Monitoring report 2023

in accordance with section 63(3) in conjunction with section 35 EnWG and section 48(3) in conjunction with section 53(3) GWB

Bundesnetzagentur Bundeskartellamt

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Monitoring report 2023

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German Energy Industry Act (EnWG) section 63(3) Reporting

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

German Competition Act (GWB) section 48(3) Activity report and monitoring reports

(3) The Bundeskartellamt shall monitor the degree of transparency, including that of wholesale prices, and the degree and effectiveness of liberalisation as well as the extent of competition on the wholesale and retail levels of the gas and electricity markets and on the gas and electricity exchanges. The Bundeskartellamt shall without delay make the data compiled from its monitoring activities available to the Bundesnetzagentur.

Monitoring Report data origin

Unless otherwise indicated, the figures in this report have been taken from the data collected during the monitoring survey carried out annually by the Bundesnetzagentur and the Bundeskartellamt. Undertakings that are active on the electricity or gas market in Germany provide data for the survey on all aspects of the value added chain (generation, network operation, metering operations, trade, marketing etc). Further data on trade is supplied by the electricity and gas stock exchanges, and by energy brokers. All the data is checked for plausibility and validated by the Bundesnetzagentur and the Bundeskartellamt. In 2023, some 6,500 undertakings overall supplied data to the two authorities. Thus the degree of coverage in each market segment, as reflected by the level of response, was well over 90% and in many areas it reached 100%. Any discrepancies between this and other data are the result of different data sources, definitions and survey periods.

Foreword

The Russian war on Ukraine has not only had a serious geopolitical and humanitarian impact on Europe, it has affected the global energy markets as well. Germany has been particularly hard hit by the repercussions of this conflict on energy supply and markets. The various consequences of the war in Ukraine on the German energy market range from extreme price rises to efforts to increase energy security and diversify energy sources. The Monitoring Report 2023 has been completely revised and redesigned to focus even more closely on the major trends of 2022. These developments, which are put in the context of the electricity and gas markets, include the ongoing energy transition as well as Germany's ambitious climate goals, which are to be implemented in an environment that is as competitive and market-compliant as possible. The promotion of renewable energy sources, such as wind and solar, continues to be a central point of economic policy, requiring, among other things, the expansion of grid capacity and the creation of favourable investment conditions.

The joint monitoring carried out in continued close and effective cooperation by the Bundesnetzagentur and the Bundeskartellamt aims to provide consumers with important information, create transparency in the market and provide an analysis of developments in competition. The Bundeskartellamt focuses on the competitive aspects of the electricity and gas value added chains, including supply to non-household customers, while the Bundesnetzagentur directs its attention towards generation, network tariffs, evaluating security of supply, and delivery to household customers.

Hard-coal and lignite power stations with a total capacity of 6.9 gigawatts returned to the electricity market in 2022 for a temporary period under the Maintenance of Substitute Power Stations Act (EKBG) in order to safeguard a stable and secure electricity and heat supply following declaration of the gas alert level. These power stations helped to ensure the stability of the stable electricity supply. In addition, in 2022 the legislators decided to extend the life of the three remaining nuclear power plants until 15 April 2023 in the interests of security of supply. The entry into force of the Gas Storage Act on 30 April 2022 and the introduction of statutory requirements for storage levels served to increase security in the supply of gas as well. The 1 November target of 95% was already reached on 25 September 2023.

Germany's net electricity generation was slighter lower in 2022 due to a drop in consumption. The share of renewables in gross electricity consumption was 45%, up from 40% in 2021.

Market concentration in electricity generation and the first-time sale of electricity (not entitled to payments under the Renewable Energy Sources Act (EEG)) saw a decrease in 2022 from the previous year as regards the market shares of the five largest undertakings, both in the volumes generated and in the generating capacity. RWE continues to lead the field of the big five by some distance in terms of both the amount of electricity generated and the amount of generation capacity.

In the more detailed analyses carried out for the latest market power report for 2022 on the competitive conditions in the electricity generation market, the Bundeskartellamt found in its analysis of general market developments that RWE had consolidated its power on the market for the first-time sale of electricity in 2022 and the first quarter of 2023. The proportion of time in which it was not possible to meet the demand for electricity without RWE was, again, well above the threshold for presuming market dominance (5% of the hours in a year). There was a further increase in 2022 in the importance of the power plant capacity operated by the next largest providers, LEAG and EnBW, for meeting Germany's demand for electricity as well as in the competitive significance of electricity imports and thus foreign power plant capacity.

The gas imports situation has seen major changes as a result of the reduction in supply and the end to deliveries from Russia since the beginning of the Russian war of aggression against Ukraine in February 2022. Gas imports from Russia via the Nord Stream 1 pipeline fell drastically over the course of the year and ultimately stopped completely at the beginning of September. The deliveries that would have come from Russia were largely replaced by additional imports from the Netherlands, Belgium, Norway and other countries, so the level was only slightly below that of the previous year. The most important sources of imported gas in Germany in 2022 were Norway, the Netherlands and Belgium, with a combined share of about 68%. What is more, Germany's first floating LNG terminal started operation in Wilhelmshaven in December 2022. It was joined by two more such terminals in Lubmin and Brunsbüttel in January and March 2023.

There was a decline in gas sales in 2022, which was due in particular to the large drop in Russian gas deliveries and possibly also to an increased focus on measures to use less gas. Market concentration among the underground storage facilities connected to the German gas network that were the focus of the concentration assessment did not change significantly. However, the market position of Gazprom Germania GmbH, one of the largest operators of natural gas storage, was transferred to Securing Energy for Europe GmbH (SEFE), which is now wholly owned by the Federation.

The aggregate market shares of the four largest electricity and gas suppliers for interval-metered and standard load profile customers in the retail markets were below the statutory thresholds for presuming market dominance in 2022, as in previous years. In light of this, the current assumption is that there is no single dominant undertaking in these markets.

Russia's invasion of Ukraine in February 2022 had far-reaching effects on the energy markets. Wholesale and retail prices for electricity and gas reached record highs. Even though wholesale prices eased around the end of 2022 and in the first quarter of 2023 and there was less volatility, price levels are still higher than before the war and the start of the energy crisis. The trend in electricity wholesale prices largely mirrors that in natural gas prices. As gas-fired power plants tend to set the price in spot trading at times of peak demand, the increase in gas prices several times over led to a similar increase in prices on the electricity exchange (merit order principle). Prices were dampened around the end of the 2022 reporting period by the reactivation of coal-fired power plants from security standby mentioned above, the return to the market of reserve power plants and the temporary extension in running time of the three remaining nuclear power stations.

The Russian war exerted a strong influence on procurement strategies, too. In particular, there was huge growth in volumes traded on the European gas exchanges in 2022, both on the spot and futures markets, although, from the exchange perspective, the latter could also be due to greater hedging needs.

The average, volume-weighted electricity price for household customers on 1 April 2023 was a record 45.19 cents per kilowatt hour (2022: 36.06 ct/kWh). The average, volume-weighted gas price for household customers was 14.80 ct/kWh on 1 April 2023, around 50% higher than in 2022 (9.88 ct/kWh). The average electricity prices for non-household customers and for heating electricity rose year-on-year as well, as did the average gas price for non-household customers. The electricity and, in particular, the gas prices for non-household customers were on average close to their respective price brakes. The rise in retail electricity and gas prices in the course of 2022 was primarily due to the much higher costs of procuring energy. Lawmakers mitigated these price rises by bringing forward the end to the surcharge under the EEG to 1 July 2022 and introducing a temporary reduction on VAT on gas to 7% from 1 October 2022. The energy price brakes already mentioned were a further means of relieving the burden on gas, electricity and heating customers. They were initially limited to 2023.

The sharp rise in electricity and gas prices caused by the war in Ukraine had a noticeable effect on customers' switching behaviour as well. There was a clear drop in household customers changing electricity supplier in 2022, with just over 4mn switches taking place. The number of household gas customers switching supplier fell by about a third to 1.15mn. These declines may be attributed to the greatly reduced choice of attractive new customer contracts available, as well as the possible effects of the price brakes. There was, for a time, no incentive to switch from the traditionally more expensive default tariffs to a tariff offered by a competitor because no or only a few, more expensive offers were available. The long-term trend of a decline in the volume of gas supplied via default contracts was actually reversed for the first time since 2010. There are now more favourably-priced competitive tariffs available again, some of them below the thresholds of the price brakes, which may have a positive effect on switching activity.

There was also a significant reduction from the previous year in the number of non-household customers changing their gas supplier and in the volume of gas affected by a switch. However, switching activity by non-household customers in the electricity sector picked up in 2022 from the year before, as some customers were able to respond more quickly to price rises.

The Bundesnetzagentur and the Bundeskartellamt will continue to pay close attention to the highly dynamic developments on the electricity and gas markets in Germany and will play a role in shaping this process within their areas of activity.

Klaus Müller
President of the
Bundesnetzagentur für Elektrizität, Gas, Telekommunikation, Post und Eisenbahnen

Andreas Mundt
President of the Bundeskartellamt

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A Electricity

1. Electricity network overview

The network balance provides an overview of supply and demand in the German electricity grid in 2022. Supply comprised a total net electricity generation of 531.7 terawatt hours (TWh), including 9.2 TWh from pumped and battery storage and physical flows from other countries into Germany's general supply networks amounting to 50.1 TWh. Demand comprised a total of 444.2 TWh (2021: 467 TWh) of electricity delivered from the general supply networks to final customers (down 4.9% on the previous year). The drop in consumption is due to various factors, including Russia's invasion of Ukraine, high energy prices on the wholesale markets, the mild weather compared to the year before and the sluggish economy in the second half of 2022.[1] Consumption by industrial, commercial and other non-household customers totalled 311 TWh and by household customers 120.8 TWh. Consumption by pumped storage and battery storage amounted to 12.4 TWh.[2] A total of 35.5 TWh of electricity was fed into networks not classed as general supply networks. Network losses totalled 28 TWh, while physical flows from Germany's networks to other countries amounted to 75.2 TWh.[3]

2. Electricity generation

Germany's net electricity generation was slighter lower in 2022 due to the drop in consumption. At 531.7 TWh, it was 2.7% down on the 2021 level. Conventional power plants recorded a decrease in generation of about 32.9 TWh (10.1%). Generation from renewable sources was up 18 TWh (8.2%) on the previous year. Renewable generation accounted for about 45% of gross electricity consumption (5 percentage points higher than the year before).[4] The highest level of feed-in from wind and solar photovoltaic (PV) (74.6 gigawatt hours (GWh)) was recorded between 1pm and 2pm on 4 April 2022. The large increase in 2022 was mainly due to the high growth in wind and solar PV capacity and the very sunny year.

Electricity generation by lignite power stations amounted to 108.0 TWh, up 5.1% on the previous year. Generation by hard coal-fired power plants totalled 58.8 TWh, up 14.4% year-on-year.

Hard-coal and lignite power stations with a total capacity of 6.9 gigawatts (GW) returned to the electricity market in 2022 for a temporary period under the Maintenance of Substitute Power Stations Act (EKBG) in order to safeguard a stable and secure electricity and heat supply, following declaration of the gas alert level. On the basis of section 50a(4) of the Energy Industry Act (EnWG) in conjunction with the Electricity Supply Expansion Ordinance (StaaV), grid reserve power plants (except for natural gas power stations) and plants from the third tendering round under the Act to Reduce and End Coal-Fired Power Generation (KVBG) that

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[1] https://www.bmwk.de/Redaktion/DE/Dossier/konjunktur-und-wachstum.html (in German)

[2] The monitoring survey only covers battery storage systems with a net rated capacity of 10 megawatts (MW) or more per site.

[3] The individual figures for consumption add up to 582.9 TWh. There is a small difference of 1.1 TWh between this sum and the total amount of electricity supplied of 581.8 TWh. The difference is due to the large number of different market participants and the complexity of the data survey.

[4] Where the share of generation from renewables is taken to be about 47.4% or more, it is usually based on the definition of consumption as the "grid load" (as, for example, on the SMARD website).

had been banned from coal-fired operation as from 31 October 2022 were allowed to return to the electricity market temporarily until 31 March 2024.

In addition, power plants on security standby under section 13g EnWG were transferred to the supply reserve in accordance with section 50d EnWG from 1 October 2022 until no later than 31 March 2024 in order to prevent supply shortages. These power plants were allowed to return to the electricity market from 1 October 2022 until 30 June 2023 following declaration of the gas alert level. All the operators of power plants transferred to the supply reserve opted to return to the market for this temporary period.

Electricity generation by natural gas power stations amounted to 65.6 TWh, down 15.6% on the previous year. One of the reasons was the high and largely increased natural gas prices on the spot and futures markets. In addition, the temporary return of coal power stations led to more electricity being produced using lignite and hard coal instead of natural gas. Nuclear generation decreased by about half year-on-year to 32.8 TWh. This significant reduction is due to the decommissioning of the Brokdorf, Gundremmingen and Grohnde nuclear power plants on 31 December 2021. Electricity generation by oil power stations reached 4.5 TWh, about the same as the year before.

Combined heat and power (CHP) plants

CHP plants generated 55.3 TWh of electricity in 2022 (down 11.4 TWh). Non-CHP electricity increased by 12.8 TWh to 142.5 TWh. The total amount of useful heat generated was 124.1 TWh (down 22.1 TWh). The primary energy source for the generation of electricity and useful heat was natural gas, accounting for 37.3 TWh of the total electricity and 53.8 TWh of the total useful heat produced. By contrast, the primary energy source for the generation of non-CHP electricity was lignite, which accounted for 86.1 TWh of the total.

The installed electrical capacity of the CHP plants increased in 2022 by 1.6 GW to 29 GW. The useful heat capacity grew by 2.1 GW to 56.4 GW. Natural gas is by far the most important energy source for CHP plants. It is used to fuel plants with a total installed electrical capacity of 16.4 GW and a total useful heat capacity of 26.6 GW.

Electricity generation capacity

The total installed generation capacity at the end of 2022 was 247.3 GW[5] (2021: 239.5 GW[6]). It comprised 96.9 GW of non-renewable and 150.4 GW of renewable capacity. Conventional capacity was down by 2.8 GW. This was due in particular to the decommissioning of nuclear and lignite power stations on 31 December 2021. By contrast, renewable capacity grew by 10.7 GW in 2022, compared to an increase of 8.6 GW from 2020 to 2021. Solar PV, onshore wind and offshore wind had the highest growth in capacity in 2022 (up 8.1 GW, 2.0 GW and 0.3 GW respectively). The installed capacity of installations eligible for payments under the Renewable Energy Sources Act (EEG) in Germany stood at 145.3 GW at the end of 2022 (2021: 134.2 GW), an increase of 11.1 GW (8.3%). A total of 220 TWh of renewable electricity was entitled to payments under the EEG in 2022, an increase of 8.0%.

Figures under the EEG

Payments to renewable energy installation operators under the EEG decreased year-on-year by 37.3% to €12.3bn. The average paid to operators under the EEG in 2022 was 5.6 cents per kilowatt hour (ct/kWh).[7] The decrease in these payments was due to the high electricity prices.

The share of all EEG payments attributable to feed-in tariffs has decreased steadily since 2010, falling to just around 17% in 2022. The largest decrease in feed-in tariffs was for onshore wind (down 96.5%). This was due above all to the high electricity prices. The share attributable to market premiums was 76%. Onshore wind, offshore wind and geothermal energy accounted for the largest share of market premiums. Other forms of direct selling accounted for 7%, of which hydropower and different types of gas had the largest shares (18% and 14% respectively).

The development corridors laid down in law were achieved for onshore wind, solar and biomass in 2022, but even more new installations are needed to meet the higher expansion targets for 2030. The installed capacity targets set for 2030 in the EEG 2023 and the Offshore Wind Energy Act (WindSeeG) are as follows: biomass 8.4 GW, solar 215 GW, onshore wind 115 GW and offshore wind 30 GW.

Auctions

Nearly all the auctions in 2022 were undersubscribed. In the year's first auction for onshore wind, bids still covered the volume auctioned. Price increases during the year led to a continual decrease in bids. The Bundesnetzagentur's price ceilings also contributed to the reversal in the trend.

There was a continual decrease in the volumes bid for in the solar and innovation auctions as well, due among other things to rising production costs and the massive increase in the volumes up for auction. The

[5] This includes power plants not currently in the market, for instance plants in the grid reserve or plants that have been shut down temporarily.

[6] The 2021 figure from the 2022 monitoring has been updated.

[7] 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.

Bundesnetzagentur also issued two determinations setting price ceilings for these auctions with the aim of improving framework conditions and promoting competition.

The auctions for biomass and biomethane (biogas that has been extracted from the gas network and converted into electricity) in 2022 were undersubscribed, as they had been since their introduction. There was a reversal in the trend in the biomass auctions in 2023; this was again probably due to the Bundesnetzagentur setting a price ceiling.

In 2022, the Bundesnetzagentur auctioned one site for an offshore wind farm in the North Sea that had been subject to a pre-investigation by the Federal Maritime and Hydrographic Agency (BSH) to analyse the marine environment, seabed, and wind and oceanographic conditions. The offshore wind farm is due to start operation in 2027 with a capacity of 980 megawatts (MW). Several bids were submitted. The successful bid was one with an award price of 0 ct/kWh, for which, however, a company exercised a right of subrogation because it had originally planned an offshore wind farm on the site.

In 2023, the Bundesnetzagentur conducted two rounds of auctions for sites for offshore wind farms with a total capacity of 8,800 MW. This was the largest ever volume auctioned in a year.

Four non-centrally pre-investigated sites with a combined volume of 7,000 MW were first up for auction: three with a capacity of 2,000 MW each in the North Sea and one with a capacity of 1,000 MW in the Baltic Sea. The wind farms are due to go into operation in 2030. The awards were made for the first time in online dynamic bidding procedures. These procedures were necessary because eight zero-cent bids for each of the sites in the North Sea and nine zero-cent bids for the site in the Baltic Sea had been submitted. The successful bidders were the ones willing to pay the highest amount for each site. There was lively competition for all the sites, with prices successively increasing in a total of between 55 and 72 bidding rounds. The proceeds from the auctions amounted to €12.6bn.

The second round of auctions was for four pre-investigated sites in the North Sea with a combined volume of 1,800 MW. The awards were made for the first time in bidding procedures with qualitative criteria, which took account of factors such as the decarbonisation of the offshore expansion projects and the use of environmentally friendly foundation technologies as well as how much bidders were willing to pay. The wind farms are due to start operation in 2028. The auctions for the pre-investigated sites were influenced by rights of subrogation for three of the four sites. The qualitative criteria did not have a decisive effect on the awards.

A total of 90% of the proceeds from the two offshore wind power auctions in 2023 will go towards bringing down electricity costs and 5% each towards marine nature conservation and promoting sustainable fishing. The contributions for marine conservation and fishing must be paid to the federal budget within one year. The contributions for lowering electricity costs must be paid in equal annual instalments to the transmission system operators required to connect the offshore wind farms over a period of 20 years beginning when a wind farm becomes operational.

Current power plant capacity

The installed generation capacity in Germany's general supply networks as at 17 November 2023 amounted to 252.8 GW (net). Non-renewable capacity was about 3.1 GW lower than at the end of 2022, mainly because of the closure of the last three nuclear power plants, Isar 2, Emsland A and Neckarwestheim 2, on 15 April 2023.

Expected new capacity and closures

A total of 1,999 MW of new conventional generation capacity is expected to be installed by 2026.[8] A total of 13,447 GW of capacity is due to be taken out of operation.

3. Market concentration

Electricity generation

Market concentration in electricity generation and the first-time sale of electricity (not entitled to payments under the EEG) saw a decrease in 2022. The aggregate market share of the five largest companies by sales (CR5) (in the period under review RWE, LEAG, EnBW, Uniper and E.ON) on the market for the first-time sale of electricity in the German market area, including Luxembourg, in terms of generation volumes in 2022 was 63.5%, compared to 67.0% in 2021. The aggregate market share of the five largest suppliers (in the reporting period: RWE, EnBW, LEAG, Vattenfall and Uniper) of *German conventional* electricity generation *capacity* at the end of 2022 was 52.1%, also lower than the share in 2021 of 55.6%.[9] However, the decrease in capacity is related above all to E.ON, which is no longer one of the five largest suppliers in this area in the report for 2022. RWE is by far the largest in the group of five in terms of both the amount of electricity generated and the amount of generation capacity. The overall decrease in capacity is due to the implementation of the nuclear and coal phase-out, which involves a significant amount of conventional generating capacity exiting the market, including plants operated by the five largest suppliers. The closure of the last three nuclear power plants, which was originally scheduled for 2022, is not taken into account in this reporting period because the plants were in operation until 15 April 2023.

EEG electricity

In terms of the volume of electricity generated entitled to payments under the EEG, as with the first-time sale of electricity, the share of the five largest companies in the German market area (RWE, LEAG, EnBW, Uniper and E.ON) in 2022 was about 5.6%. The share in 2021 was around 6.4%, although the fact must be taken into account that the five companies included Vattenfall in 2021 and not Uniper. In terms of EEG generation capacity, as with the first-time sale of electricity (RWE, EnBW, LEAG, Vattenfall and Uniper), the share of the five largest producers (RWE, LEAG, EnBW, Vattenfall and Uniper) in 2022 was about 3.1%, compared to 3.6% in 2021.

Market power report

Another decisive parameter for assessing market power in the field of electricity generation is the analysis made in the Bundeskartellamt's market power report to determine the extent to which a company's power plant fleet is indispensable for meeting the demand for electricity.[10] The analysis of general market

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[8] The new capacity only includes electricity generating plants that are currently in trial operation or under construction with a net rated capacity of 10 MW or more per site because these projects are sufficiently likely to be implemented.

[9] The figure from the Monitoring Report 2022 was corrected (see below).

[10] See for here and below: Bundeskartellamt: Wettbewerbsverhältnisse im Bereich der Erzeugung elektrischer Energie 2022, Marktmachtbericht, August 2023, page 7 et seq.

developments found that RWE had consolidated its power on the market for the first-time sale of electricity in the period from 2022 to the first quarter of 2023. The proportion of time in which it was not possible to meet the demand for electricity without RWE was also well above the threshold for presuming market dominance (5% of the hours in a year). The capacity of LEAG and EnBW was also increasingly indispensable for meeting demand. In addition, the number of market situations in which the only factor restricting the market-related scope of action of domestic electricity producers was imports, or unused foreign power plant capacity, increased in 2022 to 5.9% of the hours of the year.

Background and outlook

The closure of the last three nuclear power plants and planned closures of coal power stations have led and will lead to further decreases in the aggregate market share of the five largest producers and consequently in the degree of market concentration in terms of capacity. However, such a decrease in the degree of concentration as a result of closures also leads to a reduction in available capacity and therefore increases the competitive weight of the remaining capacity; this is reflected in the residual supply index (RSI), which is used as the basis for the analysis in the market power report. The fact must also be taken into account that hard coal-fired power plants that were taken out of the reserve and reactivated in 2022 because of the energy crisis have been deactivated again or are due to be deactivated in 2023 or 2024.

Electricity retail markets

As in previous years, the Bundeskartellamt assumes for 2022 that there is no single dominant undertaking in the two largest electricity retail markets. In 2022, the four largest companies by sales (CR4) (currently E.ON, RWE, EWE and N-Ergie) on the national market for the supply of interval-metered customers sold a total of 50.8 TWh. Their aggregate market share was 21.1%. In 2021, they sold 63.7 TWh and their market share was 25.8%.[11] In 2022, the cumulative sales of the four largest companies (currently E.ON, EnBW, Vattenfall and EWE) on the national market for the supply of standard load profile (SLP) customers on special contracts (non-default contracts and excluding heating electricity) amounted to about 49.7 TWh, compared to 41.2 TWh for the same companies in 2021. The aggregate market share of the four companies on this market in 2022 was about 44.2%, compared to 36.1% in 2021. The share of the four largest companies in both markets is still well below the statutory threshold for presuming (joint) market dominance (section 18(4) and (6) of the Competition Act (GWB)), despite a significant year-on-year increase in the market for SLP customers.

With regard to the supply of **SLP customers** on default contracts, for which regional markets are defined, the local default suppliers each have a monopoly in their individual supply/network area. The cumulative sales of the four largest companies across all default supply areas in Germany (again E.ON, EnBW, Vattenfall and EWE) amounted to 14.4 TWh of the total amount of electricity sold under default contracts of around 31.5 TWh; this corresponds to a share of about 45.9%, compared to about 42.0% in 2021.[12]

[11] A direct year-on-year comparison is not possible because in 2021 GETEC was one of the four largest companies by sales.

[12] This is a fictitious figure that only serves to illustrate the market conditions because the Bundeskartellamt's decision-making for default supply is based on regional (network area-related) markets and not a national market.

With regard to the supply of SLP customers with heating electricity, for which regional markets are also defined, the four largest companies (currently E.ON, EnBW, Vattenfall and Lichtblick) still have a relatively strong position both in a large number of individual supply areas and across all the supply areas.[13] The cumulative sales of the four largest companies across all the supply areas in Germany amounted to about 6.9 TWh of the total of 13.1 TWh for heating electricity, which corresponds to a share of 52.2%, compared to 54.7% in 2021.[14]

4. Network structure data

The four transmission system operators (TSOs) and 803 distribution system operators (DSOs) took part in the data survey for the Monitoring Report 2023. As at 4 August 2023, a total of 866 DSOs (2022: 865) were registered with the Bundesnetzagentur.

The circuit length at the TSOs' networks amounted to 36,300 kilometres (km) in 2022. The total number of final customer market locations in the TSOs' networks was 414. All of these market locations are interval-metered.

As at 31 December 2022, the DSOs' total circuit length at all network levels was about 2.2mn km. The total number of final customer market locations in all the DSOs' network areas was about 52mn. The majority of the DSOs included in the data analysis (631 or 76%) have short to medium length networks (underground and overhead cables) of up to 1,000 km. This means that the majority of the DSOs' underground and overhead lines are accounted for by about 172 companies.

The annual peak load in 2022 of 78.83 GW was registered on 1 February 2022 between 12.30pm and 12.45pm (2021: 81.37 GW on 30 November 2021 between 11.45am and 12.00pm). The annual peak load is the highest simultaneous demand for electrical capacity in a year from all customers connected to the general supply networks, including line losses. It indicates the highest demand for capacity that the energy supply network must at least be able to meet.

5. Network expansion

Current status of expansion in the transmission networks

As at 31 December 2022, 119 projects with a total length of approximately 14,054 km were listed in the Federal Requirements Plan Act (BBPlG) and the Power Grid Expansion Act (EnLAG): 25 projects had already been completed and another 14 had been at least fully approved; 52 projects were still at the approval stage; and 28 projects were waiting for submission of the initial applications for federal sectoral or spatial planning.

The total length of the EnLAG projects as at 31 December 2022 was some 1,821 km:

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[13] Lichtblick took over a large number of heating electricity customers from innogy (formerly RWE) (condition as part of the E.ON/innogy merger case (M.8870)).

[14] This is a fictitious figure that only serves to illustrate the market conditions because the Bundeskartellamt's decision-making for the supply of heating electricity to customers is based on regional (network area-related) markets and not a national market.

- about 8 km were in the spatial planning procedure;
- about 128 km were in or about to start the planning approval procedure;
- 329 km had been approved and were under or about to start construction;
- 1,356 km had been completed.

The total length of the BBPlG projects was some 12,233 km:

- about 3,719 km were about to start the approval procedure;
- about 742 km were in the federal sectoral or spatial planning procedure;
- about 5,891 km were in or about to start the planning approval or notification procedure;
- 778 km had been approved and were under or about to start construction;
- 1,103 km had been completed.
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DSOs' future grid expansion requirements

The 82 largest electricity DSOs' expected grid expansion requirements for the period up to 2032 amount to about €42bn. These DSOs reported 3,366 individual grid expansion measures with a volume of €16.46bn and measures based on additional, more generalised plans for the lower (medium voltage to low voltage) network levels with a volume of €25.48bn.[15] About 32% of the 3,366 individual measures reported are under construction, 25% are at the planning stage, and 43% are "envisaged". The reinforcement, optimisation, new build and replacement measures cover a total length of about 93,136 km. Further information can be found in the report on the status and expansion of the distribution networks.[16]

6. Investments by electricity network operators

In 2022, investments in and expenditure on network infrastructure by the network operators amounted to about €13,119mn (2021: €13,556mn) (both figures under commercial law).[17] The total comprised €8,843mn of investments and expenditure by the DSOs and €4,276mn by the four TSOs. Investments by the TSOs in 2022 were down by about 19% on the previous year (2021: €4,677mn, 2022: €3,917mn), while investments by the DSOs were up by 18% (2021: €4,835mn, 2022: €5,733mn). Both the TSOs and the DSOs planned higher investments for 2023.

7. Electricity supply disruptions

For the year 2022, 855 network operators reported 157,245 interruptions in supply at low and medium voltage level for the calculation of the system average interruption duration index (SAIDIEnWG). This is a decrease of

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[15] The figures only cover expansion measures that are designed to increase transmission capacity.

[16] www.bundesnetzagentur.de/netzausbau

[17] 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).

9,370 interruptions compared to the year before. The figure of 12.2 minutes per year per connected final customer for the low and medium voltage levels is below the previous year's average of 12.7 minutes. The reliability of supply thus remained at a high level in 2022.

8. Congestion management

The volume of congestion measures (electricity-related and voltage-related adjustments through redispatching, countertrading and grid reserve use) in 2022 was 19% up on the year before at 32,772 GWh. This includes redispatching measures for renewables with a volume of 8,063 GWh. In 2022, curtailments of renewable electricity due to electricity-related and voltage-related congestion amounted to about 3.3% of total renewable generation. This means almost 97% of the renewable energy generated could be transported and used.

Generally speaking, the increase in the volume of congestion management measures is due to the growth in wind capacity, which is located relatively far from demand centres, changes in the conditions for electricity trading with other countries, and delays in network expansion. The following specific factors also had an effect in 2022:

- Low water levels and coal transport: in the first quarter of 2022, long dry periods led to lower water levels on the Rhine, preventing vessels from carrying full loads of coal. This affected the operational readiness of power plants in southern Germany. The higher degree of use of the power lines running from north to south resulted in an increase in the need for redispatching measures.
- Electricity exports and flows: a lower level of availability at French nuclear power plants led to an increase in electricity exports and changes in the flows from east to west.
- Closure of the Gundremmingen C nuclear power plant: the plant's closure at the end of 2021 resulted in a higher level of utilisation of the power lines in southern Germany.
- Weather conditions: several storms in February 2022 and strong winds in April led to an increase in wind generation and the degree of network utilisation.
- More cost transparency: the introduction of "Redispatch 2.0" means that the network operators are now also responsible for economic balancing for curtailments of renewables and CHP plants. This has led to a shift in the associated costs, which are visible in the costs for positive redispatching. This shift aims to make the overall structure fairer and more efficient, and thus avoid costs, but increases the redispatching volumes and costs visible in this case.

The costs for congestion management measures for the whole of 2022 were provisionally put at about €4.2bn, well above the previous year's figure (2021: €2.3bn). The increase of just over 83% in the costs is due to the increase in the volume of measures and especially to the large rise in fuel prices (coal, gas and oil). Further information on congestion management is available on the Bundesnetzagentur's website at https://www.bundesnetzagentur.de/Systemstudie (in German).

9. Electricity network tariffs

There was a clear increase in the volume-weighted network tariffs (including meter operation charges) for household customers for 2023 (up 1.2 ct/kWh). The volume-weighted average network tariff for household customers with an annual consumption of 2,500 kWh to 5,000 kWh was 9.35 ct/kWh.

The arithmetic mean tariffs for non-household customers for 2023 are higher than the previous year's levels. The network tariffs (including meter operation charges) for commercial customers increased by about 8% to 7.42 ct/kWh (2022: 6.85 ct/kWh). The network tariffs (including meter operation charges) for industrial customers increased by about 12% to 3.30 ct/kWh (2022: 2.96 ct/kWh).

These increases confirm the information provided last year by the DSOs under the Bundesnetzagentur's responsibility about the provisional network tariffs for 2023. Reasons include rising congestion management costs for some DSOs, investments in the networks, and increasing costs for the procurement of loss energy due to higher electricity prices on the exchange. A number of DSOs also anticipated a decrease in volumes because of energy-saving measures.
Average TSO tariffs in 2023 were largely stable compared to 2022. This is due to financing under the Electricity Price Brake Act (StromPBG), which kept the TSOs' revenue caps at 2022 levels. In 2023, uniform network tariffs across the country were applicable for the first time. The last stage of the national harmonisation process meant that not all of the TSOs' tariffs remained exactly the same.

Based on information from a random sample of DSOs under the Bundesnetzagentur's responsibility about the provisional network tariffs for 2024, there will be another noticeable increase in average DSO network tariffs in Germany. Reasons include a further increase in the costs for the procurement of loss energy due to higher electricity prices on the exchange and the start of the fourth regulatory period. In 2024, the cost level in the cost examination with the base year 2021 will be factored into the network tariffs for the first time. The network costs recognised for the operators under the Bundesnetzagentur's responsibility are higher than those recognised in the last cost examination with the base year 2016. A number of DSOs again anticipate a decrease in volumes. The federal government raised the possibility of a financial contribution towards the TSOs' transmission network costs for 2023. In light of this, the TSOs were largely able to keep their network tariffs stable. The possible financing depends, however, on implementation in law.

10. Electric vehicles/charging stations/load control

Electric vehicles/charging stations

Publicly accessible electric vehicle charge points must meet certain minimum technical requirements. The operators of charging infrastructure accessible to the public have to notify the Bundesnetzagentur of their infrastructure so that compliance with the requirements can be checked as set out in the Charging Station Ordinance (LSV). The Bundesnetzagentur publishes monthly figures and information on publicly accessible charging infrastructure based on the operators' notifications on its website at https://www.bundesnetzagentur.de/DE/Fachthemen/ElektrizitaetundGas/E-Mobilitaet/start.html (in German).

In 2022, as in the previous two years, there was an increase of about 40% in the number of publicly accessible electric vehicle charge points. At the end of 2022, more than 82,000 publicly accessible charge points with a total power above 2.5 GW were in operation. The Bundesnetzagentur publishes comprehensive data on a regular basis at https://www.bundesnetzagentur.de/ladeinfrastruktur (in German).

Load control

Section 14a EnWG gives DSOs at the low voltage level the ability to use consumers' flexibility to avoid localised overloading. DSOs can conclude agreements with final customers with controllable devices such as heat pumps, electric vehicles and night storage heaters allowing the DSOs to control the consumption of the devices in return for a reduced network tariff.

In 2022, agreements were in place for a total of 1,808,565 controllable consumer devices, about as many as the year before (down 4,442). There was another decrease in the number of night storage heating systems covered by such agreements, while there was a slight increase in the number of heat pumps and electric vehicles.

11. Costs for system services

The net costs for system services, which are passed on to final customers, were considerably higher in 2022 than in 2021 at about €5.8bn (2021: €3.4bn). Major costs were the costs for congestion management at about €4.2bn (2021: €2.3bn), contracting frequency containment reserves (FCR), automatic frequency restoration reserves (aFRR) and manual frequency restoration reserves (mFRR) at a total of €0.6bn (2021: €0.6bn), and loss energy at €0.8bn (2021: €0.5bn).

12. Balancing services

There was another slight year-on-year decrease in the average volumes of the three qualities of balancing services tendered in 2022. The volume of FCR tendered amounted to 555 MW (2021: 562 MW). The average volume of positive aFRR tendered was 1,996 MW (2021: 2,092 MW), while the average volume of negative aFRR tendered was 1,901 MW (2021: 1,972 MW). The average volume of positive mFRR tendered was 922 MW (2021: 1,098 MW) and the average volume of negative mFRR tendered was 422 MW (2021: 576 MW).

The average monthly volume of aFRR and mFRR used in 2022 was similar to the previous year. April again had the highest average volume of these two types of reserves used with 235 MW, up 11 MW on the previous year.

The upper price limit for balancing energy of €9,999 per megawatt hour (MWh), which had been introduced by decision BK6-20-370 of 16 December 2020, was suspended following a decision by the Federal Court of Justice (BGH). The technical upper price limit of €99,999/MWh was therefore applicable again for an interim period. Since the European target model for balancing energy went live on 22 June 2022, a harmonised European upper price limit for balancing energy of €15,000/MWh has applied. At the same time, cost-based calculation of the imbalance price was replaced by price-based calculation in accordance with the provisions of Commission Regulation (EU) 2017/2195. Imbalance prices are now based on the prices on the European platforms for the exchange of balancing energy, PICASSO (aFRR) and MARI (mFRR). This series of changes led to a large increase in the imbalance price especially in the first half of 2022. The average volume-weighted imbalance price in the case of a short portfolio was €454.78/MWh, an increase of 129% on the previous year. The average volume-weighted imbalance price in the case of a long portfolio was negative €16.54/MWh (2021: €16.77/MWh).

13. Cross-border electricity trade

Electricity exports again exceeded imports in 2022. Germany's electricity exports were up slightly in 2022 compared to a year earlier. Cross-border trade volumes for electricity amounted to 94 TWh in 2022 (2021: 93 TWh), comprising about 60 TWh of exports and about 33 TWh of imports. This makes Germany still one of Europe's biggest electricity exporters. Germany's export balance in 2022 was therefore about 27 TWh.

14. Wholesale electricity markets

The situation in the energy markets has intensified further in the wake of Russia's invasion of Ukraine in February 2022. Although markets have slightly recovered since September 2022, wholesale electricity prices were much higher and very volatile in the year as a whole. The trend in the prices largely mirrors that in natural gas prices. As gas-fired power plants tend to set the prices in spot trading at times of peak demand, the increase in gas prices several times over led to a similar increase in prices on the electricity exchange (merit order principle). Price developments were slowed towards the end of 2022 by the reactivation of power plants on security standby and the return of reserve power plants to the market, although gas power plants still tend to set the prices when demand for electricity is high. There was also a decrease in the trading volume and liquidity of the wholesale electricity markets in 2022.

Spot market trading volumes

There was a year-on-year decrease of about 10% in the total trading volume of the coupled day-ahead midday auctions (classed as spot market trading) from 218.7 TWh in 2021 to around 196.5 TWh in 2022. The total volume comprised 154.3 TWh on EPEX SPOT, 33.3 TWh on Nord Pool and 8.9 TWh on EXAA. The volume of the independent day-ahead 10.15am auction on EXAA for the German bidding zone amounted to about 1.2 TWh in 2022.

Developments on the intraday market were different, with a year-on-year increase in the total trading volume of about 5 TWh or 7% to 79.1 TWh. There was an increase in the intraday trading volume on EPEX SPOT to 70.4 TWh, with intraday auctions accounting for about 8.1 TWh and continuous intraday trading 62.3 TWh. The volume of continuous intraday trading on Nord Pool in the Germany/Luxembourg bidding zone amounted to about 8.7 TWh in 2022, more than twice the volume in 2021 of 4.2 TWh.

Futures market trading volumes

On-exchange futures trading volumes recorded even larger decreases than spot trading. In 2022, the on-exchange trading volume for German power futures amounted to 898 TWh, down about 38% on the previous year. The decrease was due to factors including the uncertain market environment caused by Russia's war in Ukraine, high levels of volatility in wholesale prices and rising inflation during the year. Trading for German power futures in 2022 was primarily for contracts for 2023 as the fulfilment year with about 451 TWh. Trading for longer-term contracts for each of the subsequent years was down on the previous year.

Volumes traded off-exchange via broker platforms also recorded decreases. The total volume traded by these brokers in 2022 amounted to about 2,704 TWh compared to 3,512 TWh in 2021. Developments in trading volumes can also be followed through the London Energy Brokers' Association (LEBA), although it does not represent all broker platforms surveyed. There was a decrease in the volume of transactions brokered by LEBA members. The trading volume for German power brokered by LEBA members decreased by about 52% from 4,345 TWh in 2021 to 2,074 TWh in 2022.[18]

The volume of over-the-counter (OTC) clearing of German power futures on EEX decreased by about 20% in 2022 to 1,393 TWh. This volume accounted for about 61% of the relevant total trading volume on EEX, compared to 55% in 2021. OTC clearing has accounted for the majority of futures trading since 2019. There was also a decrease in the volume registered for clearing with the LEBA. The registered volume for German power futures in 2022 was about 1,238 TWh, about 60% of the total OTC volume brokered by LEBA members. This means that OTC clearing accounts for the majority of the total trading by LEBA members.

German power options play no role in exchange trading on EEX; there were again no such transactions. However, there are German power options that are agreed off-exchange and cleared on EEX. In 2022, German power options agreed off-exchange and cleared OTC on EEX amounted to 41 TWh. This is 3% of the total volume of German power futures traded. The volume of OTC clearing of options in 2022 was about 56% down on the previous year.

Spot market prices

Prices on the wholesale electricity markets have increased considerably and are fluctuating mainly because of the above-mentioned geopolitical situation and electricity supplier insolvencies. The arithmetic annual average baseload day-ahead price on the spot market in 2022 was about €234.53/MWh, an increase of about 141% on the previous year's average of €97.12/MWh.

There were numerous extreme baseload and peak load prices in the coupled auctions in 2022. The range of the middle 80% of the graded baseload prices in 2022 increased to €310.2/MWh, compared to only €144.54/MWh in 2021. There was also a large increase in the range of the middle 80% of the graded peak load prices from €172.78/MWh in 2021 to €692.54/MWh in 2022.

Negative baseload and peak load prices were recorded on only one day.[19] The lowest baseload price of negative €1.43/MWh and the lowest peak load price of negative €1.49/MWh were both recorded on 31 December 2022. In 2021, the lowest baseload price was negative €8.23/MWh and the lowest peak load price negative €19.56/MWh. The highest baseload and peak load prices were both higher than the year before. In 2022, the highest baseload price was €691.11/MWh, about 62% up on the previous year's highest price of €427.50/MWh. It was recorded on 26 August 2022. The highest peak load price for 2022 was recorded on the same day and was €720.26/MWh, about 41% up on the previous year's highest price of €510.52/MWh.

Futures market prices

[18] See LEBA Monthly Volume Reports.

[19] Negative prices are prices signals on the electricity market that occur when, for example, a high level of inflexible electricity generation coincides with a low level of demand. Inflexible electricity sources cannot be shut down and started up again quickly without considerable expense or need to keep operating because of other supply obligations (heat, industrial processes, balancing reserves contracts). Financial support in the case of negative prices may also be a significant factor contributing to negative prices.

There was also a large increase in the average prices for year-ahead futures. The annual average price for German power futures traded for 2023 was €298.86/MWh, about 238% up on the previous year's average for futures traded for 2022 of €88.42/MWh. The annual average price for Phelix peak year futures in 2022 was €400.17/MWh, about 273% up on the previous year's average of €107.23/MWh.

There was also a large increase in 2022 in the prices for front year futures; prices reached their highest level at the end of August and fell again by the end of the year. The German power peak year futures price was about €121.63/MWh at the beginning of the year and about €238.85/MWh at the end of December. Prices increased over the course of the year and especially in the summer months; the highest prices were recorded on 26 August 2022, when they reached €985/MWh for base year futures and as much as €1,295/MWh for peak year futures.

15. Retail electricity markets

Contract structure for non-household customers

In 2022, about 1,370 electricity suppliers (individual legal entities) provided information on the market locations served and on the amount of electricity supplied to interval-metered customers (2021: 1,411). The 1,370 electricity suppliers include many affiliated companies, hence the number of suppliers is not equal to the number of competitors acting independently of each other.

In 2022, interval-metered customers were supplied with just under 240.2 TWh of electricity at 391,977 market locations, compared to about 246.6 TWh at 376,086 market locations in 2021. A total of 99.9% of this amount was supplied under non-default contracts. It is still unusual, but not impossible, for interval-metered customers to be supplied under default supply or fallback supply. About 0.23 TWh of electricity was supplied to interval-metered customers under default or fallback supply. This is about 0.1% of the total volume supplied to interval-metered customers.

About 21.6% of the total volume delivered to interval-metered customers was supplied under a contract with the default supplier on non-default terms and about 78.3% under a contract with a legal entity other than the local default supplier. In 2021, 24.0% of the total volume was supplied under non-default contracts with the default supplier and 75.9% under contracts with other suppliers. Developments in the past few years show that default supply and non-default contracts with the default supplier are playing an increasingly less important role in the acquisition of interval-metered customers in the electricity sector.

Contract structure and competitive situation for household customers

There was a slight decrease in the number of different electricity suppliers from which household customers could choose. In 2022, final customers could choose between an average of 157 suppliers (not taking account of corporate groups) (2021: 167). The average number of suppliers for household customers in Germany was 136 (2021: 147).

In 2022, 39% of the total volume delivered to household customers was supplied under a contract with a supplier other than the local default supplier. Overall, about 61% of the volume is still provided by default suppliers (under either default or other contracts). About 24% of the volume delivered to household customers was supplied under a default contract, about the same as in the year before (2021: 25%). As in the previous year, about 37% of the total volume delivered to household customers was supplied under a non-default contract with the local default supplier (2021: 37%). The strong position held by default suppliers in their service areas was therefore more or less unchanged from the year before. The share of green electricity in the total volume of electricity supplied to household customers in Germany also increased in 2022 to 43% (2021: 37%).

Supplier switches by non-household customers

The volume-based switch rate across all consumption categories above 10 MWh/year was 12.6%, compared to 10.7% the year before. The switch rate for non-household customers has been more or less constant for several years. The rise in energy prices, to which a number of non-household customers were able to react, may be one of the reasons for the increase in the rate in 2022. The monitoring survey does not analyse what percentage of non-household customers have switched supplier once, more than once or not at all over a period of several years.

Supplier switches by household customers

There was a clear decrease in the number of supplier switches in 2022 to just over 4mn. The switch rate based on the total number of household customers was 8.2% (2021: 9.7%). The large increase in electricity prices in the wake of Russia's invasion of Ukraine had a noticeable effect on customers' switching behaviour as well. The large reduction in supplier switches also reflects the much more limited choice of attractive new-customer contracts. There was, for a time, no incentive to switch from the traditionally more expensive default tariffs to a competitive tariff because no or only a few, more expensive offers were available.

Contract switches by household customers

In 2022, the number and volume of changes of contract with the existing supplier increased by nearly 100%, compared to a clear decrease of about 16% in 2021.[20] About 3mn household customers (with a total consumption of about 7.5 TWh) changed their existing contract with their supplier (2021: 1.5mn with a total of 3.7 TWh).

Terminations and disconnections

In 2022, suppliers (default suppliers and their competitors) terminated a total of 205,083 customer contracts because, for example, customers were late paying their bills. Overall, 91% (186,900) of these terminations were for non-default contracts. The average level of arrears that led to a supplier terminating a contract with their customer was €170. A smaller proportion (9% or 18,183) of the terminations were for default contracts. The termination of a default supply contract is only permitted under stringent conditions. The supplier must not be under an obligation to provide default supply. It must therefore be economically unreasonable for the default supplier to continue supply.

The number of disconnections carried out by the network operators in 2022 was 208,506, representing a decrease of 11% compared to the previous year (2021: 234,926). The number of disconnection notices issued by

[20] A customer's change to a new electricity tariff with the same electricity supplier at their own request.

suppliers to household customers was very much higher, although it was lower than the year before. The number of notices issued was approximately 3.7mn, of which about 676,000 were passed on to the network operator with a request for disconnection (2021: 4mn notices and 740,000 requests). One of the reasons for the decrease in the number of disconnections is presumably the introduction in December 2021 of stricter conditions for disconnecting customers on default contracts (Electricity Default Supply Ordinance (StromGVV)). A look at the number of disconnections over the course of the year shows that there were fewer disconnections in the energy-intensive first and fourth quarters than in the rest of the year.

Prepay systems

Closely related to the topic of disconnections and terminations is also that of prepay systems under section 14 StromGVV, such as cash meters and smart card readers. The default supplier is entitled to require advance payment for electricity consumption in a billing period if, based on the individual circumstances, there are grounds to assume that the customer will not meet their payment obligations or meet them in time. According to 306 electricity suppliers, a total of some 13,000 household customers on default contracts had cash or smart card meters, or comparable prepayment systems, in 2022 (2021: 19,670). In 2022, 1,945 prepay systems were newly installed and 1,760 existing ones were removed. The numbers of such systems are therefore still very low. Costs for meter operation of a cash or smart card meter, or a comparable prepayment system, averaged €25.90 per year and meter in 2022.

Electricity prices for industrial customers – annual consumption of 24 GWh

The average total price, without VAT and possible reductions, for an annual consumption of 24 GWh as at 1 April 2023 was 23.25 ct/kWh, up by 0.74 ct/kWh or about 3% on the previous year's average of 22.51 ct/kWh. There was an increase above all in the component controlled by the supplier from 12.77 ct/kWh in 2022 to 16.70 ct/kWh in 2023. The end of some surcharges may help to explain why there was only a slight increase in the total price. The EEG surcharge, which stood at 3.72 ct/kWh the year before, no longer applies at all. By contrast, the net network tariff increased year-on-year from 2.94 ct/kWh to 3.30 ct/kWh.[21] This is not necessarily the tariff that was actually payable by final customers because the electricity price brake was already in place (section 5(2) paras 1 and 2 StromPBG). In addition, the setting of a reference price may have had the effect of a price anchor to a certain extent.

These prices apply to an (industrial) customer with an annual consumption of 24 GWh not eligible for any of the statutory reductions available (such as in the network tariff, concession fee or electricity tax). The price component not controlled by the supplier for an industrial customer eligible for these reductions would be 0.43 ct/kWh, compared to 6.15 ct/kWh for a customer not eligible for any reductions. Customers meeting the requirements in the relevant statutory provisions are eligible for reductions in the network tariff, concession fee, electricity tax and the surcharges under the CHP Act (KWKG), section 19 of the Electricity Network Tariffs Ordinance (StromNEV) and section 17f EnWG. The eligibility requirements differ for each of the possible reductions. The monitoring survey does not collect data on whether there are any cases in practice in which all the possible maximum reductions are, or can be, claimed.

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[21] The figures for industrial customers are based on information from 192 electricity suppliers (2021: 197).

Electricity prices for commercial customers – annual consumption of 50 MWh

In the second category of an annual consumption of 50 MWh, the typical consumption of a commercial customer, the average total price without VAT on the reporting date of 1 April 2023 was 33.06 ct/kWh, up by 7.41 ct/kWh or about 28.0% on the previous year's average of 25.65 ct/kWh.[22] This is quite close to the electricity gross reference price set in section 5(2) paras 1 and 2 StromPBG, which suggests that the reference price may have acted as a pricing guide. The increase is largely due to the rise in the price component controlled by the supplier. This rose by 10.02 ct/kWh or 91% from 11.03 ct/kWh in 2022 to about 21.05 ct/kWh. Overall, the price component controlled by the supplier makes up about 64% of the total prices, compared to only about 43% the year before. The end of the EEG surcharge and the surcharge under the Interruptible Loads Ordinance (AbLaV) for customers in this consumption category mitigated a further increase in prices. It should be noted that in these consumption categories the arithmetic mean does not reflect the considerable spread of the network tariffs and the heterogeneity of the network operators.

Electricity prices for household customers

Data was collected from the suppliers operating in Germany on the prices for household customers as at 1 April 2023. There was a very large increase in the average price (including VAT) to 45.19 ct/kWh (2022: 36.06 ct/kWh). This average is calculated by weighting the prices for the individual contract models for an annual consumption of 2,500 kWh to 5,000 kWh to obtain a reliable indicator for the electricity price for household customers in Germany.

The electricity price is made up of a component controlled by the supplier (energy procurement, distribution and margin) and a component not controlled by the supplier (such as levies and taxes). The component not controlled by the supplier accounted for 48% of the price in 2023 and was much smaller than in the previous year (2022: 62%), while the component controlled by the supplier accounted for about 52% and was therefore considerably larger (2022: 38%). The reason is the large increase in wholesale prices in recent years, which has had an effect in particular on the energy volumes procured under long-term arrangements by suppliers. These volumes (procured one, two or three years in advance) make up about 90% of the total procured by suppliers for 2023.

The average price for household customers on default contracts with an annual consumption of 2,500 kWh to 5,000 kWh increased in 2023 to 47.88 ct/kWh (2022: 35.70 ct/kWh). The average price for customers on a non-default contract with their default supplier was 44.81 ct/kWh (2022: 34.86 ct/kWh). The price for customers on a contract with a supplier other than their local default supplier increased by about 18% to 43.99 ct/kWh (2022: 37.22 ct/kWh). In 2023, prices for customers with a supplier other than their local default supplier were again lower than prices with the default supplier. The previous year's trend of prices with the local default supplier being lower than prices with other suppliers therefore did not continue. This is presumably due to the suppliers' different procurement strategies. While default suppliers tend to have longer-term procurement strategies, suppliers not operating as a default supplier presumably usually procure

[22] The figures for commercial customers are based on information from 905 electricity suppliers (2021: 940).

their energy at shorter notice and were therefore able to benefit sooner from the more recent fall in wholesale prices.

Surcharges

In 2022, the network operators passed on about €10.455bn in surcharges to the network users. This total comprises the EEG surcharge (€6.43bn), the offshore network surcharge (€1.47bn), the section 19 StromNEV surcharge (€1.21bn), the KWKG surcharge (€1.33bn) and the interruptible loads surcharge (€0.015bn).

The costs of financial assistance under the EEG were originally forecast at €12.96bn. The large increase in exchange prices for electricity in 2022 led to a large rise in the TSOs' revenue from marketing electricity eligible for fixed payments. In addition, the sum of EEG assistance payments was much smaller than forecast because of the high wholesale electricity prices. The costs of EEG financial assistance were therefore much lower than forecast. The EEG surcharge was reduced to 0 ct/kWh with effect from 1 July 2022. As from 2023, financial assistance for the expansion of renewable energy is part of the federal budget.

The interruptible loads surcharge was levied for the last time for 2022 because the relevant ordinance is no longer in force.

Electricity price brake

The sharp rises in energy costs have led legislators to relieve the burden on gas, electricity and heat customers. The idea behind the StromPBG is to lessen the burden on electricity customers. The relief will be financed mainly through a levy on the surplus revenue earned by operators of electricity generating plants (with a capacity above 1 MW) who have benefited from the increase in electricity prices on the wholesale markets.

The price brake applies from 1 March 2023 until 31 December 2023, with back payments for January and February 2023 being made in March 2023.[23] The Bundesnetzagentur is responsible for ensuring that the levy on surplus revenue is imposed correctly and for overseeing the overall system of incoming and outgoing payments under the StromPBG.

The levy on surplus revenue earned by operators of electricity generating plants is one way of refinancing the relief payments. Electricity producers must submit a self-assessment. The deadline for the self-assessment to report levy payments for the first accounting period (December 2022 to March 2023) was 31 July 2023. By the beginning of August 2023, about 80% of the 12,000 operators of electricity generating plants subject to the levy had submitted a full self-assessment, reporting a total sum of about €406mn in levy payments to finance the relief. These figures are expected to increase as a result of late reports.

The Bundesnetzagentur checks the electricity producers' self-assessments in order to determine the exact amount payable. It can also take action as provided for by the StromPBG against plant operators who have not submitted a self-assessment in order to set the amount to be paid.

[23] As at 2 November 2023.

Consumer advice and protection

The energy consumer advice service is the national point of contact for consumers who want information on their rights in the energy sector, applicable legal regulations or dispute resolution options. In the period up to 30 October 2023, the Bundesnetzagentur received a total of 58,080 telephone, email, online and letter queries and complaints (compared to 23,585 in the same period in 2022). This represents a year-on-year increase of more than 140%. The increase is primarily due to a much higher number of telephone calls. The number of consumers calling the advice service in the period up to 30 October 2023 was 29,393 (compared to just under 7,000 in the same period in 2022). These figures do not include complaints about unsolicited marketing calls for electricity or gas supply contracts, which are recorded separately. In addition, 4,900 written complaints were received in the period from 1 January to 31 October 2023.

The majority (nearly 70%) of the queries and complaints received were about electricity. About 25%, considerably more than in previous years (2022: just under 20%), were about gas.

One of the main topics of interest in both sectors was prices. This was triggered in particular by the introduction of the electricity and gas price brakes. Consumers had specific questions about eligibility for relief, general questions about the effects of political developments on energy prices, and specific questions about their monthly payments and energy bills.

There was an increase in interest about switching energy suppliers and in questions about disconnecting from gas, installing heat pumps and the possibility of using solar PV installations and wallbox chargers.

Up-to-date consumer information and further information on the topics mentioned here are available online at www.bnetza.de/verbraucherservice-energie (in German).

16. Heating electricity

Contract structure and supplier switching

The volume of electricity supplied for heating was lower than in the previous year. One of the possible reasons is customers cutting back on the amount of electricity they use – saving on heating, lowering temperatures – because of the ongoing energy crisis and the mild start to the winter at the end of 2022. Another reason is the shift in the technology used, with customers replacing old night storage heating systems with modern heat pumps when making renovations. According to the volumes reported by about 1,107 suppliers of heating electricity (2021: 1,181 suppliers), about 13.1 TWh of heating electricity was supplied to customers at just under 1.98mn market locations. This corresponds to an average supply of just under 6,612 kWh per market location. This compares to the previous year's figures of just under 7,210 kWh per market location and a total volume of 14.3 TWh supplied to 1.98mn market locations.

The volume supplied for night storage heating systems amounted to just under 8.4 TWh at 1.24mn market locations. This compares to a volume for heat pumps of just over 4.5 TWh at about 0.74mn market locations. Night storage heating accounts for the largest share of consumption, with about 65.8% of volume and 62.4% of market locations. The share of heat pumps compared to night storage heating has steadily increased over the years. The total number of market locations supplied for heat pumps increased year-on-year by about 5.9%, while the total number of night storage heating systems fell by about 3.2%. This is also reflected in the shares in the total volume sold and the number of market locations supplied for heating electricity. In 2022, heat pumps accounted for as much as 37.6% of market locations and 34.2% of the volume, compared to 35.6% and 31.2% the year before.

The figures on consumption volumes and market locations provided by the DSOs in the monitoring survey roughly correspond to the results of the supplier survey. According to the data from 804 DSOs (2021: 809), a total of 12.4 TWh of heating electricity was supplied to just under 2.1mn market locations (night storage heating and heat pumps) in 2022. The DSOs do not provide separate figures for night storage heating systems and heat pumps.

Suppliers were also asked how the heating electricity they supplied was divided between network areas where they were the default supplier and network areas where they were not the default supplier. The share of heating electricity supplied in 2022 by a legal entity other than the local default supplier was slightly lower than the year before. In 2022, about 38.1% of the total volume of heating electricity supplied was accounted for by suppliers other than the default supplier (2021: about 38.8%). There was also a slight decrease in the percentage of heating electricity market locations not served by the default supplier from 37.9% to 36.2%. The share accounted for by non-default suppliers in 2022 is therefore more or less the same as in the previous years. The most recent major change in the market structure was in 2019 and 2020 when E.ON and Innogy merged. The merger was only cleared subject to certain commitments, among other reasons because of competition problems in the heating electricity sector. E.ON SE's heating electricity business was subsequently sold to Lichtblick SE. Irrespective of the conditions set by the European Commission, Innogy SE's heating electricity business was transferred to a new E.ON subsidiary, Deine Wärmeenergie GmbH & Co. KG, when E.ON acquired control of Innogy SE. The two companies still jointly account for a large share of the volumes delivered by non-default suppliers.

According to the data provided by the DSOs, the supplier switching rate in the heating electricity segment based on the number of market locations was lower in 2022 than in the previous year, and was even lower than in 2017. In 2022, supplier switches involved only about 87,750 heating electricity market locations with a total heating electricity volume of about 507.5 GWh. The switch rate in terms of both volume and the number of market locations is 4.1%, compared to 4.6% in terms of volume and 5.3% in terms of the number of market locations in 2021. The decrease in the switch rate is presumably due to the fact that, for a time in 2022, only very few alternative offers or very expensive new-customer contracts were available from most heating electricity suppliers, as identified by the Bundeskartellamt in the Westenergie/Rheinenergie/rhenag proceedings (margin no 139).

Price level

According to the data provided by the suppliers, the arithmetic mean of the total gross price (including VAT) for night storage heating was 36.31 ct/kWh on 1 April 2023, up by about 45% on the previous year's level of 25.07 ct/kWh. The arithmetic mean of the total gross price for electricity for heat pumps was 36.90 ct/kWh, also up by about 44% on the previous year's level of 25.55 ct/kWh.[24] This is quite close to the electricity gross

[24] The figures are based on information on electricity prices for night storage heating systems from 856 suppliers (2021: 877) and for heat pumps from 876 suppliers (2021: 868).

reference price set in section 5(2) paras 1 and 2 StromPBG, which suggests that the reference price may have acted as a pricing guide. According to the explanatory notes on the amendment of the StromPBG and the introduction of a reference price for heating electricity, the reference price for electricity (including heating electricity), at the time 40 ct/kWh, was higher than the prices charged separately for heating electricity and was not used much. The new reference price for heating electricity was not introduced until 1 August 2023 and is about 28 ct/kWh.[25]

The main reason for the increase in heating electricity prices is the rise in procurement costs as a result of the energy crisis. The part of the electricity price for night storage heating systems that is controlled by the supplier, which comprises procurement costs, distribution costs and the supplier's margin, increased year-on-year by about 124% from 10.21 ct/kWh to 22.90 ct/kWh. The part of the electricity price for heat pumps controlled by the supplier also increased by about 122% from 10.48 ct/kWh to 23.25 ct/kWh on 1 April 2023. The components controlled by the supplier make up about 63% of the total price of electricity for both night storage heating systems and heat pumps, while taxes, surcharges and concession fees account for about 37%. Unlike the year before, the EEG surcharge and the section 18 AbLaV surcharge no longer applied, but this was not sufficient to lessen the price increase.

In addition, there were a number of changes for heat pumps that are not taken into account in the above analyses. One change was that section 22 of the Energy Financing Act (EnFG) set the CHP and offshore surcharges payable for electricity for heat pumps with a separate meter to zero. The total gross price for electricity for heat pumps including this reduction would be just 35.36 ct/kWh and therefore lower for the first time than the price for electricity for night storage heating systems. A number of companies have already updated their list of prices for heat pumps to take this into account.

17. Electricity metering

The undertakings reported a total of 52,689,369 meter locations for electricity. The German state of North Rhine-Westphalia has the highest number of meter locations, with more than 11mn.

A total of about 5.2mn final customers are affected by the mandatory installation of smart metering systems within the meaning of section 29 in conjunction with sections 31 and 32 of the Metering Act (MsbG). The majority of these are final customers with an annual electricity consumption of between 6,000 and 10,000 kWh at nearly 2mn meter locations. There are also about 1.2mn meter locations for consumer devices covered by section 14a EnWG. A total of 225,100 mandatory smart metering systems across all final customer categories were installed, up by 95,100 on the year before. In addition, almost 45,000 optional smart metering systems were installed for customers with a consumption of less than 6,000 kWh. As in previous years, there was also an increase in the installation of mandatory modern metering equipment.

In 2022, there was again a clear trend away from electromechanical meters in the SLP customer category, which includes all household customers. Overall, the number of electromechanical meters has fallen by about 3.5mn. There was consequently a large increase in the number of modern metering devices as defined

[25] See Article 2 of the Act amending the Act on the Brake on Gas and Heat Prices, the Act on the Electricity Price Brake and other energy, environmental and social legislation (EWPBGuaÄndG).

in section 2 para 15 MsbG that are not connected to a communications network. Modern metering equipment is now in use at a total of about 17.1mn meter locations.

Total investment in and expenditure on metering increased in 2022 by about €20mn to some €754mn, about €82.7mn below the forecast. This year's forecast of a total of €936mn is higher than the figure forecast the previous year. The total investment volume of some €754mn in 2022 includes about €380mn for smart metering systems and modern metering equipment, up by approximately €21mn on the year before. The forecast for 2023 indicates another clear increase to about €557mn.

B Gas

1. Gas network overview

In 2022, approximately 154.5 TWh of gas was delivered to final customers from the transmission system operators' (TSO) network (2021: 188.7 TWh). The volume of gas delivered was thus about 18% less than the level of the previous year. Total gas delivered from the network of the distribution system operators (DSOs) amounted to 641.4 TWh in 2022, down by almost 169 TWh or about 21% compared to the previous year (2021: 810.2 TWh).

The total amount of gas available in Germany was about 1,404.4 TWh in 2022, of which 47 TWh came from domestic sources, while 1,441 TWh was imported. In 2022, the annual storage balance – the difference between the gas that entered and exited storage in a year – was minus 93.7 TWh. The negative storage balance figure means that overall, less gas was withdrawn from storage than was injected into it. Moreover, 10.4 TWh of biogas upgraded to natural gas quality was fed into the German natural gas system in 2022.

Just over 38% (513.9 TWh) of the gas available was exported to Germany's neighbours. About 20% less gas (795.9 TWh from 998.9 TWh in 2021) was fed out to final customers.

With regard to gas transmission networks, the quantity of gas procured directly on the market by mostly large final customers (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 59.9 TWh (2021: 79.3 TWh), equivalent to about 39% of the total quantity of gas supplied by the TSOs to final customers. As regards gas distribution networks, the amount of gas procured without a conventional supplier contract amounted to 34.8 TWh, compared with 45.9 TWh in 2021, corresponding to a share of just over 5% of the DSOs' total gas supplies.

The difference between the offtake volumes of the system operators, 795.9 TWh (2021: 998.9 TWh), and the gas delivered by gas suppliers, 766.9 TWh (2021: 908.9 TWh) is comprised of the amount of gas procured directly on the market by final customers and survey-related variations.

The total quantity of gas supplied by general supply networks in Germany fell in 2022 by 203 TWh or about 20% year-on-year to 795.9 TWh. The quantity of gas supplied to household customers as defined in section 3 para 22 of the Energy Industry Act (EnWG) fell by just over 15% to 254.9 TWh (2021: 300.8 TWh). Gas supplies to gas-fired power stations with a nominal capacity of at least 10 MW decreased by about 17% to 85.4 TWh (2021: 102.7 TWh). Based on the reported volumes of gas sold by suppliers to standard load profile (SLP) and interval-metered customers, about 443.8 TWh went to interval-metered customers and about 352.1 TWh to SLP customers. The majority of SLP customers are household and smaller commercial customers.

2. Market concentration

Concentration in the individual gas markets did not change significantly in 2022 despite the decline in gas sales, which was due in particular to the large drop in Russian gas deliveries and possibly also to an increased focus on measures to use less gas. However, there were changes in the market structure as Gazprom Germania GmbH – along with its gas storage subsidiary, astora GmbH – was initially put under the fiduciary management of the Bundesnetzagentur and then renamed Securing Energy for Europe GmbH (SEFE). The Federal Ministry for Economic Affairs and Climate Action (BMWK) ordered SEFE to be nationalised on 14 November 2022, since when it has been fully owned by the Federation.[26]

Underground gas storage facilities

The underground storage facilities connected to the German gas network and relevant to the depiction of concentration had a maximum usable volume of working gas of about 297.1 TWh on 31 December 2022 (31 December 2021: 291.3 TWh). The aggregate working gas volume of the three companies with the largest storage capacities was about 194.6 TWh on 31 December 2022 (31 December 2021: 195.0 TWh), which corresponds to a share of about 65.5% of the total volume. This proportion has seen only a very small decline from the previous year (66.9%), so the level of market concentration here is still high.

Gas retail markets

During the 2022 reporting year, sales from suppliers to SLP customers totalled 346.1 TWh of gas (2021: 402.7 TWh) and to interval-metered customers 418.7 TWh (2021: 508.3 TWh), which was around 16% lower total sales than in 2021.[27] As well as measures taken to reduce gas consumption and safeguard supply and a warmer than average winter, these figures can be explained by the high and volatile market prices (see also section IB14), which led to lower demand. Of the total amount supplied to SLP customers in 2022, about 294.1 TWh was under non-default contracts (2021: 348.9 TWh) and 52.1 TWh was under default contracts (2021: 53.7 TWh).

The cumulative sales of the four largest companies to SLP customers were 95.3 TWh, of which about 79.7 TWh was under non-default contracts, while to interval-metered customers they were about 109.7 TWh. The aggregate market share of the four largest companies by sales was thus 28.2% for SLP customers (2021: 25.5%) and 26.2% for interval-metered customers (2021: 24.4%). Although both these figures are slightly higher than in the previous year, they are still well under the statutory thresholds for presuming market dominance (section 18(6) of the Competition Act (GWB)).[28]

[26] In an order of 14 November 2022, the BMWK took capital measures under section 17a of the Energy Security of Supply Act (EnSiG), leading to a full change of ownership and nationalisation at SEFE. Since then, SEFE has been wholly owned by the Federation. The fiduciary management by the Bundesnetzagentur ended at midnight on 15 December 2022.

[27] "Sales" here and in the whole section on gas retail markets refers to the amount delivered by suppliers to their customers in units of energy.

[28] When considering these percentages, it should be noted that the monitoring survey of gas suppliers has a high but not complete market coverage, so the figures are only approximate.

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. The new natural gas supply structure will affect more than four million household, commercial and industrial customers with an estimated 4.9mn appliances burning gaseous fuels. All of these appliances must gradually be converted from L-gas to H-gas. Gastransport Nord, Gasunie Deutschland Transport Services, Nowega, Open Grid Europe and Thyssengas are the TSOs directly affected by the market area conversion. Between 2023 and 2027, about 4,300 more conversions will be carried out for interval-metered customers and about 2.1mn for SLP customers.

From a total of 33 network operators, 723,747 appliances were registered in 2022, of which 284,449 (39.3%) were condensing boilers and 70,423 (9.7%) self-adaptive appliances. The proportion of condensing boilers had been 45.6% in 2021 and that of self-adaptive appliances 11.3%. During the reporting period, 412,279 appliances were adapted for SLP customers and 848 for interval-metered customers. A total of 7,480 appliances that were to be adapted could not be, a proportion of 1.0% (2021: 1.7%).

A total of 1,999 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 (2021: 2,281). There was a clear increase in the number of customers making use of the reimbursement granted under the Gas Appliance Reimbursement Ordinance (GasGKErstV), 290 compared to 241 the year before.

The conversion costs are shared evenly across all gas customers in Germany in the form of a charge. In 2022 this charge amounted to €0.7335/kWh/h/a. In 2023 it increased to €0.7547/kWh/h/a due to the increase in the number of appliances to be converted and the expected drop in the level of exit capacity likely to be booked or ordered annually in all networks in the country. The charge for 2024 was set at €0.6711/kWh/h/a.

Apart from this, there is no direct impact on the gas bills of individual customers. 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.

In 2022, the market area conversion was again overshadowed by Russia's war on Ukraine, which triggered uncertainty among many people about the security of supply after the conversion to H-gas. Network operators and companies carrying out the adjustments responded to this uncertainty by providing transparent information. Overall, the market area conversion is on schedule and making good progress. More information on it may be found in section **IIIB3**.

4. Gas imports and exports

Gas imports

Gas flows from Russia to Germany were last at a normal level of around 1,800 GWh/day on 10 May 2022. The halting of Russian gas deliveries to Poland and Bulgaria has so far had no impact on gas imports to Germany. Following Russia's imposition of sanctions on Gazprom Germania and almost all the company's subsidiaries, the volumes of gas flowing through Ukraine to Waidhaus in Germany fell by more than 25% from one day to the next as a result of the reduction in transit flows. On 14 June 2022, gas flows from the Nord Stream 1 pipeline were at about 60% of maximum capacity, but were reduced to 40% the following day. As from

11 July 2022, they fell to zero, because, it was announced, of planned maintenance work on the Nord Stream 1 pipeline scheduled until 21 July 2022. Gas flows through Nord Stream 1 resumed on 22 July 2022 and were at about 40% of maximum capacity. On 27 July 2022, there was another, announced reduction in gas flows from Nord Stream 1 to around 20% of maximum capacity. These reduced gas flows through the Nord Stream 1 pipeline were then suspended indefinitely on 2 September 2022, reportedly for technical reasons. On 26 September 2022, a sudden drop in pressure, caused by an explosion, was identified first in Nord Stream 2's pipe A and then in both Nord Stream 1 pipes. The presumed attacks on the Nord Stream 1 and 2 pipelines did not have any effect on the gas supply. No gas had been delivered through Nord Stream 1 since the beginning of September anyway, and Nord Stream 2 had never been put into operation.

The total volume of natural gas imported into Germany in 2022 was 1,441 TWh. Imports to Germany were thus down by 17 TWh from the previous year's figure of 1,458 TWh. The most important sources of imported gas in Germany in 2022 were Norway, the Netherlands and Belgium, with a total volume of 983 TWh or about 68% of all imports to the country. In view of the conflict in Ukraine, Russian gas deliveries lost their significant role. The share of Russian pipeline gas in 2022 was just 21% (2021: 63%). The Netherlands, as an established and liquid European trading hub and point of arrival for liquefied natural gas (LNG) shipments and a country with connections to natural gas fields in Norway and the United Kingdom, is an especially significant source of imports for Germany. In addition, Germany's first floating LNG terminal (floating storage and regasification unit (FSRU)) started operation in Wilhelmshaven in December 2022. It was joined by two more such terminals in Lubmin and Brunsbüttel in January and March 2023.

Gas exports

In 2022, the total volume of natural gas exported by Germany was 513.9 TWh. Based on the previous year's figure of 749 TWh, exports from Germany fell by 235 TWh. Gas was mainly exported to Czechia, Poland and Austria (415 TWh).

Gas production

Germany has its own sources of gas, but these have been losing significance due to the increasing exhaustion of the large deposits and the resulting natural decline in output from year to year. The reserves-to-production ratio of the raw gas reserves has been falling for years. It dropped from 7.4 years in 2021 to 7.3 in 2022.

5. Biogas

A total of 238 plants injected biogas into the network in 2022 (2021: 233). The total contractually agreed input capacity was 2.624mn kWh/h (2021: 2.548mn kWh/h). The annual injection of biogas was 10,158.1mn kWh (2021: 10,141.5mn kWh).

The costs incurred from the connection of biogas injection facilities are spread among all networks in the market area in accordance with the requirements of section 20b of the Gas Network Tariffs Ordinance (GasNEV). The costs for biogas passed on by gas network operators to all network users amounted to about €180mn in 2022 (2021: €192mn). That was the equivalent of about €0.0177 per kWh of biogas injected (2021: €0.0191/kWh), 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. More information on the injection of biogas may be found in section **IIIB4**.

6. Underground gas storage facilities

Germany's gas storage facilities are key to the supply of gas, in particular in the winter months. The total maximum usable volume of working gas in underground storage facilities as at 31 December 2022 was 286 TWh (2021: 279 TWh). Of this, 140 TWh (2021: 137 TWh) was accounted for by cavern storage, 125 TWh (2021: 120 TWh) by pore storage and 21 TWh (2021: 22 TWh) by other storage facilities.

The entry into force of the Gas Storage Act on 30 April 2022 and the introduction of statutory requirements for storage levels serve to further increase security in the supply of gas in Germany. The storage level requirements were originally 80% on 1 October, 90% on 1 November and 40% on 1 February of each year. These requirements were raised again by a ministerial ordinance on 29 July 2022. The targets for 1 October and 1 November were increased to 85% and 95% respectively, while the target for 1 February was left at 40%.

The target storage level of 85% for 1 October 2023 was already reached by the end of July 2023. The 1 November target of 95% was reached on 25 September 2023. Storage levels on 2 November 2023, the editorial deadline for the monitoring report, stood at 99.91%. The charge valid under section 35e EnWG to secure the storage level requirements for gas storage facilities (gas storage neutrality charge) was €0.59/MWh from 1 January 2023. Since 1 July 2023, it has been €1.45/MWh. More information on gas storage facilities may be found in section **IIIB5**.

7. Network structure data

All 16 TSOs took part in the 2023 Monitoring Report data survey. As at 31 December 2022, the length of pipelines in the transmission system was about 43,300 km and included around 3,500 exit points for delivery to final customers, 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 system was 529.

As at 2 November 2023, a total of 704 gas DSOs were registered with the Bundesnetzagentur, 665 (just over 95%) of whom took part in the 2023 monitoring survey. As at 31 December 2022, the total length of pipelines in the gas distribution system including house connections was around 527,000 km and included about 10.8mn exit points for delivery to final customers, 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 31 December 2022, there were 14.5mn 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 12.9mn. The majority of gas DSOs (585 operators) have short to medium length systems of up to 1,000 km, and 90 DSOs have gas systems with a total length of more than 1,000 km.

There are a total of around 6,700 entry points to the gas distribution networks, of which 478 are for emergency entry only. A look at the number of market locations served by the DSOs shows that only 29 DSOs supply more than 100,000 each, the same as in 2021. Of the total of 14.5mn market locations supplied by the DSOs in Germany, some 48% (6.9mn or 326 TWh offtake volume) of the total gas supplies are served by DSOs that supply more than 100,000 customers. The majority (around 57%) of DSOs active in Germany supply between 1,000 and 10,000 gas customers.

8. Gas network expansion

The sea change in energy policy has made it necessary to speed up significantly the transition from natural gas to green and climate neutral gases, such as hydrogen. The inclusion of LNG requires the existing gas networks to be adapted as well. These developments have had a major influence on the Gas Network Development Plan (NDP) 2022-2032, reflecting these new realities.

Following the submission of the draft Gas NDP 2022-2032 by the TSOs, the Bundesnetzagentur carried out a written consultation of all actual and potential network users from 16 May to 13 June 2023. The Bundesnetzagentur then takes this as the basis to examine the Gas NDP 2022-2032. The process is concluded with a request for amendment. The TSOs then have three months to make the required amendments.

9. Investments by gas network operators

TSOs

In 2022, the 16 German gas TSOs invested a total of €820mn (2021: €679mn) in network infrastructure. Of this, €587mn (2021: €420mn) was accounted for by investments in new builds, upgrades and expansion projects and €233mn (2021: €259mn) by investments in network infrastructure maintenance and renewal.

Across all TSOs, expenditure on maintenance and repair of network infrastructure amounted to €446mn in 2022 (2021: €358mn), with expenditure lower than in the previous year but within the usual range of fluctuation. The TSOs' planned expenditure for 2023 is €480mn.

DSOs

Over 600 gas DSOs reported a combined investment volume of €1,445mn in network infrastructure for 2022 (2021: 1,736mn). Investments in new builds, upgrades and expansion accounted for €795mn of the total (2021: €1,101mn), while €650mn went into maintenance and renewal (2021: €635mn). The projected total investment for 2023 is €1,450mn.

Service and maintenance expenses, based on the data provided by the DSOs, totalled €1,191mn in 2022 (2021: €1,204mn). The projected investment in servicing and maintenance for 2023 is €1,250mn.

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 conditions. While 143 of the surveyed gas DSOs reported investments of between €1mn and €5mn, 58 gas DSOs made investments totalling more than €5mn.

Of the surveyed gas DSOs, 239 reported total expenditures in the bracket between €100,001 and €500,000, while 53 gas DSOs reported expenditures totalling more than €5mn.

10. Capacity offer and marketing

In the 2021/2022 gas year, the total firm entry capacity offered across the Germany-wide market area Trading Hub Europe (THE) was 549.0 GWh/h, which was just over 1% more than in the year before

(2020/2021: 543 GWh/h). About 39%, or 212.8 GWh/h, of the total entry capacity was firm, freely allocable capacity (FZK; 2020/2021: 242 GWh/h).

The total firm exit capacity offered in the THE market area in the 2021/22 gas year was 367.5 GWh/h, corresponding to a small decrease of 1.4% (2020/2021: 372.8 GWh/h). It should be noted that not every TSO offers all capacity products. The aggregated values therefore cannot be projected onto each individual TSO.

A comparison of the data on entry and exit capacity reveals a number of differences. For instance, it is apparent that, overall, in the 2021/2022 gas year more entry capacity was booked than exit capacity. Consequently the total volume of entry capacity booked was 337.4 GWh/h, significantly exceeding the exit capacity booked, which amounted to a total of 213.7 GWh/h. 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. The German gas network access model does not oblige suppliers to book equivalent exit capacity when supplying gas in this way. In addition, the analysis of the entry and exit capacity bookings clearly illustrates that, during the period under review, most bookings were for longer-term capacity products.

Across Germany, the TSOs reported a nominated quantity of 1,699 TWh in 2022 at all entry points where there is a nomination obligation (2021: 1,882 TWh). In contrast, nominated quantities at exit points were considerably lower, totalling 806 TWh (2021: 905 TWh). 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. The exit points where there is a nomination obligation are cross-border and market area interconnection points and connection points to storage facilities and domestic production. Network connection points to final customers, on the other hand, are not subject to a nomination obligation. More information on available capacity may be found in section **IIIC4**.

11. Gas supply disruptions

In 2022, the average interruption in supply per connected final customer was 1.52 minutes (2021: 2.18 minutes), which is somewhat below the long-term average of 1.54 minutes a year. This figure shows that the German gas network still has a high quality of supply even during a time of crisis. There was a large variation in the interruption times among the federal states, ranging from 0.08 minutes in Hamburg to 5.85 minutes in Saxony-Anhalt. More information on gas supply disruptions may be found in section **IIIC5**.

12. Gas network tariffs

The average volume-weighted network tariff including the charges for metering and meter operation for household customers (volume-weighted across all contract categories) was 1.89 ct/kWh as at 1 April 2023. This was a significant rise of about 17% from the previous year (2022: 1.62 ct/kWh). For commercial customers, as at 1 April 2023 the arithmetic mean of the network tariff including the charges for metering and meter operation was 1.48 ct/kWh (2022: 1.25 ct/kWh). For industrial customers, as at 1 April 2023 the arithmetic mean of the network tariff including the charges for metering and meter operation was 0.39 ct/kWh (2022: 0.44 ct/kWh).

For the Germany-wide market area THE, on 25 November 2022 the TSOs published adjusted entry and exit tariffs for firm, freely allocable annual capacity for 2023 of €6.03/kWh/h/a (2022: €3.51/kWh/h/a). On 25 May 2023, the TSOs published the entry and exit tariffs for firm, freely allocable annual capacity for 2024, which will be €5.10/kWh/h/a from 1 January 2024. The tariff for the booking of firm, freely allocable entry and exit capacity will be around 15% lower in 2024 than it was in 2023.

The distribution network tariffs for 2024 provisionally reported on 15 October show a decline across all customer groups. The figures are based on a random sample of network operators under the responsibility of the Bundesnetzagentur. No firm statements on the precise extent of the decrease can be made at the time of going to press. It is due to lower costs for the use of downstream network levels, resulting from factors including lower prices for compressor energy in the transmission systems as well as sales forecasts that are higher than the year before.

13. Balancing gas and imbalance gas

As gas is mainly purchased on the exchange, procurement prices for external balancing gas are on the same level as general market prices.

The gas auction system was launched on 1 October 2022. Companies can offer volumes of gas via the balance responsible party. THE, which is responsible for the German gas market area, can now accept offers to reduce gas consumption in the event of shortages, which will stabilise the networks if needed.

A balancing neutrality charge for interval-metered and SLP customers is payable, in line with the GaBi Gas 2.0 determination, to make up the expected shortfall from the use of balancing gas and imbalance gas. It is borne by the balance responsible parties that serve exit points connecting users with either standard load profiles or interval metering. For the period of validity as of 1 October 2022, a neutrality charge of €5.70/MWh was levied for SLP customers and €3.90/MWh for interval-metered customers. From 1 October 2023, both these charges will be cut to €0/MWh.

14. Wholesale gas markets

The situation in the natural gas markets changed dramatically in the wake of Russia's invasion of Ukraine. This primarily involved the gradual cessation of direct supply with Russian gas. It took some time for this to be replaced with other natural gas imports and, since the end of 2022, with increased deliveries of LNG. Although some normality returned to the markets towards the end of the second half of 2022, wholesale prices were much higher in the year as a whole and were very volatile. This trend has continued in 2023, albeit at a somewhat lower level.

Volume of gas trading

There was strong volume growth on the European gas exchanges in 2022, shown here using the example of the European Energy Exchange AG and its subsidiaries (EEX).[29] From the exchange perspective, this was due to factors including the greater demand for exchange-traded hedging instruments because of the uncertain market environment caused by Russia's war in Ukraine, high levels of price volatility and rising inflation

[29] There are other gas exchanges as well as the leading one, EEX, such as CME Group and ICE. There are plans to include these in the energy monitoring in the coming years.

during the year.[30] The total volume of trade, including cleared volume, in the German national market area THE since its formation in October 2021 was about 1,754 TWh in 2022, corresponding to growth of 164.2% year-on-year (2021: 664 TWh). The volume traded on the spot market also rose in 2022 to about 1,106 TWh compared with about 582 TWh in 2021. The focus of spot trading in 2022, as in the previous years, was on day-ahead contracts. The futures trading volume rose from around 82 TWh in 2021 to about 649 TWh, almost eight times higher (691%). EEX considered that the main reason for this growth was the greater need for hedging and reduction of the counterparty credit risk, as hedging in consumption-related market segments is gaining relevance for market participants.

Day-ahead prices

The (unweighted) annual average for THE in the European Gas Spot Index (EGSI) published by EEX was €124.98/MWh in 2022. The previous year, the comparative values for the daily reference price up to September 2021 were €30.29/MWh for NCG and €30.33/MWh for GASPOOL and from October 2021 €95.67/MWh for THE, which corresponds to a 2022 price rise of about 312.5% for NCG and GASPOOL and about 30.6% for THE. The EGSI monthly average throughout 2022 ranged from €81.06/MWh in February to €235.18/MWh in August. The strong rise in the EGSI, which was already becoming evident in the fourth quarter of 2021, continued until August 2022, after which the index fell significantly again.

The European Gas Index Deutschland (EGIX) is based on exchange transactions concluded in the relevant front-month contracts (THE). In 2022, the EGIX ranged from €81.62/MWh in March to €234.51/MWh in September. The (unweighted) average of the 12 monthly values was €132.94/MWh, the equivalent of an about 244% increase year-on-year from €38.64/MWh.

The (unweighted) average of the monthly border prices (as calculated by the Federal Office for Economic Affairs and Export Control (BAFA)) was €79.26/MWh in 2022, compared with €26.02/MWh in 2021 (up 204.6%). This development shows that the EGIX rose much more strongly than average BAFA prices in 2022.

Over-the-counter wholesale trade

The nine broker platforms participating in this year's data monitoring reported having brokered natural gas transactions for delivery to Germany for an uncleared total volume of 2,010 TWh (2021 with nine brokers: 2,392 TWh), of which 766 TWh was for contracts with delivery in 2022 and a delivery time of at least one week. The decline of approximately 15.9% year-on-year in the total volume of the brokers, which is particularly evident in the delivery periods Y+2 and Y+3, is likely to be due to a reticence to buy in a time of much higher and volatile prices and possible expectations of falling prices in the course of trading on the part of customers.

Short-term transactions on the spot market with a delivery period of less than a week only made up about 8.6% of the trading reported by the nine broker platforms for 2022 (2021: 5.2%), with the other 91.4% relating to the futures market. Transactions for the current and the next year were thus the clear focus of the brokers in natural gas trading.

[30] EEX Group Finanzergebnisse 2022, page 9.

While the gas traded in 2022 (including spot trades) made up about 46.7% of the total volume, about 38.6% was traded for the following year, 2023, up from 33.5% the previous year. A share of about 14.6% was taken by transactions with delivery times in 2024 and beyond, down from 26.3% the year before.

Trading at virtual trading points

The gas volumes nominated at the THE virtual trading point dropped only slightly to 3,639 TWh in 2022 from 3,807 TWh the year before, with about 91.9% of the nomination volume being taken up by H-gas and the remaining 8.1% by L-gas.

As in the years before, the monthly nomination volumes display seasonal variations. In the months of May to September 2022, the monthly nomination volume at the virtual trading point was no more than 277 TWh. The lowest nomination volume was about 237 TWh in June 2022 and the annual peak was 373 TWh in December 2022.

There has been a slight year-on-year drop in the number of active trading participants in THE since October 2021.[31] It averaged 415 per month for H-gas in 2022 and 192 for L-gas, down from 424 and 197 respectively the year before.

15. Retail gas markets

Number of suppliers

The disruption on the gas market related to the Russian attack on Ukraine, which temporarily resulted in a huge rise in wholesale prices, led to some energy suppliers leaving the market in the course of 2022. A total of 21 energy suppliers told the Bundesnetzagentur during 2022 that they would stop supplying household customers. Five of them were exclusively gas suppliers. By the editorial deadline of this report on 2 November 2023, 13 energy suppliers had ended their activities in 2023, with a further five planning to cease them by the end of the year. This development meant that 2022 was the first time the number of active gas suppliers for all final customers in the different network areas fell. The number of gas distribution systems in which more than 100 gas suppliers were active dropped from 70.3% to 63.8%. Across the country, each household customer could choose from an average of 111 gas suppliers (2022: 113 gas suppliers). The number of gas suppliers active nationwide fell from 65 in 2021 to 52 in 2022.[32] It remains to be seen whether this trend will continue or whether it was a one-off effect of the temporarily very sharp increase in gas procurement costs on the business and procurement strategy of some gas suppliers.

[31] An active participant in the virtual trading point is one who has made at least one nomination in the relevant month.

[32] 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.

Procurement strategies of gas suppliers

Despite the striking developments in the wholesale markets, no significant differences between the procurement strategies of 2021 and 2022 may be identified. Just over 50% (2021: 48%) of the gas suppliers taking part in the survey had a mixed procurement strategy of short-term and long-term procurement. About 46% (2021: 47%) of the gas suppliers had only long-term procurement, while just over 4% (2021: 5%) used only short-term procurement to acquire the gas volumes needed. There are no major differences in the procurement strategies for the supply of household and non-household customers.

Contract structure of non-household customers

Interval-metered customers were supplied with just over 418.7 TWh of gas in 44,225 market locations in 2022.[33] These are all non-household customers (industrial and commercial customers, gas-fired power plants). Over 99% of this supply took place on non-default contracts with the default supplier (97.7 TWh) and contracts with suppliers that are not the default supplier (320.7 TWh).[34] It is unusual, but not impossible, for interval-metered customers to be supplied under default supply or fallback supply. Around 0.3 TWh of gas was supplied to interval-metered customers under default or fallback supply. This is less than 0.1% of the total volume supplied to interval-metered customers.

