Bundesnetzagentur Bundeskartellamt

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Report

Monitoring report 2015

Monitoring report 2015

in accordance with section 63(3) i. c. w. section 35 EnWG
and section 48(3) i. c. w. section 53(3) GWB
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Courtesy translation for your convenience

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German Energy Act section 63(3)
Reporting

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

German Competition Act section 53(3)
Activity report

(3) The Bundeskartellamt shall prepare a report on its monitoring activities under section 48(3) in agreement with the Bundesnetzagentur to the extent that aspects of regulation of the distribution networks are concerned, and shall transmit the report to the Bundesnetzagentur.

Foreword

The *Energiewende* is still setting the pace for the fast dynamic growth in the electricity and gas markets in Germany. This Monitoring Report documents and analyses the progress made so far. The Bundeskartellamt and the Bundesnetzagentur have continued to work closely together in collecting the data for the year and in preparing the report. The Bundeskartellamt focuses on the competitive aspects of the electricity and gas value added chains, whilst the Bundesnetzagentur directs its attention towards the network areas, security of supply and delivery to household customers. The active participation of the energy undertakings has made it possible to increase the market coverage and validity of the data collected since last year. In fact, the level of response achieved a degree of coverage of well over 90%, allowing us to speak of a full data survey of the market. The analysis of this data has produced a thorough, comprehensive and detailed picture of market developments – also within the context of long-term trends.

In 2014, the year under review, electricity generation was characterised by a decrease in generation from conventional sources accompanied by an increase in generation using renewables. The network expansion needed for this is still not managing to keep pace with the changes in the power generation landscape. In the 2014 year under review, the network operators had to take increased steps to safeguard network and system stability. The volume of unused energy as a result of feed-in management measures rose almost threefold from 555 GWh to 1,581 GWh. Compared to the prior year, the transmission system operators' (TSOs') redispatching measures, which are a means of intervening in generating schedules, had to increase by 6% to a total of 8,453 hours.

On the whole there have been further improvements in the competitive conditions on the electricity markets. One aspect of this improvement is that the largest electricity producers have seen a decline in their market power over the last few years. In addition, there is a lot of liquidity on the electricity wholesale markets, which is facilitating market entry. In response to the growing feed-in rates of energy from renewable sources, electricity can now be traded on the exchange at even shorter notice and at shorter intervals. Consequently, there is no longer any single dominant supplier in either of the two largest electricity retail markets. Following many years of hardly any customers switching, there was a significant increase in the number of night storage and electric heating customers who switched supplier in 2014. In other electricity supply areas, the rate of supplier switching among electricity customers was more or less the same as in the previous year. Electricity prices for final consumers as of 1 April 2015 showed a slight year-on-year decrease. This can be attributed not only to competition within the wholesale and retail trade but also to a fall in wholesale prices.

Germany's position as a natural gas transit country for Europe was strengthened even further with a rise in gas imports and exports from the prior year. The main sources of imports for Germany remain Russia and the Commonwealth of Independent States (CIS), Norway and the Netherlands. Whereas the main recipients of Germany's exports were the Czech Republic, Switzerland, Austria and France.

The 2014 year under review also gave rise to distinctly lower wholesale prices for gas. Import prices are now based mainly on exchange prices for natural gas rather than on oil prices as before. A liquid nationwide wholesale market for natural gas has since become established and there is also competition between the providers at national level in the major retail markets. As a result of a reduction in the price component that is affected by competition, gas prices for final customers fell slightly as of 1 April 2015.

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

Jochen Homann

Bundesnetzagentur für Elektrizität, Gas, Telekommunikation, Post und Eisenbahnen
President

Andreas Mundt

Bundeskartellamt

President

Key findings

Electricity generation and security of supply

In 2014, the year under review, electricity generation was characterised by a decrease in generation from conventional sources accompanied by an increase in generation using renewables. Overall, the net volume of electricity produced fell by 12.2 TWh from 593.5 TWh in 2013 to 581.3 TWh in 2014.

The market power of the largest electricity producers has decreased significantly over the last few years. In 2014 the cumulative share of the four largest electricity producers in the market for the first-time sale of electricity was around 67%. This is comparable with the previous year's figure and represents a decrease of 6 percentage points compared to 2010.

In 2014, the average interruption in supply per connected final consumer was 12.28 minutes. The level of electricity supply reliability was thus 99.998%.

Development of renewable energy

The net volume of electricity produced from renewable energy sources increased by 8.4 TWh to 154.8 TWh in 2014. The biggest growth was in onshore wind electricity generation with a volume of 55.9 TWh.

The installations register was launched. The idea behind the register it to enable expansion to be monitored and funding rates calculated on the basis of expansion and also to make it easier to integrate renewable energy.

Confirmation of the electricity network development plan 2024

The Bundesnetzagentur confirmed 63 of the total of 92 projects proposed by the transmission system operators (TSOs). These projects comprise some 3,050 km of lines that will be reinforced or optimised and around 2,750 km of new lines. The Bundesnetzagentur came to the conclusion in its assessment of corridor D that a line between Wolmirstedt and Isar/Landshut as the southern grid connection point would also be practicable.

Redispatch and feed-in management

The redispatch measures taken by the TSOs to manage current and voltage situations increased year on year by 6% to 8,453 hours; one reason for the increase was the slow progress in network expansion. Reductions through redispatch measures corresponded to 0.58% of total generation from installations not eligible for payments under the Renewable Energy Sources Act. The TSOs put their net costs for redispatch in 2014 at €186.7m.

The volume of unused energy as a result of feed-in management measures rose almost threefold from 555 GWh in 2013 to 1,581 GWh. This, however, is still just 1.16% of the total net volume of electricity produced by installations eligible for payments under the Renewable Energy Sources Act. The sum total of compensation payments increased by around 89% to some €83m. The first quarter of 2015 has already seen another increase in the volume of unused energy and hence the amount of compensation paid.

Electricity network charges

Network charges stabilised between 2013 and 2015. The network charge for household customers with a default contract was more or less the same as in the previous year (up 0.04 ct/kWh).

Wholesale electricity markets

In 2014 the wholesale electricity markets were marked once again by high liquidity. While there were further increases in the volumes traded in the spot and futures markets, there was a fall in the volume of trading via broker platforms.

There was a further decrease in the average wholesale prices in 2014. Average spot market prices fell by 13% year on year, whilst average futures were quoted 10% lower for the following year.

Retail electricity markets

The Bundeskartellamt assumes that there is no longer any single dominant supplier in either of the two largest electricity retail markets. The cumulative market share of the four largest undertakings in the national market for supplying interval metered customers was 33%, and 36% in the market for supplying non-interval metered customers under a special contract (above all household customers).

The supplier switching rate among electricity customers was more or less the same as in the previous year. The volume-based supplier switching rate for non-household customers in 2014 was around 11%, and 9% for household customers. Almost 3.8m household customers switched electricity supplier in 2014.

Electricity prices for final consumers as of 1 April 2015 showed a slight year on year decrease. This is due to a reduction in the price component that can be controlled by the supplier. As of 1 April 2015, the average price for household customers with an annual consumption of 3,500 kWh had fallen by 1.4% to 29.11 ct/kWh (including VAT) in a year on year comparison. Nevertheless, the electricity prices paid by household customers in Germany are the second highest in Europe after Denmark. Germany's high prices are caused by the above-average heavy burden of taxes, surcharges and levies, which account for around 52% of the prices.

There was a significant increase in the number of night storage and heat pump electricity customers who switched supplier in 2014, following many years with hardly any customers switching. The percentage of night storage and heat pump electricity customers served in 2014 by a supplier other than their local default supplier was more than 4%, twice as many as in the year before. The last two years have seen an increase in transparency for end customers and in the services available to these customers from national suppliers.

Electricity imports and exports

In 2014, as in the previous years, the volume of Germany's exports was considerably higher than that of its imports. Exports remained practically unchanged at 59.17 TWh in 2014 compared to 59.4 TWh in 2013. Overall, the German export balance rose from 32.49 TWh in 2013 to 34.52 TWh in 2014. The total balance reflects a decline in imports from 26.95 TWh to 24.66 TWh. Cross-border trade in electricity provides added value for the economy as a whole in all of the countries concerned. In Germany, the additional demand from other countries for German (renewable) electricity has an effect on the prices German electricity producers can achieve.

Gas imports and exports

There was a year on year increase in imports and exports. The volume of gas imported into Germany rose by some 16.5 TWh from 1,771.7 TWh to 1,788.2 TWh. There was also a rise in exports. The volume of gas exported increased from 725.8 TWh in 2013 to 852.9 TWh in 2014.

The main sources of imports remain Russia and the Commonwealth of Independent States (CIS), Norway and the Netherlands. The main recipients of Germany's exports were the Czech Republic, Switzerland, Austria and France.

Gas supply interruptions

In 2014 the average interruption in supply per connected final consumer (SAIDI), taking account of an accident at the Rhine-Main natural gas pipeline, was 16.8 minutes, although it cannot be said that there was a real deterioration in national security of supply. The SAIDI figure not including the accident would be 1.3 minutes and thus in line with the long-term average for gas supply interruptions. The level of gas supply reliability excluding the accident remained at 99.999%, and 99.996% including the accident.

Gas storage facilities

The market for the operation of underground natural gas storage facilities is relatively highly concentrated. The aggregate market share at the end of 2014 of the three largest storage facility operators was some 75%. There was an increase in the level of concentration in the year under review following several years of decreases.

Despite large differences in weather conditions and gas prices, there were adequate natural gas storage levels in the past winters.

Wholesale natural gas markets

There was a further increase in the liquidity of the wholesale markets in 2014, with significant growth at bilateral wholesale level. The on-exchange trading volumes even more than doubled.

The year under review was marked by a significant drop in wholesale gas prices. The various price indices showed a year on year decrease of between 15% and 22%.

Retail gas markets

The levels of concentration in the two largest gas retail markets are well below the statutory thresholds for presuming market dominance. The cumulative market share of the three largest undertakings in the market for supplying interval metered customers was 32%, and 22% in the market for supplying non-interval metered customers under a special contract (above all household customers).

The supplier switching rate among gas customers was more or less the same as in the previous year. The volume-based supplier switching rate for non-household customers in 2014 was around 12%, and 10% for household customers. More than 1m household customers switched gas supplier in 2014.

The slight downward trend in gas retail prices continued. There was a year on year decrease of about 0.1 ct/kWh in the prices for the individual household and non-household customer groups. The average price as of 1 April 2015 for household customers with an annual consumption of 23,269 kWh and a special contract with their default supplier was around 6.7 ct/kWh (including VAT). The average price as of 1 April 2015 for "industrial" customers with an annual consumption of 116 GWh was just under 3.5 ct/kWh (excluding VAT) and thus the lowest ever since data on gas prices was first collected for the monitoring reports.

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1. Summary

1.1 Generation and security of supply

In 2014, the year under review, power generation was characterised by further growth in capacity from renewables. Altogether, growth in renewables capacity amounted to 6.5 GW, and was thus comparable with that in 2013 (6.7 GW). Onshore wind and solar energy recorded the highest growth with increases of 4.0 GW and 1.9 GW respectively. The total (net) installed generating capacity thus rose to 196.2 GW as of 31 December 2014, of which 106.2 GW was accounted for by non-renewable and 90.0 GW by renewable energy sources.

Supply (including electricity imports) in 2014 amounted to 606 TWh (2013: 617.7 TWh). Demand for electricity in 2014 totalled 608 TWh (2013: 620.9 TWh).[1] Net electricity generation in Germany in 2014 came to 581.3 TWh (2013: 593.5 TWh). One particular reason for the reductions is the relatively mild winter in the period under review. The volume of electricity generated using non-renewable sources decreased by 4.6% compared to the previous year. Natural gas and hard coal power plants recorded the largest year on year decreases of 8.3 TWh (-14.3%) and 6.4 TWh (-5.5%) respectively. The volume of electricity generated using brown coal fell in 2014 by 4.2 TWh or 2.8%, marking the first decrease in a while in generation by brown coal power plants.

The market power of the largest electricity producers has decreased significantly over the last few years. Since 2009, electricity generating capacity in Germany and Europe has been higher than that needed to meet demand. An increasing proportion of the demand is being covered by electricity generated from renewable sources. Better options for importing electricity as a result of progressive market coupling could narrow the room to manoeuvre in the market for the first-time sale of electricity, while a decline in cross-border transmission capacity would have the opposite effect. The market for the first-time sale of electricity remains highly concentrated, however, with the four largest electricity producers having a cumulative market share of 67%. This is comparable with the previous year's figure and represents a decrease of 6 percentage points compared to 2010.

The net volume of electricity produced from renewable energy sources increased by 8.4 TWh or 5.7% from 146.4 TWh in 2013 to 154.8 TWh in 2014. The biggest growth was in onshore wind electricity generation, which rose by 5.1 TWh to 55.9 TWh. The volume of electricity generated by solar power was 33.0 TWh, a year on year increase of 3.4 TWh. The largest percentage increase was recorded by offshore wind energy with 60.2%, which was due to a doubling in the installed capacity in 2014 from 0.5 GW to 1.0 GW.

The total installed capacity of installations in Germany eligible for payments under the Renewable Energy Sources Act (EEG) was 85.3 GW as of 31 December 2014 (31 December 2013: around 78.8 GW). This represents an increase in 2014 of around 6.5 GW or 8.2%. Under the Renewable Energy Sources Act, a total of 136.1 TWh of electricity from renewable energy installations was financially supported. This was 11.2 TWh or 9.0% more

[1] The difference between the supply and demand figures is due to differences in data collection.

than in the previous year. The total sum paid to the renewable energy installation operators by the operators to whose networks the installations are connected was €21,374m, which represents a year on year increase of 8.8%. As in the past few years, the bulk of the payments – some 60% or €12,769m – went to installations receiving fixed feed-in tariffs. The share of the payments made for direct selling increased by 10 percentage points compared to the previous year.

The reliability of electricity supply has maintained a constant high level. In 2014, the average interruption in supply per connected final consumer (SAIDI) was 12.28 minutes. One of the main reasons for the improvement in the quality of supply in 2014 is the relatively small number of interruptions caused by atmospheric effects, which in turn is due to the fact that there were only few instances of extreme weather in 2014.

1.2 Cross-border trading

Germany remains the hub for electricity exchange within the central European interconnected system. The average available transmission capacity remained practically unchanged at 21,193 MW in 2014. Changes arose in export capacity: whilst capacity at the French border fell by 3.5%, capacity at the border to Sweden rose by 3.5% and at the border to Switzerland by as much as 13.4%. As regards import capacity, changes were most noticeable at the Polish and Czech border, where it rose by 8.0%, and at the Danish border and the Swedish border, where it fell by 11.6% and 7.1% respectively. The main reasons for the changes in capacity were technical outages and maintenance work carried out by the transmission system operators (TSOs).

Traded volumes in electricity exchange across Germany's network borders fell slightly by 2.9% from 86.4 TWh in 2013 to 83.8 TWh in 2014. This is due in particular to the decline in imports, while exports remained virtually unchanged. The net export surplus of traded electricity thus rose again from 32.5 TWh in 2013 to 34.5 TWh in 2014. In 2011, this figure was only 3.0 TWh. Overall, the traded export volume stood at approximately €1,901m and the import volume at about €840m. Average export revenues were €32.12 per MWh, whereas import costs averaged €34.05 per MWh.

1.3 Networks

Grid expansion

Taking into account the third quarterly report for 2015, 558 km or about 30% of the total 1,876 km of power lines planned under the Power Grid Expansion Act (EnLAG) have been completed. The TSOs anticipate that some 40% of the lines will be completed by 2016. So far, none of the underground cable pilot lines have been put into operation. The TSO Amprion is completing final construction work for the first 380-kV underground cable pilot project in Raesfeld.

The Bundesnetzagentur approved the fourth scenario framework in December 2014, providing the basis for the onshore and offshore network development plans 2025. The scenario framework took account both of the new conditions resulting from the Renewable Energy Sources Act Reform and of the federal government's climate change goals (reducing greenhouse gas emissions and increasing efficiency in the electricity sector).

The onshore network development plan 2024 was consulted on and assessed by the TSOs and the Bundesnetzagentur. Most of the projects listed in the Federal Requirements Plan were retained. However, the revised draft of the network development plan 2024 included some important changes to the first draft (such as a new form of regionalisation and changes in grid connection points). The Bundesnetzagentur received over 34,000 responses to its consultation. The Bundesnetzagentur confirmed 63 of a total of 92 projects proposed by the TSOs. These projects comprise some 3,050 km of lines that will be reinforced or optimised and around 2,750 km of new lines. The confirmed onshore network development plan 2024 therefore essentially reflects the Bundesnetzagentur's preliminary assessment findings published in February 2015. However, a further key conclusion from the Bundesnetzagentur's assessment of corridor D – initiated following the coalition talks held on 1 July 2015 – was that a line running from Wolmirstedt to Isar/Landshut as the southern grid connection point would also be practicable. The Bundesnetzagentur nonetheless held firm with its confirmation of the line between Wolmirstedt and Gundremmingen as it is restricted to the network-related aspects set out in legislation when assessing the necessity of projects for securing energy supply. It is up to the legislator to decide to what extent additional aspects can be taken into account or certain aspects weighted differently when defining the network expansion requirements in the Federal Requirements Plan Act. In this context the alternative route from Wolmirstedt to Isar/Landshut, including the additional work required to adapt the AC network between Ottenhofen and Oberbachern, can be seen as a viable alternative.

The Bundesnetzagentur also consulted on and assessed the offshore network development plan 2024 at the same time as the onshore plan. As a result of the Renewable Energy Sources Act Reform, the total installed capacity of offshore wind farms is expected to reach 9.7 GW in 2024, with 8.5 GW in the North Sea and 1.2 GW in the Baltic Sea. 7.1 GW of capacity in the North Sea is already accounted for by the "start network", with 1.4 GW still to be connected under the offshore plan. The "start network" in the Baltic Sea covers 1.1 GW, leaving just 0.1 GW of capacity to be connected under the plan. Since a system linking offshore wind farms in the North Sea has a transmission capacity of 900 MW, the Bundesnetzagentur has approved two systems to accommodate the 1.4 GW of capacity still required. The Bundesnetzagentur has approved one 500-MW system in the Baltic Sea to enable full connection of standard-size wind farms.

The following projects within the Bundesnetzagentur's responsibility have entered the federal sectoral planning stage:

- project no 11 in the Federal Requirements Plan Act: Bertikow – Pasewalk,

- corridor A south: project no 2 in the Federal Requirements Plan Act: Osterath – Philippsburg, known as "Ultranet".

In addition, an application for federal sectoral planning was made in December 2014 for the SuedLink project; the application is currently under revision by the project developer.

In 2014, investments in and expenditure on network infrastructure by the four German TSOs amounted to approximately €1,769m (2013: €1,335m). Investments in new builds, upgrades and expansion projects rose from €880m in 2013 to €1,248m in 2014. The investments and expenditure incurred by the distribution system operators (DSOs) rose from €5,778m in 2013 to €6,193m in 2014 after several years of decreases. The number of DSOs carrying out optimisation, reinforcement or expansion measures in their networks remained steady in the period under review.

In 2014, the TSOs took redispatch measures to manage current and voltage situations pursuant to section 13(1) of the Energy Act (EnWG) – adjusting feed-in from generating facilities to ensure network stability and security – over a total of 8,453 hours, an increase of 6% compared with 2013 (7,965 hours). In total, redispatch intervention measures were carried out on 330 days in 2014 (2013: 232). These measures, including balancing countermeasures, added up to a total of 5,197 GWh (sum of increases and decreases) (2013: 4,604 GWh). Reductions through redispatch measures corresponded to 0.58% of the total generation from installations not eligible for payments under the Renewable Energy Sources Act. The TSOs gave their net basic costs of system services for redispatch in 2014 as being €186.7m. The rulings issued by the Higher Regional Court of Düsseldorf on 28 April 2015 led the Bundesnetzagentur to revoke its determination on calculating compensation payments for redispatch measures. The court rulings may lead to retroactive changes in the redispatch costs incurred in the last few years. As in the previous years, the measures primarily affected the TenneT and 50Hertz control areas. The transmission lines around the Lehrte substation and the transmission line between the Remptendorf and Redwitz substations bore the largest loads.

In 2014, one TSO carried out an adjustment measure under section 13(2) of the Energy Act. In addition, eight DSOs took adjustment measures on a total of 265 days. The measures for conventional installations comprised a total volume of 5.8 GWh. The total volume of curtailed feed-in from renewable energy installations was 3 GWh. Three DSOs also took support measures under section 13(2) and (2a) and section 14(1c) of the Energy Act at the instigation of a TSO. These measures resulted in a reduction of about 2 GWh in electricity feed-in.

The volume of unused energy as a result of feed-in management measures under section 11 of the Renewable Energy Sources Act (2012) rose markedly in 2014 to 1,581 GWh and was thus almost three times higher than that in 2013 (555 GWh). This brings the proportion of unused energy in relation to the total amount of energy produced by installations eligible for payments under the Renewable Energy Sources Act to 1.16%. The sum total of compensation payments also increased significantly from €43.7m in 2013 to some €83m. In 2014, as in the previous years, feed-in management measures primarily involved wind power plants, which accounted for 77.3% of the total volume of unused energy (2013: 86.6%). The share of solar installations affected has risen and in 2014 reached 15.5% (2013: 11.8%). Every region in Germany is now affected by feed-in management measures although the majority of total unused energy is accounted for by the northern federal states.

Network charges have stabilised. The charges as of 1 April 2015 for the three defined customer groups based on consumption were as follows:

- household customers (default supply), annual consumption 3,500 kWh: 6.51 ct/kWh,
- "business customers", annual consumption 50 MWh: 5.77 ct/kWh.
- "industrial customers", annual consumption 24 GWh, without a reduction under section 19(2) of the Electricity Network Charges Ordinance (StromNEV): 2.12 ct/kWh.

System stability

The transmission system is typically subject to its greatest pressure during the winter months when, because of seasonal conditions and in particular in northern Germany, a large volume of electricity is fed in, causing high-volume flows. The TSOs have so far been concerned primarily with the problematic power flows from north to south, but the high-volume flows from west to east – from Germany to Poland – are now also creating problems in maintaining system security. This too, however, is due to the north-south imbalance between electricity generation and consumption, together with the high volume of electricity exported from

Germany to Austria. The TSOs require a sufficient level of redispatch potential through secured power plant capacity in southern Germany and in southern neighbouring countries to maintain secure operation of the grid in such critical circumstances. All active power plants connected to the grid are required to provide such capacity. TSOs may also use capacity from backup power stations – power plants in Germany and neighbouring countries which have already been closed or are due to close shortly – should capacity from active power plants not be available. Contracts have been concluded with plant operators from Austria, Italy, France and Switzerland. The reserve capacity requirements identified for 2014/2015 amounted to 3,636 MW. This total includes the additional reserve capacity needed because of the closure of Grafenrheinfeld power station earlier than originally planned before the end of 2015. Reserve capacity was provided on a total of seven days in the period under review. The reserve capacity requirements for 2015/2016 have been put at 7,515 MW. For the first time, the TSOs and the Bundesnetzagentur identified and confirmed a reserve capacity range – between 6,700 MW and 7,800 MW – before giving the final figure. This is because it is not possible to specify the precise reserve capacity until the TSOs know which plants they have actually been able to contract. The exact figure depends for instance on the location of the power stations.

The backup power stations include facilities in Germany that have been scheduled for temporary or final closure but rated by the TSOs as systemically relevant and hence prevented by the TSOs or the Bundesnetzagentur from being closed (section 13a of the Energy Act). By the beginning of November 2015 the Bundesnetzagentur had been notified of the planned shutdown of 69 facilities with a total net nominal capacity of 14,367.7 MW. In 2014, the Bundesnetzagentur approved the designation as systemically relevant of four facilities with a combined net nominal capacity of 1,022 MW. In 2015, the Bundesnetzagentur has so far approved the designation of two facilities with a total generation capacity of 1,037 MW. Overall, a total capacity of 3,847.1 MW was secured in Germany for potential redispatch.

Future plans for power plants – both new facilities and closures – are particularly relevant to supply security. Facilities with a combined capacity of 4,186 MW have been notified as scheduled for final shutdown up to 2019 (although in some cases the TSOs still need to check if the facilities can be rated as systemically relevant). The capacity of the facilities to be closed is 924 MW lower than the capacity of 5,110 MW of the plants to be constructed up to 2019 (including pumped storage power stations in Luxembourg and Austria). In contrast to the situation in Germany as a whole, there is a negative balance between new builds and planned closures in southern Germany. Facilities with a combined capacity of 2,944 MW have been notified as scheduled for final closure in the south of Germany up to 2019. Gundremmingen B and Philippsburg 2 nuclear power stations, which are due to shut down in 2017 and 2019 respectively, account for 2,686 MW of this total capacity alone. By contrast, the facilities under construction (including pumped storage stations in Luxembourg and Austria) have a combined capacity of just 621 MW. This results in a negative balance of 2,323 MW between new builds and closures in southern Germany up to 2019.

System services

The net costs of the TSOs' system services decreased slightly by €94m from €1,131m in 2013 to €1,037m in 2014. A large part of the total costs is accounted for by the costs for keeping reserves of balancing power – €437m compared to €594m in 2013 – and for energy to compensate for grid losses – €288m compared to €333m in 2013. The cost structure of the system services changed once again in 2014 from that of 2013. There was a fall in the total costs for balancing power of €157m, most notably because of the lower costs for secondary control and minute reserves (down €125m and €51m respectively). One reason for this is the slight decrease in the volume of these balancing reserves. By contrast, there was a small increase of €18m in the costs for primary control.

1.4 Wholesale

In 2014 the wholesale electricity markets were marked once again by high liquidity. Well-functioning wholesale markets are fundamental to competition in the electricity sector. Spot and futures markets are crucial for meeting suppliers' short and longer term electricity requirements. Adequate liquidity with sufficient volume on both the supply and the demand side improves opportunities for new suppliers to enter the market. Alongside bilateral, over-the-counter wholesale trade, power exchanges play a key role. They create a reliable trading forum and at the same time provide important price signals for market participants in other electricity sectors.

There was a further increase in the liquidity of the spot and futures markets. The volume of day-ahead trading on EPEX SPOT and EXAA increased from 254 TWh in 2013 to 269 TWh in 2014. The volume of intraday trading on EPEX SPOT grew by 30%. The volume of electricity futures contracts trading on EEX rose by 21% from 669 TWh to 812 TWh. By contrast, there was a fall of 17% in the volume of futures trading via broker platforms. In 2014 broker platforms brokered electricity futures contracts with a total volume of some 4,900 TWh.

There was a further decrease in the average wholesale prices in 2014. Average prices on the spot markets showed a year on year decrease of around 13%. The average daily price dispersion was smaller in a year on year comparison. Prices for electricity futures also fell in 2014. At €35.09 per MWh, the annual average Phelix Base Year Future price fell just over 10% from the previous year. The annual average Phelix Peak Year Future price was €44.40 per MWh and therefore half the all-time peak reached in 2008.

One key change in the year under review was the introduction of auctions for 15-minute contracts by both EPEX SPOT and EXAA. In December 2014 EPEX SPOT introduced an intraday auction for 15-minute contracts running separately from the auction for 60-minute contracts. Since September 2014 the EXAA day-ahead auction allows simultaneous trading for quarter hours and hours. In addition, EPEX SPOT reduced the minimum lead time for intraday trading. Since July 2015 trading for electricity contracts for the German control areas and within the Austrian control area is possible up to 30 minutes before delivery.

Adding 15-minute contracts to the trading options and reducing the lead times takes account in particular of the increase in the volume of electricity fed in from intermittent (renewable) sources. The sales volumes of the TSOs using the power exchanges primarily to market electricity from renewables once again fell in a year on year comparison. The percentage of electricity sold by the TSOs on EPEX SPOT has fallen from 38% in 2011 to 21% in 2014. This is a result of the increase in the volume of renewable electricity sold directly.

1.5 Retail

The number of electricity suppliers from whom retail customers can choose increased again. In 2014, final consumers could choose between an average of 106 suppliers in each network area (not taking account of corporate groups). The average number of suppliers for household customers was 91.

The number of household customers switching supplier has increased significantly since 2006. The data from the 2015 survey shows that a relative majority of household customers – 43.2% – have a special contract with their local default supplier (2013: 45%). The percentage of household customers with a default contract decreased again from 34.1% in 2013 to 32.8%. There was a further increase in the percentage of household customers who no longer have a contract with their default supplier: 24% of all household customers are now served by a company other than their local default supplier, compared to 20.9% in 2013. Overall, around 76% of all households are served by their default supplier (under either a default or a special contract). The strong position that default suppliers continue to have in their service areas therefore weakened further in the year under review.

By contrast, default suppliers played a relatively small role in serving non-household customers. Some 66% of the total volume of electricity delivered to interval metered customers in 2014 was supplied by a legal entity other than the local default supplier, while only around 34% was supplied under a special contract with the default supplier. Less than 1% of all interval metered customers have a default contract. The supplier switching rate for non-household customers in 2014 was about 11%. This rate has remained more or less steady since 2006.

The Bundeskartellamt assumes that there is no longer any single dominant supplier in either of the two largest electricity retail markets. The cumulative market share of the four largest undertakings in the national market for supplying interval metered customers was 33%, and 36% in the national market for supplying non-interval metered customers under a special contract (above all household customers, excluding night storage and heat pump electricity customers). These figures are considerably lower than the statutory thresholds for presuming market dominance.

The number of household customers whose supply was disconnected at their default supplier's request was more or less the same as in the previous year. Overall, suppliers issued around 6.3m disconnection notices to household customers with default contracts. Of these, 1.4m were subsequently passed on to the relevant network operator for disconnection. Ultimately only 351,802 customers were actually disconnected at the default suppliers' request. These figures are based on the data provided by 739 DSOs and 887 suppliers. For the first time data was also collected on the use – at the default suppliers' request – of prepay systems such as pay as you go meters using cash or smart cards. In total, around 17,300 prepay systems were installed in 2014.

Electricity prices for non-household customers as of 1 April 2015 showed a slight year on year decrease. This is due to a reduction in the price component that can be controlled by the supplier. The individual price for industrial customers depends to a large extent on special statutory regulations enabling certain price components to be reduced. These regulations aim primarily to reduce prices for undertakings with a high electricity consumption. The average price as of 1 April 2015 for customers that cannot claim any incentives and that have an annual consumption of 24 GWh was around 14.8 ct/kWh (excluding VAT), of which about 10.6 ct/kWh was accounted for by surcharges, taxes, network charges and levies. This would be higher than the European average. In cases where industrial customers qualify for the statutory incentive scheme, the state-controlled surcharges, taxes, network charges and levies could be cut from 10.6 ct/kWh to below 1 ct/kWh. This would then result in electricity prices for industrial customers that are lower than the European average. The average electricity price as of 1 April 2015 for non-household customers with an annual consumption of 50 MWh was around 21.5 ct/kWh (excluding VAT).

Following large increases in the past few years the prices for household customers showed a slight decrease in the period under review. As of 1 April 2015, the average price for household customers with a default contract and an annual consumption of 3,500 kWh had fallen by 1.4% to 30.08 ct/kWh (including VAT) in a year on year comparison. Prices for the two other customer groups – those with a special contract with their default supplier or a contract with a supplier other than their local default supplier – also decreased slightly. Electricity prices for customers with a special contract with their default supplier and an annual consumption of 3,500 kWh averaged 28.96 ct/kWh and for those with a contract with a supplier other than the local default supplier were an average 27.85 ct/kWh. The volume-weighted average across all three groups was 29.11 ct/kWh (including VAT) as of 1 April 2015. In a European comparison only Denmark had higher electricity prices than Germany. Germany's high prices are caused by a heavy burden of surcharges, taxes and levies. The state-controlled price components remain stable despite the increase in the surcharges payable under the Combined Heat and Power Act (KWKG) and section 19 of the Electricity Network Charges Ordinance, thanks to a decrease in the surcharges payable under the Renewable Energy Sources Act and for interruptible loads and to a refund of the offshore liability surcharge. The total share of the state-controlled price components (taxes, levies, surcharges and network charges) amounts to about 74%. The competitive component of the electricity price found in "energy procurement, supply, other costs and margin" now comprises only about 26% of the average total price.

As of 1 April 2015, there was a reduction of around 4% in the "energy procurement, supply, other costs and margin" component of the price, leading to a dampening effect on total prices. This component has again fallen in all price categories for household customers. The decrease could be related in particular to the reduction in wholesale prices.

As a rule, customers can save additional costs from a default contract by switching contract and even more by switching supplier. Special bonuses offered by suppliers are an added incentive for customers to switch supplier.

There was a significant increase in the number of night storage and heat pump electricity customers who switched supplier, following many years with hardly any customers switching. The last two years have seen an increase in transparency for end customers and in the services offered by national suppliers. In 2014 over 2% of these customers switched supplier. This brings the percentage of customers served in 2014 by a supplier other than their local default supplier to more than 4%, twice as many as in the year before. Electricity prices for these customers were more or less the same as in the previous year. The average price as of 1 April 2015 for night storage electricity customers with an annual consumption of 7,500 kWh was around 20.4 ct/kWh, and 21.4 ct/kWh for heat pump electricity customers.

2. Market overview

Network structure figures 2014

	TSOs	DSOs	Total
Network operators (number)	4	813	817
Total circuit length (km)	34,612	1,772,400	1,807,012
Extra high voltage	34,388	349	34,737
High voltage	224	96,149	96,373
Medium voltage	0	511,591	511,591
Low voltage	0	1,164,311	1,164,311
Total final customers (meter points)	565	50,087,805	50,088,370
Industrial, business and other non-household customers		3,169,102	3,169,102
Household customers		46,918,703	46,918,703

Table 1: Network structure figures 2014

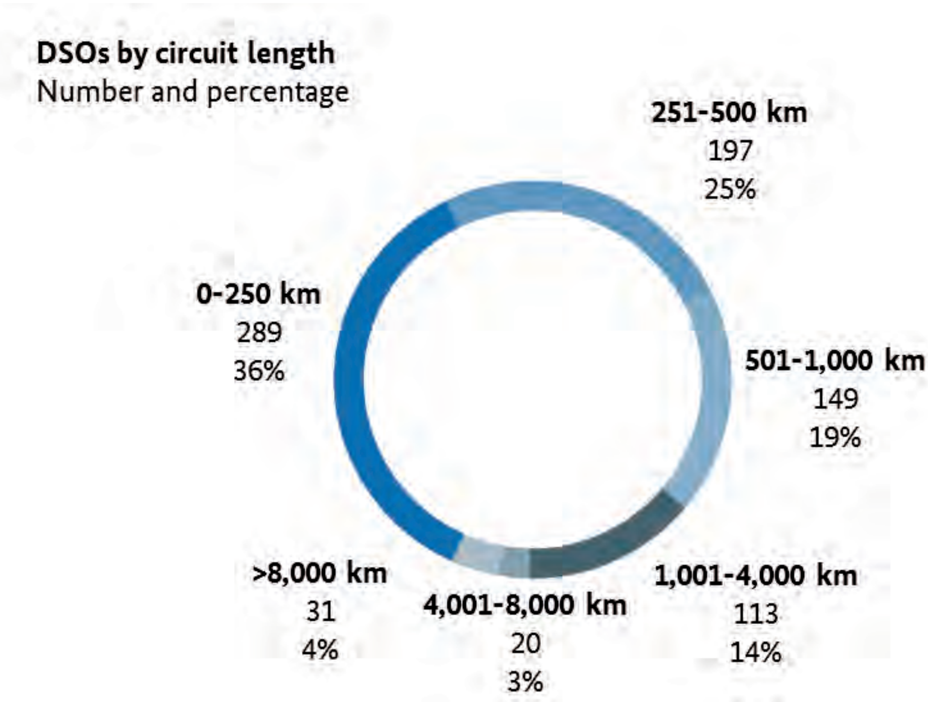

Figure 1: Distribution system operators by circuit length

Market and network balance 2014

	TSOs	DSOs	Total
Total net nominal generation capacity (GW) as of 31 December 2014			196.2
Facilities using non-renewable energy sources			106.2
Facilities using renewable energy sources			90.0
Generation facilities eligible for payments under the RES Act			85.3
Total net generation (TWh) 2014 (including electricity not fed into general supply networks)			581.3
From facilities using non-renewable energy sources			426.5
From facilities using renewable energy sources			154.8
Facilities eligible for payments under the RES Act			136.1
Net amount of electricity not fed into general supply networks (TWh) in 2014[1]			27.1
Losses (TWh)	6.4	17.5 [2]	23.9
Extra high voltage	5.1	0.0	5.1
High voltage (including EHV/HV)	1.3	3.3	4.6
Medium voltage (including HV/MV)	0.0	5.6	5.6
Low voltage (including MV/LV)	0.0	8.6	8.6
Cross-border trading (TWh) (implemented exchange schedules)			83.8
Imports			24.7
Exports			59.2
Consumption (in TWh)[3]	37.2	460.6	497.8
Industrial, business and other non-household customers	28.6	338.7	367.3
Household customers	0.0	120.2	120.2
Pumped storage	8.6	1.7	10.3

[1] Own use by industrial, business and domestic users, excluding consumption by Deutsche Bahn AG for traction purposes
[2] The figure for distribution losses in the previous year (2013) had to be subsequently adjusted from 19.9 to 18.0 TWh
[3] Including consumption by Deutsche Bahn AG for traction purposes

Table 2: Market and network balance 2014

The market and network balance provides an overview of supply and demand in the German electricity grid in 2014. Total electricity supply was 606 TWh, comprising the net total of electricity generated of 581.3 TWh (including 9.5 TWh from pumped storage) and imports amounting to 24.7 TWh. Total electricity consumption from general supply networks was 497.8 TWh, comprising 487.5 TWh for final consumers and 10.3 TWh for pumped storage stations. Pumped storage stations generally consume more than they generate because of the electricity used for generation. The net total of electricity generated but not fed into general supply networks (industrial, business and domestic own use) was 27.1 TWh. Distribution and transmission losses amounted to 23.9 TWh and exports 59.2 TWh. The sum of the individual entries for demand is 608.0 TWh. The statistical difference between this and the total supply of 606.0 TWh is 2.0 TWh or 0.3%.

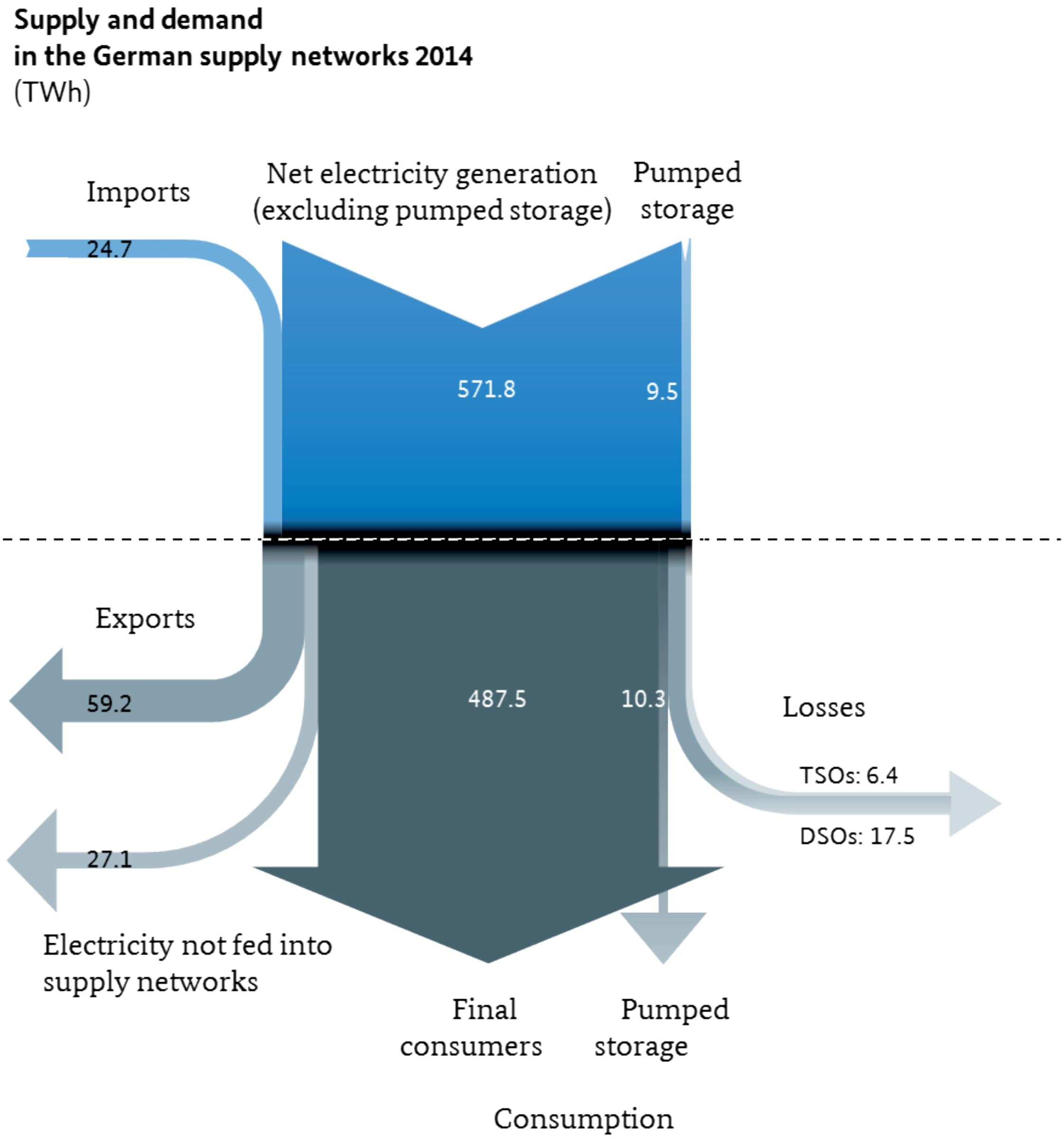

Figure 2: Supply and demand in the German supply networks 2014

The four German TSOs took part in the Bundesnetzagentur's 2015 monitoring survey. The TSOs' total circuit length (overhead lines and underground cables) was 34,612 km as of 31 December 2014 (see Table 1 on page 27). The total number of meter points in the four TSOs' network areas, excluding virtual meter points as defined in the Metering Code 2006, was 565. All of the meter points were for interval metered customers. Total consumption of the 157 final consumers connected to the TSOs' networks was 28.6 TWh as of 31 December 2014, down around 2 TWh on the previous year.

As of 3 August 2015 a total of 880 electricity DSOs were registered with the Bundesnetzagentur, 813 of whom took part in the 2015 survey. According to the data provided by the 813 DSOs, total consumption of the DSOs' 49,577,896 final consumers in 2014 was 458.9 TWh, down 9.4 TWh on a year earlier.

The DSOs' total circuit length (lines and cables) at all network levels was 1,772,400 km as of 31 December 2014. The total number of meter points supplied in the DSOs' network areas was 50,087,805, including 367,867 meter points for interval metered customers and 46,918,703 meter points for household customers as defined in section 3 para 22 of the Energy Act.

Number of TSOs and DSOs in Germany

	2007	2008	2009	2010	2011	2012	2013	2014	2015
TSOs	4	4	4	4	4	4	4	4	4
Total DSOs	877	855	862	866	869	883	883	884	880
DSOs with fewer than 100,000 connected customers	799	779	787	790	793	807	812	812	803

Table 3: Number of TSOs and DSOs in Germany 2007 to 2015

The majority of DSOs (635 or 80%) have networks with a short to medium circuit length (lines and cables) of up to 1,000 km. 164 DSOs have networks with a total circuit length of more than 1,000 km. Figure 1 on page 27 shows a breakdown of DSOs by circuit length.

The following table shows the consumption of electricity in 2014 by final consumers in the network areas of the TSOs and DSOs surveyed.

Final consumption by customer category

Category	TSOs (TWh)	DSOs (TWh)	TSOs + DSOs (TWh)	Percentage (%)
≤10 MWh/year	0	120.2	120.2	24.7
10 MWh/year - 2 GWh/year	0.1	124.7	124.8	25.6
>2 GWh/year	28.5	214.0	242.6	49.8
Total	28.6	458.9	487.5	100.0

Table 4: Final consumption by customer category based on data from DSOs and TSOs[2]

Overall, final electricity consumption in Germany, based on consumption at meter points in general supply networks, was down around 11.5 TWh or 2.4% on a year earlier.

Although the number of non-household customers with an annual consumption of more than 2 GWh is relatively small, these customers account for about half of the total electricity consumption in Germany. Consumption by these large consumers was about 1% up on the previous year. Smaller non-household customers (annual consumption >10 MWh and ≤2 GWh) accounted for 25.6% of total consumption in 2014, down nearly 7% on a year earlier. The largest customer group in terms of numbers comprises final consumers with an annual consumption of ≤10 MWh and almost entirely household customers. This group accounted for about 24.7% of total consumption in 2014, down nearly 5% on 2013.

There were no significant changes in the DSOs' structure, which remained primarily regional. As in the previous year, more than three quarters of the DSOs surveyed supply up to 30,000 meter points, while around 10% of all DSOs supply more than 100,000 meter points. The latter supply about 77% (38.2m) of all meter points with about 74% (341 TWh) of the total electricity consumed. The following chart shows a breakdown of DSOs by the number of meter points supplied.

[2] Figures may not sum exactly owing to rounding.

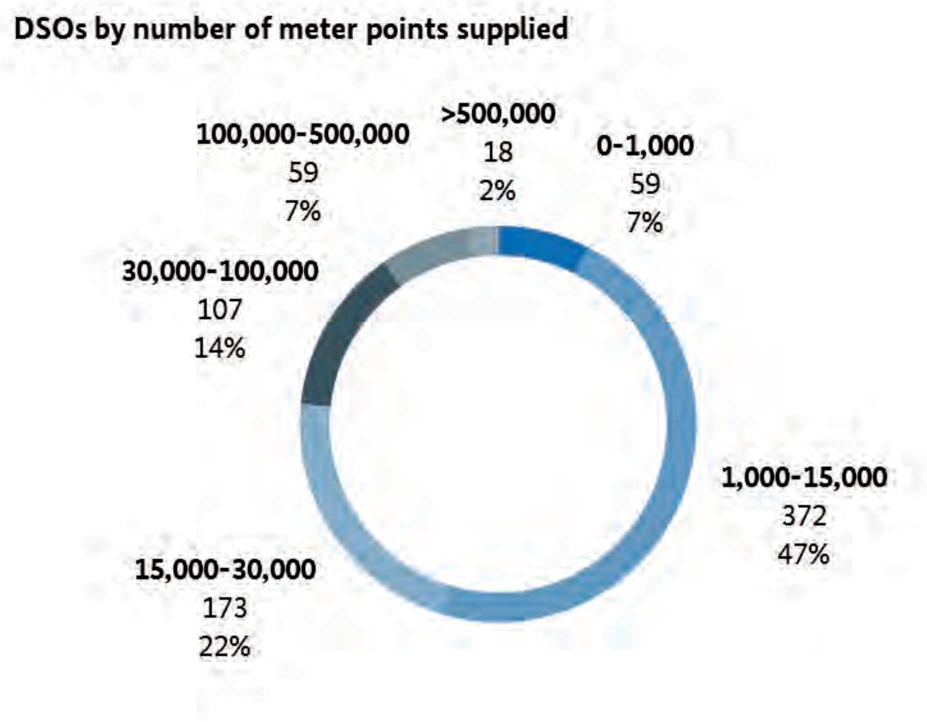

Figure 3: DSOs by number of meter points supplied

3. Market concentration

The degree of market concentration is a good indicator of the intensity of competition. Market shares are generally a good reference point for estimating market power because they represent (for the period of reference) the extent to which demand in the relevant market was actually satisfied by a company.[3] For the purpose of energy monitoring, however, an [4]extensive analysis of market power has not yet been required. Such an analysis would include a residual supply analysis with regard to electricity generation.[5]

There are typically two ways to represent the market share distribution, i.e. the market concentration: One is the Herfindahl-Hirschman Index or the sum of the market shares of the three, four or five competitors with the largest market shares ("concentration ratios", CR3 - CR4 - CR5). The larger the market share covered by only a few competitors, the higher the market concentration. In view of the (historically evolved) structure of the electricity markets, the following analysis uses the market shares of the four strongest suppliers as a point of reference to measure market concentration.

The report examines the market concentration on the economically significant market for the first-time sale of electricity (generation of electricity for further resale) and on the two largest retail markets for electricity (sales to end consumers). The market shares on the retail markets are estimated with the help of the so-called

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[3] Cf. Bundeskartellamt, Guidance on substantive merger control, para. 25.

[4] The Federal Government is considering introducing a regular report on market power in electricity generation. Cf. Federal Ministry for Economic Affairs and Energy, White Paper "An Electricity Market for Germany's Energy Transition", July 2015, p. 61.

[5] Cf. Bundeskartellamt, Sector Inquiry Electricity Generation and Wholesale Markets, 2011, p.96 ff (available only in German).

"dominance method". The market shares on the market for the first-time sale of electricity are calculated on the basis of competition law principles, which renders more accurate results (the following box explains the differences between the two calculation methods).

Calculation of (group) market shares under competition law vs. calculation of market shares with the "dominance method"

For the calculation of market shares it must be defined which companies (legal persons) are to be considered as affiliated companies (and consequently as a corporate group). This step is necessary because it has to be assumed that there is no (substantial) competition between the individual companies of a group.

Competition law uses the concept of "affiliated companies" (Section 36 (2) GWB). The concept focuses on whether there is a control relationship between the companies. The turnover or sales quantities of each controlled company are fully attributed to the company group; the sales quantities of a company that is not controlled are not added to the company group's sales quantities (not even in parts). A typical example of a control relationship is a scenario where the majority of the voting rights in an affiliated company are held by another company. There are also other, less typical forms of control, for example through personal links between the companies or an agreement to confer control. If several companies act together in such a way that they can jointly exercise a controlling influence over another company, (e.g. by way of a partnership or consortium agreement), each of them is regarded as controlling. Investigating and assessing which companies belong to a certain group under these principles can sometimes be rather time-consuming.

For this reason, in energy monitoring group membership is predominantly assessed by applying the considerably simpler "dominance method". This method exclusively focuses on whether one shareholder/company holds at least 50 % of the shares in a company. If a shareholder holds more than 50 % of the shares in a company, that company's sales quantities are attributed in full to the shareholder. If two shareholders each hold 50 % of the shares in a company, they each are attributed 50 % of the sales quantities. Where there is only one shareholder holding 50 % of the shares while all other shareholders hold shares of under 50 %, half of the sales quantities are attributed to the largest shareholder; the other half is not attributed to any of the remaining shareholders. If all shareholders hold shares of below 50 %, the sales quantities of the company are not attributed to any of them (in this case the company is a "controlling company" itself).

In the case of majority participations, both calculation methods usually render the same results. However, a controlling relationship can also occur under a minority participation. Such a case would not be covered by the dominance method. A calculation of market shares under the dominance method therefore tends to render results where the market shares of the strongest company groups are too low. This applies in particular if there are strong joint ventures active in the market.

3.1 Electricity generation

The Bundeskartellamt defines one relevant product market for the first-time sale of electricity (first level of supply). In its case practice the Bundeskartellamt has recently applied the following definition criteria for the calculation of market shares:[6]

The market shares are assessed according to feed-in quantities (not capacities). Electricity which is remunerated subject to the fixed remuneration system under the Renewal Energy Sources Act (EEG) or optional direct marketing was recently included in the residual supply analysis but not in the calculation of the market shares on the market for the first-time sale of electricity.[7] Electricity from renewable energy resources is generated and fed in independently of the demand situation and electricity wholesale prices. Renewable electricity plant operators are not exposed to competition from the other ("conventional") electricity suppliers. In the case of drawing rights, the corresponding amounts or capacities are attributed not to the power plant owner but to the owner of the drawing rights, provided he decides on the use of the power plant and bears the risks and rewards of marketing the electricity.[8] Only those volumes of electricity will be considered that are fed into the general supply grid. In other words electricity fed into closed distribution networks, traction current and electricity for own consumption do not belong to the market for the first-time sale of electricity. The Bundeskartellamt defines the geographic market as a joint market for Germany and Austria. The main reasons for this are that there are no network bottlenecks at the interconnections between the two countries and that there is a common price zone for German-Austrian electricity wholesale trading. These conditions do not exist in any other neighbouring country of Germany.[9]

As in the previous year, data on the electricity capacities and volumes generated by the four strongest companies (EnBW, E.ON, RWE and Vattenfall) was additionally collected for this year's Monitoring Report based on these definitions. Data on the overall market was derived from results from a survey of producers and network operators undertaken as part of the energy monitoring activities. In addition, the Austrian energy regulator E-Control has provided aggregate data for Austria.

The results of the survey are illustrated in the following table, which also includes data from the previous year collected on the same basis for comparison:

[6] Cf. Bundeskartellamt, decision of 8 December 2011, file reference B8-94/11, RWE/Stadtwerke Unna, para. 22 ff.

[7] Cf. Bundeskartellamt, Sector Inquiry Electricity Generation and Wholesale Markets, p.73 f. (available only in German)

[8] Cf. Bundeskartellamt, Sector Inquiry Electricity Generation and Wholesale Markets, p.93 f. (available only in German)

[9] Cf. Bundeskartellamt, Sector Inquiry Electricity Generation and Wholesale Markets, p.81 ff. (available only in German)

Electricity volumes generated by the four largest German electricity producers based on the definition of the market for the first-time sale of electricity

	Germany + Austria 2013		Germany + Austria 2014		Germany 2013		Germany 2014	
	TWh	market share	TWh	market share	TWh	market share	TWh	market share
RWE	138.9	29%	135.5	30%	135.5	32%	131.9	32%
Vattenfall	77.1	16%	74.1	16%	77.1	18%	74.1	18%
EnBW[1]	50.6	11%	49.8	11%	50.6	12%	49.8	12%
E.ON	51.7	11%	43.9	10%	51.3	12%	43.6	11%
CR 4		**67%**		**67%**		**74%**		**73%**
Other companies		33%		33%		26%		27%
Total net electricity generation	475.6	100%	452.7	100%	427.8	100%	408.4	100%

Data rounded up. [1] Data of EnBW include directly marketed EEG electricity.

Table 5: Electricity volumes generated by the four largest German electricity producers based on the definition of the market for the first-time sale of electricity

The aggregate market share of the four strongest companies (CR 4) on the market for the first-time sale of electricity amounted to 67 % in 2014. This corresponds to the figure of the previous year. In comparison to 2010 the aggregate shares of the four largest suppliers (CR 4) have fallen by 6 %. The long-term decrease in market concentration is largely a consequence of E.ON's loss of market shares. Of the four strongest companies only Vattenfall was able to achieve market share increases compared with 2010.

German-Austrian electricity consumption and electricity generation volumes remained fairly constant over the last ten years. Since the volume of energy fed in from renewal energy sources also rose constantly, production from other energy sources (and consequently the volume of the market for the first-time sale of electricity) decreased. In 2014 the volume of the market for the first-time sale of electricity fell considerably - i.e. by 5, compared with the previous year (from 476 TWh to 453 TWh). The reason for this, apart from a further increase in feed-in from renewable energy, is a significant decrease in electricity consumption in 2014 (cf. chapter I.A.2). The electricity volumes generated by the four largest producers on the market for the first-time sale of electricity have fallen by around 5 %, i.e. roughly to the same extent as the market volume.

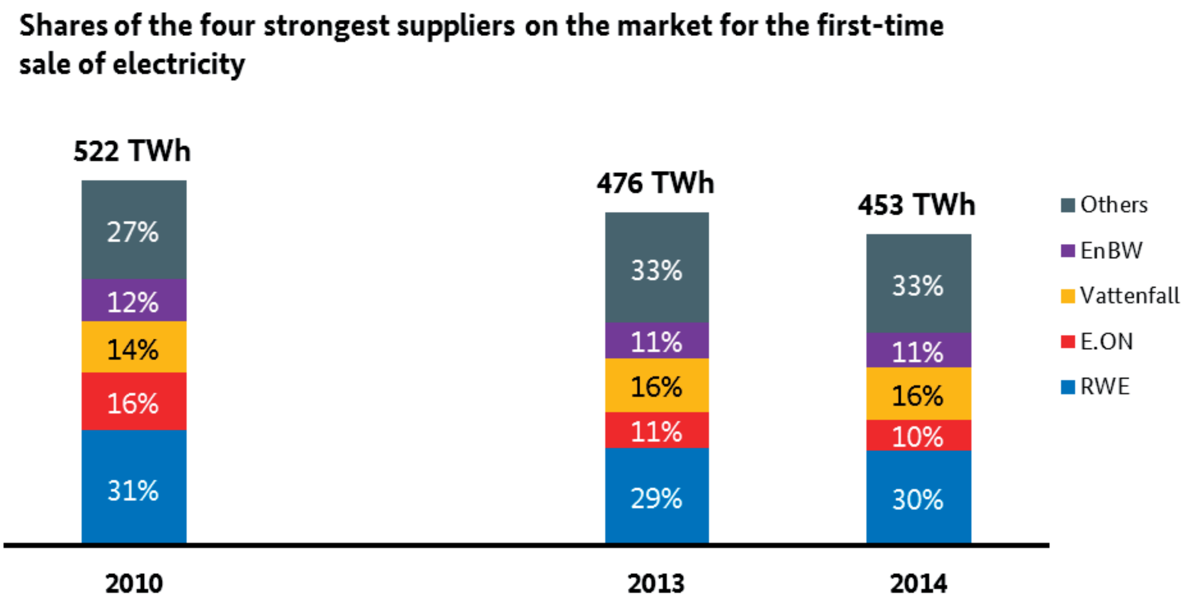

Figure 4: Shares of the four strongest suppliers on the market for the first-time sale of electricity

At around 61 % the share of the four companies of German-wide capacities which are generally available for use on the market for the first-time sale of electricity (i.e. without EEG capacities, traction-current capacity, closed power stations or volumes not fed into the general supply grid) is roughly the same as in the previous year (62%). There was hardly any change in the total volume of capacity available in Germany and Austria compared to the previous year. The capacities attributable to RWE have fallen by 2.2 GW, which represents a share of 2 % cent of the total capacity. In comparison with 2010 the share of capacity of the four largest electricity suppliers has fallen. As is the case with the generation volumes, the reduction in shares is principally due to E.ON's sunk capacity.

Generation capacities of the four largest German electricity producers based on the definition of the market for the first-time sale of electricity

	Germany + Austria 31 December 2013		Germany + Austria 31 December 2014		Germany 31 December 2013		Germany 31 December 2014	
	GW	**Share**	**GW**	**Share**	**GW**	**Share**	**GW**	**Share**
RWE	31.7	28%	29.5	26%	30.5	32%	28.3	29%
Vattenfall[1]	15.2	13%	15.9	14%	15.2	16%	15.9	16%
EnBW[2]	12.2	11%	12.4	11%	12.2	13%	12.4	13%
E.ON	11.9	10%	12.1	11%	11.7	12%	12.0	12%
CR 4		**62%**		**61%**		**72%**		**71%**
Other companies		38%		39%		28%		29%
Total capacity[3]	114.4	100%	114.7	100%	96.7	100%	97.0	100%

Data rounded up. [1] The data for Vattenfall for 31 December 2013 were corrected. [2] The data of EnBW include EEG capacities. [3] The sum of generation capacity at 31 December 2013 was corrected. The total volume provided in the report of the previous year also contained some capacity which could not be used on the market for the first-time sale of electricity (winter reserve, temporarily shut-down power stations, plants which do not feed into the general supply grid).

Table 6: Generation capacities of the four largest German electricity producers based on the definition of the market for the first-time sale of electricity

With a CR 4 of 67 % (share of electricity generation volume), the market for the first-time sale of electricity is still highly concentrated. However, compared with 2010 the degree of concentration declined. Apart from the decline in market concentration, other factors have led to a downward trend in market power. Since 2009 there have been more generation capacities in Germany and European-wide than are required to cover demand. In addition, an increased share of the demand for electricity is covered with the feed-in of renewable energy. The improved use of transmission capacities for electricity imports as a consequence of increased market coupling can help to limit the companies' scope of action on the market for the first-time sale of electricity, whereas a reduction in cross-border transmission capacity would have the opposite effect. These additional aspects are not reflected in the market shares illustrated but would be taken into consideration in an extensive analysis of market power - in particular in a residual supply analysis.

3.2 Electricity retail markets

In the electricity retail markets the Bundeskartellamt differentiates between customers with metered load profiles and customers with standard load profiles. Metered load profile customers are customers whose electricity consumption is determined on the basis of a recording load profile measurement. These are generally industrial or large-scale commercial customers. Standard load profile customers are consumers with relatively low levels of consumption. These are usually household customers and smaller commercial customers. In the case of these customers a standard load profile is assumed based on the distribution of their electricity consumption over specific time intervals.

In recent cases the Bundeskartellamt has defined a Germany-wide market for the supply of electricity to metered load profile customers. In the case of the supply of electricity to standard load profile customers, it differentiates between three product markets: (i) Supply of electric heating (network-based definition), (ii) basic supply (network-based definition), (iii) supply on the basis of special contracts (without electric heating, Germany-wide definition).[10]

In energy monitoring the sales volumes of the individual suppliers (legal persons) are collected as national total values. In the data survey a differentiation is also made in sales to standard load profile customers between electric heating, basic supply and supply on the basis of special contracts. The following analysis is based on data of around 1,100 electricity suppliers (legal persons) (2013: 1,040). In this year's monitoring activities the survey on sales quantities was improved in order to allow for a market share assessment which mirrors the Bundeskartellamt's market definition also for the Germany-wide market for the supply of standard profile customers with special contracts without electric heating.

In the reporting year 2014 these approx. 1,100 companies sold a total of approx. 268 TWh electricity Germany-wide to customers with metered load profiles (2013: 281 TWh) and approx. 160 TWh electricity to standard load customers (2013: 168 TWh). Of the total volume of sales to customers with standard load profiles, 14 TWh were accounted for by electric heating, 103 TWh by other standard load profile customers with special contracts and 43 TWh by standard load profile customers with basic supply contracts.

Based on the data provided by the individual companies it was determined which sales volumes are attributable to the four strongest companies. The aggregate sales volumes were attributed with the help of the "dominance method" according to the rules illustrated above. This method provides sufficiently exact results for the purposes of this analysis. In interpreting the percentage shares it should be borne in mind that the monitoring survey of the electricity suppliers does not cover the entire market. The percentage shares therefore only approximately reflect the actual market shares.

In 2014 the four strongest companies sold a total of approx. 88 TWh on the market for the supply of electricity to metered load profile customers. The aggregate market share of the four companies (CR 4) on the Germany-wide metered load profile customer market accordingly amounts to around 33 % (in 2013: 34 %). This value is clearly below the statutory thresholds for the presumption of a dominant position (Section 18 (4 and 6) GWB). The Bundeskartellamt assumes that there is now no dominant supplier on the market for the supply of metered load profile customers.

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

In 2014 the cumulative sales of the four strongest companies on the nationwide market for the supply of standard load profile customers with special contracts (without electric heating) amounted to approx. 37 TWh. The aggregated market share of the four companies (CR 4) on this market therefore amounts to around 36 %. This value was established based on the revised structure of the survey and is therefore not directly comparable with the companies' share of supply of electricity to standard load profile customers on the basis of special contracts indicated in the 2014 Monitoring Report (in which electric heating was included). The value of approx. 36 % representing the market share of the four largest companies is also clearly below the statutory thresholds for the presumption of a dominant position (Section 18 (4 and 6) GWB). The Bundeskartellamt assumes that there is now no dominant supplier on the nationwide market for the supply of standard load profile customers without electric heating on the basis of special contracts.

On the basis of the monitoring data the shares of total sales to all standard load profile customers, i.e. including electric heating and basic supply customers, can also be calculated. However, the total values thus established do not correspond with the Bundeskartellamt's market definition practice They only represent the size of the shares of the strongest companies in the Germany-wide assessment of all standard load profile customers. The volume of electricity supplied by the four strongest companies to all standard load profile customers amounts to approx. 65 TWh, which corresponds to a CR 4 of around 41% (2013: 43%): The share of all standard load profile customers is therefore significantly greater than in the assessment of only standard load profile customers with special contracts (without electric heating). The reason for this is that in the areas of electric heating and basic supply the four strongest companies account for higher shares of the Germany-wide sales volumes than in the area of special contracts for standard load profile customers without electric heating.

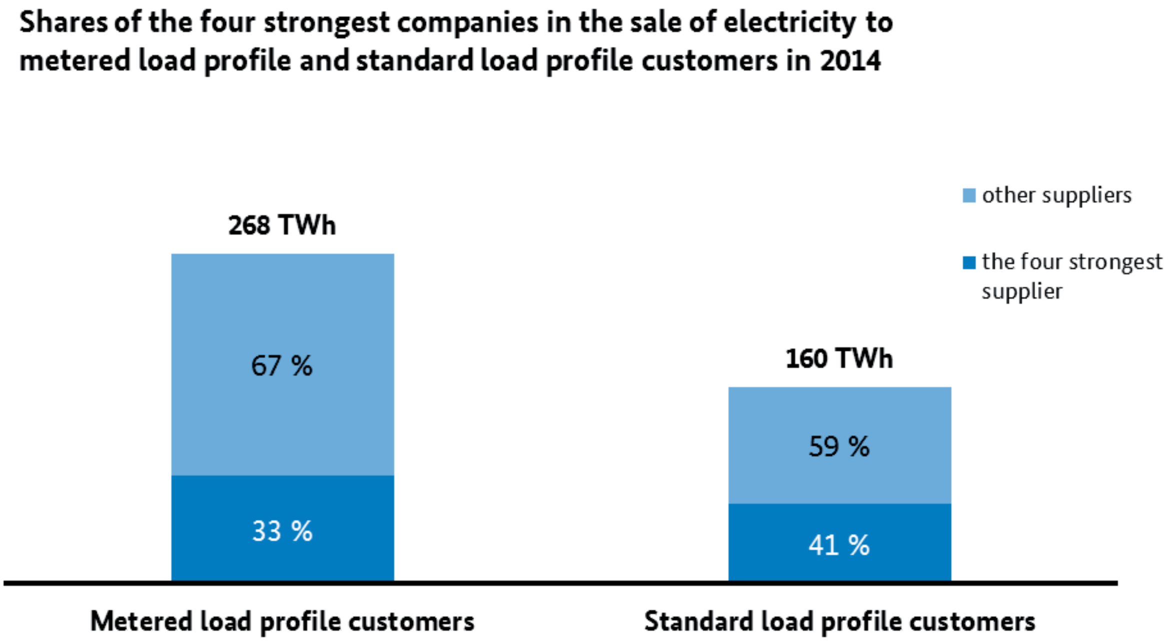

Figure 5: Share of the four strongest companies in the sale of electricity to metered load profile and standard load profile customers in 2014

B Generation and security of supply

1. Existing capacity and structure of the generation sector

In 2014, electricity generation was marked by a further increase in capacity from renewables (see Figure 4 on page 36). Capacity from all renewable sources increased by 6.5 GW, comparable to the increase of 6.7 GW in 2013. Onshore wind and solar photovoltaic showed the largest increases with 4.0 GW and 1.9 GW respectively. Capacity from the non-renewable sources covered in the survey increased in the same period by 0.9 GW. This development is mainly due to improved data on natural gas installations with a capacity of less than 10 MW not eligible for payments under the Renewable Energy Sources Act (up 0.5 GW). The total (net) installed generating capacity thus rose by 7.5 GW from 188.7 GW as at 31 December 2013 to 196.2 GW as at 31 December 2014.[11] This comprises 106.2 GW from non-renewables and 90.0 GW from renewables.

