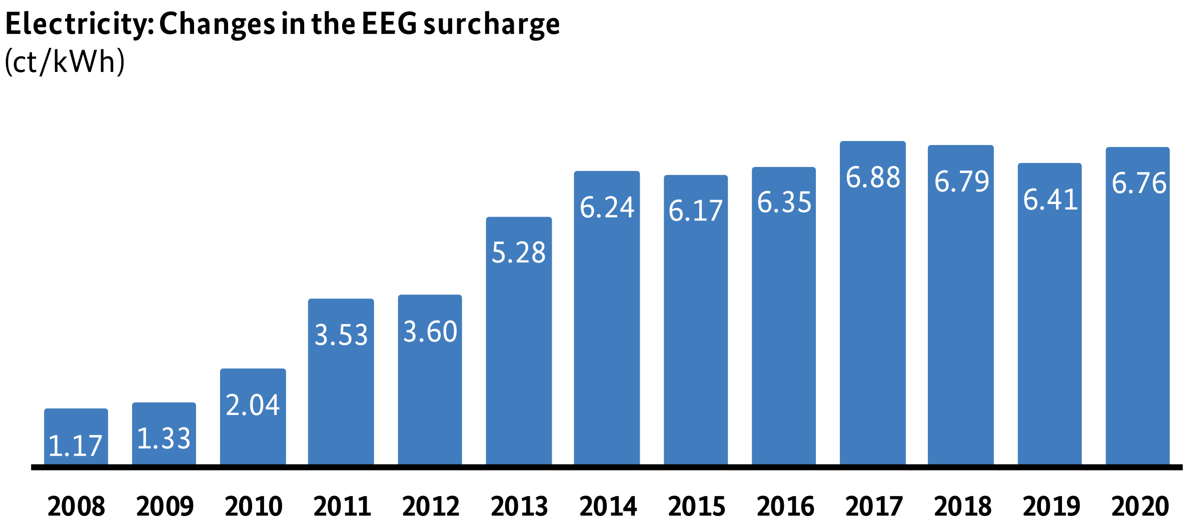

Figure 34: Changes in the EEG surcharge

2.2.3 Lowering of the values to be applied (reference values for calculating the payment entitlement)

Automatic cost reduction mechanisms were introduced in the EEG 2014 to reflect the cost reductions derived from technological advancements. Thus, as of September 2014, the values to be applied for solar energy are reduced by a set percentage each month. For onshore wind power, the values to be applied have been reduced on a quarterly basis as from 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 development corridor is exceeded, the degression rate used for calculation purposes is automatically increased, thus lowering the values 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 installation data recorded in the core energy market data register.

In 2018 and 2019, a substantial rise in solar capacity was recorded compared to 2017 and this meant that the target corridor in the respective reference periods was again exceeded. The value to be applied was therefore reduced by 1% in each month from August 2018 to April 2019 and by 1.4% in each month from May to October 2019. New build up to September 2019 was slightly above the target corridor and resulted in a further slight reduction of 1% up to January 2020.

The target corridor (2.4 to 2.5 GW gross total per year) was exceeded twice in the relevant development period for wind energy (August 2016 to April 2018) for the calculation of the reduction in the value to be applied. The value to be applied was thus reduced by 2.4% for each of the four quarters of 2018. Since 1 January 2019, the remuneration for electricity from onshore wind installations which are not required to participate in auctions (installations with an installed capacity of up to 750 kW and pilot wind turbines) has been calculated on the basis of the bids awarded in previous auctions using the average of award prices from the year before last (section 46b(1) EEG). The value to be applied for wind installations commissioned in 2019 was 4.63 ct/kWh.

Electricity: Lowering of the values to be applied Solar energy

Relevant reference period for calculating actual reduction	Growth corridor (MW)	Actual growth in reference period (MW)	Applied reduction	Reduction cycle	Period of validity of reduction
Sep 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
Stipulated 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		1,966	0.0%		Nov 17 - Jan 18
(Jul 2017 - Dec 2017) x2		1,704	0.0%		Feb 18 - Apr 18
(Oct 2017 - Mar 2018) x2		2,037	0.0%		May 18 - Jul 18
(Jan 2018 - Jun 2018) x2		2,727	1.0%		Aug 18 - Oct 18
(Apr. 2018 - Sep 2018) x2		3,193	1.0%		Nov 18 - Jan 19
(Jul 2018 - Dec 2018) x2		2,570	1.0%		Feb 19 - Apr 19
(Oct 2019 - Mar 2019) x2		3,625	1.4%		May 19 - Jul 19
(Jan 2019 - Jun 2019) x2		3,662	1.4%		Aug 19 - Oct 19
(Apr. 2019 - Sep 2019) x2		2,878	1.0%		Nov 19 - Jan 20

Table 27: Lowering of the values to be applied – solar energy

Electricity: Lowering of the values to be applied
Onshore wind*

Relevant reference period for calculating actual reduction	Growth corridor (MW)	Actual growth in reference period (MW)	Applied reduction	Reduction cycle	Period of validity of reduction
Aug 2014 - Jul 2015		3,666	1.2%		Q1 2016
Nov 2014 - Oct 2015	2,400 - 2,600 (net)	3,712	1.2%	quarterly	Q2 2016
Feb 2015 - Jan 2016		3,564	1.2%		Q3 2016
May 2015 - Apr 2016		3,941	1.2%		Q4 2016
Stipulated in EEG 2017		-	1.2%	one-off	Jan 17
Stipulated in EEG 2017		-	1.05%	monthly	Mar 2017 - Aug 20
May 2016 - Apr 2017		4,676	2.4%		Q4 2017
Aug 2016 - Jul 2017	2,400 - 2,500 (gross)	5,038	2.4%		Q1 2018
Nov 2016 - Oct 2017		5,516	2.4%	quarterly	Q2 2018
Feb 2017 - Jan 2018		5,378	2.4%		Q3 2018
May 2017 - Apr 2018		5,308	2.4%		Q4 2018

* Beginning in Q1 2019 the values to be applied will be determined in auctions for onshore wind power.

Table 28: Lowering of the values to be applied – Onshore wind

2.3 Auctions

Following the amendment of the EEG at the end of 2016/beginning of 2017, the level of payment under the EEG for around 80% of new renewable capacity is now determined through competitive auctions. Since the beginning of 2017, EEG payments are only made for new onshore wind, offshore wind and biomass plants that have successfully participated in an auction. The only exceptions are for onshore wind installations and PV installations with an installed capacity of up to 750 kW and newly commissioned biomass installations with an installed capacity of up to 150 kW. Payments for these renewable energy installations continue to be fixed by law.

Bids are accepted on the basis of the price specified in the bid ("pay as bid"). Exceptions only apply to bids made by citizens' energy companies for auctions for onshore wind and existing biomass installations with an installed capacity of less than 150 kW. In these cases, rates are fixed in a uniform pricing system with the value of the highest successful bid determining the value to be applied.

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.

Auctions like those under the EEG have also been introduced under the Combined Heat and Power Act (see chapter I.B.1.9.3).

In 2018, for the first time cross-technology auctions were jointly held for onshore wind and solar installations.

The special auction procedures for onshore wind and solar installations agreed in the coalition agreement were implemented for the first time in 2019 as an important contribution to achieving national climate targets. Additional auctions on four different dates were held for 1 GW per technology. The first technology-neutral innovation auction is also planned for 2019.

There have been 38 auction rounds since 2017 with the following results:

Electricity: Auctions held from 2017 to 2019

Technology	Bidding deadlines	Award price (ct/kWh)*
Solar	1 February 2017	6.58
	1 June 2017	5.66
	1 October 2017	4.91
	1 February 2018	4.33
	1 June 2018	4.59
	1 October 2018	4.69
	1 February 2019	4.80
	1 March 2019	6.59
	1 June 2019	5.47
	1 October 2019	4.90
	1 December 2019	n.v.
Onshore wind	1 May 2018	5.71
	1 August 2018	4.28
	1 November 2018	3.82
	1 February 2018	4.73
	1 May 2018	5.73
	1 August 2018	6.16
	1 October 2018	6.26

*Volume-weighted average award price; for solar, the award price prior to receipt of the second security deposit

Table 29: Auctions held since 2017

Electricity: Auctions held from 2017 - 2019

Technologie	Bidding deadlines	Award price (ct/kWh)*
Onshore wind	1 February 2019	6.11
	1 May 2019	6.13
	1 August 2019	6.20
	1 September 2019	6.19
	1 October 2019	6.20
	1 December 2019	n.a.
Offshore wind	1 April 2017	0.44
	1 April 2018	4.66
CHP	1 December 2017	4.05
	1 June 2018	4.31
	1 December 2018	4.77
	1 June 2019	3.95
	1 December 2019	n.a.
Innovative CHP systems	1 June 2018	10.27
	1 December 2018	11.31
	1 June 2019	11.17
	1 December 2019	n.a.
Biomass	1 September 2017	14.30
	1 September 2018	14.73
	1 April 2019	12.34
	1 November 2019	n.a.
Onshore wind and solar across technologies	1 April 2018	4.67
	1 November 2018	5.27
	1 April 2019	5.66
	1 November 2019	n.a.

*Volume-weighted average award price; for solar, the award price prior to receipt of the second security deposit

Table 30: (Continued from Table 29) Auctions held since 2017

2.3.1 Solar photovoltaic auctions

Following the pilot auction for ground-mounted installations in the years 2015 to 2016, auctions have been held for all solar installations with an installed capacity of over 750 kilowatts since the beginning of 2017. Bids for projects on grassland or arable land in disadvantaged areas are acceptable if permitted by ordinance by the individual federal states (to date this has happened in Baden-Württemberg, Bavaria, Hesse, Rhineland-Palatinate and Saarland). Three auctions are held every year. In 2017 and 2018 auctions were held for 600 MW and 565 MW of installed capacity respectively. A total of 475 MW was auctioned at the scheduled auctions in February, June and October of 2019. The Bundesnetzagentur also held a special auction in March 2019 for a volume of 500 MW. Another special auction on the same scale is planned for December 2019.

The bid volumes for all the auctions were significantly oversubscribed. Competitive pressure was reflected in continuously falling award prices in the first four rounds up to February 2018 (6.58 ct/kWh to 4.91 ct/kWh): Award prices have risen again slightly between the second round of auctions in June 2018 (4.59 ct/kWh) through to the first round in February 2019 (4.80 ct/kWh). The special auction in March 2019 with a bid volume of 500 MW and a maximum permitted price of 8.91 ct/kWh resulted in a significantly higher average award price of 6.59 ct/kWh. The following scheduled auction rounds in June and October 2019 again resulted in falling award prices (5.47 ct/kWh and 4.90 ct/kWh) due in part to an adjustment of the permissible maximum price to 7.50 ct/kWh.

Award prices have fallen by 25.5% since auctions were introduced for all solar installations in early 2017. If the outcomes of the previous six auctions for ground-mounted solar installations under the Ground-mounted PV Auction Ordinance (FFAV) are also included, the award prices have fallen by 47% since the first auction round in April 2015. The current maximum payment for new solar installations determined by auction is 4.90 ct/kWh.

Electricity: Total implementation rate from solar auctions

Bidding deadline	Implemented (%)	Commissioning period (time limit))	Basis of tender
15 April 2015	99	6 May 2017	FFAV
1 August 2015	90	20 August 2017	FFAV
1 December 2015	92	18 December 2017	FFAV
1 April 2016	100	18 April 2018	FFAV
1 August 2016	96	12 August 2018	FFAV
1 December 2016	73	15 December 2018	FFAV
1 November 2016	99	5 December 2018	GEEV
1 February 2017	99	15 February 2019	EEG
1 June 2017	97	21 June 2019	EEG
1 October 2017	35	23 October 2019	EEG
1 February 2018	44	27 February 2020	EEG

Table 31: Implementation rates for all solar auctions

Awards must be implemented in between 18 and 24 months. From the previous 17 rounds, in addition to the six completed auction rounds under the Ground-mounted PV Auction Ordinance, the implementation periods for the first four solar photovoltaic auction rounds under the EEG and the Cross-Border Renewable Energy Ordinance (GEEV) have expired. These also have high rates of implementation (Table 31), which is regarded as a success. The only auction round to deviate from this success is the round completed in October 2017, which has an implementation rate of just 35%. The main reason for this was the failure to implement two very large solar projects. The implementation periods for all other auction rounds have not yet expired.

Electricity: Solar auctions 2018 - 2019

	2018			2019*			
	February	**June**	**October**	**February**	**March**	**June**	**October**
Volume put up for auction (MW)	200	182	182	175	500	150	150
Submitted bids	79	59	76	80	163	105	153
Submitted bid volume (MW)	546	360	551	465	869	556	648
Awards	24	27	31	23	118	14	27**
Volume awarded (MW)	201	182	154	170	499	205	153**
Disqualifications	16	1	3	2	17	13	11
Volume of disqualifications (MW)	67	6	25	6	192	46	44
Maximum amount (ct/kWh)	8.84	8.84	8.75	8.91	8.91	7.50	7.50
Average volume-weighted award price(ct/kWh)	4.33	4.59	4.69	4.80	6.59	5.47	4.90
Lowest bid (awarded) (ct/kWh)	3.86	3.89	3.86	4.11	3.90	4.97	4.59
Highest bid (awarded) (ct/kWh)	4.59	4.96	5.15	5.18	8.40	5.58	5.20

*The date of the December auction round for 2019 is not available

**Prior to receipt of second security. This figure may change.

Table 32: Solar photovoltaic auctions, 2018 to 2019

Figure 35 shows that over 75% of the bids awarded for solar photovoltaic auctions in 2018 and 2019 were concentrated in five federal states (Bavaria, Brandenburg, Mecklenburg-Western Pomerania, Rhineland-Palatinate and Saxony-Anhalt).

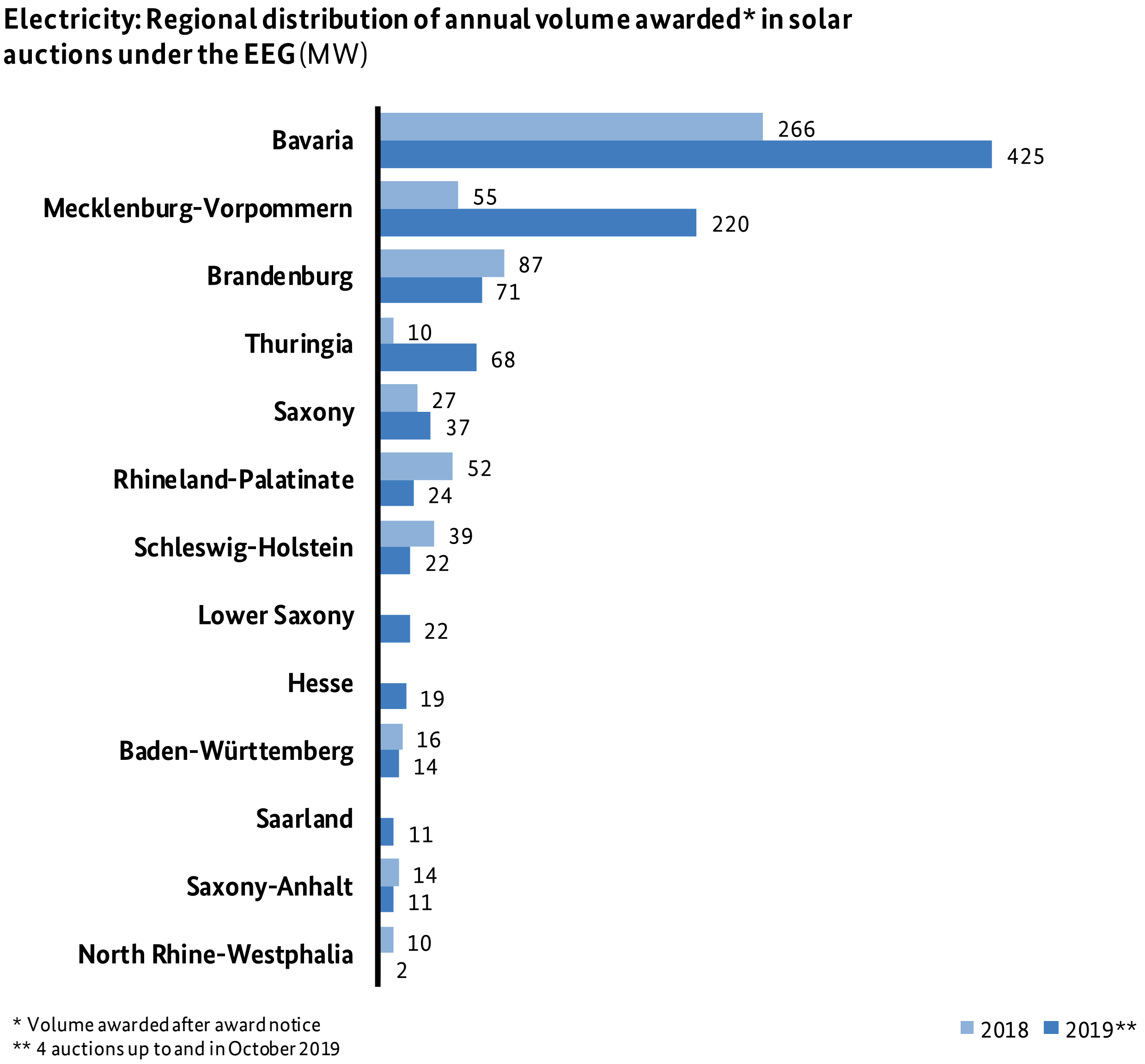

Figure 35: Regional distribution of the annual volume awarded in solar auctions

2.3.2 Onshore wind auctions

Since the beginning of 2017 payments for onshore wind plants have also been determined by auction. All onshore wind turbines with an installed capacity of at least 751 kW must participate in such auctions. The procedure involves three to four rounds of bidding with an annual auction volume of around 2,700 MW in the years 2018 and 2019. A special auction with a volume of 500 MW was also held in September 2019. Another special auction on the same scale is planned for December.

Permits pursuant to the Federal Immission Control Act must be submitted for the installations. Bids are submitted for the value to be applied to an installation at a defined 100% reference site; the actual payments may, however, diverge from this.

Electricity: Onshore wind auctions in 2018

	Feb	May	Aug	Oct
Volume put up for auction (MW)	700	670	670	670
Submitted bids	132	111	91	62
Submitted bid volume (MW)	989	604	709	389
Submitted bid volume (MW) in grid expansion area	125	100	183	93
Awards	83	111	86	57
Volume awarded (MW)	709	604	666	363
Volume awarded in grid expansion area (MW)	88	100	183	93
Disqualifications	2	0	5	5
Volume of disqualifications in MW	16	0	42	25
Maximum amount (ct/kWh)	6.3	6.3	6.3	6.3
Average volume-weighted award price (ct/kWh)	4.73	5.73	6.16	6.26
Lowest bid (awarded) (ct/kWh)	3.80	4.65	5.30	6.12
Highest bid (awarded) (ct/kWh)	5.28	6.28	6.30	6.30
Highest bid (awarded) in grid expansion area (ct/kWh)	**Upper threshold not applicable**			

Table 33: Onshore wind auctions in 2018

Electricity: Onshore wind auctions in 2019

	Feb	May	Aug	Sep	Oct	Dec
Volume put up for auction (MW)	700	650	650	500	675	500
Submitted bids	72	41	33	22	25	n.v.
Submitted bid volume (MW)	499	295	239	188	204	n.v.
Submitted bid volume (MW) in grid expansion area	156	67	16	45	29	n.v.
Awards	67	35	32	21	25	n.v.
Volume awarded (MW)	476	270	208	179	204	n.v.
Volume awarded in grid expansion area (MW)	0	0	16	37	29	n.v.
Disqualifications	5	6	1	1	0	n.v.
Volume of disqualifications in MW	23	25	31	8	0	n.v.
Maximum amount (ct/kWh)	6.2	6.2	6.2	6.2	6.2	6.2
Average volume-weighted award price (ct/kWh)	6.11	6.13	6.20	6.19	6.20	n.v.
Lowest bid (awarded) (ct/kWh)	5.24	5.94	6.19	6.19	6.19	n.v.
Highest bid (awarded) (ct/kWh)	6.20	6.20	6.20	6.20	6.20	n.v.
Highest bid (awarded) in grid expansion area (ct/kWh)	**Upper threshold not applicable**					n.v.

Table 34: Onshore wind auctions in 2019

The four auction rounds held in 2018 were marked by reduced competitive intensity, higher award prices and far lower participation by citizens' energy companies. The second round in May 2018 was slightly undersubscribed for the first time and all the qualified bids were accepted. Although the third round was slightly oversubscribed, competition remained weak and the last bidding round in October 2018 was significantly undersubscribed. The 2019 auction year for onshore wind energy continued to be marked by undersubscriptions or a lack of projects for participation in the auction procedures.

The quality of bids in wind auctions is high; the disqualification rate was around three percent in 2018 and around seven percent in 2019.

In the 2018 auction year, almost 60% of the successful bids were made in the federal states of North Rhine-Westphalia (19%), Brandenburg (18.4%), Schleswig-Holstein (10.7%) and Lower Saxony (10.1%). In 2019, these four federal states accounted for 73% of the successful bids.

Electricity: Distribution of bids and awards for onshore wind energy per federal state 2018 - 2019

	Number of bids		Bid capacity (kW)		Number of awards		Awarded capacity (kW)	
Federal state	**2019***	**2018**	**2019***	**2018**	**2019***	**2018**	**2019***	**2018**
Baden-Württemberg	4	21	22,400	195,000	4	15	22,400	157,850
Bavaria	4	18	19,130	138,150	4	16	19,130	121,950
Brandenburg	42	63	329,640	397,980	41	62	298,590	395,680
Bremen	0	1	0	3,400	0	1	0	3,400
Hesse	3	18	32,380	188,630	3	18	32,380	188,630
Mecklenburg-Vorpommern	4	32	19,300	228,100	4	25	19,300	188,250
Lower Saxony	33	39	282,680	325,476	33	34	282,680	284,276
North Rhine-Westphalia	46	84	373,340	405,000	37	64	329,450	325,550
Rhineland-Palatinate	2	40	8,800	281,350	2	32	8,800	238,800
Saarland	4	5	26,400	30,900	4	2	26,400	6,900
Saxony	4	9	6,300	31,900	3	8	5,500	29,600
Saxony-Anhalt	10	14	95,700	177,460	9	12	92,100	145,780
Schleswig-Holstein	22	38	132,650	195,550	21	36	124,250	179,150
Thuringia	15	14	76,760	91,500	15	12	76,760	76,900
Total	**193**	**396**	**1,425,480**	**2,690,396**	**180**	**337**	**1,337,740**	**2,342,716**

*Auction rounds in February, May, August, September and October 2019

Table 35: Distribution of bids and awards per federal state

The reference yield model takes account of differences in wind conditions prevailing at locations. The main explanations for the auction results are 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 (cross-border and across technologies, offshore wind, biomass)

Offshore wind auctions

Auctions to determine payments for offshore wind power plants were first held in 2017. On 1 April 2017 and 1 April 2018, a total of 3,100 MW each was tendered to existing projects for the transition period. “Existing projects” are offshore wind farms which received approval or planning permission before 1 August 2016 or for which at least a public inquiry has been held. Awards for a total of ten projects (four in 2017 and six in 2018) entitled project developers to EEG payments and to connection to the grid – financed from network charges paid by electricity consumers – as well as to operate their wind farms for 25 years. The volume-weighted average award price was 0.44 ct/kWh in 2017 and 4.66 ct/kWh in 2018. All the projects which were successful in the first round are in the North Sea; three successful projects in the second round are in the North Sea and three in the Baltic Sea.

Electricity: Offshore wind auctions 2017-2018

	1 April 2017	1 April 2018
Volume put up for auction (MW)	1,550	1,610
Submitted bids	19	16
Submitted bid volume (MW)	7,023	5,606
Awards	4	6
Volume awarded (MW)	1,490	1,610
Disqualifications	1	1
Maximum amount (ct/kWh)	12.00	10.00
Average volume-weighted award price (ct/kWh)	0.44	4.66
Lowest bid (awarded) (ct/kWh)	0.00	0.00
Highest bid (awarded) (ct/kWh)	6.00	9.83

Table 36: Offshore wind auctions

No auctions were held in 2019. The next auction will take place in 2021. For the first time, this auction will be for both a pre-assessed site and connection capacity.

Biomass auctions

The Bundesnetzagentur has held three auction rounds since the auction procedure was introduced for biomass installations in 2017. An annual rhythm at the start will be followed by bi-annual rounds in April and November from 2019.

One particular feature of biomass auctions is that installations which were already in operation were also able to take part in the auction if they were entitled to less than a further eight years of payments under the EEG.

Despite the much higher level of participation in 2018 than in the first auction round (85 as opposed to 33 bids in 2017), and in the third round (20 bids in 2019), all rounds have been significantly undersubscribed. Less than 40% and 20% respectively of the auction volume was exhausted in both 2018 and 2019 (April round). The disqualification rates (owing to formal errors in the bid documentation submitted) of just 7% of bids in 2018 and 5% of bids in 2019 were a significant improvement on 2017 (30%). The volume weighted average award price was 14.73 ct/kWh in 2018 and 12.34 ct/kWh in 2019. The average award price for new installations was 14.72 ct/kWh in 2018 and 14.57 ct/kWh in 2019. The average award price for existing installations with an installed capacity exceeding 150 kW was 14.68 ct/kWh in 2018 and 12.12 ct/kWh in 2019. Bids for existing installations with installed capacity equal to or less than 150 kW were, on average, awarded at 16.73 ct/kWh in 2018 and 16.56 ct/kWh in 2019. Regardless of the actual price at which awards were made, the value to be applied for existing installations is limited to the average in the three years preceding the auction.

Electricity: Biomass auctions in 2018/2019*

	1 September 2018			1 April 2019		
	New facilities ≥ 150 kW	Existing facilities ≤ 150 kW	Existing facilities > 150 kW	New facilities ≥ 150 kW	Existing facilities ≥ 150 kW	Existing facilities > 150 kW
Volume put up for auction (MW)		225,807			133,293	
Submitted bids	14	15	56	2	2	15
Submitted bid volume (MW)	29,847	1,370	57,741	2,966	85	22,477
Awards	13	15	51	2	2	15
Volume awarded (MW)	29,481	1,370	45,686	2,966	85	22,477
Disqualifications	1	0	5	0	0	0
Disqualifications in MW	366	0	12,055	0	0	0
Maximum amount (ct/kWh)	14.73	16.73	16.73	14.58	16.56	16.56
Average volume-weighted award price (ct/kWh)	14.72	16.73	14.68	14.57	16.56	12.12

* A further auction will be held in November 2019

Table 37: Biomass auctions in 2018/2019

Joint auction for wind and solar installations

The Bundesnetzagentur has held three technology-neutral (joint) auctions for onshore wind and solar installations since 2018. One special feature of these auctions was that account has been taken of a distribution network expansion area, i.e. districts in which the injection into the distribution network from renewable energy installations is higher than the installed peak load. The distribution network component aims to introduce a tool for pricing in the network and system integration costs resulting from additional onshore wind and solar installations and for slowing down their pace of growth in these areas. This tool applies a price surcharge (calculated according to technology: onshore wind or solar) to bids submitted in auctions for installations in the distribution network expansion area. The surcharge merely relates to the order of bids and has no effect on the payments later made for each installation.

Electricity: Results of joint auctions for onshore wind and solar energy

	April 2018	November 2018	April 2019	November 2019
Volume put up for auction (MW)	200	200	200	200
Submitted bids	54	50	109	n.v.
Submitted bid volume (MW)	395	319	720	n.v.
Awards*	31	35	15	n.v.
Total volume awarded (MW*)	205	191	201	n.v.
Solar volume awarded (MW*)	205	191	201	n.v.
Wind volume awarded (MW)	0	0	0	n.v.
Disqualifications	3	2	18	n.v.
Volume of disqualifications (MW)	30	12	58	n.v.
Maximum amount (ct/kWh)	8.84	8.75	8.91	n.v.
Average volume-weighted award price (ct/kWh)	4.67	5.27	5.66	n.v.
Lowest (awarded) bid (ct/kWh)	3.96	4.65	4.50	n.v.
Highest (awarded) bid (ct/kWh)	5.76	5.79	6.10	n.v.

*Award price after receipt of second security for solar bids.

Table 38: Joint auctions for onshore wind and solar energy 2018/2019

The auction rounds were oversubscribed by a factor of between 1.6 and 2 in 2018 and dominated by bids for solar installations. 54 bids were received in the first round in April 2018; 18 of these bids were for onshore wind installations and 36 for solar installations. All 32 bids accepted, totalling 205 MW, were exclusively for solar installations. 50 bids were received in the second round in November 2018, 1 for a wind power plant and 49 for solar installations. All the bids accepted in this round, totalling 191 MW, again were for solar installations. The volume-weighted average award price was 4.67 ct/kWh in the first round and slightly higher at 5.27 ct/kWh in the second round.

The first auction round in 2019 was oversubscribed by a factor of 3.6 and as such was even more competitive than the previous two rounds in 2018, although no bids for wind installations had been submitted. The volume-weighted average award price was 5.66 ct/kWh in the first round, which was higher than in 2018. These figures are in line with the award prices from the solar PV auctions in 2019 (solar PV auction round in June: 5.47 ct/kWh, see I.B.2.3.1).

The bids made for onshore wind are not competitive in these joint auctions. One possible reason may have been the lack of a correction factor for less windy locations which – in contrast to ordinary onshore wind auctions – was not applied. In addition, the regular wind auctions are already characterised by a lack of approved wind projects, which achieve higher award prices and for which participation in joint auctions is consequently less attractive. With solar installations a technology was successful which had already demonstrated its cost-cutting potential in previous auctions.

The special arrangements for distribution network expansion areas did not especially impact the award decision in either of the auctions. If this price markup had not been applied, however, at least one bid for wind power installations could have been accepted in the first round 2018 instead of a more expensive installation further to the south.

C Networks

1. Status of grid expansion

The expansion of the grid infrastructure is a project that affects society as a whole. Everyone should have the opportunity to become involved and all legitimate interests should be taken into consideration. The legislature has provided the opportunity for the public to participate in all decisions relating to grid expansion.

The Bundesnetzagentur wishes to make the grid expansion process transparent, clear and comprehensible for the general public. The Bundesnetzagentur goes beyond its legal obligations and hosts open information and dialogue events and method conferences.

The Bundesnetzagentur provides a broad range of information on various important grid expansion issues through several channels, including its website www.netzausbau.de, its newsletter and brochures/flyers. It is also present on other platforms such as Twitter and YouTube. People can also contact the energy grid expansion public liaison service if they have any questions or suggestions.

1.1 Monitoring of projects in the Power Grid Expansion Act

The Power Grid Expansion Act (EnLAG) was passed back in 2009, putting the focus on an accelerated expansion of the grid.

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 during the 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 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 www.netzausbau.de/vorhaben. The information is based on the quarterly reports produced by the four transmission system operators (TSOs) on the current state of construction and planning work.

Current status

The projects listed in the EnLAG as at the second quarter of 2019 comprise lines with a total length of about 1,800 km. As at the second quarter of 2019, around 40 km are in the spatial planning procedure and about 500 km are in or about to start the planning approval procedure. Overall, around 1,250 km have been approved, of which approximately 850 km – or about 46% of the total – have been completed. 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.

The following map shows the status of the EnLAG projects in the second quarter of 2019:

Electricity: status of EnLAG line expansion projects

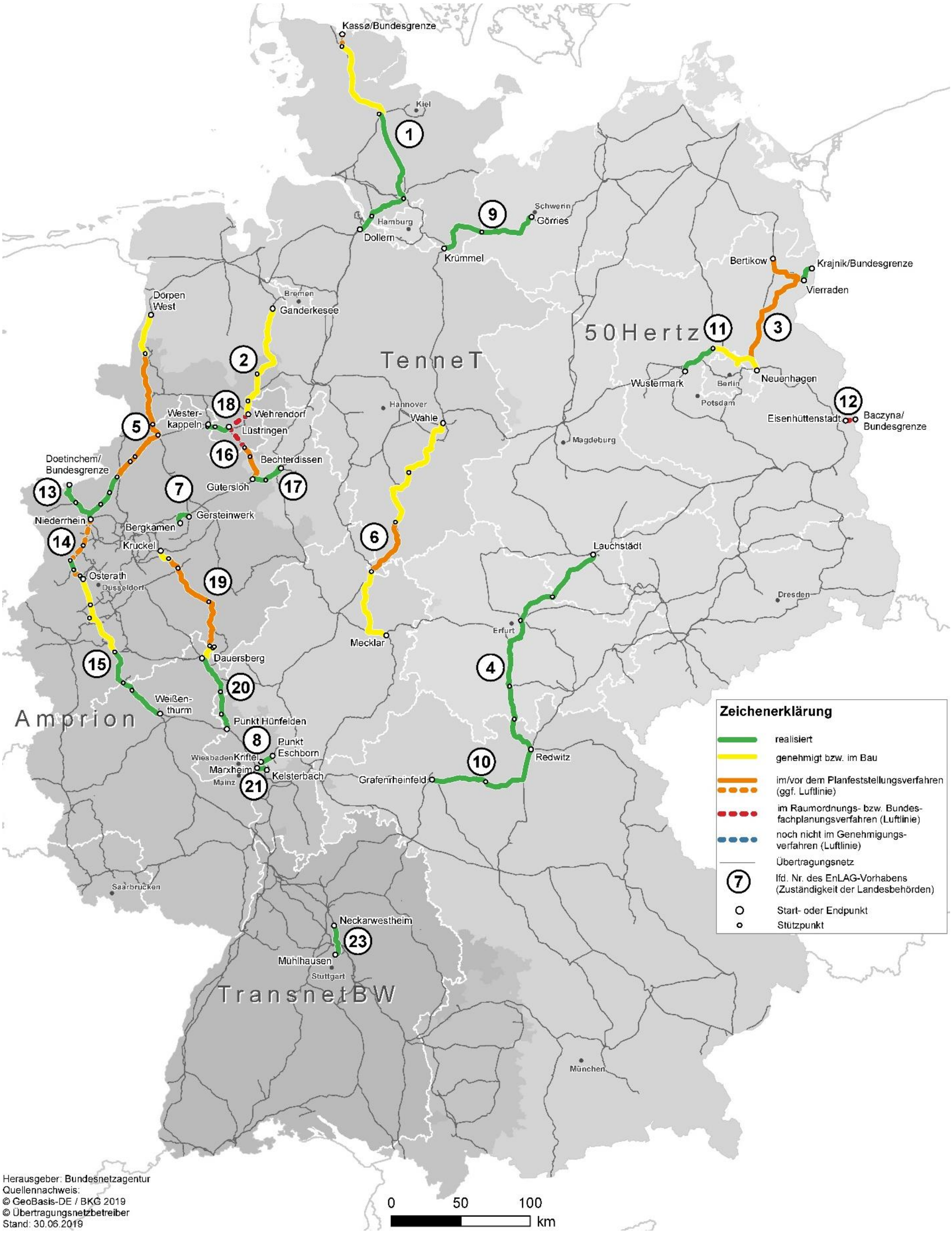

Figure 36: Status of EnLAG line expansion projects: 2nd quarter 2019

1.2 Monitoring of projects in the Federal Requirements Plan

Alongside monitoring the EnLAG projects, 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, 16 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 these projects.

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 listed in the BBPlG as at the second quarter of 2019 comprise lines with a total length of about 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. Approximately 3,600 km fall under the responsibility of the Bundesnetzagentur. As at the second quarter of 2019, approximately 2,650 km of these lines are in the federal sectoral planning procedure, around 40 km are about to start the planning approval procedure and about 250 km are in the planning approval or notification procedure.

Approximately 2,200 km of the total fall under the responsibility of the federal state authorities. As at the second quarter of 2019, around 40 km of these lines are in the spatial planning procedure and 1,200 km are in or about to start the planning approval procedure. Additionally, approximately 100 km have already been approved in the procedures carried out by the Federal Maritime and Hydrographic Agency (BSH).

In total, around 600 km have been approved, of which just under 300 km have been completed.

The following map shows the status of the projects listed in the BBPlG as at the second quarter of 2019.

Electricity: status of BBPlG expansion projects

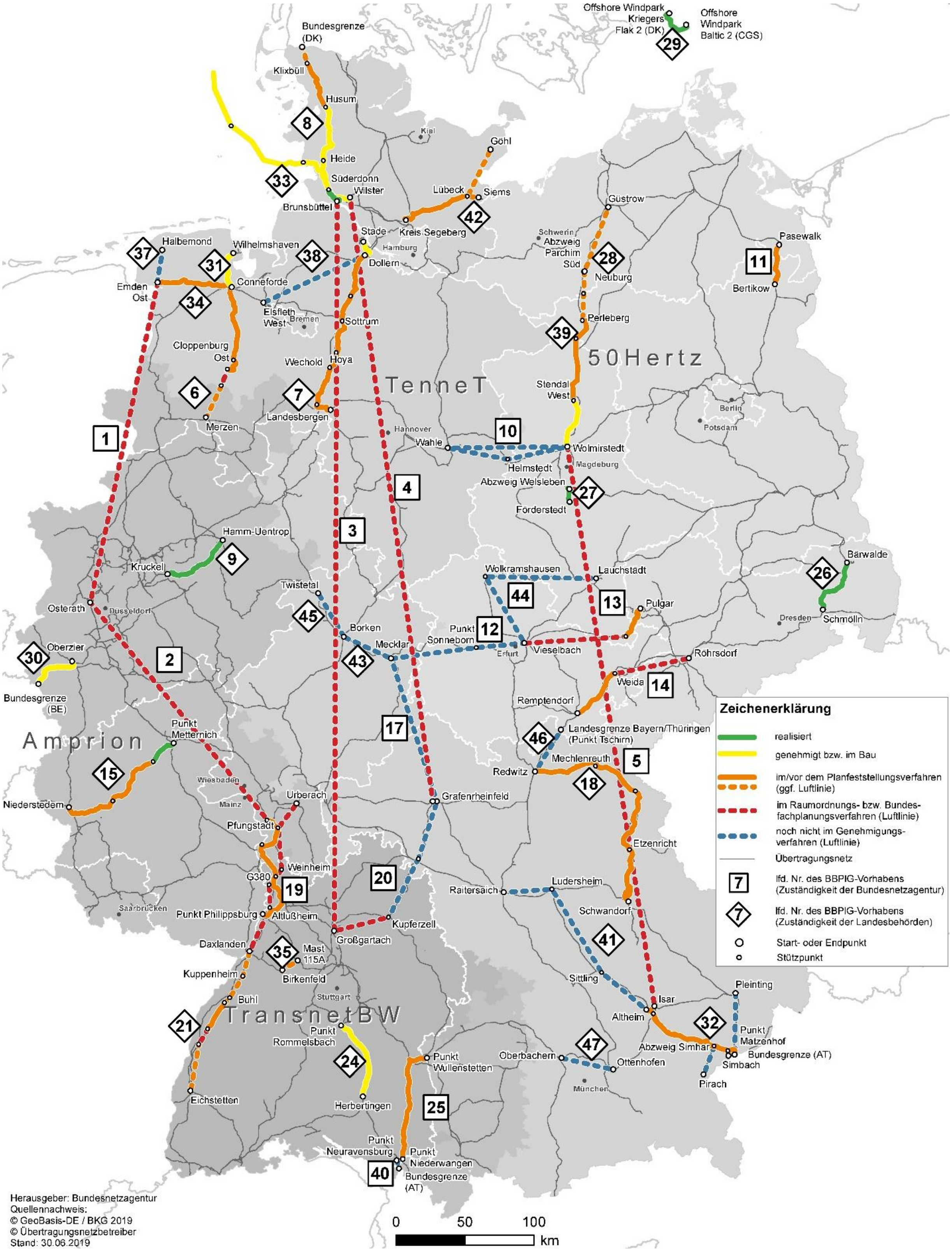

Figure 37: Status of BBPlG expansion projects: 2nd quarter 2019

1.3 Electricity network development plan status

The Network Development Plan (NDP) 2019-2030 takes account of the federal government's energy and climate targets, in particular the aim of meeting 65% of gross electricity consumption with renewables. Future developments such as coupling between the electricity, heating and transport sectors, the increasing use of storage facilities, the phase-out of coal, and the flexible use and provision of electricity feed into the planning process. The expansion and increased use of exchange capacity for electricity trading between individual countries has been agreed EU-wide. These developments also need to be taken into account in the TSOs' planning.

The NDP 2019-2030 is the first to comprise plans drawn up in coherence with the coastal federal states' spatial plans. In accordance with legislation, projects previously set out in the Offshore Network Development Plan (O-NDP) will be included in future in the NDP or the federal states' site development plan. This ensures integrated planning between the site development plan and the NDP for the required offshore transmission links, including the commissioning years and onshore grid connection points.

The TSOs 50Hertz, Amprion, TenneT and TransnetBW published their first draft of the NDP 2019-2030 on 4 February 2019, giving the public, public agencies and federal state energy supervisory authorities the opportunity to comment. On 15 April 2019, the TSOs submitted their revised draft of the NDP 2019-2030 to the Bundesnetzagentur. On 6 August 2019, the Bundesnetzagentur published its preliminary assessment findings and draft environmental report. This marked the start of the second public consultation round for the NDP 2019-2030, with the opportunity to submit comments by 16 October 2019. Confirmation of the NDP 2019-2030, taking account of the responses to the consultation, is anticipated towards the end of 2019.

The NDP 2019-2030 assesses the necessity of the projects in the Federal Requirements Plan as well as additional measures that could be required in light of the progress of the energy transition. The "NOVA" principle remains key to identifying the grid expansion requirements in the NDP. This principle ensures that optimisation measures have priority over reinforcement measures, which in turn take priority over expansion measures. The NDP 2019-2030 factors in the improved system-wide deployment of existing as well as innovative technologies to an increasing degree so as to consistently minimise additional grid expansion requirements.

According to the Bundesnetzagentur's current assessment, 96 of the 164 transmission network expansion measures proposed by the TSOs are eligible for approval, including 40 measures that are already listed in the Federal Requirements Plan. In contrast to the Federal Requirements Plan, the majority of the AC projects (approximately 2,100 km) serve to reinforce existing networks. The Bundesnetzagentur currently estimates that only around 100 km of new lines will be required in addition to those listed in the Federal Requirements Plan. The TSOs have proposed one additional HVDC corridor from the north to the south of Germany for the period up to 2030 to supplement the HVDC lines already listed in the Federal Requirements Plan. The Bundesnetzagentur's preliminary opinion following its own comprehensive assessments is that an additional HVDC corridor is in principle needed, but that the southern part of the corridor is not necessary. For the period up to 2030, the Bundesnetzagentur considers eight or nine additional transmission links in the North Sea and Baltic Sea to be necessary to connect offshore wind farms, depending on the scenario.

1.4 Optimisation and reinforcement in the transmission networks

TSOs are required to operate and maintain a safe, reliable and efficient energy supply network and to optimise, reinforce and expand the network in line with requirements, as far as is economically reasonable.

Incorporating intermittent feed-in from wind power and photovoltaic systems requires short-term forecasting, planning and coordination processes among all network operators. These complex processes need to be replicated in network operation. At the same time, the TSOs are continuously deploying new technologies in the network (eg dynamic line rating for overhead lines, phase shifters) as well as in the markets (eg smart home applications, digital technology). These new technologies can help to increase the utilisation of the existing networks but also increase the requirements on network operation. In light of the financial dimensions of grid expansion, it is even more important to find innovative and as far as possible cost-effective solutions for the optimisation and expansion of the electricity networks.

In the second draft of the NDP 2030 (2019 version), the TSOs have already taken account of specific measures to optimise and increase the utilisation of the electricity networks in their long-term grid expansion plans. There are, however, still deficits in the operational implementation of the measures, for various reasons. This applies both to measures based on state-of-the-art technology and to the testing of innovative network operating resources and operational management approaches. Special mention should be given here to the system-wide deployment of dynamic line rating for overhead lines and the accommodation of dynamic stability aspects. It is therefore essential for the measures to be based on state-of-the-art technology and implemented uniformly and at a much more accelerated pace.

Electricity: percentage of dynamic line rating for overhead lines in the extra-high voltage network (% at 380 kV level)

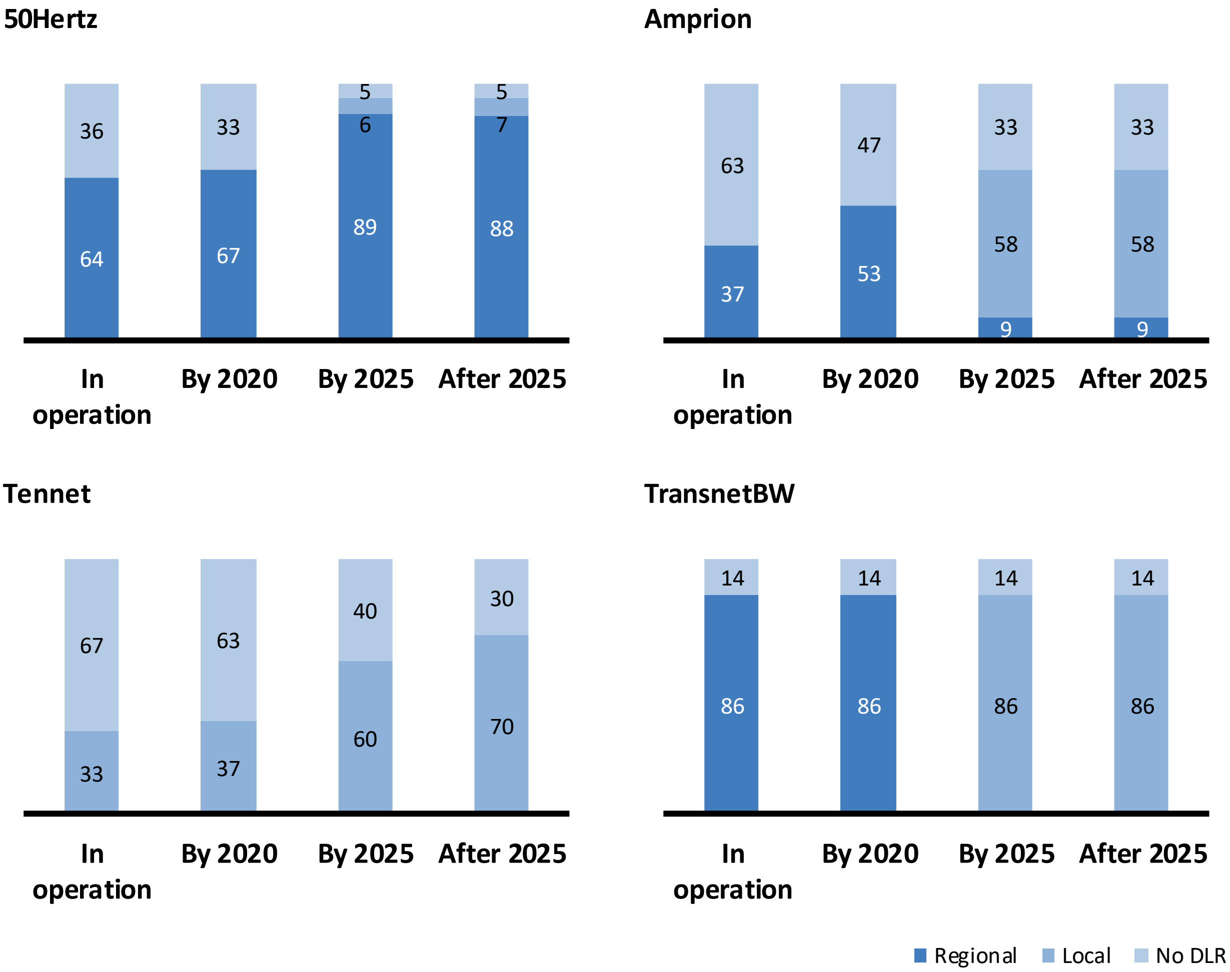

Figure 38: Percentage of dynamic line rating for overhead lines in the extra-high voltage network (380 kV)

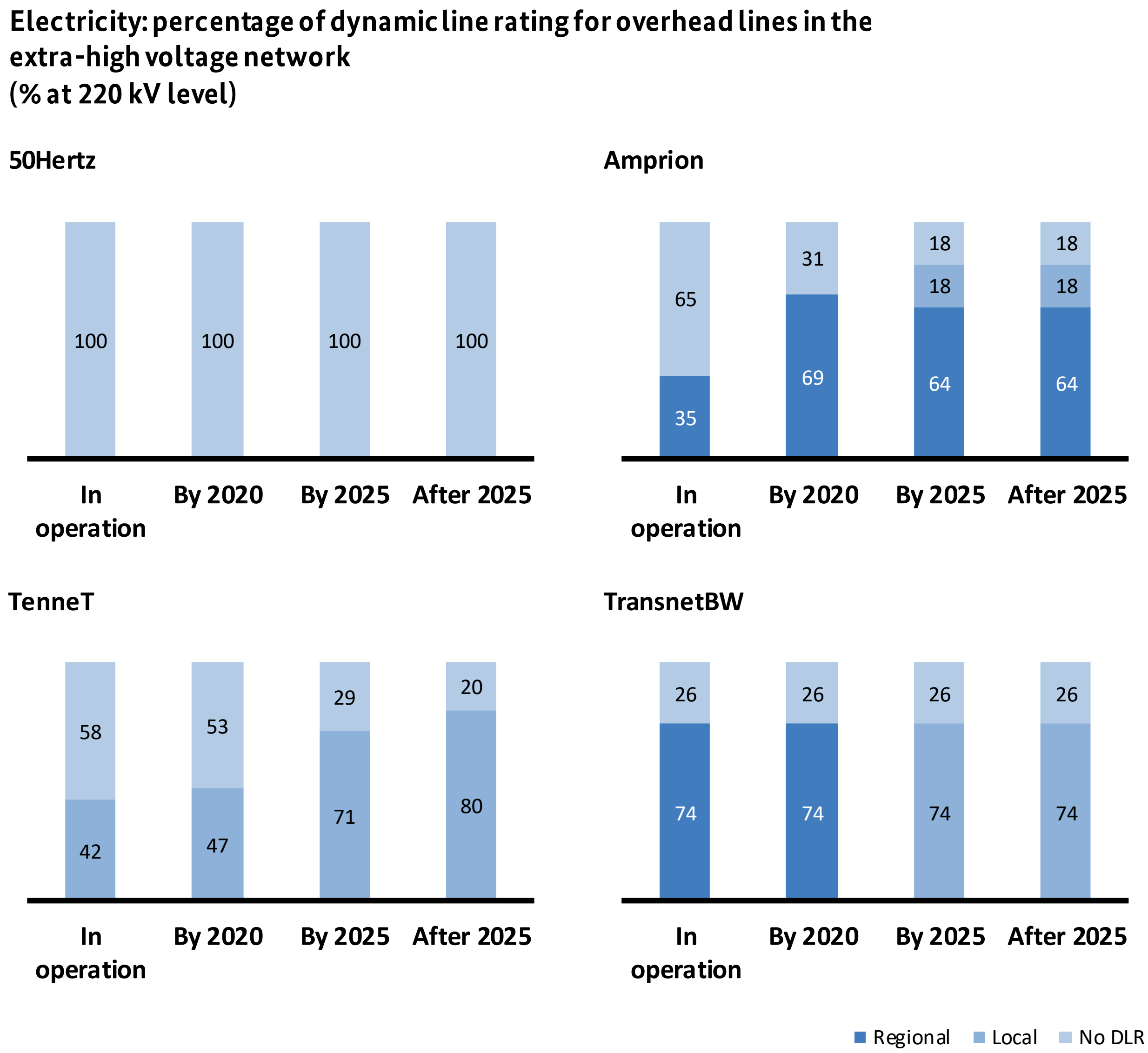

Figure 39: Percentage of dynamic line rating for overhead lines in the extra-high voltage network (220 kV)

In the transmission system, the question of to what extent the existing optimisation potential can be exploited mainly depends on whether the system is seen as a whole.

Experts largely agree that further optimisation potential still exists in the current electricity network that can be tapped in the medium term, and all the more so if this is done with uniform standards based on advanced state-of-the-art technology.

Innovative operating resources and operational management concepts also offer further considerable optimisation potential, but are partly still at the research stage as far as concerns their deployment in a closely interconnected network like the German transmission system.

2. Distribution system expansion

2.1 Optimisation, reinforcement and expansion in the distribution networks

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 approve and 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 by developing 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.

A total of 845 DSOs (815 in the previous year) took part in the 2019 monitoring and provided information about the extent to which they had taken measures to optimise their networks. A total of 644 companies reported network optimisation measures.

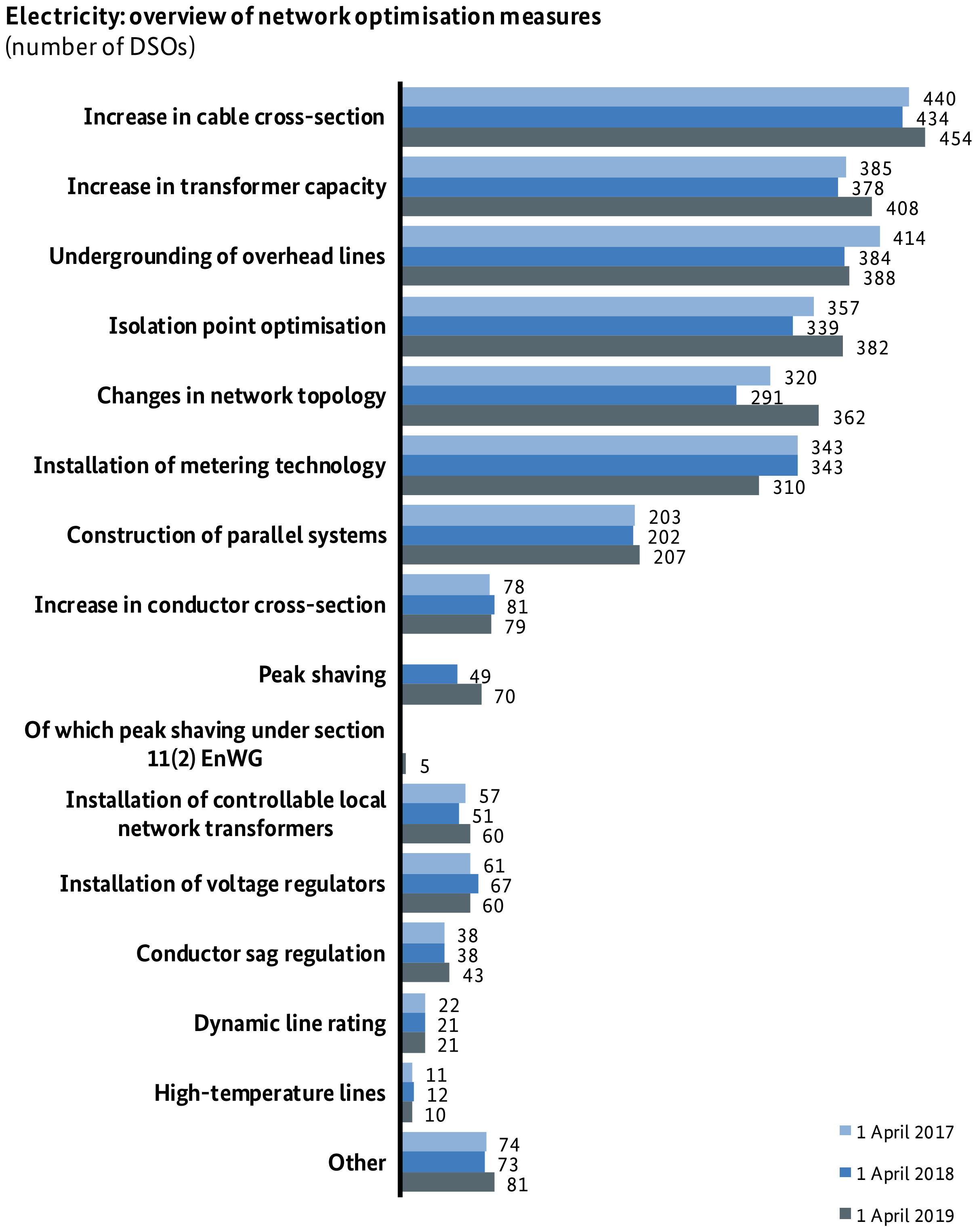

Figure 40: Overview of network optimisation measures

Figure 40 shows the measures implemented by the DSOs to optimise their networks. There were year-on-year decreases in particular in the number of measures to install voltage regulators (-7 DSOs). There was a slight rise in nearly all measures, in particular for increasing the cross-section of conductors, replacing overhead lines with underground cables, and installing metering technology. DSOs were asked for the first time for the 2018 monitoring whether they use peak shaving as a network optimisation measure. A total of 49 DSOs reported that they did; in the 2019 monitoring, the number of DSOs reporting that they used peak shaving as a network optimisation measure increased to 70[38].

2.2 Future grid expansion requirements

2.2.1 High-voltage network operators' expansion requirements

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

In this year's monitoring survey, 59 DSOs operating high-voltage networks were again asked to submit reports for the reporting year 2018 (up to 31 December 2018) so as to identify their expected grid expansion requirements for the next ten years. The reports submitted by the DSOs cover 98% of the total circuit length at high-voltage level, 69% at medium-voltage level and 65% at low-voltage level.

2.2.2 Total expansion requirements (all voltage levels)

The planned and ongoing grid expansion measures reported to the Bundesnetzagentur as at 31 December 2018 comprise a total investment volume of €13.74bn in the next ten years (2019-2029). The forecasts made by the large DSOs show another increase compared to the previous years. The increase in the investment total is mainly due to a rise in the expected grid expansion requirements at medium-voltage and low-voltage level.

Electricity: total grid expansion requirements of high-voltage network operators (€bn)

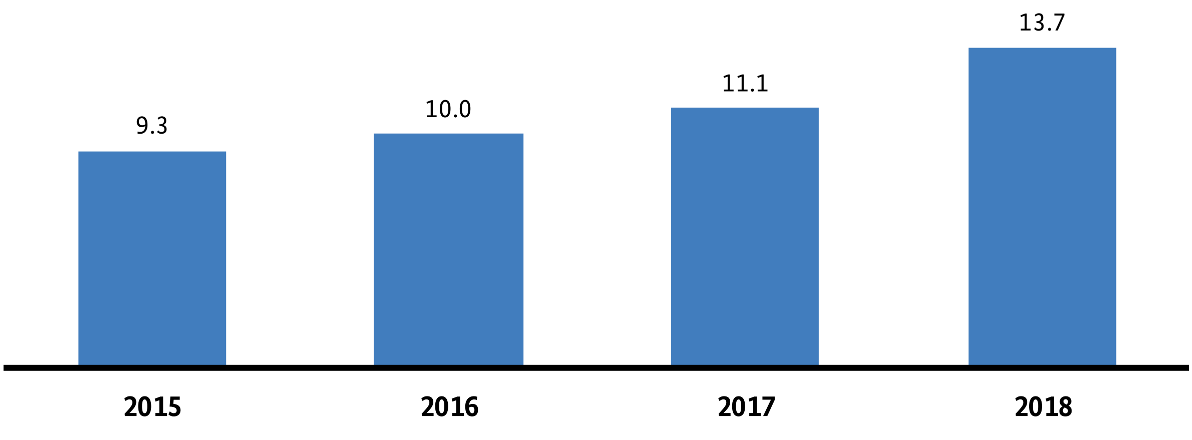

Figure 41: Total grid expansion requirements of high-voltage network operators

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

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[38] These figures for peak shaving cover not only measures under section 11(2) of the Energy Industry Act (EnWG), but all peak shaving measures. Five DSOs took measures under section 11(2) EnWG.

Electricity: grid expansion investment per DSO (all voltage levels) (€bn)

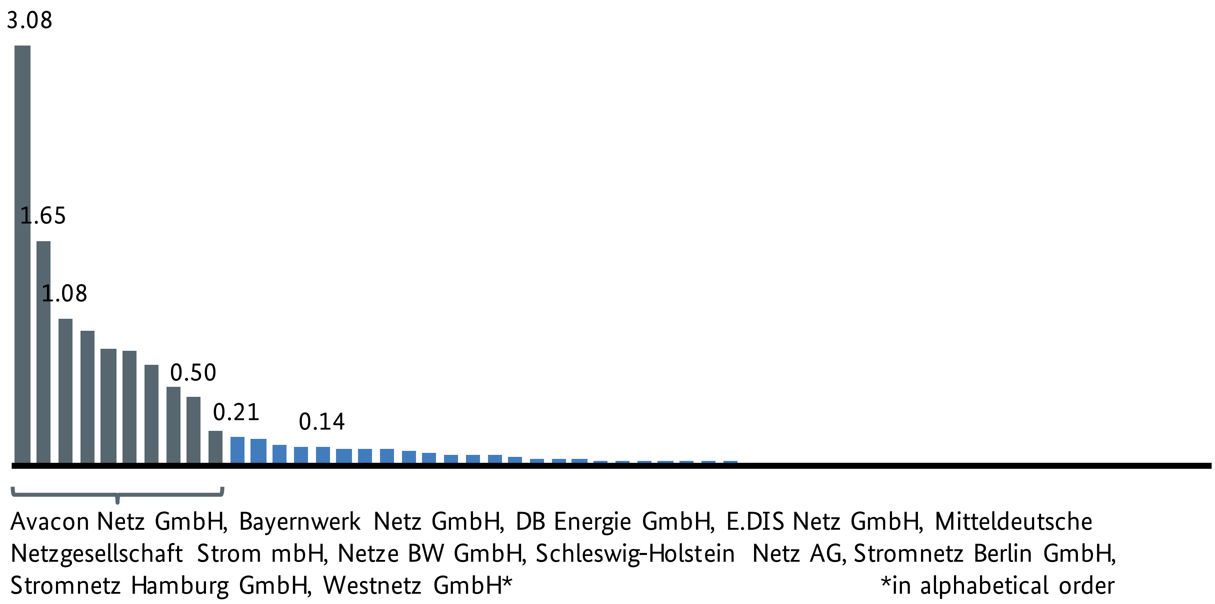

Figure 42: Grid expansion investment per DSO (all voltage levels)

Grid expansion requirements continue to be very varied.

A total of 17 DSOs forecast expansion measures comprising a volume of up to €10m in the next ten years. A further 23 DSOs forecast measures of up to €100m.

The remaining 19 DSOs forecast expansion measures comprising a high volume exceeding €100m. These 19 DSOs account for nearly 93% of the total forecast by all the DSOs. The ten 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, Netze BW GmbH, Schleswig-Holstein Netz AG, Stromnetz Berlin GmbH, Stromnetz Hamburg GmbH and Westnetz GmbH.

The forecasted grid expansion measures are necessary not only because of the growth in renewable energy and distributed generation, but to a large extent also because of restructuring and – in some cases age-related – replacement investments. Only 548 (370 as at 31 December 2017) of the 2,239 planned or ongoing measures reported are due in technical terms to the expansion in renewable energy installations. The growth in renewable energy thus accounts for around €2.6bn (31 December 2017: €1.76bn; 31 December 2016: €1.84bn) of the total planned investment volume of €13.74bn across all network and voltage levels in the distribution network.

The Bundesnetzagentur was notified of a total of 2,352 measures for the period up to 2029 (compared to 2,321 at the end of 2017, 2,089 at the end of 2016, and 1,984 at the end of 2015). At the time of the survey, 1,560 or 66% of these measures were still at the planning stage and 679 or 29% were in progress, while 66 or 3% had been completed by the beginning of 2019. A total of 47 measures (2%) originally planned for the period were no longer being followed. The figures represent a further increase in absolute terms in particular in the number of planned grid expansion measures.

Electricity: project status of total expansion requirements (all voltage levels)
(number and percentage)

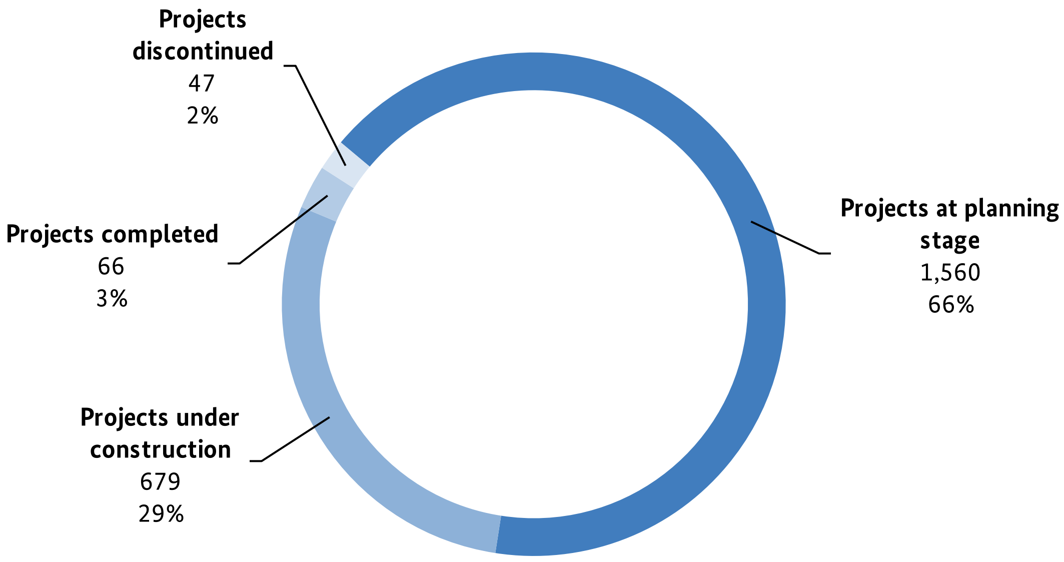

Figure 43: Project status of total expansion requirements (all voltage levels)

3. Investments

For the purposes of the monitoring survey, investments are defined as the gross additions to fixed assets capitalised in 2018 and the value of new fixed assets newly rented and hired in 2018. 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 balance sheets of the transmission system operators (TSOs) and distribution system operators (DSOs). 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).

3.1 Transmission system operators' investments and expenditure

In 2018, investments in and expenditure on network infrastructure by the four German TSOs amounted to approximately €3,366m, which is 9% more than the prior year's figure (2017: €3,094m). The difference between actual investments and expenditure in 2018 and the figure of €3,067m forecast in last year's monitoring survey is about €299m. The TSOs thus realised 110% of their planned investments and expenditure.

The individual categories for network infrastructure investments and expenditure are shown in Table 39:

Electricity: TSOs' network infrastructure investments and expenditure

	2017	2018
Investments (€m)	**2,707**	**2,954**
New build, upgrade and expansion projects other than for cross-border connections	1,971	2,123
New build, upgrade and expansion projects for cross-border connections	523	575
Maintenance and renewal excluding cross-border connections	213	249
Maintenance and renewal of cross-border connections	0	7
Expenditure (€m)	**387**	**413**
Expenditure excluding cross-border connections	383	408
Expenditure on cross-border connections	3	5
Total	**3,094**	**3,366**

Table 39: TSOs' network infrastructure investments and expenditure

Electricity: TSOs' network infrastructure investments and expenditure
(€m)

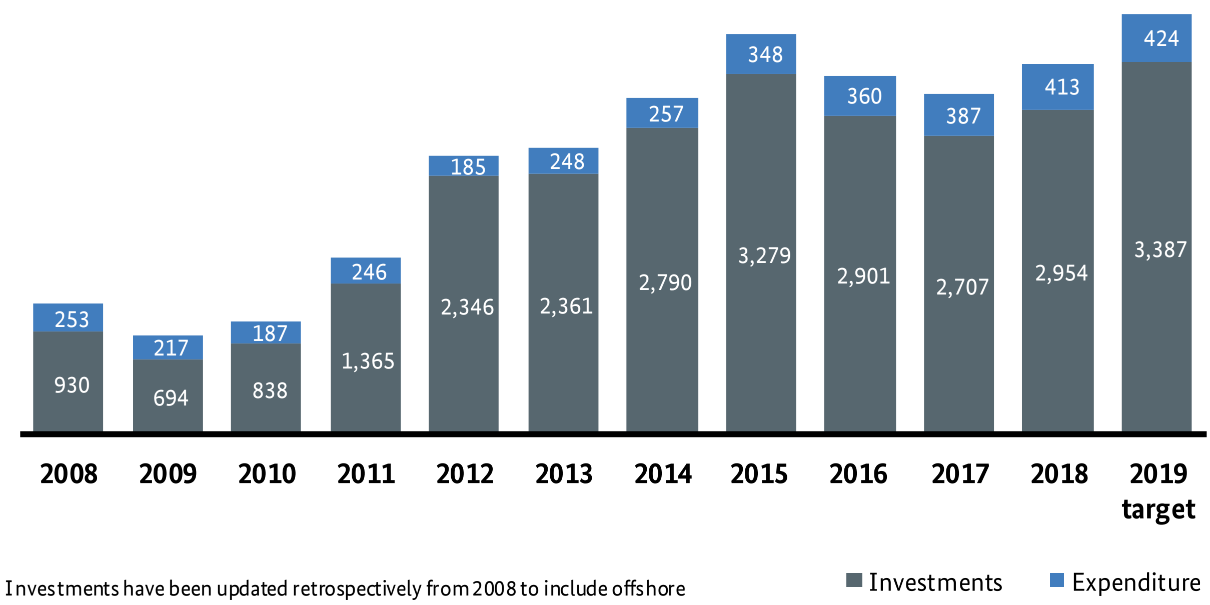

Figure 44: TSOs' network infrastructure investments and expenditure (including cross-border connections)

Total investments of around €3,387m and total expenditure of €424m are currently planned for 2019. The planned total for investments and expenditure of about €3,810m is higher than the total amount realised in previous years. Figure 44 shows the figures for investments, expenditure and cross-border connections since 2008 and the planned figures for 2019.

3.2 Distribution system operators' investments and expenditure

I n 2018, investments in and expenditure on network infrastructure by the 768 DSOs that provided data in the monitoring amounted to around €6,464m, down about 2% on the previous year's figure of €6,629m. Investments and expenditure for metering systems amounted to around €614m in 2018, compared to €575m in 2017. Detailed information on investments in metering systems can be found in I.H.7 „Metering investment and expenditure ". The planned total for investments and expenditure in 2019 is €6,860m. Figure 45 shows the figures for investments, expenditure and combined investments and expenditure since 2009 and the planned figures for 2019.

The two noticeable peaks of investment in 2011 and 2016 are likely to be related to the incentive regulation. Both years were used as base years that were decisive for the revenue that the DSOs were allowed to attain in the subsequent years. There was therefore an incentive to bring investments forward or postpone them for the base years.

Electricity: DSOs' network infrastructure investments and expenditure
(€m)

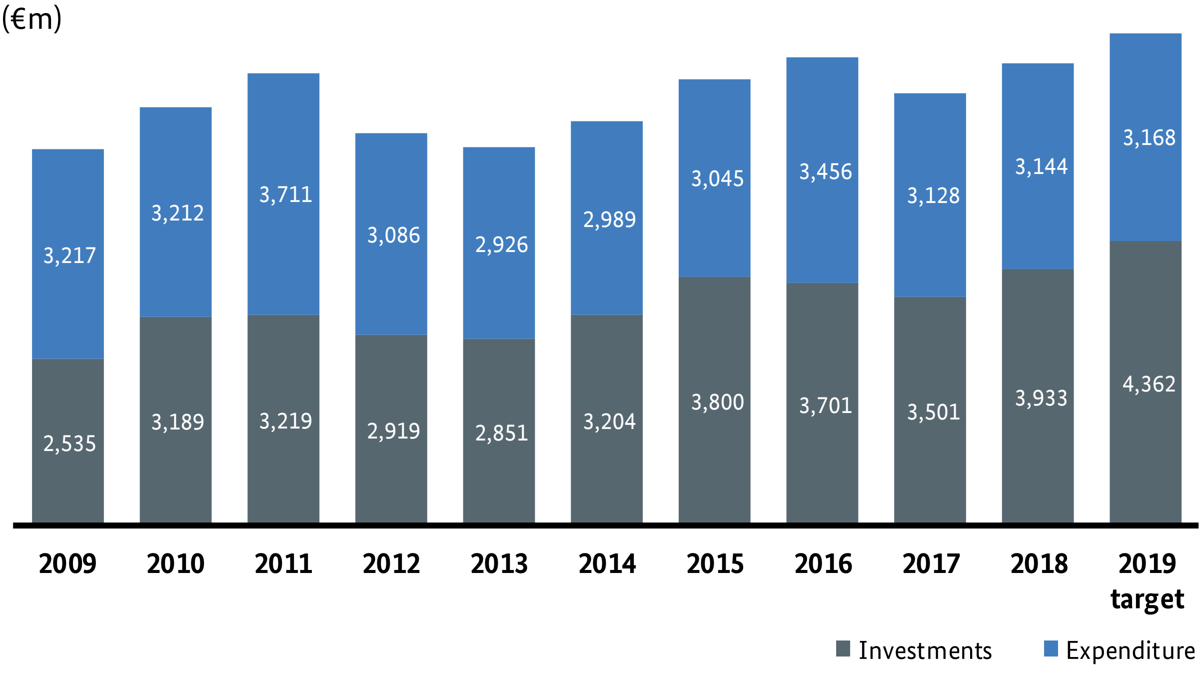

Figure 45: DSOs' network infrastructure investments and expenditure

The level of investment by DSOs depends on circuit lengths, the number of meter locations served, and other individual structural parameters, including in particular geographical factors. DSOs with longer circuits tend to have higher investments. A total of 118 or 15% of the DSOs are in the €0-€100,000 investment category. A total of 79 or around 10% of the DSOs are in the top category with investments exceeding €5m per network area. About 64% of the total investments are made by the 20 network operators with the greatest investments. Figure 46 shows the percentage of DSOs in each investment category:

Electricity: DSOs by investment in 2018
(%)

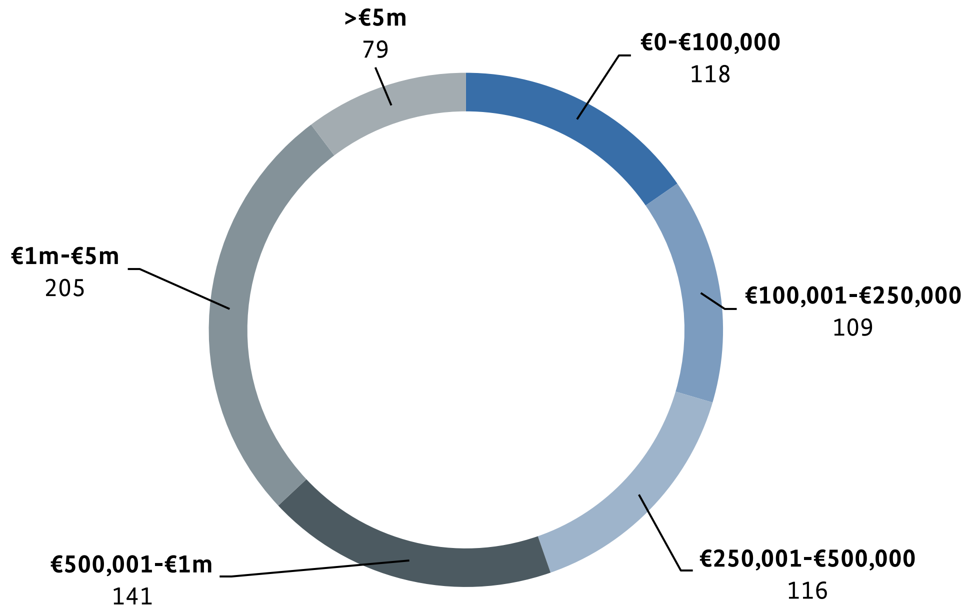

Figure 46: DSOs by investment amounts

Electricity: DSOs by expenditure in 2018
(%)

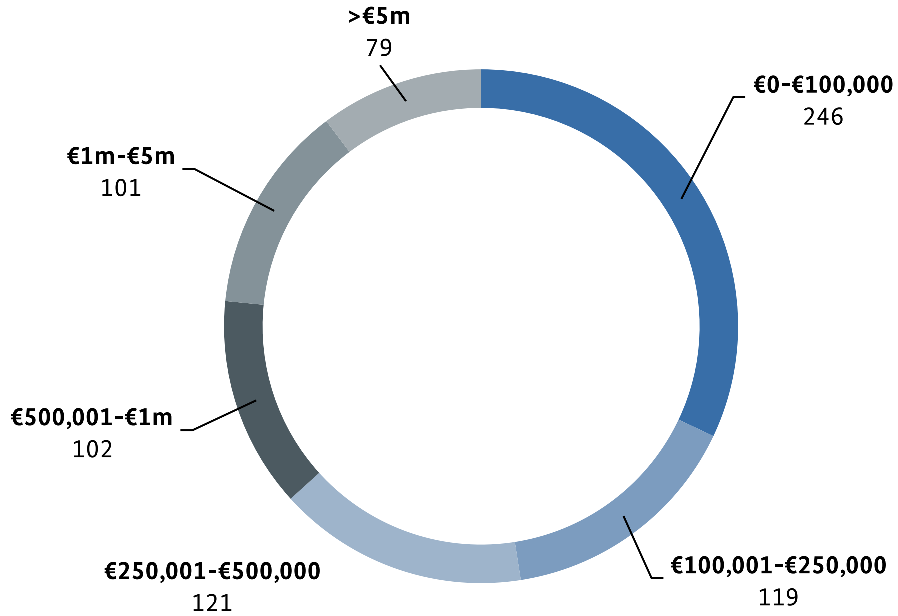

Figure 47: DSOs by expenditure amounts

A total of 246 or 32% of the DSOs are in the €0-€100,000 expenditure category; 79 or 10% of the DSOs are in the category with expenditure exceeding €5m. As can be seen in Figure 47, in 2018 about half of the DSOs – 52% – recorded network expenditure exceeding €250,000.

3.3 Investments and incentive regulation

The ARegV 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. Based on section 23 ARegV, upon application the Bundesnetzagentur grants approval for individual projects if the prerequisites stated in the ARegV have been met. Once approval has been given, TSOs may adjust their revenue caps by the operating and capital expenditure associated with their project immediately in the year in which the costs are incurred. The costs budgeted are checked by the Bundesnetzagentur in an ex-post control.

3.3.1 Expansion investments by TSOs

As of 31 March 2019, 41 new applications for investment projects have been submitted by TSOs to the competent Ruling Chamber. Costs of acquisition and production of about €18.27bn are linked to these investment measures. Compared to 2018, the number of applications submitted by the TSOs has increased slightly, while the costs linked to the projects applied for has more than doubled.

3.3.2 Expansion factor for DSOs

Under section 4(4) para 1 in conjunction with section 10 ARegV, electricity DSOs were able to 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" until the end of the second regulatory period in 2018. Such applications had to be made by 30 June each year, so the last deadline was 30 June 2017. The adjustment made took effect on 1 January of the following year.

The expansion factor ensured 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.

Overall, the adjustments made to the revenue caps for 2018 on the basis of expansion factors amounted to €416.5m. The adjustments resulted from 135 applications relating to the revenue caps for 2018, 99 of which were submitted by the deadline of 30 June 2017 and 36 in previous years.

As a result of the 2016 revision of the ARegV, the expansion factor (cf section 34(7) ARegV) is no longer used as from the third regulatory period and has been replaced by the adjustment of capital expenditure. Furthermore, it is no longer possible for DSOs to apply for investment measures under section 23 ARegV, as these also come under the adjustment of capital expenditure.

3.3.3 Capital expenditure mark-up and monitoring of the adjustment of capital expenditure

The Bundesnetzagentur introduced the capex mark-up for electricity distribution networks for the first time as from 1 January 2019. DSOs are able to apply for mark-ups on the revenue cap approved by the Bundesnetzagentur to directly take account of network infrastructure investments.

The revenue caps cover all network costs plus a return on equity, which companies may pass on to consumers through the network charges. The capex mark-up is essentially a form of pre-financing, since it enables companies to price in planned investments.

By 31 December 2018, the Bundesnetzagentur had approved capex mark-ups for distribution network expansion amounting to around €891m. This corresponds to past or planned investments totalling some €10.4bn. Through the capex mark-up, only the annual capital costs of investments, including a return on equity, feed into the revenue caps for a given calendar year.

The approved capex mark-ups relate to past or planned investments in 2017, 2018 and 2019. The capex mark-ups approved by the Bundesnetzagentur are supplemented by further investments of the 700 smaller companies under the regulatory responsibility of the federal states.

As at 30 June 2019, the Bundesnetzagentur had received 170 applications for capex mark-up approvals for 2020 (107 under the Bundesnetzagentur's own responsibility and 63 under delegated responsibility).

3.4 Rates of return for capital stock

Investments in electricity and gas networks are extremely capital-intensive. The capital stock formed provides the key assessment basis for calculating the corporate gain, the return on equity and any interest on debt necessary through equity substitution, and the imputed corporate tax. Together with the imputed depreciation, these figures form what is known as the regulatory allowed capital costs.

Rate of return on equity

The assessment basis for the capital costs is essentially determined by the costs of acquisition and production, or the depreciable residual values, of the regulatory asset base (RAB). The cost of equity is obtained by adding the necessary current assets and deducting the borrowed capital. The rate of return on equity is determined on the basis of a risk-free base rate supplemented by a risk premium. The risk-entailing return on securities in the market balance can be expected to be derived from the sum of the risk-free return and the risk premium (capital asset pricing model – CAPM). The risk premium is the product of the market price for the risk (market risk premium) and the risk that cannot be eliminated by diversification compared with the market as a whole (beta).

The level of the rate of return on equity is a key figure in regulated markets. The first chart below shows the regulatory rates of return on equity allowed under the ARegV or through actual determinations.

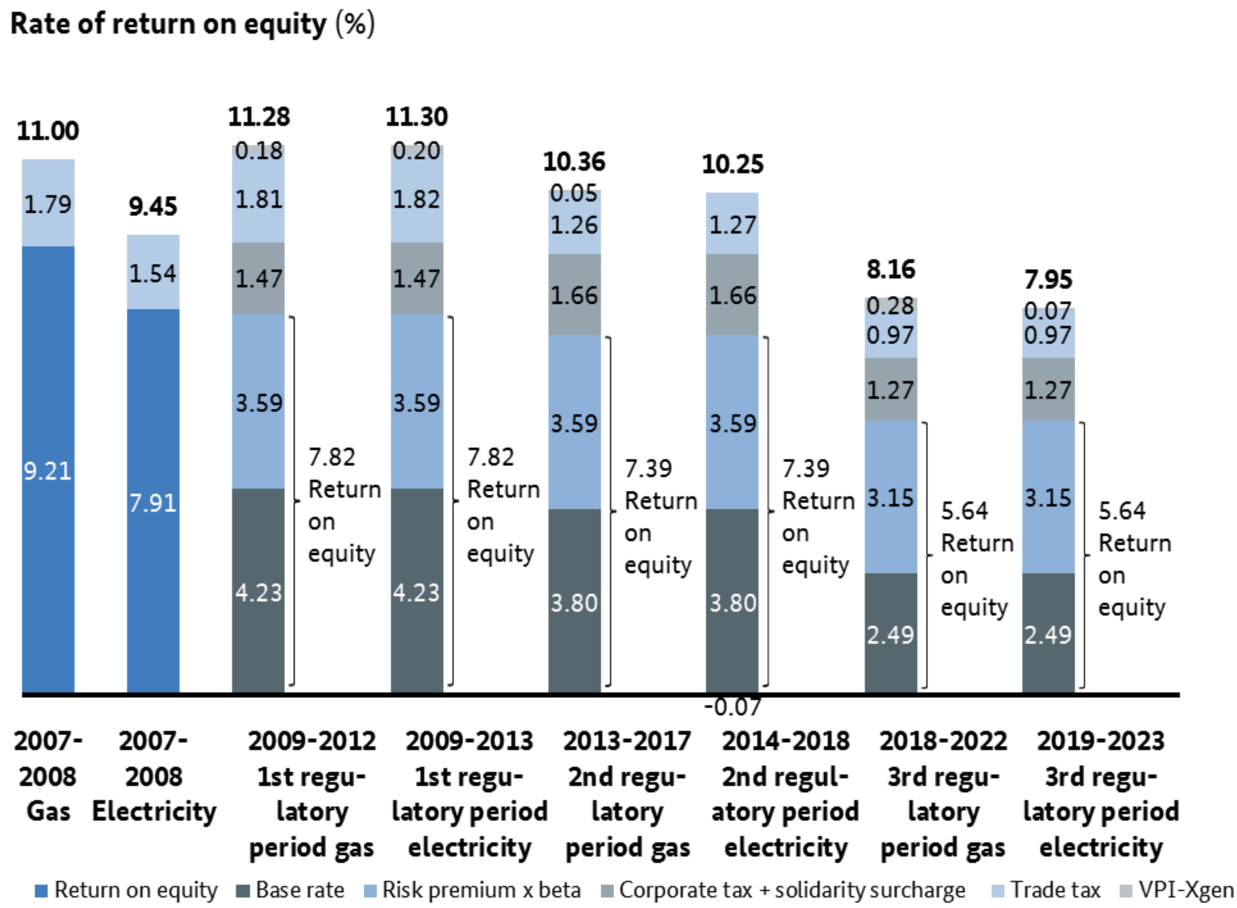

Figure 48: Rate of return on equity

The second chart compares these changes in the return on equity with a presumed annual result that would have been achieved if the input parameters had been calculated (ex post) for each individual year. The figures show the rate of return on equity (comprising the base rate and the risk premium) and the regulatory allowed corporate tax, trade tax and indexation (VPI-XGen).

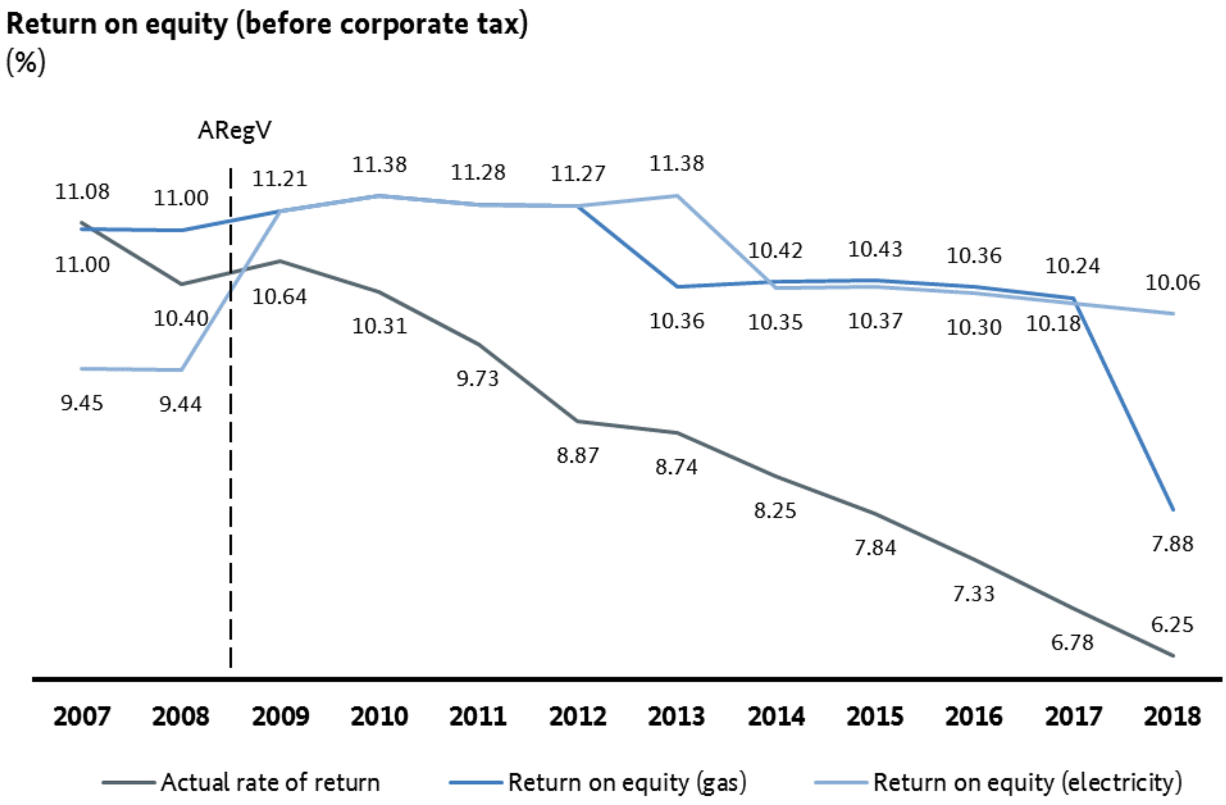

Figure 49: Return on equity (before corporate tax)

4. Electricity supply disruptions

The System Average Interruption Duration Index – $SAIDI_{EnWG}$ is the average length of supply interruption experienced by each customer in a year in the low and medium-voltage level, and is calculated from the reports of network operators about the interruptions that occurred in their network area. The $SAIDI_{EnWG}$ for 2018 is 13,91 minutes.

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

The System Average Interruption Duration Index value ($SAIDI_{EnWG}$[39]) does not take into account planned interruptions or those which occur owing to force majeure, for instance natural disasters. Only unplanned interruptions caused by atmospheric effects, third-party intervention, ripple effects from other networks or other disturbances in the network operator's area are included in the calculations.

For the year 2018, 866 operators reported 167,400 interruptions in supply for 872 networks for the calculation of the $SAIDI_{EnWG}$. The figure of 13.91 minutes calculated for the low-voltage and medium-voltage levels is below the average from 2006 to 2017 of 15.56 minutes per year. The quality of supply thus remained at a consistently high level in 2018.

Electricity: supply interruptions under section 52 EnWG (minutes)

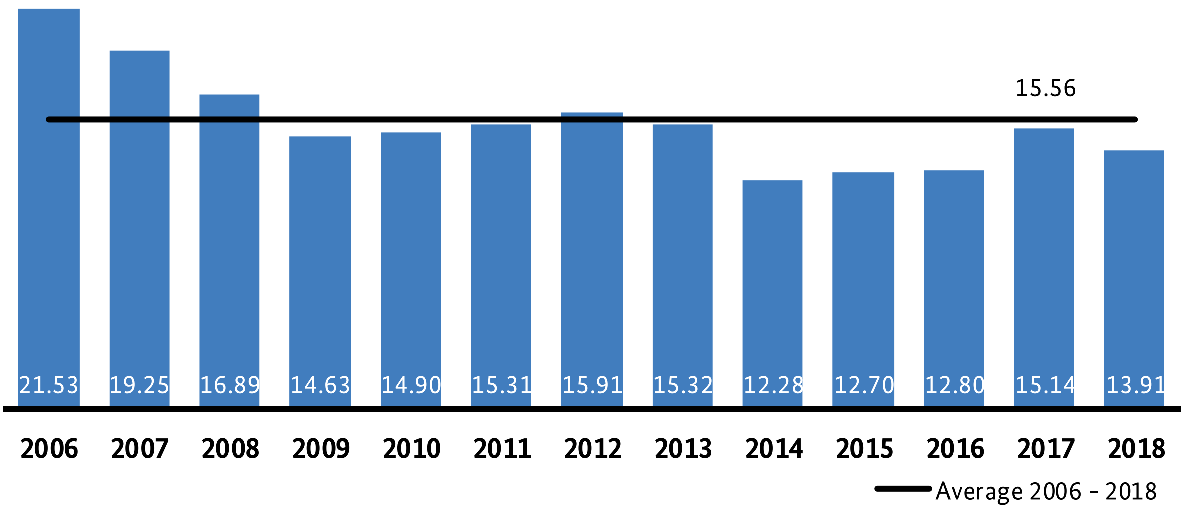

Figure 50: $SAIDI_{EnWG}$ from 2006 to 2018

The decrease in the average interruption duration is due to a decrease of 1.35 minutes to 11.57 minutes at the medium-voltage level. Last year's $SAIDI_{EnWG}$ registered a slight rise, of 0.12 minutes, to 2.35 minutes at the low-voltage level.

[39] The System Average Interruption Duration Index $SAIDI_{EnWG}$ differs from the index $SAIDI_{ARegV}$ calculated for each individual company for the quality management pursuant to the Incentive Regulation Ordinance (ARegV).

Electricity: supply interruptions under section 52 EnWG by network level (minutes)

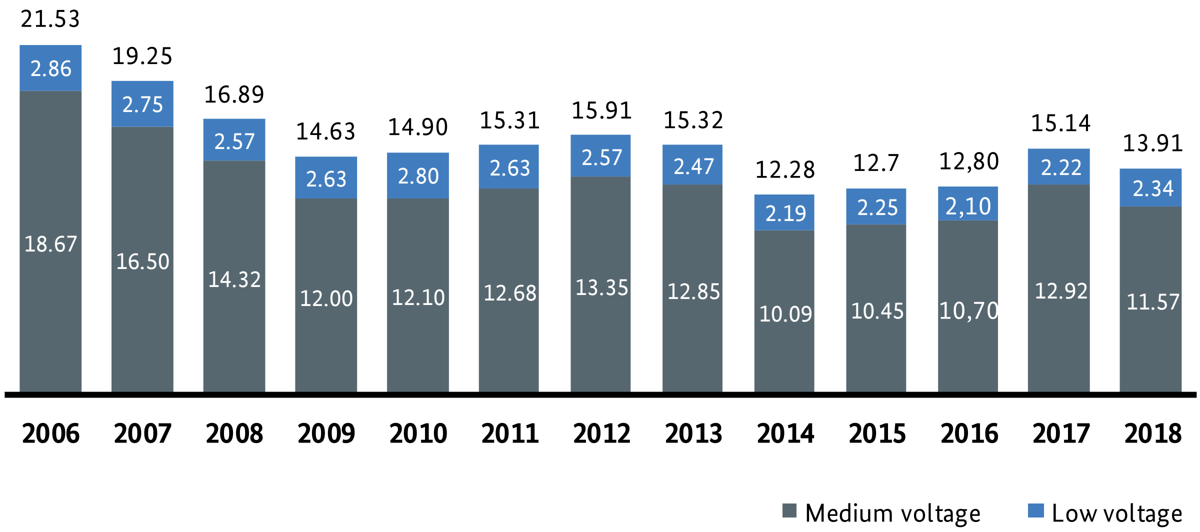

Figure 51: $SAIDI_{EnWG}$ at low-voltage and medium-voltage level from 2006 to 2018

The decrease in the $SAIDI_{EnWG}$ figure is mainly accounted for by the supply interruptions due to ripple effects at the medium-voltage level and atmospheric effects at the low-voltage and medium-voltage levels.

Ripple effects 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.

Atmospheric effects refers to interruptions caused by meteorological phenomena such as thunder, storms, ice, flooding, etc.

There were fewer outage times brought about by extreme weather conditions in 2018 than there were in 2017.

The energy transition and the associated growth in more distributed and smaller-scale generation far from load centres again do not appear to have had a significant impact on the quality of supply in 2018.

In 2017, a total of 166,560 supply interruptions were reported, but the figure was slightly higher in 2018. Despite a small increase of slightly more than 800 interruptions, the average duration decreased.

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 of renewable energy and combined heat and power (CHP) electricity at the network operator's request with compensation being paid. The curtailing of renewable generation requires a simultaneous increase in generation at another, compatible point in the network for physical balancing. These volumes are still usually balanced by the balance responsible party. However, as with redispatching, economic balancing can be carried out by the network operator as well. As from 1 October 2021 balancing by the requesting network operator will become compulsory. Balancing can lead to costs and revenues (for example due to imbalance payments) for the balance responsible party. The Bundesnetzagentur takes the view that these costs or revenues must be taken into consideration in the feed-in management compensation and are partially included in the specified estimated claims for compensation. The Bundesnetzagentur does not have data on the volumes of energy used for balancing.

- Adjustment measures: adjusting electricity feed-in and/or offtake at the network operator's request without compensation, where other measures are insufficient.

These network and system security measures are reported to the Bundesnetzagentur.

The following tables summarise the regulatory content, primary mechanisms and scope of measures (redispatching with operational and grid reserve power plants, feed-in management and adjustment measures) in 2018. They contain updated values for redispatching that may differ from the figures for 2018 published in the quarterly reports 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 the full year 2018 in the quarterly report.

Electricity: network and system security measures under section 13 of the Energy Industry Act (EnWG) in 2018

	Redispatching	Feed-in management	Adjustment measures
Legal basis and regulatory content	Sections 13(1), 13a(1) and 13b(4) EnWG Network-related and market-related measures: topological measures such as balancing energy, interruptible loads, redispatching, countertrading, use of grid reserve	Section 13(2) and (3) sentence 3 EnWG in conjunction with sections 14 and 15 EEG, for CHP installations in conjunction with section 3(1) sentence 3 KWKG Feed-in management: reduction in feed-in from renewable energy, mine gas and CHP installations	Section 13(2) EnWG 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: sections 13(1), 13a(1) and 13c EnWG	Measures at network operator's request with reimbursement of costs: section 13(2) and (3) sentence 3 in conjunction with sections 14 and 15 EEG, for CHP	Measures at network operator's request without reimbursement of costs: section 13(2) EnWG
Scope in reporting period	Total redispatching volume, increases and reductions of operational power plants, and increase of reserve power plants (not including test starts and test runs): **15,529 GWh**	Curtailed energy of installations remunerated under EEG (TSOs and DSOs): **5,403 GWh**	Curtailed volume from adjustment measures (TSOs and DSOs): **8.3 GWh**
Estimated costs in reporting period	Preliminary cost estimate for redispatching, countertrading, and use and contracting of grid reserve power plants: **€803.0m**	Preliminary estimated claims for compensation from installation operators under section 15 EEG (TSOs and DSOs): **€635.4m**	No entitlement to compensation for installation operators for adjustment measures under section 13(2) EnWG

Table 40: Network and system security measures under section 13 of the Energy Industry Act (EnWG) in 2018

Electricity: network and system security measures

		2016	2017	2018
Redispatching				
Total volume[1] of operational plants	GWh	11,475	18,456	14,875
Cost estimate[2] for redispatching	€m	223	392	352
Cost estimate for countertrading	€m	12	29	36
Grid reserve power plants				
Volume[3]	GWh	1,209	2,129	904
Cost estimate for activation	€m	103	184	85
Capacity[4]	MW	8,383	11,430	6,598
Annual costs of holding in reserve[5]	€m	183	296	330
Feed-in management				
Menge Ausfallarbeit[6]	in GWh	3,743	5,518	5,403
Schätzung Entschädigungen	in Mio. Euro	373	610	635
Feed-in adjustments				
Volume	GWh	4	35	8

[1] Amounts (reductions and increases) including countertrading and remedial action measures according to monthly report to the Bundesnetzagentur.
[2] TSOs' cost estimate based on actual measures including costs for remedial action measures.
[3] Activation of grid reserve power plants including test starts and test runs. The feed-in of grid reserve power plants is only increased.
[4] Total capacity of German and foreign grid reserve power plants in MW. As at 31 December of the respective year.
[5] Plus other costs not dependent on deployment.
[6] Reduction of installations remunerated in accordance with the EEG or KWKG.

Table 41: Overview of network and system security measures for the years 2016 to 2018

5.1 Overall development of redispatching in 2018

Section 13(1) of the Energy Industry Act (EnWG) entitles and obliges transmission system operators (TSOs) to remove threats or disruptions to the electricity supply system by taking network-related and market-related measures. Insofar as distribution system operators (DSOs) are responsible for the security and reliability of the electricity supply in their networks, these too are both authorised and required to implement such measures as set out in section 14(1) EnWG.

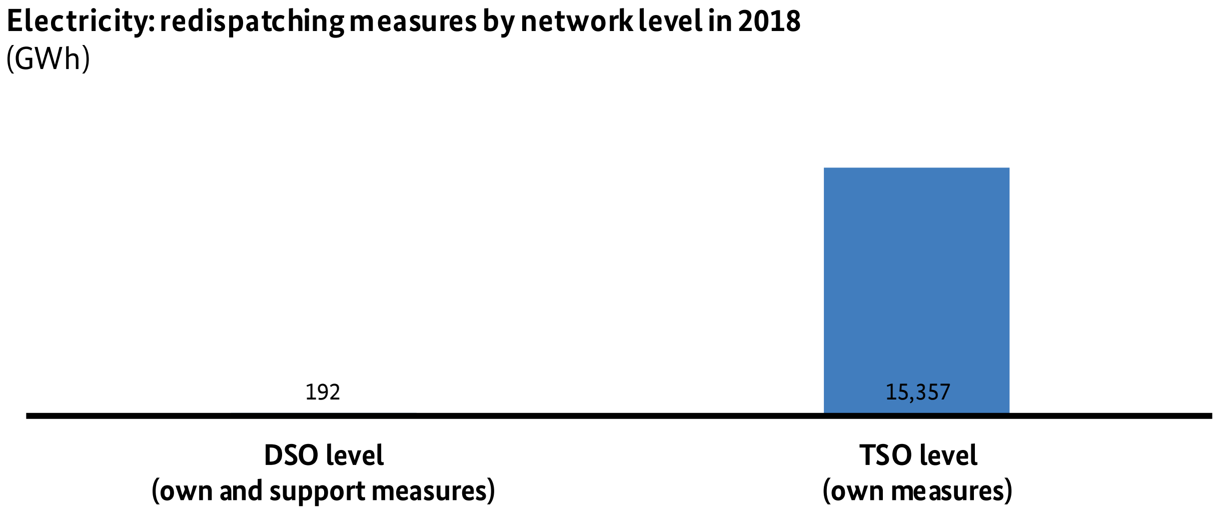

Figure 52: Redispatching measures by network level in 2018

Figure 52 shows that the majority of the redispatching measures were taken by the TSOs. Out of the total of around 192 GWh at DSO level, a sum of about 21 GWh is accounted for by DSOs' own measures requested by a total of 20 DSOs.

The following figures, tables and descriptions therefore relate to redispatching by the TSOs, as covered in the Bundesnetzagentur's quarterly reports.

Network-related measures, most notably topological measures, are taken 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. 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 secure and reliable operation of the electricity supply networks. The aim is either to prevent or relieve overloading of power lines. 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, for example, 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 2018.

In 2018, total reductions in feed-in amounted to 7,919 GWh, increases in feed-in from operational plants totalled 6,956 GWh and the use of reserve power plants accounted for 654 GWh. Overall, a total of 15,529 GWh of reductions and increases in feed-in was requested. In 2018, redispatching measures were taken on a total of 354 days.

The volume requested fell year-on-year by 24% (2017: 20,439 GWh). In 2017, in particular the unusual load flows in the first quarter that were due to various factors had led to a high need for redispatching measures. In the fourth quarter of 2017, the strain on the networks was already beginning to ease due to the commissioning of the "Thuringia power bridge". From the third quarter of 2018, however, there was another increase in redispatched volumes; one particular reason was the introduction at the end of April 2018 of the MinRAM process for flow-based capacity calculation in the CWE region. This methodology involves taking account of a standard minimum capacity of 20% per line in the capacity calculation. This increases the need for redispatching measures and is only partly compensated by the congestion management scheme introduced at the border with Austria as from 1 October 2018.

An initial estimate by the TSOs puts the costs for the operational plants for the whole of the year 2018 at around €351.5m (without countertrading costs [see I.C.5.1.3]) and thus lower than the costs for the whole of the year 2017 (€391.6m).

There are various steps to operation redispatch planning. This report makes a distinction between individual overloading measures that can be attributed to a network element and measures taken by the four TSOs together ("4-TSO process"). In the latter, the four TSOs use model calculations to carry out joint planning of redispatching at an early stage.

Since 2017, the 4-TSO measures have been reported to the Bundesnetzagentur, enabling a distinction to be made between the types of measure. In addition, detailed information on the deployment of power plants in redispatching is reported. In the whole of 2018, around 70% of redispatching measures were individual overloading measures, while 30% were 4-TSO measures.

5.1.1 Advance measures by the four TSOs

The joint requests by all four TSOs are based on modelling results carried out both before and after the market outcome for the whole of Germany. It is necessary to optimise the planning of which plants to deploy for redispatching at an early stage so that grid reserve power plants that take longer to start up can be requested in good time. The joint modelling also improves coordination between the TSOs, so it may be assumed that the power plants used can be selected efficiently. The calculations show both the requests for grid reserve power plants and planning for the use of operational plants, which are requested once the market outcome is available.

A total of 2,483 GWh was curtailed and 2,192 GWh increased on the basis of advance measures by the four TSOs (4,675 GWh overall). These measures make up 30% of the total redispatching and grid reserve volume. Only electricity-related 4-TSO redispatching measures were reported.

Most measures are electricity-related redispatching (92.8%), with just 7.2% coming under voltage-related measures.[40]

According to the TSOs, it is not possible to allocate the volumes of measures requested jointly to individual network elements that cause them. The current reports only enable conclusions to be drawn about the cause of 4-TSO measures at the aggregated level of network groups. They show that the network groups that trigger the majority of advance measures by the four TSOs are also the ones where the network elements shown under I.C.5.1.2 are located.

5.1.2 Individual overloading measures

The volume of reductions in feed-in through individual overloading measures in the whole of 2018 amounted to around 5,436 GWh. Increases in feed-in for balancing were around 5,418 GWh. Therefore the total volume of these redispatching measures (reductions and increases in feed-in) for the whole of 2018 was approximately 10,854 GWh, which represents a decrease of 25% compared to 2017.

In the whole of 2018, the Bundesnetzagentur received reports of electricity-related and voltage-related redispatching through individual overloading measures totalling about 12,154 hours. Since all measures taken to ease restrictions in the network, including 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.

Electricity: redispatching measures: individual overloading measures in 2018

Control area	Duration (hours)	Volume of feed-in reductions (GWh)	Total volume (feed-in reductions and increases) (GWh)
TenneT	9,606	4,514	9,030
50Hertz	353	171	343
TransnetBW	975	237	458
Amprion	1,220	514	1023
Total	12,154	5,436	10,854

[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.

Table 42: Redispatching: individual overloading measures in 2018

[40] See also I.C.5.1.2 for further explanations on the difference between electricity-related and voltage-related redispatching.

Electricity-related individual overloading measures

In 2018, 90% of the individual overloading measures were electricity-related. As can be seen in Table 43, the most heavily loaded network elements for electricity-related individual overloading measures in 2018 were the lines between Dörpen and Hanekenfähr, in the Altheim area at the border with Austria, and between Mecklar and Großkrotzenburg.

The power lines between Dörpen and Hanekenfähr require a very high degree of redispatching (reductions in feed-in: 624 GWh in 2018; 556 GWh in 2017) as they are used to transport the electricity generated by the offshore wind farms and the conventional power plants in the north-west. One of the reasons for the increase in reductions in feed-in is that offshore capacity (Borkum Riffgrund II in 2018) connected to the grid at Dörpen has increased without conventional generating capacity in the region decreasing.

Overloading on the line between Mecklar and Großkrotzenburg increased in 2018 (total reductions in feed-in: 617 GWh in 2018; 77 GWh in 2017). According to the TSOs, there was a general shift in the restrictions in the regions south of the Elbe river.

The lines in the Altheim area at the border with Austria were already heavily overloaded in 2017 (reductions in feed-in in 2017: 489 GWh), and the overloading continued to increase in 2018 (reductions in feed-in in 2018: 884 GWh). The majority of the measures were taken in the third quarter of the year (591 GWh); in the fourth quarter, the congestion management scheme with Austria had the effect of alleviating the restrictions (160 GWh).

In a year-on-year comparison, the line between Remptendorf and Redwitz, which caused reductions in feed-in amounting to 2,455 GWh in 2017, is noteworthy. This volume decreased to 2.3 GWh in 2018 due to the commissioning of the "Thuringia power bridge". In Schleswig-Holstein, the reinforcement of the electricity node at the Brunsbüttel transformer station increased the transmission capacity between Schleswig-Holstein and Hamburg, leading to a further decrease in measures through this previously heavily loaded network element (reported reductions in feed-in through the network element Brunsbüttel-Brunsbüttel: none in 2018; 600 GWh in 2017). Overall, grid expansion greatly reduces the need for redispatching, but in an interconnected network there are always shifts in restrictions, which may increase overloading on other network elements.

The numbering of the network elements in Table 43 and Table 44 should not be understood as a ranking, since the volumes would be listed differently if the 4-TSO advance measures, which are not shown in the tables, were included. Rather, the numbers serve to identify the network elements on the map (Figure 53), which shows the location of the critical network elements from the tables (at least 12 hours per line and a reduction in feed-in greater than 20 GWh).

Electricity: electricity-related redispatching on the most heavily affected network elements in 2018

No	Network element	Control area[1]	Duratio n (hours)	Volume of feed-in reductions (GWh)	Volume of feed-in increases (GWh)
1	Dörpen area (Dörpen-Niederlangen-Meppen-Hanekenfähr)	TenneT/ Amprion	1,344	624	606
2	Altheim area (Altheim-Sittling. Altheim-Simbach-Sankt Peter (AT))	TenneT	994	884	884
3	Dipperz-Großkrotzenburg	TenneT	578	407	405
4	Landesbergen area (Landesbergen-Wechold-Sottrum. Landesbergen-Sottrum)	TenneT	509	317	316
5	Mecklar-Dipperz	TenneT	329	210	210
6	Dollern-Wilster	TenneT	323	161	160
7	Borken-Gießen-Karben/Dillenburg/Asslar area	TenneT	267	165	165
8	Daxlanden area (Daxlanden-Maximiliansau-Goldgrund. Daxlanden-Weingarten)	TransnetBW /Amprion	256	72	80

[1] 1 The first control area denotes the TSO reporting the redispatching measure to the Bundesnetzagentur.

Table 43: Electricity-related redispatching on the most heavily affected network elements in 2018

Electricity: Electricity-related redispatching on the most heavily affected network elements: 2018

No	Network element	Control area[1]	Duration (hours)	Volume of feed-in reductions (GWh)	Volume of feed-in increases (GWh)
9	Pleinting - Sankt Peter/APG	TenneT	183	141	141
10	Ovenstädt-Bechterdissen area (Ovenstädt-Eickum-Bechterdissen)	TenneT	156	117	112
11	Etzenricht - Mechlenreuth - Redwitz	TenneT	139	94	94
12	Mecklar - Eisenach line	Tennet/ 50Hertz	133	64	64
13	Kriegenbrunn-Redwitz	TenneT	133	76	75
14	Oberzier-Sechtem-Paffendorf area (Sechtem south/north line)	Amprion	110	69	69
15	Lehrte area (Lehrte-Godenau. Godenau-Erzhausen-Hardegsen-Göttingen)	TenneT	108	23	23
16	Helmstedt - Wolmirstedt	50Hertz/ Tennet	87	93	93
17	220 kV circuit Ludersheim - Sittling	TenneT	72	62	62
18	380 kV circuit Stadorf - Krümmel	TenneT	68	41	41
19	220 kV circuit Maade - Voslapp	TenneT	60	58	57
20	Rommerskirchen-Paffendorf area (Paffendorf south/north)	Amprion	60	29	29
21	Stalldorf area (Kupferzell-Stalldorf. Grafen-rheinfeld-Stalldorf. Grafenrheinfeld-Hoepfingen)	TransnetBW	55	32	26
22	Landesbergen-Ovenstädt	TenneT	55	21	20

[1] The first control area denotes the TSO reporting the redispatching measure to the Bundesnetzagentur.

Table 44: (continuation of Table 43)Electricity-related redispatching on the most heavily affected network elements in 2018

Electricity: duration of electricity-related redispatching measures in cases of individual overloading of the most heavily affected network elements in 2018

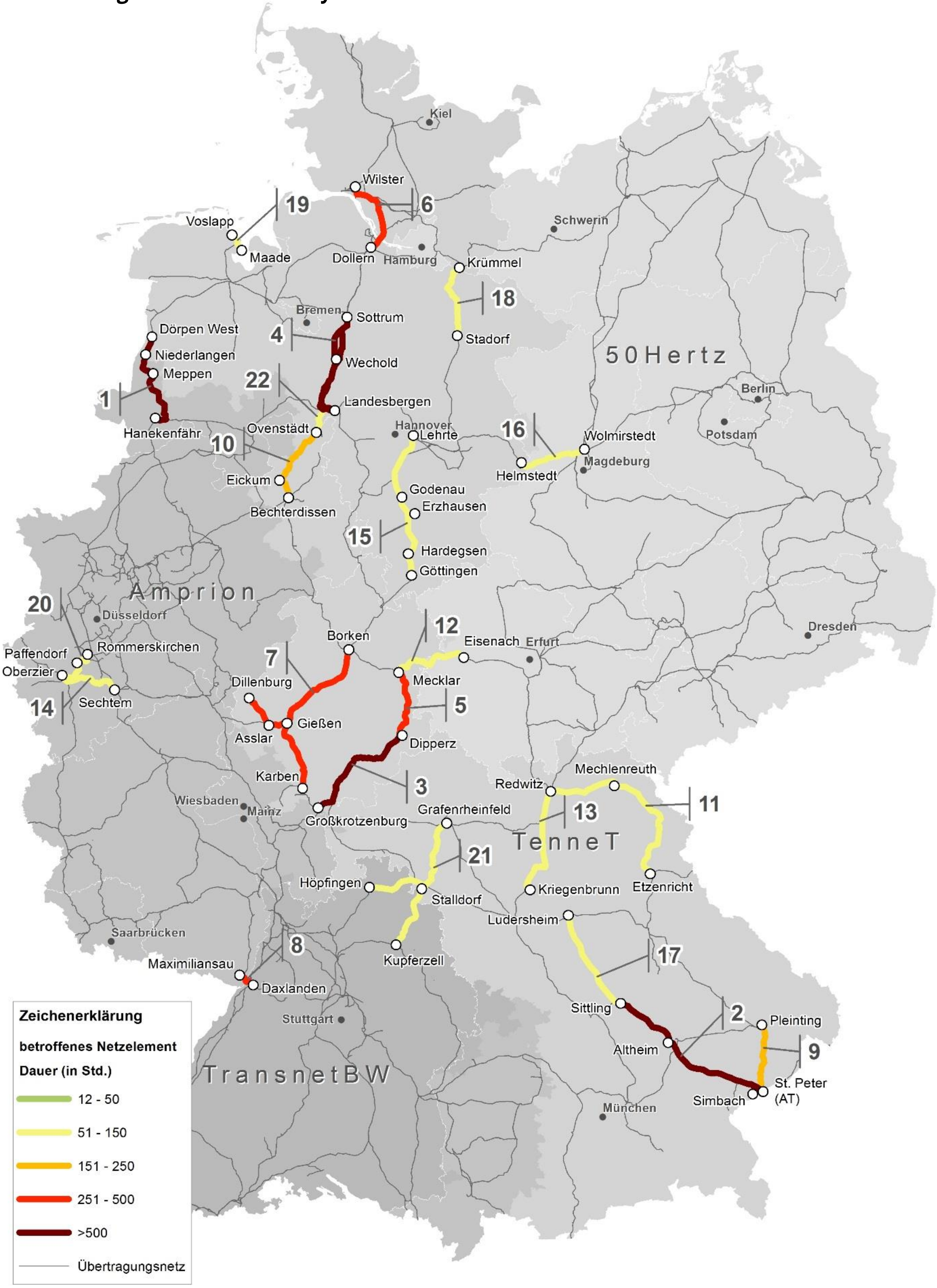

Figure 53: Duration of electricity-related redispatching measures in cases of individual overloading of the most heavily affected network elements according to TSO reports in 2018

Voltage-related individual overloading measures

In addition to electricity-related redispatching, the TSOs reported voltage-related redispatching measures totalling 2,340 hours and a volume of around 561 GWh in 2018. Voltage-related measures are balanced by counter trades on the exchange. The need for voltage-related redispatching measures in 2018 was broadly unchanged from the previous year (2017: 569 GWh). There was a decrease of 351 hours in duration compared to the whole of the previous year (2017: 2,691 hours).

The TSOs report that there is generally a greater need for voltage-related redispatching in the summer months than in the winter. This can be seen in the figures for the whole of 2018, which show that voltage-related redispatching was high in particular in the second quarter of the year.

It is usually the case that the lower load in summer leads to a greater need for reactive power in order to keep within the upper voltage limits in the networks. As well as conventional generating installations, network equipment such as phase shifters can also provide reactive power. However, currently it is mostly provided by conventional generating installations. During the summer and especially at weekends, some conventional power plants are not available on the market because of the low demand for electricity, so their provision of reactive power has to be achieved via redispatching.

Table 45 shows the duration and volume of the measures required in the individual control and network areas.[41]

[41] No overview map has been provided for practical reasons, since voltage-related redispatching takes place across larger network regions, and not in individual lines or transformer stations.

Electricity: voltage-related redispatching in 2018[1]

Network area	Duration (hours)	Volume (GWh)
TenneT control area: northern network area	**56**	**10**
Conneforde network area	56	10
TenneT: central network area	**1,702**	**417**
Ovenstädt-Bechterdissen-Borken	354	64
Borken (Borken-Dipperz-Großkrotzenburg. Gießen. Karben) network area	1,342	353
Mehrum-Grohnde-Borken network area	6	<1
TenneT control area: southern network area	**43**	**5**
Oberbayern network area	43	5
TransnetBW control area	**529**	**127**
Altbach. Wendlingen. Daxlanden area	529	127
50Hertz control area	**16**	**2**

[1] Since these measures relate to larger network regions (and not individual lines or transformer stations), the measures are only listed in tabular form and not illustrated on a map.

Table 45: Voltage-related redispatching in 2018

5.1.3 Countertrading

Unlike the usual redispatching measures, which involve curtailing or increasing the output of specific power plants, countertrading measures aim to remove network restrictions between two bidding zones. There is no specific intervention in the deployment of power plants. Instead, targeted transactions across bidding zones are used to alleviate the restriction on the interconnection line. Countertrading measures are therefore primarily suitable for situations in which, for reasons to do with the topology of the grid, it is not necessary to activate specific power plants.

Countertrading, which forms part of the individual overloading measures, made up about 1,558 GWh of the total redispatching in the whole of 2018. This represents a decrease of 13% compared to 2017. Countertrading incurred costs of around €36m in 2018, which was higher than in 2017 (€29m).

5.1.4 Deployment of grid reserve capacity

In 2018, the grid reserve was used on 166 days to provide a total of around 904 GWh of energy. Grid reserve power plants can be called upon both as a 4-TSO advance measure or as an individual overloading measure. The TSOs' preliminary estimate puts the costs of using them at about €85.2m. The preliminary costs of holding them in reserve plus other costs not dependent on their deployment amounted to €330.3m in 2018. The number of days was up on the 2017 figure of 145 days and the amount of energy provided was around 1,225 GWh lower than the previous year's figure of 2,129 GWh. The decrease in deployment in the fourth quarter of 2018 is due to the fact that as from October no plants outside Germany were contracted for the grid reserve for winter 2018/2019.

Table 46 summarises the use of the grid reserve in 2018. The average deployment in MW shows the average volume of reserve requested per day of deployment. This average value peaked in March 2018 at 584 MW. The largest volume of grid reserve use was 1,665 MW and occurred in January 2018.

Electricity: summary of grid reserve deployment in 2018

	Number of days	Average deployment (MW)	Maximum volume of use (MW)	Total (MWh)
January	16	516	1,665	174,133
February	16	483	1,134	155,387
March	25	584	1,379	295,214
April	10	235	800	31,639
May	7	270	450	17,354
June	26	236	622	78,942
July	23	243	800	71,425
August	17	215	230	48,440
September	3	34	43	260
October	9	127	600	8,715
November	8	149	550	12,006
December	6	233	600	10,707
Total	**166**			**904,222**

Source: TSOs' reports of redispatching to the Bundesnetzagentur

Table 46: Summary of grid reserve deployment in 2018

5.1.5 Deployment of power plants in redispatching

In 2018, a total volume of 11,729 GWh, made up of 6,397 GWh of reductions in feed-in and 5,333 GWh of increases, was provided by operational plants within Germany and grid reserve power plants both in and outside Germany to ease network restrictions. The difference between the feed-in reduction and increase is partly due to the fact that operational power plants are instructed by foreign TSOs for cross-border redispatching. These instructions are not included in the evaluations below. Grid reserve power plants outside Germany are included in the analysis, since they are instructed directly by the German TSOs.

Figure 54 shows a breakdown of the power plants deployed for redispatching by energy source. Lignite-fired power plants accounted for just under 42% of feed-in reductions and black coal power plants for 46% of feed-in increases in 2018. Some redispatching takes place on the exchange and is classed as "unknown" since it cannot be allocated to any one energy source. These transactions on the exchange are mainly for voltage-related redispatching. In a few cases, the TSO does not know what type of fuel the power plant uses, and these are also put down as "unknown". For plants with more than one source, it is only possible to evaluate the energy source specified in the Bundesnetzagentur power plant list, so they are allocated to their main one.

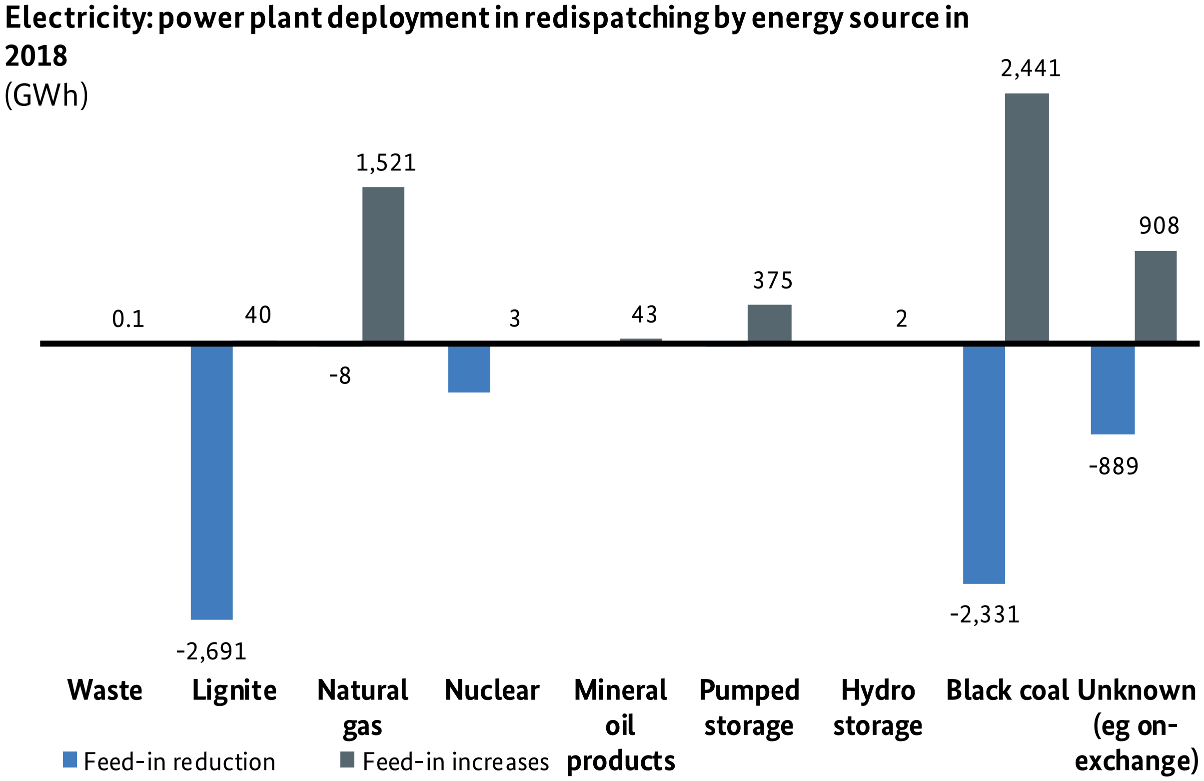

Figure 54: Power plant deployment in redispatching by energy source in 2018

Reductions and increases in feed-in are distributed differently by volume to the instructing TSO. The instructing TSO is usually the TSO in whose control area the power plant is located that is used for redispatching. For grid reserve power plants, the instructing TSO is the one that has concluded the contract with the power plant.