About 23.3% of the total volume delivered to interval-metered customers was supplied under a contract with the default supplier on non-default terms (2021: 22.8%) and about 76.6% was supplied under a contract with a legal entity other than the default supplier (2021: 77.1%). These figures show that default supply plays only a marginal role in the supply of interval-metered customers with gas and also that the local default supplier is of only secondary importance in the supply of customers via non-default contracts.

Contract structure of household customers

The temporarily high gas prices for household customers led to moderate changes in the existing contract structure for these customers. The proportion of default contracts saw a slight rise from 16% to 18% of volume in 2022 for the first time since 2010. At the same time, the proportion by volume of non-default contracts with the default supplier (47%) and contracts with a supplier other than the local default supplier (35%) each fell by one percentage point. Of the around 243.5 TWh[35] supplied by gas suppliers to household customers, 43.3 TWh was under default contracts, 115.4 TWh under non-default contracts with a default supplier and 84.8 TWh under contracts with a supplier other than the local default supplier.

[33] In the 2022 reporting year, 904 gas suppliers (individual legal entities) provided data on the market locations served and volume consumed by interval-metered customers in Germany, ie almost exclusively non-household customers (2021: 932). These gas suppliers include affiliated companies, hence the number of suppliers is not equal to the actual number of independent competitors.

[34] In accordance with section 36 EnWG, default supply only relates to household customers. Where "default supply" for non-household customers is used in the section below, it refers to "fallback supply".

[35] The volume of gas delivered to household customers as defined in section 3 para 22 EnWG was 254.9 TWh in 2022 and deviates from the figure of 243 TWh reported by gas suppliers due to incomplete data reports from gas suppliers.

Supplier switches by non-household customers

The total number of market locations of both household and non-household customers with a supplier switch dropped 39.3% from 1,992,882 in 2021 to 1,210,175 in 2022. The offtake volume of gas affected by a supplier switch also dropped steeply to 78.7 TWh from 107.6 TWh the previous year (down 26.9%). This decline indicates that it was hardly possible or much less easy to get better contractual terms by switching supplier in the year under review owing to the much higher prices in the relevant period.

Customers with at least 0.3 GWh/year (including gas power stations) are all non-household customers. In this group, the volume-based switch rate barely changed in 2022 (10.4% compared to 10.2% the year before).

Supplier switches by household customers

The number of household customers changing supplier fell by about a third to 1.15mn. The adjusted number of supplier switches in 2021 was about 1.64mn. When looking at 12.9mn household customers (according to DSO figures), the resulting overall numbers-based supplier switching rate for household customers is 8.9%, down from 12.9% in 2021. The volume of gas affected by supplier switching was 25.1 TWh in 2022. A lack of alternatives and general uncertainty caused by the very volatile wholesale prices may be reasons for the clear decrease in switches.

Contract switches by household customers

In 2022 the number and volume of changes of contract with the existing supplier rose by about 59%, following a significant drop of 30% in 2021.[36] The volume-based contract switching rate rose from 3.1% to 5.5%. In absolute terms, that meant that 0.76mn gas customers decided to change their contract, an increase of about 40%. These figures indicate that households with high consumption were most likely to move to a new contract while staying with their existing supplier.

Gas disconnections

The number of disconnections carried out by the network operators in 2022 was 22,987, representing a decrease of about 15% compared to the previous year (2021: 26,905). The overwhelming majority of disconnections occurred when customers were late paying their bills. About 65% of disconnections related to default contracts and 35% to non-default contracts.[37] About 30% of disconnections were carried out in the second and another 30% in the third quarter of the calendar year; that is to say, outside the heating season. About 4% of household customers on default contracts who were disconnected were disconnected more than once in a calendar year. Among those on non-default supply, nearly a third were affected by a disconnection more than once in 2022.

Around 60% of the gas suppliers surveyed also said they had voluntarily decided not to disconnect their customers. About half of those surveyed had already decided not to disconnect customers during the

[36] A customer's change to a new gas tariff with the same gas supplier at their own request.

[37] Non-default contracts mean both non-default contracts with the default supplier and contracts with a supplier other than the local default supplier.

pandemic. Suppliers often accommodated customers by offering them special or individual payment arrangements. There was a large increase in 2022 in the number of customers in payment difficulties being offered payment by instalment. Gas suppliers made over 160,000 offers of payment by instalment in 2022, which was accepted in about 36,000 cases (around 23%). The average length of time between an actual disconnection and a reconnection was 40 days, according to network operators. Around 2,400 disconnections were for more than 90 days. The reasons for these longer periods of disconnection may have been customers' long-term inability to pay, vacant properties or faulty customer equipment that could not be reconnected for safety reasons.

There was a small decrease of about 3% in disconnection requests from gas suppliers to network operators in 2022 (169,000 from 174,000 in 2021). The number of disconnection notices issued by gas suppliers, however, was about 10% higher. The absolute number of disconnection notices was 1.1mn in 2022 (2021: 1mn). As there is sometimes a gap between the issuing of a disconnection notice and the actual disconnection, it may be assumed that some of the disconnections notified in 2022 only took place the following year. According to the gas suppliers, the time from the first, unsuccessful demand for payment and the first reminder is 14 days on average. Between the first reminder and the disconnection request there is an average of 30 days, but in some cases much more. The average time between the disconnection request and the final notice of disconnection is about 14 days.

The amount of payment due when a disconnection notice is issued varies greatly, but the average is about €130.[38] According to the network operators, 17,403 market locations were successfully reconnected in 2022 following a disconnection (2021: 20,286). This figure is about 14% lower than in 2021. Unlike the disconnections, most of the reconnections of previously disconnected connections take place at the beginning of the heating period, in the fourth quarter of the year.

Disconnections always incur additional costs. While some gas suppliers only pass on the costs of the network operator that carried out the disconnection/reconnection, a proportion of suppliers additionally charge their customers for carrying out a disconnection. The network operators charged gas suppliers an average fee of about €58 (excluding VAT) for disconnecting a supply. They charged suppliers an average fee of about €69 (excl VAT) for reconnecting a supply. Customers were charged an average disconnection fee of about €50 (including VAT) by suppliers applying the general calculation in accordance with section 19(4) of the Gas Default Supply Ordinance (GasGVV). Suppliers not applying the general calculation charged customers an average of about €55 (inc VAT). Customers were charged an average reconnection fee of about €58 (inc VAT) by suppliers applying the general calculation and about €62 (inc VAT) by those not applying the general calculation. Gas suppliers charged an average of €3 plus reminder fees for sending a reminder to household customers who were late paying their bills and there are usually two dunning levels.

[38] Under a default supply contract, the interruption of supply may only be carried out if the customer is two monthly payments and €100 or more in arrears. If no monthly instalment has been agreed, the customer must be at least one sixth of the projected annual amount in arrears.

Terminations

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 2022, gas suppliers (default suppliers and their competitors) terminated their contractual relationship with a total of 55,233 gas customers (2021: 41,363) due to the customers' failure to fulfil a payment obligation. About 93% of these terminations related to contractual relationships outside the default supply. 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 €180 in 2022.

Prepay systems

Closely related to the topic of disconnections and terminations is also that of prepay systems under section 14 GasGVV, such as cash meters and smart card readers. The default supplier is entitled to require advance payment for gas consumption in a billing period if there are grounds to assume, based on the individual circumstances, that the customer will not meet their payment obligations or meet them in time. According to 25 suppliers, a total of 900 household customers had cash or smart card meters, or comparable prepayment systems, in 2022 compared to 931 in 2021. There were 144 new installations of prepay systems and 115 existing ones were removed in 2022. The numbers of such systems are therefore still very low. Costs for meter operation and metering averaged €27 and €15 respectively per year and meter. The yearly standing charge for gas customers was €130 on average, while the average unit price for gas charged using a prepayment meter was 13 ct/kWh.

Gas prices for industrial customers for annual consumption of 116 GWh

The arithmetic mean of the overall price (excluding VAT) for an annual consumption of 116 GWh ("industrial customer") on the reporting date of 1 April 2023 was 7.75 ct/kWh, an increase of about 14.6% year-on-year (2022: 6.76 ct/kWh).[39] The war in Ukraine probably contributed to this development. This amount is rather close to the gas reference price for industrial customers (not including gas power stations) under section 9(3) para 2 of the Act on the Brake on Gas and Heat Prices (EWPBG), which suggests that the reference price may have acted as a pricing guide. The overall price is composed of an average of 5.2% of components that cannot be controlled by suppliers: network tariffs, charges for metering and meter operation and concession fees. Another non-controllable component for suppliers is the gas tax of 0.55 ct/kWh and the carbon levy of 0.5461 ct/kWh.[40] The gas tax and carbon levy together make up about 14.1% of the average total price (excluding VAT), down from 16.2% in 2021. About 80.7% (2022: 77.3%) of the overall price is the components controlled by the supplier (gas procurement costs, distribution costs and margin). THE's current gas balancing

[39] The price questions were answered by 84 suppliers (2021: 87). More information on the answering of the price questions by the gas suppliers surveyed may be found in section IIIF4.

[40] The carbon levy was introduced in 2021.

neutrality charge for interval-metered customers is €3.90/MWh for the period from 1 October 2022 to 30 September 2023. Moreover, since 1 November 2022 the gas storage neutrality charge has been part of the gas price. It was 0.059 ct/kWh (net) until 1 July 2023, when it rose to 0.145 ct/kWh.

Gas prices for commercial customers for annual consumption of 116 MWh/a

The arithmetic mean of the overall price (excluding VAT) for an annual consumption of 116 MWh ("commercial customer") was 12.11 ct/kWh, an increase of 4.92 ct/kWh or about 68.3% from the previous year's price of 7.19 ct/kWh.[41] This amount is rather close to the gas reference price for final customers that are not industrial customers under section 9(3) para 1 EWPBG, which suggests that the reference price may have acted as a pricing guide. An average of about 22.2% (2022: 35.0%) of the overall price was made up of cost items not controlled by the supplier, such as network tariffs, the gas tax, concession fees and the carbon levy. Around 77.8% (2022: 65.0%) relates to items that allow scope for business decisions. THE's current gas balancing neutrality charge for SLP customers is €5.70/MWh for the period from 1 October 2022 to 30 September 2023. Moreover, since 1 November 2022 the gas storage neutrality charge has been part of the gas price. It was 0.059 ct/kWh (net) until 1 July 2023, when it rose to 0.145 ct/kWh. The average net amount of the non-controllable components rose from 2.44 ct/kWh in the previous year to 2.70 ct/kWh, mainly due to higher concession fees and network tariffs. The residual price component controlled by the supplier rose by 4.73 ct/kWh (from 4.69 ct/kWh as at 1 April 2022 to 9.42 ct/kWh as at 1 April 2023), thus by around 100.9%. Here, too, the effects of the war in Ukraine are likely to have played a major role.

Gas prices for household customers

The volume-weighted, average gas price for household customers across all contract categories was 14.80 ct/kWh as at 1 April 2023 (2022: 9.88 ct/kWh), an increase of about 50% on the previous year. In the average price across all contract categories, the largest price component "energy procurement, distribution and margin", which makes up around 73%, nearly doubled from 5.5 ct/kWh to 10.77 ct/kWh. The share of the state-controlled price components such as value-added tax, natural gas tax, the carbon levy and concession fees is historically low at 14.4% (2022: 27.8%). The main reason for this is that the Act temporarily reducing the value added tax rate for the supply of gas via the natural gas network (GasUStSG) retroactively cut the rate of VAT on gas deliveries from 1 October 2022 to the end of March 2024 from 19% to 7%.[42] The proportion of network tariffs was 12.8% in 2023 (2022: 16.5%).[43] The average network tariffs thus rose about 16% from 1.63 ct/kWh to 1.89 ct/kWh.

When looking at the price level of the three contract types, it is clear that default supply prices had risen most strongly by the reporting date of 1 April 2023, whereas in the year before the prices of the non-default competitors had seen the highest increases. This change in trend may be explained by the different procurement strategies and willingness to take risks. The data of the last two reporting dates show that the more short-term procurement strategy on the wholesale markets that many competitors tend to pursue can

[41] The price questions were answered by 748 suppliers (2021: 757). More information on the answering of the price questions by the gas suppliers surveyed may be found in section IIIF4.

[42] As at the editorial deadline for the Monitoring Report 2023.

[43] Including upstream network costs, charges for metering and for meter operations.

bring financial advantages and disadvantages for gas customers. The volume-weighted average gas price for customers on a default contract as at 1 April 2023 was 16.25 ct/kWh (2022: 9.51 ct/kWh), corresponding to an increase of around 70% compared to the previous year. On 1 April 2023, the volume-weighted price for customers under a non-default contract with the default supplier was 14.52 ct/kWh, an increase of about 61% compared to 2022 (9.02 ct/kWh). The volume-weighted price for a contract with a supplier other than the local default supplier as at 1 April 2023 was 14.44 ct/kWh, a rise of just over 32% compared to the previous year (2022: 10.95 ct/kWh).

Lawmakers made changes in the rules for pricing in the default and fallback supply to strengthen the rights of consumers. From 1 November 2022 onwards, it was no longer allowed to have different prices for existing and new customers in the default supply. Fallback supply prices, however, may be higher than default ones and they may be adjusted on the first or fifteenth of any month. Price data for the fallback supply, which was recorded for the first time as at 1 April 2023, showed that the average was 18.42 ct/kWh, about 13% more than the average default supply price. On 1 January 2022, the proportion of gas suppliers with higher fallback supply prices had been at a low level of about 14%. This proportion peaked at about 60% in the months of November and December 2022 and January 2023. Since then, the share of suppliers with higher fallback supply prices has been steadily falling until, by the fourth quarter of 2023, only about 14% of gas suppliers expected to have to offer higher fallback supply prices.

Energy price brakes

The sharp rises in energy costs have led legislators to relieve the burden on gas, electricity and heat customers. In 2023, for example, prices for natural gas were limited for a basic share of consumption, as set out in the EWPBG. The main idea behind the energy price brakes is that customers receive financial relief based on their forecast consumption. For private households, associations and small and medium-sized businesses with an annual consumption of up to 1.5mn kWh – that is to say, almost all customers supplied under a standard load profile – the scheme gives them reduced prices for 80% of their forecast annual consumption. Customers who manage to keep their consumption below 80% of the forecast can also keep the relief for their reductions as a "reward" for saving energy. From March 2023, the gas price was capped at 12 ct/kWh for private households for 80% of the amount they had consumed in the previous year.

Consumer advice and protection

The energy consumer advice service is the national point of contact for consumers who want information on their rights in the energy sector, applicable legal regulations or dispute resolution options. Current data and information specially focused on gas may be found in the subsection "Retail" in the section "Developments in the electricity markets" (see section IA15).

16. Gas metering[44]

The undertakings reported a total of 13.68mn meter locations for gas. North Rhine-Westphalia was the German state with the most meter locations (over 3.63mn), followed by Lower Saxony (2.02mn) and Baden-Württemberg (1.34mn).

Investments

Total investment and expenditure were down about €15mn to around €228mn in 2022, leaving expenditure around €24mn below the planned investment amounts. The forecast for 2023 totals €250mn, around the same level as last year. Of the total of about €228mn in 2022, around €36mn went to investments in new installations, upgrades and expansion, €71mn to investments in maintenance and renewal, and about €121mn on expenditure.

[44] Data based on responses from 635 undertakings.

II Electricity

A Situation in the electricity markets

1. Network overview

The network balance of an electricity network provides a comprehensive overview of the flow of electricity and the use of the electricity generated in the network. It is made up of a supply side and a demand side. The supply side comprises total net electricity generation and cross-border flows from other countries.

The demand side, by contrast, shows how the electricity generated is consumed. A significant proportion of the electricity is withdrawn by final customers from the general supply networks. Pumped and battery storage facilities also take electricity from the network. For example, pumped storage facilities use electricity to pump water to an upper reservoir for storage when prices are low and feed electricity back into the network at times of peak demand. The amount of electricity they consume is more than the amount they later generate. The demand side also includes internal consumption. This is the amount of self-produced electricity that is not fed into the general supply networks. Physical flows to other countries are also included on the demand side.

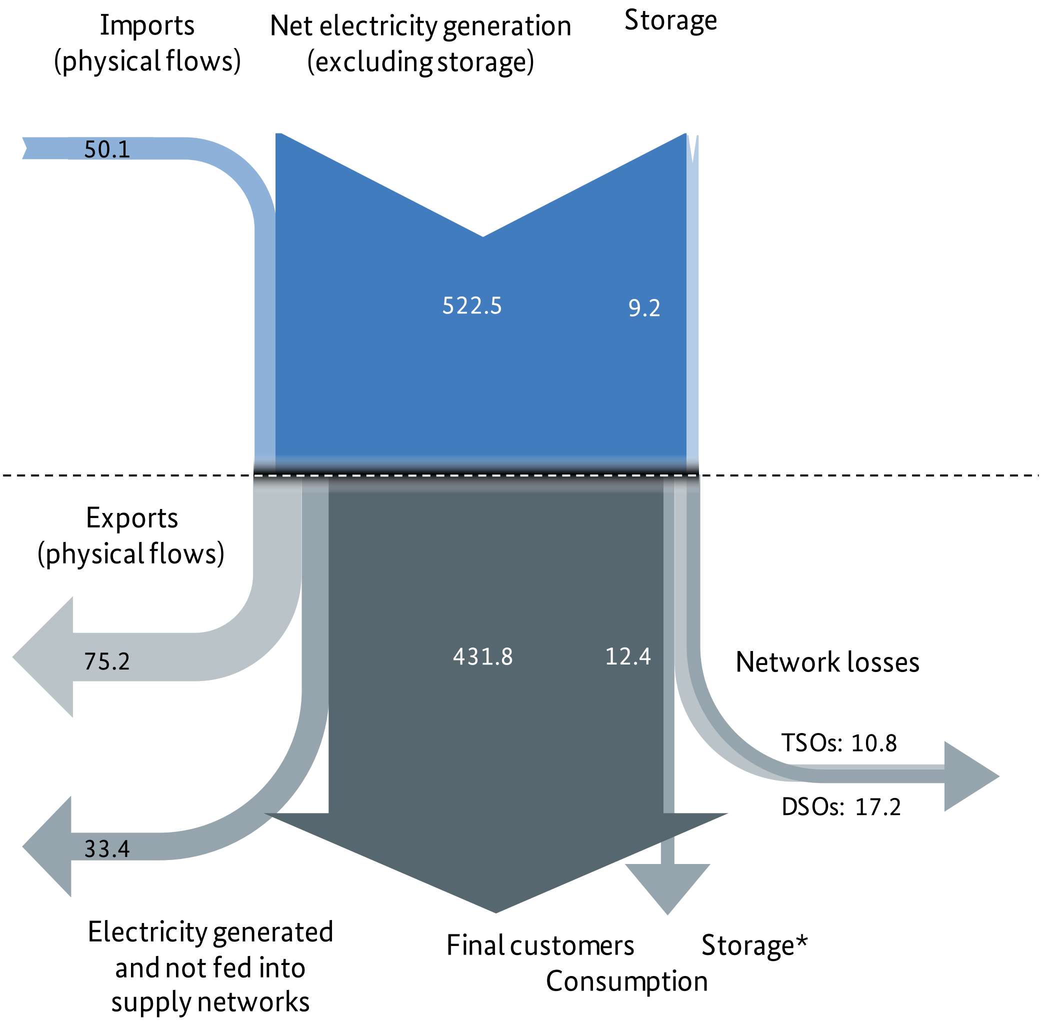
In addition to these main aspects, the network balance also takes account of network losses at transmission and distribution level. Network losses in electricity networks occur because of the electrical resistance of lines and components and lead to some of the energy fed in becoming lost in the form of heat instead of being transported to consumers.

Possible differences between the supply side and the demand side are due to the complex structure of the data survey with a large number of different market participants.

Gross electricity consumption is the sum of gross electricity generation[45] from renewable and non-renewable energy sources and cross-border flows from other countries less cross-border flows into other countries. Gross electricity generation includes power plants' internal consumption and is therefore higher than net electricity generation.

[45] The actual figure is higher because the monitoring only covers internal consumption and electricity generation from self-generation plants with an installed capacity of 10 MW or more per site.

Electricity: Supply and demand in the electricity supply system in 2022
(TWh)



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

Figure 1: Supply and demand in the supply system in 2022

Electricity: Network balance 2022

	TSOs	DSOs	Total 2022	Total 2021
Total net nominal generating capacity as at 31 December 2022 (GW)			**247.3**	**239.5**
Facilities using non-renewable energy sources			96.9	99.8
Facilities using renewable energy sources			150.4	139.7
Generation facilities eligible for payments under the Renewable Energy Sources Act (EEG)			145.3	134.2
Total net generation (including electricity not fed into general supply networks) (TWh)			**531.7**	**546.7**
Facilities using non-renewable energy sources			294.2	327.1
Pumped storage			9.2	8.6
Facilities using renewable energy sources			237.6	219.6
Generation facilities eligible for payments under the Renewable Energy Sources Act (EEG)			220.0	203.7
Net amount of electricity not fed into general supply networks (TWh)[1]			35.5	38.1
Network losses (TWh)	**10.8**	**17.2**	**28.0**	**27.7**
Extra-high voltage	9.0	< 0.1	9.0	8.2
High voltage (including EHV/HV)	1.8	3.3	5.1	5.1
Medium voltage (including HV/MV)		5.7	5.7	5.8
Low voltage (including MV/LV)		8.2	8.2	8.8
Cross-border flows (physical flows) (TWh)				
Imports			**75.2**	**70.8**
Exports			**50.1**	**51.7**
Consumption (TWh)[2]	**22.5**	**409.3**	**444.2**	**467.0**
Industrial, commercial and other non-household customers	22.5	288.5	311.0	325.0
Household customers		120.8	120.8	128.8
Pumped storage			12.4	14.1

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

Table 1: Network balance 2022

Electricity: Final consumption (excluding pumped storage) by consumption category

Category	TSOs (TWh)	DSOs (TWh)	TSOs + DSOs (TWh)	Percentage of total (%)
≤ 10 MWh/year	< 0.1	115.8	115.8	27%
10 MWh/year - 2 GWh/year	0.1	115.3	115.4	27%
> 2 GWh/year	22.4	178.2	200.6	46%
Total 2022	**22.5**	**409.3**	**431.8**	**100%**
Total 2021	25.5	428.3	453.9	

Table 2: Final consumption (excluding pumped storage) by consumption category

Electricity: Final consumption (excluding pumped storage) by load profile

Category	TSOs (TWh)	DSOs (TWh)	TSOs + DSOs (TWh)	Percentage of total (%)
Interval-metered customers	22.5	258.2	280.7	65%
Standard load profile customers		151.1	151.1	35%
Household customers within the meaning of section 3 para 22 EnWG		120.8	120.8	28%
Total 2022	**22.5**	**409.3**	**431.8**	**100%**
Total 2021	25.5	428.3	453.8	

Table 3: Final consumption (excluding pumped storage) by load profile

2. Market concentration

The degree of market concentration, which is defined by the distribution of market shares between the players on the respective market, is one of the characteristics applied to identify possible market power on the economically significant market for the generation and first-time sale of electricity and on the two major end customer markets for electricity.[46] 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.[47]

Electricity generation and first-time sale of electricity

In its normal practice the Bundeskartellamt defines a relevant product market as a market for the generation and first-time sale of electricity with physical fulfilment (summarised: market for the first-time sale of electricity). Electricity generation volumes and the required generation capacities only belong to the market for the first-time sale of electricity as defined above if the volumes produced are fed into the general supply grid, are suitable to meet the general demand for electricity and are therefore interchangeable from the customers' perspective.[48]

On the supply side, for the purposes of this monitoring report, electricity generation volumes which are currently subject to other market and competition conditions, e.g. due to specific legal obligations, are not to be included in the market for the first-time sale of electricity. This requirement tends to be fulfilled by the way in which the generation of renewable electricity is subsidised pursuant to the Renewable Energy Act (*Erneuerbare-Energien-Gesetz* – EEG).

In order to provide a rough estimate of how the degree of concentration in the market for the first-time sale of electricity would be affected if a differentiation were made between electricity generation to be subsidised under the EEG and electricity generation that is not eligible for subsidies under the EEG, this monitoring report includes separate surveys of the market shares for EEG electricity generated by the major producers which is not remunerated under the EEG system (RWE, LEAG, EnBW, E.ON and Vattenfall). 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 geographical terms, the Bundeskartellamt still defines the market as a joint market for Germany and Luxembourg based on the shared bidding zone.[49]

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[46] 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.

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

[48] This requirement is not fulfilled in the case of electricity generated for the producer's own consumption, traction current as well as balancing energy, reserve capacities and redispatching.

[49] Cf. Bundeskartellamt, Competitive conditions in the electricity generation market 2022 (Market Power Report) (in German), published in August 2023, pp. 16 ff.

The market shares relating to the market for the first-time sale of electricity (volumes and capacities) are calculated using the group market share method under competition law. This means the report looks into whether companies are considered "group companies" pursuant to Section 36(2) GWB based on whether a particular company is dependent or dominant. Where this is the case, the generated volumes and generation capacities have to be added up.[50] Producers' drawing rights to third-party power plants were also considered.

Electricity: Electricity volumes generated by the five largest German electricity producers

Germany 2021			Germany 2022		
Company	**TWh**	**Share**	**Company**	**TWh**	**Share**
RWE	77.1	26.1%	RWE	70.8	26.4%
LEAG	46.4	15.7%	LEAG	48.0	17.9%
EnBW	33.8	11.4%	EnBW	31.1	11.6%
E.ON	27.5	9.2%	E.ON	10.0	3.7%
Vattenfall	13.3	4.5%	Uniper	10.1	3.8%
CR 5	198.0	**67.0%**	**CR 5**	170.0	**63.5%**
Other companies	97.5	33.0%	Other companies	97.7	36.5%
Total net electricity generation	295.5	100%	Total net electricity generation	267.7	100%

Table 4: 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 producers' own consumption and system services)

It can be seen that there is now a considerable difference between the generated volumes (and hence the corresponding market shares) of the first three producers and those of their next closest competitors. This could indicate that it would be more useful to look into the CR3 for future market share analyses, in any case when it comes to the generated volumes. Ultimately, this is a consideration for the next monitoring report, and it must be ensured that the corresponding values can be compared to those of previous years.

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[50] Please find a detailed description in the glossary.

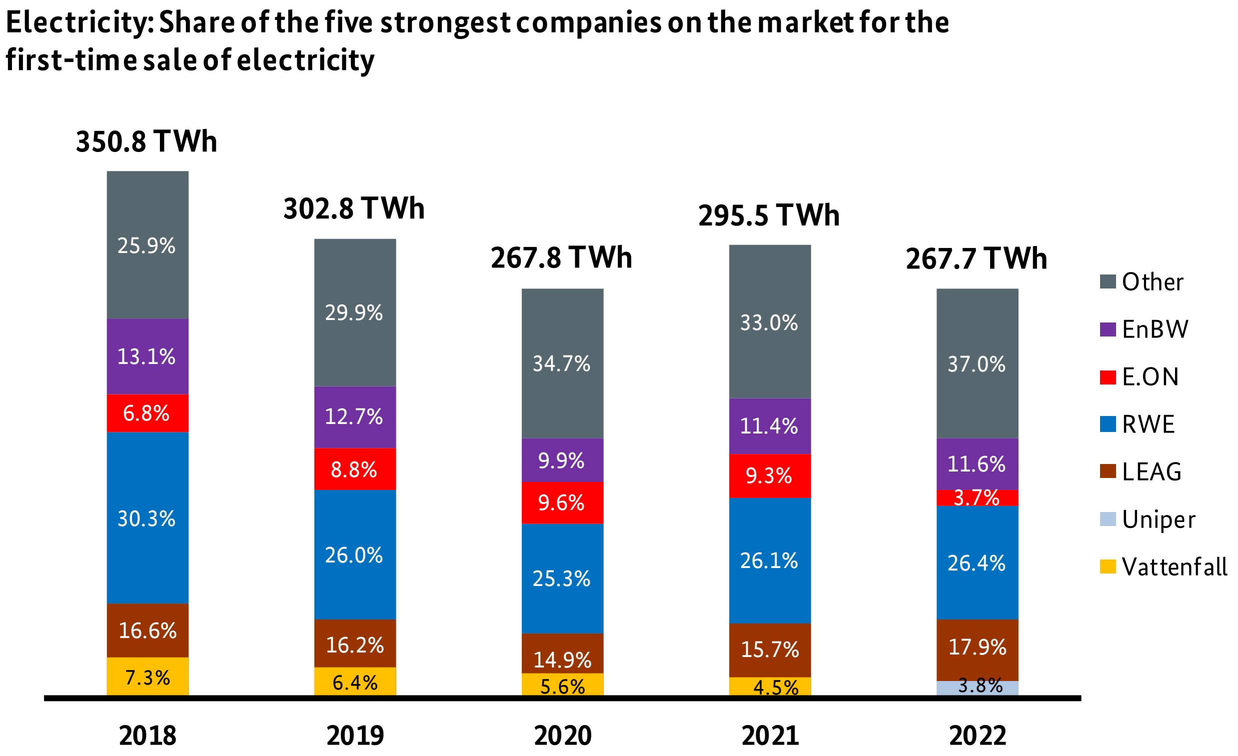

Figure 2: Shares of the five largest companies on the market for the first-time sale of electricity in the German market area

Electricity: Generation capacities of the five largest electricity producers

Germany 31 December 2021			Germany 31 December 2022		
Company	**GW**	**Share**	**Company**	**GW**	**Share**
RWE	18.2	21.0%	RWE	15.9	18.6%
EnBW	9.7	11.2%	EnBW	9.6	11.2%
LEAG	8.0	9.2%	LEAG	8.0	9.3%
Vattenfall	4.9	5.6%	Vattenfall	4.9	5.7%
Uniper	5.3	6.1%	Uniper	6.1	7.2%
CR 5	46.0	**55.6%**	**CR 5**	44.6	**52.1%**
Other companies	36.8	44.4%	Other companies	41.0	47.9%
Total capacity	82.8	100%	Total capacity	85.6	100%

Table 5: Generation capacities of the five largest electricity producers[51]

The total amount of electricity generation capacities of around 86.7 GW available as at the reference date 31 December 2022 increased by around 3.9 GW compared with 2021 – mainly because some generation capacities were recommissioned. In 2022 the following power plant reserve capacities returned to the market due to the war in Ukraine:

- Return of 2.9 GW of electricity supply reserve for a limited period:
  Under Section 50a(4) of the Energy Industry Act (*Energiewirtschaftsgesetz* — EnWG) in conjunction with the Electricity Supply Expansion Ordinance (*Stromangebotsausweitungsverordnung* — StaaV), plants may return to the market temporarily until 31 March 2024 under the condition that they do not generate electricity from natural gas. This, however, is only possible within the period for which

[51]The previous monitoring report of 2022 stated that the CR5 market share in terms of capacities was 53.0%. This value had to be corrected, because the power plants on security standby were wrongly included in the market for the first-time sale of electricity in 2021. The actual CR5 market share in 2021 was 55.6%.

the German Federal Ministry for Economic Affairs and Climate Action has activated the alert level and the emergency level of the German Emergency Plan for Gas.

- Return of 1.9 GW of electricity supply reserve for a limited period:
  As a precaution to prevent supply shortages in the gas market and thus also the electricity market, power plants were transferred to security standby pursuant to Section 50d EnWG within the meaning of Section 13g EnWG as of 1 October 2022 until 30 June 2023 at the latest. The Federal Ministry for Economic Affairs and Climate Action issued an ordinance governing the use of supply reserves stipulating that the power plants on supply reserve may market electricity for a limited period while the alert level or emergency level of the Emergency Plan for Gas is active. The limited period ran from 1 October 2022 to 30 June 2023. All operators running power plants on supply reserve made use of their right to market electricity for a limited period. On 4 October the Federal Ministry for Economic Affairs and Climate Action announced that it was amending the ordinance governing the use of supply reserves to reactivate the supply reserve as a hedging instrument for the coming winter. The new limited period in which electricity power plants on supply reserve can market electricity is now running from early October 2023 to 31 March 2024.[52]

- 2.1 GW time-limited return to the electricity market for plants of the third tendering round under the Act to Reduce and End Coal-Fired Power Generation (*Kohleverstromungsbeendigungsgesetz* – KVBG*):*
  Plants of the third tendering round under the KVBG, which would have been subject to the ban on coal-fired power generation as of 31 October 2022, were transferred to the grid reserve under Section 50a(4) EnWG as of 1 November 2022 until 31 March 2024.
  Under the StaaV, these plants can market electricity for a limited period until 31 March 2024. This, however, is only possible within the period for which the German Federal Ministry for Economic Affairs and Climate Action has activated the alert level and the emergency level of the German Emergency Plan for Gas. Almost all operators running power plants on supply reserve made use of their right to market electricity for a limited period. However, it must be taken into account that as of 31 December 2022 other capacities like the closed nuclear power plants have exited the market and that the plants returning to the market as a supply reserve currently have no option to continue their operation.

Reference to Market Power Report

A more detailed analysis of market power would in particular have to include a residual supply analysis, which is of essential importance in the Bundeskartellamt's practice for assessing market power in the electricity generation sector.[53] However, such an analysis would exceed the scope of the monitoring report. An extensive analysis up to and including the first quarter of 2023 is provided in the fourth report on competitive conditions in the electricity generation sector, which was published in August 2023. As part of this analysis,

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[52] Press release of the Federal Ministry for Economic Affairs and Climate Action: "Federal Cabinet approves temporary extension of the supply reserve as a hedging instrument for the coming winter" available at https://www.bmwk.de/Redaktion/EN/Pressemitteilungen/2023/10/20231004-federal-cabinet-approves-temporary-extension-of-the-supply-reserve-as-a-hedging-instrument-for-the-coming-winter.html

[53] Cf. Bundeskartellamt, Competitive conditions in the electricity generation market (Market Power Report) 2022, published (in German) on August 2023, pp. 7 ff.

the “Residual Supply Index” (RSI) is determined. It states the extent to which a company’s power plant fleet is residual, that is indispensable, for meeting the demand for electricity. The index takes account of the fact that at every given point in time the amount of electricity generated has to match the amount required and that storage facilities are available only to a very limited extent. The RSI is therefore an indicator of market power that is adjusted to the particular characteristics of electricity as a product.

The key finding of the RSI analysis carried out as part of the comprehensive analyses of the 2022 Market Power Report show that RWE consolidated its market power in the market for the first-time sale of electricity as part of the general market development in 2022 and the first quarter of 2023. The proportion of hours in which the demand for electricity could no longer be met without RWE clearly exceeded the threshold for the presumption of market dominance in the reporting period, which is 5% of the hours of one year. Moreover, the generation capacities of LEAG and EnBW were also already increasingly indispensable for meeting demand. Based on a conservative estimate of the potential foreign competition permanently available, the relevant proportions determined for the two companies were very close to the threshold for the presumption of market dominance. Moreover, the number of market situations in which electricity imports – thus unused capacities of foreign power plants – were the only factor that restricted the market-related scope of action of domestic electricity producers, had increased to 5.9 percent of the total number of hours of the year in 2022.

Electricity retail markets

In electricity retail markets, the Bundeskartellamt routinely differentiates between end customers whose consumption is metered based on interval metering (metered load profile customers, normally industrial or commercial customers) and standard load profile customers (customers whose consumption is normally significantly lower, for example household customers and small businesses). The Bundeskartellamt defines the market for the supply of electricity to metered load profile customers as a national market. For the supply of electricity to standard load profile customers the Bundeskartellamt currently differentiates between three product and geographic markets:[54]

(i) supply with heating electricity (network-based definition),

(ii) default supply (network-based definition),

(iii) supply on the basis of special contracts[55] (without heating electricity, defined as a national market, including volumes supplied by default suppliers based on special contracts).

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[54]Cf. Bundeskartellamt, decisions of 30 November 2009, B8-107/09, Integra/Thüga, paras 32 ff. and B8-134/21 RheinEnergie/Westenergie, paras 334 ff. (in German)

[55]Since the Energy Industry Act (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 defining the market under competition law. The term "special contract" is used in section 1(4) of the Electricity and Gas Concession Fees Ordinance (*Konzessionsabgabenverordnung* – 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 (heating electricity).

Electricity: Volumes of electricity provided by suppliers according to markets as defined by the Bundeskartellamt

	2022 in TWh	2021 in TWh
RLM	240.3	246.6
SLP	157.2	159.0
of which heating electricity	13.1	14.3
of which SLP default supply	31.5	30.7
of which SLP in special contracts*	112.5	114.0

*including volumes supplied by default suppliers based on special contracts

Table 6: Volumes of electricity provided by suppliers according to markets as defined by the Bundeskartellamt

In energy monitoring the sales volumes of individual suppliers (legal entities) are collected as national total values. Based on the data provided by the individual companies, it was determined which sales volumes were attributed to the four companies with the highest sales volumes in each market segment. The aggregate sales volumes were attributed with the help of the "dominance method". According to this method, the respective sales volumes have to be added if one company owns at least 50 percent of the shares of another company[56]. The dominance method provides meaningful results for the purposes of energy monitoring. With regard to the percentage shares provided, it should be borne in mind that the monitoring survey of the electricity suppliers covers a very large part of the market, but not the entire market and that some suppliers could not provide data on quantities so that only approximate market volumes were recorded. The percentages provided may therefore merely approximate the actual market shares.

[56] Please find a detailed description of the term dominance method in the glossary.

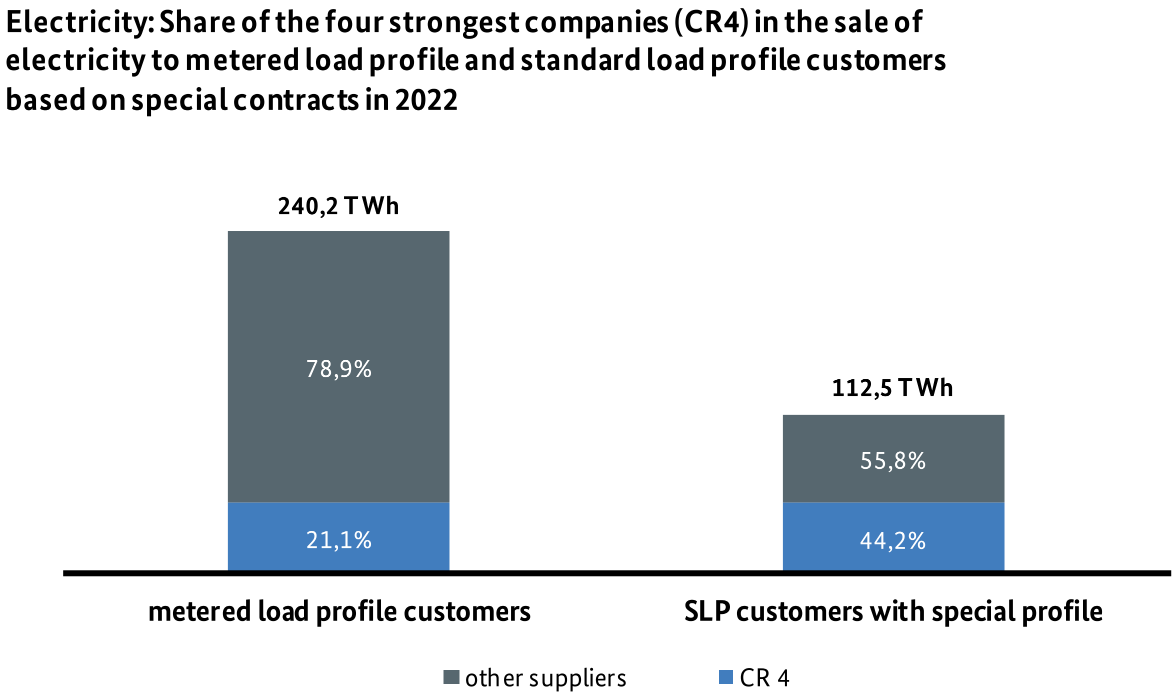

Figure 3: Share of the four strongest suppliers (CR4) to interval-metered customers and standard load profile customers based on special contracts in 2022

B Generation

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

Electricity generation

Electricity generation refers to the process of generating electrical energy. It can be broken down into non-renewable energy sources such as coal, natural gas and oil and renewable energy sources such as wind, sun and water.

Electricity generation capacity

The installed net rated capacity refers to the total capacity of all power generation plants that feed into Germany's general supply network. The installed net rated capacity is the maximum continuous capacity that a power generation plant reaches under rated conditions at the time of handover. It is important to note that actual capacity can vary due to internal and external factors. The installed net rated capacity is an important indicator for an electricity grid's capacity, which makes it possible to meet a certain region's demand for electrical energy.

Generating capacity outside of the electricity market

The total electricity generating capacity can be broken down into capacity that is currently participating in the electricity market and capacity that is outside of the electricity market. Power plants outside of the electricity market have generating capacity that does not participate in the regular electricity market. They may only feed into the general supply network upon request by the network operators and are subject to other rules. Within these two categories, the following subsets can be classified with regard to power plant status:

Generating capacity participating in the electricity market:

Power station capacity that normally participates in the electricity market.

- normal generating capacity in operation

- temporary return from the grid reserve to the electricity market

On the basis of section 50a(4) of the Energy Industry Act (EnWG) in conjunction with the Electricity Supply Expansion Ordinance (StaaV), grid reserve power plants (with the exception of natural gas plants) can resume participation in the electricity market on a temporary basis until 31 March 2024. However, this is only allowed when the alert or emergency levels of the Emergency Plan for Gas have been declared by the Federal Ministry for Economic Affairs and Climate Action (BMWK).

Plants from the third or fourth tendering rounds under the coal phase-out law (KVBG) that were banned from coal-fired operation as of 31 October 2022 or 22 May 2023 respectively were placed in the grid reserve until

31 March 2024 on the basis of the rules of section 50a(4) EnWG. The StaaV allows those power plants to participate in the electricity market until 31 March 2024.[57] Nearly all operators with a successful bid have exercised their right to a temporary return to the electricity market.

– Plant capacity in the supply reserve in accordance with section 50d EnWG.[58]

  The BMWK's Supply Reserve Access Ordinance allows the power stations in the supply reserve to participate temporarily in the electricity market.[59] Temporary participation is possible from 1 October 2022 to 30 June 2023 and from 11 October 2024 to 31 March 2025. All operators with power stations in the supply reserve have exercised their right to a temporary return to the electricity market.

Plant capacity outside of the electricity market:
Power plant capacity that does not normally participate in the electricity market.

– Power plants in the grid reserve that are important for the system under section 13b(4) and (5) EnWG

  A power plant is deemed important for the system when its permanent closure would, with sufficient probability, lead to a not inconsiderable threat to or disruption of the security or reliability of the electricity supply system and this threat or disruption cannot be removed by other appropriate measures. A power plant in the grid reserve that is important for the system is a station that must remain in operation for supply security reasons even though the operator wishes to shut it down (temporarily or permanently) or the coal-fired operation ban under the KVBG requires the operator to shut it down. The EnWG distinguishes between temporary and permanent closure. A power plant is defined as temporarily closed if the operator is able to put it back into operation again within 12 months. A power plant is defined as permanently shut down if restoring its operational readiness could not be done within 12 months.

– Capacity reserve in accordance with section 13e EnWG

  Power plants are kept in the capacity reserve to help maintain balance of the system in extraordinary and unforeseeable situations (see also IID). These are natural gas-fired power plants.

– Special grid facilities

  Special grid facilities are an instrument to quickly restore network stability in the event of actual failure of one or more facilities in the transmission system under section 11(3) EnWG in the version of 22 July 2017 (introduced by Article 1 of the Act of 17 July 2017 (Federal Law Gazette I page 2503)). Four lot groups were each awarded 300 MW by the transmission system operators (TSOs) Amprion (Biblis, RWE; Leipheim,

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[57] However, this is only allowed when the alert and emergency levels of the Emergency Plan for Gas have been declared by the Federal Ministry for Economic Affairs and Climate Action (BMWK).

[58] The costs for these power plants were between €200mn and €250mn in 2022. More detailed information is unobtainable as the operators of these facilities classify this information as operating and business secrets.

[59] See footnote 57.

LEAG), TenneT (Irsching 6, Uniper) and TransnetBW (Marbach 4, EnBW). There are no other calls for tender under the revised EnWG of 2021.

Expected growth and reduction of generating capacity

In addition to information on existing power plants, the Bundesnetzagentur also requests information in the monitoring survey on the future development of power plant capacity. The analysis of future generating capacity 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 rated capacity of 10 MW per location up to the year 2026. These projects are sufficiently likely to be implemented. The analysis of the expected closures takes into account coal power stations from the auctions where companies have been awarded a tender and from the capacity reduction path for lignite-fired power plants under the KVBG as well as power stations that are expected to be closed by 2026.[60] These will be:

- lignite power stations that are currently in the supply reserve
- closures after return from the grid reserve to the market
- closure in accordance with section 13b EnWG

Combined heat and power (CHP)

CHP plants, also known as cogeneration plants, are facilities that simultaneously generate electricity and heat. Their fuel efficiency advantage lies in the fact that they decouple useful heat from the waste heat that arises from electricity generation. This leads to a more effective use of energy and helps reduce greenhouse gas emissions.

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[60] Ending coal-fired electricity generation at a plant does not necessarily mean that all the plant's capacity will be removed from the market. It is possible for plant operators to convert their plants to other energy sources or they have already done so.

Net electricity generation in 2022

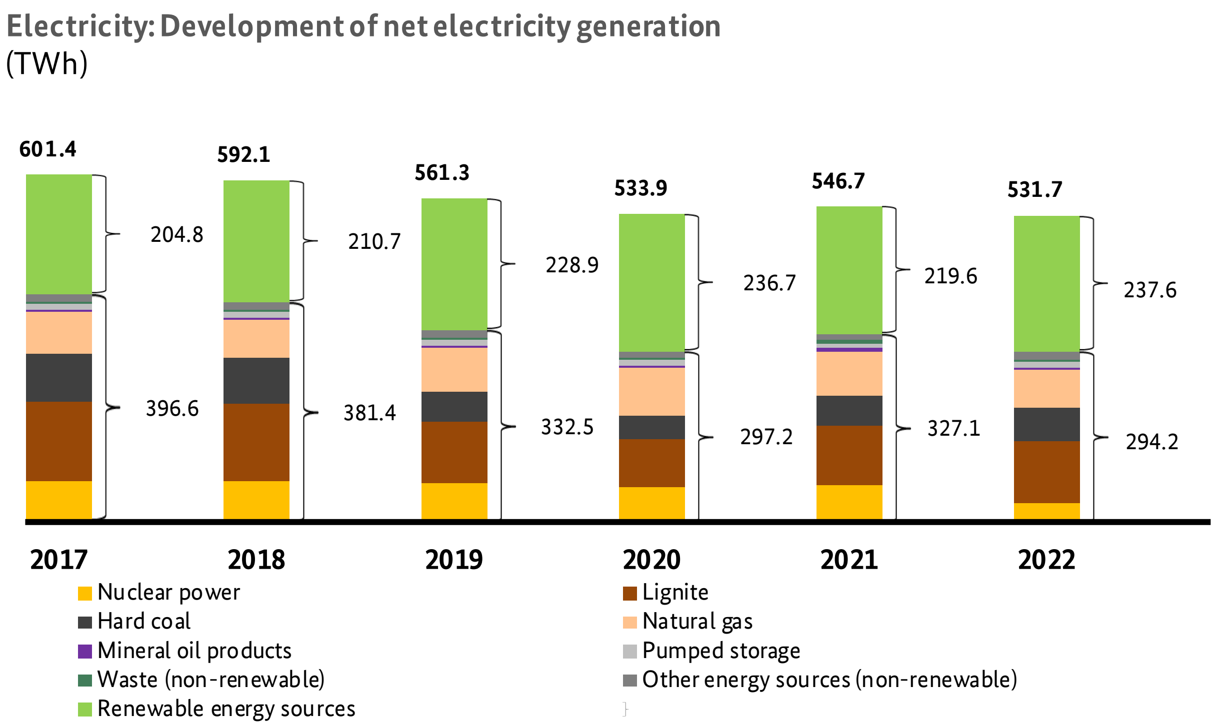


Figure 4: Net electricity generation

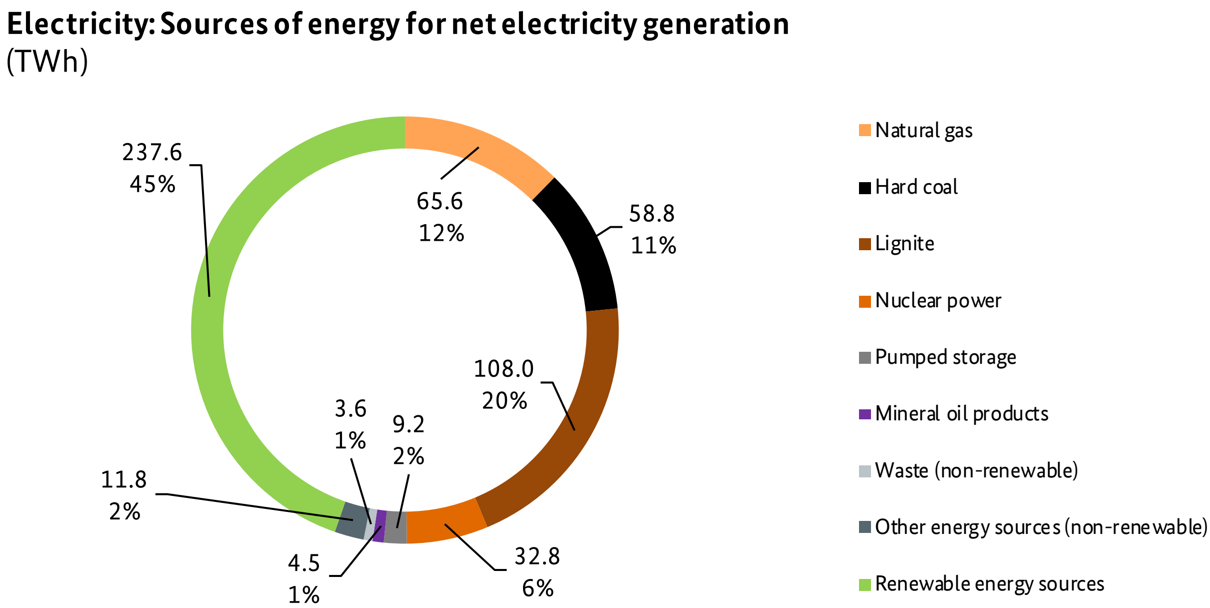


Figure 5: Share of energy sources in net electricity generation

Installed electricity generation capacity in Germany in 2022

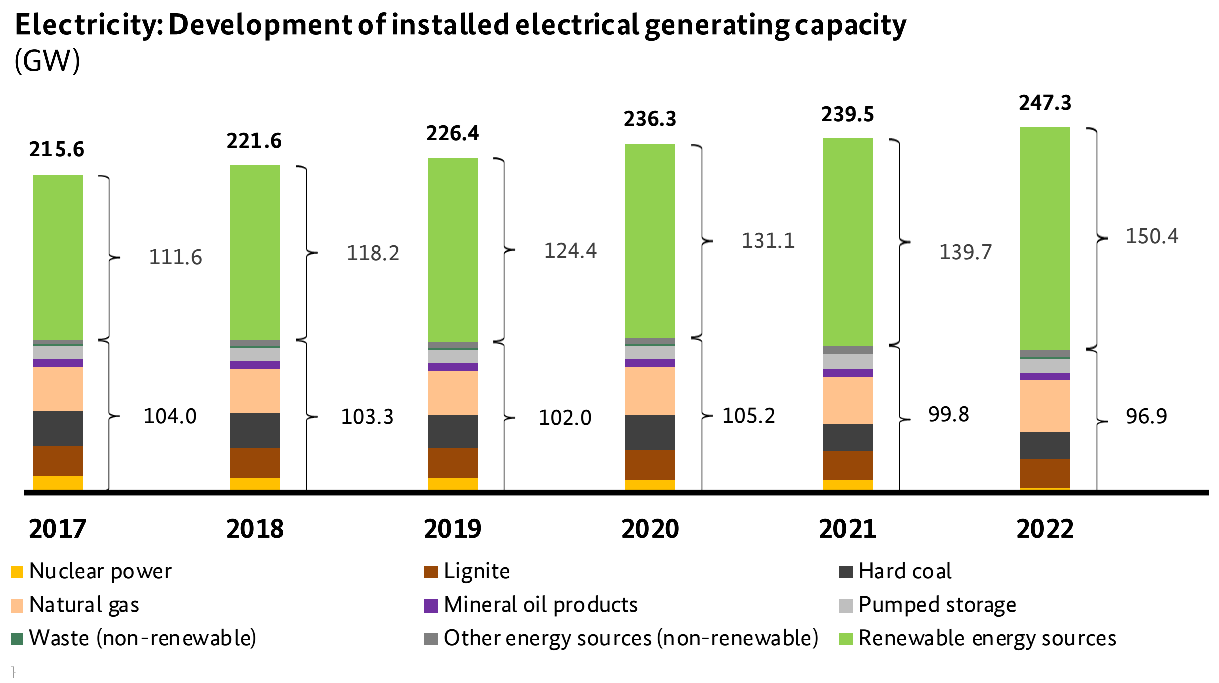


Figure 6: Installed electrical generation capacity

Current power plant capacity in Germany

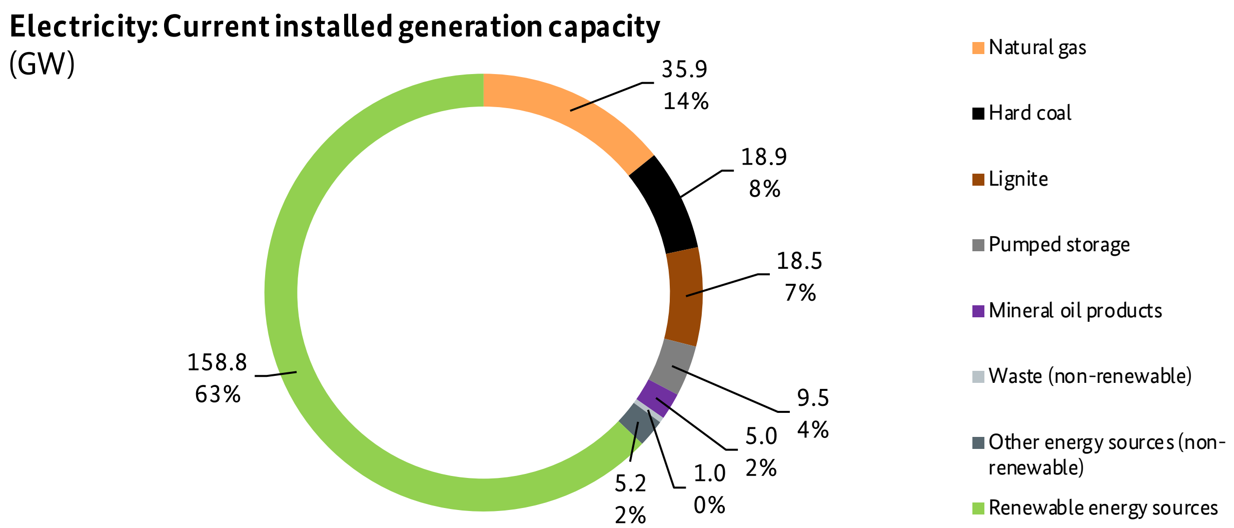


Figure 7: Current installed electrical generation capacity

Current power plant capacity by federal state

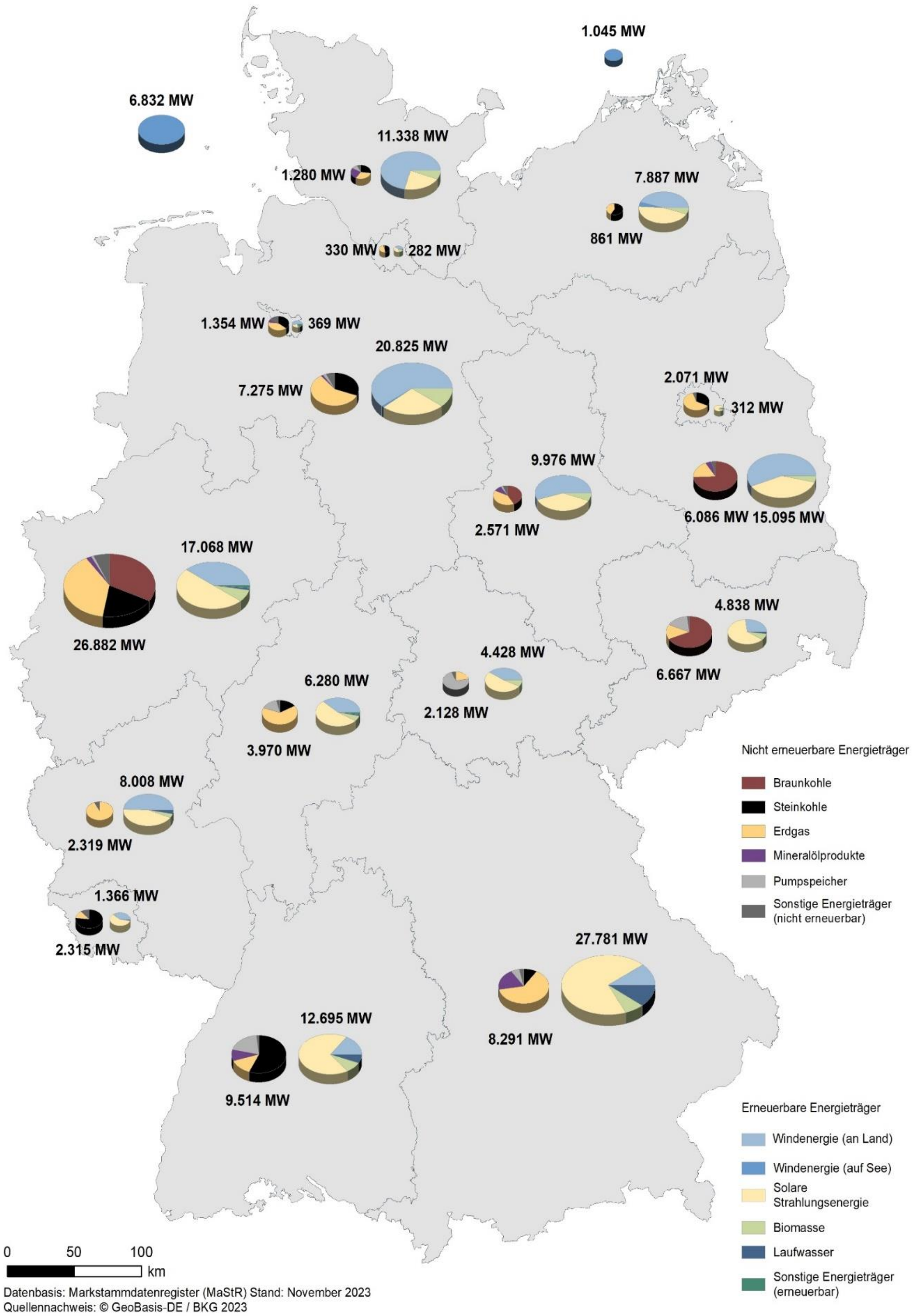


Figure 8: Current power plant capacity by federal state

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	Hard coal	Natural gas	Pumped storage	Mineral oil products	Other	Biomass	Hydropower	Offshore wind	Onshore wind	Solar	Other	Total
BW	0	5,478	1,239	1,898	719	180	1,009	692	0	1,800	9,150	44	**22,209**
BY	0	829	5,262	528	1,369	302	2,020	2,701	0	2,619	20,285	156	**36,071**
BE	0	653	1,297	0	34	87	44	0	0	17	233	18	**2,383**
BB	4,527	0	976	0	334	249	518	5	0	8,413	6,075	84	**21,181**
HB	0	469	565	0	86	234	19	10	0	201	84	56	**1,723**
HH	0	154	161	0	0	16	52	0	0	119	99	12	**612**
HE	34	699	2,418	625	25	170	309	94	0	2,434	3,331	112	**10,251**
MV	0	514	323	0	0	24	409	3	277	3,598	3,591	9	**8,748**
NI	19	2,166	4,219	200	119	552	1,951	71	224	12,274	6,245	60	**28,101**
NW	8,411	5,797	9,870	300	579	1,924	1,162	191	0	6,923	8,574	217	**43,950**
RP	0	0	2,109	0	11	199	257	236	0	3,956	3,516	43	**10,327**
SL	0	1,772	262	0	35	247	13	16	0	535	789	14	**3,681**
SN	4,403	0	1,044	1,085	17	118	327	92	0	1,317	3,094	8	**11,505**
ST	1,040	0	1,048	80	229	174	529	34	0	5,369	3,951	93	**12,546**
SH	0	342	431	119	280	107	638	5	0	7,994	2,674	28	**12,618**
TH	0	0	478	1,509	0	141	307	39	0	1,793	2,282	6	**6,556**
North Sea	0	0	0	0	0	0	0	0	6,832	0	0	0	**6,832**
Baltic Sea	0	0	0	0	0	0	0	0	1,045	0	0	0	**1,045**
Total	**18,433**	**18,873**	**31,702**	**6,344**	**3,837**	**4,724**	**9,563**	**4,189**	**8,377**	**59,362**	**73,972**	**960**	**240,338**

No detailed data is available for non-EEG installations with a capacity of less than 10 MW; the total capacity of these installations (7,931 MW) is therefore not included in the above table.

This table does not include generating capacity in Denmark, Luxembourg, Switzerland and Austria feeding into the German grid (4,503 MW).

* This table includes the following plant statuses: operational, seasonal mothballing, temporarily shut down, grid reserve, reserve capacity, grid and reserve capacity, security standby.

Table 7: Generating capacity by energy source and federal state

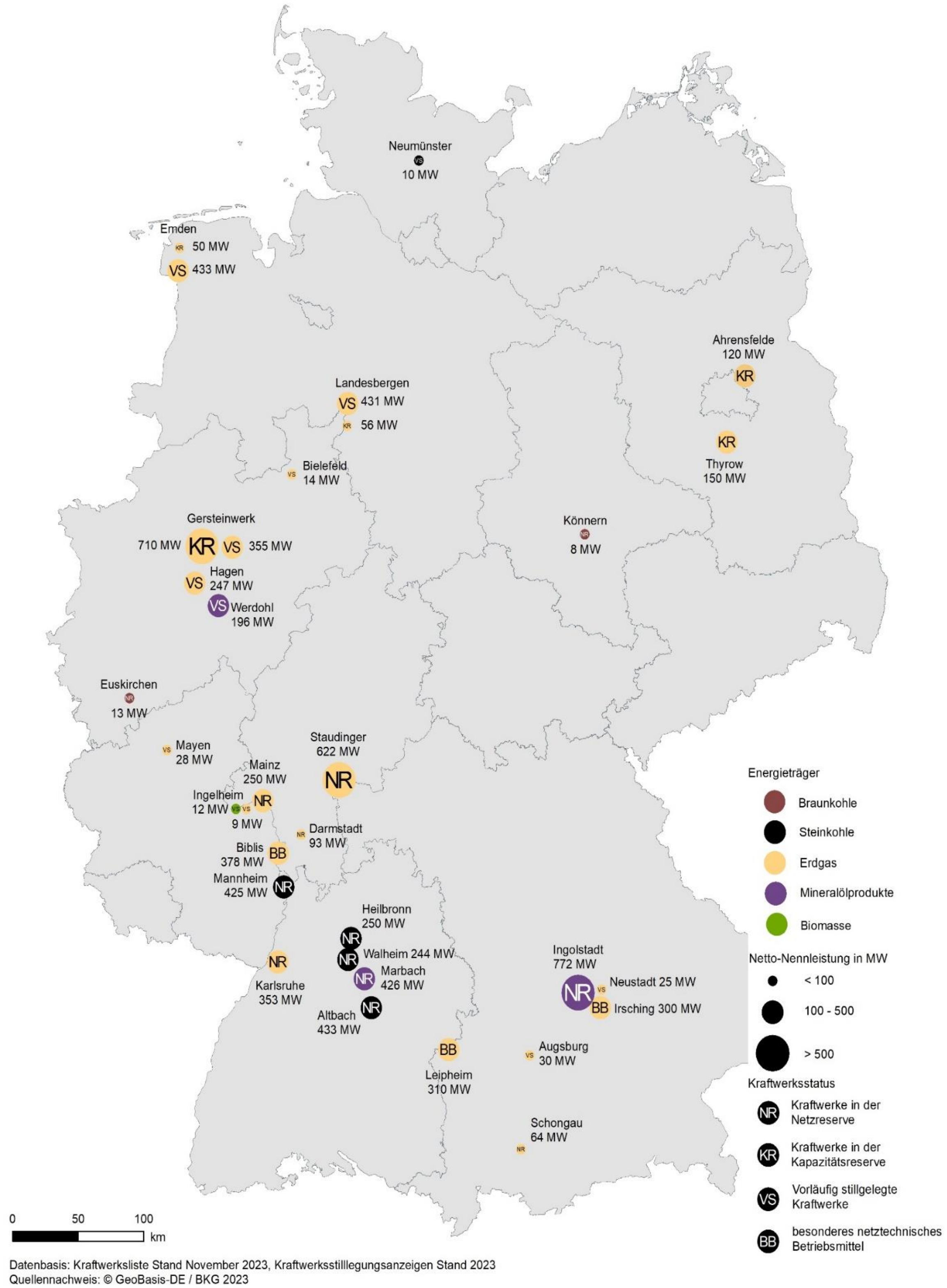


Figure 9: Power plants outside of the electricity market

Future development of non-renewable energy sources

Conventional power plant capacity expected to be added 2023 - 2026 (under construction/in trial operation)

	2023	2024	2025	2026	2023 - 2026
Natural gas	145	237	654	120	1,156
Mineral oil products	310				310
Pumped storage	16			130	146
Battery storage		220			220
Other energy sources (non-renewable)	55	112			167
Total	**526**	**569**	**654**	**250**	**1,999**

Table 8: Conventional power plant capacity expected to be added 2023 - 2026

Electricity: Power plant capacity expected to be withdrawn from the market 2023 - 2026

	2023	2024	2025	2026	2023 - 2026
Coal phase-out under KVBG*		**2,572**	**1,070**	**1,057**	**4,699**
of which legally stipulated capacity reduction path for lignite-fired power plants		1,211	321		1,532
of which auctions for hard coal-fired power plants and lignite-fired power plants(1)		1,361	749	1,057	3,167
of which from the fifth auction round		1,361(2)			1,361
of which from the sixth auction round			749(3)		749
of which from the seventh auction round				1,057(4)	1,057
Closures after completion of time in supply reserve in accordance with section 50d EnWG(5)		**1,886**			**1,886**
Closures after return from the grid reserve to the market(6)		**4,610**	**1,382**		**5,992**
Final closure notifications in accordance with section 13b EnWG(7)	**384**	**404**	**35**	**47**	**870**
Total	**384**	**9,472**	**2,487**	**1,104**	**13,447**

* It should be noted that the figures are subject to a degree of uncertainty. Among other things, ending coal-fired electricity generation at a plant does not necessarily mean that all the plant's capacity will be removed from the market since plant operators can convert (or in some cases have already converted) their plants to other energy sources.

[1] In particular for power plants in the third and fourth auction rounds with a coal ban as from 31 October 2022 or 22 May 2023 pursuant to section 52(2) KVBG , closure on or before 31 March 2024 is prohibited . These plants are automatically placed in the grid reserve once the coal ban takes effect (section 50a(4) sentences 1 and 2 EnWG).) When the alert or emergency level for gas is in effect, such plants may also return to the market for a limited time under the Electricity Supply Expansion Ordinance. Nearly all operators from the third and fourth auction rounds have made use of their right to a temporary return to the market.

[2] Awarded bid volume 1,015.6 MW and statutory reduction345 MW

[3] Awarded bid volume 472 MW and statutory reduction277 MW

[4] Awarded bid volume 279,631 MW and statutory

[5] The plants listed in section 13g(1) EnWG were placed in the supply reserve on 1 June 2023 in accordance with section 50d EnWG must be closed no later than 31 March 2024.

[6] Power plants in the grid reserve or plants from the third or fourth KVBG auction round that have resumed participation in the market for a limited time in accordance with section 50a EnWG.

[6] In so far as importance for the system has not (yet) been determined, and some operators have indicated that the construction of a replacement with another energy source is planned.

Table 9: Power plant capacity expected to be withdrawn from the market 2023 - 2026

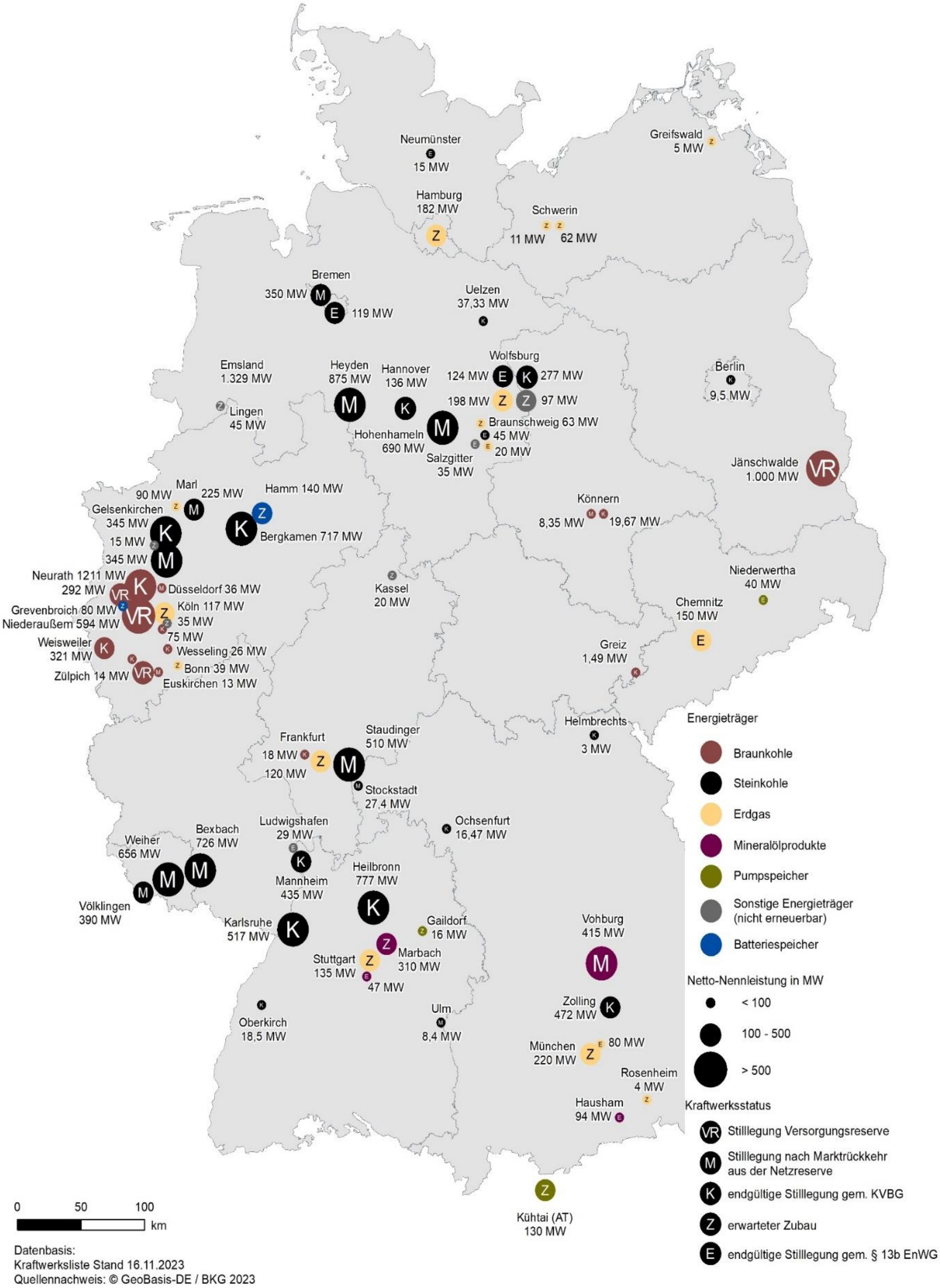


Figure 10: Power plant capacity expected to be added and withdrawn by 2026

Combined heat and power (CHP) generation

CHP plant capacity with a minimum capacity of 10 MW

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

	Electrical capacity		Net thermal capacity	
	2021	2022	2021	2022
Waste	1,211	1,211	4,084	4,084
Biomass	945	945	3,472	3,472
Lignite	1,565	1,565	4,418	4,418
Natural gas	14,755	16,388	24,486	26,559
Other	2,127	2,144	5,280	5,364
Hard coal	6,763	6,744	12,519	12,477
Total	27,366	28,997	54,259	56,374

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

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

	Electrical CHP generation volumes		Non-CHP electricity		Useful heat generation	
	2021	2022	2021	2022	2021	2021
Waste	1.6	1.8	2.4	2.2	10.1	11.3
Biomass	3.0	1.9	1.4	1.0	10.2	6.7
Lignite	3.1	3.1	79.2	86.1	12.6	12.0
Natural gas	45.9	37.3	10.6	11.2	68.4	53.8
Other	3.0	2.6	5.5	5.1	18.5	15.3
Hard coal	10.1	8.6	30.7	36.9	26.4	25.0
Total	66.7	55.3	129.8	142.5	146.2	124.1

Table 11: Electrical and thermal energy produced by CHP installations per energy source with a minimum capacity of 10 MW

2. Development of renewable energies

Development corridors

The Renewable Energy Sources Act (EEG) 2017 defined 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 2040. These development corridors were adjusted in the revised versions of the EEG 2023 and the Offshore Wind Energy Act 2023 (WindSeeG).

Forms of selling

Under the EEG 2012, installation operators were able for the first time to choose between 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 revenue) or another form of direct selling (sale of EEG electricity without claiming any other EEG payments). Subsequent amendments to the EEG all stipulate direct selling and the market premium as standard forms of selling. Only installations with a capacity of up to 100 kW can still opt for feed-in tariffs or payment of a landlord-to-tenant electricity premium. Another form of direct selling, ie selling without receiving payment under the EEG, also remains possible.

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.

Auctions

Operators of larger onshore wind, offshore wind, solar and biomass plants to be built only receive EEG payments if they have successfully participated in an auction.

Bids are accepted on the basis of the price specified in the bid ("pay as bid"). Exceptions are only made for existing biomass plants 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 must pay penalties if installations are not commissioned within the defined period. In addition to separate technology-specific auctions for onshore wind energy, offshore wind energy, solar and biomass, the technology-open innovation auction is carried out. The EEG 2021 abolished cross-technology auctions for onshore wind and solar. Auctions were introduced for rooftop solar systems (second-segment solar installations) and biomethane installations.

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

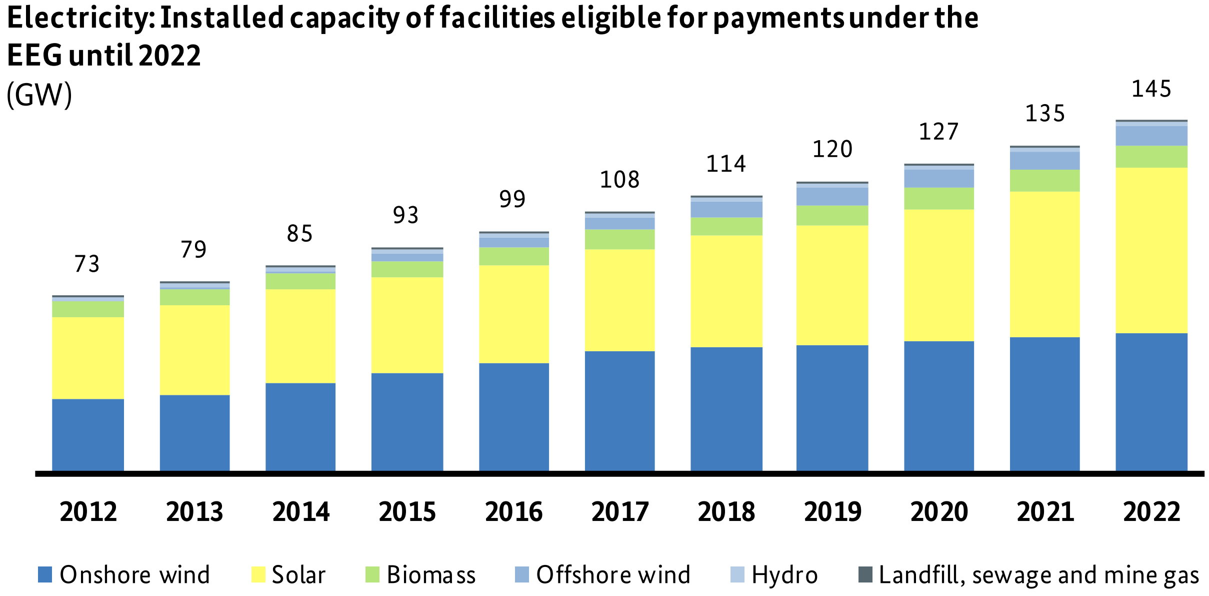


Figure 11: Installed capacity of facilities eligible for payments under the EEG up to 2022

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

	Total 31 December 2021	Total 31 December 2022	Increase/decrease in 2022	Increase/decrease compared to 2021
	in MW	in MW	in MW	(%)
Hydropower	1,639.1	1,763.9	124.9	7.6%
Gases[1]	376.1	366.8	-9.3	-2.5%
Biomass	8,854.7	8,909.2	54.5	0.6%
Geothermal	54.1	58.8	4.7	8.7%
Onshore wind	55,903.7	58,013.8	2,110.1	3.8%
Offshore wind	7,806.9	8,148.9	342.0	4.4%
Solar	60,037.8	67,479.0	7,441.2	12.4%
Total	134,672.3	144,740.5	10,068.2	7.5%

[1] Landfill, sewage and mine gas

Table 12: Installed capacity of facilities eligible for payments under the EEG by energy source

Electricity: Changes in the number of installed facilities eligible for payments under the EEG

	2017	2018	2019	2020	2021	2022	June 23
Hydropower	7,138	7,172	7,192	7,270	7,287	7,316	7,323
Gases[1]	600	593	567	587	592	607	614
Biomass	14,271	14,496	14,535	15,260	15,539	15,715	15,777
Geothermal	9	10	11	11	20	23	23
Onshore wind	27,406	28,131	28,310	28,763	28,998	29,298	29,456
Offshore wind	1,167	1,307	1,467	1,499	1,499	1,537	1,561
Solar	1,686,993	1,760,396	1,863,684	2,040,449	2,275,130	2,662,913	3,165,465
Total	1,737,584	1,812,105	1,915,766	2,093,839	2,329,065	2,717,409	3,220,219

[1] Landfill, sewage and mine gas

Table 13: Changes in the number of installed facilities eligible for payments under the EEG

Electricity: Rates of increase of installed facilities by energy source

	Total 31 December 2021	Total 31 December 2022	Increase/decrease in 2022	Increase/decrease compared to 2021
	Number	Number	Number	in %
Hydropower	7,287	7,316	29	0.4%
Gases[1]	592	607	15	2.5%
Biomass	15,539	15,715	176	1.1%
Geothermal	20	23	3	15.0%
Onshore wind	28,998	29,298	300	1.0%
Offshore wind	1499	1537	38	2.5%
Solar	2,275,130	2,662,913	387,783	17.0%
Total	2,329,065	2,717,409	388,344	16.7%

[1] Landfill, sewage and mine gas

Table 14: Rates of increase of installed facilities by energy source

Electricity: Overview of development corridors

<table>
<tr><th></th><th>Onshore wind</th><th>Offshore wind</th><th>Solar energy</th><th>Biomass</th></tr>
<tr><td>EEG 2017</td><td>2.8 GW gross expansion for 2017 to 2019;
2.9 GW gross expansion as from 2020</td><td>20 GW expansion in 2030</td><td>2.5 GW gross expansion per year</td><td>150 MW gross expansion for 2017 to 2019
200 MW gross expansion for 2020 to 2022</td></tr>
<tr><td>EEG 2021</td><td>57 GW in 2022
62 GW in 2024
65 GW in 2026
68 GW in 2028
71 GW in 2030</td><td>20 GW in 2030
40 GW in 2040</td><td>63 GW in 2022
73 GW in 2024
83 GW in 2026
95 GW in 2028
100 GW in 2030</td><td rowspan="2">8.4 GW in 2030</td></tr>
<tr><td>EEG 2023</td><td>69 GW in 2024
84 GW in 2026
99 GW in 2028
115 GW in 2030
157 GW in 2035
160 GW in 2040</td><td>30 GW in 2030
40 GW in 2035
70 GW in 2045</td><td>88 GW in 2024
128 GW in 2026
172 GW in 2028
215 GW in 2030
309 GW in 2035
400 GW in 2040</td></tr>
</table>

Table 15: Overview of development corridors

Elctricity: Expansion of onshore wind capacity
(MW)

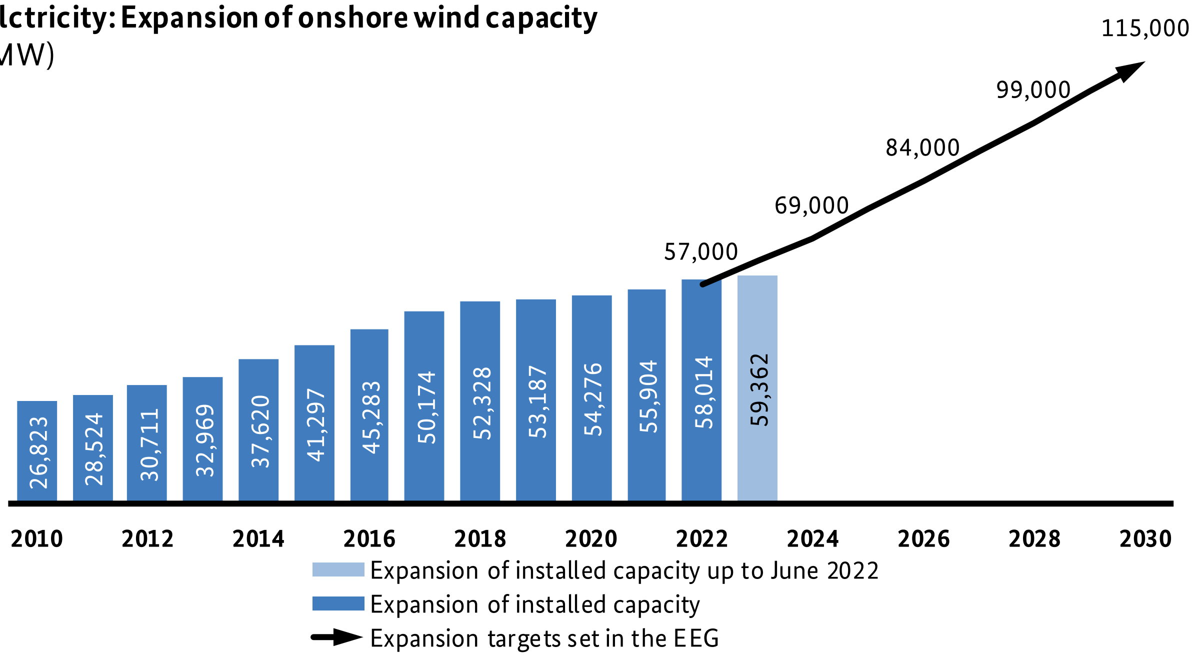


Figure 12: Expansion of onshore wind capacity

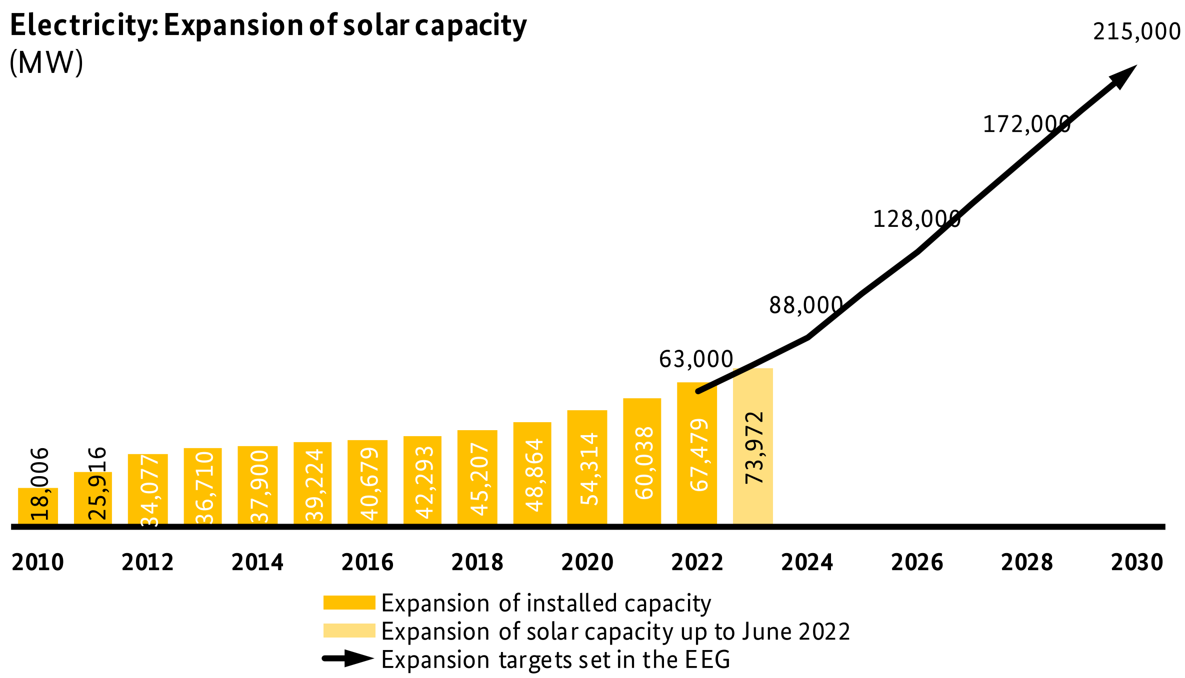


Figure 13: Expansion of solar capacity

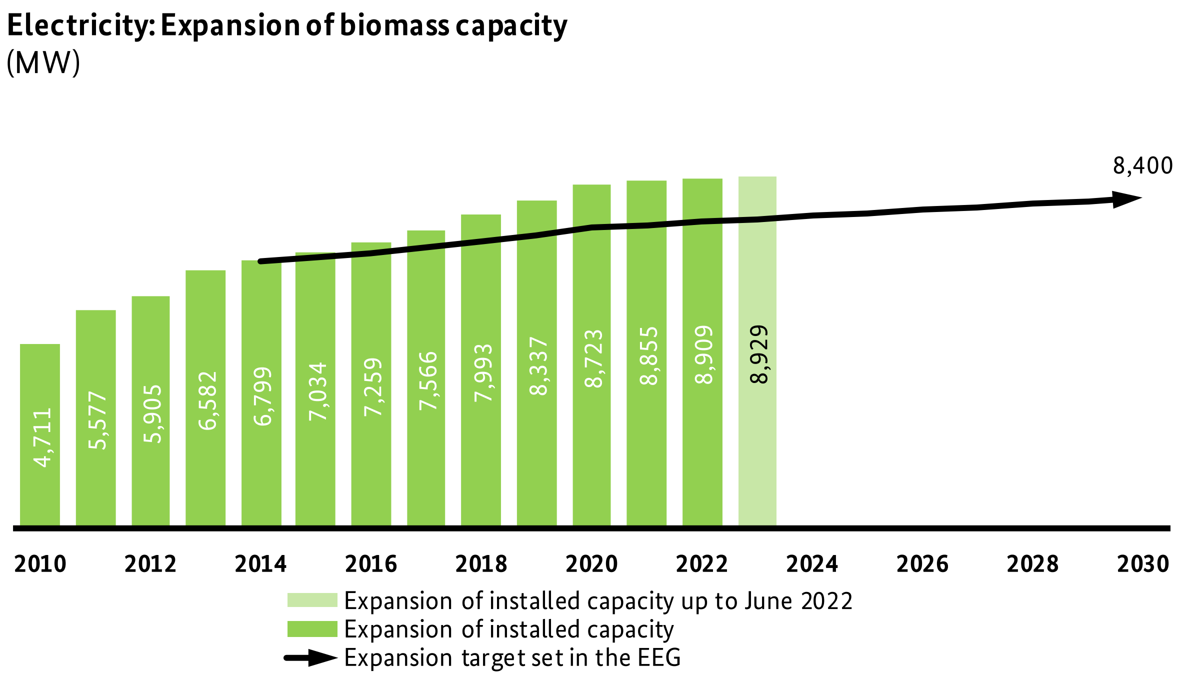


Figure 14: Expansion of biomass capacity

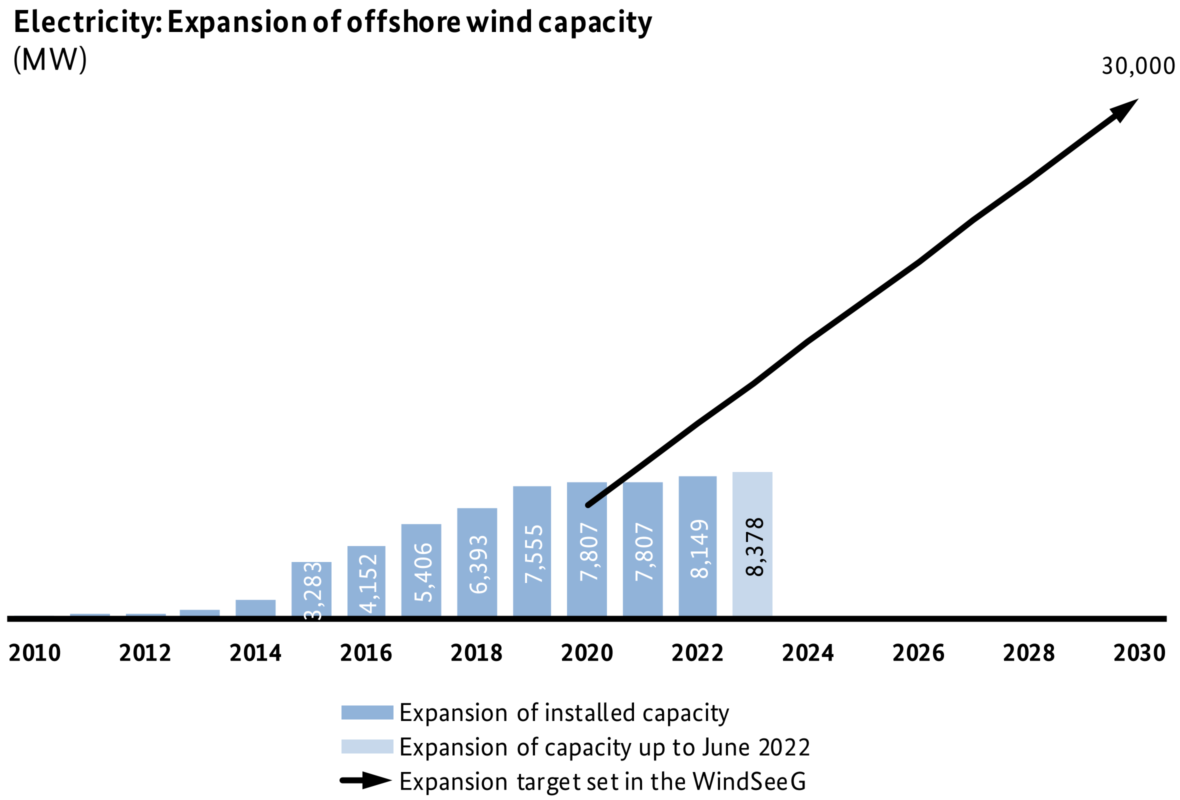


Figure 15: Expansion of offshore wind capacity

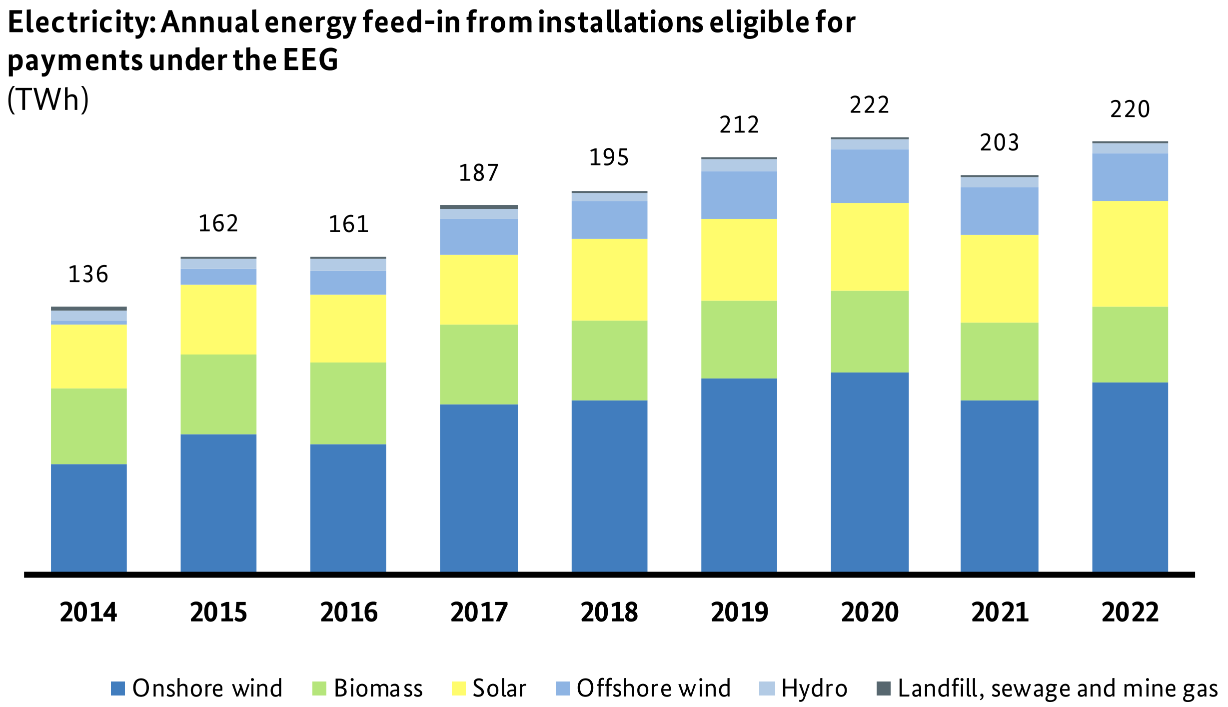


Figure 16: Changes in annual feed-in of electricity from facilities eligible for payments under the EEG

