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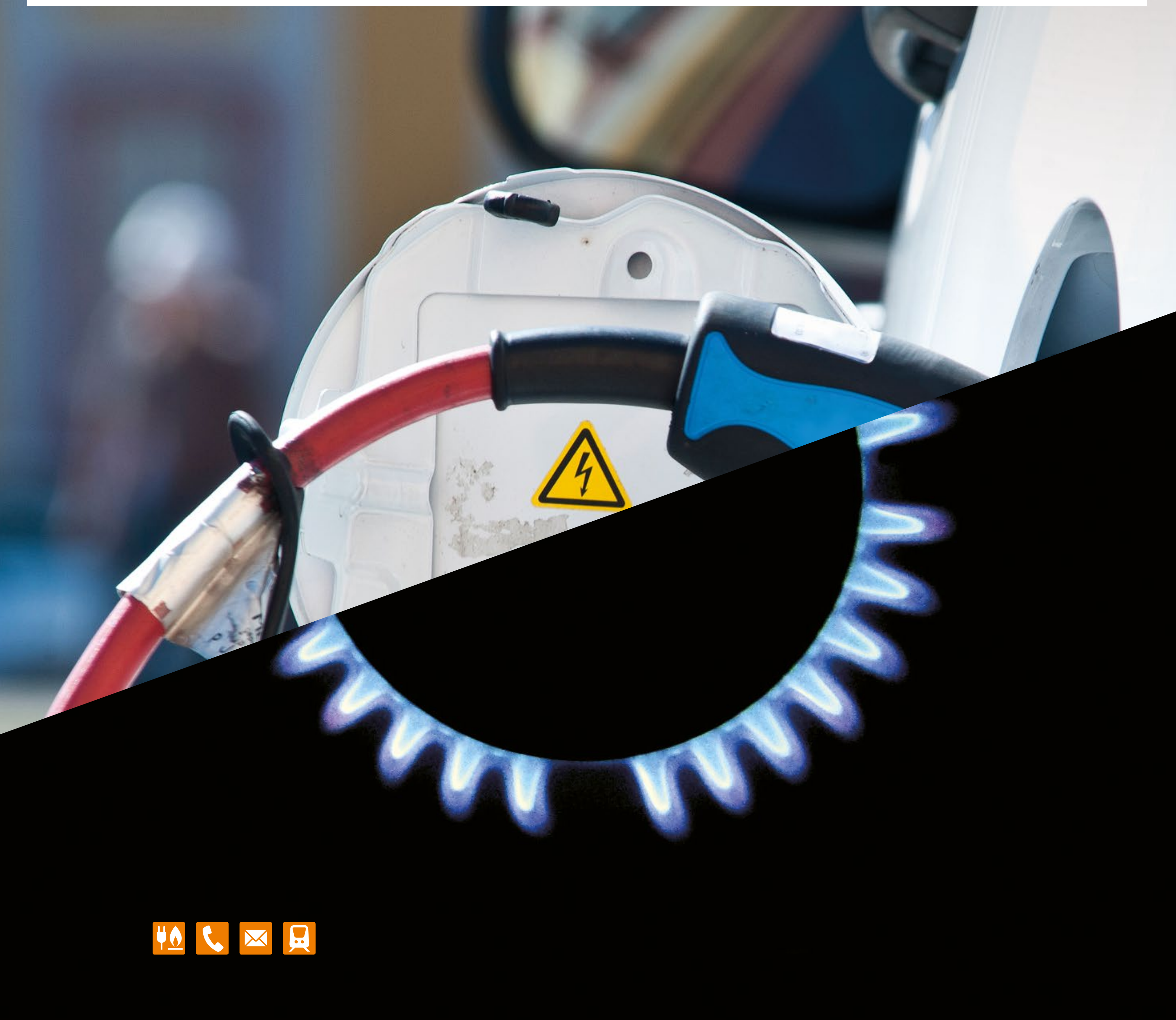
Report

Monitoring report 2020



Monitoring Report 2020

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)
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Foreword

The energy transition, the coal phase-out and climate targets are dominating headlines about the electricity and gas markets. As well as sector coupling and the possible increase in market power in electricity generation, areas of focus are the integration of charging infrastructure for electric vehicles, the conversion of the market area from L-gas to H-gas and consumer protection. The Monitoring Report documents and analyses the development of these topics. 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.

Progress continues in the energy transition. Conventionally generated electricity is losing ground to electricity from renewable sources to an even greater extent than in previous years. In particular, coal-fired power plants produced much less electricity in 2019 than the year before. The coal phase-out laid down in the Act to Reduce and End Coal-Fired Power Generation (KVBG) is encouraging this development and will continue to do so in the coming years. Following a rather weak 2018, there was a moderate upturn in generation from renewables in 2019. Electricity from renewable energy sources rose to account for 42% of gross domestic electricity consumption, thanks partly to lower demand and greater output from wind turbines.

This trend is also reflected in the market conditions for conventional electricity generation, which is not supported under the Renewable Energy Sources Act (EEG). The cumulative market share of the five largest generators in the first-time sale of electricity has continued to decline, as shown by the energy monitoring findings. Yet the recently published market power report from the Bundeskartellamt indicates that there could be an increase in the degree to which the conventional RWE power plant pool, in particular, is indispensable because of the general market shortage resulting from the phasing out of nuclear power. It is possible that RWE will increase its market power to such an extent that it exceeds the threshold for market dominance. This development could be reinforced by the phase-out of coal-fired generation.

The reorganisation of electricity production, coupled with the delays in the rollout of grid infrastructure, continues to require transmission system operators to intervene in generation in order to maintain system security. These 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 2019, although they were down on the previous year. However, among these measures, the volume of renewable energy installations curtailed by feed-in management measures saw a noticeable increase in comparison to the previous year, partly due to the weather conditions in 2019, especially during the first quarter of the year. Nevertheless, around 97% of the renewable energy marketed in 2019 was transported and made available to users.

Electricity network charges rose again in 2020 despite the exclusion of the offshore connection costs and a further reduction in the avoided network charges under the Network Charges Modernisation Act (NEMoG). Reasons for the increase included rising costs for grid expansion at all levels and high costs projected by network operators for system security measures.

The considerable growth in 2019 in trading volume and liquidity on the electricity and gas wholesale markets from the previous year is likely to have a positive effect on competition by improving market entry options for new providers and opening up opportunities for market players to diversify their choice of trading partners and products as well as their forms and methods of trading. Moreover, 2019 saw a fall in electricity and gas wholesale prices across the board.

The combined market shares of the four largest electricity and gas suppliers for standard load profile and interval-metered customers in the respective retail markets were, again, clearly below the statutory thresholds for presuming market dominance. As in the previous years, therefore, it may be assumed that there is currently no single dominant undertaking in these markets.

The positive developments on the retail electricity and gas markets regressed in some areas in 2019, with the insolvency of a major electricity and gas provider also having an impact on the market. A slight decrease in the supplier switching rate was recorded, for example, even though energy suppliers are still working hard to attract new customers with bonuses and other special offers. The number of providers available to consumers remained stable at its already high level. Household customers can, on average, now choose between more than 100 suppliers on average. The supplier switching rate for non-household customers has been fairly constant since 2009 for both electricity and gas.

On 1 April 2020, the average electricity price for household customers was at a record high of 32.05 ct/kWh. Price rises in 2020 were primarily caused by higher surcharges, network charges and the price components controlled by suppliers. There was also an increase in electricity prices for non-household customers (commercial and industrial customers). Retail gas prices were stable at a low level in 2020, while commercial and industrial customers actually paid less. There was good news regarding electricity and gas disconnections, which are carried out when customers do not pay their bills. The number of disconnections dropped in both sectors again in 2019.

The rollout of smart metering systems was launched with the announcement of technical feasibility by the Federal Office for Information Security (BSI) on 24 February 2020, after it had certified the second and third gateways needed at the end of 2019.

Gas imports and exports decreased compared to the previous year. Germany remains dependent on natural gas imports owing to the continued decline in domestic production. The regulatory framework was extended to cover gas interconnectors with third countries for the first time, affecting the natural gas pipeline Nord Stream 2, which is under construction. The fact that the storage facilities in Germany were well filled at all times is a positive factor in terms of security of supply. 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, which affects a lot of household customers, has made further progress and continued as planned despite the coronavirus pandemic.

The impact of the pandemic is only evident in some individual figures. In spring 2020, the Bundesnetzagentur and Bundeskartellamt agreed to a significant extension of the deadline for the data survey in order to relieve the pressure on network operators and market participants. A closer analysis of the consequences of the pandemic will not be possible until the Monitoring Report 2021.

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
Bundesnetzagentur für Elektrizität, Gas,
Telekommunikation, Post und Eisenbahnen

Andreas Mundt
President of the Bundeskartellamt

Key findings

Generation

The market concentration in electricity generation and in the first-time sale of electricity (not entitled to payment under the Renewable Energy Sources Act (EEG)) has shown a continued decline in recent years. In 2019, 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 70.1%, compared to 73.9% 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 57.5% and thus also significantly below the previous year's level of 60.8%.

An end to coal-fired electricity generation by 2038 at the latest was decided with the entry into force of the Act to Reduce and End Coal-Fired Power Generation (KVBG) on 14 August 2020. While large lignite-fired power plants will be shut down in line with individual closure dates set by legislation and an agreement under public law between the plant operators and the Federal Republic, the arrangements for smaller lignite-fired power plants (with a net rated capacity of up to 150 megawatts (MW)) and hard coal-fired power plants provide for auctions and regulatory closures. By the end of 2023 alone, 9 gigawatts (GW) or more of additional coal plant capacity is expected to be shut down or converted to other energy sources as a result of the KVBG. The first auction was significantly oversubscribed. Eleven bids for a total capacity of 4,787.68 MW were awarded a tender. The average price of the bids awarded a tender was €66,259 per MW and thus well below the maximum price set of €165,000 per MW. The sum total of the awards is about €317m.

At 561.3 terawatt hours (TWh), Germany's net electricity generation in 2019 was lower than the 2018 level (592.1 TWh). This represents a decline of 30.8 TWh (5.2%) compared with the previous year. Electricity generation from coal recorded a particularly large decrease of 58.5 TWh. Renewable generation showed slightly better growth again, with a year-on-year increase of 18.2 TWh compared to the previous year's increase of 6 TWh. Total electricity generation from renewables in 2019 amounted to 228.9 TWh. Electricity generation from renewable energy sources accounted for 42% of gross electricity consumption.

The total installed generating capacity stood at 226.4 GW at the end of 2019 (2018: 221.3 GW). This comprised 102.0 GW of non-renewable and 124.4 GW of renewable capacity. Renewable capacity grew in 2019 by 6.2 GW. By contrast, non-renewable capacity decreased by 1.1 GW compared with 2018.

The growth in renewable energy capacity of 6.2 GW (sum of renewable energy installations with and without payments under the EEG) is due in particular to the larger increase in solar capacity (+3.9%) compared to the previous years. Onshore and offshore wind power capacity also continued to grow. However, at 0.9 GW the net expansion of onshore wind power capacity more than halved again compared to 2.1 GW a year earlier.

Redispatching and feed-in management

Overall, the volume of network and system security measures in 2019 was smaller compared to the previous year. The costs for network and system security measures (feed-in management, redispatching, including countertrading, and grid reserve provision and use) are provisionally put at around €1.28bn and are thus also lower (2018: €1.48bn). The total volume of measures in 2020, based on the first three quarters of the year, is set to be slightly above the previous year's level. The costs show an increase of about 5%. The main reason for these developments is a shift in feed-in management measures from onshore to offshore wind. A final assessment of the year's development will be made following an analysis of the fourth quarter.

Electricity network charges

The average network charge for household customers rose by 3.8% in 2020 to 7.50 cents per kilowatt hour (ct/kWh). With respect to non-household customers, the arithmetic mean charges for commercial customers increased by 2% to 6.46 ct/kWh and for industrial customers by around 16% to 2.70 ct/kWh.

Wholesale electricity markets

There was an increase in the trading volume and liquidity of the wholesale electricity markets in 2019 with respect to both the spot market and the futures market. The Phelix-DE futures trading volume stood at 1,345 TWh in 2019, an increase of around 27%. Volumes traded off-exchange via broker platforms also recorded significant growth. There was an increase in 2019 in both the volume reported by the brokers surveyed and the volume of over-the-counter (OTC) clearing of Phelix futures. The OTC clearing volume increased by around 24%.

Wholesale electricity prices fell in 2019. The spot market Phelix day base average for 2019 was about €37.67 per megawatt hour (MWh). There was also a decrease in prices in the year-ahead futures market for 2020. On 27 December 2019, the Phelix-DE peak year-ahead future stood at €62.98/MWh, representing a decrease of around 21% compared to the beginning of the year. The Phelix-DE base year future also fell in the course of the year to €41.33/MWh, representing a decrease of around 19% compared to the beginning of 2019.

Retail electricity markets

As in previous years, the Bundeskartellamt assumes that there is currently no single dominant undertaking in either of the two largest electricity retail markets. The cumulative market share of the four largest undertakings was around 24.5% (2018: 24.4%) in the national market for supplying interval-metered customers and 34.1% (2018: 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 was 11.7% (2018: 12.3%). The percentage of household customers' consumption provided by a supplier other than the local default supplier was around 34% (2018: 31%). The number of household customers switching electricity supplier fell to 4.5m (2018: 4.7m). There was a slight increase in the number of undertakings operating in the market for household customers, giving them a choice between an average of 138 different suppliers (2018: 132). At the same time, there was a decrease in the number of customers whose electricity supply was disconnected. In 2019, just over 289,000 customers were disconnected, representing a year-on-year decrease of around 2%.

The average total price (excluding value added tax (VAT) and possible reductions) for industrial customers with an annual consumption of 24 gigawatt hours (GWh) as at 1 April 2020 was about 16.54 ct/kWh, up 0.56 ct/kWh on the average for 2019. The average total price (excluding VAT) for commercial customers with an annual consumption of 50 MWh in April 2020 was 23.03 ct/kWh, up 0.81 ct/kWh on the previous year. The increases for both industrial and commercial customers are due to the price components controlled by the supplier and the price components that the supplier cannot control.

The average price for household customers rose to 32.05 ct/kWh as at 1 April 2020. 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 price for household customers. The price component controlled by the supplier (energy procurement, supply and margin) accounted for about 7.97 ct/kWh (25%) of the total electricity price as at 1 April 2020 and had thus increased, as in the previous year. The average network charge and the meter operation charge added up to 7.50 ct/kWh in 2020, around 23% of the total price. The EEG surcharge (6.76 ct/kWh) accounted for around 21% of the total price.

Electric heating

The percentage of electricity supplied in 2019 for night storage heating and heat pumps by a legal entity other than the local default supplier was higher compared to the previous year. In 2019, around 16% (2018: 13.2%) of the electricity sold for night storage heating and as much as 20.9% (2018: 16.9%) of the electricity for heat pumps were provided by suppliers other than the default supplier.

The supplier switching rate in the electric heating segment based on the number of market locations was higher than in the previous year. The volume-related supplier switching rate for 2019 was around 7.2% (2018: 3.9%). The trend over recent years shows a steady increase in the switching rate in the electric heating segment, in particular due to newer heat pumps.

The total gross price for night storage heating was 23.14 ct/kWh as at 1 April 2020 and thus higher than the previous year's level of 21.92 ct/kWh. The average total gross price for heat pump electricity was 23.58 ct/kWh and thus also higher than the previous year's average of 22.50 ct/kWh.

Electricity imports and exports

Electricity exports again exceeded imports in 2019. Germany's electricity exports were down in 2019 compared to a year earlier. Cross-border trade volumes for electricity amounted to 72.40 TWh in 2019 (2018: 91.57 TWh). With an export balance of 25.19 TWh, Germany is, however, still one of Europe's large exporters of electricity.[1] The export surplus corresponded to €736.10m.

Gas imports and exports

The total volume of natural gas imported into Germany in 2019 was 1,703 TWh. Based on the previous year's figure of 1,760 TWh, imports to Germany were down by 57 TWh, representing a decrease of just over 3%. Gas exports also fell in 2019. The total volume exported in 2019 was 702 TWh, corresponding to a decrease of nearly 17% on the volume of 849 TWh in 2018.

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.

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[1] Up-to-date figures for commercial foreign trade and physical flows are also available at www.smard.de.

Gas supply disruptions

In 2019, the average interruption in supply per connected final consumer was 0.98 minutes per year. This value clearly reflects the high level of supply quality of the German gas network.

Market area conversion

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 4,255 conversions will have been carried out for interval-metered customers and 2,228,722 for standard load profile (SLP) customers. A total of 319,000 appliances were adapted in the course of 2019.

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 66.6% at the end of 2019, representing only a slight decrease compared to the previous year (67.1%).

The total maximum usable volume of working gas in underground storage facilities as at 31 December 2019 was 275.27 TWh. Of this, 135.63 TWh was accounted for by cavern storage, 117.54 TWh by pore storage and 22.01 TWh by other storage facilities. On 1 January 2021, the total storage level stood at around 73%.

Wholesale natural gas markets

The liquidity of the wholesale natural gas markets increased again in 2019. There was a year-on-year increase of around 22% in the total volume traded on the exchange (spot market: +7%; futures market: +30%), while the volume of off-exchange wholesale trading via broker platforms, which accounts for a much larger share, rose by 30% in 2019.

Retail gas markets

The level of concentration in the two largest gas retail markets is well below the statutory thresholds for presuming market dominance, as in the previous years. In 2019, the cumulative sales for the four largest companies to SLP customers was about 85.7 TWh and to interval-metered customers around 145 TWh. The aggregate market share of the four largest companies (CR4) in 2019 was thus 24% for SLP customers (2018: around 23%) and about 29% for interval-metered customers (2018: 31%).

The total consumption amount affected by supplier switches in 2019 was 88.9 TWh, corresponding to a very small year-on-year decrease of 0.6 TWh. The switching rate for non-household customers was 9%, as in 2018.

The number of household customers who switched supplier in 2019 fell slightly to around 1.4m (2018: 1.5m). There was a clear rise of just over 9% in the number of household customers who chose an alternative supplier rather than the default supplier right away when moving home.

The number of customers changing contract, which usually means changing to a less expensive contract, remained stable at around 0.6m. The percentage of household customers who had a contract with a supplier other than the local default supplier increased further to 34%, while the percentage of customers with a default supply contract fell to 17%. A total of 49% of household customers were supplied by the local default supplier under a non-default contract.

There was also another significant increase in the number of undertakings operating in the market. Household customers can, on average, now choose between more than 100 suppliers. At the same time, the number of gas disconnections has again fallen. In 2019, just over 31,000 customers were disconnected, representing a year-on-year decrease of around 6.5%.

The gas prices for non-household (industrial and commercial) customers showed a year-on-year decrease as at 1 April 2020. The arithmetic mean of the overall price (excluding VAT) for an annual consumption of 116 GWh ("industrial customer") was 2.53 ct/kWh, and thus 0.33 ct/kWh or around 11.5% lower 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 4.52 ct/kWh on the reporting date, a small decrease of 0.03 ct/kWh on a year earlier.

The volume-weighted gas price for household customers across all contract categories barely changed compared to the previous year and was 6.31 ct/kWh. By contrast, the gas price for customers on a default contract fell by around 4% to 6.99 ct/kWh in 2020. The decrease is mainly due to the drop in gas procurement costs, which fell by about 6% for default supply customers.

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1. Summary

1.1 Generation and security of supply

The Act to Reduce and End Coal-Fired Power Generation (KVBG) came into force on 14 August 2020. The Act sets out the arrangements for phasing out coal-fired electricity generation by 2038. While large lignite-fired power plants will be shut down in line with individual closure dates set by legislation and an agreement under public law between the plant operators and the Federal Republic, the arrangements for smaller lignite-fired power plants (with a net rated capacity of up to 150 megawatts (MW)) and hard coal-fired power plants provide for auctions and regulatory closures overseen by the Bundesnetzagentur. By the end of 2023, 9 gigawatts (GW) or more of coal plant capacity is expected to be shut down or converted to other energy sources as a result of the legislation in addition to the coal closures already laid down in law (standby lignite-fired power plants). The exact amount of coal capacity to be shut down depends in particular on the auction volumes. At present, only the volumes for the first two auctions are known. The first auction volume of 4,000 MW was significantly oversubscribed. Eleven bids for a total capacity of 4,787.68 MW were awarded a tender. The prices of the bids awarded a tender ranged from €6,047 per MW to €150,000 per MW. The average price of the bids awarded a tender was €66,259 per MW and thus well below the maximum price set of €165,000 per MW. The sum total of the awards was about €317m. At 561.3 terawatt hours (TWh), Germany's net electricity generation in 2019 was lower than the 2018 level (592.1 TWh). The decline in the overall level of net electricity generation was accompanied by a decrease in generation from non-renewable energy sources of 48.9 TWh or 12.8%. Net electricity generation from coal recorded a particularly large decrease. Electricity generation at hard coal-fired power plants was down by 26.9 TWh (-33.5%) and at lignite-fired power plants by as much as 31.7 TWh (-23.3%).

Following only slight growth in renewable generation in 2018, there was a comparatively moderate increase in 2019, up 8.6% to a total of 228.9 TWh (2018: 210.7 TWh). The share of renewable electricity as a proportion of gross electricity consumption in 2019 was 42%.[2]. Installed generating capacity was characterised in 2019 by a further increase in renewable capacity. Overall, renewable capacity growth amounted to 6.2 GW. The year-on-year increase in 2018 was 6.6 GW.[3] The largest increases here in 2019 were in solar photovoltaic (+3.9 GW), onshore wind (+0.9 GW) and offshore wind (+1.1 GW). Non-renewable generating capacity (nuclear, lignite, hard coal, natural gas, mineral oil products, pumped storage and other energy sources) decreased by a total of 1.1 GW in 2019. Total (net) installed generating capacity increased to 226.4 GW at the end of 2019. This comprised 102.0 GW of non-renewable and 124.4 GW of renewable capacity. The non-renewable generating capacity includes power stations operational in the market and power stations outside the market (for example standby lignite and grid reserve power plants).

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[2] If the share of renewables generation is taken to be about 50% or more, it usually relates to the definition of consumption as the "grid load" (for example on the SMARD website).

[3] The 2018 figure from the 2019 monitoring has been updated.

The installed capacity of installations eligible for payments under the Renewable Energy Sources Act (EEG) in Germany stood at 120.2 GW at the end of 2019 (2018: 114.0 GW). This represents an increase of 6.2 GW (+5.5%). A total of 211.9 TWh of electricity from renewable energy installations received payments under the EEG in 2019. Electricity generation from installations eligible for EEG payments thus increased by 8.5%. There was a slightly smaller increase in the total amount of EEG payments in 2019. The sum total rose by 7.5% to €27.6bn. In 2019, renewable installation operators thus received an average of 13.0 cents per kilowatt hour (ct/kWh) under the EEG.[4]

1.2 Cross-border trading

Electricity exports again exceeded imports in 2019. Germany's electricity exports were down in 2019 compared to a year earlier. Cross-border trade volumes for electricity amounted to 72.40 TWh in 2019 (2018: 91.57 TWh). With an export balance of 25.19 TWh, Germany is, however, still one of Europe's large exporters of electricity.[5] The export surplus corresponded to €736.10m.

1.3 Networks

1.3.1 Network expansion

The projects currently listed in the Power Grid Expansion Act (EnLAG) (as at the third quarter of 2020) comprise lines with a total length of about 1,831 km. Around 8 km are currently in the spatial planning procedure and around 271 km are in or about to start the planning approval procedure. A total of 558 km have been approved and are under or about to start construction, and 994 km have been completed.

The projects listed in the Federal Requirements Plan Act (BBPlG) comprise lines with a total length of about 5,868 km (as at the third quarter of 2020). The 16 projects designated as crossing federal state or national borders, which fall under the responsibility of the Bundesnetzagentur, account for around 3,542 km of this total. 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 procedures.

At the end of the third quarter of 2020, some 669 km of the total were ready to start the planning approval procedure. Around 1,710 km are in the spatial planning or federal sectoral planning procedure, and 2,724 km are in or about to start the planning approval or notification procedure. A total of 254 km have been approved and are under or about to start construction, and 511 km have been completed. Additionally, approximately 100 km have already been approved in the procedures carried out by the Federal Maritime and Hydrographic Agency (BSH).

1.3.2 Investment

In 2019, investments in and expenditure on network infrastructure by the network operators amounted to around €10,629m (2018: €9,830m) (both figures under commercial law).[6] This comprised €7,540m of

[4] 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.

[5] Up-to-date figures for commercial foreign trade and physical flows are also available at www.smard.de.

[6] 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).

investments and expenditure by the distribution system operators (DSOs) and €3,089m by the four transmission system operators (TSOs). The TSOs' investments thus decreased slightly from €2,954m in 2018 to €2,727m in 2019. The DSOs' investments increased slightly from €3,933m in 2018 to €4,337m in 2019.

1.3.3 Network and system security

Overall, the volume of network and system security measures in 2019 was smaller compared to the previous year. The costs for network and system security measures (feed-in management, redispatching, including countertrading, and grid reserve provision and use) are provisionally put at around €1.28bn and are thus also lower (2018: €1.48bn).

Redispatching measures: the reductions and increases in feed-in from conventional operational and grid reserve power plants requested as part of the redispatching process amounted in 2019 to about 13,521 gigawatt hours (GWh) (6,958 GWh of reductions and 6,563 GWh of increases). The total volume of requested reductions and increases in feed-in from power plants in 2019 was therefore lower than in 2018 (2018: 15,529 GWh). The volume of countertrading more than doubled in 2019. The increase is largely due to the bilateral agreement between Germany and Denmark. This agreement provides for minimum trading capacities across the border between western Denmark and Germany as well as for cooperation between the TSOs on countertrading measures. On the basis of the agreement, which involves an incremental increase in minimum trading capacities up to 1,300 MW by July 2019, the minimum trading capacity was raised as planned (starting from 700 MW in 2018). It is planned to increase the minimum trading capacity further in line with network expansion.

The costs for redispatching measures using operational and grid reserve power plants and for countertrading measures are provisionally put at around €373m in 2019 and are thus about 34% lower than the previous year's level (2018: €562.7m).

Grid reserve power plants: according to the Bundesnetzagentur's current information, the costs of reserving the grid reserve plant capacity plus costs not dependent on the use of the reserve are provisionally put at €196m in 2019 and are thus lower than in the previous year (2018: €278.5m). For the first time, no foreign grid reserve power plants were contracted in 2019. The costs of using the grid reserve amounted to around €81.6m.

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 high in 2019, totalling 6,482 GWh. This represents a significant increase of around 17% compared to the previous year (2018: 5,403 GWh). The amount of energy curtailed thus corresponded to 2.9% of the total amount of energy generated by renewable energy installations eligible for payments under the EEG (including direct marketing) (2018: 2.6%). The amount of compensation paid to installation operators in 2019 was about €1,058m, up around €340m on 2018 (2018: €719m). The total estimated claims from installation

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Introducing indicator-based investment monitoring according to section 33(5) of the ARegV will make it possible to carry out comparative calculations using the figures supplied under commercial law and those derived from the incentive-based regulation. 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.

operators, however, increased to €710m in 2019. The discrepancy between the figures is due to the fact that the compensation paid in 2019 does not reflect the amounts payable for the curtailments actually made in 2019. The compensation paid in 2019 may include amounts for curtailments in previous years, and claims from 2019 may not be reflected properly, as the billing period does not correspond to the period when the curtailments were made.

In 2019, as in previous years, feed-in management measures primarily involved onshore wind power plants, which accounted for 78% of the total amount of curtailed energy (2018: 72%). Offshore wind power plants, which were first affected by feed-in management measures in 2015, accounted for around 18% (about 1,188 GW) of the total amount of curtailed energy in 2019, representing a slight decrease (2018: 25% or about 1,356 GW).

The continuing high level of feed-in management measures in 2019 was due to the strong winds in the first quarter of the year. 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. In 2019, a total of five DSOs took adjustment measures. The measures to adjust electricity feed-in totalled around 9.3 GWh.

The total volume of network and system security measures in 2020, based on the first three quarters of the year, is set to be slightly above the previous year's level. The costs show an increase of about 5%. The main reason for these developments is a shift in feed-in management measures from onshore to offshore wind. A final assessment of the year's development will be made following an analysis of the fourth quarter.

1.3.4 Network charges

The volume-weighted network charges (including meter operation charges) for household customers for 2020 rose by 4% (+0.28 ct/kWh):

– household customers, annual consumption 2,500 to 5,000 kWh: volume-weighted 7.50 ct/kWh.

With respect to non-household customers, the arithmetic mean charges for commercial customers are slightly higher than the previous year's level.[7] The network charges (including meter operation charges) for commercial customers increased by 2% to about 6.46 ct/kWh (2019: 6.31 ct/kWh). The network charges (including meter operation charges) for industrial customers increased by around 16% to 2.70 ct/kWh (2019: 2.33 ct/kWh). The charges as at 1 April 2020 for the selected consumption groups were as follows:

– commercial customers, annual consumption 50 megawatt hours (MWh): arithmetic mean 6.35 ct/kWh;

– industrial customers, annual consumption 24 GWh, without a reduction under section 19(2) of the Electricity Network Charges Ordinance (StromNEV): arithmetic mean 2.70 ct/kWh.

There are large regional differences in the network charges. A comparison of all the DSOs' network charges in Germany for the three consumption groups (charges excluding meter operation) shows the following: the

[7] 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.

network charges for household customers range from 3.94 ct/kWh to 16.16 ct/kWh; the range of network charges for commercial customers is similar to that for household customers, with charges ranging from 2.85 ct/kWh to 16.16 ct/kWh; the network charges for industrial customers (without possible reductions) range from around 1.07 ct/kWh to 7.55 ct/kWh.

1.4 Costs for system services

The net costs for system services remained stable in 2019 at about €1,931.2m (2018: €1,933.2m). Major costs were the costs of reserving and using grid reserve power plants at around €278.1m (2018: €415.8m), national and cross-border redispatching at €227.2m (2018: €388.2m), the estimated claims for compensation for feed-in management measures at €709.5m (2018: €635.4m) and energy to compensate for losses at about €321.2m (2018: €288.0m). There was an increase in particular in the costs for balancing capacity, which totalled €285.7m (2018: €123.3m).

The structure of the costs for system services in 2019 was different to that in 2018 in that the costs for network and system security measures were lower while the costs for balancing capacity and for energy to compensate for losses were higher.

1.5 Wholesale

There was an increase in the trading volume and liquidity of the wholesale electricity markets in 2019. The volumes of trading in both the spot market and the futures market showed growth. The Phelix-DE futures trading volume was at 1,345 TWh, an increase of around 27% compared to the previous year. Volumes traded off-exchange via broker platforms also recorded increases.

Wholesale electricity prices fell in 2019. The spot market Phelix day base average for 2019 was about €37.67/MWh. It is difficult to make a clear comparison of prices over the years because of the bidding zone split in 2018. There was also a decrease in prices in the year-ahead futures market. On 27 December 2019, the Phelix-DE peak year-ahead future stood at €62.98/MWh, representing a decrease of around 21% compared to the beginning of the year. The Phelix-DE base year future also fell in the course of the year to €41.33/MWh, representing a decrease of around 19% compared to the beginning of 2019.

Off-exchange wholesale trading volumes also showed growth. The total volume reported by the brokers surveyed increased in 2019 to about 5,770 TWh compared to 4,956 TWh in 2018. In addition, the volume of over-the-counter (OTC) clearing of Phelix futures on EEX in 2019 was 1,302 TWh. In 2018, the volume stood at 1,053 TWh. The OTC clearing volume increased by around 24% and the off-exchange trading volume by around 27% compared with 2018.

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 2019, final consumers could choose on average between 156 suppliers in each network area (not taking account of corporate groups). The average number of suppliers for household customers was 138.

In 2019, a relative majority of 40% of household customers' consumption was supplied on non-default contracts with local default suppliers (2018: 42%). The percentage of household customers' consumption supplied under default contracts stood at 26% (2018: 27%). This represents only a very slight decrease in the percentage of consumption supplied under default contracts, as in the previous year. The percentage of household customers' consumption provided by a supplier other than the local default supplier is around 34% (2018: 31%). Overall, about 66% of all 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 has declined slightly compared to the previous year.

The number of household customers switching supplier started to grow steadily in 2006. The number of supplier switches stagnated for the first time in 2017 and remained at the same level in 2018. In 2019, the total number of supplier switches fell for the first time again to about 4.5m (2018: 4.7m). The supplier switching rate based on the total number of household customers is 9.9% (2018: 10.2%[8]) and thus around 0.3% lower than in the previous year. In addition, about 1.8m household customers changed energy supply contract 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 11.7% (2018: 12.3%).

1.6.2 Disconnections

There was a decrease in 2019 in the number of electricity customers whose supply was disconnected. The number of disconnections actually carried out by the network operators in 2019 was 289,012, representing a decrease of 2% compared to the previous year (2018: 296,370). The number of disconnection notices issued by suppliers to household customers is very much higher. The number of notices issued was approximately 4.8m, of which about 911,000 were passed on to the relevant network operator with a request for disconnection (2018: 4.9m notices and 975,000 requests).

1.6.3 Price level

The electricity prices for non-household customers as at 1 April 2020 were higher compared to the previous year. The average total price (excluding value added tax (VAT) and possible reductions) for industrial customers with an annual consumption of 24 GWh was 16.54 ct/kWh, up 0.56 ct/kWh on the average for 2019. There was also an increase in the total price (excluding VAT) for commercial customers with an annual consumption of 50 MWh, up around 0.81 ct/kWh on the previous year to 23.03 ct/kWh. These increases are due to the rise in both the price component controlled by the supplier and the price components that the supplier cannot control. Overall, the price component that is controlled by the supplier makes up around 26% of the total price, while on average about 74% of the total price comprises costs that the supplier cannot control.

Data was collected from the suppliers operating in Germany on the prices for household customers as at 1 April 2020. The average price (including VAT) increased to 32.05 ct/kWh (2019: 30.85 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 2020, the price component controlled by the supplier (energy procurement, supply and margin) accounted for around 24.9% of the total electricity price and had thus increased, as in the previous year. The network

[8] Die Lieferantenwechselquote für das Jahr 2017 wurde korrigiert.

charge in 2020 was slightly higher than in the previous year and thus still at a high level. The EEG surcharge increased by about 5% but still made up around 21% of the total price. Compared to 2019, the average price for household customers on default contracts with an annual consumption of 2,500 kWh to 5,000 kWh increased by around 6% to 33.80 ct/kWh (2019: 31.94 ct/kWh). The average price for customers on a non-default contract with their default supplier was 31.67 ct/kWh (2019: 30.46 ct/kWh). The price for customers on a contract with a supplier other than their local default supplier increased by around 2.5% to 31.22 ct/kWh (2019: 30.46 ct/kWh).

As a rule, customers on default contracts can make savings by switching contract (-2.13 ct/kWh) and switching supplier (-2.58 ct/kWh).[9] Household customers with an annual consumption of 3,500 kWh could consequently cut their electricity costs by around €90 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 €57, and those for customers switching to a non-default supplier €65.

1.6.4 Surcharges

The network operators estimated that they would pass on around €27.4bn in surcharges to network users in 2020. In order of volume, this total comprises the EEG surcharge (€23.93bn), the section 19 StromNEV surcharge (€1.03bn), the KWKG surcharge (€0.85bn), the offshore network surcharge (€1.56bn) and the interruptible loads surcharge (€0.03bn). The EEG surcharge thus continues to make up the largest part (over 87%) of total surcharges.

1.6.5 Electric heating

The percentage of electricity supplied in 2019 for night storage heating and heat pumps by a legal entity other than the local default supplier was higher compared to the previous year. In 2019, around 16% (2018: 13.2%) of the electricity for night storage heating and as much as 20.9% (2018: 16.9%) of the total electricity for heat pumps were provided by suppliers other than the default supplier.

The supplier switching rate in the electric heating segment based on the number of market locations was higher than in the previous year. The volume-related supplier switching rate for 2019 was around 7.2% (2018: 3.9%). The trend over the years shows a steady increase in the switching rate in the electric heating segment, in particular due to newer heat pumps.

The total gross price for night storage heating was 23.14 ct/kWh as at 1 April 2020 and thus also higher than the previous year's level of 21.92 ct/kWh. The average total gross price for heat pump electricity was 23.58 ct/kWh and thus also higher than the previous year's average of 22.50 ct/kWh.

1.7 Digitisation of metering

The Energy Transition Digitisation Act and the Metering Act (MsbG) contained therein made the rollout of modern metering equipment and smart metering systems legally mandatory in Germany. 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

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

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.

Default meter operators had until 30 June 2017 to notify the Bundesnetzagentur of their metering operations. Notification also serves to trigger a time period set by the MsbG: three years after the notification of metering operations, thus by 30 June 2020, the default meter operator must have installed modern metering equipment in at least 10% of its meter locations. If not, the default meter operator risks losing responsibility for default metering operations. The Bundesnetzagentur is responsible for verifying compliance with the 10% quota.

Installation of smart metering systems could theoretically have started when the first smart meter gateway was certified by the Federal Office for Information Security (BSI) on 12 December 2018. The second and third gateways were certified in October and December 2019 respectively. Installation was not compulsory for smart metering systems in 2019 because the BSI still had to determine the technical feasibility of installing smart metering systems. The BSI gave the go-ahead for the rollout of smart metering systems when it determined the technical feasibility for certain applications on 24 February 2020, thus after the 2019 reporting year.

2. Network overview

All energy market players are required as from 1 February 2018 to introduce and exclusively use a new identification code to identify market locations and meter locations. Since 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 has all the 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 2019. Total electricity supply was 600.7 TWh, comprising a net total of electricity generated of 561.3 TWh (including 9.8 TWh from pumped storage) and cross-border flows[10] from abroad amounting to 39.4 TWh. Total electricity consumption was 604.4 TWh, including 460.2 TWh for final consumers and 12.4 TWh for pumped storage stations from the general supply networks. The amount of energy consumed by pumped storage stations is 2.6 TWh higher than the amount generated because of the electricity needed for the pumping process (power station internal consumption). The net total of electricity generated but not fed into the general supply networks (industrial, commercial and domestic own use) was 38.1 TWh. It can be assumed that

[10] The physical flows, and not the trade flows, are decisive for the network balance. Trade flows (49 TWh of exports and 24 TWh of imports) are different from physical flows in the interconnected alternating current system.

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 26.9 TWh and physical flows to other countries 69.8 TWh.[11] The sum of the individual entries for use minus pumping losses is around 604.8 TWh. The difference between this and the total supply of 600.7 TWh is 4.1 TWh or 0.07%. Supply and demand are therefore almost balanced. The difference of 4.1 TWh is due to the complex structure of the data survey involving a large number of different market players.

[11] Due to incorrect reporting of transmission loss by a TSO the published figure in previous reports was around 2 TWh below the actual amount. The corrected figure for 2018 is 27.2 TWh.

Electricity: network balance 2019

Total net nominal generating capacity as at 31 December 2018 (GW)			**226.4**
Facilities using non-renewable energy sources			102.0
Facilities using renewable energy sources			124.4
Generation facilities eligible for payments under the Renewable Energy Sources Act			120.2
Total net generation (including electricity not fed into general supply networks) (TWh)			**561.3**
Facilities using non-renewable energy sources			332.5
Pumped storage			9.8
Facilities using renewable energy sources			228.9
Generation facilities eligible for payments under the Renewable Energy Sources Act			221.9
Net amount of electricity not fed into general supply networks (TWh)[1]			38.1
Losses (TWh)	**9.3**	**17.6**	**26.9**
Extra-high voltage	7.7	<0.1	7.7
High voltage (including EHV/HV)	1.6	3.2	4.8
Medium voltage (including HV/MV)		5.7	5.7
Low voltage (including MV/LV)		8.7	8.7
Cross-border flows (physical flows) (TWh)			
Imports			**69.8**
Exports			**39.4**
Consumption (TWh)[2]	**26.8**	**433.4**	**472.6**
Industrial, commercial and other non-household customers	26.8	309.7	336.5
Household customers		123.7	123.7
Pumped storage			12.4

[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: 2019 network balance based on data from TSOs, DSOs and power plant operators

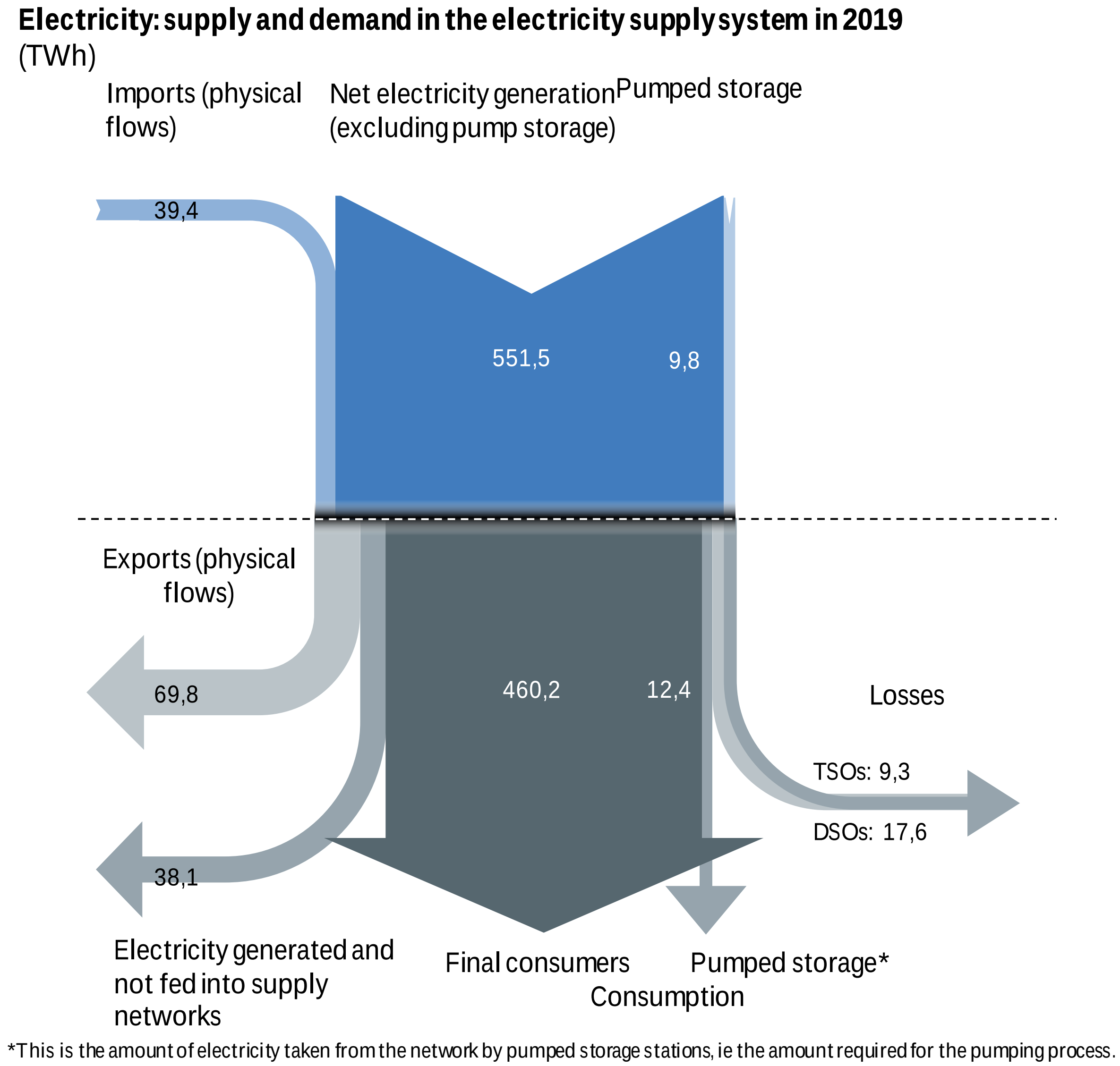

Figure 1: Supply and demand in the electricity supply system in 2019

2.2 Electricity consumption

For 2019 a gross electricity consumption reported for the monitoring survey of 554.8 TWh can be derived from the network balance presented in I.2.1 This gross consumption comprises the sum of gross electricity generation from renewable (230.9 TWh) and non-renewable (354.5 TWh) energy sources and cross-border flows into Germany (39.3 TWh) less the cross-border flows out of Germany (69.9 TWh).[12] Gross generation is higher than net generation because it includes power station internal consumption. Generation from renewable energy sources thus accounted for 42% of gross electricity consumption in 2019.

[12] 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 (%)

2017	2018	2019
36	37	42

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

Electricity: final consumption by customer category

Category	TSOs (TWh)	DSOs (TWh)	TSOs + DSOs (TWh)	Percentage of total (%)
10 MWh/year	< 0,1	117.1	117.1	25%
10 MWh/year - 2 GWh/year	0.1	122.3	122.4	27%
> 2 GWh/year	26.7	194.0	220.7	48%
Total	26.8	433.4	460.2	100%

Table 3: Final consumption (excl. 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	26.8	274.5	301.3	65%
Standard load profile customers		158.9	158.9	35%
Household customers within the meaning of section 3 para 22 EnWG		123.7	123.7	27%
Total	26.8	433.4	460.2	

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

Table 4 shows the consumption of electricity in 2019 by final consumers in the network areas of the transmission system operators (TSOs) and distribution system operators (DSOs) participating in the survey (consumption excluding pumped storage). Total consumption from the DSOs' networks was around 433.4 TWh and from the TSOs' networks 26.8 TWh. Table 3 shows 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. Customers with an annual consumption between 10 MWh and 2 GWh accounted for about one quarter of the total consumption in 2019. 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. They also accounted for around one quarter of the total consumption in 2019.

A household customer consumed on average about 2,550 kWh in 2019, 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 41.8 TWh, according to data from electricity suppliers. The average consumption for this representative case was about 3,400 kWh, and the total number of market locations around 12.2m. The largest number of household customers with around 16.5m 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 29.2 TWh and the average 1,750 kWh.

2.3 Network structure data

The TSOs and 846 DSOs took part in the 2019 Monitoring Report data survey.[14] As at 8 October 2020, a total of 883 DSOs were registered with the Bundesnetzagentur.

Electricity: TSOs and DSOs in Germany

	2015	2016	2017	2018	2019	2020
TSOs with responsibility for control areas	4	4	4	4	4	4
Total DSOs	880	875	878	890	883	874
DSOs with fewer than 100,000 connected customers	803	798	797	809	803	794
DSOs with fewer than 30,000 connected customers	605	607	625	614	645	673

Table 5: Number of TSOs and DSOs in Germany from 2015 to 2020

The following table shows the network structure figures "circuit length" and "market locations" for the TSOs and DSOs. Since 2018 the market location is the unit in the energy market in which connections are counted for delivering and balancing. It is always used when not referring to the technical connection but to the contractual relationships behind the technical connection. The number of customers, for example, is counted via the market locations, whereas the number of installed meters is counted via the meter location. The meter location thus forms the technical equivalent to the market location, though a one-to-one relationship does not exist. Multiple meter locations can be assigned to one market location, and in another possible scenario multiple market locations can be assigned to one meter location.

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

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

Electricity: network structure figures 2019

	TSOs*	DSOs	Total
Network operators (number)	7	874	881
Total circuit length (thousand km)	37.3	1,994.4	2,031.7
Extra-high voltage	36.9	0.3	37.2
High voltage	0.4	93.7	94.1
Medium voltage		545.7	545.7
Low voltage		1,354.6	1,354.6
Total final consumers (market locations) (thousand)	0.5	51,811.8	51,812.3
Industrial, commercial and other non-household customers	0.5	3,370.3	3,370.8
Household customers		48,441.5	48,441.5

* Figures include offshore holding companies

Table 6: 2019 network structure figures based on data from TSOs and DSOs

The circuit length at TSO level increased by around 500 km compared to 2018. The total number of market locations of final consumers in the TSOs' networks was about 500. 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 2019 was around 1.99m km. As shown in the following figure, the majority of the DSOs included in the data analysis (626 or 77%) have networks with a short to medium circuit length (lines and cables) of up to 1,000 km. These DSOs serve 7.4m or 14% of all market locations in Germany. A total of 184 DSOs have networks with a total circuit length of more than 1,000 km. These network operators supply 44.4m market locations, about 86% of the total.

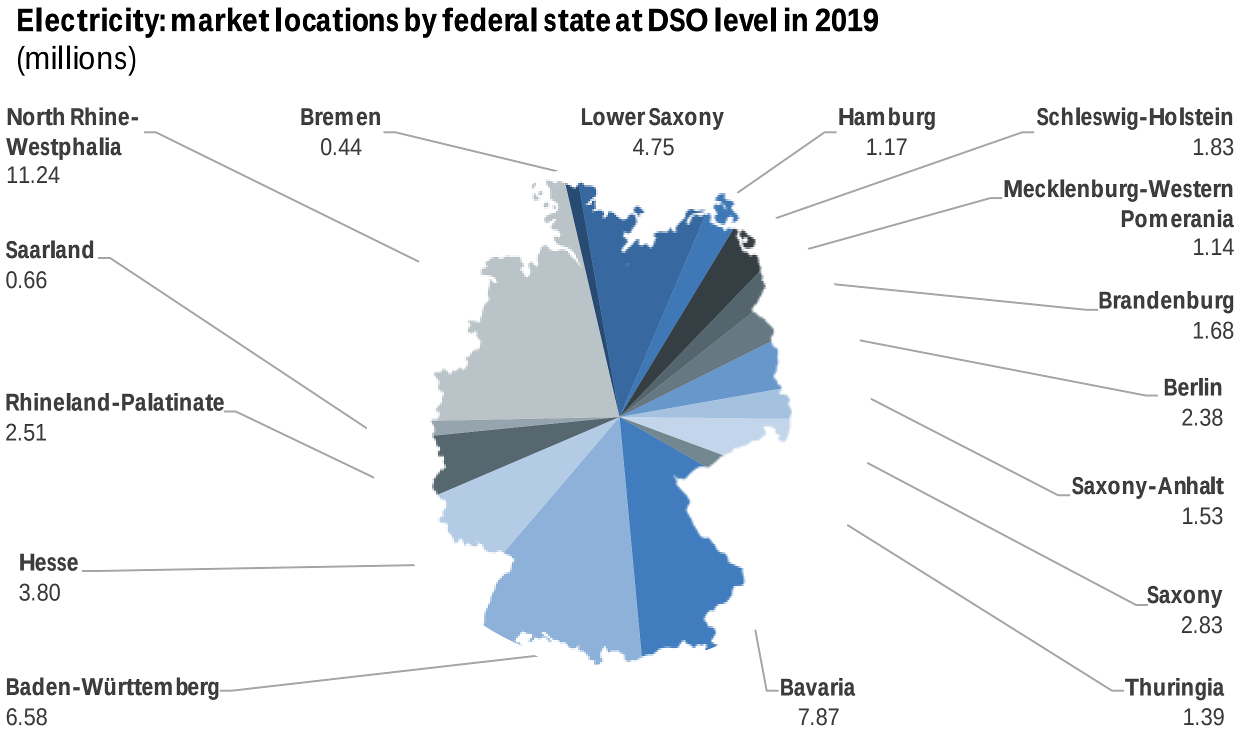

Figure 2: Market locations by federal state at DSO level based on data from DSOs

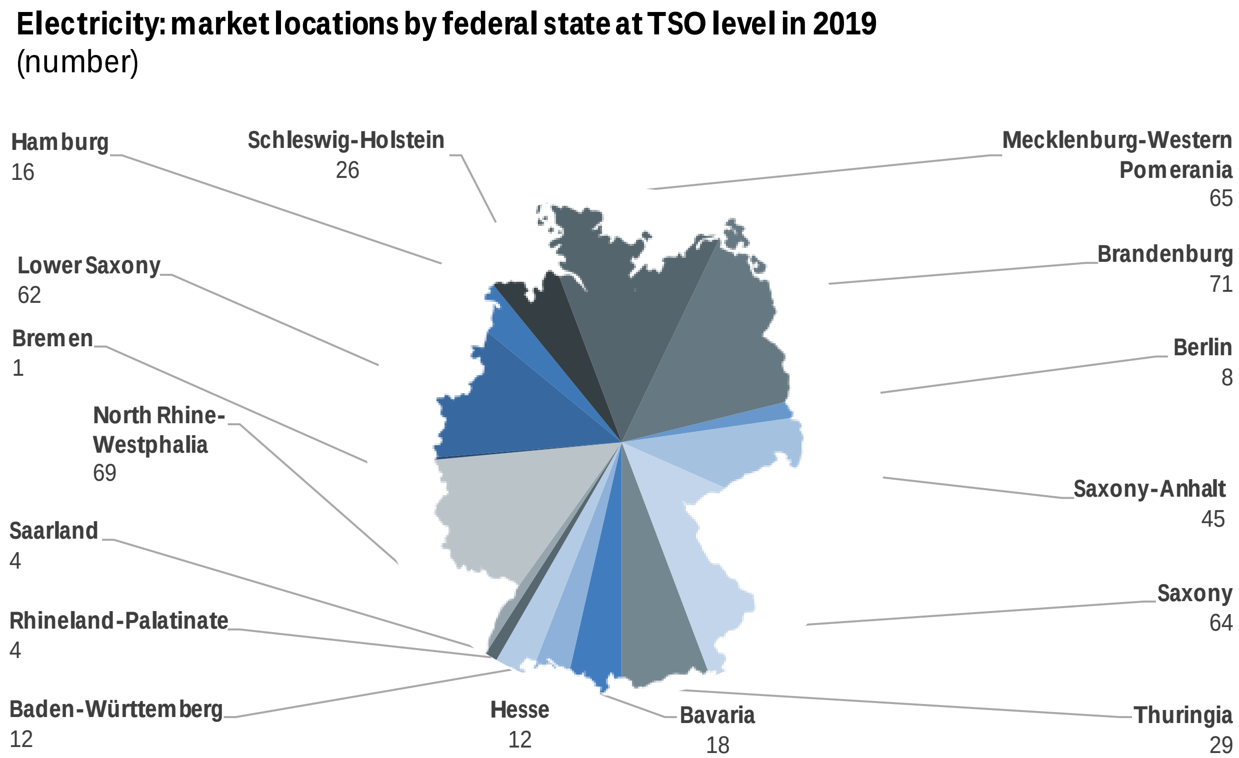

Figure 3: Market locations by federal state at TSO level based on data from TSOs

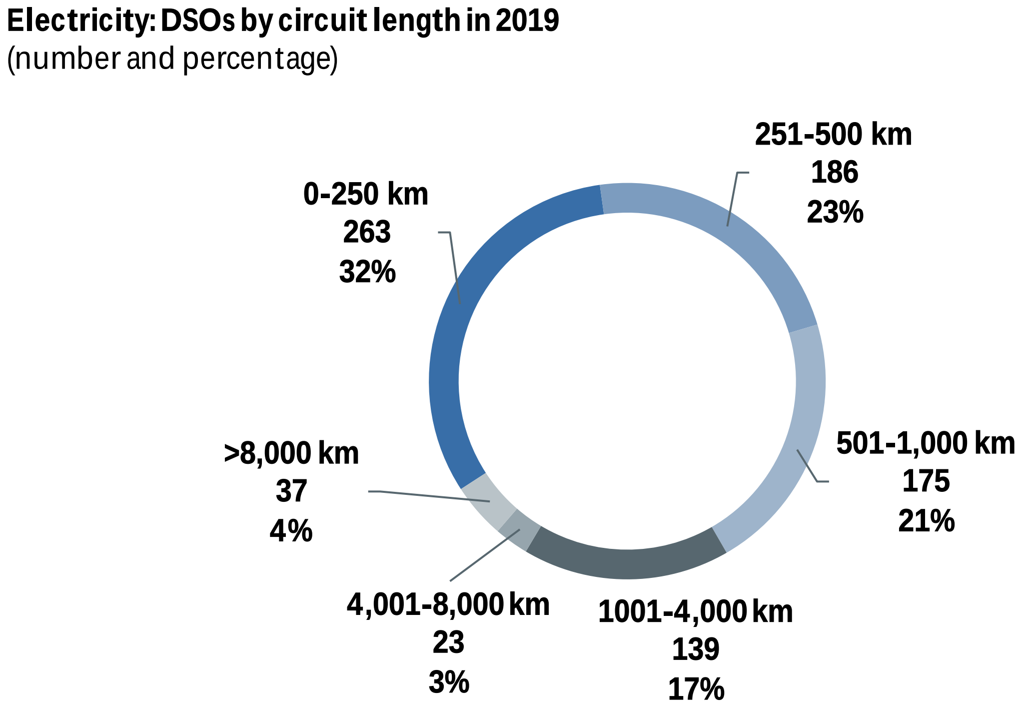

Figure 4: Number and percentage of DSOs by circuit length based on data from DSOs

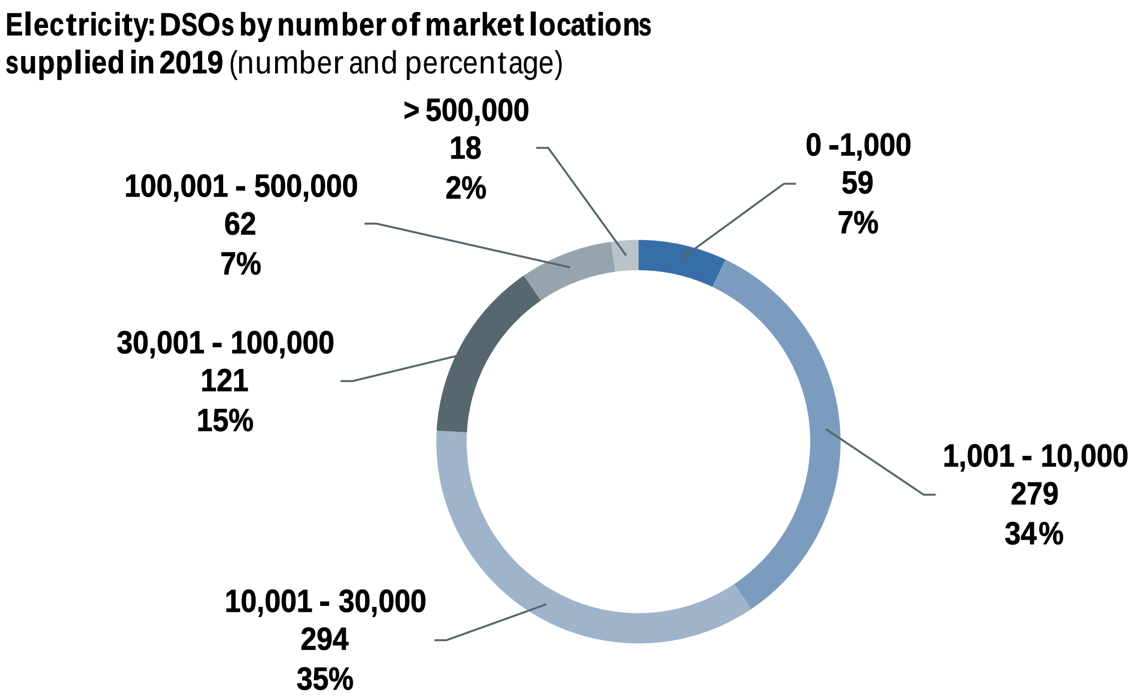

Figure 5: DSOs by number of market locations supplied based on data from DSOs

The number of market locations of final consumers in the DSOs' network areas was around 51.8m, of which about 48.4m were for household customers as defined in section 3 para 22 of the Energy Industry Act (EnWG). Around 424,600 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 9% of the companies supply more than 100,000 market locations. These 9% supply about 75% (38.8m) of all market locations.

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, as described below.

An extensive market power analysis is provided in the second report on competitive conditions in the electricity generation sector ("Market Power Report") which the Bundeskartellamt published on 28 December 2020 in accordance with Section 53 of the German Competition Act, GWB[16]. The analysis is 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 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 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 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. This tendency could increase further due to the phase-out of coal.

[15] Cf. Bundeskartellamt, press release of 26 February 2019, B8-28/19 RWE/E.ON minority shareholding with background paper; Bundeskartellamt, report dated 21 December 2019, Competitive conditions in the electricity generation market (Market Power Report) 2019, p. 23 ff.; and previous to this 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, 1786, 1811. Cf. also legislative intent, Bundestag printed paper 18/7317, 134.

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 also 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 largest power producers RWE AG, EnBW AG, LEAG GmbH, Vattenfall, E.ON SE (only first-time sale of electricity) and Uniper GmbH (only power generation capacities). At the same time these far surpassed other producers with regard to power generation capacities and electricity volumes fed into the grid (CR5).

However, there are also major differences among the group of the five largest electricity producers. With a clear market share lead of 26.0% (volume sold) and 22.2% (generation capacity), the market leader RWE is followed by four other power producers with market shares between 16.2% and 6.4% of the volume sold and between 12.1% and 5.9% of generation capacity.

As in the previous year, the points of reference for the analysis of end customer supply in 2019 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.

In the course of the RWE/E.ON transaction[18] an extensive exchange of business activities took place between the two companies. RWE concentrates on the generation and first-time sale of electricity as well as electricity wholesale whereas E.ON focuses on the operation of power distribution networks and the distribution of electricity. According to the findings of the EU Commission and the Bundeskartellamt, the resulting changes in electricity generation and the first-time sale of electricity are minor,[19] whereas the changes in electricity distribution [20] are reflected in this year's monitoring data.

The report examines the market concentration on the economically significant market for the generation and the first-time sale of electricity and on the two largest electricity retail markets. For reasons of simplicity, 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

[17] Cf. Bundeskartellamt, 29 September 2019, Guidance on Substantive Merger Control, para. 25.

[18] For further details see Monitoring Report 2019, p.501-503.

[19] EU Commission, decision of 26 February 2019, M.8871 – RWE/E.ON Assets, para. 80 ff.; Bundeskartellamt, press release and background paper of 26 February 2019 and case summary of 31 May 2019, B8-28/19 RWE/E.ON Minority Shareholding. (in German)

[20] Cf. EU Commission, decision of 17 September 2019, M.8870 E.ON-Innogy, para. 265 ff. on household customers, para. 301 ff. on electric heating customers, para 330 ff. on industrial customers.

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"

In order to calculate the 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 (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 via personnel 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

In its normal practice the Bundeskartellamt defines a relevant product market for the generation and first-time sale of electricity with physical fulfilment (market for the first-time sale of electricity). Electricity capacities and volumes generated only belong to the market for the first-time sale of electricity as defined above if they are fed into the general supply grid, are suitable to meet the same demand for electricity and are therefore interchangeable from the customer’s perspective. This requirement is not fulfilled in the case of electricity generated for own consumption, traction current as well as balancing energy, reserve capacities and redispatching. On the supply side, power generation volumes which are subject to other market and competition conditions due e.g. to specific legal obligations, are not to be included in the market for the first-time sale of electricity. Equally, electricity generation which is remunerated under the EEG is therefore also not considered part of the market for the first sale of electricity for the purpose of the Monitoring Report.

In its case practice the Bundeskartellamt has recently applied the following criteria for the calculation of market shares[21]:

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 the 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.[22] 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 electricity generation which is not remunerated under the EEG system. 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 the latter decides on the use of the power plant and bears the risks and rewards of marketing the electricity.[23]

In geographical terms the Bundeskartellamt defined the market for Germany/Luxembourg as a single market in 2019 after the bidding zone with Austria was split on 1 October 2018.[24] Data on electricity generation was collected from the five largest companies with a market share exceeding 5% based on the above definitions. In terms of the first-time sale of electricity these were RWE, LEAG, EnBW, E.ON and Vattenfall. However, in terms of electricity generating capacities from their own power plants including drawing rights to other power plants, the five largest companies were RWE, EnBW, LEAG, Vattenfall and Uniper.

The results of the survey on volumes of electricity generated in 2019 are shown in the table below. Data from the previous year is shown for comparison.

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[21] Cf. Bundeskartellamt, case summary of 31 May 2019, B8-28/19 RWE/E.ON minority shareholding, explained in detail in the Bundeskartellamt's decision of 8 December 2011, B8-94/11, RWE/Stadtwerke Unna, para. 22 ff.

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

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

[24] Tentatively already applied in the assessment of the RWE/E.ON minority shareholding; confirmed in the Bundeskartellamt's report dated 21 December 2019, Competitive conditions in the electricity generation market (Market Power Report) 2019, p. 14.

Electricity: volumes generated by the five largest German electricity producers

Germany 2018			Germany 2019		
Company	TWh	Share	Company	TWh	Share
RWE	105.9	30.2%	RWE	78.9	26.0%
LEAG	58.0	16.5%	LEAG	49.0	16.2%
EnBW	45.8	13.1%	EnBW	38.3	12.7%
Vattenfall	25.7	7.3%	Vattenfall	19.5	6.4%
E.ON	23.9	6.8%	E.ON	26.6	8.8%
CR 5	259.3	**73.9%**	**CR 5**	212.2	**70.1%**
Other companies	91.5	26.1%	Other companies	90.6	29.9%
Total net electricity generation	350.8	100%	Total net electricity generation	302.8	100%

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 including Luxembourg was 70.1% in 2019. By comparison, their market share was still 73.9% in 2018. The total net electricity generation which was not entitled to payments under the EEG fell by 48 TWh to 302.8 TWh compared to the previous year. The reason for this is that further power plant capacities were withdrawn from the market and had been partially replaced by imports. At the same time electricity generation from renewable energies entitled to payments under the EEG reached a new record level of around 211 TWh (previous year: 195 TWh), consequently replacing electricity generation not remunerated under the EEG. The volume of imported electricity continued to increase and domestic consumption decreased. RWE’s market share fell by four percent compared to the previous year. Here the changed pricing structure between coal, gas and emission rights was particularly noticeable. LEAG, EnBW and Vattenfall suffered light market share losses of between 0.5 and 0.9%. It has to be taken into account that in 2017 E.ON/Uniper were regarded as a company group. After the sale of Uniper to the Finnish energy company Fortum and its clearance by the EU Commission, E.ON and Uniper were already regarded as two separate companies in 2018. In spite of this, the volume of energy generated, in particular by the remaining E.ON nuclear plants, accounted for approx. 8.8%; this volume includes to a lesser extent the smaller generating units acquired from RWE via its shares in Innogy. Overall the reduction in capacity of the CR5 to 70.1% is chiefly attributable to a substantial reduction in RWE’s capacity.

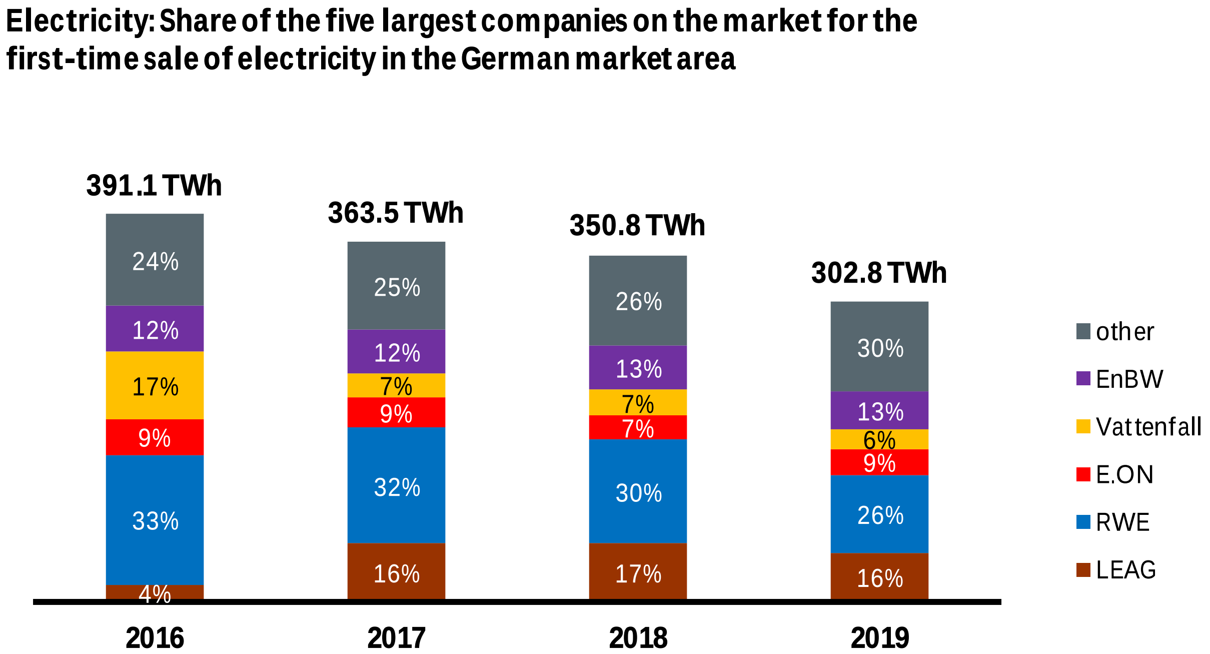

Figure 6: Share of the five largest companies on the market for the first-time sale of electricity in the German market area [25]

The five largest suppliers' share of the German non-EEG subsidised generation capacities available for use on the market for the first-time sale of electricity was 57.5% in 2019, down from 60.8% in the previous year. The total amount of power generation capacity available fell in 2019 by 1 GW year-on-year to approx. 90.2 GW. However CR5 's capacities declined by a total of 3.6 GW (from 55.5 GW in 2018 to 51.8 GW in 2019). It has to be noted here that E.ON's remaining shareholdings in nuclear power plants (via its subsidiary PreussenElektra) were not included in the CR5 share of German non-EEG generation capacity because they did not achieve the 5% market share. It also has to be taken into account that at the reference date of 31 December 2019 the capacities of the Innogy shareholdings, which previously belonged to RWE, had already been transferred to E.ON and some of this capacity had not yet been transferred back to RWE. This results in a temporary inconsistency between sales volumes recorded during the year and capacities determined at the reference date.

Nonetheless RWE also lost other power plant capacities due to the shutdown of the Dormagen and Gersteinwerk K2 power plants. The joint market share of the five largest producers and consequently the degree of market concentration is likely to decrease further as a result of the planned shut-down and decommissioning of further nuclear power plants and coal-fired power stations.

[25] 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. Ultimately Innogy's volumes of electricity sales when it was controlled by RWE were also attributed to E.ON from 19 September 2019. For this reason the respective market shares of the companies also need to be assessed accordingly.

Electricity: generation capacities of the five largest electricity producers

Germany 31 December 2018			Germany 31 December 2019		
Company	**GW**	**Share**	**Company**	**GW**	**Share**
RWE	22.9	25.1%	RWE	20.2	22.4%
EnBW	11.2	12.3%	EnBW	11.0	12.2%
Uniper	5.6	6.2%	Uniper	5.4	6.0%
Vattenfall	8.0	8.7%	Vattenfall	7.5	8.3%
LEAG	7.8	8.5%	LEAG	7.8	8.6%
CR 5	55.5	**60.8%**	**CR 5**	51.8	**57.5%**
Other companies	35.7	39.2%	Other companies	38.4	42.5%
Total capacity	91.2	100%	Total capacity	90.2	100%

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 2019 with a CR 5 of 70.1% (see Table 7). In 2018 the CR 5 still amounted to 73.9% and in 2017 even 75.5%. Hence the degree of market concentration in the German market area has decreased over the years.

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 by the feed-in of renewable energy.

The degree of market concentration is further qualified by the generation and first-time sale of electricity from plants that are eligible for payments under the 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, as illustrated above, 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 non-EEG subsidised 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 electricity which is not remunerated under the EEG system, 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. In terms of the EEG subsidised generation volume (same companies as in the generation volume i.e. excluding Uniper) the share of the five largest companies in the German market area was around 4.9% in 2019. In the previous year it was still around 4.8%. In terms of EEG generation capacities, the share of the five largest producers (here with E.ON and excluding Uniper) was around 4.0% in 2019 as in the previous year.

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 whose consumption is measured on the basis of 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, defined as a national market)[26].

Since the EnWG no longer uses the term "special contract customers" in this sense, the relevant contracts are referred to as "special contracts" in the present Monitoring Report only in the context of market definition under competition law. For the purpose of the Monitoring Report, these contracts will otherwise be referred to as "contract with the default supplier outside the default supply" or as "contract with a supplier who is not

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

the local default supplier".[27] 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 of 1,429 electricity providers (legal persons) (2018: 1.175 electricity providers). When analysing 2019 as a whole, it should be noted that there was a shift in market shares essentially only within the CR 4 due to the exchange of business activities between RWE and E.ON (see above).

Based on information provided by suppliers, in 2019 around 257.2 TWh of electricity were sold to metered load profile customers and around 156.9 TWh of electricity to standard load profile customers. 13.5 TWh of the total sales to standard load profile customers consisted of electric heating. Of the remaining 143.5 TWh sales to standard load profile customers without electric heating, 33.4 TWh went to standard load profile customers with default supply contracts, i.e. around 23.3%; 110.1 TWh went to other standard load profile customers with special contracts, i.e. around 76.7%. In 2018, 260.6 TWh of electricity were sold to metered load profile customers and 158.1 TWh to standard load profile customers. Approx. 13.3 TWh of the total sales to standard load profile customers consisted of electric heating and 34.6 TWh went to standard load profile customers with default supply contracts and 110.2 TWh to standard load profile customers with special contracts. The changes among the large suppliers illustrated above did not have a significant effect on the market shares in 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 aggregate sales volumes were attributed to the four strongest companies using the "dominance method" according to the rules 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 2019 the four strongest companies sold a total of around 63.0 TWh on the German market for the supply of electricity to metered load profile customers. The aggregate market share of the four companies was therefore 24.5%. In the previous year, the CR 4 still sold as much as 63.6 TWh, which was equivalent to a share of 24.4%. The market share of the CR 4 on the market for metered load profile customers hardly changed in 2019. 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 currently no dominant supplier on the market for the supply of metered load profile customers.

In 2019 the cumulative sales of the four strongest companies in 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 37.5 TWh (34.4 TWh in the previous year.) The aggregate market share of the CR 4 in this market was therefore around 34.1% – 31.3% in 2018. This value is also clearly below the statutory thresholds for the presumption of a dominant position. The Bundeskartellamt assumes that there is currently no

[27] 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.

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 13.9 TWh of the total default supply volume of standard load profile customers, which amounted to around 33.4 TWh. The share of the CR 4 was therefore around 41.6%. In the previous year this had been around 41.5% with cumulative sales of the CR 4 of 14.4 TWh and a total default supply volume of 34.6 TWh.

The CR 4 maintained a relatively strong position in the supply of standard load profile customers only with electric heating. The cumulative sales of the CR 4 in the German area were around 7.7 TWh of the total 13.5 TWh of electric heating. As a result, the CR 4 account for around 56.9%. This was still 59.2% in the previous year. It should be noted in this context that the sale of E.ON's electric heating business to Lichtblick GmbH was only implemented in 2020. This is likely to lead to a shift in market shares of the CR 4 in future and would therefore have a deconcentrating effect.

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 nonetheless indicative of 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 59.1 TWh of a total of 156.9 TWh. This is equivalent to an aggregate share of around 37.7%. In 2018 the volume supplied by the CR 4 was still 56.7 TWh and their market share was 35.8%. 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).

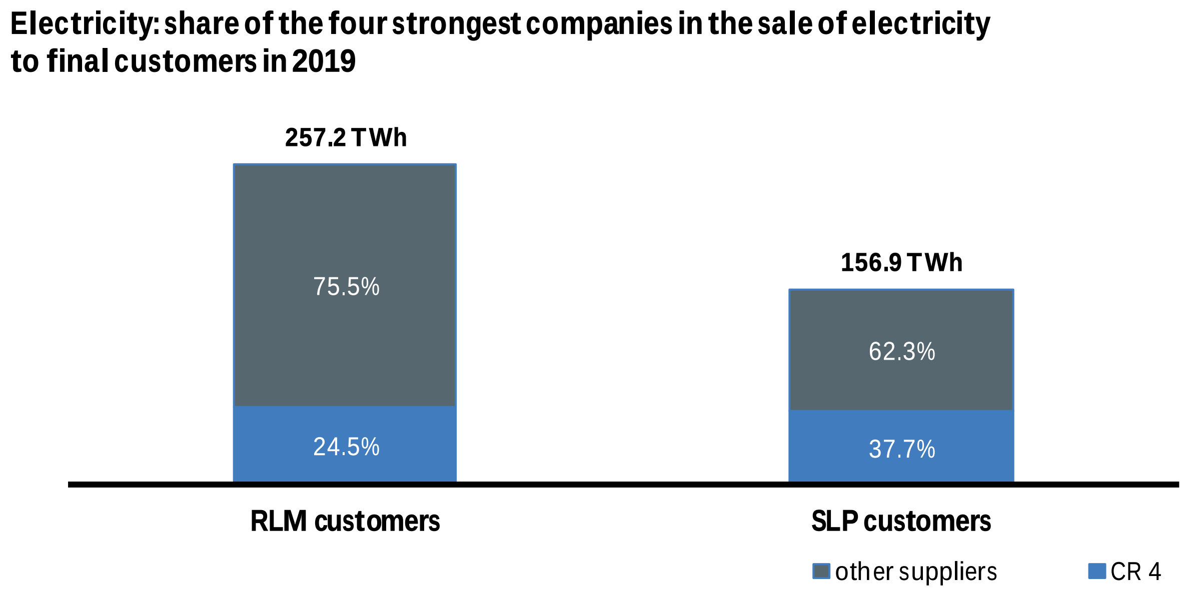

Figure 7: Shares of the four strongest companies in the sale of electricity to final customers in 2019

4. Consumer advice and protection

The **Bundesnetzagentur** and its energy consumer advice service provide support to consumers, offering comprehensive information on all issues relating to **energy customers' rights, obligations of energy suppliers, network operators and meter operators, dispute resolution, and general developments on the energy market.**

In 2020, the Bundesnetzagentur received around 18,500 telephone, email, online and postal queries and complaints. This represents a slight year-on-year decrease of 5%.

Considering the total number of household customers served (48.4m electricity and 12.8m gas customers) and the number of customers who switched supplier in 2019 (around 4.5m electricity and 0.6m gas customers), the number of queries and complaints received by the Bundesnetzagentur is relatively insignificant. However, the figures do not include complaints about nuisance calls from energy suppliers, which are dealt with by a separate complaints unit.

In 2020, the energy consumer advice service received more than 10,600 telephone calls from consumers, 6,800 emails and around 1,100 queries and complaints sent by post or using the special online form.

Number of consumer queries and complaints

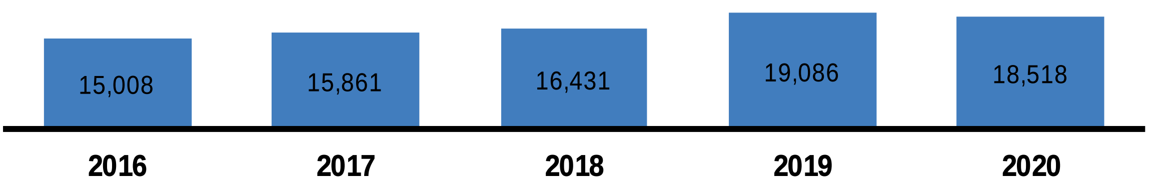

Figure 8: Number of consumer queries and complaints

Main subjects of queries and complaints

In 2020, 56% of the queries and complaints received were specifically about electricity and were mostly about contracts (default/fallback supply and competitive contracts), supplier switching, billing and renewable energy. The Federal Office for Information Security (BSI) gave the go-ahead for the rollout of smart metering systems on 24 February 2020, and consequently there was a slight increase in the number of queries about metering. The rising number of "energy transition technologies" such as solar photovoltaic (PV) installations, heat pumps and electric cars led to an increase in the number of queries about connecting to the grid. Household customers also have increasingly more specific questions about their rights and obligations as energy prosumers (for instance about registering for the core energy market data register).

The coronavirus pandemic gave rise to questions about practical issues such as replacing meters and technical inspections. Consumers also asked about special arrangements due to the coronavirus crisis (including the right to refuse to provide a service, reduced VAT rates, and extending calibration periods).

Questions also arose about transferring or continuing contracts because of companies merging or taking over customers. New guidance was published online about energy supplier insolvencies and electricity/gas supply disconnections.

Only 8% of all queries and complaints were specifically about gas issues. This figure is slightly lower than in 2019. The small number of queries about gas networks again reflects the very high level of information provided by network operators to customers affected by the conversion from L-gas to H-gas in parts of northern and western Germany.

The remaining queries (36%) were not specifically about either electricity or gas issues and included research-related questions, queries from consultancies, and matters not falling within the Bundesnetzagentur's remit.

Further information about the following topics relevant for consumers is contained in special boxes later on in the report:

– Development of renewable energies – electricity

– Changes in payments under the EEG – electricity

– Supply disruptions – electricity and gas

– Network charges – electricity and gas

– Individual network charges – electricity

– Contract structure and supplier switching – electricity and gas

– Disconnections, cash/smart card readers, tariffs and contract terminations/non-annual billing – electricity and gas

– Price level – electricity and gas

– Metering – gas

– Natural gas imports and exports

– Market area conversion – gas

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.[28] Defossilisation can occur directly through electrification, as in the case of 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.

5.1 Hydrogen

Section 3 para 10c of the Energy Industry Act (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 2019, six facilities injected hydrogen and two facilities injected synthetically produced methane (both figures as at 31 December 2019). With 2.9m kWh of hydrogen and 0.7m kWh of synthetically produced methane, however, these forms of injection accounted for only 0.037% of the total amount of biogas injected in 2019. The facilities injecting hydrogen have a total installed electric capacity of 10.3 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. In many cases, exact details of the technical specifications are not available. However, the total number of power-to-gas facilities currently in operation, including those injecting into the gas network, is estimated to be about 40, and the total installed electric capacity of these facilities is estimated to be around 30 MW.[29]

The scenarios set out in the approval of the electricity scenario framework for 2021-2035 take account of power-to-gas capacities of 3.5 GW (A 2035), 5.5 GW (B 2035), 8.5 GW (C 2035) and 10.5 GW (B 2040), in each case comprising 0.5 GW of power-to-methane capacity and the remaining capacity for power-to-hydrogen. The power-to-methane capacity potential is considered to be stable and comparatively small. As a comparison, the reference figure for 2018 includes a power-to-gas capacity of less than 0.1 GW.

[28] 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.

[29] Source: BDEW, Roadmap for gas – Decarbonisation, security of supply and flexibility with climate-neutral gas, page 17

5.2 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 15 July 2020, the Bundesnetzagentur had been notified of a total of 17,013 charging stations with 33,691 recharging points; 27,731 recharging points had a power less than or equal to 22 kW (normal-power recharging points) and 5,137 were high-power recharging points (see https://www.bnetza.de/ladesaeulenkarte).

According to the Kraftfahrt-Bundesamt (KBA – Federal Motor Transport Authority), 317,242 externally rechargeable passenger vehicles were registered in Germany as at 1 July 2020, of which 173,435 were fully electric vehicles and 143,807 plug-in hybrids.[30]

5.3 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 1,502,306 items of controllable consumer equipment. This represents a year-on-year increase of about 53,000 items of equipment (see I.C.7.2). The increase is, however, solely due to one more DSO supplying data. Without these data, the number of items of controllable consumer equipment would be 1,500 lower than the previous year.

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[30] KBA (2020), FZ 13, Stock of vehicles according to environmental characteristics.

B Generation

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

1.1 Net electricity generation in 2019

Net electricity of 561.3 TWh was generated in 2019;[31] this was around 30.8 TWh less than the 592.1 TWh generated in 2018. The reduction in the level of net electricity generation is due to a fall in gross electricity consumption. Generation from non-renewable energy sources fell in 2019 by 48.9 TWh to 332.5 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 more pronounced, however, than in the previous year. Electricity generated from renewable energy sources increased by 18.2 TWh (8.6%), from 210.7 TWh in 2018 to 228.9 TWh in 2019. Renewables accounted for 42% of gross electricity consumption [32], which totalled 555.0 TWh. Section I.B.2 contains a detailed analysis of the annual amount of energy supplied by installations eligible for payments under the EEG and its development.

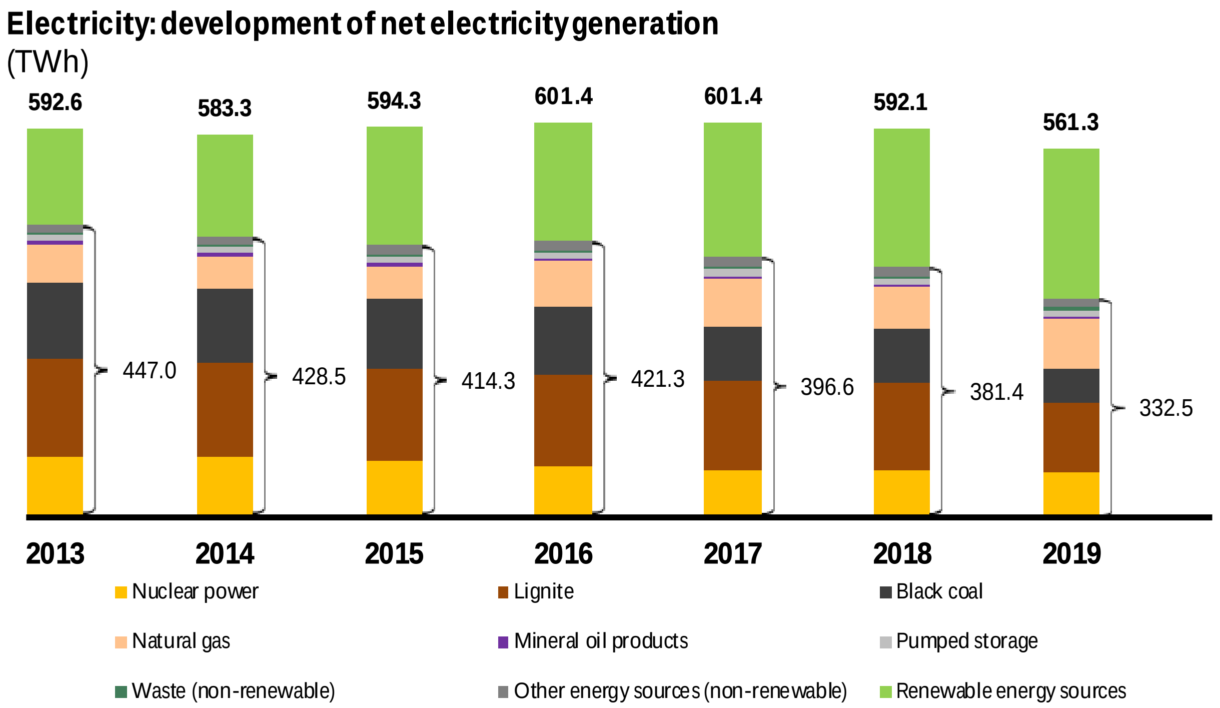

Figure 9: Development of net electricity generation (as at December 2020)

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[31] Net electricity generation was determined on the basis of the Bundesnetzagentur's monitoring report and may differ from comparable figures published elsewhere.

[32] 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.2.2 "Electricity consumption".

Net electricity generation from non-renewable energy sources fell by a total of 48.9 TWh (-12.8%) compared to 2018 from 381.4 TWh to 332.5 TWh (see Figure 9). This continues the decline reported in previous years.

Generation from natural gas-fired power plants rose again after a reduction of 64.3 TWh in 2018 to 75.5 TWh in 2019 (+17.3%). Generation from natural gas-fired power plants was therefore again at the same level as in 2011 for the first time since data collection began. This development was supported by the comparatively higher price of CO_2 certificates as well as the relative advantages arising from changes in the cost of natural gas compared to black coal.

Generation from black coal plants fell by 26.9 TWh (-33.5%) to 53.4 TWh. This reduction in generation was also due in part to further closures of black coal plants (Gersteinwerk 614 MW, Gemeinschaftskraftwerk Kiel 323 MW, Reuter C 124 MW, HKW Elberfeld 85 MW) and the increasing displacement of black coal plants by natural gas.

Electricity: development of net electricity generation (TWh)

	2014	2015	2016	2017	2018	2019
Nuclear power	91.8	85.1	78.3	70.5	70.4	69.5
Lignite	144.5	142.5	139.9	137.5	135.9	104.2
Black coal	111.6	106.1	103.3	83.5	80.3	53.4
Natural gas	50.0	48.7	68.0	72.7	64.4	75.5
Mineral oil products	3.8	4.3	3.9	3.5	3.5	3.1
Pumped storage	9.5	10.1	9.9	10.2	9.2	9.8
Waste (non-renewable)	4.3	4.2	4.3	4.3	4.2	4.1
Other energy sources (non-renewable)	12.9	13.4	13.6	14.3	13.6	12.9
Total of non-renewable energy sources	428.5	414.3	421.3	396.6	381.4	332.5
Renewable energy sources	154.8	180.0	180.2	204.7	210.7	228.9
Total	583.3	594.3	601.4	601.3	592.1	561.3

Table 9: Net electricity generation

As it has done repeatedly in recent years, generation from lignite-fired power plants declined again in 2019. In fact, the fall of 31.7 TWh from 135.9 TWh in 2018 to 104.2 TWh in 2019 (-23.3%) was even greater than in the previous years. In part, this decline was due to the transfer of more lignite-fired plants to security standby status. The transfer of the Niederaußem E and F power plant units and of Jänschwalde F on 1 October 2018 is relevant in this context as these power plants were no longer operating in the electricity market in 2019. The lignite-fired power plant units Jänschwalde E and Neurath C blocks were also the last to be transferred to lignite security standby status and no longer operated in the electricity market after 1 October 2019. There were also more power plant audits than in the previous year and these capacities were consequently temporarily unavailable to the market.

Electricity generation from nuclear power plants fell slightly from 70.4 TWh in 2018 to 69.5 TWh in 2019, a drop of -0.9 TWh.

Mineral oil-fired power plants generated 3.1 TWh, roughly equivalent to their 2018 level.

1.2 CO_2 emissions from electricity generation in 2019

The Bundesnetzagentur asked operators of power plants with a net nominal capacity of at least 10 MW to supply data on CO_2 emissions from electricity generation in 2019.[33] For CHP plants, operators only had to supply data on the share of CO_2 emissions 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 t million			Change on
	2017	2018	2019	2018
Lignite	155.7	152.8	117.0	-35.8
Black coal	74.6	72.4	47.9	-24.4
Natural gas	27.2	22.5	26.3	3.7
Mineral oil products	2.0	2.3	1.3	-1.0
Waste	7.6	7.5	8.0	0.6
Other energy sources[1]	18.4	17.2	17.1	0.0
Total	285.4	274.7	217.7	-57.0

[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, CO_2 emissions from electricity generation in 2019 fell by 57.0 million tonnes compared to 2018. This is in particular due to a reduction in the net generation

[33] CO_2 emissions from electricity generation were determined on the basis of the Bundesnetzagentur's monitoring report and may differ from comparable figures published elsewhere.

of electricity from lignite and black coal-fired power plants. Lignite-fired power plants again emitted less CO_2 in 2019, in part owing to the gradual transfer of some these power plants to security standby status (see I.B.1.7 "Power plants outside of the electricity market"). Power plant operators reported that lignite-fired power plants emitted 117.0m tonnes of CO_2 emissions in 2019, which accounted for over half of all CO_2 emissions from electricity generation (53.7%). Black coal-fired power plants emitted 47.9m tonnes of CO_2 or 24.4m tonnes less than in the previous year. In 2019, 26.3m tonnes of CO_2 were emitted in the course of generating electricity in natural gas-fired power plants, which is an increase of 3.7m tonnes (16.4%). The remaining 26.4m tonnes of CO_2 are emitted by mineral oil-fired power plants (1.3 m tonnes), waste to energy power plants (8.0m tonnes) and other energy sources (17.1m tonnes).

It should be noted that the data submitted by power plant operators do not include CO_2 emissions from generating facilities with under 10 MW of net nominal capacity.

1.3 Installed electricity generation capacity in Germany in 2019

In 2019, as in previous years, electricity generation was marked by growth in renewables at much the same level as in previous years. This was again due to slower expansion of onshore wind energy, which grew by 0.9 GW compared to 2.1 GW in 2018.

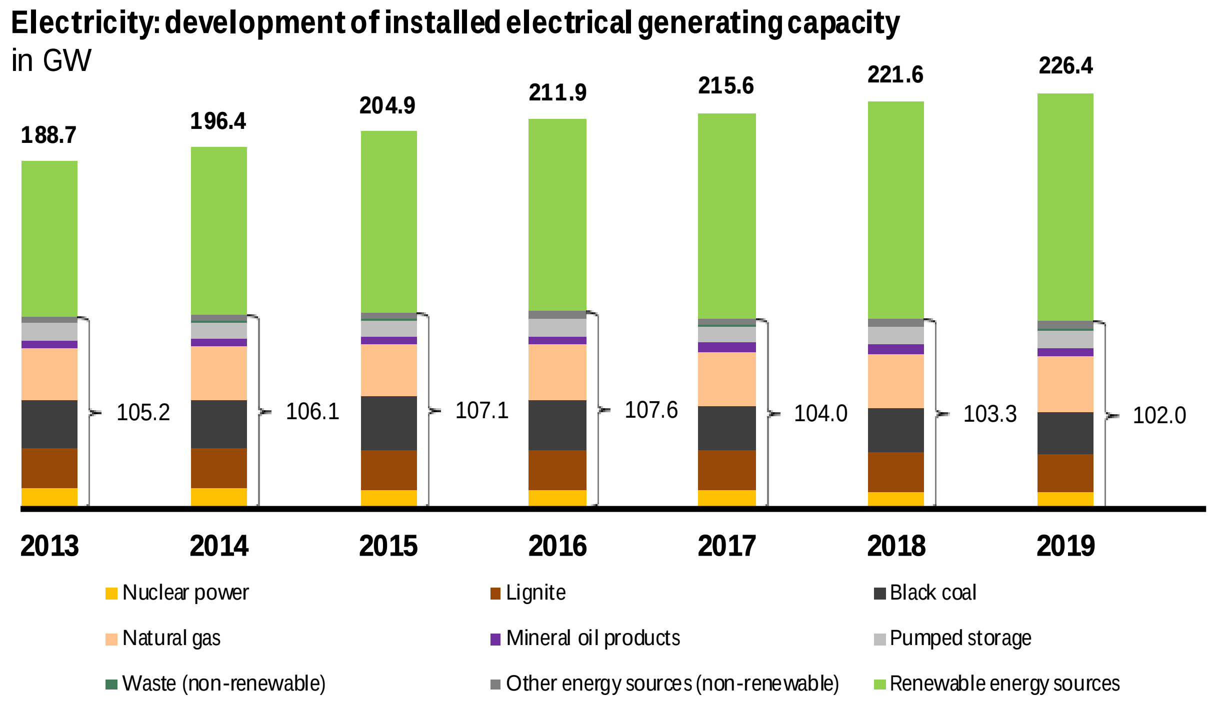


Figure 10: Development of installed generation capacity

Total (net) installed generation capacity, which includes power plants that are not currently operating in the electricity market but are grid reserve power stations or are in lignite-fired power plant security standby, rose by 5.1 GW from 221.3 GW (at the end of 2018) to 226.4 GW at the end of 2019.[34] Of this, 102.0 GW was non-renewable and 124.4 GW renewable energy capacity.

Electricity: development of installed electrical generation capacity (GW)

	2014	2015	2016	2017	2018	2019
Nuclear power	12.1	10.8	10.8	10.8	9.5	9.5
Lignite	21.1	21.4	21.3	21.1	20.9	20.9
Black coal	26.2	28.7	27.4	24.0	23.8	22.7
Natural gas	29.0	28.4	29.7	29.8	30.1	30.1
Mineral oil products	4.2	4.2	4.6	4.4	4.4	4.4
Pumped storage	9.2	9.4	9.5	9.5	9.8	9.8
Waste (non-renewable)	0.9	0.9	0.9	0.9	0.9	0.9
Other energy sources (non-renewable)	3.4	3.4	3.5	3.5	3.5	3.7
Total of non-renewable energy sources	106.1	107.1	107.6	104.0	103.1	102.0
Renewable energy sources	90.3	97.7	104.2	111.6	118.2	124.4
Total	196.4	204.9	211.8	215.6	221.3	226.4
Renewables' share of total electricity generation	**46%**	**48%**	**49%**	**52%**	**53%**	**55%**

Table 11: Development of installed generation capacity

Renewables grew by 6.2 GW in 2019 compared to 6.6 GW[35] year on year in 2018. As at the end of 2019 the share of renewable energy generation capacity in Germany's total installed generation capacity was around 55% (2018: 53%). Compared to 2011 (the year in which figures were first recorded for comparison purposes) renewable energy generation capacity has increased by 57.9 GW; this is equal to an increase of the renewables'

[34] 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.

[35] The figures taken from Monitoring 2019 have been updated for 2018.

share in the total installed generation capacity of around 15.6%. Section I.B.2 contains a detailed analysis of the installed capacity of installations eligible for payments under the EEG and its development.

Installed capacity from non-renewable sources decreased in 2019 by 1.1 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.

1.4 Current power plant capacity in Germany

Total (net) installed generation capacity is currently 229.24 GW. Of this amount, 101.5 GW was sourced from non-renewables (January 2021) and 127.7 GW from renewables (30 June 2020). Subsequent power plant closures and commissioning reduced non-renewable capacities compared to 2019 by 0.5 GW. A detailed breakdown of the development of the installed capacity by each renewable energy source can be found in section I.B.2.

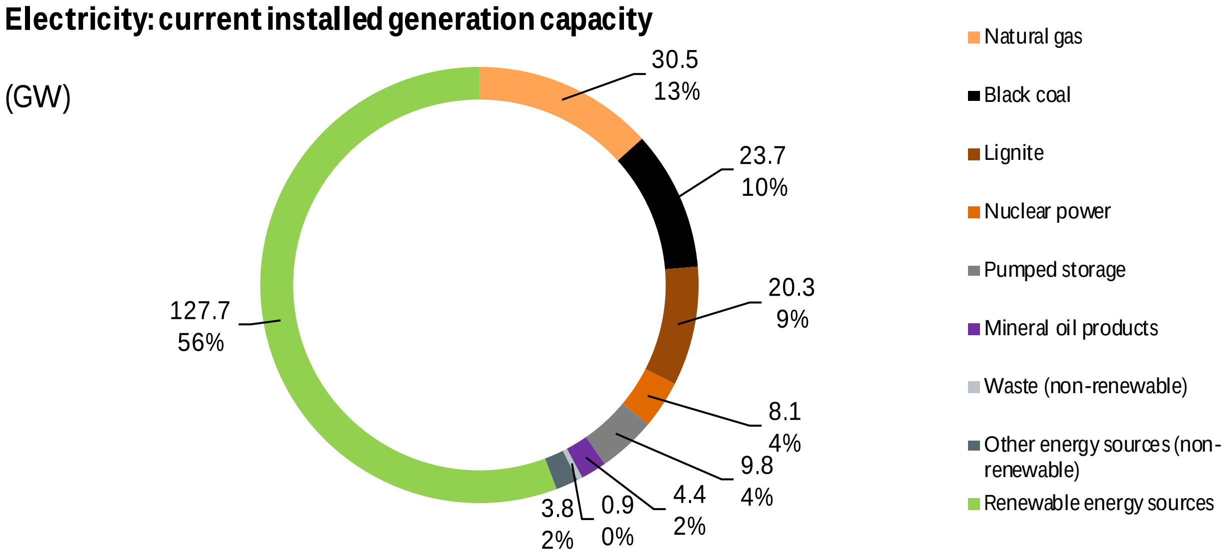


Figure 11: Current installed electrical generation capacity

Table 12 shows closures of power plant capacity since 2015. 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 2015 and up to 1 January 2021 a total capacity of 25,324 MW has been closed[36]. With 13,342 MW, the larger part has been finally closed (finally closed capacity of 119,381 MW and 3,961 MW from previous decommissioning of nuclear power plants). 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, grid reserve power stations as well as power stations subject to coal-fired electricity marketing bans or coal-fired power stations closed under the Act to Reduce and End Coal-Fired Power Generation (KVBG).

[36] Some power stations that were in the grid reserve or had been temporarily shut down were finally closed or recommissioned at a later time. The annual figures provide a snapshot of the status on the reporting date and are not the same as the figures for 5 January 2021.

Electricity: closures of power plant capacity

Year		2015	2016	2017	2018	2019	2020[1]	Total on 1 Jan 2021
Further closures during the year (MW)		3,563	4,026	6,919	2,826	3,912	5,543	25,324
of which final closure[2]	Capacity (MW)	1,377	1,688	2,763	1,767	1,753	33	9,381
	Average age in years at time	38	36	41	34	35	29	36
of which temporarily closed[2]	Capacity (MW)	661	301	78	0	0	0	982
	Average age in years at time	39	33	26	-	-	-	33
of which grid reserve	Capacity (MW)	250	1,685	2,232	0	0	425	3,185
	Average age in years at time	50	29	38	-	-	38	34
New capacity on security standby[3]	Capacity (MW)	0	352	562	1,059	757	0	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	0	1,284	0	1,402	0	3,961
	Average age in years at time	33	-	33	-	34	-	33
Coal-fired electricity marketing bans and closures under KVBG[4]	Capacity (MW)	0	0	0	0	0	5,085	5,085
	Average age in years at time	-	-	-	-	-	25	25

[1] preliminary values

[2] includes all closed plants, with and without notification

[3] The power plants on security standby will be finally closed after four years and are currently outside of the electricity market. They are no longer shown as finally closed power plants.

[4] Power plants with coal-fired electricity marketing bans and closures under Section 52 (2) KVBG are prohibited from selling capacity or energy produced using coal on the electricity market.

Table 12: Power plant capacity that has exited the market since 2013

1.5 Current power plant capacity by federal state

Figure 12 shows the location of installed generation capacity in each federal state broken down by renewable and non-renewable energy sources, including power plants that are not currently operating in the electricity market. The Figure does not include generation capacity in Luxembourg, Denmark, Switzerland and Austria that 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 that are not eligible for payments under the EEG in aggregated form and cannot therefore allocate this capacity (totalling 5.5 GW) to specific federal states.

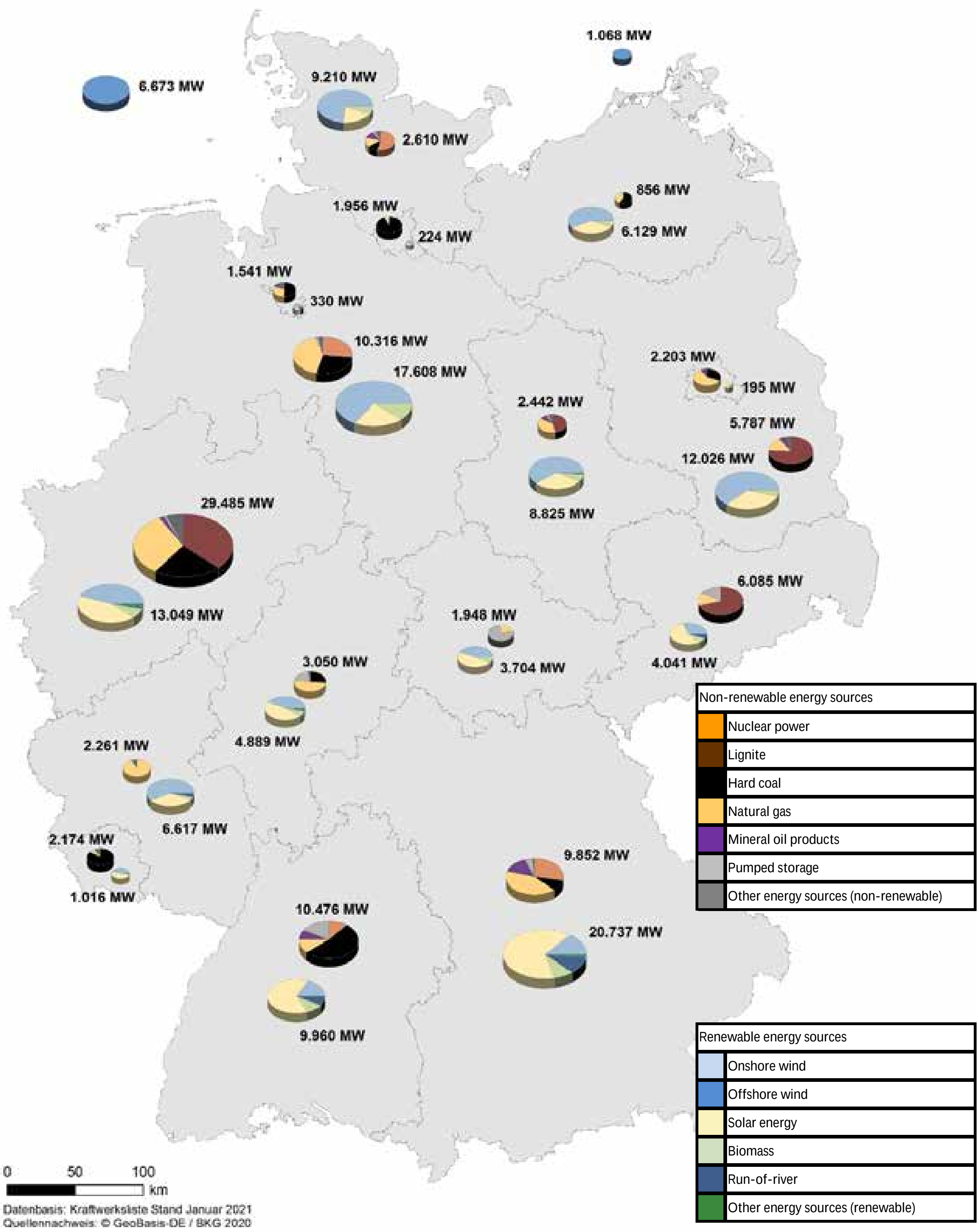


Figure 12: Generation capacity by energy source in each federal state

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	Other	Biomass	Run-of-river hydro	Offshore wind	Onshore wind	Solar	Others	Total
BW	0	5,506	1,026	1,310	1,873	702	59	987	685	0	1,619	6,586	83	**20,436**
BY	0	839	4,219	2,698	543	1,388	165	1,848	1,981	0	2,533	14,035	341	**30,590**
BE	0	653	1,314	0	0	218	18	43	0	0	12	122	18	**2,398**
BB	4,364	0	781	0	0	334	308	463	4	0	7,328	4,146	85	**17,813**
HB	0	772	459	0	0	86	224	12	10	0	211	49	48	**1,871**
HH	0	1,794	150	0	0	0	12	40	0	0	118	53	12	**2,179**
HE	34	753	1,529	0	625	25	84	287	66	0	2,115	2,316	105	**7,938**
MV	0	514	319	0	0	0	23	375	3	0	3,451	2,281	20	**6,985**
NI	0	2,928	4,057	2,696	220	56	358	1,781	69	0	11,268	4,433	56	**27,924**
NW	10,396	7,765	8,372	0	303	545	2,103	903	150	0	5,987	5,681	327	**42,533**
RP	0	13	2,059	0	0	0	189	180	231	0	3,733	2,408	66	**8,878**
SL	0	1,825	150	0	0	0	200	13	11	0	478	500	14	**3,191**
SN	4,328	0	647	0	1,085	17	8	288	213	0	1,266	2,259	16	**10,127**
ST	1,104	0	911	0	80	213	135	513	28	0	5,208	2,970	106	**11,267**
SH	0	326	317	1,410	119	276	163	571	5	0	6,760	1,847	27	**11,821**
TH	0	0	432	0	1,509	0	6	271	32	0	1,646	1,744	12	**5,652**
North Sea	0	0	0	0	0	0	0	0	0	6,673	0	0	0	**6,673**
Baltic Sea	0	0	0	0	0	0	0	0	0	1,068	0	0	0	**1,068**
Total	**20,225**	**23,688**	**26,742**	**8,114**	**6,357**	**3,859**	**4,056**	**8,576**	**3,488**	**7,741**	**53,733**	**51,430**	**1,335**	**219,343**

No detailed data is available for non-EEG installations with a capacity of less than 10 MW; the total capacity of these installations (5,531 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, electricity marketing ban

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 that 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, existing pumped storage stations and other newly built electricity storage facilities 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 2019, exemptions for storage facilities or pumped storage stations under section 118 EnWG amounted to around €226m. 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) and a discount for grid flexibility under section 19(2) sentence 1 of the Electricity Network Charges Ordinance (StromNEV).

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 that 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 13 battery-storage systems with a net nominal capacity of at least 10 MW was made for the Monitoring Report 2020. These 13 systems have a total net nominal capacity of 279 MW. 13 MW are currently under construction and are scheduled to go into operation by 2023.

All storage facilities must be registered in the Bundesneztagentur's core energy market data register (MaStR) regardless of size. There are 145,000 storage facilities registered in the market data register (27 October 2020).

There are currently also over 25 pumped storage stations[37] 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 6,359 MW. The plants active in the market generated a total of 6.4 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 2021.

Other pumped storage stations in Luxembourg and Austria with a total capacity of 3,455 MW also fed an additional 3.3 TWh of electricity into the public supply network in 2019.

Pumped storage stations therefore generated a total of 9.7 TWh of electricity. A total of 12.4 TWh electricity was removed from the grid by pumping operations. The difference of 2.7 TWh is the amount of electricity produced when water is being pumped uphill and which exceeds later generation (energy consumed by power plants for their own use).

1.7 Power plants outside of the electricity market

The total generation capacity of 101.5 GW from non-renewables (as at January 2021) can be divided into power plants operating within the electricity market (86.4 GW) and power plants operating outside of the electricity market (15.1 GW). Within these two categories, the following subsets can be classified with regard to power plant status:

Power plants operating in the electricity market:

– 85.9 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:

– 5.9 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)

– 2.4 GW: power plant capacity on security standby[38]

– 2.0 GW: plants temporarily closed.

[37] 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.

[38] The costs for these power plants were between €250m and €300m in 2019. More detailed information is unobtainable as the operators of these facilities classify this information as operating and business secrets.

– 4.8 GW: power plant capacity subject to coal-fired electricity marketing ban under section 52(2) Act to Reduce and End Coal-Fired Power Generation (KVBG).

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 (1.6 GW), black coal (2.7 GW) and mineral oil products (1.6 GW).

In accordance with section 13g EnWG, the following lignite-fired power plants in the table below have been transferred to so-called security standby status. 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 coal plants subject to an electricity marketing ban referred to above are those plants which were awarded tenders in the Bundesnetzagentur's first tendering procedure to reduce the production of electricity from black coal and lignite-fired power plants. The operator of a black coal or lignite-fired power plant subject to a ban on electricity marketing is not permitted to sell on the electricity markets any capacity or output generated by the use of black coal in black coal-fired power plants or of lignite in lignite-fired power plants.

Lignite-fired power plants in security standby status in accordance with section 13g EnWG

Name of power plant	Net nominal capacity in MW	Entry into security standby status	Final closure on
Buschhaus D	352	2016	1 October 2020
Frimmersdorf Q	278	2017	1 October 2021
Frimmersdorf P	285	2017	1 October 2021
Niederaußem F	299	2018	1 October 2022
Niederaußem E	295	2018	1 October 2022
Jänschwalde F	464	2018	1 October 2022
Jänschwalde E	465	2019	1 October 2023
Neurath C	292	2019	1 October 2023

Table 14: Lignite-fired power plants in security standby status in accordance with section 13g EnWG

The plants temporarily closed are power stations using natural gas (1.8 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 that 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.

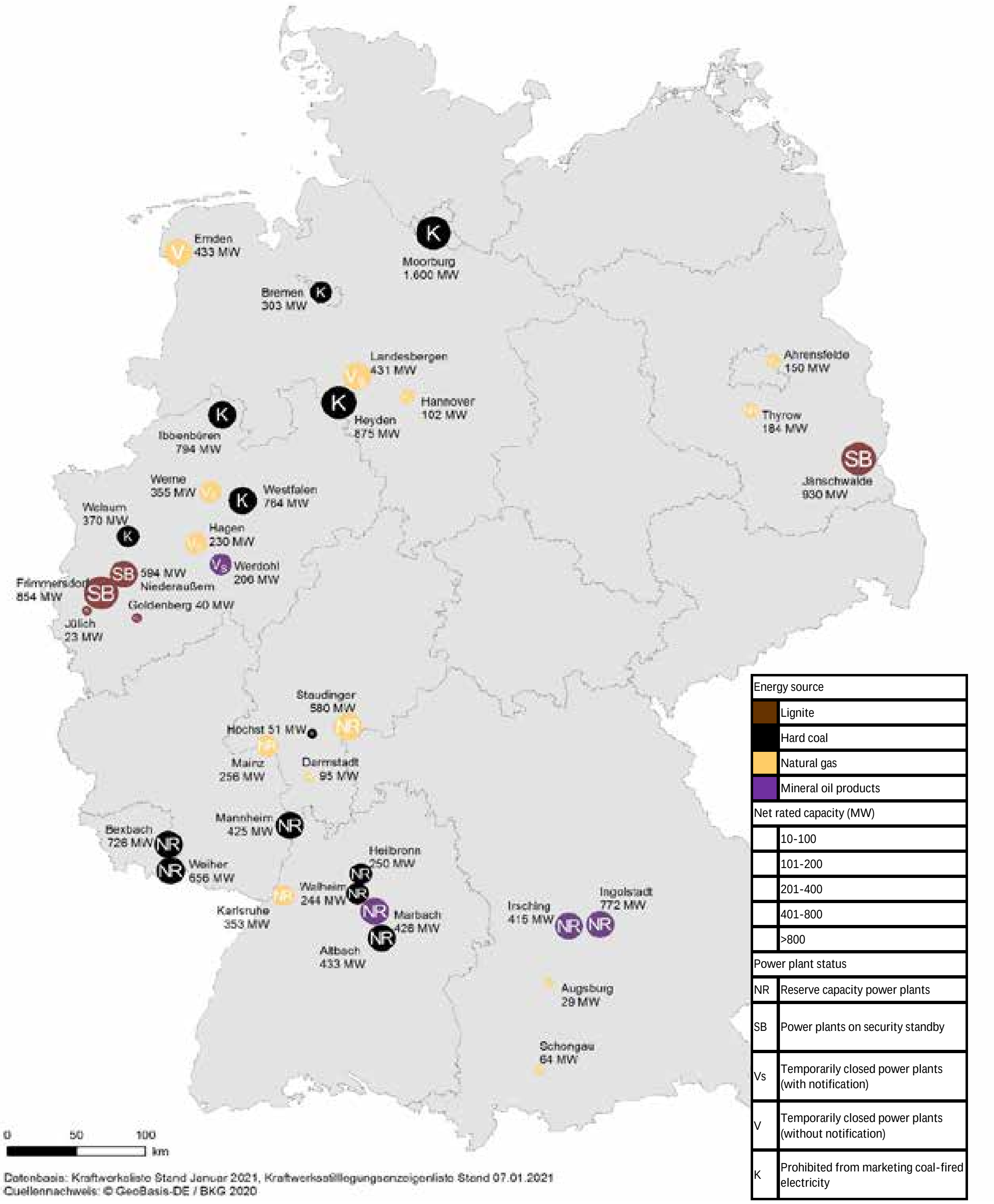


Figure 13: Power plants outside of the electricity market

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.1.8.3 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 2023. In such cases, the probability of projects being implemented is considered to be sufficiently high.

Generation capacity totalling 2,483 MW is currently in trial operation or under construction and will likely be completed in the next three years (Figure 14). The power plants projects in Germany relate to natural gas (2,361 MW), other energy sources (93 MW), battery-storage systems (13 MW) and pumped storage (16 MW).

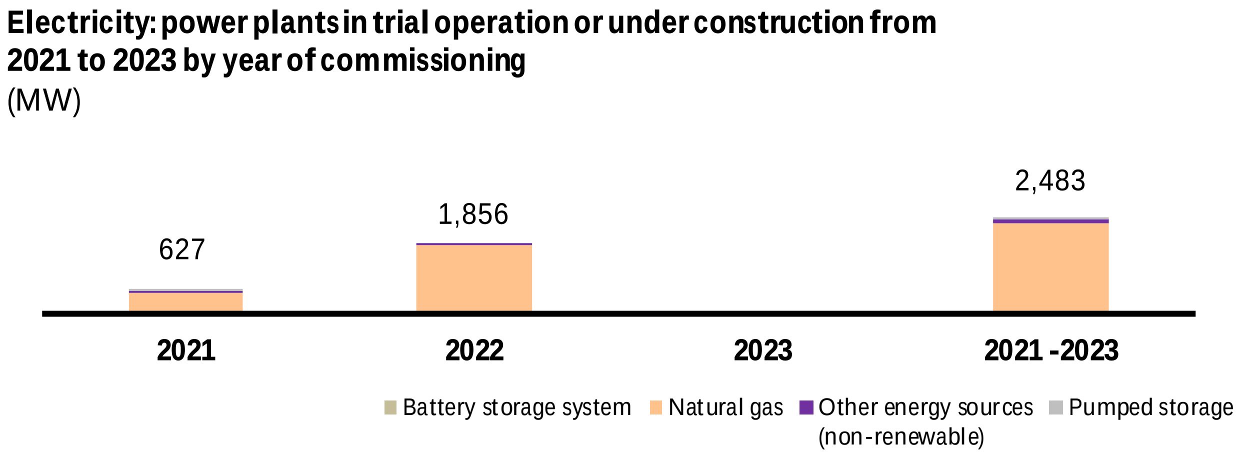


Figure 14: Power plants in trial operation or under construction

1.8.2 Auctions and reductions by law to end the production of electricity from coal

The Act to Reduce and End Coal-Fired Power Generation (KVBG) came into effect on 14 August 2020. While large lignite-fired power plants will be phased out under public contracts between operators and the federal government, black coal-fired power plants and smaller lignite-fired power plants (with a net nominal capacity of up to 150 MW) will be subject to so-called legal reductions and auctions.

1) Legally stipulated capacity reduction path for lignite-fired power plants

The KVBG law prescribes the following capacity reduction path:

Capacity reduction path for large lignite-fired power plants (KVBG)

Name of block	Net nominal capacity in MW_{el}	Final closure date
Niederaußem D	297	31 December 2020
Niederaußem C	295	31 December 2021
Neurath B	294	31 December 2021
Weisweiler E	321	31 December 2021
Neurath A	294	1 April 2022
Neurath D	607	31 December 2022
Neurath E	604	31 December 2022
Frechen / Wachtberg	120	31 December 2022
Weisweiler F	321	1 January 2025
Weisweiler G or H *	663 or 656	1 April 2028
Jänschwalde A	465	31 December 2028
Jänschwalde B	465	31 December 2028
Jänschwalde C	465	31 December 2028
Jänschwalde D	465	31 December 2028
Weisweiler H or G *	656 or 663	1 April 2029
Boxberg N and P	465 (each)	31 December 2029
Niederaußem G or H *	628 or 648	31 December 2029
Niederaußem H or G *	649 or 628	1 January 2033
Schkopau A and B	450 (each)	31 December 2034
Lippendorf R and S	875 (each)	31 December 2035
Niederaußem K	944	31 December 2038
Neurath F (BoA 2)	1,060	31 December 2038
Neurath G (BoA 3)	1,060	31 December 2038
Schwarze Pumpe A and B	750 (each)	31 December 2038
Boxberg R and Q	640 or 857	31 December 2038

* Option

Table 15: Capacity reduction path for large lignite-fired power plants (KVBG)

2) Tendering procedure for black coal-fired power plants and small lignite-fired power plants

The Bundesnetzagentur organises auctions to achieve voluntary reductions in the generation of electricity from black coal-fired power stations and smaller lignite-fired power plants. Plant operators can tender bids for the coal-fired capacity volumes that they are willing to take offline. The legal consequence when a bid is awarded a tender is a ban on coal-fired generation. This means that power plants do not necessarily have to be closed, but can switch away from coal to other energy sources instead.

Bids in the first of these auctions to take 4,000 MW offline could be submitted by 1 September 2020. The Bundesnetzagentur made awards in the first tendering procedure on 1 December 2020 and published the results on its website.

The volume put out to tender was significantly oversubscribed. Eleven bids with a total volume of 4,787,676 MW were awarded a tender. The first bid to result in oversubscription is granted a tender.

Overview of bids awarded a tender on the tendering date 1 September 2020

Name of bidder	Name of installation	Awarded bid volume (MW)
STEAG GmbH	Kraftwerk Walsum 9	370.000
Pfeifer & Langen GmbH & Co. KG	HKW Werk Jülich	22.860
swb Erzeugung AG & Co. KG	Kraftwerk Hafen Block 6	303.000
Infraserv GmbH & Co. Höchst KG	Kohleblock HKW	50.945
RWE Generation SE	Kraftwerk Westfalen	763.700
RWE Generation SE	Kraftwerk Ibbenbüren	794.000
Vattenfall Heizkraftwerk Moorburg GmbH	Heizkraftwerk Moorburg Block B	800.000
Vattenfall Heizkraftwerk Moorburg GmbH	Heizkraftwerk Moorburg Block A	800.000
Uniper Kraftwerke GmbH	Kraftwerk Heyden	875.000
Südzucker AG	Kraftwerk der Zuckerfabrik Brottewitz	3.571
Südzucker AG	Kraftwerk der Zuckerfabrik Brottewitz	4.600

Table 16: Overview of bids awarded a tender on the tendering date 1 September 2020

The prices of the bids awarded a tender ranged from €6,047 per MW to €150,000 per MW. The average award price was €66,259 per MW. Competition consequently pushed the prices of the successful bids well below the maximum price set of €165,000 per MW. Every successful bidder was paid the individual price that they had bid. The sum total of the awards was about €317m. The plants awarded a tender may no longer offer their capacity or energy produced using coal on the electricity market as from 1 January 2021.

The second tendering date for a volume of 1,500 MW was 4 January 2021. The awards in this tendering procedure are expected in spring 2021.

3) Reductions by law in the production of electricity from coal

The Act to Reduce and End Coal-Fired Power Generation (KVBG) sets out a roadmap for the reduction of production of electricity from coal; operators will not be compensated for shutdowns imposed from 2024. Shutdowns will initially only be prescribed by law if auctions are undersubscribed; at a later date, the plants to be closed will be stipulated by the Bundenetzagentur. As with tendering procedures, the legal impact of an imposed reduction will be a ban on coal-fired generation by the relevant power plant. The relevant power plant does not necessarily have to be closed, but can switch away from coal to other energy sources instead.

4) Network and supply security

The Bundesnetzagentur will continue to assess the impact of the reduction of coal-fired power generation on the security and reliability of the electricity supply system throughout the coal exit process.

The TSOs will continue to carry out system relevance tests on all power plants that are up for closure. If necessary, power plants can be transferred to the grid reserve.

1.8.3 Expected power plant closures

The legally stipulated capacity reduction path for lignite-fired power plants outlined in section I.B.1.8.2 and the tendering procedures for the voluntary termination of coal-fired power generation under the KVBG will result in substantial coal-fired power plant capacity being shut down in the years ahead. As well as the closure of coal-fired power plants in connection with the coal exit, more power stations will be closed by 2023. These will be the nuclear power plants that must be closed by law, lignite-fired power stations that at the end of the four-year security standby status will not be allowed to return to the market (see I.B.1.7) and market-driven closures by power plant operators. These latter include power plants that have been notified to the Bundesnetzagentur and scheduled for final or temporary plant closure. Unlike temporarily closed power plants, once a power plant has been permanently closed it is unlikely to return to the electricity market at a later time. For this reason the following table only includes power plants notified as scheduled for final closure. Not included are coal-fired power plants whose scheduled final closure has been notified to the Bundesnetzagentur as these power plants can take part in tendering procedures for the voluntary termination of coal-fired power generation.

The following table provides an overview of the power plant capacity that is expected to be withdrawn from the market by 2023.

Power plant capacity expected to be withdrawn from the market 2021 - 2023

	2021	2022	2023	2021 - 2023
Coal phase-out under KVBG	**2,410**	**1,625**		**4,035**
Of which legally stipulated capacity reduction path for lignite-fired power plants	910	1,625		2,535
Of which auctions for black coal-fired power stations and lignite-fired power plants	1,500			1,500
1. Auction round				0
2. Auction round	1,500			1,500
3. Auction round	Not yet determined			
4. Auction round		Not yet determined		
Closures after termination of the security standby status of lignite-fired power stations	**562**	**1,059**	**757**	**2,378**
Power stations under section 7(3) AtG	**4,058**	**4,049**		**8,107**
Notification for final closure under section 12b(5) EnWG	**373**	**0**	**0**	**373**
Natural gas	189			189
Mineral oil products	184			184
Other energy sources				0
Total	**7,403**	**6,733**	**757**	**14,893**

Table 17: Power plant capacity expected to be withdrawn from the market

In Germany as a whole, the capacity of scheduled market closures – consisting of closures or retrofitting as part of the coal phase-out (4,035 MW or more), closures after termination of the security standby status of lignite-fired power stations (2,378 MW), the statutorily required closure of nuclear power plants (8,107 MW) and notified final closures (373 MW) – will exceed the capacity of newly constructed power generating units (2,483 MW) by 12,410 MW up to the year 2023. Existing surplus capacities will therefore be reduced even further.

It should be noted that the above figures are subject to a degree of uncertainty. Firstly, the volumes to be put out to tender in the third and fourth auction rounds under the KVBG are not yet known; it is therefore not possible to provide a precise figure in the above table for the exact number of coal-fired power plants that will be closed between now and 2023. The third and fourth auction rounds will take place on 30 April and 1 October 2021. The coal-fired operation bans resulting from the tenders awarded in these procedures will take effect in 2022 and 2023. However, the end of coal-fired electricity generation at a particular plant does not necessarily mean that all the plant's capacity will be removed from the market since it is possible for plant operators to convert their plants to other energy sources (see I.B.1.8.2). Based on the non-binding declarations made by the bidders successful in the first auction round for planned use of the location, continued operation for approximately 75 MW with other fuel is expected. According to the bidders, around 1 GW will be shut down. There is still a lack of clear information on the use that is planned to be made of locations.

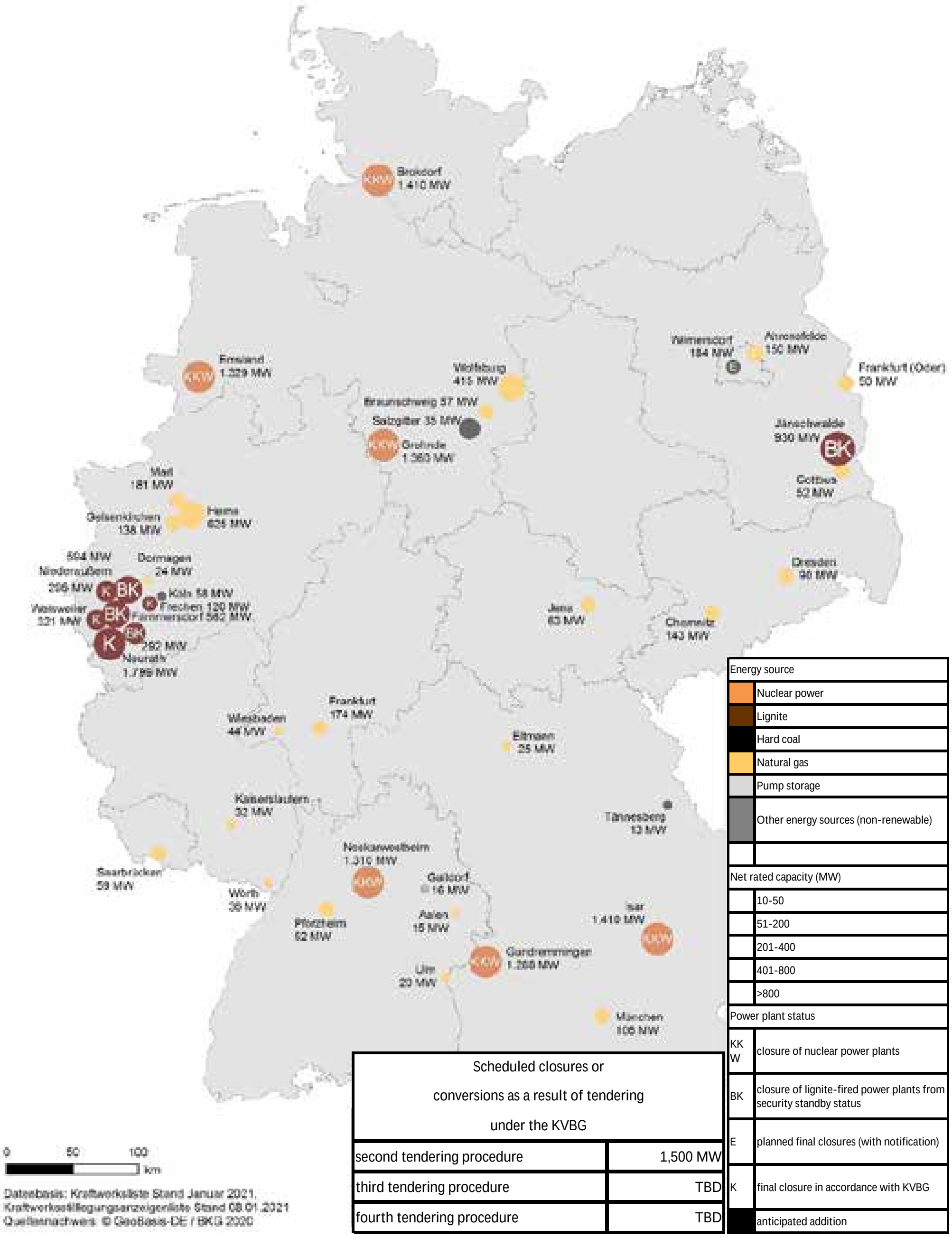


Figure 15: Locations with an expected increase in or withdrawal of generation capacity to 2023

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 table above. The final closure of a total additional capacity of 169 MW is thus expected by 2023. This concerns natural gas-fired power plants with a capacity of 101 MW and other energy sources with a capacity of 68 MW.

The capacity of power plants scheduled for closure by the year 2023 thus totals 15,062 MW.

The overall national anticipated balance of the increase and decrease of power generation capacity by 2020 is thus -15,579 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) para 2 Combined Heat and Power Act (KWKG). CHP payments are only paid 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 plants 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 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 CHP plant capacity with a minimum capacity of 10 MW

The evaluations presented in this chapter include CHP-capable German power generation units with a net nominal electrical capacity of at least 10 MW. In 2019, 482 power generation units capable of extracting heat and process steam were on the market. Of these, 250 are bigger than 10 MW and smaller than 50 MW. Since December 2017, CHP plants of this size are required to participate in CHP auctions in order to qualify as modernised or new under the Combined Heat and Power Act (KWKG); see I.B.1.9.3 „CHP auctions“). Figure 16 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.

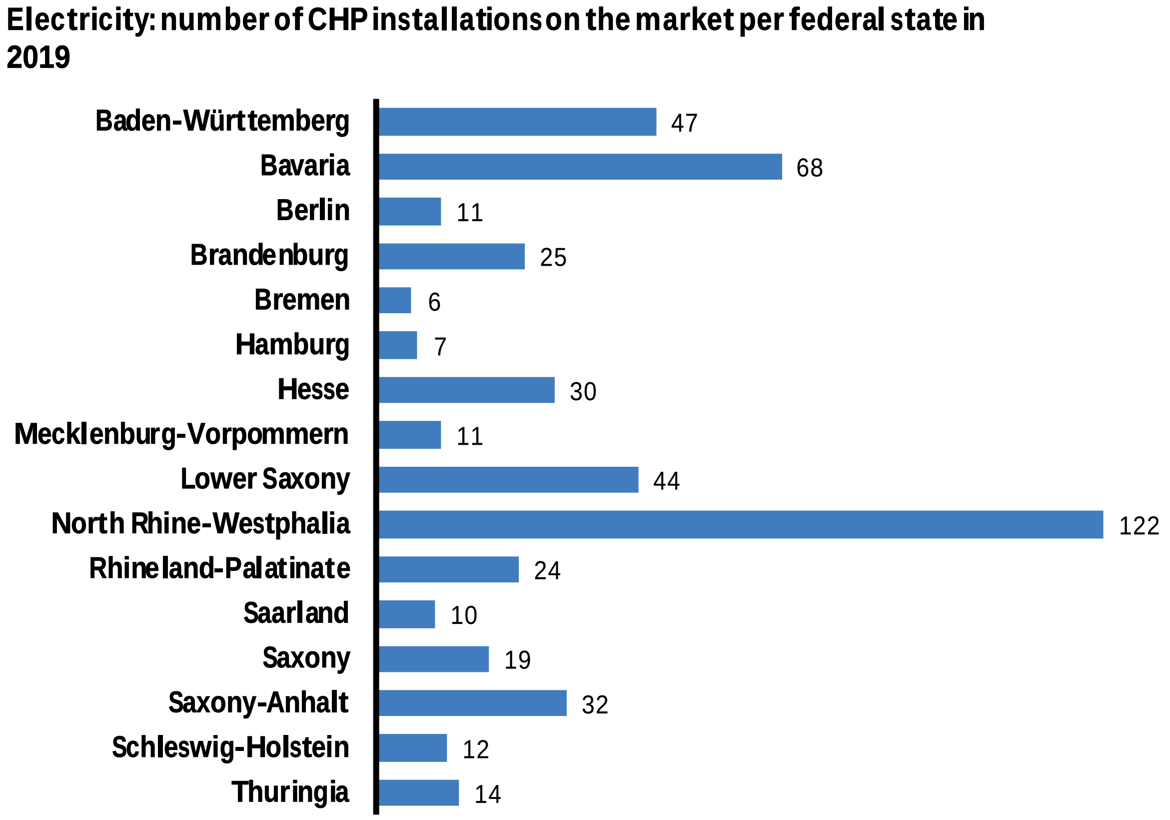


Figure 16: Number of CHP installations on the market per federal state in 2019

The installed electrical and useful heat capacity of CHP installations with a minimum capacity of 10 MW are shown separately in MW in Figure 17. The installed electrical and useful heat capacity of CHP installations are shown separately. While the installed electrical capacity of CHP plants is 20.6 GW, the useful heat capacity installed in these plants is 45.5 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. The Datteln IV power station 4, currently Germany's biggest CHP-capable power generation unit, went into operation in 2020.