As at September 2015 the total installed capacity from non-renewables was 105.3 GW and from renewables 93.9 GW (solar data as at August 2015) (see Figure 5 on page 39). Overall, the installed capacity from non-renewables was down 0.9 GW on that as at 31 December 2014. Temporary changes in capacity are due to the closure and opening of power plants, including in particular the closure of Grafenrheinfeld power station (1,275 MW net nominal capacity) earlier than originally planned at the end of June 2015. In addition, capacity from natural gas fell by 0.4 GW while capacity from hard coal increased by 0.9 GW.

Overall, capacity from renewables increased by 3.9 GW since the beginning of 2015. Offshore and onshore wind capacity showed particular increases with 1.8 GW and 1.2 GW respectively.

[11] These figures include (pumped storage and hydro) capacity in Luxembourg, Switzerland and Austria feeding into the German grid.

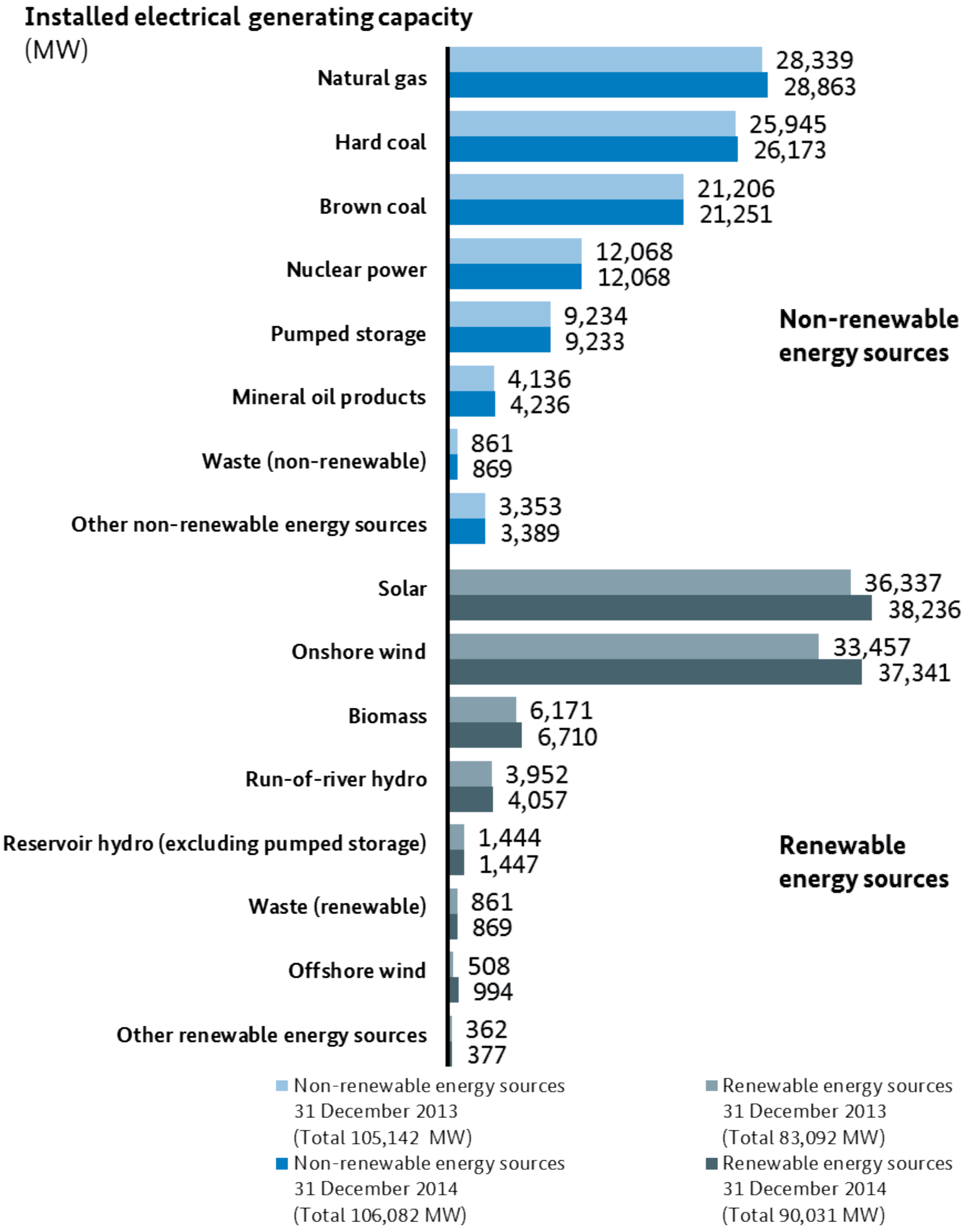

Figure 6: Installed electrical generating capacity
(net nominal capacity as at 31 December 2013/31 December 2014)

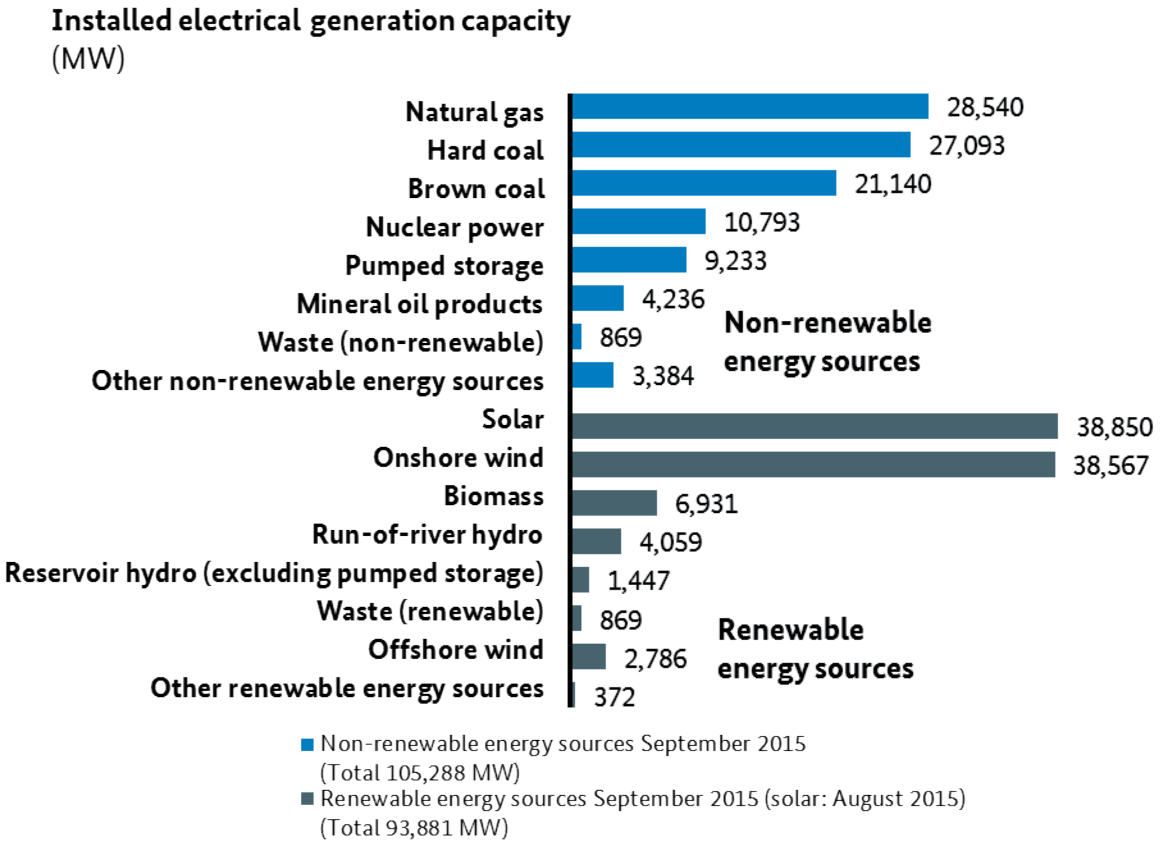

Figure 7: Installed electrical generation capacity
(net nominal capacity as at September 2015 and (solar) August 2015)

The following map shows the location and installed generating capacity of renewable and non-renewable energy plant by federal state. The figures do not include generating capacity in Luxembourg, Switzerland and Austria feeding into the German grid. The figures for non-renewable capacity include plants with a capacity of 10 MW or more. The Bundesnetzagentur does not have any detailed data on smaller installations with a capacity of less than 10 MW not eligible for payments under the Renewable Energy Sources Act and therefore cannot allocate this capacity (4,385 MW) to specific states.

Generating capacities by energy source in each federal state

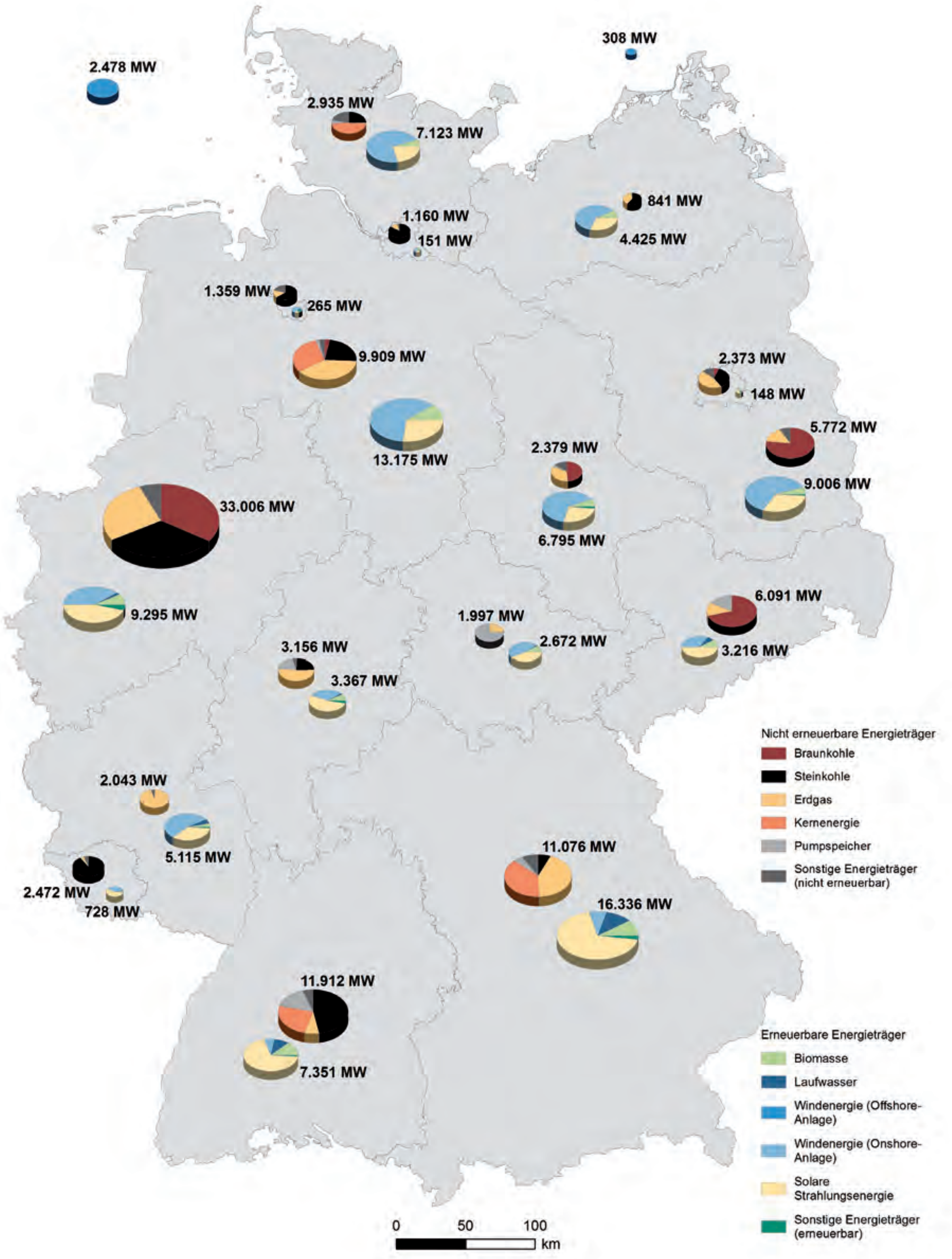

Figure 8: Generating capacities by energy source in each federal state
(net nominal capacities as at September 2015 and (solar) August 2015)

Generating capacities by energy source in each federal state
(MW)

Federal state	Non-renewable energy sources							Renewable energy sources						
	Brown coal	Hard coal	Natural gas	Nuclear power	Pumped storage	Mineral oil products	Other non-renewable sources	Biomass	Run-of-river hydro	Offshore wind	Onshore wind	Solar	Other renewable sources	Total
Baden-Württemberg	0	5,525	1,053	2,712	1,873	700	49	838	783	0	590	5,059	81	**19,263**
Bavaria	0	847	4,599	3,982	543	969	136	1,380	1,914	0	1,508	11,206	328	**27,412**
Berlin	164	777	1,087	0	0	327	18	43	0	0	4	83	18	**2,521**
Brandenburg	4,409	0	846	0	0	334	183	433	5	0	5,510	2,967	91	**14,778**
Bremen	0	896	170	0	0	88	206	7	10	0	159	41	48	**1,625**
Hamburg	0	960	150	0	0	38	12	43	0	0	59	36	12	**1,310**
Hesse	34	753	1,620	0	623	25	102	261	63	0	1,153	1,785	104	**6,523**
Mecklenburg Western Pomerania	0	514	318	0	0	0	9	345	3	0	2,662	1,394	20	**5,266**
Lower Saxony	352	2,202	4,061	2,689	220	59	326	1,297	56	0	8,211	3,542	69	**23,085**
Northrhine-Westphalia	10,621	11,643	7,917	0	291	504	2,030	718	156	0	3,769	4,321	332	**42,301**
Rhineland-Palatinate	0	13	1,922	0	0	0	107	164	232	0	2,772	1,879	68	**7,158**
Saarland	0	2,206	114	0	0	0	152	20	11	0	272	412	14	**3,200**
Saxony	4,325	0	657	0	1,085	17	8	286	208	0	1,110	1,593	19	**9,307**
Sax-Anhalt	1,152	0	781	0	80	231	135	416	26	0	4,373	1,873	107	**9,174**
Schleswig-Holstein	0	730	31	1,410	119	575	70	397	5	0	5,181	1,511	30	**10,058**
Thuringia	0	0	482	0	1,509	0	6	247	32	0	1,234	1,148	11	**4,669**
North Sea	0	0	0	0	0	0	0	0	0	2,478	0	0	0	**2,478**
Baltic Sea	0	0	0	0	0	0	0	0	0	308	0	0	0	**308**
Total	**21,056**	**27,066**	**25,807**	**10,793**	**6,343**	**3,866**	**3,549**	**6,896**	**3,504**	**2,786**	**38,567**	**38,850**	**1,351**	**190,434**

No detailed data is available for installations with a capacity of less than 10 MW not eligible for payments under the Renewable Energy Sources Act; the total capacity of these installations (4,385 MW) is therefore not included in the table.

Table 7: Generating capacities by energy source in each federal state (net nominal capacities as at September 2015 and (solar) August 2015)

The total generating capacity from non-renewables of 105.3 GW (as at September 2015) can be divided between the power plants as follows:

96.9 GW: plants in operation;

2.0 GW: plants temporarily not in operation (eg owing to repairs following damage) or with restricted operation;

3.1 GW: backup power stations (including 1.7 GW from power stations rated as systemically relevant under section 13a(2) of the Energy Act and now only operated when requested by the TSOs);

3.3 GW: plants temporarily closed.

The power stations rated as systemically relevant under section 13a(2) of the Energy Act are plants which were notified as scheduled for final closure but which may not be closed for supply security reasons (see I.A.3.2 on page 38 for more information). These stations are to be distinguished from power stations which have been rated and confirmed as systemically relevant but which are not to be operated solely for supply security purposes until a later date. The plants currently comprise power stations in southern Germany using mineral oil products (1.2 GW) and hard coal (0.5 GW).

The majority of the plants temporarily closed are natural gas fired power stations; they account for 2.7 GW of the plant capacity temporarily closed.

An additional 0.4 GW of plant capacity was mothballed in summer 2015. These plants are closed during the summer season and fired up again afterwards. The majority of the plants mothballed in the summer (0.3 GW) used hard coal.

The following map shows the location of the systemically relevant power stations, the plants temporarily closed and the plants permanently closed since 2011. The systemically relevant power stations include those stations which have been rated and confirmed as systemically relevant but which are not to be operated solely for supply security purposes until a later date. The map shows power plants which have been notified as scheduled for either temporary or final closure but which may not be closed for supply security reasons. These plants can be made operational again under section 13a(1) of the Energy Act, in contrast to plants which have been permanently closed.

Systemically relevant power stations, power plants temporarily closed and power plants permanently closed since 2011

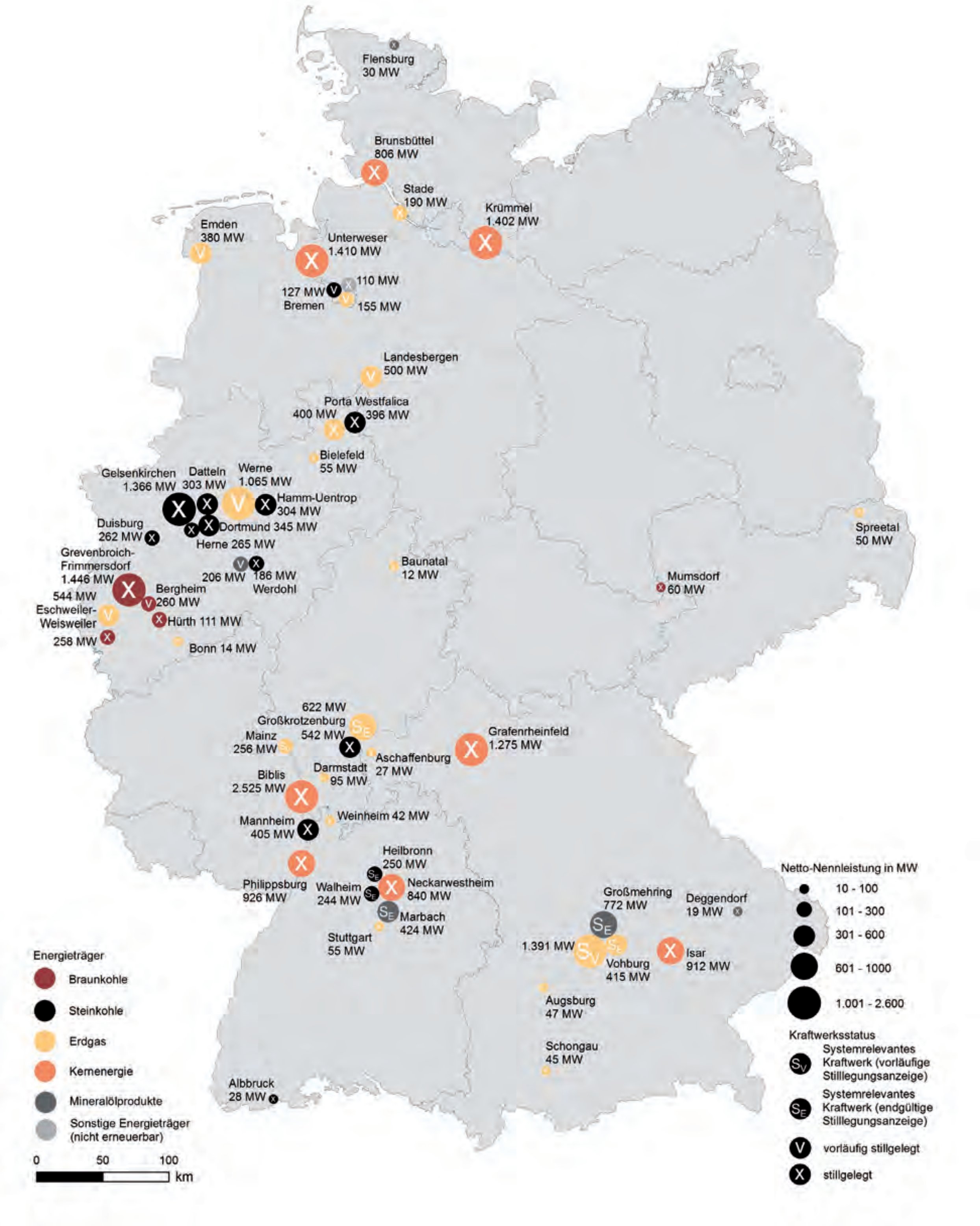

Figure 9: Location in Germany of systemically relevant power stations, power plants temporarily closed and power plants permanently closed since 2011 (net nominal capacities as at September 2015)

In 2014, electricity generation was marked by a decrease in generation from non-renewable sources. At the same time there was a further increase in generation from renewables as in previous years, as a result of increased capacity. Overall, the net amount of electricity generated fell by 12.2 TWh or 2.1%, from 593.5 TWh in 2013 to 581.3 TWh in 2014. One particular reason for the decrease is the relatively mild winter in the period under review.

All non-renewable sources (with the exception of waste) showed year-on-year decreases in generation in 2014. Overall, generation from non-renewables fell by 20.5 TWh or 4.6% to 426.6 TWh. Natural gas and hard coal power plants showed the largest decreases. Electricity generation from natural gas was 50.1 TWh, down 8.3 TWh or 14.3% on the previous year. Based on information from the network operators, 12% less gas was used by gas powered stations in 2014, reflecting the downward trend (see I.A.2 on page 27). Generation from hard coal was 110.0 TWh, a fall of 6.4 TWh or 5.5% on a year earlier. Power plants using mineral oil products showed the largest percentage decrease with 17.9%. In 2014, generation by brown coal power plants showed the first decrease in a number of years; generation fell by 4.2 TWh or 2.8% to 144.5 TWh. Nuclear generation at 91.8 TWh was broadly unchanged (down 0.3%) on 2013. The large decline in particular in generation from natural gas and mineral oil products is due to the fall in demand and more essentially the increase in generation from renewables. As in previous years, the increase in generation from renewables is leading to lower wholesale prices and in turn to a decrease in generation by plants with relatively high operating costs. This is true in particular for power plants using natural gas or mineral oil products.

Generation from renewables increased by 8.4 TWh or 5.7%, from 146.4 TWh in 2013 to 154.8 TWh in 2014. Renewables' share of net electricity generation thus rose to 26.6% in 2014. Onshore wind showed the largest increase on 2013; generation increased by 5.1 TWh or 10.0% from 50.8 TWh in 2013 to 55.9 TWh in 2014. Solar generation increased to 33.0 TWh, up 11.5% on the previous year. Offshore wind showed the largest percentage increase; generation was 60.2% (0.5 TWh) up on 2013, at 1.4 TWh.

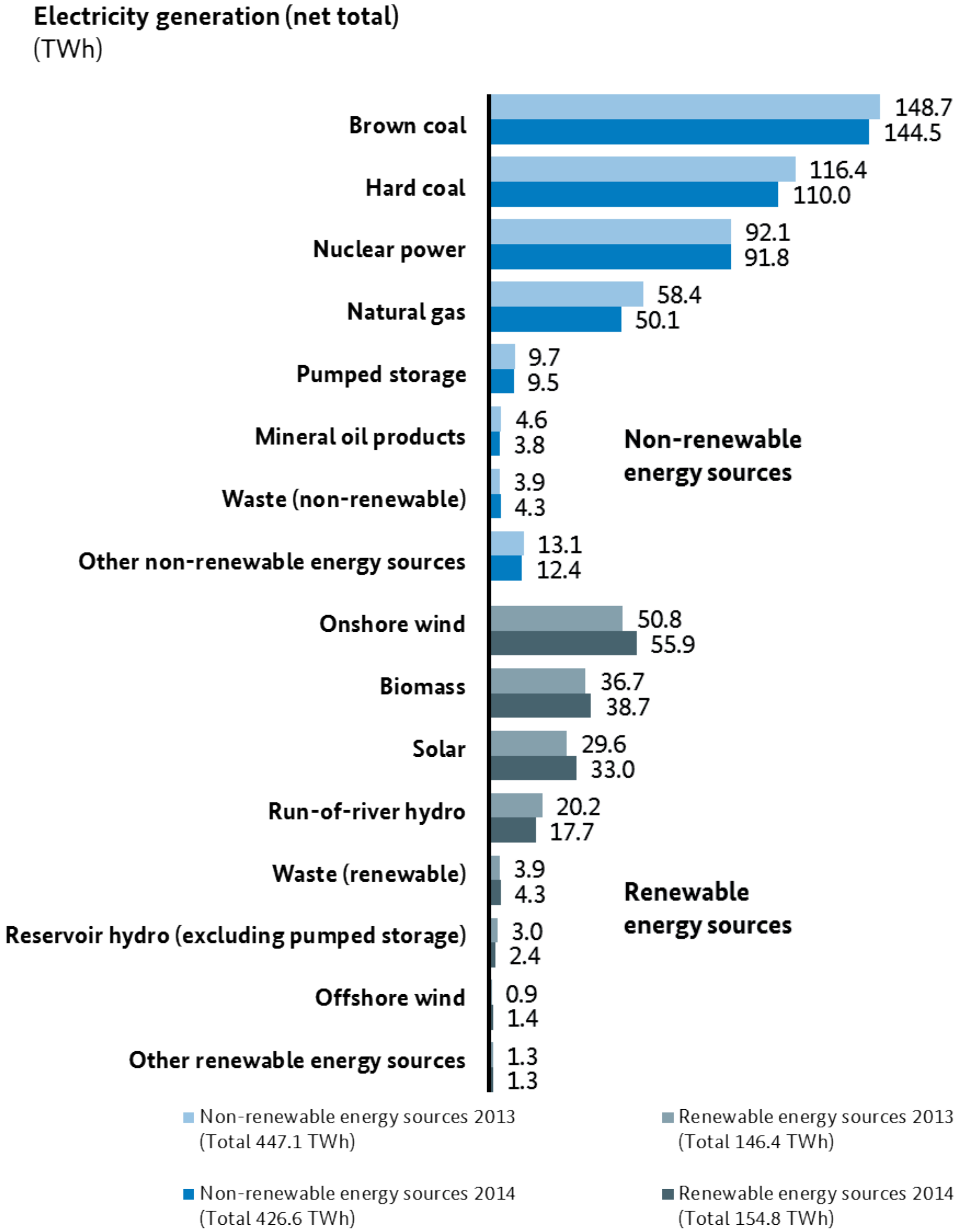

Figure 10: Electricity generation (net total) 2013/2014

2. Development of renewable energies

In the year under review, the amended Renewable Energy Sources Act (EEG) came into effect on 1 August 2014. For the sake of simplicity, reference will be made hereinafter only to the relevant paragraphs of the new EEG.

The key figures presented in this section are collected by the Bundesnetzagentur to fulfil its monitoring function in the nationwide equalisation scheme process. To this end, selected data is provided on an annual basis from the year-end accounts as per the EEG of transmission system operators (TSOs) (by 31 July), energy utilities and distribution system operators (DSOs) (by 31 May). In the publication "EEG in numbers"[12], the Bundesnetzagentur provides market stakeholders with evaluations which go beyond the key figures presented here. In particular, this publication contains evaluations for specific energy sources, federal states and access levels.

2.1 Installations register

Under the new EEG, development paths were introduced for the four key renewable energy sources. Thus, statutory corridors were established for the growth of onshore wind energy, offshore wind energy, photovoltaics and biomass. A new register, the installations register, was created to monitor deployment, calculate deployment-dependent support levels and provide data to facilitate the integration of renewable energy sources into the existing electricity supply system.

The installations register is administered by the Bundesnetzagentur and was formally launched at the beginning of August 2014. All installations commissioned since August 2014 must be recorded in this register. For installations commissioned before 1 August 2014, data must be registered if a reportable event occurs – notably, capacity changes or closures. Reporting requirements also exist for new installation licences issued from this date. Data on registered installations must be kept up to date by the operators of these installations. This makes it possible to map the entire life cycle of an installation. Beginning with the construction licence, reporting requirements range from the installation and any other changes, to the final closure of an installation. Some 1,978 reports were registered in 2014.

All data recorded in the installations register is published online at http://www.bnetza.de/anlagenregister. This provides an overview of the renewable power generation landscape for all interested parties. Transparency helps to increase acceptance of Germany's *Energiewende*.

Consideration is being given to expanding the register to conventional installations to not only reflect the expansion of renewable energies but also provide an overview of total installed capacity in Germany. However, this will require further legislative work.

Installed capacity

The total installed capacity of installations eligible for payments under the EEG was approximately 85.3 GW on 31 December 2014 (31 December 2013: around 79.2 GW). This represents an increase in the total installed capacity of such installations of around 6.1 GW in 2014, or 7.7%.

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[12] http://www.bundesnetzagentur.de/cln_1432/EN/Areas/Energy/Companies/RenewableEnergy/Facts_Figures_EEG/FactsFiguresEEG_node.html

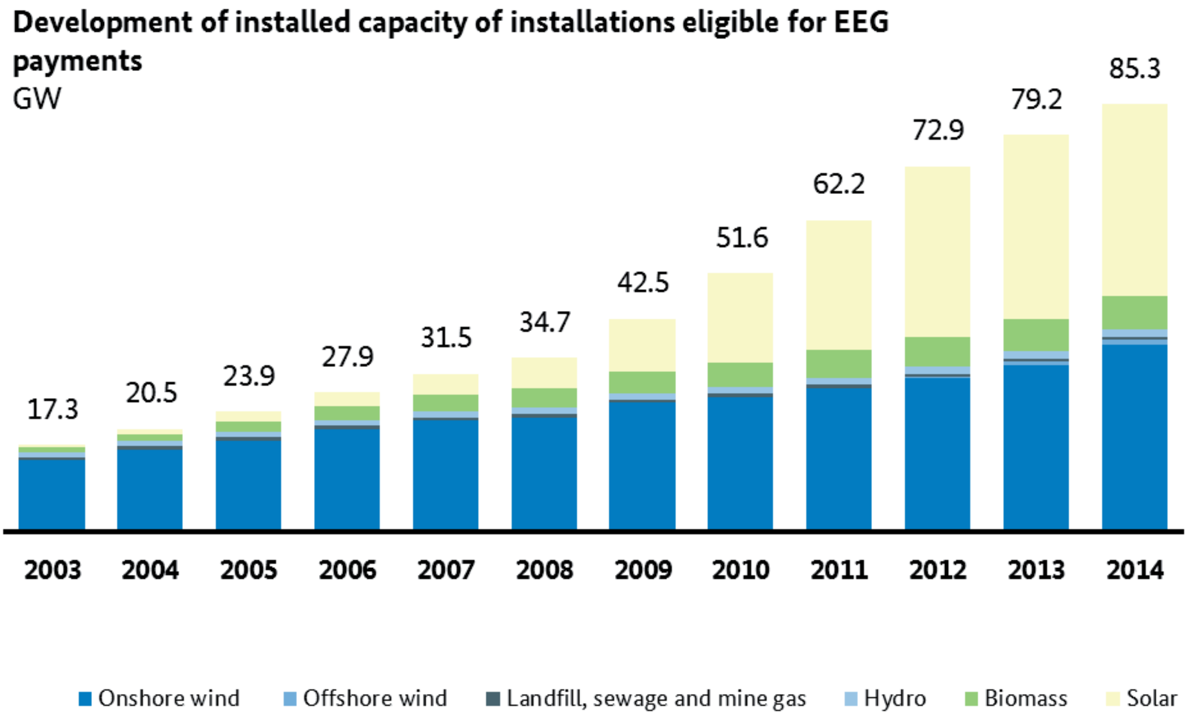

Figure 11: Development of installed capacity of installations eligible for EEG payments from 2003 to 2014

Installed capacity of installations eligible for EEG payments by energy source

	Total as of 31 December 2013 (MW)	Total as of 31 December 2014 (MW)	Increase / decrease compared with 2013 (%)
Hydro	1,564	1,557	-0.4%
Gases[1]	531	531	0.0%
Biomass	6,432	6,576	2.2%
Geothermal	30	34	11.6%
Onshore wind	33,310	37,341	12.1%
Offshore wind	622	994	59.8%
Solar	36,710	38,236	4.2%
Total	79,199	85,268	7.7%

[1] Landfill, sewage and mine gas

Table 8: Installed capacity of installations eligible for EEG payments by energy source (as of 31 December 2014/31 December 2013)

A particularly sharp rise in the capacity of onshore wind plants was recorded in 2014. Facilities with a capacity of approximately 4.0 GW were newly installed (2013: approximately 2.6 GW), which represents an increase of around 12.1%. While the deployment of solar installations also rose by a further 1.5 GW, this increase was much lower than the average growth rate of the last 10 years (3.6 GW). The deployment of biomass installations also slowed (2014: 0.14 GW; 2013: 0.53 GW).

The EEG 2014 sets out growth corridors for the deployment of the four key energy sources. For onshore wind plants, the planned increase in installed capacity is 2.5 GW per year (net). The EEG came into effect on 1 August 2014 and, in the period from August to December 2014, a net capacity increase of 2.2 GW was recorded. When extrapolated to the full year, the corridor would therefore be exceeded by a considerable margin. The corridor for photovoltaic (PV) installations is 2.5 GW per year; an additional capacity of 0.54 GW was registered as newly installed in the five months from August to December. When extrapolated to the full year, the resulting figure would be well below the planned PV value. In the case of biomass, the planned increase in installed capacity is 0.1 GW. The increase in the last five months of 2014 was 0.04 GW, which is within the planned growth corridor for this energy source. The installed capacity of offshore wind plants is set to rise to a total of 6.5 GW by 2020 and 15 GW by 2030. By December 2014 installations with an installed capacity of just under 1 GW had been commissioned.

Number of new installations

Some 61,851 new facilities were installed in 2014. This is significantly below the average of the last five years of 200,724 new installations per year. Solar installations accounted for 97.3% of new installations, onshore wind plants for 2.0% and biomass installations for 0.6%.

Number of installations eligible for EEG payments

	2008	2009	2010	2011	2012	2013	2014
Hydro	6,017	6,324	6,571	6,825	6,974	6,779	6,810
Gases[1]	653	668	672	680	684	627	623
Biomass	7,369	8,347	9,943	12,697	13,371	13,285	13,627
Geothermal	2	4	4	4	6	7	8
Onshore wind	17,125	18,503	19,264	20,204	21,339	22,411	23,634
Offshore wind	-	7	16	49	65	143	241
Solar	455,630	636,756	894,756	1,154,968	1,328,293	1,447,164	1,507,324
Total	486,796	670,609	931,226	1,195,427	1,370,732	1,490,416	1,552,267

[1] Landfill, sewage and mine gas

Table 9: Number of installations eligible for EEG payments

When considering the development of individual energy sources, special mention must be made of the substantial capacity growth of new offshore wind plants of 68.5%.

Growth rates of installations by energy source

	Total number as of 31 December 2013	Total number as of 31 December 2014	Increase / decrease compared with 2013 %
Hydro	6,779	6,810	0.5%
Gases[1]	627	623	-0.6%
Biomass	13,285	13,627	2.6%
Geothermal	7	8	14.3%
Onshore wind	22,411	23,634	5.5%
Offshore wind	143	241	68.5%
Solar	1,447,164	1,507,324	4.2%
Total	1,490,416	1,552,267	4.1%

[1] Landfill, sewage and mine gas

Table 10: Growth rates of installations eligible for EEG payments by energy source (as of 31 December 2014/31 December 2013)

2.2 Annual energy feed-in

Annual energy feed-in by energy source

In 2014 the total annual energy feed-in from installations eligible for EEG payments was 136 TWh. This represents an overall year-on-year increase of 11.2 TWh, or 8.2%.

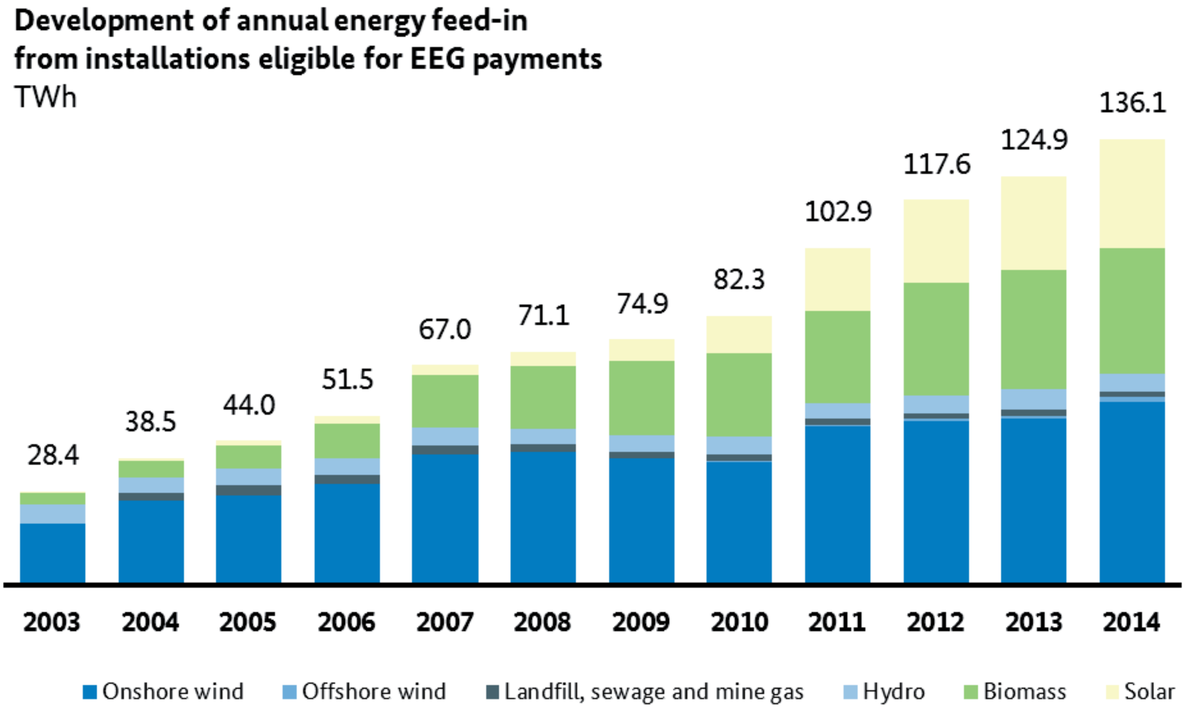

Figure 12: Development of annual energy feed-in from installations eligible for EEG payments

The largest share of annual energy feed-in of 55.9 TWh (41%) was generated by onshore wind plants, followed by biomass installations with a share of 38.3 TWh (28%) and solar installations with a share of 33.0 TWh (24%).

While the annual energy feed-in from hydropower and from landfill, sewage and mine gas fell in 2014, the annual energy feed-in generated by offshore wind plants increased. This increase in annual energy feed-in from offshore wind plants is proportionate to the rise in installed capacity.

Annual energy feed-in from installations eligible for EEG payments by energy source

	Total as of 31 December 2013	Total as of 31 December 2014	Increase / decrease compared with 2013
	GWh	GWh	%
Hydro	6,265	5,646	-11.0%
Gases[1]	1,776	1,646	-7.9%
Biomass	36,258	38,313	5.4%
Geothermal	80	98	18.6%
Onshore wind	50,803	55,908	9.1%
Offshore wind	905	1,449	37.6%
Solar	28,785	33,002	12.8%
Total	124,872	136,063	8.2%

[1]Landfill, sewage and mine gas

Table 11: Annual energy feed-in from installations eligible for EEG payments by energy source
(as of 31 December 2014/31 December 2013)

Maximum feed-in from wind power plants and solar installations

The maximum feed-in from wind power plants and solar installations increased compared with the previous years. In 2014 the maximum feed-in from wind power plants and solar installations of 37,642 MW was recorded on 14 April 2014. This was due mainly to the rise in the capacity of wind power plants and solar installations, but can also be attributed to weather conditions. On this day the peak feed-in of 23,574 MW from wind power plants, caused by a secondary low pressure system,[13] coincided with a comparatively high level of feed-in of 14,069 MW from solar installations.

[13] The upper limit is set to remain at 500 kW until 1 January 2016.

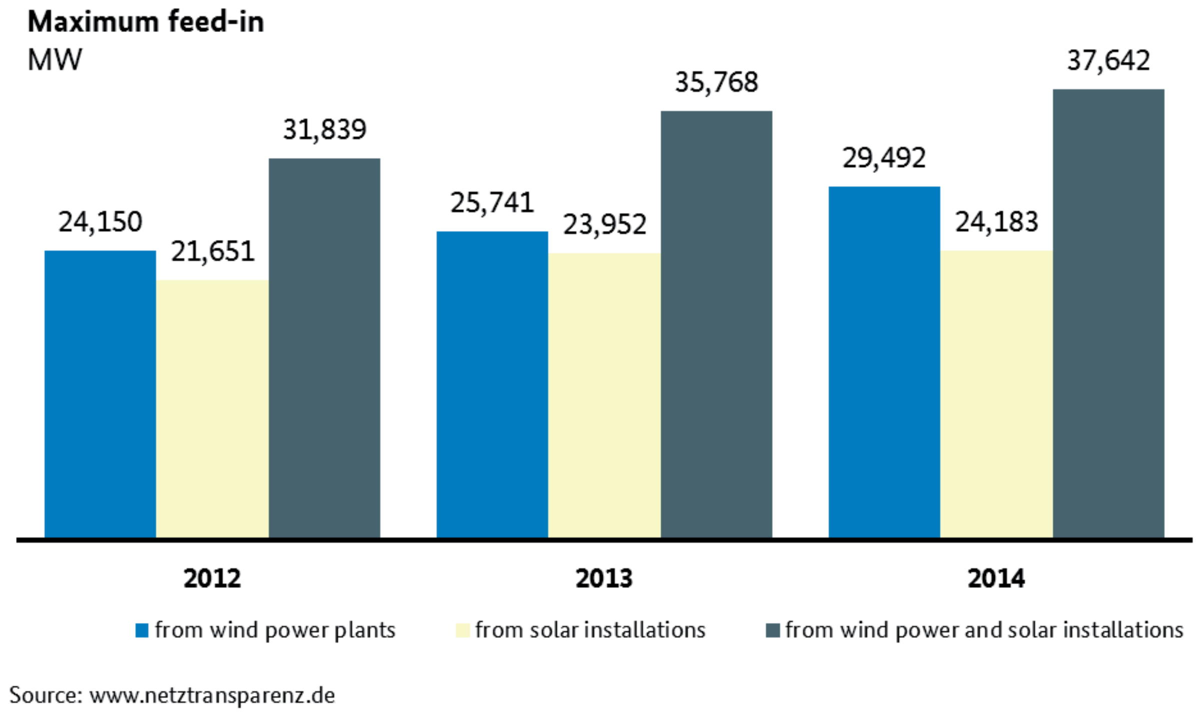

Figure 13: Maximum feed-in

In 2014 the maximum feed-in from solar installations of 24.2 GW was recorded on 6 June 2014. This increase compared with the previous years is due to both new installations and the relatively high global radiation values in June 2014 (source: Deutscher Wetterdienst [German Meteorological Service]: radiation maps for Germany).

By far the year's highest feed-in values for wind power plants (onshore and offshore) were recorded in December 2014. The peak capacity of 29,492 GW achieved on 12 December 2014 was due primarily to the gale-force winds of storm Billie. Several peak values were also observed in the first half of the year as a result of various storm systems.

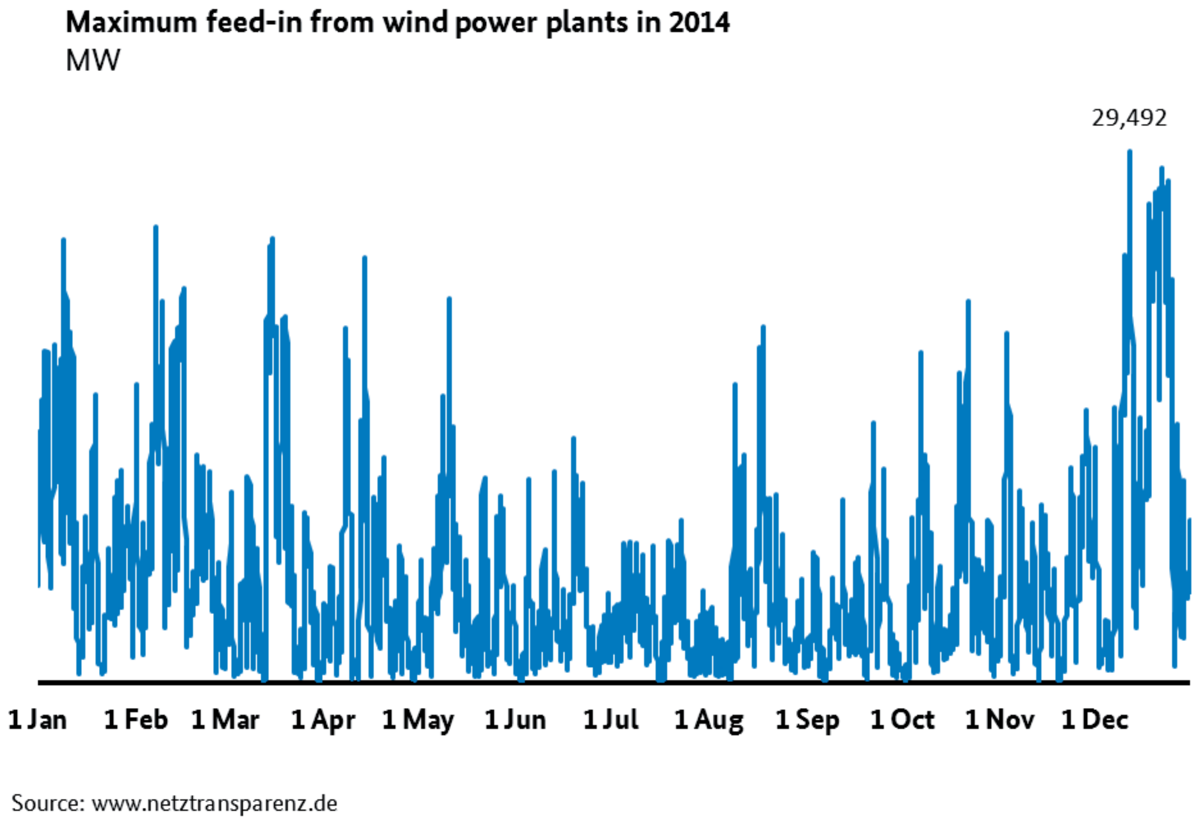

Figure 14: Maximum feed-in from wind power plants in 2014

Breakdown by fixed feed-in tariffs and direct selling

As an alternative to fixed feed-in tariffs under the EEG 2012, installation operators were able to choose between three different forms of direct selling, as provided for by section 33b EEG 2012: claiming a market premium, reducing the EEG surcharge through energy utilities (green electricity privilege), or other forms of direct selling. Under the EEG 2014, direct selling is now the standard form of selling. Only new installations with a capacity of up to 100 kW[14] can still opt for fixed feed-in tariffs; this form of financial support is also available as an emergency option for installations for which electricity is sold directly, although the financial incentives are reduced by 20% in such cases. Other forms of direct selling, ie selling without claiming financial support, also remain possible. The green electricity privilege was abolished completely.

Despite having had the option of selling renewable energy directly for some time, only a few installation operators made use of the option of direct marketing in the period from 2009 to 2012. Since the 2012 revision of the EEG there has been a clear shift towards this form of selling. In 2013 more than half of annual energy feed-in was sold directly and in 2014 a total of 62.8% of annual feed-in was sold through direct channels.

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[14] The upper limit is set to remain at 500 kW until 1 January 2016.

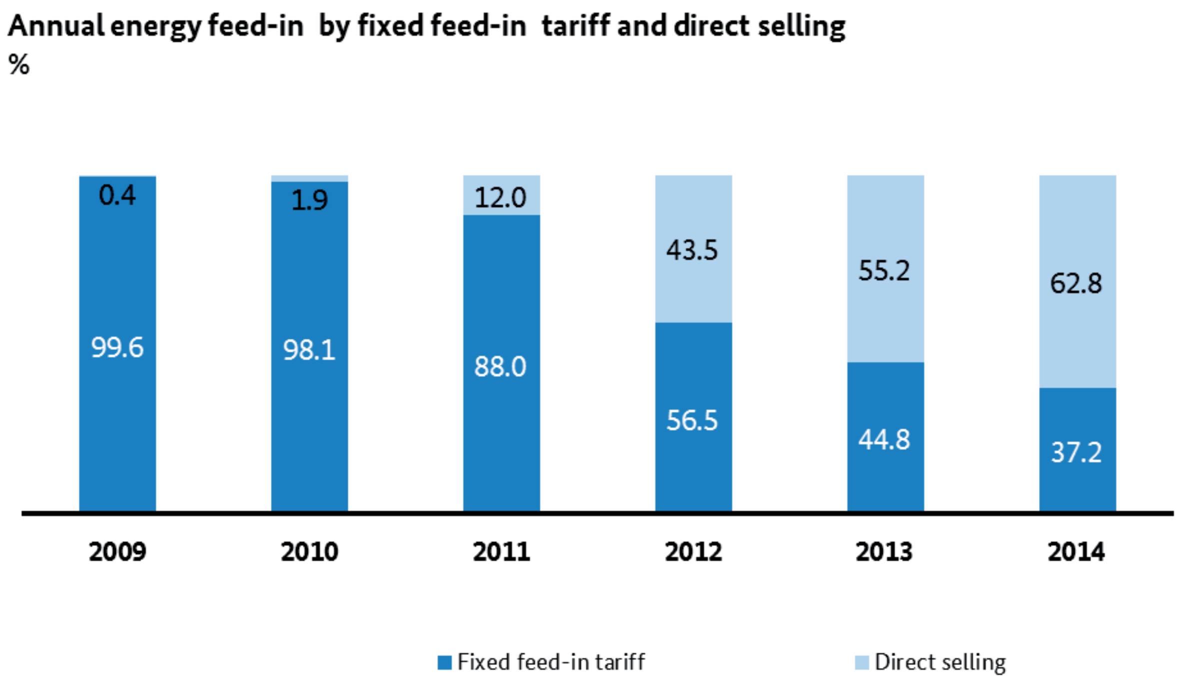

Figure 15: Development of annual energy feed-in from installations eligible for EEG payments by fixed feed-in tariff and direct selling

Table 12 shows that, for most energy sources, more than half of all energy feed-in is sold directly. In the case of onshore and offshore wind power plants, direct selling accounts for as much as almost 90% of annual feed-in. Conversely, the proportion of electricity sold directly from solar installations is relatively low (16.5%).

Annual energy feed-in from installations with a fixed feed-in tariff and installations with direct selling

	All installations GWh	Installations with feed-in tariff GWh	Installations with direct selling GWh	Share of installations with direct selling in total annual feed-in %
Hydro	5,646	2,432	3,214	56.9%
Gases[1]	1,646	625.6	1,020	62.0%
Biomass	38,314	12,814	25,499	66.6%
Geothermal	98	53.3	45	45.7%
Onshore wind	55,908	6,930	48,978	87.6%
Offshore wind	1,449	150	1,299	89.7%
Solar	33,002	27,549	5,453	16.5%
Total	136,063	50,554	85,509	62.8%

[1] Landfill, sewage and mine gas

Table 12: Annual energy feed-in from installations with a fixed feed-in tariff and for direct selling

In 2014 the main energy source for direct selling was onshore wind power, which accounted for a share of 57%. The share of energy feed-in from biomass installations also rose to 30% (2013: 24%).

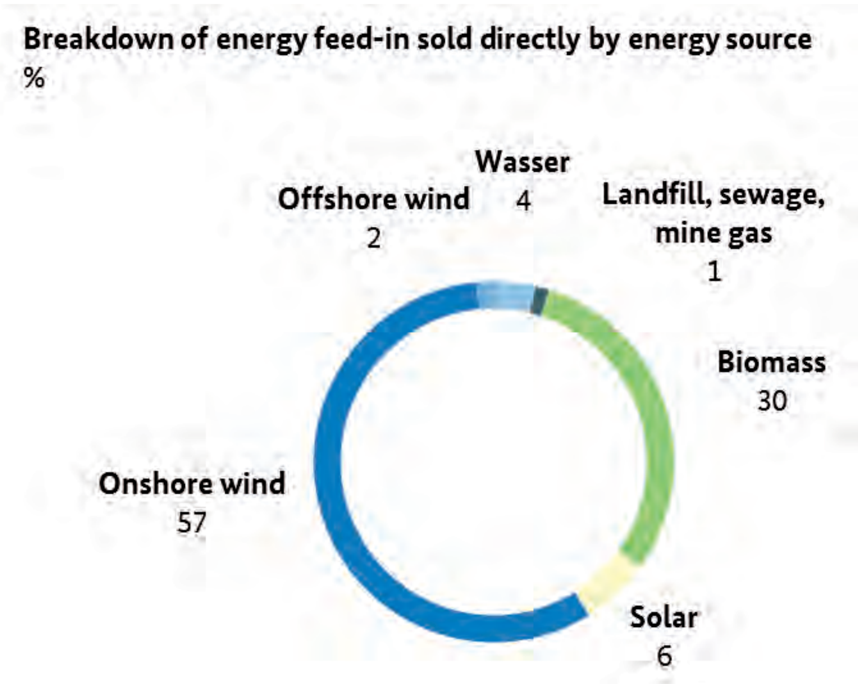

Figure 16: Breakdown of energy feed-in sold directly by energy source

2.3 Feed-in tariffs paid

Renewable energy fed into the public electricity network is remunerated by DSOs in accordance with the technology-specific reference values (rates) defined in the EEG. The feed-in tariffs are paid for the year in which the installation is commissioned and for a subsequent period of 20 years.

In 2014 a total of €21.4 billion was paid by DSOs to installation operators. Solar installations (€10.2 billion), biomass installations (€6.4 billion) and onshore wind power plants (€4 billion) accounted for significant shares of these payments.

Tariffs paid according to energy sources

	Total as of 31 December 2013 € million	Total as of 31 December 2014 € million	Increase / decrease compared with 2013 %
Hydro	420	401	-4.8%
Gases[1]	48	83	41.7%
Biomass	6,158	6,379	3.5%
Geothermal	19	22.8	18.2%
Onshore wind	3,523	4,046	12.9%
Offshore wind	123	213	42.4%
Solar	9,346	10,230	8.6%
Total	19,637	21,374	8.1%

[1] Landfill, sewage and mine gas

Table 13: Feed-in tariffs paid by energy source (as of 31 December 2014/31 December 2013)

Figure 17 shows that the 8.1% increase in feed-in tariffs paid in 2014 is below the average of the last eight years (16%).

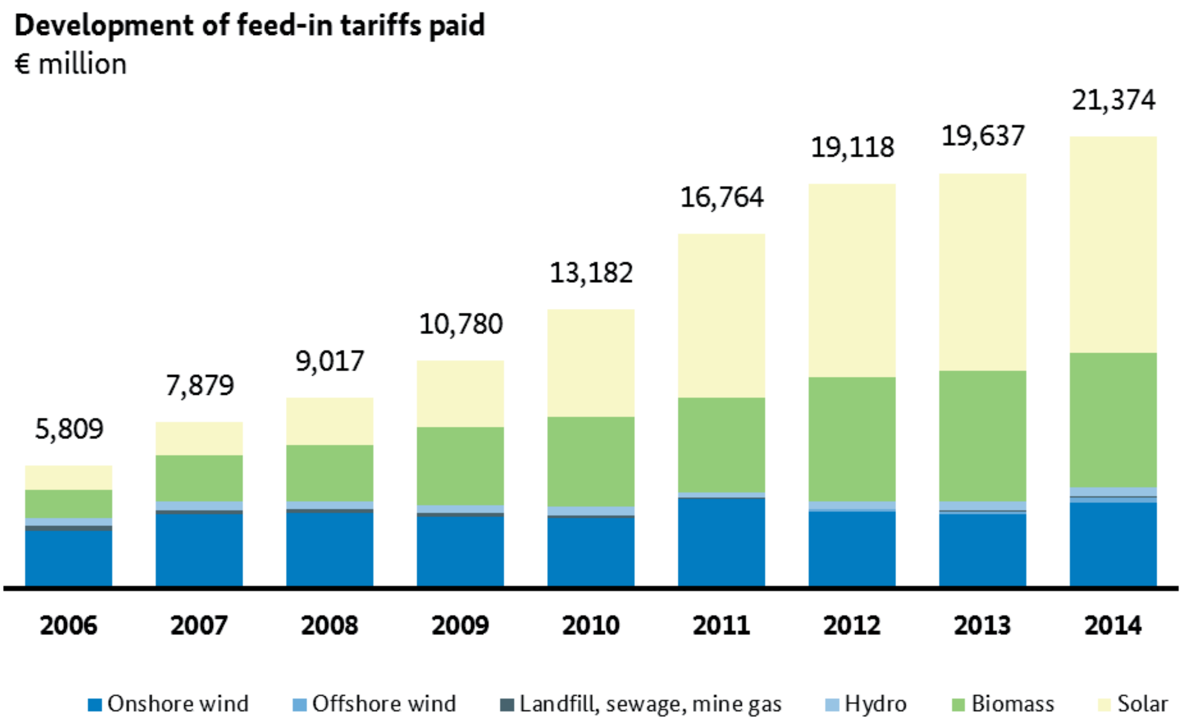

Figure 17: Development of feed-in tariffs paid by energy source

As in the previous years, the majority of feed-in tariffs paid (around 60%, or €12,769 million) were attributable to installations with a fixed feed-in tariff. By contrast, the proportion of tariffs paid for direct selling increased by 10% on the previous year.

New reference values for individual technologies are defined in the new EEG. Various rewards have also been eliminated, thus simplifying the remuneration system. To reflect the cost reductions brought about by technological advancements, mechanisms have been introduced to address these developments. Thus, the support levels for onshore wind power and PV are reduced on a quarterly basis. However, if deployment exceeds the defined corridor, support levels fall at a faster rate. If, by contrast, deployment fails to meet the statutory expectations, support levels remain the same or even rise. Calculations are based on the data recorded in the installations register and in the photovoltaic registration portal.

2.4 Auctions for solar farm funding

Since 12 February 2015 the process to determine the financial support for large-scale ground-mounted solar PV systems has been regulated by the Ground-mounted PV Auction Ordinance ("*Freiflächenausschreibungsverordnung*" or FFAV). The legal bases for this can be found in sections 2, 55 and 88 of the EEG.

The Bundesnetzagentur was responsible for conducting the pilot scheme and carries out three rounds of bidding each year on 1 April, 1 August and 1 December. Bids can be placed for a total volume of 1,200 MW of capacity in the period from 2015 to 2017, which is distributed as follows: 500 MW (2015), 400 MW (2016) and 300 MW (2017).

In the auctioning process, the level of financial support for ground-mounted solar PV systems is determined on the basis of bids. The bids must specify a price in cents per kilowatt hour (bid rate) for the electricity generated in installations and an installation capacity in kilowatts (bid volume). Support is granted to the bidders with the lowest bid rates until the total volume put out to auction has been reached.

Support is generally granted on the basis of the rate specified in the respective bid (pay-as-bid pricing). Exceptions are made for the auction deadlines on 1 August 2015 and 1 December 2015: these two rounds are conducted as a uniform price auction where the last highest successful bid sets the price for the other successful bids.

Once the successful bidder has set up and commissioned a solar farm, he can apply to the Bundesnetzagentur for an entitlement to financial support. He is entitled to financial support for his installation if the installation is located in an area which is eligible for such support and is not bigger than 10 megawatts.

Support awards lapse two years after notification if no application for an entitlement to support has been submitted by this deadline. In this case, the bidder must pay a fine.

Installations are generally remunerated as provided for in the EEG, ie via supported direct selling. Support is allocated to the bidders' installations, whereby several allocations can be made to one installation. In addition, the location specified in the bid need not necessarily correspond to the actual location. The Bundesnetzagentur calculates a level of support for each installation. Financial support is provided for a period of 20 years from the year the installation was commissioned (not 20 years including the year the installation was commissioned, as applicable elsewhere in the EEG).

The bidding rounds conducted thus far appear to have been successful: most bidders met the formal requirements, although time and again bids were disqualified due to individual errors which could have been avoided. Competition was intense. In the April 2015 round the Bundesnetzagentur received 170 bids with a volume of 715 MW. Of these bids, 37 were disqualified due to formal errors, yet the auction volume was still exceeded by around four times. With 121 valid bids for a volume of 525 MW, the auction volume of 150 MW for the second round was also significantly oversubscribed.

Distribution of support granted in the first and second auction rounds by federal state

Federal state	First auction round		Second auction round	
	Number of awards	Capacity kW	Number of awards	Capacity kW
Brandenburg	10	66,737	13	53,640
Bavaria	2	15,000	5	39,500
Mecklenburg-W. Pomerania	2	18,948	2	14,400
Lower Saxony	0	0	1	10,000
Schleswig-Holstein	0	0	1	9,999
Saxony-Anhalt	5	35,335	3	9,930
Rhineland-Palatinate	2	7,000	2	6,100
North Rhine-Westphalia	0	0	1	5,500
Baden-Württemberg	1	1,750	2	5,316
Thuringia	1	10,000	2	3,850
Hesse	2	2,200	1	1,500

Table 14: Distribution of support granted in the first and second auction rounds by federal state

In both bidding rounds, support was granted for projects in almost all non-city federal states, with a concentration in Germany's eastern states. However, successful projects are not necessarily realised in the locations specified in the bids.

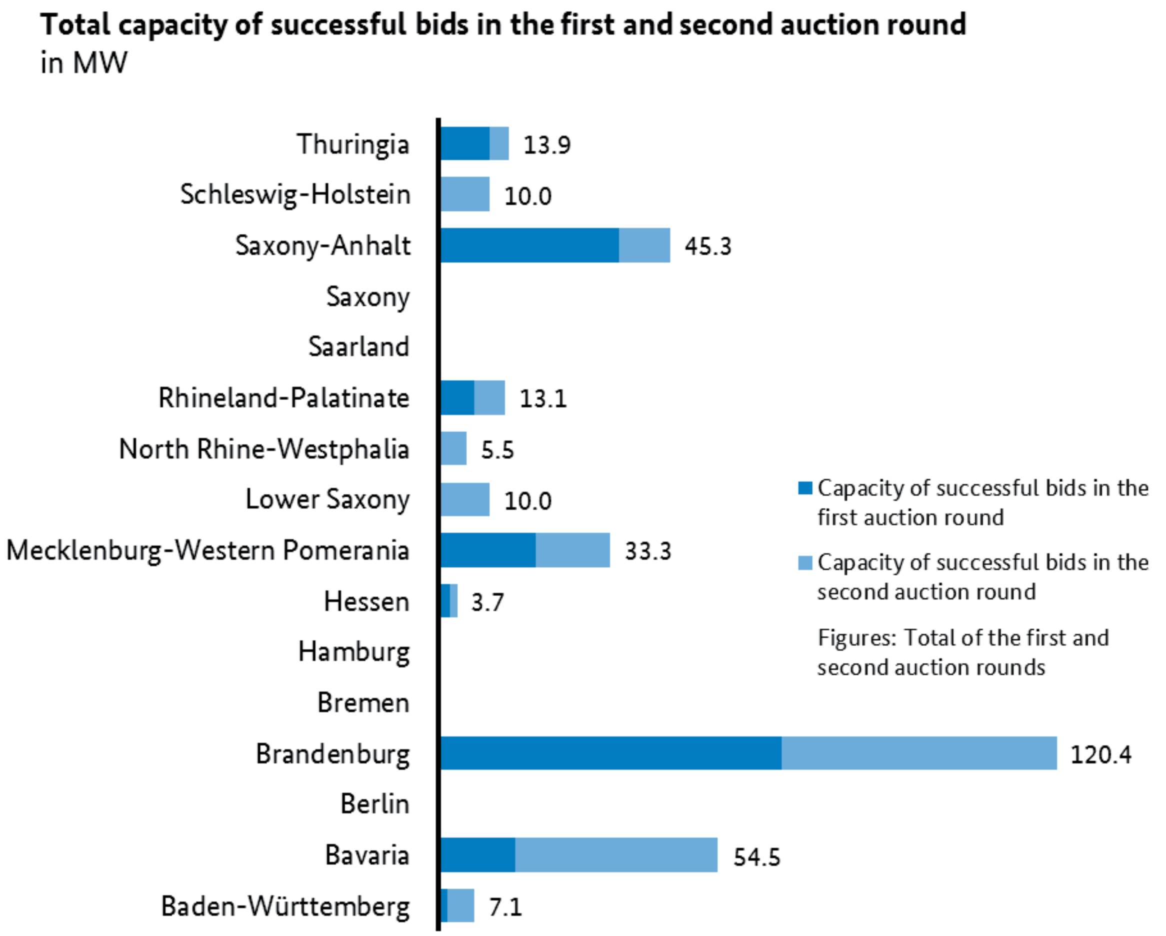

Figure 18: Successful bids in the first and second auction rounds

3. Security of supply

3.1 Expansion of conventional power plants

The future development of power plant capacity is also of relevance to the security of supply. The following section therefore begins by looking at power plant expansion. Section I.A.3.2 then examines the impact which the closure of plants is expected to have on the future development of Germany's plant capacity. The analysis of the future power plant fleet focuses exclusively on non-volatile energy sources which are of importance to the security of supply (ie excluding solar, hydro and wind). The analysis of expected growth only takes account of generating facilities currently under construction with a minimum capacity of 10 MW. In such cases, the probability of projects being implemented is considered to be sufficiently high. The outlook for 2015 takes as a starting point the plant capacity as of September 2015.