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

	Total 31 December 2021	Total 31 December 2022	Increase/decrease compared to 2021
	in GWh	in GWh	in %
Hydropower	5,592	4,825	-13.7%
Gases[1]	765	782	2.3%
Biomass	40,016	38,093	-4.8%
Geothermal	210	204	-2.8%
Onshore wind	88,502	98,035	10.8%
Offshore wind	24,015	24,754	3.1%
Solar	44,252	53,070	19.9%
Total	203,352	219,765	8.1%

[1] Landfill, sewage and mine gas

Source: Monitoring Report 2023, Bundesnetzagentur and Bundeskartellamt

Table 16: Annual feed-in of electricity from facilities eligible for payments under the EEG by energy source

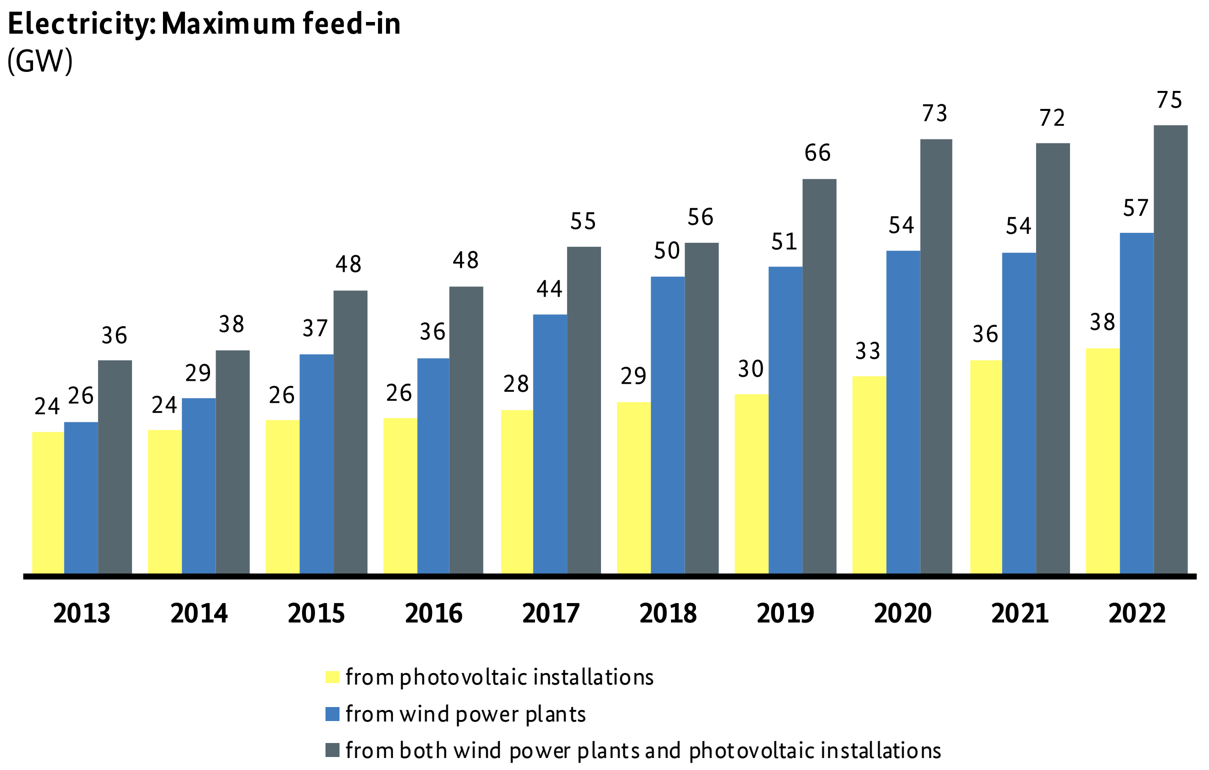


Figure 17: Maximum feed-in

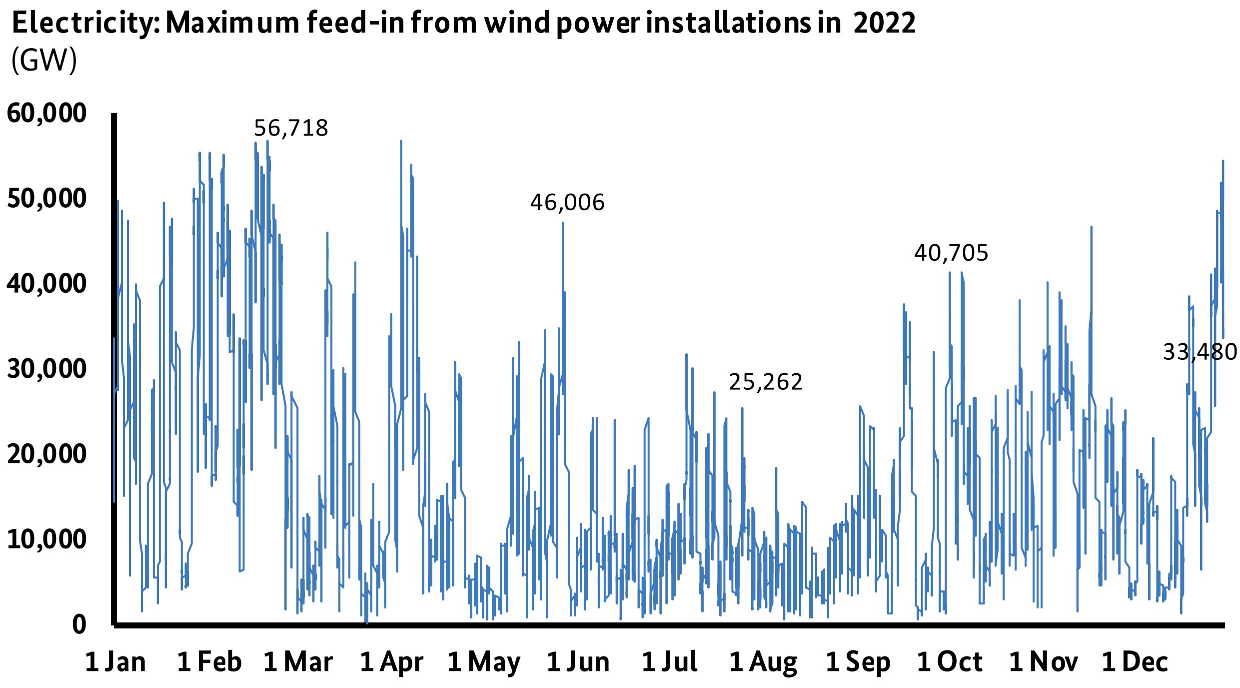


Figure 18: Maximum feed-in from wind power installations in 2022

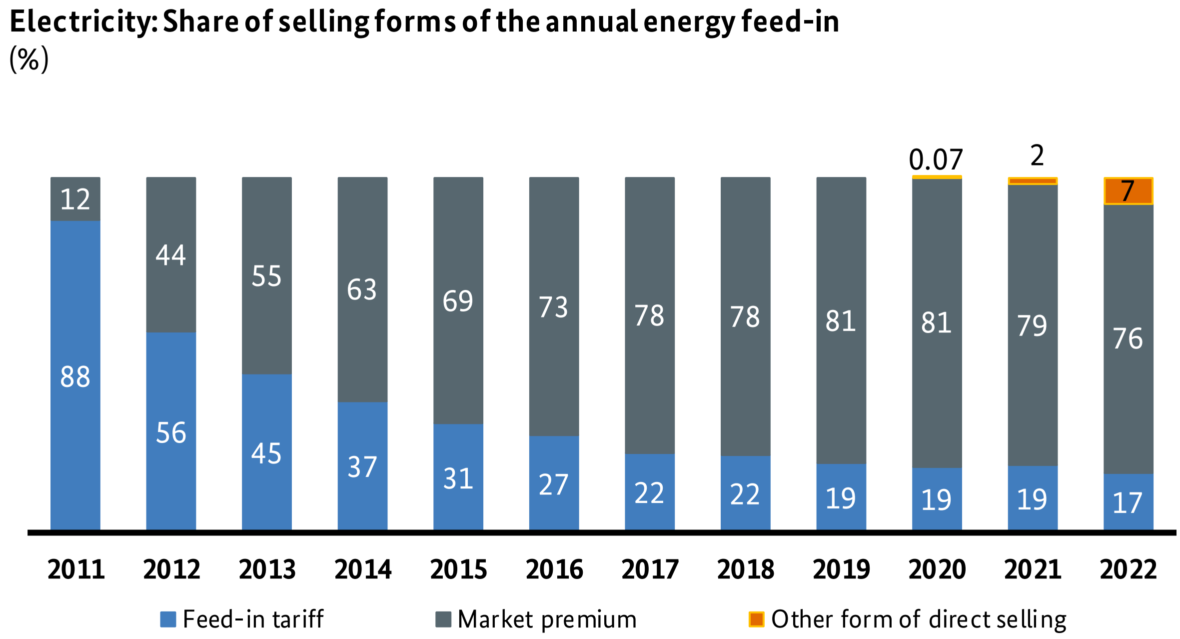


Figure 19: Percentage of selling forms of the annual energy feed-in

Electricity: Energy feed-in by form of selling and source of energy in 2022

	all in GWh	Feed-in tariff		Market premium	
		in GWh	% of total	in GWh	% of total
Hydropower	4,825	1,213	25%	2,741	57%
Gases[1]	782	58	7%	614	79%
Biomass	38,093	3,876	10%	32,740	86%
Geothermal	204	6	3%	198	97%
Onshore wind	98,035	1,009	1%	87,835	90%
Offshore wind	24,754	-	0%	22,886	92%
Solar	53,070	30,941	58%	19,517	37%
Total	**219,765**	**37,104**	**17%**	**166,531**	**76%**

[1] Landfill, sewage and mine gas

Table 17: Energy feed-in by form of selling and source of energy in 2022

Electricity: Payments by energy source

	Total 31 December 2021 (€mn)	Total 31 December 2022 (€mn)	Increase/decrease compared to 2021 (%)
Hydropower	302	131	-56.6%
Gases[1]	12	4	-65.3%
Biomass[2]	4,788	1,813	-62.1%
Geothermal	32	11	-64.9%
Onshore wind	2,334	81	-96.5%
Offshore wind	2,259	606	-73.2%
Solar	9,926	9,677	-2.5%
Total	19,652	12,323	-37.3%

[1] Landfill, sewage and mine gas

[2] Including support for flexibility

Table 18: Changes in payments under the EEG by energy source

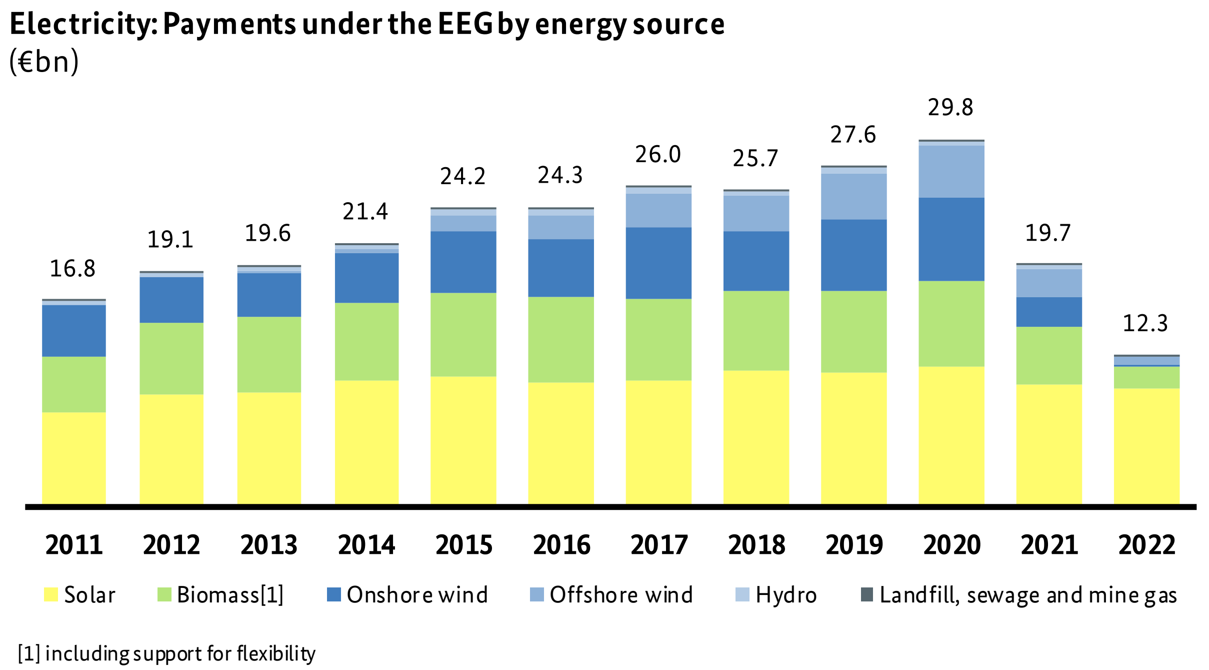


Figure 20: Changes in payments under the EEG by energy source

Electricity: Average payments under the EEG
(ct/kWh)

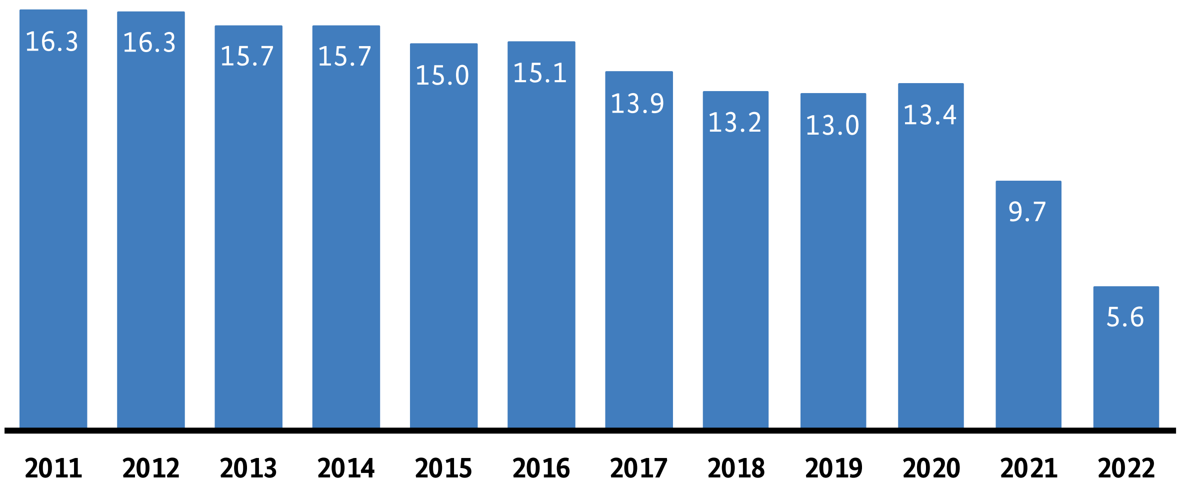


Figure 21: Changes in average payments under the EEG

Electricity: Average payments by energy source in 2022
(ct/kWh)

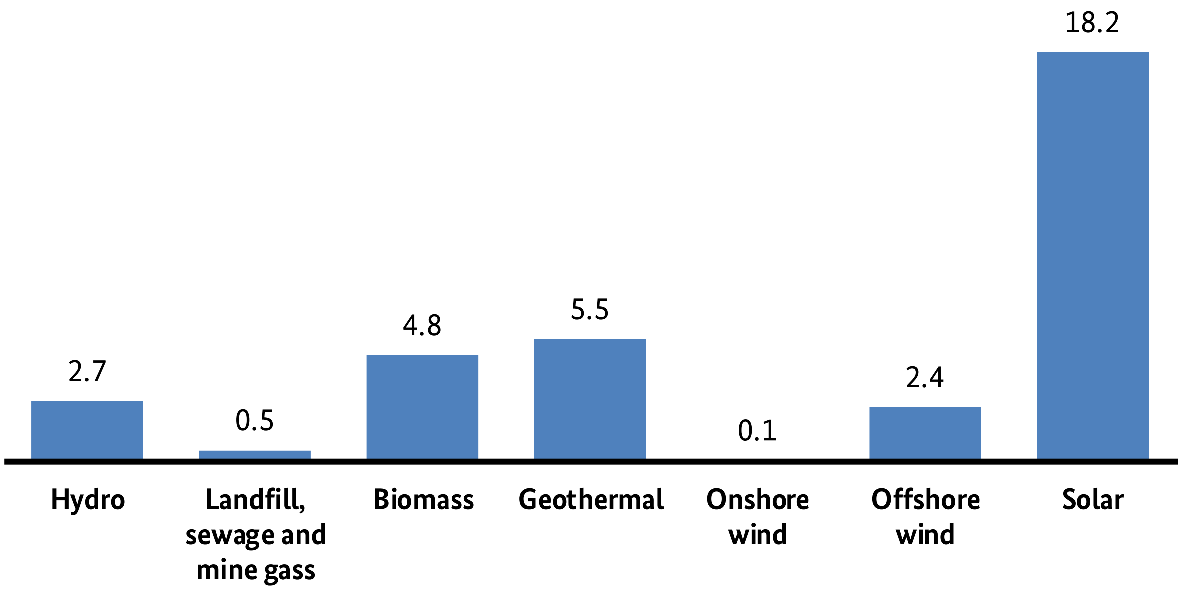


Figure 22: Average payments by energy source in 2022

Electricity: Technology-specific auctions held from 2021 to 2023 for solar and onshore wind

Technology	Bid deadline	Award price (ct/kWh)*
First-segment solar	1 March 2021	5.03
	1 June 2021	5.00
	1 November 2021	5.00
	1 March 2022	5.19
	1 June 2022	5.51
	1 March 2023	7.03
	1 July 2023	
Second-segment solar	1 June 2021	6.88
	1 December 2021	7.43
	1 April 2022	8.53
	1 August 2022	8.84
	1 February 2023	10.87
	1 June 2023	10.18
Onshore wind	1 February 2021	6.00
	1 May 2021	5.91
	1 September 2021	5.79
	1 February 2022	5.76
	1 May 2022	5.85
	1 September 2022	5.84
	1 February 2023	7.34
	1 May 2023	7.34
	1 August 2023	7.32

*Volume-weighted average award price (sliding market premium); for first-segment solar auctions the award price is applied prior to receipt of the second security deposit.

Table 19: Technology-specific auctions held from 2021 to 2023 for solar and onshore wind

Electricity: Other auctions held from 2021 to 2023 with sliding premium

Technology	Bid deadline	Award price (ct/kWh)*
Biomass	1 March 2021	17.02
	1 September 2021	17.48
	1 March 2022	15.75
	1 September 2022	17.28
	1 April 2023	18.92
Biomethane	1 December 2021	17.84
	1 October 2022	18.71
	1 April 2023	-*
	1 September 2023	-*

* Volume-weighted average award price. In these auctions, and for wind and solar, incentives are paid in the form of sliding market premiums based on exchange prices. No bids were placed in the auctions ending on 1 April 2023 and 1 September 2023.

Table 20: Other auctions held from 2021 to 2023 with sliding premium

Electricity: Other auctions held in 2022 in accordance with the CHP Auction Ordinance (KWKAusV)

Technology	Bid deadline	Award price (ct/kWh)*
CHP plants	1 June 2022	5.87
	1 December 2022	6.14
Innovative CHP systems	1 June 2022	11.74
	1 December 2022	11.22

* Volume-weighted average award price. These are "pay as bid" auctions.

Table 21: Other auctions held in 2022 in accordance with the CHP Auction Ordinance (KWKAusV)

Electricity: Other auctions held in accordance with the Innovation Auction Ordinance (InnAusV)

Technology	Bid deadline	Award price (ct/kWh)*
Innovation auction: combinations of different renewable energy sources	1 April 2021	4,29
	1 August 2021	4,55
	1 April 2022	5,42
	1 December 2022	7,39
	1 May 2023	8,84
	1 September 2023	8,33

* Volume-weighted average award price. These are "pay as bid" auctions.

Table 22: Other auctions held in accordance with the Innovation Auction Ordinance (InnAusV)

Electricity: First-segment solar auctions in 2022

	March	June	November
Volume put up for auction (MW)	1,108	1,126	890
Submitted bids	209	116	117
Submitted bid volume (MW)	1,116	714	677
Winning bids	201	109	104
Volume awarded (MW)	1,084	696	609
Excluded bids	8	6	13
Volume of excluded bids (MW)	32	17	68
Highest permissible bid (ct/kWh)	5.57	5.70	5.90
Average volume-weighted award price (ct/kWh)	5.19	5.51	5.80
Lowest bid awarded (ct/kWh)	4.05	4.87	5.20
Highest bid awarded (ct/kWh)	5.55	5.69	5.90

* The volume actually auctioned may change on the basis of legal provisions.

Table 23: First-segment solar auctions in 2022

Electricity: First-segment solar auctions in 2023

	March	July	December
Volume put up for auction (MW)	1,950	1,611	
Submitted bids	347	516	
Submitted bid volume (MW)	2,869	4,653	
Winning bids	245	124	
Volume awarded (MW)	1,952	1,673	
Excluded bids	25	21	
Volume of excluded bids (MW)	184	4,564	
Highest permissible bid (ct/kWh)	7.37	7.37	
Average volume-weighted award price (ct/kWh)	7.03	6.47	
Lowest bid awarded (ct/kWh)	5.29	5.39	
Highest bid awarded (ct/kWh)	7.30	6.65	

* The volume actually auctioned may change on the basis of legal provisions.

Table 24: First-segment solar auctions in 2023

Electricity: Implementation rates for solar installations from the first-segment solar auctions with expired implementation deadlines

Bid deadline	Implementation status in %	Deadline for commissioning (exclusion deadline)	Basis of auction
15 April 2015	99	6 May 2017	FFAV
1 August 2015	90	20 August 2017	FFAV
1 December 2015	92	18 December 2017	FFAV
1 April 2016	100	18 April 2018	FFAV
1 August 2016	96	12 August 2018	FFAV
1 December 2016	73	15 December 2018	FFAV
1 November 2016	99	5 December 2018	GEEV
1 February 2017	99	15 February 2019	EEG
1 June 2017	97	21 June 2019	EEG
1 October 2017	35	23 October 2019	EEG
1 February 2018	44	27 February 2020	EEG
1 June 2018	83	21 December 2020	EEG
1 October 2018	55	26 April 2021	EEG
1 February 2019	91	22 October 2021	EEG
1 March 2019	94	6 December 2021	EEG
1 June 2019	93	28 February 2022	EEG
1 October 2019	83	27 June 2022	EEG
1 December 2019	89	22 September 2022	EEG
1 February 2020	89	26 October 2022	EEG
1 March 2020	75	22 May 2023	EEG
1 June 2020	96	22 May 2023	EEG
1 July 2020	62	22 May 2023	EEG
1 September 2020	86	7 June 2023	EEG
1 October 2020	88	3 July 2023	EEG
1 December 2020	75	28 August 2023	EEG

Table 25: Implementation rates for solar installations from the first-segment solar auctions with expired implementation deadlines

Electricity: Onshore wind auctions in 2022

	February	May	September	December*
Volume put up for auction (MW)	1,328	1,320	1,320	603
Submitted bids	147	116	87	16
Submitted bid volume (MW)	1,356	947	773	203
Winning bids	141	114	87	14
Volume awarded (MW)	1,332	931	773	189
Excluded bids	6	2	0	2
Volume of excluded bids (MW)	24	16	0	14
Highest permissible bid (ct/kWh)	5.88	5.88	5.88	5.88
Average volume-weighted award price (ct/kWh)	5.76	5.85	5.84	6
Lowest bid awarded (ct/kWh)	4.77	5.44	5.76	6
Highest bid awarded (ct/kWh)	5.88	5.88	5.88	6

* The volume actually auctioned may change on the basis of legal provisions.

Table 26: Onshore wind auctions in 2022

Electricity: Onshore wind auctions in 2023

	February	May	August	November
Volume put up for auction (MW)	3,210	2,866	1,667	2,087
Submitted bids	126	127	142	
Submitted bid volume (MW)	1,502	1,597	1,436	
Winning bids	119	120	141	
Volume awarded (MW)	1,441	1,535	1,433	
Excluded bids	7	7	1	
Volume of excluded bids (MW)	60	62	3	
Highest permissible bid (ct/kWh)	7.35	7.35	7.35	
Average volume-weighted award price (ct/kWh)	7.34	7.34	7.32	
Lowest bid awarded (ct/kWh)	7.24	7.25	6.00	
Highest bid awarded (ct/kWh)	7.35	7.35	7.35	

Table 27: Onshore wind auctions in 2023

Electricity: Implementation rates for wind installations from the wind auctions with expired implementation deadlines

Bid deadline	Implementation status in %	Deadline for commissioning (exclusion deadline)
1 May 2017	32	26 May 2022
1 August 2017	6	22 August 2022
1 November 2017	1	29 November 2022
1 February 2018	62	1 March 2021
1 May 2018	82	25 May 2021
1 August 2018	93	24 August 2021
1 October 2018	81	26 October 2021
1 February 2019	91	23 August 2021
1 May 2019	86	22 November 2021
1 August 2019	97	16 February 2022
1 September 2019	95	19 September 2022
1 October 2019	92	25 October 2022
1 December 2019	89	27 December 2022
1 February 2020	90	27 February 2023
1 March 2020	71	22 March 2023
1 June 2020	57	22 March 2023
1 July 2020	69	22 March 2023
1 September 2020	46	11 April 2023
1 October 2020	77	2 May 2023
1 December 2020	71	28 June 2023
1 February 2021	80	7 November 2023

Table 28: Implementation rates for wind installations from the wind auctions with expired implementation deadlines

Electricity: Distribution of bids and awards for onshore wind per federal state 2021 - 2023*

	Number of bids			Capacity bid in kW			Number of winning bids			Capacity awarded in kW		
Federal state	**2021**	**2022**	**2023**	**2021**	**2022**	**2023**	**2021**	**2022**	**2023**	**2021**	**2022**	**2023**
Baden-Württ.	5	8	13	58,200	53,960	134,640	4	6	11	54,000	53,960	205,720
Bavaria	8	3	4	68,000	20,800	48,480	6	3	3	51,400	20,800	58,300
Brandenburg	63	49	24	531,060	380,500	229,460	50	38	24	459,110	380,500	283,160
Bremen	1	0		3,600	0		1	0		3,600	0	0
Hesse	16	17	2	206,480	223,340	24,100	15	13	2	171,980	223,340	68,900
MeckL-WP	13	18	7	157,200	101,900	55,180	13	12	6	157,200	101,900	105,800
Lower Saxony	52	89	32	593,800	747,290	636,650	49	74	31	574,400	747,290	973,480
N. Rhine-W.	109	90	84	707,740	620,805	895,110	90	69	80	553,290	604,841	1,316,100
Rhineland-P.	21	8	17	157,800	70,800	238,790	20	8	16	152,200	70,800	304,930
Saarland	2	4	1	17,850	34,360	4,200	1	5	1	3,450	34,360	21,000
Saxony	10	12	6	48,400	51,400	57,080	5	10	6	23,300	51,400	58,440
Saxony-Anhalt	12	28	12	136,100	143,850	286,840	11	25	12	123,500	143,850	298,440
Schl.-Holstein	107	124	40	895,300	687,250	431,320	100	84	38	869,850	667,250	664,860
Thuringia	19	15	9	122,500	64,400	56,300	17	9	9	98,500	64,400	56,300
Total	**438**	**465**	**251**	**3,704,030**	**3,200,655**	**3,098,150**	**382**	**356**	**239**	**3,295,780**	**3,164,691**	**4,415,430**

*Auction rounds in February, May and August 2023

Table 29: Distribution of bids and awards for onshore wind per federal state 2021 - 2023

Electricity: Offshore wind auctions; auction ending 1 September 2021 and 2022

	2021			2022
Site	**N-3.7**	**N-3.8**	**O-1.3**	**N-7.2**
Volume put up for auction (MW)	225	433	300	980
Volume awarded (MW)	225	433	300	225
Highest permissible bid (ct/kWh)	7.30	7.30	7.30	6.40
Award price (ct/kWh)	0.00	0.00	0.00	0.00
Lots drawn	No	Yes	Yes	No
Right of subrogation	No	Yes	Yes	Yes
Offshore transmission link	NOR-3-3	NOR-3-3	OST-1-4	NOR-7-2

Table 30: Biomass auctions in 2022

Electricity: Implementation rates for biomass plants from the biomass auctions with expired implementation deadlines

Bid deadline	Implementation status in %	Deadline for commissioning (exclusion deadline)
1 September 2017	90	25 September 2019
1 September 2018	93	27 September 2021
1 April 2019	93	25 April 2022
1 November 2019	89	2 January 2024

Table 31: Implementation rates for biomass plants from the biomass auctions with expired implementation deadlines

Electricity: Auctions for innovative installation concepts in 2022

	April	December
Volume put up for auction (MW)	397	397
Submitted bids	45	1
Submitted bid volume (MW)	435	No information*
Winning bids	43	1
Volume awarded (MW)	403	No information*
Excluded bids	0	0
Volume of excluded bids (MW)	0	0
Highest permissible bid fixed market premium (ct/kWh)	7.43	No information*
Average volume-weighted award price (ct/kWh)	5.42	No information*
Lowest bid awarded (ct/kWh)	3.95	No information*
Highest bid awarded (ct/kWh)	7.43	No information*

*Exact figures are not provided because they may allow inferences to made about the bidder.

Table 32: Auctions for innovative installation concepts in 2022

Electricity: Auctions for innovative installation concepts in 2023

	May	September
Volume put up for auction (MW)	400	400
Submitted bids	3	53
Submitted bid volume (MW)	84	779
Winning bids	3	32
Volume awarded (MW)	84	408
Excluded bids	0	21
Volume of excluded bids (MW)	0	371
Highest permissible bid fixed market premium (ct/kWh)	9.18	9.18
Average volume-weighted award price (ct/kWh)	8.84	8.33
Lowest bid awarded (ct/kWh)	8.74	7.76
Highest bid awarded (ct/kWh)	9.15	8.78

Table 33: Auctions for innovative installation concepts in 2023

Electricity: Second-segment solar auctions in 2022

	April	August	December
Volume put up for auction (MW)	767	767	202
Submitted bids	171	115	67
Submitted bid volume (MW)	212	214	128
Winning bids	163	106	56
Volume awarded (MW)	204	202	105
Excluded bids	8	7	11
Volume of excluded bids (MW)	8	12	23
Highest permissible bid (ct/kWh)	8.91	8.91	8.91
Average volume-weighted award price (ct/kWh)	8.53	8.84	9
Lowest bid awarded (ct/kWh)	7.00	8.20	8
Highest bid awarded (ct/kWh)	8.91	8.91	8.20

* The volume actually auctioned may change on the basis of legal provisions.

Table 34: Second-segment solar auctions in 2022

Electricity: Second-segment solar auctions in 2023

	February	June	October
Volume put up for auction (MW)	217	190	
Submitted bids	94	155	
Submitted bid volume (MW)	213	342	
Winning bids	87	79	
Volume awarded (MW)	195	193	
Excluded bids	7	76	
Volume of excluded bids (MW)	18	147	
Highest permissible bid (ct/kWh)	11.25	11.25	
Average volume-weighted award price (ct/kWh)	10.87	10.18	
Lowest bid awarded (ct/kWh)	9.00	8.80	
Highest bid awarded (ct/kWh)	11.25	10.80	

Table 35: Second-segment solar auctions in 2023

Electricity: Implementation rates for solar installations from the second-segment solar auctions with expired implementation deadlines

Bid deadline	Implementation status in %	Deadline for commissioning (exclusion deadline)
1 June 2021	73	22 July 2022
1 December 2021	65	23 January 2023

Table 36: Implementation rates for solar installations from the second-segment solar auctions with expired implementation deadlines

Electricity: Biomethane installation auctions 2021-2023

	December 2021	October 2022	April 2023	September 2023
Volume put up for auction (MW)	150	150	19	8
Submitted bids	21	2	0	0
Submitted bid volume (MW)	148	3.5	0	0
Winning bids	21	2	0	0
Volume awarded (MW)	148	3.5	0	0
Excluded bids	0	0	0	0
Volume of excluded bids (MW)	0	0	0	0
Highest permissible bid (ct/kWh)	19.00	18.81	19.31	19.31
Average volume-weighted award price (ct/kWh)	17.84	No info	-	-
Lowest bid awarded (ct/kWh)	16.88	No info	-	-
Highest bid awarded (ct/kWh)	18.98	No info	-	-

*Exact figures are not provided because they may allow inferences to made about the bidder.

Table 37: Biomethane installation auctions 2021-2023

Electricity: Implementation rates for joint solar and onshore wind installation auctions with expired implementation deadlines

Bid deadline	Implementation status in %	Deadline for commissioning (exclusion deadline)
1 April 2018	79	20 April 2020
1 November 2018	73	26 May 2021
1 April 2019	77	27 December 2021
1 November 2019	92	2 August 2022
1 April 2020	94	22 May 2023
1 November 2020	86	1 August 2023

Table 38: Implementation rates for joint solar and onshore wind installation auctions with expired implementation deadlines

C Networks

Electricity networks are complex systems of interconnected electrical cables, switchgear, transformers and other components that are used for the transmission (transmission network) and distribution (distribution network) of electrical energy from the sources of generation to the consumers.

The points connected to an electricity network at which electricity is fed into or taken from the network correspond to market locations (formerly meter points) within the meaning of the Electricity Network Access Ordinance (StromNZV). Energy is generated or consumed in a market location. Each market location is connected to a network with a least one cable and represents a connection point for supply and reference point for balancing.

Electricity networks can be divided into different levels, depending on how the electrical energy is transported and distributed. These levels are extra-high voltage, high voltage, medium voltage and low voltage. While the extra-high voltage network transports electrical energy over long distances at very high voltages (>380 kilovolts (kV)), the low voltage network delivers the electrical energy to final customers. The voltage is reduced to about 230 or 400 volts (V) to supply the final customers with electricity.

Transmission system operators (TSOs) and distribution system operators (DSOs) are each responsible for operating, maintaining and monitoring the transmission and distribution networks.

1. Network structure figures

Electricity: Number of network operators in Germany registered with the Bundesnetzagentur

	2018	2019	2020	2021	2022	2023
TSOs with responsibility for control areas	4	4	4	4	4	4
Total DSOs	890	883	879	873	865	866
DSOs with fewer than 100,000 connected customers	809	803	799	791	782	783
DSOs with fewer than 30,000 connected customers	614	645	678	674	664	667

Table 39: Number of network operators in Germany registered with the Bundesnetzagentur

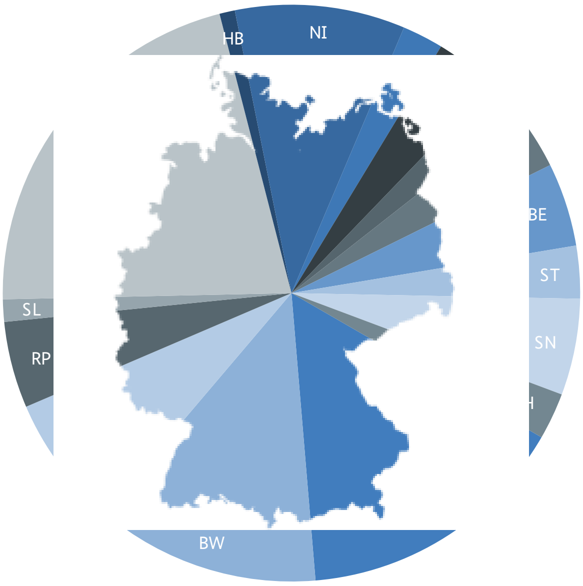
Electricity: Network structure figures 2022

	TSOs*	DSOs	Total
Network operators (number)	8*	865	865
Total circuit length (thousand km)	36.3	2,195.6	2,231.9
Extra-high voltage	36.2	0.2	36.4
High voltage	0.1	95.1	95.2
Medium voltage		530.2	530.2
Low voltage		1,570.1	1,570.1
Total final customer market locations (thousand)	0.2	52,158.4	52,158.6
Industrial, commercial and other non-household customers	0.2	3,096.7	3,096.9
Household customers		49,061.7	49,061.7
Annual peak load (GW)			78.8

* Figures include offshore holding companies and Baltic Cable AB.

Table 40: Network structure figures 2022

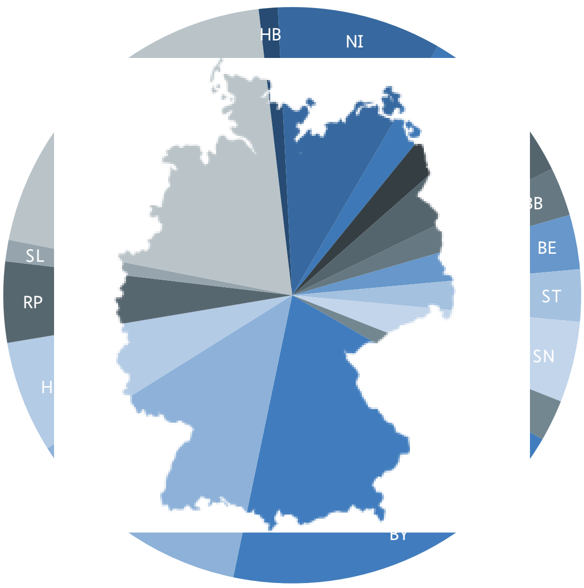
Electricity: Market locations by federal state at DSO level in 2022
(mn)



Bavaria	7.99	7.99
Baden-Württemberg	6.53	6.53
Hesse	3.83	3.83
Rhineland-Palatinate	2.53	2.53
Saarland	0.65	0.65
North Rhine-Westphalia	11.11	11.11
Bremen	0.45	0.45
Lower Saxony	4.96	4.96
Hamburg	1.20	1.20
Schleswig-Holstein	1.83	1.83
Mecklenburg-Western Pomerai	1.15	1.15
Brandenburg	1.71	1.71
Berlin	2.44	2.44
Saxony-Anhalt	1.54	1.54
Saxony	2.81	2.81
Thuringia	1.36	1.36

Figure 23: Market locations by federal state at DSO level in 2022

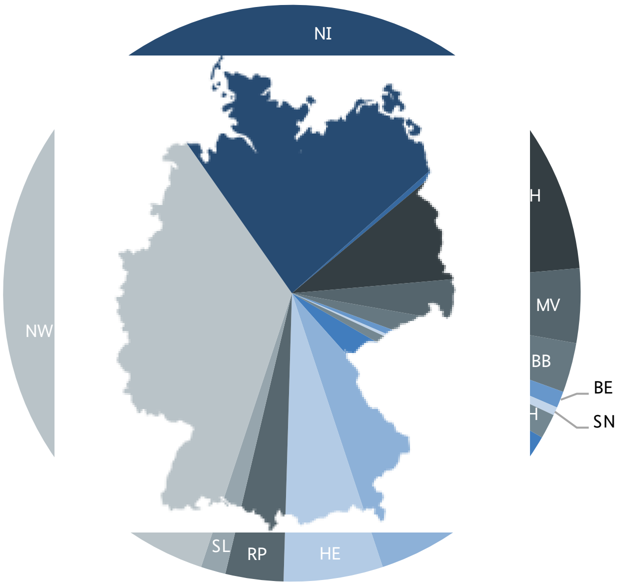
Electricity: Final consumption by federal state at DSO level in 2022
(TWh)



Bavaria	83.54
Baden-Württemberg	53.70
Hesse	26.24
Rhineland-Palatinate	18.99
Saarland	5.03
North Rhine-Westphalia	84.07
Bremen	4.43
Lower Saxony	38.58
Hamburg	10.19
Schleswig-Holstein	11.17
Mecklenburg-Western Pomeran	17.91
Brandenburg	11.40
Berlin	12.80
Saxony-Anhalt	12.25
Saxony	18.97
Thuringia	9.76

Figure 24: Final consumption by federal state at DSO level in 2022

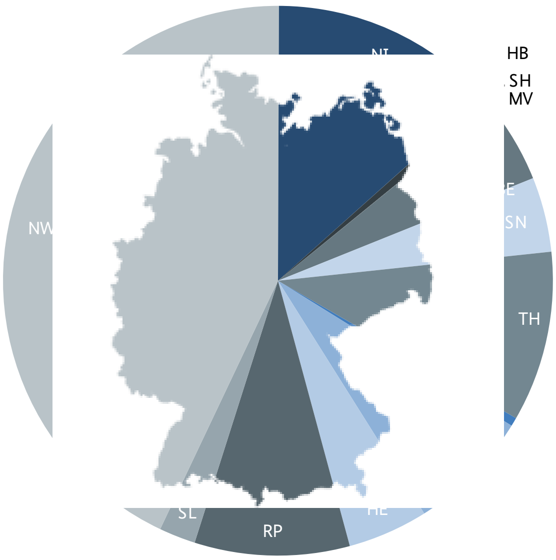
Electricity: Market locations by federal state at TSO level in 2022
(number)



Hamburg	0
Niedersachsen	50
Bremen	1
Nordrhein-Westfalen	76
Saarland	3
Rheinland-Pfalz	7
Hessen	12
Baden-Württemberg	14
Schleswig-Holstein	21
Mecklenburg-Vorpommern	9
Brandenburg	6
Berlin	2
Sachsen-Anhalt	0
Sachsen	1
Thüringen	3
Bayern	11

Figure 25: Market locations by federal state at TSO level in 2022

Electricity: Final consumption by federal state at TSO level in 2022
(GWh)



Hamburg	0
Lower Saxony	3,983
Bremen	3
North Rhine-Westphalia	12,843
Saarland	640
Rhineland-Palatinate	2,721
Hesse	1,409
Baden-Württemberg	2,159
Schleswig-Holstein	210
Mecklenburg-Western Pomerania	8
Brandenburg	1,427
Berlin	1
Saxony-Anhalt	0
Saxony	1,313
Thuringia	2,992
Bavaria	152

Figure 26: Final consumption by federal state at TSO level in 2022

Electricity: DSOs by network length in 2022
(number and percentage)

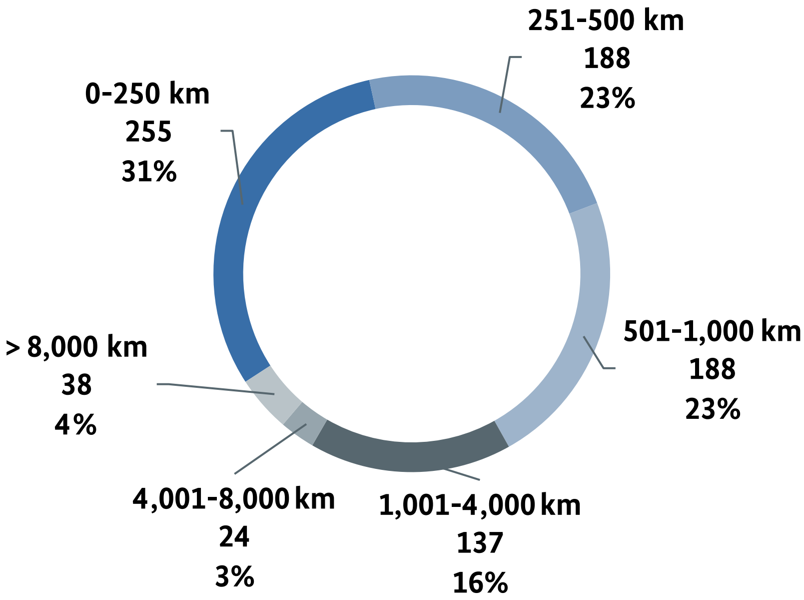


Figure 27: DSOs by network length in 2022

Electricity: DSOs by number of market locations in 2022
(number and percentage)

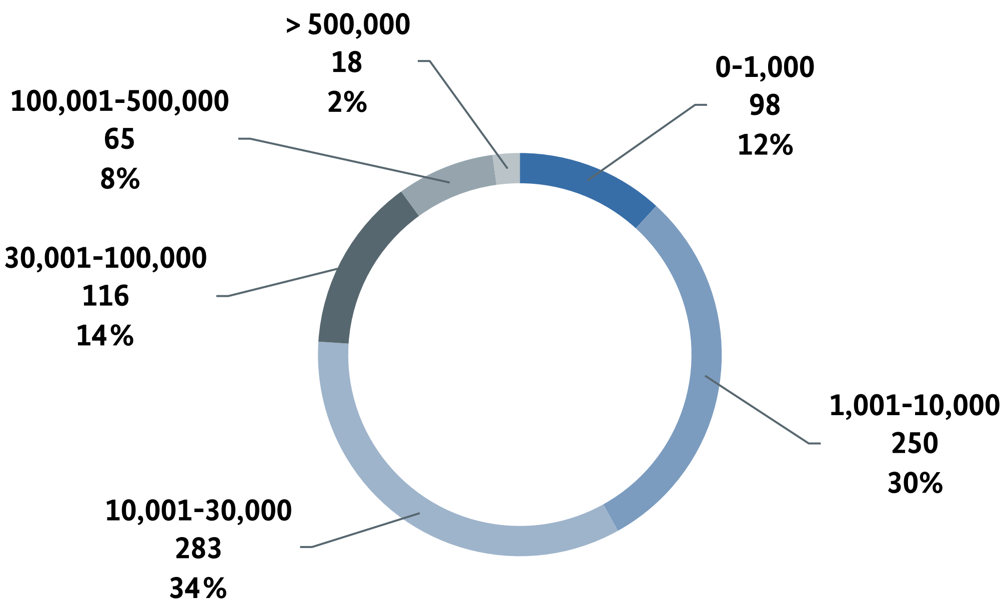


Figure 28: DSOs by number of market locations in 2022

2. Congestion management

Network operators are legally entitled and obliged to take certain measures to maintain the security and reliability of the electricity supply system. Growth in wind capacity, which is located relatively far from demand centres, changes in the conventional power plant fleet and changes in the framework conditions for electricity trading with other countries, together with delays in grid expansion, lead to strains on the networks. Congestion management measures are needed to relieve these strains. This report looks at market-related measures comprising the following instruments:

- Redispatching: reducing and increasing the feed-in of electricity from power plants under a contractual arrangement with the network operator, with costs being reimbursed, in accordance with section 13(1), section 13a(1) and section 13c of the Energy Industry Act (EnWG).
- Grid reserve power plants: contracting and deploying grid reserve plant capacity to compensate for a deficit of redispatch capacity under a contractual arrangement, with costs being reimbursed.
- Countertrading: cross-zonal exchange between two bidding zones that is initiated by the network operators to reduce physical congestion.
- Feed-in management: the separate provisions in the Renewable Energy Sources Act (EEG) for curtailing electricity from renewable and combined heat and power (CHP) plants through feed-in management (sections 14 and 15 EEG 2021) ceased to apply with effect from 1 October 2021 when the new Redispatch 2.0 system was introduced. Since 1 October 2021, decisions on the choice of redispatching measures in accordance with section 13a EnWG must take direct account of priority generation, as required by section 13 EnWG.

More information about congestion management can be found in the quarterly reports on congestion management available at www.bundesnetzagentur.de/Systemstudie (in German).

Electricity: Congestion management measures

		2019	2020	2021	2022
Redispatching					
Total volume[1] of operational plants	GWh	13,323	16,561	20,405	29,534
Cost estimate[2] for redispatching	€mn	227	240	590	2,837
Cost estimate for countertrading	€mn	64	135	397	371
Grid reserve power plants					
Volume[3]	GWh	430	635	1,280	3,238
Cost estimate for activation	€mn	82	100	249	650
Capacity[4]	MW	6,598	6,596	5,670	7,150
Annual costs of holding in reserve[5]	€mn	197	196	243	389
Redispatching with renewables (previously feed-in management)					
Volume of reductions[6]	GWh	6,482	6,146	5,818	8,071
Estimated compensation[7]	€mn	710	761	807	
Feed-in adjustments[8]					
Volume	GWh	9	16	20	

[1] Amounts (reductions and increases) including countertrading measures according to monthly reports to the Bundesnetzagentur. From 2022 the operational power plant reductions include renewable energy reductions.
[2] TSOs' cost estimate based on actual measures. From 2022 the cost estimate for redispatching includes the estimated compensation claims from renewable installation operators as well as the financial compensation for balance responsible parties under the BDEW interim solution for economic balancing.
[3] Activation of grid reserve power plants including test starts and test runs. Feed-in from 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. The separate provisions in the EEG for curtailing electricity from renewable and CHP plants through feed-in management (sections 14 and 15 EEG 2021) ceased to apply with effect from 1 October 2021 when the new Redispatch 2.0 system was introduced. From 2022 the renewable energy reductions are included in the operational power plant reductions.
[7] From 2022 the estimated compensation claims are included in the cost estimate and cannot be listed separately.
[8] Not recorded from 2022 due to the change in the reporting procedure as a result of the introduction of Redispatch 2.0.

Table 41: Congestion management measures

Electricity: Power plant reductions and increases requested in 2022
(GWh)

Federal state	Reduction	Increase
Baden-Württemberg	4	4,059
Bavaria	774	459
Berlin	4	0
Brandenburg	2,115	3
Bremen	387	11
Hamburg	-	-
Hesse	134	258
Mecklenburg-Western Pomerania	661	2
Lower Saxony	5,532	819
North Rhine-Westphalia	771	1,787
Rhineland-Palatinate	45	379
Saarland	4	265
Saxony	1,279	4
Saxony-Anhalt	667	13
Schleswig-Holstein	1,441	-
Thuringia	52	3
Not attributable (exchange, abroad)	2,285	4,825

Table 42: Power plant reductions and increases requested in 2022

Electricity: Power plant deployment for redispatching by energy source in 2022
(GWh)

Energy source	Reduction	Increase
Wind (offshore)	4,153	-
Wind (onshore)	3,186	-
Lignite	3,131	156
Hard coal	2,240	5,741
Solar	620	-
Nuclear	221	8
Natural gas	204	2,055
Biomass, including biogas	101	-
Pumped storage	16	541
CHP electricity	7	-
Run-of-river	2	-
Dammed water (without pumped storage)	1	3
Other energy sources (non-renewable)	0	1
Landfill, sewage and mine gas	0	-
Combination of renewable energy sources (exception)	0	-
Waste	0	-
Mineral oil products	0	149
Dammed water	-	-
CHP heat	-	-
Unknown[1]	2,270	4,298

[1] Some redispatching takes place on the exchange and is classed as "unknown" as it cannot be allocated to any one energy source. Some power plants deployed for redispatching are located outside Germany; this redispatching is also classed as "unknown" as the network operators do not know which energy source is used.

Table 43: Power plant deployment for redispatching by energy source in 2022

Electricity: Grid reserve deployment in 2022

	Number of days	Total (MWh)
January	31	514,216
February	28	641,281
March	28	408,639
April	30	285,640
May	30	226,912
June	27	179,430
July	31	252,924
August	27	222,967
September	23	80,957
October	26	93,777
November	19	94,440
December	26	236,803
Total	**326**	**3,237,987**

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

Table 44: Grid reserve deployment in 2022

3. Electricity supply disruptions

Interruptions to supply can occur despite the above-mentioned measures for congestion management. Network operators report to the Bundesnetzagentur each year on the time, duration, extent and cause of each supply interruption lasting longer than three minutes. The system average interruption duration index ($SAIDI_{EnWG}$) does not take into account planned interruptions or those that occur owing to force majeure.[61] Only unplanned interruptions caused by atmospheric effects, third-party intervention, ripple effects from other networks or other disturbances in a network operator's area are included in the calculations.

Electricity: Supply disruptions under section 52 EnWG by network level
(minutes)

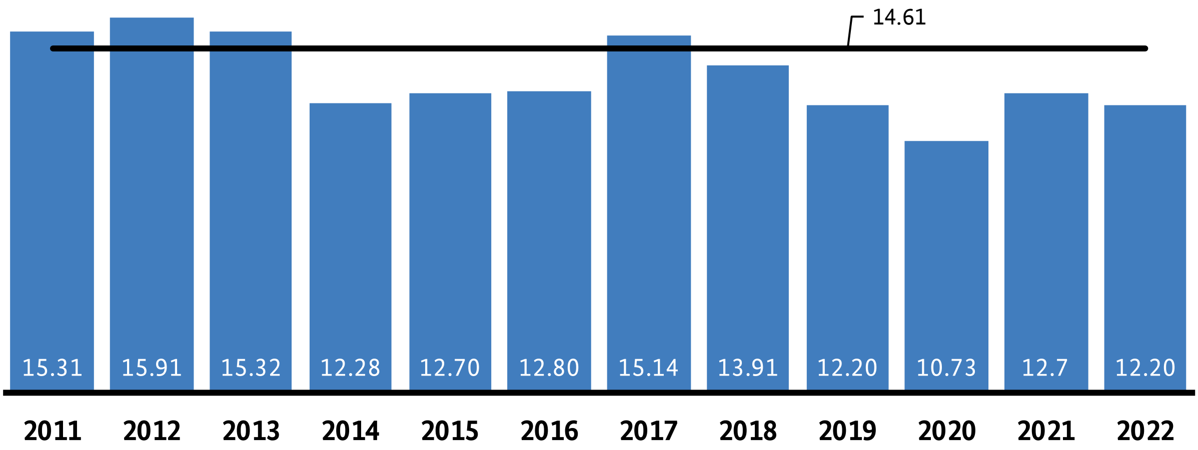


Figure 29: Supply disruptions under section 52 EnWG by network level

[61] The system average interruption duration index $SAIDI_{EnWG}$ differs from the $SAIDI_{ARegV}$ index calculated for each individual company for quality management pursuant to the Incentive Regulation Ordinance (ARegV).

4. Investments

DSOs and TSOs invest in expanding and maintaining the networks in order to safeguard a reliable supply of electricity. The figures are values under commercial law derived from the companies' balance sheets. The values under commercial law do not correspond to the implicit values included in the system operators' revenue caps in accordance with the provisions of the Incentive Regulation Ordinance (ARegV).

Investments comprise the capitalised gross additions to fixed assets and the value of fixed assets newly rented or hired.

Expenditure comprises 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.

Electricity: TSOs' network infrastructure investments and expenditure

	2021	2022
Investments (€mn)	**4,677**	**3,917**
New build, upgrade and expansion projects excluding cross-border connections	3,761	3,382
New build, upgrade and expansion projects for cross-border connections	327	162
Maintenance and renewal excluding cross-border connections	555	352
Maintenance and renewal of cross-border connections	34	21
Expenditure (€mn)	**484**	**359**
Expenditure excluding cross-border connections	476	352
Expenditure on cross-border connections	8	7
Total	**5,161**	**4,276**

Table 45: TSOs' network infrastructure investments and expenditure

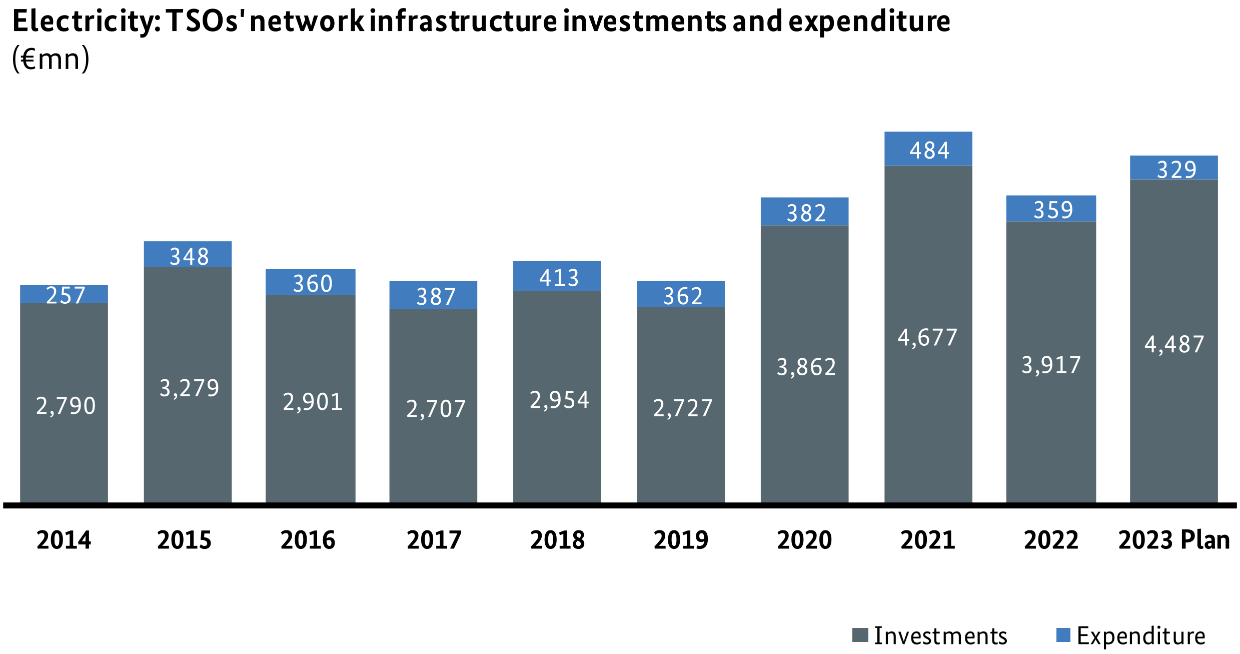


Figure 30: TSOs' network infrastructure investments and expenditure

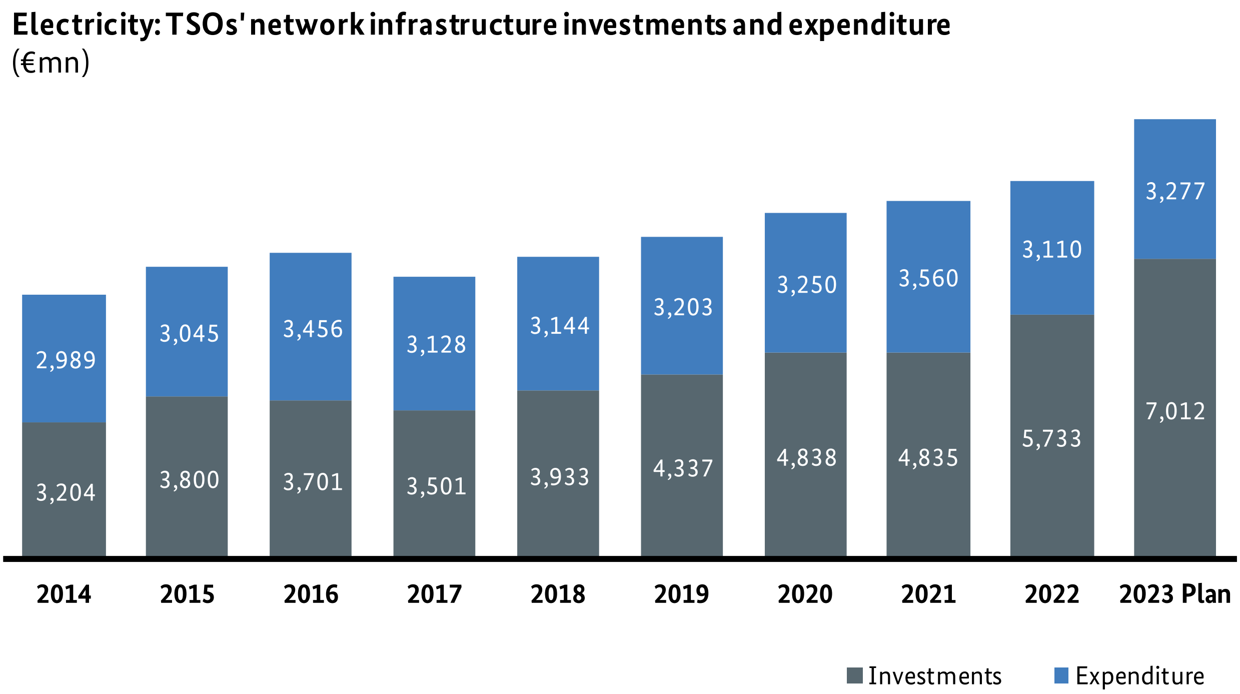


Figure 31: DSOs' network infrastructure investments and expenditure

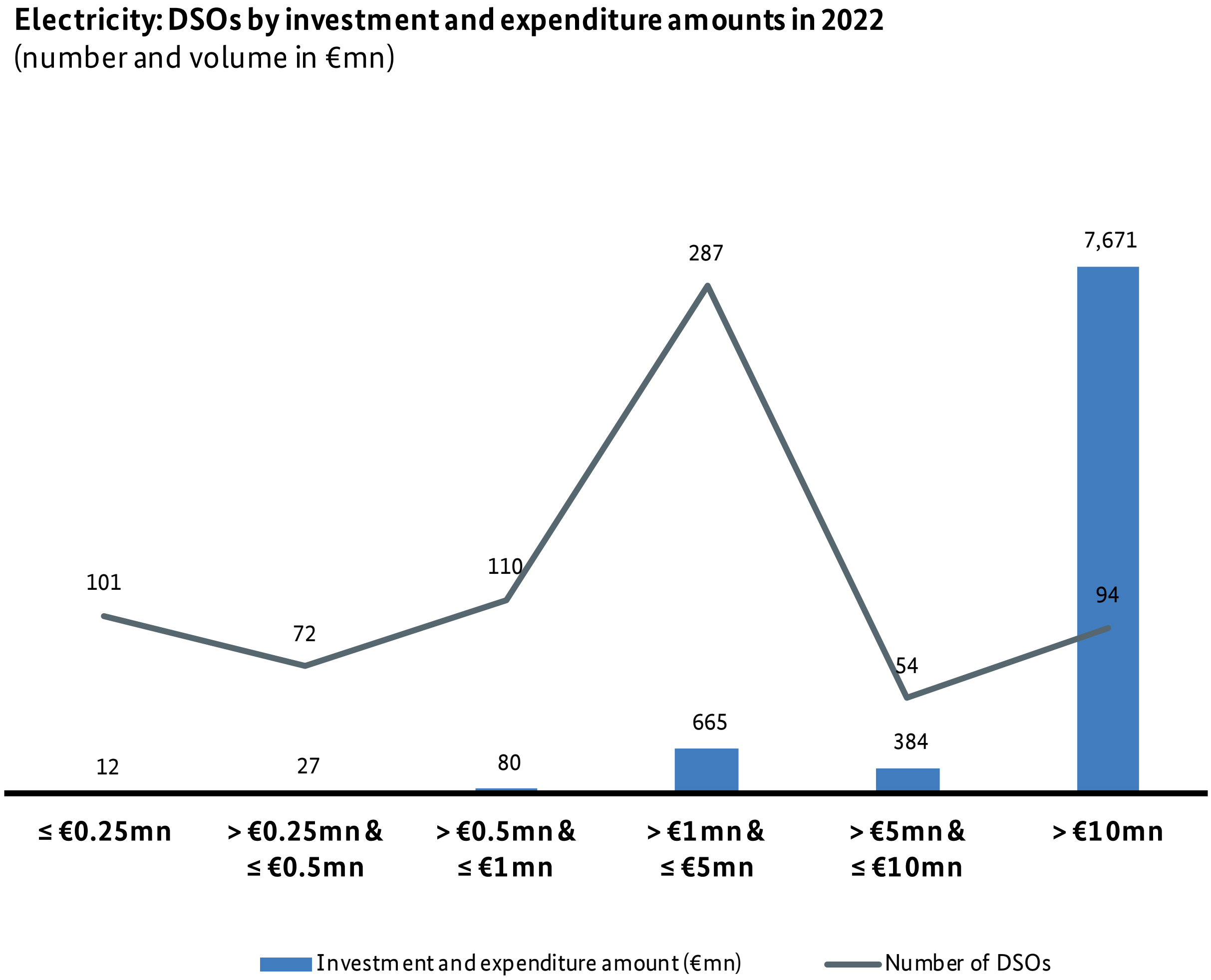


Figure 32: DSOs by investment and expenditure amounts in 2022

5. Network tariffs

Network tariffs 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 (such as expansion and system security measures) are passed on to final customers through the network tariffs. The level of network tariffs 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 very generously sized 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 congestion 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.

Network tariffs in Germany are set in three fundamental steps:

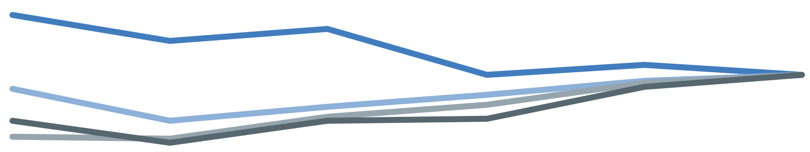
Determining the network costs
The cost basis for the network tariffs is set in five-year regulatory periods. The regulatory authority examines the network operators' costs in accordance with the principles of the Electricity Network Tariffs Ordinance (StromNEV) and on the basis of the operators' certified annual accounts in the base year. The fourth regulatory period is based on the costs of the base year 2021.

Setting the revenue caps
The recognised network costs are used to set a revenue cap in accordance with the provisions. The revenue cap stipulates the revenue a network operator is allowed to generate in a regulatory period. In addition to the recognised costs, efficiency benchmarking and various other factors such as non-controllable costs, the inflation index and the capex mark-up have an influence on the revenue cap.

Deriving the network tariffs
The network operators derive the network tariffs on the basis of the principles of the StromNEV. The allowed revenue is allocated to the various network and transformation levels as cost-reflectively as possible. The specific annual costs (in euros per kilowatt) are then calculated for each level, taking account of the allocated costs and the concurrent annual peak load and beginning with the highest network or transformation level operated. In the case of interval-metered customers, the specific costs for each level are used to set four charges (one unit charge and one capacity charge each for up to and for more than 2,500 usage hours). In this case, assumptions are made about a final customer's contribution to causing the network costs. In the case of non-interval-metered customers, a unit charge and a standing charge (in some cases) are set.

The expected revenue of the network level is determined on the basis of expected sales volumes and the derived tariffs. The difference between the allocated costs and the expected revenue of a level is passed on to the next lower level. This is repeated down to the low voltage level, which needs to cover all the costs allocated to it. The network operators publish their provisional network tariffs in October each year for the following calendar year and then publish their final tariffs in January of the year in which the tariffs apply. Reforms in the network tariff system are being discussed in light of the energy transition and changes in generation and usage structures, but any reforms must not jeopardise the stability of the networks.

Electricity: TSOs' network tariffs
(ct/kWh)



	2018	2019	2020	2021	2022	2023
TenneT	0.70	0.63	0.66	0.54	0.56	0.54
50Hertz	0.50	0.41	0.45	0.48	0.52	0.54
TransnetBW	0.37	0.36	0.42	0.45	0.52	0.54
Amprion	0.41	0.35	0.41	0.42	0.50	0.54

Figure 33: TSOs' network tariffs

Electricity: Average volume-weighted network tariffs (including meter operation) for household customers
(ct/kWh)

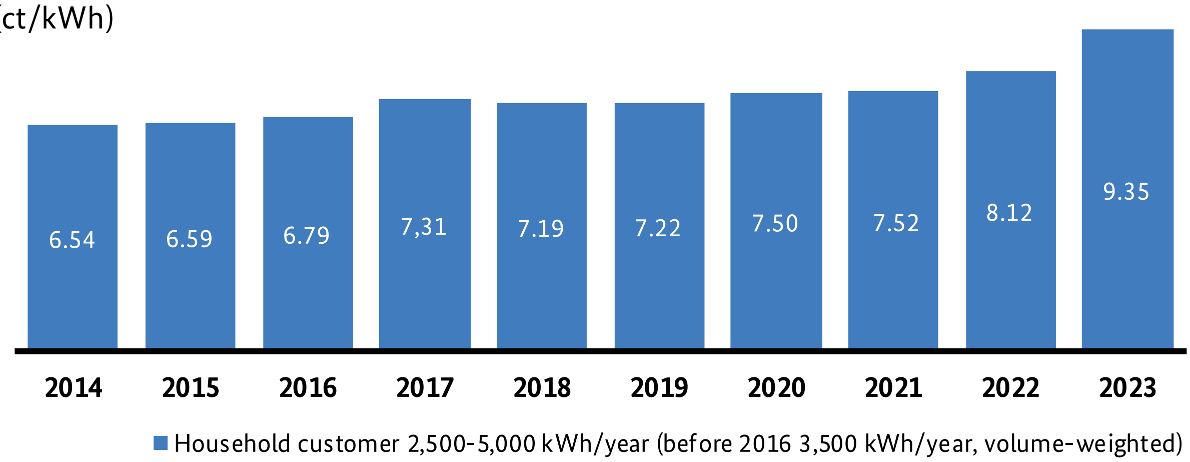


Figure 34: Average volume-weighted net network tariffs (including meter operation) for household customers

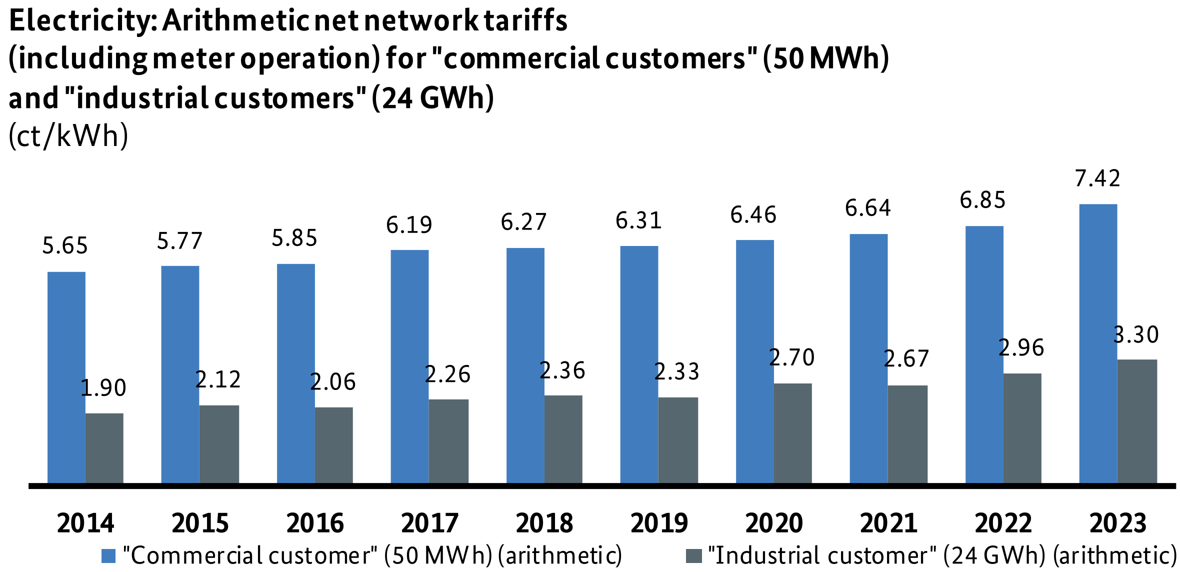


Figure 35: Arithmetic net network tariffs (including meter operation) for "commercial customers" (50 MWh) and "industrial customers" (24 GWh)

Electricity: Network tariff standing charges
(€/year)

	2018	2019	2020	2021	2022	2023
Average standing charge	37	40	52[2]	57[2]	58[2]	66[2]
Maximum standing charge	100	105	105	105	105	120
Minimum standing charge[1]	4	7	8	8	9	7
DSOs without standing charge (number)	36	42	40	31	30	40

[1] Minimum standing charge levied by DSOs with standing charges.
[2] The standing charges for 2020, 2021, 2022 and 2023 were weighted using the DSOs' delivery volumes. The unweighted averages were €42 per year for 2020, €45 per year for 2021, €47 per year for 2022 and €54 per year for 2023.

Table 46: Network tariff standing charges

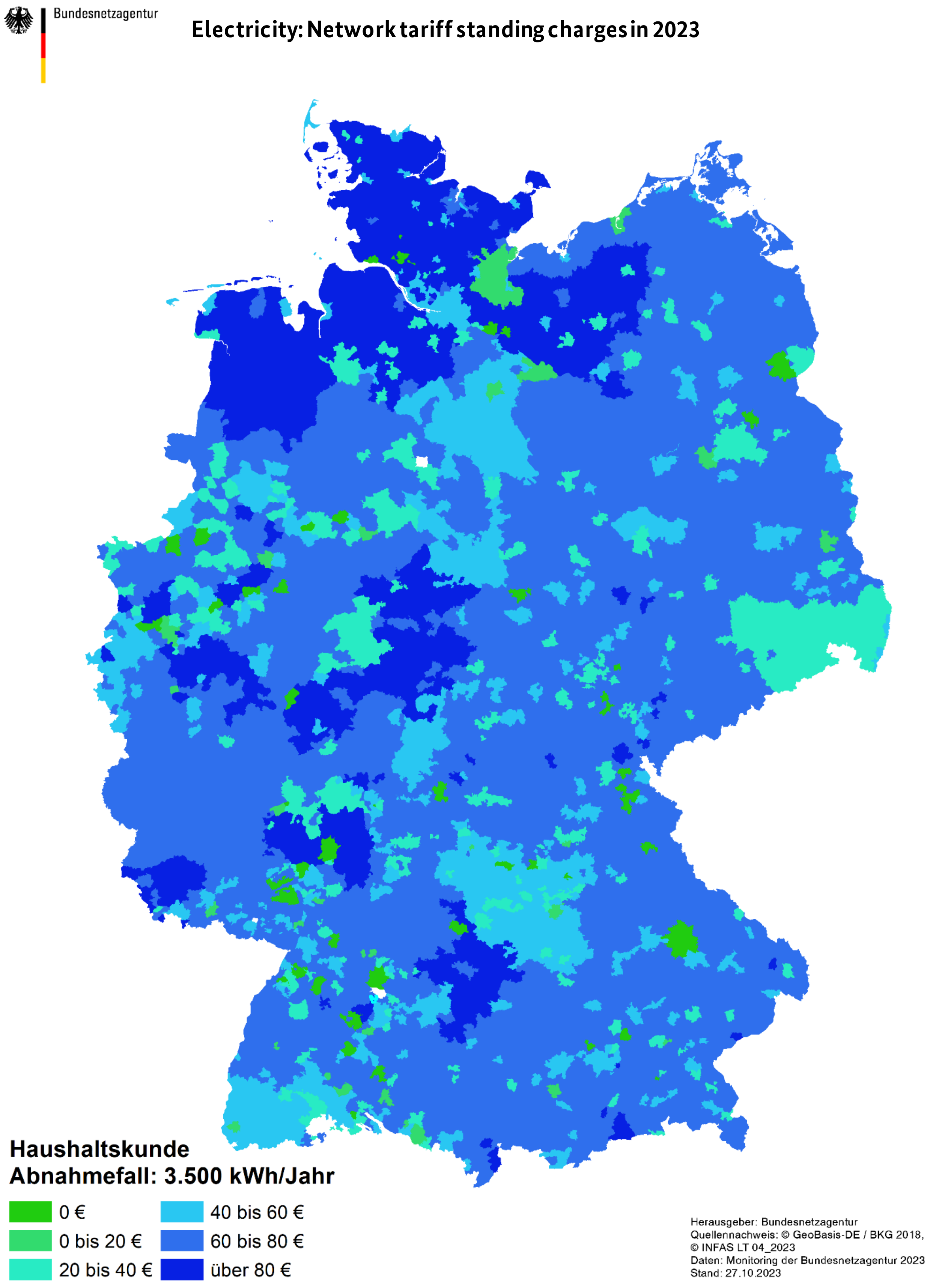


Figure 36: Network tariff standing charges

Electricity: Net network tariffs for household customers in Germany in 2023
(ct/kWh)

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks
Brandenburg	12.45	6.61	14.08	30
Schleswig-Holstein	12.15	5.42	15.29	40
Mecklenburg-Western Pomerania	11.65	6.14	14.08	18
Hamburg	10.63	8.05	15.29	5
Saarland	9.40	6.55	31.42	17
Saxony	9.01	6.34	12.64	35
Rhineland-Palatinate	8.96	5.86	14.29	49
Baden-Württemberg**	8.88	5.49	32.18	109
Saxony-Anhalt	8.70	6.20	11.90	28
North Rhine-Westphalia	8.52	5.16	12.73	96
Hesse	8.52	5.54	11.95	51
Berlin	8.37	5.28	20.30	7
Thuringia	8.33	6.35	10.79	32
Lower Saxony	8.07	5.84	12.90	71
Bavaria	7.82	4.77	14.42	202
Bremen	6.27	6.06	13.55	8

* 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 47: Net network tariffs for household customers in Germany in 2023

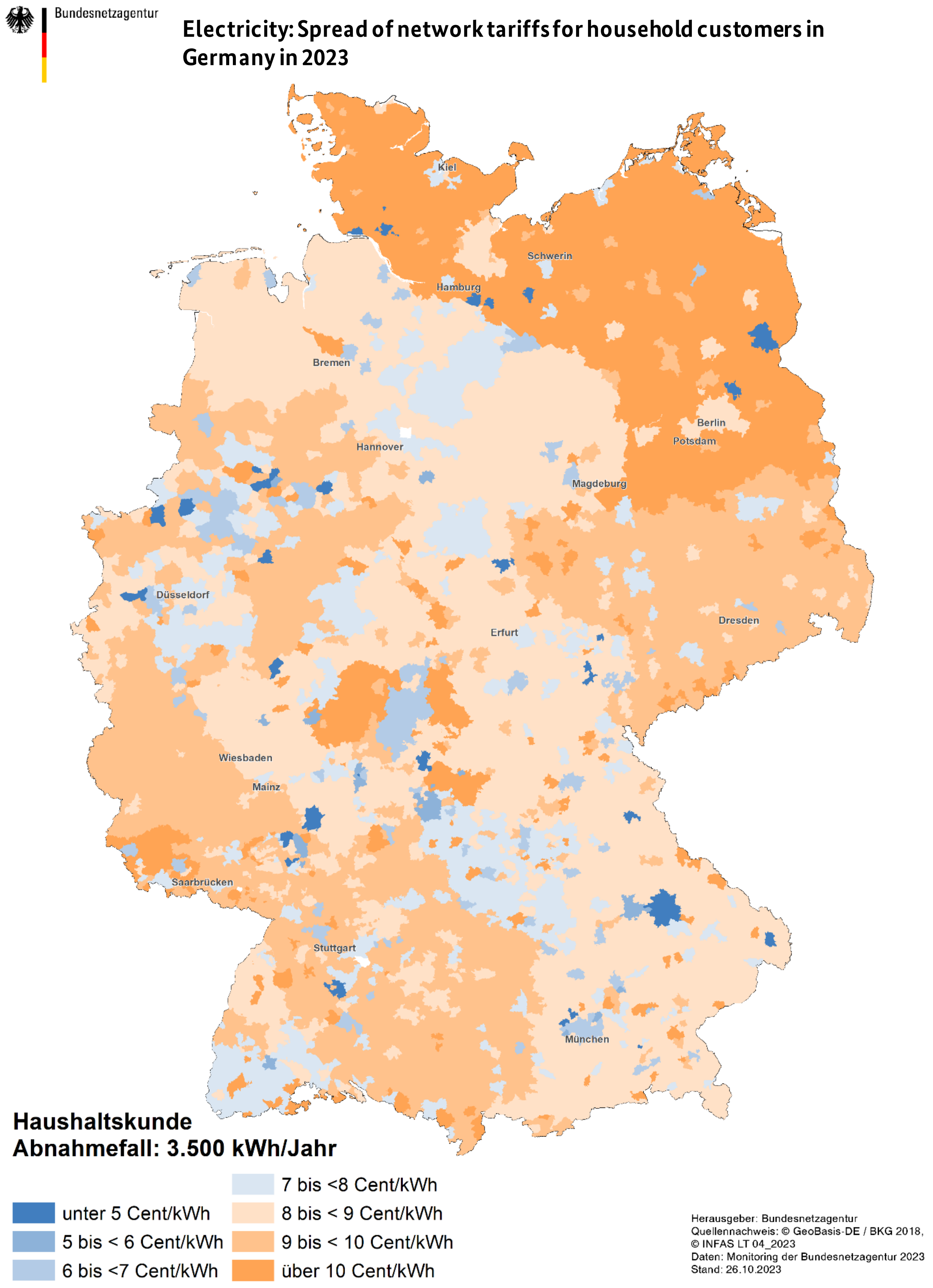


Figure 37: Spread of network tariffs for household customers in Germany in 2023

Electricity: Net network tariffs for commercial customers in Germany in 2023
(ct/kWh)

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks
Schleswig-Holstein	10.46	4.76	12.87	40
Brandenburg	10.22	4.96	13.11	30
Mecklenburg-Western Pomerania	9.52	4.88	12.04	18
Hamburg	9.01	5.06	12.77	5
Saxony	7.66	5.23	10.98	35
Berlin	7.57	2.78	19.37	7
Saarland	7.26	4.61	30.15	17
Rhineland-Palatinate	7.23	4.47	12.16	49
Baden-Württemberg**	7.20	1.39	31.99	109
Saxony-Anhalt	6.97	4.62	9.98	28
North Rhine-Westphalia	6.76	4.13	11.14	96
Thuringia	6.62	5.15	9.75	32
Hesse	6.59	3.88	9.50	51
Bavaria	6.20	3.41	13.36	202
Lower Saxony	6.00	4.25	11.98	71
Bremen	5.11	4.67	12.91	8

* 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 48: Net network tariffs for commercial customers in Germany in 2023

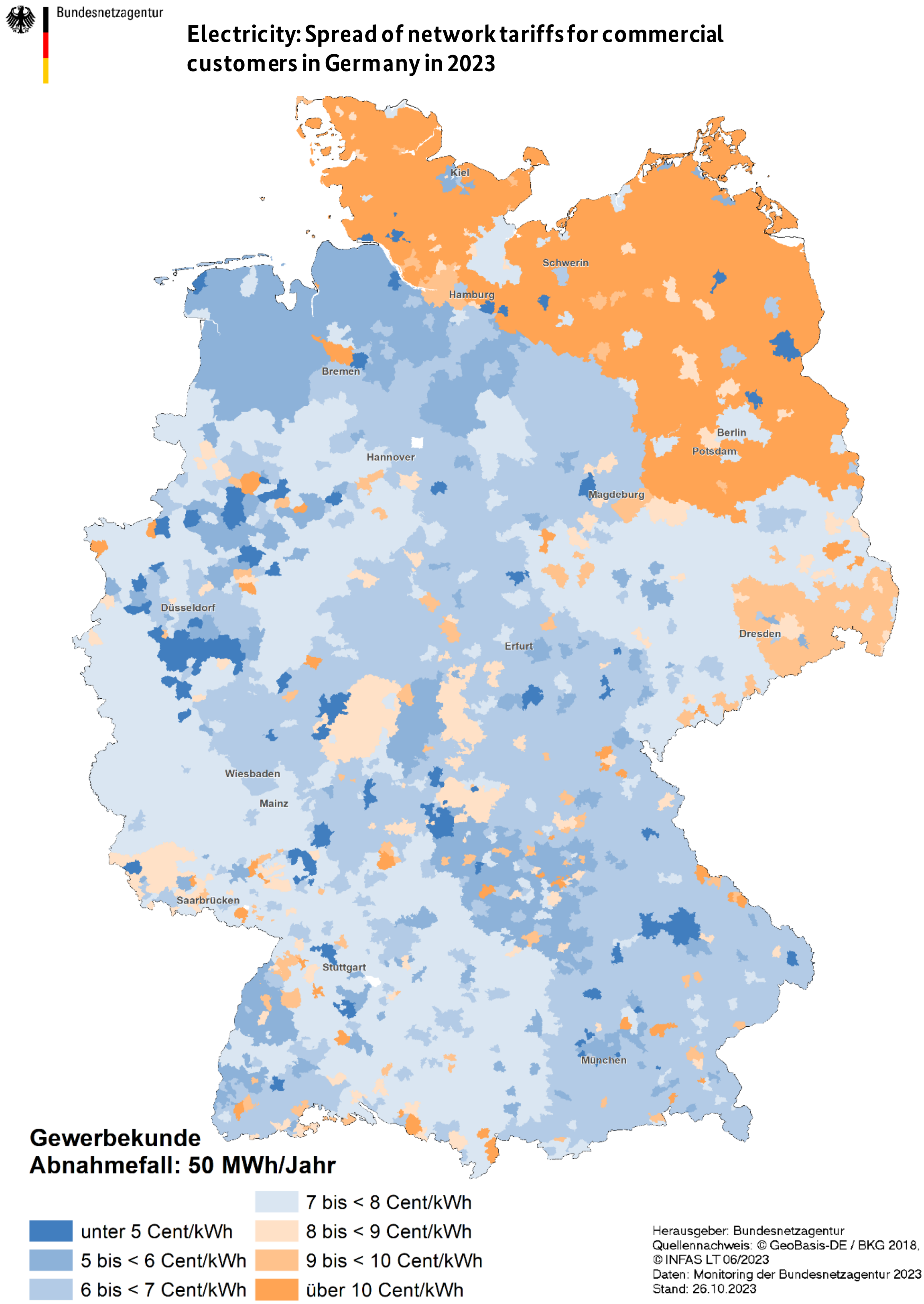


Figure 38: Spread of network tariffs for commercial customers in Germany in 2023

Electricity: Net network tariffs for industrial customers in Germany in 2023
(ct/kWh)

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks
Brandenburg	4.55	0.80	5.49	30
Mecklenburg-Western Pomerania	4.30	2.11	5.49	19
Schleswig-Holstein	4.22	1.74	8.77	39
Berlin	3.48	2.03	5.19	6
Saxony	3.45	2.43	4.69	35
Saxony-Anhalt	3.38	1.78	11.08	29
Hamburg	3.26	2.92	5.32	5
Thuringia	3.16	2.53	3.85	30
Baden-Württemberg	3.13	1.61	5.70	109
Rhineland-Palatinate	3.10	1.93	5.14	49
North Rhine-Westphalia	2.96	1.95	8.76	100
Hesse	2.96	1.93	4.95	52
Lower Saxony	2.93	1.69	5.56	72
Saarland	2.77	2.24	8.26	17
Bremen	2.76	2.69	3.87	8
Bavaria	2.60	0.97	10.60	199

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

Table 49: Net network tariffs for industrial customers in Germany in 2023

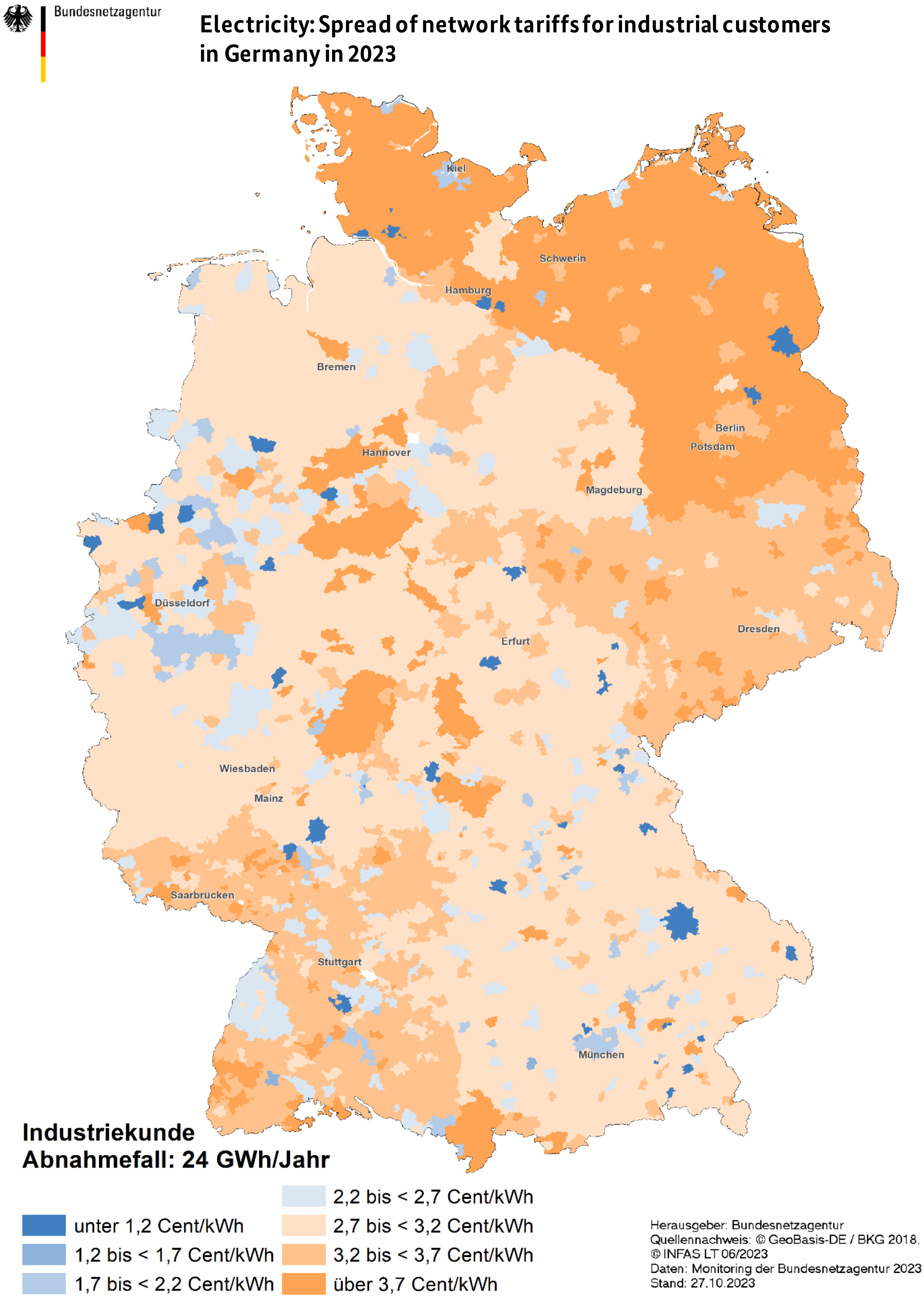


Figure 39: Spread of network tariffs for industrial customers in Germany in 2023

6. Load control

Section 14a EnWG gives DSOs at the low voltage level the ability to use consumers' flexibility. DSOs can conclude agreements with final customers with controllable devices allowing the DSOs to control the consumption of the devices in return for a reduced network tariff for the customers. The aim is to prevent these devices 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 rules are essentially designed for consumer devices such as night storage heating systems, heat pumps and electric vehicles. On the basis of the revised section 14a EnWG, the Bundesnetzagentur plans to issue determinations making it compulsory, instead of voluntary, for all controllable consumer devices connected to the low voltage network to take part in load control as from 2024. The new rules will enable DSOs to intervene and control consumption in the event of overloading. The rules will ensure the swift connection of new consumer devices as the DSOs will not be able to refuse to connect the devices on the grounds that there is not enough network capacity.

