Bundesnetzagentur Bundeskartellamt

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# Key findings and summary
## Monitoring report 2020

# Monitoring report 2020 –Key findings and summary

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# A Key findings

**Generation**

The market concentration in electricity generation and in the first-time sale of electricity (not entitled to payment under the Renewable Energy Sources Act (EEG)) has shown a continued decline in recent years. In 2019, the aggregate market share of the five largest undertakings in the market for the first-time sale of electricity based on the German market area was 70.1%, compared to 73.9% in the previous year.

With respect to the German conventional generating capacity generally available for use in the market for the first-time sale of electricity, the share of the five largest suppliers was 57.5% and thus also significantly below the previous year's level of 60.8%.

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

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

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

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

**Redispatching and feed-in management**

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

**Electricity network charges**

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

**Wholesale electricity markets**

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

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

**Retail electricity markets**

As in previous years, the Bundeskartellamt assumes that there is currently no single dominant undertaking in either of the two largest electricity retail markets. The cumulative market share of the four largest undertakings was around 24.5% (2018: 24.4%) in the national market for supplying interval-metered customers and 34.1% (2018: 31.3%) in the national market for non-interval-metered customers on special contracts.

The supplier switching rate for non-household customers has been fairly constant since 2009. The volume-based switching rate for customers with an annual consumption of more than 10 MWh was 11.7% (2018: 12.3%). The percentage of household customers' consumption provided by a supplier other than the local default supplier was around 34% (2018: 31%). The number of household customers switching electricity supplier fell to 4.5m (2018: 4.7m). There was a slight increase in the number of undertakings operating in the market for household customers, giving them a choice between an average of 138 different suppliers (2018: 132). At the same time, there was a decrease in the number of customers whose electricity supply was disconnected. In 2019, just over 289,000 customers were disconnected, representing a year-on-year decrease of around 2%.

The average total price (excluding value added tax (VAT) and possible reductions) for industrial customers with an annual consumption of 24 gigawatt hours (GWh) as at 1 April 2020 was about 16.54 ct/kWh, up 0.56 ct/kWh on the average for 2019. The average total price (excluding VAT) for commercial customers with an annual consumption of 50 MWh in April 2020 was 23.03 ct/kWh, up 0.81 ct/kWh on the previous year.

The increases for both industrial and commercial customers are due to the price components controlled by the supplier and the price components that the supplier cannot control.

The average price for household customers rose to 32.05 ct/kWh as at 1 April 2020. This average is calculated by weighting the individual prices across all contract models for an annual consumption of 2,500 kWh to 5,000 kWh according to consumption volumes to obtain a reliable average price for household customers. The price component controlled by the supplier (energy procurement, supply and margin) accounted for about 7.97 ct/kWh (25%) of the total electricity price as at 1 April 2020 and had thus increased, as in the previous year. The average network charge and the meter operation charge added up to 7.50 ct/kWh in 2020, around 23% of the total price. The EEG surcharge (6.76 ct/kWh) accounted for around 21% of the total price.

**Electric heating**

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

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

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

**Electricity imports and exports**

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

**Gas imports and exports**

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

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

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

**Gas supply disruptions**

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

**Market area conversion**

The planned conversions by individual network operators tend to take place in months when less gas is consumed, from April to October. Between 2019 and 2024, a total of 4,255 conversions will have been carried out for interval-metered customers and 2,228,722 for standard load profile (SLP) customers. A total of 319,000 appliances were adapted in the course of 2019.

**Gas storage facilities**

The market for the operation of underground natural gas storage facilities is still relatively highly concentrated, although concentration has eased over the past few years. The aggregate market share of the three largest storage facility operators stood at around 66.6% at the end of 2019, representing only a slight decrease compared to the previous year (67.1%).

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

**Wholesale natural gas markets**

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

**Retail gas markets**

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

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

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

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

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

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

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

# B Developments in the electricity markets

## 1. Summary

### 1.1 Generation and security of supply

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

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

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

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

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

## 1.2 Cross-border trading

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

## 1.3 Networks

### 1.3.1 Network expansion

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

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

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

### 1.3.2 Investment

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

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

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

[6] Investments and expenditure are defined in the glossary. The values under commercial law do not correspond to the implicit values included in the system operators' revenue cap in accordance with the provisions of the Incentive Regulation Ordinance (ARegV).