Figure 55 shows the distribution of instructions to power plants by TSO, regardless of the location of the cause of redispatching, which may be in a different control area. The TSO responsible for the control area in which the power plant required is located receives the request for deployment either from the TSO responsible for the control area where the cause is located or, in the case of advance measures, by all four TSOs jointly. In 2018, TenneT accounted for 47% of volume reductions, followed by 50Hertz (46%). Amprion (4%) and TransnetBW (3%) requested a considerably smaller volume of reductions. The majority of increases in feed-in by domestic operational plants and domestic and foreign reserve power plants was in the TenneT control area (49%). TransnetBW accounted for 34% of the increases in feed-in.

Electricity: reductions and increases in feed-in by control area in 2018 as a proportion of the total reduced or increased redispatched volume

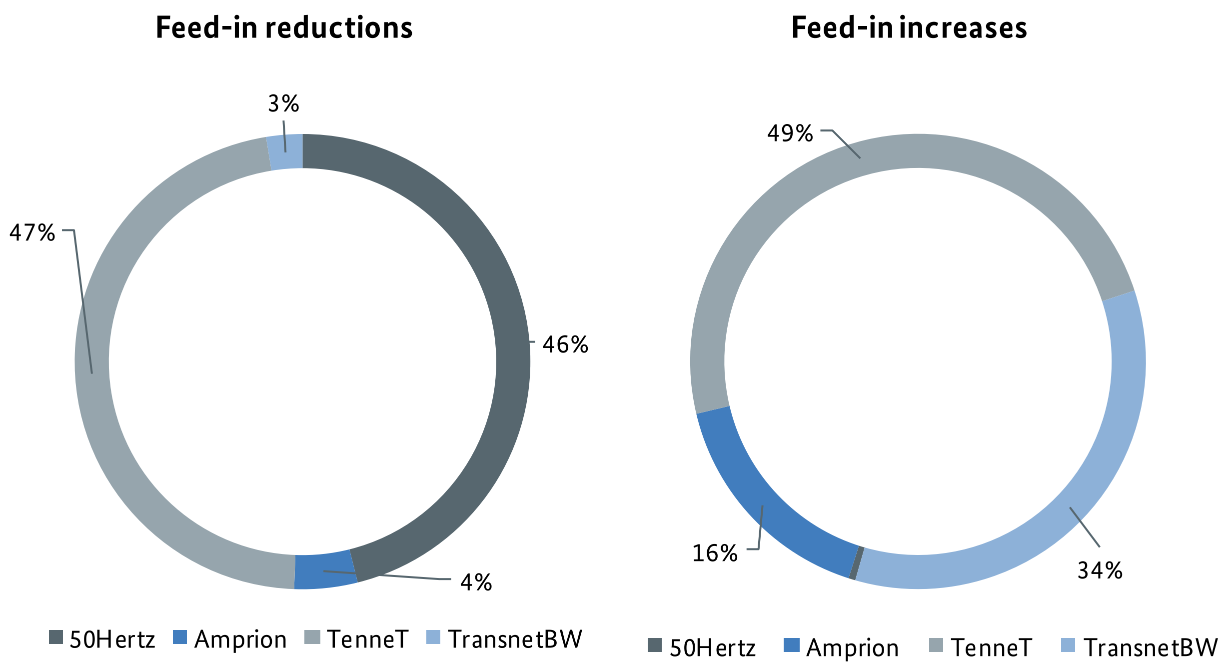

Figure 55: Requested reductions and increases in feed-in by control area in 2018 as a proportion of the total reduced or increased redispatched volume.

The maps in Figure 56 and Figure 57 show how power plants are deployed across the individual federal states. It can be seen that in particular in Baden-Württemberg and southern Hesse, power plants increased their generation to remove network restrictions. Reductions in generation were made above all in Lower Saxony, Brandenburg and Saxony. There were fewer reductions in generation in Mecklenburg-Western Pomerania than in the other northern federal states, as there is a smaller amount of installed conventional generating capacity. Foreign grid reserve and operational plants are not included.

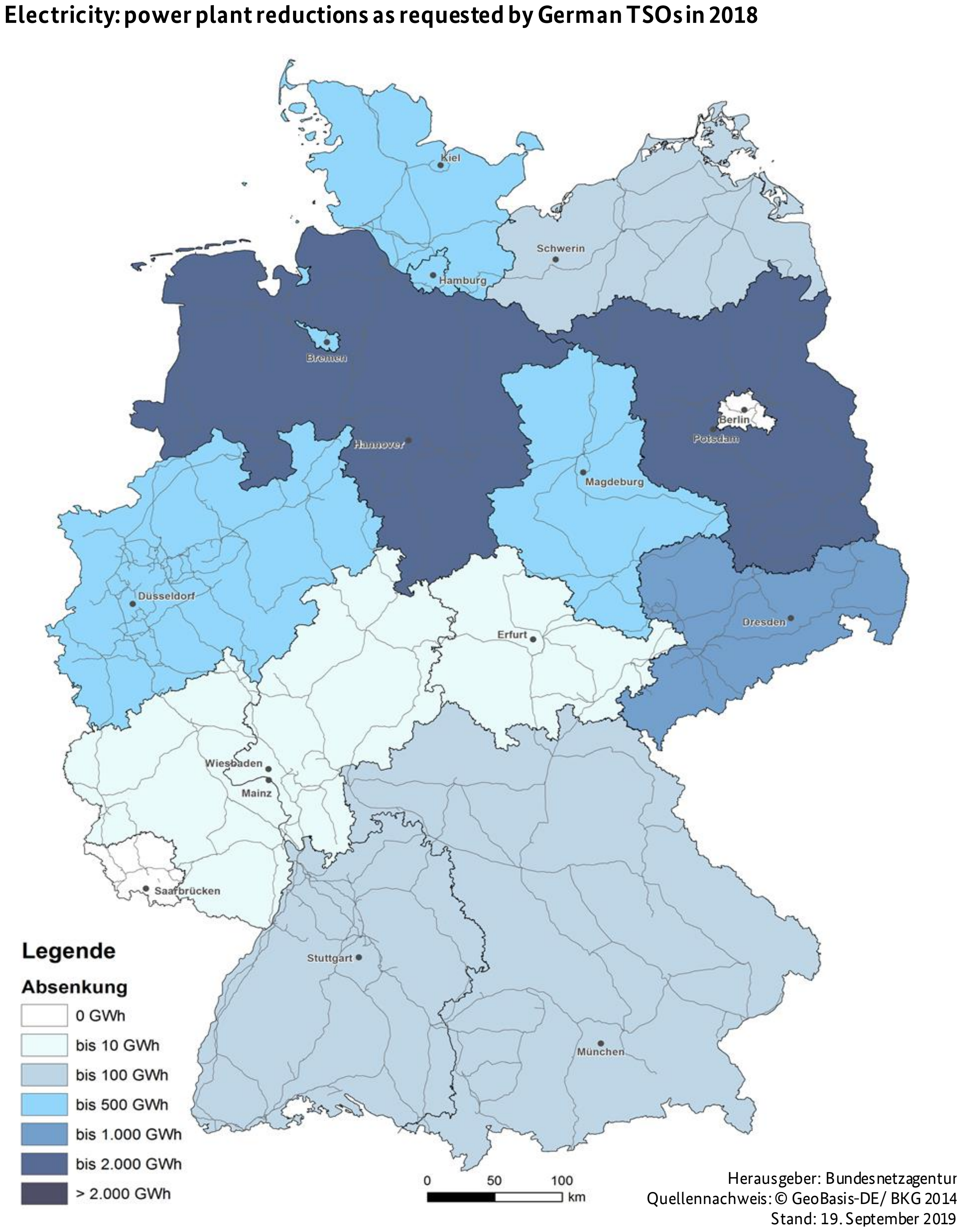

Figure 56: Power plant reductions as requested by German TSOs in 2018

Electricity: power plant increases as requested by German TSOs in 2018

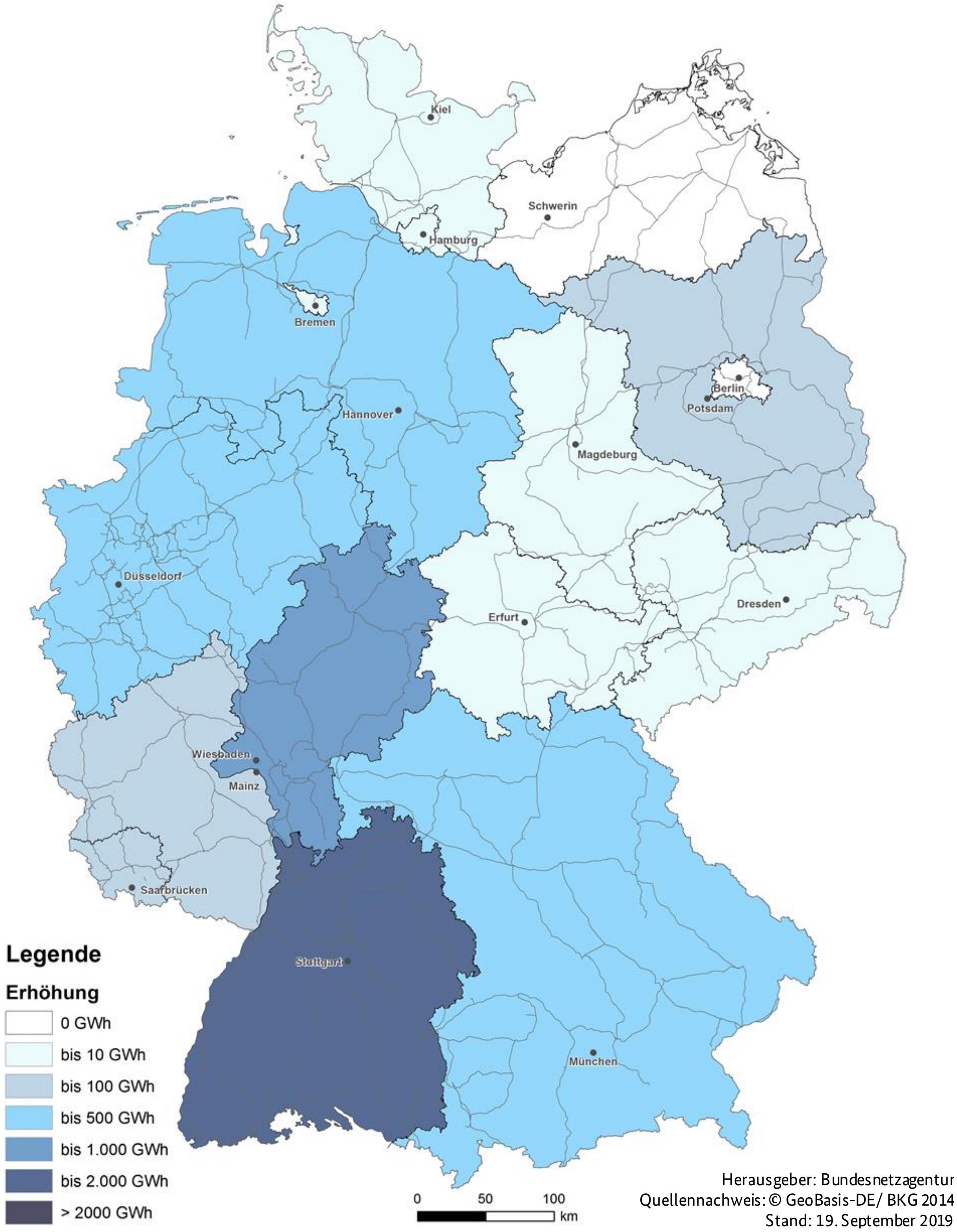

Figure 57: Power plant increases as requested by German TSOs in 2018

5.1.6 Redispatching measures duration curve

The curve illustrates the redispatching measures required in Germany in each hour over the course of the year in decreasing order of the volume of energy reduced. The curve shows in how many hours of the year the volume of redispatched energy was above or below a certain level.

Electricity: redispatched energy (reductions) in decreasing order per hour in Germany in 2018 (MWh)

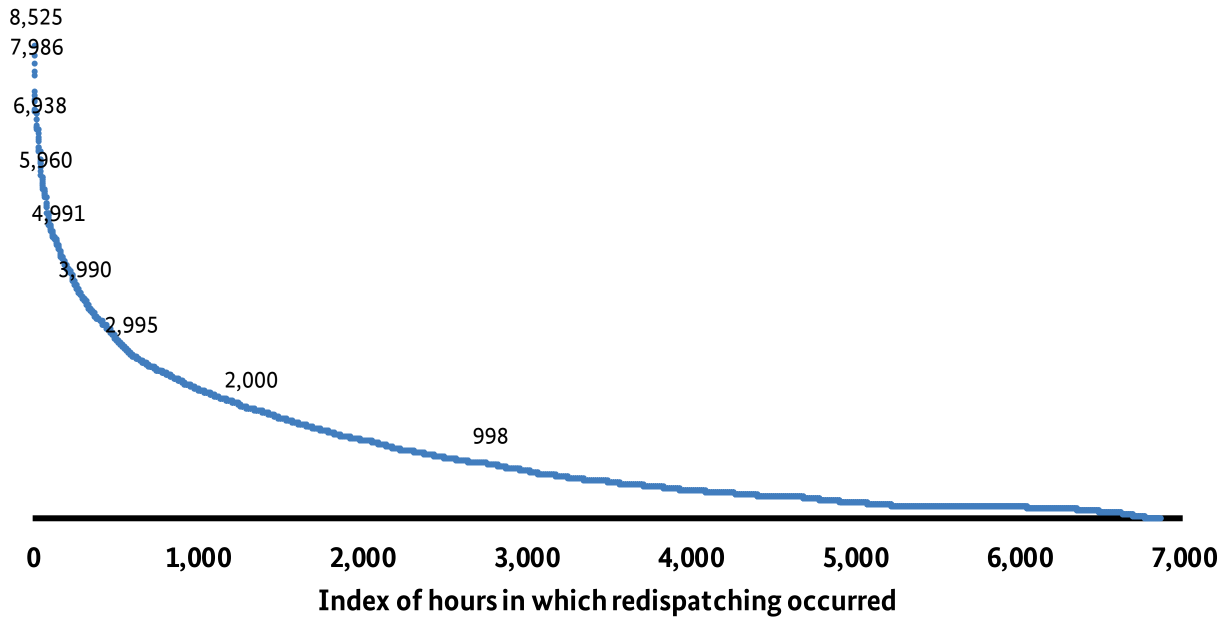

Figure 58: Redispatched energy (reductions) in decreasing order per hour in Germany in 2018

In 2018, the largest required reduction in energy was 8,524.5 MWh. The volume of redispatched energy was higher than 7,000 MWh in 25 out of 8,760 hours (0.3% of all the hours in the year), higher than 5,000 MWh in 137 hours (1.6%), higher than 3,000 MWh in 581 hours (6.6%) and higher than 1,000 MWh in 2,761 hours (31.5%). No redispatching measures were carried out in 1,895 hours, corresponding to 21.6% of all the hours in the year.

5.2 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 highly efficient CHP installations. Priority is to be given to feeding in and transporting the renewable and CHP 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 despite these measures.

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

5.2.1 Curtailed energy

The following graph shows the amount of unused energy as a result of feed-in management measures for the energy sources most affected by such measures since 2009:

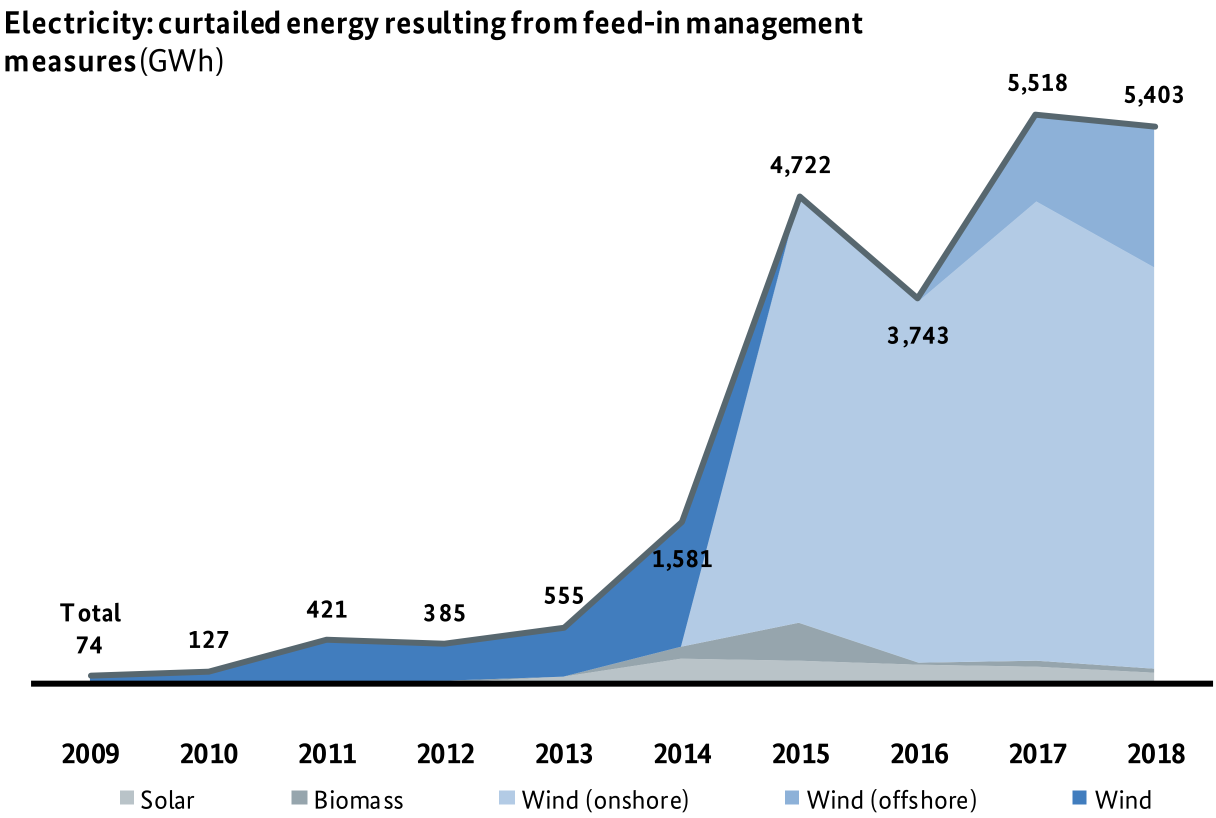

Figure 59: Curtailed energy resulting from feed-in management measures

Electricity: curtailed energy resulting from feed-in management measures (GWh)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Wind energy	73.6	125.1	409.7	358.5	480.3	1,221.5	4,124.9	3,530.1	5,287.2	5,246.9
Wind (onshore)							4,110.6	3,498.0	4,461.2	3,890.5
Wind (offshore)							14.3	32.0	826.0	1,356.3
Solar	0.1	1.7	2.6	16.1	65.5	245.2	227.7	184.1	163.1	116.5
Biomass			5.9	9.4	8.8	112.1	364.4	26.5	61.1	35.7
Other			2.4	0.8	0.2	1.8	21.1	2.6	6.6	3.6
Total	**73.7**	**126.8**	**420.6**	**384.8**	**554.8**	**1,580.6**	**4,722.3**	**3,743.2**	**5,518.0**	**5,402.7**

Table 47: 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 2.1% from 5,518 GWh in 2017 to 5,403 GWh in 2018, making the total amount of unused energy produced by renewable and CHP installations in 2018 around the same as in 2017. This corresponds to 2.8% of the total amount of electricity generated in 2018 by installations eligible for payments under the EEG (including direct selling), up from 2.9% in 2017.[42] Thus around 97% of the renewable energy marketed in 2018 was produced and transported.

The continuing high level of feed-in management measures is essentially due to various factors. One of these factors is the weather. The high level in 2018 was due to the strong winds in the first and fourth quarters generally and, above all, to the curtailment of offshore wind turbines. Compared to 2017, there was a significant rise of about 530 GWh over 2018 in curtailed energy for offshore wind turbines, which was caused by the strong growth in and commissioning of offshore wind installations in recent years. Given the level of curtailed energy and assuming that there will be a further steady increase in renewables, the measures required for network optimisation, reinforcement and expansion must be implemented without delay. Detailed and up-to-date information on feed-in management measures is included in the Bundesnetzagentur's quarterly reports on network and system security.[43]

In 2018, as in previous years, feed-in management measures primarily involved onshore wind power plants, which accounted for 72% of the total amount of curtailed energy (2017: 80.8%). Offshore wind power plants, which were first affected by feed-in management measures in 2015, accounted for around 1,356 GWh or 25% of the total amount of curtailed energy in 2018, up from around 826 GWh or 15% in 2017. CHP electricity generation was affected by curtailment from feed-in management to a far lesser extent. CHP electricity made up less than 0.1% of curtailed energy in 2018, and biomass, which is also often combined with heat generation,

[42] This does not include the amount of electricity curtailed through feed-in management.

[43] https://www.bundesnetzagentur.de/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/Versorgungssicherheit/Netz_Systemsicherheit/Netz_Systemsicherheit_node.html

made up 0.7%. 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:

Electricity: curtailed energy resulting from feed-in management measures by energy source in 2018

Energy source	Curtailed energy (GWh)	Percentage of total (%)
Wind (onshore)	3,890.54	72.0
Wind (offshore)	1,356.33	25.1
Solar	116.47	2.2
Biomass, including biogas	35.74	0.7
CHP electricity	2.47	< 0,1
Landfill, sewage and mine gas	0.60	< 0,1
Run-of-river	0.52	< 0,1
Energy source unknown	0.01	< 0,1
Total	**5,402.67**	**100**

Table 48: Curtailed energy resulting from feed-in management measures by energy source in 2018

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 2018. Overall, restrictions in the transmission networks accounted for around 87% of the energy curtailed, although installations connected to transmission networks accounted for only 26% of the energy curtailed and compensated. The remaining 74% was accounted for by installations connected to distribution networks. Support measures requested by the TSOs but taken by the DSOs accounted for the majority – 60% – of the curtailed energy (see Table 49). Compensation for the support measures taken by the DSOs must be paid by the TSOs.

Although many regions in Germany now require feed-in management measures, around 88% of curtailed energy from such measures occurs in the federal states of Schleswig-Holstein, Lower Saxony and Brandenburg. Schleswig-Holstein is particularly affected (about 53%, see Figure 60).

Electricity: network levels of curtailments and cause of feed-in management measures in 2018

	Curtailed energy (GWh)	Percentage of total curtailed energy (%)
Measures taken by TSOs (cause in transmission network)	**1,402.5**	**26**
Measures taken by DSOs	**4,000.2**	**74**
DSOs' own measures (cause in distribution network)	714.8	13
DSOs' support measures (cause in transmission network)	3,285.5	61
Total feed-in management measures	**5,402.7**	**100**

Table 49: Network levels of curtailments and cause of feed-in management measures in 2018

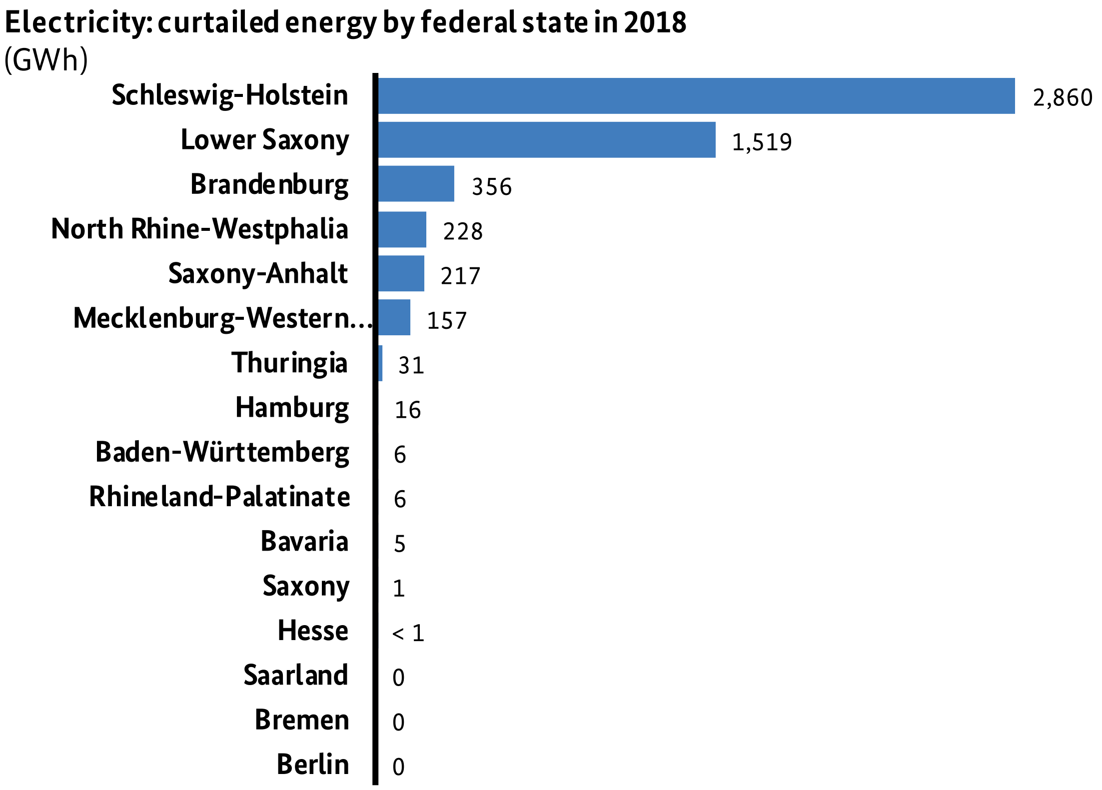

Figure 60: Curtailed energy by federal state in 2018

5.2.2 Compensation claims and payments

A distinction must be made between the estimates of the claims for compensation to installation operators for feed-in management measures in a specific year and the actual compensation paid in that year. The estimates are made by network operators based on the amount of curtailed energy from renewable energy installations and reported to the Bundesnetzagentur on a quarterly basis (since 2019 on a monthly 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 2018 may include costs arising from measures taken in 2015, 2016 and 2017. Consequently, the compensation paid in one year does not reflect the actual costs incurred for curtailments in that year. The questionnaire 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 network restrictions.[44]

The amount of compensation paid to installation operators in 2018 was about €719m, up around €145m on 2017 (€574m). Most of the compensation paid in 2018 came under the EEG payments, with only about €3,000 coming under the CHP payments. The costs of the compensation paid to the installation operators are borne by the network charges paid by final consumers, adding an average of around €13.98 per final consumer in 2018, compared to €11.37 in 2017, €10.13 in 2016, €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 in all network areas under the EEG, since no payments have to be paid for the electricity generated but not fed in from the renewable and CHP installations. Figure 61 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 2018 therefore does not reflect the actual amounts payable for the curtailments in 2018. The compensation paid in 2018 also includes amounts payable for curtailments in previous years.

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[44] 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 EEG. 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.

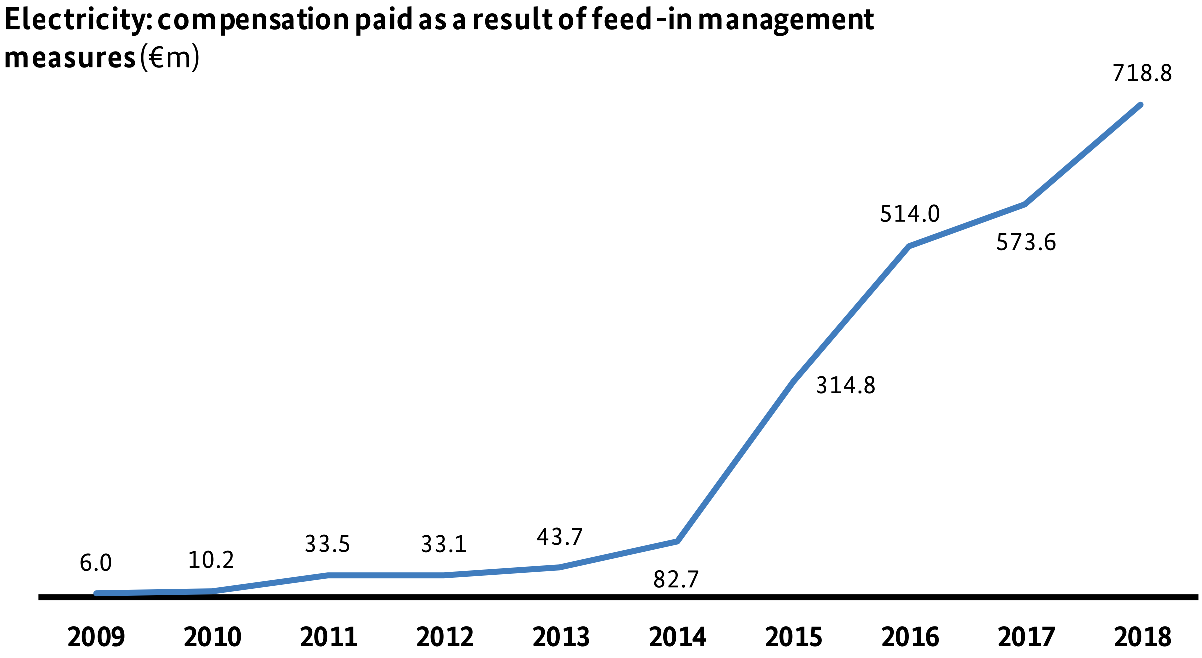


Figure 61: Compensation paid as a result of feed-in management measures

The claims for compensation from installation operators in 2018, based on the network operators' quarterly estimates, amounted to around €635m, some €25m higher than in 2017.[45]

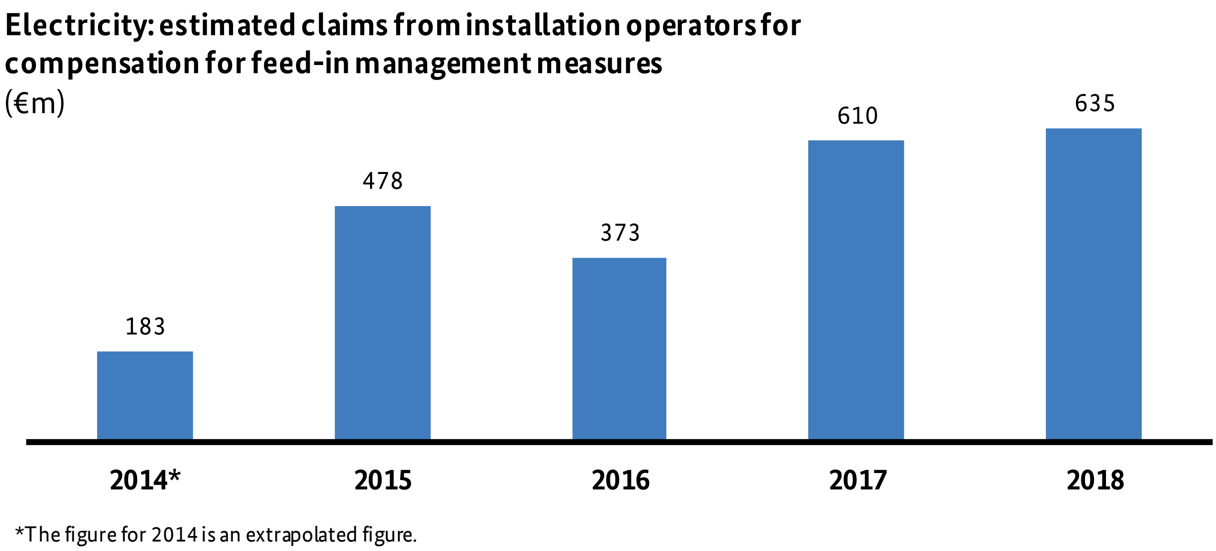


Figure 62: Estimated claims from installation operators for compensation for feed-in management measures

In 2018, the network operators paid a total of around €719m in compensation to the installation operators. Approximately €497m was compensation for curtailments actually occurring in 2018, while the remaining

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

amount of around €222m was compensation for curtailments in previous years. This means that some 78% of the claims from installation operators for compensation for curtailments in 2018, as estimated by the network operators, have already been settled. At the time of the survey, around 22% or €138m 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. The table below shows the detailed figures for the network operators' estimates of compensation claims and the actual compensation paid:

Electricity: compensation payments by measures taken and compensation paid, and causes of feed-in management measures, according to network operators' reports in 2018

	Estimated claims for compensation from installation operators (€m)		Total compensation paid (€m)		Compensation for measures in previous years (€m)
Measures taken and compensation paid by TSOs (cause in transmission network)	**269**	**42%**	**245**	**34%**	**33**
Measures taken and compensation paid by DSOs	**367**	**58%**	**473**	**66%**	**189**
DSOs' own measures (cause in distribution network)	66	10.3%	103	14%	40
DSOs' support measures (cause in transmission network)	301	47.4%	370	52%	149
Total feed-in management measures	**635**	**100%**	**719**	**100%**	**222**

Table 50: Compensation payments by measures taken and compensation paid, and causes of feed-in management measures, according to network operators' reports in 2018

5.3 Adjustment measures

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

Where DSOs are responsible for the security and reliability of the electricity supply in their networks, they too are legally entitled and obliged to take adjustment measures. Furthermore, DSOs are 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 2018, a total of five DSOs took adjustment measures, resulting in feed-in adjustments of about 8.3 GWh. Non-biodegradable waste was by far the most frequently adjusted source of energy, accounting for around 98%. Brandenburg accounted for the majority of the adjustment measures with some 92%, followed by Saxony-Anhalt with about 6% and Thuringia with around 2%.

Electricity: feed-in and offtake adjustments by energy source in 2018

Energy source	Adjustments under section 13(2) (GWh)	Percentage of total (%)
Waste (non-biodegradable)	8.11	98%
Natural gas	0.17	2%
Total	**8.28**	**100%**

Table 51: Feed-in and offtake adjustments by energy source in 2018

6. Network charges

Network charges make up part of the electricity price and have to be paid by both household customers and industrial and commercial customers. The costs for the electricity grid (eg expansion and system security measures) are passed on to final consumers using network charges.

Network charges made up around 22% of the price in 2019 for household customers with an annual consumption of between 2,500 kWh and 5,000 kWh. Following a slight decrease in 2018, the network charges for household customers increased again in 2019 from 7.19 ct/kWh to 7.22 ct/kWh.

The level of network charges varies according to network operator and region. There are many reasons for this, including:

– Network utilisation: the networks in, for example, the eastern German states are oversized and therefore not always sufficiently utilised.

– Population density: in less densely populated areas, the network costs are shared out between a small number of network users.

– Differences in the costs of feed-in management measures.

– Network age: older networks with a low residual value entail lower network costs than new networks.

– Network quality: this has a direct influence on the revenue cap through the quality element.

6.1 Setting network charges

Network charges are levied by the transmission system operators (TSOs) and distribution system operators (DSOs) and make up part of the retail price for electricity (see also I.G.4). Network charges are based on the costs incurred by the network operators for the efficient operation, maintenance and expansion of their networks. These regulated costs are the basis for the rates 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 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 in accordance with section 6 of the Incentive Regulation Ordinance (ARegV). 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 took place 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 efficient and necessary for network operation, which in turn form the basis for setting the revenue caps as from 2018.

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 ARegV. The DSOs' controllable costs are subject to an efficiency benchmarking exercise to compare the costs (input) with the scope of the services supplied (output). In the third regulatory period, a relative generic network analysis to measure efficiency is applied for TSOs.[46]

The recognised network costs form the basis of the revenue cap, taking into consideration the results of the efficiency analysis. 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 over the years of a regulatory period.

Within the regulatory period, the revenue cap can be adjusted and reviewed once a year only under certain legal conditions. The factors leading to such adjustments include:

- Changes to what are known as the permanently non-controllable costs; these costs include, for example, costs for the DSOs from avoided network charges (see I.C.6.5) or for the necessary use of upstream network levels; for all network operators costs of retrofitting renewable energy installations in accordance with the System Stability Ordinance (SysStabV) (see I.C.6.6) or feed-in management costs (see I.C.5.2). For TSOs, there is an array of costs for means to ensure security of supply and grid expansion, in particular costs for investment measures pursuant to section 23 ARegV (see section I.C.3.3), costs for redispatching with operational and grid reserve power plants (see section I.C.5.1) and costs of procuring balancing reserves (see I.D System services). Offshore transmission link costs (see I.C.6.3.1) were also included in the revenue cap until 2018 and were then transferred into the offshore network surcharge as of 1 January 2019.

- The retail price index, which reflects general inflation.

- The capex mark-up, which ensures adjustment of the DSOs' revenue cap in line with the (projected) cost of capital of investments in new assets as from the beginning of the third regulatory period on 1 January 2019. No distinction is made here between replacement and enhancement or expansion expenditure. Operators must apply for the mark-up six months in advance.

- For DSOs under the standard procedure, 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; if projected costs are included in the revenue cap, they are compared with actual developments. This applies particularly in the case of

[46] According to section 22(2) ARegV, a relative generic network analysis establishes relative divergencies between the costs of actual plant volumes and the costs of a generic network as a result of a comparison of a number of operators. The operator with the least divergence from the generic network is taken as the efficiency benchmark for establishing the efficiency levels; the efficiency level of this operator is stated at 100%.

differences between forecast and actual consumption quantities leading to higher or lower revenues, but planned volumes are included in the revenue cap for other items as well, eg various items in the permanently non-controllable costs such as costs for approved investment measures and for the necessary use of upstream network levels. The difference between the capex mark-up approved on the basis of projected values and the capex mark-up arising from the costs actually incurred will also be entered into the regulatory account. The balance of the regulatory account is subject to interest. The numerous special circumstances make settling the regulatory account a complex process.

Deriving the network charges

The network charges are derived by the network operators on the basis of the principles laid down in the StromNEV. 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 ("postage stamp" tariff) 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. The "coincidence function" (section 16 StromNEV) is applied to derive four charges from these specific annual costs: a capacity charge and a unit charge for less than 2,500 hours and for more than 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 more than 2,500 hours and less than 2,500 hours of network usage. Network users with a small number of usage hours have to pay a relatively low capacity charge and a high unit charge, while network users with a large number of usage hours have to pay a relatively high capacity charge and a low unit charge. 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, but the two charges must be "in reasonable proportion" to each other, which allows for a certain margin.

The revenues of the network level are determined on the basis of the planned sales volumes and the derived network charges. The difference between the costs allocated to the network level and the network charge revenues of the level (in other words the block of costs not covered at that level) is passed on to the next network level and added to the costs of that next level.

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 costs allocated to the level need to be covered at that level.

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) StromNEV cover the network costs (revenue cap) as determined in the first step of the process and do not exceed the costs.

In light of the significant changes in generation and usage structures as a result of the energy transition, with increasingly volatile feed-in and a rise in self-supply, and given that sector coupling aims to provide additional incentives, there has been increasing discussion about the need to adjust the system of network charges. However, any reform that were to be implemented must ensure that the grid is not overwhelmed by excessive, simultaneous loads. This discussion may – but will not necessarily – lead to changes in the structure of network charges.

Other surcharges that form components of the final consumer price are detailed in I.G.4.3.

6.2 Development of electricity network costs

The third regulatory period for electricity network operators began on 1 January 2019. The revenue caps for the years 2019 to 2023 were determined in accordance with section 4 ARegV in a cost examination with cost data from the base year 2016. The second regulatory period ran from 2014 to 2018, with the year 2011 serving as the base year.

The following table compares the network costs from the second and third regulatory periods.

Electricity: TSOs' network costs
(€m)

	2011	2016
Claimed network costs	2,420	4,025
Excluded offshore costs		962
Total reductions	144	200
Recognised network costs	2,276	2,862

Table 52: TSOs' network costs

The network costs claimed by the four TSOs, less €962m offshore costs, amounted to €3,063m (€2,420m in the base year 2011). The cost examination resulted in reductions totalling €200m (€144m). This corresponds to a reduction of 6.53% of the network costs claimed. The approved network costs thus amounted to €2,862m (€2,276m).

Electricity: network costs of the DSOs under the standard procedure (€m)

	2011	2016
Claimed network costs	17,087	18,955
Total reductions	2,564	1,782
Recognised network costs	14,523	17,173

Table 53: Network costs of the DSOs under the standard procedure

The DSOs under the Bundesnetzagentur's authority and using the standard procedure claimed network costs amounting to €18,955m (€17,087m in the base year 2011). The cost examination resulted in reductions totalling €1,782m (€2,564m). The approved network costs thus amounted to €17,173m (€14,523m), of which €7,441m (€5,055m) were classed as permanently non-controllable costs. The average weighted efficiency score was 97.33%, resulting in inefficient costs totalling €300m (rounded to a full €100m) to be removed over the third regulatory period.

Electricity: network costs of the DSOs under the simplified procedure (€m)

	2011	2016
Claimed network costs	324	441
Total reductions	35	40
Recognised network costs	289	401

Table 54: Network costs of the DSOs under the simplified procedure

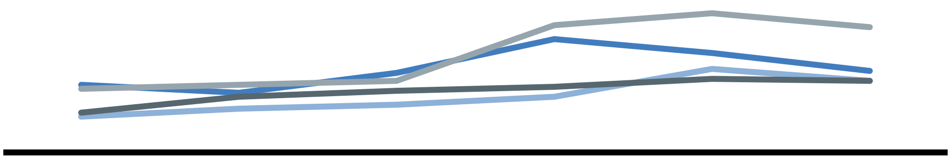
The DSOs under the Bundesnetzagentur's authority and using the simplified procedure claimed network costs amounting to €441m (€324m in the base year 2011). The cost examination resulted in reductions totalling €40m (€35m). The approved network costs thus amounted to €401m (€289), of which €202m (€130m) were classed as permanently non-controllable costs. The efficiency score set in the simplified procedure was 96.69%, resulting in inefficient costs totalling €7m to be removed over the third regulatory period.

6.3 Development of network charges in Germany

6.3.1 Development of network charges at TSO level

The following chart shows the four TSOs' network charges from 2014 to 2019 for an example large industrial customer connected to the extra-high voltage level with an annual consumption of 850 GWh, an annual maximum load of 190 MW and around 4,500 usage hours, assuming a network charge reduction of 75% pursuant to section 19(2) para 1 of the Electricity Network Charges Ordinance (StromNEV) and liability as an electricity cost-intensive company to pay only 15% of the offshore network surcharge.

Electricity: TSOs' network charges
(ct/kWh)



	2014	2015	2016	2017	2018	2019
50Hertz	0.34	0.30	0.40	0.56	0.50	0.41
Amprion	0.18	0.22	0.24	0.28	0.41	0.35
Tennet	0.32	0.33	0.35	0.64	0.70	0.63
TransnetBW	0.19	0.28	0.31	0.32	0.37	0.36

50Hertz Amprion Tennet TransnetBW

Figure 63: TSOs' network charges

There was a continual increase in the TSOs' network charges for this example large industrial customer in the control areas of TenneT, TransnetBW and Amprion up to and including 2018. The only decreases in network charges were in the 50Hertz control area in 2015 and 2018. The changes in the individual control areas are influenced in particular by the changes in the TSO's revenue caps in addition to the volume changes; these revenue caps – in turn shaped by factors including the costs for redispatching and feed-in management measures and the costs for standby power plants, the grid reserve and loss energy – have a decisive influence on the development of the network charges. For example, the decrease in the network charge in the 50Hertz control area in 2018 was largely due to the costs saved through the commissioning of the "Thuringia power bridge" and the associated savings in costs for redispatching and feed-in management measures.

The TSOs' network charges for the example large industrial customer fell again for the first time in all four control areas in 2019. The main reason for this is the implementation of the Network Charges Modernisation Act (NEMoG) (see I.C.6.5). While in 2018 the revenue caps still included the offshore connection costs and only the costs for the offshore liability surcharge were refinanced separately, in 2019 the offshore connection costs were removed from the TSOs' network charges for the first time on the basis of the NEMoG and were transferred to the new offshore network surcharge. This new surcharge now comprises the costs from the previous offshore liability surcharge together with the offshore connection costs. For the purposes of comparing the cost burden for the network users, the following table shows the regular charges in 2018 and 2019 (columns 1-3) and also the TSOs' charges for 2018 plus the offshore liability surcharge for 2018 (column 4) and the TSOs' charges for 2019 plus the new offshore network surcharge (column 5). These figures therefore include the same offshore costs. When taking account of the surcharges, the decreases in the charges are considerably smaller (column 6). There is even an increase in the TransnetBW control area. However, a customer with characteristics similar to the example industrial customer is not typical in the TransnetBW network.

Electricity: comparison of specific TSO charges in 2018 and 2019, including offshore surcharges (network charges in ct/kWh)

Control area	2018 network charge	2019 network charge	Change	2018 network charge plus offshore liability surcharge	2019 network charge plus offshore network surcharge	Change
TenneT	0.70	0.63	-9.6 %	0.72	0.69	-3.9 %
50Hertz	0.50	0.41	-17.4 %	0.52	0.47	-9.3 %
TransnetBW	0.37	0.36	-1.7 %	0.39	0.42	8.2 %
Amprion	0.41	0.35	-14.4 %	0.44	0.42	-4.8 %

Table 55: Comparison of specific TSO charges in 2018 and 2019, including offshore surcharges

The development of the TSO's network charges was also influenced in 2019 by the implementation of the first step of the harmonisation process for the TSOs' network charges, which is also anchored in the NEMoG and is to take place over a period of five years as from 1 January 2019. This process will in particular ensure that costs that are incurred regionally but are relevant for the entire network as a whole – such as network and system security costs – are also shared between all network users nationwide.

6.3.2 Development of average network charges

The analysis of average network charges in Germany is based on data on the individual price components submitted in the monitoring survey by electricity suppliers. The suppliers provide data on their average net network charges for customers in specific consumption groups and different contract categories.[47] The consumption groups are as follows:

- household customers: 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 maximum load 50 kW, annual usage period 1,000 hours, low-voltage supply (0.4 kV);

- industrial customers: annual consumption 24 GWh, annual maximum 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 reductions pursuant to section 19 StromNEV.

The electricity suppliers' data is used to calculate the national average network charge for each consumption group. The network charge for household customers is volume-weighted, while for commercial and industrial

[47] Net network charges do not include VAT.

customers it is determined arithmetically. It should be noted that the arithmetic mean reflects neither the wide spread of the network charges nor the heterogeneity of the network operators for these consumption groups.

In the period up to 2011, the first cost examinations since the introduction of regulation led to falling network charges. Various factors have influenced the rise in network charges since 2012 and the consistently high level. For example, there was an increase in distributed generation, which led to higher costs for avoided network charges, while at the same time there was an increased need for redispatching and feed-in management measures. Finally, the growth in renewable energy installations made further grid expansion necessary. All of these factors pushed up network costs. A turning point occurred in 2018, and in the period from 2017 to 2018 the volume-weighted average network charge fell by around 2%. The main reason for the drop was the effect of the NEMoG bringing down costs for avoided network charges. Despite the exclusion of the offshore connection costs from the network charges and a further reduction in the avoided network charges under the NEMoG, this trend did not continue for reasons including increasing grid expansion costs and projected high costs for system security measures. The national average network charge for household customers rose in the period from 2018 to 2019 by 4% from 7.19 ct/kWh to 7.22 ct/kWh.

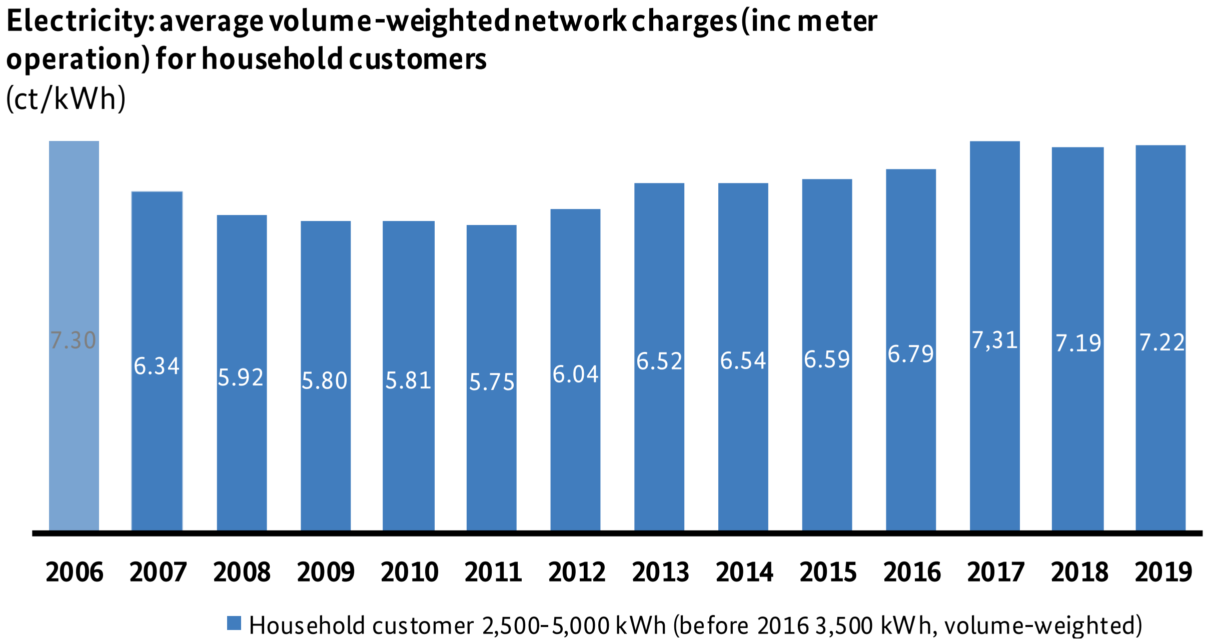


Figure 64: Average volume-weighted network charges for household customers from 2006[48] to 2019[49]

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

[49] The figures for industrial and commercial customers before 2014 were volume-weighted.

The costs for network users nationwide based on the sum of the network charges and the offshore network surcharge increased by just under 6% from 7.23 ct/kWh (7.19 ct/kWh plus 0.037 ct/kWh offshore liability surcharge) in 2018 to 7.64 ct/kWh (7.22 ct/kWh plus 0.416 ct/kWh offshore network surcharge) in 2019.

According to the network operators' information on the provisional network charges for 2020, the network charges will again rise in the coming year for reasons including an increase in expenditure for system security measures and an increase in investments.

For non-household customers the arithmetic mean charges are slightly higher and lower than the previous year's level: the charges for commercial customers rose by 0.04 ct/kWh or 1% to 6.31 ct/kWh, while the arithmetic mean charges for industrial customers with an annual energy consumption of 24 GWh decreased by 0.03 ct/kWh or around 1% to 2.33 ct/kWh.

Electricity: arithmetic net network charges (including meter operation) for "commercial customers" (50 MWh) and "industrial customers" (24 GWh)

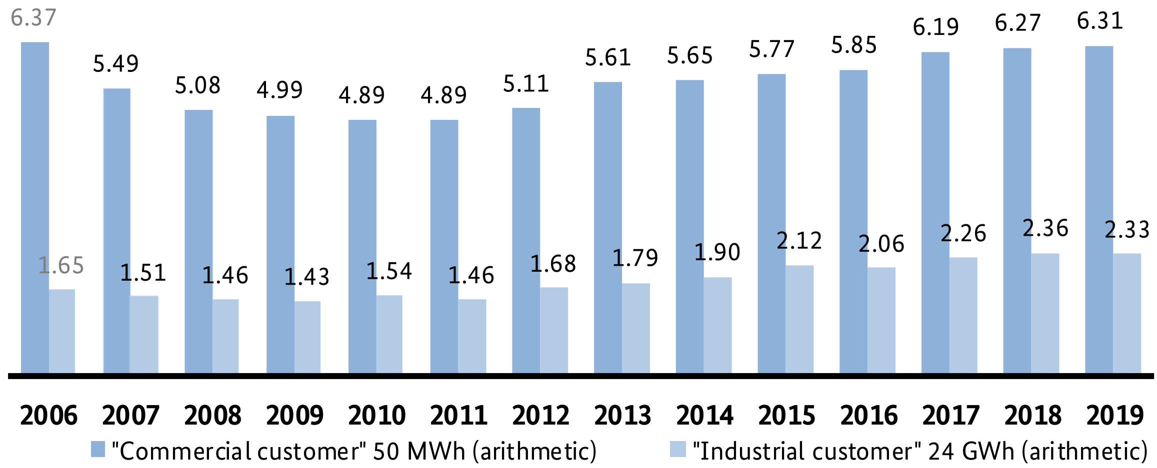
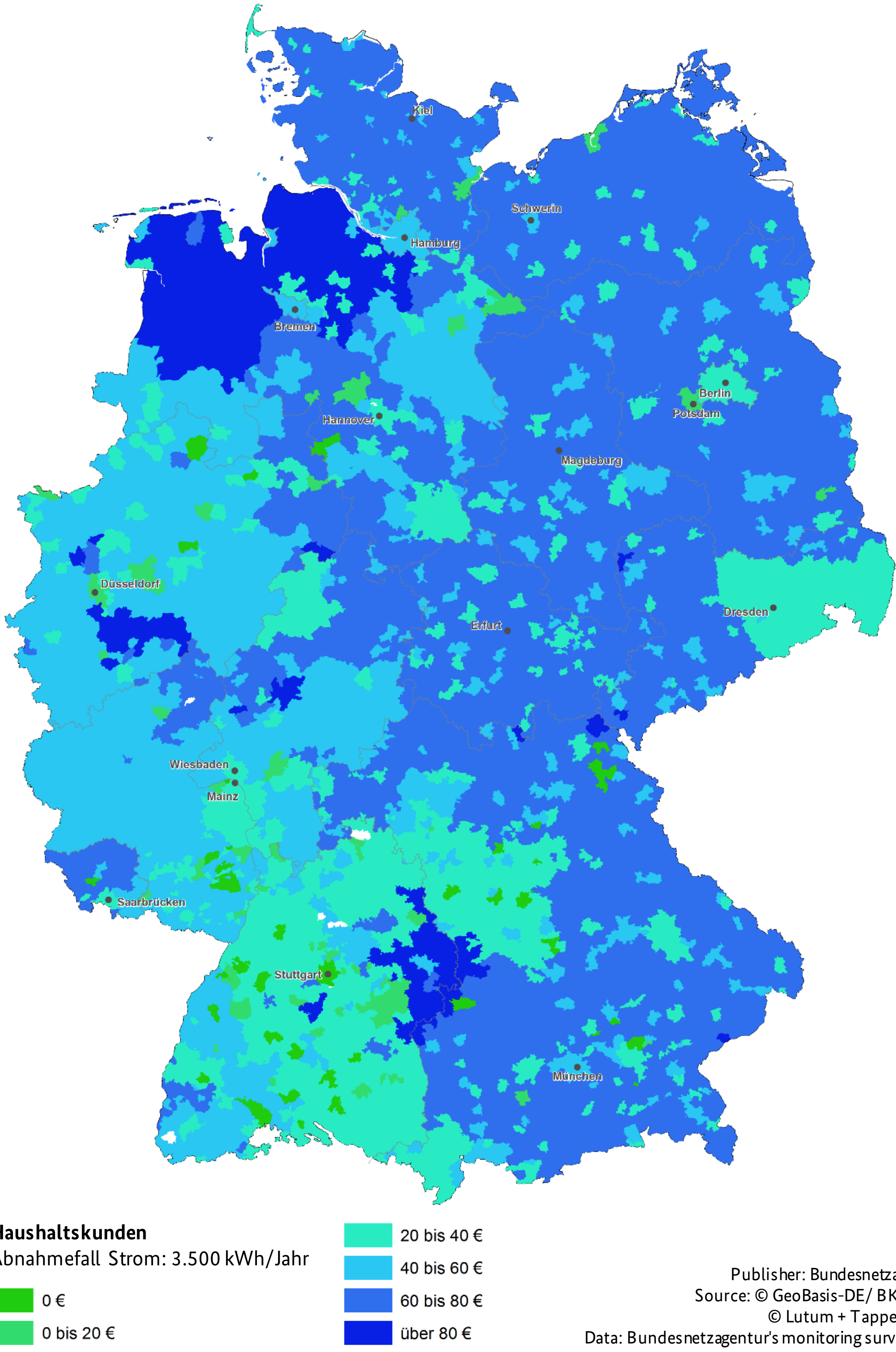


Figure 65: Arithmetic net network charges (including meter operation) for "commercial customers" (50 MWh) and "industrial customers" (24 GWh)

6.3.3 Development of standing charges

For non-interval-metered customers, the network charges are replicated either by just the unit charge or by a combination of unit and standing charge components. There are large differences in the standing charges for customers with an annual consumption of 3,500 kWh in Germany (see Figure 66). However, Table 56 shows a nationwide trend towards increasing standing charges in recent years.

Electricity: network operators' standing charges in 2019



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Source: © GeoBasis-DE/ BKG 2018
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Data: Bundesnetzagentur's monitoring survey 2019

Figure 66: Network operators' standing charges for an annual consumption of 3,500 kWh

Electricity: standing charges
(€/year)

	2017	2018	2019
Average standing charge	35	37	40
Maximum standing charge	95	100	105
Minimum standing charge [1]	6	4	7
DSOs without standing charge	46	36	42

[1] Minimum standing charge levied by DSOs.

Table 56: Standing charges

The level of standing charges is increasingly the subject of public discussion. Here, the Bundesnetzagentur continues to be in favour of a reasonable standing charge as a fixed component. The reasonableness of the standing charge is based on a comparison with the tariffs for interval-metered customers at the low-voltage level and on the costs incurred for providing network infrastructure, which very largely do not depend on actual network usage.

6.4 Regional distribution of 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 I.C.6.3 "Development of network charges in Germany"). Section 27(1) of the Electricity Network Charges Ordinance (StromNEV) 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 2019. The figures do not include the meter operation charges or VAT. 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 consumption quantity to obtain the average network charge in each federal state.[50]

The network charges for household customers range from 1.78 ct/kWh to 25.38 ct/kWh, although only very few household customers within the meaning of section 3 para 22 of the Energy Industry Act (EnWG) with a very low consumption pay the maximum charges. This represents a difference by a factor of up to 10. It is notable that network charges are comparatively high in particular in the states of Schleswig-Holstein, Brandenburg and Mecklenburg-Western Pomerania. There are also differences between urban and rural areas.

[50] Quantity weighting according to consumption group: household customers = consumption quantity for household customers within the meaning of section 3 para 22 EnWG; commercial customer = consumption quantity for standard load profile (SLP) final consumers excluding household customers; industrial customer = consumption quantity of interval-metered final consumers. The quantities for DSOs operating in more than one federal state were weighted using the relevant market location distribution.

The map below shows that many major cities (Berlin, Munich, Frankfurt am Main, Dortmund, Bremen, Stuttgart and Düsseldorf) fall into the three lowest categories of network charges of under 5 ct/kWh to 7 ct/kWh. In those cities, the network charges payable are generally lower than in the outlying areas. The federal state with the lowest average network charges is Bremen.

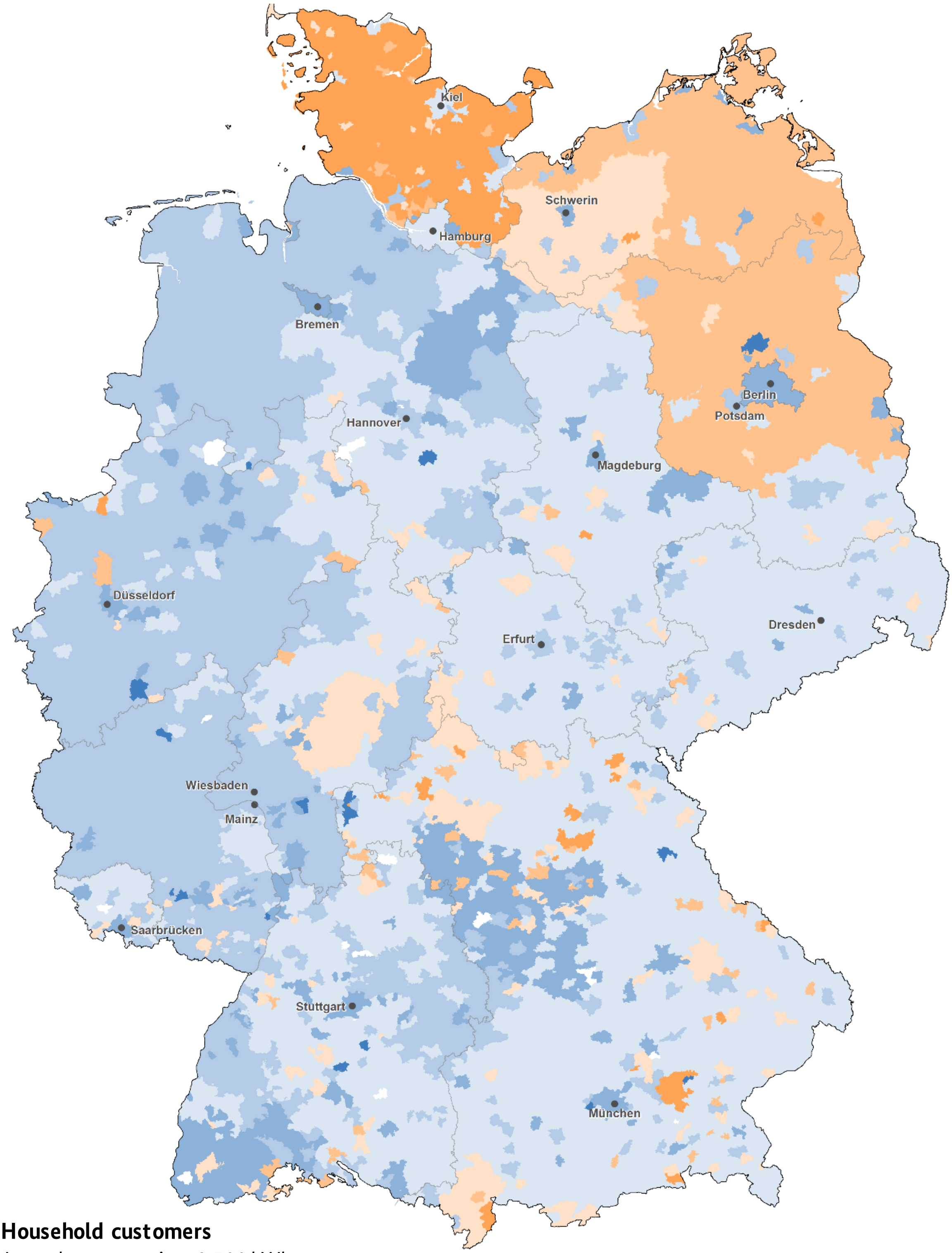
Electricity: net network charges for household customers in Germany in 2019
(ct/kWh)

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks included
Schleswig-Holstein	9.15	5.93	10.68	42
Brandenburg	8.35	3.44	16.57	29
Mecklenburg-Western Pom.	8.25	5.32	10.24	19
Hamburg	7.53	7.53	7.53	1
Saxony-Anhalt	7.17	1.78	10.10	28
Thuringia	7.12	5.55	9.96	30
Saxony	7.06	5.19	9.12	36
Bavaria	7.00	4.09	11.82	224
Lower Saxony	6.87	4.34	25,38**	70
Baden-Württemberg***	6.84	4.71	12.23	111
Saarland	6.84	5.13	16.76	17
Hesse	6.78	4.65	9.46	46
Rhineland-Palatinate	6.52	4.24	8.79	50
North Rhine-Westphalia	6.51	4.55	10.57	98
Berlin	5.58	5.58	5.63	2
Bremen	5.44	5.37	9.50	4

*The weighting was based on the total consumption volumes in each network area.
**Only affects very few household customers within the meaning of section 3 para 22 EnWG with very low consumption.
***Includes the coverage area of the German enclave of Büsingen within Switzerland.

Table 57: Net network charges for household customers in Germany in 2019

Electricity: spread of network charges for household customers in Germany in 2019



Household customers

Annual consumption: 3,500 kWh

- unter 5 Cent/kWh
- 5 bis < 6 Cent/kWh
- 6 bis < 7 Cent/kWh
- 7 bis < 8 Cent/kWh
- 8 bis < 9 Cent/kWh
- 9 bis < 10 Cent/kWh
- 10 oder größer

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Source: © GeoBasis-DE/ BKG 2018
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Data: Bundesnetzagentur's monitoring survey 2019

Figure 67: Spread of network charges for household customers in Germany in 2019

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 0.19 ct/kWh to 24.63 ct/kWh. Overall, however, charges are lower than for household customers. On average, Schleswig-Holstein and Brandenburg have the highest charges and Bremen the lowest compared to the other federal states.

Electricity: net network charges for commercial customers in Germany in 2019
(ct/kWh)

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks included
Schleswig-Holstein	7.55	4.36	9.25	42
Brandenburg	6.71	3.17	16.57	29
Mecklenburg-Western Pom.	6.58	4.29	9.04	19
Baden-Württemberg**	5.99	3.52	10.96	111
Hamburg	5.93	5.94	5.94	1
Saxony	5.73	3.73	7.56	36
Bavaria	5.61	0.67	11.74	224
Thuringia	5.54	3.75	8.16	30
Hesse	5.52	3.72	8.58	46
Saxony-Anhalt	5.41	0.19	9.03	28
Rhineland-Palatinate	5.30	3.31	8.22	50
Saarland	5.29	3.46	16.12	17
Lower Saxony	5.08	3.90	24.63	70
North Rhine-Westphalia	5.02	3.28	8.99	98
Berlin	4.78	4.70	5.12	2
Bremen	4.04	3.88	8.86	4

*The weighting was based on the total consumption volumes in each network area.
**Includes the coverage area of the German enclave of Büsingen within Switzerland.

Table 58: Net network charges for commercial customers (annual consumption 50 MWh) in Germany in 2019

Electricity: spread of network charges for commercial customers in Germany in 2019

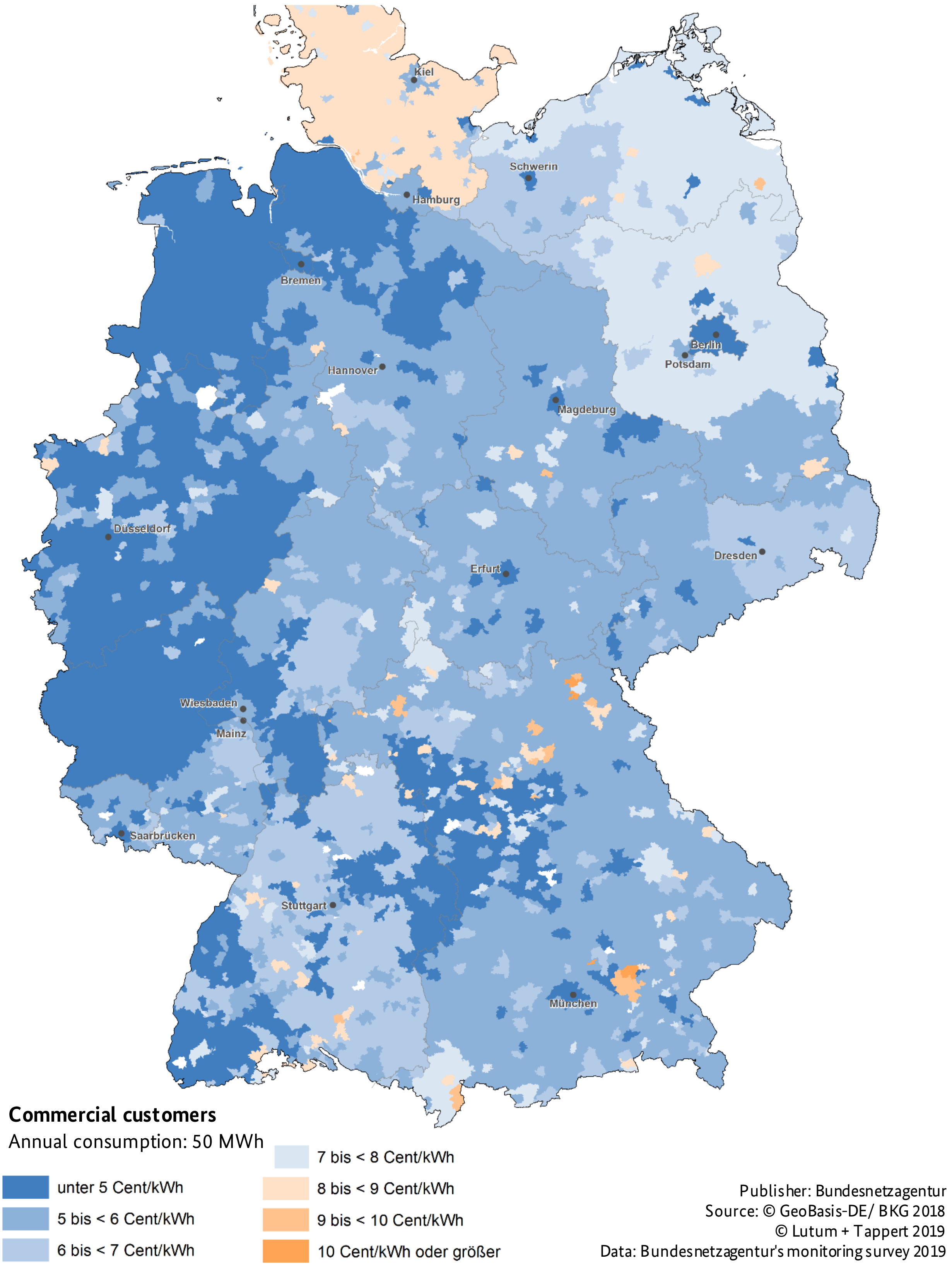


Figure 68: Spread of network charges for commercial customers (annual consumption 50 MWh) in Germany in 2019

The spread of network charges for the 24 GWh annual consumption group (industrial customers) is different. Although network charges in Schleswig-Holstein, Mecklenburg-Western Pomerania and Brandenburg, in particular, are higher than in other federal states, there are also higher charges in some other, smaller network areas. The lowest average network charges are in North Rhine-Westphalia. The network charges for industrial customers range from around 1.16 ct/kWh to 7.77 ct/kWh. These charges do not take account of possible reductions through individual network charges pursuant to section 19(2) StromNEV. In some cases, the charges for industrial customers entitled to individual network charges may therefore be lower. The map makes clear that, as for the other customer categories, the network charges payable in major cities are generally lower than in the outlying areas.

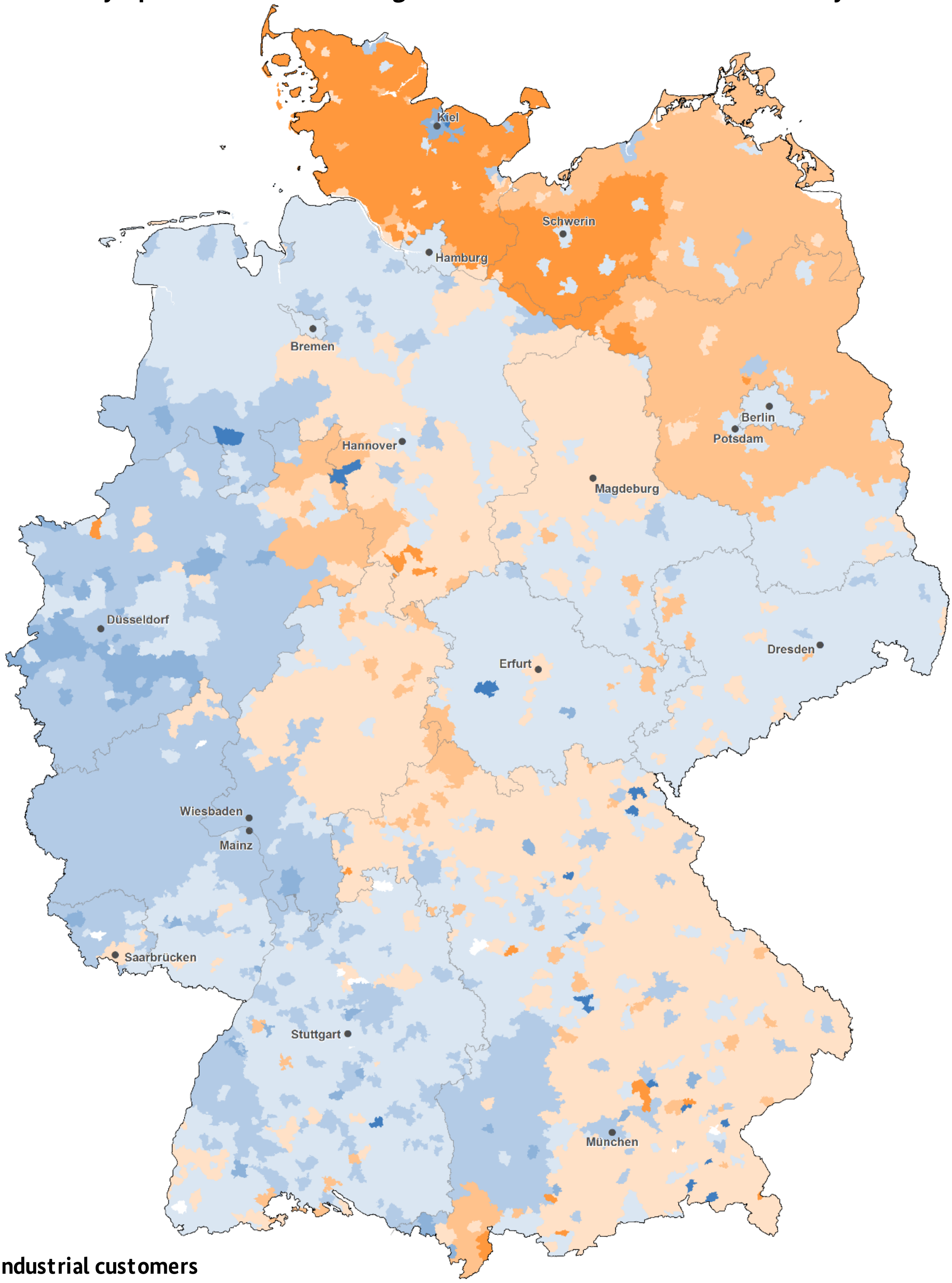
Electricity: net network charges for industrial customers in Germany in 2019
(ct/kWh)

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks included
Schleswig-Holstein	3.31	1.47	4.85	41
Mecklenburg-Western Pom.	3.01	1.86	3.80	19
Brandenburg	2.98	1.90	4.06	28
Hesse	2.86	1.56	3.64	49
Saxony-Anhalt	2.66	1.84	3.77	29
Saxony	2.60	1.85	4.56	36
Saarland	2.53	1.44	5.90	17
Bavaria	2.50	1.16	5.07	215
Thuringia	2.50	1.68	3.33	27
Berlin	2.49	2.47	2.55	2
Lower Saxony	2.48	1.30	7.77	69
Hamburg	2.43	2.43	2.43	1
Bremen	2.41	2.11	3.11	4
Baden-Württemberg	2.38	1.31	4.35	111
Rhineland-Palatinate	2.14	1.30	5.31	50
North Rhine-Westphalia	2.09	1.35	3.76	97

*The weighting was based on the total consumption volumes in each network area.

Table 59: Net network charges for industrial customers (annual consumption 24 GWh) in Germany in 2019

Electricity: spread of network charges for industrial customers in Germany in 2019



Industrial customers

Annual consumption: 24 GWh

- unter 1,2 Cent/kWh
- 1,2 bis < 1,7 Cent/kWh
- 1,7 bis < 2,2 Cent/kWh
- 2,2 bis < 2,7 Cent/kWh
- 2,7 bis < 3,2 Cent/kWh
- 3,2 bis < 3,7 Cent/kWh
- 3,7 Cent/kWh oder größer

Publisher: Bundesnetzagentur
Source: © GeoBasis-DE/ BKG 2018
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Data: Bundesnetzagentur's monitoring survey 2019

Figure 69: Spread of network charges for industrial customers (annual consumption 24 GWh) in Germany in 2019

The regional differences in network charges are due to a complex range of factors.[51] One of the main factors is lower 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 costs are still based on the networks' size. Another key factor is 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. The costs for feed-in management measures originating in the DSOs' networks have also become a factor contributing to differences in network charges. 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 revenue caps through the quality element. 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 investments in grid expansion and an increase in network and system security measures such as redispatching and reserving 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 gradually harmonised as from 2019. Uniform national charges are to apply 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 borne by all network users.

6.5 Avoided network charges

Under section 18(1) of the Electricity Network Charges Ordinance (StromNEV), operators of distributed generation facilities are entitled to payment from the operator of the distribution network into which they feed electricity. The sum paid must correspond to the network charge avoided by feeding in less 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. The aim of paying the avoided network charges to the downstream facilities was to help the downstream facilities become competitive.

The avoided network charges within the meaning of section 18(1) StromNEV had increased significantly in recent years, as a result in particular of the changes in the generation structure and the TSOs' increasing network costs. At the same time, it has become clear that the installations do not contribute to the avoidance of grid expansion.

The investments required for line expansion and the associated operational costs mean that the infrastructure costs for the upstream distribution and transmission networks will continue to rise. On account of the economic life of these investments, line expansion in the upstream network would lead to an increase in the avoided network charges in the long term.

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

The table below shows a continual increase in the total amount of avoided network charges up to 2017. The rise in costs was due to various factors, including the following:

The growth in distributed 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 volume of sales. 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 voltage levels than in the past and thus reinforces itself. This was also the subject of proceedings at the Federal Court of Justice (Bundesgerichtshof, ruling of 27 February 2018, EnVR 1/17). According to the ruling, a power plant that feeds power into the extra-high voltage network is not classed as a distributed generator within the meaning of section 18(1) StromNEV and section 3 para 11 EnWG. The Federal Court of Justice thus ruled that avoided network charges were not permissible.

In light of the negative effects and misguided incentives, the Network Charges Modernisation Act (NEMoG) was drawn up and adopted by the German Bundestag on 30 June 2017. As a result, there will be a gradual reduction in the remuneration for intermittent generators.

The following table 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.

Electricity: avoided network charges by network and substation level
(€m)

Level	2014 (actual figures)	2015 (actual figures)	2016 (actual figures)	2017 (actual figures)	2018 (actual figures)	2019 (forecast figures)
EHV/HV	9	2	4	16	4	4
HV	650	640	875	1,321	601	627
HV/MV	84	92	111	140	78	70
MV	551	594	662	798	524	412
MV/LV	38	36	50	45	38	34
LV	160	420	168	206	117	89
Total	**1,492**	**1,785**	**1,870**	**2,526**	**1,362**	**1,236**

Table 60: Avoided network charges (section 18(1) StromNEV) by network and substation level

The actual figures for 2018 and the projected figures for 2019 shown in the table indicate that the law is already having an effect. The avoided network charges will be included to a far lesser extent in the revenue caps for 2018 and 2019. There may be some compensation in the renewable energy surcharge in future, since fewer avoided network charges for intermittent plants mean lower renewable energy surcharges.

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.

- Since 2018: the remaining avoided network charges will be calculated with the highest price based on the price list for 2016: the price list for 2016 is taken as the reference price list; if future price lists include increases in charges, the charges in the reference price list are used to calculate the avoided network charges (in other words, the charges are frozen at the 2016 price list level); if future price lists include decreases in charges, the price list with the lower charges is used to calculate the avoided network charges.

Offshore connection costs and underground cabling costs have been excluded from the transmission network costs in the price list for 2016. Offshore connection costs are also being excluded from the network usage costs as from 2019 and transferred into the offshore network surcharge (referred to as the "offshore liability surcharge" up to and including 2018). The costs are being distributed between the consumers through the offshore network surcharge as from 2019. This leads to a reduction in the network costs on the one hand and to an increase in the financial burden through the offshore network surcharge on the other hand.

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

The significant increase in the number of distributed generators in recent 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 related to the frequency protection parameters for solar photovoltaic (PV) installations, the System Stability Ordinance (SysStabV) was enacted with effect from 26 June 2012, requiring PV inverters to be retrofitted. Section 10 SysStabV in conjunction with section 57(2) of the Renewable Energy Sources Act (EEG) 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 SysStabV; the excess costs are financed through the network charges as provided for by section 22 SysStabV.

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. Retrofitting was completed in 2017. The costs actually incurred in the previous years were significantly lower than forecast.[52] The resulting differences are balanced out in the network operators' incentive regulation accounts.

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

Retrofitting work on CHP, wind, hydro power and biomass installations began in 2015, also leading to increases in the revenue caps from 2017 onwards.

Electricity: retrofitting costs in the revenue caps
(€m)

	2013	2014	2015	2016	2017	2018	2019
Forecast	48.5	73.1	4.9	22.6	6.1	1.0	1.2
Actual	12.2	35.3	6.8	2.7	1.4		
Figures acc to section 22 SysStabV							
Forecast			0.0	22.4	6.1	1.0	1.2
Actual			1.3	2.6	1.4	0.5	

Table 61: Retrofitting costs in the revenue caps

It is worth noting that the forecast costs are considerably higher than the actual costs. This does not result in any disadvantages for network users, however, since the differences, together with interest, are reimbursed to network users under the incentive regulation account scheme provided for by section 5 of the Incentive Regulation Ordinance (ARegV).[53]

The TSOs expect retrofitting work to be completed in 2019. The projected figures for 2018 and 2019 are already comparatively low.

6.7 Transfer of electricity networks

Section 26(2) to (5) of the Incentive Regulation Ordinance (ARegV) 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 (EnWG)). 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.

The 2016 amendment to the ARegV has led to substantial changes in the procedure for splitting the revenue caps. Section 26 (3) to (6) of the revised Ordinance, in force since September 2016, states 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.

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

As at the end of December 2018, the Bundesnetzagentur had received 33 applications for electricity network transfers in 2018. The following graph shows the number of applications made in the last three years.

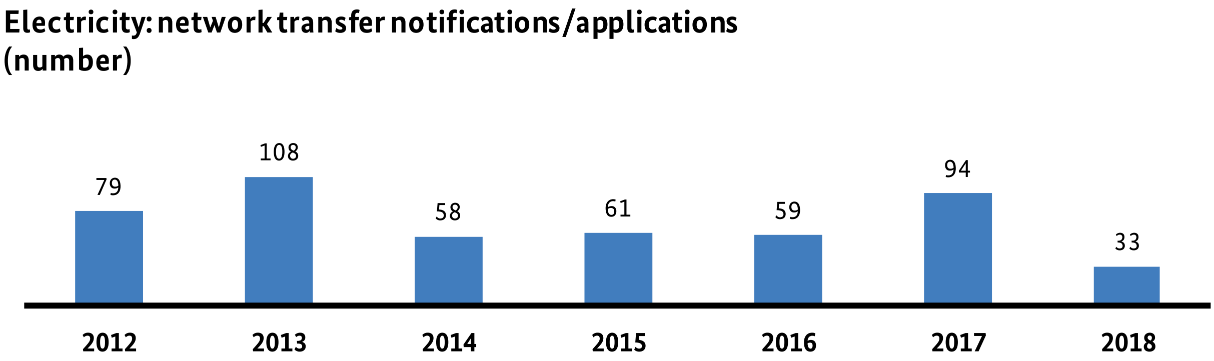


Figure 70: Network transfer notifications/ applications

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 (StromNEV) 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) sentence 1 StromNEV and electricity-intensive network users as per section 19(2) sentence 2 StromNEV. 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) StromNEV (ruling BK4-13-739 of 11 December 2013). 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) StromNEV 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 2019. In 2018, a total of 4,963 notifications for individual network charges for atypical network users were registered with the Bundesnetzagentur (see Table 62).

Electricity: notifications for individual network charges for atypical network users in accordance with section 19(2) sentence 1 StromNEV

	2015	2016	2017*	2018*	New items 2019	2019*
Total number of offtake points granted reductions	2,987	3,375	4,124	4,963	1,096	6,059
Total energy (TWh)	25.3	25.8	29.5	35.5	5.2	40.7
Total reductions (€m)	292.2	310.8	341.5	368.9	45.9	414.8

*Data for the years from 2017 to 2019 are based on forecasts from the notifications submitted and are therefore classed as estimates.

Table 62: 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 €414.83m.

The total amount of reductions in network charges granted to electricity-intensive network users in 2019 was considerably higher at €999.1m (see Table 63), although the number of notifications for reductions for these users was significantly lower. In 2019, reductions were granted for a total of 371 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 2018.

In the 2019 notification period, the Bundesnetzagentur received 163 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 €999.1m, with a total of 552 offtake points. The total amount of reductions for electricity-intensive network users is also expected to increase significantly to around €999.1m. The final figures for 2019 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.

Electricity: notifications for individual network charges for electricity-intensive network users in accordance with section 19(2) sentence 2 StromNEV

	2015	2016	2017	2018*	New items 2019	2019*
Total number of offtake points granted reductions	275	317	289	389	163	552
Total energy (TWh)	42.6	45.2	44.7	52.9	36.9	89.8
Total reductions (€m)	324.5	388.4	525.5	611.3	387.8	999.1

*Data for 2018 and 2019 are based on forecasts from the notifications submitted and are therefore classed as estimates.

Table 63: Notifications for individual network charges for electricity-intensive network users

Electricity: breakdown of total volume of reductions by network operator category (€m)

Level	2015	2016	2017	2018*	New items 2019	2019*
Transmission network	69.0	79.0	117.9	141.4	221.5	362.9
Regional network	142.0	168.0	224.9	247.9	73.6	321.5
Distribution network	114.0	141.0	182.7	222.0	92.7	314.7
Total	324.5	388.4	525.5	611.3	387.8	999.1

*Data for 2018 and 2019 are based on forecasts from the notifications submitted and are therefore classed as estimates.

Table 64: Breakdown of total volume of reductions by network operator category

Electricity: breakdown of total final consumption by network operator category (€m)

Level	2015	2016	2017	2018*	New items 2019	2019*
Transmission network	13.0	13.0	13.5	16.6	22.8	39.4
Regional network	18.0	19.0	18.2	20.1	7.8	27.9
Distribution network	12.0	13.0	13.0	16.2	6.3	22.5
Total	42.6	45.2	44.7	52.9	36.9	89.8

*Data for 2018 and 2019 are based on forecasts from the notifications submitted and are therefore classed as estimates.

Table 65: Breakdown of total final consumption by network operator category

6.9 Rescission of the network charge exemptions granted under section 18(2) of the Electricity Network Charges Ordinance (old version) for 2012 and 2013

On 28 May 2018, the European Commission ruled in the procedure for case SA.34045 in accordance with Article 108 of the Treaty on the Functioning of the European Union (TFEU) that the full exemptions from network charges granted in Germany in 2012 and 2013 on the basis of section 19(2) of the Electricity Network Charges Ordinance (StromNEV), in the version dated 4 August 2011, at least partly constituted state aid in contravention of European law and had to be rescinded.

This affected over 200 companies under the responsibility of the Bundesnetzagentur and the federal state regulatory authorities.

The repayment volume amounted to €167.8m, plus recovery interest amounting to around €10.5m, and was taken into account with the effect of reducing the section 19 surcharges for 2019 and 2020.

In 75 cases, recovery did not have to take place owing to the de minimis rule affecting recovery sums less than €200,000.

Both the European Commission Decision itself and some of the recovery decisions issued by the regulatory authorities are still the subject of pending court proceedings.

7. Electric vehicles/charging stations and load control

Drivers of electric vehicles can find information about the location and type of recharging points in Germany on the Bundesnetzagentur website. This information is provided by operators of recharging points accessible to the public and published, creating transparency. Charging points are assessed for compliance with interoperability requirements, ensuring that users can find the plug they need on any recharging point.

7.1 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 as well as all high-power charging points with a capacity of more than 22 kW 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 https://www.bundesnetzagentur.de/ladesaeulen.

The Bundesnetzagentur was notified of a total of 10,797 charging stations with 21,181 recharging points by 16 July 2019, of which 17,958 recharging points had a power less than or equal to 22 kW (normal-power recharging points) and 3,223 were high-power recharging points.

By contrast, according to information from the mineral oil industry association (MWV), there are 14,459 petrol stations in Germany as at 2019. The number of German petrol stations is falling slightly.[54]

According to the Kraftfahrt-Bundesamt (KBA – Federal Motor Transport Authority), 189,710 fully electric passenger vehicles and plug-in hybrids were registered as at 1 July 2019. Based on the data available to the Bundesnetzagentur, the appropriate number of recharging points given as an indication in Directive

[54] https://www.mwv.de/statistiken/tabellenstand

2014/94/EU of one recharging point per ten vehicles is therefore achieved nationwide (approximately one recharging point per nine vehicles).

The recharging points for electric vehicles notified are spread across the federal states as follows:

Electricity: distribution of notified charging infrastructure in the federal states

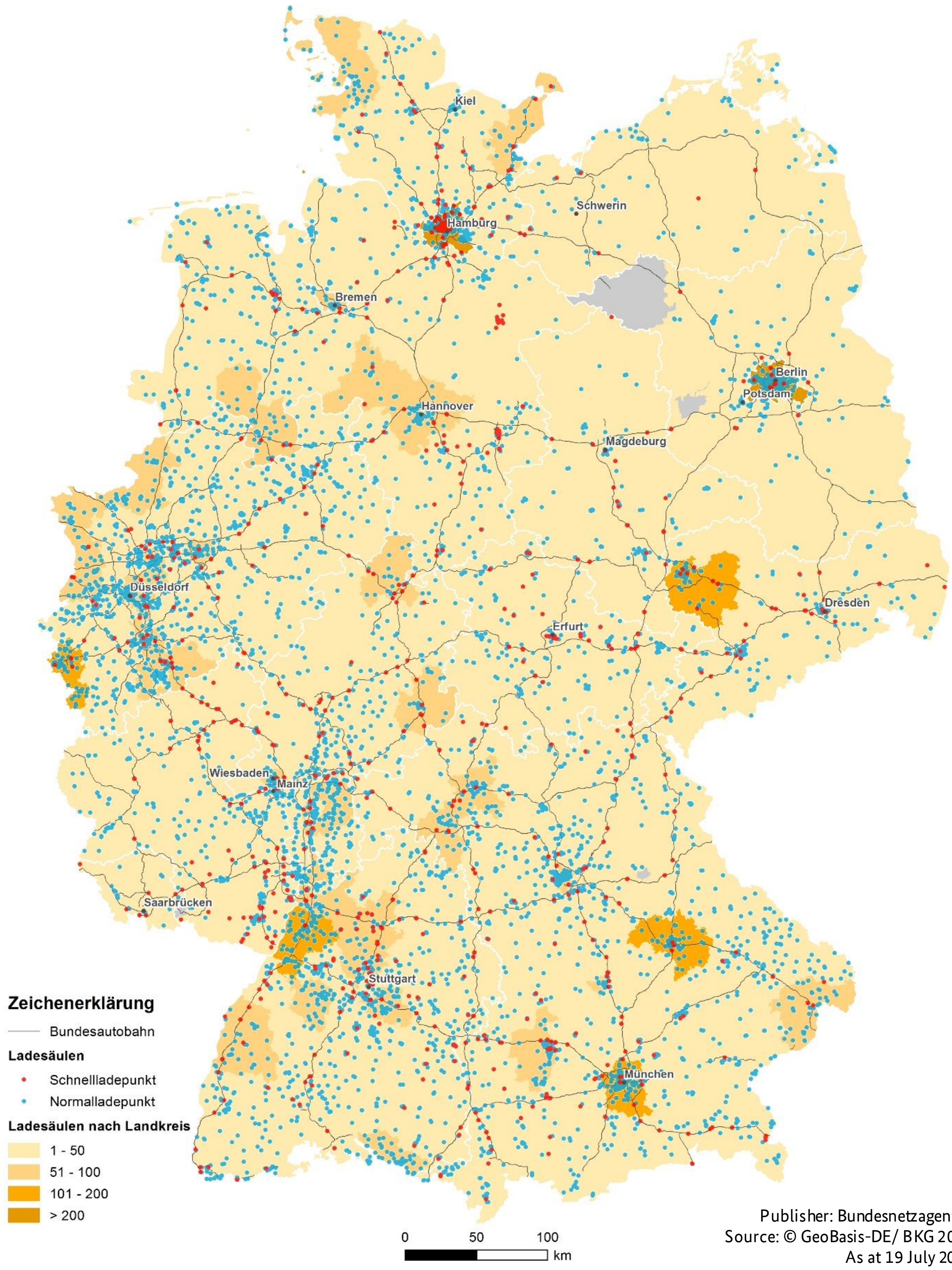
Federal state	Charging stations	Recharging points	High-power recharging points	Electric vehicles* per recharging point
Baden-Württemberg	1,589	3,094	608	12
Bavaria	2,280	4,570	633	9
Berlin	497	925	61	7
Brandenburg	220	428	71	9
Bremen	81	168	20	6
Hamburg	457	924	74	5
Hesse	785	1,503	201	11
Mecklenburg-Western Pomerania	129	241	38	6
Lower Saxony	1,017	1,879	414	8
North Rhine-Westphalia	1,983	3,894	388	9
Rhineland-Palatinate	496	961	255	9
Saarland	44	90	19	18
Saxony	341	770	142	7
Saxony-Anhalt	161	320	68	7
Schleswig-Holstein	476	932	119	7
Thuringia	315	631	136	6

*Electric vehicles and plug-in hybrids as at 1 July 2019

Table 66: Distribution of notified charging infrastructure in the federal states (as at July 2019)

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 https://www.bundesnetzagentur.de/ladesaeulenkarte.

Electricity: charging stations in Germany notified pursuant to the Charging Station



Publisher: Bundesnetzagentur
Source: © GeoBasis-DE/ BKG 2019
As at 19 July 2019

Figure 71: Charging stations in Germany notified pursuant to the Charging Station Ordinance (LSV) (as at July 2019)

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 with at least one vehicle connector of the "Combo 2" charging system. Alternating current recharging points require a "Type 2" plug system. There are still differing requirements for alternating current recharging points, depending on their charging capacity. 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 the 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 percentages relate in each case to all charging plugs at notified recharging points.

Electricity: breakdown of charging plugs by type in Germany
(%)

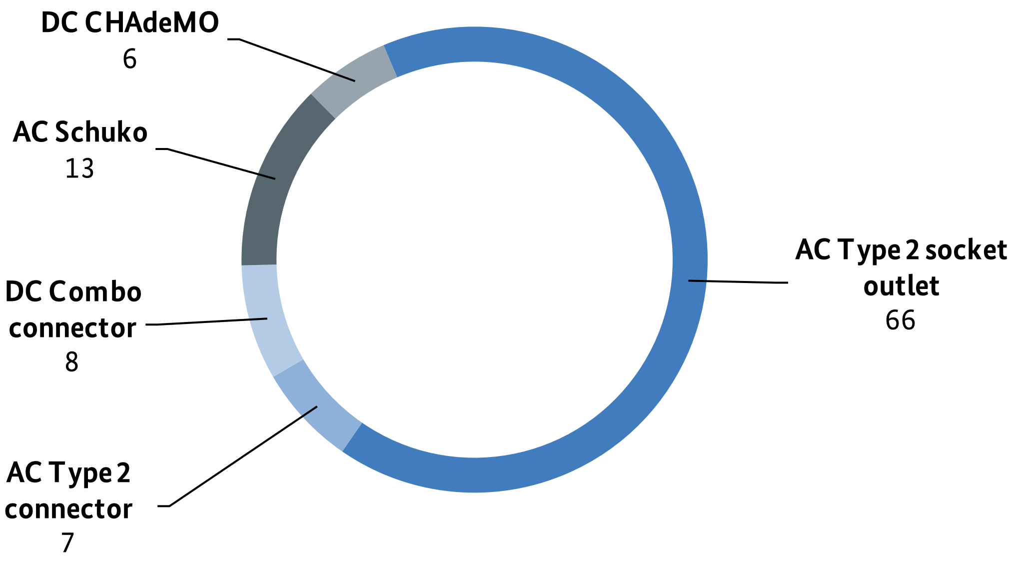


Figure 72: Breakdown of charging plugs by type in Germany

The charging capacities of the recharging points are distributed as shown in Figure 73. 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/150 kW (DC Combo connector) and 50 kW (DC CHAdeMO). An increasing number of high-power charging stations with "DC Combo connector" plugs and a power less than or equal to 350 kW are now being installed.

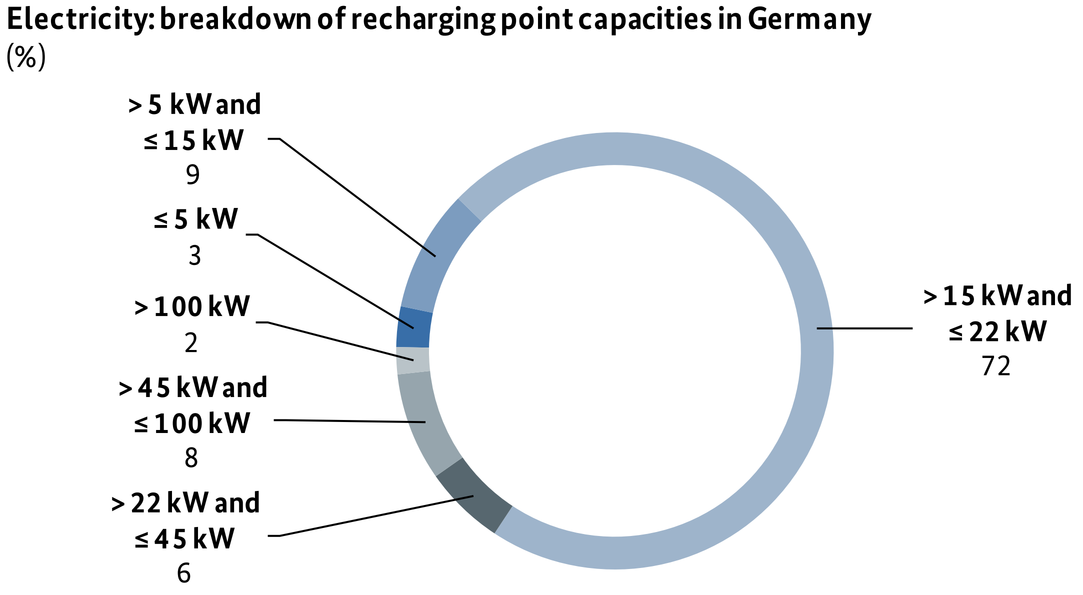


Figure 73: Breakdown of recharging point capacities in Germany

Since 2018, the Bundesnetzagentur has been working together with the PTB (Physikalisch-Technische Bundesanstalt – National Metrology Institute) and now also records the public keys for the notified recharging points. The user can enter the verification key on the metering equipment into verification software provided by the e-mobility provider.

With this software, the user can verify whether the meter data given in the invoice are identical to the actual meter results and are also actually from the recharging point at which the vehicle was charged. The charging station information published on the Bundesnetzagentur's website now includes the public keys for the charging stations concerned.

7.2 Load control

Section 14a of the Energy Industry Act (EnWG) gives DSOs at the low-voltage level the ability to use consumers' flexibility. They are able to conclude load control agreements in the interest of the grid in return for a reduction in the network charge. The aim is to prevent the consumption of a large amount of electricity from the low-voltage network at the same time, leading to localised overloading. The provision generally refers to consumer equipment such as night storage heating systems and heat pumps.

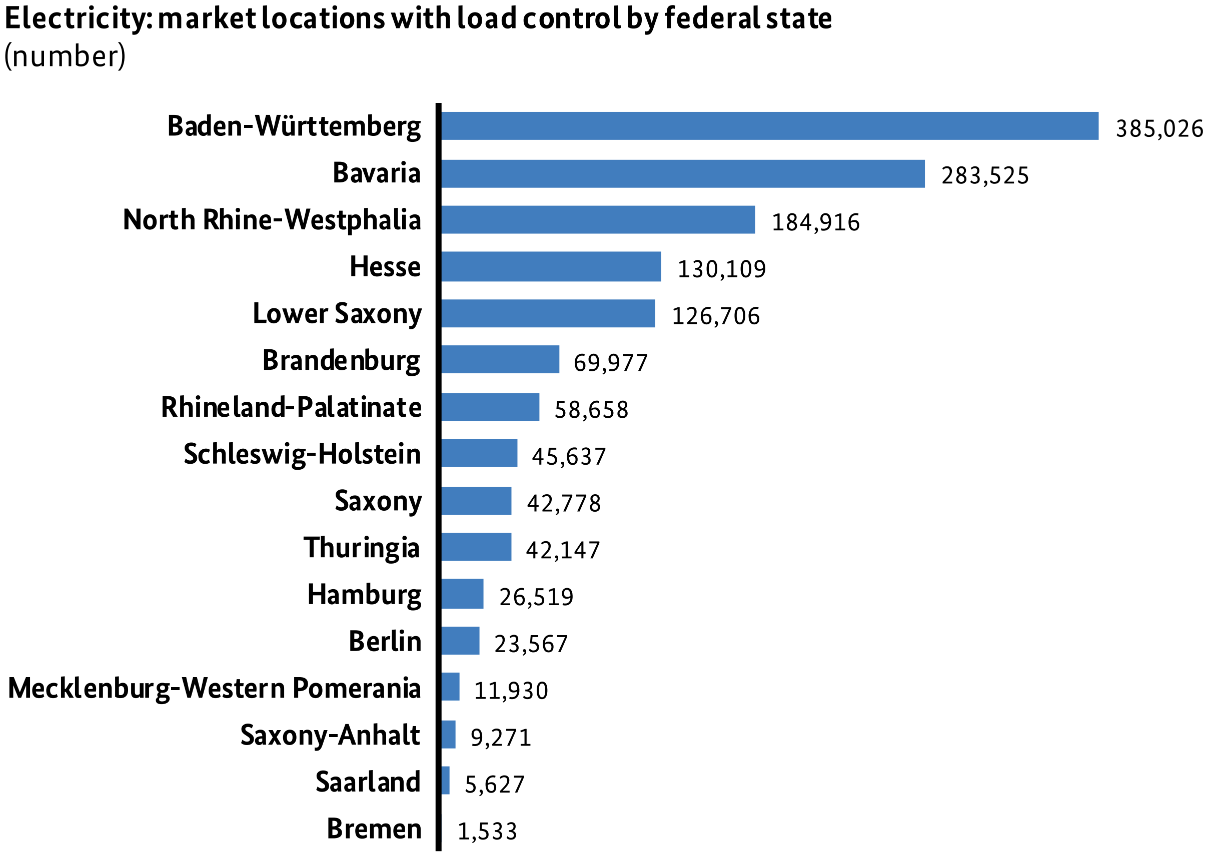


Figure 74: Market locations with load control by federal state

A total of 677 out of the 844 network operators surveyed stated that they took advantage of the provision and levied reduced network charges for a total of 1,448,759 market locations with load control. This represents a year-on-year increase of about 46,000 items of equipment. The regional distribution is shown in Figure 74. The chart shows a high concentration in Baden-Württemberg and Bavaria, with around half of all the market locations with load control in these two southern federal states. The reason for this is likely to be historical, since the provision was originally intended to create constant demand for the constant production by nuclear power plants.

Electricity: market locations with load control by load type (%)

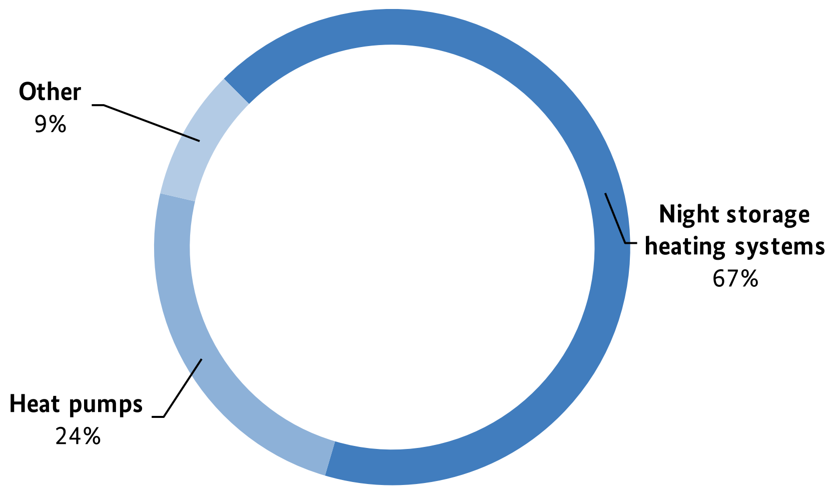


Figure 75: Breakdown of market locations with reduced network charges by load type

It is still the case that almost all the market locations with load control are for heating systems (see Figure 75), and direct electric heating also accounts for most of the "Other" loads, with only a few sprinkler or street lighting systems also counted in this category. The proportions of different types of load have changed slightly in comparison with last year, with the share of night storage heaters down about two percentage points and the share of heat pumps up by about the same amount.

The average reduction in the network charge given by network operators in return for load control is 55%, which corresponds to a discount of 3.44 ct/kWh. As the size of the discount is not specified by regulation, there is a wide range of reductions offered by network operators. The highest discount is 91% of the charge for the use of the network, while the lowest is just 6%, although the difference between the reductions for the different types of load is negligible.

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: just under 60% of the network operators use ripple control for night storage heating systems and for heat pumps, while barely 2% use the more modern remote control technology. About 5% do not use any control technology at all, while more than 30% use time switching. Figure 76 shows a more detailed breakdown of the control technologies used.

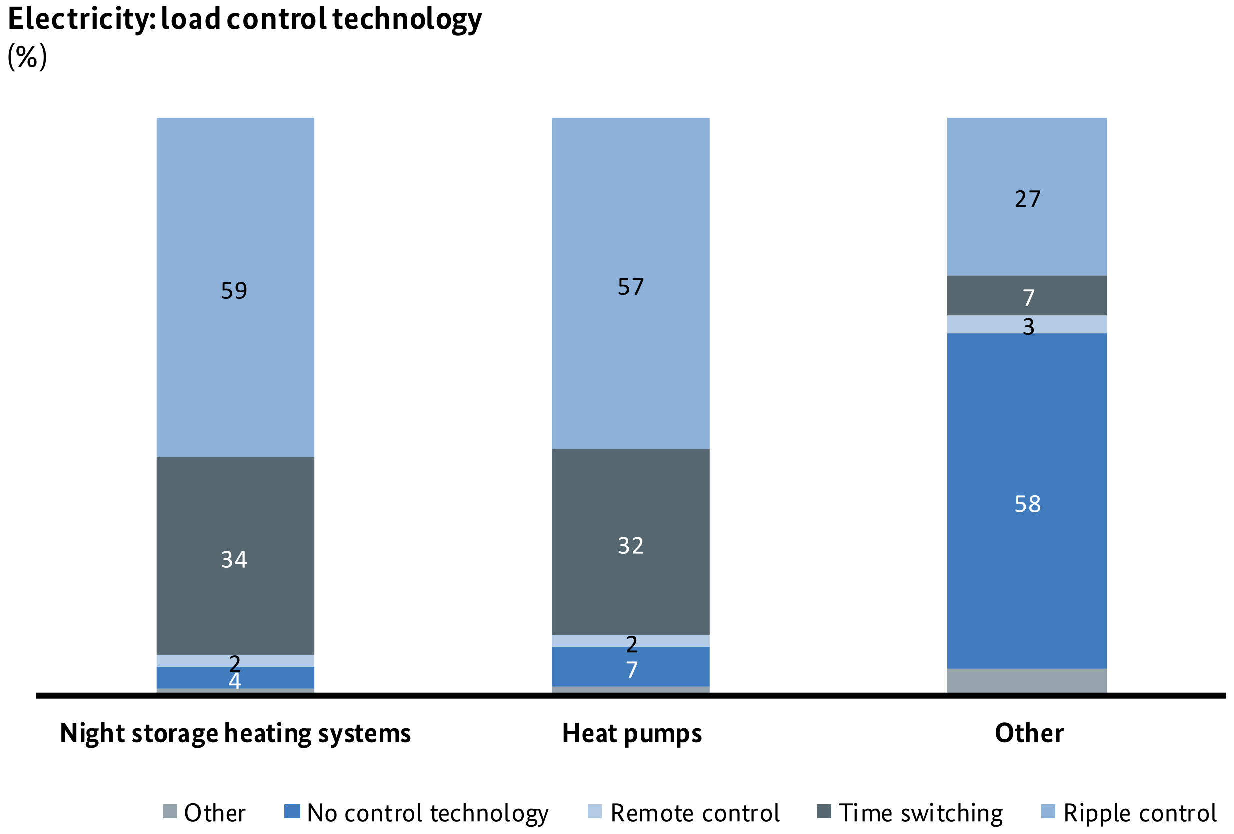


Figure 76: Load control technology

As far as a move to more modern technology is concerned, there has been no significant change from last year. In future, any loads wishing to benefit from the arrangements in section 14a EnWG 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 of the 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.

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 system frequency by contracting and using the three types of balancing services: frequency containment reserves (FCR), automatic frequency restoration reserves (aFRR) and manual frequency restoration reserves (mFRR). 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 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) are also part of the range of system services.

1. Costs for system services

The total costs for these system services[55] recovered through the network charges decreased from €1,983.1m in 2017 to about €1,881.39m in 2018.

A large part of the costs in 2018 were accounted for by the costs of contracting and using grid reserve power plants at around €415.5m (down 13% from €480.0m in 2017), national and cross-border redispatching at €351.5m (down 10% from €391.6m in 2017), the estimated claims for compensation for feed-in management measures at €635.4m (up 4% from €609.9m in 2017), contracting FCR, aFRR and mFRR at €123.3m (down 15% from €145.5m in 2017), and energy to compensate for losses at about €273.2m (down 3% from €280.4m in 2017).

One reason why the costs of contracting balancing capacity fell again, this time by €52.6m, is the further decrease in the volume of the three types of balancing capacity contracted (see also I.D.2.1). The total costs for network and system security measures (redispatching using operational and grid reserve power plants, countertrading, feed-in management) were still high at €1,438.5m but were slightly down on 2017 (see also I.C.5). Figure 77 shows the development in the costs for system services from 2014 to 2018. Figure 78 shows a breakdown of the costs for 2018.

[55] Net costs (outlay costs minus cost-reducing revenues) and costs for grid reserve power plants and interruptible loads under the AbLaV.

Electricity: costs for system services (€m)

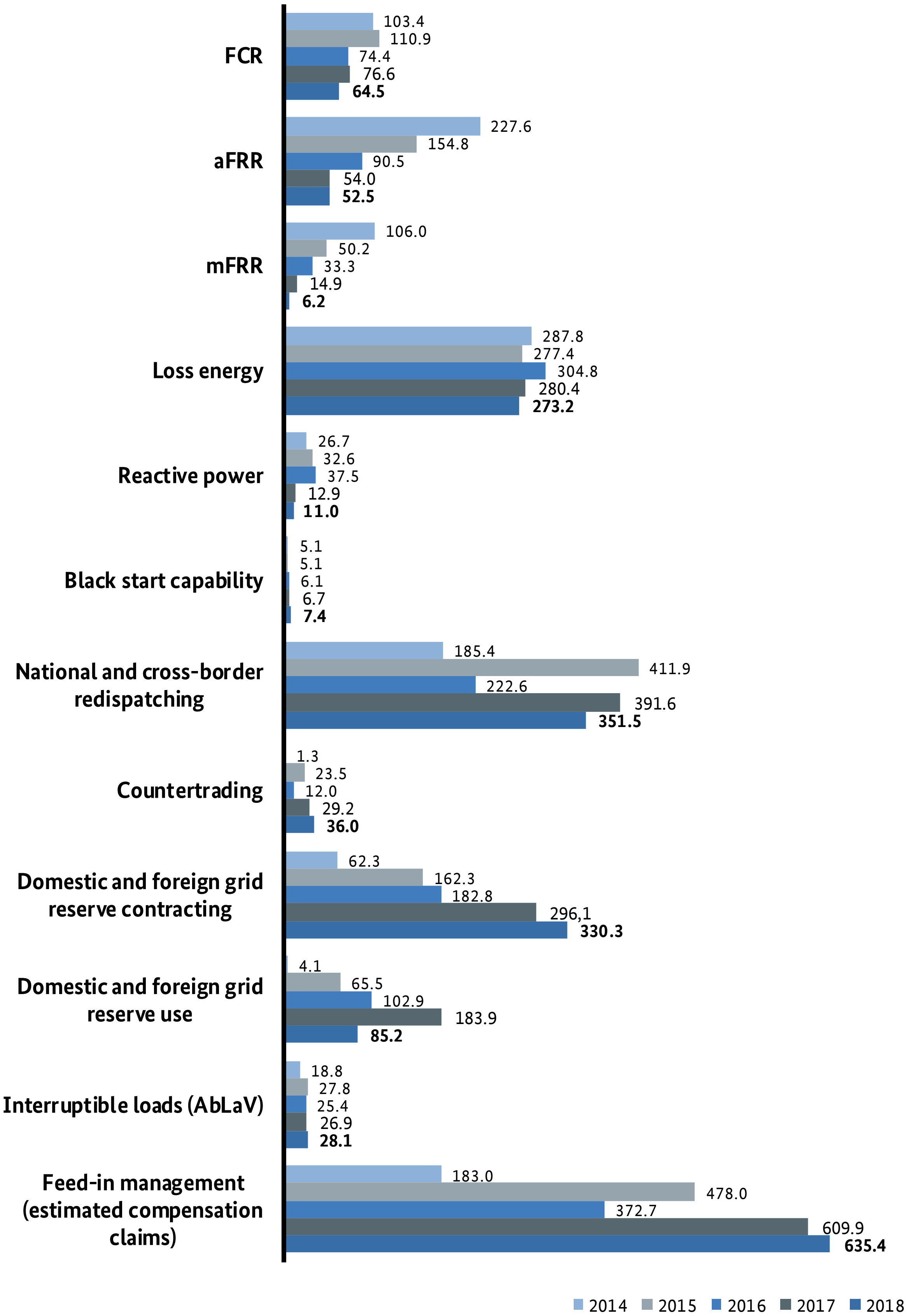
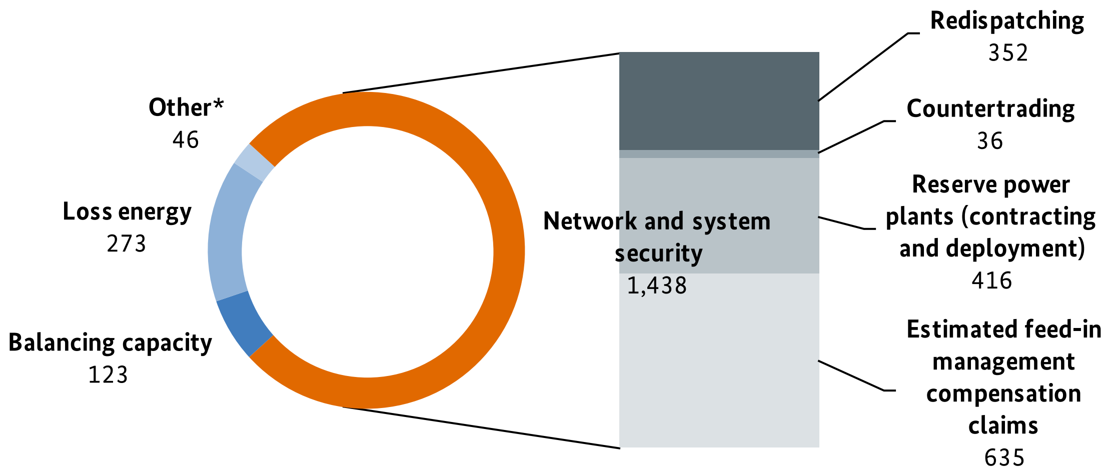


Figure 77: Costs for system services from 2014 to 2018

Electricity: breakdown of costs for system services and for network and system security in 2018 (€m)



*Other: reactive power, black start capability, interruptible loads under AbLaV

Figure 78: Breakdown of the costs for system services and for network and system security in 2018

2. Balancing services

The transmission system operators (TSOs) contract balancing capacity and use it in the form of balancing energy as required to continuously balance demand and generation in the electricity supply system and thus maintain the stability and frequency of the system. The provision of balancing capacity and/or balancing energy is referred to as balancing services.[56] The TSOs can contract and use three types of balancing service that are used in a certain order:

– Frequency containment reserves (FCR) – FCR are used to maintain the system frequency. They regulate positive and negative frequency deviations in the electricity system automatically and continuously within 30 seconds. The period of time covered for each disturbance is from zero to 15 minutes. After 15 minutes, the capacity must be released so that it is available again to regulate new, unforeseeable frequency deviations. The energy delivered is not metered or charged for.[57]

– Frequency restoration reserves with automatic activation (aFRR) – aFFR are a type of frequency restoration reserve used to restore the system frequency to the nominal frequency of 50 Hz after a disturbance. They are activated automatically by the TSOs and must be fully available within five minutes

[56] Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing, Article 2 point (3).

[57] Only balancing capacity prices are paid for FCR. Balancing energy prices are not paid because the positive and negative capacity delivered averages out to zero. On average, in the course of a contract period, the same amount of electrical energy is fed into the grid as is withdrawn. In addition, charging balancing energy prices would entail considerable transaction costs as a result of continuous frequency balancing.

of activation by the connecting TSO. The period of time covered for each disturbance is from 30 seconds to 15 minutes.

– Frequency restoration reserves with manual activation (mFRR) – mFFR are also a type of frequency restoration reserve. They are activated manually and used to support or replace aFRR and must be fully available within 15 minutes.

The following figure shows the order and time frame for the use of the different types of balancing service.

Electricity: order and time frame for the use of balancing services

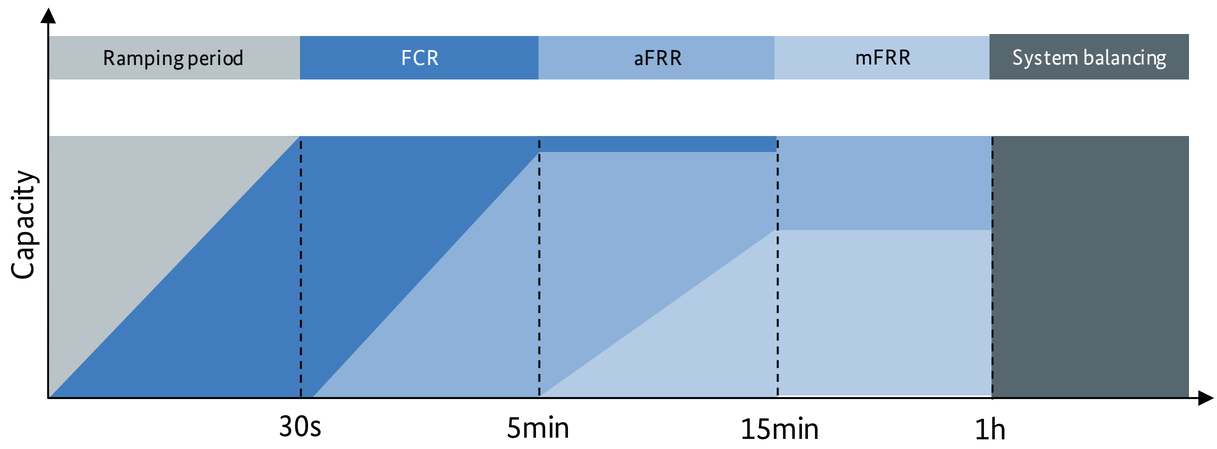


Figure 79: Order and time frame for the use of balancing services

A distinction is made between positive and negative balancing services. If, at any one time, less energy is fed into the system than is required, the system frequency will be below the nominal frequency of 50 Hz. Positive balancing services are required to restore the system frequency to the nominal frequency. In this case, the TSO will – on a short-term basis – need more energy to be fed into the system and/or less energy to be consumed. The TSO procures both types of balancing service from balancing service providers. If, at any one time, more energy is fed into the system than is required, there will be too much power in the system and the system frequency will be above the nominal frequency of 50 Hz. In this case, the TSO will – on a short-term basis – need negative balancing services in the form of electricity consumers withdrawing more electricity from the system and/or electricity generators feeding less electricity into the system. The TSO also procures these services from balancing service providers.

A grid control cooperation comprising the control areas of the four responsible TSOs (50Hertz, Amprion, TenneT and TransnetBW) has been in place in Germany since 2010. The cooperation creates a nationally uniform, integrated market mechanism for aFRR and mFRR and thus optimises the costs of using balancing capacity for the whole of Germany. Under the cooperation, the imbalances in the individual control areas are netted so that only what remains has to be compensated for by using balancing services. Inefficient use in the different control areas is almost completely eliminated and the volume of balancing capacity required is reduced.

Module 1 of the national cooperation, which aims to prevent the inefficient use of aFRR, has been expanded over the past few years into an international cooperation. Under the International Grid Control Cooperation (IGCC), Germany cooperates with Denmark, the Netherlands, Switzerland, Czechia, Belgium, Austria and France to avoid the inefficient use of balancing services. Since no fixed transmission capacity at the borders is reserved for the cross-border exchange of energy (only the free capacity available can be used to exchange the balancing energy), the TSOs in each country still need to contract sufficient balancing capacity nationally to cover their own requirements. The cooperation under IGCC is, however, reflected by the decrease in the activated volumes of aFRR and, indirectly, mFRR (see also I.D.3.3).

2.1 Tendering for balancing capacity

Up until now, the TSOs responsible for the control areas in Germany have procured the balancing capacity that they require for system balancing in national tendering processes in accordance with the provisions of the Bundesnetzagentur's determinations on FCR, aFRR and mFRR.

The tendering for the procurement of aFRR and mFRR will, however, be redesigned following the entry into force of new European provisions.[58]

The new provisions require the TSOs to introduce a balancing energy market for aFRR and mFRR. The Bundesnetzagentur approved the TSOs' balancing market application on 2 October 2019 (BK6 18 004 RAM). Under the approval, there will be separate tendering processes for balancing capacity and balancing energy as from mid 2020. Up until now, balancing energy could only be delivered by providers participating in the capacity market; in future, balancing energy may be delivered by all pre-qualified providers and – in contrast to the current design of the tendering process – will be independent of participation in the capacity market.

FCR will be procured as a symmetric product. No distinction will be made between positive and negative balancing services. Nor will a distinction be made between "holding" and "delivering" FCR capacity and consequently there will be no separate tendering processes for FCR capacity and energy and therefore no balancing energy market.