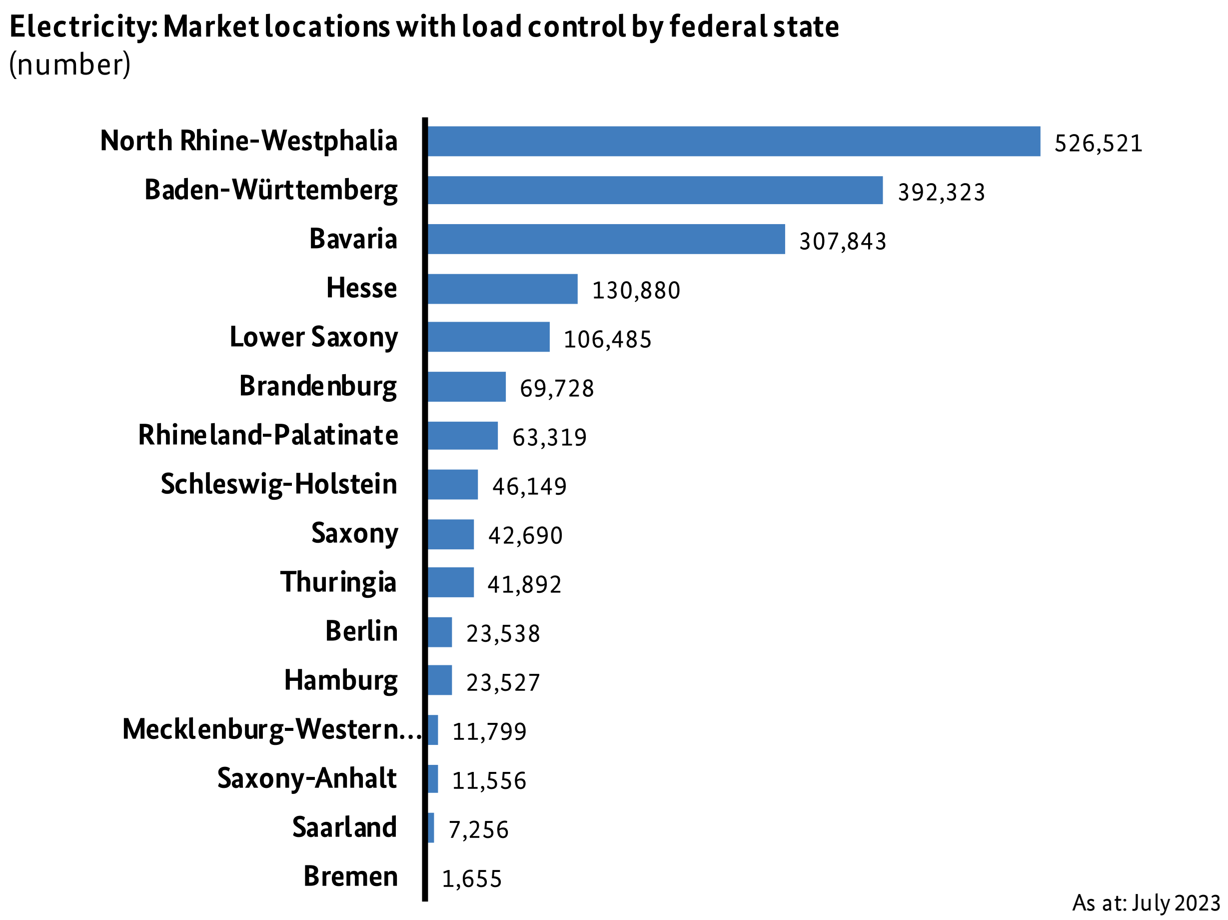


Figure 40: Market locations with load control by federal state

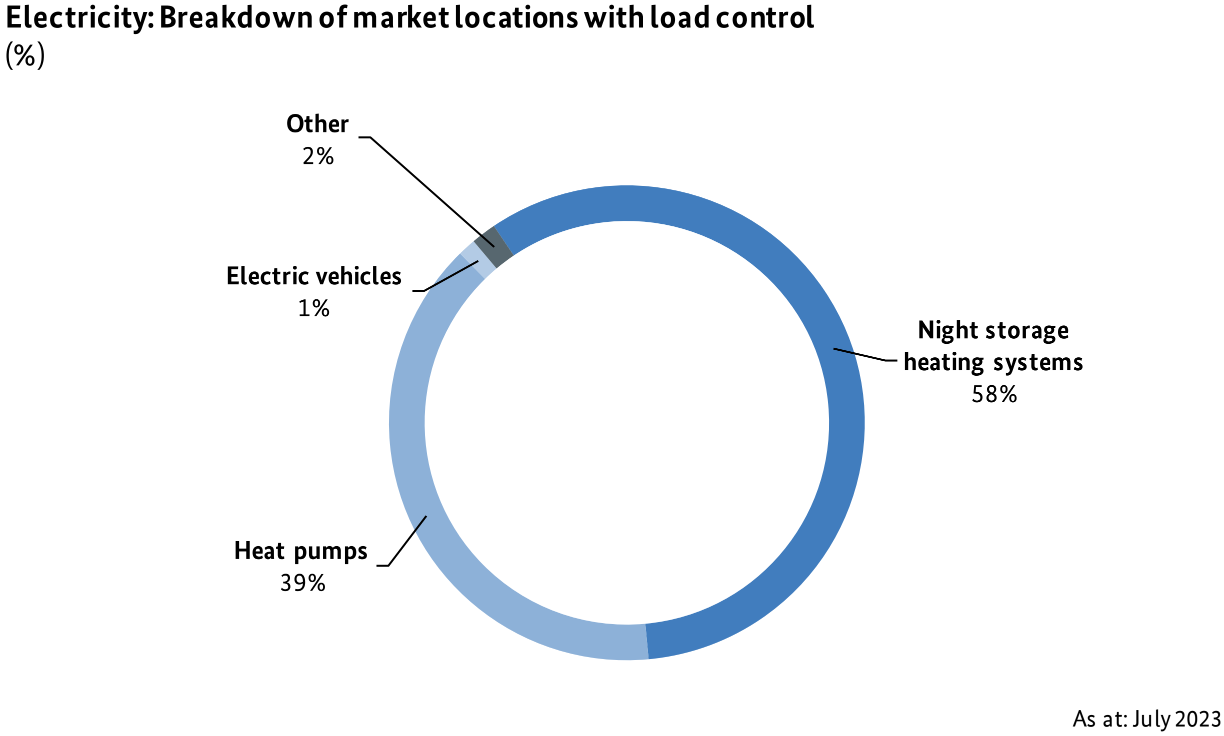


Figure 41: Breakdown of market locations with load control

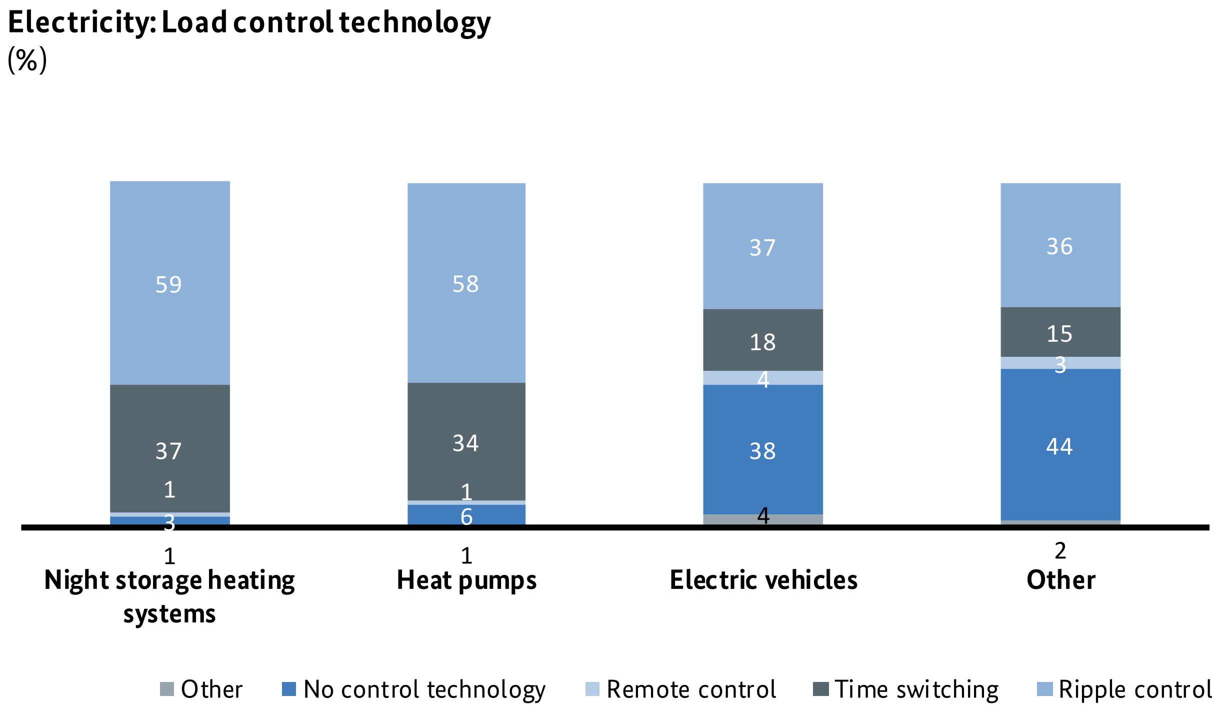


Figure 42: Load control technology

D System services

Guaranteeing system stability is one of the core tasks of the transmission system operators (TSOs) and is performed using system services. The costs for system services are passed on to the final customers through the network tariffs, among other things.

The system services covered in this report comprise measures that can be subdivided into five areas:

- Maintaining the system frequency by contracting and using frequency containment reserves (FCR), automatic frequency restoration reserves (aFRR) and manual frequency restoration reserves (mFRR) and using interruptible loads. The Interruptible Loads Ordinance (AbLav) ceased to apply as from 1 July 2022 in accordance with section 20(2) AbLaV. This report therefore does not look in depth at interruptible loads. More information on balancing services can be found below.
- Maintaining voltage stability by providing reactive power: generators, in particular, can increase the voltage in the network when they feed in electricity. However, they need to feed in part of the electricity as reactive power to ensure that the voltage does not become too high. Reactive power is also used for dynamic voltage control to ensure safe operation of the network.
- Covering network losses: loss energy is the energy required to compensate for the energy lost during transport in the network. The costs for loss energy are therefore the costs of procuring this energy.
- Restoring supply by providing black start capability: black start capability is the ability of a power plant to start up again independently following a total blackout and feed electricity into the network without relying on external electricity sources.
- Managing congestion to remedy network overloading using redispatching measures.[62]

Other types of capacity that cannot return to the regular electricity market are also kept in reserve. These include the following mechanisms:

- grid reserve in accordance with section 13d EnWG
- capacity reserve in accordance with section 13e EnWG
- security standby pool of lignite power plants in accordance with section 13g EnWG
- special grid facilities in accordance with section 11(3) EnWG 2017.

The grid reserve was introduced by the Grid Reserve Ordinance (NetzResV), which entered into force on 6 July 2013. The NetzResV requires the TSOs to make an annual system analysis in order to determine the reserve capacity needed for redispatching measures to safeguard network stability. The Bundesnetzagentur examines the analysis and announces the reserve generating capacity needed in an annual notice. The Bundesnetzagentur was notified of a required reserve capacity of 8,264 megawatts (MW) for winter 2022/2023. The capacity reserve serves to provide additional capacity at times when, despite free pricing on the wholesale

[62] Detailed information about congestion management can be found in section IIC2 and in the quarterly reports on congestion management available at https://www.bundesnetzagentur.de/systemstudie (in German).

market, there is not enough electricity on offer to cover the total demand. Existing generating facilities, storage facilities or loads outside the electricity market are kept in reserve and are used when needed and requested by the TSOs once the market alternatives have been exhausted. The TSOs carry out joint tendering for the capacity reserve every two years.

The security standby pool of lignite power plants was introduced by the Electricity Market Act in 2016. Under the measure, eight lignite power plant blocks with a total capacity of 2.7 gigawatts (GW) were earmarked to be successively transferred to the security standby pool and permanently closed after four years. The power plants on security standby must be able to be restarted within 10 days of a request from the TSOs and thus serve to safeguard the German electricity system in longer-term extreme situations.

1. Costs for system services

Electricity: Costs for system services recovered through the network tariffs
(€mn)

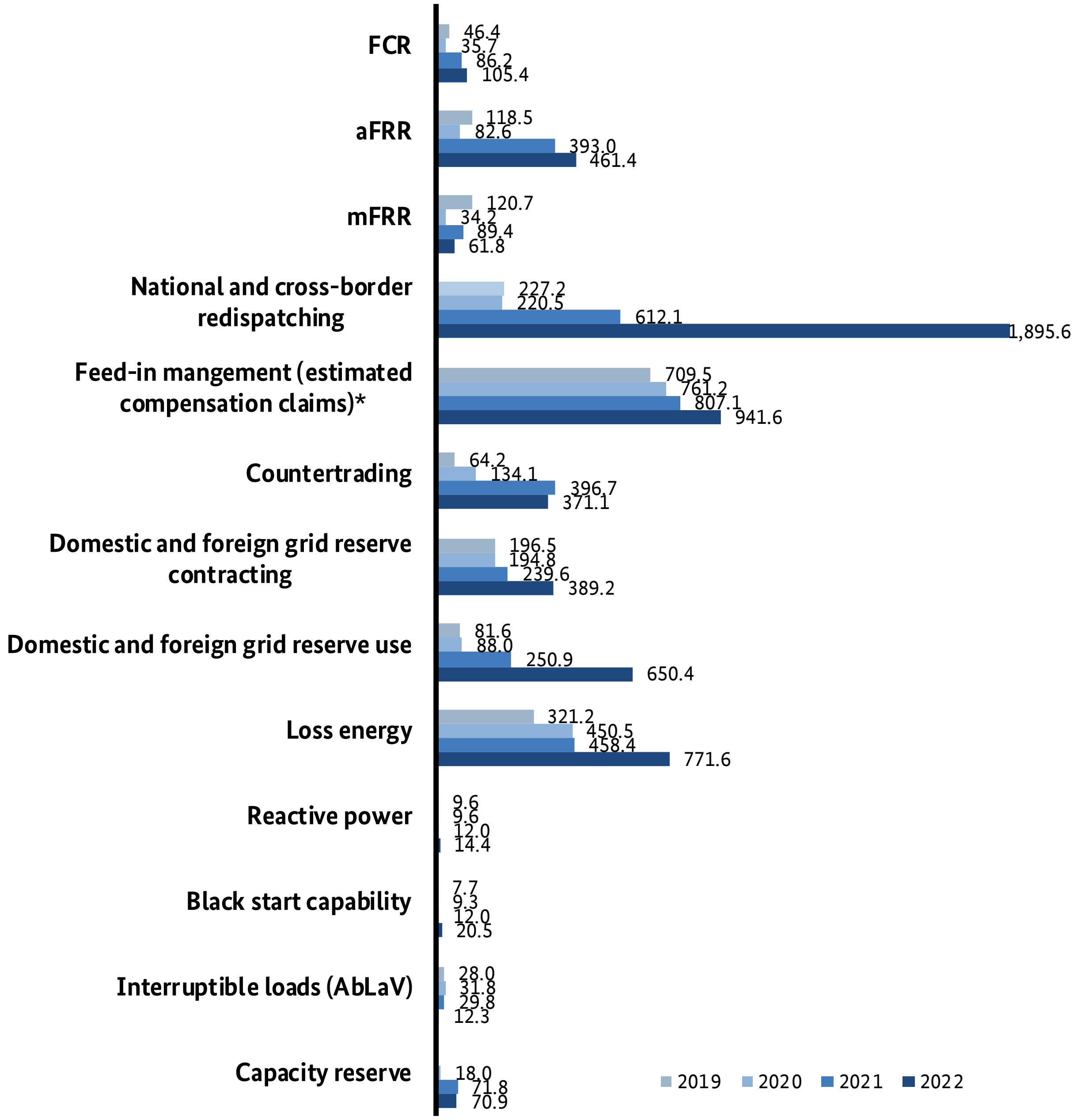
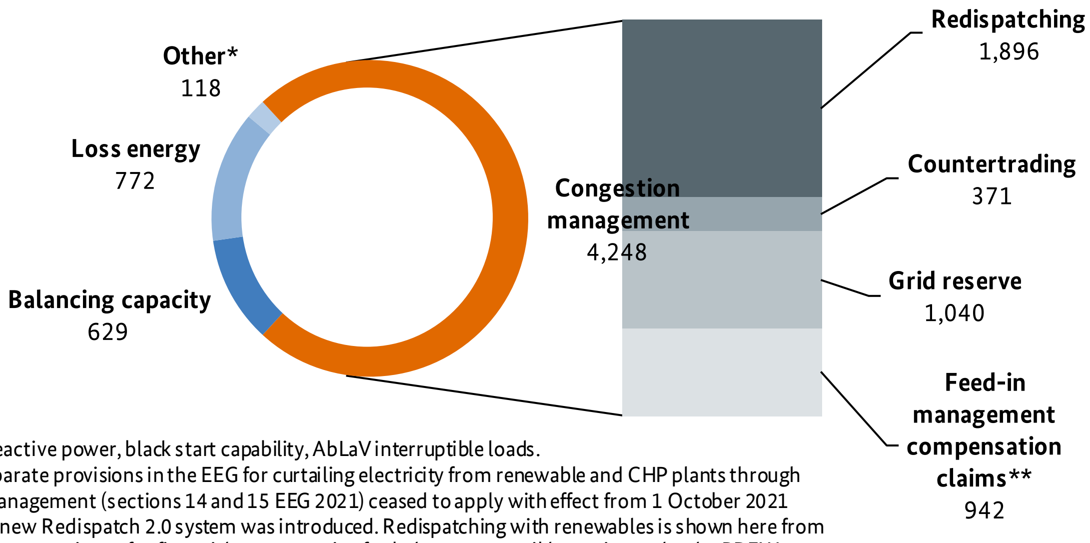


Figure 43: Costs for system services recovered through the network tariffs

Electricity: Breakdown of the costs for system services and for congestion management measures in 2022
(€mn)



*Other: reactive power, black start capability, AbLaV interruptible loads.
**The separate provisions in the EEG for curtailing electricity from renewable and CHP plants through feed-in management (sections 14 and 15 EEG 2021) ceased to apply with effect from 1 October 2021 when the new Redispatch 2.0 system was introduced. Redispatching with renewables is shown here from 2022. The cost estimate for financial compensation for balance responsible parties under the BDEW interim solution is included here from 2022.

Figure 44: Breakdown of the costs for system services and for congestion management measures in 2022

2. Balancing services

Demand and generation in the electricity supply system must be balanced at all times to guarantee the stability of the system. Any imbalances lead to fluctuations in the system frequency. The TSOs contract balancing capacity and use it in the form of balancing energy to balance out any deficit or surplus in power. The provision of balancing capacity and/or balancing energy is referred to as balancing services.[63]

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.
- Frequency restoration reserves with automatic activation (aFRR) – aFRR are a type of frequency restoration reserve used to restore the system frequency to the nominal frequency of 50 Hz after a disturbance. They 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.

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

- Frequency restoration reserves with manual activation (mFRR) – mFRR are also a type of frequency restoration reserve. They are used to support or replace aFRR and must be fully available within 12.5 minutes. mFRR are usually provided as scheduled deliveries at 15-minute intervals; they can also be activated directly outside the 15-minute schedule.

The TSOs with responsibility for control areas (50Hertz, Amprion, TenneT and TransnetBW) make up the grid control cooperation in Germany comprising the TSOs' four individual control areas. 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.

Balancing capacity and balancing energy are procured in two separate, successive markets:

- Balancing capacity market: this is where the balancing capacity to be held is procured. Each day, four-hour products for the three types of reserve are tendered for the following day. Awards and remuneration are based on the balancing capacity price.
- Balancing energy market: this is where the energy bids for aFRR and mFRR with a product validity period of 15 minutes are procured. The balancing energy market opens following the announcement of the results of the balancing capacity market auctions and closes 25 minutes before the start of each product validity period. Providers with successful price bids in the balancing capacity market must submit a bid in the balancing energy market. Providers who have not bid in the balancing capacity market or who have not successfully bid and so have no remuneration based on the balancing capacity price can also submit balancing energy bids.

A distinction is made between positive and negative balancing services. If there is too little power in the system, the system frequency will go below 50 Hz. Positive balancing services are needed to restore the system frequency to the nominal frequency by feeding in more energy or consuming less energy. If there is too much power in the system, the system frequency will go above 50 Hz. In this case, negative balancing services are needed where electricity consumers withdraw more electricity from the system or generators feed less electricity into the system at short notice. The TSOs procure both positive and negative balancing services from balancing service providers.

FCR are procured as a symmetric product. Providers must therefore provide the capacity offered in the balancing capacity market in both directions. Positive and negative aFRR and mFRR are tendered as separate products.

The Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation (PICASSO) and the Manually Activated Reserves Initiative (MARI) were implemented in June 2022 to enable the European exchange of balancing energy. PICASSO serves the exchange of aFRR products and MARI the exchange of mFRR.

The costs for contracting balancing capacity are included in the network tariffs through the capacity charge and are thus borne by consumers. The costs for the actual use of balancing capacity – by activating physical balancing energy – are settled under what is known as the imbalance settlement directly with the balance responsible parties causing the imbalance. Economic balancing energy is the electrical energy needed to compensate for an imbalance in a balancing group. While, as described above, only the control area balance is 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 economic balancing energy and billed to the balancing group responsible for the imbalance. The amount of economic balancing energy is often higher than the amount of physical balancing energy actually activated. The costs for the economic balancing energy are determined every 15 minutes using a uniform imbalance price applicable to all the control areas.

Electricity: Order and time frame for the use of balancing services

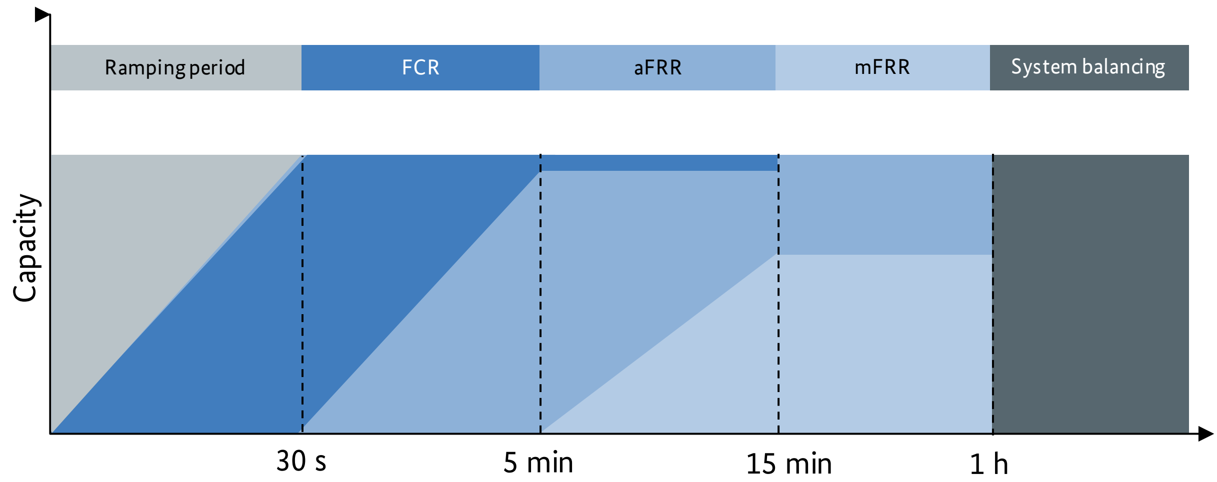
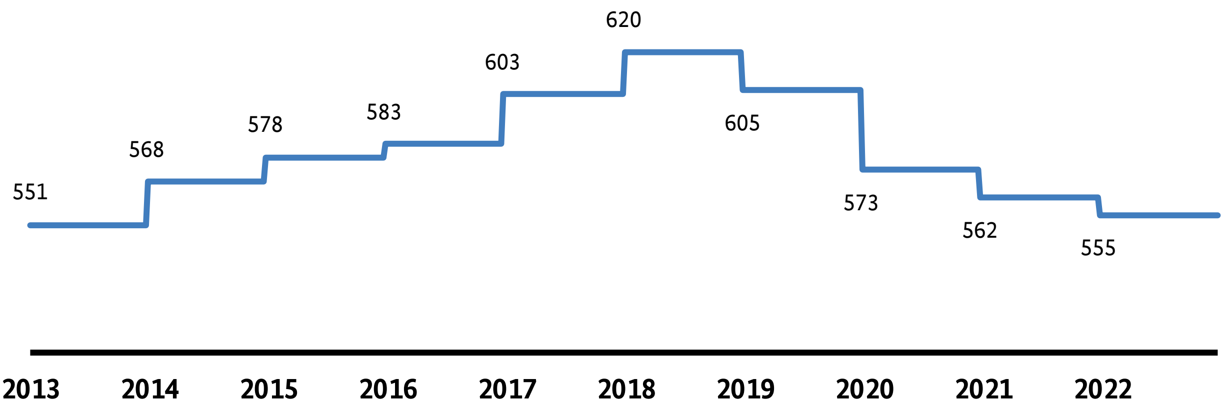


Figure 45: Order and time frame for the use of balancing services

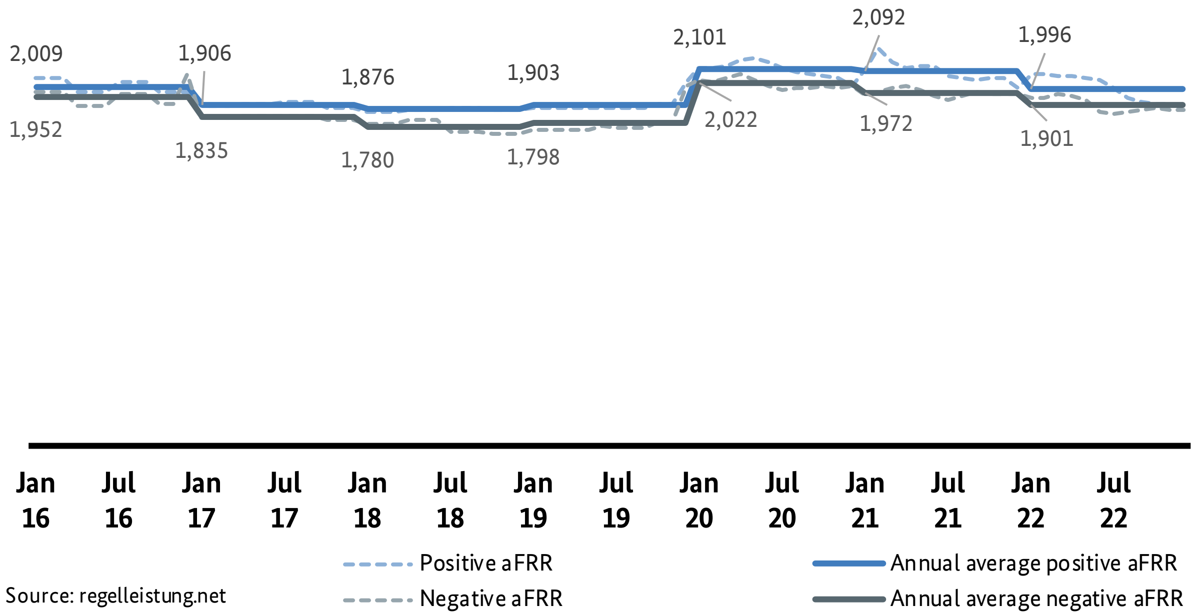
Electricity: FCR tendered in the control areas of 50Hertz, Amprion, TenneT and TransnetBW
(MW)



Source: regelleistung.net

Figure 46: FCR tendered in the control areas of 50Hertz, Amprion, TenneT and TransnetBW

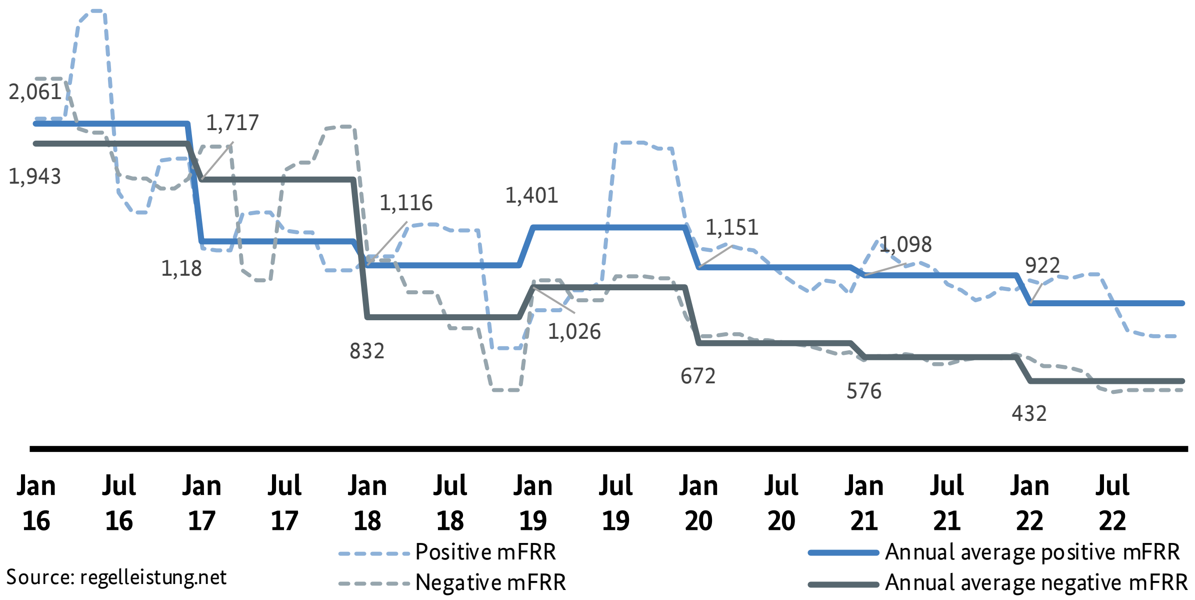
Electricity: aFRR tendered in the control areas of 50Hertz, Amprion, TenneT and TransnetBW
(MW)



Source: regelleistung.net

Figure 47: aFRR tendered in the control areas of 50Hertz, Amprion, TenneT and TransnetBW

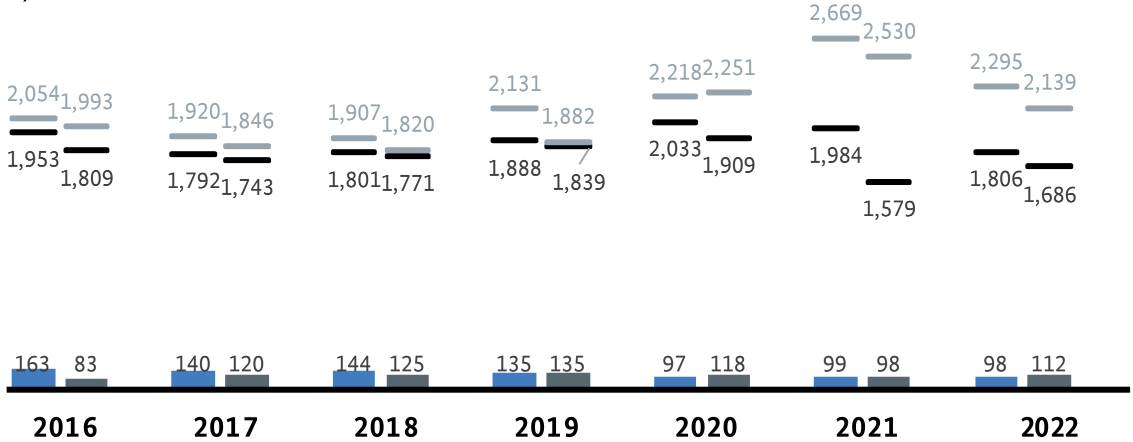
Electricity: mFRR tendered in the control areas of 50Hertz, Amprion, TenneT and TransnetBW
(MW)



Source: regelleistung.net

Figure 48: mFRR tendered in the control areas of 50Hertz, Amprion, TenneT and TransnetBW

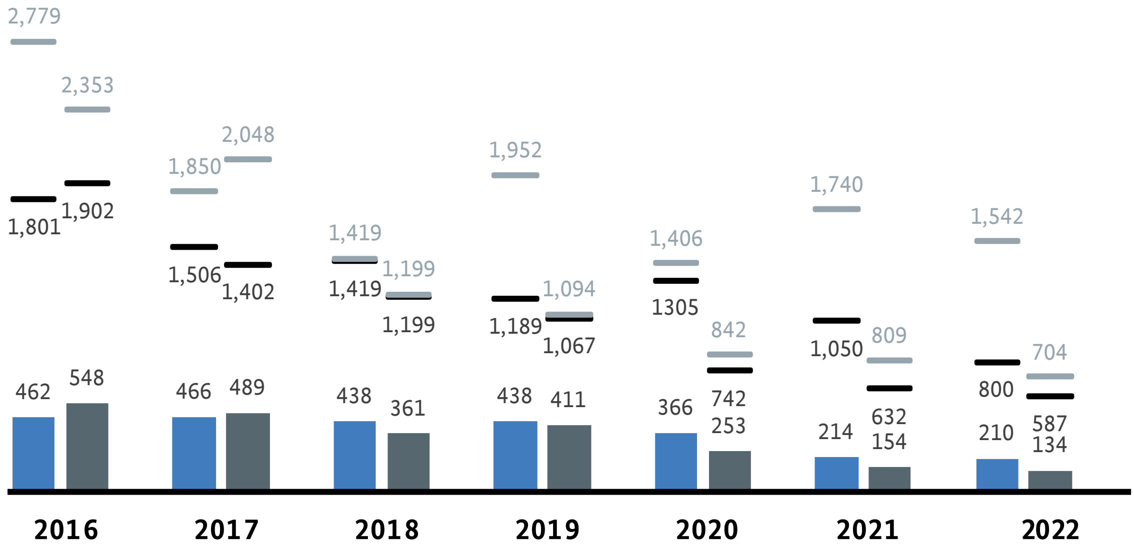
Electricity: Average volume of aFRR used, including aFRR drawn and delivered under online netting in the national grid control cooperation
(MW)



Source: regelleistung.net

Figure 49: Average volume of aFRR used, including aFRR drawn and delivered under online netting in the national grid control cooperation

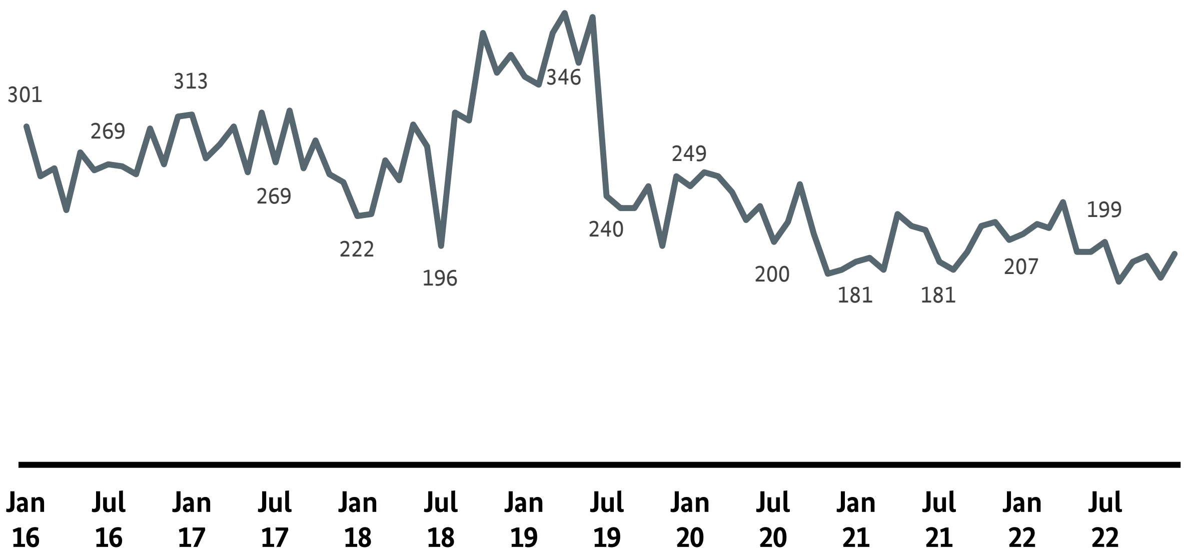
Electricity: Average use of mFRR in the national grid control cooperation
(MW)



Source: regelleistung.net

Figure 50: Average use of mFRR in the national grid control cooperation

Electricity: Average volume of balancing capacity used (aFRR and mFRR)
(MW)



Source: regelleistung.net

Figure 51: Average volume of balancing capacity used

Electricity: Maximum imbalance prices

Year	Uniform single imbalance price (€/MWh)
2016	1,212.80
2017	24,455.05
2018	2,013.51
2019	2,865.11
2020	15,859.10
2021	3,804.59
2022	11,443.11

Source: regelleistung.net

Table 50: Maximum imbalance prices

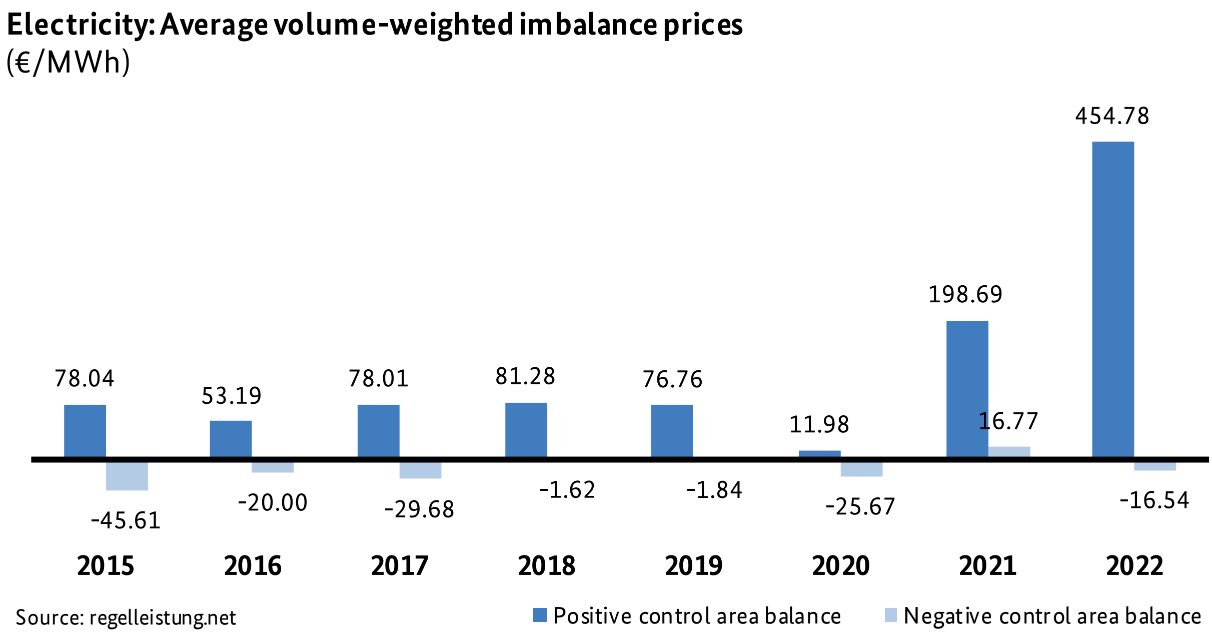


Figure 52: Average volume-weighted imbalance prices

E Cross-border trading and European integration

The countries of Europe are part of a European interconnected system for the exchange of electricity in which Germany acts as a central hub. The ongoing development of the European internal market for electricity is integrating electricity markets even more closely, which facilitates cross-border trade and ensures the secure, cost-efficient and sustainable supply of electricity.

Europe's internal market for electricity is divided into separate bidding zones in which electricity prices are determined according to supply and demand. Germany and Luxembourg constitute a common bidding zone with uniform prices. Electricity is traded within the bidding zone without capacity restrictions from the generator to the consumer. To make this work, physical congestion is rectified within a bidding zone either through redispatching measures and network expansion or congestion is taken into account when calculating cross-border capacity. However, the European regulatory framework, with its provisions for rising minimum capacities, is placing more and more constraints on how much leeway is allowed when calculating capacity, which is increasing pressure on network expansion and redispatching measures.

The physical exchange of electricity takes place mainly in two time frames:

- In the day-ahead market, electricity is auctioned for the following day. The auction applies marginal pricing, whereby the last winning bid sets the price for all transactions.
- Intraday trading mainly involves the continuous buying and selling of electricity (with one-hour, half-hour or quarter-hour settlement periods). This means that the price of each accepted bid is different (pay as bid).

Most day-ahead and intraday markets in Europe are coupled, meaning that available capacity between bidding zones is directly linked to the volume of electricity auctioned. 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. All the countries of the European Union are now coupled in the Single Day-ahead Coupling (SDAC). The aim of this market coupling is the efficient use of the limited transmission capacities between the bidding zones. The Single Intraday Coupling (SIDC) creates a consistent cross-border intraday electricity market that enables market participants to buy and sell electricity flexibly and in real time. Market participants are increasingly dependent on intraday trading as production from renewable sources is on the rise.

Limited interconnection capacities and certain internal network elements can physically restrict cross-border electricity trading. In Europe the capacities made available on the day-ahead market are determined in one of two ways:

- **Net Transfer Capacity (NTC)**
  In this process the TSOs involved agree on the available capacity for trading at each bidding zone border. The largest feasible value for all parties determines the available trading capacity. This value is 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 calculates the transmission capacity algorithmically. A grid model and the

trading results are used to achieve a capacity allocation that maximises welfare. This calculation method takes account of all relevant bidding zone borders, load flows and lines.

Regulation (EU) 2015/1222 sets flow-based market coupling as the target model for central Europe. It was launched in June 2022 in the Core region for day-ahead trading.[64] This model makes it possible to more efficiently determine the cross-border exchanges and thus facilitates the integration of renewable energies in the internal electricity market. Plans are underway to expand the model to intraday trading.

Trade flows between bidding zones differ from measured physical flows. As physical electricity flows always follow the path of least resistance, unscheduled flows such as loop and transit flows arise. Transmission losses, cross-border redispatch and measurement tolerances also result in (sometimes large) differences between physical flows and actual trade flows at a border. The unscheduled flows at each border are calculated as the difference between the net physical flows and the net actual trade flows and include the above-mentioned effects.

The actual trade flows 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. Imports and exports are evaluated by multiplying the trading volumes of actual trade flows by the day-ahead price for the Germany/Luxembourg bidding zone. Rational market behaviour is assumed insofar as longer-term contracts will only be fulfilled if the price levels are appropriate. 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 revenue.

Under Article 1 of Regulation (EU) No 838/2010, the TSOs receive inter-TSO compensation (ITC) through the ENTSO-E ITC fund for the costs incurred from hosting cross-border flows of electricity (transit flows) on their networks. This fund covers the costs of loss energy and of infrastructure for cross-border flows. The European Union Agency for the Cooperation of Energy Regulators (ACER) publishes a report each year on the implementation of the ITC mechanism.

[64] The Core region consists of Belgium, Germany, France, Croatia, Luxembourg, the Netherlands, Austria, Poland, Romania, Slovenia, Slovakia, Czechia and Hungary.

1. Average available transmission capacity

Electricity: Export and import capacity

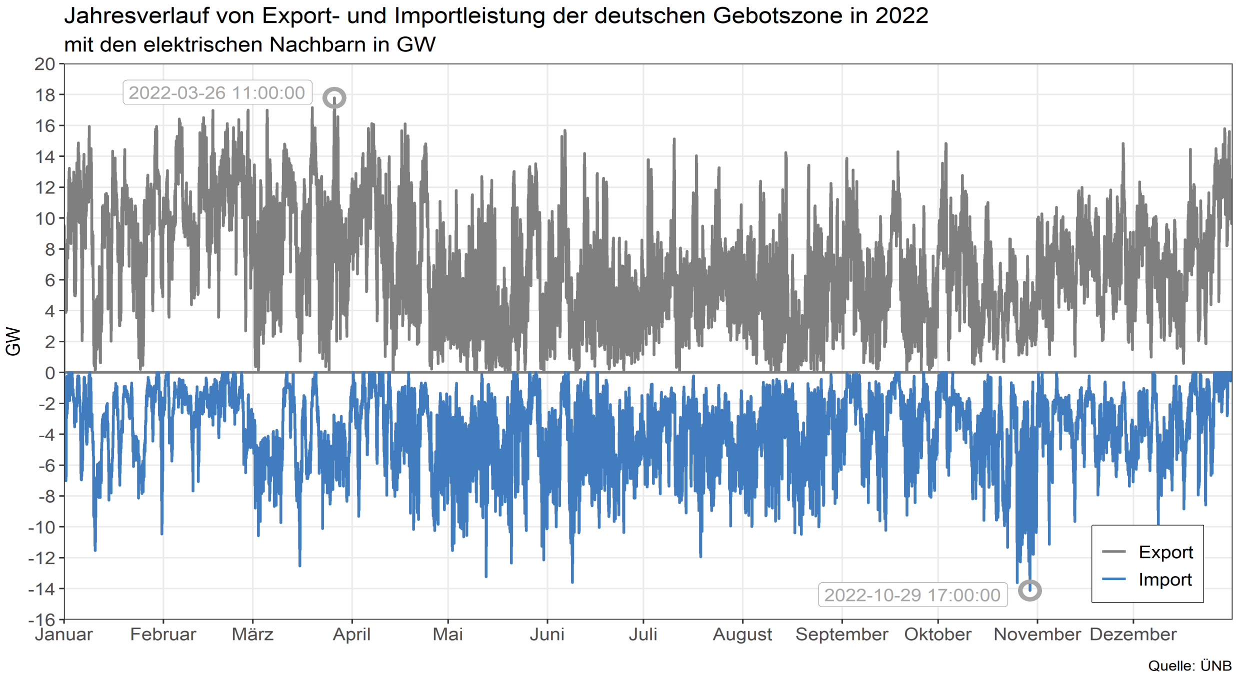
		2020		2021		2022	
		Export	Import	Export	Import	Export	Import
NTC	CH	1.264	3.708	1.347	3.629	1.341	3.946
	CZ	1.050	1.421	1.055	1.376	1.745	1.596
	DK	2.181	1.901	2.931	2.644	3.157	2.888
	NO	35	23	1.134	669	1.050	955
	PL	1.042	1.415	1.055	1.376	978	1.355
	SE	322	516	462	548	448	530
Flow Based	AT	4.864	5.028	4.988	4.945	5.337	5.477
	BE	572	572	922	922	987	987
	CZ					3.471	4.906
	FR	5.820	4.810	6.102	5.299	6.216	6.588
	NL	3.016	3.561	3.206	4.111	3.168	4.033
	PL					1.810	2.734

Tschechien und Polen: NTC-Werte bis einschließlich 08.06.22; Flow Based-Werte seit 09.06.22 mit Inbetriebnahme der Core Flow Based Kapazitätsberechnung

Quelle: ÜNB

Figure 53: Export and import capacity

Electricity: Exported and imported power
(GW)



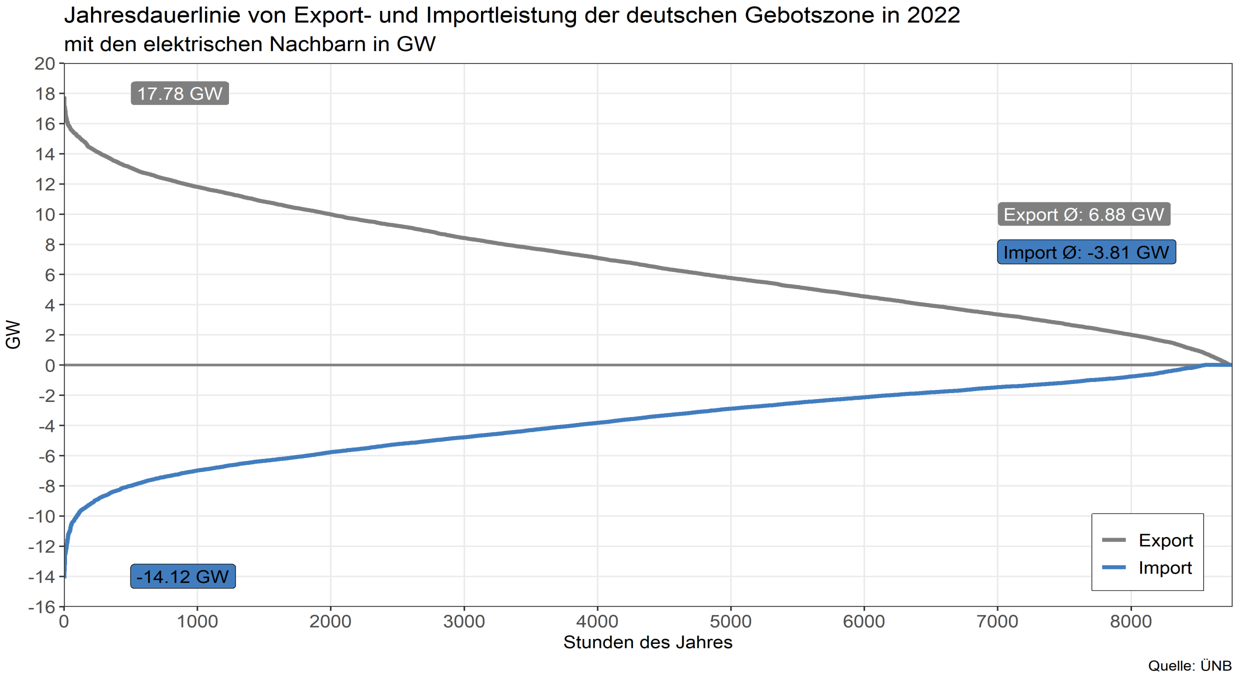


Figure 54: Exported and imported power

2. Cross-border flows and actual trade flows

Electricity: Exchange schedules (cross-border electricity trade) and physical

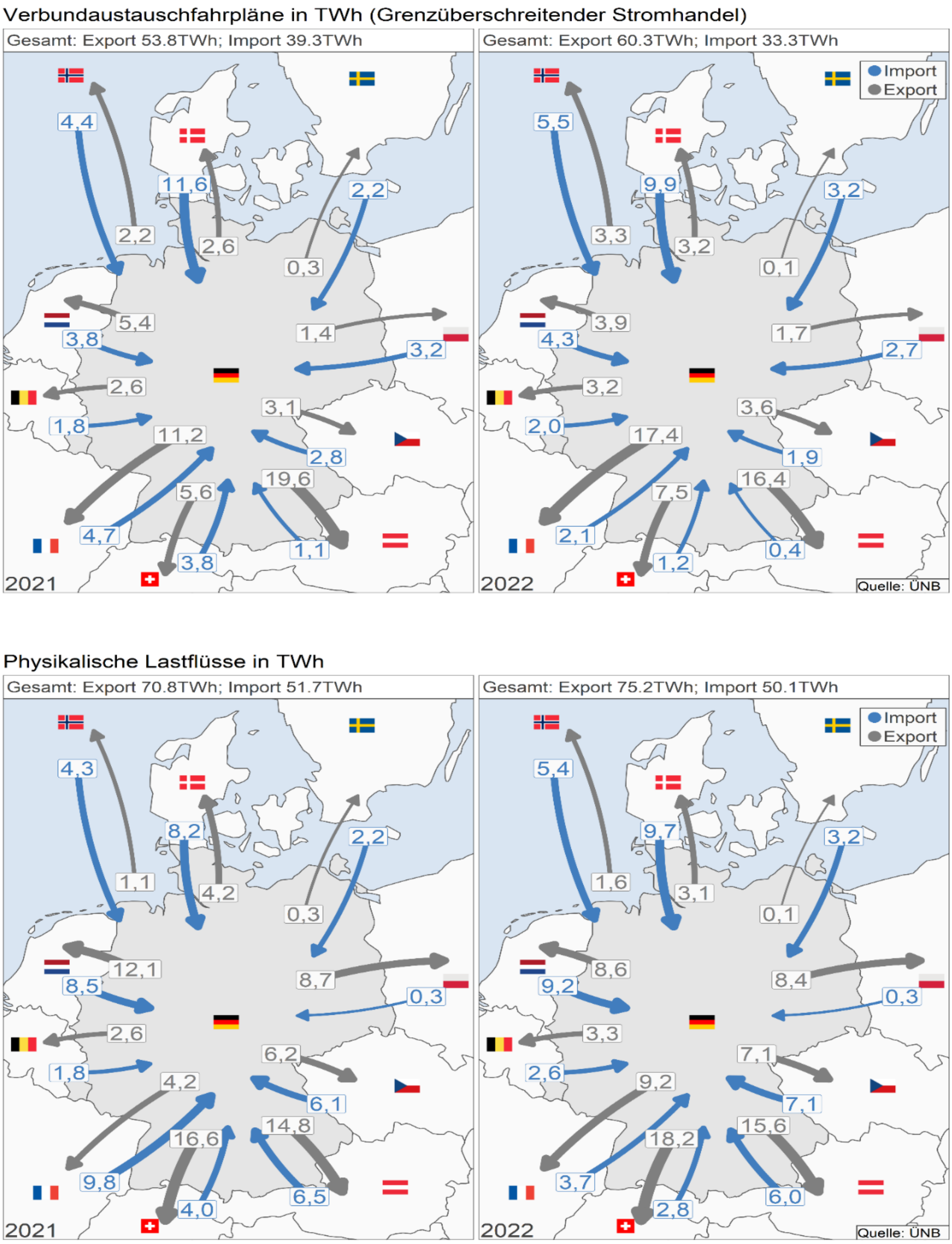


Figure 55: Exchange schedules (cross-border electricity trade) and physical flows

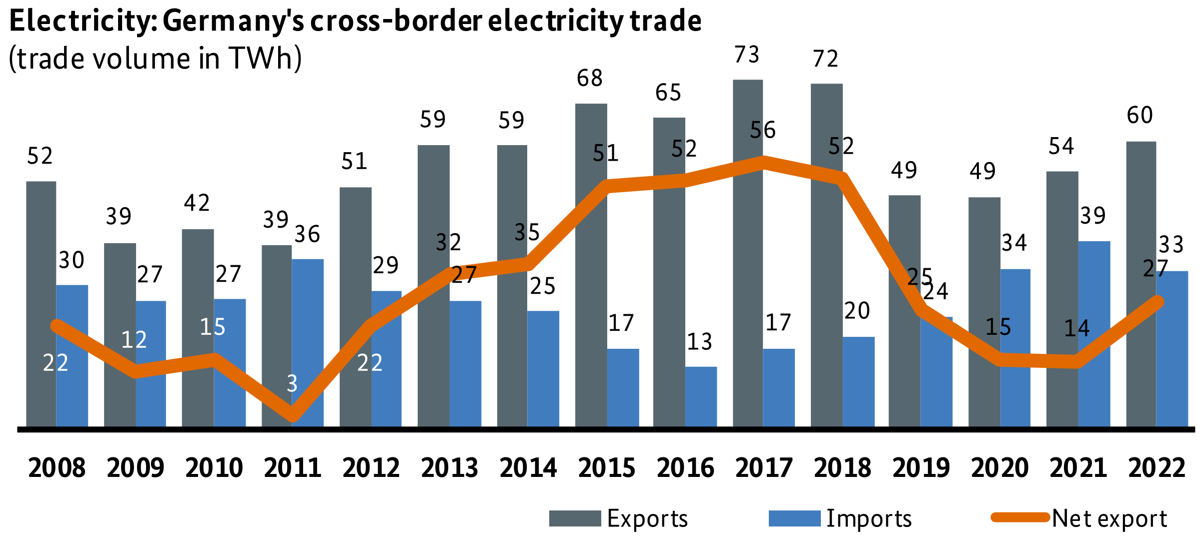


Figure 56: Germany's cross-border electricity trade

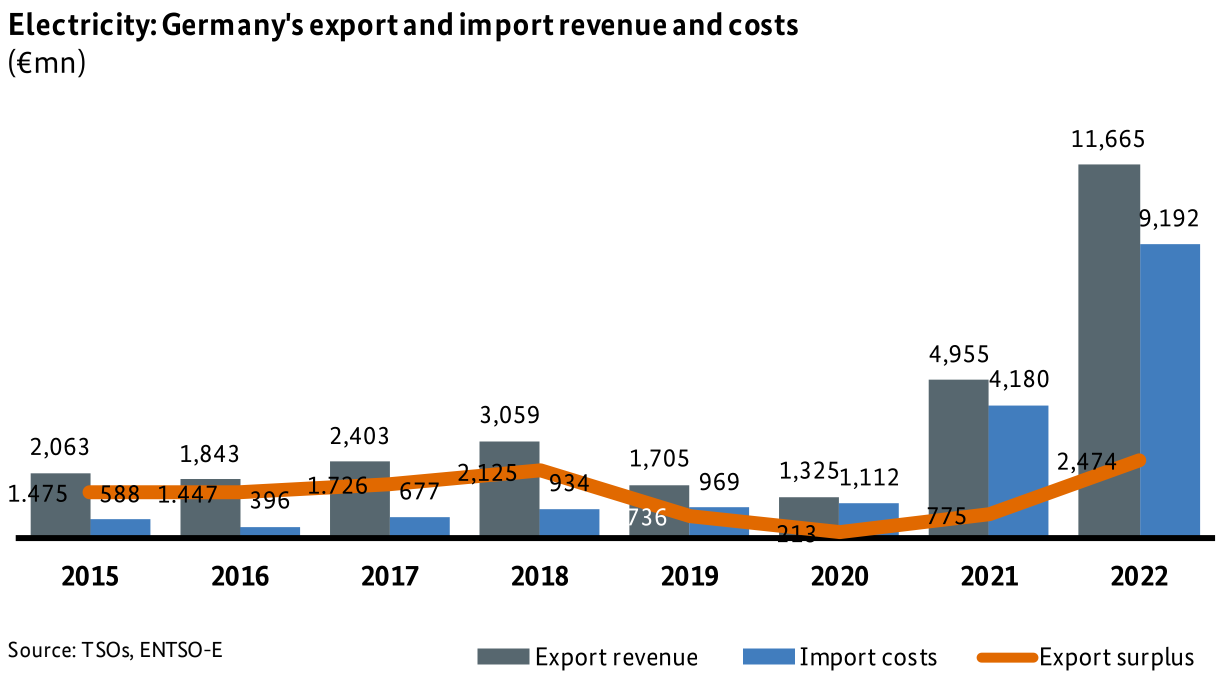


Figure 57: Germany's export and import revenue and costs

3. Unscheduled flows

Electricity: Unscheduled flows
(TWh)

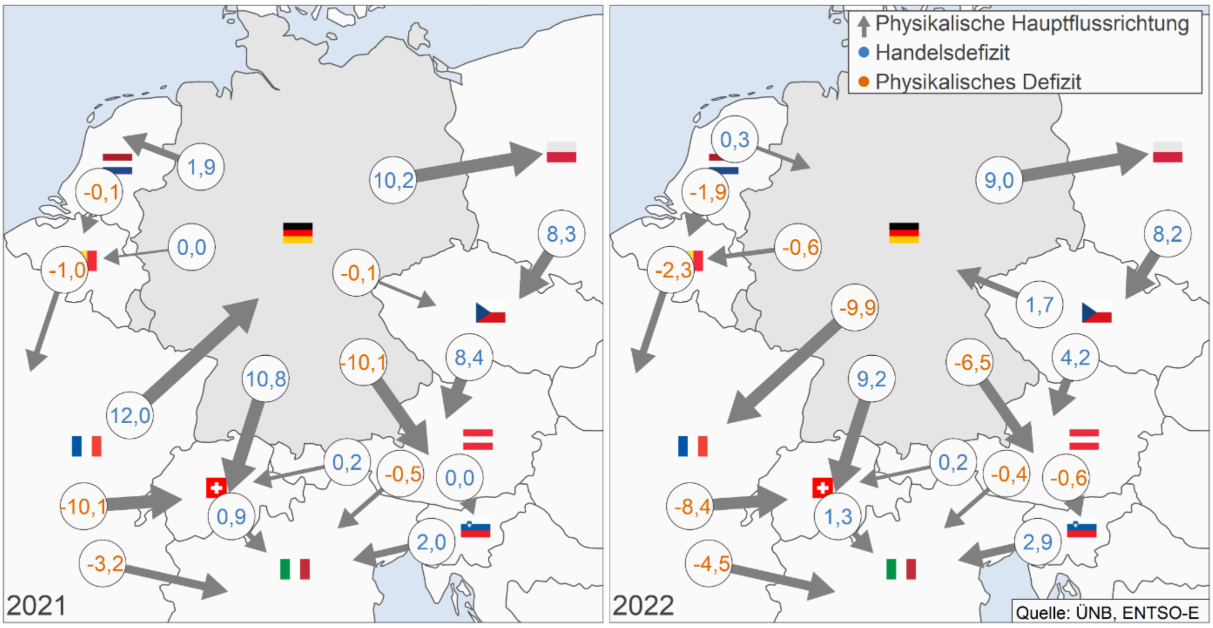
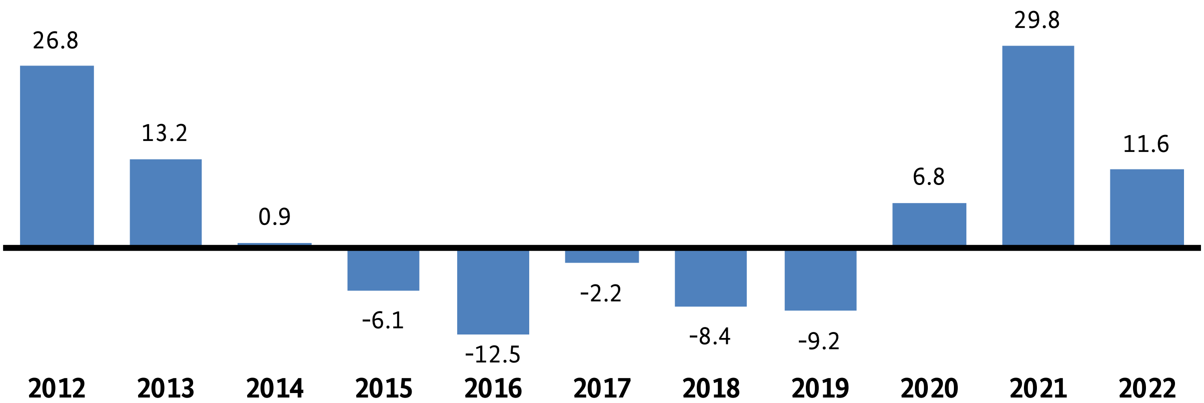


Figure 58: Unscheduled flows

4. Revenue from compensation payments for cross-border flows

Electricity: Net compensation payments from the ITC fund to the four TSOs



Source: ACER

Figure 59: Net compensation payments from the ITC fund to the four TSOs

F Wholesale electricity markets

Liquid wholesale markets – both on the electricity exchanges and as part of over-the-counter wholesale trading ("OTC trading") – 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 enable the hedging of price risks in the medium and long term, play an important role. Sufficient liquidity, that is easy tradability of electricity for suppliers and buyers, improves the chances for new suppliers and buyers 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.

Wholesale electricity trading takes place both on energy exchanges and as part of over-the-counter (OTC) wholesale trading, where in some cases it is arranged by a broker.

1. On-exchange wholesale trading

The analysis of on-exchange electricity trading covers the Germany/Luxembourg market area and the exchanges in Leipzig (European Energy Exchange AG – EEX), Paris (EPEX SPOT SE), Vienna (EXAA Abwicklungsstelle für Energieprodukte AG) and Berlin/Oslo (Nord Pool AS), which again participated in the energy monitoring data collection this year. While EEX offers electricity futures, EPEX SPOT, Nord Pool and EXAA cover spot market products. The players on the exchanges are registered electricity trading participants.[65]

[65] Not every company needs to have its own access to the exchanges. Alternatively, companies can use the services of brokers registered with the exchanges. Large corporations often combine their trading activities in an affiliate with relevant exchange registration.

Electriciy: Development of number of registered electricity trading participants on the exchanges

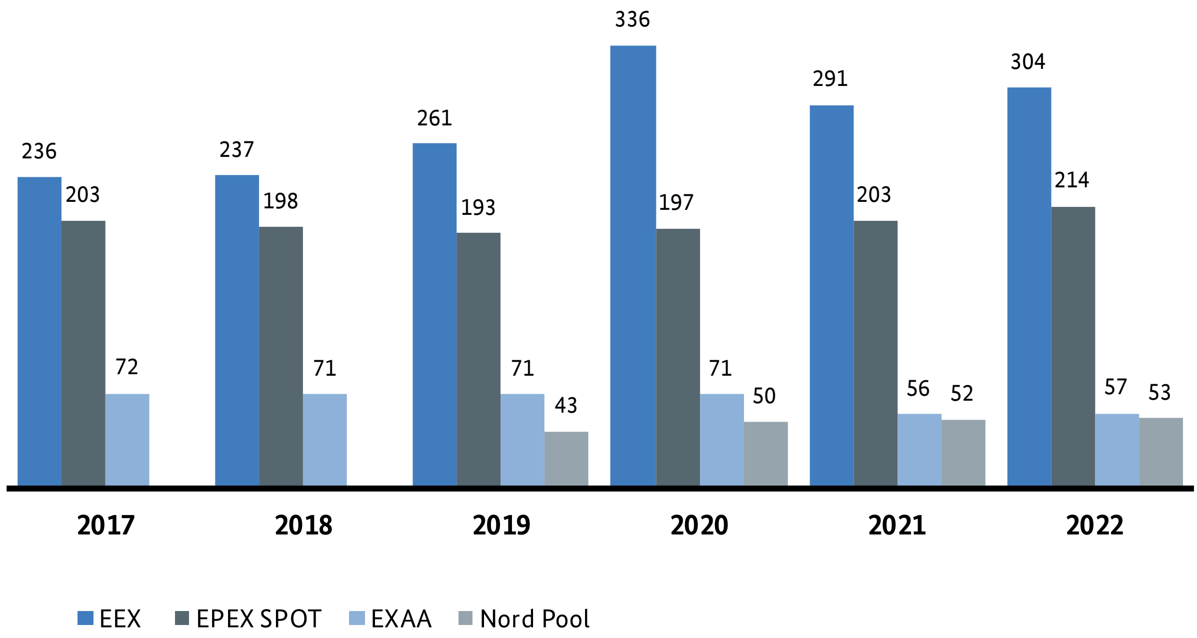


Figure 60: Development of number of registered electricity trading participants on the exchanges

On-exchange trading in electricity takes the form of spot or futures trading, which fulfil different, mostly complementary, functions. While the spot market, like over-the-counter trading, focuses on the physical settlement of the electricity supply contract (supply to a balancing group), on-exchange-traded futures are largely settled financially. Financial settlement means that ultimately no electricity is supplied between the contracting parties on the agreed due date; instead, the difference between the pre-agreed futures price and the spot market price is settled in cash. The spot market bids resulting from the choice of physical settlement of German power futures positions on the EEX exchange that can be placed on EPEX SPOT provide the relevant link.

1.1 Spot markets

On on-exchange spot markets electricity is auctioned a day ahead and then traded for the following and current day (intraday). The spot markets examined here, EPEX SPOT, Nord Pool and EXAA, all offer day-ahead trading. EPEX SPOT and Nord Pool also offer -> continuous intraday trading. Contracts can be physically settled (supply of electricity) on the two on-exchange spot markets for Luxembourg (Creos) and for the four German control areas (50Hertz, Amprion, TenneT, TransnetBW).

Spot markets – Day-ahead trading

Since 2 July 2019 day-ahead trading has been possible across all bidding zones of the western Europe region (and therefore also in the German bidding zone) within the context of single day-ahead coupling (SDAC).[66] The Day-Ahead Flow-Based Market Coupling project has been in operation since 8 June 2022. As a result, the previous western Europe region has been expanded and day-ahead market coupling is now also possible in Croatia, the Czech Republic, Hungary, Poland, Romania, Slovakia and Slovenia. Since then, day-ahead market coupling has therefore taken place in the core capacity calculation region (Core CCR).[67] On this basis, market participants can access the midday auction for the Germany/Luxembourg market area via each of the three approved exchanges named above[68] (NEMO – Nominated Electricity Market Operator). In this auction, a central auction algorithm calculates a single day-ahead price (SDAC price) for each bidding zone based on all the orders placed in time, taking into account the available capacities of the interconnectors. The SDAC price determined in this way is the binding auction price for every electricity exchange within a bidding zone; it is therefore irrelevant on which electricity exchange market participants conduct their trading.

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 coupled day-ahead auction. Bids for the complete or partial physical settlement of futures traded on EEX (futures positions) may also be submitted. In addition to the SDAC auction, EXAA currently offers another earlier, independent and non-coupled day-ahead auction at 10.15am for the Germany/Luxembourg market area. The earlier auction time on the EXAA exchange at 10.15am provides traders with a first relevant price signal for the remaining trading day.

Spot markets – Intraday trading

Since 13 June 2018 the bidding zone Germany/Luxembourg has been coupled with other European markets within the context of single intraday coupling (SIDC).[69] This gives market participants access to the entire European market liquidity, irrespective of the exchange on which they trade. In the German bidding zone, both Nord Pool and EPEX SPOT provide access to cross-zonal intraday trading.[70] Continuous intraday trading on EPEX SPOT and Nord Pool involves single hours, 15-minute periods and standardised blocks. Electricity contracts for the German control areas can be traded on EPEX SPOT up to 30 minutes before commencement of supply (coupled within the SIDC framework only up to 60 minutes before commencement of supply), on Nord Pool up to 20 minutes before commencement of supply and on EPEX SPOT up to 5 minutes before commencement of supply within the control areas and up to the time of supply on Nord Pool.[71] Currently, intraday cross-border capacities between the four German TSO control areas are only made available at 6pm

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[66] Legal basis: Commission Regulation (EU) 2015/1222 of 24 July 2015 (CACM Regulation).

[67] https://www.nemo-committee.eu/assets/files/successful-go-live-of-the-core-fb-mc-project-.pdf, last accessed on 30 August 2023.

[68] Nasdaq Oslo ASA is also approved for day-ahead trading but is not yet operating, source: https://www.nemo-committee.eu/designated-NEMOs.pdf, last accessed on 29 August 2023.

[69] Austria, Belgium, Denmark, Estonia, Finland, France, Latvia, Lithuania, Luxembourg, Norway, Netherlands, Portugal, Spain, Sweden; since November 2020 Bulgaria, Croatia, Czech Republic, Hungary, Poland, Romania and Slovenia; since September 2021 Italy.

[70] For further information please see BNetzA, decisions BK6-18-098 and BK6-16-017 (preceding decision for the DE/AT/LU bidding zone), available in German at: https://www.bundesnetzagentur.de/DE/Beschlusskammern/1_GZ/BK6-GZ/2018/BK6-18-098/BK6-18-098_beschluss_vom_04_10_2018.html?nn=872010.

[71] ACER 2018: Acer adopts a decision on intraday cross-zonal gate opening and closure time, available at: https://documents.acer.europa.eu/Media/News/Pages/ACER-adopts-a-decision-on-intraday-cross-zonal-gate-opening-and-closure-time.aspx dated 7 May 2018, last accessed on 1 September 2022.

on the previous day. The German TSOs have now undertaken to provide unlimited transmission capacity between the four German TSO control areas from 3pm to 6pm, allowing trading on the SIDC platform throughout Germany.

The so-called shared order books (SOB) are essential for SIDC. Under the CACM Regulation all NEMOs active in the SIDC context are obliged to submit orders received from their market participants to the SOB immediately upon their receipt. When transmission capacity is available, orders to trade are automatically collated across bidding zones to maximise the use of the transmission capacities. This obligation for NEMOs to submit their orders to the SOB ends at the intraday cross-zonal gate closure time 60 minutes prior to the commencement of supply since this is the time when cross-border trading closes and cross-border capacities are no longer available. Intraday trading within the Germany/Luxembourg bidding zone continues until the actual commencement of supply. This means that it is also necessary for all NEMOs in the Germany/Luxembourg bidding zone to have access to intraday orders in the last 60 minutes.[72]

NEMO ETPA Holding B.V., nominated in the Netherlands, notified the Bundesnetzagentur on 14 June 2023 pursuant to Article 4(5) of Regulation (EU) 2015/1222 of its intention to implement intraday market coupling in Germany from 1 September 2023.[73] So far, ETPA has not yet taken up business activities in Germany.

[72] The CACM Regulation is currently being amended. ACER suggests that the sharing of the books be extended to the entire intraday trading period and not only when cross-border capacities are available.

[73] https://www.bundesnetzagentur.de/DE/Fachthemen/ElektrizitaetundGas/HandelundVertrieb/NEMO/start.html, last accessed on 29 August 2023.

1.1.1 Trading volumes

Electricity: Development of spot market volumes on EPEX SPOT, Nord Pool and EXAA
in TWh

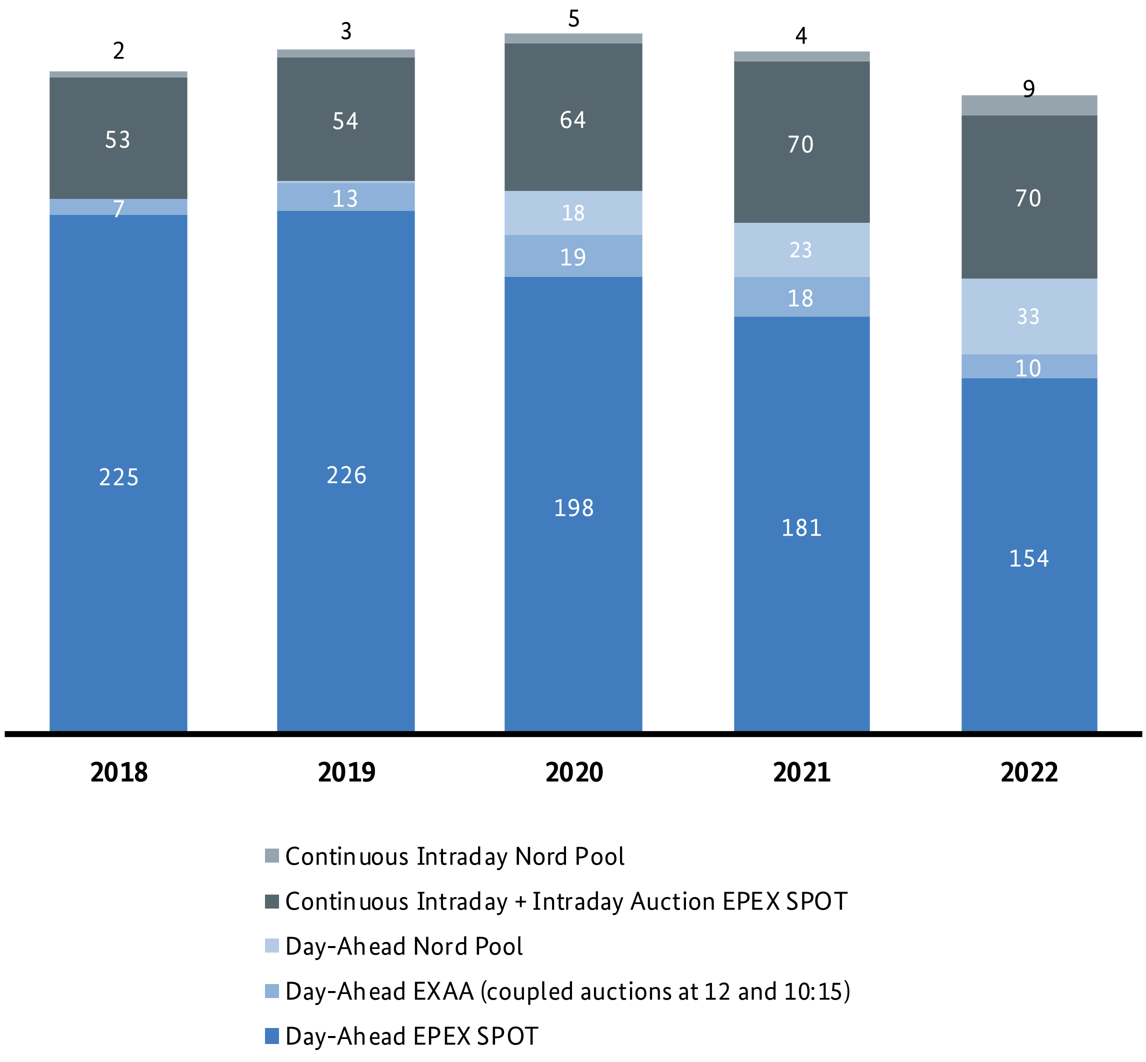

Figure 61: Development of spot market volumes on EPEX SPOT, Nord Pool and EXAA[74]

[74] The illustration of trading volumes has been adjusted from 2020 onwards to reflect the participation of several electricity exchanges in the coupled day-ahead auction. The volumes shown for 2020 represent the average of purchase and sales orders fulfilled on each electricity exchange over the year. In this and previous reports the trading volumes on EPEX SPOT for the day-ahead auction in the years before 2020 are reported as the sum of the maximum purchase and sales volumes per hour of supply. In the event of several electricity exchanges participating in an auction, this method, when applied to all participants, would overstate the total volume of electricity traded. Due to the change in the calculation method, the figures for the coupled day-ahead auction from 2020 onwards are

1.1.2 Price level

The most commonly used price index for the spot market in the German market area is the SDAC. The day-ahead baseload is the arithmetic mean of the 24 single-hour prices of the coupled day-ahead auction of a given day, and the day-peak load is the arithmetic mean of hours 9 to 20 of a day, that is 8am to 8pm.

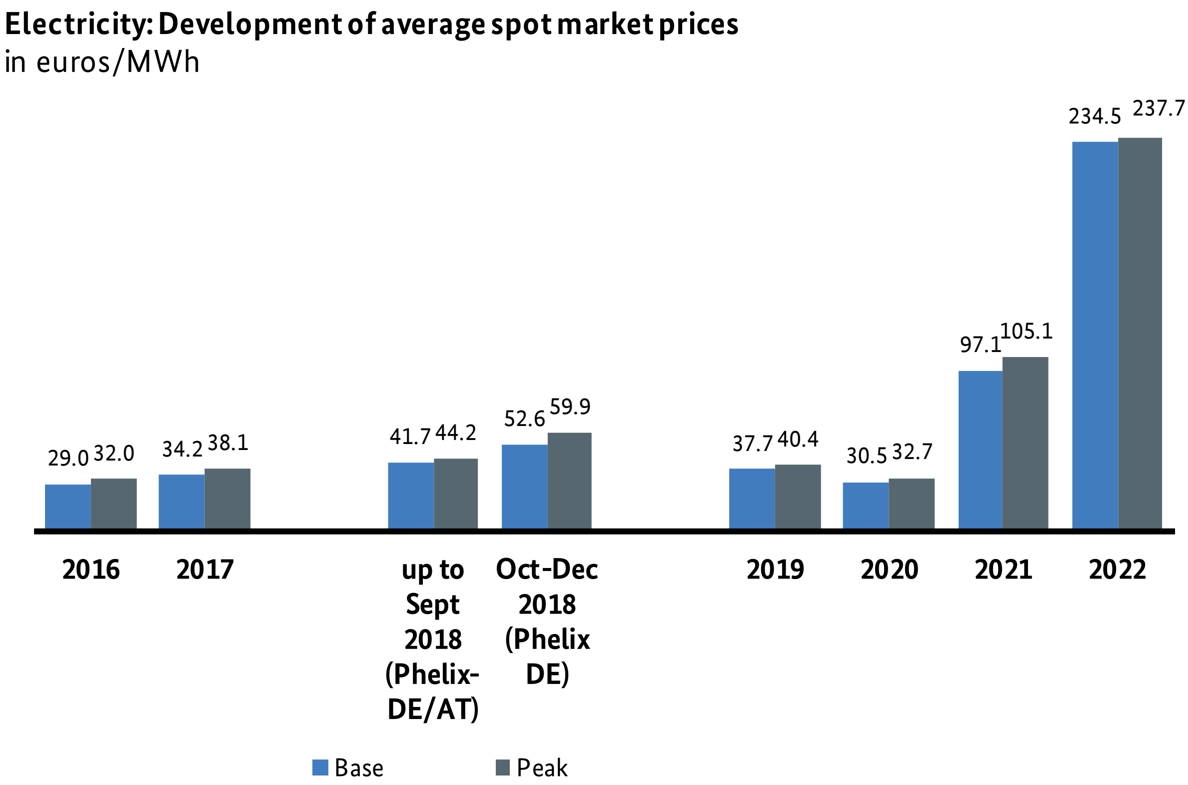

Figure 62: Development of the average spot market prices of the coupled auction

Spot markets – Price dispersion

As in previous years SDAC prices exhibit considerable dispersion over the year. The arithmetic mean of the daily prices – using the baseload as an example – reflects the rise in uncertain energy markets in 2022.

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not fully comparable with the previous years' figures. Using the previous calculation method, the sum of the maximum purchase and sales volumes per hour of supply traded on EPEX SPOT in 2020 was approximately 216 TWh.
The continuous intraday trading volumes in 2020 and in previous years already represent the average number of purchase and sales orders fulfilled on each electricity exchange throughout the year.

Electricity: Development of the Day Baseload prices in 2022
in euros/MWh

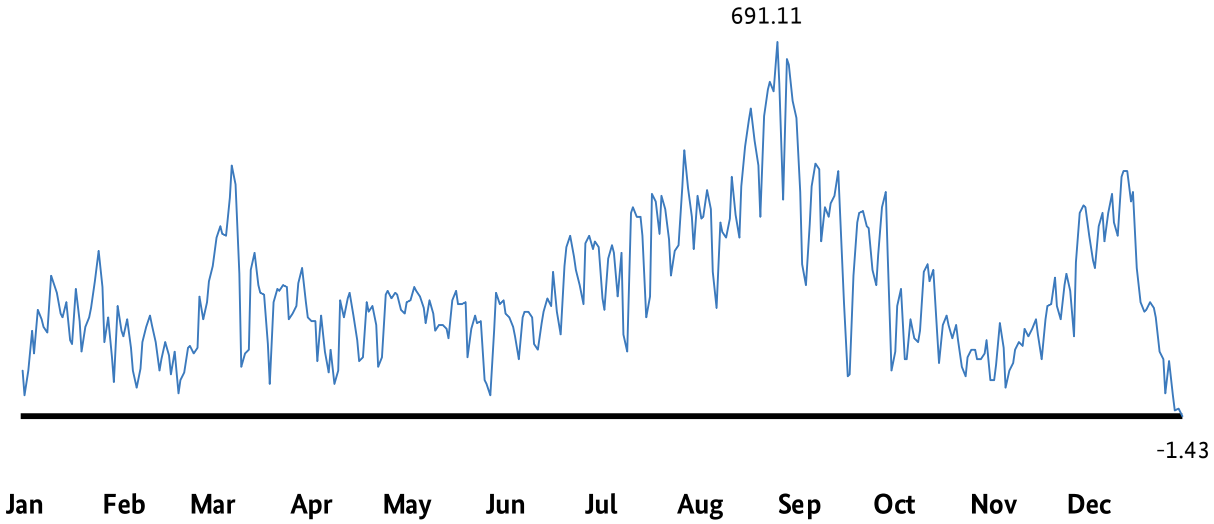


Figure 63: Development of the Day Baseload prices in 2022

Electricity: Ranges of the baseload and peak load prices
in euro/MWh

	Middle 80 percent	Range of middle 80 percent	Extreme values	Range of extreme values
	Quantile 10 and 90 of graded values		min – max	
Base 2020	13.72 – 46.26	32.54	-26.13 – 75.03	101.16
Base 2021	40.26 - 184.81	144.54	-8.23 – 427.5	435.73
Base 2022	96.29 - 406.50	310.2	-1.43 – 691.11	692.54
Peak 2020	11.58 – 52.39	40.81	-45.64 – 103.79	149.43
Peak 2021	38.73 - 211.50	172.78	-19.56 – 510.52	530.08
Peak 2022	93.06 - 423.02	329.97	-1.49 – 720.26	721.75

Table 51: Ranges of the baseload and peak load prices between 2020 and 2022

1.2 Futures markets

Futures with standardised maturities can be traded on EEX for the Germany/Luxembourg market area. 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 in the futures market, excluding OTC clearing. An annual average can be calculated using the German Power Futures prices for the following year recorded on the EEX exchange on individual trading days. This average would correspond to the average electricity purchase price or electricity sales price of a market player if the player had purchased or sold the electricity not at short notice but continuously in the preceding year.

