Bundesnetzagentur Bundeskartellamt

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Report

Monitoring report 2018 - key findings

Key findings

Generation

At 601.4 TWh, Germany's net electricity generation in 2017 corresponded to the 2016 level (601.4 TWh). Generation from non-renewable energy sources decreased disproportionately by 24.7 TWh. After only a slight increase in renewable electricity generation in 2016, there was a substantial increase of 24.6 TWh in 2017, with renewable electricity generation being equivalent to 36% of gross electricity consumption.

The generation landscape was characterised in 2017 by further growth in installed renewable energy capacity. At the end of 2017, installed renewable capacity had increased year-on-year by approximately 8.3 GW. Altogether, total generating capacity rose from 211.9 GW in 2016 to 217.6 GW in 2017, with 105.1 GW of non-renewable and 112.5 GW of renewable capacity.

The market power of the largest conventional electricity producers (electricity not eligible for payments under the Renewable Energy Sources Act – EEG) has decreased significantly over the last years. The cumulative market share of the five largest electricity producers in the German-Austrian market has decreased from 69.4% in 2016 to 67.5% in 2017. If the cumulative market share of the five largest undertakings were viewed only for the German market for the first-time sale of electricity, in line with the current split of the previously joint bidding zone, this would be 75.5% compared with 76.5% in 2016. Thus also this market definition shows a decline in market concentration.

Development of renewable energy generation

The growth in renewable energy capacity of 8.3 GW (sum of renewable energy installations with and without payments under the EEG) is due in particular to the continued expansion of onshore wind capacity. Onshore wind recorded a year-on-year increase of 5.0 GW, solar energy 1.7 GW, and offshore wind 1.3 GW.

Compared with 2016, onshore wind generation significantly increased by 20.0 TWh or 30.1%, on account of the higher wind levels in 2017. The amount of electricity generated through solar recorded a slight year-on-year increase of 0.9 TWh or 2.7%. Offshore wind generation was also up, showing an increase of 5.3 TWh or 44%. Total renewable electricity generation was thus 24.6 TWh or 13.7% higher than in 2016. Renewable electricity generation was equivalent to 36% of gross electricity consumption (579.9 TWh) in 2017. Payments to renewable installation operators under the Renewable Energy Sources Act averaged 13.9 ct/kWh in 2017.

Since 2017 competitive auctions have been introduced to determine the level of payments for new renewable energy and combined heat and power (CHP) installations, and a total of 24 auctions have been held (six for solar photovoltaic installations, seven for onshore wind installations, two for offshore wind projects, three for CHP installations, two for innovative CHP systems and two for biomass plants). Additionally, in 2018, for the first time, two joint auctions combining onshore wind and solar installations were held, and two auctions were launched for innovative CHP systems.

Electricity supply interruptions

In 2017, the average interruption in supply per connected final consumer was 15.14 minutes and thus below the ten-year average from 2006 to 2016 of 15.59 minutes. The quality of supply thus remained at a consistently high level in 2017.

Redispatch and feed-in management

In 2017 the need for redispatching increased. The total reductions in feed-in of conventional electricity sources due to redispatching amounted to 10,200 GWh in 2017, while the increases in feed-in by market power plants and grid reserve power plants added up to 10,239 GWh (in total 20,439 GWh). The reductions in feed-in from power plants as a result of redispatching measures thus corresponded to 2.6% of total non-renewable generation fed into the grid. Cost for redispatching measures with market and grid reserve power plants went up to €901m in 2017. The increase in redispatching measures essentially occurred in the first quarter of 2017, when a combination of various circumstances put an exceptionally severe strain on electricity networks, despite low wind power feed-in. Upon the full commissioning of the "Thuringia power bridge" on 14 September 2017 redispatching measures went down again in the fourth quarter of 2017.

With a total of 5,518 GWh the amount of renewable energy curtailed as a result of feed-in management measures recorded a new high in 2017. The amount of electricity curtailed was up just over 47% year-on-year (3,743 GWh in 2016). This corresponds to 2.9% of the total amount of electricity generated[1] by renewable energy installations eligible for payments under the Renewable Energy Sources Act (including direct selling) compared with 2.3% in 2016. The total estimated claims from installation operators rose to €610m in 2017. One reason for the increase in feed-in management measures and related costs is the connection of new offshore wind farms in 2016 and 2017. This reflects the clear need for grid expansion in the Emsland to transport the electricity generated by the offshore wind farms.

Electricity network charges

Having been broadly stable in the period between 2013 and 2015, the network charges for household customers showed an increase in 2016 and 2017. In 2018 the average network charge for household customers went down again by 0.13 ct/kWh or just under 2% to 7.17 ct/kWh.

Wholesale electricity markets

The liquidity of the wholesale electricity markets in 2017 recorded a considerable decline. One reason for this was the introduction of congestion management at the German-Austrian border as of 1 October 2018, thus effectively splitting the joint German-Austrian market area (referred to as bidding zone split).[2] Market participants had a chance to prepare for this development at an early stage purchasing new products specifically launched by EEX for the German market area, so-called Phelix DE futures. By the end of 2017, the liquidity and trading volume had clearly shifted from Phelix DE/AT futures to Phelix DE futures.

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

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

Volumes in on-exchange futures trading and volumes traded via broker platforms decreased, while there were different trends regarding spot market trading volumes. The volume of day-ahead trading decreased slightly, while the volume of intraday trading increased by approximately 15%.

For the first time since 2011 average wholesale prices for electricity increased in 2017. Spot market prices were up about 18% year-on-year, and futures were quoted approximately 22% higher.. The volume of OTC clearing of Phelix DE/AT futures on EEX went down significantly in 2017.

Retail electricity markets

The retail markets are continuing to develop positively. The Bundeskartellamt assumes that there is no longer any single dominant undertaking in either of the two largest electricity retail markets. The cumulative market shares of the four largest undertakings showed a further year-on-year decrease, down to around 25% in the national market for supplying interval-metered customers and 33% in the national market for non interval metered customers on special contracts.

About 31% of all household customers are now served by a supplier other than their local default supplier, thus for the first time making this share exceed the share of default supply customers. In 2017, once again, more than 4.7m household customers switched supplier. There was also a continued increase in the number of undertakings operating in the market. Household customers can choose between an average of 124 different suppliers.

The supplier switching rate for non-household customers has been fairly constant since 2009. The rate for non household customers with an annual consumption of more than 10 MWh reached a new high of 13.0% in 2017, compared with 12.7% in 2016.

The average total price (excluding VAT and possible reductions) for industrial customers with an annual consumption of 24 GWh was 15.30 ct/kWh, up 0.40 ct/kWh on the previous year; the increase is mainly accounted for by the price components controlled by the supplier. The average total price (excluding VAT) for commercial customers with an annual consumption of 50 MWh in April 2018 was 21.56 ct/kWh, representing a decrease on the previous year of 0.14 ct/kWh.