In the past, balancing capacity has been mainly provided by conventional power plants. It is now also increasingly being offered by battery storage systems. Renewable generators providing balancing capacity today include hydro power and, in particular, biogas plants. 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 the electricity supply in the future. To make it easier for flexible generators such as wind turbines to participate in the balancing markets, in June 2017 the Bundesnetzagentur issued new tendering conditions and publication requirements for aFRR and mFRR (BK6 15 158/159).[59] As a result, in July 2018 the tendering frequency for aFRR was changed from one week to one calendar day. In addition, the product validity period was shortened considerably to four hours. These changes 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 mFRR included changing the tendering frequency from one working day to one calendar day. In addition, new rules

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[58] Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing and Regulation (EU) 2019/943 of the European Parliament and of the Council 5 June 2019 on the internal market for electricity

[59] A pilot project initiated by the TSOs responsible for the control areas and initially running until the end of 2019 already gives wind generators the opportunity to pre-qualify as mFRR providers and to provide mFRR.

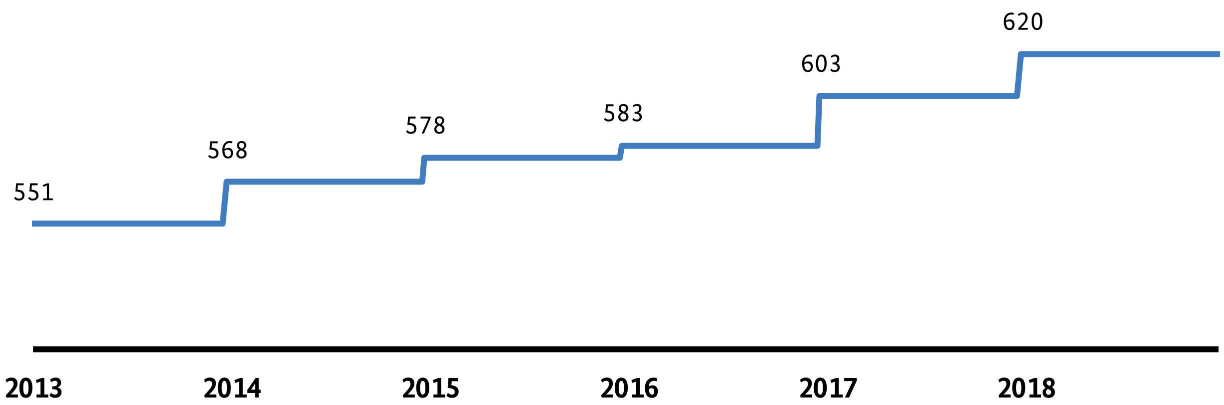
were introduced on the minimum bid volumes and safeguards for both aFRR and mFRR. These framework conditions also apply in the balancing energy market.

The national grid control cooperation and the determinations issued by the Bundesnetzagentur contribute to increasing competition among balancing service providers by creating a national market for aFRR and mFRR and aligning the tendering conditions. By 24 June 2019, the number of pre-qualified balancing service providers stood at 30 for FCR (2018: 24; 2013: 14), 37 for aFRR (2018: 38; 2013: 20) and 45 for mFRR (2018: 46; 2013: 36).[60] There has thus been another large increase in the number of FCR providers. Following large increases in the number of pre-qualified providers for aFRR and mFRR in recent years, the number of providers of these types of balancing service has remained stable at a high level. The large number of balancing service providers shows how attractive the balancing service markets are.

Procurement of FCR

FCR procurement needs are determined jointly by the European Network of Transmission System Operators for Electricity (ENTSO E) and are based on the simultaneous failure of the two largest power plant blocks within the network area. The total amount – currently 3,000 MW – is divided proportionally between the participating TSOs; the proportions are recalculated each year on the basis of the electricity feed-in in the previous year. Figure 80 shows a continued slight increase in the amount of FCR to be contracted by the German TSOs in recent years. In 2018, there was another small increase to 620 MW from 603 MW in 2017.

Electricity: FCR tendered in the control areas of 50Hertz, Amprion, TenneT and TransnetBW (MW)



Source: regelleistung.net

Figure 80: FCR tendered in the control areas of 50Hertz, Amprion, TenneT and TransnetBW

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

Procurement of aFRR

Figure 81 shows that there was another slight decrease in the average volume of both positive and negative aFRR tendered in 2018. The average volume of positive aFRR tendered was 1,876 MW (2017: 1,906 MW) and the average volume of negative aFRR tendered was 1,780 MW (2017: 1,835 MW).

Electricity: aFRR tendered in the control areas of 50Hertz, Amprion, TenneT and TransnetBW
(MW)

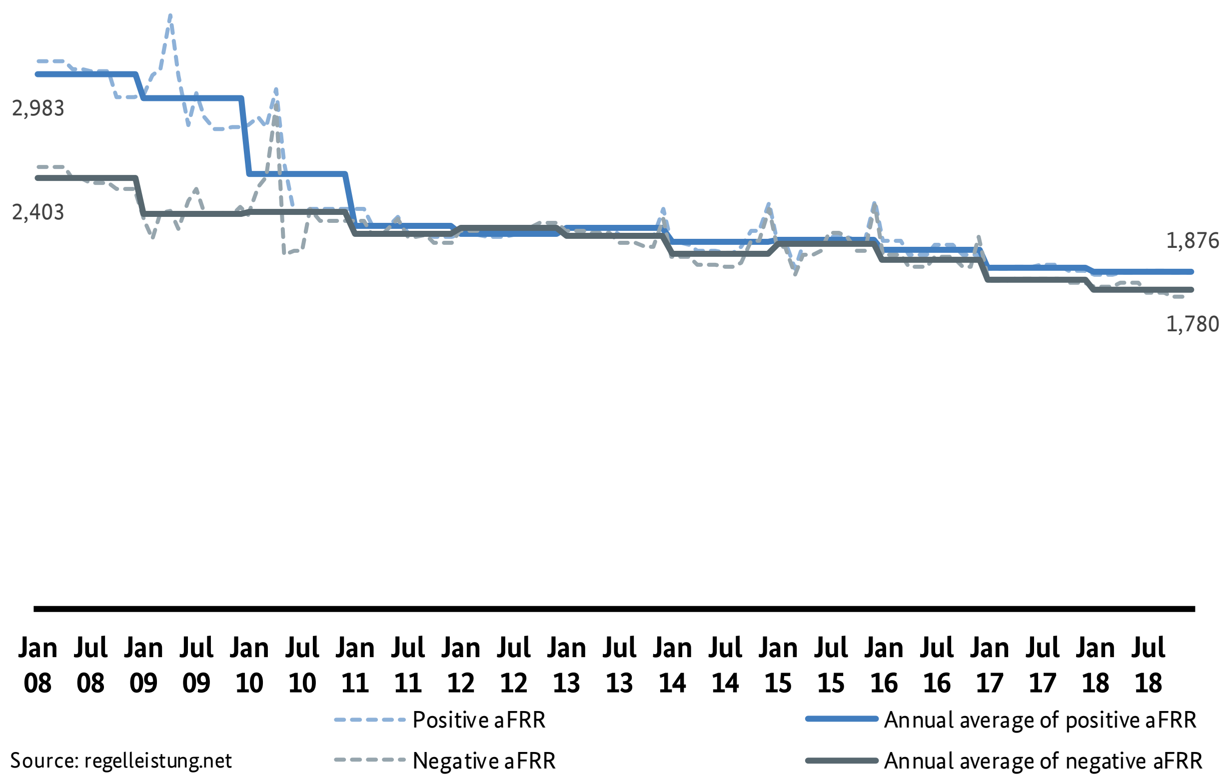


Figure 81: aFRR tendered in the control areas of 50Hertz, Amprion, TenneT and TransnetBW

Similarly, there was another slight decrease in the highest and lowest volumes of positive and negative aFRR tendered compared to the previous year (see Table 67).

Electricity: range of aFRR tendered by the TSOs

	Year	Capacity tendered (MW)	
		Min	Max
aFRR (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
	2017	1,890	1,920
	2018	1,869	1,907
aFRR (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
	2017	1,818	1,846
	2018	1,745	1,820

Source: regelleistung.net

Table 67: Range of aFRR tendered by the TSOs

An analysis of recent years shows that there have only been small fluctuations in the volumes tendered during the course of each year, even though there was a small increase in 2018. The volumes of positive aFRR tendered in 2018 ranged from 1,869 MW to 1,907 MW (2017: from 1,890 MW to 1,920 MW) and the volumes of negative aFRR from 1,745 MW to 1,820 MW (2017: from 1,818 MW to 1,846 MW).

Procurement of mFRR

The picture is less uniform when it comes to mFRR. While there was a continued decrease in the average volume of positive mFRR tendered from 3,191 MW to 1,907 MW between 2008 and 2012, the average volumes in 2013 and 2014 were 2,482 MW and 2,376 MW respectively. Since 2015, the average volume of positive mFRR tendered has been decreasing continually. In 2018, the average volume decreased again to 1,166 MW from 1,318 MW in 2017. However, demand for positive mFRR ranged from 641 MW to 1,419 MW.

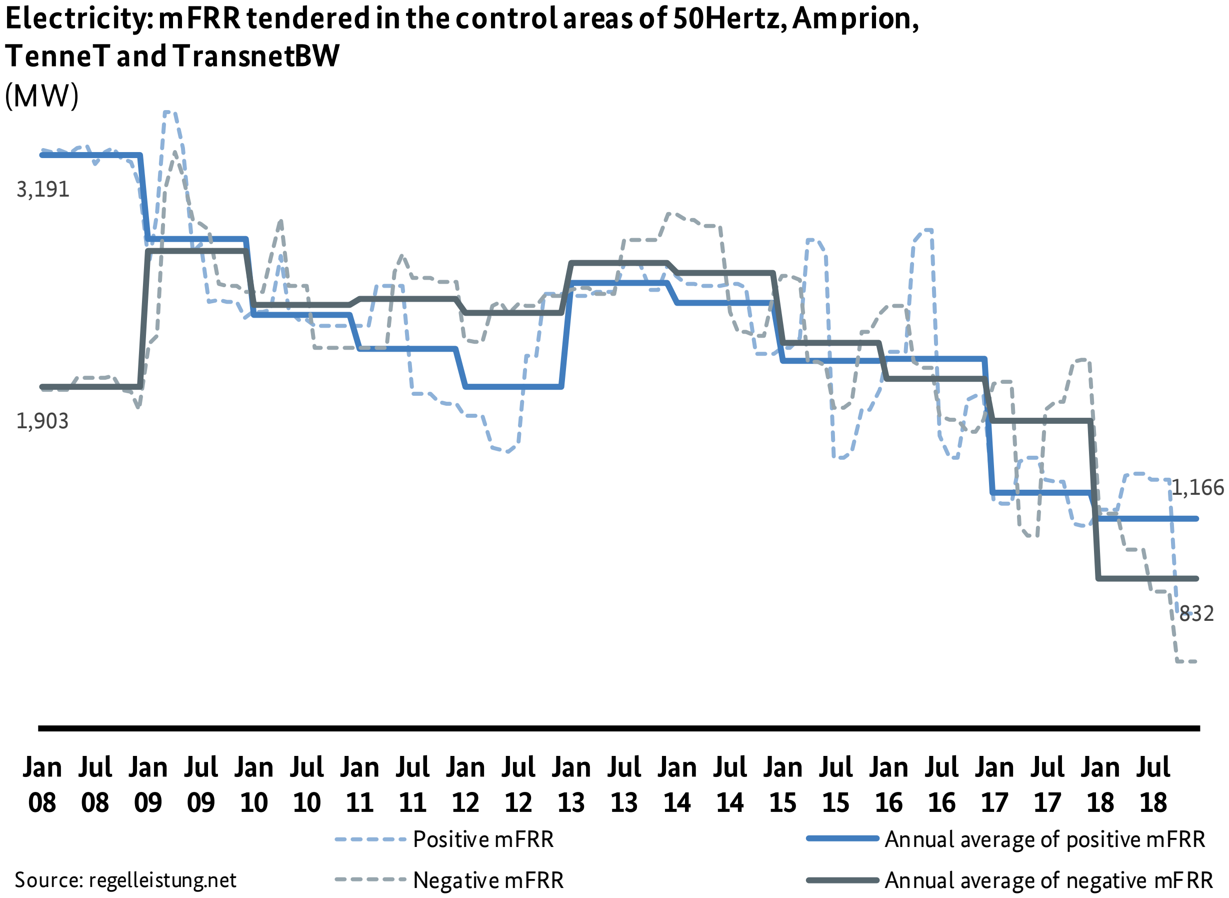


Figure 82: mFFR tendered in the control areas of 50Hertz, Amprion, TenneT and TransnetBW

There was a year-on-year decrease in the average volume of negative mFRR tendered from 1,717 MW in 2017 to 832 MW in 2018. The volume tendered decreased continuously in the course of the year from the high of 1,199 MW in January 2018 to the low of 375 MW in December 2018. The range between the highest and lowest volumes of negative mFRR tendered narrowed again, having widened in the previous year (see also Table 68).

Electricity: range of mFRR tendered by the TSOs

	Year	Capacity tendered (MW)	
		Min	Max
aFRR (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
	2017	1,131	1,850
	2018	641	1,419
aFRR (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
	2017	1,072	2,048
	2018	375	1,199

Source: regelleistung.net

Table 68: Range of mFRR tendered by the TSOs

2.2 Use of balancing capacity

Electrical energy can be stored only to a certain extent. To ensure that the amount of electrical energy generated is always the same as the amount of energy consumed, each generator and each consumer is allocated to a balancing group. Balance responsible parties (regional suppliers, electricity traders, suppliers, etc) are obliged to maintain the balance in their balancing group every quarter of an hour. In other words, the energy delivered to and drawn from the balancing group must balance each other out. Differences between the forecast and actual consumption of different balancing groups within the four control areas in Germany partly balance each other out (netting). Only the remaining difference – the sum of all the balancing group imbalances within the national grid control cooperation (known as the control area balance) – is compensated by using positive or negative balancing capacity through activating positive or negative balancing energy.

Figure 81 shows that the total volume of aFFR tendered and contracted has remained at a similar, comparatively low level in the last few years. The actual use of aFRR has also remained at a virtually constant level since 2013. The average volume of (positive and negative) aFRR used in 2018 was only slightly higher compared to the previous year.

Electricity: average volume of aFRR used, including aFRR drawn and delivered under online netting in the national grid control cooperation
(MW)

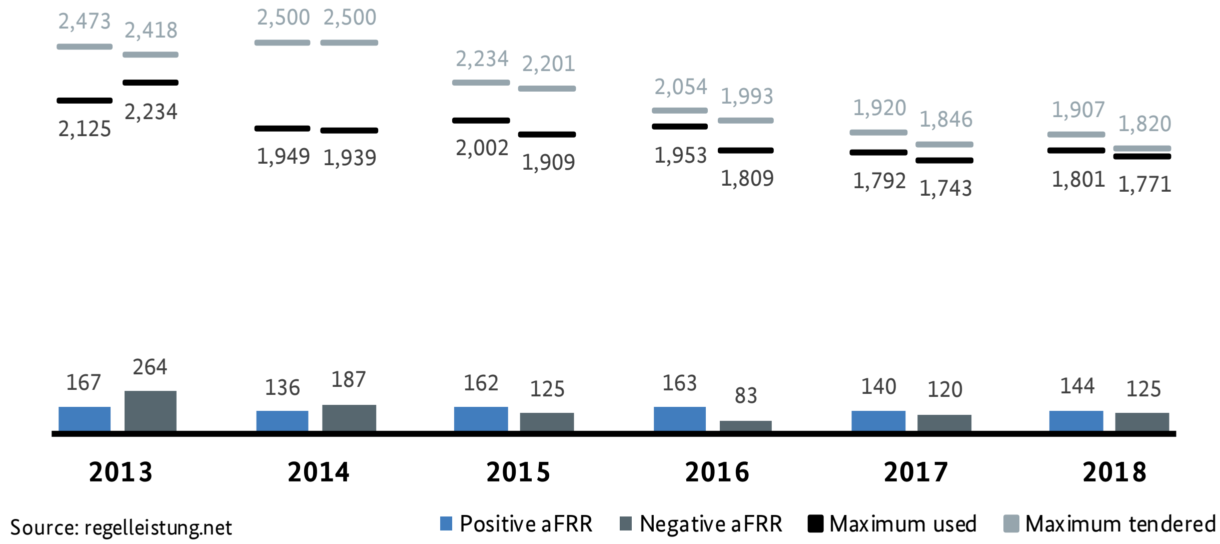


Figure 83: Average volume of aFRR used, including aFRR drawn and delivered under online netting in the national grid control cooperation

In 2018, the total amount of positive aFRR activated was some 1.3 TWh (2017: 1.2 TWh), and the total amount of negative aFRR activated was 1.1 TWh (2017: 1.1 TWh). The total sum of energy is virtually unchanged on the previous year.

On average in 2018, just under 8% of the average volume of positive aFRR tendered and just under 7% of the average volume of negative aFRR tendered was used (see Figure 83). It should be noted, however, that in a total of 88 quarter hours in the year, at least 80% of the average volume of the balancing capacity held was required; overall this confirms the necessity of the volumes tendered. The highest volumes of positive and negative aFRR requested (1,801 MW and 1,771 MW respectively) were only slightly lower than the highest volumes of capacity tendered (1,907 MW and 1,820 MW respectively).

The Bundesnetzagentur publishes market data on balancing capacity on its SMARD platform, where it is possible to view graphs and tables of the procured and activated volumes of the different types of balancing capacity.[61]

[61] https://smard.de/home/marktdaten/78?marketDataAttributes={"resolution":"hour","from":1535148000000,"to":1536097532454, "moduleIds":[18000426,18000427,18000428,18000429],"selectedCategory":null,"activeChart":true,"region":"DE","style":"color"}

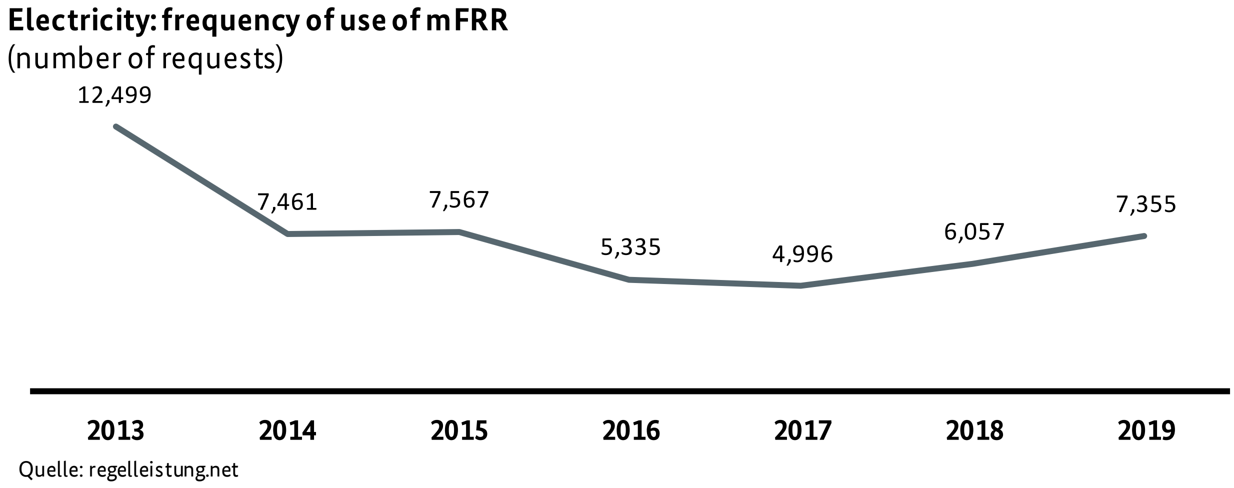


Figure 84: Frequency of use of mFRR

At 6,057, the total number of requests for mFRR was around 20% higher than in the previous year. Overall, there were 2,308 requests for negative mFRR in 2018, compared to 1,641 in 2017, and 3,749 requests for positive mFRR, compared to 3,355 in 2017.[62]

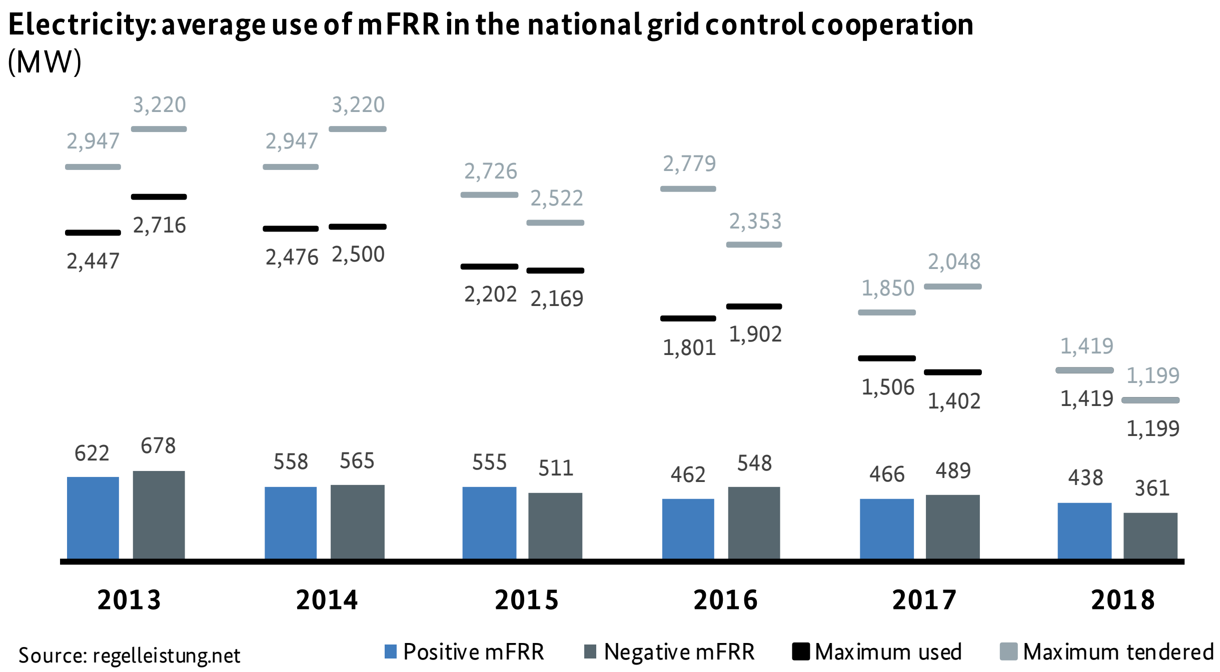


Figure 85: Average use of mFRR in the national grid control cooperation

In the quarter hours in which mFRR is requested, on average 31% of the positive mFRR tendered and 30% of the negative mFRR tendered is used. There was a small decrease in the average volume of positive mFRR

[62] The number of requests for aFRR is not illustrated separately because it is requested in nearly every quarter hour.

requested from 466 MW in 2017 to 438 MW in 2018. Likewise, there was a decrease in the average volume of negative mFRR requested from 489 MW in 2017 to 361 MW in 2018.

As with aFRR, however, it must be noted that in several quarter hours almost all of the mFRR held was required. In 422 cases, at least 80% of the average balancing capacity held was required; overall, this again confirms the necessity of the volumes tendered.

While aFRR is used in nearly all of the 35,040 quarter hours of a normal year, mFRR is only rarely used. Thus the actual frequency of use for aFRR is more or less the same as the possible frequency of use. By contrast, in 2018 only about 1% of the average volume of positive and negative mFRR tendered was used.

In 2018, a total of about 123 GWh of positive mFRR (2017: 135 GWh) and 63 GWh of negative mFRR (2017: 72 GWh) was activated. The frequency of use of both positive and negative mFRR has therefore increased, while the volume of positive and negative mFRR activated has decreased.

Figure 86 illustrates the average use of aFRR and mFRR in each calendar week from 2013 to 2018. Following a continual decrease in the average volume of aFRR and mFRR used and a decrease in volatility up to 2017, both the average volume of balancing capacity used and the volatility increased in 2018. The average volume of balancing capacity used remained at a high level up to mid-2019.

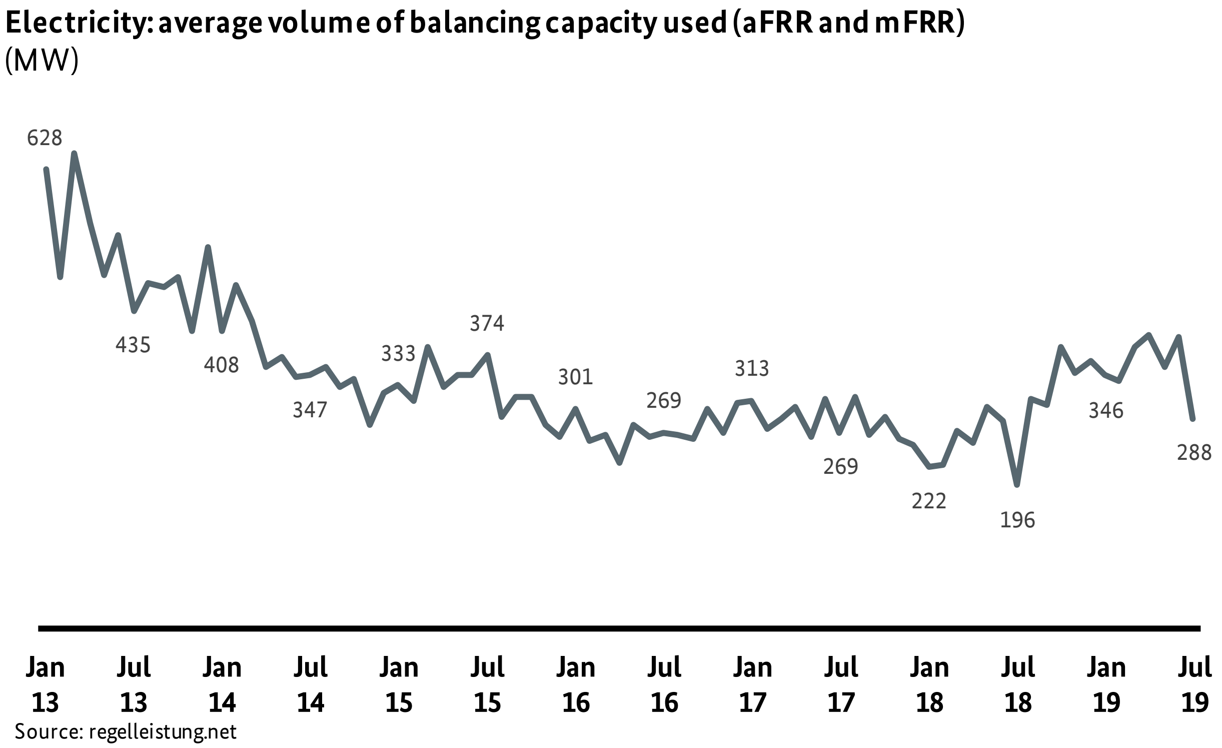


Figure 86: Average volume of balancing capacity used (aFRR and mFRR)

2.3 Imbalance prices

While the costs for contracting balancing capacity are included in the network charges through the network capacity charge and are thus borne by consumers, the costs for the actual use of balancing capacity – by activating balancing energy – are settled under what is known as the imbalance settlement directly with the balance responsible parties causing the imbalance.

Balancing energy is the electrical energy that is required to compensate for an imbalance in the system balance. While – as described above – only the control area balance is actually compensated by the use of balancing capacity, each individual imbalance in a balancing group has to be balanced out by the TSO responsible with positive or negative balancing energy and billed to the party responsible for the imbalance (even if the imbalance caused can be compensated by an imbalance in another balancing group). The amount of balancing energy used is therefore usually several times higher than the amount of balancing energy actually activated. The imbalance price is determined for each quarter hour as a uniform single imbalance price applicable to all the control areas (reBAP), which is basically calculated by dividing the total costs of the balancing energy used in the four control areas (based on the balancing energy price) with the corresponding total amount of balancing energy used in each quarter hour. The imbalance price thus has the effect of a surcharge that shares the costs for the balancing energy actually activated between the balance responsible parties that have caused an imbalance.

The exact imbalance price calculation methodology is based on the Bundesnetzagentur's determination that came into effect in December 2012 (BK6-12-024). The aim of the determination was to provide better incentives for the proper management of balancing groups with a view to preventing system-relevant imbalances. In cases where the balance of energy activated for control within the national grid control cooperation is close to zero (known as "zero crossings"), extreme imbalance prices may occur uniformly across all the control areas owing to the calculation formula used. In the period up to April 2016, the imbalance price was limited in such cases to the price of the highest balancing energy bid activated in the particular quarter hour. However, if the energy prices bid by the suppliers were correspondingly 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).[63] In cases where the imbalance within the national grid control cooperation 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.[64]

The highest ever imbalance price within the national grid control cooperation was €24,455/MWh in 2017 (see Table 69). Further details about this high imbalance price may be found in the Monitoring Report 2018 on page 187. This imbalance price, which is by far the highest to date, was due to the activation of mFRR balancing energy bids at a price of €77,777/MWh. While similarly high bids had been made in the past for both aFRR and mFRR, on 17 October 2017 these bids occurred for the first time not at the end but in the middle of the merit order list, so that a considerable number of such bids were activated. A causal analysis of the extremely high balancing energy bids revealed that the award mechanism for procuring balancing energy – under which bids were awarded on the sole basis of the balancing capacity price – needed to be adjusted. Under the determinations issued in 2018 (BK6 18 019 and BK6 18 020), the award mechanism was changed so

[63] Bundesnetzagentur communication on using the linearised multi-step model (in German): https://www.bundesnetzagentur.de/DE/Service-Funktionen/Beschlusskammern/1_GZ/BK6-GZ/2012/2012_0001bis0999/2012_001bis099/BK6-12-024/BK6-12-024_Mitteilung_vom_20_04_2016.html

[64] More detailed explanations may be found at https://www.regelleistung.net/ext/static/rebap.

that bids are awarded on the basis of the balancing energy price bid as well as the balancing capacity price. These determinations were annulled by the Higher Regional Court of Düsseldorf's ruling of 22 July 2019 (VI 3 Kart 806/18 [V]).

Electricity: maximum imbalance prices

Year	National grid control cooperation (€/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
2017	24,455.05
2018	2,013.51

Source: regelleistung.net

Table 69: Maximum imbalance prices

In 2018, the highest imbalance price was around €2,014/MWh. The price exceeded €500/MWh in a total of 3,043 quarter hours in 2018.

In 2018, the average volume-weighted imbalance price (per quarter hour) within the national grid control cooperation in the case of a positive control area imbalance (short portfolio: balancing service providers reduce consumption or increase feed-in) was up 4% on the previous year at €81.28/MWh. The average volume-weighted imbalance price in the case of a positive control area imbalance was thus around 84% above the average (peak) intraday trading price in 2018.[65] The average volume-weighted imbalance price in the case of a negative control area imbalance (long portfolio: balancing service providers increase consumption or reduce feed-in) was €1.62/MWh and thus near €0/MWh for the first time.

[65] Based on the EPEX SPOT average (peak) intraday trading price of €44.22/MWh for 2018.

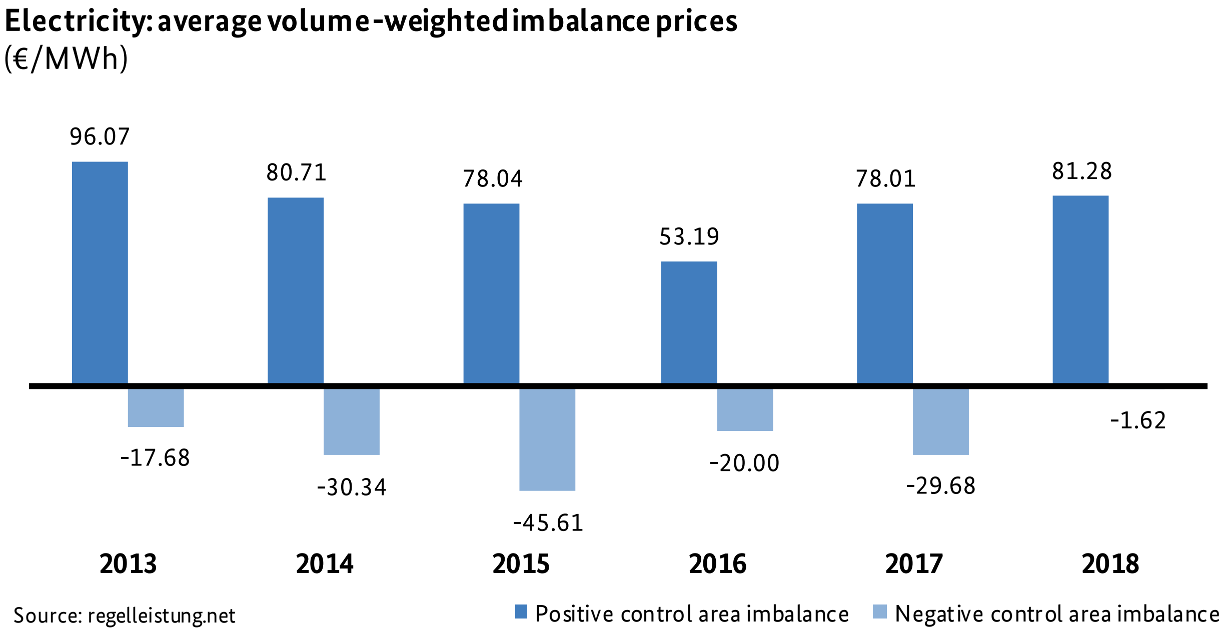


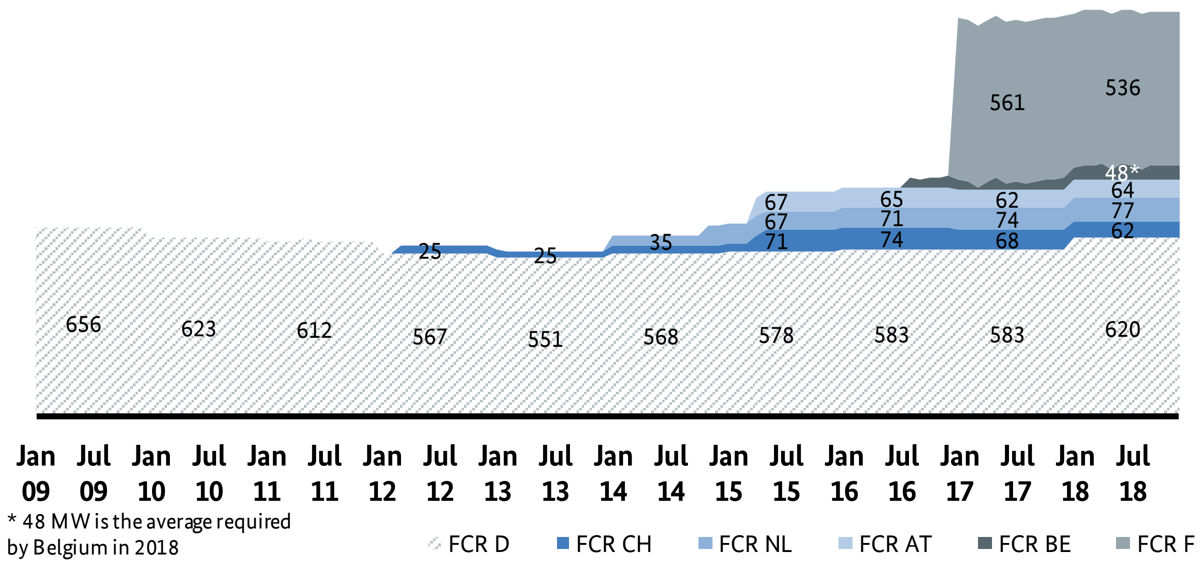
Figure 87: Average volume-weighted imbalance prices

3. European developments in the field of electricity balancing

3.1 International frequency containment reserves cooperation

To further reduce the costs for balancing services, the German TSOs are seeking to achieve further cross-border harmonisation of the markets for frequency containment reserves (FCR) in cooperation with the Bundesnetzagentur and other European TSOs and regulators.

Electricity: total volume of FCR tendered in the control areas of the German TSOs, Swissgrid (CH), TenneT (NL), APG (AT), ELIA (BE) and RTE (F) (MW)



* 48 MW is the average required by Belgium in 2018
Source: regelleistung.net

Figure 88: Total volume of FCR tendered in the control areas of the German TSOs, Swissgrid (CH), TenneT (NL), APG (AT), ELIA (BE) and RTE (F)

The Swiss network operator Swissgrid joined the German TSOs' joint FCR tendering scheme in March 2012; the volume of FCR procured for Switzerland has risen from an initial 25 MW to the current 62 MW. TenneT TSO BV in the Netherlands joined in January 2014. Following an initial volume of 35 MW, currently 77 MW of the Netherlands' FCR requirements are procured in the joint tendering. In April 2015, the joint FCR cooperation between Germany, the Netherlands and Switzerland was coupled with Austria and Switzerland's FCR tendering scheme. The average volume procured for Austria in 2018 was 64 MW. The Belgian network operator ELIA joined the joint FCR tendering in August 2016 and the French TSO RTE joined in January 2017. The average volume procured for Belgium in 2018 was 48 MW and for France, 536 MW. The scheme has created the largest FCR market in Europe, comprising a total volume of around 1,400 MW. The joint FCR tendering is open to all pre-qualified providers in the participating countries and follows the joint harmonised provisions approved by the competent regulatory authorities pursuant to Regulation (EU) 2017/2195 (see BK6 18 006).

Most recently, the FCR cooperation's product design underwent further development.[66] The main changes were as follows:

– the tendering frequency was changed from one week to one working day as from 1 July 2019 and to one calendar day as from 1 July 2020;

[66] In accordance with the decision of 13 December 2018 (BK6 18 006).

- the product validity period was shortened from one week to one day as from 1 July 2019 and to four hours (six products per day) as from 1 July 2020;

- the settlement scheme was changed from pay-as-bid to marginal pricing as from 1 July 2019.

3.2 International expansion of grid control cooperation

Over the last few years, the German TSOs have been pushing forward the expansion of module 1 of their national grid control cooperation, which aims to prevent the inefficient use of automatic frequency restoration reserves (aFRR) across different control areas. Under the International Grid Control Cooperation (IGCC), Germany and the following countries cooperate to avoid inefficient use of aFRR: Denmark (since October 2011), the Netherlands (since February 2012), Switzerland (since March 2012), Czechia (since June 2012), Belgium (since October 2012) Austria (since April 2014) and France (since February 2016). IGCC expanded again in February 2019 when Croatia and Slovenia joined.

IGCC enables the imbalances and hence the demand for aFRR 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 deficit. 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. Regulation (EU) 2017/2105 (Electricity Balancing Regulation) requires all European TSOs using aFRR to implement imbalance netting in the future.

IGCC has been designated by ENTSO-E as a European pilot project to provide technical and organisational experience at an early stage; the project is intended to be developed into the European platform for the imbalance netting process. The project is being accompanied by the regulators, led by the Bundesnetzagentur.

3.3 SRL-Kooperation zwischen Deutschland und Österreich

Since 2016, the German TSOs responsible for the control areas have cooperated with the Austrian TSO APG with regard to the use of automatic frequency restoration reserves (aFRR). The use of aFRR is based on a common merit order list. This ensures that – provided that sufficient cross-border transmission capacity between Germany and Austria is available and there are no network restrictions – only the most economically efficient aFRR bid in the two countries is used. This enables the costs for balancing energy to be reduced. If cooperation is not possible, for instance because of a lack of cross-border transmission capacity or operative network restrictions, the German and Austrian TSOs use aFRR at a national level as before. This form of cooperation between the German and Austrian TSOs is also important with regard to Regulation (EU) 2017/2195, which entered into force at the end of 2017 and which provides for the cross-border use of balancing energy based on a common merit order list, with a view to further integrating balancing markets in the future.

In the near future, the TSOs in Germany and Austria responsible for the control areas also plan the cross-border procurement of part of their national aFRR requirements. Relevant harmonised provisions for joint aFRR procurement in Germany and Austria were approved pursuant to Regulation (EU) 2017/2195 by the Bundesnetzagentur and the Austrian regulatory authority E-Control at the end of 2018 (see BK6-18-064).

4. Interruptible loads

4.1 TSOs' tendering for interruptible loads

The legal basis for tendering for interruptible loads is the Interruptible Loads Ordinance (AbLaV), which entered into force in January 2013 and was replaced by a revised version with effect from 1 October 2016. As of April 2017, 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.

On 20 February 2019, the Bundesnetzagentur opened formal determination proceedings on adjusting the total capacity for immediate and fast interruption. Following the opening of the proceedings, significant changes were seen with respect to participation in the weekly auctions as well as the number of requests to use interruptible capacity and the volume of capacity requested. There was a significant rise in the average bid volumes. The volumes for quickly interruptible loads, in particular, were only just under the 750 MW limit. In individual instances, the bid volume exceeded the volume tendered. In light of this, the Bundesnetzagentur has decided to postpone its planned decision on adjusting the total capacity for immediate and fast interruption for the time being.

The following graph shows the capacity tendered and contracted for immediate and fast interruption in 2018 and thus prior to the opening of the formal determination proceedings on adjusting the total interruptible capacity. The graph shows that the total capacity contracted has remained nearly stable – and well below the total capacity tendered – over the whole period, with the ratio of immediate to fast interruption also nearly constant, with a few exceptions.

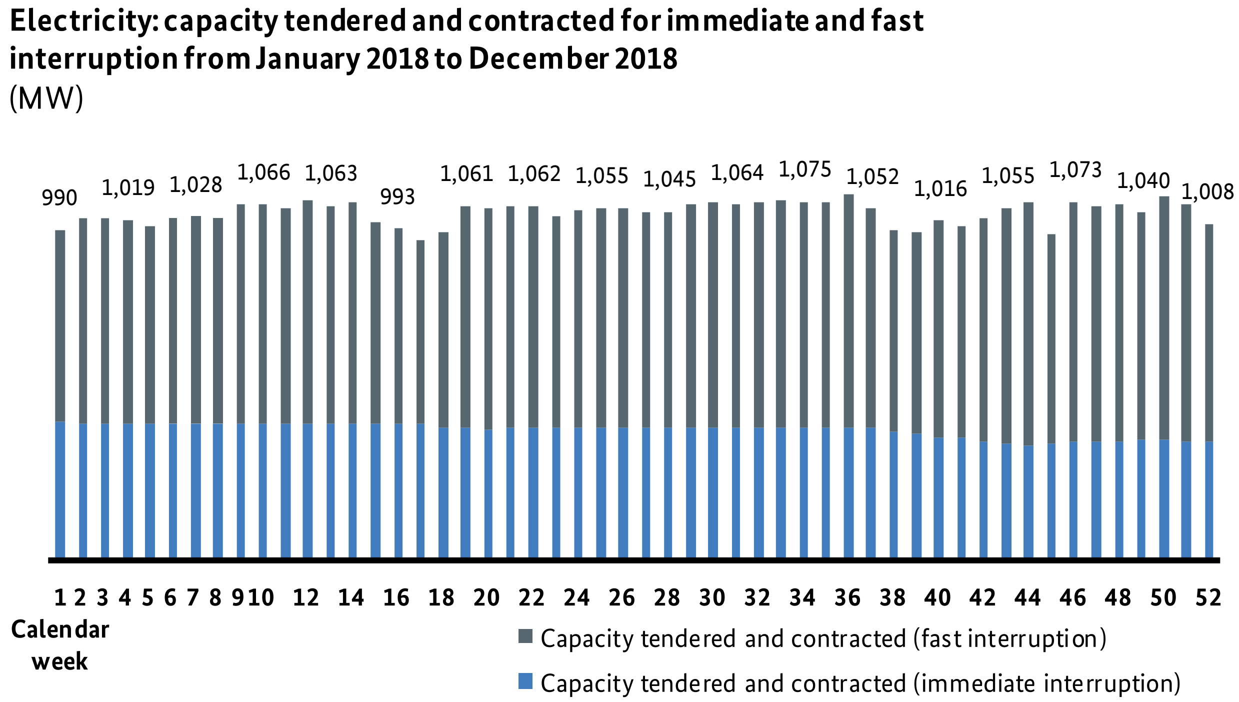


Figure 89: Capacity tendered and contracted for immediate and fast interruption from January 2018 to December 2018

4.2 Pre-qualified capacity

By the end of 2018, 21 interruptible loads with a total interruptible capacity of 559 MW had taken part in the initial pre-qualification procedure pursuant to section 9 AbLaV, and 17 of them, with a total interruptible capacity of 496 MW, had successfully pre-qualified.

Ten consumer devices with a total interruptible capacity of 929 MW have now successfully pre-qualified as immediately interruptible loads. One consortium has also pre-qualified as an immediately interruptible load; the consortium enables smaller consumer devices to be marketed together as an interruptible load. In addition, 27 consumer devices pursuant to section 2 para 11 AbLaV and three consortia pursuant to section 2 para 12 AbLaV have pre-qualified as quickly interruptible loads. The pre-qualified capacity of quickly interruptible loads in 2018 thus amounted to 1,316 MW. The majority of the loads are connected to Amprion's control area, while others are in the control areas of 50Hertz and TenneT TSO.

4.3 Use of interruptible loads

In 2018, interruptible loads were used comparably with the use of balancing capacity to balance the system on 13 days. Reductions in consumption of up to 740 MW were activated simultaneously for between 15 minutes and eight hours. The interruptible loads were always used to balance the system at the same time as positive manual frequency restoration reserves (mFRR). Nearly all the positive mFRR had to be used on eight days. The highest energy price used for positive mFRR at the time the interruptible loads were used was €1,550/MWh, compared to an energy price of €400/MWh for the interruptible loads used. Interruptible loads were used only twice in 2018 for redispatching purposes, once with an interruptible capacity of 86 MW for 30 minutes and once with an interruptible capacity of 291 MW for one hour.

The contracted immediately interruptible loads were registered on time as not available for 542 hours, thus 48,408 MWh of interruptible energy was not available from the immediately interruptible loads. The quickly interruptible loads were registered as not available in 2018 for as much as 3,922 hours, thus 97,690 MWh of interruptible energy was not available from the quickly interruptible loads. In addition, quickly interruptible loads were not available in an unreliable manner for 1,068 hours in 2018, and thus 1,068 MWh of interruptible energy was not available from the loads. Significant use was therefore made of the opportunity to register the contracted interruptible capacity as not available by the interruptible loads the day before. The loads are thus not available for TSOs for system balancing or redispatching and are not paid capacity costs during the time they are unavailable. Nevertheless, during the whole period the contracted loads were not registered as not available because of alternative marketing on the balancing or the spot market.

4.4 Costs for interruptible loads

The energy-based costs for the actual reductions in consumption in 2018 were higher at €952,774 (2017: €293,935), reflecting the increase in the use of interruptible loads compared with the previous year. By comparison, the capacity-based costs for contracting the interruptible loads in 2018 remained nearly stable at €26,770,491 (2017: €26,940,103). The average interruptible capacity available in the period under review was 967 MW. The total costs for interruptible loads, including transaction costs, amounted to €28,078,288 in 2018 (2017: €28,120,570).

4.5 Increasable loads ("use, don't curtail")

In January 2018, the Bundesnetzagentur agreed on a voluntary commitment known as "use, don't curtail" with the three relevant TSOs: TenneT, Amprion and 50Hertz. This enables the TSOs to contract with CHP installation operators in the "network expansion area" for the reduction of active power feed-in while continuing to supply electrical energy to maintain heat supplies. The aim is to avoid feed-in management measures (FIMM) in the network expansion area and, at the same time, to make new redispatch potential available. Under the voluntary commitments a power plant is suitable for the economic and efficient elimination of congestion if the savings obtained from the avoided FIMM are projected to cover at least the required investment costs forecast over the five-year period following commissioning (duration of the contracts). This means that an across-the-board efficiency approach – one not related to grid costs – is adopted. The above TSOs offered to enter into such contracts with plant operators in the course of 2018, but no contracts were concluded. The first actual contracts are to be expected in the 50Hertz control area in 2019.

5. Findings from the data survey on demand-side management

In 2018, the Bundesnetzagentur and the Federal Ministry for Economic Affairs and Energy (BMWi) again monitored the contribution of demand-side management to the security of the electricity supply. In this data survey, which now takes place annually, the Bundesnetzagentur collects information from undertakings and associations of undertakings (final consumers) that have consumed at least 50 GWh of electricity per year in the last two calendar years. The authority's objective is to analyse the current and future contribution of demand-side management to security of supply on the electricity markets. In calculating the annual electricity consumption, all sites with at least 10 GWh were counted for final consumers with an annual consumption of over 50 GWh.

A total of 486 undertakings with 1,112 sites took part in the survey, compared to 490 undertakings with 1,112 sites in 2017. The total electricity consumption across all sites of these industrial companies was 153 TWh, compared to 154 TWh in 2017.

Electricity: electricity consumption by sector/market coverage of DSM in 2018 (TWh/%)

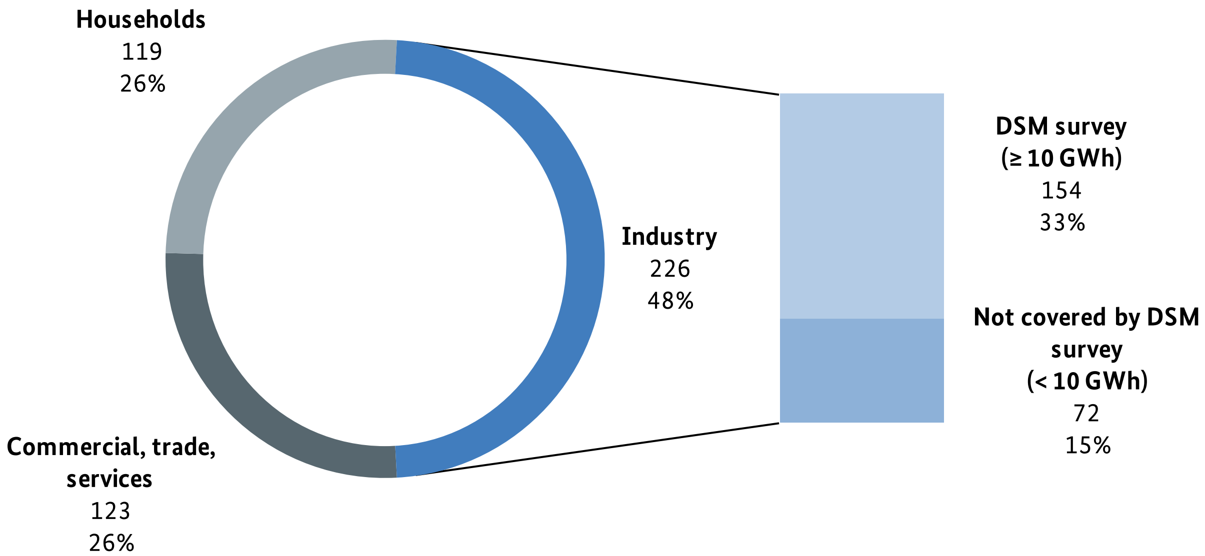


Figure 90: Electricity consumption by sector/market coverage of demand-side management in 2018

A total of 577 of the 1,112 sites participating in 2018 reported that they already had a demand-side management system in place, compared with 552 in 2017. Major consumers from particularly energy-intensive industries, such as chemicals, steel and paper, were particularly likely to use a demand-side management system. The highest proportion of sites operating a demand-side management system was for foundries.

**Electricity: undertaking sites with and without demand-side management system – top 10
(number/TWh) (sorted by number of sites with DSM)**

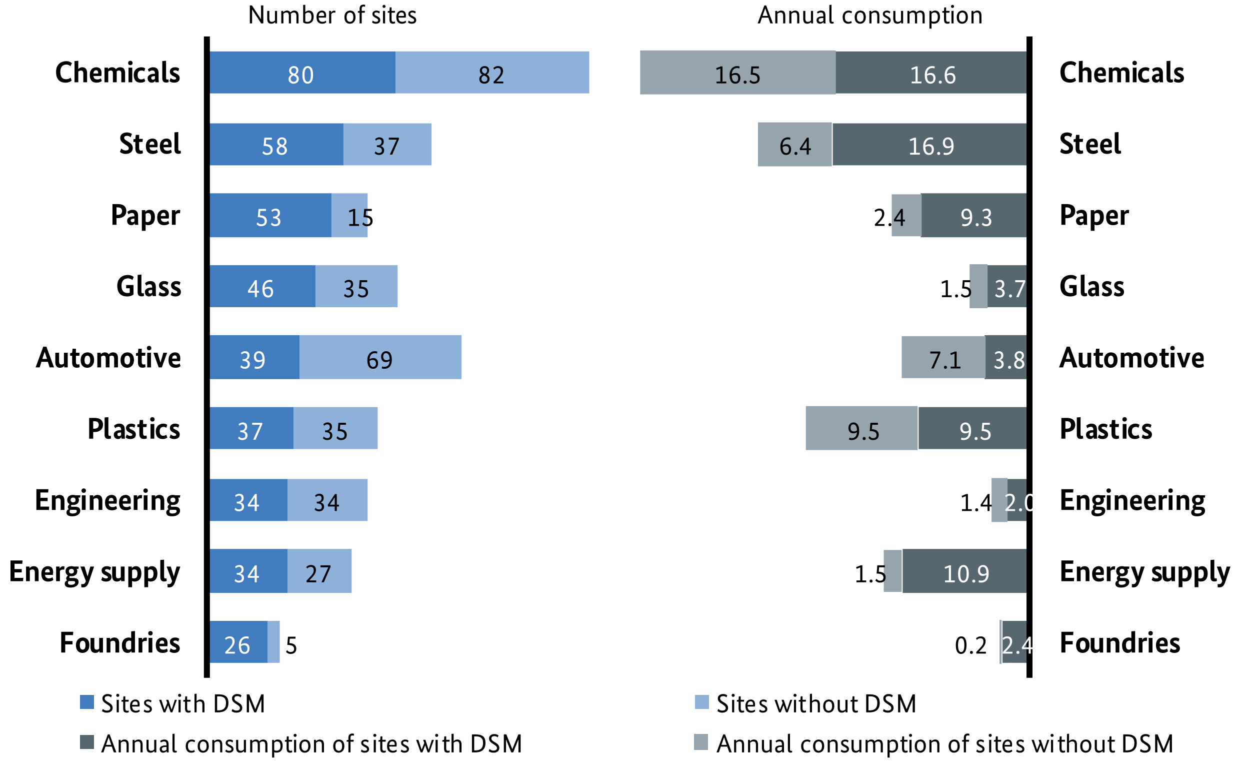


Figure 91: Undertaking sites with and without demand-side management system – top 10

Undertakings specified as reasons for the use of demand-side management in particular section 17(2) of the Electricity Network Charges Ordinance (StromNEV) (network charge optimisation – peak load reduction to reduce annual capacity price) and section 19(2) para 2 StromNEV (network charge reduction – compliance with annual minimum consumption and full load hours) as well as the optimisation of electricity purchase prices. The Interruptible Loads Ordinance (AbLaV) and redispatching were only rarely mentioned.

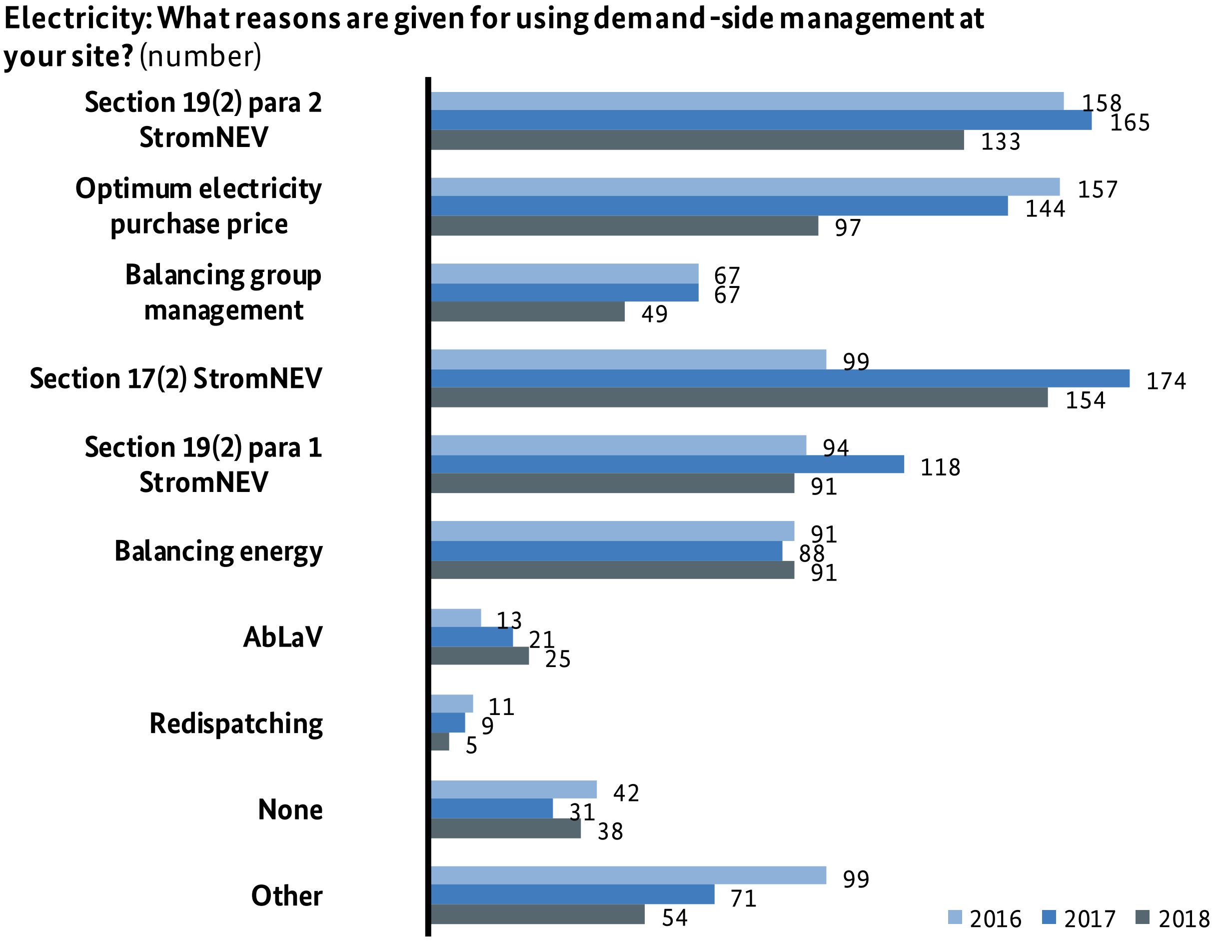


Figure 92: What reasons are given for using demand-side management at your site?

Sites mainly control demand-side management themselves. In 2017, 484 sites said they controlled their demand-side management themselves. This figure fell by 46 sites, or 1.1%, to 438 in 2018. The table below provides an overview of the different types of control.

Electricity: Which party controls demand-side management at your site? (number)

Controlling party	2016	2017	2018
Self	415	484	438
Company and network operator	18	25	19
Company and electricity supplier	14	16	3
Company and energy service provider	14	10	8
Company and third party	9	7	13
Network operator	4	4	4
Energy service provider	3	2	2
Other	2	2	3
Energy supplier	1	2	4
Total	480	552	494

Table 70: Data on control of demand-side management

In answer to the question on obstacles to using or increasing demand-side management, sites highlighted organisational obstacles (such as linked production processes, supply obligations, personnel organisation) and technical obstacles (such as no increasable or reducible loads, product quality, plant security) as reasons not to use or at least not to increase demand-side management. Since a different methodology was used in the survey for 2018, it is not possible to compare these results with those from previous years.

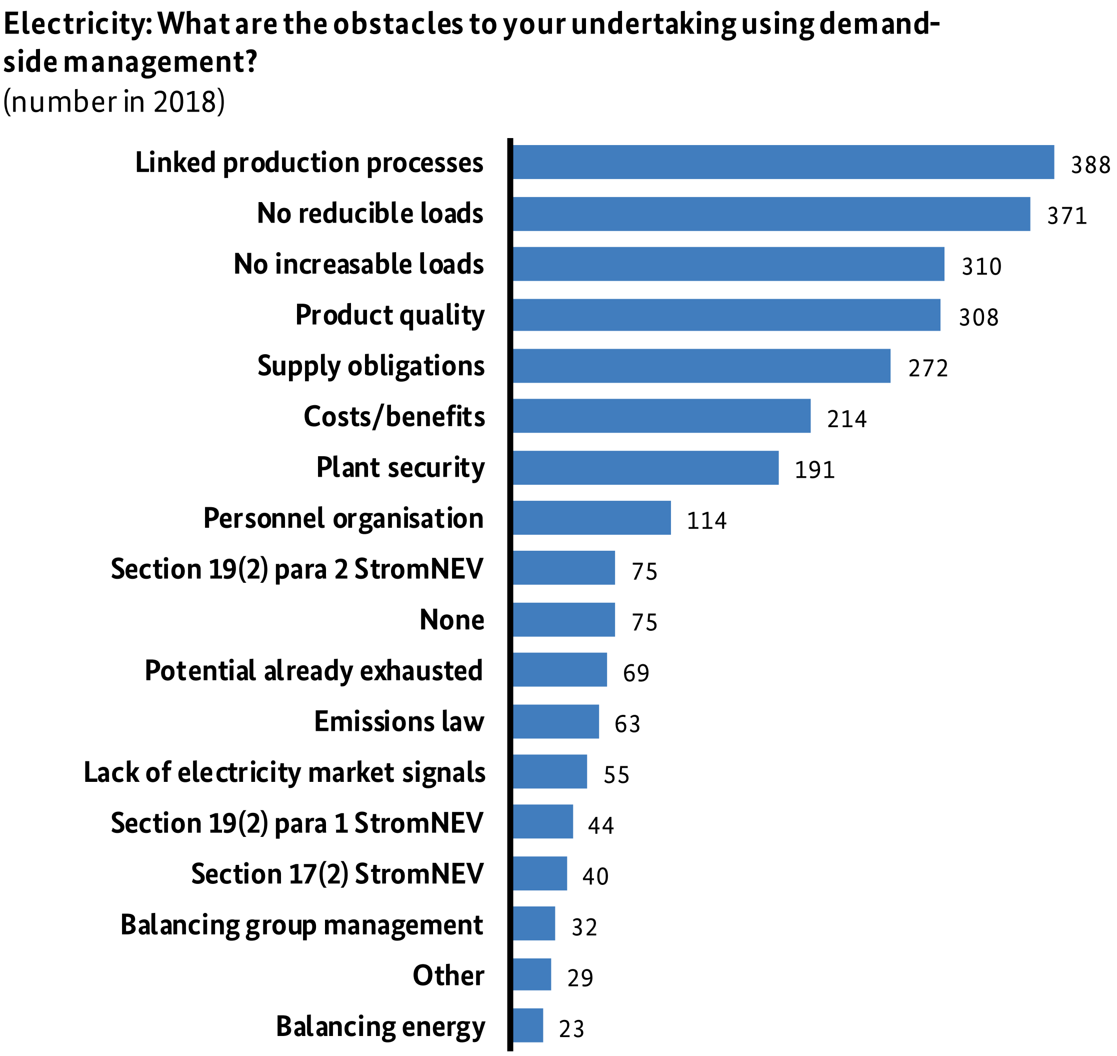


Figure 93: What are the obstacles to your undertaking using demand-side management?

The majority of registered sites are not planning any measures to reduce loads with demand-side management or to reduce them more than they already do. However, the number of sites that are planning measures is higher than in 2016. The breakdown can be seen in the chart below.

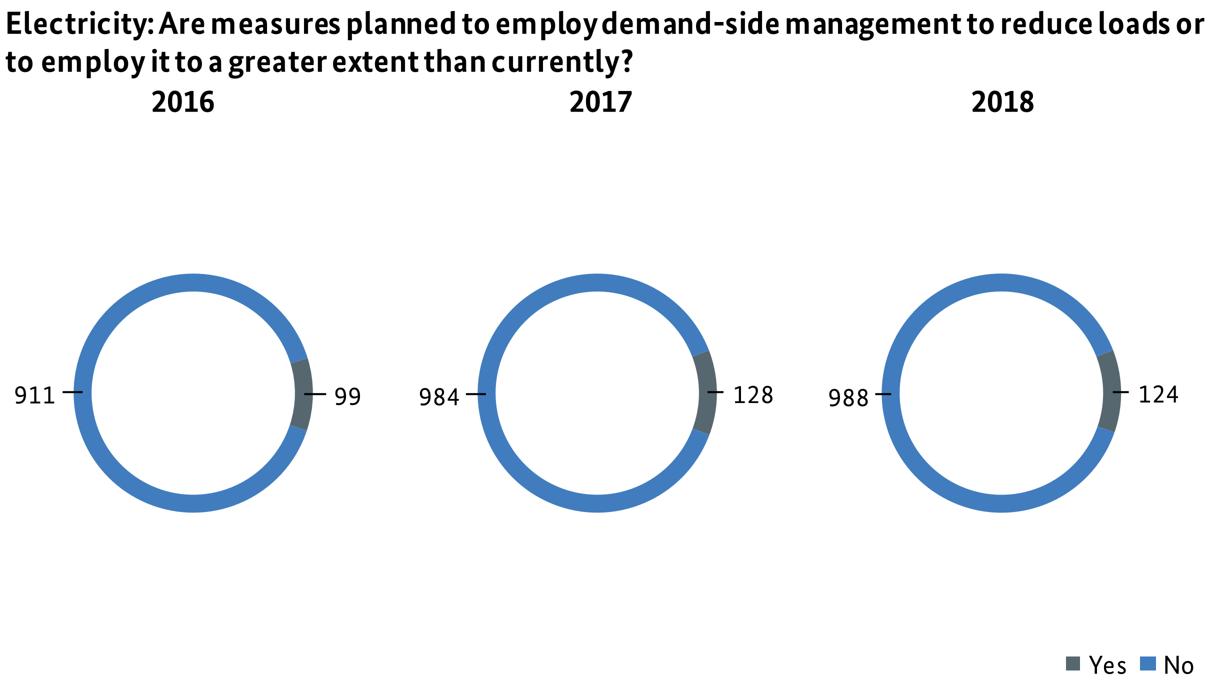


Figure 94: Are measures planned to employ demand-side management to reduce loads or to employ it to a greater extent than currently?

E Cross-border trading and European integration

The countries of the European Union are part of a European interconnected system for the exchange of electricity in which Germany acts as a central hub. The aim of the envisaged European internal market for electricity is to integrate electricity markets more closely, to facilitate cross-border trade and to ensure secure, cost-efficient and sustainable supply of electricity.

The Bundesnetzagentur cooperates with other regulatory authorities in Europe (National Regulatory Authorities – NRAs) and the Agency for the Cooperation of Energy Regulators (ACER) on implementing European Union rules.

On the way to creating the internal market for electricity, Europe is divided into separate bidding zones in which electricity prices are determined according to supply and demand. Electricity is transported within the bidding zone free of congestion (ie without capacity restrictions) from the generator to the consumer. This only works if physical congestion is rectified within a price zone by means of redispatch measures and network expansion or if internal overloading of power lines is taken into account in the calculation of interconnector capacity. At the end of the reporting year, Germany and Luxembourg constituted a common bidding zone with uniform prices. The common bidding zone with Austria ceased to exist on 1 October 2018. Due to price differentials between bidding zones, cross-border trading may be limited by transmission capacity constraints.

Compared to the previous year, the volume of electricity exported by Germany fell slightly for the first time in 2018. However, total cross-border traded volumes rose slightly in 2018 to 91.6 TWh (2017: 90 TWh). Germany's export balance of 52.45 TWh and export surplus of €2,125m makes it a major electricity exporter in Europe. Nonetheless, despite the lower volume, the monetary value of the export surplus actually increased (2017: €1,725 m).

1. Power exchanges and market coupling

The electricity which is traded for physical delivery in Europe is traded mainly in two time frames:

- In the day-ahead market electricity is auctioned for the following day. The auction applies a marginal pricing procedure in which the last accepted bid sets the price for all transactions.

- Intraday trading mainly involves the continuous buying and selling of electricity (with one-hour, half-hour or quarter-hour settlement periods). This means that the price of each accepted bid is different (pay as bid).

Most day-ahead and intraday markets in Europe are coupled. This means that available capacity between bidding zones is directly linked to the volume of electricity auctioned, so that neither the seller nor the buyer need to worry about the transmission of the electricity, ie the cross-border capacity. This procedure, in which two market participants in different bidding zones are able to trade with each other without any additional steps, is referred to as implicit capacity allocation. In contrast, explicit capacity allocation, in which transmission rights between bidding zones have to be acquired in addition to the actual transaction itself, is becoming less important.

The so-called MRC (Multi-Regional Coupling) now couples 20 European countries (accounting for over 85% of European electricity consumption). The aim of market coupling is the efficient use of available day-ahead and intraday transmission capacity between the participating countries. The MRC results in an alignment of prices on the day-ahead markets while the capacity is allocated at the individual borders also according to potential welfare benefits. Indeed, price convergence, which serves as an indicator for the efficient use of interconnector capacity, is significantly higher in coupled regions than in uncoupled regions.

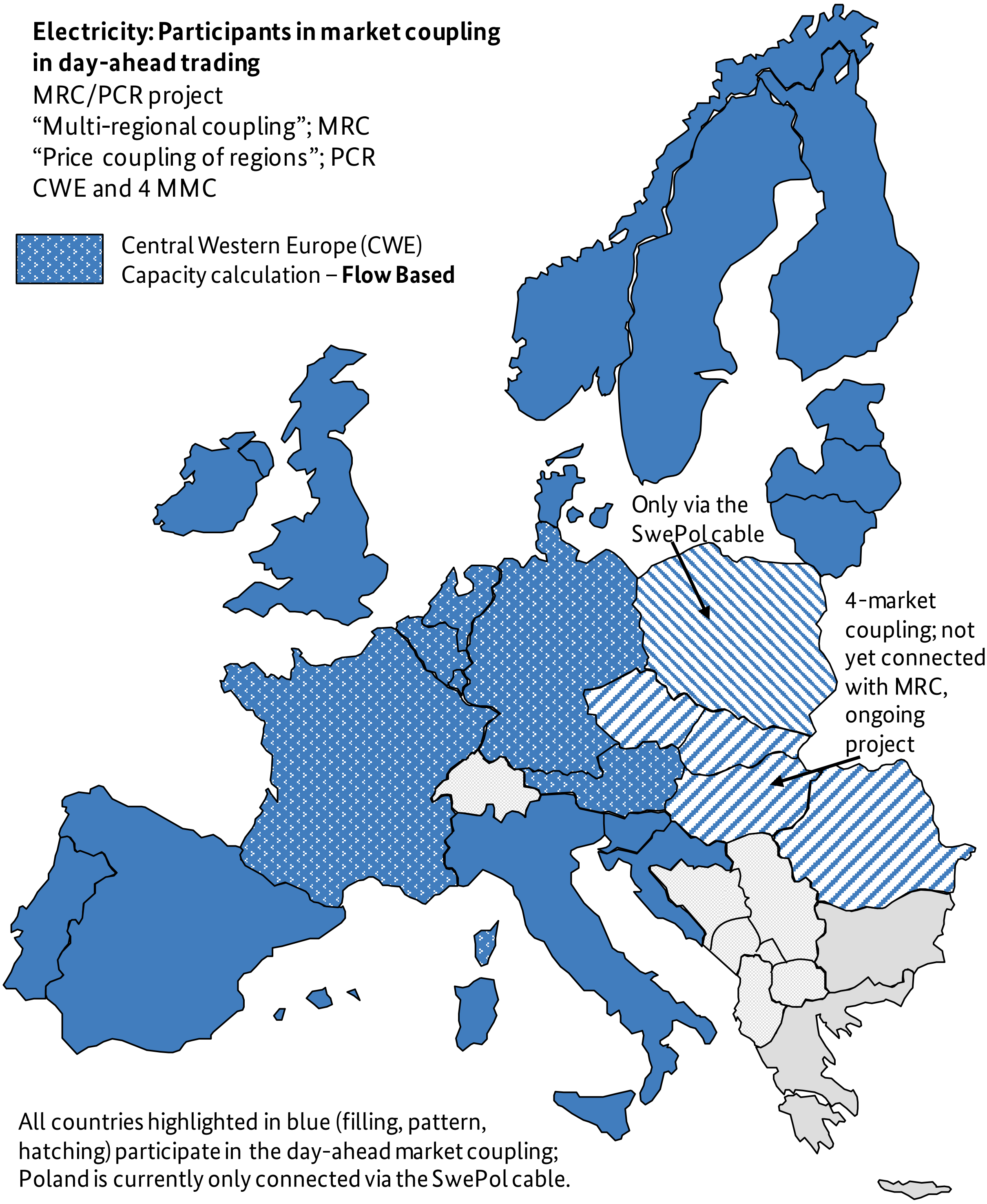


Figure 95: Participants in day-ahead market coupling

2. Calculation of capacities for cross-border trade

Transmission capacity between bidding zones is a scarce resource. Limited interconnector capacity and also internal network elements which are highly sensitive to cross-border trading may act as a natural physical limit on cross-border trading.

In Europe the capacities made available to day-ahead electricity markets are determined either by the Net Transfer Capacity (NTC) calculation or by the flow-based market coupling (FBMC) algorithm.

Net Transfer Capacity (NTC)

In the NTC process, TSOs bilaterally agree on the available – notably long-term – cross-border capacity for trading. The overall trading capacity at the border is determined by the lower NTC value of both sides of the border based on the historical load capacity of the part of the respective domestic grid leading to the border.

Flow-Based Market Coupling (FBMC)

Flow-Based Market Coupling for Central Western Europe (CWE: Belgium, Germany, France, Luxembourg, the Netherlands and Austria) calculates (exclusively) the day-ahead cross-border transmission capacity algorithmically. A grid model and the trading results are used to achieve a capacity allocation that maximises welfare. This calculation methodology not only takes account of particular borders but of all the flows of electricity in the area including the transmission lines relevant for trading.

The CACM Regulation (EU) 2015/1222 establishing a guideline on capacity allocation and congestion management defines flow-based market coupling as the target model for central Europe. For this reason, justified grounds must be given if any region decides not to use a flow-based approach as its capacity calculation methodology (cf. CACM Article 20 et seq.). This cross-border, regional capacity calculation methodology for the geographically larger Core Region (consisting of CWE and CEE, whereby CEE is made up of the borders between Austria, Croatia, Czech Republic, Germany, Hungary, Poland, Romania, Slovenia and Slovakia) is expected to be introduced by the end of 2020.

3. Average available cross-zonal capacity

The mean available cross-zonal capacity is the amount of electricity which can be transmitted between two bidding zones made available to the market on an hourly basis averaged over the year. Both import and export capacities have been analysed. Different methodologies were applied for the two procedures presented in I.E.2:

Net Transfer Capacity (NTC)

For this report, the average available cross-zonal capacity was determined using the annual average of the German TSOs' hourly NTC values. The average values determined represent the capacity basically made available to the market without being fully used in both trading directions.

Flow-Based Market Coupling (FBMC)

The trading capacities used as a result of the FBMC are always geared to optimising welfare and these values do therefore not reflect the average cross-zonal capacity actually made available. As the cross-zonal trading capacities in FBMC are dependent on each other, it is not possible to provide an independent value per border, as is the case with the NTC process. A trading capacity is evaluated as the estimated value for each border which can only be achieved if no electricity is traded at any other FBMC borders. These hourly values are then used to calculate the average transmission capacity. The FBMC data for this report have been provided by the TSOs and the Joint Allocation Office (JAO).

The fundamentally different approach taken makes it impossible to compare the capacity values at NTC and FBMC borders directly with each other. The values for the development of German import and export capacities have therefore been aggregated and shown separately in Table 71 and Table 72.

Electricity: Import capacity

Border	2016	2017		2018	
			Change compared to previous year (%)		Change compared to previous year (%)
NTC					
CH → DE	4,000.00	4,000.00	0	3,888.25	-3
CZ → DE	1,295.00	1,289.89	0	1,442.00	12
DK → DE	731.03	1,026.80	40	1,465.57	43
PL → DE	1,260.41	1,301.82	3	1,358.29	4
SE → DE	411.41	415.26	1	450.39	8
Flow-based					
AT → DE *				4,999.43	
FR → DE	4,011.40	3,763.79	-6	4,323.96	15
NL → DE	2,225.46	2,345.85	5	2,504.17	7

Source: TSOs, ENTSO-E, JAO, Nord Pool; *bidding zone split DE/AT in October 2018

Table 71: Overview of development of import capacities

Electricity: Export capacity

Border	2016	2017	2017 Change compared to previous year (%)	2018	2018 Change compared to previous year (%)
			NTC		
DE → CH	1,469.64	1,501.23	2	1,394.25	-7
DE → CZ	139.44	580.21	316	1,235.23	113
DE → DK	1,830.73	1,901.86	4	1,850.68	-3
DE → PL	140.53	604.14	330	1,002.97	66
DE → SE	350.61	248.32	-29	232.39	-6
			Flow-based		
AT → DE *				5,051.92	
DE → FR	3,179.63	3,545.89	12	4,995.58	41
DE → NL	3,080.11	2,917.94	-5	3,212.04	10

Source: TSOs, ENTSO-E, JAO , Nord Pool; *bidding zone split DE/AT in October 2018

Table 72: Overview of development of export capacities

Reasons for the long-term changes in capacity include construction of new lines and other grid elements (such as phase-shifters or transformers). In addition, on 26 April 2018 a mandatory minimum capacity share of 20% of the interconnector capacity was introduced in the CWE region for flow-based market coupling (minRAM process), which will also increase available capacity in the region. Year on year changes in capacity may also be due to outages and maintenance work.

The bilateral agreement between Germany and Denmark brought about an increase in the capacity available for electricity trade across the border between western Denmark and Germany in the second half of 2018. This agreement provides for minimum capacity for trading across the border between western Denmark and Germany as well as for a TSO collaboration on countertrading measures. On the basis of this agreement, which involves an incremental increase in minimum capacities available for trade up to 1,100 MW by 2020, the minimum capacity available for trade was raised as planned to 700 MW by the end of 2018.

As a result of antitrust investigations opened by the European Commission, the German TSO TenneT is required, in addition to the existing agreement, to take further measures to promote the exchange of electricity at the border with western Denmark and to guarantee a minimum capacity available for trade of 1,300 MW with no cost cap. These requirements will be implemented step by step in 2019 and adjusted accordingly with the commissioning of the planned expansion of interconnector capacity.

4. Cross-zonal load flows and realised trade flows

The physical load flows measured at bidding zone borders are related to the realised exchange schedules, or trade flows. The latter are to be seen as virtual electricity flows triggered by commercial transactions. Commercial transactions (schedules) and thus physical load flows should maximise welfare and economic efficiency by bringing electricity from a zone in which prices are temporarily lower to a zone where the price is higher. Theoretically, the balance of physical flows and trade flows should in an overall view be nearly identical. However, this is often not the case owing to unscheduled flows (loop and transit flows, see I.E.5 on page 235 onwards), transmission losses, cross-border redispatch and measurement tolerances. As physical electricity flows always follow the path of least resistance, physical load flows and realised trade flows at individual borders may differ considerably from each other (see Figure 96 and Figure 97). This is unavoidable in a highly meshed network with large bidding zones.

The realised 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. Figure 96 and Figure 97 show the realised exchange schedules and the physical load flows at Germany's borders in 2017 and 2018. Tables 73 to 75 show summarised values.

Electricity: Exchange schedules (Cross-border trading, net)
in TWh

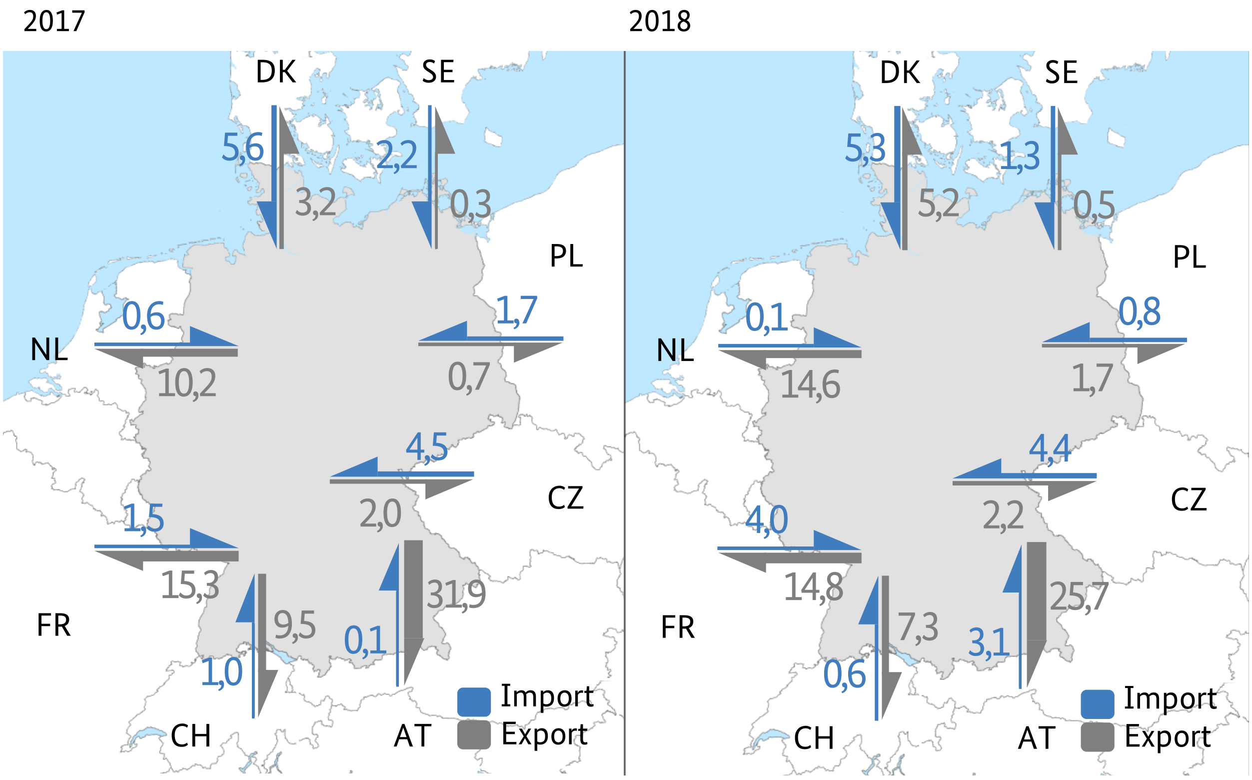


Figure 96: Exchange schedules (cross-zonal trading)

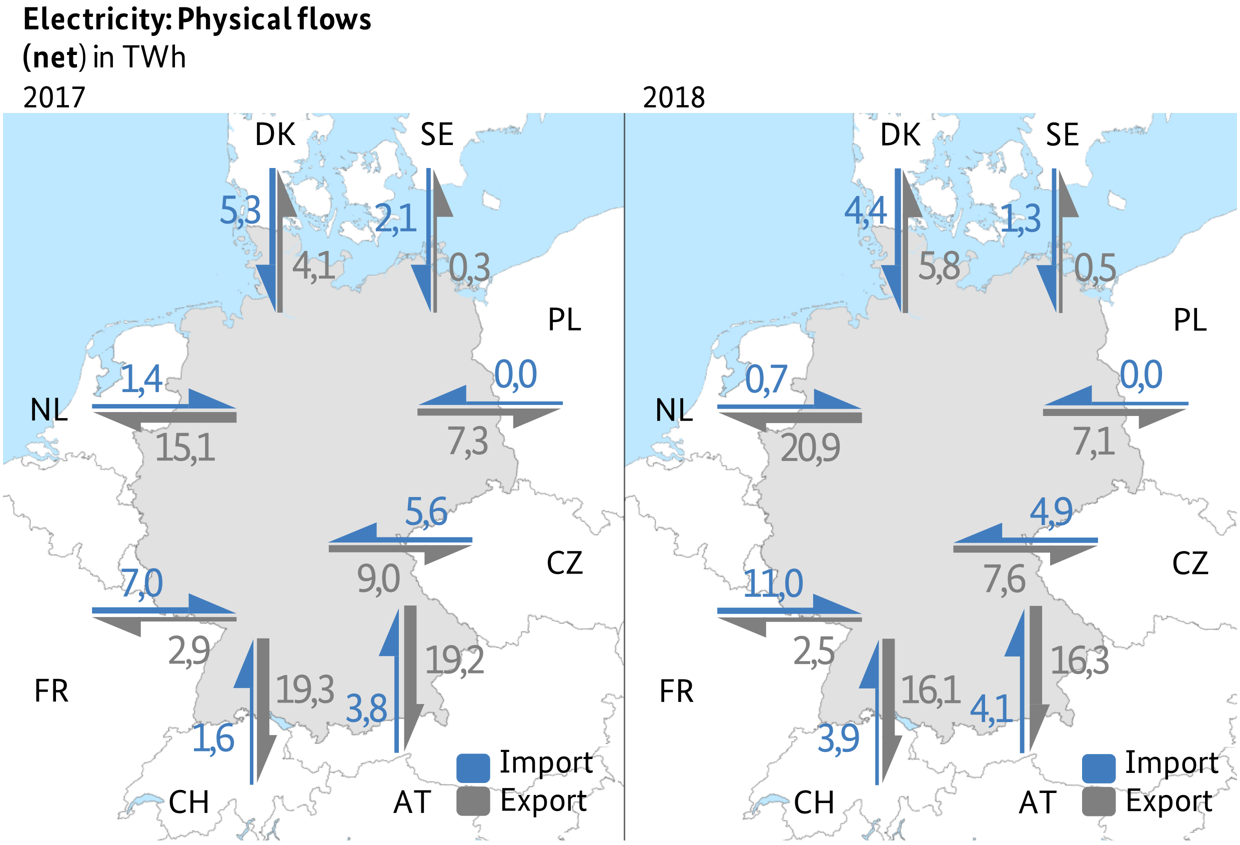


Figure 97: Physical flows

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

	Actual physical flows in 2017	Binding exchange schedules 2017	Actual physical flows in 2018	Binding exchange schedules 2018
Imports	26.7	17.1	30.3	19.6
Exports	77.3	72.9	76.8	72.0
Balance	50.6	55.8	46.5	52.5

Source: TSOs, ENTSO-E

Table 73: Comparison of the balance of cross-zonal electricity flows

Electricity: Comparison of imports from cross-border flows
(TWh)

	Actual physical flows in 2017	Binding exchange schedules in 2017	Actual physical flows in 2018	Binding exchange schedules in 2018
AT → DE	3.8	0.1	4.1	3.1
CH → DE	1.6	1.0	3.9	0.6
CZ → DE	5.6	4.5	4.9	4.4
DK→ DE	5.3	5.6	4.4	5.3
FR → DE	7.0	1.5	11.0	4.0
NL → DE	1.4	0.6	0.7	0.1
PL→ DE	0.0	1.7	0.0	0.8
SE → DE	2.1	2.2	1.3	1.3

Source: TSOs, ENTSO-E

Table 74: Comparison of imports from cross-zonal flows

Electricity: Comparison of exports from cross-border flows
(TWh)

	Actual physical flows in 2017	Binding exchange schedules in 2017	Actual physical flows in 2018	Binding exchange schedules in 2018
DE → AT	19.2	31.9	16.3	25.7
DE → CH	19.3	9.5	16.1	7.3
DE → CZ	9.0	2.0	7.6	2.2
DE→ DK	4.1	3.2	5.8	5.2
DE → FR	2.9	15.3	2.5	14.8
DE → NL	15.1	10.2	20.9	14.6
DE→ PL	7.3	0.7	7.1	1.7
DE → SE	0.3	0.3	0.5	0.5

Source: TSOs, ENTSO-E

Table 75: Comparison of exports from cross-zonal flows

The following figure clearly shows the extent to which actual physical flows differ from realised exchange schedules.

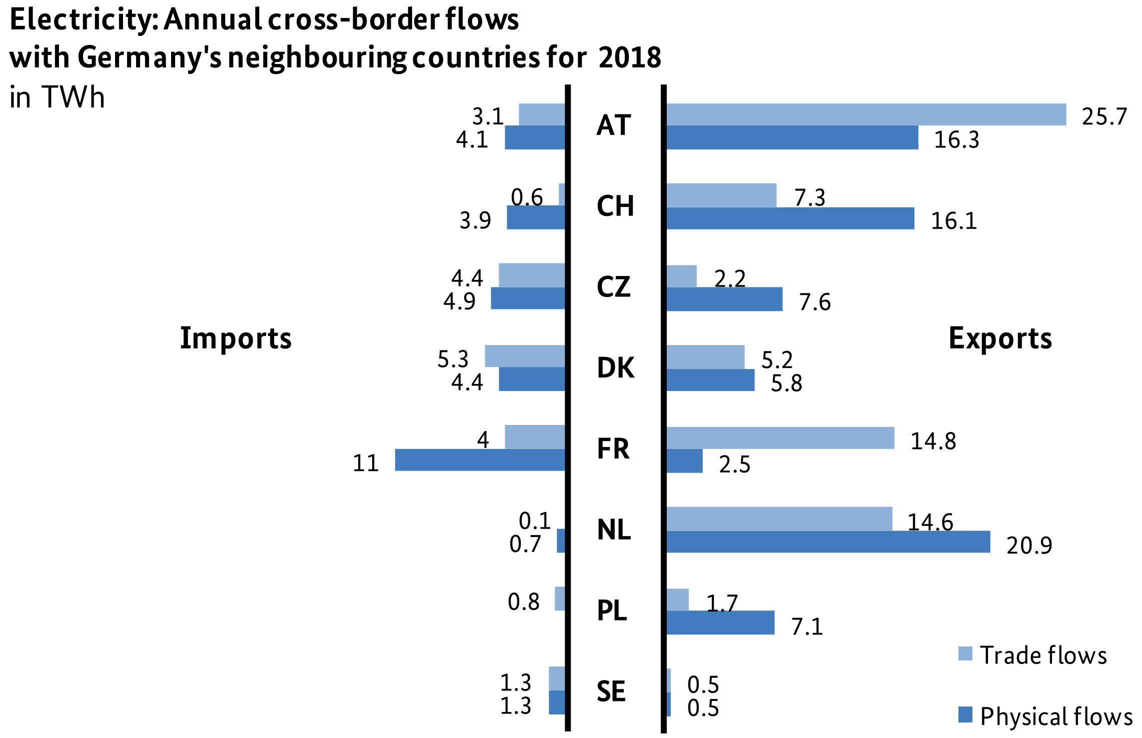


Figure 98: Total annual cross-zonal load flows and exchange schedules in 2018

In the period from 2011 to 2014, exports have risen continuously and imports fallen. Volumes of exports and imports have been relatively constant since 2015.

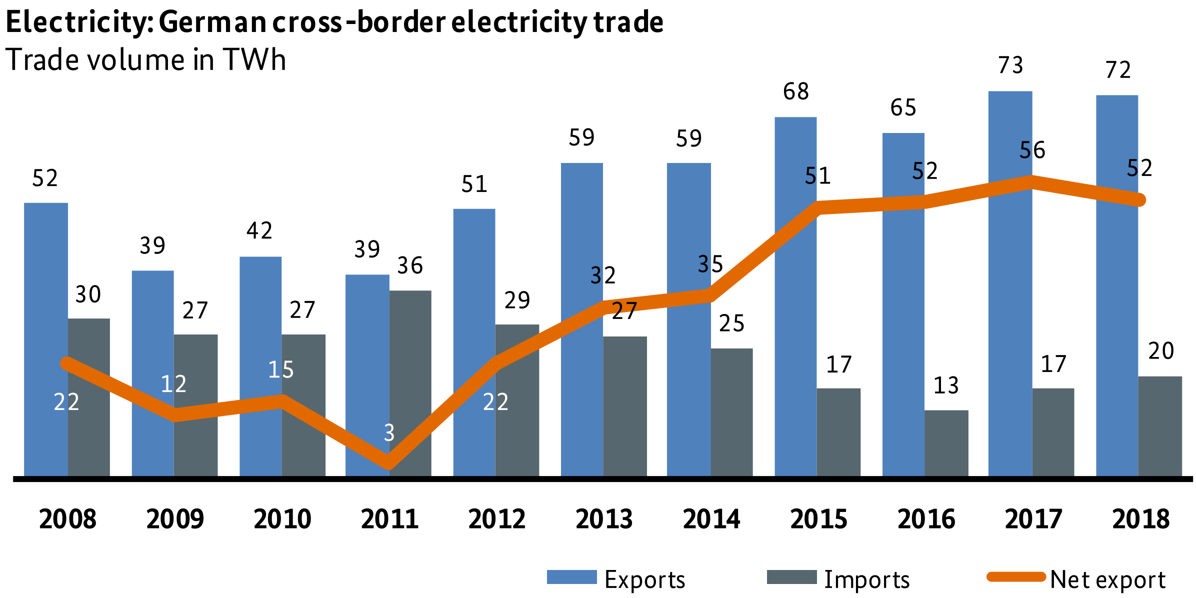


Figure 99: German cross-border electricity trade

Imports and exports are evaluated by multiplying the trading volumes of realised exchange schedules with the day-ahead EPEX Spot price. Rational market behaviour is assumed insofar as longer-term contracts will only be fulfilled if the price incentives are right. If they are not, electricity is purchased in the cheaper local market.

The monetary value of electricity imported to or exported from Germany is calculated by regarding imports as costs and exports as revenues.

Electricity: Monetary development of cross-border electricity trade

	2017		2018	
	TWh	Trade in € million	TWh	Trade in € million
Exports	72.95	2,402.98	72.01	3,058.90
Imports	17.11	677.37	19.56	934.28
Balance	55.77	1,725.61	52.45	2,124.62
Export revenues (€/MWh)		32.94		41.93
Import costs (€/MWh)		39.60		54.62

Table 76: Monetary development of cross-zonal electricity trade (trade flows)

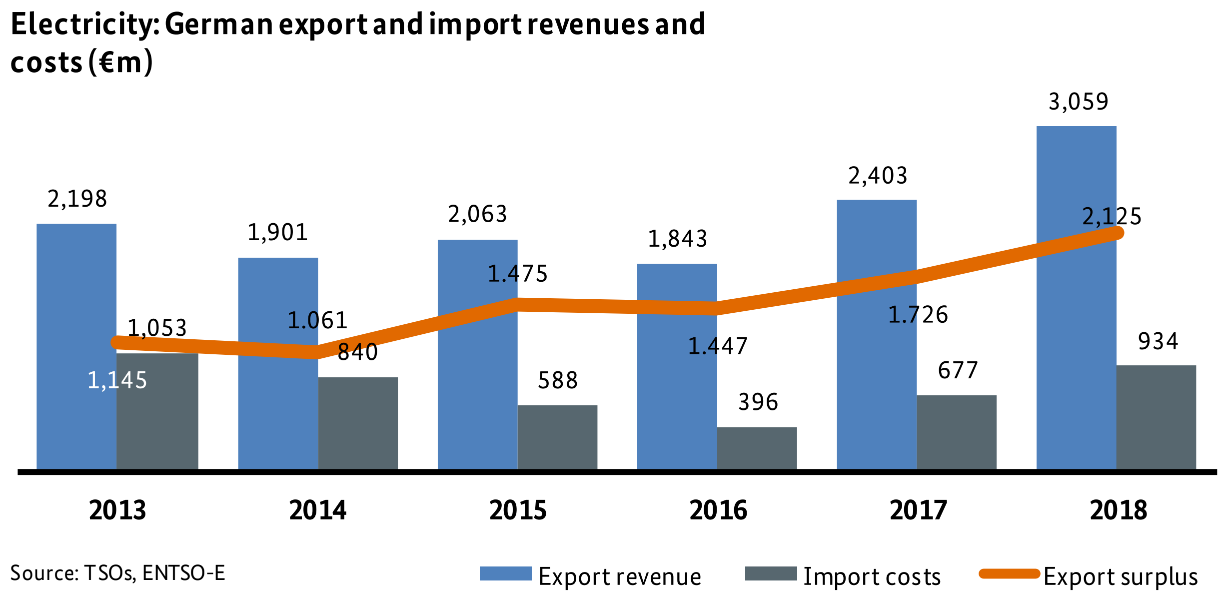


Figure 100: German export and import revenues and costs

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

5. Unscheduled flows

Electricity always flows from a source to a sink taking the path of least resistance. For this reason, unscheduled flows cannot be avoided in an electricity trading system which is organised in zones. Unscheduled flows occur if the volume of electricity sold differs from the actual physical flows of electricity. Unscheduled flows can take two particular forms. Transit flows of electricity run from one bidding zone to another passing through a zone which is not involved in the commercial transaction. Loop flows of electricity occur when power from one bidding zone passes through a bidding zone which is not involved in the commercial transaction before returning to the zone from which it originated. There are no clear dividing lines between the effects of both types of flow. As a large producer of energy in Europe and due to its geographical position as a large territorial state in the centre of Europe, Germany induces and absorbs unscheduled transit and loop flows in and from neighbouring countries. The extent to which unscheduled flows should be allowed to restrict cross-border trade in Europe is contentious.

The unscheduled flows are determined as annual aggregate figures from the difference between the physical flow and the realised exchange schedules thereby deducting the export surplus from the physical exports.

The following example demonstrates how unscheduled flows are calculated: In 2018, Germany imported (trade) 0.1 TWh from and exported 14.6 TWh to the Netherlands. This is equal to an export surplus (trade) of 14.5 TWh. At the same time, 0.7 TWh flowed physically from the Netherlands to Germany. In contrast, 20.9 TWh flowed from Germany to the Netherlands. This is equal to an export surplus (physical) of 20.2 TWh. This means that on balance (trade minus physical) 5.7 TWh of electricity flowed from Germany to the Netherlands which had not been traded between the two countries. This is called an unscheduled flow.

The following diagrams show the unscheduled flows arising from the difference between net physical and trade flows from the Germany/Austria/Luxembourg market area (ie bidding zone) to its neighbouring countries and vice versa.

Electricity: Unscheduled flows
TWh

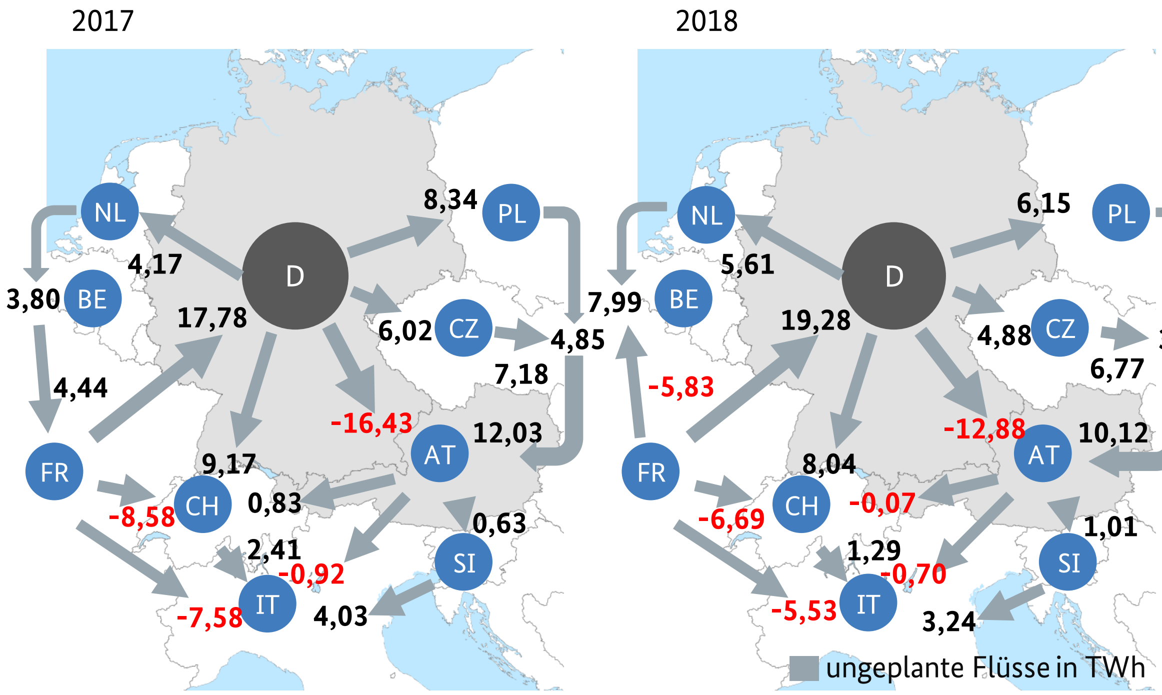


Figure 101: Unscheduled flows in 2018 compared to 2017

The arrows show the main direction of physical flow and the figures show the trade deficit: red figures reflect a physical deficit (trade > physics) while the black figures illustrate a trade deficit (physics > trade). In 2018, for example, the net physical flow from Germany to Austria was 12.88 TWh less than the volume of trade.

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 return, loop and transit flows from France 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 electricity likewise overflows into the Czech and Polish grid systems on its way to Austria. Unscheduled 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, electricity trading between different market areas inevitably results in unscheduled flows. These unscheduled flows are the result, in particular, of the high volumes transported due to electricity trading within Germany and Europe. This could only be prevented by switching completely to a direct current grid, which would not be feasible technically.

6. 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 2018 are the following: The four German TSOs received compensation for losses and the provision of infrastructure totalling €1.28m and paid contributions of €9.72m. This means that on balance the German TSOs contributed a net amount of €8.44m to the ITC fund. As a result, Germany was a net contributor to the ITC fund in 2018 for the fourth year running (2017: €-2.15m, 2016: €-12.48m, 2015: €-6.1m, 2014: €7.65m, 2013: €13.21m, 2012: €26.8m). 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. Compared to the previous year the net contributions have again increased significantly and is in line with similarly high net contributions in previous years.

7. Current developments in the European electricity sector

7.1 Clean energy for all Europeans Package (CEP)

The CEP is a new framework for core areas of the internal European electricity market. The CEP seeks to promote energy efficiency, to establish the EU's global leadership on renewables and to strengthen consumer rights. The package also focuses on designing the configuration of bidding zones and the calculation of cross-border capacity. A minimum rate of 70% of transmission capacities must be made available for cross-border trade in electricity by 31 December 2025. The Bundesnetzagentur argued for the continued application of the uniform German bidding zone.

The “Clean Energy for all Europeans Package” is a comprehensive legislative package for the further integration of the European internal market for electricity. The relevant legislative texts were published in the Official Journal of the European Union on 21 December 2018 and 14 June 2019. The package includes:

- Directive (EU) 2018/2001 on the promotion of the use of energy from renewable sources (recast of the renewable energies Directive 2009/28/EC)

- Directives (EU) 2018/844 and 2018/2002/EU amending energy efficiency Directive 2012/27/EU and Directive 2010/31/EU on the energy performance of buildings

- Directive (EU) 2019/944 on the Internal Market for Electricity (recast of the internal market for electricity Directive 2009/72/EC and amending the energy efficiency Directive 2012/27/EU)

- Regulation (EU) 2019/943 on the internal market for electricity (amendment of Regulation (EC) 714/2009 conditions for network access for electricity)

- Regulation (EU) 2019/941 on risk-preparedness in the electricity sector (replaces the electricity SoS Directive 2005/89/EC)

- Regulation (EU) 2019/942 establishing ACER (amendment of the ACER Regulation (EC) 713/2009)

– Regulation (EU) 2018/1999 on the Governance of the Energy Union.

New rules will also be applied to enhanced cooperation between transmission system operators in regional coordination centres.

Other key points include the handling of feed-in priority for renewable energies and the privileging of self-consumption. The CEP also addresses issues linked to the new players proposed by the Commission, including the structure, composition and tasks of the EU DSO Entity, the active consumer and the renewable energy community. Another focus is on revising the ACER Regulation, including the internal rules, in order to ensure a balance of power between the ACER Director and the Board of Regulators. Regulatory authorities all have one vote each in the Board of Regulators.

7.2 German/Austrian congestion management

One of the most important developments in 2018 was the introduction on 1 October 2018 of congestion management between the electricity wholesale markets in Germany and Austria. This bidding zone split had become necessary because the unrestricted trade flows of recent years no longer reflected the physical reality. In contrast to electricity trading within Germany, not even the additional power lines which are planned to be built between Germany and Austria will be sufficient to transport the cross-border flows of electricity generated from electricity trading. These trade flows would therefore have required permanent expensive system security measures and unscheduled flows through neighbouring countries. In the long run this would not have been economically sensible nor would it have been permissible under energy law.

After intensive discussions, the Bundesnetzagentur and the Austrian regulatory authority E-Control first reached agreement on the modalities for the introduction of congestion management in May 2017. The established minimum capacity of 4.9 GW will be secured by 1 GW (or rather 1.5 GW from October 2019) from redispatch power plants in Austria. The long-term transmission rights will be issued as Financial Transmission Rights (FTRs) and capacity calculation will be based on the flow-based market coupling methodology used in the Central Western Europe (CWE) region. This method is the European target model. Its purpose is to achieve the optimal allocation of cross-zonal trading capacities to each border.

The technical and IT implementation of the border into the CWE market coupling algorithm for the allocation of trading capacity has worked smoothly. Since 1 October the algorithm has consistently produced a result within the calculation period. Cooperation in the project has been exemplary and was also supported by the CWE parties. The timely introduction of congestion management means that the number of critical network situations can be reduced and network security increased throughout Germany. Trading capacity at the other external borders is also expected to increase and unscheduled flows to fall.

The capacities traded from Germany to Austria were auctioned in October 2018 for €0.88/MWh; the price in November 2018 was €5.75/MWh and in December 2018 €3.82/MWh. As both generation and demand is affected by weather conditions, the price difference is, as anticipated, significantly higher in the winter months (November to March) than in the summer. The results of the annual auction provide a resilient average price difference: annual capacity in 2019 of 2,940 MW (60% of 4,900 MW) was traded at €3.33/MWh. The TSOs calculated an average price difference of €3.52/MWh as part of an extensive market simulation before congestion management was introduced. This figure exceeded the price difference expected by the market, which based on the EEX Phelix future had anticipated €2.5/MWh for 2019 and €3.0/MWh for 2020. The price fo the annual capacity is therefore within the anticipated price range of €1.5 to €3.5/MWh.

7.3 CWE Region Flow-based Market Coupling: Introduction of minRAM

A mandatory minimum share of 20% of transmission capacity to be made available for trading was introduced in the CWE region for flow based market coupling on 26 April 2018, referred to as the "20% minRAM". This means that a corresponding minimum share of 20% must be made available for cross-border electricity trading on each relevant line in the CWE flow-based system. The aim of the measure is to strengthen cross-border electricity trading in the region. However, the measure must not interfere with system security and may therefore be suspended if the TSOs involved determine that making the 20% minRAM available would pose network and system security problems.

7.4 Assistance for Belgium

Belgium did not have enough national generating capacity for the winter half-year 2018/2019 and did not expect to be able to meet its own electricity demand at all times. This was due in particular to the numerous unscheduled periods during which Belgian nuclear reactors were unavailable in November 2018. The Belgian government therefore requested assistance from its neighbouring countries. The European neighbours showed solidarity and supported Belgium as well as they could to ensure that there were no power failures. The Bundesnetzagentur actively supported this process with the regulatory authorities, ministries and transmission system operators in CWE region countries. It was agreed that the German TSOs will comply with the 20% minRAM wherever possible, provided that this does not jeopardise network and system security. The Belgian TSO Elia was given the option of giving notice of critical days in advance and of requesting permission from the other CWE TSOs to make changes in the capacity calculation for day-ahead trading. These measures are intended to increase imports to Belgium ("market measures"). The other TSOs in the CWE region check whether this is possible with regard to the security of their own networks and systems. The agreement also facilitates higher volumes in intraday trading and cross-border cooperation between TSOs to coordinate network and system security measures shortly before real time. The Bundesnetzagentur will continue to monitor future developments in the network and generation field in Germany's neighbouring countries.

7.5 Implementation of European network codes and guidelines

Further progress was made in 2018 on the implementation of EU network codes and guidelines in relation to the further development of the single European electricity market in the areas of grid connection, market and system operation.

Capacity management

TSOs and nominated electricity market operators are working with NRAs and ACER on the implementation of the CACM Regulation (Regulation (EU) 2015/1222) for cross-border congestion management, capacity calculation and capacity allocation for day-ahead and intraday trading. The regulatory authorities and ACER issued approval decisions under the CACM Regulation. In this context approval was given for the guidelines on the coupling algorithms, the relevant products and the necessary back-up measures, the times at which intraday trading opens and closes and the fallback procedures for capacity allocation. This rulebook is the foundation for the single European electricity market. A major step forward in this context was also the launch on 12 June 2018 of the cross-border intraday (XBID) solution, which supplements the day-ahead market by linking continuous intraday trading between Belgium, Denmark, Germany, Estonia, Finland, France, Latvia, Lithuania, Luxembourg, Norway, the Netherlands, Austria, Portugal, Sweden and Spain. The other European countries will join the system in a second implementation wave in 2019. The aim of coupling is to increase the efficiency of intraday trading and thereby enhance welfare.

In the German market, the capacity calculation method for the capacity calculation region Core is also particularly relevant. This is a further development of the CWE region's flow-based capacity calculation method and is used to incorporate the entire network, and not just particular cross-border network elements, in the calculations. This enables more transmission capacity to be made available for cross-border trading.

The regulatory work was coordinated in a joint working group involving all regulatory authorities and TSOs in the Core capacity calculation region. This resulted in a proposal being made by TSOs in June 2018, which was partly adapted to the regulatory authorities' request for amendments. As the regulatory authorities of the member states of the Core Region failed to agree on a joint approval of this proposal, the procedure was referred to ACER for decision in August 2018. This body then reached a decision on the submitted TSOs' proposal in February 2019 and determined the capacity calculation method for day ahead and intraday trading of electricity. The Bundesnetzagentur has appealed and the decision by ACER is therefore not yet legally valid.

The FCA Regulation on forward capacity allocation (Regulation (EU) 2016/1719) is also being implemented. In 2018/19 the TSOs worked with the NRAs to complete and approve the methodology for sharing the congestion income from long-term capacity allocation (Art. 57 FCA GL). The European methodologies on generation and load data provision and on the common grid model, the regional design of long-term transmission rights and their border-specific nomination rules were also completed and approved in 2018.

System balancing

The first steps towards implementation by TSOs of the EB Guideline (Regulation (EU) 2017/2195), which contains rules on the integration of what are still largely nationally organised balancing energy markets and on the cross-border exchange of balancing energy, began in mid-2018.

By means of comments on and evaluations of proposals consulted on by European TSOs, the Bundesnetzagentur joined the procedure at an early stage in 2018 by participating in the preparation of a total of eight European proposals foreseen by the EB Guideline. Topics included product characteristics, pricing, the harmonisation of settlement and the design of European platforms for the future cross-border activation of balancing energy. These were accompanied by additional national proposals for the development of the national balancing energy market. A request for amendment by the competent European regulatory authorities in September set the ball rolling for approval in December 2018 regarding the regional proposals for the further development of the market design regarding the international primary balancing energy cooperation. The Bundesnetzagentur also dealt with applications from TSOs to lay the groundwork for the future joint cross-border procurement of secondary balancing energy in Germany and Austria.

The pan-European applications from all European TSOs should – based on the new legal framework in the CEP – be approved in 2019 by ACER instead of by the NRAs.

System operation

The SO Guideline (Regulation (EU) 2017/1485) deals inter alia with the harmonisation in the area of system operation and the definition of security limits. Implementation will require TSOs to develop various terms and conditions as well as methodologies, which will also involve participation/approval by the relevant regulatory authorities. In 2018, these included, at the European level, the key organisational requirements, roles and responsibilities in relation to data exchange on operational security, the methodologies for creating common grid models as well as the methodologies for coordinating the operational security analysis and for assessing the relevance of assets for outage coordination. At the synchronous area level, the common TSOs' proposal for the determination of load-frequency control blocks was approved and various other methodologies, conditions and values, which must be included in the operational agreements for each synchronous area or load-frequency control block, were developed. The scope of data exchange with DSOs and significant grid users was also determined nationally.

The E&R Regulation on electricity emergency and restoration (Regulation (EU) 2017/2196) also concerns system operation. The TSOs developed their system defence and restoration plans in 2018. Certain modalities (e.g. for system services, market suspension) are subject to approval by the Bundesnetzagentur.

7.6 Bidding zone review

Discussions in Europe on the future design of the electricity market continues to focus on the reconfiguration of current bidding zones. In this respect, the CACM Guideline provides for a review every three years, beginning with the entry into force of this Regulation (2015), of the efficient configuration of the existing bidding zones by the participating TSOs, NRAs and ACER.

The bidding zone study process was launched in 2013 – as an "early implementation" ahead of the CACM Guideline which came into force in 2014 – and carried out by the European Network of Transmission System Operators for Electricity (ENTSO-E). The technical report providing the data basis was submitted by the TSOs in January 2014. In December 2016 ACER took its decision to carry out the bidding zone study on the basis of this report. Two consultancy firms provided support with the calculation of model-based scenarios. The bidding zone study was completed and published on 5 April 2018 following a public consultation which was held in the spring of 2018. The study considered various expert-based scenarios on the splitting and merging of bidding zones. Splitting the large territorial states Germany, France and Poland, merging Netherlands-Belgium and Slovakia-Czech Republic, splitting Germany-Austria and the existing bidding zones configuration have all been analysed. The analysis has, in the unanimous view of the participating regulatory authorities and European TSOs, been considered insufficiently reliable. The analysis was performed for the first time and consequently proved to be so complex that quantitative statements were impossible to obtain. It only provided a qualitative evaluation of the different bidding zone configurations as the model-based results were unusable.

The complexity of the methodology (nodal pricing approach with flow-based calculation) and the insufficient data quality and availability (differing means of operating and controlling the 220 kV grid) were such that a final and specific recommendation could not be made. The report therefore recommends maintaining the existing bidding zone configuration in Europe. The Bundesnetzagentur welcomes this outcome and has worked within the process to ensure that appropriate account is taken of criteria such as the planned grid expansion. The resulting grid status is sufficient for a congestion-free management of the single German bidding zone.

Inclusion of further states in the day-ahead multi-regional market coupling (MRC)

The so-called 4M market coupling (4 MMC) countries, CZ, HU, SK and RO, are planned to be included along with PL in the existing MRC in the framework of an interim project (Figure 95). This was agreed by the regulatory authorities of these countries, the Austrian regulatory authority E-Control and the Bundesnetzagentur in December 2018. This should strengthen the integration of the region's day-ahead market until the Core flow-based project takes effect. Market coupling should facilitate a more efficient allocation of cross-border transmission capacities and an improved price formation on the regional day-ahead markets. This should increase both liquidity and trading options as well as price convergence.

F Wholesale market

Well-functioning wholesale markets are vital to competition in the electricity sector. 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.

There were different developments in the trade volumes and liquidity of the electricity wholesale markets in 2018. On the one hand there was a slight decline in the trading volumes on the spot market. There was a decline in the volume of day-ahead trading whilst the volume of intraday trading rose. Another important development in electricity wholesale trading was the splitting of the joint market area on 1 October 2018 which de facto split the joint Germany/Austria market area (so-called bidding zone splitting).[67]

Futures trading volumes increased slightly. In 2018 the Phelix-DE/AT was almost completely replaced with the Phelix-DE. The volumes traded via broker platforms also increased [68]. In 2018 the OTC clearing volume of Phelix-DE futures on the EEX also increased significantly at 1,053 TWh and now equals the volume of exchange trading.

In 2018 average electricity wholesale prices continued to rise significantly. Spot market prices (for the joint German/Austrian market area up to 30 September 2018) rose by approx. 22% year-on-year and futures for the subsequent year (for the Germany/Luxembourg market area) were quoted approximately 33% higher.

1. On-exchange wholesale trading

The review of on-exchange electricity trading relates to the market area covering Germany and Luxembourg and to the exchanges in Leipzig (European Energy Exchange AG– EEX), Paris (EPEX SPOT SE)[69] and Vienna (Abwicklungsstelle für Energieprodukte AG– EXAA). EEX offers electricity products in futures trading; EPEX SPOT SE and EXAA supply electricity products on the spot markets: These exchanges took part in collecting energy monitoring data again this year.[70] As the joint Germany/ Luxembourg/ Austria market area existed

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[67] This bidding zone was dissolved on 1 October 2018, leaving a separate German/Luxembourg and Austrian bidding zone. The Bundesnetzagentur and the Austrian energy regulator E-Control agreed on this measure on 15 May 2017. Cf:. https://www.bmwi.de/Redaktion/EN/Pressemitteilungen/2017/20170515-federal-network-agency-and-e-control-agree-on-congestion-management-at-german-austrian-border.html (retrieved on 13 September 2018)

[68] The volume reported to the Bundeskartellamt is smaller than the previous year. However, one large broker did not transmit any data. If the quantity from the previous year is applied, this results in slight increases.

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

[70] In addition, Nord Pool Spot AG also provides facilities for the trading of electricity destined for Germany. It offers intraday trading to Germany as the supply area. The trading volume in 2018 was around 2.3 TWh. In 2017 it was still around 2.5 TWh. The exchange also offers the trading of market coupling products for Germany (from and to Sweden or Denmark)

until 1 October 2018, the report also briefly assesses this market area. This results in a transfer of the products on the spot market from the joint market area to a split market area, whereby the key focus after the split is on the German market area.

The total number of participants authorised at the electricity exchanges in the Germany/ Luxembourg market area remained stable or fell slightly in recent years. On 31 December 2018 a new all-time high was reached solely on the EEX with 237 participants (2017: 236 participants). However, the number of participants on the EPEX Spot fell to 198 (2017: 203 participants); the number of participants authorised at the EXAA fell to 71 (2017: 72 participants).

Development of number of registered electricity trading participants on EEX, EPEX SPOT and EXAA

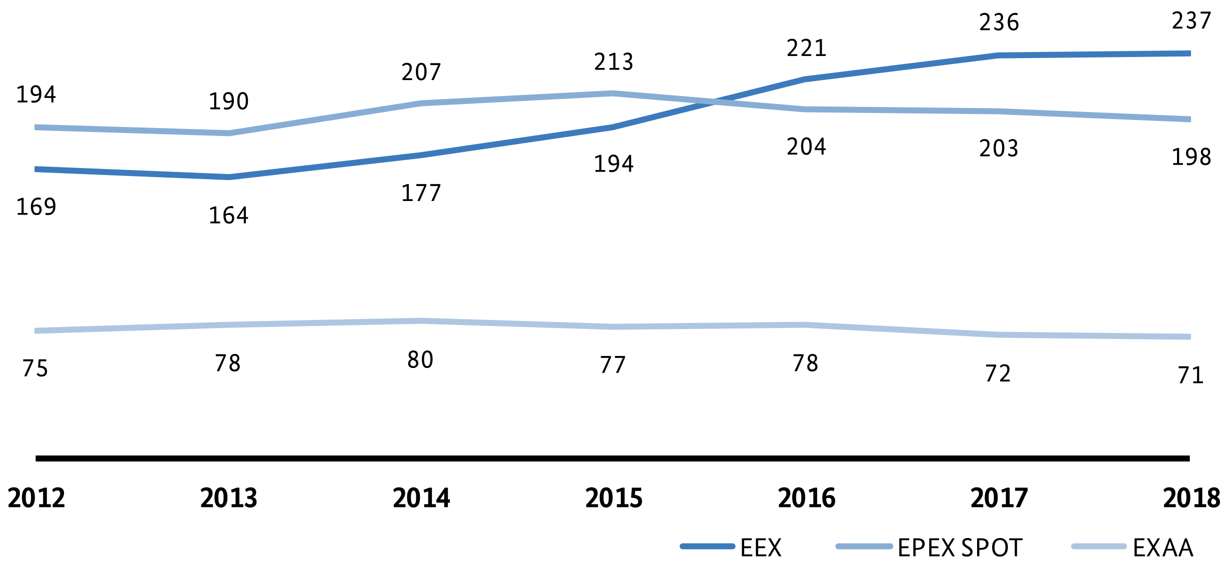

Figure 102: Development of the number of registered electricity trading participants on EEX, EPEX SPOT and EXAA

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.

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 and the futures markets 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 could be physically fulfilled (supply of electricity) on the two on-exchange spot markets for the Austrian control area (APG) until 30 September 2018, and for Luxembourg (Creos) and 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 10:30 a.m.) The EXAA now also offers a coupled auction at 12:00 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. Since September 2014 quarter hours have been traded in day-ahead auctions on EXAA alongside single hours and blocks. EPEX SPOT introduced an auction for quarter-hour contracts (known as "intraday auctions") alongside its hour contracts for the German control areas in December 2014. This auction is held daily at 3:00 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 blocks and at 4 p.m. for 15-minute periods. It is possible to trade electricity contracts for the German control areas up to 30 minutes before commencement of supply and up to 5 minutes before commencement of supply within the control areas.

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 green certificates with physical electricity.

1.1.1 Trading volumes

The volume of day-ahead trading on EPEX SPOT was 224.6 TWh in 2018, a slight decline of 3.7% compared to the previous year (233.2 TWh). However, the volume of intraday trading rose to 52.8 TWh, an increase of around 5.8 TWh or around 12.5 % over the previous year. The volume of the day-ahead market on EXAA also declined by approx. 13.9% and amounted to around 7.2 TWh.

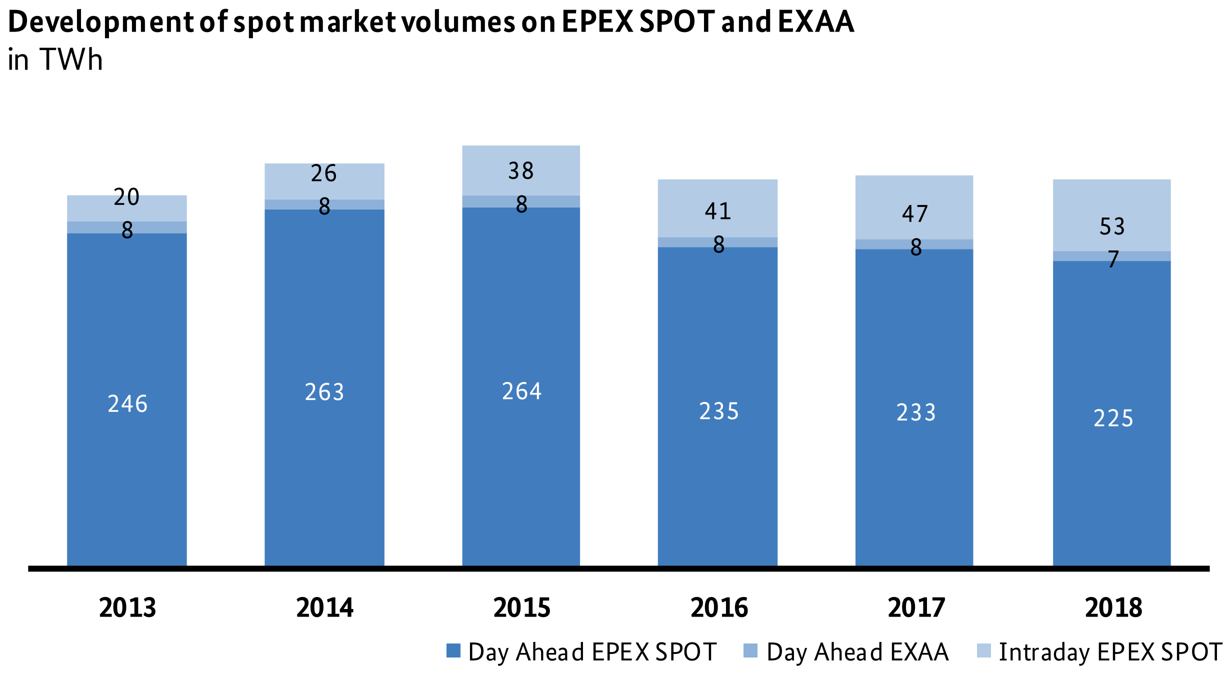

Figure 103: Development of spot market volumes on EPEX SPOT and EXAA

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 2018 was 120 (compared to 124 buyers in 2017) and the average number of sellers was 116 (compared to 112 in 2017). An average of 156 participants (compared to 155 participants in the previous year), or about 79 per cent of all registered participants, were active per trading day. The number of net buyers per trading day (balance in favour of “purchase”) was 81 participants in 2018, slightly below the level of previous years. The number of net sellers (balance in favour of “sale”) rose to 75.