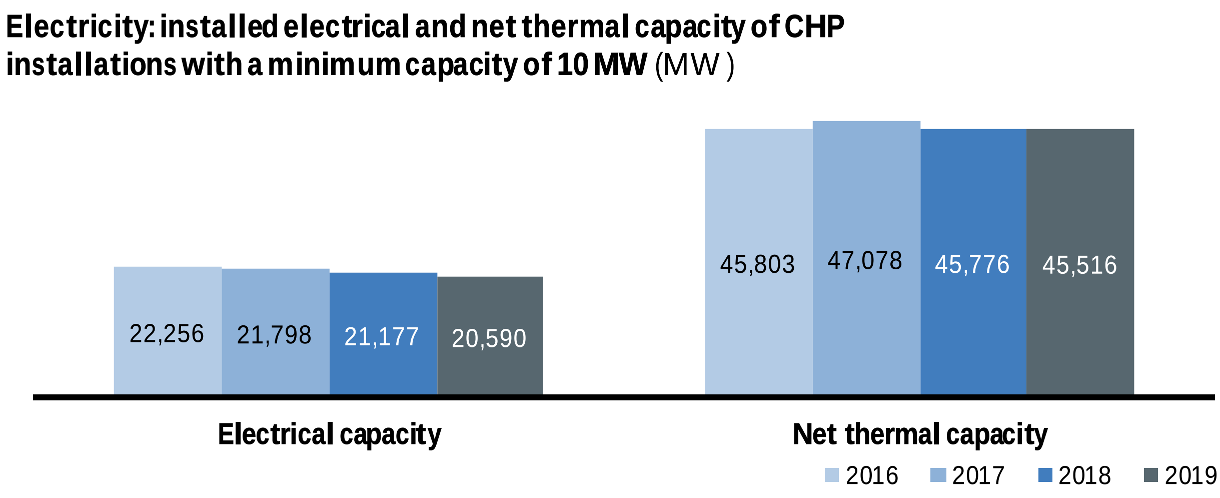


Figure 17: Installed electrical and net thermal capacity of CHP plants with a minimum capacity of 10 MW

The installed (electrical and thermal) capacity is sourced as follows (Table 18). 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, particularly in the field of natural gas, have an installed electrical capacity of less than 10 MW. These 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 power plants by energy source with a minimum capacity of 10 MW (MW)

	Electrical power		Effective thermal power	
	2018	2019	2018	2019
Waste	748	748	3,605	3,605
Biomass	466	466	1,430	1,862
Lignite	1,077	1,107	4,884	4,974
Natural gas	11,441	11,161	19,904	19,701
Others	1,290	1,290	3,898	4,334
Black coal	6,155	5,818	12,055	11,040
Total	21,177	20,590	45,776	45,516

Table 18: Installed electrical and net thermal capacity of CHP plants with a minimum capacity of 10 MW by energy source (MW)

The CHP-capable power generation units on which this evaluation is based produced 140.0 TWh useful heat and 67.6 TWh of electricity in 2019. The amount of electricity produced by CHP plants increased by around 2 TWh in 2019 (+3%) remaining at the same level as in the previous year. The amount of useful heat generated in 2019 rose by 3 TWh (+2%) to remain at much the same level as in the previous year. In 2019, 130.8 TWh of non-CHP electricity was generated, or 18% (-23.4 TWh) less than in the previous year. The fall in generation of non-CHP electricity arises from the energy sources black coal (-36%), lignite (-20%) and waste (-20%). In contrast, 25% more non-CHP electricity was generated from natural gas-fired power plants than in 2018. This means that overall non-CHP electricity generation was in line with the drop in electricity generation from non-renewable sources. 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 and section 3(1) sentence 3 KWKG and can therefore only be used for redispatching once priority measures have been exhausted.[39]

[39] With the entry into force of the Redispatch 2.0 mechanism on 1 October 2021 the relativised minimum factor of 5 applies to CHP electricity in accordance with the minimum factor stipulation of 30 November 2020.

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

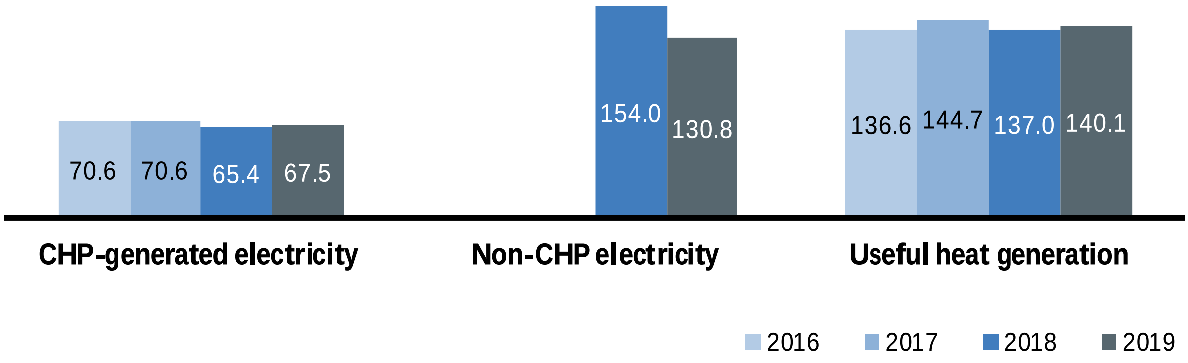


Figure 18: Amount of electricity and useful heat produced by CHP plants with a minimum capacity of 10 MW

The most important energy sources for the generation of CHP electricity and useful heat are natural gas and black coal (see Table 19). Natural gas is a particularly important energy source for electricity generated by CHP plants through heat extraction and accounts for 67% of total generation. Whereas for useful heat, 43% is generated from natural gas and 20% from black coal.

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

	Total CHP electricity generated		Condensing electricity		Useful thermal power generated	
	2018	**2019**	**2018**	**2019**	**2018**	**2019**
Waste	2.8	2.9	2.7	2.3	11.2	12.0
Biomass	1.6	2.2	1.2	1.3	7.1	9.3
Lignite	3.6	3.2	86.6	72.3	14.2	13.7
Natural gas	42.5	45.2	12.1	16.1	59.6	60.0
Others	4.1	3.9	4.6	4.4	16.6	17.5
Black coal	10.8	10.2	46.8	34.4	29.0	27.6
Total	65.4	67.6	154.0	130.8	137.7	140.1

Table 19: Amount of electricity and useful heat produced by CHP plants with a minimum capacity of 10 MW by energy source

1.9.2 CHP plants newly registered in the core energy market data register

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.

In the calendar year 2019, 5,212 plants with a total net nominal capacity of 959 MW were registered. The significantly higher figures compared to the previous year (2018: 525 plants, 3,588 MW) are partly due to the fact that, for the first time, the 2019 data also included CHP plants using renewable energy sources. A corresponding evaluation has only been possible since the core energy market data register online portal was launched on 31 January 2019.

Most commissioned CHP plants run on natural gas (4,379) followed by plants which run on biomass (596). These sources of energy are used by over 95% of CHP plants and account for more than 85% of net nominal capacity.

Electricity: CHP plants newly registered in 2019

Month	Net nominal capacity in MW	Number
January	40	395
February	63	395
March	40	427
April	354	413
May	37	398
June	30	346
July	36	396
August	28	366
September	39	472
October	72	529
November	154	513
December	66	562
Total	**959**	**5,212**

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

Table 20: Commissioning of CHP plants

Electricity: commissioning by energy source in 2019

Capacity class	Net nominal capacity in MW	Number
Other gases	16	166
Biomass	328	596
Natural gas	481	4,379
Geothermal	4	1
Sewage sludge	1	5
Mineral oil products	2	57
Non-biogenic waste	12	1
Heat	115	7
Total	**959**	**5,212**

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

Table 21: Commissioning by energy sources

Electricity: commissioning by capacity classes in 2019

Capacity class	Net nominal capacity in MW	Number
50 kW	43	4,351
50 kW - 250 kW	49	331
250 kW - 1 MW	244	422
1 MW - 10 MW	291	104
> 10 MW	332	4
Total	**959**	**5,212**

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

Table 22: Commissioning by capacity classes

Electricity: commissioning by federal state in 2019

Federal state	Net nominal capacity	Number
Baden-Württemberg	58	1,019
Bavaria	133	868
Berlin	303	94
Brandenburg	10	137
Bremen	1	34
Hamburg	2	84
Hesse	18	394
Mecklenburg-Vorpommern	15	86
Lower Saxony	116	639
North Rhine-Westphalia	87	799
Rhineland-Palatinate	109	247
Saarland	1	34
Saxony	11	230
Saxony-Anhalt	30	143
Schleswig-Holstein	52	277
Thuringia	13	127
Total	**959**	**5,212**

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

Table 23: Commissioning by federal state

Most (4,351) of the commissioned CHP plants produced up to 50 kW. This accounts for over 80% of all newly registered plants. The largest net nominal capacity is attributable to the 1 to 10 MW and over 10 MW plant classes, which account for over 65% of new capacity (623 MW).

Most plants were commissioned in Baden-Württemberg (1,019), Bavaria (868) and North Rhine-Westphalia (799). In terms of net nominal capacity, the highest share was installed in Berlin. This is due to the commissioning of the new combined cycle gas turbine (CCGT) Lichterfelde plant, which has a capacity of 303 MW.

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. The latter include a CHP plant, an innovative renewable heat source (eg solar energy, geothermal energy, heat pump) and an electric heat generator.

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

Tendering date	1 Dec 2017	1 Jun 2018	3 Dec 2018	3 Jun 2019	2 Dec 2019	2 Jun 2020
CHP installations						
Auction volume	100 MW	93 MW	77 MW	51 MW	80 MW	75 MW
Number of bids	20 (225 MW)	15 (96 MW)	18 (126 MW)	13 (87 MW)	13 (58 MW)	22 (71 MW)
Number of awards	7 (82 MW)	14 (91 MW)	12 (100 MW)	4 (46 MW)	12 (53 MW)	21 (69 MW)
Excluded bids	0	1 (4 MW)	3 (8 MW)	0	3 (8 MW)	1 (2 MW)
Average award price*	4.05 ct/kWh	4.31 ct/kWh	4.77 ct/kWh	3.95 ct/kWh	5.12 ct/kWh	6.22 ct/kWh
Innovative CHP systems						
Auction volume		25 MW	29 MW	30 MW	25 MW	29 MW
Number of bids		7 (23 MW)	3 (13 MW)	5 (22 MW)	10 (43 MW)	13 (44 MW)
Number of awards		5 (21 MW)	3 (13 MW)	5 (22 MW)	5 (20 MW)	8 (26 MW)
Excluded bids		2 (2 MW)	0	0	1 (9 MW)	1 (2 MW)
Average award price*		10.27 ct/kWh	11.31 ct/kWh	11.17 ct/kWh	10.25 ct/kWh	10.22 ct/kWh

*Volume weighted

Table 24: CHP auctions

2. Development of renewable energies

An essential cornerstone of the 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, ie 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 (81%) of renewable electricity generated in Germany in 2019 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 124.4 GW of capacity installed at the end of 2019, 120.2 GW was eligible for EEG payments. This chapter therefore examines renewable energies eligible for payments in more detail.

The 4.2 GW of renewable energy capacity not eligible for payments is primarily accounted for by the energy sources run-of-river power (2.3 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. Non-eligible renewable sources generated 17.7 TWh of electricity in 2019. The majority of that energy was generated in run-of-river and dammed water power plants (13.3 TWh in total) and in waste- fired power plants (4.1 TWh).

The key figures presented in this section are collected by the Bundesnetzagentur to fulfil its supervisory function in the nationwide EEG equalisation scheme. 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 2019", 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.[40]

2.1.1 Installed capacity[41]

As at 31 December 2019, the total installed capacity of installations eligible for payments in accordance with the EEG was approximately 120.2 GW. Around 6.2 GW of the total additional capacity eligible for payments was installed in 2019, representing an increase of around 5.5%.

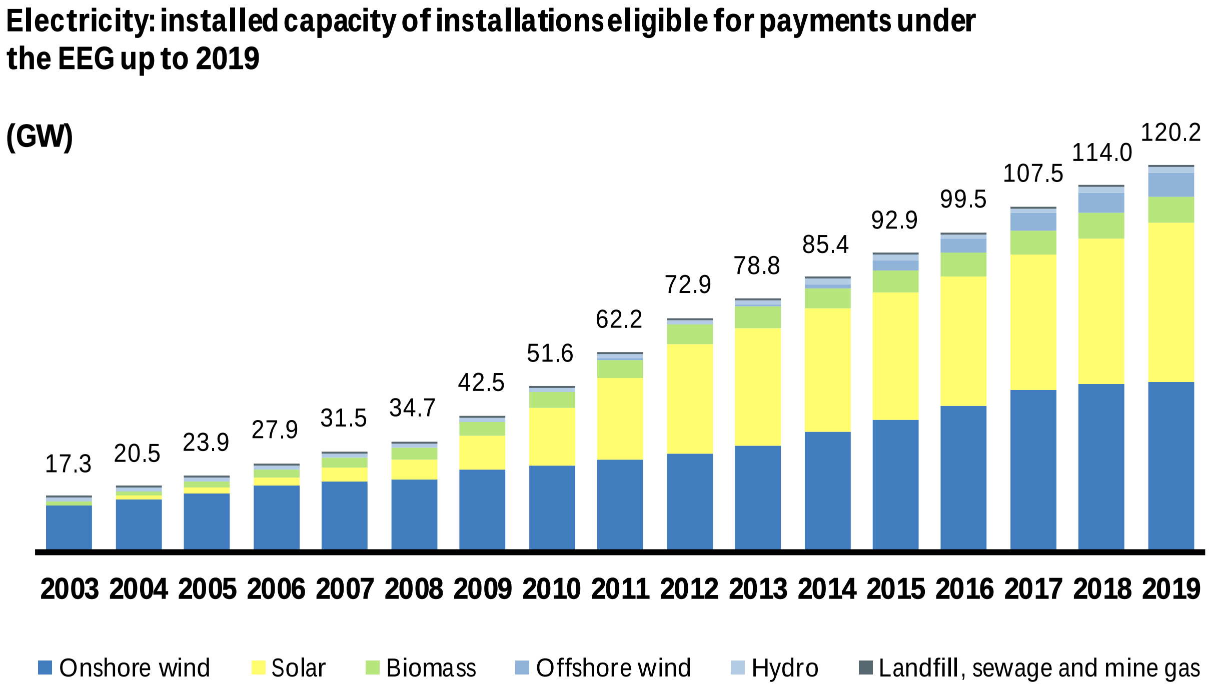


Figure 19: Installed capacity of installations eligible for payments under the EEG up to 2019

Solar capacity rose sharply again in 2019. Some 3.9 GW of new capacity was installed in 2019, compared to an average of 1.7 GW annually over the previous five years. Offshore and onshore wind energy also continued to grow. Nonetheless, net expansion of onshore wind installation capacity (0.9 GW) was less than half the net new build in the previous two years (2018: 2.2 GW, 2017: 4.9 GW). Offshore wind power plants with a capacity of 1.1 GW were newly installed (2018: approximately 1.0 GW), which represents an increase of 17.8%. The 0.3 GW expansion in biomass installations was lower than in the previous year (2018: 0.4 GW).

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

[41] The figures on the installed capacity by renewable energy source for the year 2019 may still be subject to change and have not yet been agreed with the Working Group on Renewable Energy Statistics (AGEE-Stat).

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

	Total 31 December 2018	Total 31 December 2019	Increase / Decrease in 2019	Increase / Decrease compared to 2018
	in MW	in MW	in MW	in %
Hydro	1,598.7	1,610.1	11.4	0.7%
Gases[1]	419.9	422.3	2.3	0.6%
Biomass	7,993.1	8,325.6	332.5	4.2%
Geothermal	41.6	47.1	5.5	13.2%
Onshore wind	52,328.2	53,192.6	864.3	1.7%
Offshore wind	6,392.8	7,528.3	1,135.5	17.8%
Solar	45,207.4	49,096.4	3,888.9	8.6%
Total	113,981.7	120,222.3	6,240.6	5.5%

[1] Landfill, sewage and mine gas

Table 25: Installed capacity of installations eligible for payments under the EEG by energy source (as at 31 December)

Some 108,838 new facilities were installed in 2019.[42] Solar installations accounted for 97.3% of new installations, onshore wind installations for 1.5% and biomass installations for 0.8%; the remainder is shared among other technologies. The growth rates of installations eligible for payments under the EEG are shown in Table 26.

Table 27 shows the growth rates of EEG installations eligible for payments by energy source.

[42] The installation figures by renewable energy source for the year 2019 may still be subject to change and have not yet been agreed with the Working Group on Renewable Energy Statistics (AGEE-Stat).

Electricity: changes in the installed capacity of installations eligible for payments under the EEG

	2014	2015	2016	2017	2018	2019	Jun 20
Hydro	6,947	7,078	7,041	7,138	7,172	7,222	7,254
Gases[1]	627	630	612	600	593	602	601
Biomass	14,024	14,113	14,186	14,271	14,496	15,122	15,437
Geothermal	8	9	10	9	10	11	11
Onshore wind	23,593	24,696	26,057	27,406	28,131	28,363	28,498
Offshore wind	241	789	945	1,167	1,307	1,467	1,498
Solar	1,521,365	1,572,922	1,622,405	1,686,993	1,760,396	1,868,156	1,949,022
Total	1,566,805	1,620,237	1,671,256	1,737,584	1,812,105	1,920,943	2,002,321

[1] Landfill, sewage and mine gas

Table 26: Changes in the number of installations eligible for payments under the EEG

Electricity: growth rates of installations by energy source

	Total 31 December 2018	Total 31 December 2019	Increase / Decrease in 2019	Increase / Decrease compared to 2018
	Number	Number	Number	in %
Hydro	7,172	7,222	50	0.7%
Gases[1]	593	602	9	1.5%
Biomass	14,496	15,122	626	4.3%
Geothermal	10	11	1	10.0%
Onshore wind	28,131	28,363	232	0.8%
Offshore wind	1,307	1,467	160	12.2%
Solar	1,760,396	1,868,156	107,760	6.1%
Total	1,812,105	1,920,943	108,838	6.0%

Landfill, sewage and mine gas

Table 27: 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	2.5 GW gross increase per year	100 MW gross increase per year
EEG 2017	2.8 GW gross increase for 2017 to 2019; 2.9 GW gross increase as of 2020	20 GW increase in 2030		150 MW gross increase for 2017 to 2019 200 MW gross increase for 2020 to 2022
EEG 2021	57 GW in 2022 62 GW in 2024 65 GW in 2026 68 GW in 2028 71 GW in 2030	20 GW in 2030	63 GW in 2022 73 GW in 2024 83 GW in 2026 95 GW in 2028 100 GW in 2030	8.4 GW in 2030

Table 28: 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. Since 2018, the net increase has halved in comparison to the previous year and the increase in 2018 and 2019 fell well below the development targets.

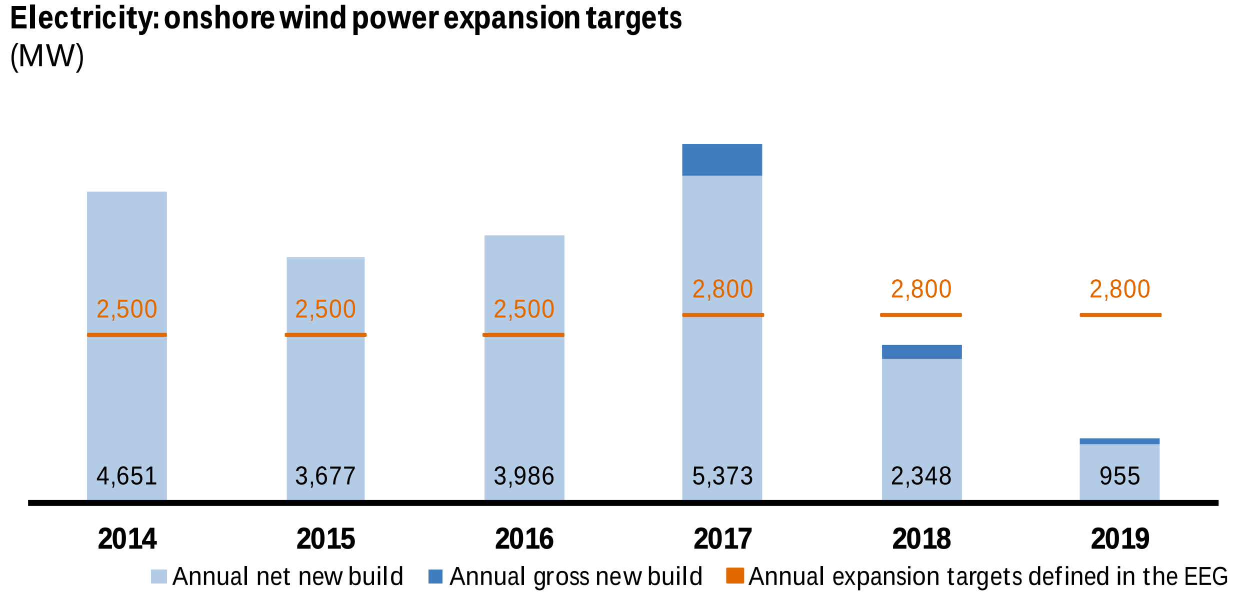


Figure 20: Onshore wind development targets

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 again and even exceeded in 2019 by 1,389 MW.

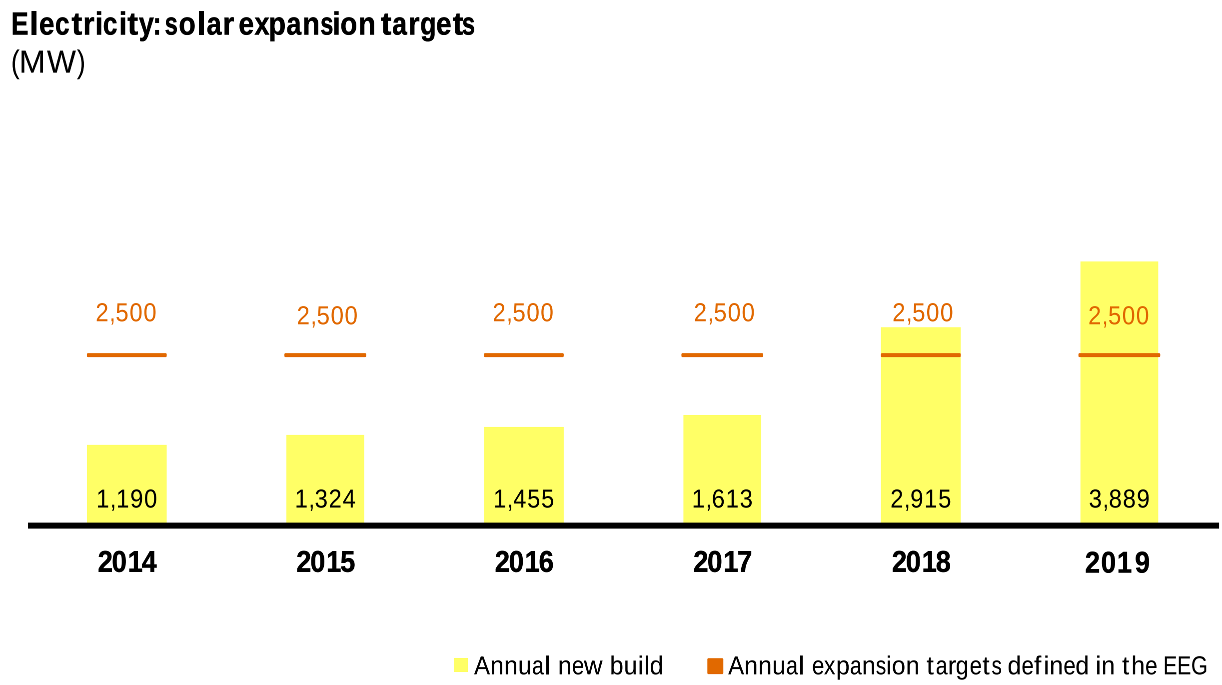


Figure 21: Solar development targets

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. Development targets have been substantially exceeded since 2014. Around twice as much capacity has been built annually than foreseen in the EEG.

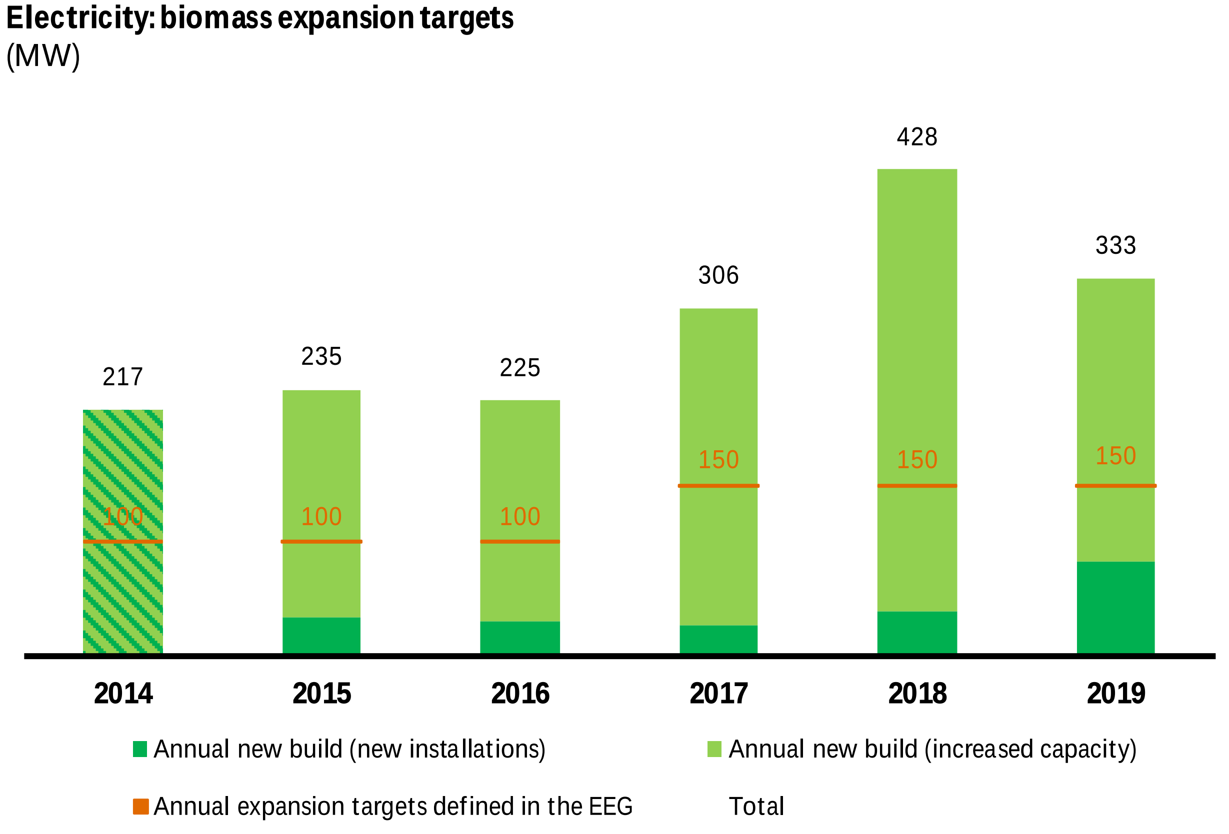


Figure 22: Biomass expansion targets

For offshore wind, the first development target of 6,500 MW was met in March 2019 and an average of around 1,100 MW net new build will be required every year up to 2030 to meet the 20 GW target for that year.

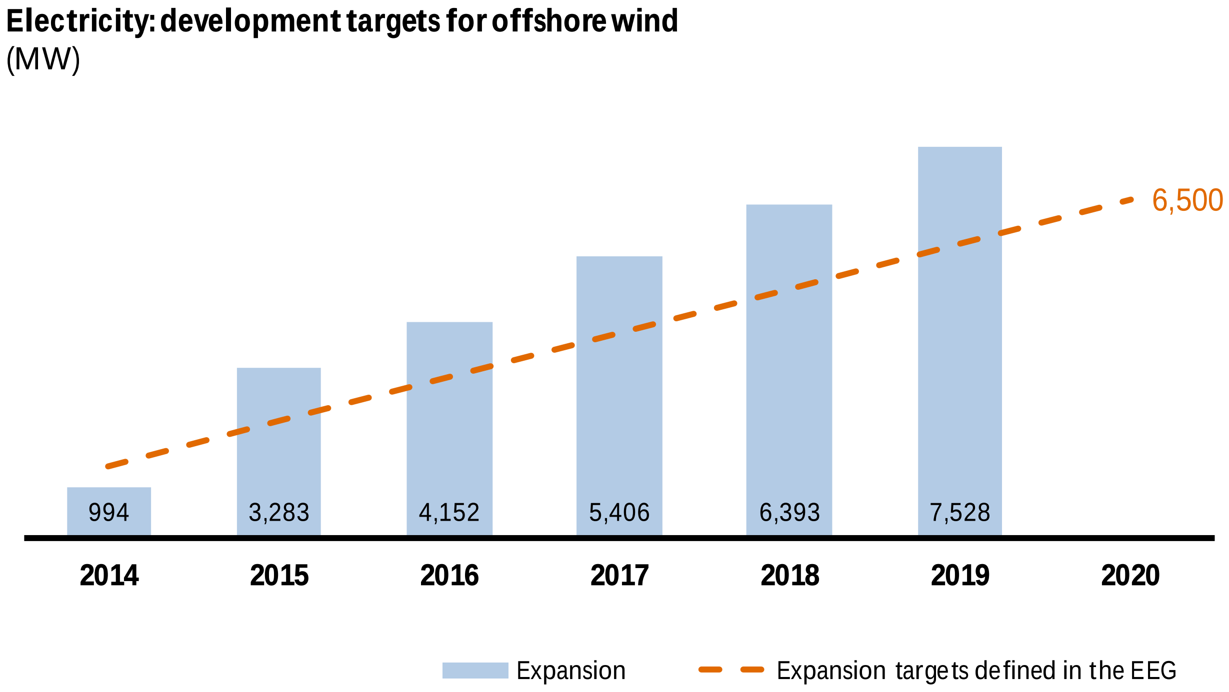


Figure 23: Offshore wind development targets

In order to achieve the target of 65% gross electricity consumption from renewable energies by 2030, 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 2021 to 2035 scenario framework of the applicable network development plans. 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 rates of growth of gross electricity consumption assumed in the scenarios. For this reason, the assumed average annual gross rise of 3.78 GW to 4.37 GW for onshore wind and of 5.03 GW to 5.65 GW for solar installations is significantly higher than the EEG targets. A target value for biomass plants of between 6.8 GW and 8.7 GW has been defined for the year 2035. At 28.0 GW to 34.0 GW the target value for the year 2035 for offshore wind assumed in the 2021 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 2019 the total annual energy feed-in of electricity from installations eligible for payments under the EEG was 211.9 TWh. Total annual electricity feed-in has increased by 8.4% compared to the previous year (2018: 195.4 TWh). At 99.2 TWh or 47%, the largest share of this electricity was generated by onshore wind installations, followed by solar installations with a share of 41.4 TWh (20%) and biomass installations with a share of 40.2 TWh (19%).

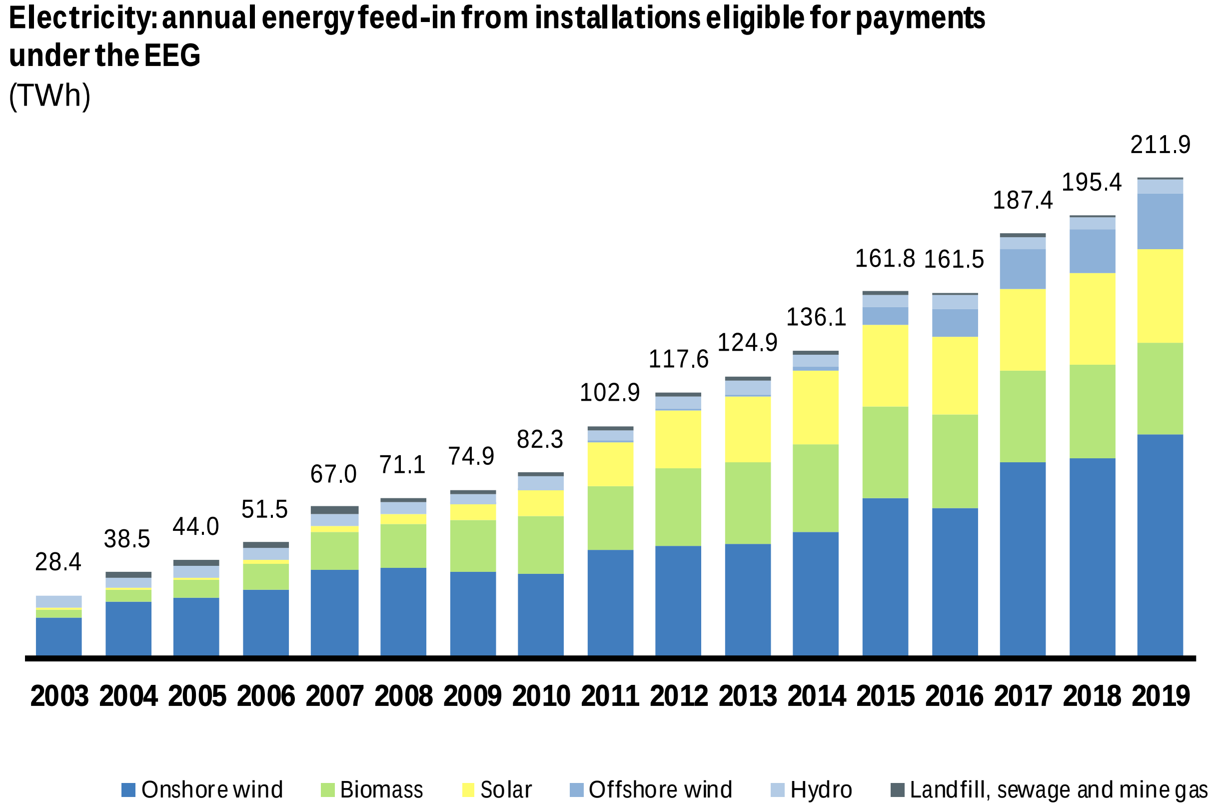


Figure 24: Changes in annual feed-in of electricity from installations eligible for payments under the EEG

Annual feed-in of electricity from hydro rose by 14.2% compared to the previous year. This is largely due to the increase in levels of precipitation in 2019 compared to the previous year, particularly in Bavaria and

Baden-Württemberg, where most hydroelectric plants are located.[43] The annual energy feed-in of gas fell by 9.1%.

The annual feed-in of electricity from solar installations rose by just 1.4%. This small increase can best be explained by the record number of sunshine hours and global radiation in 2018.[44] In comparison with these figures, good new build of solar capacity in 2019 alongside average sunshine hours and global radiation resulted in low growth.

The annual feed-in from wind power, and particularly offshore wind power plants, increased strongly compared to the previous year by 27.1%. This increase is in part due to continued strong growth in this area (see Table 20). The increase may also be due to relatively high wind speeds in 2019, as shown in Figure 25.

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

	Total 31 December 2018	Total 31 December 2019	Increase / Decrease compared to 2018
	in GWh	in GWh	in %
Hydro	4,857	5,548	14.2%
Gases[1]	1,170	1,063	-9.1%
Biomass	40,480	40,152	-0.8%
Geothermal	165	187	13.2%
Onshore wind	88,710	99,166	11.8%
Offshore wind	19,179	24,379	27.1%
Solar	40,807	41,383	1.4%
Total	195,368	211,879	8.5%

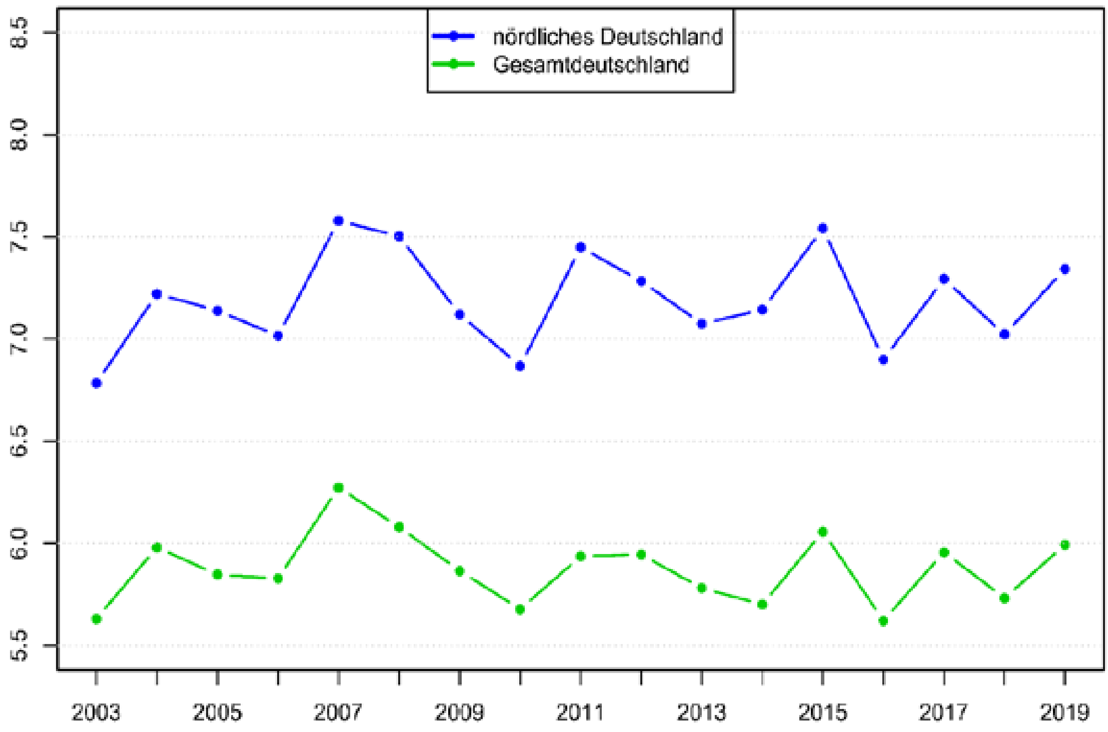
[1] Landfill, sewage and mine gas

Table 29: Annual energy feed-in from EEG installations eligible for payments by energy source (on 31 December)

[43] Source: Monthly Report on the Development of Renewable Power Generation and Output in Germany - January 2020, Working Group on Renewable Energy Statistics (AGEE-Stat)

[44] 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

Annual average wind speed in Germany at 100 metre elevation



Annual average wind speed in all of Germany and the northern part of Germany at an altitude of 100 metres. The data is based on the global atmospheric reanalysis "ERA-5" of the European Copernicus Climate Change Service (C3S) and represents the average value over the following ranges: Germany: approx 6°E - 15°E, approx 48°N - 55°N; northern Germany: approx 6°E- 15°E, approx 52°N - 55°N: (Source: German Weather Service, National Climate Monitoring based on C3S- ERA-5: Hersbach et al., 2020; DOI: 10.1002/qj3803).

Figure 25: Annual average wind speed at 100 metre 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 significantly compared with previous years. In 2019, the maximum feed-in from wind power installations and solar installations of 66.2 GW was recorded on 23 April 2019 whereby 60% of this peak feed-in was due to wind power. On this day, wind installations fed up to 40.8 GW into the grid. This coincided with a high level of feed-in from solar installations (25.4 GW). Figure 26 shows the maximum feed-in from wind power installations and solar installations between 2012 and 2019.

In 2019, the maximum feed-in from solar installations alone of 30.2 GW was recorded on 19 April 2019. The year's highest feed-in values for wind power (onshore and offshore) were recorded in March 2019. The peak level of 51.4 GW achieved on 15 March 2019 was due primarily to the gale force winds deep low pressure system HEINZ. Several peak values were also observed in the course of the year as a result of various storm systems. Figure 27 shows the development of feed-in from wind power installations in 2019.

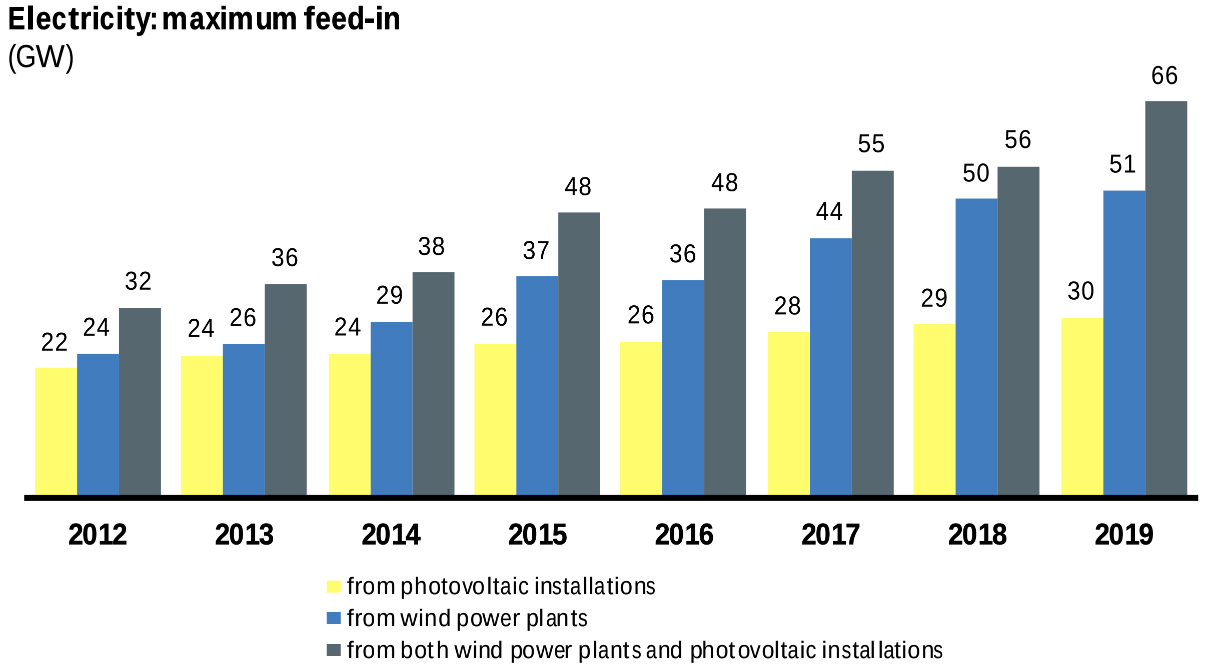


Figure 26: Maximum feed-in

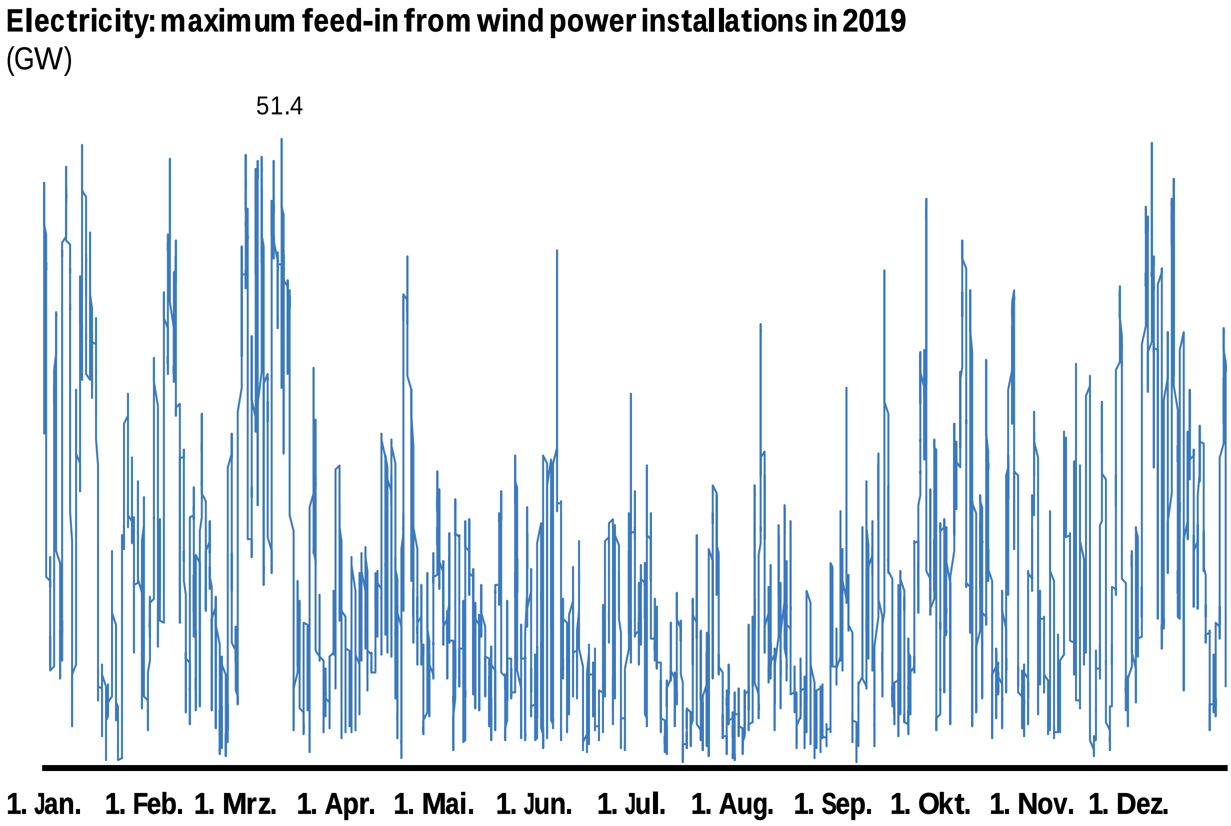


Figure 27: Maximum feed-in from wind in 2019

2.1.4 Form of selling

Under section 33b 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 profits), a reduction to 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 or payment of a tenant electricity supplement. Another form of direct selling, ie 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 2019, fixed feed-in tariffs were only paid for 19% of electricity supplied (see Figure 28).

Table 30 shows that 81% annual energy feed-in is already remunerated under the EEG in the form of the market premium. This is 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. At 31% (2018: 29%), the proportion of electricity from solar installations paid a market premium is still relatively low but growing continually.

In 2019, the main energy source for direct selling was onshore wind power, which accounted for a share of 56% (2018: 55.7%), followed by biomass with a share of 19.5% and wind power at 14.3%.

Electricity: annual energy feed-in from installations with a fixed feed-in tariff or direct selling
(%)

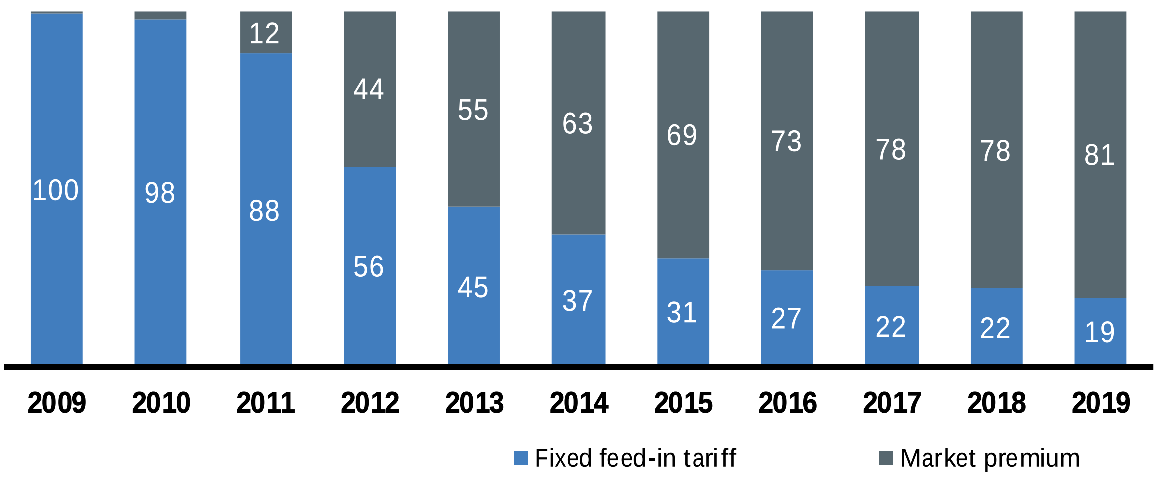


Figure 28: Annual feed-in of electricity from installations eligible for payments under the EEG by feed-in tariff or market premium

Electricity: annual feed-in of electricity from installations eligible for payments under the EEG by 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 in %
Hydro	5,548	2,119	3,429	62%
Gases[1]	1,063	238	825	78%
Biomass	40,152	6,860	33,293	83%
Geothermal	187	14	173	92%
Onshore wind	99,166	3,495	95,672	96%
Offshore wind	24,379	0	24,379	100%
Solar	41,383	28,457	12,926	31%
Total	**211,879**	**41,182**	**170,697**	**81%**

[1] Landfill, sewage and mine gas

Table 30: Annual feed-in of electricity from installations with a fixed feed-in tariff and market premium

Electricity: breakdown by energy source of annual feed-in from installations with market premium for 2019

(%)

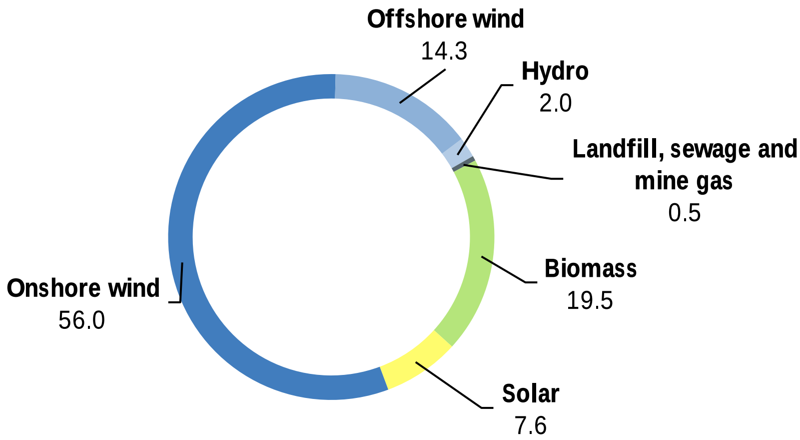


Figure 29: Breakdown of the annual feed-in from installations with market premium by energy source

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 19%), 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 (81%) 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 usually made from the year in which the installation is commissioned and for a subsequent period of 20 years.

In 2019 a total of €27.6bn 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 2019 the majority of payments were made to installation operators entitled to the market premium (feed-in tariff: 45.5%, market premium: 59.5%). Market premiums again rose in comparison with the previous year (2018: 54.5%).

Solar installations (€11.0bn), biomass installations (€6.6bn) and onshore wind installations (€5.8bn) accounted for significant shares of these payments.

Electricity: payments by energy source

	Total 31 December 2018 (€ million)	Total 31 December 2019 (€ million)	Increase / Decrease compared to 2018 (%)
Hydro	348	400	14.7%
Gases[1]	45	45	1.8%
Biomass[2]	6,393	6,603	3.3%
Geothermal	35	40	14.6%
Onshore wind	4,859	5,817	19.7%
Offshore wind	2,850	3,731	30.9%
Solar	11,176	10,996	-1.6%
Total	25,706	27,633	7.5%

[1] Landfill, sewage and mine gas

[2] Including support for flexibility

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

Figure 30 shows that, compared with the previous year, payments increased by 7.5% and payments for offshore wind installations increased in particular in correlation with the increase in annual energy feed-in, see Table 30.

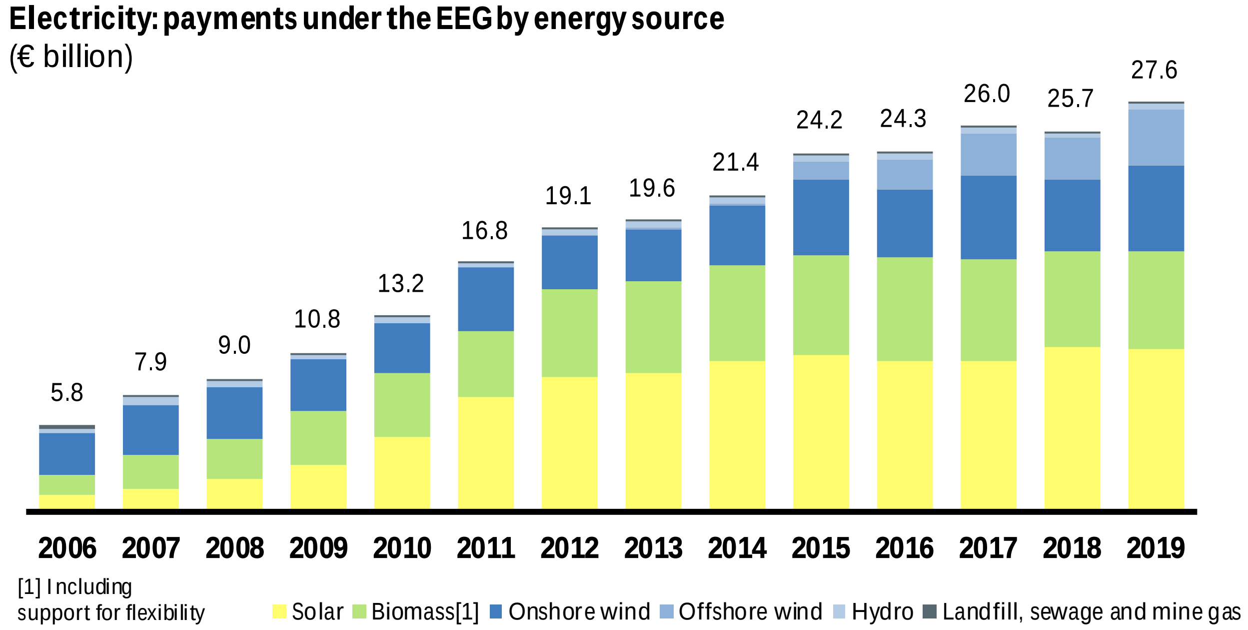


Figure 30: Changes in payments under the EEG by energy source

Renewable energy operators received an average of 13.0 ct/kWh in payments under the EEG [45] in 2019. Payments for the different energy sources varied significantly, however. For example, operators of solar installations received an average of 26.6 ct/kWh in 2019, while operators of onshore wind installations received an average of 5.9 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 31 shows the average payments under the EEG compared with previous years.

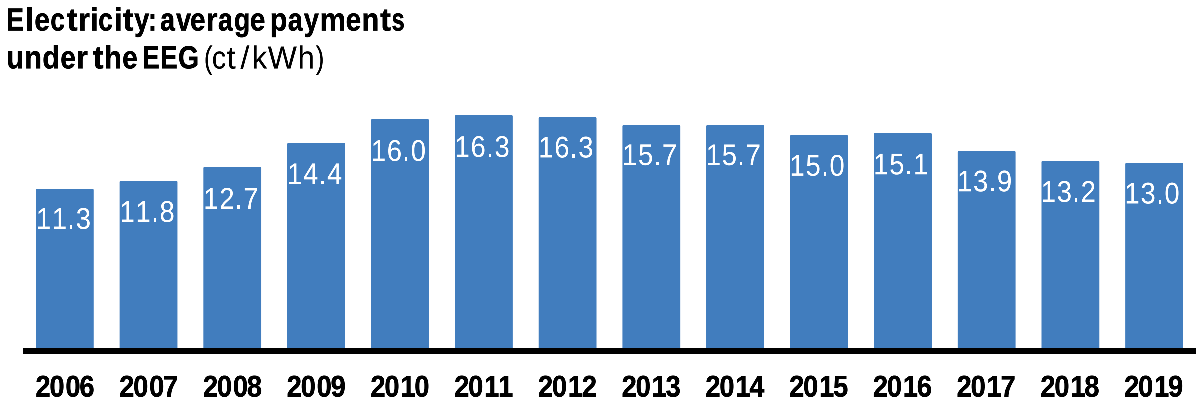


Figure 31: Changes in average payments under the EEG

2.2.2 Changes in the EEG surcharge

Payments under the EEG are for the most part refinanced through the EEG surcharge. Figure 32 shows that the EEG surcharge has been comparatively stable at between 6.2 and 6.9 ct/kWh since 2014, despite the capacity for which payments are made under the EEG since 2014 having increased by almost 50%. 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.

EEG payments have been covered entirely by the EEG surcharge up to 2020. Pro-rata federal funding will be provided for the first time in 2021. The EEG surcharge peaked at 6.5 ct/kWh in 2021. The additional financial resources are financed by federal subsidies. This prevents a sharp year-on-year increase in the surcharge, which would otherwise have occurred as a result of the Covid-19 pandemic. It is, however, slightly lower than in 2020. The EEG surcharge has been capped at 6 ct/kWh.

The Covid-19 pandemic has generated considerable additional financial requirements because the revenues generated from the surcharge have fallen as less electricity has been consumed and because revenues from the sale of renewable electricity on power exchanges also went down as wholesale prices fell. Together these resulted in a record deficit on the EEG account, which must be balanced in 2021.

[45] 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.

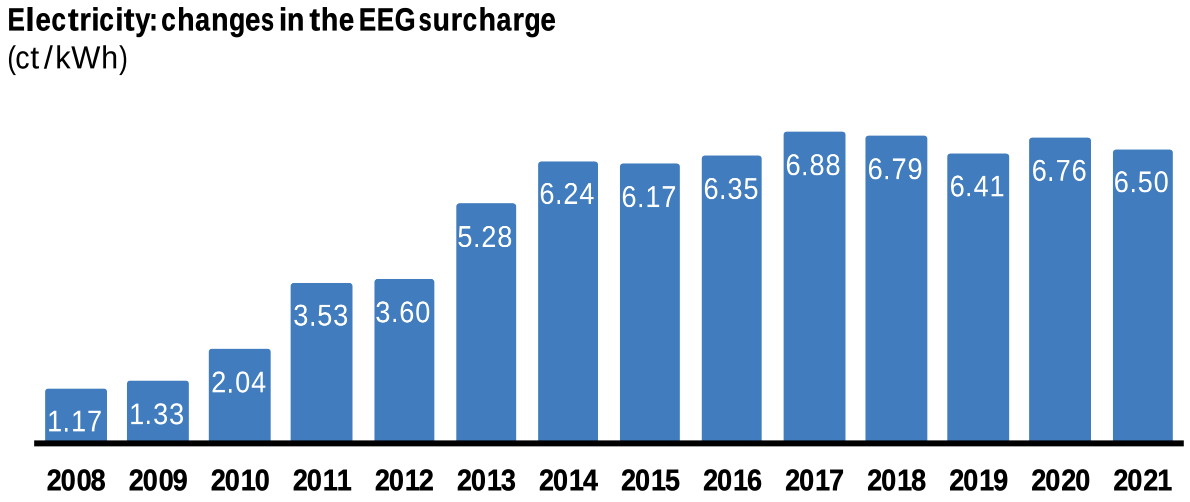


Figure 32: Changes in the EEG surcharge

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. 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, 2019 and 2020, a substantial rise in solar was recorded and this meant that the target corridor in the respective reference periods was exceeded. The value to be applied was therefore reduced by 1.4% in almost every month from May 2019. The only exceptions are the months November 2019 to January 2020 during which expansion only slightly exceeded the target corridor and resulted in a small reduction of 1.0%.

Since 1 January 2019, the remuneration for electricity from onshore wind installations that 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 of 4.63 ct/kWh was applied for wind installations commissioned in 2019 and 6.04 ct/kWh for wind installations commissioned in 2020.

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	2400 - 2600 (gross)	2,398	0.25%	monthly	Q3 2014
Dec 2013 - Nov 2014		1,953	0.25%		Q1 2015
Mar 2014 - Feb 2015		1,811	0.25%		Q2 2015
Jun 2014 - May 2015		1,581	0.25%		Q3 2015
Sep 2014 - Aug 2015		1,437	0.0%		Q4 2015
Dec 2014 - Nov 2015		1,419	0.0%		Q1 2016
Mar 2015 - Feb 2016		1,367	0.0%		Q2 2016
Jun 2015 - May 2016		1,336	0.0%		Q3 2016
Sep 2015 - Aug 2016		1,096	0.0%		Q4 2016
Fixed in EEG 2017	2500 (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. 2017) 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 2018 - 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
(Jul 2019 - Dec 2019) x2		2,936	1.4%		Feb 20 - Apr 20
(Oct 2019 - Mar 2020) x2		3,242	1.4%		May 20 - Jul 20
(Jan 2020 - Jun 2020) x2		3,800	1.4%		Aug 20 - Oct 20

Table 32: Lowering of the values to be applied – solar energy

2.3 Auctions

Operators of new onshore wind, offshore wind and biomass plants only receive EEG payments if they have successfully participated in an auction. This affects around 80% of new EEG-funded renewable capacity. 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 I.B.1.9.3).

In addition to technology-specific auctions for onshore wind, offshore wind, solar and biomass installations (since 2017), cross-technology auctions were held for the first time in 2018 for onshore and solar installations. The first technology-neutral innovation auction was held in 2020.

There were 43 auction rounds in the 2019-2020 period with the following results:

Electricity: technology-specific auction rounds for solar and onshore wind installations 2019 - 2020

Technology	Tendering dates	Winning bids (ct/kWh)*
Solar	01.02.2019	4.80
	01.03.2019	6.59
	01.06.2019	5.47
	01.10.2019	4.90
	01.12.2019	5.68
	01.02.2020	5.01
	01.03.2020	5.18
	01.06.2020	5.27
	01.07.2020	5.18
	01.09.2020	5.22
	01.10.2020	5.23
	01.12.2020	n.v.
Onshore wind	01.02.2019	6.11
	01.05.2019	6.13
	01.08.2019	6.20
	02.09.2019	6.19
	01.10.2019	6.20
	01.12.2019	6.11
	01.02.2020	6.18
	01.03.2020	6.07
	01.06.2020	6.14
	01.07.2020	6.14
	01.09.2020	6.20
	01.10.2020	6.11
	01.12.2020	n.v.

*Volume-weighted average winning bid; for solar power, the winning bid is applied prior to receipt of second securities.

Table 33: Auctions held in 2019 and 2020 for solar and onshore wind installations

Electricity: other auctions rounds held from 2019 - 2020

Technology	Tendering dates	Winning bids (ct/kWh)*
CHP	01.06.2019	3.95
	01.12.2019	5.12
	01.06.2020	6.23
	01.12.2020	n.v.
Innovative CHP systems	01.06.2019	11.17
	01.12.2019	10.25
	01.06.2020	10.63
	01.12.2020	n.v.
Biomass	01.04.2019	12.34
	01.11.2019	12.47
	01.04.2020	13.99
	01.11.2020	14.85
Onshore wind and solar across all technologies	01.04.2019	5.66
	01.11.2019	5.40
	01.04.2020	5.33
	01.11.2020	5.33
Innovation auction: Single systems	01.09.2020	2.65
Innovation auction: System combinations	01.09.2020	4.50

*Volume-weighted average winning bid; for solar power, the winning bid is applied prior to receipt of the second security deposit.

Table 34: Auctions held in 2019 and 2020 for biomass, CHP, cross-technology and innovative technologies

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). In 2019, five auction rounds were held for 1,475 MW. A total of 308 solar projects (bids) with a volume of 1,592 MW were awarded a tender. Seven auction rounds for 1,299 MW were held in 2020. By the sixth round in October 2020, 1,056 MW for 25 solar projects had been awarded a tender.

The bid volumes for all photovoltaic auctions have so far been significantly oversubscribed. The initial sharp decline in the award price in the first four auction rounds between February 2017 and February 2018 (6.58 ct/kWh to 4.91 ct/kWh) was not sustained in subsequent rounds. In the course of 2019 award prices generally rose slightly to between 4.80 ct/kWh (February 2019) and 5.68 ct/kWh (December 2019) with one outlier for the special auction in March 2019: A bid volume of 500 MW for this special auction and a maximum permitted price of 8.91 ct/kWh resulted in a significantly higher average award price of 6.59 ct/kWh. An adjustment of the permissible maximum price to 7.50 ct/kWh successfully slowed this upward movement. In the first six auctions of the year 2020 award prices settled in the lower 5 ct range and oscillated between 5.01 ct/kWh (February) and 5.27 ct/kWh (June).

Average award prices have fallen by 21% since auctions were introduced for all solar installations in 2017. The highest award price in the period under review was 6.59 ct/kWh (March 2019) and the lowest award price was 4.33 ct/kWh (February 2018). The current average payment (in October 2020) for new solar installations determined by auction up to 2022 is 5.23 ct/kWh. This price realistically reflects average solar power generation costs.

Electricity: implementation rates for solar installations from solar auctions with expired implementation periods

Tendering date	Implementation status (%)	Commissioning period (exclusion deadline)	Basis of tender
15.04.2015	99	06.05.2017	FFAV
01.08.2015	90	20.08.2017	FFAV
01.12.2015	92	18.12.2017	FFAV
01.04.2016	100	18.04.2018	FFAV
01.08.2016	96	12.08.2018	FFAV
01.12.2016	73	15.12.2018	FFAV
01.11.2016	99	05.12.2018	GEEV
01.02.2017	99	15.02.2019	EEG
01.06.2017	97	21.06.2019	EEG
01.10.2017	35	23.10.2019	EEG
01.02.2018	44	27.02.2020	EEG
01.06.2018	83*	21.12.2020	EEG

*Provisional figures - The original implementation period has been extended by six months by law as a result of the Covid-19 pandemic.

Table 35: Implementation rates for all solar auctions

Awards must be implemented within 18 to 24 months. From the previous 25 rounds (including FFAV and GEEV) in addition to the six completed auction rounds under the Ground-mounted PV Auction Ordinance (FFAV), the implementation periods for the first six solar photovoltaic auction rounds under the EEG and the Cross-Border Renewable Energy Ordinance (GEEV) have expired. These all have high rates of implementation (Table 35), which is regarded as a success. The only auction rounds to deviate from this success are those completed in October 2017 and February 2018, which had implementation rates of just 35% and 44% respectively. The main reason for this was the failure to implement two very large solar projects. As a result of the Covid-19 pandemic, the implementation periods for all tenders awarded prior to 1 March 2020, and for those whose implementation periods have not yet expired, have been extended by six months. This means that the ultimate rates of implementation for the June and October 2018 auction rounds will only be apparent at the end of 2020 or in March 2021. The implementation periods for all other auction rounds have not yet expired either.

Electricity: solar auctions in 2019

	Feb	March	June	Oct	Dec
Volume put up for auction (MW)	175	500	150	150	500
Submitted bids	80	163	105	153	346
Submitted bid volume (MW)	465	869	556	648	1,344
Winning bids*	24	121	14	27	122
Volume awarded (MW)*	178	505	205	153	551
Excluded bids	2	17	13	11	76
Volume of excluded bids (MW)	6	192	46	44	235
Maximum rate (ct/kWh)	8.91	8.91	7.50	7.50	7.50
Average volume-weighted winning bid (ct/kWh)	4.80	6.59	5.47	4.90	5.68
Lowest bid (awarded) (ct/kWh)	4.11	3.90	4.97	4.59	4.70
Highest bid (awarded) (ct/kWh)	5.18	8.40	5.58	5.20	6.20

**Prior to receipt of the second security deposit.

Table 36: Solar auctions in 2019

Electricity: solar auctions in 2020*

	Feb	March	June	July	Sep	Oct
Volume put up for auction (MW)	100	300	96	193	257	96
Submitted bids	98	190	101	174	163	87
Submitted bid volume (MW)	493	838	447	779	675	393
Winning bids**	18	51	21	30	75	30
Volume awarded (MW)**	101	301	100	193	258	103
Excluded bids	12	9	9	18	16	9
Volume of excluded bids (MW)	77	35	18	70	73	37
Maximum rate (ct/kWh)	7.50	7.50	7.50	7.50	7.50	7.50
Average volume-weighted winning bid (ct/kWh)	5.01	5.18	5.27	5.18	5.22	5.23
Lowest bid (awarded) (ct/kWh)	3.55	4.64	4.90	4.69	4.80	4.98
Highest bid (awarded) (ct/kWh)	5.21	5.48	5.40	5.36	5.39	5.36

*The date of the December auction round for the 2020 period is not available

**Prior to receipt of the second security deposit.

Table 37: Solar auctions in 2020

Figure 33 shows that over 50% of the bids awarded for solar photovoltaic auctions in 2019 and 2020 were concentrated in Bavaria, in part due to the increase from 70 to 200 bids awarded following the amendment of the ordinance in Bavaria that opens up disadvantaged areas for solar farms.

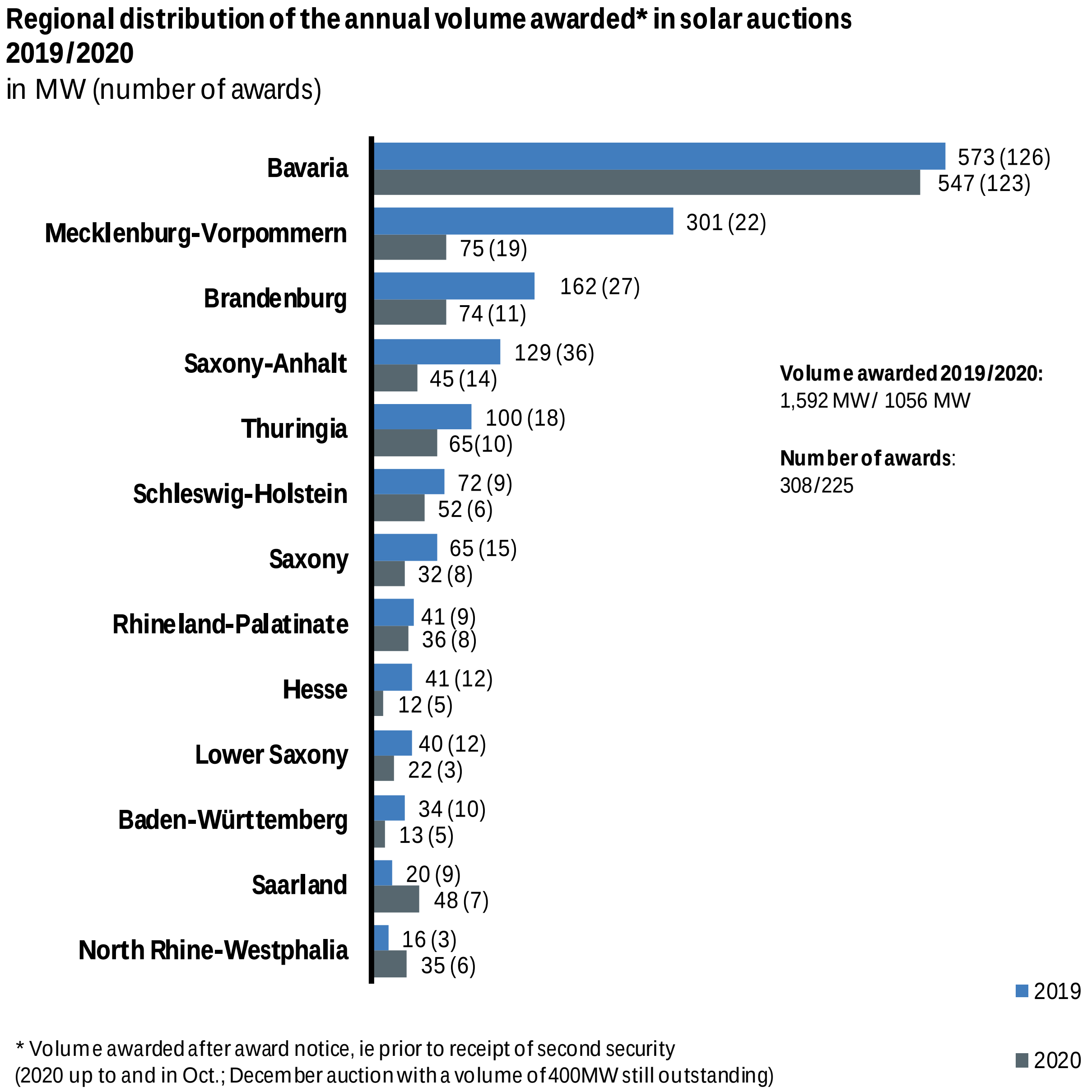


Figure 33: Regional distribution of the annual volume awarded in EEG solar auctions 2019/2020

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. 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.

In 2019, auctions were held for 3,675 MW in six different auction rounds. In 2020, seven auctions were held for 3,493 MW. Five of six rounds in 2019 were significantly undersubscribed. A volume of just 1,846 MW was awarded and the envisaged development corridor was consequently not reached. Only the last round in December was slightly oversubscribed (Table 38). The picture remained unchanged in 2020. All the rounds up to the sixth, which was held in October, were largely oversubscribed. The lack of competition was reflected by the high award prices, all of which are just below the highest bid of 6.2 ct/kWh (Table 39). In the period under review from February 2019 – October 2020, the lowest average award price of 6.07 ct/kWh was achieved in the March 2020 auction round.

One major reason for the lack of participation in the tenders for onshore wind is the lack of federal immission control permits, which must be submitted for participation in the tendering procedure. Decision-making in approval procedures for wind power plants is subject to various nature conservation and species protection regulations, construction planning and regional planning law, as well as aviation law. Nature conservation and species protection law, in particular, make it difficult to obtain new permits for the building of onshore wind installations. Since autumn 2018, various working groups have been trying to identify the reasons why permits are so difficult to obtain and are working on ways of reviving the expansion of onshore wind energy as a mainstay of the energy transition. A tentative increase in the number of permits being issued suggests that this may be successful.

Electricity: auctions for onshore wind plants in 2019

	Feb	May	Aug	Sep	Oct	Dec	2019 total
Volume put up for auction (MW)	700	650	650	500	675	500	3,675
Submitted bids	72	41	33	22	25	76	269
Submitted bid volume (MW)	499	295	239	188	204	686	2,111
Submitted bid volume (MW) in grid expansion area (NAG)	156	67	16	45	29	104	417
Winning bids	67	35	32	21	25	56	236
Volume awarded (MW)	476	270	208	179	204	509	1,846
Volume awarded in the NAG (MW)	0	0	16	37	29	97	178.75
Excluded bids	5	6	1	1	0	2	15
Excluded bids in MW	23	25	31	8	0	28	115
Maximum rate (ct/kWh)	6.20	6.20	6.20	6.20	6.20	6.20	6.20
Average volume-weighted winning bid (ct/kWh)	6.11	6.13	6.20	6.19	6.20	6.11	6.16
Lowest bid (awarded) (ct/kWh)	5.24	5.94	6.19	6.19	6.19	5.74	5.92
Highest bid (awarded) (ct/kWh)	6.20	6.20	6.20	6.20	6.20	6.18	6.20

Table 38: Auctions for onshore wind energy 2019

Electricity: auctions for onshore wind installations in 2020

	Feb	March	June	July	Sep	Oct	Dec
Volume put up for auction (MW)	900	300	826	275	367	826	367
Submitted bids	67	25	62	26	25	89	n.v.
Submitted bid volume (MW)	527	194	468	191	310	769	n.v.
Submitted bid volume (MW) in grid expansion area (NAG)	115	85	148	57	72	349	n.v.
Winning bids	66	20	61	26	25	74	n.v.
Volume awarded (MW)	523	151	464	191	287	659	n.v.
Volume awarded in the NAG (MW)	115	56	148	57	87	268	n.v.
Excluded bids	1	2	1	0	2	3	n.v.
Excluded bids in MW	4	18	4	0	23	48	n.v.
Maximum rate (ct/kWh)	6.20	6.20	6.20	6.20	6.20	6.20	6.20
Average volume-weighted winning bid (ct/kWh)	6.18	6.07	6.14	6.14	6.20	6.11	n.v.
Lowest bid (awarded) (ct/kWh)	5.76	5.74	5.90	6.00	5.99	5.60	n.v.
Highest bid (awarded) (ct/kWh)	6.20	6.20	6.20	6.20	6.20	6.20	n.v.
Highest bid in the NAG (awarded) (ct/kWh)	Not relevant	5.98	Not relevant			n.v.	

Table 39: Auctions for onshore wind energy 2020

From a regional perspective (Table 40), 76% of the volume awarded in wind energy auctions in 2019 was concentrated on the four federal states of Brandenburg (26%), North Rhine-Westphalia (22%), Lower Saxony (19%) and Schleswig-Holstein (9%). In 2020, 71% of the volume awarded was also concentrated in these federal states.

Electricity: distribution of bids and awards for onshore wind energy per federal state 2019 - 2020*

	Number of bids		Capacity bids in kW		Number of awards		Awarded capacity in kW	
Federal state	**2020**	**2019**	**2020**	**2019**	**2020**	**2019**	**2020**	**2019**
Baden-Württ.	8	6	79,500	43,400	8	5	79,500	26,600
Bavaria	2	7	27,000	34,730	1	6	13,500	31,130
Berlin	1	0	4,200	0	1	0	4,200	0
Brandenburg	35	61	427,600	539,600	33	58	394,000	472,850
Hesse	5	11	71,900	67,180	5	11	71,900	67,180
Meckl.-Vorp.	9	6	115,900	57,100	6	6	99,200	57,100
Lower Saxony	40	39	443,650	392,730	38	36	418,450	355,930
N. Rhine-W.	60	61	374,400	483,370	58	48	367,300	402,080
Rhinel.-Pal.	12	5	90,200	32,800	12	5	90,200	32,800
Saarland	0	6	0	42,900	0	6	0	42,900
Saxony	7	4	60,600	6,300	6	3	49,400	5,500
Saxony-Anhalt	12	11	149,300	102,900	12	9	149,300	92,100
Schlesw.-Holst.	83	30	511,840	188,150	68	27	429,090	172,850
Thuringia	21	22	106,500	120,160	21	16	106,500	87,760
Total	**295**	**269**	**2,462,590**	**2,111,320**	**269**	**236**	**2,272,540**	**1,846,780**

*Auction rounds in February, May, August, September and October 2020

Table 40: Distribution of bids and awards per federal state

2.3.3 Other auctions (offshore wind, biomass, joint and innovation auctions)

No offshore wind auctions were held in the 2019 – 2020 period. The next auction will take place in 2021. For the first time, this auction will be for a pre-assessed site and defined installed capacity.

Biomass auctions

The Bundesnetzagentur has held six auction rounds since the auction procedure was introduced for biomass installations in 2017. An annual rhythm at the start has been followed by bi-annual rounds in April and November since 2019. In each of the two rounds 100 MW will be put out to tender; this volume is adjusted upwards largely due to the bid volumes not awarded in the previous year. As a result, a total of 267 MW and of 335 MW were auctioned in 2019 and 2020 respectively.

One particular feature of this procedure is that installations that are already in operation are also able to take part in auctions if they are only eligible for payments under the EEG for a maximum of a further eight years. Consequently, most of the submitted bid volume in all the rounds was for existing biomass installations.

So far all auction rounds have been significantly oversubscribed. This trend also continued in 2019 and 2020. The volume-weighted average for all winning bids was 12.45 ct/kWh in 2019 and 14.02 ct/kWh in 2020. The medium winning bids for new installations were 14.57 ct/kWh in 2019 and 14.44 in 2020. On average, bids for existing installations with installed capacity exceeding 150 kW were awarded at 12.30 ct/kWh in 2019 and 13.56 ct/kWh in 2020. Bids for existing installations with installed capacity equal to or less than 150 kW were, on average, awarded at 16.56 ct/kWh in 2019 and 16.40 ct/kWh in 2020. 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 2019

	1 April 2019			1 November 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)	133,293			133,293		
Submitted bids	2	2	15	2	12	42
Submitted bid volume (MW)	2,966	85	22,477	18,150	881	57,772
Winning bids	2	2	15	1	9	40
Volume awarded (MW)*	2,966	85	22,477	1,150	708	54,867
Excluded bids	0	0	0	1	3	2
Volume of excluded bids (MW)	0	0	0	17,000	173	2,905
Maximum rate (ct/kWh)	14.58	16.56	16.56	14.58	16.56	16.56
Average volume-weighted winning bid (ct/kWh)	14.57	16.56	12.12	14.58	16.56	12.37

Table 41: Biomass auctions in 2019

Electricity: biomass auctions in 2020

	1 April 2020			1 November 2020		
	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)		167,770			167,770	
Submitted bids	5	5	31	n.v.	n.v.	n.v.
Submitted bid volume (MW)	43,126	396	48,964	n.v.	n.v.	n.v.
Winning bids	5	5	28	n.v.	n.v.	n.v.
Volume awarded (MW)*	43,126	396	46,934	n.v.	n.v.	n.v.
Excluded bids	0	0	3	n.v.	n.v.	n.v.
Volume of excluded bids (MW)	0	0	2,030	n.v.	n.v.	n.v.
Maximum rate (ct/kWh)	14.44	16.40	16.40	14.44	16.40	16.40
Average volume-weighted winning bid (ct/kWh)	14.44	16.40	13.56	14.44	16.40	13.56

Table 42: Biomass auctions in 2020

Joint auction for wind and solar installations

The Bundesnetzagentur has held six technology-neutral (joint) auctions for onshore wind and solar installations twice a year since 2018. One special feature of these auctions was that account has been taken of a distribution network expansion area, ie 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 photovoltaic and onshore wind installations

	2020		2019	
	November	**April**	**November**	**April**
Volume put up for auction (MW)	200	200	200	200
Submitted bids	91	113	103	109
Submitted bid volume (MW)	518	553	514	720
Winning bids*	43	30	37	15
Total volume awarded in MW*	202	204	203	201
Volume of winning bids, solar in MW*	202	204	203	201
Volume of winning bids, wind in MW	-	-	-	-
Excluded bids	7	12	13	18
Volume of excluded bids (MW)	43	24	86	58
Maximum rate (ct/kWh)	7.50	7.50	7.50	8.91
Average volume weighted winning bid (ct/kWh)	5.33	5.33	5.40	5.66
Lowest bid (awarded) (ct/kWh)	5.18	4.97	4.88	4.50
Highest bid (awarded) (ct/kWh)	5.45	5.61	5.74	6.10

*Winning bid after receipt of second security deposits for solar bids.

Table 43: Joint auctions for onshore wind and solar energy 2019/ 2020

The joint auctions for onshore wind and solar energy are always very well frequented or significantly oversubscribed. In contrast to 2018 (19 bids – no awards), not a single wind project took part in an auction in either 2019 or 2020. 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. In this respect, the joint auctions may also be considered as additional solar auctions, which are also characterised by lively competition.

The volume-weighted average award price fell from 5.66 ct/kWh in the first 2019 round in April to 5.40 ct/kWh in the second round in November. In 2020, the award prices dropped again to 5.33 ct/kWh. The results are comparable with the prices awarded in the technology-specific solar auctions in 2019 and 2020. They are slightly higher.

The special arrangements for distribution network expansion areas did not especially impact the award decision continually in either of the auction rounds.

Innovation auctions individual renewable energy sources (wind, solar, biomass) or combinations or grouping of different renewable energy sources

The Bundesnetzagentur held its first innovation auction under the Innovation Auction Ordinance (InnAusV) in September 2020. In the first round of this new type of tendering procedure, bids could either be submitted for individual renewable technologies (onshore wind, biomass and solar) or for combinations of several installations using different renewable energies or of combined renewable generation and storage systems.

In addition to the new target group of system combinations, one of the key innovative elements in the auction design was the introduction of the payment of a fixed instead of a sliding premium as well as endogenous volume management in the absence of competition (subscription to the auction volume). The reference yield model and special arrangements for citizens' energy companies do not apply to onshore wind installations.

The first auction round for 650MW was substantially oversubscribed, with 133 bids for a bid volume of 1,095 MW. Most bids were for system combinations (785 MW for 83 bids). The remaining bids (310 MW for 50 bids) were for individual solar installations. Renewable onshore wind and biomass technologies and biomass played no role at all for individual installations. A total of 73 bids with a total capacity of 677 MW were successful, including 394 MW for 28 system combinations. The selection of system combination was dominated by the combination of solar installations with storage.

The highest bids were 3.0 ct/kWh for single systems and 7.5 ct/kWh for system combinations. The average award price corresponding to a fixed payable premium was 2.65 ct/kWh for single systems (for awards of between 0.96 ct/kWh and 3 ct/kWh) and 4.50 ct/kWh for system combinations (for awards of between 1.94 ct/kWh and 5.52 ct/kWh).

C Networks

1. Current status of grid expansion

As part of its monitoring, the Bundesnetzagentur provides quarterly updates on the progress in planning and construction that has occurred for individual projects in the transmission system during the previous three months. This covers the projects from the Federal Requirements Plan Act (BBPlG) and the Power Grid Expansion Act (EnLAG). The Bundesnetzagentur publishes the updates on its website at www.netzausbau.de/vorhaben.

1.1 Monitoring of EnLAG projects

The current version of the law contains 22 projects that require urgent implementation in order to meet energy requirements. Project nos 22 and 24 were deleted after a review was carried out during the process of drafting the Electricity Network Development Plans (NDPs) 2022 and 2024. Six of the 22 projects have been designated as pilot projects for underground cabling. These projects have been earmarked as feasible for partial undergrounding under certain conditions.

The individual federal state authorities are responsible for conducting the spatial planning and planning approval procedures for the EnLAG projects.

Current status

The projects currently listed in the EnLAG (as at the third quarter of 2020) comprise lines with a total length of some 1,831 km. Around 8 km are currently in the spatial planning procedure and around 271 km are in or about to start the planning approval procedure. A total of 558 km have been approved and are under or about to start construction, and 994 km have been completed.

The following map shows the status of the EnLAG projects in the third quarter of 2020.

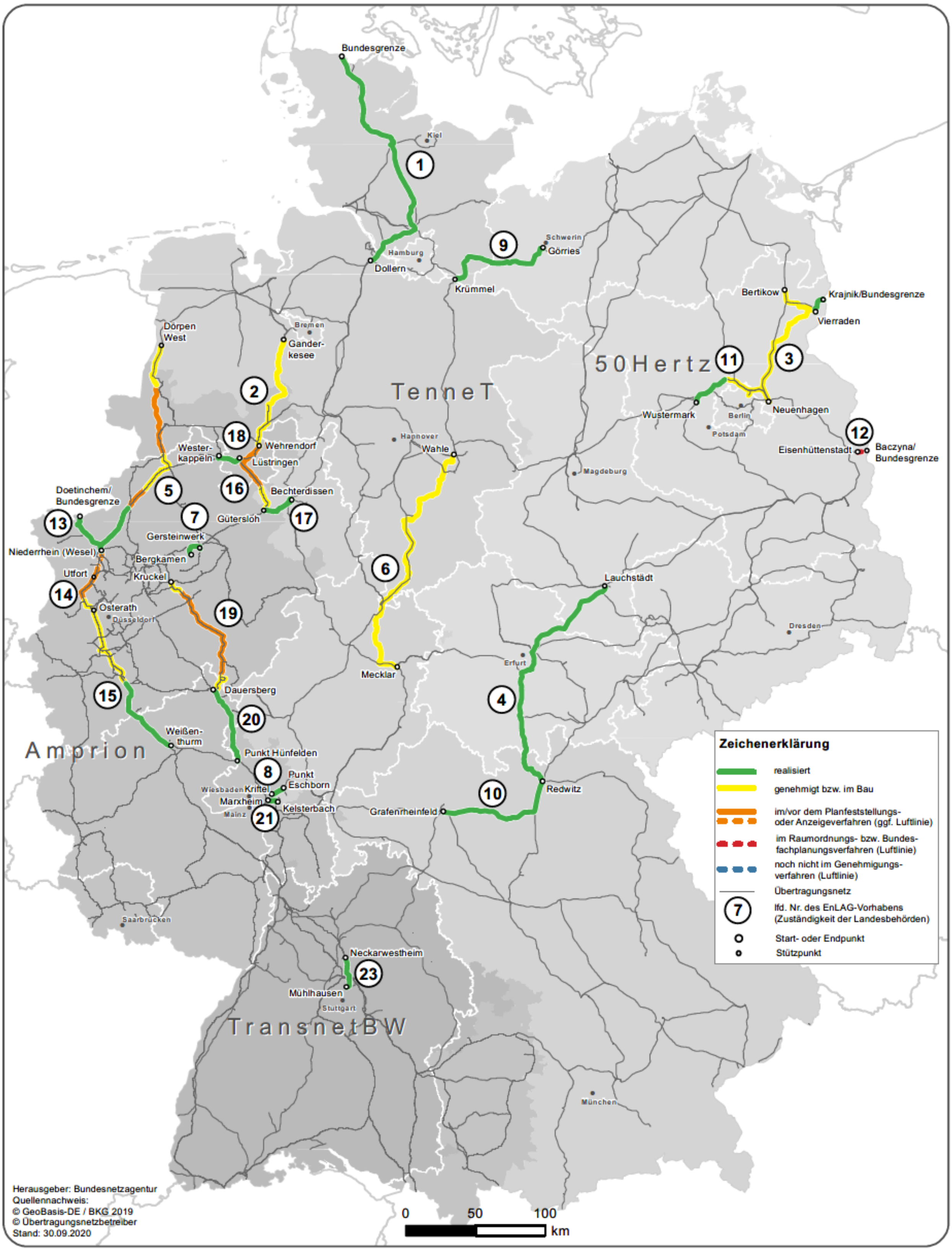


Figure 34: Status of EnLAG line expansion projects: 3rd quarter 2020

1.2 Monitoring of BBPlG projects

The current version of the law contains 43 projects that have been confirmed as necessary to meet energy supply requirements and that require urgent implementation in order to guarantee secure and reliable network operation. Of these 43 projects, 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 possible partial undergrounding. In addition, one project is a pilot project using high-temperature superconductors and two are submarine cable projects.

Current status

The projects listed in the BBPlG comprise lines with a total length of about 5,868 km (as at the third quarter of 2020). The 16 projects designated as crossing federal state or national borders, which fall under the responsibility of the Bundesnetzagentur, account for around 3,542 km of this total. The total length of the lines in Germany will largely depend on the route of the north-south corridors and will become apparent in the course of the procedure.

At the end of the third quarter of 2020, some 753 km were ready to start the planning approval procedure. Around 1,710 km are in the spatial planning or federal sectoral planning procedure, and 2,724 km are in or about to start the planning approval or notification procedure. A total of 254 km have been approved and are under or about to start construction,
and 511 km have been completed. Additionally, approximately 100 km have already been approved in the procedures carried out by the Federal Maritime and Hydrographic Agency (BSH).

The following map shows the status of the BBPlG projects in the third quarter of 2020.

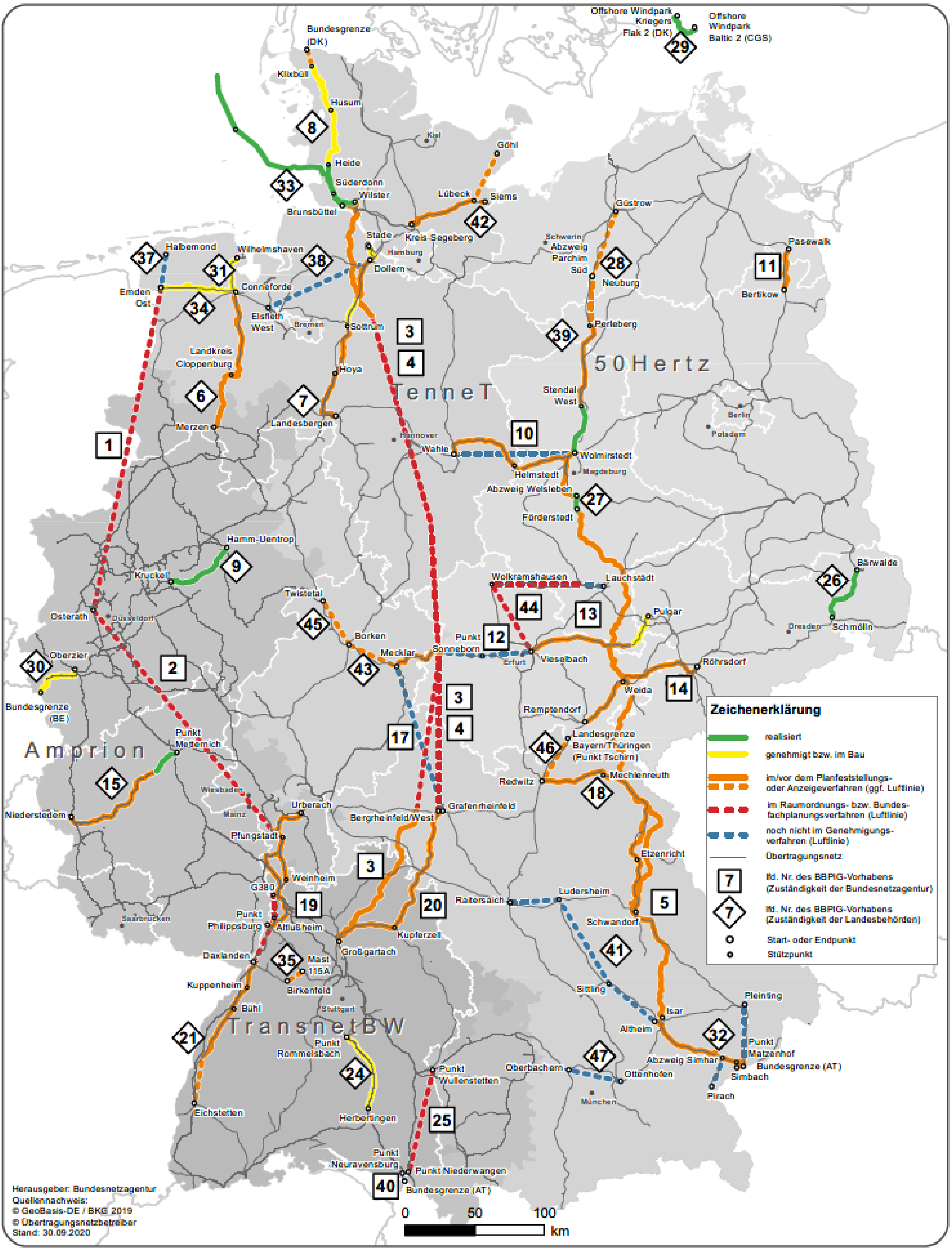


Figure 35: Status of BBPlG expansion projects: 3rd quarter 2020

1.3 Electricity network development plan status

The Bundesnetzagentur confirmed the Electricity Network Development Plan 2019-2030 (NDP 2019-2030) on 20 December 2019 and published it online at www.netzausbau.de, confirming 114 of the total 165 proposed projects. Public agencies and members of the public took a great interest in the confirmation process. A ten-week public participation process took place before the process of establishing requirements. The Bundesnetzagentur received over 800 responses to its consultation. It was confirmed that all the projects in the applicable Federal Requirements Plan from 2015 are still necessary.

The NDP 2019-2030 is the first NDP to include the planning for offshore transmission links, replacing the previous offshore NDP, and is based on the determinations of the site development plan (FEP). On the basis of the provisions of the FEP, the NDP defines the necessary offshore transmission links with their commissioning years and onshore grid connection points.

For the period up to 2030, seven or eight additional transmission links in the North Sea and Baltic Sea will be confirmed as necessary to connect offshore wind farms, depending on the scenario. The goal of connecting 20 GW of offshore wind farms by 2030 will therefore be possible.

1.4 Optimisation and reinforcement in the transmission networks

The NDP confirms the measures for optimising, reinforcing and expanding the grid in line with requirements that are effective and necessary for secure and reliable network operation up to 2030. The NDP process first identifies likely future restrictions in the grid. The measures that are necessary to ease the restrictions are determined following the three-step "NOVA" principle that all possible optimisation measures should be taken before reinforcement measures or, if necessary, expansion measures are considered.

Optimisation measures comprise various different measures that can be carried out in the existing grid with the aim of increasing the use of the existing grid and making the best possible use of the transmission capacity available. One example is increasing the voltage of an overhead line that is capable of operating at 380 kV but that is only operated at 220 kV. Another example is dynamic line rating (DLR) for overhead lines, which enables the use of existing lines to be varied depending on the weather conditions, as lines are capable of transmitting more electricity when it is windy or cool. In addition, flow management measures can be taken to optimise the use of existing networks. Such measures enable the active management of power flows in the highly meshed AC network and thus a more even use of the network. Looking ahead, innovative operational management concepts offer further potential for optimisation. The Bundesnetzagentur laid the groundwork for testing reactive network operating resources by confirming the "grid booster" pilot installations in the NDP 2019-2030.

Reinforcement measures comprise measures to replace or add to existing operating resources, for example in installations, by replacing cabling to uprate 220 kV overhead lines to 380 kV, by replacing cabling with high-current cables or high-temperature superconductors, by installing additional circuits on existing masts, or by installing new high-capacity lines along existing routes.

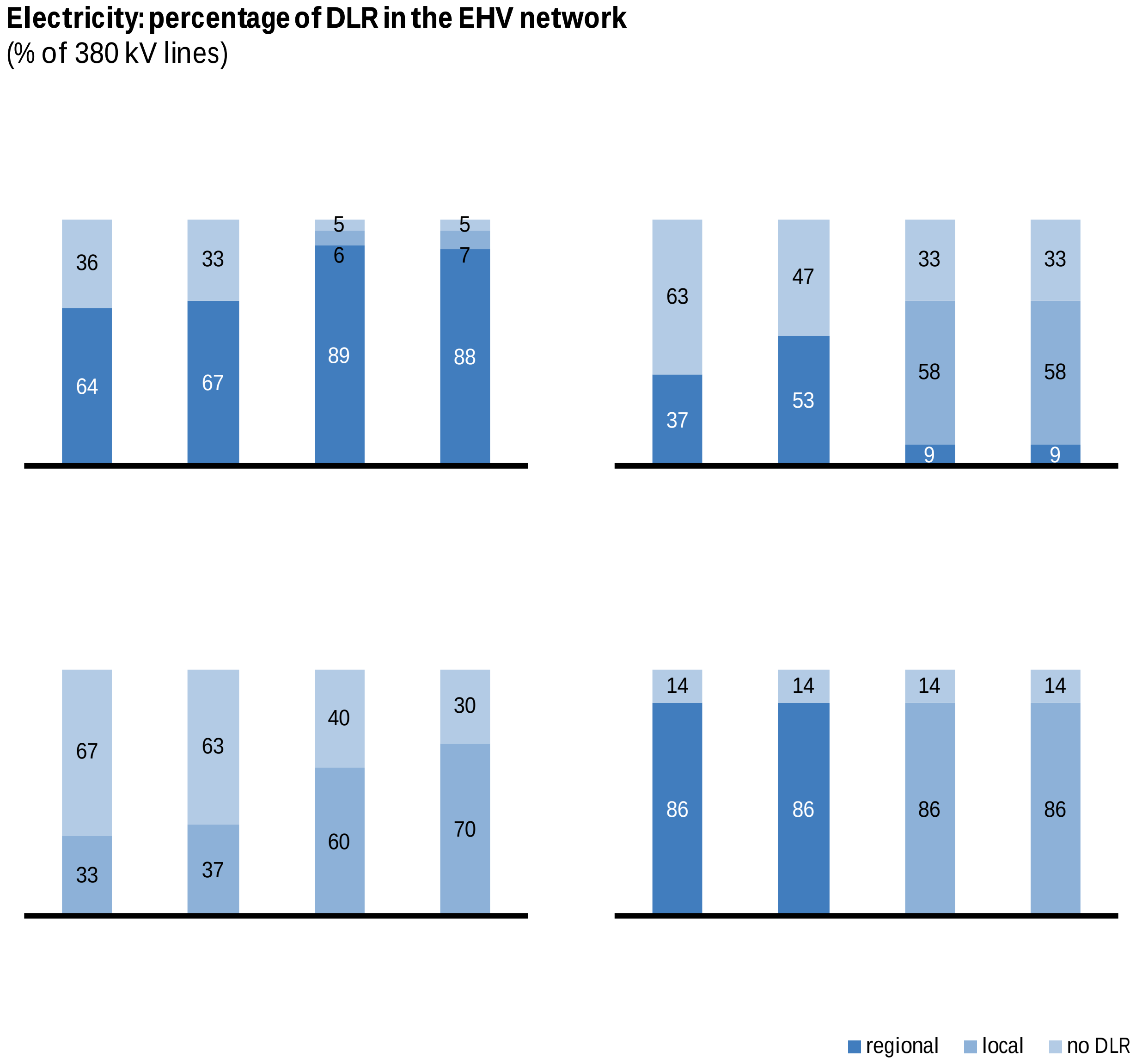


Figure 36: Percentage of overhead line DLR in the extra-high voltage (EHV) network (380 kV)[46]

Expansion measures in the narrower sense comprise measures to extend the network by adding new substations or adding lines along new routes.

[46] A distinction is made between two measurement methods for overhead line DLR:

regional: account is taken of regional weather conditions; fixed summer/winter periods with a different current carrying capacity (ampacity) for all circuits (deviations can be made depending on the weather conditions); general assumption for optimised line operation (following corresponding upgrading);

local: account is also taken of local weather conditions. (Definitions based on CIGRE.)

Electricity: percentage of DLR in the EHV network
(% of 220 kV lines)

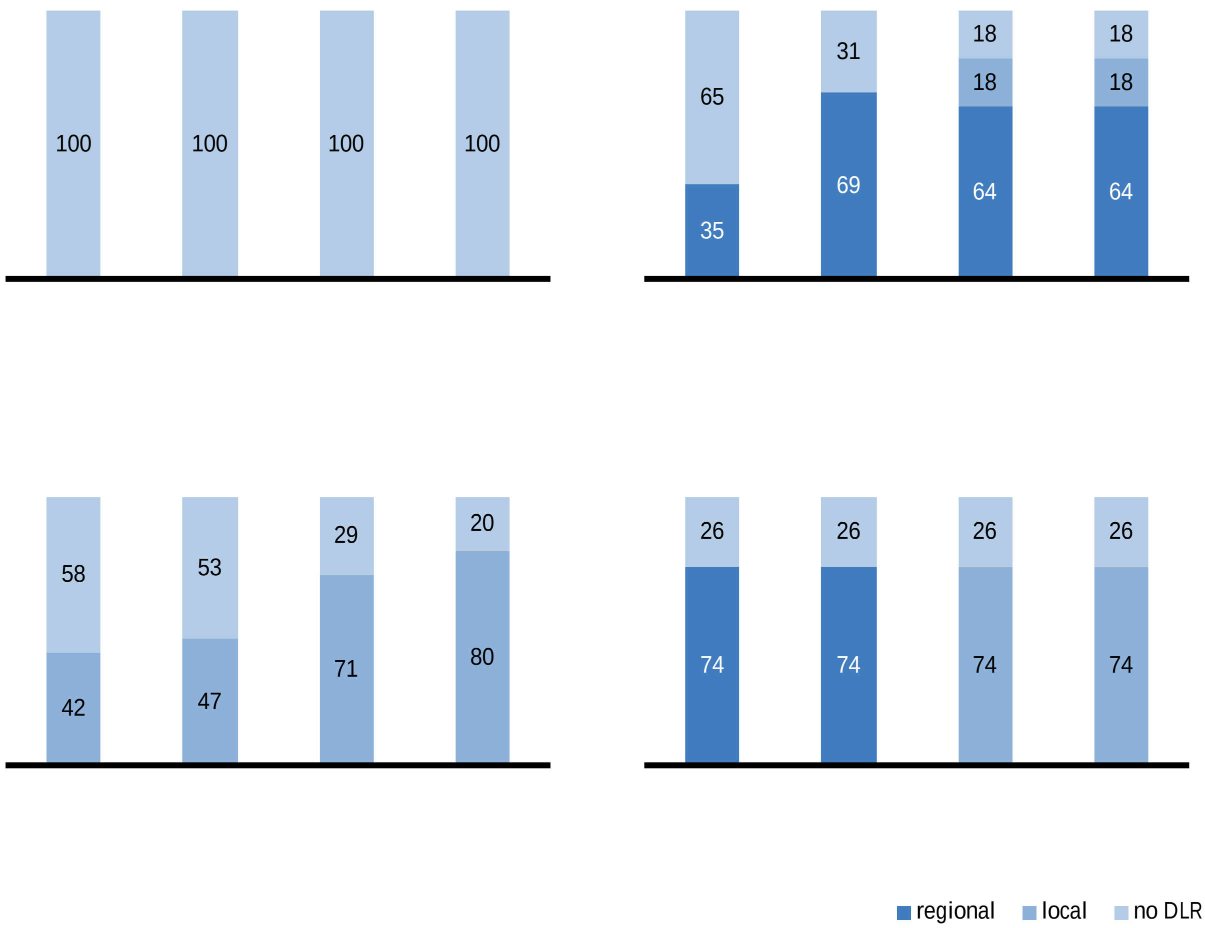


Figure 37: Percentage of overhead line DLR in the extra-high voltage (EHV) network (220kV)[47]

Such expansion measures are only proposed by the TSOs if optimisation and/or reinforcement measures are not sufficient or cannot be considered for other reasons.

Optimisation measures that are not explicitly proposed as measures, such as overhead line DLR, are assumed to have been carried out where technically feasible and legally permissible. For instance, the data are configured to assume that overhead line DLR – in other words increasing the ampacity of overhead lines in windy or cold conditions – is undertaken across the grid in the target year. Flow management measures that optimise the use of existing networks and an optimum network topology are also assumed in the planning.

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[47] A distinction is made between two measurement methods for overhead line DLR:
regional: account is taken of regional weather conditions; fixed summer/winter periods with a different current carrying capacity (ampacity) for all circuits (deviations can be made depending on the weather conditions); general assumption for optimised line operation (following corresponding upgrading);
local: account is also taken of local weather conditions. (Definitions based on CIGRE.)

However, new measures, such as new phase-shifting transformers, are generally included in the NDP and are subject to examination by the Bundesnetzagentur.

The NDP 2019-2030 assumed a greater use of optimisation measures in the existing grid compared to the NDP 2017-2030. These measures include improved overhead line DLR, the use of additional phase-shifting transformers to even out power flows, and the construction of pilot installations to test innovative network management concepts.

Two grid booster pilot installations and four phase-shifting transformers were approved in the NDP 2019-2030. A total of 11 phase-shifting transformers had been examined and confirmed as necessary in the NDP 2017-2030.

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 837 DSOs (845 in the previous year) provided information about the extent to which they had taken measures to optimise their networks. A total of 641 companies reported network optimisation measures.

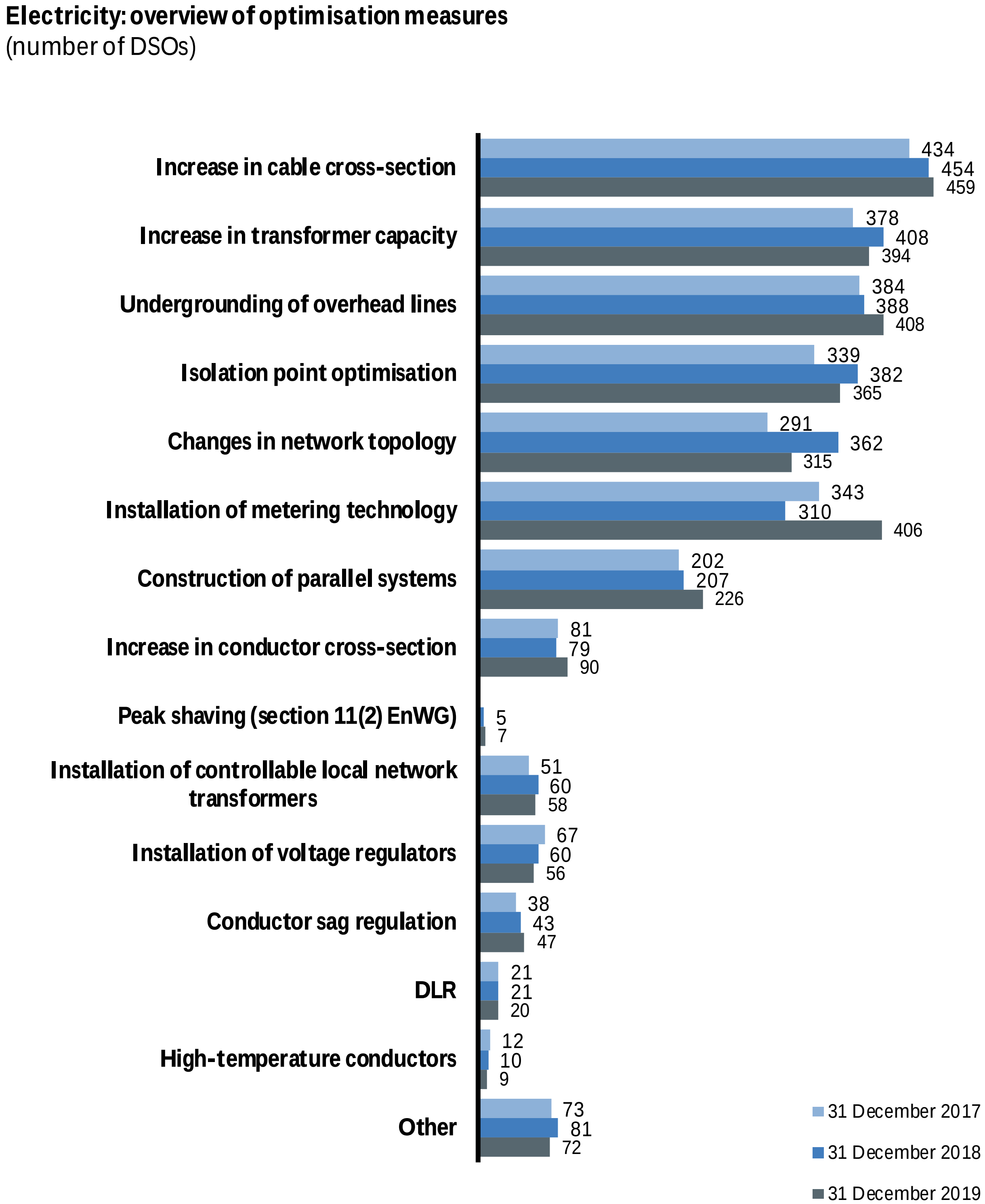


Figure 38: Overview of network optimisation measures

Figure 38 shows the measures implemented by the DSOs to optimise their networks. There were year-on-year decreases in particular in the number of measures involving changes to the network topology (-47 DSOs). There was a slight increase most notably in the number of measures for installing metering technology (+96 DSOs).

2.2 Future grid expansion requirements

The Bundesnetzagentur requests information from the DSOs about the status of their networks and their expansion plans for the next ten years on an annual basis pursuant to section 14(1a) and (1b) of the Energy Industry Act (EnWG) in order to be able to assess the DSOs' future grid expansion requirements. In 2020, 59 DSOs operating high-voltage (HV) (110 kV) networks were asked to report information pursuant to section 14(1a) and (1b) EnWG. One additional DSO particularly affected by feed-in management measures was also asked for information pursuant to section 14(1a) EnWG. The information from this DSO is not included below in order to be able to make a direct comparison with previous years. The information reported by the DSOs on the status of their networks and their expansion plans was current as at 31 December 2019. The reports submitted by the DSOs in 2020 cover about 98% of Germany's total circuit length at HV level, about 73% at medium-voltage (MV) level and even about 66% at low-voltage (LV) level.

Electricity: total grid expansion requirements of HV network operators
(€bn)

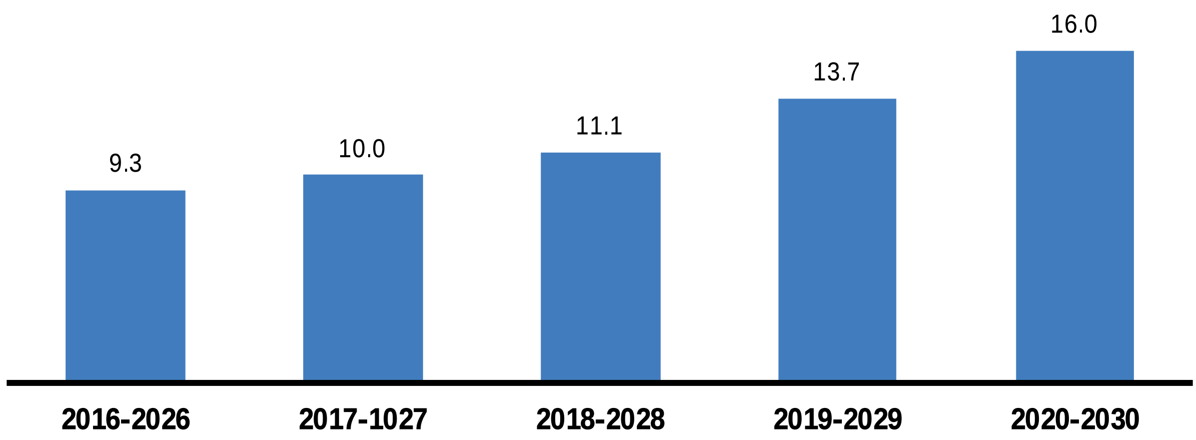
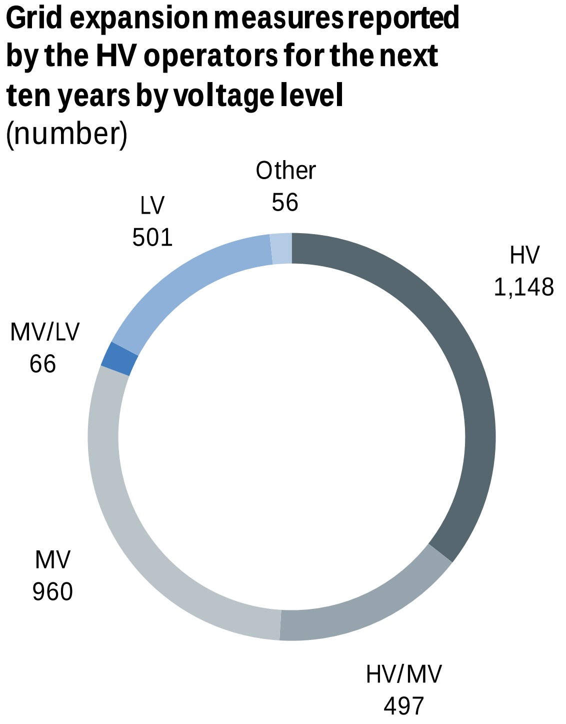


Figure 39: Total electricity grid expansion requirements according to reports pursuant to section 14(1a) and (1b) EnWG

The reported grid expansion requirements in Germany for the next ten years increased year-on-year by about €2.3bn from a total of €13.7bn (2,352 reported measures) as at 31 December 2018 to €16.0bn (3,228 reported measures) as at 31 December 2019. The above chart shows the total grid expansion requirements reported in 2020 and in the previous years. The total investment volume of €16.0bn would translate into an annual investment total of about €1.6bn, assuming an even level of investment. Two factors must be taken into account here: firstly, this figure only comprises the measures reported by the HV network operators and, secondly, measures at the LV levels are planned much less in advance; this means that the ten-year reports do not reflect all the investments. The information reported by DSOs pursuant to section 14(1a) and (1b) EnWG only needs to include replacement and renewal measures if the measures involve reinforcement or optimisation. Measures that only involve replacement and renewal – in other words, measures that are not designed to increase the network capacity – are therefore only partly included.

The actual investment figure of €4,665m given in I.C.3.2) includes all replacement and renewal investments – including those not involving reinforcement or optimisation – and is based on the information reported by all the DSOs and is therefore correspondingly higher.



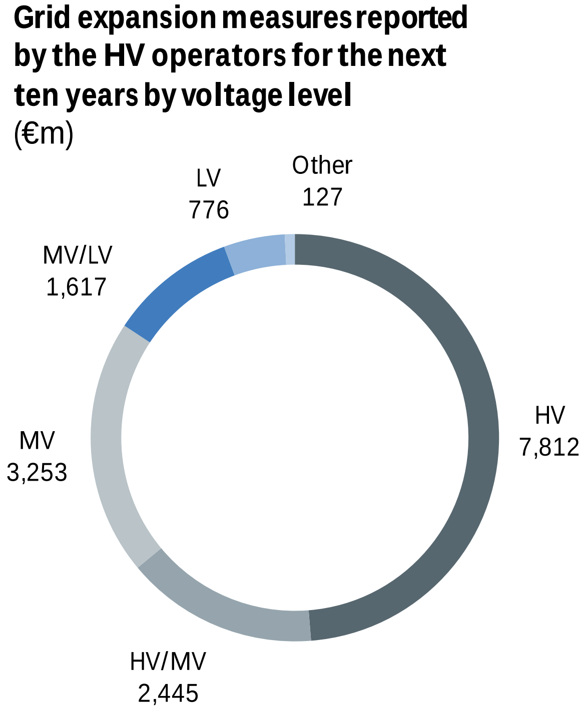
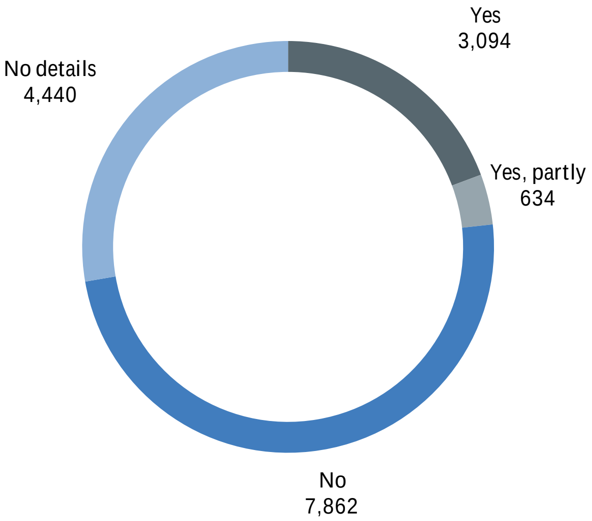


Figure 40: Number and costs of the measures reported for each network level for the next ten years

In total, 37.7% of the 3,228 measures reported to the Bundesnetzagentur as at 31 December 2019 were classed as in progress, 21.1% as in specific planning and 40.6% as envisaged.[48] No status was given for 0.6% of the measures. Overall, the measures reported were spread over the HV to LV levels. The two charts above show a breakdown of the measures by voltage level. In the charts, the "Other" category comprises measures for which the voltage level was not specified and measures relating to more than one voltage level. One of the measures included in this category relates to the EHV/HV transformation level. The charts show that the HV level accounts for about half (49) of the reported grid expansion costs. It should be noted that measures for the HV level are planned much further ahead than measures for the MV and LV levels; measures for the MV and LV levels are not usually planned up to ten years in advance because of the shorter implementation timescales and simpler approval procedures involved.

[48] A measure is classed as in specific planning in particular when the necessary public-law planning or approval procedure for the measure has been initiated, when the operator has already made an investment decision for the expansion measure or when the operator assumes that the measure will be implemented within the next five years.

Are the grid expansion measures in the next ten years due to the growth in renewable energy?
(€m)



Are the grid expansion measures in the next ten years intended to ease restrictions?
(€m)

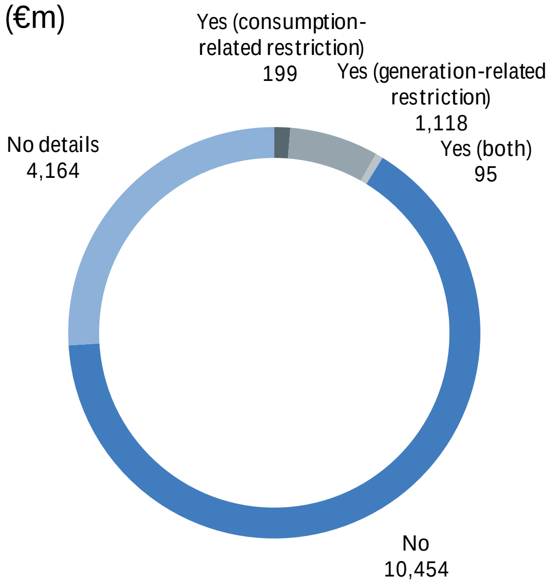


Figure 41: Grid expansion due to the growth in renewable energy and to ease grid restrictions in the next ten years

From the perspective of the Bundesnetzagentur, the distribution networks have become increasingly important in recent years as the energy transition has progressed. In particular, integrating renewable energy installations and electric vehicle charging points into the general supply network poses new challenges for the DSOs. It is therefore interesting to see how these two issues are reflected in the information on the measures reported to the Bundesnetzagentur (see charts above). As in the past, most of the future grid expansion measures are not intended to ease restrictions in the grid. This fact and the steady increase in total investments indicate that the DSOs are making forward-looking investments in their networks.

The table below shows a breakdown of the 60 DSOs by investment volume. The 21 DSOs with an investment volume exceeding €100m account for 92.9% of the total grid expansion requirements reported. The highest volume reported was €3.16bn. The average volume was €272m per DSO.

The DSOs with the ten highest investment volumes as at 31 December 2019 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.[49]

[49] In alphabetical order.

DSOs' investment costs for the next ten years

	Number of DSOs	Total (€m)
All DSOs surveyed	59	16,030*
DSOs > €1bn	6	9,497
€1bn > DSOs > €100m	15	5,402
€100m > DSOs > €50m	7	549
€50m > DSOs > €10m	19	556
€10m > DSOs	9	27
Not applicable	3	

* Rounding difference

Table 44: HV network operators' planned grid expansion requirements for the next ten years

3. Investments

For the purposes of the monitoring survey, investments are defined as the gross additions to fixed assets capitalised in 2019 and the value of new fixed assets newly rented and hired in 2019. 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 2019, investments in and expenditure on network infrastructure by the four German TSOs amounted to approximately €3,089m, down 8% on the previous year’s figure of €3,366m. The difference between actual investments and expenditure in 2019 and the figure of €3,810m forecast in last year's monitoring survey is about €720m. The TSOs thus realised 81% of their planned investments and expenditure.

The individual categories for network infrastructure investments and expenditure are shown in Table 45:

Electricity: TSOs' network infrastructure investments and expenditure

	2018	2019
Investments (€m)	**2,954**	**2,727**
New build, upgrade and expansion projects other than for cross-border connections	2,123	1,922
New build, upgrade and expansion projects for cross-border connections	575	511
Maintenance and renewal excluding cross-border connections	249	287
Maintenance and renewal of cross-border connections	7	7
Expenditure (€m)	**413**	**362**
Expenditure excluding cross-border connections	408	359
Expenditure on cross-border connections	5	3
Total	**3,366**	**3,089**

Table 45: TSOs' network infrastructure investments and expenditure

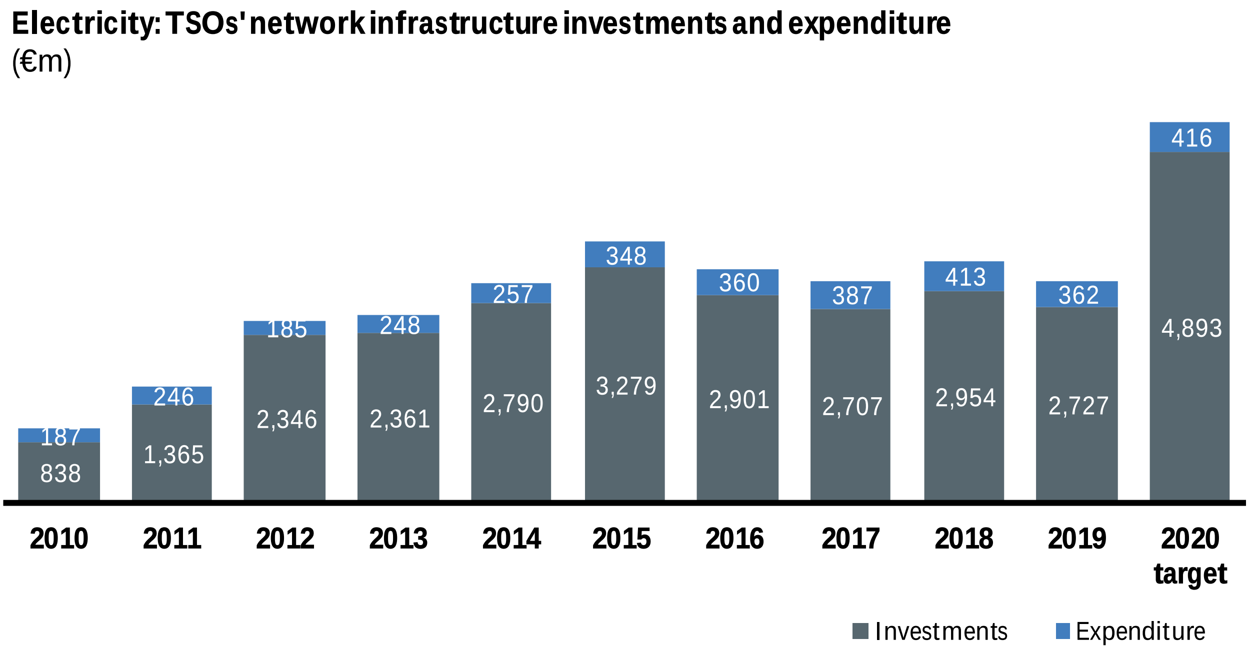


Figure 42: TSOs' network infrastructure investments and expenditure (including cross-border connections)

Total investments of around €4,893m and total expenditure of €416m are currently planned for 2020. The planned total for investments and expenditure of about €5,309m is higher than the total amount realised in previous years. This shows that refinancing conditions continue to be seen as very favourable by investors for the future.

3.2 Distribution system operators' investments and expenditure

In 2019, investments in and expenditure on network infrastructure by the 757 DSOs that provided data in the monitoring amounted to around €7,540m, up about 7% on the previous year's figure of €7,078m. Investments and expenditure for metering systems amounted to around €418m in 2019, compared to €614m in 2018. Detailed information on investments in metering systems can be found in I.H.7. The planned total for investments and expenditure in 2020 is €7,957m.

Figure 43 shows the figures for investments, expenditure and combined investments and expenditure since 2010 and the planned figures for 2020. 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.

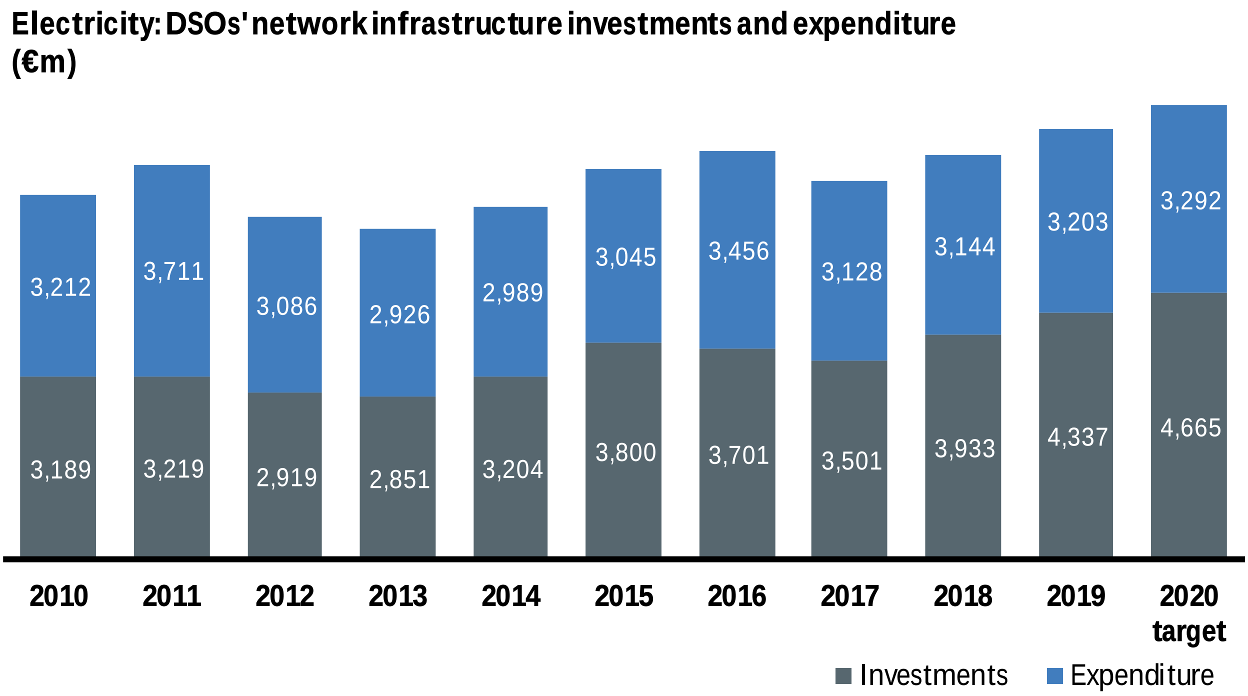


Figure 43: DSOs' network infrastructure investments and expenditure

The level of investment by DSOs depends on circuit lengths, the number of meter locations served, and other individual structural parameters, especially geographical factors. DSOs with longer circuits tend to have higher investments. In the distribution networks, too, the network operators' observable behaviour confirms the very attractive present and future refinancing options.

A total of 90 of the DSOs, or 12%, are in the top category with investments exceeding €10m per network area and account for 85% of the investments. Figure 44 shows investment categories by the total number of DSOs and the investment and expenditure amounts.

Electricity: DSOs by investment and expenditure amounts in 2019
Number and volume (€m)

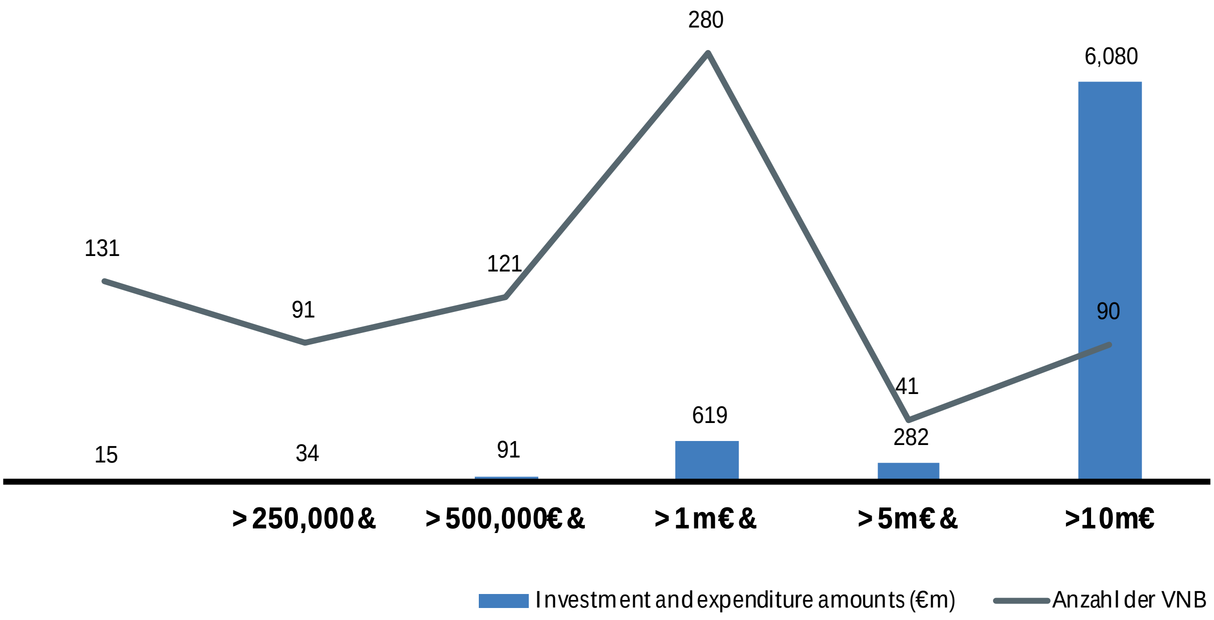


Figure 44: Number of distribution system operators by investment and expenditure amounts

3.3 Investments and incentive regulation

The ARegV gives network operators the opportunity to budget for expansion, replacement 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. Upon application the Bundesnetzagentur also grants approval based on section 10a ARegV for investments made after the base year in assets that are necessary for operation. Once approval has been obtained, DSOs may adjust their revenue caps and thereby refinance the capital expenditure associated with their investments in the same 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 2020, 43 new applications for investment projects have been submitted by TSOs to the competent Ruling Chamber. Costs of acquisition and production of about €7bn are linked to these investment measures. Compared to 2019, the number of applications submitted by the TSOs has increased minimally, while the costs linked to the projects applied for has more than halved.

Capital expenditure mark-up

The Bundesnetzagentur introduced the capex mark-up for electricity distribution systems 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 2019, the Bundesnetzagentur had approved capex mark-ups for distribution network expansion amounting to around €1bn. This corresponds to past or planned investments totalling some €13bn. 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.

As at 30 June 2020, the Bundesnetzagentur had received 169 applications for capex mark-up approvals for 2021 (102 under the Bundesnetzagentur's own responsibility and 67 under delegated responsibility). Thus nearly all companies under federal responsibility and 90% of the companies under responsibility of the federal states have used this instrument.

The approved capex mark-ups relate to past or planned investments in 2017, 2018, 2019, 2020 and 2021. The capex mark-ups approved by the Bundesnetzagentur are in addition to further investments of the 700 companies under the regulatory responsibility of the federal states.

The difference arising from the actual capital costs from investments can be calculated with the approved capex mark-up for the first time in 2020. This difference is entered into the 2019 regulatory account (application by 30 June 2020).

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.

3.4.1 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 derive 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.

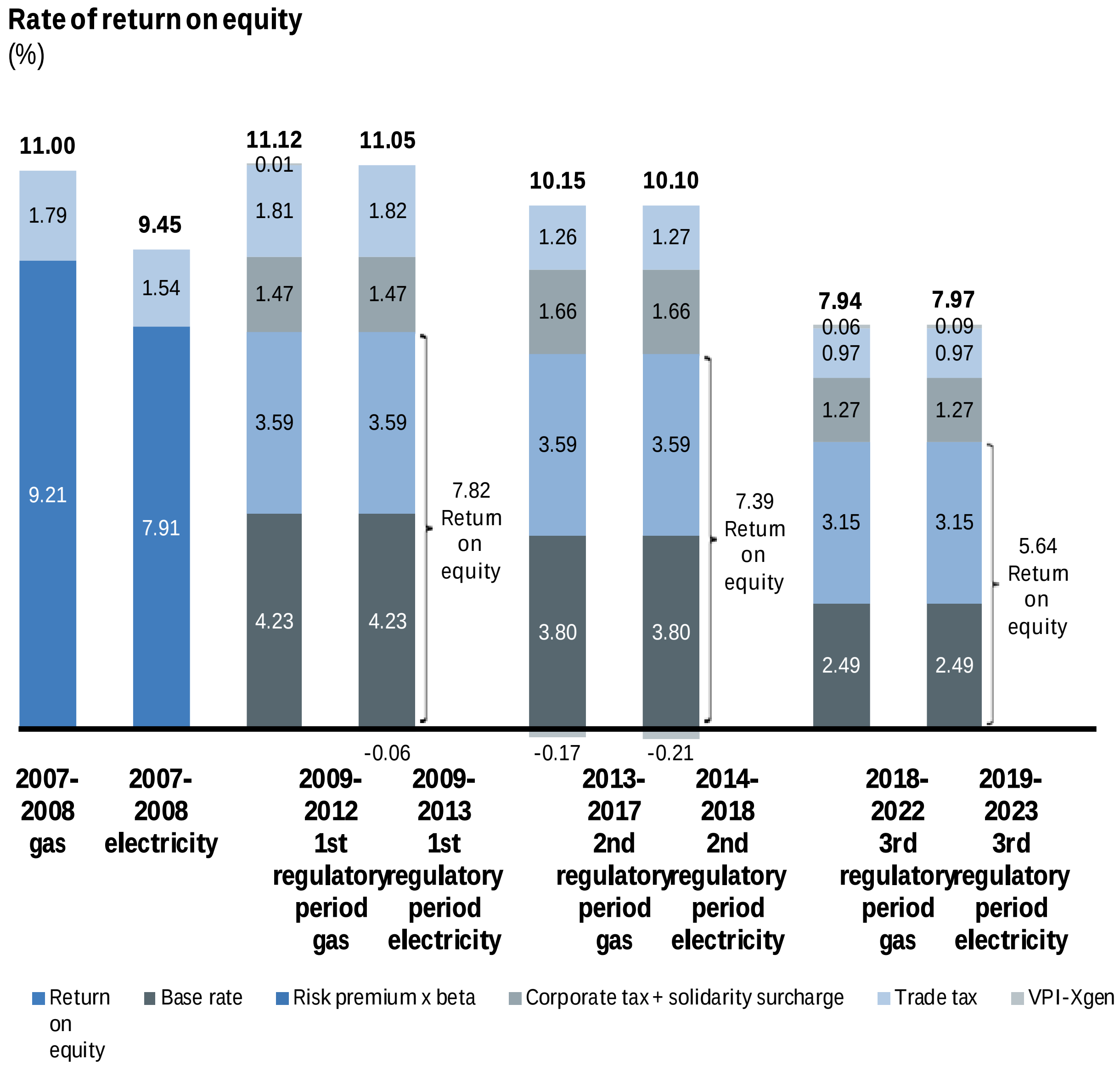


Figure 45: Rate of return on equity

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).