As at 1 April 2018, the average price for household customers had remained broadly unchanged, amounting to 29.88 ct/kWh, compared with 29.86 ct/kWh in 2017. This average value is calculated by weighting the individual prices across all contract models according to their consumption for an annual consumption of between 2,500 kWh and 5,000 kWh, producing a reliable average for the electricity price for household customers. As at 1 April 2018 the price component controlled by the supplier (energy procurement, supply and margin) accounts for about 6.74 ct/kWh or 22.6% of the total price, and has thus increased for the first time since 2011. This increase can be related in particular to the increasing wholesale prices in 2017, which are now gradually passed on to household customers. By contrast, average network charges fell in 2018 for the first time since 2011 but still remain at a high level, accounting for 22.9% of the total price. The same applies to the renewable energy surcharge, which also decreased but still accounts for 22.7% of the total price. Together with the reduction of the surcharge payable under the CHP Act this is having a dampening effect on rising prices in 2018.

Electric heating

Electric heating prices were slightly higher than in 2017. The arithmetic mean of the gross total price for night storage heating customers as at 1 April 2018 was 21.08 ct/kWh, slightly up on the previous year's level of 20.94 ct/kWh. The arithmetic mean of the total price for heat pump electricity was 21.71 ct/kWh, slightly up on 2017. In general, prices for heat pump electricity are approximately 0.63 ct/kWh higher than for night storage heating.

There has been a steady increase in switching activity among electric heating customers, albeit at a low level, following many years with hardly any customers switching. This increase in the switching rate indicates a higher degree of competition. Yet at the same time, the switching rates are still far below those for household electricity and non-household customers. The supplier switching rate for 2017 was around 4%. There is a steady increase in the share of electricity provided for heating purposes and electric heating meter points provided by a supplier other than the local default supplier, now standing at around 12%.

Electricity imports and exports

Electricity exports again exceeded imports in 2017. The trading volume showed a total year-on-year increase of 15.2%. With an export balance of 55.8 TWh Germany is one of Europe’s large exporters of electricity.

Gas imports and exports

The volume of gas imported into Germany rose by some 35 TWh or around 2% from 1,641 TWh in 2016 to 1,676 TWh in 2017. Gas exports decreased in 2017. While the volume of gas exported was at 770.4 TWh in 2016, in 2017 it was at 743.5 TWh, down some 27 TWh or 3.5%.

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

Gas supply interruptions

In 2017, the average interruption in supply per connected final consumer was 0.99 minutes per year. The reliability of gas supply remains at a constantly high level.

Market area conversion

The conversion of German L-gas networks to H-gas started well in 2015 with the conversion of smaller network areas. Since 2017 larger network operators such as Westnetz, Avacon and wesernetz Bremen have also been undergoing the conversion process.

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 cumulative market share of the three largest storage facility operators stood at around 68.2% at the end of 2017, remaining the same as in the previous year.

On 31 December 2017 the total maximum usable volume of working gas in these storage facilities was 280.1 TWh. Of this, 132.22 TWh was accounted for by cavern storage, 125.86 TWh by pore storage facilities and 22.01 TWh by other storage facilities. As at 1 November 2017 the storage level of gas storage facilities was at over 87%.

Wholesale natural gas markets

Overall, the liquidity of the wholesale natural gas markets decreased significantly in 2017. The volume traded on the spot market rose by some 5% year-on-year, but the futures trading volume fell by about 34% to levels slightly below those of 2015. There was a decrease of about 20% in volumes of bilateral wholesale trading via broker platforms in 2017.

Unlike 2016, 2017 was marked by, in part, significantly higher wholesale gas prices. The various price indices (daily reference prices, cross-border prices, as calculated by the Federal Office for Economic Affairs and Export Control) show a year-on-year increase between 12% and 24%.

Retail gas markets

The levels of concentration in the two largest gas retail markets continue to be well below the statutory thresholds for presuming market dominance. In 2017, cumulative sales for the four largest companies to customers with standard load profile (SLP) were about 87 TWh and about 138 TWh for interval-metered customers. The cumulative market share of the four largest companies (CR4) in 2017 was around 23% for SLP customers (2016: 25%) and about 30% for interval-metered customers (2016: 28%).

The retail gas markets are continuing to develop positively. Over 1.5m household customers switched gas supplier in 2017; yet the number of customers switching gas supplier stagnated at the previous year's level or even recorded a slight decline.

After switching rates for non-household customers had remained virtually constant between 11% and 13% for several years, 2017 saw a decline to 8.9%. In 2017, total consumption affected by supplier switches was about 15% lower than in the previous year.

At 891,000, the total number of customers changing contract continued to develop positively in 2017. Overall, the percentage of household customers who have a contract with a supplier other than the local default supplier continues to decline, reaching 19% in 2017. There was also another significant increase in the number of undertakings operating in the market. Household customers can choose on average between 98 different suppliers. At the same time, the number of gas disconnections decreased. In 2017, a total of almost 38,000 customers were disconnected, representing a year-on-year decrease of around 1.5%.

Varying developments were recorded for gas prices for non-household (industrial and commercial) customers as at 1 April 2018 compared with the previous year. The arithmetic mean of the overall price (excluding VAT) for an annual consumption of 116 GWh ("industrial customer") of 2.82 ct/kWh is 0.13 ct/kWh or around 5% higher than the previous year's figure of 2.69 ct/kWh. By contrast, the arithmetic mean of the overall price (excluding VAT) for an annual consumption of 116 MWh ("commercial customer") of 4.40 ct/kWh is 0.1 ct/kWh or around 2% lower than last year's price.

Gas prices for household customers as at 1 April 2018 once again showed a year-on-year decrease, but it was not as marked as in previous years. One of the reasons for the fall in prices was the drop in procurement costs, reflected in the price component "energy procurement, supply and margin". The volume-weighted average across all groups of household customers with average consumption was down 1.3% or 0.08 ct/kWh to 6.07 ct/kWh (including VAT), compared with 2017. Taxes, levies and network charges make up around 50% of the total gas price in Germany.

A Developments in the electricity markets

1. Summary

1.1 Generation and security of supply

At 601.4 TWh, Germany's net electricity generation in 2017 corresponded to the 2016 level (601.4 TWh). Generation from non-renewable energy sources decreased by 24.7 TWh. There was a 6.3% year-on-year increase in net electricity generation from gas-fired power plants and of 2.5% from pumped storage stations, while net electricity generation from conventional sources declined. Nuclear generation was down 7.8 TWh or 9.9% on 2016. Generation by hard coal-fired power plants fell by 19.8 TWh or 19.2%. Generation by lignite-fired plants was 2.0 TWh or 1.4% lower.