1.1.3 Price dependence of bids

Bids in day-ahead auctions on EPEX SPOT 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.

The high proportion of price-independent bids on EPEX SPOT fell in 2018 compared to the previous year. Approx. 60% of purchase bids submitted were price-independent compared to 67% in 2017. The proportion of price-independent bids among selling bids submitted was 62.6%, up by around three per cent compared to the previous year.[71]

[71] The percentage shares of price-independent and price-dependent selling bids shown in the 2018 monitoring report were corrected. The respective volumes shown are correct.

Price dependence of bids submitted in hour auctions on EPEX SPOT in 2018

	Selling bids		Purchase bids	
	Volume in TWh	Share	Volume in TWh	Share
Price independent bids	105.9	62.6%	100.7	59.5%
submitted by TSOs	35.1		0.4	
physically fulfilled Phelix Futures	17.7		21.9	
others	53.1		78.4	
Price dependent bids	63.2	37.4%	68.4	40.5%
in blocks	12.4		6.8	
market coupling	28.1		7.7	
of which price dependent bids	22.8		53.9	
Total	169.1	100%	169.1	100%

Table 77: Price dependence of bids submitted in hour auctions on EPEX SPOT in 2018

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 98.9%.[72] However, according to the power exchanges, the volume marketed by the transmission system operators continued to fall to around 35.1 TWh (38.6 TWh in 2017 and even 41.6 TWh in 2016).

The reason for the decline is the continuously rising proportion of the volumes remunerated under the EEG in the form of the market premium (cf. chapter I.B.2.1.3). The installed capacity of installations that sell electricity via direct marketing under Section 21b (1) no. 1 EEG 2017 (eligible for market premiums) has increased. In January 2018, the market premium was drawn on by operators of installations with a capacity of approximately 68 GW; in December 2018 it was already drawn on by installations with a capacity of just under 74 GW. The installed capacity of installations with other direct marketing under Section 21b (1) no. 4 EEG 2017 also rose from around 210 MW to over 268 MW in the same period (January to December 2018).[73]

On the seller side, the volume of bids on EPEX SPOT for the physical fulfilment of Phelix Futures fell from 27 TWh in 2017 to 18 TWh in 2018. On the buyer side, the volume also fell from 45 TWh to 22 TWh in 2018.

[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) EEG) on a spot market exchange and offer them on a price-independent basis.

[73] For information provided by the TSOs on direct marketing, see https://www.netztransparenz.de/portals/1/Direktvermarktung-Uebersicht_Dezember2018.pdf, retrieved on 9 August 2019.

1.1.4 Price level

The most commonly used price index on the spot market for the 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. The following figure shows the average price of Phelix-DE/AT for the German/Austria/Luxembourg market area up to 30 September 2018. After the bidding zone splitting on 1 October, 2018, only the Phelix-DE average applied to the Germany/Luxembourg market area for the rest of 2018.

Average spot market prices rose further in 2018. If the joint market area including Austria is considered, the Phelix day base average rose by around 22% from €34.20 /MWh to €41.73/MWh. At €44.22/MWh the Phelix day peak was also nearly 16% above the previous year's level of €38.06/MWh. If only the German/Luxembourg market area is considered, the Phelix day base average for the last quarter (from 1 October, 2018) was around €52.60/MWh and the average Phelix day peak average at €59.90/MWh.

If only the development in prices in the comparable period from January to 30 September of 2017 and 2018 is considered, when the joint bidding zone still existed, average spot market prices rose. The Phelix day base average for the first three quarters of 2017 rose from €34.57/MWh to €41.73/MWh for the first three quarters of 2018. The average baseload future rose by around 21%. At €44.22/MWh the Phelix day peak in 2018 was also nearly 18% higher than the previous year's level.

Development of average spot market prices on EPEX SPOT in Euro/MWh

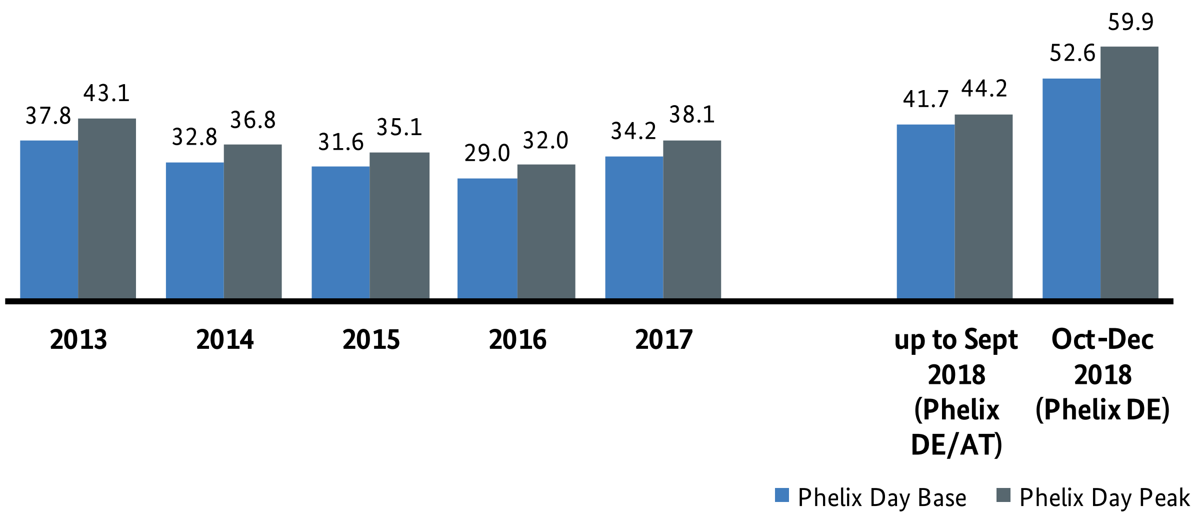

Figure 104: Development of average spot market prices on EPEX SPOT

Compared to the development in price of the Phelix day base for Germany and Austria at the beginning of the bidding zone splitting from 1 October, the prices in Germany were lower than in Austria. In the last quarter the average spot market price for Phelix day base-DE was approx. €52.60/MWh, whilst the price for Phelix day base-AT was €59.93/MWh. The Austrian price was thus approx. 13.9% higher than the Phelix-DE A peakload comparison also showed that the Phelix day peak-DE was around 12.1% lower than the Phelix day peak-AT.

Development of Phelix day base-DE and Phelix day base-AT from October to December 2018 in Euro/MWh

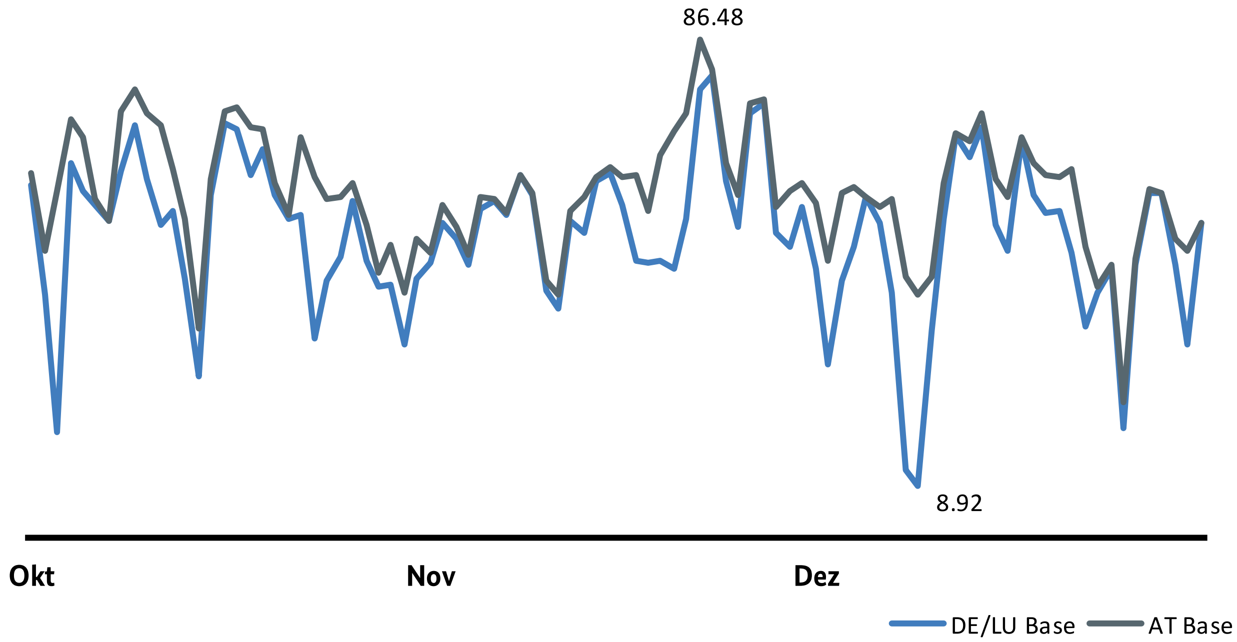

Figure 105: Development of the Phelix day base-DE and Phelix day base-AT from October to December 2018

The bEXA and Phelix indices for 2018 are very close to each other. If one considers the products for the joint bidding zone, electricity prices were for the first time higher in 2018 in the day ahead auctions on EPEX SPOT than on EXAA. This applies to both the base as well as the peak price. The difference between Phelix day base and bEXAbase was around €-0.05/MWh, compared with €0.29/MWh in 2017. The difference between Phelix day peak and bEXApeak was around €0.09/MWh and €0.34/MWh in 2017.

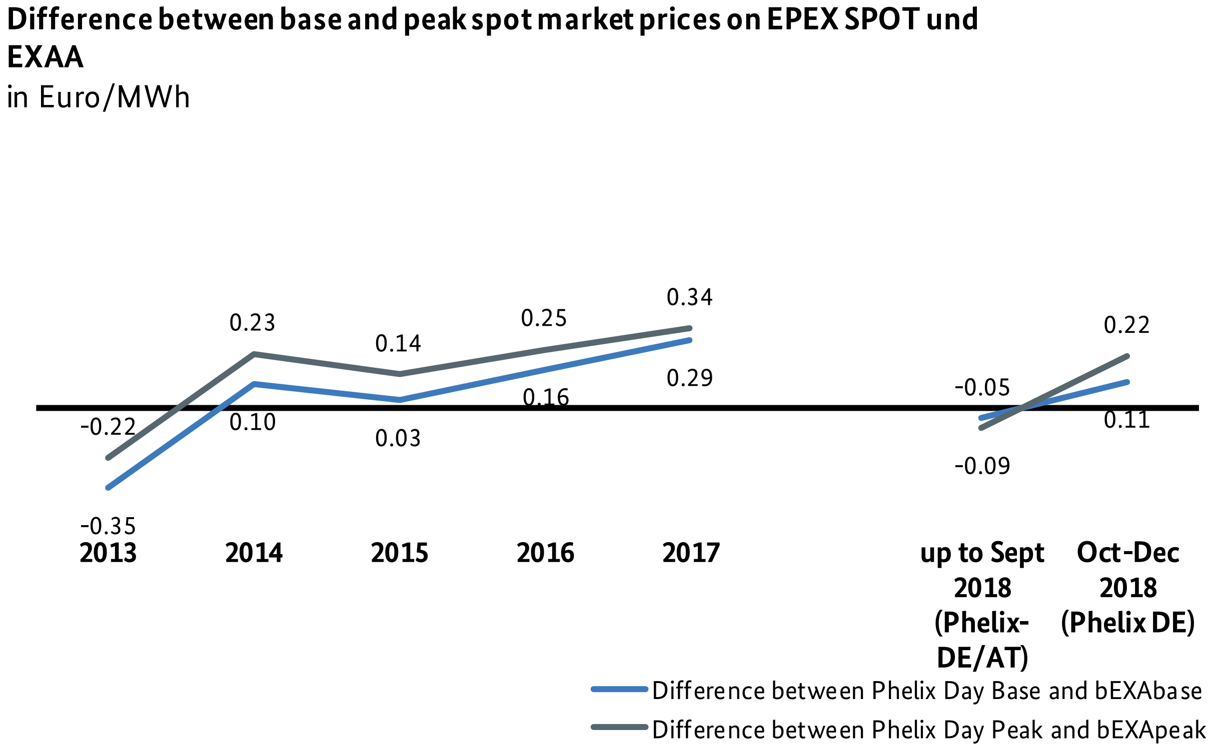

Figure 106: Difference between base and peak spot market prices on EPEX SPOT and EXAA

1.1.5 Price dispersion

As in previous years, daily average spot market prices exhibit considerable dispersion. The following figure shows the development of spot market prices over the year, using the Phelix-DE/AT day base and from 1st October the Phelix-DE day base as examples. 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 2018 that went far beyond the usual fluctuations. The price rose continually until the end of the year.

Development of Phelix day base in 2018
in Euro/MWh

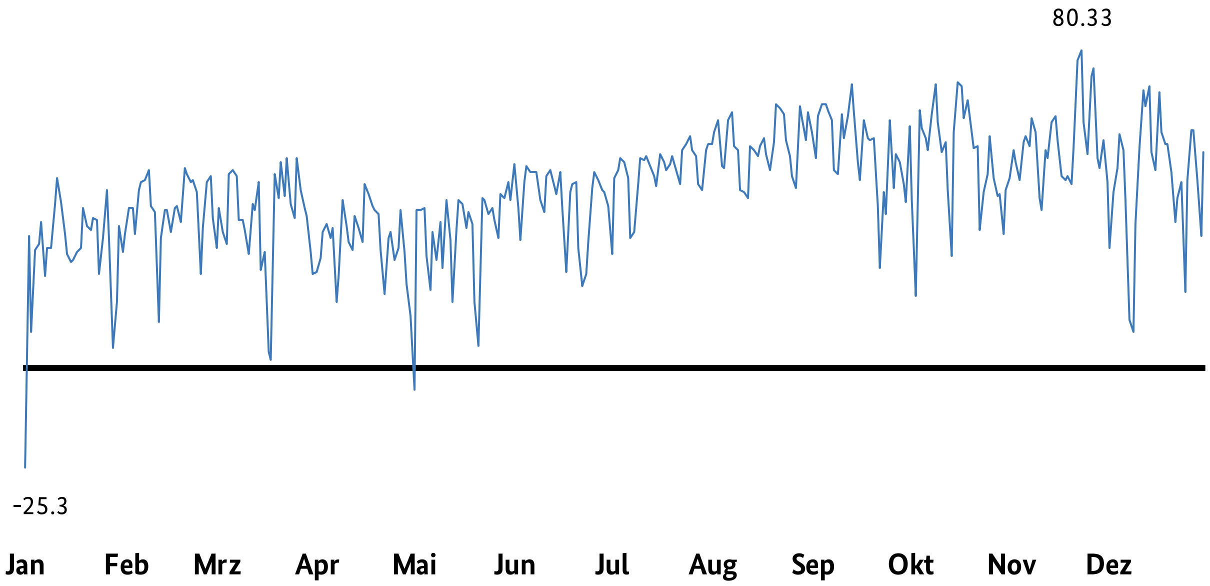

Figure 107: Development of Phelix day base in 2018

There were significant positive and negative values in the Phelix base and peak on EPEX SPOT in 2018. The range of the middle 80% of the graded Phelix day base values rose significantly in 2018. In 2017 the difference was still €12.03 /MWh – in 2018 the difference was €22.57/MWh. The corresponding peak range of the middle 80% also rose significantly from €16.26/MWh in 2017 to €23.75/MWh.

There were two negative values[74] in the Phelix day base and in the Phelix day peak in 2018. Negative average values in the Phelix day peak were registered on two other days. The Phelix day base reached its lowest value on 1 January 2018 at €-25.30/MWh. The Phelix day peak reached its lowest value on the same day at €-21.46. In 2017 the minimum day base value was still €-52.11 /MWh and the minimum day peak value was €-45.27/MWh.

The maximum values of both indices also decreased compared to the previous year. In 2018 the highest Phelix day base value was €80.33/MWh, or around 20% below the previous year's value. In 2017 the highest Phelix day base price was still €101.92/MWh.

The maximum day base price was reached on 23 November 2018. The reason for this maximum value could have been the cold spell along with fog and rain on that day. The Phelix day peak value was €97.48/MWh in 2018, falling from €130.18/MWh in 2017, which is equivalent to an decrease of around 25%.

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[74] 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.

Price ranges of Phelix day base and Phelix day peak between 2016 and 2018 in Euro/MWh

	Middle 80%	Range of middle 80%	Extreme values	Range of extreme values
	10 to 90 percentile of values		Min – Max	
Base 2016	18.57 to 40.38	21.81	-12.89 to 60.06	72.95
Base 2017	27.95 to 39.98	12.03	-52.11 to 101.92	154.03
Base 2018	33.55 to 56.12	22.57	-25.30 to 80.33	105.63
Peak 2016	18.38 to 46.94	28.56	-36.46 to 76.84	113.3
Peak 2017	28.35 to 44.61	16.26	-45.27 to 130.18	175.45
Peak 2018	37.16 to 60.91	23.75	-21.46 to 97.48	118.94

Table 78: Price ranges of Phelix day base and Phelix day peak between 2016 and 2018

1.2 Futures markets

Futures with standardised maturities can be traded on EEX for the German/Luxembourg 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 German intraday 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.[75] Since March 2017 the "German Intraday Floor Futures" programme has been extended. The Floor Futures serve to hedge against low prices.[76] Since October 2016 participants admitted to the EEX can also trade in wind power futures and thus hedge against the growing share and resulting volume risks of the generation of wind power.[77]

In April 2017 the EEX already started trading separate electricity futures only for Germany and from June 2017 only for Austria with a view to the planned splitting of the German/Austrian bidding zone.[78] The purely Phelix-DE as well as purely Phelix-AT contracts were settled against the respective day ahead auctions of both countries. Existing DE/AT contracts will be settled proportionately between Germany and Austria with a weighting of 9 to 1.[79]

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

[76] Cf. EEX press release of 18 January 2017. https://www.eex.com/de/about/newsroom/news-detail/eex-erweitert-angebot-fuer-strommarkt-um-floor-futures-und-schweizerische-tages--und-wochenend--futures-/63300

[77] Cf EEX press release of 31 August 2016, https://www.eex.com/de/about/newsroom/news-detail/eex--handel-mit-wind-power-futures-startet-anfang-oktober/56352

[78] 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

[79] Cf. EEX press release of 18 May 2017. https://www.eex.com/blob/67092/19d592fdc571849f2d306e1d5605ce83/20170518-customer-information---extension-of-phelix-de-futures-data.pdf, retrieved on 24 September 2019

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

1.2.1 Trading volumes

Following substantial decline in 2017 to 786 TWh (purely Phelix-DE trading volumes amounted to 196 TWh) the on-exchange trading volumes of Phelix DE/AT futures had to be assessed differently. From 2018, with the splitting of the bidding zones on 1 October the focus will lie primarily with the assessment of trading volumes for Phelix DE. These were 1,058 TWh in 2018 (in the case of Phelix DE/AT these still amounted to 27 TWh). The following graph shows the development of the products Phelix DE/AT and Phelix DE. It is clear from this that the Phelix-DE/AT has lost in importance over time and the Phelix DE for Germany has replaced the Phelix-DE/AT.

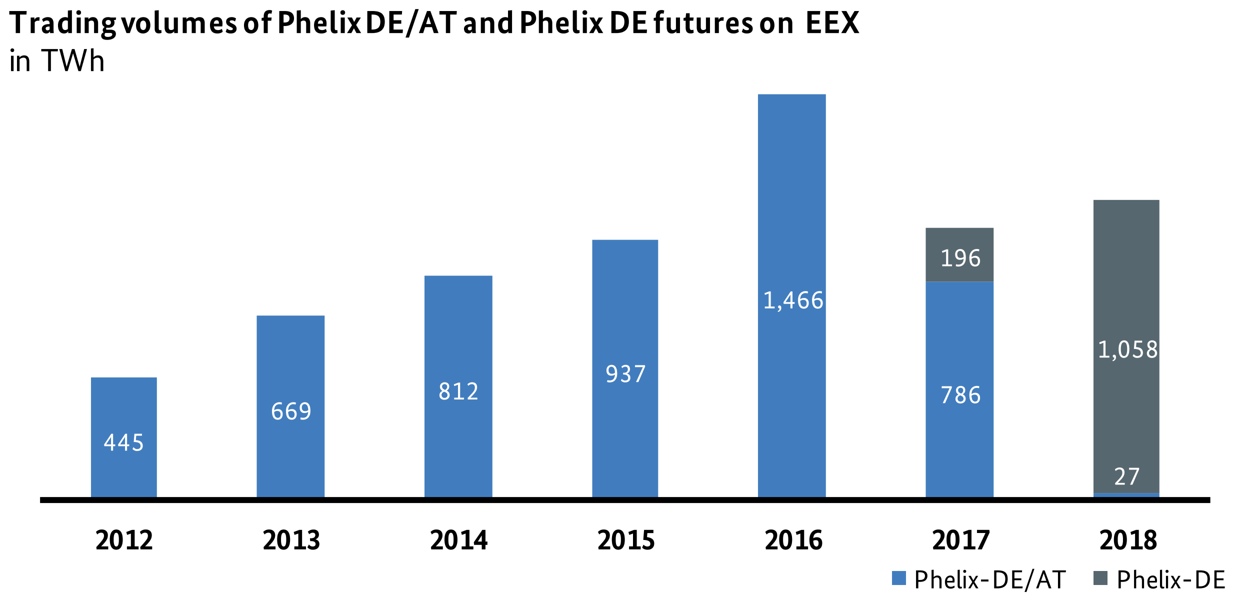

Figure 108: Trading volumes of Phelix DE/AT and Phelix DE futures on EEX

Phelix DE predominantly focussed on contracts for the year ahead (2019) as the fulfilment year with some 62 % of the total trading volume, i.e. around 655 TWh. Trading for the current year made up the second largest share with approximately 18%, i.e. a total of 191 TWh. Trading for 2021 and the next few years significantly increased compared to the previous year. Trading for 2020 increased by over 100% to around 161 TWh. Trading volumes for the 3rd subsequent year also more than doubled to 43 TWh and increased to approx. 8 TWh for the 4th subsequent year.

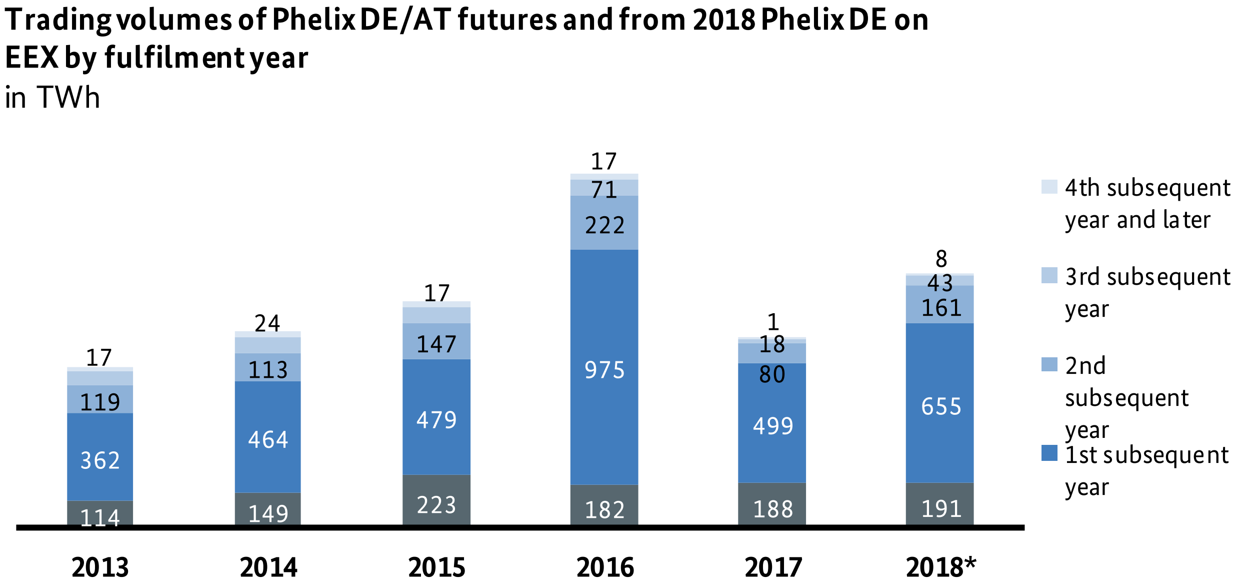

Figure 109: Trading volumes of Phelix DE/AT futures and from 2018 Phelix DE on EEX by fulfilment year

1.2.2 Price level

The Phelix year futures base and peak are the two most important futures traded on EEX for the German/Luxembourg 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 2018 futures prices increased significantly. One reason for this was the shutdown or removal of power plants from the market. On 27 December 2018 the Phelix DE peak year ahead future was quoted at a price of €66.26/MWh and was around 43% higher than the beginning of the year. The Phelix DE base year future also rose to €54.44 /MWh. This corresponds to an increase of approx. 48% from the beginning of the year.

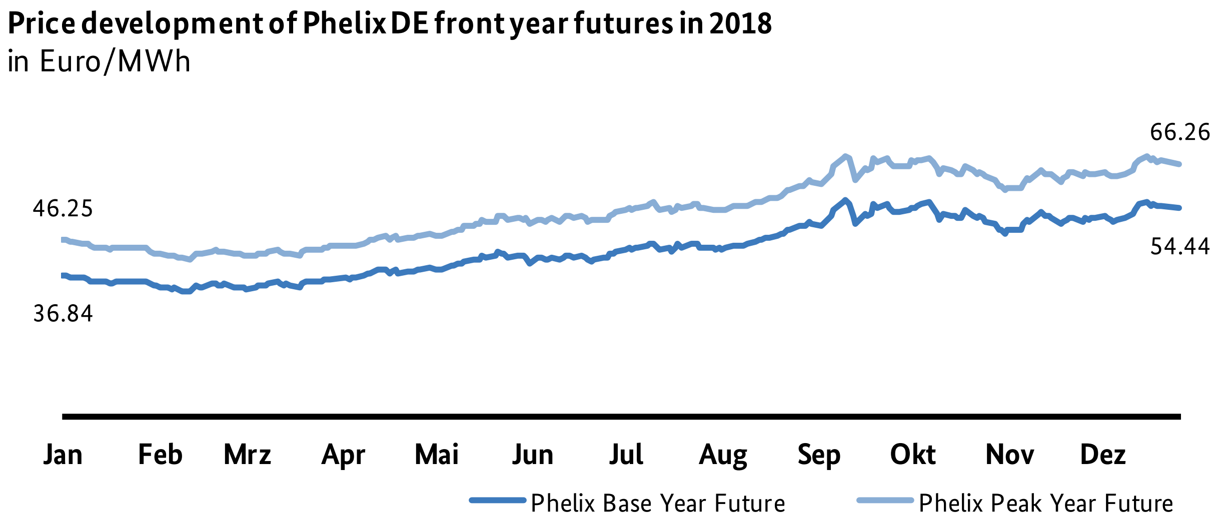

Figure 110: Price development of Phelix DE front year futures in 2018

An annual average can be calculated on the basis of the Phelix DE front year futures prices recorded on the 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 DE futures prices rose again compared to the previous year, where the Phelix DE/AT future was still in place. With an annual average of €43.84/MWh, the Phelix base year future rose by €11.46/MWh from €32.38/MWh in 2017, a rise of approximately 35%. The price of the Phelix peak front year futures averaged €53.95/MWh over the year. The price increased by €13.44/MWh, or around 33 per cent, from the previous year's figure of €40.51/MWh. The downward trend from 2013 to 2016 has therefore reversed.

Development of annual averages of Phelix DE front year futures prices on EEX
in Euro/MWh

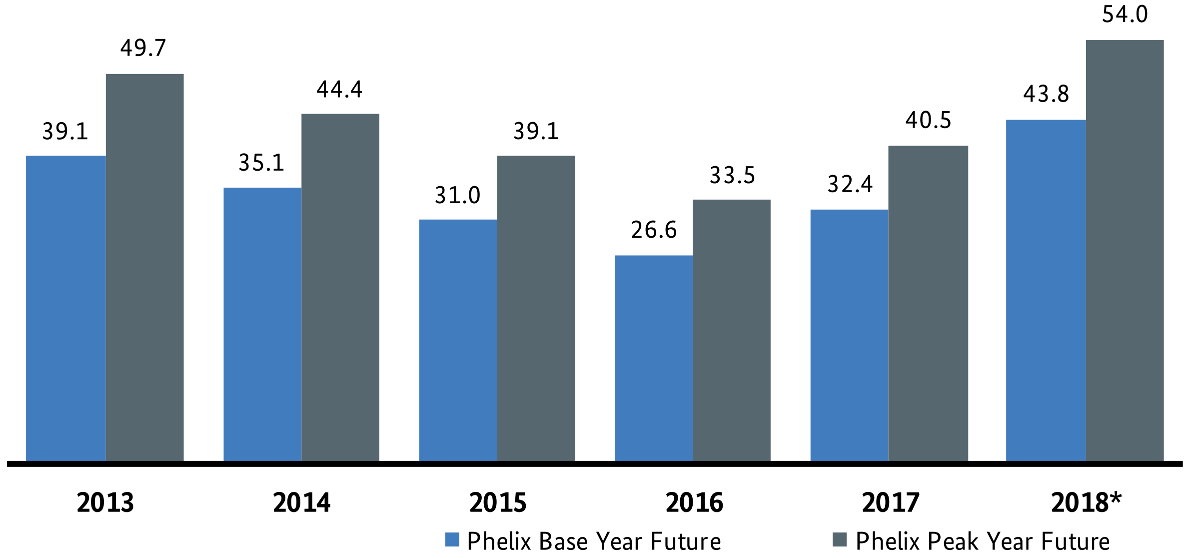

Figure 111: Development of annual averages of Phelix DE front year futures prices on EEX

The annual average price difference between base and peak products was €10.11/MWh. In 2017 the difference was still €8.13/MWh. The peak price was therefore around 23% higher than the base price.

1.3 Trading volumes by exchange participants

1.3.1 Share of market makers

An exchange participant who has undertaken to publish binding purchase and sale prices (quotations) at the same time is referred to as a market maker. 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.

Three companies acted as market makers on the EEX futures market for Phelix Futures for the German market area in the reporting period: Uniper Global Commodities SE, RWE Supply & Trading GmbH and Vattenfall Energy Trading GmbH. However the market makers were not active during the entire reporting period , but only during several months. The market makers' share of the purchase volume was approx. 18%, up from 9 per cent in the previous year. On the sales side the volume also rose to 17% compared with 8% in the previous year.[80]

In addition to agreements with market makers, EEX maintains contracts with trading participants who are committed to strengthening liquidity to an individually agreed extent. These companies generated approximately 2% of the total trading volume (sales and purchases) in 2018, 5% less than in the previous year.

Four market makers were active on the day-ahead market of EXAA in the reporting period. Verbund Trading GmbH, Uniper Global Commodities SE, Danske Commodities AS and RWE Supply & Trading GmbH. In 2018, the cumulative share of transactions carried out by companies in their role as market makers was 2.9 per cent of the purchase volume of the day-ahead auction (1.9 per cent in 2017) and 5.1 per cent of the sales volume (5.5 per cent in 2017).

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, due to the growing importance of direct marketing.

The share of TSOs in the day-ahead sales volume of EPEX SPOT has been declining for a number of years but was approx. 19% in 2018, slightly higher than in the previous year when it was approx. 17%. By comparison, their share was still 28 % in 2012. The volumes marketed by the TSOs also declined in absolute terms. There was a slight increase in volume in 2018. The on-exchange day-ahead sales volume marketed by TSOs was approximately 41.2 TWh in 2018; in 2017, this value was still around 38.6 TWh and even higher in the previous years. In 2012 it was approx. 69.5 TWh and in 2014 approx. 50.5 TWh. The TSOs generated a very small spot market volume of about 0.5% on the buyer side.

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 participants with the highest turnover can change over the years, so that the cumulative share of turnover does not necessarily relate to the same

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[80] EEX trading data does not differentiate between trade conducted by market makers and non-market makers. The data on the share of the market makers can thus be overstated as well as understated.

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]

The share of the five purchasers with the highest turnover in the day-ahead trading volume on EPEX SPOT rose from 33% in 2017 to 35%. The corresponding share on the seller side fell compared to the previous year. The cumulative share of the five sellers with the highest turnover was approximately 30% in 2018. This was still 32% in the previous year. The previously higher shares on the seller side are primarily due to the TSO's higher sales volumes at that time.

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

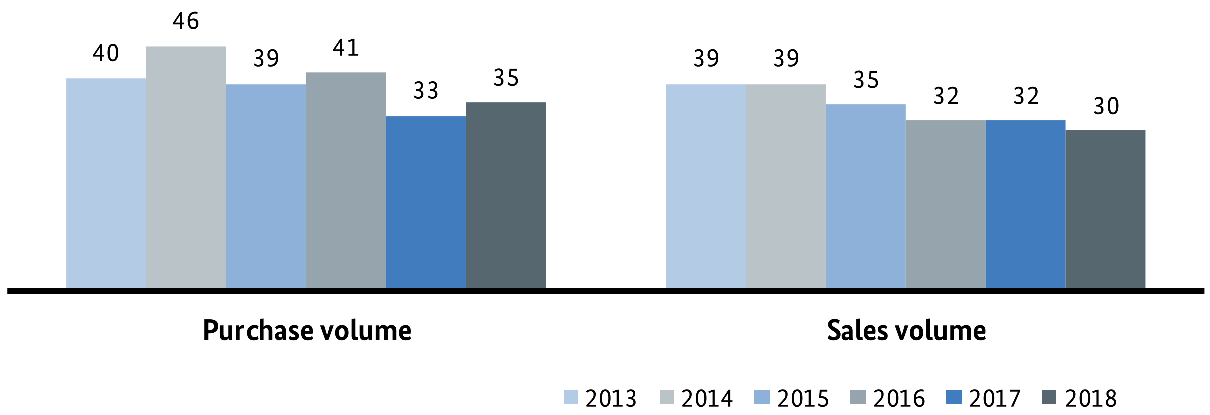

Figure 112: Share of the five sellers and five buyers with the highest turnover in the day-ahead volume of EPEX SPOT

The share of the five buyers of Phelix-DE futures with the highest turnover on EEX (excluding OTC clearing) increased from around 29% in 2017 to 35% in 2018. The share of the five sellers with the highest turnover rose from around 32% in 2017 to 35% in 2018.

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. Moreover, the trading places have developed from bilateral to multilateral trading places where not only buyers and sellers but also intermediaries, brokers, etc. are active.

Brokers play a major role in bilateral and multilateral wholesale trading. They act as intermediaries between buyers and sellers and pool information on the supply and demand of electricity transactions. Electronic

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

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 transactions 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 2018 different broker platforms were once again surveyed with regard to bilateral wholesale trading (see sections below). Data on OTC clearing on EEX was also collected. The surveys revealed a stable high level of liquidity in bilateral electricity wholesale trading in 2018.

2.1 Broker platforms

During monitoring, operators of broker platforms are also asked to answer questions on the contracts they have brokered. Many brokers provide an electronic platform to conduct their brokerage services.

Ten brokers (eleven 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 4,956 TWh in 2018 compared to 5,671 TWh in 2017. The data of one of the larger brokers on the market for 2018 was missing because it did not transmit any volumes. However, if the volume transmitted by this broker in the previous year were added to this year, the total volume of these eleven brokers would roughly reach the previous year's level. Data from the London Energy Brokers' Association (LEBA), which, however, does not include all broker platforms, also showed a similar observation. The volume of trading transactions brokered by LEBA members rose slightly. The trading volume for German power brokered by LEBA members rose from 5.262 TWh to 5.330 TWh, or by around 1% year-on-year.[83]

Contracts for the year ahead continue to make up the majority of electricity transactions brokered on broker platforms with 59 % (64% in the previous year), followed by the activities for the current year with 25% (19% 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 only minimally shifted.

[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 London Energy Brokers' Association, Monthly Volume Report: https://cdn.evia.org.uk/content/monthly_vol_reports/LEBA%20Energy%20Volume%20Report%20December%202018.pdf (retrieved on 12 September August 2019).

Volume of electricity traded via broker platforms in 2018 by fulfilment period

Fullfilment period	Volumes traded in TWh	Share
Intraday	0	-
Day-Ahead	73	1%
less than 1 week	67	1%
over 1 week	1,242	25%
1st subsequent year	2,917	59%
2nd subsequent year	532	11%
3rd subsequent year	115	2%
4th subsequent year	10	0%
Total	**4,956**	**100%**

Table 79: Volume of electricity traded via broker platforms in 2018 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, see above) 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 1,053 TWh in 2018. The volume was still 905 TWh in 2017. 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 volume has increased slightly since 2013. This reached an all-time high in 2016. Compared to 2017 the volume increased, both in OTC and on-exchange trading. The OTC clearing volume increased by approx. 16% and on-exchange trading by approx. 35% compared to the previous year.

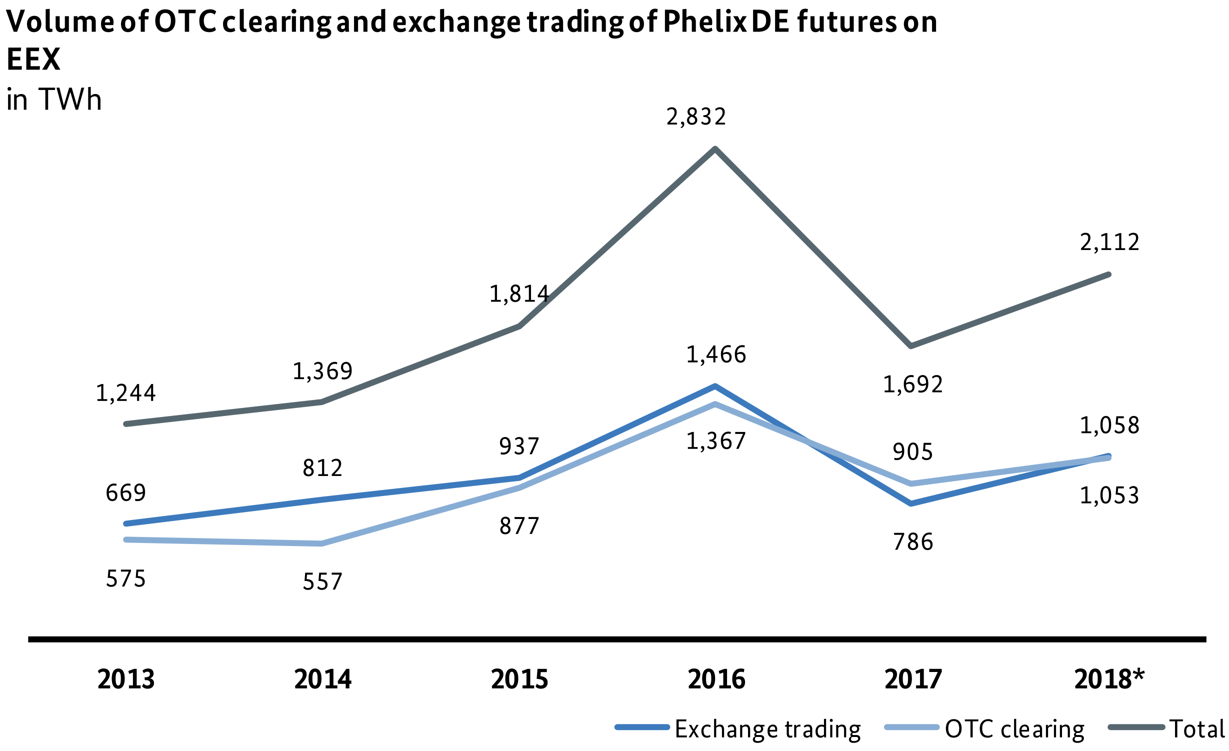

Figure 113: Volume of OTC clearing and exchange trading of Phelix DE futures on EEX

According to LEBA, the volume for German power registered by LEBA members for clearing was approx. 915 TWh in 2018, which is equivalent to a share of about 17% of the total OTC contracts brokered by LEBA members. By contrast the corresponding figures were around 16% of the total volume with a volume of approx. 859 TWh in 2017.[84]

Phelix options had no bearing on exchange trading on EEX. As in the previous year there were no such transactions in 2018. By contrast, OTC clearing of Phelix options agreed off the exchange has practical significance: Phelix options accounted for a share of 177 TWh or 17% of OTC clearing in 2018 while the remaining 877 TWh or 83% of OTC clearing consisted of Phelix futures. The OTC clearing volume for options rose significantly by approx. 49% over the previous year. The distribution of the volumes registered on EEX for OTC clearing across the various fulfilment periods in 2018 shifted minimally compared to the previous year. While in 2017 approx. 64% consisted of contracts for the year ahead, this figure fell to 62% in 2018 (654 TWh). Around 24% (260 TWh) related to 2018 itself. Around 11% related to the year after next (trading for 2020). Later fulfilment periods made up only a small share.

[84] Cfl. https:/www.leba.org.uk/pages/index.cfm?page_id=59 (retrieved on 14 August 2019). The total volume of German power brokered by LEBA members was 5,330 TWh for the whole of 2018.

OTC clearing-volume of Phelix futures on EEX by fulfilment year in TWh

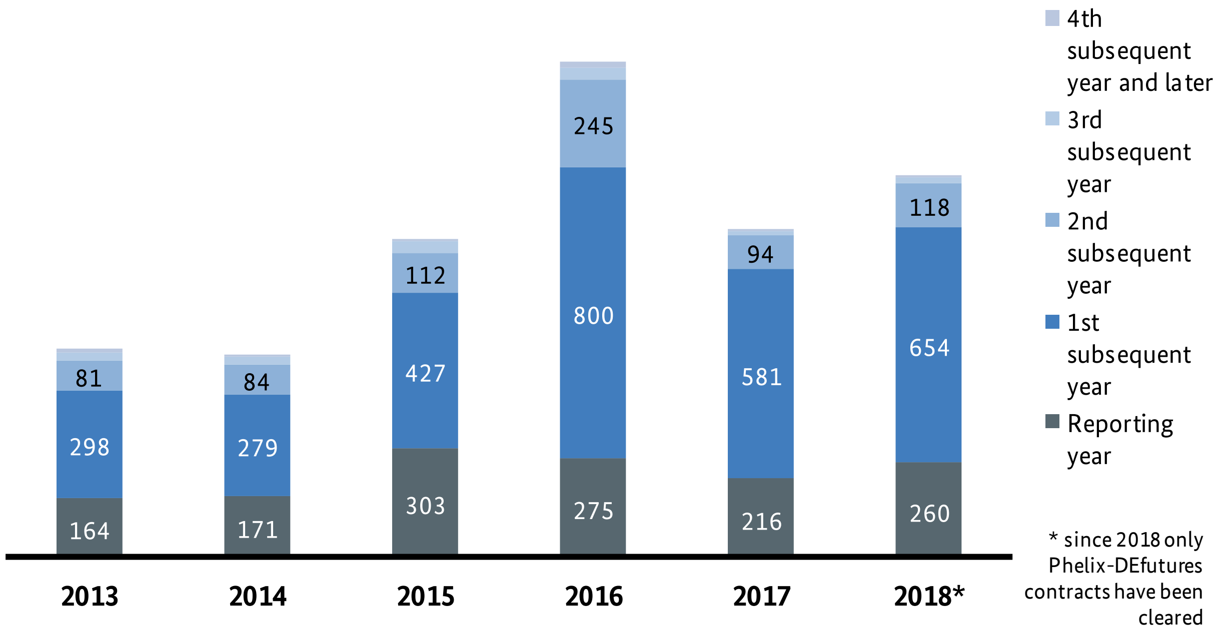

Figure 114: OTC clearing volume of Phelix futures on EEX by fulfilment year

The majority of the OTC clearing volume of Phelix futures on EEX is generated by just a few broker platforms. The five (broker) companies that registered the largest volumes for OTC clearing in 2018 accounted for about 53% of all purchases and 54% of all sales (the figures for 2017 were around 55% of all purchases and 60% of all sales).

G Retail

1. Supplier structure and number of providers

In total, at least 1,485 companies were operating as electricity suppliers in the year 2018. The suppliers are considered to be individual legal entities without taking company affiliations and links into account.

Around 50.9m market locations of final consumers were recorded in the monitoring survey. As Figure 115 shows, of 1,421 suppliers, approximately 84% serve less than 30,000 market locations. This amounts to just under 8.1m market locations in this category (around 16% of all market locations). Some 6% of all suppliers serve over 100,000 market locations each. In absolute terms, these 6% serve around 36.1m market locations and therefore 71% of all customers, which is a similar figure to the previous year. Hence the majority of companies operating as suppliers continue to have a customer base made up of a relatively small number of market locations, whereas 88 large suppliers serve the largest number of market locations in absolute terms. A large number of suppliers therefore does not automatically translate into a high level of competition.

Electricity: Number and share of suppliers serving the given number of market locations
not taking company affiliations into account

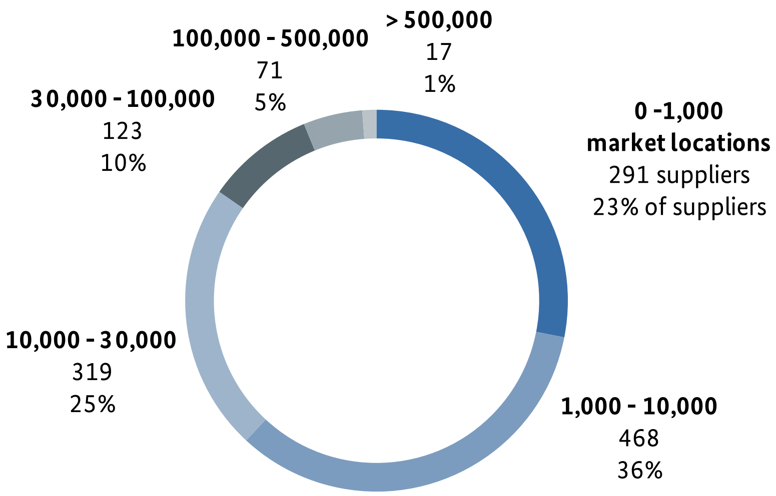

Figure 115: Number of suppliers by number of market locations supplied

A comprehensive picture of the supplier structure emerges from an evaluation of the regional activity of the suppliers. The analysis of the data submitted by 1,263 suppliers shows that nearly half of them only operate regionally. 91 suppliers, or around 7%, supply customers in more than 500 network areas (see Figure 116). This figure can be taken as the approximate number of suppliers that operate throughout the whole of Germany. Another figure that depicts the nationwide activity of suppliers is the number of federal states supplied: 214 suppliers have concluded contracts in all 16 federal states. On a national average, a supplier has customers in 93 network areas (2017: 92 network areas).

Electricity: Number and share of suppliers serving customers in the given number of network areas
not taking campany affiliations into account

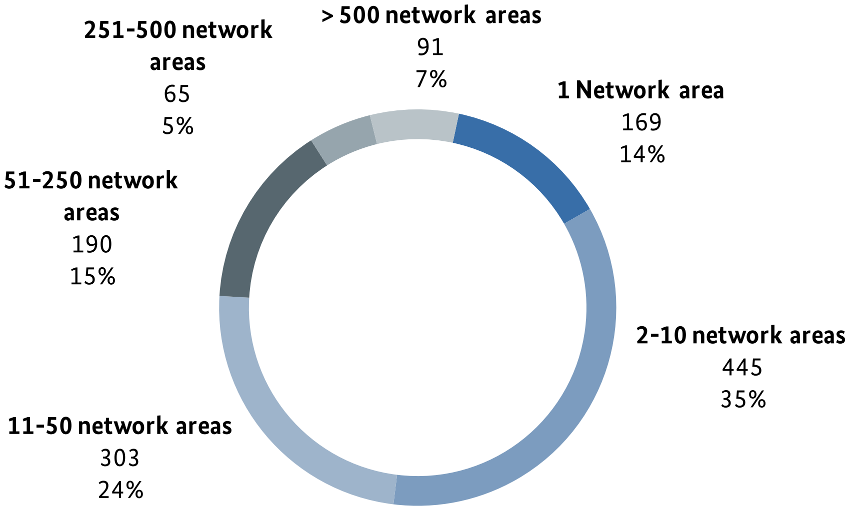

Figure 116: Number of suppliers by number of network areas supplied

Although the majority of suppliers continue to operate regionally, the number of suppliers that electricity customers could choose from increased once again in 2017. An evaluation of the data supplied by 832 distribution system operators on the number of suppliers that supply consumers in each network area produced the following results (see Figure 117): In 2018, more that 50 suppliers operated in over 89% of network areas (737 network areas). In the year 2008 this figure was 33.6% of the network areas (226 network areas). Today more than 100 suppliers operate in around 72% of the network areas, whereas five years ago it was only 40.3% (319 network areas). On average, final consumers in Germany were able to choose between 149 suppliers (2017: 143) in 2018, while household customers were able to choose between 132 suppliers (2017: 124).

Electricity: Breakdown of network areas by number of suppliers operating
in %, not taking company affiliations into account

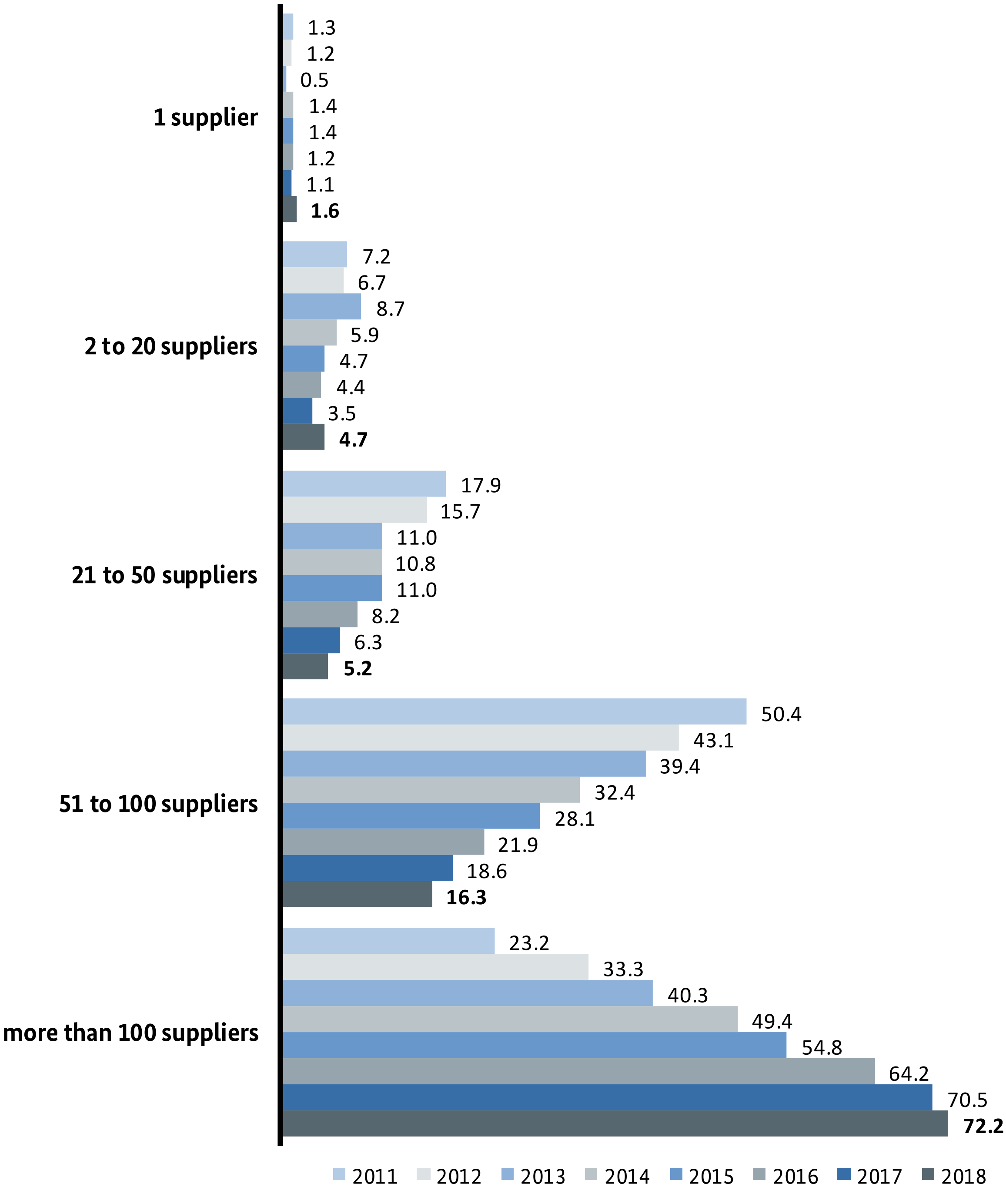

Figure 117: Breakdown of network areas by number of suppliers operating

2. Contract structure and supplier switching

The consistently high number of household customers who are supplied with electricity under a default supply contract or another contract with the default supplier shows that not all consumers are making use of their switching potential yet.

Consumers can inform themselves about their contract terms (default supply status, price stability, contract period etc.) and about their supplier's current prices, and compare these terms and prices with those of other suppliers.

Switching rates and processes are important indicators of the level of competition. The collection of key figures for supplier switches is based on relevant indicators that best reflect the actual switching behaviour. For monitoring purposes, the term "supplier switch" refers to the process by which a final consumer's market location is assigned to a new supplier. As a rule, moving house is not considered a supplier switch. In this context, it must be noted that the change of supplier refers to a change in the supplying legal entity. According to this definition, a supplier switch 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 switching can therefore deviate from the figures reported. In addition to supplier switches, the monitoring report also analyses household customers' choice of supplier upon moving house if they choose a supplier other than the default supplier. The term switch of contract refers to a switch that takes place within the same company.

In order to calculate the indicators, network operators (DSOs and TSOs) and suppliers collect data on contract structures and supplier switches for each specific customer group. Final consumers of electricity 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, 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.

[85] Section 3(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 and 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, if their annual consumption exceeds 10,000 kilowatt hours.

According to the supplier data, the volume of electricity sold to all final consumers in 2018 reached approximately 418.8 TWh. In the previous year, this figure was 423.8 TWh. In 2018, around 260.6 TWh of this amount was supplied to interval-metered customers and 158.2 TWh to SLP customers (including 13.3 TWh of electricity for thermal night storage and heat pumps). The majority of SLP customers are household customers. In 2018, household customers were supplied with around 116.7 TWh, including electricity for heating systems.

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,
- non-default contract with the local default supplier and
- contract with a supplier other than the local default supplier.

For the purposes 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 non-default supply contract or is defined specifically ("non-default contract with the local default supplier" or "contract with a supplier other than the local default supplier"). An analysis on the basis of these three categories makes it possible to draw conclusions as to the extent of the decline in the importance of default supply and the position of default suppliers since the liberalisation of the energy market. The corresponding figures, however, should not be directly interpreted as "cumulative net switching figures since liberalisation". It must be noted that for monitoring purposes the legal entity is taken to be the contracting party; thus a contract with a company affiliated with the default supplier falls under the category "contract with a supplier other than the local default supplier". 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).

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[88], the majority are industrial or high-consumption non-household customers.

In the reporting year 2018, approximately 1,318 electricity suppliers (individual legal entities) provided data on the meter points supplied and on the consumption of interval-metered customers (1,200 in the previous

[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.

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

year). The 1,318 electricity suppliers include many affiliated companies, so that the number of suppliers does not equal the number of competitors.

The companies supplied just under 260.6 TWh of electricity to the approximately 368,377 meter points of interval-metered customers in 2018 (approx. 261.2 TWH was supplied to 372,100 meter points in the previous year). 99.8% of this was supplied under contracts outside of default supply [89]. It is unusual, but not impossible, for interval-metered customers to be supplied under default or fallback supply contracts. A total of 0.56 TWh of electricity was supplied to interval-metered customers with a default or fallback supply, which is 0.2% of the total electricity supplied to interval-metered customers.

27.1% of the total electricity for interval-metered customers was supplied under a special contract with the default supplier (divided between around 41.6% of all interval meter points). Approximately 72.7% of the total electricity was supplied under a contract with a legal entity other than the local default supplier (divided between approximately 56.3% of all meter points). In the previous year, 27.4% of the volume was sold under special contracts with the default supplier and 72.3% under special contracts with other suppliers. Developments over the last few years show that with regard to the volume sold, default supply and special contracts with the default supplier outside the default supply are losing in importance for the acquisition of interval-metered electricity customers.

Elektrizität: Vertragsstruktur bei RLM-Kunden im Jahr 2018
Menge und Verteilung

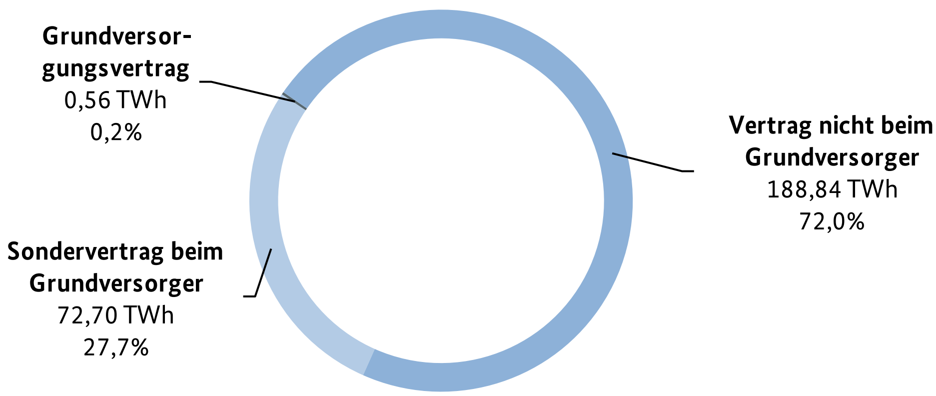

Figure 118: Contract structure for interval-metered customers in 2018

2.1.2 Supplier switching

Data on the supplier switching rates among different customer groups in 2018 and the consumption volumes attributed to these customers was collected in the TSO and DSO surveys. The surveys differentiated between the following consumption categories: Large industrial customers typically fall into the >2 GWh/year

[89] In accordance with Section 36 of the German Energy Act (EnWG), default supply relates only to household customers. Any mention in the following of default supply of non-household customers refers to fallback supply.

category, and a wide range of non-household customers such as restaurants, office buildings, or hospitals fall into the 10 MWh/year to 2 GWh/year category. The survey produced the following results:

Supplier switching by consumption category in 2018

Consumption category	Number of meter points with supplier switching	Share of all meter points in consumption category	Consumption volume at meter points with switching in TWh	Share of consumption volume in consumption category
>10 MWh/year – 2 GWh/year	228,356	10.9%	17.7	14.4%
> 2 GWh/year	3,156	17.9%	27	11.2%
Total non-household customers	**231,512**	**11.0%**	**44.7**	**12.3%**

Table 80: Supplier switching by consumption category in 2018

The volume-based switching rate for the categories with a consumption exceeding 10 MWh/year was 12.3% in 2018. The switching rate in the previous year was 13.0%. 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.

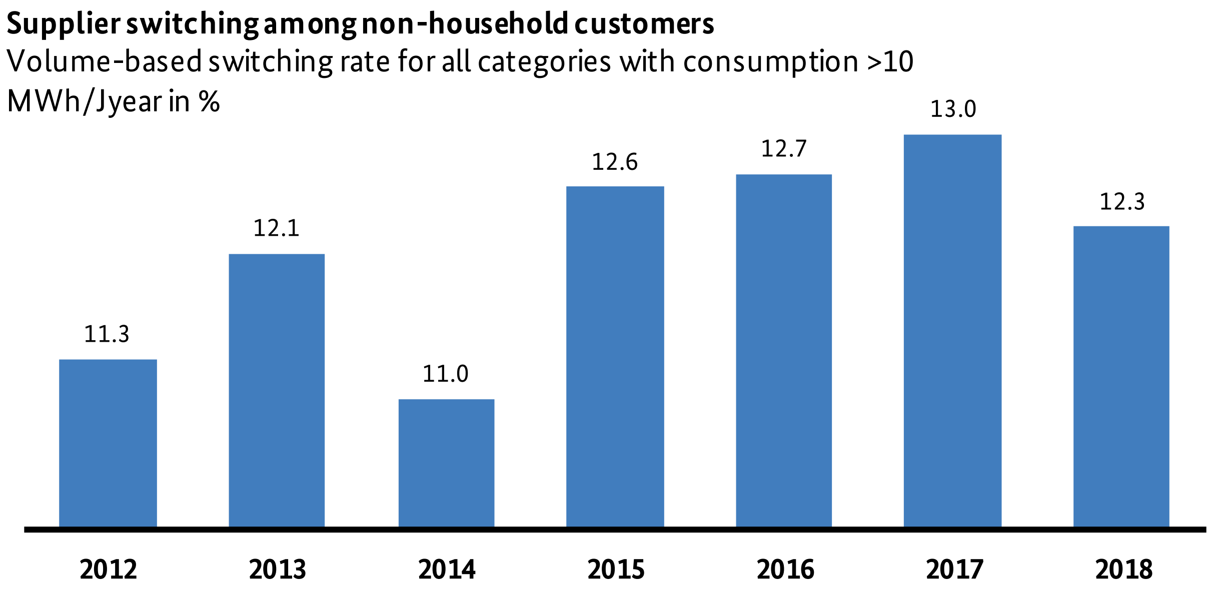

Figure 119: Supplier switching among non-household customers

2.2 Household customers

2.2.1 Contract structure

The data from the monitoring report shows that in 2018 the category "non-default contract with the default supplier" accounted for around 42% of electricity consumption by household customers (2017: 41%). The percentage of household customers with a standard default supply contract is 27% of electricity consumption (2017: 28%). The percentage of customers served by a contract with a company other than their local default supplier was 31%, the same level as the previous year. Overall, 69% of all households are still served by the default supplier. Thus the position of the default suppliers in their respective service areas remains strong.

Electricity: Contract structure of household customers in 2018
TWh and percentage

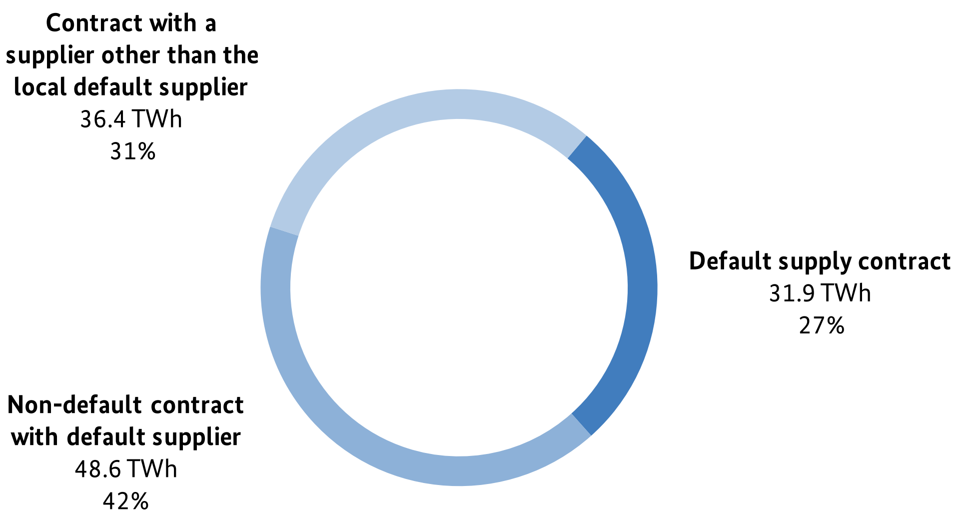

Figure 120: Contract structure of household customers in 2018

2.2.2 Switch of contract

Electricity: Contract switches by household customers in 2018

Category	Contract switches in TWh	Percentage of total consumption	Number of contract switches	Percentage of total number of household customers
Household customers who switched their existing energy supply contracts with their supplier	6,4 TWh	5.5%	1,98 Mio.	4.3%

Table 81: Contract switches by household customers (based on survey of electricity suppliers)

Table 81 depicts contract switches within a company carried out on the customer's request. The total number of contract switches was around 1.98m, which is below the previous year's figure (2017: 2.63m contract switches). The volume of electricity involved in the contract switches amounted to approximately 6.4 TWh. This results in a number and volume-based contract switching rate of 4.3% and 5.5% respectively. The number of switches within a company thus declined in comparison to the previous year.

2.2.3 Supplier switch

The supplier switching rate is comprised of the number of switches to another supplier and the number of switches when customers choose a supplier other than the default supplier when moving home. Electric heating customers are not taken into account here. At 4.7m the total number of household customers switching supplier is at a similar level to the previous year.

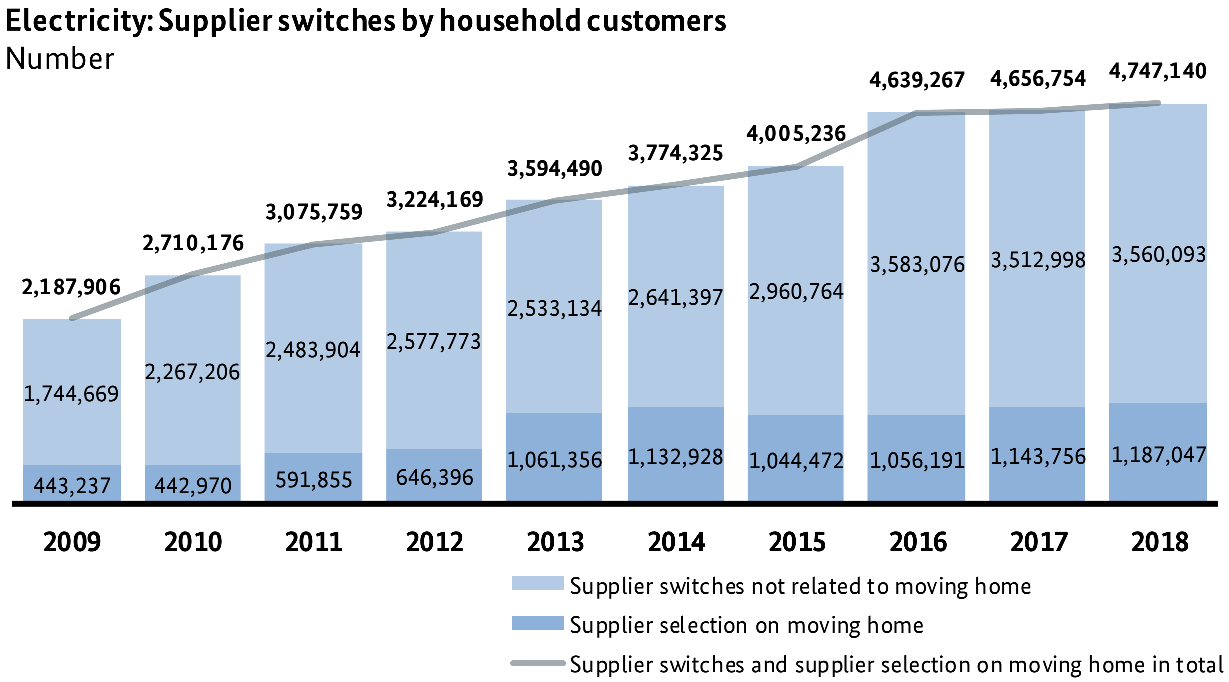

Figure 121: Supplier switches by household electricity customers[90]

In 2018 the overall supplier switching rate was approximately 10.2% for household customers and has thus remained constant since the previous year (2017: 10.2%).[91] These switches entail an electricity volume of about 14.1 TWh, which is roughly at the same level as the previous year's figure (2017: 14.2 TWh). This corresponds to a switching rate based on volume of 12.4%, which is higher than the number-based switching rate. This may suggest that customers with a high level of electricity consumption are more prone to switching suppliers.

[90] Due to insolvencies in the years 2011 and 2013, the number of switches has been adjusted by an estimated number of 500,000 insolvency-related switches per year.

[91] The supplier switching rate for 2017 has been corrected.

A joint view of the contract and supplier switches in 2018 makes it possible to determine the number of household customers who undertook a change in their energy supply contract. A total of around 6.7m switches were made.

3. Disconnections, cash/smart card readers, tariffs and contract terminations

A customer who fails to make a payment to the electricity supplier, for example, will receive a chargeable reminder, accompanied, or followed, by a disconnection notice.

Disconnection (interruption) of supply is carried out at the earliest four weeks after the disconnection notice. The date of the actual disconnection must be announced to the customer three working days in advance.

Under a default supply contract, the interruption of power supply may only be carried out if the customer is €100 or more in arrears.

The supplier may charge the customer a price for issuing notices, disconnecting supply, as well as for reinstating service. These charges can vary considerably, depending on supplier and network operator. Under a default supply contract, customers can demand verifiable documentation of the basis for calculation.

If changes in consumption are foreseeable, consumers can adjust their advance payments, thereby avoiding high one-off back payments. By changing tariff or supplier, consumers can lower their energy costs. They can also receive energy cost counselling from consumer advice centres, for example.

3.1 Disconnection of supply

In 2018, the Bundesnetzagentur questioned network operators and electricity suppliers about disconnection notices and disconnection requests, as well as the number of actual disconnections carried out, along with the associated costs. In 2018, the number of disconnections carried out by network operators was at 296,370, which is 10% lower than the previous year's figure (2017: 330,098).[92] Based on the total number of market locations of final consumers, the disconnection rate thus is 0.6%.

To request a disconnection under section 24(3) of the Low Voltage Network Connection Ordinance (NAV), the supplier must be contractually entitled to do so vis-à-vis the connection user, and must convince the network operator that the contractual prerequisites for disconnection between supplier and connection user are met. The rights and obligations that are in effect between network operator and network user are regulated in the

[92] The overall figure for 2017 had to be retroactively corrected due to inaccurate information submitted.

network usage contract/supplier framework agreement for electricity, which is specified by the Bundesnetzagentur and regulates the possibility to disconnect supply at the request of any supplier.

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 the appropriate notice has been given. Non-default suppliers stipulate the regulations governing failure to fulfil payment obligations in their contracts.

Figure 122 shows how often suppliers issued notices threatening disconnection of supply due to failure to fulfil payment obligations, how often they issued disconnection requests with the pertinent network operator and how often those disconnections were carried out.

Electricity: Disconnections based on supplier data
Number (2015 to 2018)

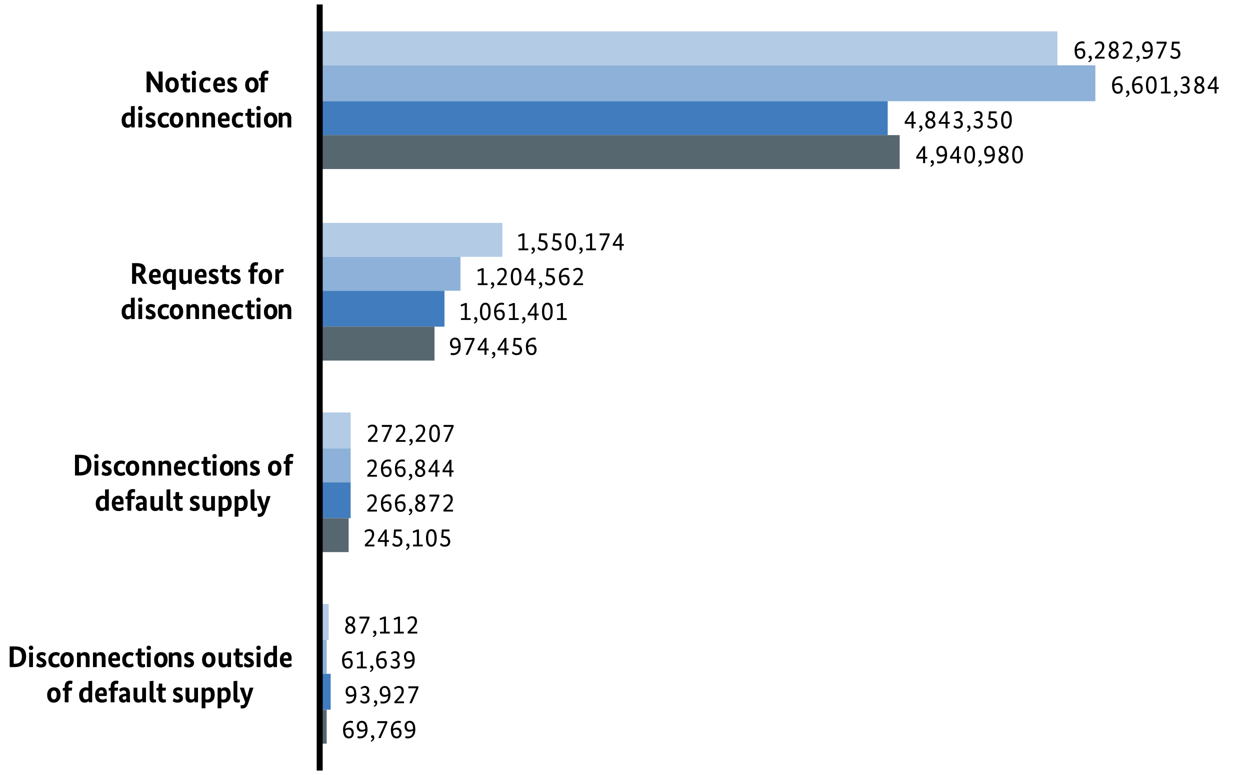

Figure 122: Disconnection notices, requests for disconnection and disconnections within and outside of default supply, based on survey of suppliers

According to the data provided by suppliers, disconnection notices were sent off when, on average, a customer was €131 in arrears. In total, around 4.9m disconnection notices were issued to household customers. Of this amount, approximately 0.97m, or 20%, resulted in electricity being disconnected by the pertinent network operator. According to supplier data, in just under 6% of the cases of disconnection notices was supply actually disconnected.

Suppliers also responded that there were around 245,105 cases of disconnection of customers with default supply. 1.6% of household customers with default supply contracts were affected by a disconnection. Disconnections outside of default supply contracts were carried out in approximately 69,769 cases (i.e. a 26% decline compared to the previous year.[93] According to information provided by the suppliers, around 18% of disconnections involve 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 customers an additional fee of their own. The electricity suppliers were asked whether they charge the flat rate according to section 19(4) StromGVV. Using this flat rate calculation, suppliers charged their customers an additional average price of around €41.95 (including VAT),[94] with the actual price ranging between €2 and €199. Suppliers who did not carry out a flat rate calculation charged their customers an average price of €47.95 (including VAT), with the actual price ranging between €5 and €150. For reconnection, electricity suppliers using the flat rate model charged their customers an average of approximately €44.14 (including VAT), with the actual cost ranging between €2 and €150, while suppliers who did not use the flat rate model charged an average of €48.88 (including VAT), with the actual charges varying from around €5 to €150. Suppliers charged household customers an average of €3.75 for issuing a reminder because of arrears in payment.

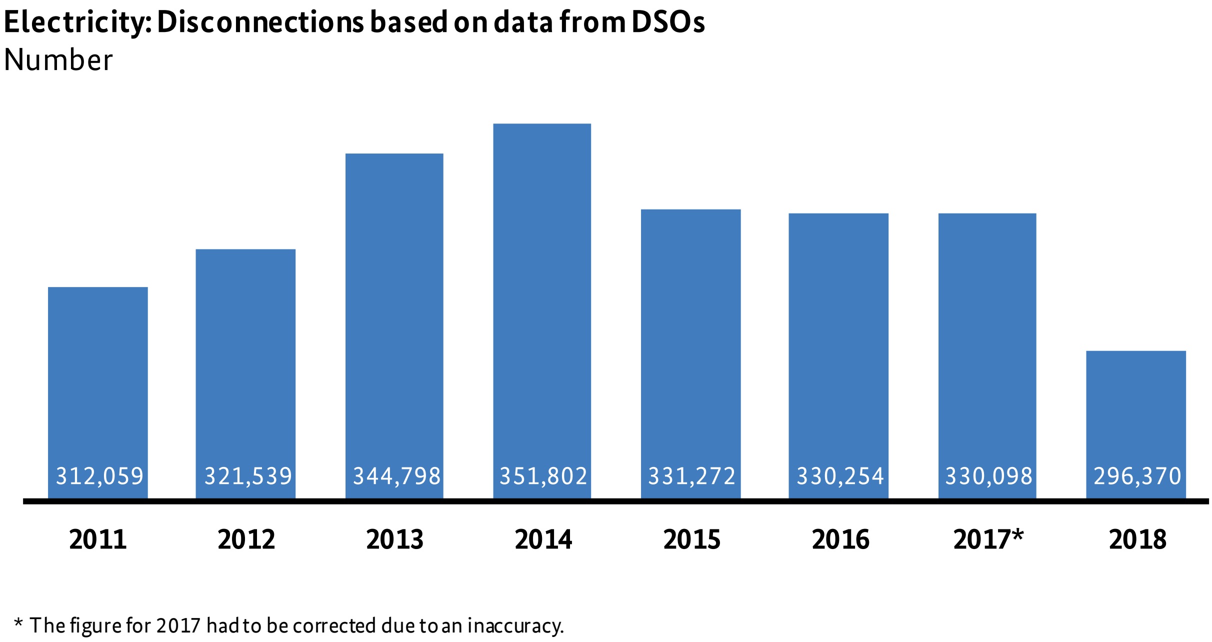

Figure 123: Disconnections based on data from DSOs[95]

[93] The total number of disconnections reported by suppliers always deviates from the disconnections actually carried out by the network operator. For the total number of disconnections, the Bundesnetzagentur uses the data submitted by network operators.

[94] Suppliers' own costs, not including costs incurred with the commissioned network operator.

[95] The figures from 2011 to 2014 show the disconnections requested by the local default supplier. As of 2015 the figures include the disconnections reported by all suppliers.

Figure 123 shows the development of disconnections of final consumers from 2011 to 2018. A total of 296,370 disconnections and 276,223 reconnections were carried out in 2018. The following table shows the distribution of disconnections broken down by federal state:

Electricity: Number of disconnections by federal state in 2018 (DSO data)

	Number of disconnections (within and outside of default supply)	Percentage of market locations of final consumers in the federal state
Bremen	4,785	1.08
Hamburg	9,645	0.83
North Rhine-Westfalia	89,210	0.80
Berlin	18,975	0.80
Saxony-Anhalt	12,052	0.79
Schleswig-Holstein	10,475	0.59
Hessen	22,148	0.58
Mecklenburg-Western Pomerania	6,141	0.54
Saxony	14,844	0.52
Rhineland-Palatinate	12,772	0.51
Saarland	3,181	0.50
Lower Saxony	23,280	0.49
Thuringia	6,295	0.46
Brandenburg	7,117	0.42
Bavaria	29,506	0.38
Baden-Württemberg	24,502	0.37

Table 82: Number of disconnections by federal state in 2018[96]

It must be noted when looking at Table 82 that 0.5% of all disconnections could not be attributed to an individual federal state.

The network operators charged the electricity suppliers an average amount of €51.68 (excluding VAT) for disconnecting supply, with the actual costs charged ranging between €3 and €175. The average amount

[96] The number for Hesse from the previous year 2017 had to be corrected due to an incorrect data submission: The published figure of 34,351 disconnections (0.92% of final consumers in the federal state) was adjusted down to 22,795 disconnections (0.61% of final consumers in the federal state) as a result of the correction.

charged for reinstating supply to household customers was €54.94 (excluding VAT), with the actual charges varying from €3 to €225.

The DSOs were asked to provide information on the duration of disconnections for the first time in 2018. The average length of time between an actual disconnection and a reconnection was 14 days (for reasons of clarity, this figure only includes cases in which both disconnection and reconnection were carried out in 2018). 17,835 disconnections lasted longer than 90 days. DSOs were not asked to provide a reason for these longer disconnection periods, which may have been due to customers' long-term inability to pay, vacant properties or faulty customer facilities that could not be reconnected for safety reasons.

3.2 Terminations

Despite issuing a disconnection notice and disconnection request, 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. For the default supplier, continued supply must be deemed to be economically unreasonable. In 2018, suppliers (default and non-default suppliers) terminated a total of nearly 185,989 contracts with their customers (2017: approximately 158.461). The average customer arrears upon termination of the energy supply contract was €196.53.

3.3 Cash meters and smart card readers

In the 2018 monitoring survey, meter operators and suppliers were again surveyed on prepayment systems in accordance with 14 StromGVV, such as cash meters or smart card readers. Over the course of 2018, such prepayment systems were installed on behalf of the local default supplier at about 19,300 household customers' points of consumption. This corresponds to 0.04% of all market locations of household customers in Germany. In just under 850 cases, a cash meter or smart card reader was newly installed in the 2018 calendar year, with about 900 such meters being removed again.

3.4 Tariffs

Suppliers are required to offer load-based tariffs or time-of-use tariffs to final consumers of electricity, insofar as this is technically feasible and economically reasonable (section 40(5) EnWG). In 2018, around 9% of suppliers offered load-based tariffs, while some 62% of suppliers offered time-of-use tariffs in 2018 (2017: 64%).

Overall, 25% of suppliers offer an online tariff that both can be concluded online (e.g. on the company's website or through a price comparison platform) and for which bills are available online. However, of the biggest suppliers, which account for 80% of electricity supply to household customers, 84% offer an online tariff.

Separate tariffs that include energy saving incentives are currently offered by 6% of companies.

One supplier offers tariffs with dynamic pricing that reflect the price on the day-ahead market in intervals; this requires the installation of a corresponding meter.[97]

[97] With regard to dynamic pricing, the 2018 Monitoring Report contains incorrect information supplied by the suppliers.

Increasingly, tariffs for bundled products are being offered on the market. In 2018, 82 companies (5.5% of all companies) offered so-called bundle tariffs, under which suppliers link the electricity contract with other products and services. Among large companies with more than 500,000 market locations, the share was 31.3%. Among companies with 10,000 to 200,000 market locations, it is primarily municipal utility companies who offer bundle tariffs.

Electricity tariffs were often tied to other energy sector services such as natural gas, heating oil, pellets, district heating, heat pumps, electromobility services or solar PV systems, but they were also linked with hardware, telecommunications services, water supply, insurance policies and vouchers or event tickets.

Electricity: Products offered on bundle tariffs

Product category	Frequency
Natural gas	34
Hardware	8
Telecommunications, internet	7
Water	5
Solar PV systems/ landlord-to-tenant electricity	5
Other	20
n.a.	18
Total	82

Electricity: Size of companies offering bundle tariffs

Number of meters	Percentage
1 < 1,000	1.3%
1000 < 10,000	3.7%
10,000 < 30,000	8.6%
30,000 < 100,000	9.0%
100,000 < 500,000	18.1%
< 500,000	31.3%
Total	5.5%

Table 83: Products offered on bundle tariffs and size of companies offering them

3.5 Billing cycles of less than one year

Section 40(3) EnWG also requires suppliers to offer final consumers monthly, quarterly or semi-annual bills. In 2018, 105 suppliers stated that they carry out monthly, quarterly or semi-annual billing for household customers in approximately 37,100 cases in total (2017: 39,900). The average charge (including VAT) for each additional billing was approximately €10 with customer reading and approximately €14 without customer reading.

4. Price level

Suppliers that provide final consumers with electricity in Germany submit information in the monitoring survey about the retail prices their companies charged on 1 April 2019 for various consumption levels. Suppliers are asked to provide price data on the consumption level for household customers for six different consumption bands. The lowest level covers an annual electricity consumption of under 1,000 kWh, while the highest level covers an annual electricity consumption of over 15,000 kWh. The standard case for household customers is in the 2,500 kWh to 5,000 kWh consumption band.

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.

The companies give the overall price, including the non-variable price components such as the capacity price, standing charge and service charge, in cents per kilowatt hour (ct/kWh). The final price is broken down into individual price components. This includes components that the supplier cannot control but that may vary from one network area to another, such as network charges, concession fees and meter operation charges. Furthermore, the state-controlled surcharges and taxes are 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 provided their "average" overall price for the six consumption levels of household customers for each of the three different contract types (see below).[98]

For household customers, companies were asked to provide data on the individual price components for the six consumption bands for the following three contract types:

- default supply contract,
- non-default contract with the local default supplier (after change of contract) and
- contract with a supplier other than the local default supplier (after switch of supplier).

The findings of the supplier survey are presented in the following by contract type per 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 2019 and 1 April 2018, it should be noted that minor changes in the calculated averages do not necessarily indicate a trend, but could instead come about through the participation of different suppliers in the survey.

[98] If a company cannot calculate an average price due to the many different tariffs they offer, one representative tariff is chosen.

The electricity price that customers pay to their supplier is made up of a number of price components: In addition to the energy and supply costs and the margin, the main components are the network charge, the concession fee and various surcharges and taxes. There is usually a monthly non-variable base price and a kilowatt-hour price. Consumers with a low consumption level tend to profit from a contract with a low base rate, while those with a high consumption level profit from a contract with a low kilowatt-hour price.

Electricity prices are not subject to price regulation in Germany.

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 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). In the following consumption category the VAT is not indicated because of the input tax deduction.

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 of 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 205 suppliers (214 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%

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 2019

	Data spread between 10th and 90th percentile of reported range in ct/kWh	**Arithmetic mean** in ct/kWH
Price components outside supplier's control		
Net network charge	1.49 - 3.29	2.32
Metering	0.00 - 0.01	0.01
Concession fee	0.09 - 0.11	0.11
EEG surcharge		6.41
other surcharges[1]		0.76
Electricity tax		2.05
Price component cntrollable by supplier (remaining amount)	3.11 - 5.30	4.33
Total price (without VAT)	**14.11 - 17.65**	**15.98**

[1] surcharge under KWKG (0.280 ct/kWh), surcharge under Sect.19 StromNEV (0.061 ct/kWh), surcharge under Section 18 AbLaV (0.005 ct/kWh), offshore net surcharge (0.416 ct/kWh)

Table 84: Price level for the 24 GWh/year consumption category without reductions on 1 April 2019

The arithmetic mean of the price component controllable by the supplier rose from 3.71 ct/kWH in the previous year to 4.33 ct/kWh in 2019, representing an increase of almost 17%. The surcharges totalled 7.17 ct/kWh (including an EEG surcharge of 6.41 ct/kWh). The other surcharges in this consumption category rose to 0.76 ct/kWh as in particular the connection costs of larger offshore windparks are no longer to be funded in the future via network charges but via the newly introduced offshore network surcharge which includes the previous offshore liability surcharge. The average net network charge remained constant compared to the previous year at 2.32 ct/kWh (2.33 ct/kWh in 2017). As the spread of net network charges is very high, the average charge does not necessarily represent the actual development.[99]

The average overall price (excluding VAT and excluding possible reductions) of 15.98 ct/kWh was 0.68 ct/kWh above the arithmetic mean of the figures collected in the previous year. Due to the alignment of tariffs for industrial customers to wholesale prices described above, price increases can be passed on more quickly to these customers than to household customers. In particular, the price component which is controllable by the supplier rose accordingly.

By definition, these prices were based on the assumption that (industrial) customers with an annual consumption of 24 GWh were not eligible for any of the statutory reductions available. In the consumption category thus defined, cost items outside the supplier's control accounted for a total of 11.65 ct/kWh, or about 73%, 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 11 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.[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 27 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 "correct" average price for industrial customers.

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[99] It should be noted that the arithmetic mean does not reflect the wide spread of network charges and the heterogeneous nature of the network operators in these consumption categories.

[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) sentence 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.

Possible reductions for the 24 GWh/year consumption category on 1 April 2019

Price survey on 1 April 2019	Estimated charge	possible reduction	remaining balance
EEG surcharge	6.41	-6.09	0.32
Electricity tax	2.05	-2.05	0.00
Net network charge	2.32	-1.86	0.46
other surcharges	0.76	-0.64	0.12
concession fees	0.11	-0.11	0.00
Total	**11.65**	**-10.74**	**0.90**

Table 85: Possible reductions for the 24 GWh/year consumption category on 1 April 2019

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 2019. Data was requested from suppliers that had at least one customer with an annual consumption between 10 MWh and 100 MWh. Since this consumption 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 969 suppliers (888 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 2019

	Spread between 10 and 90 %of reported values in ct/kWh	Arithmetic mean in ct/kWh	Share of total price
Price components outside supplier's control			
net network charge	4.37 - 8.00	6.03	27%
metering	0.02 - 0.90	0.28	1%
concession fee	0.11 - 1.59	0.76	3%
EEG surcharge		6.41	29%
other surcharges [1]		1.01	5%
electricity tax		2.05	9%
Price component controllable by supplier (remaining balance)	3.65 - 7.81	5.69	26%
Net total price	**19.46 - 24.90**	**22.22**	**100%**

[1] surcharge under KWKG (0.280 ct/kWh), surcharge under Section 19 StromNEV (0.305 ct/kWh), surcharge under Section 18 AbLaV (0.005 ct/kWh), offshore network surcharge (0.416 ct/kWh)

Table 86: Price level for the 50 MWh/year consumption category on 1 April 2019

The remaining balance that can be controlled by the supplier increased again. Whereas in April 2018 this value was at 5.14 ct/kWh, by April 2019 it had risen to 5.69 ct/kWh – an increase of 0.55 ct/kWh.

The renewable energy surcharge fell from 6.79 ct/kWh in the previous year to 6.41 ct/kWh. The other surcharges rose from 0.76 ct/kWh to 1.01 ct/kWh. The main reason for this was the introduction of the offshore network surcharge. The average net network charge rose by 0.08 ct/kWh to 6.03 ct/kWh in 2019. As the spread of net network charges is very high, the average charge does not necessarily represent the actual development.[102]

[102] It should be noted that the arithmetic mean does not reflect the wide spread of network charges and the heterogeneous nature of the network operators in these consumption categories.

The average overall price excluding VAT of 22.22 ct/kWh in April 2019 rose by 0.66 ct/kWh compared to the previous year's figure. This increase is mainly accounted for by a rise in the price component which can be controlled by the supplier. This accounts for around 26% (in 2017 24%) of the overall price, whereby an average of about 74% of the overall price relates to cost items outside the supplier's control, in particular the renewable energy surcharge and the network charge.

4.2 Household customers

In this section, retail prices and individual price components for household customers are examined and set out in tabular form as the volume-weighted averages for the three different types of tariffs in six 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[103, 104]): annual electricity consumption below 1.000 kWh
- band II (DB): annual electricity consumption from 1,000 kWh to 2.500 kWh
- band III (DC): annual electricity consumption from 2,500 kWh to 5.000 kWh
- band IV: annual electricity consumption from 5,000 kWh to 10.000 kWh
- band V: annual electricity consumption from 10,000 kWh to 15.000 kWh
- band VI (DE): annual electricity consumption from 15.000 kWh

First the volume-weighted average price across all types of contracts for household customers was looked at in the representative annual consumption band from 2,500 kWh to 5,000 kWh (band III). In section I.G.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, the volume-weighted overall price across all contract categories for band III is examined. The average price for all household customers in consumption band III is taken as a key figure. It is calculated by weighting the individual prices for the three types of contract (default supply; non-default supply; contract with a supplier other than the local default supplier) by the respective amount of electricity consumed. The average price calculated as at 1 April 2019 was 30.85 ct/kWh, which is an increase from the previous year (2018: 29.88 ct/kWh). Table 87 provides a detailed breakdown of the individual price components of the volume-weighted average price. The change relative to the previous year is shown in Table 88.

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

[104] The charge for billing is now part of the net network charge, in accordance with section 7(2) of the Metering Act and section 17(7) third sentence of the StromNEV. With regard to the other price components, section 17(7) first sentence of the StromNEV specifies that as from 1 January 2017 the charge for meter operations must also include the charge for metering.

Average volume-weighted price, across all types of contract, for household customers with an annual consumption between 2,500 kWh and 5,000 kWh (band III; Eurostat: DC) as at 1 April 2019 (ct/kWh)

Price component	Volume-weighted average across all types of contract (ct/kWh)	Percentage of total price
Energy and supply, margin	7.61	24.7
Net network charge	6.89	22.3
Meter operation charge	0.33	1.1
Concession fee	1.62	5.3
EEG surcharge	6.41	20.8
KWKG surcharge	0.28	0.9
Surcharge under section 19 StromNEV	0.31	1.0
Surcharge under section 18 AbLaV	0.01	0.0
Offshore grid surcharge	0.42	1.3
Electricity tax	2.05	6.6
VAT	4.93	16.0
Total	**30.85**	**100.0**

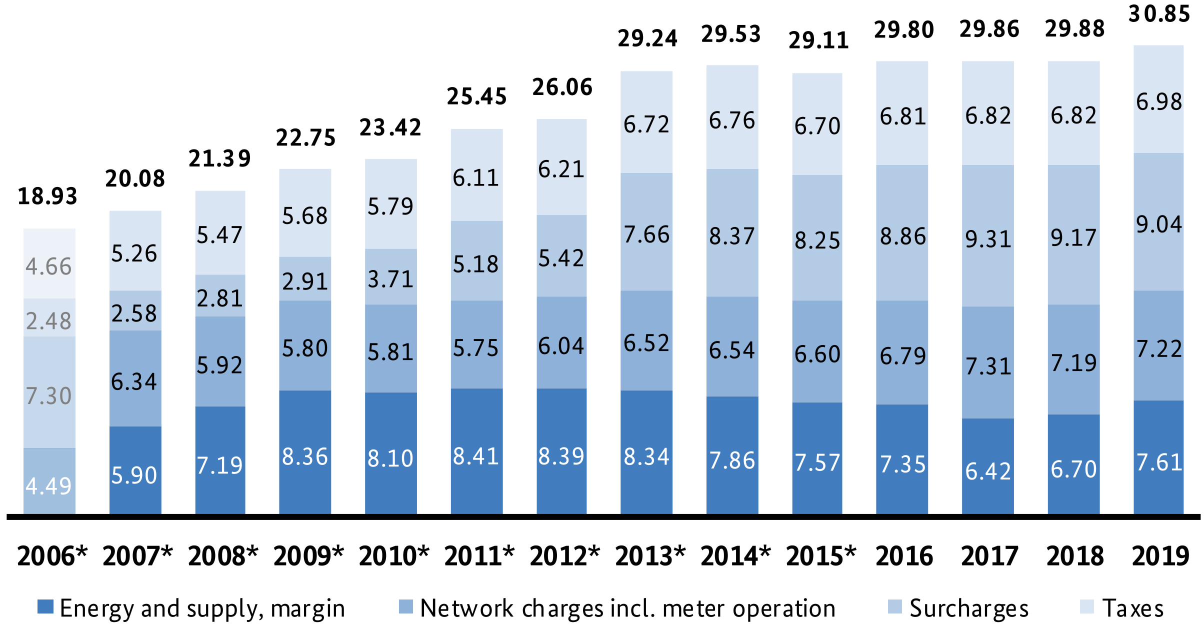
Table 87: Average volume-weighted price for household customers in consumption band III across all types of contract as at 1 April 2019

Electricity: Change in volume-weighted price level for household customers across all types of contracts from 1 April 2018 to 1 April 2019 (band III; Eurostat: DC)

Price component	Volume-weighted average across all types of contract (ct/kWh)	Change in level of price component	
		(ct/kWh)	(%)
Energy and supply, margin	7.61	0.91	12.0
Net network charge	6.89	0.01	0.2
Meter operation charge	0.33	0.02	5.7
Concession fee	1.62	0.01	0.9
EEG surcharge	6.41	-0.39	-6.0
KWKG surcharge	0.28	-0.07	-25.0
Surcharge under section 19 StromNEV	0.31	-0.07	-21.3
Surcharge under section 18 AbLaV	0.01	-0.01	-120.0
Offshore grid surcharge	0.42	0.38	90.4
Electricity tax	2.05	0.00	0.0
VAT	4.93	0.16	3.1
Total	**30.85**	**0.97**	**3.1**

Table 88: Change in the volume-weighted price level for household customers across all types of contract from 1 April 2018 to 1 April 2019 (consumption band between 2,500 kWh and 5,000 kWh per year)

Electricity: Price for household customers with an annual consumption from 2,500 kWh to 5,000 kWh, volume-weighted across all types of contract, as at 1 April (in ct/kWh)



* Based on annual consumption of 3,500 kWh.

Figure 124: Development of the electricity price for household customers, volume-weighted across all types of contract

Figure 124 shows the development of the average price for household customers. In 2019 the price was over 30 ct/kWh for the first time, which is primarily attributable to the steady increase of the price component energy and supply costs and margin. The following section therefore takes a closer look at the price components.

Figure 125 shows that surcharges, taxes and levies account for a total of 52% of the average electricity price for household customers. The net network charge including meter operations accounts for a share of around 23%. The share of the electricity price that the supplier can control (energy and supply costs and margin) accounts for around 24.7% in 2019 (previous year: 22.4%). The following section presents the development of these essential components of the volume-weighted electricity price for household customers.

Electricity: Breakdown of retail price for household customers with an annual consumption from 2,500 kWh to 5,000 kWh as at 1 April 2019 (volume-weighted average across all types of contract, band III, Eurostat: DC) (%)

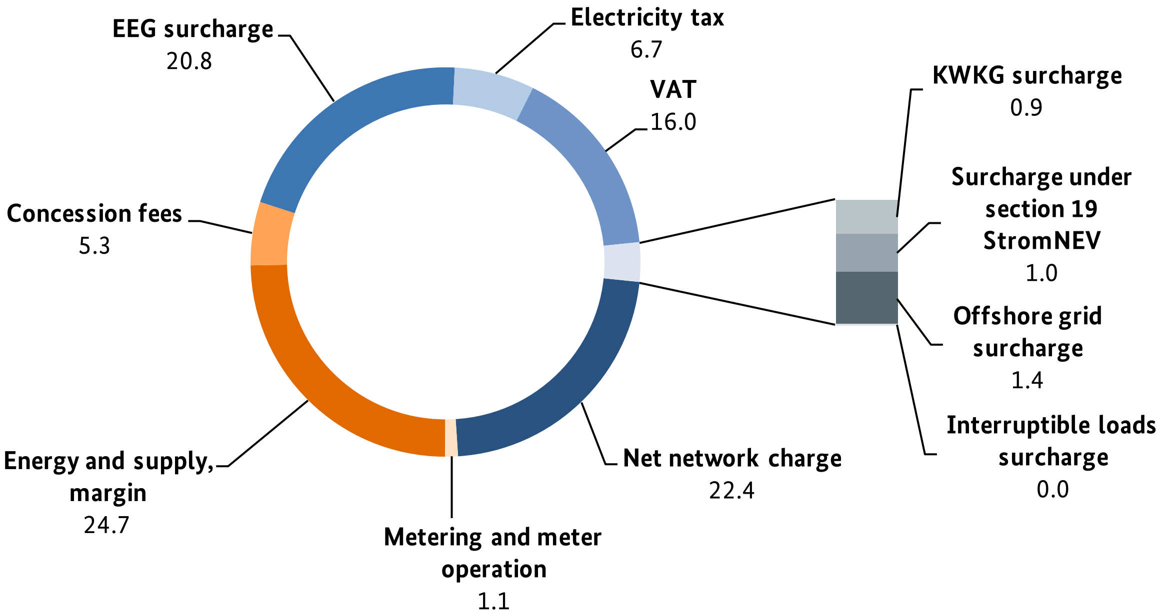


Figure 125: Breakdown of the retail price for household customers in consumption band III as at 1 April 2019 (volume-weighted average across all types of contracts)[105]

First, a look at the network charges [106] shows a relatively sharp increase until 2017, following successive decreases in the period up to 2011. In 2018, the average network charge fell for the first time since 2011. In 2019, the figure stabilised at a level close to that of the previous year. The network charge thus continues to be high.

[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.

[106] Net network charges, including charges for meter operation

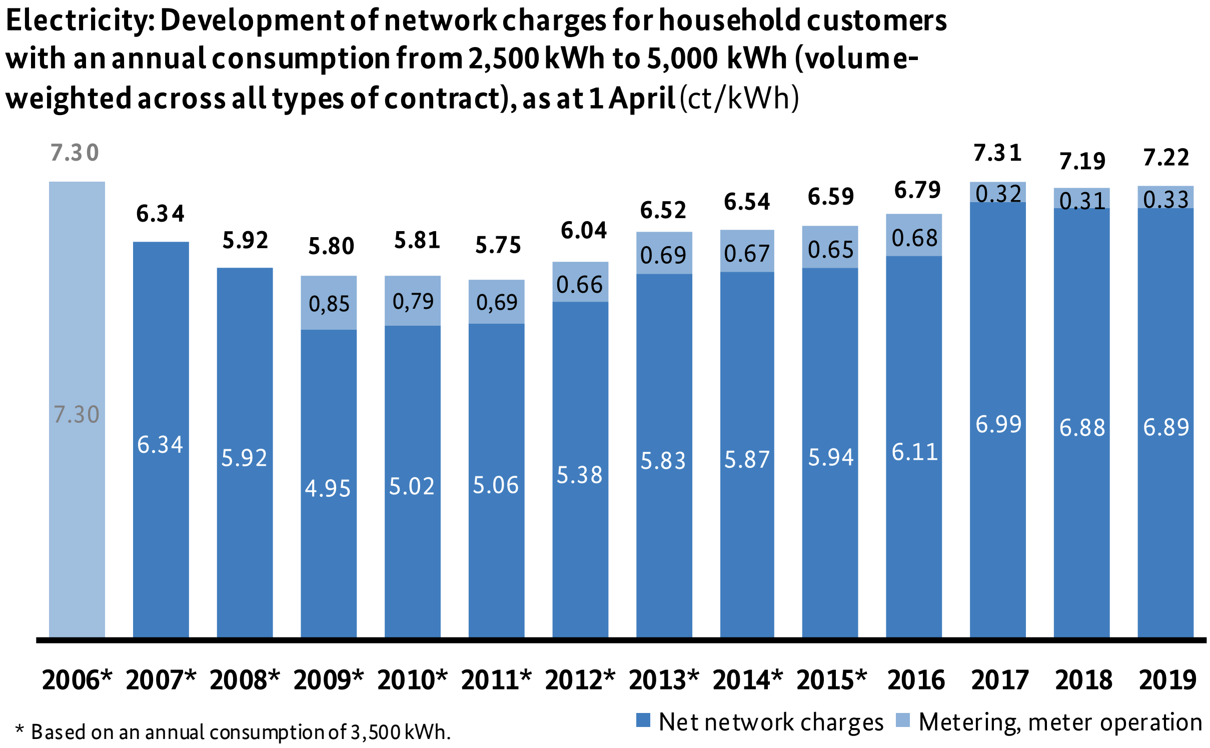


Figure 126: Development of network charges for household customers, including charges for meter operation

There has again been a noticeable decrease in other taxes and levies. These include in particular the renewable energy surcharge (EEG surcharge) and the surcharge as regulated under the KWKG (see chapter I.G.4.3 „Surcharges"). The EEG 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 2019 fell to 6.41 ct/kWh, thus accounting for around 21% of the total electricity price. Figure 127 shows the changes in the renewable energy surcharge in more detail.

Electricity: EEG surcharge and percentge of household customer price
(ct/kWh, %)

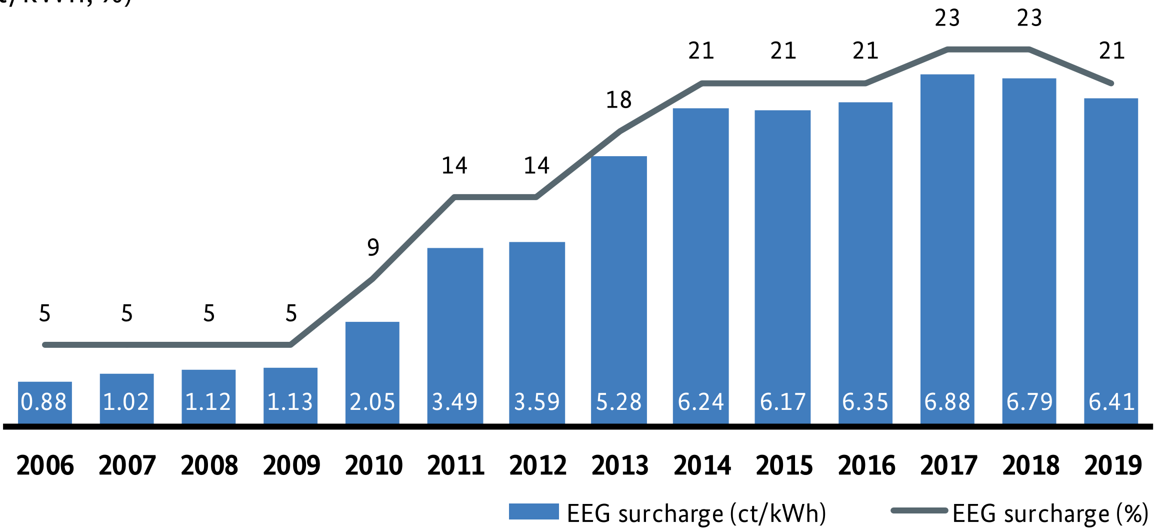
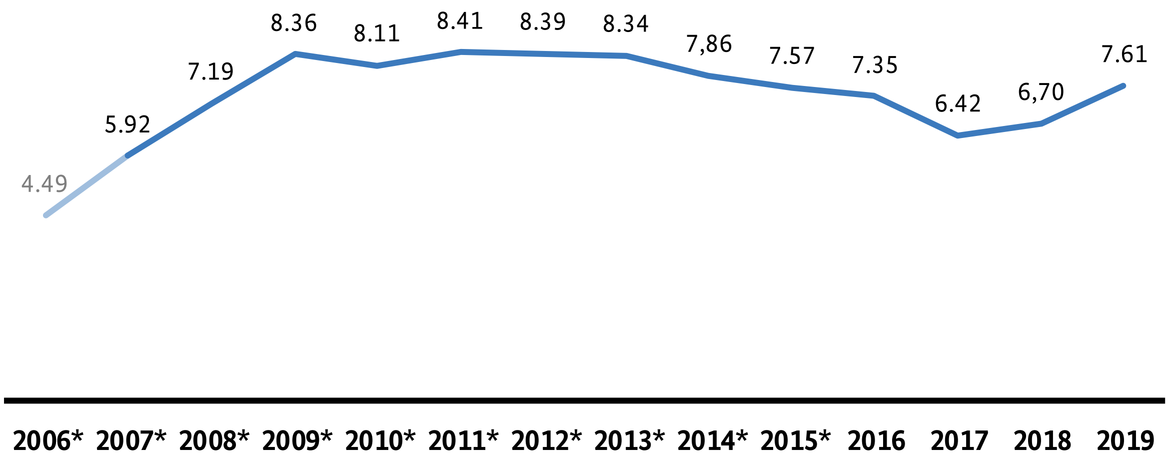


Figure 127: Renewable energy surcharge and percentage of household customer price

The price component of “energy and supply costs and margin” (see figure below) remained largely stable in the period from 2009 to 2013. While this supplier-controlled price component has fallen steadily since 2014, in 2019 it increased by nearly 12% (+0.91 ct/kWh); in 2018 it had risen to 6.70 ct/kWh. This increase could be attributable in particular to the increase in wholesale prices in 2018 (see chapter I.F "Wholesale market“, page 243). These higher prices are gradually being passed on to household customers.

Electricity: Development of price component "energy and supply costs and margin” for household customers with an annual consumption from 2,500 kWh to 5,000 kWh as at 1 April (volume-weighted average across all types of contract) (ct/kWh)



* Based on an annual consumption of 3,500 kWh.

Figure 128: Development of the price component “energy and supply costs and margin” for household customers

4.2.2 Household customer prices by consumption bands

From the data provided by suppliers, average prices can be derived for default supply contracts, for non-default contracts with the default supplier and for contracts with a supplier other than the local default supplier. The following section examines the prices for the six consumption bands of household customers.

It is important to note that the average network charge given for each type of tariff are calculated using the figures provided by the suppliers, who in turn provide the charges averaged over all the networks they supply. This results in a different network charge for each of the three tariffs. The large number of network areas leads to considerable heterogeneity in both the supplier structure and the contract structure of customers supplied. For example, suppliers can supply electricity to a majority of their customers with particularly high or particularly low network charges, regardless of whether they are customers with default supply contracts or not. The opposite case is also possible. Due to this distribution of customers in the various network areas according to each contract type, the three types of supply result in different volume-weighted average network charges. In each network area, the network charge is independent of the contract type. The following tables should therefore not be taken to mean, for example, that default supply is the contract type with the highest network charge.

The volume-weighted prices were calculated using the prices as at 1 April 2019 and the consumption volumes for 2018. The use of new consumption bands since 2016 is due to a change in the methodology used by Eurostat to collect price data. This monitoring report shows the results for six consumption bands.

Band I: Annual electricity consumption up to 1.000 kWh

Electricity: Average volume-weighted prices per type of contract for household customers with an annual consumption up to 1,000 kWh (band I; Eurostat: DA) as at 1 April 2019 (ct/kWh)

Price component	Default contract	Non-default contract with a default supplier	Contract with a supplier other than the local default supplier
Energy and supply, margin	12.72	10.94	10.93
Net network charge	15.31	13.58	12.80
Meter operation charge	2.01	1.85	1.78
Concession fee	1.61	1.68	1.76
EEG surcharge	6.41	6.41	6.41
KWKG surcharge	0.28	0.28	0.28
Surcharge under section 19 StromNEV	0.31	0.31	0.31
Surcharge under section 18 AbLaV	0.01	0.01	0.01
Offshore grid surcharge	0.42	0.42	0.42
Electricity tax	2.05	2.05	2.05
VAT	7.81	7.13	6.98
Total	**48.92**	**44.65**	**43.71**

Table 89: Average volume-weighted prices per type of contract for household customers in consumption band I as at 1 April 2019

Please note that in the low consumption bands prices include the non-variable price components (capacity price, standing charge, service charge etc). The combination of lower consumption levels with the non-variable price components such as the base price thus results in a higher kilowatt-hour rate in this table.

Band II: Annual electricity consumption from 1,000 kWh to 2.500 kWh:

Electricity: Average volume-weighted prices per type of contract for household customers with an annual consumption from 1,000 kWh to 2,500 kWh (band II; Eurostat: DB) as at 1 April 2019 (ct/kWh)

Price component	Default contract	Non-default contract with a default supplier	Contract with a supplier other than the local default supplier
Energy and supply, margin	9.11	7.93	7.69
Net network charge	8.34	7.87	8.14
Meter operation charge	0.61	0.61	0.68
Concession fee	1.62	1.60	1.69
EEG surcharge	6.41	6.41	6.41
KWKG surcharge	0.28	0.28	0.28
Surcharge under section 19 StromNEV	0.31	0.31	0.31
Surcharge under section 18 AbLaV	0.01	0.01	0.01
Offshore grid surcharge	0.42	0.42	0.42
Electricity tax	2.05	2.05	2.05
VAT	5.54	5.22	5.25
Total	**34.69**	**32.68**	**32.91**

Table 90: Average volume-weighted prices per type of contract for household customers in consumption band II as at 1 April 2019

Band III: Annual electricity consumption from 2,500 kWh to 5.000 kWh

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 the individual price components analysed in more detail and shown in time series.

Electricity: Average volume-weighted prices per type of contract for household customers with an annual consumption from 2,500 kWh to 5,000 kWh (band lII; Eurostat: DC) as at 1 April 2019 (ct/kWh)

Price component	Default contract	Non-default contract with a default supplier	Contract with a supplier other than the local default supplier
Energy and supply, margin	8.54	7.37	7.21
Net network charge	6.87	6.83	6.98
Meter operation charge	0.32	0.32	0.35
Concession fee	1.66	1.62	1.60
EEG surcharge	6.41	6.41	6.41
KWKG surcharge	0.28	0.28	0.28
Surcharge under section 19 StromNEV	0.31	0.31	0.31
Surcharge under section 18 AbLaV	0.01	0.01	0.01
Offshore grid surcharge	0.42	0.42	0.42
Electricity tax	2.05	2.05	2.05
VAT	5.10	4.86	4.86
Total	**31.94**	**30.46**	**30.46**

Table 91: Average volume-weighted prices per type of contract for household customers in consumption band III as at 1 April 2019

A comparison of the three types of contract – default, non-default contract with a default supplier (usually after changing contract) and contract with a supplier other than the local default supplier – makes it clear that default tariffs are still the most expensive option for customers with an annual consumption of between 2,500 kWh and 5,000 kWh. At the same time, a direct comparison is only possible to a limited extent. While the average consumption in 2018 for customers on default tariffs was around 2,020 kWh, the average for customers on non-default tariffs with the default supplier and customers who had switched from their default supplier was about 36% higher, at around 2,750 kWh.

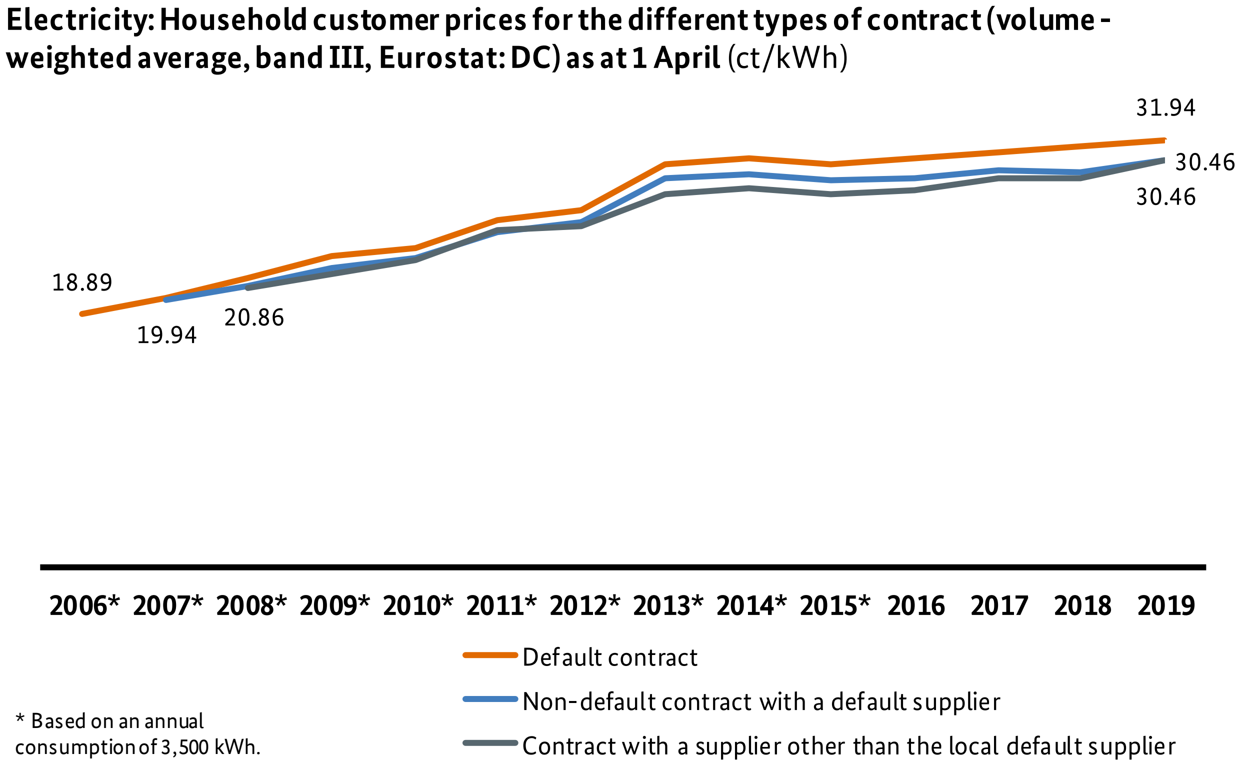


Figure 129: Household customer prices for the different types of contract (volume-weighted average, band III, Eurostat: DC)

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. Since 2013 the prices for non-default contracts with the default supplier and contracts with a supplier other than the local default supplier have been converging more and more; in 2019, for the first time, they are at the same level. On average, prices for customers who switched from the local default supplier to a new supplier are the cheapest. In ten years during the period under review, average prices for customers who had switched from their local default supplier were – to a greater or lesser extent – lower than those for customers on a non-default contract with their default supplier. This shows that default suppliers want to keep their regional customers and for this reason offer attractive prices.

Household customers can achieve additional savings compared to a default supply contract by changing contract with the default supplier (-1.48 ct/kWh) or by switching supplier (-1.48 ct/kWh).[107]

For a household customer with an annual consumption of 3,500 kWh, this amounts to savings in energy costs of around €52 per year.

At 8.54 ct/kWh on 1 April 2019, the price component that can be controlled by the supplier, including energy and supply costs, was nearly 18% higher for customers on default tariffs than for customers who had switched

[107] The cost savings apply to the consumption band between 2,500 kWh and 5,000 kWh/year.

from their default supplier; the average amount for the latter group was 7.21 ct/kWh. In 2018, the difference between the two groups was 38%. Customers on non-default contracts with their local default supplier paid an average of 7.37 ct/kWh (2018: 6.57 ct/kWh) for energy and supply costs and the margin and thus around 16% less than 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 that can be controlled by the supplier. The following figure provides a detailed overview of the trend.

Electricity: Development of the price component "energy and supply costs and margin" for household customers for the different types of contract (volume-weighted average, band III, Eurostat: DC) as at 1 April
(ct/kWh)

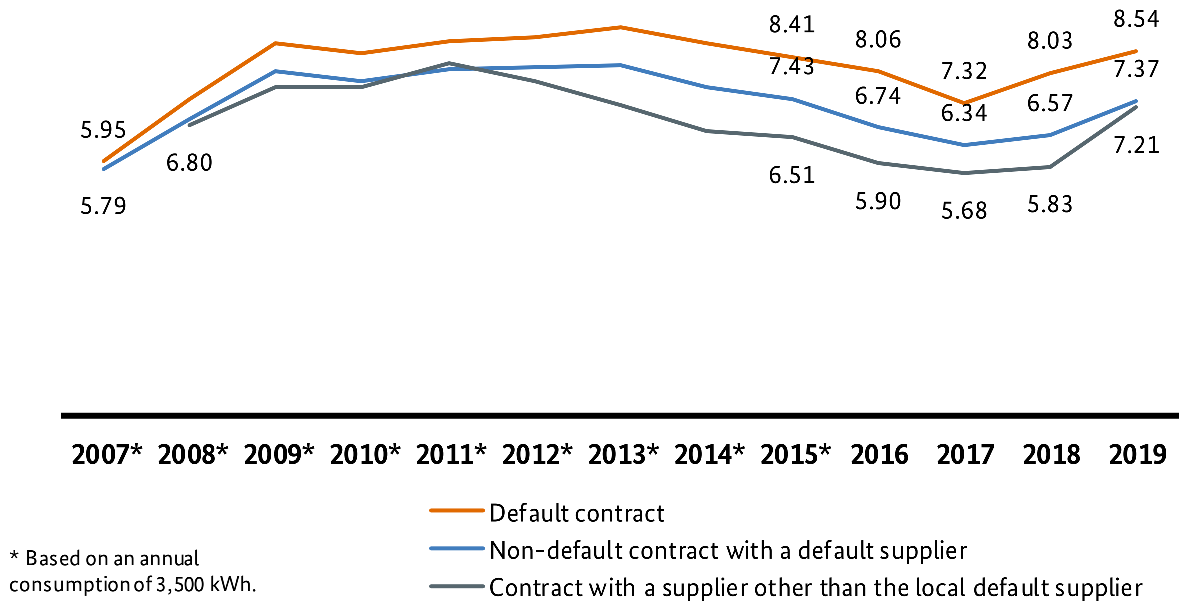


Figure 130: Development of the price component "energy and supply costs and margin" for household customers

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 either to the customer (e.g. price stability) or to the supplier (e.g. prepayment, minimum contract period), which is then compensated for between the parties elsewhere (overall price).

The suppliers were questioned specifically about such features. Minimum contract periods and price stability were found to be especially common. The minimum period of non-default contracts with the local default supplier is 11 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 €256, with an average payment of €55. Contracts with a supplier other than the local default supplier offer one-off payments also ranging from €5 to €256, with an average payment of €64.

The following table provides an overview of the various special bonuses and schemes offered by electricity suppliers:

Electricity: Special bonuses and schemes for household customers

As at 1 April 2019	Household customers			
	Non-default contract with the default supplier		Contract with supplier other than the default supplier	
	No. of tariffs	Average scope	Number of tariffs	Average scope
Minimum contract period	354	11 months	464	11 months
Price stability	322	14 months	398	14 months
Advance payment	62	11 months	41	12 months
One-off bonus payment	129	55	207	64
Free kilowatt hours	7	200 kWh	10	220 kWh
Deposit	6	-	4	-
Other bonuses and special arrangements	103	-	121	-

Table 92: Special bonuses and schemes for household customers

Band IV: Annual electricity consumption from 5,000 kWh to 10.000 kWh

Band IV as used in the monitoring survey represents household customers with an above-average annual consumption from 5,000 kWh to 10,000 kWh. The following table shows the results of the survey.

Electricity: Average volume-weighted prices per type of contract for household customers with an annual consumption from 5,000 kWh to 10,000 kWh (band lV) as at 1 April 2019
(ct/kWh)

Price component	Default contract	Non-default contract with a default supplier	Contract with a supplier other than the local default supplier
Energy and supply, margin	8.23	7.25	6.27
Net network charge	6.34	6.01	6.19
Meter operation charge	0.15	0.16	0.21
Concession fee	1.52	1.56	1.54
EEG surcharge	6.41	6.41	6.41
KWKG surcharge	0.28	0.28	0.28
Surcharge under section 19 StromNEV	0.31	0.31	0.31
Surcharge under section 18 AbLaV	0.01	0.01	0.01
Offshore grid surcharge	0.42	0.42	0.42
Electricity tax	2.05	2.05	2.05
VAT	4.89	4.64	4.50
Total	**30.60**	**29.08**	**28.18**

Table 93: Average volume-weighted prices per type of contract for household customers in consumption band IV as at 1 April 2019

Band V and band VI: Annual electricity consumption from 10,000 kWh to 15,000 kWh and annual electricity consumption from 15.000 kWh

For the first time, the 2018 monitoring report included data provided by suppliers on bands V and VI. Bands V and VI consist of household customers with a very high annual consumption from 10,000 kWh to 15,000 kWh and of 15,000 kWh and more. The following table shows the results of the survey.