1.2.1 Trading volumes

Electricity: Trading volume of futures on EEX
in TWh

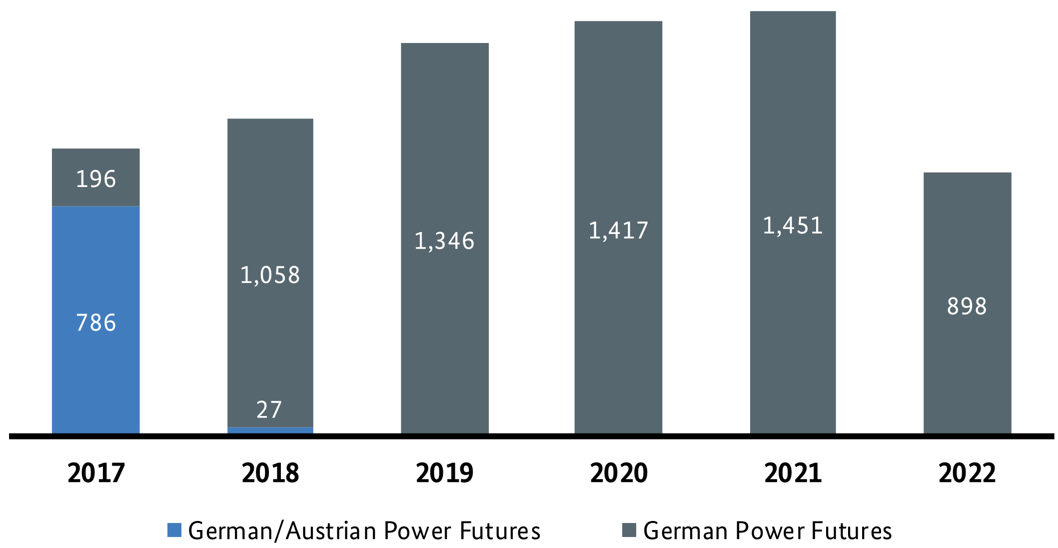


Figure 64: Trading volume of German/Austrian Power Futures and German Power Futures on EEX

Electricity: Trading volumes of German Power Futures on EEX by settlement year
in TWh

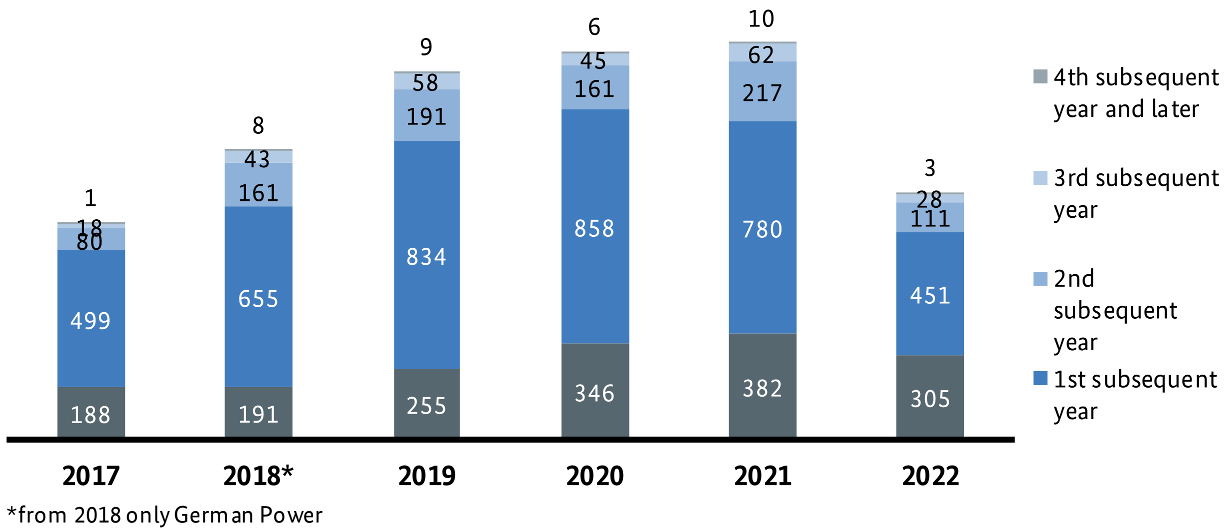


Figure 65: Trading volumes of German Power Futures by settlement year

1.2.2 Price level

Figure 66: Development of German Power Future Base-Year prices and German Power Future Peak-Year prices in 2022

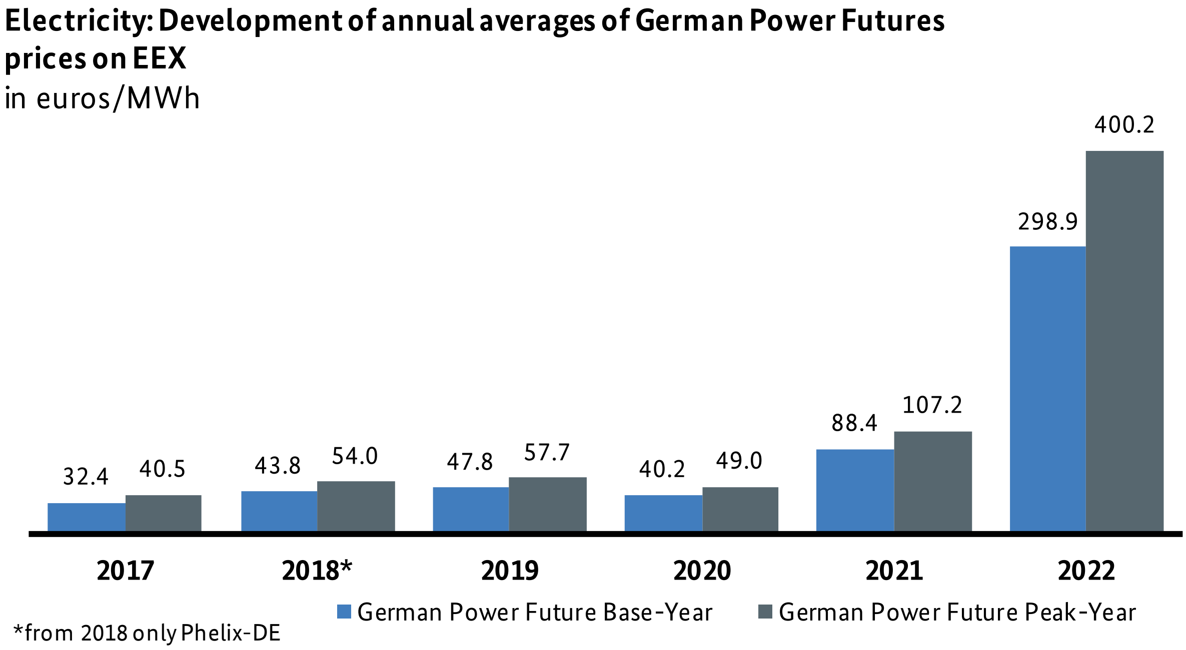


Figure 67: Development of annual averages of the German Power Futures prices on EEX

2. Off-exchange wholesale trading

Off-exchange wholesale trading (OTC trading) is characterised by the fact that the contracting parties are known to each other (or become known to each other at the latest when concluding the transaction) and that the parties can flexibly agree on the individual details of the contract. The surveys carried out to monitor OTC trading aim to record the amount, structure and development of (bilateral) trading volumes. However, in contrast to on-exchange trading, it is not possible to provide a complete picture of wholesale trading since there are no clearly definable market places and no standard set of contract types in off-exchange trading. Moreover, trading platforms have developed from bilateral to multilateral trading platforms, involving not only buyers and sellers but also intermediaries, brokers, etc.

Brokers play an important part in the transition from bilateral to multilateral wholesale trading. They act as intermediaries between buyers and sellers, pooling information on supply and demand for electricity transactions. Electronic broker platforms are used to bring together interested parties on the supply and demand sides, thereby increasing the chances of the two parties reaching an agreement.

In 2022 various broker platforms were once again surveyed in relation to off-exchange wholesale trading (see sections below). Data on OTC clearing on EEX were also collected.

2.1 Broker platforms

As part of the monitoring, broker platform operators are also asked to answer questions about the contracts they have brokered. Many brokers offer an electronic platform to conduct their brokerage services. Nine brokers (ten in the previous year) who brokered electricity trading transactions with Germany as the supply area participated in this year's collection of wholesale trading data.

Electricity: Volume of electricity traded via broker platforms in 2022 by settlement year

Settlement period	Volumes traded in TWh	Share
Intraday	4	0%
Day ahead	64	2%
less than 1 week	14	1%
more than 1 week	782	29%
1st subsequent year	1,310	48%
2nd subsequent year	391	14%
3rd subsequent year	119	4%
4th subsequent year	21	1%
Total	**2,704**	**100%**

Table 52: Volume of electricity traded via broker platforms in 2022 by settlement period

2.2 OTC Clearing

Alongside on-exchange trading, on-exchange -> OTC clearing plays a special role in off-exchange wholesale trading. OTC transactions that correspond to standard exchange-traded products can be registered on the exchange, whereby the exchange or its clearing house becomes the trading participants' contracting party and bears the counterparty risk. While without applying this method the default risk in OTC trading can be reduced or hedged by various means, it cannot be eliminated altogether. Another factor is that including OTC transactions can in some cases reduce the amount of the collateral required for exchange trading, in futures for example, that has to be deposited with the clearing bank.

By registering on the exchanges, the contracting parties ensure that their contract is subsequently treated as an exchange-traded transaction, meaning both parties are regarded as if 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[75]) for all futures products that are also approved for exchange trading on EEX and for EPEX SPOT.

As OTC clearing is used to (retroactively) treat contracts as exchange-traded futures, the development of the OTC clearing volume should also be considered in the context of the exchange-traded futures market volume:

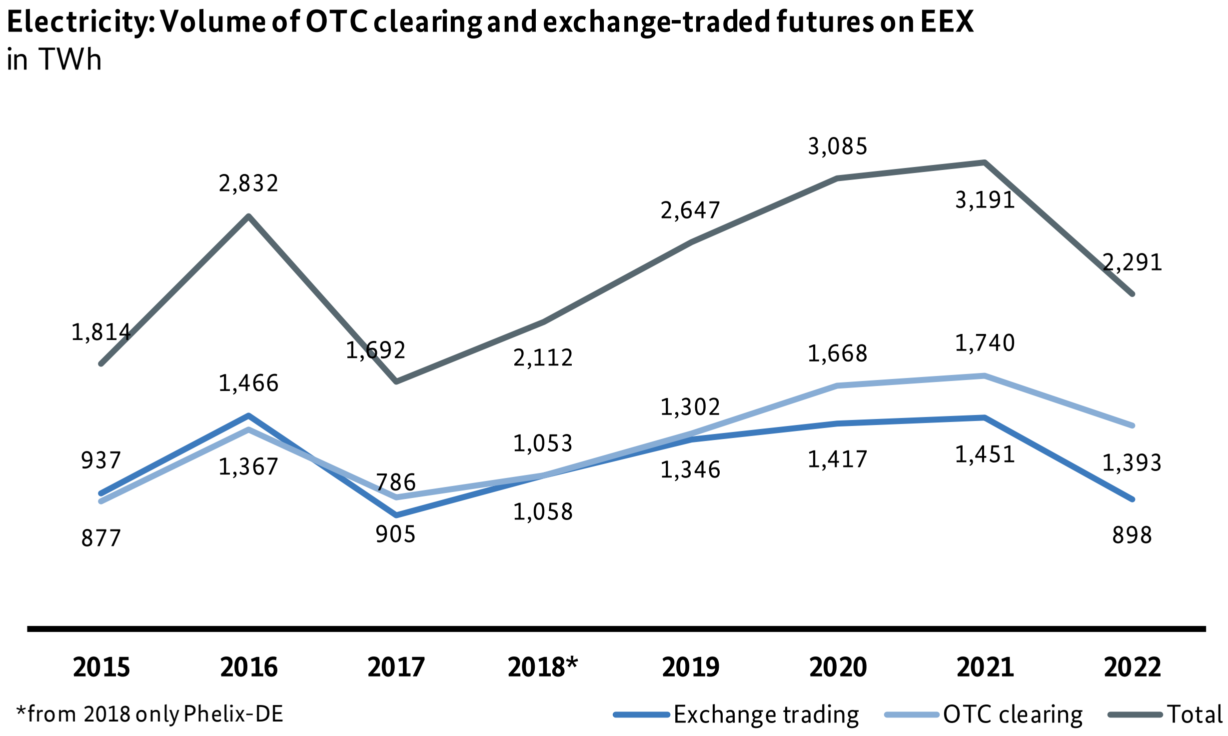


Figure 68: Volume of OTC clearing and exchange-traded German Power Futures

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

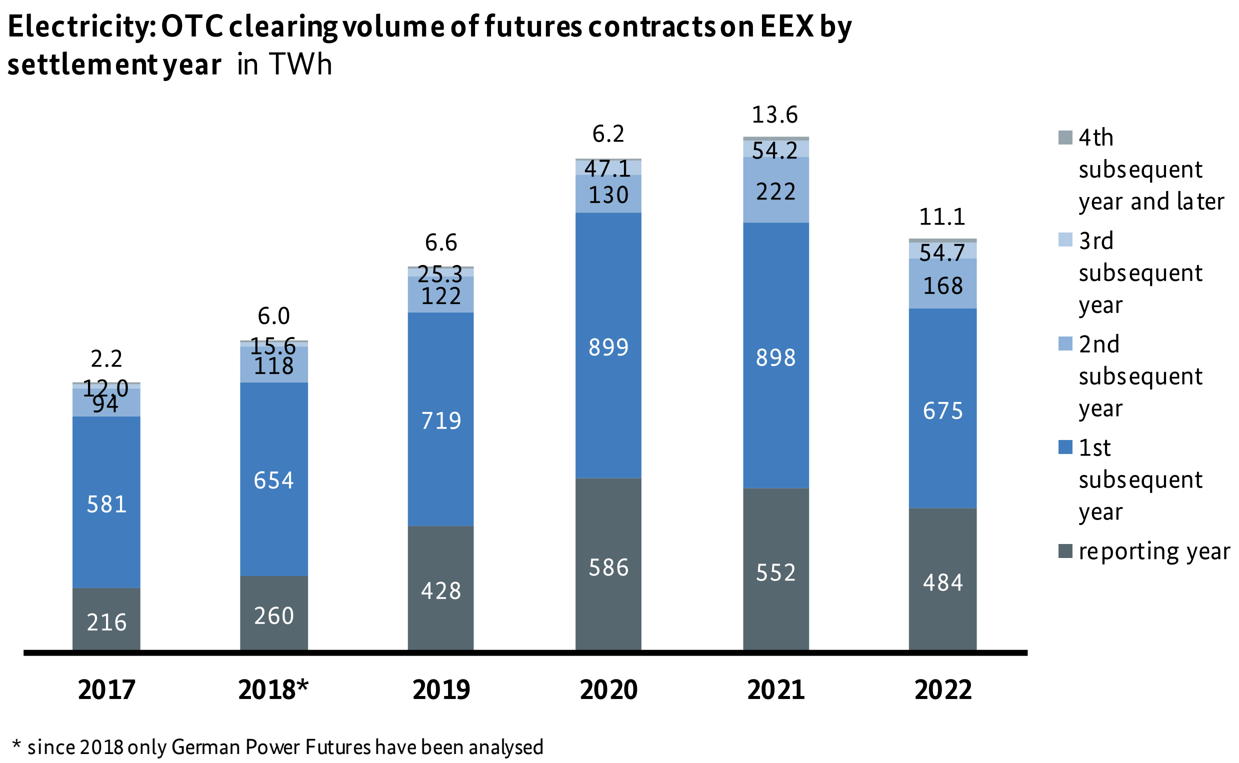


Figure 69: OTC clearing volume of futures on EEX by settlement year

G Retail

In the electricity retail sector, private households, businesses and industrial customers can buy electricity from various suppliers. As customers have free choice of electricity supplier, the market is characterised by a high level of competitive intensity. Electricity utility suppliers on the retail market offer various tariffs with different price structures and contract terms and conditions. These tariffs may be based on a fixed price, a unit price or a combination of the two. Customers can choose the supplier and tariff best suited to their individual needs and preferences.

Energy utilities have to meet stringent legal and regulatory requirements on the retail market in order to ensure fair conditions for consumers. Regulatory authorities monitor the market to make sure that suppliers offer transparent tariffs and comply with fair practices. In sum, the electricity retail market enables consumers in Germany to select a supplier according to their needs and preferences and to benefit from competition and a wide range of offers. More detailed explanations may be found in the glossary to this report. More data may be found on www.SMARD.de.

1. Supplier structure and number of providers

Over 1,400 suppliers are responsible for supplying final customers with electricity. They do this by providing electricity at market locations. Electricity customers can usually choose from a number of different regional or national suppliers. Only in the case of default supply do customers not have the right to choose. Default supply refers to supply by the electricity utility that has the most household customers in the local network area.

Electricity: Suppliers by number of market locations supplied in 2022
not taking company affiliations into account

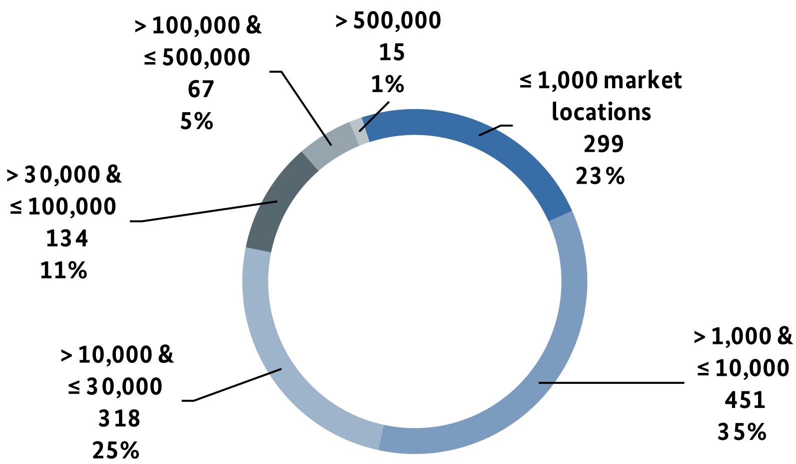


Figure 70: Suppliers by number of market locations supplied in 2022 (number and percentage)

Electricity: Suppliers by number of network areas supplied in 2022
not taking company affiliations into account

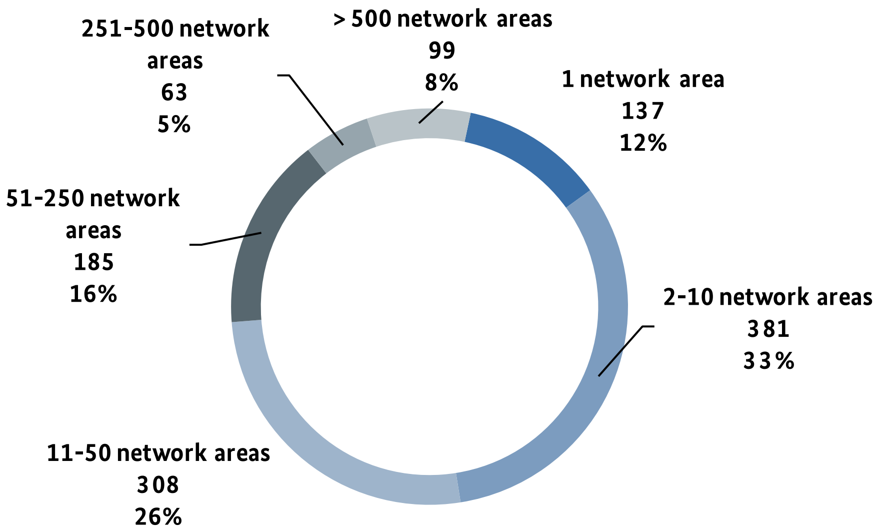


Figure 71: Suppliers by number of network areas supplied in 2022 (number and percentage)

Electricity: Breakdown of network areas by number of suppliers operating
in %, not taking company affiliations into account

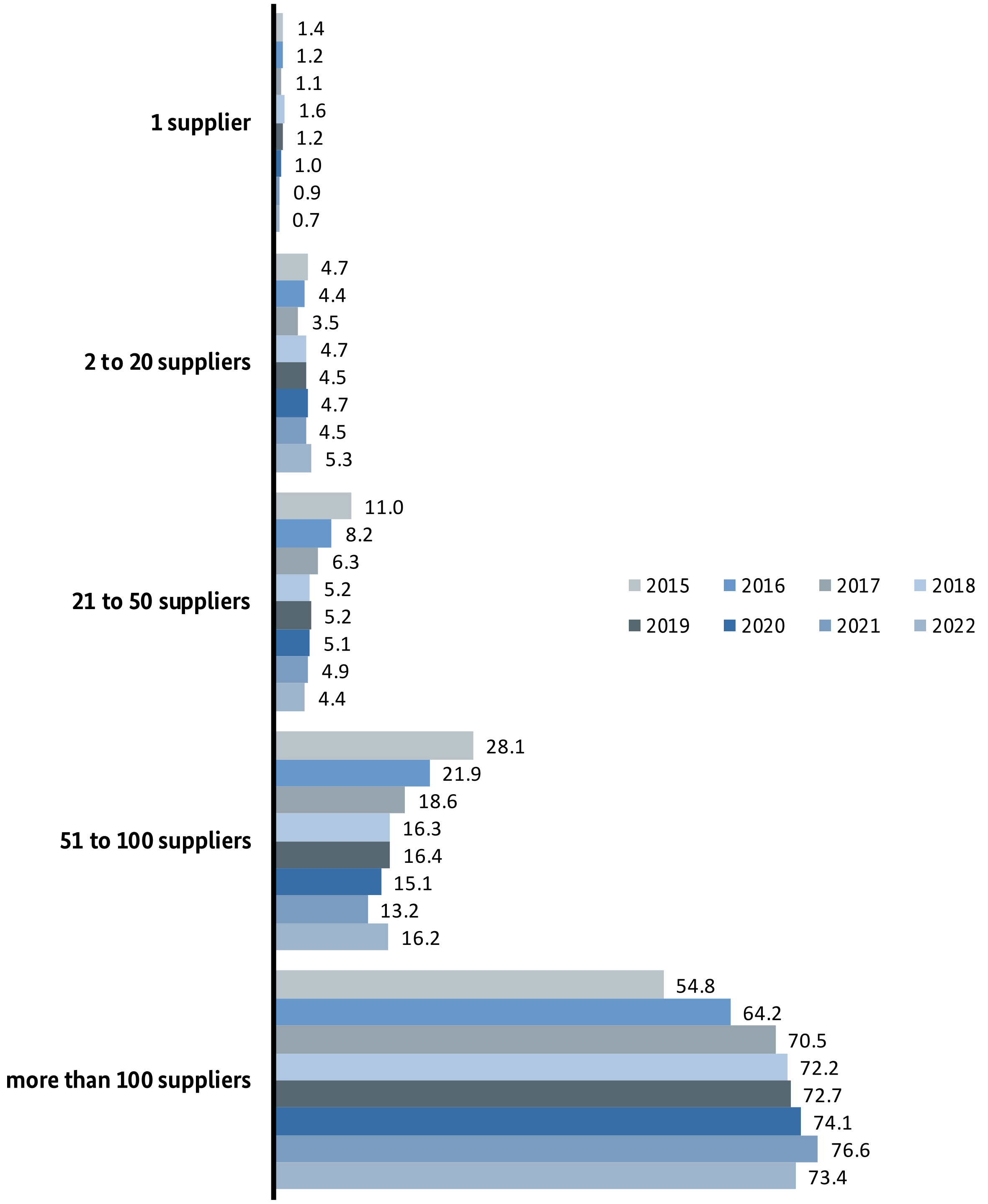


Figure 72: Breakdown of network areas by number of suppliers operating

2. Contract structure and supplier switching

Final customers can be grouped, according to their metering profile, into customers with and without interval metering. The latter will have their consumption over a set period estimated using a standard load profile (SLP). Final customers can also be grouped into household, commercial and industrial customers. Household customers are defined in the German Energy Industry Act (EnWG) mostly according to qualitative characteristics.[76] Non-household customers are also referred to as business and industrial customers. There is no generally recognised definition of either commercial or industrial customers yet.[77]

There are three types of electricity supply contracts. They differ in terms of contract modalities, suppliers' obligations and prices:

- default contract with the default supplier,
- non-default contract with the default supplier,
- contract with a supplier that is not the local default supplier.

Hence switching contract or supplier are ways to influence the price of electricity and contract modalities. In this context, supplier switching is the process of allocating a final customer's market location to a new supplier. Final customers moving into or out of a location are not considered as switching suppliers. Supplier changes within the same corporation are referred to as contract changes.

Data on the supplier switching rates among different customer groups and the consumption volumes attributed to these customers was collected in the transmission system operators (TSO) and distribution system operators (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 (ie commercial customers) fall into the 10 MWh/year to 2 GWh/year category.

[76] Section 3 para 22 EnWG defines household customers as final customers 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 kWh.

[77] Customers from the fields of independent professions, agriculture, services and public administration are normally grouped under "commercial customers" if their annual consumption exceeds 10,000 kWh.

Electricity: Contract structure for interval-metered customers in 2022
Volume and share

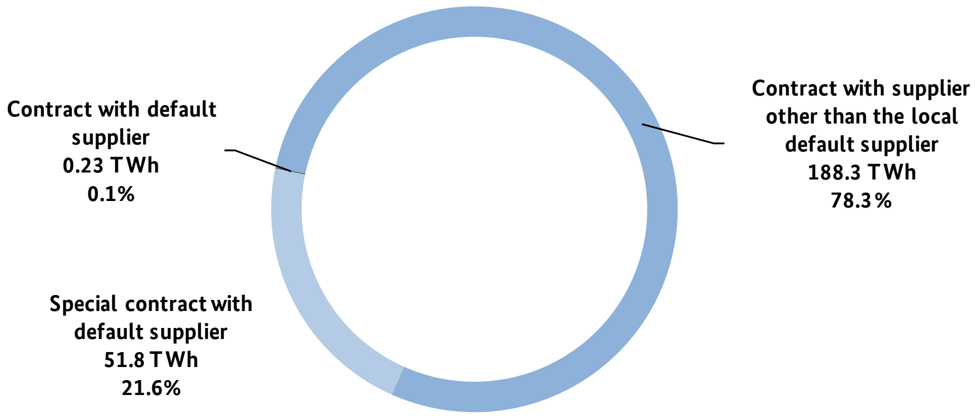


Figure 73: Contract structure for interval-metered customers in 2022 according to data from electricity suppliers

Electricity: Contract structure of household customers in 2022
volume (TWh) and share (%)

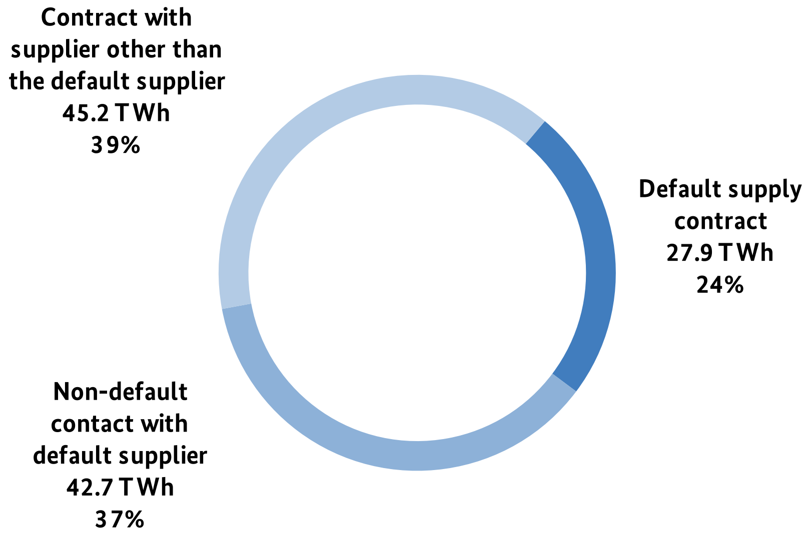


Figure 74: Contract structure of household customers in 2022

Electricity: Supplier switching by consumption category in 2022

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	199,262	9.9%	16.6	14.0%
> 2 GWh/year	2,617	15.3%	25.0	11.8%
Total non-household customers	**201,897**	**10.0%**	**41.6**	**12.6%**

Table 53: Supplier switching by consumption category in 2022

Electricity: Development of supplier switching among non-household customers
Volume-based switching rate for all consumption categories exceeding 10 MWh/year (%)

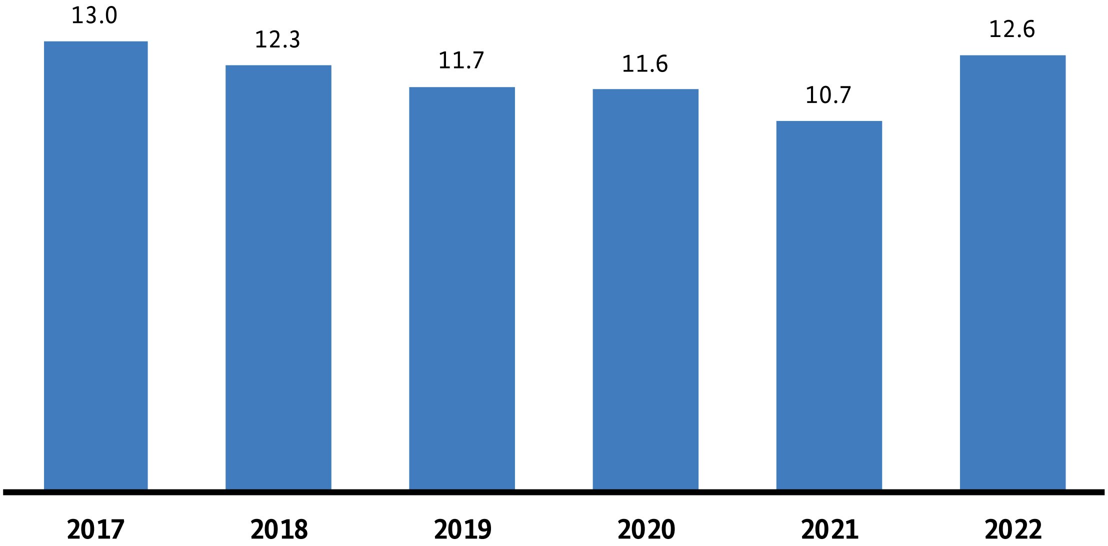


Figure 75: Supplier switching among non-household customers

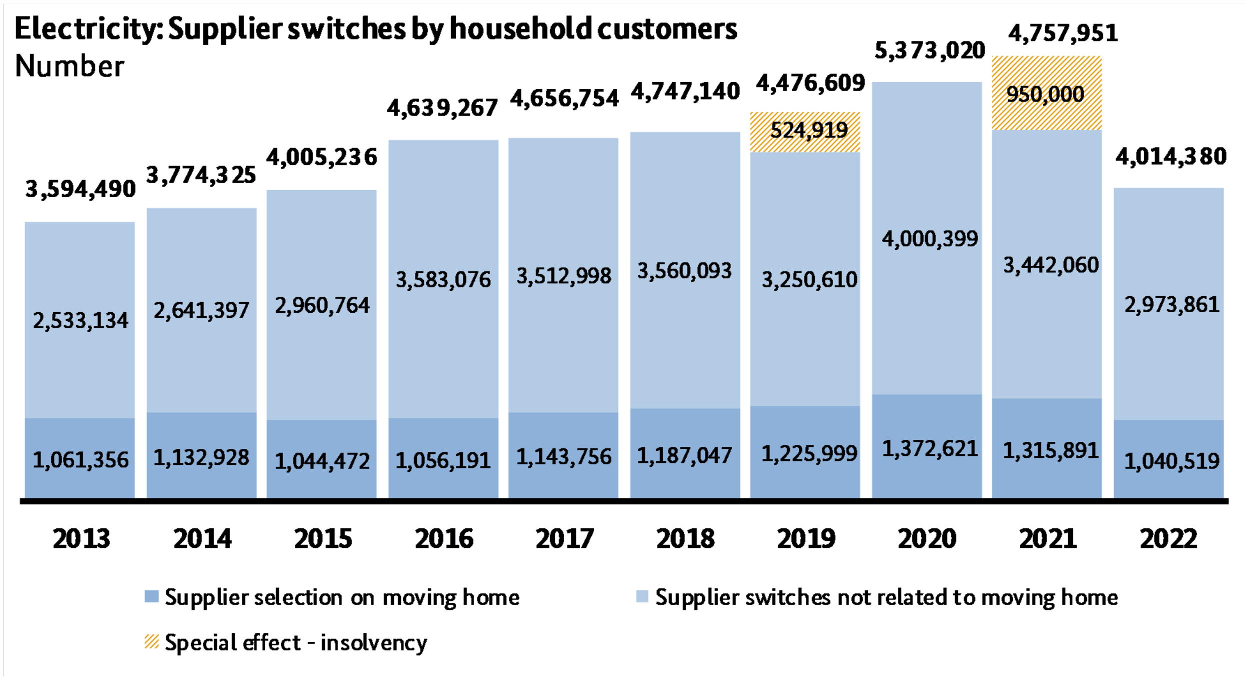


Figure 76: Supplier switches by household customers

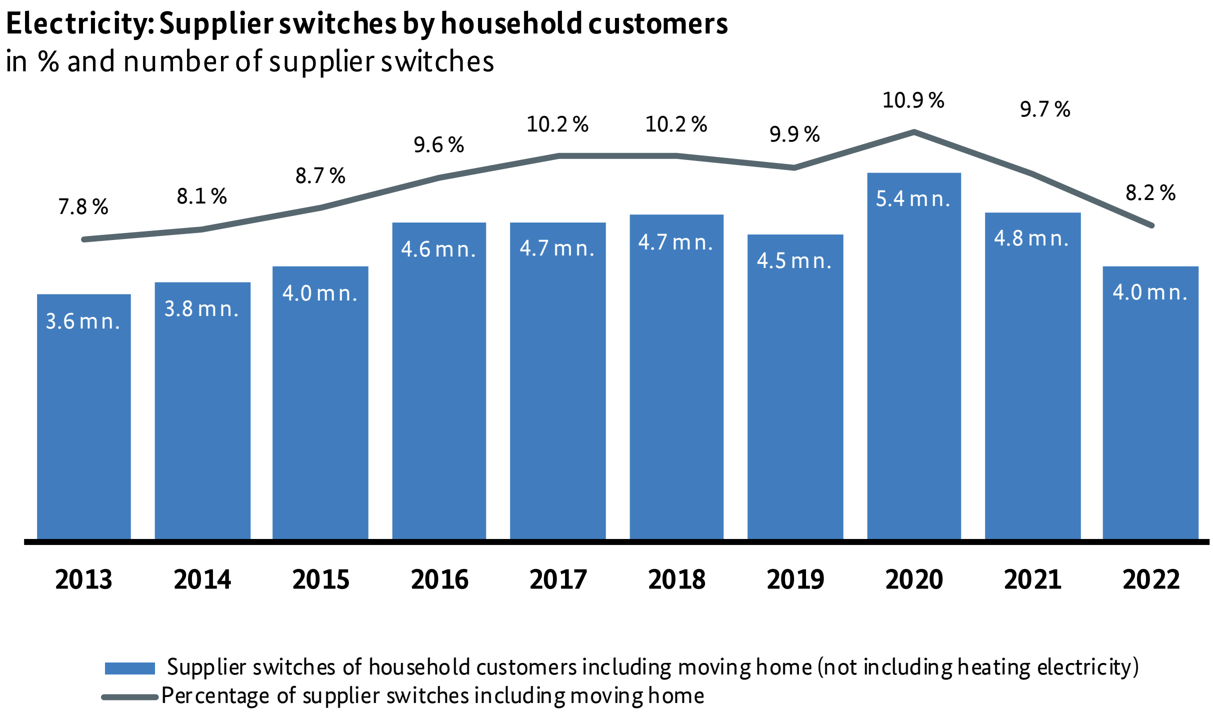


Figure 77: Household customer switching rate

Electricity: Household customer contract switches in 2022 and 2021

Category	Contract switches in TWh	Share of total consumption	Number of contract switches	Share of total number of household customers
2022 Household customers who switched their existing energy supply contract with their supplier	7.5 TWh	6.5%	3.03mn	6.4%
2021 Household customers who switched their existing energy supply contract with their supplier	3.7 TWh	3.1 %	1.53mn	3.3 %

Table 54: Household customer contract switches in 2022 and 2021

3. Terminations and disconnections, non-annual billing

Default suppliers are generally obliged to supply all household customers in their network area under the general terms and conditions and general prices of default supply. An exception is made if it is economically unreasonable for the default supplier to supply the customer (section 36(1) EnWG). A supplier can only terminate a default supply contract if it is not subject to a default supply obligation (section 20(1) of the Electricity Default Supply Ordinance (StromGVV)/Gas Default Supply Ordinance (GasGVV)). In exceptional cases, the default supplier may terminate the contract without notice if the prerequisites to interrupt supply have been met repeatedly (section 19 StromGVV/GasGVV). The default supplier must warn the customer of the termination without notice two weeks in advance (section 21 StromGVV)/GasGVV).

Non-default energy suppliers can terminate existing energy supply contracts under the contractual arrangements and provisions of civil law.

Energy suppliers terminating contracts with household customers, whether as part of the default supply or under other contracts, must do so in text form (section 41b(1) sentence 1 EnWG and section 20(2) sentence 1 StromGVV/GasGVV).

To request a disconnection under section 24(3) of the Low Voltage Network Connection Ordinance (NAV), the supplier must credibly show the network operator that the contractual prerequisites for disconnection between supplier and connection user are met. The rights and obligations of the 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 discontinue supply at the request of any supplier.
Under the StromGVV, default suppliers have the right to disconnect supplies to customers, in particular upon failure to fulfil payment obligations in the amount of two monthly instalments (or one sixth of the annual

rate), at least €100 and after the appropriate notice has been given. Competitive suppliers put clauses regarding non-fulfilment of payment obligations in their contracts.

Electricity: Number of terminations within and outside default supply and the average level of arrears (based on data from suppliers)

<table>
<tr><th>Year</th><th>Number of terminations within default supply</th><th>Number of terminations outside default supply</th><th>Average level of arrears</th></tr>
<tr><td>2018</td><td colspan="2">185,989</td><td>197</td></tr>
<tr><td>2019</td><td colspan="2">221,209</td><td>176</td></tr>
<tr><td>2020</td><td colspan="2">173,627</td><td>168</td></tr>
<tr><td>2021</td><td>18,673</td><td>169,985</td><td>184</td></tr>
<tr><td>2022</td><td>18,183</td><td>186,900</td><td>170</td></tr>
</table>

Table 55: Number of terminations within and outside default supply and the average level of arrears

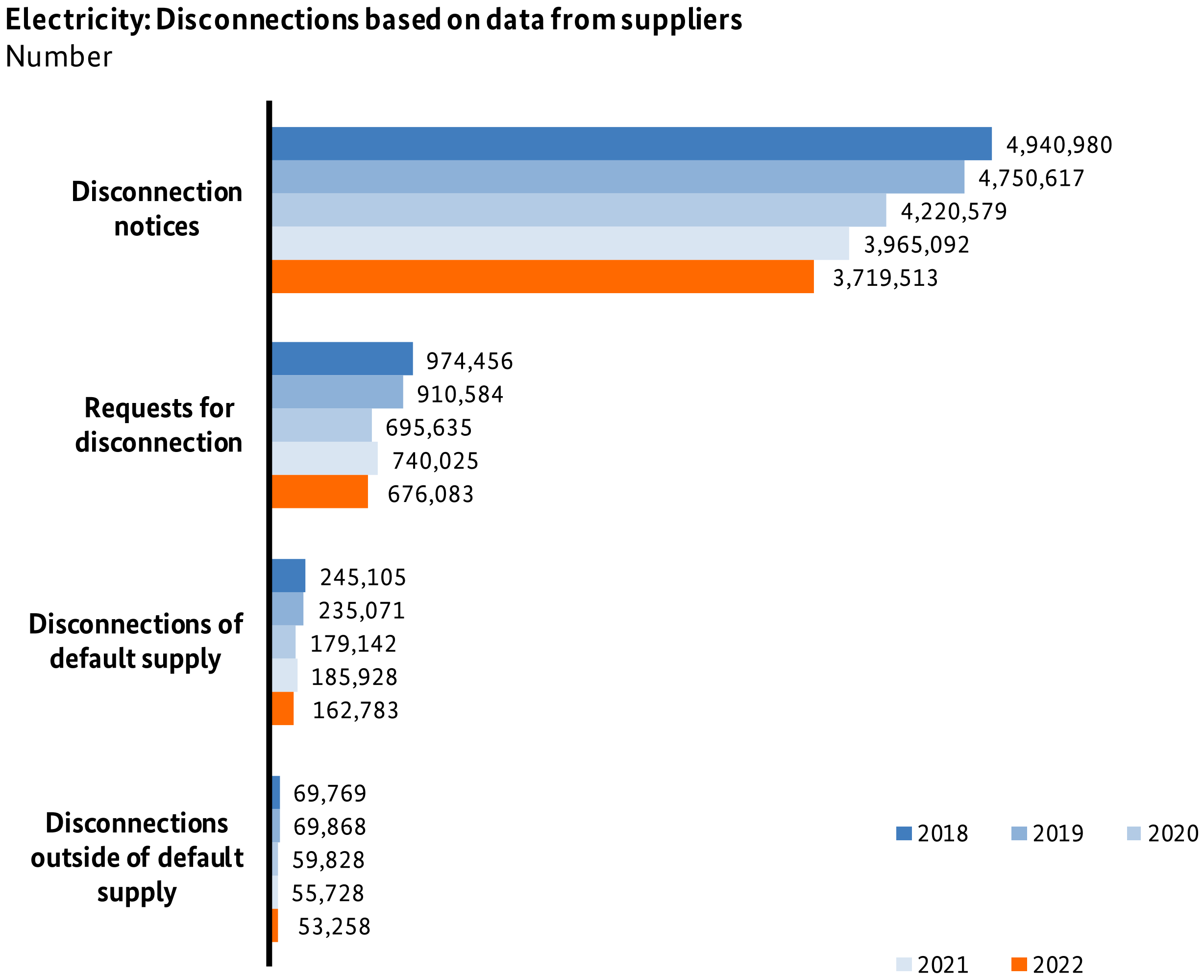


Figure 78: Disconnections based on data from suppliers

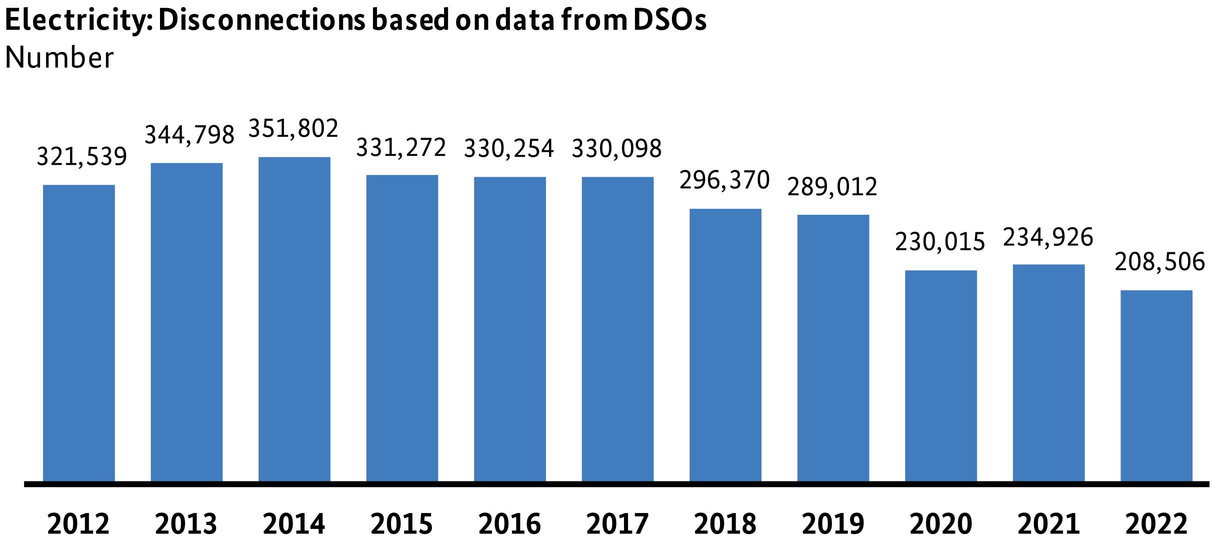


Figure 79: Disconnections based on data from DSOs

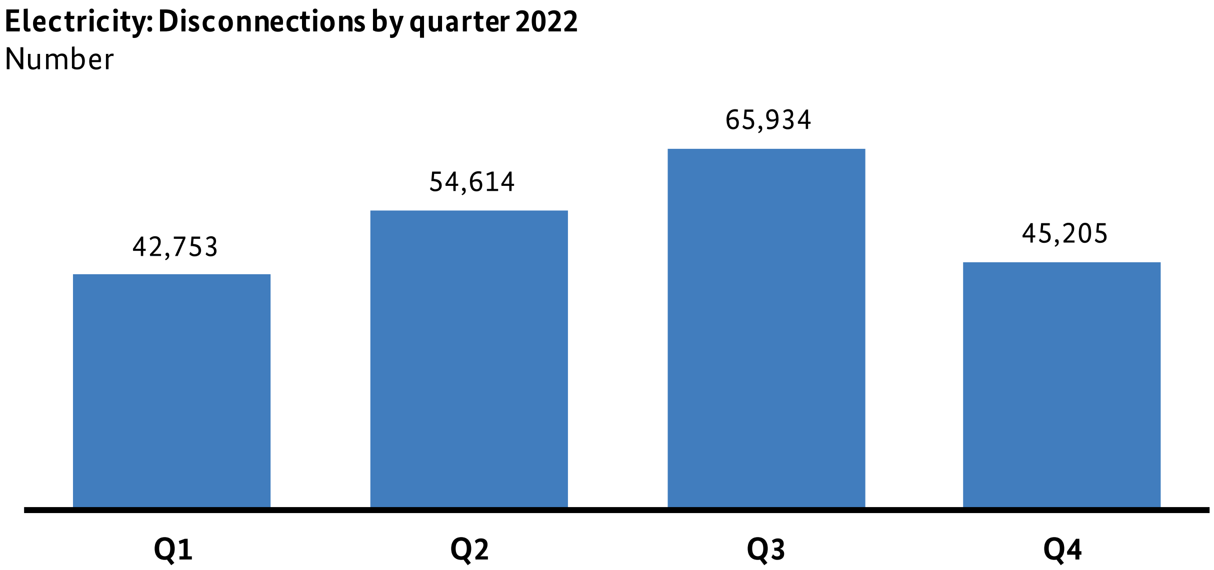


Figure 80: Disconnections in each quarter of 2022

Electricity: Number of disconnections by federal state in 2022 (DSO data)

	Number of disconnections (within and outside of default supply)	Percentage of market locations of final customers in the federal state
Saxony-Anhalt	10,456	0.68%
North Rhine-Westphalia	67,439	0.61%
Saarland	3,762	0.58%
Saxony	14,207	0.50%
Thuringia	6,152	0.45%
Hesse	16,038	0.42%
Rhineland-Palatinate	10,568	0.42%
Bremen	1,628	0.36%
Mecklenburg-Western Pomerania	5,986	0.36%
Schleswig-Holstein	6,594	0.36%
Hamburg	4,233	0.35%
Berlin	8,202	0.34%
Brandenburg	7,004	0.27%
Bavaria	19,460	0.24%
Lower Saxony	11,738	0.24%
Baden-Württemberg	15,039	0.23%

Table 56: Number of disconnections by federal state in 2022

Electricity: Non-annual billing in 2022

	Non-annual billing, number	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)
Non-annual billing for household customers	78,859	€7.45 (€1 - €59)	€9.14 (€1 - €65)
of which monthly	82.0%		
of which quarterly	2.7%		
of which semi-annually	15.3%		

Table 57: Non-annual billing in 2022

4. Tariffs

Electricity suppliers are required to offer load-based tariffs or time-of-use tariffs to final customers insofar as this is technically feasible and economically reasonable (section 41a(1) EnWG). A dynamic electricity tariff, similar to an electricity tariff that is static, consists of a monthly base price and an energy-based price per kilowatt hour consumed. While the monthly base price covers the fixed costs for the power connection and the meter, the energy-based price includes energy procurement costs, distribution and margin, network tariffs and various taxes, levies and surcharges. The special feature of a dynamic tariff is that the energy procurement costs that are part of the energy-based price are coupled with the exchange price that is determined daily for every hour of the following day on the spot market of the European Power Exchange (EPEX SPOT). Thus electricity price fluctuations that occur over time are passed on to the electricity customers, who can adjust their consumption. A smart metering system is required for a dynamic electricity tariff.

Bundled tariffs, under which suppliers link the electricity contract with other products and services, are bundled together with other energy sector services such as natural gas and PV installations, or they can also be combined with hardware, telecommunications services or water supply. Other coupled products include heating oil, pellets, district heating, heat pumps, electromobility services, insurance policies, vouchers and event tickets.

Electricity: Number of electricity suppliers that offer variable pricing

Tariffs	Number in 2022
Load-based tariffs	51
Time-of-use tariffs	563
Dynamic tariffs	52
Other tariffs with energy saving incentives	42

Table 58: Number of electricity suppliers that offer variable pricing

Electricity: Size of the companies that offered bundled tariffs in 2022

Number of meter locations	Number
1 < 1,000	4
1000 < 10,000	17
10,000 < 30,000	38
30,000 < 100,000	26
100,000 < 500,000	23
> 500,000	4
Total number of companies offering bundled tariffs	**112**

Table 59: Size of the companies that offered bundled tariffs in 2022

Electricity: Products offered in bundled tariffs in 2022

Product category	Number
Natural gas	49
Hardware	17
Telecommunications, internet	18
Water	9
Solar/tenants' electricity	34
Other	32
Total	**159**

Table 60: Products offered in bundled tariffs in 2022

5. Price level

Electricity prices in Germany are not state-controlled. The electricity price is set by the market and is composed of factors controlled by the supplier such as electricity procurement costs, distribution costs and margin, and factors not controlled by the supplier such as network tariffs, concession fees and charges for meter operations, surcharges and taxes. Discounts due to government price brakes are not factored in.

Electricity suppliers can choose whether to procure their electricity through long-term contracts or on the spot market. Long-term contracts can provide a certain price stability since prices are set over a longer period of time, whereas prices on the spot market can fluctuate sharply, depending on supply and demand. Choosing one of the two procurement strategies can affect the average electricity price. For this reason the Bundesnetzagentur also monitors the relationship between wholesale and retail prices.

The network tariffs, concession fees and the charge for meter operations may vary between network areas; the supplier cannot influence them. Electricity suppliers usually charge a monthly base price and a kilowatt-hour price. Low-consumption customers are more likely to benefit from a contract with a low base price while high-consumption customers benefit from a low kilowatt-hour price.

To ensure comparability of electricity prices, two more consumption categories were defined in addition to household customers with an annual consumption of 3,500 kWh.

a) Customers with an annual consumption of 50 MWh and an annual usage time of 1,000 hours (annual peak load of 50 kW; low voltage supply of 0.4 kV) fit the consumption profile of a commercial customer. Given the moderate level of consumption, individual contract arrangements play a significantly smaller role than in the 24 GWh/year consumption category.

b) The customer group with an annual consumption in the 24 GWh range consists entirely of interval-metered customers, ie 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 tariff groups for consumers who fall into the 24 GWh/year category, but offer customer-specific deals.

Price level, non-household customers - 24 GWh/year consumption category ("industrial customers")

The wide range of options with regard to contractual arrangements is very important to these interval-metered customers. Suppliers generally do not use tariff groups for customers that 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 tariffs directly with the network operator. In extreme cases, these types of contracts may in terms of their economic effect even result in suppliers merely providing balancing group management services for their customers. For high-consumption customers, the distinction between retail and wholesale trading is therefore 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 level questions were based on the assumption that none of the possible reductions applied to the customers concerned (section 19(2) of the Ordinance concerning Tariffs for Access to Electricity Networks (StromNEV), section 36 of the Combined Heat and Power Act (KWKG), section 17f EnWG). In the following consumption category the VAT is not indicated because of the VAT deduction.

The 24 GWh/year consumption category was defined as an annual usage period of 6,000 hours (annual peak load of 4,000 kW; medium voltage supply of 10 or 20 kV). Data was collected only from suppliers with at least one customer with an annual consumption between 10 GWh and 50 GWh. This customer profile essentially applies to only a limited number of suppliers.

For industrial customers some cost items that are not controlled by the supplier are omitted from the overall price. Customers meeting the requirements in the relevant statutory provisions, on the other hand, are eligible for reductions in the network tariff, concession fee, electricity tax and the surcharges under the KWKG, section 19 StromNEV and section 17f EnWG. There are different eligibility requirements for the various possible reductions. The monitoring survey does not collect data on whether there are any cases in practice in which all the possible maximum reductions are, or can be, claimed.

Electricity: Price level as at 1 April 2023 for the 24 GWh/year consumption category without reductions

	Spread between 10% and 90% of figures provided by suppliers arranged in order of size (ct/kWh)	**Arithmetic mean** (ct/kWh)
Price components outside the supplier's control		
Net network tariff	1.83 - 4.89	3.3
Metering, meter operation	0.00 - 0.06	0.05
Concession fees	0.05 - 0.11	0.14
Surcharges[1]		1.01
Electricity tax		2.05
Price components that can be controlled by the supplier (remaining balance)	6.57 - 29.83	16.70
Total price (excl VAT)	**13.39 - 36.14**	**23.26**

Surcharge under KWKG (0.378 ct/kWh), surcharge under section 19 StromNEV (0.066 ct/kWh), offshore network surcharge (0.591 ct/kWh)

Table 61: Price level as at 1 April 2023 for the 24 GWh/year consumption category without reductions according to data from electricity suppliers

Electricity: Possible reductions for the 24 GWh per year consumption category

Prices as at 1 April 2023	Assumed value	Possible reduction	Amount remaining
Electricity tax	2.05	-2.05	0.00
Net network tariff	2.94	-2.64	0.30
Other surcharges	1.01	-0.89	0.12
Concession fees	0.14	-0.14	0.00
Total	**6.15**	**-5.72**	**0.43**

Table 62: Price level as at 1 April 2023 for the 24 GWh/year consumption category according to data from electricity suppliers

Price level, non-household customers - 50 MWh/year consumption category ("commercial customers")

The 50 MWh/year consumption category 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 around 14 times higher than the 3,500 kWh/year consumption category ("household customers") and is also around two thousandths of the 24 GWh/year consumption category ("industrial customers"). 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 provide 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 2022. 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 generally required to use interval metering, it is safe to assume that consumption in this category is often measured using a standard load profile.

Electricity: Price level for the 50 MWh per year consumption category as at 1 April 2023

	Spread between 10% and 90% of figures provided by suppliers arranged in order of size (ct/kWh)	Arithmetic mean (ct/kWh)	Share of total price
Price components outside the supplier's control			
Net network tariff	5.04 - 10.18	7.42	22%
Metering operation	0.02 - 0.96	0.37	1%
Concession fees	0.11 - 1.59	0.81	2%
Surcharges[1]		1.37	4%
Electricity tax		2.05	8%
Price components that can be controlled by the supplier (remaining balance)	9.46 - 33.32	21.05	64%
Net total price	**20.99 - 46.36**	**33.06**	**100%**

Surcharge under KWKG (0.378 ct/kWh), surcharge under section 19 StromNEV (0.066 ct/kWh), offshore network surcharge (0.591 ct/kWh)

Table 63: Price level as at 1 April 2023 for customers with annual consumption of 50 MWh according to data from electricity suppliers

Price level, household customers

Section 3(22) EnWG defines household customers as final customers 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. The tables and figures below look at retail prices for an average household customer with a consumption volume between 2,500 kWh and 5,000 kWh.

Electricity: Average volume-weighted price for household customers with an annual consumption ranging from 2,500 kWh to 5,000 kWh in all contract categories (band III, Eurostat: DC) As at 1 April 2023
in ct/kWh

Price component	Volume-weighted average across all contract categories (ct/kWh)	Percentage of total price
Distribution and margin	5.26	11.6
Energy procurement	18.33	40.6
Net network tariff	8.98	19.8
Meter operations charge	0.37	0.8
Concession fees	1.62	3.6
CHP Act surcharge	0.36	0.8
Section 19 StromNEV surcharge	0.42	0.9
Offshore network surcharge	0.59	1.3
Electricity tax	2.05	4.5
VAT	7.21	16.0
Total	**45.19**	**100.0**

Table 64: Average volume-weighted price for household customers with an annual consumption ranging from 2,500 kWh to 5,000 kWh in all contract categories (band III, Eurostat: DC)

Electricity: Change in the volume-weighted price for household customers in all contract categories from 1 April 2022 to 1 April 2023 with an annual consumption between 2,500 kWh and 5,000 kWh (band III, Eurostat: DC)
in ct/kWh

Price component	Volume-weighted average across all contract categories (ct/kWh)	Change in level of price component	
		in ct/kWh	%
Distribution and margin	5.26	0.99	18.8
Energy procurement	18.33	9.06	49.4
Net network tariff	8.98	1.22	13.6
Meter operations charge	0.37	0.01	2.2
Concession fees	1.62	-0.02	-1.0
EEG surcharge	0.00	-3.72	-100.0
CHP Act surcharge	0.36	-0.02	-5.0
Section 19 StromNEV surcharge	0.42	-0.02	-4.0
Section 18 Interruptible Loads Ordinance surcharge	0.00	0.00	-100.0
Offshore network surcharge	0.59	0.17	29.0
Electricity tax	2.05	0.00	0.0
VAT	7.21	1.46	20.2
Total	**45.19**	**9.13**	**20.2**

Table 65: Change in the volume-weighted price level for household customers in all contract categories from 1 April 2022 to 1 April 2023 with an annual consumption between 2,500 kWh and 5,000 kWh (band III, Eurostat: DC)

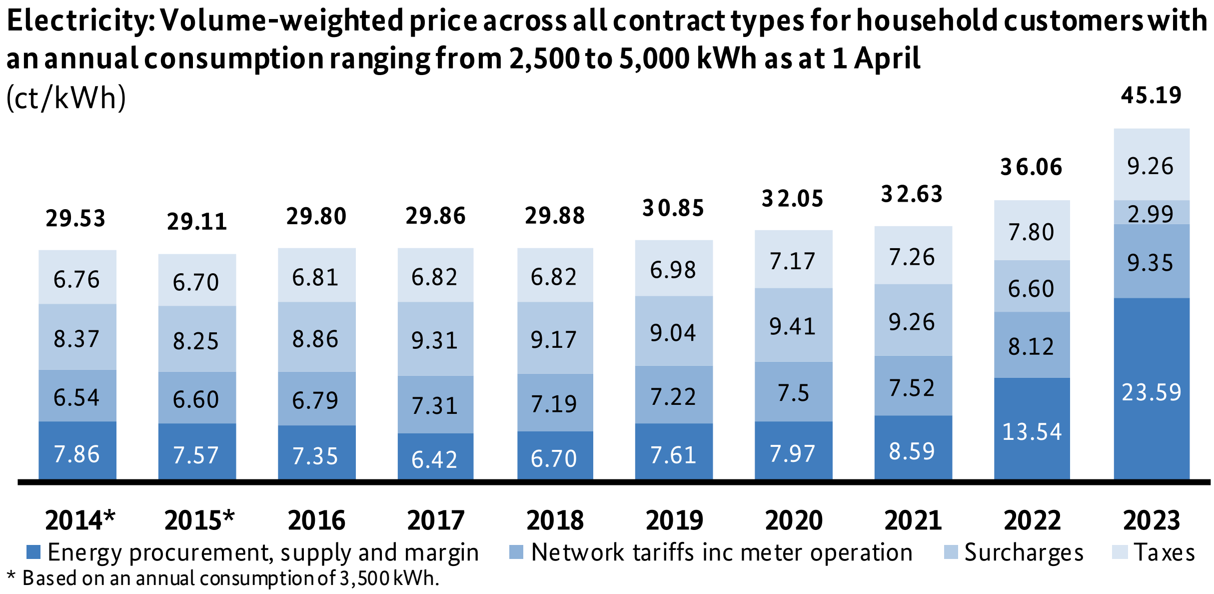


Figure 81: Volume-weighted price for household customers in all contract categories with an annual consumption ranging from 2,500 kWh to 5,000 kWh

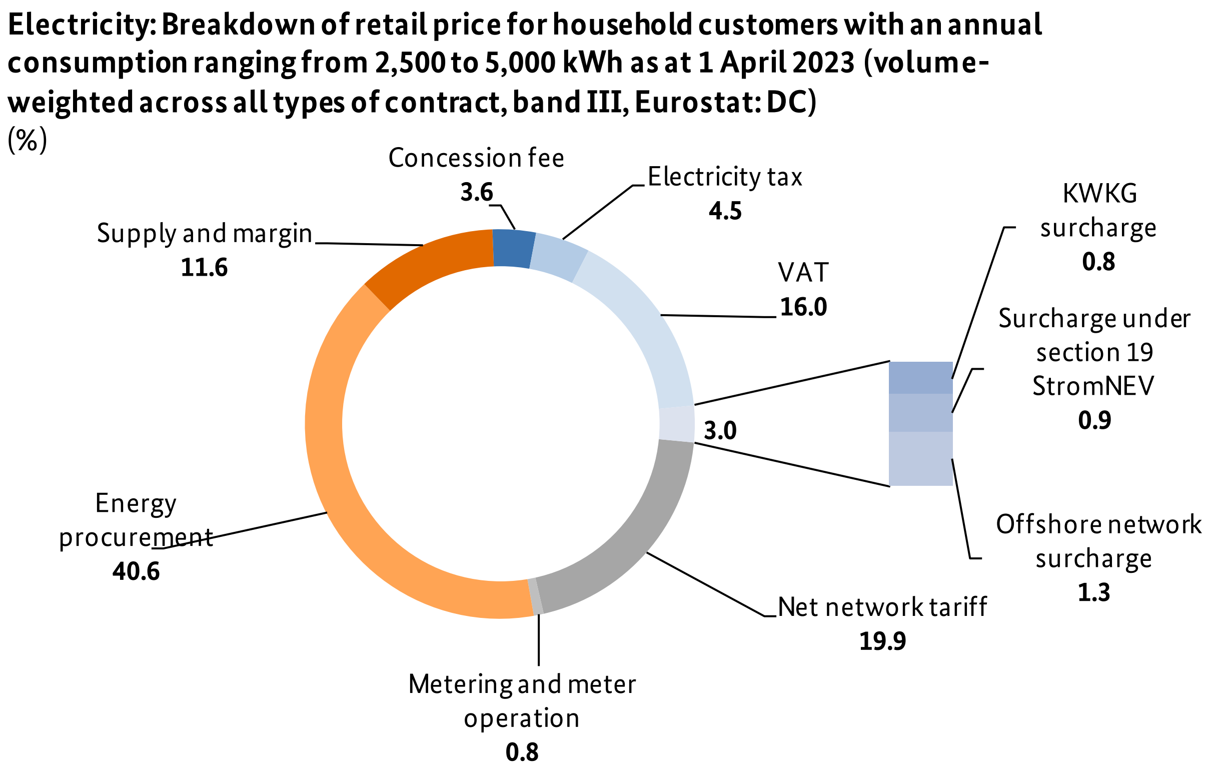


Figure 82: Breakdown of the retail price for household customers with an annual consumption ranging from 2,500 kWh to 5,000 kWh as at 1 April 2023

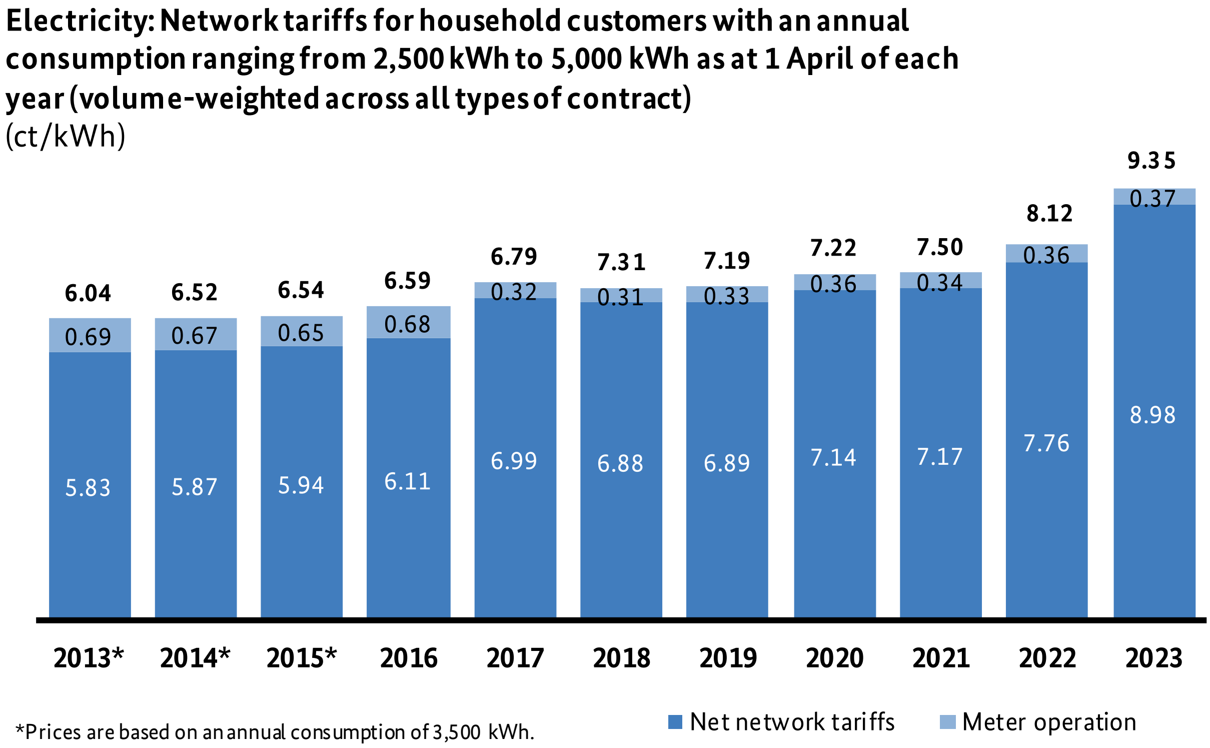


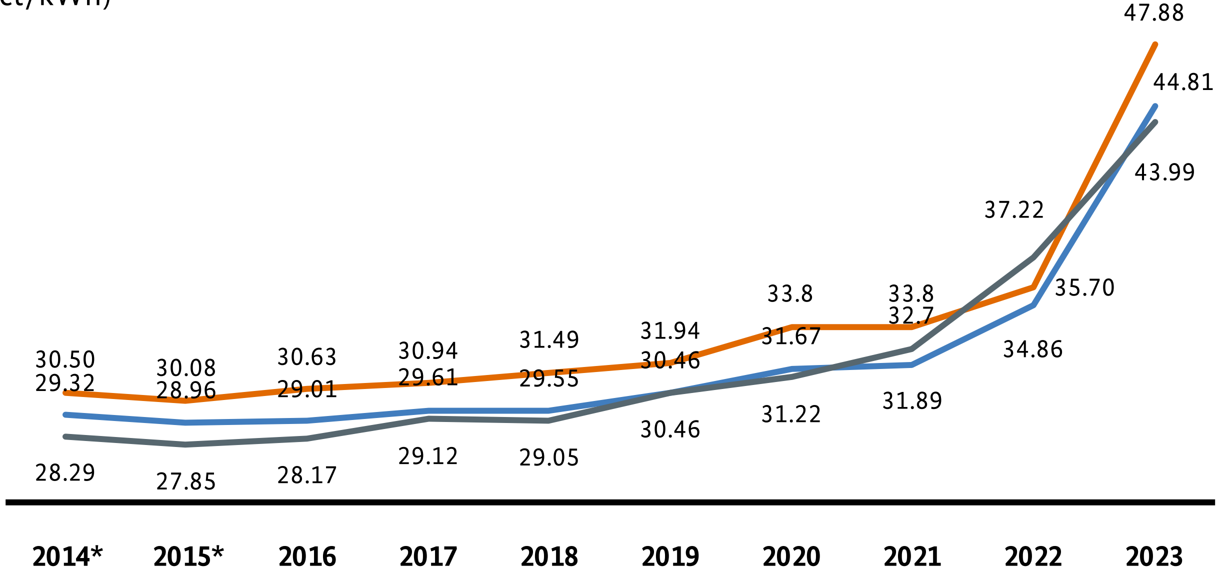
Figure 83: Network tariff for household customers with an annual consumption ranging from 2,500 kWh to 5,000 kWh as at 1 April of each year

Electricity: Average volume-weighted price by contract category for household customers with an annual consumption ranging from 2,500 kWh to 5,000 kWh (band III, Eurostat: DC)
As at 1 April 2023
in ct/kWh

Price component	Fallback supply contract	Default contract	Non-default contract with default supplier	Contract with a supplier other than the local default supplier
Distribution and margin	6.16	6.41	5.02	4.83
Energy procurement	**18.16**	**19.40**	**18.36**	**17.67**
Net network tariff	9.40	8.97	8.90	9.06
Meter operations charge	0.38	0.38	0.36	0.38
Concession fees	1.66	1.66	1.61	1.61
EEG surcharge				
CHP Act surcharge	0.36	0.36	0.36	0.36
Section 19 StromNEV surcharge	0.42	0.42	0.42	0.42
Section 18 Interruptible Loads Ordinance surcharge				
Offshore network surcharge	0.59	0.59	0.59	0.59
Electricity tax	2.05	2.05	2.05	2.05
VAT	7.44	7.64	7.15	7.02
Total	**46.62**	**47.89**	**44.82**	**43.99**

Table 66: Average volume-weighted price by contract category for household customers with an annual consumption ranging from 2,500 kWh to 5,000 kWh (band III, Eurostat: DC)

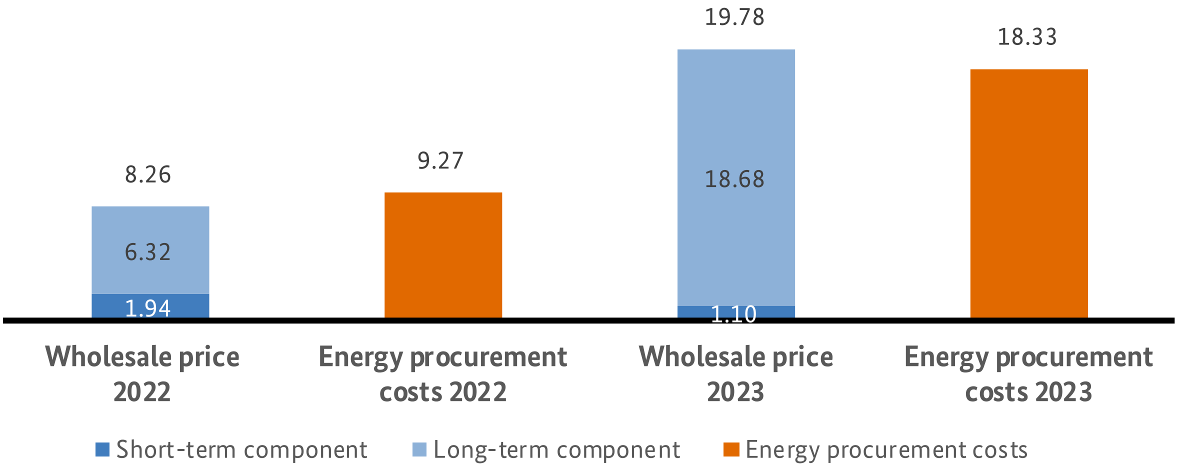
Electricity: Household customer prices for the different types of contract as at 1 April (volume-weighted average, band III, Eurostat: DC)
(ct/kWh)



* Based on an annual consumption of 3,500 kWh.

Figure 84: Household customer prices by contract category

Electricity: Relationship between wholesale and retail prices*
(ct/kWh)



*The wholesale price listed here is calculated on the basis of the electricity suppliers' average procurement strategy.

Figure 85: Relationship between wholesale and retail prices

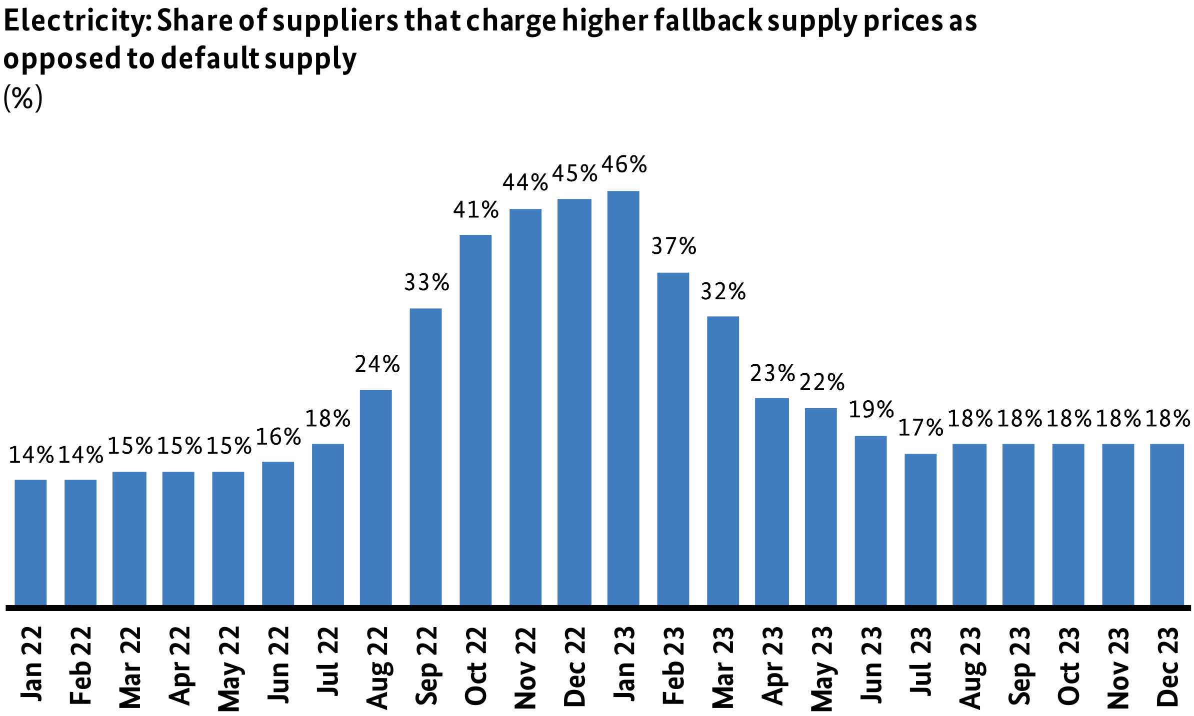


Figure 86: Share of suppliers that charge higher fallback supply prices as opposed to default supply

Special bonuses and schemes

Besides the overall price, 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 (eg price stability) or to the supplier (eg prepayment, minimum contract period), which is then compensated for between the parties elsewhere (overall price).

Green electricity tariffs

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 marketing, 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. 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.

Electricity: Green electricity delivered to household customers and other final customers in 2022

Category		Total electricity supplied	Total green electricity supplied	Percentage of green electricity volume and meter points
Household customers	TWh	115.5	49.9	43.2%
	Market locations (thousand)	47,557	20,001	42.1%
Other final customers	TWh	277.1	45.0	16.2%
	Market locations (thousand)	4,341	6,154	141.8%
Total	TWh	392.6	94.9	24.2%
	Market locations (thousand)	51,898	26,155	50.4%

Table 67: Green electricity delivered to household customers and other final customers in 2022

Electricity: Green electricity share and number of household customers supplied
(%)

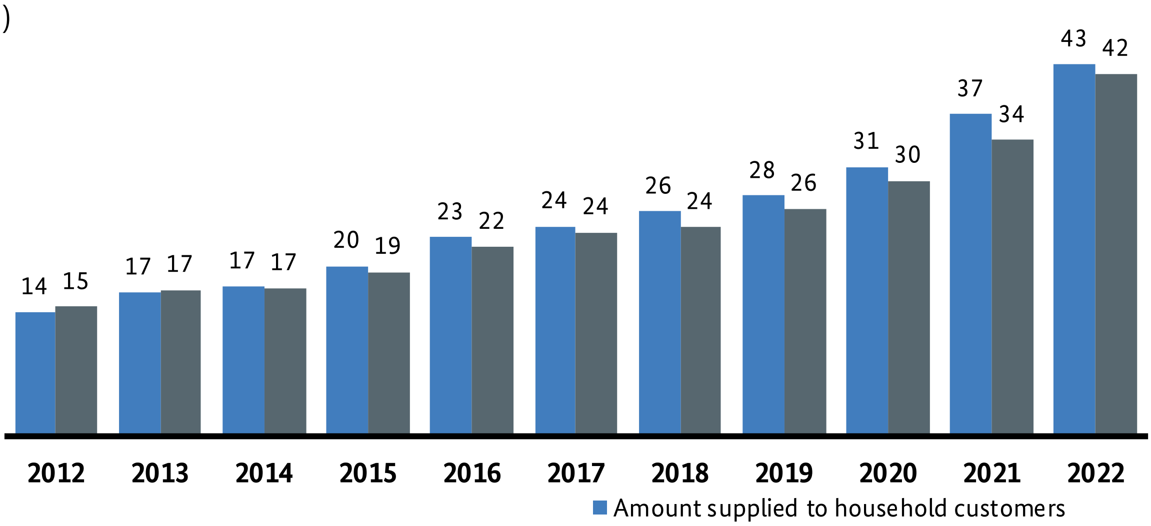


Figure 87: Green electricity volumes and number of household customers

Electricity: Change in volume-weighted price of green electricity from 1 April 2022 to 1 April 2023 for household customers with an annual consumption ranging from 2,500 kWh to 5,000 kWh (band III; Eurostat:DC)

Price component	Volume-weighted average across all contract categories (ct/kWh)	Change in level of price component	
		in ct/kWh	%
Distribution and margin	2.74	-0.95	-34.7
Energy procurement	17.66	6.72	38.0
Net network tariff	9.18	1.24	13.5
Meter operations charge	0.33	-0.23	-70.8
Concession fees	1.47	-0.17	-11.7
EEG surcharge	0.00	-3.72	100.0
KWKG surcharge	0.36	-0.02	-5.9
Section 19 StromNEV surcharge	0.42	-0.02	-4.8
Section 18 Interruptible Loads Ordinance surcharge	0.00	0.00	100.0
Offshore network surcharge	0.59	0.17	29.1
Electricity tax	2.05	0.00	0.0
VAT	6.61	0.57	8.6
Total	**41.41**	**5.29**	**12.8**

Table 68: Change in volume-weighted price of green electricity from 1 April 2022 to 1 April 2023 for household customers with an annual consumption ranging from 2,500 kWh to 5,000 kWh (band III; Eurostat:DC)

Electricity: Breakdown of green electricity retail price components for household customers with an annual consumption ranging from 2,500 kWh to 5,000 kWh (DC), as at 1 April 2023
(%)

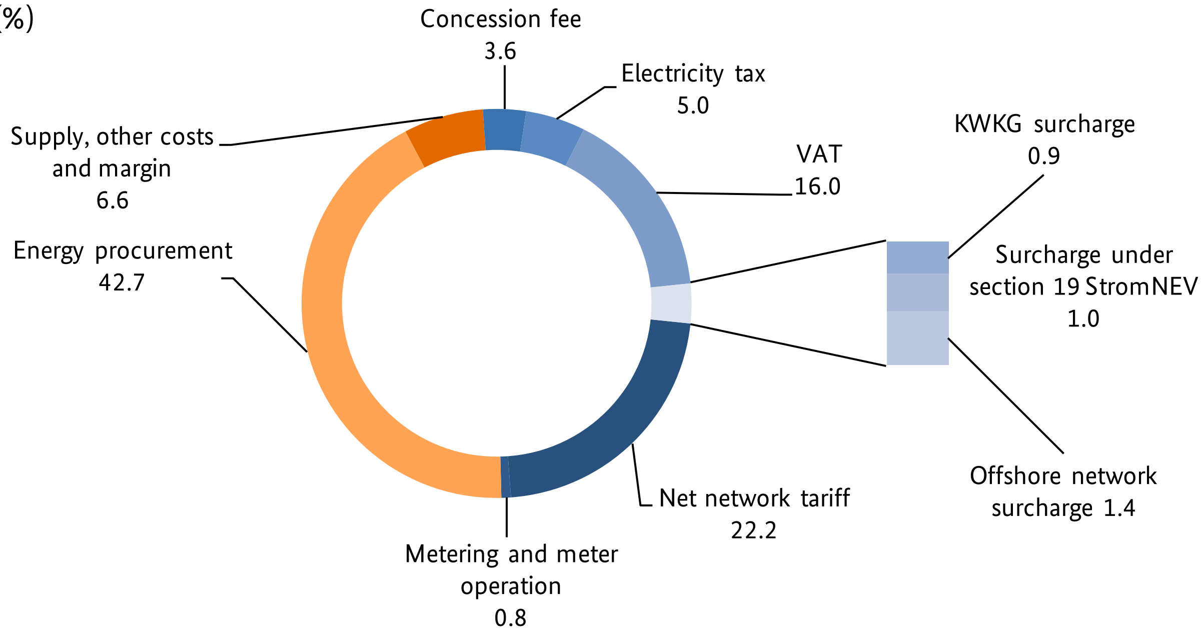


Figure 88: Breakdown of green electricity retail price components for household customers with an annual consumption ranging from 2,500 kWh to 5,000 kWh (DC)

Electricity: Special bonuses and schemes for household customers on green electricity tariffs

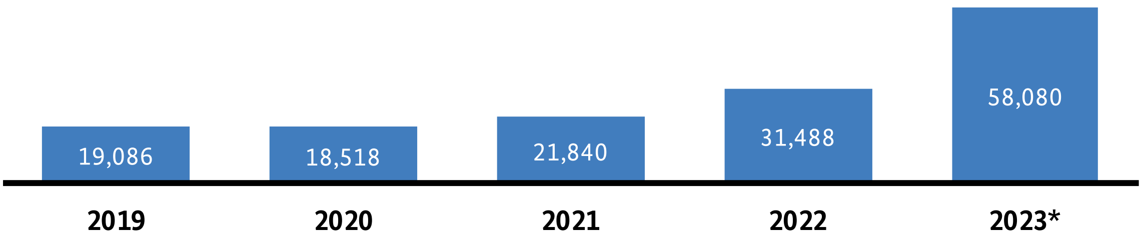
1 April 2023	Household customers (green electricity)	
	Number of tariffs	Average scope
Minimum contract period	360	11 months
Price stability	293	13 months
Prepayment	40	10 months
One-off bonus payment	101	€43
Free kilowatt hours	2	119 kWh
Deposit	1	-
Other bonuses and special arrangements	51	-

Table 69: Special bonuses and schemes for household customers on green electricity tariffs

6. Consumer advice and protection

The energy consumer advice service is the national point of contact for consumers who want information on their rights in the energy sector, applicable legal regulations or dispute resolution options.

Number of consumer queries and complaints



* October 2023

Figure 89: Number of consumer queries and complaints

7. Heating electricity

Heating electricity is the electricity supplied to operate controllable consumer devices for the purposes of room heating. These devices are primarily heat pumps or night storage heating. Due to the different purpose of consumption there are significant differences in the consumption pattern compared to ordinary household electricity. In addition, the prices for heating electricity tariffs are lower. Separate heating tariffs for heat pumps and night storage heating generally require a controllable consumer device within the meaning of section 14a EnWG. Because it is possible to interrupt consumption there are lower network tariffs for supplying. Here metering is done through a separate meter. The separate metering features a single tariff meter for household electricity and a dual tariff meter (peak price/off-peak price) for heating electricity. Alternatively, metering can be conducted together with regular household electricity using a dual tariff meter, which records the consumption at low-demand (off-peak price) times and at all other (peak price) times. In addition to the lower network tariffs, the concession fees in connection with heating electricity tariffs are also lower than they are in connection with other household electricity. Price data was collected on night storage tariffs and heat pump tariffs as at 1 April 2023. Suppliers were asked to base their figures on an annual consumption of 7,500 kWh. 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 market locations 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.

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".

Electricity: Heating electricity delivery volume overview

	2022			2021		
	Night storage heating	Heat pump	Total	Night storage heating	Heat pump	Total
Volume in TWh	8.6	4.5	13.1	9.8	4.4	14.3
Number of market locations (million)	1.24	0.75	1.98	1.28	0.70	1.98
Percentage of total volume	65.8%	34.2%	100%	68.8%	31.2%	100%
Percentage of total market locations	62.4%	37.6%	100%	64.4%	35.6%	100%
Average per market location in kWh	6,612			7,210		

Table 70: Delivery volume overview and number of heating electricity market locations according to data from electricity suppliers[78]

Electricity: Heating electricity customers supplied by a supplier other than the regional default supplier

Volume and market location percentages of total heating electricity supplied

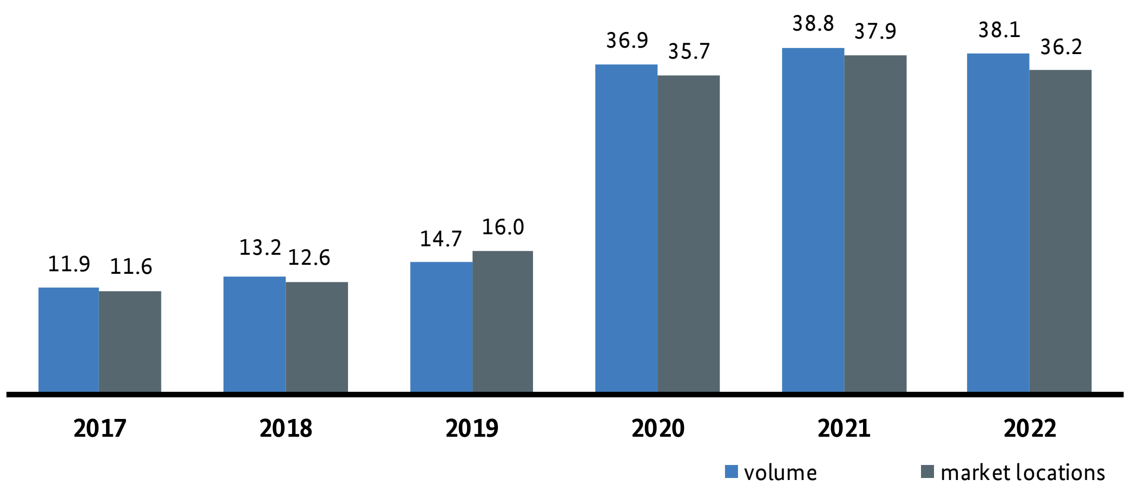


Figure 90: Percentage of heating electricity volume and market locations served by a supplier other than the regional default supplier according to data from electricity suppliers

[78] The year 2021 was subsequently corrected in comparison with the latest monitoring report. A large supplier that was until now unable to distinguish between heat pumps and night storage heating was able to provide a retroactive estimate in 2022 thanks to a system switch. This estimate was taken into account, and as a result there was a slight increase in the number of night storage heating market locations. The total number remained unchanged.

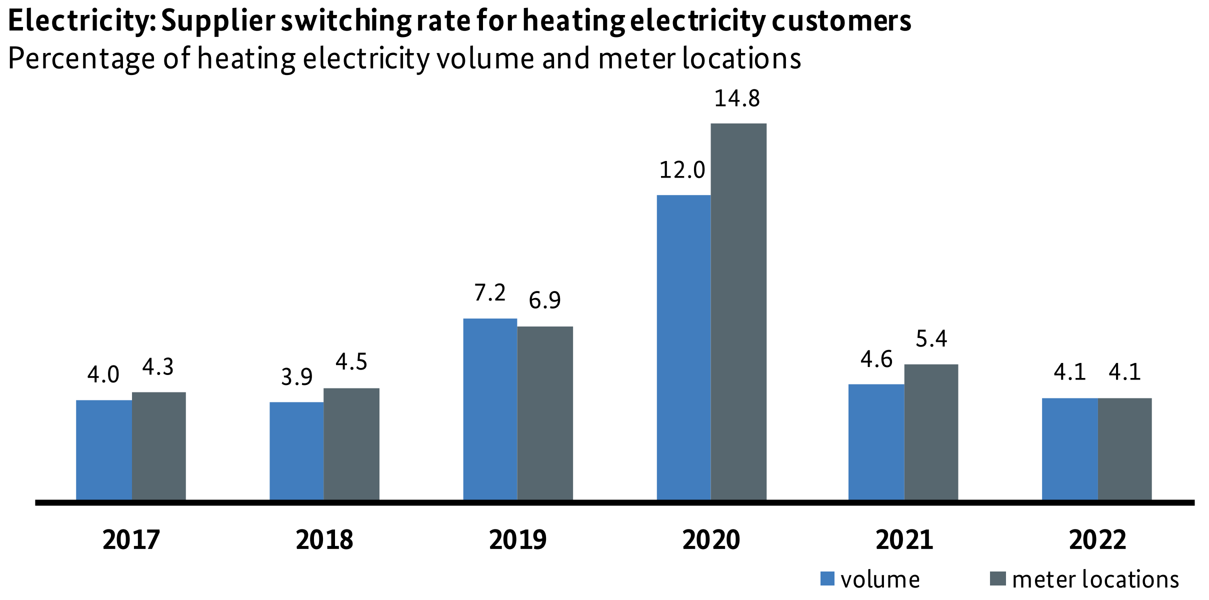


Figure 91: Supplier switching rate for heating electricity customers according to data from electricity DSOs

Electricity: Price level as at 1 April 2023 for night storage heating with annual consumption of 7,500 kWh

	Spread between 10% and 90% of figures provided by suppliers (ct/kWh)	**Arithmetic mean** (ct/kWh)	**Share of total price**
Price components outside the supplier's control			
Net network tariff	1.52 - 5.30	3.40	9%
Metering operation	0.12 - 0.48	0.40	1%
Concession fees	0.11 - 1.32	0.40	2%
Surcharges[1]		1.37	4%
Electricity tax		2.05	6%
VAT	3.85 - 7.99	5.80	16%
Price components that can be controlled by the supplier (remaining balance)	11.99 - 34.24	22.90	63%
Total price (excl VAT)	**24.11 - 50.05**	**36.31**	**100%**

[1] CHP Act (0.357 ct/kWh), section 19(2) StromNEV (0.417 ct/kWh), offshore network surcharge (0.591 ct/kWh)

Table 71: Price level as at 1 April 2023 for night storage heating with a consumption of 7,500 kWh/year according to data from electricity suppliers

Electricity: Price level as at 1 April 2023 for heat pumps with a consumption of 7,500 kWh per year

	Spread between 10% and 90% of figures provided by suppliers (ct/kWh)	**Arithmetic mean** (ct/kWh)	**Share of total price**
Price components outside the supplier's control			
Net network tariff	1.71 - 5.58	3.54	10%
Metering operation	0.11 - 0.50	0.37	1%
Concession fees	0.11 - 1.32	0.43	1%
Surcharges[1]		1.37	4%
Electricity tax		2.05	6%
VAT	3.94 - 8.03	5.89	16%
Price components that can be controlled by the supplier (remaining balance)	12.52 - 34.71	23.25	63%
Total price (excl VAT)	**24.65 - 50.32**	**36.90**	**100%**

[1] CHP Act (0.357 ct/kWh), section 19(2) StromNEV (0.417 ct/kWh), offshore network surcharge (0.591 ct/kWh)

Table 72: Price level as at 1 April 2023 for heat pump heating with a consumption of 7,500 kWh/year according to data from electricity suppliers

H 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.