After only a slight increase in renewable electricity generation in 2016, there was a substantial increase of 13.7% to a total of 204.8 TWh in 2017, compared with 180.2 TWh in 2016, corresponding to a share of 36% of gross electricity consumption.

The generation landscape was characterised in 2017 by a further increase in installed renewable energy capacity. Altogether, growth in renewable capacity amounted to 8.3 GW, compared with a year-on-year increase of 6.5 GW in 2016[3]. The highest growth in generating capacity was recorded for onshore wind (up 5.0 GW), offshore wind (up 1.3 GW) and solar energy (up 1.7 GW). Non-renewable generating capacity (nuclear, lignite, hard coal, natural gas, mineral oil products, pumped storage and other non-renewable energy sources) decreased in 2017 by 2.5 GW. Total (net) installed generating capacity increased to 217.6 GW at the end of 2017, with 105.1 GW of non-renewable and 112.5 GW of renewable capacity.

The total installed capacity of installations eligible for payments under the Renewable Energy Sources Act (EGG) in Germany stood at 107.8 GW at the end of 2017, compared with 99.5 GW a year earlier. This represents an increase of around 8.3 GW or 8.3%. A total of 187.4 TWh of electricity from renewable energy installations received payments in 2017, up 16.1% compared with 161.5 TWh in 2016. Due to the increase in electricity generation from EEG subsidised installations, payments under the Renewable Energy Sources rose to a total of €26.0bn, up 7% on 2016. In 2017, the average payable to installation operators under the Renewable Energy Sources Act[4] was 13.9 ct/kWh. In 2016, for the first time, the majority of the payments – 52.3% – were made to installation operators eligible for market premiums. This trend continued in 2017, with 43.3% of payments made under the feed-in tariff scheme and 56.7% as market premiums.

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

[3] The 2016 figure from the 2017 monitoring has been updated.

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

The auctions for solar photovoltaic installations have so far been marked by a high level of competition. Up to the June 2018 auction the average volume-weighted award price fell in each successive auction from 9.17/ ct/kWh to 4.59 ct/kWh, while it went slightly up again to 4.69 ct/kWh in the last auction.

The auctions held for onshore wind energy (together comprising a total volume of 2,800 MW) were significantly oversubscribed. Citizens' energy companies showed a particularly strong presence in these auctions. Unlike in the previous year's auctions, the results of the four auctions completed in 2018, without applying special rules to citizens' energy companies, were marked by reduced competitive intensity, higher award prices and far lower participation by citizens' energy companies. The second auction in May 2018 was, for the first time, slightly undersubscribed, while the last one in October was clearly undersubscribed, with the bids submitted covering only 59% of the volume offered. In the last three auctions in 2018 all the qualified bids were successful.

The lowest average volume-weighted award price of 3.82 ct/kWh was paid in the third auction, and the highest of 6.26 ct/kWh in the fourth and last auction in 2018.

In the auctions held in April 2017 and April 2018 to determine payments for offshore wind energy, ten bids for projects with a total capacity of 3,100 MW were accepted. The prices awarded ranged from 0.00 ct/kWh to 9.83 ct/kWh.

The auctions for new and existing biomass plants held in September 2017 and September 2018 were both undersubscribed, with the bids submitted covering 33% and 39%, respectively, of the volume offered. The average volume-weighted award price of all the bids accepted was 14.30 ct/kWh for the 2017 auction and 14.73 ct/kWh for the 2018 auction.

In April and October 2018, the Bundesnetzagentur conducted the first joint auctions for onshore wind energy and solar power installations. For the first auction in April 2018 some 54 bids were received, of which 18 were for onshore wind and 36 for solar power installations. All 32 bids accepted, totalling 210 MW, were for solar power installations only.

In 2017, the average interruption in supply per connected final consumer was 15.14 minutes and thus below the ten-year average from 2006 to 2016 of 15.59 minutes. The quality of supply thus remained at a consistently high level in 2017.

1.2 Cross-border trading

Electricity exports again exceeded imports in 2017. The trading volume showed a total year-on-year increase of 15.2%. Germany thus forms the hub for electricity exchange in Europe and plays a key role within the central interconnected system. The average available transmission capacity to neighbouring countries was 1.3% higher in 2017 than in 2016.

Total cross-border traded volumes in 2017 accounted for 90 TWh. With an export balance of 55.8 TWh Germany is one of Europe's large exporters of electricity, with exports amounting to €1,726m.

1.3 Networks

1.3.1 Grid expansion

Based on the third quarterly report for 2018, some 1,200 km of the total of about 1,800 km of power lines listed in the Power Grid Expansion Act (EnLAG) have been approved, with around 800 km of these – about 45% of the total – completed. The TSOs anticipate that some 70% of the line kilometres listed in the Act will be completed by 2020. So far, none of the underground cable pilot lines have been put into full operation. Operational testing is in progress for the first 380 kV underground cable pilot project in Raesfeld.

Alongside monitoring the projects in the Power Grid Expansion Act, the Bundesnetzagentur publishes quarterly updates on the status of the expansion projects listed in the Federal Requirements Plan Act (BBPlG). The projects currently listed in the Federal Requirements Plan Act as at the third quarter of 2018 comprise lines with a total length of about 5,900 km. According to the network development plan, around 3,050 km of these lines will serve to reinforce the system. The total length of the lines in Germany will largely depend on the route of the north-south corridors and will become apparent over the course of the procedure. In total, around 600 km have been approved and about 150 km have been completed. Thus the planning procedures that were initiated following the decision to build the DC lines using underground cables are on schedule for 2025.

1.3.2 Investments

In 2017, investments in and expenditure on network infrastructure by the network operators amounted to around €9,727m, compared with €10,418m in 2016 (both values under commercial law[5]). The investments and expenditure incurred by the distribution system operators (DSOs) in 2017 amounted to €6,629m, while the four German transmission system operators (TSOs) spent €3,096m. The TSOs' investments in new builds, upgrades and expansion projects fell slightly from €2,298m in 2016 to €1,972m in 2017, while the DSOs' investments in new builds, upgrades and expansion projects increased slightly from €1,812m in 2016 to €1,829m in 2017. At a total of €1,627m, the DSOs' investments in maintenance and renewal are considerably higher than those of the TSOs, totalling €213m in 2017. The investment time series were updated retrospectively to include TSOs' offshore investments up to 2008. There was a slight increase in the number of DSOs carrying out measures to enhance, reinforce or expand their networks as at 1 April 2018.