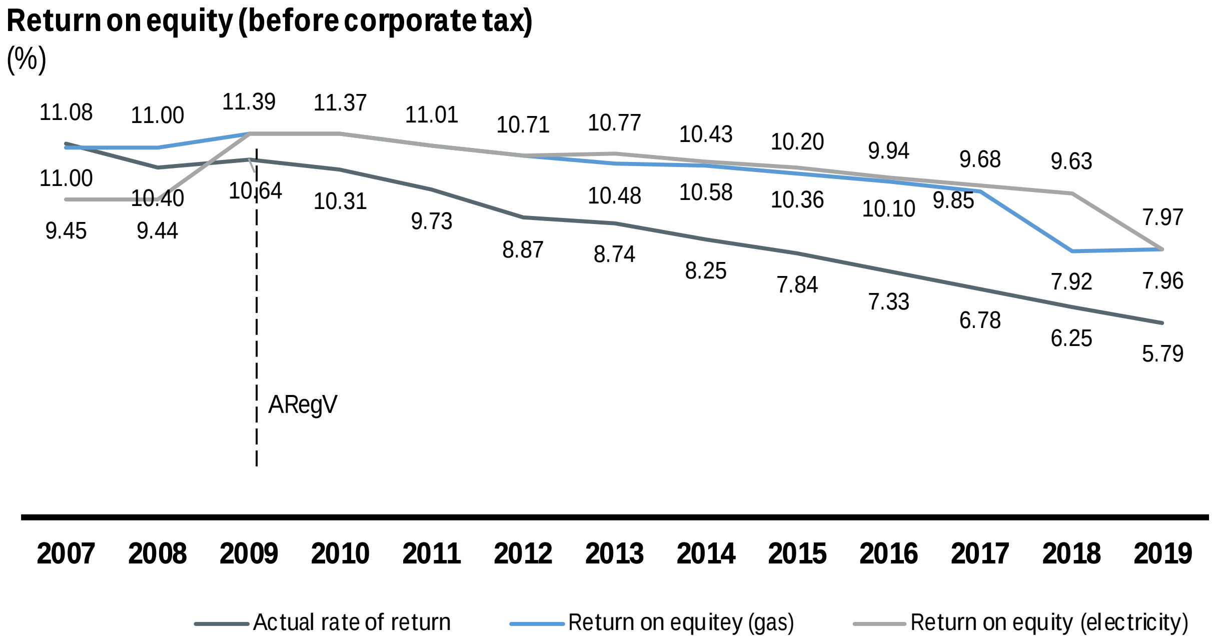


Figure 46: Return on equity (before corporate tax)

3.4.2 Equity II interest rate

Equity can be substituted with borrowed capital. Completely substituting equity with leverage is, however, practically not possible since no debt capital provider would likely be willing to supply capital without any recoverable assets. The higher the equity investment, the lower the stipulated interest rate on borrowings tends to be. When the equity investment is more than 40%, however, a regulatory thesis is applied whereby the equity investment is no longer worthwhile since an effect from lowering the interest rate on borrowings is missing. Following this thesis, using equity investment beyond the 40% equity ratio is inefficient. Competing companies have an incentive to choose the most economical capital structure, whereby equity is usually more expensive than borrowed capital. Therefore having an equity ratio that is too high is considered inefficient. Any available equity capital in the capital structure earns at an interest rate (averaging over 10 years) stipulated under section 7(7) of the Electricity and Gas Network Charges Ordinances (StromNEV and GasNEV) and referred to as the "equity II interest rate". The figure below shows the equity II interest rates actually applied during cost examination, the annual results under StromNEV/GasNEV (10-year average) and the development of the rates by year.

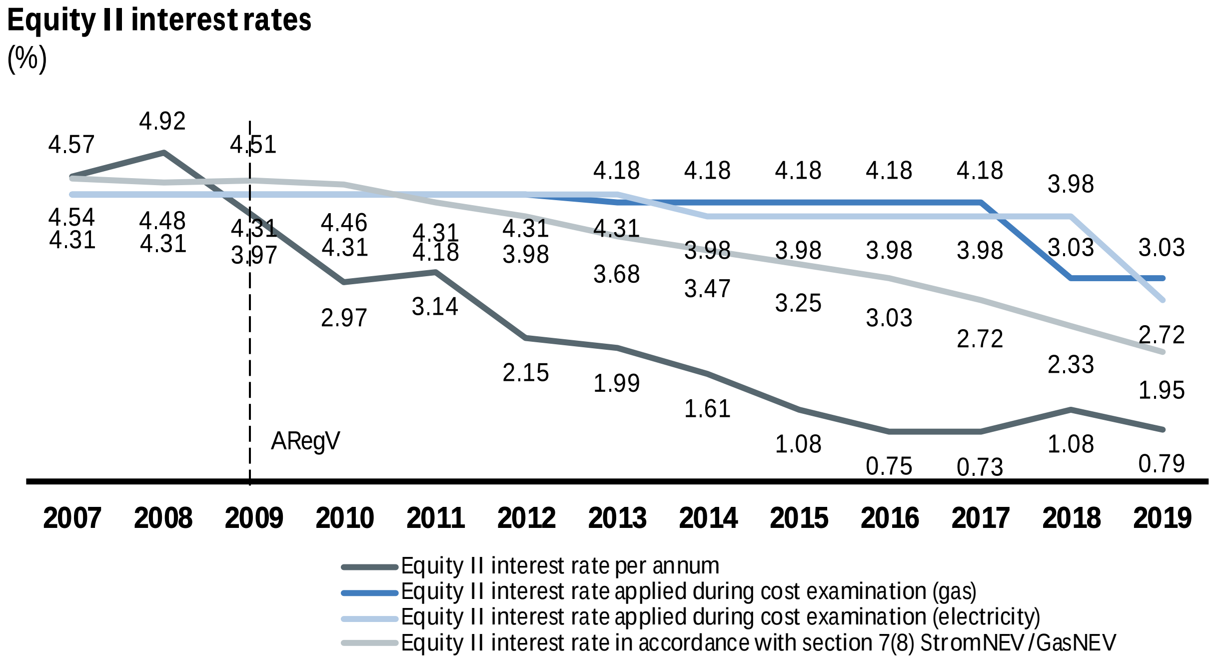


Figure 47: Equity II interest rates

3.4.3 Interest rate on borrowings

In the various regulatory areas, borrowings are generally recognised in the amount of the actual financing conditions unless interest rates typical for the market are exceeded. The individual assessment is defined, however, by a different threshold, depending on the form of regulation. The interest rate on borrowings that may generally be taken into account for the electricity and gas networks is shown in the graph below, listed by normal incentive regulatory regime (budget principle) and investment measure regime. As of the third regulatory period the adjustment of capital expenditure for DSOs has been in effect. Here the interest rate on borrowings is calculated as is done with leverage using the normal incentive regulatory regime. For the third regulatory period this was set to 3.03% and 2.72% for gas and electricity respectively.

4. Electricity supply disruptions

The System Average Interruption Duration Index ($SAIDI_{EnWG}$) is the average length of supply interruption experienced per connected final 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 2019 is 12.20 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 ($SAIDI_{EnWG}$[50]) does not take into account planned interruptions or those that 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 all interruption causes used for calculating the number of interruptions in the 2019 reporting year there was a decline in the effects of supply interruptions at both the low-voltage and the medium-voltage levels.

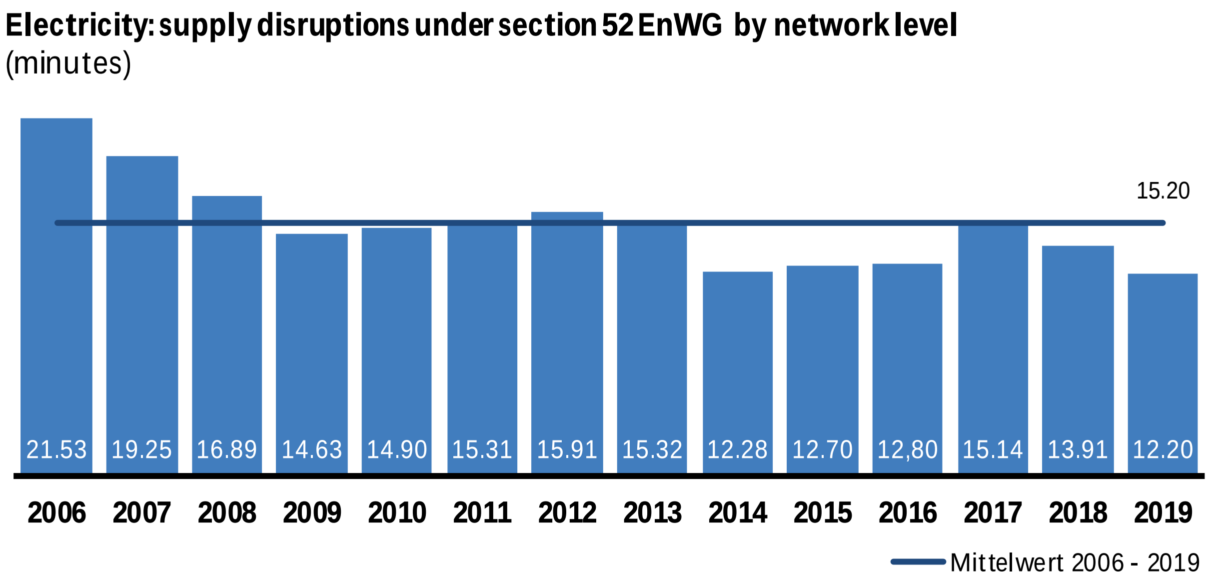


Figure 48: Supply disruptions under section 52 EnWG by network level

For the year 2019, 859 operators reported 159,826 interruptions in supply for 865 networks for the calculation of the $SAIDI_{EnWG}$. The annual figure of 12.20 minutes (Figure 48) for the low-voltage and medium-voltage level is the lowest figure on record since the average length of supply interruptions was first recorded in 2006. The quality of supply thus remained at a high level in 2019.

There were fewer outage times brought about by extreme weather conditions in 2019 than there were in 2018.

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 2019.

[50] 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).

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. The current measures include the following:

– 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 and the associated costs 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 2019. The figures are continually updated and so may differ from the figures published in the Bundesnetzagentur's quarterly reports. These quarterly figures are published online at www.bundesnetzagentur.de/systemstudie. The tables show that the volume of network and system security measures in 2019 was smaller compared to the previous year. The costs for network and system security measures (feed-in management, redispatching, including countertrading, and grid reserve provision and use) are provisionally put at around €1.28bn and are thus also lower (2018: €1.48bn).

The total volume of network and system security measures in 2020, based on the first three quarters of the year, is set to be slightly above the previous year's level. The costs show an increase of about 5%. The main reason for this development is a shift in feed-in management measures from onshore to offshore wind. A final assessment of the year's development will be made following an analysis of the fourth quarter.

Elektrizität: Netz- und Systemsicherheitsmaßnahmen nach §13 EnWG im Jahr 2019

	Redispatch	Einspeisemanagement	Anpassungsmaßnahmen
Gesetzliche Grundlage und Regelungs-inhalt	§ 13 Abs. 1. § 13 a Abs. 1. § 13b Absatz 4 EnWG: Netz- und marktbezogene Maßnahmen: Netzschaltungen, wie beispielsweise Regelenergie, ab- und zuschaltbare Lasten, Redispatch und Countertrading, Netzreserveeinsätze	§ 13 Abs. 2. 3 S. 3 EnWG i.V.m. §§ 14. 15 EEG. für KWK-Anlagen i.V.m. § 3 Abs. 1 S. 3 KWKG Einspeisemanagement: Reduzierung der Einspeiseleistung von EE-. Grubengas- und KWK-Anlagen	§ 13 Abs. 2 EnWG: Anpassung von Stromeinspeisungen. Stromtransiten und Stromabnahmen
Vorgaben für betroffene Anlagen-betreiber	Maßnahmen nach vertraglicher Vereinbarung mit dem Netzbetreiber mit Ersatz der Kosten nach § 13 Abs. 1. § 13 a Abs. 1. § 13c EnWG	Maßnahmen auf Verlangen des Netzbetreibers mit Ersatz der Kosten nach § 13 Abs. 2. 3 S. 3 EnWG i.V.m. §§ 14. 15 EEG. für KWK-Anlagen i.V.m. § 3 Abs. 1 S. 3 KWKG	Maßnahmen auf Verlangen des Netzbetreibers ohne Ersatz der Kosten nach § 13 Abs. 2 EnWG
Umfang im Berichts-zeitraum	Redispatch Gesamtmenge Erhöhungen + Reduzierungen von Marktkraftwerken und Erhöhung Reservekraftwerken (ohne Probestarts und Testfahrten): **13.521 GWh**	Ausfallarbeit der EEG-vergüteten Anlagen (ÜNB und VNB): **6.482 GWh**	Abgeregelte Menge durch Anpassungsmaßnahmen (ÜNB und VNB): **9,3 GWh**
Kosten-schätzung im Berichts-zeitraum	Vorläufige Kostenschätzung für Redispatch. Countertrading sowie Einsatz und Vorhaltung Netzreservekraftwerke: **569,5 Mio. Euro**	Vorläufige geschätzte Entschädigungsansprüche von Anlagenbetreibern nach § 15 EEG (ÜNB und VNB): **709,5 Mio. Euro**	Keine Entschädigungsansprüche für Anlagenbetreiber bei Anpassungen nach § 13 Abs. 2 EnWG

Table 46: Network and system security measures under section 13 of the Energy Industry Act (EnWG) in 2019

Electricity: network and system security measures

		2017	2018	2019	Q1-Q3 2020
Redispatching					
Total volume[1] of operational plants	GWh	18,456	14,875	13,323	10,851
Cost estimate[2] for redispatching	€m	392	388	227	143
Cost estimate for countertrading	€m	29	37	64	85
Grid reserve power plants					
Volume[3]	GWh	2,129	904	430	385
Cost estimate for activation	€m	184	137	82	66
Capacity[4]	MW	11,430	6,598	6,598	6,596
Annual costs of holding in reserve[5]	€m	296	279	197	148
Feed-in management					
Volume of curtailed energy[6]	GWh	5,518	5,403	6,482	4,776
Estimated compensation	€m	610	635	710	579
Feed-in adjustments					
Volume	GWh	35	8	9	14

[1] Amounts (reductions and increases) including countertrading and remedial action measures according to monthly reports 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 47: Overview of network and system security measures

5.1 Overall development of redispatching in 2019

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.

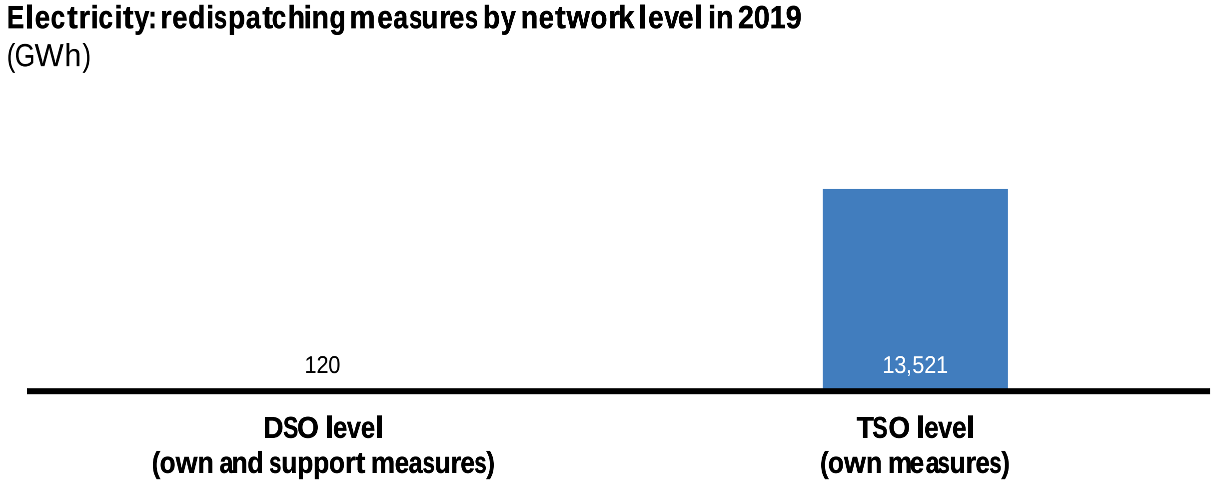


Figure 49: Redispatching measures by network level in 2019

Figure 49 shows that the majority of the redispatching measures were taken by the TSOs. Out of the around 120 GWh at DSO level, a total of about 50 GWh is accounted for by DSOs' own measures requested by 19 DSOs.

The following figures, tables and descriptions therefore relate to redispatching by the TSOs, as presented 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 is undertaken by network operators to ensure the secure and reliable operation of the electricity supply networks. The aim is either to prevent or to relieve overloading of power lines by intervening in the market-based operating schedules of generating units to shift feed-in. In other words, power plants are instructed, either under a contractual arrangement or a statutory obligation, to reduce their feed-in while, at the same time, other power plants are instructed to increase their feed-in. 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. Network operators reimburse the plant operators involved in the redispatching measures for any additional costs incurred, while any costs saved (for example fuel costs) have to be reimbursed to the network operators.

A distinction is made between electricity-related and voltage-related redispatching. Electricity-related redispatching is used to avoid or relieve 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. Redispatching measures may also involve other countries, in particular Austria.

The following table shows a breakdown of the redispatching measures taken in 2019.

Redispatching within the meaning of section 13(1) EnWG in 2019 (GWh)

	2019	2018
Total	13,521	15,529
Breakdown into reductions/increases	13,521	15,529
Reductions	6,958	7,919
Increases	6,563	7,610
Operational power plants	6,365	6,956
Grid reserve power plants (without test runs/test starts)	198	654
Breakdown by type of measure	13,521	15,529
Individual overloading measures	10,800	10,854
4-TSO measures	2,721	4,675
Breakdown by reason for measure	13,521	15,529
Voltage-related	1,792	1,120
Electricity-related	11,730	14,409
Breakdown by geographical components	13,521	15,529
Non-cross-border	7,881	10,610
Cross-border	5,640	4,919
Countertrading	3,210	1,558

Table 48: Redispatching within the meaning of section 13(1) EnWG in 2019

The reductions and increases in feed-in from conventional operational and grid reserve power plants requested as part of the redispatching process amounted in 2019 to about 13,521 GWh (6,958 GWh of reductions and 6,563 GWh of increases). The total volume of requested reductions and increases in feed-in from power plants in 2019 was therefore lower than in 2018 (2018: 15,529 GWh). The volume of countertrading more than doubled in 2019. The increase is largely due to the bilateral agreement between Germany and Denmark. This agreement provides for minimum trading capacities across the border between western Denmark and Germany as well as for cooperation between the TSOs on countertrading measures. On the basis of the agreement, which involves an incremental increase in minimum trading capacities up to 1,300 MW by July 2019, the minimum trading capacity was raised as planned (starting from 700 MW in 2018). It is planned to increase the minimum trading capacity further in line with network expansion.

The costs for redispatching measures using operational power plants are provisionally put at around €227.2m in 2019 and are thus about 41% lower than the previous year's level (2018: €388.2m).

There are various steps to operational 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.

5.1.1 Advance measures by the four TSOs

The joint requests by all four TSOs are based on modelling results. 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 are the basis for both the requests for grid reserve power plants and the planning for the use of operational plants. An additional step was integrated into the joint planning process in 2019, and the whole deployment planning process is due to run on a dedicated server (RES) as from 2021.

A total of 1,548 GWh was curtailed and 1,173 GWh increased on the basis of advance measures by the four TSOs (2,721 GWh overall). These measures make up 20.1% of the total redispatching and grid reserve volume.

According to the TSOs, it is not currently possible to allocate the jointly requested volumes of measures to the individual network elements that cause them. However, it is clear that the network elements that trigger the majority of advance measures by the four TSOs are also the ones listed in I.C.5.1.2.

5.1.2 Individual overloading measures

The volume of reductions in feed-in through individual overloading measures in the whole of 2019 amounted to around 5,410 GWh. Increases in feed-in for balancing were around 5,390 GWh. Thus the total volume of these redispatching measures (reductions and increases in feed-in) was approximately 10,800 GWh, which represents a decrease of 13% compared to 2018.

Electricity-related individual overloading measures

In 2019, 87% of the individual overloading measures were electricity-related. Table 49 shows that the most heavily loaded network elements for electricity-related individual overloading measures were the lines between Dipperz and Großkrotzenburg, in the Altheim area at the border with Austria, and between Dörpen and Hanekenfähr.

The numbering of the network elements in Table 49 and Table 50 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. The numbers serve to identify the network elements on the map (Figure 50), which shows the location of the critical network elements from the tables (at least 50 hours per line).

Electricity: electricity-related redispatching on the most heavily affected network elements in 2019

No	Network element	Control area[1]	Duration (hours)	Volume of feed-in reductions (GWh)	Volume of feed-in increases (GWh)
1	Dipperz - Großkrotzenburg	TenneT	1,052	753	739
2	Altheim (Altheim-Sittling, Altheim-Simbach-Sankt Peter (AT))	TenneT	999	777	777
3	Dörpen (Dörpen-Niederlangen-Meppen-Hanekenfähr)	TenneT/ Amprion	715	289	286
4	Flensburg-Kassoe/Ensted (DK)	TenneT	495	94	94
5	Dollern-Sottrum	TenneT	254	140	139
6	Landesbergen (Landesbergen-Wechold-Sottrum)	TenneT	251	145	144
7	Ovenstädt-Bechterdissen (Ovenstädt-Eickum-Bechterdissen)	TenneT	205	132	129
8	Mecklar - Dipperz	TenneT	191	72	72
9	Sottrum - Huntorf - Conneforde	TenneT	160	57	57
10	Lehrte - Mehrum circuit	TenneT	156	21	21

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

Table 49: Electricity-related redispatching on the most heavily affected network elements in 2019

Electricity: electricity-related redispatching on the most heavily affected network elements in 2019

No	Network element	Control area[1]	Duration (hours)	Volume of feed-in reductions (GWh)	Volume of feed-in increases (GWh)
11	Neuenhagen - Vierraden - Pasewalk line	50Hertz	148	40	40
12	Audorf - Flensburg	TenneT	143	38	38
13	Dollern-Wilster	TenneT	131	60	60
14	Borken/Gießen	TenneT	110	42	42
15	Sechtem (Sechtem-Paffendorf-Oberzier)	Amprion	99	19	17
16	Ensdorf - Vigy line	Amprion	93	37	38
17	Pleinting - Sankt Peter/APG circuit	TenneT	92	39	39
18	Grohnde - Vörden - Bergshausen	TenneT	68	38	38
19	Hamburg north - Hamburg east line	50Hertz/ TenneT	60	16	16
20	Landesbergen - Ovenstädt circuit	TenneT	54	24	24
21	Streumen - Röhrsdorf	50Hertz	50	12	12

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

Table 50: (continuation of Table 49) Electricity-related redispatching on the most heavily affected network elements in 2019

Elektrizität: Dauer von strombedingten Redispatch Einzelüberlastungsmaßnahmen auf den am stärksten betroffenen Netzelementen im Gesamtjahr 2019

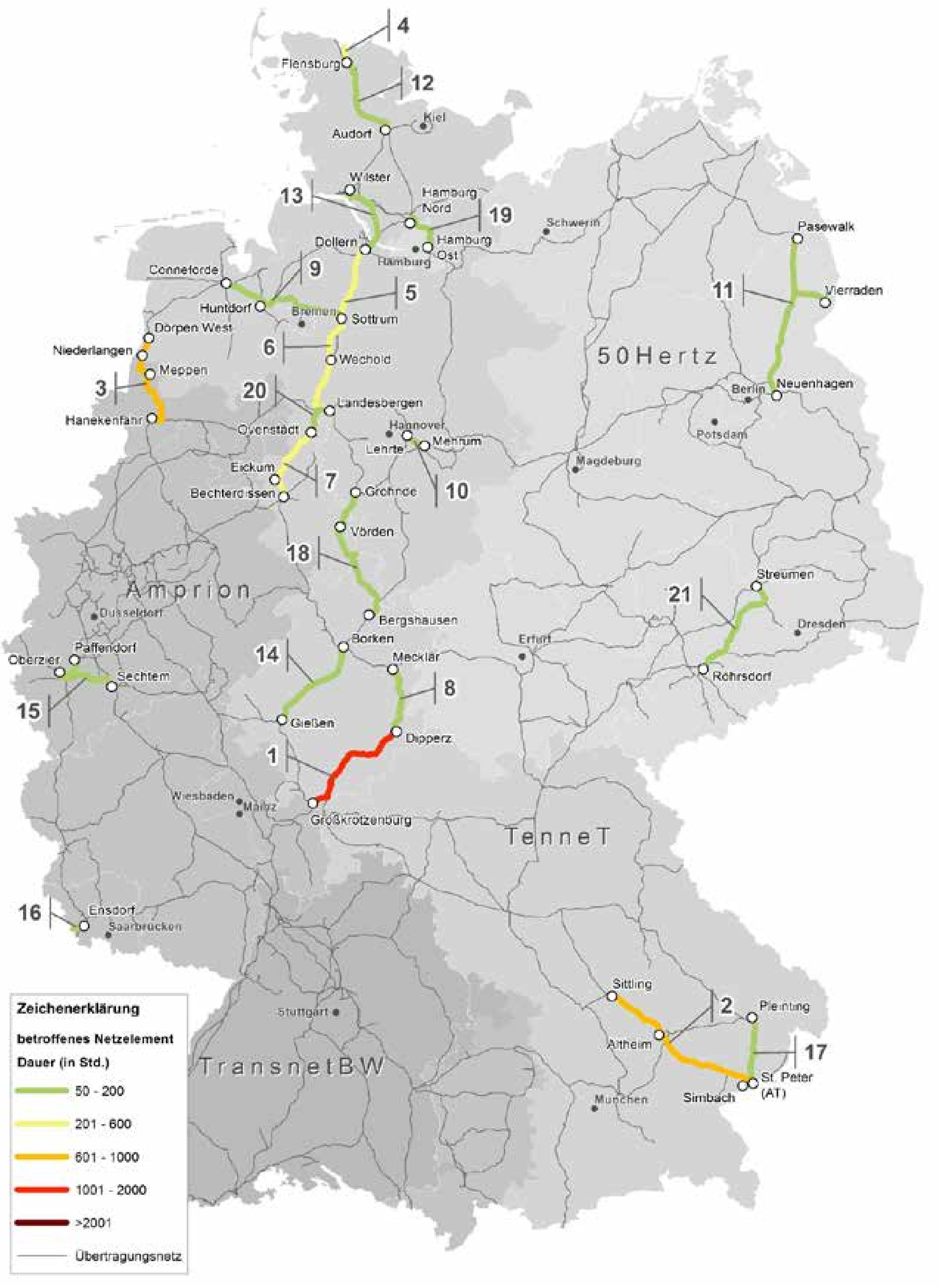


Figure 50: Duration of electricity-related redispatching measures in cases of individual overloading of the most heavily affected network elements in 2019

Voltage-related individual overloading measures

In addition to electricity-related redispatching, the TSOs reported voltage-related redispatching measures with a total volume of around 1,792 GWh in 2019. Voltage-related measures are balanced by counter trades on the exchange. [51] The need for voltage-related redispatching measures was greater than in the previous year (2018: 1,120 GWh).

Table 51 shows the duration and volume of the measures required in the individual control and network areas.[52]

Electricity: voltage-related redispatching in 2019[1]

Network area	Duration (hours)	Volume (GWh)
TenneT control area	**3,102**	**1,205**
Dipperz - Großkrotzenburg	1,457	685
Oberbayern network area (voltage)	759	183
Ovenstädt-Bechterdissen-Borken network area (voltage)	736	295
Mittelfranken network area (voltage)	63	14
Mehrum-Grohnde-Borken	49	17
Borken/Gießen	20	8
Lehrte-Helmstedt-Krümmel network area (voltage)	13	2
Conneforde	2	0
TransnetBW control area	**1,278**	**529**
Altbach Daxlanden network area	1,262	525
Dellmensingen-Wendlingen	16	3
50Hertz control area	**119**	**58**

[1] Since voltage-related redispatching measures relate to larger network regions (and not individual lines or transformer stations), the measures are not illustrated on a map.

Table 51: Voltage-related redispatching in 2019

5.1.3 Deployment of power plants in redispatching

In 2019, a total volume of 9,984 GWh (4,965 GWh of reductions and 5,020 GWh of increases in feed-in) was provided by operational plants within Germany and grid reserve power plants both in and outside Germany

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[51] Voltage-related redispatching involves adjusting the feed-in from power plants in order to make adjustments to the reactive power provided. Voltage-related measures often do not need to be balanced locally and are therefore usually balanced via the intraday market.

[52] No overview map is provided since voltage-related redispatching relates to larger network regions and not to individual lines or transformer stations.

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 51 shows a breakdown of the power plants deployed for redispatching by energy source. 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.

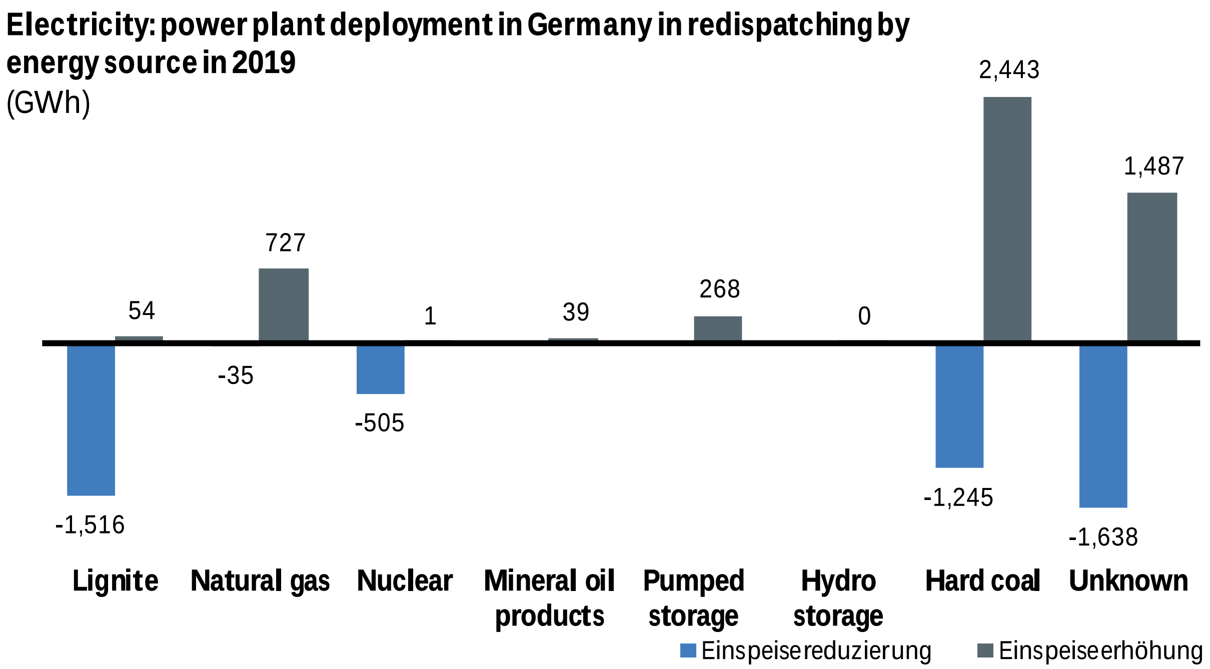


Figure 51: Power plant deployment in redispatching by energy source in 2019

The maps in Figure 52 and Figure 53 show how power plants are deployed across the individual federal states.

Elektrizität: Kraftwerksreduzierungen auf Anforderung der deutschen ÜNB im Jahr 2019

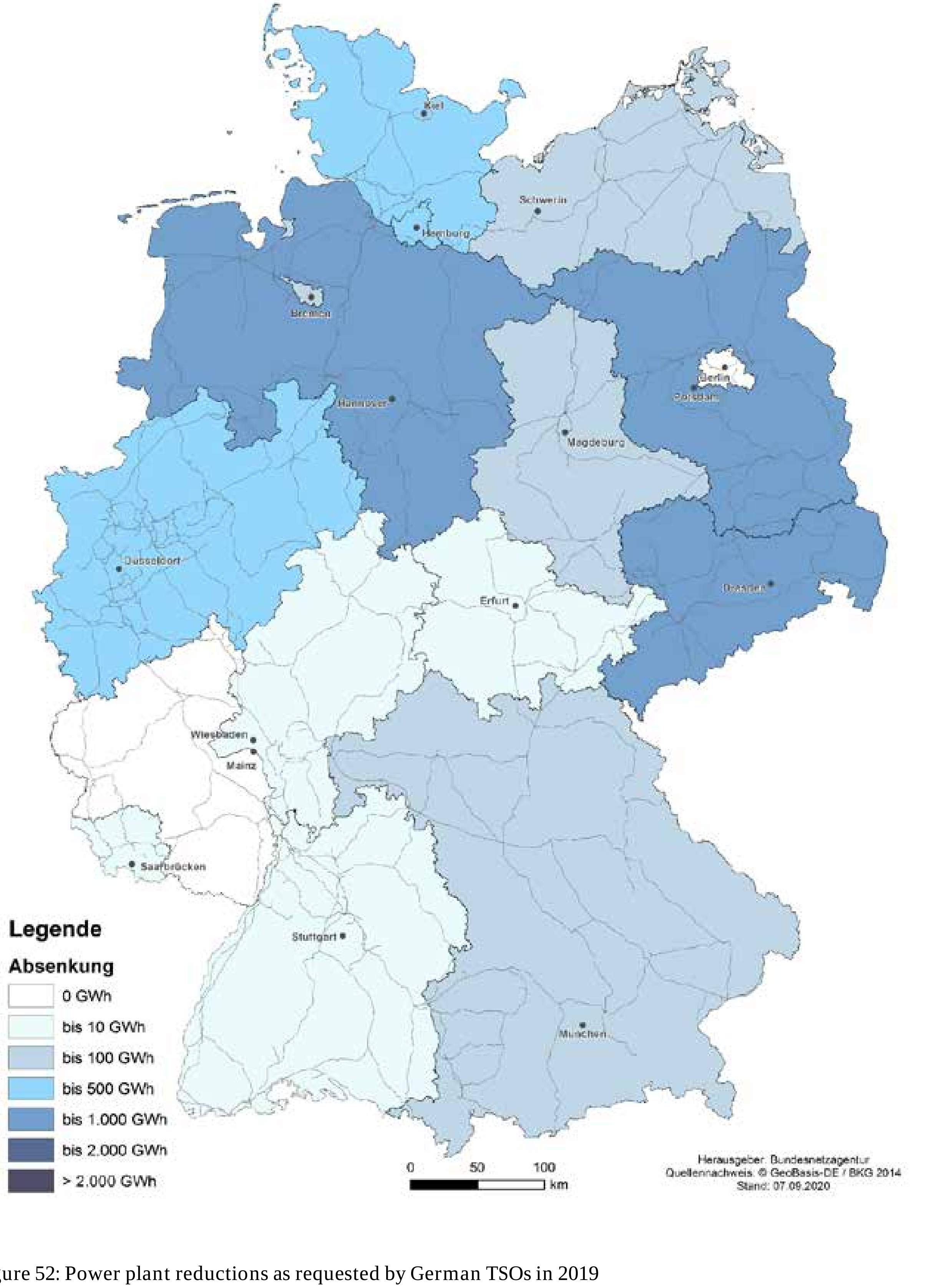


Figure 52: Power plant reductions as requested by German TSOs in 2019

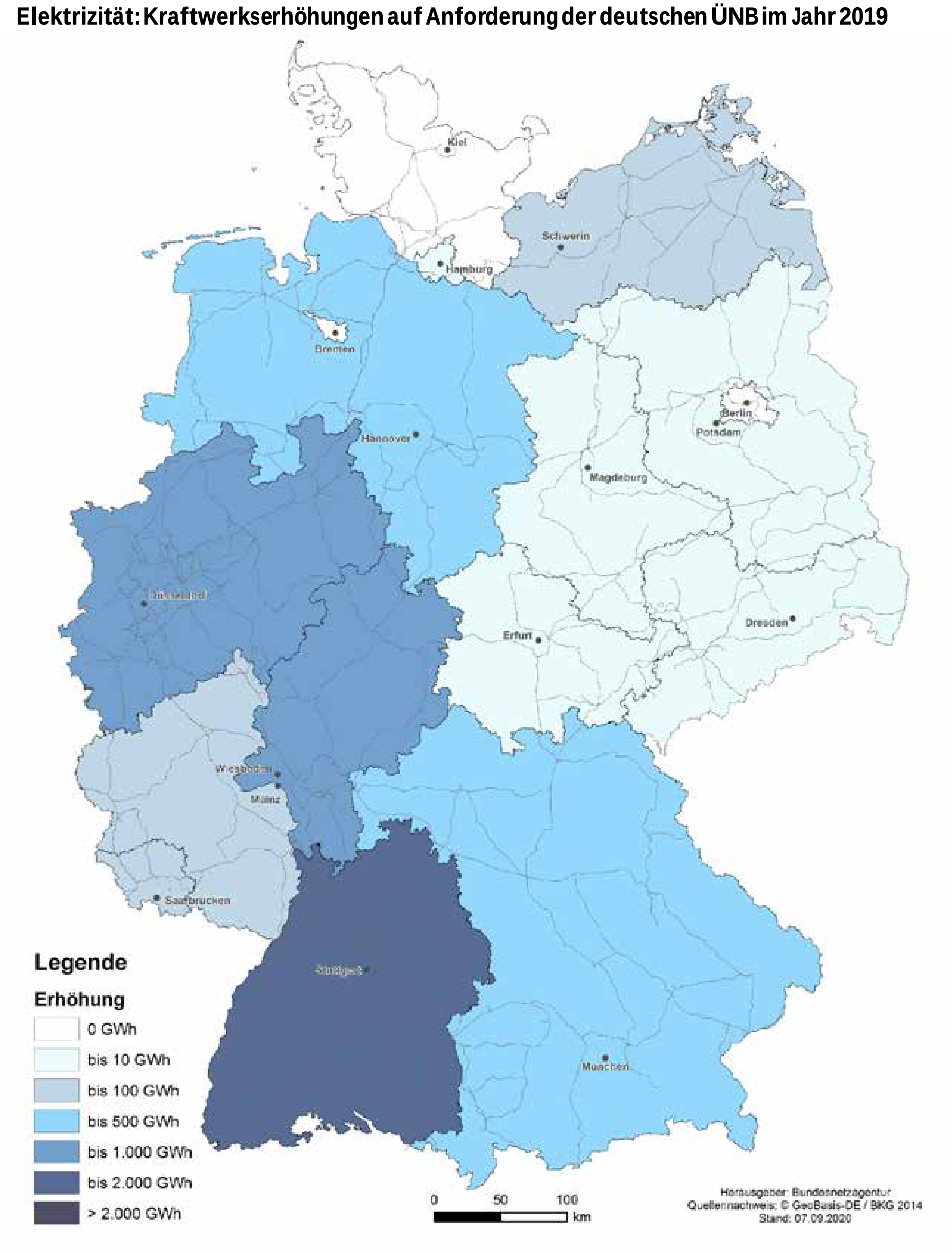


Figure 53: Power plant increases as requested by German TSOs in 2019

5.1.4 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 2019 (MW)

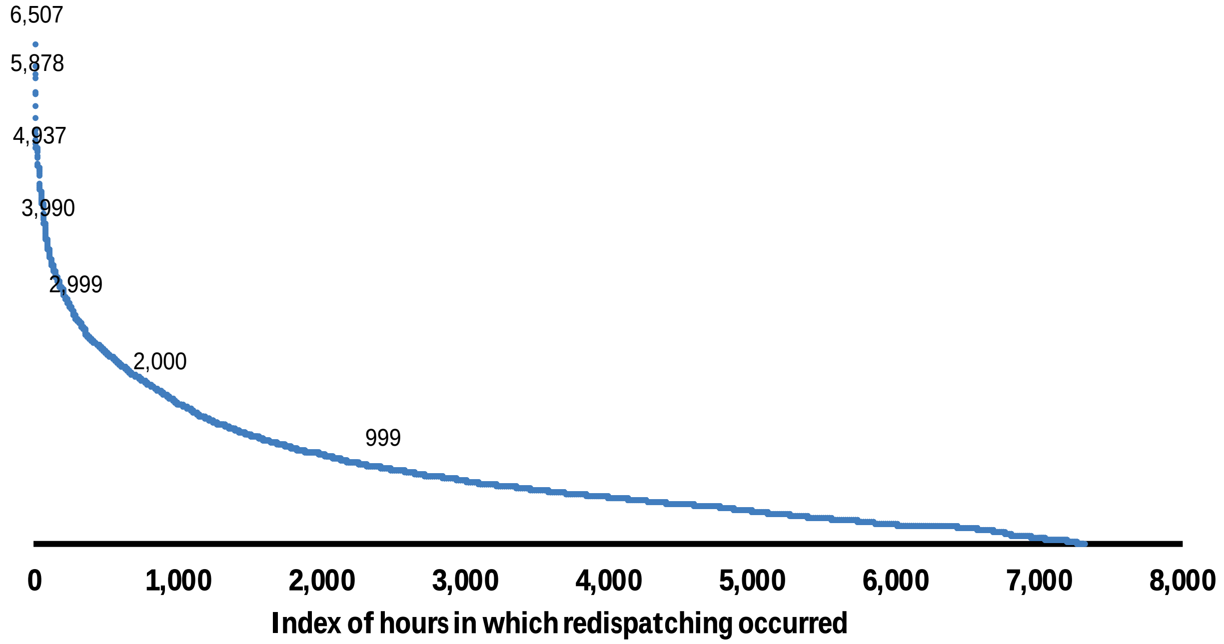


Figure 54: Nach Menge geordneter Redispatch Einsatz (Absenkung) je Stunde in Deutschland 2019

Redispatched energy (reductions) in decreasing order per hour in Germany in 2019

In 2019, the largest required reduction was 6,507 MW. The volume of redispatched energy was higher than 5,000 MW in 21 individual hours. No redispatching measures were carried out in 1,444 hours.

5.1.5 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 3,210 GWh of the total redispatching volume in the whole of 2019. This is more than twice as much as in the previous year (2018: 1,558 GWh). Countertrading incurred costs of around €64m, which also represents a large year-on-year increase (2018: €37m).

The increase is largely due to the bilateral agreement between Germany and Denmark. This agreement provides for minimum trading capacities across the border between western Denmark and Germany as well as for cooperation between the TSOs on countertrading measures. On the basis of the agreement, which involves an incremental increase in minimum trading capacities up to 1,300 MW by July 2019, the minimum trading capacity was raised as planned (starting from 700 MW in 2018). It is planned to increase the minimum trading capacity further in line with network expansion.

5.1.6 Deployment of grid reserve capacity

In 2019, the grid reserve was used on 152 days to provide a total of around 429 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 estimate the costs of using them at about €81.6m. The preliminary costs of holding them in reserve plus other costs not dependent on their deployment amounted to €196.5m.

Table 52 summarises the use of the grid reserve. The average deployment in MW shows the average volume of reserve requested per day of deployment. This average value peaked in August at 295 MW. The largest volume of grid reserve use was 1,000 MW and occurred in July.

Electricity: summary of grid reserve deployment in 2019

	Number of days	Average deployment (MW)	Maximum volume of use (MW)	Total (MWh)
January	19	201	700	69,977
February	10	186	865	25,984
March	10	207	590	30,205
April	19	146	622	30,057
May	14	122	500	22,637
June	19	280	980	87,832
July	12	258	1,000	35,143
August	10	295	820	35,659
September	9	132	385	12,368
October	11	210	560	38,931
November	10	214	635	22,450
December	9	144	744	18,264
Total	**152**			**429,505**

Source: TSOs' reports of redispatching power plant deployment to the Bundesnetzagentur

Table 52: Summary of grid reserve deployment in 2019

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 chart below 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.

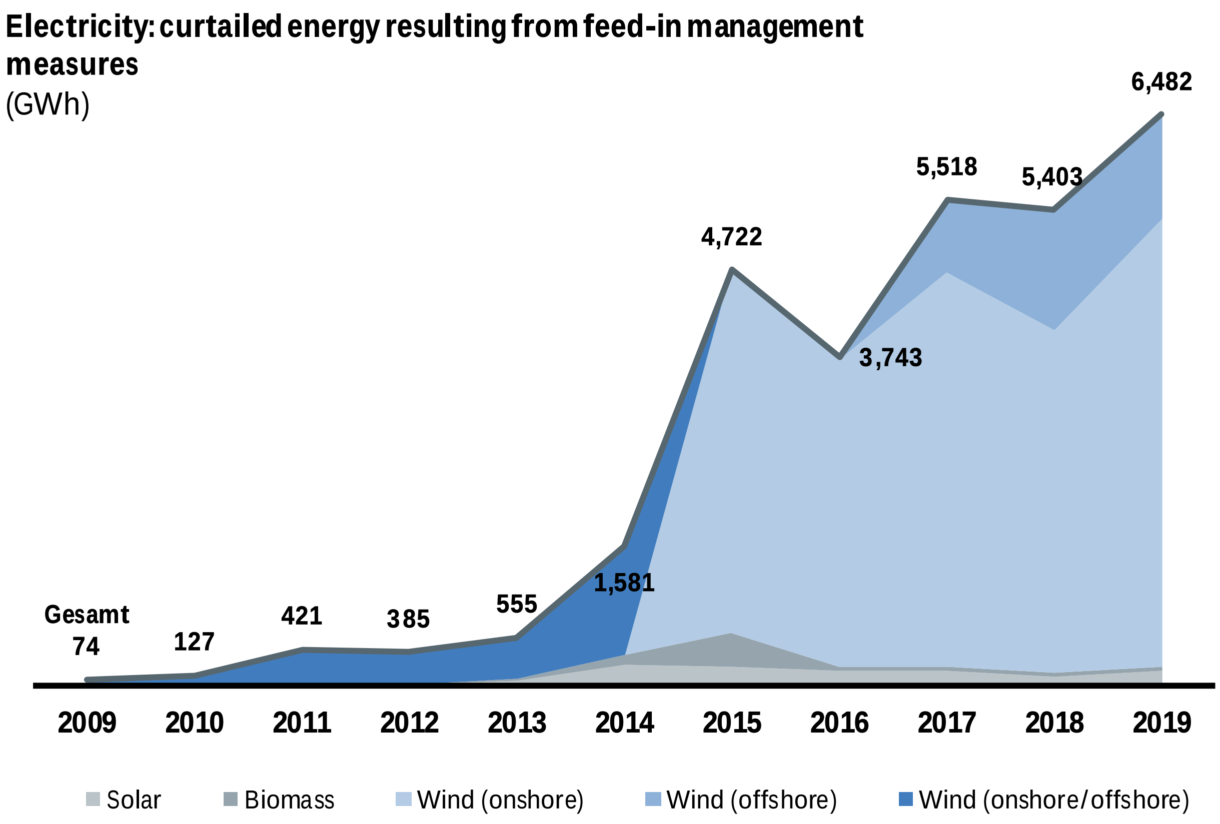


Figure 55: Curtailed energy resulting from feed-in management measures

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

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Wind energy	125.1	409.7	358.5	480.3	1,221.5	4,124.9	3,530.1	5,287.2	5,246.9	6,272.5
Wind (onshore)						4,110.6	3,498.0	4,461.2	3,890.5	5,084.8
Wind (offshore)						14.3	32.0	826.0	1,356.3	1,187.6
Solar	1.7	2.6	16.1	65.5	245.2	227.7	184.1	163.1	116.5	177.6
Biomass		5.9	9.4	8.8	112.1	364.4	26.5	61.1	35.7	30.2
Other		2.4	0.8	0.2	1.8	21.1	2.6	6.6	3.6	2.3
Total	**126.8**	**420.6**	**384.8**	**554.8**	**1,580.6**	**4,722.3**	**3,743.2**	**5,518.0**	**5,402.7**	**6,482.5**

Table 53: Curtailed energy resulting from feed-in management measures

The amount of energy curtailed as a result of feed-in management measures increased by a good 19% from 5,402 GWh in 2018 to 6,482 GWh. This represents a significant year-on-year increase in the amount of unused energy produced by renewable and CHP installations. The amount of energy curtailed as a result of feed-in management measures corresponds to 2.9% of the total amount of electricity generated by installations eligible for payments under the EEG (including direct selling) (2018: 2.6%).[53] Thus around 97% of the renewable energy marketed in 2019 was produced and made available to users.

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 can be explained by the very windy first quarter of 2019. Compared to 2018, there was a significant rise of about 1,194 GWh over 2019 in the amount of onshore wind energy curtailed. 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.[54]

In 2019, as in previous years, feed-in management measures primarily involved onshore wind power plants, which accounted for around 78% of the total amount of curtailed energy (2018: 72%). Offshore wind power plants, which were first affected by feed-in management measures in 2015, accounted for around 18% (about 1,188 GW) of the total amount of curtailed energy in 2019, representing a slight decrease (2018: 25% or about 1,356 GW). 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 2019, and biomass, which is also often combined with heat generation, made up 0.5%. The table below shows the individual amounts of curtailed energy and the percentages of the total amount for the energy sources affected by feed-in management measures.

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

[54] https://www.bundesnetzagentur.de/systemstudie

Electricity: curtailed energy resulting from feed-in management measures by energy source in 2019

Energy source	Curtailed energy (GWh)	Percentage of total (%)
Wind (onshore)	5,084.83	78.4
Wind (offshore)	1,187.63	18.3
Solar	177.60	2.7
Biomass, including biogas	30.15	0.5
Run-of-river	1.24	< 0,1
CHP electricity	0.87	< 0,1
Landfill, sewage and mine gas	0.13	< 0,1
Other	0.03	< 0,1
Total	**6,482.49**	**100**

Table 54: Curtailed energy resulting from feed-in management measures by energy source in 2019

The network operators' reports on system and network security measures provided the following details of the use of feed-in management: the operators' monthly reports to the Bundesnetzagentur show that the TSOs were responsible for the majority of the feed-in management measures taken in 2019. Overall, restrictions in the transmission networks accounted for around 83% of the energy curtailed, although installations connected to transmission networks accounted for only around 19% of the energy curtailed and compensated. The remaining amount – approximately 81% – was accounted for by installations connected to distribution networks. Support measures requested by the TSOs but taken by the DSOs accounted for the majority – 63% – of the curtailed energy (see Table 55). 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 81% of curtailed energy from such measures occurs in the federal states of Schleswig-Holstein and Lower Saxony, with Schleswig-Holstein being particularly affected (about 58%, see Figure 56).

Electricity: network levels of curtailments and cause of feed-in management measures in 2019

	Curtailed energy (GWh)	Percentage of total curtailed energy (%)
Measures taken by TSOs (cause in transmission network)	**1,249.6**	**19**
Measures taken by DSOs	**5,232.8**	**81**
DSOs' own measures (cause in distribution network)	1,132.7	17
DSOs' support measures (cause in transmission network)	4,100.1	63
Total feed-in management measures	**6,482.4**	**100**

Table 55: Network levels of curtailments and cause of feed-in management measures in 2019

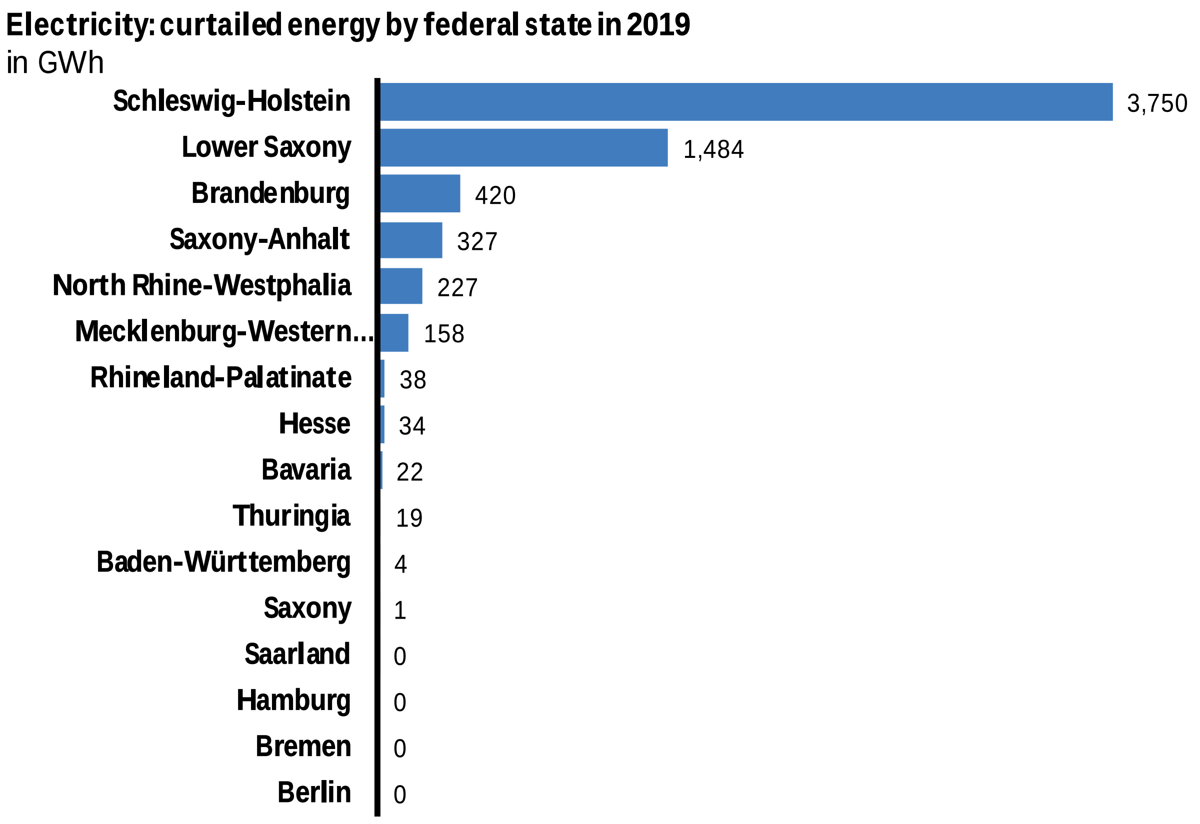


Figure 56: Curtailed energy by federal state in 2019

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 monthly basis. The costs incurred can therefore be directly compared with the amount of curtailed energy.

The actual compensation paid is the amount of compensation paid by the TSOs and DSOs to installation operators during the year under review. This is reported once a year in the monitoring survey. It includes the costs of compensation for measures taken up to three years previously. 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.[55]

The amount of compensation paid to installation operators in 2019 was about €1,058m, up around €340m on 2018 (2018: €719m; 2017: €574m; 2016: €514m). Most of the compensation paid in 2019 came under the EEG payments, with about €109,000 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 €20.43 per final consumer in 2019 (2018: €13.98; 2017: €11.37; 2016: €10.13; 2015: €6.26; 2014: €1.65). 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. The chart 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 2019 therefore does not reflect the actual amounts payable for the curtailments in 2019. The compensation paid in 2019 also includes amounts payable for curtailments in previous years.

[55] 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.

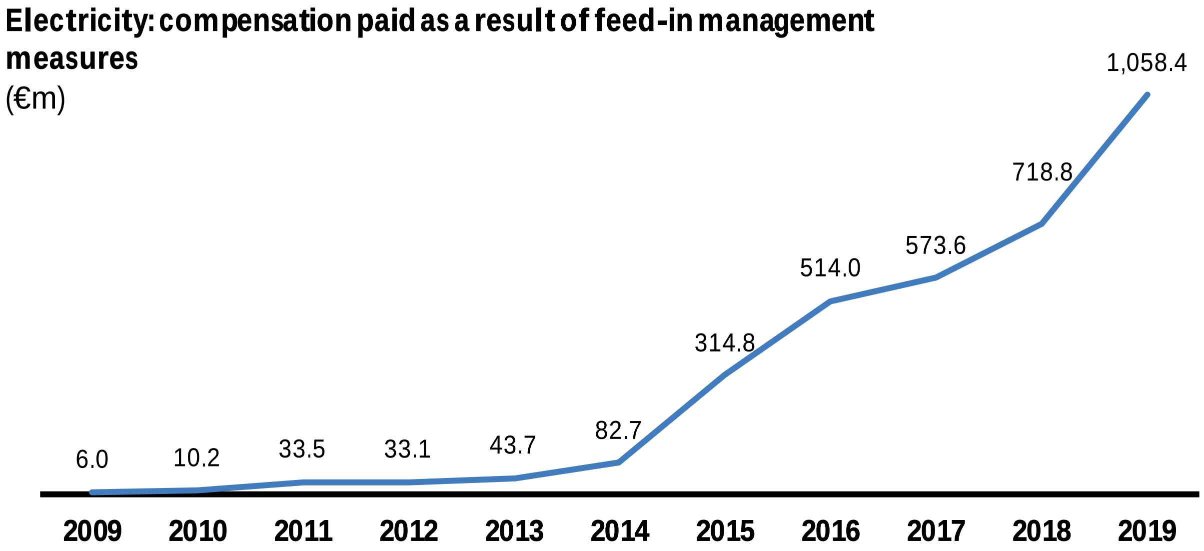


Figure 57: Compensation paid as a result of feed-in management measures

The claims for compensation from installation operators in 2019, based on the network operators' monthly estimates, amounted to around €710m, some €75m higher than in 2018.[56]

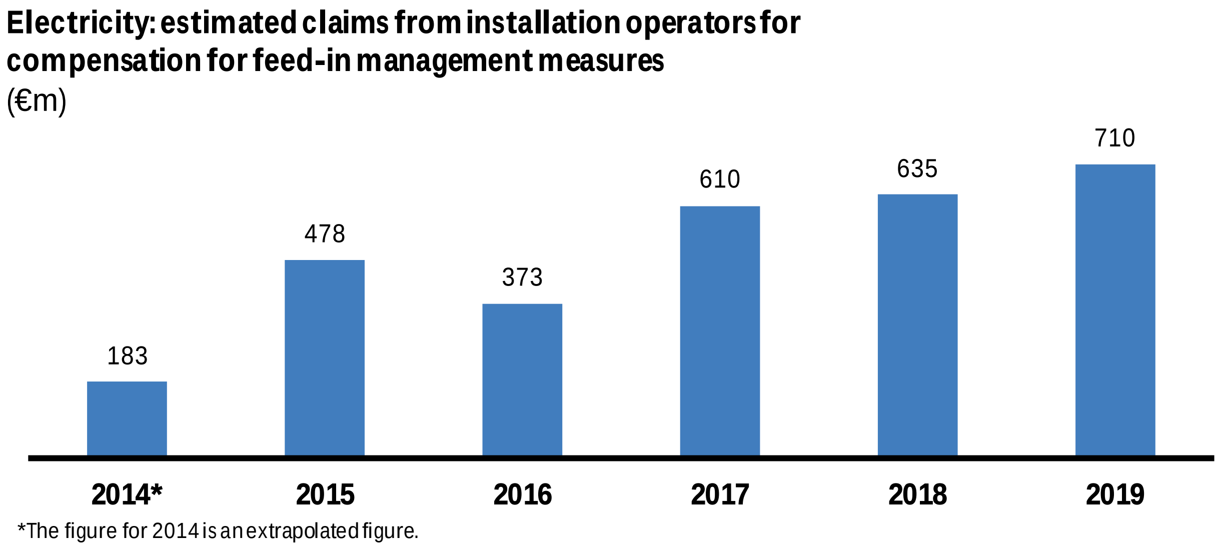


Figure 58: Estimated claims from installation operators for compensation for feed-in management measures

In 2019, the network operators paid a total of around €1,058m in compensation to the installation operators. Approximately €634m was compensation for curtailments actually occurring in 2019, while the remaining amount of around €424m was compensation for curtailments in previous years. This means that some 89% of the claims from installation operators for compensation for curtailments in 2019, as estimated by the network operators, have already been settled. At the time of the survey, around 40% (€286m) of the estimated compensation claims had not yet been settled; this will have a knock-on effect on the amount of

[56] See the Bundesnetzagentur's quarterly reports available at https://www.bundesnetzagentur.de/systemstudie

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 2019

	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)	**243**	**34%**	**526**	**50%**	**262**
Measures taken and compensation paid by DSOs	**466**	**66%**	**532**	**50%**	**162**
DSOs' own measures (cause in distribution network)	82	11.5%	145	13.7%	46
DSOs' support measures (cause in transmission network)	385	54.2%	387	36.6%	116
Total feed-in management measures	**710**	**100%**	**1,058**	**100%**	**424**

Table 56: Compensation payments by measures taken and compensation paid, and causes of feed-in management measures, according to network operators' reports in 2019

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 2019, a total of four DSOs took adjustment measures. The measures to adjust electricity feed-in totalled around 9.3 GWh. Non-biodegradable waste was by far the most frequently adjusted source of energy, accounting for around 97%. Brandenburg accounted for the majority of the adjustment measures with some 86%, followed by Saxony-Anhalt with about 12% and Thuringia with around 2%.

Electricity: feed-in and offtake adjustments by energy source in 2019

Energy source	Adjustments under section 13(2) (GWh)	Percentage of total (%)
Waste (non-biodegradable)	9.04	97%
Natural gas	0.26	3%
Total	**9.30**	**100%**

Table 57: Feed-in and offtake adjustments by energy source in 2019

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 2020 for household customers with an annual consumption of between 2,500 kWh and 5,000 kWh. Following a slight increase in 2019, the network charges for household customers increased again in 2020 from 7.22 ct/kWh to 7.50 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 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 as set out below.

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 cost examination for the currently ongoing third regulatory period (2019-2023) 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 current revenue caps. The fourth regulatory period begins on 1 January 2024 on the basis of the costs of the year 2021.

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.[57]

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.6.4) 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) 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 of the 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 chapter I.D).

– 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 investment 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

[57] 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%.

revenue cap, they are compared with actual developments. This applies particularly in the case of 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.

According to section 31 ARegV the revenue caps allowed for the individual network operators are to be published by the competent regulatory authority.

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 2,500 hours or more 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 expected 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 expected 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.

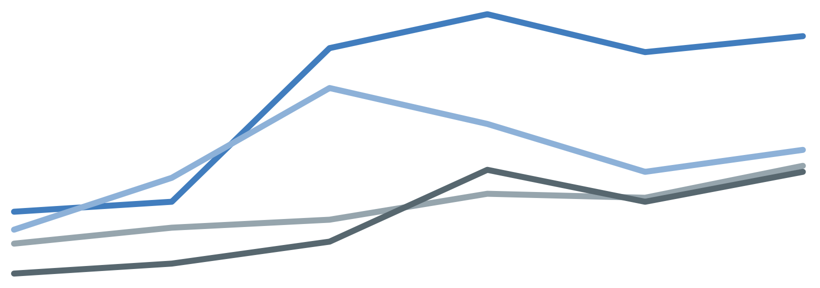
Other surcharges that form components of the final consumer price are detailed in I.G.4.3.

6.2 Development of network charges in Germany

6.2.1 Development of network charges at TSO level

The following chart shows the four TSOs' network charges from 2015 to 2020 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 StromNEV.

Electricity: TSOs' network charges
(ct/kWh)



	2015	2016	2017	2018	2019	2020
TenneT	0.33	0.35	0.64	0.70	0.63	0.66
50Hertz	0.30	0.40	0.56	0.50	0.41	0.45
TransnetBW	0.28	0.31	0.32	0.37	0.36	0.42
Amprion	0.22	0.24	0.28	0.41	0.35	0.41

TenneT 50Hertz TransnetBW Amprion

Figure 59: 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 decrease in network charges was in the 50Hertz control area in 2018. The changes to network charges 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 investment and for standby power plants, the grid reserve and loss energy – have a decisive influence on the development of the network charges. Thus the decrease in the network charge in the 50Hertz control area in 2018 was largely due to the costs saved through redispatching and feed-in management measures in the commissioning of the "Thuringia power bridge".

The TSOs' network charges for the example large industrial customer fell again in all four control areas for the first time in 2019. The main reason for this was the implementation of the Network Charges Modernisation Act (NEMoG), on the basis of which in 2019 the offshore connection costs were removed from the TSOs' network charges for the first time and transferred to the new offshore network surcharge. (If the offshore costs in 2018 and 2019 were presented in such a way that the offshore cost items are comparable, the decreases in the charges in 2019 appear significantly less than in 2018. In the TransnetBW control area there is even an increase in network charges for the sample customer[58]).

In 2020 the TSOs' network charges increased for the example large industrial customer then again in all four control areas - by 5.2% at TenneT, 9.3% at 50 Hertz, 16% at TransnetBW, and 15.7% at Ampron. This increase is largely the result of a revenue cap increase at all four TSOs, which is due, among other things, to increases in the costs of investment measures as a result of the ongoing network expansion and the increased planning costs for procuring balancing energy caused by higher balancing energy prices in the reference period 2018/19 (see section D.1 Costs for system services).

The development of the TSO's network charges was also influenced in 2020 by the implementation of the second 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. After 20% in the previous year, 40% of the respective TSO revenue cap is now shared throughout Germany. 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 increasingly shared between all network users nationwide. In 2020 only customers in the TenneT network derived a benefit from this, whereas in other TSOs' networks it led to a sharp increase in network charges.

6.2.2 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.[59] The consumption groups are as follows:

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[58] For a breakdown of the offshore network surcharge and an analysis of the comparability of the network charges with and without a surcharge see also the Monitoring Report 2019 Chapter 6.3.1.

[59] Net network charges do not include VAT.

– 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 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 as well as the consistently high level. For instance there was an increase in distributed feed-in, 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 power stations 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 again in 2020 by 3.9% from 7.22 ct/kWh to 7.50 ct/kWh.

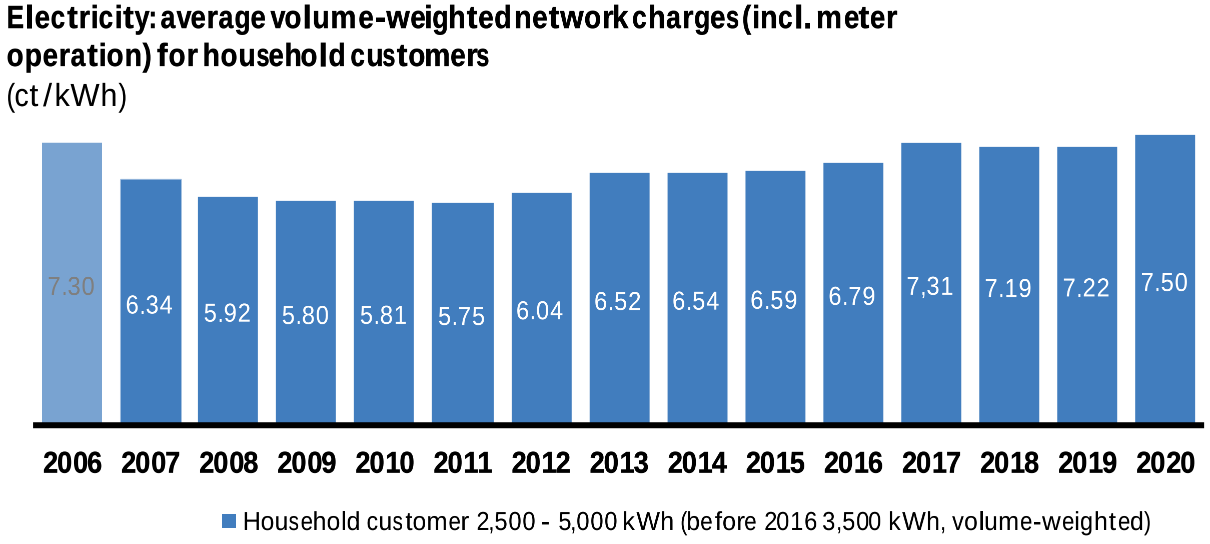

Figure 60: Average volume-weighted network charges for household customers from 2006[60] to 2020

According to the network operators' information on the provisional network charges for 2021, network charges by DSOs within the responsibility of the Bundesnetzagentur will remain on average virtually constant or increase only slightly. There are, however, significant differences between individual DSOs and among the control areas.

For non-household customers the arithmetic mean charges are higher than the previous year's level. The charges for commercial customers rose by +0.15 ct/kWh or slightly above 2% to 6.46 ct/kWh, while the arithmetic mean charges for industrial customers with an annual energy consumption of 24 GWh increased considerably by +0.37 ct/kWh or around 16% to 2.70 ct/kWh.

[60] 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.

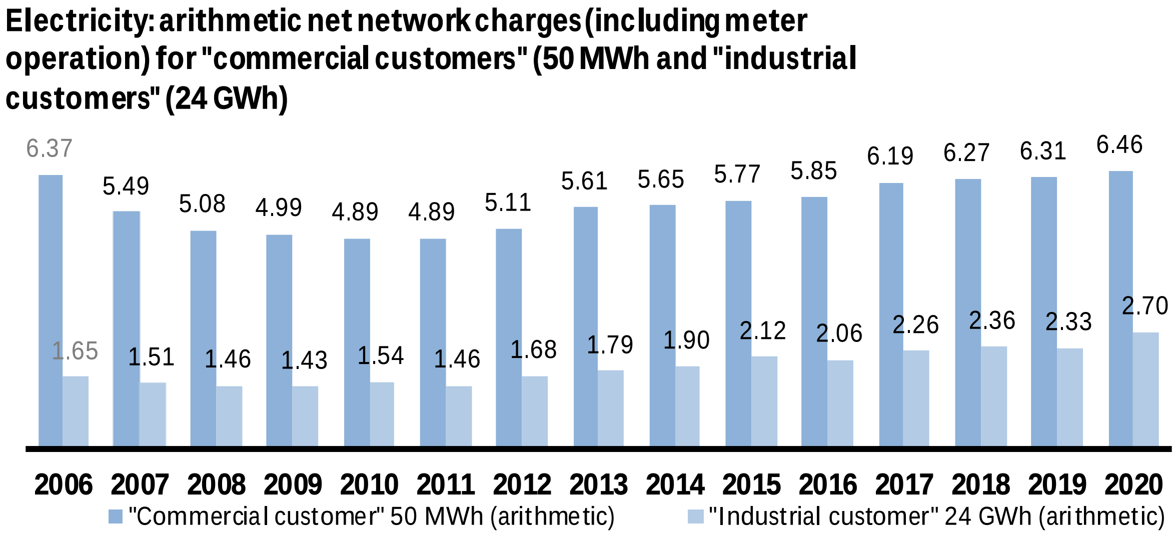

Figure 61: Arithmetic net network charges[61] (including meter operation) for "commercial customers" (50 MWh) and "industrial customers" (24 GWh)

6.2.3 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 SLP customers in Germany (see Figure 62). However, Table 58 shows a nationwide trend towards increasing standing charges in recent years. The maximum standing charge in 2020 remained at the previous year's level (2019: €105 per year).

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

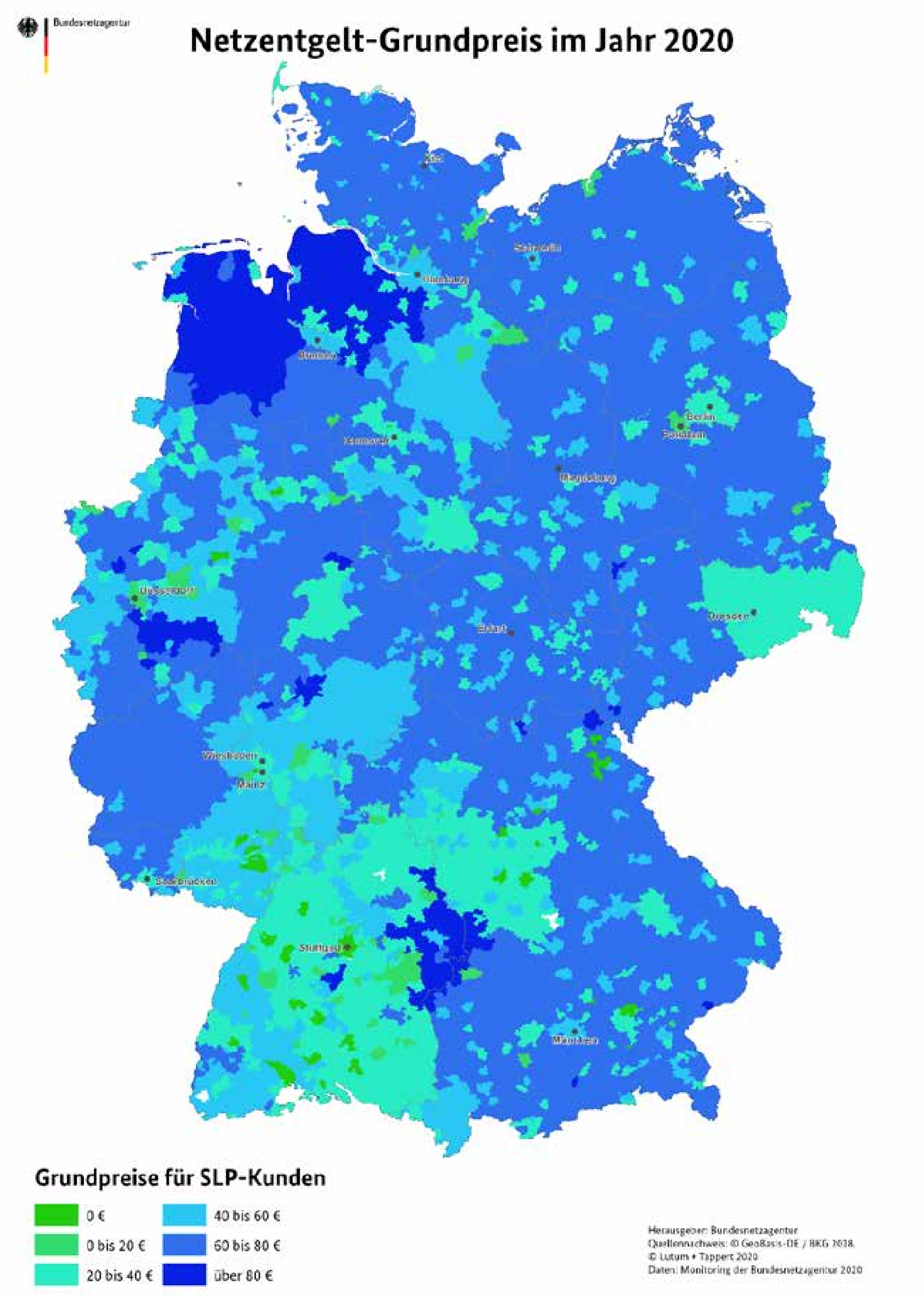

Figure 62: Network operators’ standing charges per year for SLP customers

Electricity: standing charges
(€/year)

	2017	2018	2019	2020
Average standing charge	35	37	40	52[2]
Maximum standing charge	95	100	105	105
Minimum standing charge [1]	6	4	7	8
DSOs without standing charge	46	36	42	40

[1] Minimum standing charge levied by DSOs.
[2] The standing charge for 2020 was weighted with DSO delivery volumes. Unweighted average: €42 per year.

Table 58: 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.

6.3 Regional distribution of network charges

There are large regional differences in the network charges. To compare network charges across Germany, the monitoring survey has collected information for the first time from the DSOs about the current network charges in their network areas. Information can then be compiled relating to the three consumption groups (household, commercial and industrial customers – see I.C.6.2. 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 requested 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.[62]

Results of the monitoring survey show that the DSOs' network charges for household customers range from 3.94 ct/kWh to 16.16 ct/kWh, which, in the extreme case, represents a difference by a factor of around four. It is notable that network charges are comparatively high primarily in the states of Schleswig-Holstein, Brandenburg, Hamburg and Mecklenburg-Western Pomerania. There are also differences between urban and

[62] 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.

rural areas. 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. The table below shows that the averaging of network charges obscures local and regional differences. As can be seen on the map on the following page, there are also exceptions in the federal states, with scattered network charges that are higher or lower than those in the surrounding area.

Electricity: net network charges for household customers in Germany in 2020
(ct/kWh)

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks included
Schleswig-Holstein	9.63	5.39	11.38	44
Brandenburg	8.45	4.79	14.20	36
Hamburg	8.17	4.34	11.38	11
Mecklenburg-Western Pom.	8.13	4.97	9.48	22
Saxony-Anhalt	7.52	5.01	10.39	34
Saarland	7.39	4.88	15.78	20
Thuringia	7.27	5.55	8.84	38
Lower Saxony	7.17	5.01	11.34	77
Saxony	7.16	5.19	9.34	42
Baden-Württemberg**	7.01	3.94	11.07	132
Bavaria	6.97	4.13	11.82	242
Hesse	6.92	4.34	9.82	65
Rhineland-Palatinate	6.79	4.80	8.76	56
North Rhine-Westphalia	6.72	4.34	16.16	118
Berlin	5.59	4.34	9.90	12
Bremen	5.56	4.34	8.66	10

* 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 59: Net network charges for household customers in Germany in 2020

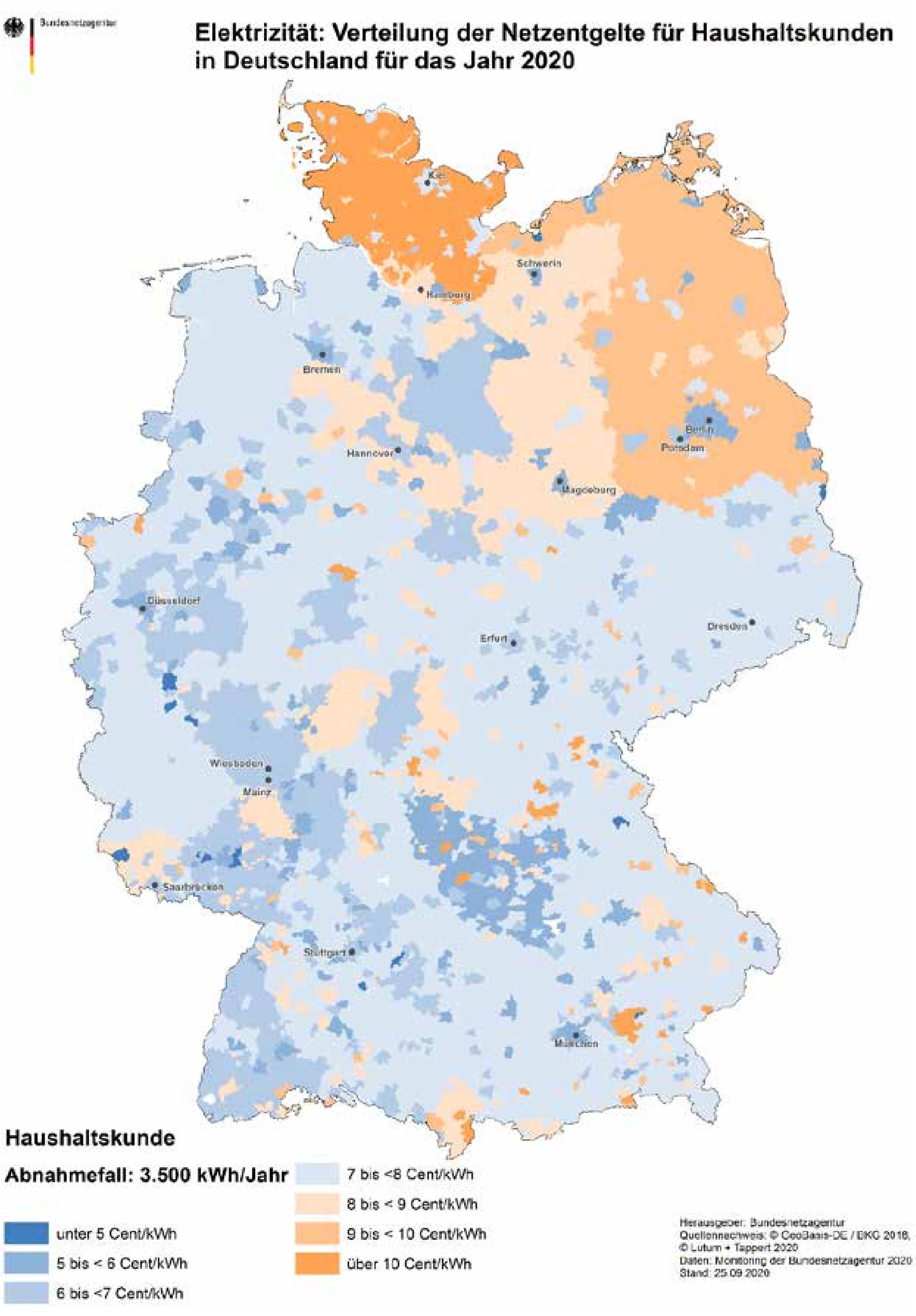

Figure 63: Spread of network charges for household customers in Germany in 2020

The spread of network charges for the 50 MWh annual consumption group (commercial customers) is similar to that for household customers, with charges ranging from 2.85 ct/kWh to 16.16 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 2020
(ct/kWh)

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks included
Schleswig-Holstein	7.79	4.79	9.53	47
Brandenburg	6.72	3.17	14.00	40
Hamburg	6.56	4.34	9.53	11
Mecklenburg-Western Pom.	6.45	4.21	8.35	21
Baden-Württemberg**	6.09	2.85	10.27	132
Saarland	5.63	3.42	15.14	20
Saxony	5.77	3.39	7.85	42
Thuringia	5.75	3.98	7.57	38
Saxony-Anhalt	5.52	4.13	9.32	34
Hesse	5.54	3.84	8.86	65
Bavaria	5.44	3.52	11.74	242
Rhineland-Palatinate	5.37	3.35	8.46	56
Lower Saxony	5.32	3.88	10.54	79
North Rhine-Westphalia	5.19	3.48	16.16	118
Berlin	4.74	4.34	8.75	13
Bremen	4.22	3.88	8.02	10

* 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 60: Net network charges for commercial customers (annual consumption 50 MWh) in Germany in 2020

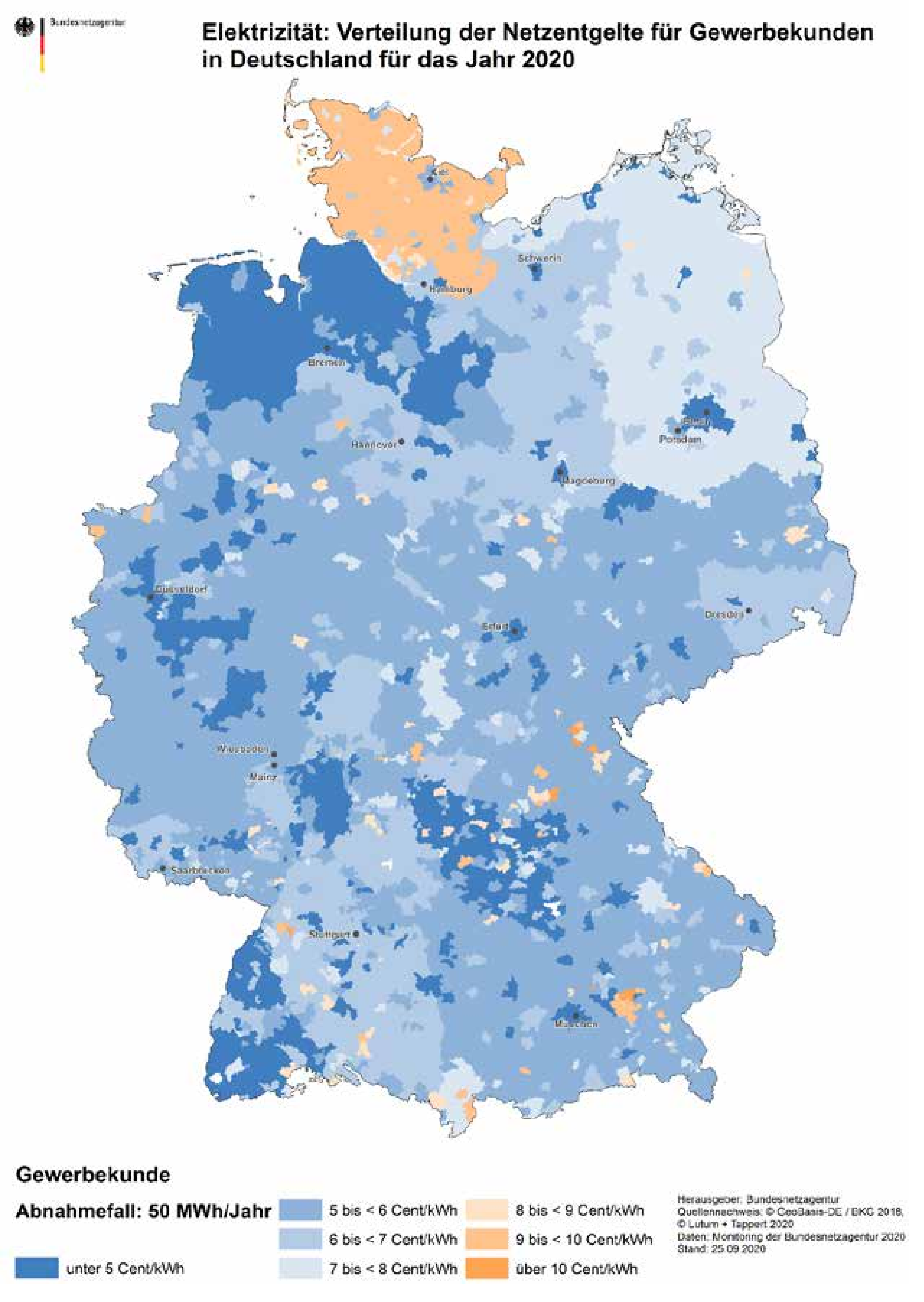

Figure 64: Spread of network charges for commercial customers (annual consumption 50 MWh) in Germany in 2020

The spread of network charges for the 24 GWh annual consumption group (industrial customers) is different. The network charges are also higher in Schleswig-Holstein than anywhere else in the country. The lowest average network charges are in Saarland. The network charges for industrial customers range from around 1.07 ct/kWh to 7.55 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 2020
(ct/kWh)

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks included
Schleswig-Holstein	3.44	1.56	5.50	45
Brandenburg	3.03	1.90	4.10	39
Mecklenburg-Western Pomeran	3.00	1.86	4.18	20
Hesse	2.87	1.36	3.97	67
Saxony-Anhalt	2.79	1.87	3.87	35
Thuringia	2.73	1.68	5.13	36
Saxony	2.66	1.72	6.62	42
Lower Saxony	2.61	1.47	4.44	80
Hamburg	2.61	2.09	4.12	11
Bavaria	2.53	1.16	7.55	232
Berlin	2.48	2.09	4.10	13
Baden-Württemberg	2.44	1.07	4.77	133
Bremen	2.41	2.09	3.24	10
Rhineland-Palatinate	2.24	1.61	3.17	56
North Rhine-Westphalia	2.23	1.38	4.29	119
Saarland	2.16	1.48	4.63	20

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

Table 61: Net network charges for industrial customers (annual consumption 24 GWh) in Germany in 2020

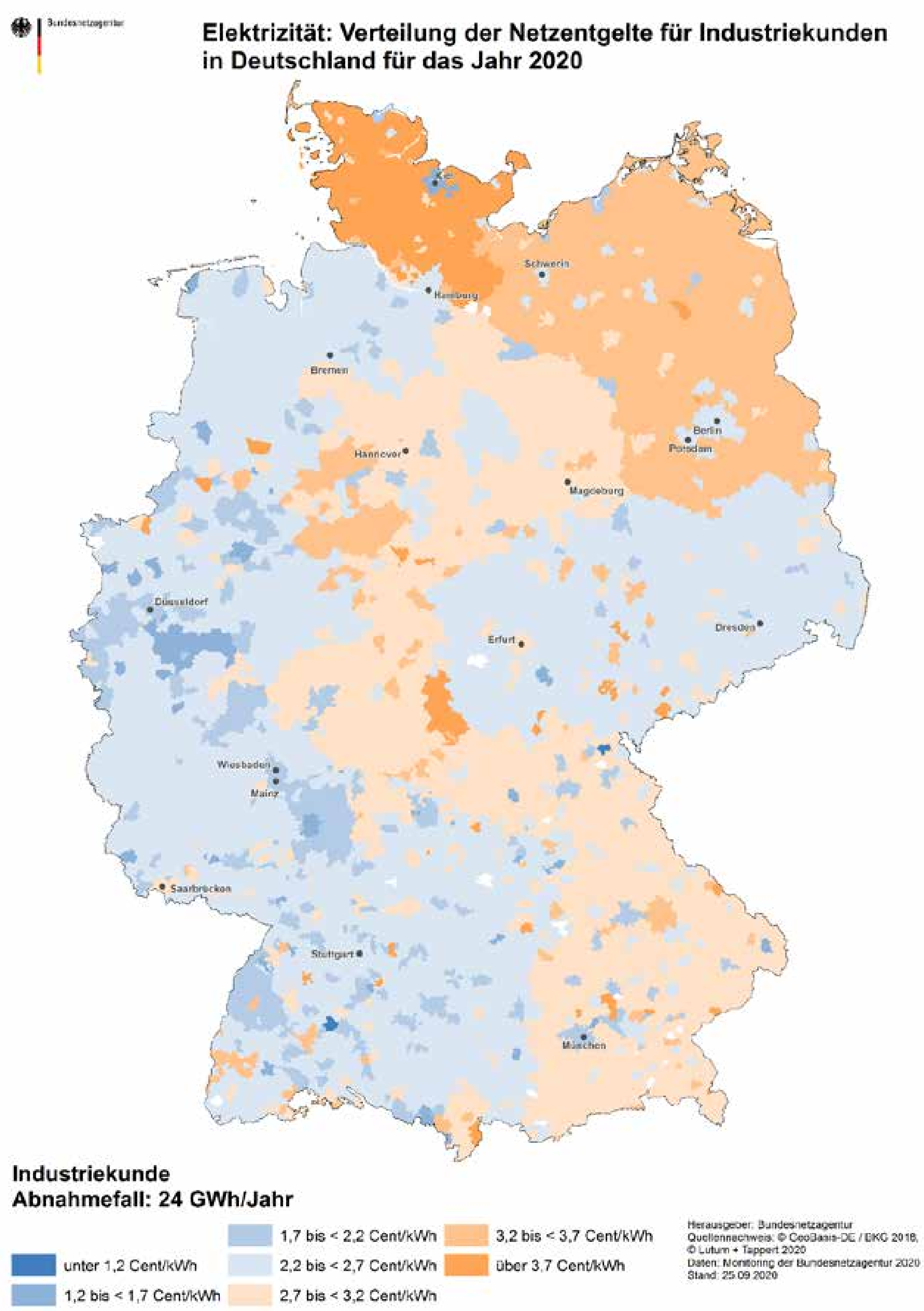

Figure 65: Spread of network charges for industrial customers (annual consumption 24 MWh) in Germany in 2020

The regional differences in network charges are due to a complex range of factors.[63] 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 among 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.

6.4 Avoided network charges

Subject of assessment

Under section 18(1) of the Electricity Network Charges Ordinance (StromNEV), operators of distributed generation plants 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.

In 2017 the Network Charges Modernisation Act (NEMoG) came into force,[64] which adjusted, among other things, the group of recipients and the amount of the avoided network charges.

The initiated changes concerning the avoided network charges can be divided into four stages.[65]

The Bundesnetzagentur has taken the completion of the third stage of the NEMoG as an opportunity to draw an interim conclusion about the effects of the avoided network charges.

Effective from 1 January 2018 the avoided network charges per kW of output and per kWh of work by the DSOs are "capped" for all distributed generators at the level of the adjusted charges for 2016. Prior to the

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

[64] The Network Charges Modernisation Act of 17 July 2017, Federal Law Gazette Part I page 2503; Bundestag Printed Paper 18/11528 of 15 March 2017 contains the draft bill by the Federal Government with reasoning, the response by the Bundesrat and the counter-response by the federal government.

[65] For detailed explanations (in German) of the changes see https://www.bundesnetzagentur.de/DE/Service-Funktionen/Beschlusskammern/BK08/BK8_61_Archiv/BK08_ALT/BK8_99_Downloads/Downloads/EOG_Hinweise_2018.pdf, S. 11 ff.

reform a significant part of the calculation basis for the avoided network charges were windfall profits. The offshore expansion costs in the charges at the transport network level resulted in higher upstream network costs and thus higher network charges in the distribution networks. That is to say, the level of the avoided network charges grew in particular as a result of network expansion measures, which under no circumstances can be avoided through distributed feed-in. In the adjusted price list for 2016, costs for offshore connection and added costs for underground cables in accordance with the Power Grid Expansion Act (EnLAG) were removed from network expansion costs. The adjusted price sheets for 2016 are referred to as reference price lists.[66] In this way an increase in the avoided network charges is controlled only by the actual "output avoided" and "work avoided" of the distributed generation plants and is no longer influenced by the general increase in network charges. On the contrary, a decreasing effect is possible: The general network charges for a given year are to be applied (stage I) if they are below the reference price.

Moreover, no avoided network charges were payable as from 2018 for new facilities with volatile generation[67] pursuant to section 120(1) para 2 of the Energy Industry Act (EnWG). This also applied to volatile generation facilities that are "resized" to a different voltage level. They are to be treated as new facilities and were excluded from the payment of avoided network charges beginning in 2018 (stage II).

In addition, starting in 2018 the avoided network charges for volatile facilities already in existence were gradually reduced. Whereas in 2018 66% and in 2019 33% of the avoided network charges were still remunerated, beginning with the 2020 calendar year the avoided network charges for volatile generation facilities will be eliminated entirely (stage III).

For the final stage (stage IV) beginning on 1 January 2023 new, non-volatile generation facilities will be excluded from the avoided network charges provision. The non-volatile facilities already in existence will remain under the provision with no time limit.

Positive effects of the NEMoG on network charges nationwide

In the years prior to the introduction of the NEMoG, the amount of avoided network charges paid was continually on the rise and reached its peak in 2017 at €2.5bn.[68] The NEMoG had the effect of reducing the amount of avoided network charges paid in 2018 to €1.3bn. In 2019 the actual costs fell to €1.2bn, of which €0.2bn were for volatile renewable generation facilities.

[66] Bourwieg and Brockmeier describe in detail the procedure for calculating the reference price lists in ER 6/2017, page 236 et seq (in German).

[67] Volatile generation within the meaning of section 3 para 38a EnWG is the generation of electricity from wind power plants and solar installations. Avoided network charges continue to be determined and remunerated for other facilities under the Renewable Energy Sources Act.

[68] These figures each relate to the network operators under the responsibility of the Bundesnetzagentur. The avoided network charges paid by the network operators under the responsibility of the federal states are not reported to the Bundesnetzagentur and therefore cannot be taken into account.

A further decrease in avoided network charges is expected in 2020 when the support for volatile facilities ends. This decrease is already noticeable in the budget figures, which estimate the avoided network charges at €1.028bn.[69]

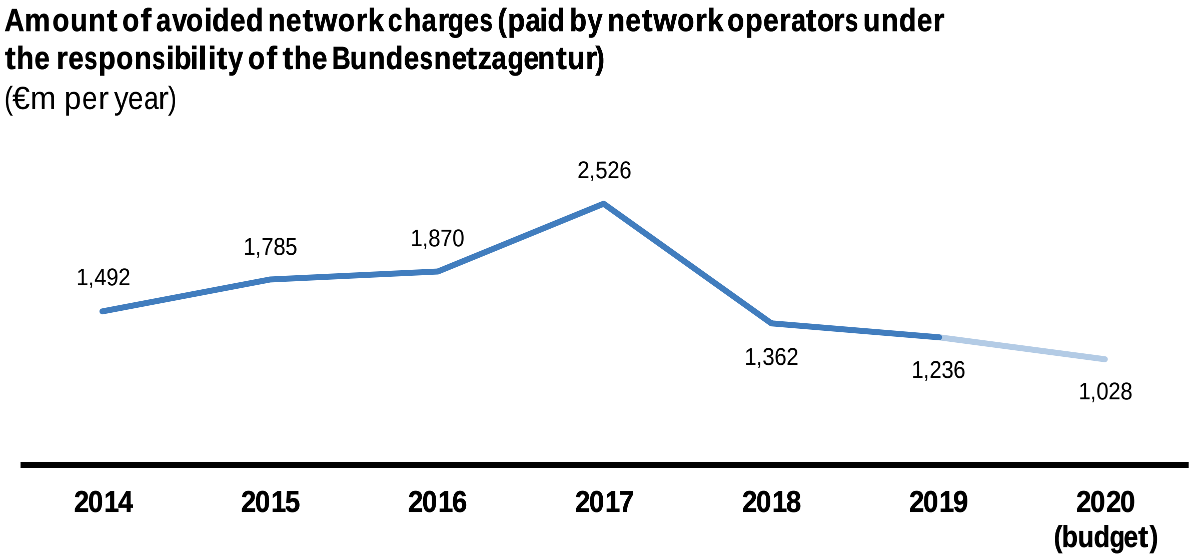

Figure 66: Amount of avoided network charges (paid by network operators under the responsibility of the Bundesnetzagentur)[70]

Relieving effect particularly for consumers in northern and eastern Germany

The network operator into whose network area distributed feed-in is provided is responsible for paying the avoided network charges since it is in this network that upstream network charges are avoided. The network operator then passes these costs on to its network users. Accordingly, network users in network areas with a high amount of distributed feed-in are more heavily burdened than network users in areas with a low amount of distributed feed-in.

Nationwide 4% to 5% of the network charges stem from costs that arise for network operators through paying avoided network charges.

The network charges are increased through distributed generation for customers in the downstream networks in which no distributed feed-in takes place. This is caused by the existing capacity of the jointly used upstream network (for example, of the transmission network) being used to a lesser extent. The continuing infrastructure costs are, however, distributed among the smaller scale customers and hence the specific network charges increase.

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[69] Because network operator companies can report and refinance the costs for avoided network charges on a planned basis and have a 1½-year delay before they must deliver the actual costs, final figures for 2020 are not yet available.

[70] Due to the termination of administrative agreements, figures of the network operators under the responsibility of the federal states of Mecklenburg-Western Pomerania and Thuringia are no longer included as from 2020. Figures from the federal state regulatory authorities are currently not available.

Regionally, those network users in the federal states of eastern Germany where loads are light were disproportionately burdened by avoided network charges. Accordingly, the network users in these regions also benefit the most from the changes to the NEMoG. This is exemplified by household customers of two distribution system operators covering large areas of eastern German federal states as shown in the table below.

Avoided network charges as a portion of the network charges for households (low voltage non-metered) taking cascading into account (%)

Eastern Germany DSO	Percentage in 2017	Percentage in 2020	Decrease in %
WEMAG Netz GmbH	16.9	12.1	-28.4
MITNetz	14.3	4.5	-68.5

Table 62: Percentage of avoided network charges as a portion of the network charges for households (low voltage non-metered) for 2017 compared with 2020 taking cascading into account.

The NEMoG reduces costs from avoided network charges and harmonises the TSOs' network charges. A harmonisation effect is noticeable with a further slight increase in the network charges (see Figure 67). Because the avoided network charges for volatile generators are being eliminated entirely in 2020 and the TSOs' network charges will continue to be gradually harmonised, the harmonisation visible in Figure 67 will also continue.

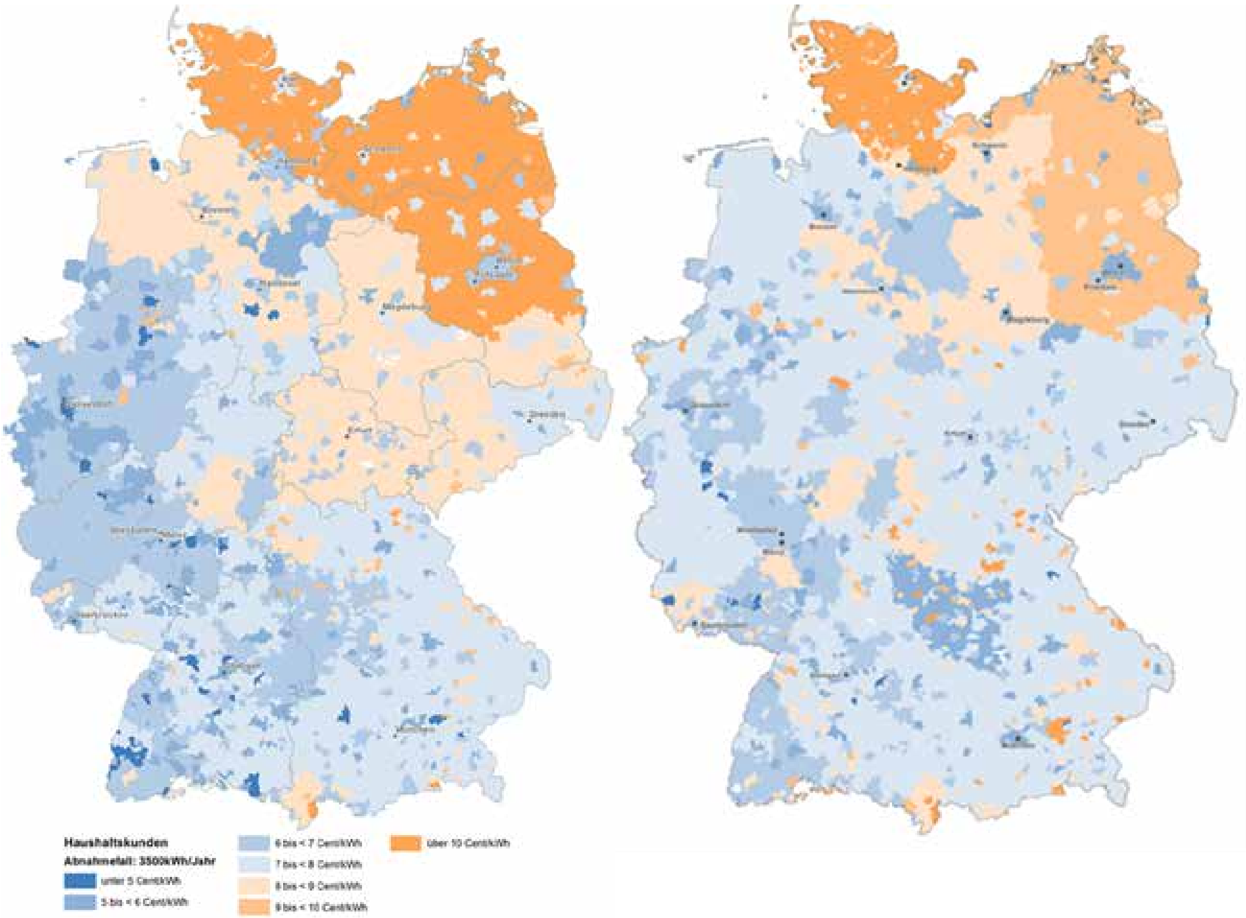

Figure 67: Network charges by region for household customers in 2017 (left) and 2020 (right).

Remaining burden from avoided network charges

Non-volatile facilities that went into operation before 1 January 2023 will continue to be remunerated. This includes mainly the following fuels:

- Waste
- Battery storage power station
- Biomass
- Lignite
- Landfill gas
- Natural gas
- Geothermal
- Pit gas
- Sewage treatment plant gas
- Run-of-river
- Mineral oil products
- Dammed water
- Hard coal

Continuing payment of avoided network charges to operators of non-volatile facilities will continue to cause an uneven burden on network users in individual network areas. This is evident when looking at the minimum and maximum values of the avoided network charges paid per network operator.

Only a single-digit number of the approximately 200 public supply network operators within the responsibility of the Bundesnetzagentur submitted projections for avoided network charges in the amount of €0 for 2020. Thus no generation facilities entitled to receive payment of avoided network charges feed into these network areas Table 63 below shows the maximum burden from avoided network charges in 2020:

Electricity: maximum burden from avoided network charges in 2020

Maximum cost of avoided network charges for a DSO in % of the total revenue cap[1]	35%
Maximum cost of avoided network charges for a DSO in absolute figures	€129m

[1] This means that 35% of the DSO's revenues are accounted for solely by the costs that this DSO incurs through the payment of avoided network charges to distributed generators.

Table 63: Maximum burden from avoided network charges in 2020

The highest budgeted amount measured in absolute figures for avoided network charges was reported by a large, national network operator. The highest budgeted percentage amount of the revenue cap set by the Bundesnetzagentur was submitted by a municipal network operator whose avoided network charges amount to 35% of the revenue cap.

Stage III's effect on the overall costs for electricity customers

No longer including the operators of volatile generation facilities in the mechanism of avoided network charges as a result of the NEMoG did not lead directly to relief for electricity customers overall. Renewable power plant operators, including operators of wind plants and solar installations, did not directly receive payment for avoided network charges prior to their elimination in accordance with section 18(1) StromNEV. The avoided network charges for the volatile generators were paid by the DSO in accordance with section 57(3) EEG to the TSOs' EEG account, from which the renewable energy input was and continues to be remunerated. The elimination of the avoided network charges for operators of volatile wind plants and solar installations did not lead to a reduction in the state-guaranteed feed-in tariff for the operators. The removal of the avoided network charges was compensated by increasing the renewable energy surcharge by the same amount, so the NEMoG actually has no direct effect for operators of volatile generation facilities.

As already described, the customers of each distribution network bear the costs for avoided network charges. However, final customers nationwide bear the higher costs for the EEG surcharge.
In this respect one objective of the NEMoG was met, which was to reduce the uneven regional burden that avoided network charges place on network costs.

No findings of allocative disincentives

Section 18(1) page 1 StromNEV states that new facilities going into operation after 31 December 2022 are not entitled to any funding through network charges.

As rising network charges in the past always led to increases in avoided network charges, there was reason to presume that an increasing number of distributed generation plants would be built in regions with particularly high network charges because of the economic incentives of avoided network charges. This would have affected precisely those regions with especially high renewable energy input, which would have been cause to view the addition of conventional generation plants in these regions as an allocative disincentive.

This presumption, however, could not be verified on the basis of the data available.

Since 2015 only 11 new distributed generation plants with a nominal capacity of at least 10 MW have gone into operation in the new federal states and the northern German federal states of Bremen, Hamburg, Lower Saxony and Schleswig-Holstein, that is to say those federal states in which payment of avoided network charges is the highest per kW or kWh.[71] Accordingly, neither the increased amount paid for avoided network charges, which followed the sharp increase of general network charges prior to the introduction of the NEMoG, nor the foreseeable phasing out of the institution of avoided network charges for new facilities led to an increase in the commissioning of conventional distributed electricity generating plants.

This leads to the conclusion that the amount of avoided network charges for power plant operators does not guide investment, nor is the amount reliably predictable. In particular, the avoided network charges for output avoided, ie the capacity fed into the grid by the distributed generation plants at the time of the annual peak load, cannot be precisely determined or included in dispatch planning by plant operators. At the same time, the output avoided constitutes the majority of the avoided network charges at the high and medium voltage level.[72]

Accordingly it can be said that the payment of avoided network charges does not appear to be an investment incentive in its own right for plant operators and as a result (rightly) does not seem to be decisive for a power station's investment calculations. Thus the payments are often not a predictable source of income, but rather they have the characteristic of a random bonus for the power station without having an effect on the energy industry.

No network expansion saved by avoided network charges

The concept of avoided network charges assumes that distributed feed-in will reduce consumption from, and thus use of, the upstream network, thereby saving network infrastructure costs.[73] The operators of the distributed generation plants should receive the resulting savings as remuneration. The remuneration that would otherwise be paid by the upstream network operator is provisionally set as the level since the actual amount of remuneration avoided cannot be determined.

The introduction of the principle of avoided network charges was based on the assumption that electricity flows from the highest to the lowest voltage level. This basic assumption of avoided network charges, specifically that distributed feed-in would lead to a reduction in network expansion measures in the medium to long-term, originated around the turn of the millennium.

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[71] See the Bundesnetzagentur List of Power Plants (in German), last updated on 1 April 2020, available at https://www.bundesnetzagentur.de/SharedDocs/Downloads/DE/Sachgebiete/Energie/Unternehmen_Institutionen/Versorgungssicherheit/Erzeugungskapazitaeten/Kraftwerksliste/Kraftwerksliste_2020_1.html?nn=320094

[72] For example in 2018 the DSOs under the responsibility of the Bundesnetzagentur paid high voltage distributed feeders €493m for output avoided but only €109m for work avoided.

[73] See most recently, for example, the statement in Bundestag Printed Paper 18/11528 of 15 March 2017, page 12.

This assumption was repeatedly criticised and the Bundesnetzagentur took the NEMoG as a turning point to consider the opportunity to consider the various instruments that can be used to guide and support network expansion on the basis of this basic assumption.

The network is generally dimensioned so that the peak load of the year for electricity can be met solely by taking from the upstream transmission network and not taking distributed feed-in into account,.

The amount of electricity and capacity provided through distributed feed-in effectively equates to less consumption from the upstream network level. If the capacity were not fed in from nearby, the same amount of electricity would be taken from the upstream network and priced. This means that elimination of the avoided network charges would not entirely eliminate the costs, but rather there would be higher upstream network charges for the local network operator, which would be passed on to the consumer. The amount of those charges cannot be predicted since the elimination of remuneration does not regularly eliminate distributed feed-in, neither from volatile feed-in from renewable generation facilities nor from conventional generation, which for other energy industry-related reasons was likewise established for distributed generation (eg to use cogeneration potential or for group generation among industrial consumers). In this respect upstream network costs are partially saved. However, it is clear that actual network (expansion) costs are not saved.

The following section is about the exceptions in the past where smaller network dimensioning was chosen due to distributed feed-in.

There are deviations from general practice when the feed-in from distributed generation plants exceeds the peak load of the year and the network dimensions must be increased accordingly to transport the electricity. This is caused mostly by the expansion of renewable generation facilities. The next section examines whether conventional distributed power stations also cause an expansion of network infrastructure.

Smaller dimensioned networks due to distributed feed-in

Less than ten DSOs under the Bundesnetzagentur's authority have dimensioned their networks smaller in the past due to distributed feed-in from conventional power stations and proportionately saved network infrastructure costs as was intended with avoided network charges.

However, this approach requires that a sufficient amount of capacity can still be provided at times when there is a scheduled overhaul, an unexpected outage or a plant closure. First and foremost, the operation of power generation plants must be economically sustainable, which for a long time has often not been the case. Due to the development of wholesale electricity prices in recent years, continuous feed-in from conventional power stations is often no longer economical. DSOs who were unable to meet their entire grid load from the upstream network due to inadequate network dimensioning have to fear high costs for local power stations that are essential for the system so that those power plants can constantly provide enough capacity.

Consequently, these DSOs then also expanded their connection to the grid to the upstream network operator, which in turn is reflected in the number of investment measure requests submitted to the Bundesnetzagentur.

This shows that DSOs cannot rely on distributed feed-in when planning long-term network dimensioning. There are no contractual commitments in the current rules of section 18 StromNEV that would require a distributed power station to provide continual or selective feed-in, for example, as a condition for the payment of avoided network charges. A preliminary assessment tells us that this would also not be helpful since a generation plant's profitability cannot be secured through avoided network charges and therefore further long-term (more than 10 years) financing of such facilities through the network users' local network charges would be necessary. Adequately dimensioning the network has regularly proven to be more efficient than constantly having to maintain reserve capacity.[74]

Previously in an integrated supply landscape there were certainly isolated instances where distribution networks dimensioned their networks smaller due to distributed feed-in and saved network infrastructure costs. The money that was saved, though, later led to additional costs in the course of implementing the energy transition. The costs that were previously saved on network infrastructure are then incurred during network expansion.

Network expansion for new connections of distributed conventional power stations

Connecting high-capacity fossil fuel power stations to the distribution network often means expanding the distribution network. The DSOs report any such expansion to the Bundesnetzagentur, and a newly connected fossil fuel power station typically costs in the tens of millions of euros. Expanding the network infrastructure is not necessary if a new power station is built on the site of an old, decommissioned power plant and the newly installed capacity does not significantly exceed the previously installed capacity.

Summary

The changes to avoided network charges introduced by the NEMoG have been effective. Capping the avoided network charges and eliminating them for volatile generators reduced avoided network charges from around €2.5bn in 2017 to around €1bn in 2020. This reduction is particularly beneficial for network users in rural areas of the new federal states. Starting in 2023 new distributed power stations will no longer receive avoided network charges. From that time onward the avoided network charges will continue to slowly decline.

Nevertheless avoided network charges still make up a significant portion (4% to 5%) of electricity customers' network charges over the long term.

After 10 years of network development planning it cannot be ascertained that distributed power plants, either renewable or conventional, save network infrastructure costs.

6.5 Transfer of electricity networks

Section 26(2) to (5) of the 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

[74] It was in this context that the Enervie Vernetzt GmbH case became publicly known in 2014. Since it was no longer possible to provide security of supply in the Enervie distribution network without operation of the distributed power stations, which had become economically unfeasible, these Enervie power stations were supposed to maintain reserve capacity. A search for other solutions ensued due to the dramatic economic consequences. As a result, Enervie also expanded its connection to the grid to the upstream network operator, see https://www.energate-messenger.de/news/148029/enervie-und-bundesnetzagentur-skizzieren-loesung-fuer-versorgungssicherheit.

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. 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.

As at the end of December 2019, the Bundesnetzagentur had received 76 applications for electricity network transfers in 2019. The following graph shows the number of applications made in the last six years. In 2019, ruling chamber 8 took decisions on 47 electricity network transfers.

Electricity: network transfer notifications / applications
(number)

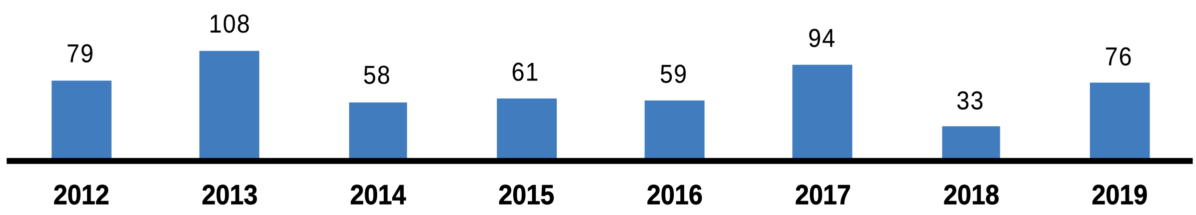

Figure 68: Network transfer notifications/applications

6.6 Individual network charges – StromNEV section 19(2)

Individual network charges can be agreed with the network operator by individual companies entitled to do so and, subject to the legal criteria, lead to a reduction in network charges for the company in question.

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 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) first sentence of the Ordinance and electricity-intensive network users as per section 19(2) second sentence.

While atypical network users shift their peak load to outside the network's peak load period, electricity-intensive network users have at the same time even and permanent consumption patterns. The criteria for determining these individual network charges were 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 2020. In 2019, a total 6,475 notifications for individual network charges for atypical network users were registered with the Bundesnetzagentur (see Table 64).

In the 2020 notification period, the Bundesnetzagentur received 786 further notifications for individual network charges in connection with atypical network users. Based on a preliminary estimate, the total realised amount of reductions in network charges granted for atypical users is set to increase again to some €330.1m, with a total of 7,261 billed offtake points.

Electricity: notifications for individual network charges for atypical network users

	2014	2015	2016	2017	2018[1]	2019[2]	New items 2020	2020[2]
Total number of offtake points granted reductions	1,500	2,987	3,375	5,210	5,344	6,475	+786	7,261
Total energy (TWh)	8.6	25.3	25.8	27.9	31.9	36.9	+2,02	38.9
Total reductions (€m)	85.6	292.2	310.8	271.8	262.9	308.4	+21,7	330.1

[1] Information based on acquired consumption data.

[2]Data for the years 2019 and 2020 are based on forecasts from the notifications submitted and are therefore classed as etimates.

Table 64: Notifications for individual network charges for atypical network users

The total amount of reductions in network charges granted to electricity-intensive network users in 2019 was considerably higher at around €778.4m (see Table 66), although the number of notifications for reductions for these users was significantly lower. In 2019, reductions were granted for a total of 501 offtake points for final consumers such as large businesses or industrial enterprises with particularly energy-intensive production processes.

For 2020 the total amount of reductions for electricity-intensive network users is expected to increase further to around €859.9m. The number of beneficiary offtake points is expected to increase to 571.

At the time this report was prepared, it was not possible to assess whether and to what extent the Covid-19 pandemic has had an effect on the consumption behaviour of electricity-intensive network users.

Elektrizität: Anzeigenbestand des individuellen Netzentgeltes für stromintensive Netznutzung

	2014	2015	2016	2017	2018[1]	2019[2]	Neuzugänge in 2020	2020[2]
Abgerechnete individuelle Netzentgeltvereinbarungen	255	275	317	345	378	501	+70,0	571
Jahresarbeit in TWh	40,0	42,6	45,2	47,3	48,7	70,4	+6,0	76,4
Reduzierungsvolumen in Mio. Euro	272,4	324,5	388,4	523,8	560,8	778,4	+81,5	859,9

[1] Die Angaben beruhen auf übernommenen Verbrauchswerten.

[2]Die Angaben für die Jahre 2019 und 2020 basieren auf Prognosen aus den eingereichten Anzeigen und gelten somit als geschätzte Werte.

Table 65: Notifications for individual network charges for electricity-intensive network users

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

	2014	2015	2016	2017	2018[1]	2019[2]	New items in 2020	2020[2]
Transmission network	59.0	69.0	79.0	117.9	155.5	276.2	+1,8	278
Regional network	124.0	142.0	168.0	225.8	219.2	250.6	+33,1	284
Distribution network	90.0	114.0	141.0	180.1	186.1	251.6	+46,6	298.2
Total	272.4	324.5	388.4	523.8	560.8	778.4	+81,5	859.9

[1] Information based on acquired consumption data.

[2]Data for the years 2019 and 2020 are based on forecasts from the notifications submitted and are therefore classed as etimates.

Table 66: Breakdown of total volume of reductions for electricity-intensive network users by network level category.

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

	2014	2015	2016	2017	2018[1]	2019[2]	New items in 2020	2020[2]
Transmission network	13.0	13.0	13.0	13.5	13.9	27.6	+0,2	27.8
Regional network	16.0	18.0	19.0	18.2	18.9	21.9	+2,7	24.6
Distribution network	11.0	12.0	13.0	12.9	15.8	20.8	+3,1	23.9
Total	40.0	42.6	45.2	44.6	48.7	70.3	+6,0	76.3

[1] Information based on acquired consumption data.

[2]Data for the years 2019 and 2020 are based on forecasts from the notifications submitted and are therefore classed as etimates.

Table 67: Breakdown of total final consumption for electricity-intensive network users by network level category.

The final figures for 2020 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.

6.7 Rescission of the network charge exemptions granted under section 18(2) of the StromNEV (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 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 individual cases under the responsibility of the Bundesnetzagentur and the regulatory authorities of the federal states.

The repayment volume amounted to €166m, plus recovery interest amounting to around €10m, 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

7.1 Electric vehicles/charging stations

The federal government's target in its programme to promote electromobility is for there to be one million electric vehicles on Germany's roads by 2022. To enable this target to be met, incentives have been created both for the purchase of electric vehicles and for the deployment of the required infrastructure nationwide. For the operators of electricity supply networks, the programme to promote electromobility means a large number of new consumption units that need to be connected to and supplied by the existing distribution networks. By 2030, there are to be one million publicly accessible recharging points alone.[75] The charging capacities, which are high compared to normal household applications, and the potentially high simultaneous demand in the evenings are creating new challenges for the network operators.

The network operators are therefore reliant on sufficient information about the number and location of electric vehicle recharging points in their networks in order to be able to guarantee forward-looking capacity planning and the safe operation of their networks at all times. Recharging points installed in private households could theoretically be connected without involving the network operator because the capacity of some existing building connections is sufficient. Because of this, a provision was incorporated into section 19 of the Low Voltage Connection Ordinance (NAV) in March 2019 requiring all electric vehicle charging infrastructure to be notified to the network operator. In addition, the operation of charging infrastructure with a capacity exceeding 12 kVA requires the prior agreement of the network operator, with the network operator having two months to investigate and respond to a request for agreement. If agreement is refused, the network operator must give the reasons in writing and must specify any remedial measures that could be taken by the network or infrastructure operator and the time needed for these measures.

In 2019, the network operators were notified of a total of 16,429 recharging points in accordance with section 19(2) NAV. This figure includes all private and public recharging points that are to be notified to the network operators.

In 91 cases, it was not immediately possible to agree to the charging infrastructure being connected.

The most common reasons for network operators refusing agreement were:

– insufficient capacity and safety of the existing building connection;

– lack of reserve capacity in the network;

– risk of voltage limits being exceeded;

– lack of short-circuit capacity in the network.

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[75] A recharging point is defined in section 2 para 6 LSV as infrastructure that is suitable and intended for charging electric vehicles and that is capable of charging only one electric vehicle at a time. The number of recharging points accessible to the public is therefore equal to the number of electric vehicles that can be charged at public points at any one time.

The most common measures proposed to charging infrastructure operators to remedy the reasons for not being able to connect infrastructure were:

– modernising and upgrading the building connection;

– installing a new building connection;

– restricting the charging capacity or recommending smaller-scale charging infrastructure;

– reinforcing and expanding the network.

Key to the success of electromobility alongside successful integration into the electricity networks is the nationwide deployment of interoperable and publicly accessible charging infrastructure. At EU level, requirements for the operation of charging infrastructure accessible to the public and for the interoperability of the technology used were therefore introduced in 2014 in Directive 2014/94/EU on the deployment of alternative fuels infrastructure. Germany was the first country to transpose the requirements into national law with the Charging Station Ordinance (LSV), which entered into force on 17 March 2016. The LSV specifies minimum technical requirements for the safe and interoperable deployment and operation of electric vehicle recharging points accessible to the public. These include binding provisions on the charging plugs used and an obligation to notify the Bundesnetzagentur.

The Bundesnetzagentur has been recording the notifications from operators of normal and high-power recharging points since July 2016 with a view to assessing the safety and interoperability requirements applicable to publicly accessible recharging points. 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 recharging 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 revised version of the LSV of June 2017 also requires operators of publicly accessible recharging points to enable electric vehicle users to charge their vehicles on an ad hoc basis without entering into a long-term contract for authentication and use. The Bundesnetzagentur was notified of a total of 17,013 charging stations with 33,691 recharging points by 15 July 2020, of which 27,731 recharging points had a power less than or equal to 22 kW (normal-power recharging points) and 5,137 were high-power recharging points. A total of 5,203 of these charging stations and 10,185 of these recharging points were taken into operation in 2019.

By comparison, according to the Kraftfahrt-Bundesamt (KBA – Federal Motor Transport Authority), 173,435 fully electric passenger vehicles and 143,807 plug-in hybrids were registered as at 1 July 2020. Based on the data available to the Bundesnetzagentur, the appropriate number of recharging points given as an indication in Directive 2014/94/EU of one recharging point per ten vehicles is therefore achieved nationwide (approximately one recharging point per nine vehicles). The actual need for an appropriate supply of charging infrastructure can, however, vary considerably between regions and depends on many factors, such as the availability of charging infrastructure where electric vehicle users live and work and developments in charging and battery capacity.

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	2,552	5,065	935	7
Bavaria	3,580	7,153	929	6
Berlin	649	1,235	126	5
Brandenburg	327	652	114	6
Bremen	146	295	46	4
Hamburg	583	1,192	130	4
Hesse	1,114	2,143	332	7
Mecklenburg-Western Pomerania	197	374	66	4
Lower Saxony	1,839	3,546	564	4
North Rhine-Westphalia	3,057	5,992	636	6
Rhineland-Palatinate	740	1,451	377	6
Saarland	114	241	45	7
Saxony	680	1,491	288	3
Saxony-Anhalt	314	628	153	4
Schleswig-Holstein	717	1,418	212	5
Thuringia	404	815	184	4

*Electric vehicles and plug-in hybrids as at 1 July 2020

Table 68: Distribution of notified charging infrastructure in the federal states (as at July 2020)

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.

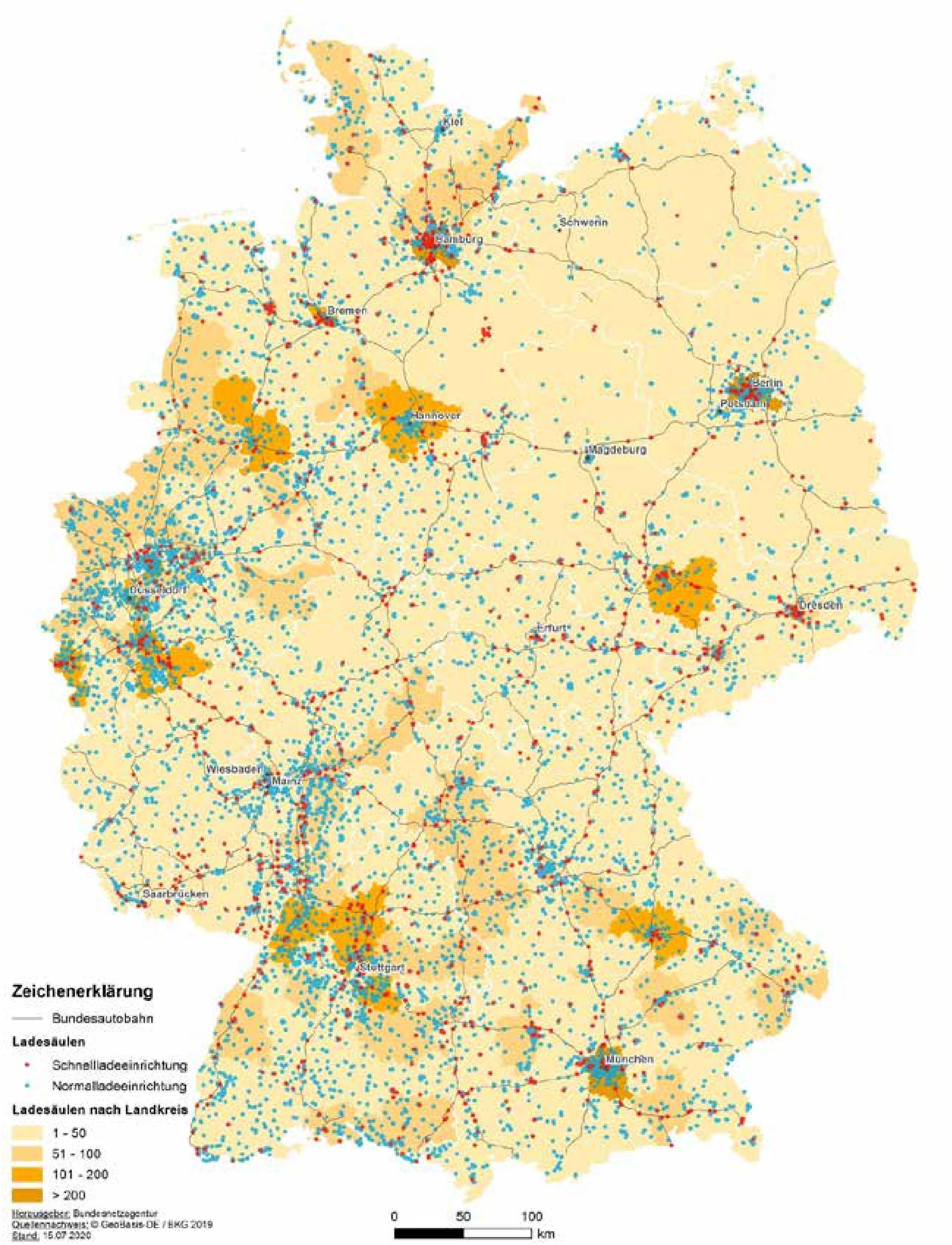
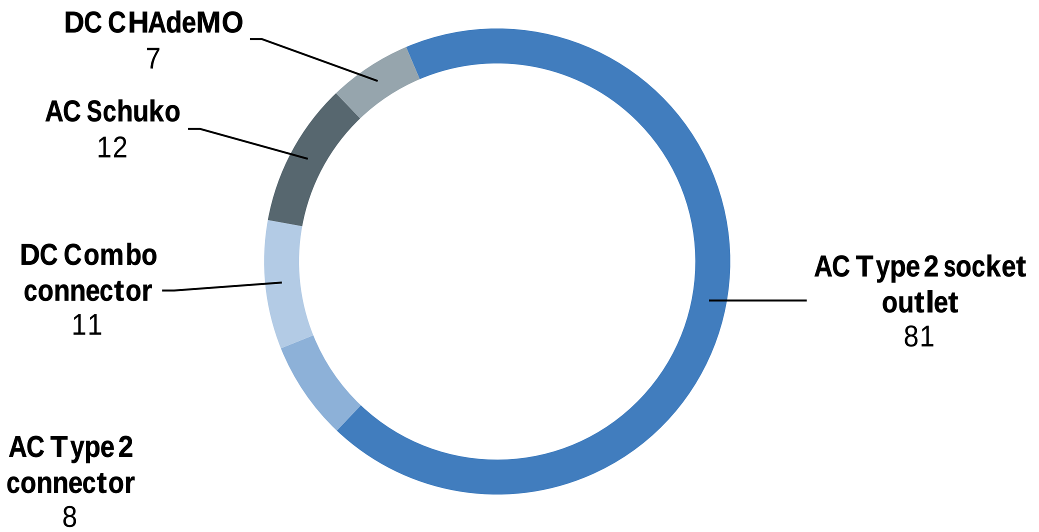


Figure 69: Charging stations in Germany notified pursuant to the LSV, as at July 2020

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 "Combo 2" vehicle connector. 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
(%)



As at July 2020

Figure 70: Breakdown of charging plugs by type in Germany

The charging capacities of the recharging points are distributed as shown in Figure 71. 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. The number of high-power recharging points in operation with a power between 150 kW and 350 kW has increased from only about 150 at the beginning of 2019 to more than 700.

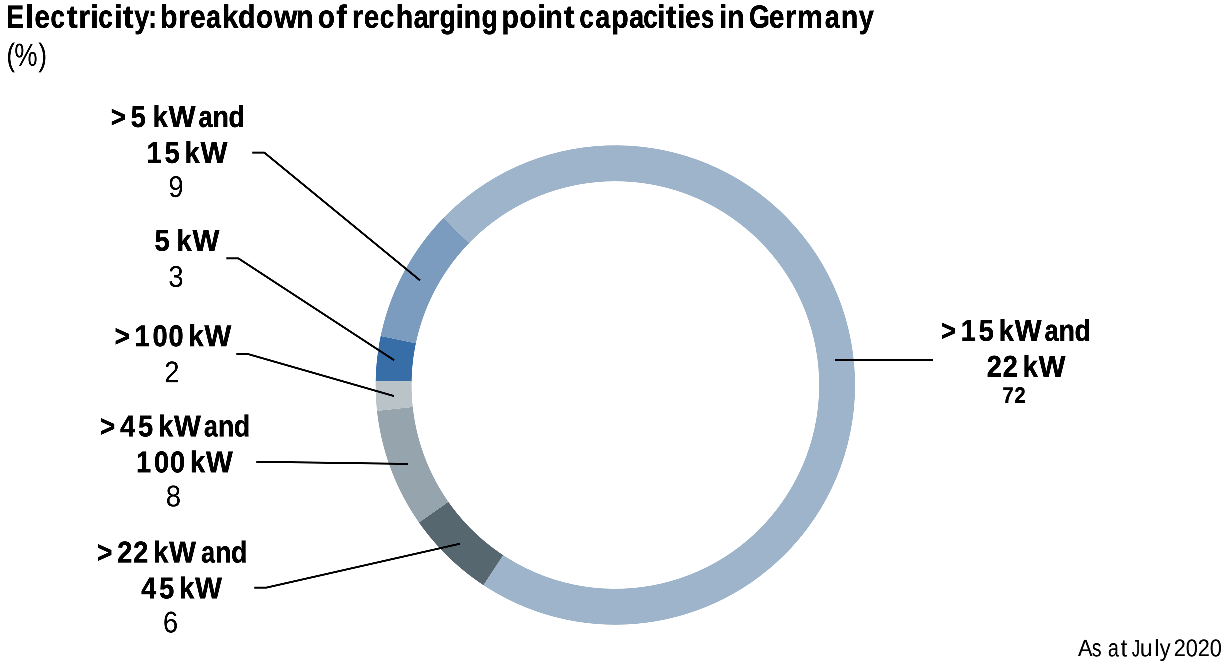


Figure 71: Breakdown of recharging point capacities in Germany

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.

A mixed picture emerged from the data supplied by the providers surveyed on the prices payable for charging electric vehicles at publicly accessible recharging points. The charging prices payable by electric vehicle users fluctuate between charging infrastructure operators as well as with respect to the terms of payment (provider-own access card, third-party provider access card, recharging on an ad hoc basis in accordance with section 4 LSV). Such fluctuations are common in the early stages of a developing market.

7.2 Load control

Section 14a of the Energy Industry Act (EnWG) gives distribution system operators (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 with final consumers with controllable (previously interruptible) consumer equipment, in return for a reduction in the network charge. The aim is to prevent this equipment from consuming a large amount of electricity from the low-voltage network at times when consumption is already high and from thus causing localised overloading. The arrangement is essentially designed for consumer equipment such as night storage heating systems, heat pumps and electric vehicles.