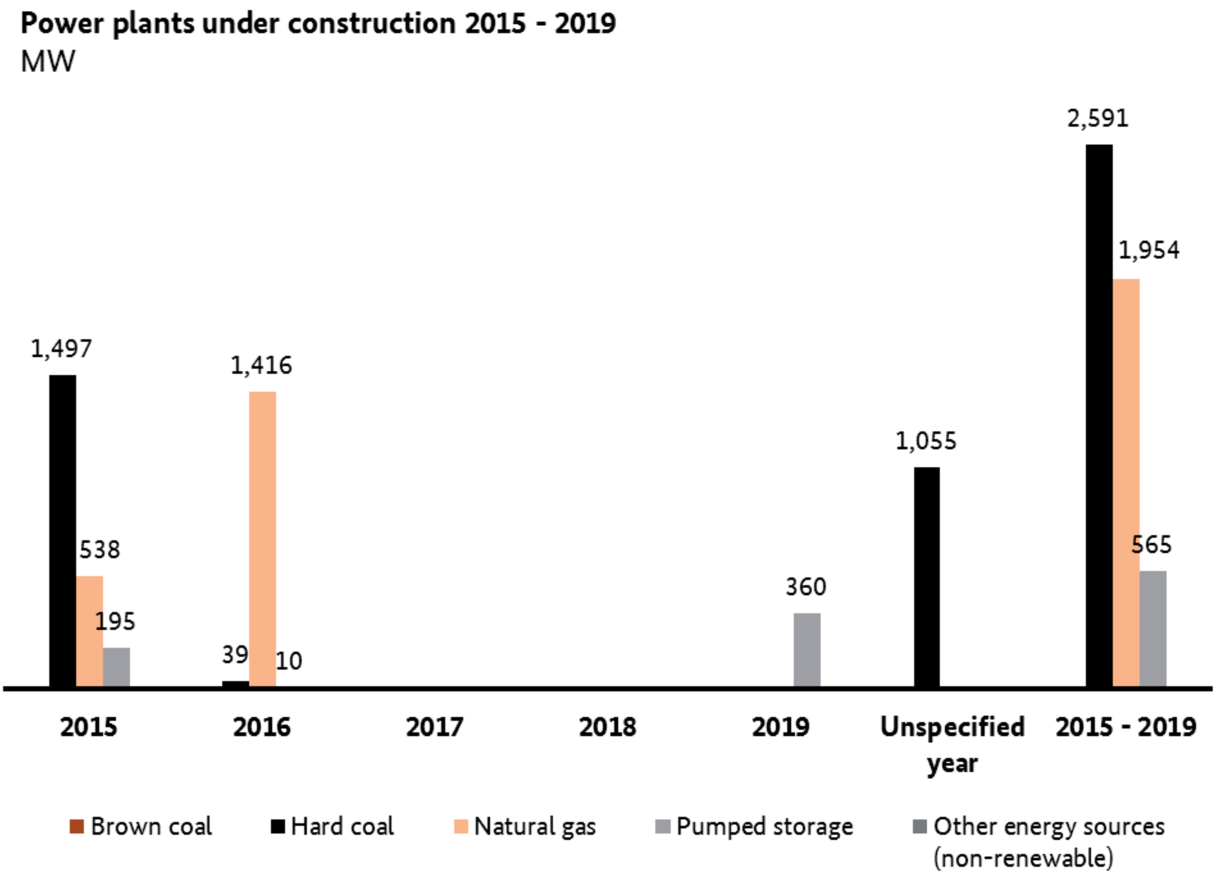

Figure 19: Power plants under construction from 2015 to 2019
(national planning data for net nominal capacity for 2015 to 2019, correct as of September 2015)

Non-volatile generation capacity totalling 5,110 MW is currently under construction across the country, and will likely be completed by 2019. The capacity expansion projects under way in Germany relate solely to hard coal (2,591 MW) and natural gas (1,954 MW). In the case of hard coal, 1,055 MW is attributable to the planned Datteln 4 hard-coal fired power plant alone, the completion date of which is still unknown. Pumped storage plants with a total capacity of 565 MW are also currently under construction in Luxembourg and Austria; energy from these plants will be fed into the German network. There are currently no projects under way for pumped storage plants in Germany.

The regional distribution of the above-mentioned projects, which is relevant to supply security, is analysed in section I.A.3.2 in connection with the reduction in power plants.

3.2 Reserve power plants and power plant closures

As a rule, the transmission system is subject to the greatest pressure in the period from October to April. At this time of year high input from wind power plants can occur in the control area of 50Hertz and in the northern part of the TenneT network, causing high load flows in the grid. In addition to problematic flows from north to south, which have been the focus thus far, strong flows from Germany to Poland are currently making it more difficult for TSOs to maintain system security. However, this must also be viewed within the context of the north-south divide between energy generation and consumption, including high energy exports from Germany to Austria. A significant share of the electricity sold is generated in northern Germany and flows in "loop flows" through the networks in Poland and the Czech Republic to Austria. However, the networks in the neighbouring eastern countries and interconnectors with Germany are not of a sufficient scale to handle these loop flows. Without countermeasures, the security of supply in these countries would therefore be jeopardised.

To avoid power outages, TSOs must ensure that the network load caused by electricity flows does not reach a level that could damage or destroy network components. To prevent this from happening, TSOs take precautionary steps known as redispatch measures, whereby TSOs instruct power plants upstream of the network sections at risk to reduce their feed-in in order to reduce network damage at this point. Alternatively, or simultaneously, power plants downstream of the overloaded sections are instructed to increase their feed-in accordingly.

When an imbalance between north and south occurs, there is a surplus of electricity fed into the grid in northern Germany while demand for energy in southern parts of Germany is higher than feed-in there. As a rule, there is sufficient plant capacity in southern Germany for TSOs to implement the necessary redispatch measures. This applies especially in winter when it is extremely cold, energy consumption is very high and feed-in from wind and solar installations is low (known as "dark phases"). However, when winds are particularly high the capacity of power plants in southern Germany is too low to provide the necessary redispatch capacity for secure network operation.

In light of this, TSOs have to find the additional redispatch capacity needed to manage such situations. To do so, they call on reserve power plants. In Germany, reserve power plants are plants which are no longer in service or which are about to be taken offline. These plants can be instructed to remain on standby for exclusive use by TSOs and, upon their request, to feed electricity into the grid for the redispatch measure. Reserve capacity is also sourced from plants in neighbouring countries. Contracts are concluded with the plant operators, on the basis of which the plants can be called on to provide reserve capacity. To date contracts have been concluded with plant operators in Austria, Italy, France and Switzerland.

The total reserve capacity calculated by TSOs and subsequently confirmed by the Bundesnetzagentur was 3,636 MW for 2014/2015. This includes the additional reserve capacity required due to the early closure of the Grafenrheinfeld nuclear power plant, which was brought forward from the end of 2015 to the end of June 2015.

Reserve capacity was needed for a total of seven days in winter 2014/2015. On 20 December 2014 some 2,411 MW of the total available reserve capacity was used. In addition to strong winds, which are the main reason for TSOs to request additional capacity from reserve power plants, the decision to use reserve plants on this day was driven mainly by the high unavailability of power plants in southern Germany. Similar conditions were observed on 22 December 2014, but only 785 MW of additional capacity was required on that day. The next request for around 1,600 MW was made on 16 March 2015 after a particularly high level of feed-in from renewable energy power plants of 10 GW was forecast in the control area of 50Hertz in the period around noon. Reserve power plant capacity was used again in the period from 30 March to 2 April 2015 due to storm Niklas. The maximum feed-in from renewable energies reached a new high of 47.6 GW on 30 March 2015 between the hours of 14:00 and 15:00. The total available reserve capacity of 3,636 MW was largely exhausted during individual hours of this four-day period.

For the period 2015/2016 TSOs and the Bundesnetzagentur have for the first time identified and confirmed a range of between 6,700 MW and 7,800 MW for required reserve capacity. This was prompted by the fact that the exact volume of reserve capacity can only be determined once the TSOs know which power plants they can ultimately call on for reserve capacity. The exact volume of reserve capacity therefore depends on the geographical location of available reserve power plants. For example, to avoid overloading from west to east it is more effective to use power plants in Poland than power plants in neighbouring countries to the south of Germany. However, because no suitable bids were made by Polish power plant operators, the required reserve capacity of 7,515 MW is near the upper end of the specified range. The reserve capacity of 7,515 MW consists of 2,995 MW from domestic reserve power plants and 3,413 MW from foreign reserve power plants, which was contracted prior to 2015. An additional 1,107 MW of foreign reserve capacity was contracted in 2015.

Reserve power plants also include those plants in Germany, the closure of which has been prohibited by either TSOs (in the case of systemically relevant temporary closures) or the Bundesnetzagentur (in the case of systemically relevant final closures). To prevent closure-related risks to system security, plant operators are obliged to give notification of planned closures (section 13a of the EnWG). From the end of 2012 to the beginning of November 2015 notification was provided for the closure of a total of 69 power generation units with a net nominal capacity of 14,367.7 MW.

Notification has been given for the final closure of 50 power generation units with a total net nominal capacity of 9,185.1 MW and for the temporary closure of 19 plants with a total net nominal capacity of 5,182.6 MW.

Of these closure notifications, a total of 36 relate to the period from January 2014 to November 2015. These plants account for a total generation capacity of 6,016.8 MW. 27 plants with a generation capacity of 3,325.7 MW are marked for final closure, while nine plants with a total generation capacity of 2,691.1 MW are marked for temporary closure. Of all the notifications of final plant closures, ie including those submitted before January 2014, 11 plants with a total generation capacity of 2,727.4 MW have now been declared systemically relevant by the responsible TSOs. The systemic relevance of four of these plants, with a total net nominal capacity of 1,022 MW, was confirmed by the Bundesnetzagentur in 2014. Thus far in 2015 the Bundesnetzagentur has confirmed the systemic relevance of two plants with a total generation capacity of 1,037 MW. Of all the notifications of temporary plant closures, six plants with a capacity of 1,788.1 MW were declared to be systemically relevant by TSOs in 2015. A total domestic redispatch potential of 3,847.1 MW has therefore been secured since January 2014.

The future development of Germany's power plant fleet is based on the planned expansion of power plant capacity (see section I.A.3.1) and the above-mentioned notifications of planned power plant closures. This is relevant for the future security of supply. The figure below shows the regional distribution of the expected expansion and reduction of power generation units with a minimum capacity of 10 MW for the period up to 2019. The figure shows the locations of power generation units which have been marked for final closure. It also takes into account the statutory decommissioning of nuclear power plants by 2019. Not included is the planned decommissioning in 2021 and 2022 of the Brokdorf, Gundremmingen C, Grohnde, Neckarwestheim 2, Lingen and Isar 2 nuclear power plants, with a total net capacity of 8,107 MW. Likewise, planned temporary plant closures are not included as, unlike final closures, these can be brought back online pursuant to section 13a(1) EnWG for the purposes of supply security.

In Germany as a whole, the capacity expansion of power generation units under construction (5,110 MW) exceeds the capacity marked for final closure by 2019 (4,186 MW) by 924 MW. The total number of plants marked for final closure does not include systemically relevant power plants as the closure of such power plants is prohibited. For the purposes of supply security, a differentiated analysis of northern and southern Germany is of interest in connection with the future development of power plants. In line with scientific data and public debate, the Main river line will hereinafter be used as the dividing line between northern and southern Germany. South of the Main, 621 MW of power plant capacity is currently under construction. By contrast, a capacity of 2,944 MW is marked for final closure in southern Germany by 2019. Some 2,686 MW of this is attributable to the Gundremmingen B (scheduled for decommissioning in 2017) and Philippsburg 2 (scheduled for decommissioning in 2019) nuclear power plants alone. This leaves a considerable deficit of -2,323 MW in southern Germany by 2019. Conversely, the planned expansion of power plants north of the Main river exceeds planned closures. A total capacity of 4,489 MW is under construction (including Datteln 4) compared with the planned closure of plants with a capacity of 1,242 MW. This equates to a positive balance of 3,247 MW by 2019. Based on this outlook for non-renewable power plants, the north-south divide will be further compounded by 2019.

Locations with an expected increase or decrease in power generation capacity

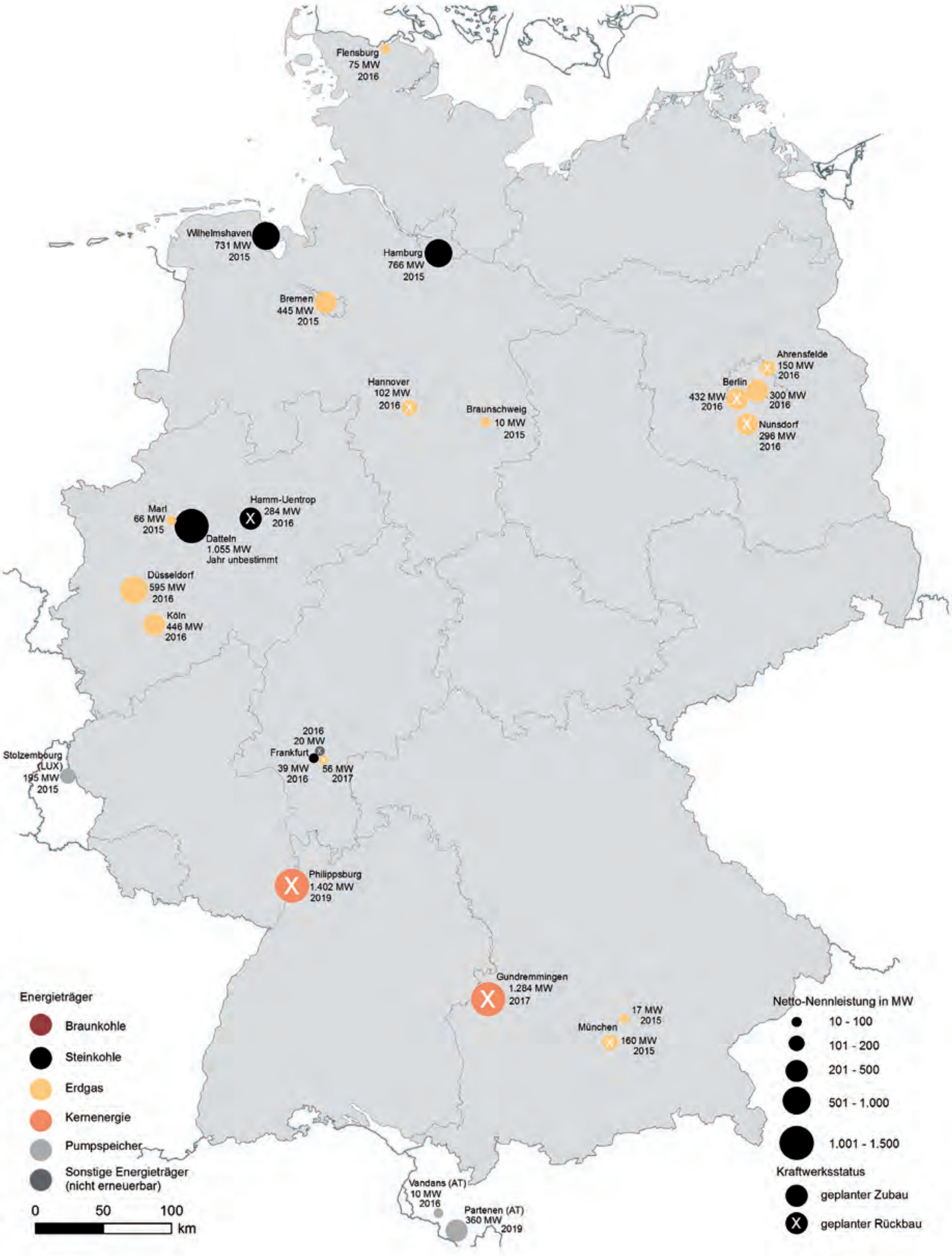

Figure 20: Locations with an expected increase or decrease in power generation units (as of September 2015)

In addition to the above-mentioned formal notifications of planned final closures, the Bundesnetzagentur was also informed of further plans to close power generation units during the course of its monitoring activities. The final closure of a total additional capacity of 1,717 MW is thus expected by 2019. This relates specifically to brown-coal power plants with a capacity of 1,208 MW[15], hard-coal fired power plants with a capacity of 288 MW, natural gas power plants with a capacity of 187 MW and other energy sources with a capacity of 34 MW.

The total reduction in power plant capacity by 2019 is therefore expected to be 5,903 MW. Some 2,944 MW of this is located in southern Germany. In Germany as a whole, the overall balance of the expansion and reduction of power plant capacity by 2019, including the pumped storage plants under construction in Luxembourg and Austria, is therefore -793 MW. This balance is calculated on the basis of power generation units under construction minus formal notifications of final plant closures pursuant to section 13a(1) EnWG, nuclear power plant closures and final closures identified through the monitoring process. The overall balance for southern Germany in the same period is much less favourable (-2,323 MW).

3.3 Supply disruptions in the electricity network

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

874 network operators reported some 173,825 interruptions in supply for 884 networks in 2014 for the calculation of the system average interruption duration index (SAIDI) for end customers.[16] The figure of 12.28 minutes calculated for the low and medium voltage levels is much lower than the average figure for the last eight years (average for 2006 to 2013: 16.72 minutes). The reliability of electricity supply was therefore 99.998%. The quality of supply thus maintained a constant high level throughout 2014.

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[15] Standby mode for backup purposes ("*Sicherheitsbereitschaft*") pursuant to section 13g EnWG-E is not taken into account here.

[16] The SAIDI is calculated for Germany by weighting all reported supply interruptions – for low voltage levels – by the number of end customers affected and – for medium voltage levels – by the interrupted rated apparent power.

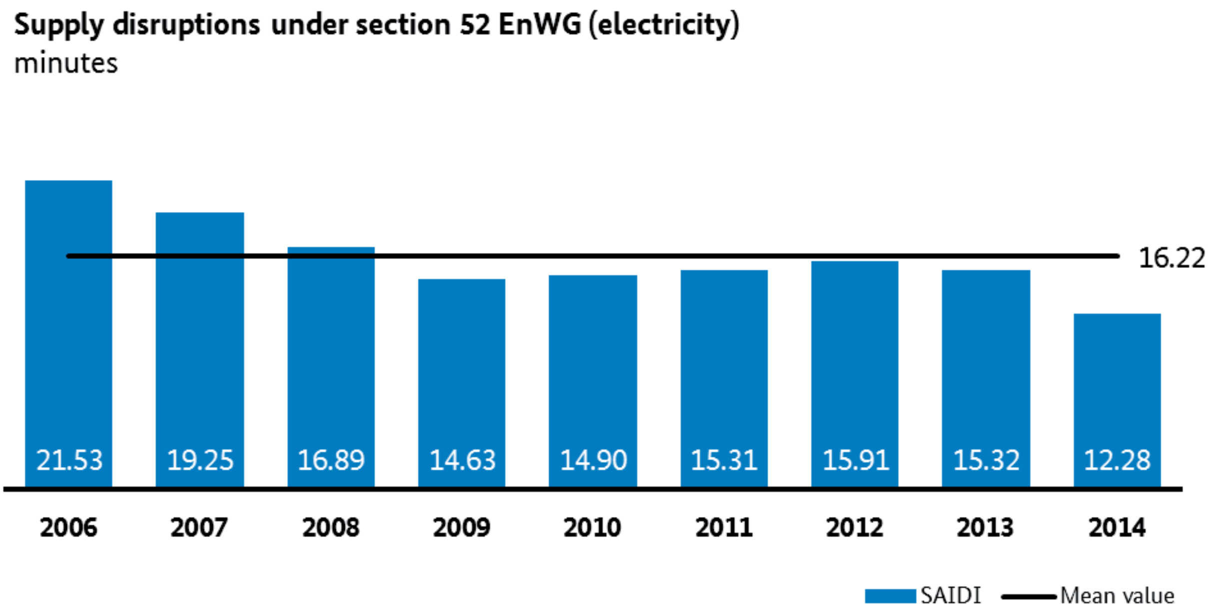

Figure 21: Supply disruptions under section 52 EnWG (electricity)

The decrease in the average interruption duration is due mainly to a decrease of 2.76 minutes from 12.85 minutes to 10.09 minutes at the medium voltage level. The average interruption duration at the low voltage level also decreased by 0.28 minutes from 2.47 minutes to 2.19 minutes.

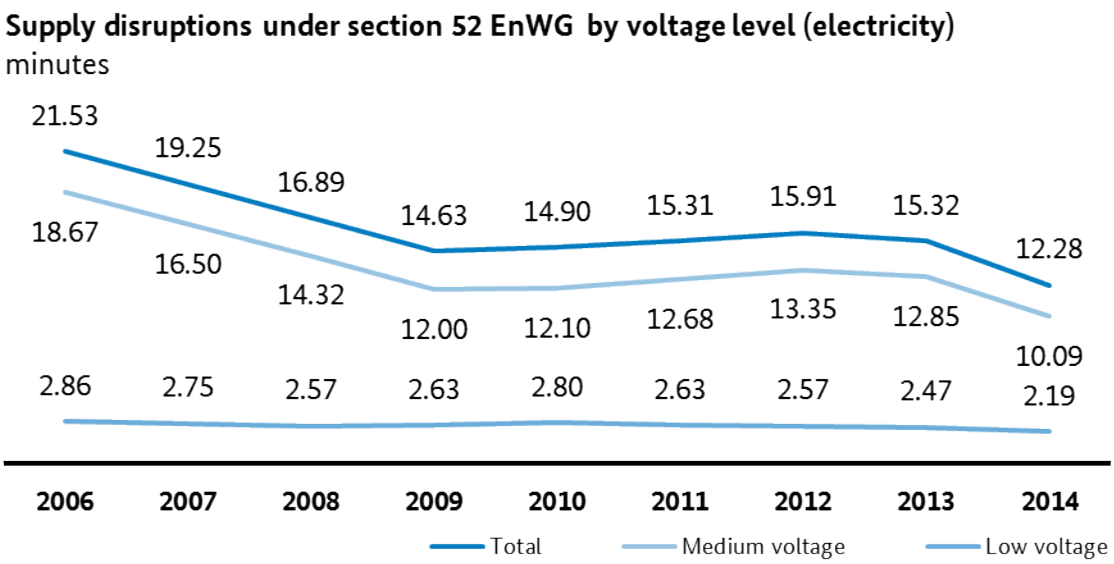

Figure 22: Supply disruptions under section 52 EnWG by voltage level (electricity)

There were several reasons for the improvement in quality of supply in 2014. A significant factor was the considerable reduction in “atmospheric effects” and “disruptions caused by ripple effects” (approximately 35% in each case). According to the Bundesnetzagentur, atmospheric effects primarily include thunderstorms, storms, ice, sleet, snow, hoar frost, fog, condensation (including in connection with pollution), moisture penetration from rainfall, thaw, flooding, cold, heat and conductor gallop. The reduction in this type of disruption can be attributed to the fact there were few extreme weather events in 2014.

Disruptions caused by ripple effects are defined as supply interruptions in a network caused by a disturbance in an upstream or downstream network or at the end customer's facility or by an interruption in supply at power plants feeding in electricity. A substantial share of disruptions caused by ripple effects is attributable to atmospheric effects at upstream network levels. A concurrent decrease in both causation factors is therefore plausible.

There was also a slight reduction in disruptions "in the network operator's area of responsibility". These include interruptions in supply caused by, for example, operating switching equipment with mechanical faults, swapping equipment, operating errors, overloading equipment, and faults in support, protection and other technical equipment.

In the case of supply disruptions caused by "third-party intervention", there were no perceptible changes compared with the previous year.

There are no grounds to believe that the *Energiewende* and the associated increase in decentralised power generation had a significant effect on the quality of energy supply in 2014.

A further reduction in the number of supply disruptions was observed in 2014. Overall the number of supply disruptions fell by 5,314 year on year (2014: 173,825; 2013: 179,139).

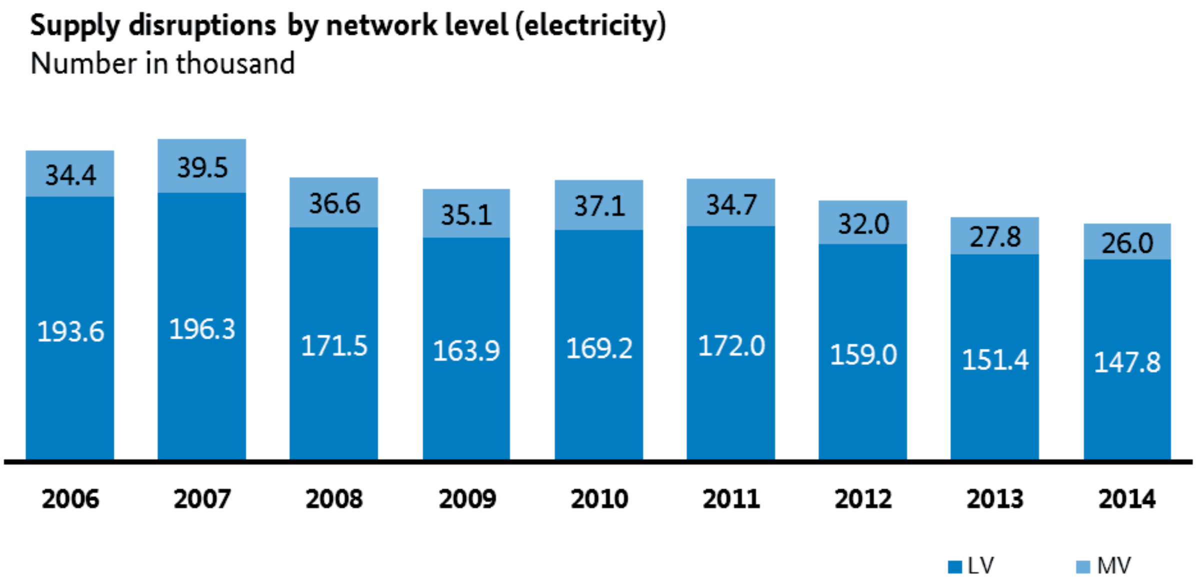

Figure 23: Number of supply disruptions by network level (electricity)

The SAIDI value does not take into account planned interruptions, nor those which occur owing to force majeure, for instance natural disasters. Only unplanned interruptions caused by atmospheric effects, third-party intervention, ripple effects from other networks or other disturbances in the network operator's area are included in the calculations.

C Networks

1. Status of network expansion

1.1 Power Grid Expansion Act 2009

The purpose of the Power Grid Expansion Act (EnLAG), which was passed in 2009, is to speed up the installation of extra-high voltage electricity lines for expanded transmission networks. For the first time this Act sets down in law the power line construction measures which are necessary.

The current amendment to this legislation specifies 23 projects which require urgent implementation in order to meet energy requirements. The transmission system operators have not included EnLAG Project 24 in the 2024 network development plan as there are alternative grid solutions available and this project is no longer required to meet energy demand.

The four German transmission system operators (TSOs), TenneT, 50Hertz, Amprion and TransnetBW, are responsible for planning, establishing and operating these projects. The relevant federal state authorities are responsible for conducting the applicable spatial planning and planning approval procedures for construction of a total of 1,876 km of new lines. The Bundesnetzagentur regularly documents the status of approval procedures for specific projects on its website at http://www.netzausbau.de. This is based on the current state of construction and planning work, as detailed in quarterly reports produced by the four TSOs.

Of the total 1,876 kilometres of lines which are required, 558 kilometres (or around 30%) have so far been constructed based on the third quarterly report for 2015. The TSOs expect around 40% of the kilometres of line provided for by the Power Grid Expansion Act (EnLAG) to be completed by 2016. To date, none of the projects with pilot routes for underground cables has gone into operation. TSO Amprion is carrying out the final construction work for the first 380-kV underground cable pilot project in Raesfeld.

The following map shows the current expansion status of EnLAG procedures up to the third quarter of 2015:

Progress on expanding power lines under the Power Grid Expansion Act (EnLAG) by the third quarter of 2015

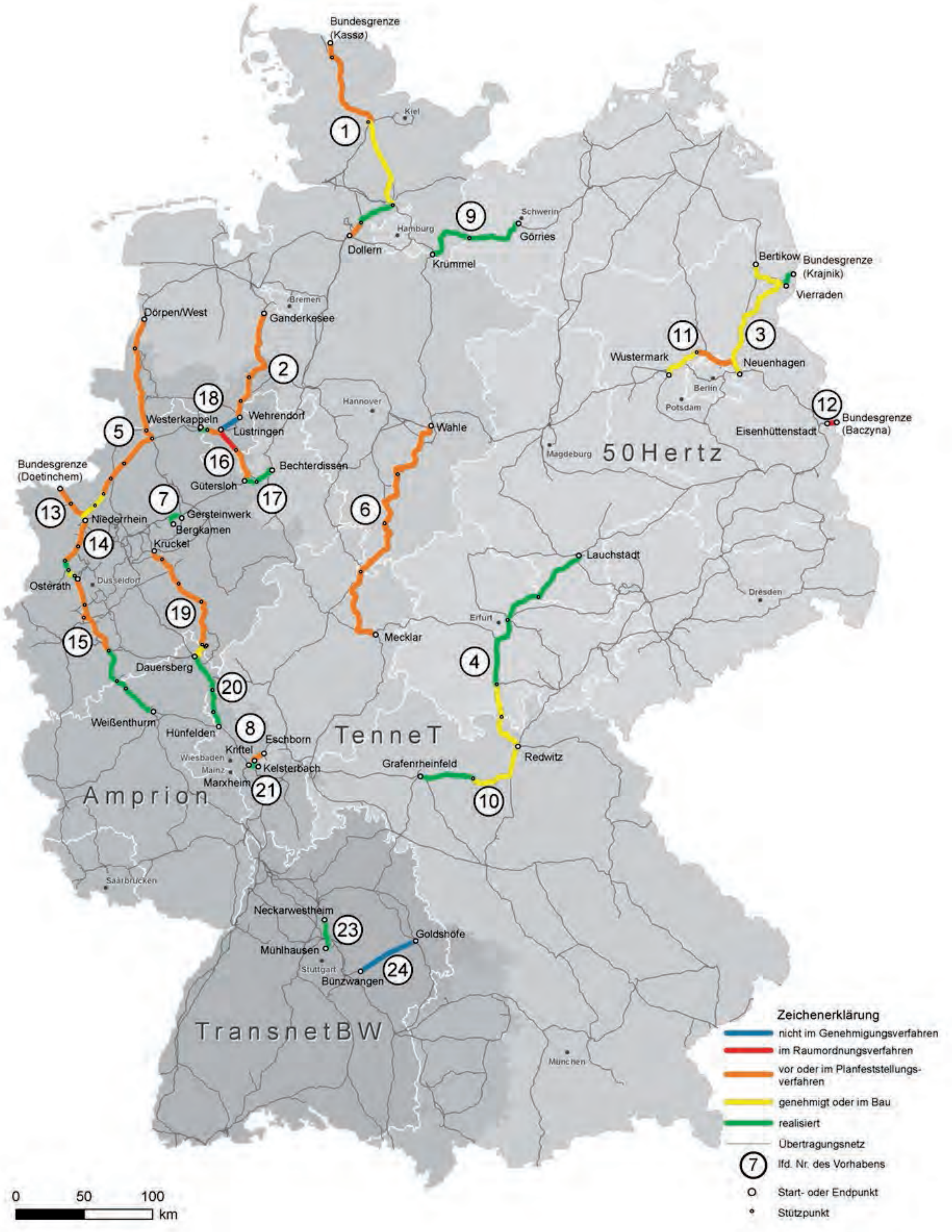

Figure 24: Progress on expanding power lines under the Power Grid Expansion Act (EnLAG) by the third quarter of 2015

1.2 Scenario framework

Both network development plans are based on the scenario framework which is produced once a year by the TSOs in compliance with section 12a EnWG and which is subject to the approval of the Bundesnetzagentur. The scenario framework presents different development pathways (scenarios) to describe the probable development of electricity generating capacity and consumption in ten and twenty years' time.

The first two scenario frameworks were approved by the Bundesnetzagentur at the end of 2011 and 2012 and the third scenario framework in August 2013.

The fourth scenario framework was approved by the Bundesnetzagentur in December 2014. This lays the groundwork for the 2025 onshore electricity network development plan and the 2025 offshore electricity network development plan. This scenario framework takes account of both the changed framework conditions emerging from the reform of the Renewable Energy Sources Act (EEG) and the federal government's climate change objectives (carbon emission reduction targets and improved efficiency in the electricity sector).

Installed generating capacity in the 2015 scenario framework
(GW)

Energy source	Reference 2013	Scenario A 2025	Scenario B1 2025	Scenario B1 2035	Scenario B2 2025	Scenario B2 2035	Scenario C 2025
Nuclear	12.1	0.0	0.0	0.0	0.0	0.0	0.0
Brown coal	21.2	14.2	12.6	9.1	12.6	9.1	10.2
Hard coal	25.9	25.8	21.8	11.0	21.8	11.0	14.9
Natural gas	26.7	26.5	29.9	40.7	29.9	40.7	29.5
Oil	4.1	1.3	1.1	0.8	1.1	0.8	1.1
Pumped storage	6.4	8.6	8.6	12.7	8.6	12.7	8.6
Other non-renew. sources	4.7	3.2	3.1	3.1	3.1	3.1	3.1
Total generation non-renew. sources	**101.1**	**79.6**	**77.3**	**77.5**	**77.3**	**77.5**	**67.4**
Onshore wind	33.8	53.0	63.8	88.8	63.8	88.8	59.0
Offshore wind	0.5	8.9	10.5	18.5	10.5	18.5	10.5
Solar photovoltaics	36.3	54.1	54.9	59.9	54.9	59.9	54.1
Biomasse	6.2	6.4	7.4	8.4	7.4	8.4	6.4
Hydro	3.9	3.9	4.0	4.2	4.0	4.2	3.9
Other renewable sources	0.4	0.5	0.8	1.2	0.8	1.2	0.5
Total generation renew. sources	**81.1**	**126.8**	**141.4**	**181.0**	**141.4**	**181.0**	**134.4**
Total generation	**182.2**	**206.4**	**218.7**	**258.5**	**218.7**	**258.5**	**201.8**

Net electricity consumption
(TWh)

Net electricity consumption[1]	543.6	543.6	543.6	543.6	543.6	543.6	516.4

Annual peak load
(GW)

Annual peak load[2]	82.8	84.0	84.0	84.0	84.0	84.0	79.8

Market modelling

	Max. carbon emissions of		
Requirements for market modelling	187m tonnes in 2025	134m tonnes in 2035	187m tonnes in 2025

Table 15: talled generating capacity in scenario framework 2025

1.3 Onshore electricity network development plan 2024

The amendment of the Energy Act (EnWG) in 2011 created a new procedure for the expansion of the extra-high voltage network. Since 2012 the four German TSOs have been required to produce annual network development plans which detail all the effective measures for improving the grid to meet demand and for reinforcing and expanding the onshore grid which will be necessary in the next ten to twenty years to ensure continued operation of the network. Network development plans are produced every year and this allows them to take account of new economic and technological developments and changes from a very early stage. The network development plans are consulted by TSOs and the Bundesnetzagentur and are then examined and subsequently confirmed by the Bundesnetzagentur. The confirmed network development plans are submitted to the federal government in the form of a draft Federal Requirements Plan Act by the Bundesnetzagentur at least every three years. The federal requirements plan adopted by the legislator endorses the energy economy's urgent need for the projects specified in the plan.

The transmission system operators published the first draft of the 2024 onshore electricity network development plan on 16 April 2014 for consultation up to 28 May 2014. They then submitted the revised draft plan to the Bundesnetzagentur for evaluation on 4 November 2014. The analyses and calculations undertaken by the TSOs for the 2024 network development plan do not differ significantly from previous expansion planning. All the scenarios confirm a high level of demand for north-south transmissions. Most of the projects in the federal requirements plan will be retained. The revised 2024 draft network development plan does, however, include some important changes to the first draft (including a new form of regionalisation and changes in grid connection points). The Bundesnetzagentur carefully evaluated the revised draft in the period from early November 2014 through to the end of February 2015 and held consultations from the end of February through to mid May 2015. Over 34,000 comments were received by the Bundesnetzagentur during the consultation procedure.

The Bundesnetzagentur confirmed 63 of the 92 measures applied for by the TSOs. These measures include around 3,050 km of optimisation and reinforcement measures to existing routes and around 2,750 km of newly constructed routes. The outcome of the confirmed 2024 network development plan therefore basically reflects the results of the Bundesnetzagentur's evaluation as published in February 2015. However, one important addition is the conclusion reached by the Bundesnetzagentur in its evaluation of corridor D that a link between Wolmirstedt and Isar/Landshut would also be suitable as a southern grid connection point. This would necessarily entail the regional strengthening of the AC grid between Ottenhofen and Oberbachern. This supplementary evaluation of corridor D was launched on the basis of coalition talks held on 1 July 2015. The Bundesnetzagentur nonetheless upholds its confirmation of the Wolmirstedt-Gundremmingen link as it is limited to the legally enshrined technical aspects of the grid which are necessary for an evaluation of the energy supply requirements. It is the prerogative of the legislator to decide what additional aspects should be included or not, or what aspects should be weighted differently, when making binding specifications on the required grid expansion measures in the Federal Requirements Plan Act. On this basis the alternative measure from Wolmirstedt to Isar / Landshut, including the additionally required strengthening measures for the AC grid, may also be given priority.

In order to take some of the pressure off of the Grafenrheinfeld region, the Bundesnetzagentur has called on the TSOs, in its confirmation of the 2024 network development plan, to develop possible alternatives, as part of the 2025 network development plan, to the requested construction measures M28b and M74. This includes proposals which would replace the two measures with alternative measures with other grid connection points.

After completion of this evaluation of the 2025 network development plan - including the participation of public authorities and the general public as well as an electrotechnical assessment by the Bundesnetzagentur - a decision must then be taken as to whether and then how the grid connection points which are currently specified in the Federal Requirements Plan Act need to be changed.

Overview of NDP 2024 evaluation findings

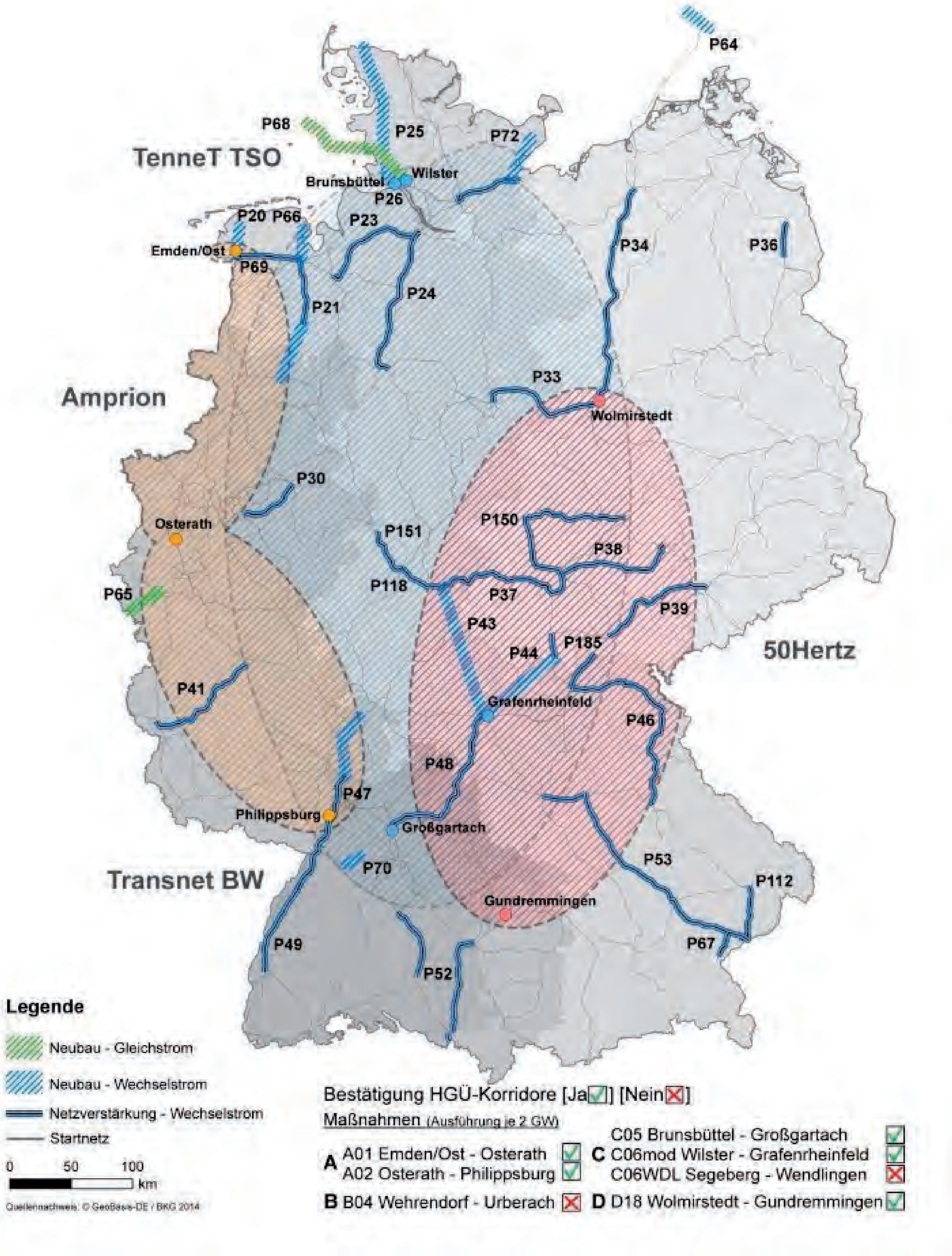

Figure 25: Overview of NDP 2024evaluation findings

Confirmed route measures NDP 2024

Project	Measure	Type	Planned complet. (TSOs)
Corridor A	A01: Emden/east – Osterath	Expansion of DC network	2022
Corridor A	A02: Osterath – Philippsburg	Reinforcement and expansion of DC network	2019
Corridor C	C05: Brunsbüttel – Großgartach	Reinforcement and expansion of DC network	2022
Corridor C	C06 mod: Wilster – Grafenrheinfeld	Expansion of DC network	2022
Corridor D	D18: Wolmirstedt – Gundremmingen	Expansion of DC network	2024
P20	M69: Emden/east – Halbemond region	Network expansion	2021
P21	M51a: Conneforde – Cloppenburg/east	Network reinforcement	2022
P21	M51b: Cloppenburg/east – Merzen	Network expansion	2022
P23	M20: Dollern – Elsfleth/West	Network reinforcement	2024
P24	M71: Schnee (previously Stade) – Sottrum	Network reinforcement	2021
P24	M72: Sottrum – Wechold	Network reinforcement	2022
P24	M73: Wechold – Landesbergen	Network reinforcement	2022
P25	M42: Süderdonn (previously Barlt) – Heide	Network expansion	2017
P25	M42a: Brunsbüttel – Süderdonn (previously Barlt)	Network expansion	2016
P25	M43: Heide – Husum	Network expansion	2018
P25	M44: Husum – Niebüll	Network expansion	2018
P25	M45: Niebüll – Danish border	Network expansion	2021
P30	M61: Hamm/Uentrop – Kruckel	Network reinforcement	2018
P33	M24a: Wolmirstedt – Helmstedt – Wahle	Network reinforcement	2022
P33	M24b: Wolmirstedt – Wahle	Network reinforcement	2024
P34	M22a: Perleberg – Stendal/West – Wolmirstedt	Network reinforcement	2020
P34	M22b: Parchim/south – Perleberg	Network reinforcement	2020
P34	M22c: Güstrow – Parchim/south	Network reinforcement	2020
P36	M21: Bertikow – Pasewalk	Network reinforcement	2018
P37	M25a: Vieselbach – Schmalwasser Dam pumped storage station (Sonneborn)	Network reinforcement	2022
P37	M25b: Schmalwasser Dam pumped storage station (Sonneborn) – Mecklar	Network reinforcement	2023

Table 16: Confirmed route measures NDP 2024 (corridor A - D; P20 - P37)

Confirmed route measures NDP 2024

Project	Measure	Type	Planned complet. (TSOs)
P38	M27: Pulgar – Vieselbach	Network reinforcement	2024
P39	M29: Röhrsdorf – Weida – Remptendorf	Network reinforcement	2021
P41	M57: Point Metternich – Niederstedem	Network reinforcement	2018-2021
P43	M74: Mecklar – Grafenrheinfeld (subject to the assessment of alternatives in NDP2025)	Network expansion	2022
P44	M28a: Altenfeld – Schalkau	Network reinforcement	2024
P44	M28b: Schalkau – Grafenrheinfeld (subject to the assessment of alternatives in NDP2025)	Network expansion	2024
P46	M56: Redwitz – Mechlenreuth – Etzenricht – Schwandorf	Network reinforcement	2020
P47	M31: Weinheim – Daxlanden	Network reinforcement	2022
P47	M32: Weinheim – G380	Network reinforcement	2022
P47	M33: G380 – Altlußheim	Network reinforcement	2022
P47	M34: Altlußheim – Daxlanden	Network reinforcement	2022
P47	M60: Urberach – Pfungstadt – Weinheim	Network expansion	2022
P48	M38a: Grafenrheinfeld – Kupferzell	Network reinforcement	2020
P48	M39: Kupferzell – Großgartach	Network reinforcement	2020
P49	M41a: Daxlanden – Kuppenheim – Bühl – Eichstetten	Network reinforcement	2021
P52	M93: Point Rommelsbach – Herbertingen	Network reinforcement	2018
P52	M94b: Point Neuravensburg – Point at German/Austrian border	Network reinforcement	2023
P52	M95: Point Wullenstetten – Point Niederwangen	Network reinforcement	2020
P53	M54: Raitersaich – Ludersheim	Network reinforcement	2024
P53	M350: Ludersheim – Sittling – Altheim	Network reinforcement	2024
P64	M107: Combined Grid Solution (CGS)	Network expansion	2018

Table 17: Confirmed route measures NDP 2024 (P38 - P64)

Confirmed route measures NDP 2024

Project	Measure	Type	Planned complet. (TSOs)
P65	M98: Oberzier – Point at German/Belgian border	Expansion of DC network	2018
P66	M101: Wilhelmshaven – Conneforde	Network expansion	2018
P67	M102: Simbach branch	Network reinforcement	2018
P67	M103: Altheim – German/Austrian border	Network reinforcement	2018
P68	M108: Germany – Norway	Expansion of DC network	2018
P69	M105: Emden/east – Conneforde	Network reinforcement	2019
P70	M106: Birkenfeld – mast 115A	Network expansion	2019
P72	M351: Göhl region – Lübeck region	Network expansion	2021
P72	M49: Lübeck region – Siems	Network reinforcement	2021
P72	M50: Lübeck region – Segeberg district	Network reinforcement	2019
P112	M201: Pleinting – St. Peter	Network reinforcement	2022
P112	M212: Pirach branch	Network reinforcement	2022
P118	M207: Borken – Mecklar	Network reinforcement	2021
P150	M352: Lauchstädt – Wolkramshausen – Vieselbach	Network reinforcement	2024
P151	M353: Borken – Twistetal	Network reinforcement	2021
P185	M420: Redwitz – Bavaria/Thuringia state border (Tschirn)	Network reinforcement	No data provided

Table 18: Confirmed route measures NDP 2024 (P65 - P185)

Overview of kilometres

	NDP 2024 2nd draft (TSOs)	NDP 2024 confirmed	NDP 2024 not confirmed	NDP 2023 confirmed	BBPlG 2013
AC construction	650 km	648 km	2 km*	600 km	650 km
DC corridors	2,300 km	1,750 km**	550 km	1,600 km	1,600 km
New DC interconnectors	350 km***	350 km***		450 km	450 km
AC network reinforcement	3,700 km	2,750 km	950 km	2,500 km	2,000 km
AC/DC switchover	300 km	300 km		300 km	300 km
Total	**7,300 km**	**5,798 km**	**1,502 km**	**5,450 km**	**5,000 km**

* This relates to measures P115 M205 and P154 M356, each covering 1 km of new AC line.

** On account of changes in corridor D this figure differs by 150 km compared with the prior year.

*** On account of changes in project P64 this figure differs by 100 km compared with the prior year.

Table 19: Overview of kilometres

Overview of number of measures

	total	confirmed	not confirmed
NDP 2024	92	63	29
of which in BBPlG	48	43	5

Table 20: Overview of number of measures

1.4 Offshore electricity network development plan 2024

In addition to their onshore network development plans, TSOs have also been required since 2013 to produce offshore expansion plans (offshore network development plans) for the connection of off-shore wind farms.

Between 16 April and 28 May 2014, the transmission system operators also put out the draft 2024 offshore network development plan for consultation, in parallel to the draft onshore network development plan, and submitted the revised draft to the Bundesnetzagentur for evaluation on 4 November 2014. The Bundesnetzagentur issued this revised draft with the draft for the onshore network development plan for consultation.

Following amendment of the EEG, installed generating capacity of 9.7 GW of offshore wind energy is anticipated for 2024. 8.5 GW of this capacity will be generated in the North Sea and 1.2 GW in the Baltic Sea. 7.1 GW are already covered in the North Sea by the "starting grid" and only a further 1.4 GW will need to be connected under the offshore network development plan. In the Baltic Sea the starting grid provides 1.1 GW, which means that just 0.1 GW will need to be connected under the 2024 offshore network development plan. As one transmission link in the North Sea has a transmission capacity of 900 MW, the Bundesnetzagentur has confirmed two such systems to link up the 1.4 GW which is still required. For the Baltic Sea the Bundesnetzagentur has confirmed a 500MW transmission link to enable the full connection of standard sized wind farms.

Overview of evaluation findings for the North Sea – NDP 2024

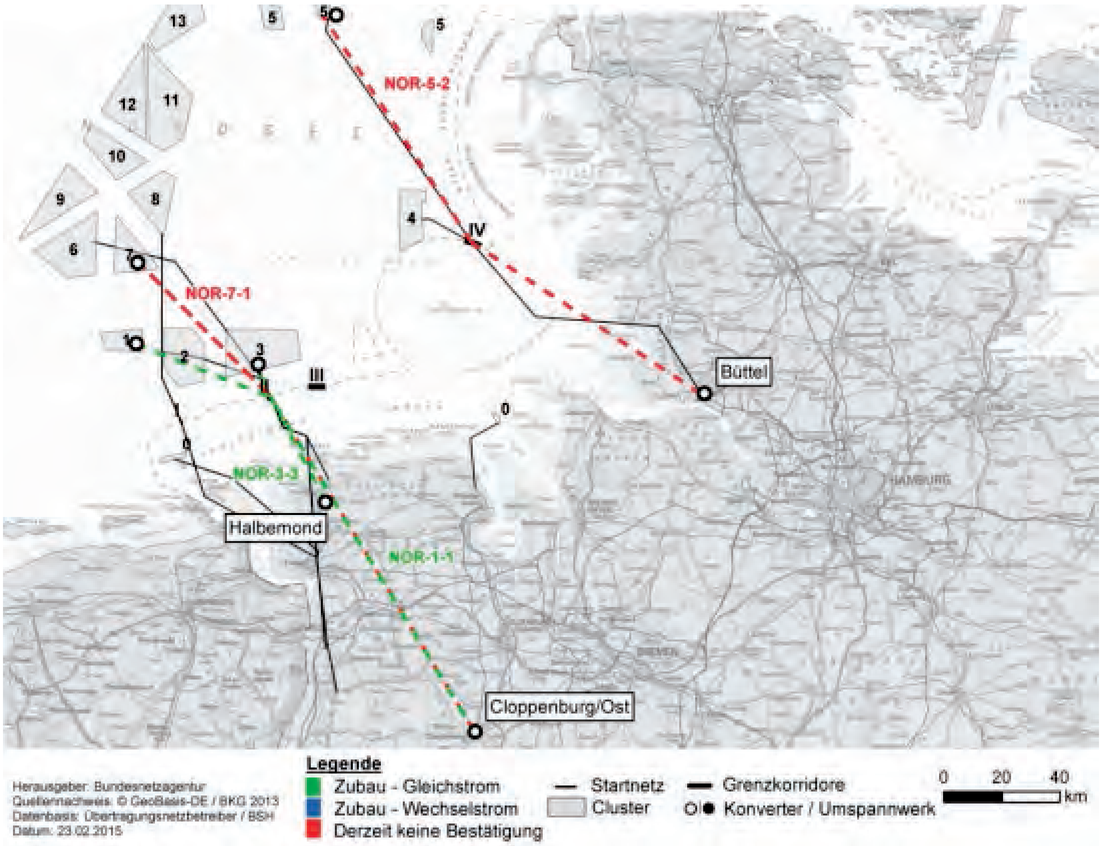

Figure 26: Overview of evaluation findings for the North Sea - NDP 2024

Overview of evaluation findings for the Baltic Sea - NDP 2024

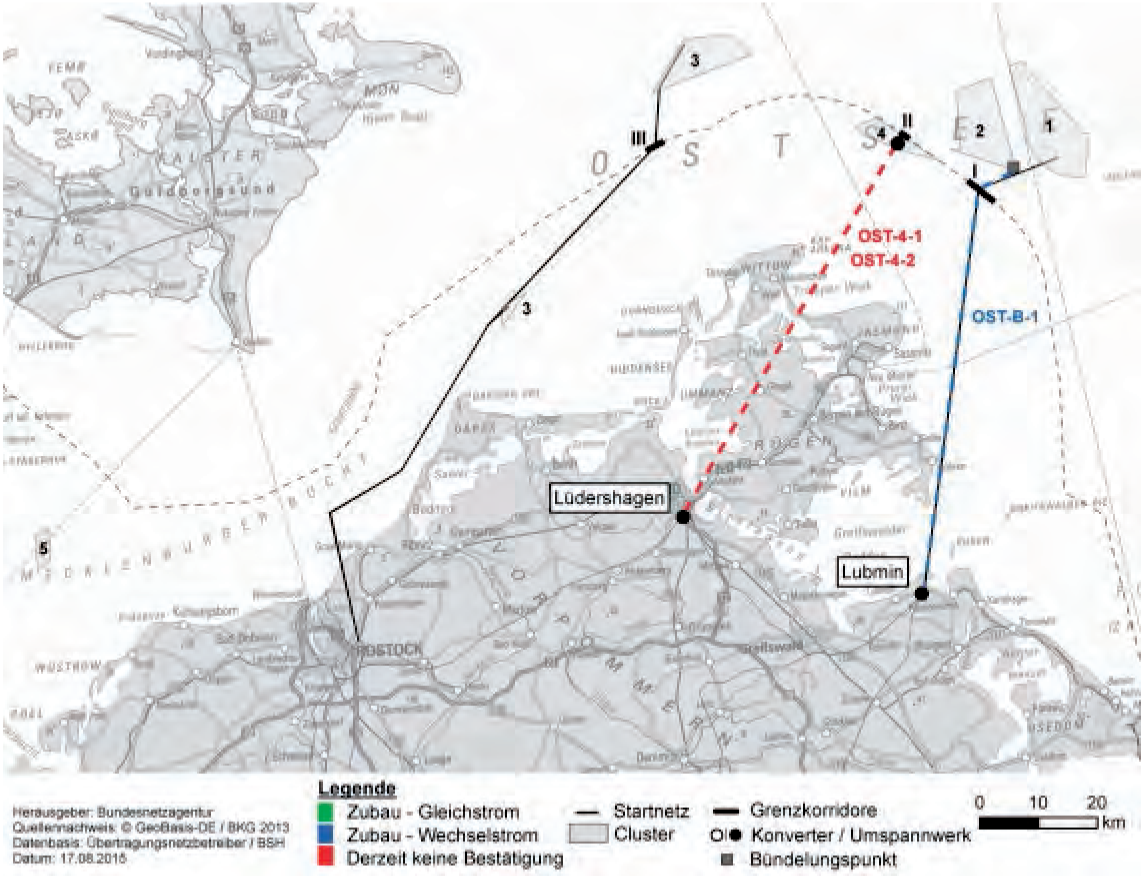

Figure 27: Overview of evaluation findings for the Baltic Sea - NDP 2024

1.5 Federal sectoral planning

The Federal Requirements Plan Act (BBPIG), which is based on the confirmed 2022 network development plan, came into effect in July 2013. The federal requirements plan identifies 36 projects which are necessary to meet energy supply requirements in Germany and to ensure that the grid remains secure and stable. 16 of these projects which cross state or national borders within the meaning of the Grid Expansion Acceleration Act are the responsibility of the Bundesnetzagentur. The Bundesnetzagentur will also carry out federal sectoral planning and go through the subsequent planning approval procedure.

Federal sectoral planning is the first step in specifying the actual spatial implications of projects. The outcome is legally binding for the following planning approval procedures.

The objective of this federal sectoral planning is to specify a spatially acceptable route corridor. These 500m to 1,000m wide corridors are where the extra-high voltage power lines will later run. One central feature and cornerstone of grid expansion is the high voltage direct current (HVDC) corridors. These lines must be completed as a matter of urgency, in part owing to the shutdown of nuclear power plants and their length of several hundred kilometres.

Alongside EnLAG project monitoring, the Bundesnetzagentur also publishes the procedural status of expansion projects under the Federal Requirements Plan Act on its website. Further detailed information about specific projects is also available.

Federal sectoral planning begins with an application submitted by the relevant project developer. Federal sectoral planning has been launched for the following projects for which the Bundesnetzagentur is responsible:

Project no. 11 BBPlG (Bertikow – Pasewalk)

The first formal procedure began in August 2014 with the application for federal sectoral planning for project no. 11 Federal Requirements Plan Act (Bertikow – Pasewalk) and the evaluation of the submitted documents by the Bundesnetzagentur.

The Bundesnetzagentur held a public scoping conference in Torgelow on 24 September 2014. The Bundesnetzagentur defined the study scope on the basis of the application documents and after taking into account the insights produced by the scoping conference and the information subsequently received about the environmental and spatial compatibility of the proposed route corridor and possible alternatives. This was published on 18 November 2014 and is available on the Bundesnetzagentur's website. The project developer submitted documents under section 8 NABEG in late July 2015. The Bundesnetzagentur is currently assessing whether these documents are complete.

Corridor A South: Project no. 2 under the Federal Requirements Plan Act Osterath – Philippsburg ("Ultranet")

Project developers Amprion and TransnetBW have submitted an application for federal sectoral planning to the Bundesnetzagentur for the first three of five envisaged sections of project no. 2.

The application for the first section between Riedstadt in Hesse and Mannheim-Wallstadt in Baden-Württemberg was submitted on 2 December 2014. The scoping conferences were held in Weinheim on 24 February 2015 and in Bingen on 3 March 2015. Two scoping conferences were required to consider an alternative between Bürstadt and Weißenthurm. The Bundesnetzagentur has defined the content of further evaluations with the help of the findings from the scoping conferences. The Bundesnetzagentur published the definition of the study scope on 25 June 2015, determining the required content of the documents which must be submitted by the project developer.

Project developer TransnetBW submitted its application for federal sectoral planning for the second section of Mannheim-Wallstadt to Philippsburg to the Bundesnetzagentur on 29 December 2014. The scoping conference for this section was held in the Stadthalle Hockenheim on 14 April 2015. After the scoping conference work began on preparing the study scope for this section under section 7(4) NABEG; this work was published in early September 2015. It defined for this section the required contents of the documents which must be submitted by the project developer (section 8 NABEG).

Amprion also made an application for federal sectoral planning for the third section from Osterath to Rommerskirchen in the middle of next year. In early October 2015, it submitted revised application documents which will be used for federal sector planning.

Amprion submitted an application for federal sector planning under section 6 NABEG for the section between Weißenthurm and Riedstadt on 29 October 2015. The Bundesnetzagentur is currently assessing whether these documents are complete.

Corridor C: Projects no. 3 and no. 4 under the Federal Requirements Plan Act
Brunsbüttel - Großgartach and Wilster - Grafenrheinfeld ("SuedLink")

On 12 December 2014, the responsible project developer, TenneT TSO GmbH (TenneT), submitted an application for federal sectoral planning for project no. 4 of the annex to the Federal Requirements Plan Act (BBPlG) from Wilster in Schleswig-Holstein to Grafenrheinfeld in Bavaria. The Bundesnetzagentur assessed the legal and technical aspects of the application and notified the project developer on 9 February 2015 that the submitted documents needed to be revised.

On 1 July 2015, the governing coalition agreed to give priority in law to underground cabling for HVDC projects. The route corridor proposed on 12 December 2014 and the proposed alternatives have nonetheless been developed by project developer TenneT in accordance with previous statutory regulations with priority being given to overhead lines.

The new policy will impact the ongoing federal sectoral planning procedure for project no. 4 of the "SuedLink". The Bundesnetzagentur assumes that this will continue with the determination of other corridor routes. This will have an impact on all the planning steps in the application. Project developer TenneT issued a public declaration on 28 July 2015 to the effect that prioritisation of underground cabling would require a realignment of the planning of any potential route corridors.

Project no. 3 between the grid connection points Brunsbüttel in Schleswig Holstein and Großgartach in Baden-Württemberg by project developers TenneT and TransnetBW, which is also part of "Suedlink", has not yet been applied for. The political agreement for "SuedLink" includes the objective of taking both projects across a shared main route across a distance which will be defined during the procedure. In this context the project coordinators have already announced that they will be submitting a revised application for federal sectoral planning for project no. 4 to coincide with the application for project no. 3 to the Bundesnetzagentur in order to exploit potential acceleration effects.

1.6 Network connection of offshore wind farms

The new EEG which came into force on 1 August 2014 represents a fundamental change in the regime for the connection of offshore wind farms. The legislator has limited the total connection capacity which may be allocated to offshore wind farms in the North and Baltic Seas to 6.5 GW. This volume will only rise from the year 2021 onwards by 800 MW annually. However, under the transitional arrangements in section 118(14) EnWG, the regulatory authority is authorised to allocate up to 7.7 GW prior to 1 January 2018.

On 20 August 2014 the Bundesnetzagentur stipulated rules for the allocation procedure for offshore connection capacity. These rules define the conditions which must be met for an application for allocation of transmission capacity on existing power lines or lines which are being built to connect wind farms to the grid. They also determine the way in which auctions are held if connection capacity is in short supply.

The Bundesnetzagentur opened the first allocation process based on these rules on 3 September 2014. Taking account of all existing unconditional grid connection commitments, it was possible to allocate up to

1,722.7 MW of the maximum allocable connection capacity of 7.7 GW on the planned grid connection lines in the North and Baltic Seas. The Bundesnetzagentur reached a decision on the admission of applicants to the allocation process on 23 October 2014. Appeals against the defined allocation process and the decision regarding admission to the process were lodged with the Oberlandesgericht Düsseldorf (Higher Regional Court Düsseldorf). After a settlement was reached on the advice of the Oberlandesgericht Düsseldorf and after the appeal was withdrawn the first allocation process was completed on 21 January 2015. A total of 1,511.6 MW of grid connection capacity in the North and Baltic Seas was allocated without an auction being conducted.

This meant that, upon conclusion of the first capacity allocation process, there was still 211.1 MW of maximum allocable capacity available. This capacity was offered in a second capacity allocation process which was opened by the Bundesnetzagentur on 1 April 2015. A total of six applications were admitted for participation in the second capacity allocation process. As the demand for capacity in the six offers which were admitted exceeded the maximum allocable capacity, an auction needed to be performed to arrive at a clear and appropriate result for the allocation of capacity. The auction was held on 3 November 2015. A total of four applications obtained the full volume of capacity applied for by auction; one application was partially met. The auction produced a market clearing price of €101.00/MW.

On 26 August 2014 the Bundesnetzagentur also opened a relocation procedure under section 17d(5) EnWG. This procedure concerned the relocation of the 400 MW feed-in capacity of the offshore wind farm Global Tech I from the BorWin 2 grid connection line to the BorWin 3 grid connection line. In this way the Bundesnetzagentur fulfilled its statutory duty to assess the possibility of promoting the orderly and efficient use and exploitation of offshore grid connection lines by relocating previously granted or existing network connections. In this procedure the Bundesnetzagentur reached a decision on 23 March 2015 to relocate the connection capacity of the "Global Tech I" offshore wind park of 400 MW from the BorWin 2 grid connection line in Cluster 6 to the BorWin 3 grid connection line in Cluster 8. The capacity then freed up on the BorWin 2 line of 400 MW can now be used to connect the 210 MW "Deutsche Bucht" offshore wind farm to the grid without the need to construct the BorWin 4 grid connection line. Not constructing the BorWin 4 line as part of the starting grid will save grid users around €1.8bn.

By 1 July 2015 a total of 28 applications had been submitted to the Bundesnetzagentur for the approval of investments in the connection of OWFs with a total volume of €20.2bn, of which 25 applications with a volume of €19.1bn have already been approved.

2. Investments

2.1 Investments in transmission networks (incl. cross-border interconnections)

In 2014 the four German TSOs together spent approximately €1,769m (2013: €1,335 m) on investment in and expenditure on network infrastructure. Included in this spending are investments in and expenditure on cross-border interconnections amounting to approximately €74m (2013: €16m). Actual expenditure on network infrastructure deviated by €16m from the planning values reported in 2013 (planning values for 2014: approximately €1,758m). The transmission system operators have thus met their planned investment and expenditure costs in full. Investments in new build, extension and expansion other than interconnections exceeded planned spending of €1,248m by around 19% (planned: €1,047m). In contrast, investments in maintenance and renewal and expenditure excluding interconnections were, at €206m and €241m, 60% and

44% below the planned values (planned €328m and €347m). The investments planned for interconnections in particular have increased by over fivefold for new build, extension and expansion at €71m compared with the previous year (previous year: €14m). Actual investments have doubled compared to planned investments (planned: €35m). Expenditure on cross-border interconnections of around €2.5m was made as planned. Total investments of around €2,327m and total expenditure of €318m are planned for the year 2015. This amounts to total investments and expenditure of around €2,644m or a planned increase of almost 50%. The following diagram shows the investments and expenditure, including interconnections, both separately and in aggregate since the year 2008 as well as the values planned for the year 2015.

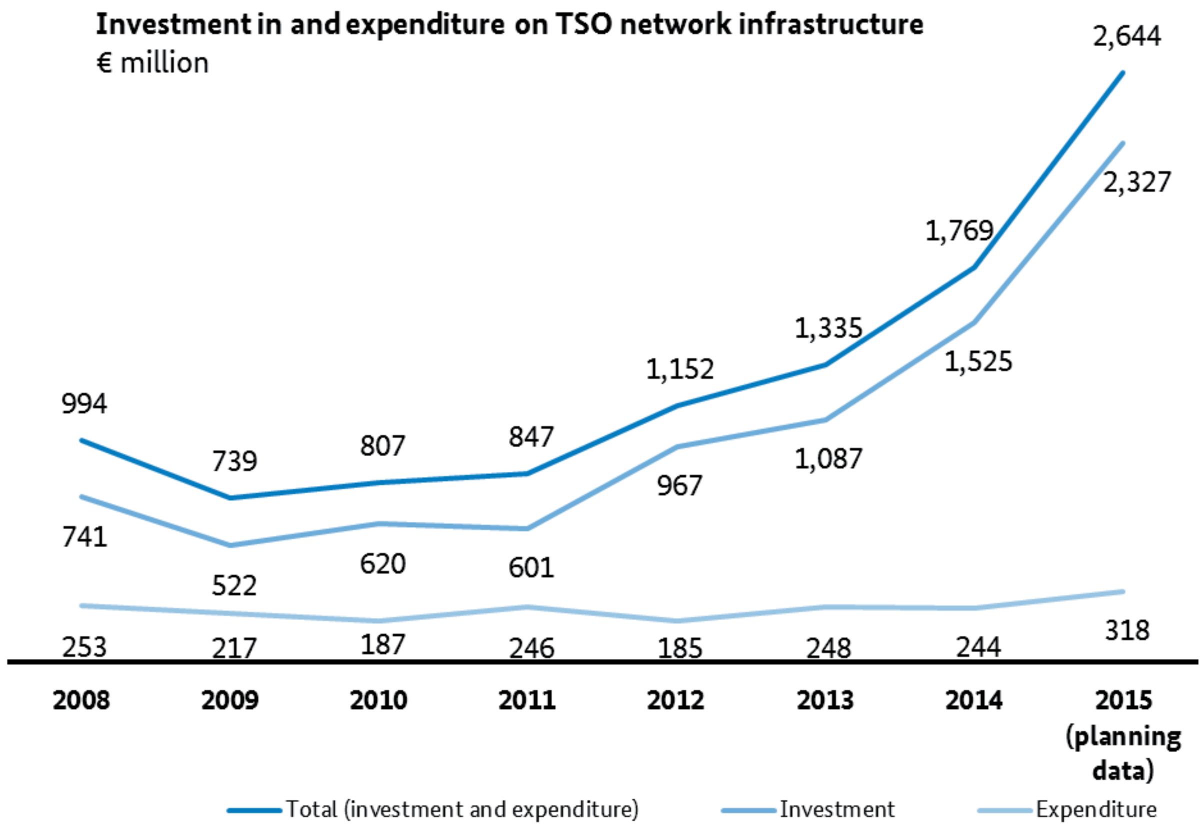

Figure 28: Investment in and expenditure on TSO network infrastructure since 2008 (including cross-border interconnections)

2.2 Investments and expenditure by electricity distribution system operators

Investments in and expenditure on network infrastructure by 808 DSOs totalled approximately €6,193m in 2014 (2013: €5,778m). This figure includes investments in and expenditure on metering/control devices and communication infrastructure amounting to approximately €478m (2012: €463m). The target volume of investment in distribution networks of €3,070m planned by DSOs for 2014 was exceeded by €134m with actual investment amounting to €3,204m. On the other hand, spending with a planned volume of €2,568m was substantially exceeded by €421m and amounted to €2,989m. Overall, with a plus of €555m, total DSO spending on the network infrastructure substantially exceeded the planning values for 2014 of €5,638m. For the coming year of 2015, the DSOs plan continuing growth in the volume of investment in the distribution networks for new installations, extension, expansion, maintenance and renewal of approximately 14% up to €3,646m and stable costs for spending of €3,002m.