1.3.3 Network and system security and system stability

Redispatching measures serve to maintain network and system security. In 2017, the reductions in feed-in from conventional power plants as a result of redispatching measures corresponded to 2.6% of total non-renewable generation fed into the grid. In absolute terms, total reductions in feed-in amounted to 10,200 GWh, increases in feed-in from operational plants to 8,256 GWh and increases in feed-in due to the use of grid

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

reserve power plants to 2,129 GWh[6]. Overall, a total of 20,439 GWh[7] of reductions and increases in feed-in was requested for the relief of line congestion.

This reflects a considerable increase in the need for redispatching measures compared with previous years, which was mainly due to exceptional circumstances between the beginning of January and the beginning of February 2017. The severe strain on electricity networks during this period was the result of various factors, such as the unusual load flows in Germany, with large flows of electricity mainly to the south-west, the cold period throughout Europe in combination with high loads and low generation from wind and solar power installations, accompanied by the non-availability of power stations.

Throughout the year, network congestion increased significantly, primarily in the Emsland. Power lines in the Emsland running from Dörpen to Hanekenfähr are used in particular to transport electricity from offshore wind farms in the North Sea. The strain on the previously heavily congested Remptendorf-Redwitz network element, however, has eased since the full commissioning of the "Thuringia power bridge" network expansion project on 14 September 2017. Measured in time, congestion on the "Remptendorf-Redwitz" line went down to only 18 hours in the fourth quarter of 2017, compared with 945 hours a year earlier.

The high demand for redispatching in 2017 is also reflected in the TSOs' estimated costs of the relevant measures. According to these estimates, redispatching costs were up around €169m from €222.6m in 2016 to about €391.6m in 2017, with another €29.2m to be added for counter trading measures and another €479.9m for providing and using grid reserve power plants.

The amount of energy curtailed as a result of feed-in management measures, i.e. the curtailing of installations receiving payments under the EEG or the CHP Act, also recorded a new high in 2017, totalling 5,518 GWh. This reflects a year-on-year increase of just over 47%, compared with 3,743 GWh in 2016. This corresponds to 2.9% of the total amount of electricity generated[8] by renewable energy installations eligible for payments under the Renewable Energy Sources Act (including direct selling) compared with 2.3% in 2016. The amount of compensation claims paid to installation operators in 2017 was €574m, down around €69m on 2016 (€643m). The total estimated claims from installation operators, however, rose to €610m in 2017. The discrepancy between the figures is due to the fact that the compensation paid in 2017 does not reflect the compensation for energy curtailments in 2017. The compensation paid in 2017 may include amounts payable for curtailments in previous years and claims from 2017 may not be reflected properly, as the billing period does not correspond to the period when the measures were taken.

In 2017, as in previous years, feed-in management measures primarily involved onshore wind power plants, accounting for 80.8% of the total amount of curtailed energy, down from 93,5% in 2016. Offshore wind power plants, which were first affected by feed-in management measures in 2015, accounted for about 826 GW or 15% of the total amount of curtailed energy in 2017, up from around 32 GW or 0.9% in 2016.

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[6] This total value on the use of grid reserve power plants also includes test starts and test runs.

[7] This total value on the requests for using grid reserve power plants to manage congestion does not include test starts and test runs.

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

The main reason for the increased feed-in management measures in 2017 was the curtailment of offshore wind power plants in addition to the wind situation and the growth of renewable capacity. Given the increased need for feed-in management measures and assuming that there will be a further steady increase in renewables, the measures required for network optimisation, reinforcement and expansion must be implemented without delay. Once again, this applies to the networks in the Dörpen region, which are also affected by redispatching measures; as regards feed-in management measures, the substation level between high voltage and extra-high voltage in Schleswig-Holstein deserves particular consideration.

In 2017, a total of three distribution system operators took adjustment measures, resulting in feed-in adjustments of about 34.5 GWh.

In total, the costs for network and system security[9] amounted to about €1,510.7m in 2017, up around €369.4m on the 2015 peak of €1,141.3m.

1.3.4 Network charges

The volume-weighted network charges (including meter operation charges) for household customers went down by 0.13 ct/kWh or just under 2%.

- household customers, annual consumption 2,500-5,000 kWh: volume weighted 7.17 ct/kWh

One reason for the fall in average network charges in 2018 is the Network Charges Modernisation Act, which was adopted by the German Bundestag on 30 June 2017 and helps amend the mechanism of avoided network charges. The lower forecast data for avoided network charges are a first indicator of the Act's impact. Regardless of the implementation of the Network Charges Modernisation Act, the Bundesnetzagentur still sees a need to continue the reform of the avoided network charges regime to minimise misguided incentives and windfall profits.

For household customers the arithmetic mean charges are up on a year earlier[10]. The network charges (including meter operation charges) for commercial customers increased by 1% (2016: 6.19 ct/kWh) and those for industrial customers by 4% (2016: 2.26 ct/kWh). The charges as at 1 April 2018 for the three consumption groups were as follows:

- commercial customers, annual consumption 50 MWh: arithmetic mean 6.27 ct/kWh

- industrial customers, annual consumption 24 GWh, without a reduction under section 19(2) of the Electricity Network Charges Ordinance (StromNEV): arithmetic mean 2.36 ct/kWh

There are large regional differences in the network charges. A comparison of the network charges in Germany for the three consumption groups, based on all the DSOs' published price lists (charges excluding metering

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

[10] 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 three consumption groups.

operation), shows the following: The network charges for household customers range from 2.5 ct/kWh to 25.4 ct/kWh, with only very few customers paying this maximum charge. The range of network charges for commercial customers is similar to that for household customers, with charges ranging from 2.2 ct/kWh to 24.6 ct/kWh. The network charges for industrial customers (without possible reductions) range from around 0.6 ct/kWh to 5.8 ct/kWh.

1.4 System services

The net costs for system services in a broader sense increased by €518.2m from about €1,464.9m in 2016 to €1,983.1m in 2017. A large part of the costs is accounted for by the costs of reserving and using grid reserve power plants at around €479.9m (2016: €285.7m), national and cross-border redispatching at just under €291.6m (2016: €222.6m), the estimated claims for compensation for feed-in management measures at €609.9m (2016: €372.7m), procuring primary, secondary and tertiary control reserves at €145.5m (2016: €198.1m), and energy to compensate for losses at about €280.4m (2016: €304.8m).

The structure of the system service costs changed in 2017 from 2016. The total net costs for balancing energy fell by €52.6m. One reason for this fall is the further slight decrease in the volumes of the three types of balancing reserve procured. An increase of around €693m was mainly recorded for the costs for network and system security measures.