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

#### 1.3.3 Network and system security

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

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

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

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

The amount of energy curtailed as a result of feed-in management measures, that is the curtailing of installations receiving payments under the EEG or the Combined Heat and Power Act (KWKG), was high in 2019, totalling 6,482 GWh. This represents a significant increase of around 17% compared to the previous year (2018: 5,403 GWh). The amount of energy curtailed thus corresponded to 2.9% of the total amount of energy generated by renewable energy installations eligible for payments under the EEG (including direct marketing) (2018: 2.6%). The amount of compensation paid to installation operators in 2019 was about €1,058m, up around €340m on 2018 (2018: €719m). The total estimated claims from installation

Introducing indicator-based investment monitoring according to section 33(5) of the ARegV will make it possible to carry out comparative calculations using the figures supplied under commercial law and those derived from the incentive-based regulation. Medium to long-term trends can be derived from the evaluations on the basis of the survey of commercial values. The introduction of an index-based investment monitoring pursuant to section 33(5) ARegV is currently being prepared by the Bundesnetzagentur taking account of the effort required for companies to transmit data.

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

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

The continuing high level of feed-in management measures in 2019 was due to the strong winds in the first quarter of the year. Given the increased need for feed-in management measures and assuming that there will be a further steady increase in renewables, the measures required for network optimisation, reinforcement and expansion must be implemented without delay. In 2019, a total of five DSOs took adjustment measures. The measures to adjust electricity feed-in totalled around 9.3 GWh.

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

#### 1.3.4 Network charges

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

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

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

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

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

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

There are large regional differences in the network charges. A comparison of all the DSOs' network charges in Germany for the three consumption groups (charges excluding meter operation) shows the following: the network charges for household customers range from 3.94 ct/kWh to 16.16 ct/kWh; the range of network charges for commercial customers is similar to that for household customers, with charges ranging from 2.85 ct/kWh to 16.16 ct/kWh; the network charges for industrial customers (without possible reductions) range from around 1.07 ct/kWh to 7.55 ct/kWh.

## 1.4 Costs for system services

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

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

## 1.5 Wholesale

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

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

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

## 1.6 Retail

### 1.6.1 Contract structure and competition

In the retail market, there was no further increase in the number of electricity suppliers available to consumers. In 2019, final consumers could choose on average between 156 suppliers in each network area (not taking account of corporate groups). The average number of suppliers for household customers was 138.

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

The number of household customers switching supplier started to grow steadily in 2006. The number of supplier switches stagnated for the first time in 2017 and remained at the same level in 2018. In 2019, the total number of supplier switches fell for the first time again to about 4.5m (2018: 4.7m). The supplier switching rate based on the total number of household customers is 9.9% (2018: 10.2%) and thus around 0.3% lower than in the previous year. In addition, about 1.8m household customers changed energy supply contract with the same supplier. The switching rate for non-household customers – with an annual consumption of more than 10 MWh – based on consumption volumes was 11.7% (2018: 12.3%).

#### 1.6.2 Disconnections

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

#### 1.6.3 Price level

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

Data was collected from the suppliers operating in Germany on the prices for household customers as at 1 April 2020. The average price (including VAT) increased to 32.05 ct/kWh (2019: 30.85 ct/kWh). This average is calculated by weighting the individual prices across all contract models for an annual consumption of 2,500 kWh to 5,000 kWh according to consumption volumes to obtain a reliable average for the electricity price for household customers.

In 2020, the price component controlled by the supplier (energy procurement, supply and margin) accounted for around 24.9% of the total electricity price and had thus increased, as in the previous year. The network charge in 2020 was slightly higher than in the previous year and thus still at a high level. The EEG surcharge increased by about 5% but still made up around 21% of the total price. Compared to 2019, the average price for household customers on default contracts with an annual consumption of 2,500 kWh to 5,000 kWh increased by around 6% to 33.80 ct/kWh (2019: 31.94 ct/kWh). The average price for customers on a non-default contract with their default supplier was 31.67 ct/kWh (2019: 30.46 ct/kWh). The price for customers on a contract with a supplier other than their local default supplier increased by around 2.5% to 31.22 ct/kWh (2019: 30.46 ct/kWh).