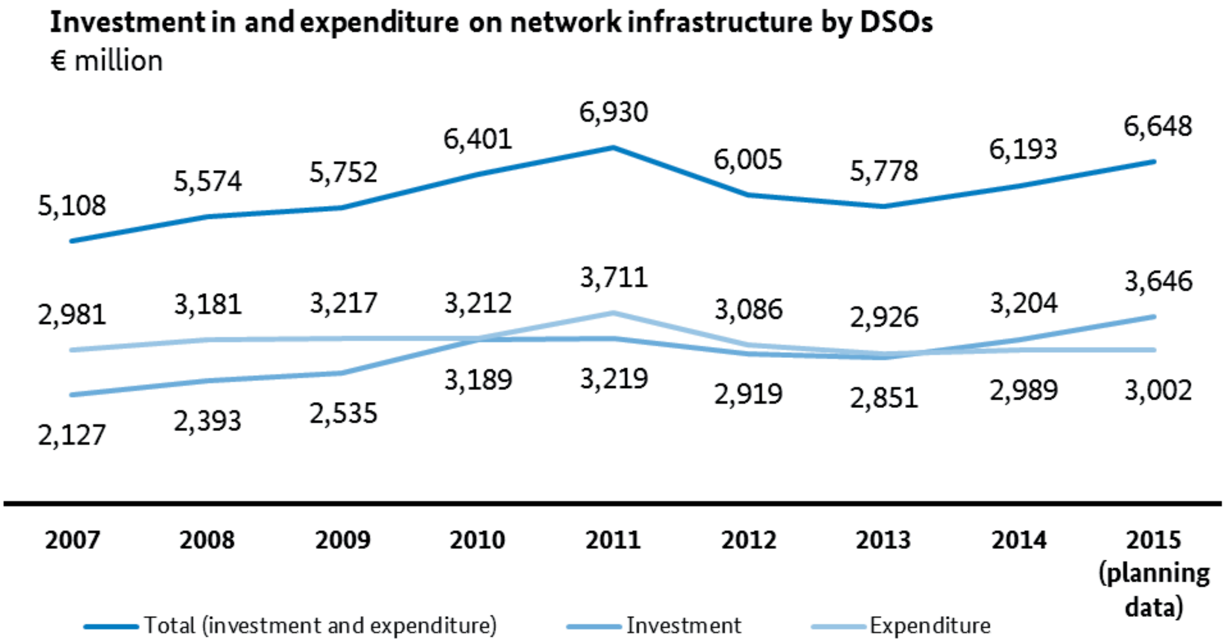

Figure 29: Investments in and expenditure on network infrastructure
(including metering/control devices and communication infrastructure) by DSOs

The level of DSO investment depends on circuit lengths, the number of meter points served as well as other individual structure parameters, including geographical circumstances. As a rule, DSOs tend to invest more the longer their circuits are. Almost one quarter of DSOs (196) are in the €0 to €100,000 investment category. Around 9% of companies (70) have peak investments of over €5m per network area. The following diagram shows the various categories of investment as percentages of the total number of network operators:

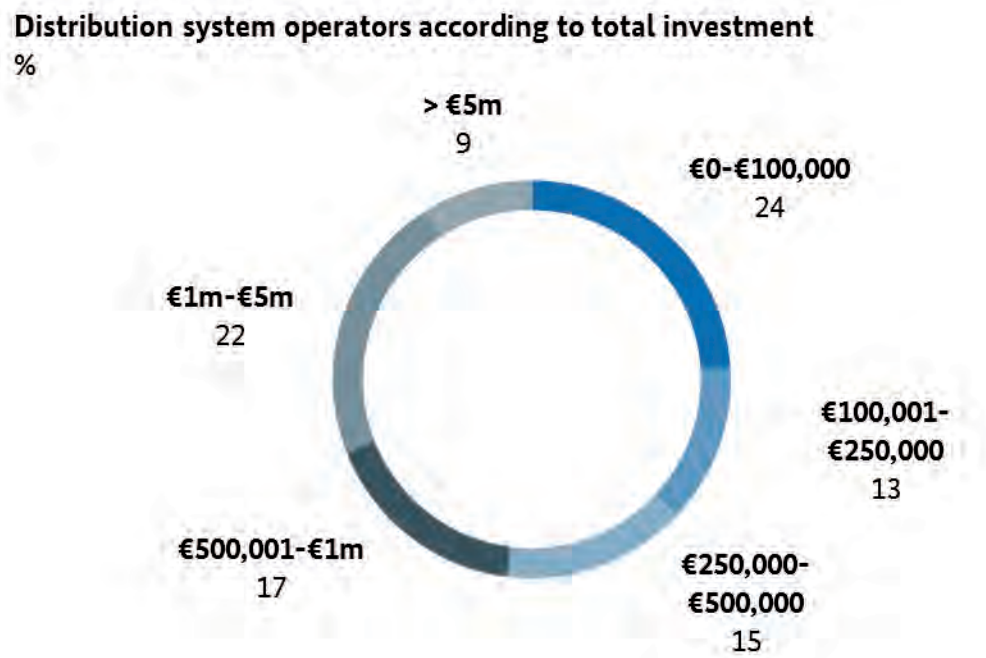

Figure 30: Distribution system operators according to total investment

The data notified for the monitoring report on the distribution of expenditure by DSOs shows that the number of companies reporting expenditure of up to €100,000 has risen by almost 100 to 36% (294 companies). There are 70 companies, accounting for 9% of the total, in the highest category with expenditure of over €5m. In the year under review 2014, almost half of the DSOs (49 percent) posted expenditure exceeding €250,000 for their networks:

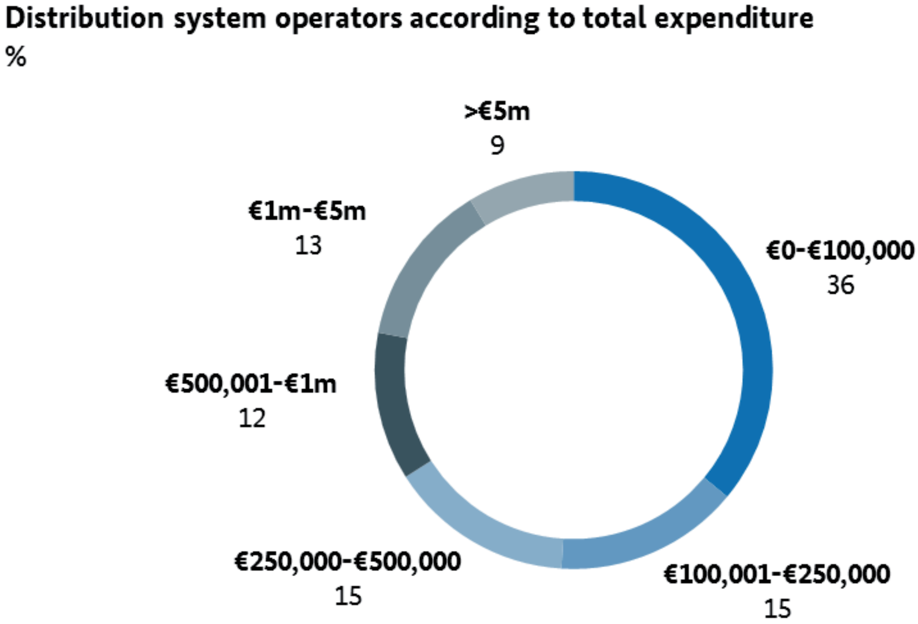

Figure 31: Distribution system operators according to total expenditure

2.3 Measures for the optimisation, reinforcement and expansion of the distribution system

The DSOs are obliged under section 11(1) EnWG and section 12 EEG to optimise, reinforce and expand their networks to reflect the state of the art without undue delay, in order to ensure the uptake, transmission, and distribution of electricity. The strong expansion in renewable energy installations, coupled with the legal obligation to connect and purchase regardless of network capacity, represents a considerable challenge for DSOs. Alongside conventional expansion measures, system operators are primarily responding to these challenges by developing increasingly smart grids which will allow them to adapt to changing requirements over time. The way forward and the measures adopted may differ considerably from one system operator to the next. Given the highly heterogeneous nature of grids in Germany, future energy developments mean that all DSOs need to develop and implement their own strategies for achieving efficient grid operations. It is actually quite useful in this context that so many networks are in any case due for modernisation. In many cases it will therefore be possible to convert grids by investing the financial returns from existing systems (intelligent restructuring) without any associated increases in network costs.

As of 1 April 2015 a total of 807 (1 April 2014: 817) DSOs had provided information about the extent to which they had taken action to optimise, reinforce and expand their networks. This means that slightly fewer measures to optimise and expand networks were taken than in the previous year. There was a slight increase, on the other hand, in the number of network reinforcement measures taken. The modernisation measures in the third year in succession have thus remained at a high and stable level. The following diagram shows the development of measures since 2009.

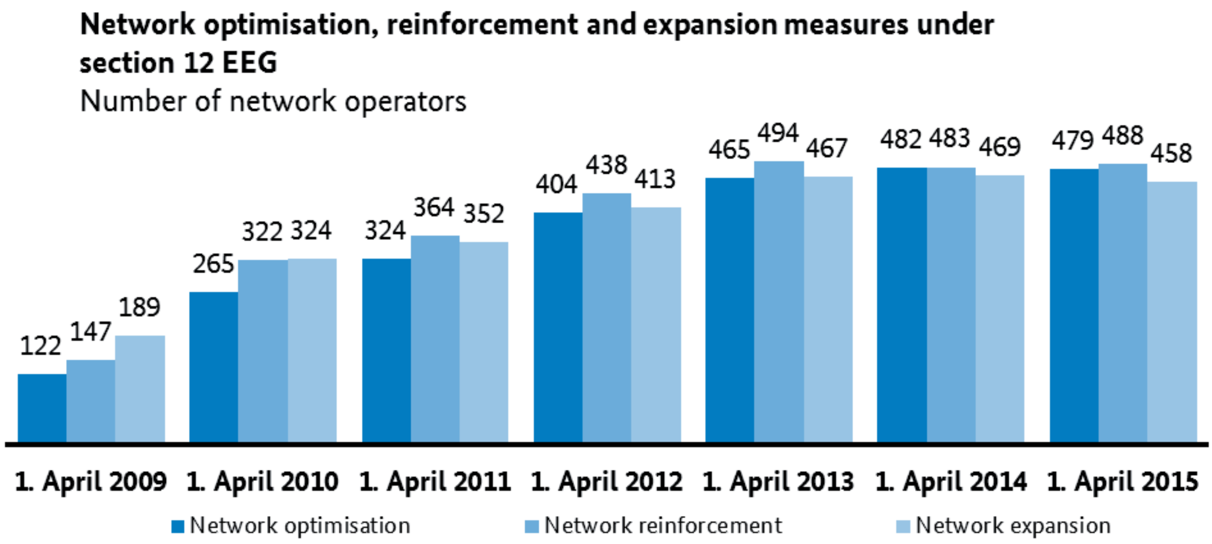

Figure 32: Network optimisation, reinforcement and expansion measures in accordance with section 12 EEG

The following network optimisation and reinforcement measures are being implemented by DSOs.

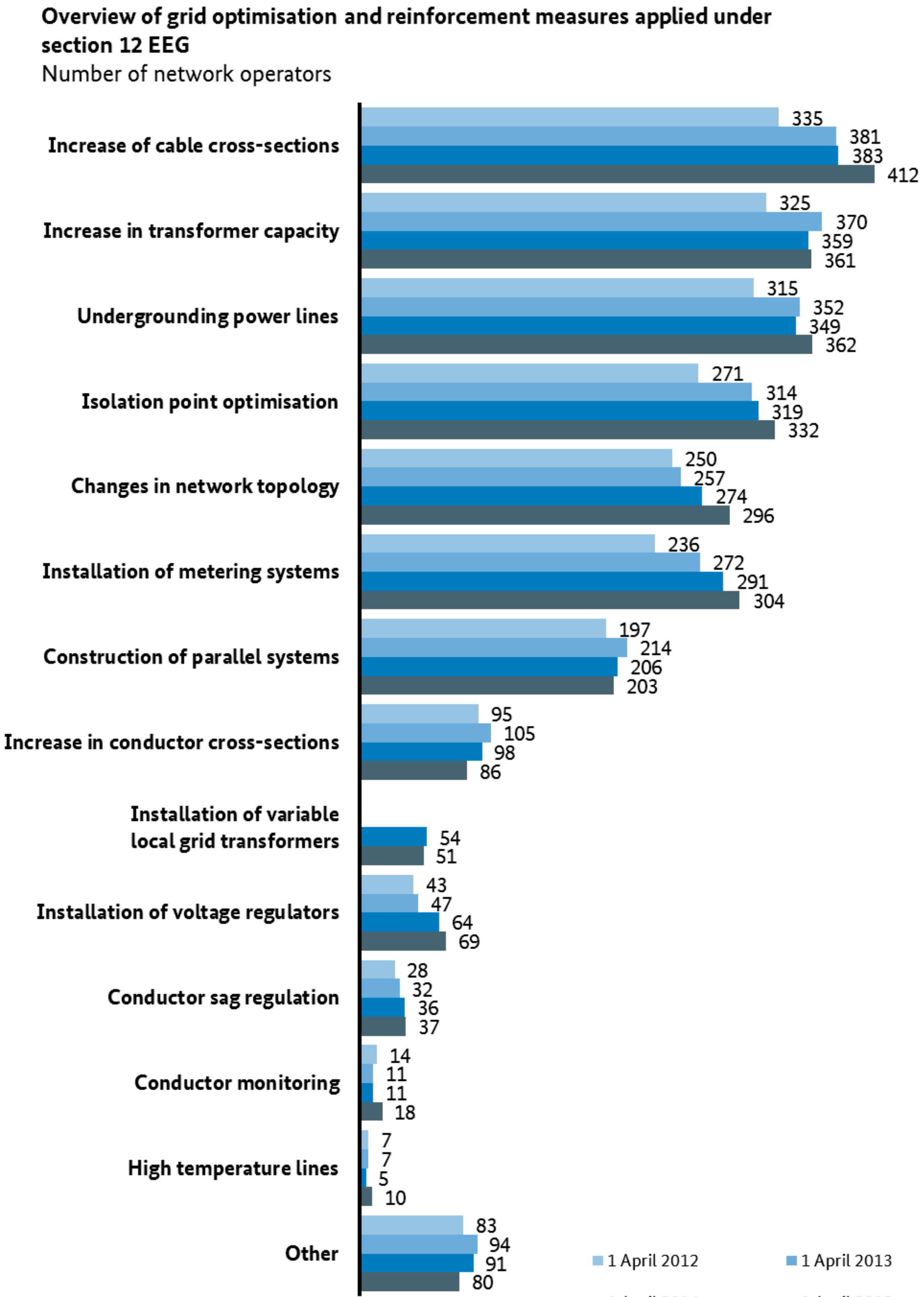

Figure 33: Overview of grid optimisation and reinforcement measures applied under section 12 of the EEG

Increases since the previous year include, in particular, measures to increase cable cross-sections and changes in network topology. Somewhat less has been done than last year to increase transformer capacity, to build parallel systems, to increase conductor cross sections or other measures.

2.4 Grid expansion requirements in the distribution system

Operators of high voltage networks with a rated voltage of 110 kilovolts are required by section 14(1b) EnWG to report annually on the grid status of their networks and the impact of any anticipated expansion in feed-in installations - including in particular the production of electricity from renewable energy sources – on their network in the next 10 years.

The survey excluded DSOs whose 110-kV networks consist solely of short stub lines with a small total power line length, and DSOs which function solely as utilities for an industrial or chemicals park or similar. The survey for 2014 was sent to a total of 56 DSOs.

The Bundesnetzagentur has also requested a network status and network expansion planning report in compliance with section 14(1a) EnWG from these 56 DSOs for the additionally operated low-voltage levels.

The reports submitted by the surveyed DSOs cover 98% of the circuit lengths at the high-voltage level, 70% at the medium-voltage level and 66% at the low-voltage level. At medium and low-voltage, approximately 60% of the network users connected to these tiers of the network are also covered.

Total expansion requirements (all voltage levels)

Total expansion requirements of €6.6bn in the next 10 years (2015 – 2025) were reported to the Bundesnetzagentur. Compared to previous years, expansion requirements (31 December 2012: €5.5bn / 52 DSOs; 31 December 2013: €6bn / 53 DSOs) have again gone up. The following diagram shows the grid expansion requirements forecast by DSOs at all voltage levels.

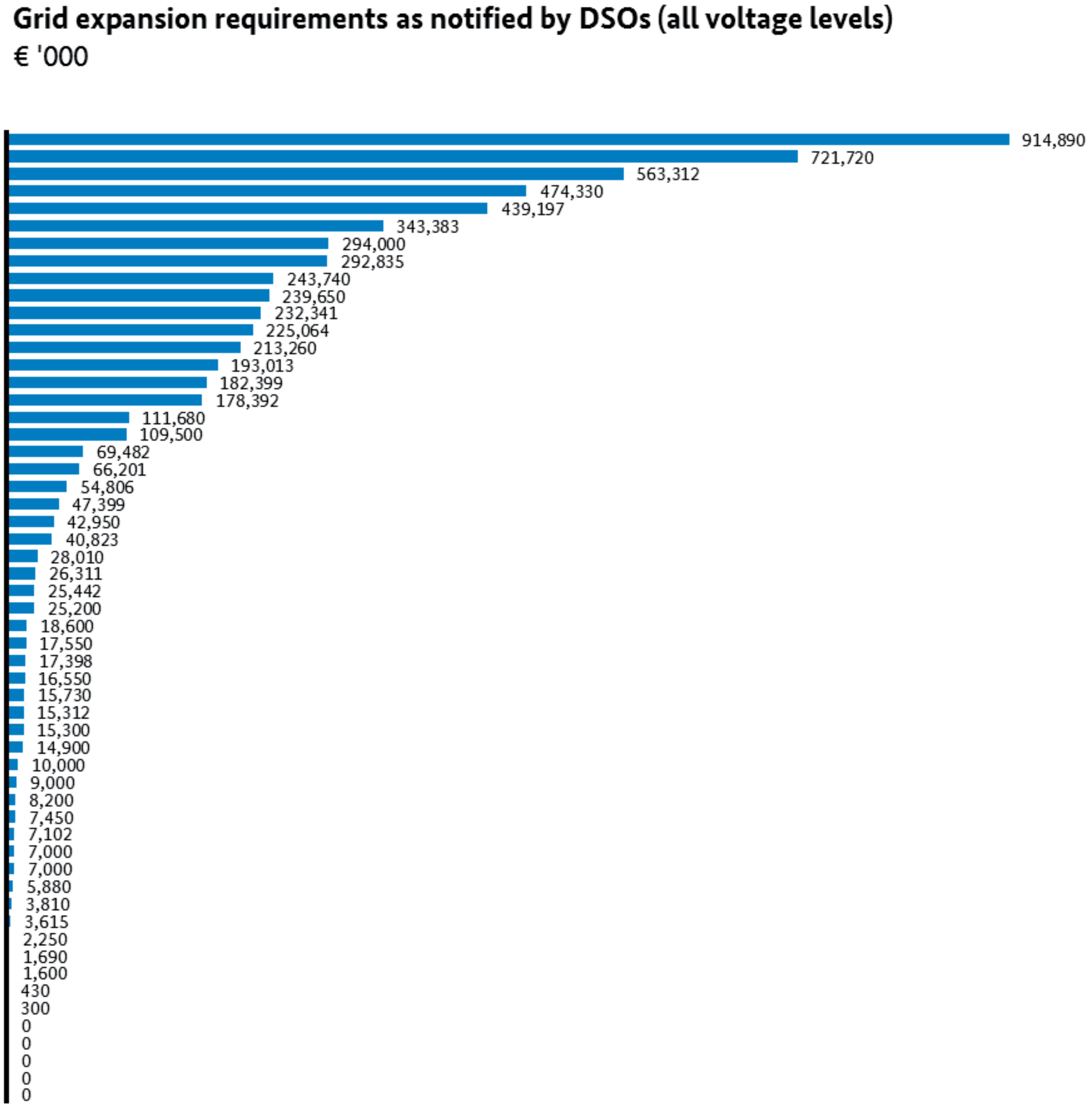

Figure 34: Grid expansion requirements as notified by DSOs (all voltage levels)

The diagram shows highly heterogeneous grid expansion requirements. 20 DSOs project grid expansion requirements of ≤ €10,000,000 in the next 10 years; 18 DSOs identify expansion requirements of ≤ €100,000,000, another 18 DSOs projected grid expansion requirements of > €100,000,000. The 18 DSOs with the greatest grid expansion requirements account for 90% of total requirements. The projected grid expansion requirement is usually higher for network operators which distribute electricity at different voltage levels with a large circuit length.

The forecast grid expansion requirements are not only due to growing renewable energy capacities and distributed generation, but also to a large extent to restructuring and replacement investments. These investments are, for example, made to operate grids more efficiently by adjusting network topologies to changed supply tasks, to respond to the Thomas steel problem, to dismantle the 220-kV level or to ensure that waterways and bird life are protected.

The evaluations also show that many distribution system operators continue to find it difficult to plan the expansion of grids for periods of time of 10 years. Not only are new measures added every year, measures which have not yet been implemented also cease to be relevant. Planning uncertainties arise in particular from the growth in renewable energy systems and their unpredictable impact on the electricity network, which means that robust forecasts are often only possible up to a maximum of 2 – 3 years in advance. In this context, great uncertainties arise with regard to the future locations of plants in combination with highly dynamic growth and frequent changes in the legal framework. Other reasons include the protracted procedures for obtaining official permits, objections raised by public agencies or land owners and delays in grid expansion in transmission networks.

A total of 1,318 measures (21 December 2012: 1,006; 31 December 2013: 1,263) were submitted to the Bundesnetzagentur for the period 2015 to 2025. Of these 66% were still at the planning stage at the time of the survey, 32% of the measures were under construction and 2% had been completed by early 2015.

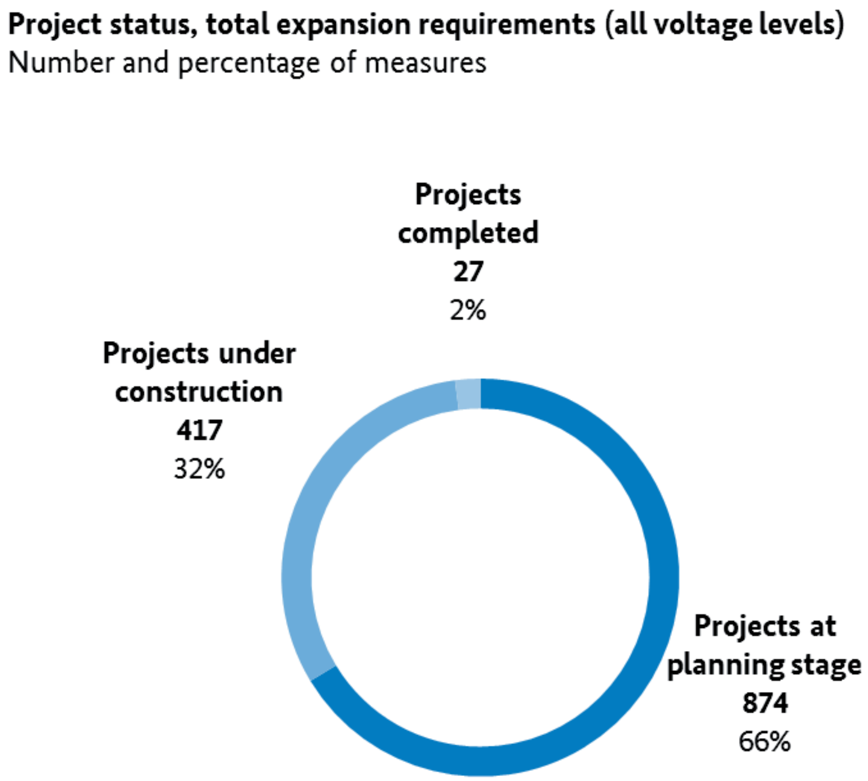

Figure 35: Project status, total expansion requirements (all voltage levels)

Expansion requirement in anticipation of increased feed-in at the high-voltage level

If the measures submitted for the high voltage level under section 14(1b) EnWG are considered separately, the expansion requirements from the perspective of the network operators amount to €2.6bn over the next 10 years (2015-2025). 23 of the 57 surveyed DSOs have submitted measures for this purpose.

The measures were identified on the basis of all forms of expansion of feed-in installations – not just those producing electricity from renewable energy. In larger cities, for example, combined cycle gas turbine plants were given as reasons for expansion.

The following diagram shows the requirements for grid expansion at the high-voltage level as forecast by DSOs.

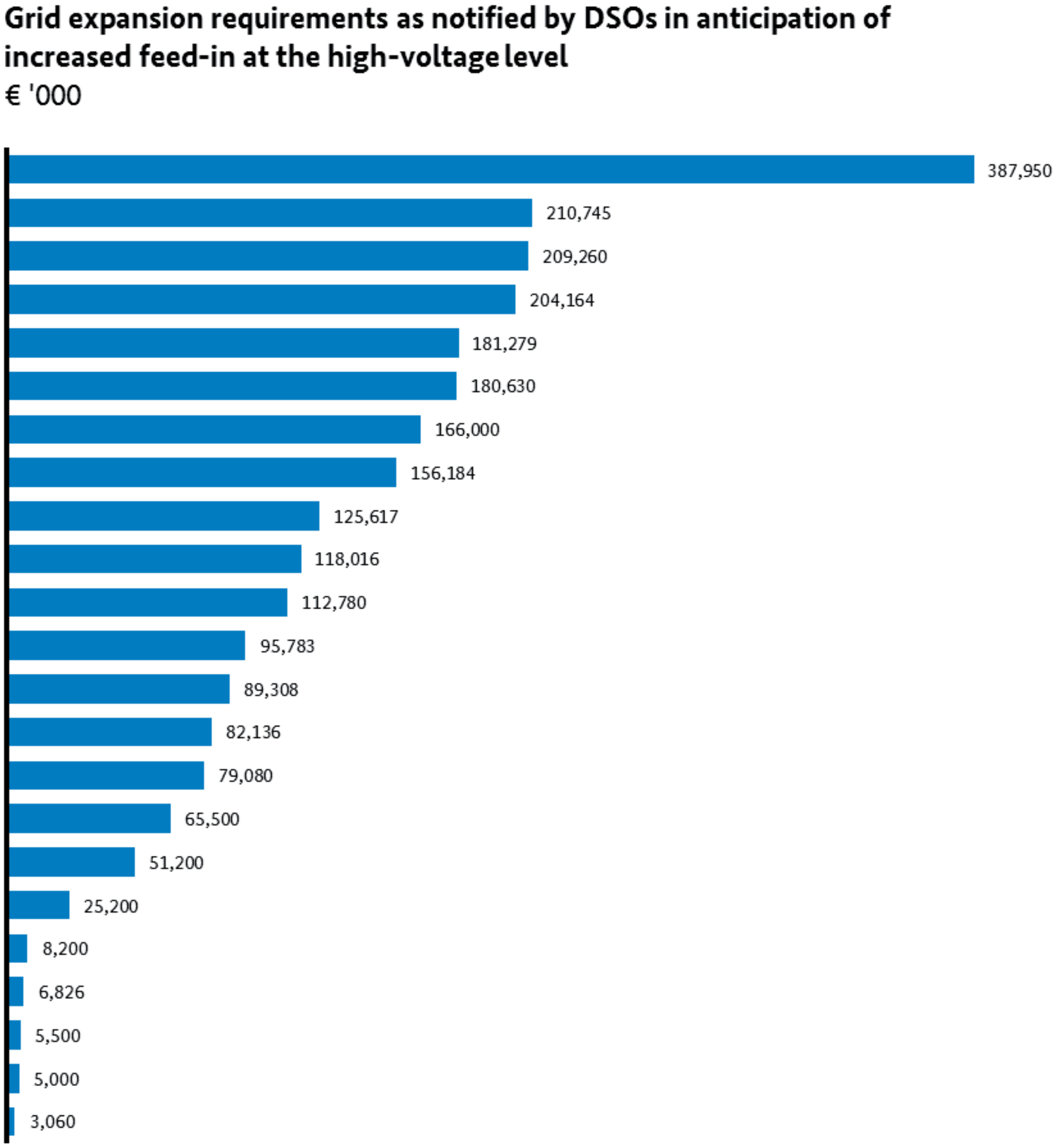

Figure 36: Grid expansion requirements as notified by DSOs in anticipation of increased feed-in facilities at the high-voltage level

The distribution is highly heterogeneous here as well; this is due to the different network structures and, in particular, the level of previously installed capacity and projected increase in output from renewable energy systems.

It is also apparent that all operators of high-voltage networks which have notified feed-in management measures to the Bundesnetzagentur have also notified the need to expand high-voltage grids to cope with the anticipated expansion in feed-in installations, especially for the generation of electricity from renewable energy sources.

A total of 318 measures were submitted to the Bundesnetzagentur for the period 2015 to 2025. Of these 62% were still at the planning stage at the time of the survey, 34% of the measures were under construction and 4% had been completed by early 2015.

Project status, grid expansion requirements in anticipation of increased feed-in at the high-voltage level
Number and percentage of measures

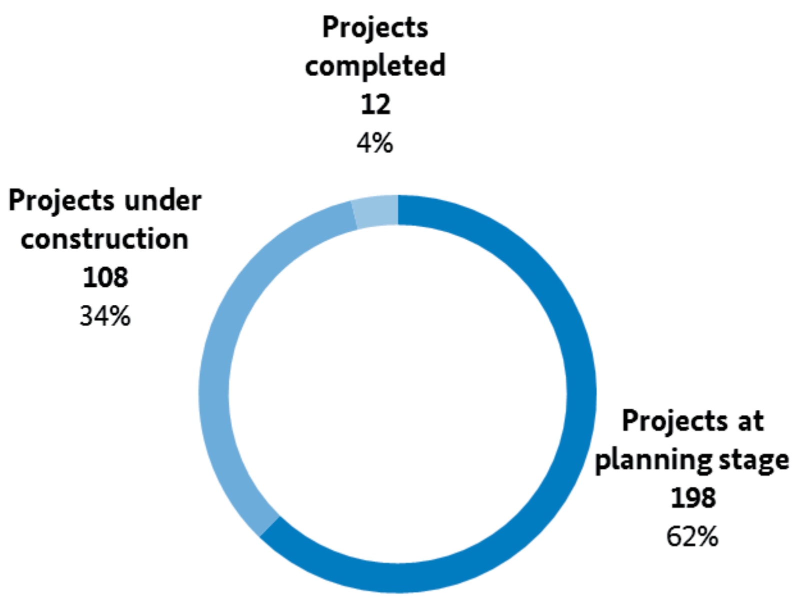

Figure 37: Project status, grid expansion requirements in anticipation of increased feed-in facilities at the high-voltage level

3. Network and system security measures (section 13 of the Energy Act)

Section 13 of the Energy Act, which sets out the requirements for network and system responsibility at the various network levels, entitles and obliges system operators (both TSOs and DSOs) to take certain measures to maintain the security and reliability of the electricity supply system. A distinction is made between three types of measure:

- measures under section 13(1) of the Energy Act (eg redispatching),

- measures under section 13(2) of the Energy Act, and

– measures under section 13(2) of the Energy Act in conjunction with section 14 of the Renewable Energy Sources Act (feed-in management).

The following table lists the three types of measure together with the volume and costs of the measures taken in 2014:

Network and system security measures under section 13 of the Energy Act

Legal basis	Energy Act section 13(1)	Energy Act section 13(2)	Energy Act section 13(2) in conjunction with Renewable Energy Sources Act section 14(1)
Measures provided for; main mechanisms	Network-related and market-related measures: topological measures, such as balancing energy, reduced and increased loads, redispatching and countertrading	Adjustment of electricity feed-in, transit and offtake	Feed-in management: reduction of feed-in from renewable energy, mine gas and combined heat and power (CHP) installations
Volume of measures taken in 2014	TSOs' redispatching: 5,197 GWh total volume	Adjustments: 1 TSO: 0.2 GWh, 8 DSOs: 9 GWh; Support measures: 3 DSOs: 5 GWh	Unused energy (TSOs and DSOs): 1,581 GWh
Costs of measures taken in 2014	Redispatching through TSOs' system services: €186.7m	No rights to compensation for installation operators in the event of curtailments under section 13(2) of the Energy Act	Compensation payments to installation operators under section 15 of the Renewable Energy Sources Act: €83m

Table 21: Network and system security measures under section 13 of the Energy Act

The following subsections provide a detailed view of the deployment of the different network and system security measures.

3.1 Redispatching

Section 13(1) of the Energy Act entitles and obliges TSOs to remove threats or disruptions to the electricity supply system by taking network-related and market-related measures. Where DSOs are responsible for the security and reliability of the electricity supply in their networks, they too are entitled and obliged under section 14(1) of the Energy Act to take such measures.

Network-related measures, most notably topological measures, are taken by the TSOs practically every day of the year. Market-related measures primarily take the form of congestion management measures. A distinction can basically be made between redispatching and countertrading.

Redispatching means measures to intervene in the market-based operating schedule of generating units to change feed-in, prevent overloading of power lines (preventive redispatching) or relieve overloading (curative redispatching). Electricity-related redispatching is used to avoid or relieve sudden congestion on lines or in substations, while voltage-related redispatching is used to maintain the voltage in the network area affected by providing reactive power. Redispatching can be an internal measure applicable to one control area only or a wider measure applicable to more than one control area. Overall feed-in is maintained at a constant level by reducing feed-in from one or more generating units while increasing feed-in from one or more other units (in the areas to be balanced).

Countertrading is also used to avoid or relieve congestion by changing the planned operating schedule of generating units. In contrast to redispatching, however, countertrading involves commercial transactions, and there is no obligation for the plant operators to enter into such transactions. Countertrading has little practical significance compared to redispatching.

The German TSOs submit detailed data on redispatching to the Bundesnetzagentur on a monthly basis as provided for by section 13(5) of the Energy Act. The following analysis is based on the data submitted in 2013 and 2014.

Calendar year 2013

The following table lists the areas particularly affected by tense network situations in 2013 and where the TSOs used redispatching to prevent "n-1" violations:

Electricity-related redispatching on the most heavily affected network elements 2013

Network element	Control area	Duration (hours)	Volume (GWh)[1]
Lehrte area (Lehrte-Mehrum, -Godenau, -Göttingen)	TenneT	2,102	256
Remptendorf - Redwitz	50Hertz/ TenneT	1,581	923
Mecklar area (Mecklar-Borken, Mecklar-Dipperz)	TenneT	629	367
Conneforde area (Conneforde-Dollern-Sottrum-Wechold-Diele)	TenneT	607	87
Bärwalde-Schmölln	50Hertz	359	142
Vierraden - Krajnik (PL)	50Hertz	346	142
Hamburg-Flensburg area (Hamburg Nord-Audorf-Kassö (DK))	TenneT	247	7
St. Peter area (Altheim - Simbach - St. Peter, Altheim-Sittling, Pleitning-St. Peter)	TenneT	130	25
Brunsbüttel-50 Hertz-Zone (Hamburg Nord)	TenneT	80	25
Grafenrheinfeld-Kupferzell	Transnet BW	66	18

[1] The volume for the individual network elements is based on the number of measures taken. The volume of balancing counter trades (increase in feed-in) is not taken into account. This allows the extent to be determined to which the network elements were physically overloaded and to which feed-in needed to be reduced to relieve the overloading.

Table 22: Electricity-related redispatching on the most heavily affected network elements in 2013 as reported by the TSOs

In 2013, as in previous years, an above average level of redispatching occurred in particular in the area around Lehrte substation in TenneT's control area and on the line between Remptendorf (50Hertz) and Redwitz (TenneT). The third highest occurrence of overloading was on the lines around Mecklar substation in TenneT's control area.

Redispatching in the German transmission network in 2013 totalled 7,965 hours.

Calendar year 2014 (year under review)

In the period between 1 January 2014 and 31 December 2014 the Bundesnetzagentur received reports of electricity-related and voltage-related redispatching totalling 8,453 hours, up 6% on the previous year. In total, redispatching occurred on 330 days in 2014 compared to 232 days in 2013. This means that redispatching now occurs almost daily. The total amount of energy redispatched was 2,600 GWh. The amount of energy used in balancing counter trades totalled 2,597 GWh. Thus the total amount of energy required for balancing in 2014 (energy redispatched plus counter trades) was about 5,197 GWh, compared to 4,604 GWh in 2013. This represents a year on year increase of around 13%. Reductions in feed-in through redispatching in 2014 corresponded to 0.58% of total generation from installations not eligible for financial support under the Renewable Energy Sources Act. In all, increases and reductions in feed-in through redispatching amounted to around 1.17% of total generation from installations not eligible for financial support. The TSOs put their net costs for redispatching[17] in 2014 at €186.7m. Redispatching occurred mainly in the TenneT and 50Hertz control areas. Details are shown in the following table:

Redispatching 2014

Control area	Duration (hours)	Volume (GWh)	Total volume (energy redispatched plus balancing countertrades) (GWh)	Net costs for redispatching (€m)
TenneT	5,000	813	1,629	186.7
50Hertz	3,230	1,751	3,502	
Transnet BW	119	16	25	
Amprion	104	20	41	

Table 23: Redispatching 2014

Redispatching in 2014 was mainly electricity-related, with measures totalling 6,989 hours and 2,368 GWh; 6,630 or 95% of these hours related to the following network elements:

[17] Including costs for countertrading totalling €1.3m

Electricity-related redispatching on the most heavily affected network elements 2014

Network element	Control area	Duration (hours)	Volume (GWh)
Lehrte area (Lehrte-Mehrum, -Godenau, -Göttingen)	TenneT	1,901	
Remptendorf - Redwitz	50Hertz/ TenneT	1,694	1,073
Vierraden - Krajnik area (PL) (Vierraden, Krajnik, Pasewalk, Neuenhagen)	TenneT	1,047	351
Conneforde area (Conneforde-Dollern-Sottrum-Wechold-Diele)	TenneT	767	124
Hamburg-Flensburg area (Hamburg Nord-Audorf-Flensburg)	TenneT	401	52
Bärwalde-Schmölln	50Hertz	319	122
Mecklar area (Mecklar-Borken, Mecklar-Dipperz)	TenneT	266	130
Vöhringen-Dellmensingen	Amprion	88	18
Borken-Gießen area (Borken-Gießen-Großkrotzenburg)	TenneT	77	22
Röhrsdorf-Hradec (CZ)	50Hertz	70	38

Table 24: Electricity-related redispatching on the most heavily affected network elements in 2014 as reported by the TSOs

Redispatching was required in particular in the areas around the lines between Lehrte and Mehrum and between Remptendorf and Redwitz, which account for 27.2% and 24.2% of all electricity-related redispatching respectively. In addition, the TSOs took further measures totalling 359 hours on network elements. In each case, the measures lasted fewer than 50 hours for each line.

The following map shows the location of the particularly critical network elements (number of hours per line >50) listed in the above table:

Electricity-related redispatching on the most heavily affected network elements in 2014 as reported by the TSOs

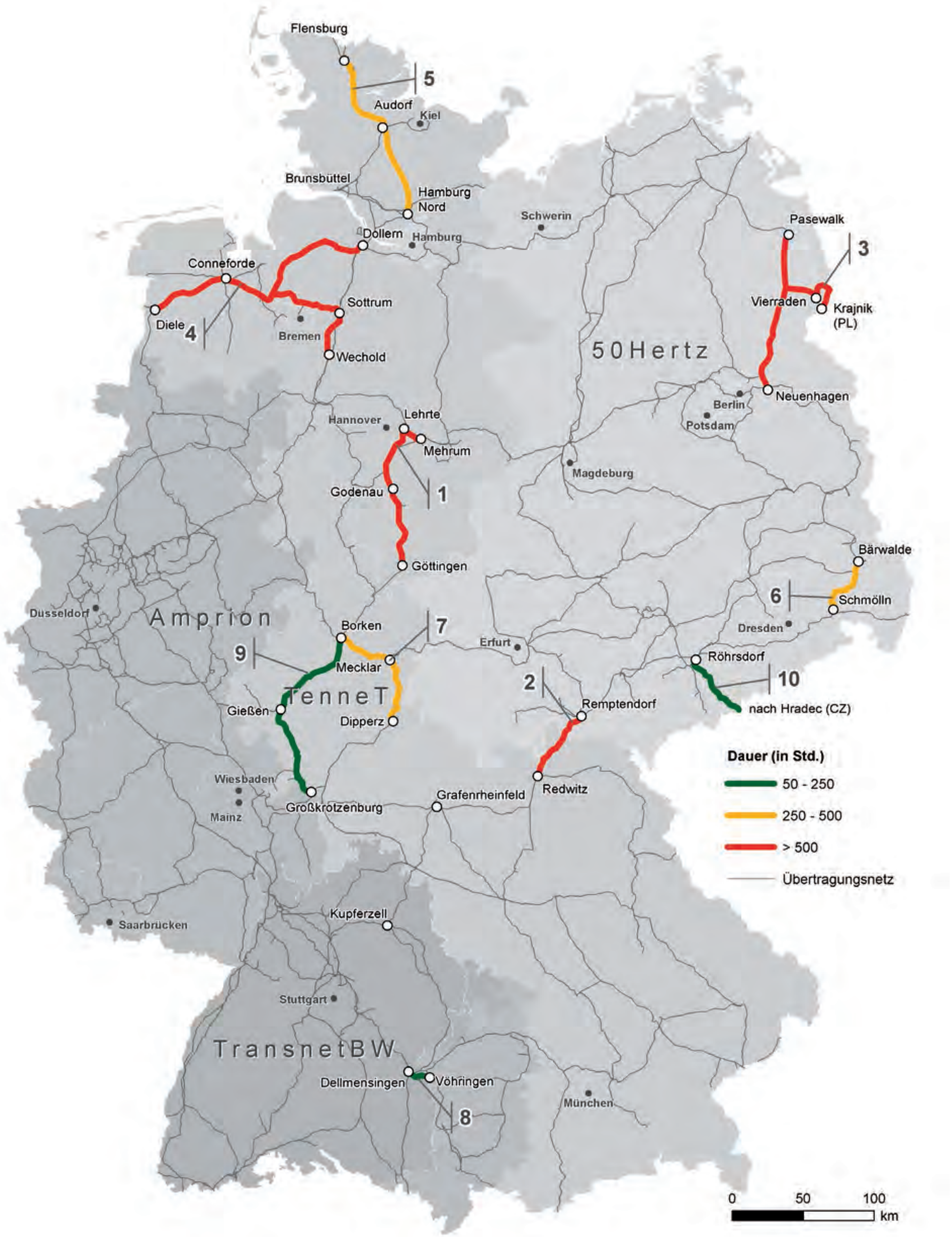

Figure 38: Electricity-related redispatching on the most heavily affected network elements in 2014 as reported by the TSOs

In addition to electricity-related redispatching, voltage-related redispatching totalling 1,464 hours occurred in TenneT's control area in 2014. The total amount of energy redispatched was 232 GWh. The northern network area in TenneT's control area was most heavily affected, accounting for more than 47% of the hours.

Voltage-related redispatching on the most heavily affected network elements 2014

Network area	Duration (hours)	Volume (GWh)
TenneT control area: northern network area	690	91
TenneT control area: central network area	489	86
TenneT control area: southern network area	285	55

Table 25: Voltage-related redispatching on the most heavily affected network elements in 2014
as reported by the TSOs

Developments from 2013 to 2014

Redispatching on the line between Lehrte and Mehrum substations and the neighbouring substations in 2014 was down by 201 hours on 2013, representing the first ever decrease. However, these network elements remain the most heavily loaded in Germany. The continuing high level of redispatching underlines the need to strengthen and expand the grid around Mehrum.[18] Redispatching on the line between Remptendorf and Redwitz was up 113 hours on 2013. This line therefore also remains one of the more heavily loaded network elements. The situation is not expected to improve until the Thuringia power bridge (Power Grid Expansion Act project no 4) has been completed.

There was a particular increase in redispatching on the line between Vierraden and Krajnik, in the network area of the Polish TSO PSE, which was up 701 hours on 2013. The areas around Conneforde and Hamburg-Flensburg substations also showed increases. Plans are also in place to strengthen and expand these network elements.

In 2014 there was a decrease in redispatching on other network elements previously subject to overloading, with a particular decrease in the Mecklar and St. Peter areas.

The following table details the changes in electricity-related redispatching on the most heavily affected network elements in the German transmission network:

[18] NDP measure M205: 380-kV substation and 380/220-kV transformer in Mehrum

Changes in electricity-related redispatching on the most heavily affected network elements 2013-2014

Network element	Control area	2014: duration (hours)	Absolute change (hours) on 2013
Lehrte area (Lehrte-Mehrum, Lehrte-Godenau, Lehrte-Göttingen)	TenneT	1,901	-201
Remptendorf – Redwitz	50Hertz/TenneT	1,694	113
Vierraden - Krajnik (PL) area (Vierraden, Krajnik, Pasewalk, Neuenhagen)	50Hertz	1,047	701
Conneforde area (Conneforde-Dollern-Sottrum-Wechold-Diele)	TenneT	767	160
Hamburg-Flensburg area (Hamburg Nord-Audorf-Flensburg)	TenneT	401	154
Bärwalde-Schmölln	50Hertz	319	-40
Mecklar area (Mecklar-Borken, Mecklar-Dipperz)	TenneT	266	-363
Vöhringen-Dellmensingen	Amprion	88	69
Borken-Gießen area (Borken-Gießen-Großkrotzenburg)	TenneT	77	77
Röhrsdorf-Hradec (CZ)	50Hertz	70	70
St. Peter area (Altheim-Simbach-St.Peter, Altheim-Sittling, Pleitning-St.Peter)	TenneT	12	-118
Brunsbüttel-50Hertz control area (Hamburg-Nord)	TenneT	42	-38
Grafenrheinfeld-Kupferzell	TransnetBW	0	-66

Table 26: Changes in electricity-related redispatching on the most heavily affected network elements 2013-2014

There was a slight decrease in the duration and volume of voltage-related redispatching in 2014. The total duration was down 95 hours on 2013.

The figures show that in 2014 it was again primarily the 50Hertz and TenneT control areas which were subject to heavy loads at certain times. Despite this, the German TSOs were in a position at all times to deal with the situation appropriately. The TSOs and the Bundesnetzagentur do not expect the need for redispatching to decline in the near future.

In view of the ruling issued by the Higher Regional Court in Düsseldorf on 28 April 2015 revoking the Bundesnetzagentur's rulings on redispatching (BK6-11-098 and BK8-12-019) and the accompanying statement that not only expenses but also further costs incurred and potential revenues lost in the event of redispatching are reimbursable, there may be a subsequent change in the costs for redispatching of the past few years.

3.2 Measures under section 13(2) of the Energy Act

Section 13(2) of the Energy Act entitles and obliges TSOs to adjust all electricity feed-in, transit and offtake or to demand such adjustment (adjustment measures) where a threat or disruption to the security or reliability of the electricity supply system cannot be removed or cannot be removed in timely manner by network-related or market-related measures as referred to in section 13(1) of the Act.

Where DSOs are responsible for the security and reliability of the electricity supply in their networks, they too are entitled and obliged under section 14(1) of the Energy Act to take adjustment measures as referred to in section 13(2) of the Act. Furthermore, section 14(1c) of the Act requires DSOs to support the measures taken by the TSOs as instructed by the TSOs (support measures).

Curtailing feed-in from renewable energy installations under section 13(2) of the Energy Act may also be necessary in situations other than those covered by the feed-in management provisions if the threat to the system is caused not by congestion but by another security problem. The measures to be taken in these cases do not affect grid expansion measures that may be required in the particular network area concerned.

In 2014, one TSO carried out an adjustment measure under section 13(2) of the Energy Act; the feed-in adjustments were made over 2.5 hours on one day and comprised 245 MWh.

In addition, seven DSOs took adjustment measures under section 13(2) and 14(1) of the Energy Act on a total of 92 days. Measures curtailing feed-in from conventional installations were taken for 448 hours on 46 days and comprised a total volume of just under 5,800 MWh. Measures curtailing feed-in from renewable installations were taken for around 2,000 hours on 46 days and comprised a total volume of 0.3 MWh.

Furthermore, three DSOs took support measures under section 13(2) and (2a) and section 14(1c) of the Energy Act at the instigation of a TSO on a total of 27 days. Here, measures curtailing feed-in from conventional installations were taken for just under 115 hours on 21 days and comprised a total volume of 2,148 MWh. Measures curtailing feed-in from renewable installations were taken for 138 hours on 6 days and comprised a total volume of 31 MWh.

3.3 Feed-in management measures and compensation under sections 14 and 15 of the Renewable Energy Sources Act[19]

Feed-in management is a special measure regulated by law to increase network security and relating to renewable energy, mine gas and combined heat and power (CHP) installations. Priority is to be given to feeding in and transporting the climate friendly electricity generated by these installations (section 11(1) and (5) of the Renewable Energy Sources Act and section 4(1) and (4) second sentence of the Combined Heat and Power Act). Under specific conditions, however, the system operators responsible may also temporarily curtail priority feed-in from these installations if network capacities are not sufficient to transport the total amount of electricity generated (section 13(2) and (2a) third sentence of the Energy Act in conjunction with sections 14 and 15 of the Renewable Energy Sources Act and, in the case of CHP installations, section 4(1) second sentence of the Combined Heat and Power Act). Importantly, such feed-in management is only permitted once the priority measures for conventional installations have been exhausted. The expansion obligations of the operator answerable for the congestion remain in parallel to these measures.

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

The following table shows the volume and costs of the feed-in management measures reported for 2014:

[19] The new Renewable Energy Sources Act came into force on 1 August 2014. For simplification, reference is made to the sections in the new version only.

Unused energy under section 14 and compensation payments under section 15 of the Renewable Energy Sources Act in 2014

	Unused energy section 14 RES Act (kWh)		Compensation section 15 RES Act (€)	
Implementation and payment of compensation by the TSO	61,251,176	4%	25,911,535	31%
Implementation and payment of compensation by the DSO	1,519,299,144	96%	56,779,970	69%
Own measures	659,123,194	42%	42,110,630	51%
Support measures by the DSOs	860,175,949	54%	14,669,340	18%
Total feed-in management measures	1,580,550,320	100%	82,691,505	100%

Table 27: Unused energy under section 14 and compensation payments under section 15 of the Renewable Energy Sources Act in 2014

The amount of energy not fed in as a result of feed-in management measures rose almost threefold from 555 GWh in 2013 to 1,581 GWh. This is 1.16% of the total net volume of electricity generated in 2014 by installations eligible for financial support under the Renewable Energy Sources Act (including direct selling), up from 0.44% in 2013.

Measures in the transmission network accounted for around 4% of the energy not fed in and some 31% of the compensation paid, with the remaining 96% and 69% accounted for by the distribution networks. The measures taken by the DSOs can be divided into "own measures" (42% of the total unused energy) and – for the larger part – "support measures" (54% of the total unused energy). Support measures are taken to manage feed-in when network operators are unable to relieve congestion by implementing their own measures on installations connected to their networks and therefore request the support of downstream operators. The downstream operators then manage feed-in from the installations available in their own network areas. The majority of support measures were taken at the TSOs' request; overall, congestion in the transmission networks accounted for around 58% of the unused energy, compared to 30% in 2013.

On average, the network operators took feed-in management measures on 57 days in the year. Two operators in the north of Germany had to take measures on well over half of the days in the year.

The increase in feed-in management measures is due to various factors: the continued increase in the amount of energy from renewable sources; the work still required to optimise, strengthen and expand the networks, in particular to build more substations to feed the renewable electricity back into the upstream extra high voltage network; to a lesser extent, the increased congestion and hence need for feed-in management measures caused temporarily during construction phases of the DSOs' network expansion projects, when for instance parts of the network are taken out of operation or operation is restricted.

Another factor is the weather. In 2014 there were various peaks in feed-in particularly in the first half of the year owing to a number of storms (see chapter I.B.2.2 on page 52).

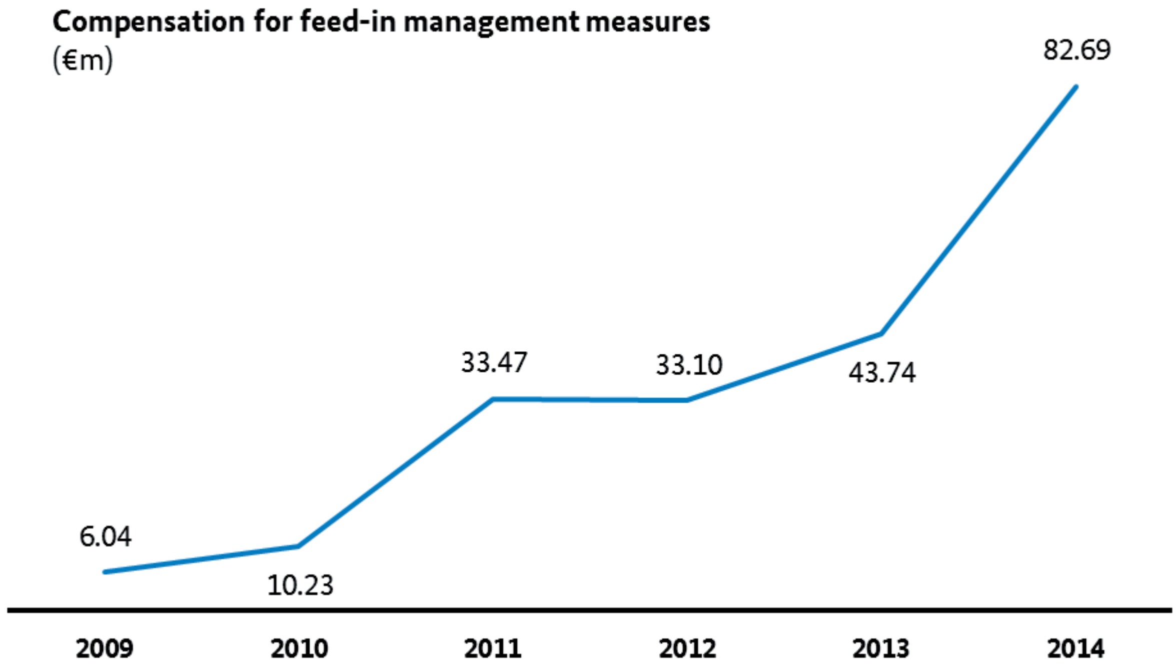

Figure 39: Compensation for feed-in management measures

The total amount of compensation paid increased by some 89% from €43.7m in 2013 to €82.7m. The compensation paid to the operators of the renewable and CHP installations affected by feed-in management measures – in economic terms similar to conventional plants whose feed-in has been curtailed through redispatching – is such that the operators are in more or less the same position as if feed-in from their installations had not been prevented by congestion.[20] The costs of compensation are borne by the network charges paid by the final consumers, adding an average of around €1.65 per final consumer per year, up from €0.86 in the previous year. The additional cost will be higher for consumers in regions particularly affected by feed-in management measures. These higher costs are offset by lower surcharges payable by the consumers under the Renewable Energy Sources Act, since no financial support has to be paid for the electricity generated but not fed in from the renewable and CHP installations.

The compensation payments are generally settled through bills from the installation operators, although a number of network operators also offer credits (without bills from the installation operators). The compensation paid in 2014 therefore does not reflect the actual amounts payable for the volume of unused

[20] Feed-in management measures carry considerably fewer residual risks for the renewable and CHP installation operators through for instance the cost-sharing arrangement under section 15 of the Renewable Energy Sources Act. Plants whose feed-in has been curtailed receive equivalent amounts of electricity from the network operator through redispatching; this eliminates marketing risks created by congestion.

energy in 2014. Installation operators have issued bills for just 28% of the total amount of unused energy in 2014. In addition, the compensation paid in 2014 comprises amounts payable for unused energy in previous years. This also applies to the figures for all previous years. At the time of the survey, 72% of the total unused energy in 2014 had not yet been compensated; this in turn will have an effect on the amount of compensation paid in the coming years.

Using a rough extrapolation, based for simplification on average support rates for the different energy sources, the compensation payable for renewable and CHP electricity curtailments in 2014 is estimated to be some €183m.[21]

Another significant increase in feed-in management measures is also expected in 2015. The first quarter of 2015 has already seen a further rise in the volume of unused energy and hence the amount of compensation paid.

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

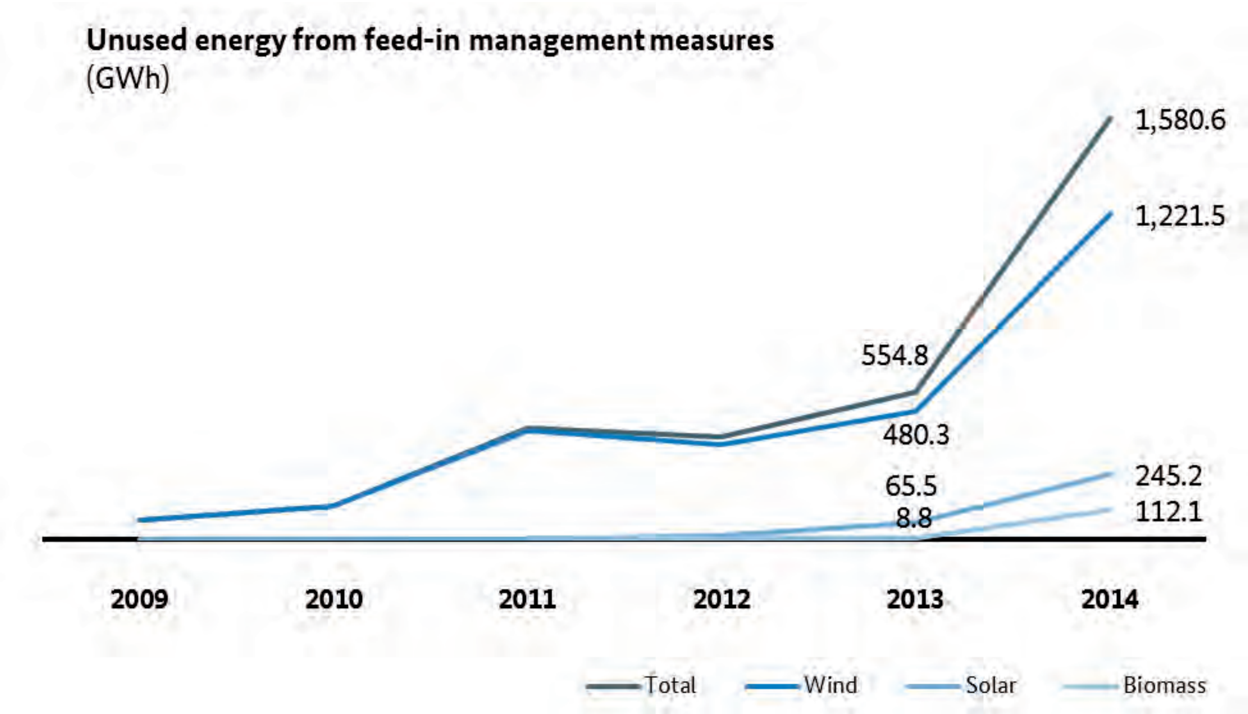

Figure 40: Unused energy from feed-in management measures

As in previous years, feed-in management measures in 2014 were applied primarily to wind installations, which accounted for 77.3% of the total amount of unused energy, compared to 86.6% in 2013. The amount of

[21] The calculation is based on the following assumptions: average support rates are calculated by dividing the total amount paid in support for each energy source in 2014 by the total amount of energy fed in by each energy source in that year (wind: 7.24 ct/kWh; solar: 31 ct/kWh; biomass: 16.65 ct/kWh). The uncompensated unused energy was calculated using the breakdown in Table 28: Unused energy from feed-in management measures by energy source on page 111.

unused energy accounted for by photovoltaic installations increased year on year from 11.8% to 15.5%. There was a particularly large increase in the amount of energy curtailed from biomass plants. This rose from around 1.6% in 2013 to 7.1% in 2014 (up 5.5 percentage points) of the total amount of unused energy.

Unused energy as a result of feed-in management measures by energy source

Energy source	Unused energy (including heat) (kWh)	%
Wind	1,221,494,081	77.3
Solar	245,171,408	15.5
Biomass	112,087,722	7.1
Gas	236,543	<0,1
Water	774,035	<0,1
Geothermal	0	0.0
CHP	786,529	<0,1
Total	1,580,550,318	100.0

Table 28: Unused energy from feed-in management measures by energy source

Overall, two TSOs and 17 DSOs took feed-in management measures in 2014. All of Germany's regions are now affected by such measures, although 96% of the unused energy is a result of measures taken in the northern federal states, and in particular in Schleswig-Holstein.

4. Network charges

4.1 Changes in network charges

The following graph shows the changes in the average volume-weighted[22] network charges (ct/kWh) for three consumption levels from 1 April 2006 to 1 April 2015, whereby the year 2006 was marked by special effects arising from the introduction of regulation. The charges for billing, metering and meter operation are included in the figures. The electricity suppliers' data on which the figures are based was highly diversified. Furthermore, several changes were made to the system of data collection over the years. The network charges are based on the following consumption levels:

- household customers with a standard default supply contract: annual consumption 3,500 kWh, low voltage supply;

[22] The network charge for non-household customers (industrial and commercial customers) for 2014 and 2015 was determined arithmetically.

- commercial customers: annual consumption 50 MWh, annual peak load 50 kW, annual usage period 1,000 hours, low voltage supply (0.4 kV)
  (figures for non-interval metered customers were to be given on the basis of supply without interval metering);

- industrial customers: annual consumption 24 GWh, annual peak load 4,000 kW, annual usage period 6,000 hours, medium voltage supply (10 kV/20 kV); no account is taken here of the surcharges and reductions under section 19 of the Electricity Network Charges Ordinance.

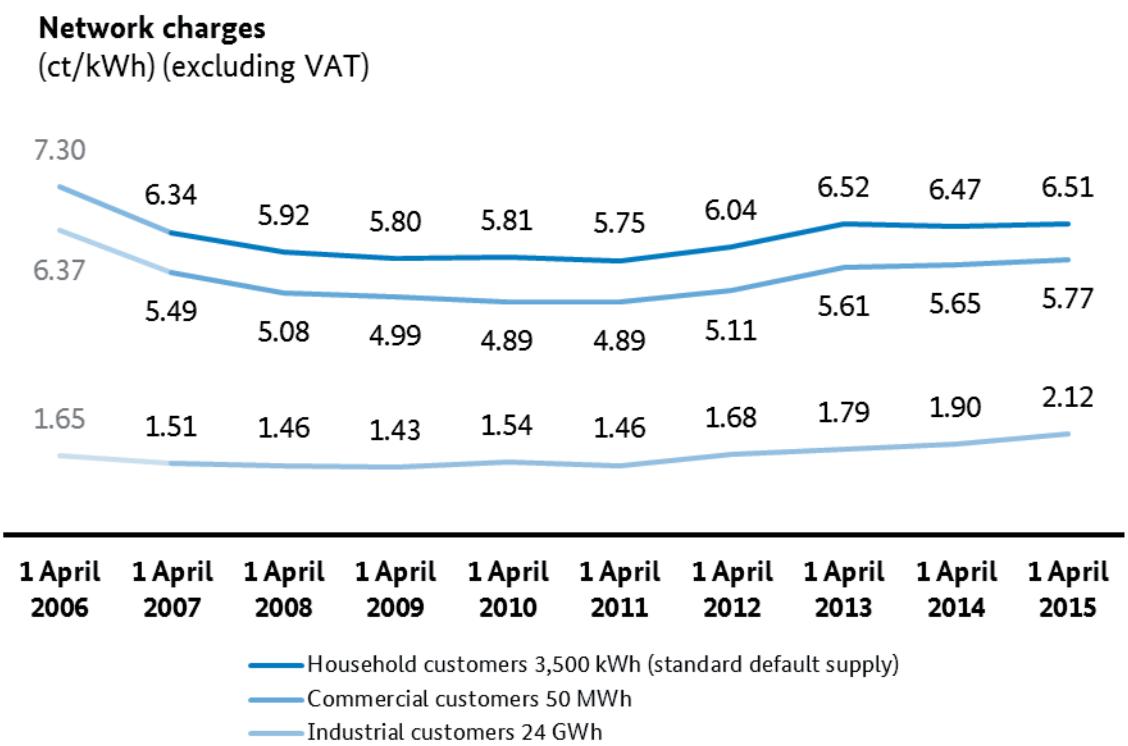

Figure 41: Network charges for three consumption levels 2006[23] to 2015[24]

The average volume-weighted network charges for household customers (low voltage), commercial customers (low voltage, interval metering) and industrial customers (medium voltage) remained relatively stable in the period from 1 April 2013 to 1 April 2015. There was a slight increase of 0.04 ct/kWh on 2014 for household customers. The increase in the charge for industrial customers was 0.22 ct/kWh, and 0.12 ct/kWh for commercial customers.

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

[24] The figures for industrial and commercial customers as from 2014 were determined arithmetically.

Regulation of network usage charges in the electricity sector was introduced in 2005, with a focus on reducing existing monopoly profits and inefficiencies in network operations. Following initial reductions in the network costs and the resulting charges, the charge for household customers increased in 2013 by almost 8%, for commercial customers by nearly 10% and for industrial customers by 6.5%. As in the previous year, the costs for household customers are now stabilising again. Network costs for industrial and commercial customers have risen slightly as in the previous year.

Network regulation contributes to dampening the rise in prices in the electricity markets. Electricity prices have increased markedly since 2007 in particular on account of the renewable energy surcharge. Since network charges have remained relatively stable over the same period, the percentage of the total electricity price that they account for has decreased overall for industrial, commercial and household customers. The data collected shows that the percentage of the total volume-weighted electricity price for household customers that is accounted for by network charges decreased slightly by about 1% in 2015 compared with 2014; network charges now make up around 20% of the price, with the price for household customers having fallen overall. Network charges account for around 14% of the total arithmetic price for industrial customers and 27% of the price for commercial customers.

4.2 Expansion factor for electricity

Under section 4(4) para 1 in conjunction with section 10 of the Incentive Regulation Ordinance, electricity DSOs can apply – once a year by 30 June of the calendar year – for an adjustment to the revenue cap based on an expansion factor for the network and substation levels downstream of the high voltage (110 kV) level. The adjustment made takes effect on 1 January of the following year. Any adjustments to the revenue cap are granted up to the end of the particular regulatory period. Operators may reapply for the expansion factor at the beginning of a new regulatory period if there is a change in their supply services compared to the base year of the new period.

The idea behind the expansion factor is to ensure that the costs of expansion investments resulting from a lasting change in a DSO's supply services during a particular regulatory period are taken into account with as little delay as possible when setting the revenue cap. To achieve this aim in light of the investments made necessary by the energy transition, the expansion factor was modified by a determination issued by Ruling Chamber 8 (BK8-10/004): with effect from applications submitted for 30 June 2010 a new parameter – number of feed-in points for distributed generation units – can be used in addition to the parameters listed in section 10(2) of the Ordinance when determining the expansion factor. Connecting distributed generation plants to an electricity distribution network can bring about lasting changes in a DSO's supply services. Since the procedure for applying for and implementing the expansion factor means that there is a slight delay between a change occurring in the parameters for supply services and an expansion factor-based adjustment to the revenue cap taking effect, the Bundesnetzagentur recommended in its evaluation report that this delay should be eliminated completely.