1.5 Wholesale

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

The liquidity of the wholesale electricity markets in 2017 recorded a considerable decline. One reason for this was the introduction of congestion management at the German-Austrian border as of 1 October 2018, thus effectively splitting the joint German-Austrian market area (referred to as bidding zone split).[11] Market participants had a chance to prepare for this development at an early stage purchasing new products specifically launched by EEX for the German market area, so-called Phelix DE futures. By the end of 2017, the liquidity and trading volume had clearly shifted from Phelix DE/AT futures to Phelix DE futures.

While in July the share of Phelix-DE accounted for only 24% of the total Phelix-DE and Phelix DE/AT futures, it exceeded Phelix-DE/AT between October and November. By December 2017 Phelix-DE had significantly gained in importance, accounting for as much as 62% of the total futures for Germany.

Volumes in on-exchange futures trading and volumes traded via broker platforms decreased, while there were different trends regarding spot market trading volumes. The volume of day-ahead trading on EPEX SPOT in

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

2017 was around 233 TWh, slightly down on the previous year's volume of 235 TWh, while the volume of intraday trading increased by approximately 15% to 47 TWh. The volume of day-ahead trading on EXAA remained stable at around 8 TWh in 2017. The on-exchange trading volumes of Phelix futures increased significantly again, following considerable growth in the previous years: volumes decreased in 2017 by 46% from 1,466 TWh to over 786 TWh.

For the first time since 2011 average spot market prices increased in 2017. The Phelix day base average on EPEX SPOT rose by about 18% from €28.98/MWh to €34.20/MWh. At €38.06/MWh, the Phelix day peak was also nearly 19% above the previous year's level of €32.01/MWh. The gap between the Phelix day base and the Phelix day peak was around €3.86/MWh in 2017; thus the day peak was some 11% above the day base.

The annual averages of the Phelix-DE/AT future prices rose again compared with a year earlier. At €32.38/MWh, the average Phelix base year future price was €5.81/MWh or around 22% higher than the previous year’s average price of €26.58/MWh. The price of the Phelix peak front year future averaged €40.51/MWh over the year. This was exactly €7/MWh or around 21% up on the figure from previous year's average of €33.51/MWh. The volume of OTC clearing of Phelix DE/AT futures on EEX went down significantly in 2017.

Since the introduction of the Phelix-DE future on 25 April 2017 the base year future as well as the peak year future prices have more or less adjusted to the level of the “old” Phelix-DE/AT, only showing a difference of around €0.05/MWh.

1.6 Retail

1.6.1 Contract structure and competition

On the retail market there was another increase in the number of electricity suppliers available to retail customers. In 2017, final consumers could choose on average between 143 suppliers in each network area (not taking account of corporate groups). The average number of suppliers for household customers was 124.

The number of household customers switching supplier has increased steadily since 2006. In 2017 the number of customers switching electricity supplier stabilised at a high level of around 4.7m, compared with 4.6m in 2016. On the whole, the switching rate for household customers was at 11.8%, slightly up from 11.4% in 2016, and the rate for non household customers with an annual consumption of more than 10 MWh stood at 13.0%, up from 12.7% in 2016. In addition, around 2.6m household customers switched contracts with the same supplier.

In 2017, a relative majority of household customers – 41.2% compared with 40.9% in 2016 – were on non-default contracts with their local default supplier. The percentage of household customers on default contracts stood at 27.6%, representing another year-on-year decrease from 30.6% in 2016. About 31% of all household customers are now served by a supplier other than their local default supplier compared with 28.6% in 2016, and this share is continuously growing. Overall, around 69% of all households are still served by their default supplier (under either default or other contracts). Thus the strong position that default suppliers still have in their respective service areas slightly weakened year-on-year.

1.6.2 Disconnections

There was a decrease in 2017 in the number of electricity customers whose supply was disconnected. The number of household customers whose supply was disconnected by the network operator at the local default supplier's request rose by 11,773 to 330,242. Additionally, 13,623 disconnections were carried out on behalf of a supplier other than the local default supplier. Based on information from the network operators, there was a total of 343,865 disconnections. Suppliers issued around 4.8m disconnection notices to household customers, which reflects a significant year-on-year increase. Of these, about 1.1m were subsequently passed on to the relevant network operator with a request for disconnection.

1.6.3 Price level

Data was collected from the suppliers operating in Germany on the prices for household customers as at 1 April 2018. The average price (including VAT) had remained broadly unchanged, amounting to 29.88 ct/kWh, compared with 29.86 ct/kWh in 2017. This average value is calculated by weighting the individual prices across all contract models according to their consumption for an annual consumption of between 2,500 kWh and 5,000 kWh, producing a reliable average for the electricity price of household customers.

In 2018 the price component controlled by the supplier (energy procurement, supply and margin) accounts for about 22.6% of the total price, and has thus increased for the first time since 2011. This increase can be related in particular to the increasing wholesale prices in 2017, which are now gradually passed on to household customers. By contrast, average network charges fell again in 2018 for the first time since 2011, but still remain at a high level accounting for 22.9% of the total price. The same applies to the renewable energy surcharge, which also decreased but still accounts for 22.7% of the total price. Together with the reduction of the surcharge payable under the CHP Act, this is having a dampening effect on rising prices in 2018.

The average price for household customers on default contracts with an annual consumption of between 2,500 kWh and 5,000 kWh increased by about 1.7% to 31.47 ct/kWh from 30.94 ct/kWh in 2017. The average price for non-default contracts with the default supplier remained largely constant, amounting to 29.63 ct/kWh, compared with 29.61 ct/kWh in 2017, while prices for customers on a contract with a supplier other than the local default supplier went down to 28.80 ct/kWh in 2018, from 29.12 ct/kWh in 2017.

As a rule, customers on default contracts can make savings by switching contract and even more by switching supplier, saving up to 1.84 ct/kWh and 2.67 ct/kWh respectively.[12] Household customers with an annual consumption of 3,500 kWh could consequently cut their energy costs by around €64 (change of contract) or €93 (change of supplier) per year. Special bonuses offered by suppliers, including one-off bonus payments, are an added incentive for customers to switch. One-off bonus payments for customers switching to special contracts with their local default supplier average €55, and those for customers switching to a non-default supplier €63.

Varying developments were recorded for electricity prices for non-household customers as at 1 April 2018 compared with the previous year. The average total price (excluding VAT and possible reductions) for industrial customers with an annual consumption of 24 GWh was 15.30 ct/kWh, up 0.40 ct/kWh on the

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

previous year; the increase is mainly accounted for by the price components controlled by the supplier. By contrast, the average total price (excluding VAT) for commercial customers with an annual consumption of 50 MWh was 21.56 ct/kWh, representing a decrease on the previous year of 0.14 ct/kWh.