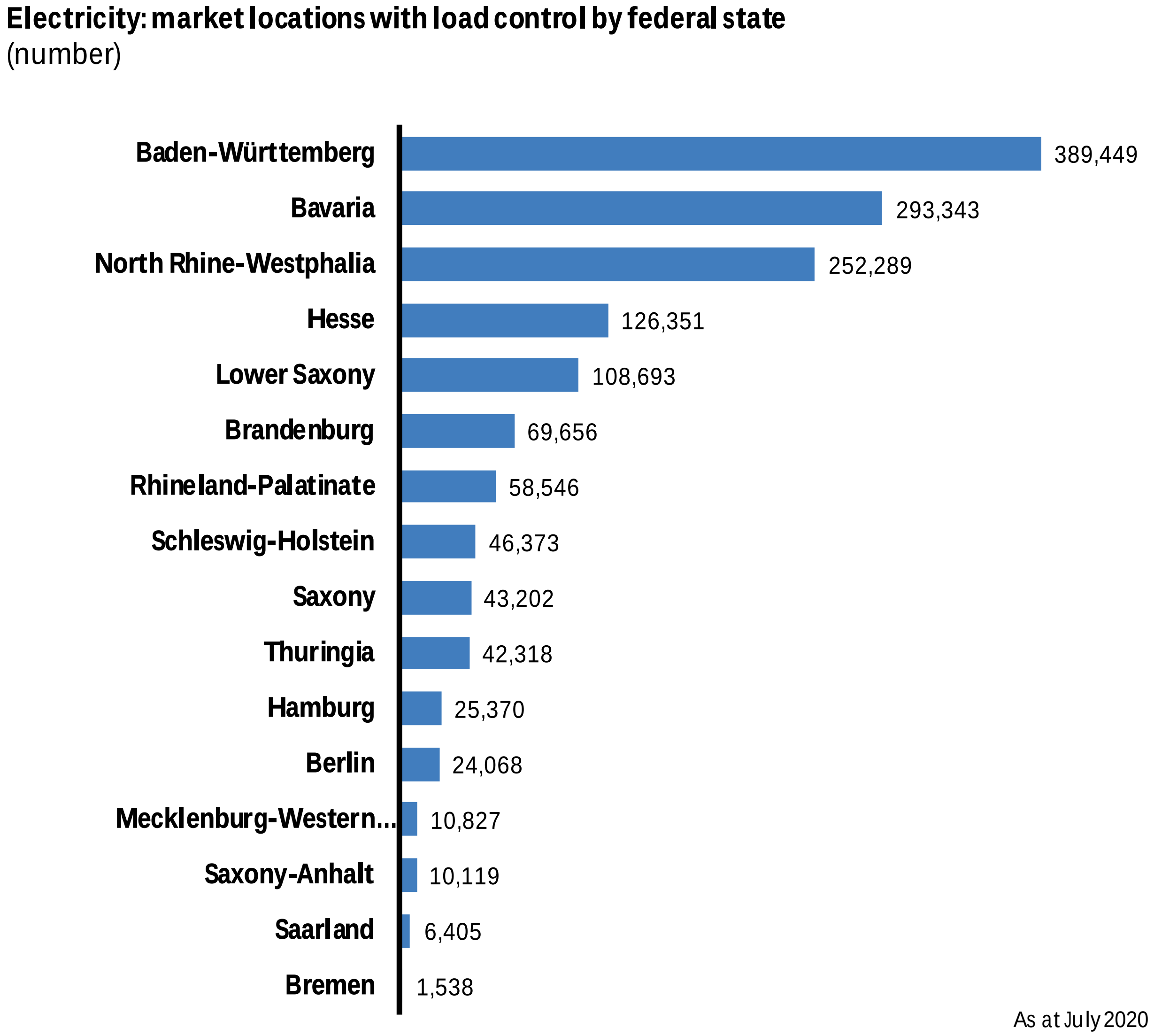


Figure 72: Market locations with load control by federal state

A total of 686 out of the 838 network operators surveyed stated that they took advantage of the provision and levied reduced network charges for a total of 1,502,360 market locations with load control. The number of market locations with load control is about 53,000 higher than in the previous year, but this is due to data being provided by one additional DSO that had not reported data in previous years. Without these additional data, the number would be around 1,500 lower than in the previous year. The regional distribution is shown in Figure 72. As in previous years, 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.

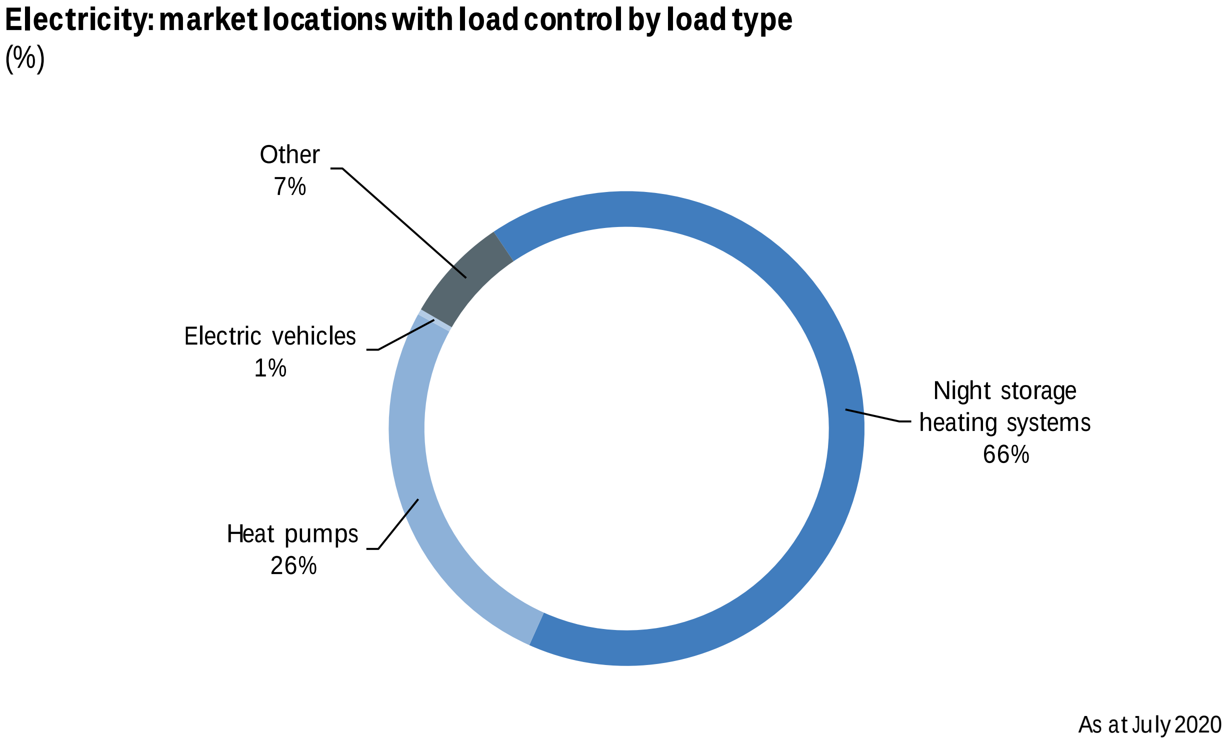


Figure 73: Breakdown of market locations with reduced network charges by load type

It is still the case that almost all the market locations with load control are for heating systems (see Figure 73), 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 the different types of load have changed slightly in comparison with last year. The share of night storage heating systems is down by about one percentage point, while the share of heat pumps is up by two percentage points. The share of the "Other" loads is down slightly; one reason for this is that a new, separate category has been introduced for electric vehicle charging infrastructure, which accounts for 0.38%.

The average reduction in the network charge given by network operators in return for load control is about 57%, which corresponds to an average discount of 3.69 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 85% of the charge for the use of the network, while the lowest is just 16%, 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, while barely 2% use the more modern remote control technology. About 5% of the network operators do not use any control technology at all, while about a third use time switching. The use of control technology for electric vehicles is very different. Ripple control accounts for only about a quarter, remote control technology also accounts for around 2% in this case, but only just over 11% of network operators use time switching. What is striking, however, is that no control technology at all is used for well over half of the electric vehicles, even though the vehicles benefit from section 14a network charges. Figure 74 shows a more detailed breakdown of the control technologies used.

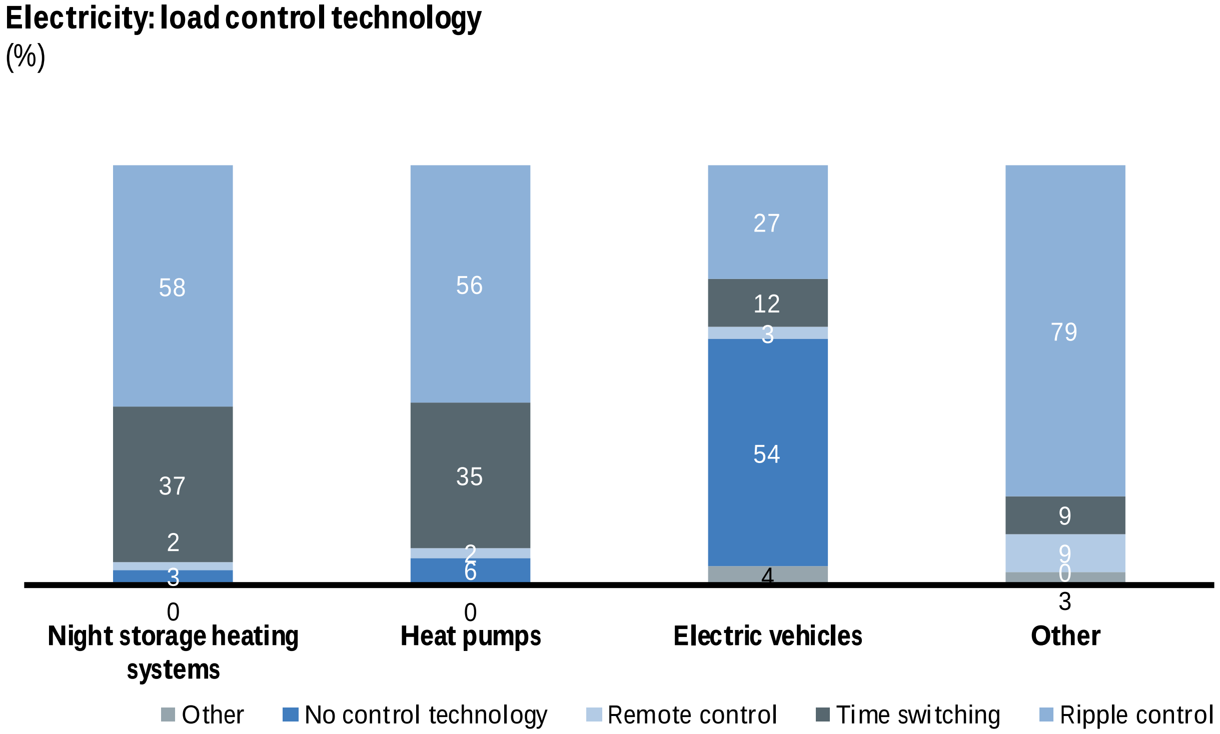


Figure 74: Load control technology

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. This applies as soon as the Federal Office for Information Security (BSI) has determined the technical feasibility. 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, maintaining voltage stability in particular by means of reactive power, providing 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 recovered through the network charges amounted to €1,931.2m in 2019 (2018: €1,933.2m).[76]

Major costs in 2019 were the costs of reserving and using grid reserve power plants at around €278.1m (2018: €415.8m; -33%), national and cross-border redispatching at €227.2m (2018: €388.2m; -41%), the estimated claims for compensation for feed-in management measures at €709.5m (2018: €635.4m; +12%) and energy to compensate for losses at about €321.2m (2018: €288.0m; +12%). There was an increase in particular in the costs for contracting the balancing reserves FCR, aFRR and mFRR, which totalled €285.7m (2018: €123.3m; +132%). One of the reasons for the large increase is the application of the mixed price procedure in the tendering for aFRR und mFRR from October 2018 to July 2019, which resulted in higher capacity prices for aFRR and mFRR compared to the previous award procedure (price effect). Another reason is that from July 2019 onwards the TSOs tendered significantly larger volumes of mFRR than in the same period of the previous year (volume effect). The increase in the volumes is due to a change in the methodology used by the TSOs to determine the volumes of balancing capacity to be tendered. The volumes of balancing capacity tendered for the third and fourth quarters of 2019 were based on the volumes used in the previous twelve months, while up to and including the second quarter of 2019, the volumes tendered were based on the figures for the same quarters in the previous four years. The change in the methodology resulted in a significant increase in the volumes tendered, in particular for positive mFRR, because of the larger volumes used since the fourth quarter of 2018.

[76] Net costs (outlay costs minus cost-reducing revenues)

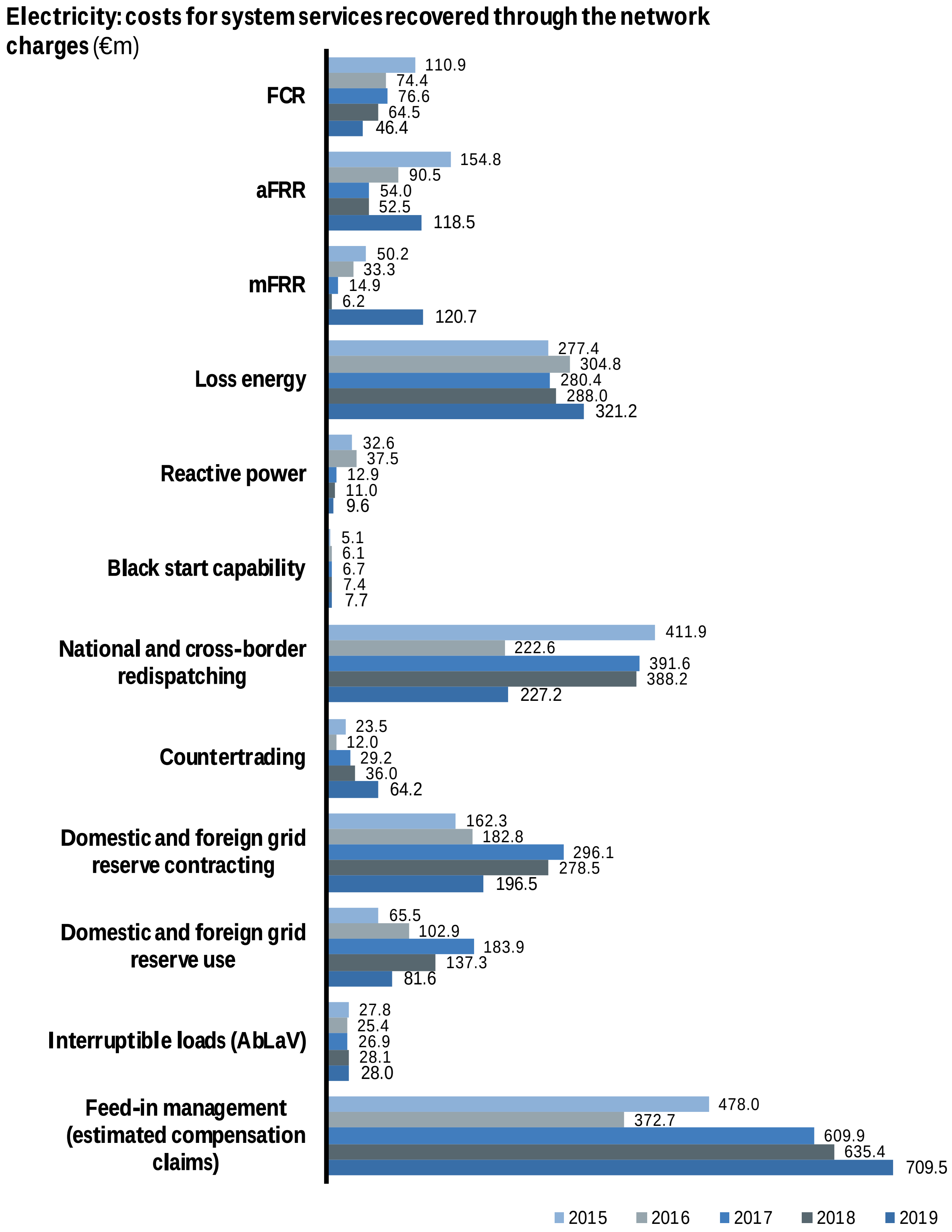
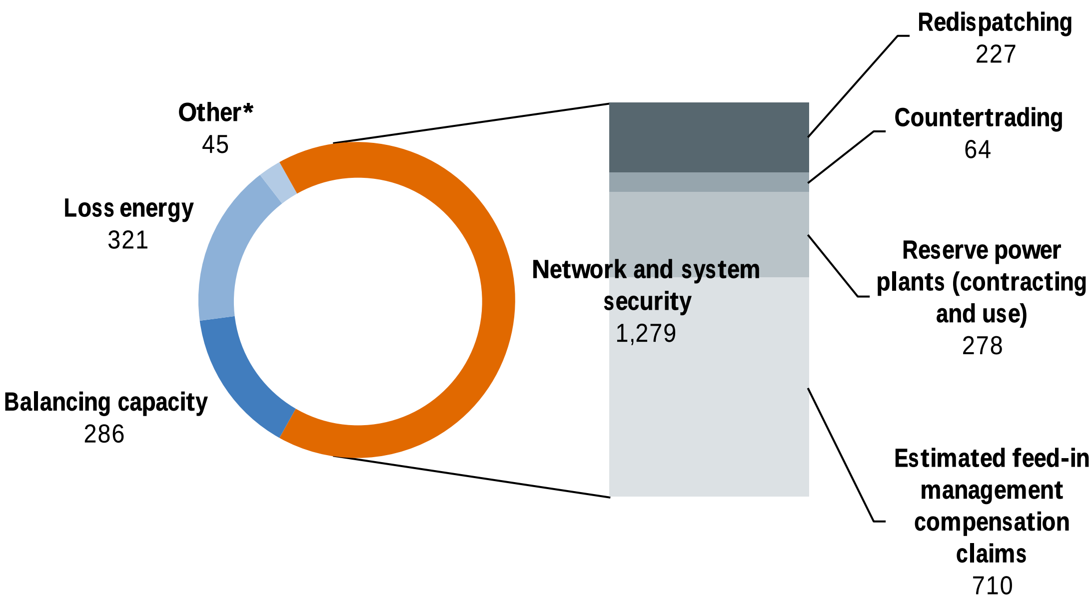


Figure 75: Costs for system services recovered through the network charges

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 €1,279.0m but were again down on the previous year (see also I.C.5). Figure 75 shows the development in the costs for system services from 2015 to 2019. Figure 76 shows a breakdown of the costs for 2019.

Electricity: breakdown of the costs for system services and for network and system security in 2019
(€m)



*Other: reactive power, black start capability, interruptible loads under AbLaV

Figure 76: Breakdown of the costs for system services and for network and system security in 2019

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.[77] 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.[78]

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[77] Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing, Article 2 point (3)

[78] 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.

– 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 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

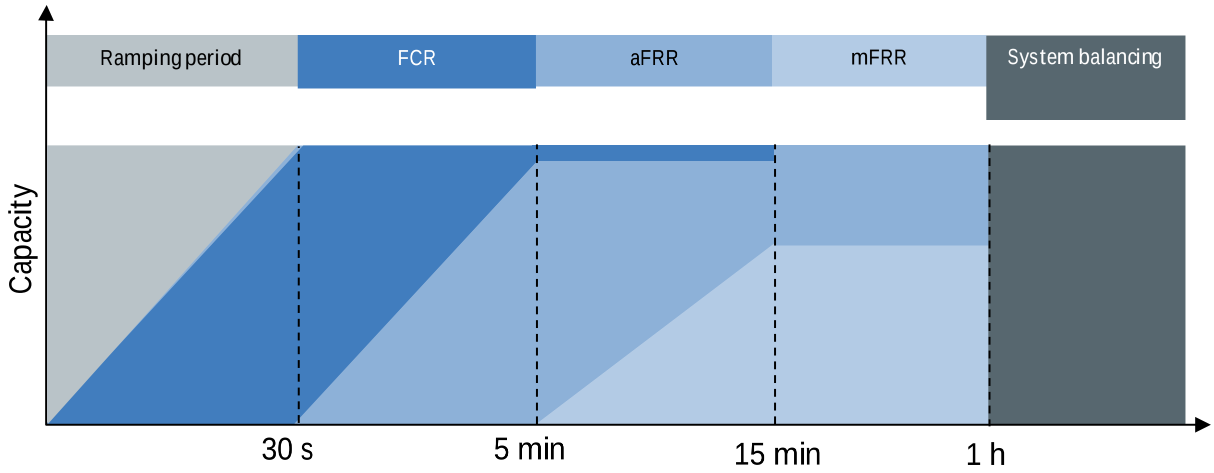


Figure 77: Order and time frame for the use of balancing services

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, France, Croatia and Slovenia 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

The TSOs responsible for the control areas in Germany procure the balancing capacity that they require for system balancing in national tendering processes in accordance with the provisions of the Bundesnetzagentur's determinations and approvals on FCR[79], aFRR[80] and mFRR.

The tendering for the procurement of aFRR and mFRR was, however, redesigned following the entry into force of new European provisions.[81] The new provisions require the TSOs to introduce a balancing energy market for aFRR and mFRR. The Bundesnetzagentur approved the TSOs' application for the introduction of a balancing energy market in Germany on 2 October 2019 (BK6-18-004-RAM). As of 2 November 2020 there are separate tendering processes for balancing capacity and balancing energy. In the past, balancing energy could only be delivered by providers successfully bidding in the capacity market; now, balancing energy may be delivered by all pre-qualified providers and – in contrast to the previous design of the tendering process – is independent of participation in the capacity market.

FCR is procured as a symmetric product. No distinction is made between positive and negative balancing services. Nor is a distinction made between "holding" and "delivering" FCR capacity and consequently there are no separate tendering processes for FCR capacity and energy and therefore no balancing energy market.

In the past, balancing capacity was 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). As a result, in July 2018 the tendering frequency for aFRR was changed from one week to one calendar day. In addition, the product length was shortened considerably to four hours. These changes are essential in particular for wind and photovoltaic generators to be able to

[79] Ausschreibungen gemäß Beschluss BK6-18-006 vom 13. Dezember 2018. Siehe I.D.3.1

[80] Gemeinsame Ausschreibung von Deutschland und Österreich seit Anfang 2020 gemäß den Beschlüssen BK6-18-064 vom 18. Dezember 2018 und BK6-19-160 vom 12. Dezember 2019. Siehe I.D.3.3

[81] Verordnung (EU) 2017/2195 der Kommission vom 23. November 2017 zur Festlegung einer Leitlinie über den Systemausgleich im Elektrizitätsversorgungssystem sowie Verordnung (EU) 2019/943 vom 5. Juni 2019 über den Elektrizitätsbinnenmarkt.

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 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 balancing energy market is designed to make it easier for flexible generators to participate in the balancing markets because balancing energy bids can be submitted and changed up to one hour before the product is delivered.

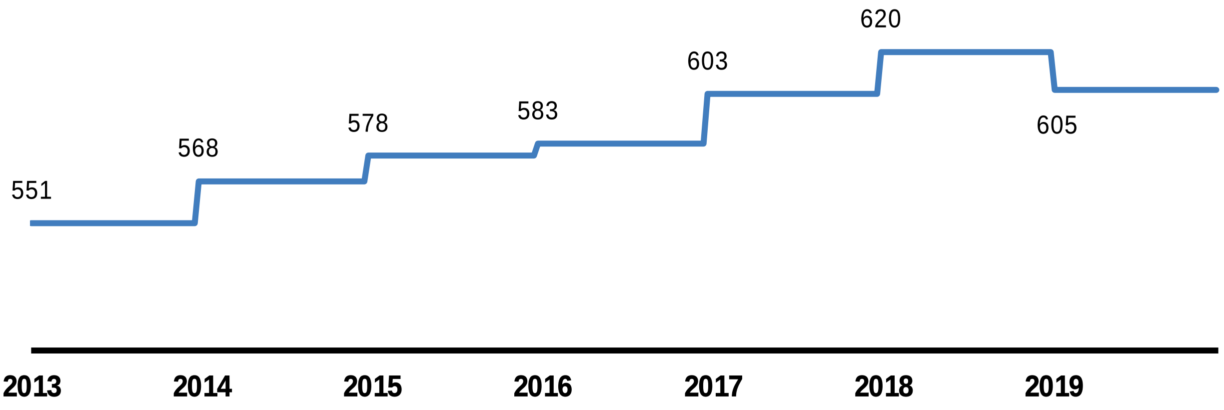
As from the delivery day 10 December 2019, the requirements for positive and negative aFRR and mFRR are determined not on a quarterly basis but in a dynamic process in which the individual requirements are determined for each four-hour product.

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 14 July 2020, the number of pre-qualified balancing service providers stood at 29 for FCR (2019: 30; 2018: 24), 35 for aFRR (2019: 37; 2018: 38) and 40 for mFRR (2019: 45; 2018: 46). There was therefore a slight decrease in the number of pre-qualified providers for all three types of balancing services.

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 78 shows a continued slight increase in the amount of FCR to be contracted by the German TSOs in recent years. In 2019, however, the first deviation from this trend was recorded, with the volume of FCR tendered decreasing slightly from 620 MW in 2018 to 605 MW.

Electricity: FCR tendered in the control areas of 50Hertz, Amprion, TenneT and TransnetBW
(MW)



Source: regelleistung.net

Figure 78: FCR tendered in the control areas of 50Hertz, Amprion, TenneT and TransnetBW

Procurement of aFRR

Figure 79 shows that in 2019 there was a slight increase in the average volume of both positive and negative aFRR tendered compared with the previous years. The average volume of positive aFRR tendered was 1,903 MW (2018: 1,876 MW) and the average volume of negative aFRR tendered was 1,798 MW (2018: 1,780 MW).

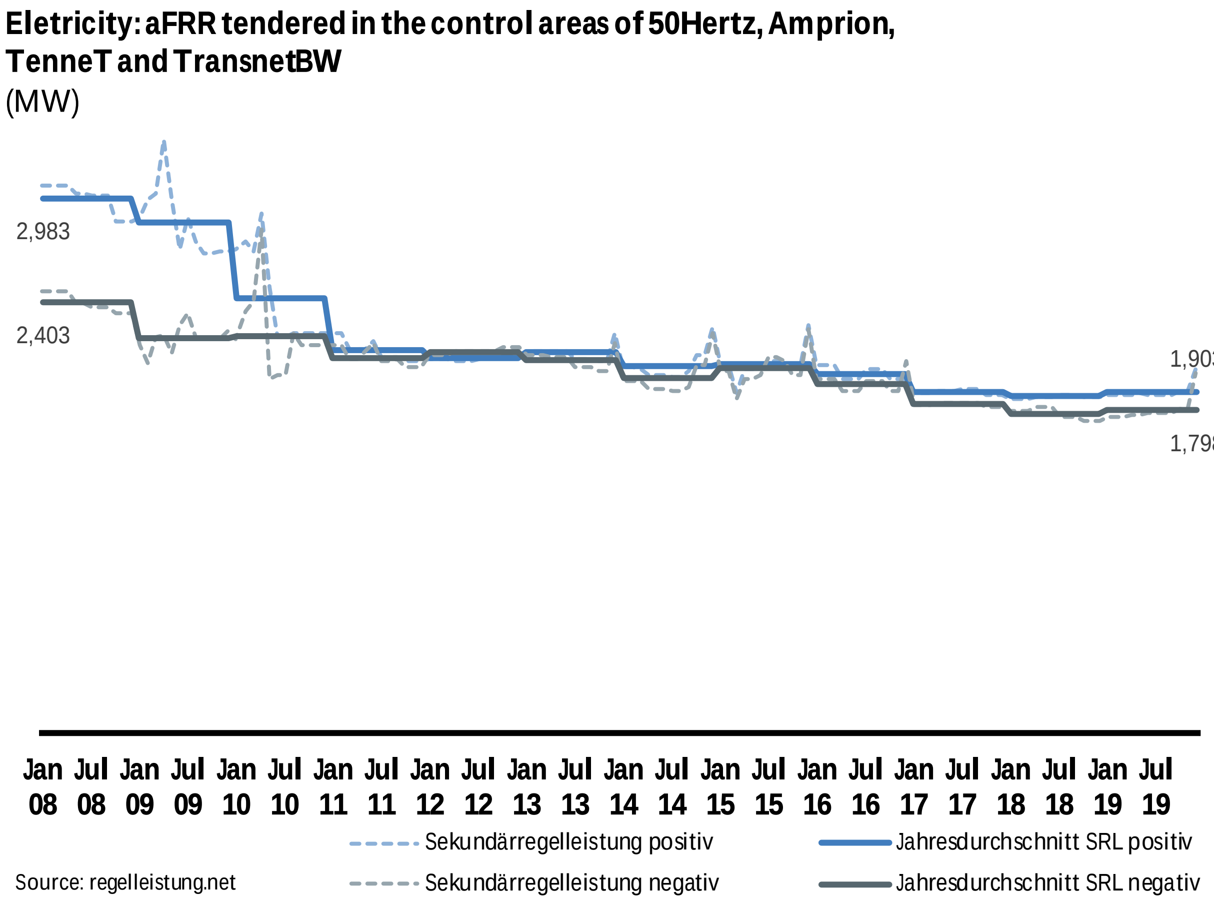


Figure 79: aFRR tendered in the control areas of 50Hertz, Amprion, TenneT and TransnetBW

Similarly, there was also an increase in the highest and lowest volumes of positive and negative aFRR tendered compared to the previous year (see Table 69). While the lowest volumes are very close to those in previous years, there was a larger increase in the highest volumes tendered.

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

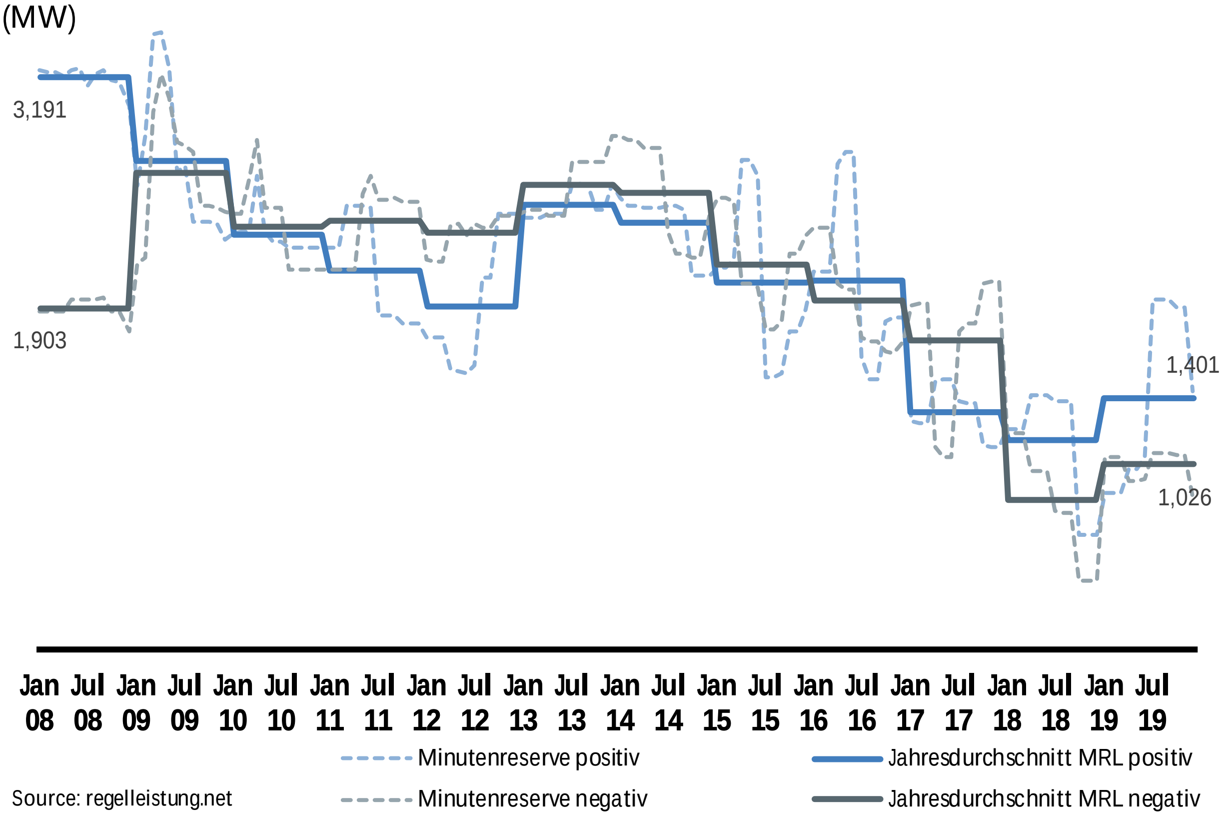
Source: regelleistung.net

Table 69: Range of aFRR tendered by the TSOs

Procurement of mFRR

Since 2015, the average volume of positive mFRR tendered had been decreasing continually. In 2019, by contrast, there was a year-on-year increase in the average volume from 1,166 MW to 1,401 MW. However, demand for positive mFRR ranged from 874 MW to 1,952 MW.

Electricity: mFRR tendered in the control areas of 50Hertz, Amprion, TenneT and TransnetBW



Source: regelleistung.net

Figure 80: mFFR tendered in the control areas of 50Hertz, Amprion, TenneT and TransnetBW

There was a year-on-year increase in the average volume of negative mFRR tendered from 832 MW to 1,026 MW. The volumes of negative mFRR tendered in 2019 ranged from 644 MW to 1,094 MW. The lowest volume is higher than in the previous year, while the highest volume is lower. The range for negative mFRR is therefore much smaller (see Table 70).

Electricity: range of mFRR tendered by the TSOs

	Year	Capacity tendered (MW)	
		Min	Max
mFRR (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
mFRR (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
	2019	644	1,094

Source: regelleistung.net

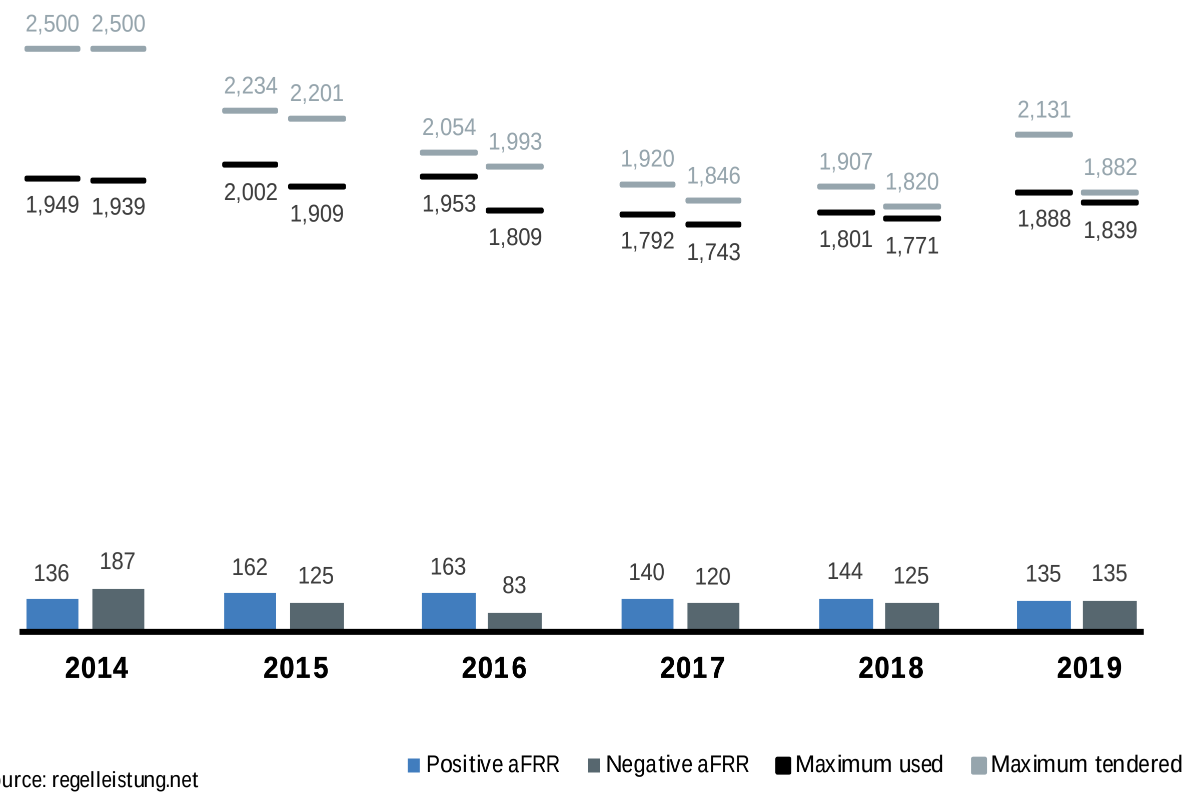
Table 70: Range of mFRR tendered by the TSOs

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 2019 was again 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)



Source: regelleistung.net

Figure 81: Average volume of aFRR used, including aFRR drawn and delivered under online netting in the national grid control cooperation

In 2019, the total amount of positive aFRR activated was around 1.2 TWh (2018: 1.3 TWh), and the total amount of negative aFRR activated was 1.2 TWh (2018: 1.1 TWh). The total sum of energy is therefore virtually unchanged from the previous year.

On average in 2019, just under 7% of the average volume of positive aFRR tendered and just under 8% of the average volume of negative aFRR tendered was used. It should be noted, however, that in a total of 140 quarter hours in the year, at least 80% of the average balancing capacity held, and in some cases all 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 (1,888 MW and 1,839 MW respectively) were, at least in the case of negative aFRR, only slightly lower than the highest volume of capacity tendered (1,882 MW) (positive aFRR: 2,131 MW). In June 2019, there were some instances where the total volume of positive aFRR held was requested.

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.[82]

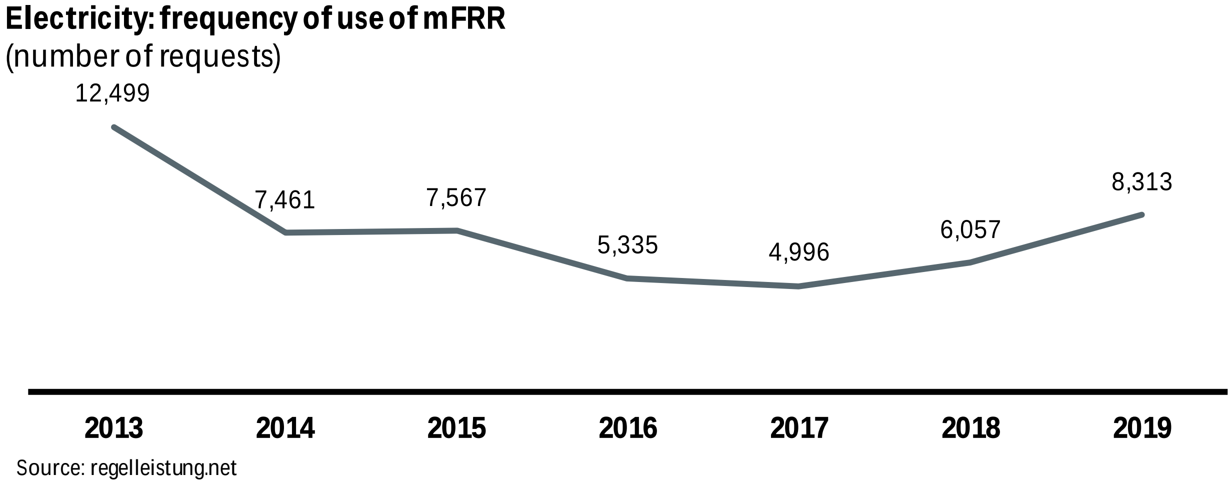


Figure 82: Frequency of use of mFRR

At 8,313, the total number of requests for mFRR was around 20% higher than in the previous year. Overall, there were 3,042 requests for negative mFRR in 2019 (2018: 2,308) and 5,271 requests for positive mFRR (2018: 3,749).[83]

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82 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"}

83 The number of requests for aFRR is not illustrated separately because it is requested in nearly every quarter hour.

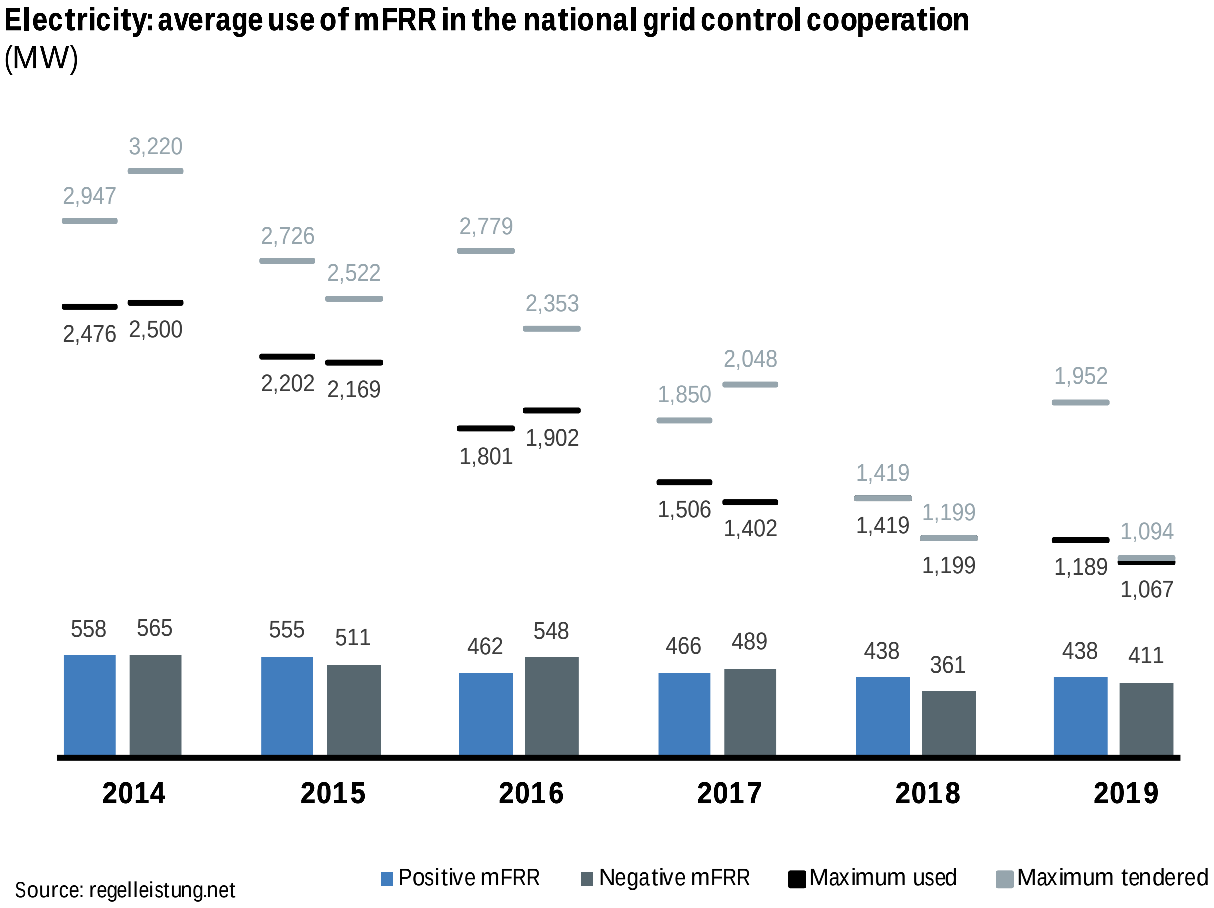

Figure 83: Average use of mFRR in the national grid control cooperation

In the quarter hours in which mFRR were requested, on average 43% of the positive mFRR tendered and 41% of the negative mFRR tendered were used. The average volume of positive mFRR requested in 2019 was 438 MW, exactly the same as in 2018 (438 MW). At 411 MW, the average volume of negative mFRR requested in 2019 was higher than in the previous year (2018: 361 MW).

As with aFRR, however, it must be noted that in several quarter hours all or almost all of the mFRR balancing capacity held was required. In 283 cases, at least 80% of the average balancing capacity held was required. In June 2019, there were some instances where the total volume of positive mFRR held was requested.

While aFRR are used in nearly all of the 35,040 quarter hours of a normal year, mFRR are 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, the volumes of positive and negative mFRR used in 2019 amounted to only about 2% and 1% respectively of the average volumes tendered.

In 2019, a total of about 186 GWh of positive mFRR (2018: 123 GWh) and a total of 102 GWh of negative mFRR (2018: 63 GWh) were activated.

Figure 84 illustrates the average use of aFRR and mFRR in each calendar week from 2013 to 2019. 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 and then decreased again in the second half of 2019.

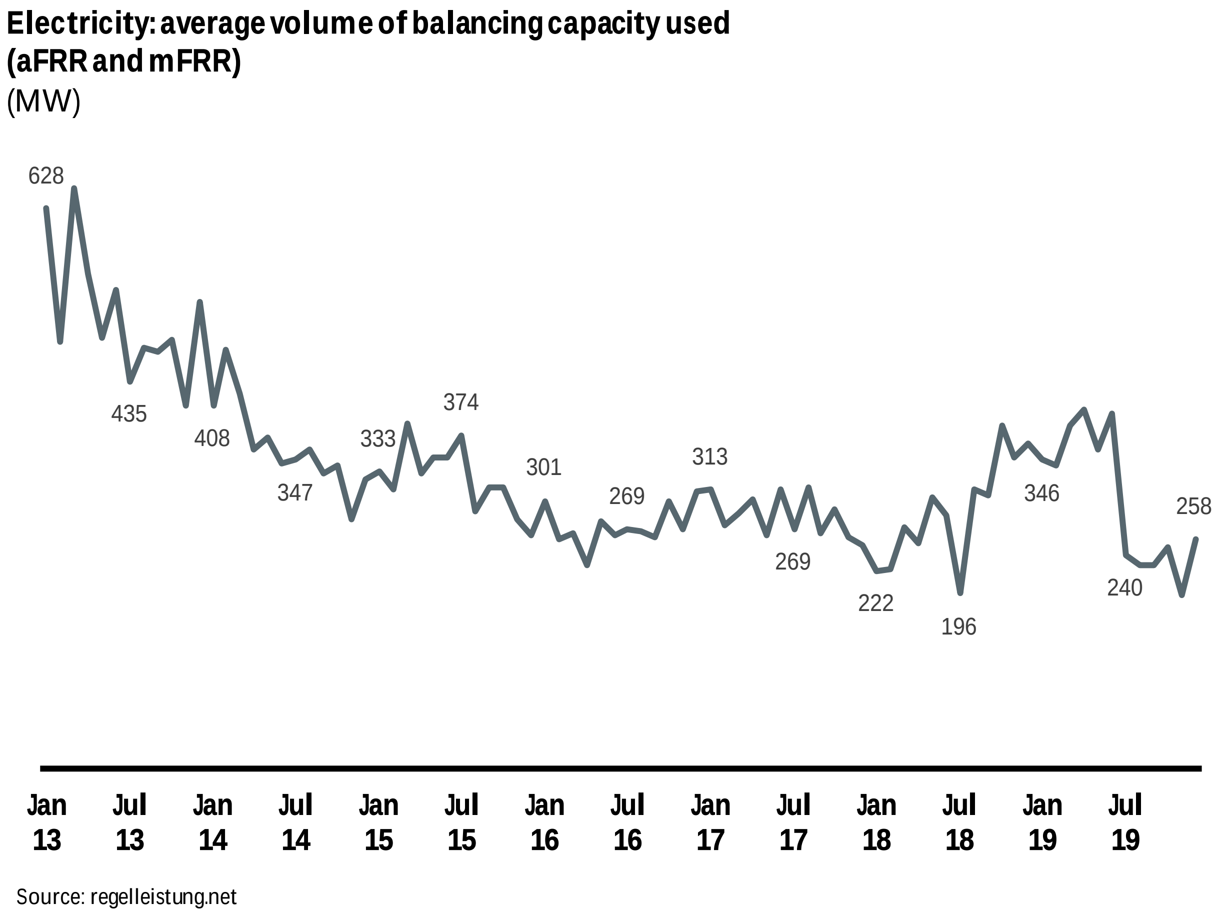

Figure 84: Average volume of balancing capacity used (aFRR and mFRR)

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 balancing group 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 is to provide better incentives for the proper management of balancing groups with a view to preventing system-relevant imbalances. To this end, the imbalance price was coupled to a market-price index (known as market-price coupling). The system-relevant imbalances in the German transmission system that occurred on three days in June 2019 made it clear that the method for calculating the imbalance price needed to be changed. The TSOs therefore amended the market-price coupling for the imbalance price and, in December 2019, submitted a proposal for the revised market-price coupling to the Bundesnetzagentur for approval. The new market-price coupling, which was approved in May 2020 (BK6-19-552) and introduced in July 2020, has new thresholds for the imbalance price comprising an "ID-AEP" price index calculated by the TSOs and a minimum margin.[84] This creates a stronger financial incentive for balance responsible parties to compensate for imbalances through electricity trading instead of using balancing energy and thus impedes arbitrage against the imbalance price.

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
2019	2,865.11

Source: regelleistung.net

Table 71: Maximum imbalance prices

In 2019, the highest imbalance price was around €2,865/MWh. The price exceeded €500/MWh in a total of 33 quarter hours in 2019.

[84] https://www.bundesnetzagentur.de/DE/Service-Funktionen/Beschlusskammern/1_GZ/BK6-GZ/2019/BK6-19-552/Beschluss/BK6-19-552_Beschluss.html?nn=869698

In 2019, 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 €4.52/MWh down on the previous year at €76.76/MWh. The average volume-weighted imbalance price in the case of a positive control area imbalance was thus 90% above the average (peak) intraday trading price in 2019.[85] 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 negative €1.84/MWh and thus similar to the previous year's level.

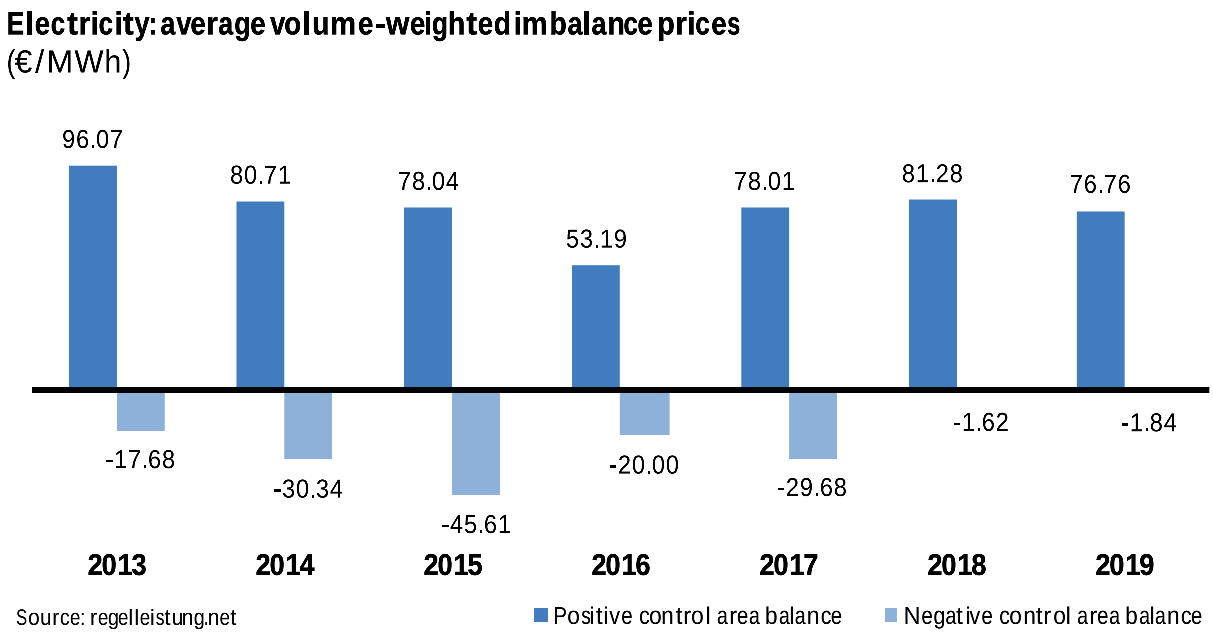

Figure 85: Average volume-weighted imbalance prices

3. European developments in the field of electricity balancing

3.1 International frequency containment reserves cooperation

To reduce the costs for balancing services further, the German transmission system operators (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.

[85] Based on the EPEX SPOT average (peak) intraday trading price of €40.40/MWh for 2019.

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)

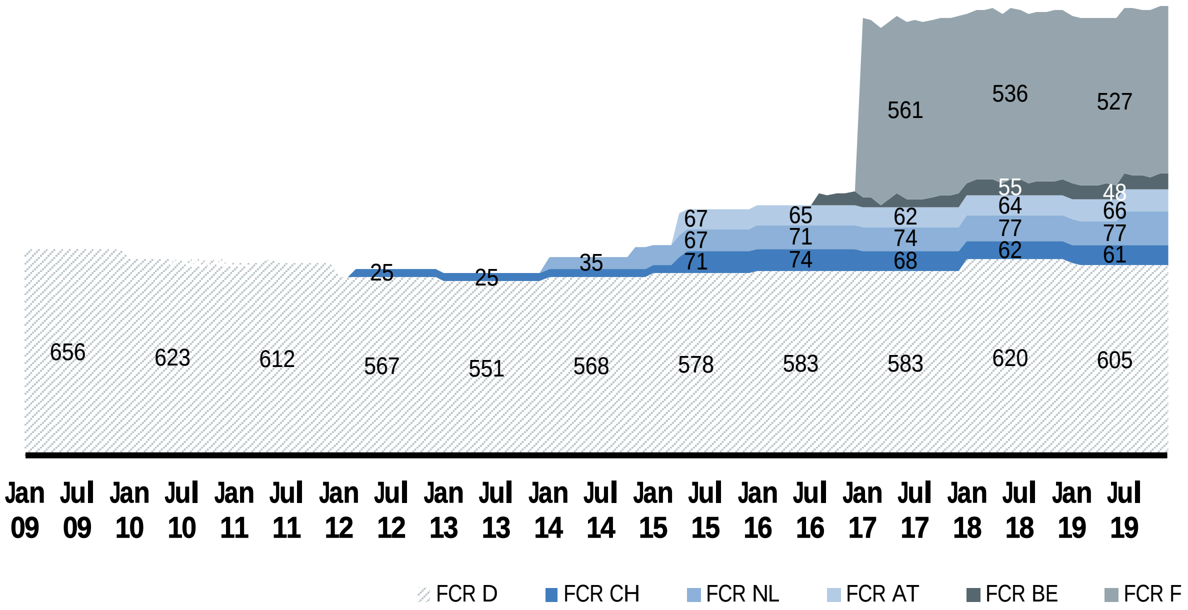

Figure 86: Total volume of FCR tendered in the control areas of the German TSOs, Swissgrid (CH), TenneT (NL), APG (AT), ELIA (BE) and RTE (F)

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 61 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 66 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, 527 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.[86]. The main changes were as follows:

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[86] See decision of 13 December 2018 (BK6-18-006).

– 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;

– the product length 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;

– indivisible bids with a maximum bid size of 25 MW were allowed as from 1 July 2019.

3.2 Approved methods for the future European balancing energy exchange platforms

The implementation of Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing involves cooperation between the European TSOs for the cross-border exchange of balancing energy. With the aim of integrating the European balancing energy markets, joint platforms have been established to promote the exchange of balancing energy from frequency restoration reserves (FRR). In addition, a harmonised imbalance settlement mechanism (imbalance price system) creates pan-European incentives for market players to maintain the balance within their balancing groups and maintain system stability.

In January 2020, the Agency for the Cooperation of Energy Regulators (ACER) approved the implementation plans for the two European cross-border balancing energy platforms. The PICASSO platform (pursuant to Article 21 of Regulation (EU) 2017/2195) will serve the exchange of balancing energy from automatic frequency restoration reserves (aFRR) and the MARI platform (pursuant to Article 20 of Regulation (EU) 2017/2195) the exchange of balancing energy from manual frequency restoration reserves (mFRR). The two platforms will enable the pan-European exchange of balancing energy from aFRR and mFRR, enhance the efficiency of system balancing and increase the liquidity of the balancing markets. Both platforms are due to go live in 2022.

Approval was also given for a harmonised imbalance settlement mechanism (pursuant to Article 52(2) of Regulation (EU) 2017/2195), which lays down the key components for calculating the imbalance price. The harmonised mechanism improves consistency in imbalance pricing and creates a uniform framework for the integration of the balancing markets within the EU.

3.3 Automatic frequency restoration reserves cooperation between Germany and Austria

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.

Since December 2019, Germany and Austria have requested mFRR in a cross-border process. This means that the two countries already activate all frequency restoration reserves (FRR) jointly on the basis of common merit order lists.

Since February 2020, part of the national aFRR requirements have also been procured in a cross-border process. Joint procurement is currently limited to 80 MW. 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 Transmission system operators' tendering for interruptible loads

The legal basis for tendering for interruptible loads is the Interruptible Loads Ordinance (AbLaV), which first entered into force in January 2013 and was replaced by a revised version with effect from 1 October 2016. The transmission system operators (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, moderate changes were seen with respect to participation in the weekly auctions and significant changes with respect to the number of requests to use interruptible capacity and the volume of capacity requested. These changes included a noticeable increase 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 2019. The graph shows that the capacity contracted for immediate interruption remained virtually constant over the whole period and was well below the total capacity tendered. By contrast, the capacity for fast interruption increased in the reporting period to up to 857 MW. The reason for contracting more than 750 MW of interruptible capacity is that section 11 AbLaV allows more capacity to be contracted if the volume tendered (750 MW) is not covered without accepting one further bid that results in the capacity contracted exceeding 750 MW. The ratio of immediately to quickly interruptible loads is due to fluctuations in the quickly interruptible loads offered.

Electricity: capacity tendered and contracted for immediate and fast interruption from January 2019 to December 2019 (MW)

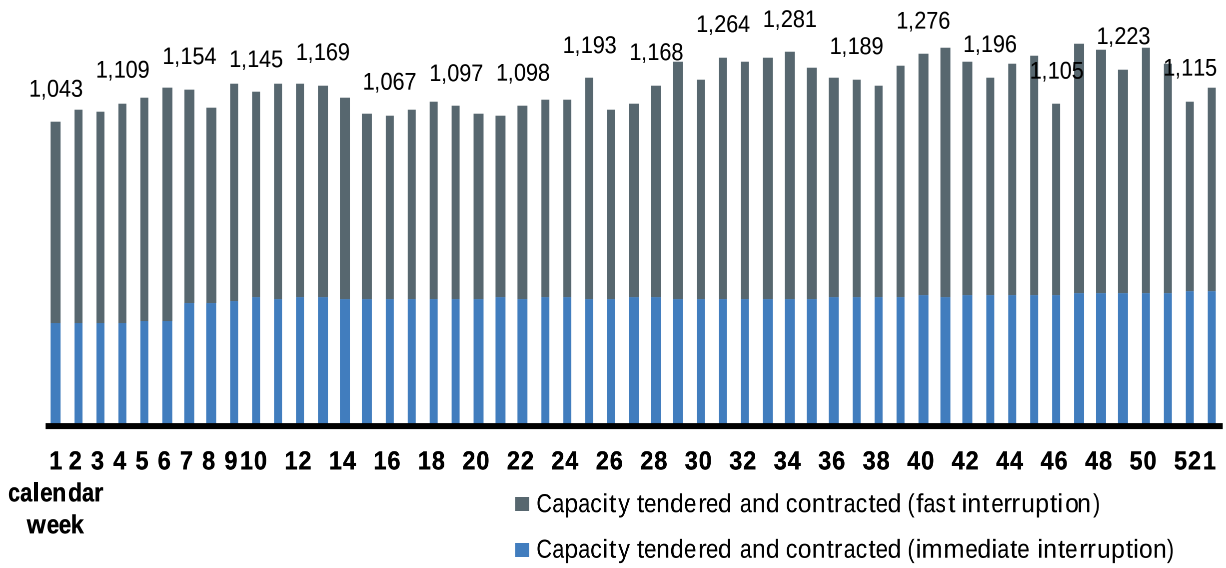

Figure 87: Capacity tendered and contracted for immediate and fast interruption from January 2019 to December 2019 (MW)

4.2 Pre-qualified capacity

By the end of 2019, an additional 11 interruptible loads with a total interruptible capacity of 186 MW had taken part in the initial pre-qualification procedure pursuant to section 9 AbLaV, and all 11 of them had successfully pre-qualified.

Nine consumer devices with a total interruptible capacity of 793 MW were therefore pre-qualified as immediately interruptible loads in 2019. In addition, 37 consumer devices pursuant to section 2 para 11 AbLaV with a total interruptible capacity of 1500 MW were pre-qualified as quickly interruptible loads. Some of these consumer devices are also pre-qualified as immediately interruptible loads. No consortia pursuant to section 2 para 12 AbLaV pre-qualified as interruptible loads. The pre-qualified capacity of immediately interruptible loads in 2019 was 136 MW lower than in the previous year. The pre-qualified capacity of quickly interruptible loads in 2019 was 184 MW higher than in the previous year. The majority of the loads are connected to Amprion GmbH's control area, while others are in the control areas of 50Hertz GmbH and TenneT TSO GmbH.

4.3 Use of interruptible loads

In 2019, interruptible loads were used comparably with the use of balancing capacity to balance the system on 18 days. The highest interruptible load capacity of 1,316 MW was requested on 25 June 2019. The interruptible loads were always used to balance the system at the same time as positive manual frequency restoration reserves (mFRR). All the positive mFRR had to be used on 13 days. Interruptible loads were not used in 2019 for redispatching purposes. Interruptible loads were used for test purposes on one day.

The contracted immediately interruptible loads were registered on time as not available for 611 hours, thus 67,610 MWh of interruptible energy was not available from the immediately interruptible loads. By contrast, the quickly interruptible loads were registered as not available in 2019 for as many as 32,008 hours, thus 519,821 MWh of interruptible energy was not available from the quickly interruptible loads. In addition, quickly interruptible loads were not available without being registered for 2,300 hours in 2019, and thus 51,295 MWh of interruptible energy was not available from the loads. Significant use was therefore made of the opportunity to register the unavailability of contracted interruptible loads one day in advance. The loads are then not available to TSOs for system balancing or redispatching. 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 2019 were higher at €2,933,093 (2018: €952,774; 2017: €293,935), reflecting the increase in the use of interruptible loads compared with the previous year. There was a comparatively small increase in the capacity-based costs for contracting the interruptible loads to €28,013,447 (2018: €26,770,491; 2017: €26,940,103). The TSOs' transaction costs for implementing the AbLaV fell in 2019 to €306,112 (2018: €355,023; 2017: €886,532). The total costs for interruptible loads therefore amounted to €31,252,653 in 2019 (2018: €28,078,289; 2017: €28,120,570). The increase in costs is due to an increase both in the capacity contracted and in the use of the interruptible loads.

4.5 Increasable loads ("use, don't curtail")

In January 2018, the TSOs TenneT, Amprion and 50Hertz entered into a voluntary commitment known as "use, don't curtail", enabling them to contract with combined heat and power (CHP) plant operators in the "network expansion area" for the reduction of active power feed-in while still 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-mentioned TSOs offered to enter into contracts with plant operators in the course of 2018 and 2019. No contracts were concluded in 2018. In the control area of 50Hertz, three contracts for about 140 MW of redispatch load and an additional approximately 57 MW of increasable load from power-to-heat were concluded in 2019. Further negotiations are ongoing.

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 ongoing development of the European internal market for electricity is to integrate electricity markets more closely, to facilitate cross-border trade and to ensure the 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.

The internal market for electricity is divided into separate bidding zones in which electricity prices are determined according to supply and demand. Electricity is transported within a 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 bidding zone by means of redispatch measures and network expansion or if internal overloading of power lines is taken into account in the calculated cross-border capacity. Germany and Luxembourg constitute a common bidding zone with uniform prices. The common bidding zone with Austria ceased to exist on 1 October 2018. Due to congestion between bidding zones, cross-border trading may be limited by the transmission capacity available.

As in the previous year, the volume of electricity exported by Germany fell. However, cross-border traded volumes in 2019 still totalled 72.4 TWh (2018: 91.6 TWh). Germany's export balance of 25.19 TWh makes it a major electricity exporter in Europe.[87] The export surplus corresponded to €736.10 m.

1. Power exchanges and market coupling

Electricity for 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).

[87] Daily updated commercial import/export and physical load flow figures are available at www.smard.de.

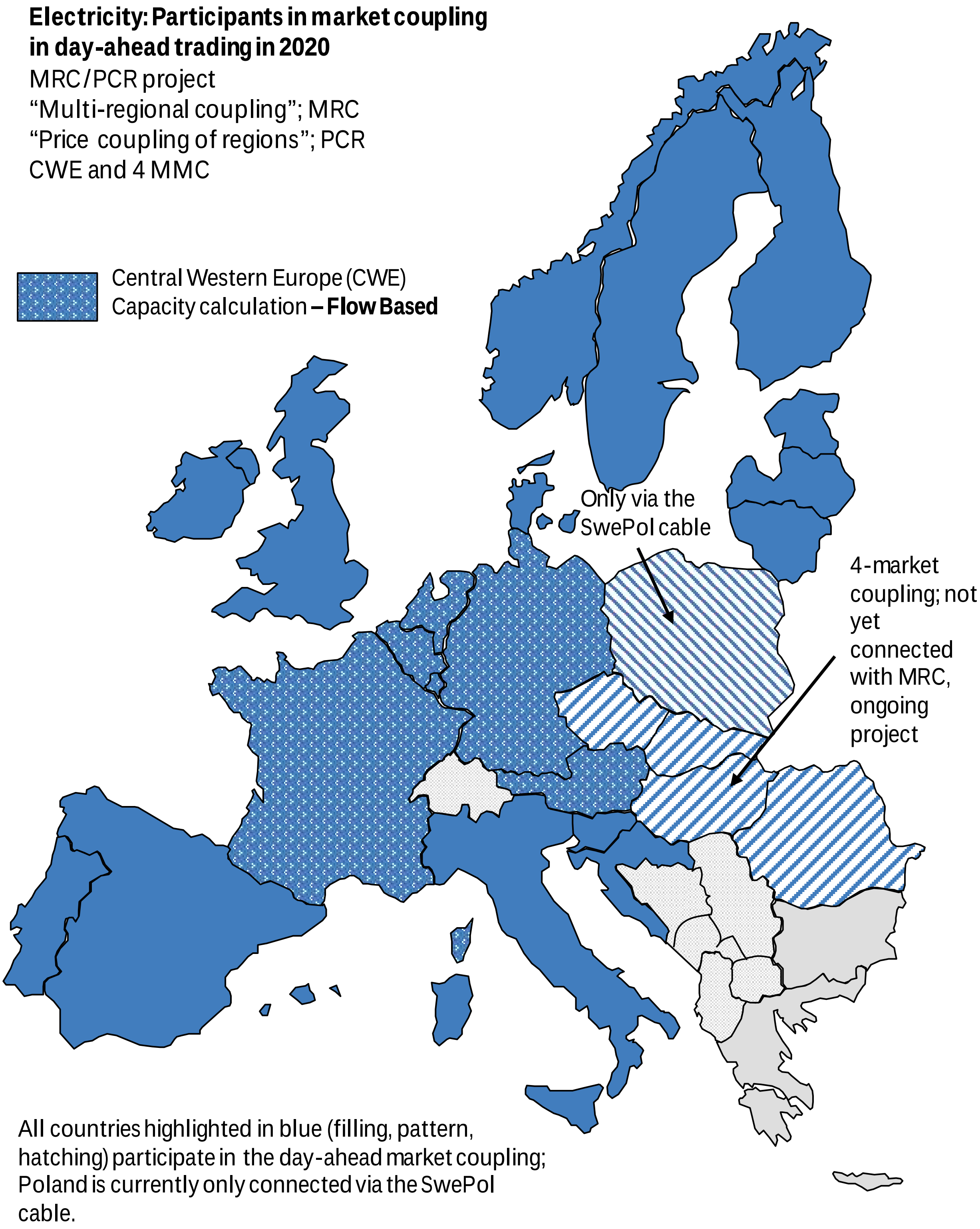

Figure 88: Participants in market coupling in day-ahead trading in 2020

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 of electricity, is becoming less important.

The MRC (Multi-Regional Coupling) now couples 20 European countries in the day-ahead timeframe, which account 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 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.

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 that 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 – also for 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 also of all the flows of electricity in the area including the internal transmission lines relevant for trading.

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. 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 in 2022.

3. Average available cross-zonal capacity

The mean available cross-zonal capacity is the amount of electricity that can be transmitted between two bidding zones 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 not therefore 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 that 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 with each other. The values for the development of German import and export capacities have therefore been aggregated and shown separately in Table 72 and Table 73.

Electricity: Import capacity

Border	2017	2018		2019	
			Change compared to previous year (%)		Change compared to previous year (%)
		NTC			
CH DE	4,000.00	3,888.25	-3	3,491.04	-10
CZ DE	1,289.89	1,442.00	12	1,416.35	-2
DK DE	1,026.80	1,465.57	43	1,782.23	22
PL DE	1,301.82	1,358.29	4	1,249.22	-8
SE DE	415.26	450.39	8	533.56	18
		Flow-based			
AT DE *		4,999.43		5,080.67	2
FR DE	3,763.79	4,323.96	15	3,748.00	-13
NL DE	2,345.85	2,504.17	7	3,246.32	30

Source: TSOs, ENTSO-E, JAO, Nord Pool; *bidding zone split DE/AT in October 2018

Table 72: Overview of the development of import capacities

Electricity: Export capacity

Border		2017	2018	2018: Change compared to previous year (%)	2019	2019: Change compared to previous year (%)
			NTC			
DE	CH	1,501.23	1,394.25	-7	1,342.98	-4
DE	CZ	580.21	1,235.23	113	1,348.30	9
DE	DK	1,901.86	1,850.68	-3	1,965.43	6
DE	PL	604.14	1,002.97	66	904.03	-10
DE	SE	248.32	232.39	-6	248.55	7
			Flow-based			
AT	DE *		5,051.92		4,984.73	-1
DE	FR	3,545.89	4,995.58	41	5,488.41	10
DE	NL	2,917.94	3,212.04	10	3,301.61	3

Source: TSOs, ENTSO-E, JAO, Nord Pool; *bidding zone split DE/AT in October 2018

Table 73: Overview of the 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 increased 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 trading 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 in line with the contract to 900 MW for the period 1 January 2019 to 31 March 2019 and after that to 1,000 MW through to the end of 2019.

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. 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-border 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 224 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 89 and Figure 90). 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 89 and Figure 90 show the realised exchange schedules and the physical load flows at Germany's borders in 2018 and 2019. Tables 74 to 76 show summarised values.

Electricity: Exchange schedules (cross-border trading, net) (TWh)

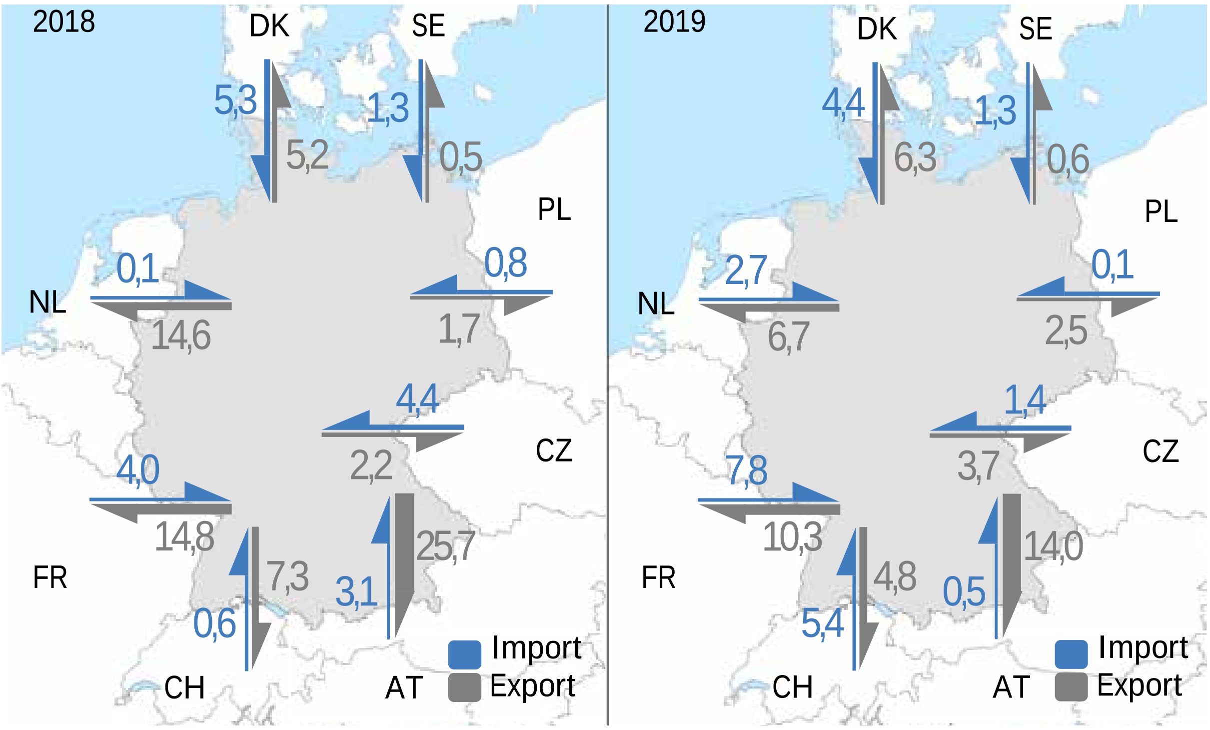

Figure 89: Exchange schedules (cross-border trading)

Electricity: Physical flows (net) (TWh)

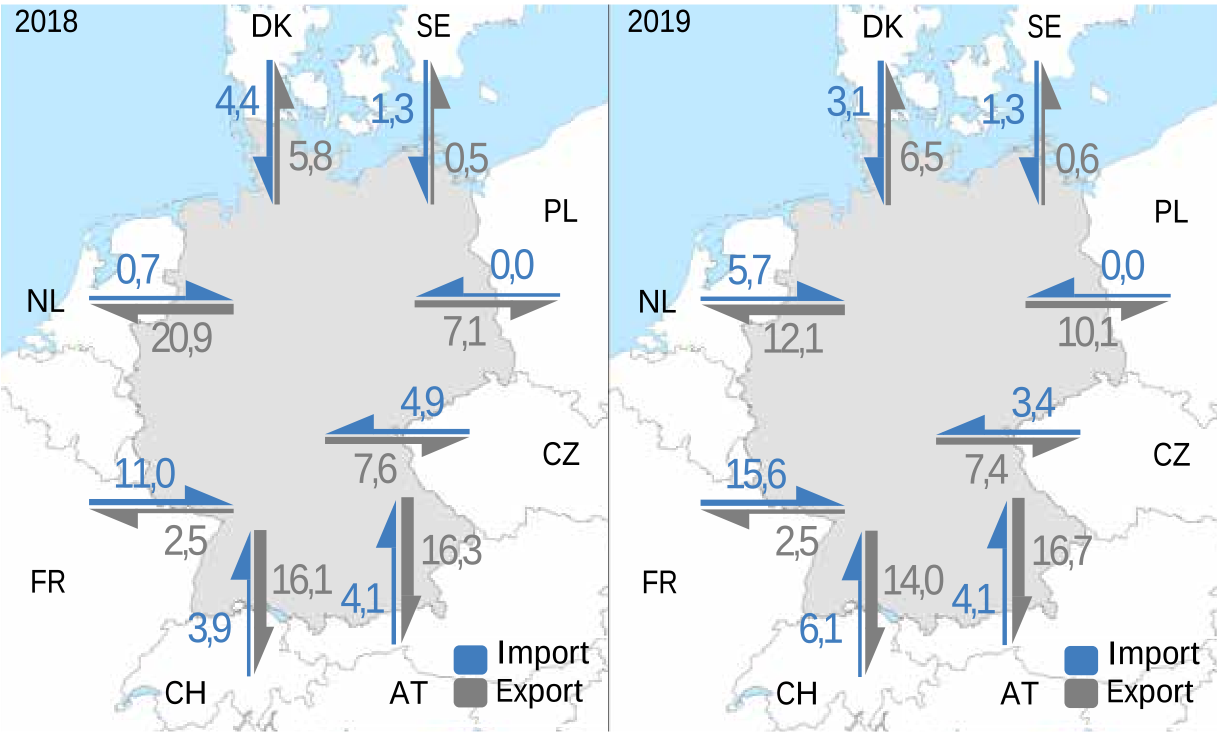

Figure 90: Physical flows

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

	Actual physical flows in 2018	Binding exchange schedules 2018	Actual physical flows in 2019	Binding exchange schedules 2019
Imports	30.3	19.6	39.4	23.6
Exports	76.8	72.0	69.8	48.8
Balance	46.5	52.5	30.4	25.2

Source: TSOs, ENTSO-E

Table 74: Comparison of the balance of cross-border electricity flows

Electricity: Comparison of imports from cross-border flows
(TWh)

	Actual physical flows in 2018	Binding exchange schedules in 2018	Actual physical flows in 2019	Binding exchange schedules in 2019
AT DE	4.1	3.1	4.1	0.5
CH DE	3.9	0.6	6.1	5.4
CZ DE	4.9	4.4	3.4	1.4
DK DE	4.4	5.3	3.1	4.4
FR DE	11.0	4.0	15.6	7.8
NL DE	0.7	0.1	5.7	2.7
PL DE	0.0	0.8	0.0	0.1
SE DE	1.3	1.3	1.3	1.3

Source: TSOs, ENTSO-E

Table 75: Comparison of imports from cross-border flows

Electricity: Comparison of exports from cross-border flows
(TWh)

	Actual physical flows in 2018	Binding exchange schedules in 2018	Actual physical flows in 2019	Binding exchange schedules in 2019
DE AT	16.3	25.7	16.7	14.0
DE CH	16.1	7.3	14.0	4.8
DE CZ	7.6	2.2	7.4	3.7
DE DK	5.8	5.2	6.5	6.3
DE FR	2.5	14.8	2.5	10.3
DE NL	20.9	14.6	12.1	6.7
DE PL	7.1	1.7	10.1	2.5
DE SE	0.5	0.5	0.6	0.6

Source: TSOs, ENTSO-E

Table 76: Comparison of exports from cross-border flows

The following diagram clearly shows the extent to which actual physical flows differ from realised exchange schedules.

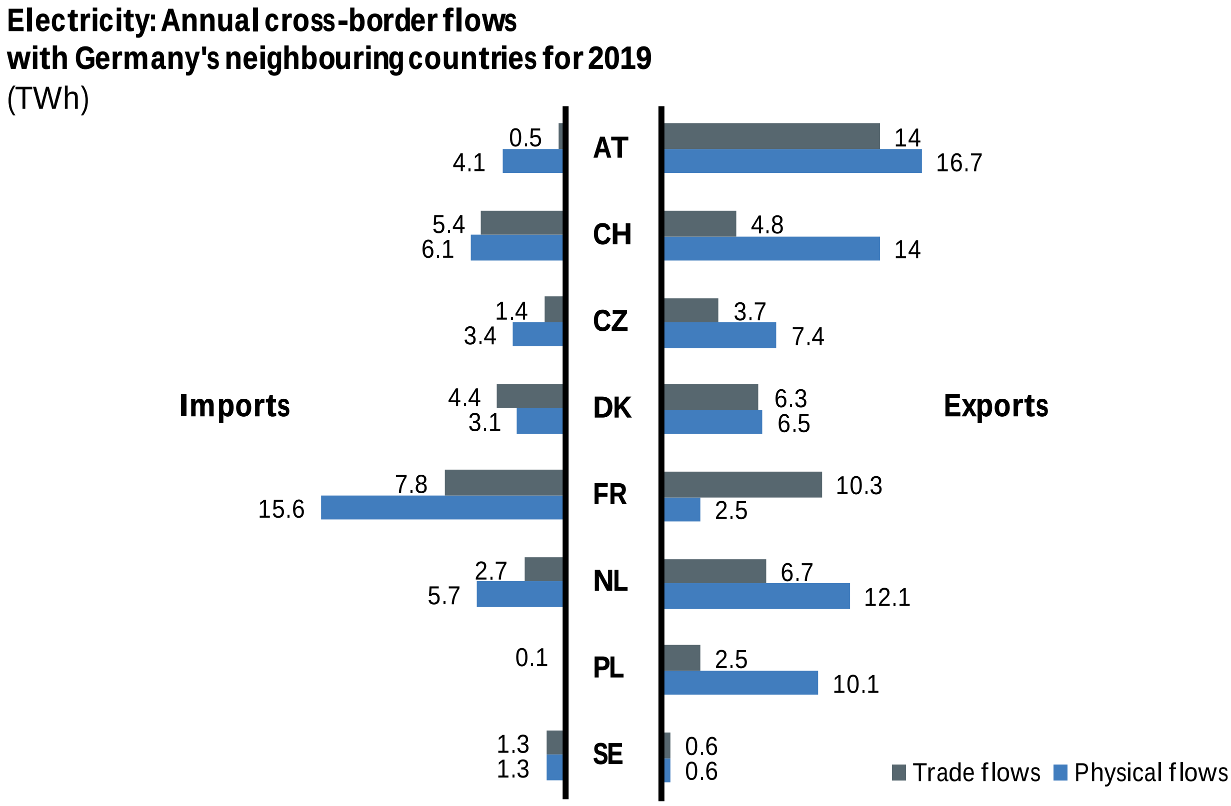

Figure 91: Total annual cross-border load flows and exchange schedules in 2019

In the period from 2011 to 2014, exports have risen continuously and imports fallen. Exports decreased in 2019. One reason for this is congestion management at the German/Austrian border. Exports to Austria fell by 11.7 TWh between 2018 and 2019.

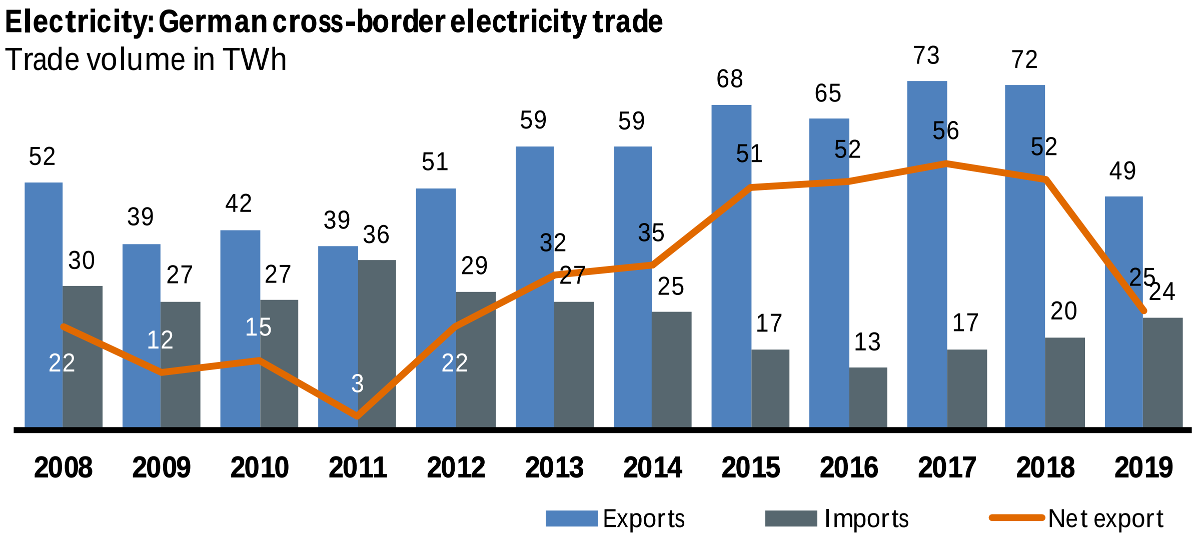

Figure 92: German cross-border electricity trade

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

	2018		2019	
	TWh	Trade in € million	TWh	Trade in € million
Exports	72.01	3,058.90	48.79	1,705.00
Imports	19.56	934.28	23.60	968.90
Balance	52.45	2,124.62	25.19	736.10
Export revenues (€/MWh)		32.94		23.68
Import costs (€/MWh)		39.60		49.54

Table 77: Monetary development of cross-border electricity trade (trade flows)

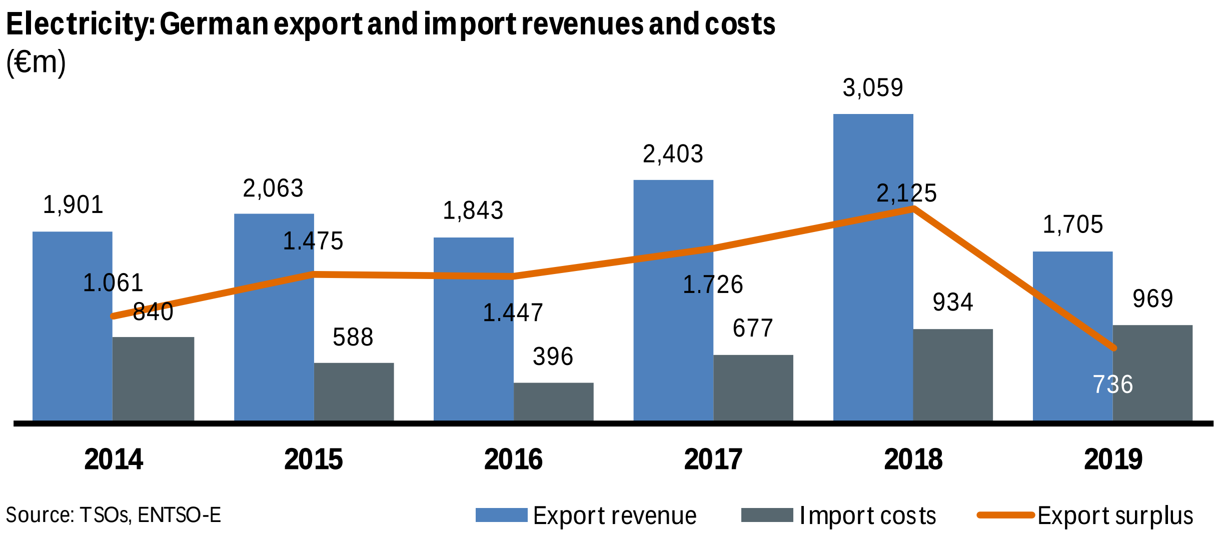

Figure 93: German export and import revenues and costs

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 that 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 bidding zone that is not involved in the commercial transaction. In contrast, loop flows of electricity occur whenever electricity from one bidding zone passes through a bidding zone that 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. Article 16 (8) Regulation (EU) 2019/943 stipulates that 70% of transmission capacities must be made available for cross-border trade in electricity while 30% may be used for internal and loop flows and a reliability margin.

The unscheduled flows are determined as annual aggregate figures for each border 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 2019, Germany imported (trade) 2.7 TWh from and exported 6.7 TWh to the Netherlands. This is equal to an export surplus (trade) of 4 TWh. At the same time, 5.7 TWh flowed physically from the Netherlands to Germany. In contrast, 12.1 TWh flowed from Germany to the Netherlands. This is equal to an export surplus (physical) of 6.4 TWh. This means that on balance (trade minus physical) 2.4 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 (or the Germany/Luxembourg market area since October 2018) to its neighbouring countries and vice versa.

Electricity: Unscheduled flows
(TWh)

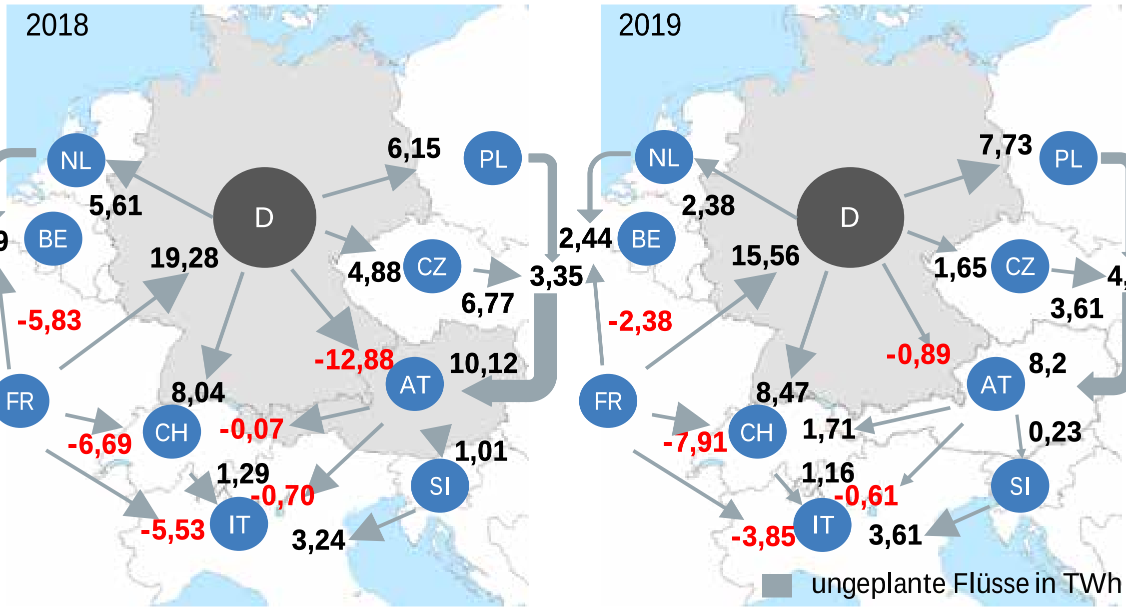

Figure 94: Unscheduled flows

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 2019, for example, the net physical flow from France to Switzerland was 7.91 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 that 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.

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

Pursuant to 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 2019 are the following: The four German TSOs received compensation for losses and the provision of infrastructure totalling €6.62m and paid contributions of €15.79m. This means that on balance the German TSOs contributed a net amount of €9.17m to the ITC fund. As a result, Germany was a net contributor to the ITC fund in 2019 for the fifth year running (2018: €-8.44m, 2017: €-2.15m, 2016: €-12.48m, 2015: €-6.1m, 2014: €0.91m, 2013: €13.21m, 2012: €26.8m). This trend has emerged in recent years and is mainly due to the large increase in Germany's electricity exports and the related cross-border flows. With a moderate increase of 8.7%, the net contribution is at the same level as last year. However, there has been a noticeable increase in both compensation and contribution payments: While compensation payments were €5.34m higher, German TSOs had to pay around €6m more in contributions.

7. Current developments in the European electricity sector

7.1 Clean energy for all Europeans Package (CEP)

A comprehensive legislative package for the further integration of the European internal market for electricity, the Clean Energy for all Europeans Package (CEP), was adopted in 2019. This package included the new Regulation (EU) 2019/943 on the internal market for electricity, which came into effect on 1 January 2020.

Minimum capacity available for trade and the national action plan

One aspect of the Regulation on the internal market for electricity is that it requires EU Member States to make a minimum of 70% of transmission capacities available for cross-zonal trade. Just in time for the new Regulation to come into force, the federal government submitted its action plan, which enables this minimum trading capacity to be reached in stages by 31 December 2025. The Bundesnetzagentur's task was to work with the TSOs on the development of principles for the calculation and reporting of the starting point of the linear trajectory of minimum trading capacities and to publish them on its homepage by the end of 2019. The TSOs then calculated and published the starting points so that the corresponding capacities could be made available for cross-border trading from 1 January 2020. Since then the Bundesnetzagentur has been monitoring compliance with the minimum values.

In the first half of 2020, the Bundesnetzagentur concentrated in particular on implementing the minimum cross-zonal capacity on the DE-SE4 (Baltic Cable) border at which the action plan and the start value calculation applied a minimum capacity of 248MW for the year 2020. As not enough liquidity is available in the small SE4 bidding zone to provide sufficient countertrade potential, it was not possible initially to achieve this value for the direction DE >>SE4 without endangering system security in Sweden or risking load shedding in SE4. It was therefore necessary to apply new technical processes with the transmission system operators Baltic Cable and TenneT and the distribution system operator Schleswig-Holstein Netze AG. Implementation was accompanied by the Bundesnetzagentur and completed by the end of August 2020. As a result, shortfalls in minimum capacity and risks to system security in SE4 can now be avoided.

System operation regions and regional coordination centres

In early April 2020, ACER reached a decision – diverging from the contents of the original ENTSO-E proposal submitted for public consultation in Oct/Nov 2019 by ENTSOE and in January 2020 by ACER – on the definition of system operation regions (SORs) for Europe. The SORs are the geographical basis for the responsibilities of the regional coordination centres (RCCs). European lawmakers envisage these regional coordination centres emerging from existing regional security coordinators (RSCs) and taking on additional new tasks relating to cross-border coordination between transmission system operators, including risk-preparedness, electrical emergency and restoration, training and certification, calculation of capacity requirements and the dimensioning and procurement of reserve capacity. To this end, in mid-2020 the relevant transmission system operators submitted their proposals for the establishment of the RCCs for SORs - such as TSCNET and Coreso for the "Central Europe SOR" (CE SOR), which also includes Germany - to the responsible regulatory authorities. The Bundesnetzagentur works with the regulatory authorities and CE SOR transmission system operators to review and revise the proposal and aims to have reached a decision by early 2021. The RCCs should commence operations on 1 July 2022 and implement the task referred to above.

7.2 Implementation of European network codes and guidelines

Further progress was made in 2019 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 Regulation (EU) 2015/1222 for cross-border congestion management, capacity calculation and capacity allocation for day-ahead and intraday trading. In 2018, the regulatory authorities and ACER issued approval decisions under this 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 bedrock on which the single European electricity market stands. 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. Other European countries joined the system in a second implementation wave in late 2019: Bulgaria, Croatia, Poland, Romania, Slovenia, Czechia. 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. This method is used to incorporate the entire network relevant to cross-border exchange, and not just particular cross-border network elements, in the calculations. This should enable more transmission capacity to be made available for cross-border trading.

The regulatory work was coordinated in a joint working group, which involved 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 were unable to agree joint approval of this proposal, the procedure was referred to ACER for decision in August 2018. This body then reached a decision on the TSOs' submitted proposal in February 2019 and thereby 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 action for a declaration of nullity being brought by the Bundesnetzagentur is currently pending before the European Court of Justice (ECJ). The court has not yet ruled.

The Regulation on forward capacity allocation (Regulation (EU) 2016/1719) is also being implemented. In 2019/20, the relevant TSOs worked with the NRAs to complete and approve the methodology for the regional structuring of long-term transmission rights to enable long-term, financial transmission rights to be issued at the new NL-DK1 bidding zone border (COBRA cable). The analogous method for the CORE capacity calculation region is also in its final phase. The regional methodology for the coordinated sharing of long-term and cross-zonal capacity for the CORE and HANSA capacity calculation regions was completed and approved. By contrast, the methodology for the calculation of long-term capacities is still in a conceptual phase.

System balancing

The first steps towards implementation by TSOs of 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.

ACER has since approved the main methodologies in accordance with the Regulation, which are driving the harmonisation of European balancing energy markets. In the future, the PICASSO (aFRR) and MARI (mFRR) platforms will enable aFRR and mFRR to be exchanged across Europe. The harmonisation of imbalance settlement is a further step towards a single framework for the integration of balancing energy markets in the EU.

System operation

Regulation (EU) 2017/1485 deals inter alia with European 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 2019, these included, at the European level and regional level, methodologies for the coordination of operational security analyses. At the synchronous area level, diverse methodologies, conditions and values, which must be included in the operational agreements for each synchronous area or load-frequency control block, were developed and approved. A proposal for additional properties of frequency containment reserves was also developed and a cost-benefit study performed for the definition of a minimum delivery period for frequency containment reserves with limited energy storage.

Regulation (EU) 2017/2196 on electricity emergency and restoration also concerns system operation. The TSOs had developed their system defence and restoration plans by the end of 2018. Certain modalities (e.g. for system services for restoration, market suspension) were revised by the network operators in 2019 with the involvement of the Bundesnetzagentur and after consultation with market players before being finally approved by the Bundesnetzagentur in 2020.

7.3 Bidding zone review

Discussions in Europe on the design of the electricity market continue to focus on the reconfiguration of current bidding zones. In this respect, Regulation (EU) 2015/1222 provides for a review every three years, beginning with the Regulation’s entry into force in 2015, of the efficient configuration of the existing bidding zones by the participating TSOs, NRAs and ACER.

The applicable provisions of the CACM Guideline have now been supplemented by Regulation (EU) 2019/943 on the internal market for electricity. These changes will result in shorter processing times, greater involvement of the key TSOs and, if the regulatory authorities fail to reach agreement, full adoption by ACER.

Regulation (EU) 2019/943 on the internal market for electricity required TSOs to submit a proposal by 5 October 2019 for a methodology and for bidding zone configurations to be considered. It was agreed that the review process would benefit from analysing geographical regions parallel to each other. However, not all geographical regions were able to agree on the bidding zone configurations to be included in the review process. As a result, Continental Europe has not submitted any bidding zone configurations.

Due to the lack of agreement among the regulatory authorities, the bidding zone review process has been officially transferred to ACER. ACER is now responsible for defining the methodology, including bidding zone configurations. As there is not enough data for the model-based reconfiguring of bidding zones, a separate decision will be taken on the methodology and on the configurations. Once the methodology has been approved, the TSOs will have one year in which to accumulate and provide nodal data. On the basis of these data, a second decision will be taken to determine the configuration for the bidding zone study. The methodology for the bidding zones study was approved unanimously on 18 November 2020. The Bundesnetzagentur continues to support the retention of the German bidding zone and the zonal market model.

7.4 Inclusion of further states in the day-ahead multi-regional market coupling (MRC)

In an interim project, 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 (Figure 88). 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. The aim of market coupling is to facilitate a more efficient allocation of cross-border transmission capacities and improved price formation on regional day-ahead markets. This should increase both liquidity and trading options as well as price convergence. According to current planning, the project should be completed in the second quarter of 2021.

F Wholesale

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 off the exchange (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 was an overall increase in trading volume and liquidity in the electricity wholesale markets in 2019. There was an increase in trading volume in the spot market in 2019, in this case the day ahead and intraday-market. 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).[88]

Futures trading volumes also increased. The on-exchange trading volume of Phelix DE futures increased by approx. 27% in 2019 to 1,345 TWh. The volumes traded via broker platforms also increased. In 2019 the OTC clearing volume of Phelix DE futures on the EEX also increased by around 23% to 1,302 TWh and has now almost reached the volume of exchange trading. There was a decline in electricity wholesale prices in 2019. The average spot market price for Phelix day base was around €37.67/MWh. It is difficult to provide a quantified comparison of the prices over the years because of the splitting of the bidding zone in 2018. The prices on the futures market for the subsequent year also fell. On 27 December 2019 the Phelix DE peak year ahead future was quoted at a price of €62.98/MWh and was around 21% lower than the beginning of the year. The Phelix DE base year future also fell during the year to €41.33/MWh. This represents a decrease of around 19% since the beginning of the year 2019.

1. On-exchange wholesale trading

The review of on-exchange electricity trading relates to the German/Luxembourg market area and to the exchanges in Leipzig (European Energy Exchange AG – EEX), Paris (EPEX SPOT SE)[89] and Vienna (Abwicklungsstelle für Energieprodukte AG – EXAA) and Oslo (Nord Pool AS).

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[88] 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)

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

EEX offers electricity products in futures trading; EPEX SPOT, EXAA and Nord Pool on the spot markets89. These exchanges took part in collecting energy monitoring data again this year.[90] Since 1 October 2018 the market areas Germany/Luxembourg and Austria have been separate market areas. The key focus after the split is on the German market.

The total number of participants authorised at the electricity exchanges in the Germany/Luxembourg market area has differed slightly in recent years. On the one hand the number of participants on the EEX is constantly increasing whereas the number of participants on the EPEX Spot is constantly falling. On 31 December 2019 a new all-time high was reached on the EEX with 261 participants (2018: 237 participants). However, the number of participants on the EPEX Spot fell to 193 (2018: 198 participants); the number of participants authorised at the EXAA remained the same as the previous year: 71.

Electricity: development of number of registered trading participants on EEX, EPEX SPOT and EXAA

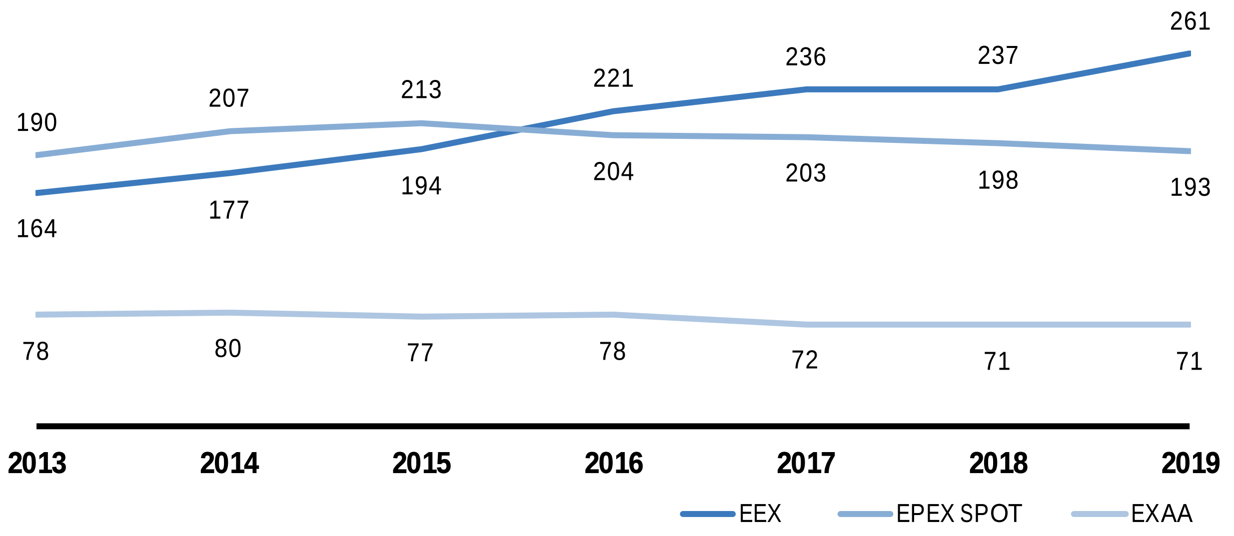

Figure 95: Development of the number of registered electricity trading participants on EEX, EPEX SPOT and EXAA

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 settled 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-

[90] 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 2019 was around 3.2 TWh. In 2018 it was around 2.3 TWh and in 2017 around 2.5 TWh. The exchange also offers the trading of market coupling products for Germany (from and to Sweden or Denmark)

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 spot markets examined here, EPEX SPOT, EXAA and Nord Pool, offer day-ahead trading and also 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).

Since 2 July 2019 the “Multiple NEMO Arrangement” (MNA) applies to all bidding zones of the CWE region (and likewise also to the German bidding zone). This enables every nominated exchange (NEMO) to allow its market participants access to the 12:00 market coupling auction for the respective bidding zones. The auction prices are calculated using a key auction algorithm, by which every NEMO within a bidding zone receives the same auction prices, i.e. this is not an exclusively EPEX auction but an auction operated within the framework of the European market coupling.

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.

Continuous intraday trading on EPEX SPOT and Nord Pool 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 the 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 electricity certificates with physical electricity.

1.1.1 Trading volumes

The volume of day-ahead trading on EPEX Spot was 226.41 TWh in 2019, an increase of around 0.8% compared to the previous year (224.6 TWh). The volume of intraday trading also rose to 53.66 TWh, representing an increase of around 0.85 TWh or approx. 1.6 % over 2018. The volume of the independent 10:15 a.m. day-ahead auction on EXAA for the German bidding zone declined by approx. 48% and amounted to around 3.73 TWh. The reason for this decline is that for the reporting year 2019 more figures are provided for the Germany bidding zone only and not, as in the past years, the total trading volume for both bidding zones (AT+DE-LU). This did not result in a decline in trading volume but merely a change of counting system. It also has to be considered that the total trading volume in the Germany bidding zone on the EXAA amounted to around 8.94 TWh in the 12:00 p.m. Market Coupling Auction. The volume of intraday trading on the Nord

Pool exchange amounted to around 3.2 TWh in 2019, an increase of approx. 39% over the previous year (2.3 TWh).

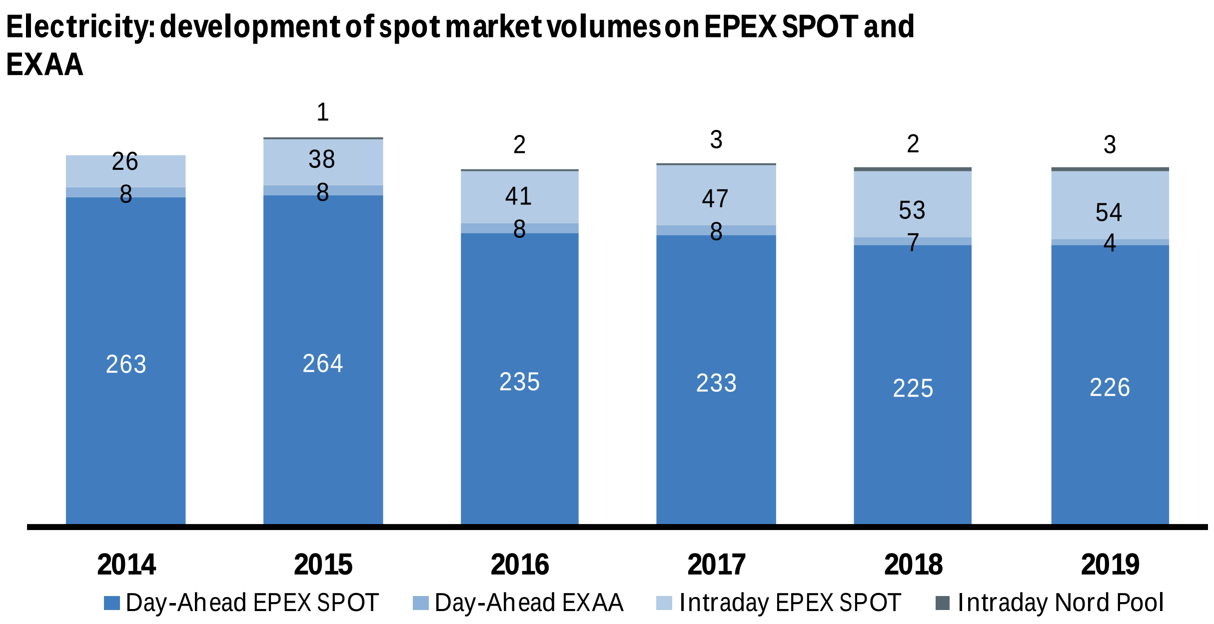

Figure 96: Development of spot market volumes on EPEX SPOT, EXAA and Nord Pool

1.1.2 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 already high proportion of price-independent bids on EPEX SPOT fell further in 2019 compared to the previous year. Approx. 65.9% of purchase bids submitted were price-independent in 2019 compared to 59.5% in 2018. The proportion of price-independent bids among selling bids submitted was 55.4%, compared to 62.6% in the previous year.

Electricity: price dependence of bids submitted in hour acutions on EPEX SPOT in 2019

	Selling bids		Purchase bids	
	Volume in TWh	Share	Volume in TWh	Share
Price independent bids	125.3	55.4%	149.3	65.9%
submitted by TSOs	39.7		0.5	
physically fulfilled Phelix Futures	14.3		42.2	
others	71.4		10.6	
Price dependent bids	101.1	44.6%	77.1	34.1%
in blocks	16.7		7.7	
market coupling	45.4		17.3	
of which price dependent bids	38.9		52.2	
Total	226.4	100%	226.4	100%

Table 78: Price dependence of bids submitted in hour auctions on EPEX SPOT in 2019

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%.[91] According to the power exchanges, the volume marketed by the transmission system operators increased to around 39.7 TWh (35.1 TWh in 2018 and 38.6 TWh in 2017).

The reason for the increase 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 2019, the market premium was drawn on by operators of installations with a capacity of approximately 75.3 GW; in December 2019 it was already drawn on by installations with a capacity of just under 79.6 GW. The installed capacity of installations with other direct marketing under Section 21b (1) no. 4 EEG 2017 fell from around 291 MW to 230 MW in the same period (January to December 2019).[92]

1.1.3 Price level

The most common price index used for 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

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

[92] For information provided by the TSOs on direct marketing, see https://www.netztransparenz.de/portals/1/Direktvermarktung-Uebersicht_Dezember2019.pdf, retrieved on 16 July 2020 retrieved on 9 August 2019.

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 Germany/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 fell in 2019. It is difficult to provide a quantified comparison of the prices over the years because of the splitting of the bidding zone in 2018. The average spot market price for Phelix day base was around €37.67/MWh. A comparison with the same product Phelix-Base DE would give a decrease of around 28%. However, the period of time used for the comparison in 2018 would only be the months of October to December, months which tend to be cold and dark and therefore in which the price of electricity is comparably higher. If the Phelix day base average of €37.67/MWh for 2019 is compared with the average from January 2018 to September 2018 for Phelix DE/AT, the decrease amounts to around 9.7%. It should be emphasized here that this was the joint bidding zone in the first three quarters of 2018, i.e. from January to September.

The Phelix day peak DE average for 2019 was approx. €40.43/MWh. If this price is compared with the average for 2018 - this time for the product Phelix day peak DE/AT and only for the first three quarters of 2018, it is almost 8.6% below the price of the previous year of €44.22/MWh.

Electricity: development of average spot market prices on EPEX SPOT in euros/MWh

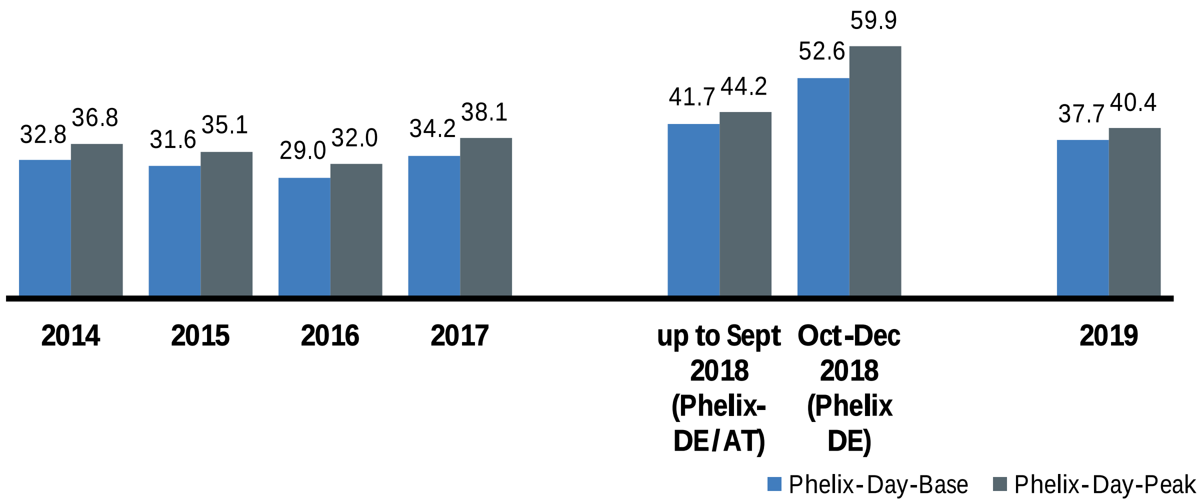

Figure 97: Development of average spot market prices on EPEX SPOT

The bEXA and Phelix indices for 2019 are very close to each other. If one considers the products for the German bidding zone, electricity prices were lower in 2019 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 €0.23/MWh. The difference between Phelix day peak and bEXApeak was around €0.21/MWh.

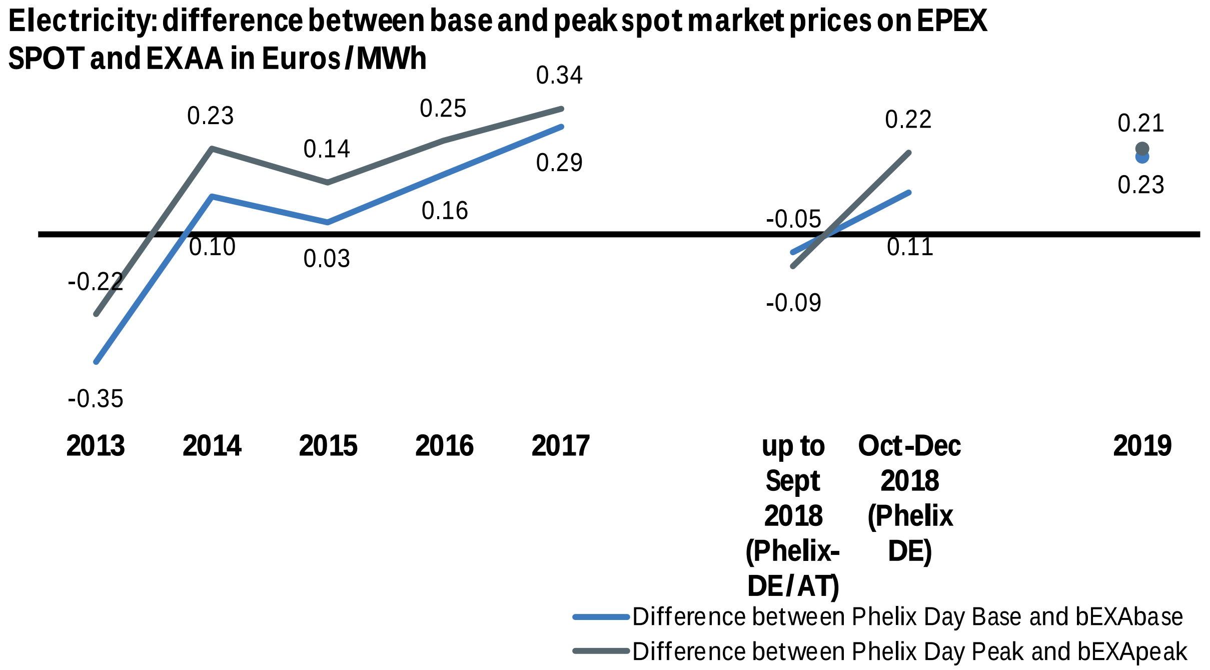

Figure 98: Difference between base and peak spot market prices on EPEX SPOT and EXAA

1.1.4 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 day base as an example. Daily average prices typically have a weekly profile with lower prices at the weekend. As in the previous year there were some occasional peaks and troughs in 2019 that went far beyond the usual fluctuations.

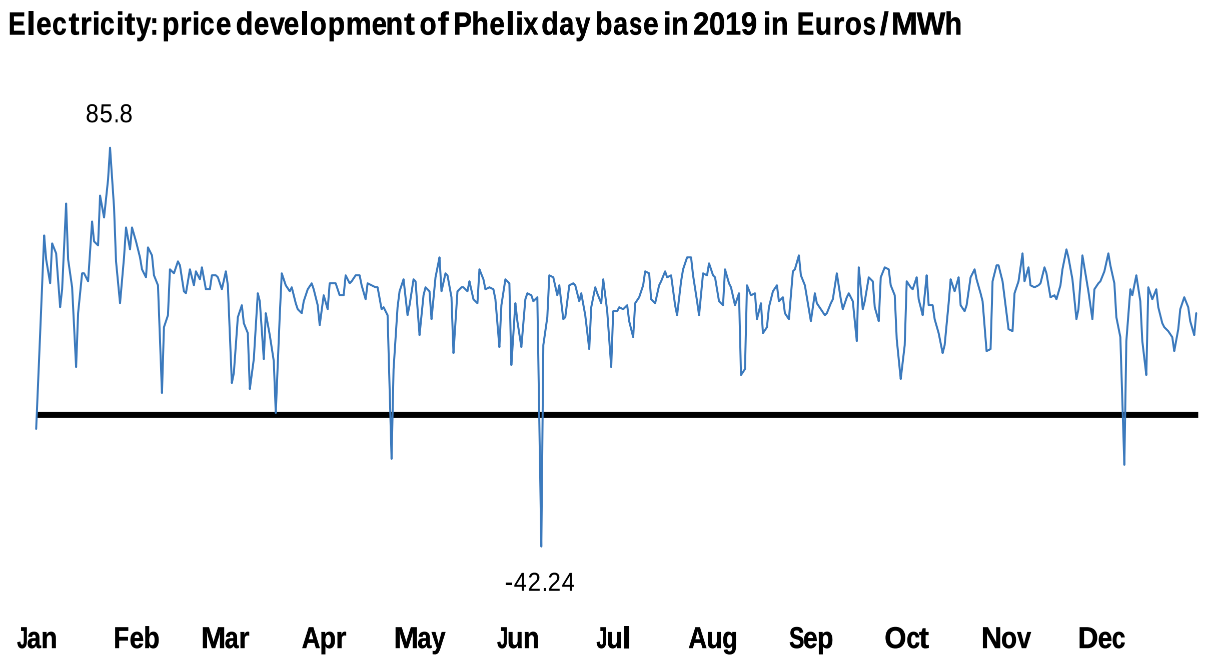

Figure 99: Development of Phelix day base in 2019

There were significant positive and negative extreme values in the Phelix base and peak prices on EPEX SPOT in 2019. The range of the middle 80% of the graded Phelix day base values rose in 2019 to €23.08/MWh. In 2018 the difference amounted to €22.57/MWh. The corresponding peak range of the middle 80% also rose significantly from €16.26/MWh in 2017 to €23.75/MWh in 2018 and to €25.69/MWh in 2019.

Negative values were reached in the Phelix day base prices on four days in 2019, and even on six days in the case of the Phelix day peak prices.[93] The Phelix day base reached its lowest value of €-42.24/MWh on 8 June 2019. The Phelix day peak registered its lowest value on the same day at €-65.94. In 2018 the minimum day base value was still €-25.30 /MWh and the minimum day peak value was €-21.46/MWh.

The maximum values of both indices also increased compared to the previous year. In 2019 the highest Phelix day base value was €85.80/MWh, or around 7% above the previous year's value. In 2018 the highest Phelix day base price was still €80.33/MWh. The maximum day base price was reached on 24 January 2019. 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 €102.74/MWh in 2019, an increase of around 5% compared to €97.48/MWh in 2018.

Electricity: price ranges of Phelix day base and Phelix day peak in Euro/MWh

	Middle 80%	Range of middle 80%	Extreme values	Range of extreme values
	10 to 90 percentile of values		Min – Max	
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
Base 2019	18.38 to 46.94	28.56	-36.46 to 76.84	113.30
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
Peak 2019	27.79 to 53.47	25.69	-65.94 to 102.74	168.68

Table 79: Price ranges of Phelix day base and Phelix day peak between 2017 and 2019

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.

The following section deals solely with on-exchange transaction volumes, excluding OTC clearing (cf. section I.F.2.2 „OTC Clearing").

[93] Negative prices are price signals on the electricity market that occur when high e.g. inflexible power generation meets weak demand. Inflexible power sources cannot be quickly shut down and started up again without major expense. Ongoing subsidies for negative prices can also play a significant role in generating negative prices.

1.2.1 Trading volumes Handelsvolumen

The on-exchange trading volume of Phelix DE futures in 2019 amounted to 1,345 TWh. From 2018, with the splitting of the bidding zones on 1 October the focus lay primarily with the assessment of trading volumes for Phelix DE. These amounted to 1,058 TWh in 2018 (in the case of Phelix DE/AT these still amounted to 27 TWh). 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. The following graph shows the development of the products Phelix DE/AT and Phelix DE.

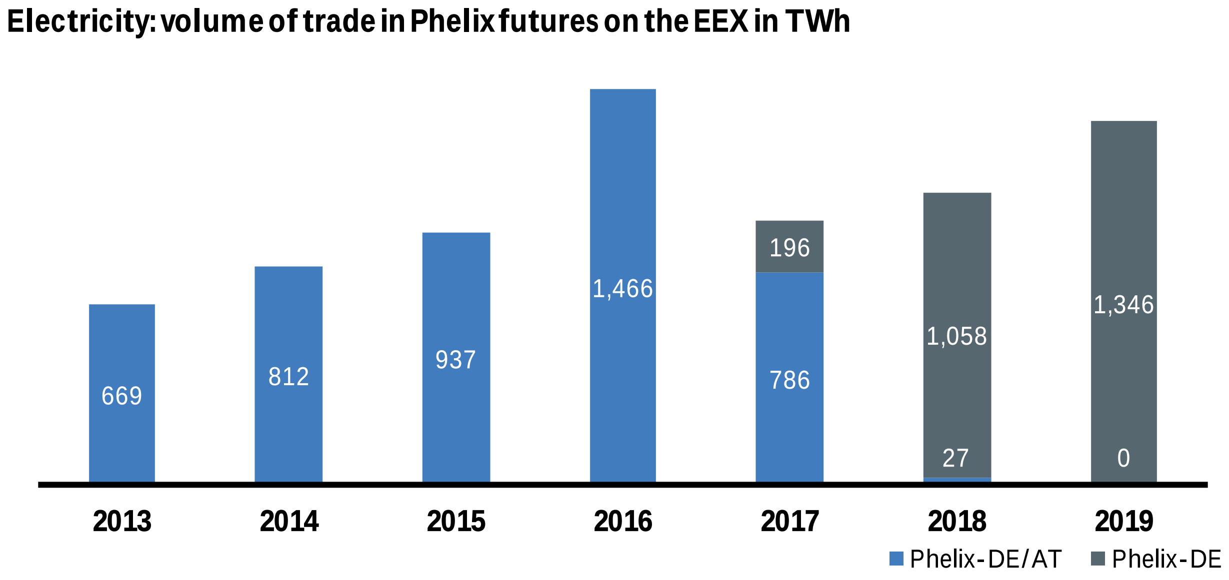

Figure 100: Trading volumes of Phelix DE/AT and Phelix DE futures on EEX

Exchange trading in Phelix DE futures predominantly focussed on contracts for the year ahead (2020) as the fulfilment year with approx. 62 % of the total trading volume, i.e. 834 TWh. Trading for 2019 made up the second largest share with approximately 19%, i.e. 255 TWh in total. Trading for 2021 and the next few years increased proportionally in comparison with the previous year. Trading for 2021 increased by over 18% to around 191 TWh. Trading volumes for the 3rd subsequent year also increased by around 32% to 58 TWh. The trading volume for the 4th subsequent year remained at around 8.7 TWh.

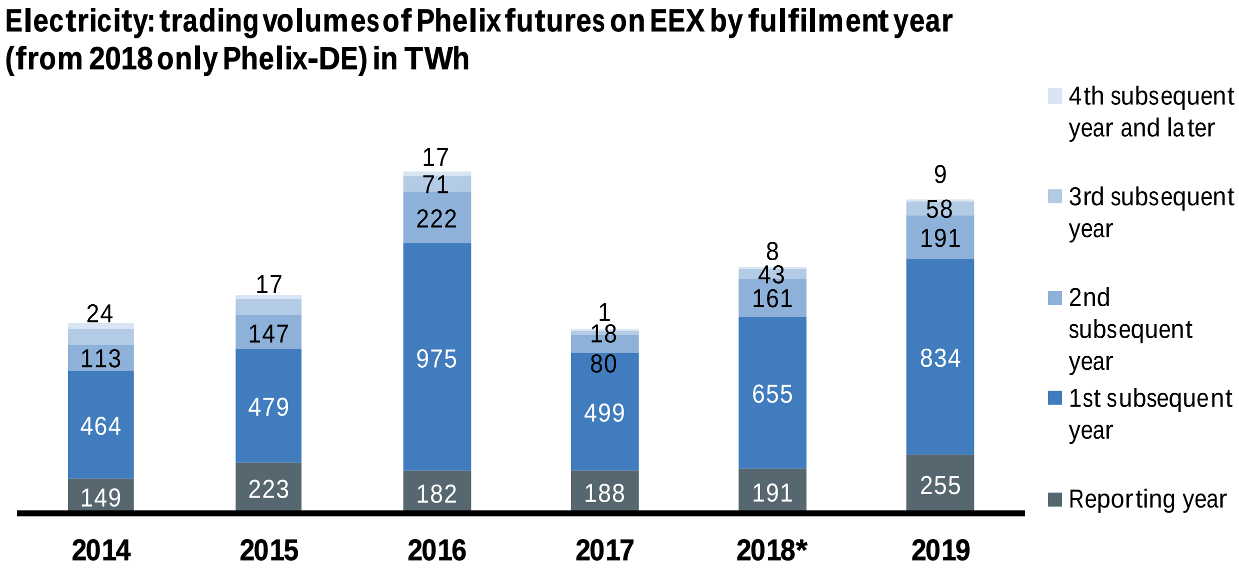

Figure 101: Trading volumes of Phelix DE/AT futures and from 2018 Phelix DE futures on EEX by fulfilment year

1.2.2 Price level

The Phelix base and peak year futures are the two most important futures traded on EEX for the German/Luxembourg market area in terms of volume.

In the course of 2019 futures prices fell. On 27 December 2019 the Phelix DE peak year ahead future was quoted at a price of €62.98/MWh and was around 21% lower than the beginning of the year. The Phelix DE base year future also fell during the year to €41.33/MWh. This represents a decrease of around 19% since the beginning of the year.

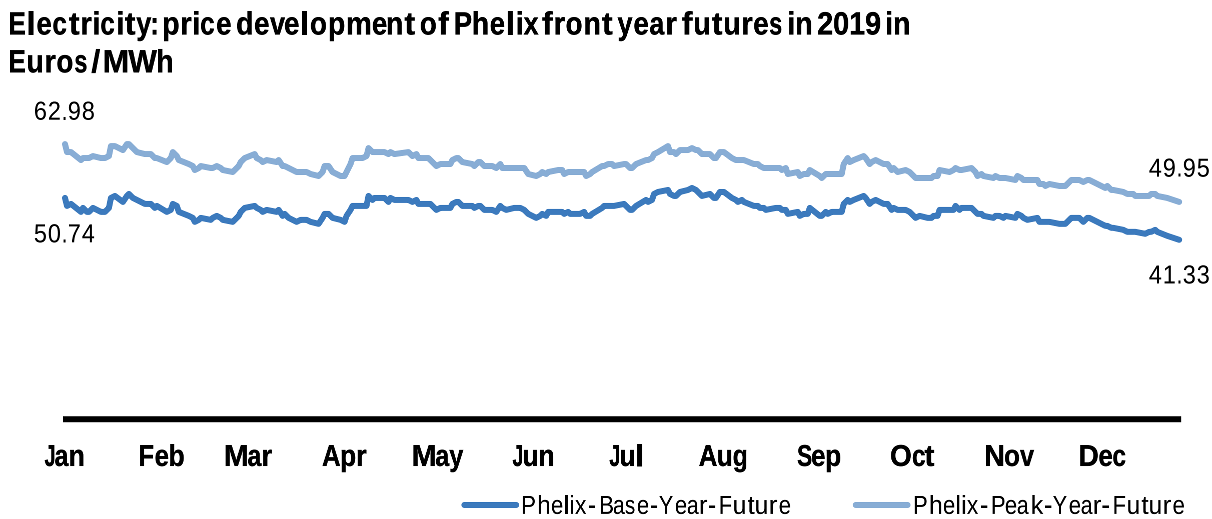

Figure 102: Price development of Phelix DE front year futures in 2019

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 year-on-year. With an annual average of €47.82/MWh, the Phelix base year future rose by €3.98/MWh from €43.84/MWh in 2018, a rise of approximately 9%. The price of the Phelix peak front year futures averaged €57.67/MWh over the year. The price increased by €3.72/MWh, or around 7 per cent, from the previous year's figure of €53.95/MWh.

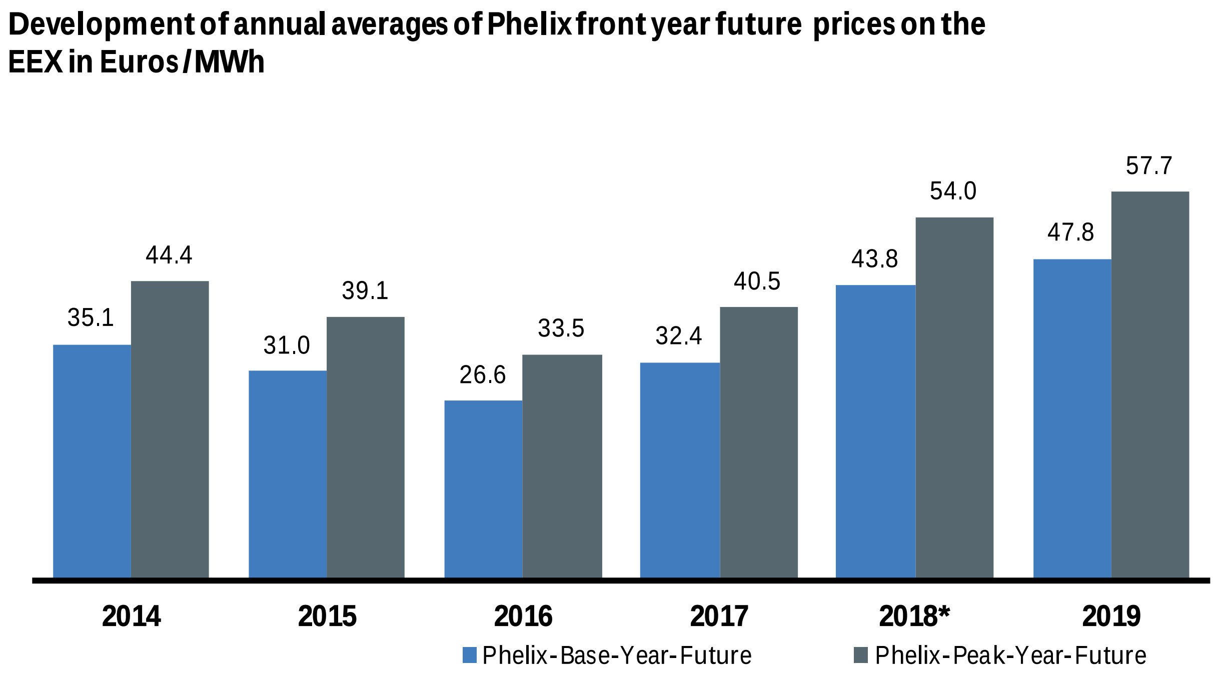

Figure 103: Development of annual averages of Phelix DE front year futures prices on EEX

The annual average price difference between base and peak products was €9.85/MWh. In 2018 the difference was still €10.11/MWh. The peak price was therefore around 21% 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.

Four 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, EDF Trading Limited and Vattenfall Energy Trading GmbH. However it is possible that the market makers were not active during the entire reporting period, but only for several months. The market makers' share of the purchase volume was thus approx. 18.9% and remains more or less the same as the share in the previous year, i.e. 18.4%. On the sales side, the volume increased to 21.9% from 16.9% in the previous year.[94]

In addition to agreements with market makers, EEX maintains contracts with trading participants who are committed to strengthening liquidity to an individually agreed extent. In terms of trading volume, these companies accounted in total for about 4.9% and 4.5% respectively of purchases and sales in 2019. In the previous year their share of purchases was around 2% and their share of sales also 2%.

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 significance of direct marketing by the power plant operators.

The share of TSOs in the day-ahead sales volume on EPEX SPOT has been declining for a number of years but was approx. 18% in 2019, slightly lower than in the previous year when it was approx. 19%. By comparison: Their share was still 28 % in 2012. The volumes marketed by the TSOs also declined in absolute terms over the years. The on-exchange day-ahead sales volume marketed by TSOs was approximately 41.3 TWh in 2019; in 2018, this value was still around 41.6. In the years previous to this the sales volume marketed by the TSOs was higher; in 2012 it was still approx. 69.6 TWh and in 2014 approx. 50.6 TWh. The TSOs generated a very small spot market volume of about 0.9% 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 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.[95]

The share of the five purchasers with the highest turnover of the day-ahead trading volume on EPEX SPOT in 2019 rose from 35.4% in 2018 to 37.2%. The corresponding share on the seller side also increased compared to the previous year. The cumulative share of the five sellers with the highest turnover was approximately 31.4% in 2019. This was still 30.1% in the previous year.

[94] 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.

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

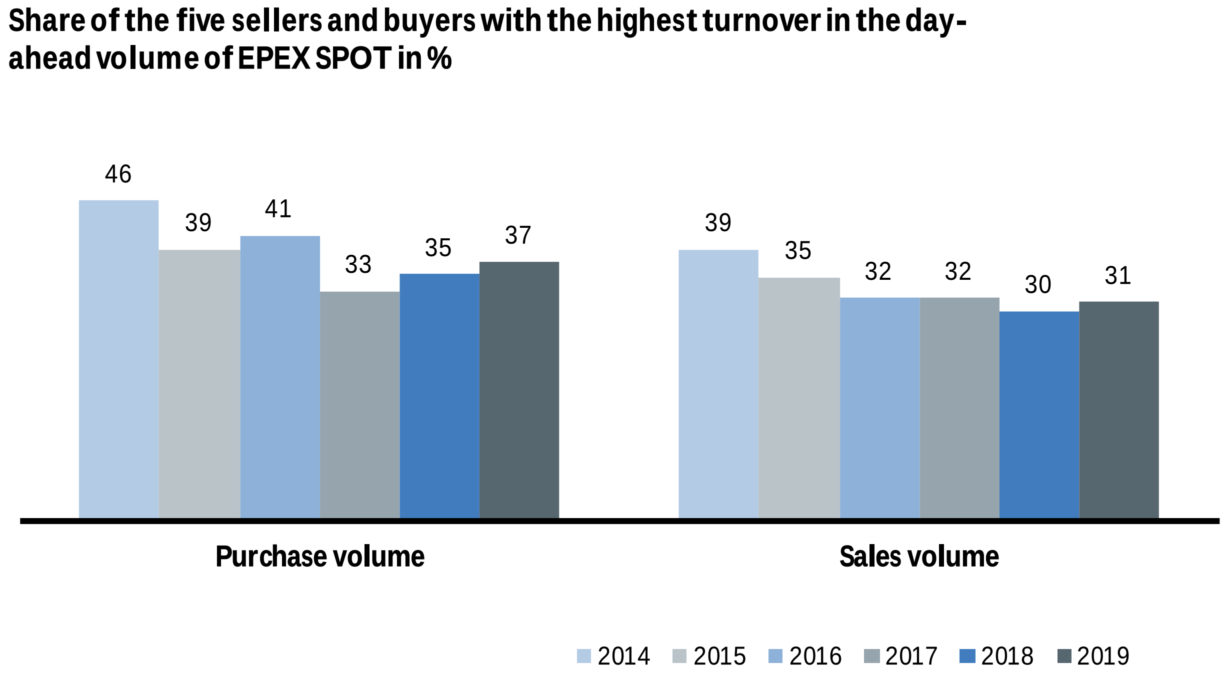

Figure 104: Share of the five sellers and five buyers with the highest turnover in the day-ahead volume of EPEX SPOT

The share of the five buyers of Phelix DE futures with the highest turnover on EEX (excluding OTC clearing) declined from around 34.8% in 2018 to 31.3% in 2019. The share of the five sellers with the highest turnover rose from around 34.9% in 2018 to 35.2% in 2019.

2. Off-exchange wholesale trading

Off the exchange (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 demand and offer of electricity transactions. Electronic broker platforms are used to bring interested parties on the supply and demand sides together and so increase the chances of the two parties reaching an agreement.

On-exchange OTC clearing plays a special role. OTC trading transactions can be registered on the exchange to hedge the parties' trading risk.[96] OTC clearing therefore represents an interface between on-exchange and off-exchange electricity wholesale trading.

In 2019 different broker platforms were once again surveyed with regard to off-exchange wholesale trading (see sections below). Data on OTC clearing on EEX was also collected. The surveys again revealed an increased level of liquidity in off-exchange electricity wholesale trading in 2019.

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.