With its budget approach and resulting efficiency incentives, the expansion factor contributes to achieving an intelligent and technology neutral implementation of the energy transition. It is not designed to compensate every operator for the specific investment costs of each expansion measure year for year, but rather acts as a technology neutral bridge between the base years with optimisation incentives.

Overall, the adjustments made to the revenue caps for 2014 on the basis of expansion factors amounted to €192m. These adjustments resulted from 118 applications submitted for 30 June 2013.

4.3 Costs of retrofitting in response to the 50.2 Hz problem

The strong rise in the number of distributed generation installations over the last few years has meant that the way these installations operate within the electricity supply network has long been of considerable importance to the stability of the network. As a solution to the "50.2 Hz problem", relating to the frequency protection parameters for solar photovoltaic (PV) installations, the System Stability Ordinance was enacted with effect from 26 June 2012, requiring PV inverters to be retrofitted. Retrofitting of the installations is still in progress.

The new regulation in section 10 of the Ordinance represents a compromise, since originally the costs of retrofitting were to be recovered through the renewable energy surcharge. The question of how the costs of retrofitting PV installations to solve the 50.2 Hz problem should be borne became a point of discussion. At the time, the Bundesnetzagentur argued that the costs should be recovered through the renewables surcharge because the increase in renewable energy feed-in had made the retrofitting necessary. As a result, section 10 of the Ordinance provides for the costs to be shared between the network charges and the surcharge.

The 2015 amendment to the Ordinance extended the retrofitting requirements to apply to operators of combined heat and power (CHP) installations. The operators must bear a certain proportion of the costs themselves, and excess costs can be financed through the network charges. These costs had yet to take effect, however, in the 2014 period under review.

Retrofitting measures based on section 10 of the Ordinance were carried out by numerous network operators in the period from 2013 to 2015 and have resulted in corresponding increases in the revenue caps.

An initial evaluation of the associated costs has produced the following results:

Retrofitting costs

2013 budget	2014 budget	2015 budget
48,494,099 Euro	73,079,212 Euro	4,902,000 Euro

Table 29: Retrofitting costs

The retrofitting measures have thus directly resulted in around €126m being added to the network charges.

Recovering the costs through the network charges only would widen the existing regional differences in charges (higher in the south and east, lower in the west), already a topic of political discussion, as regions with a large number of installations being retrofitted would face an increase in network charges.

4.4 Avoided network charges

Under section 18(1) of the Electricity Network Charges Ordinance, operators of distributed generation plants are entitled to a fee from the operator of the distribution network into which they feed electricity. The fee must correspond to the network charge avoided by feeding in electricity at a distribution network or substation level. The concept of avoided upstream network charges may not be confused with avoided costs. As a rule network costs are not avoided by plants at lower voltage levels.

The concept of avoided network charges originated in the Associations' Agreement II/II+: plants connected downstream are generally smaller and thus generate electricity at higher costs than large-scale plants at extra high voltage level. The plants compete on the power exchange through the electricity price. This does not take into account the plants' locational advantage compared to larger scale plants: electricity is generated closer to demand. The aim of paying the avoided network charges to the downstream plant was to acknowledge generation close to demand and make downstream plants competitive.[25]

The avoided network charges within the meaning of section 18(1) of the Electricity Network Charges Ordinance have experienced a highly dynamic development over recent years, as a result in particular of the changes in the generation structure. The shift from a central, static landscape with large-scale power plants to an array of distributed generation plants has a considerable impact on the level of expenditure for distributed feed-in.

The following table shows a breakdown of the avoided network charges for each network and substation level. The figures comprise the sum of the avoided network charges for the network operators under the Bundesnetzagentur's responsibility through its own or an official delegation of powers.[26]

[25] See German Association of Local Utilities (VKU) (2015): http://www.vku.de/energie/netzzugang-netzanschluss-elektrizitaet/vermiedene-netznutzungsentgelte/historie.html (accessed March 2015).

[26] From 2014 Lower Saxony assumed responsibility for the network operators previously delegated to the Bundesnetzagentur. The Bundesnetzagentur does not have figures for the avoided network charges for 2013 (reported in 2014).

Avoided network charges by network and substation level (section 18(1) StromNEV)
(€m)

Level	2011 (actual figures)	2012 (actual figures)	2013 (actual figures)	2015 (forecast figures)
EHV/HV	79	65	67	24
HV	464	484	478	659
HV/MV	65	77	88	107
MV	345	494	463	532
MV/LV	16	30	36	42
LV	94	144	142	183
Total	1,063	1,294	1,274	1,547

Table 30: Avoided network charges (section 18(1) of the Electricity Network Charges Ordinance) by network and substation level

The figures show a continual increase in the total amount of avoided network charges. The rise in costs is due to various factors, including the following:

The growth in distributed generation means the existing capacity of the upstream network is used to a lesser extent. The infrastructure costs which remain are spread over a smaller marketed volume. This leads to an increase in the network charges at the upstream network level, which in turn results in an increase in the avoided network charges since they are based on the network charges at the upstream network or substation level.

As a result of the investments required for line expansion and the associated operational costs, the infrastructure costs for the upstream network will continue to rise. On account of the economic life of these investments, line expansion in the upstream network – owing in particular to renewable energy installations – leads to an increase in the avoided network charges in the long term.

The increasing offshore expansion costs at the transport network level lead to higher upstream network costs and thus higher network charges in the distribution networks. There is therefore a need for changes to the system of avoided network charges to dampen the rise in prices.

In the long term a decrease in infrastructure costs would only be possible if there was a real shift in the load from the transport level to the distribution network level. In the event that electricity should be fed back to the upstream level, however, further investment in the transport network would be needed.

D System services

Guaranteeing system stability is one of the TSOs' core tasks and is performed using system services. System services comprise procuring and using the three types of balancing reserve:

- primary,
- secondary and
- tertiary control reserves.

They also include procuring energy to cover losses, reactive power and black start capability, and national and cross border redispatching and countertrading, as well as the procurement of reserve power plant capacity[27] and interruptible loads under the Interruptible Loads Ordinance (AbLaV)[28].

[27] The costs shown for reserve power plants (in and outside Germany) comprise only the capacity prices, ie the amounts paid to cover the costs incurred in keeping the plants ready for operation. The figures relate to the winter half-years beginning with the 2011/2012 winter (marked in the chart as 2011).

[28] The figures for interruptible loads under the Interruptible Loads Ordinance are likewise based on the capacity prices.

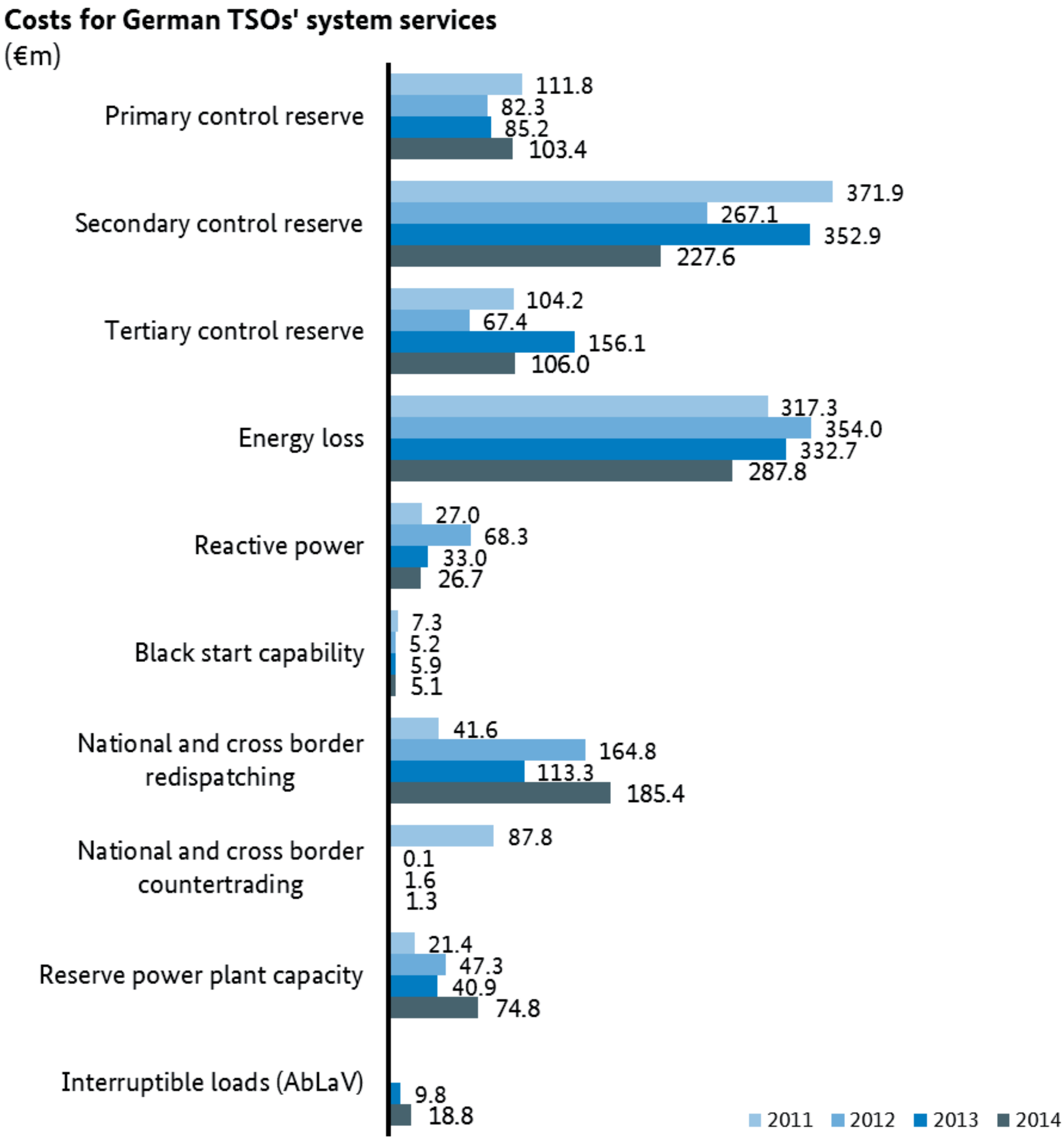

Figure 42: Costs for German TSOs' system services[29] 2011 to 2014

The total costs for system services recovered through the network charges fell slightly from €1,178m in 2013 to €1,096m in 2014. The cost reducing revenues totalled €59m, compared to €46m in 2013. As a result, there was a decrease in the net costs from €1,131m in 2013 to €1,037m in 2014. A large part of the costs is accounted for by the costs of procuring primary, secondary and tertiary control reserves – just under €437m compared to €594m in 2013 – and energy to compensate for losses – at around €288m compared to €333m in 2013.

[29] Net costs (outlay costs minus cost reducing revenues) and costs for reserve power plants and interruptible loads under the Interruptible Loads Ordinance.

The structure of the costs for system services also changed. There was a decrease of €157m in the total net costs for balancing, as a result in particular of the lower costs for secondary and tertiary reserves (down €125m and €50m respectively). One reason for this is the slight decrease in the volume procured of these two types of reserve (see below). By contrast, there was a small increase of €18m in the costs for primary reserve. There was also an increase in the net costs for redispatching as a result of increases in both national and cross border redispatching (up €46m and €25m respectively).

Breakdown of costs for German TSOs' system services 2014
(€m)

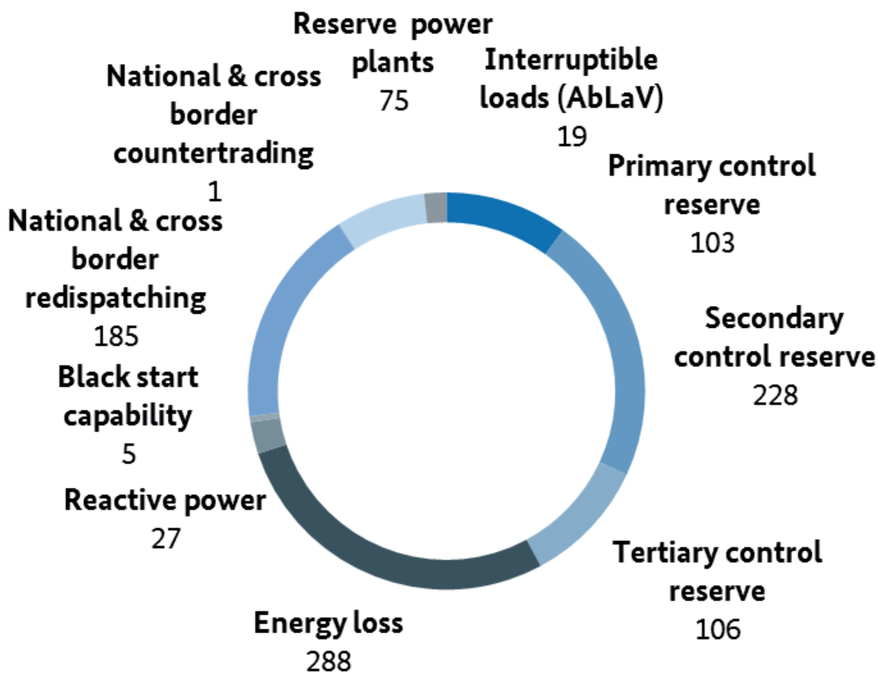

Figure 43: Breakdown of costs for German TSOs' system services 2014

1. Balancing services

The TSOs procure and activate balancing reserves and energy to balance demand and generation in the electricity supply system and thus maintain the stability and frequency of the system. The reserves are procured by the TSOs in national tendering processes in accordance with the Bundesnetzagentur's determinations issued in 2011 (BK6-10-097/098/099). While the costs of procuring balancing reserves are covered by the network charges, the actual energy activated is settled in the form of balancing energy with the balancing group managers (dealers, suppliers) causing the imbalances.

A grid control cooperation scheme, covering the control areas of all four German TSOs (50Hertz, Amprion, TenneT and TransnetBW), was completed when Amprion joined in 2010 as instructed by the Bundesnetzagentur. The scheme, with a modular structure, prevents inefficient use of secondary and tertiary control reserves and dimensions the balancing reserve requirements for all four control areas together. The scheme also creates a nationally uniform, integrated market mechanism for secondary and tertiary reserves and optimises the costs of using balancing reserves for the whole of Germany. The imbalances in the individual control areas are netted so that only what remains has to be compensated for by activating reserves. Inefficient use is almost completely eliminated and the volume of balancing capacity required is reduced, as reflected by the lower levels of secondary and tertiary reserves tendered and energy activated.

In 2011 the Bundesnetzagentur issued determinations within this context on

- reducing minimum bid volumes,
- shortening tendering periods,
- pooling and
- providing collateral for investments in the primary, secondary and tertiary reserve markets.

One of the aims of the determinations is to encourage new suppliers to enter the market and to further open up the balancing markets for other technologies, for example interruptible consumption or storage facilities.

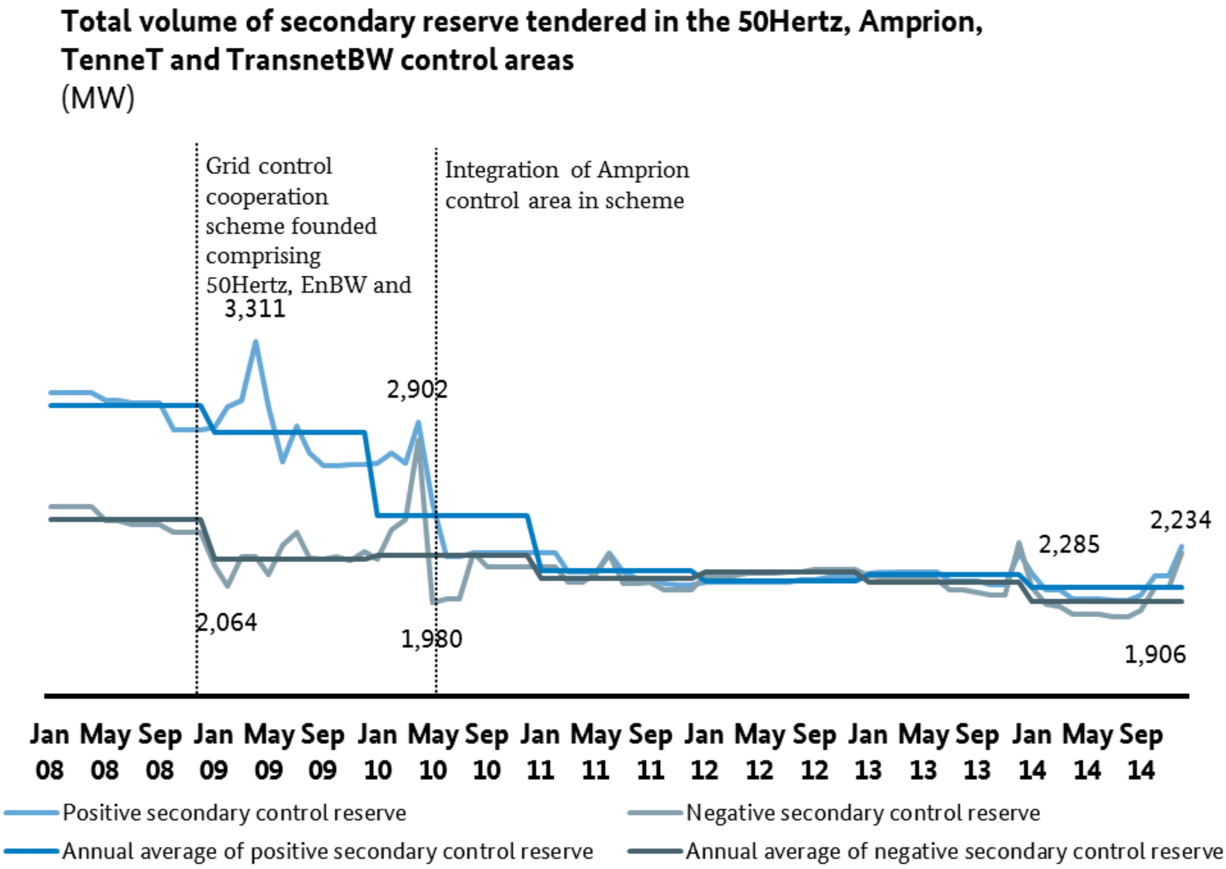

Figure 44: Total volume of secondary reserve tendered in the control areas of 50Hertz, Amprion, TenneT and TransnetBW

There was a slight decrease in the average volume of secondary reserve tendered in 2014. The average volume of negative secondary reserve tendered fell from 2,081 MW in 2013 to 1,987 MW. The average volume of positive secondary reserve tendered also fell from 2,122 MW in 2013 to 2,058 MW.

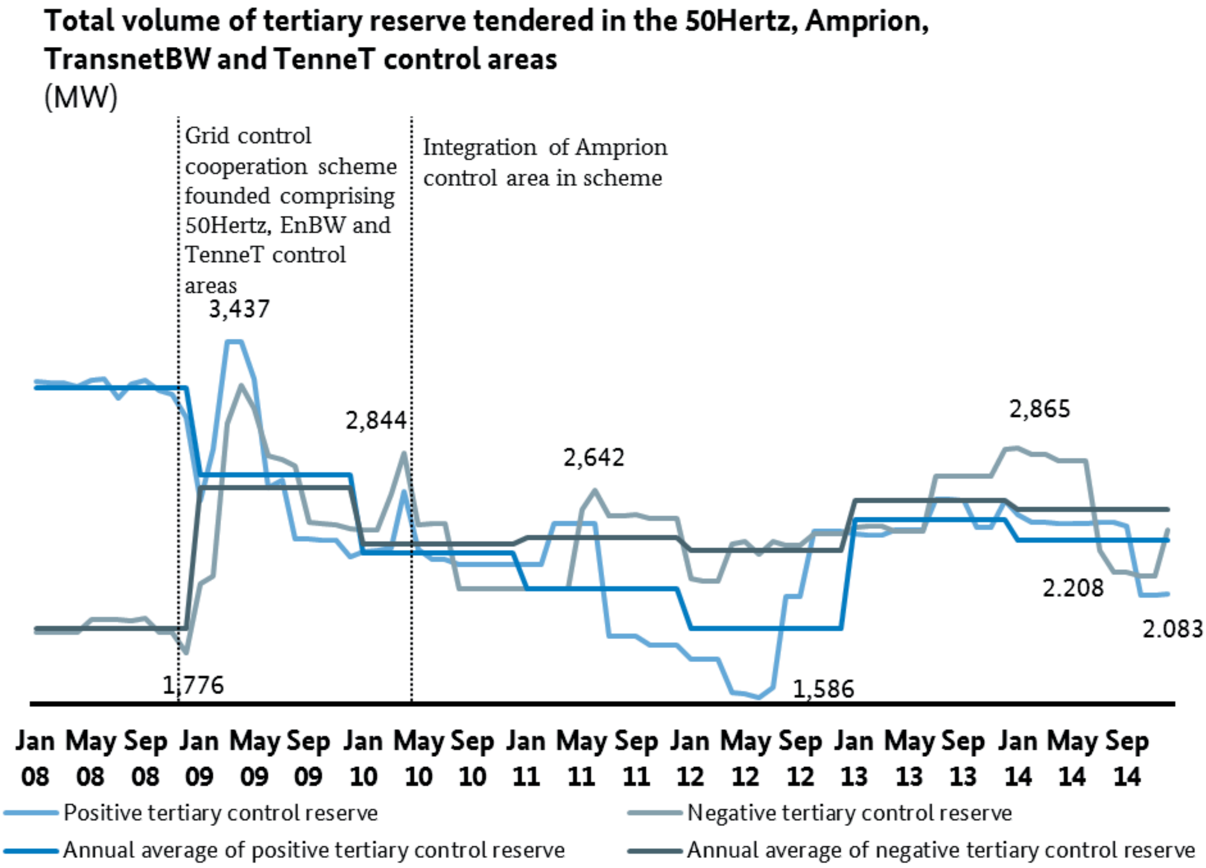

Figure 45: Total volume of tertiary reserve tendered in the control areas of 50Hertz, Amprion, TenneT and TransnetBW

The picture is less uniform when it comes to tertiary reserve. While there was a continued decline in the average volume of positive tertiary reserve tendered from 2,309 MW to 1,907 MW between 2010 and 2012, the average volume in 2013 was 2,483 MW. In 2014, the average volume tendered fell to 2,376 MW. Following a substantial increase in the demand for positive tertiary reserve from a historic low of 1,552 MW in May 2012 to a high of 2,593 MW in August 2013, demand stabilised in the first three quarters of 2014 at some 2,470 MW. The average volume of positive tertiary reserve tendered then fell in the fourth quarter of 2014 to 2,083 MW.

There was a slight year on year decrease in the annual average volume of negative tertiary reserve procured. The average tendered in 2014 was 2,540 MW, although volumes fluctuated considerably during the course of the year. In January the average volume of negative tertiary reserve tendered stood at 2,876 MW; this decreased in the period up to November to 2,184 MW before increasing again in December to reach 2,432 MW.

Overall, therefore, the change in the volumes of positive and negative tertiary reserve tendered within the twelve-month period is considerably more volatile than for secondary reserve. This is due in part to changes in generating patterns and the continued increase in the number of renewable energy installations in Germany.

The range of the volumes of primary, secondary and tertiary control reserves tendered in 2014 can be seen in the following table:

Balancing reserves (minimum and maximum volumes) tendered by the TSOs 2013 and 2014
(MW)

		Primary control reserve		Secondary control reserve				Tertiary control reserve			
				Positive		Negative		Positive		Negative	
		2013	2014	2013	2014	2013	2014	2013	2014	2013	2014
Capacity tendered (MW)	min	551	568	2,073	1,992	2,018	1,906	2,406	2,083	2,413	2,184
	max	551	568	2,473	2,500	2,418	2,500	2,947	2,947	3,220	3,220

Source: www.regelleistung.net

Table 31: Balancing reserves (minimum and maximum volumes) tendered by the TSOs 2013 and 2014

There was a year on year increase in the maximum volumes of positive and negative secondary reserve tendered, while the maximum volumes of both positive and negative tertiary reserve tendered remained unchanged. At the same time there was a decrease in the minimum volumes of secondary and tertiary reserves tendered, with the overall effect of widening the range between the minimum and maximum levels. The demand for primary reserve increased from 551 MW in 2013 to 568 MW in 2014, thus reaching the 2012 level again. Overall, the volume tendered for Germany has decreased slightly since 2009.

The German TSOs are seeking to harmonise the primary reserve markets across the borders in cooperation with the Bundesnetzagentur and foreign TSOs and regulators. Swissgrid joined the German TSOs' primary reserve tendering scheme as the fifth TSO on 12 March 2012. A total volume of 25 MW of Switzerland's primary reserve requirements is tendered in line with the German regulations, with Swissgrid acting as the connecting TSO for the Swiss providers. The tendering procedure is open to both current German and pre-qualified Swiss providers. TenneT TSO BV in the Netherlands joined the joint tendering scheme as the sixth TSO on 7 January 2014. Here, an initial volume of 35 MW and since November 2014 a total volume of 70 MW of the Netherlands' primary reserve requirements is tendered in line with the German regulations, with TenneT TSO BV acting as the connecting TSO for the providers in the Netherlands. The tendering procedure is open to both current German providers and pre-qualified providers from the Netherlands. On 7 April 2015 the international joint primary reserve tendering scheme was coupled with Austria and Switzerland's joint scheme. The German TSOs are also considering joint primary reserve tendering with other countries.

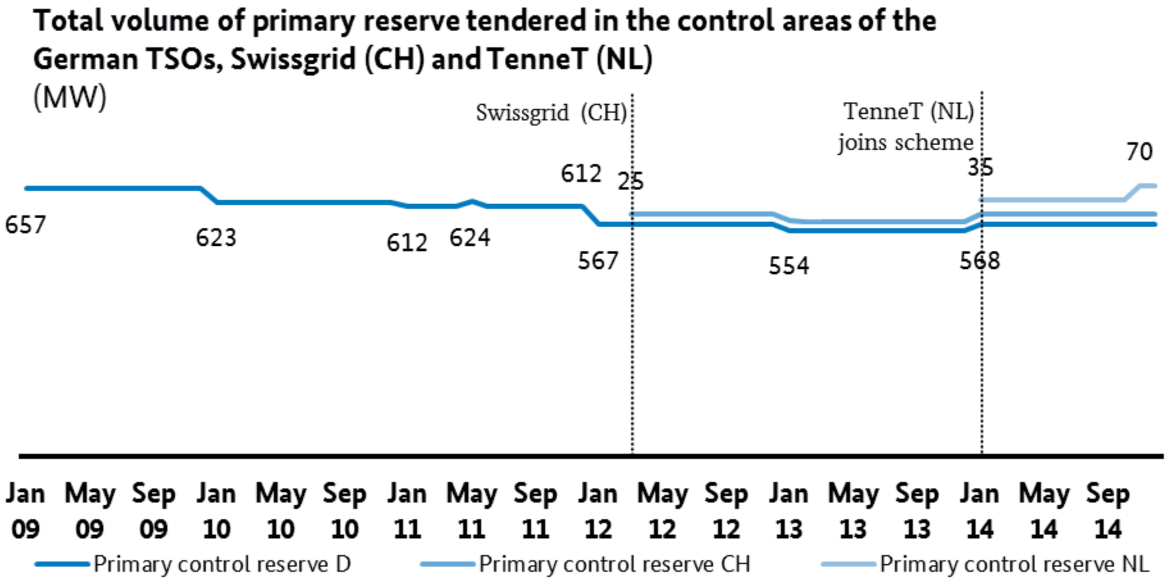

Figure 46: Total volume of primary reserve tendered in the control areas of the German TSOs, Swissgrid (CH) and TenneT (NL)

The grid control cooperation scheme and the determinations issued by the Bundesnetzagentur contribute to increasing the potential for competition by enlarging the market area, creating a national market for secondary and tertiary reserves and aligning the conditions for tendering. By 20 July 2015 the number of pre-qualified secondary reserve providers had risen to 31 (compared to 15 in 2010 and 20 in 2013) and that of tertiary reserve providers to 42 (compared to 35 in 2010 and 36 in 2013). The number of primary reserve providers was 16, compared to 14 in 2013. The growth in the number of balancing service providers over the last few years shows how attractive this market is. In particular the possibility for one single provider to pool several small installations into one virtual power plant has had a positive effect on competition.

2. Use of secondary control reserve

As Figure 44 shows, the total volume of secondary control reserve tendered and procured between 2011 and 2014 remained at a similar, comparatively low level. There was another decrease in the volume of secondary reserve actually used in 2014 compared to 2013.

The total amount of energy activated for positive secondary control in 2014 was some 1.2 TWh (compared to 1.5 TWh in 2013) and that for negative secondary control 1.6 TWh (compared to 2.3 TWh in 2013). The total amount of energy activated for secondary control hence decreased from 3.8 TWh in 2013 to around 2.8 TWh in 2014, with a slight shift towards positive secondary control. Hence on average in 2014 around 6.5% of the average volume of positive secondary reserve tendered and about 9.3% of the average volume of negative secondary reserve tendered was used. It must be noted, however, that in several quarter hours in the year almost all of the secondary reserve capacity was required; overall this confirms the necessity of the volumes tendered.

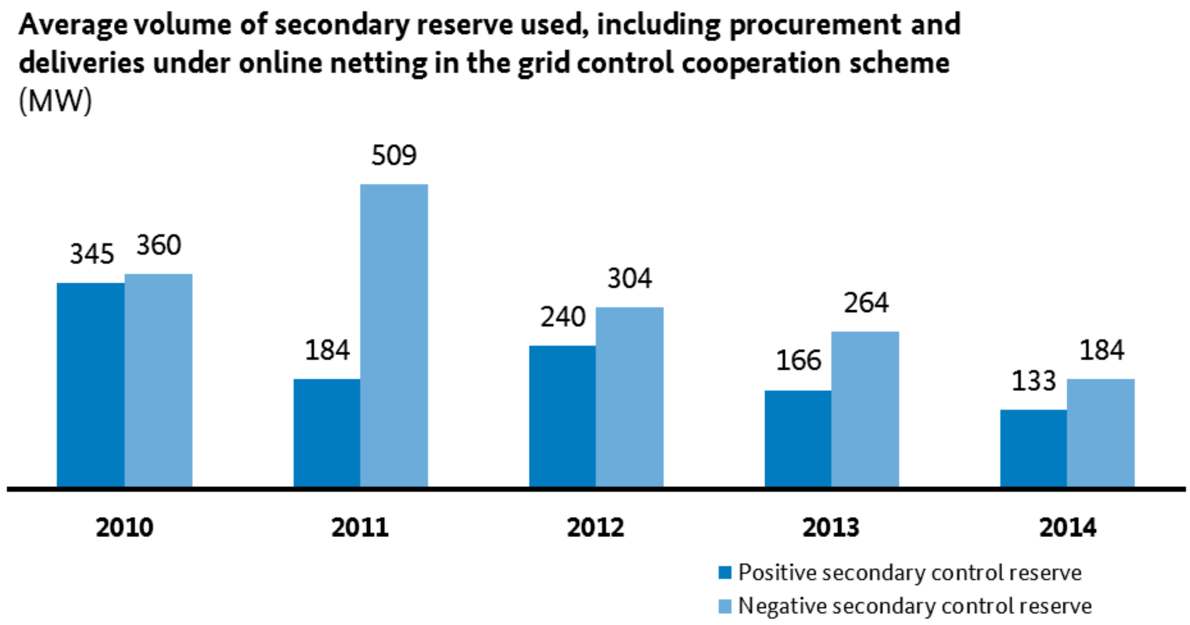

Figure 47: Average volume of secondary reserve used, including procurement and deliveries under online netting in the grid control cooperation scheme

3. Use of tertiary control reserve

The frequency of use of tertiary control reserve also decreased further in 2014. The total number of dispatch requests was 7,451, representing a year on year decrease of a good 40%. This is due in particular to the decrease in the use of negative tertiary reserve. Overall, there were 3,769 requests for negative tertiary reserve in 2014 (compared to 8,187 in 2013) and 3,682 requests for positive tertiary reserve (compared to 4,294 in 2013).

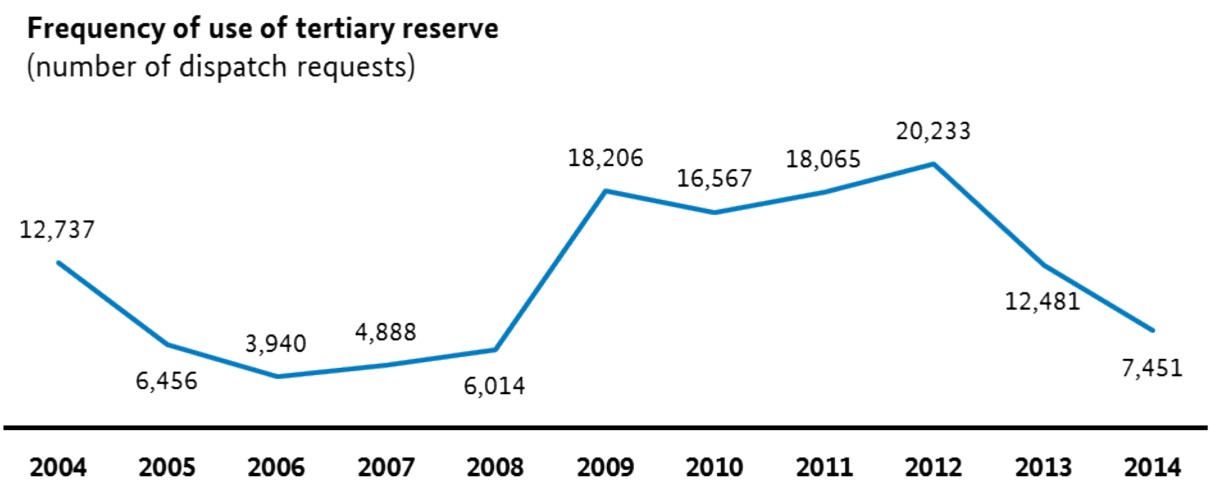

Figure 48: Frequency of use of tertiary reserve

The use of positive and negative tertiary reserve decreased in all four control areas, with the exception of positive tertiary reserve in the 50Hertz control area.

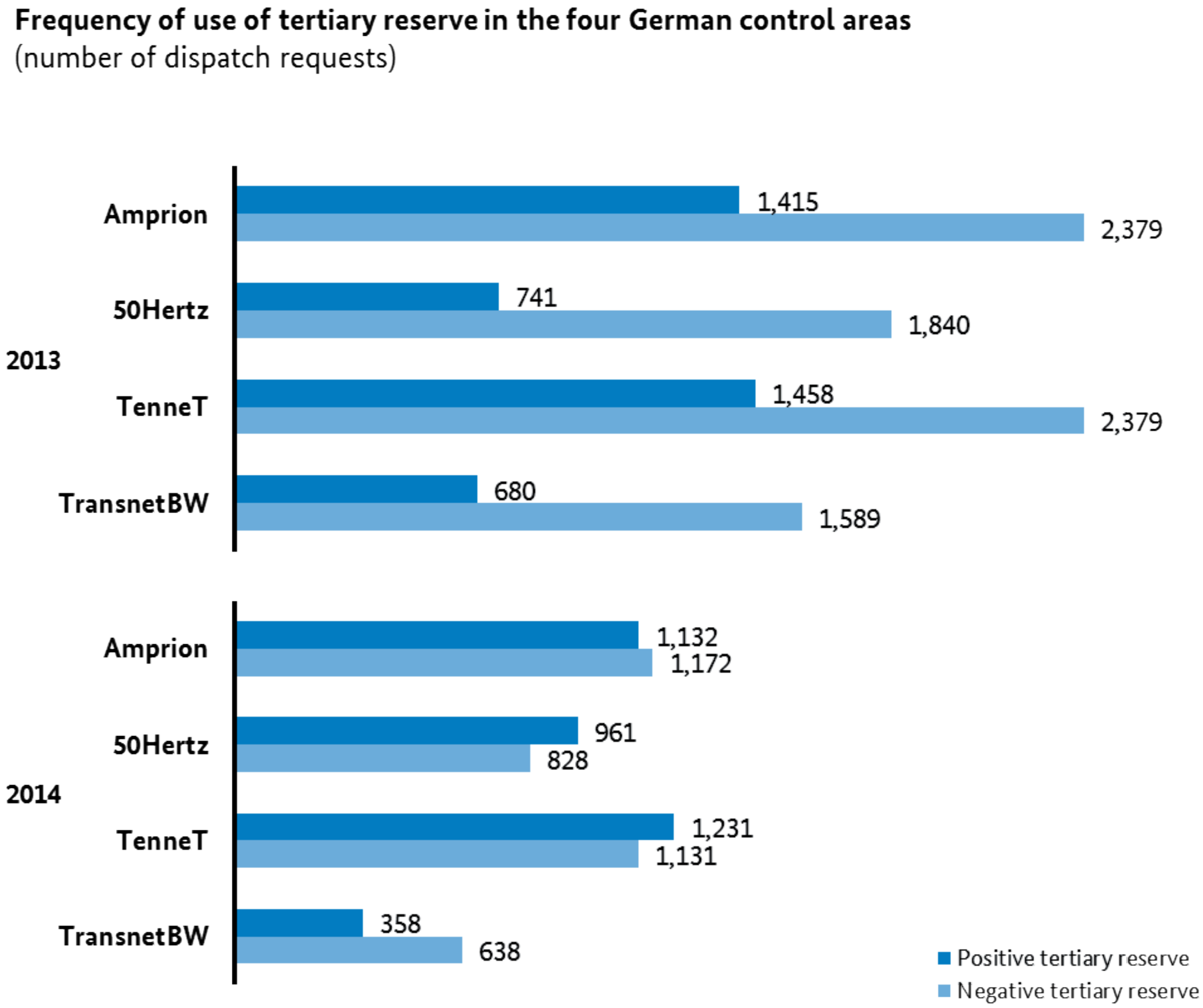

Figure 49: Frequency of use of tertiary reserve in the four German control areas 2013 and 2014

There was a decrease in the average volume of positive tertiary reserve requested from 201 MW in 2013 to approximately 176 MW in 2014. Likewise, there was a decrease in the average volume of negative tertiary reserve requested from 215 MW in 2013 to some 184 MW in 2014. On average in 2014 around 7% of the average volume of both positive and negative tertiary reserve tendered was used. As with secondary reserve, however, it must be noted that in several quarter hours in the year almost all of the tertiary reserve capacity was required; overall this again confirms the necessity of the volumes tendered.

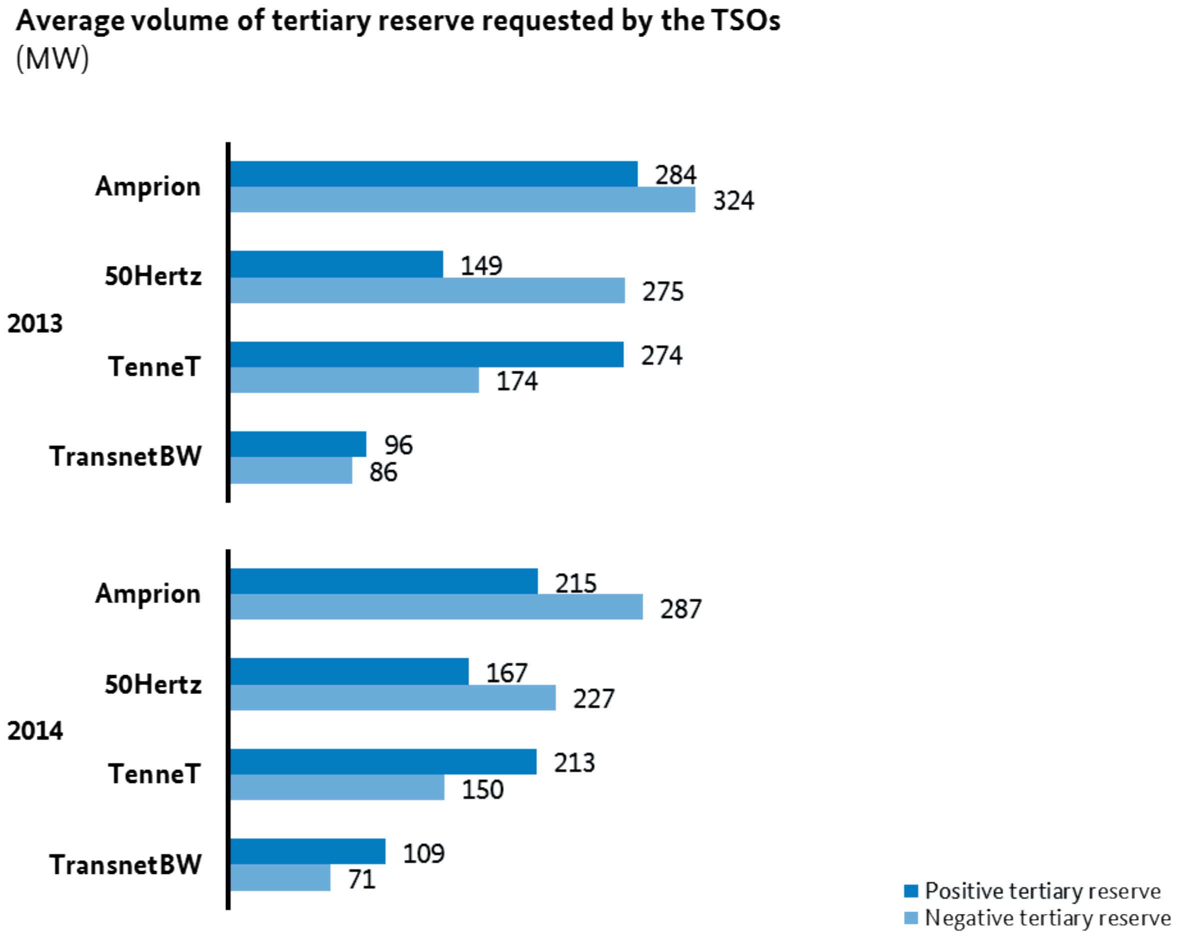

Figure 50: Average volume of tertiary reserve requested by the TSOs 2013 and 2014

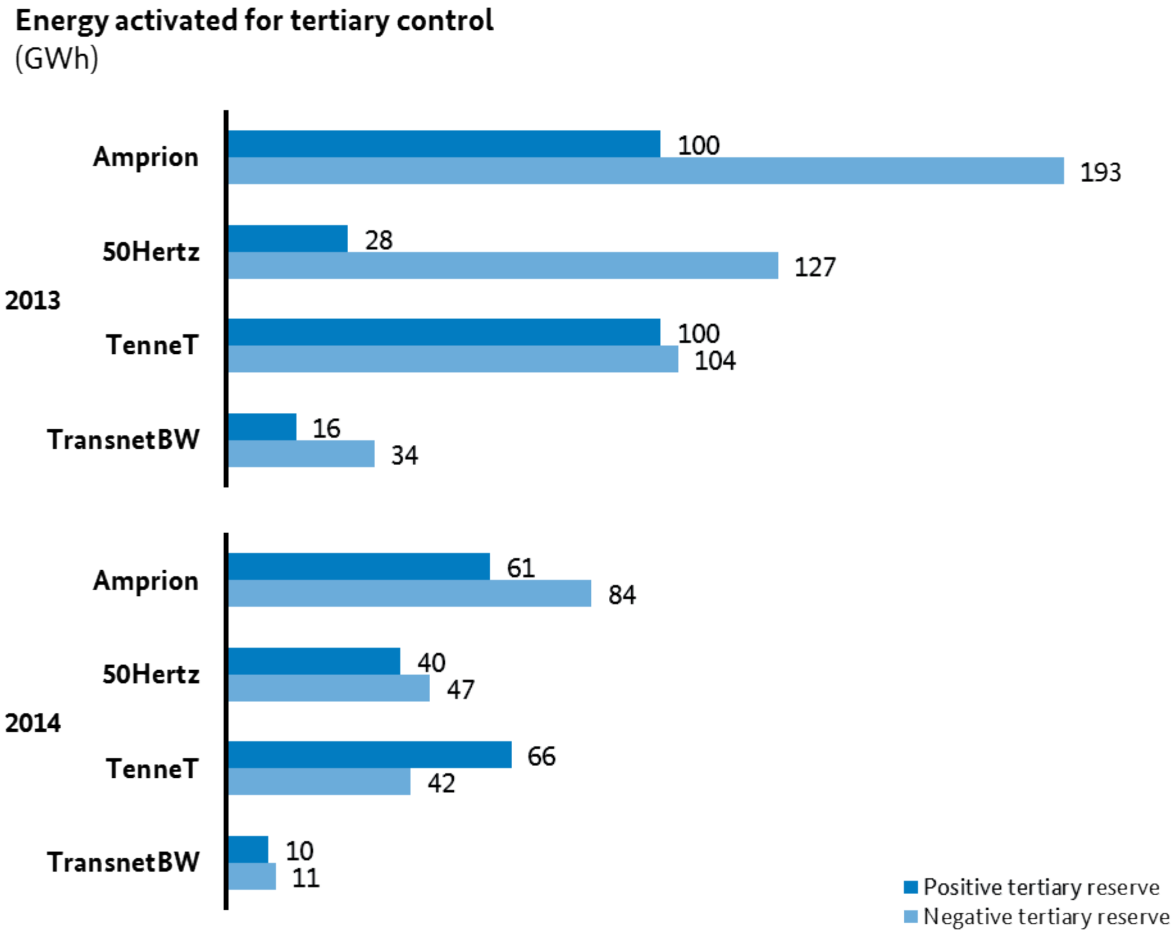

Figure 51: Energy activated for tertiary control 2013 and 2014

The total amount of energy activated for positive tertiary control in 2014 was 176 GWh (compared to 244 GWh in 2013) and that for negative tertiary control 185 GWh (compared to 458 GWh in 2013). Hence the trend seen in the previous year of a shift away from negative to positive tertiary control was not confirmed. The amounts of energy activated for positive and negative tertiary control began to converge again in 2014.

The following line graph shows the average use of energy for secondary and tertiary control in each calendar month in the period from 2009 to 2014. It also shows an average for each period. A change in the grid control cooperation scheme (eg setting up, Amprion joining) marks the beginning of a period. The graph illustrates the scheme's savings potential in terms of activated energy since January 2011. It also shows the decrease in the total average amount of energy activated for secondary and tertiary control and a reduction in volatility over time.

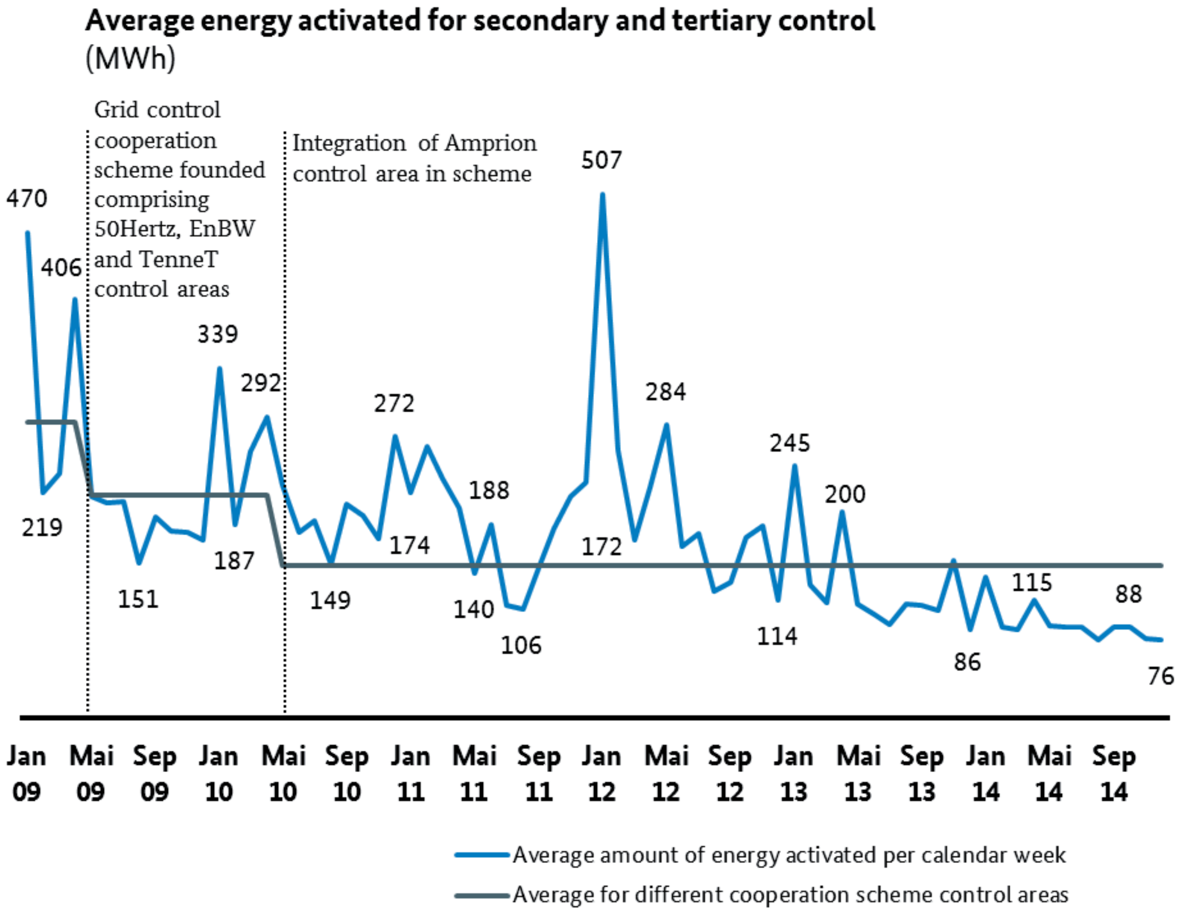

Figure 52: Average amount of energy activated for secondary and tertiary control

4. One-off event: solar eclipse on 20 March 2015

One challenge to the stability of the electricity network during the 2014/2015 winter season was the partial solar eclipse over Europe on 20 March 2015. The reduction in solar radiation from around 09:30 and its return at about 12:00 was expected to cause high variations in photovoltaic feed-in depending on how clear sky conditions were.[30] This led the German TSOs to implement numerous measures in cooperation with their European counterparts. One particular step was to procure a considerably larger amount of reserves to balance the high variations in photovoltaic injection if necessary. Another was to increase staffing at the TSOs' network control centres.

With mostly clear sky conditions, large changes in injection of more than 4,000 MW per quarter hour (10:15-10:30) were measured after the maximum impact of the solar eclipse (see Figure 53).

[30] See for instance the study conducted by the University of Applied Sciences in Berlin on the impact of the solar eclipse in March 2015 on solar generation in Germany (HTW Berlin: "*Einfluss der Sonnenfinsternis im März 2015 auf die Solarstromerzeugung in Deutschland*").

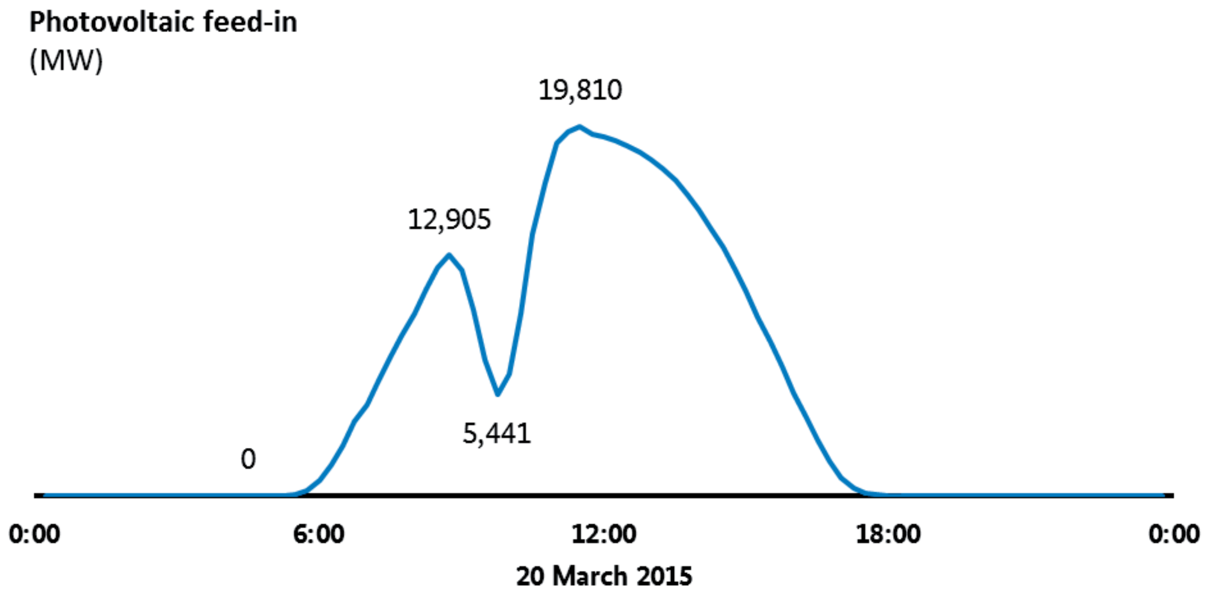

Figure 53: Photovoltaic feed-in (MW) between 00:00 and 24:00 on 20 March 2015 (source: ENTSO E[31])

The market managed to balance the decrease and subsequent increase in photovoltaic feed-in with a relatively small level of reserves and contractual interruptible loads being needed.

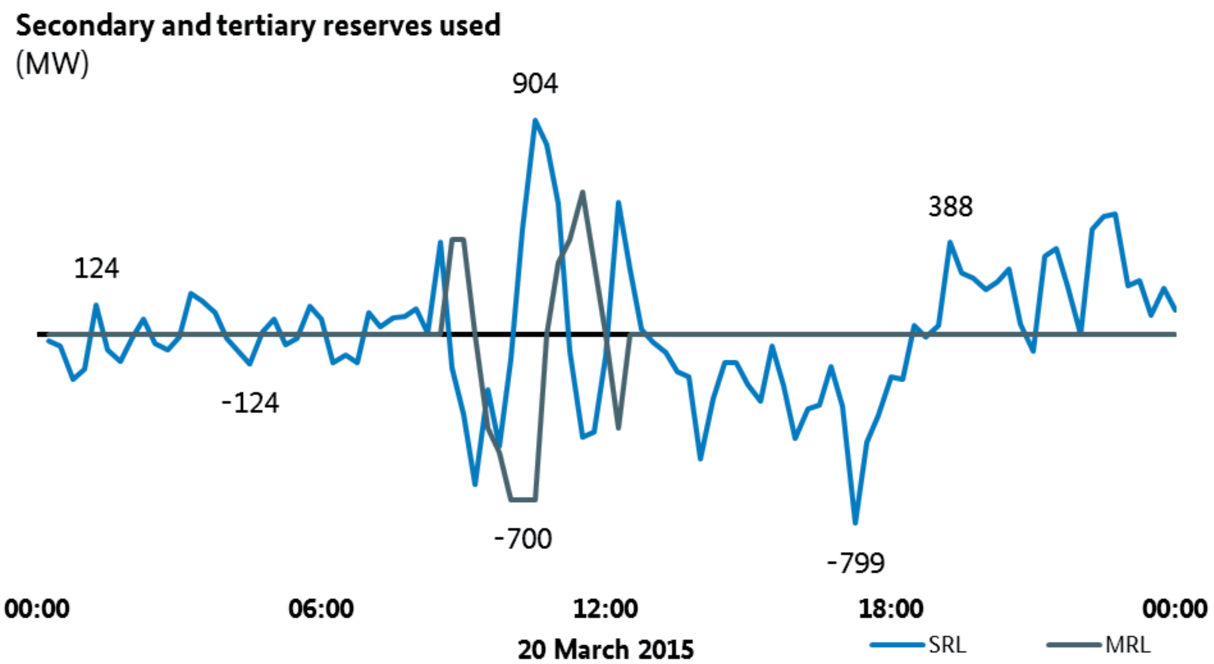

Figure 54: Secondary and tertiary reserves used on 20 March 2015 (source: TSOs[32])

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[31] transparency.entsoe.eu

5. Balancing energy

The regulations laid down by the Bundesnetzagentur reforming the balancing energy price system came into effect on 1 December 2012. The aim is to provide better incentives for the proper management of balancing groups with a view to preventing system-relevant imbalances such as occurred in February 2012.

The maximum balancing energy price within the grid control cooperation scheme rose significantly in 2014 to €5,998.41/MWh.[33] Overall, the maximum price exceeded €2,000/MWh on twelve occasions in 2014.

Maximum balancing energy prices

Year	Grid control cooperation scheme (€/MWh)
2010	600.90
2011	551.60
2012	1,501.20
2013	1,608.20
2014	5,998.41

Table 32: Maximum balancing energy prices 2010 to 2014

Under the cooperation scheme, the average 15-minute price for balancing energy in 2014 in the case of a positive control area balance (short portfolio) was some €75.42/MWh, and in the case of a negative balance (long portfolio) around -€24.22/MWh. The average balancing energy price was therefore around 128%[34] higher than the average intraday trading price in 2014. There was another year on year decrease in the average price for balancing energy in the case of a short portfolio. There was also a further decrease in the average price in the case of a long portfolio.

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[32] http://www.netztransparenz.de

[33] In cases where the balance of energy activated for control within the grid control cooperation scheme is close to zero ("zero crossings"), the mathematical formula applied may result in high prices. In these cases, the balancing energy price is limited to the maximum price of a control energy bid activated in the particular quarter hour. If high prices are bid by the suppliers, the balancing energy prices will also be high despite being capped.

[34] Based on the EPEX SPOT average intraday trading price of €33.14/MWh for 2014.

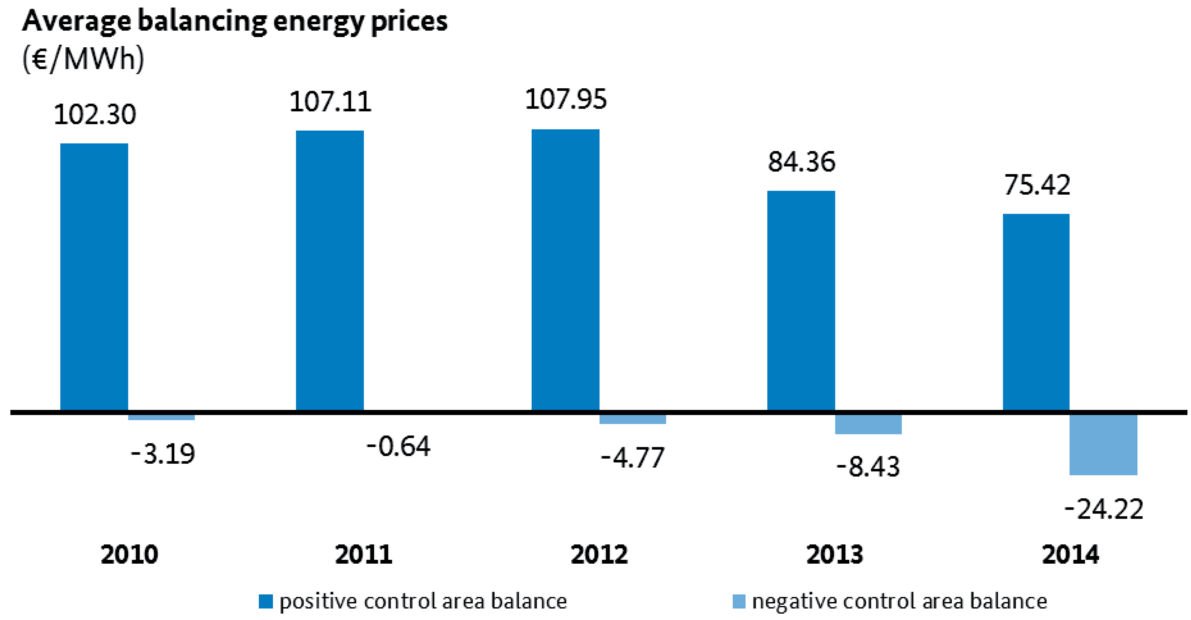

Figure 55: Average balancing energy prices 2010 to 2014

The following graph shows the frequency distribution of balancing energy prices in the grid control cooperation scheme in 2013 and 2014. As in previous years, there was an accumulation of prices around €0/MWh in the case of a negative control area balance in 2014. In the case of a positive control area balance there was also a greater frequency of prices in 2014 between €40/MWh and €90/MWh.

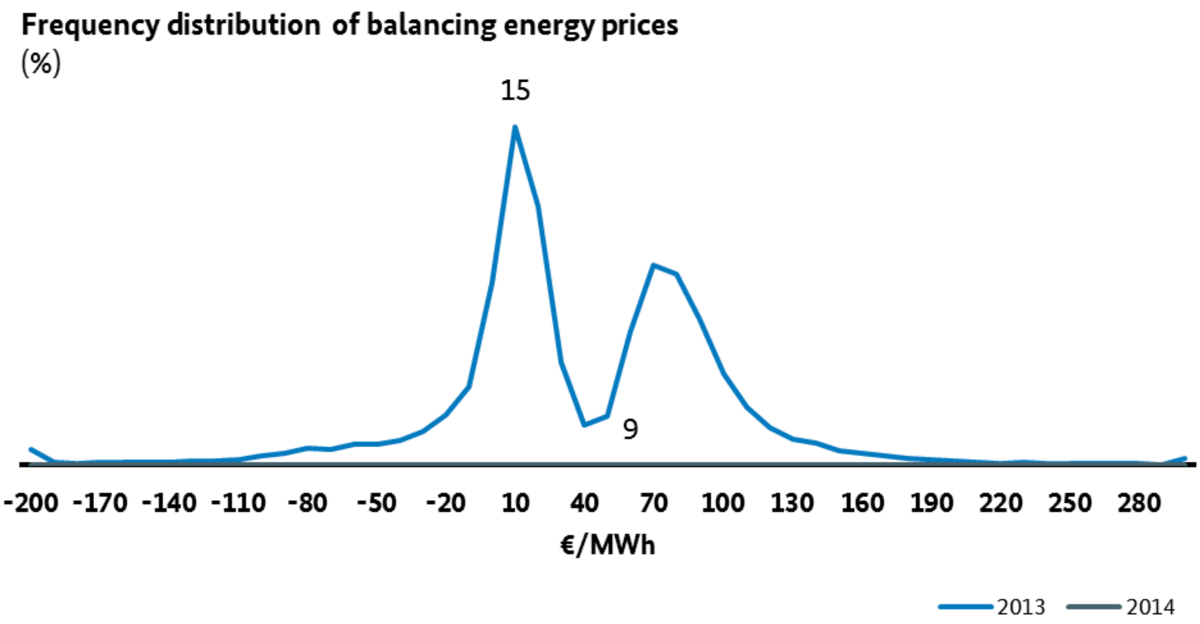

Figure 56: Frequency distribution of balancing energy prices 2013 and 2014

6. Intraday trading

Section 5(1) of the Electricity Network Access Ordinance (StromNZV) allows schedule notifications – in which balancing group managers notify TSOs about planned electricity supply and commercial transactions in the period from the day following submission until the next working day (based on quarter hour figures) – to be submitted up to 14:30 on a given day. Schedules can also be modified during the day, enabling balancing group managers to respond to short term changes in supply and demand. The following graph shows the number and volume of intraday changes to schedules in 2014:

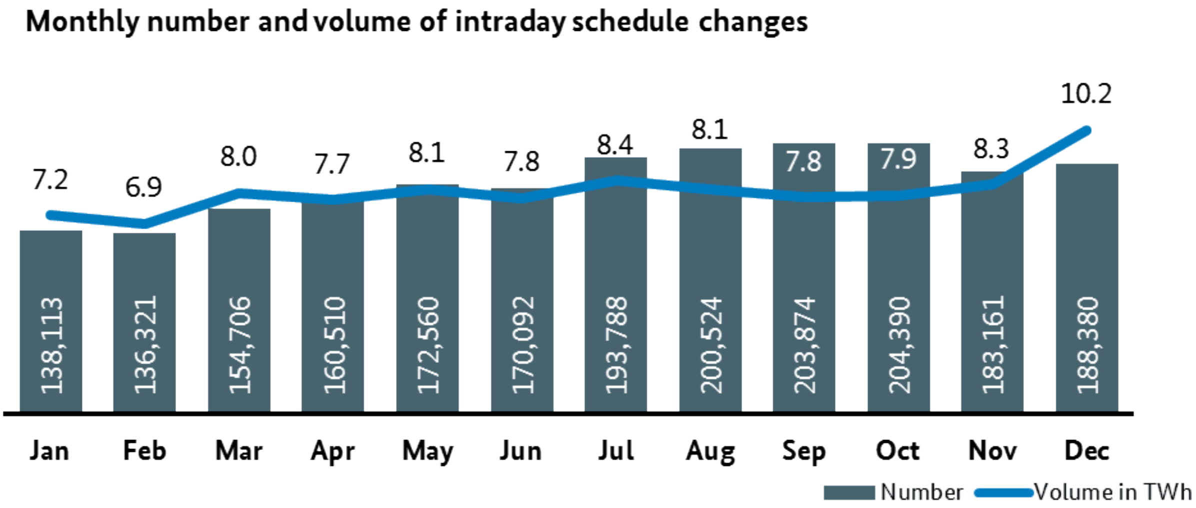

Figure 57: Monthly number and volume of intraday schedule changes 2014

In 2014, a total number of 2,106,419 schedule changes accounted for a total volume of 96.5 TWh, compared to 1,286,752 changes and 75.5 TWh in 2013. On average, 175,000 schedule changes were made each month in 2014, the highest monthly number being 204,390 in October and the lowest 136,321 in February. One reason for the repeated steep increase in both the number and volume of intraday schedule changes is the increase in fluctuating feed-in from renewables which frequently needs to be balanced out during the day through intraday trading.

7. International expansion of grid control cooperation

Over the last few years the German TSOs have been pushing forward the expansion of module 1 of their joint grid control cooperation scheme, which aims to prevent the inefficient use of secondary reserve across different control areas. Cooperation to avoid inefficient use of secondary control reserve is carried out with the following countries: Denmark (since October 2011), the Netherlands (since February 2012), Switzerland (since March 2012), the Czech Republic (since June 2012), Belgium (since October 2012) and Austria (since April 2014). The participation of further countries in the international scheme is desirable and is supported by the Bundesnetzagentur.

The International Grid Control Cooperation (IGCC) enables the imbalances and hence the demand for secondary reserve in the participating control areas to be automatically registered and physically netted ("imbalance netting"): TSOs with a surplus of energy in their control areas provide power to those with a shortage. No cross border transmission capacity needs to be reserved for this exchange of energy: the maximum amount of energy that can be exchanged across the border corresponds to the remaining capacity available after the close of trading in the intraday market.

The international cooperation scheme has already achieved cost savings totalling around €200m through avoiding inefficient use of reserves. Since the concept of physically netting imbalances also promises high welfare gains for the whole of Europe, the Network Code on Electricity Balancing requires all European TSOs to implement imbalance netting in the future.

E Cross-border trading and European integration

As in the years prior to 2014, Germany was once again the electricity exchange hub within the central interconnected system. The average available transmission capacity to neighbouring countries changed only slightly in 2014. Compared to 2013, the averaged import and export capacity rose by 0.3% to 21,193 MW; in 2013 it had even fallen by 2.8% when compared to 2012.

Total cross-border traded volumes fell slightly from 86.3 TWh in 2013 to 83.8 TWh in 2014, corresponding to a 2.9% reduction. This reflects a decline in imports of 8.5% from 26.95 TWh in 2013 to 24.66 TWh in 2014. Exports remained practically unchanged with only a slight decrease of 0.4% from 59.43 TWh in 2013 to 59.17 TWh in 2014. Overall, the German export balance rose from 32.49 TWh in 2013 to 34.52 TWh in 2014, corresponding to a rise of 6.3%.