As a rule, customers on default contracts can make savings by switching contract (-2.13 ct/kWh) and switching supplier (-2.58 ct/kWh).[8] Household customers with an annual consumption of 3,500 kWh could consequently cut their electricity costs by around €90 per year. Special bonuses offered by suppliers, including one-off bonus payments, are an added incentive for customers to switch. One-off bonus payments for customers switching to non-default contracts with their local default supplier average €57, and those for customers switching to a non-default supplier €65.

#### 1.6.4 Surcharges

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

#### 1.6.5 Electric heating

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

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

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

### 1.7 Digitisation of metering

The Energy Transition Digitisation Act and the Metering Act (MsbG) contained therein made the rollout of modern metering equipment and smart metering systems legally mandatory in Germany. Whereas in the past household customers were mainly equipped with analogue Ferraris meters, modern metering systems consist of digital meters that are connected to a communication unit (smart meter gateway) via an interface. Modern

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

metering systems do not transmit any data. They are referred to as smart metering systems when they are connected to a smart meter gateway, enabling them to transmit the data recorded by the meter.

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

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

# C Developments in the gas markets

## 1. Summary

### 1.1 Production, imports and exports, and storage

In 2019, natural gas production in Germany fell by 0.2bn $m^3$ to 6.0bn $m^3$ of gas (with calorific adjustment), down 3% from 6.2bn $m^3$ in 2018. The decline in production is chiefly due to the increasing exhaustion of the large deposits and the resulting natural decline in output. The reserves-to-production ratio of proven and probable natural gas reserves, calculated on the basis of the previous year's production and reserves, was 7.0 years as at 1 January 2020.

The total volume of natural gas imported into Germany in 2019 was 1,703 TWh. Imports to Germany were thus down by 57 TWh from the previous year's figure of 1,760 TWh. Imports from Norway rose by just over 18%, while imports from Russia through the Nord Stream pipeline were down 0.1%.

In 2019, the total volume of natural gas exported by Germany was 702 TWh. Based on the previous year's figure of 849 TWh, exports from Germany fell by 148 TWh. When looking at the destination countries, the focus here is on the countries that Germany exports to at their given cross-border interconnection point. Around 52% (2018: 48%) of German natural gas exports went to Czechia, a drop of 11% compared to the previous year's figure. There was a large decrease of 90% in exports to Denmark. Although this was a significant change from the year before, such developments are not unusual as part of market activity. There was also a drop of 54% in exports to France, primarily because the amount of gas imported by that country depends on the availability of its nuclear power plants. Exports to Austria, meanwhile, were up 1.5%.

The total maximum usable volume of working gas in underground storage facilities as at 31 December 2019 was 275.27 TWh.[9] Of this, 135.63 TWh was accounted for by cavern storage, 117.54 TWh by pore storage and 22.01 TWh by other storage facilities.

Short-term (up to 1 October 2019) freely bookable working gas capacity saw a significant decline in volume, whereas there was an increase in the capacity still bookable for 2021. As for the longer term, the volume of medium-term bookable working gas rose again but the volume of long-term working gas declined. On 1 January 2021, the total storage level stood at around 73%.

The market for the operation of underground natural gas storage facilities is still highly concentrated, although concentration has eased over the past few years. The aggregate market share of the three largest storage facility operators stood at around 66.6% at the end of 2019, representing a slight decrease compared to the previous year (67.1%).

[9] This figure includes the 7 Fields storage facility and part of the Haidach storage facility, both of which are located in Austria. They are included because they are directly connected to the German gas network and thus have an impact on it. Equally, storage facilities that are located in Germany but only connected to the network in the Netherlands are not taken into account since they have no direct impact on the German gas network.

## 1.2 Networks

### 1.2.1 Network expansion

On 1 July 2020, the gas transmission system operators (TSOs) submitted their draft of the Network Development Plan (NDP) 2020-2030 to the Bundesnetzagentur. For the most part, the measures in the Gas NDP 2018-2028 are confirmed by the modelling results of the Gas NDP 2020-2030. The TSOs are also proposing a further 54 measures to expand the natural gas network in the period up to 2030, with an investment volume of €2.2bn.