Electricity: Average volume-weighted prices per type of contract for household customers with an annual consumption from 10,000 kWh to 15,000 kWh (band V) as at 1 April 2019
(ct/kWh)

Price component	Default contract	Non-default contract with a default supplier	Contract with a supplier other than the local default supplier
Energy and supply, margin	7.96	6.12	5.84
Net network charge	6.05	5.71	5.75
Meter operation charge	0.10	0.13	0.18
Concession fee	1.54	1.58	1.50
EEG surcharge	6.41	6.41	6.41
KWKG surcharge	0.28	0.28	0.28
Surcharge under sectionn 19 StromNEV	0.31	0.31	0.31
Surcharge under section 18 AbLaV	0.01	0.01	0.01
Offshore grid surcharge	0.42	0.42	0.42
Electricity tax	2.05	2.05	2.05
VAT	4.77	4.37	4.32
Total	**29.88**	**27.37**	**27.06**

Table 94: Average volume-weighted prices per type of contract for household customers in consumption band V as at 1 April 2019

Electricity: Average volume-weighted prices per type of contract for household customers with an annual consumption above 15,000 kWh (band VI) as at 1 April 2019 (ct/kWh)

Price component	Default contract	Non-default contract with a default supplier	Contract with a supplier other than the local default supplier
Energy and supply, margin	8.09	5.81	7.52
Net network charge	5.67	5.71	5.39
Meter operation charge	0.07	0.06	0.18
Concession fee	1.54	1.62	1.55
EEG surcharge	6.41	6.41	6.41
KWKG surcharge	0.28	0.28	0.28
Surcharge under section 19 StromNEV	0.31	0.31	0.31
Surcharge under section 18 AbLaV	0.01	0.01	0.01
Offshore grid surcharge	0.42	0.42	0.42
Electricity tax	2.05	2.05	2.05
VAT	4.72	4.30	2.54
Total	**29.55**	**26.95**	**26.65**

Table 95: Average volume-weighted prices per type of contract for household customers in consumption band VI as at 1 April 2019

4.3 Surcharges

In the electricity sector, surcharges still account for a significant share of the electricity price. In the following section, the surcharges are listed according to volume:

EEG surcharge

Under section 60(1) EEG, transmission system operators are entitled and obliged to demand from electricity suppliers which supply electricity to final consumers the costs for the necessary expenses following deduction of the revenues attained, proportionate to the electricity supplied and in accordance with the Renewable Energy Sources Ordinance (EEG surcharge).

The EEG surcharge payments cover the difference between the TSOs' revenue and expenditures in implementing the EEG in accordance with section 3(3) and 3(4) of the Renewable Energy Sources Ordinance (EEV), as well as section 6 of the Renewable Energy Sources Implementing Ordinance (EEAV).

The surcharge is determined and announced by 15 October of each year for the following calendar year by the transmission system operators. A detailed overview of the development of the EEG surcharge over the past years is provided on page 289

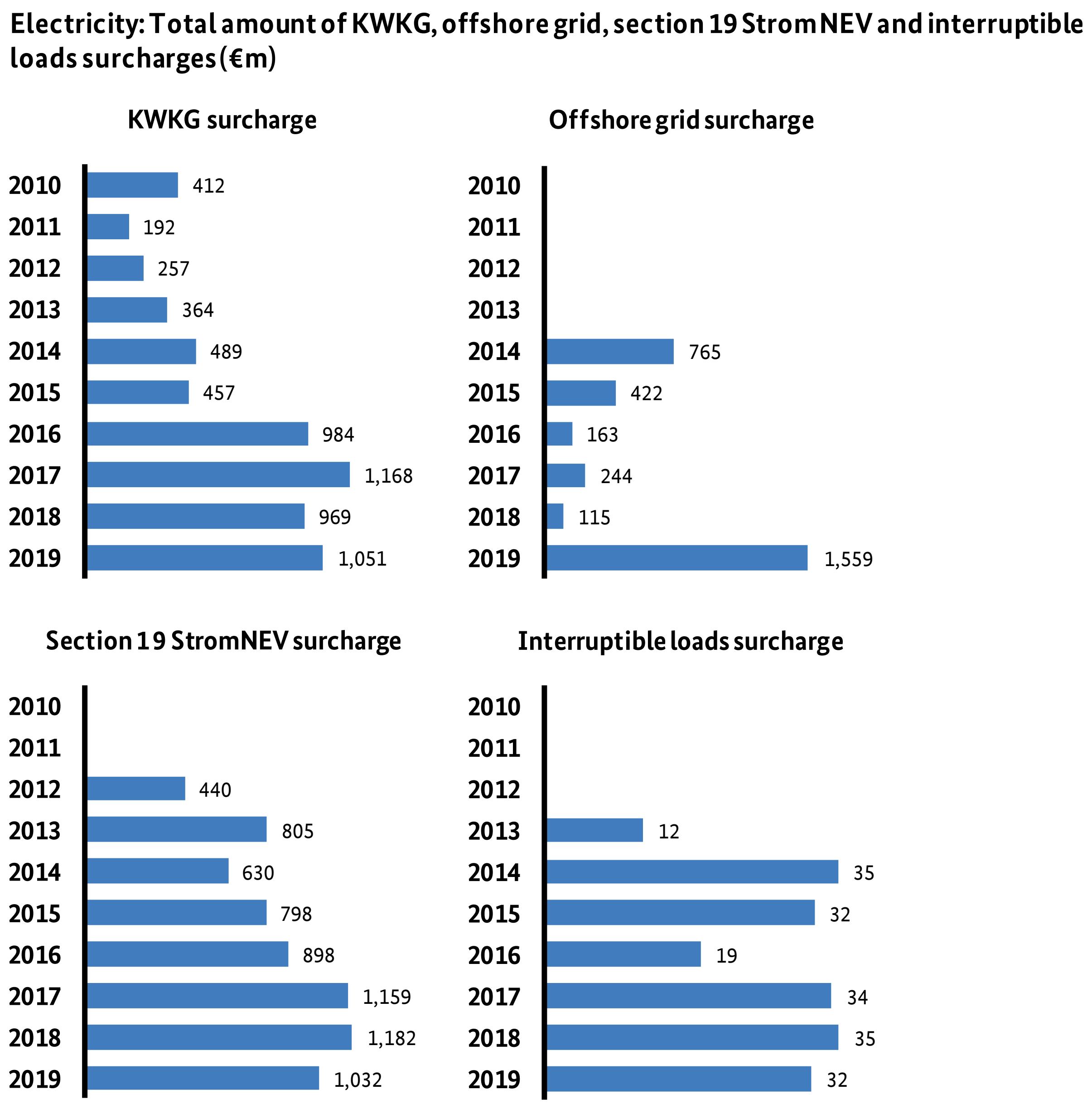


Figure 131: Total amount of KWKG, offshore grid, section 19 StromNEV and interruptible loads surcharges

KWKG surcharge

Under sections 26a and 26b of the Combined Heat and Power Act (KWKG), the transmission system operators are obliged to determine the KWKG surcharge for the following calendar year in a transparent way. The annual accounts from previous calendar years serve as the basis for the determination of the KWKG surcharge.

Revenue from the KWKG surcharge is used to cover costs associated with the financing of combined heat and power plants.

The KWKG surcharge is determined and announced by 25 October of each year for the following calendar year by the TSOs. The diagram above shows the development of the KWKG surcharge over the past years.

Offshore network surcharge

Under section 17f(5) EnWG, network operators are entitled to pass on the costs for compensation payments to final consumers in the form of a surcharge on network charges. In addition, as of 2019, the "new" offshore network surcharge also includes the costs of installing and operating offshore transmission links. Whereas the latter had previously been part of the regular network costs and were included in the network charges that customers paid, with the new Network Charges Modernisation Act they are now treated separately. The aim of the legislator was to make the costs of the offshore transmission links more transparent.

The offshore network surcharge is determined and announced by 15 October for the following calendar year by the TSOs. The surcharge is calculated based on a forecast of the expected recoverable costs for the subsequent year, taking into account any possible actual deviations from the forecasts for the previous years. The diagram above shows the development of the offshore network surcharge (until 2018 offshore liability surcharge) over the past years.

Section 19 StromNEV surcharge

Under the Electricity Network Charges Ordinance (StromNEV), final consumers can request an individual network charge as provided for by section 19(2) StromNEV. TSOs are obliged to reimburse downstream DSOs for revenue lost as a result of individual network charges. TSOs must balance these payments as well as their own lost revenue among themselves. The resulting lost revenue is passed on to all final consumers as a portion of the network charges.

The revenue from the surcharge under section 19 StromNEV is used to cover lost network charge proceeds brought on by reductions of the network charge.

The section 19 StromNEV surcharge is determined and announced by 25 October of each year for the following calendar year by the TSOs. The diagram above shows the development of the section 19 StromNEV surcharge over the past years.

Interruptible loads surcharge

Each year the German TSOs calculate the interruptible loads surcharge based on section 18 of the Interruptible Loads Ordinance (AbLaV). For 2016, final consumers were not subject to this charge due to the fact that the amendment of the AbLaV Ordinance had not yet been completed at the time the surcharge was determined.

The interruptible loads surcharge covers the costs for the provision and interruption of loads for the purpose of adjusting consumption according to the needs of TSOs.

The interruptible loads surcharge is determined and announced by 25 October of each year for the following calendar year by the TSOs. The diagram above shows the development of the interruptible loads surcharge over the past years.

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 (DSOs).

Compared to the previous year, heating electricity consumption fell slightly in 2018. According to the volumes reported by around 1,000 heating electricity suppliers, about 13.29 TWh of heating electricity was supplied to just under 2.03 million meter points during the reporting period. This corresponds to an average supply of just under 6,356 kWh per meter point. The previous year's figure was just under 7,150 kWh per meter point, with a total volume of 14.47 TWh at 2.03 million meter points.

According to the data provided by the suppliers, just under 10.55 TWh was supplied for night storage heating at 1.61 million night storage meter points; resulting in an average of about 6,528 kWh per meter point in 2018. The volume of electricity supplied to the approximately 475,225 meter points for heat pumps amounted to just over 2.74 TWh, or an average of about 5,771 kWh/year. Night storage heating accounts for the largest share of consumption (79% in terms of volume and 77% of meter points). There was a slight increase in the share of heat pumps. In 2018 the share of heat pumps accounted for 23% of meter points and 21% in terms of volume. In the previous year it accounted for 22% of meter points and 19% in terms of volume. 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, and therefore gave an estimate of the breakdown or entered the total in only one of the two categories. 930 of the 1,000 electric heating suppliers provided data on volume and meter points for both night storage heating and heat pumps.

The data on consumption volumes and number of meter points collected from the DSOs during the monitoring survey roughly corresponds to the results of the supplier survey. According to the data provided by 811 DSOs, a total of 13.41 TWh of heating electricity was supplied to just under 2.1 million meter points (night storage heating and heat pumps) in 2018. 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. In contrast to the electricity 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.[108]

The share of heating electricity supplied in 2018 by a legal entity other than the regional default supplier rose from 1.71 TWh to 1.75 TWh year-on-year-on-year. However, around 13.2% of the entire heating electricity volume in 2018 came from suppliers other than the default supplier compared with 11.9% in 2017. The

[108] Cf. Bundeskartellamt - Electric Heating - overview and proceedings, September 2010, pp. 9-10.

number of heating electricity meter points not served by the default supplier also increased from 11.6% to 12.6%.

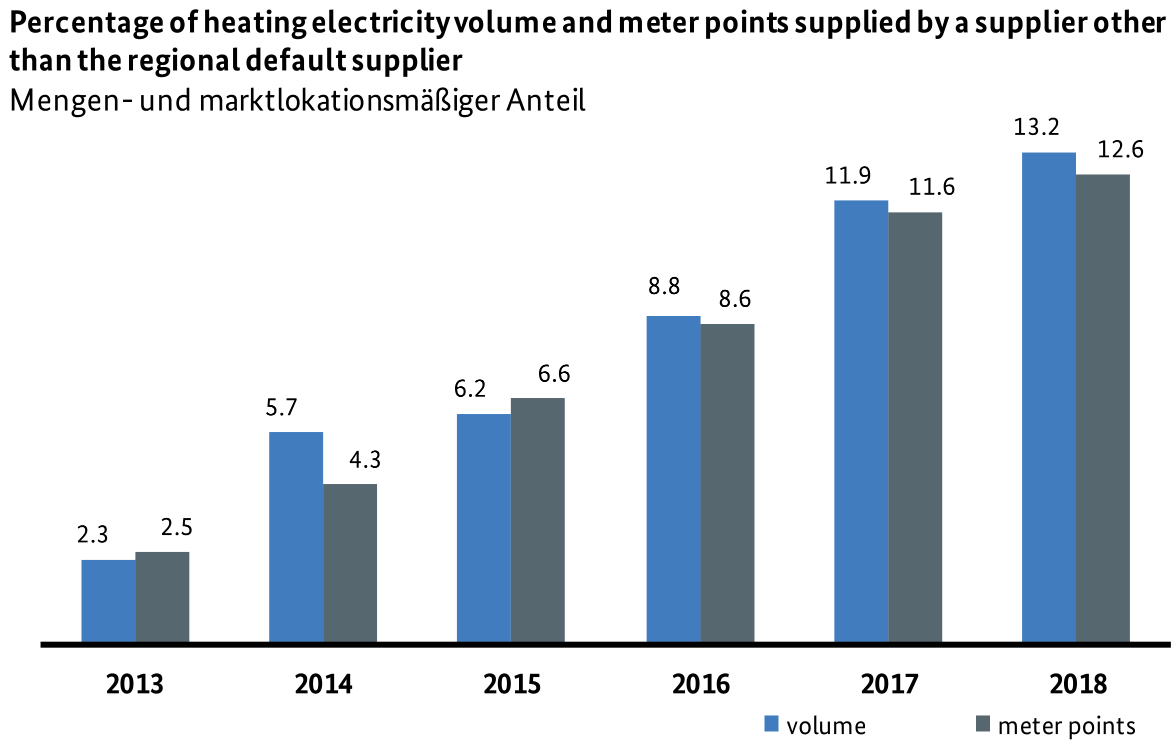


Figure 132: Percentage of heating electricity volume and meter points supplied by a supplier other than the regional default supplier

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 70,550 meter points in 2017 to over 88,426 meter points in 2018. 18.6% (16% in 2017) of the heat pump meter points were served by a legal entity other than the default supplier as well as 16.9% of the number of heat pumps supplied (15.5% in 2017).

According to the data provided by the DSOs, there was a slight increase in supplier switching rates based on the number of meter points supplied in the heating electricity sector. The data shows that there was a change of supplier at about 94,950 heating electricity meter points. These meter points accounted for about 528 GWh of heating electricity in 2018. This represents a switching rate of 3.9% in terms of consumption volume and 4.5% of meter points.

In the previous year, there was a change of supplier at just under 87,550 meter points, accounting for a volume of around 550 GWh. This corresponds to a switching rate of 4% in terms of consumption volume and 4.3% of meter points. The trend over the years shows that switching rates for heating electricity have continuously risen - with a strong increase from 2015 to 2016. The switching rate in 2018 remained at roughly the same level as in the previous year.

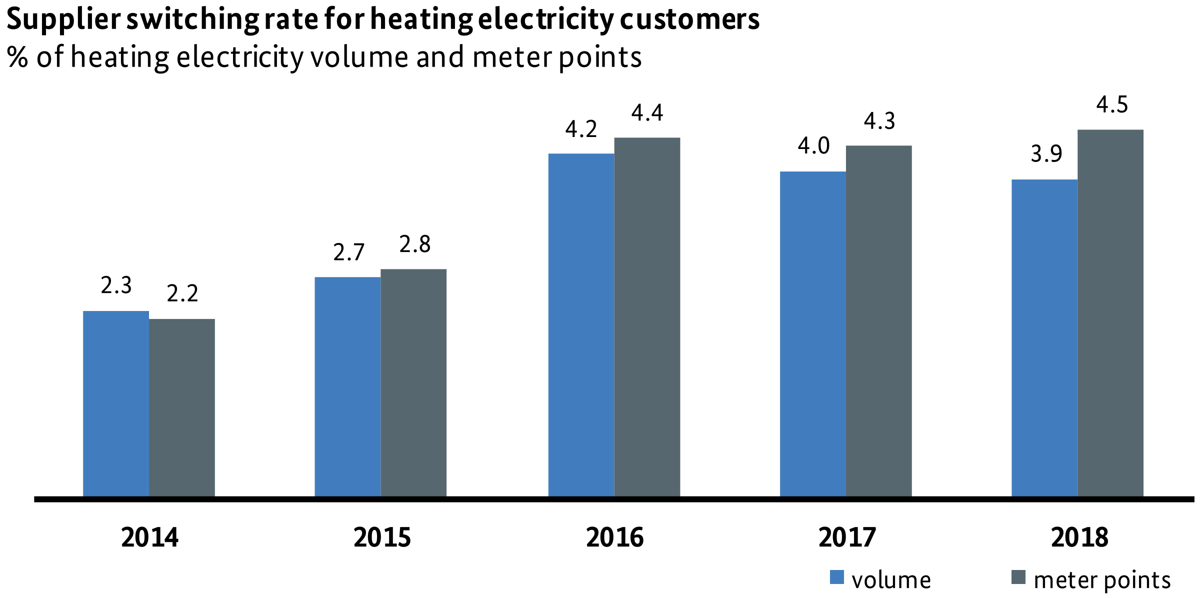


Figure 133: Supplier switching rate for heating electricity customers

569 of the 811 DSOs that provided data on heating electricity volumes also reported figures on supplier switching. These 569 DSOs represent around 99% of the heating electricity volume and meter points of all 811 DSOs that provided data on heating electricity. This means that the survey was able to cover a large share of the market and only a few, mainly small DSOs could not report figures on supplier switching.[109]

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 1.1% and 9.6%.

The percentage of heating electricity and meter points supplied by a legal entity other than the regional default supplier is steadily increasing. 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

Price data was collected on night storage tariffs and heat pump tariffs as at 1 April 2019. Suppliers were asked to base their figures on a consumption of 7,500 kWh/year. The following analysis is based on the price data for night storage heating provided by 883 suppliers (774 in the previous year) and the price data for heat pumps provided by 864 suppliers (758 in the previous year).

[109] Several DSOs also pointed out that they had no data, or only individual data, in the electric heating sector for analysis. The reasons why around 242 suppliers provided no data are generally insufficient evaluation possibilities or limited resources for survey purposes.

According to the data provided by the suppliers, the arithmetic mean of the total gross price for night storage heating was 21.92 ct/kWh (including VAT) on 1 April 2019, which is slightly above the previous year's level of 21.08 ct/kWh. The arithmetic mean of the total gross price for heat pump electricity was 22.50 ct/kWh, which was also up on the previous year's level of 21.71 ct/kWh).

Price level on 1 April 2019 for night storage heating with a consumption of 7,500 kWh/year

	Spread between 10 and 90 % of suppliers in ct/kWh	**Arithmetic mean** in ct/kWh	**Share of total price**
Price components outside supplier's control			
Net network charge	1.50 - 4.20	2.78	13%
Metering	0.12 - 0.49	0.32	1%
Concession fee	0.11 - 1.02	0.41	2%
EEG surcharge		6.41	29%
other surcharges[1]		1.01	5%
electricity tax		2.05	9%
VAT	3.05 - 3.99	3.50	16%
price component which can be controlled by supplier (remaining balance)	3.41 - 7.55	5.45	25%
Total price (incl. VAT)	19.09 - 24.99	21.92	100%

[1] KWKG (0.28 ct/kWh), Section 19 (2) StromNEV (0.31 ct/kWh), surcharge under Section 18 AbLaV (0.01 ct/kWh), Offshore network surcharge (0.42 ct/kWh)

Table 96: Price level on 1 April 2019 for night storage heating with a consumption of 7,500 kWh/year

The remaining balance that can be controlled by the supplier, which includes energy and supply costs and the margin, was 5.45 ct/kWh for night storage heating, which rose again above the previous year's level of 4.73 ct/kWh. This was equivalent to an increase of about 15%. However, this amount is still smaller than in 2012 and 2013, when the price component controlled by the supplier averaged 5.72 ct/kWh in 2012 and 5.80 ct/kWh in 2013. The trend over the last two years shows that this price component has risen steadily in the heating electricity sector.

The remaining balance that can be controlled by the supplier also increased significantly in the heat pump sector, to 5.74 ct/kWh of by approx. 13% as at 1 April 2019, compared to 5.08 ct/kWh in the previous year. The price component controlled by the supplier makes up about 25% of the total price for night storage heating and about 26% of the total price for heat pumps. About 75% of the price for night storage heating and 74% of the price for heat pumps consists of taxes, surcharges and concession fees. Compared to the previous year the total of all fixed surcharges increased slightly, mainly due to the increase in the offshore liability surcharge. The Bundeskartellamt has set the concession fee at 0.11 ct/kWh because heating electricity is supplied under special contracts.[110] 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.

[110] Cf. Bundeskartellamt, Heizstrom – Überblick und Verfahren (Electric Heating - overview and proceedings), September 2010, pp. 9-10.

Price level at 1 April 2019 for heat pumps with a consumption of 7,500 kWh/year

	Spread between 10 und 90 % of suppliers in ct/kWh	**Arithmetic mean** in ct/kWh	**Share of total price**
Price components outside the supplier's control			
Net network charge	1.50 - 4.59	2.95	13%
metering	0.12 - 0.46	0.30	1%
concession fee	0.11 - 1.32	0.46	2%
EEG surcharge		6.41	28%
other surcharges[1]		1.01	4%
electricity tax		2.05	9%
VAT	3.15 - 4.04	3.59	16%
price components which can be controlled by supplier	3.60 - 7.70	5.74	26%
Total price (incl. VAT)	19.74 - 25.27	22.50	100%

[1] KWKG (0.28 ct/kWh), Section 19 (2) StromNEV (0.31 ct/kWh), surcharge under Section 18 AbLaV (0.01 ct/kWh), Offshore network surcharge (0.42 ct/kWh)

Table 97: Price level at 1 April 2019 for heat pumps with a consumption of 7,500 kWh/year

6. Green electricity segment

In the 2019 survey, information was also collected from suppliers on the volume of green electricity delivered to final consumers. For the purposes of this monitoring survey, a green electricity tariff is a tariff 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. The amount of green electricity supplied to household customers and other final consumers in 2018 and the share of green electricity in the total amount of electricity supplied in 2018 are presented below.

Electricity: Green electricity supplied to household customers and other final consumers in 2018

	Category	Total electricity supplied	Total green electricity supplied	Share of green electricity in total consumption and meters
Household customers	TWh	116.7	30.5	26.1%
	Market locations (thousand)	46,439	11,285	24.3%
Other final consumers	TWh	287.7	31.2	10.8%
	Market locations (thousand)	4,354	780	17.9%
Total	TWh	404.4	61.7	15.3%
	Market locations (thousand)	50,793	12,065	23.8%

Table 98: Green electricity supplied to household customers and other final consumers in 2018

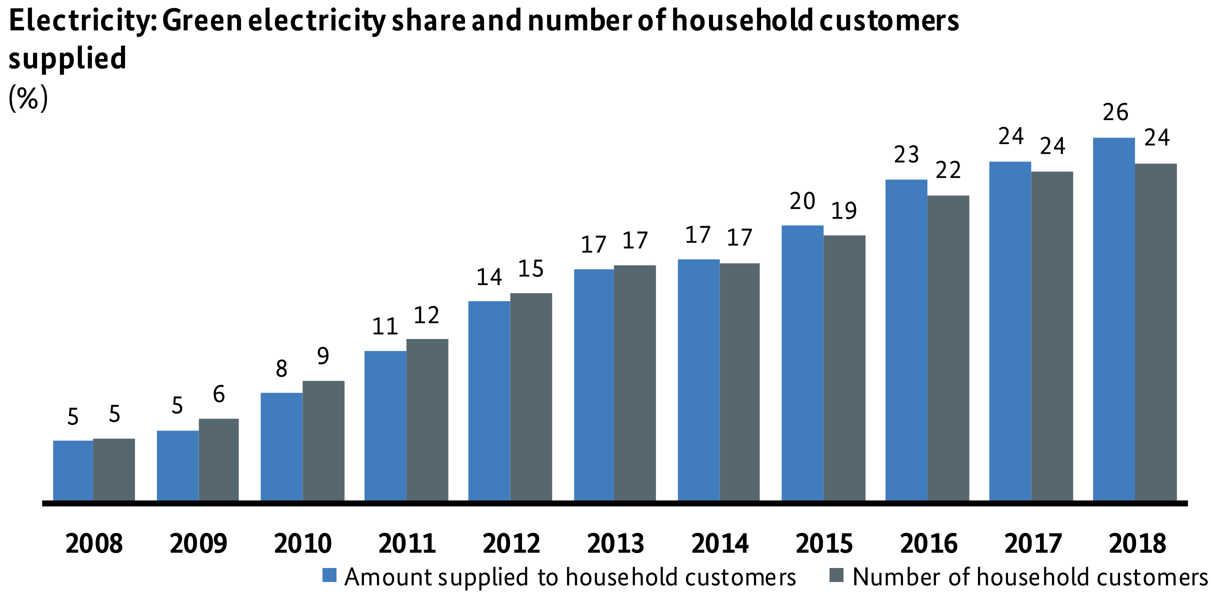


Figure 134: Green electricity share and number of household customers supplied

There was a further increase in the share of green electricity supplied to household customers in 2018. The number of households supplied with green electricity increased by a total of more than 300,000 market locations. The share of green electricity in total consumption rose by 1.7%. The number of household customers supplied with green electricity is now at around 11.3m market locations.

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.

Electricity: Average volume-weighted prices for household customers with an annual consumption between 2,500 kWh and 5,000 kWh (band III; Eurostat: DC) as at 1 April 2019 (ct/kWh)

Price component	Volume-weighted average (ct/kWh)	Percentage of total price
Energy and supply, margin	7.21	23.7
Net network charge	6.87	22.6
Charge for meter operations	0.42	1.4
Concession fee	1.60	5.3
EEG surcharge	6.41	21.1
KWKG surcharge	0.28	0.9
Surcharge under section 19 StromNEV	0.31	1.0
Surcharge under section 18 AbLaV	0.01	0.0
Offshore grid surcharge	0.42	1.4
Electricity tax	2.05	6.7
VAT	4.86	16.0
Total	**30.42**	**100.0**

Table 99: Average volume-weighted prices for green electricity for household customers in consumption band III as at 1 April 2019

The average volume-weighted retail price for household customers with an annual consumption from 2,500 kWh to 5,000 kWh increased to 30.42 ct/kWh as at 1 April 2019 (previous year: 29.24 ct/kWh). Household customers thus pay around 4% 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:

Electricity: Breakdown of the retail price for household customers with annual consumption from 2,500 kWh to 5,000 kWh (DC) for green electricity, as at 1 April 2019 (%)

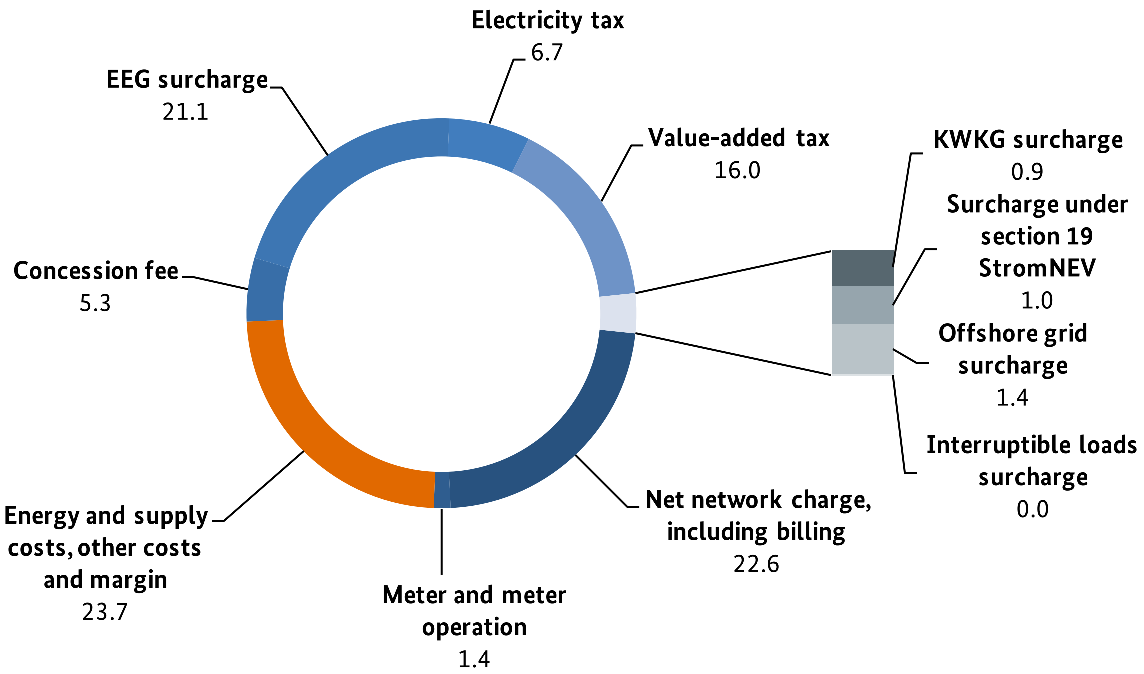


Figure 135: Breakdown of the retail price for household customers in consumption band III as at 1 April 2019 for green electricity[111]

As is the case with conventional electricity, many suppliers offer their customers a range of special bonuses and schemes that can have a further effect on prices under various tariffs. The number of price components (and various possible combinations of elements) make it difficult to compare the wide range of competitive tariffs. One-off bonus payments for household customers supplied with green electricity range from €5 to €256, with an average payment of €59. 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.

[111] 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 therefore the dividend and the total price at 119% is the divisor.

Electricity: Special bonuses and schemes for household customers (green electricity)

As at 1 April 2019	Household customers (green electricity)	
	Number of tariffs	Average scope
Minimum contract period	468	10 months
Price stability	399	14 months
Prepayment	45	11 months
One-off bonus payment	173	59
Free kilowatt hours	10	195 kWh
Deposit	4	-
Other bonuses and special arrangements	122	-

Table 100: 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 bonus 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 for the second six-month period 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 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.[112] However, the relevant regulation (EU) No 2016/1952, Article 3, allows the individual Member States a certain degree of freedom in the choice of a survey method, which can lead to national differences.

7.1 Non-household customers

Eurostat publishes price statistics for seven different consumer groups in the non-household sector that differ according to annual consumption ("consumption bands"). The following section describes the 20 to

[112] For details see: https://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2008:298:0009:0019:DE:PDF (retrieved on 27 May 2019).

70 GWh/year consumption band as an example. The 24 GWh/year category ("industrial customers"), for which specific price data is collected, falls into this consumption band.

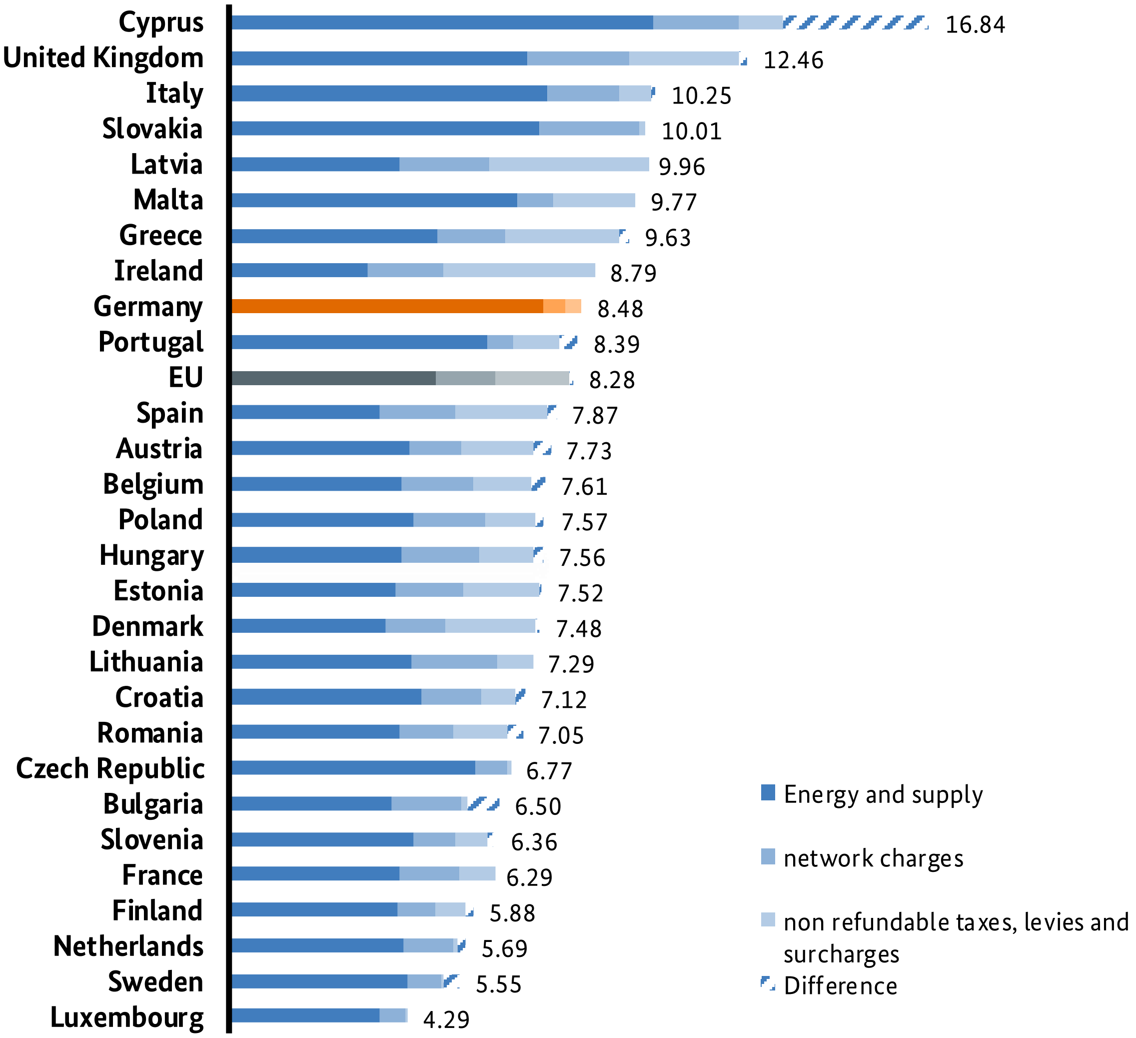
The customer group with an annual consumption of 20 to 70 GWh consists of mainly industrial customers who can deduct national VAT on a regular basis. As a result, the total price has been adjusted for VAT for the purpose of a European-wide comparison. Besides VAT there are various other taxes, levies and surcharges resulting from specific national factors. These costs can be recovered by this customer group and – like the VAT – can also be 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" I.G.4.1).

According to the Eurostat data, there are significant differences in the price of electricity for industrial customers across Europe. Cyprus has the highest net price at 16.84 ct/kWh, while Luxembourg has the lowest, at 4.29 ct/kWh. The EU average is 8.28 ct/kWh. 1.78 ct/kWh of this average consists of non-recoverable taxes, levies and surcharges and 6.40 ct/kWh is made up of network charges and the remaining balance controlled by the supplier ("energy and supply"). At 5.16 ct/kWh, the adjusted net price in Germany is just under 1.24 ct/kWh below the European average of 6.40 ct/kWh. The German net price is comprised of 1.84 ct/kWh network charges and 3.32 ct/kWh "energy and supply". 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 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.[113] 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 3.63 ct/kWh, or almost twice as much as the European average of 1.78 ct/kWh. The resulting net price for Germany is 8.48 ct/kWh, which is slightly higher than the European average of 8.28 ct/kWh.

[113] Cf. Eurostat, Electricity Prices – Price Systems 2014, 2015 Edition: https://ec.europa.eu/eurostat/documents/38154/42201/Electricity-prices-Price-systems-2014.pdf/7291df5a-dff1-40fb-bd49-544117dd1c10 (retrieved on 27 May 2019).

Comparison of European electricity prices in the second half of 2018 for non-household consumers with an annual consumption between 20 GWh and 70 GWh, without refundable taxes, levies and surcharges



Source: Eurostat
Remark: For Greece there is no differentiation of network charges and energy and supply.
Some countries are marked with a hatched difference. This difference results from the fact that electricity prices are collected every six months by Eurostat, but the different price components of the electricity price are only queried. throughout the year. .

Figure 136: Comparison of European electricity prices in the second half of 2018 for non-household consumers with an annual consumption between 20 GWh and 70 GWh

7.2 Household consumers

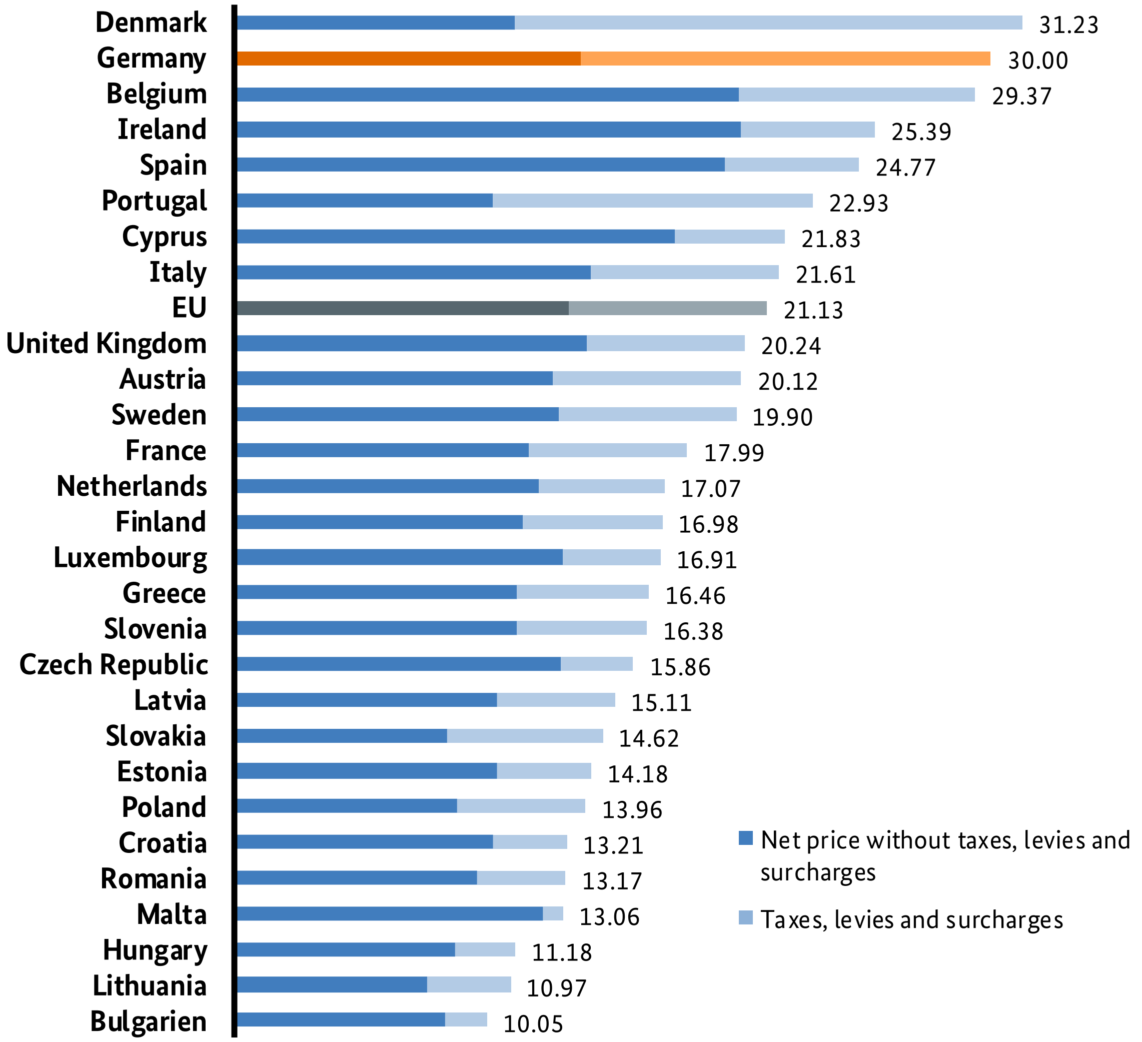
Eurostat takes five different consumption bands into consideration when comparing household customer prices. The volumes consumed by household customers in Germany are mostly in the middle category, with an annual consumption between 2,500 kWh and 5,000 kWh. The following shows an EU comparison of the 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. Based on the calculation method used by the German Association of Energy and Water Industries, Germany has the second highest price among the 28

EU Member States, at 30.00 ct/kWh. Only Denmark has higher prices for household consumers than Germany, at 31.23 ct/kWh. Prices in Germany are about 41% higher than the EU average of 21.13 ct/kWh.

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, 7.84 ct/kWh on average consist of surcharges, taxes and levies, whereas in Germany these components account for more than twice as much, with 16.22 ct/kWh. By contrast, at 13.78 ct/kWh, the net price adjusted for all taxes, surcharges and levies in Germany is slightly above the EU average of 13.29 ct/kWh.

Comparison of European electricity prices in the 2nd half of 2018 for household customers with an annual consumption between 2,500 kWh and 5,000 kWh in ct/kWh ; incl. VAT and all other taxes



Source: Eurostat

Figure 137: Comparison of European electricity prices in the second half of 2018 for household customers with an annual consumption between 2,500 kWh and 5,000 kWh

H Metering

Before the Metering Act entered into force in September 2016, suppliers had to include meter operation in their electricity bills. Under the new law, the supplier is no longer required to send a combined bill if modern metering equipment or smart metering systems are used. This is not the case with conventional monitoring facilities. The supplier is still required to bill conventional monitoring facilities.

It is therefore possible that consumers will receive a bill from the meter operator for the meter operation and another one from their supplier for the electricity itself. Under such circumstances, it is advisable for them to check that the meter operation is really no longer included in the supplier's bill.

1. Digitisation of metering

The entry into force of the Metering Act (MsbG) in September 2016 triggered significant changes in metering. The Metering Act requires the comprehensive rollout of modern metering equipment and smart metering systems. The implementation of the rollout and the legal deadlines concomitant with it are, however, dependent on many different factors. One important factor in the implementation is the technical availability of modern metering equipment and smart metering systems.

Since the beginning of 2017, the first modern metering systems have been available on the market and have been installed by the first default meter operators on a large scale.

However, it was not possible to start the rollout of smart metering systems in 2017, since no smart meter gateways certified by the Federal Office for Information Security (BSI) were available on the market. Therefore the BSI was also not able to determine technical feasibility. This will not happen until at least three independent manufacturers make smart metering systems available on the market. The first smart metering system was certified by the BSI in December 2018, and the second in September 2019. It is unlikely that a rollout of smart metering systems will occur before the end of 2019.

2. The network operator as the default meter operator and independent meter operators

There were 892 companies operating a total of 54,084,176 meters [114] who responded to the questions about electricity metering for the monitoring survey in 2019.

Meter operation is carried out mostly by the network operator as the default meter operator. The default meter operator may also outsource to another company, either in a transfer or an in-house process. Companies wishing to take over the default metering operations and not already approved as a network operator under section 4 of the Energy Industry Act must obtain approval from the Bundesnetzagentur under section 4 of the Metering Act. In 2018 the application from one company wishing to take on metering operations as a joint service for multiple companies was approved. No applications have so far been received in 2019.

The 892 meter operators had the following roles in 2018 (some of them were active in more than one market role).

Electricity: Meter operator roles within the meaning of the Metering Act

	Number	
	Conventional metering operations	**Metering operations of modern metering equipment or smart meters**
Network operator as default meter operator within the meaning of the MsbG	832	760
Network operator as non-default meter operator offering its meter services on the market	30	19
Supplier acting as meter operator	61	40
Third-party, independent meter operator	50	24

Table 101: Meter operator roles within the meaning of the Metering Act according to data provided by electricity meter operators

A connection user can choose which company is to be responsible for the installation, operation, maintenance of metering equipment and systems, and metering (in accordance with section 5 MsbG). A competing third

[114] The term “meter location” corresponds to the term “meter” within the meaning of section 2 para 11 of the Metering Act. A meter location is a location at which energy is measured and that includes all technical equipment required to collect and, if necessary, transmit the meter data. All relevant physical quantities at a point in time are collected no more than once at a meter location.

party can be responsible instead of the default meter operator. Independent operators take on the activity of metering operations in the network areas of 786 DSOs, according to data received in the monitoring survey. They may be network operators that offer metering operations outside their own networks, they may be suppliers or they may be independent meter operators with no other market role. There is a large variation in the number of meter operators between the different networks. In 48 networks, between 30 and 50 independent meter operators are active, but in 86 networks there is only a choice between the default meter operator and two to four others. The following graph shows the number of independent meter operators regardless of the size of the network.

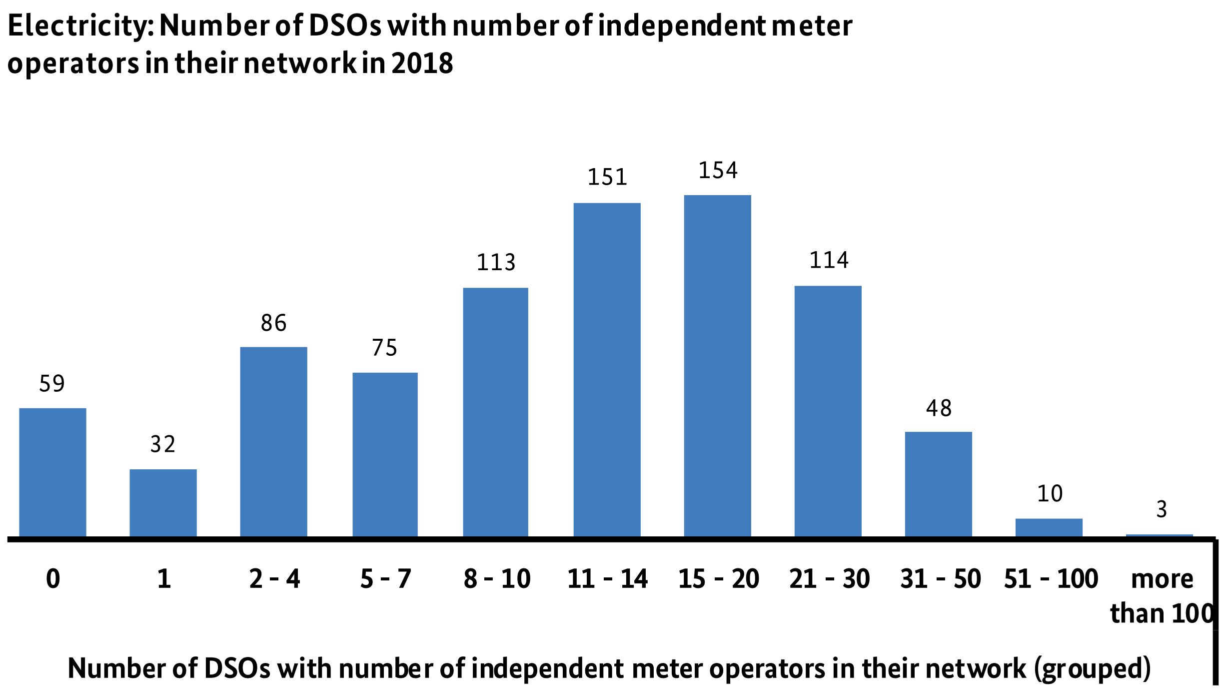


Figure 138: Number of DSOs with number of independent meter operators in their network (grouped)

Regardless of network size, the average number of meter operators active in one distribution system area is about 15. The highest number is 118 independent meter operators in one network area.

Independent meter operators cover about 317,410 meter locations in the distribution networks, which equates to a share of less than 1% of the total number of meter locations in these networks. This low proportion can be seen in Figure 139. The meter locations where independent meter operators are active are shown in proportion to the total meter locations of a network area. There are very few networks, only about 6% of the total, where more than 1% of meter locations are covered by independent meter operators.

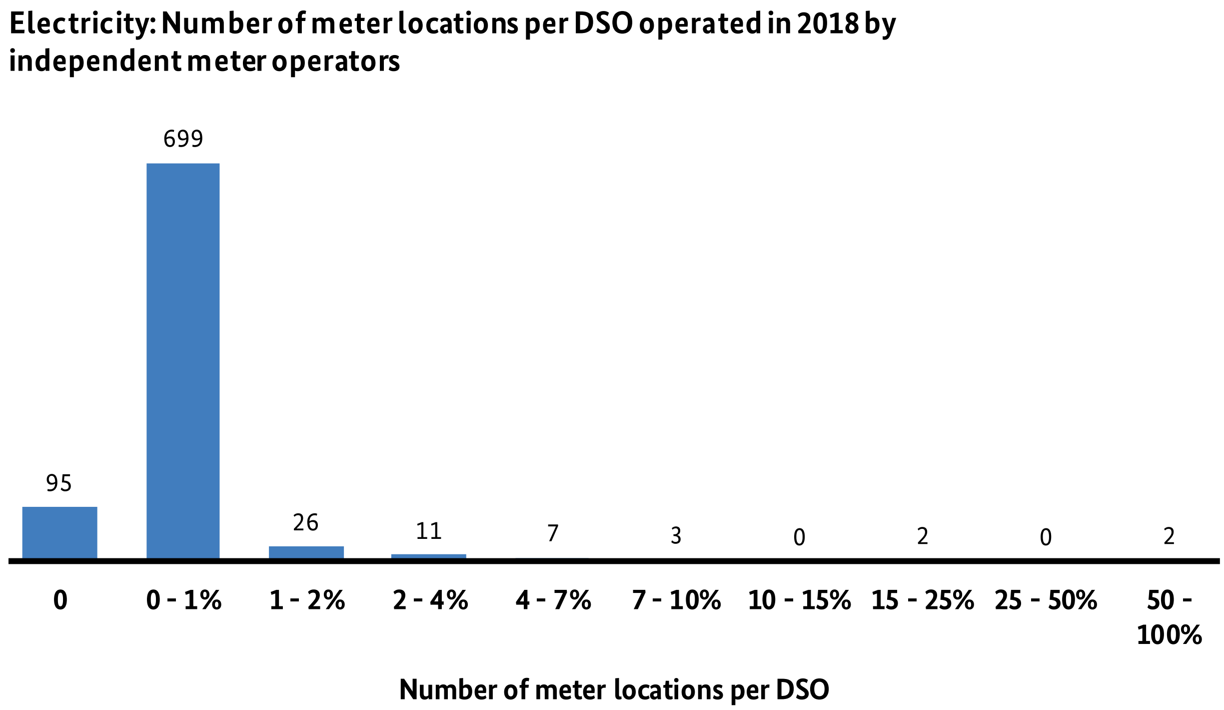


Figure 139: Number of meter locations per DSO operated by independent meter operators

The total number of meter locations is broken down by federal state as shown in Table 102. The table shows that the German state of North Rhine-Westphalia has the highest number of meter locations - more than 10m.

Electricity: Number of meter locations by federal state

	meter location – consumption	meter location – feed-in
Baden-Württemberg	6,364,600	243,961
Bavaria	7,630,750	476,775
Berlin	2,372,391	9,525
Brandenburg	1,676,128	40,288
Bremen	442,762	4,592
Hamburg	1,164,864	4,588
Hesse	3,746,488	120,823
Mecklenburg-Western Pomerania	1,117,046	18,941
Lower Saxony	4,537,966	187,087
North Rhine-Westphalia	10,672,006	209,790
Rhineland-Palatinate	2,471,631	108,473
Saarland	626,209	21,643
Saxony	2,826,714	41,690
Saxony-Anhalt	1,537,041	31,668
Schleswig-Holstein	1,768,324	51,471
Thuringia	1,345,643	32,562

Table 102: Number of meter locations by federal state

3. Requirements of section 29 et seq of the Metering Act

Under the Metering Act, meters with an annual electricity consumption of over 6,000 kWh must be included in the rollout of smart metering systems. Around five million final consumers in various consumption categories are affected by the mandatory installation within the meaning of section 29 in conjunction with sections 31 and 32 of the Metering Act. With nearly 2.1m meter locations, the majority of these are final consumers with an annual consumption of between 6,000 and 10,000 kWh. The following tables show the number of meter locations with mandatory installation of smart meters, broken down by the consumer groups used in the Metering Act. The grey columns in the tables refer to the future rollout of smart metering systems within the meaning of section 29 of the Metering Act. The companies were unable to provide any information about this since in the 2018 reporting year there was only one smart metering system available on the market that was certified by the Federal Office for Information Security (BSI). On the other hand, it is possible to see a sharp rise in modern metering equipment, which has been on the market since early 2017. Consequently, the number of installed Ferraris meters is falling, as they are being replaced by modern metering equipment.

Electricity: Meter locations requiring smart meters under section 29 in conj. with sections 31 a

	Number of meter locations			
	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	2,046,722	210,196	97,756	
> 10,000 kWh & ≤ 20,000 kWh	1,004,389	109,437	36,300	
> 20,000 kWh & ≤ 50,000 kWh	510,785	73,217	14,186	
> 50,000 kWh & ≤ 100,000 kWh	151,066	36,669	2,709	
> 100,000 kWh	241,590	130,232	519	
Consumer devices in accordance with section 14a EnWG	1,054,789	85,689	21,597	
of which meter locations at charging stations for electric vehicles	3,323	715	441	
Installed capacity at plant operators in accordance with section 2 para 1 of the Metering Act				
> 7 kW & ≤ 15 kW	528,450	56,654	19,799	
> 15 kW & ≤ 30 kW	251,627	27,716	5,972	
> 30 kW & ≤ 100 kW	136,650	21,702	1,889	
> 100 kW	365,529	38,845	344	

Table 103: Mandatory installations within the meaning of section 29 in conjunction with sections 31 and 32 of the Metering Act.

For final consumers with annual consumption of 6,000 kWh or less, section 29 in conjunction with section 31 of the Metering Act gives the default meter operator the right to decide whether to install smart metering systems (voluntary installation) or just to install modern metering equipment. Meter operators reported approximately 39m final consumers for a possible optional installation. Of these, final consumers with an annual electricity consumption of less than 2,000 kWh form the largest group.

Electricity: Optional installation within the meaning of section 29 in conj. with section 31 of tl

	Number of meter locations			
	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 of:				
≤ 2,000 kWh	20,080,481	2,233,293	1,060,910	
> 2,000 kWh & ≤ 3,000 kWh	8,461,321	845,040	414,643	
> 3,000 kWh & ≤ 4,000 kWh	5,571,002	492,918	274,902	
> 4,000 kWh & ≤ 6,000 kWh	5,218,596	375,251	223,391	
Installed capacity at plant operators in accordance with section 2 para 1 of the Metering Act				
> 1 kW & ≤ 7 kW	543,995	98,452	20,199	

Table 104: Voluntary installation within the meaning of section 29 in conjunction with section 31 of the Metering Act.

In response to the question in the monitoring survey as to whether the default meter operator is planning on equipping meter locations of final consumers whose annual consumption is below 6,000 kWh with a smart metering system, 57 companies responded with "Yes" and 372 responded with "No". 399 companies remain undecided.

4. Organisation of metering operations

In addition to the installation of metering equipment, metering operations include the operation, maintenance and billing of metering operations, as well as gateway administration. Companies are free to choose between performing these tasks themselves or transferring some of them to service providers. The answers to the questions in the monitoring survey indicate that the majority of meter operators perform these tasks themselves. One exception is smart meter gateway administration, where there is a growing tendency to employ external service providers. Companies performing gateway administration must be certified by the BSI. As of 31 October 2019, the BSI has certified 38 companies as gateway administrators. The stringent security requirements make gateway administration a business sector where service providers are likely to continue to specialise in the future, rather than companies doing it themselves. It is only likely to be worth companies doing their own gateway administration if they have at least a certain number of meter locations under their responsibility.

The individual types of activities are shown in Figure 139.

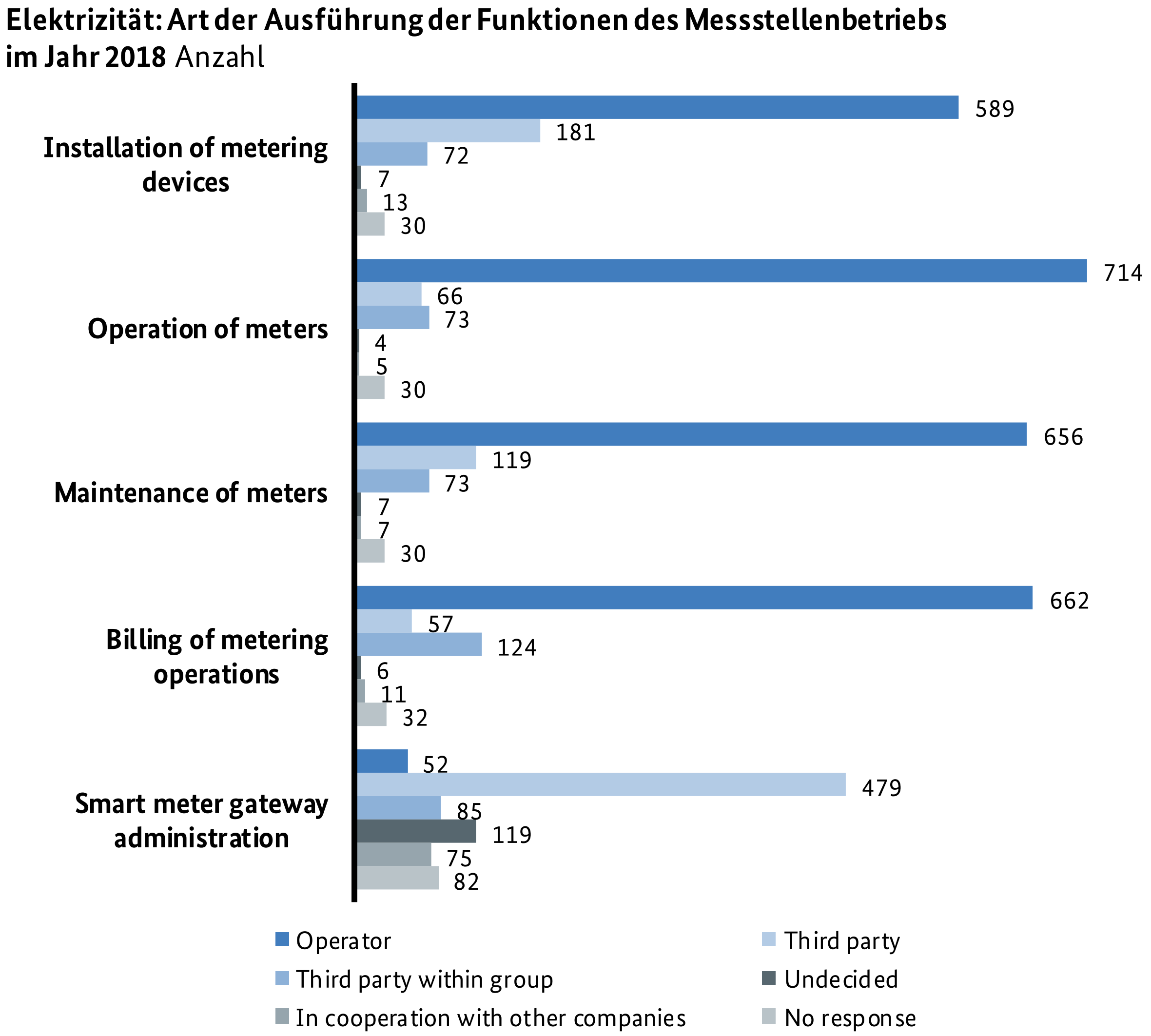


Figure 140: Performance of the activities related to metering operations

The Metering Act only regulates the nationwide rollout of modern metering equipment and smart metering systems for electricity. New gas meters can only be legally installed if they can be securely connected with a smart meter gateway. If meters have a smart meter gateway, default meter operators are obliged to connect it if it is technically possible to do so. However, since smart metering systems are not yet available for a connection on the gas market, it is not yet possible to comply with the obligations set forth in the law. So for sectors other than electricity - such as gas, heating and district heating, or water - most companies do not offer metering via the smart meter gateway. For the other sectors, the percentage of companies that provide additional metering operations is between 4% and 8% of the total number of the companies offering metering operations. Only for the gas sector is the number somewhat higher, with 123 providers (see Figure 141).

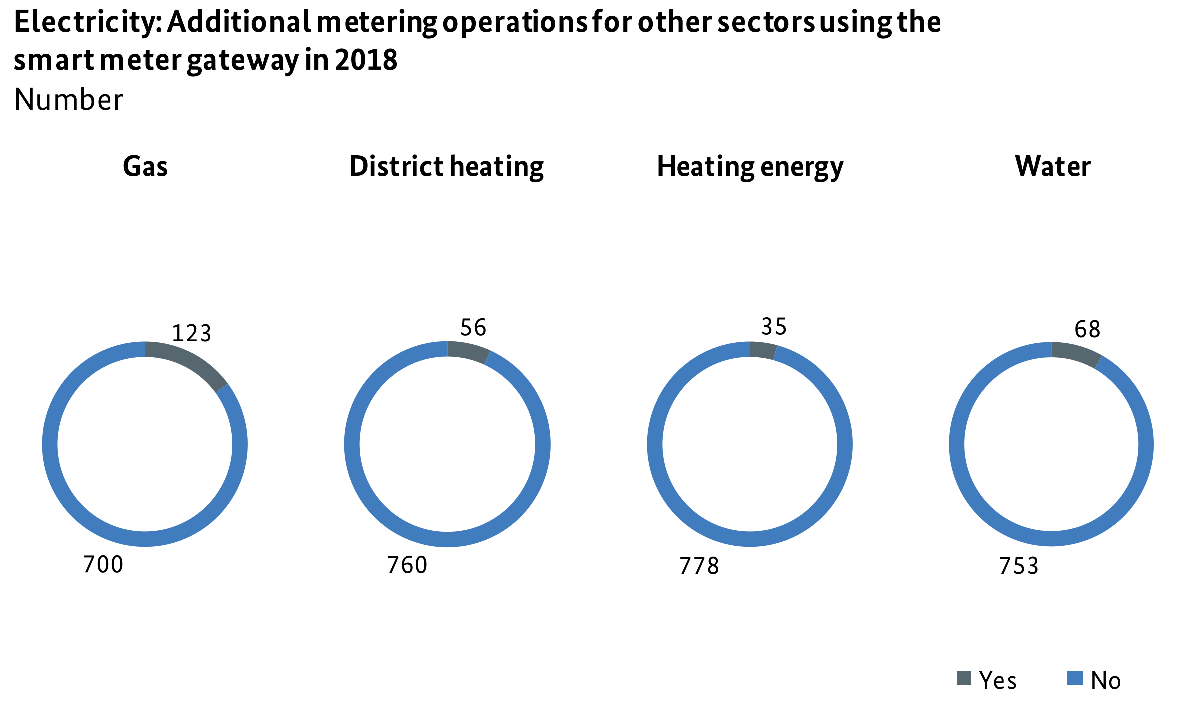


Figure 141: Additional metering operations for other sectors using the smart meter gateway

Both default meter operators and third party meter operators have the option of offering additional metering services for smart metering systems within the meaning of section 35(2) of the Metering Act. Although the majority of companies also provide current and voltage transformers, up to now very few of them offer other services such as using smart metering systems for prepayment (see chapter I.G.3.3), setting up or using smart metering systems for load control, or making smart meter gateways available and technically operating them for value-added services. At the same time, the number of meter operators that have not yet made a decision on additional services is high in all categories. This could be related to the fact that the smart metering systems are not yet available. Without the systems in place, many services can not yet be offered. Figure 142 shows the evaluation of additional services.

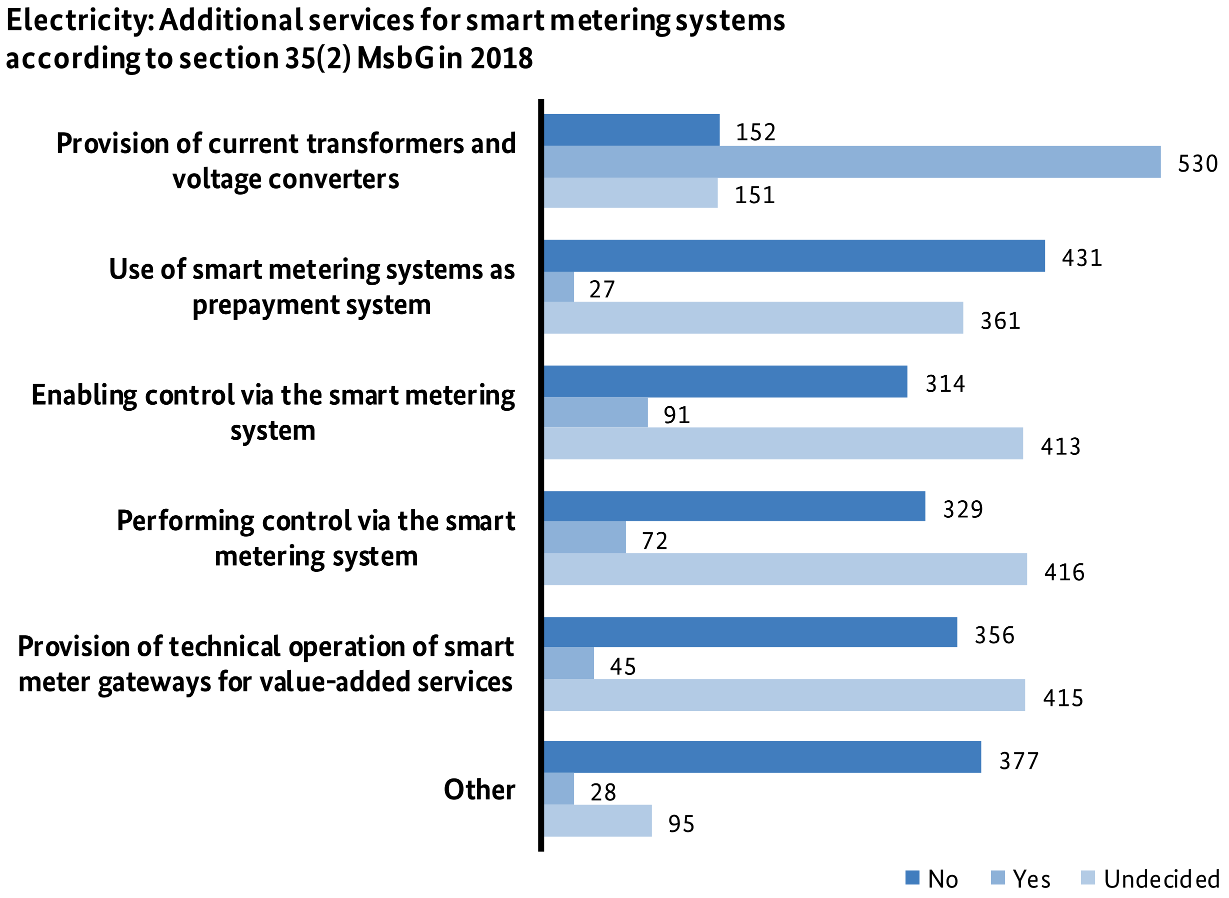


Figure 142: Additional services for smart metering systems

A large majority (81%) of meter operators do not sell products that combine electricity supply and meter operation (see Figure 143).

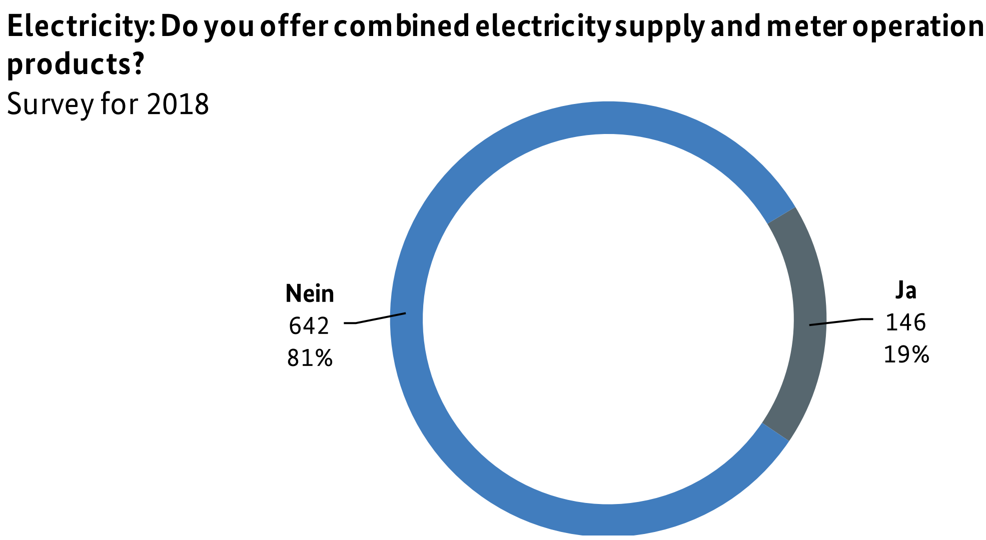


Figure 143: Combined products for electricity supply and meter operation

Although the billing of the connection user/owner for meter operation is no longer required to take place via the supplier, this is still usually the case. Presumably suppliers and meter operators have made agreements to continue to bill meter operation jointly as part of the electricity bill. There has been some increase in mixed billing models – where billing sometimes occurs separately and sometimes via the suppler – but this is still far less common than billing via the supplier (see graph below).

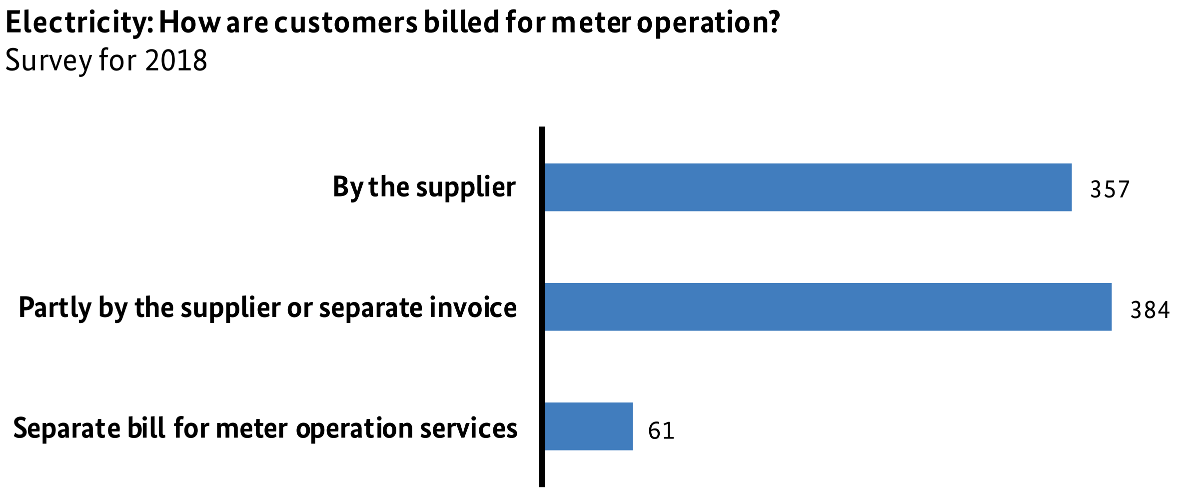


Figure 144: Billing the connection user/owner for meter operation

5. Metering technology used for household customers

Meter operators provided the following information on the type of technology used in meters and metering systems for standard load profile (SLP) customers in Germany:

Electricity: Meter technology employed for standard load profile (SLP) customers

Requirement	Meter locations 2017	Meter locations 2018
Electromechanical metering systems (with current transformers and three-phase meters based on the Ferraris principle)	41,225,392	40,080,363
of which two-tariff and multiple-tariff meters (Ferraris principle)	2,624,019	2,480,879
Electronic meter device (basic meter not connected to a communication network) in accordance with section 2 para 15 of the Metering Act	6,967,445	7,823,861
Modern measuring device (not connected to a communication network) in accordance with section 2 para 15 of the Metering Act	558,574	2,547,165
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 (eg EDL40)	462,026	461,288
Smart metering systems in accordance with section 2 para 7 of the Metering Act		

Table 105: Meter technology employed for standard load profile (SLP) customers

The availability of modern metering equipment from the start of 2018 led to a clear move away from electromechanical meters during the year for SLP customers, which also includes all household customers. This is due to the availability of modern metering equipment since 2017. There was therefore a jump in 2018 in the number of modern metering devices that comply with section 2 para 15 of the Metering Act and are not connected to a communications network. Modern metering equipment is now fitted at about 2.5m meter locations. The total number of electromechanical metering systems has dropped by about 1.1m meter locations. The number of electronic meters has risen sharply over the previous year so that there are currently about 8m meter locations where these types of meters are used. There has been another small drop in the use of two-tariff and multiple-tariff meters to around 2.5m. The number of metering systems pursuant to section 2 para 13 of the Metering Act that are not smart metering systems remained constant and are still installed at nearly half a million meter locations of SLP customers.

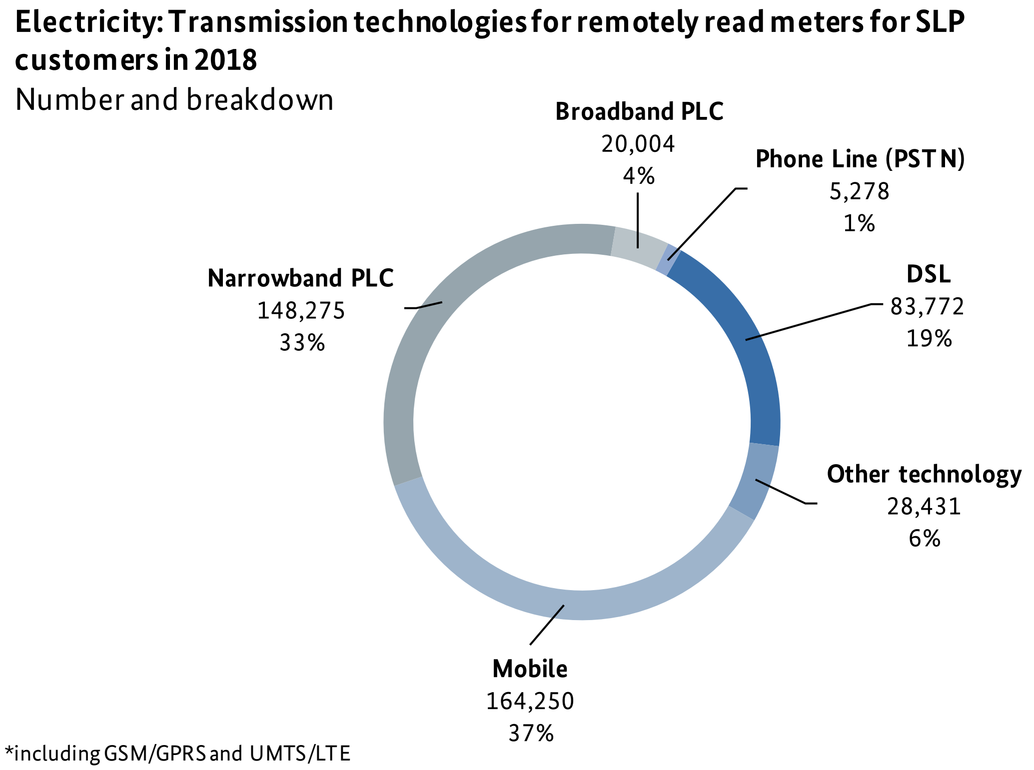


Figure 145: Transmission technologies for remotely read meters for SLP customers

Only about 450,000 of the nearly 51m meter locations for household customers are read remotely. As a rule, meters still have to be read manually once a year. The amount of data transmission via power line communication (PLC) declined by nearly 12,000 meter locations compared to the previous year. It is mainly the sharp rise in transmission via mobile communications that stands in contrast to the overall financial decline of PLC technology. PLC transmission technology is now being used in just 37% of cases, while mobile transmissions are likewise used in 37% of cases. The number of transmissions via telephone lines (PSTN) and broadband (DSL) is relatively stable.

6. Metering technology used for interval-metered customers

According to information provided by the meter operators, the number of final consumers with interval metering totals around 400,000 meter locations. Interval-metered customers are solely non-residential customers from the industry and business sector.

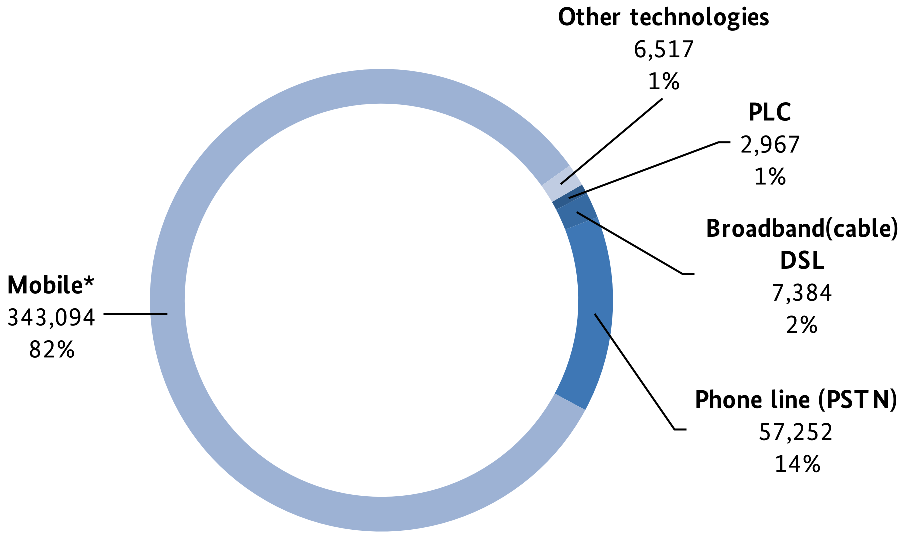
Electricity: Meter technology employed for interval-metered customers

Requirement	Meter locations 2018
Metering equipment in the interval-metered segment	395,633
Metering systems in accordance with sections 21d and 21e EnWG	61,509
Other	4,025

Table 106: Meter technology employed for interval-metered customers

The following diagram shows the number and breakdown of transmission technologies used.

Electricity: Transmission technologies for remotely read meters for interval-metered customers in 2018
Number and breakdown



*including PMR, GSM/GPRS and UMTS/LTE

Figure 146: Transmission technologies for interval-metered customers

There were some changes in the transmission technology landscape for interval-metered customers compared with 2017. There was a decrease in meter readings transmitted via mobile communication and transmissions via telephone lines. As in 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. The prevailing trend of telephone-line transmission falling and mobile transmission rising by a comparable amount is also apparent for interval-metered customers. 82% of remote read meters now communicate by mobile transmission.

7. Metering investment and expenditure

Total investment and expenditure [115] on metering was up about €45m to around €620m in 2018, leaving expenditures around €54m below the planned investment amounts.

Investment in new installations, upgrades and expansion made in 2018 lagged around 14% behind projected figures for the year. Investments in maintenance and renewal were around 20% below what was planned. Expenditure amounts were almost identical to the forecast figures.

This year's forecast figures are at the same level as the prior year and - if fully implemented - would lead to an increase in investments and to a sustained level in expenditures.

Of the €620m invested in 2018, investment in smart metering systems and modern metering equipment was around €130m, which is more than twice as much as in the prior year. There is projected to be a significant rise in this proportion to about €230m in 2019.

[115] Definitions are provided in the section I.C.3 Invest in the Networks chapter (starting on page 124).

Electricity: Metering investment and expenditure
€ million

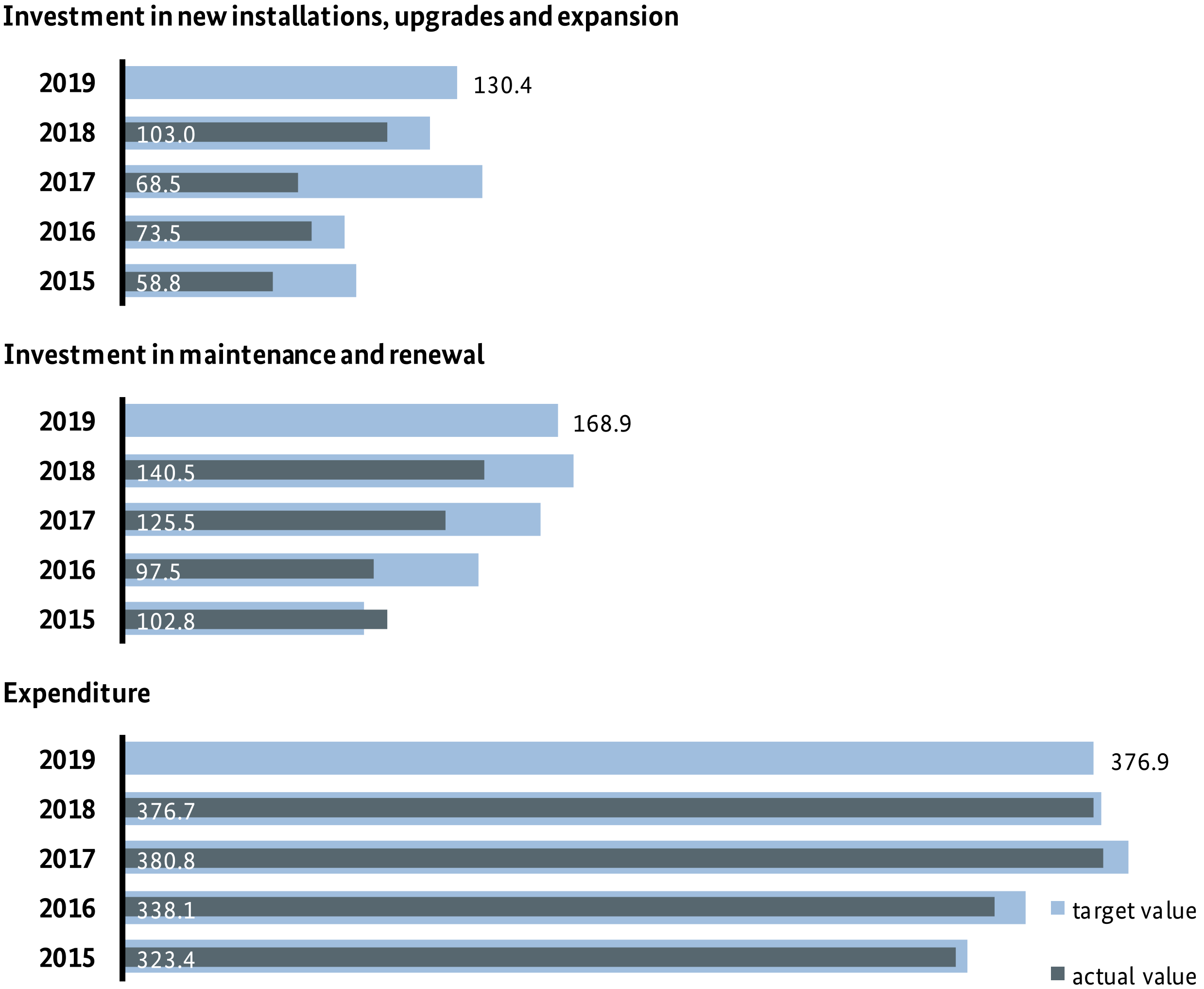


Figure 147: Metering investment and expenditure

8. Final consumer prices for metering equipment

For the third 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 107. The prices for standard services as defined in section 35(1) of the Metering Act range on average between €93.88 and €720.32 per year, depending on the final consumer group and installed capacity of installation operators. The prices for voluntary installation within the meaning of section 29 in conjunction with section 31 of the Metering Act are also shown in Table 107. Depending on the final consumer group, they vary, on average, between €22.14 and €53.94 per year. Table 108 shows that final consumers are charged on average €19.77 per year for modern metering equipment within the meaning of section 29 in conjunction with section 32 of the Metering Act. Both tables make clear that average prices for meter operation are very close to the legal maximums.

Electricity: Prices for standard services within the meaning of section 35(1) of the Metering Act for carrying out metering operations in 2018 (€ / year)

	Average price	Price cap
Final consumers with annual power consumption		
≤ 2,000 kWh**	22.14	23.00
> 2,000 kWh & ≤ 3,000**	28.20	30.00
> 3,000 kWh & ≤ 4,000**	36.80	40.00
> 4,000 kWh & ≤ 6,000**	53.94	60.00
> 6,000 kWh & ≤ 10,000	93.88	100.00
> 10,000 kWh & ≤ 20,000 kWh	122.97	130.00
> 20,000 kWh & ≤ 50,000 kWh	161.17	170.00
> 50,000 kWh & ≤ 100,000 kWh	190.53	200.00
> 100,000 kWh	720.32	
Consumer devices within the meaning of section 14a EnWG	94.86	100.00
Installed capacity at plant operators in accordance with section 2 para 1 of the Metering Act		
> 1 kW & ≤ 7 kW**	53.43	60.00
> 7 kW & ≤ 15 kW	94.56	100.00
> 15 kW & ≤ 30 kW	123.45	130.00
> 30 kW & ≤ 100 kW	189.85	200.00
> 100 kW	423.76	

* in accordance with section 35(1) of the Metering Act

Table 107: Prices for standard services within the meaning of section 35(1) of the Metering Act for carrying out metering operations

Electricity: Prices for voluntary installation within the meaning of section 29 in conjunction with section 32 of the Metering Act in 2018 (€ / year)

	Average price	Price cap
Modern metering device as defined in the Metering Act	19.77	20.00

Table 108: Prices for voluntary installation 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 2018, natural gas production in Germany fell by 1bn m³ to 6.2bn m³ of gas (with calorific adjustment)[116] (2017: 7.2bn m³). This corresponds to a decrease of 13.3% compared to 2017. 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 8.0 years as at 1 January 2019, the same as in the previous year.

The total volume of natural gas imported into Germany in 2018 was 1,760 TWh. Based on the previous year's figure of 1,676 TWh, imports to Germany increased by 83 TWh or just over 5%. Imports from Norway dropped by just over 11%, while imports from Russia through the Nord Stream pipeline rose by 14.9%.

In 2018, Germany exported a total of 849.1 TWh of natural gas. Based on the previous year's figure of 743.5 TWh, exports increased by 105.6 TWh, corresponding to a rise of 14%. Around 48% (2017: 50%) of the natural gas exported by Germany went to Czechia, with exports to the country up 10% on the previous year. There was a clear increase in exports to Luxembourg (+67.1%) and the Netherlands (+54.2%) and a clear decrease in exports to Poland (25.9%) and Austria (8.9%).

The total maximum usable volume of working gas in underground storage facilities as at 31 December 2018 was 280.02 TWh. Of this, 134.12 TWh was accounted for by cavern storage, 123.89 TWh by pore storage and 22.01 TWh by other storage facilities.

The volume of short-term (up to 1 October 2018) freely bookable working gas declined slightly again, as did the capacities still bookable for 2020. There was another increase in the volume of long-term bookable working gas from 2021. Overall, customers are tending towards shorter-term bookings in the storage market.

Owing to the mild winter 2018/2019, the storage level at natural gas storage facilities in Germany at the beginning of the storage year 2019/20 still stood at over 50%. Due to the good supply of gas and low prices in the gas markets, the storage facilities were filled to a very good level during the summer half-year. On 1 November 2019, the total storage level stood at over 99%.

The market for the operation of underground natural gas storage facilities is still highly concentrated, although concentration has eased over the past few years. The aggregate market share of the three largest

[116] 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/m³). 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 from 2 kWh/m³ to 12 kWh/m³).

storage facility operators stood at around 67.1% at the end of 2018, representing a slight decrease compared to the previous year (68.2%).

1.2 Networks

1.2.1 Network expansion

On 20 December 2018, the Bundesnetzagentur decided on the gas network development plan (NDP) 2018-2028 submitted by the transmission system operators (TSOs). The NDP, which is binding for the TSOs, comprises a total of 156 measures with an investment volume of about €7bn. The measures involve the construction of new transmission lines with a total length of 1,364 km and 499 MW of additional compressor capacity over the next ten years. The TSOs incorporated the necessary changes and published the binding gas NDP 2018-2028 on time. The majority of the network expansion measures in the NDP result from the conversion from L-gas to H-gas in Germany that is to be completed by 2030 and from the connection of planned new power stations.

The TSOs' publication of the scenario framework for the gas NDP 2020-2030 marked the start of the next NDP cycle in June 2019. The scenario framework sets out the input parameters for the next gas NDP: planning assumptions for capacity for a time frame of ten years, for example resulting from future capacity requirements in downstream distribution networks and from the planned connection of new gas power stations, gas storage facilities or LNG facilities to the transmission network.

1.2.2 Investments

In 2018, investments in and expenditure on network infrastructure by the 16 German TSOs amounted to €1.45bn (2017: €970m) (both values under commercial law).[117]Total investments of €1.65bn are planned for 2019, corresponding to an increase of 13% compared to 2018. This relatively high fluctuation is due to investments in large-scale, one-off projects.

In the 2019 monitoring, 600 gas distribution system operators (DSOs) reported total network infrastructure investments in 2018 of €1,273m (2017: €1,031m) in new builds, upgrades and expansion (€798m (2017: €623m)) and in maintenance and renewal (€475m (2017: €408m)). For 2019, a total investment of €1,371m is foreseen.

Service and maintenance expenses, based on the data provided by the DSOs, totalled €1,078m in 2018 (2017: €1,084m). For 2019, service and maintenance expenses amounting to €1,116m are foreseen.

1.2.3 Supply interruptions

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 interruptions

[117] 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).

experienced by a customer over a period of one year and was 0.48 minutes per year in 2018 (2017: 0.99 minutes per year).

1.2.4 Network charges

The average network charge (including metering and meter operation charges) for household customers independent of the type of supply contract is currently around 1.56 ct/kWh and thus just over 3% higher than in the previous year.

1.2.5 Network balance

The total quantity of gas supplied by general supply networks in Germany fell slightly in 2018 by 13.6 TWh to 928.1 TWh (2017: 941.7 TWh)[118], representing a year-on-year decrease of just over 1.4%. The quantity of gas supplied to household customers (as defined in section 3 para 22 of the Energy Industry Act (EnWG)) rose by just over 1.3% to 275.2 TWh (2017: 278.8 TWh). Gas supplies to gas-fired power stations with a nominal capacity of at least 10 MW fell, after several years of increases. Gas supplies in 2018 totalled 87.8 TWh (2017: 98.1 TWh), just over 10% lower than in 2017.

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) – in other words not using the classic route via a supplier, and instead approaching the network operator as a shipper (paying the transport charges themselves) – amounted to 72.57 TWh, equivalent to just over 42% of the total quantity of gas supplied by the TSOs. With regard to gas distribution networks, the quantity of gas procured without a conventional supplier contract amounted to around 40 TWh, corresponding to a share of just over 5% of the DSOs' total gas supplies.

1.2.6 Market area conversion

The conversion of German L-gas networks to H-gas began in 2015 with the smaller network operators and has since been in progress as planned with the larger network operators such as Westnetz, EWE Netz and wesernetz Bremen. The highest annual figure of around 550,000 converted appliances will be reached in the coming years.

1.3 Wholesale

Liquid wholesale markets are vital to ensure well-functioning markets along the entire 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 one supplier long-term. Market players can choose from a wide range of competing trading partners and maintain a diversified portfolio of short and long-term contracts. Liquid wholesale markets thus facilitate market entry for new providers and ultimately promote competition for final consumers. The Bundeskartellamt now defines the wholesale market for natural gas as a national market and no longer defines markets based on their respective network or market area.

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[118] The DSOs' gas supplies figure for 2017 was adjusted to 758.4 TWh following the submission of a data correction. The total quantity of gas supplied by TSOs and DSOs in 2017 therefore amounted to 941.7 TWh.

Overall, the liquidity of the wholesale natural gas markets decreased in 2018. While there was an increase of around 13% in the total volume traded on the exchange in 2018, there was a decrease of about 14% in the volume of bilateral wholesale trading via broker platforms, which accounts for a much larger share.

The volume traded on the spot market rose in 2018 by 26% to around 391 TWh (2017: 309 TWh). As in previous years, the focus of spot trading for both market areas in 2018 was on day-ahead contracts (NCG: 132.9 TWh (2017: 115.8 TWh); GASPOOL: 102.8 TWh (2017: 69.3 TWh)). The futures trading volume fell from around 86 TWh in 2017 to about 58 TWh in 2018, corresponding to a decrease of some 33%.

In 2018, broker platforms reported having brokered natural gas transactions for delivery to Germany for an amount totalling 2,289 TWh (2017: 2,672 TWh), representing a decrease of around 14%. Of this, 858 TWh was for contracts with delivery in 2018 and a delivery time of at least one week.

As in the previous year, wholesale gas prices in 2018 showed some considerable increases. The various price indices (EGIX, cross-border prices, as calculated by the Federal Office for Economic Affairs and Export Control (BAFA)) show a year-on-year increase of between 13% and 28%. A fully reliable year-on-year comparison for the European Gas Spot Index (EGSI) introduced in September 2017 will not be possible until next year.

1.4 Retail

1.4.1 Contract structure and competition

An overall analysis of how household customers were supplied in 2018 in terms of volume shows that half of them (50%) were supplied by the local default supplier under a non-default contract and were supplied with 124.7 TWh of gas (2017: 51%/126.4 TWh).

Only 18% of household customers had a default supply contract in 2018 and were supplied with 45.3 TWh of gas (2017: 19%/47.3 TWh). The percentage of household customers who had a contract with a supplier other than the local default supplier once again increased and was 32% for a total of 79.1 TWh of gas (2017: 30%/75.5 TWh).[119] Thus supply by the default supplier at a default tariff is the least popular form of supply.

The gas sold to non-household customers is mainly to interval-metered customers. About 25.7% of the total volume delivered to these customers was supplied under a contract with the default supplier on non-default terms (2017: 29%) and about 74.2% was supplied under a contract with a legal entity other than the default supplier (2017: 71%). These figures show that default supply is of only minor significance in the acquisition of interval-metered customers in the gas sector.

The total number of customers switching contract in 2018 was 0.6m; the volume of gas delivered to these customers was approximately 13.4 TWh. The volume-based switching rate was therefore 5.4%.

The number of household customers who switched gas supplier fell slightly again by just under 1% year-on-year to 1.2m (down 7,256 supplier switches). There was a clear rise of nearly 6% in the number of household

[119] Die gesamte durch die Gaslieferanten mitgeteilte Gasabgabemenge an Haushaltskunden in Höhe von 249,1 TWh weicht von der durch die VNB Gas mitgeteilte Ausspeisemenge an Haushaltskunden in Höhe von 275,2 TWh ab, da die Marktabdeckung der Abfrage im Bereich der Netzbetreiber höher ist.

customers who immediately chose an alternative supplier rather than the default supplier when moving home. In 2018, there was an increase in the overall switching rate for household customers due to the rise in the number of customers who switched when moving home. When looking at 12.9m household customers (according to DSO figures), the resulting overall numbers-based supplier switching rate for household customers is 11.5%.

The total consumption affected by supplier switches in 2018 was 89.5 TWh, corresponding to a year-on-year increase of 1.5 TWh or about 2%. The switching rate for non-household customers was 9.0%, representing an increase of around 0.9 percentage points compared to the previous year.

The levels of concentration in the two largest gas retail markets continue to be well below the statutory thresholds for presuming market dominance. In 2018, cumulative sales for the four largest companies to customers with a standard load profile (SLP) were about 86 TWh (2017: 87 TWh) and around 138 TWh (2017: 138 TWh) for interval-metered customers. The aggregate market share of the four largest companies (CR4) in 2018 was around 23% for SLP customers, and thus the same as in the previous year, and about 31% for interval-metered customers (2017: 30%).

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 2018. In 2018, more than 50 gas suppliers were operating in 94% of the network areas. Final consumers in over 62% of network areas had a choice of more than 100 gas suppliers. If viewed separately, the trend for household customers is similarly positive. In nearly 89% of network areas, household customers have a choice of 50 or more gas suppliers. More than 100 gas suppliers are operating in 45% of network areas.

1.4.2 Gas disconnections

The number of disconnections actually carried out by the network operators in 2018 was 33,145, representing a decrease of 17% compared to the previous year (2017: 40,048). This corresponds to 0.2% of gas connections based on all market locations of final consumers.

According to the gas suppliers' data, a disconnection notice is issued when a customer is on average around €120 in arrears. A total of 1.2m disconnection notices were issued to household customers, of which around 0.2m or 17% were passed on to the relevant network operator with a request for disconnection. The suppliers' data shows that a total of around 3% of the notices actually resulted in the customer being disconnected.

The gas suppliers stated that in some 26,731 cases they had disconnected customers with default contracts. This corresponds to 0.2% of household customers on default contracts. According to the suppliers' data, customers with non-default contracts were disconnected in about 11,940 cases, corresponding to 0.1% of non-default customers. The gas suppliers stated that around 10% of disconnections were repeated disconnections of the same customer.

1.4.3 Price level

The volume-weighted gas price for household customers across all contract categories as at 1 April 2019 was 6.34 ct/kWh, representing the first increase in three years. The price increased by around 4.4%. With respect to the individual price components, the largest increases were in energy procurement, supply and margin (+5.7%) and network charges (+4.2%).

The volume-weighted gas price for customers on a default contract as at 1 April 2019 was 7.28 ct/kWh (2018: 6.64 ct/kWh), corresponding to an increase of around 10% compared to the previous year. The volume-weighted gas price for customers on a non-default contract with the default supplier was 6.44 ct/kWh (2018: 6.06 ct/kWh), equivalent to a year-on-year increase of about 6%. The volume-weighted gas price for customers on a contract with a supplier other than the local default supplier was 6.22 ct/kWh (2018: 5.71 ct/kWh), representing an increase of around 9% compared to the previous year.

The average household customer with a gas consumption of 23,250 kWh could save an average of €195 a year as at 1 April 2019 by changing contract. The average potential saving for the year through changing supplier was €245.

The price component "energy procurement, supply and margin" for default supply customers was 3.74 ct/kWh as at 1 April 2019 (2018: 3.29 ct/kWh). This represents an increase of around 14%. The gas procurement costs in the price for customers supplied under a non-default contract with the default supplier increased by around 10% from 3.01 ct/kWh to 3.30 ct/kWh. The gas procurements costs for customers supplied under a contract with a supplier other than the local default supplier increased by around 14% to 3.02 ct/kWh (2018: 2.66 ct/kWh).

Special bonuses offered by gas suppliers, including one-off bonus payments, are an added incentive for customers to switch. These one-off payments amount to an average of €75 to €80.

The gas prices for non-household (industrial and commercial) customers as at 1 April 2019 showed year-on-year increases. The arithmetic mean of the overall price (excluding VAT) for an annual consumption of 116 GWh ("industrial customer") was 2.86 ct/kWh and thus 0.04 ct/kWh or around 1.4% higher than the previous year's figure. The part of the total price controlled by the supplier increased by 0.07 ct/kWh and thus to nearly 70%. The arithmetic mean of the overall price (excluding VAT) for an annual consumption of 116 MWh ("commercial customer") was 4.55 ct/kWh and thus 0.15 ct/kWh or around 3.4% higher than the previous year's figure. The part of the total price controlled by the supplier also increased by 0.15 ct/kWh and thus to nearly 60%.

The prices paid by household and non-household customers in Germany in the second half of 2018 were below the EU average. The net gas price in Germany in the annual consumption range of 27.8 GWh to 278 GWh was 2.65 ct/kWh, which was at the lower end of the scale. The EU average was 2.81 ct/kWh. On an EU average, the net price is subject to about 8% (0.22 ct/kWh) of non-refundable taxes and levies. In this regard, Germany's figure of about 15% (0.40 ct/kWh) is higher than average. Compared with the gas prices for industrial customers, there are relatively large differences between the gas prices for household customers across the EU. The gas price for household customers in Germany was 6.08 ct/kWh and thus around 2% below the EU average (6.20 ct/kWh). Taxes and levies amounted to an average of 1.57 ct/kWh in Germany. The EU average was 1.68 ct/kWh.

2. Network overview

With its determinations on the electricity and gas market communication interim model of 20 December 2016 (BK6-16-200/BK7-16-142) the Bundesnetzagentur required all energy market players to introduce and exclusively use a new identification code to identify market locations and meter locations as from 1 February 2018. In the Monitoring Report 2019 the term "meter point" has therefore been replaced by the terms "market location" and "meter location", as applicable.

Energy is generated or consumed in a market location. The market location is connected to the network by means of at least one line. The market location is a connecting point for supply and balancing.

A meter location is a location at which energy is measured and that includes all technical equipment required to collect and, if necessary, transmit the meter data. All relevant physical quantities at a point in time are collected no more than once at a meter location. The term "meter location" corresponds to the term "meter" within the meaning of section 2 para 11 of the Metering Act (MsbG).

All 16 TSOs took part in the 2019 Monitoring Report data survey. As at 31 December 2018, the length of pipelines in the transmission system was about 38,500 km and included around 3,270 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 registered final customer market locations in the transmission network was around 550 and approximately 173.6 TWh of gas was delivered to final consumers from the DSO network, compared to 183 TWh in 2017. The volume of gas delivered from the DSO network was thus about 5% less than the level of the previous year.

As of 5 November 2019, a total of 708 gas DSOs were registered with the Bundesnetzagentur, 688 (about 97%) of whom took part in the 2019 monitoring survey. As of 31 December 2018, the total length of pipelines in the gas distribution network was around 512,000 km and included about 11.1m 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 2018, there were 14.4m registered final customer market locations in the gas distribution network. The number of market locations for household customers as defined in section 3 para 22 EnWG was 12.5m. Total gas supplies from the network of the DSOs amounted to 754.5 TWh in 2018, down by around 3.9 TWh compared to the previous year.[120] The quantity of gas supplied to household customers as defined in section 3 para 22 EnWG dropped slightly by 3.7 TWh or around 1% to 275.2 TWh.

A simplified comparison between the supply and demand of natural gas in 2018 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 about 1,815 TWh in 2018. Around 4% came from domestic sources (70 TWh), the rest (1,760 TWh) was imported. The balance of gas that entered and exited storage in 2018 amounted to -25 TWh, so there was more gas being

[120] The DSOs' gas supplies figure for 2017 was adjusted to 758.4 TWh following the submission of a data correction.

injected into the storage facilities than withdrawn from them. Moreover, 10.3 TWh of biogas upgraded to natural gas quality was fed into the German natural gas network in the year.

Around 48% (849.1 TWh) of available gas volumes in Germany were transported to neighbouring countries in Europe. Final consumers used 928.1 TWh of gas in Germany.

Gas: gas available and gas use in Germany in 2018
(TWh)

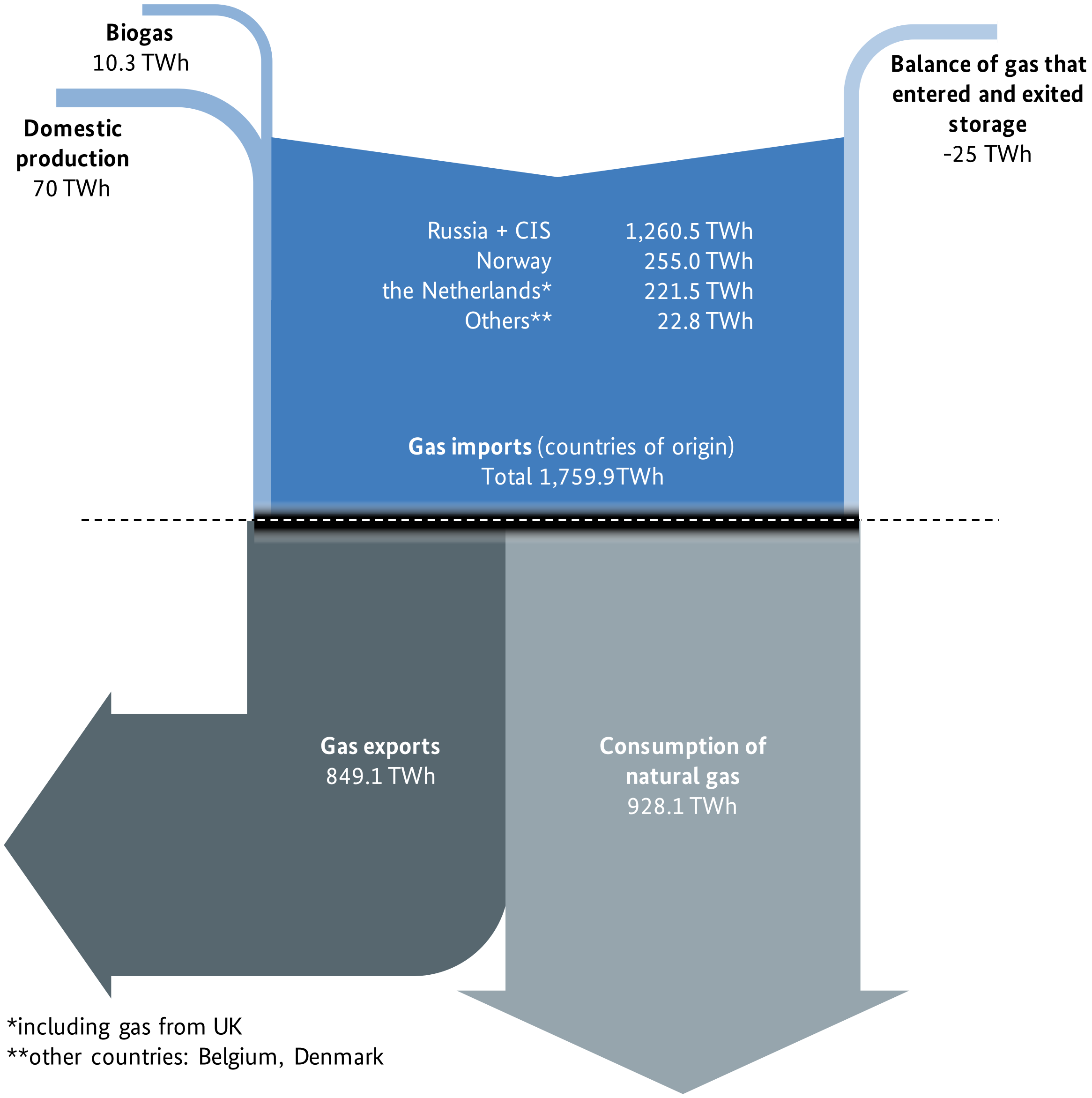


Figure 148: Gas available and gas use in Germany in 2018[121]

[121] Because of the infrastructure in place, recorded import volumes may also include transit flows or loop flows (eg volumes of gas that leave Germany at the Olbernhau cross-border interconnection point using the GAZELLE gas pipeline and then re-enter the German network at the Waidhaus cross-border interconnection point). These loop flows are not shown in the diagram.

Gas: number of gas network operators in Germany registered with the Bundesnetzagentur

	2014	2015	2016	2017	2018	2019
Transmission system operators (TSOs)	17	17	16	16	16	16
Distribution system operators (DSOs)	714	714	715	717	718	708
DSOs with fewer than 100,000 connected customers	689	689	690	692	693	683
DSOs with fewer than 15,000 connected customers*	492	495	497	510	510	508

*Data based on data from gas DSOs. Differences result from the different annual populations.

Table 109: Number of gas network operators in Germany registered with the Bundesnetzagentur as at 5 November 2019

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 the table below.

The majority of gas DSOs (598 operators) have short to medium length networks of up to 1,000 km, but 79 DSOs have gas networks with a total length of more than 1,000 km. The following figure shows a percentage breakdown of DSOs according to network length:

Gas: DSOs by pipeline network length
number of network operators and share f total

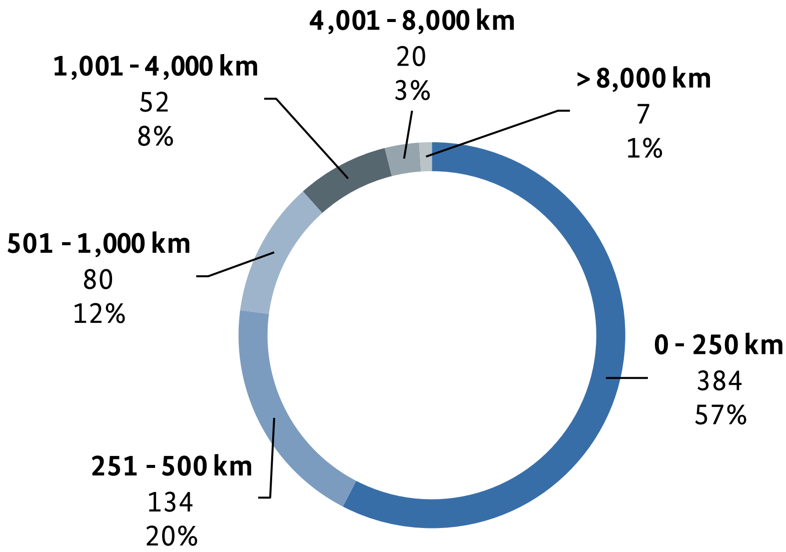


Figure 149: DSOs by gas pipeline network length as stated in the DSO survey– as at 31 December 2018

Gas: 2018 network structure figures

	TSOs	DSOs	Total no of TSOs and DSOs
Network operators (number)	**16**	**688**	**704**
Network length (km)	**38.5**	**512.2**	**550.7**
≤ 0.1 bar	0	176.8	176.8
> 0.1 – 1 bar	0	249.0	249.0
> 1 bar	38.5	86.4	124.9
Number of offtake points (thousand)	**3.5**	**11,100.0**	**111,003.5**
≤ 0.1 bar	0.0	6.3	6.3
> 0.1 – 1 bar	0.0	4.5	4.5
> 1 bar	3.5	0.3	0.3
Market locations and final consumers (thousand)	0.6	14,440.0	14,440.6
Industrial and commercial customers and other non-household customers	0.6	1,600.0	1,600.6
Household customers	0.0	12,840.0	12,840.0

Table 110: 2018 network structure figures according to the TSO and DSO survey– as at 31 December 2018

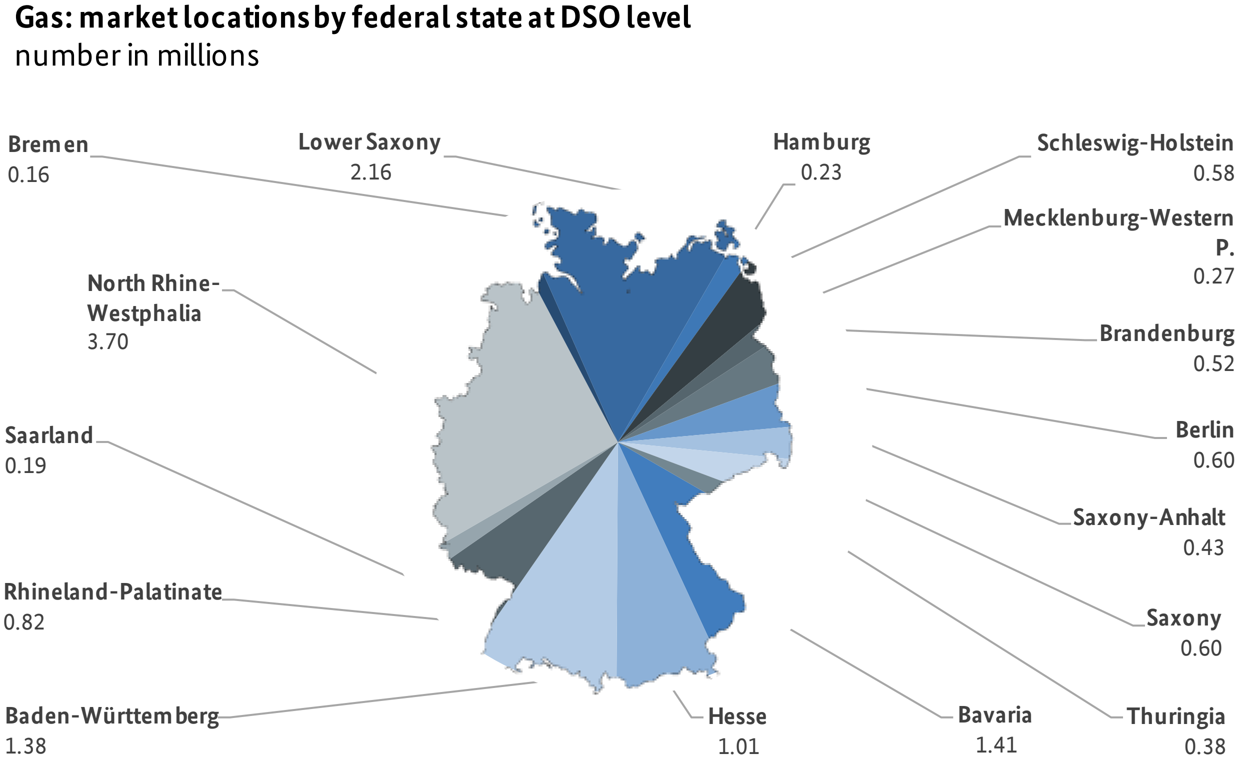


Figure 150: Market locations by federal state at DSO level as stated in the DSO survey – as at 31 December 2018

Gas: market locations by federal state at TSO level
number

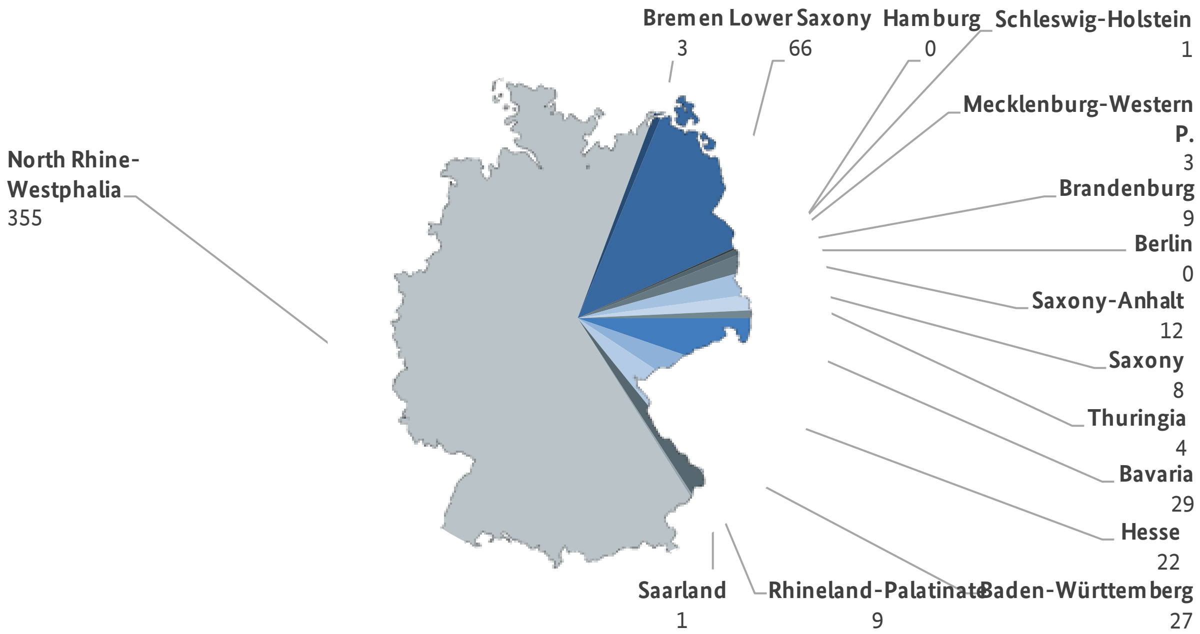


Figure 151: Market locations by federal state at TSO level as stated in the TSO survey – as at 31 December 2018

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 2018.

Gas: exit volumes in 2018 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	<0,1	<0,1%	332.8	44.1%
> 300 MWh/year ≤ 10,000 MWh/year	0.5	0.3%	125.6	16.6%
> 10,000 MWh/year ≤ 100,000 MWh/year	5.8	3.3%	106.6	14.1%
> 100,000 MWh/year	129.4	74.5%	139.5	18.5%
Gas-fired power plants with ≥ 10 MW net nominal capacity	37.8	21.8%	50.0	6.6%
Total	173.6	100%	754.5	100%

Table 111: Gas exit volumes in 2018 broken down by final consumer category, according to the survey of gas TSOs and DSOs

The following consolidated overview includes the total gas exit volumes of TSOs and DSOs and the quantity of gas provided to final consumers by suppliers for 2018. Once again, gas TSOs and DSOs were asked in the 2018 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 traditional 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 72.5 TWh (2017: 80.7 TWh), equivalent to about 42% of the total quantity of gas delivered by TSOs to final consumers. As regards gas distribution networks, the amount of gas procured without a conventional supplier contract amounted to 39.8 TWh, compared with 38 TWh in 2017, corresponding to a share of approximately 5% of the DSOs' total gas supplies.

The difference between the 2018 exit volumes of the system operators, 928.1 TWh (2017: 941.7 TWh,)[122]) and the gas delivered by gas suppliers, 817.6 TWh (2017: 830.1 TWh) is approximately equivalent to the amount of gas procured directly on the market without using a supplier (112.3 TWh).[123]

[122] The DSOs' gas supplies figure for 2017 was adjusted to 758.4 TWh following the submission of a data correction. The total quantity of gas supplied by TSOs and DSOs in 2017 therefore amounted to 941.7 TWh.

[123] Variations in data quality and response frequency mean that the difference calculated is slightly over the figure calculated for gas procured on the market.

Gas: total exit volumes in 2018, according to the survey of gas TSOs and DSOs and total volumes of gas delivered according to gas supplier survey, broken down by final customer category

	TSO and DSO exit volume (TWh)	Share of total	Total volume of gas delivered by suppliers (TWh)	Share of total amount
≤ 300 MWh/year	332.9	35.9%	317.5	38.8%
> 300 MWh/year ≤ 10,000 MWh/year	126.1	13.6%	112.6	13.8%
> 10,000 MWh/year ≤ 100,000 MWh/year	112.4	12.1%	99.7	12.2%
> 100,000 MWh/year	268.9	29.0%	221.2	27.0%
Gas-fired power plants with ≥ 10 MW net nominal capacity	87.8	9.5%	67.6	8.3%
Total	928.1	100.0%	818.6	100.0%

Table 112: Total gas exit volumes in 2018, according to the survey of gas TSOs and DSOs and total volumes of gas delivered according to gas supplier survey

The total quantity of gas supplied by general supply networks in Germany fell in 2018 by about 13.6 TWh or just over 1.4% year-on-year to 928.1 TWh. The quantity of gas supplied to household customers (as defined in section 3 para 22 EnWG) rose by just over 1.3% to 275.2 TWh (2017: 278.8 TWh). Gas supplies to gas-fired power stations with a nominal capacity of at least 10 MW fell, after several years of increases. Gas supplies in 2018 totalled 87.8 TWh (2017: 98.1 TWh), just over 10% lower than in 2017.

The structure of the gas retail market remained for the most part unchanged. There is a total of 6,142 entry points to the gas distribution networks, of which 211 are for emergency entry only. A look at the number of market locations served by the DSOs shows that only 26 DSOs supply more than 100,000 each. Out of a total of 14.4m market locations supplied by the DSOs in Germany, some 45% (6.4m), accounting for just over 43% (326.9 TWh) of the total gas supplies, are served by DSOs that supply more than 100,000 customers. The majority (about 60%) of DSOs active in Germany supply between 1,000 and 10,000 gas customers.

Gas: DSOs by number of market locations supplied
number and distribution

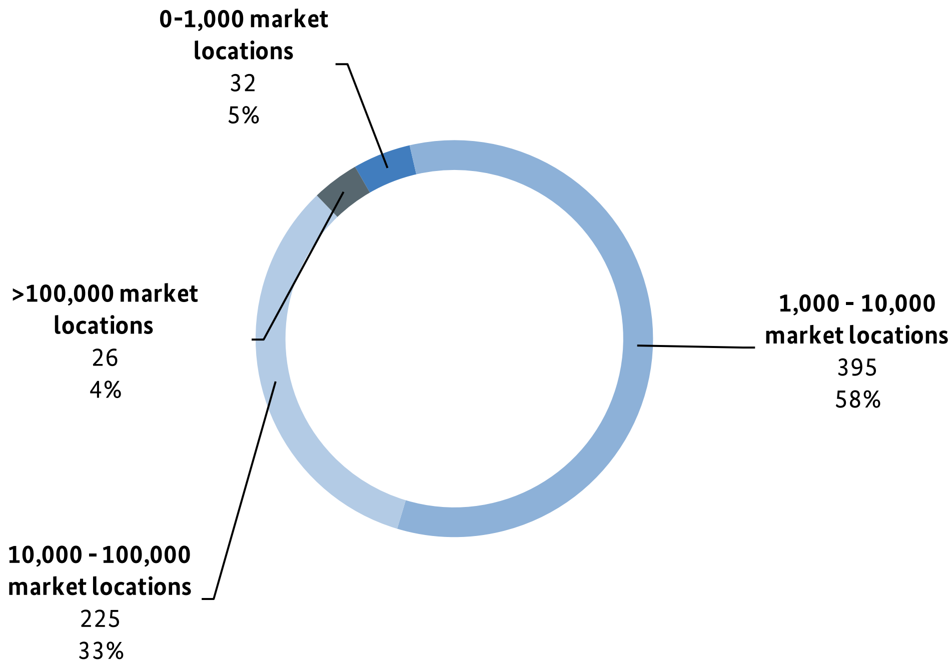


Figure 152: DSOs by number of market locations supplied (data from the gas DSO survey) – as at 31 December 2018

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.[124] 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. A key parameter for measuring the degree of market concentration on the gas markets is the working gas volume in underground natural gas storage facilities, which represents the highest market level.

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

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

including the Haidach and 7Fields storage facilities in Austria.[125] 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 but ultimately left open the exact market definition.[126] The Haidach and 7Fields storage facilities in Austria will be fully included in the following assessment to illustrate the concentration in the market for the operation of underground natural gas storage facilities. Data was therefore collected from 24 legal entities. The Bundeskartellamt calculates the market shares in this market on the basis of storage capacities (maximum usable working gas volume).[127] Companies were attributed to a group according to the dominance method (cf. the methodological notes in section "Electricity market" I.A.3 Market concentration, p. 41).