1.6.4 Surcharges

Part of the price is due to surcharges, which make up around 25% of the total of the average price mentioned above. Network operators estimated that they would pass on nearly €26.08bn in surcharges to network users in 2018. In order of volume, surcharges include: the renewable energy surcharge (€23.8bn), the surcharge under section 19 of the Electricity Network Charges Ordinance (€1.07bn), the surcharge payable under the Combined Heat and Power Act (€0.97bn), the offshore liability surcharge as per section 17f of the Energy Industry Act (€0.19bn) and the interruptible loads surcharge (€0.05bn). The renewable energy surcharge thus continues to make up over 90% of total surcharges.

1.7 Digital metering

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

Since the beginning of 2017, the first modern metering systems have been available in the market and have been installed by the first metering operators on a large scale. It has still not been possible to start the rollout of smart metering systems in 2017, since no BSI-certified smart meter gateways were yet available in the market. However, in light of the statutory requirements set out in the Act and advances in metering technology, a large scale rollout of modern metering equipment and smart metering systems is expected in the coming years.

B Developments in the gas markets

1. Summary

1.1 Production, imports and exports, and storage

In 2017, natural gas production in Germany fell by 0.6bn m^3 to 7.2bn m^3 of gas (with calorific adjustment). This corresponds to a decline of 8.1% compared with the previous year. The decline in production is chiefly due to the increasing exhaustion of the large deposits and the resulting natural decline in output. The reserves-to-production ratio of proven and probable natural gas reserves, calculated on the basis of the previous year's production and reserves, was 8.0 years as at 1 January 2018 (2017: 8.1 years).

The total volume of natural gas imported into Germany in 2017 was 1,676 TWh, up 35 TWh or just over 2% on the previous year's figure of 1,641 TWh. Imports from Norway dropped by just over 9%, while imports from Russia through the Nord Stream pipeline rose by 16.6%.

In 2017, Germany exported a total of 743.5 TWh of natural gas, down 27 TWh or 3.5% on the previous year's figure of 770.4 TWh. About 50% of the natural gas exported by Germany went to the Czechia, which is an increase of 5.4% compared with 2016. Exports to Belgium and Poland rose sharply by 93.1% and 23.1% respectively, while there was a clear decrease in exports to Luxembourg (36.2%), the Netherlands (-27.5%) and Austria (-20.5%).

The total maximum usable volume of working gas in underground storage facilities as at 31 December 2017 was 280.1 TWh. Of this, 132.22 TWh was accounted for by cavern storage, 125.86 TWh by pore storage facilities and 22.01 TWh by other storage facilities.

The volume of short-term (up to the beginning of the gas year 2017/2018 on 1 October 2017) freely bookable working gas declined slightly, whereas the capacities bookable for 2019 increased. There was also an increase in the volume of long-term bookable working gas from 2020. Compared with the previous year, the volume of working gas that can be booked five years in advance declined slightly. Overall, customers are tending towards shorter-term bookings in the storage market.

On 1 October 2018, at the beginning of the 2018/2019 gas year, the total storage level of German storage facilities was around 80% compared with 85% in 2017. As at 1 November 2018 the storage level of these storage facilities was over 87%.

The market for the operation of underground natural gas storage facilities is still relatively highly concentrated, although concentration has eased over the past years. The cumulative market share of the three largest storage facility operators stood at around 68.2% at the end of 2017, remaining the same as in the previous year. The considerable decline in 2016 was largely due to reduced concentration in the storage market resulting from the takeover of VNG AG by EnBW AG.

1.2 Networks

1.2.1 Network expansion

On 1 April 2018, the transmission system operators (TSOs) submitted their draft gas NDP 2018-2028 to the Bundesnetzagentur. Essentially, the results of the gas NDP 2018-2028 confirm the measures set out in the gas NDP 2016-2026. In addition, the TSOs are proposing a further 41 expansion measures up to 2028. The TSOs' proposal includes the expansion of the gas transmission system by an additional 1,390 km and an increase in the capacity of compressor stations by around 499 MW. Investment costs have gone up significantly from €4.5bn in the gas NDP 2016-2026 to €7.0bn in the gas NDP 2018-2028.

This increase is mainly accounted for by the planned European Gas Pipeline Link (EUGAL), which will receive gas from the planned import pipeline Nord Stream 2 to transport it within Germany and to the Czech Republic. The planned pipeline will be 480 km long, running from Lubmin on the Baltic Sea to Deutschneudorf on the German-Czech border. Investment costs for only the EUGAL pipeline amount to around €2.3bn. If all the other expansion measures directly related to the EUGAL pipeline are included, such as connection to the existing network, the total cost of investment will be around €2.7bn. This adds up to an estimated €175m of annual capital cost to be paid by the TSOs Gascade, Fluxys D, Gasunie Deutschland and Ontras in the coming years. Shippers have already made long-term capacity bookings for the incremental capacity created by EUGAL and by other network expansion measures to transport gas from Nord Stream 2. According to the TSOs, these bookings will make an essential contribution to refinancing investments. The total volume of bookings received for incremental capacity related to Nord Stream 2 is equivalent to around €200m per year for the next few years. This does not yet take account of possible changes in the network charges and bookings of further available capacity.

Moreover, the connection of two planned power plants will result in a requirement for further network expansion measures. For the first time, the gas NDP now includes a liquefied natural gas (LNG) terminal at Brunsbüttel on the German coast, which, based on the information from the TSOs, will also create the need for network expansion.

1.2.2 Investments

In 2017, investments in and expenditure on network infrastructure by the 16 German TSOs amounted to €970m compared with €469.9m in 2016 (both values under commercial law).[13] Total investments of €1.49bn are planned for 2018, corresponding to a year-on-year increase of 53%. This relatively high fluctuation is due to investments in large-scale, one-off projects.

Investments of gas distribution system operators (DSOs) declined from €2,315m in 2015 to €1,031m in 2016. Service and maintenance expenses amounted to €1,084m in 2017, based on the data provided by the gas DSOs.

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

In the 2018 monitoring, around 645 gas DSOs reported total network infrastructure investments of €1,031m in new builds, upgrades and expansion (€623m) and in maintenance and renewal (€408m). For 2018, a total investment of €1,244m is foreseen.

1.2.3 Supply interruptions

As in previous years, the Bundesnetzagentur conducted a comprehensive survey of all gas supply interruptions throughout the Federal Republic of Germany. The System Average Interruption Duration Index (SAIDI) determined from the results of this survey reflects the average duration of supply disruptions experienced by a customer over a period of one year and was 0.99 minutes per year in 2017 compared with 1.03 minutes per year in 2016.

1.2.4 Network charges

The average volume-weighted network charge, including metering and meter operation charges, for default supply of household customers in consumption band II was 1.51 ct/kWh on 1 April 2018, slightly up on the previous year's level.