Expansion measures for access to three liquefied natural gas (LNG) terminals on the German North Sea coast will enable LNG to be supplied directly into the national transmission system. The integration of the LNG terminals into the transmission system will bring opportunities to import gas from different sources, which will enhance security of supply and could exert price pressure on traditional importers.

Another issue in the Gas NDP 2020-2030 is the merger of the currently separate market areas NetConnect Germany (NCG) and GASPOOL. This provision is set out in section 21 of the Gas Network Access Ordinance (GasNZV) and is expected to be implemented on 1 October 2021.

The overall expansion proposed by the TSOs for the natural gas transport system includes the expansion of transmission pipelines (approximate length 1,594 km) and of compressor stations (approximate capacity 405 MW). Compared to the previous expansion proposal in the Gas NDP 2018-2028, total investment costs have risen slightly from €7.0bn to €7.8bn.

The TSOs included green gas projects (injection and offtake of hydrogen, synthetic methane) for the first time in the Gas NDP 2020-2030 and modelled them in a separate green gas variant. However, under current legislation pure hydrogen pipelines are not subject to regulation and are therefore not included in the binding part of the NDP. The TSOs have thus proposed 47 measures for the creation of a hydrogen transport system in the Gas NDP 2020-2030 in addition to the natural gas infrastructure measures and subject to changes in the law and regulations. The pipeline length in the expansion proposal is 1,294 km, of which 151 km can be newly built and 1,142 km achieved by repurposing existing natural gas lines. The investment volume for the creation of a hydrogen network will amount to €0.7bn in the period up to 2030, according to the proposal. A detailed presentation of these green gas variants and the related expansion proposal, as well as an outlook, may be found in section II.C.1.1.

### 1.2.2 Extension of the regulatory framework to gas interconnectors with third countries

Directive (EU) 2019/692 of the European Parliament and of the Council of 17 April 2019 extended the scope of the Gas Directive 2009/73/EC to include interconnectors between a Member State and a third country. The parts of the interconnectors in the national territory and territorial sea of the respective Member State are now subject to regulation, although Article 49a of the above-mentioned Gas Directive provides for a possible exemption (derogation) from regulation for lines that have already been completed. The new section 28b of the German Energy Industry Act (EnWG), which transposes Article 49a of the amended Gas Directive in identical wording into German law, sets out that the part of a gas interconnector located in German territory/territorial sea is to be exempted from regulation provided that certain conditions are met. As well as the existence of "objective reasons", it is necessary in particular that the gas interconnector was completed before 23 May 2019. Ruling Chamber 7 received applications for such a derogation for the Nord Stream pipeline, which has been in operation since 2011, on 20 December 2019 (BK7-19-108) and for Nord Stream 2 on 10 January 2020 (BK7-20-004).

The provision in Article 49a(3) of the Gas Directive set out that the decisions had to be made by 24 May 2020. Despite the constraints caused by the coronavirus pandemic in March and April, both sets of proceedings met the deadline, with the application for derogation for Nord Stream 2 being rejected on 14 May 2020, while for Nord Stream the application was granted in accordance with section 28b EnWG on 20 May 2020. Non-confidential versions of the decisions and statements from the Member States have been published on the ruling chamber's website in German and English. The decisions were also transmitted to the European Commission in accordance with section 28b(8) EnWG.

On 15 June 2020, the applicant filed an appeal with the Higher Regional Court (OLG) in Düsseldorf against the rejection of the derogation for Nord Stream 2.

The reasons for the decisions were as follows:

**Nord Stream 2 (BK7-20-004):**

The application for derogation submitted by Nord Stream 2 AG for the part of its Nord Stream 2 pipeline located in German territory was rejected because the pipeline had not been completely laid as at 23 May 2019. When/once it is put into operation, therefore, Nord Stream 2 will be subject to the regulatory requirements of the EnWG and European rules on unbundling, network access and cost regulation. The ruling chamber understands the term "completion" in a constructional/technical sense. The applicant, by contrast, believes it to mean completion in an economically functional sense and refers to the investment decision, which was made well before 23 May 2019.

All Member States had the opportunity to examine Nord Stream 2 AG's application, with its annexes, and to submit a response. Responses were received from ten Member States. Their contributions to the consultation were taken into account in the decision, as was the joint statement submitted by PGNiG S.A. and PGNiG Supply & Trading GmbH, which were summoned to the proceedings upon application in a decision of 18 March 2020. The Bundeskartellamt did not provide a response. Neither the Member States nor the parties summoned shared the viewpoint of the applicant as regards the term "completion".