The market for the operation of underground natural gas storage facilities is still highly concentrated, although concentration eased to a certain extent 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 market concentration assessment was around 296.4 TWh on 31 December 2018 (in 2017: 299.0 TWh). On 31 December 2018, the aggregate working gas volume of the three companies with the largest storage capacities amounted to approx. 198.9 TWh (2017: 204.7 TWhWh). The CR3 value was around 67.1% and was slightly lower than in the previous year (CR3 value: 68.2%)

Development of working gas volumes of natural gas storage facilities in TWh and the shares of the three largest suppliers

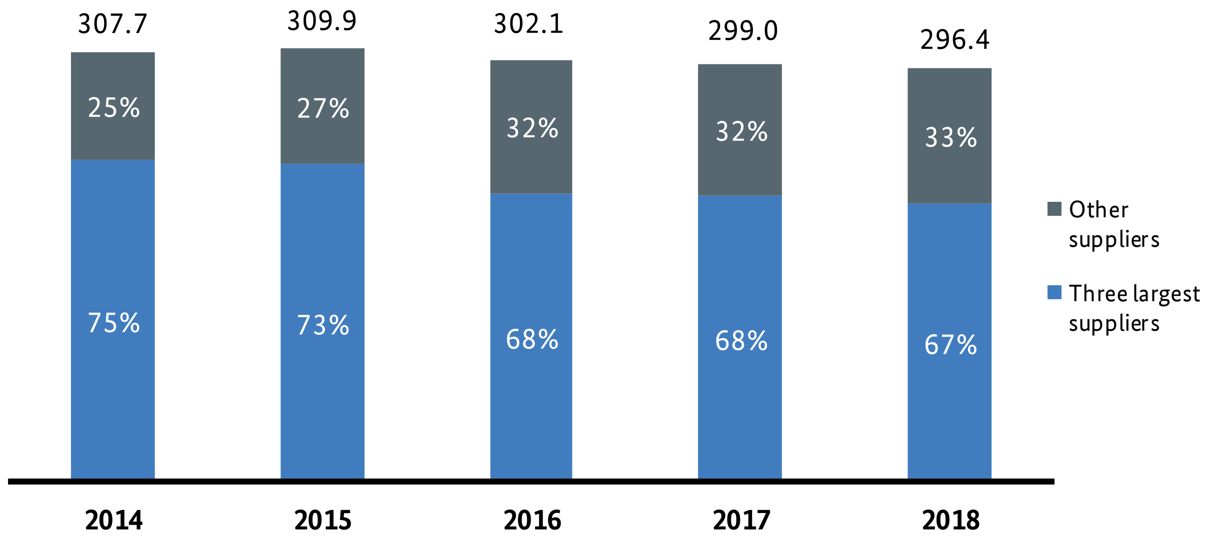


Figure 153: Development of the working gas volumes of natural gas storage facilities in TWh and the shares of the three largest suppliers

[125] Cf. Bundeskartellamt, decision of 23 October 2014, B8-69/14 – EWE/VNG, para. 215 ff., Bundeskartellamt, decision of 31 January 2012, B8-116/11 - Gazprom/VNG para. 208 ff.

[126] Cf. COMP/M.6910 – Gazprom/Wintershall of 3.12.2013. para. 30 ff.

[127] Cf. Bundeskartellamt, decision of 23.10.2014, B8-69/14 – EWE/VNG, para. 236 ff.

3.2 Gas retail markets

On the gas retail markets the Bundeskartellamt differentiates between customers with metered load profiles and those with standard load profiles. Metered load profile customers are customers whose gas consumption is determined on the basis of a recording load profile measurement. 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. These are usually 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. see the comments in "Market concentration" chapter I.A.3 from page 41). 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.[128]

In energy monitoring the sales volumes of the individual suppliers (legal entities) are collected as national total values [129]. In the survey a differentiation is made between default supply to standard load profile customers and supply on the basis of special contracts. The following analysis is based on the data provided by around 993 gas suppliers (legal entities) (966 in the previous year). In 2018 these companies sold a total of approx. 367.4 TWh of gas to standard load profile customers in Germany (378 TWh in the previous year) and 450.1 TWh of gas to customers with metered load profiles (454 TWh in the previous year). Of the total volume of sales to standard load profile customers, special contracts accounted for approx. 313.4 TWh (321 TWh in the previous year) and default supply contracts for 54.0 TWh. (58 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 and in particular allows for year-on-year comparisons on a homogenous and ongoing calculation basis (see methodological notes in section I Electricity market, "Market Concentration" section, p. 44).

The Monitoring Report analyses the market concentration (CR) of the four strongest companies on the gas retail market. The cumulative sales of the four strongest companies to customers with standard load profiles amounted to around 85.6 TWh in 2018, of which approx. 72.7 TWh consisted of special contracts. Cumulative sales to customers with metered load profiles were around 138.4 TWh. The cumulative market share of the four largest companies in 2018 was around 23% for standard load profile customers (2017: CR4: 24%) and 31% for interval-metered customers (2017 CR4: 30%). Both market shares continue to be significantly below the statutory thresholds for the presumption of market dominance (Section 18(6) GWB). There was thus only a slight change in the market concentration of the four strongest companies supplying gas to standard load profile customers and interval-metered customers. 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.

[128] Cf. Bundeskartellamt, decision of 23 December 2014, B8-69/14 – EWE/VNG, para. 129-214.

[129] Sales here, as in the entire subsection "Gas retail markets" consist of the volume of gas which the suppliers supply to their customers in energy-working units

Share of the four strongest suppliers in the sale of gas to metered load profile (RLM) and standard load profile (SLP) customers in 2018

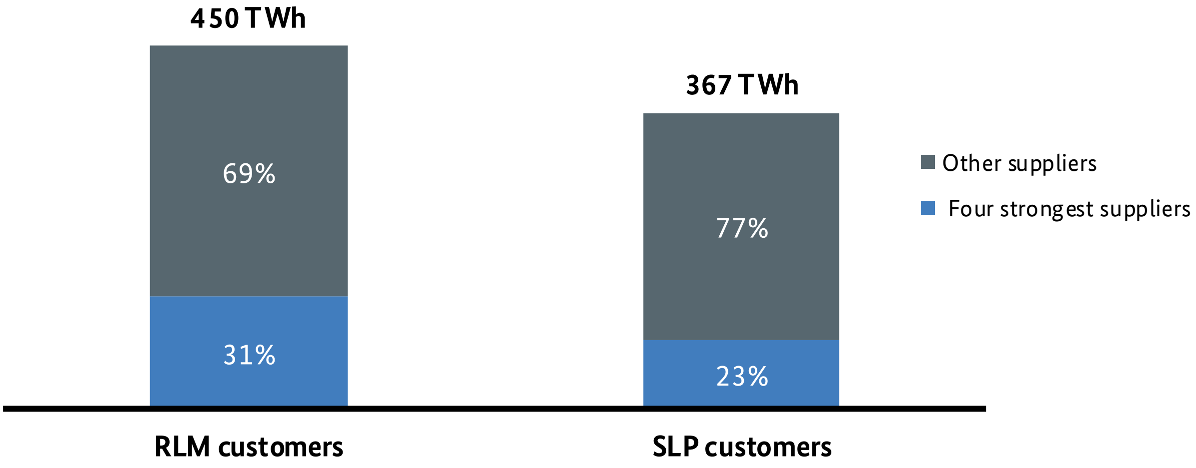


Figure 154: Share of the four strongest suppliers in the sale of gas to metered load profile (RLM) and standard load profile (SLP) customers in 2018

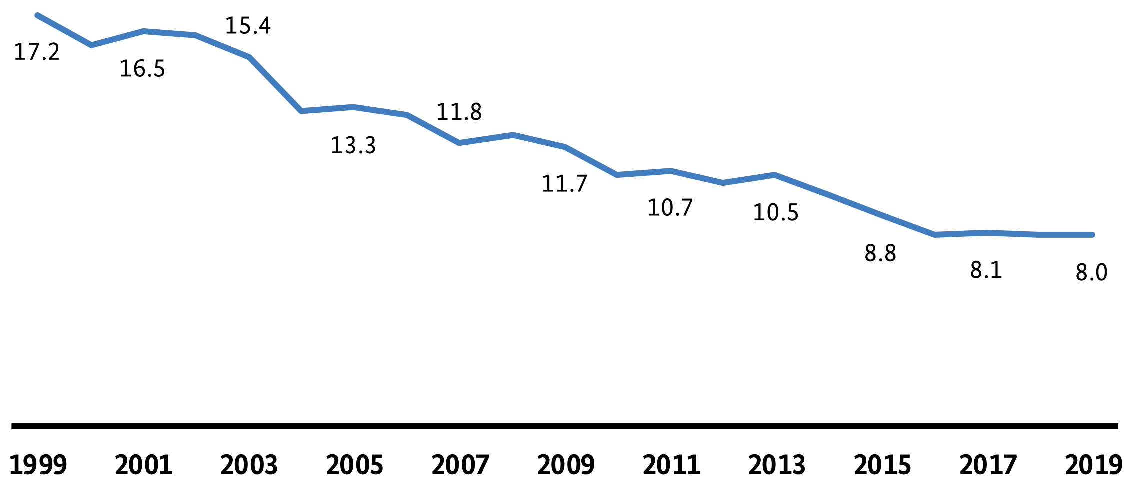
B Gas supplies

1. Production of natural gas in Germany

In 2018, natural gas production in Germany fell by 1bn m^3 to 6.2bn m^3 of gas (with calorific adjustment).[130] This corresponds to a decrease of 13.3% compared to 2017. The decline in production is chiefly due to the increasing exhaustion of the large deposits and the resulting natural decline in output.[131] Another factor is the lack of major new gas finds.

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 8.0 years as at 1 January 2019, the same as in the previous year. 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.[132]

Gas: reserves-to-production ratio of German natural gas reserves (years)



Source: State Authority for Mining, Energy and Geology (LBEG), Lower Saxony

Figure 155: Reserves-to-production ratio of German natural gas reserves since 1999

[130] 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 from 2 kWh/m^3 to 12 kWh/m^3).

[131] Source: Annual report "Erdöl- und Erdgasreserven in der Bundesrepublik Deutschland am 1. Januar 2018" [Crude Oil and Natural Gas Reserves in the Federal Republic of Germany as at 1 January 2018]; State Authority for Mining, Energy and Geology (LBEG), Lower Saxony.

[132] Ibid.

2. Natural gas imports and exports

Just over 70% of gas imported into Germany comes from Russia and the Commonwealth of Independent States (CIS). Imports from Russia (including CIS) rose about 15% year-on-year, while imports from Norway and the Netherlands declined.

Germany's geographical position gives it the status of a gas hub, with gas imports arriving in the country largely being passed on, often to France and the Netherlands.

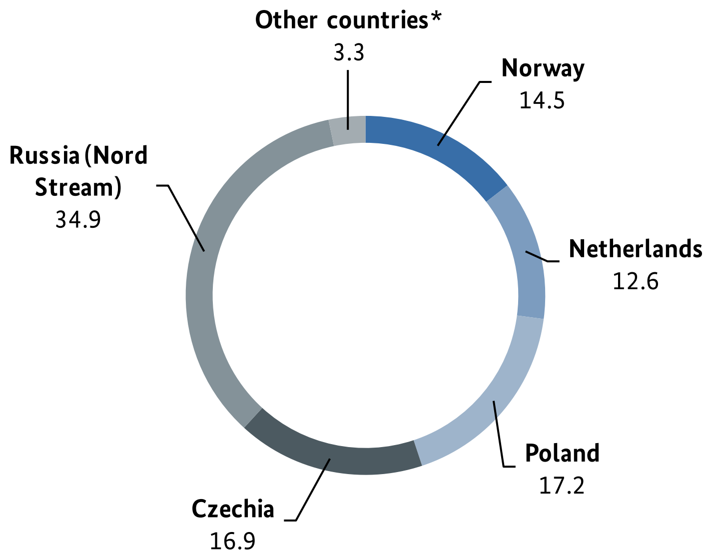
Domestic production is becoming less significant each year as deposits run out.

The monitoring report bases its assessment of imports and exports on the physical gas flows that enter and exit Germany at cross-border interconnection 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 interconnection point using the GAZELLE gas pipeline and then re-enter the German network at the Waidhaus cross-border interconnection point).

In 2018, the total volume of natural gas imported into Germany was 1,760 TWh. Based on the previous year's figure of 1,676 TWh, imports to Germany increased by 83 TWh or just over 5%. When looking at the countries of origin, the focus here is on the countries that Germany imports from at their given cross-border interconnection point. Imports from Norway dropped by just over 11%, while imports from Russia through the Nord Stream pipeline rose by 14.9%.

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 have eased trading and provided further alternatives for gas traders.

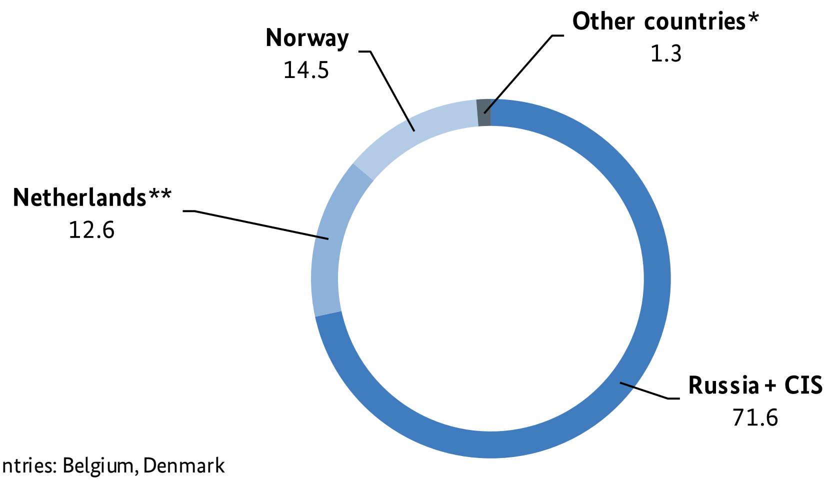
Gas: volumes imported to Germany (physical load flows) in 2018, according to transfer country (%)



* Other countries: Belgium, Denmark, Austria

Figure 156: Gas volumes imported to Germany in 2018, according to transfer country

Gas: volumes imported to Germany (physical load flows) in 2018, accourding to source country
(%)

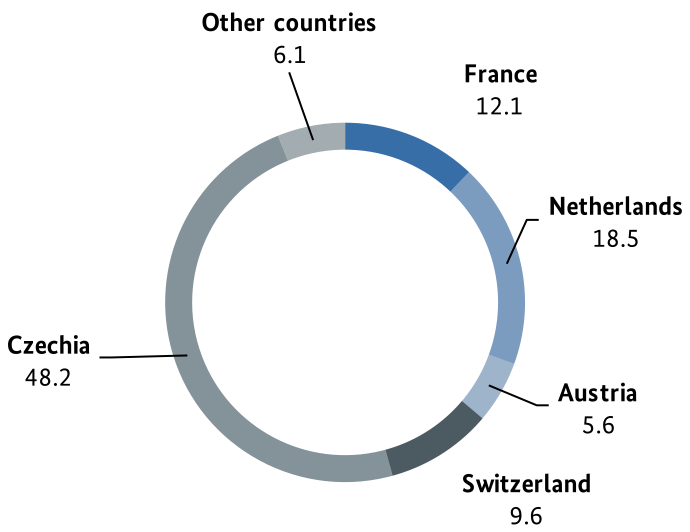


* Other countries: Belgium, Denmark
** Includes gas from UK

Figure 157: Gas volumes imported to Germany in 2018, according to source country

In 2018, the total volume of natural gas exported by Germany was 849.1 TWh. Compared to the previous year's figure of 743.5 TWh, exports from Germany increased by 105.6 TWh (14%). When looking at the destination countries, the focus here is on the countries that Germany exports to at their given cross-border interconnection point. Around 48% (previous year: 50%) of German natural gas exports went to Czechia, an increase of 10% compared to the previous year's figures. There was a clear increase in exports to Luxembourg (+67.1%) and the Netherlands (+54.2%) and a clear decrease in exports to Poland (25.9%) and Austria (8.9%).

Gas: volumes exported from Germany (physical load flows) in 2018, according to importing country
(%)



* Other countries: Belgium, Denmark, Luxembourg, Poland

Figure 158: Gas volumes exported from Germany in 2018, according to importing country

The tables below provide a consolidated overview of 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 2018 and 2017.

Gas: changes in imports (physical load flows)

Transfer country	Imports 2018 (TWh)	Imports 2017 (TWh)	Year-on-year change (TWh)	Year-on-year change (%)
Russia (Nord Stream)	614.6	535.0	79.6	14.9
Poland	313.5	305.8	7.7	2.5
Czechia	297.4	226.9	70.5	31.1
Norway	255.0	286.1	-31.1	-10.9
Netherlands	221.5	266.7	-45.2	-16.9
Austria	35.1	22.3	12.8	57.1
Belgium	16.8	29.6	-12.8	-43.3
Denmark	6.0	4.1	1.9	46.4
Total	1,759.9	1,676.5	83.4	5.0

Table 113: Changes in gas imports between 2018 and 2017

Gas: changes in exports (physical load flows)

Importing country	Exports 2018 (TWh)	Exports 2017 (TWh)	Year on year change (TWh)	Year on year change (%)
Czechia	408.8	370.6	38.3	10.3
Netherlands	156.8	101.6	55.1	54.2
France	102.4	83.9	18.5	22.0
Switzerland	81.3	86.7	-5.5	-6.3
Austria	47.5	52.1	-4.6	-8.9
Belgium	43.8	39.4	4.4	11.2
Poland	4.7	6.3	-1.6	-25.8
Luxembourg	2.9	1.7	1.1	67.0
Denmark	1.0	1.1	-0.1	-5.0
Total	849.1	743.5	105.6	14.2

Table 114: Changes in gas exports between 2018 and 2017

According to the survey of gas suppliers and wholesalers, there are 25 companies importing gas into and 19 companies exporting gas from Germany.

3. Market area conversion

Over the next few years, gas supplies in north-western Germany will be converted from L-gas to H-gas. Almost 5m appliances burning L-gas, such as gas cookers, gas-fired boilers and heating systems, have to be converted.

The conversion costs are shared evenly across all gas customers in Germany in the form of a charge. In 2018 this charge amounted to €0.2587 kWh/h/a. As a result of the increasing numbers of areas being converted, the charge for 2019 rose to €0.3181 kWh/h/a, and in 2020 it will increase to €0.579 kWh/h/a. While the conversion charge is not specified separately on consumers' gas bills, indirectly it leads to higher tariffs. Crucially, owners of appliances requiring adjustment must not be charged for hours worked or for materials needed for the technical adjustment.

The procedure for conversion is as follows: before the conversion itself is carried out, employees of the network operator visit the customers and register all gas appliances. On the date set for the conversion (about a year after the appliances are registered), skilled technicians carry out any necessary modifications of the appliances, such as replacing burner nozzles or adjusting the settings. In a small number of cases technical adjustment of the appliance is not possible, for instance because the manufacturer has gone out of business. In such cases customers have to replace the appliance at their own expense. Claims for reimbursement of up to €600 for gas heating can be made against the network operator under section 19a EnWG and the Gas Appliance Reimbursement Ordinance (GasGKErstV). Further details and information on any other subsidies that may be available are provided on the Bundesnetzagentur website or by the network operator. At a later date, network operator personnel carry out random inspections to monitor the converted appliances.

These employees always call ahead suggesting a date for an appointment, never visit without prior arrangement and always carry the relevant identification.

Market area conversion, ie the conversion from low-calorific L-gas to high-calorific H-gas coordinated by the TSOs, is a central issue for gas supply. H-gas is mainly produced in Russia and Norway and has a higher calorific value than L-gas. Since the two types of gas have very different calorific values, they must be transported via separate transmission systems so that each heating appliance can be supplied with the appropriate gas. Technical adjustment of heating appliances in the course of the market area conversion is therefore essential to guarantee safe operation in future.

L-gas regions in the northern and western parts of Germany are having to be converted because of continually falling domestic production and declining volumes of L-gas imported from the Netherlands. According to current estimates, no more gas will be exported from the Netherlands to Germany as of 1 October 2029. The resulting scarcity of L-gas resources means that L-gas will largely disappear from the German gas market by 2030. This is why the companies responsible, namely the TSOs and affected DSOs, are taking the necessary steps to prevent the declining availability of L-gas from adversely affecting the security of supply. The new natural gas supply structure will affect more than four million household, commercial and industrial customers with an estimated 4.9m appliances burning gaseous fuels. All of these appliances must gradually be converted from L-gas to H-gas.

The conversion of German L-gas networks to supply H-gas started well in 2015 with the conversion of smaller network areas. Some larger network operators such as Westnetz, Avacon and wesernetz Bremen are now also in the process of converting their networks.

Gastransport Nord, Gasunie Deutschland Transport Services, Nowega, Open Grid Europe and Thyssengas are the 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, 950 were left and one year later, 922. In 2018, the figure was 900.

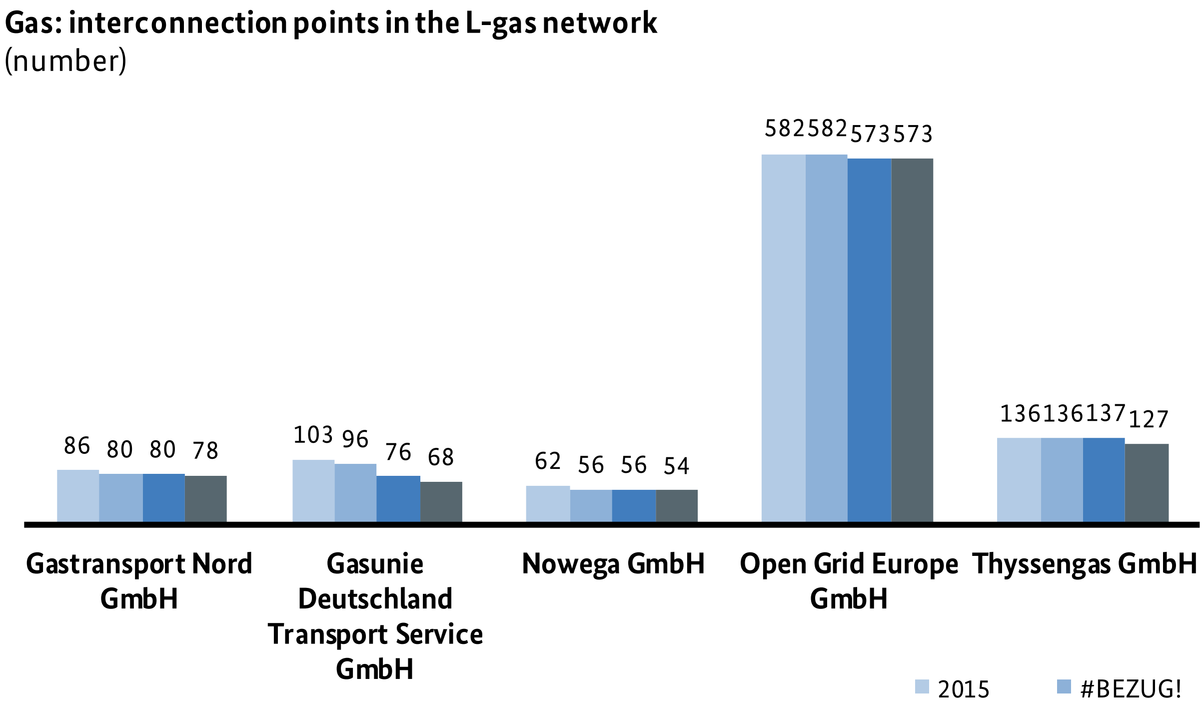


Figure 159: Interconnection points in the L-gas network, 2015 to 2018

The planned conversions by individual network operators tend to take place in months when less gas is consumed, from April to October. Between 2019 and 2024, a total of 3,358 conversions will have been carried out for interval-metered customers and 2,269,430 for standard load profile (SLP) customers.

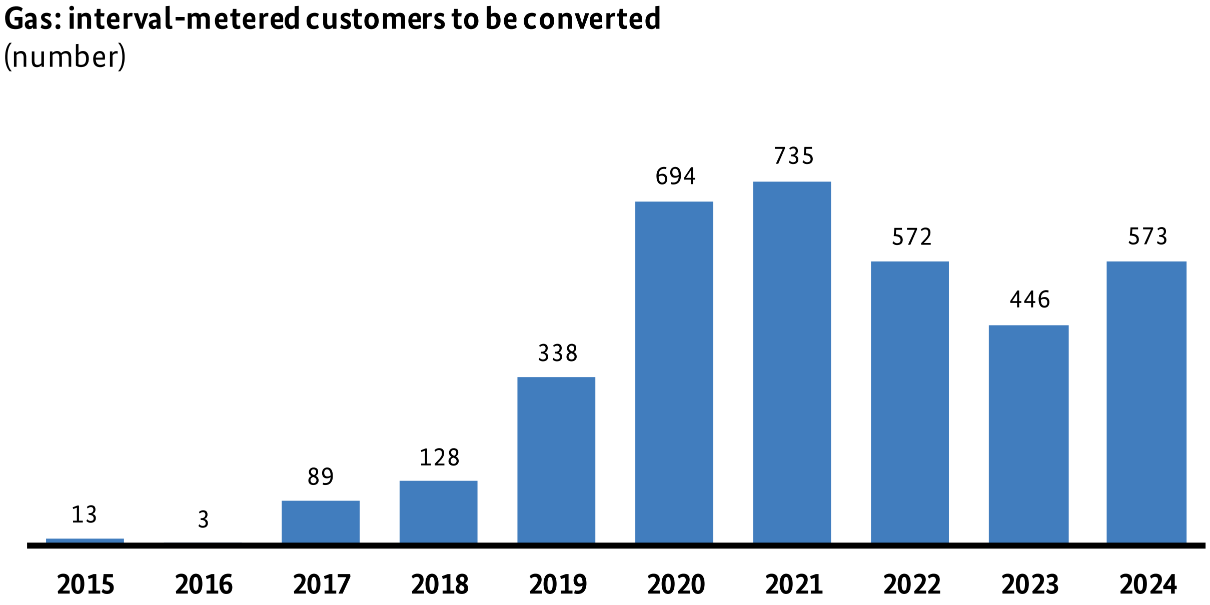


Figure 160: Interval-metered customers to be converted by 2024

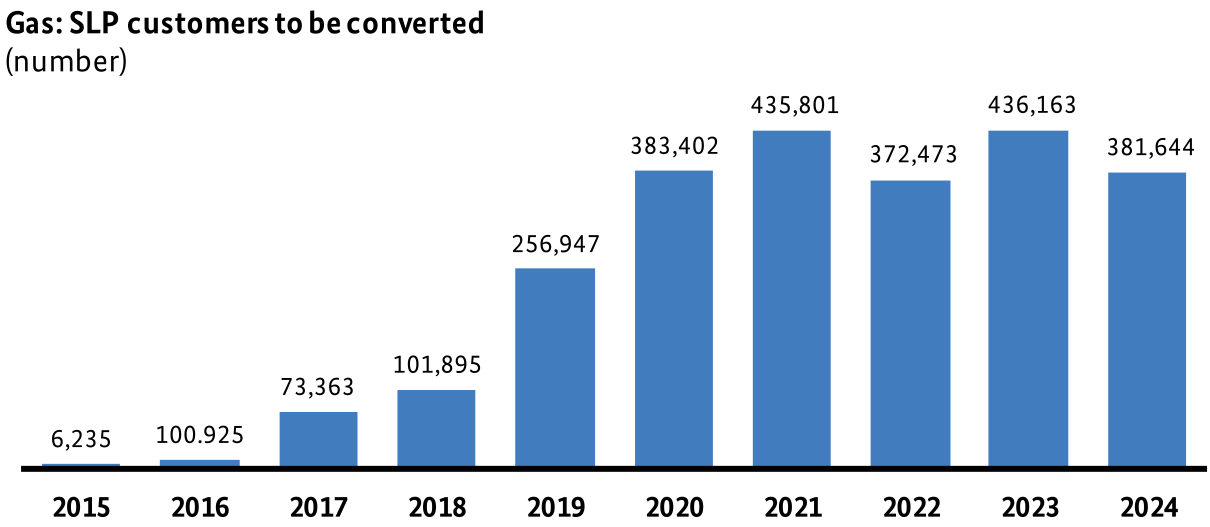


Figure 161: SLP customers to be converted by 2024

To cope 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, a list is compiled of all appliances burning gaseous fuels that are connected to 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 are adapted to match the new gas quality. In most cases, this 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 40 active companies, up from 31 a year ago. There continued to be a high response rate to the calls for bids from the network operators to carry out this work in 2018. In contrast to the previous year's survey, fewer companies are now sharing one package, especially for the services relating to registration and to conversion and adjustment. This is due to the fact that many companies have reached a size that allows them to carry out the work themselves and that there is less coordination required of network operators if they commission fewer companies. As a result of the rapidly growing number of appliances that require adjustment, companies sometimes have to carry out several assignments in parallel. This has hitherto been largely successful, but considerably more staff will be needed in the coming years as adjustments peak at around 550,000 appliances a year.

On average, 7.3 service providers bid for the "registration of appliances" package, of which, on average, 2.6 bids were successful. On average, 4.5 companies submitted bids for the "monitoring registration" package, of which, on average, exactly one company was successful. On average, 7.4 bidders bid for the "conversions and appliance adjustments" package, which was assigned to, on average, 2.6 companies. On average, 4.6 bids were submitted for the "inspection of conversions and appliance adjustments" package, of which, on average, exactly one company was successful. On average, 4.4 companies were interested in taking on the important tasks of the project management team. In this case, on average, only one company was successful in its bids.

Gas: bids and awards for individual task packages for the market area conversion

Task package	Bids			Awards		
	2016	2017	2018	2016	2017	2018
Appliance registration	5.8	7.1	7.3	2.1	3.8	2.6
Monitoring the registration process	4.7	5.2	4.5	1.2	1.2	1.0
Conversion and appliance adjustments	5.7	7.0	7.4	2.2	3.7	2.6
Inspection of conversions and appliance adjustments	4.5	5.2	4.6	1.1	1.5	1.0
Project management	4.0	4.2	4.4	1.1	1.1	1.0

Table 115: Comparison of bids and awards for individual task packages for the market area conversion, 2016 to 2018

From a total of 30 network operators, 462,802 appliances were registered in 2018, of which 202,643 were condensing boilers (43.8%) and 36,147 self-adaptive appliances (7.8%). The proportion of condensing boilers had only been 32.9% in 2017 and that of self-adaptive appliances 7.8%. During the reporting period, 128,863 appliances were adapted for SLP customers and 186 for interval-metered customers. A total of 2,232 appliances, or just 1.7% of those due to be adjusted, could not be adapted, down from 3% in the previous year. A total of 1,210 customers made use of the entitlement for a €100 rebate granted under section 19a(3) EnWG for the purchase of a new appliance that does not require adaptation in the course of market area conversion (2017: 457). Only 19 customers made use of the reimbursement granted under the Gas Appliance Reimbursement Ordinance (GasGKErstV), compared to two in 2017.

The market area conversion poses a variety of challenges to the various groups involved, 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 a market area conversion forum, the fourth of its kind, in 2019 to allow affected parties the opportunity to obtain information and participate in discussion. Along with the latest report on gas production from the Netherlands economics ministry and the overview of the whole process provided by network operators, this year's event focused on the customer's viewpoint of the market area conversion. The challenges facing industrial customers in the years ahead, even when all their appliances have been converted to H-gas, were up for discussion. There will be far greater fluctuations in gas quality within the permissible range in future owing to the varied sources of supply. The consumer advice centres of Lower Saxony and Bremen presented the most common causes for complaint of final consumers. However, network operators were also praised for their successful efforts to make the changeover process as easy as possible for customers. Information about these events can be found on the Bundesnetzagentur website.[133]

According to data submitted by the two market area managers, NetConnect Germany GmbH & Co. KG and GASPOOL Balancing Services GmbH, a total of €506m was spent on the market area conversion charge referred to in section 19a EnWG between 2015, when the charge was first levied, and 2020 (planning costs for 2020 are included). In 2018 this charge amounted to €0.2587 kWh/h/a nationwide. As a result of the increasing numbers of areas being converted, the charge for 2019 rose to €0.3181 kWh/h/a, and in 2020 it will increase to €0.579 kWh/h/a. The rise is due in particular to the large increase in the number of appliances to be converted and associated costs. Moreover the number of points at which the market area conversion charge is levied has fallen. From 2020, the charge will no longer be levied at interconnection points to other market areas or storage facilities, as set out in the REGENT determinations made by Ruling Chamber 9 (BK9-18/610-NCG and BK9-18/611-GP). It therefore follows that additional revenue from increased capacity bookings will bring down the market area conversion charge. Over the course of the next few years, the market area conversion charge is expected to rise further as a result of the growing number of adjustments to appliances being carried out.

[133] Forums on 27 April 2016, 26 April 2017 and 18 April 2018

Gas: Market area conversion in individual network areas over the coming years

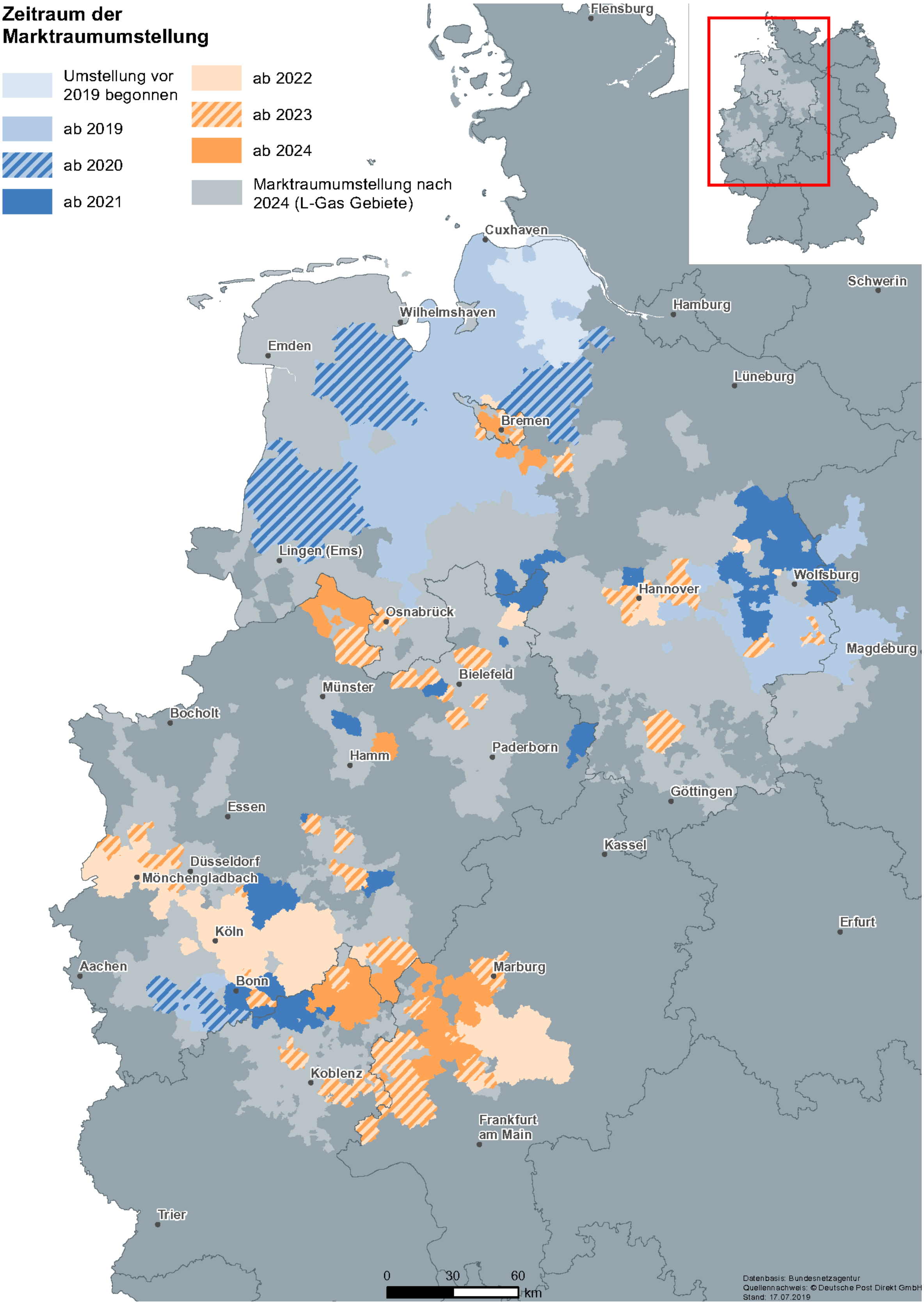


Figure 162: Market area conversion in individual network areas over the coming years

4. Biogas (including synthesis gas)

As at 31 December 2018, key biogas injection figures within the meaning of section 3 para 10c EnWG were as follows:

Gas: biogas injection key figures in 2018

	Injection (million kWh/a)	Number of plants
Biomethane	9,610.0	191
Hydrogen produced by water electrolysis provided that the electricity used to perform electrolysis is mainly and verifiably derived from renewable energy sources within the meaning of Directive 2009/28/EC (OJ L 140, 5 June 2009, p 16)	1.4	3
Synthetically produced methane provided that the electricity used to perform electrolysis and the carbon dioxide or carbon monoxide used for methanation are mainly and verifiably derived from renewable energy sources within the meaning of Directive 2009/28/EC (OJ L 140, 5 June 2009, p 16)	1.1	2
Other (gas from biomass, landfill gas, sewage treatment plant gas and mine gas)	754.0	25
Total	10,366.5	221

Table 116: Biogas injection, key figures for 2018

The costs for biogas passed on by gas network operators to all network users amounted to about €199.5m in 2018. That was the equivalent of about €0.0192 per kWh of biogas consumed, which is approximately the same as the average over several years as there is a close correlation between the network operators' costs and injected volumes.

5. Gas storage facilities

5.1 Access to underground storage facilities

Twenty-four companies operating and marketing a total of 33 underground natural gas storage facilities took part in the 2019 monitoring survey. On 31 December 2018 the maximum usable working gas volume in these storage facilities was 280.02 TWh.[134] Of this, 134.12 TWh was accounted for by cavern storage, 123.89 TWh by pore storage facilities and 22.01 TWh 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 (257.26 TWh, compared to 22.77 TWh for L-gas).

Gas: maximum usable volume of working gas in underground natural gas storage as at 31 December 2018 (TWh)

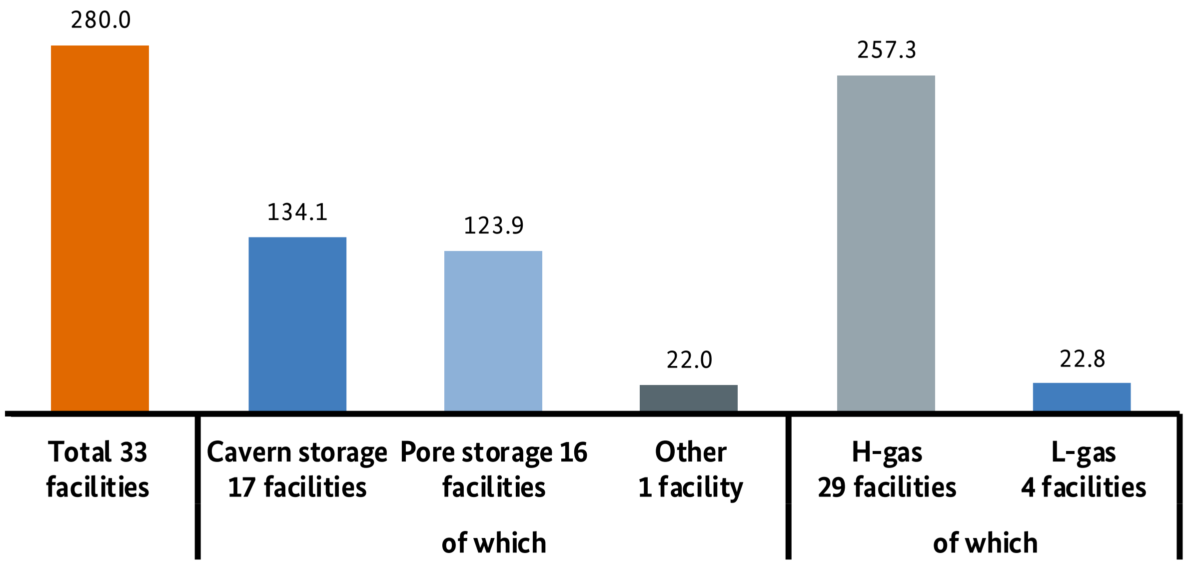


Figure 163: Maximum usable volume of working gas in underground natural gas storage facilities as at 31 December 2018

[134] 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 network in the Netherlands, are not taken into account since they have no direct impact on the German gas network.

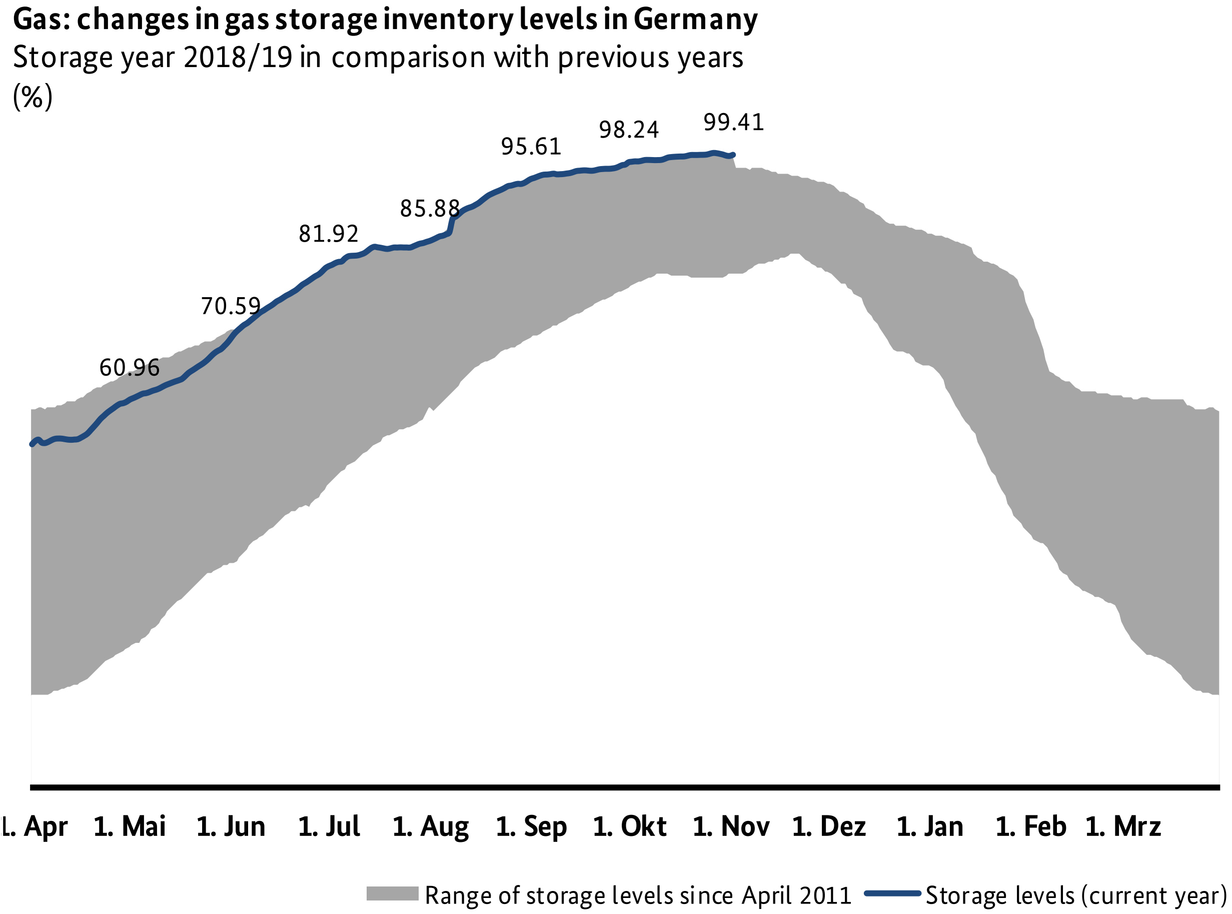


Figure 164: Changes in gas storage inventory levels in Germany – as at 1 November 2019

Owing to the mild winter 2018/2019, the storage level at natural gas storage facilities in Germany at the beginning of the storage year 2019/20 still stood at over 50%. Due to the good supply of gas and low prices in the gas markets, the storage facilities were filled to a very good level during the summer half-year. On 1 November 2019, the total storage level stood at over 99%.

5.2 Use of underground storage facilities for production operations

Production operations involve the use of storage facilities by companies that produce gas in Germany. In 2018, around 0.5% of the maximum usable volume of working gas in underground 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 278.62 TWh in 2018 (compared to 278.68 TWh in 2017). The total injection capacity was 151.00 GWh/h and the withdrawal capacity was 292.00 GWh/h.

5.3 Use of underground storage facilities – customer trends

According to the data provided by 24 companies, the average number of storage customers in 2018 was 5.3, compared to 6.1 in 2014, 6.1 in 2015, 5.8 in 2016 and 5.9 in 2017. The table below shows the trend in the number of customers per storage facility operator.

Gas: changes in the number of customers per storage facility operator
(number of storage companies)

No of customers	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
1	12	7	8	8	7	9	8	10	11	9	10
2	3	3	2	2	3	3	4	2	2	2	4
3 - 9	6	6	7	6	7	7	5	4	6	6	4
10 - 15	2	2	2	1	2	2	3	3	1	3	4
16 - 20	0	1	1	1	1	2	1	1	2	3	2
> 20	0	0	0	1	1	1	2	2	2	0	0

Table 117: Changes in the number of customers per storage facility operator over the years

5.4 Capacity trends

The following chart shows the working gas capacity still bookable on 31 December 2018 in underground natural gas storage facilities compared to the previous years.

Gas: changes in the freely bookable working gas capacity, as offered on 31 December, in the subsequent periods from 2014 to 2018
(TWh)

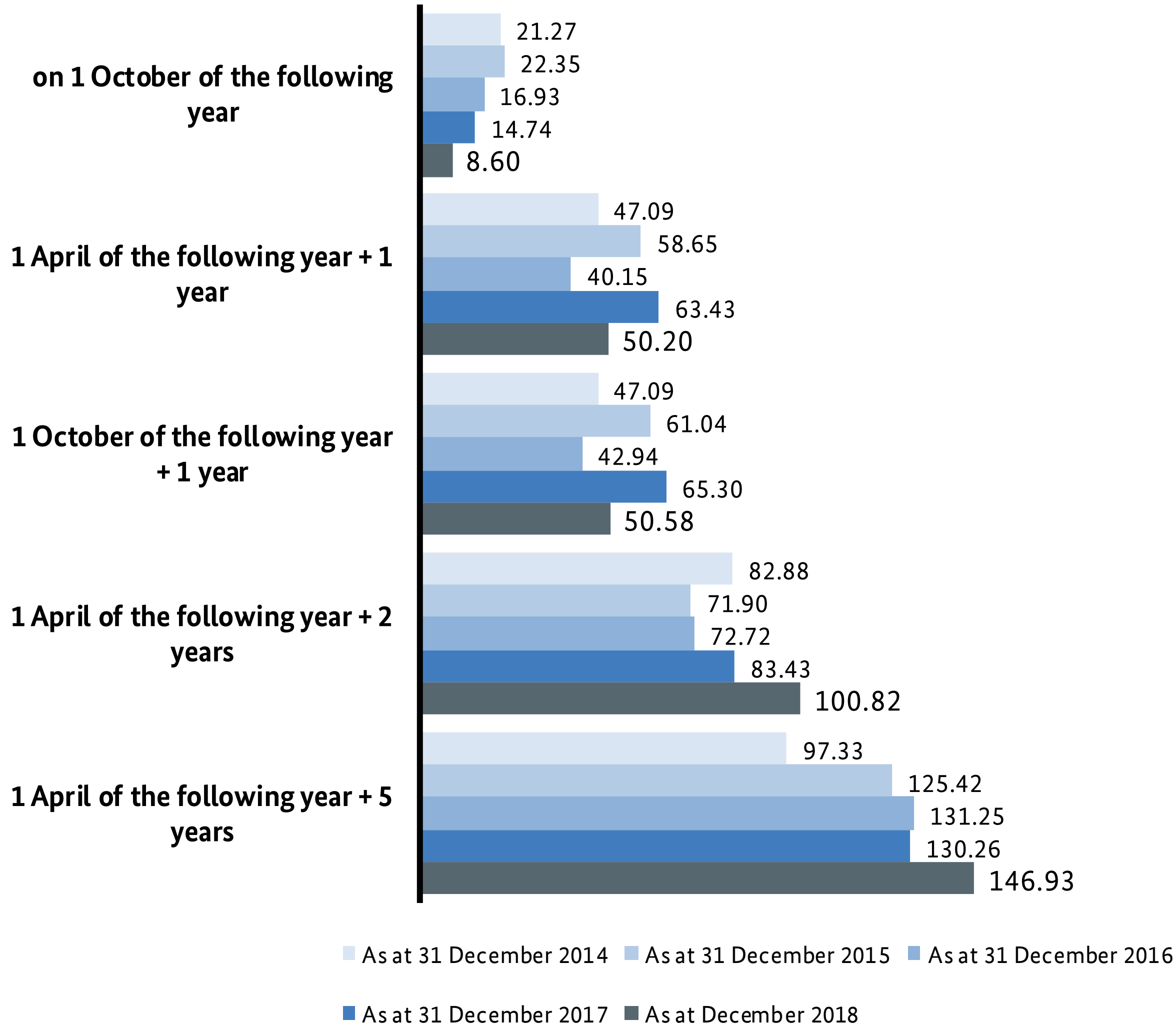


Figure 165: Changes in the freely bookable working gas capacity as at 31 December in the subsequent periods

The volume of short-term (up to 1 October 2018) freely bookable working gas declined slightly again, as did the capacities still bookable for 2020. There was another increase in the volume of long-term bookable working gas from 2021. Overall, customers are tending towards shorter-term bookings in the storage market.

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, the Gas NDP must be published every two years (in even-numbered years). The content of the Gas NDP focuses firstly on expansion measures resulting from the connection of new gas power plants – there is an interconnection here with the electricity market – and of gas storage facilities and industrial customers, with an additional focus on changes in demand from downstream distribution networks. A further demand-related factor triggering network expansion measures is the conversion of numerous network areas from low-calorific L-gas to high-calorific H-gas, which will largely be completed by 2030.

On 29 March 2018, the TSOs submitted their draft Gas NDP 2018–2028 to the Bundesnetzagentur. On 20 December 2018, after reviewing the plan, the Bundesnetzagentur came to a decision on the Gas NDP 2018–2028 with the formulation of a modification request.

With its decision the Bundesnetzagentur also confirmed the EUGAL pipeline, without modification requirements. With an investment volume of approximately €2.3bn, EUGAL is the largest single project in the Gas NDP to date and, once built, will transport gas from the planned Nord Stream extension from Lubmin to Deutschneudorf on the German-Czech border. In light of the network data submitted by the TSOs, in particular, the review showed that there are no cheaper alternatives to the pipeline. Long-term bookings have already been made for the additional capacity to be created in Lubmin within the framework of the “more capacity” project, a Europe-wide market survey of transport customers carried out by certain TSOs. According to the TSOs these bookings will contribute significantly to the refinancing of the investment costs.

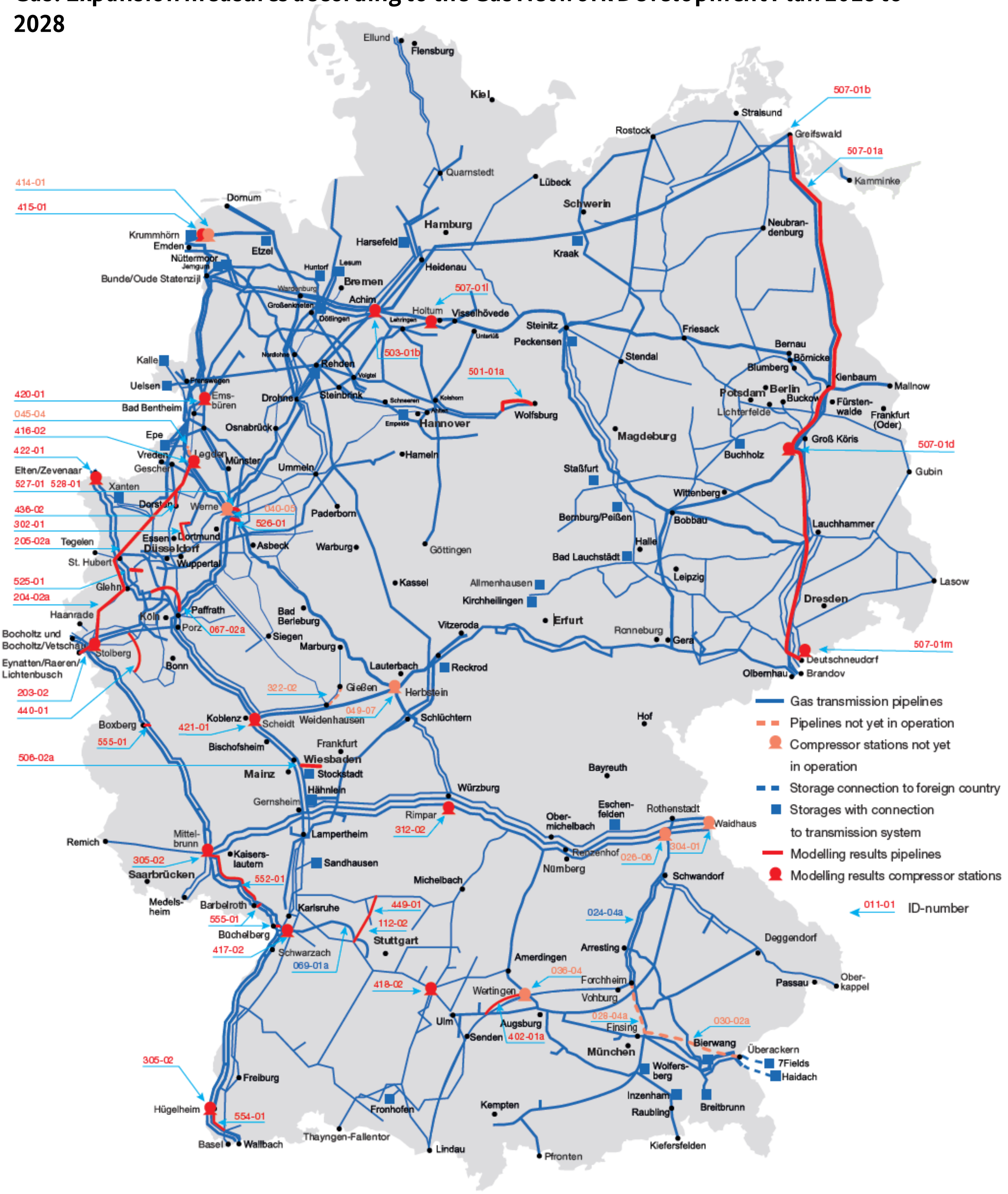
Four measures had to be removed from the plan following the modification request because they are not within the scope of the Gas NDP. One of these was the planned pipeline link to a terminal for liquefied natural gas (LNG) in Brunsbüttel that, in the opinion of the Bundesnetzagentur, fell under the responsibility of the developer of the LNG terminal. Its decision on the Gas NDP does not mean that the Bundesnetzagentur has taken a position on the probability of the terminal actually being built. During the review of the Gas Network Development Plan, the Bundesnetzagentur does not decide on whether an LNG terminal will be built but merely assesses whether the expansion measures that the TSOs have introduced into the plan and that have to be carried out within the transmission system in order to offer the required capacity for such a terminal are needs-based.

The TENP I pipeline, which runs from the German-Dutch border to Wallbach on the German-Swiss border, is currently subject to transport restrictions due to corrosion damage. Following the TSOs' decision that the affected sections of the pipeline cannot be put back into operation, they have incorporated the measures required to maintain security of supply into the NDP to compensate for the restrictions. In order for these measures to be realised the TSOs will invest a total of €171m over the coming years.

Furthermore, the TSOs submitted the results of remodelling in due time, which they were obliged to carry out following the modification request. They established that there was an equally appropriate alternative to a pipeline project which they had to remove from the Gas NDP 2018–2028. The alternative project, with expected investment costs of €8.3m, has the same objectives and is significantly less expensive than the originally planned pipeline project, which would have involved investment costs of approximately €33m. The official decision to incorporate the alternative project into the plan was made on 26 April 2019.

The plan, which is binding for the TSOs, thus comprises a total of 156 measures with an investment volume of €7bn. It includes the construction of new transmission pipelines with a total length of 1,364 km and additional compressor capacity of 499 MW. The TSOs have implemented the required changes and subsequently published the binding Gas NDP 2018-2028 on time.

Gas: Expansion measures according to the Gas Network Development Plan 2018 to 2028



Source: transmission system operators

Figure 166: Expansion measures according to the Gas Network Development Plan 2018-2028 (source: transmission system operators)

The TSOs submitted the implementation report on the Gas NDP 2018-2028 on 1 April 2019. Since 2017, this report must be drawn up every two years (in odd-numbered years). 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 was then submitted for comprehensive consultation by the Bundesnetzagentur. 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 process of establishing the Gas Network Development Plan 2020 to 2030 began in June 2019 with the publication of the consultation document on the scenario framework by the TSOs.

The scenario framework contains the input variables necessary to prepare the Gas NDP: assumptions relating to capacity planning within a ten-year time frame, for instance on the basis of future capacity requirements in downstream distribution networks and on the planned connection of new gas-fired power plants, gas storage facilities or LNG facilities to the transmission network.

For the first time in the NDP process, the TSOs are also taking account of hydrogen and synthetic natural gas (SNG), so-called green gases. A market survey was undertaken, giving companies and project managers the opportunity to report any green gas projects for which concrete implementation plans were in place to the TSOs by the middle of July 2019 so that these projects could be taken into account during the preparation of the Gas NDP 2020-2030 if appropriate.

Another issue in the current process is the merger of the currently separate market areas NetConnect Germany (NCG) and GASPOOL. This provision is set out in section 21 of the Gas Network Access Ordinance (GasNZV) and is expected to be implemented on 1 October 2021. The market area merger affects the nature and extent of the capacity that can be presented and secured in a Germany-wide market area across the existing physical network infrastructure. For this reason, in the current scenario framework the TSOs describe a new capacity model which addresses the challenge resulting from the market area merger. The model uses simulation calculations based on historic cases of network usage and on potential market shifts to examine the impacts of the market area merger on the capacity offer. In order to resolve the ensuing bottlenecks, the TSOs outline various solutions including the use of market-based instruments (MBIs). The next Gas NDP 2020-2030 is expected to include an assessment of whether the bottlenecks can be resolved more efficiently by investing in the network infrastructure or using market-based instruments.

In the scenario framework the TSOs also describe the current situation regarding the LNG terminals, which are to be connected to the German transmission system in the event of a positive investment decision. Currently efforts are being made to construct LNG terminals with a connection to the transmission network at three sites in Germany (Brunsbüttel, Wilhelmshaven and Stade). A fourth project being planned in Rostock (a small-scale LNG terminal) does not need to be connected to the transmission network. Last year saw improvements to the regulatory framework for establishing the LNG infrastructure. From now on the TSOs are obliged to build the pipeline links between LNG facilities and the transmission system, thereby connecting the facilities to the gas network and ensuring their access to the market. At the same time this provision means that the LNG facility operators are largely exempt from their previous obligation to bear the costs. The intention is to increase planning and investment security for the operators of the new terminals being constructed, to facilitate realisation of the projects and to make them economically more attractive. Not least, the new provision also benefits consumers, as additional opportunities to import gas may exert price pressure on traditional importers. Moreover, LNG terminals enable the diversification of gas import options and can facilitate the introduction of low-CO2 and CO2-free synthetic gases.

1.2 Incremental Capacities – market-based process for creating additional gas transport capacity

Commission Regulation (EU) No 2017/459 establishing a network code on capacity allocation mechanisms in gas transmission systems (NC CAM) entered into force on 16 March 2017.

The Regulation includes provisions for a new process to assess the market demand for additional gas transport capacity at cross-border interconnection points (so-called incremental capacity process). The TSOs use the results of the process as a sound basis for determining the demand for network expansion.

The incremental capacity process, which all TSOs within the EU must carry out every two years beginning in April 2017, can be subdivided into three phases: a demand assessment, followed by – if it is found that there is demand for incremental capacity at cross-border interconnection points – a structured design phase and finally a booking and realisation phase.

Incremental capacity process 2017 to 2019

a) Demand assessment

The market demand assessment process was completed by the TSOs in July 2017. In the course of this process the TSOs evaluated all demand indications for additional gas transport capacity at market area borders into and within Germany. Demand indications for incremental gas capacity were registered at four market area borders into/out of Germany (NCG-Eastern market area (Austria), GASPOOL-Poland, Russian Federation-GASPOOL and GASPOOL-Netherlands) and one demand indication at the market area border within Germany, GASPOOL to NCG.

b) Design phase

Immediately after the market demand assessment reports were published, the TSOs launched the respective design phases for these demand indications. During this period, until October 2017, the TSOs carried out technical studies on projects providing incremental capacity at market area and/or cross-border interconnection points. This entailed investigating what expansion measures were needed for pipelines and compressors in order to meet the registered demand for incremental capacity.

This second phase of the process concluded with the drafting of project proposals and determination of the parameters for the economic test for the referenced projects providing incremental capacity; the TSOs concerned then submitted the proposals and parameters to the responsible national regulatory authorities for coordinated approval.

The first such notice of approval for the creation of gas transport capacity was issued as early as 25 April 2018 with respect to the German-Austrian cross-border interconnection point Überackern/Überackern SUDAL. At the request of the Austrian regulatory authority E-Control, the approval process – which normally takes two years – was completed within one year.

The Poland–Germany (GASPOOL) process had the aim of enabling physical gas flow between Poland and GASPOOL in both directions. However, it was not possible to implement the project proposal because there was no joint capacity-booking platform for the marketing of capacities. This was a prerequisite for implementation of the project.

The process at the Lubmin cross-border interconnection point (Nord Stream 2 landing terminal) into Germany (GASPOOL) envisaged an increase in entry capacity and consequently gas volumes being delivered from Nord Stream 2 into Germany(NCG) and into the Netherlands. The project proposal could not be approved because it did not reflect the demand indications submitted by shippers. As a result of the uncertainty surrounding implementation of the market area merger, the TSOs were not able to turn all demand indications at this border into project proposals in full.

The process relating to demand for exit capacity from the GASPOOL market area into the Dutch market area was approved subject to conditions.

c) Booking phase

In the two processes in which the project proposals were approved, the incremental gas transport capacity was subsequently offered to the market participants for binding booking.

The incremental capacity at the German-Austrian border was offered to market participants on the PRISMA booking platform on 2 July 2018. However, the market participants did not make sufficient use of the opportunity to book this capacity in order for the project to be realised.

The incremental capacity at the German-Dutch border was offered to market participants at the annual auction on 1 July 2019. However, the market participants did not make use of the opportunity to make binding bookings for this incremental capacity. Consequently the project was not realised.

Incremental capacity process 2019 to 2021

The start of the annual auction on 1 July 2019 marked the beginning of the next cycle of the incremental capacity process 2019 to 2021. The TSOs received the participants' non-binding demand indications for incremental capacity at market area and cross-border interconnection points, which enabled them to use market demand assessments to determine the demand for incremental capacity.

The Bundesnetzagentur has actively accompanied the incremental capacity process since early 2017. In order to increase transparency, it has developed a calculation tool to be used for the economic test pursuant to Article 22 NC CAM. Network users and TSOs can download the tool (in German and English) from the Bundesnetzagentur website.

The Bundesnetzagentur website also contains further information and links to ongoing and completed incremental capacity processes.[135]

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[135] https://www.bundesnetzagentur.de/EN/Areas/Energy/Companies/GridDevelopment/Gas/IncrementalCapacities/IncrementalCap_node.html

2. Investments

Investments as defined in the monitoring survey are considered to be gross additions to fixed assets capitalised in 2018 and the value of new fixed assets newly rented in 2018. 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).

2.1 Investments and expenditure by TSOs

In 2018 the 16 German TSOs invested a total of €1.45bn (2017: €970m) in network infrastructure. Of this total, €1.30bn (2017: €848m) was investment in new installations, expansion and extension and €156m (2017: €122m) investment in maintenance and renewal of network infrastructure. With regard to the distribution of investment expenditure between the two German market areas, the data showed a shift towards GASPOOL. Of the total investments in 2018, the larger share, 62%, was now attributed to the transmission systems in the GASPOOL market area and 38% to the NCG market area (2017: 31% GASPOOL, 69% NCG). The investments planned for 2019 amount to a total of €1.65bn, which would equate to an increase of 13% compared to 2018. This relatively large fluctuation in investment expenditure is a result of capital-intensive investment in a few individual large-scale projects.

Across all TSOs, expenditure on maintenance, repair and expansion of network infrastructure amounted to €313m in 2018 (2017: €306m), with expenditure in 2018 and planned expenditure for 2019 shared almost equally between the two market areas (2017: 55% NCG, 45% GASPOOL).

The overall total for investments and expenditure across all TSOs is approximately €1.76bn. The chart below shows investments and expenditure both separately and as a sum total since 2013, as well as the planned figures for 2019.

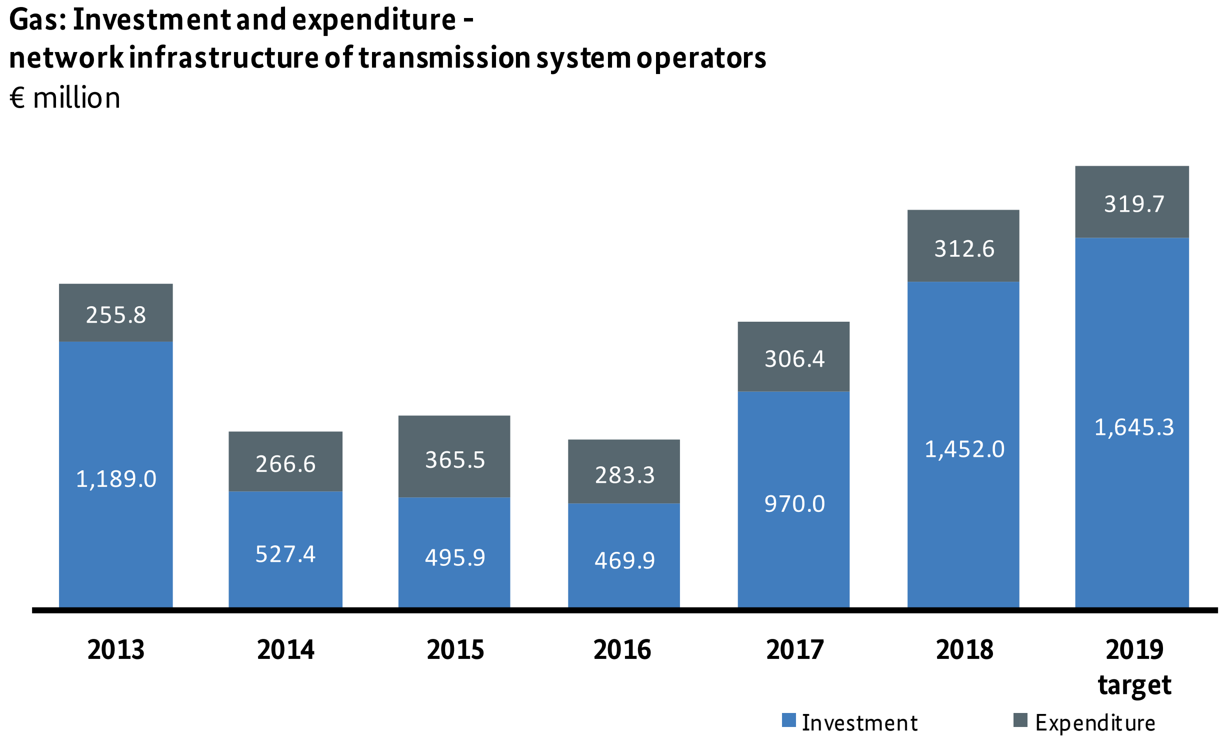


Figure 167: Investments in and expenditure on network infrastructure by gas TSOs

2.2 Investments in and expenditure on network infrastructure by gas DSOs

In the course of data collection for the 2019 Monitoring Report, 600 gas DSOs declared investment in new installations, expansions and extensions (€798m compared to €623m in 2017) and maintenance and repair (€475m compared to €408m in 2017) of network infrastructure, totalling €1,273m compared to €1,031m in 2017. The projected total investment for 2019 is €1,371m.

According to the gas DSOs' reports, expenditure on maintenance and repair in 2018 was €1,078m (2017: €1,084m). The projected expenditure on maintenance and repair for 2019 is €1,116m.

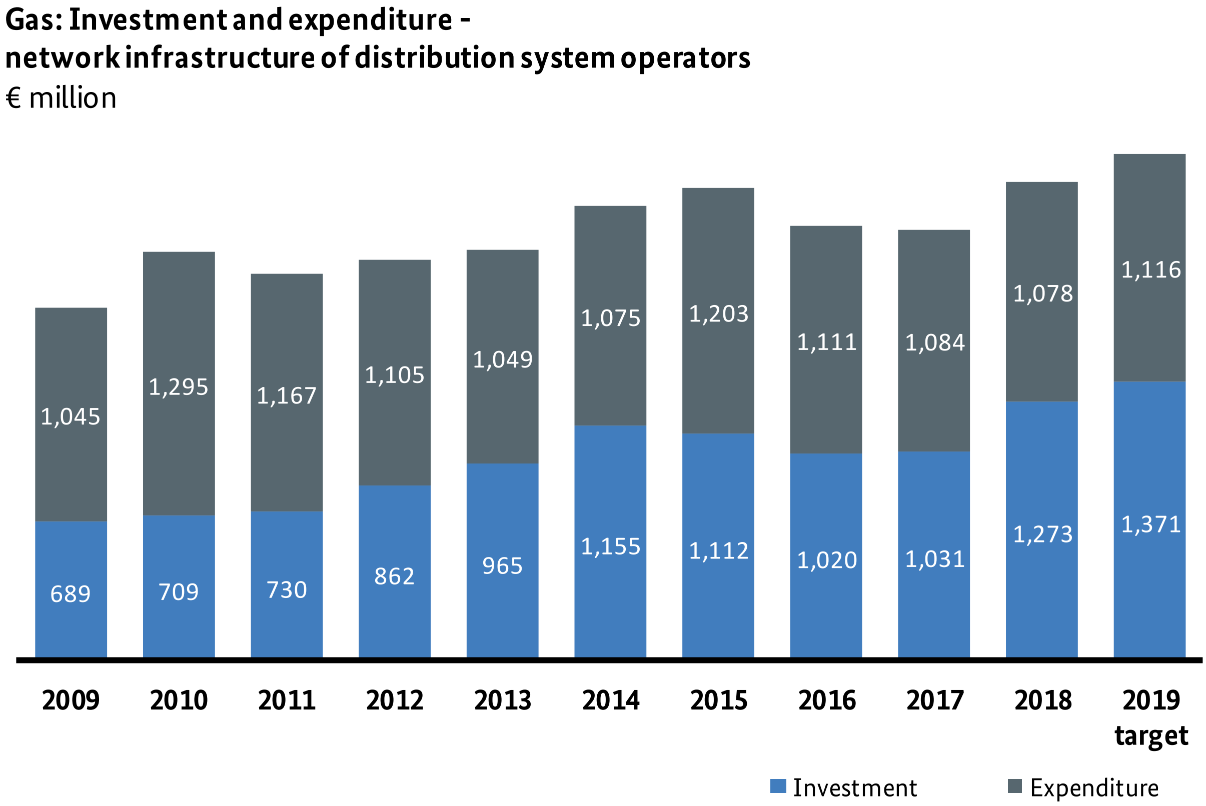


Figure 168: Investments in and expenditure on network infrastructure by gas DSOs

The level of DSO investment depends on the length of their gas pipeline network and the number of market locations served as well as other individual structure parameters, including, in particular, geographical circumstances. While 146 of the surveyed gas DSOs reported investments of between €1m and €5m, only 49 gas DSOs made investments totalling more than €5m.[136]

[136] These figures are based on data submitted by 614 DSOs.

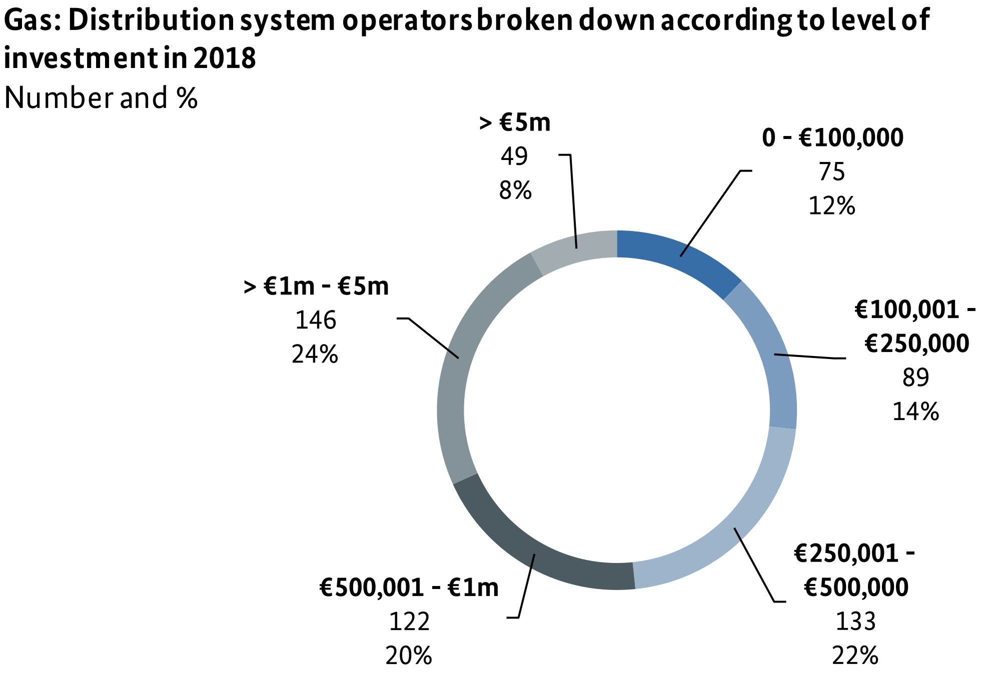


Figure 169: Distribution of gas DSOs according to level of investment in 2018

Of the surveyed gas DSOs, 143 reported total expenditures in the bracket between €100,001 and €250,000, while only 49 gas DSOs reported expenditures totalling more than €5m.[137]

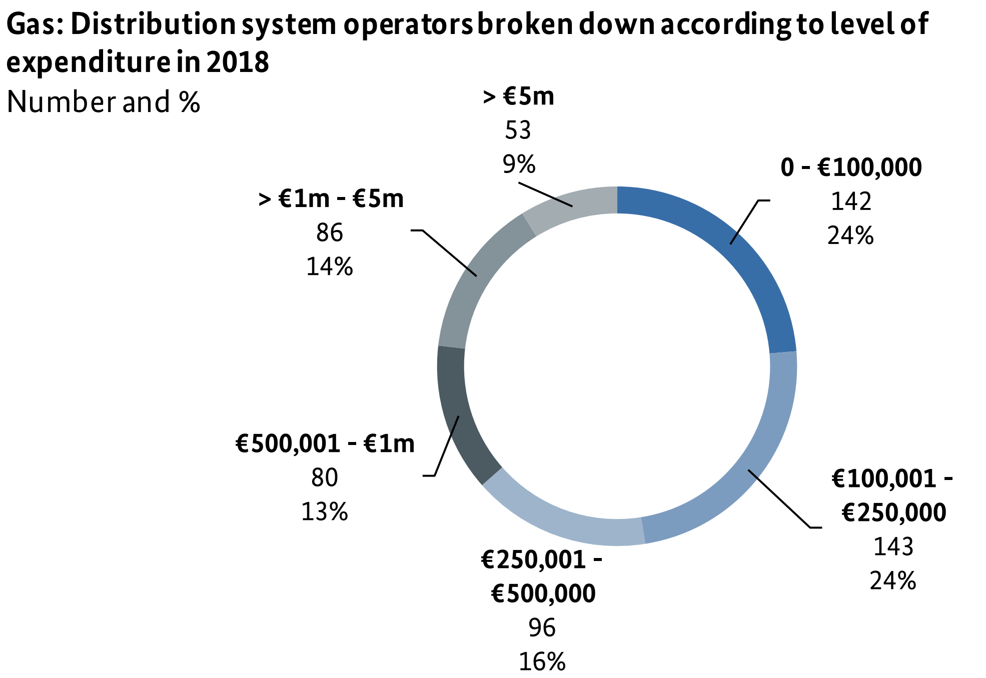


Figure 170: Distribution of gas DSOs according to level of expenditure in 2018

[137] These figures are based on data submitted by 600 DSOs.

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 charges. Based on section 23 ARegV, upon application the Bundesnetzagentur grants approval for individual projects if the prerequisites stated in the Ordinance have been met. Once the approval has been given, the TSOs may adjust their 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.

2.3.1 Investment in network expansion by the TSOs

As of 31 March 2019, gas TSOs had submitted 15 new applications for investment projects totalling approximately €1.05bn to the Bundesnetzagentur. While the number of applications submitted by the TSOs remained almost the same compared to 2018, the investment volume covered by the applications increased nearly fivefold.

2.3.2 Capex mark-up and monitoring of the capex true-up

For the first time during the process of setting the revenue caps for gas for the third regulatory period (2018 to 2022), the Bundesnetzagentur used the annual capital cost deduction in accordance with section 6(3) of the Incentive Regulation Ordinance (ARegV), the instrument newly introduced in 2016. This involves deducting the capital expenditure resulting from the decrease in residual value over time from the capital costs in the baseline year that are included in the base level calculated on the basis of the cost assessment concluded in 2017. The deduction is carried out for each year of the regulatory period.

The capex mark-up (section 10a ARegV), which has the opposite effect, is designed as an annual application procedure. In this case rising capital costs resulting from investments are incorporated in the annual revenue cap. In the second half of 2018 the Bundesnetzagentur took decisions on 153 capex mark-up applications for 2019 that were submitted by the gas network operators under its responsibility, with planned investments totalling €826.3m.

The difference arising from the actual capital costs from investments can be calculated with the approved capex mark-up in 2020 for the first time. This difference is entered via the incentive regulation account.

2.4 Verzinsungshöhen des Kapitalstocks

With regard to the levels of interest on capital stock in the gas sector, a cross-sector evaluation of the equity interest rate is included in section I.C.3.4 from page 134.

3. Capacity offer and marketing

3.1 Available entry and exit capacities

As in previous years, for the 2017/2018 gas year, too, questions were asked concerning the marketing of transport capacity and were answered by the TSOs. The offered transport capacities relate to the right to inject or withdraw gas into/from the network. The volume of gas that shippers actually inject into or withdraw from the transmission network when making use of this right may differ from the volume offered. This section distinguishes between the various capacity products offered on the market, whereas the next section differentiates according to the duration of the corresponding entry and exit capacity products. The questions principally concerned the median offer of and/or demand for firm capacity at cross-border and market area interconnection points and also at storage facility connection point, power stations and final consumers.

This survey does not include the reserve capacity agreed with the downstream network operators within the internal booking process since the network interconnection points with distribution networks are not marketed directly to shippers (see section II.C.3.5 for more information on internal booking).

The total entry capacity offered across both market areas was 504.2 GWh/h, an increase of 18.2 GWh/h compared to the previous year. The offer of firm and freely allocable capacity (FZK) amounted to 145.6 GWh/h, corresponding to about 53.3% of the total entry capacity offered in the GASPOOL market area. In the NCG market area the equivalent share is 43.3%. However, the volume of this product offered (the product which ensures that shippers are able to allocate their entry capacity without restrictions) increased by 7.1% compared to 2016/17, to 99.9 GWh/h. The total volume of entry capacity offered in the NCG market area equates to around 45.8% of the total entry capacity offered across both market areas. The remaining and larger share of 54.2% is attributed to the GASPOOL market area.

Gas: Entry capacity offered in the 2017/2018 gas year
GWh/h

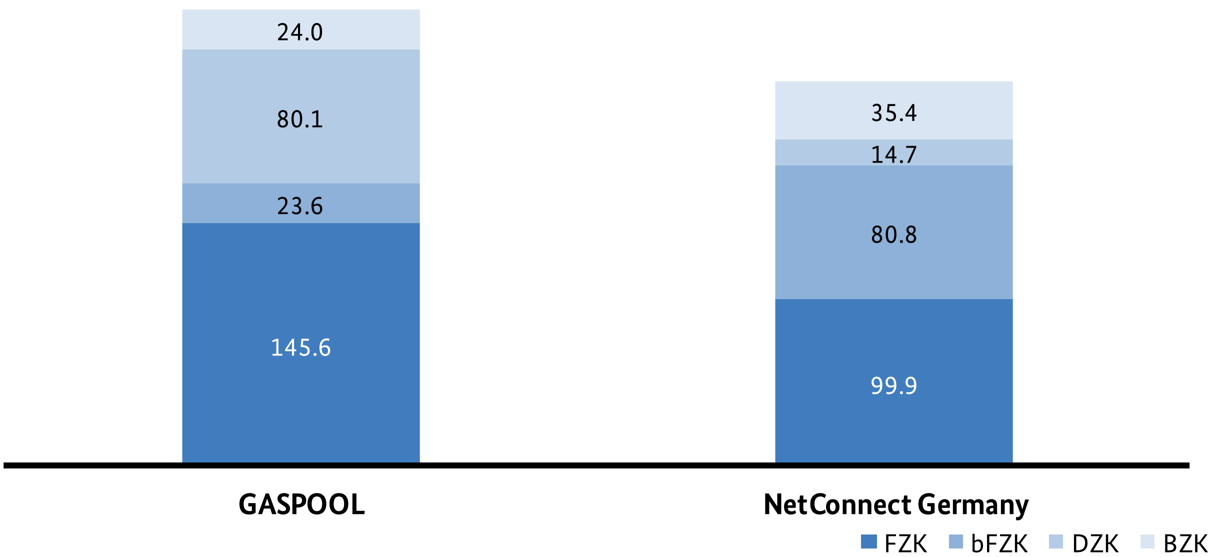


Figure 171: Entry capacity offered

The total exit capacity offered across both market areas was 353.8 GWh/h, therefore remaining at the same level as 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.

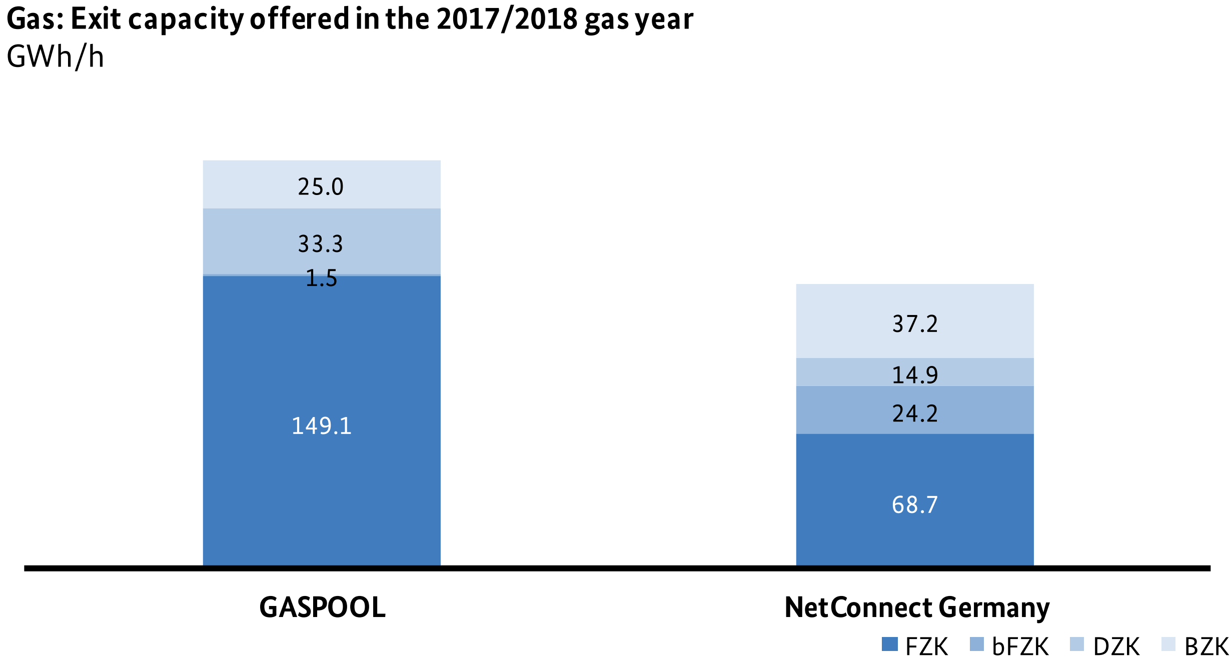


Figure 172: Exit capacity offered

As described above, the capacities for distribution networks and therefore the majority of final consumers are not included in this list because they are not marketed directly to the shippers by the transmission system operators. These marketing levels should therefore not lead to the drawing of incorrect conclusions. Overall, the German gas networks have more exit capacity than entry capacity across all network levels. This is apparent from the scale of internal bookings by the DSOs (see section II.C.3.5). In 2018, the total capacity booked with TSOs by downstream DSOs was 269.7 GWh/h. This is roughly 76% of the bookable capacity offered in the 2017/2018 gas year considered in this report. As the periods under review are different, however, it is not appropriate to simply add the two figures together.

According to section 12 para 3 of the cooperation agreement (KoV) X annex 1, renominations carried out by the balancing group manager 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 maximum of 20% of booked (firm) capacity, half of the nominated capacity is allowed for downward renomination. Renomination beyond these restrictions remains possible but is equated to the nomination of interruptible capacities. The restrictions allow TSOs to offer more capacity on a daily basis than is the case in a base case without a renomination restriction. In the year 2018, the offer of additional entry capacity through TSOs' renomination restrictions amounted to 1.547m kWh/h in the NCG market area, which corresponds to a decrease of 16.1% compared with the year 2017. The offer of corresponding exit capacity also decreased, by 23.4% to 2.008 GWh/h. In the GASPOOL market area the additional entry capacity resulting from the renomination restriction decreased by 8.4% to 8,167 GWh/h, while on the exit side there was an increase of 1.4% to 11,249 GWh/h.

The TSOs were asked for information on the average offer of entry and exit capacities and also on the average level of bookings at cross-border and market area interconnection points and points of interconnection with storage facilities, power stations and final consumers. The survey showed that in the year under review, the booking rate for firm capacity products (FZK, bFZK, DZK, BZK) on the entry side was 49.6% and on the exit side 52.6% of corresponding capacities offered.

3.2 Product durations

The time period for which a capacity is assured depends on how the corresponding capacity product is marketed. As a general principle the entire capacity offer is initially made for a whole gas year. If demand for these capacities is lower than the amount offered, the TSOs market the remaining capacity on a quarterly basis within a gas year. If the capacity still cannot be marketed for this time frame, whether in full or in part, owing to a lack of demand, the TSOs auction the remaining capacity on a monthly basis, then on a daily basis and finally on a within-day basis.

Gas: Booking of entry capacity according to product duration and market area in the 2017/2018 gas year GWh/h

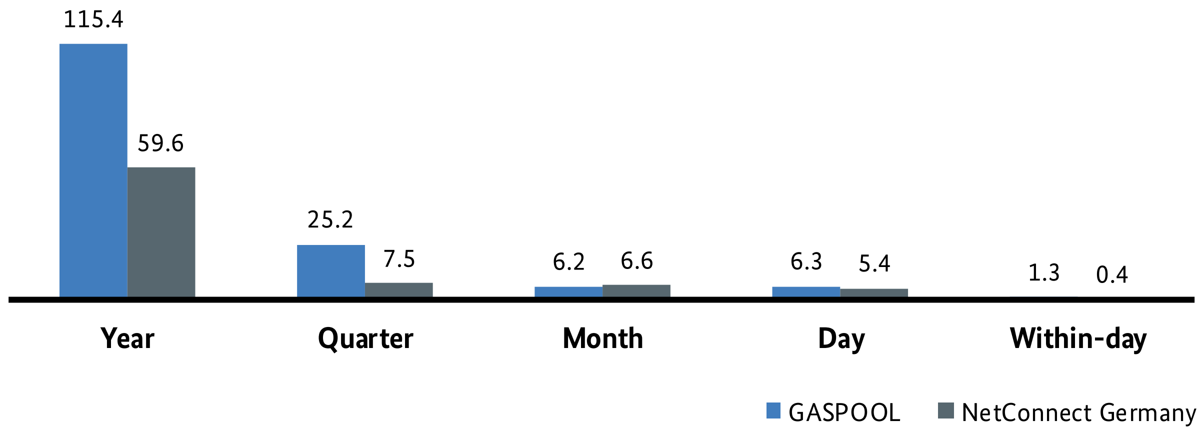


Figure 173: Booking of entry capacity according to product duration and market area

Gas: Booking of exit capacity according to product duration and market area in the 2017/2018 gas year GWh/h

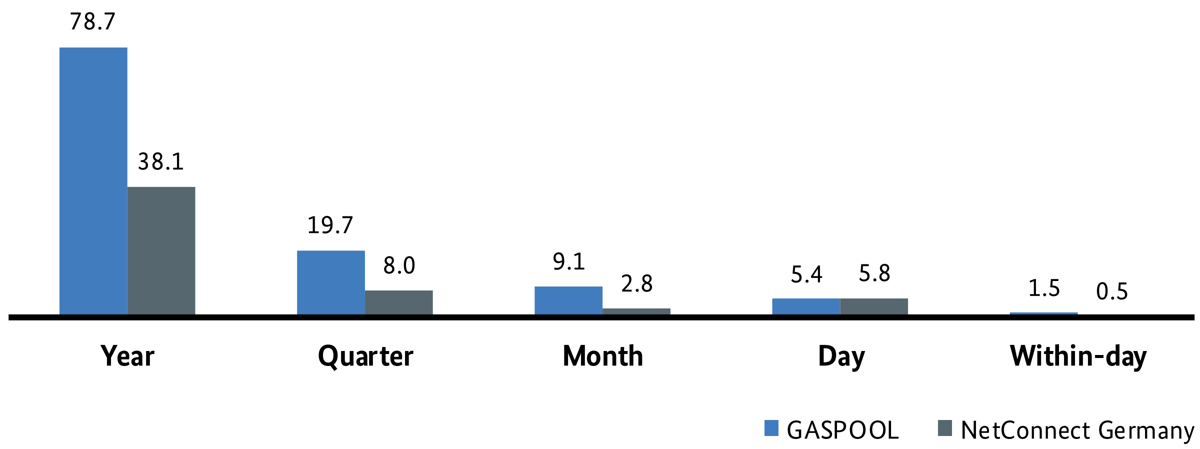


Figure 174: Booking of exit capacity according to product duration and market area

A comparison of the two charts on entry and exit capacity reveals a number of differences. For instance, it is apparent that, overall, in the 2018 gas year considerably more entry capacity was booked than exit capacity: One reason for this is that a large share of the entry capacity bookings is used to supply final customers connected to downstream distribution networks. However, the German gas network access model does not oblige suppliers to book equivalent exit capacity when supplying gas in this way. This correlation was already apparent in the charts of the corresponding capacity offers. Consequently the total volume of entry capacity booked was 233.9 GWh/h, significantly exceeding exit capacity, which amounted to a total of 169.5 GWh/h.

In addition, the chart showing the entry and exit capacity bookings clearly illustrates that, during the period under review, most bookings were for longer-term capacity products. The capacity volume booked on a long-term basis in the GASPOOL market area, with a total of 194.1 GWh/h of yearly capacity marketed and 44.9 GWh/h of quarterly capacity marketed, was significantly larger than the long-term capacity booked in the NCG market area, where the corresponding volumes were 97.7 GWh/h and 15.5 GWh/h respectively. Compared to the previous year, however, there is a clear trend towards an increase in short-term bookings. The share of within-day capacity bookings in particular has increased significantly. The fact that yearly capacity bookings are still the dominant share can mainly be explained historically because many of them result from long-term capacity agreements with durations of several years. With these agreements gradually reaching the end of their term, a further shift towards more within-year capacity bookings may become apparent over the coming years.

As part of the survey TSOs were also asked about levels of actual network use in the form of nominations by the shippers during the period under review. Across Germany, the TSOs reported a nominated quantity of 2,055 TWh at all entry points where there is a nomination obligation, a decrease of 6.8% compared to the previous year. In contrast, nominated quantities at exit points were considerably lower, totalling 1,170 TWh (an increase of 1%). The reason for the significantly lower figure on the exit side is that gas for domestic use in particular is withdrawn from the transmission network at exit points where there is no nomination obligation. Placing the reported nominations in relation to the reported capacity bookings for the same period (2017/2018 gas year), the capacity usage rate is 86.7% on the entry side and 69.7% on the exit side. However, it must be noted that these figures may be imprecise because there is not always also a nomination obligation at network points where there is a booking obligation.

3.3 Termination of capacity contracts

The termination of capacity contracts is regulated by the rules and conditions governing TSOs' entry and exit contracts. The TSOs may terminate a contract without notice for good cause, for instance if the shipper repeatedly and severely breaches important contractual provisions in spite of written warnings. Likewise, shippers have the right to terminate contracts under various circumstances, for example if capacity charges are increased over and above the increase in the consumer price index published by the Federal Statistical Office. In such cases the shippers must comply with the notice periods and terms of termination laid down in the contract, which vary according to the grounds for termination.

In 2018, a total of 18 capacity contracts with a duration of at least one month were terminated. This is a significant decrease compared to the previous year when 126 contract terminations were reported. As a general rule, in this context it is possible to differentiate between the termination of capacity contracts according to types of product and categories of network interconnection point.

Gas: Termination of capacity contracts by type of interconnection point in the 2018 calendar year
Number

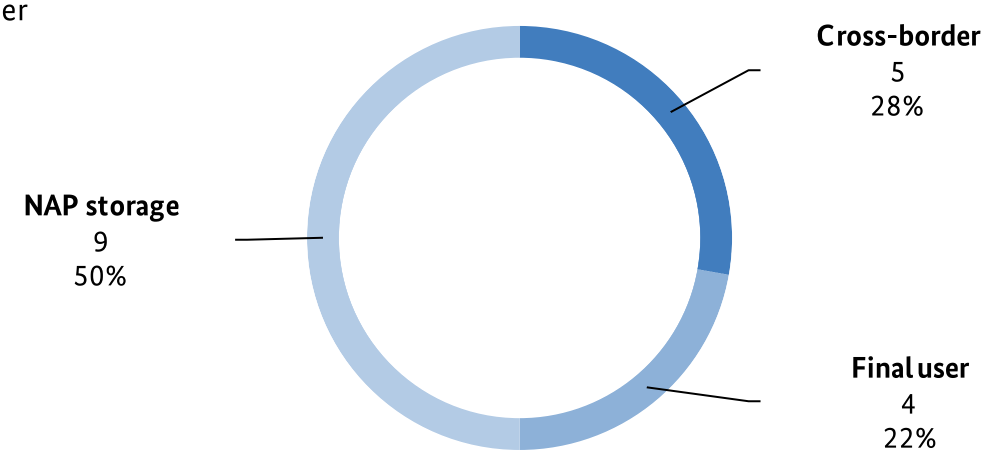


Figure 175: Termination of capacity contracts by category of interconnection point in the 2018 calendar year

A total of 18 capacity contracts were terminated, of which nine were contracts at storage facility connection points and a further five were contracts at cross-border interconnection points. The remaining four capacity contracts that were terminated were contracts relating to end users. In general terms, a considerable change in the distribution of contract terminations is observable compared to the previous year, with terminations of capacity contracts at cross-border interconnection points in particular decreasing by more than 95%.

Gas: Termination of capacity contracts by product type in the 2018 calendar year
Number

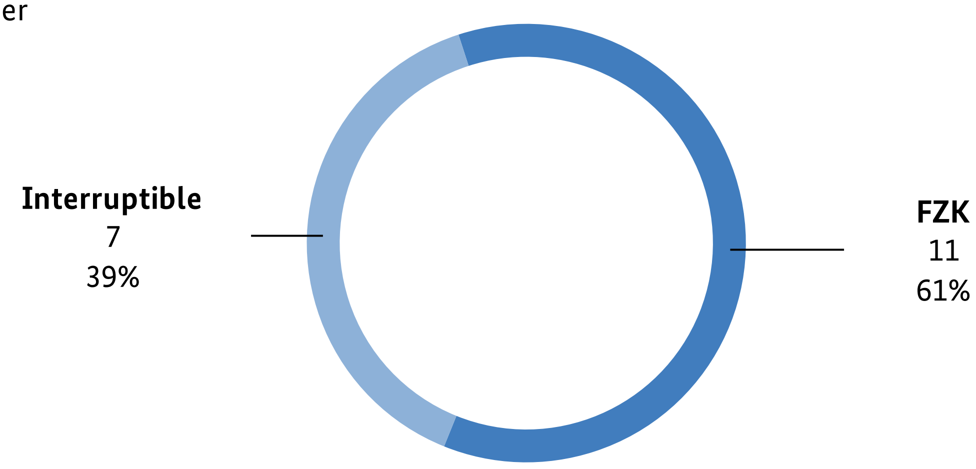


Figure 176: Termination of capacity contracts by product type

If terminated capacity contracts are differentiated according to product type, it is noticeable that in the 2018 calendar year only two product types were affected by contract terminations. Eleven contracts for FZK products were reported as having been terminated and seven for interruptible products. In the previous year contract terminations had been reported for every individual capacity type.

3.4 Interruptible capacity

Interruptible gas capacity tends to be less expensive than firm capacity. The lower price brings with it the risk that the gas may not be transported at all or only in part. Key elements for calculating the tariffs for interruptible capacity are defined in the Bundesnetzagentur's Determination for Pricing Entry and Exit Capacity ("BEATE").

Twelve suppliers and/or wholesalers, one more than in the previous gas year, reported that the interruptible capacity that they had booked was in fact interrupted during the 2017/2018 gas year.

In the 2017/2018 gas year the aggregated total duration of interruption was 2,112 hours and the aggregated number of interruptions was 239. This corresponds to a decrease in the overall duration of interruption by 61.2% compared to the previous year. The number of interruptions also fell, by more than 26.9% compared to the 2016/2017 gas year.

Both wholesalers 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 2018, 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 5.3bn kWh (2017: 3.95bn kWh). While the interruptions actually relate to capacity rights, it is possible to calculate the gas volumes affected by these interruptions based on the nominations already made for the period to be interrupted, ie the gas volumes that were already nominated at the point in time when the interruption was made known. The interruption of interruptible capacity accounted for the largest proportion of gas volumes that were not transported, at 89.6%. The interruption of FZK and/or DZK products was reported at only one cross-border interconnection point on one day, following a power failure at a compressor station. There was no significant change to the distribution of interruptions across the various network interconnection points compared to the previous year. The majority of interrupted volume (60.9% compared to 55.2% in 2017) was attributed to interruptions at storage facility connection points. Interruptions at cross-border interconnection points accounted for 33.4% (2017: 44.6%) of the total interrupted volume. As in the previous years, the smallest share of the interruptions (5.7% compared to 0.2% in 2017) was attributed to inter-market-area transports.

Gas: Interruptions in the 2018 calendar year

Interruption volume (GWh)

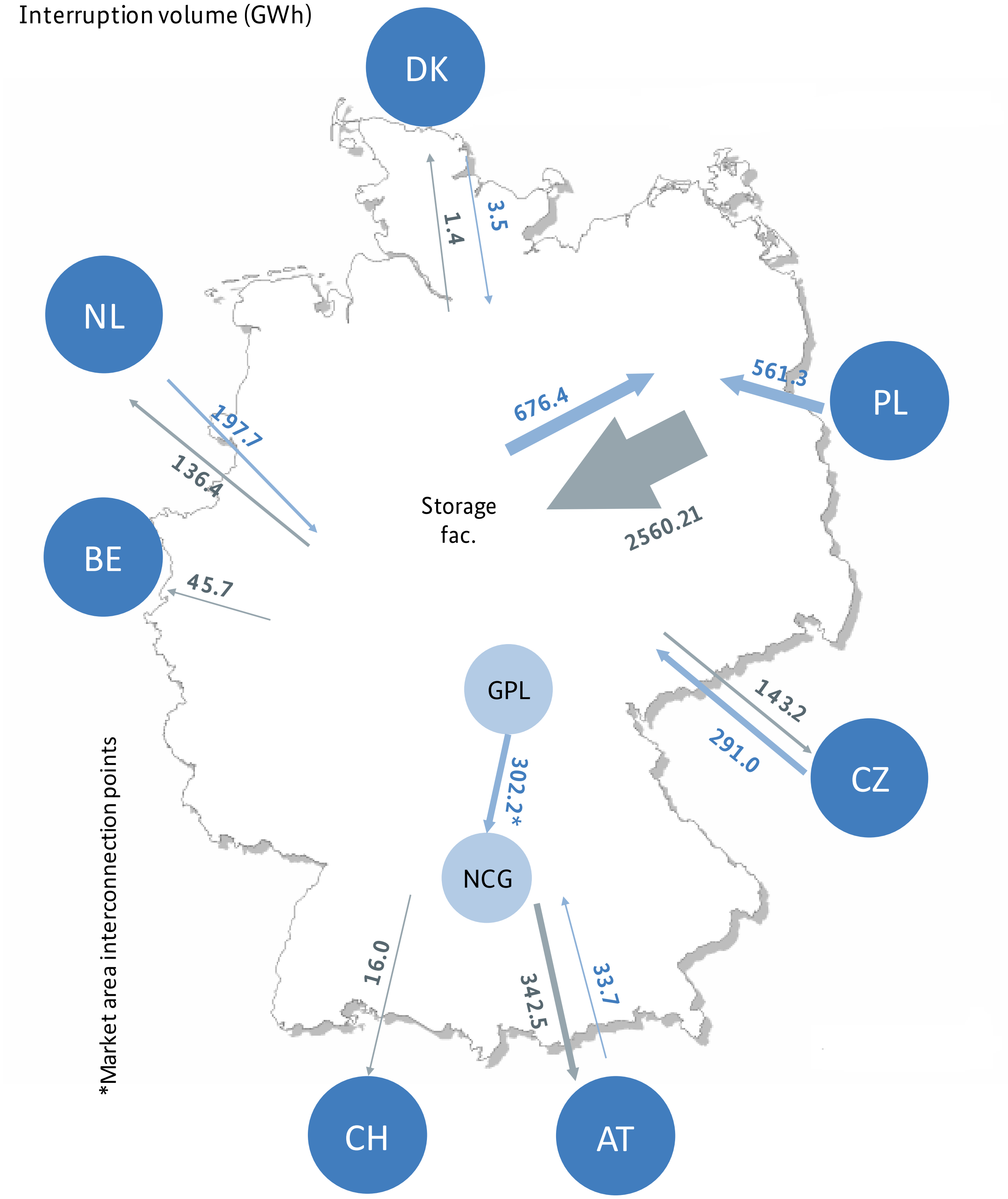


Figure 177: Interruption volumes according to region

The diagram depicts the geographical distribution of interrupted volumes at entry and exit points where there is a nomination obligation. It shows, for instance, that during the 2018 calendar year the volume of gas to be exported from Germany to the Netherlands that was subject to interruptions was 136.4 GWh and the volume of gas to be imported from the Netherlands into Germany that was subject to interruptions was 197.7 GWh.

3.5 Internal booking

A fundamental element of the TSOs' capacity model is the firm exit capacity (internal booking) agreed with the downstream network operators. Internal booking is a reserve capacity provided by the TSOs to the DSOs. It guarantees supply to customers in distribution networks without a shipper having to book capacity in those networks. Instead the shipper enters into a supplier framework contract with the relevant DSO, which enables the shipper to use the network to transport gas to exit points. The TSOs and DSOs within a market area cooperate in order to ensure the provision of capacity and thus access to the distribution networks.

The figure below shows internal bookings for the 2018 calendar year for the two market areas NCG and GASPOOL respectively.

Gas: Capacities agreed between TSOs and DSOs in 2018
GWh/h

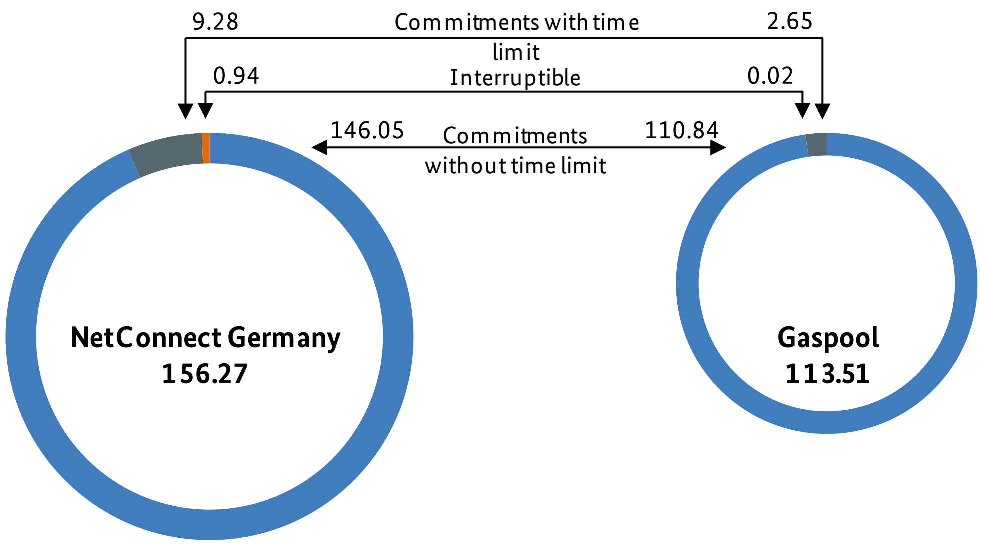


Figure 178: Capacities agreed between TSOs and DSOs

Compared to the previous year, the volume of internal bookings in the two market areas rose from a total of 260.7 GWh/h to 270.9 GWh/h in the 2018 calendar year. Of this total, reserve capacity with a volume of 256.9 GWh/h was agreed between the TSOs and the downstream network operators. The majority of this reserve capacity (146 GWh/h) agreed between the operators was agreed in the NCG market area, and the remainder (110.9 GWh/h) in the GASPOOL market area. The GASPOOL market area accounts for roughly 42.1% of all internal bookings agreed in the two market areas, with the remaining 57.9% shared accordingly among the TSOs in the NCG market area. Across Germany the share of firm capacity bookings without a time limit, as a percentage of the total capacity ordered internally, increased slightly from 93.8% in the previous year to 94.8% in the 2018 calendar year.

4. Gas supply disruptions

Every year the Bundesnetzagentur calculates the average gas supply interruption duration for all final customers in Germany (SAIDI: system average interruption duration index). In 2018 the SAIDI was 0.48 minutes. Security of supply for gas in Germany is thus very high.

As in the previous years, the Bundesnetzagentur again conducted a comprehensive survey of all gas supply interruptions throughout Germany. Gas network operators in Germany are obliged to report all interruptions in supply within their systems to the Bundesnetzagentur by 30 April of each year.

The Bundesnetzagentur uses the information to calculate the average interruption duration per final customer over the course of the year (SAIDI).

Only unplanned interruptions caused by third-party intervention, disturbances in the network operator's area, ripple effects from other networks or other disturbances are included in the calculations.

Gas: SAIDI results for 2018

Pressure range	Specific SAIDI	Comments
≤ 100mbar	0.45 min/Jahr	Household and small-volume consumers
> 100mbar	0.03 min/Jahr	High-volume consumers, gas-fired power plants
> 100mbar	0.00 min/Jahr	Downstream network operators (not part of SAIDI)
All pressure ranges	0.48 min/Jahr	SAIDI figure for all final customers

Table 118: SAIDI gas results for 2018

The Bundesnetzagentur has calculated the SAIDI figures for gas network operators in Germany since 2006. The trend over time is shown in the figure below.

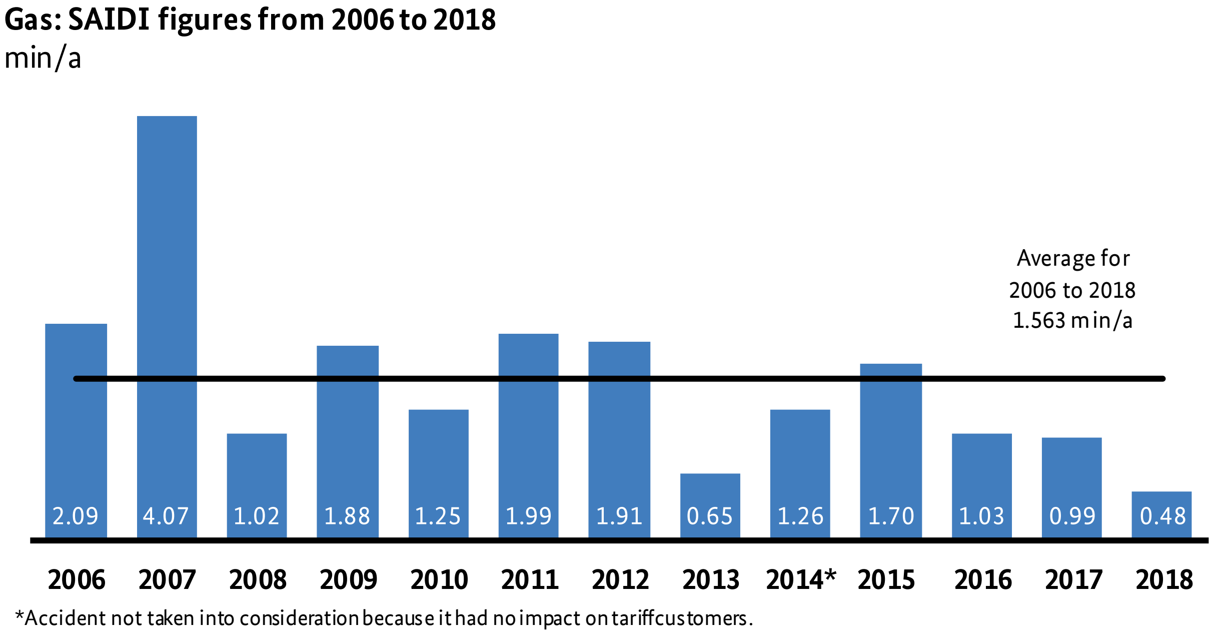


Figure 179: SAIDI gas figures for the period from 2006 to 2018

5. Network charges

The network charges are the means of spreading the costs of operation, maintenance and expansion of networks among all network users, ie also consumers.

Network charges account for a substantial share (25%) of the total gas price.

For an average household customer, the average network charge irrespective of the type of supply and including charges for metering and meter operation is currently around 1.56 ct/kWh, an increase of slightly more than three percent compared to the previous year.

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 II.F „Retail“ (Gas)). The network charges are the means of spreading the costs of operation, maintenance and expansion of networks among all network users. 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, ie 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 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.

The network charges imposed by the network users are determined on the basis of the calculated revenue caps. In principle, section 3 GasNEV allows for two different tariff systems to be used for this purpose within the framework of cost unit accounting. Entry and exit capacity charges as prescribed by section 13 GasNEV are the norm. These charges apply in the case of TSOs and regional DSOs. From 1 January 2020 the structure of the TSOs' capacity charges is prescribed by the provisions of NC TAR (see also section "II.C.5.6 Network code on harmonised transmission tariff structures (NC TAR)"). The network charge system for gas networks thus differs significantly from the system for electricity networks, which currently has neither entry tariffs nor capacity charges. 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 local distribution networks

The exit tariffs charged by local DSOs comprise two components, a capacity price and a commodity price. The so-called network participation model is often used 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 costs 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 directly connected to a local transport pipeline. 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 the revenue caps for gas

The 2015 costs were used to set the base level for calculating the revenue caps for the third regulatory period (2018 to 2022).

The data on the number of network operators under the responsibility of the Bundesnetzagentur varies over time as a result of networks splitting or merging and the accompanying change in network operator numbers and whether the network operators belong to the regulatory scope of the regulatory authorities of the federal states or the Bundesnetzagentur, as well as in the event of changes in delegated responsibility.

The table below compares the costs of the second (base year 2010) and third regulatory periods.

Gas: Development of the revenue caps
€ (million)

Base level, third regulatory period - transmission system operators		
	2010	2015
Network costs applied for	2,119	2,252
Absolute reduction	150	286
Approved network costs	**1,969**	**1,967**
of which permanently non-controllable costs	111	216
of which temporarily non-controllable costs "efficient costs"	1,854	1,737
of which controllable costs "inefficient costs"	4	13
Base level, third regulatory period - distribution system operators		
Standard procedure	**2010**	**2015**
Network costs applied for	3,798	4,413
of which upstream network costs	442	941
Absolute reduction	470	473
Approved network costs	**3,328**	**3,939**
of which permanently non-controllable costs	430	1,074
of which temporarily non-controllable costs "efficient costs"	2,754	2,662
of which controllable costs "inefficient costs"	144	203
Simplified procedure	**2010**	**2015**
Blanket efficiency figure	90%	93%
Network costs applied for	231	258
of which upstream network costs	37	62
Absolute reduction	30	19
Approved network costs	**200**	**239**
of which permanently non-controllable costs	90	74
of which temporarily non-controllable costs "efficient costs"	100	154
of which controllable costs "inefficient costs"	11	11

Table 119: Development of the revenue caps

5.3 Development of average network charges in Germany

The figure below shows the development of the average volume-weighted net gas network charges including upstream network costs for three consumption categories in ct/kWh from 1 April 2007 to 1 April 2019. The charges for metering and meter operation have been added to the network charges shown in the figure below.

Since 1 January 2017 the charge for accounting forms part of the network charges 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 charges shown are based on the following three consumption categories:

– Household customers (volume-weighted across all contract categories): 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 charges were determined with respect to the average consumption of 23,269 kWh.

– „Commercial 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).

The data submitted by the suppliers is then used to calculate an average network charge for each consumption group for the whole territory of the Federal Republic of Germany. The network charge for household customers is calculated on a volume-weighted basis, while that for business and industrial customers is calculated arithmetically. It should be noted that in these consumption categories the arithmetic mean does not reflect the considerable spread of the network charges and the heterogeneity of the network operators.

As of 1 April 2019, the average volume-weighted network charge including the charges for metering and meter operation (volume-weighted across all contract categories) for household customers in consumption band II was 1.56 ct/kWh (2018: 1.51 ct/kWh), an increase of slightly more than three percent compared to the previous year. For commercial customers, as of 1 April 2019 the arithmetic mean of the network charge including the charges for metering and meter operation was 1.26 ct/kWh (2018: 1.25 ct/kWh). For industrial customers, as of 1 April 2019 the arithmetic mean of the network charge including the charges for metering and meter operation decreased to 0.32 ct/kWh (2018: 0.33 ct/kWh), thus roughly 3.9% lower than the arithmetic mean as of 1 April 2018 and remaining at a low level.

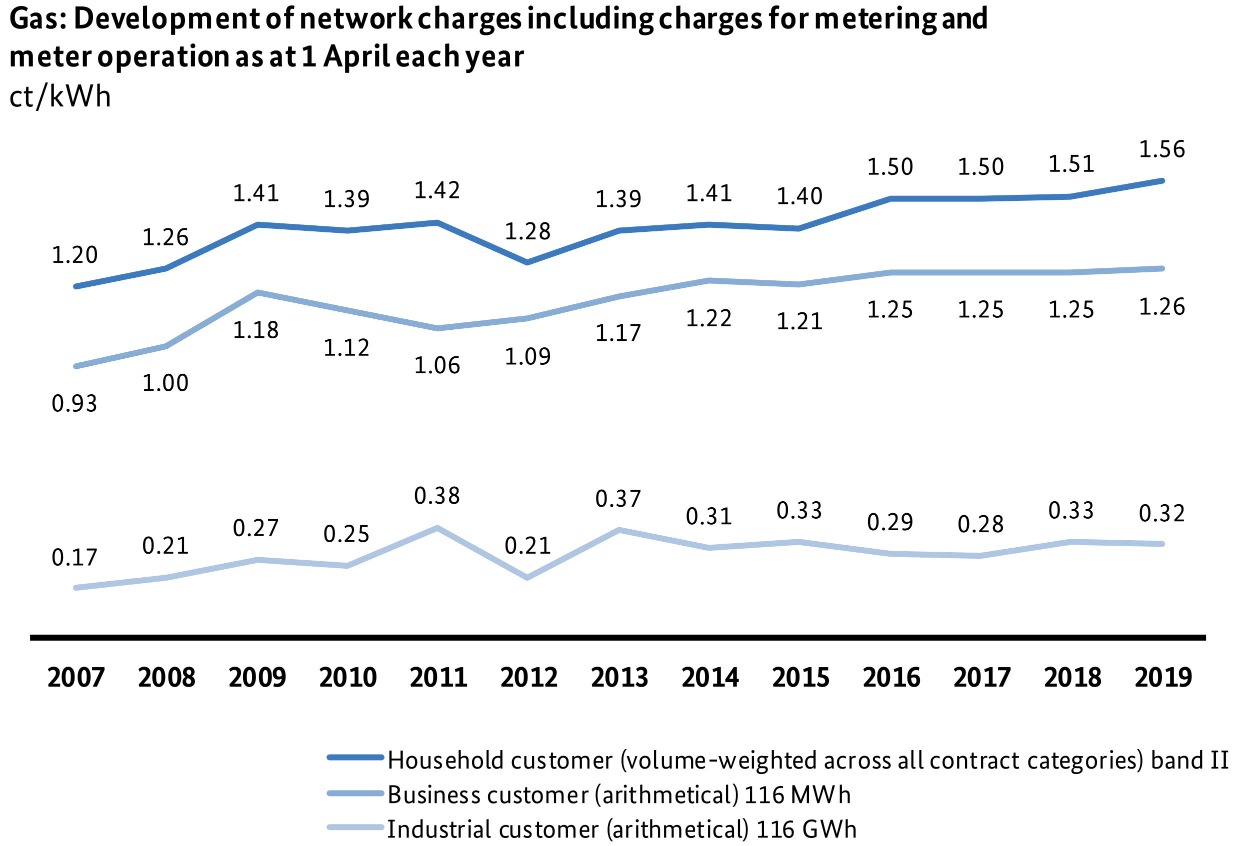


Figure 180: Development of network charges for gas (including charges for metering and meter operation) according to the survey of gas suppliers

Compared to 2019, on average a rise in the low single-digit percentage range is anticipated in 2020 for the underlying consumption categories concerning DSOs. The definitive charges for the DSOs will not be published until 1 January 2020.

The definitive charges at the level of the TSOs were already published on 30 June 2019. Some TSOs' charges will change significantly from 2019 to 2020 because from 1 January 2020 charges are calculated across the entire market area and not, as before, separately for each individual TSO (see section II.C.5.6). The reason for the changes in network charges is neither appreciable changes to the revenue caps of individual network operators nor completely different booking behaviour but a change in the system for calculating the charges. As of 1 January 2020, the TSOs' charges are calculated on the basis of the new reference price methodology of a joint postage stamp tariff for each market area.

5.4 Regional distribution of network charges

There is wide regional variation in the level of network charges. 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) in order to compare network charges in Germany. According to section 27(1) GasNEV all network operators are obliged to publish the network charges 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 2018 network charges 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 charges. For the sake of clarity, network charges are divided into six (household and business customers) or five (industrial customers) categories. Just over 700 gas networks were analysed to determine the level of network charges for household and business customers respectively. This corresponds to market coverage of 98% in both areas. The network charges were also entered in a chart broken down by federal state, in which the individual network charges are weighted with the respective offtake volume of the individual network operator for the federal state in question in order to obtain information on the average network charge level in each state.

The lowest gas network charges for household customers across Germany are set at 0.65 ct/kWh, and the highest at 3.36 ct/kWh. With the exception of Saarland, there is an East to West gradient with regard to the distribution of network charges. The average network charge for household customers in the new federal states (not including Berlin) is 1.65 ct/kWh (2018: 1.58 ct/kWh), while the average in the old states (including Berlin) is 1.39 ct/kWh (2018: 1.36 ct/kWh). Compared to the previous year, gas network charges have thus increased on average by slightly more than 4% in the new federal states and by around 2% in the old states. Looking at the averages by federal state, the highest network charges for household customers are found in Saarland and Mecklenburg-Western Pomerania, and the lowest in Berlin and Hamburg.

Gas: Net network charges for household customers in Germany for 2019
ct/kWh

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks considered
Saarland	1.78	1.15	2.36	18
Mecklenburg-Western P.	1.77	1.07	2.29	22
Brandenburg	1.73	0.84	3.36	29
Saxony-Anhalt	1.72	1.19	2.77	28
Bremen	1.56	1.54	1.67	2
Thuringia	1.52	1.05	2.14	30
North RhineWestphalia	1.52	0.73	2.85	120
Saxony	1.51	1.07	2.11	37
Baden-Württemberg	1.47	0.87	3.13	105
Rhineland-Palatinate	1.39	0.83	1.92	35
Hesse	1.39	0.99	1.77	44
Schleswig-Holstein	1.32	0.92	1.80	42
Bavaria	1.29	0.88	2.88	108
Lower Saxony	1.25	0.65	1.85	62
Hamburg	1.22	1.22	1.22	1
Berlin	1.12	1.12	1.12	1

* The number of meter points belonging to the operators in the respective network areas was used as the basis for weighting.