Eleven brokers (ten in the previous year) who brokered electricity trading transactions with Germany as a supply area took part in this year's collection of wholesale trading data. The total volume brokered by them was around 5,770 TWh in 2019 compared to 4,956 TWh in 2018. The data of one of the larger brokers on the market was included in the 2019 analysis which had not transmitted any volumes in the previous year. Data from the London Energy Brokers' Association (LEBA), which, however, does not include all broker platforms surveyed, also showed a similar observation. There was a slight decrease in the volume of trading transactions brokered by LEBA members. The trading volume for German power brokered by LEBA members fell from 5,330 TWh to 4,757 TWh, or by around 11% year-on-year.[97]

Contracts for the year ahead (2020) 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 2019 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.

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

[97] See London Energy Brokers' Association, Monthly Volume Report: https://www.lebaltd.com/monthly-volume-reports/ (retrieved on 31 July 2020).

Electricity: volume of electricity traded via broker platforms in 2019 by fulfilment period

Fulfilment period	Volumes traded in TWh	Share
Intraday	0	-
Day Ahead	111	2%
less than 1 week	95	2%
over 1 week	2,370	41%
1st subsequent year	2,788	48%
2nd subsequent year	466	8%
3rd subsequent year	134	2%
4th subsequent year	12	< 1%
Total	**5,770**	**100%**

Table 80: Volume of electricity traded via broker platforms in 2019 by fulfilment period

2.2 OTC Clearing

Alongside the on-exchange EEX order book trade, on-exchange OTC clearing played a special role in off-exchange wholesale trading. In OTC clearing, the exchange, or its clearing house, is the contracting party of the trading participants 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 1,302 TWh in 2019. The volume was still 1,053 TWh in 2018. 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 2018 the volume increased, both in OTC and on-exchange trading. The OTC clearing volume increased by approx. 24% and on-exchange trading by approx. 27% compared to the previous year.

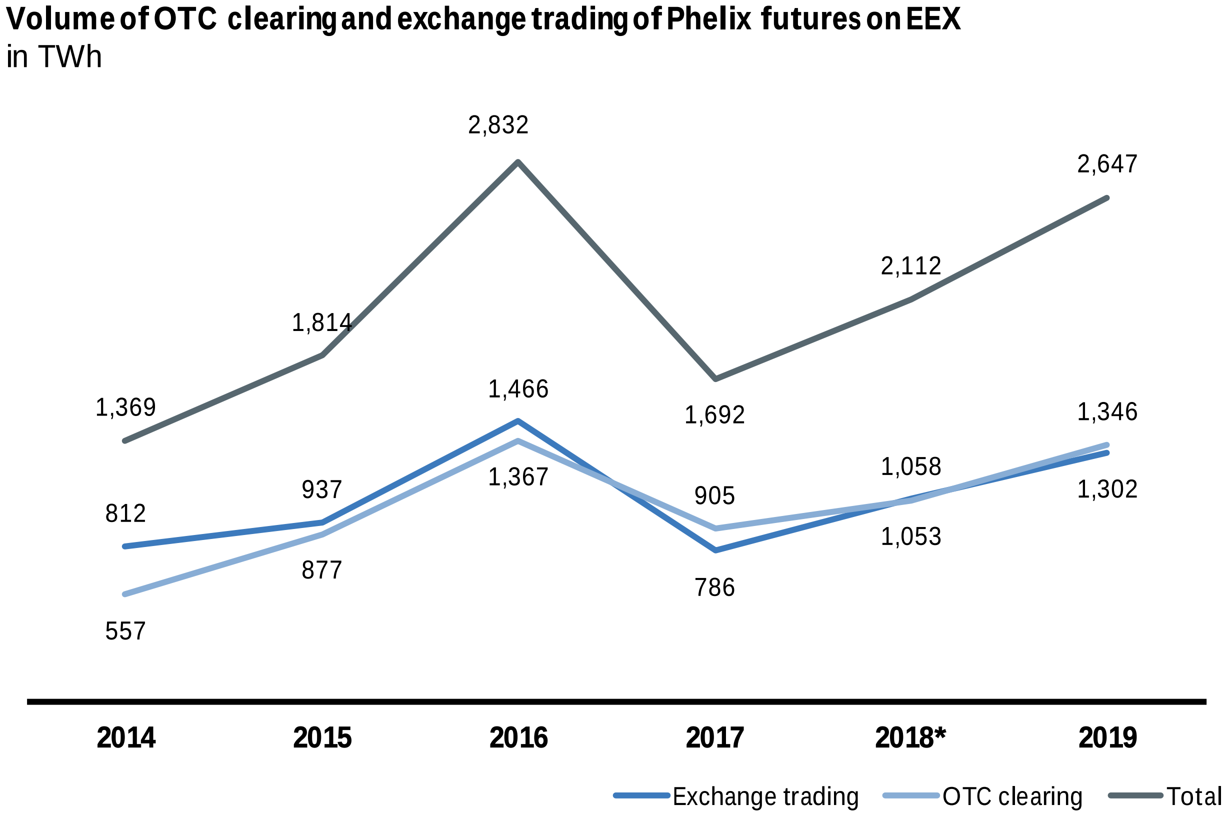

Figure 105: Volume of OTC clearing and exchange trading of Phelix DE futures on EEX

According to LEBA, the volume for German power registered by LEBA members for clearing was approx. 1,240 TWh in 2019, which is equivalent to a share of about 26% of the total OTC contracts brokered by LEBA members. By contrast the corresponding figures were around 17% of the total volume with a volume of approx. 915 TWh in 2018.[98]

The Phelix options had no bearing on exchange trading on the EEX. As in the previous year there were no such transactions in 2019. By contrast, OTC clearing of Phelix options agreed off the exchange has practical significance: Phelix options accounted for a share of 49 TWh or 4% of OTC clearing in 2019 while the remaining 1,252 TWh or 96% of OTC clearing consisted of Phelix futures. The OTC clearing volume for options decreased significantly by approx. 72% over the previous year.

The distribution of the volumes registered on EEX for OTC clearing across the various fulfilment periods in 2019 shifted compared to the previous year. While in 2018 approx. 62% consisted of contracts for 2019, this figure fell to 55% in 2019 (719 Twh) for 2020 contracts. Around 33% (428 TWh) related to 2019 itself. In 2018 this was still around 25% or 259 TWh. Around 9% related to the year after next (trading for 2021). Later fulfilment periods made up only a small share.

[98] Cf. https://www.lebaltd.com/monthly-volume-reports/ (retrieved on 31 July 2020). The total volume of German power brokered by LEBA members was 4,757 TWh for 2019.

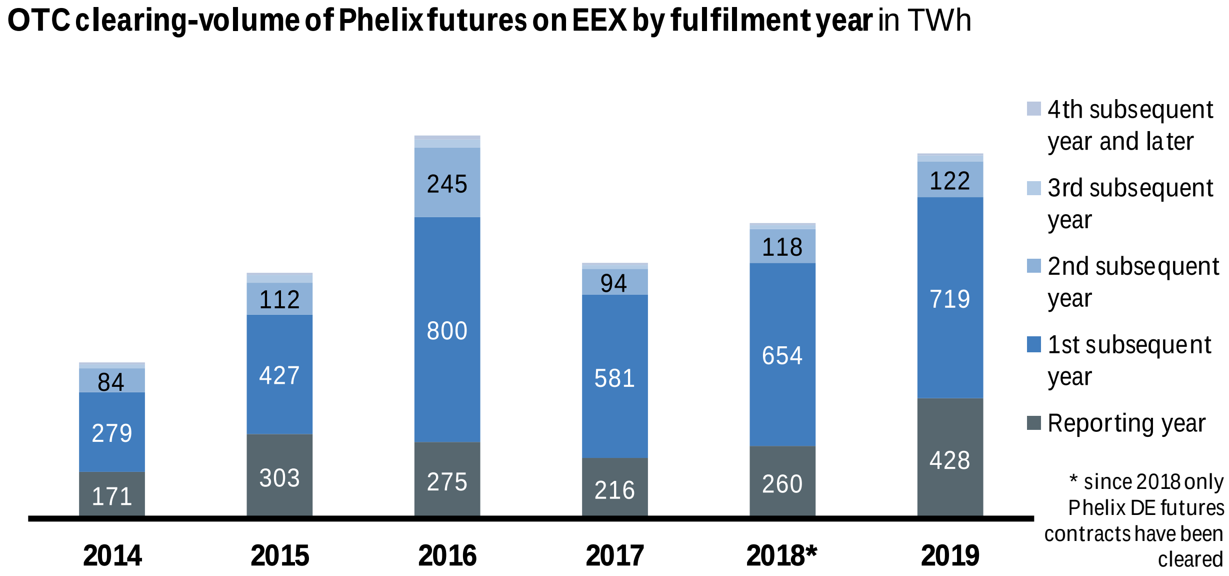

Figure 106: OTC clearing volume of Phelix futures on EEX by fulfilment year

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 2019 accounted for about 45% of all purchases and 46% of all sales (in 2018 they accounted for around 53% of all purchases and 54% of all sales).

G Retail

1. Supplier structure and number of providers

In total, at least 1,430 companies were operating as electricity suppliers in the year 2019. Suppliers are considered to be individual legal entities without taking company affiliations or links into account.

Around 51.0m market locations of final consumers were recorded in the monitoring survey. As Figure Figure 107 shows, of 1,387 suppliers, approximately 84% serve fewer than 30,000 market locations. This amounts to just under 8.2m market locations in this category (around 16% of all market locations). Some 6% of all suppliers serve more than 100,000 market locations each. In absolute terms, these 6% serve around 35.9m market locations and therefore around 70% of all customers, which is a similar figure to the previous year. The 86 large suppliers serve the largest number of market locations in Germany. Hence the majority of companies operating as suppliers continue to have a customer base made up of a relatively small number of market locations. A large number of suppliers therefore does not automatically translate into a high level of competition.

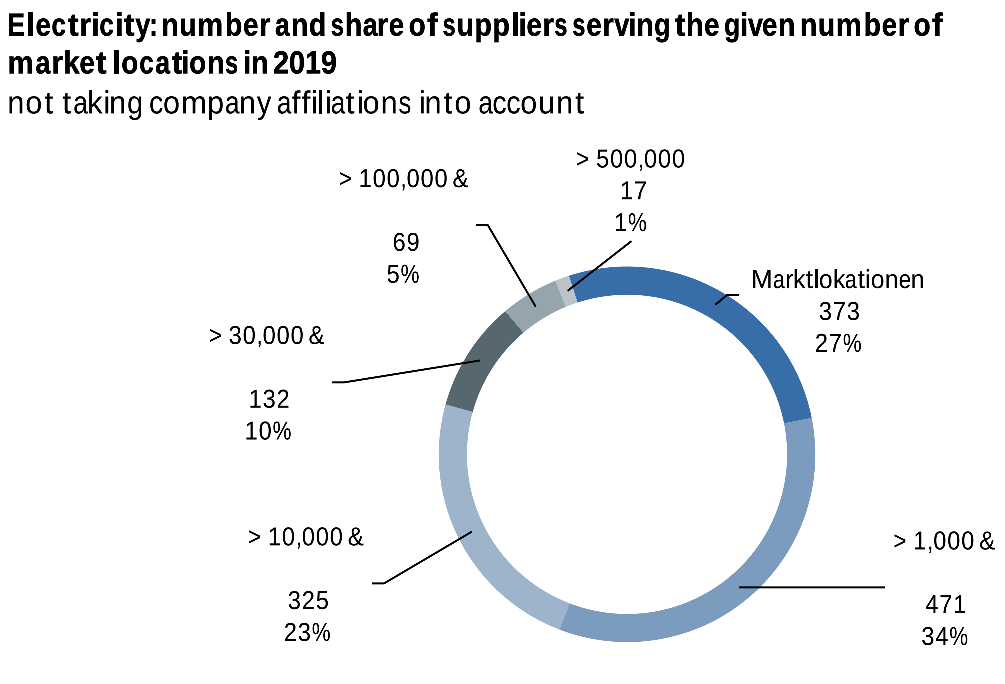

Figure 107: Number of suppliers by number of market locations supplied

A more comprehensive picture of the supplier structure emerges from an evaluation of the regional activity of the suppliers. The analysis of the data submitted by 1,224 suppliers shows that nearly half of them only operate regionally. Some 100 suppliers, or around 8%, supply customers in more than 500 network areas (see Figure 108). 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: 205 suppliers have concluded contracts in all 16 federal states. On a national average, a supplier has customers in 97 network areas (2018: 93 network areas).

Electricity: number and share of suppliers serving customers in the given number of network areas in 2019
not taking company affiliations into account

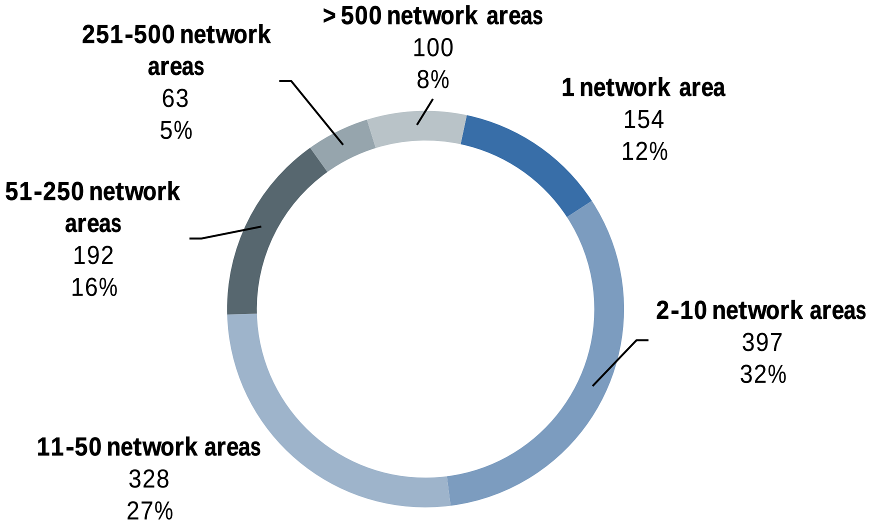

Figure 108: Number of suppliers by number of network areas supplied

Although the majority of suppliers continue to operate regionally, the number of suppliers that electricity customers could choose from has increased over the past eight years. An evaluation of the data supplied by 827 distribution system operators on the number of suppliers that supply the consumers in each network area produced the following results (see Figure 109): In 2019, more than 50 suppliers operated in 89% of all network areas (737 network areas). In the year 2008 this figure was 50% of the network areas (362 network areas). Today more than 100 suppliers operate in around 73% of the network areas, whereas five years ago it was only 49% (392 network areas). On average, final consumers in Germany were able to choose between 156 suppliers in 2019 (2018: 149), while household customers were able to choose between 138 suppliers (2018: 132).

Electricity: breakdown of network areas by number of suppliers operating
(%) not taking company affiliations into account

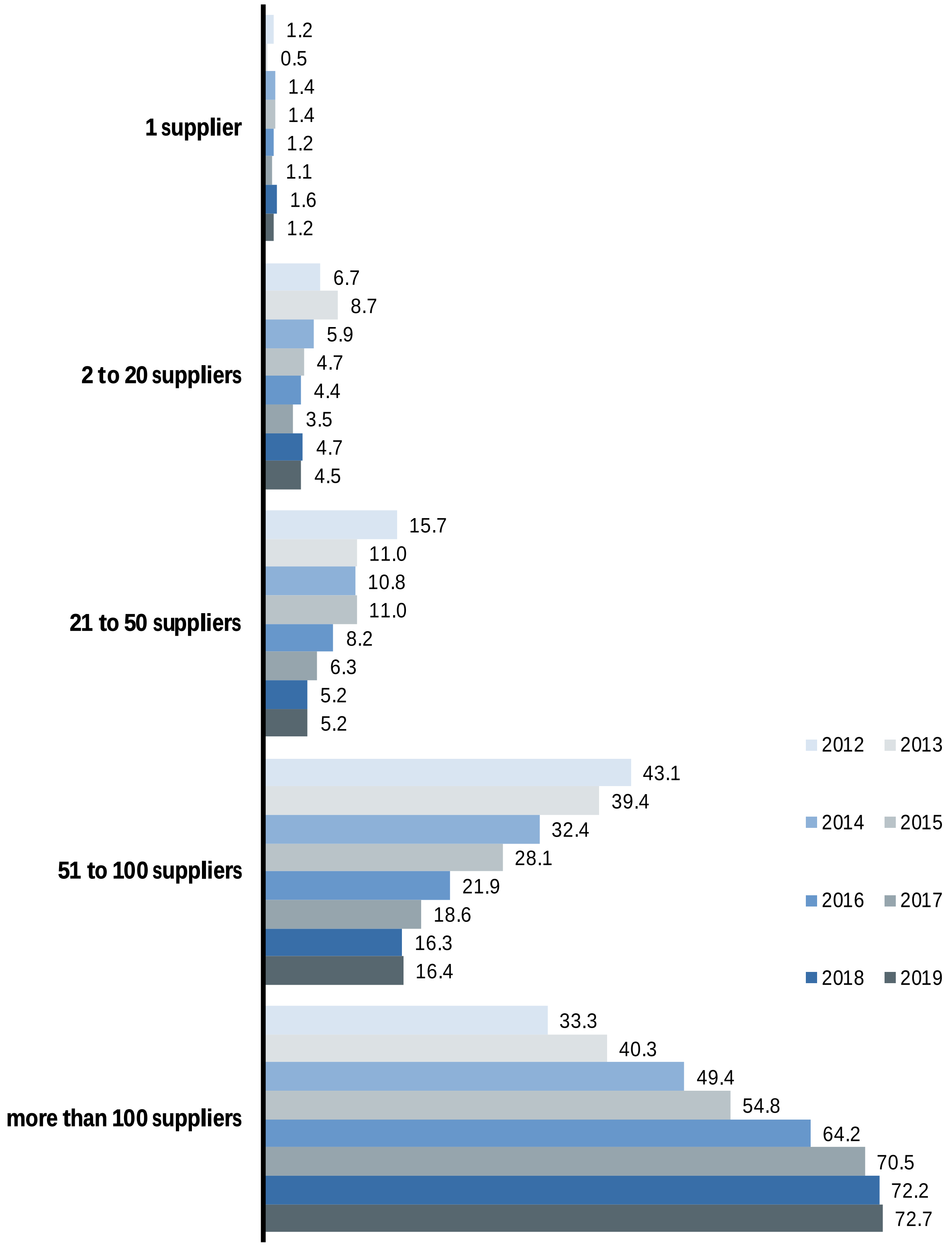

Figure 109: Breakdown of network areas by number of suppliers operating

2. Contract structure and supplier switching

40% of household customers are supplied with electricity under a non-default contract with the local default supplier. Around 26%of household customers are supplied under a standard default tariff. 34% of household customers have a contract with a supplier other than the local default supplier.

A total of 66% of all households are still served by the default supplier. Thus the position of the default suppliers in their respective service areas remains strong.

In 2019, around 4.5m household customers switched electricity suppliers. 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 supplier and thus to access a cheaper electricity contract.

Consumers are recommended to find out what kind 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.

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 into or out of premises 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 switches can therefore deviate from the figures registered. 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[99]. 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 [100] on the one hand and industrial customers on the other. For monitoring purposes as well, a strict separation of these two customer groups is not undertaken.

According to supplier data, the volume of electricity sold to all final consumers in 2019 was approximately 414.1 TWh. In the previous year, this figure was 418.8 TWh. In 2019, around 257.2 TWh of this amount was supplied to interval-metered customers and 156.9 TWh to SLP customers (including 13.5 TWh of electricity for thermal night storage heating and heat pumps). The majority of SLP customers are household customers. In 2019, household customers were supplied with around 123.7 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 purpose of this analysis, the default supply contract category also includes auxiliary energy supply (section 38 EnWG) and doubtful cases.[101] 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 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).

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[99] 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.

[100] The category “commercial customers” usually also includes customers from the liberal professions, agriculture, services and public administration, if their annual consumption does not exceed 10,000 kilowatt hours.

[101] 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.

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[102], the majority are industrial or high-consumption non-household customers.

In the reporting year 2019, 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 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 2019 (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 [103]. 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 still losing in importance for the acquisition of interval-metered electricity customers.

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

[103] In accordance with Section 36 of the German Energy Act (EnWG), default supply relates only to household customers. Any mention in the following of the default supply of non-household customers refers to fallback supply.

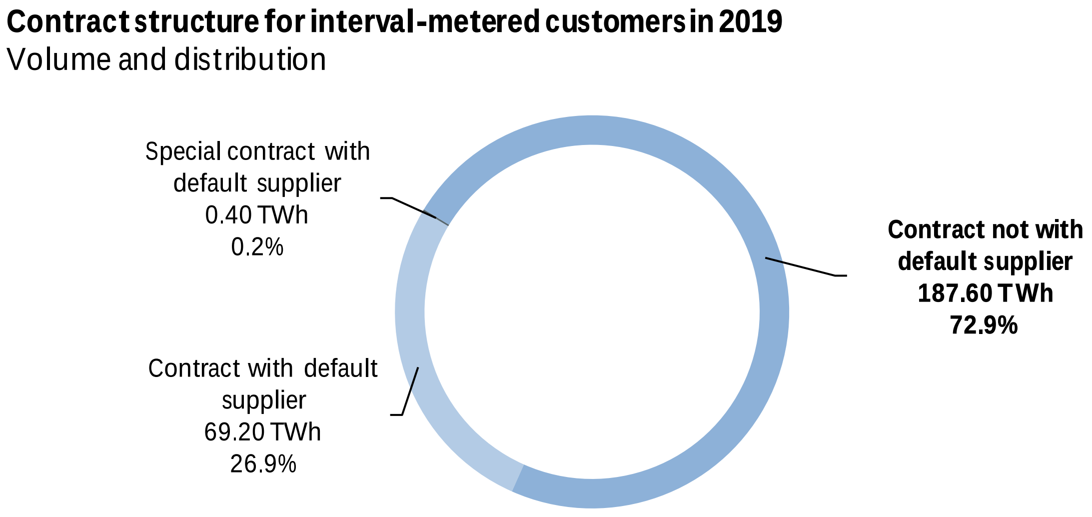

Figure 110: Contract structure for interval-metered customers in 2019

2.1.2 Supplier switching

Data on the supplier switching rates among different customer groups in 2019 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 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:

Electricity: supplier switching by consumption category in 2019

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	299,333	14.2%	17.0	13.8%
> 2 GWh/year	2,950	17.3%	24.3	10.5%
Total non-household customers	**302,284**	**14.2%**	**41.2**	**11.7%**

Table 81: Supplier switching by consumption category in 2019

The volume-based switching rate for the categories with a consumption exceeding 10 MWh/year was 11.7% in 2019. The switching rate in the previous year was 12.3%. 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.

Supplier-switching among non-household customers Volume-based switching rate for all consumption categories exceeding >10 MWh/year in %

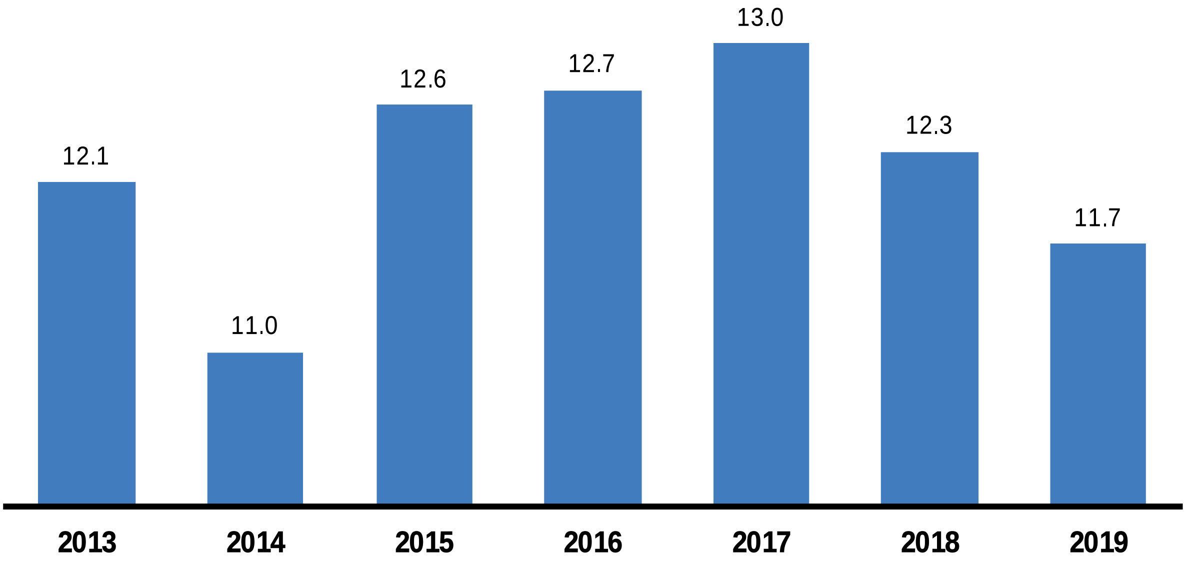

Figure 111: Supplier switching among non-household customers

2.2 Household customers

2.2.1 Contract structure

The data from the monitoring report shows that in 2019 the category "non-default contract with the default supplier" accounted for around 40% of electricity consumption by household customers (2018: 42%). The percentage of household customers with a standard default supply contract is 26% of electricity consumption (2018: 27%). The percentage of customers served by a contract with a company other than their local default supplier was 34% (2018: 31%). Overall, 66% of all households are still served by the default supplier (2018: 69%). Thus the position of the default suppliers in their respective service areas remains strong.

Electricity: contract structure of household customers in 2019
TWh and percentage

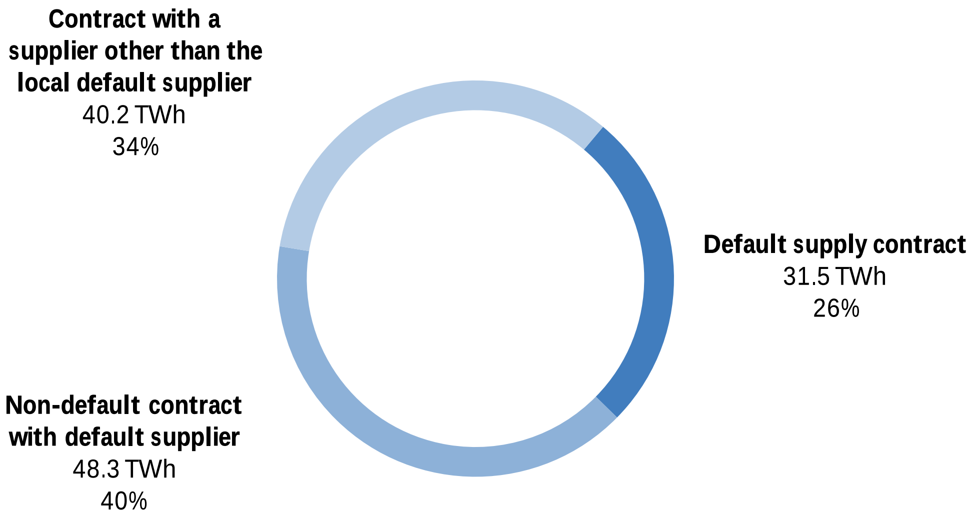

Figure 112: Contract structure of household customers in 2019

2.2.2 Switch of contract

Table 82 depicts contract switches within a company carried out at the customer's request. The total number of contract switches was around 1.83m, which is below the previous year's figure (2018: 1.98m contract switches). The corresponding volume of electricity involved in the contract switches amounted to approximately 5.6 TWh. This results in a number and volume-based contract switching rate of 3.9% and 4.6% respectively. The number of switches within a company thus declined in comparison to the previous year.

Electricity: Contract switches by household customers in 2019

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 contract with their supplier	5.6 TWh	4.6%	1.83m	3.9%

Table 82: Contract switches by household customers (based on survey of electricity suppliers)

2.2.3 Supplier switch

The supplier switching rate of household customers 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. In 2019 the total number of household customers switching supplier was around 270,000, which is significantly lower than the previous year's level of 4.7 million. In the analysis of the monitoring data, the special effect caused by insolvencies was deducted from the total number of active (voluntary) supplier changes. Customers of suppliers affected by insolvency reverted to a default supply contract with their default supplier or chose a contract with a different supplier. Since these supplier switches were not counted as active (voluntary) changes, they were deducted from the total number. The available data does not allow for an ex-post differentiation between a change of supplier that is unrelated to moving house and a change of supplier that takes place when moving into a house.

In 2019 the overall supplier switching rate was approximately 9.9% for household customers and has thus declined slightly since the previous year (2018: 10.2%). These switches entail an electricity volume of about 14.6 TWh, which is roughly at the same level as the previous year's figure (2018: 14.1 TWh). This corresponds to a switching rate based on volume of 11.8%, 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. Figure 114 shows the increasing trend in the rate of supplier switches since 2009.

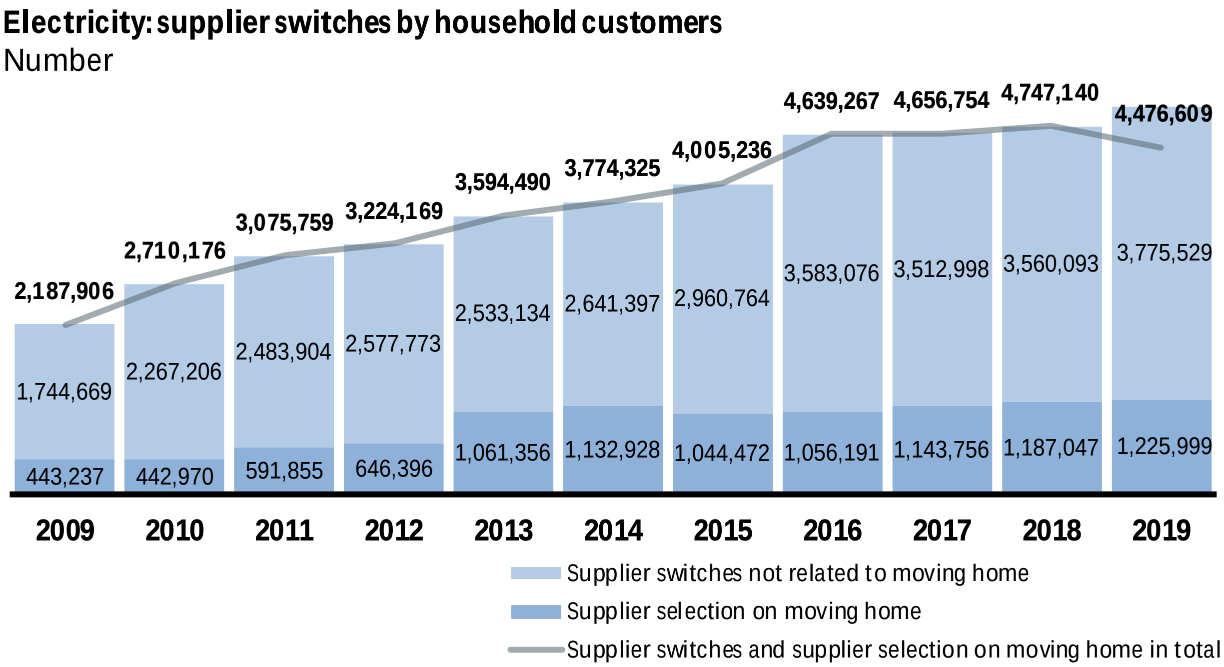

Figure 113: Supplier switches by household electricity customers [104]

[104] Due to insolvencies, the number of switches for the years 2011 and 2013 have been adjusted by approximately 500,000 insolvency-related switches per year.

Supplier switches by household customers in % and number of supplier switches

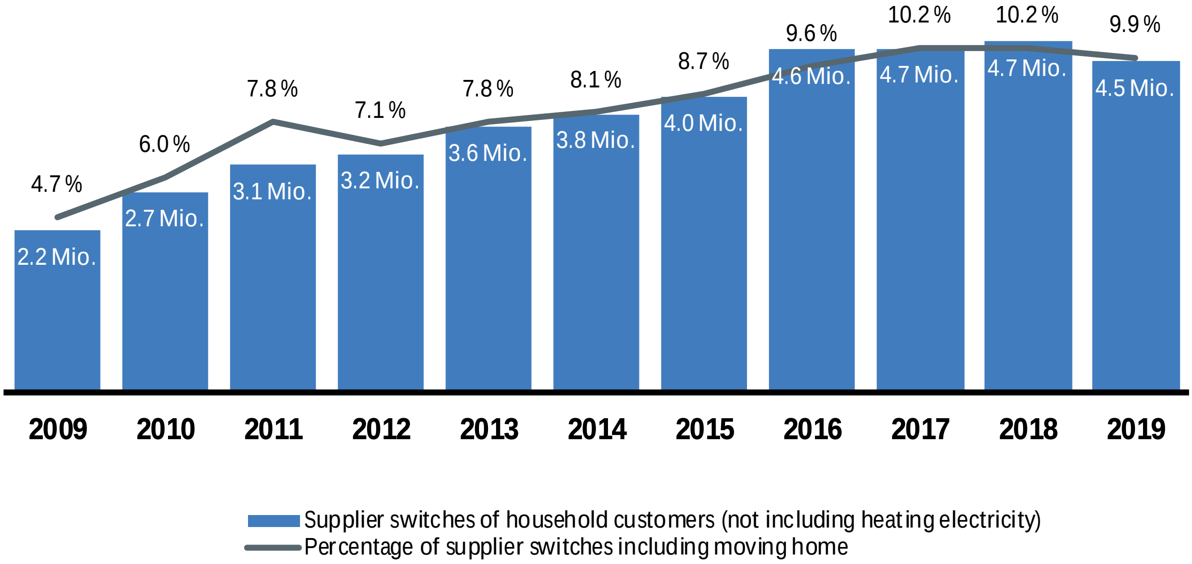

Figure 114: Supplier switches by household electricity customers

A joint view of the contract and supplier switches in 2019 makes it possible to determine the number of household customers who undertook a change in their energy supply contract. A total of around 6.3m switches were made.

3. Disconnections, cash/smart card reader, tariffs and contract terminations

A customer who fails to make a payment to the electricity supplier 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 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 in arrears. The default supplier is also required to verify the proportionality of the decision to disconnect supply.

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 also lower their energy costs. They can also receive energy cost counselling from consumer advice centres, for example.

In 2020 – as a result of the COVID-10 pandemic – a right to refuse performance was introduced, effective between April 1 and June 30 (Art. 240 section 1 EGBGB), which also applied to energy supply contracts. In addition, some suppliers announced that they would forgo carrying out disconnections. It is therefore possible that the number of disconnections will be lower in 2020 than in the previous year.

3.1 Disconnections of supply

In 2019, the Bundesnetzagentur questioned network operators and electricity suppliers about disconnection notices and disconnection requests, as well as about the number of actual disconnections carried out, along with the associated costs. In 2019, the number of disconnections carried out by network operators was at 289,012 which is 2% lower than the previous year's figure (2018: 296,370). 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 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 115 shows how often during the year 2019 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.

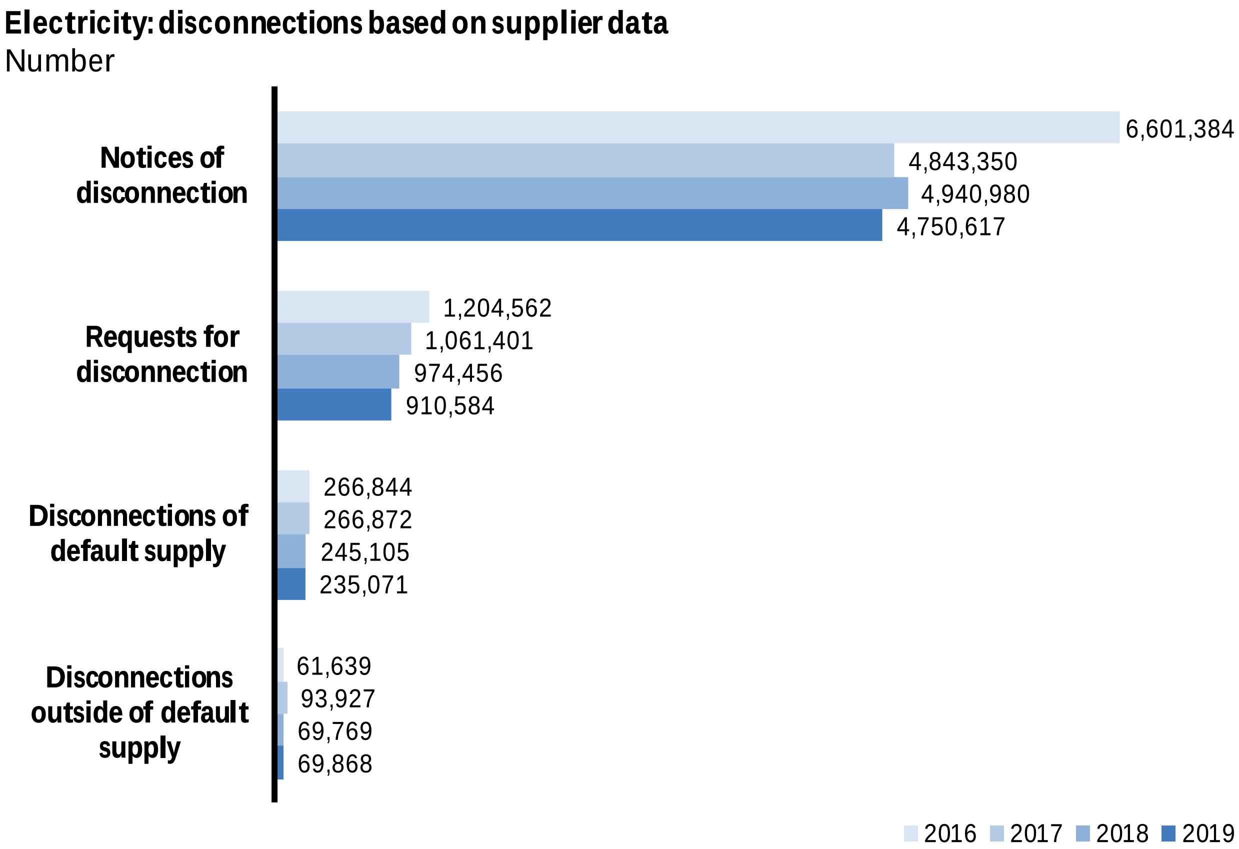

Figure 115: Disconnection notices, requests for disconnection and disconnections within and outside of default supply, based on survey of suppliers

According to the data provided by suppliers, disconnection notices were sent off when, on average, a customer was €118 in arrears. In total, around 4.75m disconnection notices were issued to household customers. Of this amount, approximately 0.91m, or 19%, resulted in electricity being disconnected by the pertinent network operator. According to supplier data, in just under 6% of the cases of disconnection notices being issued was supply actually disconnected.

Suppliers also responded that there were around 235,071 cases of disconnection of customers with default supply. 1.5% of household customers with default supply contracts were affected by a disconnection. According to data proved by suppliers, disconnections outside of default supply contracts were carried out in approximately 69,868 cases.[105] Suppliers reported that around 8% 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 €39 (including VAT),[106] with the actual price ranging between €1 and €199. Suppliers who did not carry out a flat rate calculation charged their customers an average of €44 (including VAT), with the actual cost ranging between €4 and €130. For reconnection, electricity suppliers using the flat rate model charged their customers an average of approximately €44 (including VAT), with the actual cost ranging between €1 and €140, while suppliers who did not use the flat rate model charged an average of €50 (including VAT), with the actual charges varying from around €5 to €130. Suppliers charged household customers an average of €3.40 for issuing a reminder because of arrears in payment.

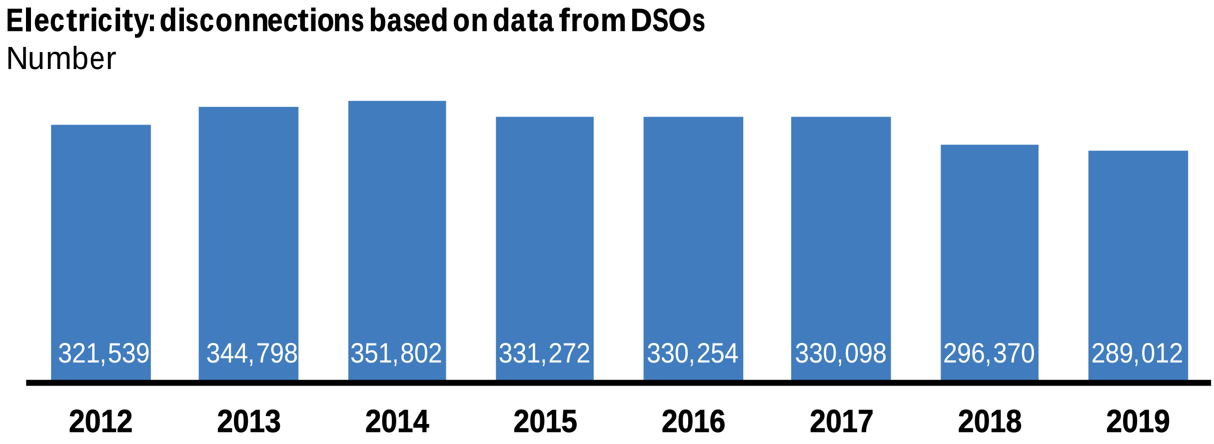

Figure 116: Disconnections based on data from DSOs [107]

A total of 289,012 disconnections and 269,719 reconnections were carried out in 2019. The following table shows the distribution of disconnections broken down by federal state:

[105] The total number of disconnections reported by suppliers always deviates from the disconnection actually carried out by the network operator. For the total number of disconnections, the Bundesnetzagentur uses the data submitted by the network operator.

[106] Supplier's own costs, not including costs incurred with the commissioned network operator.

[107] The figures from 2011 to 2014 entail those disconnections requested by the local default supplier. As of 2015 the figure entails the disconnections from all suppliers.

Electricity: number of disconnections by federal state in 2019 (DSO data)

	Number of disconnections (within and outside of default supply)	Percentage of market locations of final consumers in the federal state
Saxony-Anhalt	12,924	0.85
Northe Rhine-Westfalia	93,758	0.83
Berlin	18,181	0.76
Hamburg	7,989	0.68
Saxony	17,336	0.61
Bremen	2,617	0.59
Schleswig-Holstein	10,656	0.58
Mecklenburg-Western Pomerania	6,573	0.58
Hessen	21,627	0.57
Saarland	3,662	0.56
Rhineland-Palatinate	13,282	0.53
Thuringia	7,121	0.51
Lower Saxony	21,258	0.45
Brandenburg	6,780	0.40
Baveria	27,040	0.34
Baden-Württemberg	18,195	0.28

Table 83: Number of disconnections by federal state in 2019

It must be noted when looking at Table 83 that around 0.1% of all disconnections carried out by DSOs could not be attributed to an individual federal state.

The network operators charged the electricity suppliers an average amount of €53 (excluding VAT) for disconnecting supply, with the actual costs charged ranging between around €12 and €175. The average amount charged for reinstating supply to household customers was €56 (excluding VAT), with the actual charges varying from €14 to €152.

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 2019). 15,935 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 and where there is no obligation to provide basic services. For the default supplier, continued supply must be deemed to be economically reasonable. In 2019, suppliers (default and non-default suppliers) terminated a total of nearly 221,209 contracts with their customers (2018: approximately 185,989). The average customer arrears upon termination of the energy supply contract was €176.

3.3 Cash meters and smart card readers

In the 2019 monitoring survey, meter operators and suppliers were again surveyed on prepayment systems in accordance with section 14 StromGVV, such as cash meters or smart card readers. Over the course of 2019, such prepayment systems were installed on behalf of the local default supplier at about 18,400 household customers' points of consumption. This corresponds to 0.04% of all market locations of household customers in Germany. In just under 3,600 cases, a cash meter or smart card reader was newly installed in the 2019 calendar year, with about 2,800 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 2019, around 9% of suppliers offered load-based tariffs, while some 62% of suppliers offered time-of-use tariffs.

Overall, 30% of suppliers offer an online-only tariff that can be concluded online (e.g. on the company's website or through a price comparison portal) and for which bills are available online. However, of the biggest suppliers, which account for 80% of electricity supply to household customers, 77% offer an online tariff.

Separate tariffs that include energy saving incentives are currently offered by around 8% of companies.

Two suppliers offer tariffs with dynamic pricing that reflect the price on the day-ahead market in intervals; this requires the installation of a corresponding meter. Both the rollout of smart metering systems and the continued support for dynamic contracts, including through European regulations, can encourage the interest of additional consumers in the future and lead to an increase in the number of contracts concluded. However, a qualitative evaluation of this development can only take place as the rollout of smart metering systems progresses. The scope of the rollout totalling around 1,000 smart metering systems in the reporting year 2019 does not yet allow for any accurate conclusions to be made regarding the development of dynamic tariffs.

In 2019, 122 companies (or 9% 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 around 47%. Among companies with 10,000 to 200,000 market locations, primarily municipal utility companies offer bundle tariffs.

Electricity tariffs were often tied to other energy sector services such as natural gas or PV systems, but were also linked with hardware, telecommunications services or water supply. Other linked products include heating oil, pellets, district heating, heat pumps, electromobility services, insurance policies, vouchers and event tickets.

Electricity: products offered on bundled tariffs in 2019

Product category	Frequency
Natural gas	62
Hardware	16
Telecommunications, Internet	23
Water	8
Solar PV systems/tenants' electricity	28
Other	21
Total	**158**

Electricity: size of companies offering bundled tariffs in 2019

Number of market locations	Percentage
1 < 1,000	1%
1,000 < 10,000	5%
10,000 < 30,000	14%
30,000 < 100,000	18%
100,000 < 500,000	28%
< 500,000	47%
Total	**9%**

Table 84: Products offered on bundle tariffs and size of the 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 2019, 164 suppliers stated that they carry out monthly, quarterly or semi-annual billing for household customers (2018: 37,100). The average charge (including VAT) for each additional billing was approximately €14 with customer reading and approximately €18 without customer reading.

4. Price level

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.

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 2020 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 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, ie 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.

Since the analysis of the price level is based on the reference date of 1 April, 2020, the temporary VAT reduction from 19% to 16% that was effective from 1 July 2020 to 31 December 2020 was not taken into account.

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).[108]

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 a 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 2020 and 1 April 2019, 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.

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 directly 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 annual 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

[108] If a company cannot calculate an average price due to the many different tariffs they offer, one representative tariff is chosen.

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 191 suppliers (205 in the previous year).

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

Electricity: Price level for 24 GWh/year consumption category without reductions on 1 April 2020

	Data spread between 10th and 90th percentile of reported range in ct/kWh	**Arithmetic mean** in ct/kWh
Network charge	1.62 - 3.95	2.66
Metering	0.00 - 0.01	0.04
Concession fee	0.00 - 0.12	0.12
EEG surcharge		6.76
other surcharges[1]		0.71
Electricity tax		2.05
	2.88 - 5.38	4.20
Total price (excl. VAT)	**14.48 - 18.62**	**16.54**

[1] Surcharge under KWKG (0.226 ct/kWh), surcharge under Sect. 19 StromNEV (0.063 ct/kWh), Surcharge under Sect. 18 AbLaV (0.0075 ct/kWh) Offshor network surcharge (0.416 ct/kWh)

Table 85: Price level for the 24 GWh/year consumption category without reductions on 1 April 2020

The arithmetic mean of the price component controllable by the supplier fell from 4.33 ct/kWH in the previous year to 4.20 ct/kWh in 2020, representing a decline of around 3 %. The surcharges totalled 7.466 ct/kWh (including an EEG surcharge of 6.756 ct/kWh). The other surcharges fell in this consumption to

0.71 ct/kWh. The average net network charge increased to 2.659 ct/kWh (2.32 ct/kWh in the previous year). As the spread of net network charges is very wide, the average charge does not necessarily represent the actual development.[109] The average overall price (excluding VAT and excluding possible reductions) of 16.54 ct/kWh was 0.56 ct/kWh above the arithmetic mean of the figures collected in the previous year (15.98 ct/kWh). Due to the alignment of tariffs for industrial customers to wholesale prices described above, price reductions can be passed on more quickly to these customers than to household customers. In particular, the price component which is controllable by the supplier fell 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 12.30 ct/kWh, or about 75% 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 12 ct/kWh to below 1 ct/kWh.[110]

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 also be reduced.[111] 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.

[109] 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.

[110] 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.

[111] 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.

Electricity: possible reductions for the 24 GWh/year consumption category on 1 April 2020

Price survey on 1 April 2020	Estimated charge	Possible reduction	Remaining balance
EEG surcharge	6.76	-6.43	0.33
Electricity tax	2.05	-2.05	0.00
Net network charge	2.66	-2.13	0.53
Other surcharges	0.71	-0.60	0.12
Concession fees	0.12	-0.12	0.00
Total	**12.30**	**-11.32**	**0.98**

Table 86: Possible reductions for the 24 GWh/year consumption category on 1 April 2020

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 2020. 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 often measured using a standard load profile.

The following price analysis of the consumption category was based on data from 938 suppliers (969 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:

Electricity: price level for the 50 MWh/year consumption category on 1 April 2020

	Spread between 10 and 90 percentile of reported values in ct/kWh	Arithmetic mean in ct/kWh	Share of total price
Net network charge	4.38 - 8.26	6.17	27%
Metering	0.02 - 0.90	0.29	1%
Concession fee	0.11 - 1.59	0.80	3%
EEG surcharge		6.76	29%
Other surcharges [1]		1.01	4%
Electricity tax		2.05	9%
	3.71 - 8.11	5.96	26%
Net total price	**20.35 - 25.79**	**23.03**	**100%**

[1] Surcharge under KWKG (0.226 ct/kWh), surcharge under Sect. 19 StromNEV (0.358 ct/kWh), surcharge under Sect. 18 AbLaV (0.007 ct/kWh), offshore network surcharge (0.416 ct/kWh)

Table 87: Price level for the 50 MWh/year consumption category on 1 April 2020

The remaining balance that can be controlled by the supplier increased again. Whereas in April 2019 this value was at 5.69 ct/kWh, by April 2020 it had risen to 5.96 ct/kWh – an increase of 0.27 ct/kWh.

The renewable energy surcharge rose from 6.41 ct/kWh in the previous year to 6.76 ct/kWh. Other surcharges remained at the same level as the previous year, 1.01 ct/kWh. The average net network charge rose from 6.03 ct/kWh in the previous year to 6.17 ct/kWh. As the spread of net network charges is very wide, the average charge does not necessarily represent the actual development.[112]

The average overall price excluding VAT of 23.03 ct/kWh in April 2020 had risen by 0.81 ct/kWh compared to the previous year's figure of 22.2 ct/kWh. This increase is mainly accounted for by a rise of 66.6% in the price

[112] 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.

component which cannot be controlled by the supplier and a rise of approx. 33.3% in the price component which can be controlled by the supplier. This price component altogether accounts for around 26% 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[113, 114]): 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 above 15,000 kWh

First the volume-weighted average price across all types of contracts for household customers was looked at in the representative consumption band from 2,500 kWh to 5,000 kWh (band III). In section 4.2.2 individual consumption bands are subsequently analysed, with the focus on the consumption band of a typical household customer in band III.

4.2.1 Volume-weighted price across all contract categories for household customers (band III)

In the following tables and figures, 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 contract categories (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 2020 was 32.05 ct/kWh, which is an increase from the previous year (2019: 30.85 ct/kWh). Table 88 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 89.

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Electricity: average volume-weighted price per type of contract for household customers with an annual consumption between 2,500 kWh and 5,000 kWh (band III; Eurostat: DC) as at 1 April 2020 (ct/kWh)

Price component	Volume-weighted average across all types of contract (ct/kWh)	Percentage of total price
Energy and suppy, margin	7.97	24.9
Net network charge	7.14	22.3
Meter operation charge	0.36	1.1
Concession fee	1.64	5.1
EEG surcharge	6.76	21.1
KWKG surcharge	0.23	0.7
Section 19 StromNEV surcharge	0.36	1.1
Section 18 AbLaV surcharge	0.01	0.0
Offshore grid surcharge	0.42	1.3
Electricity tax	2.05	6.4
VAT	5.12	16.0
Total	**32.05**	**100.0**

Table 88: Average volume-weighted price for household customers in consumption band III across all types of contract as at 1 April 2020

Electricity: change in volume-weighted price level for household customers across all types of contracts from 1 April 2019 to 1 April 2020 for an annual consumption between 2,500 kWh and 5,000 kWh (band III; Eurostat: DC) as at 1 April 2020

Price component	Volume-weighted average across all types of contract (ct/kWh)	Change in level of price component	
		in ct/kWh	%
Energy and suppy, margin	7.97	0.36	4.7
Net network charge	7.14	0.24	3.5
Meter operation charge	0.36	0.03	9.9
Concession fee	1.64	0.02	1.1
EEG surcharge	6.76	0.35	5.5
KWKG surcharge	0.23	-0.05	-19.3
Section 19 StromNEV surcharge	0.36	0.05	17.4
Section 18 AbLaV surcharge	0.01	0.00	40.0
Offshore grid surcharge	0.42	0.00	0.0
Electricity tax	2.05	0.00	0.0
VAT	5.12	0.19	3.9
Total	**32.05**	**1.20**	**3.9**

Table 89: Change in the volume-weighted price level for household customers across all types of contract from 1 April 2019 to 1 April 2020 (consumption band between 2,500 kWh and 5,000 kWh per year)

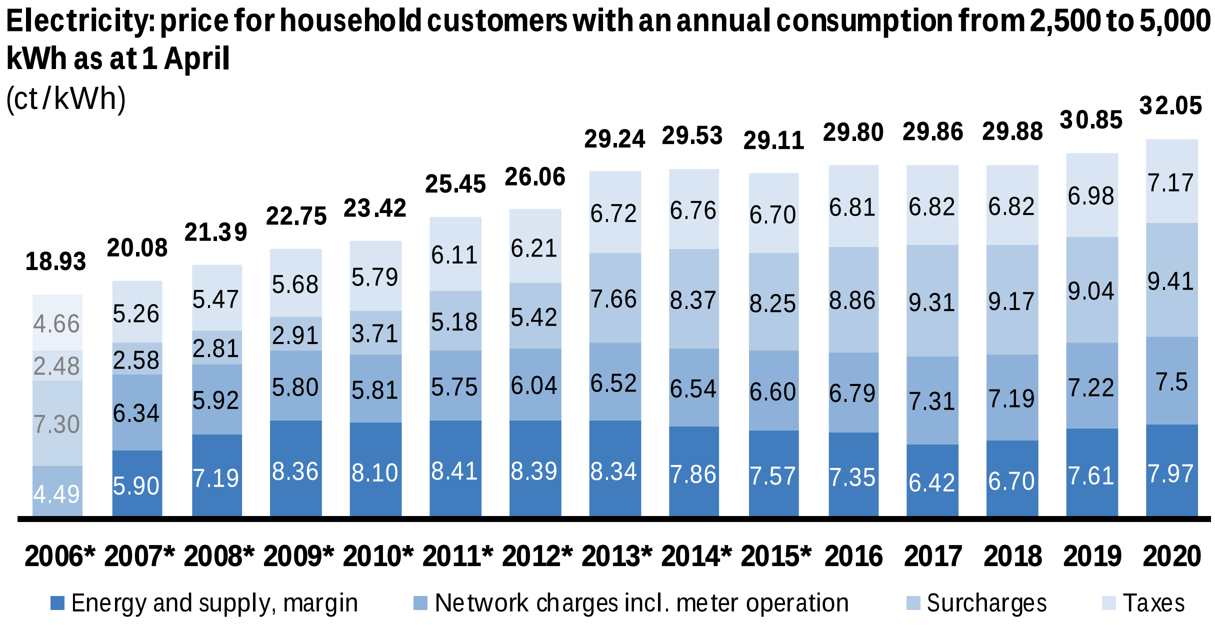


Figure 117: Development of the electricity price for household customers, volume-weighted across all types of contract

Figure 117 shows the development of the average price for household customers. In 2020 the price was around 32 ct/kWh, which is primarily attributable to the increase of the price components network charges including metering operation and energy and supply costs and the margin. The following section therefore takes a closer look at the price components.

Figure 118 shows that surcharges, taxes and levies together account for around 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 the margin) accounts for around 24.9% in 2020 (2019: 24.7%). 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 to 5,000 kWh as at 1 April 2020 (volume-weighted across all types of contract, band III, Eurostat: DC) (%)

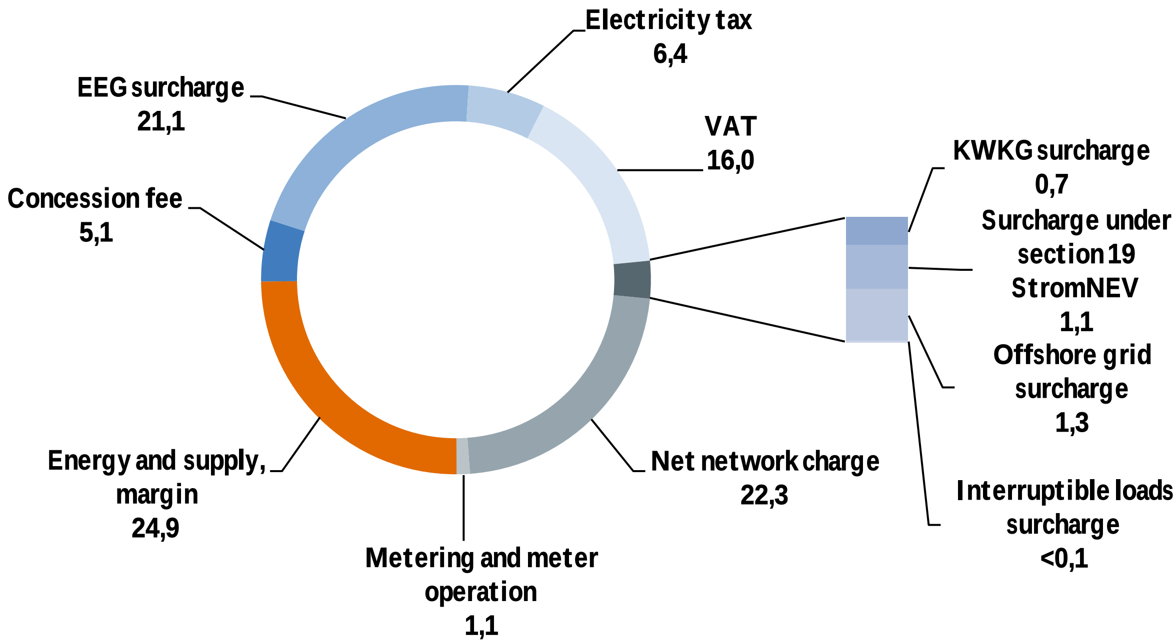


Figure 118: Breakdown of the retail price for household customers in consumption band III as of April 1 2020 (volume-weighted average across all types of contract)[115]

First, a look at the network charges [116] shows a relatively sharp increase until 2017, following successive decreases in the period up to 2011. In 2019, a slight increase in the average network charge is again noticeable. The network charge thus continues to be high.

[115] 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.

[116] Net network charge includes charges for meter operations.

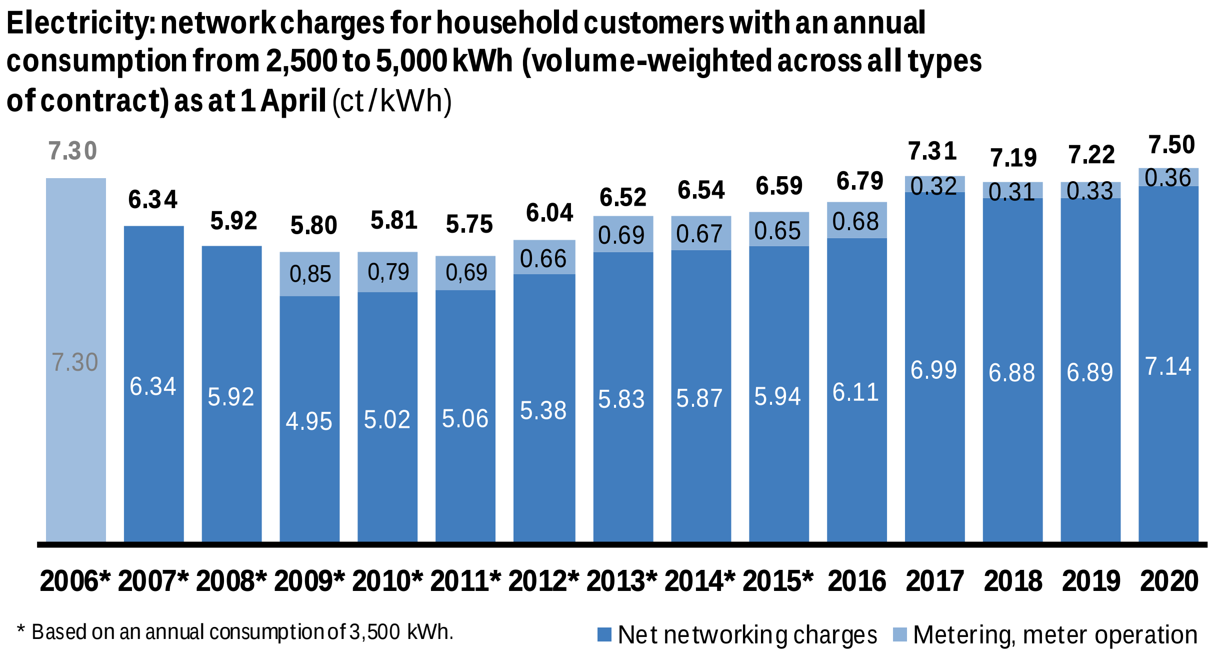


Figure 119: Development of network charges for household customers, including charges for meter operation

In 2020 there have been noticeable increases in other taxes and levies. These include in particular the renewable energy surcharge (EEG surcharge) and the surcharge under section 19 StromNEV (see section 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 2020 increased to 6.76 ct/kWh, thus accounting for around 21% of the total electricity price. Figure 120 shows the changes in the renewable energy surcharge in more detail.

The price component of “energy and supply costs and margin” (see Figure 121) remained largely stable in the period from 2009 to 2013. While this supplier-controlled price component has fallen steadily since 2014, in 2020 it increased by nearly 5% (+0.36 ct/kWh); in 2019 it had risen to 7.61 ct/kWh).

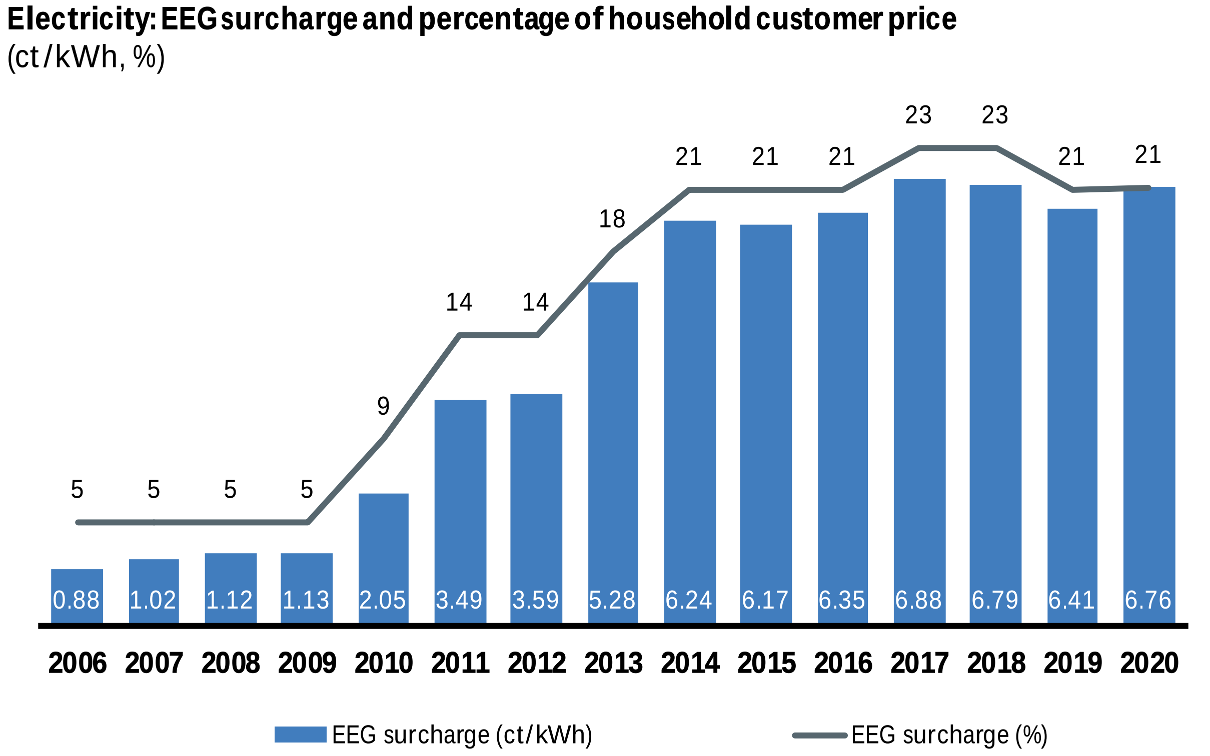


Figure 120: Renewable energy surcharge and percentage of household customer price

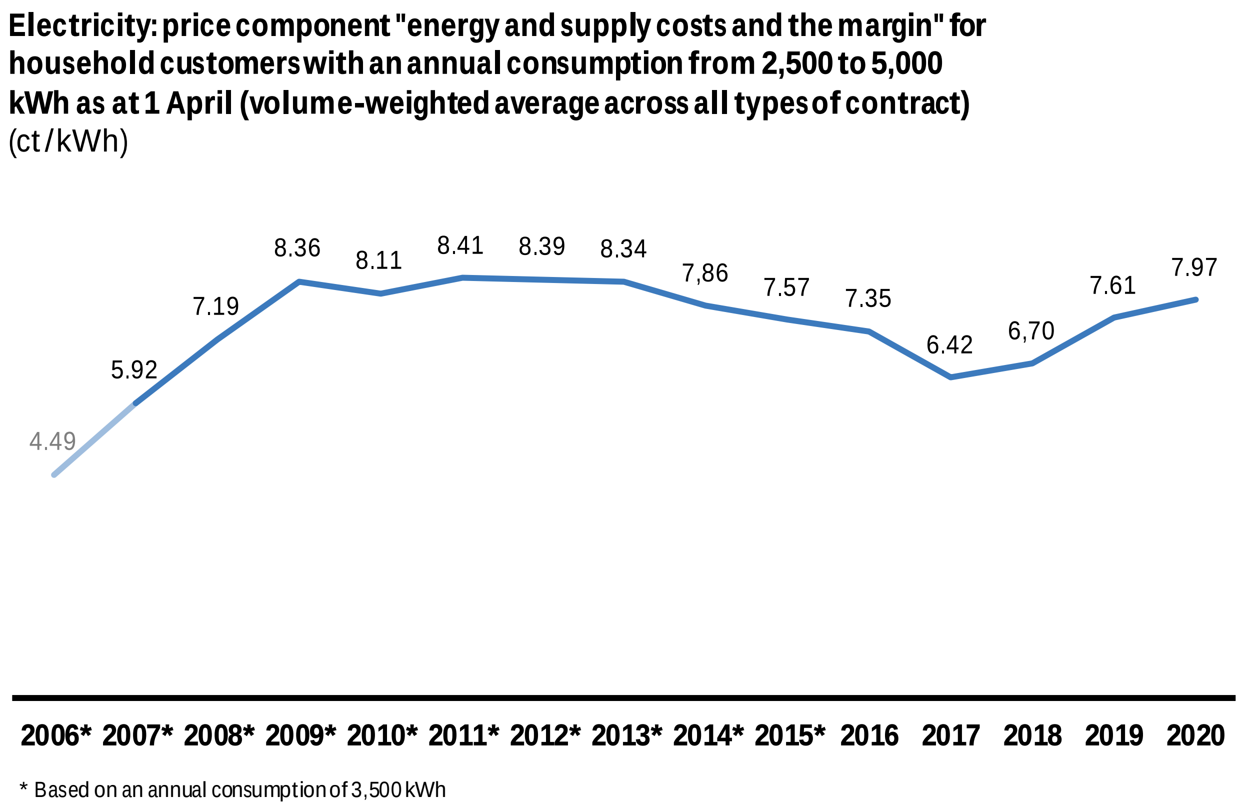


Figure 121: Change over time in the price component "energy procurement and sales and margin" for household customers

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 is 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 the default supply is the contract type with the highest network charge.

The volume-weighted prices were calculated using the prices as at 1 April 2020 and the consumption volumes for 2019. The use of new consumption bands since 2016 is due to a change in the methodology used by the European statistical authority 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 price per type of contract for household customers with an annual consumption above 1,000 kWh (band I; Eurostat: DA) as at 1 April 2020
(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	13.53	12.02	10.87
Net network charge	15.11	12.34	12.50
Meter operation charge	2.14	1.71	1.64
Concession fee	1.62	1.64	1.69
EEG surcharge	6.76	6.76	6.76
KWKG surcharge	0.23	0.23	0.23
Section 19 StromNEV surcharge	0.36	0.36	0.36
Section 18 AbLaV surcharge	0.01	0.01	0.01
Offshore grid surcharge	0.42	0.42	0.42
Electricity tax	2.05	2.05	2.05
VAT	8.02	7.13	6.94
Total	**50.23**	**44.65**	**43.45**

Table 90: Average volume-weighted prices per type of contract for household customers in consumption band I as at 1 April 2020

Please note that in the low consumption bands prices include 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 standing charge thus results in a higher per kilowatt-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 2020 (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	10.18	8.87	8.06
Net network charge	8.40	7.79	8.25
Meter operation charge	0.63	0.62	0.67
Concession fee	1.63	1.64	1.65
EEG surcharge	6.76	6.76	6.76
KWKG surcharge	0.23	0.23	0.23
Section 19 StromNEV surcharge	0.36	0.36	0.36
Section 18 AbLaV surcharge	0.01	0.01	0.01
Offshore grid surcharge	0.42	0.42	0.42
Electricity tax	2.05	2.05	2.05
VAT	5.82	5.46	5.40
Total	**36.47**	**34.19**	**33.85**

Table 91: Average volume-weighted prices per type of contract for household customers in consumption band II as at 1 April 2020

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 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 III; Eurostat: DC) as at 1 April 2020 (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	9.31	7.83	7.22
Net network charge	7.22	6.90	7.30
Meter operation charge	0.37	0.37	0.35
Concession fee	1.70	1.70	1.55
EEG surcharge	6.76	6.76	6.76
KWKG surcharge	0.23	0.23	0.23
Section 19 StromNEV surcharge	0.36	0.36	0.36
Section 18 AbLaV surcharge	0.01	0.01	0.01
Offshore grid surcharge	0.42	0.42	0.42
Electricity tax	2.05	2.05	2.05
VAT	5.40	5.06	4.98
Total	**33.80**	**31.67**	**31.22**

Table 92: Average volume-weighted prices per type of contract for household customers in consumption band III as at 1 April 2020

A comparison of the three types of contract – default contract, non-default contract with the 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 2020 for customers on default tariffs was around 2,009 kWh, the average consumption for customers on non-default contracts with the default supplier and customers who had switched from their default supplier was around 38% higher, at around 2,781 kWh.

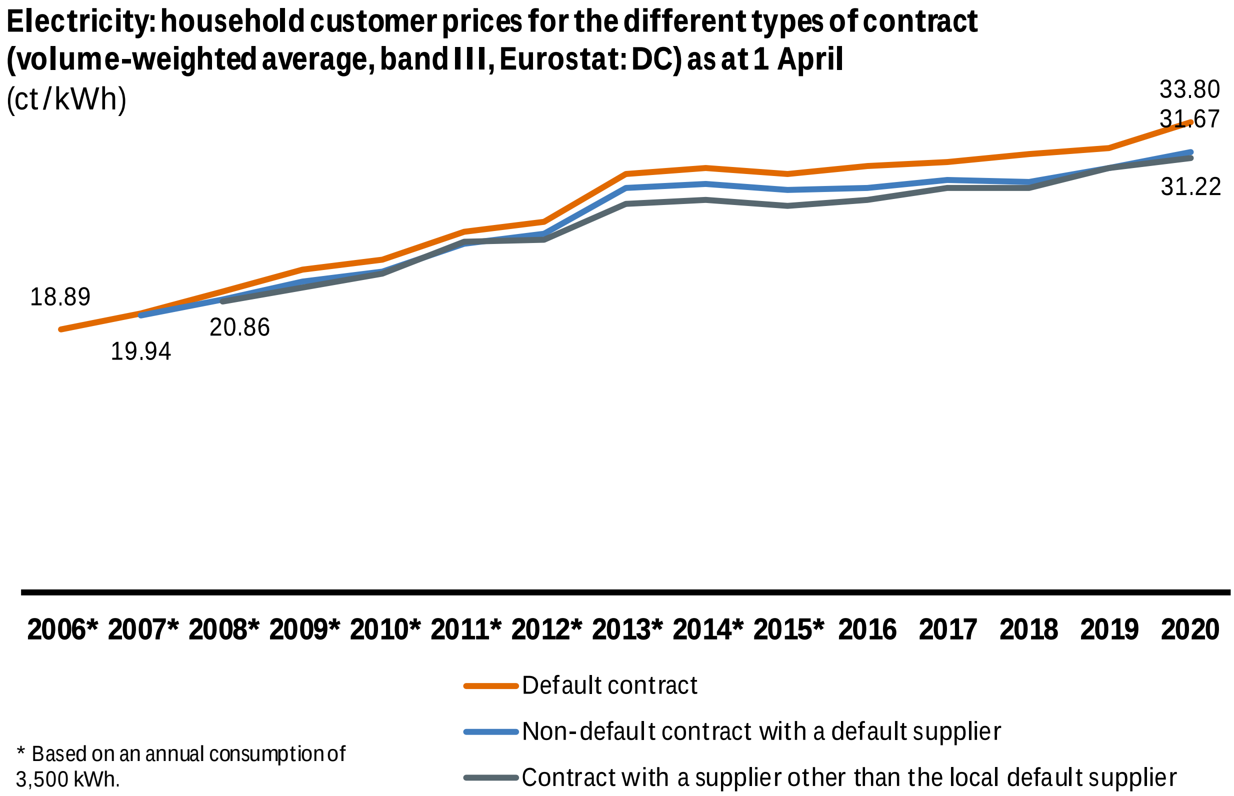


Figure 122: Household customer prices for the different types of contract (volume-weighted average, band III, Eurostat: DC)

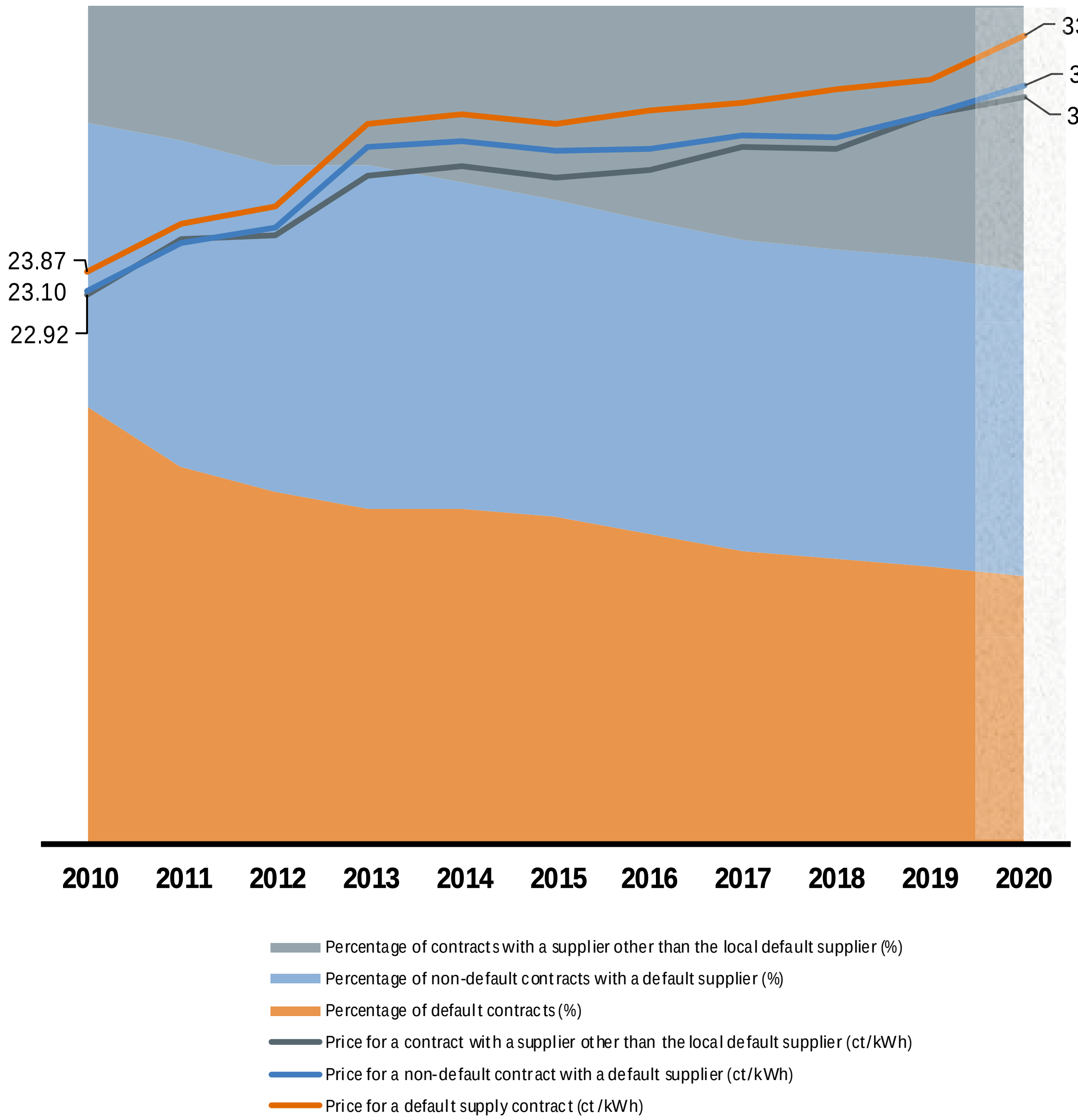
A comparison of the average prices for the three types of tariffs shows that throughout the period since 2008, default tariffs were the most expensive option for household customers. Prices for customers on non-default contracts with the default supplier were consistently cheaper over the same period 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 who is not the local default supplier have been converging more and more; in 2019, for the first time, they were at the same level. In 2020 the price for these two contract types is again diverging, with the difference amounting to around 0.4 ct/kWh. On average, prices for customers who switched from the local default supplier to a new supplier are the cheapest. In eleven 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 (-2.13 ct/kWh) or by switching supplier (-2.58 ct/kWh).[117] For a household customer with an annual consumption of 3,500 kWh, this amounts to savings in energy costs of around €90 per year.

[117] The cost savings apply to the consumption band between 2,500 kWh and 5,000 kWh/year.

The following figure shows the changes in the electricity price against the background of the development trend in the three types of supply, that is, default contract, non-default contract with a default supplier and contract with a supplier other than the local default supplier.

Electricity: household customer prices (band III, Eurostat DC) as at 1 April in ct/kWh and percentage of household customers for the different types of contract



The percentages for the different types of contract for 2020 are not yet available and are shown here basd on the trend from previous years.

Figure 123: Household customer prices for electricity and percentage for the different types of contract

At 9.31 ct/kWh on 1 April 2020, the price component that can be controlled by the supplier, including energy and supply costs, was nearly 29% higher for customers on default tariffs than for customers who had switched from their local default supplier; the average price for the latter group was 7.22 ct/kWh. In 2019, the difference between the two groups was 18%. Customers on non-default contracts with their local default supplier paid an average of 7.83 ct/kWh (2019: 7.37 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:

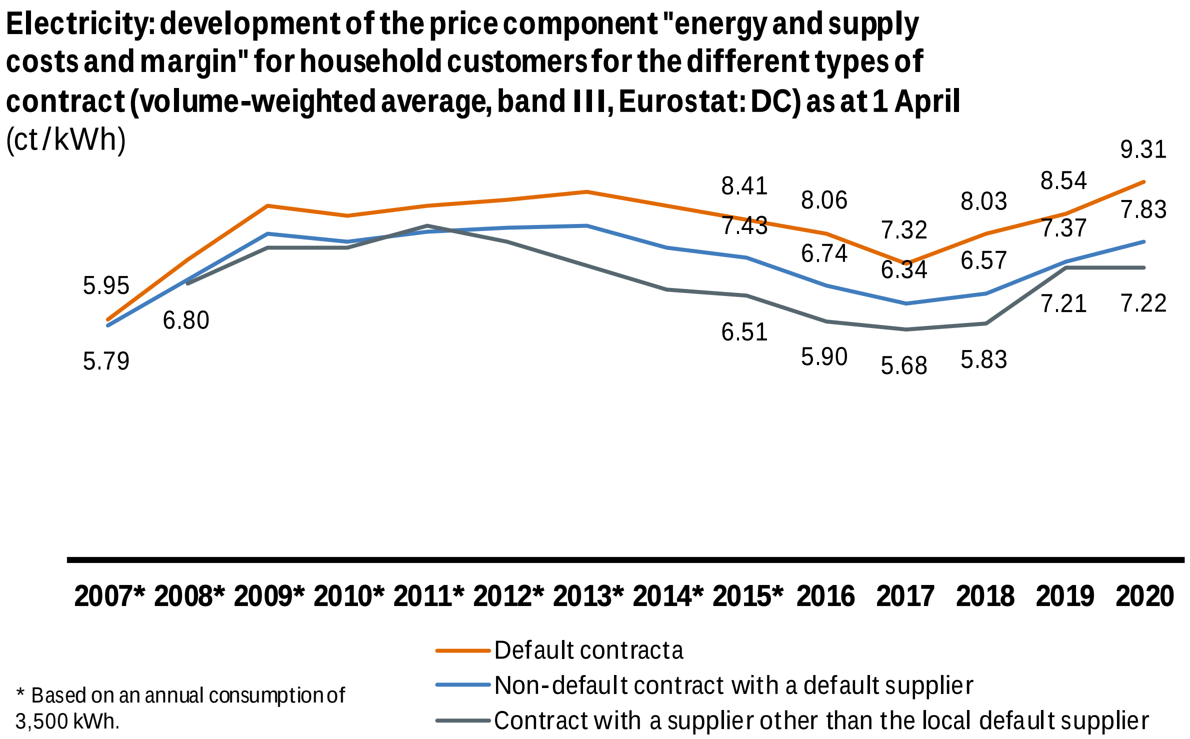


Figure 124: Development of the price component “energy and supply costs and margin” for household customers

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. pre-payment, minimum contract period), which is then compensated for between the parties elsewhere (overall price).

The suppliers were questioned specifically about any 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 local 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 from €5 to €273, with an average payment of €57. Contracts with a supplier other than the local default supplier offer one-off payments ranging from €5 to €300, with an average payment of €65.

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 April 2020	Household customers			
	Non-default contract with the default supplier		Contract with supplier other than the default supplier	
	No. of tariffs	Average scope	No. of tariffs	Average scope
Minimum contract period	341	11 months	425	11 months
Price stability	259	14 months	152	14 months
Advance payment	64	10 months	48	10 months
One-off bonus payment	100	€ 57	208	€ 65
Free kilowatt hours	9	204 kWh	3	150 kWh
Deposit	6	-	5	-
Other bonuses and special arrangements	106	-	152	-

Table 93: 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 IV) as at 1 April 2020
(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	8.62	7.27	6.22
Net network charge	6.64	6.07	6.41
Meter operation charge	0.20	0.21	0.26
Concession fee	1.55	1.60	1.50
EEG surcharge	6.76	6.76	6.76
KWKG surcharge	0.23	0.23	0.23
Section 19 StromNEV surcharge	0.36	0.36	0.36
Section 18 AbLaV surcharge	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	4.74	4.60
Total	**31.93**	**29.70**	**28.80**

Table 94: Average volume-weighted prices per type of contract for household customers in consumption band IV as at 1 April 2020

Band V and band VI: Annual electricity consumption from 10,000 kWh to 15,000 kWh and annual electricity consumption above 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 15,000 kWh and more, respectively. The following tables show the results of the data analysis for 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 2020
(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	8.52	7.05	5.87
Net network charge	6.35	5.79	5.89
Meter operation charge	0.13	0.15	0.22
Concession fee	1.53	1.57	1.50
EEG surcharge	6.76	6.76	6.76
KWKG surcharge	0.23	0.23	0.23
Section 19 StromNEV surcharge	0.36	0.36	0.36
Section 18 AbLaV surcharge	0.01	0.01	0.01
Offshore grid surcharge	0.42	0.42	0.42
Electricity tax	2.05	2.05	2.05
VAT	5.01	4.63	4.43
Total	**31.35**	**29.01**	**27.73**

Table 95: Average volume-weighted prices per type of contract for household customers in consumption band V as at 1 April 2020

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 2020 (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	8.64	6.63	5.86
Net network charge	6.00	5.71	5.59
Meter operation charge	0.08	0.11	0.25
Concession fee	1.55	1.58	1.58
EEG surcharge	6.76	6.76	6.76
KWKG surcharge	0.23	0.23	0.23
Section 19 StromNEV surcharge	0.36	0.36	0.36
Section 18 AbLaV surcharge	0.01	0.01	0.01
Offshore grid surcharge	0.42	0.42	0.42
Electricity tax	2.05	2.05	2.05
VAT	4.96	4.53	4.39
Total	**31.05**	**28.39**	**27.47**

Table 96: Average volume-weighted prices per type of contract for household customers in consumption band VI as at 1 April 2020

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:

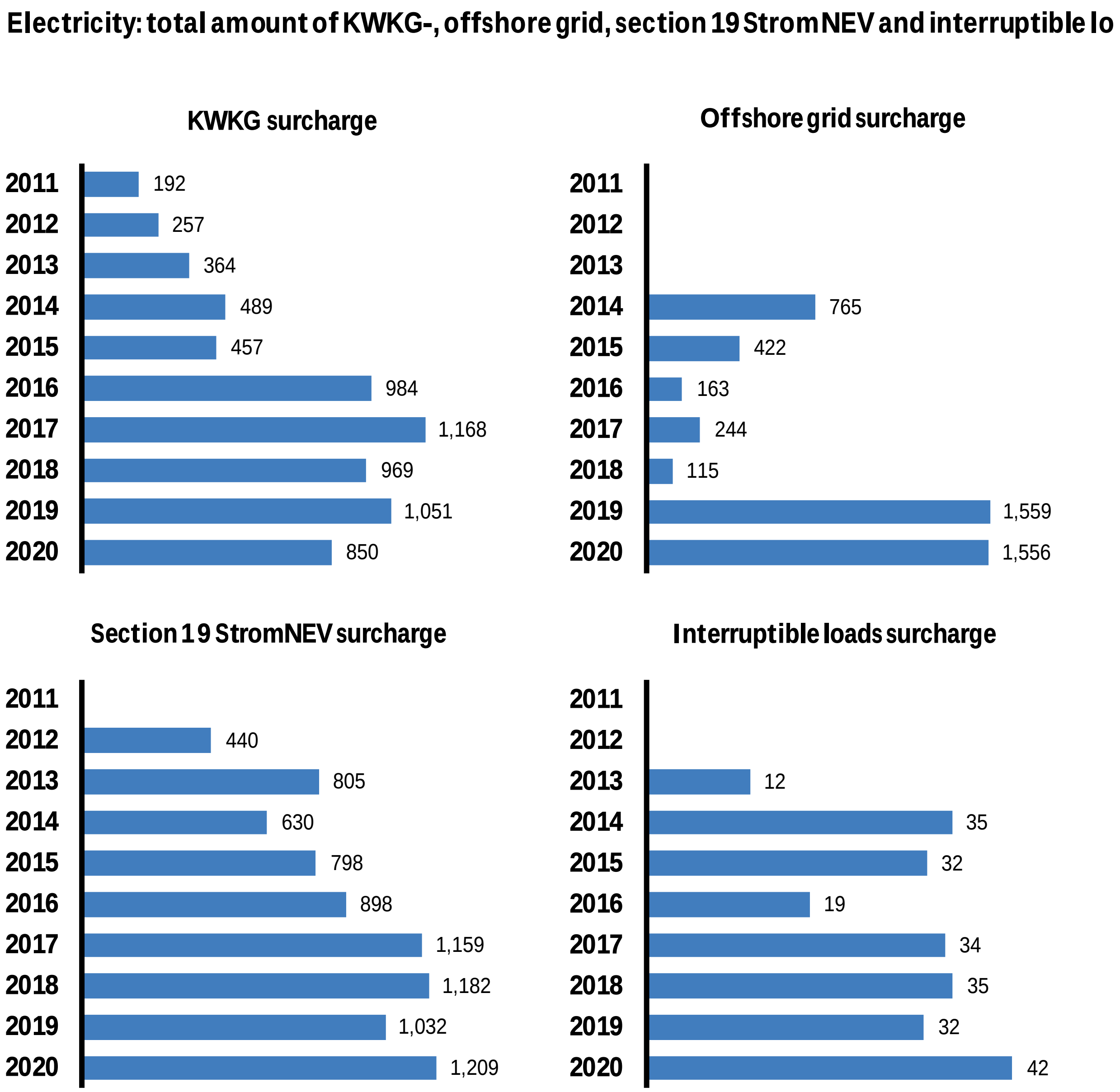


Figure 125: Total amount of KWKG, offshore grid, section 19 StromNEV and interruptible loads surcharges

EEG surcharge

Under section 60(1) EEG, transmission system operators are entitled and obliged to demand from electricity suppliers who supply electricity to final consumers the costs for the necessary expenses following deduction of the revenue 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.

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.

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 offshore network surcharge also includes the costs of installing and operating offshore transmission links.

The offshore network surcharge is determined and announced by 15 October of each year for the following calendar year by the transmission system operators. 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.

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 revenues 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.

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.

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).

In 2019 overall heating electricity consumption increased slightly compared to the previous year but in terms of meter points decreased, if only minimally. According to the volumes reported by around 1,000 electric heating suppliers, about 13.47 TWh of heating electricity was supplied to customers at just under 2.12 million meter points during the reporting period. This corresponds to an average supply of just under 6,333 kWh per meter point. The previous year's figure was just under 6,356 kWh per meter point, with a total volume of 13.29 TWh to 2.03 million meter points.

According to the data provided by the suppliers, just under 10.4 TWh was supplied for night storage heating to 1.61 million night storage meter points, resulting in an average of about 6,458 Kwh per meter point in 2019. The volume of electricity supplied to the approximately 512,889 meter points for heat pumps amounted to just over 3.05 TWh, or an average of about 5,940 kWh/year. Night storage heating accounts for the largest share of consumption (77.4% in terms of volume and 75.9% in terms of meter points). There was a slight increase in the share of heat pumps compared to night storage heating. In 2019 the share of heat pumps accounted for 24.1% of meter points and 22.6% in terms of volume. In the previous year it accounted for 23% of meter points and 21% 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 on the one hand and heat pumps on the other and therefore estimated the breakdown or entered the total in only one of the two categories.

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 834 DSOs, a total of 13.36 TWh of heating electricity was supplied to just under 2.06 million meter points (night storage heating and heat pumps) in 2019. 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 the 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.[118]

The share of heating electricity supplied in 2019 by a legal entity other than the regional default supplier rose from 1.75 TWh in the previous year to 2.15 TWh. Around 16% of the total heating electricity volume in 2019 came from suppliers other than the default supplier (2018:13.2%). The number of heating electricity meter points not served by the default supplier also increased from 12.6% to 14.7%.

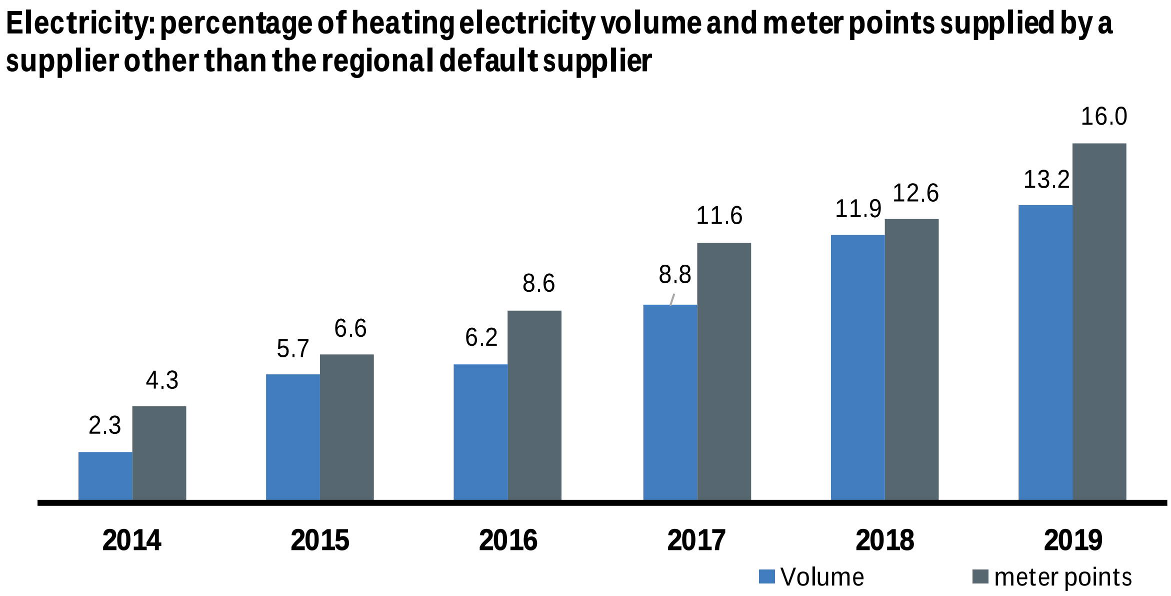


Figure 126: Percentage of heating electricity volume and meter points supplied by a supplier other than the regional default supplier

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 88,426 meter points in 2018 to over 98,567 meter points in 2019. A total of 19.2% (2018: 18.6%) of all the heat pump meter points as well as 20.9% of the total number of heat pumps supplied (2018: 16.9%) were served by a legal entity other than the default supplier.

According to the data provided by the DSOs, there was an increase in supplier switching rates based on the number of meter points supplied in the heating electricity sector compared to the previous year. The data shows that there was a change of supplier at about 142,064 heating electricity meter points. These meter points accounted for about 967 GWh of heating electricity in 2019. This represents a switching rate of 7.2% in terms of consumption volume and 6.9% in terms of meter points.

In the previous year, there was a change of supplier at just under 94,950 meter points, accounting for a volume of around 528 GWh. This corresponds to a switching rate of 3.9% in terms of consumption volume and of 4.6% in terms of meter points. The trend over several years shows that switching rates for heating electricity have continuously risen - with a strong increase from 2015 to 2016 and again in 2019.

[118] Cf. Bundeskartellamt, Heizstrom – Überblick und Verfahren (Electric Heating - overview and proceedings), September 2010, pp. 9-10.

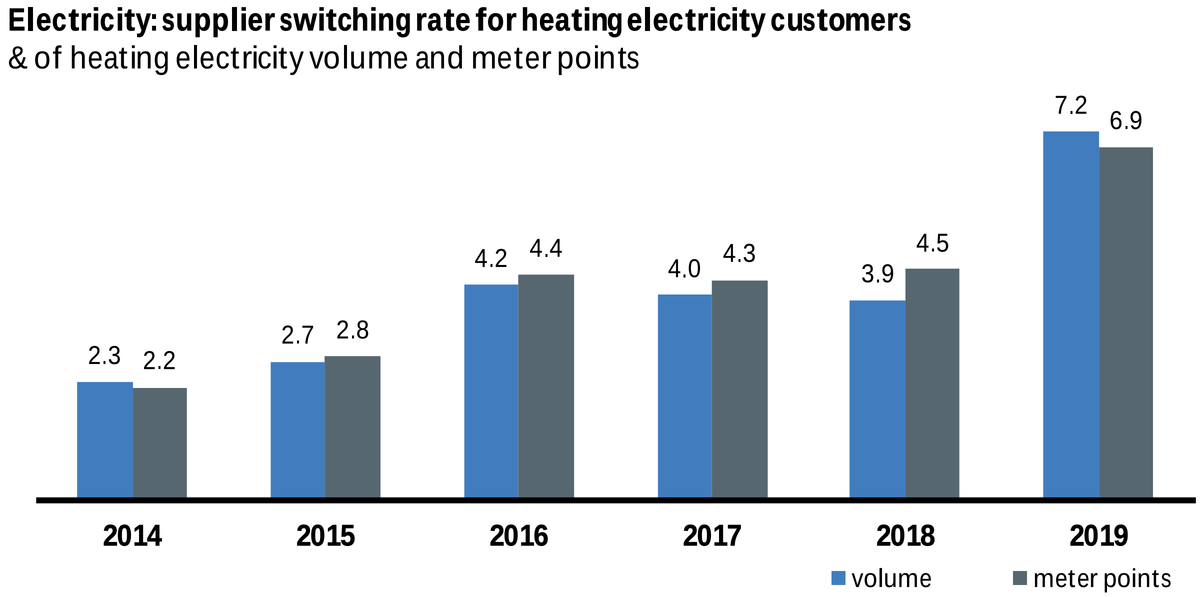


Figure 127: Supplier switching rate for heating electricity customers

570 of the 804 DSOs that provided data on heating electricity volumes also reported figures on supplier switching. These 570 DSOs represent around 99% of the heating electricity volume and meter points of all 804 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.[119] 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% and 13.7%.

The percentage of heating electricity and meter points supplied by a legal entity other than the regional default supplier is, however, 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 expanded over the last two years. Consumers can now find locally available suppliers more easily, for instance by using internet portals, looking in consumer magazines or obtaining information from the consumer advice centres. Switching rates in the heating electricity sector are slowly approaching 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 2020. 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 866 suppliers (2018: 883 suppliers) and the price data for heat pumps provided by 846 suppliers (2018: 864 suppliers).

According to the data provided by the suppliers, the arithmetic mean of the total gross price for night storage heating was 23.14 ct/kWh (including VAT) on 1 April 2020, which is above the previous year's level of

[119] Several DSOs also pointed out that they had no data, or only individual data, in the heating electricity sector for analysis. The reasons why around 242 suppliers provided no data were insufficient evaluation possibilities or limited resources for survey purposes.

21.92 ct/kWh. The arithmetic mean of the total gross price for heat pump electricity was 23.58 ct/kWh, which was also up on the previous year's level of 22.50 ct/kWh).

Electricity: price level on 1 April 2020 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	1.60 - 4.28	2.88	12%
Metering	0.12 - 0.47	0.31	1%
Concession fee	0.11 - 0.99	0.40	2%
EEG surcharge		6.76	29%
other surcharges[1]		1.01	5%
electricity tax		2.05	9%
VAT	3.26 - 4.19	3.69	16%
Price component which can be con-trolled by supplier (remaining balance)	3.90 - 8.27	6.04	26%
Total price (incl. VAT)	**20.39 - 26.24**	**23.14**	**100%**

[1] KWKG (0,226 ct/kWh), Section 19 (2) StromNEV (0,358 ct/kWh), surcharge under Section18 AbLaV (0,007 ct/kWh), Offshore network surcharge (0,416 ct/kWh)

Table 97: Price level on 1 April 2020 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 6.04 ct/kWh for night storage heating, which rose again by around 11% above the previous year's level (2019) of 5.45 ct/kWh. The trend over the last two years shows that the price component that can be controlled by the supplier has risen steadily in the heating electricity sector.

The remaining balance that can be controlled by the supplier also increased significantly again in the heat pump sector to 6.28 ct/kWh as at 1 April 2020, compared to 5.74 ct/kWh in the previous year, i.e. by around 9%. The price component controlled by the supplier makes up about 26% of the total price for night storage heating and about 27% of the total price for heat pumps. About 74% of the price for night storage heating and 73% of the price for heat pumps consists of taxes, surcharges and concession fees. Compared to the previous year, the total of all fixed surcharges rose slightly. The Bundeskartellamt has set the concession fee at 0.11 ct/kWh because heating electricity is supplied under special contracts.[120] 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.

Electricity: price level at 1 April 2020 for heat pumps 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 the supplier's control			
Net network charge	1.55 - 4.62	2.99	13%
Metering	0.12 - 0.46	0.30	1%
Concession fee	0.11 - 1.32	0.43	2%
EEG surcharge		6.76	29%
other surcharges[1]		1.01	4%
electricity tax		2.05	9%
VAT	3.33 - 4.25	3.76	16%
Price components which can be controlled by supplier (remaining balance)	4.02 - 8.56	6.28	27%
Total price (incl. VAT)	**20.86 - 26.62**	**23.58**	**100%**

[1] KWKG (0,226 ct/kWh), Section 19 (2) StromNEV (0,358 ct/kWh), surcharge under Section 18 AbLaV (0,007 ct/kWh), Offshore network surcharge (0,416 ct/kWh)

Table 98: Price level at 1 April 2020 for heat pumps with a consumption of 7,500 kWh/year

[120] Cf. Bundeskartellamt, Heizstrom – Überblick und Verfahren (Electric Heating - overview and proceedings), September 2010, pp. 9-10.

6. Green electricity segment

In the 2020 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 for electricity that, on account of green electricity labelling or other marking, is shown to have been produced with a high share/high promotion of efficient or regenerative production technologies and that is offered/traded at a separate tariff. The amount of green electricity supplied to household customers and other final consumers in 2019 and the share of green electricity in the total amount of electricity supplied in 2019 are presented below.

Electricity: green electricity supplied to household customers and other final consumers in 2019

	Category	Total electricity supplied	Total green electricity supplied	Share of green electricity in total volume and market locations
Household customers	TWh	119.8	33.4	27.9%
	Market locations (thousand)	47,700	12,605	26.4%
Other final consumers	TWh	276.4	32.3	11.7%
	Market locations (thousand)	3,221	1,133	35.2%
Total	TWh	396.2	65.7	16.6%
	Market locations (thousand)	50,921	13,738	27.0%

Table 99: Green electricity supplied to household customers and other final consumers in 2019

Electricity: green electricity share and number of household customers supplied

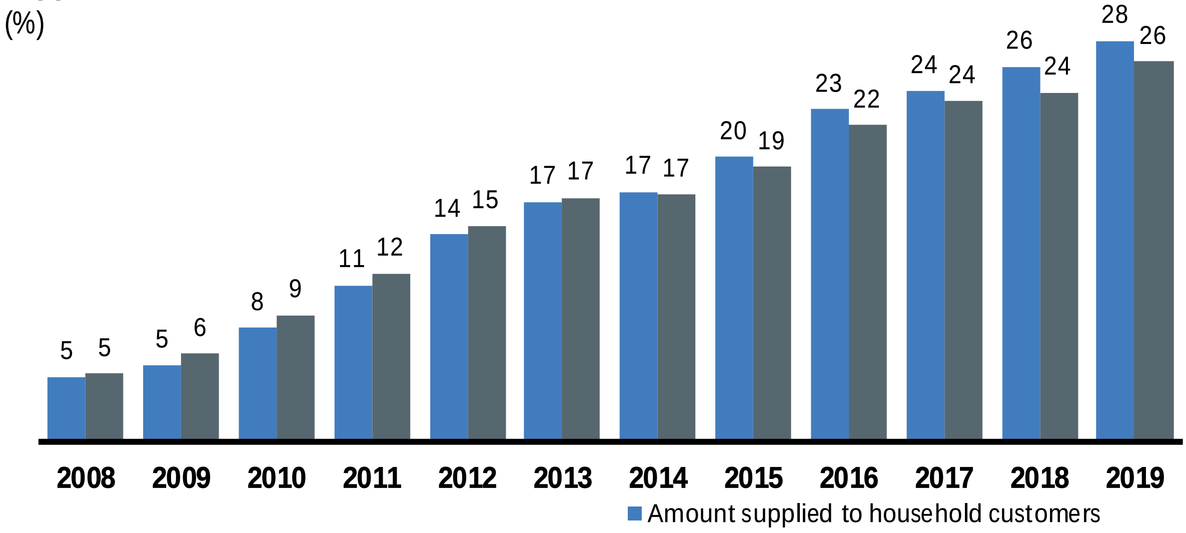


Figure 128: Green electricity share and number of household customers supplied

There was a further increase in the share of green electricity supplied to household customers in 2019. The number of household customers supplied with green electricity increased by a total of more than 1.3m market locations. The share of green electricity in total consumption rose by 2.1%. The number of household customers supplied with green electricity is now at around 12.6m 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 price per type 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 2020 (ct/kWh)

Price component	Volume-weighted average (ct/kWh)	Percentage of total price
Energy and supply, margin	7.59	24.0
Net network charge	7.17	22.7
Meter operation charge	0.42	1.3
Concession fee	1.61	5.1
EEG surcharge	6.76	21.3
KWKG surcharge	0.23	0.7
Section 19 StromNEV surcharge	0.36	1.1
Section 18 AbLaV surcharge	0.01	0.0
Offshore grid surcharge	0.42	1.3
Electricity tax	2.05	6.5
VAT	5.05	16.0
Total	**31.66**	**100.0**

Table 100: Average volume-weighted prices for green electricity for household customers in consumption band III as at 1 April 2020

The average volume-weighted retail price for green electricity for household customers with an annual consumption from 2,500 kWh to 5,000 kWh increased to 31.66 ct/kWh as at 1 April 2020 (previous year: 30.42 ct/kWh). Household customers thus pay around 1% more[121] for green electricity than they did in the previous year.

[121] The difference is calculated from the price for green electricity in band III and the average volume-weighted price across all types of contract for household customers in band III.

The following diagram shows the percentage distribution of the individual price components for green electricity:

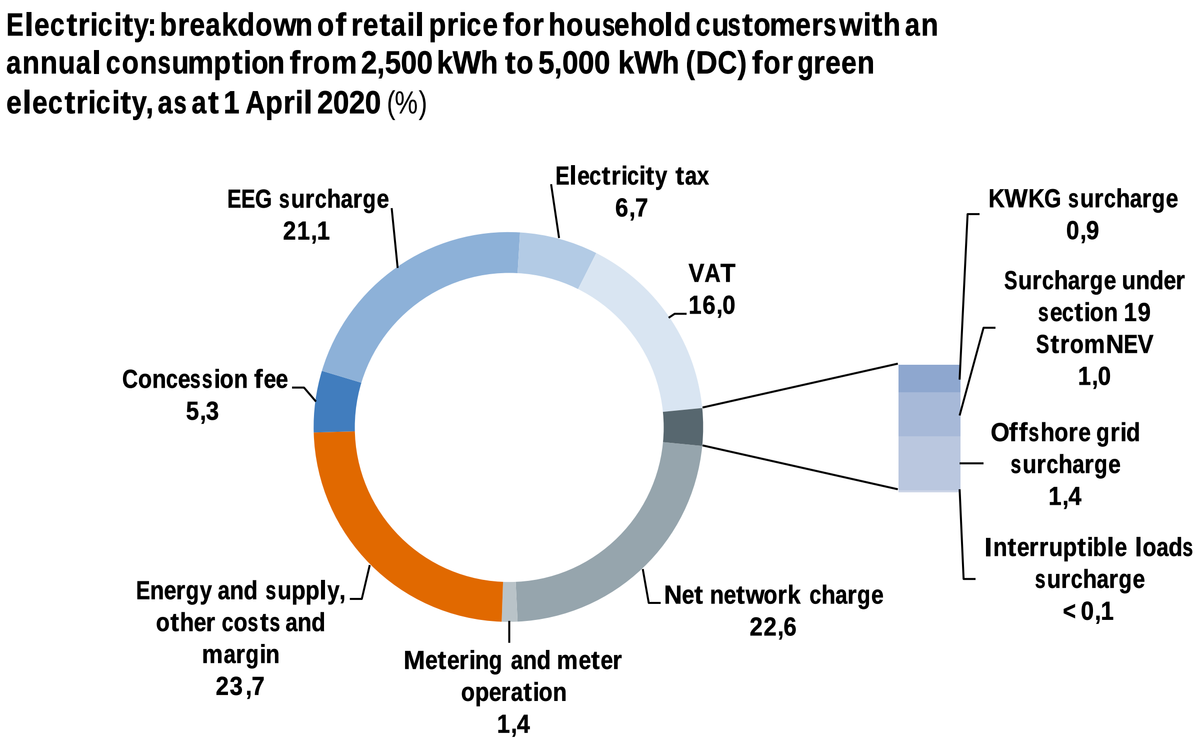


Figure 129: Breakdown of the retail price for green electricity for household customers in consumption band III as at 1 April 2020[122]

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 for green electricity range from €5 to €300, with an average payment of €61. 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.

[122] 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.

Electricity: special bonuses and schemes for household customers (green electricity)

As at 1 April 2020	Household customers (green electricity)	
	Number of tariffs	Average scope
Minimum contract period	424	11 months
Price stability	393	14 months
Prepayment	51	10 months
One-off bonus payment	177	€ 61
Free kilowatt hours	13	154 kWh
Deposit	6	-
Other bonuses and special arrangements	154	-

Table 101: 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, for Germany on data provided by the Federal Statistical Office.[123] However, the prices determined during monitoring cannot be directly compared with the data provided by Eurostat because of the different survey method used by the Federal Statistical Office. Rules on the classification, analysis and presentation of the price data aim to ensure European-wide comparability.[124] However, the relevant Regulation (EU) No 2016/1952, Article 3, allows the individual Member States a certain degree of freedom in the choice of survey method, which can lead to national differences.

[123] The average prices for electricity and natural gas in Germany for the second six-month period of 2019 were determined by the Federal Statistical Office. Before this the price data were collected by the German Association of Energy and Water Industries on behalf of the Federal Ministry for Economic Affairs and Energy. This change naturally also brought about changes in the survey methods, e.g. size and composition of the sample or the fact that administrative and tax data can now be used to determine the amount of tax, levies and surcharges actually paid.

[124] For further detail see: https://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2008:298:0009:0019:EN:PDF (retrieved on19 Junehttps://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2008:298:0009:0019:DE:PDF 2020).

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 70 GWh/year consumption band as an example. The 24 GWh/year category ("industrial customers"), for which specific price data is collected during monitoring falls into this consumption band.

The customer group with an annual consumption of 20 to 70 GWh consists of mainly industrial customers. These customers can usually deduct national VAT. For this reason, 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 16.95 ct/kWh, while Luxembourg has the lowest, at 4.53 ct/kWh. The EU average is 8.91 ct/kWh. 2.68 ct/kWh of this average consists of non-recoverable taxes, levies and surcharges and 6.29 ct/kWh is made up of network charges and the remaining balance controlled by the supplier ("energy and supply"). At 5.13 ct/kWh, the adjusted net price in Germany is just under 1.16 ct/kWh below the European average of 6.29 ct/kWh. The German net price is comprised of 2.04 ct/kWh network charges and 3.09 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.[125] 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 5.80 ct/kWh and therefore more than twice as much as the European average of 2.68 ct/kWh. The resulting net price for Germany is 10.93 ct/kWh, which is higher than the European average of 8.91 ct/kWh.

[125] 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 19 June 2020).

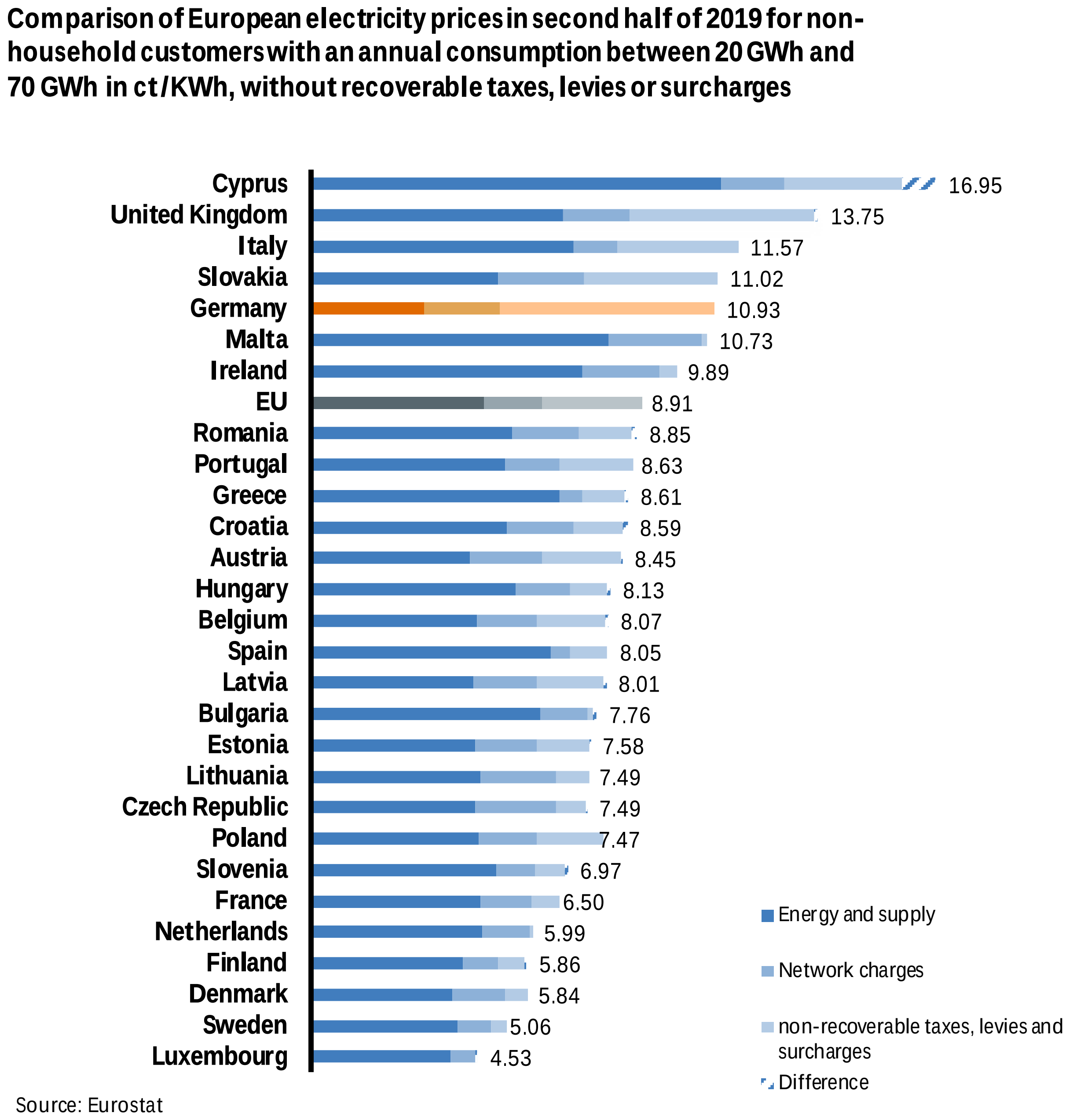


Figure 130: Comparison of European electricity prices in the second half of 2019 for non-household consumers with an annual consumption between 20 GWh and 70 GWh

7.2 Household consumers

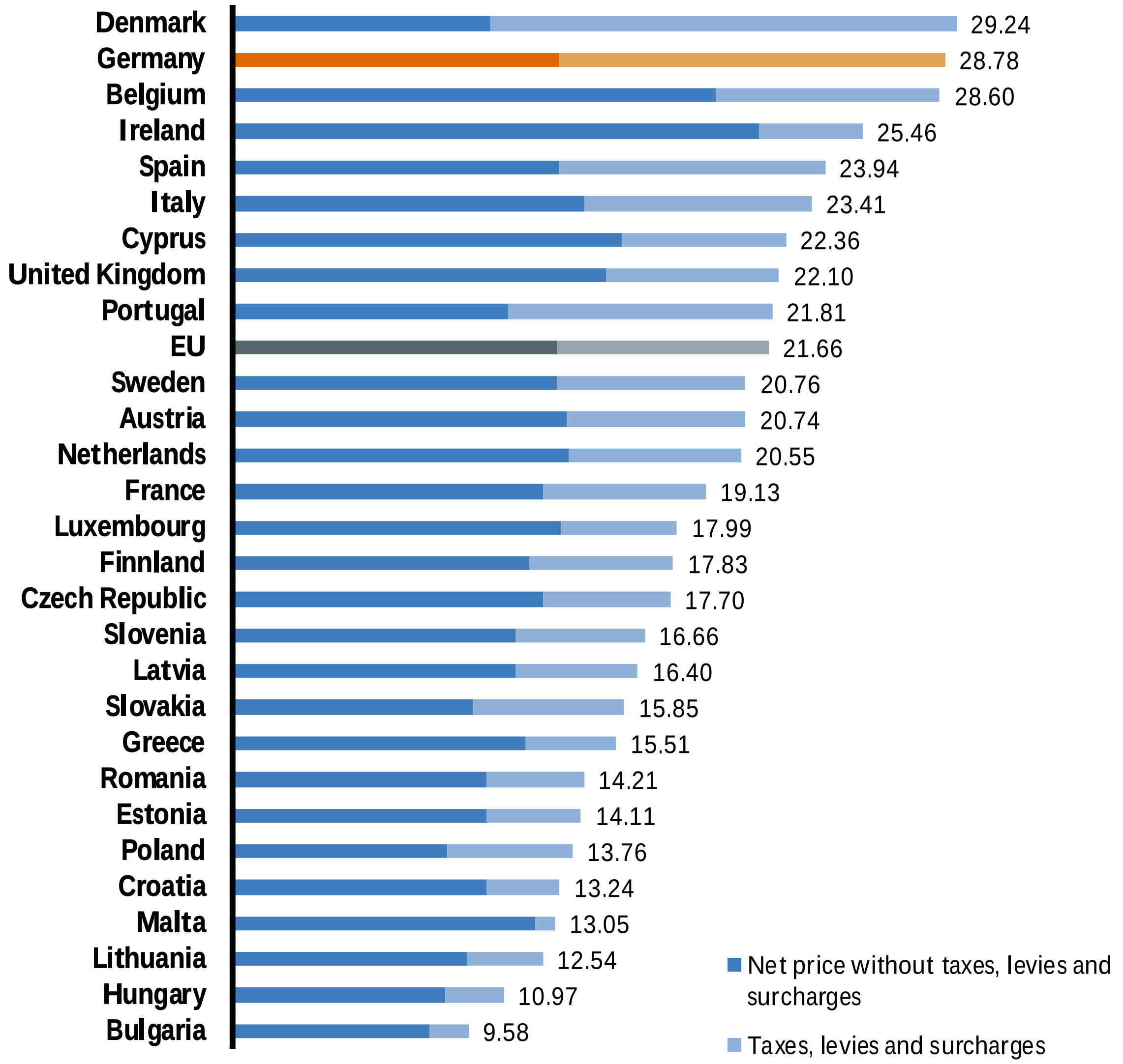
Eurostat takes five different consumption bands into consideration when comparing household customer prices. The volumes consumed by household customers in Germany are mostly in the middle category, with an annual consumption between 2,500 kWh and 5,000 kWh. The following shows an EU comparison of the 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 Federal Statistical Office, Germany has the second highest price among the 28 EU Member States, at 28.78

ct/kWh. Only Denmark has higher prices for household consumers than Germany, at 29.24 ct/kWh. Prices in Germany are about 33% higher than the EU average of 21.66 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, 8.56 ct/kWh on average consist of surcharges, taxes and levies, whereas in Germany these components account for more than 80% as much, at 15.60 ct/kWh. By contrast, at 13.18 ct/kWh, the net price adjusted for all taxes, surcharges and levies in Germany is on an equal par with the EU average of 13.1 ct/kWh.

Comparison of European electricity prices in the second half of 2019 for household customers with an annual consumption between 2,500 kWh uad 5,000 kWh



Source: Eurostat

Figure 131: Comparison of European electricity prices in the second half of 2019 for household customers with an annual consumption between 2,500 kWh and 5,000 kWh.

H Metering

1. Digitisation of metering

The Energy Transition Digitisation Act and the Metering Act (MsbG) contained therein made the rollout of modern metering equipment and smart metering systems legally mandatory in Germany. The implementation of the rollout and the legal deadlines concomitant with it are dependent on many different factors. One important factor in the implementation is the technical availability of modern metering equipment and smart metering systems.

The first modern metering systems have been available on the market since the beginning of 2017 and have already been installed by the default meter operators.

The default meter operators were required to notify the Bundesnetzagentur by 30 June 2017 of their metering operations and thereby their intention to continue as default meter operators. Notification also served to trigger a time period set by the Metering Act: three years after the notification of responsibility for default metering operations, thus by 30 June 2020, the default meter operator must have installed modern metering equipment in at least 10% of its meter locations. If not, the default meter operator risks losing responsibility for default metering operations. The Bundesnetzagentur is responsible for verifying compliance with the 10% quota.

Installation of smart metering systems could theoretically have started when the first smart meter gateway was certified by the Federal Office for Information Security (BSI) on 12 December 2018. The second and third gateways were certified in October and December 2019 respectively. Installation was not compulsory for smart metering systems in 2019 because the BSI still had to determine the technical feasibility of installing smart metering systems. After having determined the technical feasibility for certain applications, the BSI gave the go-ahead for the rollout of smart metering systems on 24 February 2020, thus after the 2019 reporting year.

2. The network operator as the default meter operator and independent meter operators

There were 862 companies operating a total of 52,715,135 meters who responded to the questions about electricity metering for the monitoring survey in 2020. 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 has all the 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.

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 2020 the application from one company wishing to take on metering operations as a joint service for multiple companies was approved. This brought the total number of approvals under section 4 of the Metering Act to four.

The 809 meter operators for conventional meter operation and 773 meter operators for meter operation of modern metering equipment and smart metering systems had the following roles in 2019 (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	809	773
Network operator as non-default meter operator offering ist meter services on the market	29	24
Supplier acting as meter operator	58	45
Third-party, independent meter operator	44	24

Table 102: Meter operator roles within the meaning of the Metering Act according to data provided by electricity meter operators

This overview shows that the network operator usually performs the role of meter operator and that only in a few cases does the supplier or independent meter operator take on this role. With only 24 companies (around 3% of all meter operators) as independent meter operators, the meter operation of modern metering equipment and smart metering systems is clearly dominated by the joint roles of network operator and meter operator.

A connection user can choose which company is to be responsible for the installation, operation, maintenance of metering equipment and systems, and metering under section 5 of the Metering Act. A competing third party can be responsible instead of the default meter operator. Independent operators take on the activity of metering operations in the network areas of 789 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 54 networks, between 30 and 50 independent meter operators are active, but in 68 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.

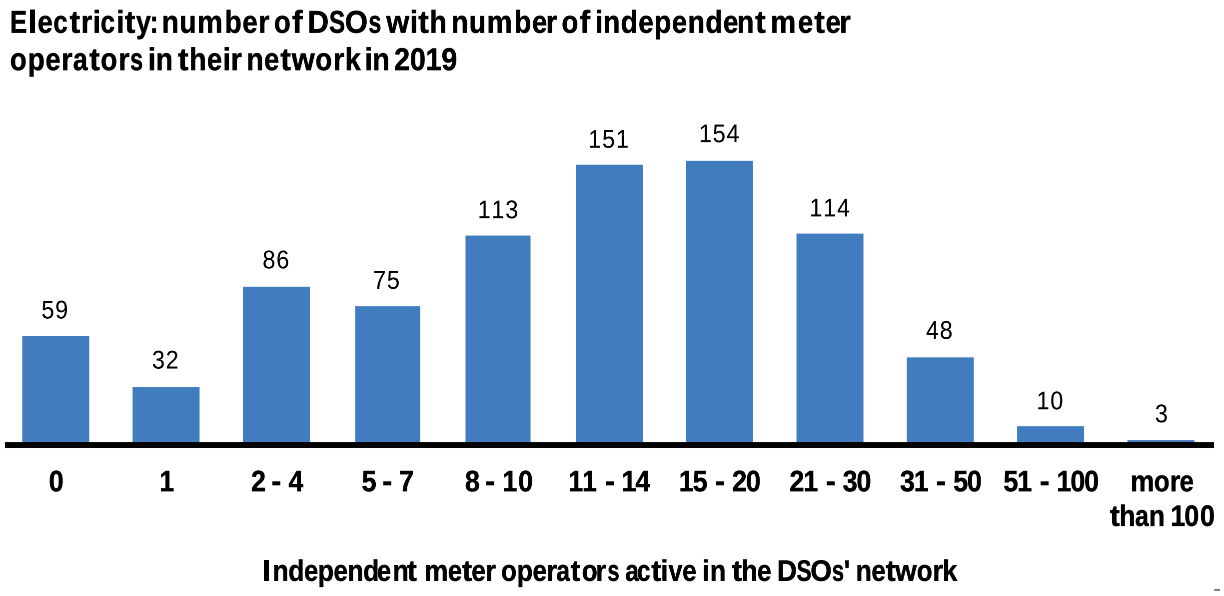


Figure 132: Number of DSOs with number of independent meter operators in their network (grouped)

Regardless of network size, the average number of meter operators active in one distribution system area is about 15. The highest number is 171 independent meter operators in one network area.

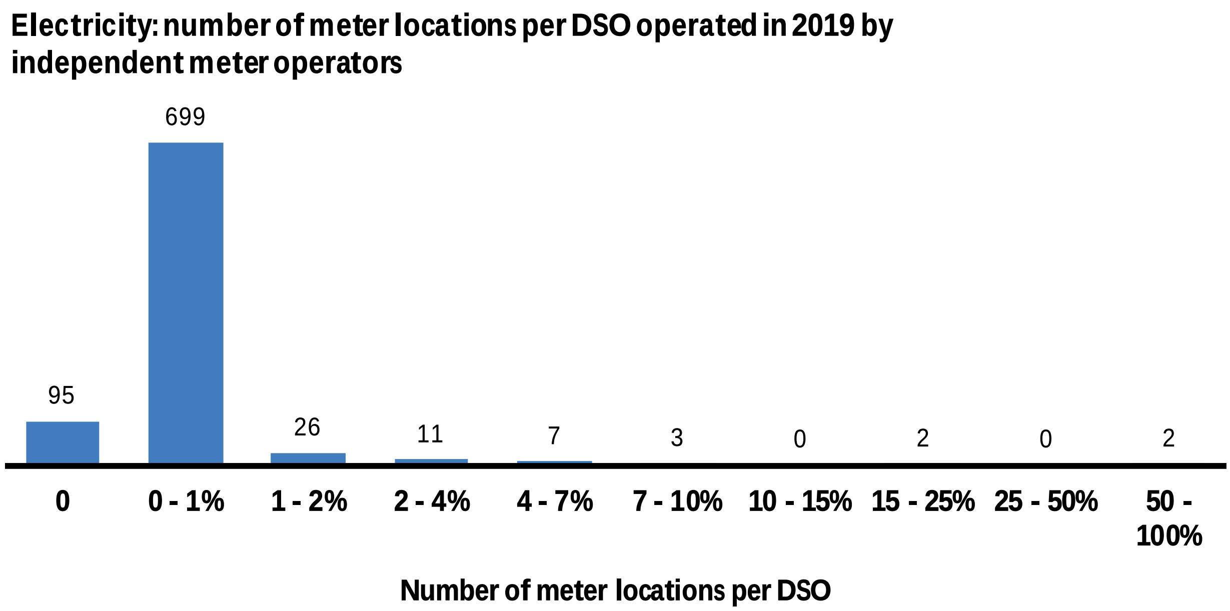


Figure 133: Number of meter locations per DSO operated by independent meter operators

Independent meter operators cover about 386,000 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 133. 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 all networks, where more than 1% of meter locations are covered by independent meter operators.

The total number of meter locations is broken down by federal state as shown in Table 103. The table shows that the German state of North Rhine-Westphalia has the highest number of meter locations at around 11 million.

Electricity: number of meter locations by federal state

	meter location - consumption	meter location - feed-in
Baden-Württemberg	6,397,101	255,988
Bavaria	7,766,654	635,470
Berlin	2,380,383	9,232
Brandenburg	1,636,907	47,409
Bremen	445,215	3,514
Hamburg	1,166,862	4,603
Hesse	3,804,071	131,604
Mecklenburg-Western Pomerania	1,043,555	22,833
Lower Saxony	4,707,505	190,179
North Rhine-Wesphalia	10,954,393	223,741
Rhineland-Palatinate	2,460,953	81,341
Saarland	642,560	29,018
Saxony	2,861,432	48,029
Saxony-Anhalt	1,565,667	35,273
Schleswig-Holstein	1,784,122	60,173
Thuringia	1,338,482	30,494

Table 103: 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. For the first time the companies were able to provide information about this since in the 2019 reporting year smart metering systems certified by the BSI had just become available on the market. In recent years the BSI certified the smart meter gateways as the communication unit in four different manufacturers’ smart metering systems.

Electricity: overview of the smart meter gateways certified in accordance with section 24 of the Metering Act

Certification number	Product name	Applicant	Date
BSI-DSZ-CC-0831-2018	SMGW-Integrationsmodul Version 1.0	OPENLiMiT SignCubes AG Sponsor: Power Plus Communications AG	12 December 2018
BSI-DSZ-CC-0822-2019	SMARTY IQ-GPRS / LTE, Version 1.0	Sagemcom Dr. Neuhaus GmbH	25 September 2019
BSI-DSZ-CC-0919-2019	CASA 1.0	EMH metering GmbH & Co.KG	17 December 2019
BSI-DSZ-CC-0918-2020	CONEXA 3.0 Version 1.0	Theben AG	24 July 2020

As at 23 November 2020. Source: https://www.bsi.bund.de/DE/Themen/DigitaleGesellschaft/SmartMeter/SmartMeterGateway/Zertifikate24Msbg/zertifikate24MsbG_node.html

Table 104: Overview of the smart meter gateways certified in accordance with section 24 of the Metering Act as at 23 November 2020.

The BSI determined the technical feasibility as defined in section 30 of the Metering Act as at 24 February 2020 and the mandatory rollout of smart metering systems began.

The number of smart metering systems installed by the deadline of 31 December 2019 (around 1,000) is very small. Given that the rollout of smart metering systems was not yet mandatory in 2019, the slow start to smart meter rollout is understandable.

As in the previous year, there was a sharp rise in installed modern metering equipment. Whereas there were only 2.2m meter locations with modern metering equipment in the 2018 reporting year, that figure had already reached 5.8m in the 2019 reporting year. 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 conjunction with secti

Information as at 31 December 2019	Number of meter locations: Total	equipped with metering systems in acc. with section 19(5) of the Metering Act	equipped with modern metering devices as defined in the Metering Act	equipped with smart metering systems as defined in the Metering Act
Final consumers with annual power consumption				
> 6.000 kWh & 10.000 kWh	2,055,556	204,569	223,953	115
> 10.000 kWh & 20.000 kWh	1,008,652	101,314	96,771	201
> 20.000 kWh & 50.000 kWh	524,706	69,492	43,300	139
> 50.000 kWh & 100.000 kWh	155,272	40,492	8,664	29
> 100.000 kWh	255,260	130,002	3,517	0
Consumer devices in accordance with section 14a EnWG	1,169,515	76,821	96,659	11
of which meter locations at charging stations for electric vehicles	6,183	548	2,048	0
Installed capacity at plant operators in accordance with section 2 para 1 of the Metering Act				
> 7 kW & 15 kW	627,515	62,948	72,149	59
> 15 kW & 30 kW	306,208	30,932	27,134	13
> 30 kW & 100 kW	158,309	29,612	8,113	1
> 100 kW	367,312	53,942	959	0

Table 105: 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 choose whether to install smart metering systems voluntarily (referred to as an optional installation) or just to install modern metering equipment.

Meter operators reported approximately 40.8m 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 conjunction with section 31 of the Metering Act

	Number of meter locations			
	Total	equipped with metering systems in acc. with section 19(5) of the Metering Act	equipped with modern metering devices as defined in the Metering Act	equipped with smart metering systems as defined in the Metering Act
Final consumers with annual power consumption of:				
2.000 kWh	21,715,311	2,112,119	2,836,715	310
> 2.000 kWh & 3.000 kWh	8,942,014	762,400	1,137,926	53
> 3.000 kWh & 4.000 kWh	5,550,327	441,505	655,590	31
> 4.000 kWh & 6.000 kWh	4,553,009	391,607	509,940	44
Installed capacity at plant operators in accordance with section 2 para 1 of the Metering Act				
> 1 kW & 7 kW	621,255	83,803	79,581	2

Table 106: 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 carrying out gateway administration have to be certified by the

BSI. As of 31 October 2020, the BSI[126] has certified 41 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.

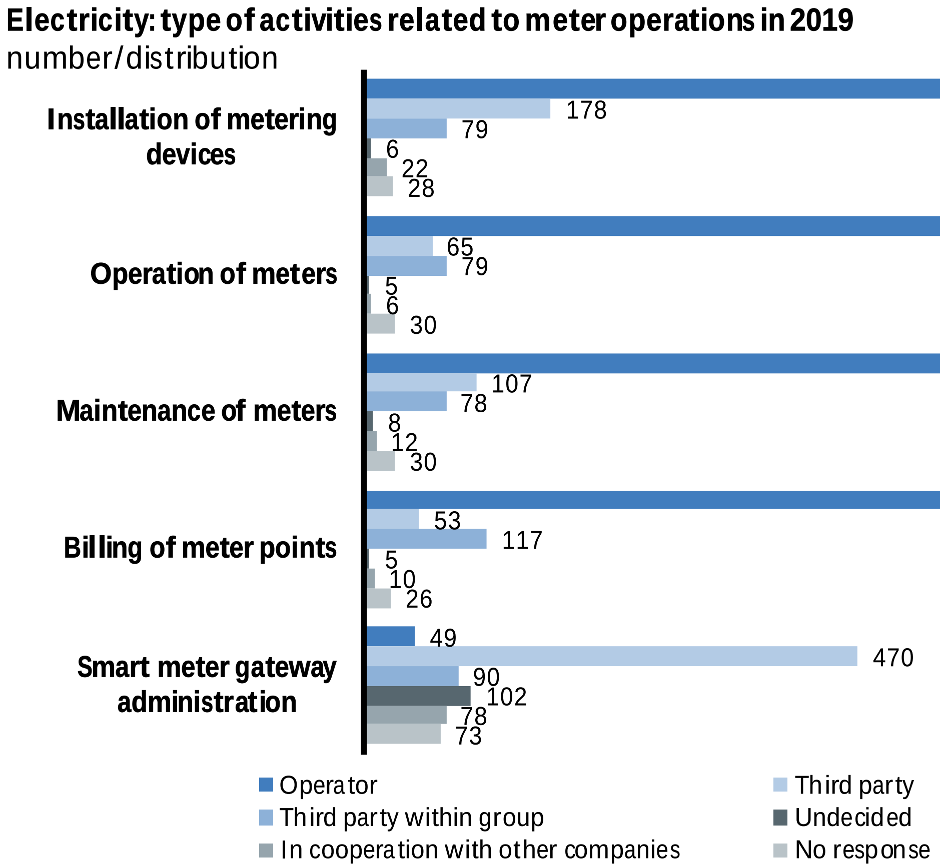


Figure 134: Performance of the activities related to metering operations

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. Owing to the very small number of smart metering systems installed in the 2019 reporting year, the number of connected gas meters has not been included in the current monitoring report.

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

[126] https://www.bsi.bund.de/DE/Themen/DigitaleGesellschaft/SmartMeter/AdministrationBetrieb/Zertifikate25Msbg/zertifikate25MsbG_node.html

metering operations. Only for the gas sector is the number somewhat higher, with 111 providers (see Figure 135).