**Nord Stream (BK7-19-108):**

The Nord Stream pipeline was granted a derogation from regulatory requirements for the part of it located in the German territorial sea retroactively for a period of 20 years as from 12 December 2019, because the conditions for derogation set out in section 28b(1) EnWG were met. Nord Stream was completed before 23 May 2019 and the first connection point of the line with the network of a Member State is in Germany. There is also an objective reason (in this case, "reasons of security of supply"). An improvement in the security of supply had previously been confirmed by the TEN-E decision (Decision No 1364/2006/EC) from 2006 and the planning approval decision of the Stralsund mining authority from 2009. Moreover, the derogation will not be detrimental to competition on or the effective functioning of the internal market in natural gas in the European Union, or to security of supply in the Union. Therefore, the pipeline is exempted from the provisions of sections 8-10e EnWG and sections 20-28 EnWG, ie from certain provisions relating to unbundling and third-party access. However, Nord Stream remains subject to other provisions of the EnWG; the provisions of sections 6a, 6b and 11 et seq, for example, still apply.

During the proceedings, all Member States had the opportunity to examine the application, with its annexes, and to submit a response. Responses were received from six Member States. The statement submitted by the Bundeskartellamt when authorities were given an opportunity to state their views was taken into account in the decision, as were the responses from Member States.

#### 1.2.3 Investment

In 2019 the 16 German TSOs invested a total of €1.33bn (2018: €1.45bn) in network infrastructure. Of this, €1.08bn (2018: €1.30bn) was accounted for by investments in new builds, upgrades and expansion projects and €249m (2018: €156m) by investments in network infrastructure maintenance and renewal.

Across all TSOs, expenditure on maintenance, repair and expansion of network infrastructure amounted to €322m in 2019 (2018: €313m), with expenditure in 2019 and planned expenditure for 2020 shared almost equally between the two market areas.

The overall total for investments and expenditure across all TSOs in 2019 was approximately €1.65bn (2018: €1.76bn).

In the course of data collection for the 2020 Monitoring Report, 600 gas DSOs declared a total investment volume for 2019 of €1,488m (compared to €1,272m in 2018), comprising €940m in new installations, expansions and extensions (€798m in 2018) and €549m in maintenance and repair of network infrastructure (€475m in 2018). For 2020, the projected total investment is €1,527m.

Service and maintenance expenses, based on the data provided by the DSOs, totalled €1,152m in 2019 (2018: €1,078m). The projected expenditure on service and maintenance for 2020 is €1,289m.

#### 1.2.4 Supply interruptions

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

#### 1.2.5 Network charges

As of 1 April 2020, the average volume-weighted network charge including the charges for metering and meter operation (volume-weighted across all contract categories) for household customers in consumption band II was 1.56 ct/kWh, unchanged from the previous year. The lowest gas network charges for household customers across Germany are set at 0.65 ct/kWh, and the highest at 3.65 ct/kWh. The East to West gradient in the distribution of network charges levelled off slightly. The average network charge for household customers in the new federal states (not including Berlin) is 1.60 ct/kWh (2019: 1.65 ct/kWh), while the average in the old states (including Berlin) is 1.42 ct/kWh (2019: 1.39 ct/kWh). Compared to the previous year, gas network charges for household customers have thus decreased by slightly more than 3% on average in the new federal states and increased by just over 2% in the old states.

#### 1.2.6 Network balance

The total quantity of gas supplied by general supply networks in Germany rose in 2019 by about 19.9 TWh or just over 2.5% year-on-year to 948 TWh. The quantity of gas supplied to household customers (as defined in section 3 para 22 EnWG) rose by just over 2.7% to 282.5 TWh (2018: 275.2 TWh). Gas supplies to gas-fired power stations with a nominal capacity of at least 10 MW increased by about 12% to 98.3 TWh (2018: 87.8 TWh).