1. Average available transmission capacity

Of key importance to the European internal electricity market is the availability of transmission capacity between the countries in Europe. The average available transmission capacity was determined using the TSOs' annual average hourly net transfer capacity (NTC) values, where available. Gaps were filled using average NTC values taking the ENTSO-E formulae[35] as the basis of calculation.

[35] Care was taken to ensure that border values were determined using data from the same source. Only a limited comparison can be made of the capacity of individual countries, however, as the NTC values transmitted on an hourly basis by the TSOs may deviate from the average values calculated using ENTSO-E formulae owing to the use of different calculation methods. Details of the NTC calculation methods used by ENTSO-E and the German TSOs can be found at https://www.entsoe.eu/publications/market-reports/ntc-values/Pages/default.aspx

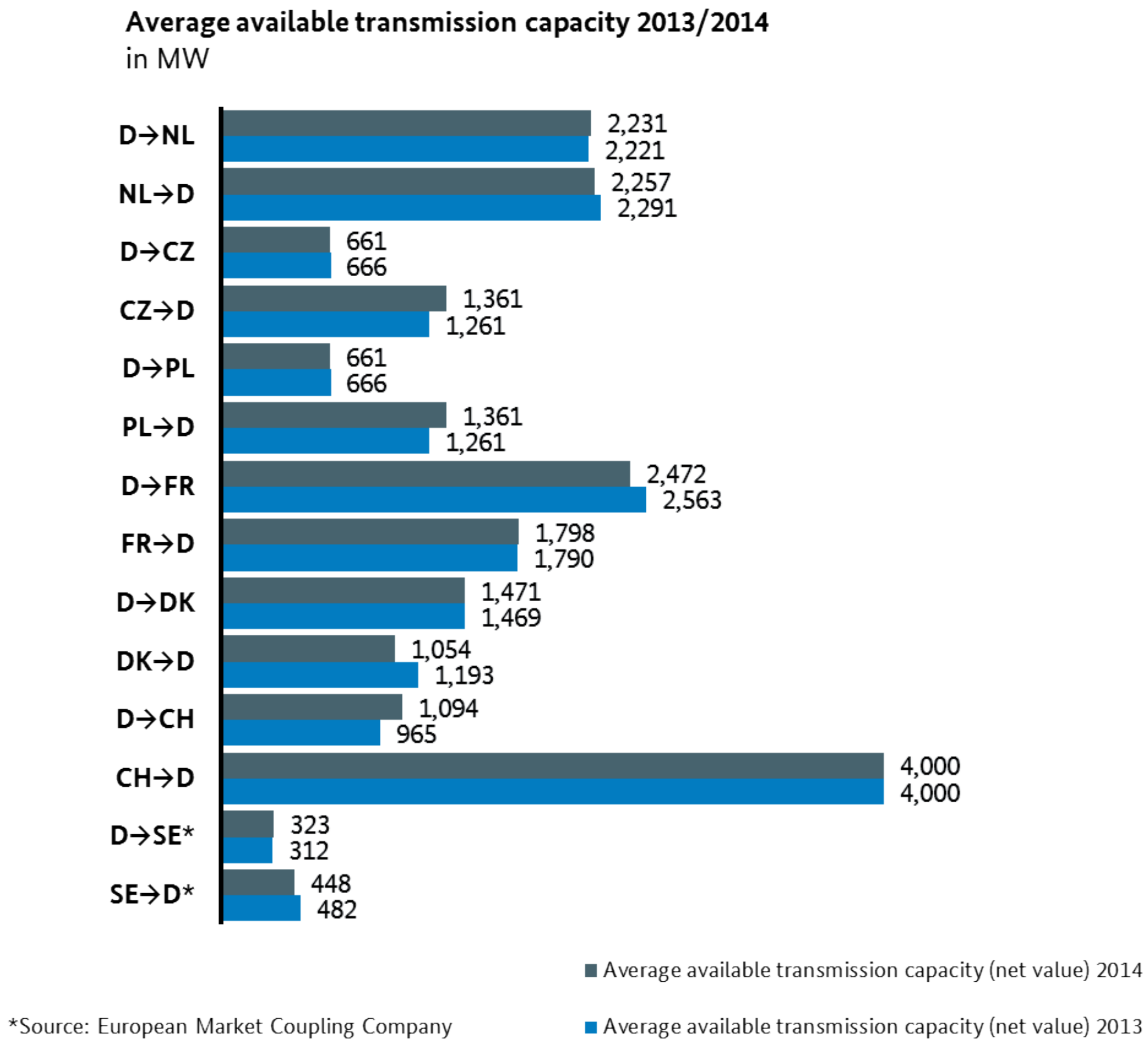

Figure 58: Average available transmission capacity

A change in import capacity was most noticeable at the Polish, Czech, Swedish and Danish borders; import capacity fell by 11.6% at the Danish border and 7.1% at the Swedish border. An increase in import capacity of 8% was recorded at both the Polish border and the Czech border.

Changes also occurred in export capacity with capacity falling by 3.5% at the border with France compared to a rise of 3.5% at the Swedish border. The biggest increase occurred at the Swiss border at 13.4%.

Amongst the reasons for the changes in capacity are technical breakdowns and maintenance work to the transmission system lines. The German TSOs are required to carry out maintenance and repairs to transmission lines as quickly and efficiently as possible to guarantee a smooth exchange of electricity with other countries. Average available transmission capacity over all German cross-border interconnectors increased by 0.3% from a total of 21,137 MW in 2013 to 21,193 MW (import and export capacity) in 2014. All the figures are summarised in the table below.[36]

Import capacity trend

	(Net) average available transmission capacity 2013 MW	(Net) average available transmission capacity 2014 MW	Change %
NL → D	2,291.1	2,257.2	-1.5
PL → D	1,260.6	1,361.2	8.0
CZ → D	1,260.6	1,361.2	8.0
FR → D	1,790.5	1,798.5	0.5
DK → D	1,192.5	1,054.2	-11.6
CH → D	4,000.0	4,000.0	0.0
SE → D	481.7	447.6	-7.1
Total	12,277.0	12,279.7	0.0

Table 33: Import capacity trend from 2013 to 2014

Export capacity trend

	(Net) average available transmission capacity 2013 MW	(Net) average available transmission capacity 2014 MW	Change %
D → NL	2,220.7	2,231.2	0.5
D → PL	665.7	660.6	-0.8
D → CZ	665.7	660.6	-0.8
D → FR	2,562.9	2,472.2	-3.5
D → DK	1,468.7	1,471.5	0.2
D → CH	964.7	1,094.2	13.4
D → SE	312.4	323.3	3.5
Total	8,860.8	8,913.5	0.6

Table 34: Export capacity trend from 2013 to 2014

[36] The data used was provided by the German TSOs, plausibility checks were carried out by the Bundesnetzagentur.

2. Cross-border load flows and implemented exchange schedules

The exchange schedules implemented are decisive in assessing the net balance of electricity imports and exports at each external border and at all of Germany's borders as a whole.

These exchange schedules reflect excess generation, or demand shortage, and hence follow the rules of the market. The following diagram shows the exchange schedules implemented at Germany's borders in 2014.

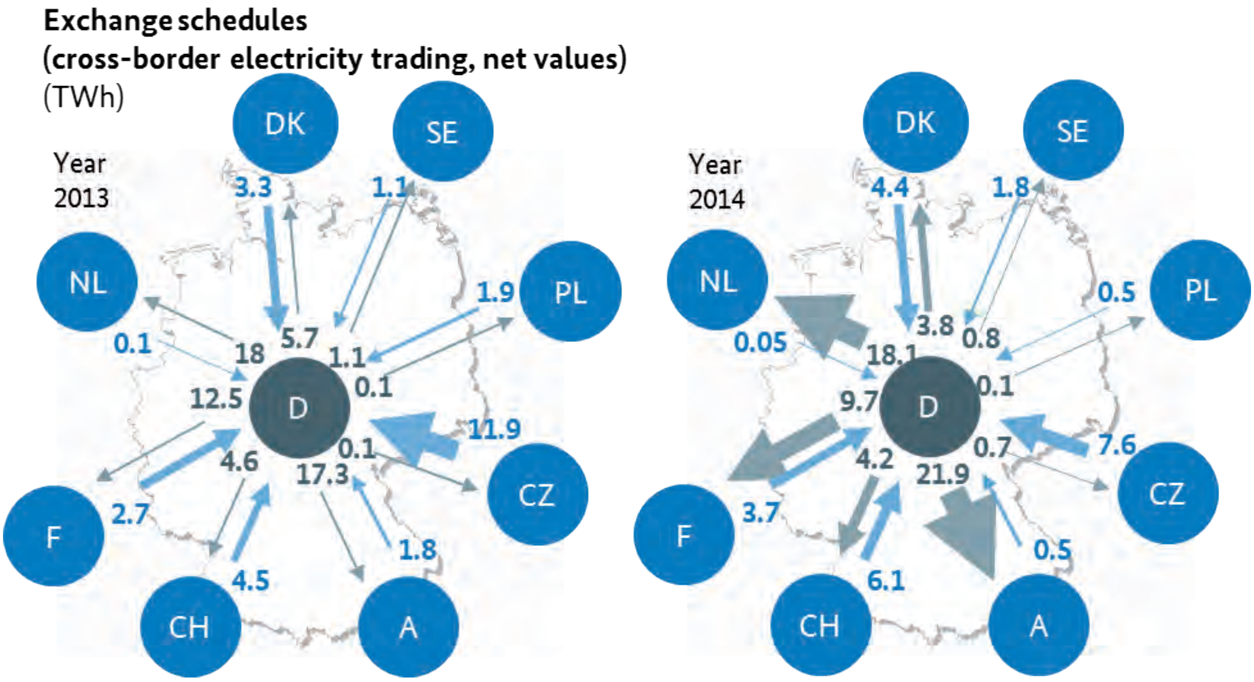

Figure 59: Exchange schedules (cross-border electricity trading)

The rise in exports in 2014 is linked to the increase in electricity generated by renewable sources and to falling prices on the German power exchange. In 2014 the average EPEX day-ahead spot price shrank to just €32.76 per megawatt hour, whereas in 2013 the average price was €37.78. All the figures are summarised in the tables below.[37]

[37] The data used was provided by the German TSOs, plausibility checks were carried out by the Bundesnetzagentur.

Comparison of imports from cross-border flows
(TWh)

	Actual physical flow 2013	Binding exchange schedules 2013	Actual physical flow 2014	Binding exchange schedules 2014
NL → D	0.3	0.1	0.4	0.1
PL → D	0.5	1.9	0.1	0.5
CZ → D	9.4	11.6	6.3	7.6
FR → D	11.8	2.7	14.8	3.7
DK → D	3.2	3.3	4.5	4.4
CH → D	3.7	4.5	4.6	6.1
AT → D	5.7	1.8	4.1	0.5
SE → D	1.1	1.1	1.8	1.8

Table 35: Comparison of imports from cross-border flows

Comparison of exports from cross-border flows
(TWh)

	Actual physical flow 2013	Binding exchange schedules 2013	Actual physical flow 2014	Binding exchange schedules 2014
D → NL	24.6	18.0	24.3	18.1
D → PL	5.5	0.1	9.2	0.1
D → CZ	2.5	0.1	3.8	0.7
D → FR	1.2	12.5	0.8	9.7
D → DK	5.8	5.7	4.0	3.8
D → CH	11.7	4.6	11.5	4.2
D → AT	14.4	17.3	14.5	21.9
D → SE	1.0	1.1	0.8	0.8

Table 36: Comparison of exports from cross-border flows

Comparison of the balance of cross-border flows
(TWh)

	Actual physical flow 2013	Binding exchange schedules 2013	Actual physical flow 2014	Binding exchange schedules 2014
Imports	35.8	26.9	36.4	24.7
Exports	66.5	59.4	68.9	59.2
Balance	30.7	32.5	32.5	34.5

Table 37: Comparison of the balance of cross-border flows

Monetary trends in cross-border exchanges in electricity

	2013		2014	
	in TWh	Trade volume in €	in TWh	Trade volume in €
Export	59.44	2,197,629,995.34	59.17	1,900,557,809.92
Import	26.95	1,052,899,357.22	24.66	839,647,858.29
Balance	32.49	1,144,730,638.12	34.52	1,060,909,951.63
Export revenues in €/MWh		36.98		32.12
Import costs in €/MWh		39.07		34.05

Table 38: Monetary trends in cross-border exchanges in electricity[38]

Changes in cross-border trading volumes between Germany and its neighbouring countries reflect changes in the price differences. The reasons for these differences depend on a wide range of factors that have a direct influence on the merit order and therefore especially on wholesale prices in the individual countries. This means that changes in trading volumes are not determined solely by the German market, but also reflect shifts in supply and demand in each neighbouring country.

The actual physical load flows shown in the following diagram deviate from the exchange schedules for each border[39].

[38] The Bundesnetzagentur bases the evaluation of exports and imports on the applicable hourly spot market prices on the EPEX Spot exchange. We assume that electricity will only be imported if the German prices are higher than those of other countries and that electricity will only be exported if it is cheaper than in other countries. In this respect we are assuming rational market behaviour to be such that even long-term contracts will only be fulfilled by actual exports or imports if the effective price level provides an appropriate reason to do so.

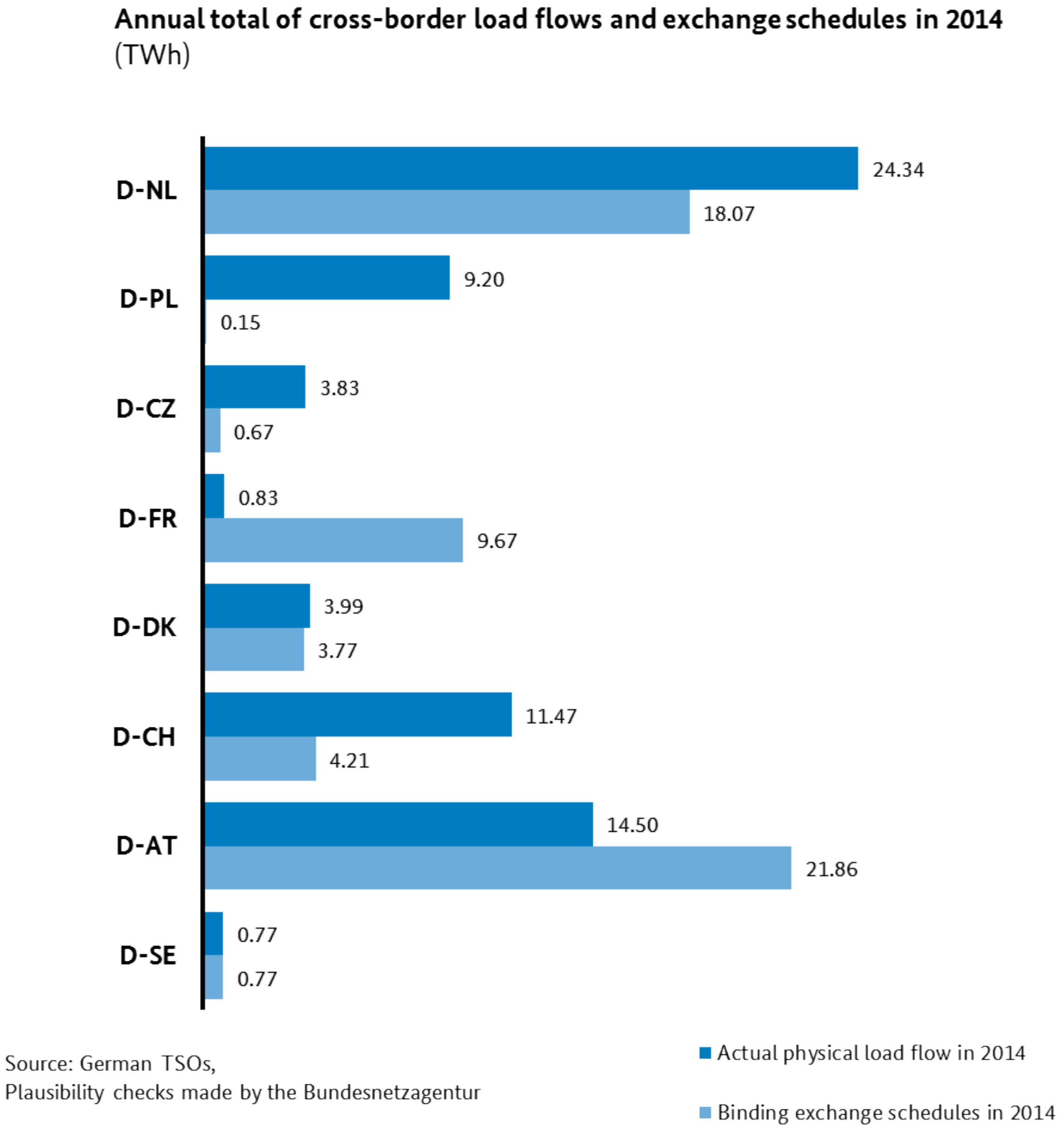

Figure 60: Annual total of cross-border load flows and exchange schedules in 2014

Germany, Austria and Luxembourg form a common market area where electricity can be traded without restrictions, hence these borders have not been considered in I.E.1. Current developments, however, provide grounds for a more in-depth examination of the exchange of electricity between Germany and Austria. The *Energiewende* and the expansion of renewable energy sources have led to a fall in the trading price of electricity in Germany. Consequently, this caused a considerable rise in electricity imports from 7.3 TWh to

[39] The total net export balance for the exchange schedules implemented and actual physical flows – with the exception of transmission losses – is identical across all German cross-border interconnectors. However, the values at each border generally differ as actual flows follow the purely physical path of least resistance and, on account of the interconnected transmission systems, can deviate from the exchange schedules implemented and go indirectly from regions with high generation capacity via third countries (eg from France via Germany/Switzerland to Italy).

21.9 TWh in the period 2010 to 2014 from Germany into Austria. Peak exports at certain hours have since even achieved figures of more than 7 GW. On the assumption that the transmission capacity (NTC) from Germany to Austria would be limited to 5,500 MW[40], it can be seen that this figure was exceeded in 2014 in 254 separate hours, corresponding to 2.9% of the 8,760 hours in a year.

The following diagram shows the trading flow (daily maximum figure) from Germany to Austria in relation to an assumed NTC of 5,500 MW.

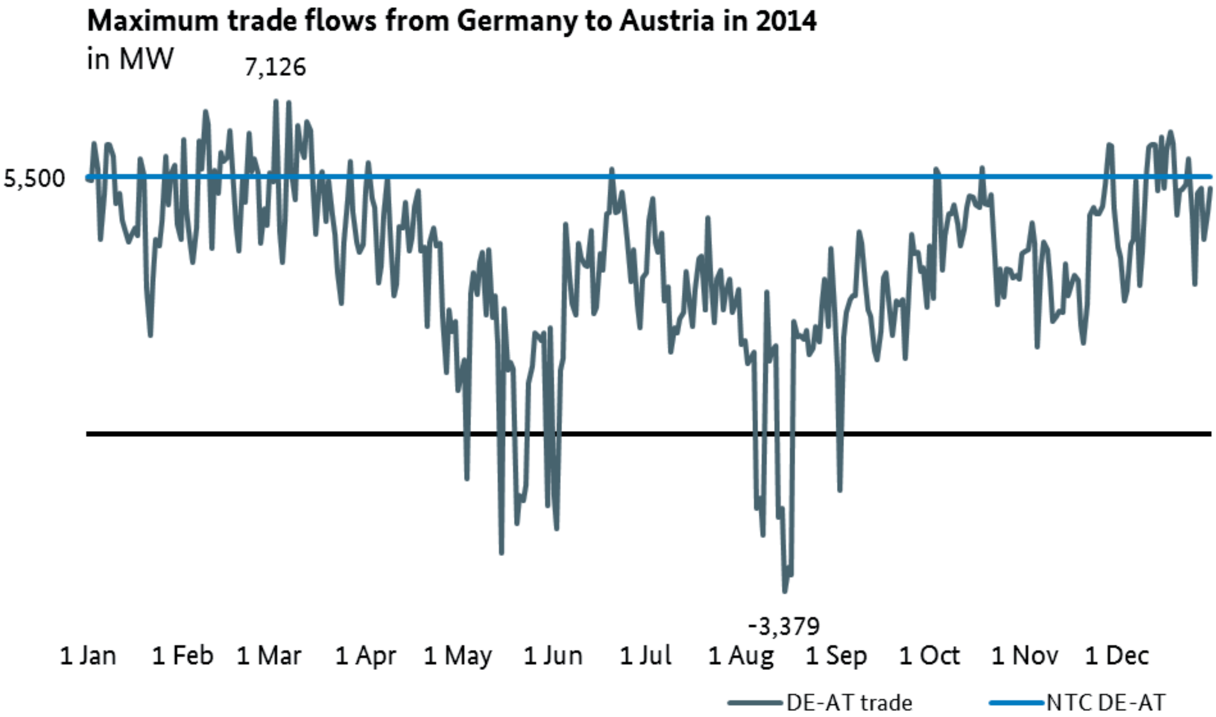

Figure 61: Maximum trade flows in relation to the theoretical NTC for 2014[41]

3. Unplanned flows

In principle, any examination of imports and exports should only involve those amounts of electricity traded between countries. A distinction must be made here in examining the transmission lines that the traded amounts of electricity actually (physically) flow along and whether such flows are loop-flows or transit flows possibly passing through third countries.[42] The following diagrams show the unplanned flows from Germany to neighbouring countries and back again.

[40] Figure from the Network Development Plan 2014.

[41] Negative export trade flows corresponding to imports from Austria into Germany.

[42] The Bundesnetzagentur only uses the exchange schedules of the TSOs (trade flows) to determine the figures. It is more feasible to use the exchange schedule figures in any related public discussion as these figures reflect trading activity. In contrast, the physical flows are based on a number of factors, including loop-flows from German-German commercial transactions that are physically transported via foreign transmission systems.

Unplanned flows from Germany to neighbouring countries and back again (loop-flows)
(TWh)

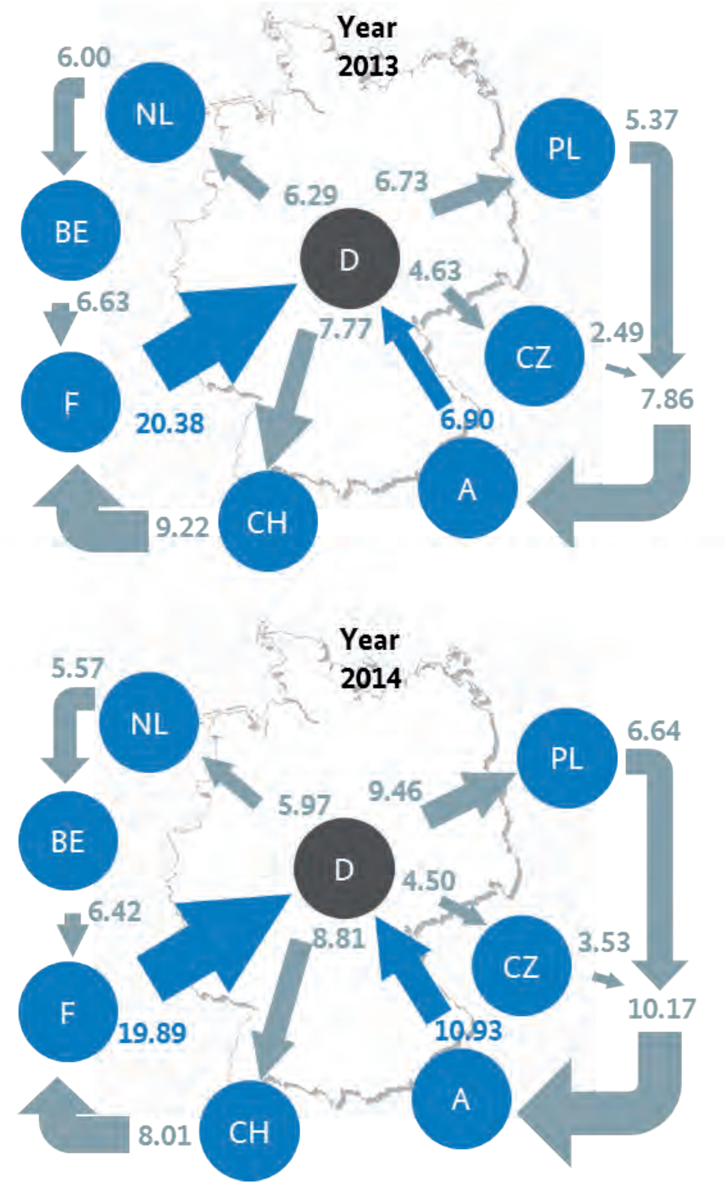

Figure 62: Unplanned flows from Germany to neighbouring countries and back again (loop-flows)

As can be seen in the diagrams, electricity follows the law of physics and always takes the path of least resistance.

Exchanges in electricity between different market areas inevitably lead to a more or less high volume of unplanned electricity flows. The high level of traffic, alongside comparatively little progress in network expansion at present, is also affecting Germany's neighbouring countries. To avoid the problem of unplanned electricity flows causing network instability abroad, Germany is actively taking part in various measures to analyse and solve these problems. The first steps have already been taken to curb unplanned electricity flows in the form of a virtual phase shifter at the German-Polish border, which has established a cross-border redispatch regime to increase network stability in Poland and Germany. A next step is to install physical phase shifters at the borders with Poland and the Czech Republic, which will help give priority to the electricity produced in Germany and consumed in the German-Austrian bidding zone when it flows through its own network.

4. Revenue from compensation payments for cross-border load flows

Under Article 1 of Commission Regulation (EU) No 838/2010, the TSOs receive inter-TSO compensation (ITC) for the costs incurred due to hosting cross-border flows of electricity (transit flows) on their networks. ENTSO-E has set up an ITC fund for the purpose of compensating the TSOs. The fund is to cover the cost of losses incurred on national transmission systems as a result of hosting cross-border electricity flows, as well as the costs of making infrastructure available to host these cross-border flows.

Every year ACER publishes a report for the European Commission on the implementation of the ITC mechanism as per point 1.4 in Part A of the Annex to Commission Regulation No 838/2010. According to the ACER report, the latest figures for ITC in 2014 are as follows: The four German TSOs received compensation of €7.65m for energy loss and for making infrastructure available and, in return, contributed €6.74m. On balance this represents an amount of €13.21m (2013: €26.8m), which the German TSOs received net as compensation payments from the ITC mechanism. Thus in the 2014 ITC year, Germany was once again a net recipient of payments from the ITC fund. The sharp decline in net sales of just over 93% compared with the 2013 ITC year is largely due to the international price development for energy losses and the increase in German electricity exports.

ICT mechanisms compensation payments for German TSOs
in € million

2011	2012	2013	2014
20.97	26.79	13.21	0.91

Table 39: ITC mechanism compensation payments for German TSOs

5. Market coupling of European electricity wholesale markets

The creation of a European internal electricity market is a stated aim of the European Union. Under point 3.2 of Annex I to Regulation (EC) No 714/2009, known as the Electricity Regulation, this aim is to be implemented step-by-step in individual European regions.

In February 2014 the day-ahead markets in the networked regions of Central Western Europe (Austria, Belgium, France, Germany, Luxembourg and the Netherlands) and of North-Western Europe (Denmark, Finland, Norway and Sweden), as well as Estonia, Lithuania, Latvia, the United Kingdom and Poland via the SwePol link, were connected together. Spain and Portugal then became connected in May 2014. This means that three-quarters of the day-ahead European electricity markets have now been successfully coupled. The next significant step in creating the European internal electricity market was attained with the coupling of the Italian borders to Austria, France and Slovenia in February 2015.

The aim of market coupling is the efficient use of day-ahead available transmission capacity between participating countries. This increases the welfare gains that can arise from cross-border exchanges in electricity. As a result, the method leads to an alignment of prices on the national day-ahead markets involved. Indeed, price convergence, as an indicator of the efficient use of interconnector capacities, is significantly higher in coupled regions than it is in uncoupled regions.

At the European level, the Bundesnetzagentur is coordinating the implementation of market coupling throughout the whole of Europe as part of regulatory authority cooperation within ACER.

6. Flow-based capacity allocation

The European Commission Regulation establishing a Guideline on Capacity Allocation and Congestion Management for Electricity (known as the CACM Guideline) defines flow-based market coupling as the target model for short-term capacity management in Central Europe. The essential basis of this is provided by flow-based capacity calculation. This involves taking account of the physical flows that specific commercial transactions are expected to generate at the capacity calculation stage and then determining the remaining available transmission capacities according to efficiency criteria and system security aspects, which guarantees greater system security and the improved use of transmission capacity.

Following the successful introduction of market coupling in Central Western Europe (CWE region) in autumn 2010, implementation of the flow-based capacity calculation method started. The project partners continued with this work in 2014. The flow-based capacity calculation method was successfully launched in the CWE region on 20 May 2015. As was expected from the tests, the initial results have confirmed a rise in transmission capacity and, consequently, greater price convergence between the participating countries.

In addition to Central Western Europe, work is currently taking place in Central Eastern Europe to introduce the flow-based capacity calculation method, which is expected to be launched in 2018 according to the latest planning. Subsequently the two regions will be connected.

Therefore it is essential that the work in the two regions is well-coordinated from the start to ensure compatibility. The focus here will be on identifying common standards in both regions, drawing up a common timetable for the implementation, accompanying the cross-regional harmonisation process and producing a final report following successful market coupling.

7. Regulation for capacity allocation and congestion management

The CACM Guideline entered into force on 14 August 2015 as the first binding regulatory instrument based on Regulation (EC) No 1228/2003 of the European Parliament and of the Council of 26 June 2003 on conditions for access to the network for cross-border exchanges in electricity. Specifically, it sets out principles for congestion management methods for capacity allocation in day-ahead and intraday trading. It also specifies the method to be used to calculate cross-border electricity transmission capacity.

Furthermore the guideline also sets out that day-ahead capacity trading is to take place implicitly, that is, at the same time as commercial electricity trading, which should occur by means of a single price coupling algorithm. In principle, intraday trading should also be organised implicitly. Although explicit allocation can also continue to take place as long as the regulatory authorities concerned request this. Intraday capacity is to be traded via a single platform and linked to the exchanges' order books to enable implicit trading. The daily process will allow for regional auctions in addition to continuous cross-border trading.

A flow-based capacity calculation method is to be introduced for day-ahead and intraday capacity that determines cross-border transmission capacity on the basis of commercial transactions and critical network elements.

The Regulation provides for the national regulatory authorities to approve the methods developed by the TSOs and/or nominated electricity market operators (NEMOs). The regulatory authorities have the right to request changes to the methods submitted for approval. The CACM guideline also contains clear and consistent deadlines for the key trading time frames to provide a common timetable for trading.

Even before the CACM guideline entered into force, the regional initiatives established in the electricity sector launched various early implementation projects with respect to the models in the Framework Guidelines and the ENTSO-E draft regulation. Some of these projects build on others begun in the regions before 2010.

7.1 Early Implementation Cross Border Intraday Project

The Cross Border Intraday Project (XBID Project) was launched as early as in February 2007. At the time the project was still a Central Western European one. The project is now no longer restricted just to this region but covers the entire "Northwest Europe Plus" region, whose territory includes the following EU and EEA member states: Germany, France, the Netherlands, Belgium, Luxembourg, Austria, the United Kingdom, Denmark, Sweden, Finland, Norway, Spain and Italy. Switzerland is also participating in the project but as an observer. According to the CACM guideline, Switzerland's active participation depends on it adopting the most important provisions in the European Union's acquis unionaire legislation relating to the electricity industry and on concluding an intergovernmental agreement with the European Union. This agreement should clearly set out the electricity cooperation between Switzerland and the EU, especially the institutional issues.

The XBID project suffered serious initial delays. This was due to the power exchanges involved not being able to agree at first on a joint IT provider to be commissioned with designing and developing the trading platform. Progress was made on the project, however, during 2014 and in the first half of 2015 as a result of the parties to the project, which together with the TSOs from the Member States listed above include the APX/BelPex, EPEX SPOT, GME, Nord Pool Spot and OMIE power exchanges, agreeing to finalise an agreement with Deutsche Börse AG (DBAG), the IT provider that was chosen in 2013. DBAG was thus charged with designing and developing the XBID platform. The platform, which will comprise a capacity management module and a joint order book, is to be used to bundle and then link the power exchanges' local electricity trading systems with the TSOs' available cross-border transmission capacity. This will facilitate the continuous and implicit matching of trading in electricity supply in one bidding zone with demand for it in another region's bidding zone, always provided that sufficient cross-border transmission capacity is available to process the trades. To enable the bundling of the order books and the capacity calculations, at the same time as developing the main XBID platform the parties to the project will also work on developing local implementation projects. As part of its collaboration within the ACER working groups and decision-making bodies, the Bundesnetzagentur has played a role in the project parties reaching agreement and finalising the contractual basis of the project. The XBID platform will be completed by 2016 and, following the test phase procedures, final commissioning is expected in 2017.

7.2 Early Implementation Bidding Zone Review

The issue of redefining the current bidding zones is coming increasingly to the fore in discussions at European level about the future design of the electricity market.

The CACM guideline provides for a joint assessment of the bidding zone configuration by the TSOs, the national regulatory authorities and ACER every three years once the regulation is in force.

The assessment process is divided into four procedural steps: first of all it provides for the TSOs to submit a technical report within nine months of a request from ACER. In each case the report is to examine the current bidding zone configuration from a grid perspective. At the same time, in cooperation with the national regulatory authorities, ACER will draw up a market report that examines the distribution of market power and market liquidity in the existing bidding zones. Based on the results of these two reports, ACER will decide whether a review of the bidding zone configuration should be carried out, in which case the TSOs will examine any possible bidding zone re-configurations. The review gives priority to criteria relating to network security, market efficiency and the stability of the bidding zones.

As part of this review, the TSOs are to propose alternative bidding zone configurations, as necessary, which market players can then give their views on in a public consultation. The result of the TSOs' review should be presented within 15 months of the decision to commence the review process and may comprise both maintaining the existing bidding zones and amending the bidding zone configurations. The Regulation provides for the national regulatory authorities, following transfer of decision-making powers from the Member States, to reach an agreement within six months on the proposal to maintain or amend the existing bidding zone configurations based on the results of the review.

Germany welcomes this process, which enables the much-discussed issue of altering bidding zones, particularly with respect to the German-Austrian bidding zone, to be examined for the first time in a structured procedure at a European level.

The procedure described above on the review of existing bidding zone configurations is already being followed on a voluntary basis as part of early implementation of the CACM guideline in anticipation of its entry into force.

8. Network code on long-term capacity allocation

A separate network code, based on the same Framework Directive as the CACM Regulation, has been developed for long-term capacity allocation, ie annual and monthly capacity. Upon completion of the public consultation process, the final version of the network code was delivered to ACER in October 2013. In its reasoned opinion ACER commenced by pointing out material deviations to the proposed framework guidelines to ENTSO-E that still existed in the network code and requesting swift implementation. The network code revision continued in 2014. The European Commission comitology procedure started in 2015.

It is planned to set up physical or financial transmission rights at each border for forward capacity allocation, together with a single platform at European level for secondary trading with long-term transmission rights.

In addition, the rules on transfer of responsibility for short-term shortening of allocated capacity are to be harmonised.

9. Network codes on network connection conditions for generators, HVDC transmission system operators, distribution system operators and consumers

In achieving a European internal market for electricity and to secure network integrity, it is important to establish the most standardised network connection conditions possible for market participants that connect their facilities to the power system. These market participants include operators of generation plants, of HVDC cables, of major electricity consumption units (such as energy-intensive industrial enterprises), demand-side management providers and distribution system operators. A standard applicable framework has been created through the adoption of directly applicable EU regulations in all Member States. Thus the three network codes set out standard requirements for frequency control, for fault ride-through capability, as well as requirements for system restoration, idle power and demand side response, to give just a few examples.

Extensive amendments were made to the three network codes in 2014 and 2015 in light of these requirements and at the same time it was possible to remove a number of doubts regarding regulatory provisions for all network connection codes. This finally resulted in the regulation, which lays down a network code on requirements for grid connection applicable to all generators, being accepted unanimously by the Member States of the European Union by means of the comitology procedure. Following its submission for scrutiny by the Council of Ministers and the European Parliament, this network code is expected to enter into force by the end of 2015. On 11 September 2015 the regulation laying down a network code on requirements for grid connections of high-voltage direct current systems and for DC-connected wind power plants was adopted. On 16 October 2015 the Commission's draft regulation on laying down a network code on requirements for grid connections for consumption units was finally submitted to comitology and was adopted by the Member States. Both of these network codes are expected to enter into force in the first quarter of 2016.

10. Network Code on Electricity Balancing

In December 2013 ENTSO-E submitted the network code on electricity balancing it had developed to ACER for review. ACER's analysis revealed that the network code did not correspond in all respects with ACER's framework guideline on electricity balancing and thus ENTSO-E revised the network code in summer 2014, subsequently re-submitting it to ACER for review in September 2014. In November 2014 ACER requested that ENTSO-E start development of essential parts of the network code on electricity balancing immediately as part of early implementation in order to make effective use of the time until the network code entered into force.

The aim of the Network Code is to integrate the balancing markets in Europe, which are currently organised on a largely national basis. Harmonising the balancing products and rules will facilitate the cross border exchange of balancing energy within Europe and promote competition between balancing service providers. One particular aim is to facilitate the inclusion of load management and renewable energy sources in the balancing market. Additionally, it is intended to guarantee the existence of reliable day-ahead and intraday markets. The Network Code therefore enables TSOs to make more efficient future use of available resources, thus reducing the costs for keeping reserves and using balancing energy. At the same time, European security of supply will be strengthened.

In July 2015 ACER recommended that the European Commission adopt the network code on electricity balancing, at the same time taking into account the numerous proposed amendments as compared to the version submitted by ENTSO-E in September 2014. The proposed amendments aim to facilitate the integration of the European markets for system balancing energy, to create legal clarity and to improve enforceability. Before the network code on electricity balancing is transformed into a European directive via the comitology procedure, which would make it generally valid and directly applicable in all Member States, the European Commission first of all intends to review the network code in detail, taking into account the outcome of the consultation on the new European electricity market design. From its position within ACER, the Bundesnetzagentur will continue to play a decisive role in the development of the European energy balancing markets and will actively support the implementation process of the network code for electricity balancing.

F The wholesale market

Functioning wholesale markets are vital to competition in the electricity industry. Spot markets, on which volumes of electricity which are needed, or not needed, in the near future can be bought or sold, and futures markets, which amongst other things facilitate the hedging of price risks in the medium and long term, equally take on a major role. Sufficient liquidity, that is an adequate volume on the supply and demand sides, improves the scope for market entry for new suppliers. Market players are given the opportunity to diversify their selection of trading partners and products, as well as forms and procedures of trading. In addition to bilateral wholesale trading (known as "OTC" or over-the-counter trading), central importance attaches to electricity exchanges. Such exchanges create a reliable trading place, at the same time as also providing major price signals for market players in other areas of the electricity industry.

The liquidity of the electricity wholesale markets remained stable at a high level in 2014. While there was once again considerable volume growth in on-exchange forward trading, volumes traded via broker platforms saw a decline. Average electricity wholesale prices fell further in 2014. Average spot market prices on EPEX SPOT fell by roughly 13 per cent year-on-year, whilst average futures contracts were quoted roughly 10 per cent lower for the following year on EEX.

1. On-exchange wholesale trading

As in previous years under report, the observation of on-exchange electricity trading relates to the market area of Germany and Austria and to the exchanges in Leipzig (EEX), Paris (EPEX SPOT) and Vienna (EXAA). The exchanges have once more participated this year in the data collection in energy monitoring. Since Germany and Austria constitute one single supply area, the individual types of electricity contract ("products") are traded on all three exchanges at exchange prices ("one price zone") which are uniform for both countries. The European Energy Exchange AG (EEX) offers electricity products in forward trading, whilst EPEX SPOT SE and Energy Exchange Austria/EXAA Abwicklungsstelle für Energieprodukte AG (EXAA) supply electricity products in the spot market area[43]. In addition, the Nord Pool Spot AS also facilitates the trading of electricity destined for Germany,[44] but this exchange is not presented in any further detail below.

The exchanges have become established as major trading places. The number of participants authorised at the exchanges for electricity trading in the Germany/Austria market area has been at a stable level for several years. New maximum values were reached on all three exchanges on the reference date 31 December 2014.

[43] There are company affiliations between EEX and EPEX SPOT, which were restructured as of 1 January 2015. EEX is now the indirect majority shareholder of EPEX SPOT; see EEX and Powernext SA press statement of 21 October 2014.

[44] Nord Pool Spot offers intraday trading of electricity destined for Germany (volume of trade in 2014: approximately 1 TWh) and the trading of market coupling products for Germany (from and to Sweden and Denmark).

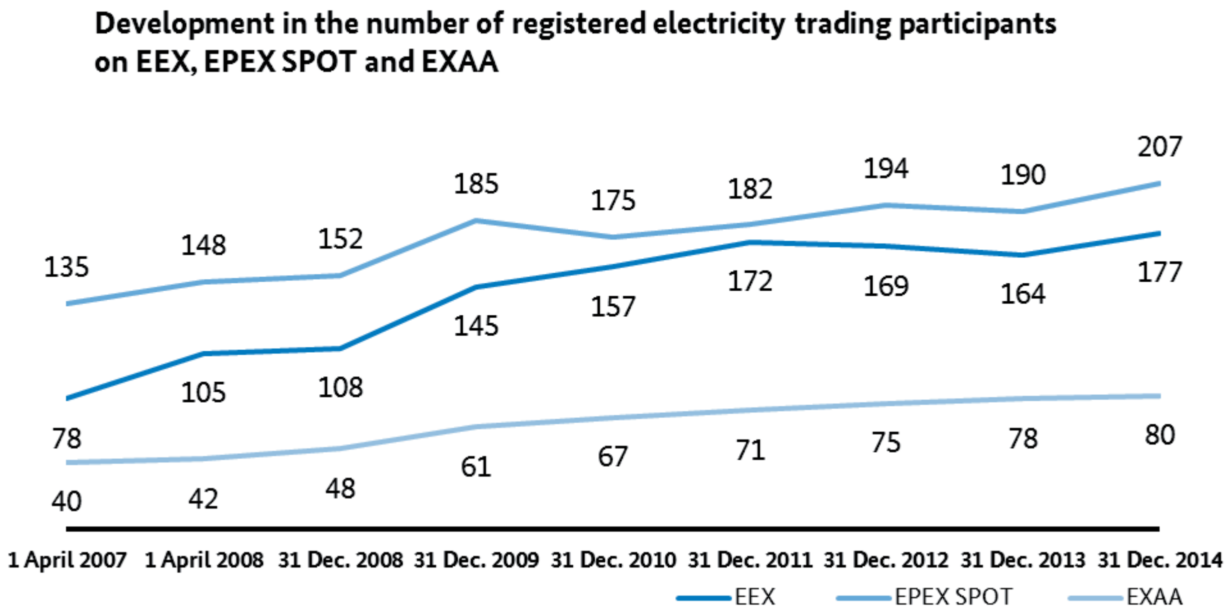

Figure 63: Development in the number of registered electricity trading participants on EEX, EPEX SPOT and EXAA

Not every company operating at wholesale level needs to have its own access to the exchange in order to take up the possibilities offered by the exchange. In fact, companies can also take up services offered by brokers that are registered on the exchanges. Polls of wholesalers and suppliers during data collection confirm that use is being made of this to a relevant extent. Larger groups frequently combine their trading activities in a group company which has the appropriate exchange registration. The following spectrum of participants emerges according to the categories by which EPEX SPOT and EEX classify their exchange participants.

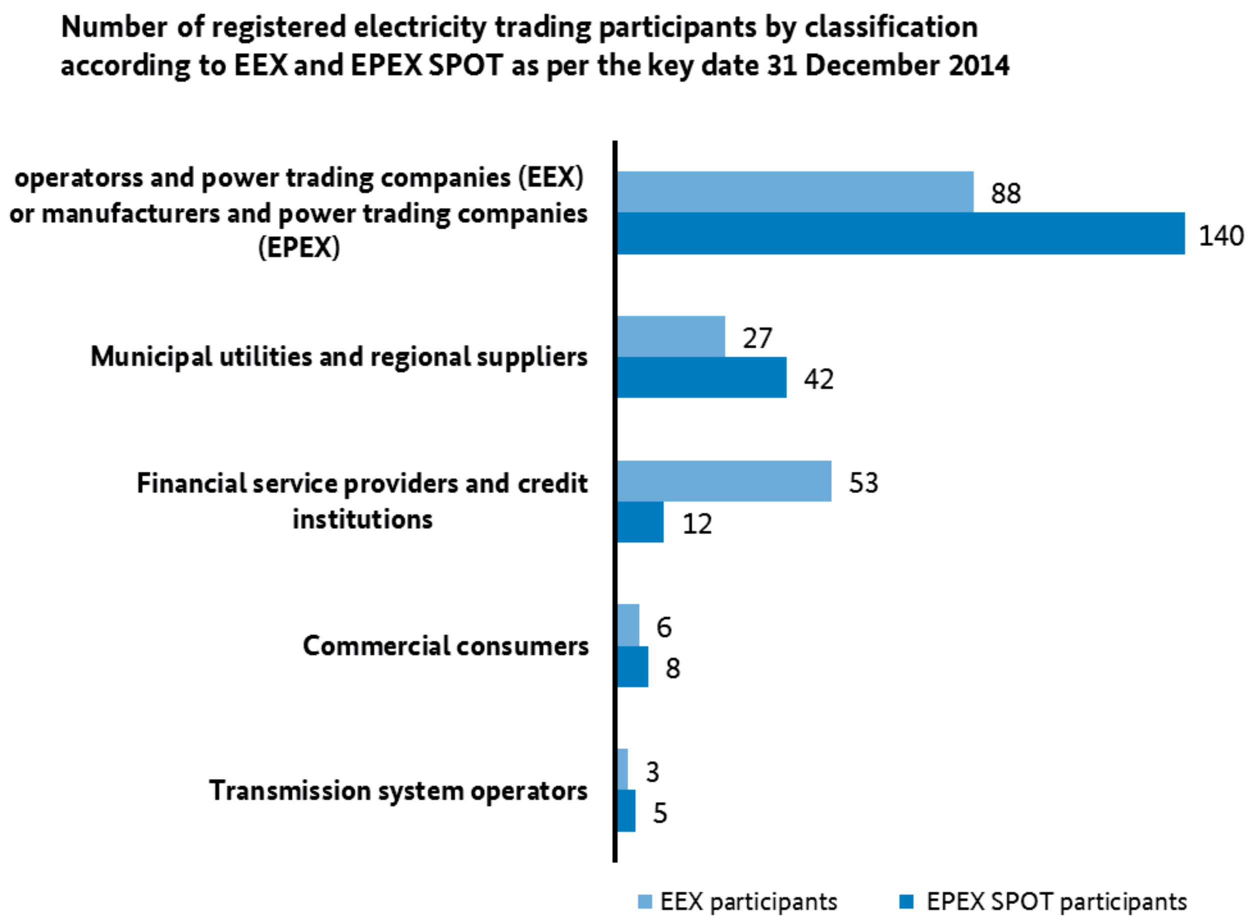

Figure 64: Number of registered electricity trading participants by classification according to EEX and EPEX SPOT as per the key date 31 December 2014

Forward trading and spot trading perform different but largely complementary functions. Whilst on the spot market the focus is on the physical fulfilment of the electricity supply contract (supply to a balance group), futures contracts are largely performed financially. Financial performance means that no supply of electricity ultimately takes place between the contracting partners as per the agreed performance date, but cash compensation is provided for the difference between the pre-agreed futures price and the spot market price. The bids possible on EPEX SPOT for Phelix futures originating from futures trading on EEX which are fulfilled physically are a link between the two exchanges. The on-exchange spot markets (section I.F.1.1) and the futures markets (I.F.1.2) are presented separately below.

1.1 Spot markets

Electricity is traded on the on-exchange spot markets on the previous day (day-ahead auction) and with shorter lead times (intraday). The two spot markets under observation here, EPEX SPOT and EXAA, both offer day-ahead trading; EPEX SPOT also offers continuous intraday trading. The contracts can be physically fulfilled (supply of electricity) on both these on-exchange spot markets to the Austrian control area (APG) and to the German control areas (50Hertz, Amprion, TenneT, TransnetBW).

The day-ahead auction on EPEX SPOT takes place at 12 noon every day (the final result is published after 12:40 p.m.). Auctions on EXAA are concentrated on five days per week, the time of the auction being earlier than on EPEX SPOT (trading closes at 10:12 a.m. and the final result is announced at 10:20 a.m.). In addition to individual hours and standardised blocks, a self-selected combination of individual hours (user-defined blocks) can also be traded in the day-ahead auction of EPEX SPOT. Furthermore, bids for complete or partly physical fulfilment of futures traded on EEX (futures positions) can be submitted.

An important innovation during the period under report is the introduction of auctions for contracts for quarters of an hour on both EXAA and EPEX SPOT. Quarters of an hour have been traded in day-ahead auctions on EXAA simultaneously alongside individual hours and blocks since September 2014. In contrast, EPEX SPOT introduced an auction for quarter-of-an-hour contracts (known as intraday auctions) for the German control areas in December 2014, which is held at a separate time from the auction for individual hours. This auction takes place each day at 3 p.m. (result from 3:10 p.m.). All three auction formats are uniform price auctions.

In addition to individual hours and 15-minute periods, continuous intraday trading at EPEX SPOT also concerns standardised or user-defined blocks. Intraday trading begins at 3 p.m. for supplies the following day and at 4 p.m. for the 15-minute periods. EPEX SPOT has reduced the minimum period between the auction and the commencement of supply in intraday trading. Since July 2015, it has been possible to trade electricity contracts for the German control areas and within the Austrian control area up to 30 minutes before the commencement of supply.[45] The continuous intraday trading of fifteen-minute periods was extended to include Austria on 1 October 2015 (control area APG).[46]

The expansion of the trading opportunities to include quarter-of-an-hour contracts and reduction in the minimum period between the auction and the commencement of supply in particular takes account of the increased input of electricity from supply-dependent (renewable) sources. For example, a transmission network operator (50Hertz) participated in EXAA when it introduced trade with quarter-of-an-hour contracts.[47] Another product that facilitates the market integration of renewable energies in the spot market sector is green electricity tradable on EXAA.[48]

Trading volumes

The volume of day-ahead trading on EPEX SPOT was 263 TWh in the year under report 2014, which corresponds to growth of some 17 TWh. The volume of intraday trading increased once more, to 26.4 TWh (0.5 TWh of which was accounted for by the supply area Austria). The volume of the day-ahead market on EXAA remained stable in the year under report 2014, at 7.8 TWh (of which approximately 60 per cent was accounted for by the German control areas).

[45] Cf. EPEX SPOT press statement of 16 July 2015.

[46] Cf. EPEX SPOT press statement of 2 October 2015.

[47] Cf. http://www.exaa.at/de/spotmarkt-strom/handelsteilnehmer (retrieved on 27 August 2015)

[48] The trading volume of this product, which was introduced in 2012, was approx. 24 GWh in 2014.

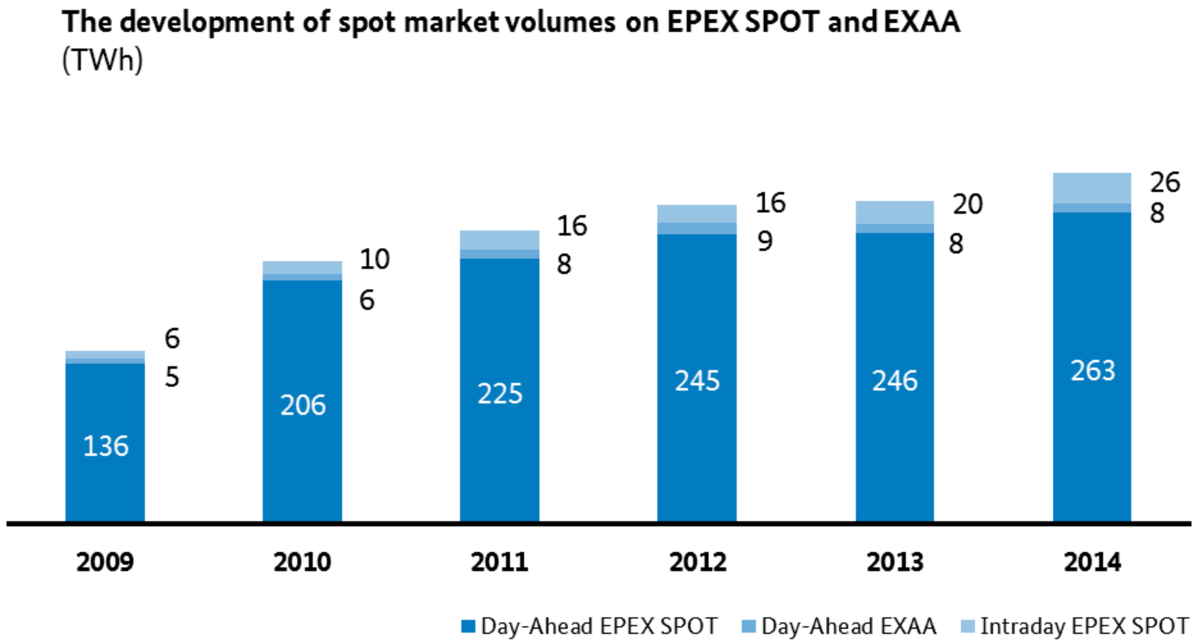

Figure 65: The development of spot market volumes on EPEX SPOT and EXAA

Number of active participants

Regarding the number of participants active on both exchanges, too, there are no major changes to report.

A participant registered on EPEX SPOT is regarded as "active" on the trading day if the participant implemented at least one bid (purchase or sale). An average of 163 participants (in 2013: 156 participants), and hence roughly 79 per cent of all registered participants (in comparison with 82 per cent in 2013), were active per trading day. The average number of active buyers (125 in 2014 and 122 in 2013) and sellers (121 in 2014 and 118 in 2013) once again rose slightly. The number of net buyers per trading day (balance towards "purchase") is roughly at the previous years' level, with 83 participants in 2014 (81 in 2013; 83 in 2012). The number of net sellers (balance towards "sale") continued the upwards trend; the number rose further from 68 in 2012 and 75 in 2013 to 80 in 2014.

A participant registered on EXAA is regarded as "active" if at least one bid (purchase or sale) has been implemented, related to each supply day.[49] An average of roughly 40 participants (previous year: 39) and hence once more roughly half of all registered participants, were active per supply day. More than 70 per cent of all participants in EXAA (57 in comparison with 52 in 2013) have trading accounts in the German control areas. An average of almost 25 participants (in 2013: 20) per supply day implemented bids for supplies into the German control areas.

[49] The different approach – supply day instead of trading day – is intended to facilitate an equal view of the values of the two spot market places despite the different trading conditions (auction days, auction times). Because of further differences between EPEX SPOT and EXAA, however, this is only possible to a limited degree.

Price dependence of the bids

Bids in day-ahead auctions on EPEX SPOT and EXAA can be submitted on a price-dependent or price-independent basis. Unlike a price-dependent bid (limit order), in a price-independent bid (market order), the participant does not set fixed price-volume combinations. Price independence means that the volume is to be bought or sold regardless of a price limit.

The relatively high proportion of price-independent bids on EPEX SPOT rose in the year under report.
77 percent of the purchase bids in 2014 were price-independent (2011-2013: 70-73 percent). The proportion of price-independent bids among the selling bids that were implemented was some 73 percent, corresponding approximately to the previous year's level of 72 per cent (in 2011 and 2012, the proportion was still 82-83 percent).

Price dependence of the bids implemented in EPEX SPOT's hour auctions

	Executed sales bids in 2014		**Executed purchase bids in 2014**	
	Volume in TWh	Percentage of total	Volume in TWh	Percentage of total
Price-independent bids	191.27	72.7%	201.45	76.6%
of which via TSOs	50.50		0.49	
of which physically settled Phelix Futures	48.48		69.92	
other	92.29		131.05	
Price-dependent bids s. l.	71.65	27.3%	61.47	23.4%
of which blocks	12.85		4.39	
of which MCC	28.49		9.36	
of which price-dependent bids s. s.	30.31		47.72	
Total	262.92	100%	262.92	100%

Table 40: Price dependence of the bids implemented in EPEX SPOT's hour auctions in 2014

The marketing of renewable energy (EEG) volumes by transmission system operators, which once again took place almost completely price-independently (99.8 percent), plays a major role on the seller side.[50] However, the volume marketed by the transmission system operators, approximately 51 TWh, fell further (2013: 55 TWh, 2012: 70 TWh). The volume of bids on EPEX SPOT for the physical fulfilment of Phelix futures rose both on the seller side (by 14 TWh) and on the buyer side (by 7 TWh).

The bids implemented on EXAA are spread by price dependence in an opposite relationship. On EXAA, 69 percent (5.4 TWh) of purchase bids and 79 percent of sales bids (6.2 TWh) are contingent on price conditions. In comparison with EPEX SPOT, the proportion of price-limited bids on EXAA is larger, which EXAA considers to be a result of the fact that the auction takes place approximately two hours earlier.[51]

Price level

The price index that is most common for the spot market for the market area Germany/Austria is the Phelix ("Physical Electricity Index"), published by EEX/ EPEX SPOT. The Phelix day base is the arithmetic mean of the 24 individual hours of a day, whilst the Phelix day peak is the arithmetic mean of the hours from 9 to 20 (i.e. 8 a.m. to 8 p.m.). EXAA publishes the bEXAbase and the bEXApeak, which relate to the corresponding individual hours (for the same market area).

The average spot market prices fell once more in 2014. The average of the Phelix day base fell from 37.78 Euro/MWh to 32.76 Euro/MWh, i.e. by roughly 13 percent, and thus to the lowest level since 2007. At a value of 36.80 Euro/MWh, the Phelix day peak was also nearly 14 percent below the previous year's level. The difference between the Phelix day base and the Phelix day peak has fallen steadily since 2008 and was 4.0 Euro/MWh in 2014. Thus, the average Phelix day peak in 2014 was only 12 percent higher than the Phelix day base (in comparison with 28 percent higher in 2007).

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[50] Under Section 1 (1) of the Equalisation Scheme Execution Ordinance (*Verordnung zur Ausführung der Verordnung zur Weiterentwicklung des bundesweiten Ausgleichsmechanismus* – AusglMechAV), transmission system operators are obliged to market on a spot market exchange the hourly inputs of renewable energies predicted for the following day for which there is an entitlement to feed-in tariffs (Section 19 (1) (2) of the German Renewable Energy Sources Act – *Gesetz für den Ausbau erneuerbarer Energien* - EEG), and to offer them price-independently.

[51] According to EXAA, this is also why there is a closer correlation between EXAA price results and OTC prices. Cf. EXAA annual report 2014, p. 23.

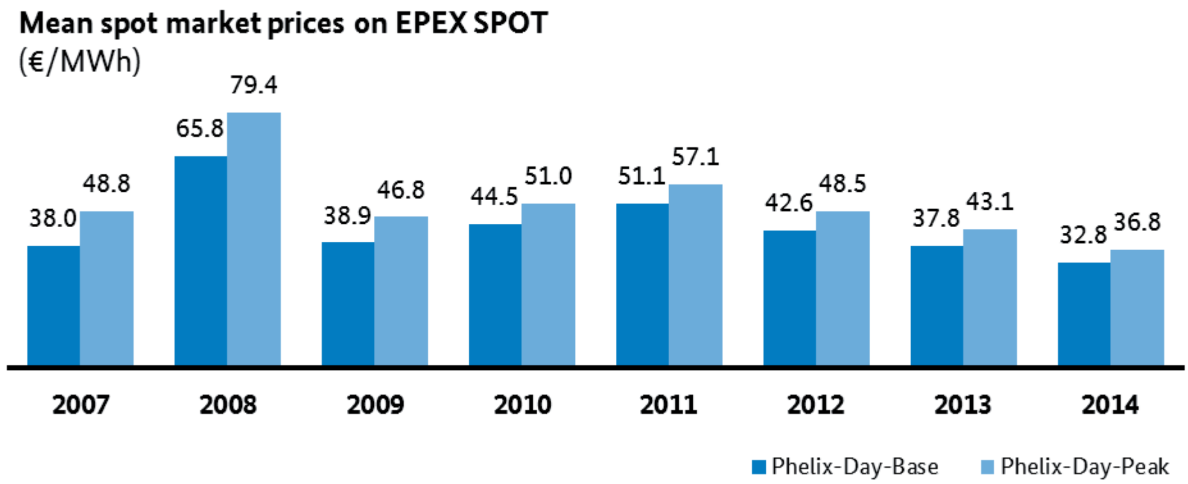

Figure 66: Mean spot market prices on EPEX SPOT

The bEXA and Phelix indices for 2014 – as in the previous years – are very close to each other. Unlike in the previous year, the annual average electricity prices in 2014 in day-ahead auctions were lower on EPEX SPOT (Phelix) than on EXAA (bEXA).

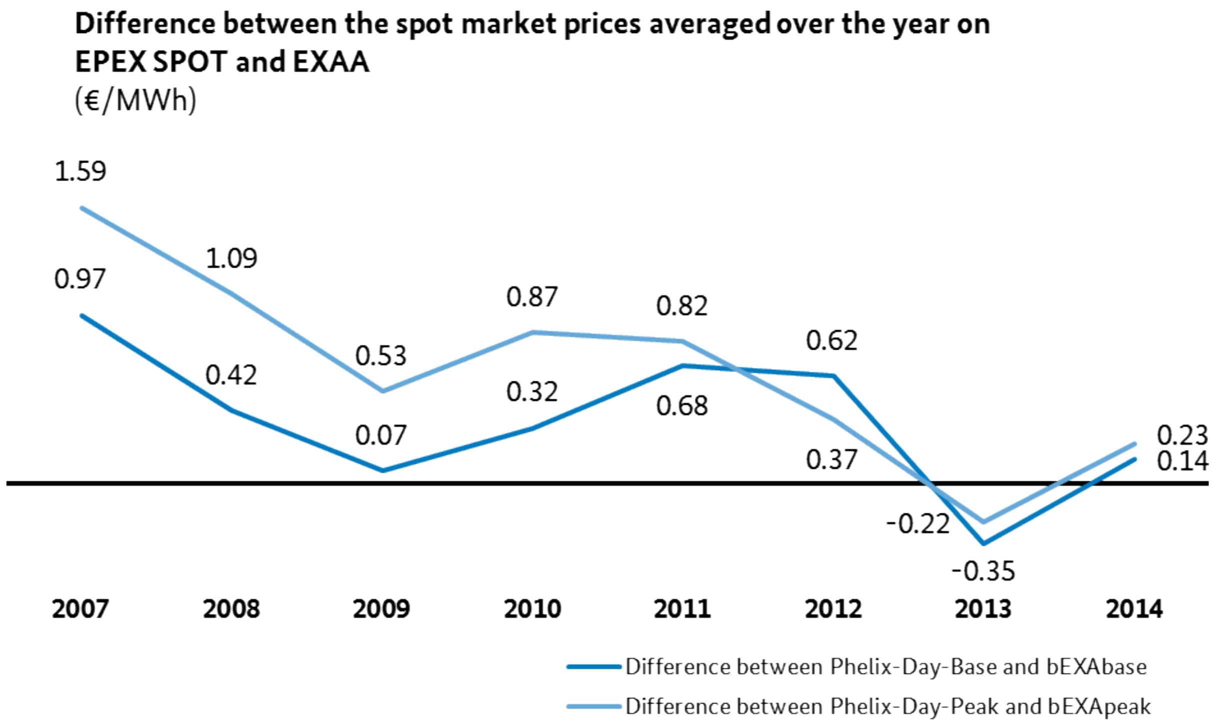

Figure 67: Difference between the spot market prices averaged over the year on EPEX SPOT and EXAA

Price spread

As in the previous years, the spot market prices averaged over a day demonstrate a considerable spread. Figure 6 shows the development in spot market prices over the year, taking the example of the Phelix day base. The prices averaged over a day typically have a weekly profile with lower prices at the weekend. Further, a tendency towards lower prices in the summer months than in the winter months is to be observed. The bEXAbase, which is not shown in the figure, follows the same pattern.

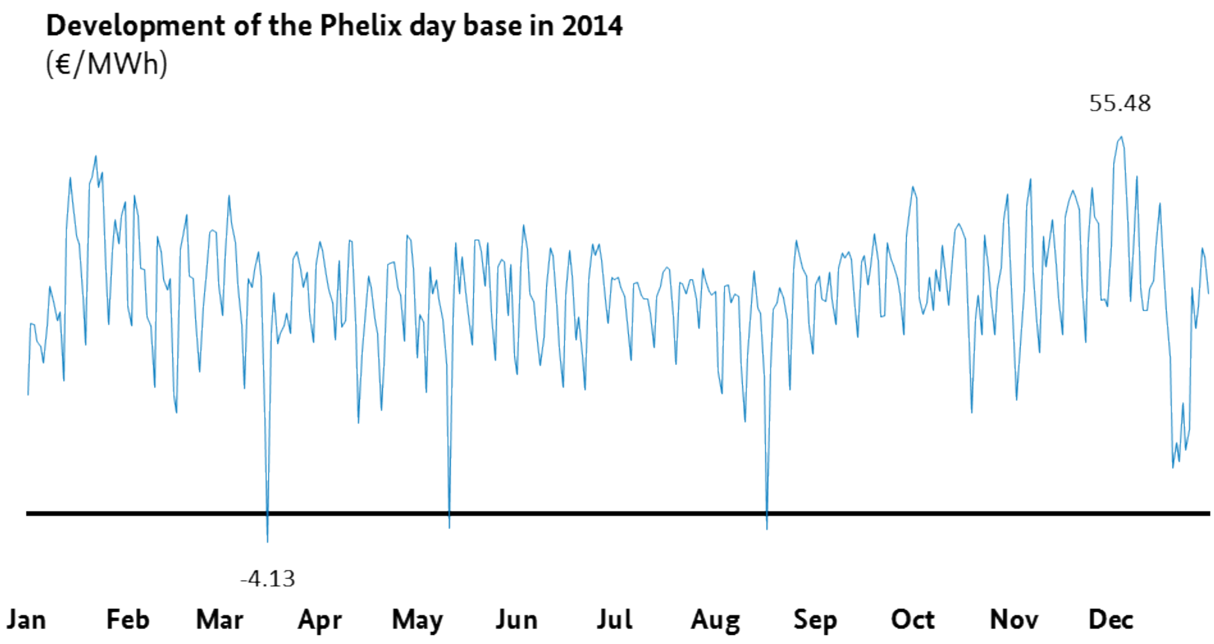

Figure 68: Development of the Phelix day base in 2014

A reduction in the spread was to be seen year-on-year in the base and peak prices on EPEX SPOT in 2014 – in contrast to the development in the previous year. The range of the mid-50 percent of the graded Phelix day base values was 9.69 Euro/MWh in 2014, down by 38 percent on 2013.[52] The corresponding range of peak prices fell by 42 percent. The range of the mid-80 percent of the graded values fell by 30 percent (base) and 23 percent (peak). There were three negative values in the Phelix day base and the Phelix day peak in 2014 (on 16 March, corresponding to the minimum of all values, and on 11 May and 17 August).

Overall, it can be observed that the spot market prices averaged over a day were at a lower level in 2014 and within a narrower range.