Installation of smart metering systems was able to start 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. The BSI then published its formal market statement on 31 January 2020, determining that smart metering systems could be installed. On 24 February 2020 the BSI announced a general administrative order for immediate enforcement. For the default meter operators this marked the beginning of the mandatory rollout of smart metering systems. The MsbG was amended by the Act Relaunching the Digitisation of the Energy Transition (GNDEW) in May 2023, thus finalising a systemic change. The formal market statement from the BSI was therefore waived in favour of an agile rollout with a timeline set out in law.

Final customers in various consumption categories are affected by the mandatory installation within the meaning of section 29 in conjunction with sections 31 and 32 MsbG. For final customers with annual consumption of 6,000 kWh or less, the MsbG gives the default meter operator the right to choose whether to install smart metering systems (referred to as an optional installation) or just to install modern metering equipment. Under the MsbG, meters with an average annual electricity consumption of over 6,000 kWh must be included in the rollout of smart metering systems. Furthermore, the amended GNDEW gives final customers with an annual electricity consumption of less than 6,000 kWh the option to request their meter operator to install an intelligent metering system from 2025.

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 assume the default metering operations and not already approved as a network operator under section 4 of the Energy Industry Act (EnWG) must obtain approval from the Bundesnetzagentur under section 4 MsbG. In addition to the actual operation, "metering operations" include the installation of metering equipment, maintenance, billing and smart meter gateway administration. Companies are free to choose between performing these tasks themselves or transferring some of them to service providers.

In the electricity sector the MsbG regulates the provision of the grid-based energy supply with modern metering equipment and smart metering systems. New gas meters can only be installed under the MsbG if they can be securely connected with a smart meter gateway. If meters have a smart metering system and thus a smart meter gateway, default meter operators are obliged to connect it if it is technically possible to do so.

Electricity: Meter operator roles within the meaning of the MsbG in 2022

	Number	
	Conventional meter operation	Meter operation of modern metering equipment or smart metering systems
Role as default meter operator within the meaning of the MsbG	633	753
Default meter operator offering meter services in the market as a third party	44	43
Supplier with meter operator activities	49	47
Independent third party that provides metering services	32	17

Table 73: Meter operator roles within the meaning of the MsbG according to data provided by electricity meter operators as at 31 December 2022

Electricity: Number of meter locations by federal state in 2022
(mn)

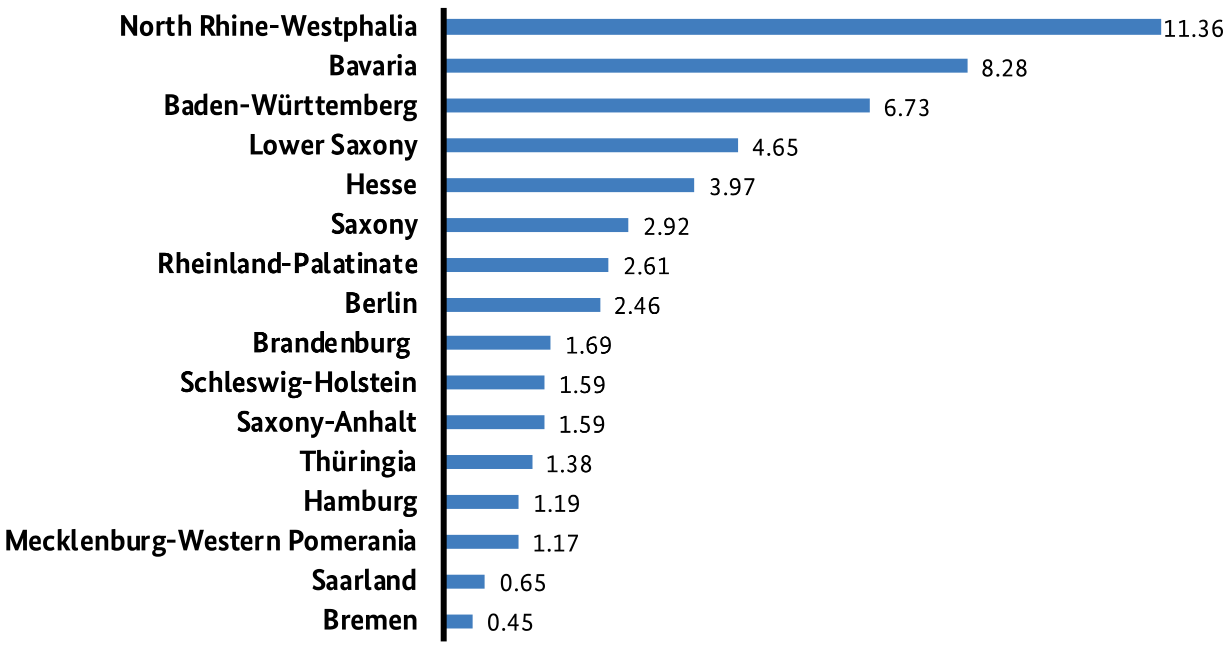


Figure 92: Number of meter locations by federal state

Electricity: Mandatory installation within the meaning of section 29 in conjunction with sections 31 and 31 MsbG (old version) in 2022

Information as at 31 December 2022	Number of meter locations			
	Total	Equipped with metering systems in accordance with section 19(5) MsbG	Equipped with modern metering equipment within the meaning of the MsbG	Equipped with smart metering systems within the meaning of the MsbG
Final customers with annual power consumption				
> 6,000 kWh and ≤ 10,000 kWh	2,004,355	149,603	617,957	103,249
> 10,000 kWh and ≤ 20,000 kWh	994,977	82,186	301,903	73,397
> 20,000 kWh and ≤ 50,000 kWh	494,399	61,454	132,416	40,330
> 50,000 kWh and ≤ 100,000 kWh	145,065	42,573	24,072	7,118
100,000 kWh	250,423	120,882	6,810	369
Consumer devices as defined in section 14a EnWG	1,238,964	86,113	346,461	553
of which meter locations at charge points for electric vehicles	23,335	2,691	14,046	92
Installed capacity at plant operators in accordance with section 2 para 4 MsbG				
> 7 kW and ≤ 15 kW	988,034	61,106	426,822	777
> 15 kW and ≤ 30 kW	401,895	30,717	133,124	661
> 30 kW and ≤ 100 kW	197,010	28,137	43,582	187
> 100 kW	98,046	54,439	2,396	13

Table 74: Mandatory installation within the meaning of section 29 in conjunction with section 31 MsbG (old version) as at 31 December 2022

Electricity: Voluntary installation within the meaning of section 29 in conjunction with sections 31 MsbG (old version) in 2022

	Number of meter locations			
	Total	Equipped with metering systems in accordance with section 19(5) MsbG	Equipped with modern metering equipment within the meaning of the MsbG	Equipped with smart metering systems within the meaning of the MsbG
Final customers with annual power consumption:				
≤ 2.000 kWh	23,853,526	1,881,904	8,262,012	13,014
> 2,000 kWh and ≤ 3,000 kWh	9,145,718	735,786	3,063,378	3,614
> 3,000 kWh and ≤ 4,000 kWh	5,771,245	418,185	1,946,942	4,485
> 4,000 kWh and ≤ 6,000 kWh	4,528,459	325,747	1,463,289	23,680
Installed capacity at plant operators in accordance with section 2 para 1 MsbG				
> 1 kW and ≤ 7 kW	767,310	58,426	301,010	194

Table 75: Voluntary installation within the meaning of section 29 in conjunction with section 31 MsbG (old version) as at 31 December 2022

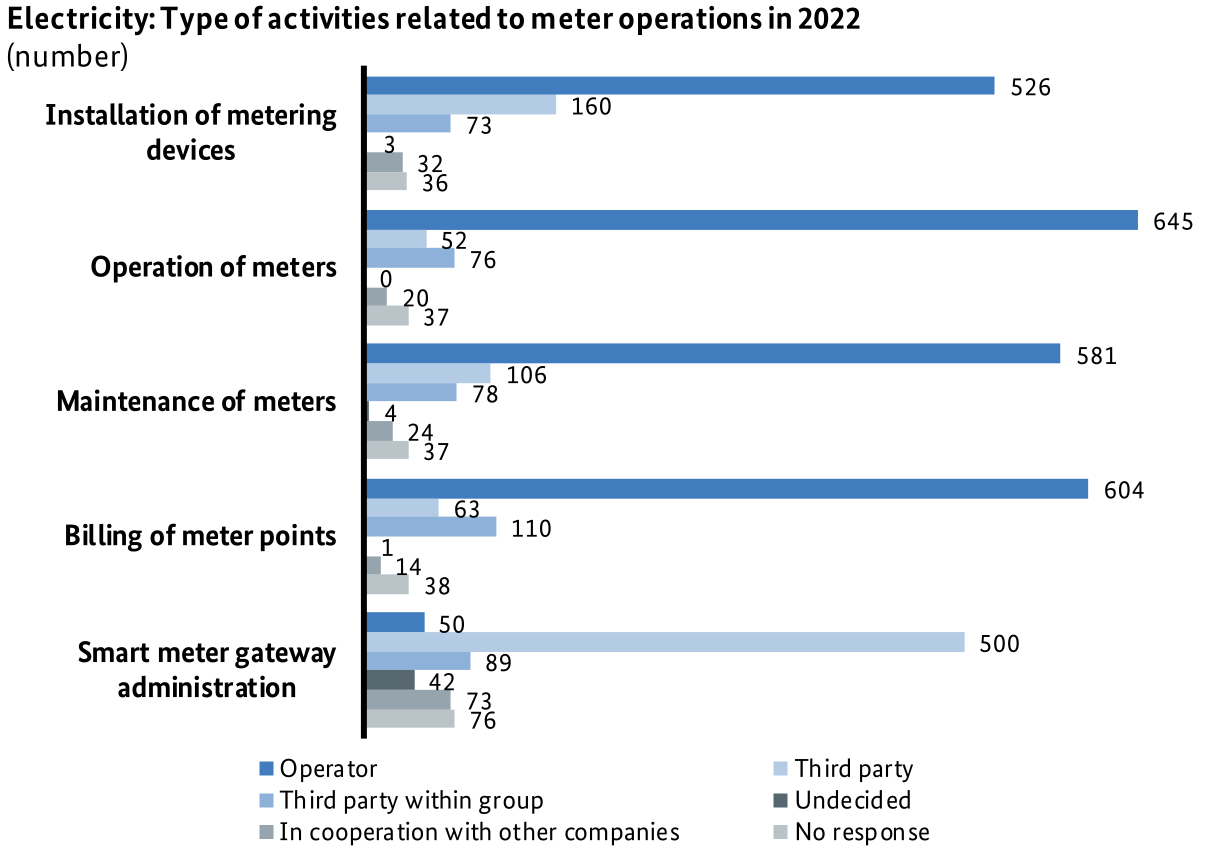


Figure 93: Type of activities related to metering operations as at 31 December 2022

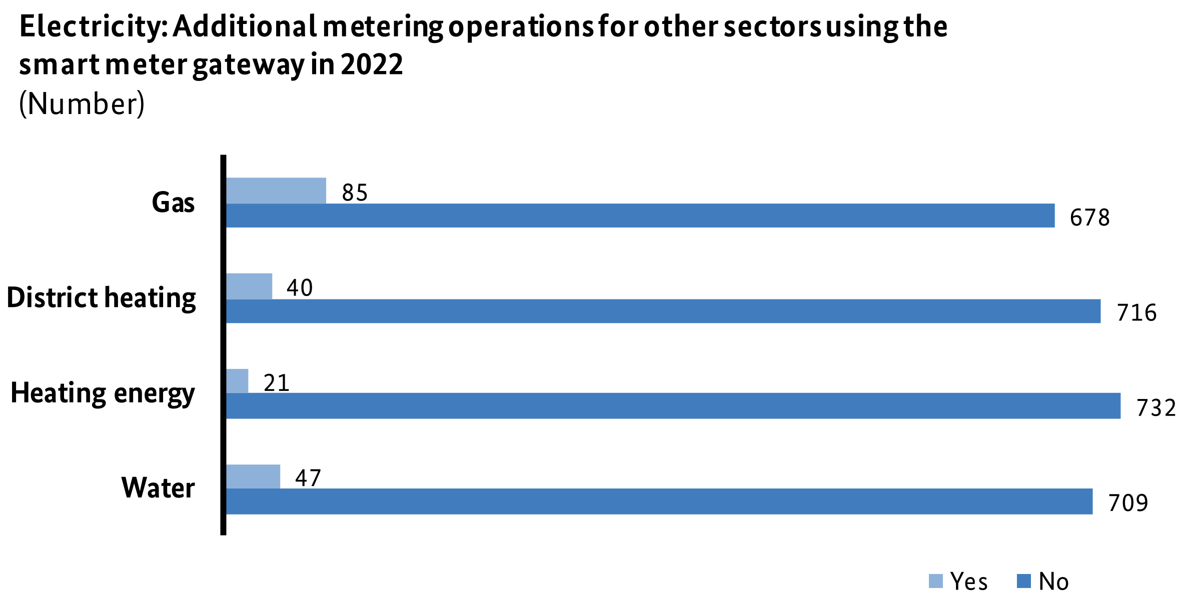


Figure 94: Additional metering operations for other sectors using the smart meter gateway as at 31 December 2022

Electricity: Do you offer products combining electricity supply and meter operation?
Survey for 2022

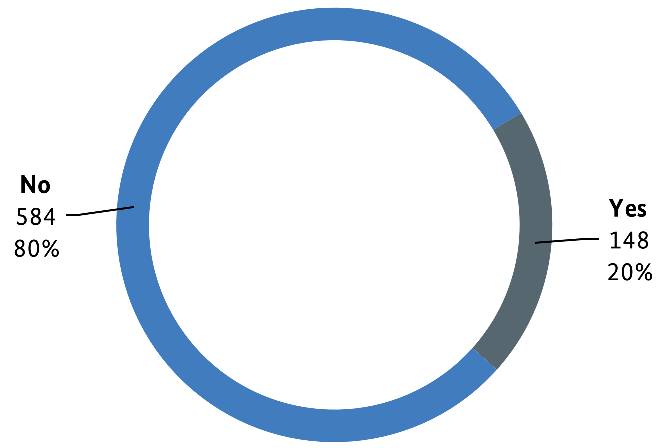


Figure 95: Combined products for electricity supply and meter operation as at 31 December 2022

Electricity: How are customers billed for meter operation?
Survey for 2022

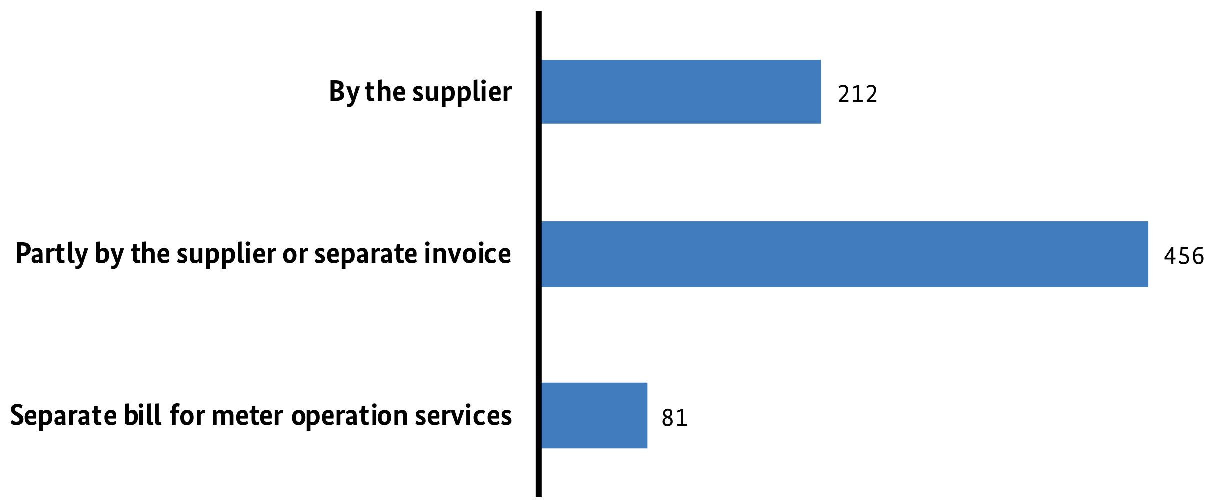


Figure 96: Billing the connection user/owner for meter operation as at 31 December 2022

Electricity: Meter technology employed in meters/meter devices and metering systems for standard load profile (SLP) customers

Requirement	Meter locations in 2021	Meter locations in 2022
Electromechanical meters (alternating current and 3-phase current meters based on the Ferraris principle)	30,180,731	26,714,186
of which are two-tariff and multiple-tariff meters (Ferraris principle)	1,843,208	1,706,823
Electronic meter device (basic meter not connected to a communication network) as defined in section 2 para 15 MsbG	6,497,685	6,132,559
Modern metering equipment (not connected to a communication network) as defined in section 2 para 15 MsbG	13,813,899	17,304,415
Metering systems in accordance with section 2 para 13 MsbG that are not smart metering systems as defined in section 2 para 7 MsbG (eg EDL40)	361,839	329,928
Smart metering systems as defined in section 2 para 7 MsbG	133,460	272,024

Table 76: Meter technology employed for standard load profile (SLP) customers as at 31 December 2022

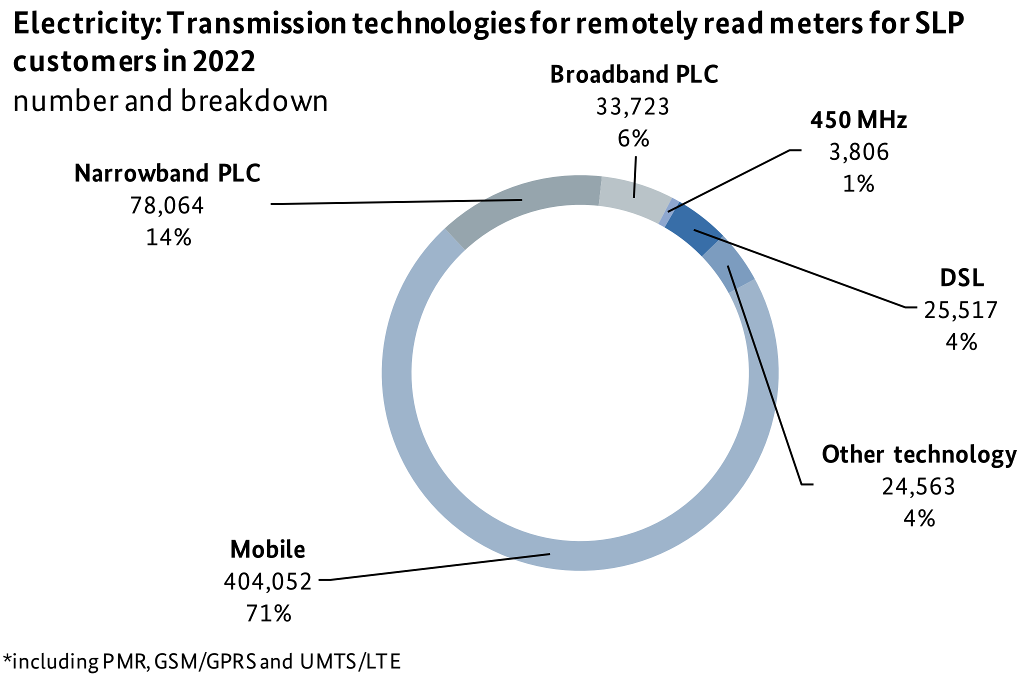


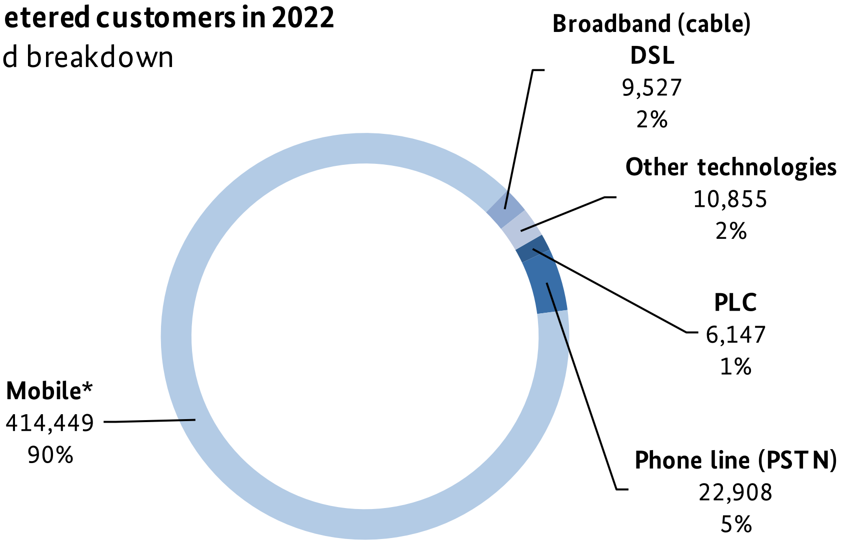
Figure 97: Transmission technologies for remotely read meters for SLP customers as at 31 December 2022

Electricity: Meter technology employed for interval-metered customers

Requirement	Meter locations in 2022
Metering equipment in the interval-metered segment (> 100,000 kWh/year)	404,088
Metering systems in accordance with section 2 para 13 MsbG that are not smart metering systems as defined in section 2 para 7 MsbG (eg EDL40) (≤ 100,000 kWh/year)	367,100
Optional installation of BSI-certified smart metering systems	48,866
Other	7,420

Table 77: Meter technology employed for interval-metered customers as at 31 December 2022

Electricity: Transmission technology for remotely read meters for interval-metered customers in 2022
number and breakdown



*including PMR, GSM/GPRS and UMTS/LTE

Figure 98: Transmission technologies for remotely read meters for interval-metered customers as at 31 December 2022

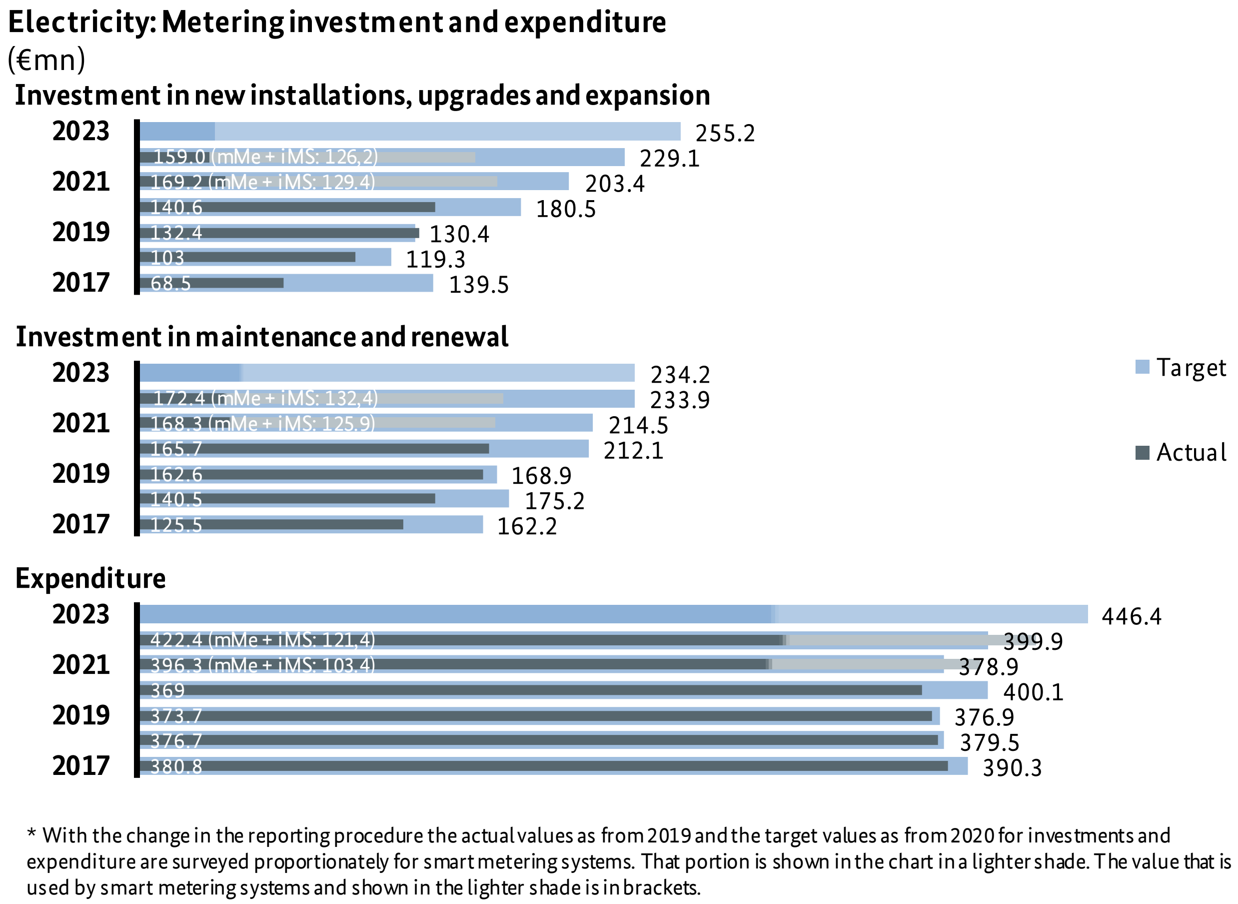


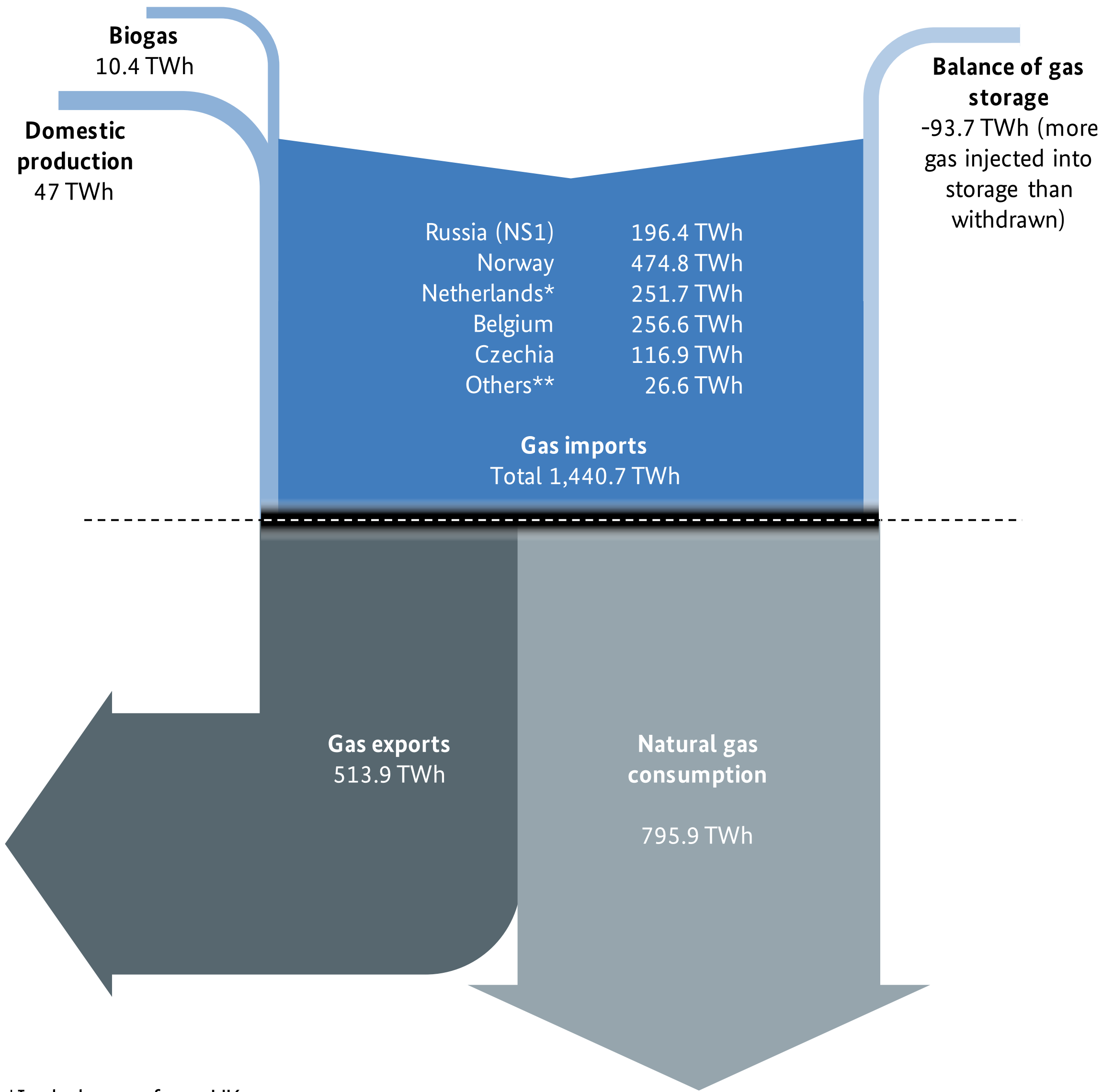
Figure 99: Metering investment and expenditure

III Gas

A Situation in the gas markets

1. Network overview

Gas: gas available and gas use in the supply network in 2022
(TWh)



*Includes gas from UK
**Other countries: Austria, Switzerland, Poland, France

Figure 100: Gas available and gas use in Germany in 2022

Gas: Offtake volumes in 2022 broken down by final customer category, according to the survey of gas TSOs and DSOs

	TSO offtake volume (TWh)	Share of total	DSO offtake volume (TWh)	Share of total
≤ 300 MWh/year	< 0.1	< 0.1%	289.0	45.1%
> 300 MWh/year ≤ 10,000 MWh/year	0.5	0.3%	112.5	17.5%
> 10,000 MWh/year ≤ 100,000 MWh/year	5.9	3.8%	89.5	14.0%
> 100,000 MWh/year	108.3	70.1%	104.8	16.3%
Gas power plants ≥ 10 MW net nominal capacity	39.8	25.8%	45.6	7.1%
Total	154.5	100%	641.4	100%

Table 78: Gas offtake volumes in 2022 broken down by final customer category, according to data from the gas TSOs and DSOs

Gas: Total offtake volumes in 2022 according to survey of gas TSOs and DSOs and volume delivered according to supplier survey, broken down by final customer category

	TSO and DSO offtake volumes (TWh)	Share of total	Volume delivered by suppliers (TWh)	Share of total
≤ 300 MWh/year	289.0	36.3%	300.7	39.2%
> 300 MWh/year ≤ 10,000 MWh/year	113.0	14.2%	105.6	13.8%
> 10,000 MWh/year ≤ 100,000 MWh/year	95.4	12.0%	89.7	11.7%
> 100,000 MWh/year	213.1	26.8%	205.1	26.7%
Gas power plants ≥ 10 MW net rated capacity	85.4	10.7%	65.8	8.6%
Total	795.9	100.0%	766.9	100.0%

Table 79: Total gas offtake volumes in 2022, according to data from the gas TSOs and DSOs and total volumes of gas delivered according to data from gas suppliers

2. Market concentration

Also in the gas sector, 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 in this sector because they represent the extent to which demand in the relevant market was actually satisfied by a company during the reference period.

To represent the market share distribution, i.e. the market concentration, CR3 values or CR4 values are used in the following: The larger the market share covered by only a few competitors, the higher the market concentration. A significant indicator of the degree of concentration in the gas markets is the share of companies in the total working gas volume in underground natural gas storage facilities.

Underground gas storage facilities

In its decisional practice the Bundeskartellamt defines the relevant product market for the operation of underground gas storage facilities as including both porous rock and cavern storage facilities. In geographical terms the Bundeskartellamt most recently defined this market as a national market and in the process also considered including the Haidach and 7Fields storage facilities in Austria.[79] These two storage facilities are located near the German border in Austria and are connected directly or indirectly to the German gas networks. The European Commission also recently considered this alternative market definition and a number of other alternatives, but ultimately left open the exact market definition.[80] The Haidach and 7Fields storage facilities in Austria are fully included in the following assessment to illustrate the concentration in the market for the operation of underground gas storage facilities.[81] Data were therefore collected from 24 legal entities. The Bundeskartellamt calculates the market shares in this market on the basis of storage capacities (maximum usable working gas volume).[82] Companies were attributed to a group according to the dominance method.

[79] See Bundeskartellamt, decision of 23 October 2014, B8-69/14 – EWE/VNG, paras. 225 ff., Bundeskartellamt, decision of 31 January 2012, B8-116/11 – Gazprom/VNG, paras. 208 ff.

[80] See COMP M./9641 – SNAM/FSI/OLT of 11 February 2020, para. 30.

[81] At the end of 2022 the Haidach storage facility was connected to the Austrian market area (transmission level) via the Penta-West pipeline. For this reason some degree of uncertainty in the total working gas volume considered cannot be excluded in this year's assessment. The agreement between Germany and Austria of 17 February 2023 concerning the joint use of the Haidach and 7Fields natural gas storage facilities determined, among other things, the responsibility for meeting the filling targets for the Haidach facility, which can only be taken into account in the next monitoring report.

[82] See Bundeskartellamt, decision of 23 October 2014, B8-69/14 – EWE/VNG, paras. 236 ff.

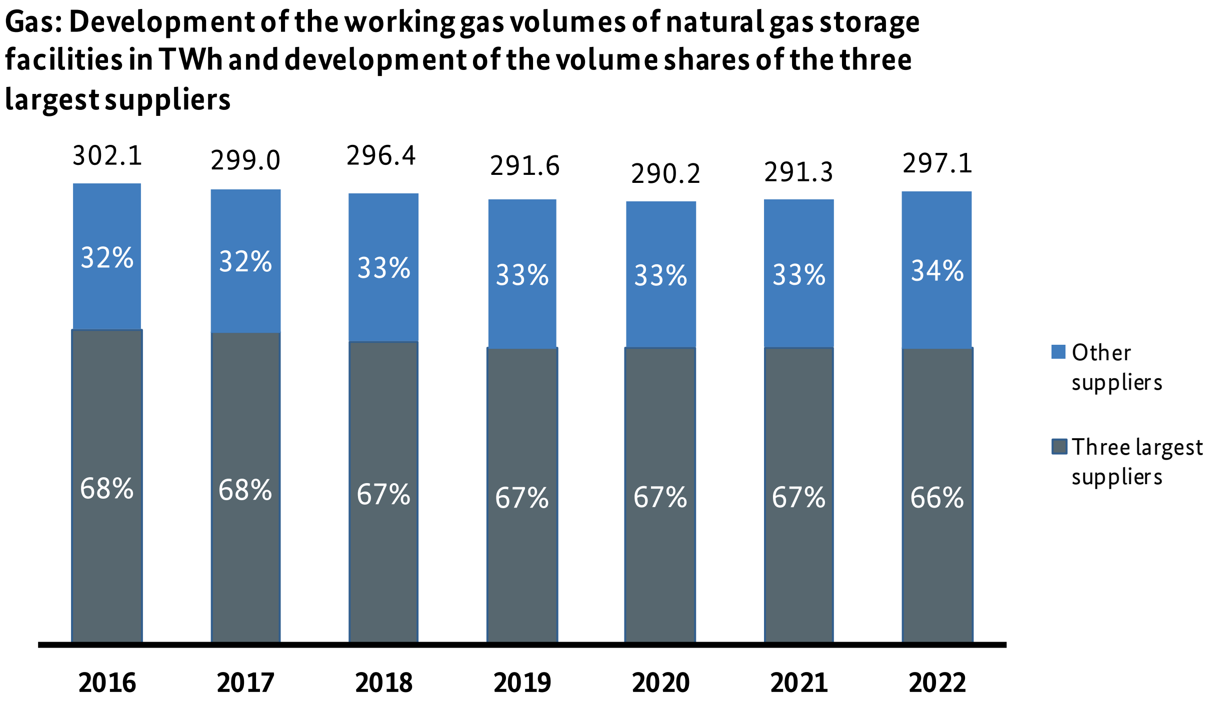


Figure 101: Development of the working gas volume of natural gas storage facilities and the volume shares of the three suppliers (CR3) with the largest storage capacities

Gas retail markets

On the gas retail markets the Bundeskartellamt differentiates between metered load profile customers and standard load profile customers. The market for the supply of gas to customers with metered load profiles and the market for the supply of gas to customers with standard load profiles based on special contracts are defined as national markets. The supply of gas to standard load profile customers under a default supply contract constitutes a separate product market which continues to be defined according to the relevant network area.[83]

In energy monitoring, data on the suppliers' sales volumes at the level of individual suppliers (legal entities) are collected as national total values. With regard to sales to standard load profile customers a differentiation is made between default supply and supply under special contracts. The analysis is based on the data provided by 953 gas suppliers (legal entities) (963 in the previous year).

Sales volumes were attributed to company groups on the basis of the dominance method, which provides sufficiently accurate results for the purposes of energy monitoring and in particular allows for year-on-year comparisons on a homogeneous and ongoing calculation basis.

Gas: Development of the shares of the four strongest suppliers (CR4) in the sale of gas to metered load profile customers and standard load profile customers in 2022

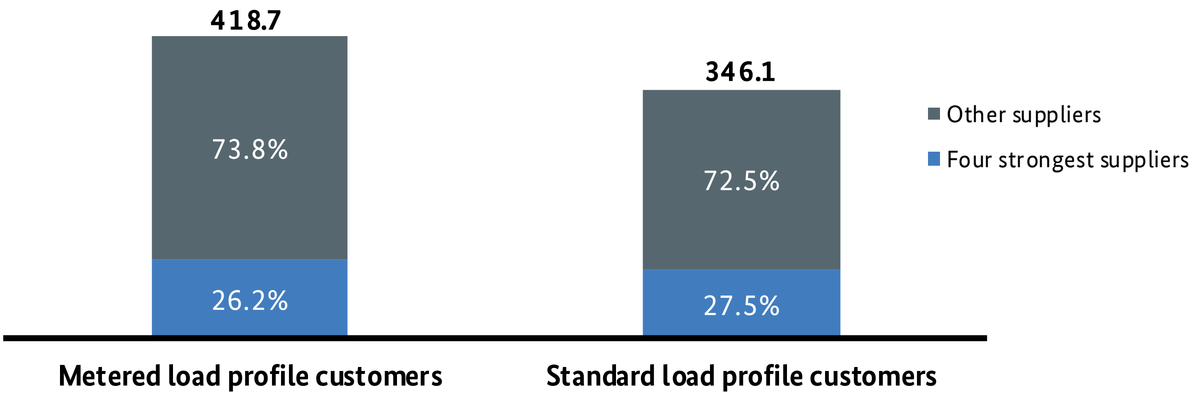


Figure 102: Development of the shares of the four strongest suppliers (CR4) in the sale of gas to metered load profile customers and standard load profile customers in 2022 according to data provided by the gas suppliers

[83] See Bundeskartellamt, decision of 23 December 2014, B8-69/14 – EWE/VNG, paras. 129-214.

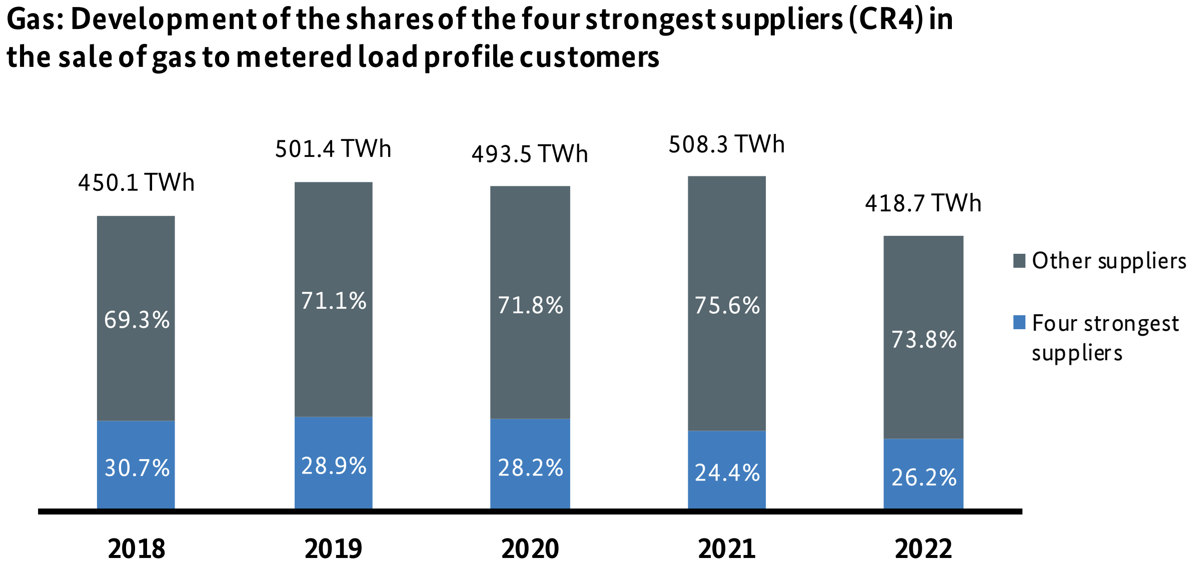


Figure 103: Development of the shares of the four strongest suppliers (CR4) in the sale of gas to metered load profile customers according to data provided by the gas suppliers

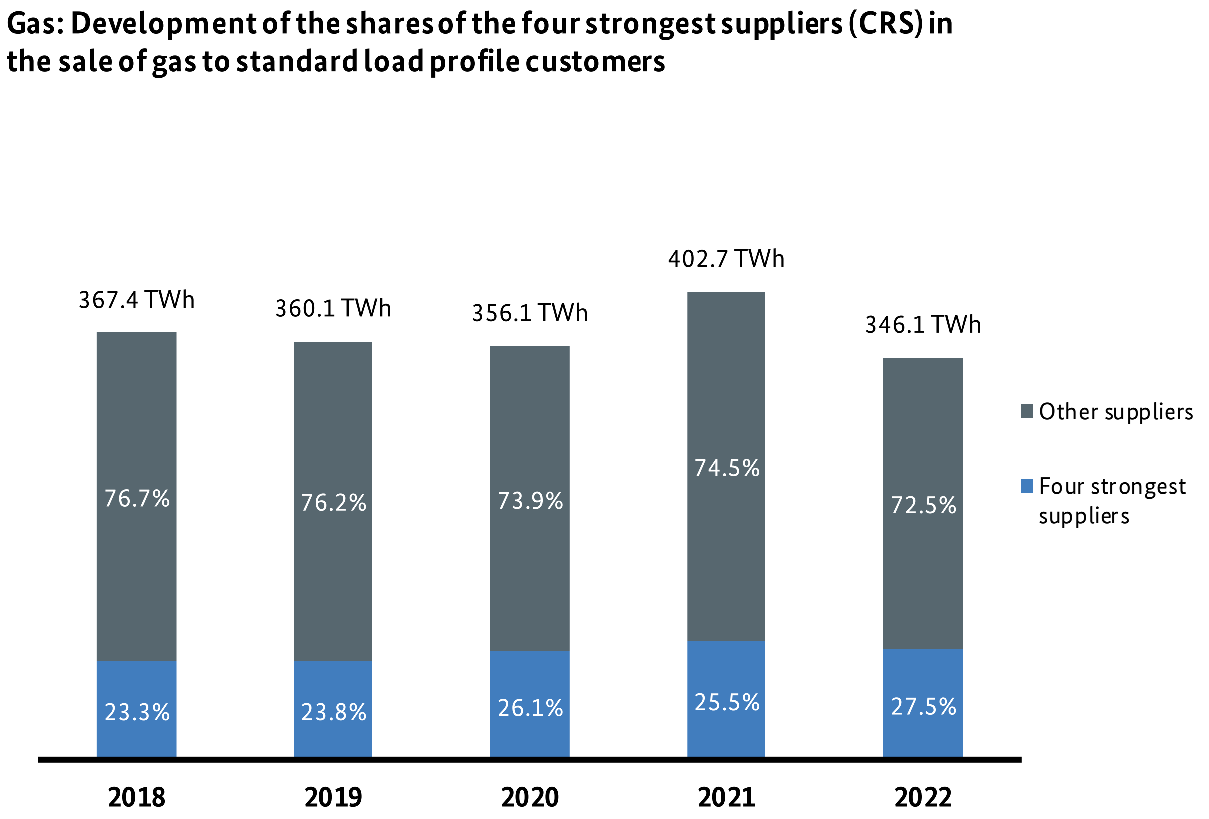


Figure 104: Development of the shares of the four strongest suppliers (CR4) in the sale of gas to standard load profile customers according to data provided by the gas suppliers

B Gas supplies

1. Production of natural gas in Germany

Germany has its own sources of gas, but these have been losing significance due to the increasing exhaustion of the large deposits and the resulting natural decline in output from year to year. Another factor is the lack of major new gas finds. The reserves-to-production ratio of the raw gas reserves has been falling for years. It is calculated on the basis of proven and probable reserves and last year's production of raw gas. The reserves-to-production ratio does not take the natural decline in output from the deposits or other factors into account and therefore should not be seen as a forecast, but rather as a snapshot and guideline figure.

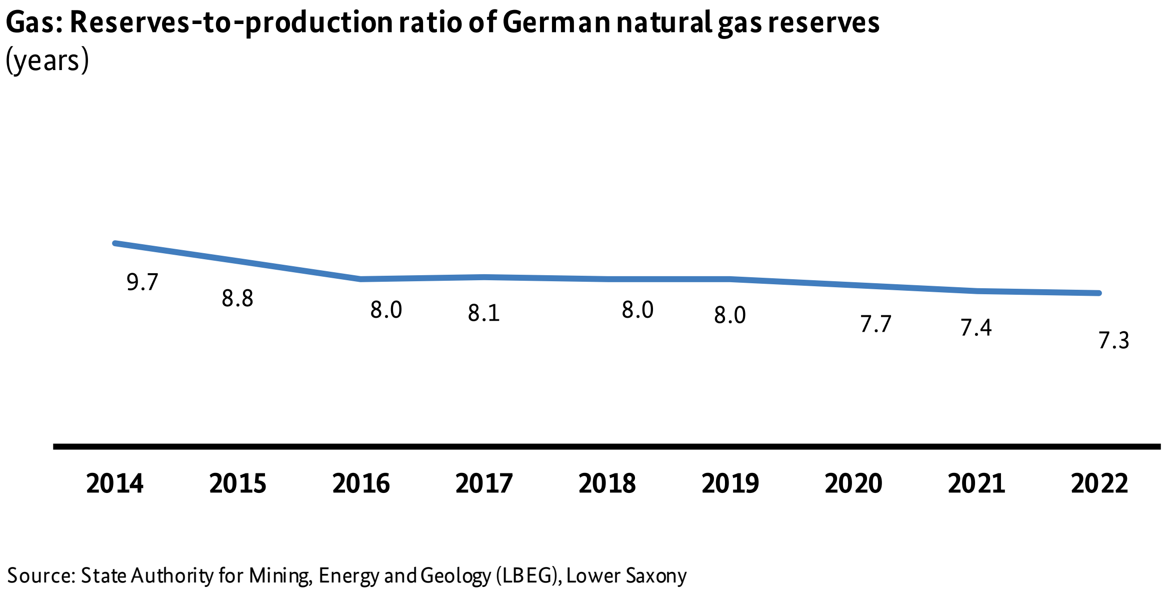


Figure 105: Reserves-to-production ratio of German natural gas reserves since 2014

2. Natural gas imports and exports

The monitoring report bases its assessment of imports and exports on the physical gas flows that enter and exit Germany at cross-border interconnection points, as reported daily by the TSOs to the Bundesnetzagentur. It is possible that, because of the infrastructure in place, recorded import and export volumes may also include loop flows.[84]

Germany gets most of the gas it needs from abroad. Germany's geographical position in the centre of Europe gives it the status of a gas hub, with gas imports arriving at the cross-border interconnection points largely

[84] One example of loop flows is 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 volumes are left out to avoid them being counted twice.

being passed on. Until the start of Russia's war on Ukraine, the majority of German gas imports came from Russian sources. Since the war began, Russian gas supplies have been gradually stopped. The volumes lost in this way have been partly made up for with additional deliveries from the Netherlands, Belgium and Norway, the creation of infrastructure for liquefied natural gas (LNG) and by reducing the consumption of gas.

When looking at the destination countries, the focus here is on the countries that Germany exports to at their respective cross-border interconnection point.

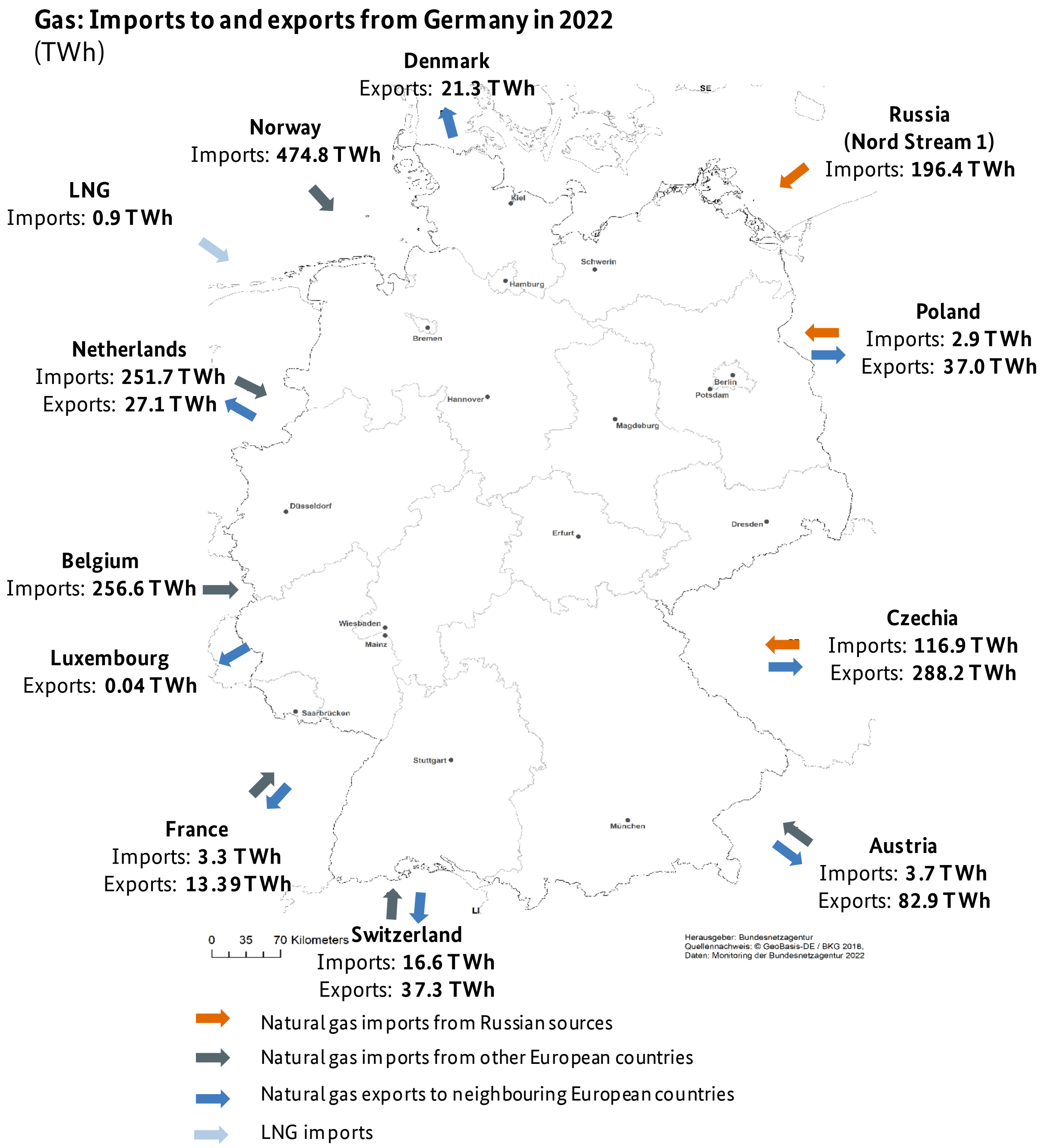


Figure 106: Gas flows to and from Germany in 2022

3. Market area conversion

The 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 the gas supply. H-gas is mainly imported from Norway and has a higher calorific value than L-gas. 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. L-gas will largely disappear from the German gas market by 2030. This is why the companies responsible, namely the TSOs and affected DSOs, are taking the necessary steps to prevent the declining availability of L-gas from adversely affecting the security of supply.

The new natural gas supply structure will affect more than four million household, commercial and industrial customers with an estimated 4.9mn appliances burning gaseous fuels.

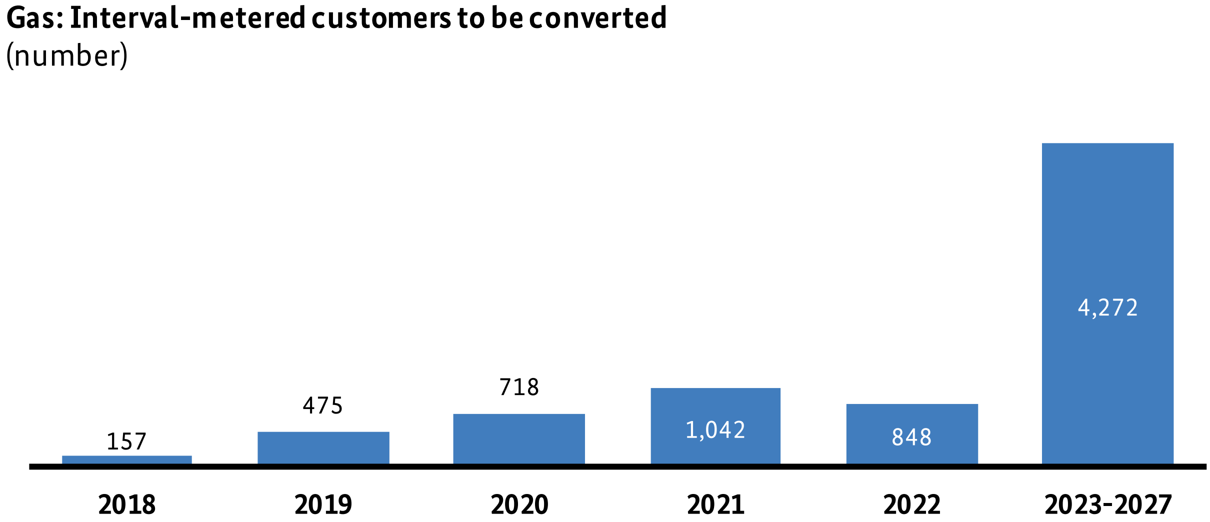


Figure 107: Interval-metered customers to be converted

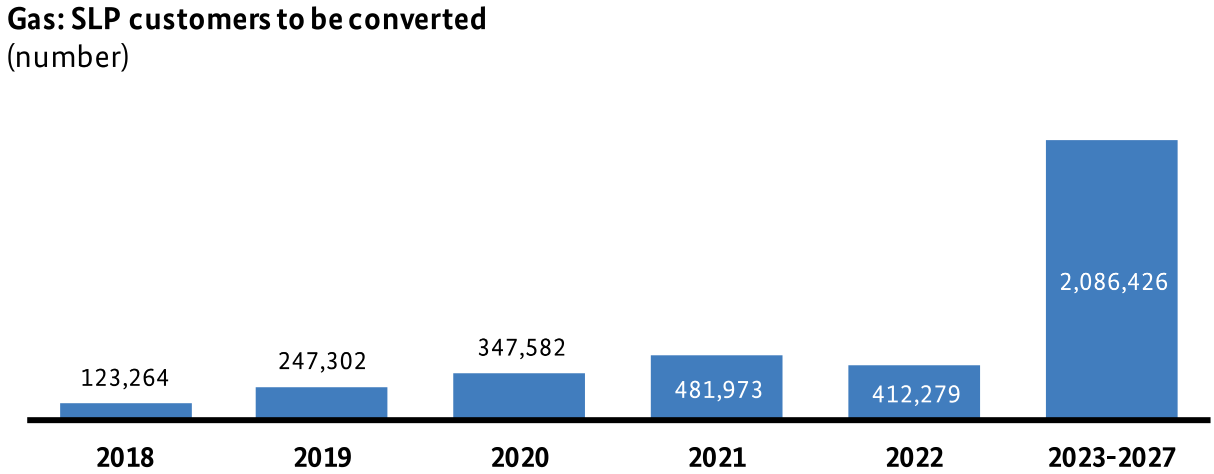


Figure 108: Standard load profile customers to be converted

Gas: Bids and awards for task packages for the market area conversion

Task packages	Bids			Awards		
	2020	2021	2022	2020	2021	2022
Appliance registration	9.4	8.5	8.0	3.6	3.4	2.7
Monitoring registration process	5.3	5.0	5.6	1.1	1.0	1.1
Conversion and adjustments	9.2	8.4	8.2	3.5	3.3	2.7
Inspection of conversion and adjustments	5.6	5.0	5.4	1.1	1.0	1.1
Project management	4.3	4.0	4.4	1.0	1.0	1.0

Table 80: Bids and awards for task packages for the market area conversion

4. Biogas (including synthesis gas)

Biogas can be generated in a fermentational or thermal process.[85] The biogas that is currently fed into the gas supply network is usually generated from fermentation, for example via anaerobic digestion. The substrates used in this process come mainly from energy crops such as maize and from manure and biowaste. The biogas produced from the fermentation of biomass consists of a maximum of 60% methane. Its methane content needs to be increased using carbon capture so that the gas meets the necessary requirements[86] and can be fed into the natural gas system. There are three main ways of upgrading the gas: pressure swing adsorption, pressurised water scrubbing and chemical scrubbing.

After being upgraded, the biogas is transferred to the connection and injection facilities, during which it is measured for volume, calorific value and other gas qualities.

The pressure then has to be increased, using a compressor, or decreased, using a gas pressure reduction station, depending on whether the upgrading process involved increasing the pressure and which pressure level the relevant gas network has.

The Gas Network Access Ordinance (GasNZV) provides the legal framework for the tools to promote the injection of biogas.

[85] The term biogas is used within the meaning of section 3 para 10f EnWG, "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)".

[86] As set out in worksheets G 260 and G 262 of the Deutscher Verein des Gas- und Wasserfachs e. V. (DVGW).

Gas: Biogas injection, key figures for 2022

	Injection, contractually agreed (mn kWh/h)	Injection (mn kWh/h)	Number of plants
Biomethane	2.559	9,818.3	214
Hydrogen produced by water electrolysis provided that the electricity used to perform electrolysis is mainly and verifiably derived from renewable energy sources[1]	0.004	1.8	7
Synthetically produced methane provided that the electricity used to perform electrolysis and the carbon dioxide or carbon monoxide used for methanation are mainly derived from renewable energy sources[1]	0.003	0.0	1
Other (gas from biomass, landfill gas, sewage treatment plant gas and mine gas)	0.058	338.0	16
Total	2.624	10,158.1	238

[1] within the meaning of Directive 2009/28/EC (OJ L 140 of 5 June 2009, page 16)

Table 81: Biogas injection, key figures for 2022

5. Gas storage facilities

Germany's gas storage facilities are key to the supply of gas, in particular in the winter months. They play an important role in balancing out seasonal fluctuations in consumption and ensuring security of supply. Thanks to its favourable geological conditions, Germany is well suited to setting up natural gas storage facilities. Cavern storage, pore storage and other underground storage facilities are all found in the country. The existing gas storage facilities are large enough to guarantee supply even in intensely cold periods or during interruptions in supply. Statistically, the maximum storage capacity could currently cover all supply for 80 days, provided that the storage facilities were full enough.

Maximum usable volume of working gas in underground storage facilities as at 31 December 2022
(TWh)

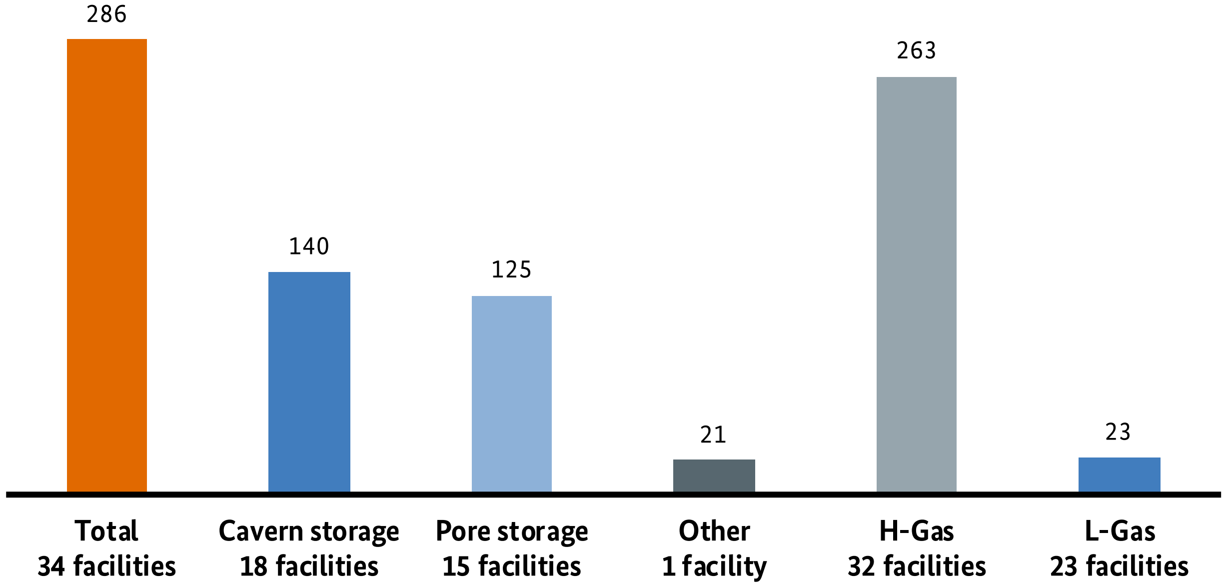


Figure 109: Maximum usable volume of working gas in underground natural gas storage facilities as at 31 December 2022

Gas: Changes in the number of customers per storage facility operator
(number of storage companies)

Number of customers	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
1	7	9	8	10	11	9	10	11	9	11	9
2	3	3	4	2	2	2	4	2	3	2	3
3 - 9	7	7	5	4	6	6	4	6	4	4	6
10 - 15	2	2	3	3	1	3	4	3	3	2	2
16 - 20	1	2	1	1	2	3	2	1	2	1	4
> 20	1	1	2	2	2	0	0	1	2	4	0

Table 82: Changes in the number of customers per storage facility operator over the years

Gas: Changes in the freely bookable working gas capacity, as offered on 31 December, in the subsequent periods from 2017 to 2022
(TWh)

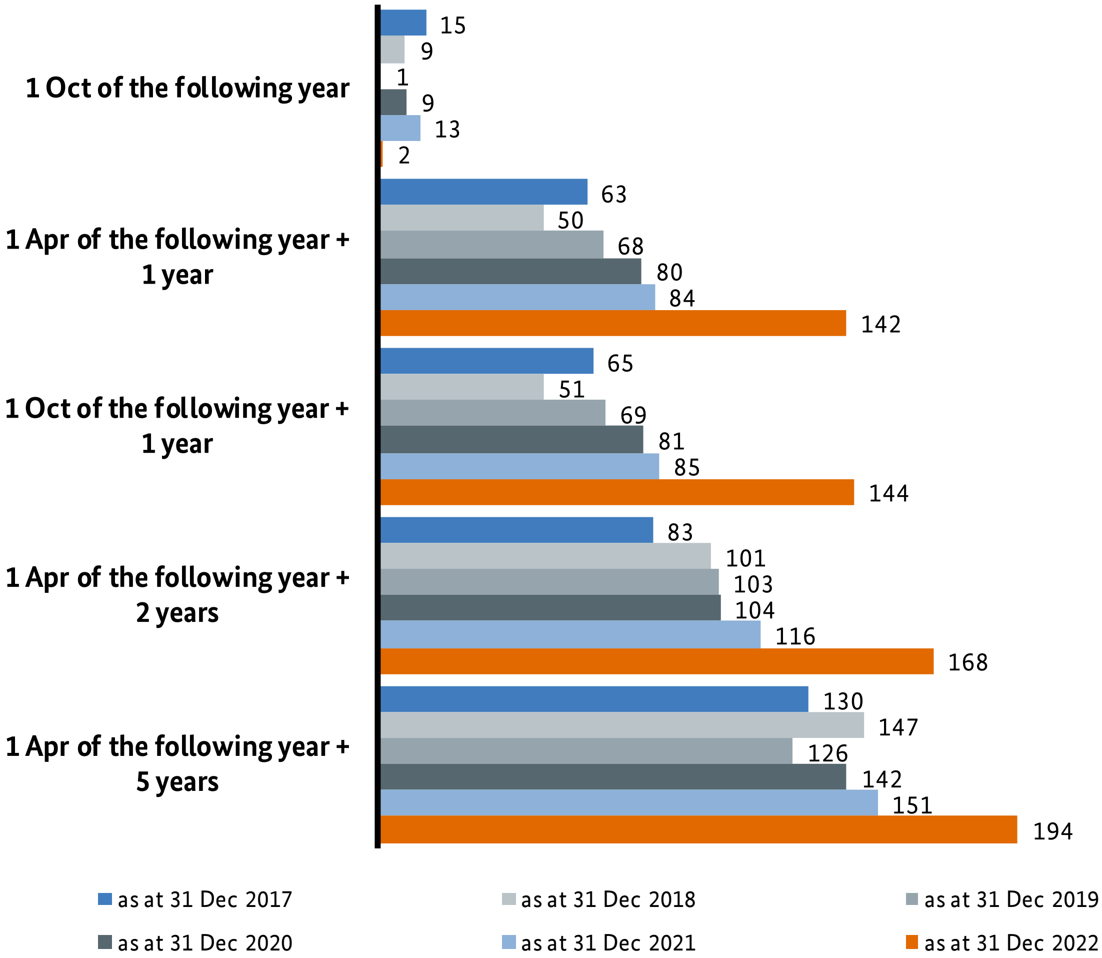


Figure 110: Changes in the freely bookable working gas capacity in the subsequent periods

C Networks

The pipes that make up the gas network are essential for transporting and distributing natural gas. Transmission lines form the backbone of the German gas network, transporting gas over long distances and enabling it to transit through Germany to neighbouring EU countries. Distribution systems serve to distribute gas to final customers and connect gas customers to the network. Gas networks are divided into different pressure ranges: low pressure (<= 100 millibar (mbar)), medium pressure (> 100 mbar to <= 1 bar) and high pressure (> 1 to 100 bar).

1. Network structure figures

The market location has been the unit in the energy market in which connections are counted for delivering and balancing since 2018. 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 locations. 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: Number of network operators in Germany registered with the Bundesnetzagentur

	2018	2019	2020	2021	2022	2023
TSOs	16	16	16	16	16	16
DSOs	718	708	703	703	702	704
DSOs with fewer than 100,000 connected customers	693	683	682	676	674	675
DSOs with fewer than 15,000 connected customers[1]	547	536	534	534	532	532

[1] Based on data from gas DSOs

Table 83: Number of gas network operators in Germany registered with the Bundesnetzagentur as at 1 July 2023

Gas: DSOs by pipeline network length (as at 31 December 2022)
(number and share)

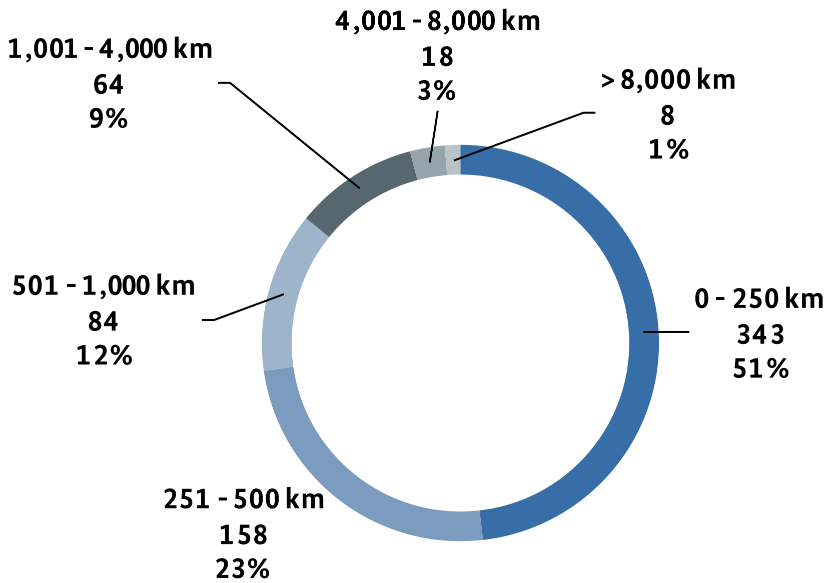


Figure 111: DSOs by gas pipeline network length according to data from gas DSOs – as at 31 December 2022

Gas: Network structure figures 2022

	TSOs	DSOs[1]	Total of TSOs and DSOs
Network operators (number)	**16**	**635**	**651**
Network length (thousand km)	**43.3**	**527.4**	**570.7**
≤ 0.1 bar	0.0	188.2	188.2
> 0.1 – 1 bar	0.0	264.1	264.1
> 1 – 5 bar	0.1	27.6	27.7
> 5 – 16 bar	2.9	27.4	30.3
> 16 bar	40.3	20.1	60.4
Total exit points (thousand)	**3.5**	**11,190.2**	**11,193.7**
≤ 0.1 bar	0.0	6,045.8	6,045.8
> 0.1 – 1 bar	0.0	4,923.6	4,923.6
> 1 – 5 bar	0.1	209.1	209.2
> 5 – 16 bar	1.2	9.4	10.6
> 16 bar	2.2	2.3	4.5
Final customer market locations (thousand)	0.5	14,480.8	14,481.3
Industrial, commercial and other non-household customers	0.5	1,606.3	1,606.8
Household customers	0.0	12,874.5	12,874.5

[1] Evaluation based on data from 635 network operators

Table 84: 2022 network structure figures according to data from gas TSOs and DSOs, as at 31 December 2022

Gas: Market locations by federal state at DSO level (as at 31 December 2022)
(number in millions)

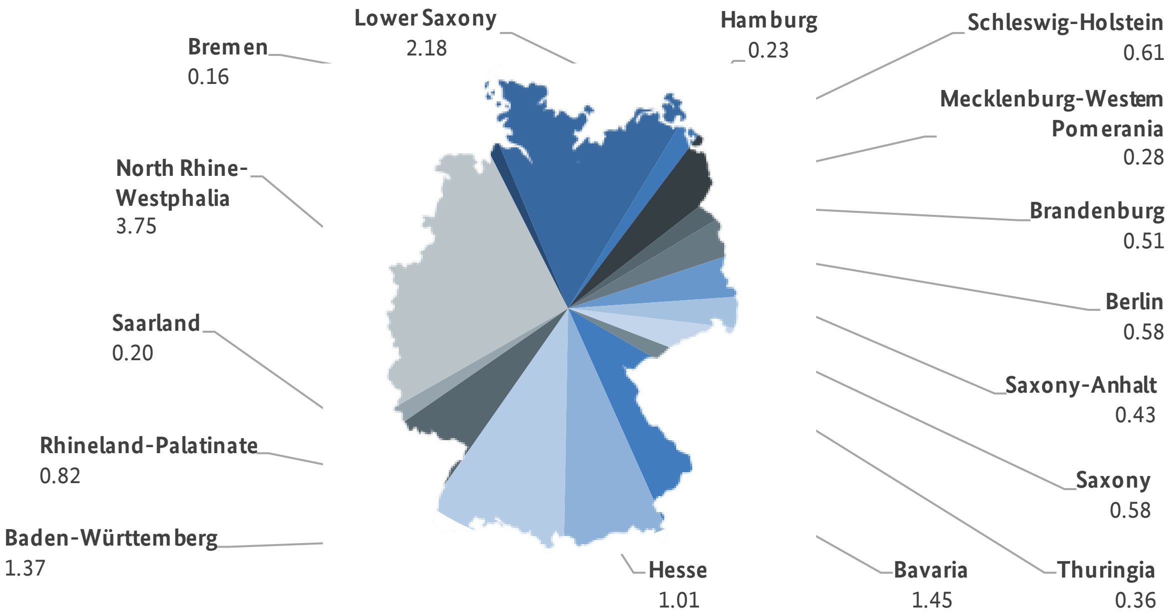


Figure 112: Market locations by federal state at DSO level according to data from gas DSOs– as at 31 December 2022

Gas: Market locations by federal state at TSO level (as at 31 December 2022)
(number)

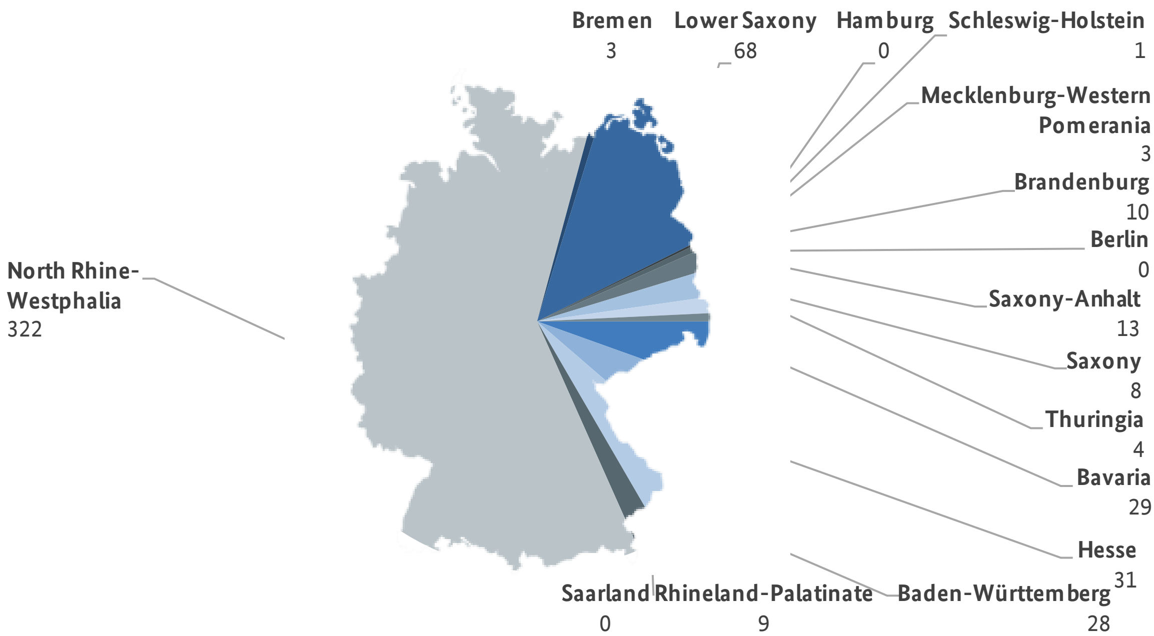


Figure 113: Market locations by federal state at TSO level according to data from gas TSOs– as at 31 December 2022

Gas: DSOs by number of market locations supplied (as at 31 December 2022)
(number and share)

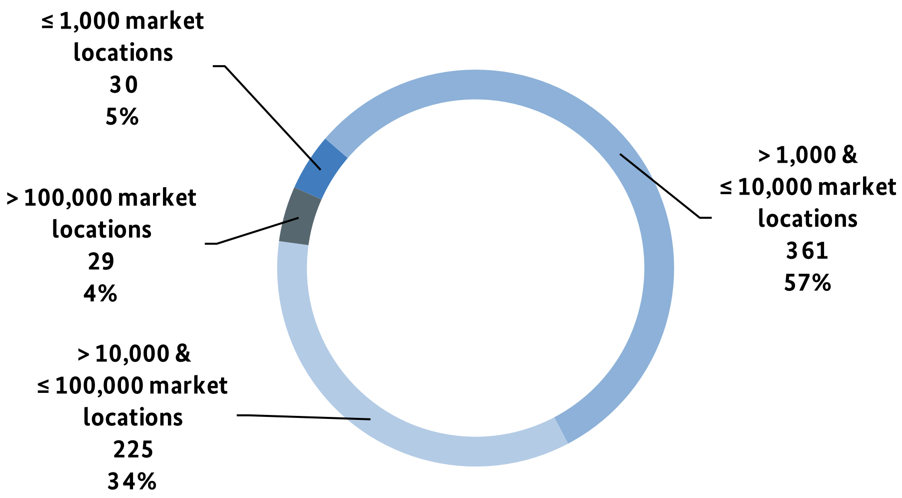


Figure 114: DSOs by number of market locations supplied according to data from gas DSOs – as at 31 December 2022

2. Network expansion - Gas Network Development Plan

The Energy Industry Act (EnWG) requires the gas transmission system operators (TSOs) to draw up a joint network development plan (NDP) covering the whole of the country in every even-numbered year. The plan must include all measures for enhancing, reinforcing and expanding the network in line with requirements and for guaranteeing security of supply that are effective and necessary for secure and reliable network operation in the next ten years. In the intervening years, the TSOs must submit a joint implementation report by 1 April.

First the TSOs draw up a scenario framework. The scenarios aim to present possible developments in the gas sector over the next 10 years. They take account of various factors, including assumptions about developments in gas production, supply and consumption and about planned investments in networks and storage facilities as well as possible supply interruptions. Once the scenario framework has been published, the TSOs give the public and downstream operators the opportunity to comment on it. After completion of the consultation process they submit the draft scenario framework to the Bundesnetzagentur. The Bundesnetzagentur assesses and confirms the scenario framework, taking account of the responses to the public consultation.

Next the NDP itself is developed. The TSOs use the scenario framework to model the network expansion requirements for the next 10 years and draw up a draft NDP. Both the public and downstream network operators have the opportunity to submit comments on it. The necessary information is provided on the website of the FNB Gas (Vereinigung der Fernleitungsnetzbetreiber Gas e.V.). Once the NDP has been revised, the TSOs submit the expanded draft to the Bundesnetzagentur. The Bundesnetzagentur holds its own consultation for all actual and potential network users and publishes the results. The Bundesnetzagentur can request the TSOs to amend the NDP within three months of publishing the consultation results. The TSOs have three months to make the amendments. The Bundesnetzagentur can decide which TSO should be responsible for implementing a certain measure in the Gas NDP. If the Bundesnetzagentur does not request any amendments within the three-month period, the NDP becomes binding for the TSOs.

Additionally, the network code on capacity allocation mechanisms (CAM NC) specifies an incremental capacity process for the market-based determination of the demand for and, if necessary, creation of additional capacity at cross-border interconnection points. The results of the process serve as a sound basis for determining the TSOs' demand for network expansion.

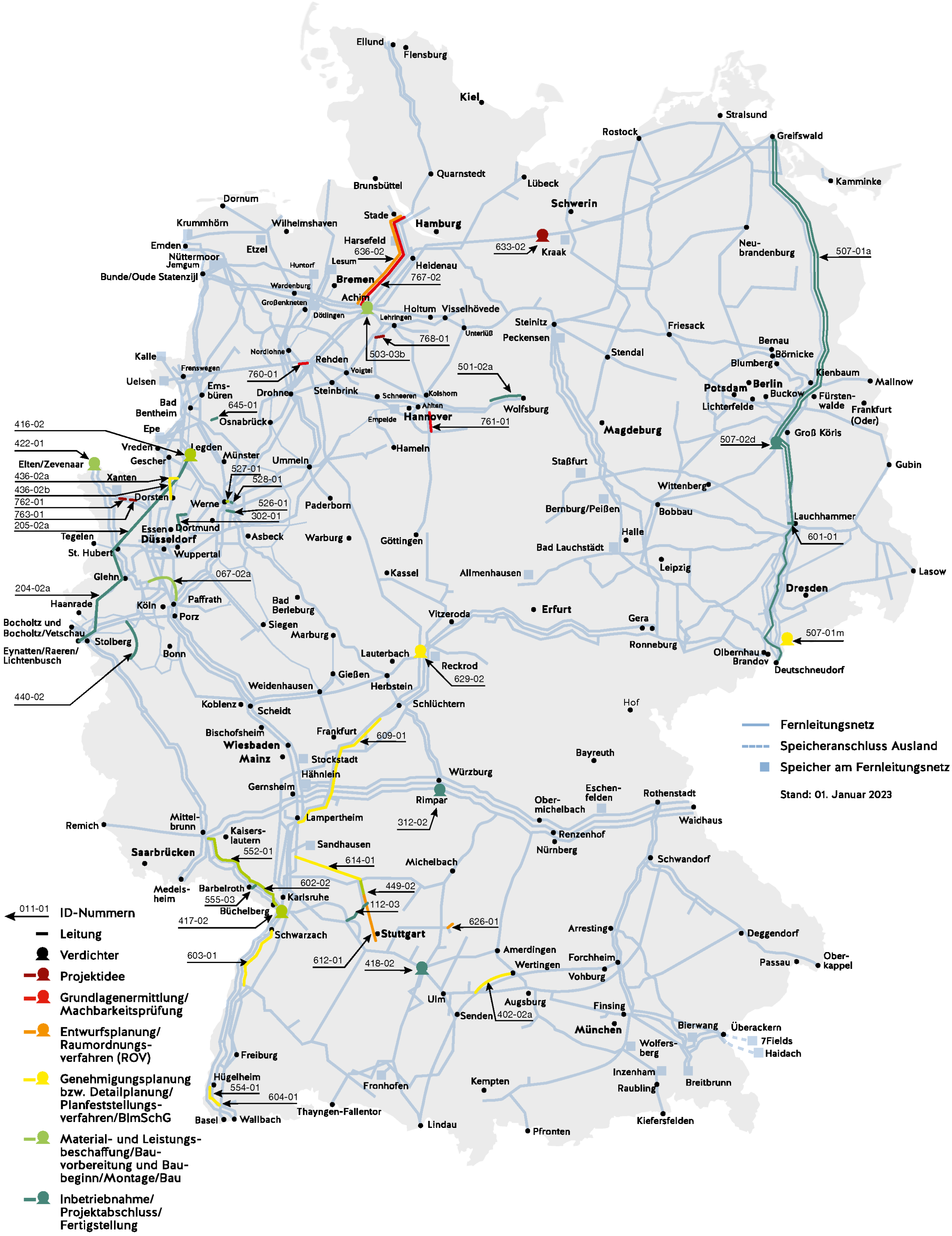


Figure 115: Implementation status of network expansion measures as at 1 January 2023 in the Gas NDP 2022-2032

3. Investments

For the purposes of the monitoring survey, investments are defined as the gross additions to fixed assets capitalised in the reporting period and the fixed assets newly rented and hired in the reporting period. Expenditure comprises all technical, administrative and management-related measures taken during the life cycle of an asset. These measures serve to maintain or restore working order so that the asset 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 values under commercial law do not correspond to the implicit values included in the operators' revenue caps in accordance with the provisions of the Gas Network Tariffs Ordinance (GasNEV) and the Incentive Regulation Ordinance (ARegV).

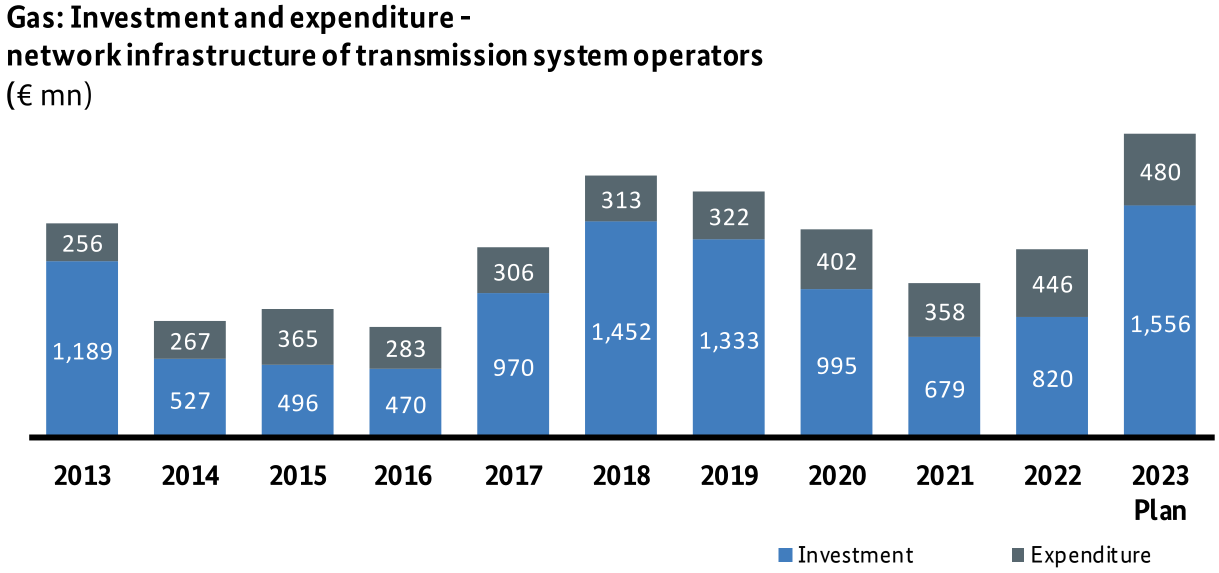


Figure 116: Investments in and expenditure on network infrastructure by gas TSOs

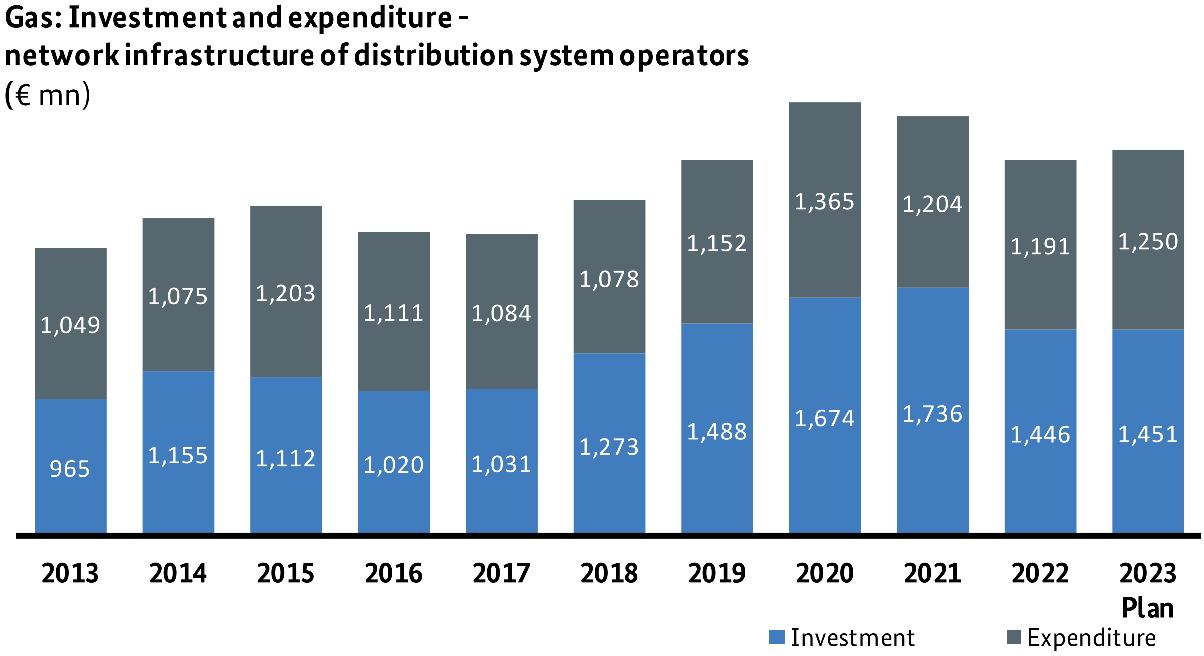


Figure 117: Investments in and expenditure on network infrastructure by gas DSOs

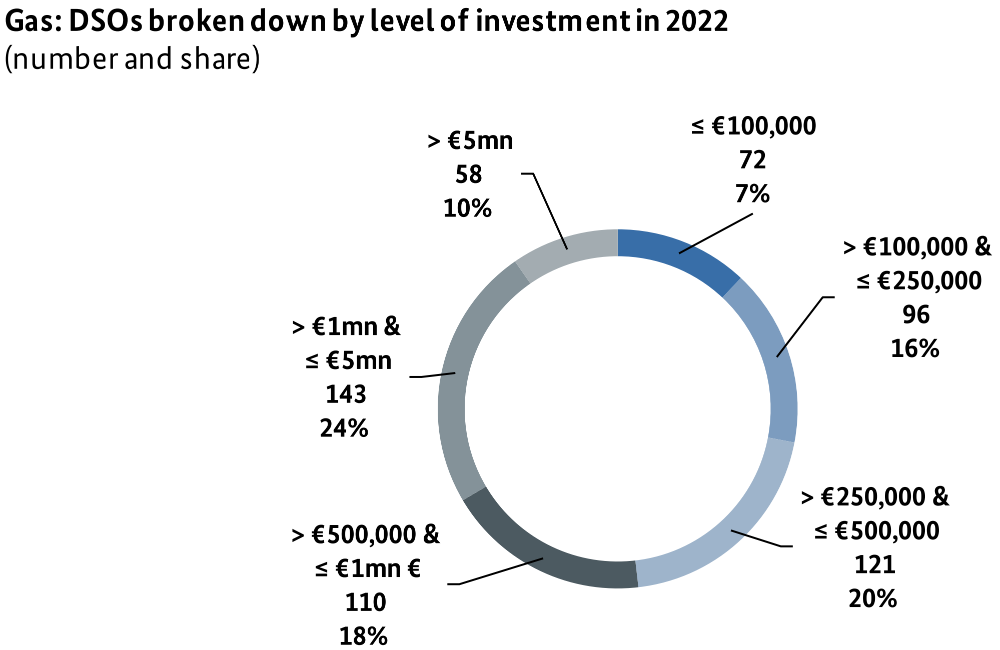


Figure 118: Distribution of gas DSOs according to level of investment in 2022

Gas: DSOs broken down by level of expenditure in 2022
(number and share)

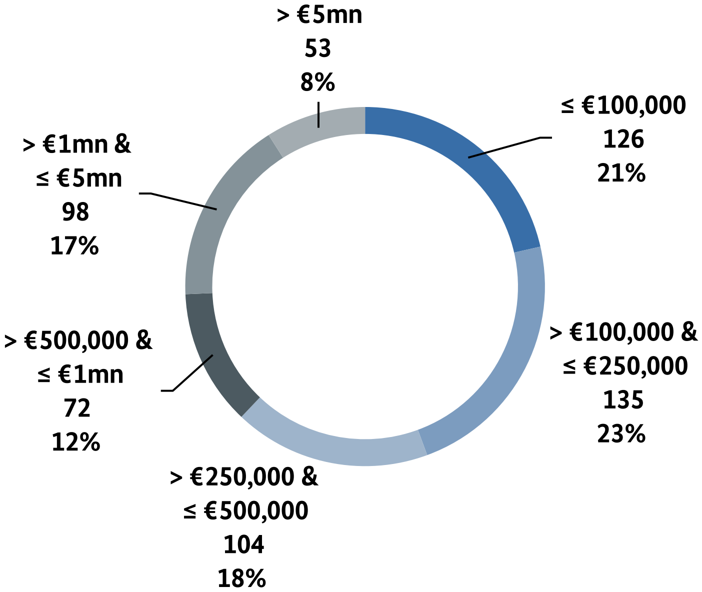


Figure 119: Distribution of gas DSOs according to level of expenditure in 2022

4. Capacity offer and marketing

Transport capacities relate to the right to inject or withdraw gas into/from a transmission network. The volume of gas to be transported when use is made of this right is reported by the shippers in a process known as nomination. This section distinguishes between the various capacity products offered on the market according to the duration of the corresponding entry and exit capacity products. The data principally concern the median offer of and/or demand for firm capacity at cross-border interconnection points and capacity demand at bookable network connection points to storage facilities, power stations and final customers.