1.2.5 Network balance

The total quantity of gas provided from general supply networks in Germany slightly decreased by 5.6 TWh or just over 0.5% from 941.3 TWh in 2016 to 935.7 TWh in 2017. The quantity of gas supplied to household customers as defined in section 3(22) of the Energy Industry Act (EnWG) rose by just over 1% from 275.6 TWh in 2016 to 278.8 TWh. Gas supplies to gas-fired power stations with a nominal capacity of at least 10 MW increased slightly, reaching 98 TWh in 2017, up just over 4% on the previous year's volume of 94 TWh.

With regard to gas transmission networks, the quantity of gas procured directly from the market by large final consumers amounted to 80.7 TWh, which is equivalent to about 44% of the total quantity of gas supplied by the TSOs. The "large final consumers" referred to here are industrial customers and gas-fired power stations that do not follow a classic route via a supplier but instead approach the network operator as a shipper and pay the transport charges themselves. As regards gas distribution networks, the amount of gas procured without a conventional supplier contract amounted to 38 TWh, compared with 45.4 TWh in 2016, corresponding to a share of approximately 5% of the DSOs' total gas supplies.

1.2.6 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. Today, larger network operators such as Westnetz, Avacon and wesernetz Bremen have also started the conversion process.

Gastransport Nord, Gasunie Germany Transport Services, Nowega, Open Grid Europe and Thyssengas are TSOs directly affected by the market area conversion. In 2015, there was a total of 969 L-gas interconnection points that still had to be converted. This figure went down to 950 in 2016 and to 922 in 2017.

The planned conversions by the individual network operators tend to take place in months when less gas is consumed, thus from April to October. By 2023, a total of 2,982 conversions will be carried out for interval-metered customers and 1,695,250 for standard load profile (SLP) customers.

1.3 Wholesale

Liquid wholesale markets are vital to ensure well-functioning markets along the entire value chain in the natural gas sector, from the procurement of natural gas through to supplying end customers. The greater the variety of options for companies to procure gas for both the short and long term at the wholesale level, the less they are tied to a single supplier long-term. The Bundeskartellamt now defines the wholesale market for natural gas as a national market and no longer defines markets based on their respective network area.

The volume traded on the spot market rose again in 2017 to about 309 TWh compared with about 295 TWh in 2016. As in previous years, the focus of spot trading for both market areas in 2017 was on day-ahead contracts (NCG: 115.8 TWh, 2016: 128.5 TWh; GASPOOL: 69.3 TWh, 2016: 51.1 TWh). The futures trading volume fell from about 130 TWh in 2016 to about 86 TWh in 2017, corresponding to a decrease of some 34%. When viewing this decline, it must be taken into account that there had been an extraordinary increase in the futures trading volume between 2015 and 2016 from about 97 TWh to about 130 TWh.

In 2017, broker platforms reported having brokered natural gas transactions for delivery to Germany for an amount totalling 2,672 TWh (2015: 3,120 TWh), of which 1,120 TWh was for contracts with delivery in 2017 (delivery time of at least one week).

In contrast to 2016, wholesale gas prices in 2017 showed some significant increases.[14] In 2017, the (unweighted) annual average daily reference prices calculated by EEX amounted to €17.51/MWh for the NCG market area and €17.28/MWh for the GASPOOL market area, up 24% and 22% respectively. The (unweighted) average cross-border price, as calculated by the Federal Office for Economic Affairs and Export Control (BAFA), amounted to €16.98/MWh in 2017, up 12% from €15.23/MWh in 2016.

1.4 Retail

1.4.1 Contract structure and competition

An overall analysis of how household customers were supplied in 2017 in terms of volume shows that the majority of them, some 51% compared with 53% in 2016, were supplied by the local default supplier under a non-default contract and were supplied with 126.4 TWh of gas (2016: 128.3 TWh). Some 19% of household customers had a default supply contract and were supplied with 47.3 TWh of gas, compared with 22% and 52.8 TWh, respectively, in 2016. The percentage of household customers who had a contract with a supplier other than the local default supplier once again increased and was 30% (2016: 25.6%) for 75.5 TWh of gas (2016: 62.4 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 27% of the total volume delivered to these customers was supplied under a contract with the default supplier on non-default terms (2016: 29%) and about 73% was supplied under a contract with a legal entity other than the default supplier (2016: 71%). The figures show that default supply is declining and of only minor significance for the supply of non-household customers in the gas sector.

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[14] Influencing factors include the world market prices for oil and LNG, weather and temperatures, the renegotiation of long-term supply contracts on the European gas market, increasing trade at European gas trading points and gas storage capacities.

The total number of household customers changing contract was approximately 891,000. The volume of gas these customers were delivered was approximately 9.5 TWh. The resulting numbers-based and volume-based change of contract rates are 7.2% and 3.8%, respectively.

The number of household customers who switched supplier fell when compared with the previous year by about 4% (down 45,759 supplier switches) to 1,212,553 compared with 1,258,312 in 2016. The number of household customers who decided to immediately switch to a supplier other than the local default supplier when moving home has remained steady (2017: 264,111; 2016: 264,954).

When looking at 12.5m household customers (according to DSO figures), the resulting overall numbers-based supplier switching rate for household customers is 11.8%, down from 12.3% in 2016.

The total volume of gas supplied to customers who switched supplier (including those who switched when moving) fell in 2017 by 3.2 TWh or just under 9% to 34 TWh (2016: 37.2 TWh). Taking into account the slight rise in gas supplied to household customers by network operators in 2017, the volume-based switching rate fell to 12.2% from 13.5% in 2016.

The volume-based supplier switching rate of 12.2% is still above the numbers-based rate of 11.8% because high-consumption household customers exhibit a greater willingness to switch. At around 24,500 kWh, the calculated annual consumption of an average gas customer that switched supplier is above the national average of 20,000 kWh.

There was a strong rise in switching rates among non-household customers between 2006 and 2010. In the following years, from 2010 to 2016, the switching rates remained more or less steady between 11% and 13%, whereas in 2017 there was a clear fall in the switching rate to 8.9% from 11.1% in 2016. Total gas consumption of 88 TWh was affected by supplier switches in all customer categories (2016: 103 TWh in total). This represents a decline of 15 TWh or 15% compared with the previous year.

As in the 2017 Monitoring Report, the present report also deals with the concentration ratio (CR) of the four largest companies in the retail gas market, whereas up until 2016 only three had been considered. The cumulative sales for the four largest companies to customers with a standard load profile (SLP) was about 87 TWh in 2017, of which about 74 TWh was supplied under special contracts. Cumulative sales to interval-metered customers were about 138 TWh. The cumulative market share of the four largest companies (CR4) in 2017 was around 23% for SLP customers and about 30% for interval-metered customers compared with 25% and 28%, respectively, in 2016. Despite a rise in interval-metered customers, the aggregated market shares for both categories of customer remained clearly below the statutory thresholds for presuming market dominance. It must also be noted with respect to the interval-metered customers that the figure refers to the four largest companies, instead of to three companies as was the case up to 2016, and as such the CR4 figure has to be seen in this perspective.