[52] 2014: upper limit 38.00 Euro/MWh – lower limit 28.31 Euro/MWh = range 9.70 Euro/MWh.
2013: upper limit 46.88 Euro/MWh – lower limit 31.23 Euro/MWh = range 15.65 Euro/MWh.

Price ranges of the Phelix day base and of the Phelix day peak

	Mid-50 percent Range of 25 to 75 of the graded values in €/MWh	**Mid-80 percent** Range of 10 to 90 of the graded values in €/MWh	**Extreme values** Lowest and highest value in €/MWh
Phelix Day Base 2012	37.65 – 49.21	29.82 – 52.82	-56.87 – 98.98
Phelix Day Base 2013	31.23 – 46.88	23.66 – 52.81	-6.28 – 62.89
Phelix Day Base 2014	28.31 – 38.00	22.29 – 42.71	-4.13 – 55.48
Phelix Day Peak 2012	41.38 – 56.03	30.33 – 60.91	10.94 – 129.94
Phelix Day Peak 2013	34.44 – 54.42	24.76 – 62.28	-18.99 – 80.50
Phelix Day Peak 2014	30.98 – 42.51	22.82 – 51.69	-17.59 – 69.39

Table 41: Price ranges of the Phelix day base and of the Phelix day peak between 2012 and 2014

A similar observation may be made on EXAA. Most of the upper and lower values in the range on bEXAbase and bEXApeak fell in comparison with the previous year and the ranges all decreased. The percentage changes in the ranges correspond to those of the Phelix day base and the Phelix day peak (with the exception of the range between the extreme values, which has fallen by just one percent).

Price ranges of the bEXAbase and of the bEXApeak

	Mid-50 percent Range of 25 to 75 of the graded values in €/MWh	**Mid-80 percent** Range of 10 to 90 of the graded values in €/MWh	**Extreme values** Lowest and highest value in €/MWh
bEXAbase 2012	37.75 – 48.74	29.24 – 53.03	5.07 – 85.66
bEXAbase 2013	30.75 – 46.56	23.80 – 51.33	1.10 – 60.62
bEXAbase 2014	28.52 – 37.92	23.27 – 42.56	4.15 – 55.86
bEXApeak 2012	41.72 – 55.90	29.06 – 62.02	10.01 – 108.00
bEXApeak 2013	34.25 – 54.51	23.14 – 61.73	4.80 – 76.40
bEXApeak 2014	30.61 – 42.76	23.69 – 51.51	-1.75 – 69.17

Table 42: Price ranges of the bEXAbase and of the bEXApeak between 2012 and 2014

1.2 Future markets

Futures can be traded on EEX for the Germany/Austria market area with standardised maturities where the subject matter of the contract is the Phelix (base value). Options may also be traded for specific Phelix futures as a matter of principle. As in the previous years, however, there were no corresponding transactions on EEX. An innovation in the futures market is the trade with cap futures, which has been possible since September 2015 (for week contracts), which are intended to hedge price peaks in consideration of the growing proportion of renewable energies in the market.[53]

The next section is based solely on the on-exchange transaction volumes not including OTC clearing (see section I.F.2.3 on OTC clearing).

Trading volume

The trading volumes of Phelix futures on the exchanges increased once again in the year under report 2014, by 21 percent to 812 TWh, following the considerable rise in the previous year (by 50 percent on 2012, from 445 TWh to 669 TWh in 2013). The number of active participants on the futures market of EEX (not including OTC clearing) averaged 53 per trading day in 2014.

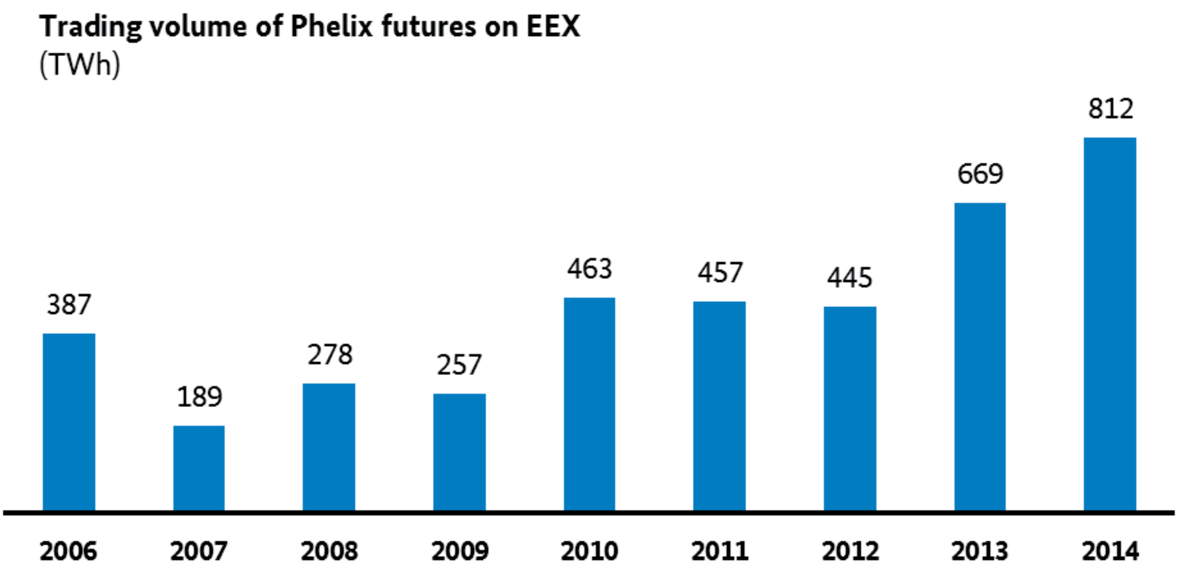

Figure 69: Trading volumes of Phelix futures on EEX

Forward trading in 2014 once more focussed on contracts with the following year (2015) as the fulfilment year (roughly 57 percent of the total trading volume). The second-largest share is accounted for by the trade for the year under report (2014), approx. 18 percent. Trading for the second following year (2016) accounted for roughly 14 percent of the contract volume. Trading for 2017 (7.8 percent) and for the future years (2.9 percent) fell, however.

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[53] Cf. EEX press statement of 14 September 2015.

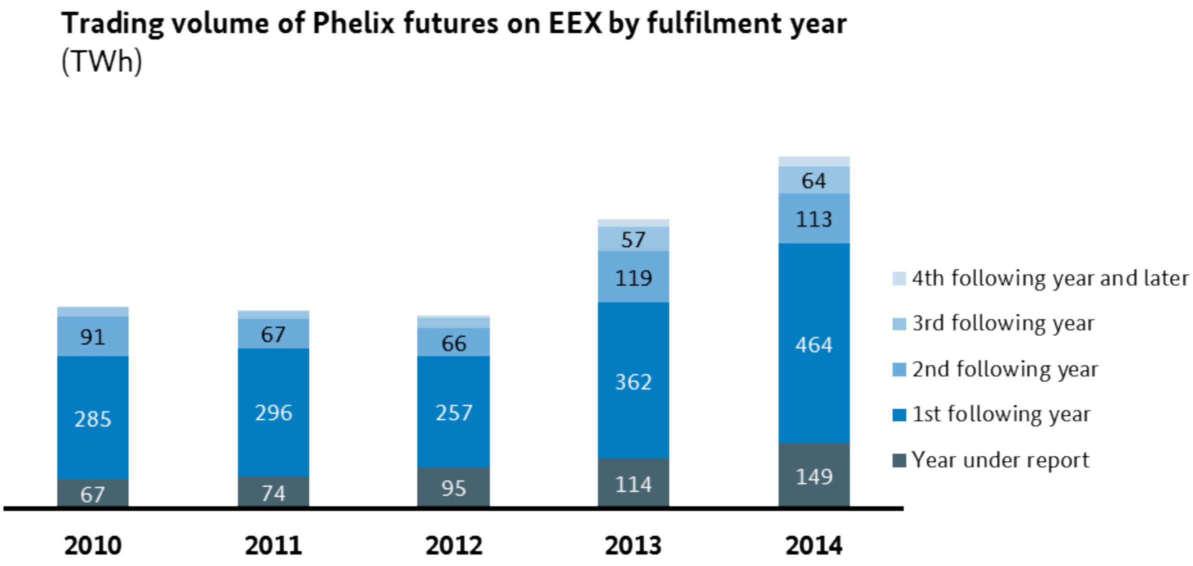

Figure 70: Trading volume of Phelix futures on EEX by fulfilment year

Price level

The two most important futures traded on EEX in terms of volume for the Germany/Austria market area are the Phelix year futures base and peak. Whilst the baseload future relates to a constant and continuous delivery rate (every hour, every day), the peakload future is based on the hours from 8:00 a.m. to 8:00 p.m. for the days Monday to Friday.

The prices for the year futures fell further over the year under report 2014. The values of both the baseload future and the peakload future were always below the prices on the corresponding trading days of the previous year. The peak price fell more strongly than the base price. The price difference between Phelix base year future 2014 and Phelix peak year future 2014 fell correspondingly over the year from 11.07 Euro/MWh to 8.68 Euro/MWh.

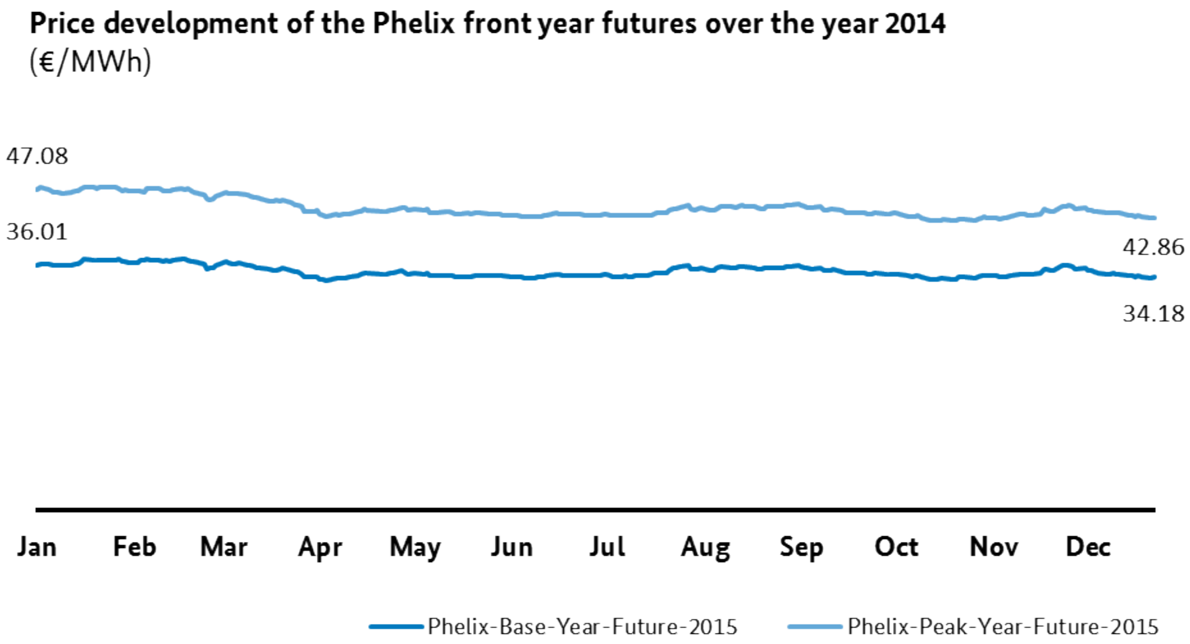

Figure 71: Price development of the Phelix front year futures over the year 2014

An annual average can be calculated from the prices of EEX front year futures on the individual trading days. This average would correspond to the average electricity purchase price (or electricity sales price) of a market player if the latter buys (or sells) the electricity not at short notice, but proportionally in the previous year.

The annual averages of the Phelix front year future prices fell once more year-on-year. At 35.09 Euro/MWh averaged over 2014, the Phelix base year future fell year-on-year (2013: 39.08 Euro/MWh) by 3.99 Euro/MWh, and hence by a good 10 percent. The price of the Phelix peak front year future averaged 44.40 Euro/MWh over the year. The year-on-year reduction (2013: 49.67 Euro/MWh) is 5.27 Euro/MWh and hence just under 11 percent. The front year base price has halved in comparison with the historic high of 2008.

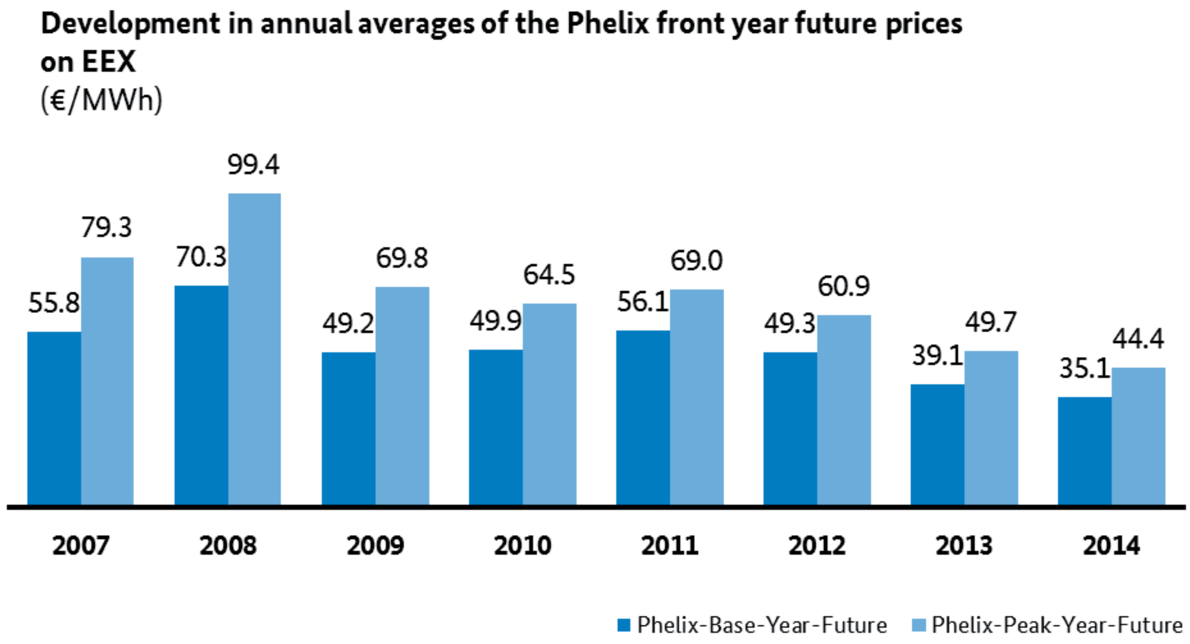

Figure 72: Development in annual averages of the Phelix front year future prices on EEX

As in the previous year, the annual average price difference between the base and peak products was approximately 27 percent. Whilst the peak price was more than 40 percent higher than the base price in the period 2007-2009, since 2010 this difference has only been between 23 and 29 percent. When taken in absolute terms, the difference fell year-on-year from 10.59 Euro/MWh (2013) to 9.31 Euro/MWh (2014).

1.3 Shares of various exchange participants in the trading volume

Share of market makers

An exchange participant who has undertaken at the same time to publish binding purchase and sales prices (quotations) is referred to as a market maker. A market maker serves to increase the liquidity of the market place. The specific conditions are regulated between the market maker and the exchange in “market maker agreements”, which contain amongst other things arrangements on quotation times, the quotation period, the minimum number of contracts and maximum spread. The companies concerned are not prevented from engaging in additional transactions (i.e. not to be counted as market maker transactions) as exchange participants.

The same four companies were active during the period under report as market makers on the futures market of EEX for Phelix futures as in previous years: E.ON Global Commodities SE, EDF Trading Limited, RWE Supply & Trading GmbH and Vattenfall Energy Trading GmbH. The cumulated share of the four market makers in the purchase and sales volumes of Phelix futures was 32 percent. This corresponds to the previous year’s level. This value refers to the turnover the companies generated in the exercise of their role as market makers, i.e. it does not include the volumes the four companies may have traded outside their function as market makers. In addition to agreements with market makers, EEX has contracts with exchange participants who have committed themselves to strengthening liquidity to an individually agreed extent. These companies accounted for a total of some 9 percent of the trading volume in 2014, both in sales and purchases.

Three market makers were active on the day-ahead market of EXAA in the period under report. The cumulated share of transactions performed by companies in their function as market makers in the purchase volume of the day-ahead auction in 2014 was 1.8 percent (2013: 3.6 percent) and in the sales volume it was 7.8 percent (2013: 5.2 percent).

Share of the transmission system operators

In accordance with the Equalisation Mechanism Ordinance (*Ausgleichsmechanismusverordnung*), the transmission system operators are obliged to sell on the spot market of an electricity exchange the renewable energy volumes passed on to them in accordance with the fixed feed-in tariffs for electricity under the Renewable Energy Sources Act. For this reason, a large share of the spot market volume is accounted for on the seller side by the transmission system operators.

The share accounted for by transmission system operators in the day-ahead sales volumes of EPEX SPOT continued to decline. This share was 21 percent in the year under report 2014, in comparison with 23 percent in 2013 (2012: 28 percent; 2011: 38 percent). The volumes to be marketed by the transmission system operators fell, also in absolute terms. The day-ahead sales volume on the exchanges marketed by the transmission system operators was some 50.5 TWh in 2014 (2013: 56.3 TWh, 2012: 69.3 TWh, 2011: 87.2 TWh).

This reduction is caused by the fact that an increasing number of renewable energy plant operators opted for direct marketing. This led to a fall in the take-up of the feed-in fee for electricity under the Renewable Energy Sources Act despite increased total renewable (EEG) energy volumes, so that the total volume to be marketed by the transmission system operators fell accordingly.[54]

On the buyer side, only a very small spot market volume is accounted for by the transmission system operators. On the futures markets, too, the latter implement only a small number of transactions.

Share accounted for by the participants with the highest turnover

The observation of the trading volume accounted for by the participants with the highest turnover provides an impression of the degree to which exchange trading is concentrated. In addition to the large electricity producers, financial institutions and transmission system operators on the spot market are among the participants with the highest turnover. In order to compare the values over time, it should be pointed out that the composition of the respective (e.g. five) participants with the highest turnover can change over the years, so that the cumulated turnover share does not necessarily relate to the same companies. Furthermore, no group view is carried out here, i.e. the turnover of a group is not aggregated if a group has several participant registrations.[55]

The share of the five purchasers with the highest turnover on the day-ahead trading volume of EPEX SPOT rose markedly in the year under report from 40 percent to 46 percent, reaching a new peak value. The corresponding share on the seller side remained unchanged in comparison with the previous year. The cumulated share of the five sellers with the highest turnover was again roughly 39 percent in 2014, a low value

[54] See for details on this section I.B.2.4.

[55] As a rule, groups only have one participant's registration.

in comparison with the years before 2013. The previously higher shares on the seller side are due mainly to the higher sales volumes of the transmission operators at this time.

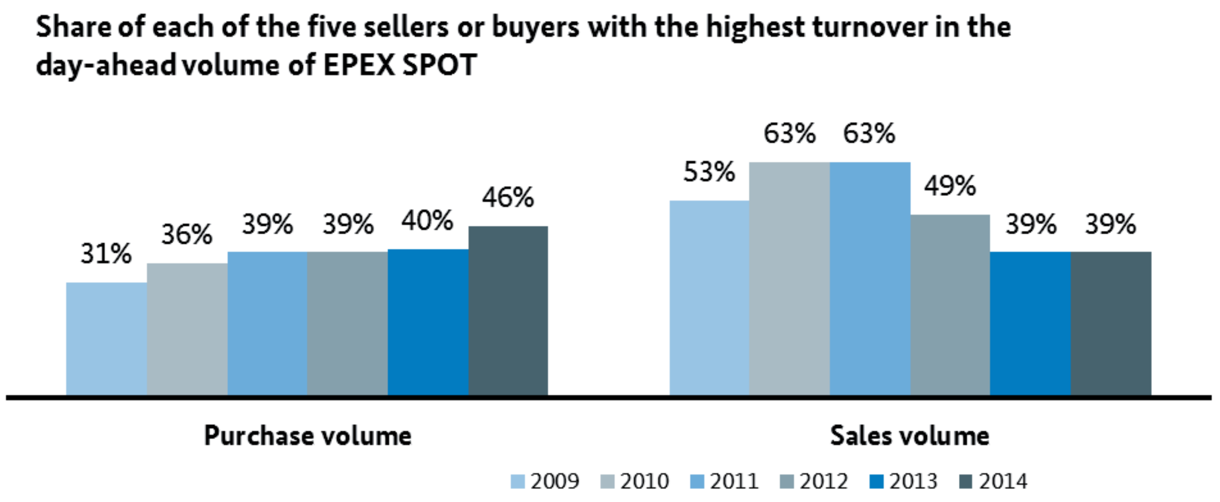

Figure 73: Share of each of the five sellers or buyers with the highest turnover in the day-ahead volume of EPEX SPOT

On EXAA as a further exchange for day-ahead auctions, the share of the participants with the highest turnover remained approximately at the previous year's level. The share of the three participants with the highest turnover, averaged over the sales or purchase volume, was 24 percent in 2014 (2013: 23 percent). If one expands to the five participants with the highest turnover, a share of 35 percent emerges in 2014 (2013: 32 percent).

On EEX, the share both of the buyers of Phelix futures with the highest turnover (not including OTC clearing) and those of the five sellers with the highest turnover is approximately 44 percent. This corresponds to an increase of four percentage points in each case on the previous year 2013.

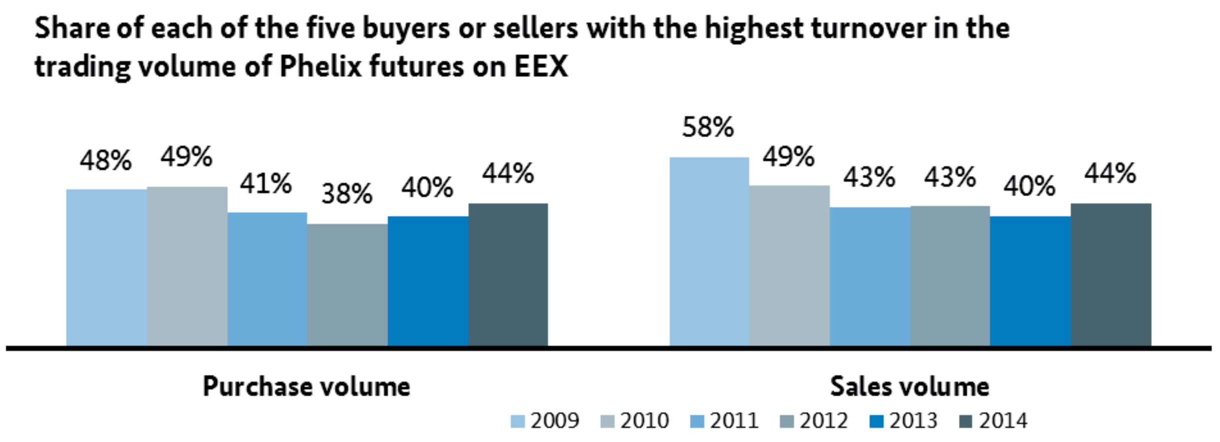

Figure 74: Share of each of the five buyers or sellers with the highest turnover in the trading volume of Phelix futures on EEX

Spread of the trading volume by exchange participant classification

The electricity exchanges assign each of the participants registered with them to a group of participants. The transaction volume accounted for by these groups of participants is not shown below by purchase and sale, but only by the shares averaged for purchase and sale in each case. The shares in the spot market volume are represented related to the transaction volume, reduced by market tying contracts (imports and exports).

Averaged shares of the groups of EPEX SPOT and EEX participants in sales and purchase volumes 2014

	EPEX SPOT	EEX
Supra-regional suppliers and energy trading companies (EEX) / electricity producers and energy trading companies (EPEX SPOT)	72%	63%
Financial service providers and credit institutions	9%	33%
Transmission system operators	11%	< 1%
Municipal utilities and regional suppliers	8%	4%
Commercial consumers	1%	1%

Table 43: Averaged shares of the groups of EPEX SPOT and EEX participants in sales and purchase volumes 2014

2. Bilateral wholesale trading

The particular feature of bilateral wholesale trading ("OTC trading", "over the counter") is that the contracting partners are known to one another (or become known to one another at the latest on concluding the transaction) and that the parties can arrange the contractual details flexibly and individually. The surveys carried out in energy monitoring for OTC trading aim to record the amount, structure and development of bilateral trading volumes. Unlike exchange trading, however, it is not possible to portray the complete bilateral wholesale volume since there are neither clearly delimitable marketplaces outside the exchanges, nor is there a fixed model of types of contract.

Brokers play a major role at bilateral wholesale level. They act as intermediaries between buyers and sellers and combine information on the supply and demand of electricity trading transactions. The connection between interested parties on the supply and demand sides is formalised on electronic broker platforms, hence increasing the chance for two parties to reach an agreement.

A specific role is played by on-exchange "OTC clearing". OTC trading can be registered with the exchange, so that the parties' trading risk is hedged.[56] OTC clearing forms an interface between on-exchange and non-exchange electricity wholesale trading.

A survey of the individual participants in OTC trading was once more carried out in the year under report for the area of bilateral wholesale trading (cf. section I.F.2.1) and with various broker platforms (cf. section I.F.2.2). Moreover, data on OTC clearing on EEX were requested (cf. section I.F.2.3). On the basis of these three surveys, a stable, high level of liquidity can be ascertained once again for the year under report 2014 in bilateral electricity wholesale trading.

2.1 Survey among wholesalers

Data provided by companies on their bilateral trading activities in 2014 (apart from on the exchanges) were collected in this year's monitoring report/activities. As had been the case in the previous years, the collection was carried out at the level of the individual companies, and incorporated both purchases and sales. Regardless of whether the companies may have only acted as buyers, or only as sellers, they are referred to below as "wholesalers".

In distinction to retail, electricity wholesale is understood within this survey as constituting all electricity supply contracts and electricity trading transactions with own-name physical or financial fulfilment in which the buyer does not consume the electricity volumes in question itself, and which do not concern any system services. Only non-exchange transactions were to be stated – including transactions via broker platforms – with Germany as the supply area.

According to this definition, contracts between two companies within a group are also "wholesale" transactions as a matter of principle. Since such intra-group transactions are not based on a mutual selection process as a rule, the companies were asked in this year's survey, as was already the case the previous year, to show the share of intra-group transactions separately. The proportion of companies completing the survey rose in comparison with the previous year (when the question was introduced). In the overall view of the individual details, the quantities stated as intra-group continue to appear to be too small.[57]

740 companies (previous year: 683; 2012: 590) provided information for the year under report 2014 on their wholesale electricity transactions outside the exchanges. Even if the participation of the companies in the survey increased further year-on-year, not all trading participants and volumes can be covered with this survey. In particular, it can be presumed that some (volume) relevant companies which have their registered offices abroad do not take part in the survey. Moreover, many electricity suppliers did not provide information on the volumes that they purchased in bilateral trading.[58] For these reasons, one can presume a

[56] EEX no longer refers to this service as "OTC clearing", but as "trade registration".

[57] Many medium-sized wholesalers have group structures, and only provided "extra-group volumes in the survey. This statement is plausible at the level of each individual company according to the definitions in the questionnaire. The frequency with which exclusively "extra-group" volumes were indicated was surprising, however,

[58] This statement is also plausible at the level of each individual company according to the definitions in the questionnaire. However, enquiries to suppliers that did not indicate that they had traded in wholesale volumes have shown that – as well as intra-group procurement, procurement often takes place through an independent service provider or through a purchasing group.

higher bilaterally-traded electricity volume than emerges from the detailed information that has been collected.

The results of the evaluation of the volume data provided by the 740 companies on the wholesale transactions concluded in 2014 were as follows:

Volume of the electricity wholesale contracts concluded on a non-exchange basis in 2014 according to the wholesaler survey

Fulfilment period	Non-exchange wholesale electricity trading volumens in TWh		of which intra-group in TWh	
	Purchase	Sale	Purchase	Sale
Intraday	13	16	8	9
Day-Ahead	200	118	120	46
2-6 days	86	82	30	20
2014, min. 7 days	903	759	221	119
2015	2,168	2,042	481	437
2016	652	613	204	183
2017	311	302	127	126
2018 and later	61	58	26	27
Total	**4,394**	**3,990**	**1,217**	**967**

Table 44: Volume of the electricity wholesale contracts concluded on a non-exchange basis in 2014 according to the wholesaler survey

The totals shown in the table are at roughly the same level as the corresponding values of the previous year's survey. The differences in comparison with the previous year's values are smaller than can be accurately measured.[59]

The spread of the bilateral trading volume over the various fulfilment periods corresponds roughly to the perception of on-exchange trading: More than half of the wholesale transactions are accounted for by the following year (2015). Just under a quarter is accounted for by later periods (2016 and subsequent years).

[59] Inaccuracies arise as a result of errors in completing the survey forms and in particular of changes in the group of participating companies. A larger number of smaller companies took part in 2014, whereas there was no response from individual companies located abroad that had indicated relatively high quantities the previous year.

Trading for the ongoing year (including short-notice trading transactions) accounts for a good quarter of the volume. Day-ahead contracts are dominant with short-notice trading transactions.[60]

The question directed at wholesalers concerning quantities was once again supplemented this year by questions on qualitative aspects of the electricity wholesale trade. The previous year's results were confirmed: 72 companies stated that they used broker platforms for futures transactions (previous year: also 72), and 60 wholesalers said that they did so for spot transactions (previous year: 68). The companies not only stated in general terms that there was a broad spectrum of service-providers. Rather, as a rule, each of the individual companies uses several individual brokers. Only a small number of companies stated that they made use of the possibility of OTC clearing on an exchange subsequent to their OTC transactions. Some 100 companies stated that they also used exchanges to buy or sell electricity.[61] Most of these companies stated that they used several exchanges[62].

2.2 Broker platforms

Because of the boundaries imposed on the direct surveying of trading participants, monitoring also includes asking the operators of broker platforms to answer questions regarding the contracts they have brokered. Brokers play a major role in bilateral electricity wholesale trading. Many brokers provide an electronic platform to support their intermediary business.

A total of twelve brokers took part in this year's data collection on wholesale trading (previous year: eleven), eleven of whom (previous year: ten) brokered electricity trading transactions with Germany as a supply area in the year under report. The volume for which they acted as brokers totalled approximately 4,946 TWh in 2014. In comparison to the values collected in the previous year – 5,930 TWh – this constitutes a decrease of approximately 17 percent.[63] According to information ascertained by the London Energy Brokers´ Association (LEBA), the trading volume for which its members acted as brokers corresponded to a reduction of approximately 18 percent on the previous year.[64]

When comparing this total volume of 4,946 TWh with the values of the wholesaler survey, it should be taken into account that the broker survey does not distinguish according to use, i.e. to an extent that is probably small, but which cannot be quantified in greater detail, the volume information includes contracts with (industrial) end customers. On the other hand, it can be presumed for the contracts brokered by brokers that all of these are non-intra-group transactions.

Also when it comes to the transactions brokered by broker platforms, contracts for the following year continue to form the clear focus of electricity trading (55 percent), followed by the activities for the current

[60] The survey on spot trading values is based on the temporal classification of intraday and day-ahead contracts in the exchange sector. Some of the companies surveyed indicated that they can only approximately assign their spot trading volumes in accordance with these fixed temporal classifications.

[61] Only a small number of indicators on (only) brokered exchange use are contained, however.

[62] EEX, EPEX SPOT, EXAA, Nord Pool Spot

[63] A volume share significantly smaller than 1 percent was accounted for by broker platforms in 2014, which also took part in this year's survey.

[64] See https://www.leba.org.uk/assets/monthly_vol_reports/LEBA%20Energy%20Volume%20Report%20December%202014.pdf (retrieved on 18 August 2015).

year (24 percent). Only small volumes are accounted for by short-term transactions with a fulfilment period of less than one week. This distribution of the fulfilment periods corresponds to that of the previous year.

Volume of electricity trading via eleven broker platforms in 2014 by fulfilment period

Fulfilment period	Volumes traded in TWh	Share in percent
Intraday	0	0%
Day-Ahead	100	2%
2-6 days	96	2%
2014, min. 7 days	1,185	24%
2015	2,726	55%
2016	618	12%
2017	200	4%
2018 and later	20	0%
Total	**4,946**	**100%**

Table 45: Volume of electricity trading via eleven broker platforms in 2014 by fulfilment period

2.3 OTC clearing

On-exchange “OTC clearing” performs a special function for bilateral wholesale trading. The exchange or its clearing house is the trading participant for the contracting partner in such trading, so that the exchange bears the counterparty default risk. The default risk can be reduced or secured in bilateral trading by various measures, but it cannot be eliminated altogether.

Using clearing for OTC transactions, the counterparty risk is transferred to the exchange or its clearing house. By registering on the exchanges, the contracting partners ensure that their contract is subsequently traded as a transaction which came about on the exchange, i.e. both parties act as if they had each bought or sold a corresponding futures market product on the exchange. OTC clearing is hence an interface between on-exchange and non-exchange electricity wholesale trading.

EEX, or its clearing house European Commodity Clearing AG (ECC), facilitates OTC clearing[65] for all futures market products which are also approved on EEX for exchange trading.

The volume of OTC clearing of Phelix futures on EEX in 2014, 557 TWh, remained roughly at the level of the previous year. Since OTC clearing leads to (retroactive) balancing with futures concluded on the exchange, the development of the OTC clearing volume is to be placed within the context of the on-exchange futures market volume. If one observes the total volumes of on-exchange forward trading and OTC, the added

[65] The term “trade registration” is used for OTC clearing in EEX’s more recent terminology.

volume is relatively constant in the long term; the total volume for 2014 reached a new all-time high, however, as was also the case the previous year. The shift of the volume away from OTC clearing to futures concluded on the exchanges that has been observed since 2008 has continued in the year under report. Whereas the OTC clearing volume stagnated in comparison with the previous year, exchange trading increased once again.

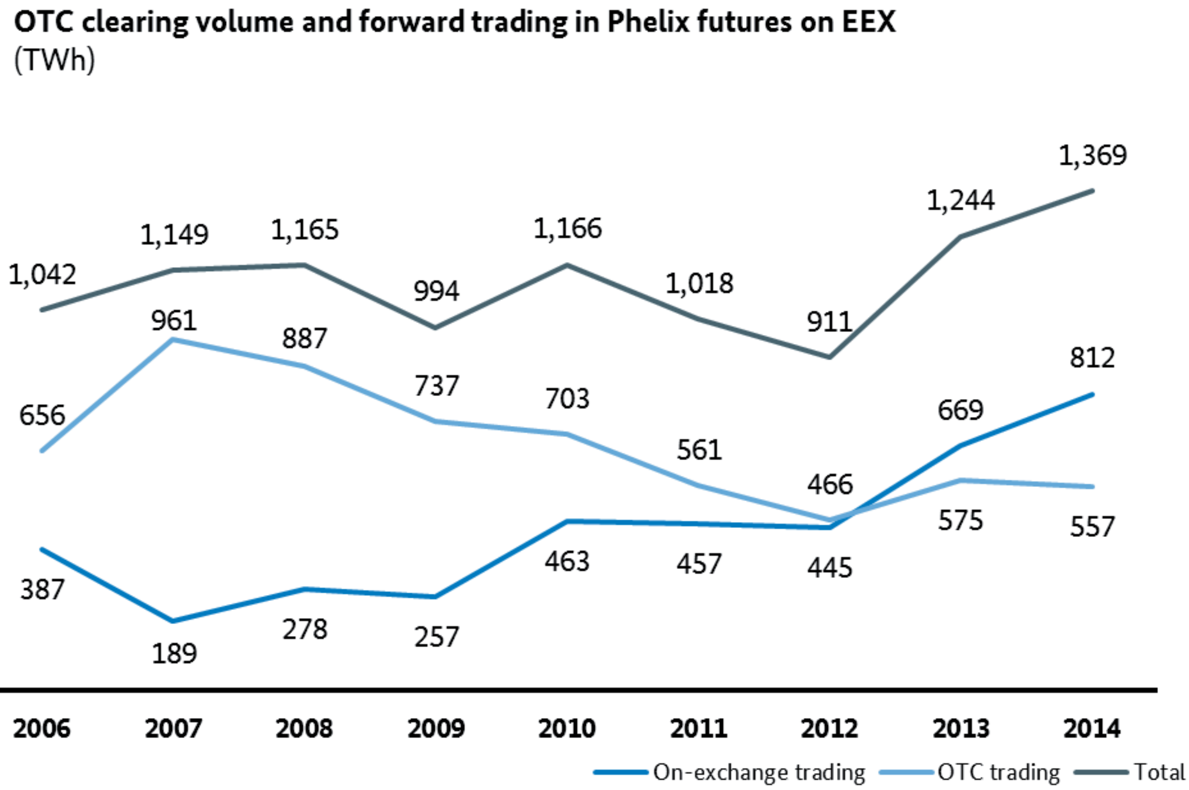

Figure 75: OTC clearing volume and forward trading in Phelix futures on EEX

Constancy in the volume of OTC clearing does not necessarily imply that the total volume of OTC trading remained at the same level as in the previous year. According to the London Energy Brokers´ Association (LEBA), the share of cleared contracts fluctuates over time. The volume registered by LEBA members (not only on EEX) for clearing for "German power" was 557 TWh in 2014 according to LEBA, corresponding to a total share of roughly 13 percent of the total OTC contracts brokered by LEBA members. By contrast, the values in question were approx.10 percent (534 TWh) in 2013 and approx. 7 percent (377 TWh) in 2012.[66]

Phelix options did not play a role in exchange trading on EEX, (i.e. there were no such transactions in the year under report – in common with the previous year). By contrast, practical significance attaches to the OTC clearing of non-exchange Phelix options agreed. In the year under report 2014, Phelix options accounted for a share of 33 TWh in OTC clearing, or 6 percent, i.e. 524 TWh (94 percent) of the OTC clearing was accounted for

[66] Cf. http://www.leba.org.uk/pages/index.cfm?page_id=59, retrieved on 18 August 2015. The total volume of German power brokered by LEBA members was 5,395 TWh (2012), 5,302 TWh (2013) and 4.367 TWh (2014).

by Phelix futures. The volume of OTC clearing of options fell slightly year-on-year (2013: 37 TWh or 6.5 percent).

The distribution of the volumes registered in 2014 on EEX for OTC clearing over the various fulfilment periods shows a structure similar to that in previous years. Half of the volume (50 percent) was accounted for by contracts for the next year (2015). Roughly 31 percent concerned the year under report 2014 itself. The year after next (trading for 2016) accounted for roughly 15 percent. Subsequent fulfilment periods only accounted for a small share of 4 percent.

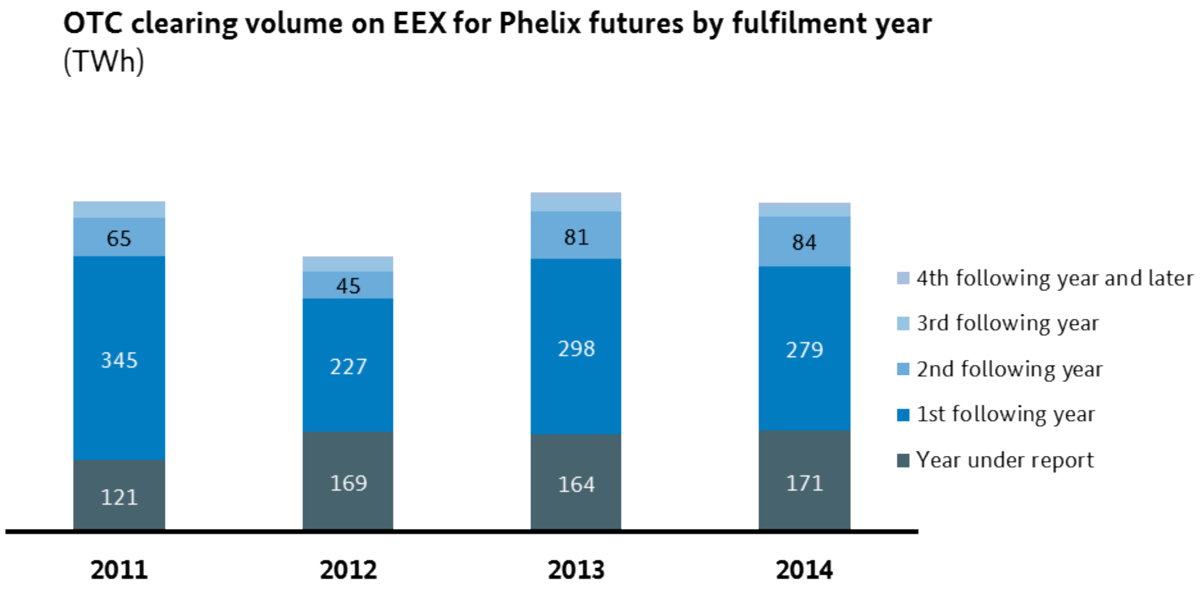

Figure 76: OTC clearing volume on EEX for Phelix futures by fulfilment year

Just a few broker platforms account for the great majority of the OTC clearing volume of Phelix futures on EEX. The five companies that reported the largest volumes to OTC clearing in 2014 accounted for 70 percent of all purchases and sales. Four of the five companies were broker platforms, both in purchases and sales.

EPEX SPOT offers OTC clearing for intraday contracts. The practical significance of this supply remains very small, however. The volume for which this accounted in 2014 was only 0.02 TWh.

G Retail

1. Supplier structure and number of providers

When looking at the retail market in the electricity sector it is worth noting how the supplier market is structured and how many suppliers are active in the market. The analysis covered data from 1,100 suppliers on the meter points served by them and clearly shows that in absolute terms most suppliers serve only a small number of meter points. For the data analysis the information provided by the suppliers was considered to be submitted from individual legal entities without taking possible company affiliations or links into account. Approximately 81% of all of the companies taking part in the monitoring and analysis belong to the group of suppliers that serve less than 30,000 meter points. At barely 7.1 million meters in total, this is only about 14% of all registered meters.[67] Some 7.7% of all suppliers serve over 100,000 meter points each; this group covers 35.8 million meter points and therefore about 73% of all the meter points registered by suppliers. Hence the majority of companies operating as suppliers have a customer base of a relatively small number of meter points; whereas some 85 large suppliers (individual legal entities) serve the largest number of meters in absolute terms.

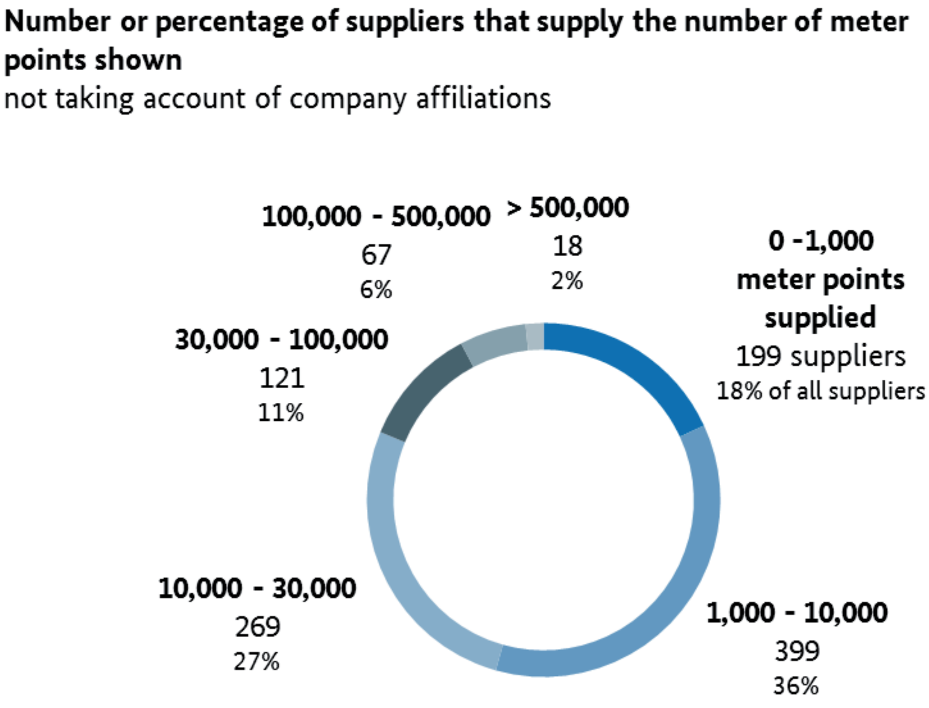

Figure 77: Number of suppliers by number of meter points supplied[68]

[67] In total, 49.2 million meters served by the suppliers were registered by final consumers.

[68] Figures may not sum exactly owing to rounding.

Electricity customers had the choice of an even larger number of suppliers (individual legal entities) than in 2013. An evaluation of the data supplied by 793 distribution network operators on the number of suppliers that supply the consumers in each network area produced the following results: In 2014 more than 50 suppliers operated in nearly 82% of all network areas (649 network areas). By way of comparison, in 2007 this number barely covered one quarter of the network areas (165 network areas). Nowadays more than 100 suppliers operate in about half the network areas, whereas two years ago it was only 33% (259 network areas). On average, final consumers in Germany can choose between 106 suppliers in their network area (2013: 97); household customers can choose between 91 suppliers (2013: 80). Despite the large number of suppliers, this does not automatically translate into a high level of competition. Many suppliers offer tariffs in several network areas yet do not acquire a significant number of customers outside their own default supply area.

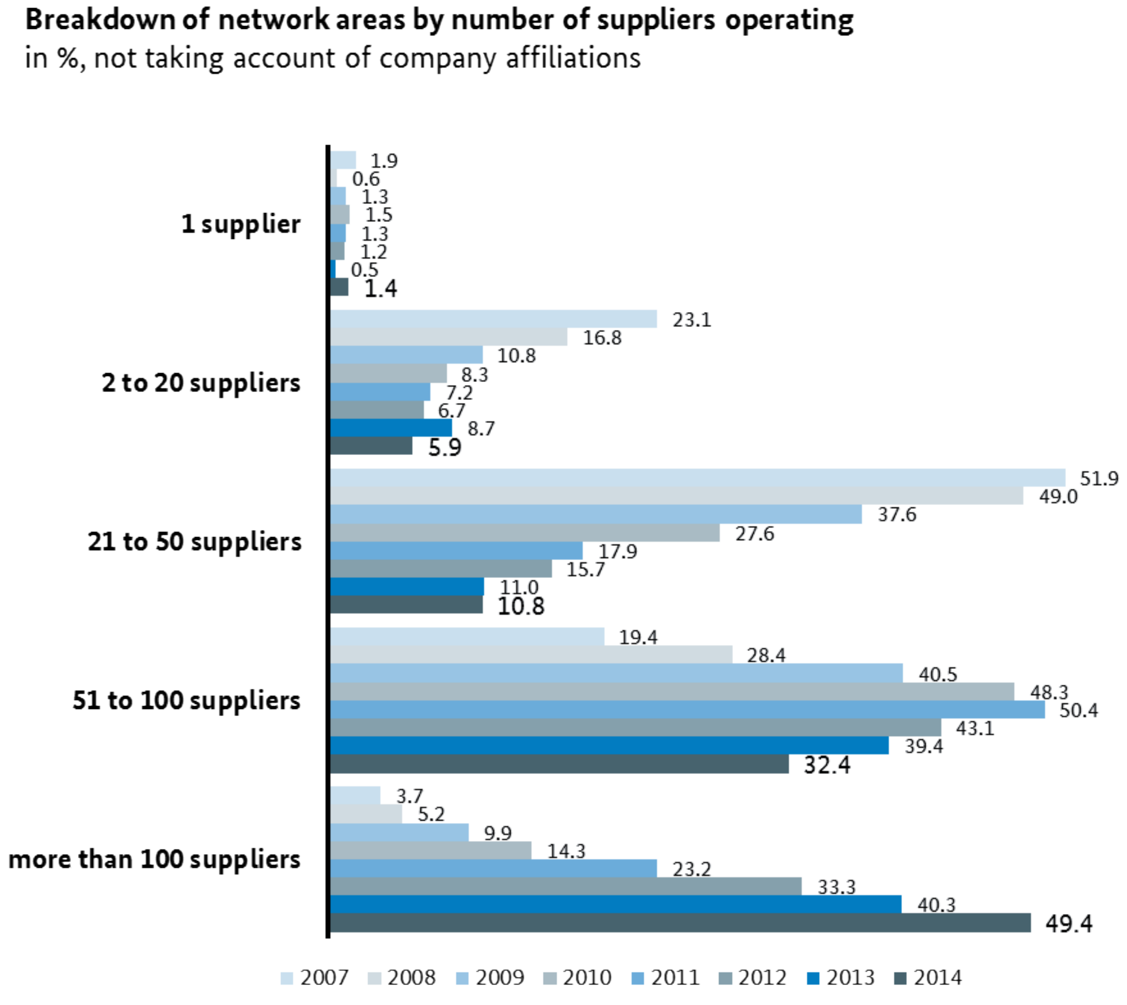

Figure 78: Breakdown of network areas by number of suppliers operating

Suppliers were also asked about the number of network areas in which they supply final consumers with electricity. An analysis of the data submitted by 992 suppliers shows that a relative majority of the individual legal entities only operate regionally. Some 55% of suppliers serve a maximum of 10 network areas, while 16% serve just one network area; 23% of suppliers operate in 11-50 network areas, with 12% operating in 51-250 network areas. Only 56 suppliers, or about 6% of all individual supplier legal entities, supply customers in more than 500 network areas. This figure can be taken as the approximate number of suppliers that operate throughout the whole of Germany. On a national average, a supplier has customers in about 75 network areas (2013: 71).

Number or percentage of suppliers that supply customers in the number of network areas shown
not taking account of company affiliations

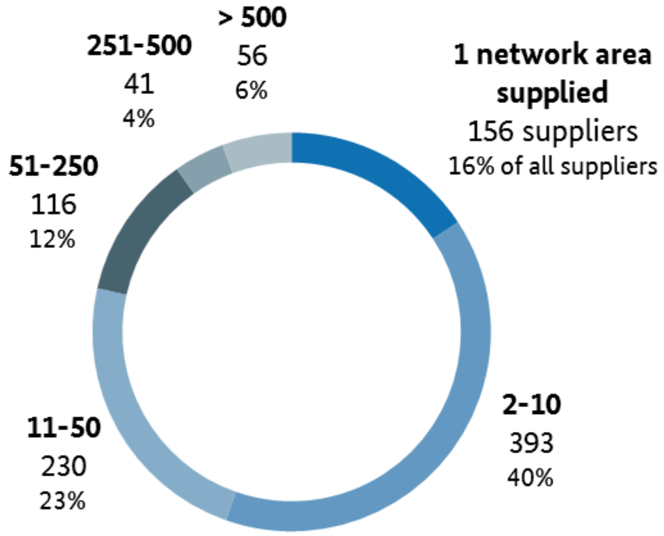

Figure 79: Breakdown of suppliers by number of network areas supplied[69]

2. Contract structure and supplier switching

Switching rates and processes are important indicators of growing competition. Collecting such key figures, however, is bound up with many difficulties and, as a result, the relevant data collection has to be limited to data that best reflects the actual switching behaviour.

As part of the monitoring, data on contract structures and supplier switches relating to each specific customer group is collected through questionnaire 2 (the market role of TSOs), questionnaire 3 (the market role of DSOs) and questionnaire 4 (the market role of suppliers).

Electricity consumers can be grouped by their metering profile into customers with and without interval metering. For customers without interval metering, consumption over a set period of time is estimated using a standard load profile (SLP).

Final consumers can also be divided into household and non-household customers. Household customers are defined in the German Energy Act (EnWG) according to qualitative characteristics.[70] All other customers are

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[69] Figures may not sum exactly owing to rounding.

non-household customers, which includes customers in the industrial, commercial, service and agricultural sectors as well as public administration.

According to questionnaire 4, the volume of electricity sold by suppliers to all final consumers in 2014 reached approximately 428 TWh.[71] Of this, 268 TWh was supplied to interval metered customers and 160 TWh to SLP customers (including 14 TWh night storage and heat pump electricity). The majority of SLP customers are household customers. In 2014 household customers were supplied with around 123 TWh.

As part of the monitoring, data is collected on the volume of electricity sold to various final consumer groups broken down into the following three contract categories:

- default supply contract,
- special contract with the default supplier and
- contract with a supplier who is not the local default supplier.

For the purposes of this analysis, the default supply contract category also includes fallback energy supply (section 38 EnWG) and doubtful cases.[72] A special contract with a default supplier is one with delivery outside the default supply contract. An analysis on the basis of these three categories makes it possible to draw conclusions as to the extent to which the importance and role of default supply have lessened since the liberalisation of the energy market. The corresponding figures, however, should not be directly interpreted as "cumulative net switching figures since liberalisation". It must be noted that for monitoring purposes the legal entity is taken to be the contracting party, thus a contract with a company affiliated with the default supplier falls under the category "contract with a supplier who is not the local default supplier".[73]

Furthermore, data was collected in questionnaires 2 and 3 (TSOs and DSOs) on the level of supplier switches, as defined in the monitoring report, in the different customer groups in 2014. The term "supplier switch" is used in the monitoring report to mean the process by which a final consumer's meter point is assigned to a new supplier. As a rule, moving into or out of premises does not meet the definition of "supplier switch", however additional household customer data is collected on how many customers choose a supplier other than the default supplier when moving home ("switch when moving home"). In this analysis, too, it must be noted that the change of supplier question refers to a change in the supplying legal entity. A network operator cannot distinguish between an internal reallocation of supply contracts to another group company and a

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[70] Section 3 para 22 EnWG defines household customers as final consumers who purchase energy primarily for their own household consumption or for their own consumption for professional, agricultural or commercial purposes not exceeding an annual consumption of 10,000 kilowatt hours.

[71] Differences in the total electricity sold to final customers, that is, the difference between a total of 430 TWh sold by suppliers as per final consumer categories and a total of 428 TWh sold to SLP and interval-metered customers, can be explained by a slight difference in the degree of completion of the relevant questions in questionnaire 4.

[72] In addition to household customers, final consumers served by fallback supply are usually included under the default supply tariff, section 38 EnWG. For monitoring purposes, suppliers were asked to allocate cases that could not be clearly categorised to "default supply".

[73] It is also possible that further ambiguities may arise, for example if the local default supplier changes.

change of supplier initiated by a customer – or only at considerable time and expense – and therefore both fall under supplier switch. The same applies to any insolvency of the former supplier or in the event that the supplier terminates the contract ("involuntary supplier switch"). The actual number of customers choosing to switch supplier is therefore lower than the number of switches registered. This figure does not reveal whether suppliers lowered prices or otherwise improved their offer to prevent customers from switching.

2.1 Non-household customers

Contract structure

The electricity sold to non-household customers is mainly to interval-metered customers where the electricity flow is recorded at short intervals ("load profile"). Interval-metered customers are characterised by high consumption[74] and thus are mainly industrial or other high-consumption non-household customers.

In the 2014 reporting year around 985 electricity suppliers (individual legal entities) provided data on the meter points served and volume consumed by interval-metered customers in Germany (2013: 925). The 985 electricity suppliers include many affiliated companies, hence the number of suppliers is not equal to the actual number of competitors.

In 2014 these suppliers served about 359,000 meter points of interval-metered customers with just under 268 TWh of electricity (2013: 281 TWh to 342,000 meter points). Over 99% of this was supplied under a special contract. It is unusual, but not impossible, for interval-metered customers to be supplied under default supply or fallback supply. Around 0.8 TWh of electricity was supplied to interval-metered customers under default or fallback supply, which is about 0.3% of the total volume supplied to interval-metered customers.

As in 2013, about 34% of the total electricity supplied to interval-metered customers was supplied under a special contract with the default supplier (divided between about 47% of all meter points in 2014) and about 66% under a contract with a legal entity other than the local default supplier (divided between about 51% of all meter points). These figures once again show that default supply is of little practical significance for interval-metered electricity customers.

[74] In accordance with section 12 of the Electricity Network Access Ordinance (StromNZV) interval metering is generally required for annual consumption above 100 MWh.

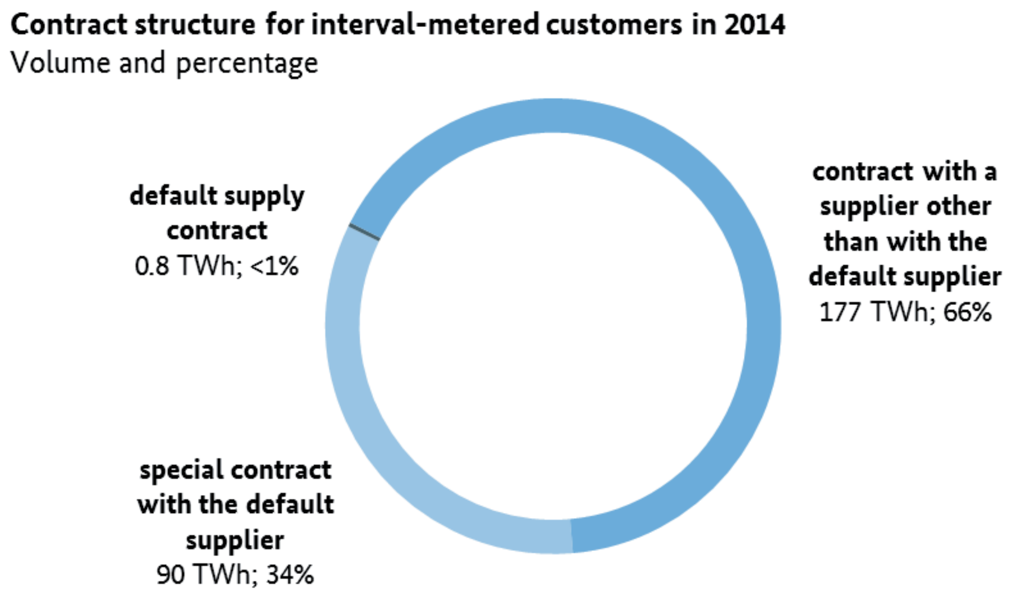

Figure 80: Contract structure for interval-metered customers in 2014

Supplier switch

Furthermore, data was collected in questionnaires 2 and 3 (TSOs and DSOs) on the level of supplier switching (as defined above) that took place in the different customer groups in 2014 and the consumption levels attributable to these customers. A distinction is made in the data collection between three consumer categories: industrial customers typically fall in the consumer category of more than 2 GWh/year, with various non-household customers falling in the 10 MWh/year to 2 GWh/year category and household customers within the meaning of section 3 para 22 EnWG falling in the category of up to 10 MWh/year. The data survey produced the following results:

Supplier switches by consumer category in 2014

Final consumer category	Number of meter points where the supplying legal entity changed in 2014	Percentage of all meter points in this category	Offtake volume at meter points where the supplier changed in 2014	Percentage of total offtake volume by consumer category in 2014
> 2 GWh/year	2,627	12.3%	25.3 TWh	10.4%
10 MWh/year – 2 GWh/year	203,504	9.5%	15.1 TWh	12.1%
<10 MWh/year	2,902,558	6.1%	7.9 TWh	6.6%

Table 46: Supplier switches in 2014 by consumer category

The consumption range above 10 MWh/year consists nearly entirely of non-household customers.[75] The volume-based switching rate in 2014 for the two categories with a consumption of more than 10 MWh/year was about 11%. Compared with 2013, this represents a decrease of 1.1 percentage points, although the difference falls within the fluctuation range of previous years. Since 2006 the switching rate in the non-household customer category has remained more or less constant. The data survey does not analyse what percentage of industrial and business customers have switched supplier once, more than once or not at all over a period of several years. Switching rates for non-household customers remain above the switching rates of household customers.

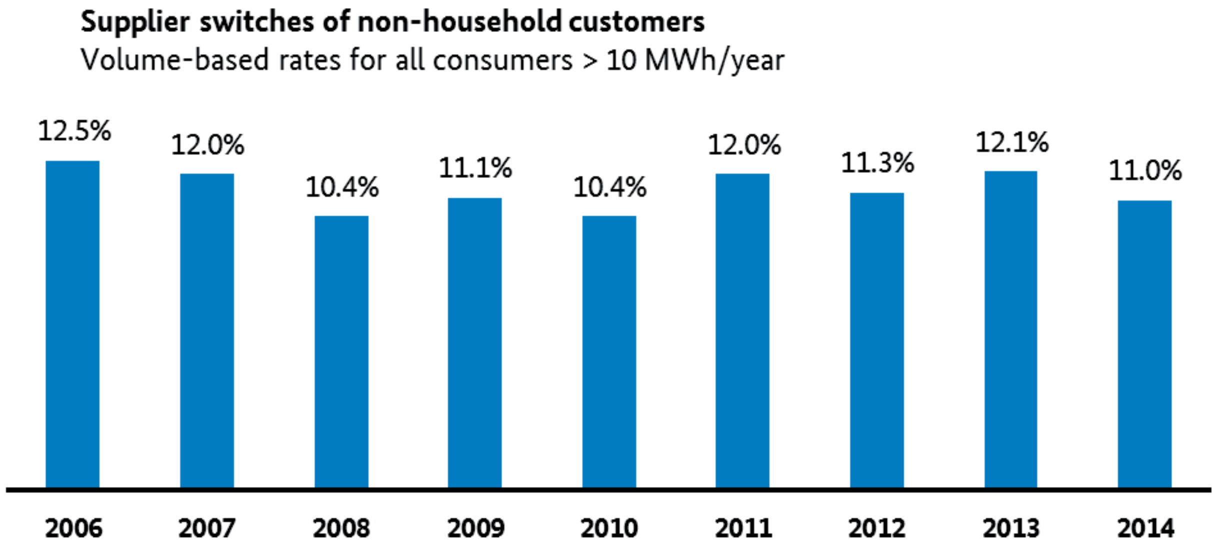

Figure 81: Supplier switches of non-household customers

2.2 Household consumers

Contract structure

The data from the 2015 monitoring data on volumes supplied to household customers shows that in 2014 a relative majority of 43.2% of household customers concluded a special contract with the local default supplier (2013: 45%). The percentage of household customers with a standard default supply contract is 32.8%. Thus the percentage of default supply customers has fallen once again when compared with the prior year (2013: 34.1%). Meanwhile, 24% of all household customers are served by a company other than the local default supplier (2013: 20.9%). Consequently, there has been a further increase in the percentage of household customers who no longer have a contract with their default supplier. However, overall about 76% of all household customers are still served by their default supplier (by way of default supply or a special contract), compared to 79% in 2013. Thus the strong position that default suppliers still have in their respective service areas weakened further in the year under review.

[75] Where the consumption is predominantly household, a final consumer is still considered to be a household customer even if the consumption exceeds 10 MWh per year (section 33 para 22 EnWG). This has to be taken into consideration, for example, for night storage and heat pump electricity customers.

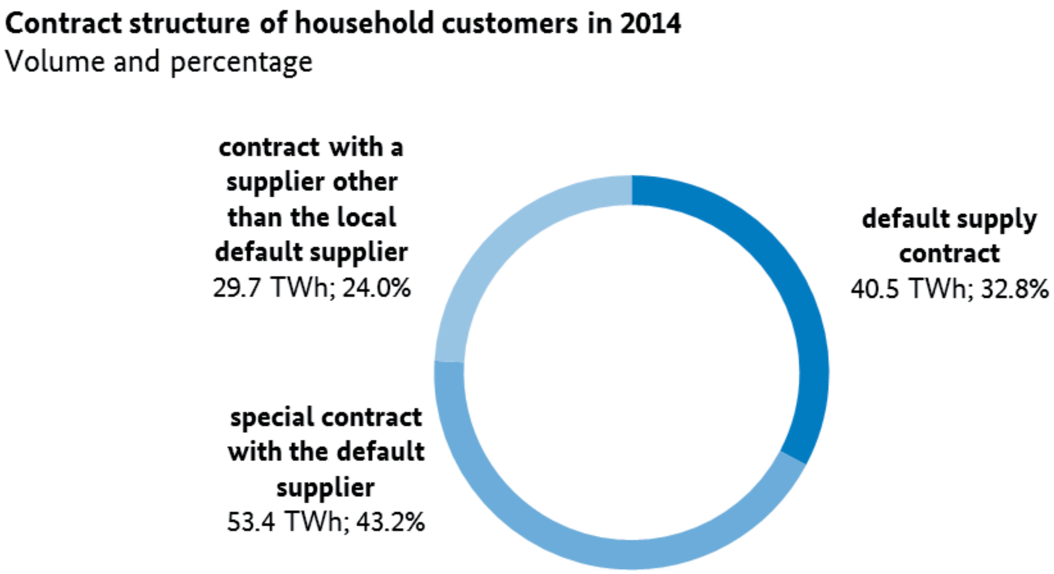

Figure 82: Contract structure of household customers

A standard load profile (SLP), which is a simplified method of metering, is used for customers whose consumption is not registered in defined intervals. An SLP is generally used only for electricity customers that consume a maximum of 100 MWh annually from the electricity distribution system (section 12 StromNZV). The majority of SLP customers are household customers. The approximate 1,100 suppliers (individual companies) that provided data on meter points and consumption amounts for the 2014 monitoring supplied power of about 160 TWh to SLP customers (including 14 TWh night storage and heat pump electricity) at 48.8 million SLP meter points (including 2.1 million night storage and heat pump electricity meter points). Of this, roughly 123 TWh or about 77% was accounted for by household customers.

In the supply of SLP customers (excluding night storage and heat pump electricity) 43 TWh (about 30%) was supplied under standard default supply contracts, 62 TWh (43%) under special contracts with the default supplier and 41 TWh (about 28%) under special contracts with another legal entity.

Higher consumption SLP customers are much more likely to have a special contract than those with lower consumption. The average (median) annual consumption of default supply customers was 2,200 kWh, for special contract customers (excluding night storage and heat pump electricity) the corresponding figure was over 3,600 kWh.

Some 780 of the approximate 1,100 suppliers (individual company level) were active as default suppliers. Many of these default suppliers have a relatively small customer base: 662 serve fewer than 50,000 meter points for SLP customers, including 344 serving fewer than 10,000 meter points.

Supplier switch

To determine the number of supplier switches by household customers, the DSOs were questioned as to the number of supplier switches, including the volume involved, at the meter points as well as the choice of supplier when moving home in their network area. The total number of household customers switching supplier, including switches made due to moving home, has risen from 3.6 million in 2013 to nearly

3.8 million in 2014. This development is both the result of a greater number of switches when moving home (up 71,000) and of a rise in the number of switches not related to moving home (up 108,000).