This survey does not include the reserve capacity agreed with the downstream network operators of the TSOs within the internal booking process since the network connection points to distribution networks are not marketed directly to shippers.

The various capacity products are defined in the determination on standardising capacity products in the gas sector (capacity product standardisation, "KASPAR"):

FZK	Firm, freely allocable capacity	enables shippers to make use of booked entry and exit capacity on an unrestricted, firm basis without having to determine a transport path.
bFZK	Conditionally firm, freely allocable capacity	enables shippers to use booked entry and exit capacity on a firm basis without specifying a transport path, provided that a pre-defined, external condition is met.
DZK	Firm, dynamically allocable capacity	enables shippers to use booked entry and exit capacity on a firm basis provided that, in the case of entry capacity, gas is injected at the booked entry point for withdrawal at a pre-specified exit point in the same market area and that, in the case of exit capacity, the gas injected at a pre-specified entry point in the same market area is withdrawn at the booked exit point. In addition, it allows shippers to use booked entry and exit capacity on an interruptible basis without specifying a transport path.
uFZK	Interruptible, freely allocable capacity	enables shippers to make use of booked entry and exit capacity on an interruptible basis without having to determine a transport path.

Capacity with limited allocability (BZK) is not defined in the KASPAR determination. Since 1 October 2021 it has no longer been permitted to offer this capacity. It was still offered, however, during the current period under review and hence is included in the following evaluations. The definition of the product essentially corresponds to that of the DZK product but with the difference that use without specifying a transport path (access to the virtual trading point) is ruled out.

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 this capacity 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.

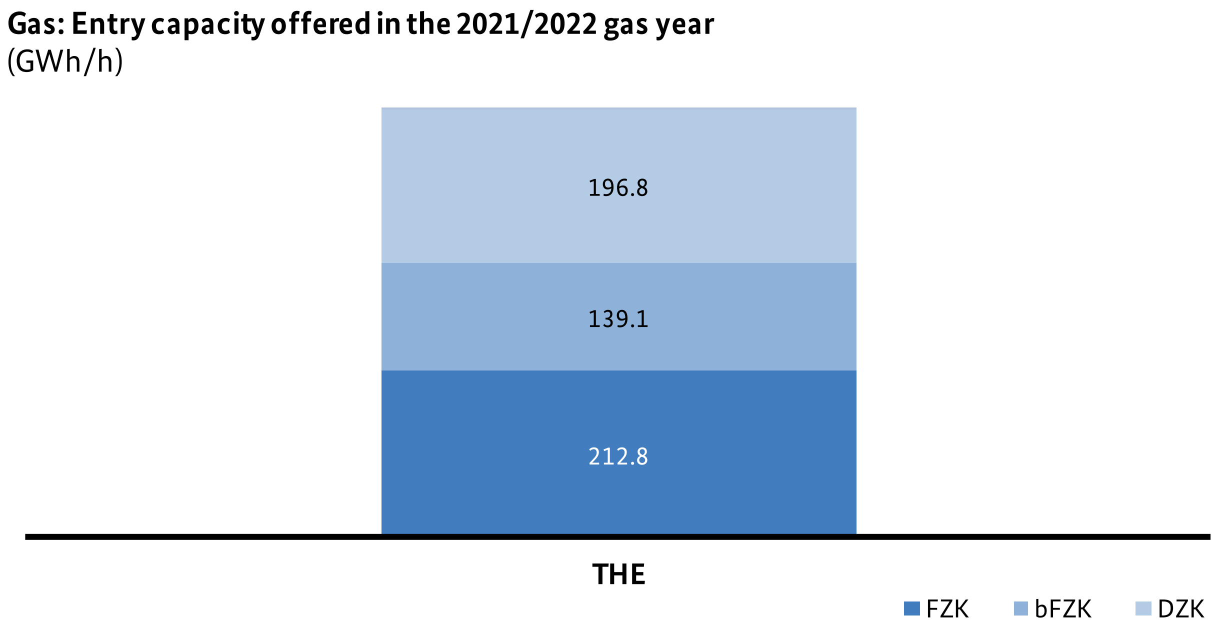


Figure 120: Entry capacity offered

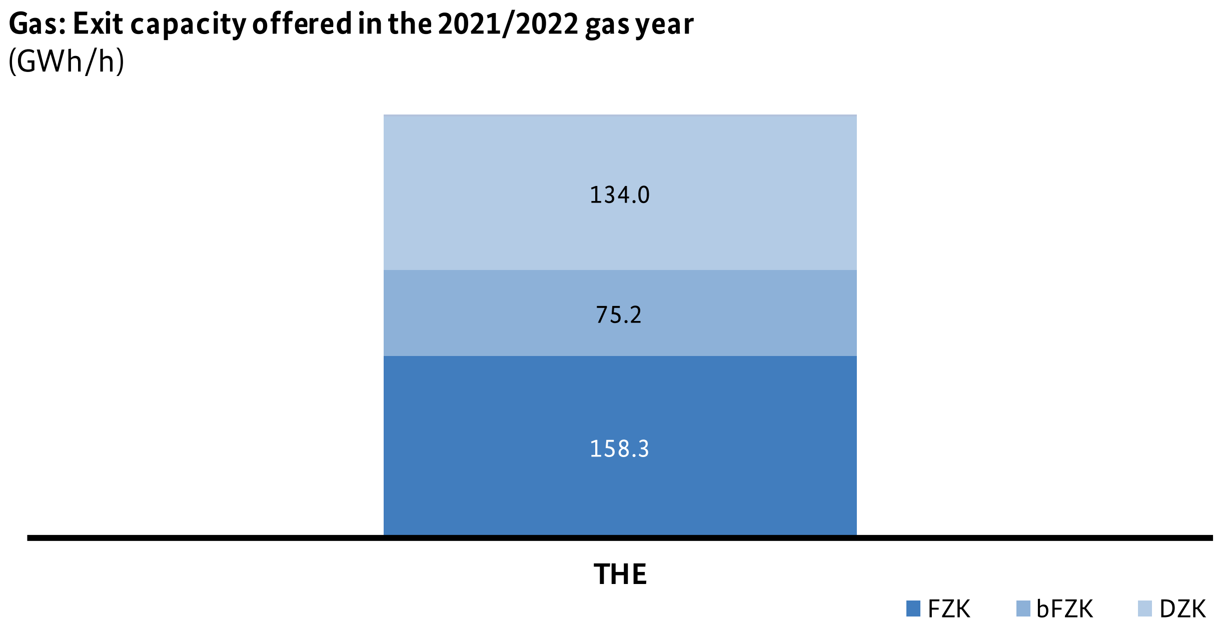


Figure 121: Exit capacity offered

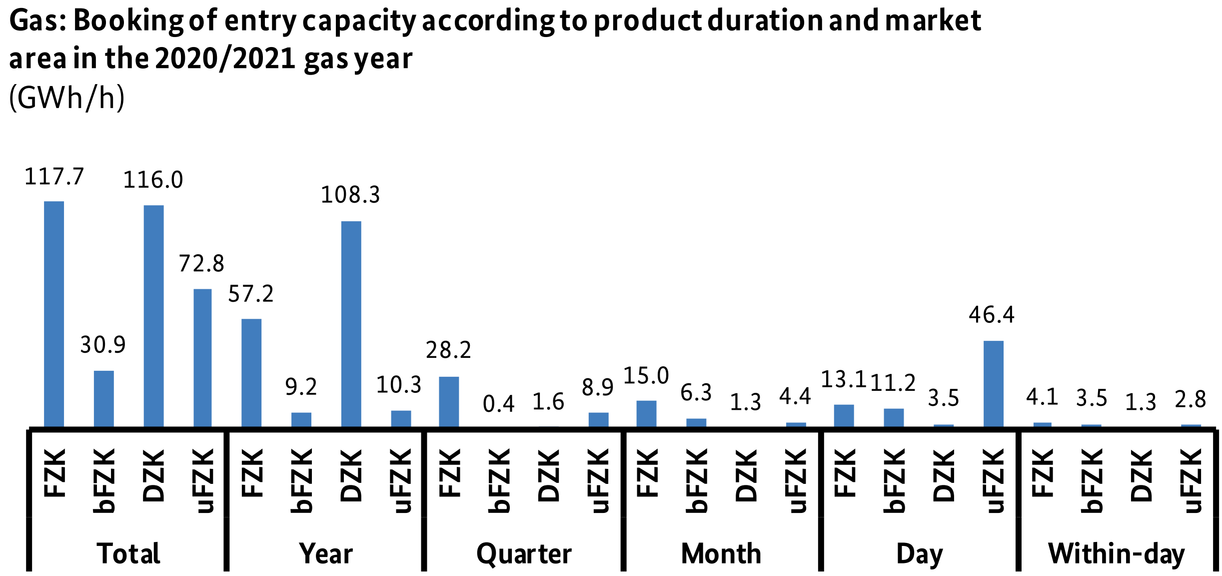


Figure 122: Booking of entry capacity by product duration

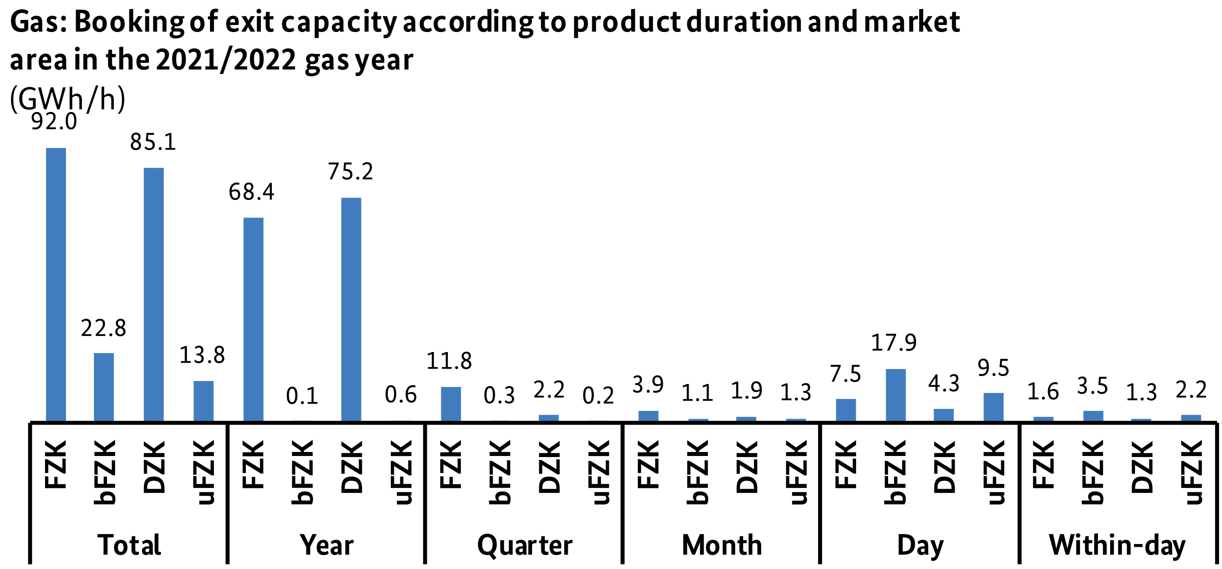


Figure 123: Booking of exit capacity by product duration

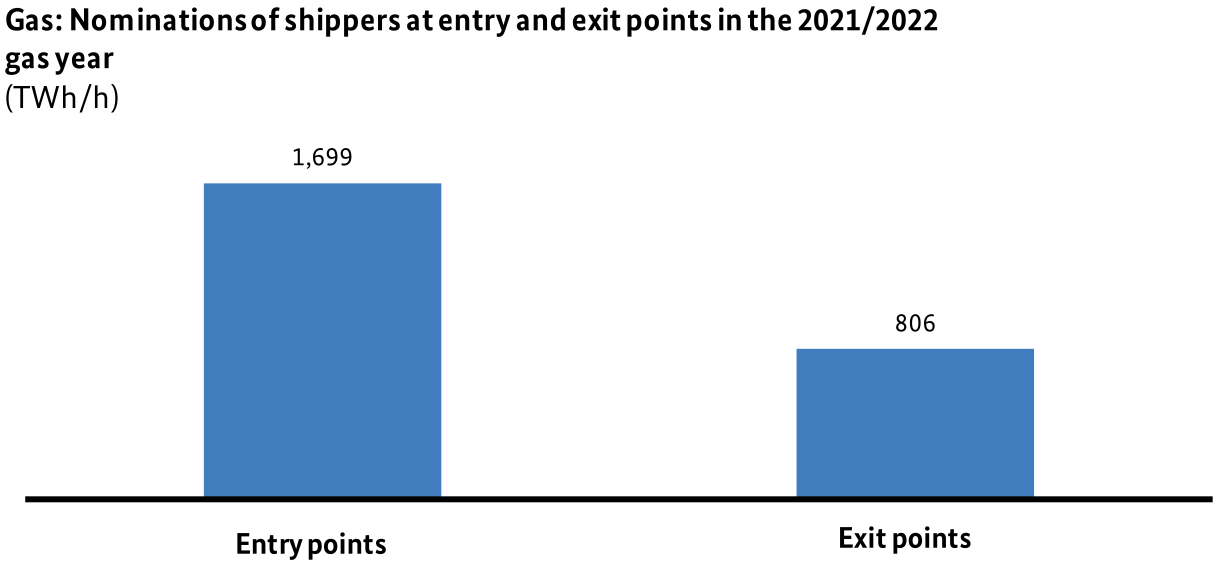


Figure 124: Booking at entry and exit points subject to a nomination obligation in the 2021/2022 gas year

5. 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). Only unplanned interruptions caused by third-party intervention, disturbances in the network operator's area, ripple effects from other networks or other disturbances are included in the calculations.

Gas: SAIDI results for 2022

Pressure level	Specific SAIDI	Notes
≤ 100 mbar	1.08 min/year	Household/low-volume customers
> 100 mbar	0.44 min/year	Major consumers, gas power plants
> 100 mbar	5.35 min/year	Downstream network operators (not part of SAIDI)
across all pressure levels	1.52 min/year	SAIDI value across all final customers

Table 85: Supply disruptions in 2022

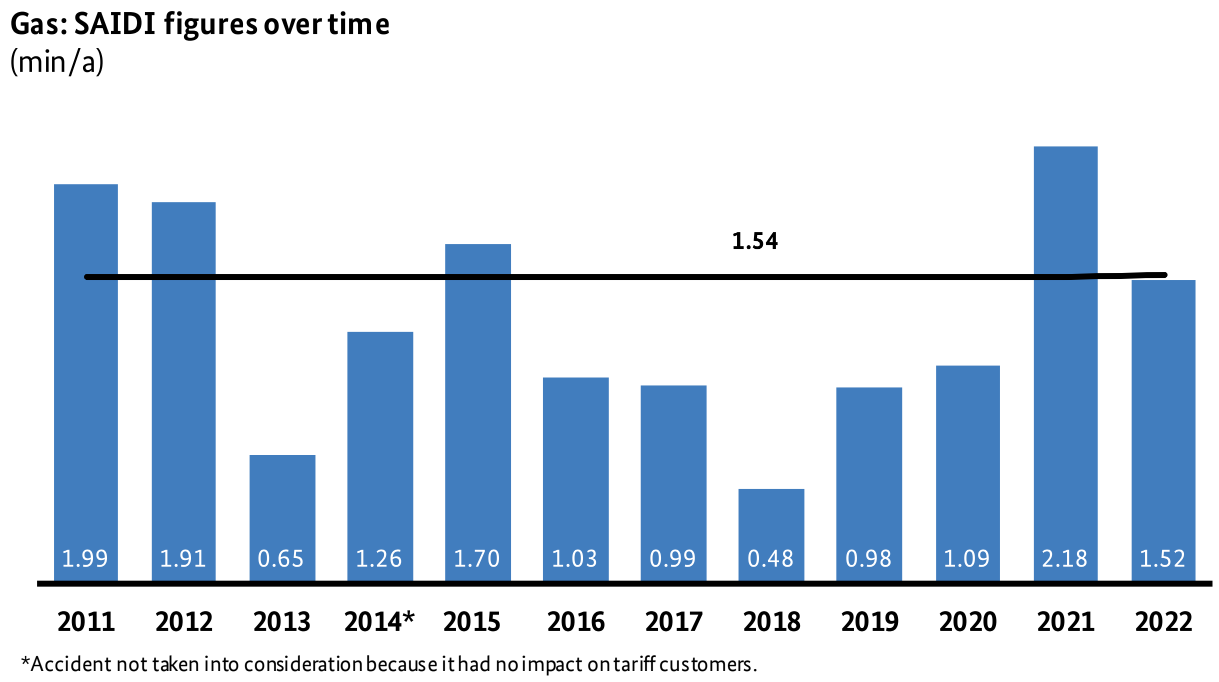


Figure 125: SAIDI gas figures for the period from 2011 to 2022

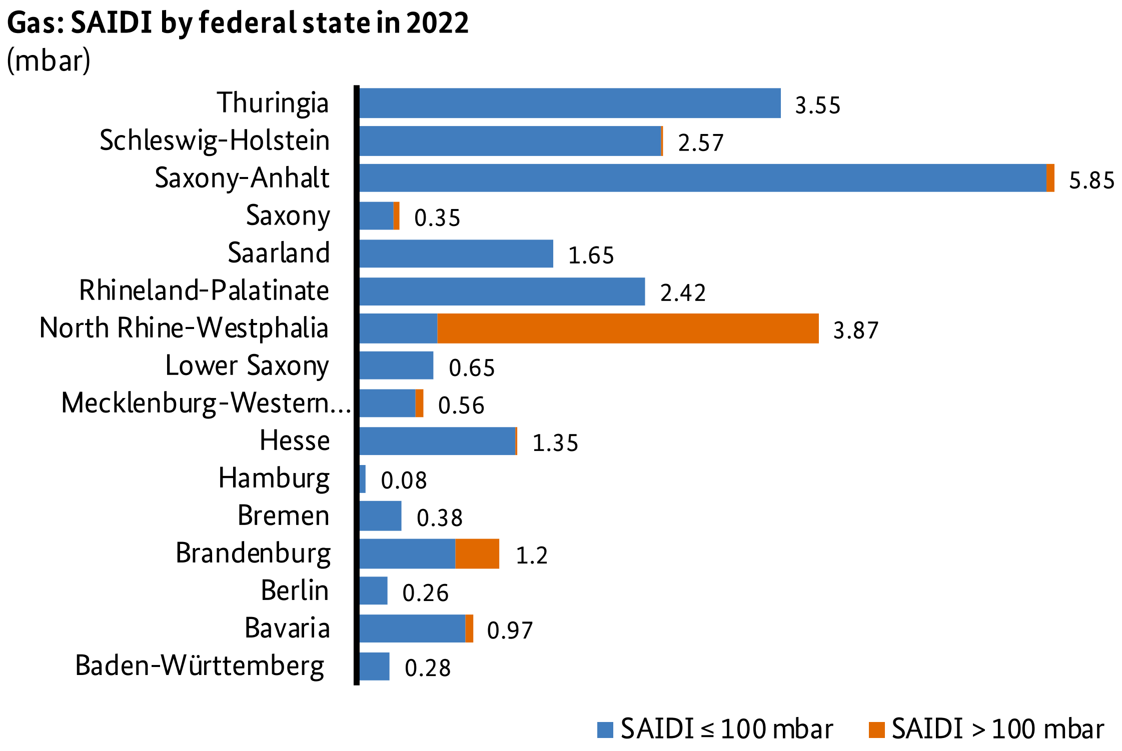


Figure 126: SAIDI gas figures, breakdown by federal state

6. Network tariffs

Network tariffs are imposed by the TSOs and DSOs and form part of the retail price. They are the means of spreading the costs of operation, maintenance and expansion of networks among all network users. The network operator's tariffs 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 tariffs are therefore a regulated part of the final price.

The revenue cap is calculated using the instruments of 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, imputed 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, consumer price index, individual 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 incentive regulation. These include, at the transmission network level, costs for investment measures in accordance with section 23 ARegV. "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 tariff system is used to share the revenues allowed for the respective network operators among the network users. The network tariffs payable by the network users are determined on the basis of the revenue caps. In principle, section 3 of the Gas Network Tariffs Ordinance (GasNEV) allows for two different tariff systems to be used for this purpose within the framework of cost unit accounting. Entry and exit capacity tariffs as prescribed by section 13 GasNEV are the norm. These apply in the case of TSOs and those DSOs that have capacity tariffs. Since 1 January 2020 the provisions of Regulation (EU) 2017/460 (TAR NC), in which harmonised requirements for the tariff structure are laid down Europe-wide, have applied for the TSOs.

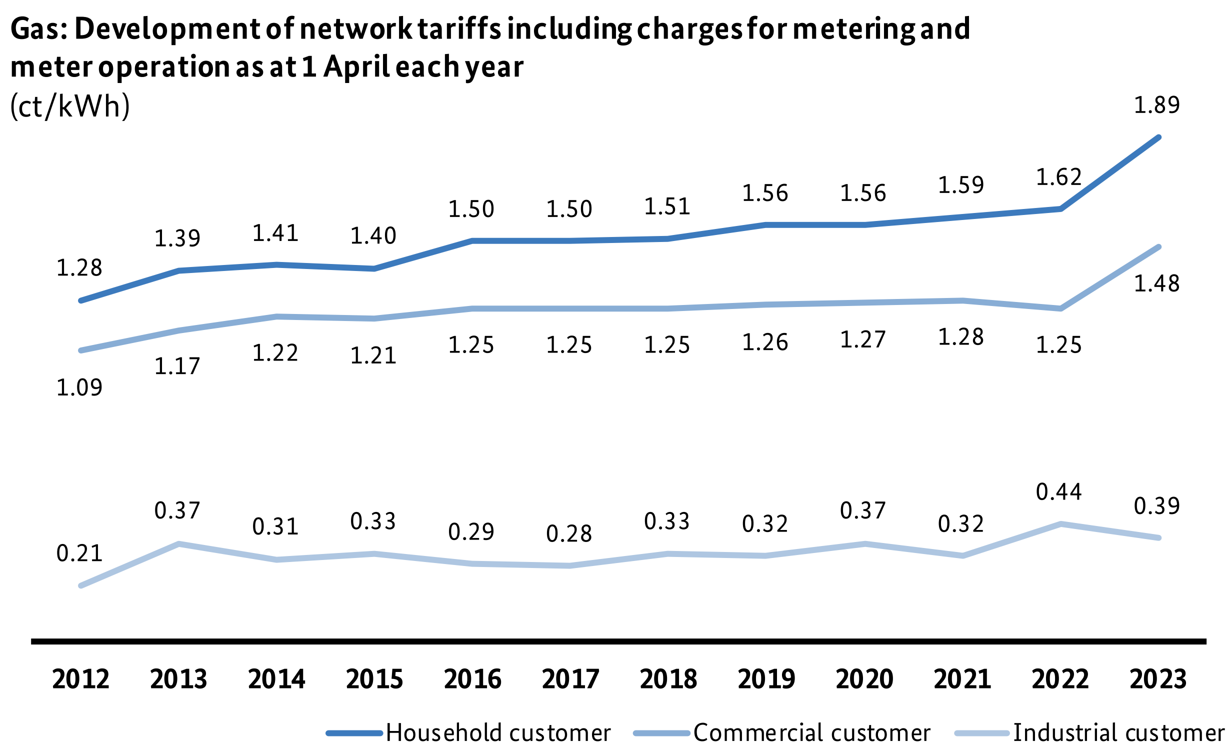


Figure 127: Development of network tariffs for gas (including charges for metering and meter operation) according to data from gas suppliers[87]

[87] In accordance with the three categories of household customers (volume-weighted across all contract categories and with consumption of 23,269 kWh), commercial customers (annual consumption of 116 MWh and no prescribed annual usage time) and industrial customers (annual consumption of 116 GWh and annual usage time of 250 days (4,000 hours).

Gas: Net network tariffs for household customers in Germany in 2023
(ct/kWh)

Federal state	Weighted average[1]	Minimum	Maximum	Number of distribution networks
Bremen	2.11	2.08	2.14	2
Saxony-Anhalt	2.00	1.30	2.75	23
Hamburg	1.96	1.96	1.96	1
Saarland	1.92	1.38	2.32	15
Mecklenburg-Western Pomeran	1.90	1.26	2.02	19
Saxony	1.90	1.31	3.17	37
Thuringia	1.88	1.26	2.74	29
Brandenburg	1.86	1.17	2.38	25
Baden-Württemberg	1.78	1.16	2.29	86
Rhineland-Palatinate	1.78	0.91	2.72	32
Berlin	1.70	1.70	1.70	1
Bavaria	1.69	0.77	4.18	97
Hesse	1.68	0.99	2.25	44
North Rhine-Westphalia	1.67	0.91	2.84	116
Schleswig-Holstein	1.62	1.09	2.46	42
Lower Saxony	1.51	0.78	2.51	57

[1] The weighting was based on the volume of gas supplied in each network area.

Table 86: Distribution of gas network tariffs for the "household customer" consumption category by federal state, as at 1 January 2023 according to data from gas DSOs

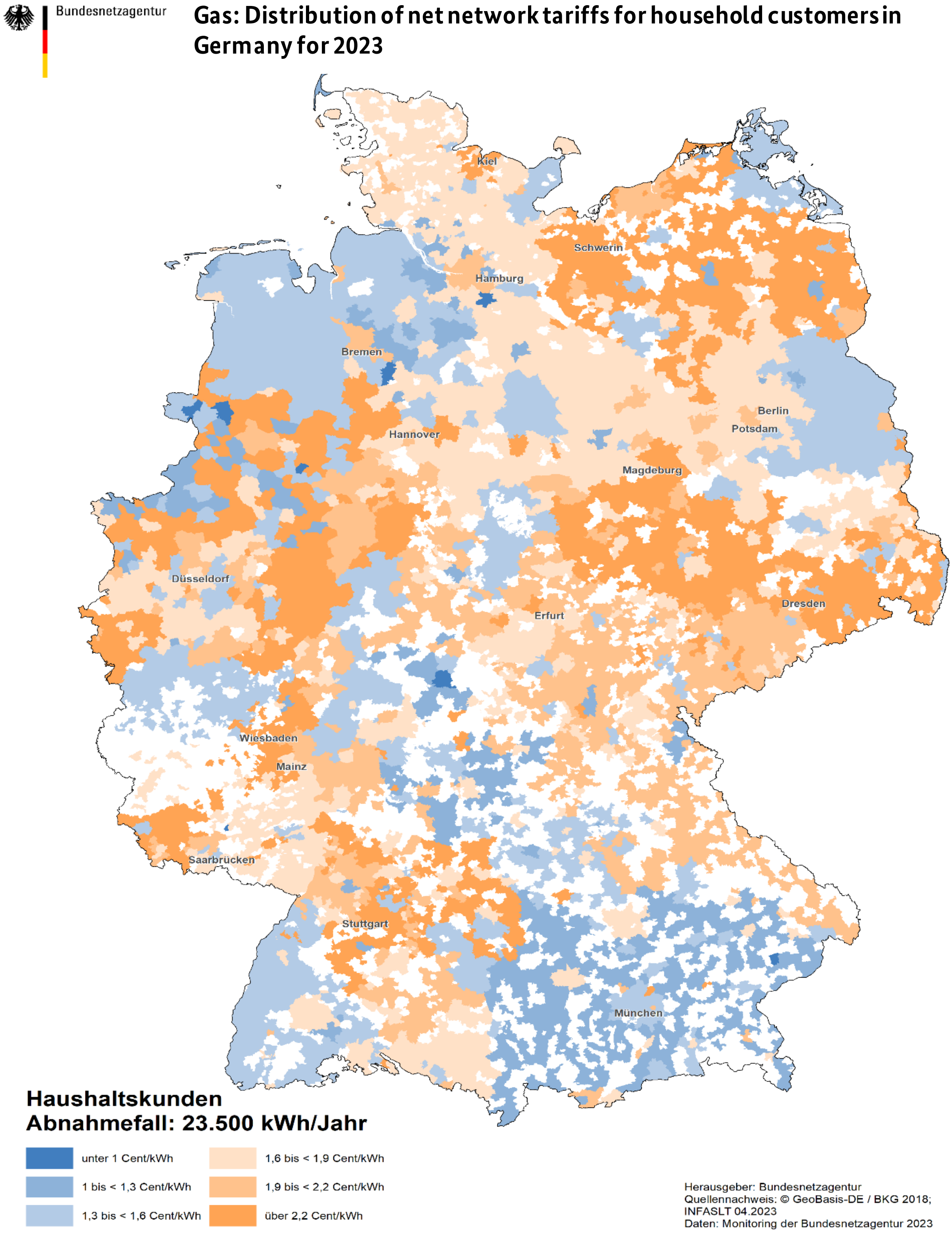


Figure 128: Distribution of gas network tariffs for the "household customer" consumption category by network area, as at 1 January 2023 according to data from gas DSOs

Gas: Net network tariffs for commercial customers in Germany in 2023
(ct/kWh)

Federal state	Weighted average[1]	Minimum	Maximum	Number of distribution networks
Saxony-Anhalt	1.73	1.12	2.21	23
Hamburg	1.67	1.67	1.67	1
Mecklenburg-Western Pomeran	1.65	1.09	2.69	19
Thuringia	1.65	0.93	2.16	29
Saxony	1.63	1.04	2.85	37
Saarland	1.62	0.77	2.09	15
Brandenburg	1.60	0.92	2.12	25
Rhineland-Palatinate	1.60	0.89	2.87	32
Baden-Württemberg	1.55	0.94	2.73	86
Berlin	1.49	1.49	1.49	1
Bavaria	1.45	0.33	3.68	97
Hesse	1.44	0.90	2.00	44
Bremen	1.43	1.42	1.43	2
North Rhine-Westphalia	1.39	0.39	2.25	116
Schleswig-Holstein	1.39	0.91	2.15	42
Lower Saxony	1.33	0.53	2.33	57

[1] The weighting was based on the number of meter points of the network operators in each network area.

Table 87: Distribution of gas network tariffs for the "commercial customer" consumption category by federal state, as at 1 January 2023 according to data from gas DSOs

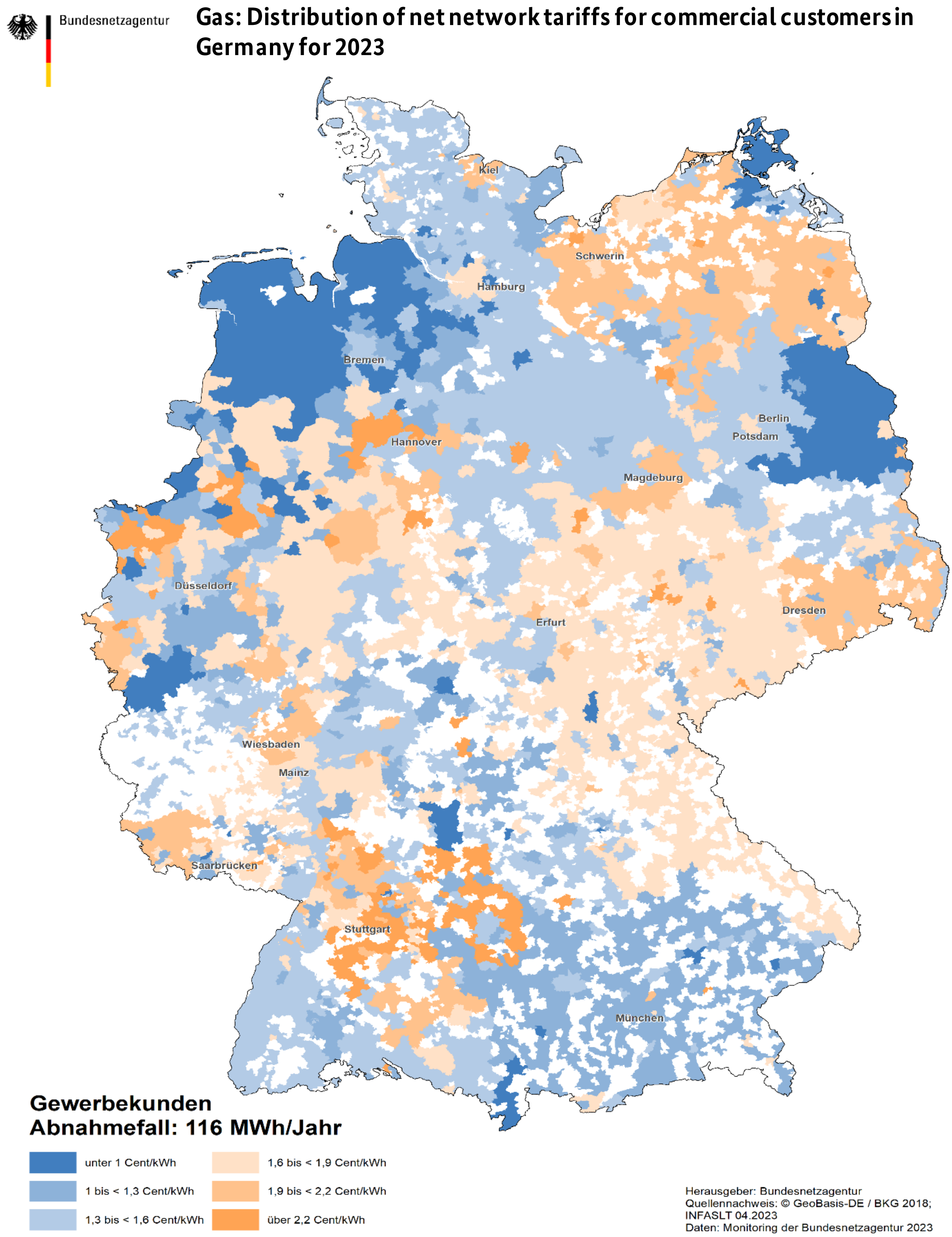


Figure 129: Distribution of gas network tariffs for the "commercial customer" consumption category by network area, as at 1 January 2023 according to data from gas DSOs

Gas: Net network tariffs for industrial customers in Germany in 2023
(ct/kWh)

Federal state	Weighted average[1]	Minimum	Maximum	Number of distribution networks
Mecklenburg-Western Pomeran	0.51	0.35	0.85	4
Saarland	0.51	0.31	0.90	5
Thuringia	0.50	0.37	0.83	8
Schleswig-Holstein	0.50	0.32	0.64	7
Saxony-Anhalt	0.43	0.18	0.64	6
Rhineland-Palatinate	0.43	0.27	0.65	14
Berlin	0.42	0.42	0.42	1
Baden-Württemberg	0.41	0.15	0.71	35
Bavaria	0.40	0.17	0.63	25
Brandenburg	0.40	0.29	0.60	10
Saxony	0.40	0.29	0.65	11
Lower Saxony	0.39	0.17	0.96	15
North Rhine-Westphalia	0.39	0.17	0.87	36
Hesse	0.37	0.08	0.61	18
Hamburg	0.37	0.37	0.37	1
Bremen	0.31	0.27	0.34	2

[1] The weighting was based on the volume of gas supplied in each network area.

Table 88: Distribution of gas network tariffs for the "industrial customer" consumption category by federal state, as at 1 January 2023 according to data from gas DSOs

Bundesnetzagentur

Gas: Distribution of net network tariffs for industrial customers in Germany for 2023

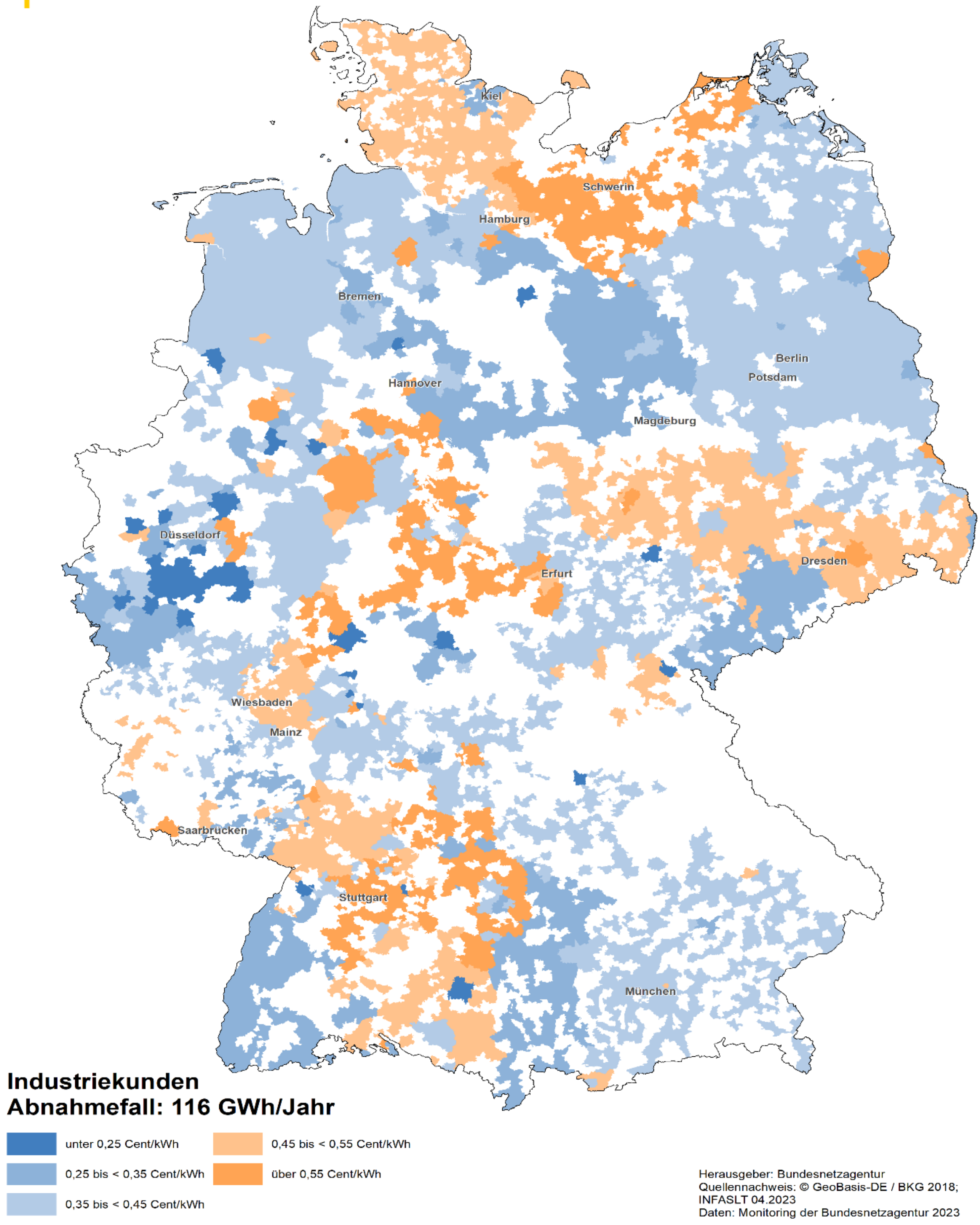


Figure 130: Distribution of gas network tariffs for the "industrial customer" consumption category by network area, as at 1 January 2023 according to data from gas DSOs

D Balancing gas and imbalance gas

1. Balancing gas

Balancing gas is used to ensure network stability and security of supply within the market area and is used by the market area manager for the physical balancing of long or short portfolios in the overall system. A distinction is to be made here between internal balancing gas, which is free of charge (network buffer within the market area), and chargeable external balancing gas (procurement through exchanges and/or a balancing platform). Balancing gas can be used in both directions: if there is a long portfolio, negative balancing gas is used. In the event of a short portfolio, positive balancing gas is used.

If internal balancing gas is not sufficient to balance the system, external balancing gas is traded by the market area manager according to a merit order list (MOL), divided into ranks 1 to 4,[88] (MOL 1 exchange-traded, MOL 2 also exchange-traded but taking account of network aspects, geographical location and gas quality, MOL 4 tender procedure).[89] In the event of a short portfolio, volumes of gas are purchased, while in the event of a long portfolio, they are sold.

Because in the winter months there are greater fluctuations regarding short and long portfolios, there is usually an increase in the share of external balancing gas during this period.

On 1 October 2021 the single German market area Trading Hub Europe (THE) launched, replacing the previous two market areas NetConnect Germany (NCG) and GASPOOL. The charts below thus refer to this single market area. The earlier data on NCG and GASPOOL may be found in previous monitoring reports or on THE's website, www.tradinghub.eu/de-de/.

[88] https://www.bundesnetzagentur.de/DE/Beschlusskammern/1_GZ/BK7-GZ/2014/BK7-14-0020/BK7-14-0020_Beschluss_download_BF.pdf?__blob=publicationFile&v=2

[89] 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 for THE.

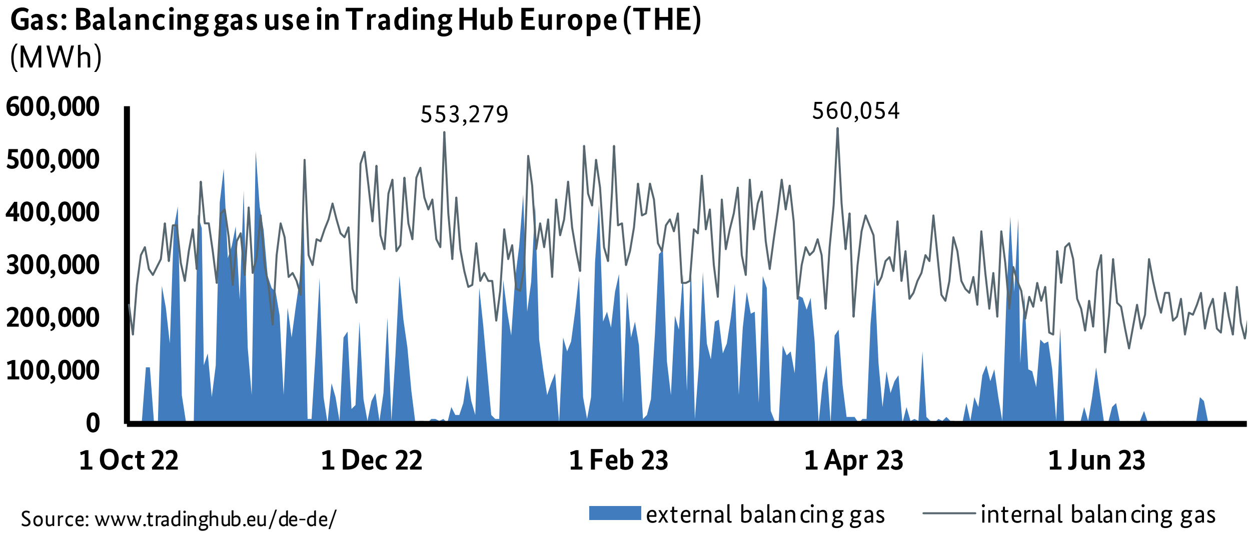


Figure 131: Balancing gas use from 1 October 2022 in the THE market area, as at July 2023

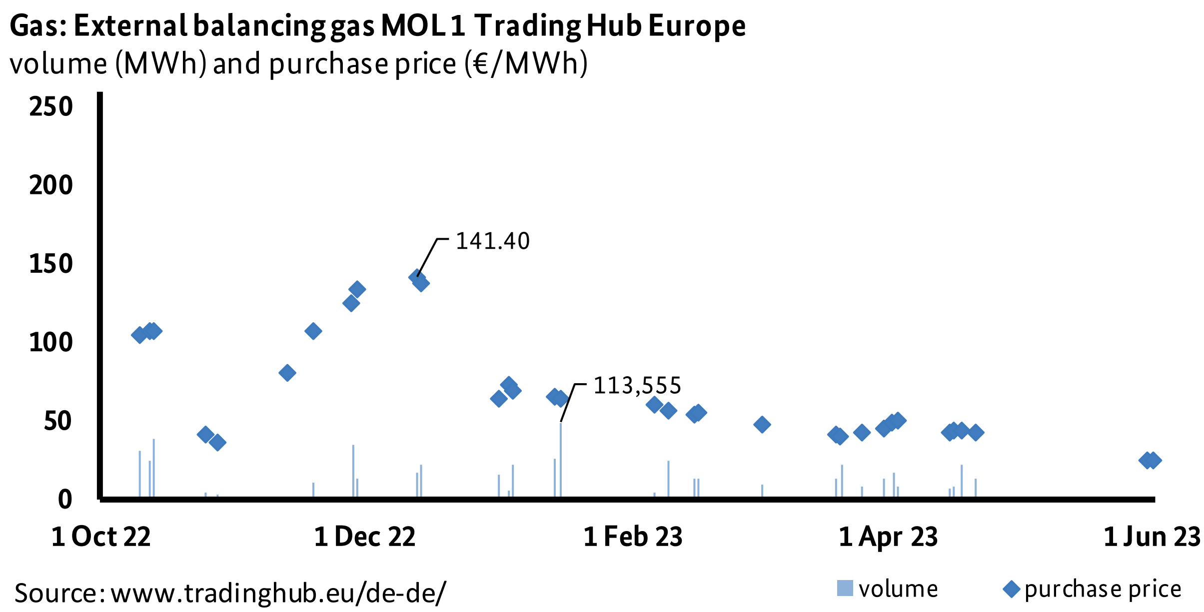


Figure 132: External balancing gas purchase prices and volumes from 1 October 2022 for MOL 1 in the THE market area, as at July 2023

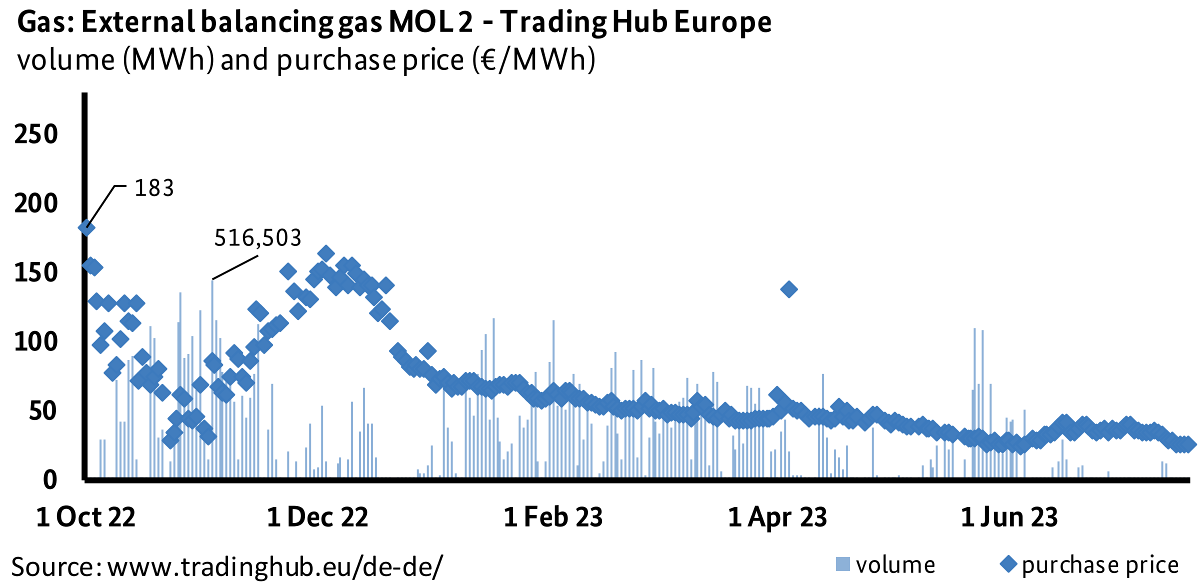


Figure 133: External balancing gas purchase prices and volumes from 1 October 2022 for MOL 2 in the THE market area, as at July 2023

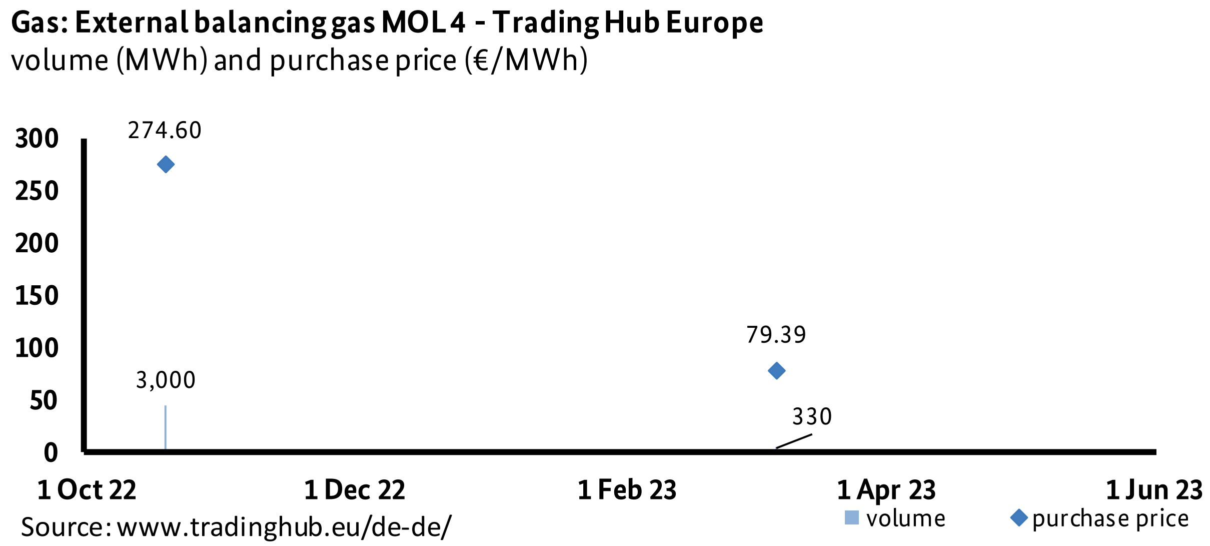


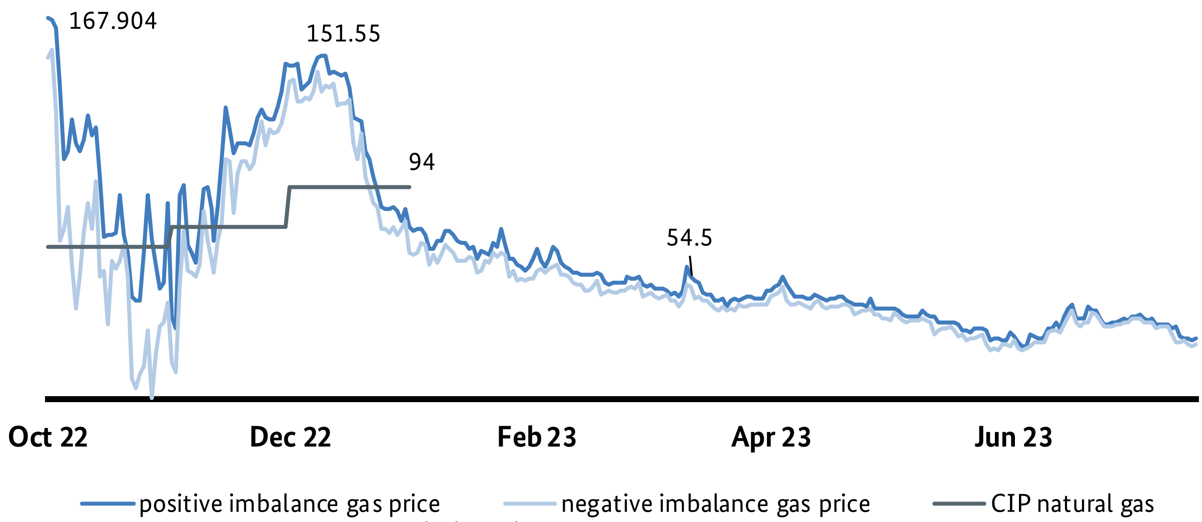
Figure 134: External balancing gas purchase prices and volumes from 1 October 2022 for MOL 4 in the THE market area, as at July 2023

2. Balancing energy, imbalance gas

The term imbalance gas refers to the individual 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 balance responsible party is charged a positive imbalance price in the case of short supply in the balancing group and a negative imbalance price in the case of surplus supply.

The positive imbalance price is the highest balancing gas price paid by the market area manager on the relevant gas day (MOL 1 and MOL 2, excluding local and hourly products) or the volume-weighted average price of gas for that day including a 2% mark-up, whichever is higher. The negative imbalance price is the lowest price for the sale of balancing gas attained by the market area manager on the relevant gas day or the volume-weighted average price of gas for that day including a 2% discount, whichever is lower. The figure below shows the development of the imbalance prices.

Gas: Development of imbalance gas price - Trading Hub Europe
(€/MWh)



Source: imbalance gas price : www.tradinghub.eu/de/de-de/,
border price: www.bafa.de, no publication from 2023 onwards

Figure 135: Development of THE imbalance prices since 1 October 2022, as at July 2023

The costs and revenues incurred by the market area manager from the gas balancing regime must be allocated to the balance responsible parties. In the process, the 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 balance responsible parties.

There are two separate neutrality charge accounts, for exit points connecting users with either standard load profiles (SLPs) or interval metering. As of 1 October 2016, the neutrality charges (for SLPs and interval metering) each apply for one year.

Since the launch of the single German market area THE, there has been only one interval-metered profile neutrality charge and one SLP neutrality charge. The previous market area managers GASPOOL and NCG each had their own neutrality charge accounts for balancing.

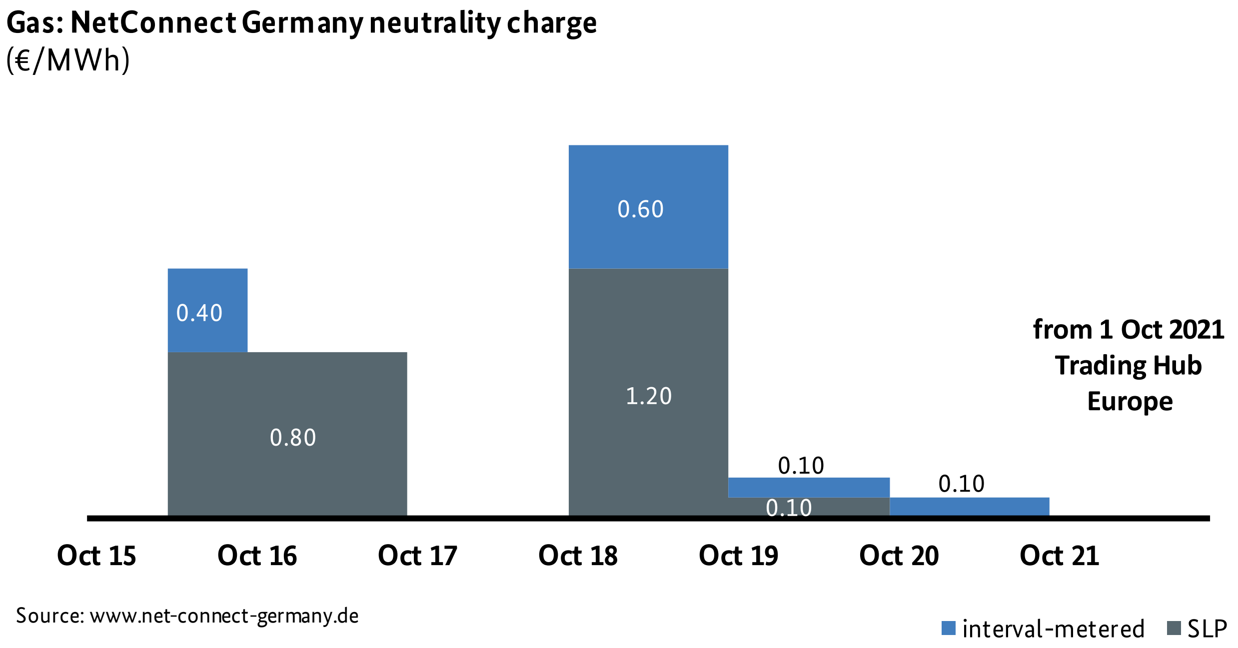


Figure 136: Neutrality charge in the NetConnect Germany market area (historical data up to 1 October 2021)

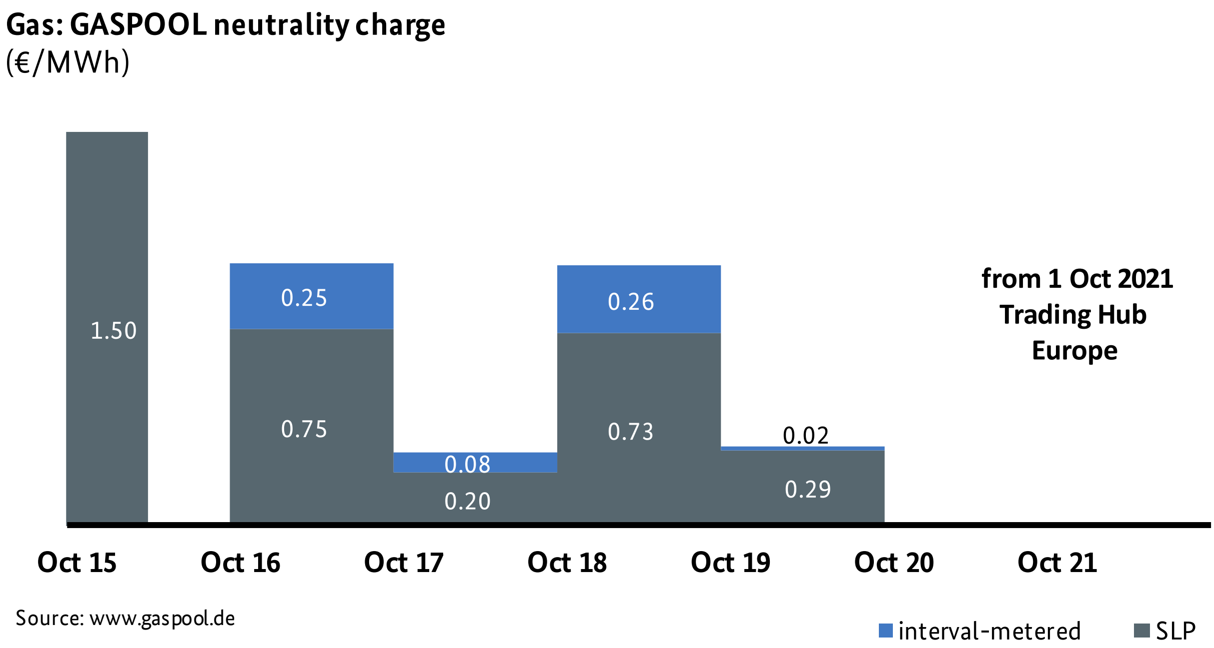


Figure 137: Neutrality charge in the GASPOOL market area (historical data up to 1 October 2021)

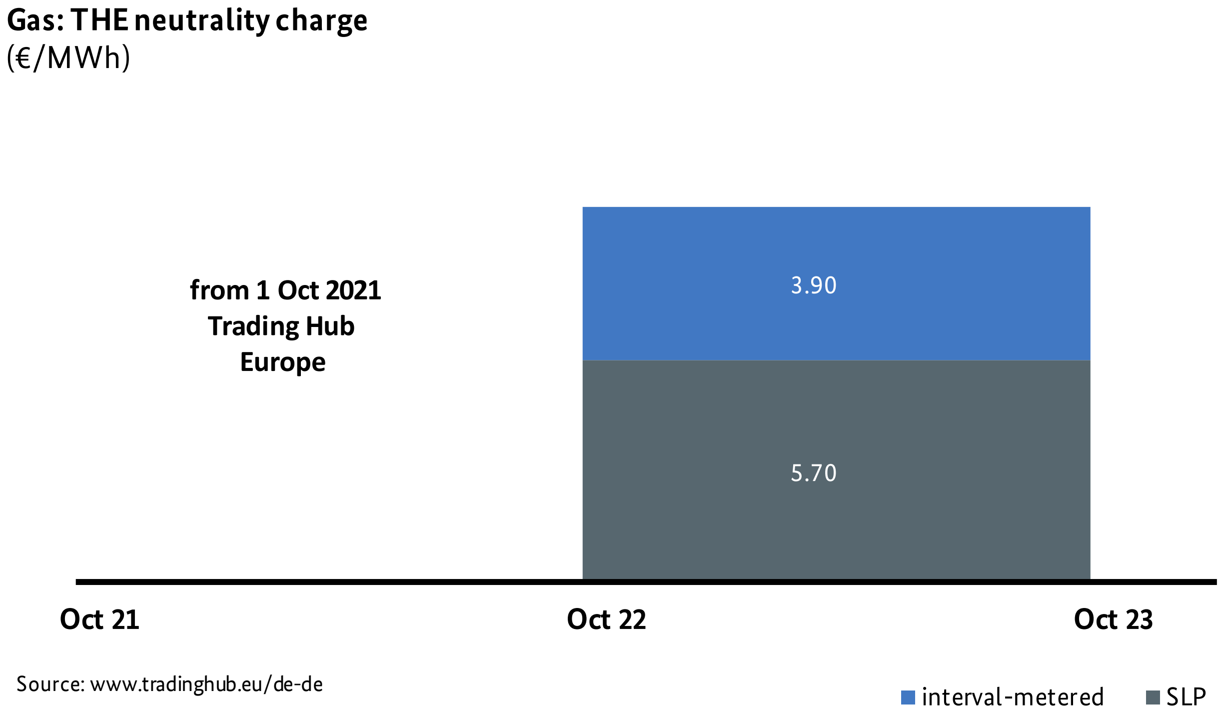


Figure 138: Neutrality charge in the THE market area from 1 October 2021

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 is a national market downstream to the gas import level and upstream to the supply of distributors and the largest end customers, and therefore no longer defines it within the limits of network or market areas. There are two types of wholesale trading: on-exchange wholesale trading and off-exchange wholesale trading.

1. On-exchange wholesale trading

Products, volumes

EEX operates the most important exchange for natural gas trading in Germany. Among other things, EEX carries out short-term and long-term trading transactions (spot market and futures market).

On 31 December 2022 the total number of participants trading on the EEX gas exchange was 212. The annual average number of active[90] participants on the spot market per trading day was 83 for THE contracts, and 25 on the futures market. 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.

On the spot market, trading in natural gas is possible 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 smaller volumes of natural gas can also be procured or sold at short notice. Quality-specific contracts (for high calorific gas or low calorific gas) are also tradable. In futures trading, futures contracts for specific months, quarters, seasons (summer/winter) and years ("calendars") can be traded. 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.

[90] Participants are considered to be active on a trading day if at least one of their bids has been fulfilled.

Gas: Development of natural gas trading volumes on EEX for the German market areas
in TWh

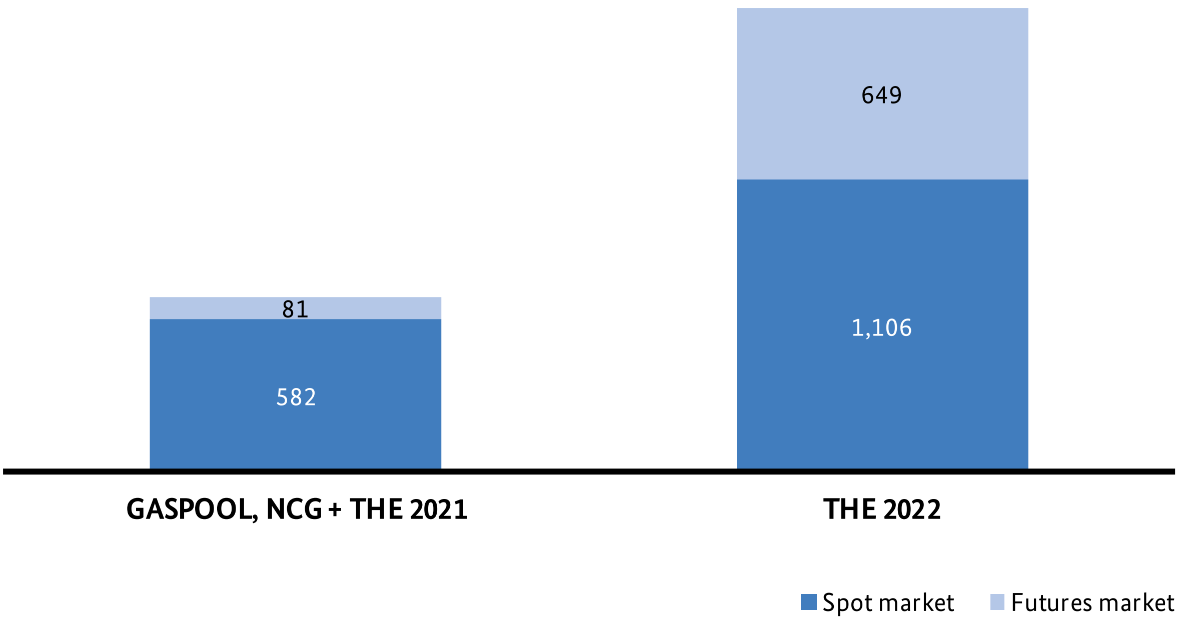


Figure 139: Development of natural gas trading volumes on EEX for the German market areas

Gas: Development of spot market gas trading volumes on EEX for the German market areas
in TWh

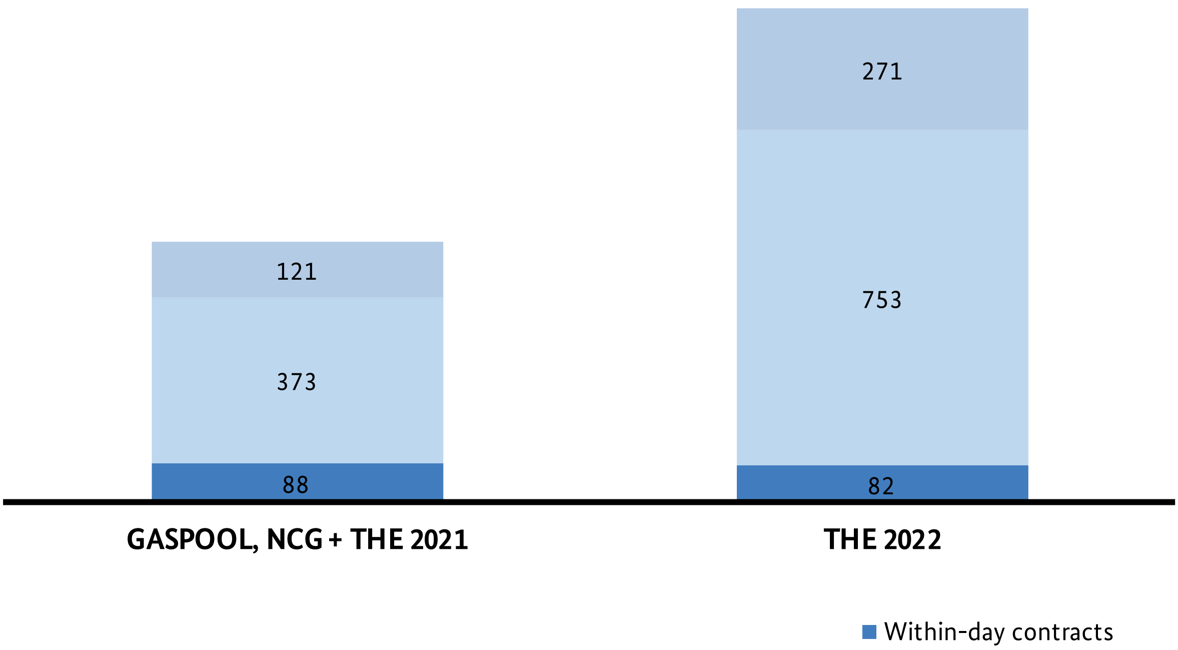


Figure 140: Development of spot market gas trading volumes on EEX for the German market areas

Wholesale prices

As an important exchange for natural gas trading in Germany, EEX publishes several price indices as a basis for reference prices for gas contracts with different procurement periods. The EGSI published by EEX shows the average costs of short-term natural gas procurement, allowing market participants to better reflect short-term price developments in their contracts. In addition, the EGIX provides a reference price for procurement within a time frame of approximately one month. It is based on transactions on the on-exchange futures market that are concluded in the latest month-ahead contracts in the market areas.[91] The price for the procurement of natural gas based on long-term supply contracts can, on the other hand, be estimated based on the BAFA border price for natural gas (see Figure 142).

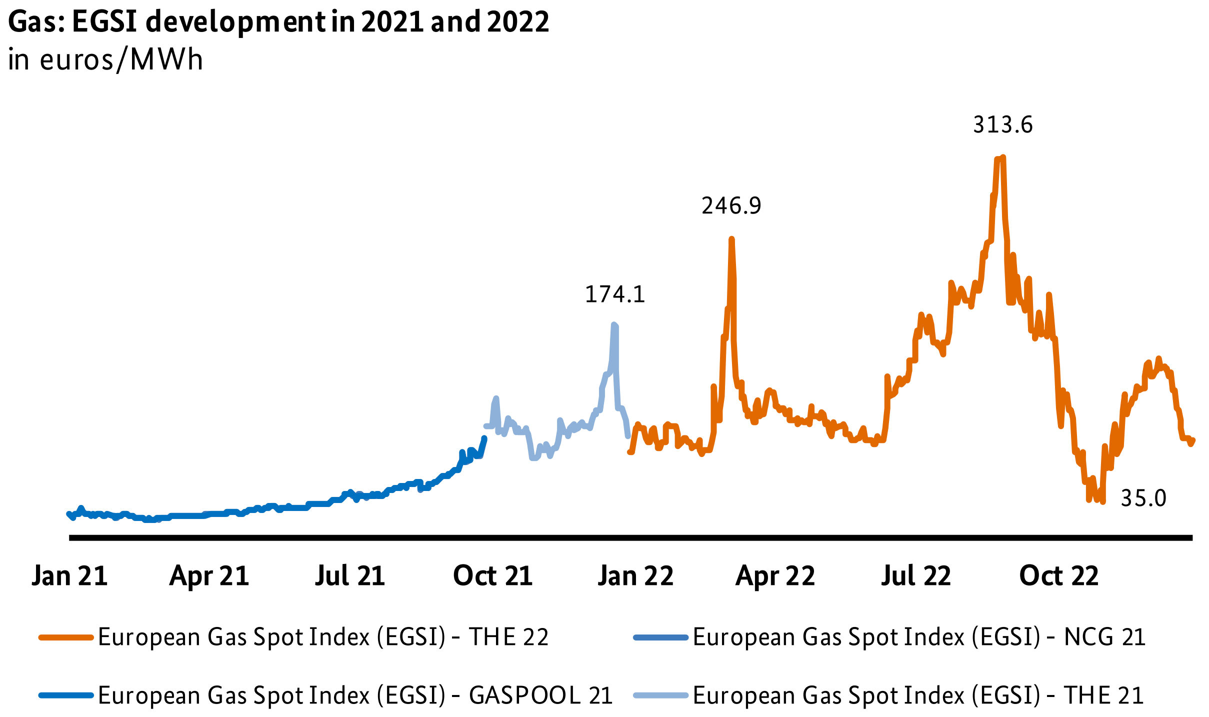


Figure 141: Year-on-year comparison of the EGSI development

The border price for each month has been calculated by the Federal Office for Economic Affairs and Export Control (BAFA) as a reference price for long-term natural gas procurement. To this end BAFA has evaluated documents relating to natural gas procured from Russian, Dutch, Norwegian, Danish and British gas extraction areas. The import quantities included in the calculation of the border price are mainly based on import agreements; spot volumes, however, are not comprehensively reflected in the imports and exports. At the end of the reporting year 2022 the Federal Ministry for Economic Affairs and Climate Action discontinued

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[91] For a detailed calculation of the values see https://www.eex.com/fileadmin/EEX/Downloads/Trading/Indices/final_EEX_Gas_Reference_Price_EGIX.pdf (last accessed on 16 August 2023).

BAFA's work of calculating the natural gas volumes entering the Federal Republic of Germany, and as of January 2023 the overview of the BAFA border price development will no longer be updated.[92] This is therefore the last time the BAFA border price is provided.

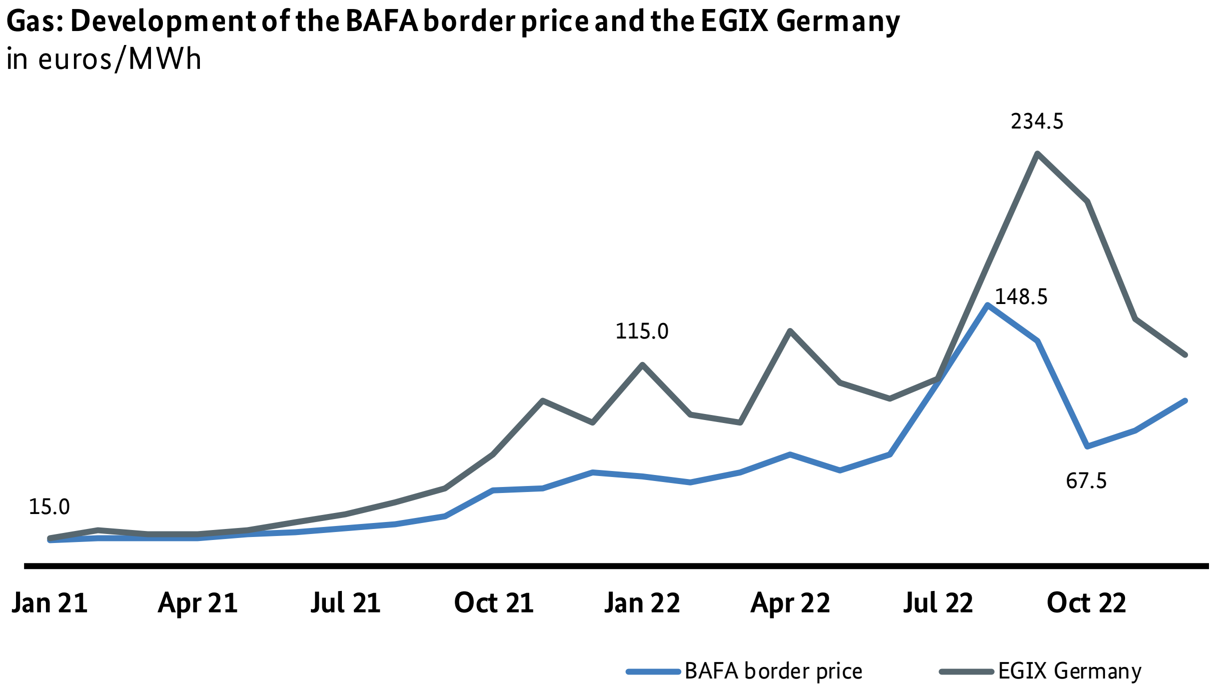

Figure 142: Development of the BAFA border price and the EGIX Germany between January 2021 and December 2022

2. Off-exchange wholesale trading

By far the largest share of wholesale trading in natural gas is carried out off-exchange ("over the counter" – OTC). Off-exchange trading offers the advantage of flexible bilateral or multilateral transactions, which, among other things, do not rely on the usual limited set of contracts on exchange markets. Brokerage via broker platforms is an important part of OTC trading.

Broker platforms

Compared with on-exchange trading, engaging a broker can reduce costs and make it easier to effect larger transactions. It also allows greater risk diversification because brokers offer services to register trading transactions brokered by them for clearance on the exchange to hedge the parties' counterparty default risk. Electronic broker platforms are used to bring interested parties on the supply and demand sides together and so increase the chances of the parties reaching an agreement.

[92] See https://www.bafa.de/DE/Energie/Rohstoffe/Erdgasstatistik/erdgas_node.html (in German, last accessed on 1 September 2023).

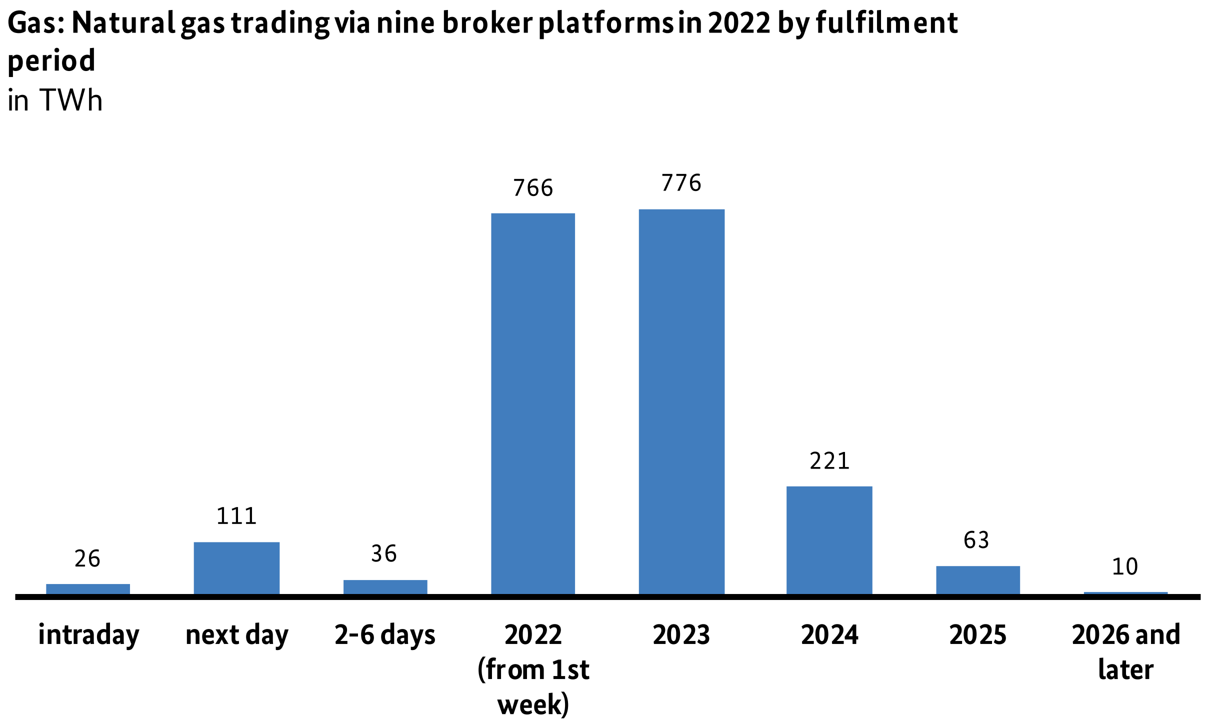

Figure 143: Natural gas trading for the German market areas via nine broker platforms in 2022 by fulfilment period

The data relating to brokered natural gas trading published by the London Energy Brokers' Association (LEBA) show a decline in the gas trading volume in 2022. Eight of the nine broker platforms that provided data on which the following analysis was based are members of LEBA. All the LEBA-affiliated broker platforms accounted for a total of 1,563 TWh for the German market areas in 2022 (2,465 TWh in the previous year), which corresponds to a year-on-year decrease of around 36.6%.

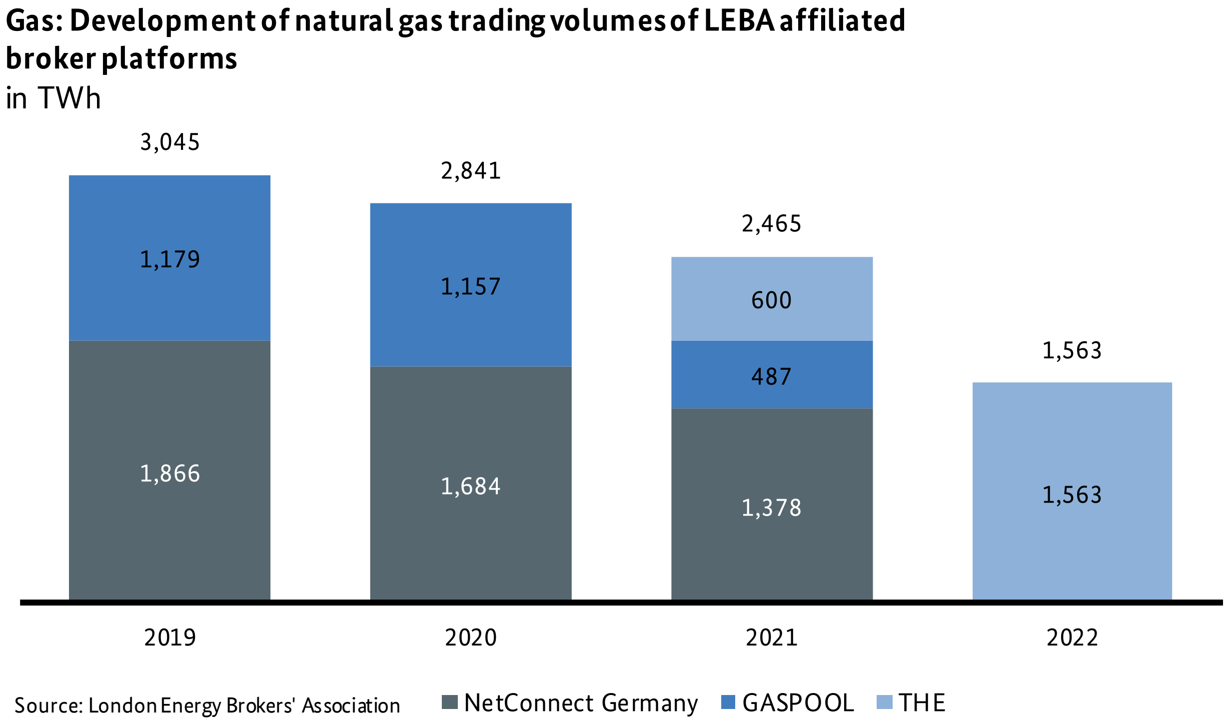

Figure 144: Development of natural gas trading volumes of LEBA-affiliated broker platforms for the German market areas

Nomination volumes at virtual trading points

The nominated volumes at the German "virtual trading points" (VTPs) are also key indicators of the liquidity of the wholesale natural gas markets.

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 case of exchange transactions. Besides, not all nomination volumes are linked to transactions on the wholesale markets, one example being transfers between balancing groups of the same company.

Gas: Development of nomination volumes at virtual trading points
in TWh

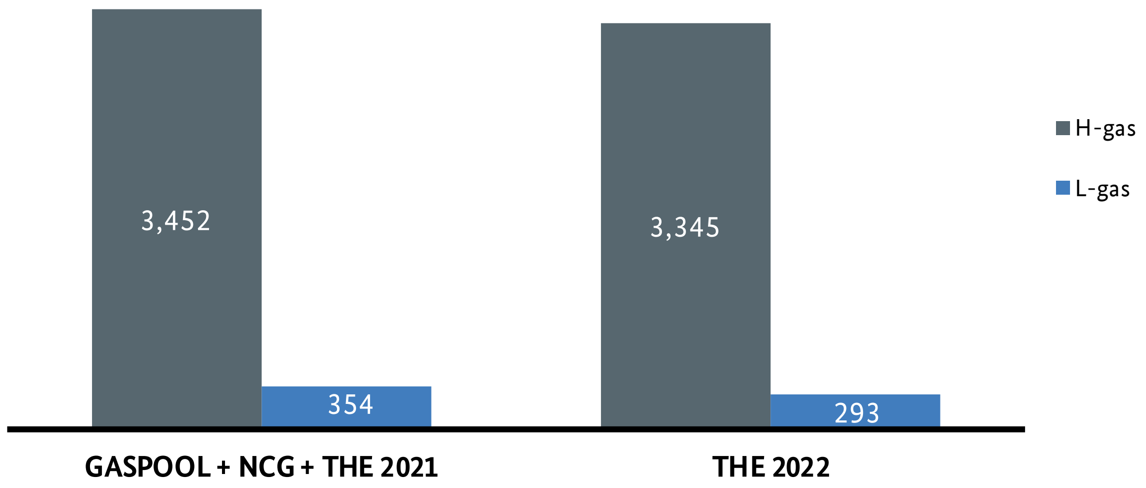

Figure 145: Development of nomination volumes at the German virtual trading points

Gas: Annual development of nomination volumes at virtual trading points in 2022
in TWh

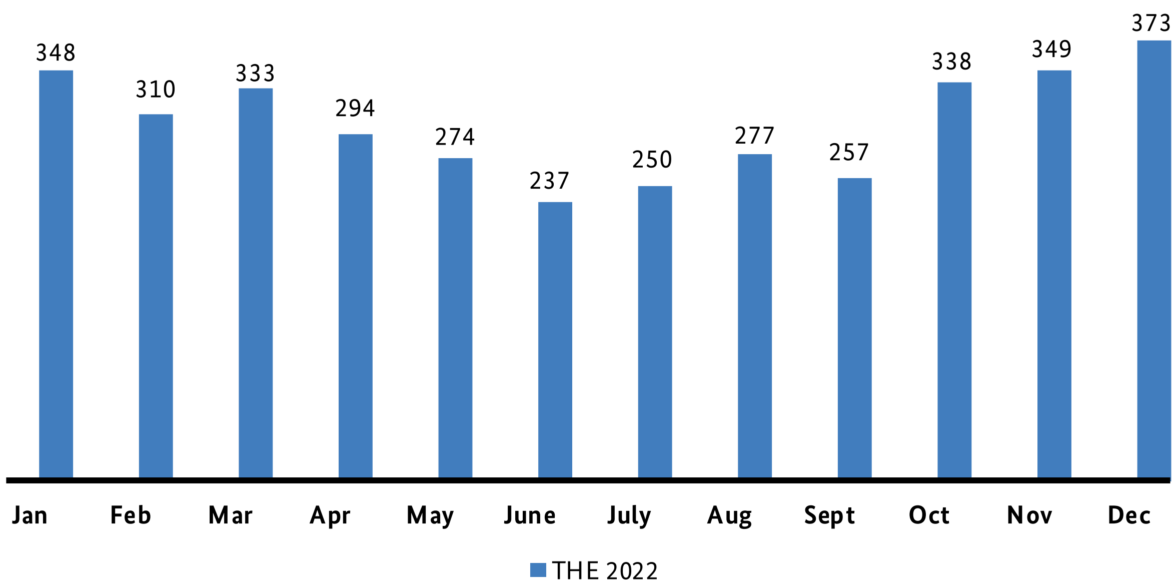

Figure 146: Annual development of nomination volumes at virtual trading points in 2022

F Retail

In the retail gas sector, private households, businesses and industrial customers can buy gas from various suppliers. As customers have free choice of gas supplier, the market is characterised by a high level of competitive intensity. Gas suppliers on the retail market offer various tariffs with different price structures and contract terms and conditions. These tariffs may be based on a fixed price, a unit price or a combination of the two. Customers can choose the supplier and tariff best suited to their individual needs and preferences. Energy utilities have to meet stringent legal and regulatory requirements on the retail market in order to ensure fair conditions for consumers. Regulatory authorities monitor the market to make sure that suppliers offer transparent tariffs and comply with fair practices. In sum, the gas retail market enables German consumers to select a supplier according to their needs and preferences and to benefit from competition and a wide range of offers. More detailed explanations may be found in the glossary to this report. More data may be found on www.SMARD.de.

1. Supplier structure and number of providers

Over 1,100 suppliers are responsible for supplying final customers with gas. They do this by providing gas at market locations. Gas customers can usually choose from a number of different regional or national suppliers. Only in the case of default supply do customers not have the right to choose. Default supply refers to supply by the gas utility that has the most household customers in the local network area. There is also a difference between a non-default contract with the default supplier, and a contract with a supplier other than the local default supplier.