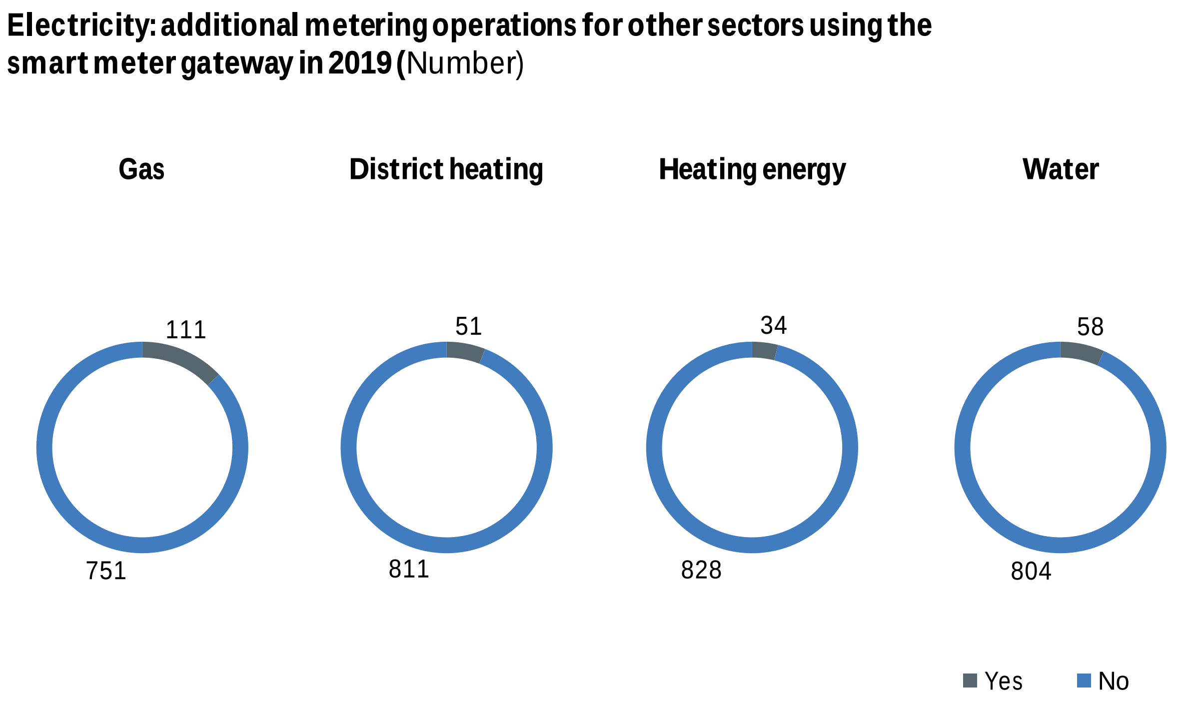


Figure 135: Additional metering operations for other sectors using the smart meter gateway

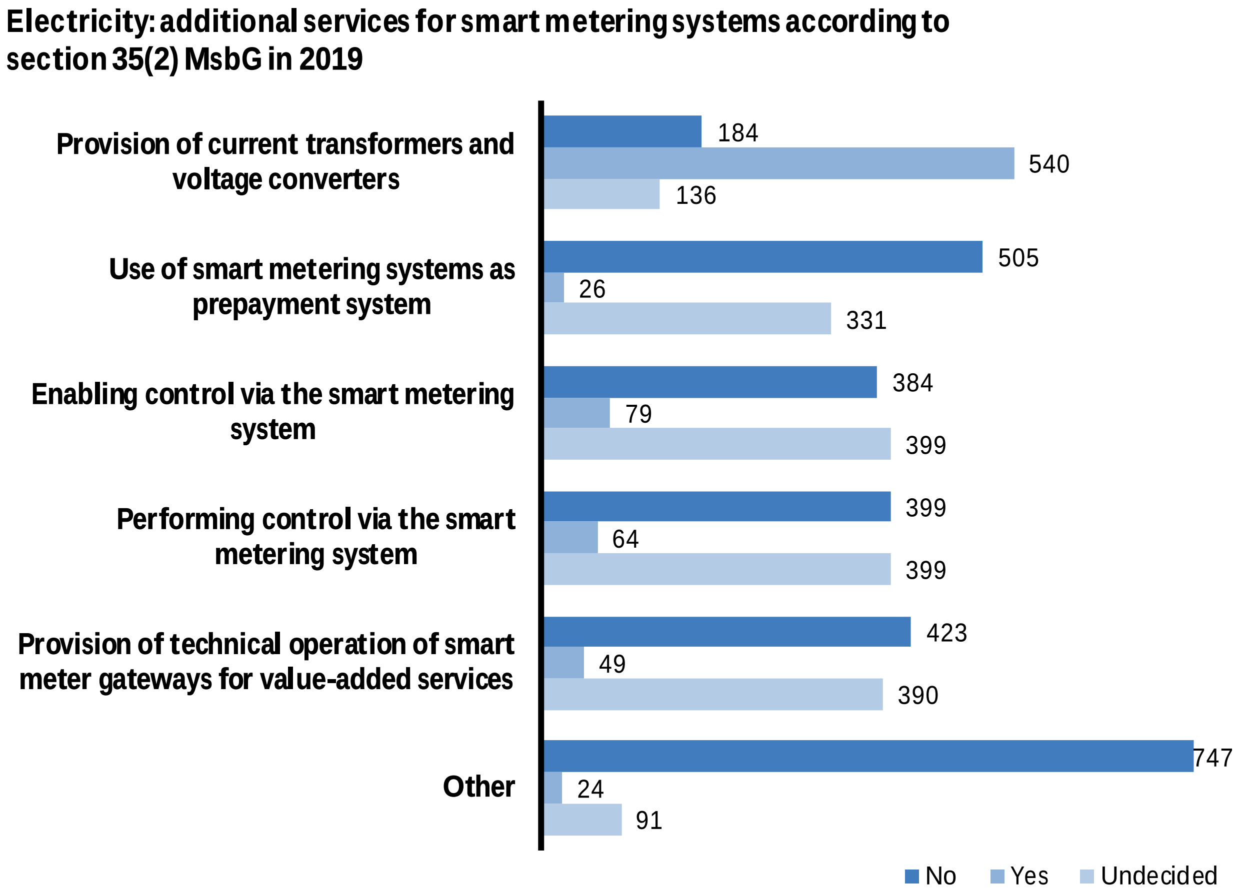


Figure 136: Additional services for smart metering systems

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 a lack of experience working with smart systems or possibly with lacking functionalities in the devices. Without the appropriate systems in place, many services cannot yet be offered. Figure 136 shows the evaluation of additional services.

A large majority (81%) of meter operators do not sell products that combine electricity supply and meter operation (see Figure 137).

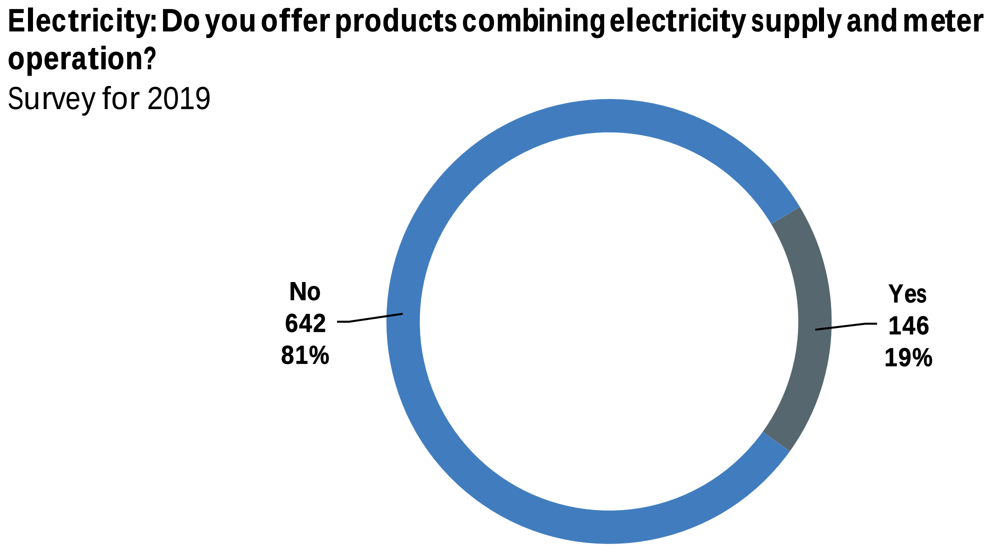


Figure 137: Combined products for electricity supply and meter operation

Although the billing of the connection user/owner for meter operation is no longer required to take place via the supplier, this is still often the case. Presumably suppliers and meter operators have made agreements to continue to bill meter operation jointly as part of the electricity bill. However, there has been an increase in mixed billing models where billing sometimes occurs separately and sometimes via the supplier. The number of companies that bill separately for meter operation services also rose from 61 in 2018 to 70 in 2019 (see graph below).

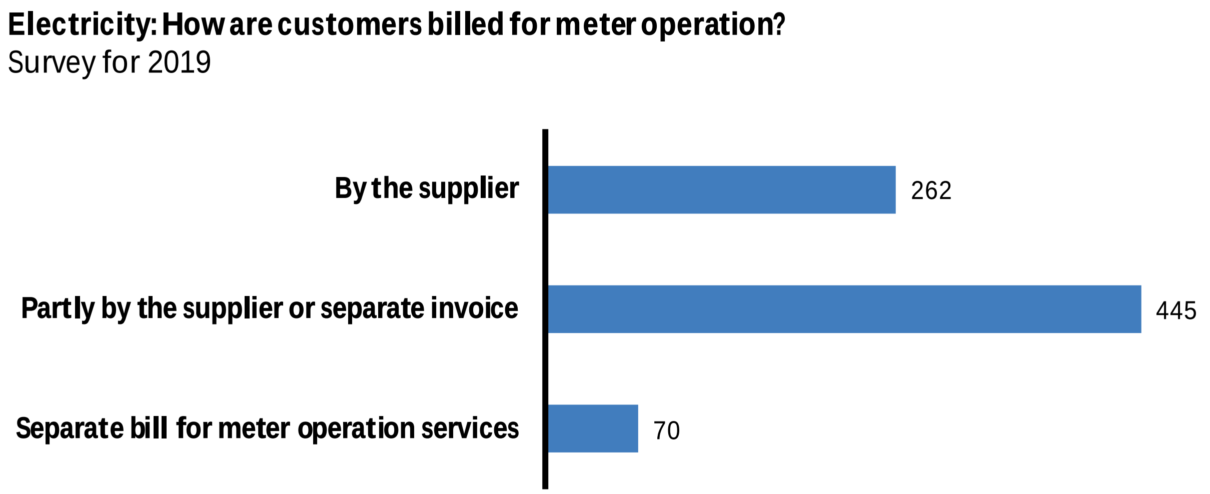


Figure 138: Billing the connection user/owner for meter operation

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 2018	Meter locations 2019
Electromechanical metering systems (with current transformers and three-phase meters based on the Ferraris principle)	40,080,363	36,696,299
of which two-tariff and multiple-tariff meters (Ferraris principle)	2,480,879	2,219,431
Electronic meter device (basic meter not connected to a communication network) in accordance with section 2 para 15 of the Metering Act	7,823,861	7,536,340
Modern measuring device (not connected to a communication network) in accordance with section 2 para 15 of the Metering Act	2,547,165	6,115,873
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)	461,288	377,536
Smart metering systems in accordance with section 2 para 7 of the Metering Act		968

Table 107: Meter technology employed for standard load profile (SLP) customers

In 2019 there was again a move away from electromechanical meters for SLP customers, which includes all household customers. This was due to the availability of modern metering equipment since the beginning of 2017 and the requirement under section 29(3) of the Metering Act to have modern metering equipment installed in at least 10% of meter locations by 30 June 2020. There was therefore again a sharp increase in 2019 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 in use at around 6.1m meter locations[127]. The total number of electromechanical metering systems has dropped by about 3.4m meter locations. The number of electronic meters has declined over the previous year so that there are currently about 7.5m 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 2.2m. The number of meter systems that are not smart metering systems as defined under section 2 par 13 of the Metering Act and are installed at around 378,000 SLP customer meter locations has also declined.

[127] Differences between Tables 105 and 106 compared with Table 107 stem from varying quality of the answers provided.

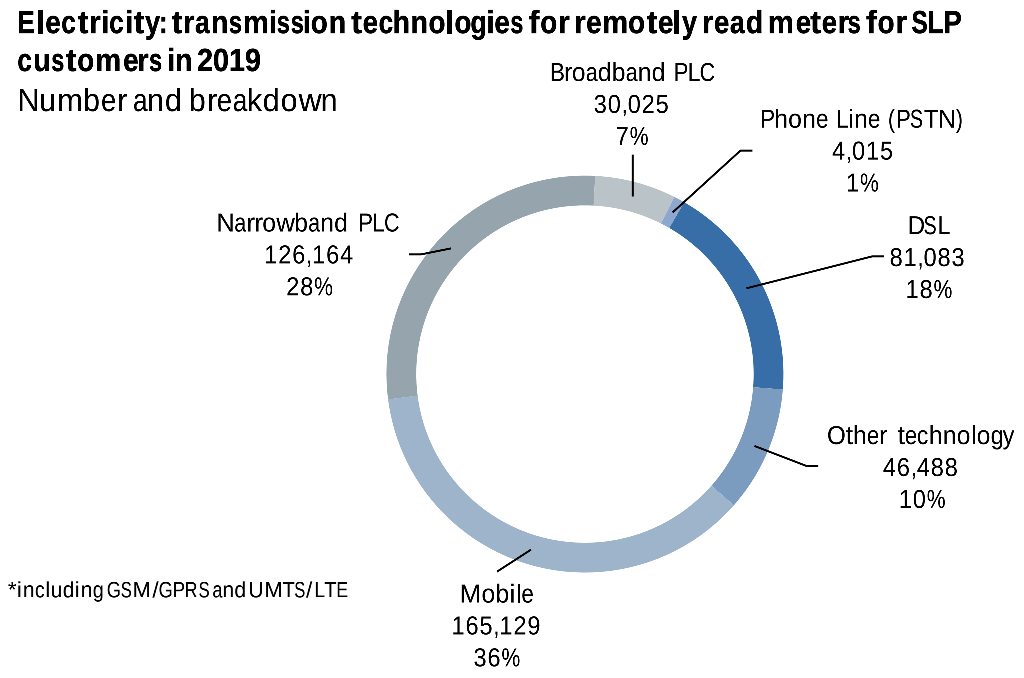


Figure 139: Transmission technologies for remotely read meters for SLP customers

Only about 453,000 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. 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 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.

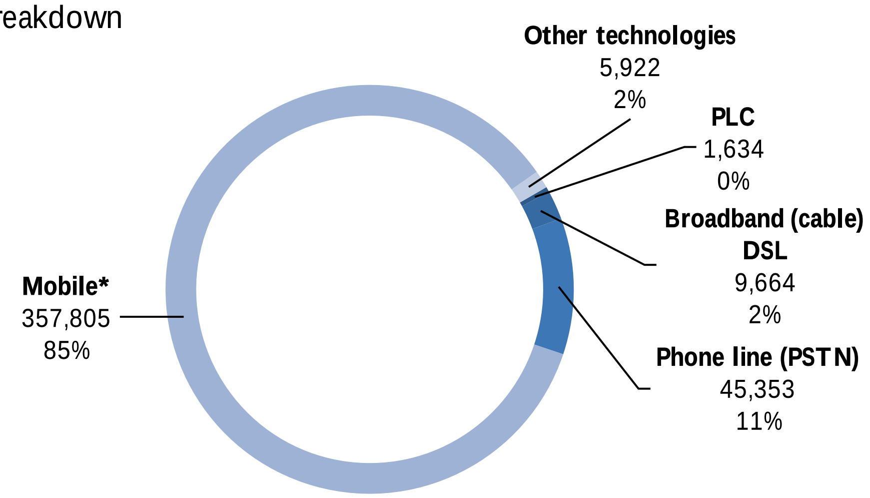
Electricity: meter technology employed for interval-metered customers

Requirement	Meter locations 2019
Metering equipment in the interval-metered segment (> 100,000 kWh/year)	392,283
Meter systems under section 2 para 13 of the Metering Act that are not smart metering systems in accordance with section 2 para 7 of the Metering Act (eg EDL 40) (100,000 kWh/year)	390,347
Optional installations of BSI-certified smart metering systems	-
Other	11,615

Table 108: Meter technology employed for interval-metered customers

Electricity: transmission technologies for remotely read meters for interval-metered customers in 2019

Number and breakdown



*including PMR, GSM/GPRS and UMTS/LTE

Figure 140: Transmission technologies for interval-metered customers

There were some changes in the transmission technology landscape for interval-metered customers compared with 2019, with remote meter readings transmitted via mobile communication rising from 82% to 85%. 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. 85% of remote read meters now communicate by mobile transmission.

7. Metering investment and expenditure

Total investment and expenditure on metering was up about €48m to around €669m in 2019, leaving expenditures around €7.5m below the planned investment amounts. Investment in new installations, upgrades and expansion made in 2019 were around 2% above projected figures for the year. Investments in maintenance and renewal were around 4% below what was planned. Expenditure amounts were almost identical to the forecast figures.

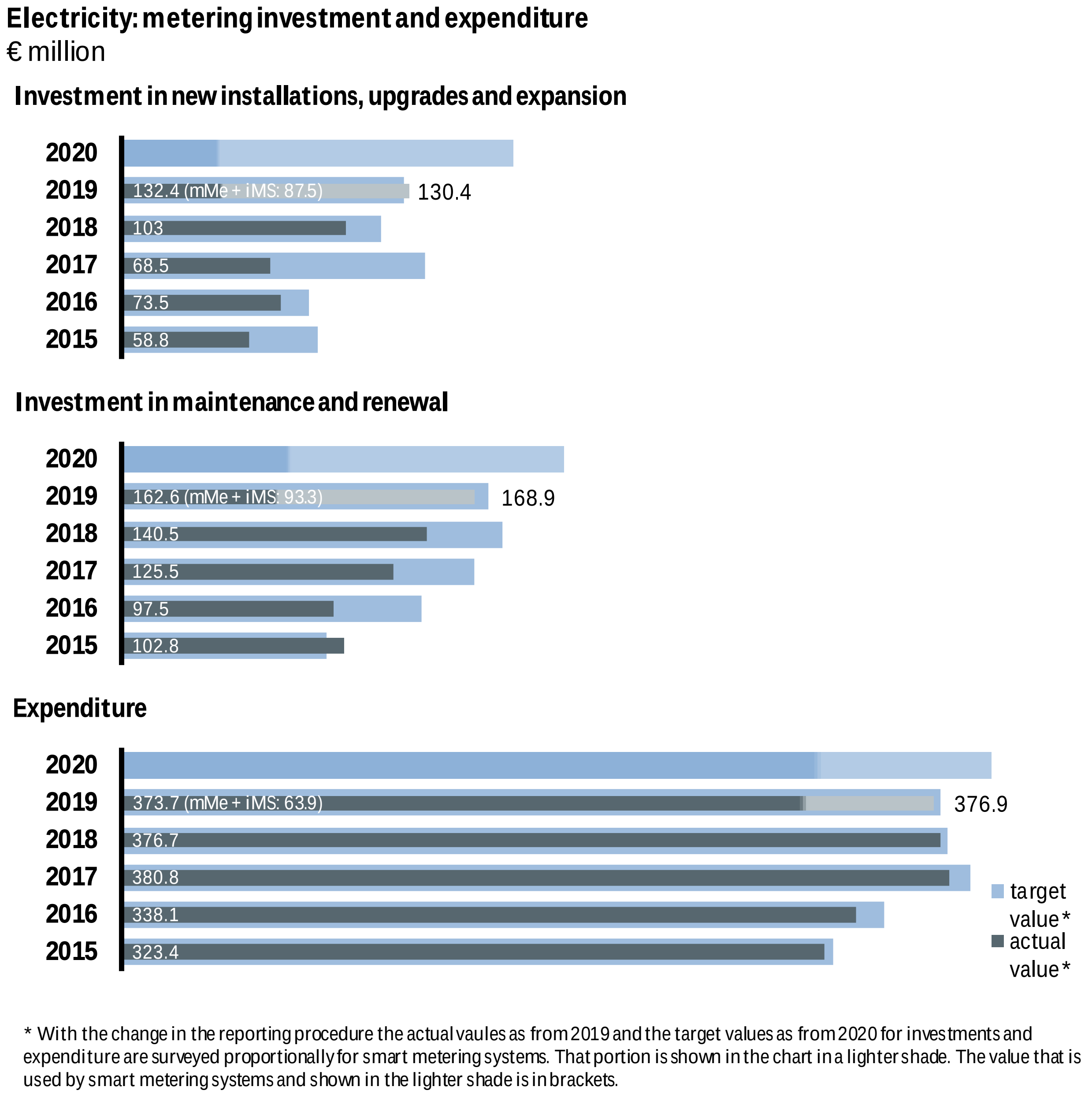


Figure 141: Metering investment and expenditure

At a total of around €784m, this year's forecast figures are significantly higher than projections from the prior year and would lead to an increase in investments and expenditures if fully implemented. Of the €669m invested in 2019, investment in smart metering systems and modern metering equipment was around €245m, which is nearly twice as much as in the prior year. However, this share is projected to rise significantly to about €349m in 2020.

8. Final consumer prices for metering equipment

For the fourth 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 109 and Table 110. The prices for standard services as defined in section 35(1) of the Metering Act range on average between €95.07 and €429.37 per year, depending on the final consumer group and installed capacity of installation operators. The published price for final consumer groups with an annual power consumption of more than 100,000 kWh in the previous year was corrected from €720.32 to €436.66, which means price changes from the previous year were small. 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 109 and Table 110. Depending on the final consumer group, they vary, on average, between €21.95 and €54.43 per year.

Electricity: prices for standard services* within the meaning of section 35(1) of the Metering Act for carrying out metering operations in 2019 (€ / year)

Final consumers with annual power consumption	Average price	Price cap
2.000 kWh**	21.95	23.00
> 2.000 kWh & 3.000**	28.10	30.00
> 3.000 kWh & 4.000**	36.95	40.00
> 4.000 kWh & 6.000**	54.43	60.00
> 6.000 kWh & 10.000	95.07	100.00
> 10.000 kWh & 20.000 kWh	124.44	130.00
> 20.000 kWh & 50.000 kWh	162.88	170.00
> 50.000 kWh & 100.000 kWh	193.62	200.00
> 100.000 kWh	429.37	
Verbrauchseinrichtungen nach § 14a EnWG	94.05	100.00

* in accordance with section 35(1) of the Metering Act

** optional installation in accordance with section 29 in conjunction with section 31 of the Metering Act

Table 109: Prices for standard services within the meaning of section 35(1) of the Metering Act for carrying out metering operations

Electricity: prices for standard services* within the meaning of section 35(1) of the Metering Act for carrying out metering operations in 2019 (€ / year)

Installed capacity at plant operators in accordanc	Average price	Price cap
> 1 kW & 7 kW**	55.14	60.00
> 7 kW & 15 kW	95.73	100.00
> 15 kW & 30 kW	124.34	130.00
> 30 kW & 100 kW	198.32	200.00
> 100 kW	404.45	

* in accordance with section 35(1) of the Metering Act

** optional installation in accordance with section 29 in conjunction with section 31 of the Metering Act

Table 110: (Continuation of Table 109) Prices for standard services within the meaning of section 35(1) of the Metering Act for carrying out metering operations

Table 111 shows that final consumers are charged on average €19.73 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 voluntary installation within the meaning of section 29 in conjunction with section 32 of the Metering Act in 2019 (€/year)

	Average price	Price cap
Modern metering device as defined in the Metering Act	19.73	20.00

Table 111: 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 2019, natural gas production in Germany fell by 0.2bn m³ to 6.0bn m³ of gas (with calorific adjustment), down 3% from 6.2bn m3 in 2018. 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 7.0 years as at 1 January 2020.

The total volume of natural gas imported into Germany in 2019 was 1,703 TWh. Imports to Germany were thus down by 57 TWh from the previous year's figure of 1,760 TWh. Imports from Norway rose by just over 18%, while imports from Russia through the Nord Stream pipeline were down 0.1%.

In 2019, the total volume of natural gas exported by Germany was 702 TWh. Based on the previous year's figure of 849 TWh, exports from Germany fell by 148 TWh. 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 52% (2018: 48%) of German natural gas exports went to Czechia, a drop of 11% compared to the previous year's figure. There was a large decrease of 90% in exports to Denmark. Although this was a significant change from the year before, such developments are not unusual as part of market activity. There was also a drop of 54% in exports to France, primarily because the amount of gas imported by that country depends on the availability of its nuclear power plants. Exports to Austria, meanwhile, were up 1.5%.

The total maximum usable volume of working gas in underground storage facilities as at 31 December 2019 was 275.27 TWh.[128]. Of this, 135.63 TWh was accounted for by cavern storage, 117.54 TWh by pore storage and 22.01 TWh by other storage facilities.

Short-term (up to 1 October 2019) freely bookable working gas capacity saw a significant decline in volume, whereas there was an increase in the capacity still bookable for 2021. As for the longer term, the volume of medium-term bookable working gas rose again but the volume of long-term working gas declined.
On 1 January 2021, the total storage level stood at around 73%.

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 storage facility operators stood at around 66.6% at the end of 2019, representing a slight decrease compared to the previous year (67.1%).

[128] This figure includes the 7 Fields storage facility and part 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.

1.2 Networks

1.2.1 Network expansion

On 1 July 2020, the gas transmission system operators (TSOs) submitted their draft of the Network Development Plan (NDP) 2020-2030 to the Bundesnetzagentur. For the most part, the measures in the Gas NDP 2018-2028 are confirmed by the modelling results of the Gas NDP 2020-2030. The TSOs are also proposing a further 54 measures to expand the natural gas network in the period up to 2030, with an investment volume of €2.2bn.

Expansion measures for access to three liquefied natural gas (LNG) terminals on the German North Sea coast will enable LNG to be supplied directly into the national transmission system. The integration of the LNG terminals into the transmission system will bring opportunities to import gas from different sources, which will enhance security of supply and could exert price pressure on traditional importers.

Another issue in the Gas NDP 2020-2030 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 overall expansion proposed by the TSOs for the natural gas transport system includes the expansion of transmission pipelines (approximate length 1,594 km) and of compressor stations (approximate capacity 405 MW). Compared to the previous expansion proposal in the Gas NDP 2018-2028, total investment costs have risen slightly from €7.0bn to €7.8bn.

The TSOs included green gas projects (injection and offtake of hydrogen, synthetic methane) for the first time in the Gas NDP 2020-2030 and modelled them in a separate green gas variant. However, under current legislation pure hydrogen pipelines are not subject to regulation and are therefore not included in the binding part of the NDP. The TSOs have thus proposed 47 measures for the creation of a hydrogen transport system in the Gas NDP 2020-2030 in addition to the natural gas infrastructure measures and subject to changes in the law and regulations. The pipeline length in the expansion proposal is 1,294 km, of which 151 km can be newly built and 1,142 km achieved by repurposing existing natural gas lines. The investment volume for the creation of a hydrogen network will amount to €0.7bn in the period up to 2030, according to the proposal. A detailed presentation of these green gas variants and the related expansion proposal, as well as an outlook, may be found in section II.C.1.1.

1.2.2 Extension of the regulatory framework to gas interconnectors with third countries

Directive (EU) 2019/692 of the European Parliament and of the Council of 17 April 2019 extended the scope of the Gas Directive 2009/73/EC to include interconnectors between a Member State and a third country. The parts of the interconnectors in the national territory and territorial sea of the respective Member State are now subject to regulation, although Article 49a of the above-mentioned Gas Directive provides for a possible exemption (derogation) from regulation for lines that have already been completed. The new section 28b of the German Energy Industry Act (EnWG), which transposes Article 49a of the amended Gas Directive in identical wording into German law, sets out that the part of a gas interconnector located in German territory/territorial sea is to be exempted from regulation provided that certain conditions are met. As well as the existence of "objective reasons", it is necessary in particular that the gas interconnector was completed before 23 May 2019. Ruling Chamber 7 received applications for such a derogation for the Nord Stream pipeline, which has been in operation since 2011, on 20 December 2019 (BK7-19-108) and for Nord Stream 2 on 10 January 2020 (BK7-20-004).

The provision in Article 49a(3) of the Gas Directive set out that the decisions had to be made by 24 May 2020. Despite the constraints caused by the coronavirus pandemic in March and April, both sets of proceedings met the deadline, with the application for derogation for Nord Stream 2 being rejected on 14 May 2020, while for Nord Stream the application was granted in accordance with section 28b EnWG on 20 May 2020. Non-confidential versions of the decisions and statements from the Member States have been published on the ruling chamber's website in German and English. The decisions were also transmitted to the European Commission in accordance with section 28b(8) EnWG.

On 15 June 2020, the applicant filed an appeal with the Higher Regional Court (OLG) in Düsseldorf against the rejection of the derogation for Nord Stream 2.

The reasons for the decisions were as follows:

Nord Stream 2 (BK7-20-004):

The application for derogation submitted by Nord Stream 2 AG for the part of its Nord Stream 2 pipeline located in German territory was rejected because the pipeline had not been completely laid as at 23 May 2019. When/once it is put into operation, therefore, Nord Stream 2 will be subject to the regulatory requirements of the EnWG and European rules on unbundling, network access and cost regulation. The ruling chamber understands the term "completion" in a constructional/technical sense. The applicant, by contrast, believes it to mean completion in an economically functional sense and refers to the investment decision, which was made well before 23 May 2019.

All Member States had the opportunity to examine Nord Stream 2 AG's application, with its annexes, and to submit a response. Responses were received from ten Member States. Their contributions to the consultation were taken into account in the decision, as was the joint statement submitted by PGNiG S.A. and PGNiG Supply & Trading GmbH, which were summoned to the proceedings upon application in a decision of 18 March 2020. The Bundeskartellamt did not provide a response. Neither the Member States nor the parties summoned shared the viewpoint of the applicant as regards the term "completion".

Nord Stream (BK7-19-108):

The Nord Stream pipeline was granted a derogation from regulatory requirements for the part of it located in the German territorial sea retroactively for a period of 20 years as from 12 December 2019, because the conditions for derogation set out in section 28b(1) EnWG were met. Nord Stream was completed before 23 May 2019 and the first connection point of the line with the network of a Member State is in Germany. There is also an objective reason (in this case, "reasons of security of supply"). An improvement in the security of supply had previously been confirmed by the TEN-E decision (Decision No 1364/2006/EC) from 2006 and the planning approval decision of the Stralsund mining authority from 2009. Moreover, the derogation will not be detrimental to competition on or the effective functioning of the internal market in natural gas in the European Union, or to security of supply in the Union. Therefore, the pipeline is exempted from the provisions of sections 8-10e EnWG and sections 20-28 EnWG, ie from certain provisions relating to unbundling and third-party access. However, Nord Stream remains subject to other provisions of the EnWG; the provisions of sections 6a, 6b and 11 et seq, for example, still apply.

During the proceedings, all Member States had the opportunity to examine the application, with its annexes, and to submit a response. Responses were received from six Member States. The statement submitted by the Bundeskartellamt when authorities were given an opportunity to state their views was taken into account in the decision, as were the responses from Member States.

1.2.3 Investment

In 2019 the 16 German TSOs invested a total of €1.33bn (2018: €1.45bn) in network infrastructure. Of this, €1.08bn (2018: €1.30bn) was accounted for by investments in new builds, upgrades and expansion projects and €249m (2018: €156m) by investments in network infrastructure maintenance and renewal.

Across all TSOs, expenditure on maintenance, repair and expansion of network infrastructure amounted to €322m in 2019 (2018: €313m), with expenditure in 2019 and planned expenditure for 2020 shared almost equally between the two market areas.

The overall total for investments and expenditure across all TSOs in 2019 was approximately €1.65bn (2018: €1.76bn).

In the course of data collection for the 2020 Monitoring Report, 600 gas DSOs declared a total investment volume for 2019 of €1,488m (compared to €1,272m in 2018), comprising €940m in new installations, expansions and extensions (€798m in 2018) and €549m in maintenance and repair of network infrastructure (€475m in 2018). For 2020, the projected total investment is €1,527m.

Service and maintenance expenses, based on the data provided by the DSOs, totalled €1,152m in 2019 (2018: €1,078m). The projected expenditure on service and maintenance for 2020 is €1,289m.

1.2.4 Supply interruptions

In 2019, the average interruption in supply per connected final consumer was 0.98 minutes per year, which is a value that clearly reflects the high level of supply quality of the German gas network.

1.2.5 Network charges

As of 1 April 2020, 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, unchanged from the previous year. The lowest gas network charges for household customers across Germany are set at 0.65 ct/kWh, and the highest at 3.65 ct/kWh. The East to West gradient in the distribution of network charges levelled off slightly. The average network charge for household customers in the new federal states (not including Berlin) is 1.60 ct/kWh (2019: 1.65 ct/kWh), while the average in the old states (including Berlin) is 1.42 ct/kWh (2019: 1.39 ct/kWh). Compared to the previous year, gas network charges for household customers have thus decreased by slightly more than 3% on average in the new federal states and increased by just over 2% in the old states.

1.2.6 Network balance

The total quantity of gas supplied by general supply networks in Germany rose in 2019 by about 19.9 TWh or just over 2.5% year-on-year to 948 TWh. The quantity of gas supplied to household customers (as defined in section 3 para 22 EnWG) rose by just over 2.7% to 282.5 TWh (2018: 275.2 TWh). Gas supplies to gas-fired power stations with a nominal capacity of at least 10 MW increased by about 12% to 98.3 TWh (2018: 87.8 TWh).

With regard to gas transmission networks, the quantity of gas procured directly on the market by large final consumers (industrial customers and gas-fired power stations) – 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 78.9 TWh (2018: 72.5 TWh), equivalent to about 42% of the total quantity of gas supplied by the TSOs to final consumers. As regards gas distribution networks, the amount of gas procured without a conventional supplier contract amounted to 42.4 TWh, compared with 39.8 TWh in 2018, corresponding to a share of approximately 5% of the DSOs' total gas supplies.

1.2.7 Market area conversion

The conversion of German L-gas networks to H-gas got off to a good start 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. 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 4,255 conversions will have been carried out for interval-metered customers and 2,228,722 for standard load profile (SLP) customers.

1.3 Wholesale

Overall, the liquidity of the wholesale natural gas markets increased significantly again in 2019. There was an increase of around 22% in the total volume traded on the exchange, while the volume of bilateral wholesale trading via broker platforms, which accounts for a much larger share, actually rose about 30% in 2019.

The volume traded on the spot market rose by 21% in 2019 to around 472 TWh (2018: 391 TWh). As in previous years, the focus of spot trading for both market areas in 2019 was on day-ahead contracts (NCG: 179.5 TWh; GASPOOL: 121.5 TWh). The futures trading volume rose from around 58 TWh in 2018 to about 75 TWh in 2019, corresponding to an increase of some 30%.

In 2019, broker platforms reported natural gas transactions for delivery to Germany had been traded for an amount totalling 2,853 TWh (2018: 2,192 TWh), representing growth of around 30%. Of this, 1,207 TWh was for contracts with delivery in 2019 and a delivery time of at least one week.

There were lower wholesale gas prices for the first time in two years in 2019. The various price indices (EGIX, border prices, as calculated by the Federal Office for Economic Affairs and Export Control (BAFA)) show a year-on-year drop of between 16% and 28%. The European Gas Spot Index (EGSI), which was measured for the first time in 2017, fell year-on-year by about 32% in the NCG market area and about 40% in GASPOOL.

1.4 Retail

1.4.1 Contract structure and competition

An overall analysis of how household customers were supplied in 2019 in terms of volume shows that nearly half of them (49%) were supplied by the local default supplier under a non-default contract, receiving 128.4 TWh of gas (2018: 50%/124.7 TWh).

Only 17% of household customers still had a default supply contract in 2019 and these were supplied with 43.7 TWh of gas (2018: 18%/45.3 TWh). The percentage of household customers who had a contract with a supplier other than the local default supplier increased again to 34% for a total of 89.9 TWh of gas (2018: 32%/79.1 TWh). 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 24.1% of the total volume delivered to these customers was supplied under a contract with the default supplier on non-default terms (2018: 25.7%) and about 75.6% was supplied under a contract with a legal entity other than the default supplier (2018 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 changing contract in 2019 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%.

The number of household customers who switched supplier in 2019 fell to 1.4m (2018: 1.5m). There was a clear rise of just over 9% in the number of household customers who chose an alternative supplier rather than the default supplier right away when moving home.

The total consumption amount affected by supplier switches in 2019 was 88.9 TWh, corresponding to a very small year-on-year decrease of 0.6 TWh. The switching rate for non-household customers was 9%, remaining stable from the previous year.

The level of concentration in the two largest gas retail markets continues to be well below the statutory thresholds for presuming market dominance. The cumulative sales for the four largest companies to SLP customers was about 86 TWh in 2019, the same as the year before. The cumulative sales for the four largest companies to interval-metered customers was about 145 TWh (2018: 138 TWh). The aggregate market share of the four largest companies (CR4) in 2019 was thus around 24% for SLP customers (2018: 23%) and about 30% for interval-metered customers, compared to 31% in 2018.

Since market liberalisation and the creation of a legal basis for an efficient 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 was maintained in 2019 as well.

In 2019, 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 91% of network areas, household customers have a choice of 50 or more gas suppliers. More than 100 gas suppliers are operating in almost 50% of network areas. On average, final consumers in Germany can choose from 129 suppliers in their network area (2018: 124); household customers can, on average, choose between 109 suppliers (2018: 104 suppliers) (these figures do not take account of corporate groups).

1.4.2 Gas disconnections

The number of disconnections actually carried out by the network operators in 2019 was 30,997, representing a decrease of 6.5% compared to the previous year (2018: 33,145). 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. Just over a million disconnection notices were issued to household customers, of which around 0.2m or 20% were passed on to the relevant network operator with a request for disconnection. The suppliers' data show that around 3% of the total notices actually resulted in the customer being disconnected.

The gas suppliers also stated that in some 22,674 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 10,406 cases, corresponding to 0.1% of non-default customers. The gas suppliers stated that around 10% of disconnections were the same customers being disconnected more than once.

1.4.3 Price level

The volume-weighted gas price for household customers across all contract categories barely changed in 2020 and was 6.31 ct/kWh. The volume-weighted gas price for customers on a default contract as at 1 April 2020 was 6.99 ct/kWh in band II (2019: 7.28 ct/kWh), corresponding to a decrease of around 4% compared to the previous year. The volume-weighted gas price for customers on a non-default contract with the default supplier as at 1 April 2020 was 6.29 ct/kWh in band II (2019: 6.44 ct/kWh), equivalent to a year-on-year decrease of just over 2%. The volume-weighted price for a contract with a supplier other than the local default supplier as at 1 April 2020 was 5.96 ct/kWh in band II, a decline of just over 4% compared to the previous year (2019: 6.22 ct/kWh).

The average household customer with gas consumption of 23,250 kWh could save an average of €163 a year as at 1 April 2020 by changing contract. The average potential saving for the year from changing supplier was €240.

The price component "energy procurement, supply and margin" for default supply customers was 3.51 ct/kWh as at 1 April 2020 (2019: 3.74 ct/kWh). That corresponds to a drop of just over 6% in gas procurement costs. The gas procurement costs in the price for customers supplied under a non-default contract with the default supplier fell by slightly more than 4% from 3.30 ct/kWh to 3.18 ct/kWh. The gas procurement costs for customers supplied under a contract with a supplier other than the local default supplier increased by just over 7% to 2.80 ct/kWh (2019: 3.02 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 €70 to €80.

The gas prices for non-household (industrial and commercial) customers showed a decrease as at 1 April 2020. The arithmetic mean of the overall price (excluding VAT) for an annual consumption of 116 GWh ("industrial customer") was 2.53 ct/kWh, and thus 0.33 ct/kWh or around 11.5% lower 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 4.52 ct/kWh on the reporting date, a small decrease of 0.03 ct/kWh on a year earlier. The proportion of the total price (about 59%) controlled by the supplier was 2.66 ct/kWh, down by only 0.03 ct/kWh.

The prices paid by non-household customers in Germany in the annual consumption range of 27.8 GWh to 278 GWh was 2.50 ct/kWh in the second half of 2019, about 0.09 cents above the EU average of 2.41 ct/kWh. On an EU average, the net price is subject to about 9.5% (0.24 ct/kWh) of non-refundable taxes and levies. In this regard, Germany's figure of about 15% (0.38 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 5.88 ct/kWh and thus around 12% below the EU average (6.70 ct/kWh). Taxes and levies amounted to an average of 1.57 ct/kWh in Germany. The EU average was 1.70 ct/kWh.

2. Network overview

All 16 TSOs took part in the 2020 Monitoring Report data survey. As at 31 December 2019, the length of pipelines in the transmission system was about 33,500 km[129] and included around 3,500 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 530 and approximately 186.9 TWh of gas was delivered to final consumers from the TSO network, compared to 173.6 TWh in 2018. The volume of gas delivered from the TSO network was thus about 8% more than the level of the previous year.

As at 4 January 2021, a total of 704 gas DSOs were registered with the Bundesnetzagentur, 685 (about 97%) of whom took part in the 2020 monitoring survey. As at 31 December 2019, the total length of pipelines in the gas distribution network was around 522,000 km and included about 10.8m exit points for delivery to final consumers, redistributors or downstream networks including the points at which gas can be taken off for delivery to storage facilities, hubs and conditioning or conversion plants. As at December 2019, there were 14.5m 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 12.8m. Total gas supplies from the network of the DSOs amounted to 761.1 TWh in 2019, up by around 10 TWh compared to the previous year. The quantity of gas supplied to household customers as defined in section 3 para 22 EnWG remained stable at about 275 TWh.

A simplified comparison between the supply and demand of natural gas in 2019 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 1,824 TWh in 2019. Around 3% of this came from domestic sources (59 TWh), while the rest (1,703 TWh) was imported. The balance of gas that entered and exited storage in 2019 amounted to 53 TWh, so there was more gas being withdrawn from the storage facilities than injected into them. Moreover, 9.8 TWh of biogas upgraded to natural gas quality was fed into the German natural gas network during the year.

Around 42% (701.06 TWh) of available gas volumes in Germany was transported to neighbouring countries in Europe in 2019. Final consumers used 948 TWh of gas in Germany.

[129] The total network length for 2019 was calculated using the adjusted definition of "network length by operating pressure/nominal pressure"; because the shares of external use are accounted for differently, it deviates from the structural data published in accordance with section 27(2) GasNEV and the network lengths given in previous monitoring reports.

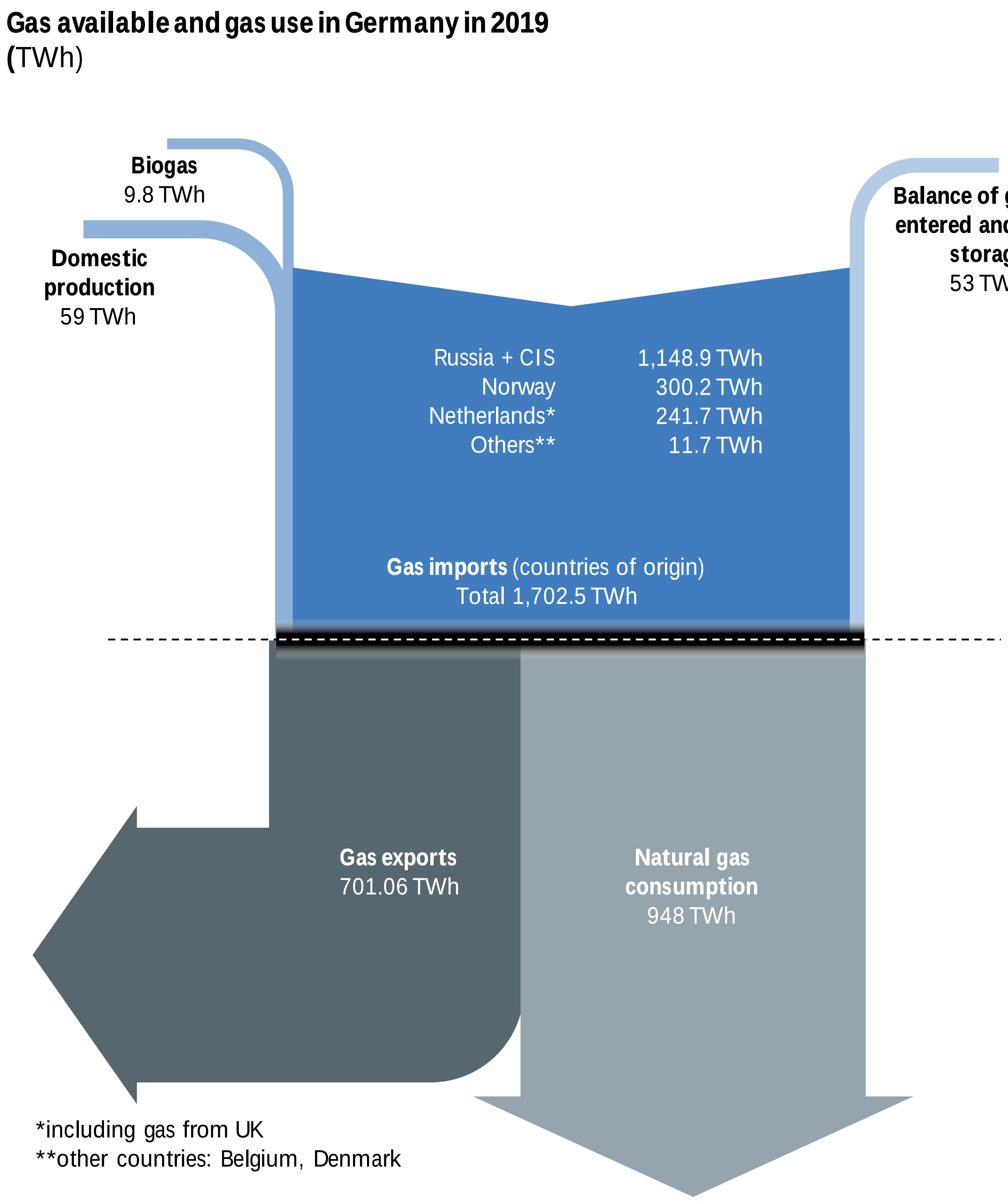


Figure 142: Gas available and gas use in Germany in 2019[130]

[130] 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

	2015	2016	2017	2018	2019	2020
Transmission system operators (TSOs)	17	16	16	16	16	16
Distribution system operators (DSOs)	714	715	717	718	708	704
DSOs with fewer than 100,000 connected customers	689	690	692	693	683	682
DSOs with fewer than 15,000 connected customers*	547	545	548	547	536	534

*Based on data from gas DSOs.

Table 112: Number of gas network operators in Germany registered with the Bundesnetzagentur as at 4 January 2021

The majority of gas DSOs (575 operators) have short to medium length networks of up to 1,000 km, but 90 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 and share

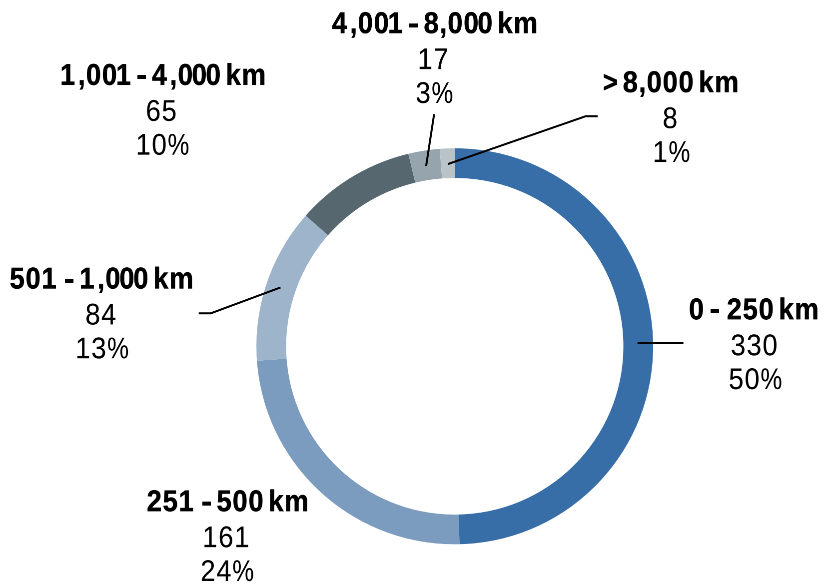


Figure 143: DSOs by gas pipeline network length as stated in the DSO survey – as at 31 December 2019

Gas network operators were asked about the total length of their networks, as well as the length subdivided into pressure ranges (nominal pressure in bar). The findings from the operators surveyed are shown in the table below. Since 2018 the market location is the unit in the energy market in which connections are counted for delivering and balancing. It is always used when referring not to the technical connection but to the contractual relationships behind the technical connection. The number of customers, for example, is counted via the market locations, whereas the number of installed meters is counted via the meter location. The meter location thus forms the technical equivalent to the market location, though a one-to-one relationship does not exist. Multiple meter locations can be assigned to one market location, and in another possible scenario multiple market locations can be assigned to one meter location.

Gas: 2019 network structure figures

	TSOs	DSOs	Total no of TSOs and DSOs
Network operators (number)	**16**	**665**	**681**
Network length (thousand km)	**33.6**	**522.1**	**555.7**
0.1 bar	0	190.7	190.7
> 0.1 – 1 bar	0	255.2	255.2
> 1 – 5 bar	0.1	28.7	28.8
> 5 – 16 bar	2.7	26.6	29.3
> 16 bar	30.8	20.9	51.7
Total no offtake points (thousand)	**3.4**	**10,846.8**	**10,850.2**
0.1 bar	0.002	6,050.2	6,050.2
> 0.1 – 1 bar	0.014	4,562.8	4,562.8
> 1 – 5 bar	0.065	222.4	222.5
> 5 – 16 bar	1.8	8.2	10.0
> 16 bar	1.6	3.2	4.8
Market locations of final consumers (thousand)	0.5	14,568.3	14,568.8
Industrial and commercial customers and other non-household customers	0.5	1,768.3	1,768.8
Household customers	0.0	12,800.0	12,800.0

Table 113: 2018 network structure figures according to the TSO and DSO survey– as at 31 December 2019

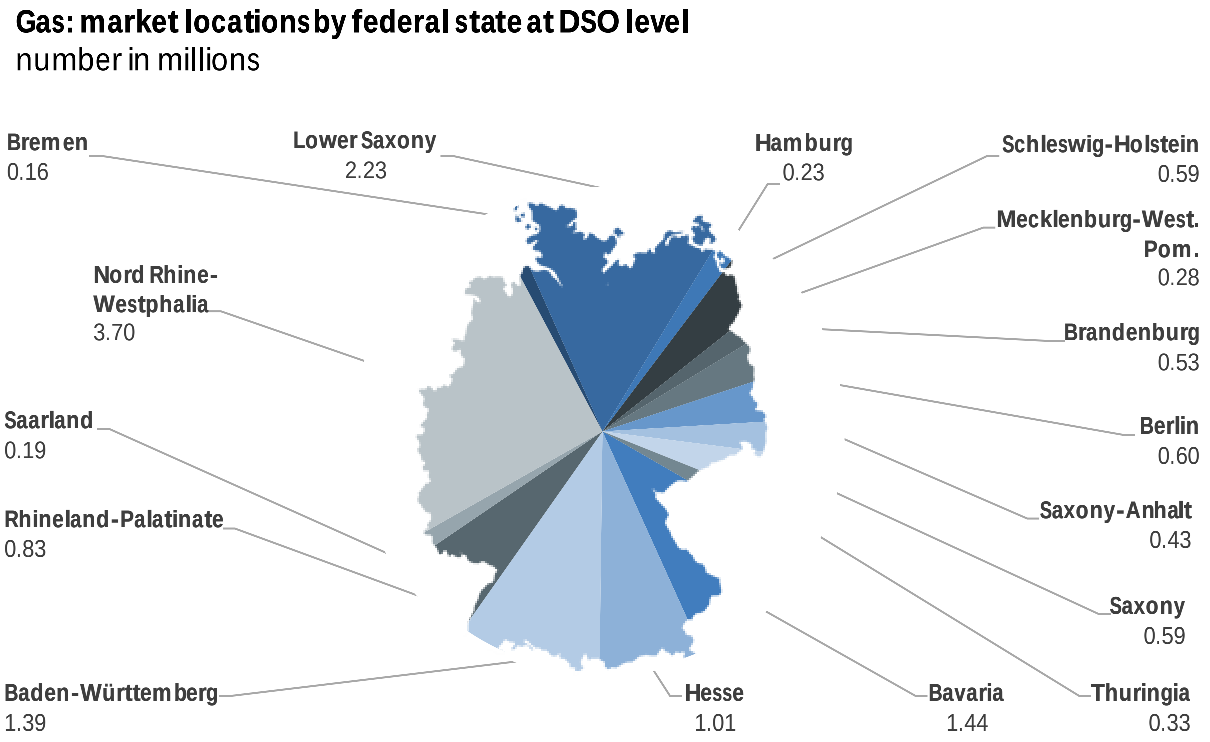


Figure 144: Market locations by federal state at DSO level as stated in the DSO survey – as at 31 December 2019

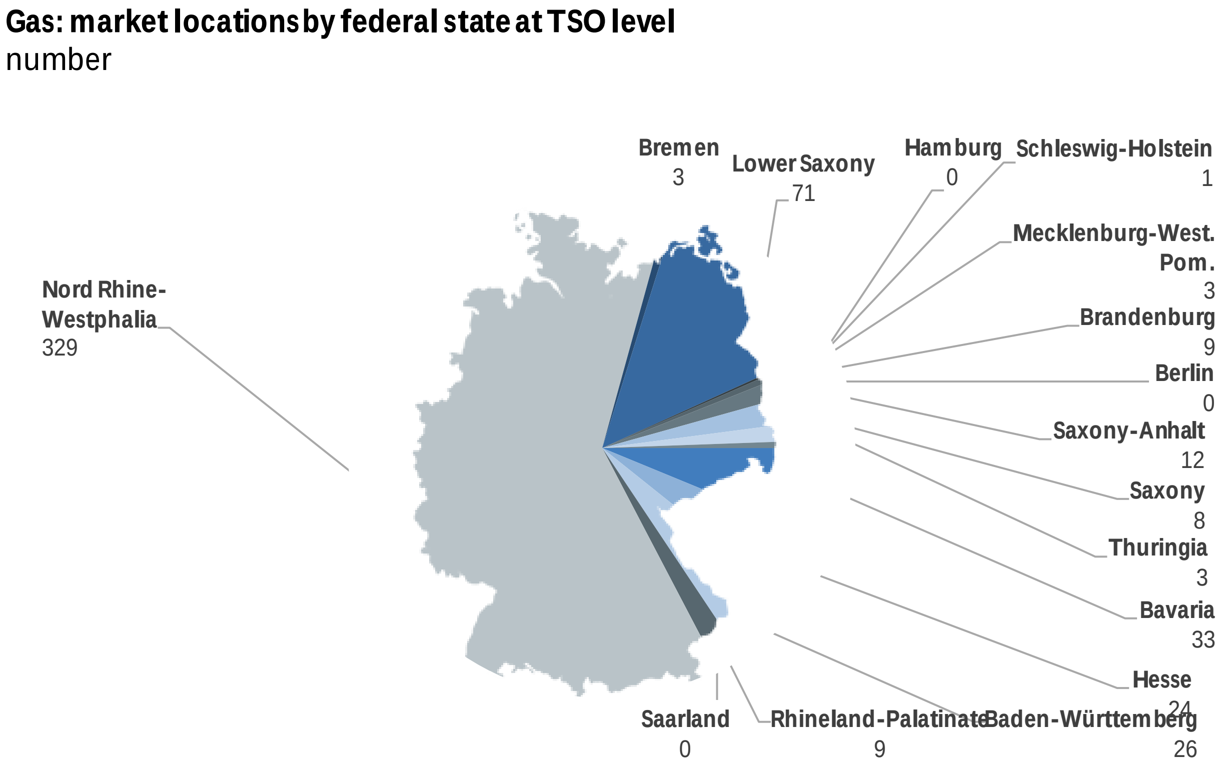


Figure 145: Market locations by federal state at TSO level as stated in the TSO survey – as at 31 December 2019

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 2019.

Gas: exit volumes in 2019 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%	336.6	44.0%
> 300 MWh/year 10,000 MWh/year	0.5	0.3%	128.4	16.8%
> 10,000 MWh/year 100,000 MWh/year	5.9	3.2%	111.0	14.5%
> 100,000 MWh/year	137.9	73.8%	131.8	17.2%
Gas power plants with 10 MW net nominal capacity	42.5	22.7%	56.7	7.4%
Total	186.9	100%	764.5	100%

Table 114: Gas exit volumes in 2019 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 2019. Once again, gas TSOs and DSOs were asked in the 2020 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 78.9 TWh (2018: 72.5 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 42.4 TWh, compared with 39.8 TWh in 2018, corresponding to a share of approximately 5% of the DSOs' total gas supplies.

The difference between the 2019 exit volumes of the system operators, 948 TWh (2018: 928.1 TWh), and the gas delivered by gas suppliers, 857.7 TWh (2018: 817.6 TWh) is approximately equivalent to the amount of gas procured directly on the market without using a supplier (121.3 TWh).[131]

[131] 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 2019, according to the survey of gas TSOs and DSOs, broken down by final customer category

	TSO and DSO exit volume (TWh)	Share of total amount	Total volume delivered by suppliers (TWh)	Share of total amount
300 MWh/year	336.7	35.4%	320.2	37.1%
> 300 MWh/year 10,000 MWh/year	128.9	13.5%	114.0	13.2%
> 10,000 MWh/year 100,000 MWh/year	116.9	12.3%	89.4	10.4%
> 100,000 MWh/year	269.7	28.3%	261.1	30.3%
Gas power plants with 10 MW net nominal capacity	99.2	10.4%	77.4	9.0%
Total	951.4	100.0%	862.1	100.0%

Table 115: Total gas exit volumes in 2019, 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 rose in 2019 by about 19.9 TWh or just over 2.1% year-on-year to 948 TWh. The quantity of gas supplied to household customers (as defined in section 3 para 22 EnWG) rose by just over 2.7% to 282.5 TWh (2018: 275.2 TWh). Gas supplies to gas-fired power stations with a nominal capacity of at least 10 MW increased by about 12% to 98.5 TWh (2018: 87.8 TWh).

The structure of the gas retail market remained for the most part unchanged. There is a total of about 6,100 entry points to the gas distribution networks, of which 226 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 14.6m market locations supplied by the DSOs in Germany, some 45% (6.4m), accounting for just over 43% (332.6 TWh) of the total gas supplies, are served by DSOs that supply more than 100,000 customers. The majority (about 62%) of DSOs active in Germany supply between 1,000 and 10,000 gas customers.

Gas: DSOs by number of market locations supplied
number and share

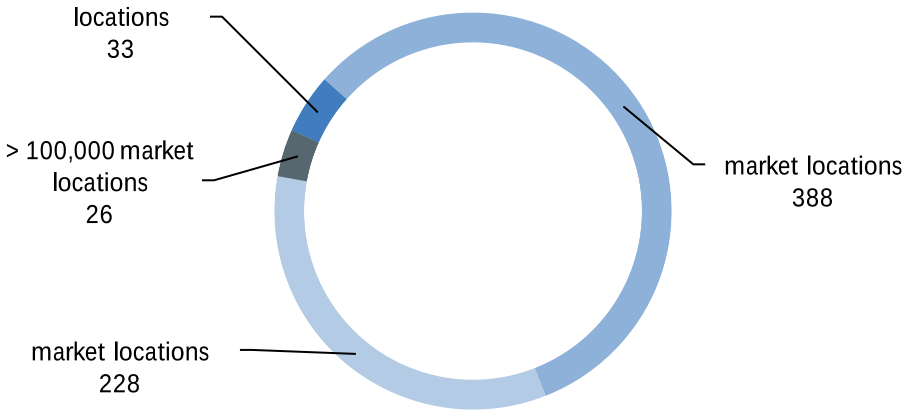


Figure 146: DSOs by number of market locations supplied as stated in the DSO survey – as at 31 December 2019

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 because they represent the extent to which demand in the relevant market was actually satisfied by one company during the reference period.[132] 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 including the Haidach and 7Fields storage facilities in Austria.[133] 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

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

[133] 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.

alternatives but ultimately left open the exact market definition.[134] 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 25 legal entities. The Bundeskartellamt calculates the market shares in this market on the basis of storage capacities (maximum usable working gas volume).[135] Companies were attributed to a group according to the dominance method (cf. the methodological notes in section I Electricity market I.3 „Market Concentration", p. 38).

The market for the operation of underground natural gas storage facilities is highly concentrated; concentration eased continuously but minimally compared to the previous years. 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 291.6 TWh on 31 December 2019 (in 2018: 296.4 TWh). On 31 December 2019, the aggregate working gas volume of the three companies with the largest storage capacities amounted to approx. 194.2 TWh (2018: 198.9 TWh). The CR3 value was around 66.6% and was only slightly lower than in the previous year (CR3 value: 67.1%).

Gas: development of working gas volume in natural gas storage facililties in TWh and the share of the three largest suppliers

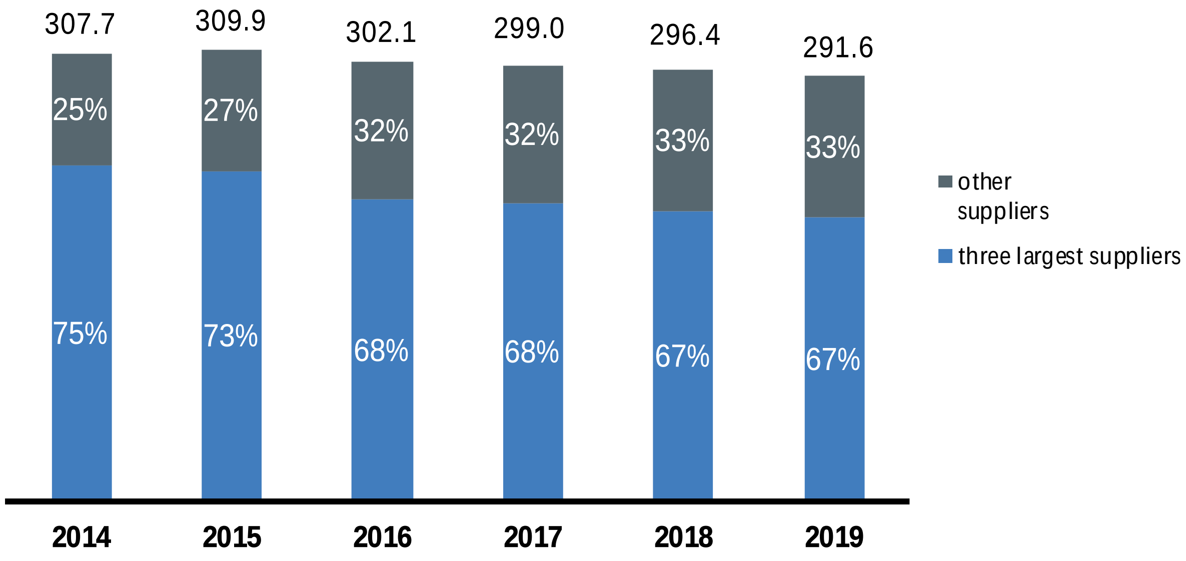


Figure 147: Development of the working gas volume of natural gas storage facilities and the share of volume of the three largest suppliers

3.2 Gas retail markets

On the gas retail markets the Bundeskartellamt differentiates between interval-metered customers and standard load profile customers. Interval-metered customers are those whose gas consumption is determined on the basis of a metered load profile. 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

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[134] Cf. COMP/M.6910 – Gazprom/Wintershall of 3. December 2013, para. 30 ff.

[135] Cf. Bundeskartellamt, decision of 23 October 2014, B8-69/14 – EWE/VNG, para. 236 ff.

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 interval-metered customers and the market for the supply of gas to standard load profile customers under special contracts as national markets (see the comments in the „Market concentration" chapter for Electricity retail markets from p. 43). 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.[136]

In energy monitoring the sales volumes of the individual suppliers (legal entities) are collected as national total values [137]. 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 970 gas suppliers (legal entities) (993 in the previous year). In 2019 these companies sold a total of 360.1 TWh of gas to standard load profile customers in Germany (2018: 367.8 TWh[138]) and 501.4 TWh of gas to interval-metered customers (2018: 455.4 TWh[139]). Of the total volume of sales to standard load profile customers, special contracts accounted for approx. 308.8 TWh (2018: 313.7 TWh) and default supply contracts for 51.3 TWh (2018: 54 TWh).

Sales volumes were attributed to company groups on the basis of the dominance method which provides sufficiently accurate results for the purposes of energy monitoring and in particular allows for year-on-year comparisons on a homogenous and ongoing calculation basis (cf. methodological notes in section I Electricity market, "Market Concentration" section, p. 38).

The Monitoring Report analyses the market concentration of the four strongest companies (CR4) on the gas retail market. Their cumulative sales to standard load profile customers amounted to around 85.7 TWh in 2019, of which approx. 73.2 TWh were accounted for by special contracts. Cumulative sales to interval-metered customers were around 145 TWh. The cumulative market share of the four largest companies in 2019 was around 24% for standard load profile customers (2018: CR4: 23%) and 29% for interval-metered customers (2018: CR4: 31%). Both market shares continue to be significantly below the statutory thresholds for the presumption of market dominance (Section 18(6) GWB). There was again only a slight change in the market concentration in relation to the four strongest companies supplying gas to standard load profile customers and interval-metered customers.[140]

[136] Cf. Bundeskartellamt, decision of 23 December 2014, B8-69/14 – EWE/VNG, para. 129-214.

[137] 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.

[138] Previous year's figure corrected due to changes in the information provided by the suppliers.

[139] Previous year's figure corrected due to changes in the information provided by the suppliers. Increase of 46 TWh in the volume of gas sold to interval-metered customers in 2019 results inter alia from the data supplied by a supplier which alone sold 34.5 TWh of gas to interval metered customers and which had not transmitted any volumes in the previous year.

[140] With regard to the percentage shares provided it should be noted that the monitoring survey among the gas suppliers covers a large proportion but not the whole of the market. The percentages consequently merely approximate the actual values.

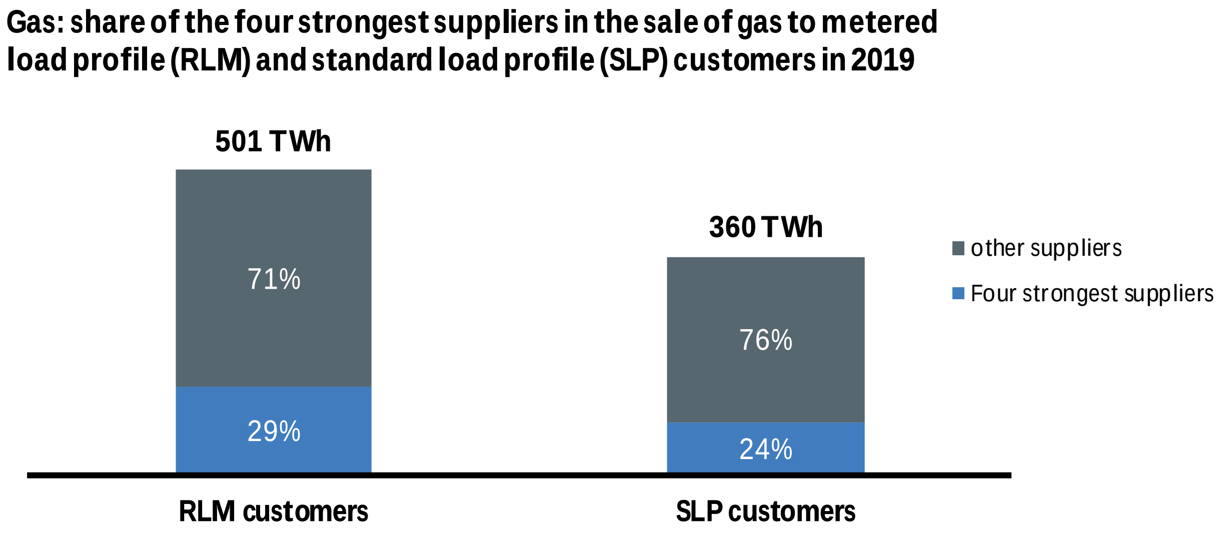


Figure 148: Share of the four strongest suppliers in the sale of gas to interval-metered customers and standard load profile customers in 2019

B Gas supplies

1. Production of natural gas in Germany

In 2019, natural gas production in Germany fell by 0.2bn m³ to 6bn m³ of gas (with calorific adjustment).[141] This corresponds to a decrease of 3.8% compared to 2018. The decline in production is chiefly due to the increasing exhaustion of the large deposits and the resulting natural decline in output.[142] Another factor is the lack of major new gas finds.

The reserves-to-production ratio of proven and probable natural gas reserves was 7.0 years as at 1 January 2020. It was calculated on the basis of the previous year's proven and probable reserves and last year's production of gas without calorific adjustment. 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.[143]

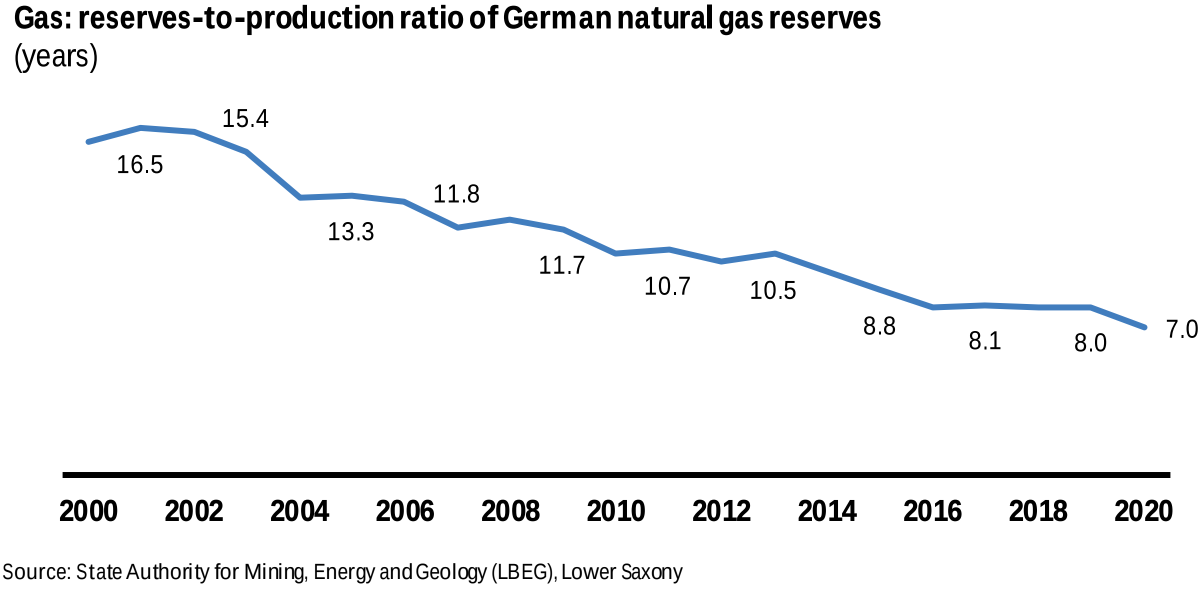


Figure 149: Reserves-to-production ratio of German natural gas reserves since 2000

[141] 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 between 2 and 12 kWh/m³).

[142] Source: Annual report "Erdöl- und Erdgasreserven in der Bundesrepublik Deutschland am 1. Januar 2020" [Crude Oil and Natural Gas Reserves in the Federal Republic of Germany as at 1 January 2020]; State Authority for Mining, Energy and Geology (LBEG), Lower Saxony.

[143] Ibid.

2. Natural gas imports and exports

Just over 68% of gas imported into Germany comes from Russia and the Commonwealth of Independent States (CIS). Imports from Russia (including CIS) fell about 0.1% year-on-year, while imports from the Netherlands rose.

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).

The total volume of natural gas imported into Germany in 2019 was 1,703 TWh. Based on the previous year's figure of 1,760 TWh, imports to Germany were down by 57 TWh, representing a decrease of just over 3%. 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 rose by just over 18%, while imports from Russia through the Nord Stream pipeline were down 0.1%.

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.

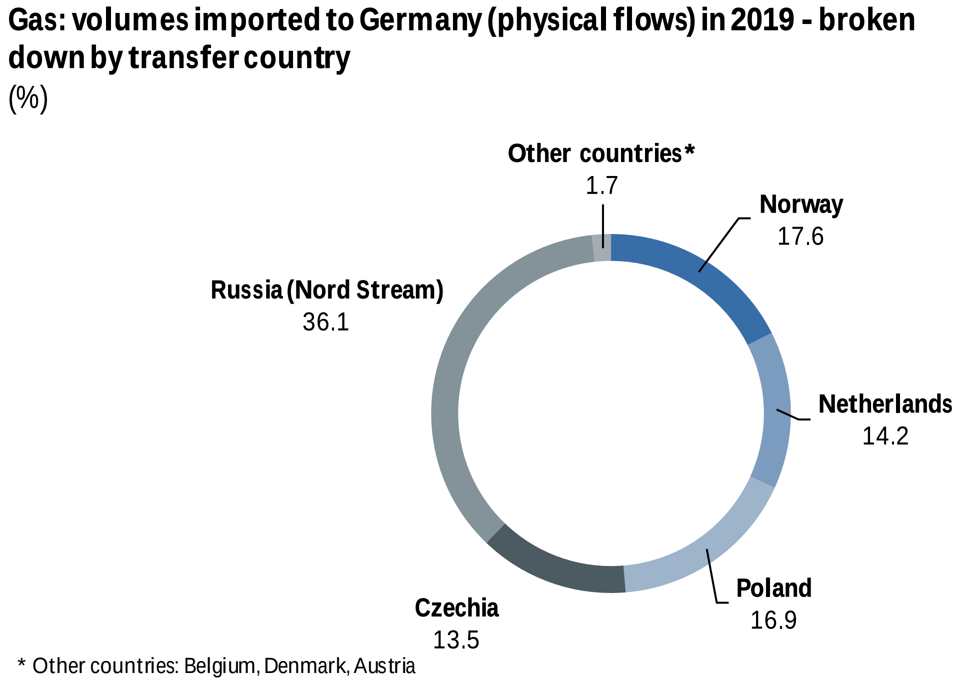


Figure 150: Gas volumes imported to Germany in 2019 by exporting country

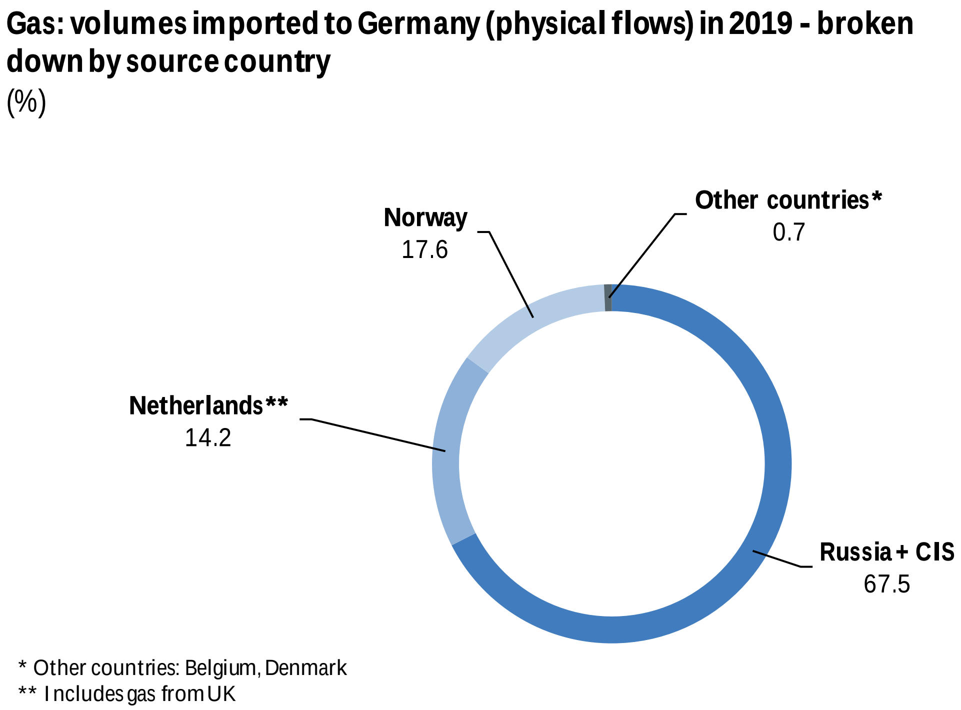
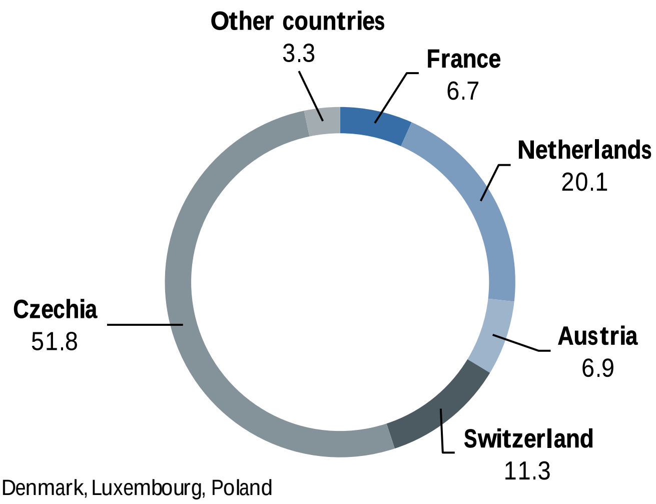


Figure 151: Gas volumes imported to Germany in 2019 by source country

In 2019, the total volume of natural gas exported by Germany was 702 TWh. Based on the previous year's figure of 849 TWh, exports from Germany fell by 148 TWh. 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 52% (2018: 48%) of German natural gas exports went to Czechia, a drop of 11% compared to the previous year's figure. There was a large decrease of 90% in exports to Denmark. Although this was a significant change from the year before, such developments are not unusual as part of market activity. There was also a drop of 54% in exports to France, primarily because the amount of gas imported by that country depends on the availability of its nuclear power plants. Exports to Austria, meanwhile, were up 1.5%.

Gas: volumes exported from Germany (physical flows) in 2019 - broken down by transfer country
(%)



* Other countries: Belgium, Denmark, Luxembourg, Poland

Figure 152: Gas volumes exported by Germany in 2019 by 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 2019 and 2018.

Gas: changes in imports (physical flows)

	Imports 2019 (TWh)	Imports 2018 (TWh)	Year-on-year change (TWh)	Year-on-year change (%)
Russia (Nord Stream)	613.9	614.6	-0.7	-0.1
Poland	287.5	313.5	-26.0	-8.3
Norway	300.2	255.0	45.2	17.7
Netherlands	241.7	221.5	20.2	9.1
Czechia	230.1	297.4	-67.3	-22.6
Austria	17.4	35.1	-17.7	-50.4
Belgium	9.3	16.8	-7.5	-44.6
Denmark	2.5	6.0	-3.5	-58.3
Total	1,702.6	1,759.9	-57.3	-3.3

Table 116: Changes in gas imports between 2019 and 2018

Gas: changes in exports (physical flows)

Importing country	Exports 2019 (TWh)	Exports 2018 (TWh)	Year-on-year change (TWh)	Year-on-year change (%)
Czechia	362.9	408.8	-45.9	-11.2
Netherlands	140.9	156.8	-15.9	-10.1
Switzerland	79.4	81.3	-1.9	-2.3
Austria	48.2	47.5	0.7	1.5
France	46.7	102.4	-55.7	-54.4
Belgium	17.6	43.8	-26.2	-59.8
Poland	4.1	4.7	-0.6	-12.0
Luxembourg	1.2	2.9	-1.7	-57.9
Denmark	0.1	1.0	-0.9	-90.4
Total	701.1	849.1	-148.0	-17.4

Table 117: Changes in gas exports between 2019 and 2018

3. Market area conversion

Over the next few years, gas supplies in north-western Germany will continue to be converted from L-gas to H-gas. A total of nearly 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 balancing charge. In 2019 this charge amounted to €0.3181 kWh/h/a. As a result of the increasing numbers of areas being converted, the charge for 2020 rose to €0.5790 kWh/h/a. In 2021, the charge will increase to €0.7291 kWh/h/a due to the increase in the number of appliances to be converted. Apart from this, there is no impact on the gas bills of individual customers. Crucially, it is not allowed to charge consumers for hours worked or for materials needed for the technical adjustment of appliances. Rather, the network operators bear the costs and then get them reimbursed from the charge.

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. Information on any subsidies that may be available is 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 significant amounts of gas will be exported from the Netherlands to Germany anymore 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 structure of natural gas supply will affect more than four million household, commercial and industrial gas customers that have an estimated 4.9m appliances burning gaseous fuels. All of these appliances must gradually be converted from L-gas to H-gas.

The conversion of German L-gas networks to H-gas got off to a good start 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.

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 4,255 conversions will have been carried out for interval-metered customers and 2,228,722 for standard load profile (SLP) customers.

There will still be conversions left for 2,081,238 SLP customers and 4,067 interval-metered customers in the period after 2024.

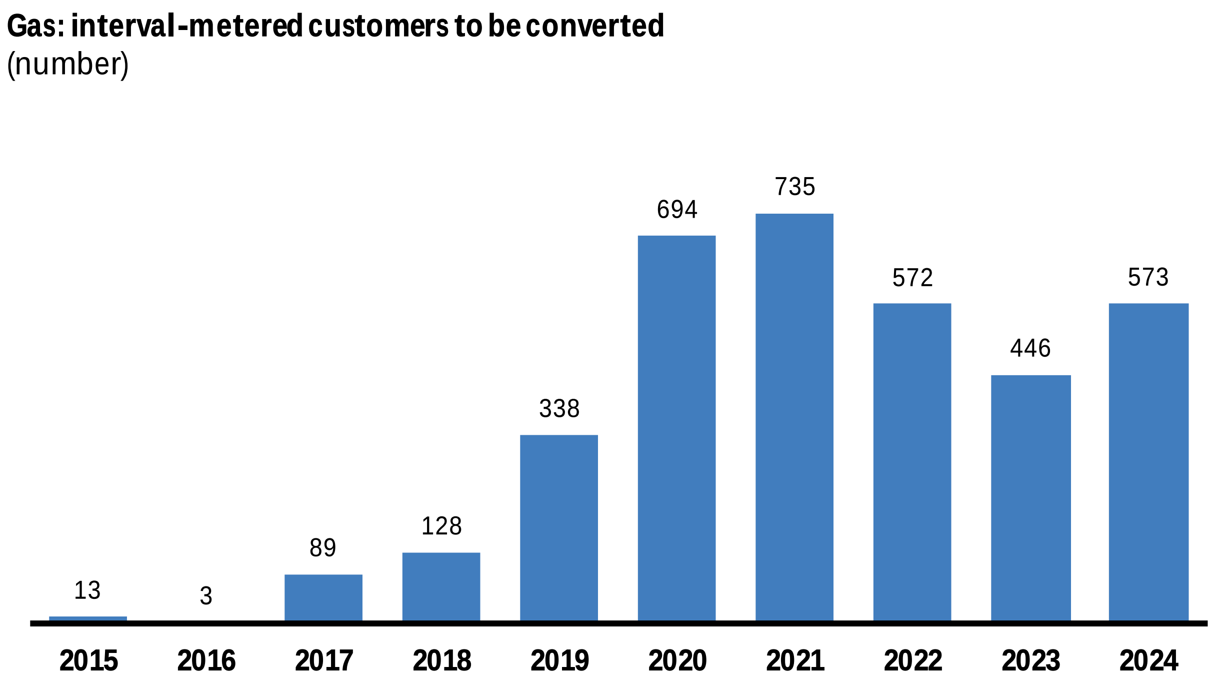


Figure 153: Interval-metered customers to be converted by 2024

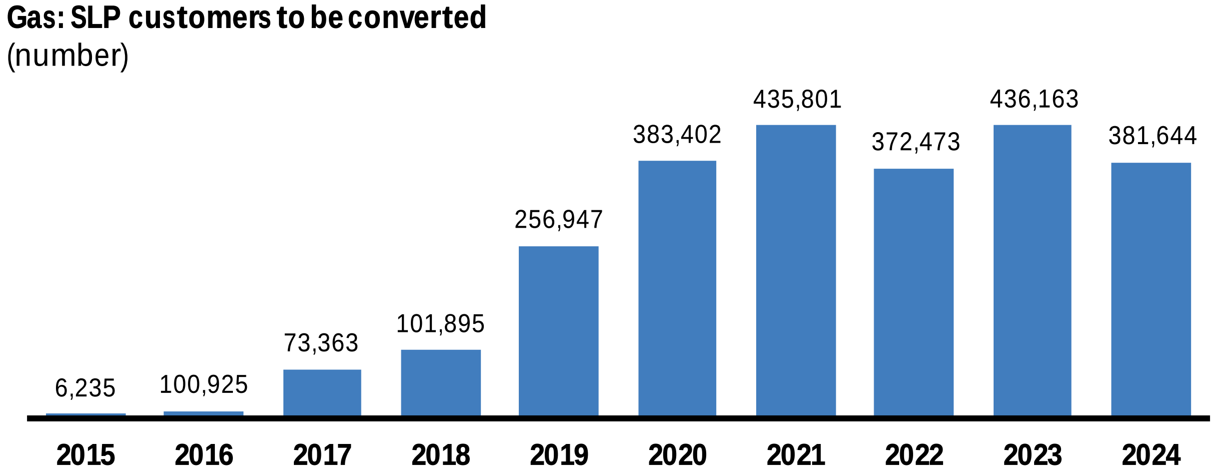


Figure 154: SLP customers to be converted by 2024

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 appliances are inspected again 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 41 active companies, up from 40 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 2019.

Gas: bids and awards for individual task packages for the market area conversion
bids and awards for individual task packages for the market area conversion

Tasks package	Bids			Awards		
	2017	2018	2019	2017	2018	2019
Appliance registration	7.1	7.3	7.3	3.8	2.6	3.3
Monitoring the registration process	5.2	4.5	4.0	1.2	1.0	1.0
Conversion and appliance adjustments	7.0	7.4	7.3	3.7	2.6	3.3
Inspection of conversions and adjustments	5.2	4.6	4.5	1.5	1.0	1.0
Project management	4.2	4.4	3.8	1.1	1.0	1.0

Table 118: Comparison of bids and awards for individual task packages for the market area conversion, 2016 to 2019

From a total of 30 network operators, 485,371 appliances were registered in 2019, of which 226,318 were condensing boilers (46.6%) and 56,801 self-adaptive appliances (11.7%). The proportion of condensing boilers had been 43.8% in 2018 and that of self-adaptive appliances 7.8%. During the reporting period, 266,530 appliances were adapted for SLP customers and 527 for interval-metered customers. A total of 5,798 appliances that were to be adapted could not be, a proportion of 2.2% (2018: 1.7%). A total of 1,523 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 (2018: 1210). There was a clear increase in the number of customers making use of the reimbursement granted under the Gas Appliance Reimbursement Ordinance (GasGKErstV): 193 compared to 19 the year before.

The market area conversion did not escape the effects of the coronavirus pandemic in 2020. The annual Market Area Conversion Forum, which was supposed to have been held for the fifth time, had to be cancelled due to anti-infection measures. Although there were initially plans to move it to autumn/winter 2020, this was ultimately not possible for the same reasons.

In particular, the pandemic directly impacted the individual stages of the market area conversion. At first, employees of the network operators or companies contracted by them had difficulty gaining access to the households of some people, who felt uncertain about the situation. At the same time, some network operators decided for reasons of civic responsibility and duty of care towards their own staff to suspend conversion activities for a time. However, neither this break nor the refused entries by some residents led to noticeable delays in the overall process. In fact, once the initial difficulties were over, the fact that more people were working from home actually made it easier to make contact with them. With the support of the industry associations DVGW and BDEW, as well as all the network operators involved, the Bundesnetzagentur established a coordinated process that ultimately enabled 99% of the planned conversions to take place in 2020. This close cooperation shows the willingness of the whole sector to make the project, which is the most important one currently facing the gas industry, a success.

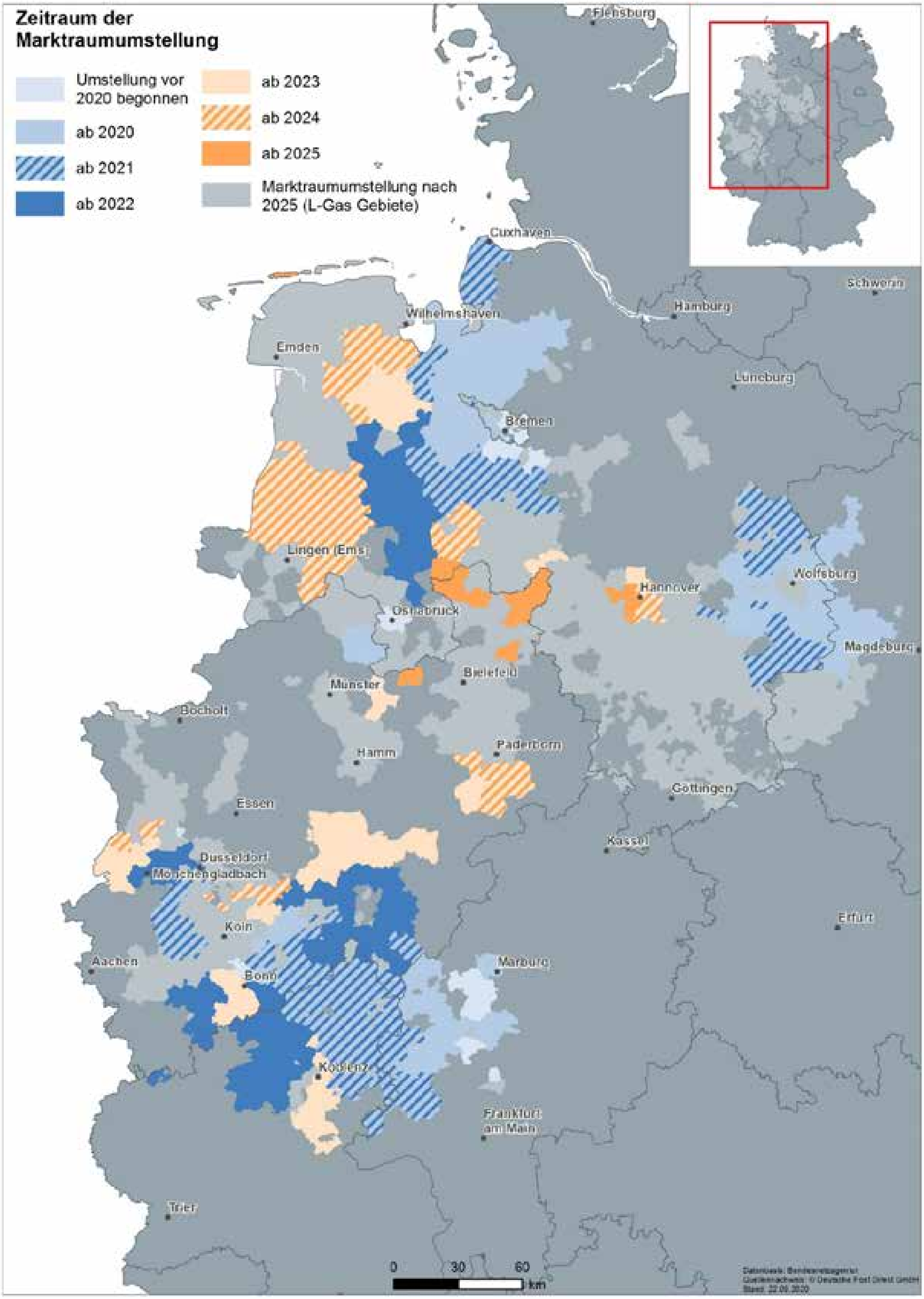


Figure 155: Market area conversion in individual network areas over the coming years

According to data submitted by the two market area managers, NetConnect Germany GmbH & Co. KG and GASPOOL Balancing Services GmbH, a total of €729m was spent on the market area conversion charge referred to in section 19a EnWG between 2015, when the charge was first levied, and 2021 (planning costs for 2021 are included). In 2019 this charge amounted to €0.3181 kWh/h/a nationwide. As a result of the increasing numbers of areas being converted, the charge for 2020 rose to €0.5790 kWh/h/a. In 2021, the charge will increase to €0.7291 kWh/h/a due to the further increase in the number of appliances to be converted. Another reason for the rise is that, due to the determinations BK9-18/610-NCG and BK9-18/611-GP, since 2020 the charge has not been levied at interconnection points to other market areas or storage points. Over the course of the next few years in particular, the market area conversion charge is expected to rise further as a result of the growing number of adjustments to appliances being carried out.

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 number of appliances being converted each year will plateau at about 550,000 in the coming years.

4. Biogas (including synthesis gas)

As at 31 December 2019, key biogas injection figures within the meaning of section 3 para 10c EnWG were as follows:

Gas: biogas injection key figures in 2019

	Injection, contractually agreed (million kWh/h)	Injection (million kWh/a)	Number of plants
Biomethane	2.293	9,348.0	199
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]	0.003	2.9	6
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	0.042	0.7	2
Other (gas from biomass, landfill gas, sewage treatment plant gas and mine gas)	0.028	400.0	20
Total	2.366	9,751.6	227

[1] within the meaning of Directive 2009/28/EC (OJ L 140, 5 June 2009, p. 16)

Table 119: Biogas injection key figures for 2019

The costs for biogas passed on by gas network operators to all network users amounted to about €203m in 2019. That was the equivalent of about €0.0208 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 2020 monitoring survey. On 31 December 2019 the maximum usable working gas volume in these storage facilities was 275.27 TWh.[144] Of this, 135.63 TWh was accounted for by cavern storage, 117.54 TWh by pore storage 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 (252.14 TWh, compared to 23.13 TWh for L-gas).

[144] In diesem Wert sind die in Österreich gelegenen Speicher 7 Fields und Haidach (letzterer nur anteilig) enthalten, da sie direkt an das deutsche Gasnetz angeschlossen sind und somit Auswirkungen auf das deutsche Netz haben. Entsprechend werden in Deutschland gelegene, aber nur an das niederländische Netz angeschlossene Speicher nicht berücksichtigt, da sie keine unmittelbaren Auswirkungen auf das deutsche Gasnetz haben.

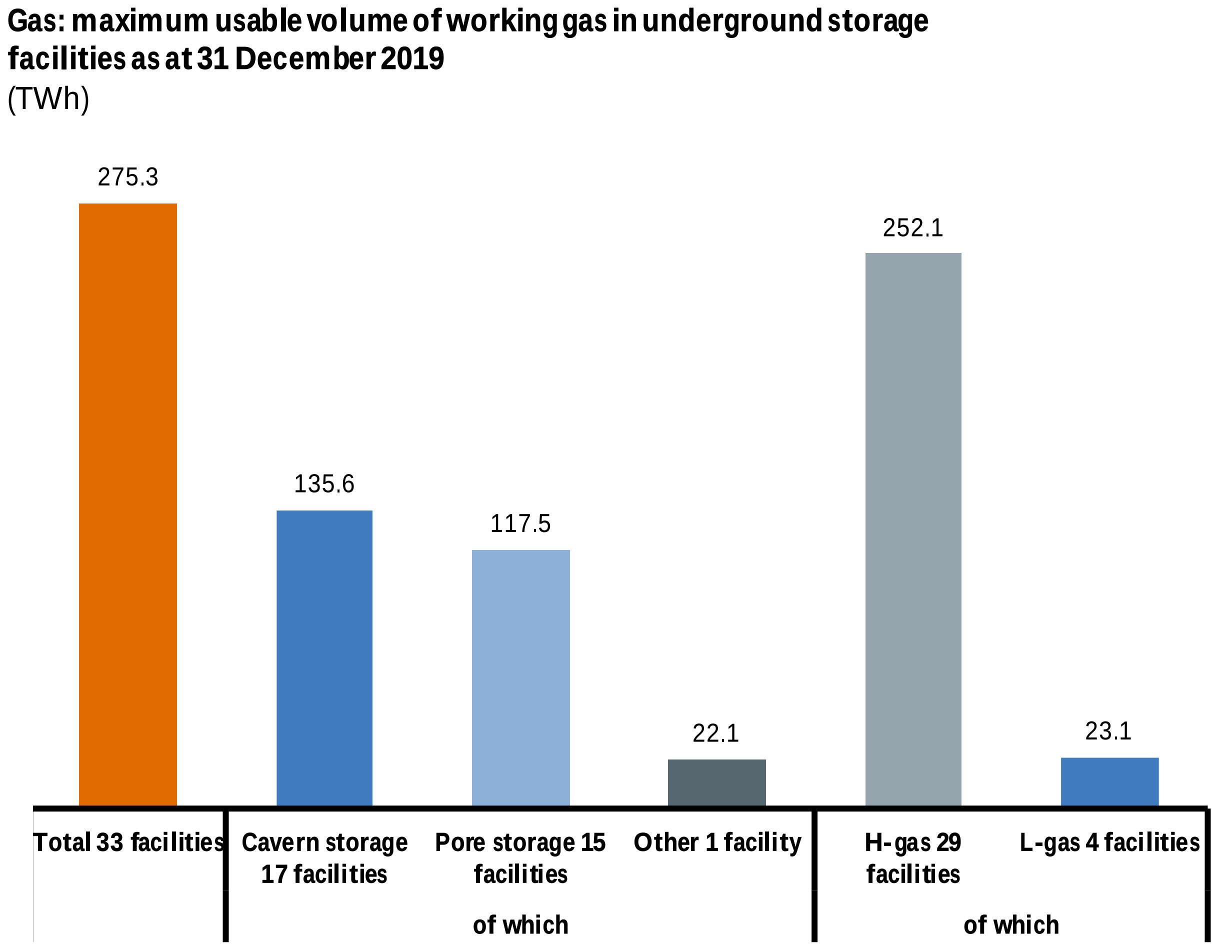


Figure 156: Maximum usable volume of working gas in underground natural gas storage facilities as at 31 December 2019

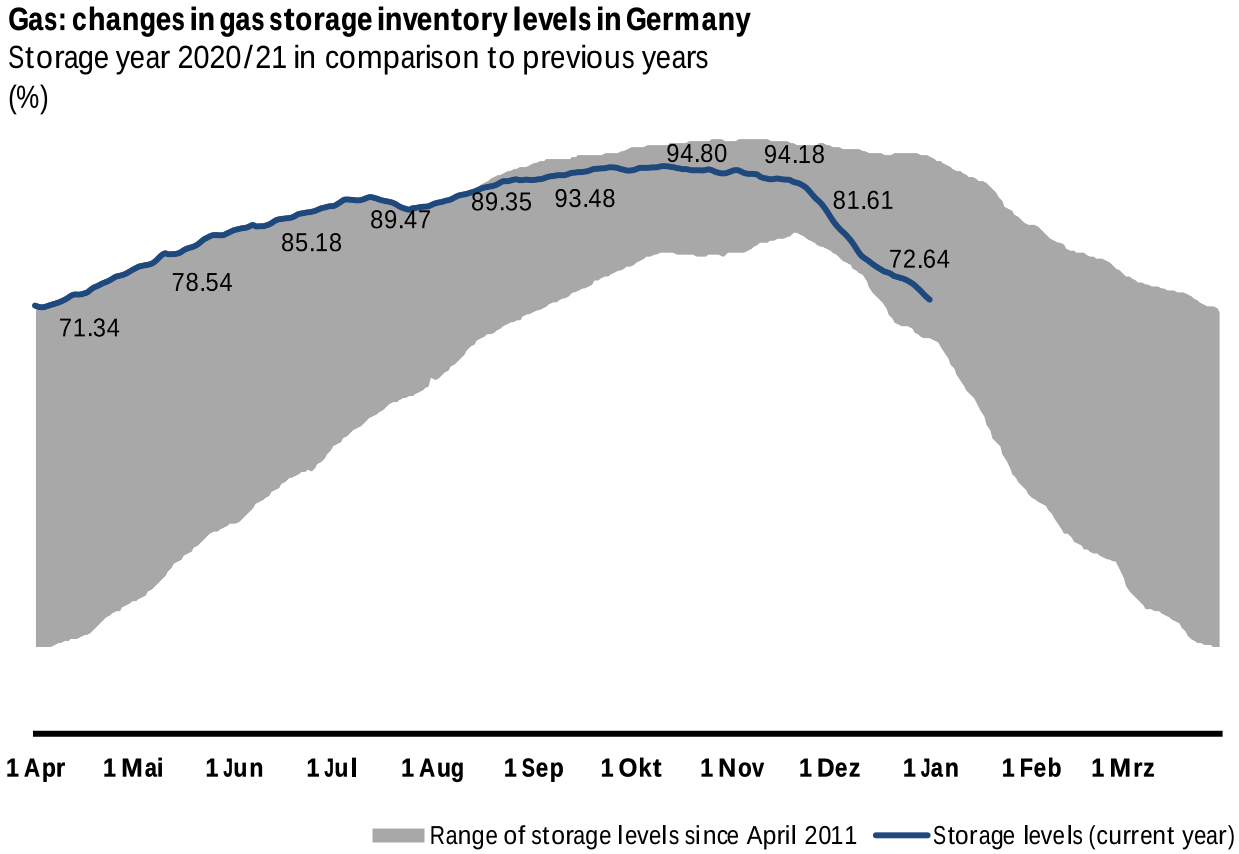


Figure 157: Changes in gas storage inventory levels in Germany – as at 1 January 2021

On 1 January 2021, the total storage level stood at around 73%.

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 273.86 TWh in 2019 (compared to 278.62 TWh in 2018). The total injection capacity was 154.30 GWh/h and the withdrawal capacity was 292.12 GWh/h.

5.3 Use of underground storage facili

Of the 24 storage facility operators, 22 of them answered the question about the use of their storage facility by integrated undertakings within the meaning of section 3 para 38 EnWG. The range of their answers went from no use by integrated undertakings to 100% use by them. Overall, about 64% of storage volume (around 166.6 TWh) of the 22 operators that responded was booked by integrated undertakings. For more than half of the storage facility operators that responded (13 of them), the booking rate by integrated undertakings was over 75% (corresponding to 138.4 TWh in total).

According to the data provided by 24 companies, the average number of storage customers remained 5.3 in 2019, (6.1 in 2015, 5.8 in 2016, 5.9 in 2017 and 5.3 in 2018). 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	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1	8	8	7	9	8	10	11	9	10	11
2	2	2	3	3	4	2	2	2	4	2
3 - 9	7	6	7	7	5	4	6	6	4	6
10 - 15	2	1	2	2	3	3	1	3	4	3
16 - 20	1	1	1	2	1	1	2	3	2	1
> 20	0	1	1	1	2	2	2	0	0	1

Table 120: 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 2019 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 2015 to 2019
(TWh)

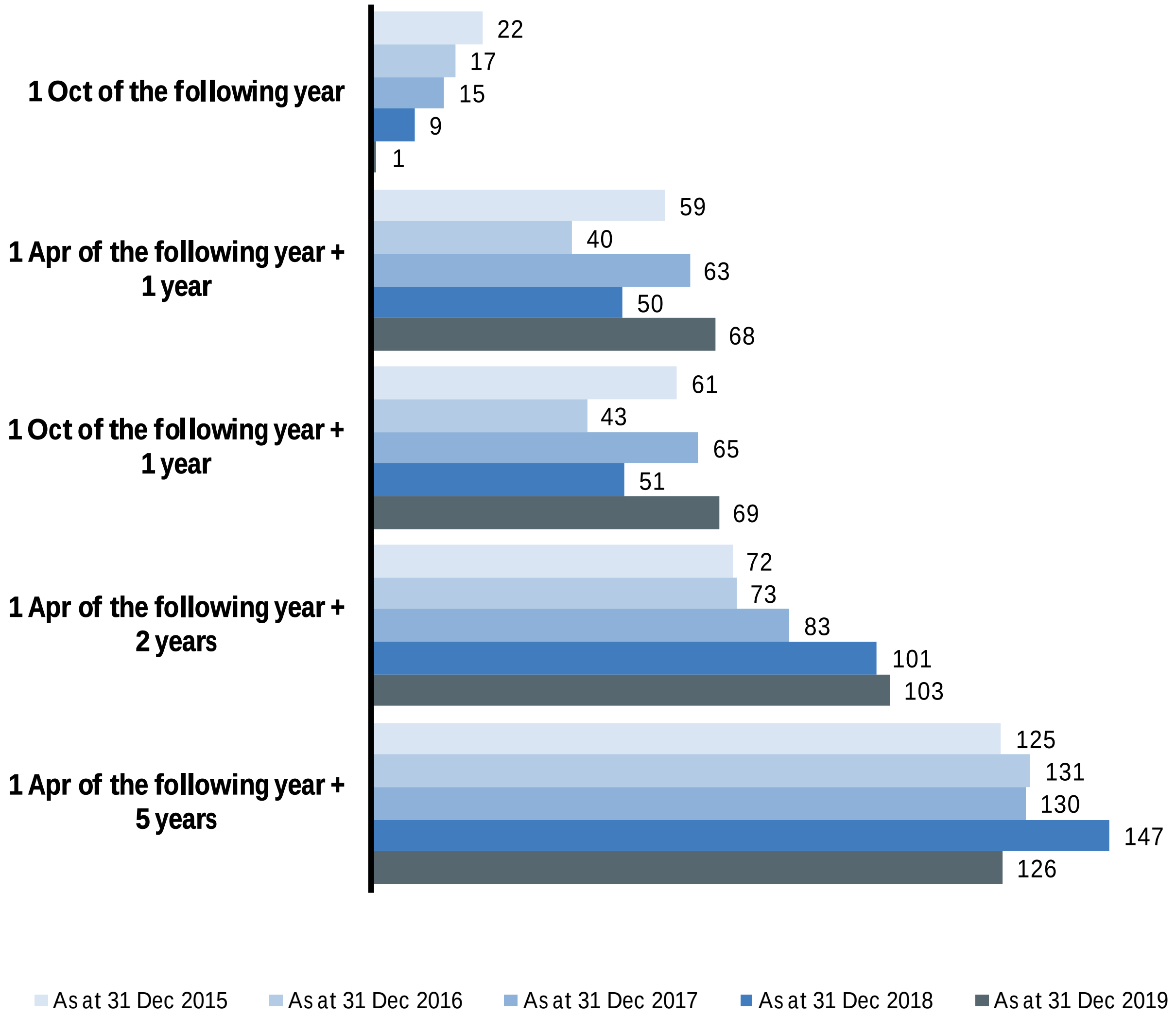


Figure 158: Changes in the freely bookable working gas capacity in the subsequent periods

Short-term (up to 1 October 2019) freely bookable working gas capacity saw a significant decline in volume, whereas there was an increase in the capacity still bookable for 2021. As for the longer term, the volume of medium-term bookable working gas rose again but the volume of long-term working gas declined.

C Networks

1. Network expansion

1.1 Gas Network Development Plan

The gas network development plan (Gas NDP) is used to determine 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 Gas NDP focuses 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. It also looks at connections between the German gas transmission network and those in neighbouring European countries and at capacity needs in the downstream networks. The TSOs used the Gas NDP 2020-2030 as a transparency platform to describe pipeline projects for hydrogen transportation, the first time the document has been used for this purpose. However, on the basis of the current legal framework, projects exclusively involving hydrogen are not subject to regulation and are therefore not included in the mandatory part of the Gas Network Development Plan.

On 1 July 2020, the TSOs submitted their draft Gas NDP 2020-2030 to the Bundesnetzagentur. Essentially, the measures in the Gas NDP 2018-2028 are confirmed by the modelling results of the Gas NDP 2020-2030. In addition, looking ahead to 2030, the TSOs propose a further 54 expansion measures for the natural gas network with an investment volume of €2.2bn.

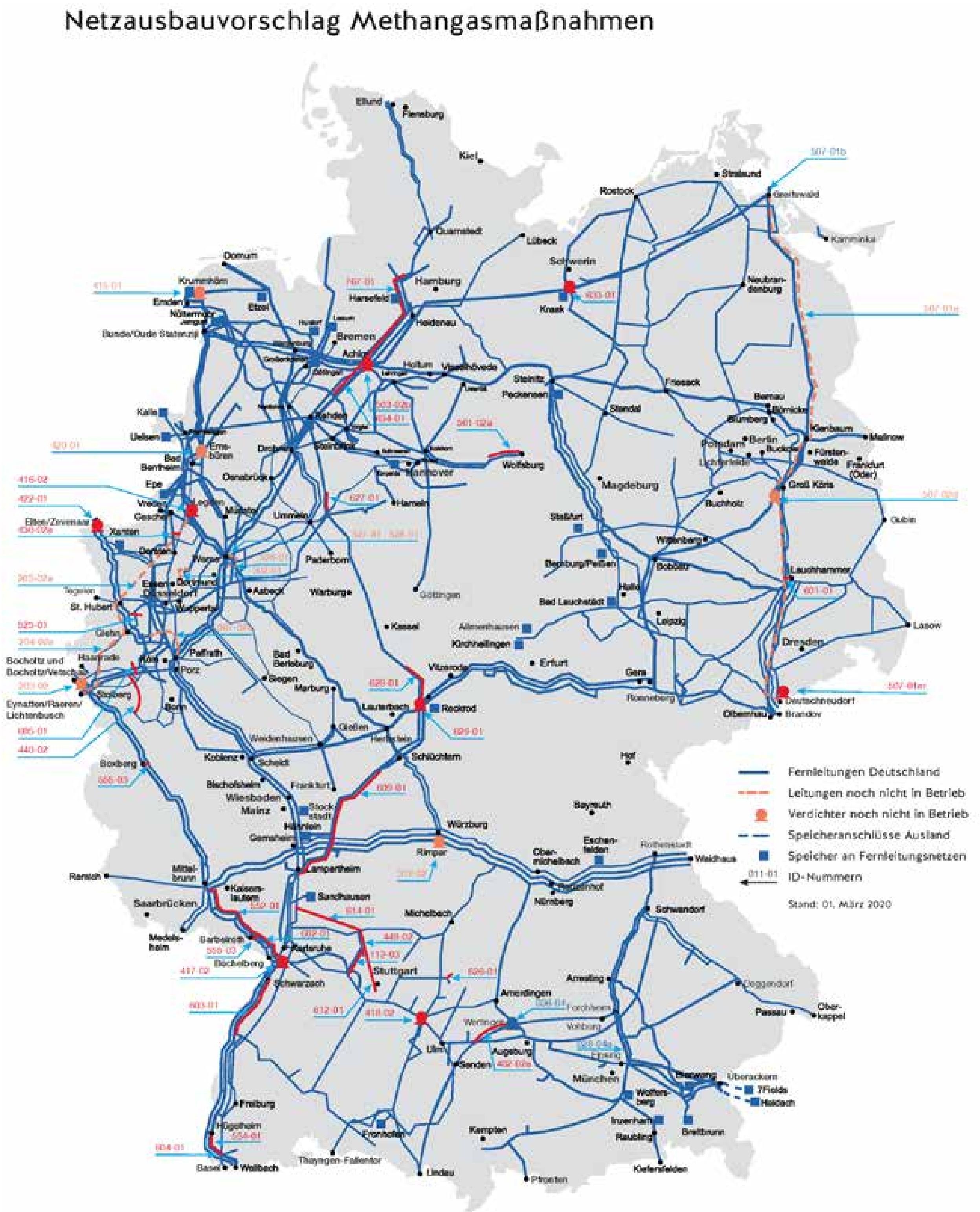


Figure 159: Expansion measures for the natural gas network according to the TSOs' expansion proposal for the Gas NDP 2020-2030 (source: Association of Transmission System Operators for Gas e.V. (FNB Gas))

Expansion measures creating access for three of the terminals for liquefied natural gas (LNG) located on the German North Sea coast will make it possible to import LNG volumes directly into the German transmission system. Integrating the LNG terminals into the transmission system makes it possible to import gas from various different supply sources. This contributes to increasing security of supply and may exert price pressure on traditional importers.

The Gas NDP 2020-2030 also includes several network expansion measures aimed at, among other things, increasing the transfer of gas volumes into the terranets bw network as well as transporting gas volumes to supply final customers in Baden-Württemberg. It is likely that this trend will continue, in particular due to increased demand from gas-fired power plants and downstream distribution system operators.

The Gas NDP 2020-2030 also addresses the merger of the currently separate market areas NetConnect Germany 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. The existing market areas currently exchange only relatively small volumes of gas, which means that market area interconnection points will become bottlenecks for transport in the joint market area. In order to resolve these bottlenecks, the TSOs propose, among other things, using network- and market-based instruments (MBIs). For this reason, the draft document on the Gas NDP 2020-2030 for the first time compares the costs of using MBIs and network expansion measures to resolve network bottlenecks. In the average scenario, the forecasted costs relating to the use of MBIs increase from €0.6m in the 2021/2022 gas year to €5.8m in the 2025/2026 gas year. As no notable physical network expansion can be achieved with costs on a comparable scale, the TSOs do not propose further measures to reduce MBI costs in the Gas NDP 2020-2030.

The TSOs' proposal for the expansion of the natural gas transport system includes the expansion of transmission pipelines (approximate length 1.594 km) and the expansion of compressor stations (approximate capacity 405 MW). Compared to the previous expansion proposal included in the Gas NDP 2018-2028, total investment costs for natural gas infrastructure have risen slightly from €7.0bn to €7.8bn.

For the first time in the NDP process, the TSOs are also considering hydrogen and synthetic natural gas (SNG), so-called green gases. A market survey was undertaken, where companies and project managers reported 31 green gas projects for which concrete implementation plans had been made. In order to ensure the presence of hydrogen inputs (sources) and offtakes (sinks) in a potential hydrogen network, it was examined whether at the time of the survey – using minor expansion measures, if necessary – natural gas pipelines can be separated out from the transmission network or it is necessary to construct new hydrogen pipelines. The modelling established that 24 measures to convert pipeline systems currently used for natural gas transport, nine minor measures within the natural gas system facilitating the conversion of larger transport pipelines and 14 measures to build new hydrogen pipelines would enable 22 green gas projects to be connected to form a hydrogen network. For nine projects it was found that connection was economically unviable due to a lack of potential for conversion and their long distance from the rest of the hydrogen network. Of these, for five measures the modelling identified the possibility of admixture, taking into account flow mechanics and the maximum tolerated hydrogen concentration of 2%. For the other projects without connections to the hydrogen network, methanation of green hydrogen is necessary before it can be injected into the natural gas network. Subsequently it was determined that for one project no possibility of connection could be found by 2030, the year under consideration.

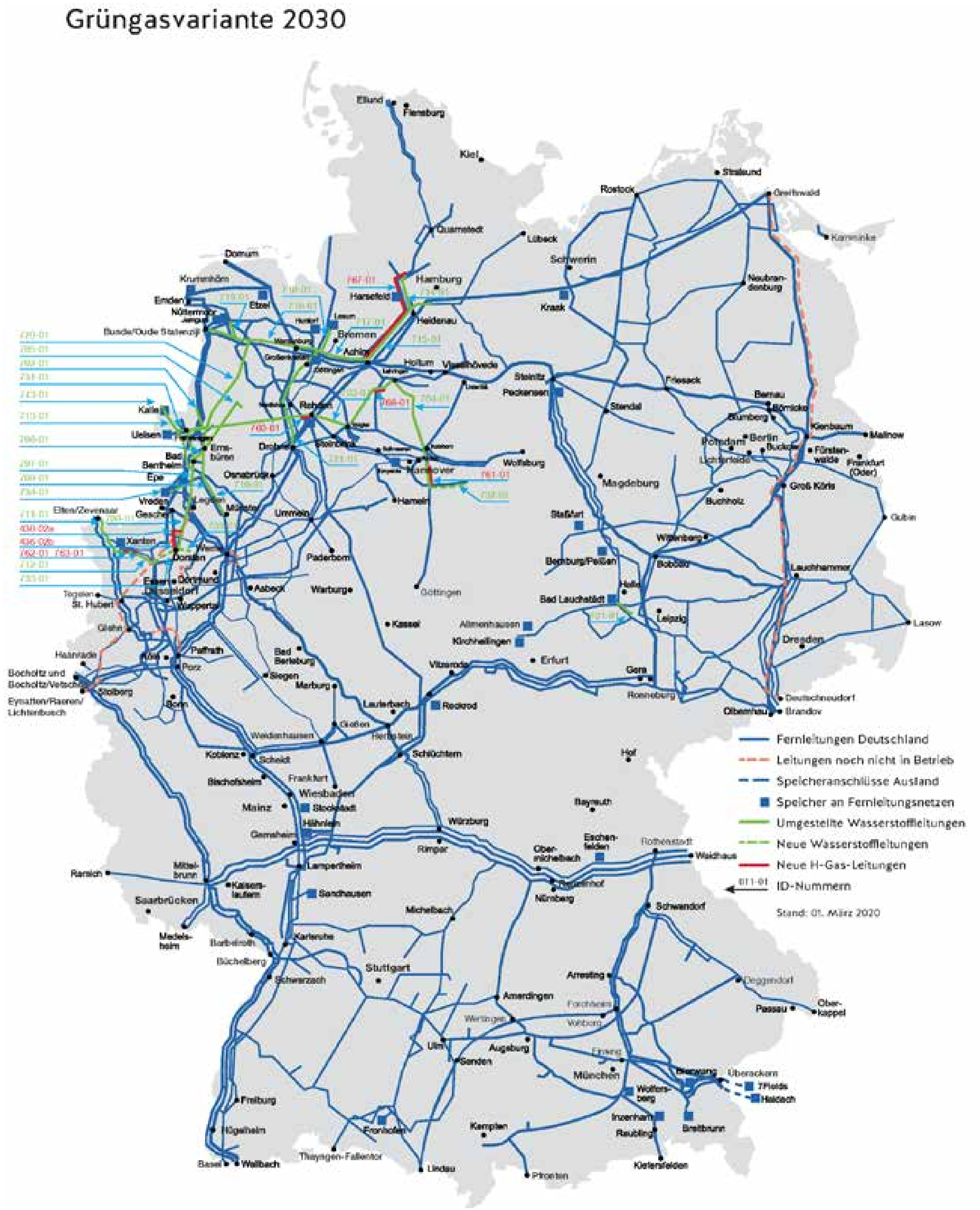


Figure 160: Expansion measures for a potential hydrogen network according to the TSOs' expansion proposal for the Gas NDP 2020-2030 (source: Association of Transmission System Operators for Gas e.V. (FNB Gas))

Subject to changes to legal and subordinate regulatory requirements and in addition to natural gas infrastructure projects, the TSOs propose 47 further measures to establish a hydrogen transport system within the context of the Gas NDP 2020-2030. The expansion proposal comprises a pipeline length of 1,294 km, of which 151 km would be newly built and 1,142 km would be obtained through conversion of existing natural gas pipelines. The network concept for hydrogen transportation does not initially require compressor stations for intermediate compression along the transport route. Consequently, the investment volume for establishment of the hydrogen network amounts to €0.7bn for the period up to 2030.

In light of the major role attributed to hydrogen within the context of decarbonisation, both infrastructure planning and issues surrounding regulation and financing are the subject of intense debate. The Bundesnetzagentur made a significant contribution to the debate by publishing its analysis of the current regulatory situation for hydrogen networks and the associated market consultation. These discussions and the results of evaluation of the consultation are already being taken into account in the elaboration of a legal framework for the launch phase of a hydrogen-based economy. Transitional arrangements are conceivable for infrastructure design, during which the Gas NDP would continue to be used to create transparency until a network development planning for hydrogen has been established.

1.2 Incremental capacity – 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 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 2019 to 2021

a) Demand assessment

The market demand assessment process was completed by the TSOs in October 2019. In the course of this process the TSOs evaluated all demand indications for additional gas transport capacity at the market area borders into Germany (Trading Hub Europe – THE). Demand indications for incremental gas capacity and/or capacity to be upgraded were registered at six market area borders into/out of Germany (Denmark-THE, Russian Federation-THE, Poland (Mallnow)-THE, Poland (GCP)-THE, THE-Netherlands and Germany-Switzerland).

b) Design phase

After the market demand assessment reports were published, the TSOs launched the design phase for these demand indications. During this period, until August 2020, the TSOs carried out technical studies on projects providing incremental capacity at 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. In August and September 2020, the TSOs concerned also conducted a consultation on their results to lay the groundwork for concrete project proposals.

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 will submit these proposals to the responsible national regulatory authorities for coordinated approval.

The project proposals were expected to be submitted in autumn 2020. Particularly in light of the market area merger and changes to the framework conditions, and given the interdependency of the individual projects in the event of their realisation, designing and reviewing the projects during the 2019-2021 incremental capacity cycle is especially challenging. The subsequent approval process for the individual projects, coordinated between the neighbouring regulatory authorities, is planned to be concluded by April 2021 at the latest.

c) Booking phase and market testing

Once approval has been granted, the new gas transport capacity is offered to the market participants for binding booking together with any existing capacity.

As a rule, auctions are used to allocate additional capacity at cross-border interconnection points. If the outcome of the economic test is positive – in other words sufficient binding capacity is booked to cover the specified proportion of investment costs – the gas transport capacity must be created by the TSOs concerned. The project will then be included in the network development plan, at the size confirmed by the market.

The Bundesnetzagentur has actively accompanied this process since early 2017. In order to increase transparency, the Bundesnetzagentur 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.

2. Investments

Investments as defined in the monitoring survey are considered to be gross additions to fixed assets capitalised in 2019 and the value of new fixed assets newly rented in 2019. 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 2019 the 16 German TSOs invested a total of €1.33bn (2018: €1.45 bn) in network infrastructure. Of this total, €1.08bn (2018: €1.30bn) was investment in new installations, expansion and extension and €249m (2018: €156m) investment in maintenance and renewal of network infrastructure.

With regard to the distribution of investment expenditure between the two German market areas, the data confirmed the shift towards GASPOOL. In 2017 the distribution figures were of a similar order of magnitude but the allocation to the market areas was reversed. Of the total investments in 2019, a significantly larger share, 66%, was attributed to the transmission systems in the GASPOOL market area and 34% to the NCG market area (2018: 62% GASPOOL, 38% NCG). The investments planned for 2020 amount to a total of €1.06bn, which would equate to a decrease of 21% compared to 2019. This relatively large fluctuation in investment expenditure in network infrastructure and the distribution between the two market areas are 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 €322m in 2019 (2018: €313m), with expenditure in 2019 and planned expenditure for 2020 shared equally between the two market areas.

The overall total for investments and expenditure 2019 across all TSOs was approximately €1.65bn (2018: €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.

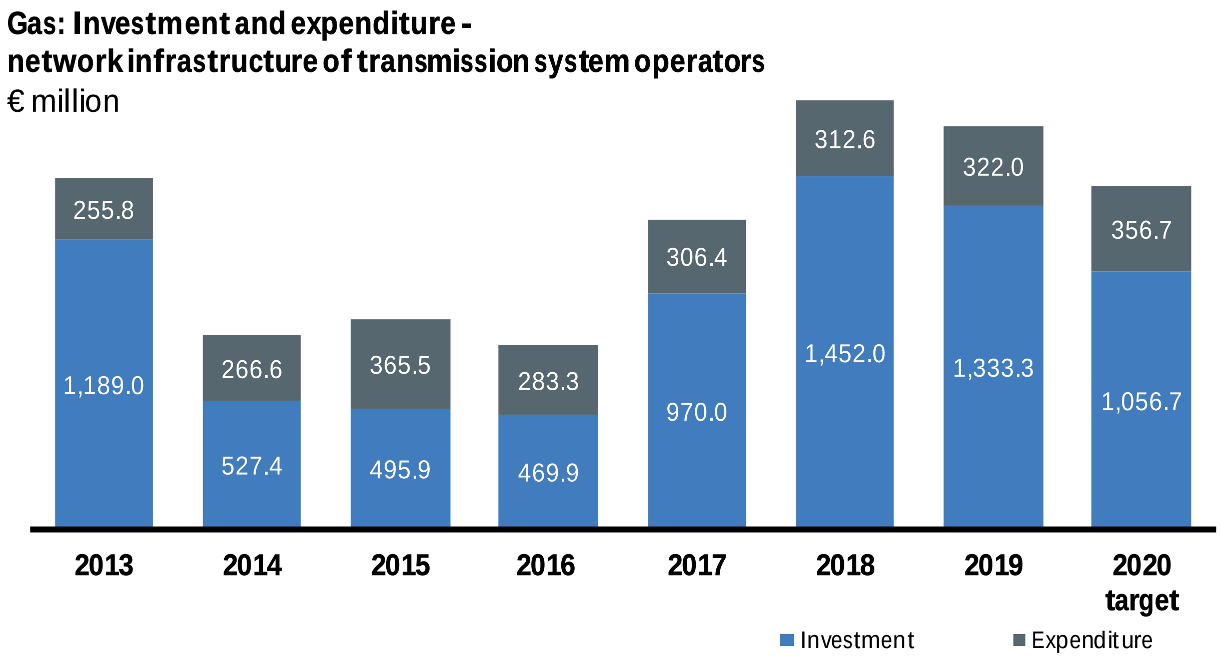


Figure 161: Investments in and expenditure on network infrastructure by TSOs

2.2 Investments in and expenditure on network infrastructure by gas DSOs

In the course of data collection for the 2020 Monitoring Report, 600 gas DSOs declared investment in new installations, expansions and extensions (€940m compared to €798m in 2018) and maintenance and repair (€549m compared to €475m in 2018) of network infrastructure, totalling €1,488m compared to €1,272m in 2018. The projected total investment for 2020 is €1,527m.

According to the gas DSOs' reports, expenditure on maintenance and repair in 2019 was €1,152m. (2018: €1,078m). The projected expenditure on maintenance and repair for 2020 is €1,289m.

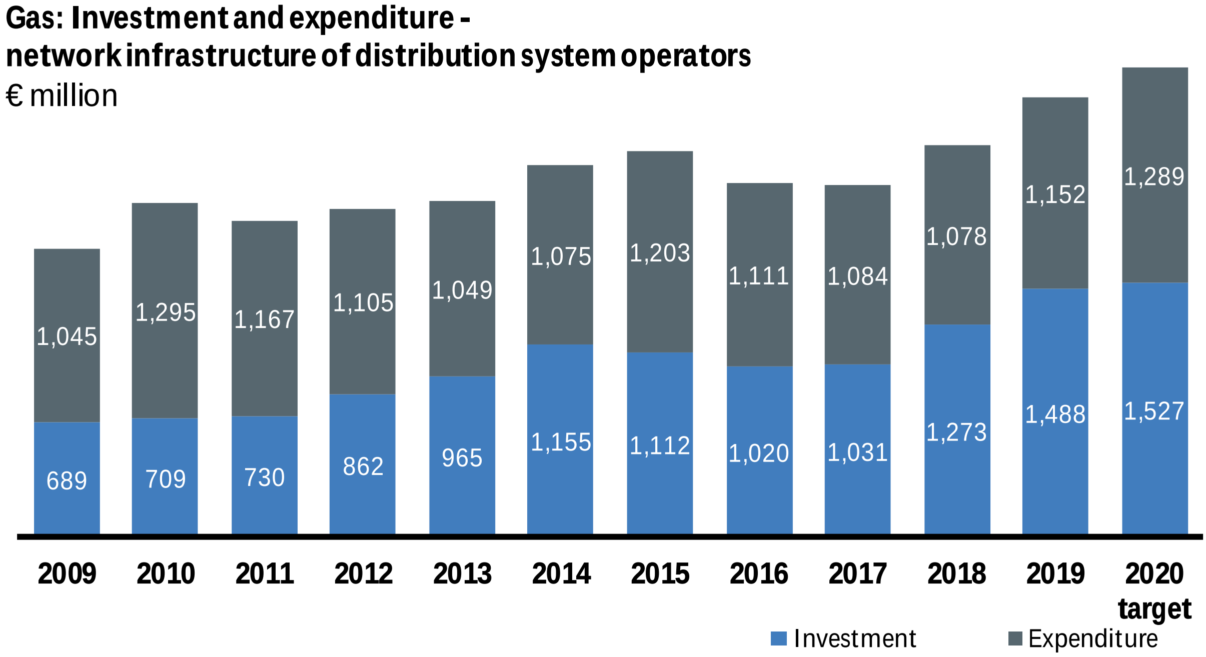


Figure 162: Investments in and expenditure on network infrastructure by gas DSOs

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 153 of the surveyed gas DSOs reported investments of between €1m and €5m, 59 gas DSOs made investments totalling more than €5m.[145]

Of the surveyed gas DSOs, 134 reported total expenditures in the bracket between €100,001 and €250,000, while 57 gas DSOs reported expenditures totalling more than €5m.[146]

[145] These figures are based on data submitted by 574 DSOs.

[146] These figures are based on data submitted by 600 DSOs.

Gas: Distribution system operators broken down according to level of investment in 2019
Number and %

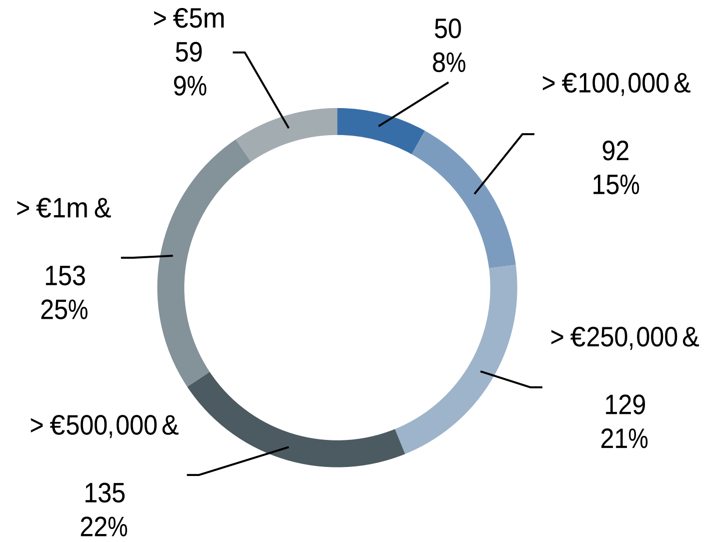


Figure 163: Distribution of gas DSOs according to level of investment in 2019

Gas: Distribution system operators broken down according to level of expenditure in 2019
Number and %

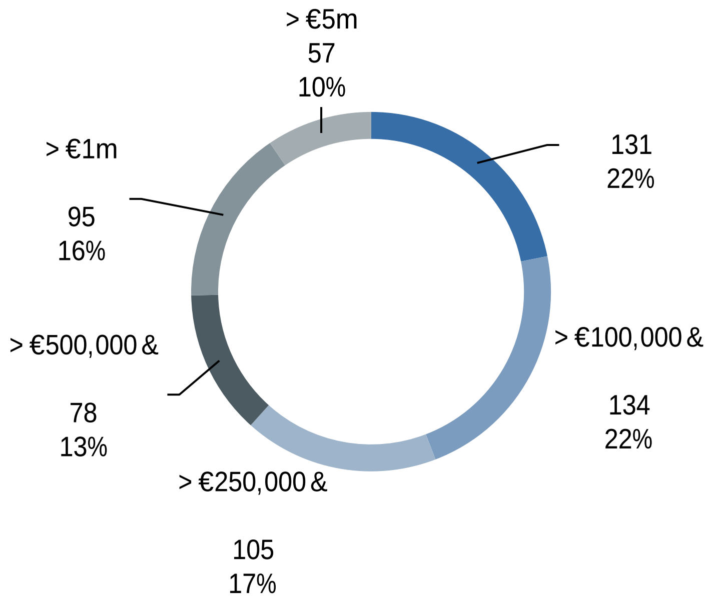


Figure 164: Distribution of gas DSOs according to level of expenditure in 2019

2.3 Investments and incentive-based regulation

The Incentive Regulation Ordinance (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 approval has been granted, 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. Similarly, on the basis of section 10a ARegV the Bundesnetzagentur grants approval upon application for investments in operationally necessary assets made after the base year. Once approval has been granted, the DSOs may adjust their revenue cap and thereby refinance the capital costs associated with the investments likewise 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 2020, the TSOs had submitted 38 applications for investment projects to the competent Ruling Chamber. The costs of acquisition and production linked to these measures amount to €2.3bn. Compared to 2019, the number of applications submitted by the TSOs more than doubled, as did the investment volume covered by the applications. This increase in the number of applications is a result of the Gas NDP being drawn up every two years as the TSOs usually submit their applications at the time of their inclusion in the NDP in accordance with section 23 ARegV.

2.4 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.

2.4.1 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.