Table 120: Distribution of network charges for gas household customers in Germany, as at 1 January 2019

Network charges for household customers in 2019

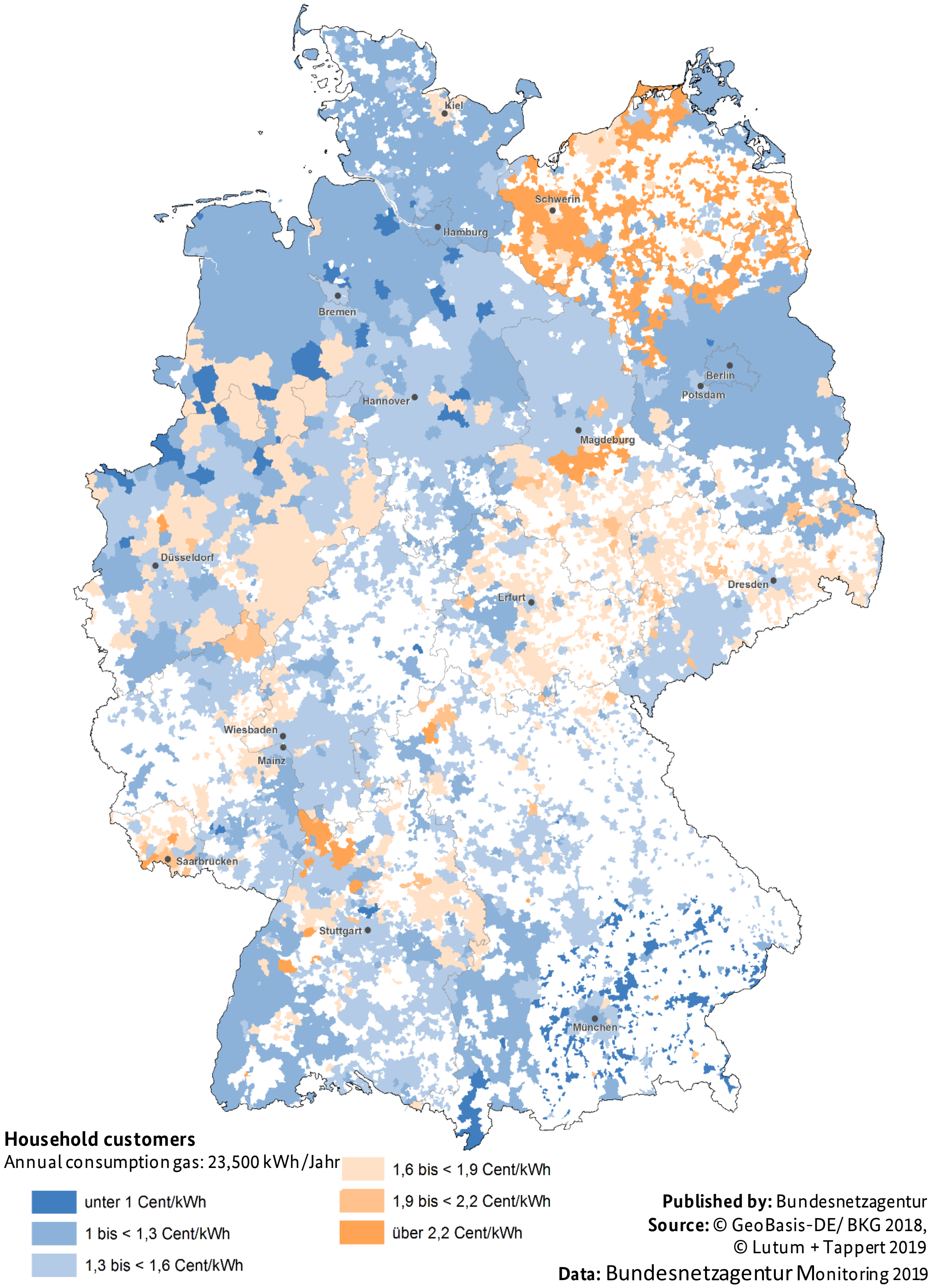


Figure 181: Distribution of gas network charges for household customers, as at 1 January 2019

The distribution of network charges for commercial customers is similar to that for household customers. Across Germany, the spread between the lowest and highest network charges extends from 0.42 ct/kWh to 3.36 ct/kWh. As for household customers, there is a difference between the new and old federal states in the distribution of network charges for commercial customers. The average network charge for commercial customers in the new federal states (not including Berlin) is 1.51 ct/kWh (2018: 1.34 ct/kWh), while the average in the old states (including Berlin) is 1.30 ct/kWh (2018: 1.11 ct/kWh). Compared to the previous year, network charges for commercial customers have thus increased on average by 13% in the new federal states and by around 17% in the old states. Looking at the averages by federal state, the highest network charges for commercial customers are found in Brandenburg and Saxony-Anhalt, and the lowest in Berlin and Bavaria.

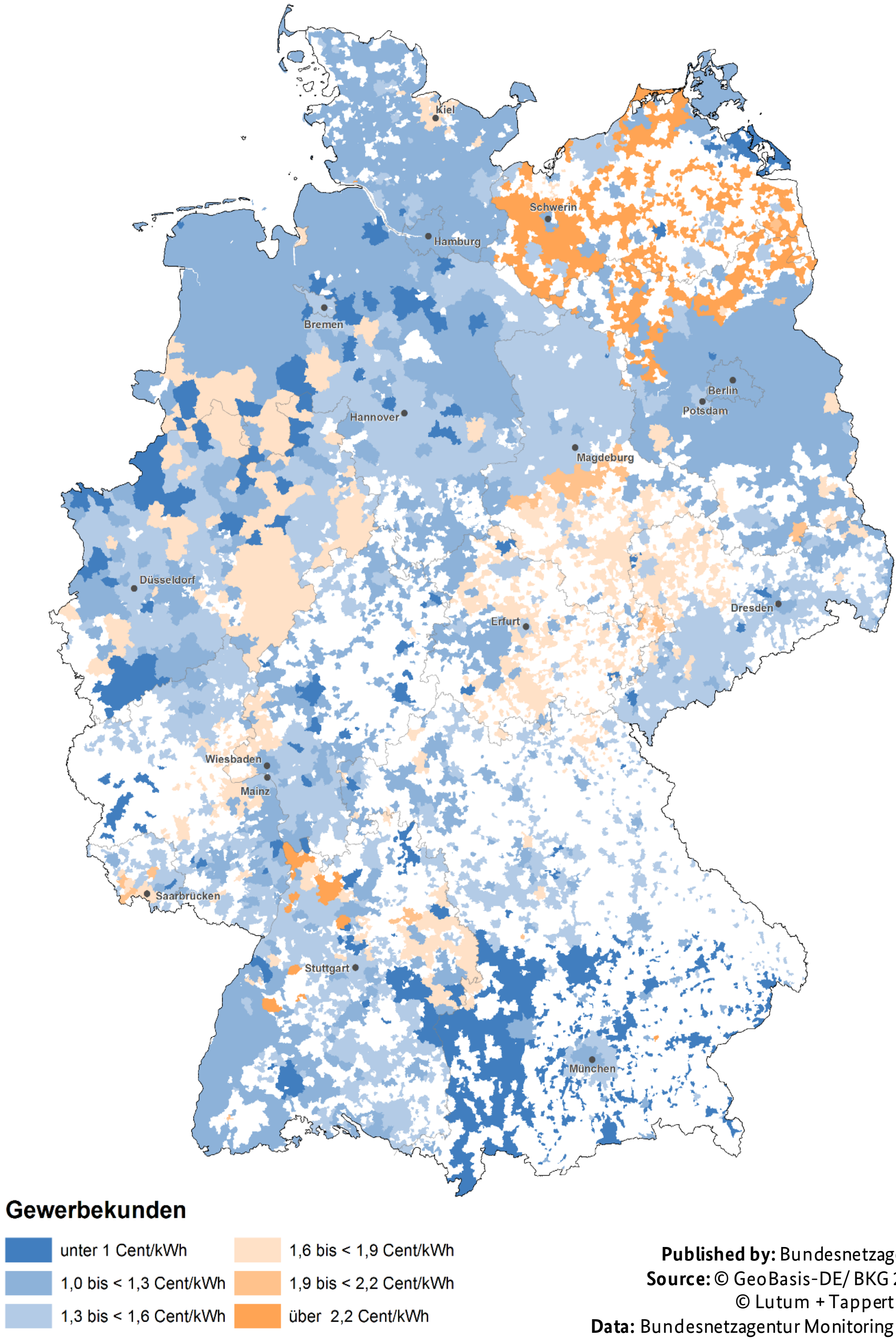
Gas: Net network charges for business customers in Germany for 2019
ct/kWh

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks considered
Brandenburg	1.67	0.84	3.36	29
Saxony-Anhalt	1.58	0.99	2.22	29
Mecklenburg-Western P.	1.57	0.90	2.29	22
Bremen	1.56	1.54	1.67	2
Saarland	1.53	0.84	2.14	18
Thuringia	1.39	0.87	1.93	30
North Rhine-Westphalia	1.36	0.42	2.58	121
Saxony	1.34	0.88	1.80	37
Baden-Württemberg	1.33	0.73	2.67	105
Schleswig-Holstein	1.31	0.92	2.21	43
Rhineland-Palatinate	1.27	0.74	1.62	35
Hesse	1.27	0.89	1.65	45
Hamburg	1.22	1.22	1.22	1
Lower Saxony	1.20	0.53	1.71	62
Bavaria	1.15	0.73	2.38	108
Berlin	1.12	1.12	1.12	1

* The number of meter points belonging to the operators in the respective network areas was used as the basis for weighting.

Table 121: Distribution of gas network charges for commercial customers in Germany, as at 1 January 2019

Network charges for business customers in 2019



Published by: Bundesnetzagentur
Source: © GeoBasis-DE/ BKG 2018, © Lutum + Tappert 2019
Data: Bundesnetzagentur Monitoring 2019

Figure 182: Distribution of gas network charges for commercial customers in Germany, as at 1 January 2019

Only gas networks that have at least one customer withdrawing at least 116 GWh were taken into account when determining the average network charges for industrial customers. Figures from 132 gas network operators were thus included in the analysis of network charges for industrial customers. Across Germany, the spread between the lowest and highest gas network charges extends from 0.16 ct/kWh to 0.90 ct/kWh. The average network charge for industrial customers in the new federal states (not including Berlin) is 0.35 ct/kWh (2018: 0.35 ct/kWh), while the average in the old states (including Berlin) is 0.30 ct/kWh (2018: 0.30 ct/kWh). The network charges for industrial customers have thus remained unchanged compared to the previous year. Looking at the averages by federal state, the highest network charges for industrial customers are found in Saarland and Brandenburg, and the lowest in Bremen and Hamburg.

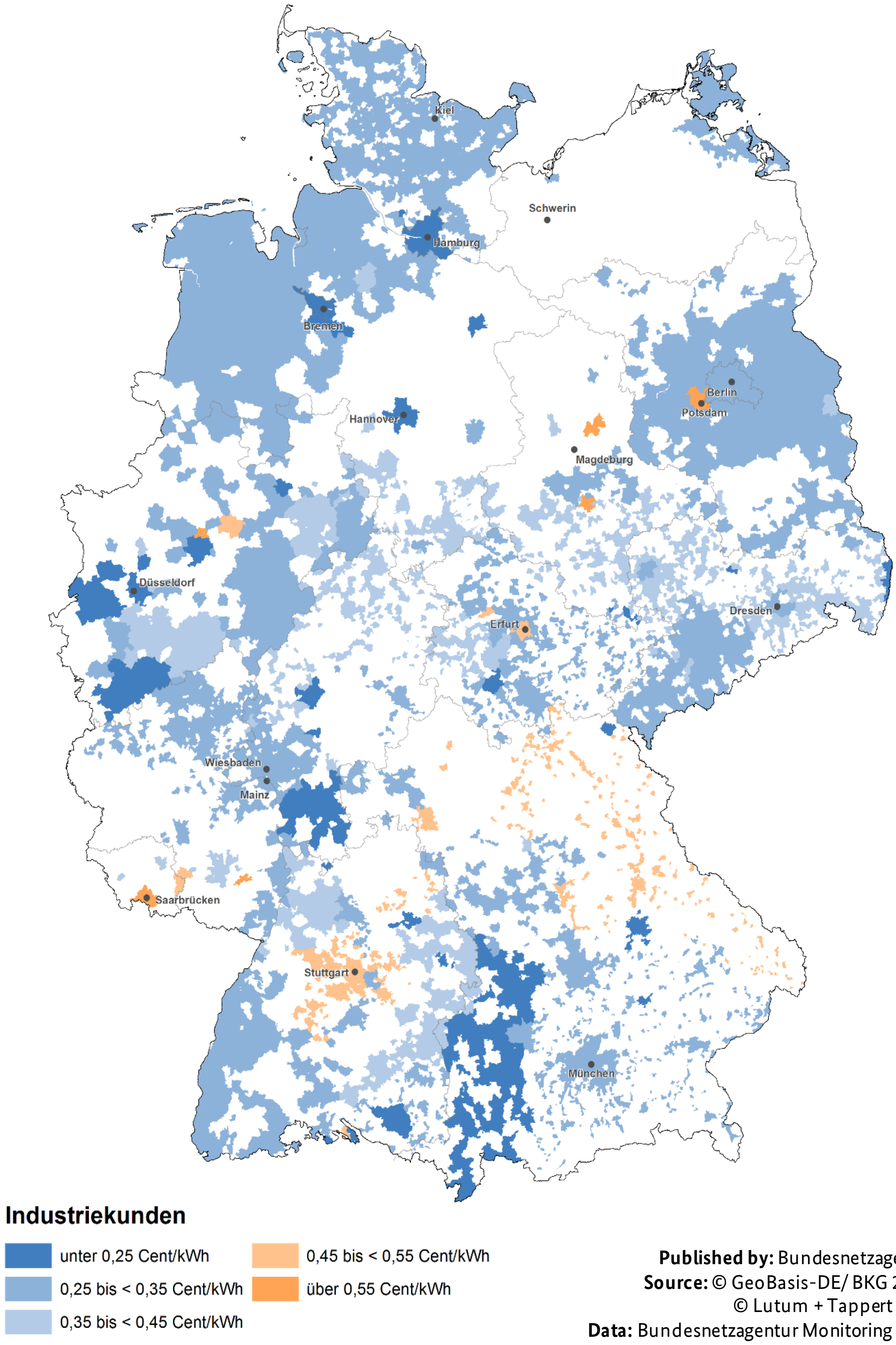
Gas: Net network charges for industrial customers in Germany for 2019
ct/kWh

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks considered
Saarland	0.45	0.39	0.81	4
Brandenburg	0.41	0.27	0.55	3
Thuringia	0.36	0.20	0.53	7
Saxony-Anhalt	0.33	0.21	0.90	9
Mecklenburg-Western P.	0.33	0.31	0.34	2
Rhineland-Palatinate	0.33	0.27	0.66	7
Saxony	0.31	0.18	0.37	7
Baden-Württemberg	0.31	0.21	0.49	20
Hesse	0.31	0.18	0.43	14
Lower Saxony	0.31	0.21	0.45	8
North Rhine-Westphalia	0.30	0.16	0.57	22
Schleswig-Holstein	0.29	0.24	0.31	5
Bavaria	0.29	0.17	0.53	20
Berlin	0.29	0.29	0.29	1
Bremen	0.22	0.21	0.26	2
Hamburg	0.22	0.22	0.22	1

* The number of meter points belonging to the operators in the respective network areas was used as the basis for weighting.

Table 122: Distribution of gas network charges for industrial customers in Germany, as at 1 January 2019

Network charges for industrial customers in 2019



Published by: Bundesnetzagentur
Source: © GeoBasis-DE/ BKG 2018, © Lutum + Tappert 2019
Data: Bundesnetzagentur Monitoring 2019

Figure 183: Distribution of gas network charges for industrial customers in Germany, as at 1 January 2019

The reasons for the regional differences in network charges are manifold. Key factors are lower levels of utilisation of the networks and 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 cost driver 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 the charges. More recently built networks have higher residual values, which increases specific capital costs and in turn leads to higher charges. As a result of their greater depreciation, older networks have lower residual values and therefore lower capital costs, thus in turn leading to lower charges. However, with advancing age, networks incur higher costs for maintenance and repair, which have a corrective effect that tends to equalise the charges.

5.5 Network transfers

In the event of a partial transfer of an energy supply network to a different network operator, in accordance with section 26(2-5) ARegV the regulatory authority specifies the share of the revenue cap to be transferred between the affected network operators.

The amendment to ARegV which came into effect in 2016 brought significant changes to this procedure. According to section 26(3-5) ARegV as applicable since September 2016, when an energy supply network is partly transferred to a different network operator the regulatory authority must define ex officio the shares of the revenue caps for the part of the network being transferred if the affected parties do not come to an agreement.

5.6 Network code on harmonised transmission tariff structures (NC TAR)

On 29 March 2019 the Bundesnetzagentur approved the initial determinations (REGENT, MARGIT, BEATE 2.0 and AMELIE) in order to implement Regulation (EU) 2017/460 establishing a network code on harmonised transmission tariff structures (NC TAR), which entered into force on 6 April 2017, within the specified period. These determinations in large part replace the previous national provisions on tariff setting for TSOs with effect from 1 January 2020, and are the result of an extensive consultation process. Among other things the REGENT determination stipulates that the reference price methodology to be used is the postage stamp, to be applied jointly across the market area. The postage stamp method results in uniform entry and exit tariffs across a market area, and is a noticeable change from the previous situation where each individual TSO calculated tariffs separately. For 2020, the entry and exit tariffs for firm annual capacity in the NCG market area are €4.07 kWh/h/a and in the GASPOOL market area €3.36 kWh/h/a. The tariffs of Open Grid Europe, the largest transmission system operator in Germany, will remain at almost the same level compared to 2019 (-€ 0.02), while the tariffs of Gascade, the second-largest transmission system operator in Germany, will increase by € 0.72 (27%). Larger tariff changes are noticeable for some smaller TSOs – both increases and reductions.

At the end of May 2019 the Higher Regional Court of Düsseldorf rejected several expedited proceedings for an order establishing the suspensory effect of complaints filed simultaneously against the REGENT and AMELIE determinations. The court is not expected to take a decision on the other pending complaints against these determinations before the beginning of 2020. Following these decisions, the determinations may also be subject to proceedings at the Federal Court of Justice.

Against the background of the intended merger of the two current German market areas into one single market area by 1 October 2021, the Bundesnetzagentur also initiated further determination proceedings (REGENT 2021, MARGIT 2021 and AMELIE 2021) in May 2019.

D Balancing

1. Balancing gas and imbalance gas

1.1 Balancing 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). External balancing gas is procured by the market area managers according to a merit order list (MOL), divided into ranks 1, 2 and 4.

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.

Gas: balancing gas use in NetConnect Germany market area
MWh

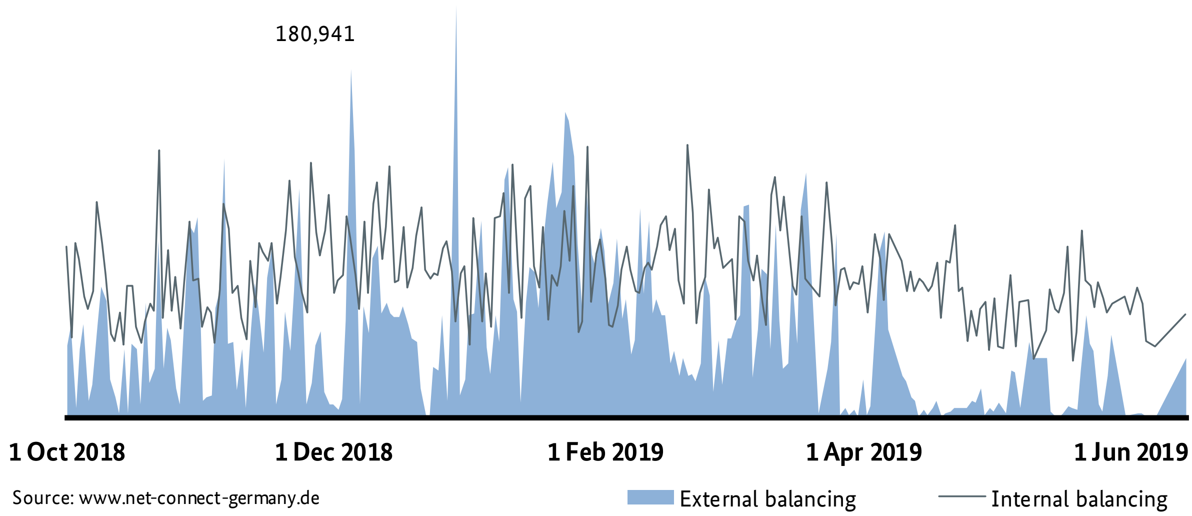


Figure 184: Balancing gas use from 1 October 2018 in the NetConnect Germany market area, as at July 2019

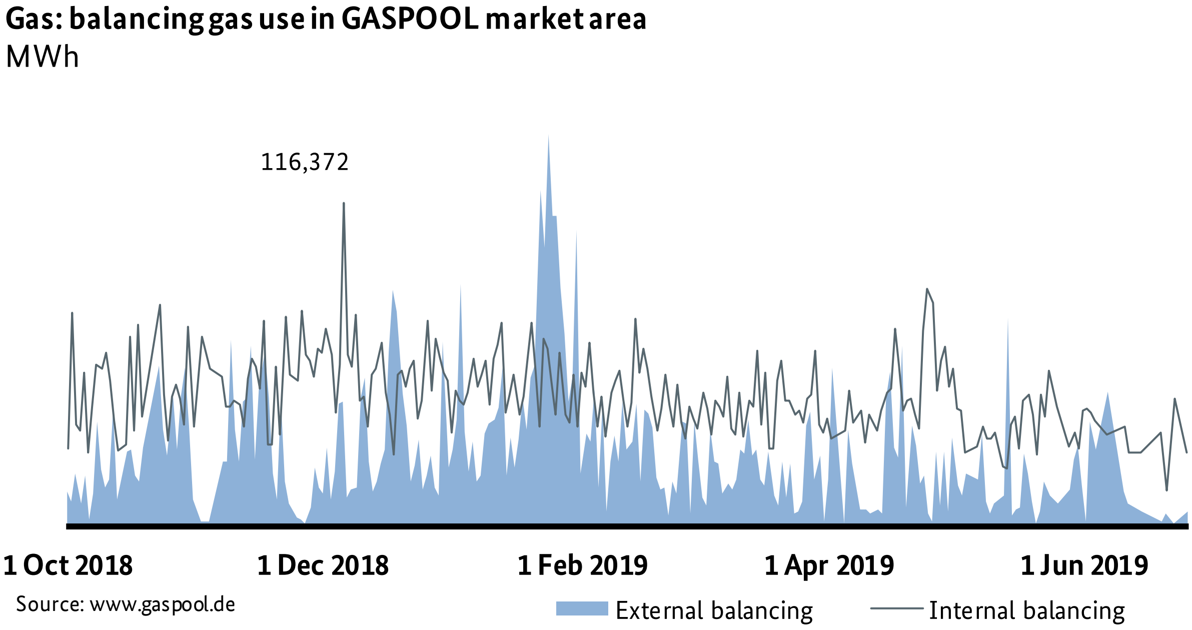


Figure 185: Balancing gas use from 1 October 2018 in the GASPOOL market area, as at July 2019

The purchase prices for balancing gas depicted below are calculated as an average of the daily balancing gas prices.

The charts show that the demand for external balancing gas in both market areas is mainly covered by products from MOL ranks 1 and 2. Quality-specific products within MOL rank 2 account for the largest proportion of the procured volume.[138]

As purchasing is mainly exchange-traded, the purchase prices are on the same level as general market prices.

[138] The short-term, bilateral balancing gas products previously included in MOL rank 3 were able to be replaced by exchange-traded products. Consequently, there are no products in MOL rank 3 anymore, neither in GASPOOL nor in NetConnect Germany.

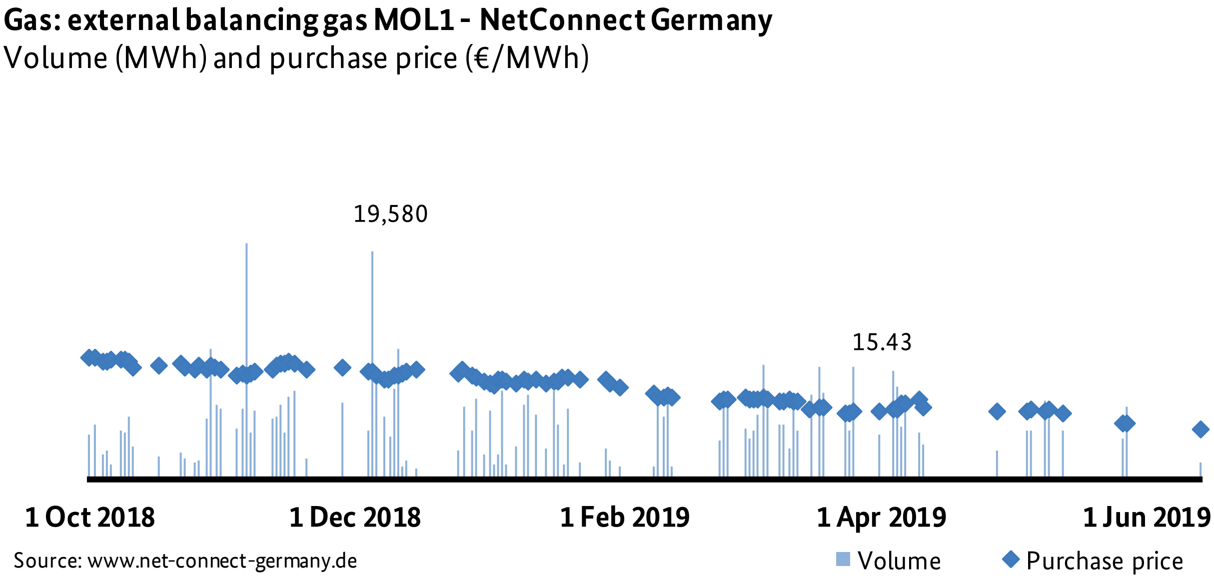


Figure 186: External balancing gas purchase prices and volumes from 1 October 2018 for MOL 1 in the NetConnect Germany market area, as at June 2019

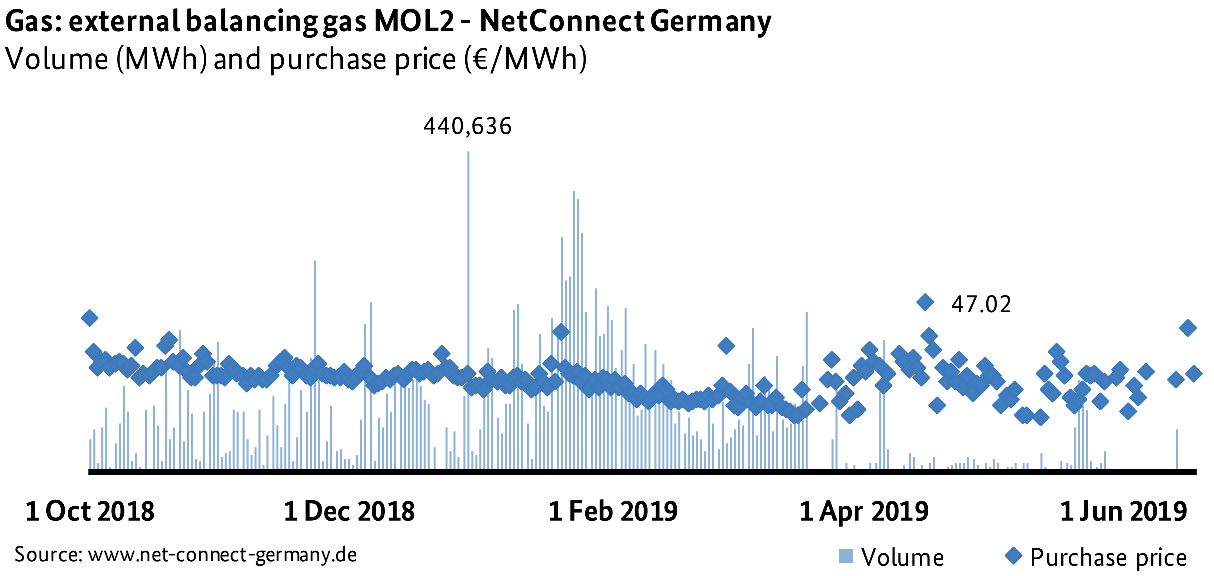


Figure 187: External balancing gas purchase prices and volumes from 1 October 2018 for MOL 2 in the NetConnect Germany market area, as at June 2019

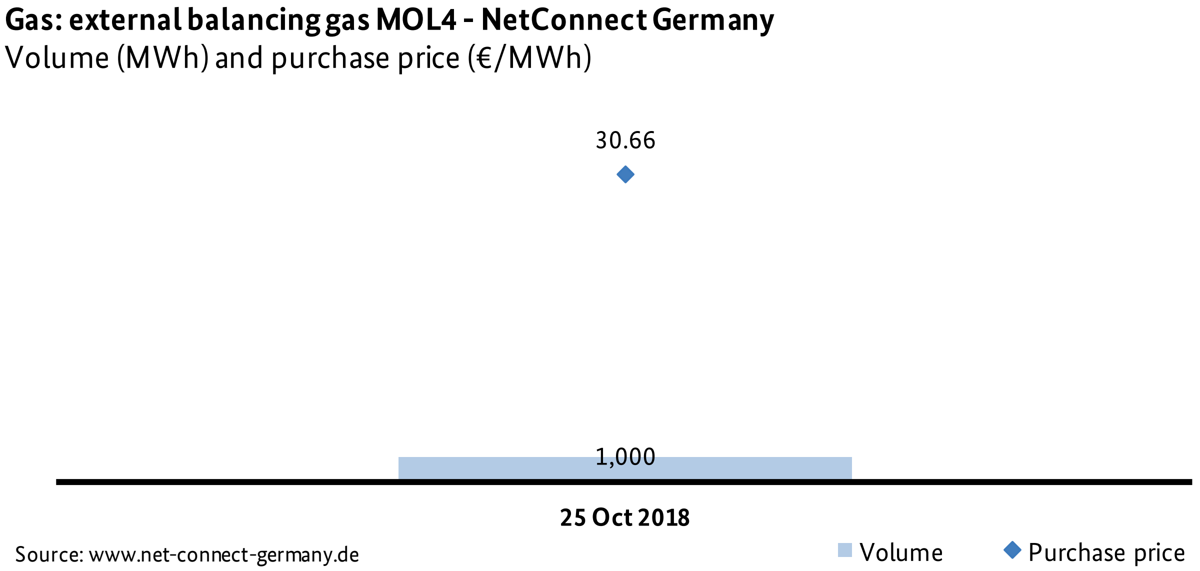


Figure 188: External balancing gas purchase prices and volumes from 1 October 2018 for MOL 4 in the NetConnect Germany market area, as at June 2019

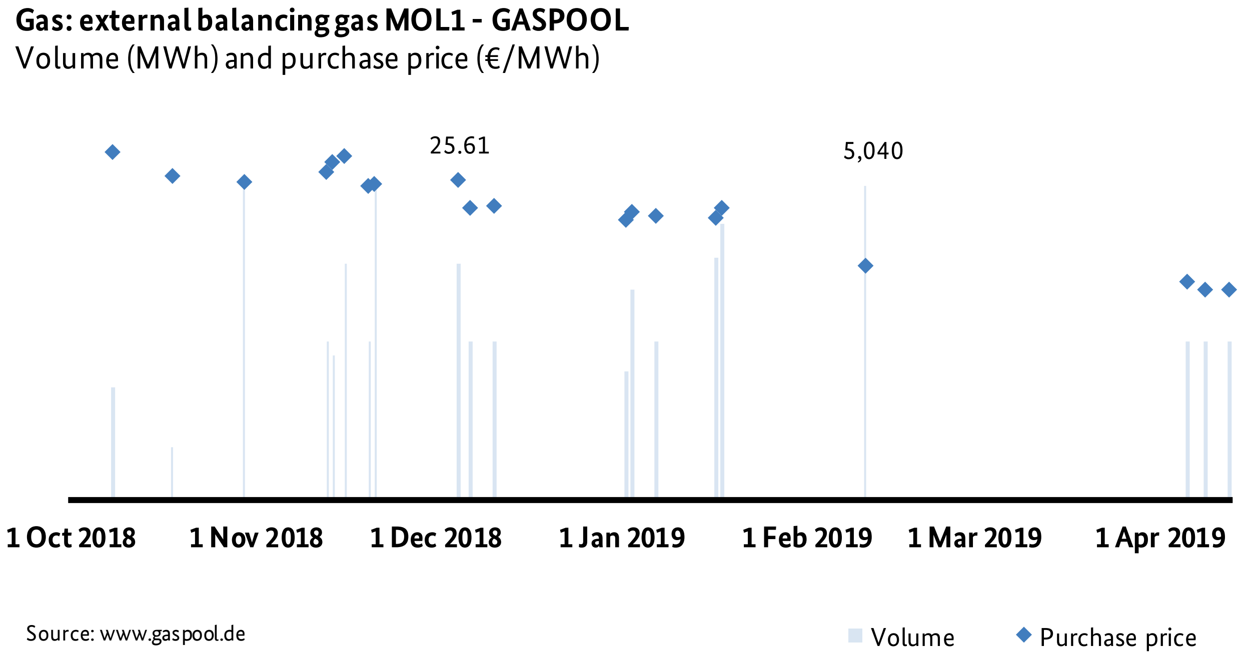


Figure 189: External balancing gas purchase prices and volumes from 1 October 2018 for MOL 1 in the GASPOOL market area, as at June 2019

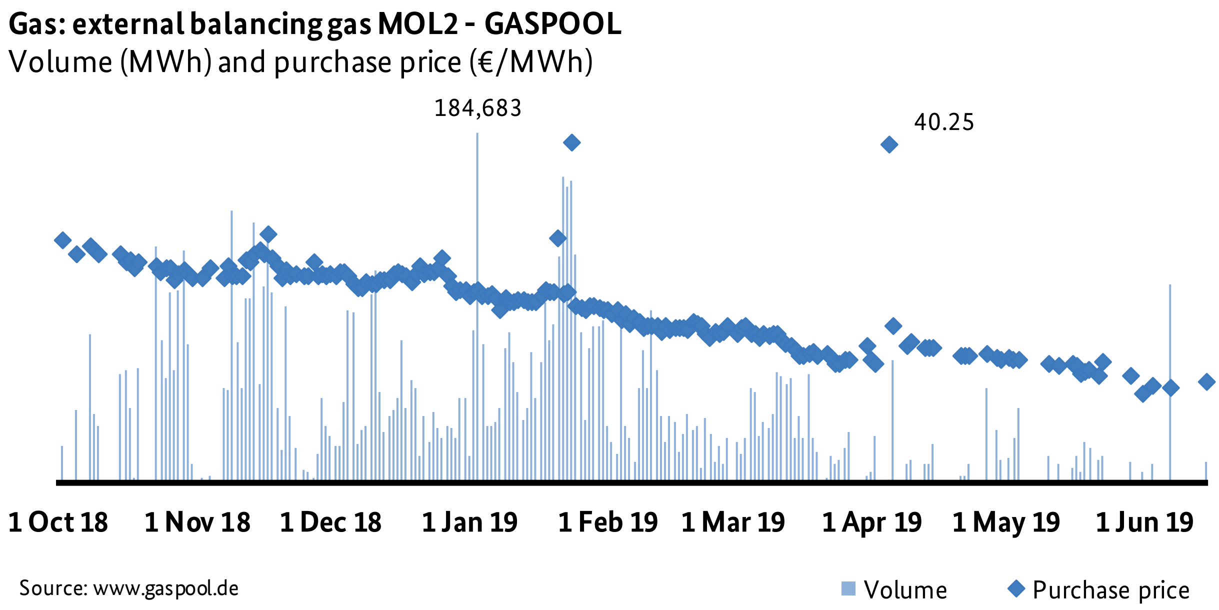


Figure 190: External balancing gas purchase prices and volumes from 1 October 2018 for MOL 2 in the GASPOOL market area, as at June 2019

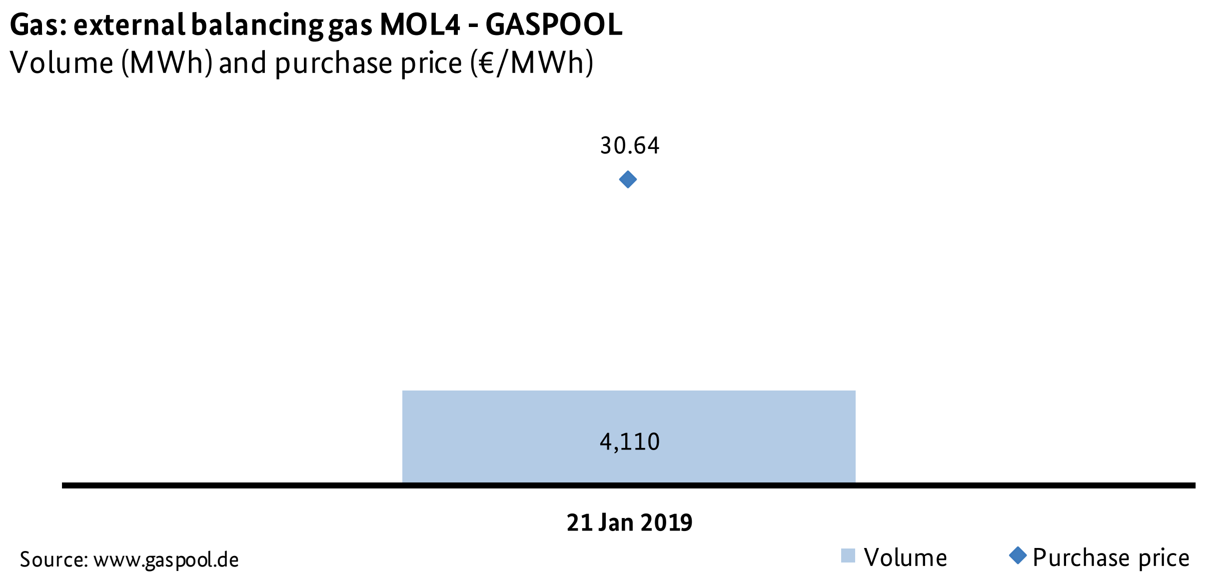


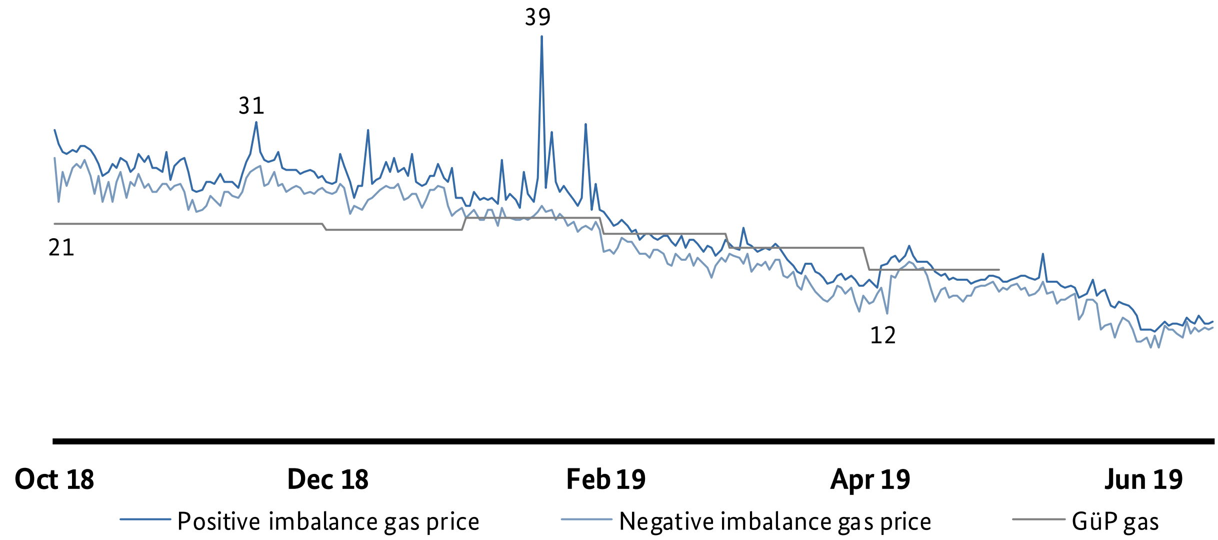
Figure 191: External balancing gas purchase prices and volumes from 1 October 2018 for MOL 4 in the GASPOOL market area, as at June 2019

1.2 Imbalance gas

In the gas market, 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.

To calculate the imbalance prices, the balancing gas prices (MOL 1 and MOL 2, excluding local and hourly balancing products) and the volume-weighted average price of gas including a 2% addition/deduction are used to set the positive and negative imbalance prices. As a result, the two market areas may have different imbalance prices. The figure below shows the development of the imbalance price.

Gas: development of imbalance gas price - NetConnect Germany
€/MWh



Source: Imbalance price MAM: ww.net-connect-germany.de, cross-border point (GüP:) www.bafa.de, as at July 2019

Figure 192: Development of NetConnect Germany imbalance prices since 1 October 2018, as at June 2019

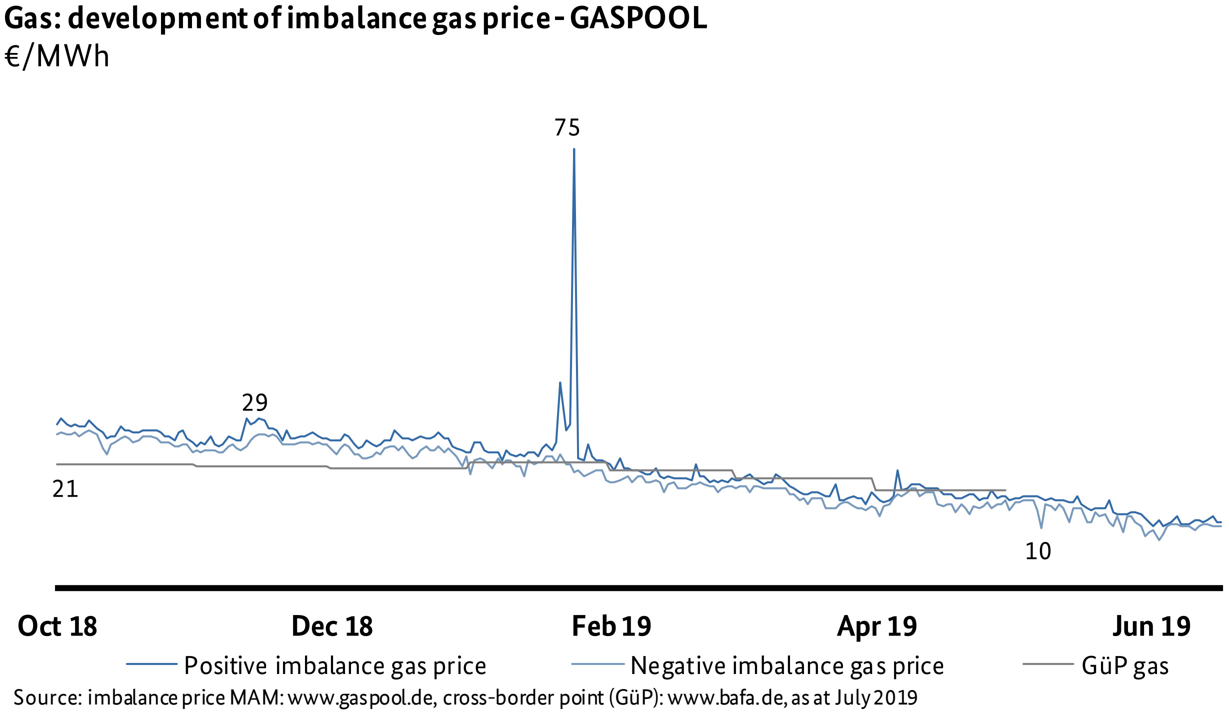


Figure 193: Development of GASPOOL imbalance prices since 1 October 2017, as at June 2019

2. Development of the neutrality charge for balancing

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, as well as a liquidity buffer, for the neutrality charge account.

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, for exit points connecting either grid users with standard load profiles (SLP) or metered load profiles. 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 metered load profile) each apply for one year.

For the period of validity as of 1 October 2018, a neutrality charge of €1.20/MWh will be levied for SLP customers and €0.6/MWh for customers with metered load profiles in the NCG market area. For the same period, a neutrality charge of €0.73/MWh will be levied for SLP and €0.26/MWh for metered load profiles in the GASPOOL market area.

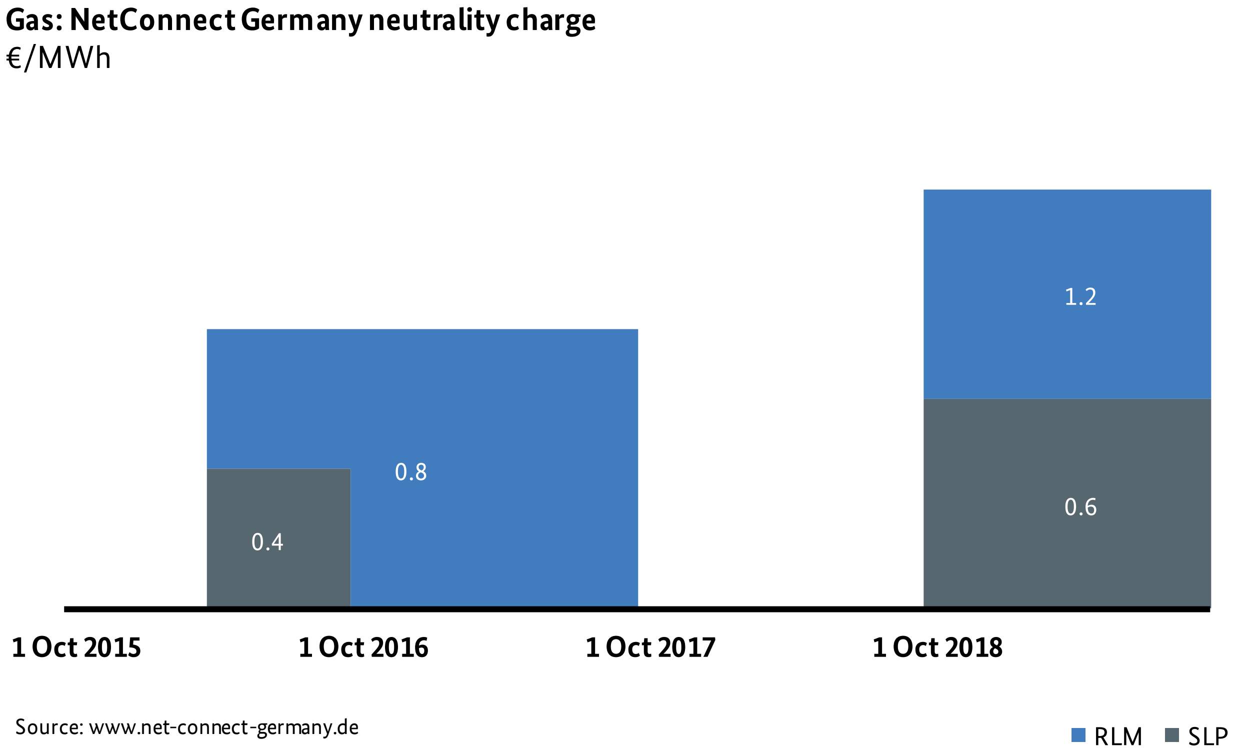


Figure 194: Neutrality charge in the NetConnect Germany market area, as at June2019

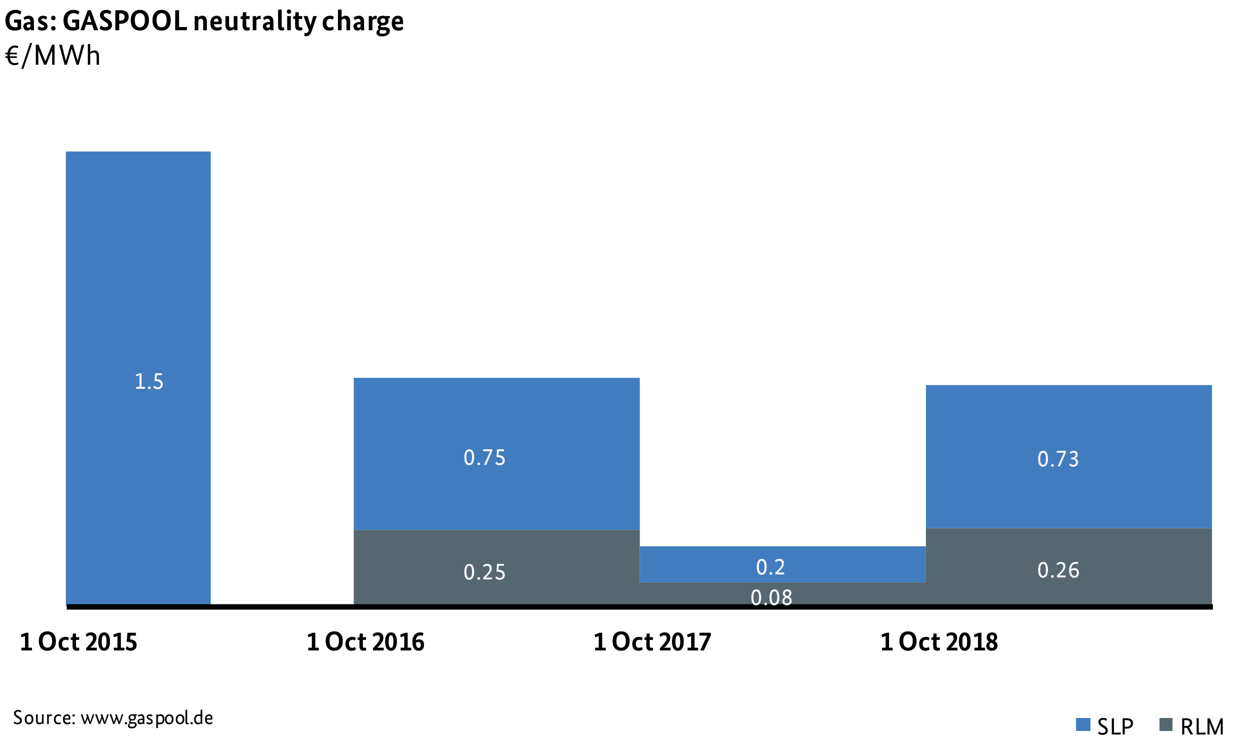


Figure 195: Neutrality charge in the GASPOOL market area, as at June 2019

3. Standard load profiles

Network operators use standard load profiles (SLPs) to allocate offtake quantities of final consumers, especially household and small business customers. They are used by 97.3% of network operators. Customers with an installed capacity of at least 500 kW or annual consumption of at least 1.5m kWh must be interval-metered. The opportunity to deviate from this limit was taken by 5.5% of network operators, of which 39.5% stated that they reduced the limit for network-related reasons. In 52.6% of cases, the limits were agreed individually with shippers. According to the information provided, half of these agreed figures applied only to individual customer groups and the other half to all customer groups.

Network operators can use two types of 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 2018, the synthetic SLP profiles were used by 81.4% of operators (2017: 81.2%); analytical profiles were used by 13.8% of operators, compared to 14.1% in 2017. The synthetic profiles of the Technical University of Munich (TU München), used in the versions of 2002 and 2005, are clearly dominant with a market coverage of 93.9%. This figure, too, remains almost as high as the previous year (94.5%). The TU München offers a range of different profiles which reflect the offtake behaviour of various customer groups. In response to the question whether all available profiles were applied, 47.6% of network operators said they were, compared to 46.5% in 2017. As in the previous years, two to three profiles were generally used for household customers, whereas eight profiles were used on average for business customers.

Of network operators using the analytical profiles, 11.5% of them used the two-day delay method, with just 3.6% stating they apply the optimisation procedure to minimise the two-day delay. Whatever method was used, only 5.1% of operators made adjustments to the load profiles owing to large deviations from forecasts, compared to 7.6% in 2017. These adjustments consisted of applying correction factors, changing coefficients or other measures.

The network operator's network account balances all gas injected into a network against the allocated offtake quantities to final consumers and transfers to downstream networks, storage facilities, adjacent market areas and foreign networks from the network. The market area managers settle these network accounts in the case of a short or long portfolio. The network accounts of 49.5% of network operators were settled due to short portfolios in at least one month (18.8% did not provide any data). The average number of months for these network operators was 3.2. The average across all network operators was two months.

The network accounts of 56.2% of network operators were settled due to long portfolios in at least one month of the gas year 2017/2018 (20.1% did not provide any data). The average number of months for these network operators was 8.8 in the gas year 2017/2018. The average including those network operators whose accounts were not settled was 6.1 months during the period. According to 49.2% of network operators, they had waived the credit from the settling of long portfolios.

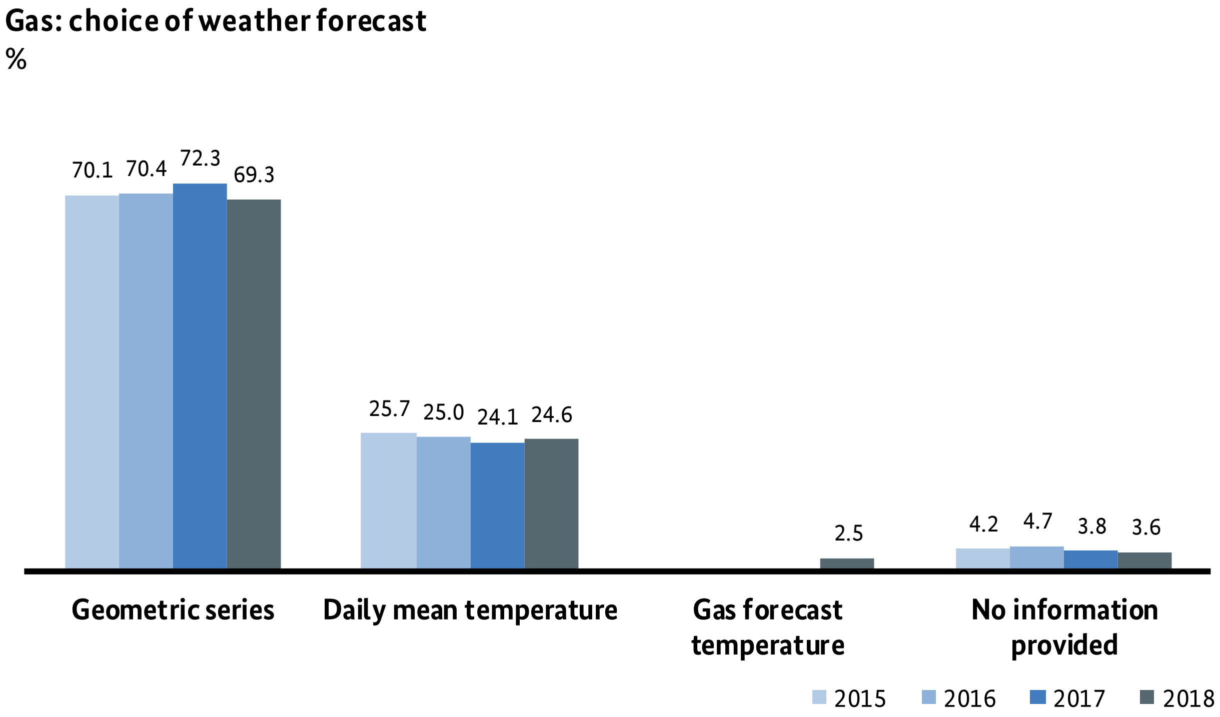


Figure 196: Choice of weather forecast

Due to the strong temperature dependence of SLP profiles, there is a continuing strong preference for 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. The use of the gas forecast temperature was also included in the survey for the first time in this reporting period, with 2.5% of network operators stating they used it. It appears that some network operators have moved to this method from the use of the geometric series.

E 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 the 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. The volume of on-exchange gas trading rose by around 13% in 2018. However the volume of brokered bilateral wholesale trading fell by around 14%. In the final analysis the latter effect prevailed, showing a light reduction in liquidity on the gas wholesale markets in 2018.

As in the previous year 2018 was characterised by significantly higher gas wholesale prices. For example, the EGIX, which is used as a reference price for the medium-term procurement market, rose by an unweighted annual average of around 28% compared to 2017.

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 ahead 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. Market participants mainly use the futures market 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 November 2017 EEX has held

100% of the shares in Powernext SA. In September 2019 the EEX Group announced its intention to integrate Powernext's business into EEX AG under an exchange licence as of 1 January 2020.[139]

EEX and Powernext trade on the European gas market is operated on the joint platform PEGAS. PEGAS allows its members to trade spot and futures market products for the German, Austrian, Belgian, Czech, Danish, Dutch, French, Italian, Spanish and UK gas market areas. Futures can be traded for specific months, quarters, seasons (summer/winter) or years (so-called calendars). In addition, in the second half of 2017 a new European spot market index "European Gas Spot Index" (EGSI) was introduced to the EEX to allow market participants to better mirror short-term price developments in their contracts. The price index covers the gas markets of Germany (Gaspool and NCG), the Netherlands (TTF), France (TRF, up to October 2018: PEG Nord and TRS), Austria (CEGH VTP), Denmark (ETF) and Belgium (ZTP). As of January 2018 the EGSI completely replaced the daily reference price which has since not been determined.

A total volume of 1,963 TWh was traded on the EEX Group's gas markets in 2018. This corresponds to a year-on-year decline of around 1% (1,982 in 2017). The spot market accounted for 1,111 TWh (828 TWh in 2017) and a total volume of 852 TWh was traded on the futures market (1,154 TWh in 2017).[140] The corresponding shares of the spot and futures markets of the total volume were therefore reversed in relation to 2017.

The entire trading volume on PEGAS relating to the German market areas GASPOOL and NCG, including "cleared volume" was around 449 TWh in 2018, an increase of around 53 TWh, or 13%, on the previous year's figure of 396 TWh. The trading volume increased in both market areas compared to the previous year. The trading volume for the GASPOOL market area increased by approximately 38 TWh or around 28% and by 15 TWh or around 6% for the NCG market area. The on-exchange volume traded on the spot market increased again in 2018 and was around 391 TWh (around 309 TWh in the previous year). In 2018, as in previous years, the majority of spot market transactions for both market areas focused on day-ahead contracts (NCG: 132.9 TWh, 115.8 TWh in the previous year); GASPOOL: 102.8 TWh, (69.3 TWh in the previous year). The trading volume of futures contracts fell from about 86 TWh in 2017 to about 58 TWh in 2018, corresponding to a decline of 33%.

[139] See https://www.eex.com/de/about/newsroom/news-detail/pressemitteilung--eex-und-powernext-beabsichten-buendelung-der-stromtermin--und-gasmaerkte-unter-einer-boersenlizenz/99798 (retrieved on 5 September 2019)

[140] EEX Group Annual Report 2018, p. 64

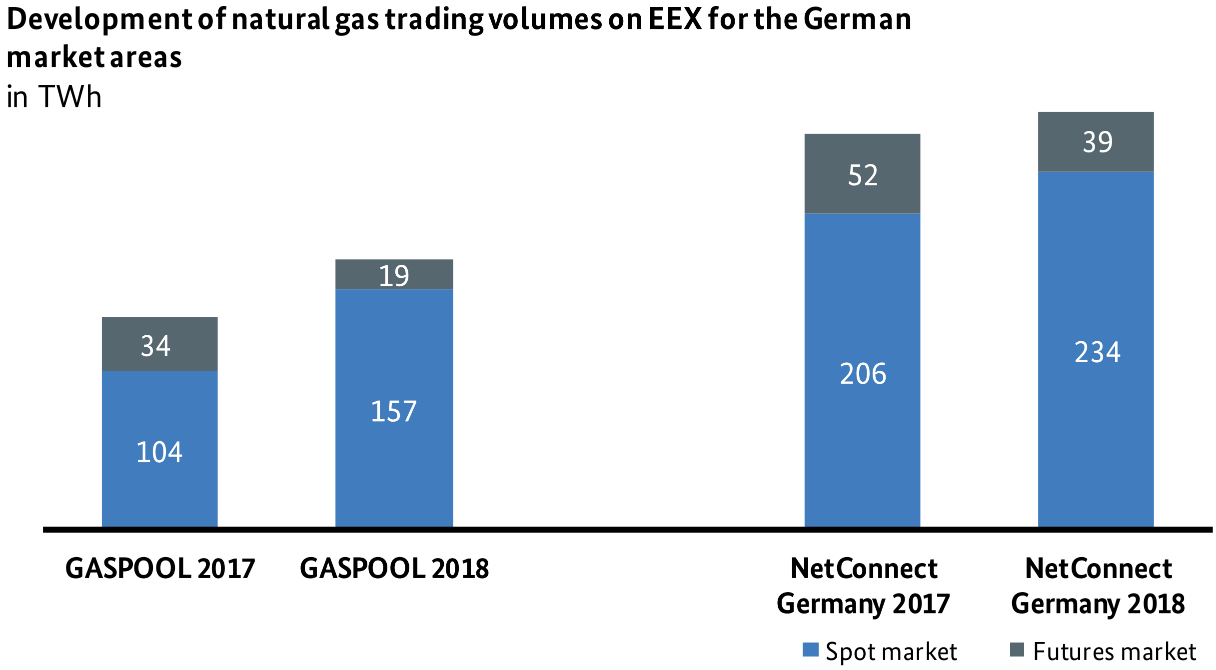


Figure 197: Development of natural gas trading volumes on EEX for the German market areas

The annual average number of active [141] participants on the spot market per trading day was 87 for NCG contracts (84 in the previous year) and around 75 for GASPOOL contracts (around 71 in the previous year). By contrast, the average number of active participants on the futures market per trading day was around 5.6 (NCG: 8.9 in the previous year) and around 3.6 (GASPOOL: 6.4 in the previous year). The comparison of these figures has to take account of the fact that, owing to their term, futures contracts are geared towards higher quantities purchased 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.

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 the usual limited set of contracts on exchange markets. 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 offer and supply of short-term and long-term natural gas trading products. Engaging a broker can reduce research costs and make it easier to effect large transactions. At the same time this allows greater risk diversification because brokers offer services to register trading transactions brokered by them for clearing on the exchange to hedge

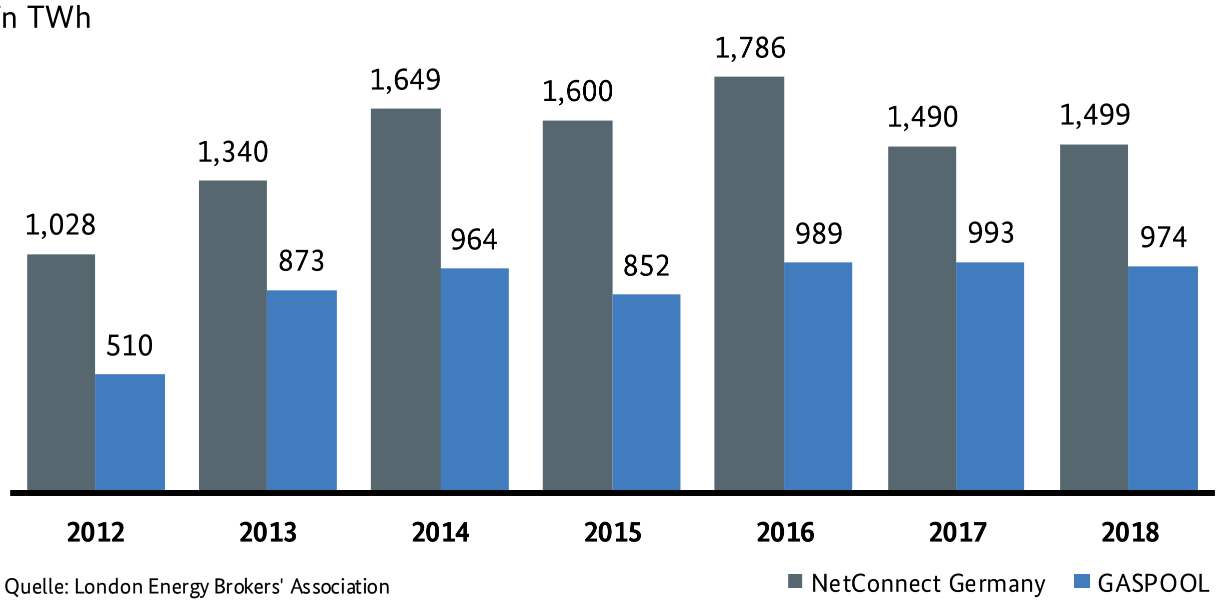
[141] Participants are considered to be active on a trading day if at least one of their bids has been submitted.

the counterparty default risk of the parties. 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.

Eight broker platforms (nine in the previous year) took part in this year's collection of wholesale trading data. The natural gas trading transactions brokered by these broker platforms in 2018 with Germany as the supply area comprised a total volume of 2,289 TWh (2,672 TWh in the previous year), of which 858 TWh were contracts to be fulfilled in 2018 (fulfilment period of one week or more).

The decrease in volume is confirmed by the figures relating to brokered natural gas trading for the GASPOOL market area published by the London Energy Brokers Association (LEBA). LEBA registers a slight increase in volume for its members for the NCG market area[142]. Six of the eight 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 2,473 TWh for the two German market areas in 2018 (2,483 in 2017).

Development of natural gas trading volumes of LEBA affiliated broker platforms for German market areas
in TWh



Quelle: London Energy Brokers' Association

Figure 198: Development of natural gas trading volumes of LEBA-affiliated broker platforms for German market areas

On the spot market short-term transactions with a fulfilment period of less than one week account for about 19 % of the trade brokered by the eight broker platforms whereas 81% are futures contracts. 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 2018 (including spot trading) constitutes as much as 56% of the total volume and still as much as 30 % for the subsequent year 2019, the share of transactions with

[142] See London Energy Borkers' Association, OTC Energy Volume Report, https://cdn.evia.org.uk/content/monthly_vol_reports/LEBA%20Energy%20Volume%20Report%20December%202018.pdf (retrieved on 12 August 2019)

supply dates in 2020 and later is 13 per cent. This structure largely corresponds to the previous year's result with a slight increase in the quota for transactions with supply dates in 2020 and later (plus 3%).

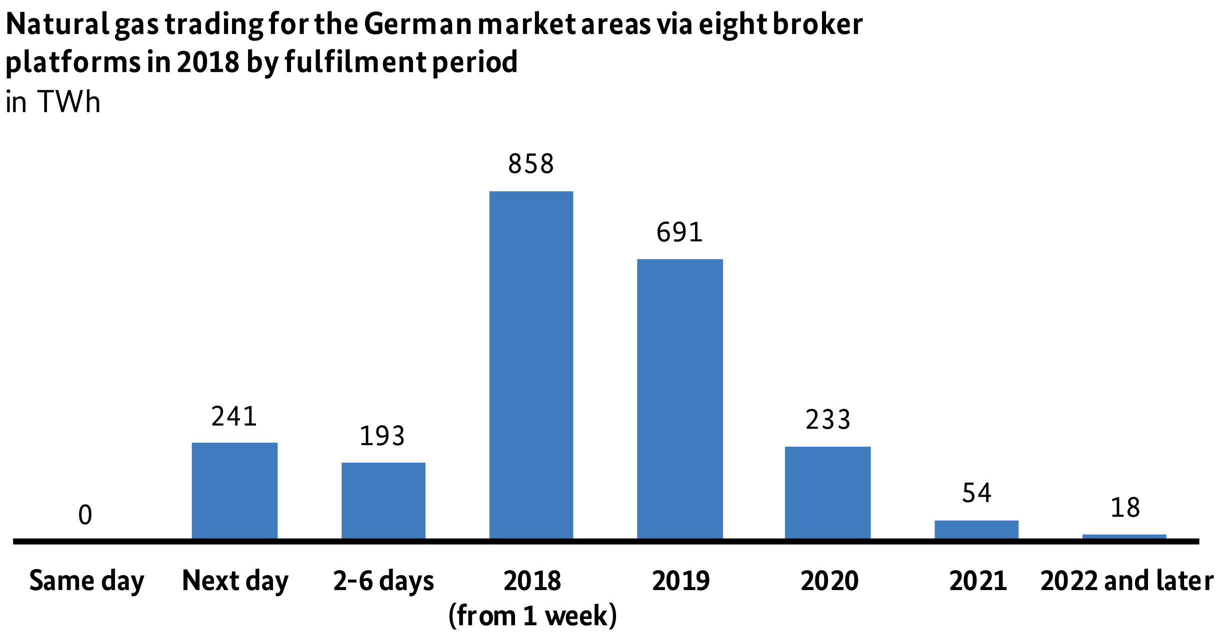


Figure 199: Natural gas trading for the German market areas via eight broker platforms in 2018 by fulfilment period

2.2 Nomination volumes at virtual trading points

The nominated 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.

Wholesale transactions with physical fulfilment are generally reflected in increasing nomination volumes. 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.

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 slightly from a total of 3,620 TWh in the previous year to 3,780 TWh, an increase of about 4%. The GASPOOL VTP accounted for about 46% of the nomination volume, and the NCG VTP for 54%. Almost 90% of the nomination volume consisted of high calorific gas, the remaining 10% of low calorific gas.

The nomination volumes of high calorific gas at GASPOOL VTP increased moderately (about 12%) year-on-year. The nominated value of high calorific gas at NGG VTP remained at roughly the same level as the previous year. The nominated volumes of low calorific gas increased at around 2% at GASPOOL VTP. This was based on substantially lower trading volumes. The nominated volumes of low calorific gas decreased by around 5% at NCG VTP.

Development of nomination volumes at the German virtual trading points
in TWh

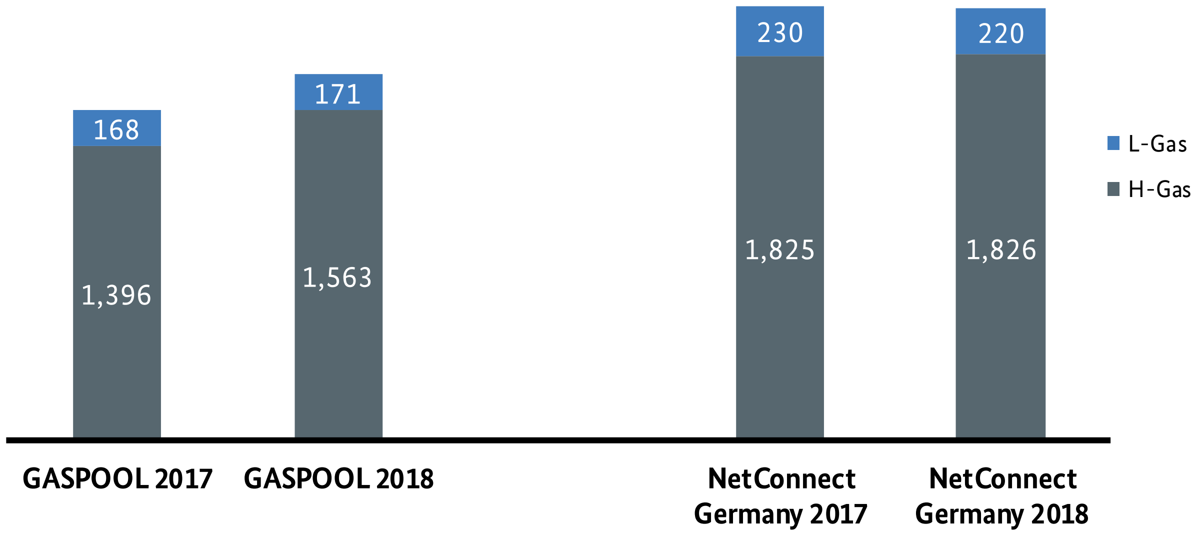


Figure 200: Development of nomination volumes at the German virtual trading points

As in previous years, the monthly nomination volumes reflect seasonal differences. The (aggregated) monthly nomination volumes of both VTPs peaked at 258 TWh between May and August 2018. The lowest nomination volume was around 241 TWh in June 2018; the annual peak of around 402 TWh was reached in March 2018.

Annual development of nomination volumes at virtual trading points in 2017 and 2018
in TWh

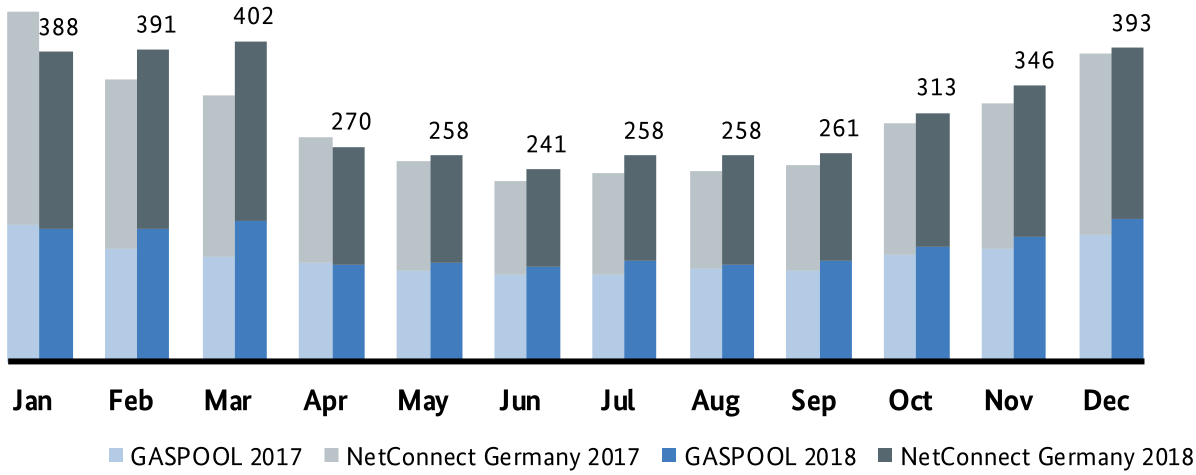


Figure 201: Annual development of nomination volumes at virtual trading points in 2017 and 2018

The number of active trading participants, i.e. companies that carried out at least one nomination in the relevant month, changed again in 2018. The number of active trading participants in the NCG market area fell from 328 to 327 for high calorific gas whereas the number of active participants for low calorific gas rose from 175 to 180. The annual average number of active participants in the GASPOOL market area fell year-on-year from 298 to 292 for high calorific gas and from 154 to 150 for low calorific gas.

3. Wholesale prices

As an important exchange for natural gas trading in Germany the EEX publishes several price indices as bases for reference prices for gas contracts for procurement within different timeframes. The EGSI 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 416 below, gives an approximate indication of the price of natural gas procurement on the basis of long-term supply contracts.

EEX determined daily reference prices on the on-exchange spot market for the GASPOOL and NCG market areas up to the end of 2017 by calculating the volume-weighted average of the prices across all trading transactions for gas supply days on the last day before physical fulfilment.[143] In September 2017 the EEX introduced the European Gas Spot Index (EGSI), which has since replaced the daily reference price as a short-term price index. The EGSI is determined by calculating the volume-weighted average. Unlike the daily reference price the EGSI is calculated at least one day before the date of fulfilment. This differs if a trading day is preceded by a weekend or banking holiday[144]. For ease of comparison the EGSI is analysed in this report exclusively according to the trading prices and volumes of so-called “day ahead” products.

The EGSI’s close relationship to its predecessor can be supported empirically. In the period from September to December 2017, in which both indices were determined for the NCG and GASPOOL market areas, only minimal differences were established in the unweighted monthly averages and a parallel development.

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[143] For details of the calculation method see https://www.eex.com/blob/9276/b906c6cf0b59cd53d7bfe33d15080b75/2013-11-28-beschreibung-tagesreferenzpreis-pdf-data.pdf (retrieved on 23 August 2019).

[144] For details of the calculation method and further details see https://www.eex.com/de/about/newsroom/news-detail/action-required---pegas-erdgas--index-harmonisierung-und-zusaetzliche-marktdaten/76706 and https://www.powernext.com/sites/default/files/download_center_files/03%20Business%20Development%20Outlook%20-%20Sirko%20Beidatsch.pdf (both retrieved on 23 August 2019).

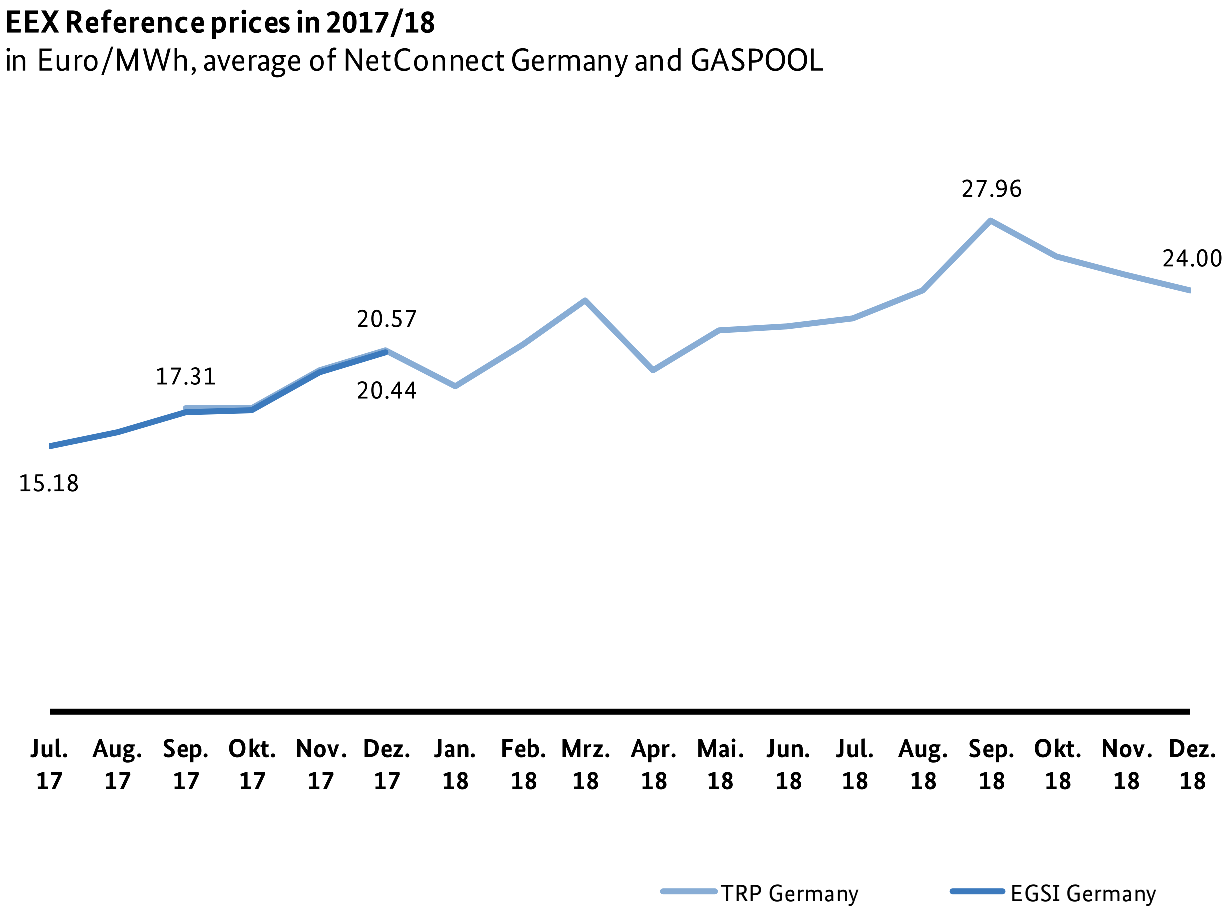

Figure 202: Development of the monthly average[145] of both EEX reference prices with special focus on the overlapping interval at the end of 2017

In 2018 the EGSI amounted to €22.95/MWh as the (unweighted) annual average for the NCG market area and also €22.95/MWh for the GASPOOL market area. In 2017 the comparative figures for the daily reference price were €17.51/MWh for NCG and €17.28/MWh for GASPOOL. The EGSI fluctuated in the course of 2018 between €17.40/MWh (at 30 January 2018) and €60.93/MWh (at 1 March 2018).

[145] The figure shows the unweighted average of the daily reference price and EGSI derived from the indices of the unweighted monthly aggregate values for the NCG and GASPOOL market areas

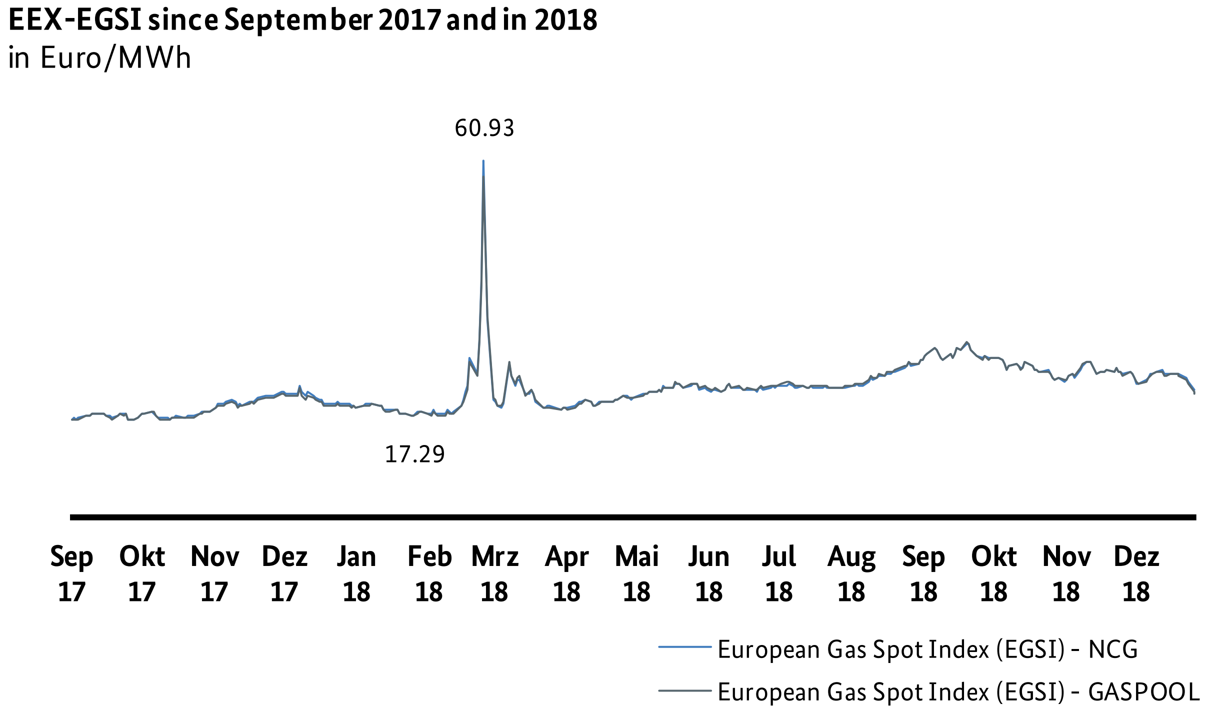

Figure 203: EEX-EGSI in 2018

The deviations between the EGSI for NCG and GASPOOL in 2018 were again minimal. On 247 of 253 exchange trading days the difference was max. 2%. The difference reached a higher level of more than 3% on six days only.

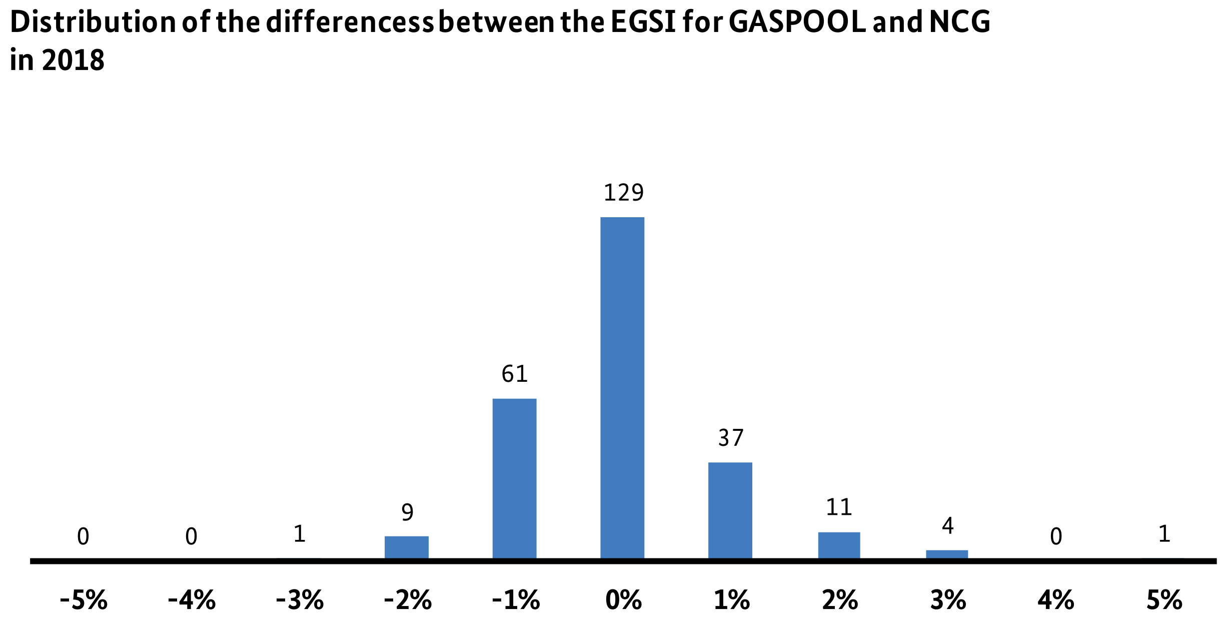

Figure 204: Distribution of the differences between the EGSI for GASPOOL and NCG in 2018

The EGIX Germany is a monthly reference price for the futures market for medium-term trading contracts. 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 2018 the EGIX Germany ranged from €18.23/MWh in March to €27.88/MWh in October. The arithmetic mean of the twelve monthly figures was €21.98/MWh, an increase of approximately 28% compared to the previous year's figure of €17.11/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 agreed in import contracts[147], spot volumes and prices are largely disregarded.

The monthly BAFA cross-border prices for natural gas ranged from €13.01 /MWh to €20.94/MWh between 2016 and 2018. The (unweighted) average of the monthly cross-border prices was €19.15 /MWh in 2018, up by 13% from the 2017 figure of €16.98/MWh.

Development of the BAFA cross-border price and the EGIX Germany between 2016 and 2018
in Euro/MWh

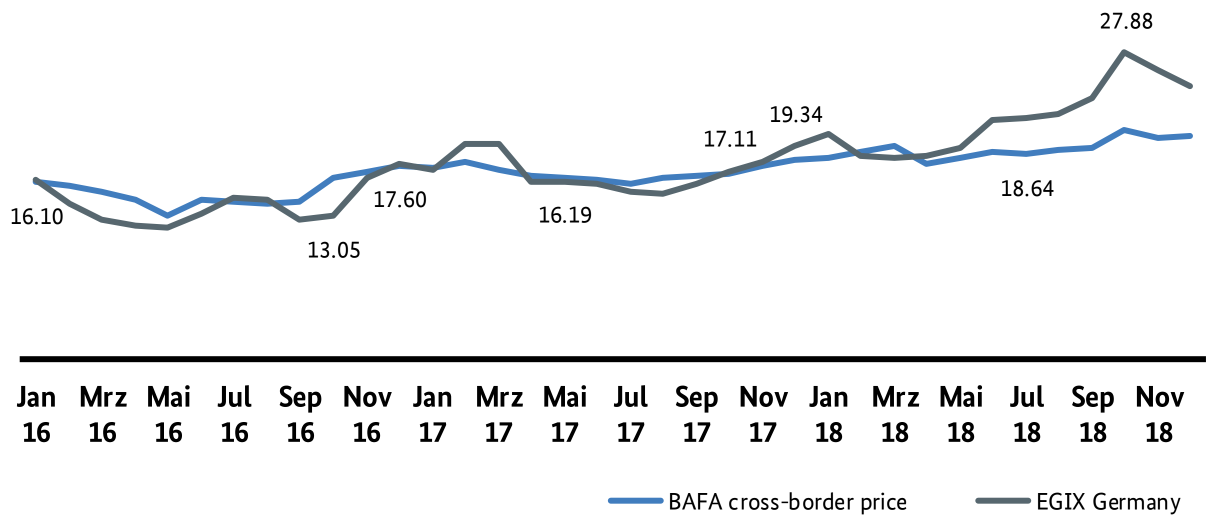

Figure 205: Development of the BAFA cross-border price and the EGIX Germany between 2016 and 2018

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 EGSI 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 2018 clearly shows that it is aligned with natural gas exchange prices.

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[146] For a detailed calculation of the values see https://www.powernext.com/sites/default/files/download_center_files/20190801_PEGAS_Reference_Price_EGIX.pdf (retrieved on 8 August 2019).

[147] See https://www.bafa.de/SharedDocs/Downloads/DE/Energie/egas_aufkommen_export_1991.html (retrieved on 8 August 2019).

F Retail

1. Supplier structure and number of providers

A total of 1,028 gas suppliers were surveyed for the 2019 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 (511 companies or 52%) supplied between 1,001 and 10,000 market locations each. These 511 suppliers delivered gas to 2.1m or 15% of the total number of market locations. The amount of gas that these suppliers delivered to final consumers was 131.8 TWh. Based on the total calculated volume of gas delivered of 818.6 TWh, this corresponds to a share of 16%.

The smallest group of gas suppliers (comprising 23 companies or just over 2%), in which each company supplies more than 100,000 market locations, supplies 5.7m or about 41% of the final consumer market locations. The amount of gas that these suppliers delivered to final consumers was 195.6 TWh. Based on the total reported volume of gas delivered of 818.6 TWh, this corresponds to a share of just over 24%. 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 market locations.

Gas: suppliers by number of market locations supplied (number and percentage) these figures do not take account of company affiliations

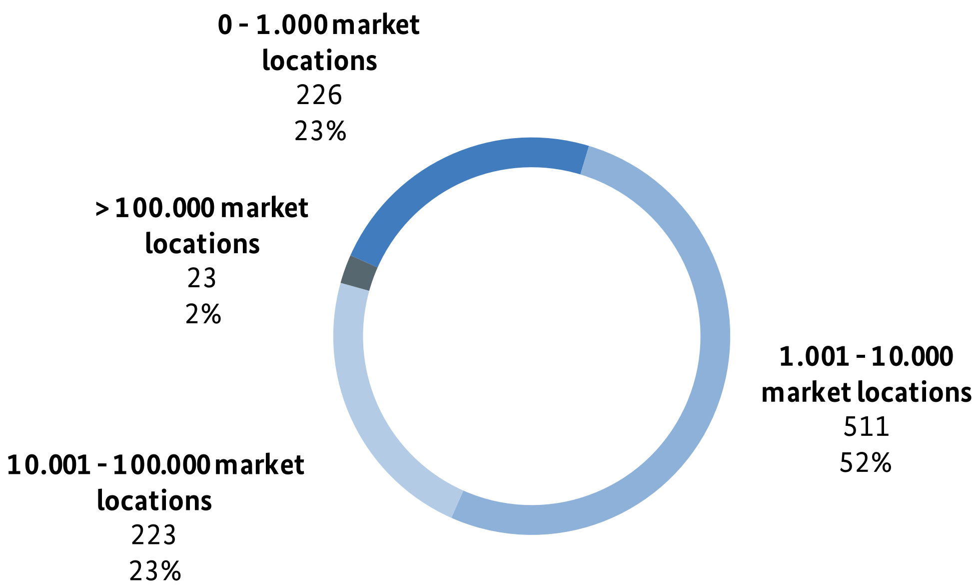

Figure 206: Gas suppliers by number of market locations supplied (number and percentage) – as at 31 December 2018

One indicator of the degree of choice for gas customers is the number of suppliers in each network area. In the 2019 survey, 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 mean a high level of competition, but does give an indication of potential competition.

Since market liberalisation and the creation of a legal basis for a well-functioning supplier switch, there has been a steady rise in the number of active gas suppliers for all final consumers in the different network areas. This positive trend continued in 2018 as well.

In 2018, more than 50 gas suppliers were operating in 94% of network areas. Final consumers in over 62% of network areas had a choice of more than 100 gas suppliers. If viewed separately, the trend for household customers is similarly positive. In nearly 89% of network areas, household customers have a choice of 50 or more gas suppliers. More than 100 gas suppliers are operating in 45% of network areas.

On average, final consumers in Germany can choose from 124 suppliers in their network area; household customers can, on average, choose between 104 suppliers (these figures do not take account of corporate groups).

Gas: breakdown of network areas by number of suppliers operating
(all final consumers (left graph) and household consumers (right graph))
in %, not taking account of company affiliations

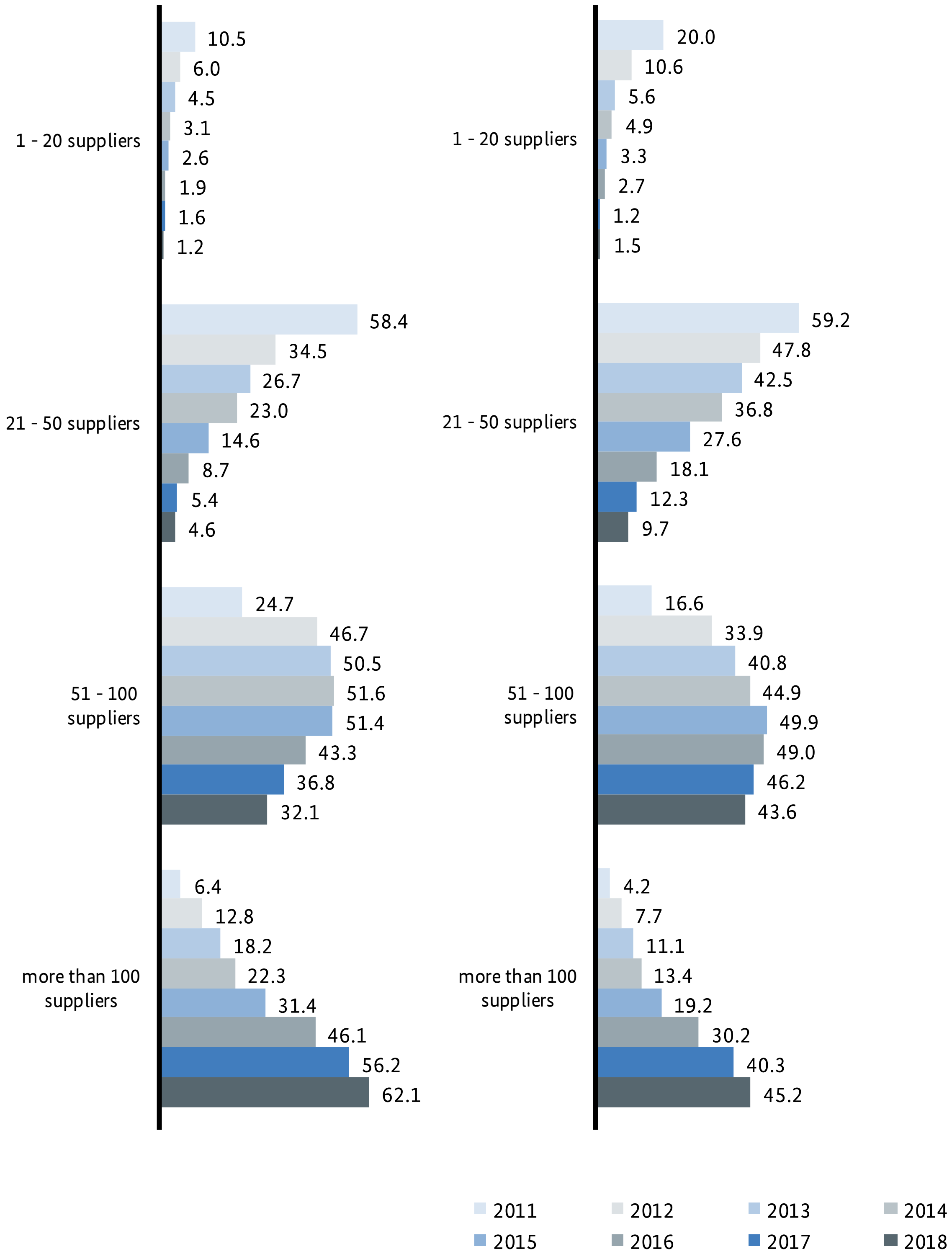

Figure 207: Breakdown of network areas by number of suppliers operating according to the survey of gas DSOs – as at 31 December 2018

Suppliers were also asked about the number of network areas in which they supply final consumers with gas. Only 17% of the gas suppliers operate in just one established network area. Most of them (32%) supply final consumers in at most 10 network areas with gas and are therefore only active regionally. In order to determine the number of gas suppliers active nationwide, if a supplier is active in more than 500 network areas they are counted as active across all of Germany. A total of 49 gas suppliers (6%) fulfil this criterion and are regarded as suppliers that are active nationwide. On average, gas suppliers in Germany are active in around 79 network areas. A further criterion to measure nationwide activity of suppliers is the number of federal states in which they supply gas, with 120 suppliers having contracts in all 16 federal states.

Gas: suppliers by number of network areas supplied (number and percentage)
these figures do not take account of company affiliations

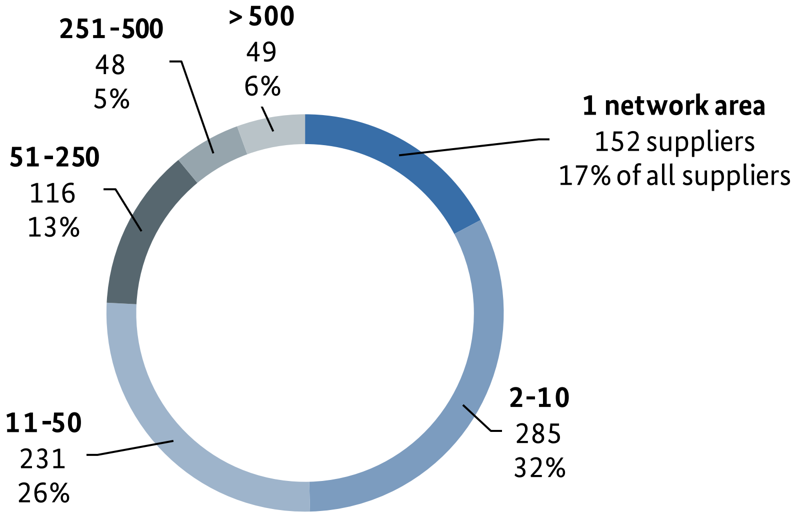

Figure 208: Gas suppliers by number of network areas supplied (number and percentage), according to the survey of gas suppliers – as at 31 December 2018

2. Contract structure and supplier switching

Half of Germany's 12.4m household customers have a non-default contract with the local default supplier. About 18% have a standard contract with their default supplier. Around a third of household customers have a gas supply contract with a supplier that is not the local default one.

The proportion of expensive default contracts has been falling for years, while the proportion of contracts with suppliers other than the local default supplier has been rising continually.

About 1.5m household customers switched gas supplier in 2018. People moving house or moving into new homes, in particular, are more and more likely to turn directly to a supplier that is not the local default one and thus to access a cheaper gas contract.

Consumers are recommended to find out what type of contract they have (default or otherwise) and to compare the prices of their current supplier with those of competitors. Switching contracts with the existing supplier or changing supplier can usually save customers money.

Changes in switching rates and processes are important indicators of the level of competition. There are challenges involved with the collection of such data, however, and the relevant data collection thus has to be limited to data that best reflects the actual switching behaviour.

In the monitoring survey, data on contract structures and supplier switching is collected through questions 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 Energy Industry Act (EnWG) according to qualitative characteristics.[148] All other customers are non-household customers, which include customers in the industrial, commercial, service and agricultural sectors as well as public administration.

According to gas retailers and suppliers, the total quantity of gas supplied to all final consumers in 2018 reached 818.6 TWh (2017: 832 TWh). Based on the reported volumes of gas sold to SLP and interval-metered customers, about 450.1 TWh went to interval-metered customers and about 367.4 TWh to SLP customers,

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[148] 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.

compared to 454 TWh and 378 TWh respectively in the previous year.[149]. The majority of SLP customers are household customers. In 2018 household customers within the meaning of section 3 para 22 EnWG were supplied with around 253.1 TWh (2017: 238.5 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,

– non-default contract with the default supplier, and

– contract 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.[150] 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) of the Electricity and Gas Concession Fees Ordinance, KAV). An evaluation 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".[151]

Once again, gas suppliers were asked how many household customers switched or changed their energy supply contract in the 2018 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 2018. A supplier switch, as defined in the monitoring survey, means the process by which a final consumer's meter location 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

[149] The small difference between the amount of 817.5 TWh (total of interval-metered and SLP volumes) and the total volume of 818.6 TWh is due to different data from the suppliers surveyed.

[150] 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".

[151] It is also possible that further ambiguities may arise, for example if the local default supplier changes.

switched suppliers may deviate slightly from the figures established in the survey. In addition to supplier switches, the choice of supplier made by household customers upon moving home was also analysed.

2.1 Non-household customers

2.1.1 Contract structure

Gas volumes for non-household customers are predominantly supplied to interval-metered customers whose gas consumption is recorded at short (e.g. quarter hourly) intervals, ("load profile"). Such customers are characterised by high consumption and/or high energy requirements.[152] 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 around 804 gas suppliers (separate legal entities) provided information on metering points and on the volumes supplied to metered load profile customers (804 suppliers responded in the previous year). The 804 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 450.1 TWH of gas to metered load profile customers via more than 39,509 metering points in 2018. Over 99% of this volume was supplied under contracts with the default supplier outside the default supply[153] (115.6 TWh) and under contracts with suppliers other than the local default supplier (333.9 TWh). It is unusual but not impossible for interval-metered customers to be supplied under default or fallback supply contracts. Around 0.6 TWh of gas was supplied to metered load profile customers with a default or fall-back supply contract. This corresponds to about 0.13% of the total volume supplied to such customers.

About 25.7% of the total volume supplied to metered load profile customers (29% in 2017) was sold under contracts with the default supplier outside the default supply and about 74.2% (71% in 2017) under supply contracts with a legal entity other than the default supplier. The figures show that default supply status is of only minor importance for the acquisition of gas customers with a metered load profile.

152 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.

153 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 “fallback supply”.

Contract structure for interval-metered customers in 2018

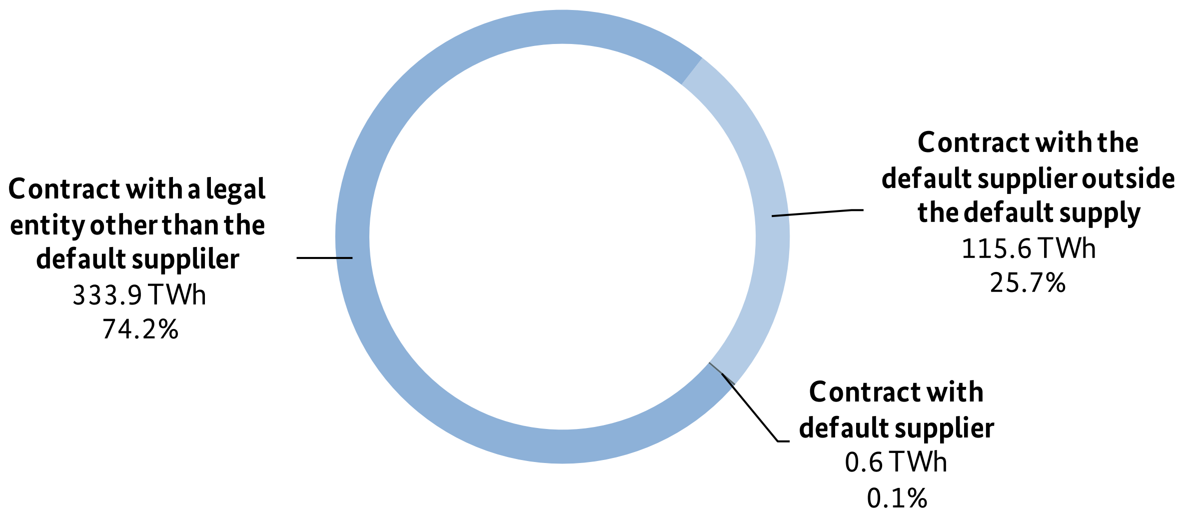

Figure 209: Contract structure for interval-metered customers in 2018

2.1.2 Supplier switching

Data on the supplier switching rates (as defined for monitoring, s.a.) of different customer groups in 2018 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 2018

Consumption category	Number of metering points with change of supplier	Share of all metering points in consumption category	Consumption volume at metering points with change of supplier	Share of total consumption volume in consumption category
< 0.3 GWh/Jahr	1,444,784	10.3%	36.5 TWh	11.2%
≥ 0.3 GWh/Jahr < 10 GWh/Jahr	16,298	13.2%	16.7 TWh	13.5%
≥ 10 GWh/Jahr < 100 GWh/Jahr	857	15.1%	14.9 TWh	13.6%
≥ 100 GWh/Jahr	117	17.7%	19.8 TWh	7.4%
Gaskraftwerke	4	1.9%	1.8 TWh	2.0%
Gesamt	**1,462,060**		**89.5 TWh**	

Table 123: Supplier switching by consumption category in 2018

The total number of metering points with a change of supplier increased by 48,857 (3.5%) compared to the previous year. This increase is attributable to almost all consumption categories and, with the exception of consumers with an annual consumption of more than 100 GWh, includes consumers in the smallest consumption category to gas-fired power plants. In 2018, the total gas volume affected by supplier switching was approx. 89.5 TWh in all five categories. Compared to the previous year, it increased by 1.5 TWh.

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 9.0 per cent in 2018. In 2017 it was moderately lower at 8.1%[154].

[154] The switching rate in 2017 was reported as 8.9% in the 2018 Monitoring Report. Due to subsequent corrections made by individual legal entities surveyed (suppliers etc.) this figure was corrected to 8.1%.

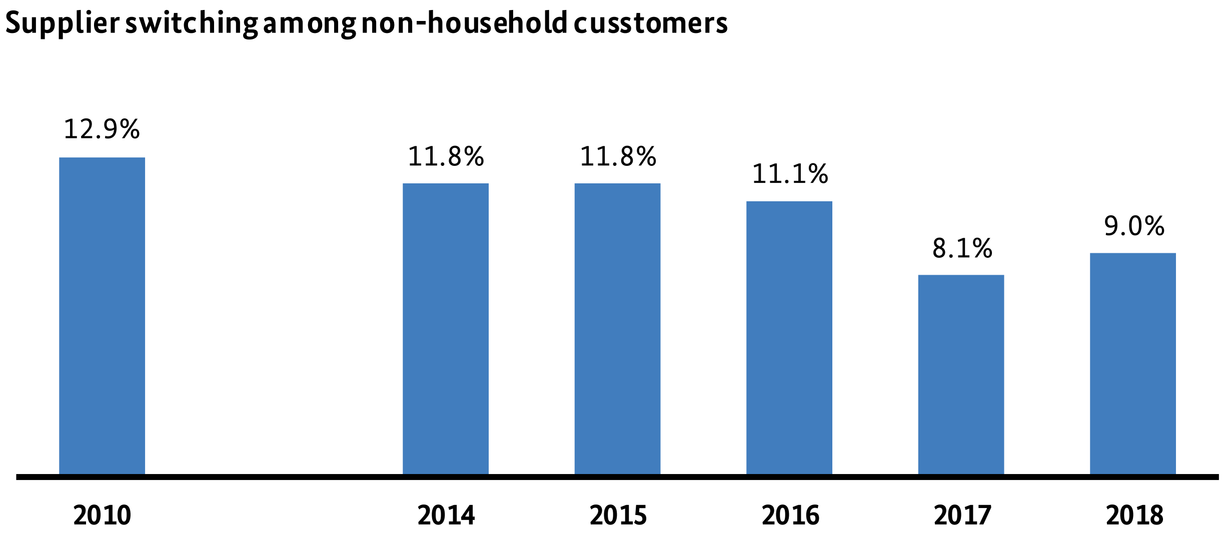

Figure 210: Supplier switching among non-household customers

2.2 Household customers

2.2.1 Contract structure

In the data survey for the 2019 Monitoring Report, the survey of quantities of gas supplied to household customers was broken down into three different consumption bands:

- Band I (D1): annual consumption up to 20 GJ (5,556 kWh)
- Band II (D2): annual consumption from 20 GJ (5,556 kWh) to 200 GJ (55,556 kWh)
- Band III (D3): annual consumption of 200 GJ (55,556 kWh) or more.
- An overall analysis of how household customers were supplied in 2018 in terms of volume shows that half of them (50%) were supplied by the local default supplier under a non-default contract and were supplied with 124.7 TWh of gas (2017: 51%/126.4 TWh).
- Only 18% of household customers still had a default supply contract in 2018 and these were supplied with 45.3 TWh of gas (2017: 19%/47.3 TWh). The percentage of household customers who had a contract with a supplier other than the local default supplier once again increased and was 32% for a total of 79.1 TWh of gas (2017: 30%/75.5 TWh).[155] Thus supply by the default supplier at a default tariff is the least popular form of supply.

[155] The total volume of gas supplied to household customers reported by gas suppliers of 249.1 TWh differs from the amount reported by gas DSOs (275.2 TWh) because the market coverage of the network operator survey is higher.

Gas: contract structure for household customers
breakdown of gas volumes delivered

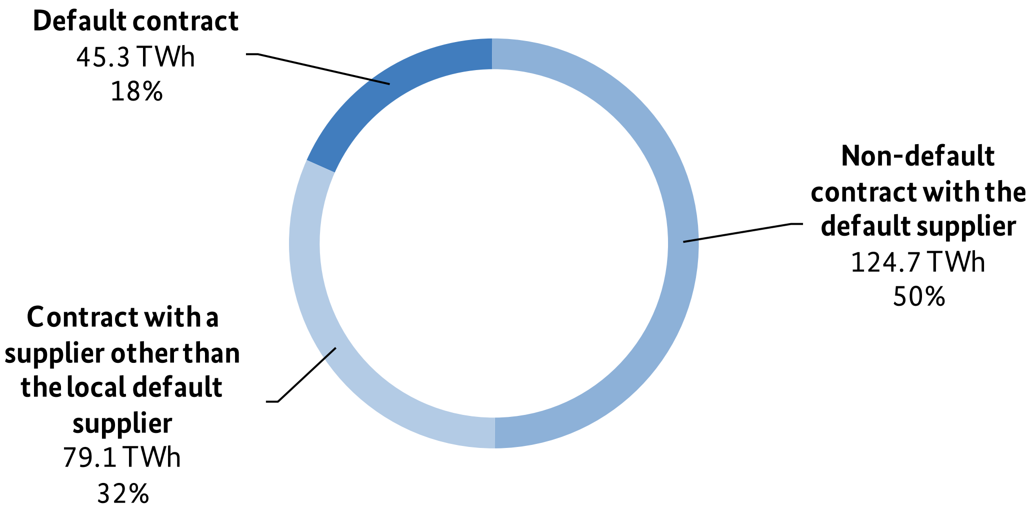

Figure 211: Contract structure for household customers (volume of gas delivered) according to survey of gas suppliers– as at 31 December 2018

Gas: share of supplies to household customers broken down by tariff according to survey of gas suppliers
(%)

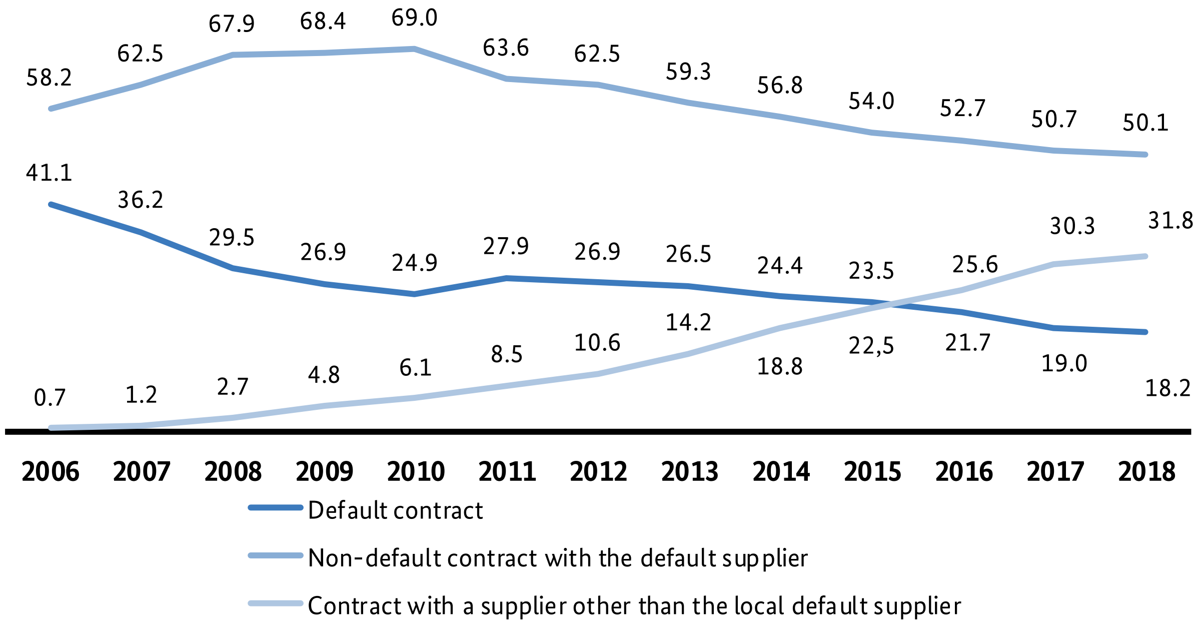

Figure 212: Share of gas supplies to household customers broken down by tariff according to survey of gas suppliers

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. Although disproportionately high at 43%, this figure was lower than the 43.9% from the previous year. By contrast, the majority of customers with average (D2) and high (D3) consumption were supplied under a non-default contract with the local default supplier.[156]

Gas: contract stucture for household customers (volume and distribution) broken down by consumption bands D1, D2 and D3

Vertragsart	Band I with a consumption of < 5,556 kWh (20 GJ)		Band II with a consumption of ≥ 5,556 kWh (20 GJ) < 55,556 kWh (200 GJ)		Band III with a consumption of ≥ 55,556 kWh (200 GJ)	
	Volume (TWh)	Distribution (%)	Volume (TWh)	Distribution (%)	Volume (TWh)	Distribution (%)
Default contract	2.3	43	33.6	19	6.6	13
Non-default contract with the default supplier	1.8	33	88.5	51	28.0	54
Contract with a supplier other than the local default supplier	1.3	23	52.6	30	17.3	33
Total	5.4	100	174.7	100	51.9	100

Table 124: Contract structure for household customers (volume) broken down into consumption bands – as at 31 December 2018

When focusing on the number of household customers supplied in 2018, it becomes clear that a relative majority of 44% 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 about 70% of household customers are supplied by the default supplier under a default contract or a contract outside of default supply.[157]

[156] The analysis is based on a reported volume of gas supplied to household customers of 231.9 TWh. The difference from the total reported volume of gas supplied to household customers by all gas suppliers of 249.1 TWh is due to a lack of data from some suppliers.

[157] The total number of household customers reported by gas suppliers of 12.4m differs from the number of household customers reported by DSOs (12.9m) because the market coverage of the network operator survey is higher.

Gas: contract structure for household customers
number and percentage of customers supplied

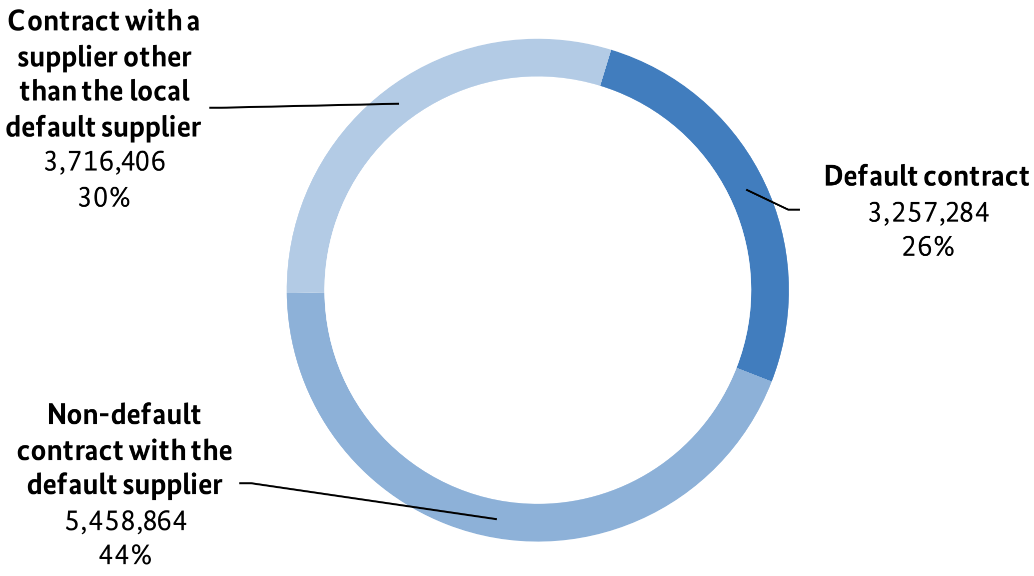

Figure 213: Contract structure for household customers (number of customers supplied) according to survey of gas suppliers– as at 31 December 2018

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 (53.2%). The majority of customers with average (D2) and high (D3) consumption were supplied under a non-default contract with the default supplier.[158]

[158] The analysis is based on a reported total number of household customers of 11.7m. The difference from the total reported number of household customers of all gas suppliers of 12.4m is due to a lack of data from some suppliers.

Gas: contract structure for household customs (number and distribution), broken down by consumption bands D1, D2 and D3

Contract type	Band I with a consumption of < 5,556 kWh (20 GJ)		Band II with a consumption of ≥ 5,556 kWh (20 GJ) and < 55,556 kWh (200 GJ)		Band III with a consumption of ≥ 55,556 kWh (200 GJ)	
	Number (m)	Distribution (%)	Number (%)	Distribution (%)	Number (m)	Distribution (%)
Default contract	1.1	52	2.0	22	0.1	17
Non-default contract with the default supplier	0.6	29	4.3	48	0.3	50
Contract with a supplier other than the local default supplier	0.4	19	2.7	30	0.2	33
Total	2.1	100	9.0	100	0.6	100

Table 125: Contract structure for gas household customers (number of customers supplied), broken down by consumption bands– as at 31 December 2018

2.2.2 Vertragswechsel

Gas suppliers were asked about household customers that changed contract at their own request in 2018.[159] The total number of customers changing contract in 2018 was 0.6m. The volume of gas these customers were delivered was approximately 13.4 TWh. The volume-based switching rate was therefore 5.4%.

[159] 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.

Gas: household customers that changed their contracts

Category	Subsequent consumption in 2018	Share of total consumption (249.1 TWh) (%)	Number of contracts changed in 2018	Share of all household customers (12.4 m) (%)
Household customers that changed their contract with their existing supplier	13.4	5.4	0,6m	4.8

Table 126: Gas household customers that changed their contracts in 2018 according to survey of gas suppliers

2.2.3 Lieferantenwechsel

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 market locations 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 fell slightly again by just under 1% year-on-year to 1.2m (down 7,256 supplier switches). There was a clear rise of nearly 6% in the number of household customers who immediately chose an alternative supplier rather than the default supplier when moving home.

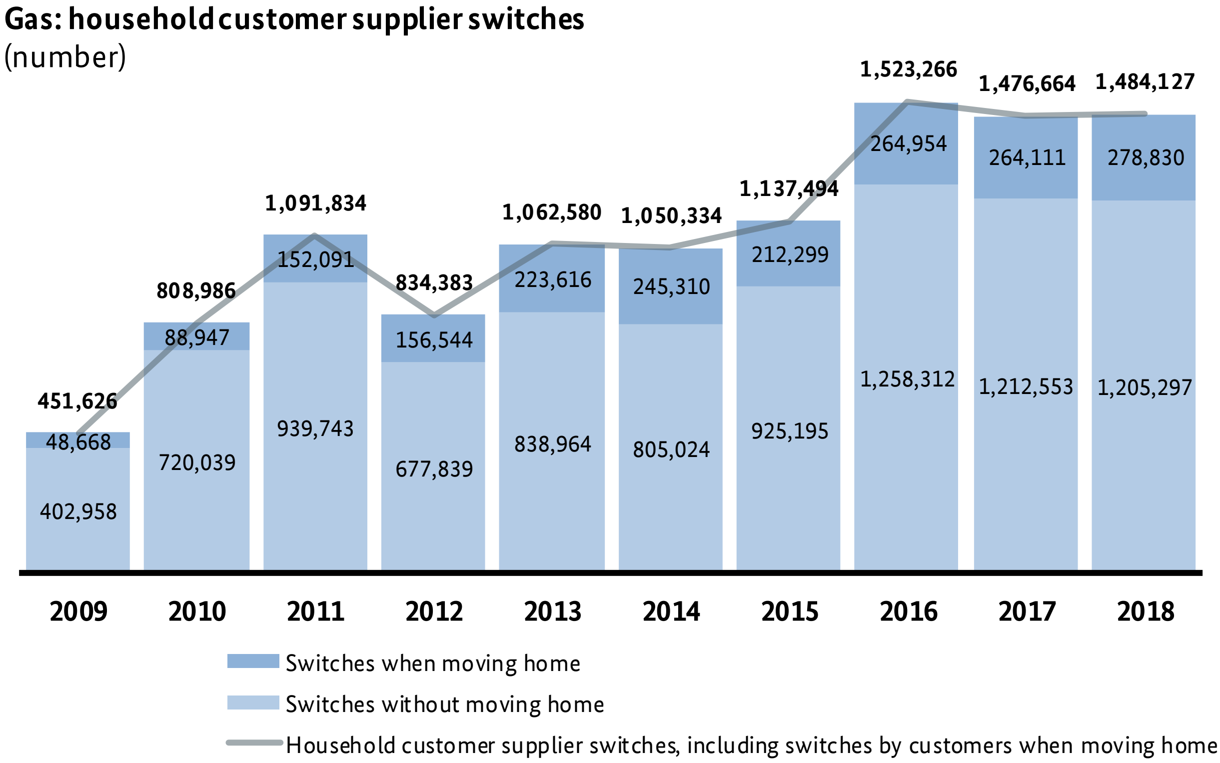

Figure 214: Household customer supplier switches according to the survey of gas DSOs

In 2018, there was an increase in the overall switching rate for household customers due to the rise in the number of customers who switched when moving home. When looking at 12.9m household customers (according to DSO figures), the resulting overall numbers-based supplier switching rate for household customers is 11.5%.[160]

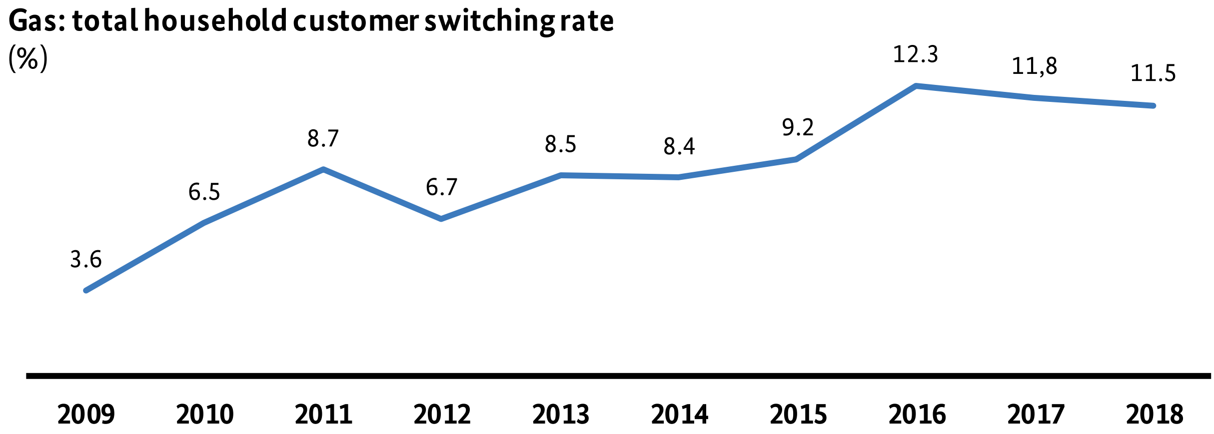

Figure 215: Total household customer switching rate based on DSO data survey

The gas DSOs were also asked to provide information on the volumes of gas recorded at the market locations 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 who switched when moving) rose in 2018 by 4 TWh or just under 9% to 34.3 TWh (2017: 34 TWh).