Gas: Suppliers by number of market locations supplied (number and percentage as at 31 December 2022)
(figures do not take account of company affiliations)

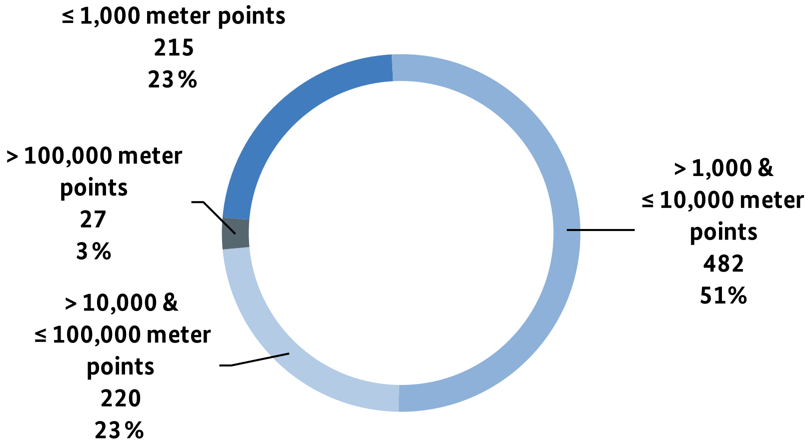

Figure 147: Gas suppliers by number of market locations supplied (number and percentage) – as at 31 December 2022

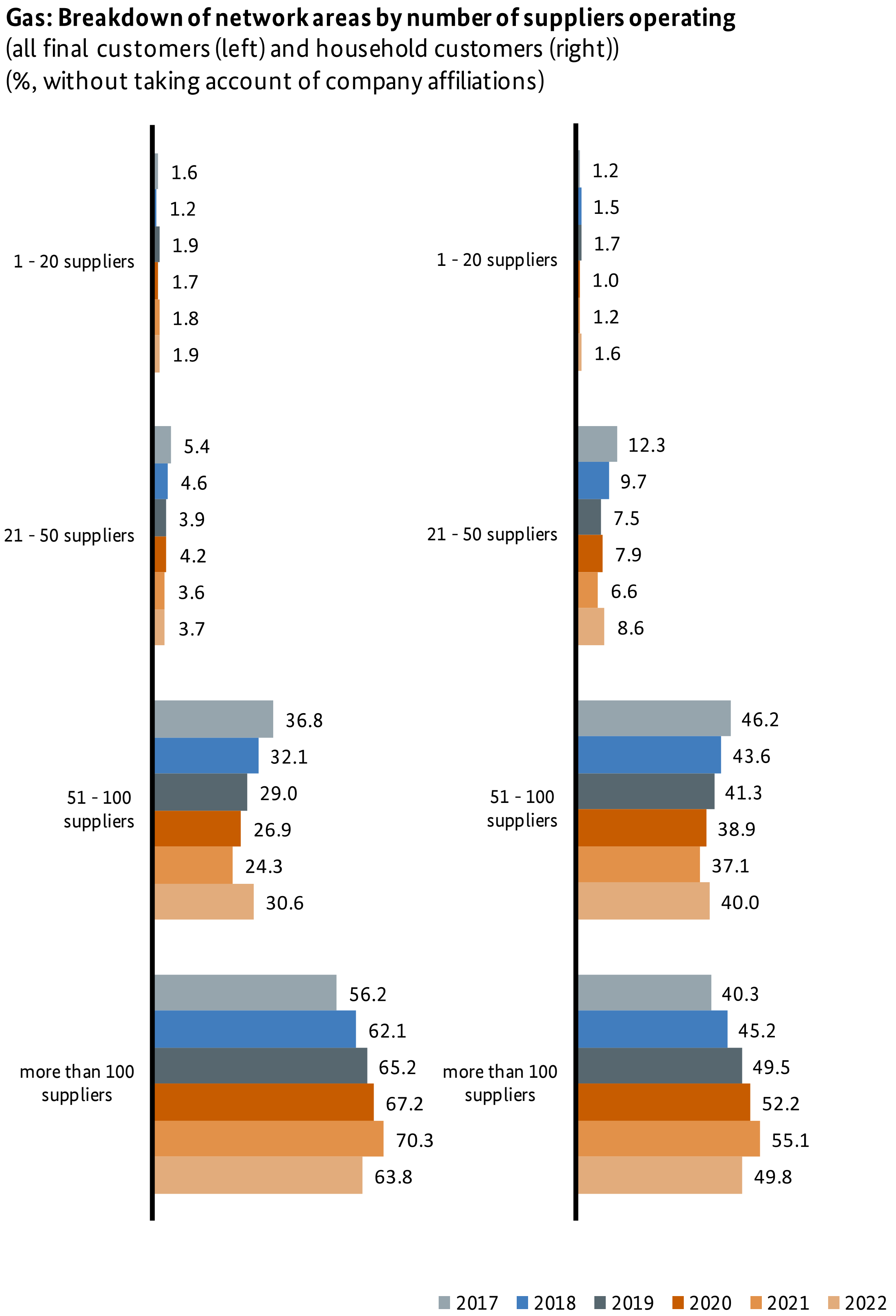

Figure 148: Breakdown of network areas by number of suppliers operating according to data from gas DSOs – as at 31 December 2022

Gas: Number and percentage of suppliers supplying customers in the number of network areas shown
(figures do not take account of company affiliations)

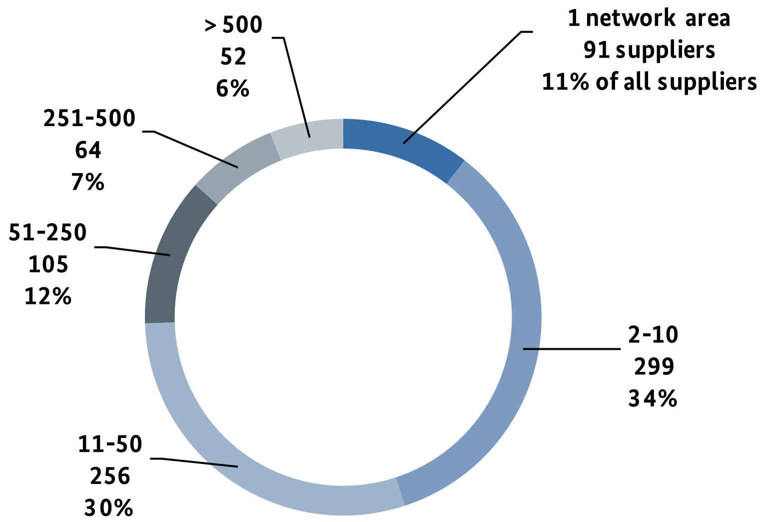

Figure 149: Gas suppliers by number of network areas supplied (number and percentage), according to data from gas suppliers – as at 31 December 2022

2. Contract structure, supplier and contract switching

Contract structure

The data survey for the monitoring report divides the gas supplied to final customer groups into the following 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 evaluation, "default contracts" include energy supplied in the context of fallback supply (section 38 of the Energy Industry Act (EnWG)) and doubtful cases. It should be noted that the legal entity is taken to be the contracting party.

Gas final customers are divided into interval-metered customers, whose gas is measured at short intervals of, for example, 15 minutes (load profile), and non-interval-metered customers. For customers without interval metering, consumption over a set period of time is estimated using a standard load profile (SLP). Interval-metered customers are all high-consumption, non-household customers such as industrial customers or gas power stations.

Final customers can also be divided into household and non-household customers. Household customers are defined in the EnWG primarily according to qualitative characteristics.[93] All other customers are non-household customers, which include customers in the industrial, commercial, service and agricultural sectors

[93] Section 3 para 22 EnWG defines household customers as final customers 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.

as well as public administration. The gas sold to non-household customers is mainly to interval-metered customers.

Gas: Contract structure for interval-metered customers in 2022
(volume and breakdown)

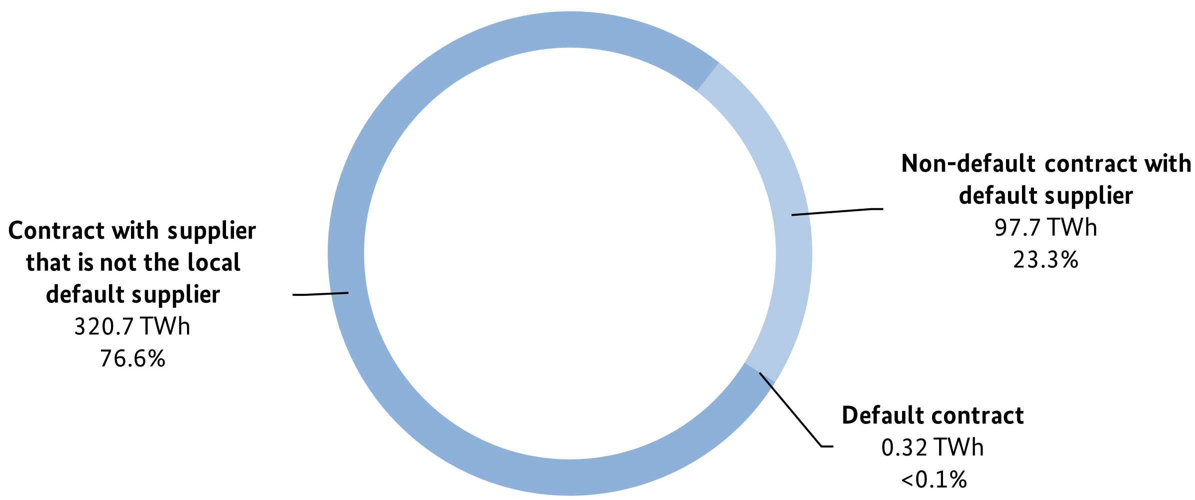

Figure 150: Contract structure for interval-metered customers in 2022 according to data from gas suppliers

Gas: Contract structure for household customers (as at 31 December 2022)
(volume and breakdown)

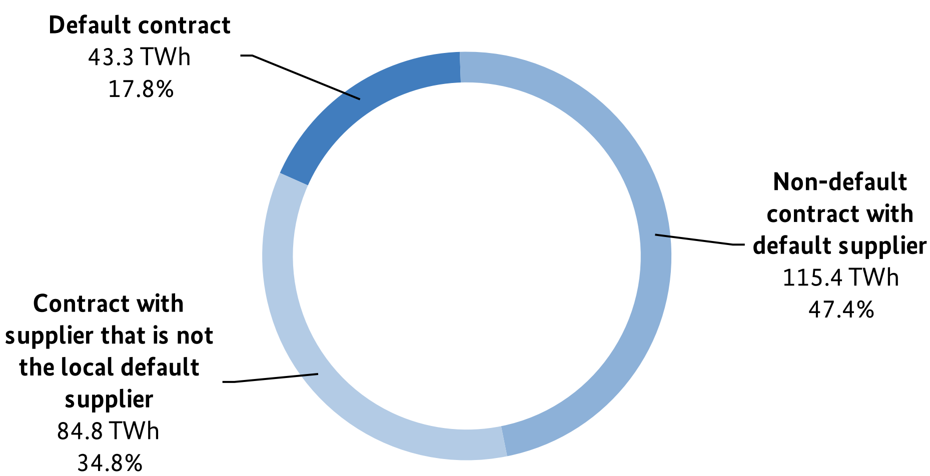

Figure 151: Contract structure for household customers (volume of gas delivered) as at 31 December 2022 according to data from gas suppliers

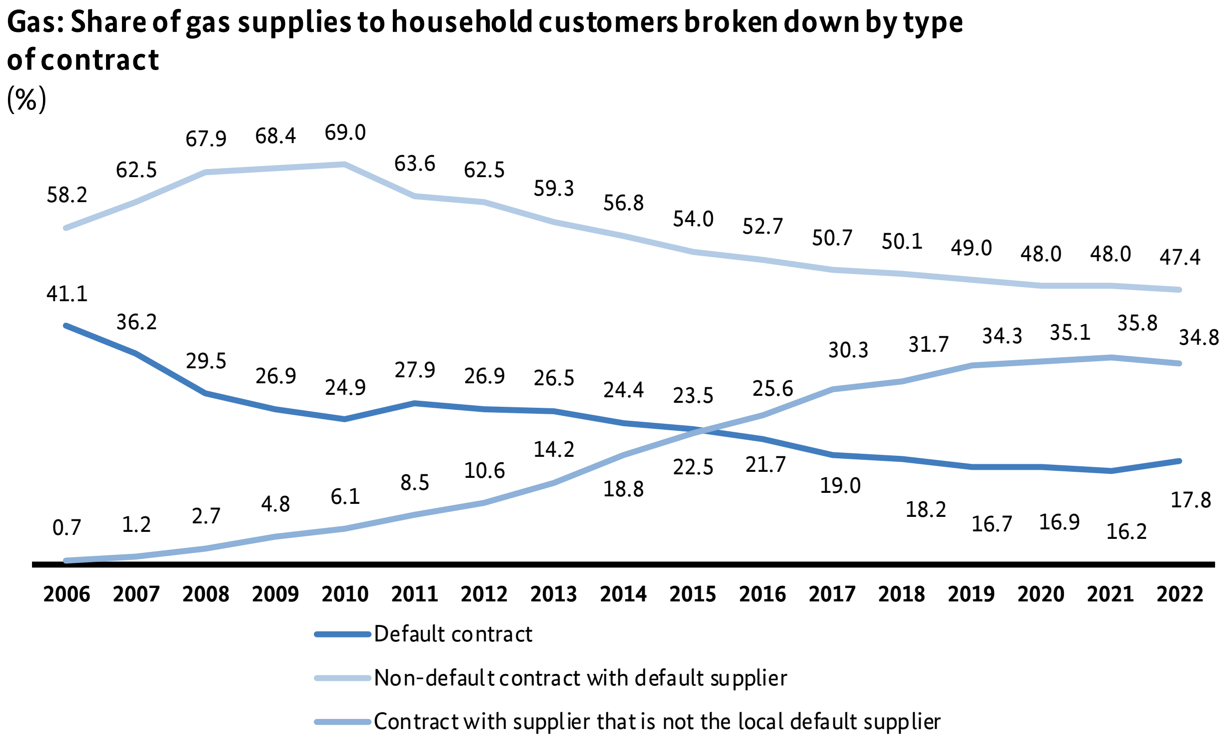

Figure 152: Share of gas supplied to household customers broken down by type of contract according to data from gas suppliers as at 31 December 2022

Gas: Contract structure of household customers (volume and distribution) in consumption band II, D3

Contract type	Band II with consumption of ≥ 5,556 kWh (20 GJ) and < 55,556 kWh (200 GJ)			
	2021		2022	
	Volume (TWh)	Distribution (%)	Volume (TWh)	Distribution (%)
Default contract	32.9	16.9	33.5	18.1
Non-default contract with default supplier	93.5	48.1	87.5	47.2
Contract with a supplier other than the local default supplier	67.8	34.9	64.5	34.8
Total	194.2	100.0	185.5	100.0

Table 89: Contract structure for household customers (volume) for a typical household customer example (Eurostat band II, D3) as at 31 December 2022 according to data from gas suppliers

Gas: Contract structure for household customers (as at 31 December 2022)
(number in millions and percentage)

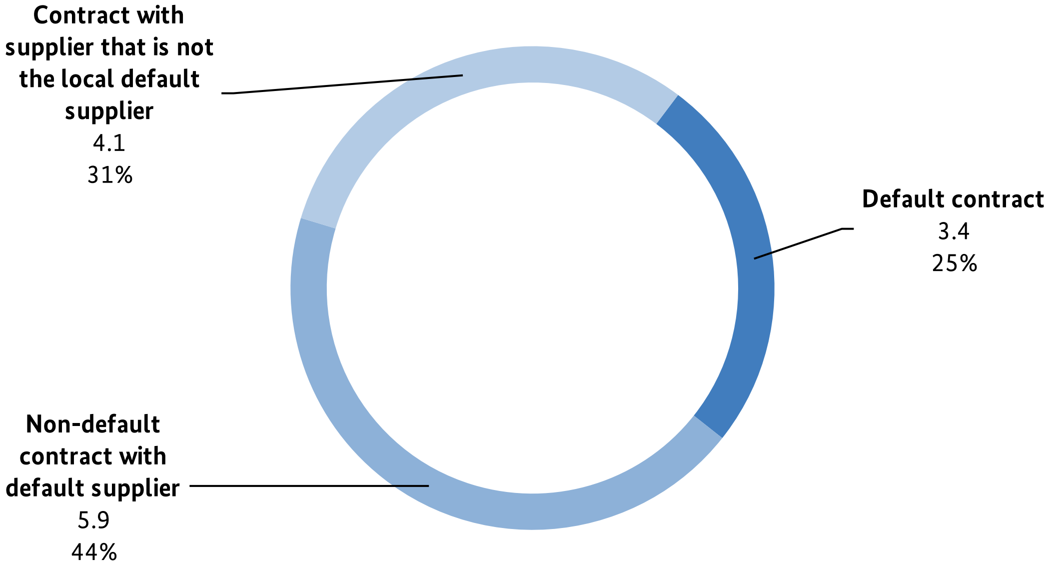

Figure 153: Contract structure for household customers (number of customers supplied) as at 31 December 2022 according to data from gas suppliers

Gas: Contract structure of household customers (number and distribution) in consumption band II, D3

Contract type	Band II with consumption of ≥ 5,556 kWh (20 GJ) and < 55,556 kWh (200 GJ)			
	2021		2022	
	Number (mn)	Distribution (%)	Number (mn)	Distribution (%)
Default contract	1.8	18.9	2.2	21.8
Non-default contract with default supplier	4.3	45.3	4.5	44.6
Contract with a supplier other than the local default supplier	3.4	35.8	3.4	33.7
Total	9.5	100.0	10.1	100.0

Table 90: Contract structure for household customers (number of customers supplied) for a typical household customer example (Eurostat band II, D3) as at 31 December 20222 according to data from gas suppliers

Supplier and contract switching

Changes in switching rates and processes are important indicators of the level of competition. For monitoring purposes, the term "supplier switch" refers to the process by which a final customer's market location is assigned to a new supplier. As a rule, moving into or out of premises is not considered a supplier switch. The change of supplier refers to a change in the supplying legal entity. An internal reallocation of supply contracts to another group company is also classed as a supplier switch, as is "involuntary switching" caused by the insolvency of the previous supplier or the supplier terminating the contract. New contracts with the existing supplier are known as contract switches. The monitoring survey of gas TSOs and DSOs does not analyse what percentage of industrial and commercial customers have switched supplier once, more than once or not at all over the course of the year.

The survey focuses on the consumption in the final customer segment as a whole. The supplier switching figures are broken down into five different consumption categories. The consumption category of < 0.3 GWh/year is mostly made up of household customers. It also includes some smaller non-household customers that cannot be separated from the rest of the group, leading to a slightly unclear differentiation between the two customer groups. The four consumption categories of at least 0.3 GWh/year (including gas power stations) are all non-household customers. To ensure a clear categorisation, only the top four consumption categories with final consumption of at least 0.3 GWh/year, including gas power stations, were used to calculate the switching rate for non-household customers.

Gas: Supplier switches in 2022 by consumption category

Final customer category	Number of meter points at which the supplier changed	Share of all meter points in the consumption category	Consumption at meter points at which the supplier changed	Share of total consumption in the consumption category
< 0.3 GWh/year	1,192,412	8.6%	26.2 TWh	9.1%
≥ 0.3 GWh/year < 10 GWh/year	15,600	13.5%	16.2 TWh	14.3%
≥ 10 GWh/year < 100 GWh/year	1,977	51.3%	11.6 TWh	12.0%
≥ 100 GWh/year	181	3.7%	22.3 TWh	10.4%
Gas power plants	5	2.3%	2.4 TWh	2.9%
Total	**1,210,175**		**78.7 TWh**	

Table 91: Supplier switches in 2022 by consumption category according to data from the gas TSOs and DSOs

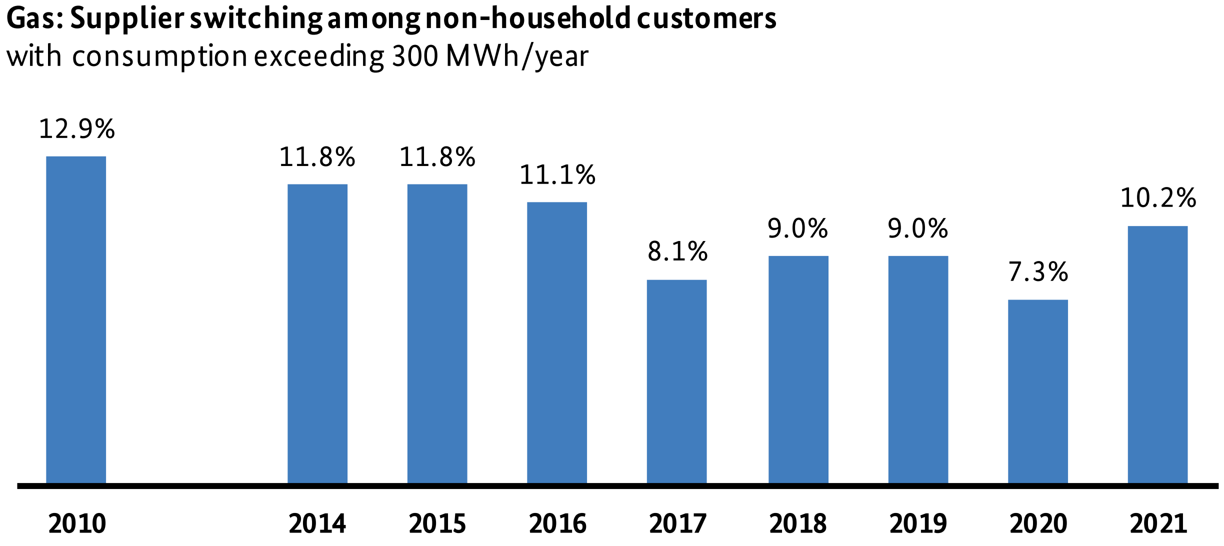

Figure 154: Non-household customer supplier switches according to data from the gas TSOs and DSOs

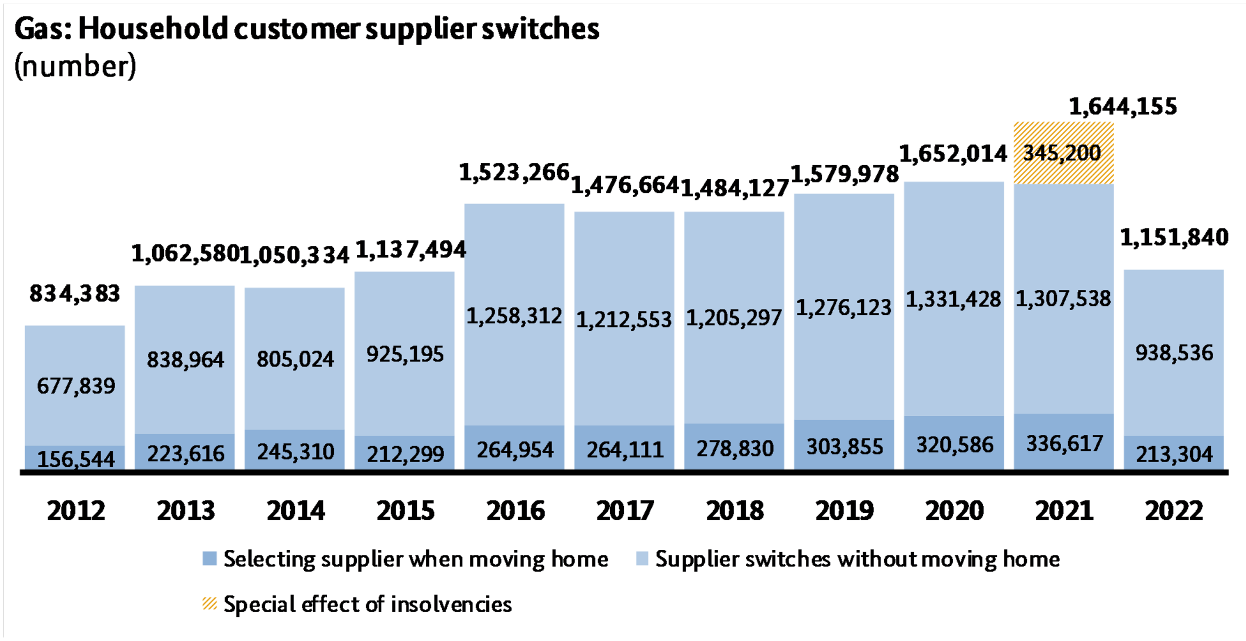

Figure 155: Household customer supplier switches according to data from gas DSOs

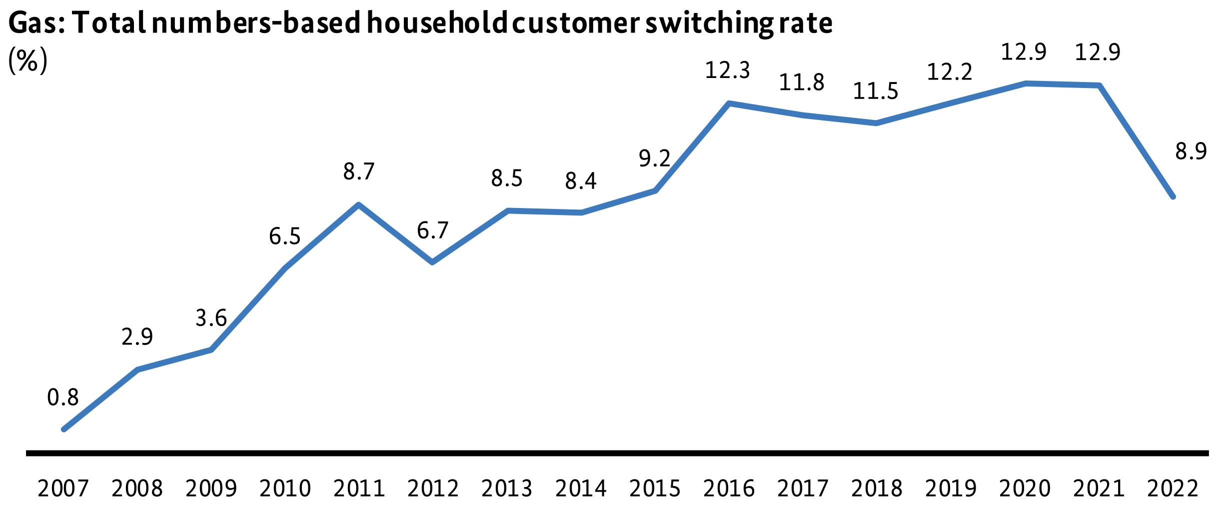

Figure 156: Total numbers-based household customer switching rate according to data from gas DSOs

Gas: Contract switches by household customers

Category	2021 contract switches (TWh)	Share of total consumption (273.1 TWh) (%)	2021 contract switches (number)	Share of all household customers (13.3mn) (%)
Household customers that changed their gas contract with their existing supplier	8.5	3.1	0.54mn	4.1
Category	**2022 contract switches (TWh)**	**Share of total consumption (242.9 TWh) (%)**	**2022 contract switches (number)**	**Share of all household customers (12.8mn) (%)**
Household customers that changed their gas contract with their existing supplier	13.4	5.5	0.76mn	5.9

Table 92: Household customer contract switches in 2021 and 2022 according to data from gas suppliers

3. Disconnections and terminations, non-annual billing

Customers owing money to their supplier are sent a reminder with a fee, together with or followed by a disconnection notice. If a customer does not pay, the supplier can request the network operator to disconnect the customer (interrupt the energy supply).

Default suppliers are generally obliged to supply all household customers in their network area under the general terms and conditions and general prices of default supply. An exception is made if it is economically unreasonable for the default supplier to supply the customer (section 36(1) EnWG). A supplier can only terminate a default supply contract if it is not subject to a default supply obligation (section 20(1) of the Gas Default Supply Ordinance (GasGVV)). In exceptional cases, the default supplier may terminate the contract without notice if the conditions for the interruption of supply have been met repeatedly (section 19 GasGVV). The default supplier must warn the customer of the termination without notice two weeks in advance (section 21 GasGVV).

Non-default energy suppliers can terminate existing energy supply contracts under the contractual arrangements and provisions of civil law. Energy suppliers terminating contracts with household customers, whether as part of the default supply or under other contracts, must do so in text form (section 41b(1) sentence 1 EnWG and section 20(2) sentence 1 GasGVV).

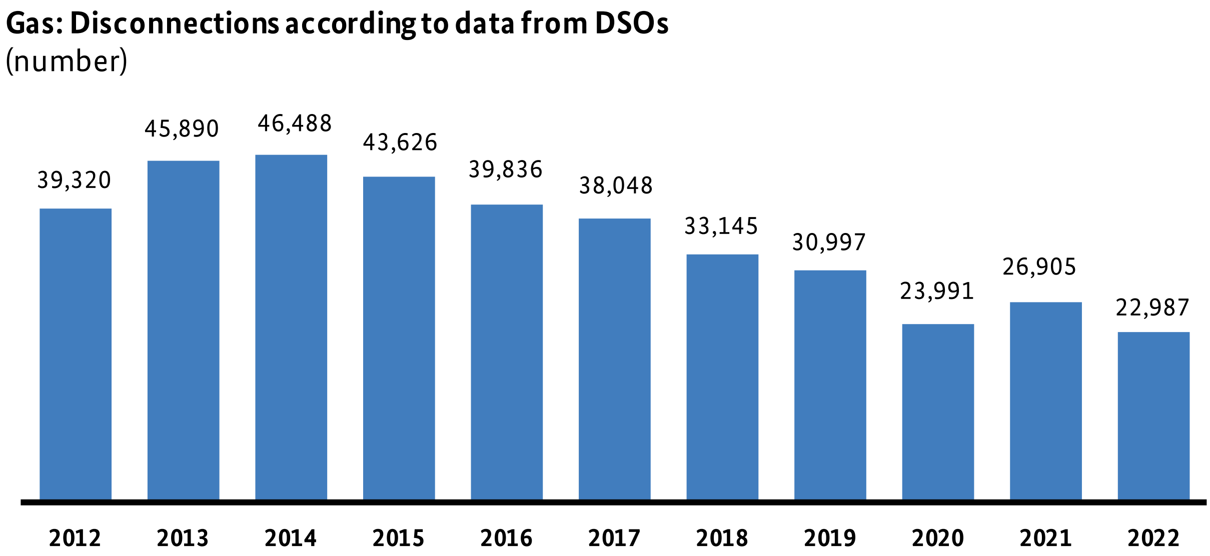

Figure 157: Gas disconnections from 2013 to 2022 according to data from gas DSOs

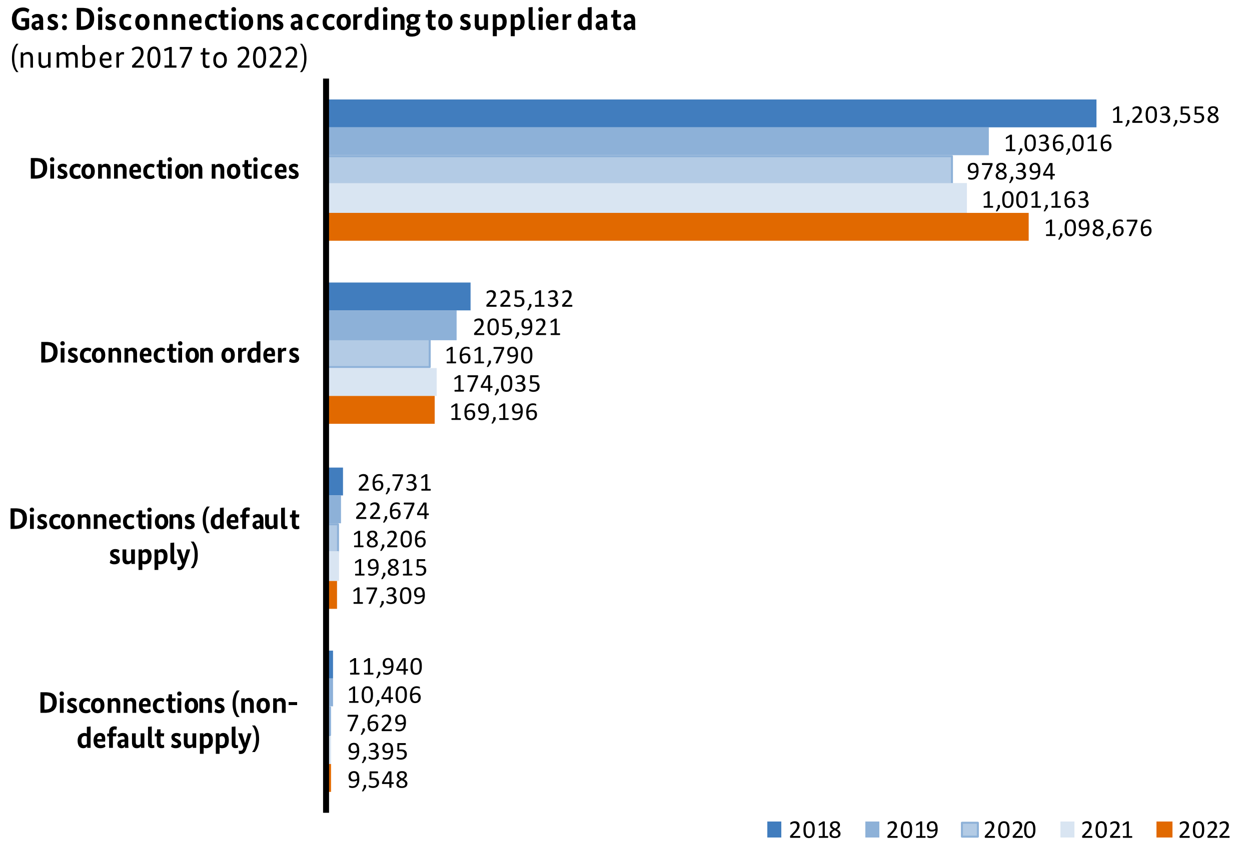

Figure 158: Disconnection notices, disconnection orders and disconnections for gas within and outside default supply according to data from gas suppliers

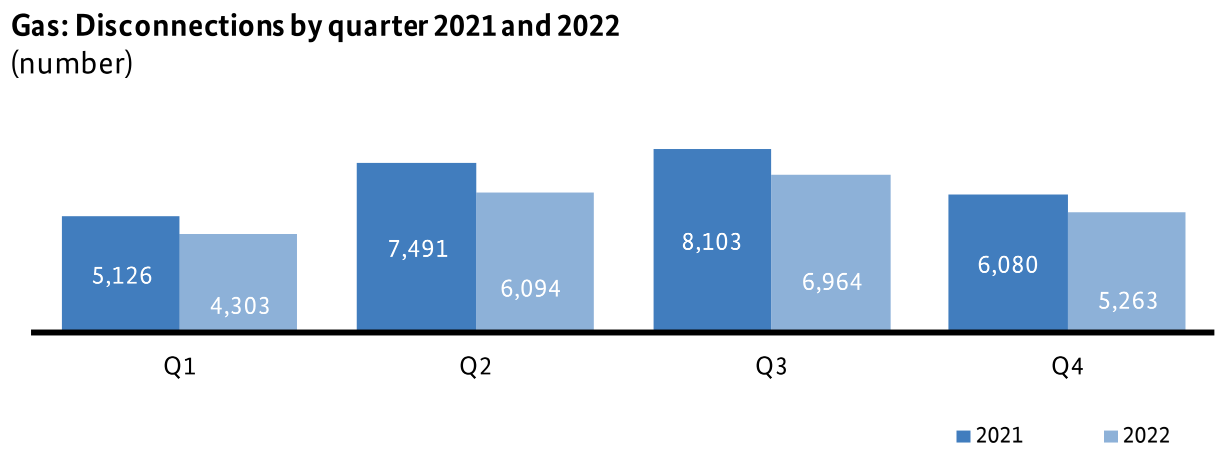

Figure 159: Gas disconnections in each quarter of 2021 and 2022 according to data from gas DSOs

Gas: Number of disconnections in 2022 by federal state according to data from DSOs

	Number of disconnections (default/non-default supply)	Share of market locations of final customers in Germany (%)
North Rhine-Westphalia	11,832	0.32
Berlin	1,258	0.22
Hesse	1,893	0.19
Saxony-Anhalt	657	0.16
Rhineland-Palatinate	1,290	0.16
Thuringia	513	0.14
Saarland	239	0.12
Saxony	697	0.12
Baden-Württemberg	1,410	0.10
Lower Saxony	2,237	0.10
Bavaria	1,296	0.09
Schleswig-Holstein	455	0.07
Brandenburg	312	0.06
Mecklenburg-Western Pomerania	144	0.05
Hamburg	40	0.02
Bremen	6	0.00
Germany total	**24,279**	0.17

Table 93: Gas disconnections by federal state in 2022 according to data from gas DSOs

Gas: Non-annual billing in 2022

	Non-annual billing, number	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)
Non-annual billing for household customers	33,980	€14.20 (€2 - €50)	€18.30 (€1.50 - €65)
of which monthly	18.5%		
of which quarterly	6.8%		
of which semi-annually	74.7%		

Table 94: Non-annual billing for gas household customers in 2021 according to data from gas suppliers

4. Price level

Gas prices in Germany are not state-controlled. The gas price is set by the market and is composed of factors controlled by the supplier such as gas procurement costs, distribution costs and margin, and factors not controlled by the supplier such as network tariffs, concession fees and charges for metering and meter operations, surcharges and taxes.

To ensure the comparability of gas prices, customers are divided into categories: household customers, who come under Eurostat band II (D3) with consumption from 20 gigajoules (GJ) (5,556 kWh) to 200 GJ (55,556 kWh), and two other groups. Customers with annual consumption in the 116 GWh range are only interval-metered customers and, in general, these are industrial customers. The variety of opportunities for customer-specific contracts plays a significant role for this customer group. In general, suppliers do not have any specific tariff groups for consumers of 116 GWh per year but, instead, make offers tailored to individual customers. Customers with an annual consumption of 116 GWh are defined as having an annual usage time of 250 days (4,000 hours).

The consumption category of 116 MWh/year has no specified annual usage time and is made up of, for example, commercial customers with lower consumption levels. It covers volumes well below the threshold of 1.5 GWh.[94] This category is a thousandth of the consumption of an industrial customer (about 116 GWh) and five times the average annual consumption of a household customer (about 23 MWh). Given the moderate level of consumption, individual contractual arrangements play a significantly smaller role than for the 116 GWh per year consumption category. 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

[94] Network operators have to use interval metering for consumption of 1.5 GWh or more.

consumption were asked to provide data (between 50 GWh and 200 GWh and between 50 MWh and 200 MWh respectively). 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. Indirect charges like the biogas neutrality charge and the market area conversion charge are included in the network tariffs.

Gas prices for non-household customers

116 GWh per year ("industrial customer")

Gas: Price level for the 116 GWh/year consumption category as at 1 April 2023

	Spread between 10% and 90% of figures provided by suppliers arranged in order of size (ct/kWh)	**Arithmetic mean** (ct/kWh)	**Share of total price**
Price components outside the supplier's control			
Net network tariff	0.16 - 0.6	0.39	5.0%
Metering, meter operation	0.00 - 0.01	0.015	0.2%
Concession fee[1]	0.00	0.00	0.0%
Carbon levy	0.5461	0.5461	7.0%
Gas tax	0.55	0.55	7.1%
Price components that can be controlled by the supplier (remaining balance)	1.80 - 11.30	6.26	80.7%
Total price (excl VAT)	3.19 - 12.80	7.75	

[1] Under section 2(4) and (5) para 1 of the Electricity and Gas Concession Fees Ordinance (KAV), concession fees for special contract customers are only incurred for the first 5 GWh (0.03 ct/kWh). If this price component is transferred to the entire consumption volume, the average is correspondingly lower, ie on average (rounded) 0.00 ct/kWh for the consumption category of 116 GWh

Table 95: Price level as at 1 April 2023 for customers with an annual consumption of 116 GWh according to data from gas suppliers

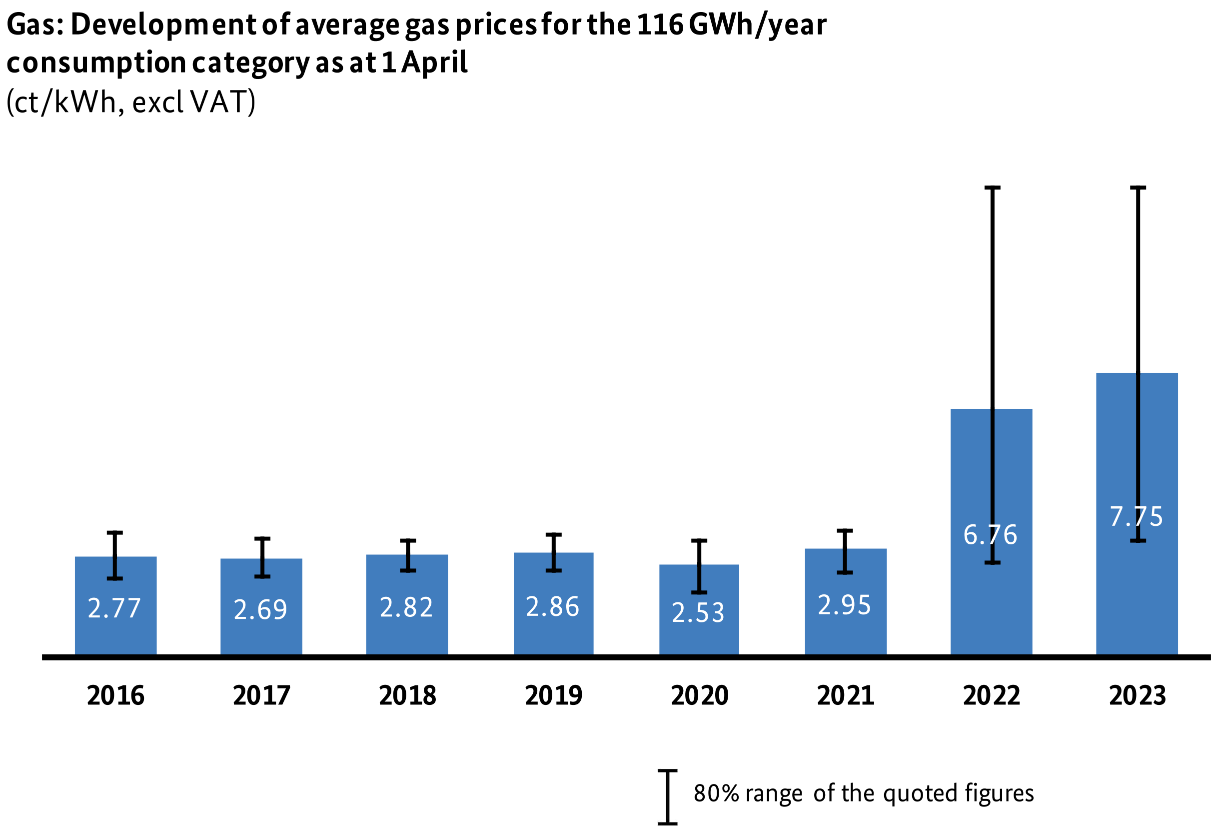

Figure 160: Average gas prices for customers with an annual consumption of 116 GWh according to data from gas suppliers

116 MWh/year ("commercial customer")

Gas: Price level for the 116 MWh/year consumption category as at 1 April 2023

	Spread between 10% and 90% of figures provided by suppliers arranged in order of size (ct/kWh)	**Arithmetic mean** (ct/kWh)	**Share of total price**
Price components outside the supplier's control			
Net network tariff	1.02 - 1.98	1.48	12.2%
Metering, meter operation	0.01 - 0.10	0.05	0.5%
Concession fee[1]	0.03 - 0.03	0.07	0.5%
Carbon levy	0.5461	0.5461	4.5%
Gas tax	0.55	0.55	4.5%
Price components that can be controlled by the supplier (remaining balance)	3.69 - 14.76	9.42	77.8%
Total price (excl VAT)	6.29 - 17.76	12.11	

[1] 69 of the 748 suppliers quoted a concession fee of more than 0.03 ct/kWh. These were suppliers with rather low supply volumes. A concession fee exceeding 0.03 ct/kWh is plausible in the supply of non-household customers in default supply (see section 2(2) para 2 b KAV).

Table 96: Price level as at 1 April 2023 for customers with an annual consumption of 116 MWh according to data from gas suppliers

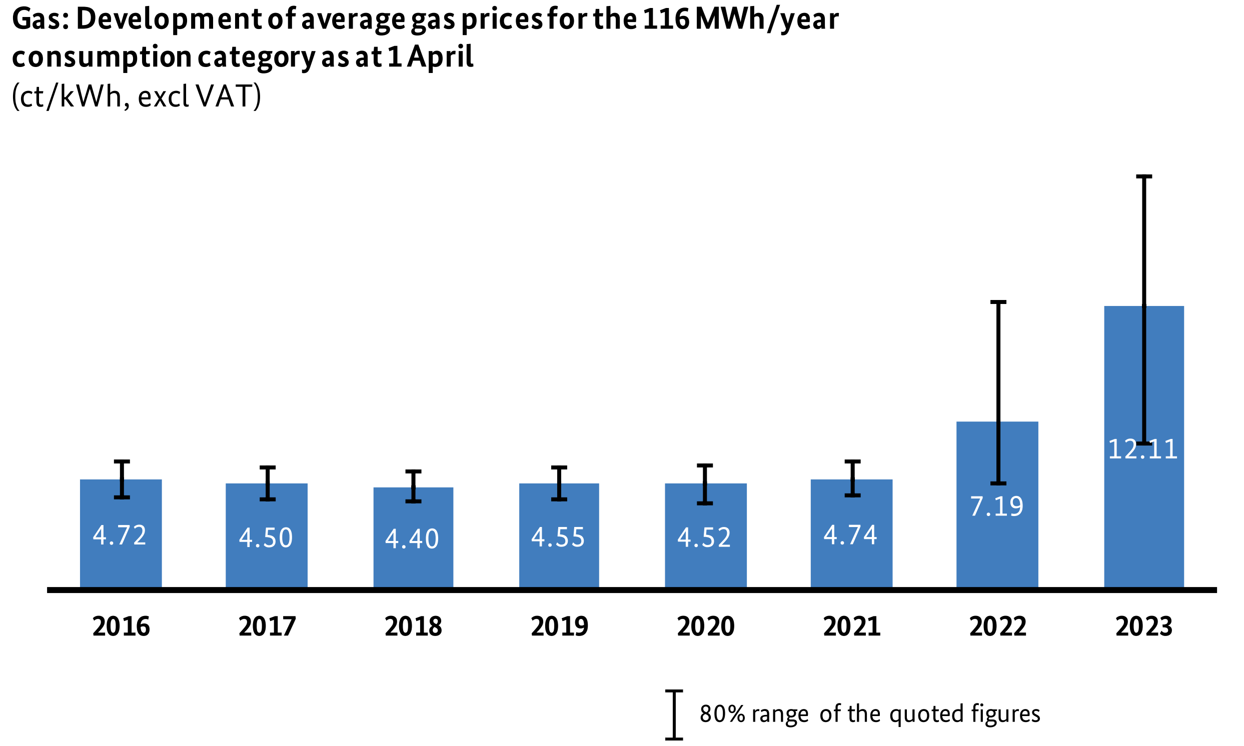

Figure 161: Average gas prices for customers with an annual consumption of 116 MWh according to data from gas suppliers

Gas prices for household customers

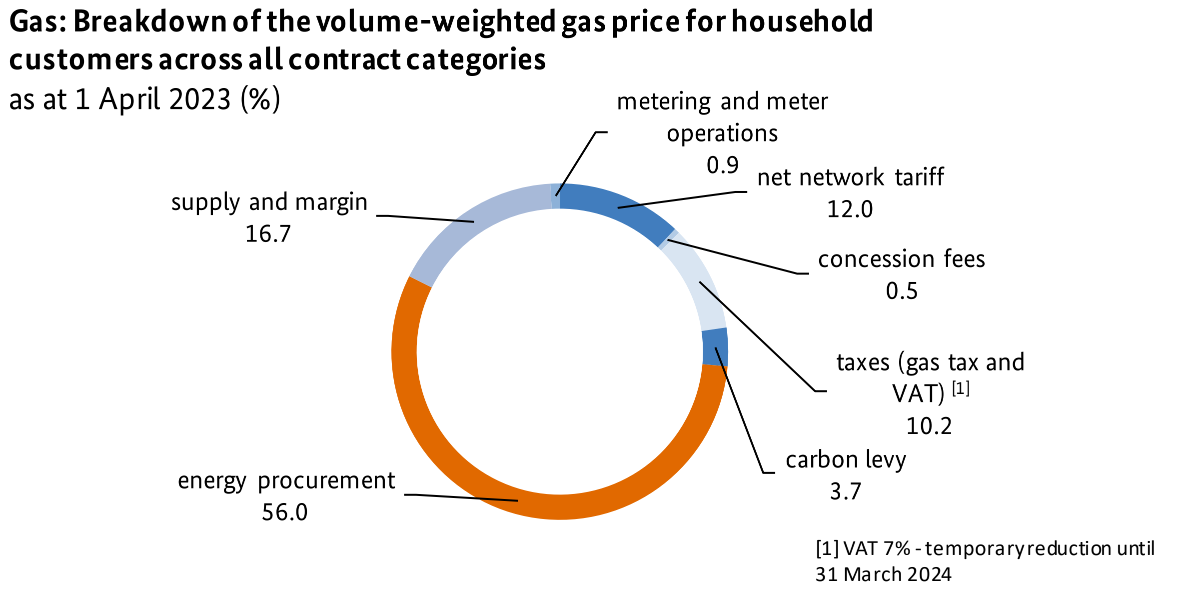

Figure 162: Breakdown of the volume-weighted gas price across all contract categories for household customers according to data from gas suppliers

Gas: Average volume-weighted price across all contract categories for household customers as at 1 April 2023 (ct/kWh)

Price component	Volume-weighted average across all tariffs (ct/kWh)	Share of total price (%)
Network tariff including upstream network costs	1.78	12.0%
Metering charge	0.04	0.3%
Meter operations charge	0.07	0.5%
Concession fee	0.08	0.5%
Carbon levy	0.5461	3.7%
Current gas tax	0.55	3.7%
VAT[1]	0.96	6.5%
Energy procurement	8.30	56.1%
Distribution and margin	2.47	16.7%
Total	**14.80**	**100.0%**

[1] VAT 7% - temporary rate reduction until 31 March 2024

Table 97: Average volume-weighted price across all contract categories for household customers according to data from gas suppliers

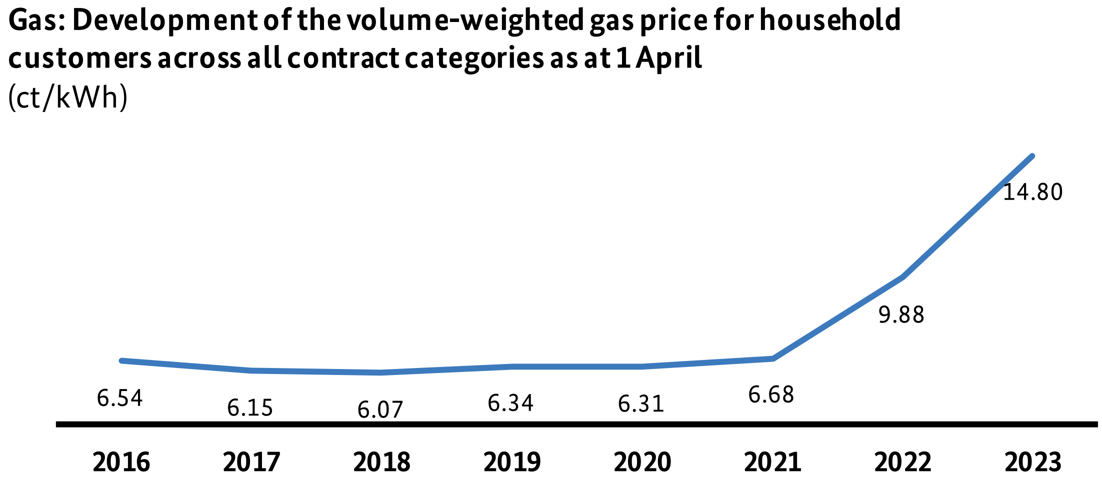

Figure 163: Volume-weighted gas prices across all contract categories for household customers according to data from gas suppliers

Gas: Average volume-weighted prices for household customers in each contract category as at 1 April 2023 (ct/kWh)

Price component	Fallback supply contract	Default supply contract	Non-default contract with default supplier	Contract with a supplier other than the local default supplier
Net network tariff including upstream network costs	1.77	1.73	1.79	1.80
Metering charge	0.05	0.03	0.04	0.05
Meter operations charge	0.09	0.06	0.06	0.09
Concession fee	0.25	0.25	0.04	0.04
Carbon levy	0.5461	0.5461	0.5461	0.5461
Current gas tax	0.55	0.55	0.55	0.55
VAT[1]	1.21	1.05	0.95	0.94
Energy procurement	9.79	8.34	8.20	8.40
Distribution and margin	4.16	3.69	2.34	2.02
Total	**18.42**	**16.25**	**14.52**	**14.44**

[1] VAT 7% - temporary rate reduction until 31 March 2024

Table 98: Average volume-weighted prices for household customers by contract category according to data from gas suppliers

Gas: Development of gas prices for household customers as at 1 April
(ct/kWh)

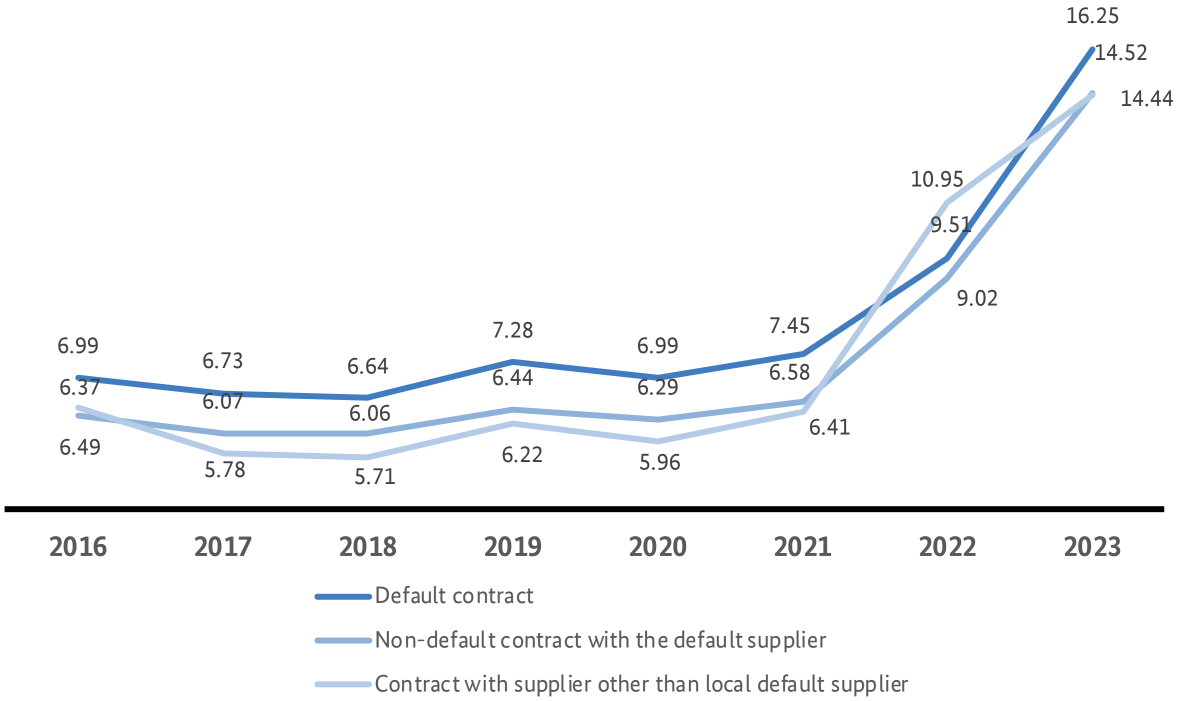

Figure 164: Gas prices for household customers according to data from gas suppliers

Gas: "Energy procurement, distribution and margin" price component for household customers as at 1 April
(ct/kWh)

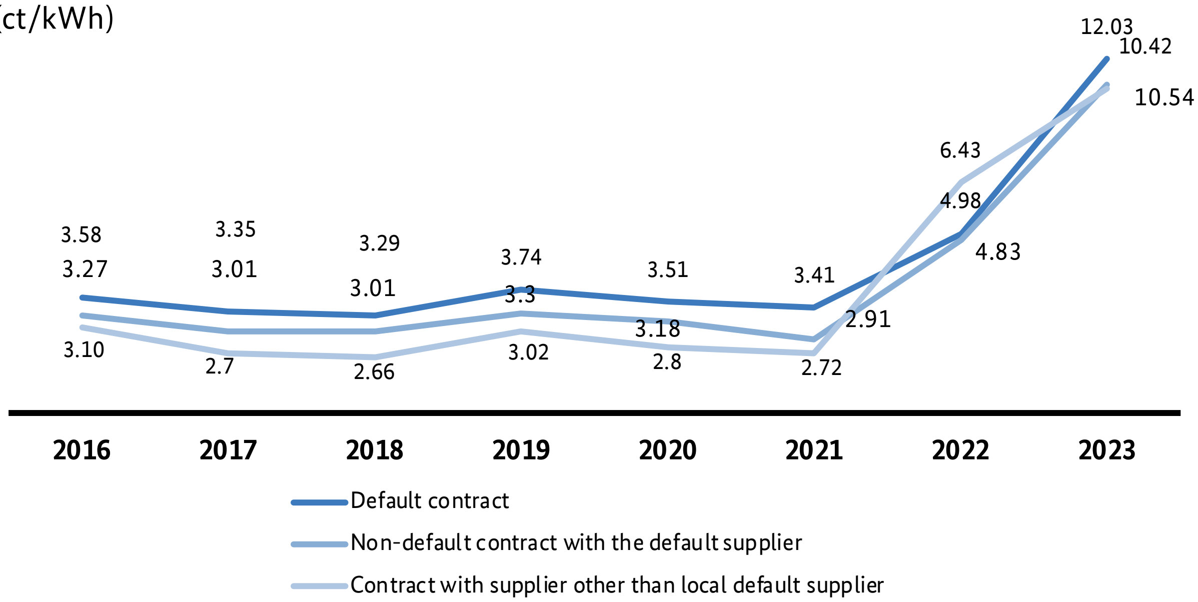

Figure 165: "Energy procurement, distribution and margin" price component for household customers according to data from gas suppliers

Gas suppliers with higher fallback supply prices between January 2022 and December 2023
(number)

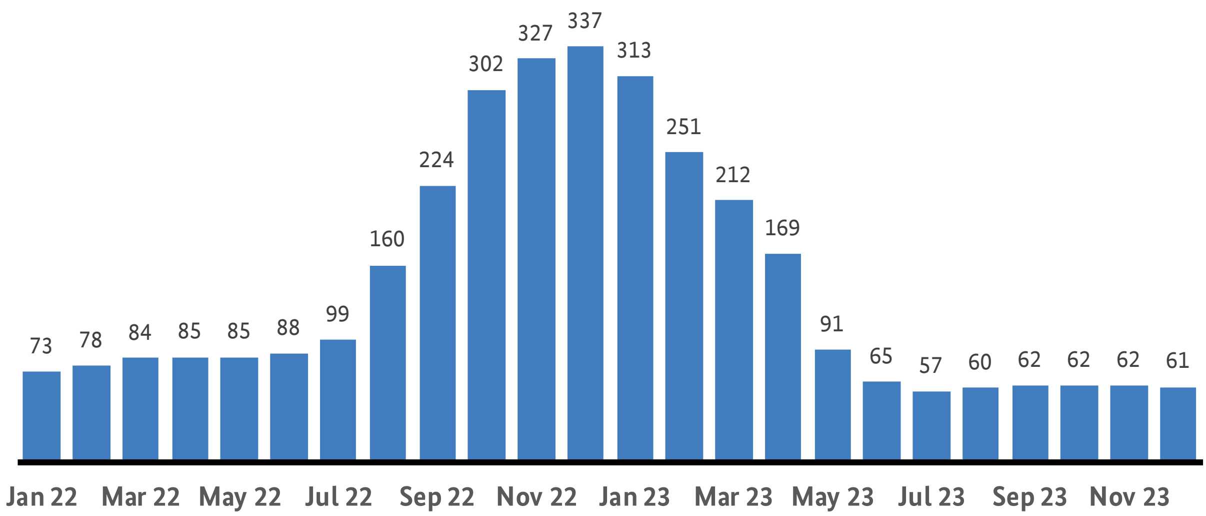

Figure 166: Number of gas suppliers with higher fallback supply prices between January 2022 and December 2023 according to data from gas suppliers

G Metering[95]

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 (EnWG) must obtain approval from the Bundesnetzagentur under section 4 of the Metering Act (MsbG). 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 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.

[95] The results presented in this chapter take into account information collected from 635 companies.

Gas: Meter operator roles

Function	2022
Network operator acting as default meter operator within the meaning of section 2 para 4 MsbG (until 2016: network operator acting as meter operator within the meaning of section 21b(1) EnWG)	624
Network operator acting as meter operator without default responsibility and providing (metering) services in the market (until 2016: network operator acting as meter operator within the meaning of section 21b(2) EnWG, providing (metering) services in the market)	8
Supplier with meter operator activities	12
Independent third party that provides metering services	9

Table 99: Distribution of network operator roles according to data provided by gas meter operators as at 31 December 2022

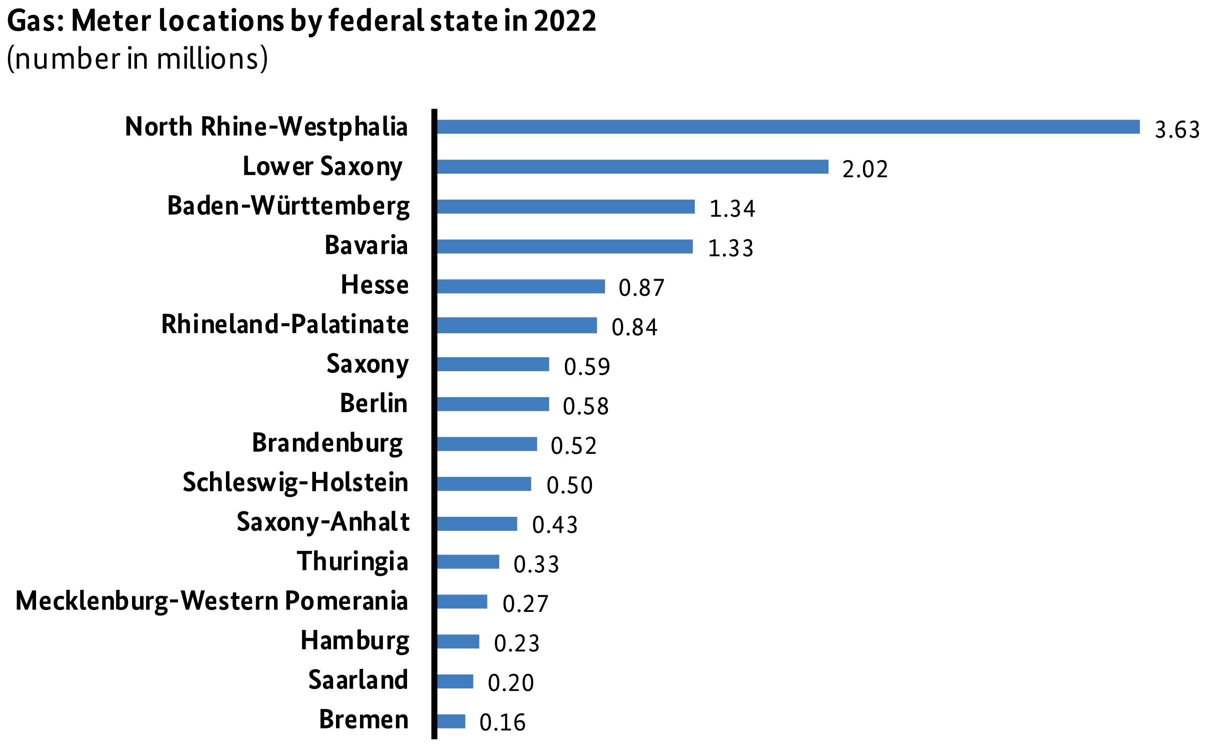

Figure 167: Number of meter locations by federal state in 2022

Gas: Metering equipment for SLP customers in 2022

Types of metering equipment used by meter operators for SLP customers	Number of meter locations by meter size		
	G1.6 to G6	G10 to G25	G40+
Diaphragm gas meters with mechanical counter	4,135,043	136,651	16,247
Diaphragm gas meters with mechanical counter and pulse output	7,883,322	252,070	25,067
Diaphragm gas meters with electronic counter and manufacturer-specific output (eg Cyble, Absolute Encoder)	933,098	33,887	5,439
Diaphragm gas meters with electronic counter	2,644	224	137
Ultrasonic gas meters	2,488	-	145
Load/interval meters as for interval-metered customers	235	392	3,034
Other mechanical gas meters	8,036	2,697	26,588
Other electronic gas meters	1,440	21	786
Number of meters that can be converted so that they can be connected to a smart meter gateway within the meaning of section 2 para 19 MsbG	6,959,820	221,976	33,566
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 para 19 MsbG	361,660	19,071	4,098

Table 100: Breakdown of metering equipment used by SLP customers as at 31 December 2022, by meter size

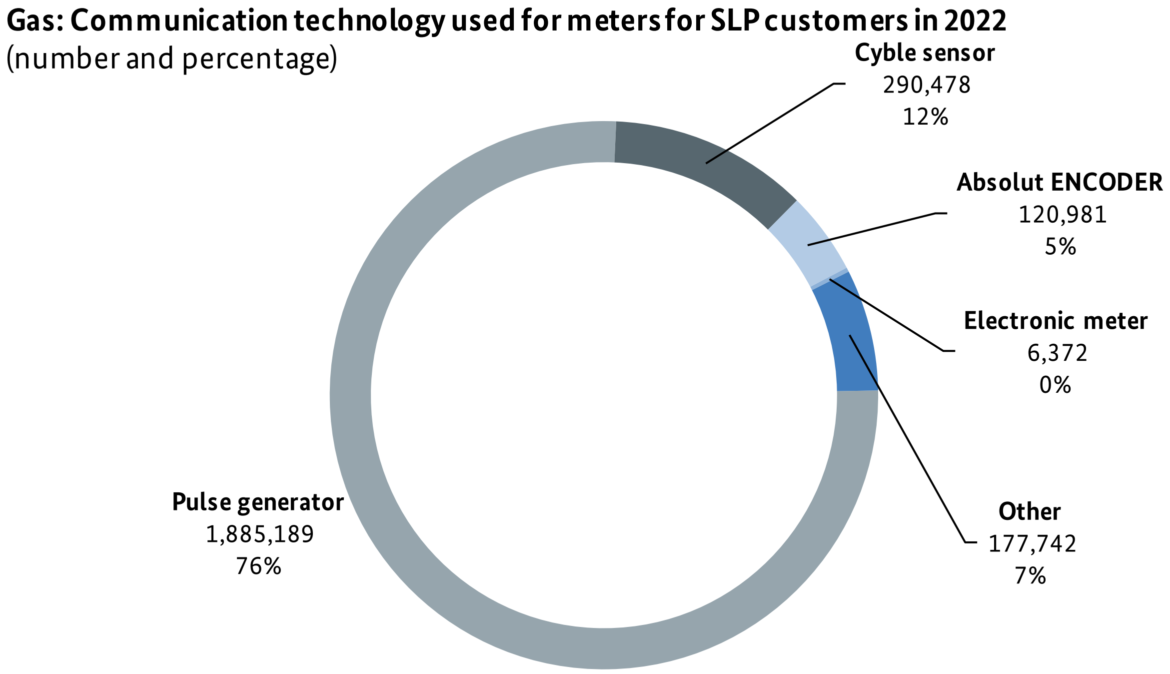

Figure 168: Communication technology used for meters for SLP customers - as at 31 December 2022

Gas: Metering technologies for interval-metered customers in 2022

Function	Number of meter locations
Transmitting meter with pulse output/encoder meter + recording device/data storage	13,020
Transmitting meter with pulse output/encoder meter + gas volume converter	9,821
Transmitting meter with pulse output/encoder meter + calorific value converter	409
Transmitting meter with pulse output/encoder meter + gas volume converter + recording device/data storage	15,372
Transmitting meter with pulse output/encoder meter + temperature volume converter + recording device/data storage	1,185
Transmitting meter with pulse output/encoder meter + smart meter gateway	1
Other	95

Table 101: Breakdown of metering technologies used for interval-metered customers as at 31 December 2022

Gas: Communication link-up systems used for interval-metered customers in 2022
(number and percentage)

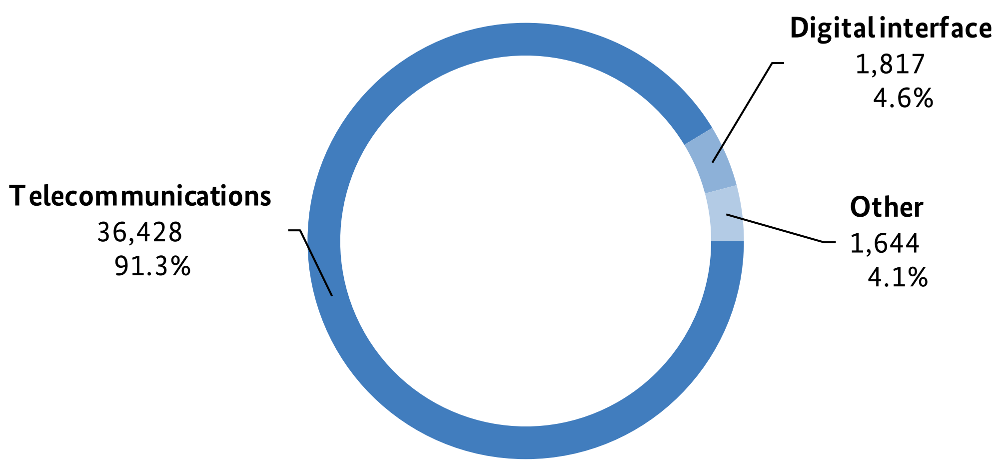

Figure 169: Number and percentage of communication link-up systems used for interval-metered customers as at 31 December 2022

Gas: Metering investment and expenditure
(€m)

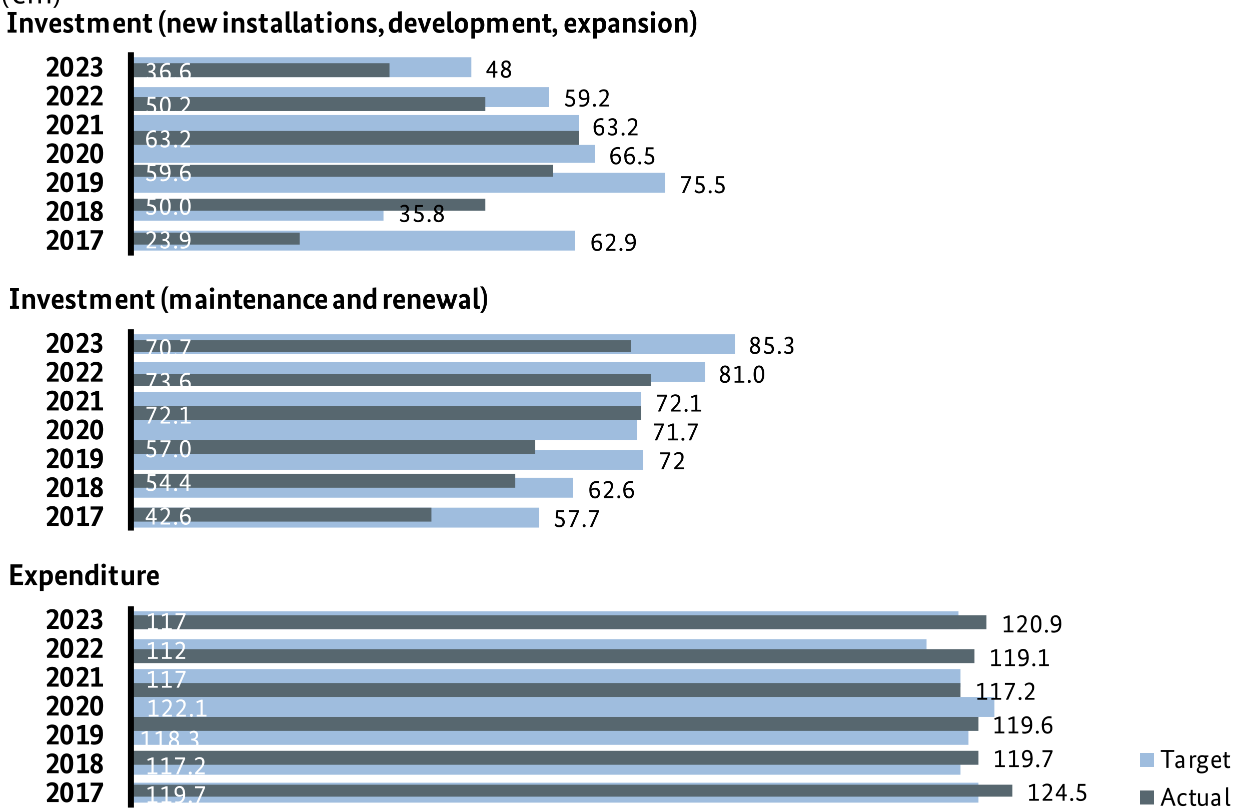

Figure 170: Metering investment and expenditure

Lists

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List of abbreviations

Abbreviation	Definition
AbLaV	Interruptible Loads Ordinance
ACER	European Union Agency for the Cooperation of Energy Regulators
aFRR	automatic frequency restoration reserves
ARegV	Incentive Regulation Ordinance
BAFA	Federal Office for Economic Affairs and Export Control
BBPlG	Federal Requirements Plan Act
bFZK	conditionally firm, freely allocable capacity
BImSchG	Federal Immission Control Act
BMWK	Federal Ministry for Economic Affairs and Climate Action
bn	billion
BSH	Federal Maritime and Hydrographic Agency
BSI	Federal Office for Information Security
BZK	capacity with limited allocability
CACM Regulation	Commission Regulation (EU) 2015/1222 establishing a guideline on capacity allocation and congestion management
CAM NC	Network Code on Capacity Allocation Mechanisms in Gas Transmission Systems
capex	capital expenditure
CAPM	capital asset pricing model
CCR	Capacity Calculation Region
CHP	Combined heat and power
CR	concentration ratio
ct	cent
ct/kWh	cents per kilowatt hour

DSL	Digital Subscriber Line
DSO	distribution system operator
DVGW	Deutscher Verein des Gas- und Wasserfaches e.V. (association of the gas and water industry)
DZK	firm, dynamically allocable capacity
EEG	Renewable Energy Sources Act
EEX	European Energy Exchange AG
EGIX	European Gas Index
EGSI	European Gas Spot Index
EHV	extra high voltage
EKBG	Maintenance of Substitute Power Stations Act
EnLAG	Power Grid Expansion Act
EnSiG	Energy Security of Supply Act
ENTSO-E	European Network of Transmission System Operators for Electricity
EnWG	Energy Industry Act
EPEX	European Power Exchange
EWPBGuaÄndG	Act amending the Act on the Brake on Gas and Heat Prices, the Act on the Electricity Price Brake and other energy, environmental and social legislation
FBMC	flow-based market coupling
FCR	frequency containment reserves
FNB Gas	Vereinigung der Fernleitungsnetzbetreiber Gas e.V. (association of gas TSOs)
FZK	firm, freely allocable capacity
Gas NDP	Gas Network Development Plan
GasGKErstV	Gas Appliance Reimbursement Ordinance
GasGVV	Gas Default Supply Ordinance
GasNEV	Gas Network Tariffs Ordinance

GasUStSG	Act temporarily reducing the value added tax rate for the supply of gas via the natural gas network
GJ	gigajoule
GNDEW	Act Relaunching the Digitisation of the Energy Transition
GPRS	General Packet Radio Service
GSM	Global System for Mobile Communications
GWB	Competition Act
GW	gigawatt
GWh	gigawatt hour
H-gas	high-calorific gas
HV	high voltage
Hz	hertz
InnAusV	Innovation Auction Ordinance
ITC	inter-TSO compensation
KASPAR	capacity product standardisation
KAV	Electricity and Gas Concession Fees Ordinance
km	kilometre
kV	kilovolt
KVBG	Act to Reduce and End Coal-Fired Power Generation
kWh	kilowatt hour
KWKAusV	CHP Auction Ordinance
KWKG	Combined Heat and Power Act
LBEG	State Authority for Mining, Energy and Geology
LEBA	London Energy Brokers' Association
L-gas	low-calorific gas
LNG	liquefied natural gas
LSV	Charging Station Ordinance
LTE	Long Term Evolution

LV	low voltage
MARI	Manually Activated Reserves Initiative
MaStR	core energy market data register
MaStRV	Core Energy Market Data Register Ordinance
mbar	millibar
mFRR	manual frequency restoration reserves
mn	million
MOL	merit order list
MsbG	Metering Act
MV	medium voltage
MW	megawatt
MWh	megawatt hour
NABEG 2.0	Grid Expansion Acceleration Act
NAV	Low Voltage Network Connection Ordinance
NCG	NetConnect Germany
NDP	Network Development Plan
NEMoG	Network Tariffs Modernisation Act
NetzResV	Grid Reserve Ordinance
no	number
NRA	National Regulatory Authority
NTC	Net Transfer Capacity
OTC	over the counter
PIA	preliminary initial assessment
PICASSO	Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation
PLC	power line communication
PSTN	Public Switched Telephone Network

PV	photovoltaic
RCC	regional coordination centre
SAIDI	System Average Interruption Duration Index
SDAC	Single Day-Ahead Coupling
SEFE	Securing Energy for Europe GmbH
SIDC	Single Intraday Coupling
SLP	standard load profile
SMARD	Bundesnetzagentur's electricity market data platform
StaaV	Electricity Supply Expansion Ordinance
StromGVV	Electricity Default Supply Ordinance
StromNEV	Electricity Network Tariffs Ordinance
StromNZV	Electricity Network Access Ordinance
StromPBG	Electricity Price Brake Act
TAR NC	European network code on harmonised transmission tariff structure
THE	Trading Hub Europe
TSO	transmission system operator
TWh	terawatt hour
uFZK	interruptible, freely allocable capacity
UMTS	Universal Mobile Telecommunications System
V	volt
VAT	Valued Added Tax
VPI	consumer price index
WindSeeG	Offshore Wind Energy Act

Glossary

The definitions pursuant to section 3 of the Energy Industry Act (EnWG), section 2 of the Electricity Network Access Ordinance (StromNZV), section 2 of the Gas Network Access Ordinance (GasNZV), section 2 of the Electricity Network Tariffs Ordinance (StromNEV), section 2 of the Gas Network Tariffs 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 AktG	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 customers)	Peak load, expressed in kilowatt (kW), as metered in 15-minute readings, in the course of a year.
Annual usage period (final customers)	The annual usage period is the quotient of the energy withdrawn from the network in an accounting year and the annual peak load 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 period in days = annual consumption divided by maximum daily amount). The usage period in hours indicates the number of hours required to withdraw the annual consumption volume by taking off the maximum hourly amount (usage period in hours = annual consumption divided by maximum hourly amount) (see annex 4 to section 16(2),(3) sentence 2 StromNEV).
BAFA border price	The border price as a reference price for the long-term procurement of natural gas was determined for every month by the Federal Office for Economic Affairs and Export Control (BAFA) by evaluating the documentation available to BAFA on natural gas imported from Russian, Netherlands, Norwegian, Danish and British production regions. The import volumes taken into account in determining the border price are mainly based on import contracts; spot volumes, by contrast, are not fully represented in the imports and exports.
Balancing capacity	Balancing capacity is maintained to ensure a constant balance between electricity generation and consumption.
Balancing energy, imbalance gas	*electricity*

	The activated energy that is settled with the balance responsible parties causing the imbalances. Balancing energy is therefore the allocation of activation costs for balancing capacity and represents the economic settlement of the activated energy. *gas* Difference between entry and exit quantities established by the market area manager for each balancing group in the market area at the end of each balancing period and settled with the balance responsible parties (see section 23(2) GasNZV).
Balancing group	As regarding electricity within a control area, the aggregation of feed-in and withdrawal points that serves the purpose of minimising deviations between feed-in and withdrawal 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 flows, which represent the actual cross-border flow of electricity, exchange schedules reflect the commercial cross-border exchange of electricity. Physical 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.
CAM NC	Network code on capacity allocation mechanisms in gas transmission systems established by Commission Regulation (EU) 2017/459.
Cavern storage facilities	Artificial hollows in salt domes created by drilling and solution mining. These facilities often have higher injection and withdrawal capacities and a lower cushion gas requirement, but are also smaller in volume.
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 metering charge.
CHP net rated capacity (electrical active power)	For rated thermal capacity, proportion of the net rated capacity directly linked to heat extraction. The proportion of electrical capacity exclusively related to the generation of electricity is not included here.
Circuit length	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.
Clearing	Clearing refers to the financial and physical settlement of transactions on the exchange.
CO_2 emissions from power generation	The CO_2 released from a specific generating unit during power generation. For CHP plants the proportion of CO_2 emissions that are to be allocated to power generation according to Working Sheet AGFW FW 309 Part 6 "Energy rating of district heating - Determining the specific CO_2 emission criteria" (December 2014).
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.
Consumption	Amount of electricity delivered by electricity network operators to final customers.
Contract switch	A customer's change to a new tariff with the same energy supplier at their own request.
Conventional meter operation	Conventional meter operation includes all metering systems that are not modern metering equipment or smart metering systems (eg Ferraris meters, electronic household meters, EDL21, EDL40, meters for interval-metered customers, 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 trading	Day-ahead trading on the EPEX Spot (the EEX spot market) is for energy supplied the next day.
Default supplier	The gas and electricity company providing default supply in a network area as provided for by section 36(1) EnWG.
Default supply	Energy supply by the default supplier to household customers on the basis of general terms and conditions and general prices (see section 36 EnWG).
Delivery volume	Amount of electricity or gas delivered by electricity or gas suppliers to final customers.
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 a single shareholder holds more than 50% of a company's shares, that company's sales will be fully attributed to that shareholder. If two shareholders each hold 50% of a company's shares, they will each be attributed 50% of the sales. 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 is the parent 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 customer 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.

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.
EGIX	The European Gas Index (EGIX) provides a monthly reference price for medium-term contracts on the futures market. It is based on the trades on the futures market concluded in the current front month contracts in the market areas. On the basis of these trades, the volume-weighted average price (daily index) of all trades is calculated for each day of trading. The EGIX corresponds to the arithmetic mean of all daily indices relating to identical front month contracts.
EGSI	The European Gas Spot Index (EGSI) is calculated as a volume-weighted average; it represents the price level on the spot market and thus the average costs for the short-term procurement of natural gas. One index each is calculated for the gas markets in Germany (THE), the Netherlands (TTF), France (TRF), Austria (CEGH VTP), Denmark (ETF) and Belgium (ZTP). The EGSI replaces the daily reference price as a short-term price index. Unlike the daily reference price, the EGSI is calculated at least one day before the delivery date. If a trading day is preceded by a weekend or a bank holiday, the calculation is different. For better comparability, the analysis of the EGSI in this report is therefore based solely on trading prices and volumes for day-ahead products.
Energy Information Network (EIN)	Communication of power plant deployment planning data for conventional generating installations with a rated capacity of at least 10 MW and a connection to networks with a rated voltage of at least 110 kV to the TSOs to ensure that the network and system is operated securely (see Bundesnetzagentur decision BK6-13-200).
Energy price component	The price component that is controlled by the supplier, made up of energy procurement, distribution and margin.
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 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 the obligation 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.

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) sentence 2 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) sentence 3 EnWG in conjunction with sections 14 and 15 EEG and, in the case of CHP installations, section 4(1) sentence 2 KWKG). Importantly, such feed-in management is only permitted once the priority curtailment measures for conventional installations have been exhausted. The expansion obligations of the operators responsible 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 curtailed energy and heat 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 reserve capacity	Grid reserve capacity is a price element for customers with their own generation or network operators 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.
Grid/network connection	*electricity* Pursuant to section 5 of the Low Voltage Connection Ordinance (NAV), the grid connection connects the general electricity network to the electrical installation of the customer. It begins at the branching-off point of the low voltage distribution network and ends with the service fuse, unless a different agreement has been made; in any case, the provisions relating to grid connection are applicable to the service fuse. In the

	case of power plants, the grid connection is the provision of the line that connects the generating installation and the connection point, and its linkage with the connection point (section 2 para 2 of the Power Plant Grid Connection Ordinance (KraftNAV)). *gas* Pursuant to section 5 of the Low Pressure Connection Ordinance (NDAV), the network connection joins the general supply network with the customer's gas facilities from the supply pipeline to the internal pipes on the premises. It comprises the connecting pipe, any shut-off device outside the building, insulator, main shut-off device and any in-house pressure regulator. The provisions on connection to the network are still applicable to the pressure regulator when it is installed after the end of the network connection but located within the customer's system.
Gross 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).
Heating electricity	Heating electricity is the electricity supplied to operate controllable loads for the purposes of room heating. Controllable loads essentially comprise overnight storage heaters and electric heat pumps.
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 metering	Measurement of the power used by final customers in a defined period. Interval 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 interval metering.
Interval-metered customer	*electricity* Final customers with an annual electricity offtake exceeding 100,000 kWh. *gas* Final customers with an annual gas offtake exceeding 1.5mn kWh 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).
L-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 tariffs 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 tariffs 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 (MsbG) regarding the communicative integration of the controllable loads. (section 14a EnWG, version in force until 31 December 2022)
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.
Loss energy	The energy required for the compensation of technical power losses.
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 customers 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 participants who, for a minimum period of time during a trading day, have both a buy and a sell quote in their order books 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 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 charge	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) sentence 1 GasNEV).

Metering service	Metering the energy supplied in accordance with verification regulations and processing the metered data for billing purposes.
Modern metering equipment	A metering system reflecting actual electricity consumption and actual time of use that can be safely connected to a communication network via a smart meter gateway.
Natural gas reserves	Secure reserves: in known deposits based on reservoir engineering or geological findings that can be extracted with a high degree of certainty under current economic and technical conditions (90% probability). Probable reserves: a probability level of 50%.
Net capacity	The power a generating unit delivers to the supply system (transmission and distribution networks, consumers) at the high-voltage side of the transformer. It corresponds to the gross capacity less the power consumed by the unit in the process of generation, even if this is not supplied by the generating unit itself but by a different source (VGB, 2012).
Net electricity generation	A generating unit's gross electricity generation less the energy consumed in the process of generation. Unless otherwise indicated, the net electricity output relates to the reference period (VGB, 2012).
Net network tariffs	*electricity* Electricity network tariff, from 1 January 2017 including billing tariff, not including charges for meter operations, VAT, concession fees, surcharges payable under the EEG and KWKG and other surcharges. *gas* Gas network tariff, from 1 January 2017 including billing tariff, not including charges for metering and meter operations, VAT and concession fees.
Net thermal capacity	The maximum useful heat generation under rated conditions that a CHP installation can supply.
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 tariffs to network operators. However, it is also permissible for final customers to use the network, in which case, the final customer pays the network tariffs to the network operator.
Network area	Entire area over which the network and transformation levels of a network operator extend.
Network level	Areas of power supply networks in which electrical energy is transmitted or distributed at extra-high, high, medium or low voltage (section 2 para 6 StromNEV) low voltage ≤ 1 kV medium voltage > 1 kV and ≤ 72.5 kV high voltage > 72.5 kV and ≤ 125 kV extra-high voltage > 125 kV
Network losses	The energy lost in the transmission and distribution system, known as network losses, is the difference between the electrical energy physically delivered to the system and the energy drawn from the system within the same period (see VGB, 2012).

Nominal pressure	The nominal pressure specifies a reference designation for pipeline systems. In accordance with DIN EN ISO, nominal pressure is given using the abbreviation PN (pressure nominal) followed by a dimensionless whole number representing the design pressure in bar at room temperature (20°C). EN 1333 specifies the following nominal pressure levels: PN 2.5 - PN 6 - PN 10 - PN 16 - PN 25 - PN 40 - PN 63 - PN 100 - PN 160 - PN 250 - PN 320 - PN 400.
Nomination	Shippers' duty to notify the network operator, by 2pm at the latest, of their intended use of the latter's entry and exit capacity for each hour of the following day.
Non-CHP electricity (net)	Gross non-CHP 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 non-CHP electricity generation. The net non-CHP electricity generated by a generating installation is the gross non-CHP generation less the non-CHP electricity for self-consumption (in a reporting period).
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.
Offtake volume	Amount of gas taken off by gas network operators.
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-exchange trading.
Peak load	Load profile for constant electricity supply or consumption over a period of 12 hours from 8am to 8pm every working day. Peak load electricity has a higher monetary value than baseload.
Phelix (Physical Electricity Index)	*spot market*: 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. *futures market*: 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 facilities	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".

Rated capacity	Maximum capacity at which a plant can be operated for a sustained period under rated conditions at the time of handover. Capacity changes are only permitted in conjunction with major modifications of the rated conditions and structural alterations at the plant. Until the exact rated capacity has been determined, the value ordered in the supply contract should be indicated. If it is unclear whether the value ordered complies with the actual permit and operating conditions expected, a preliminary average rated capacity is to be determined and applied until definitive measurement results are available. The average is to be fixed in such a way that higher or lower production levels, over a normal year, will be offset (eg on account of the cooling water temperature curve). The definitive rated capacity of a power plant unit is determined when the plant has been handed over, usually when the acceptance measurement results are available. It should be noted that the rated conditions apply to an annual average, ie that seasonal changes (for example in the cooling water and air inlet temperature) and internal electrical and steam-side requirements balance out, and that exemplary conditions used in the acceptance test, eg special closed circuit switching, must be converted to normal operating conditions. The rated capacity, unlike the maximum capacity, may not be adjusted to a temporary change in capacity. The rated capacity may not be changed in the case of a reduction in capacity as a result of, or to prevent, damage, nor may it be reduced on account of ageing, deterioration or pollution. Capacity changes require: - additional investment with a view to increasing the plant's capacity, eg retrofitting to enhance efficiency; - the decommissioning or removal of parts of the plant, accepting a loss of capacity; - operation of the plant outside the design range stipulated in the supply contracts on a permanent basis, ie for the rest of its life, for external reasons, or - a restriction of capacity, imposed by statutory regulations or orders of public authorities without there being a technical fault in the plant, until the end of its operating life (VGB, 2012).
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 rectify at short notice 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 was an instrument set out in the EEG and laid down in greater detail in sections 60 et seq of the Act. The surcharge was used to finance the expansion of renewable energies. Renewable energy facility operators that fed electricity into the general supply network received a payment from network operators that had been set under the EEG or determined through auctions. The funds required were passed on to electricity consumers by the renewable energy surcharge. All electricity consumers paid the renewable energy surcharge as part of the electricity price. The TSOs calculated the surcharge. They were required to determine and publish the surcharge for the following calendar year by 15 October each year. The network operators published this online at www.netztransparenz.de. The Bundesnetzagentur ensured that it had been determined properly. The surcharge was reduced to 0 ct/kWh with effect from 1 July 2022. It was abolished with effect from 31 December 2022. Financial assistance for renewable energy is now part of the federal budget (Climate and Transformation Fund) in accordance with the Energy Financing Act (EnFG).
SLP customer (standard load profile customer)	*electricity* 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.) *gas* Section 24 GasNZV defines standard load profile customers as final customers with a maximum annual offtake of 1.5mn 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.
Transformation level	Areas in power supply networks in which electrical energy is transformed from extra-high to high voltage, high to medium voltage and medium to low voltage (section 2 para 7 StromNEV). An additional transformation within one of the separate network levels (eg within the medium voltage level) is part of that network level.
Underground storage facilities	These are notably pore, cavern and aquifer storage facilities.
Usage time (final customers)	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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