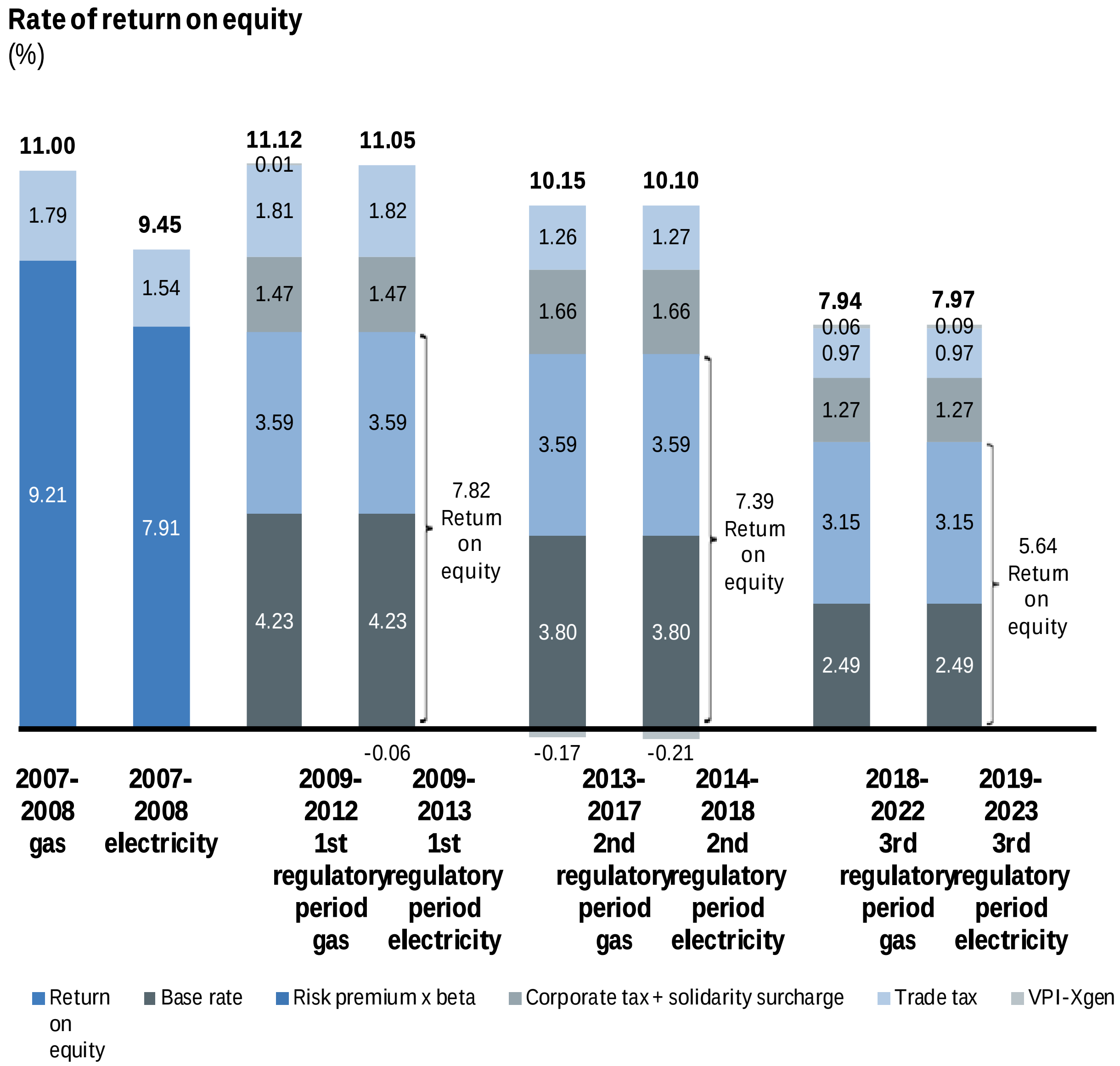


Figure 165: Entwicklung der regulatorisch gewährten EK-Renditen

Rate of return on equity

2.4.2 Rate of return on equity II

The rate of return on equity may be substituted by the use of borrowed capital. However, in practice complete substitution by borrowed capital is impossible because no outside creditors are likely to be willing to advance capital without any recoverable assets. The higher the level of equity capital, the lower the rate of return on borrowed capital demanded should tend to be. However, due to regulatory provisions, there is an argument that, if the level of equity capital exceeds 40%, it is no longer worthwhile as it cancels out the lowering effect on the rate of return on borrowed capital, in other words, an equity ratio exceeding 40% means the equity is used inefficiently. Consequently, the return on the equity in the capital structure over and above that is calculated using the rate of return determined in accordance with section 7 para 7 StromNEV or GasNEV (averaging over 10 years) (rate of return on equity EKII). The figure below shows on the one hand the EKII rates of return actually used for cost examination and, on the other, the annual results according to StromNEV/GasNEV (10-year average) as well as the annual development of the underlying series of figures.

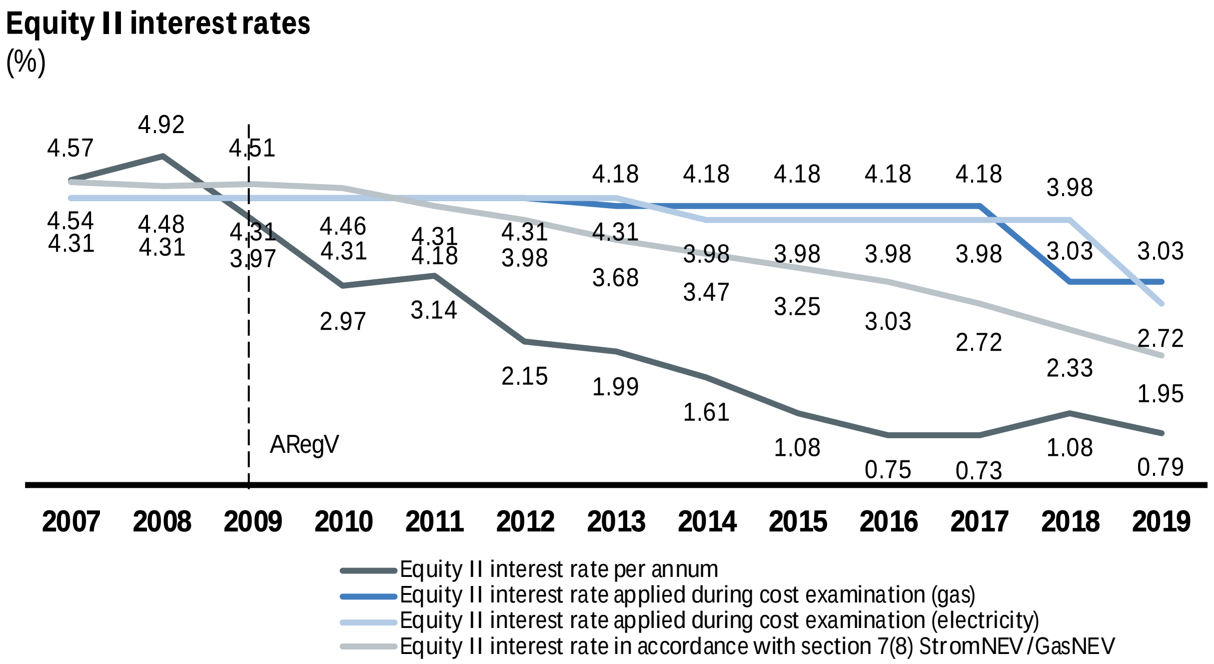


Figure 166: Trend in rates of return on equity II

2.4.3 Rate of return on borrowed capital

Within the scope of the various regulatory systems, borrowed capital is recognised in keeping with the actual interest rates at which financing was obtained unless the interest rates exceed customary market levels. However, assessment of individual cases is defined by a different eligibility limit, dependent on the type of regulation applied. The figure below shows the levels of the rate of return on borrowed capital – shown separately under a normal incentive regulation system (budget principle) or under an investment measures system – that can be taken into account in principle for the electricity and gas networks as set out above. Starting from the third regulatory period, the DSOs have also used the capital expenditure (capex) true-up, for which the rate of return on borrowed capital is calculated in line with the borrowing using the normal incentive regulation system. Accordingly, 3.03% was set for the gas sector and 2.72% for the electricity sector for the third regulatory period.

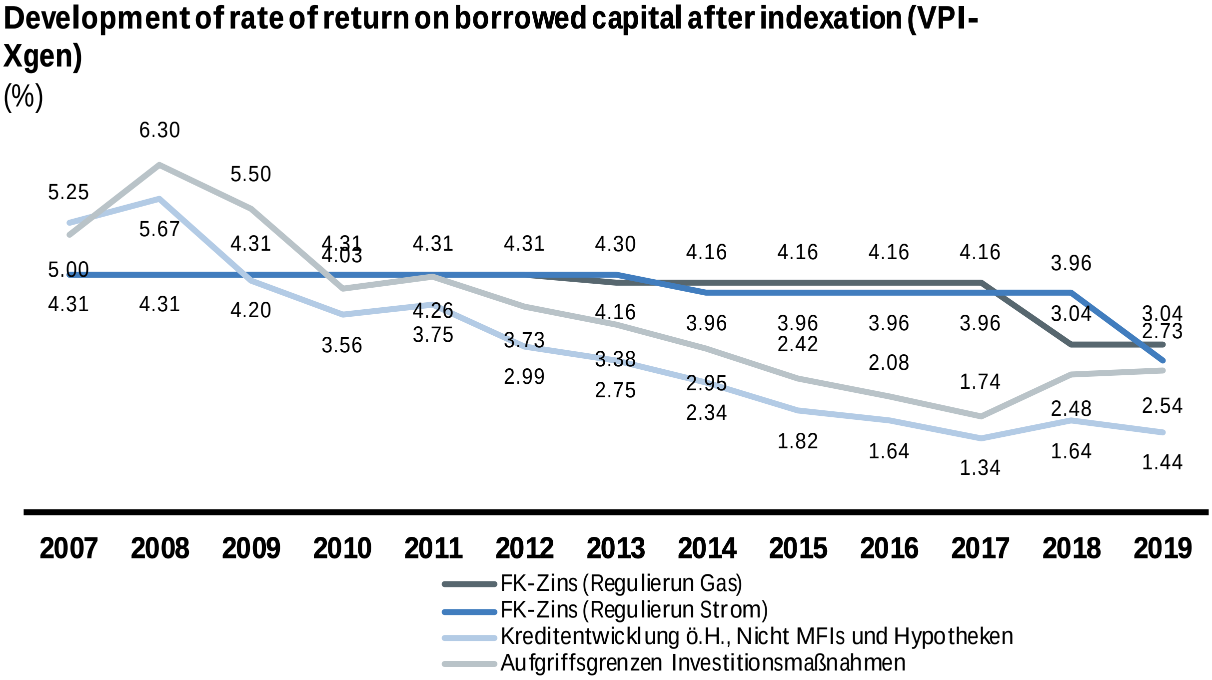


Figure 167: Rate of return on borrowed capital after indexation (VPI-XGen)

2.5 Capex mark-up B

The Bundesnetzagentur implemented the capex mark-up, a newly introduced instrument (section 10a ARegV), for the gas distribution networks at the start of the third regulatory period (as of 1 January 2018). This allows DSOs to apply every year for a mark-up on the revenue cap approved by the Bundesnetzagentur with respect to new investments that have previously not been taken into account. This includes both investments that have already been made and planned investments.

The capex mark-up comprises the annual imputed capital costs in the form of depreciation, return on equity and trade tax and is incorporated into the revenue cap of the network operator.

In the second half of 2019, Ruling Chamber 9 took decisions on 128 capex mark-up applications for 2020 that were submitted by the gas network operators under its responsibility. A total of just under €311m was approved as capex mark-up.

As of 30 June 2020, 128 applications for capex mark-up approval had been submitted by the network operators for 2021, amounting to a total capex mark-up of approximately €403m. Individual applications are approved within the months following submission, enabling the revenue cap to be adjusted within the meaning of the ARegV instrument.

3. Capacity offer and marketing

3.1 Available entry and exit capacities

As in previous years, for the 2018/2019 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 to be transported when use is made of this right is reported by the shippers by means of nomination. 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 points of bookable entry/exit points to storage facilities, power stations and final consumers.

This survey does not include the reserve capacity agreed with the downstream network operators within the internal booking process since the exit points to distribution networks are not marketed directly to shippers (see section II.C.3.5 for more information on internal booking).

During the period under review virtual interconnection points were created at various borders between neighbouring market areas. The legal basis for this is contained in Article 19 (9) of Regulation (EU) No 984/2013 establishing a Network Code on Capacity Allocation Mechanisms in Gas Transmission Systems and supplementing Regulation (EC) No 715/2009. Accordingly, as of 1 January 2018, in cases where two or more interconnection points connect the same two adjacent market areas, the TSOs concerned were obliged to offer the capacities available at these interconnection points at one virtual interconnection point (VIP). The aim is that these VIPs should facilitate economic and efficient use of the system. The marketing of capacities at these points changes in as much as the capacities at a VIP are offered by so-called VIP TSOs. Capacities that were not contracted at the time of VIP implementation were therefore transferred to VIPs from various TSOs' physical interconnection points that were previously bookable individually. Although this results in shifts in the TSOs' capacity offers compared to the previous period under review, the implementation of VIP use should not have any appreciable impact on the aggregated figures at the level of market areas. Changes compared to the previous year would only occur in cases where the creation of VIPs itself results in an increase of the capacity offer. A reduction in capacity resulting from the creation of a VIP is ruled out by the network code, as it would mean that one of the conditions required for creating VIPs is not met.

In 2019, the total firm entry capacity offered across both market areas was 517 Gwh/h, an increase of 12.8 GWh/h compared to the previous year. The offer of firm and freely allocable capacity (FZK) amounted to 148 GWh/h, corresponding to about 53.3% of the total entry capacity offered in the GASPOOL market area, an increase of 1.6% compared to the previous year. In the NCG market area the FZK offered was 97.1 Gwh/h, corresponding to a share of 41.3% of the total capacity offered. The volume of this product offered (the product which ensures that shippers are able to allocate their entry capacity without restrictions) thus decreased by 2.8% in the NCG market area. The total volume of entry capacity offered in the NCG market area equates to around 45.5% of the total entry capacity offered across both market areas. The remaining and larger share of 54.5% is attributed to the GASPOOL market area.

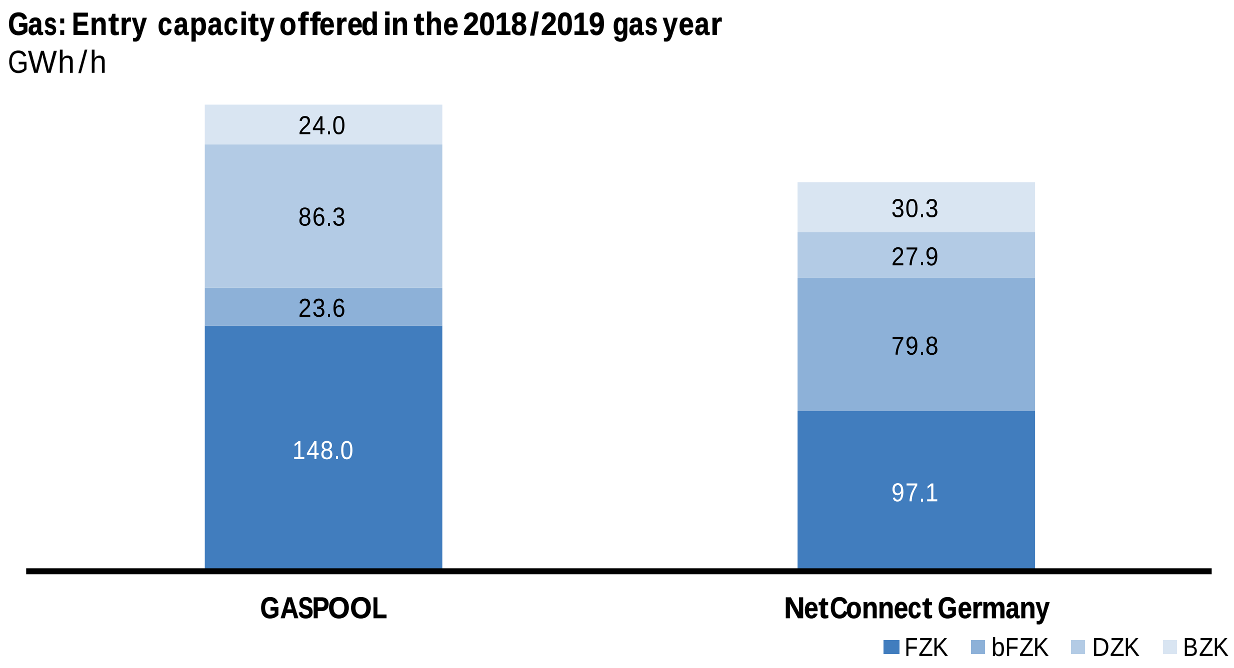


Figure 168: Entry capacity offered

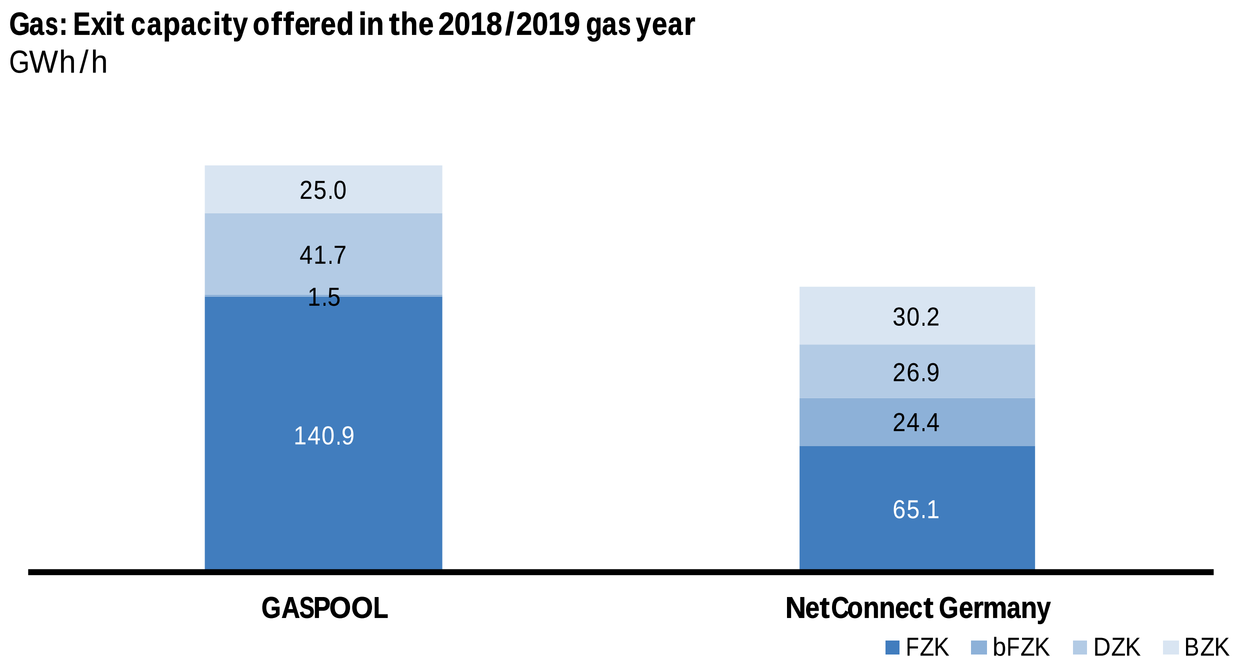


Figure 169: Exit capacity offered

In 2019, the total firm exit capacity offered across both market areas was 355.6 GWh/h, a slight increase of 0.5% compared to the previous year. It should be noted that not every TSO offers all capacity products. The aggregated developments therefore cannot be projected onto each individual TSO.

The period under review does not include the commissioning of the first section of the European Gas Pipeline Link (EUGAL), which took place on 1 January 2020. The pipeline connects the Lubmin II natural gas receiving station near Greifswald with the Czech network area. Lubmin II is intended to receive the additional gas volumes delivered through the Nord Stream extension. The entry capacity into the GASPOOL market area at the time of commissioning was 40.1 Gwh/h. By 2026, according to information from the TSOs, this will have increased in several stages to 78.6 Gwh/h under the scenario framework of the Gas NDP 2020-2030.

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 TSOs. 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 so-called internal bookings by the DSOs (see section II.C.3.5). In 2019, the total capacity booked with TSOs by downstream DSOs was 271.2 GWh/h. This is roughly 80.2% of the bookable exit capacity offered in the 2018/2019 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.

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 entry/exit points to storage facilities, power stations and final consumers. These two figures can then be used to calculate the average booking rate at the bookable entry and exit points. The survey showed that in 2019, the year under review, the booking rate for firm capacity products (FZK, bFZK, DZK, BZK) was 48.1% (2018: 49.6%) on the entry side and 58.9% (2018: 52.6%) on the exit side 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 2018/2019 gas year GWh/h

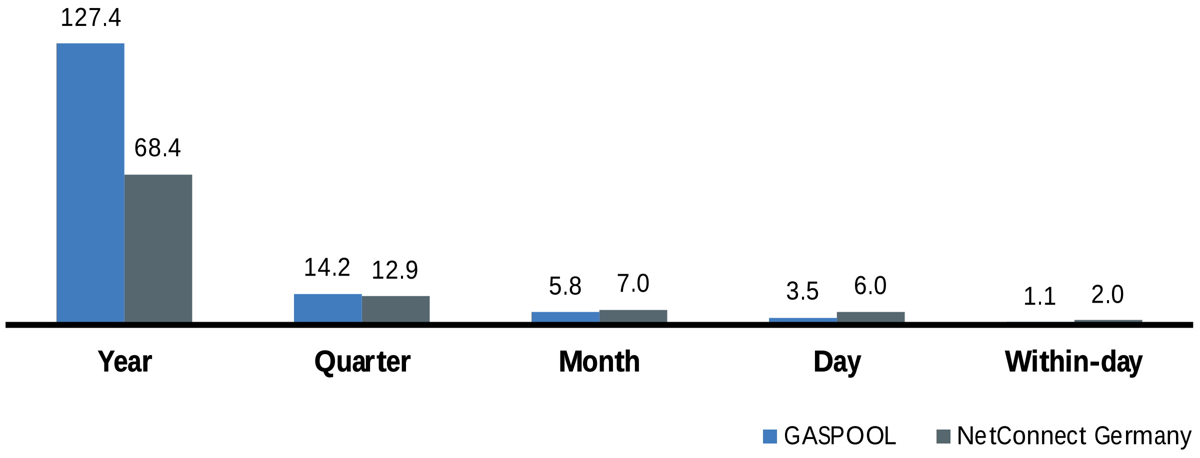


Figure 170: Booking of entry capacity according to product duration and market area

Gas: Booking of exit capacity according to product duration and market area in the 2018/2019 gas year GWh/h

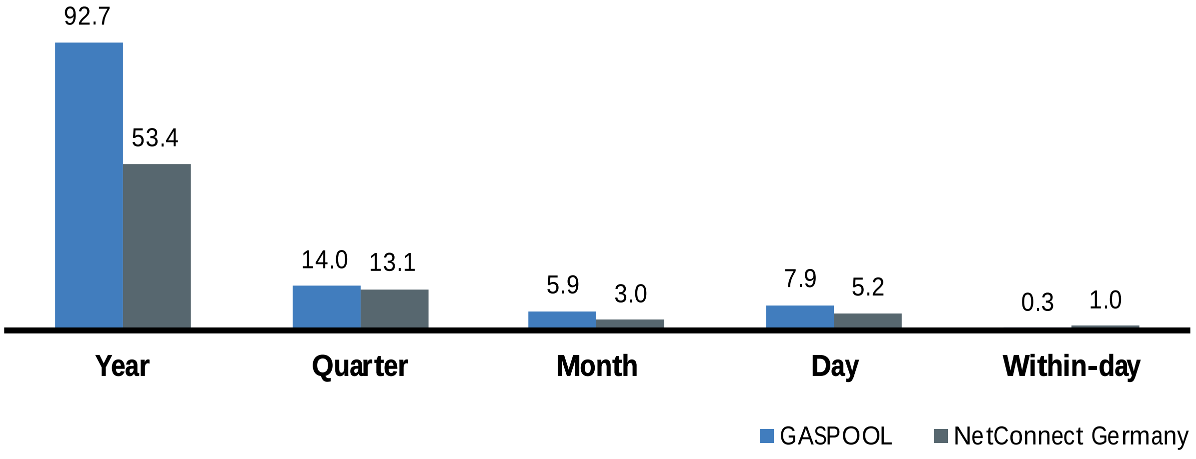


Figure 171: Booking of exit capacity according to product duration and market area

The values shown in the graph relate to the level of bookings in the period under review, regardless of when the corresponding capacities were booked. 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 2018/19 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 248.2 GWh/h, significantly exceeding exit capacity, which amounted to a total of 196.5 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 220.1 GWh/h of yearly capacity marketed and 28.2 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 121.8 GWh/h and 26.1 GWh/h respectively. The distribution between individual product durations is similar to that of the previous year. The exception was one TSO who reported a significant shift from quarterly bookings towards yearly bookings. The fact that yearly capacity bookings are still the dominant share overall 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 1,983 TWh at all entry points where there is a nomination obligation, a decrease of 3.5% compared to the previous year. In contrast, nominated quantities at exit points were considerably lower in 2019, totalling 997 TWh (a decrease of 14.8% compared to 2018). 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.

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 rise 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 2019, a total of 67 capacity contracts with a duration of at least one month were terminated. This is a significant increase compared to 2018 when 18 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 entry/exit point.

Gas: Termination of capacity contracts by type of entry/exit point in the 2019 calendar year
Number

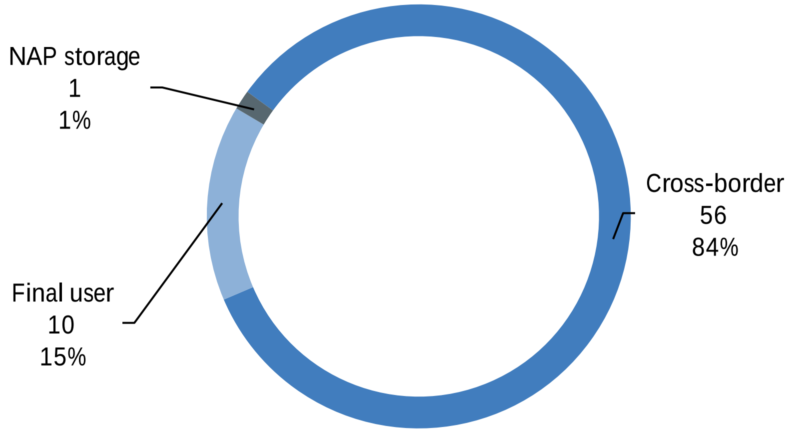


Figure 172: Termination of capacity contracts by category of entry/exit point in the 2019 calendar year

A total of 67 capacity contracts were terminated, of which 56 were contracts at cross-border interconnection points. A further ten capacity contracts were terminated at exit points to final consumers. The one remaining capacity contract was terminated at a network connection point to a storage facility. In general terms, a considerable change in the distribution of contract terminations is observable compared to 2018, when half of all terminated capacity contracts were contracts at storage facility connection points.

Gas: Termination of capacity contracts by product type in the 2019 calendar year
Number

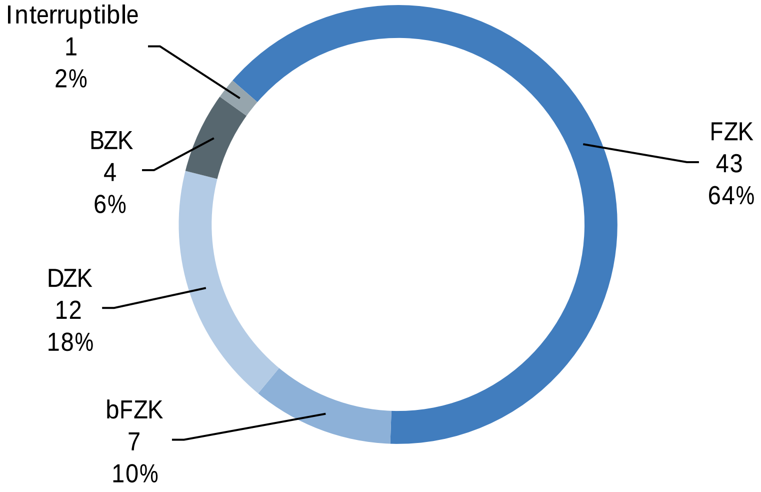


Figure 173: Termination of capacity contracts by product type

Differentiating terminated capacity contracts according to product type shows that most of them, namely 43, were terminated FZK capacity contracts. However, in contrast to 2018 when only interruptible or FZK capacity contracts were terminated, the current period under review also includes terminations of contracts relating to other product types.

3.4 Interruptible capacity

Interruptible capacities enable shippers to make use of booked entry and exit capacities on an interruptible basis without having to determine a transport path.

Gas: Interruptions in the 2019 calendar years

Interruption volume (GWh)

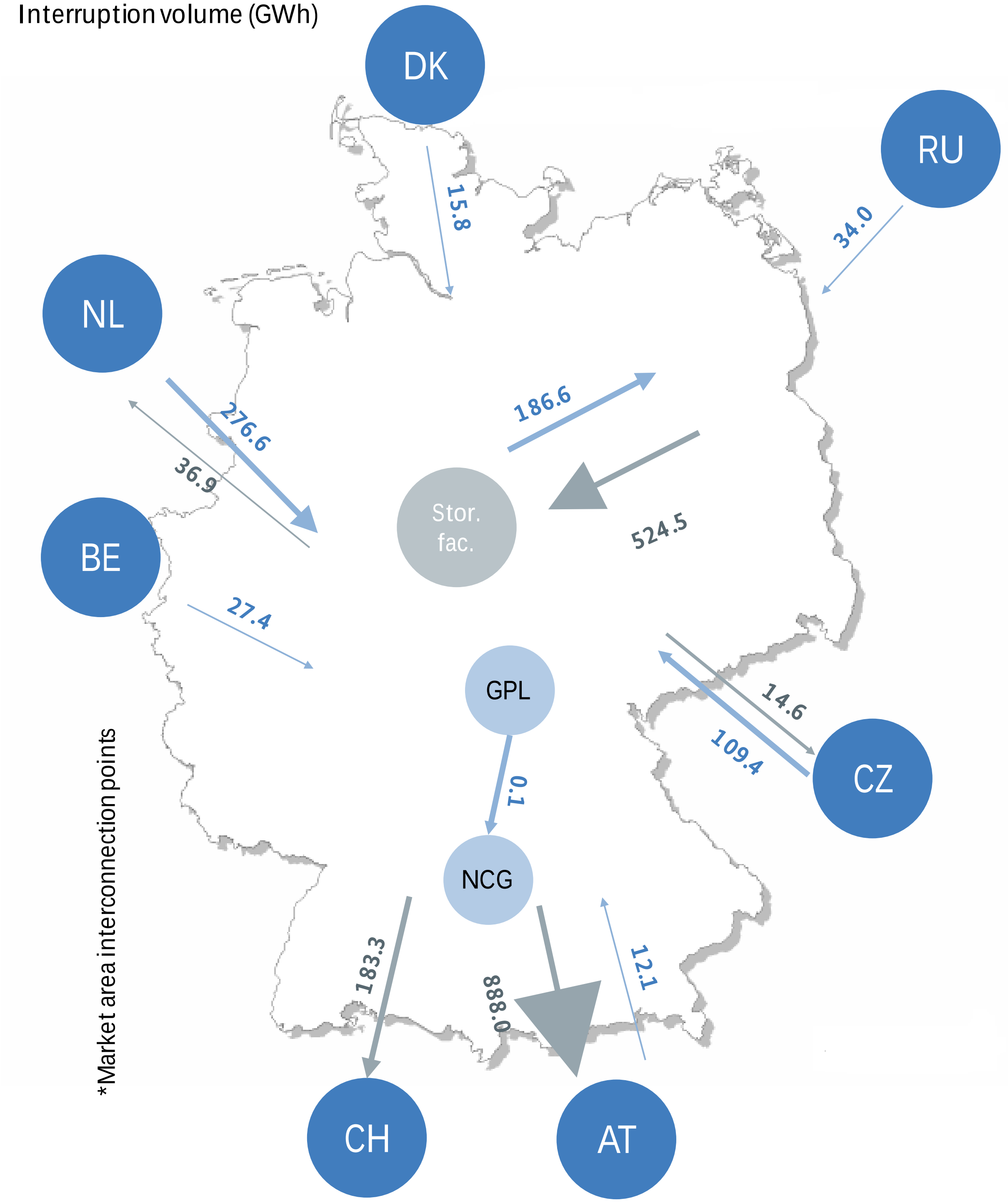


Figure 174: Interruption volumes according to region

Transmission system operators were surveyed on all interruptions issued in the calendar year 2019 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 2019, the volume of initially (re-)nominated gas that was not transported through all entry and exit points into or out of the market area was 2.4 TWh (2018: 5.3 TWh). 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 99.4%. Only a small proportion of interruptions was attributed to FZK products. The distribution of interruptions across the various entry/exit points shows that cross-border interconnection points account for the largest proportion of interrupted volumes (70.9%) with the remaining 29.1% mainly attributed to storage facility entry/exit points. Compared to these figures, interruptions issued at market area interconnection points are negligible.

Figure 174 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 2019 calendar year the volume of gas to be exported from Germany to the Netherlands that was subject to interruptions was 36.9 GWh and the volume of gas to be imported from the Netherlands into Germany that was subject to interruptions was 276.6 GWh. The initially nominated and/or renominated volumes at the exit points into Austria's Eastern market area accounted for the largest proportion of the total interrupted volume, amounting to 888 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 2019 calendar year for the two market areas NCG and GASPOOL respectively.

Gas: Capacities agreed between TSOs and DSOs in 2019
GWh/h

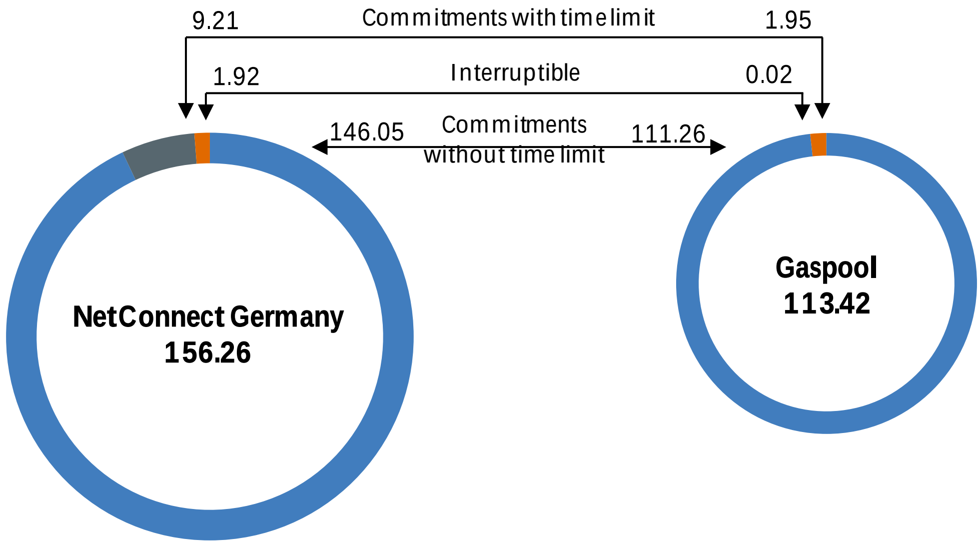


Figure 175: Capacities agreed between TSOs and DSOs

Compared to the previous year, the volume of internal bookings in the two market areas rose from a total of 270.9 GWh/h to 271.4 GWh/h in the 2019 calendar year. Of this total, reserve capacity with a volume of 269.7 GWh/h was agreed between the TSOs and the downstream network operators. The majority of this reserve capacity (156.3 GWh/h) agreed between the operators was agreed in the NCG market area, and the remainder (113.42 GWh/h) in the GASPOOL 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 94.8% in the previous year to 95.1% in the 2019 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 2019 the SAIDI was 0.98 minutes, which means that once again it was below the long-standing average of 1.5 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 the following factors are included in the calculations:

- third-party intervention,
- disturbances in the network operator's area,
- ripple effects from other networks or
- other disturbances.

Gas: SAIDI results for 2019

Pressure range	Specific SAIDI	Comments
	0.72 min/a	Household and small-volume consumers
> 100mbar	0.26 min/a	High-volume consumers, gas-fired power plants
> 100mbar	0.34 min/a	Downstream network operators (not part of SAIDI)
All pressure ranges	0.98 min/a	SAIDI figure for all final customers

Table 121: SAIDI results for 2019

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.

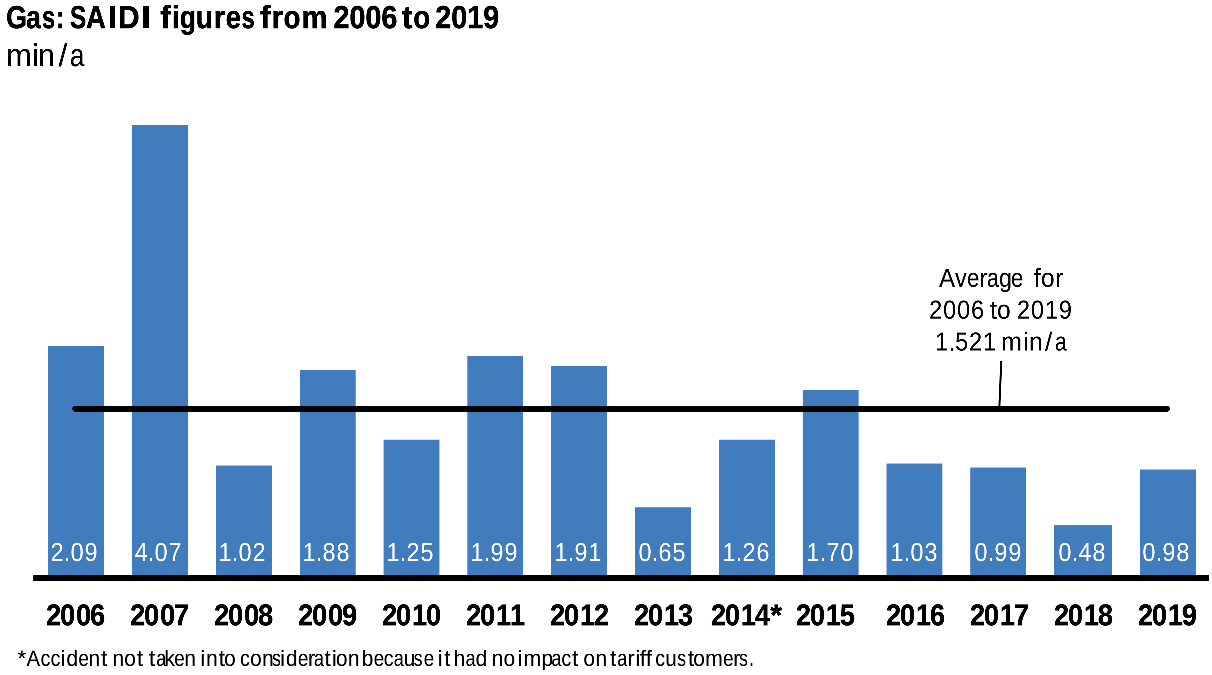


Figure 176: SAIDI gas figures for the period from 2006 to 2019

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 and has remained unchanged 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. Since 1 January 2020 the structure of the TSOs' capacity charges has been prescribed by the provisions of NC TAR (see also section II.C.5.5 „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) a typical reserve capacity relative to the volume consumed is set. Non-interval-metered customers are charged a commodity price and a base price.

Other systems apart from the network participation model are also used to calculate tariffs. In the main, these systems yield comparable results with respect to tariff degression and likewise do not depend on an individual customer's specific connection situation.

On 1 January each year the network operators must demonstrate to the regulatory authority that the established tariff system does not exceed the revenue cap. In the event of a downward adjustment of the revenue cap according to the rules of the Incentive Regulation Ordinance, the network operators are obliged to adjust their tariffs, whereas in the event of an upward adjustment they have the right to do so but it is not mandatory.

5.2 Development of average network charges in Germany

The figure below shows the development of the average volume-weighted net gas network charges for three consumption categories in ct/kWh from 1 April 2007 to 1 April 2020. 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 commercial 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 2020, 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 (2019: 1.56 ct/kWh) and therefore remained unchanged compared to the previous year. For commercial customers, as of 1 April 2020 the arithmetic mean of the network charge including the charges for metering and meter operation was 1.27 ct/kWh (2019: 1.26 ct/kWh). For industrial customers, as of 1 April 2020 the arithmetic mean of the network charge including the charges for metering and meter operation increased to 0.37 ct/kWh (2019: 0.32 ct/kWh), an increase of roughly 16% compared to 1 April 2019.

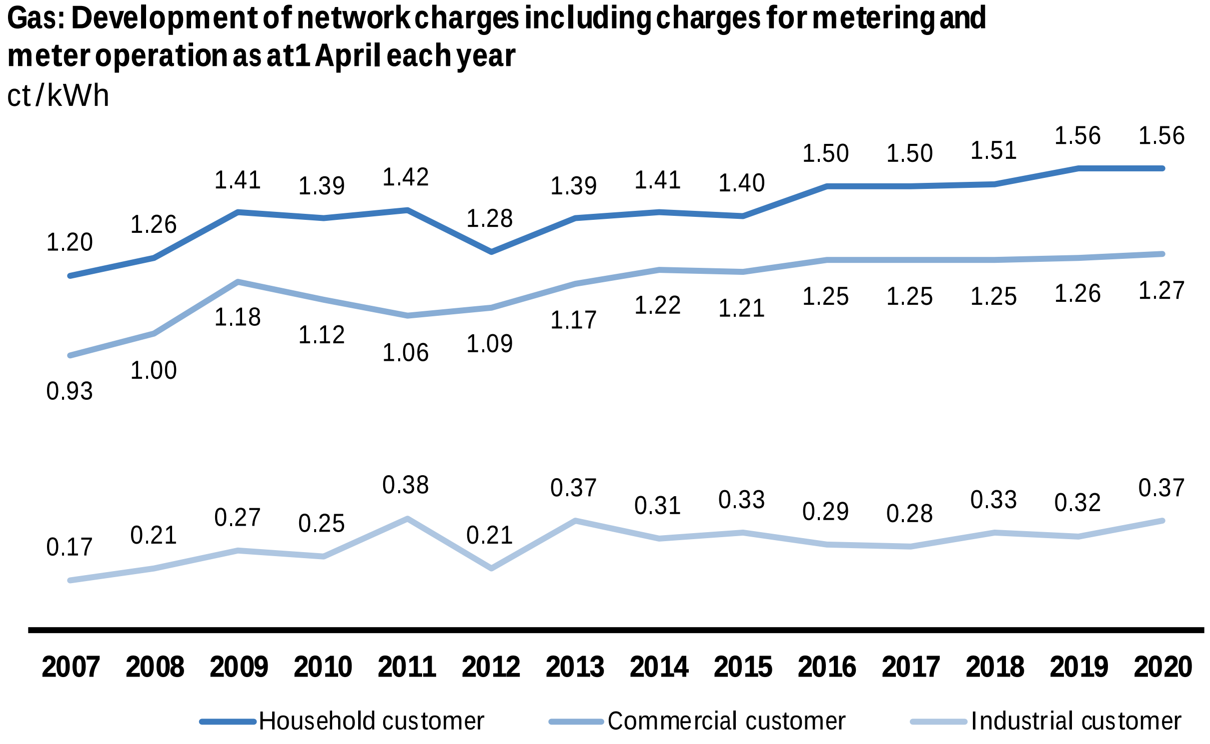


Figure 177: Development of network charges for gas (including charges for metering and meter operation) according to the survey of gas suppliers

Some TSOs' charges changed 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.5.5). The reason for the changes in network charges was 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. Since 1 January 2020, the TSOs' charges have been calculated on the basis of the new reference price methodology of a joint postage stamp tariff for each market area.

With regard to DSOs, on average network charges for household customers will increase slightly in 2021. There will also be slight increases in charges for commercial and industrial customers connected to the distribution network level.

With regard to TSOs, there will be a change to charges in the course of the 2021 calendar year, on 1 October 2021. The reason for this is the market area merger taking place on this day. The definitive charges for the period from 1 January 2021 to 1 October 2021 were published for them on 1 June 2020. The charges for firm, freely allocable capacity with a duration of one year will decrease by 1% in the GASPOOL market area compared to the 2020 charges, and by 7% in the NCG market area. At the end of September the TSOs published the provisional charges for the single Germany-wide Trading Hub Europe (THE) market area as of 1 October 2021. These charges are higher than those set in the two previous market areas.

5.3 Regional distribution of network charges

There is regional variation in the level of network charges. For the first time, the DSOs were surveyed on the level of network charges for the three consumption categories (household, commercial and industrial customers) considered in the report in order to compare network charges in Germany. 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 and to enhance visual demarcation on the maps used in the document, network charges are divided into six (household and commercial customers) or five (industrial customers) categories. 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 3.65 ct/kWh. The East to West gradient in the distribution of network tariffs has decreased slightly. The average network charge for household customers in the new federal states (not including Berlin) is 1.60 ct/kWh (2019: 1.65 ct/kWh), while the average in the old states (including Berlin) is 1.42 ct/kWh (2019: 1.39 ct/kWh). Compared to the previous year, gas network charges for household customers in the new federal states have thus fallen by slightly more than 3% on average compared to the previous year, whereas they have risen by slightly more than 2% in the old federal states. Looking at the averages by federal state, the highest network charges for household customers are found in Mecklenburg-Western Pomerania and Saarland, and the lowest in Berlin and Lower Saxony.

Gas: Net network charges for household customers in Germany for 2020
ct/kWh

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks considered
Mecklenburg-Western P.	1,84	1,03	2,78	22
Saarland	1,78	1,03	2,35	16
Thuringia	1,61	1,05	2,16	28
Saxony-Anhalt	1,56	1,05	2,77	29
Bremen	1,56	1,54	1,67	2
North Rhine-Westphalia	1,54	0,74	2,85	118
Baden-Württemberg	1,50	1,01	3,24	101
Saxony	1,49	1,10	3,65	36
Brandenburg	1,48	0,74	3,35	28
Rhineland-Palatinate	1,42	0,83	2,17	33
Hesse	1,41	0,97	1,77	44
Hamburg	1,37	1,37	1,37	1
Schleswig-Holstein	1,37	0,91	1,87	39
Bavaria	1,35	0,92	2,60	108
Lower Saxony	1,27	0,65	1,90	65
Berlin	1,16	1,16	1,16	1

* The gas offtake volume of the network operators in the respective network areas was used as the basis for weighting.

Table 122: Distribution of gas network charges for household customers in Germany, as at 1 January 2020

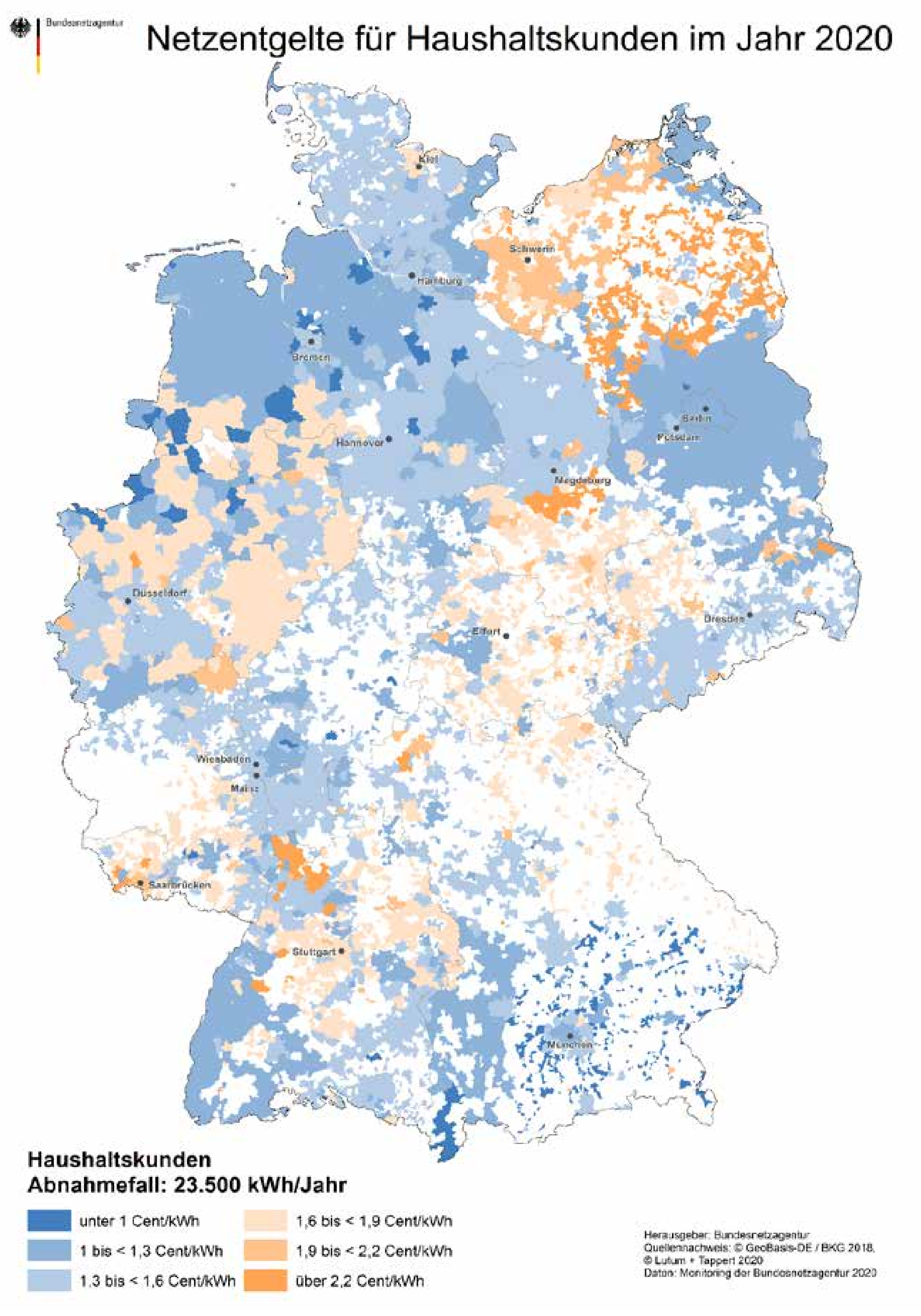


Figure 178: Distribution of gas network charges for household customers, as at 1 January 2020

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 0.45 ct/kWh to 3.25 ct/kWh. There is still a gradient in the distribution of network charges between the new and old federal states: the average network charge for commercial customers in the new federal states (not including Berlin) is 1.35 ct/kWh (2019: 1.51 ct/kWh), while the average in the old states (including Berlin) is 1.20 ct/kWh (2019: 1.30 ct/kWh). Compared to the previous year, network charges for commercial customers in the new federal states have thus decreased on average by slightly more than 10% and by around 8% in the old states. Looking at the averages by federal state, the highest network charges for commercial customers are found in Mecklenburg-Western Pomerania and Saarland, and the lowest in Lower Saxony and Berlin.

Gas: Net network charges for commercial customers in Germany in 2020
(ct/kWh)

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks considered
Mecklenburg-Western Pomeran	1.60	0.85	2.59	22
Saarland	1.48	0.75	2.08	16
Thuringia	1.34	0.87	1.83	28
Saxony-Anhalt	1.34	0.90	2.22	29
Baden-Württemberg	1.33	0.86	2.60	101
North Rhine-Westphalia	1.28	0.45	2.58	118
Brandenburg	1.27	0.63	3.25	28
Rhineland-Palatinate	1.25	0.77	1.86	33
Saxony	1.22	0.89	1.80	36
Hesse	1.20	0.75	1.62	44
Bavaria	1.19	0.79	2.43	108
Hamburg	1.17	1.17	1.17	1
Bremen	1.16	1.16	1.19	2
Schleswig-Holstein	1.14	0.75	2.21	40
Berlin	0.99	0.99	0.99	1
Lower Saxony	0.97	0.53	1.76	65

* The number of meter points belonging to the operators in the respective network areas was used as the basis for weighing.

Table 123: Distribution of gas network charges for commercial customers in Germany, as at 1 January 2020

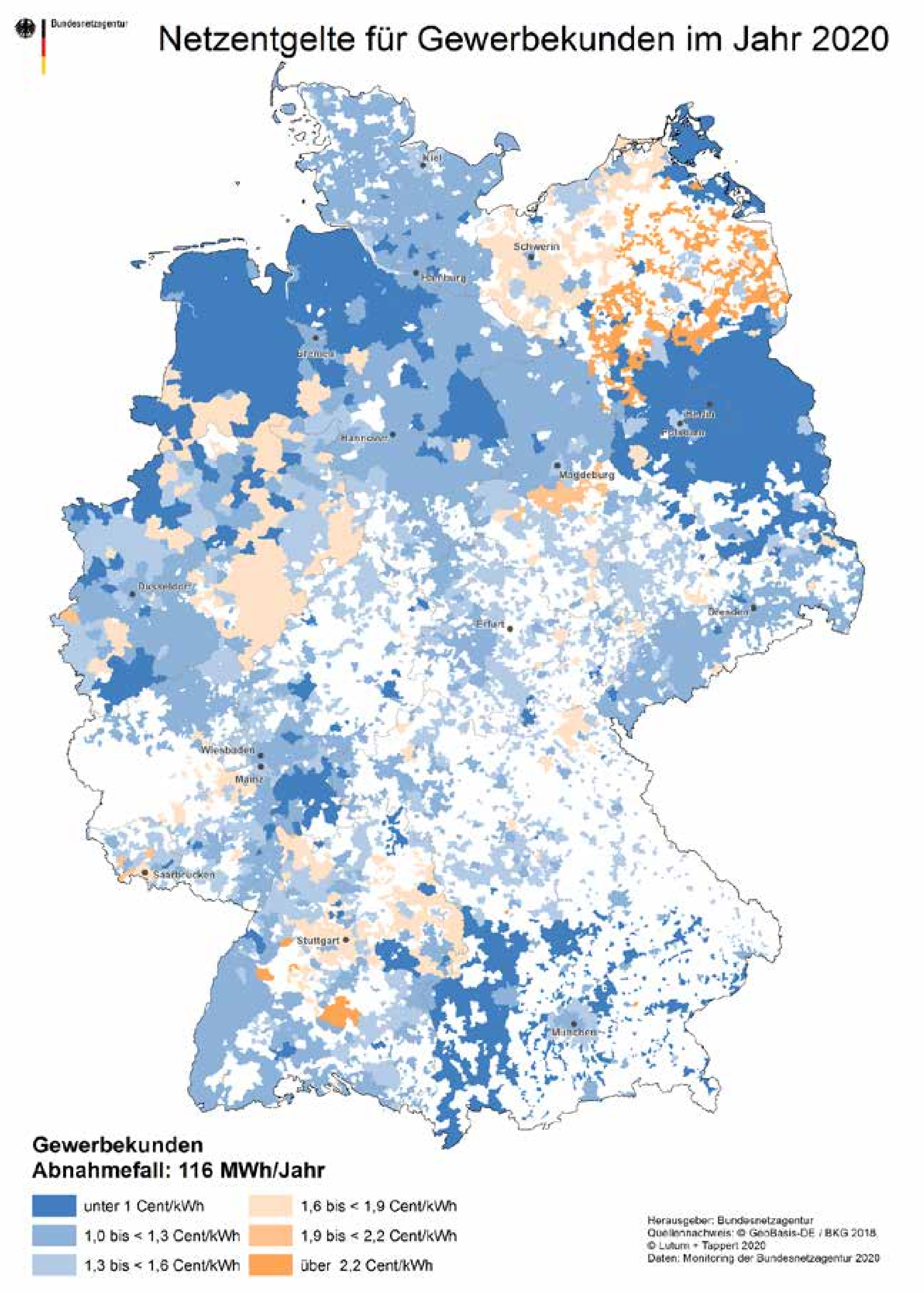


Figure 179: Distribution of gas network charges for commercial customers in Germany, as at 1 January 2020

Only gas networks that have at least one customer withdrawing at least 116 GWh should be taken into account when determining the average network charges for industrial customers. Figures from 214 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 0.09 ct/kWh to 0.96 ct/kWh. The average network charge for industrial customers in the new federal states (not including Berlin) is 0.31 ct/kWh (2019: 0.35 ct/kWh), while the average in the old states (including Berlin) is 0.30 ct/kWh (2019: 0.30 ct/kWh). Compared to the previous year, network charges for industrial customers in the new federal states have decreased by slightly more than 11%, while they have remained unchanged in the old federal states. Looking at the averages by federal state, the highest network tariffs for industrial customers are found in Saarland and Mecklenburg-Western Pomerania, and the lowest in Hamburg and Bremen.

Gas: Net network charges for industrial customers in Germany in 2020
(ct/kWh)

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks considered
Saarland	0.50	0.42	0.67	4
Mecklenburg-Western Pomeran	0.40	0.26	0.57	7
Lower Saxony	0.35	0.17	0.71	21
Schleswig-Holstein	0.33	0.23	0.35	6
Rhineland-Palatinate	0.33	0.09	0.49	11
Saxony	0.32	0.16	0.64	9
Baden-Württemberg	0.31	0.10	0.96	40
Hesse	0.31	0.09	0.48	17
North Rhine-Westphalia	0.30	0.17	0.90	44
Berlin	0.29	0.29	0.29	1
Bavaria	0.29	0.17	0.53	23
Brandenburg	0.28	0.21	0.68	12
Saxony-Anhalt	0.28	0.21	0.90	8
Thuringia	0.25	0.22	0.51	8
Bremen	0.24	0.23	0.30	2
Hamburg	0.24	0.24	0.24	1

* The quantity of gas supplied by the operators in the respective network areas was used as the basis for weighing.

Table 124: Distribution of gas network charges for industrial customers in Germany, as at 1 January 2020

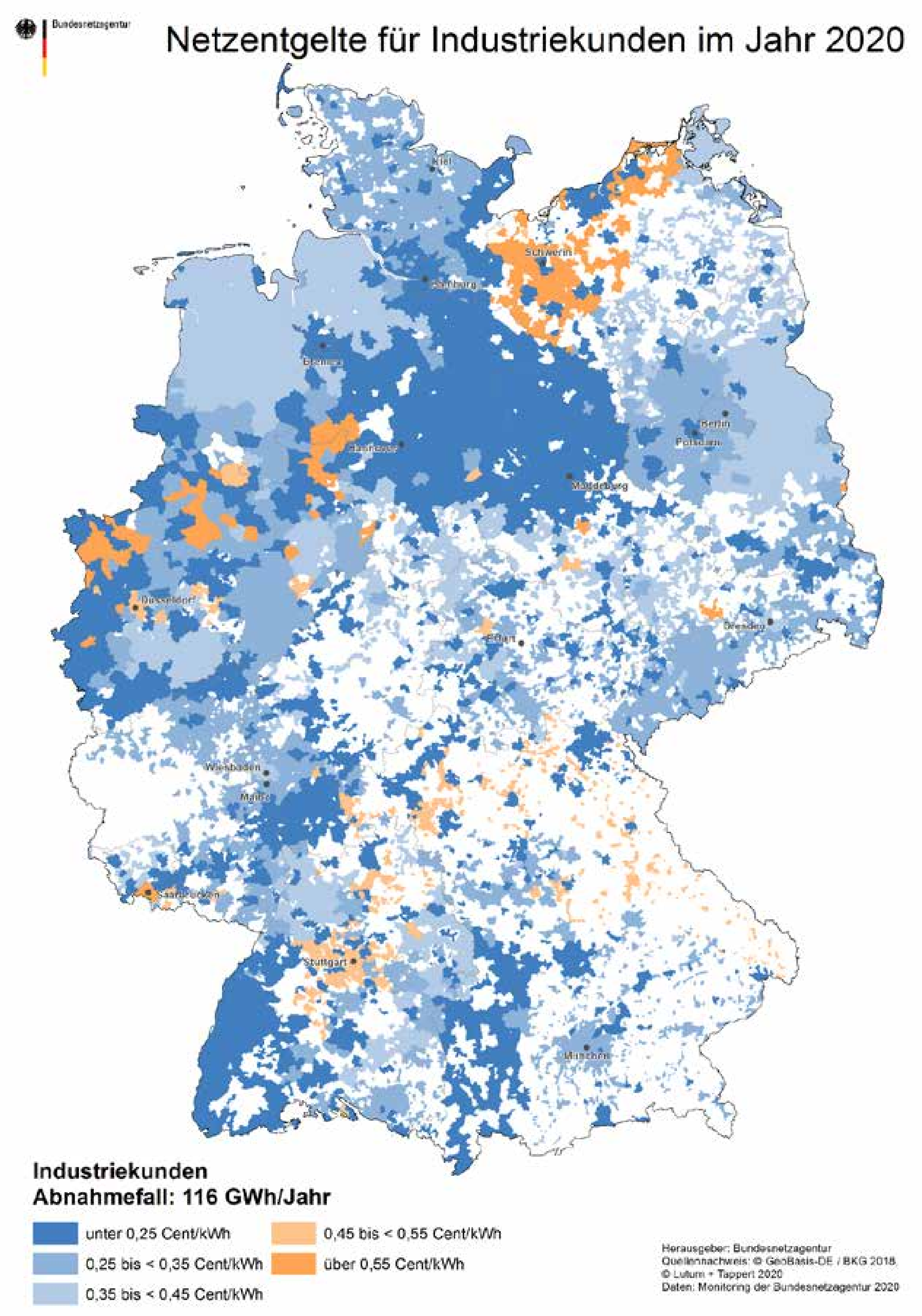


Figure 180: Distribution of gas network charges for industrial customers in Germany, as at 1 January 2020

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.

5.4 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. For the first time, the Bundesnetzagentur opened proceedings for so-called disputed network transfers. These related to network transfers from the second regulatory period. The Bundesnetzagentur has taken final decisions on the matter.

5.5 Network code on harmonised transmission tariff structures (NC TAR)

On 11 September 2020 the Bundesnetzagentur issued new determinations on implementation of the network code on harmonised transmission tariff structures against the background of the intended market merger due to take place on 1 October 2021. The determinations govern various aspects of tariff setting across individual market areas, ranging from the basic principles of tariff setting by way of the standard postage stamp (REGENT) to discounting and surcharge arrangements (MARGIT and BEATE 2.0) and, finally, the compensation payments between the TSOs resulting from these arrangements (AMELIE).

The new determinations are subsequent decisions following on from corresponding determinations from 2019 that are still applicable with reference to the as yet separate market areas until 30 September 2021. The content of the determinations does not differ significantly from that of the preceding determinations. The increase in the discount for interruptible capacity products applied in accordance with the MARGIT 2021 determination is also under consideration for national points in the context of adjustment of the BEATE 2.0 determination (BK9-20/608).

The preceding determinations were confirmed in full by the Higher Regional Court of Düsseldorf on 16 September 2020. The determinations may still be subject to proceedings at the Federal Court of Justice.

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.

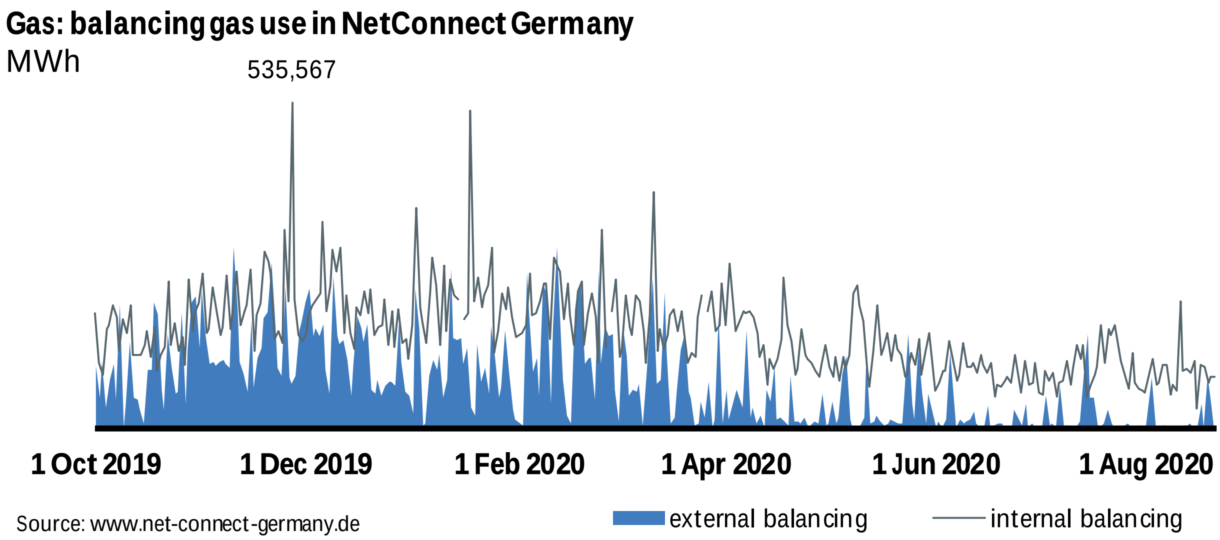


Figure 181: Balancing gas use from 1 October 2019 in the NetConnect Germany market area, as at August 2020

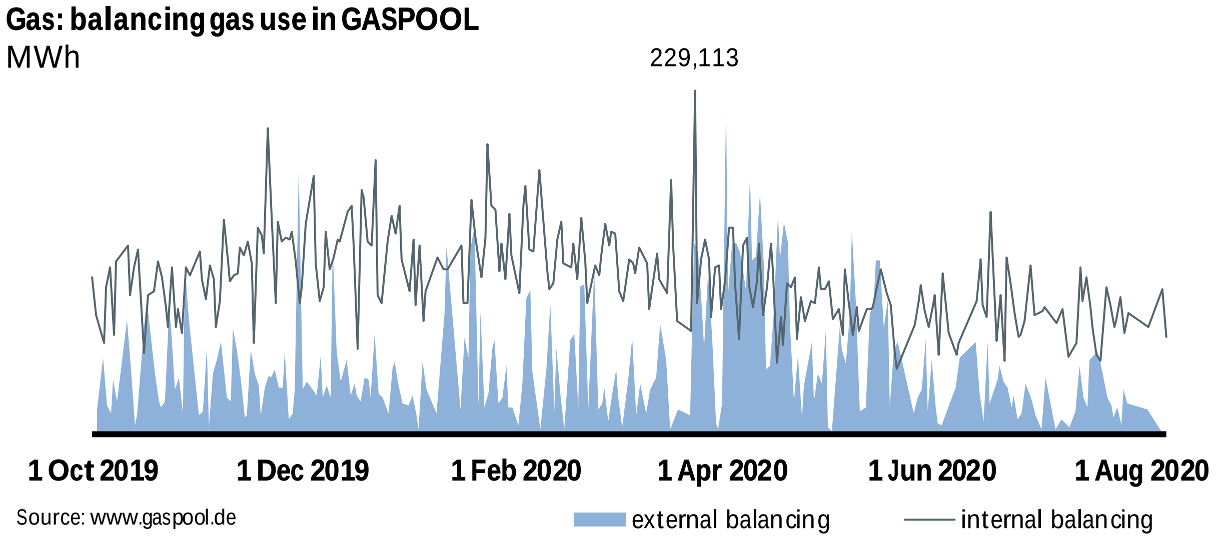


Figure 182: Balancing gas use from 1 October 2019 in the GASPOOL market area, as at August 2020

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.[147] As purchasing is mainly exchange-traded, the purchase prices are on the same level as general market prices.

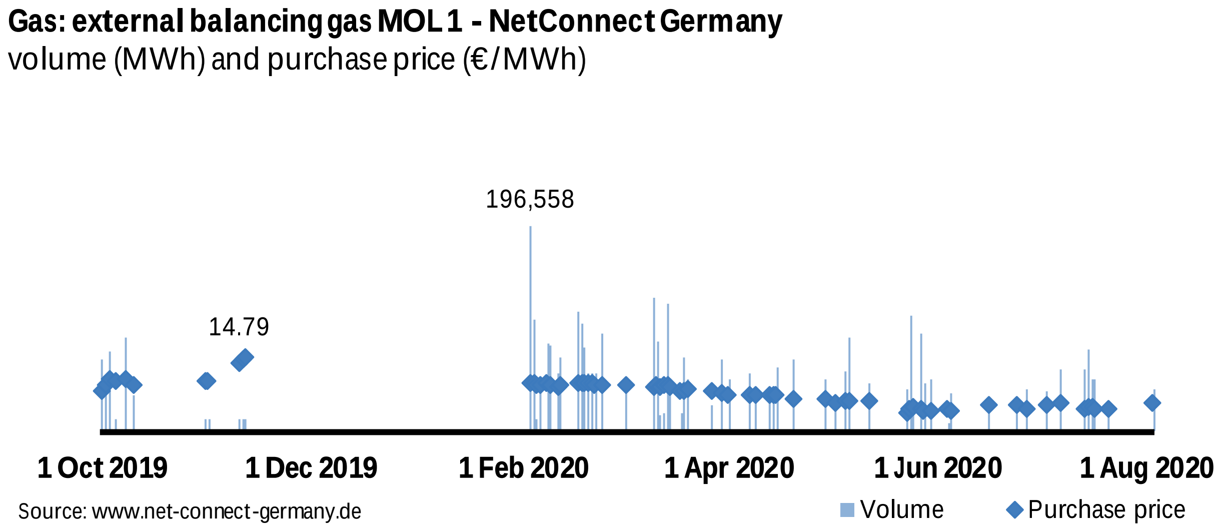


Figure 183: External balancing gas purchase prices and volumes from 1 October 2019 for MOL 1 in the NetConnect Germany market area, as at August 2020

[147] 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.

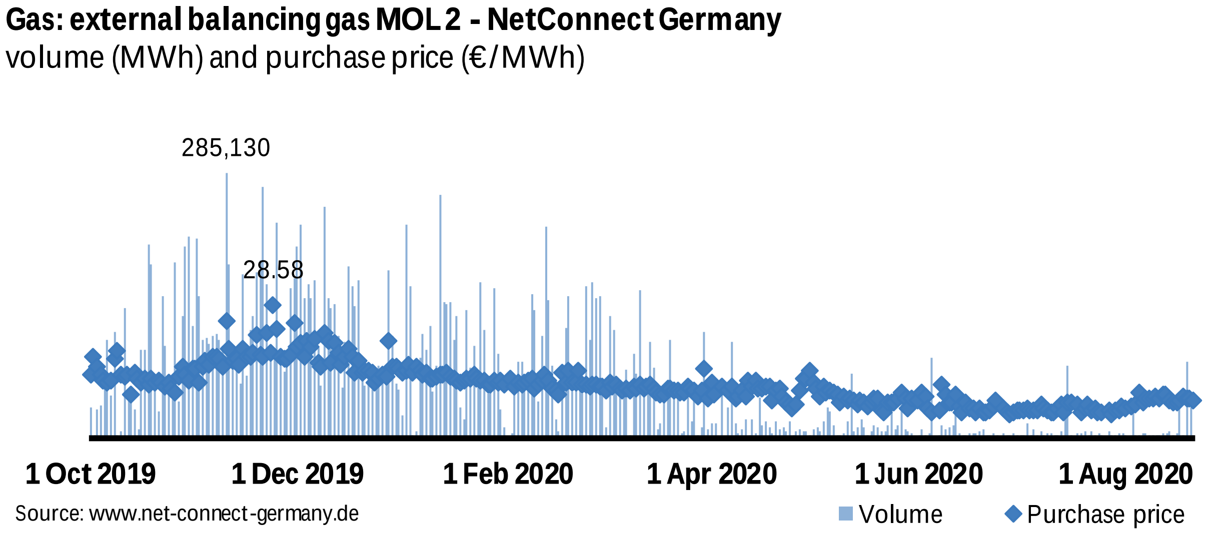


Figure 184: External balancing gas purchase prices and volumes from 1 October 2019 for MOL 2 in the NetConnect Germany market area, as at August 2020

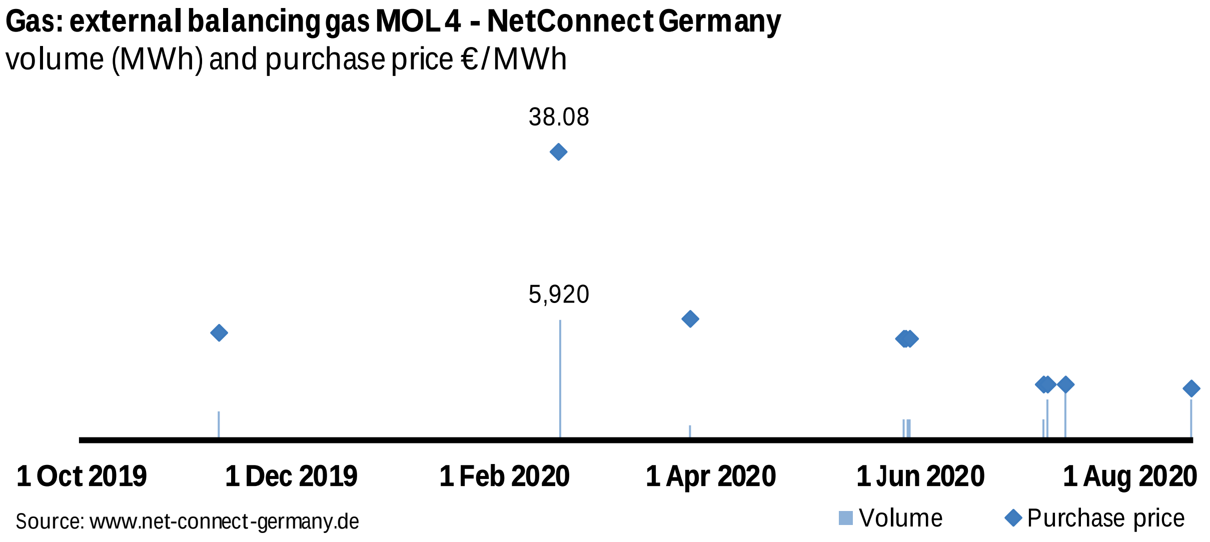


Figure 185: External balancing gas purchase prices and volumes from 1 October 2019 for MOL 4 in the NetConnect Germany market area, as at August 2020

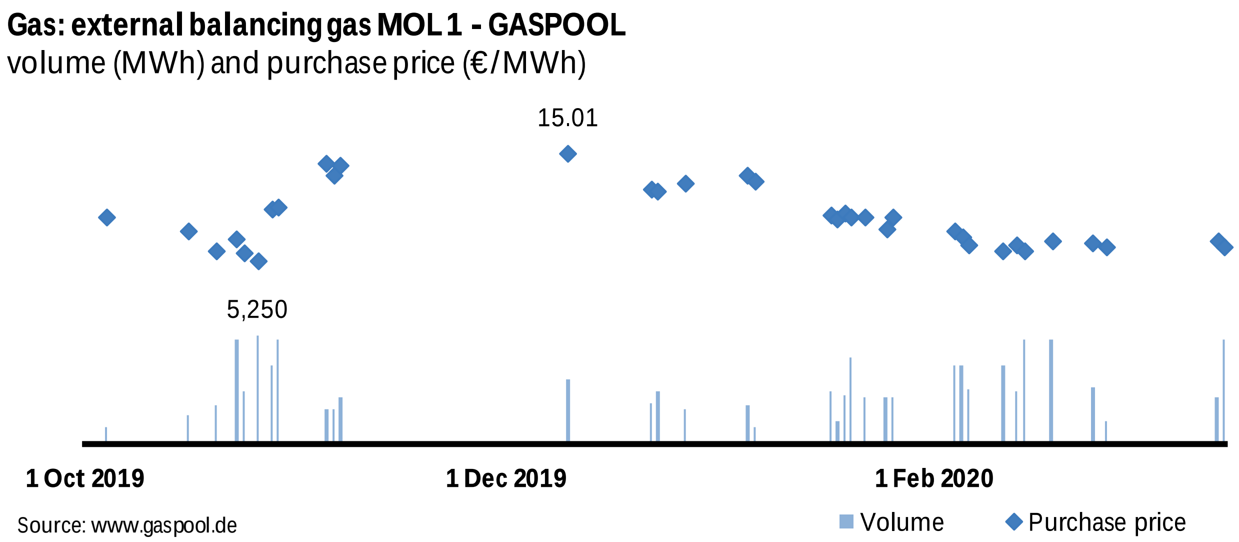


Figure 186: External balancing gas purchase prices and volumes from 1 October 2019 for MOL 1 in the GASPOOL market area, as at August 2020

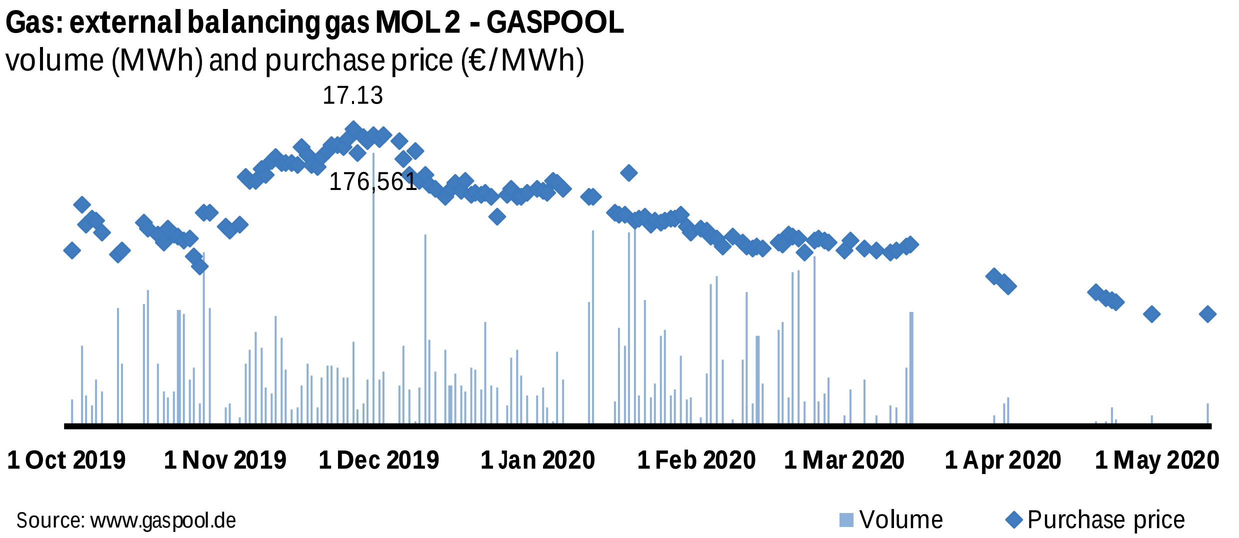


Figure 187: External balancing gas purchase prices and volumes from 1 October 2019 for MOL 2 in the GASPOOL market area, as at August 2020

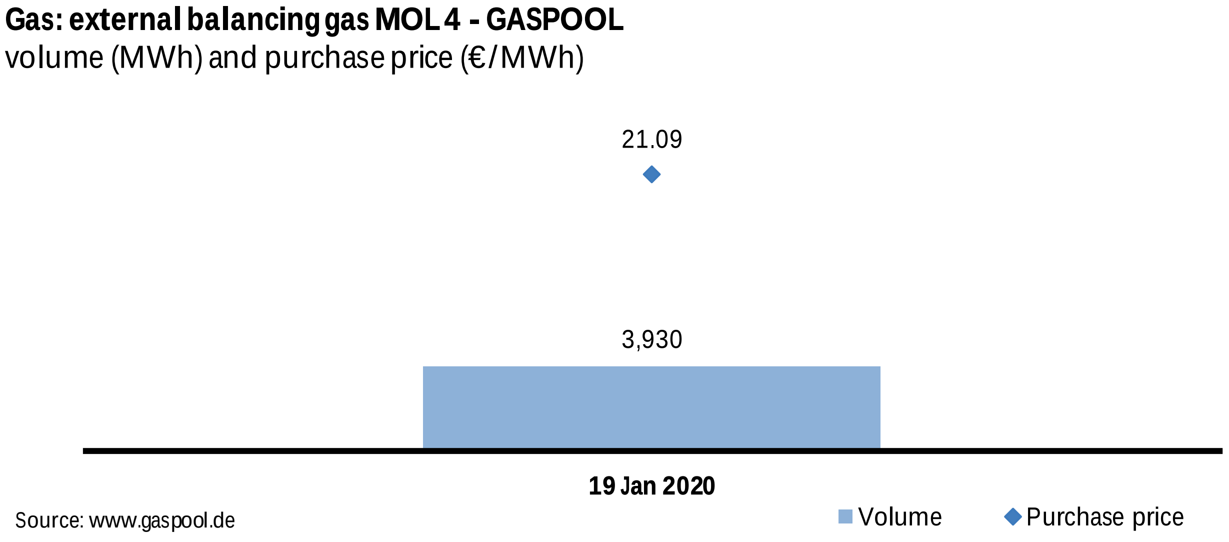


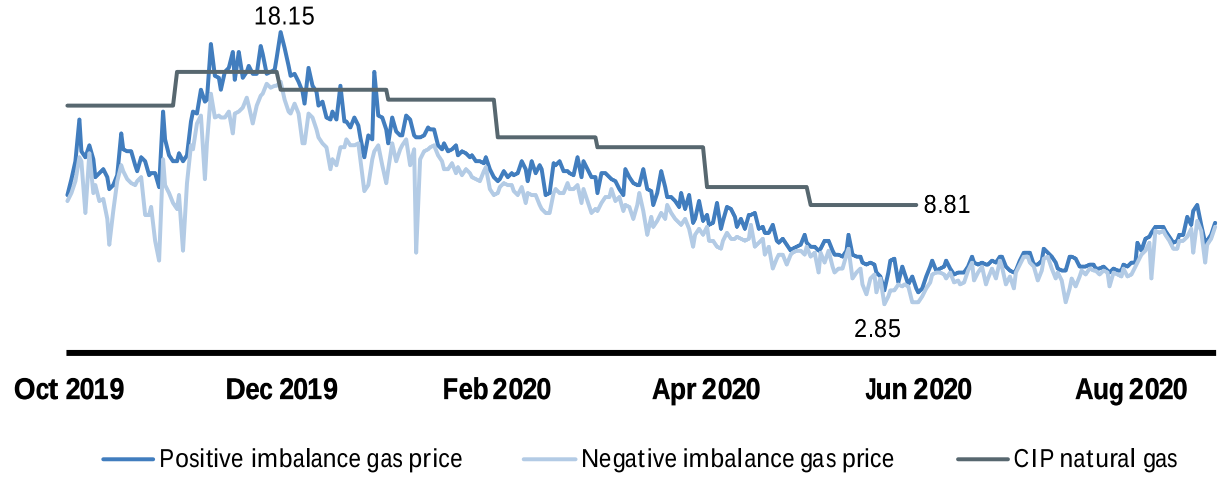
Figure 188: External balancing gas purchase prices and volumes from 1 October 2019 for MOL 4 in the GASPOOL market area, as at August 2020

1.2 Imbalance gas

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.

The balancing gas prices (MOL 1 and MOL 2, excluding local and hourly 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. The border price for natural gas, ie the import price for natural gas at the German border, is shown as a comparative value.

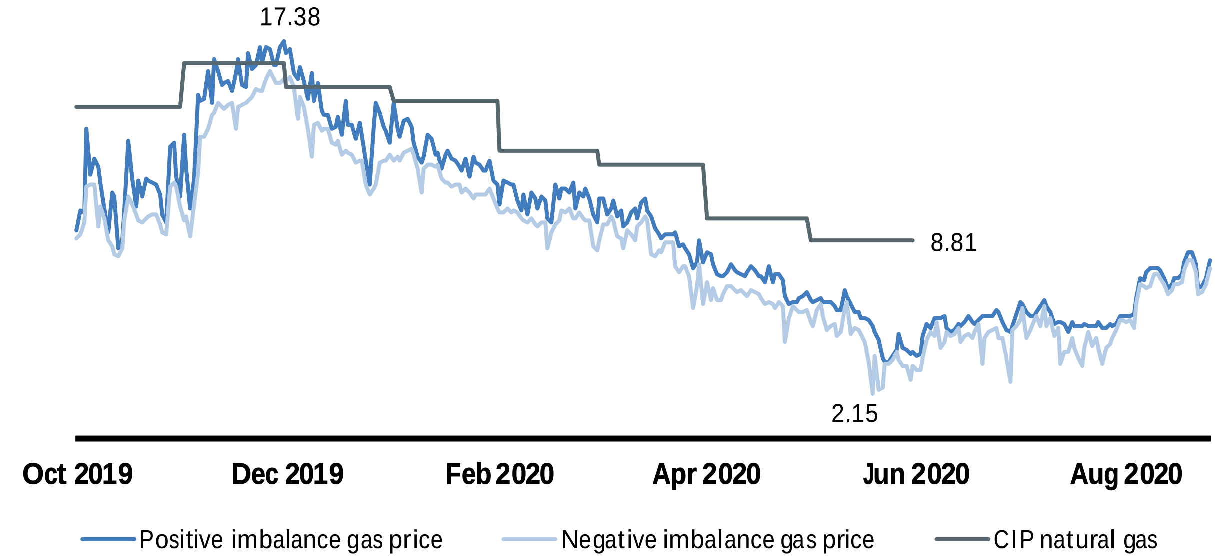
Gas: development of imbalance gas price - NetConnect Germany
€/MWh



Source: imbalance price MAM: www.net-connect-germany.de, cross-border interconnection point (CIP): www.bafa.de, as at July 2019

Figure 189: Development of NetConnect Germany imbalance prices since 1 October 2019, as at August 2020

Gas: development of imbalance gas price - GASPOOL
€/MWh



Source: imbalance price MAM: www.gaspool.de, cross-border interconnection point (CIP): www.bafa.de, as at July 2019

Figure 190: Development of GASPOOL imbalance prices since 1 October 2019, as at August 2020

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 respective market area manager forecasts the future costs and revenues for their neutrality charge account. If the costs are forecast to exceed revenues, the market area manager levies a neutrality charge from the respective balancing group managers.

The market area managers are required to set up two separate neutrality charge accounts, for exit points connecting either grid users with standard load profiles (SLP) or metered load profiles. The neutrality charges (SLP and metered load profile) each apply for one year.

The increasing procurement of balancing gas at the exchanges and a well-functioning balancing system, among other factors, have allowed both of the market area managers to temporarily lower the balancing neutrality charges to €0.00/MWh for several periods. For the period of validity as of 1 October 2020, a neutrality charge of €0.00/MWh will be levied for SLP customers and €0.10/MWh for customers with metered load profiles in the NCG market area. For the same period, a neutrality charge of €0.00/MWh will be levied for SLPs and €0.00/MWh for metered load profiles in the GASPOOL market area.

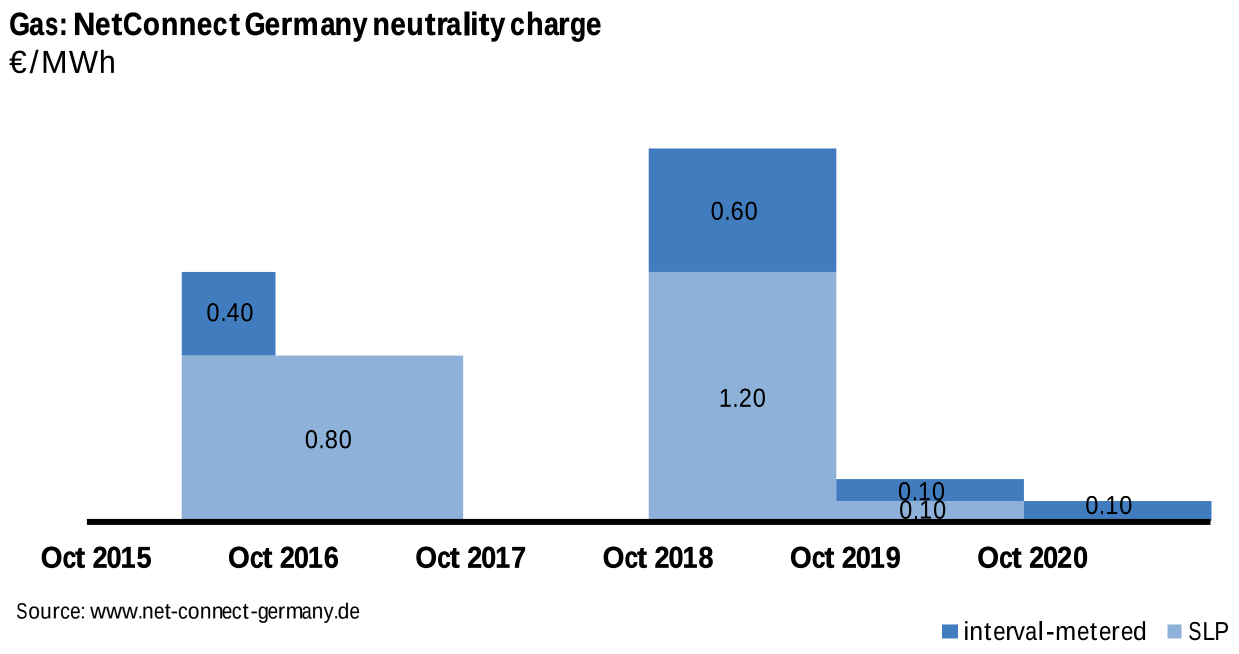


Figure 191: Neutrality charge in the NetConnect Germany market area, as at August 2020

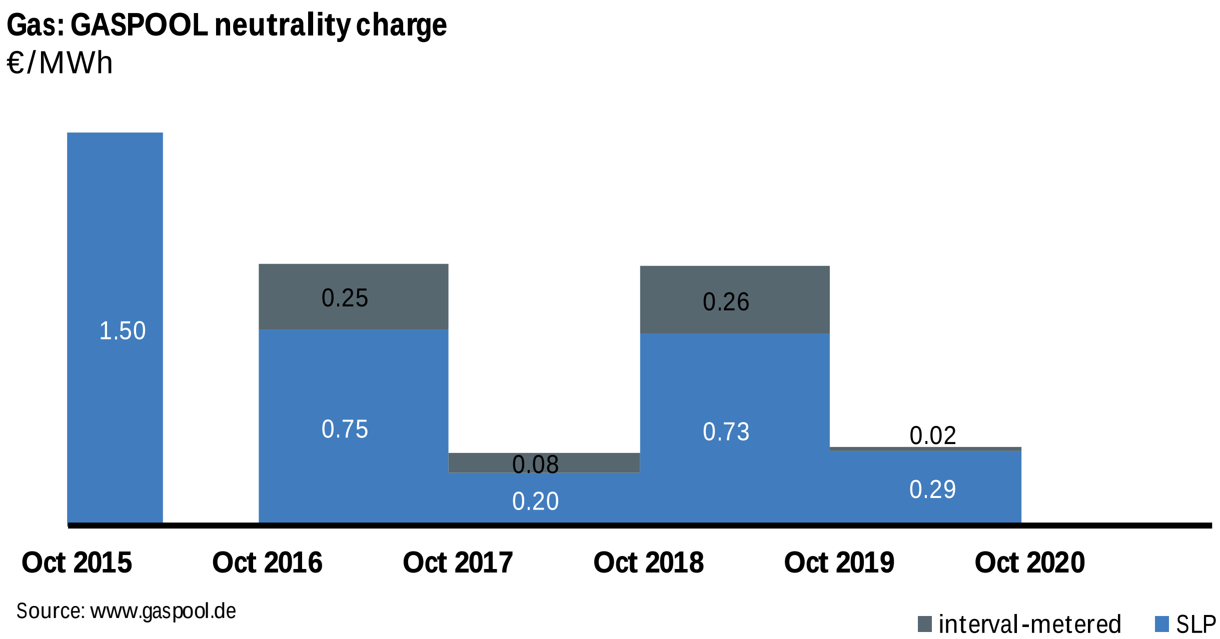


Figure 192: Neutrality charge in the GASPOOL market area, as at August 2020

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 97.4% of network operators. Customers with an installed capacity of at least 500 kW or annual consumption of at least 1.5m kWh must generally be interval-metered. The opportunity to deviate from this limit was taken by 4.2% of network operators, of which 34.5% stated that they reduced the limit for network-related reasons. In 58.6% of cases, the limits were agreed individually with shippers. According to the information provided, 52.9% of these agreed figures applied only to individual customer groups and the other 47.1% 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 2019, the synthetic SLPs were used by 80.8% of operators (2018: 81.4%); analytical profiles were used by 14.1% of operators, compared to 13.8% in 2018.

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 94.3%. This figure, too, remains almost unchanged from the previous year (93.9%).

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, 46.1% of network operators said they were, compared to 47.6% in 2018. As in the previous years, two to three profiles were generally used for household customers, whereas nine profiles were used on average for business customers (2018: eight).

Of network operators using the analytical profiles, 85.4% of them used the two-day delay method, with 25% stating they apply an optimisation procedure to minimise the two-day delay.

Whatever method was used, only 5.3% of operators made adjustments to the load profiles owing to large deviations from forecasts, compared to 5.1% in 2018. 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 48.2% of network operators were settled due to short portfolios in at least one month (no data from the network operator: 17.1%). The previous year, the figure was 49.5%. The average number of months for these network operators was three. The average across all network operators was 1.8 months.

The network accounts of 57% of network operators were settled due to long portfolios in at least one month (2018: 56.2%, no data from the network operator: 17.7%). The average number of months for these network operators was 9.4. The average including those network operators whose accounts were not settled was 6.5 months.

According to 53% of network operators, they had waived the credit from the settling of long portfolios.

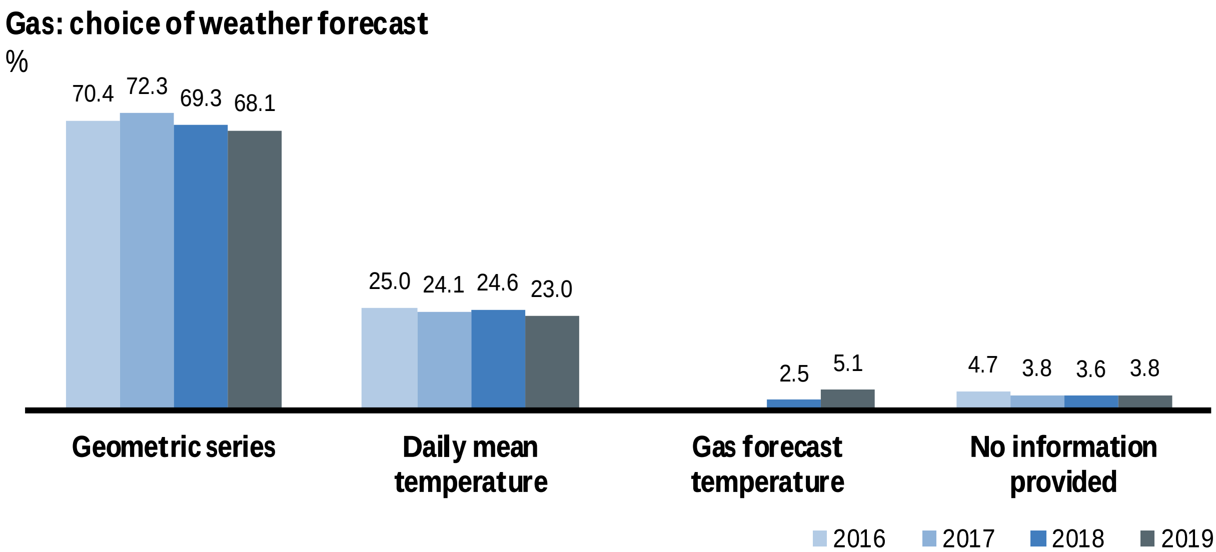


Figure 193: Choice of weather forecast

As SLPs are greatly temperature-dependent, 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 second time in 2019, with 5.1% of network operators stating they used it. This percentage is twice as high as the previous year (2.5%).

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 or several suppliers in the long term. Market players can thus choose from a variety of competing trading partners and hold a diversified portfolio of short-term and long-term trading contracts. Liquid wholesale markets make it easier for new suppliers 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. Natural gas wholesale trading is done to a large extent via off-exchange broker platforms. The volume of brokered wholesale trading has increased by 30%. The volume of on-exchange gas wholesale trading, of the EEX Group, for example, rose in 2019 by around 22%. In addition to the EEX, there are other gas exchanges such as the ICE, Gazprom ESP and Tender 365.

In 2019 there was a significant reduction in gas wholesale trading prices for the first time again. For example, the EGIX, which is used as a reference price for the medium-term procurement market, fell by an unweighted annual average of around 28% compared to 2018.

1. On-exchange wholesale trading

The European Energy Exchange AG already mentioned and its subsidiaries (referred to collectively as EEX below) operate an exchange for natural gas trading in Germany. As in previous years, EEX took part in this year's data collection in the course of monitoring.[148] 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.[149]

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 smaller 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.

Up to 31 December 2019 all EEX and Powernext trade on the European gas market was 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. On 1 January 2020

[148] It is intended to include other exchanges in the collection of data for energy monitoring in the coming years.

[149] In 2021 these two market areas are to be combined into one joint German market area.

Powernext's business was integrated into EEX AG under an exchange licence. On this date the EEX took over the operation of the former Powernext spot and futures markets for natural gas.

Futures can be traded for specific months, quarters, seasons (summer/winter) or years (calendars). In addition, in the second half of 2017 the EEC introduced a new European spot market index "European Gas Spot Index" (EGSI) to enable 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). A total volume of 2,542 TWh was traded on the EEX Group's gas markets in 2019. This represents an increase of about 30% (2018: 1,963 TWh). The spot market accounted for 1,454 TWh (2018: 1,111 TWh) and a total volume of 1,088 TWh was traded on the futures market (2018: 852 TWh). This growth on both submarkets could mainly be attributed to growth in the total market, whereby additional market shares could be gained in the spot market (plus 7% in comparison to the previous year).[150] The entire trading volume on PEGAS relating to the German market areas GASPOOL and NCG, including "cleared volume", was around 548 TWh in 2019, an increase of around 99 TWh, or 22%, on the previous year's figure of 449 TWh. The trading volume increased in both market areas compared to 2018. The trading volume for the GASPOOL market area increased by 25 TWh or around 14.5%, and by 74 TWh or around 27% for the NCG market area. The on-exchange volume traded on the spot market increased again in 2019 and was around 472 TWh (2018: around 391 TWh). In 2019 – as in previous years– the majority of spot market transactions for both market areas focused on day-ahead contracts ((NCG: 179.5 TWh, 132.9 TWh in the previous year; GASPOOL: 121.5 TWh, 102.8 TWh in the previous year). The trading volume of futures contracts rose from about 58 TWh in 2018 to about 75 TWh, corresponding to an increase of around 30%.

[150] EEX Group Annual Report 2019, p. 39.

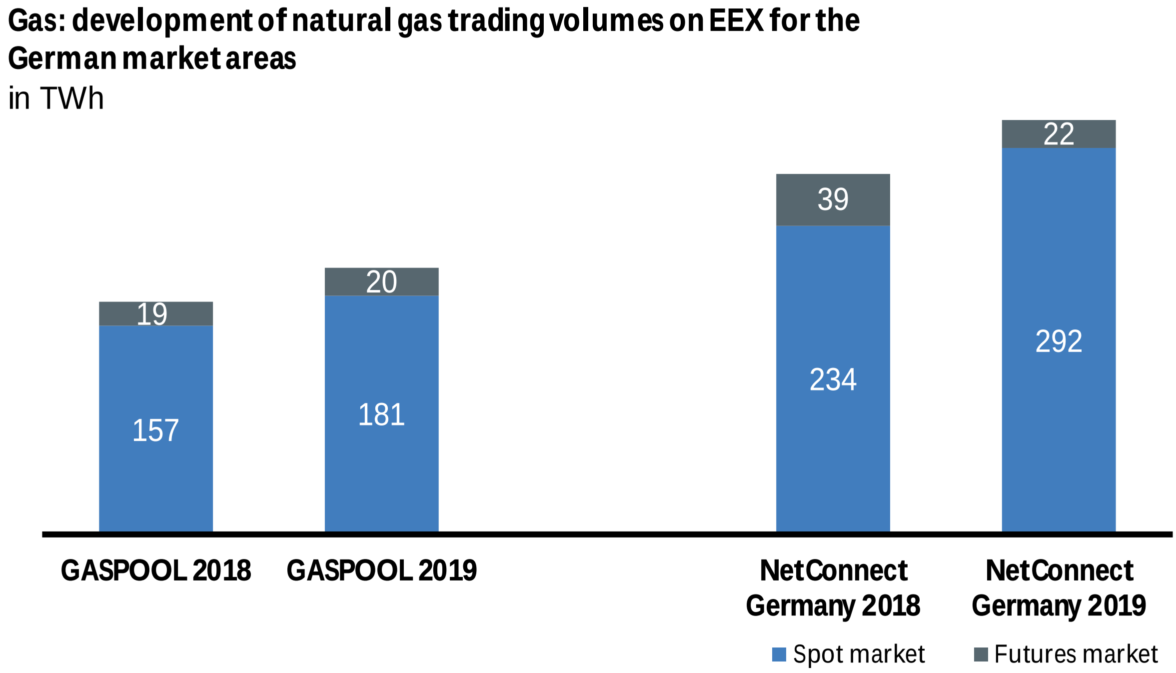


Figure 194: Development of natural gas trading volumes on EEX for the German market areas

The annual average number of active [151] participants on the spot market per trading day was 89 for NCG contracts (2018: 87) and around 77 for GASPOOL contracts (2018: 75). By contrast, the average number of active participants on the futures market per trading day was around 7.5 for the NCG market area (2018: 5.6) and around 3.9 for the GASPOOL market area (2018: 3.6). The comparison of these figures has to take account of the fact that, based on 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. Off-exchange wholesale trading

By far the largest share of wholesale trading in natural gas is carried out on a bilateral basis, i.e. off-exchange ("over the counter" – OTC). Off-exchange trading offers the advantage of flexible bilateral or multilateral 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 supply of and demand for short-term and long-term natural gas trading products. Engaging a broker can reduce search 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 clearance on the exchange to hedge the counterparty default risk of the parties. Electronic broker platforms are used to bring interested

[151] Participants are considered to be active on a trading day if at least one of their bids has been submitted.

parties on the supply and demand sides together and so increase the chances of the parties reaching an agreement.

Nine broker platforms (eight 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 2019 with Germany as the supply area comprised a total volume of 2,853 TWh (2,192 TWh in the previous year)[152] of which 1,207 TWh were contracts to be fulfilled in 2019 (fulfilment period of one week or more).

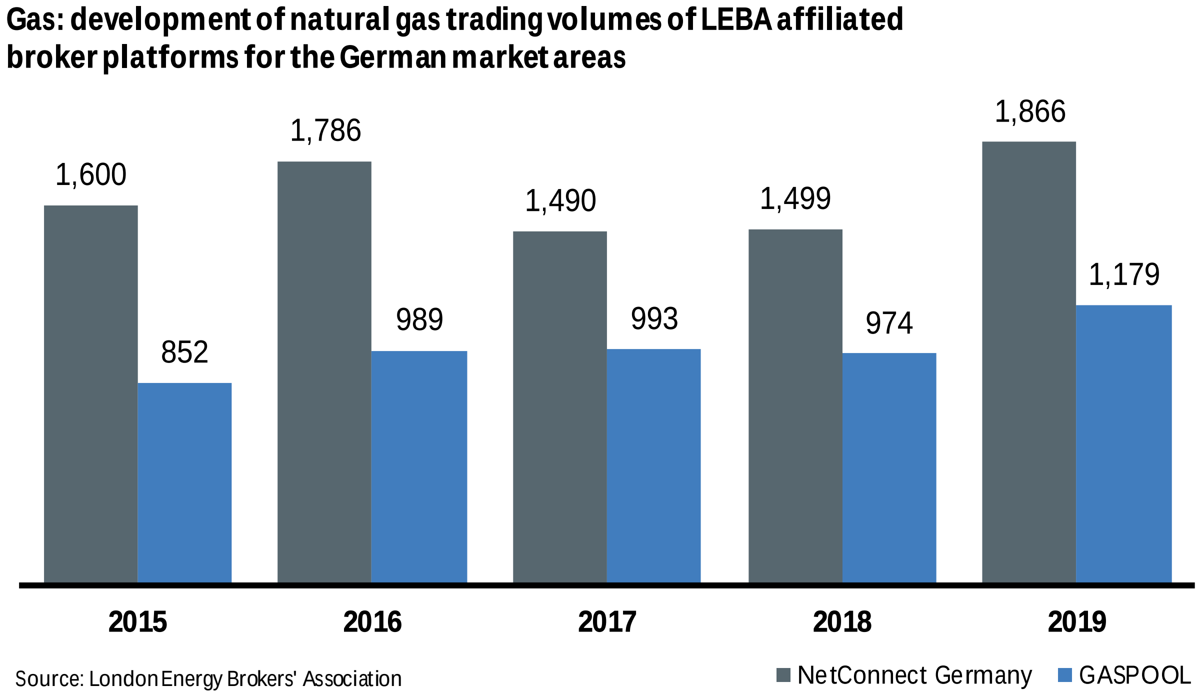


Figure 195: Development of natural gas trading volumes of LEBA-affiliated broker platforms for the German market areas

The increase in volume is confirmed by the figures relating to brokered natural gas trading for the GASPOOL and NCG market areas published by the London Energy Brokers Association (LEBA). Six of the nine broker platforms that provided data on which the above evaluation was based are members of LEBA. All the LEBA-affiliated broker platforms accounted for a total of 3,045 TWh for the two German market areas in 2019 (2,473 in 2018).[153]

On the spot market short-term transactions with a fulfilment period of less than one week account for about 13% of the trade brokered by the eight broker platforms whereas 87% 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 2019 (including spot trading) constitutes as much as 56% of the total volume and still as much as 30% for the subsequent year 2020, the share of transactions with

[152] Value corrected due to revised 2018 data.

[153] See London Energy Brokers` Association, OTC Energy Volume Report, https://www.lebaltd.com/monthly-volume-reports/ (retrieved on 8 October 2020).

supply dates in 2021 and later is 12%. This structure largely corresponds to the previous year's result with a slight increase in the quota for transactions with supply dates for the subsequent year 2020 (plus 2%).

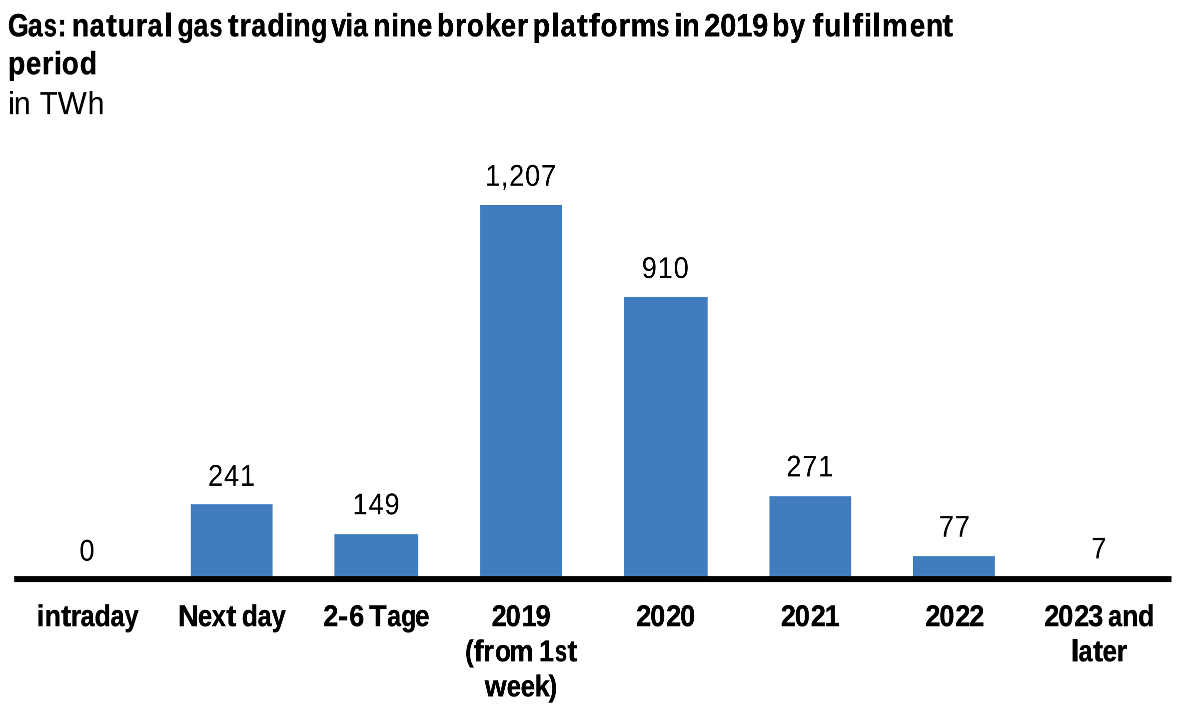


Figure 196: Natural gas trading for the German market areas via nine broker platforms in 2019 by fulfilment period

2.2 Nomination volumes at virtual trading points

The nominated volumes at the two German virtual trading points (VTPs) of NCG and GASPOOL are also 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 from a total of 3,780 TWh in the previous year to 4,033 TWh in 2019, an increase of about 6.7%. The GASPOOL VTP accounted for about 46% of the nomination volume, and the NCG VTP for 54%. Almost 91% of the nomination volume consisted of high calorific gas, the remaining 9% of low calorific gas.[154]

The nomination volume of high calorific gas at the GASPOOL VTP increased again by about 125 TWh (around 8%) year-on-year. The nomination volume at the NCG VTP increased by 144 TWh to 1,970 TWh (also around 8%). 17 TWh less low calorific gas was traded at the GASPOOL VTP, which represents a decrease of around 10%, based, however, on much lower trading volumes. An increase of only 1 TWh (approx. 0.5%) was registered at the NCG VTP in 2019.

Gas: development of nomination volumes at the German virtual trading points in TWh

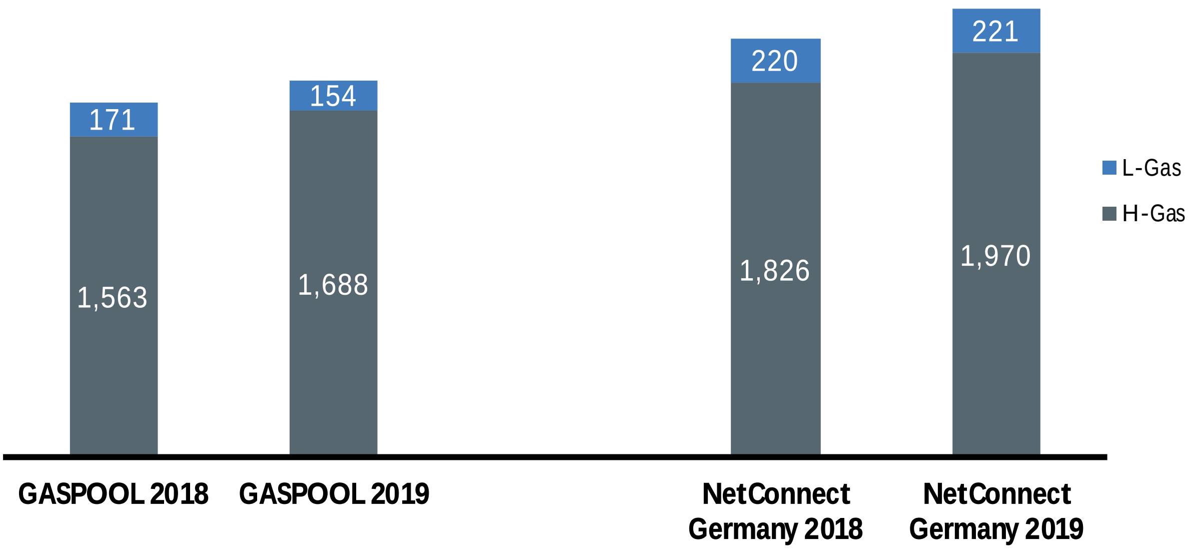


Figure 197: Development of nomination volumes at the German virtual trading points

As in previous years, the monthly nomination volumes reflect seasonal differences. The (aggregated) monthly nomination volumes of both VTPs peaked at 293 TWh between June and August 2019. The lowest nomination volume was around 268 TWh in August 2019; the annual peak of around 433.5 TWh was reached in January 2019.

[154] As a result of the merging of the NCG und GASPOOL market areas in 2021, there will only be one virtual trading point, the “Trading Hub Europe“; cf. https://www.energate-messenger.de/news/195040/deutsches-marktgebiet-wird-trading-hub-europe-heissen, http://www.marktgebietszusammenlegung.de/

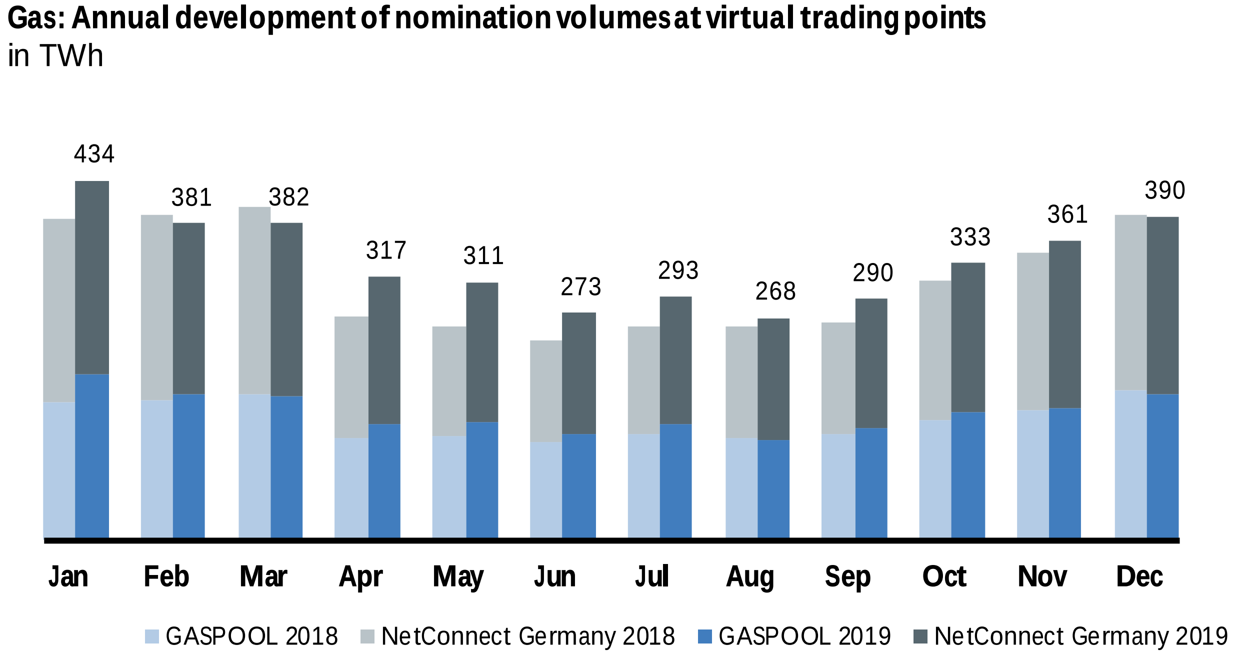


Figure 198: Annual development of nomination volumes at virtual trading points in 2018 and 2019

The number of active trading participants, i.e. companies that carried out at least one nomination in the relevant month, changed again in 2019. The number of active trading participants in the NCG market area rose from 327 to 340 for high calorific gas whereas the number of active participants for low calorific gas fell from 180 to 179. The annual average number of active participants in the GASPOOL market area fell year-on-year from 292 to 289 for high calorific gas and from 150 to 142 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 406 below, gives an approximate indication of the price of natural gas procurement on the basis of long-term supply contracts.

The 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. 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 also 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[155]. 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.

In 2019 the EGSI amounted to €14.18/MWh as the (unweighted) annual average for the NCG market area and €13.75/MWh for the GASPOOL market area. In 2018 the comparative figures for the daily reference price were each €22.95/MWh for NCG and GASPOOL: The EGSI fluctuated in the course of 2019 between €7.79/MWh (at 5 September 2019) and €23.24/MWh (at 18 January 2019) in both market areas.

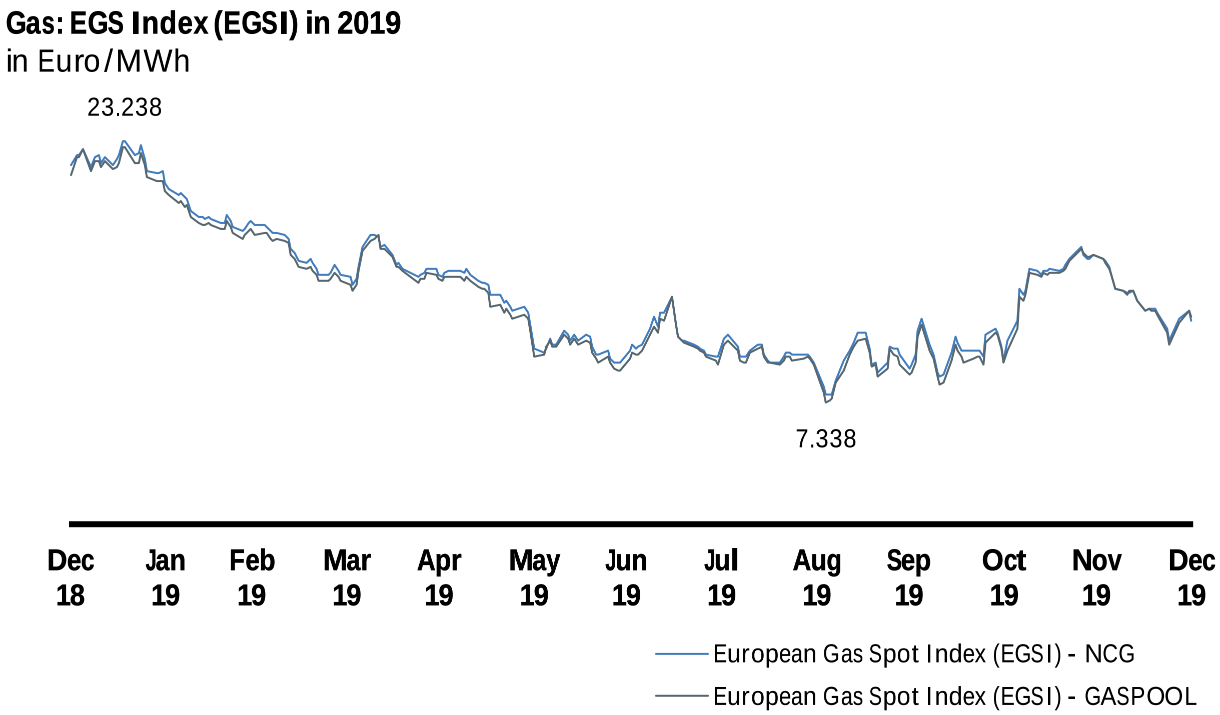


Figure 199: EEX-EGSI in 2019

The deviations between the EGSI for NCG and GASPOOL in 2019 were substantially greater than in 2018. On 42 trading days the price difference was 3% (2018: 11 trading days) and 4% on 25 trading days. Only on 162 of 251 exchange trading days (2018: 247 of 253 exchange trading days) did the difference reach a level of max. 2%.

[155] 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).

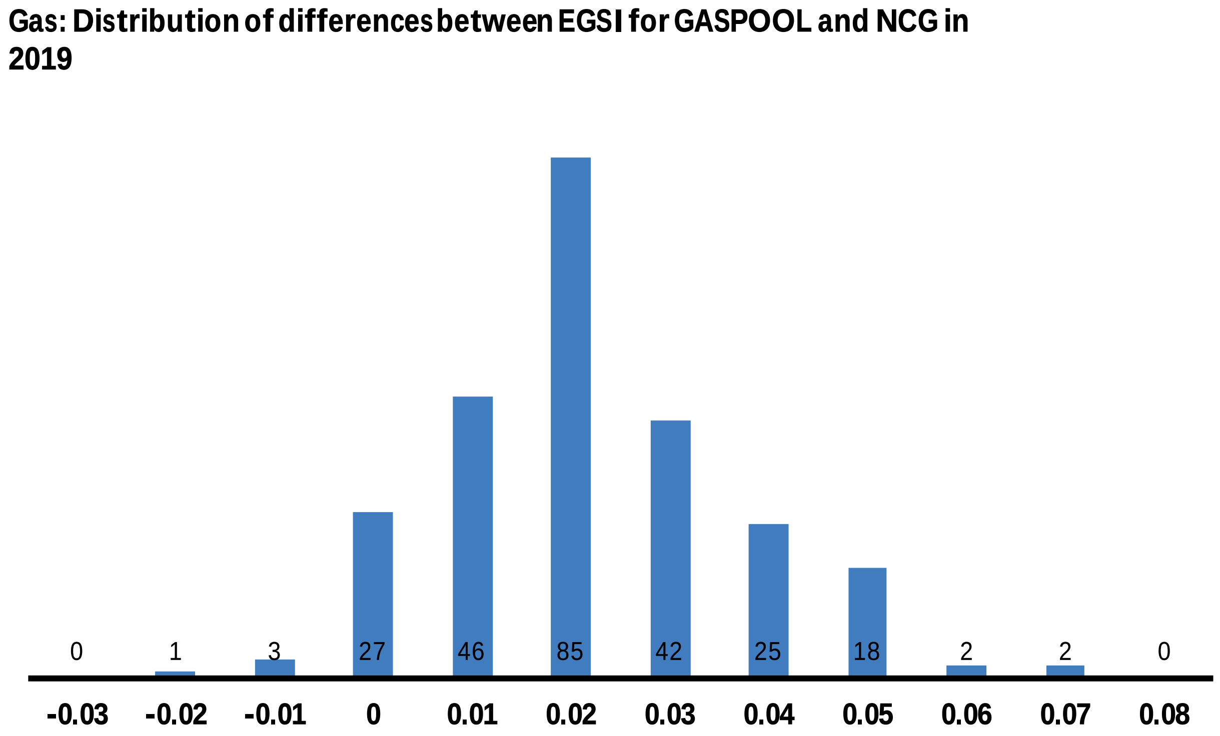


Figure 200: Distribution of the differences between the EGSI for GASPOOL and NCG in 2019

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[156]. In 2019 the EGIX Germany ranged from €11.11/MWh in August to €24.13MWh in January. The arithmetic mean of the twelve monthly figures was €15.75/MWh, a decrease of approximately 28% compared to the previous year's figure of €21.98/MWh.

The cross-border price for each month is calculated by the Federal Office for Economic Affairs and Export Control (Bundesamt fur 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[157], spot volumes and prices are largely disregarded.

The monthly BAFA cross-border prices for natural gas ranged from €12.20 /MWh to €21.68/MWh between 2016 and 2019. The (unweighted) average of the monthly cross-border prices was €15.99/MWh in 2019, down by 16.5% from the 2018 figure of €19.15/MWh.

[156] 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 3 November 2020).

[157] See https://www.bafa.de/SharedDocs/Downloads/DE/Energie/egas_aufkommen_export_1991.html (retrieved on 3 November).

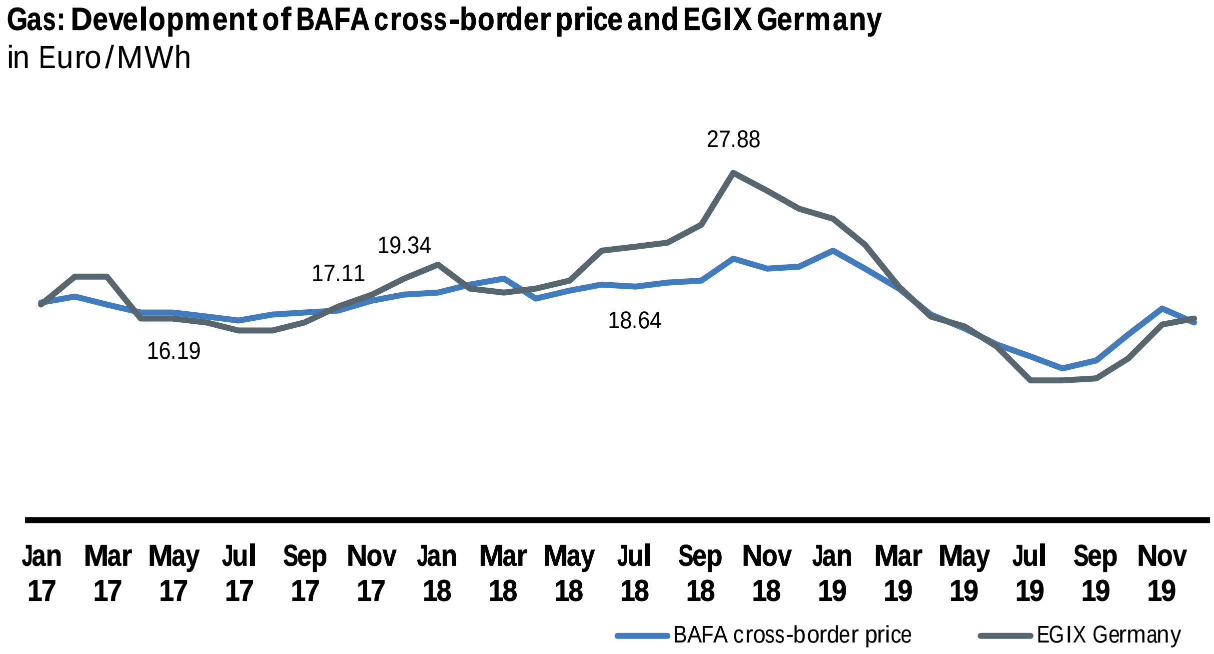


Figure 201: Development of the BAFA cross-border price and the EGIX Germany between 2017 and 2019

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 2019 again clearly shows that it is aligned with natural gas exchange prices.

F Retail

1. Supplier structure and number of providers

A total of 1,010 gas suppliers were surveyed for the 2020 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 (507 companies or 52%) supplied between 1,001 and 10,000 market locations each. These 507 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 140.5 TWh. Based on the total calculated volume of gas delivered of 857.7 TWh, this corresponds to a share of 16%.

The smallest group of gas suppliers (comprising 24 companies or just over 2%), in which each company supplies more than 100,000 market locations, supplies 5.9m or about 42% of the final consumer market locations. The amount of gas that these suppliers delivered to final consumers was 210.5 TWh. Based on the total reported volume of gas delivered of 857.7 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 (numbers and percentage)
figures do not take account of company affiliations

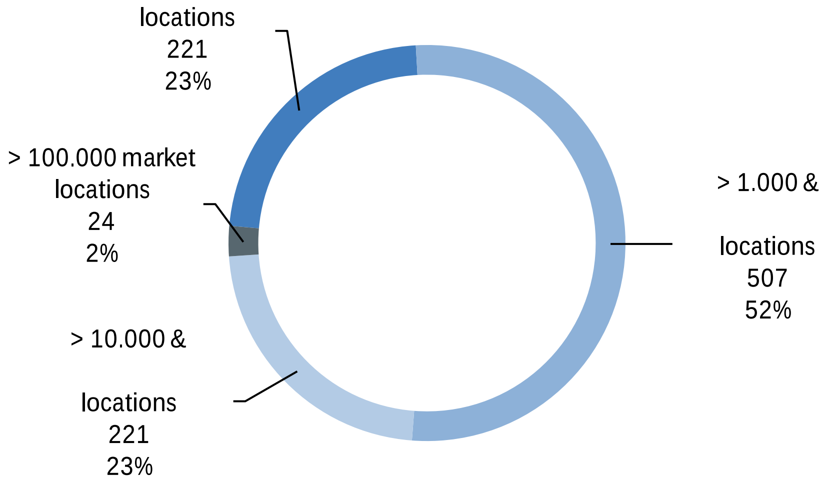


Figure 202: Gas suppliers by number of market locations supplied (number and percentage) – as at 31 December 2019

Gas: breakdown of network areas by number of suppliers operating
(all final consumers (left graph) and household customers (right graph))

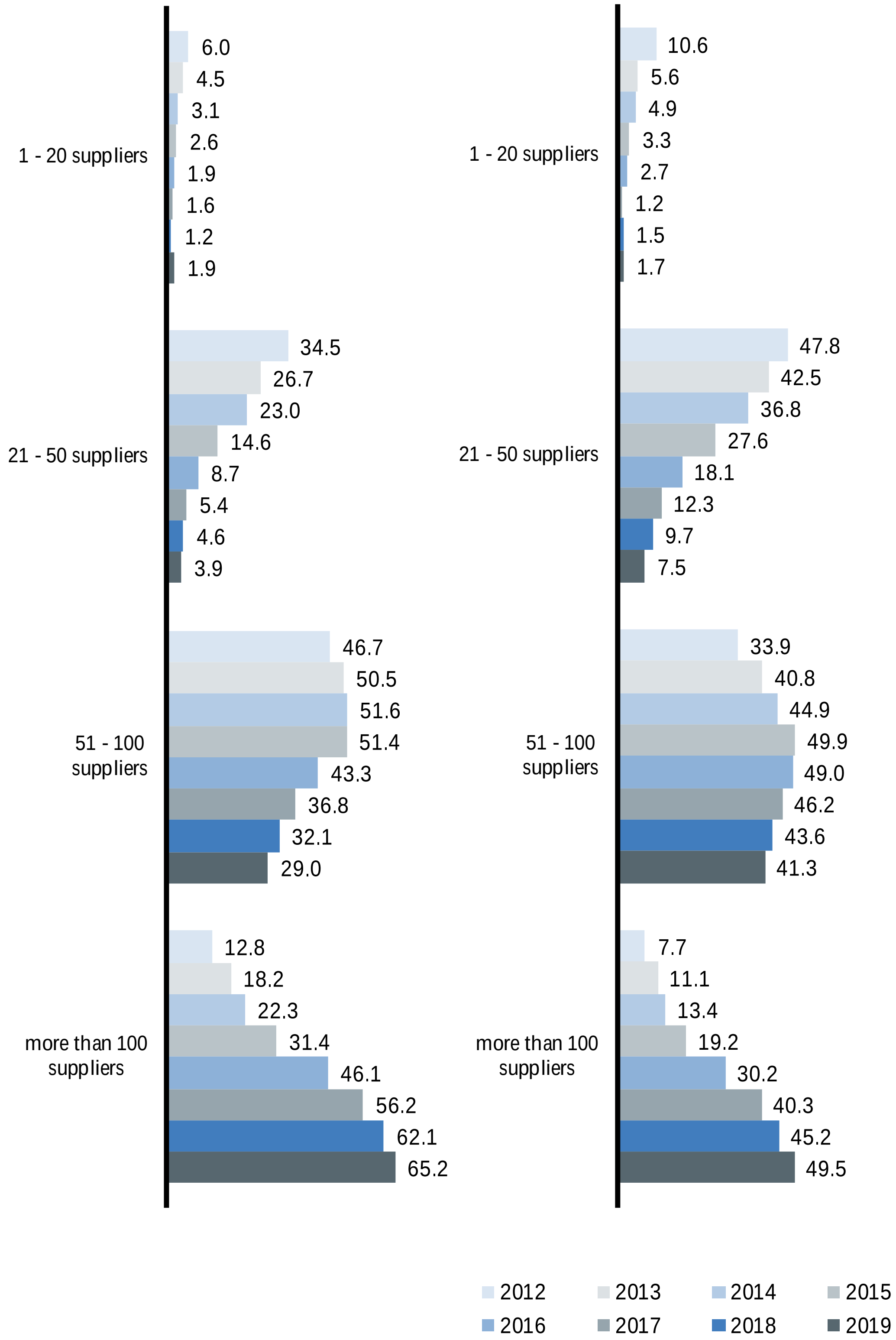


Figure 203: Breakdown of network areas by number of suppliers operating according to the survey of gas DSOs – as at 31 December 2019

One indicator of the degree of choice for gas customers is the number of suppliers in each network area. In the 2020 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 an efficient 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 was maintained in 2019 as well.

In 2019, more than 50 gas suppliers were operating in 94% of network areas. Final consumers in over 65% 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 91% of network areas, household customers have a choice of 50 or more gas suppliers. More than 100 gas suppliers are operating in almost 50% of network areas.

On average, final consumers in Germany can choose from 129 suppliers in their network area (2018: 124); household customers can, on average, choose between 109 suppliers (2018: 104 suppliers) (these figures do not take account of corporate groups).

Gas: suppliers by number of network areas supplied (number and percentage)
figures do not take account of company affiliations

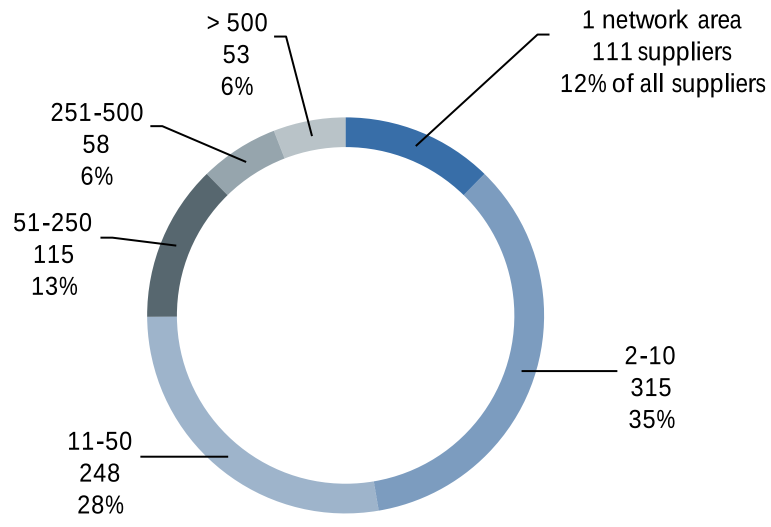


Figure 204: Gas suppliers by number of network areas supplied (number and percentage), according to the survey of gas suppliers – as at 31 December 2019

Suppliers were also asked about the number of network areas in which they supply final consumers with gas. Only 12% of the gas suppliers operate in just one established network area. Most of them (35%) supply final consumers with gas in at most 10 network areas 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 53 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 83 network areas. Another figure that depicts the nationwide activity of suppliers is the number of federal states supplied: 120 suppliers have concluded contracts in all 16 federal states.

2. Contract structure and supplier switching

Half of Germany's 12.5m household customers have a non-default contract with the local default supplier. About 17% 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 a supplier other than the local default supplier has been rising continually.

Nearly 1.6m household customers switched gas supplier in 2019. 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.[158] All other customers are

[158] 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.

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 2019 reached 857.7 TWh (2018: 818.6 TWh). Based on the reported volumes of gas sold to SLP and interval-metered customers, about 501.4 TWh went to interval-metered customers and about 360.1 TWh to SLP customers, compared to 450.1 TWh and 376.4 TWh respectively in the previous year.[159] The majority of SLP customers are household customers. In 2019 household customers within the meaning of section 3 para 22 EnWG were supplied with around 262 TWh (2018: 253.1 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.[160] 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".[161]

Once again, gas suppliers were asked how many household customers switched or changed their energy supply contract in the 2019 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 2019. A supplier switch, as defined in the monitoring survey, means the process by which a final

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[159] The difference between the amount of 861.5 TWh (total of interval-metered and SLP volumes) and the total volume of 857.7 TWh is due to different data from the suppliers surveyed.

[160] 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".

[161] It is also possible that further ambiguities may arise, for example if the local default supplier changes.

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 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.[162] All interval-metered customers are non-household customers with a high level of consumption, such as industrial customers or gas power plants.

In the reporting year 2019, 907 gas suppliers (separate legal entities) provided information on metering points and on the volumes supplied to interval-metered customers (in 2018: 934). The 907 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 501.4 TWH of gas to interval-metered customers via more than 44,982 metering points in 2019. Over 99% of this volume was supplied under contracts with the default supplier outside the default supply[163] (120.9 TWh) and under contracts with suppliers other than the local default supplier (380.3 TWh). It is unusual but not impossible for interval-metered customers to be supplied under default or fallback supply contracts. Around 0.3 TWh of gas was supplied to interval-metered customers with a default or fall-back supply contract. This corresponds to about 0.05% of the total volume supplied to such customers.

About 24.1% of the total volume supplied to interval-metered customers in 2019 (25.7% in 2018) was sold under contracts with the default supplier outside the default supply and about 75.9% (74.2% in 2018) was sold 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 interval-metered gas customers.

[162] 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.

[163] In accordance with Section 36 of the German Energy Act (EnWG), default supply only applies to household customers. In the following, the term default supply used in connection with non-household customers refers to "fallback supply".