Since market liberalisation and the creation of a legal basis for a well-functioning supplier switch, there has been a steady positive development in the number of active gas suppliers for all final consumers in the different network areas. This positive trend continued in 2017 as well. In 2017, more than 50 gas suppliers were operating in 93% of the network areas. Final consumers in over 56% of network areas had a choice of more than 100 gas suppliers. If viewed separately, the trend for household customers is similarly positive. In about 87% of network areas, household customers have a choice of 50 or more gas suppliers. More than 100 gas suppliers are operating in 40% of network areas. On average, final consumers in Germany can choose between 116 suppliers in their network area; household customers can, on average, choose between 98 suppliers (these figures do not take account of corporate groups).

1.4.2 Gas disconnections

In 2017 the number of disconnections carried out by DSOs on behalf of the local default supplier fell to 37,992 (2016: 38,576), which represents a drop in disconnections of about 600 or well over 1.5% when compared with the previous year. Additionally, 2,056 gas disconnections, up from 1,260 in 2016, were carried out on behalf of a supplier other than the local default supplier. In 2017 the DSOs re-connected the gas supply for about 29,029 (2016: 30,633) of the meters disconnected by DSOs on behalf of the local default supplier.

When compared with the previous year, this is about 1,600 meter points fewer. The decline in re-connected meter points is largely due to a general decrease in gas disconnections. In addition, supply was also restored to about 1,946 meter points (2016: 1,486) on behalf of gas suppliers other than the local default supplier.

Compared with the previous year, the number of disconnection notices issued by all gas suppliers of 1,124,435 was a considerable fall from 1,286,050 in 2016, down some 12.5%. The number of disconnection orders fell by 14.8% to 231,875, down from 272,135 in 2016.

According to the gas suppliers, 37,750 (2016: 38,004) disconnection notices (for customers on a default contract or a non-default contract with the default supplier) ended with an actual disconnection carried out by the network operator responsible. This signifies a decrease of 1,254 disconnections compared with the previous year. A comparison of the number of disconnection notices issued with the number of disconnections actually carried out clearly shows that over 3% of the notices issued actually resulted in a disconnection being carried out by the DSO. Furthermore, the gas suppliers stated that in 25,382 cases (2016: 26,707) they had disconnected customers with a default contract. The disconnection rate of 0.8% with respect to the total number of customers under a default contract was thus less than one percent on average. Disconnection of non-default customers was carried out in 12,368 cases compared with 12,297 disconnections in 2016. The disconnection rate for non-default customers was 0.2%.

1.4.3 Price level

As at 1 April 2018, retail prices for gas had again fallen slightly compared with 1 April 2017.

The average price for household customers across all three contract categories (ie default supply contract, non-default contract with the default supplier, and contract with a supplier other than the local default supplier) decreased by 1.3% to 6.07 ct/kWh (including VAT) as at 1 April 2018 (1 April 2017: 6.15 ct/kWh).

The gas price for default supply dropped 1.3% to 6.64 ct/kWh (including VAT) as at 1 April 2018. The gas price for non-default contracts with the default supplier fell only slightly by 0.2% and was 6.06 ct/kWh (including VAT) as at 1 April 2018. Likewise the gas price for a contract with a supplier other than the local default supplier fell by 1.2% to 5.71 ct/kWh (including VAT) as at 1 April 2018. Gas prices for consumers under contract with a supplier other than the local default supplier thus reached the lowest level they have been since the first survey on 1 April 2008.

With regard to the main component of the gas price for household customers in band II, which is the price component that can be controlled by the supplier: "energy procurement, supply and margin", it is notable that in 2018 this price component for customers with a supplier other than the local default supplier hit the lowest level since the survey started of 2.66 ct/kWh. Moreover, the price component "energy procurement, supply and margin" for default supply customers fell to 3.29 ct/kWh as at 1 April 2018. This price component was steady at 3.01 ct/kWh as at 1 April 2018 for customers with a non-default contract with their default supplier

Customers on default tariffs can make savings by switching tariff or supplier. The average household customer with gas consumption of 23,250 kWh could save an average of €135 a year as at 1 April 2018 by changing contract. The average potential saving for the year through changing supplier was €216.

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

Varying developments were recorded in 2017 for gas prices for non-household (industrial and commercial) customers compared with the previous year. The arithmetic mean of the overall price (excluding VAT) for an annual consumption of 116 GWh ("industrial customer") of 2.82 ct/kWh is 0.13 ct/kWh or around 5% higher than the previous year's figure of 2.69 ct/kWh. Components of the overall price that are not under the control of the supplier (in particular, network charges and levies) fell by a scant 1% compared with the previous year.

By contrast, the arithmetic mean of the overall price (excluding VAT) for an annual consumption of 116 MWh ("commercial customer") of 4.40 ct/kWh is 0.1 ct/kWh or around 2% lower than last year's price. The absolute level of the price components that are not controlled by the suppliers (in particular network charges and levies) has remained stable at 1.84 ct/kWh in a year-on-year comparison. By contrast, the residual price component controlled by the supplier decreased by 0.12 ct/kWh (from 2.67 ct/kWh in 2016 to 2.55 ct/kWh in 2017), thus by around 4%.

German household customers paid slightly more than the European average for gas, while non-household customers paid significantly more. The net gas price in the annual consumption range of 27.8 GWh to 278 GWh ("industrial customer") is 2.64 ct/kWh, which is at the upper end of the scale. The EU average is 2.40 ct/kWh. On a European average, the net price is subject to about 10% (0.24 ct/kWh) of non-refundable taxes and levies. In this regard, Germany reports a higher than average figure of about 15% (0.40 ct/kWh). Unlike the industrial customer sector, there are major differences in gas prices for household customers across Europe. The gas price for household customers in Germany (6.42 ct/kWh) is only slightly above the EU average (6.36 ct/kWh).

The prices for industrial customers (annual consumption 116 GWh) show significantly smaller differences in a European comparison than the prices for household customers do. The net gas price in the annual consumption range of 27.8 GWh to 278 GWh is 2.55 ct/kWh, which is at the upper end of the scale. The EU average is 2.31 ct/kWh. On a European average, the net price is subject to about 10% (0.21 ct/kWh) of non-refundable taxes and levies. In this regard, Germany has a higher than average figure of about 18% (0.40 ct/kWh).

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