Taking into account the slight drop in gas supplied to household customers by network operators in 2018, the volume-based switching rate rose to 12.5% from 12.2% in the year before. The volume-based supplier switching rate of 12.5% is still above the numbers-based rate of 11.5% because high-consumption household customers exhibit a greater willingness to switch. At around 24,000 kWh, the calculated annual consumption of an average gas customer that switched supplier is above the national average of 20,000 kWh.

[160] The switching rate fell in percentage terms despite an increase in absolute numbers, because a greater number of market locations of household customers was reported for 2018.

Gas: household customer supplier switches in 2018, including switches by customers when moving home

Category	Subsequent consumption in 2018 (TWh)	Share of total consumption (275.2 TWh) (%)	Number of contract changed in 2018	Share of all household customers (12.9m) (%)
Household customer supplier switches without moving home	28.6	10.4	1,2m	9.3
Household customers who immediately chose an alternative supplier rather than the default supplier when moving home	5.8	2.1	0,3m	2.3
Total	34.4	12.5	1,5m	11.6

Table 127: Gas household customer supplier switches in 2018, including switches by customers when moving home

3. Gas supply disconnections and contract terminations, cash/smart card meters and non-annual billing

Around 33,000 gas customers were affected by disconnections in 2018.

Before suppliers can issue a disconnection notice, they must first send customers owing money a reminder with a fee. The gas can only actually be cut off at least four weeks after a disconnection notice has been issued. Customers must be given three working days' notice of the actual disconnection date.

Unlike for electricity, for gas there is no lower limit for debt that can lead to the supply being disconnected. The reminder fee, disconnection and reconnection can lead to large additional costs for gas customers, which vary according to supplier and network operator. In many cases, consumers have a right to an itemised bill.

Consumers who may have difficulty paying their bills are recommended to find out what type of contract they currently have (default or otherwise) and to compare the prices of their current supplier with those of competitors. A new and cheaper gas contract might help to avoid potential payment problems that could lead to disconnection.

3.1 Disconnections and terminations

In 2018, the Bundesnetzagentur asked network operators and gas suppliers about disconnection notices, disconnection orders, disconnections that were actually carried out and the costs each action incurred. The number of disconnections actually carried out by the network operators in 2018 was 33,145, representing a decrease of 13% compared to the previous year (2017: 38,048). This corresponds to 0.2% of gas connections based on all market locations of final consumers.

To issue an order to disconnect a customer, in accordance with section 24(3) of the Low Pressure Network Connection Ordinance (NDAV), the supplier must be contractually entitled to do so and must credibly show to the network operator that the contractual requirements for an interruption of supply between the supplier and the customer are met. The rights and obligations of network operators and network users are set out in the network usage and suppliers' framework contract (gas) determined by the Bundesnetzagentur, which includes the possibility of disconnection on the instructions of (any) supplier.

In contrast to the Electricity Default Supply Ordinance (StromGVV), the Gas Default Supply Ordinance (GasGVV) does not specify a minimum level of arrears for supply disconnection. Competitive suppliers can put clauses regarding non-fulfilment of payment obligations in their contracts.

The chart below shows how often suppliers issued disconnection notices to customers that had failed to meet payment obligations in 2018 and how often they ordered the network operator responsible to disconnect supplies or carried out the disconnection themselves.

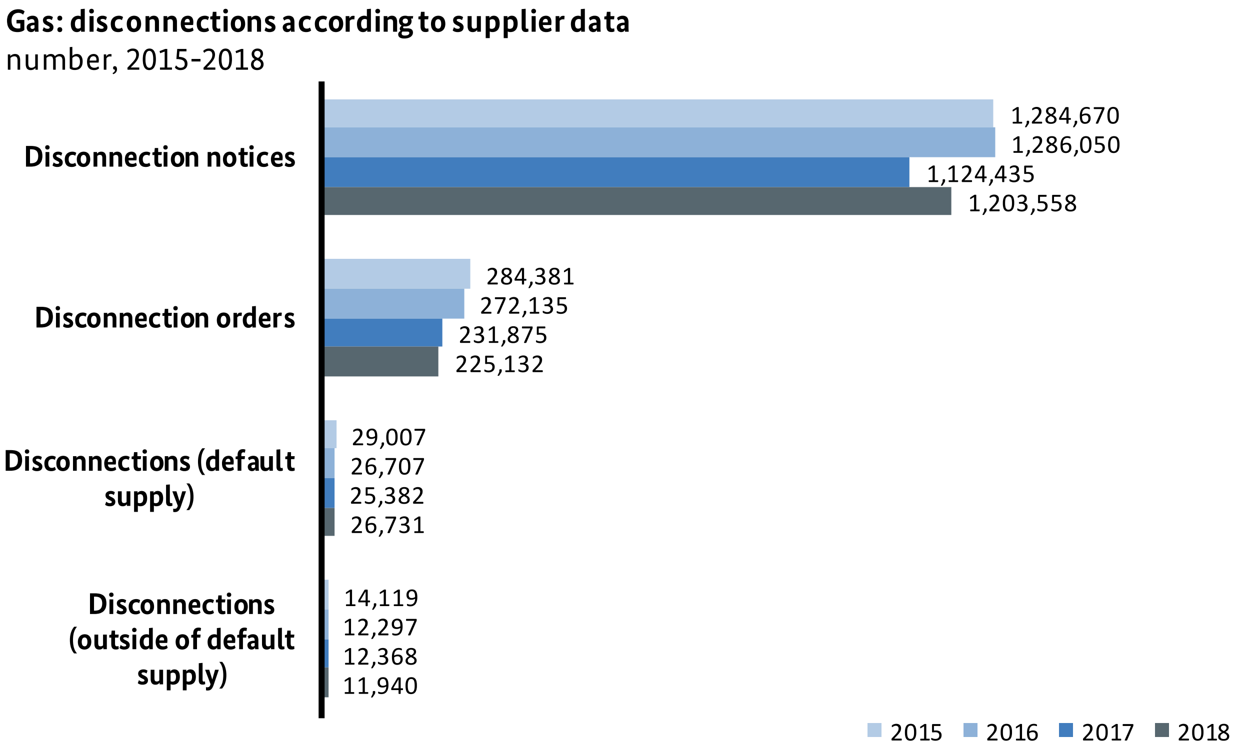

Figure 216: Disconnection notices, disconnection orders and disconnections for gas within and outside default supply, according to data from suppliers

According to the gas suppliers' data, a disconnection notice is issued when a customer is on average around €120 in arrears. A total of about 1.2m disconnection notices were issued to household customers, of which around 0.2m or 17% were passed on to the relevant network operator with a request for disconnection. The suppliers' data show that a total of around 3% of the notices actually resulted in the customer being disconnected.

The gas suppliers stated that in some 26,731 cases they had disconnected customers with default contracts. This corresponds to 0.2% of household customers on default contracts. According to the suppliers' data, customers with non-default contracts were disconnected in about 11,940 cases, corresponding to 0.1% of non-default customers.[161]

The gas suppliers stated that around 10% of disconnections were the same customers being disconnected more than once.

While some suppliers only passed on the costs of the network operator which carried out the disconnection/reconnection, a proportion of suppliers additionally charged their customers for carrying out a disconnection. Suppliers were asked if they use a general calculation in accordance with section 19(4) GasGVV for such a charge. Suppliers applying this general calculation charged customers an average of about €47 (inc VAT)[162], with charges ranging from €1.50 to €210. Suppliers not applying the general calculation charged customers an average of about €49 (inc VAT), with charges ranging from €5 to €210. Customers were charged an average reconnection fee of about €56 (inc VAT) by suppliers applying the general calculation, with the actual fees charged again ranging from €1.50 to €222. Suppliers not applying the general calculation charged an average of about €58 (inc VAT), with a range from about €4 to €210. Gas suppliers imposed a reminder fee averaging €3.70 on household customers who were late paying their bills.

[161] The total number of disconnections reported by gas suppliers is not the same as the number of disconnections actually carried out by network operators. This is partly due to the greater market coverage and better data quality of network operators. In addition, some gas suppliers only collect data on disconnections as a total number for all energy sources. The Bundesnetzagentur therefore uses reports from network operators for its figure on the total number of disconnections.

[162] The supplier's own costs, not including costs incurred by the network operator carrying out the disconnection.

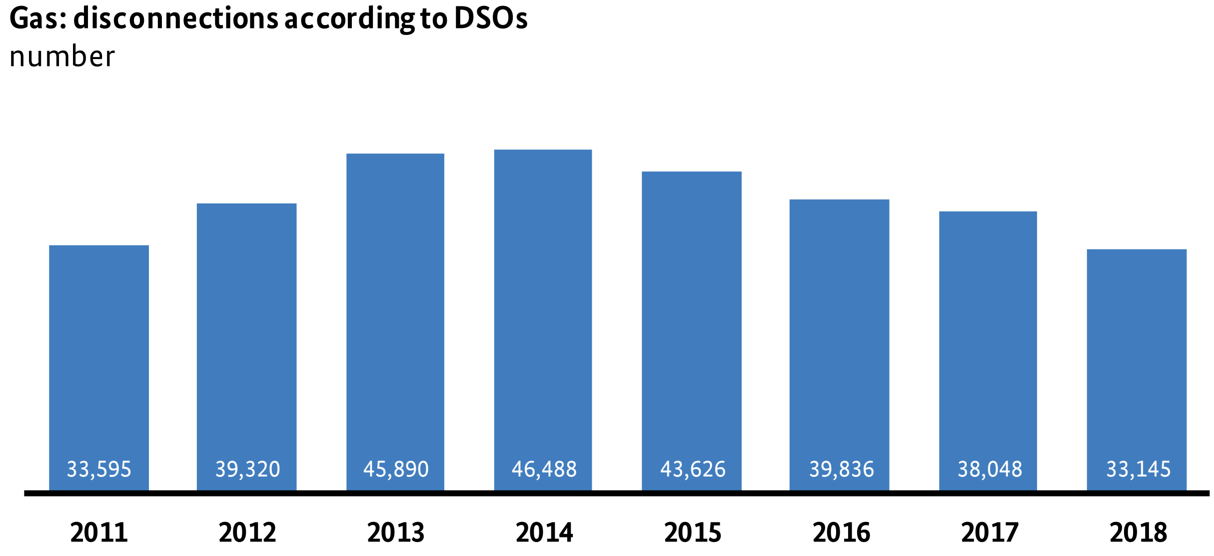

Figure 217: Gas disconnections according to DSOs, from 2011 to 2018[163]

The above chart shows the development of disconnections of gas final customers from 2011 to 2018. A total of 33,145 disconnections and 33,211 reconnections were carried out in 2018. Broken down by federal state, the disconnections were distributed as follows:[164]

[163] The figure for 2017 was adjusted following the submission of a data correction.

[164] The total sums only amount to 99.8% because 0.2% of all disconnections could not be attributed to a federal state.

Gas: disconnections by federal state in 2018 according to data from DSOs

	No of disconnections	Proportion of market locations per federal state (%)
Berlin	2,195	0.37
North Rhine-Westphalia	13,023	0.35
Hesse	2,474	0.24
Rhineland-Palatinate	1,850	0.23
Saxony-Anhalt	919	0.22
Lower Saxony	4,477	0.21
Saarland	401	0.21
Brandenburg	963	0.18
Schleswig-Holstein	1,013	0.18
Hamburg	397	0.17
Bavaria	2,206	0.16
Sachsen	786	0.13
Baden-Württemberg	1,693	0.12
Thuringia	472	0.12
Mecklenburg-Western Pomerania	278	0.10
Bremen	55	0.04
total in Germany	**33,202**	0.23

Table 128: Gas disconnections by federal state in 2018, according to data from DSOs

The network operators charged gas suppliers an average fee of about €60 (excluding VAT) for disconnecting a supply, with the actual costs charged ranging from €12.50 to €400. They charged suppliers an average fee of about €68 (exc VAT) for reconnecting a supply, with the actual costs charged ranging from €15 to €408.

DSOs were asked about the duration of disconnections for the first time in 2018. The average length of time between an actual disconnection and a reconnection was 36 days (for reasons of clarity, this figure only includes cases in which both disconnection and reconnection took place in 2018). Around 3,900 disconnections were for more than 90 days. The survey did not ask about the reason for these longer periods of disconnection, which may have been due to customers' long-term inability to pay, vacant properties or faulty customer facilities that could not be reconnected for safety reasons.

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 2018, gas suppliers (default suppliers and their competitors) had to terminate their contractual relationship with a total of 54,377 gas customers (2017: 41,998) due to the customers' 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. The average level of arrears for a household customer that led to a contract being terminated was about €170 in 2018, with charges ranging from €10 to €5,000.

3.2 Cash meters and smart card meters

Gas metering operators and gas suppliers answered questions on prepayment systems, as per section 14 of the Gas Default Supply Ordinance (GasGVV), such as cash meters or smart card meters. According to 40 suppliers, a total of 1,081 household customers had cash or smart card meters, or comparable prepayment systems, in 2018 compared to 1,125 in 2017. There were 278 new installations of prepay systems and 170 existing ones were removed in 2018. Costs for meter operation and metering averaged €23.50 and €5.10 respectively per year and meter. The average annual base price charged to customers was €130, with the costs charged ranging from €12 to €250. The average kilowatt-hour rate for gas billed using a prepayment meter was 6.4 ct/kWh and ranged from 3.6 ct/kWh to 9.4 ct/kWh.

3.3 Abweichende Abrechnung

Section 40(3) EnWG requires gas suppliers to offer final consumers monthly, quarterly or half yearly bills. The survey showed that demand for bills that are not the usual annual ones remains low.

Gas: non-annual billing in 2018

	Requests	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	4,006	€14.60 (€2 - €50)	€17.80 (€2 - €58)
Monthly	457		
Quarterly	172		
Semi-annual	1,290		
No data on period	2,087		

Table 129: Non-annual billing for gas household customers in 2018 according to gas supplier survey

4. Price level

Gas prices for household customers rose by an average of 4.4% year-on-year as at 1 April 2019 across all types of supply. Prices rose particularly sharply, by just over 10%, for default supply customers.

At an average of 7.28 ct/kWh, default supply remains the most expensive type of supply. Even changing contracts with the local default supplier can lead to average savings of about 12% per kWh, while savings of about 15% per kWh can be achieved by switching supplier. The average household customer can save up to €195 a year by changing contract with their local default supplier. **The average potential saving from switching supplier is up to €245 a year.**

The main reasons for the rise in gas prices are the increases in gas procurement costs (6%) and network charges (4%).

Suppliers of gas to final consumers in Germany were asked the retail prices their companies charged on 1 April 2019 for various consumption levels. Household customers' consumption levels were divided into three consumption bands. Prices for these bands were surveyed in various categories. The lowest category covers an annual gas consumption of up to 20 GJ (5,556 kWh), while the highest category is for annual consumption of at least 200 GJ (55,556 kWh). The typical household customer has consumption in the band from 20 GJ (5,556 kWh) to 200 GJ (55,556 kWh). Furthermore, as in previous years, the consumption levels of 116 MWh (= 417.6 GJ for "commercial customers") and 116 GWh (= 417,600 GJ for "industrial customers") were analysed.

Suppliers were asked to give the overall price in cents per kilowatt hour (ct/kWh) and to include the non-variable price components such as the service price, base price and transfer or internal price. Suppliers were also asked to provide a breakdown of the price components that they cannot control, including, in particular, network charges,[165] 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,

[165] Since 1 January 2017, the component "charge for billing" has been part of the network charges and is no longer reported separately.

- non-default contract with the default supplier,

- contract with a supplier other than the local default supplier.

The findings are set out below, broken down by customer category and consumption level. The results have been compared to the previous year's figures to illustrate long-term trends. When comparing the figures as they stood as at 1 April 2019 and 1 April 2018, it should be noted that differences in the calculated averages are lower in some cases than the tolerance of error for the data collection method.

The survey was addressed to all suppliers operating in Germany. However, with regard to the prices for the 116 GWh/year and 116 MWh/year consumption levels, only those suppliers that served at least one customer whose gas demand fell within the range of the relevant level of consumption were asked to provide data (this applied to 100 and 794 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 gas 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.

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 was based on data from 100 suppliers (99 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. 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 116 GWh/year consumption category on 1 April 2019

	Spread between 10 and 90 % of figures provided by suppliers in ct/kWh	**Arithmetic mean** in ct/kWh	**Share of total price**
Price components outside the supplier's control			
Net network charge	0.15 - 0.43	0.31	11.0%
Metering	0.00 - 0.009	0.003	0.1%
Concession fee[1]	0.00	0.00	0.0%
Gas tax	0.55	0.55	19.2%
Price components controllable by supplier (remaining balance)	1.61 - 2.39	2.00	69.8%
Total price (without VAT)	2.37 - 3.34	2.86	

[1] Under Section 2 (5) sentence 1 KAV concession fees only apply for the first 5 GWh (0.03 ct/kWh) in the case of customers with special contracts. When lthis price component is levied on the total consumption volume, it accounts for a low arithmetic mean, in the case of a consumption of 116 GWh an average of 0.00 ct/kWh.

Table 130: Price level for the 116 GWh/year consumption category on 1 April 2019

The average overall price (excluding VAT) for an annual consumption of 116 GW/h ("industrial customer") was 2.86 ct/kWh, (2.82 ct/kWh in the previous year). An average of 11.1% of the average overall price relates to cost items outside the supplier’s control: network tariffs, metering and concession fees. Gas tax is another cost item which is outside the supplier’s control. It accounts for 19.2% of the average overall price (excluding VAT). Hence approx. 69.8% (68% in the previous year) of the price is made up of price components that can be controlled by the supplier (gas procurement costs, supply costs and the margin). The share of the price components that cannot be controlled by the supplier is much higher than in the case of household customers or non-household customers with low consumption (see below).

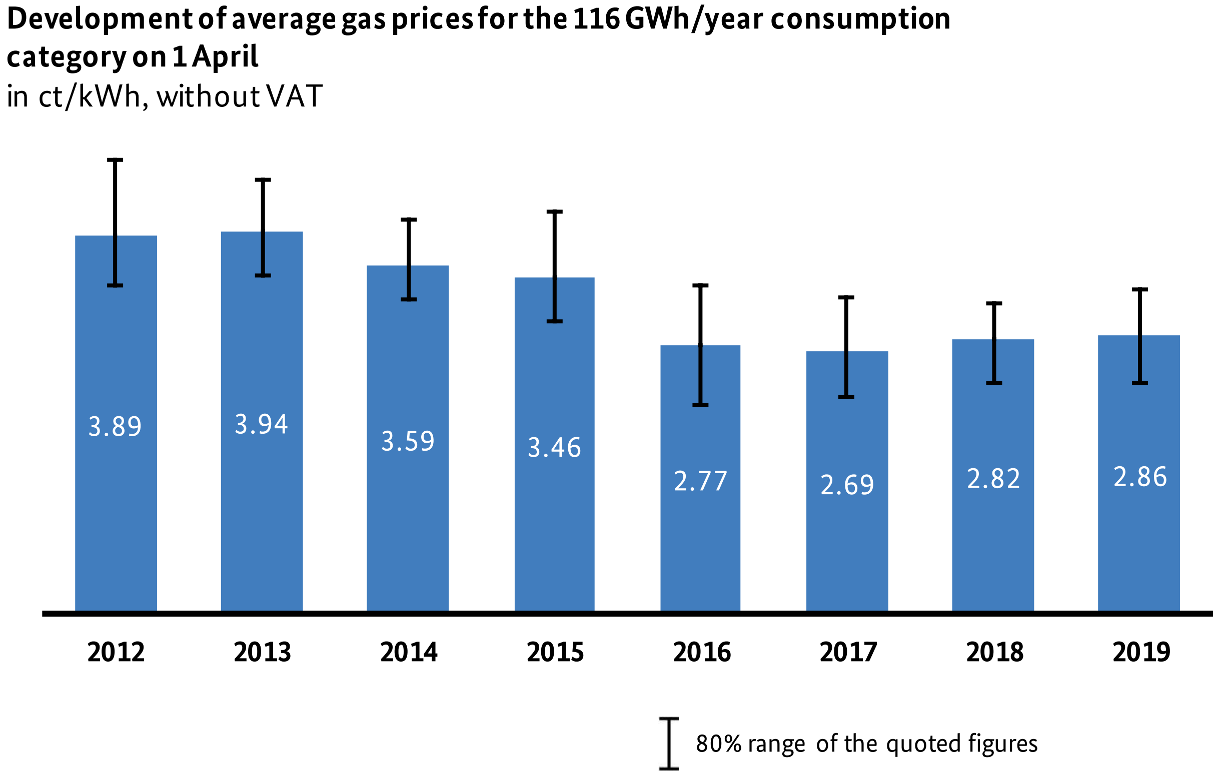

Figure 218: Development of average gas prices for the 116 GWh/year consumption category

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 well 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 2019. 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 794 suppliers (786 in the previous year).

As in the case with the industrial customers, this data was used to calculate the averages of the overall price and of the individual price components and the data spread for each price component was also analysed in terms of ranges. As in the industrial customer consumption category, 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 116 MWh/year consumption category on 1 April 2019

	Spread between 10 and 90 % of figures provided by the suppliers in ct/kWh	**Arithmetic mean** in ct/kWh	**Share of total price**
Price components outside the supplier's control			
Net network charge	0.89 - 1.56	1.22	26.8%
Metering	0.01 - 0.07	0.04	1.0%
concession fee [1]	0.03 - 0.03	0.04	0.9%
Gas tax	0.55	0.55	12.1%
Price component controllable by supplier (remaining balance)	2.09 - 3.35	2.70	59.4%
Total price (without VAT)	3.88 - 5.22	4.55	

[1] 69 of the 794 suppliers quoted a concession fee of more than 0.03 ct/kWh. These were suppliers with low supply volumes. A concession fee exceeding 0.03 ct/kWh is plausible in the suply of a non-household customer in default supply (cf. Section 2 (2) no. 2b KAV).

Table 131: Price level for the 116 MWh/year consumption category on 1 April 2019

This year, an average 41% 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). Approx. 59% relate to price elements that provide scope for commercial decisions.

The arithmetic mean of the overall price of 4.55 ct/kWh (excluding VAT) is 0.15 ct/kWh or around 3.5% higher than the previous year's figure. The absolute amount of the price components outside the supplier's control rose to 1.85 ct/kWh, 0.01 ct/kWh higher than in the previous year. The remaining balance that can be controlled by the supplier rose by 0.15 ct/kWh (from 2.55 ct/kWh on 1 April 2018 to 2.70 ct/kWh on 1 April 2019) or by about 6%.

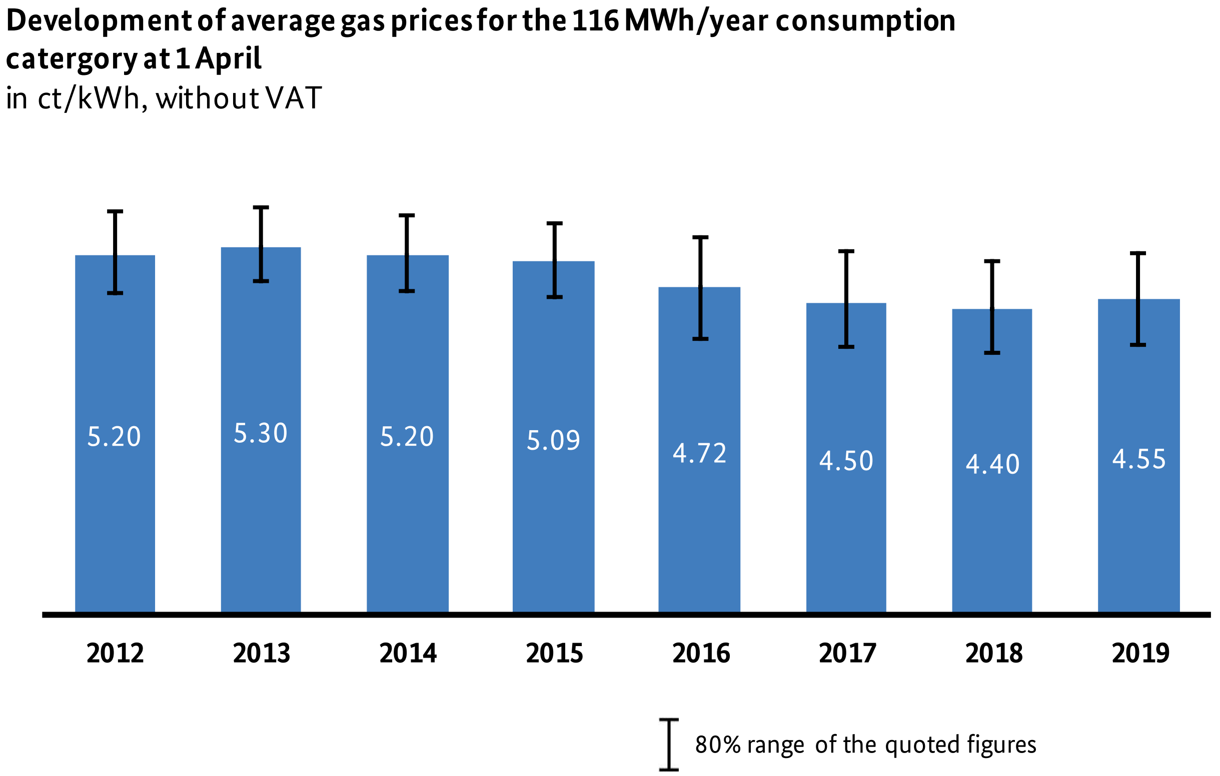

Figure 219: Development of average gas prices for the 116 MWh/year consumption category

4.2 Household customers

Household customer prices were divided into three bands for the survey:

- Band I (D1[166]): annual consumption up to 20 GJ (5,556 kWh)
- Band II (D2): annual consumption from 20 GJ (5,556 kWh) to 200 GJ (55,556 kWh),
- Band III (D3): annual consumption of 200 GJ (55,556 kWh) or more.

The survey of gas prices in consumption bands took into consideration the European survey of prices carried out by Eurostat. The total quantities of gas that were delivered by each supplier as at 31 December 2018 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 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 of the three types of supply contract. Since 1 January 2017, the charge for billing has been part of the network charges and is no longer reported separately.

[166] "D1", "D2" and "D3" refer to the consumption bands defined by Eurostat.

4.2.1 Volume-weighted price across all contract categories for household customers (Band II)

The great variety of the components that form the prices makes it 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, non-default contract with the default supplier (usually after change of contract), and contract with a supplier other than the local default supplier (usually after supplier switch) – 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 from 20 GJ (5,556 kWh) to 200 GJ (55,556 kWh), which best reflects the average consumption of household customers in Germany of 20,000 kWh, was selected for the diagram presenting the total synthetic price across all contract categories on 1 April 2019.

Gas: average volume-weighted price across all contract categories for household customers for an annual consumption from 20 GJ (5,556 kWh) to 200 GJ (55,556 kWh) per year (band II; Eurostat: D2) as of 1 April 2019 (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	3.13	49.4%
Network charge including upstream network costs	1.48	23.3%
Charge for metering	0.02	0.3%
Charge for meter operations	0.07	1.1%
Concession fees	0.08	1.3%
Current gas tax	0.55	8.7%
VAT	1.01	15.9%
Total	6.34	100.0%

Table 132: Average volume-weighted price across all contract categories for household customers in consumption band II according to the gas supplier survey

Gas: composition of the volume-weighted gas price across all contract categories for household customers - consumption band II
prices as at 1 April 2019 (%)

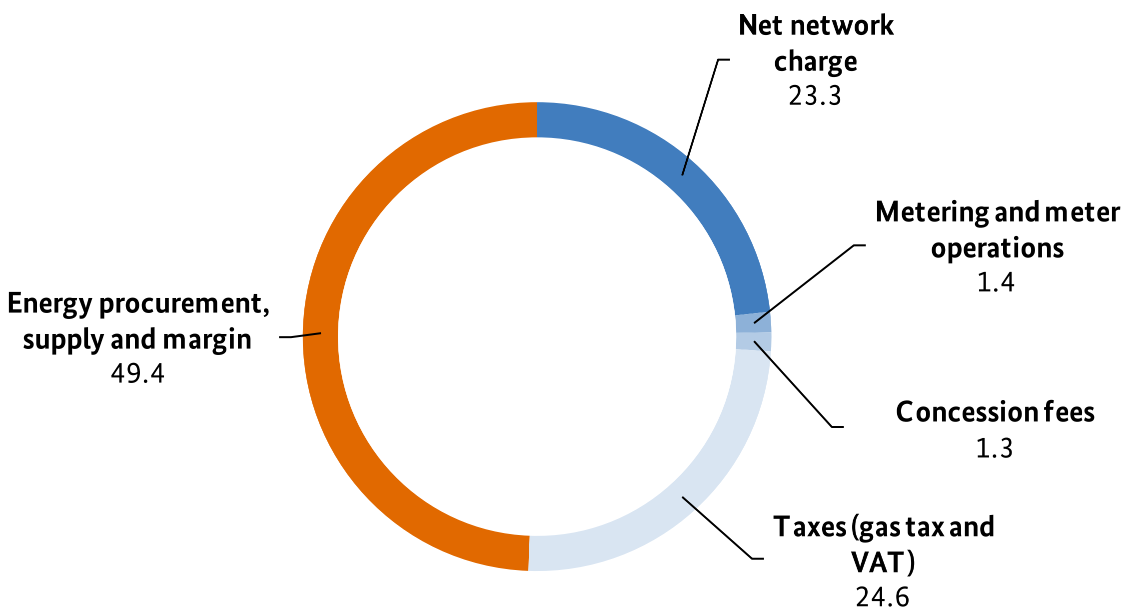

Figure 220: Breakdown of the volume-weighted gas price across all contract categories for household customers– consumption band II according to the gas supplier survey

Gas: change in the volume-weighted price across all contract categories for household customers. Consumption band from 20 GJ (5,556 kWh) to 200 GJ (55,556 kWh), (band II; Eurostat: D2)

Price component	Volume-weighted average across all tariffs on 1 April 2018 (ct/kWh)	Volume-weighted average across all tariffs on 1 April 2018 (ct/kWh)	Change in the price component	
			(ct/kWh)	%
Price component for energy procurement, supply and margin	2.96	3.13	0.17	5.7%
Network charge including upstream network costs	1.42	1.48	0.06	4.2%
Charge for metering	0.02	0.02	0.00	0.0%
Charge for meter operations	0.07	0.07	0.00	0.0%
Concession fees	0.08	0.08	0.00	0.0%
Current gas tax	0.55	0.55	0.00	0.0%
VAT	0.97	1.01	0.04	4.1%
Total	6.07	6.34	0.27	4.4%

Table 133: 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 2018 and 1 April 2019 according to the gas supplier survey

The volume-weighted gas price for household customers across all contract categories rose for the first time in three years. The price increased by around 4.4% as at 1 April 2019. With respect to the individual price components, the largest increases were in energy procurement, supply and margin (+5.7%) and network charges (+4.2%).

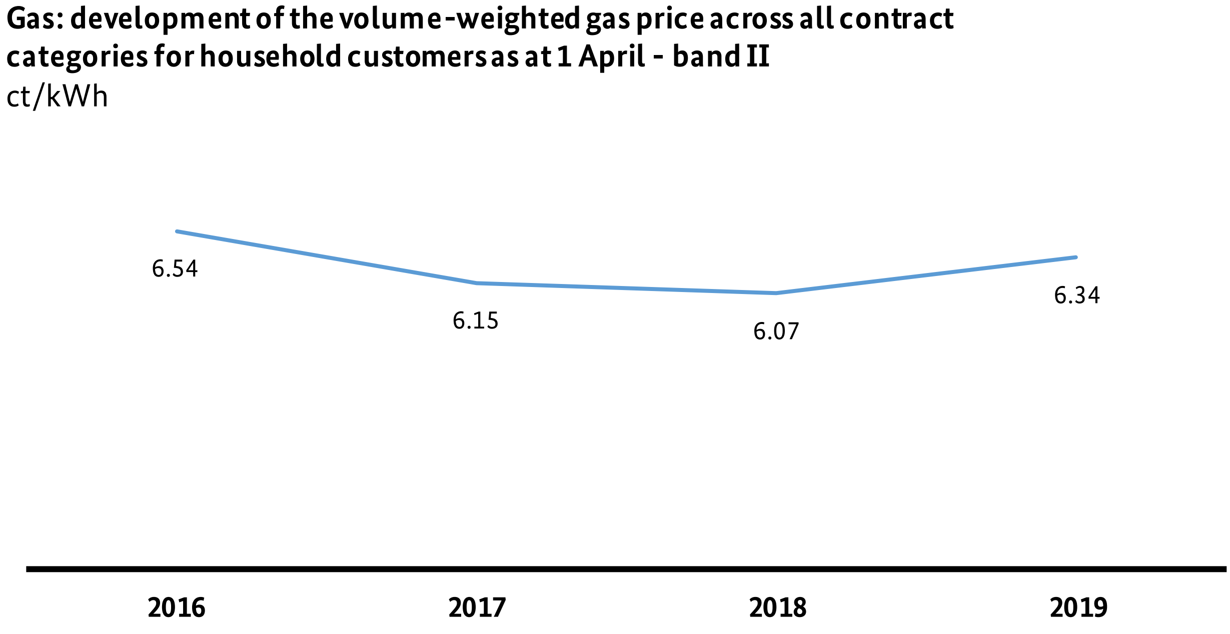

Figure 221: Volume-weighted gas price across all contract categories for household customers according to the gas supplier survey

4.2.2 Household customer prices by consumption band

The tables below provide detailed information on the breakdown of the gas price for household customers, broken down by individual bands I to III and contract category.

Gas: average volume-weighted price per contract category for household customers with a consumption up to 20 GJ (5,556 kWh) per year (band I; Eurostat: D1) as of 1 April 2019
(ct/kWh)

Price component	Default contract	Non-default contract with the default supplier	Contract with a supplier other than the local default supplier
Price component for energy procurement, supply and margin	4.67	4.54	4.40
Network charge including upstream network costs	2.45	2.33	2.03
Charge for metering	0.23	0.13	0.12
Charge for meter operations	0.45	0.41	0.42
Concession fees	0.44	0.04	0.03
Current gas tax	0.55	0.55	0.55
VAT	1.67	1.52	1.55
Total	10.46	9.52	9.79

Table 134: Average volume-weighted price per contract category for household customers in consumption band I according to the gas supplier survey

Gas: average volume-weighted price per contract category for household customers with a consumption from 20 GJ (5,556 kWh) to 200 GJ (55,556 kWh) per year (band II; Eurostat: D2 as at 1 April 2019 (ct/kWh)

Price component	Default contract	Non-default contract with the default supplier	Contract with a supplier other than the local default supplier
Price component for energy procurement, supply and margin	3.74	3.30	3.02
Network charge including upstream network costs	1.47	1.45	1.54
Charge for metering	0.02	0.02	0.02
Charge for meter operations	0.07	0.05	0.07
Concession fees	0.27	0.04	0.03
Current gas tax	0.55	0.55	0.55
VAT	1.16	1.03	0.99
Total	7.28	6.44	6.22

Table 135: Average volume-weighted price per contract category for household customers in consumption band II according to the gas supplier survey

Gas: average volume-weighted price per contract category for household customers with a consumption over 200 GJ (55,556 kWh) per year (band III; Eurostat: D3) as at 1 April 2018 (ct/kWh)

Price component	Default contract	Non-default contract with the default supplier	Contract with a supplier other than the local default supplier
Price component for energy procurement, supply and margin	3.27	2.88	2.67
Network charge including upstream network costs	1.21	1.25	1.16
Charge for metering	0.01	0.01	0.01
Charge for meter operations	0.02	0.02	0.03
Concession fees	0.26	0.04	0.03
Current gas tax	0.55	0.55	0.55
VAT	1.02	0.90	0.85
Total	6.34	5.65	5.30

Table 136: Average volume-weighted price per contract category for household customers in consumption band III according to the gas supplier survey

Supply under a default contract

The volume-weighted gas price for customers on a default contract as at 1 April 2019 was 7.28 ct/kWh in band II (2018: 6.64 ct/kWh), corresponding to an increase of around 10% compared to the previous year.

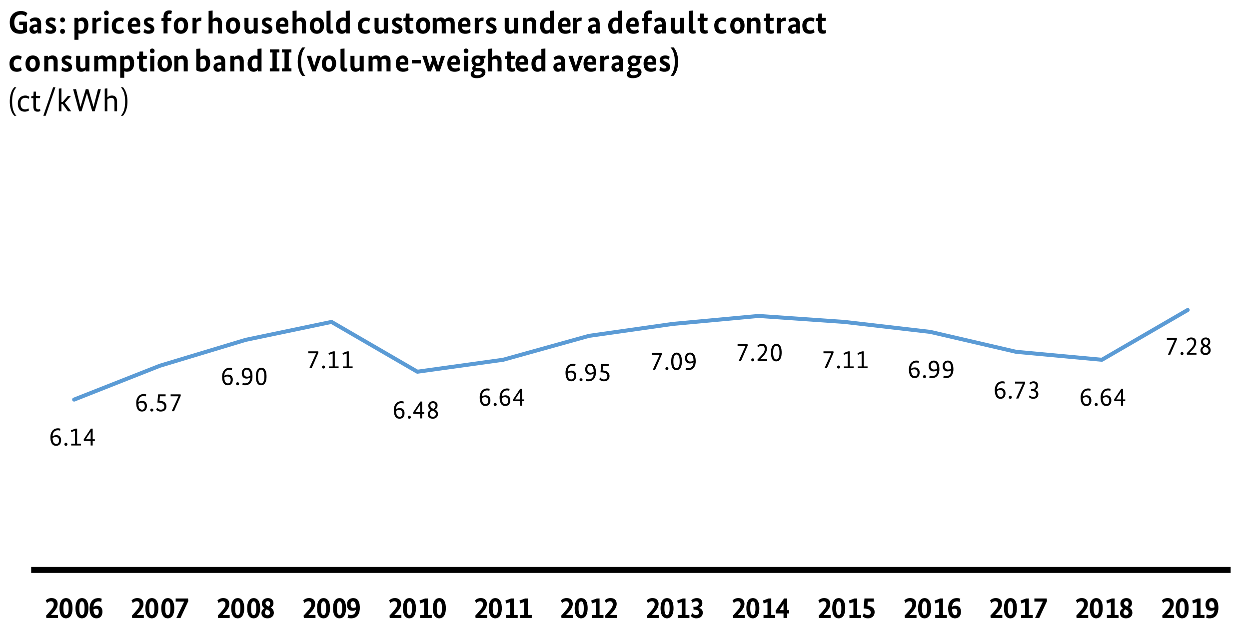

Figure 222: Gas prices for household customers under a default contract (volume-weighted averages) – consumption band II according to the gas supplier survey

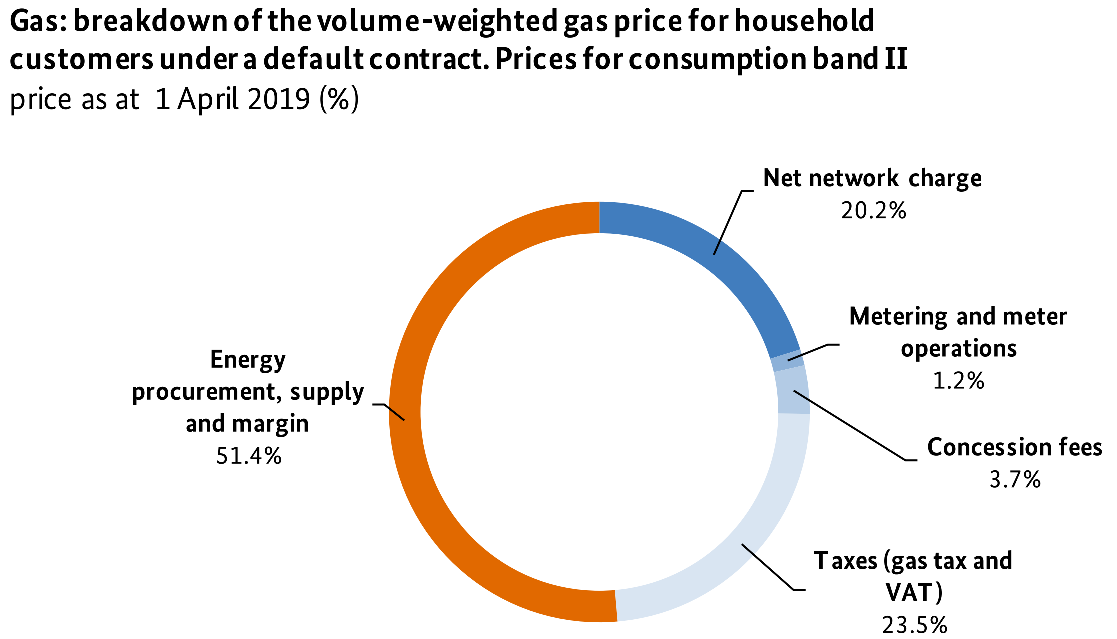

Figure 223: Breakdown of the volume-weighted gas price for household customers under a default contract. Prices for consumption band II, as at 1 April 2019 – according to the gas supplier survey

Supply by the default supplier under a non-default contract

On 1 April 2019, the volume-weighted price for customers under a non-default contract with the default supplier in consumption band II was 6.44 ct/kWh, an increase of about 6% compared to 2018 (6.06 ct/kWh).

Gas: household customer gas prices under a non-default contract with the default supplier - band II (volume-weighted averages) as at 1 April of the respective year
(ct/kWh)

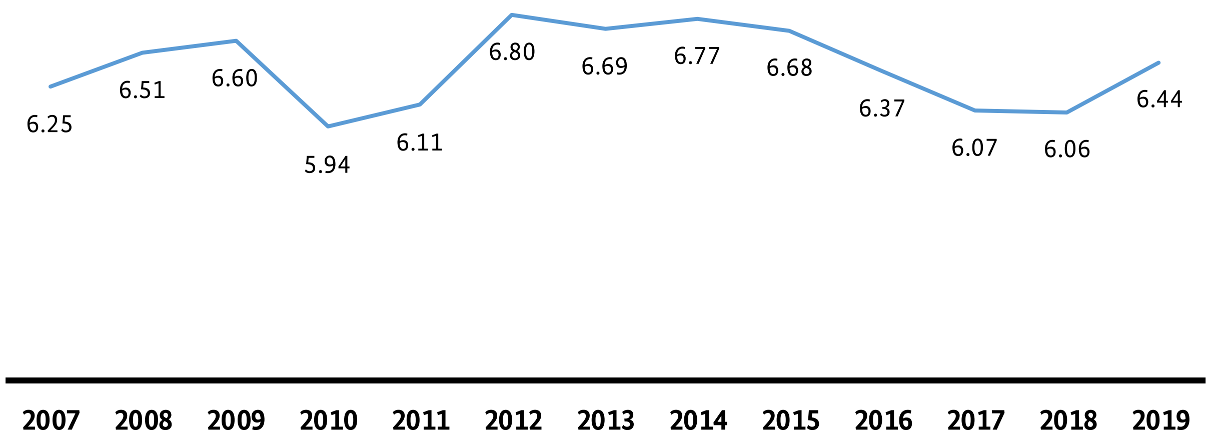

Figure 224: Household customer gas prices under a non-default contract with the default supplier (volume-weighted averages) – consumption band II according to the gas supplier survey

Gas: breakdown of the volume-weighted gas price for household customers under a non-default contract with the default suppler - band II price as at 1 April 2019 (%)

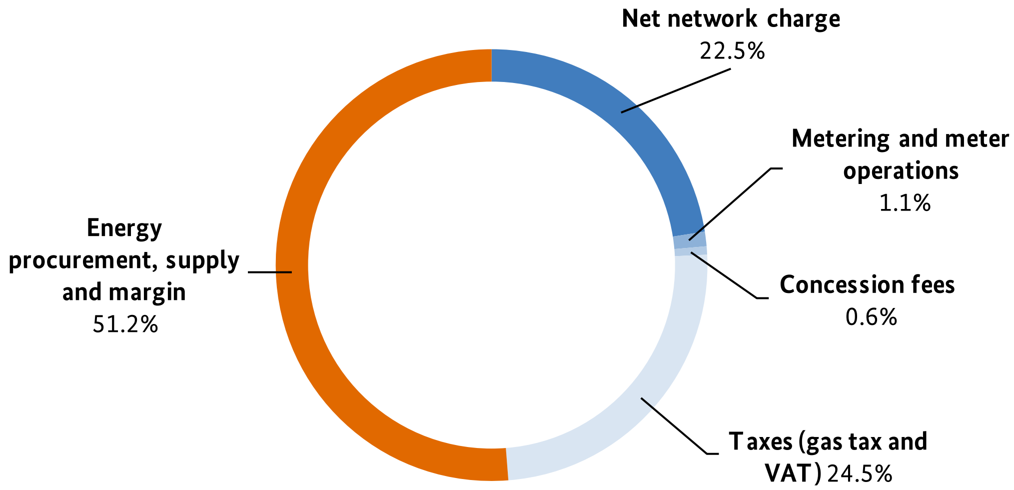

Figure 225: Breakdown of the volume-weighted gas price for household customers under a non-default contract with the default supplier. Prices for consumption band II, as at 1 April 2019– according to the gas supplier survey

Supply under a contract with a supplier other than the local default supplier

On 1 April 2019, the volume-weighted price for a contract with a supplier other than the local default supplier in consumption band II was 6.22 ct/kWh, an increase of about 9% compared to the previous year (2018: 5.71 ct/kWh).

Gas: prices for household customers under a contract with a supplier other than the local default supplier - band II (volume-weighted averages) as at 1 April of the respective year
(ct/kWh)

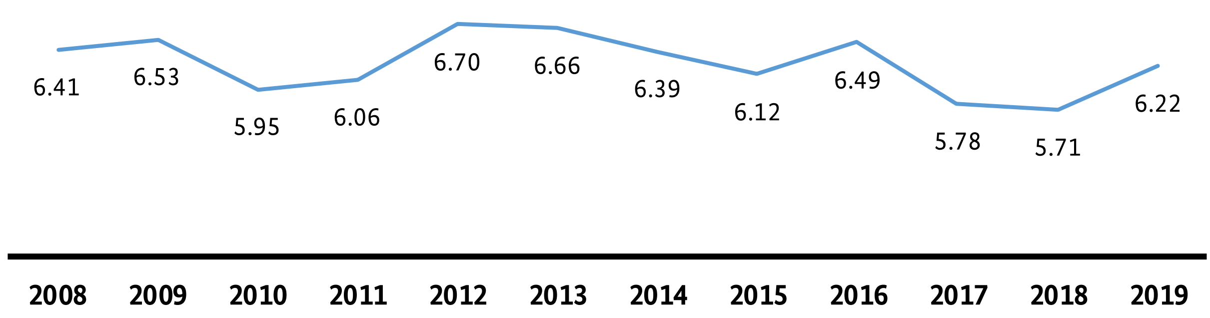

Figure 226: Gas prices for household customers under a contract with a supplier other than the local default supplier (volume-weighted averages) – consumption band II according to the gas supplier survey

Gas: breakdown of the volume-weighted gas price for household customers under a contract with a supplier other than the local default supplier - band II
price as at 1 April 2019 (%)

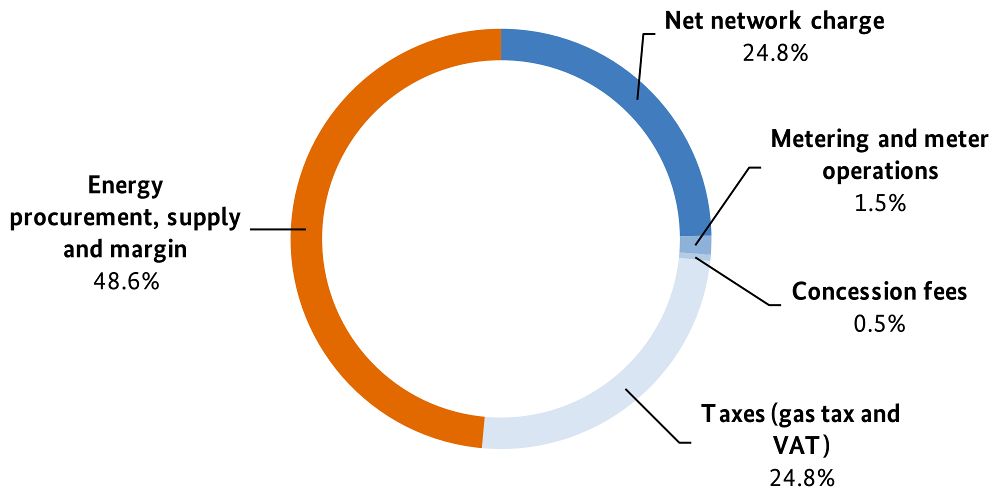

Figure 227: Breakdown of the volume-weighted gas price for household customers under a contract with a supplier other than the local default supplier, as at 1 April 2019– consumption band II according to the gas supplier survey

Customers on default contracts can make savings by switching contract or supplier. The average household customer with gas consumption of 23,250 kWh could save an average of €195 a year as at 1 April 2019 by changing contract. The average potential saving for the year through changing supplier was €245.

Gas: household customer gas prices - consumption band II as at 1 April (volume-weighted averages)
(ct/kWh)

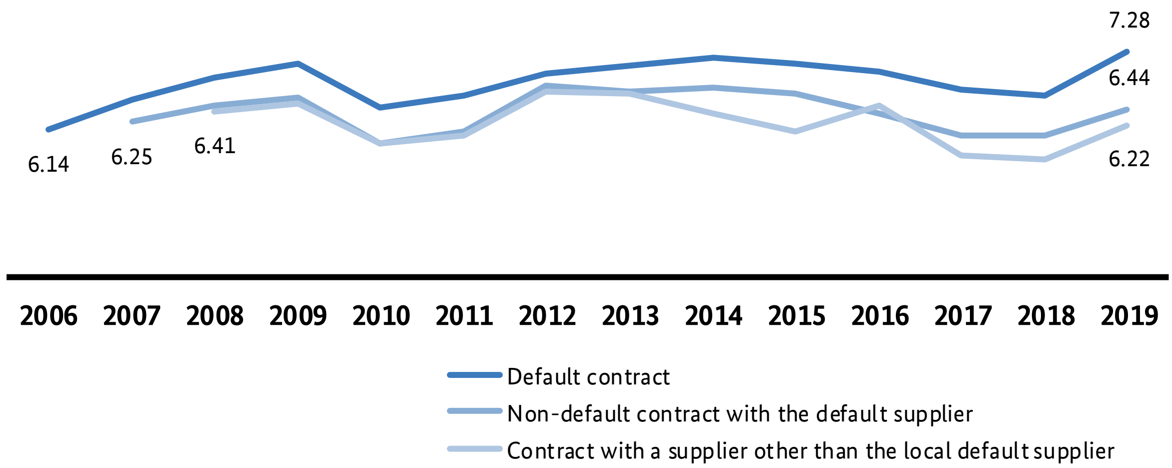

Figure 228: Household customer gas prices – consumption band II according to gas supplier survey

The price component "energy procurement, supply and margin" for default supply customers was 3.74 ct/kWh as at 1 April 2019 (2018: 3.29 ct/kWh). This represents an increase of around 14%. The gas procurement costs in the price for customers supplied under a non-default contract with the default supplier increased by around 10% from 3.01 ct/kWh to 3.30 ct/kWh. The gas procurement costs for customers supplied under a contract with a supplier other than the local default supplier increased by around 14% to 3.02 ct/kWh (2018: 2.66 ct/kWh).

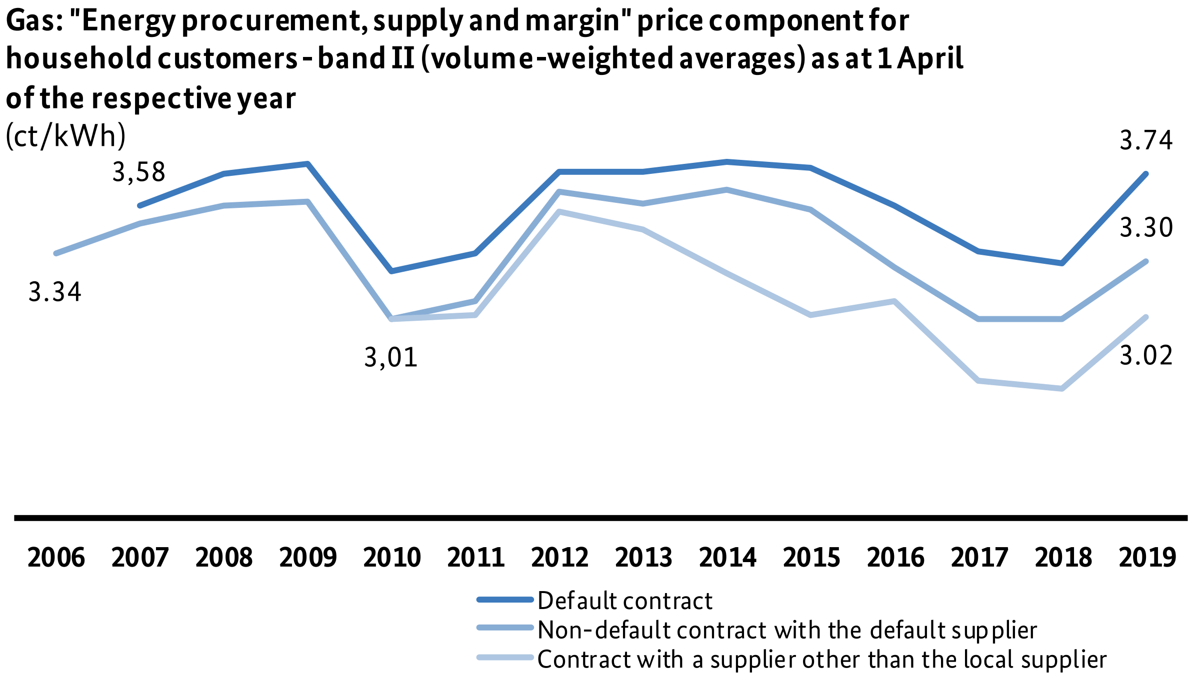

Figure 229: "Energy procurement, supply and margin“ price component for household customers – consumption band II according to the gas supplier survey

Special bonuses and schemes

In addition to differences in the total price, non-default contracts with the default supplier and contracts with a supplier other than the local default supplier have 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, 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 €330. These one-off payments amount to an average of €75 to €80.

Gas: special bonuses and schemes for household customers

As at 1 April 2019	Household customers			
	Non-default contract with the default supplier		Contract with a supplier other than the local default supplier	
	No. tariffs reported by surveyed companies	Average length/ amount	No. tariffs reported by surveyed companies	Average length/ amount
Minimum contract period	339	12 months	392	12 months
Price stability	308	16 months	373	16 months
Advance payment	50	10 months	38	9 months
One-off bonus payment	128	70	184	80
Free kilowatt hours	12	1,300 kWh	8	510 kWh
Deposit	7	-	7	-
Other bonuses	78	-	83	-
Other special arrangements	30	-	30	-

Table 137: 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. As in the comparison of European electricity prices, 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 relevant regulation (EU) No 2016/1952, Article 3, allows the individual Member States a certain degree of freedom in the choice of a survey method, which can lead 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, falls into this consumption range.

The customer group with this level of consumption consists mainly of industrial customers. These customers 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. These components have also been deducted from the gross price in accordance with the Eurostat classification.[167] 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. According to prices published by Eurostat, the volume-weighted[168] average EU price for non-household customers with an annual consumption of between 27.8 and 278 GWh in the second half of 2018 was 2.62 ct/kWh. The arithmetic mean of the gas prices in the participating Member States was approx. 2.81 ct/kWh. The net gas price paid by German non-household customers in the second half of 2018 in this consumption category was 2.65 ct/kWh. The price paid by German consumers of natural gas per kilowatt hour was therefore around 6% less than the EU average price. In a European comparison taxes and levies which Member States impose for gas consumption, vary to a large extent. Non-recoverable taxes and levies amount to an average of approx. 8% (0.22 ct/kWh) of the net price in Europe. The figure of about 18% (0.40 ct/kWh) for Germany in 2018 is above average in this respect.

[167] For more information on country-specific deductions see Eurostat, Gas Prices – Price Systems 2014, 2015 Edition: https://ec.europa.eu/eurostat/documents/38154/42201/Gas-prices-Price-systems-2014.pdf/30ac83ad-8daa-438c-b5cf-b52273794f78 (retrieved on 27 May 2019).

[168] For details on the calculation method of the EU aggregates in para. 18.1: https://ec.europa.eu/eurostat/cache/metadata/en/nrg_pc_202_esms.htm#stat_process1554804191624 (retrieved on 29 August 2019)

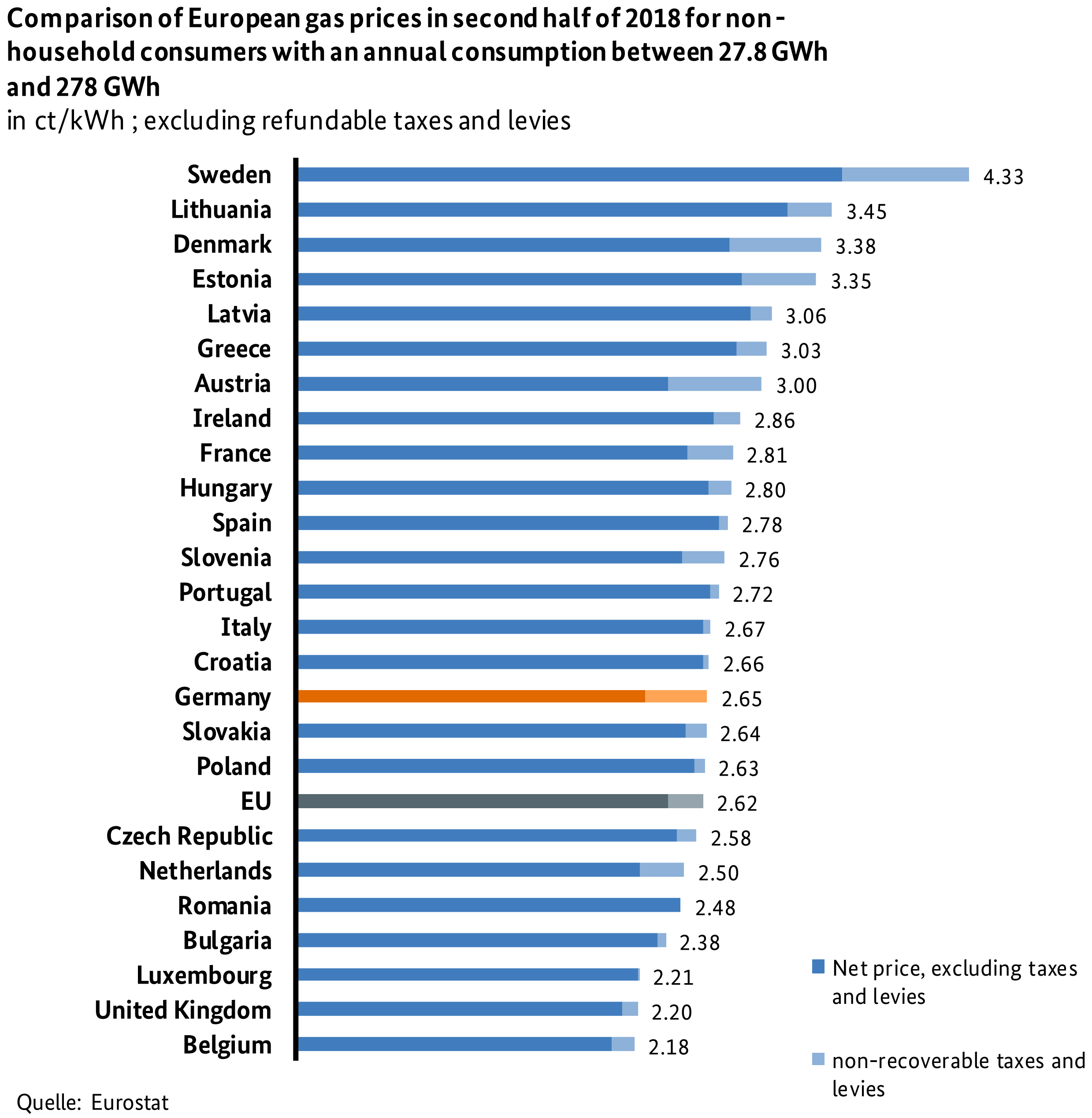

Figure 230: Comparison of European gas prices in the second half of 2018 for non-household consumers with an annual consumption between 27.8 GWh and 278 GWh[169]

5.2 Household consumers

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, falls into the medium Eurostat consumption band. The following shows an EU comparison of the medium

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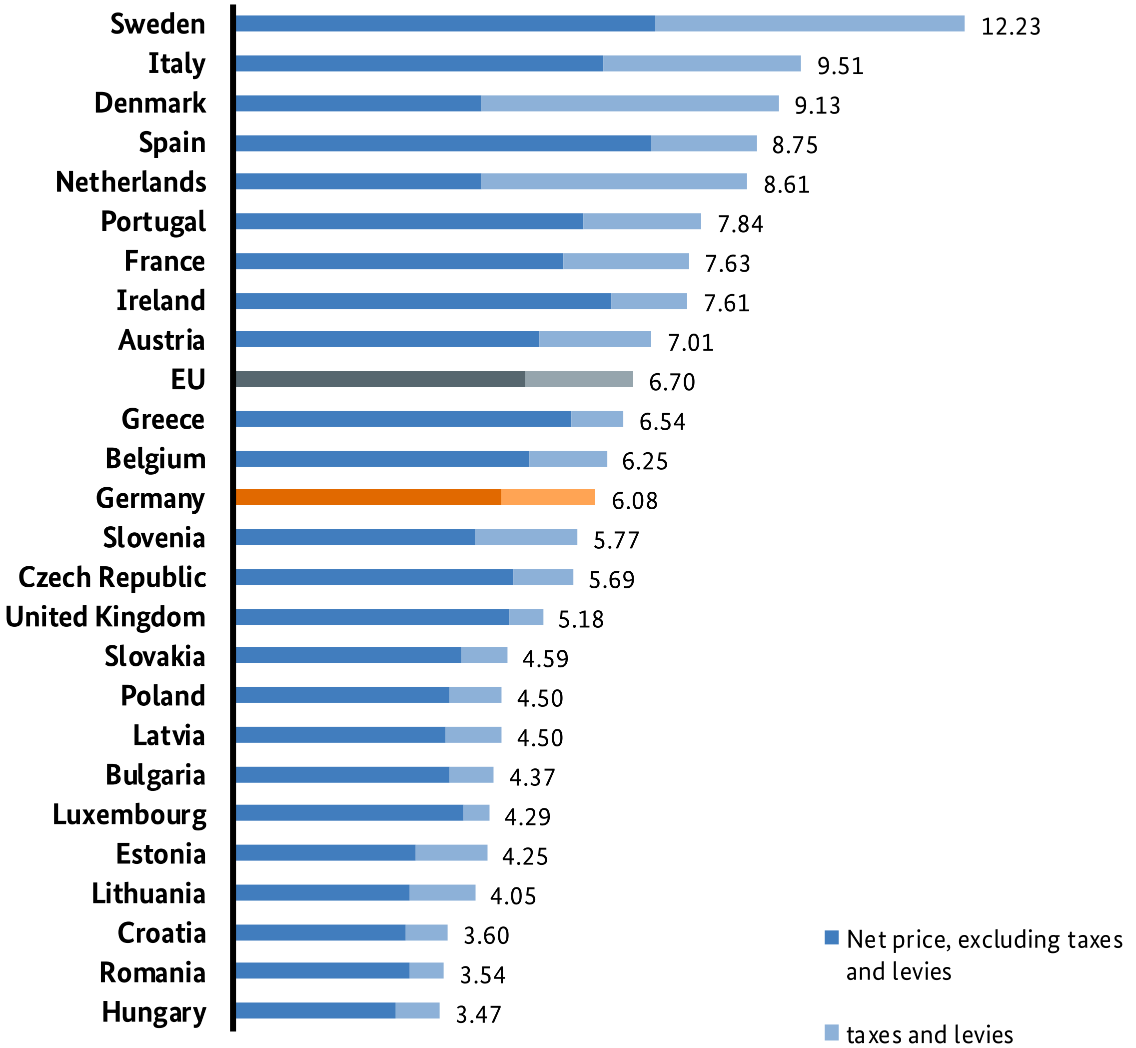
[169] The Eurostat comparison does not include prices in Finland, Malta and Cyprus. The price for Romania is an estimate.

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 Germany, the Czech Republic and the United Kingdom. They paid more than three times as much as customers in Lithuania, Croatia, Romania and Hungary. According to prices published by Eurostat, the volume-weighted average EU price for household customers in the second half of 2018 was 6.70 ct/kWh. The arithmetic mean of the gas prices in the participating Member States was approx. 6.20 ct/kWh. The gas price paid by household customers in Germany was 6.08 ct/kWh. The price paid by German consumers of natural gas per kilowatt hour was therefore around 2% less than the EU average price

The percentage of the overall price for household customers made up by taxes and levies also varies widely across the EU. While taxes and levies account for only about 10% of the price in Luxembourg, they make up about 54% of the price in Denmark. Germany's figure of about 26% again matches the European average in this respect. Around 1.57 ct/kWh of the overall price in Germany consists of taxes and levies; the EU average is 1.68 ct/kWh (about 27%).

Comparison of European gas prices in the second half of 2018 for household customers with an annual consumption between 5,555 kWh and 55,555 kWh
in ct/kWh ; incl. VAT



Quelle: Eurostat

Figure 231: Comparison of European gas prices in the second half of 2018 for household customers with an annual consumption between 5,555 kWh and 55,555 kWh[170]

[170] The Eurostat comparison does not include prices in Finland, Malta and Cyprus. The price for Romania is an estimate.

G Metering

Metering was completely revamped in Germany with the adoption of the Metering Act (MsbG). The "basic responsibility for meter operations" is now legally defined for the first time and a distinction has been made between the basic responsibility for conventional metering systems and basic responsibility for modern metering devices and smart meters. The basic responsibility for both categories of equipment lies with network operators. Since 1 October 2017, it has been possible to transfer the basic responsibility for modern electricity metering devices and smart electricity meters to a third party service provider. For gas metering, however, this is not possible, because section 41 et seq MsbG only applies to modern electricity metering devices and smart electricity meters.

Moreover, the obligatory rollout of modern metering devices and smart meters is only envisaged for the electricity sector, while for gas there are only requirements regarding the ability of gas metering equipment to be connected to a smart meter gateway or regarding the connection to existing smart meters.

1. The network operator as the default meter operator and independent meter operators

The results presented in this chapter take into account information collected from 672 companies. This paints the following picture for 2018 with regard to the distribution of market roles:

Gas: meter operator roles

Function	2018
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)	658
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)	11
Supplier with meter operator activities	14
Independent third party that provides metering services	5

Table 138: Distribution of network operator roles according to data provided by gas meter operators as at 31 December 2018

The table below shows the total reported meter locations broken down by federal state. It can be seen that North Rhine-Westphalia has the most meter locations (approximately 3.5m), followed by Lower Saxony (2.1m), Bavaria (1.4m) and Baden-Württemberg (1.3m).

Gas: number of meter locations by federal state in 2018

Federal state	Number
Baden-Württemberg	1,293,955
Bavaria	1,381,340
Berlin	602,490
Brandenburg	534,440
Bremen	155,688
Hamburg	229,499
Hesse	999,499
Mecklenburg-Western Pomerania	319,305
Lower Saxony	2,100,710
North Rhine-Westphalia	3,538,027
Rhineland-Palatinate	792,021
Saarland	217,764
Saxony	595,340
Saxony-Anhalt	418,252
Schleswig-Holstein	553,491
Thuringia	358,113

Table 139: Number of meter locations by federal state

2. Metering technology used for household customers

As at 31 December 2018, approximately 4.8 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 para 19 MsbG. About 451,000 meters have already been converted so that they can be connected to a smart meter gateway within the meaning of section 2 para 19 MsbG.

Gas: metering equipment used by SLP customers in 2018

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+
Diaphragm gas meters with mechanical counter	7,130,637	239,602	28,216
Diaphragm gas meters with mechanical counter and pulse output	6,232,563	247,545	70,339
Diaphragm gas meters with mechanical counter and manufacturer-specific output (eg: Cyble, absolute encoder)	413,844	12,445	2,935
Diaphragm gas meters with electronic counter	8,891	829	589
Ultrasonic gas meters	9,025	51	163
Load/interval meters as for interval-metered customers	199	830	2,683
Other mechanical gas meters	10,148	2,894	27,648
Other electronic gas meters	2,154	-	289
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	4,605,781	136,657	25,290
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	430,499	16,268	4,109

Table 140: Breakdown of metering equipment used by SLP customers as at 31 December 2018, according to meter size[171]

The overwhelming majority of meters use pulse generators as their communication technology (93%). Only about 7% use Cyble sensors, absolute encoders, electronic meters or other means.

[171] Meter size according to DVGW.

Gas: communication technology used for meters for SLP customers in 2018
(number and percentage)

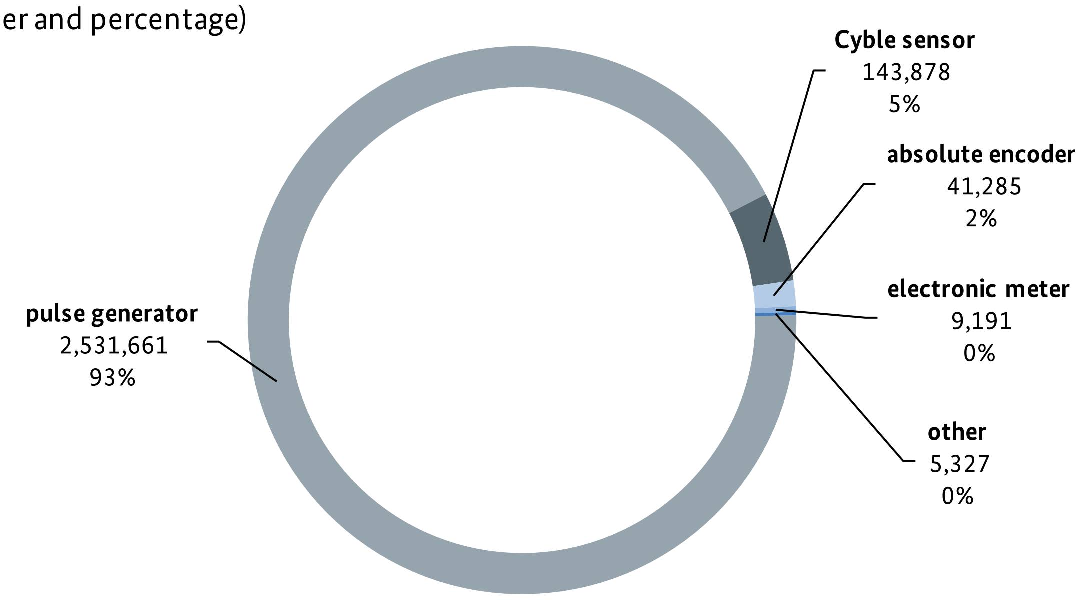


Figure 232: Communication technology used for meters for SLP customers – as at 31 December 2018

Most meters for SLP customers (about 60%) use telecommunication technology such as traditional telephone lines, DSL or mobile communications as their interface technology.

Gas: interface technology for SLP customer meters in 2018
(number and percentage)

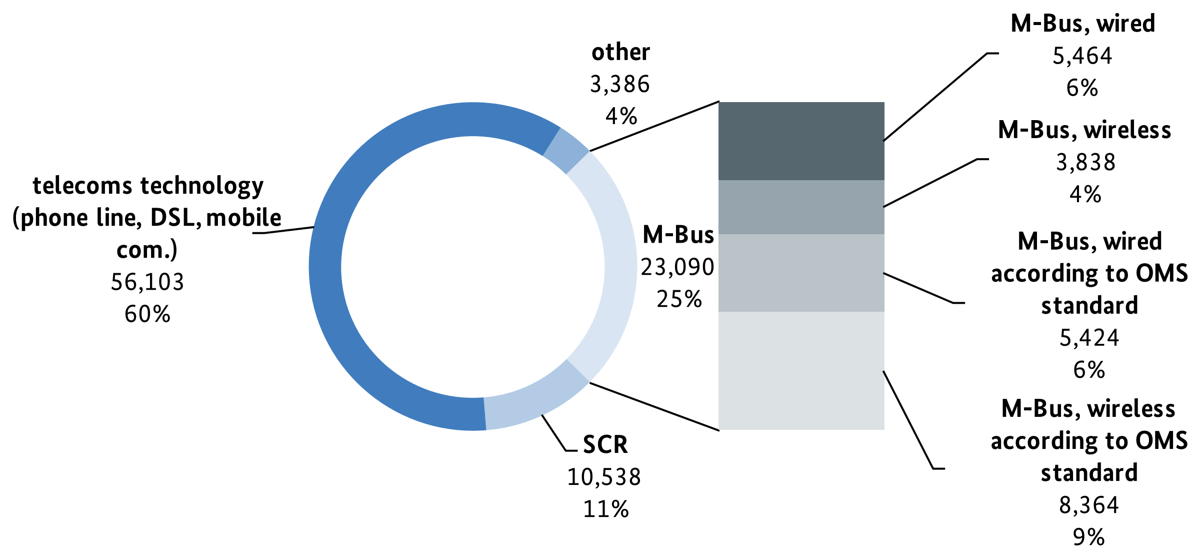


Figure 233: Interface technology for SLP customer meters – as at 31 December 2018

3. Metering technology used for interval-metered customers

The distribution of metering technology employed for interval-metered customers in 2018 is as follows:

Gas: metering technologies used for interval-metered customers in 2018

Function	No. of meter points
Transmitting meter with a pulse output/encoder meter + a recording device/data storage	16,597
Transmitting meter with a pulse output/encoder meter + volume converter	9,888
Transmitting meter with a pulse output/encoder meter + calorific value volume converter	405
Transmitting meter with a pulse output/encoder meter + volume converter + recording device/data storage	14,860
Transmitting meter with a pulse output/encoder meter + temperature volume converter + recording device/data storage	768
Transmitting meter with a pulse output/encoder meter + smart meter gateway	44
Other	206

Table 141: Breakdown of metering technologies used for interval-metered customers – as at 31 December 2018

The metering technology used by interval-metered customers transmits data almost exclusively via telecommunication systems (89.6%). Telecommunications include mobile communications up to 2.5G (GSM, GPRS, EDGE), mobile communications up to 3G (UMTS, HSDPA, LTE), telephone lines, DSL and broadband as well as power lines. The digital interface for gas meters is worth mentioning as an alternative technology used to transfer meter data, with 6.9% of interval-metered customers using this interface.

Gas: communication link-up systems used for interval-metered customers in 2018 (number and percentage)

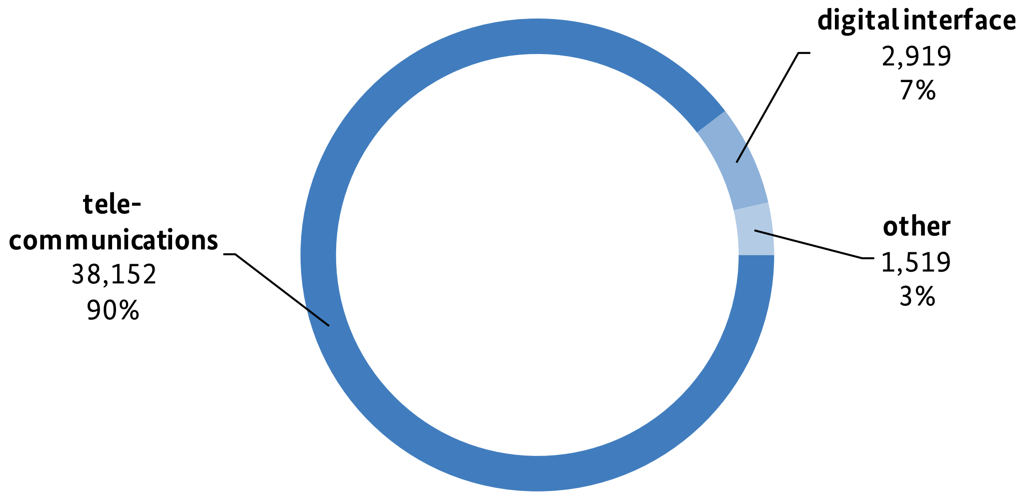


Figure 234: Number and percentage of communication link-up systems used for interval-metered customers – as at 31 December 2018

4. 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 meter operators.

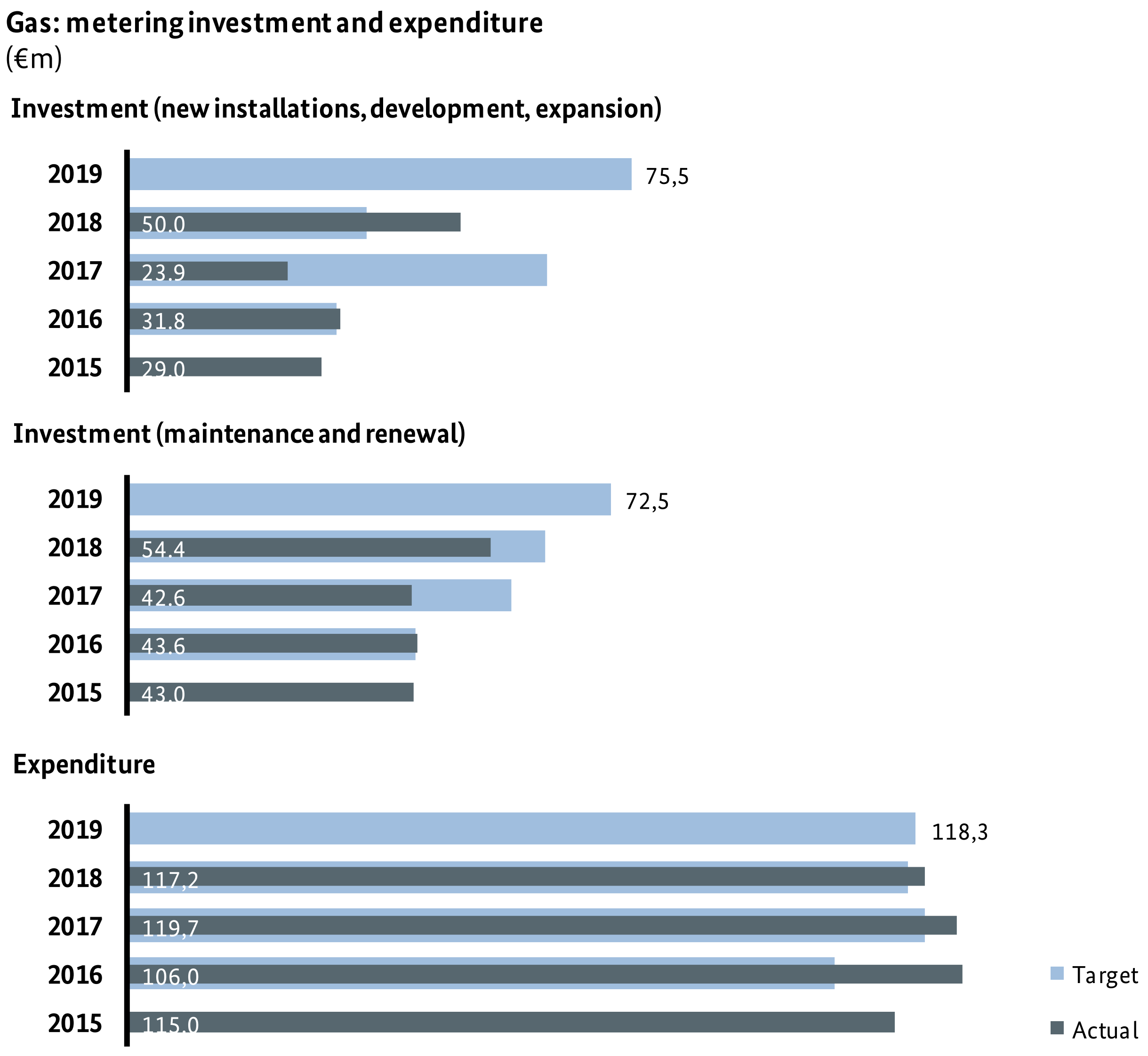


Figure 235: Metering investment and expenditure

III General topics

A Market Transparency Unit for Wholesale Electricity and Gas Markets

The tasks of the Market Transparency Unit for Wholesale Electricity and Gas Markets are carried out jointly by the Bundesnetzagentur and the Bundeskartellamt. The joint market monitoring is based on the transaction and fundamental data transmitted since October 2017 to the Market Transparency Unit by the Agency for the Cooperation of Energy Regulators (ACER).

At present, 4,515 market participants are registered in Germany, and 14,473 market participants are registered in the whole of the EU.[172] The Bundesnetzagentur started registering market participants within the meaning of Regulation (EU) No 1227/2011 on wholesale energy market integrity and transparency (REMIT) on 6 March 2015. Market participants entering into electricity or gas wholesale transactions that are required to be reported must register with the Bundesnetzagentur. The majority of the market participants registered in 2015 and 2016 after the reporting obligations first came into force. The number of new registrations made each year since 2017 has been considerably smaller.[173]

New registrations under REMIT

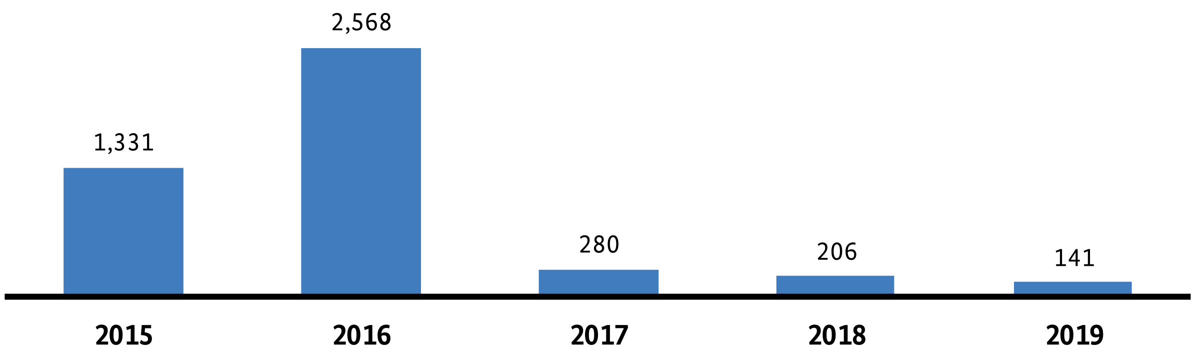


Figure 236: New registrations under REMIT in Germany per year[172]

ACER receives transaction data from all the registered market participants on their activities in the wholesale electricity and gas markets. The data relate to both transactions for electricity and gas products and transactions for entry, exit and transmission capacity. ACER also collects fundamental data from transmission system operators (TSOs) relating to networks and generation.

The Market Transparency Unit receives from ACER the transaction data relevant for monitoring the German markets. It also receives the fundamental data for all EU countries.

[172] As at: 23 October 2019.

[173] Eleven registered market participants have been deleted since registering began, for example because of changes in the legal form of the companies.

Most of the data transmitted to the Market Transparency Unit relate to transactions for electricity and gas products. The transaction data comprise orders to trade and trades concluded. An order is an offer to buy or sell electricity or gas that can be accepted by another market participant. If an order is accepted by another market participant, a transaction is concluded between the two market participants. The following data were transmitted for the period from December 2017 to August 2019:

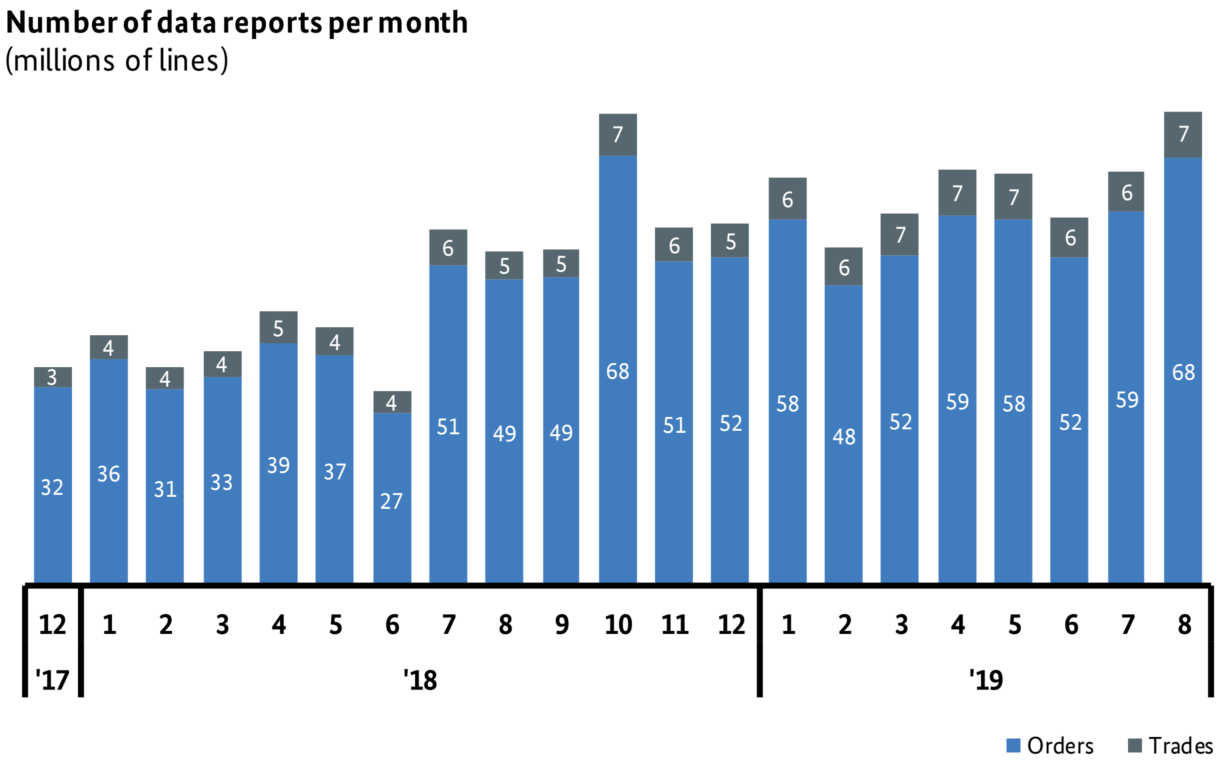


Figure 237: Number of data reports on orders and trades received per month by the Market Transparency Unit

Buy and sell bids are usually reported separately. The number of reports is not directly related to the number of orders issued or transactions concluded. The reports also include corrections and deletions, and one order may therefore be the subject of several technical reports.

The number of reports on orders is considerably higher than the number of reports on trades. This is mainly because each market participant aims to secure the most favourable conditions possible for their transaction and may therefore change an order several times or cancel an order, for instance in response to orders from other market participants or changes in market conditions.

The following diagram shows a breakdown of the data reports into exchange trading, trades via broker platforms, and bilateral contracts.

Breakdown of the data reports on trades and orders from December 2017 to August 2019
(%)

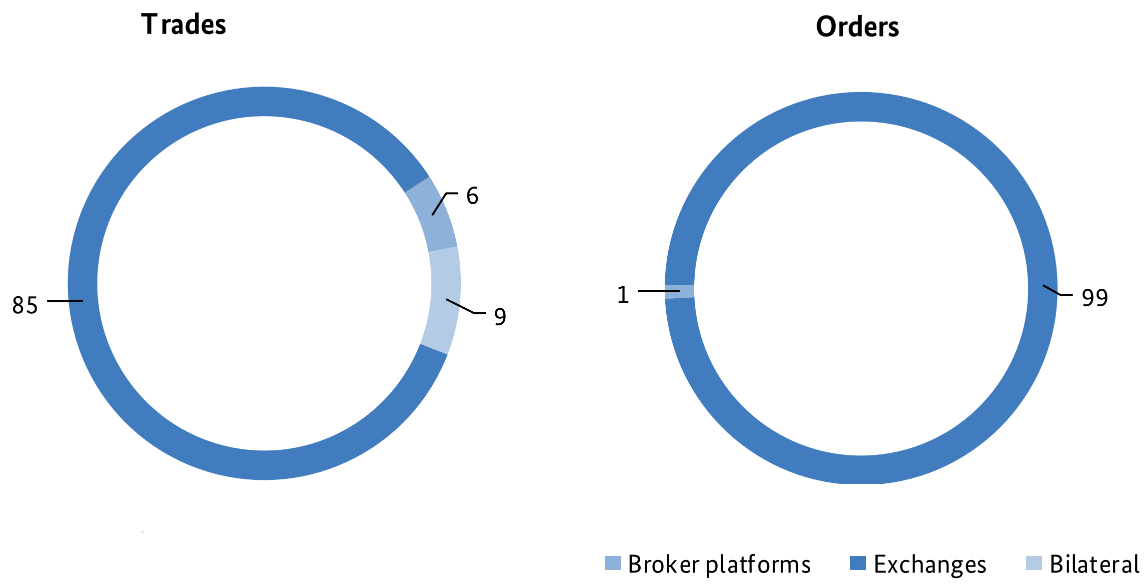


Figure 238: Reports on trades and orders by marketplace

The diagram shows that the vast majority of data reports on both orders and trades were transmitted by exchanges. This is due to the fact that a large number of low-volume and short-duration transactions are concluded on the electricity and gas exchanges. The exact opposite is true for transactions concluded via broker platforms and bilateral contracts; a smaller number of these trades are concluded but for high volumes and usually longer durations. An analysis of the volumes traded on the individual exchanges and broker platforms is included in the sections on electricity and gas wholesale trading.

B Guidelines for the control of abusive practices in the electricity generation sector

The Bundeskartellamt and the Bundesnetzagentur have drawn up guidelines for the control of abusive practices in the electricity generation and wholesale trade sector under competition and energy wholesale law. The guidelines set out the main intention, the rules of application and the scope of the control of abusive practices on the market for the first-time sale of electricity, and deal with issues of interpretation of the Regulation on wholesale energy market integrity and transparency (REMIT) with respect to wholesale energy trading. They were published on 27 September 2019 and are available on the Bundeskartellamt and Bundesnetzagentur websites.

In the course of discussions about the Electricity Market Act, concerns were repeatedly expressed that the prohibition of abusive practices under competition law would act as an implicit price cap, blocking price peaks caused by scarcity (see Monitoring Report 2016, page 375) and thus jeopardising the legal certainty needed for investments in power plants. The Bundeskartellamt has not shared these concerns in the past and does not do so now. However, to allay such fears, it proposed publishing guidelines for the control of abusive practices in the electricity generation sector. The Federal Ministry for Economic Affairs and Energy (BMWi) agreed to the proposal and included the guidelines in its 20 measures for the improvement of the electricity market. The Bundesnetzagentur and Bundeskartellamt started to draw up the joint guidelines, which also included questions about the scope of the market manipulation ban under REMIT.

In 2016, the Bundeskartellamt conducted an initial consultation on issues of competition law requiring clarification (the eight responses received can be accessed on the Bundeskartellamt website). The two authorities then worked on a draft, which was put out for a two-month consultation in spring 2019. A total of twelve responses were received from electricity producers, associations, electricity exchanges, a national regulatory authority and a scientific institute. The comments were studied closely and taken into consideration in the final version of the guidelines, which were published on 27 September 2019. They are available in German on the websites of the Bundeskartellamt (www.bundeskartellamt.de → Missbrauchsaufsicht → Materialien) and the Bundesnetzagentur (www.bundesnetzagentur.de → Elektrizität und Gas → Handel/Vertrieb → MTS und REMIT).

C Selected activities of the Bundesnetzagentur

1. Tasks under REMIT

The Bundesnetzagentur monitors the wholesale energy market in accordance with Regulation (EU) No 1227/2011 on wholesale energy market integrity and transparency (REMIT). Insider trading and market manipulation are prohibited under Articles 3 and 5, respectively, of REMIT.

Insider trading is the use of inside information, the attempted use on one's own account, the disclosure of inside information to third parties, or the recommendation/inducement to acquire or dispose of wholesale energy products on the basis of inside information. Insider trading may refer, for example, to transactions concluded prior to the publication of power plant failures.

Market manipulation is the entering into a transaction or issuing an order that gives, or is likely to give, false or misleading signals as to the supply of, demand for, or price of wholesale energy products. This could include placing orders with no intention of executing them or "wash trades", ie trading with oneself.

Exchanges, broker platforms, market participants and ACER can report suspicious trading activity by one or more market participants. Reports received by the Bundesnetzagentur are referred to below as "suspected breaches", ie cases where there is suspicion of a breach of REMIT.

The number of suspected breaches has been rising since the authority started its monitoring activity in 2012.

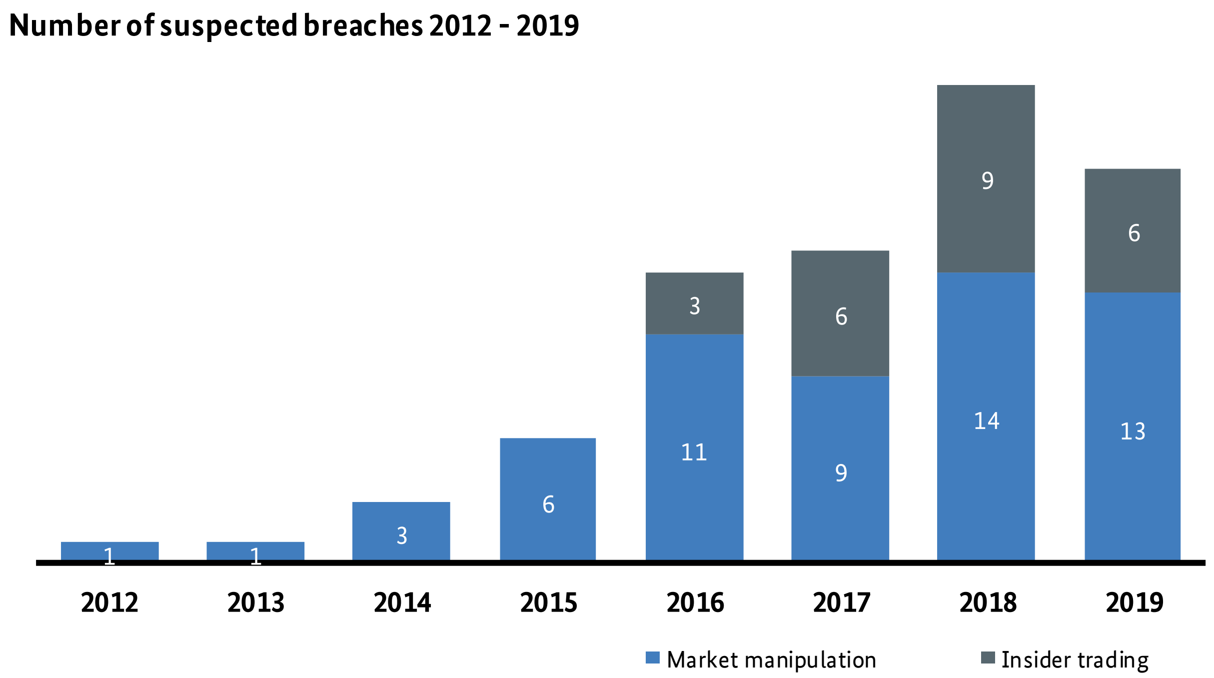


Figure 239: Suspected breaches, 2012 to 2019[174]

The Bundesnetzagentur processed a total of 82 suspected breaches between 2012 and 2019.

a) Closed cases

The cases received by the authority are first subjected to an initial analysis using trading data provided by ACER and, where necessary, other data surveys. If the initial analysis does not provide sufficient evidence of a breach of REMIT, the case is closed. In the case of a regulatory offence, other factors like insignificance or lack of risk of repetition may also lead to the case being dropped. Of the 82 suspected breaches, 38 of them have so far been closed.

[174] As at: 30 August 2019

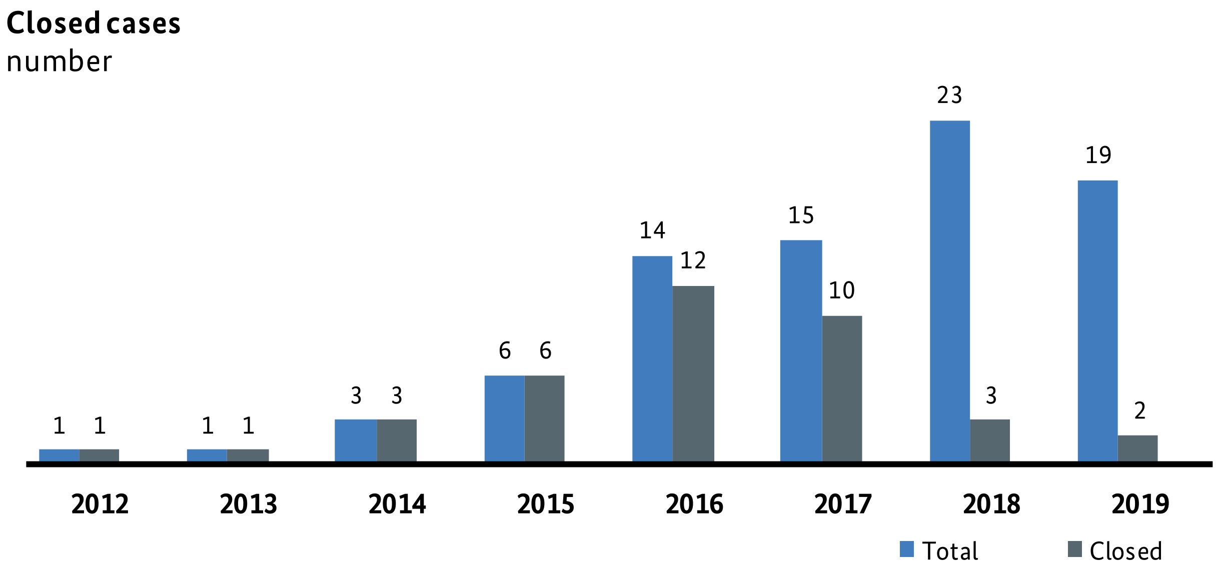


Figure 240: Suspected breaches closed, 2012 to 2019[175]

b) Breaches incurring penalties

If the initial analysis provides sufficient indication of a breach of REMIT, the Bundesnetzagentur conducts its own investigation. If the investigation shows that there has been a breach of REMIT, the Bundesnetzagentur can start regulatory offence proceedings. It has so far only done so in one case, which was concluded in February 2019 with the imposition of fines. This first case of market manipulation is explained below. If the breach may have criminal law consequences, the Bundesnetzagentur passes it on to the prosecution service.

c) Cross-border cases and internal processing

There are other categories of suspected breaches in addition to those cases that have been closed or incurred penalties. Cross-border processing is currently ongoing in 19 cases involving regulatory authorities of other EU Member States. An example of a cross-border case would be when the trading activity on the exchange took place in a different EU Member State to the one in which the market participant is registered and has its headquarters. Internal processing continues in 24 other cases.

[175] As at: 30 August 2019

Market manipulation in gas wholesale trading

In November 2016, the Bundesnetzagentur received information about possible breaches of REMIT in trading on the gas trading platform PEGAS. Since March 2016, PEGAS has been offering 24 hourly products for each day for gas delivery at the points of supply of Elten and Vreden (border between Germany and the Netherlands, point of supply Germany). The most important player in the trade with these products is the market area manager NetConnect Germany (NCG). NCG uses these hourly products to cover its short-term balancing requirements by buying or selling volumes of gas. In fact, this market segment was launched on PEGAS primarily for this purpose. The Bundesnetzagentur's analysis shows that NCG is involved in almost all transactions with these products.

At that time, NCG used its website to inform market participants a few hours in advance approximately how much balancing gas would be acquired. NCG's acquisition process is automated. By following NCG's previous trades, other market participants were thus often able to work out the exact time when NCG would buy or sell, down to the second. The information provided to the Bundesnetzagentur accused two traders from Düsseldorf-based energy company Uniper Global Commodities SE (Uniper) of five instances of market manipulation. They were said to have entered bids and offers for the same product into the order book in such a way that made it impossible for other companies to make better offers to NCG. The Bundesnetzagentur's analysis confirmed the allegations and led to the discovery of a further case.

The details of the alleged market manipulation were as follows: just when NCG was about to buy a larger volume of gas, trader 1 (Uniper) submitted a large offer (in some cases more than 1,000 MW). At the same time, trader 2 (Uniper) submitted a bid for just 1 MW at a price that was exactly one increment below the offer. Such a bid is known as an iceberg order. As soon as someone accepts the offer, ie buys 1 MW, another bid of 1 MW automatically becomes visible in the order book (hidden orders). Iceberg orders are a usual and, in themselves, legal type of trading order. There cannot be an offer on the market that is lower than an existing bid. If another market participant, therefore, wanted to submit a lower offer than the one submitted by trader 1, this would initially be combined with the bid for 1 MW submitted by trader 2. This process would be repeated until all hidden orders had been executed or pulled from the market. Only after all hidden orders had been executed, therefore, could another (better) offer be made to NCG. The Uniper traders used this method to exclude other market participants from the market for several seconds, making themselves the only possible sellers to NCG. Because, as already explained, other market participants were also able to know the exact second when NCG would become active on the market, and because market participants generally submit their offers (automatically) at the last moment, this strategy was successful for the Uniper traders.

Although an iceberg order is a legal trading instrument, in this case it was used to block the market and represented a breach of Article 5 in conjunction with Article 2 point 2a(i) of REMIT (market manipulation), as NCG was misled about the offer situation.

Uniper was accused of having violated its duty of supervision. Both the company and one of the traders stated that the trading behaviour described had been a strategy intended to beat automated trading algorithms. Uniper had an obligation to have suitable and necessary means of supervision in place to prevent manipulative trading strategies or at least make them more difficult.

Fines of €1,500 and €2,000 were imposed on the two traders. Uniper received a fine of €150,000 for negligently violating its duty of supervision. The administrative orders imposing the fines are final and absolute.

As part of ACER's market monitoring responsibilities under REMIT, experts have been examining all trading data EU-wide for irregularities using a specially designed monitoring system and particular parameters since early 2018. ACER is uniquely placed to carry out this task since it has an overview of electricity and gas trading both across borders and across market places. It complements the monitoring activities of the market places and the national regulatory authorities. ACER regularly sends the results of its analyses – known as alerts – to the relevant national regulatory authorities. These alerts initially show anomalies flagged up from the data available to ACER, such as outliers from certain defined ranges. The Bundesnetzagentur received 350 alerts from ACER in 2018 and works closely together with the agency. The alerts may lead to suspected breaches and further investigations. Such suspected breaches are also included in Figure Suspected breaches, 2012 to 2019.

2. Core energy market data register

Operators of electricity generating installations are required to register themselves and their installations in the core energy market data register (MaStR). They can do so online at www.marktstammdatenregister.de. The "help" page provides all information necessary, including a video that goes through each step of the registration process.

The registration requirement applies even if no financial support is claimed and if the installation does not feed any electricity into the grid.

The Bundesnetzagentur has been organising compulsory registrations of energy installations for many years. The requirement has applied to solar installations (PV registration portal) since 2009 and to all installations under the Renewable Energy Sources Act since 2014 (installations register). In addition, there is a "power plant list" of all conventional installations with an installed capacity of more than 10 MW. The Bundesnetzagentur maintains its own register of energy market players, which facilitates communication with them, among other things ("energy client").

While each of these registers is important for its intended purpose, they are not particularly useful for other purposes. This drawback led to the decision in 2013 to set up an overarching, standardised register of all energy generating installations and energy market players.

This online register went live on 31 January 2019 after several years of preparatory work, including an intensive consultation process. It is available at the following website: https://www.marktstammdatenregister.de.

The online portal has a "help" section with detailed explanations on the core energy market data register and its many functions.

Registration requirements and reducing red tape

All electricity and gas generating installations must be registered in the core energy market data register. The operators of these installations and all other market players must be entered in the register as well. The Core Energy Market Data Register Ordinance sets out the requirements regarding registration and maintenance of the entered data.

The primary aim of the register is to reduce unnecessary bureaucracy by using it as a central reference point for all data transfers. Registration in this single register ensures that all communication partners can be related to the correct "object".

Start-up phase

During the two-year start-up phase, which runs until 31 January 2021, all electricity and gas market players are required to register themselves and, where applicable, their installations, in the online register. It is not relevant to the installation registration whether the installation receives financial support or whether it actually feeds electricity into the grid. All installations that produce electricity or gas must be registered. This requirement is directed primarily at the operators of the around two million solar installations that are operated in Germany. It also affects the 100,000 electricity storage facilities that were already subject to a registration requirement if they were attached to installations eligible for EEG funding.

Registrations opened in January 2019 and immediately got off to a strong start, as can be seen in the chart below. The day with the most registrations so far – over 4,500 – was the first full day the register was online: Friday, 1 February 2019.

Registrations of existing installations will pick up pace as of autumn 2019, because the network operators are then going to inform installation operators in writing about their obligations.

Migrated data on existing installations

Data on all existing installations that had already been included in one of the many previous registers at the Bundesnetzagentur, the network operators or other authorities have been migrated into the core energy market data register. These data were thoroughly compared, standardised and checked for plausibility.

The migrated data are missing various details compared to the data that is included in the core energy market data registrations. In particular, the migrated data do not assign the installations to an installation operator or network operator. The detailed information and assignment of installations required by the Core Energy Market Data Register Ordinance mean that a new registration has to be carried out for each migrated data record.

Many core energy market data register users believe that they do not need to re-register their existing installations because the installations are already included in the migrated data. However, this is not the case, because data protection law prohibits the operators being shown all data necessary for the assignment, some of which is confidential. A new registration always has to be made.

Data publication

Almost all data entered in the register are publicly available, with the exception of the exact locations of installations with a capacity of less than 30 kW and the core data of natural persons. All public data can be analysed on the online portal of the core energy market data register. In addition, the Bundesnetzagentur publishes excerpts of the whole data for certain reference days on its website, www.bundesnetzagentur.de/mastr.

These publications are very useful for many institutions, in particular those involved with the electricity industry, and represent a clear improvement in data provision.

D Selected activities of the Bundeskartellamtes

Merger control proceedings in the energy sector: RWE AG / E.ON SE

In February 2019 the Bundeskartellamt cleared the acquisition by RWE AG ("RWE") of a minority holding of 16.67% in E.ON SE ("E.ON") (file no. B8-28/19). The acquisition is part of an extensive exchange of business activities between the two companies and includes the following key elements:

- E.ON acquires RWE's entire share in Innogy SE ("Innogy") of 76.69 % and makes a voluntary takeover offer to the minority shareholders of RWE's Innogy unit. After acquiring the shares in Innogy, E.ON will transfer Innogy's renewable energy and gas storage business back to RWE (reverse carve out assets).

- RWE acquires the main share of E.ON's renewables business as well as the minority shareholdings held by E.ON subsidiary PreussenElektra in the RWE-operated Emsland and Gundremmingen nuclear power plants (transfer assets).

- Furthermore, RWE acquires E.ON shares from authorised capital and consequently a share of 16.67% of E.ON's voting share capital.

Ultimately RWE will thus focus on conventional and renewable electricity generation, gas storage and gas and electricity wholesale trading. E.ON will concentrate on the retail supply of electricity and gas to end customers and the operation of distribution networks.

Due to the complex nature of the transaction structure chosen by the parties, the EU Commission and the Bundeskartellamt were the competent authorities to examine parts of the overall transaction. The first two stages of the transaction fall within the competence of the EU Commission because they constitute concentrations which are subject to the European Community Merger Regulation (ECMR)[176] and the turnovers of the participating companies exceed the thresholds of the ECMR[177].

RWE's acquisition of a 16.67% minority shareholding in E.ON fell within the Bundeskartellamt's area of competence as this does not give RWE any control over E.ON and therefore does not constitute a concentration under European law. However, according to the Bundeskartellamt's assessment it fulfils the elements of a concentration under the German Competition Act, GWB, in respect of the acquisition of a material competitive influence on another undertaking.[178]

The "Transfer Assets" part of the transaction (file no. M.8871) was cleared by the EU Commission in February 2019 at the same time as the minority shareholding was notified to the Bundeskartellamt (see above). The E.ON/Innogy merger (file no. M.8870) was cleared in September 2019 following an in-depth examination

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[176] Art. 3 (1) ECMR ("acquisition of control").

[177] Art. 1 (2) lit. a and lit. b ECMR ("Community dimension").

[178] Within the meaning of Section 37 (1) no. 4 GWB.

subject to conditions which included the surrender of most of the contracts with heating electricity customers and of a number of charging stations on motorways.[179]

The Bundeskartellamt's substantive assessment of the merger project which was carried out in close cooperation with the EU Commission, centred on the horizontal effects of the merger on the market for the generation and first-time sale of electricity. The merger also affected other markets for the supply of electricity and gas.[180]

On conclusion of the overall transaction the market position of the target company E.ON on the market for the first-time sale of electricity will be determined by the shareholdings held by E.ON subsidiary PreussenElektra in the remaining nuclear plants. However, E.ON's relevant generation capacities will be reduced with the gradual shutdown of the Grohnde and Brokdorf nuclear power plants by the end of 2021 and entirely eliminated after the shutdown of the Isar 2 nuclear power plant by the end of 2022. E.ON will then have only small and smallest non-EEG-subsidised installations mainly operated by itself and its Innogy subsidiaries (in total distinctly less than 1 % of non-EEG-subsidised capacity in Germany). According to the results of monitoring activities in the energy sector in 2017, RWE achieved a market share of 29.9% on the market for the first-time sale of electricity; (2018: 30.2%). Its share in 2016 still amounted to 33.5%.[181] As a result of the acquisition of the transfer assets as the part of the transaction subject to examination by the EU Commission and in consideration of the sale of the reverse carve out assets, RWE's market share will increase marginally by less than 1%. However, this increase will no longer apply after the nuclear phase-out. The merger will therefore have only minor, temporary effects on the market for the first-time sale of electricity.

In order to gain a more accurate picture of RWE's current market position which reflects the specifics of the market for the first-time sale of electricity, the Bundeskartellamt also examined the Residual Supply Index (RSI). The RSI defines the periods in which a specific electricity producer is indispensable for meeting the demand for electricity. It takes account of the fact that at every given period the amount of electricity produced has to match the amount required and that storage facilities are only very limited. This index can thus be used to measure the extent of market power held by a company as the latter can significantly influence the amount of electricity available by the way it operates its power plants and - e.g. by strategically withholding capacity - can also significantly influence the electricity price.

The results of the investigations to determine the RSI show that RWE is currently indispensable for meeting the demand for electricity over a significant number of hours in the year. However, the number of pivotal hours has not yet reached the level necessary to presume a dominant position. Irrespective of the transaction now cleared, the nuclear phase-out by the end of 2022 is likely to mean that the level of indispensability of RWE's fleet of conventional power plants, and consequently RWE's market power, will increase significantly. This development could be further exacerbated depending on the concrete implementation of the planned coal phase-out. According to these analyses and general market developments, RWE's prospective market

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[179] Details on this part of the overall transaction are available on the European Commission's website at https://europa.eu/rapid/press-release_IP-19-5582_en.htm

[180] The assessment of the substantive effects of the merger in all these areas was based on the effects of the overall transaction, i.e. it was assumed that the parts of the transaction notified to the European Commission would also be implemented as stated in the notification.

[181] The assessment was based on the figures for 2017 because figures for 2018 were not available at the time of the examination.

power is likely to increase to a degree in excess of the threshold above which market dominance is presumed. However, according to the information currently available, at the stage at which it could reach a critical degree, RWE's market power will no longer be strengthened by its minority holding in E.ON. It could thus be ruled out that the acquisition of the minority holding would significantly impede effective competition.

RWE's acquisition of a 16.67 % minority holding in E.ON, which was examined by the Bundeskartellamt, was also not expected to significantly impede effective competition. The minority holding will not give RWE control over E.ON's remaining generating capacities. With this level of holding RWE will not be in a position to exert its influence in day-to-day operations against E.ON's interests, e.g. by cutting back production at E.ON's power plants in RWE's interest. RWE will, however, have a proportional share of the profits of E.ON's power plants. However this will not increase RWE's possibilities and incentives to withhold capacities to raise prices, which would qualify as a significant impediment to competition.

In this constellation RWE's future market position on the upstream markets and that of E.ON on the downstream markets will not impede effective competition at the vertical level. The transaction even has a deconcentrating effect in that it will significantly reduce RWE's possibilities to influence the activities of Innogy which it has controlled up to now by divesting it to E.ON. According to the Bundeskartellamt's investigations no anti-competitive effects were expected in the gas sector due to significantly lower market shares or no overlaps in the areas of activity of the two companies.

The merger project and its examination under merger control is described in detail in the case summary B8-28/19 "Acquisition by RWE AG of a minority shareholding of 16.67% in E.ON SE" at: https://www.bundeskartellamt.de/SharedDocs/Entscheidung/DE/Fallberichte/Fusionskontrolle/2019/B8-28-19.html

Lists

List of authorship

Joint texts

Key findings

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Introduction to Retail: Price level (I.G.4)

Gas markets summary (II.A.1)

Introduction to Retail: Contract structure and supplier switching (II.F.2)

Introduction to Retail: Price level (II.F.4)

Market Transparency Unit for Wholesale Electricity and Gas Markets (III.A)

Guidelines for the control of abusive practices in the electricity generation sector (III.B)

(Text passages in these four sections authored as listed below)

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C Networks

D System services

E Cross-border trading and European integration

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Abbreviation	Definition
AbLaV	Interruptible Loads Ordinance
AC	alternating current
ACER	Agency for the Cooperation of Energy Regulators
aFRR	Frequency restoration reserves with automatic activation
AktG	Stock Corporation Act
ARegV	Incentive Regulation Ordinance
AT	Austria
BAFA	Federal Office for Economic Affairs and Export Control
BBPlG	Federal Requirements Plan Act
BE	Belgium
BMWi	Federal Ministry for Economic Affairs and Energy
bn	billion
BSH	Federal Maritime and Hydrographic Agency
BSI	Federal Office for Information Security
CAPM	capital asset pricing model
CH	Switzerland
CHP	combined heat and power
CIS	Commonwealth of Independent States
CO2	carbon dioxide
CR	concentration ratio
ct/kWh	cents per kilowatt hour
CWE	Central Western Europe
DC	direct current
DSL	digital subscriber line
DSO	distribution system operator
DVGW	German Technical and Scientific Association for Gas and Water
DZK	dynamically allocable capacity
EEAV	Renewable Energy Sources Implementing Ordinance
EEG	Renewable Energy Sources Act
EEV	Renewable Energy Sources Ordinance
EEX	European Energy Exchange
EGIX	European Gas Index
EGSI	European Gas Spot Index
EnLAG	Power Grid Expansion Act

EnWG	Energy Industry Act
ENTSO-E	European Network of Transmission System Operators for Electricity
EPEX	European Power Exchange
EU	European Union
F	France
FCR	Frequency containment reserves
FFAV	Ground-mounted PV Auction Ordinance
FFIM	feed-in management measures
FBMC	flow-based market coupling
FZK	firm and freely allocable capacity
GasNEV	Gas Network Charges Ordinance
GasNZV	Gas Network Access Ordinance
GasGKErstV	Gas Appliance Reimbursement Ordinance
GasGVV	Gas Default Supply Ordinance
GEEV	Cross-Border Renewable Energy Ordinance
GJ	gigajoule
GPRS	general packet radio service
GSM	Global System for Mobile Communications
GW	gigawatt
GWB	Competition Act
GWh	gigawatt hour
HSDPA	High Speed Downlink Packet Access
HVDC	high voltage direct current
IGCC	International Grid Control Cooperation
KAV	Electricity and Gas Concession Fees Ordinance
KBA	Federal Motor Transport Authority
km	kilometre
kV	kilovolt
kWh	kilowatt hour
KWKG	Combined Heat and Power Act
KraftNAV	Power Plant Grid Connection Ordinance
LBEG	State Authority for Mining, Energy and Geology
LNG	liquid natural gas
LSV	Charging Station Ordinance
LTE	Long Term Evolution
m	million
m3	cubic metre
MaStRV	Core Energy Market Data Register Ordinance

mFRR	Frequency restoration reserves with manual activation
MinRAM	minimum remaining available margin
MOL	merit order list
MsbG	Metering Act
MW	megawatt
MWh	megawatt hour
NABEG	Grid Expansion Acceleration Act
NAP	Network connection point
NAV	Low Voltage Network Connection Ordinance
NCG	NetConnect Germany
Ncm	normal cubic metre
NDAV	Low Pressure Network Connection Ordinance
NDP	Network Development Plan
NL	Netherlands
no.	number
NOVA	network optimisation before reinforcement before new construction
NTC	net transfer capacity
OJ	Official Journal
OMS	open metering system
O-NDP	Offshore Network Development Plan
OTC	over-the-counter
PN	pressure nominal
PV	photovoltaic
REMIT	Regulation on wholesale energy market integrity and transparency
SAIDI	System Average Interruption Duration Index
SLP	Standard load profile
StromGVV	Electricity Default Supply Ordinance
StromNEV	Electricity Network Charges Ordinance
TSO	transmission system operator
TWh	terawatt hour
UMTS	Universal Mobile Telecommunications System
VAT	value added tax
AbLaV	Interruptible Loads Ordinance
AC	alternating current
ACER	Agency for the Cooperation of Energy Regulators
aFRR	Frequency restoration reserves with automatic activation
AktG	Stock Corporation Act
ARegV	Incentive Regulation Ordinance

AT	Austria
BAFA	Federal Office for Economic Affairs and Export Control
BBPlG	Federal Requirements Plan Act

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) of the Energy Act may also be necessary in situations other than those covered by the feed-in management provisions if the threat to the system is caused not by congestion but by another security problem. Adjustments pursuant to section 13(2) 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 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).
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.
CHP electricity	CHP electricity is the mathematical product of useful heat and power-to-heat ratio of the CHP installation; for installations without equipment for the removal of waste heat, the entire net electricity generation is CHP electricity.
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 level of market concentration.
Condensing electricity	*Gross condensing electricity generation:* Gross condensing electricity is the part of the gross electricity generated in a reporting period that occurs when the working fluid in a steam turbine is cooled to the ambient temperature and thus the full, possible enthalpy change is used to generate electricity. Electricity generation in gas turbines, CHPS operated by combustion engines and fuel cells without heat recovery is "uncoupled electricity generation" and can therefore be equated to condensing electricity generation.

	Net condensing electricity generation: The net condensing electricity generated by a generating installation is the gross condensing electricity generation less the condensing electricity for self-consumption (in a reporting period).
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) Energy Act.
Default supply	Energy supply by the default supplier to household customers on the basis of general terms and conditions and general prices (see section 36 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)
Dynamic prices	Prices of an electricity supply contract between a supplier and a final consumer that reflects the price on the spot market, including the day-ahead market, in intervals corresponding to at least the billing interval of the market in question.
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 other) 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).
Federal sectoral planning	Federal sectoral planning is a procedural step that precedes planning approval. It sets out the route corridors with binding effect. These route corridors are approximately 500m to 1000m-wide strips of land along which the future power lines will run. The Bundesnetzagentur carries out the federal sectoral planning for those projects identified under the Federal Requirements Plan Act that cross federal state and/or national borders.
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 Market Coupling (FBMC)	Starting from the planned commercial flows (trades), the capacity available in the transmission network for cross-border electricity trading is determined and allocated on the basis of the actual flows in the network. FBMC thus makes it possible to allocate transmission capacity in line with the actual market situation as reflected by

	the bids, bringing the market and network sides closer together and leading to a result that is more beneficial to welfare.
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 which, on account of green electricity labelling or other marking, is shown to have been produced with a high share/high promotion of efficient or regenerative production technologies and which is offered/traded at a 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 but located 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/m³ and a Wobbe index from 12.8 kWh/m³ to 15.7 kWh/m³.
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).
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/m^3 and a Wobbe index from 10.5 kWh/m^3 to 13.0 kWh/m^3.
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 = 1 km, L2 = 1 km and L3 = 1 km, then the length of the circuit = 1 km). 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.
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 location	Energy is generated or consumed in a market location. The market location is connected to the network by means of at least one line. The market location is a connecting point for supply and balancing. In the data survey 2019, the relevant questionnaires use the terms "market location" (contracts) and "meter location" (meters) instead of "meter point".
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.
Meter location	A meter location is a location at which energy is measured and that includes all technical equipment required to collect and, if necessary, transmit the meter data. All relevant physical quantities at a point in time are collected no more than once at a meter location. The term "meter location" corresponds to the term "meter" within the meaning of section 2 para 11 of the Metering Act (MsbG). In the data survey 2019, the relevant questionnaires use the terms "market location" (contracts) and "meter location" (meters) instead of "meter point".
Meter point	Point in the grid at which the flow of energy, or the amount of gas transported, is recorded for billing purposes (see section2(28) of the Metering Act). In the data survey 2020, the relevant questionnaires use the terms "market location" (contracts) and "meter location" (meters) instead of "meter point".
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 capacity and reactive capacity). 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.
Modern metering equipment	A metering system reflecting actual electricity consumption and actual time of use that can be safely connected to a communication network via a smart meter gateway.
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 (NTC)	Net transfer capacity of two neighbouring countries (calculated as total transfer 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	1. 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 2. medium voltage > 1 kV and ≤ 72.5 kV 3. high voltage > 72.5 kV and ≤ 125 kV extra-high voltage > 125 kV
Network losses	The energy lost in the transmission and distribution system is the difference between the electrical energy physically delivered to the system and the energy drawn from the system within the same period (see VGB, 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 para 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).
Planning approval	The planning approval procedure is the last stage of the planning process when expanding or converting the network. The public, public agencies and associations are involved in the planning approval procedure, in which the exact route and form of the expansion measure are decided.
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 secure and reliable operation of the electricity supply networks. The aim is either to prevent or relieve overloading of power lines. 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, for example, 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).
SLP customer (standard load profile customer)	*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.)
Smart meter gateway	The communication unit of a smart metering system, which can connect modern metering equipment and other technical equipment – including in particular generating installations under the EEG and the KWKG – safely to a communication network, ensuring data protection, data security and interoperability while meeting requirements for protection profiles and technical guidelines. The gateway has functions for recording, processing and transmitting data.
Smart metering system	A modern metering system connected to a communication network via a smart meter gateway for the purpose of recording electrical energy reflecting actual energy consumption and actual time of use.
Spot market	Market where transactions are handled immediately (intraday and day-ahead auctions).
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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Last revised

27 November 2019

Print

Bundesnetzagentur

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Text

Bundesnetzagentur
Referat 603

Bundeskartellamt
Arbeitsgruppe Energie-Monitoring