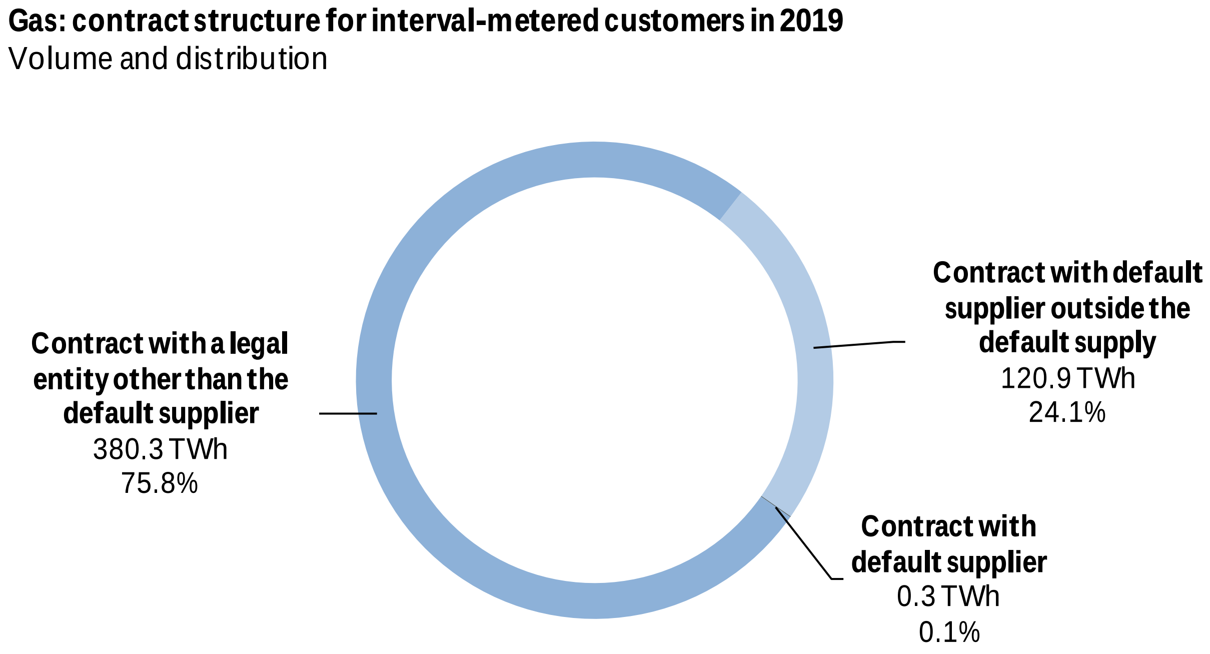


Figure 205: Contract structure for interval-metered customers in 2019

2.1.2 Supplier switching

Data on the supplier switching rates (as defined for monitoring, see above) of different customer groups in 2019 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 the four highest consumption categories with a final consumption exceeding 0.3 GWh/year, including gas-fired power plants. The survey produced the following results:

Gas: supplier switching by consumption category in 2019

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/year	1,472,169	10.4%	34.7 TWh	10.5%
0,3 GWh/year < 10 GWh/year	14,969	11.2%	15.8 TWh	12.4%
10 GWh/year < 100 GWh/year	1,142	27.3%	15.8 TWh	14.5%
100 GWh/year	158	29.2%	12.6 TWh	6.4%
Gas-fired power plants	4	2.0%	3.7 TWh	3.8%
Total	**1,488,442**		**82.6 TWh**	

Table 125: Supplier switching by consumption category in 2019

The total number of metering points with a change of supplier in 2019 increased from 1,462,060 in 2018 to 1,488,442 (+1.8%). An increase was registered in

categories compared to 2018. In 2019, the total gas volume affected by supplier switching was approx. 82.6 TWh in all five categories. Compared to the previous year, it fell by around 8 per cent (89.5 TWh in 2018).

Gas: supplier switching among non-household customers
with a consumption exceeding 300 MWh/year

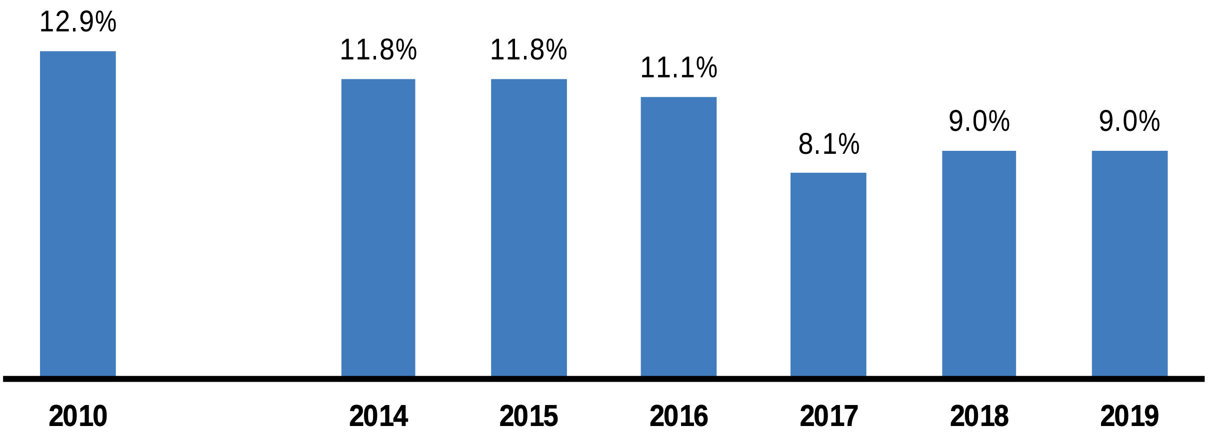


Figure 206: Supplier switching among non-household customers

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% again as in 2019.

2.2 Household customers

2.2.1 Contract structure

In the data survey for the 2020 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 2019 in terms of volume shows that nearly half of them (49%) were supplied by the local default supplier under a non-default contract, receiving 128.4 TWh of gas (2018: 50%/124.7 TWh).

Only 17% of household customers still had a default supply contract in 2019 and these were supplied with 43.7 TWh of gas (2018: 18%/45.3 TWh). The percentage of household customers who had a contract with a supplier other than the local default supplier increased again to 34% for a total of 89.9 TWh of gas (2018: 32%/79.1 TWh).[164] Thus supply by the default supplier at a default tariff is the least popular form of supply.

[164] The total volume of gas supplied to household customers reported by gas suppliers of 262 TWh differs from the amount reported by gas DSOs (282.5 TWh) because the market coverage of the network operator survey is higher.

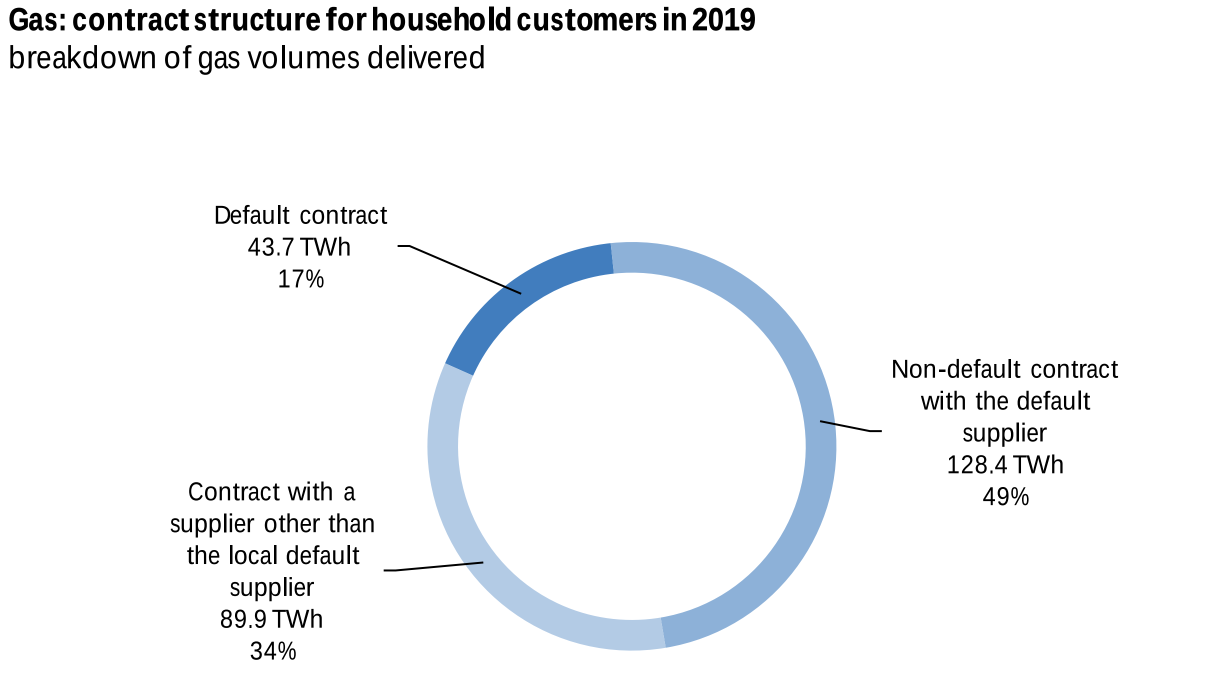


Figure 207: Contract structure for household customers (volume of gas delivered) according to survey of gas suppliers – as at 31 December 2019

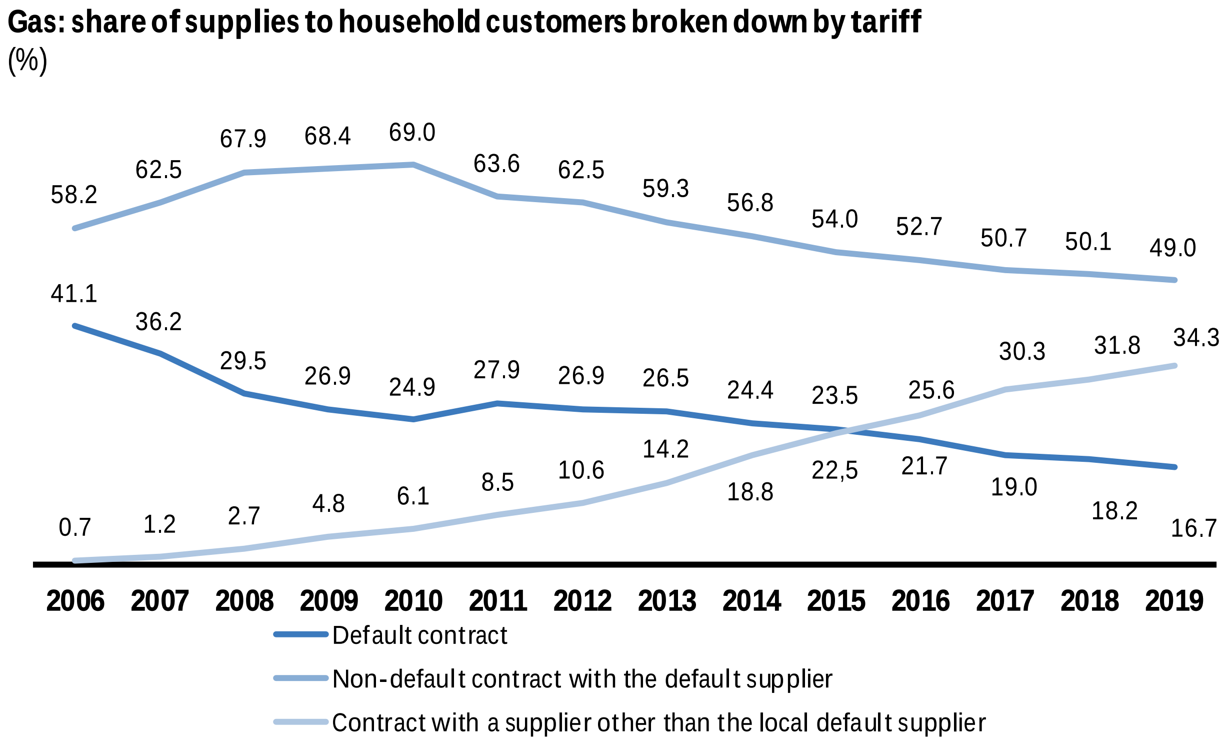


Figure 208: Share of gas supplies to household customers broken down by tariff according to survey of gas suppliers – as at 31 December 2019

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 41%, this figure was lower than the 43% 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.[165]

Gas: contract stucture for household customers (volume 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) < 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	2.4	41	32.8	18	6.4	10
Non-default contract with the default supplier	1.9	32	90.2	50	31.9	52
Contract with a supplier other than the local default supplier	1.6	23	58.2	32	22.8	37
Total	5.9	100	181.2	100	61.1	100

Table 126: Contract structure for household customers (volume) broken down into consumption bands – as at 31 December 2019

When focusing on the number of household customers supplied in 2019, it becomes clear that a relative majority of 43% of them had a non-default contract with the local default supplier. In terms of the volume of gas delivered and the number of customers supplied, a total of about 66% and 68% respectively of household customers are supplied by the default supplier under a default contract or a contract outside of default supply.[166]

165 The analysis is based on a reported volume of gas supplied to household customers of 248.2 TWh. The difference from the total reported volume of gas supplied to household customers by all gas suppliers of 262 TWh is due to a lack of data from some suppliers.

166 The total number of household customers reported by gas suppliers of 12.5m differs from the number of household customers reported by DSOs (12.8m) because the market coverage of the network operator survey is higher.

Gas: contract structure for household customers
number and percentage of customers supplied

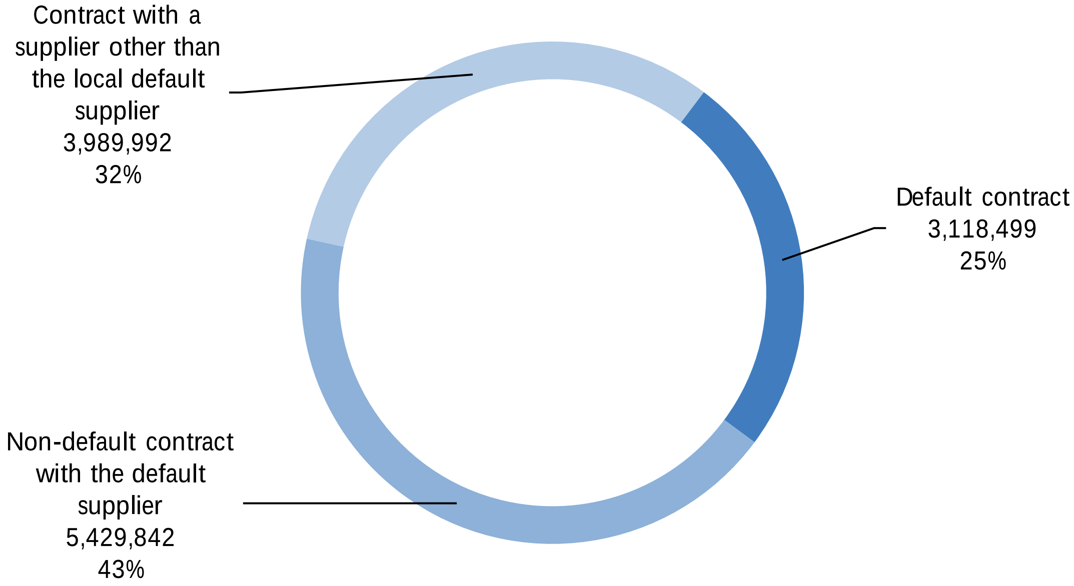


Figure 209: Contract structure for household customers (number of customers supplied) according to survey of gas suppliers – as at 31 December 2019

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 (50%). The majority of customers with average (D2) and high (D3) consumption were supplied under a non-default contract with the default supplier.[167]

[167] The analysis is based on a reported total number of household customers of 11.9m. The difference from the total reported number of household customers of all gas suppliers of 12.5m is due to a lack of data from some suppliers.

Gas: contract structure for household customers (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 (m)	Distribution (%)	Number (m)	Distribution (%)
Default contract	1.1	50	1.8	22	0.1	17
Non-default contract with the default supplier	0.6	27	4.4	48	0.3	50
Contract with a supplier other than the local default supplier	0.5	23	2.9	30	0.2	33
Total	2.2	100	9.1	100	0.6	100

Table 127: Contract structure for gas household customers (number) broken down into consumption bands – as at 31 December 2019

2.2.2 Change of contract

Gas suppliers were asked about household customers that changed contract at their own request in 2019.[168] The total number of customers changing contract in 2019 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%.

Gas: household customers that changed their contracts

Category	Subsequent consumption in 2019 (TWh)	Share of total consumption (262 TWh) (%)	Number of contracts changed in 2019	Share of all household customers (12.5m) (%)
Household customers that changed their contract with their existing supplier	13.7	5.2	0,6m	4.8

Table 128: Gas household customers that changed their contracts in 2019 according to survey of gas suppliers

2.2.3 Supplier switch

To determine the number of supplier switches by household customers, the DSOs were asked to provide information on the number of customers switching and volumes involved at market locations as well as

[168] 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.

information concerning customers choosing a supplier other than the default supplier within the meaning of section 36(2) EnWG immediately when moving home.

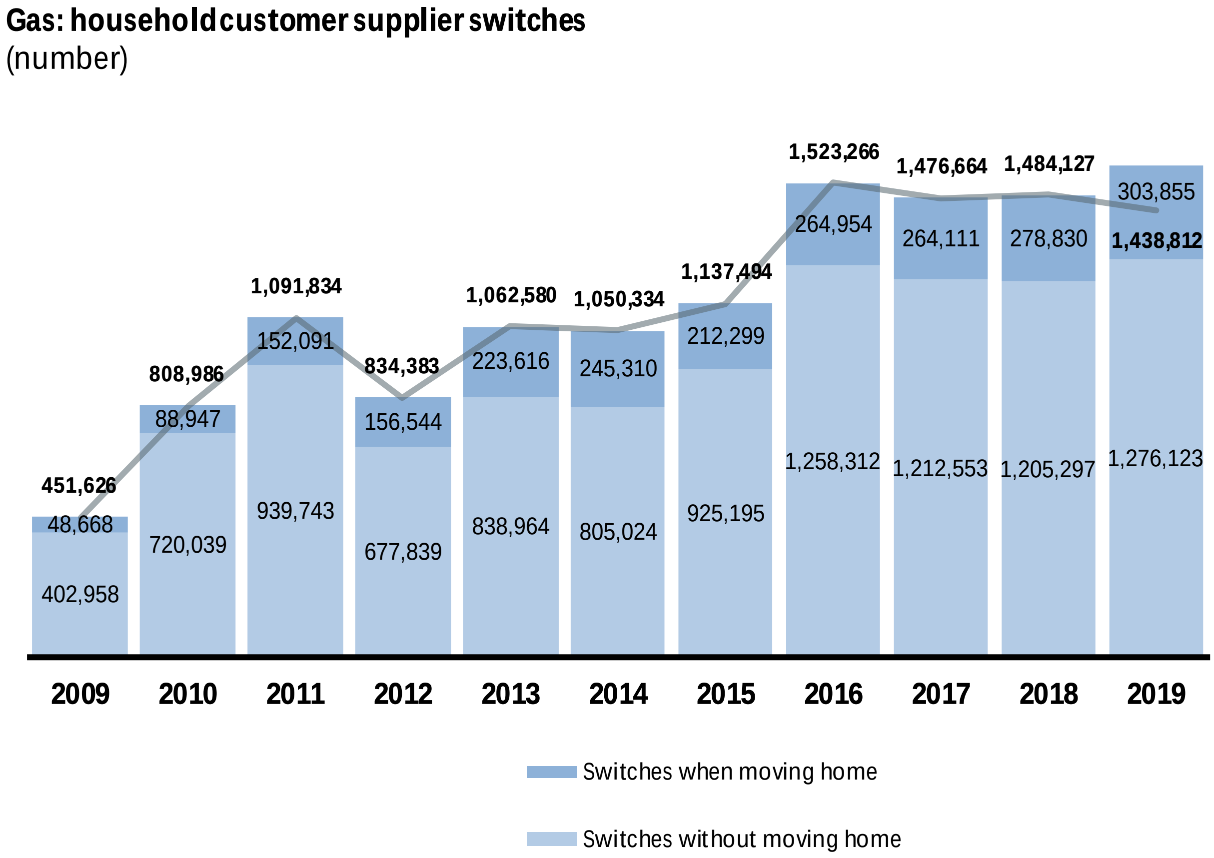


Figure 210: Household customer supplier switches according to the survey of gas DSOs

In 2019, the total number of household customers who switched supplier fell by about 45,000 to around 1.44m. The number of household customers who switched because of their supplier becoming insolvent was deducted from the total number of active (voluntary) supplier switches for the purposes of evaluating the data collected. The insolvent suppliers' customers were automatically transferred to a default contract with their default supplier or they took up an offer from another supplier. These customer switches are not classed as active (voluntary) switches and are therefore deducted from the total number. It is not possible to break down the numbers provided into customers who have switched supplier without moving home and customers who have switched supplier 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 11.3%. The volume of gas supplied to these customers who switched supplier was 35.1 TWh, approximately the same as in the year before (2018: 34.3 TWh). The volume-based switching rate of 12.4% is above the numbers-based rate because high-consumption customers exhibit a greater willingness to switch. The following figure shows the numbers-based switching rates since 2009:

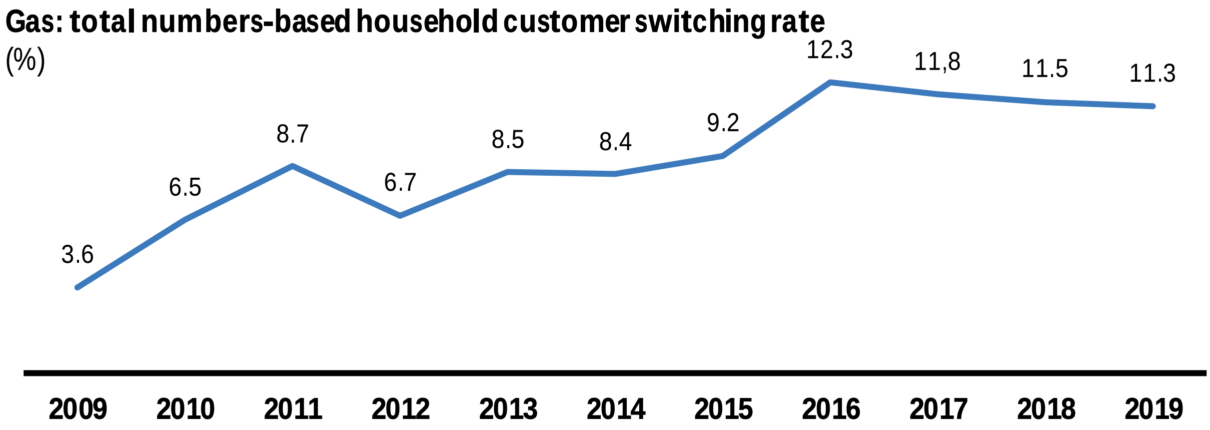


Figure 211: Total numbers-based household customer switching rate based on DSO data survey

Gas: household customer supplier switches, including switches by customers when moving home

Category	Subsequent consumption in 2019 (TWh)	Share of total consumption (282.5 TWh) (%)	Number of contracts changed in 2019	Share of all household customers (12.9m) (%)
Household customer supplier switches without moving home	29.1	10.3	1,3m	10.1
Household customers who immediately chose an alternative supplier rather than the default supplier when moving home	6.0	2.1	0,3m	2.3
Total	35.1	12.4	1,6m	12.4

Table 129: Gas household customer supplier switches in 2019, including switches by customers when moving home

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.

3. Gas supply disconnections and contract terminations, cash/smart card meters and non-annual billing

Around 31,000 gas customers were affected by disconnections in 2019.

Customers owing money to their supplier are sent a reminder with a fee, together with or followed by a disconnection notice.

The gas supply cannot actually be disconnected (interrupted) until at least four weeks after a disconnection notice has been issued, with customers being given three working days' notice of the disconnection date.

Unlike for electricity, for gas there is no lower limit for debt that can lead to the supply being disconnected. Irrespective of this, default suppliers are required to check that any action is proportionate. Suppliers can charge their customers for reminders, disconnections and reconnections, with the costs varying considerably between suppliers and network operators. Customers on default supply contracts have a right to an itemised bill for these costs.

Consumers expecting changes in their consumption can avoid large back payments by changing their instalment payments. Consumers can also lower their energy costs by switching tariff or supplier. Advice about energy costs is available from consumer advice centres, amongst others.

In 2020, as a result of the Covid-19 pandemic, a right to refuse to provide a service (Article 240(1) of the Introductory Act to the Civil Code (EGBGB)) was introduced for the period between 1 April and 30 June, which also applied to energy supply contracts. Some suppliers also announced that they would not be making any disconnections. It is entirely possible that the number of disconnections carried out in 2020 will be lower.

3.1 Disconnections and terminations

In 2019, 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 2019 was 30,997, representing a decrease of 6.5% compared to the previous year (2018: 33,145). 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. Irrespective of this, default suppliers are required to check that any action is proportionate. 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 2019 and how often they ordered the network operator responsible to disconnect supplies or carried out the disconnection.

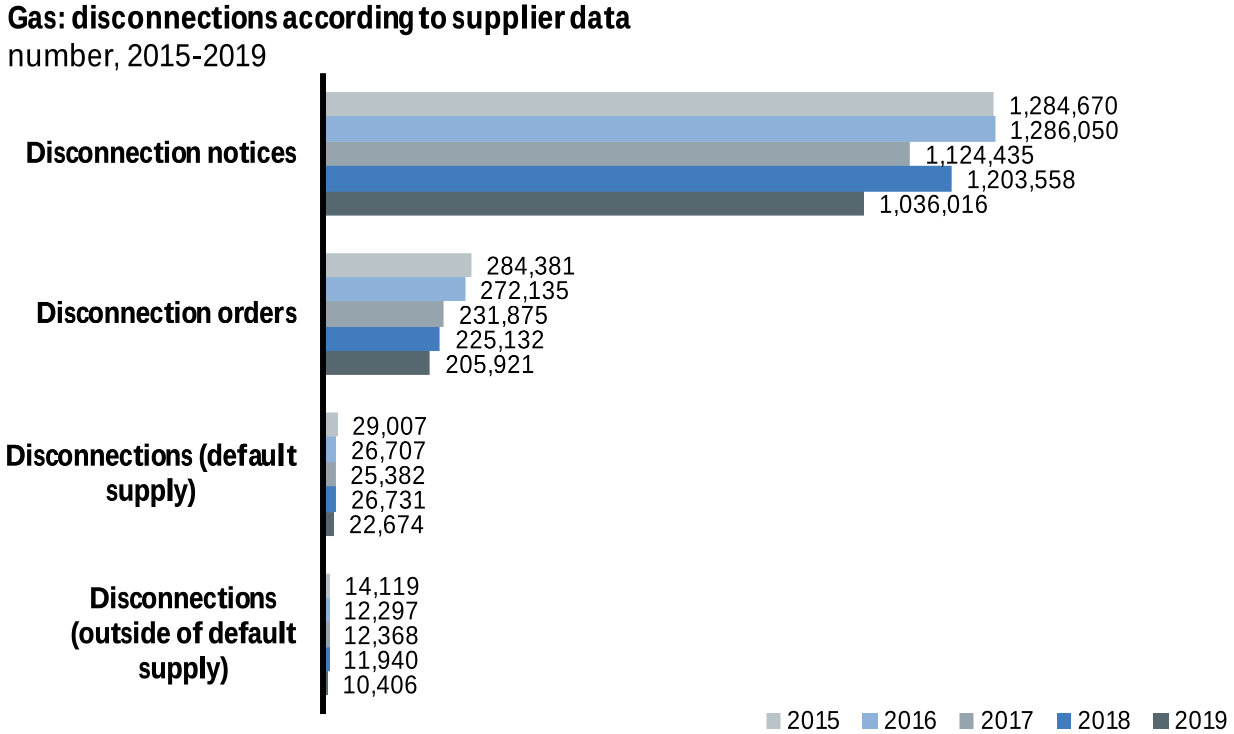


Figure 212: Disconnection notices, disconnection orders and disconnections for gas within and outside default supply, according to data from suppliers

According to the gas suppliers' data, a disconnection notice is issued when a customer is on average around €120 in arrears. Just over a million disconnection notices were issued to household customers, of which around 0.2m or 20% were passed on to the relevant network operator with a request for disconnection. The suppliers' data show that around 3% of the total notices actually resulted in the customer being disconnected.

The gas suppliers stated that in some 22,674 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 10,406 cases, corresponding to 0.1% of non-default customers.

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 that 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 (including VAT), although the charge ranged from €1.40 to €210. Suppliers not applying the general calculation charged customers an average of about €49 (including VAT), although the charge ranged from €3.50 to €210. Customers were charged an average reconnection fee of about €56 (including VAT) by suppliers applying the general calculation, with the actual fees charged again ranging from €1.40 to €222. Suppliers not applying the general calculation charged an average of about €60 (including VAT), with a range from about €4 to €210. Gas suppliers imposed a reminder fee averaging €3.30 on household customers who were late paying their bills, although the fee ranged from €3.30 to €30.

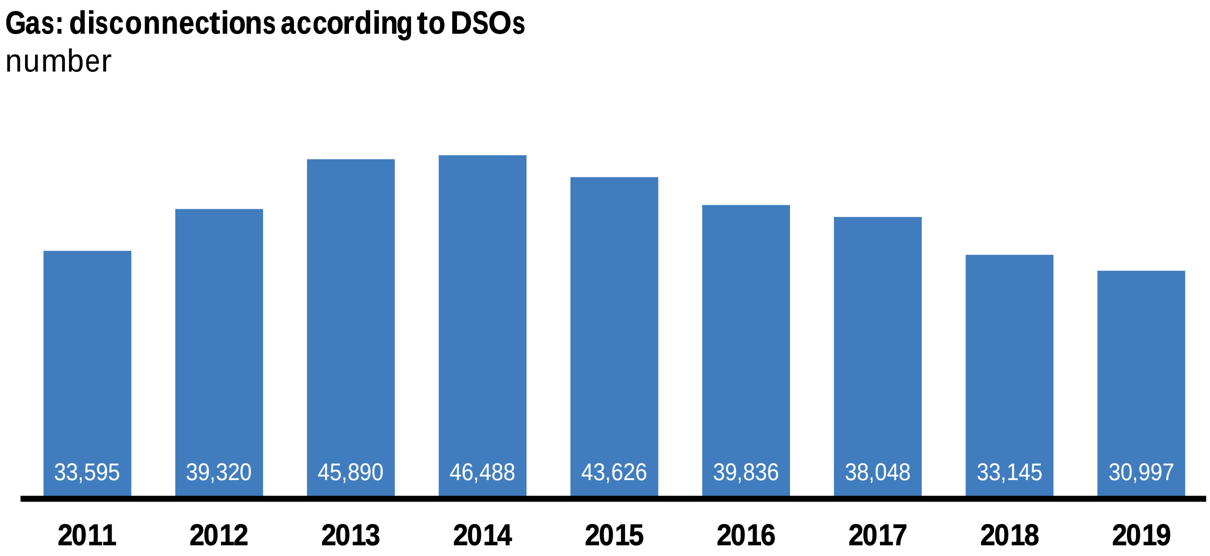


Figure 213: Gas disconnections according to DSOs, from 2011 to 2019

The above chart shows the development of disconnections of gas final customers from 2011 to 2019. A total of 30,997 disconnections (2018: 33,145) and around 24,500 reconnections were carried out in 2019. The following table shows the distribution of disconnections broken down by federal state:

Gas: disconnections by federal state in 2019 according to data from DSOs

	Number of disconnections (within and outside of default supply)	Proportion of final consumer market locations per federal state (%)
North Rhine-Westphalia	13,333	0.36
Berlin	1,690	0.28
Hesse	2,266	0.22
Brandenburg	1,038	0.20
Lower Saxony	4,196	0.19
Rhineland-Palatinate	1,368	0.17
Saxony-Anhalt	670	0.16
Schleswig-Holstein	906	0.15
Thuringia	484	0.15
Hamburg	310	0.14
Saxony	776	0.13
Saarland	249	0.13
Baden-Württemberg	1,803	0.13
Bavaria	1,694	0.12
Mecklenburg-Western Pomerania	284	0.10
Bremen	15	0.01
Total in Germany	**31,082**	**0.20**

Table 130: Gas disconnections by federal state in 2019, according to data from DSOs[169]

The network operators charged gas suppliers an average fee of about €57 (excluding VAT) for disconnecting a supply, with the actual costs charged ranging from €12.50 to €220. They charged suppliers an average fee of about €68 (excluding VAT) for reconnecting a supply, with the actual costs charged ranging from €15 to €350.

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 2019). Around 3,400 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.

[169] The difference between the sum of the disconnections reported for each federal state (31,082) and the total number of disconnections reported by the DSOs (30,997) is due to statistical differences.

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 2019, gas suppliers (default suppliers and their competitors) had to terminate their contractual relationship with a total of 54,463 gas customers (2018: 54,377) 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 2019, although this figure ranged from €5 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 46 suppliers, a total of 1,093 household customers had cash or smart card meters, or comparable prepayment systems, in 2019 compared to 1,081 in 2018. There were 199 new installations of prepay systems and 214 existing ones were removed in 2019. Costs for meter operation and metering averaged €32 and €5 respectively per year and meter. The average annual base price charged to customers was €120, with the costs charged ranging from €2.40 to €230. The average kilowatt-hour rate for gas billed using a prepayment meter was 7.75 ct/kWh and ranged from 4.12 ct/kWh to 28 ct/kWh.

3.3 Non-annual billing

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 2019

	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	€15.40 (€1.85 - €208)	€19.50 (€1.28 - €208)
Monthly	589		
Quarterly	153		
Semi-annual	1,041		

Table 131: Non-annual billing for gas household customers in 2019 according to gas supplier survey

4. Price level

The gas prices for household customers across all types of supply as at 1 April 2020 were stable compared with the previous year and averaged 6.31 ct/kWh. By contrast, the gas price for customers on a default contract fell by around 4%. The decrease is mainly due to the drop in gas procurement costs, which fell by about 6% for default supply customers.

At an average of 6.99 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 €163 a year by switching to a different contract with their local default supplier. **The average potential saving from switching supplier is up to €240 a year.**

Suppliers of gas to final consumers in Germany were asked the retail prices their companies charged on 1 April 2020 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, concession fees and charges for metering and meter operations.[170] 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. As the analysis is of prices as at 1 April 2020, the lower VAT rate of 16% instead of 19% applicable from 1 July 2020 to 31 December 2020 was not taken into account. 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

[170] 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 2020 and 1 April 2019, 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 98 and 777 suppliers respectively).

4.1 Non-household customers

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

The customer group with an annual consumption in the 116 GWh range consists entirely of interval-metered customers, i.e. generally industrial customers. The wide range of options with regard to contractual arrangements is very important to this customer group. Suppliers generally do not use specific tariff groups for consumers who fall into the 116 GWh/year category but offer customer-specific deals. Their customers include those with a full supply and those whose negotiated consumption (in the amount relevant to this category) represents only part of their procurement portfolio. For high-consumption customers the distinction between gas retail and wholesale trading is inherently fluid as 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 98 suppliers (100 in the previous year).

Gas: price level for 116 GWh/year consumption category on 1 April 2020

	Spread between 10 and 90 percentile 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 - 0.73	0.37	14.5%
Metering	0.00 - 0.004	0.002	0.1%
Concession fee[1]	0.00	0.00	0.0%
Gas tax	0.55	0.55	21.7%
Price component controllable by supplier (remaining balance)	0.95 - 2.23	1.62	63.9%
Total prices (excl. VAT)	1.80 - 3.20	2.53	

[1] Under Sect.2 (5) sentence 1 KAV concession fees only apply for the first 5 G/Wh (0.03 ct/kWh) in the case of customers with special contracts. When this 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 132: Price level for the 116 GWh/year consumption category on 1 April 2020

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. Results of the analysis can be found in Table 132.

The average overall price (excluding VAT) for an annual consumption of 116 GW/h ("industrial customer") was 2.53 ct/kWh, (2019: 2.86 ct/kWh). An average of 14.5% 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 21.7% of the average overall price (excluding VAT). Hence approx. 63.9% (2019: 69.8%) 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).

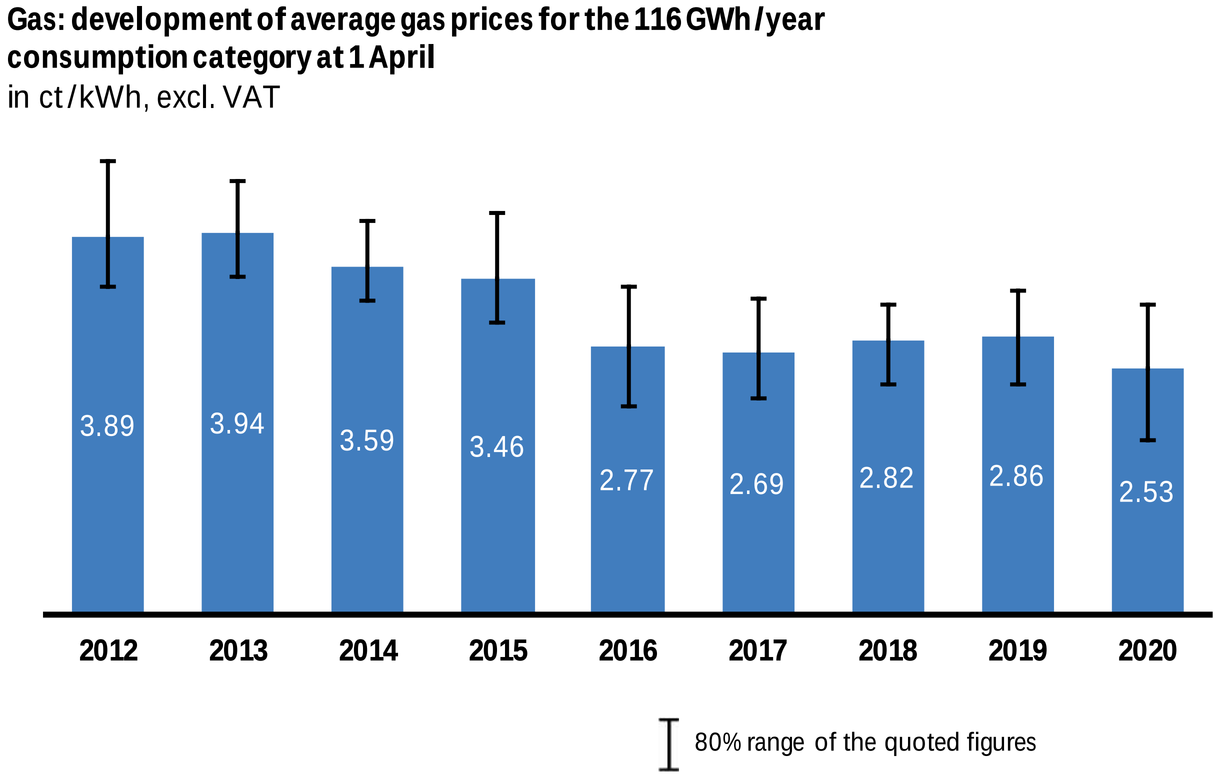


Figure 214: Development of average gas prices for the 116 GWh/year consumption category

116 MWh/year consumption category ("commercial customers")

The non-household customer category based on an annual consumption of 116 MWh includes e.g. 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 threshold 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 01 April 2020. 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 777 suppliers (794 in 2019).

Gas: price level for the 116 MWh/year consumption category on 1 April 2020

	Spread between 10 and 90 percentile 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	0.90 - 1.57	1.22	27.1%
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	12.2%
Price component controllable by supplier (remaining balance)	1.94 - 3.32	2.66	58.8%
Total price (excl. VAT)	3.70 - 5.27	4.52	

[1] 80 of the 777 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 supply of a non-household customer in default supply (cf..Sect. 2 (2) no. 2 b KAV).

Table 133: Price level for the 116 MWh/year consumption category on 1 April 2020

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. Results of the analysis can be found in Table 133.

As in the previous 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). Around 59% relates to price elements that provide scope for commercial decisions.

The arithmetic mean of the overall price of 4.52 ct/kWh (excluding VAT.) is 0.03 ct/kWh lower than the previous year's figure. The average net amount of the price components outside the supplier's control rose to 1.86 ct/kWh, 0.01 ct/kWh higher than in the previous year. The remaining balance that can be controlled by the supplier fell by 0.04 ct/kWh (from 2.70 ct/kWh on 1 April 2019 to 2.66 ct/kWh on 1 April 2020) or by about 1.6%.

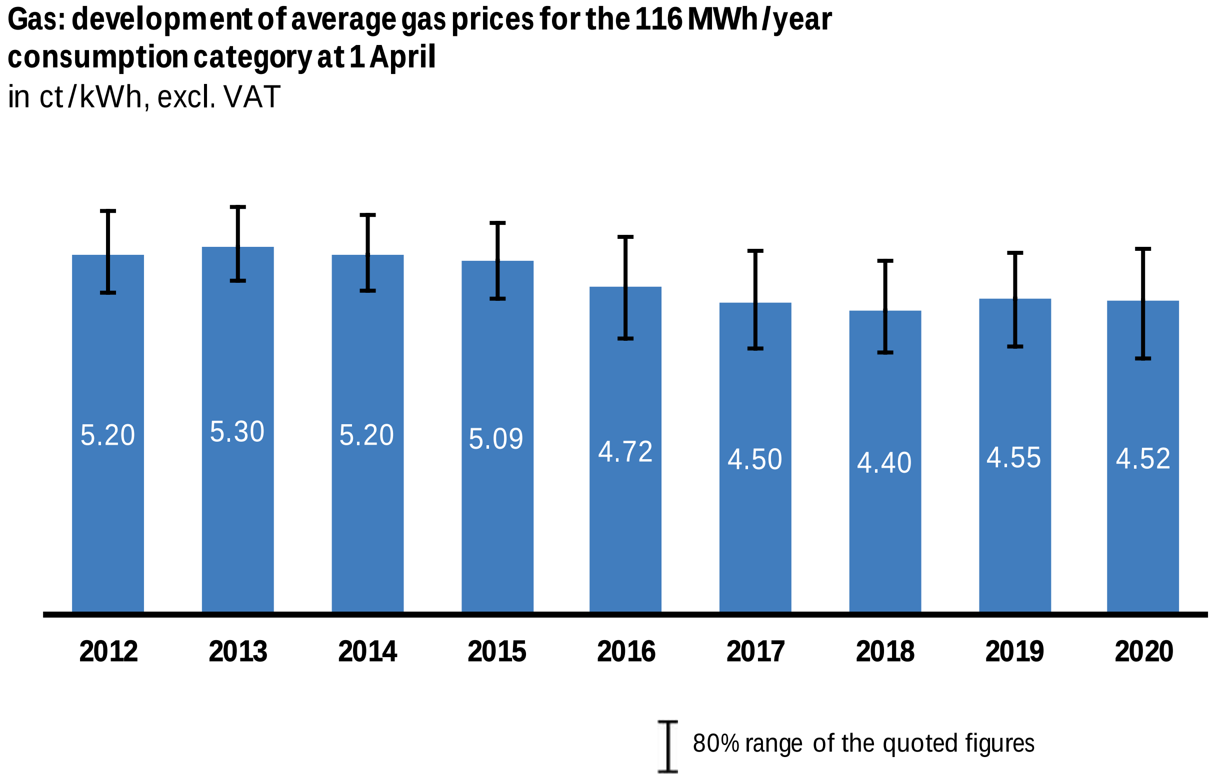


Figure 215: Development of average gas prices for the 116 MWh/year consumption category

4.2 Household customers

Household customer prices were divided into three bands for the survey:

– band I (D1): 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.[171]

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 2019 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.

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

[171] "D1", "D2" and "D3" refer to the consumption bands defined by Eurostat.

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 2020 (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	3.12	49.4%
Network charge including upstream network costs	1.47	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	16.0%
Total	6.31	100.0%

Table 134: Average volume-weighted price across all contract categories for household customers in consumption band II according to the gas supplier survey

Gas: breakdown of the volume-weighted gas price across all contract categories for household customers - consumption band II
price as at 1 April 2020 (%)

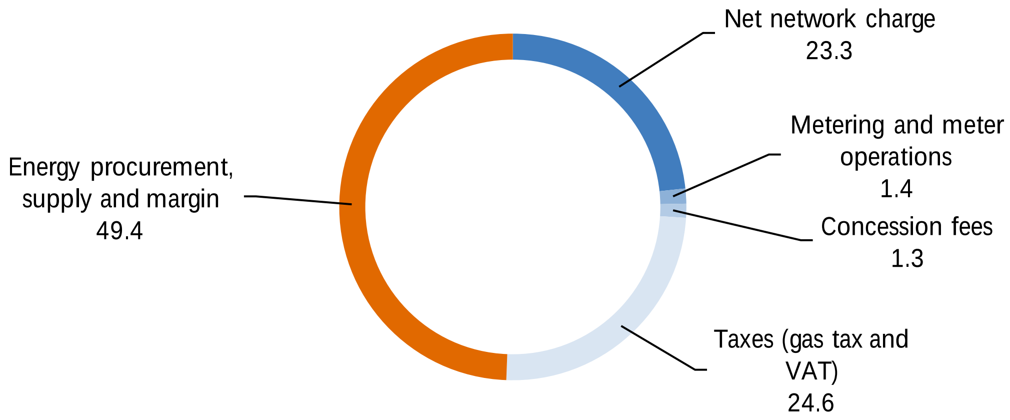


Figure 216: Breakdown of the volume-weighted gas price across all contract categories for household customers – consumption band II according to the gas supplier survey

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 2019 (ct/kWh)	Volume-weighted average across all tariffs on 1 April 2020 (ct/kWh)	Change in the price component	
			(ct/kWh)	%
Price component for energy procurement, supply and margin	3.13	3.12	-0.01	-0.3%
Network charge including upstream network costs	1.48	1.47	-0.01	-0.7%
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	1.01	1.01	0.00	0.0%
Total	6.34	6.31	-0.03	-0.5%

Table 135: Changes in the volume-weighted price across all contract categories for household customers (for an annual consumption between 20 GJ (5,556 kWh) and 200 GJ (55,556 kWh)) between 1 April 2019 and 1 April 2020 according to the gas supplier survey

Gas: development of the volume-weighted gas price across all contract categories for household customers as at 1 April of the respective year - band II
(ct/kWh)

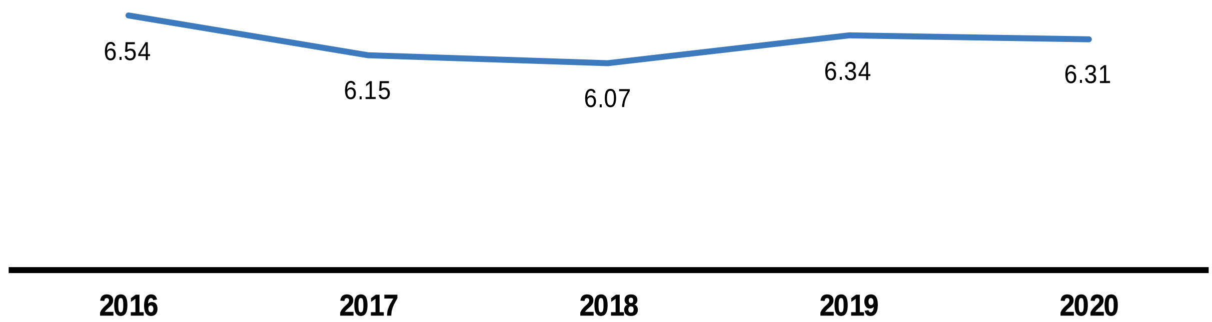


Figure 217: Volume-weighted gas price across all contract categories for household customers according to the gas supplier survey

The volume-weighted gas price for household customers across all contract categories barely changed compared to the previous year and was 6.31 ct/kWh.

4.2.2 Household customer prices by consumption band

The tables below provide detailed information on the composition of the gas price for household customers, broken down by individual bands I to III and contract category.

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 2020 (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	4.76	4.69	4.47
Network charge including upstream network costs	2.44	2.31	2.28
Charge for metering	0.20	0.12	0.15
Charge for meter operations	0.50	0.42	0.35
Concession fees	0.47	0.05	0.03
Current gas tax	0.55	0.55	0.55
VAT	1.70	1.55	1.49
Total	10.62	9.69	9.31

Table 136: 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 2020 (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	3.51	3.18	2.80
Network charge including upstream network costs	1.45	1.45	1.52
Charge for metering	0.02	0.02	0.03
Charge for meter operations	0.07	0.06	0.08
Concession fees	0.27	0.03	0.03
Current gas tax	0.55	0.55	0.55
VAT	1.12	1.00	0.95
Total	6.99	6.29	5.96

Table 137: 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 2020
(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	3.30	2.86	2.63
Network charge including upstream network costs	1.23	1.28	1.34
Charge for metering	0.01	0.01	0.01
Charge for meter operations	0.03	0.03	0.03
Concession fees	0.28	0.04	0.03
Current gas tax	0.55	0.55	0.55
VAT	1.03	0.90	0.87
Total	6.43	5.67	5.46

Table 138: 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 2020 was 6.99 ct/kWh in band II (2019: 7.28 ct/kWh), corresponding to a decrease of around 4% compared to the previous year.

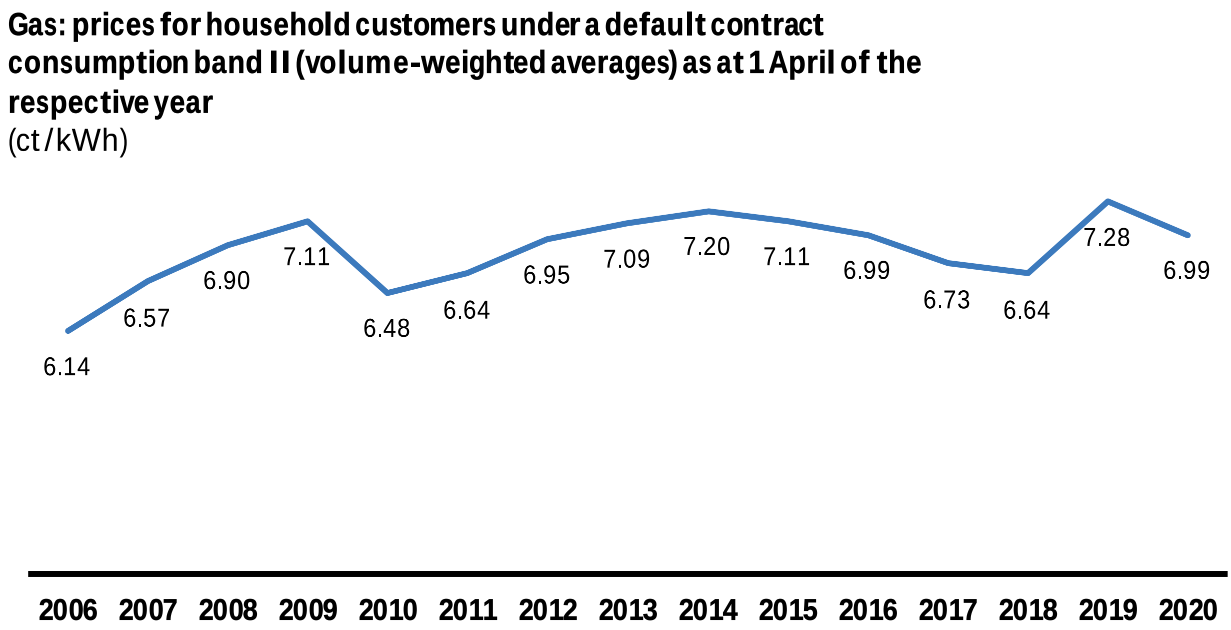


Figure 218: Gas prices for household customers under a default contract (volume-weighted averages) – consumption band II according to the gas supplier survey

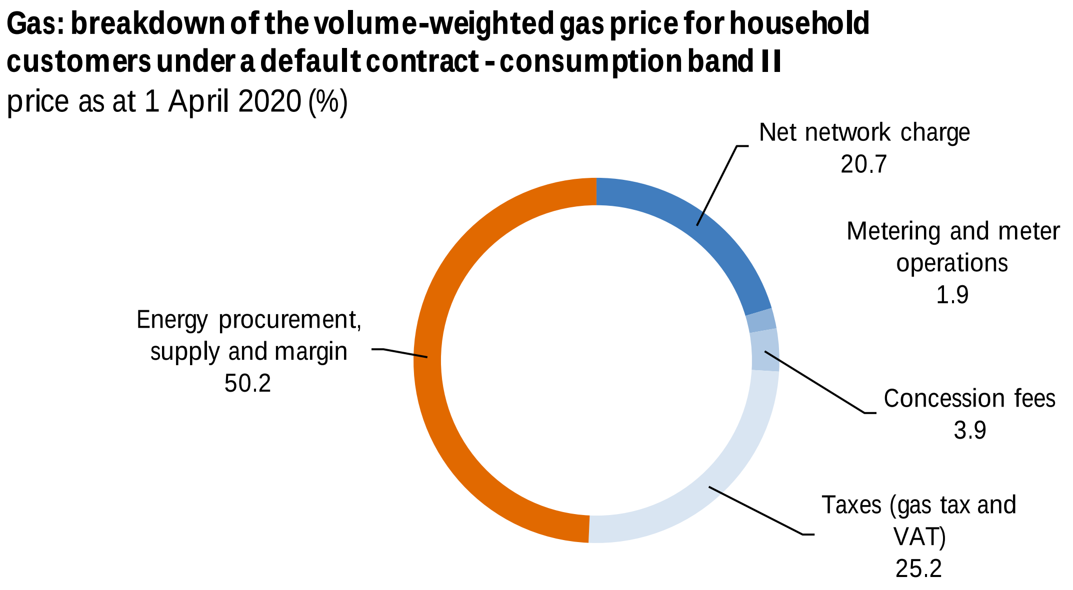


Figure 219: Breakdown of the volume-weighted gas price for household customers under a default contract. Prices for consumption band II, as at 1 April 2020 – according to the gas supplier survey

Supply by the default supplier under a non-default contract

The volume-weighted gas price for customers on a non-default contract with the default supplier as at 1 April 2020 was 6.29 ct/kWh in band II (2019: 6.44 ct/kWh), equivalent to a year-on-year decrease of just over 2%.

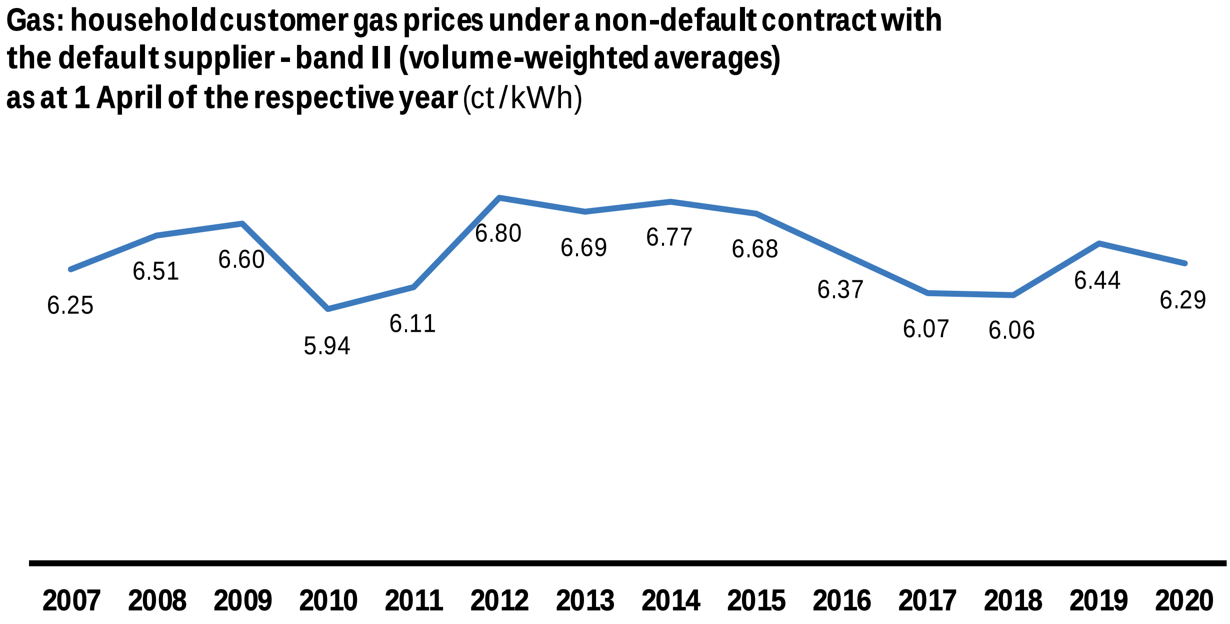


Figure 220: Household customer gas prices under a non-default contract with the default supplier (volume-weighted averages) – consumption band II according to the gas supplier survey

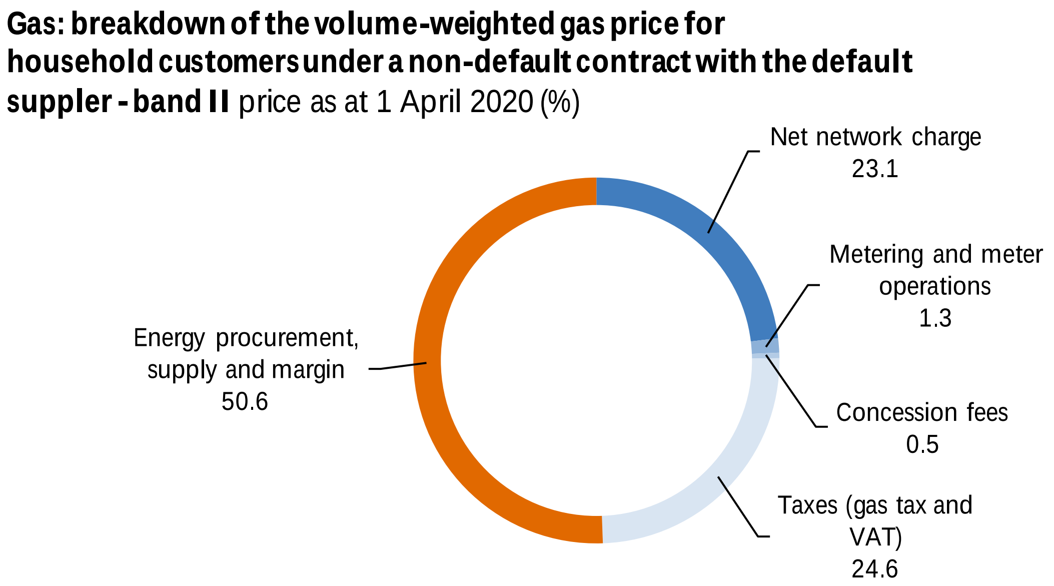


Figure 221: Breakdown of the volume-weighted gas price for household customers under a non-default contract with the default supplier. Prices for consumption band II, as at 1 April 2020 – according to the gas supplier survey

Supply under a contract with a supplier other than the local default supplier

On 1 April 2020, the volume-weighted price for a contract with a supplier other than the local default supplier in consumption band II was 5.96 ct/kWh, a decrease of just over 4% compared to the previous year (2019: 6.22 ct/kWh).

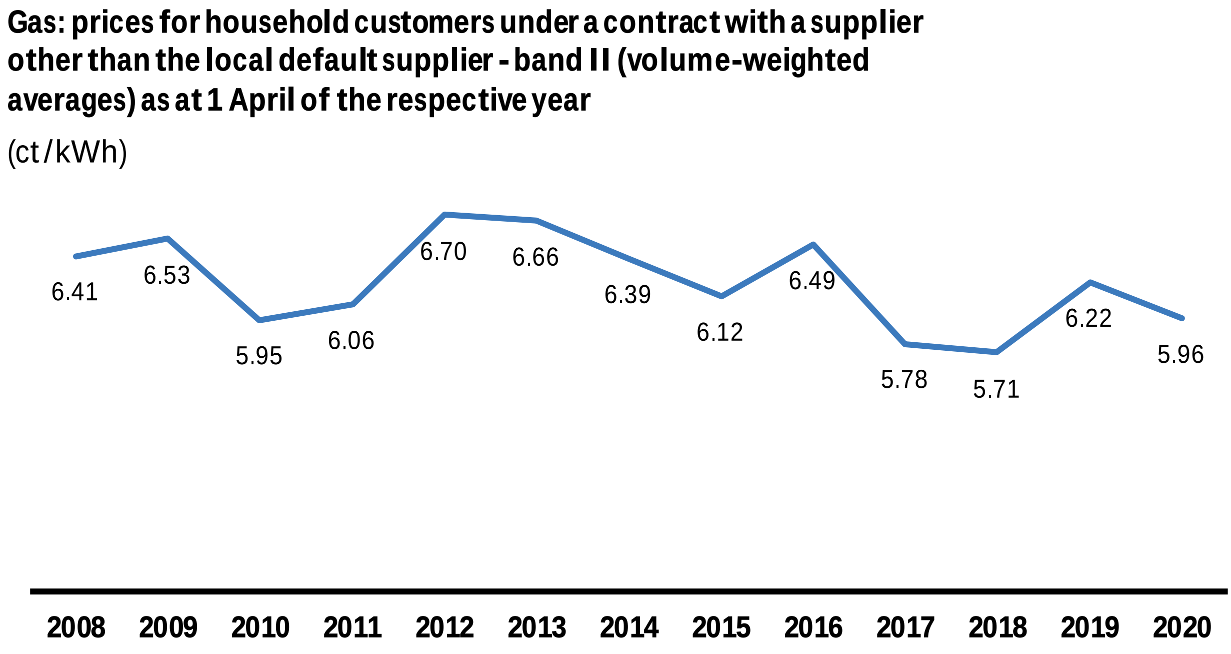


Figure 222: Gas prices for household customers under a contract with a supplier other than the local default supplier (volume-weighted averages) – consumption band II according to the gas supplier survey

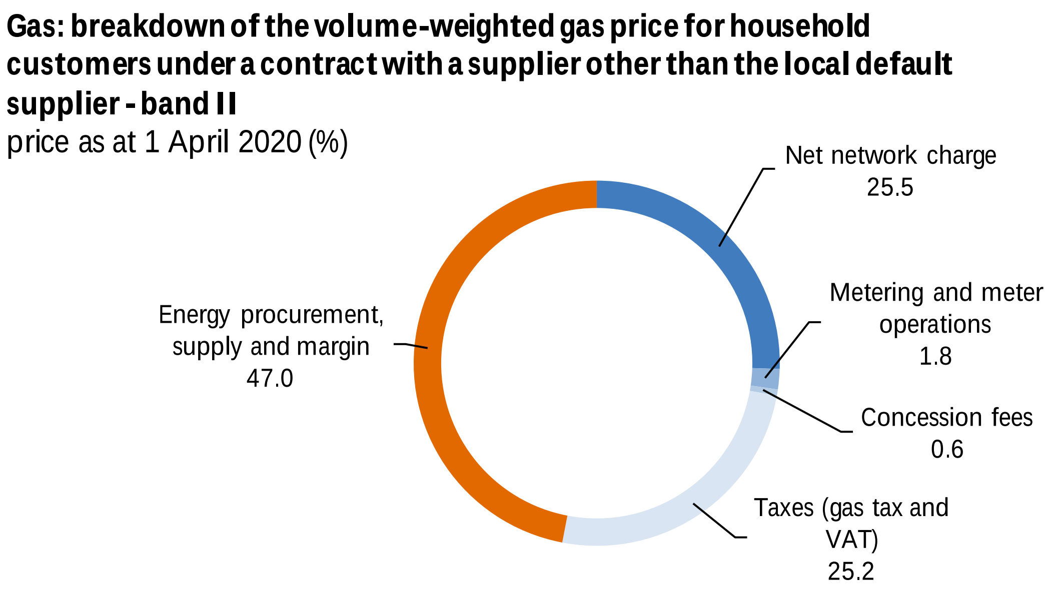


Figure 223: Breakdown of the volume-weighted gas price for household customers under a contract with a supplier other than the local default supplier, as at 1 April 2020 – consumption band II according to the gas supplier survey

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 €163 a year as at 1 April 2020 by changing contract. The average potential saving for the year from changing supplier was €240.

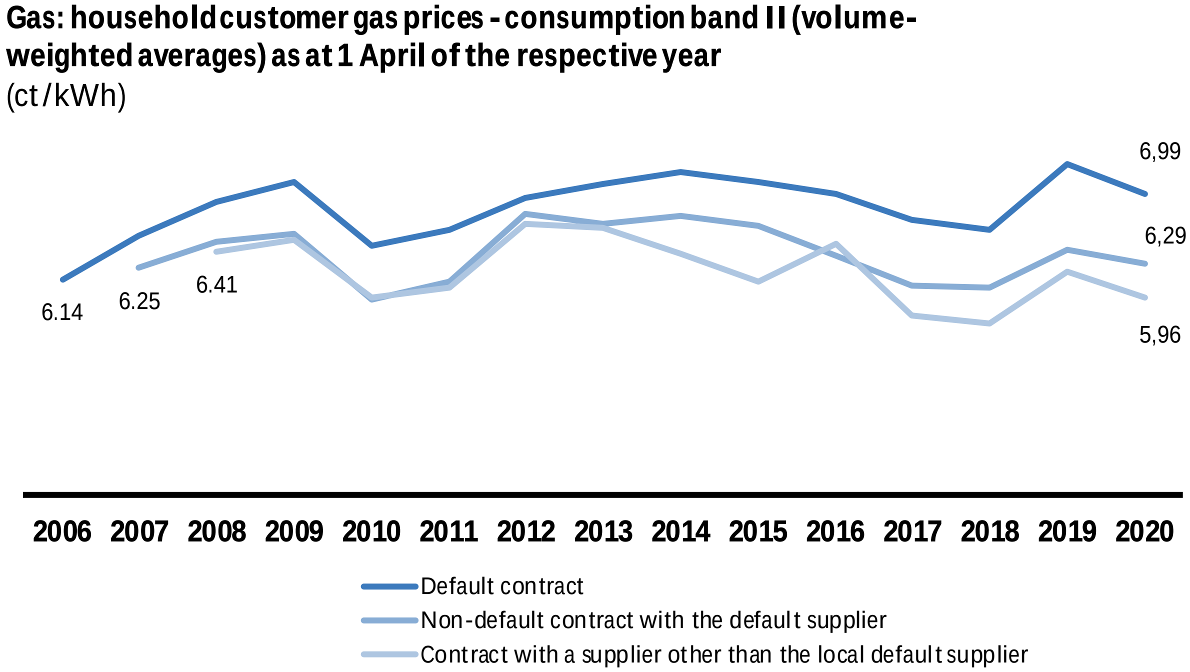
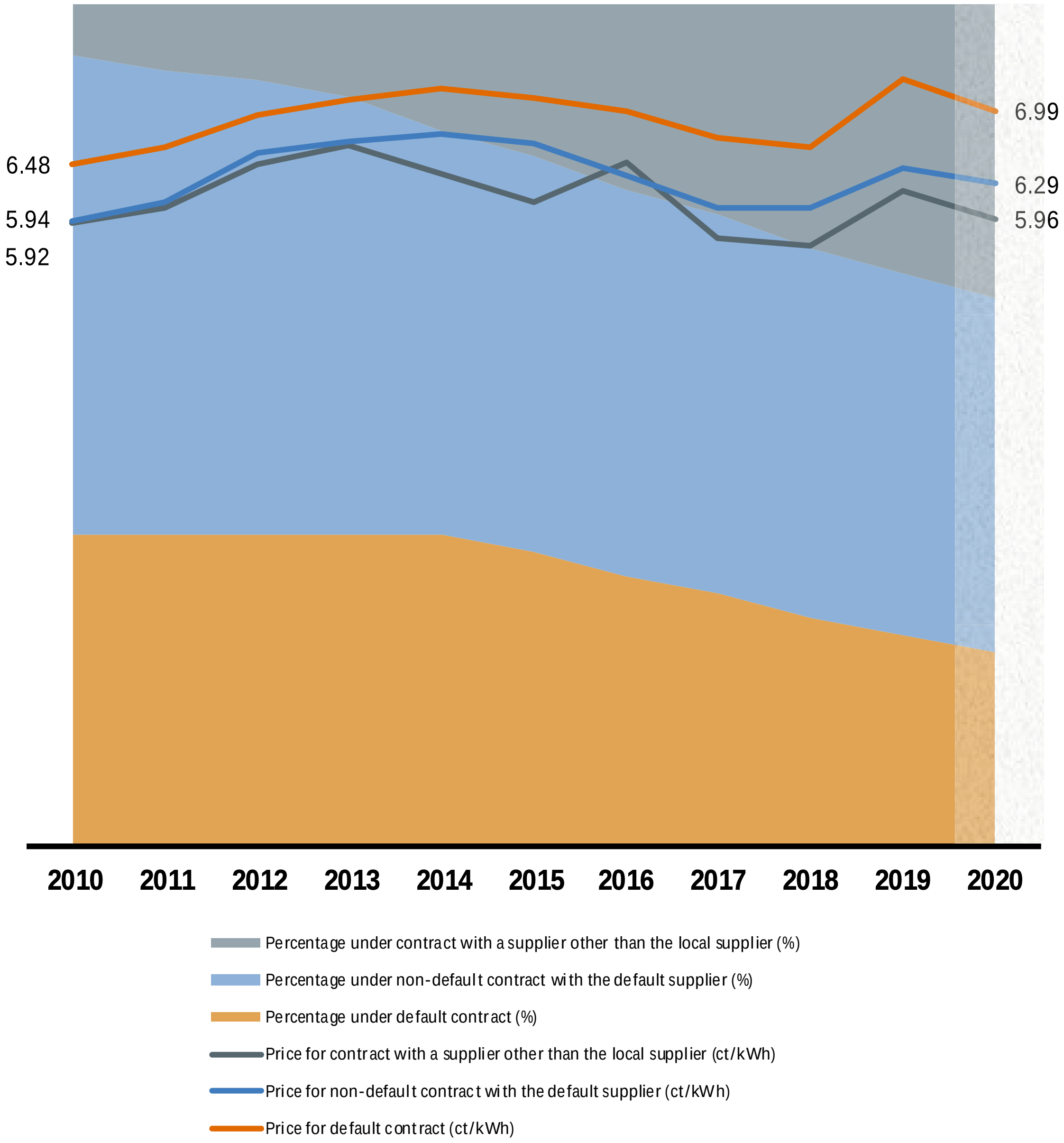


Figure 224: Household customer gas prices – consumption band II according to gas supplier survey

The following chart shows the gas prices compared with the percentages of the three types of supply – default contract, non-default contract with the default supplier and contract with a supplier other than the local default supplier.

Gas: household customer prices (band II, Eurostat D2, as at 1 April) (ct/kWh) and percentages of household customers per contract type (%)



The percentages shown for the different types of contract for 2020 are a continuation of the trends from previous years are they were not yet available.

Figure 225: Household customer gas prices and percentages for each type of contract

The price component "energy procurement, supply and margin" for default supply customers was 3.51 ct/kWh as at 1 April 2020 (2019: 3.74 ct/kWh). That corresponds to a drop of just over 6% in gas procurement costs. The gas procurement costs in the price for customers supplied under a non-default contract with the default supplier fell by slightly more than 4% from 3.30 ct/kWh to 3.18 ct/kWh. The gas procurement costs for customers supplied under a contract with a supplier other than the local default supplier decreased by just over 7% to 2.80 ct/kWh (2019: 3.02 ct/kWh).

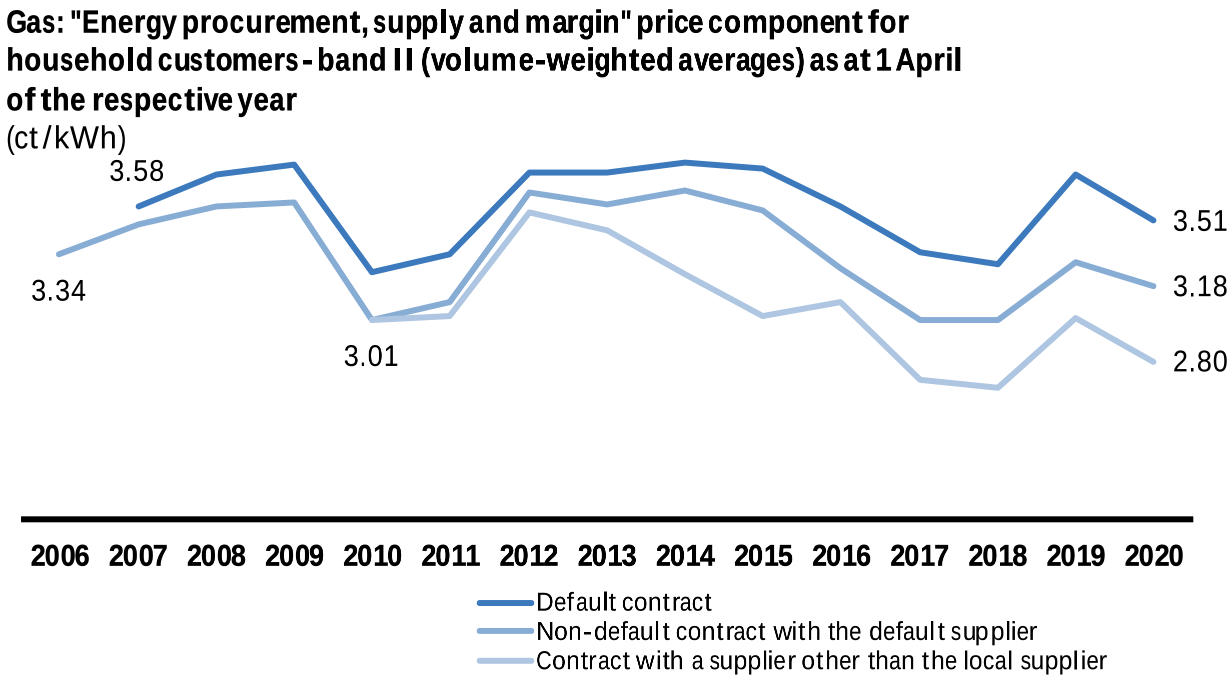


Figure 226: "Energy procurement, supply and margin" price component for household customers – consumption band II according to the gas supplier survey

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 €70 to €80.

Gas: special bonuses and schemes for household customers

As at 1 April 2020	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	380	12 months
Price stability	318	16 months	373	16 months
Advance payment	50	10 months	31	9 months
One-off bonus payment	126	€ 70	194	€ 80
Free kilowatt hours	8	1,300 kWh	8	510 kWh
Deposit	7	-	7	-
Other bonuses	86	-	91	-
Other special arrangements	30	-	28	-

Table 139: Special bonuses and schemes for household customers

5. Comparison of European gas prices

Eurostat, the statistical office of the European Union, publishes average end consumer gas prices for each six-month period paid by household customers and non-household customers in EU Member States. The figures published for each consumer group include (i) the price including all taxes and levies, (ii) the price excluding recoverable taxes and levies (particularly excluding VAT) and (iii) the price excluding taxes and levies. Eurostat does not collect the data itself but relies on data from national bodies, for Germany on data provided by the Federal Statistical Office.[172] These are not comparable with the data collected during monitoring because of the different survey method used by the Federal Statistical Office. 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 survey method, which can lead to national differences.

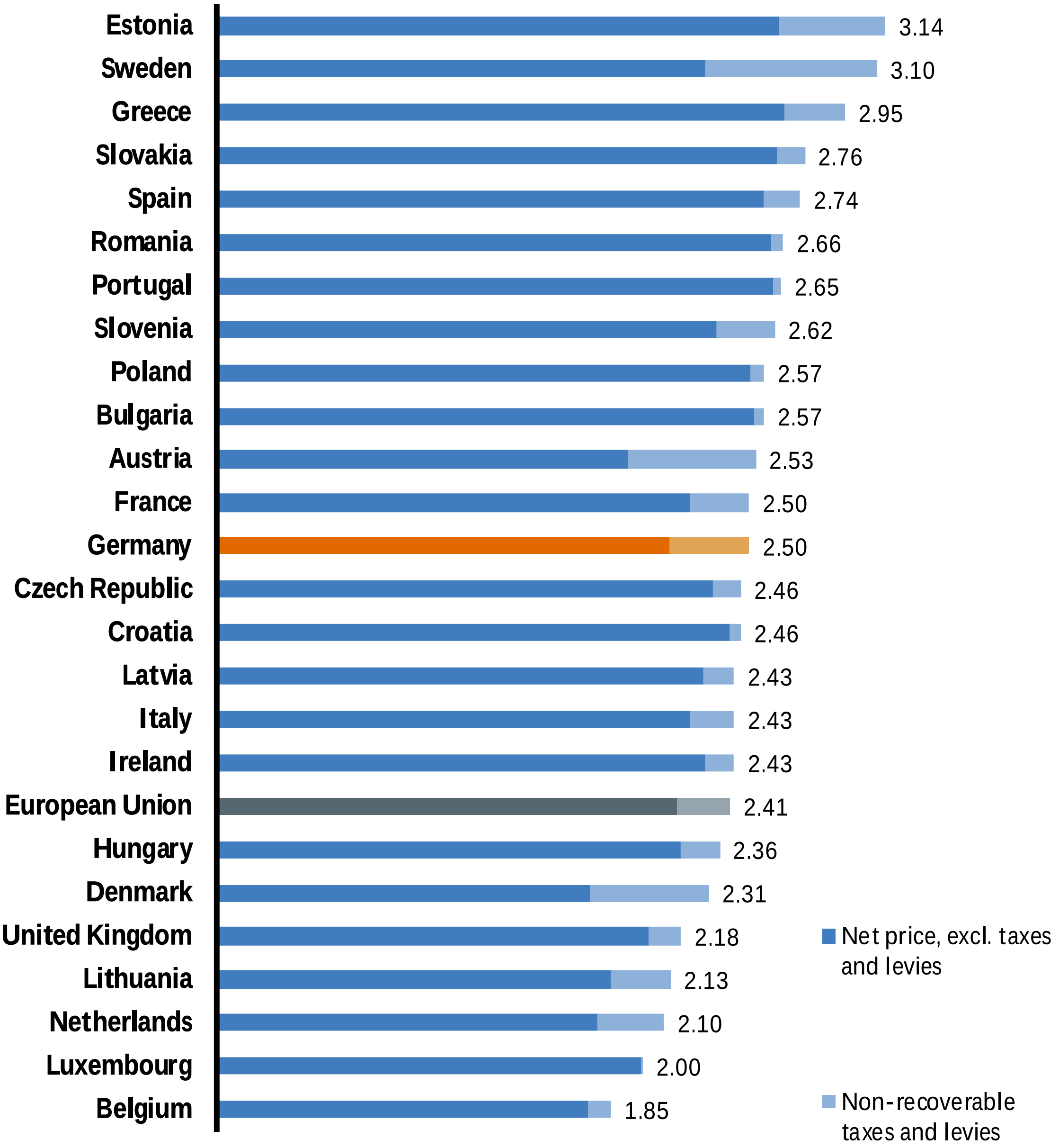
5.1 Non-household customers

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

[172] The average prices for electricity and natural gas in Germany for the second six-month period of 2019 were determined by the Federal Statistical Office. Before this the price data were collected by the German Association of Energy and Water Industries on behalf of the Federal Ministry for Economic Affairs and Energy. This change naturally also brought about changes in the survey methods, e.g. size and composition of the sample or the fact that administrative and tax data can now be used to determine the amount of tax, levies and surcharges actually paid.

bands. The 116 GWh/year category ("industrial customers"), for which specific price data are collected during monitoring, falls into this consumption range.

Gas: comparison of European gas prices in second half of 2019 for non-household customers with an annual consumption of between 27.8 GWh and 278 GWh
in ct/kWh ; without refundable taxes and levies



Source: Eurostat

Figure 227: Comparison of European gas prices in the second half of 2019 for non-household consumers with an annual consumption between 27.8 GWh and 278 GWh[173]

[173] The Eurostat comparison does not include prices in Finland, Malta and Cyprus. The price for Romania is an estimate.

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.[174] 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[175] average EU price for non-household customers with an annual consumption of between 27.8 and 278 GWh in the second half of 2019 was 2.41 ct/kWh. The arithmetic mean of the gas prices in the participating Member States was approx. 2.50 ct/kWh. The net gas price paid by German non-household customers in the second half of 2019 in this consumption category was also 2.50 ct/kWh, which is exactly the arithmetically determined EU average. 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. 9.5% (0.24 ct/kWh) of the net price in Europe. The figure of about 15% (0.38 ct/kWh) for Germany in 2019 is above average in this respect.

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 are collected during monitoring, falls into the medium Eurostat consumption band. The following shows an EU comparison of the medium consumption band. Household customers generally cannot have taxes and levies refunded, which is why the total price including VAT is relevant to these customers.

In contrast to prices in the industrial customer sector, gas prices for household customers vary greatly in Europe. Household customers in Sweden pay more than twice as much for natural gas as customers in Germany and more than three times as much as customers in Latvia, Romania and Hungary. According to Eurostat, the volume-weighted average EU price for household customers in the second half of 2019 was 6.70 ct/kWh and thus remained unchanged in comparison to the previous year. The arithmetic mean of the gas prices in the participating Member States was approx. 6.16 ct/kWh. The gas price paid by household customers in Germany was 5.88 ct/kWh. The price paid by German consumers of natural gas per kilowatt hour was therefore around 5% lower than the EU average price

The percentage of the overall price for household customers made up by taxes and levies also varied widely across the EU. While taxes and levies account for only about 8% of the price in Greece, they make up about 75% of the price in Denmark. Germany's figure of about 32% again matches the European average in this

[174] For more information on country-specific deductions see Eurostat, Gas Prices – Price Systems 2014, 2015 edition: http://ec.europa.eu/eurostat/documents/38154/42201/Gas-prices-Price-systems-2014.pdf/30ac83ad-8daa-438c-b5cf-b52273794f78 (retrieved on 10 November 2020).

[175] 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 10 November 2020)

respect. Around 1.57 ct/kWh of the overall price in Germany consists of taxes and levies; the EU average is 1.70 ct/kWh (about 33%).

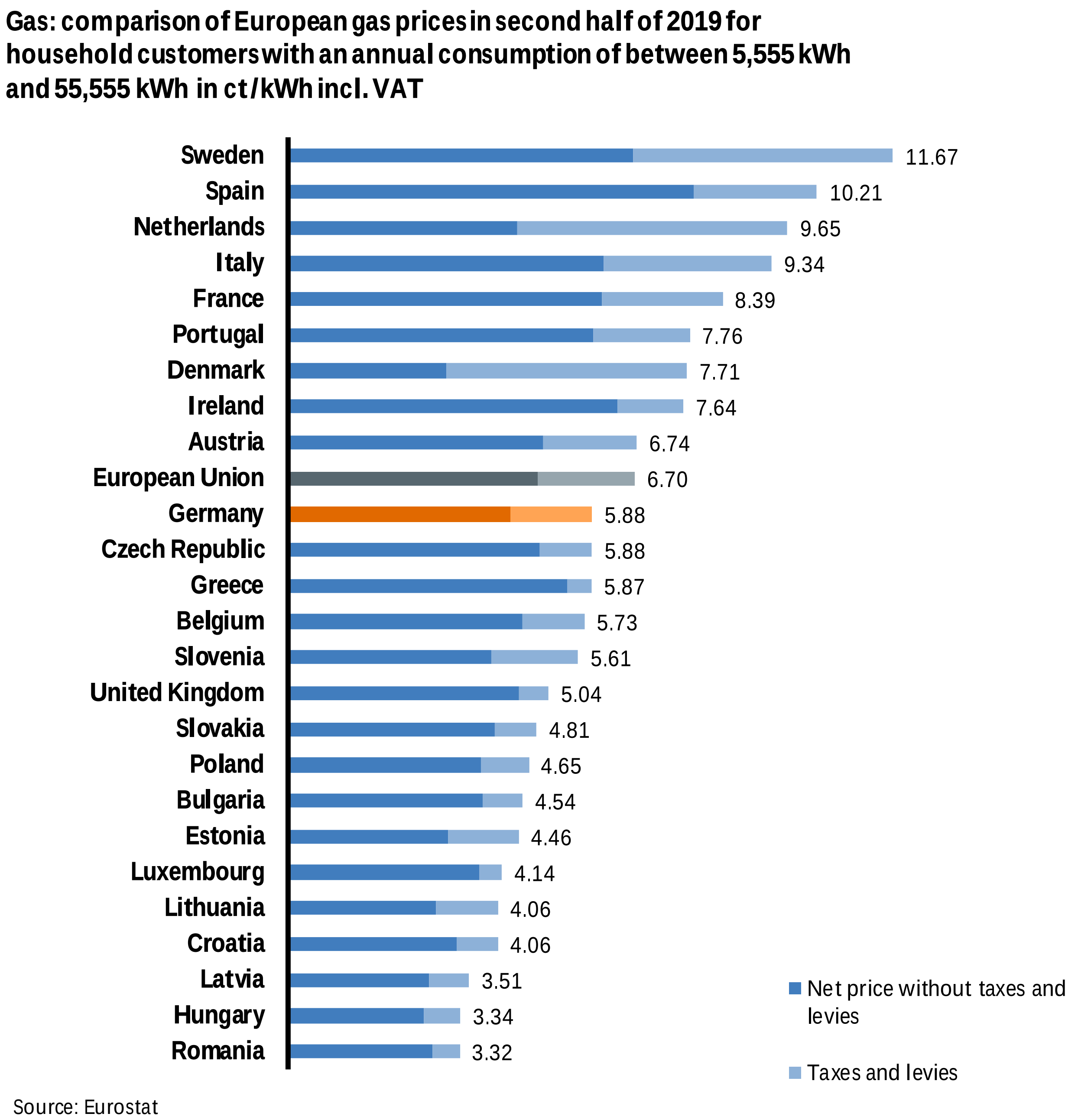


Figure 228: Comparison of European gas prices in the second half of 2019 for household customers with an annual consumption between 5,555 kWh and 55,555 kWh [176]

[176] The Eurostat comparison does not include prices in Finland, Malta and Cyprus. The price for Romania is an estimate.

G Metering

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 650 companies. This paints the following picture for 2019 with regard to the distribution of market roles:

Gas: meter operator roles

Function	2019
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)	637
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)	6
Supplier with meter operator activities	10
Independent third party that provides metering services	6

Table 140: Distribution of network operator roles according to data provided by gas meter operators as at 31 December 2019

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 3.6m), followed by Lower Saxony (2.1m), Bavaria (1.4m) and Baden-Württemberg (1.3m).

Gas: number of meter locations by federal state in 2019

Federal state	Number
Baden-Württemberg	1,344,897
Bavaria	1,414,488
Berlin	596,118
Brandenburg	539,479
Bremen	155,892
Hamburg	230,296
Hesse	986,715
Mecklenburg-Western Pomerania	263,809
Lower Saxony	2,158,580
North Rhine-Westphalia	3,652,977
Rhineland-Palatinate	802,444
Saarland	189,745
Saxony	589,484
Saxony-Anhalt	424,738
Schleswig-Holstein	553,189
Thuringia	359,487

Table 141: Number of meter locations by federal state in 2019

2. Metering technology used for household customers

As at 31 December 2019, approximately 5.9 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.

Gas: metering equipment used by SLP customers in 2019

Types of metering equipment used by meter operators for SLP customers	No. of meter points by meter size		
	G1.6 bis G6	G10 bis G25	G40+
Diaphragm gas meters with mechanical counter	5,861,819	198,595	23,956
Diaphragm gas meters with mechanical counter and pulse output	7,181,046	229,863	44,332
Diaphragm gas meters with mechanical counter and manufacturer-specific output (eg Cyble, Absolut-ENCODER)	595,917	16,691	3,533
Diaphragm gas meters with electronic counter	5,880	226	108
Ultrasonic gas meters	9,828	-	55
Load/interval meters as for interval-metered customers	75	577	2,692
Other mechanical gas meters	8,638	2,647	27,620
Other electronic gas meters	13,731	389	430
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	5,658,370	171,404	34,684
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	203,430	5,628	2,849

Table 142: Breakdown of metering equipment used by SLP customers as at 31 December 2019, according to meter size[177]

The overwhelming majority of meters use pulse generators as their communication technology (86%). Only about 14% use Cyble sensors, absolute encoders, electronic meters or other means.

[177] Meter size according to DVGW.

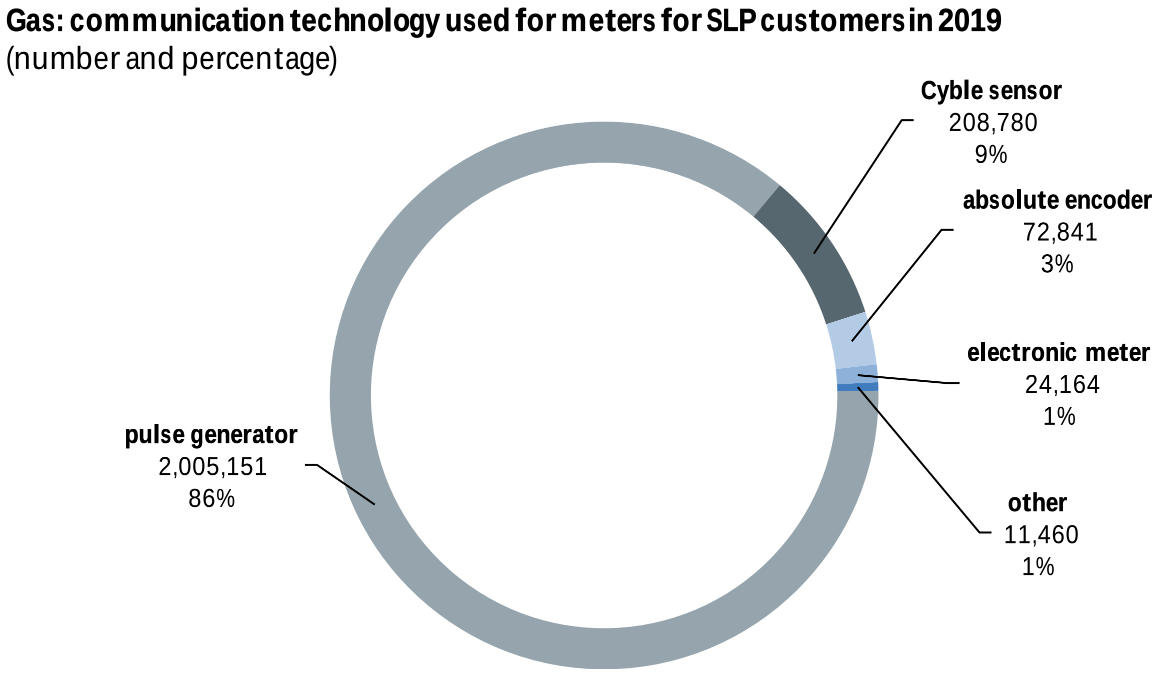


Figure 229: Communication technology used for meters for SLP customers – as at 31 December 2019

Most meters for SLP customers (about 55%) use telecommunication technology such as traditional telephone lines, DSL or mobile communications as their interface technology.

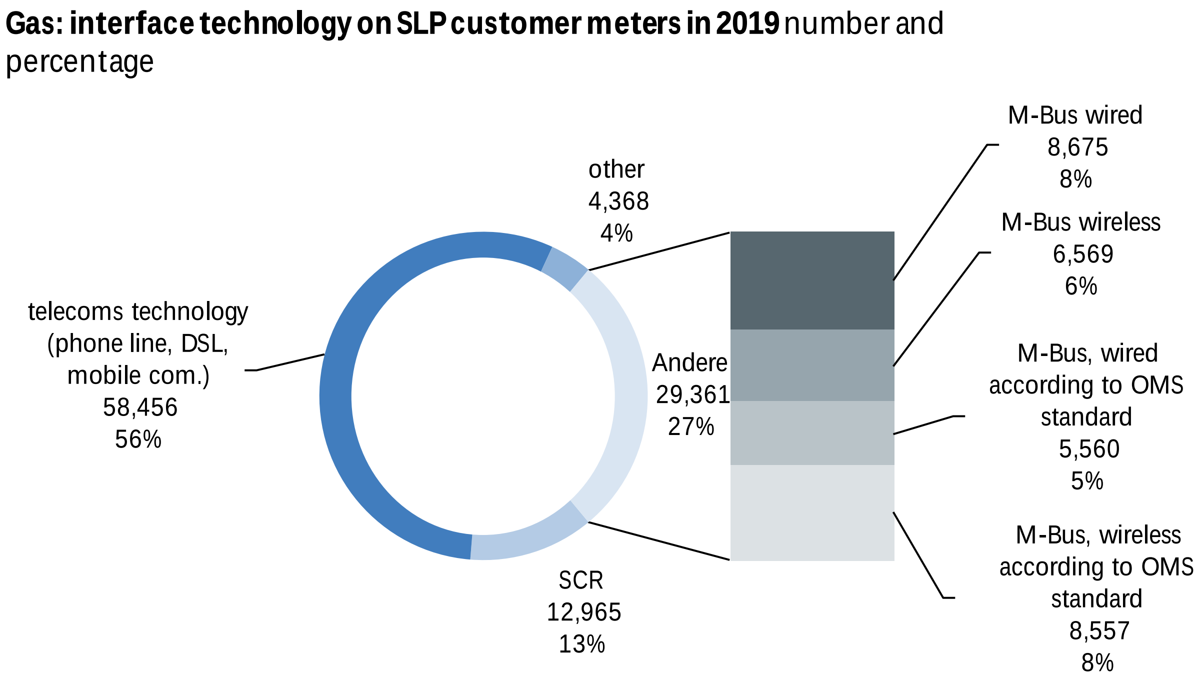


Figure 230: Interface technology on SLP customer meters – as at 31 December 2019

3. Metering technology used for interval-metered customers

The distribution of metering technology employed for interval-metered customers in 2019 is as follows:

Gas: metering technologies used for interval-metered customers in 2019

Function	No. of meter locations
Transmitting meter with a pulse output/encoder meter + a recording device/data storage	15,996
Transmitting meter with a pulse output/encoder meter + volume converter	9,133
Transmitting meter with a pulse output/encoder meter + calorific value volume converter	284
Transmitting meter with a pulse output/encoder meter + volume converter + recording device/data storage	15,373
Transmitting meter with a pulse output/encoder meter + temperature volume converter + recording device/data storage	670
Transmitting meter with a pulse output/encoder meter + smart meter gateway	8
Other	32

Table 143: Breakdown of metering technologies used for interval-metered customers as at 31 December 2019

Gas: communication link-up systems used for interval-metered customers in 2019
(number and percentage)

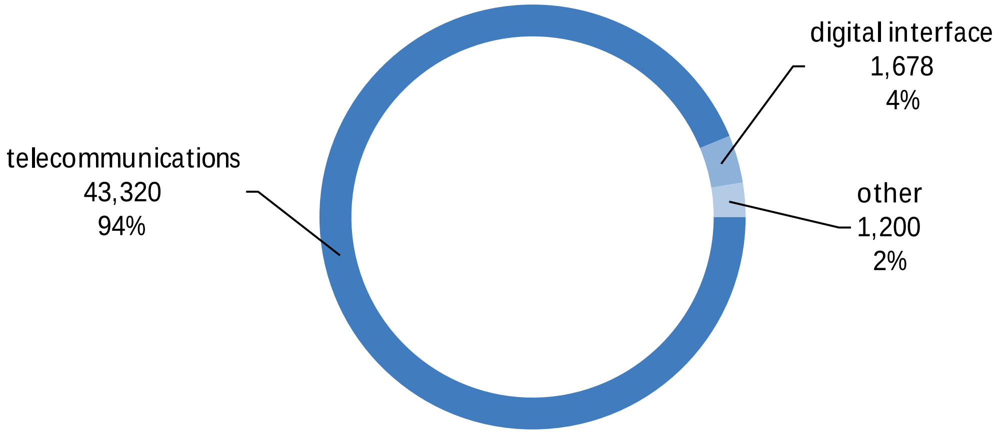


Figure 231: Number and percentage of communication link-up systems used for interval-metered customers – as at 31 December 2019

The metering technology used by interval-metered customers transmits data almost exclusively via telecommunication systems (93.8%). 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 must be mentioned as an alternative technology used to transfer meter data, with 3.6% of interval-metered customers using this interface.

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 650 gas meter operators.

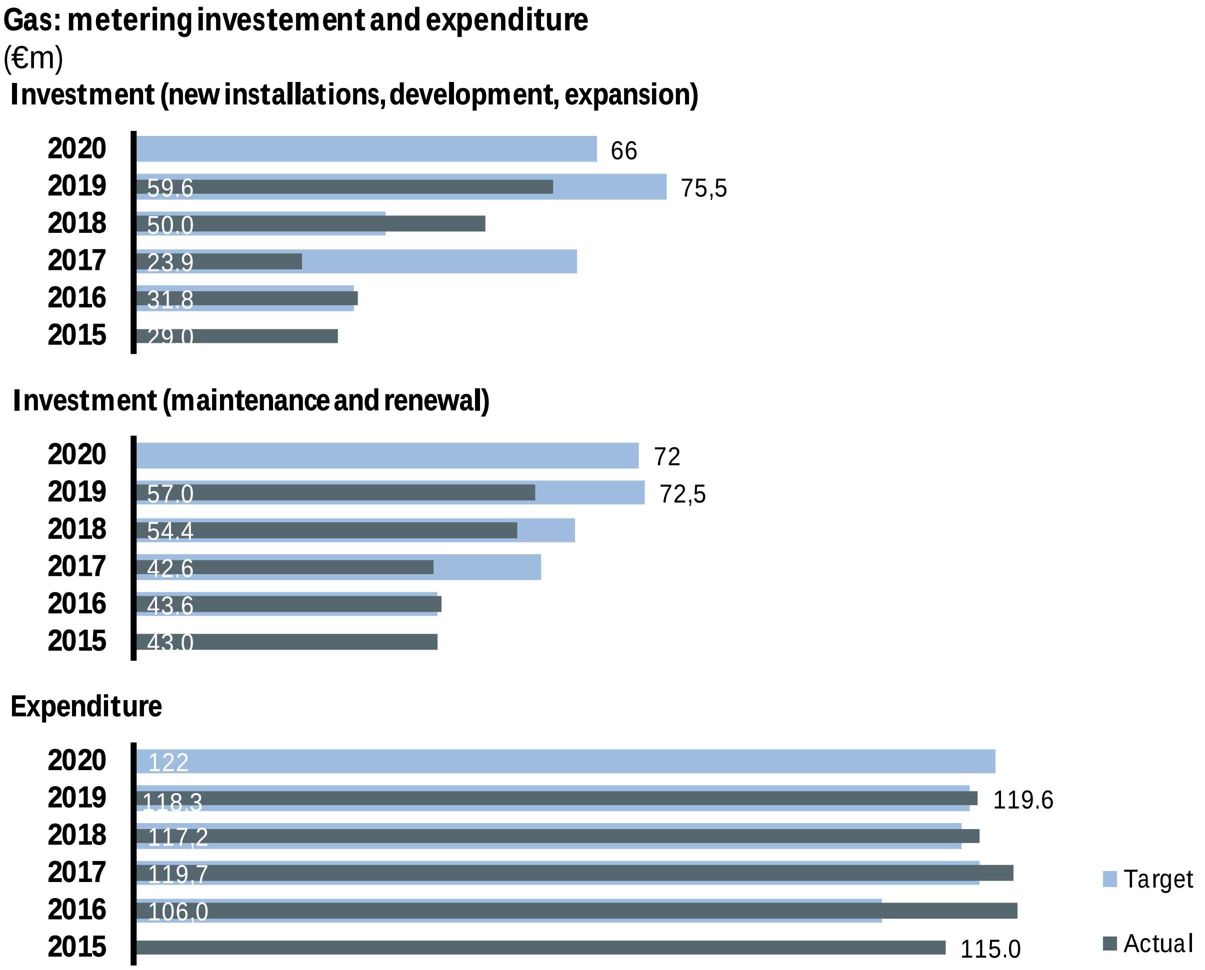


Figure 232: Metering investment and expenditure

III General topics

A Market Transparency Unit for Wholesale Electricity and Gas Markets[178]

The Bundesnetzagentur and the Bundeskartellamt carry out joint monitoring within the Market Transparency Unit for Wholesale Electricity and Gas Markets with the aim of ensuring fair pricing on the wholesale markets. The joint market monitoring is based on the transaction and fundamental data reported by the market participants.

Market participants entering into electricity or gas wholesale transactions that require reporting must register with the competent energy regulator in accordance with Regulation (EU) No 1227/2011 on wholesale energy market integrity and transparency (REMIT). The Bundesnetzagentur has been registering market participants for Germany since March 2015. At present, 4,745 market participants are registered in Germany, and 15,587 market participants are registered in the whole of the EU. 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.[179]

New registrations under REMIT

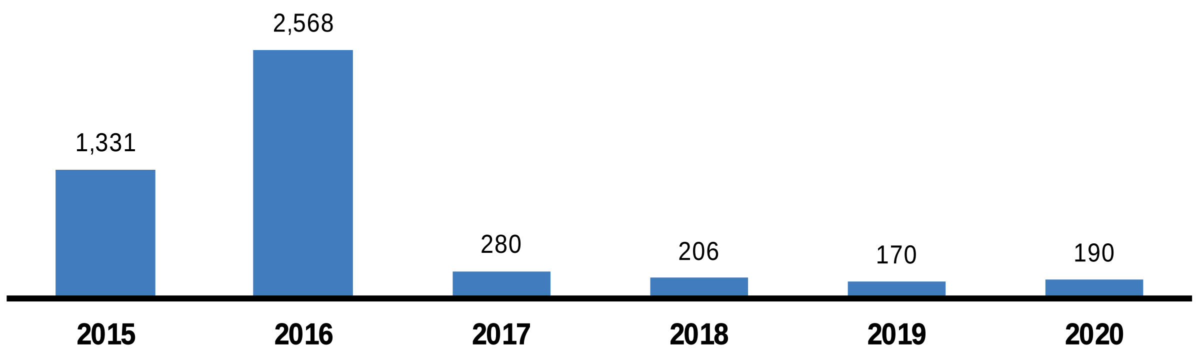


Figure 233: New registrations under REMIT in Germany per year

ACER[180] receives data from all the registered market participants on their trading 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.

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[178] Also constitutes the activity report of the Market Transparency Unit under section 47h(2) of the German Competition Act (GWB).

[179] Some registered market participants have been deleted since registering began, for example because of changes in the legal form of the companies.

[180] Agency for the Cooperation of Energy Regulators

The Market Transparency Unit receives the transaction data relevant for monitoring the German markets from ACER. It also receives the fundamental data for all EU countries.

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 chart shows the volume of data received:

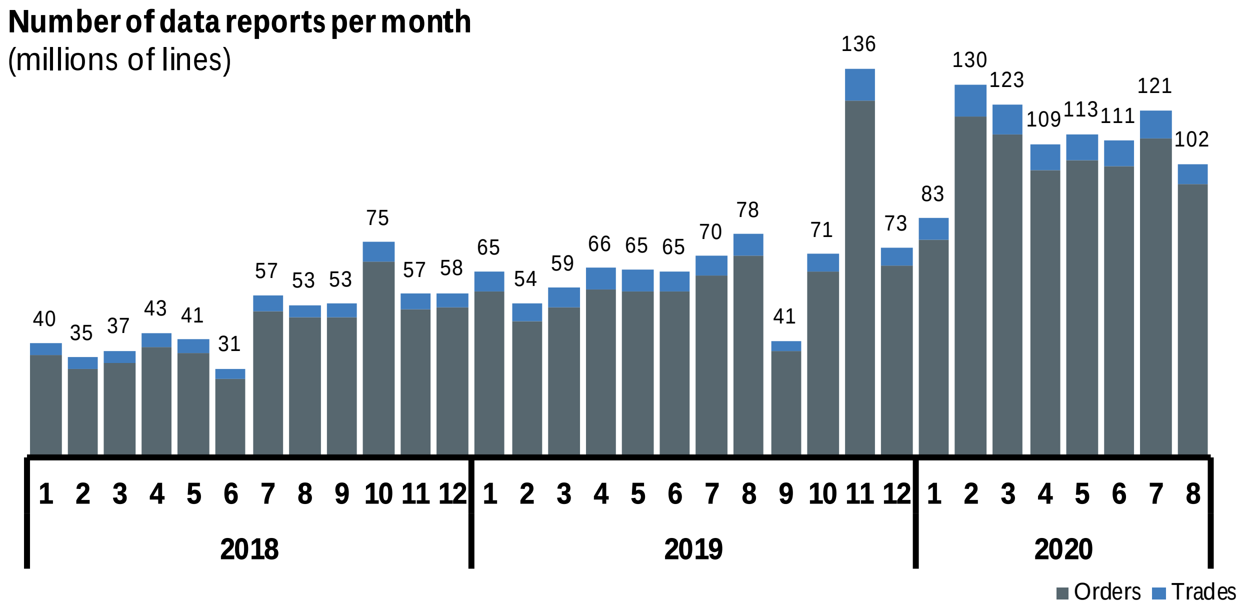

Figure 234: Number of data reports on orders and trades received per month by the Market Transparency Unit[181]

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 chart shows a steady increase in the number of reports on orders since 2018 (2020: average of 103m per month; 2019: 63m per month; 2018: 44m per month). There has also been a continuous increase in the number of reports on trades concluded (2020: average of 9m per month; 2019: 7m per month; 2018: 5m per

[181] Technical delays in the transmission of data may mean that reports are received relating to previous reporting periods. The figures presented may have been updated and may therefore differ from those published in previous monitoring reports.

month). Possible reasons, in addition to the technical aspects of data reporting, include the increased use of automatic trading algorithms.

The following diagram shows a breakdown of the data reported in the period from December 2017 to August 2020 into the categories exchange trading, trades via broker platforms, and bilateral contracts.

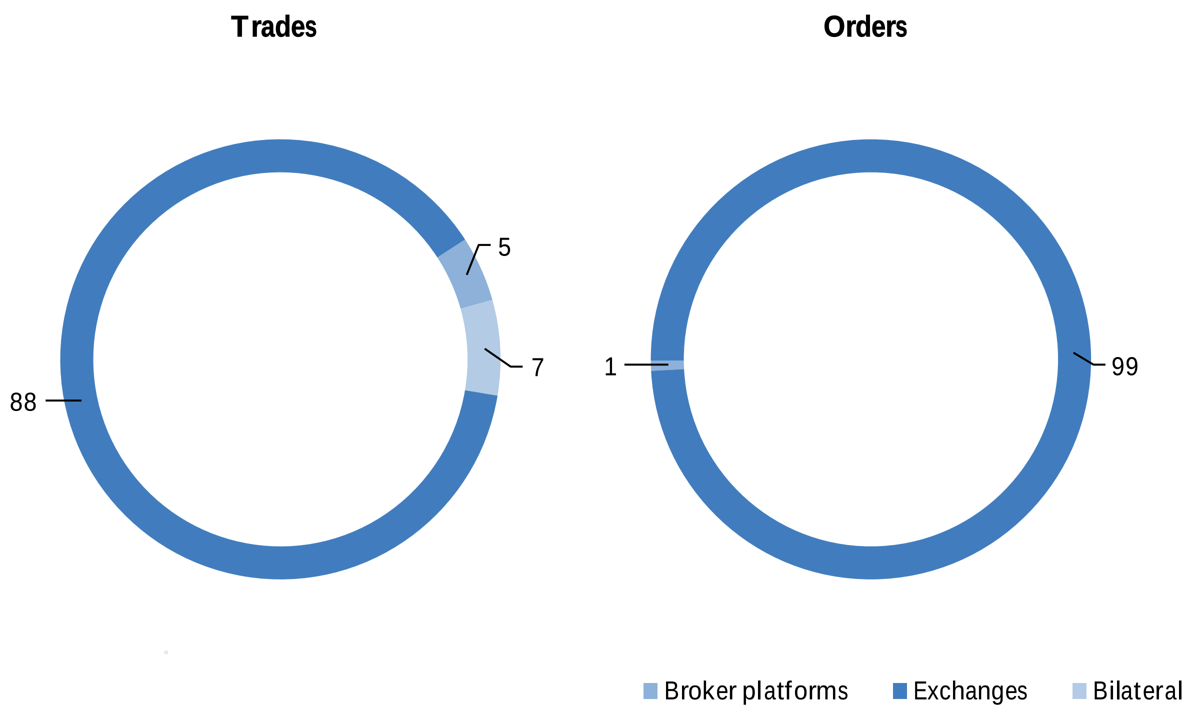

Figure 235: Reports on trades and orders by marketplace

The diagram shows that the vast majority of data reports on both orders and trades were transmitted by exchanges. This is because 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 Selected activities of the Bundesnetzagentur

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). The prohibitions on insider trading (Article 3) and market manipulation (Article 5) form the core 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", in other words trading with oneself.

Exchanges, broker platforms, market participants, the Agency for the Cooperation of Energy Regulators (ACER) and anonymous sources can report suspicious trading activity by one or more market participants. Reports received by the Bundesnetzagentur are referred to below as "suspected breaches", in other words 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.

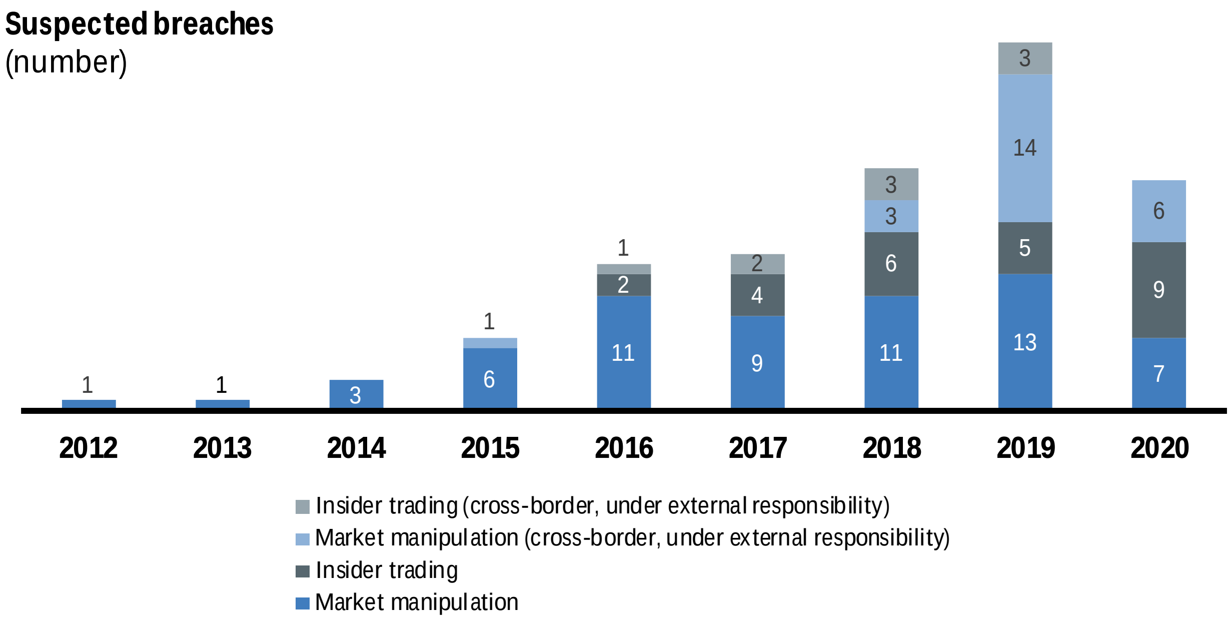

Figure 236: Suspected breaches, 2012 to 2020

a) Cross-border cases

Some of the suspected breaches reported are cases with cross-border aspects. An example of a cross-border case would be when the trading activity on the exchange relates to a product of a different Member State to the one in which the market participant is registered and has its headquarters. Cross-border cases are processed with the involvement of or under the lead responsibility of energy regulators in other Member States. A total of 33 cases are currently being processed under the lead responsibility of another energy regulator.

b) Internal processing

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. Overall, 60 out of the 88 suspected breaches processed internally have so far been closed.

If there is still an indication of a breach of REMIT after the initial analysis, the Bundesnetzagentur conducts its own investigation. If the investigation produces sufficient evidence to confirm the suspicion, the Bundesnetzagentur can start regulatory offence proceedings. If the breach may have criminal law consequences, the Bundesnetzagentur passes it on to the prosecution service.

The Bundesnetzagentur has so far concluded one case with three orders imposing fines. It has not yet passed on any cases to the prosecution service. A total of 26 cases are currently being processed.

In one case, the Bundesnetzagentur initiated regulatory offence proceedings in 2020 against three market participants. The case relates to the events surrounding the imbalances in the transmission system that occurred in June 2019. On three days in June 2019, the transmission system operators had to make full use of the balancing energy for longer periods and take other measures to keep the system stable. The administrative fines proceedings under REMIT focus on the trading behaviour of the market participants and thus the issue of whether the extreme situation on the three days in June was exploited on the trading side. As the exchange price was at times considerably higher than the imbalance price, there is reason to suspect that some market participants had been deliberately selling electricity on the intraday market at very high prices without actually intending to procure or generate the electricity.[182]

[182] See page 206 for details of the new imbalance price calculation methodology.

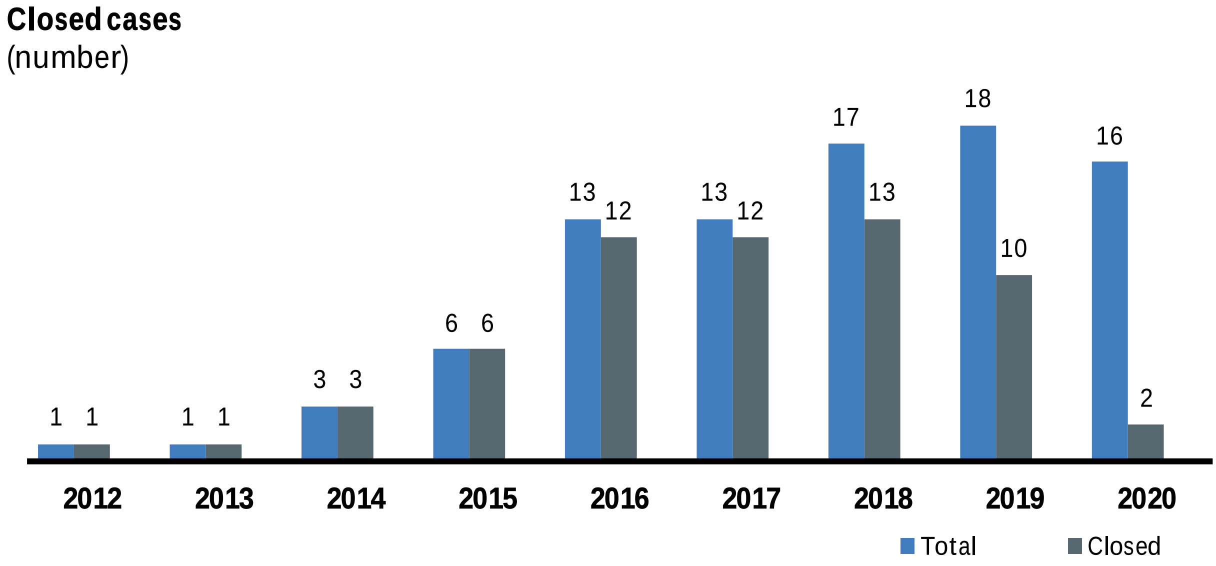

Figure 237: Suspected breaches closed, 2012 to 2020[183]

c) Suspected breaches identified by ACER

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 alerts may lead to suspected breaches. ACER first carries out a preliminary initial assessment (PIA), involving a more detailed analysis of the data and its own assessment of whether there are grounds to suspect a breach. The PIA is then forwarded to the energy regulator(s) responsible for further processing. Seven of the suspected breaches reported to the Bundesnetzagentur came from ACER as PIAs, and four of them are being processed under the lead responsibility of the Bundesnetzagentur.

[183] The figures shown as the total are the total number of cases processed internally and therefore differ from the totals presented in previous monitoring reports.

C Selected activities of the Bundeskartellamt

Sector inquiry into publicly accessible charging infrastructure for electric vehicles

In July 2020 the Bundeskartellamt launched a sector inquiry into the provision and marketing of publicly accessible charging infrastructure for electric vehicles.

The aim of the inquiry is to examine publicly accessible charging facilities either on public street space or private property which can be used by an indeterminate group of persons or one which can only be defined on the basis of general characteristics. The Bundeskartellamt has recently received an increasing number of complaints about prices and conditions at the charging stations.

According to the plans of the German federal government a nationwide charging infrastructure in Germany is to be established by 2030, which in particular also includes publicly accessible charging facilities. The aim of the sector inquiry is to identify structural competition problems in the provision and marketing of this publicly accessible charging structure in the early market phase in order to contribute to the successful expansion of e-mobility.

The process of setting up and operating charging stations is not subject to the comprehensive regulation of electricity networks. Potential competition problems occurring in this sector can, however, be addressed by competition law. To ensure effective competition, non-discriminatory access to potential locations for charging stations as well as the specific terms and conditions applying at the charging stations are of key importance.

In the sector inquiry the Bundeskartellamt asks the relevant players for information about the planning and current status of publicly accessible charging infrastructure in cities, municipalities and on the motorways. In a second phase the authority will focus on issues of access to charging stations for mobility service providers and final consumers and the effects on competition.

The results and conclusions to be drawn from the inquiry will be summarised and published in a report.

Lists

List of authorship

Joint texts

Key findings

Electricity markets summary (I.A.1)

Introduction to Retail: Contract structure and supplier switching (I.G.2)

Introduction to Retail: Price level (I.G.4)

Gas markets summary (II.A.1)

Introduction to Retail: Contract structure and supplier switching (II.F.2)

Introduction to Retail: Price level (II.F.4)

Market Transparency Unit for Wholesale Electricity and Gas Markets (III.A)

(Text passages in these four sections authored as listed below)

Authorship of the Bundesnetzagentur (explanations)

I Electricity market

A Developments in the electricity markets (in the following sections:)

2. Network overview

4. Consumer advice and protection

B Generation

C Networks

D System services

E Cross-border trading and European integration

G Retail (in the following sections:)

1. Supplier structure and number of providers

2.2 Contract structure and supplier switching, household customers

3. Disconnections, cash/smart card readers, tariffs and contract terminations

4.2 Price level, household customers

6. Green electricity segment

H Metering

II Gas market

A Developments in the gas markets (in the following sections:)

2. Network overview

B Gas supplies

C Networks

D Balancing

F Retail (in the following sections:)

1. Supplier structure and number of providers

2.2 Contract structure and supplier switching, household customers

3. Gas supply disconnections and contract terminations, cash/smart card meters and non-annual billing

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G Metering

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B Selected activities of the Bundesnetzagentur

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3. Market concentration

F Wholesale market

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List of abbreviations

Abbreviation	Definition
AbLaV	Interruptible Loads Ordinance
AC	alternating current
ACER	Agency for the Cooperation of Energy Regulators
aFRR	frequency restoration reserves with automatic activation
ARegV	Incentive Regulation Ordinance
AT	Austria
BAFA	Federal Office for Economic Affairs and Export Control
BBPlG	Federal Requirements Plan Act
BDEW	Bundesverband der Energie- und Wasserwirtschaft e.V.
BE	Belgium
bFZK	conditionally firm, freely allocable capacity
bn	billion
BSH	Federal Maritime and Hydrographic Agency
BSI	Federal Office for Information Security
BZK	firm capacity with restricted allocability
capex	capital expenditure
CAPM	capital asset pricing model
CH	Switzerland
CHP	combined heat and power
CIGRE	Conseil International des Grands Réseaux Électriques
CIS	Commonwealth of Independent States
CO2	carbon dioxide
CR	concentration ratio
ct/kWh	cents per kilowatt hour
CWE	Central Western Europe
DC	direct current
DLR	dynamic line rating
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
EGBGB	Introductory Act to the Civil Code
EGIX	European Gas Index
EGSI	European Gas Spot Index
EHV	extra-high voltage
EKII	equity II
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
FEP	site development plan
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
HV	high voltage
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
kVA	kilovolt ampere

KVBG	Act to Reduce and End Coal-Fired Power Generation
kW	kilowatt
kWh	kilowatt hour
KWKG	Combined Heat and Power Act
LBEG	State Authority for Mining, Energy and Geology
LNG	liquid natural gas
LSV	Charging Station Ordinance
LTE	Long Term Evolution
LV	low voltage
m	million
m3	cubic metre
MARI	Manually Activated Reserves Initiative
MaStRV	Core Energy Market Data Register Ordinance
MBI	market-based instrument
mFRR	frequency restoration reserves with manual activation
MinRAM	minimum remaining available margin
MOL	merit order list
MsbG	Metering Act
MV	medium voltage
MW	megawatt
MWh	megawatt hour
NABEG	Grid Expansion Acceleration Act
NAP	Network connection point
NAV	Low Voltage Network Connection Ordinance
NCG	NetConnect Germany
NDAV	Low Pressure Network Connection Ordinance
NDP	Network Development Plan
NeMoG	Network Charges Modernisation Act
NL	Netherlands
no.	number
NTC	net transfer capacity
n.v.	not available (nicht vorhanden)
OJ	Official Journal
OLG	higher regional court

Glossary

The definitions pursuant to section 3 of the Energy Industry Act (EnWG), section 2 of the Electricity Network Access Ordinance (StromNZV), section 2 of the Gas Network Access Ordinance (GasNZV), section 2 of the Electricity Network Charges Ordinance (StromNEV), section 2 of the Gas Network Charges Ordinance (GasNEV), section 3 of the Renewable Energy Sources Act (EEG) and section 2 of the Combined Heat and Power Act (KWKG) apply. In addition the following definitions apply:

Term	Definition
Adjustment measures	Section 13(2) EnWG entitles and obliges TSOs to adjust all electricity feed-in, transit and offtake or to demand such adjustment (adjustment measures) where a threat or disruption to the security or reliability of the electricity supply system cannot be removed or cannot be removed in a timely manner by network-related or market-related measures as referred to in section 13(1) EnWG. Where DSOs are responsible for the security and reliability of the electricity supply in their networks, they too are entitled and obliged under section 14(1) EnWG to take adjustment measures as referred to in section 13(2) EnWG. Furthermore, section 14(1c) EnWG requires DSOs to support the TSOs' measures as required by the TSOs with the DSOs' own measures (support measures). Curtailing feed-in from renewable energy installations under section 13(2) EnWG may also be necessary in situations other than those covered by the feed-in management provisions if the threat to the system is caused not by congestion but by another security problem. Adjustments pursuant to section 13(2) EnWG constitute emergency measures and as such are without compensation.
Affiliated undertakings within the meaning of section 15 Stock Corporation Act	As set out in the German Stock Corporation Act: legally independent companies that in relation to each other are subsidiary and parent company (section 16), controlled and controlling companies (section 17), members of a group (section 18), undertakings with cross-shareholdings (section 19) or parties to a company agreement (sections 291 and 292).
Annual peak load (final consumer)	Peak load, expressed in kilowatt (kW), as metered in 15 minute readings, in the course of a year.
Annual usage time (final consumer)	The annual usage time is the quotient of the energy drawn from the grid in an accounting year and the annual maximum capacity used in that year. It gives the number of days that would be required to withdraw the annual consumption volume by taking off the maximum daily amount (usage time in days = annual consumption divided by maximum daily amount). The usage time in hours indicates the number of hours required to withdraw the annual consumption volume by taking off the maximum hourly amount (usage time in hours = annual consumption divided by maximum hourly amount) (see annex 4 to section 16(2),(3) sentence 2 StromNEV).
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 para 10a 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. 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 meter operations	Charge for meter installation, operation and maintenance. In accordance with section 17(7) sentence 1 StromNEV, in the electricity sector only a "charge for meter operations" may be shown from 1 January 2017. This includes the charge for metering.
Charge for metering	In the gas sector, the charge for reading the meter, reading out and passing on the meter data to the authorised party (section 15(7) first sentence GasNEV).
CHP net nominal capacity (electrical active power)	For rated thermal capacity, proportion of the net nominal capacity directly linked to heat extraction. The proportion of electrical capacity exclusively related to the generation of electricity is not included here.
CO2 emissions from power generation	The CO2 released during power generation. For CHP plants the proportion of CO2 emissions that are to be allocated to power generation according to Working Sheet AGFW FW 309 Part 6 "Energy rating of district heating - Determining the specific CO2 emission criteria" (December 2014).
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 (net)	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 unit 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. 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 meter operation	Conventional meter operation includes all metering systems that are not modern metering equipment or smart metering system (eg Ferraris meters, eHZ, EDL21, EDL40, RLM meters, etc.)

Core data	Company data for the successful processing of business transactions. These include contract data such as a customer’s name, address and meter number.
Countertrading	Countertrading is a measure used by the TSOs to avoid overloading in the electricity grid. It is used when the agreed minimum trading capacity exceeds the capacity that can be transported in the networks. In this case, a countertrade is organised. This enables a minimum level of trading to be guaranteed at all times without the networks being overloaded.
Day-ahead trade	Day-ahead trading on the EPEX Spot (the EEX spot market) is for energy supplied the next day.
Default supplier	The gas and electricity company providing default supply in a network area as provided for by section 36(1) EnWG.
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	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. 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, CO2 emission rights and coal. EEX holds a 51% equity investment in the Paris-based EPEX Spot, which operates the power spot markets for Germany, France, Austria and Switzerland. The electricity futures market is operated by EEX Power Derivates GmbH (a 100% subsidiary of EEX). Since November 2017 EEX has been the sole shareholder in Powernext SA, also based in Paris, which operates short-term gas trading (see EEX). Because Powernext has been fully integrated into EEX since 1 January 2020, EEX offers all its products in a single marketplace.
Electric heating	Electricity for heating is the electricity supplied to operate controllable consumer devices for the purposes of room heating. Controllable consumer devices essentially comprises overnight storage heaters and electric heat pumps.
Energy Information Network (EIN)	Communication of power plant deployment planning data for conventional generating installations with a nominal capacity of at least 10 MW and a connection to networks with a nominal voltage of at least 110 kV to the TSO for ensuring that the network and system is operated securely (see Bundesnetzagentur decision BK6-13-200).
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.
ENTSO-E	ENTSO-E is the association of European transmission system operators (TSOs) with the objective of creating a liberalised European internal market for electricity. The association is headquartered in Brussels. The EU Transparency Regulation (Regulation (EU) No 543/2013) was adopted by the European Commission. The Regulation sets out that from January 2015 ENTSO-E must operate a central information transparency platform for fundamental data in the European electricity market. All market participants named in the Regulation such as operators of power plants and storage facilities, consumption units, electricity network operators and other market participants such as electricity exchanges and auction offices for transmission capacities are required to comply with the Regulation's reporting requirements. In Germany the Market Transparency Unit of the Bundesnetzagentur and the Bundeskartellamt (Article 4(6) EU Transparency Regulation) ensure compliance for the German market.
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).
Feed-in management	This is a special measure regulated by law to increase network security relating to renewable energy, mine gas and combined heat and power (CHP) installations. Priority is to be given to feeding in and transporting the electricity generated by these installations (section 11(1) and (5) EEG and section 4(1) and (4) second sentence KWKG). Under specific conditions, however, the system operators responsible may also temporarily curtail priority feed-in from these installations if network capacities are not sufficient to transport the total amount of electricity generated (section 13(2) and (3) third sentence EnWG in conjunction with sections 14 and 15 EEG and, in the case of CHP installations, section 4(1) second sentence KWKG). Importantly, such feed-in management is only permitted once the priority measures for conventional installations have been exhausted. The expansion obligations of the operator answerable for the network restrictions remain in parallel to these measures. The operator of an installation with curtailed feed-in is entitled to compensation for the energy and heat not fed in as provided for in section 15(1) EEG The costs of compensation must be borne by the operator in whose network the cause for the feed-in management measure is located. The operator to whose network the installation with curtailed feed-in is connected is obliged to pay the compensation to the operator of the installation with curtailed feed-in. If the cause lay with another operator, that operator is held responsible and is required to reimburse the costs of compensation to the operator to whose network the installation is connected.
Flow Based Allocation (FBA)	Flow based allocation of capacity. Starting from the planned commercial flows (trades), the capacity available for cross-border electricity trading is determined and allocated on the basis of the actual flows in the network. FBA thus makes it possible to allocate transmission capacity in line with the actual market situation as reflected by the bids.
Futures	Contractual obligation to buy (futures buyer) or deliver (futures seller) a specified amount of, for example, electricity, gas or emission rights at a fixed price in a defined future period (period of delivery). Futures contracts are settled either physically or financially.
Futures market	Market for trading futures and derivatives. It differs from the spot market in that obligation and settlement do not take place at the same time.
Green electricity tariff	Tariff for electricity 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	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)). 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.
Grid reserve capacity	Grid reserve capacity is a price element for customers with their own generation or network operator into whose network such generating installations feed. For failures due to disruptions or routine inspections, a grid reserve capacity of up to 600 hours per billing year can be contractually agreed.
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, enabling the short-term optimisation of procurement and sale.
Investments	For the purposes of the energy monitoring survey, investments are defined as the gross additions to fixed assets capitalised in the reporting period and the total value of new fixed assets newly rented and hired in the reporting period. Gross additions also include leased goods capitalised by the lessee. The gross additions must be notified without deductible input value added tax. The value of internally generated assets as capitalised in the fixed asset account (production costs) is to be included. Notification is also required of assets under construction (work commenced for operational purposes, as far as capitalised). If a special "assets under construction" summary account is kept, notification should be made only of the gross additions without the holdings shown in the account at the beginning of the year under review. Payments on account should be included only if the parts of assets under construction for which they were made have been settled and if they have been capitalised. Not included are the acquisition of holdings, securities etc (financial assets), the acquisition of concessions, patents, licences etc and the acquisition of entire undertakings or businesses and the acquisition of rental equipment formerly used in the undertaking, additions to fixed assets in branch offices or specialist units in other countries and financing charges for investments (Federal Statistical Office, 2007).
Length of circuit	System length (the three phases L1+L2+L3 together) of cables at the network levels LV, MV, HV and EHV. (For example: If L1 = 1km, L2 = 1km and L3 = 1km, then the length of the circuit = 1km). In the case of different phase lengths, the average length in kilometres must be determined. The number of cables used per phase is irrelevant for the length of circuit. However, cables or overhead lines leased by, or otherwise made available to the network operator, should be included to the extent they are operated by the network operator. Lines with share of external use 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 and the lines of street lighting systems.

	Circuit lengths of street lighting systems are only included if the costs for electricity distribution are part of the fiscal year's activity report. Planned cables, those under construction or leased out to third parties, and cables or overhead lines that have been decommissioned are not included.
L-gas (low calorific gas)	A second-family gas with a lower amount of methane (80 to 87 volume percent) and higher volume percentages of nitrogen and carbon dioxide than h-gas. It has a medium calorific value of 9.77 kWh/m³ and a Wobbe index from 10.5 kWh/m³ to 13.0 kWh/m³.
Load control in the low voltage network (formerly load interruption)	Electricity distribution system operators are required to give a reduction in network charges to suppliers and final customers at the low voltage level with whom they have concluded network access agreements, in return for being able to control meter points with load control for the benefit of the network. Electric vehicles are counted as controllable loads within the meaning of sentence 1. The federal government is empowered, by ordinance having the force of law and requiring the consent of the German Bundesrat, to give concrete shape to the obligation pursuant to sentences 1 and 2, in particular by providing a framework for the reduction of network charges and the contractual arrangements, and by defining control actions that are reserved for network operators and control actions that are reserved for third parties, in particular suppliers. It must observe the further requirements of the Metering Act regarding the communicative integration of the controllable loads. (section 14a EnWG)
Load-metered final customers	Measurement of the power used by final consumers in a defined period. Load metering is used to establish a load profile showing a final customer's consumption over a defined period. A distinction is made between customers with and customers without load metering.
Load-variable price plan	A load-variable price plan is a tariff for electricity where the price of electricity depends on electricity demand and network utilisation.
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.
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 has all the 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).
Meter point	Point in the grid at which the flow of energy, or the amount of gas transported, is recorded for billing purposes (see section 2(28) of the Metering Act).
Metering service Modern metering equipment	Metering the energy supplied in accordance with verification regulations and processing the metered data for billing purposes. 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. Modern metering equipment
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 network charge, from 1 January 2017 including billing charge, not including charges for meter operations, VAT, concession fees, surcharges payable under the EEG and KWKG as well as other surcharges. 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	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)

Ökostromtarif	low voltage medium voltage high voltage extra-high voltage
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 capacity	Maximum capacity at which a plant can be operated for a sustained period under rated conditions at the time of handover. Capacity changes are only permitted in conjunction with major modifications of the nominal conditions and structural alterations at the plant. Until the exact nominal capacity has been determined, the value ordered in the supply contract should be indicated. If it is unclear whether the value ordered complies with the actual permit and operating conditions expected, a preliminary average nominal capacity is to be determined and applied until definitive measurement results are available. The average is to be fixed in such a way that higher or lower production levels, over a normal year, will be offset (eg on account of the cooling water temperature curve). The definitive nominal capacity of a power plant unit is determined when the plant has been handed over, usually when the acceptance measurement results are available. It should be noted that the rated conditions apply to an annual average, ie that seasonal changes (for example in the cooling water and air inlet temperature) and internal electrical and steam-side requirements balance out, and that exemplary conditions used in the acceptance test, eg special closed circuit switching, must be converted to normal operating conditions. The nominal capacity, unlike the maximum capacity, may not be adjusted to a temporary change in capacity. The nominal capacity may not be changed in the case of a reduction in capacity as a result of, or to prevent, damage, nor may it be reduced on account of ageing, deterioration or pollution. Capacity changes require: • additional investment with a view to increasing the plant's capacity, eg retrofitting to enhance efficiency; • the decommissioning or removal of parts of the plant, accepting a loss of capacity; • operation of the plant outside the design range stipulated in the supply contracts on a permanent basis, ie for the rest of its life, for external reasons, or • a restriction of capacity, imposed by statutory regulations or orders of public authorities without there being a technical fault in the plant, until the end of its operating life (VGB, 2012).
Nominal pressure	The nominal pressure specifies a reference designation for pipeline systems. In accordance with DIN EN ISO, nominal pressure is given using the abbreviation PN (pressure nominal) followed by a dimensionless whole number representing the design pressure in bar at room temperature (20°C). EN 1333 specifies the following nominal pressure levels: PN 2.5 - PN 6 - PN 10 - PN 16 - PN 25 - PN 40 - PN 63 - PN 100 - PN 160 - PN 250 - PN 320 - PN 400.
Nomination	Shippers' duty to notify the network operator, by 2pm at the latest, of their intended use of the latter's entry and exit capacity for each hour of the following day.
Normal cubic metre (Ncm)	Section 2 para 11 GasNZV defines a normal cubic metre as the quantity of gas that, 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.

Online tariff	A tariff that can be concluded online (eg on the company's website or through a price comparison platform) and for which bills are available online.
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-
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. : The EEX has the Phelix-DE year future for electricity contracts for the next calendar year or subsequent years for the market area of Germany (both base and peak). All contracts can be traded for baseload or peak load.
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.
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 to 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.
SLP customer (standard load profile customer)	ct Section 12 StromNZV defines standard load profile customers as final customers with an annual offtake 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.) 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.)
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 that 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.
Thermal effective output	The maximum useful heat generation under rated conditions that a CHP installation can supply.
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.
Universal service	Energy supply by the default supplier to household customers on the basis of general terms and conditions and general prices (see section 36 EnWG).
Usage time (final consumer)	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). 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)
Useful heat	The heat extracted from a CHP process that is applied outside the CHP plant for space heating, hot water systems, cooling or process heat (see section 2(26) KWKG).
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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