With regard to gas transmission networks, the quantity of gas procured directly on the market by large final consumers (industrial customers and gas-fired power stations) – in other words not using the classic route via a supplier, and instead approaching the network operator as a shipper (paying the transport charges themselves) – amounted to 78.9 TWh (2018: 72.5 TWh), equivalent to about 42% of the total quantity of gas supplied by the TSOs to final consumers. As regards gas distribution networks, the amount of gas procured without a conventional supplier contract amounted to 42.4 TWh, compared with 39.8 TWh in 2018, corresponding to a share of approximately 5% of the DSOs' total gas supplies.

### 1.2.7 Market area conversion

The conversion of German L-gas networks to H-gas got off to a good start in 2015 with the conversion of smaller network areas. Some larger network operators such as Westnetz, Avacon and wesernetz Bremen are now also in the process of converting their networks. The planned conversions by individual network operators tend to take place in months when less gas is consumed, from April to October. Between 2019 and 2024, a total of 4,255 conversions will have been carried out for interval-metered customers and 2,228,722 for standard load profile (SLP) customers.

## 1.3 Wholesale

Overall, the liquidity of the wholesale natural gas markets increased significantly again in 2019. There was an increase of around 22% in the total volume traded on the exchange, while the volume of bilateral wholesale trading via broker platforms, which accounts for a much larger share, actually rose about 30% in 2019.

The volume traded on the spot market rose by 21% in 2019 to around 472 TWh (2018: 391 TWh). As in previous years, the focus of spot trading for both market areas in 2019 was on day-ahead contracts (NCG: 179.5 TWh; GASPOOL: 121.5 TWh). The futures trading volume rose from around 58 TWh in 2018 to about 75 TWh in 2019, corresponding to an increase of some 30%.

In 2019, broker platforms reported natural gas transactions for delivery to Germany had been traded for an amount totalling 2,853 TWh (2018: 2,192 TWh), representing growth of around 30%. Of this, 1,207 TWh was for contracts with delivery in 2019 and a delivery time of at least one week.

There were lower wholesale gas prices for the first time in two years in 2019. The various price indices (EGIX, border prices, as calculated by the Federal Office for Economic Affairs and Export Control (BAFA)) show a year-on-year drop of between 16% and 28%. The European Gas Spot Index (EGSI), which was measured for the first time in 2017, fell year-on-year by about 32% in the NCG market area and about 40% in GASPOOL.

## 1.4 Retail

### 1.4.1 Contract structure and competition

An overall analysis of how household customers were supplied in 2019 in terms of volume shows that nearly half of them (49%) were supplied by the local default supplier under a non-default contract, receiving 128.4 TWh of gas (2018: 50%/124.7 TWh).

Only 17% of household customers still had a default supply contract in 2019 and these were supplied with 43.7 TWh of gas (2018: 18%/45.3 TWh). The percentage of household customers who had a contract with a supplier other than the local default supplier increased again to 34% for a total of 89.9 TWh of gas (2018: 32%/79.1 TWh). Thus supply by the default supplier at a default tariff is the least popular form of supply.

The gas sold to non-household customers is mainly to interval-metered customers. About 24.1% of the total volume delivered to these customers was supplied under a contract with the default supplier on non-default terms (2018: 25.7%) and about 75.6% was supplied under a contract with a legal entity other than the default supplier (2018 71%). These figures show that default supply is of only minor significance in the acquisition of interval-metered customers in the gas sector.

The total number of customers changing contract in 2019 was 0.6m. The volume of gas these customers were delivered was approximately 13.4 TWh. The volume-based switching rate was therefore 5.4%.

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

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

The level of concentration in the two largest gas retail markets continues to be well below the statutory thresholds for presuming market dominance. The cumulative sales for the four largest companies to SLP customers was about 86 TWh in 2019, the same as the year before. The cumulative sales for the four largest companies to interval-metered customers was about 145 TWh (2018: 138 TWh). The aggregate market share of the four largest companies (CR4) in 2019 was thus around 24% for SLP customers (2018: 23%) and about 30% for interval-metered customers, compared to 31% in 2018.

Since market liberalisation and the creation of a legal basis for an efficient supplier switch, there has been a steady rise in the number of active gas suppliers for all final consumers in the different network areas. This positive trend was maintained in 2019 as well.

In 2019, more than 50 gas suppliers were operating in 94% of network areas. Final consumers in over 62% of network areas had a choice of more than 100 gas suppliers. If viewed separately, the trend for household customers is similarly positive. In nearly 91% of network areas, household customers have a choice of 50 or more gas suppliers. More than 100 gas suppliers are operating in almost 50% of network areas. On average, final consumers in Germany can choose from 129 suppliers in their network area (2018: 124); household customers can, on average, choose between 109 suppliers (2018: 104 suppliers) (these figures do not take account of corporate groups).

### 1.4.2 Gas disconnections

The number of disconnections actually carried out by the network operators in 2019 was 30,997, representing a decrease of 6.5% compared to the previous year (2018: 33,145). This corresponds to 0.2% of gas connections based on all market locations of final consumers.

According to the gas suppliers' data, a disconnection notice is issued when a customer is on average around €120 in arrears. Just over a million disconnection notices were issued to household customers, of which around 0.2m or 20% were passed on to the relevant network operator with a request for disconnection. The suppliers' data show that around 3% of the total notices actually resulted in the customer being disconnected.

The gas suppliers also stated that in some 22,674 cases they had disconnected customers with default contracts. This corresponds to 0.2% of household customers on default contracts. According to the suppliers' data, customers with non-default contracts were disconnected in 10,406 cases, corresponding to 0.1% of non-default customers. The gas suppliers stated that around 10% of disconnections were the same customers being disconnected more than once.

### 1.4.3 Price level

The volume-weighted gas price for household customers across all contract categories barely changed in 2020 and was 6.31 ct/kWh. The volume-weighted gas price for customers on a default contract as at 1 April 2020 was 6.99 ct/kWh in band II (2019: 7.28 ct/kWh), corresponding to a decrease of around 4% compared to the previous year. The volume-weighted gas price for customers on a non-default contract with the default supplier as at 1 April 2020 was 6.29 ct/kWh in band II (2019: 6.44 ct/kWh), equivalent to a year-on-year decrease of just over 2%. The volume-weighted price for a contract with a supplier other than the local default supplier as at 1 April 2020 was 5.96 ct/kWh in band II, a decline of just over 4% compared to the previous year (2019: 6.22 ct/kWh).

The average household customer with gas consumption of 23,250 kWh could save an average of €163 a year as at 1 April 2020 by changing contract. The average potential saving for the year from changing supplier was €240.

The price component "energy procurement, supply and margin" for default supply customers was 3.51 ct/kWh as at 1 April 2020 (2019: 3.74 ct/kWh). That corresponds to a drop of just over 6% in gas procurement costs. The gas procurement costs in the price for customers supplied under a non-default contract with the default supplier fell by slightly more than 4% from 3.30 ct/kWh to 3.18 ct/kWh. The gas procurement costs for customers supplied under a contract with a supplier other than the local default supplier increased by just over 7% to 2.80 ct/kWh (2019: 3.02 ct/kWh).

Special bonuses offered by gas suppliers, including one-off bonus payments, are an added incentive for customers to switch. These one-off payments amount to an average of €70 to €80.

The gas prices for non-household (industrial and commercial) customers showed a decrease as at 1 April 2020. The arithmetic mean of the overall price (excluding VAT) for an annual consumption of 116 GWh ("industrial customer") was 2.53 ct/kWh, and thus 0.33 ct/kWh or around 11.5% lower than the previous year's figure. The arithmetic mean of the overall price (excluding VAT) for an annual consumption of 116 MWh ("commercial customer") was 4.52 ct/kWh on the reporting date, a small decrease of 0.03 ct/kWh on a year earlier. The proportion of the total price (about 59%) controlled by the supplier was 2.66 ct/kWh, down by only 0.03 ct/kWh.

The prices paid by non-household customers in Germany in the annual consumption range of 27.8 GWh to 278 GWh was 2.50 ct/kWh in the second half of 2019, about 0.09 cents above the EU average of 2.41 ct/kWh. On an EU average, the net price is subject to about 9.5% (0.24 ct/kWh) of non-refundable taxes and levies. In this regard, Germany's figure of about 15% (0.38 ct/kWh) is higher than average. Compared with the gas prices for industrial customers, there are relatively large differences between the gas prices for household customers across the EU. The gas price for household customers in Germany was 5.88 ct/kWh and thus around 12% below the EU average (6.70 ct/kWh). Taxes and levies amounted to an average of 1.57 ct/kWh in Germany. The EU average was 1.70 ct/kWh.

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