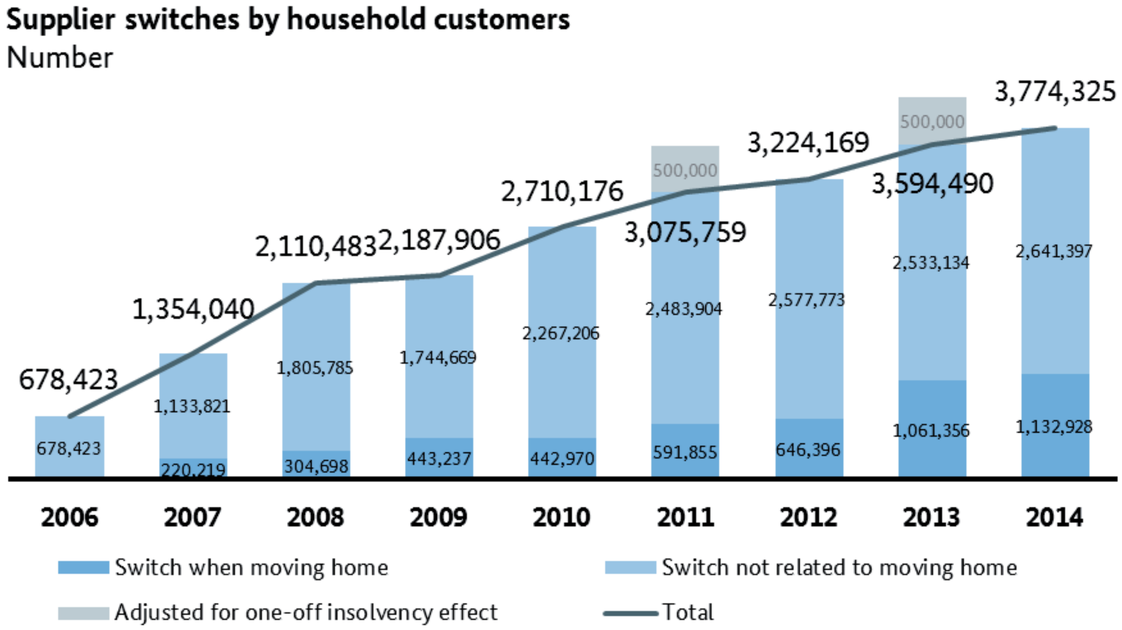

Figure 83: Number of supplier switches by household customers

When viewing the trend in supplier switches from 2006 to 2014, one-off effects have to be taken into account for 2011 and 2013 as a consequence of the insolvency of two large cut-price electricity suppliers. The customers affected were initially switched to fallback supply and subsequently, insofar as they had not switched to another supplier themselves, were transferred to the default supply of the local default supplier. An estimated 500,000 customers were affected (also when taking the monitoring figures into account). By definition, such an atypical procedure is recorded as a switch, despite the fact that it is not based on a customer deciding to make the switch. It is therefore appropriate to remove the estimated portion of "switches brought on" by the insolvency. After adjusting the figures from 2011 and 2013 by removing the approximate 500,000 switches brought on by insolvency, a more correct picture of the rise in the number of switches other than for moving home is given for those years. A detailed view of the trend, taking the one-off insolvency effects of 2011 and 2013 into account, is shown in the following table:

Number of supplier switches by household customers

Change from prior year	Adjusted[1] for one-off effect of insolvency		Unadjusted for one-off effect of insolvency	
	absolute	%	absolute	%
2008-2009	-61,117	-9.1	-61,117	-9.1
2009-2010	522,538	30	522,538	30
2010-2011	216,698	9.6	716,698	31.6
2011-2012	93,869	3.8	-406,131	-13.6
2012-2013	-44,639	-1.7	455,361	17.8
2013-2014	108,263	4.3	108,263	4.3

[1] A fixed number of 500,000 switches have been deleted from the switch figures for 2011 and 2013 in the adjusted figures.

Table 47: Changes in supplier switch figures for household customers other than for moving home (with and without adjustment for one-off insolvency effects)

Around 2,641,000 switches have been determined for 2014 excluding moving home. This is some 5.6% of household customers and corresponds to a rise of about 4.3% in the number of switches since 2013. These switches represent about 8.2 TWh, which in absolute terms shows a slight decline when compared with the prior year's figure of 8.4 TWh. As electricity consumption fell overall in 2014, when switches upon moving home are excluded, the percentage switching rate of 6.8% of total electricity supplied to household customers is more or less the same rate as in 2013 of 6.7%.

In addition to the switching figures shown for household customers that exclude switches when moving home, the number of household customers that immediately chose an alternative supplier, rather than the default one, when moving into new premises rose to 1,132,000. At 2.4 TWh, the electricity amounts registered for supplier switches correspond to the prior year's amount.

Supplier switches by household customers adjusted for insolvency, including switches when moving home

Category	2014: Supplier switches in TWh	Percentage of total offtake volume (120.2 TWh)	2014: Number of supplier switches	Percentage of total household customers
Household customers switching supplier without moving home	8.2	6.8	2,641,397	5.6
Household customers who switched to a supplier other than the default supplier when moving home	2.4	2	1,132,928	2.4
Total	10.6	8.8	3,774,325	8.0

Table 48: Household customer supplier switches adjusted for insolvency, including switches when moving home[76]

A joint view of household customer supplier switches that includes switches when moving home gives rise to a total of 3.8 million switches for 2014 with a total electricity volume of 10.6 TWh. This corresponds to a switching rate based on electricity volume and number of switches of 8.8% and 8.0% respectively. The volume-based rate was slightly above the quantity-based rate, which suggests that a household customer's high level of electricity consumption positively influences a decision to switch. The average volume of electricity consumed by a household customer that made a switch was approximately 3,100 kWh in 2014. In contrast to this, household customers that were supplied by a default supplier consumed only about 2,200 kWh on average.

3. Disconnection notices, disconnections, cash or smart card meters, tariffs and terminations

3.1 Disconnection of supply

In 2014, the Bundesnetzagentur once again carried out surveys of the tariffs offered and questioned network operators and electricity suppliers about disconnection notices and requests made to DSOs for disconnection, as well as the number of actual disconnections carried out under section 19(2) of the Electricity Default Supply Ordinance (StromGVV) and the associated costs. The following analysis is based on the data provided by 739 DSOs and 887 suppliers.

[76] Figures may not sum exactly owing to rounding.

Disconnection notices, requests for disconnection of default supply; disconnection on behalf of the local default supplier
Number (electricity)

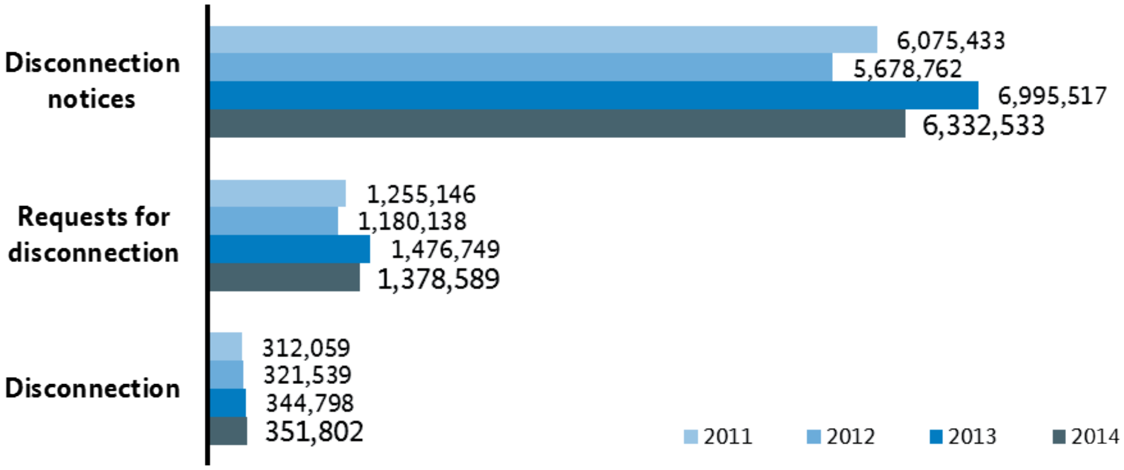

Figure 84: Disconnection notices and requests for disconnection of default supply; disconnection on behalf of the local default supplier (electricity)[77]

Under the StromGVV, default suppliers have the right to to disconnect supplies to customers, in particular upon failure to fulfil payment obligations of at least €100 and after appropriate notice has been given. Compared with the prior year, the number of disconnections carried out on behalf of the local default supplier has risen only slightly to 351,802. Overall, there were roughly 7,000 disconnections more at meter points than in the prior year. This figure is based on information from the DSOs, who ultimately carry out the disconnections on behalf of the suppliers. Based on the total number of meter points at the distribution system level in Germany that were included in the monitoring data collection, the market coverage rate for this question was about 98.2%.

At the same time the suppliers were asked how often in the 2014 year under review they had issued disconnection notices to customers that had failed to meet payment obligations and how often they had requested the network operator responsible to disconnect supplies. The companies responded that they had issued almost 6.3 million disconnection notices to household customers. According to the data provided by the companies, disconnection notices threatening to cut customers off are sent when the statutory requirements of section 19 StromGVV are met and when, on average, a customer is €121 in arrears. However, although just under 6.3 million disconnection notices were issued, only about 1.4 million of these resulted in electricity being disconnected by the pertinent network operator.

Ultimately, the network operators carried out 351,802 actual disconnections of household customers on behalf of local default suppliers. As a percentage of all household customers in Germany the disconnections amounted to about 0.75%. On the whole, the relationship depicted in the 2014 Monitoring Report between

[77] It is important to note with regard to the data for 2011 that some suppliers could only provide estimates of the number of disconnection notices and requests.

threatened disconnections, disconnection requests and actual disconnections of supply has shifted somewhat: of the 6.3 million disconnection notices, only about 22% led to a request for disconnection by the supplier. Only in just less than 6% of the approximate 6.3 million cases of disconnection notice was the supply actually cut off by the network operator. According to information provided by the suppliers, in 2014 the ratio between total disconnections and the number of household customers affected was 1 to 0.94. This means that an estimated 6% of disconnections involved repeat disconnections of the same customers.

The DSOs charged their customers an average fee of €47 for disconnecting a supply, with the actual costs charged ranging from €12 to €146. The average fee to household customers for reinstating supply to a meter point was €50, although the fees charged varied from €10 to €132.

3.2 Cash meters and smart card meters

In the 2015 monitoring, information was collected for the first time for the 2014 year under review on prepayment systems in accordance with section 14 StromGVV, such as cash meters or smart card meters. The questions addressed to the distribution network operators and suppliers revealed the following findings: over the course of 2014, prepayment systems were installed on behalf of default suppliers at about 17,300 household customer offtake points in 354 network areas. This represents a mere 0.04% of all household customer meter points in Germany. In about 4,800 cases, a chip or smart card meter was newly installed in the 2014 calendar year, with about 3,000 of this type of meter being taken out again.

3.3 Tariffs and terminations of contract

Section 40(5) EnWG requires suppliers to offer load-based tariffs or time of use tariffs to final consumers of electricity insofar as this is technically feasible and economically reasonable. In the 2014 year under review, only about 10% of suppliers offered load-based tariffs. Some 74% of suppliers offered time of use tariffs[78], with about 13% offering other tariffs, too.

Section 40(3) EnWG also requires suppliers to offer final consumers monthly, quarterly or half yearly bills. Customer demand for such billing cycles remained low in 2014 with some 143 companies registering about 14,000 customer enquiries for billing cycles of less than one year. Despite the still comparatively low number overall, it must be pointed out that demand for shorter billing cycles has increased when compared to the prior year (2013: 133 companies, 11,600[79] enquiries).

Despite the relatively high number of disconnection notices and supplier requests for disconnection, very few suppliers actually terminate service with their customers. In 2014, suppliers terminated about 150,000 contracts with their customers overall. The average customer arrears upon a termination of contract was roughly €162.

Disconnections are usually only carried out for default supply. Termination of a default supply contract is only permitted under stringent conditions: there must be no obligation to provide basic services or the requirements for disconnection must have been met repeatedly. Disconnections and disconnection notices

[78] In particular these included special tariffs for heating electricity and heat pump electricity.

[79] The original figure given in the 2014 Monitoring Report has been subsequently amended.

for customers with a special contract are rare since it is easier and less expensive for the supplier to terminate the contract.

4. Price level

For monitoring purposes, suppliers that provide final consumers with electricity in Germany were asked about the retail prices their companies charged on 1 April 2015 for three consumption levels. The three consumption levels are based on annual consumption of 3,500 kWh, 50 MWh and 24 GWh. These consumption figures are for a household customer and two different non-household customers.

Suppliers were asked to give the overall price in cents per kilowatt hour (ct/kWh) to include the non-variable price components such as the service price, base price and transfer or internal price. Suppliers were also asked to provide a breakdown of the individual price components that the suppliers cannot control but may vary from one network area to another, including network charges, concession fees and charges for billing, metering and meter operations. Ultimately the state-controlled surcharges and taxes were taken into account in the total price, that is, the value added and electricity taxes, surcharges under the EEG, KWKG and section 19(2) StromNEV, and for offshore liability and interruptible loads. After deducting these transitory items from the overall price, the amount remaining is the amount controlled by the supplier, which includes the costs of electricity procurement and distribution, other costs and the supplier's margin.

The suppliers were asked to provide their "average" overall prices and price components for each of the three consumption levels. Some of the companies questioned once again drew attention to the fact that they were unable to provide average figures on account of their inter-regional activity and/or customer-specific pricing. Some individual companies have separately pointed out that they have selected a specific tariff as being representative due to the large number of tariffs and/or the large number of networks involved.

Companies were asked to provide data on the price components for the lowest consumption level of 3,500 kWh per year (household customer) for three different contract types (see page 197):

- default supply contract,
- special contract with the default supplier and
- contract with a supplier other than the local default supplier.

The findings are presented separately in the following by consumption level or customer category. To better illustrate any long-term trends, a comparison is made in each case with the prior year's figures. When comparing the figures as at 1 April 2015 and 1 April 2014, it should be noted that differences in the calculated averages are partially below the margin of error associated with the data collection method. Therefore it is not possible to say whether the increase or decrease in the price or a price component in a year-on-year comparison was statistically significant.

As in the prior year (although not included in earlier price data), non-default suppliers were included in the companies questioned about prices. With regards to the prices for the 50 MWh per year and 24 GWh per year consumption levels, for the second consecutive year only those suppliers were asked to provide data that served at least one customer whose electricity demand fell under the relevant level of consumption.

4.1 Non-household customers

24 GWh per year ("industrial customer")

Consumers with annual consumption in the 24 GWh range are served only as interval-metered customers and, in general, they tend to be industrial customers. The wide scope for customer-specific contracts plays a large role for this customer group. In general, suppliers do not have any specific tariff groups for consumers of 24 GWh per year but, instead, tailor pricing according to individual customers, regardless of whether these are customers receiving the full range of services or those customers whose negotiated offtake is only part of their procurement portfolio. The contract prices are often indexed to the wholesale prices. In some cases the suppliers' customers themselves are responsible for paying the network charges to the network operator. In the extreme case, such contract models may be set up in such a way that in economic terms the "supplier" only provides balancing group management services to the customer. Thus for high-consumption customers the distinction between retail and wholesale trading may be quite fluid.

Of particular significance for tailor-made prices for industrial customers are special statutory regulations enabling certain price components to be reduced. These regulations aim primarily to reduce prices for undertakings with a high electricity consumption. The scale of price components that are not controlled by the supplier and the corresponding impact on individual prices vary according to the maximum possible level of exemption available to a company in the consumption category of 24 GWh per year. However, the price question was framed under the assumption that none of the possible reduction measures were relevant for the customers involved (section 63ff EEG, section 19(2) StromNEV, section 9(7) para 3 KWKG, section 17f EnWG).

The customer category was defined as having annual consumption of 24 GWh with an annual usage period of 6,000 hours (annual peak load 4,000 kW; medium voltage supply 10 or 20 kV). Only those suppliers with at least one customer with annual consumption of between 10 GWh and 50 GWh were asked to provide data. This customer profile led to only a small group of suppliers being addressed. The following price analysis by consumption is based on data from 212 suppliers (prior year: 208 suppliers). More than half of the 212 suppliers had fewer than ten customers whose annual consumption was more than 24 GWh.

This data was used to calculate the arithmetic mean of the total price and the individual price components. The spread of data for each price component was also analysed using ranges. The 10th percentile represents the lower limit and the 90th percentile the upper limit of each range, which means that in each case the middle 80% of the figures provided by the suppliers lie within the stated range. The analysis produced the following results:

Price level for customers with annual consumption of 24 GWh without reductions (1 April 2015)

	Spread in 10-90 percentile range of supplier information sorted by size in ct/kWh	**Average** (arithmetic) in ct/kWh
Price components that cannot be controlled by the supplier		
Net network tariff	1.25 - 2.90	2.06
Charge for billing, metering and meter operations	0.00 - 0.04	0.06[1]
Concession fee	0.11 – 0.11	0.12[2]
Surcharge under EEG	6.17	6.17
Other surcharges[3]	0.16	0.16
Electricity tax	2.05	2.05
Price components that can be controlled by the supplier (residual amount)	3.35 - 5.48	4.19
Total price (excl. VAT)	13.45 - 16.48	14.80

[1] More than 90% of the suppliers stated a figure of 0.04 ct/kWh or less for metrology. As a few suppliers stated a significantly higher figure, the arithmetic mean is more than 0.04 ct/kWh.
[2] About 90% of suppliers stated a concession fee of 0.11 ct/kWh. As a few suppliers stated a significantly higher value, the arithmetic mean is more than 0.11 ct/kWh.
[3] KWKG (0.051 ct/kWh), section 19(2) StromNEV (0.057 ct/kWh), offshore liability (0.046 ct/kWh) and interruptible loads (0.006 ct/kWh)

Table 49: Price level for customers with annual consumption of 24 GWh without reductions (1 April 2015)

The arithmetic mean of the price component controlled by the supplier has gone down again, falling by 0.42 ct/kWh from 4.61 ct/kWh to 4.19 ct/kWh (change to prior year: reduction of 0.82 ct/kWh).[80] The surcharges, however, have barely dropped and totalled 6.33 ct/kWh (of which the EEG surcharge accounted for 6.17 ct/kWh) and thus were 0.10 ct/kWh less than in the prior year. Whereas in contrast, the average net network tariff rose by 0.20 ct/kWh from 1.86 ct/kW to 2.06 ct/kWh. The average overall price (excluding VAT and any possible reductions) of 14.80 ct/kWh is 0.31 ct/kWh lower than the prior year's arithmetic mean.

[80] The data spread stated above must be taken into account in any comparison of these averages.

By definition, these prices imply that an (industrial) customer with annual consumption of 24 GWh is not eligible for any of the statutory reductions available. In this specific consumption category, 10.61 ct/kWh of the overall price, equivalent to about 70%, is accounted for by cost items that the supplier has no control over. If, on the other hand, electricity consumers are able to meet the requirements stipulated in the applicable regulations and statutes, reductions are made in the network charges, in concession fees, in electricity tax and the surcharges under the EEG, KWKG, section 19 StromNEV and section 17f EnWG. If all these possible reductions are exploited, the price component that is not under the control of the supplier could fall from over 10 ct/kWh to less than 1 ct/kWh.[81]

The most significant reduction possible involves the EEG surcharge. This may be reduced by up to 95% for annual consumption of 24 GWh depending on the specific case; the actual reduction amount possible depends on several factors according to section 64 EEG. Pursuant to section 19(2) second sentence StromNEV, the net network charge may be reduced by up to 80%.[82] The electricity tax may be completely remitted, repaid or reimbursed in accordance with section 9a StromStG. In relation to the overall price, quantitatively less significant possible reductions apply to the concession fees under section 2(4) first sentence KAV and to the surcharges under section 9 KWKG and section 17f EnWG. Monitoring data was not collected on the extent to which industrial customers actually make use of the individual possible reductions. Again, in this respect, the monitoring data cannot be used to make statements on a specific average price for industrial customers.

Possible reductions for a consumption level of 24 GWh per year on 1 April 2015

	Assumed or ascertained figure in the price query in ct/kWh	**Possible reduction to** in ct/kWh	Residual amount in ct/kWh
EEG surcharge	6.17	-5.86	0.31
Electricity tax	2.05	-2.05	0.00
Net network tariff	2.06	-1.65	0.41
Other surcharges	0.16	-0.07	0.09
Concession fees	0.12	-0.12	0.00
Total	**10.56**	**-9.75**	**0.81**

Table 50: Possible reductions for consumption category of 24 GWh per year as of 1 April 2015

[81] The eligibility requirements differ regarding the various possible reductions. During the monitoring data was not collected on whether in practice there are any cases in which all the possible maximum reductions are, or may be, exploited.

[82] The even greater reductions possible under section 19(2) third sentence StromNEV are not relevant for this consumption category, which is defined as having 6,000 hours of use.

50 MWh/year ("commercial customer")

The following consumption category for a commercial customer is defined as annual consumption of 50 MWh with an annual period of use of 1,000 hours (annual peak load of 50 kW; low voltage supply 0.4 kV). An annual consumption of 50 MWh is fourteen times times higher than that of a household customer of 3,500 kWh and two thousandths that of the 24 GWh per year consumption category. Given the moderate level of consumption, individual contractual arrangements play a significantly smaller role than for the 24 GWh per year consumption category. Suppliers were asked to provide plausible estimates of prices for customers with consumption similar to that of the consumption category, based on their terms and conditions applicable on 1 April 2015. For this purpose, suppliers that had at least one customer with annual consumption between 10 MWh and 100 MWh were asked to provide data. Since this consumption level is below the 100 MWh threshold, above which network operators are required to use interval metering, it can be assumed that a standard load profile (SLP) is frequently used for such customers.

The following price analysis for the consumption category is based on data from 827 suppliers (prior year: 763). The data was used to calculate the arithmetic mean of the overall price and of the individual price components. The data distribution for each price component was also analysed using ranges that the median 80% of the figures provided by the suppliers fell under. The analysis produced the following results:

Price level for the consumption category of 50 MWh per year on 1 April 2015

	Spread in the 10-90 percentile range of supplier data sorted by size in ct/kWh	**Average** (arithmetic) in ct/kWh	**Percentage of total price**
Price components that cannot be controlled by the supplier			
Net network charge	4.10 - 6.83	5.44	25%
Charge for billing, metering and meter operations	0.04 – 1.20	0.33	2%
Concession fee	0.11 – 1.59	0.97	4%
Surcharge under EEG	6.17	6.17	29%
Other surcharges[1]	0.45	0.45	2%
Electricity tax	2.05	2.05	10%
Price components that can be controlled by the supplier (residual amount)	4.24 - 7.90	6.08	28%
Total price (excl. VAT)	19.12 - 23.60	21.47	

[1] KWKG (0.254 ct/kWh), section 19(2) StromNEV (0.237 ct/kWh), offshore liability (-0.051 ct/kWh) and interruptible loads (0.006 ct/kWh)

Table 51: Price level for customers with annual consumption of 50 MWh as of 1 April 2015

The residual price component controlled by the supplier has once again fallen, decreasing from 6.39 ct/kWh on average to 6.08 ct/kWh (prior year: decrease of 0.90 ct/kWh).[83] The surcharges fell overall by 0.15 ct/kWh whereas the net network charge rose by 0.09 ct/kWh. The average overall price (excluding VAT) of 21.47 ct/kWh is 0.39 ct/kWh lower than the arithmetic mean of the figure provided for the prior year (21.86 ct/kWh). Thus, on average, price components that the supplier cannot control account for about 72% of the overall price in this consumption category (network charges, metrology, surcharges, electricity tax and concession fees). Only about 28% relate to items that allow scope for business decisions.

[83] In any comparison of these averages,the spread data referred to above must be taken into account.

4.2 Household customers

In the following, retail prices for household customers are considered to be volume-weighted averages[84] for a typical consumption category (household with annual consumption of 3,500 kWh, low voltage supply (0.4 kV)) for the relevant contracts. Analyses were made of these to arrive at the average price for

- a default supply contract,
- a special contract with the default supplier and for
- a contract with a supplier other than the local default supplier.

In addition a volume-weighted total price across all tariff categories was determined.[85]

Following strong price increases for many years and a slowing down in the prior year in the rate of increase, in 2015 the upwards trend came to an end and prices fell. Compared with 2014, the price went down for all customer groups – those with default supply, those with a special contract with their default supplier and those with a contract with a supplier other than their local default supplier.

In the default supply category, 660 companies provided data on tariffs and quantities for the 2015 monitoring. Based on the data submitted, a volume weighted average price of 30.08 ct/kWh was determined for 1 April 2015.[86] This means that, as of 1 April 2014, the price for customers receiving default supply was about 1.4% or 0.42 ct/kWh below the prior year's figure, placing it at the same level as in 2013. This is the first price reduction since the start of data collection in 2006. Within nine years the price has risen by 11.19 ct/kWh from an original price of 18.89 ct/kWh, corresponding to an increase of around 59%. The changes in the volume weighted average price for default supply are shown in more detail in the following diagram.

[84] The overall price including VAT is shown for household customers, all individual price components are net of VAT.

[85] All volume weighted prices as at 1 April are calculated for the consumption quantities of each supplier in the prior year (eg price weighting on 1 April 2015 compared with the 2014 quantity sold).

[86] The arithmetic mean is around 0.37 ct/kWh below the volume weighted price.

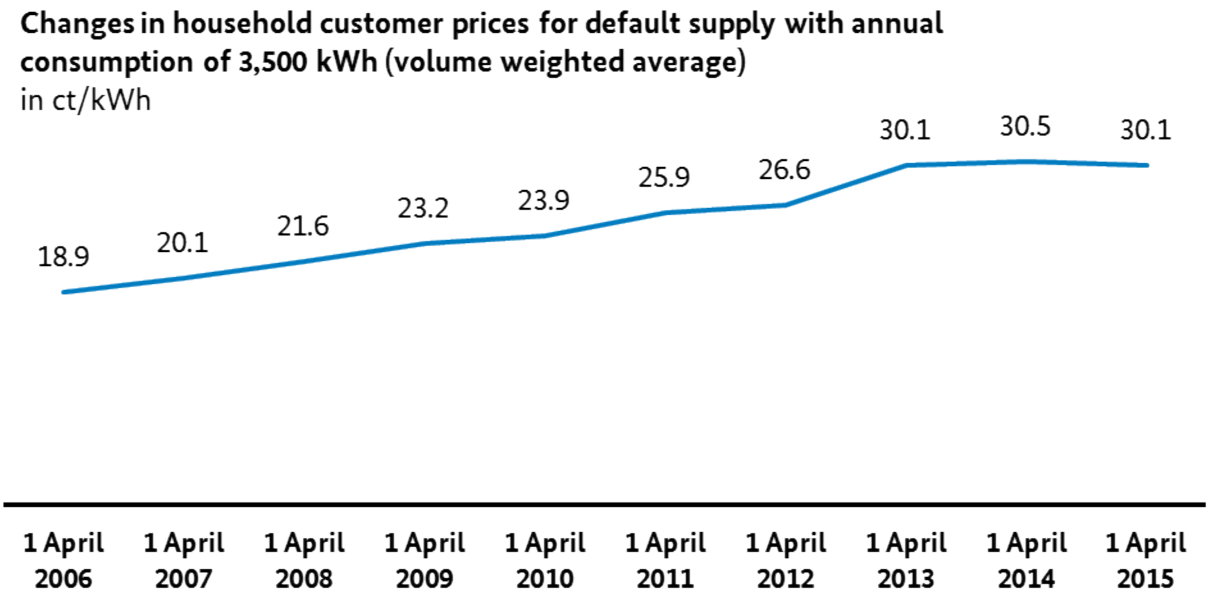

Figure 85: Changes in household customer prices for default supply with annual consumption of 3,500 kWh from 2006 until 2015 (volume weighted average)

Some 633 suppliers provided data on tariffs and volumes for the "special contract with the default supplier" category. On the basis of the data submitted, a volume weighted average price of 28.96 ct/kWh incl. VAT was determined as of 1 April 2015.[87] Hence the price for customers that changed from default supply to a special contract with the default supplier was barely 1% or 0.36 ct/kWh less than the figure determined in 2014. This is also the first price reduction in this tariff category since the start of data collection in 2007. Thus the price has risen by 9.02 ct/kWh over this eight-year period, which represents an increase of 45%. The changes in volume weighted average prices under a special contract with the default supplier are illustrated in the following diagram.

[87] The arithmetic mean is about 0.74 ct/kWh below the volume weighted price determined.

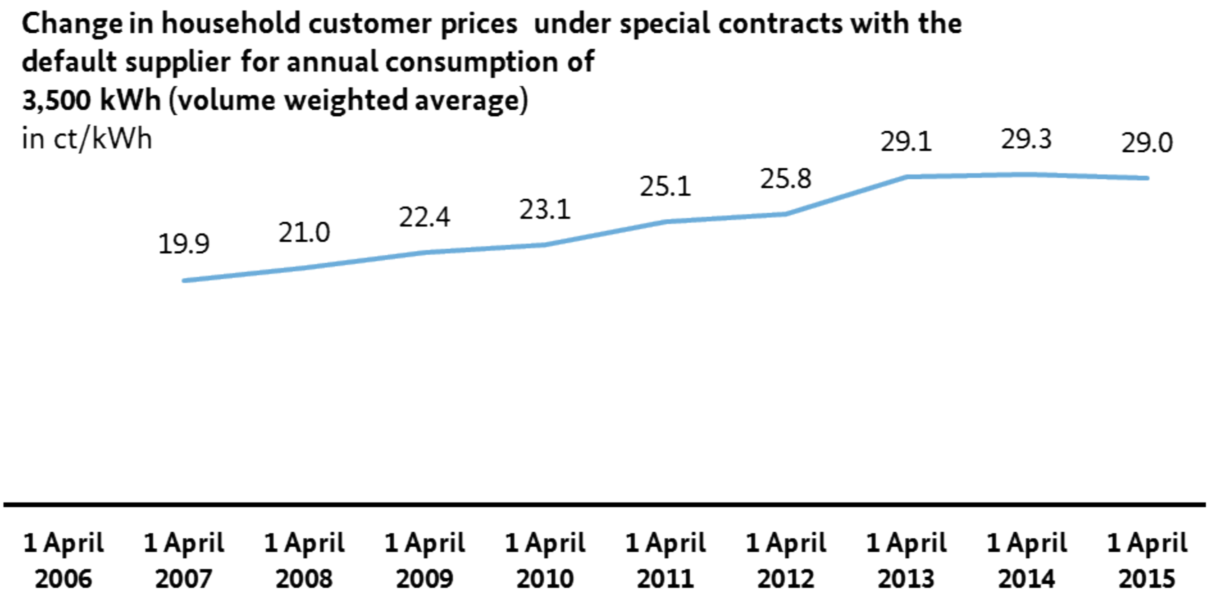

Figure 86: Changes in household customer prices for annual consumption of 3,500 kWh under a special contract with the default supplier from 2007 until 2015 (volume weighted mean)

Some 659 suppliers provided data on tariffs and volumes for the category of contracts that are not concluded with the local default supplier. On the basis of the data submitted, a volume weighted average price of 27.85 ct/kWh incl. VAT was determined as of 1 April 2015.[88] Hence the price for customers whose supplier is not the local default supplier is a good 1.5% or 0.44 ct/kWh less than the prior year's figure. This is also the first price reduction in this category since the start of data collection in 2008. The price has risen over this seven-year period by 6.99 ct/kWh, which represents an increase of 34%. The changes in the volume weighted average prices are illustrated in the following diagram.

[88] The arithmetic mean is about 0.34 ct/kWh above the volume weighted price determined.

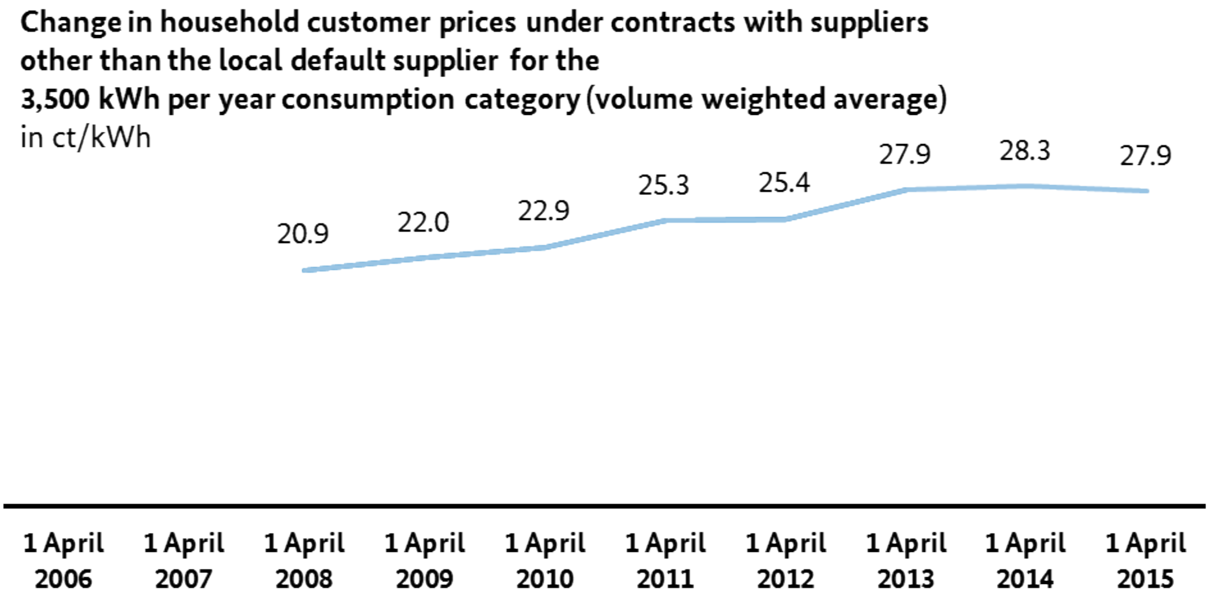

Figure 87: Change in household customer prices for annual consumption of 3,500 kWh under a contract with a supplier who is not the local default supplier from 2008 until 2015 (volume weighted average)

A direct comparison of the three tariff categories of a default supply contract, a special contract with the default supplier and a contract with a supplier other than the local default supplier makes it clear that for the most part and for annual consumption of 3,500 kWh the default supply continues to represent for the most expensive means of obtaining supply. At the same time, direct comparison is only possible to a limited extent as default supply customers have significantly lower annual consumption than special contract customers. While default supply customers consumed an average of 2,210 kWh in 2013, the average consumption of special contract customers with the default supplier and customers of non-default suppliers was about 38% higher at roughly 3,039 kWh.

Household customers can still obtain lower prices through concluding a special contract or switching supplier, although as a rule a switch of supplier represents the more favourable alternative with respect to prices. A comparison of the averages of the three categories since 2008 shows that for annual consumption of 3,500 kWh a default supply contract has constantly been the most expensive electricity category for household customers. Over the same time period, a special contract with the default supplier has been cheaper than the default supply every year. The choice of a supplier other than the local default supplier would likewise on average have been a cheaper alternative over the whole time period than default supply. In seven of the eight years under review, the average price of supply from a non-default supplier was – to a greater or lesser extent – below that of the price of a special contract with a default supplier.

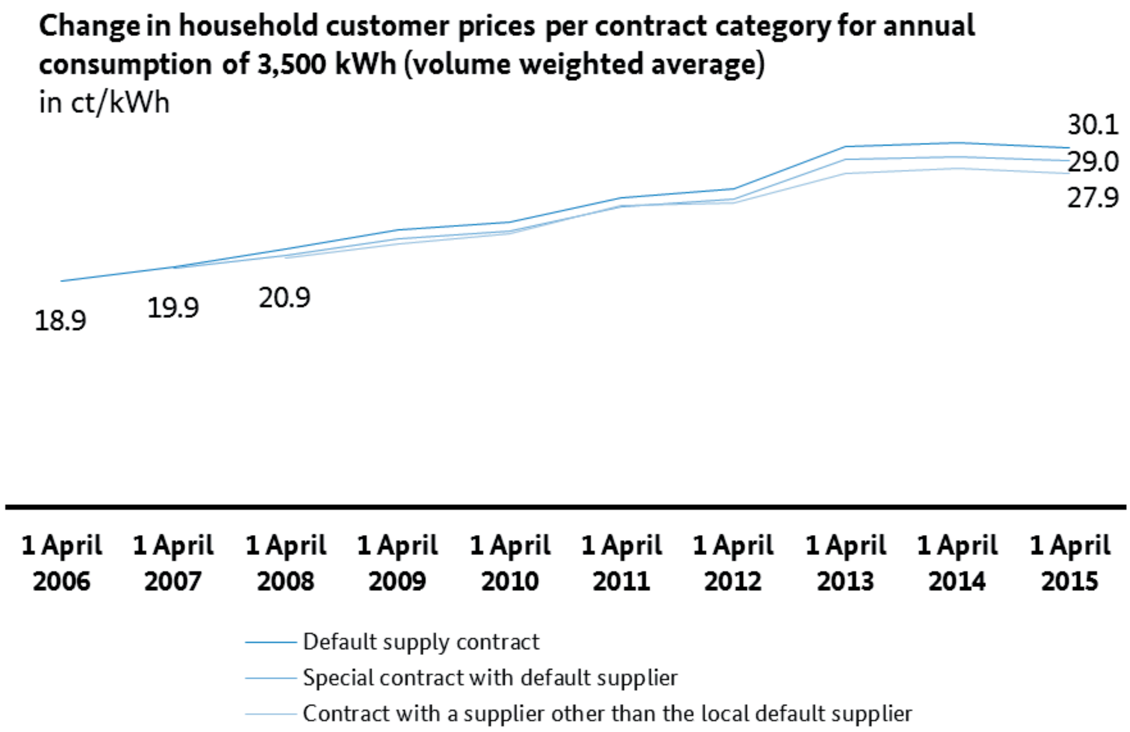

Figure 88: Change in household customer prices per contract category from 2006 to 2015 (volume weighted average price per tariff)

Data was also collected from the default suppliers on household customers with respect to the overall price and the individual price components. As certain price components are set by legislation (surcharges, electricity tax) or are regulated for the network area (net network tariff), a significant variable when comparing the categories of default supply, a special contract with a default supplier and contracts with suppliers other than the local default supplier is the price component that the supplier can control ("energy procurement and supply; other costs and the margin"). The relevant data from suppliers was analysed as follows:

- 660 default supply,
- 633 special contract with the default supplier,
- 659 suppliers other than the local default supplier.

This data has been included in the following diagram.

As of 1 April 2015 the average volume weighted price in the tariff category of suppliers other than the local default supplier was 2.23 ct/kWh, or 7% less than the default supply price. However, if the unweighted average prices were compared, the difference would be only 1.52 ct/kWh or 5%. The difference between default supply and a special contract with the default supplier was 1.12 ct/kWh or 4% (volume weighted). The volume weighted difference between a special contract with the default supplier and a supplier other than the local default supplier amounted to 1.11 ct/kWh or 4%. Again, the price differences between the contract categories are mainly found in the different amounts of the price component controlled by the suppliers (including energy procurement and supply).

In the default supply the price component controlled by the default supplier, including the cost of energy procurement and supply, for annual consumption of 3,500 kWh with a volume-weighted price of 8.41 ct/kWh as of 1 April 2015 was 30% above the volume-weighted average price of 6.51 ct/kWh of suppliers other than the default supplier, which was calculated from the data submissions. In 2014 the difference between the two categories was still only 31%. A volume weighted average of 7.43 ct/kWh (prior year: 7.70 ct/kWh) was determined as the price component for energy procurement, supply, other costs and the margin in special agreements with the local default supplier. This means the relevant price component in the special agreements with the local default supplier category is 12% less than that of the default supply category. In any direct comparison of these figures, other differences between the three customer groups – besides the different consumption figures – must be taken into consideration. For instance, default supply contracts contain shorter notice periods and on average a higher risk of non-payment. As such, these risk costs are also included in the price component controlled by the supplier. Lastly, the inaccuracy associated with the system of data collection and analysis also has to be taken into account. The following figure provides a detailed overview of the trend.

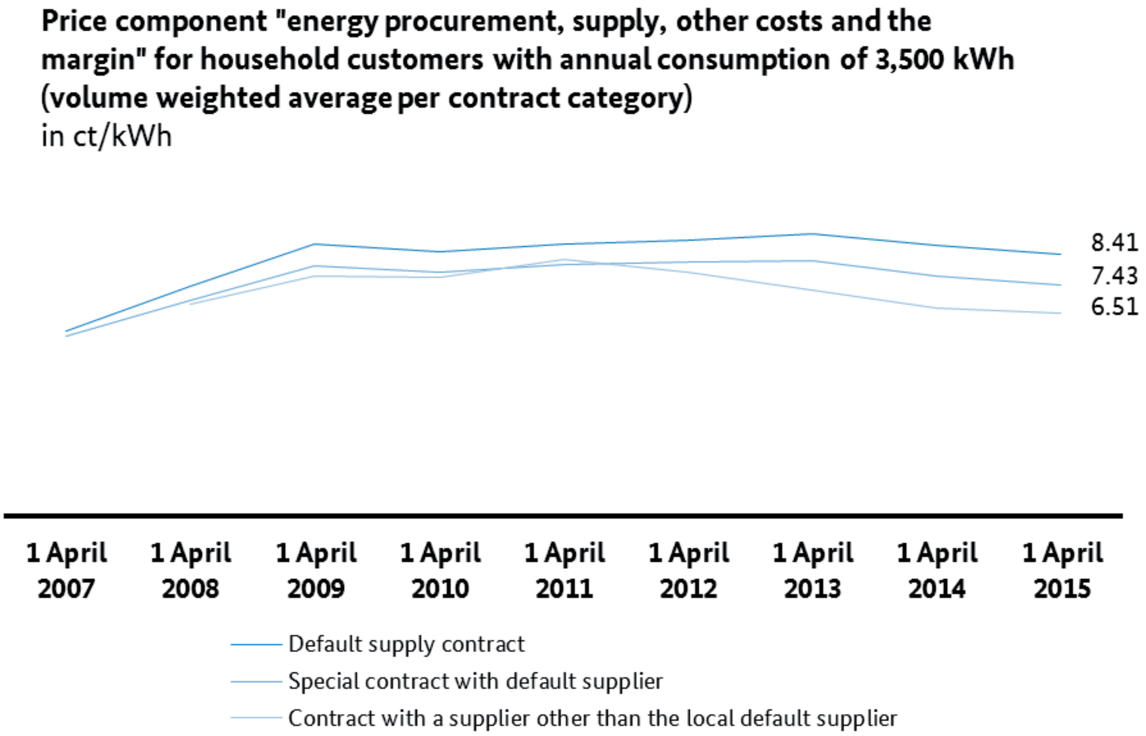

Figure 89: Price component for "energy procurement and supply, other costs and the margin" for household customers with annual consumption of 3,500 kWh from 2007 to 2015 (volume weighted average per contract category)

A comparison of the price component controlled by the supplier ("energy procurement, supply, other costs and the margin") in the three contract categories makes clear that this price component has been falling in the category of suppliers other than the local default supplier since 2011. Once again this year, as in 2013 and 2014, the price components that are controlled by the suppliers were lower in all three contract models.

Electricity prices for household customers comprise the costs of procurement and supply plus network charges, surcharges, taxes and levies. The individual price components in the various contract categories are listed in the table below.

Average retail price for household customers per contract category with annual consumption of 3,500 kWh

Household customers (volume weighted) 1 April 2015 in ct/kWh	Default supply contract	Special contract with the default supplier	Contract with a supplier other than the local default supplier
Net network tariff	5.88	5.97	6.00
Charge for billing	0.32	0.33	0.36
Metering charge	0.08	0.08	0.10
Charge for meter operation	0.23	0.23	0.24
Energy procurement, supply, other costs and the margin	8.41	7.43	6.51
Concession fees	1.68	1.64	1.53
Surcharge under EEG	6.17	6.17	6.17
Surcharge under KWKG	0.25	0.25	0.25
Surcharge under section 19 StromNEV	0.24	0.24	0.24
Offshore liability surcharge	-0.05	-0.05	-0.05
Interruptible loads surcharge	0.01	0.01	0.01
Electricity tax	2.05	2.05	2.05
VAT	4.80	4.62	4.45
Total	30.08	28.96	27.85

Table 52: Average retail price level for household customers with annual consumption of 3,500 kWh by contract category as of 1 April 2015

Besides the total price, special contracts may contain a range of other features that suppliers use to compete for customers. These features may offer greater security to the customer (eg guaranteed stable prices) or to the supplier (eg payment in advance, minimum contract term), which is then compensated for between the parties elsewhere (total price).

The suppliers were questioned separately about any such features. This revealed that a minimum contract term or a price stability guarantee are especially common. On average, special contracts had a minimum term of 11 months. They offered price stability, in general, of more than 15 months.

The following table provides an overview of the various special bonuses and arrangements that are offered by electricity suppliers:

Special bonuses and arrangements for household customers

As of 1 April 2015	Household customers			
	Special contract with the default supplier		Contract with a supplier other than the local default supplier	
	No of tariffs	Average scope	No of tariffs	Average scope
Minimum contract term	351	10 months	408	11 months
Price stability	294	15 months	364	14 months
Advance payment	61	11 months	46	11 months
One-off bonus payment	89	€ 54	156	€ 61
Deposit	6	-	2	-
Other bonuses and special arrangements	96	-	107	-

Table 53: Special bonuses and arrangements for household customers in 2015

The number of the variously combinable elements that form the prices makes it difficult to compare tariffs whose diversity is of relevance to competition. The individual average price for household customers with annual consumption of 3,500 kWh is presented as a key figure in the following. For this purpose a volume weighted average across all tariff categories is calculated by weighting the individual price of each of the three contract categories with their respective volume of electricity sold. As of the key date of 1 April 2015, this calculation resulted in an average price of 29.11 ct/kWh. A detailed breakdown of the individual price components is provided below.

Average volume weighted retail price for household customers with annual consumption of 3,500 kWh across all contract categories

Household customers (volume weighted) 1 April 2015	Volume weighted average across all tariffs in ct/kWh	Percentage of total price
Net network charge	5.94	20.4
Billing charge	0.33	1.1
Metering charge	0.09	0.3
Meter operation charge	0.23	0.8
Energy procurement, supply, other costs and margin	7.57	26.0
Concession fee	1.63	5.6
Surcharge under EEG	6.17	21.2
Surcharge under KWKG	0.25	0.9
Surcharge under section 19 StromNEV	0.24	0.8
Offshore liability surcharge	-0.05	-0.2
Surcharge for interruptible loads	0.01	0.0
Electricity tax	2.05	7.0
VAT	4.65	16.0
Total	29.11	100

Table 54: Average volume weighted retail price level across all contract categories for household customers with annual consumption of 3,500 kWh as of 1 April 2015

A view of the percentage distribution of the individual price components is given in the following illustration.

Breakdown of the retail price for household customers with annual consumption of 3,500 kWh as at 1 April 2015 (across all tariffs volume weighted average)
in %

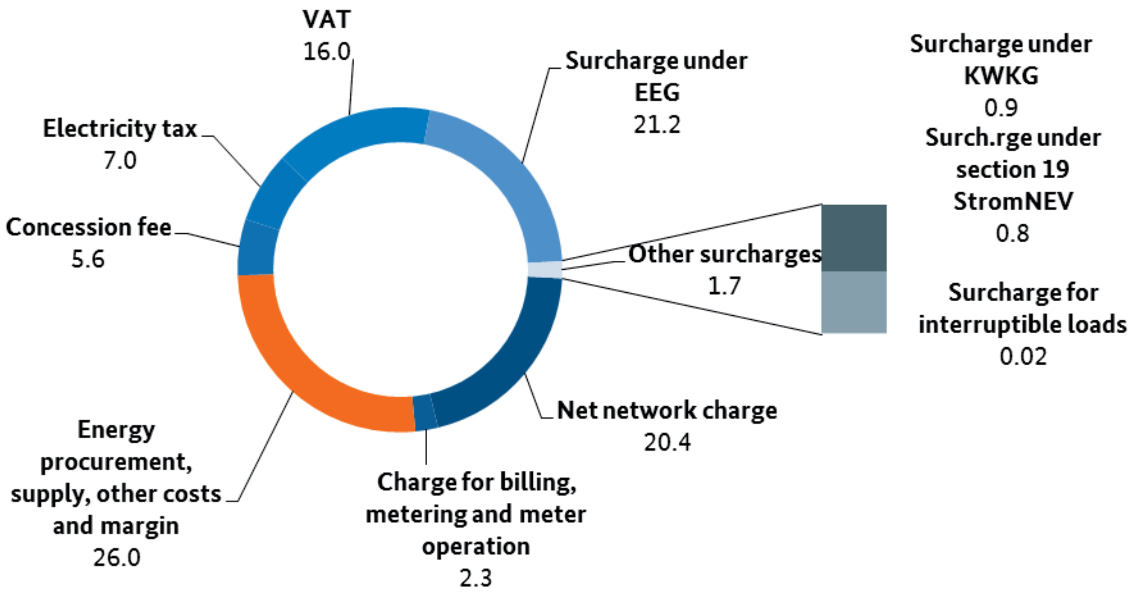

Figure 90: Breakdown of the retail price (volume weighted average across all tariffs) for household customers with annual consumption of 3,500 kWh as of 1 April 2015[89]

The net network charge (excluding VAT) accounts for 20.4% of the total electricity price (including VAT) for household customers. The charges for billing, metering and meter operation account for 2.3% of the total price, while 28% is attributed to the costs of energy procurement and supply. The taxes (electricity and VAT) add up to 23% with total surcharges and levies (surcharges under EEG, KWKG, section 19 StromNEV, concession fees and interruptible loads) amounting to about 28.5%. At 21.2% the EEG surcharge makes up the largest share by far. In total, surcharges, taxes and levies account for more than 51% of the average electricity price for household customers.

The following shows the change in the volume weighted electricity price across all tariffs from 1 April 2014 to 1 April 2015 for the offtake volume of 3,500 kWh per year. This year the price of electricity fell slightly by just over 1.4% (down 0.42 ct/kWh) and thus, for the first time since the start of data collection in 2006, it was nearly half a cent below the 2014 price. This slight reduction in the electricity price arises mainly from a fall of 0.29 ct/kWh in the price component controlled by the supplier. In addition to this, the offshore liability surcharge changed this year. As a result of the forecasts being too high last year, excess surcharges were paid this year of just under €468 million and will be repaid to the A-category[90] final consumers, thereby reducing the electricity price by 0.051 ct/kWh. Consequently, the offshore liability surcharge decreases by about

[89] The orange coloured portion represents the price component controlled by the supplier.

[90] Final consumer group A: final consumer electricity volumes in each case for the first 1,000,000 kWh per offtake point

0.3 ct/kWh in a year-on-year comparison and hence compensates for the rise in other surcharges (section 19 StromNEV and KWKG).

Change in volume weighted price across all contract categories for household customers with annual consumption of 3,500 kWh

	Volume weighted average across all tariffs in ct/kWh	Change relative to the level of the price component	
		in ct/kWh	in %
Net network charge	5.94	0.08	1
Billing charge	0.33	0.00	-1
Metering charge	0.09	-0.01	-9
Meter operation charge	0.23	-0.01	-3
Energy procurement, supply, other costs and margin	7.57	-0.29	-4
Concession fee	1.63	0.03	2
Surcharge under EEG	6.17	-0.07	-1
Surcharge under KWKG	0.25	0.08	43
Surcharge under section 19 StromNEV	0.24	0.15	158
Offshore liability surcharge	-0.05	-0.30	-120
Surcharge for interruptible loads	0.01	0.00	-33
Electricity tax	2.05	0.00	0
Value added tax	4.65	-0.07	-1
Total	29.11	-0.42	-1

Table 55: Change in the volume weighted price level for household customers across all tariffs

Next the change in the essential price components of the volume weighted electricity price for household customers with annual consumption of 3,500 kWh will be presented. In the first instance, the network charges were examined. Following a period in which these network charges[91] fell consistently until 2011, they rose again slightly in 2015 by 0.8% (up 0.05 ct/kWh) compared with the prior year 2014. Over an eight-year reporting period, network charges have risen by 0.25 ct/kWh, or just less than 4%. This examination includes network charges excluding surcharges under section 19 StromNEV of 0.24 ct/kWh.[92]

The billing, metering and meter operations components of the network charge have once again fallen by 0.02 ct/kWh compared with 2014. Since 2009 these price components have fallen by a total of 0.2 ct/kWh. In percentage terms, the charges for billing, metering and meter operation in 2015 accounted for about 10% of the network charges and the net network charge accounted for approximately 90% of the network charges.

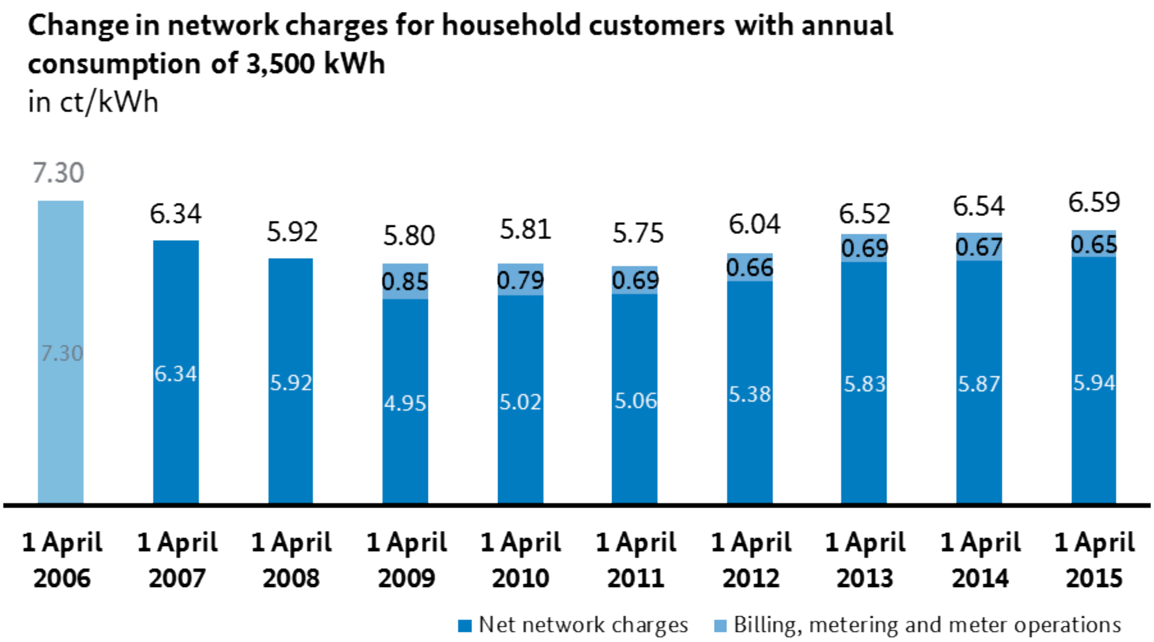

Figure 91: Change in network charges for household customers with annual consumption of 3,500 kWh from 2006[93] to 2015[94]

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[91] Net network charges include charges for billing, metering and meter operations.

[92] The surcharge under section 19 StromNEV was still taken into account in the network charges in 2011 but since 2012 it has been reported separately.

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

[94] The price component "billing metering and meter operation" was not treated as a separate item for data collection in the period 2006 to 2008 and is therefore included in the net network charges.

Finally an overview is given of the change in the remaining price components in the volume weighted household customer price across all tariff categories. The portion of the electricity price attributable to the network charge (including billing, metering and meter operation) has been constantly rising since 2011. Most especially, a clear increase can be noted in taxes and levies during the period 2010 to 2014. These appear to have remained steady this year for the first time and represent a somewhat smaller proportion of the electricity price than in the prior year. The price component for energy procurement, supply, other costs and the margin essentially remained steady in the period 2009 to 2013, whereas a rise had been recorded in the period from 2007 to 2009. In 2014 the price components controlled by the supplier fell markedly by nearly six percentage points. A further decline of nearly 4% (down 0.29 ct/kWh) could also be noted between 1 April 2014 and 1 April 2015. This decline could be caused specifically by the continually falling wholesale prices (see chapter I.F from page 149). These are apparently now having an effect on the household customer prices in all three contract models.

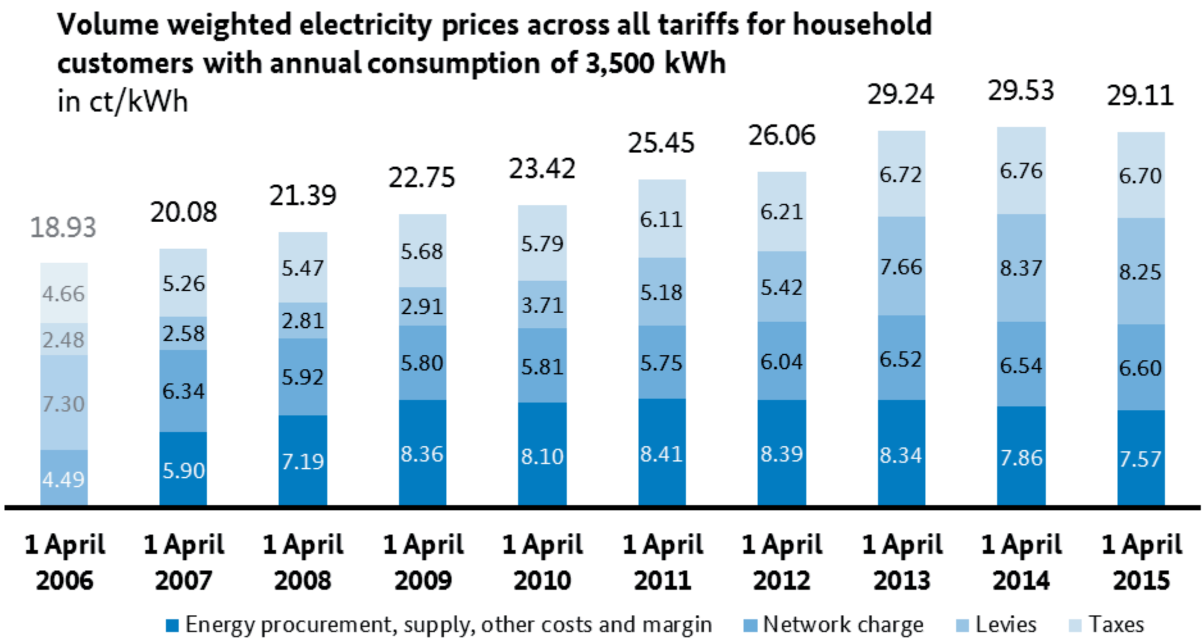

Figure 92: Volume-weighted electricity prices across all tariffs for household customers with annual consumption of 3,500 kWh from 2006[95] to 2015[96]

The EEG surcharges make up a particularly large share of the increase in levies. The EEG surcharge is used to balance out the EEG costs incurred by the TSOs (in particular the remuneration payments to installation operators) and EEG energy sales by TSOs on the spot market. The surcharge level is announced by the TSOs

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

[96] Figures may not sum exactly owing to rounding.

every year on 15 October for the following calendar year. The Bundesnetzagentur monitors the surcharge calculation to ensure it has been properly calculated. The EEG surcharge for 2015 fell to 6.17 ct/kWh. This is due in particular to the fact that as of 30 September 2014 the EEG account reported a surplus of more than €1.3 billion. This was taken into account in the re-calculation and thus resulted in a slight reduction. The disproportionately strong increase in the EEG surcharge in recent years means that it accounts for a constantly growing proportion of the electricity price. For the first time since its introduction, the EEG surcharge went down slightly this year, although the percentage of the total electricity price that it accounted for was still 21%. In 2010 the EEG surcharge was only 2.05 ct/kWh and it accounted for 8.8% of the total price. Details are given of the changes in the EEG surcharge in the following diagram.

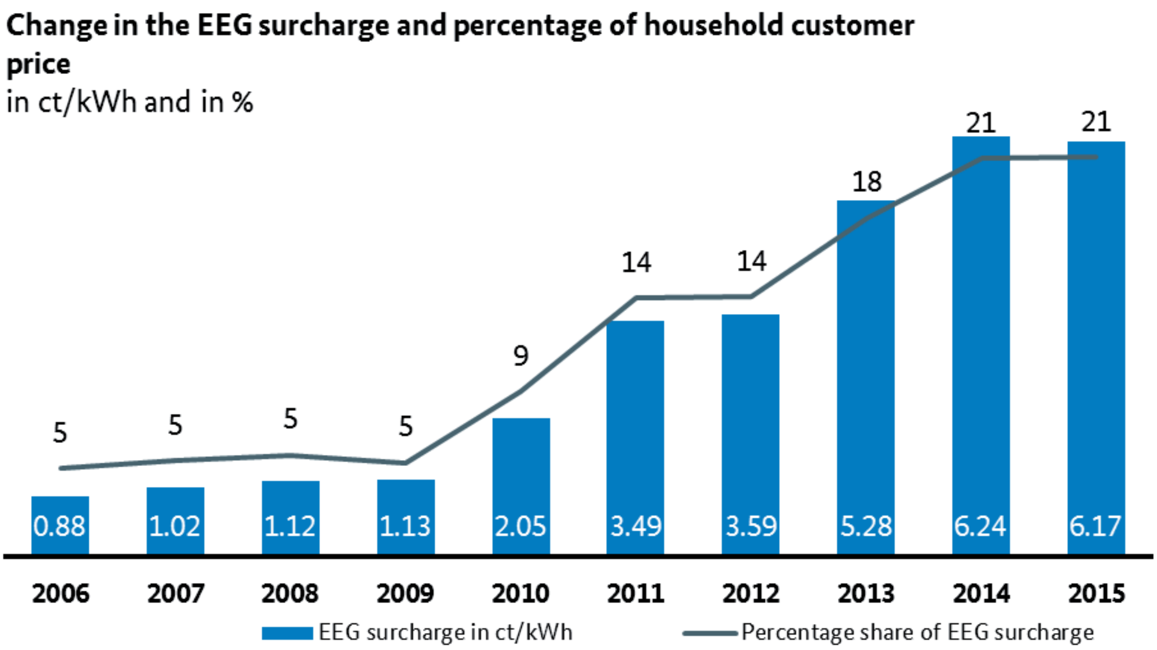

Figure 93: Change in EEG surcharge and percentage of household customer price from 2006 to 2015 (volume weighted averages across all tariffs)

The following illustrates the change in the energy procurement, supply, other costs and margin price component from 2006 to 2015.[97] In the prior year the price component controlled by the supplier was 7.86 ct/kWh and thus 27% of the volume weighted total price, however this year it fell by 0.29 ct/kWh to 7.57 ct/kWh and thus forms 26% of the volume weighted total price for electricity across all tariffs. Hence the percentage of the overall price that is open to influence by the business decisions of the supplier has decreased once again. Due to this, and due to the somewhat lower state-determined price components, electricity prices for household customers have fallen for the first time in all three contract categories this year. The following shows the price component for energy procurement, supply, other costs and the margin from 2006 to 2015.

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[97] A change to the questionnaire sent to the suppliers means that since 2014 the individual price components for energy procurement and supply have not been reported separately.

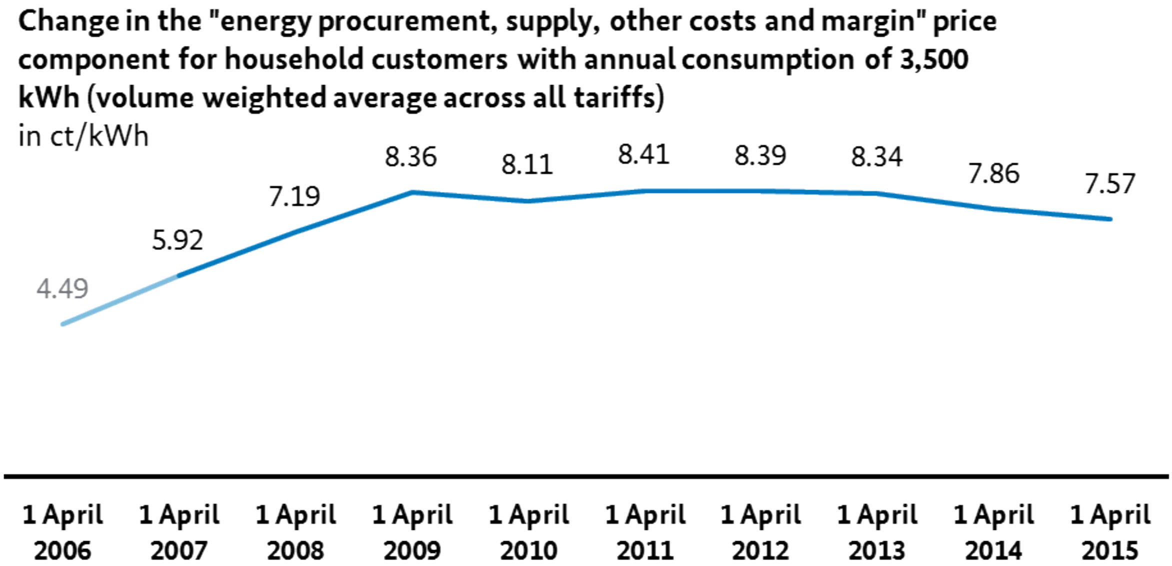

Figure 94: Change in the "energy procurement and supply, other costs and the margin" price component for household customers with annual consumption of 3,500 kWh from 2006[98] to 2015[99] (volume weighted average for all tariffs)

5. Night storage (electricity for heating)

During this year's monitoring data was again collected on contract arrangements, on supplier switching and on the price of electricity for heating purposes (night storage heaters and heat pumps) from both suppliers and distribution system operators.

Due to the mild weather in the 2014 reporting year, consumption of electricity for heating purposes fell noticeably when compared with the prior year. According to the volumes reported by a total of 846 suppliers of electricity for heating purposes, customers were supplied with about 13.6 TWh of electricity at just under 2.1 million meter points during this reporting period. This represents the supply of just under 6,600 kWh per meter point in 2014 on average, whereas in the prior year this figure was just over 7,800 kWh per meter point (15.7 TWh at 2.0 million meter points).

Delivery to night storage heaters accounted for an electricity volume of just under 11.6 TWh according to the data provided by the suppliers. On average, about 6,800 kWh per year are supplied to the 1.7 million night storage meter points. In contrast, the delivery volume for heating pumps was just over 2.0 TWh at about

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

[99] Since 2012 data on energy procurement has been collected from the suppliers. In 2006 to 2011 this was calculated on the basis of data collected on procurement volume and price data from the European Energy Exchange (EEX). As a consequence of changing the data collection method, a comparison with prior years is somewhat limited.

355,000 meter points; this gives rise to an average of about 5,700 kWh per year. Night storage heating accounts for the largest share of consumption (85% of volume and 83% of meter points). Heat pumps, however, continue to play a subordinate role (17% of meter points and 15% of volume). Nearly all suppliers of heating electricity deliver to both customers with night storage heaters and those with heat pumps. Several suppliers have explained that they are not able to provide an exact breakdown of the volumes and meter points attributable specifically to night storage heaters or to heat pumps[100] and therefore have given an estimate of the breakdown or have entered the total for both categories in one category. Some 769 of the 846 electric heating suppliers provided data on volume and meter points for both night storage and heat pumps.

The data received during the monitoring from the DSOs on consumption volumes and the number of meter points roughly corresponds to the findings from the supplier responses. According to the data reported by 722 DSOs, a total of 12.4 TWh was supplied to just under 2.0 million meter points (night storage and heat pumps) in 2014.

5.1 Contract structure and supplier switching

As in previous years, suppliers were asked how their night storage and heat pump electricity supply was distributed across those network areas where they were the default supplier and those where they were not the default supplier. The questionnaire refers to the default supplier status of the legal entity supplying the electricity, hence company affiliations are not taken into account (see in more detail: section I.G.2). Other than in section I.G.2 when analysing the supply of heating electricity by the local default supplier, no distinction is made between the categories of "default supply contract" and "special contract with a default supplier" as in the Federal Cartel Office's view electricity for heating is always supplied under special contracts.[101]

The percentage of night storage and heat pump electricity customers served in 2014 by a legal entity other than the local default supplier was nearly double that of the prior year. In 2014, about 4.3% of electric heating meter points, 72,000 of which were for night storage and 18,000 for heat pumps, were not, or no longer, supplied by the local default supplier. Some 770 GWh, or in other words 5.7% of the entire electric heating supply, was accounted for by suppliers other than the default supplier in 2014. In the prior year this share was still about 2.4% at the meter point or 2.3% as regards volume.

[100] One reason given for this was that, from a sales perspective, there was no (price) difference between night storage and heat pumps.

[101] See Federal Cartel Office, "Heizstrom - Überblick und Verfahren" (Electric heating - overview and proceedings), September 2010, pages 9-10.

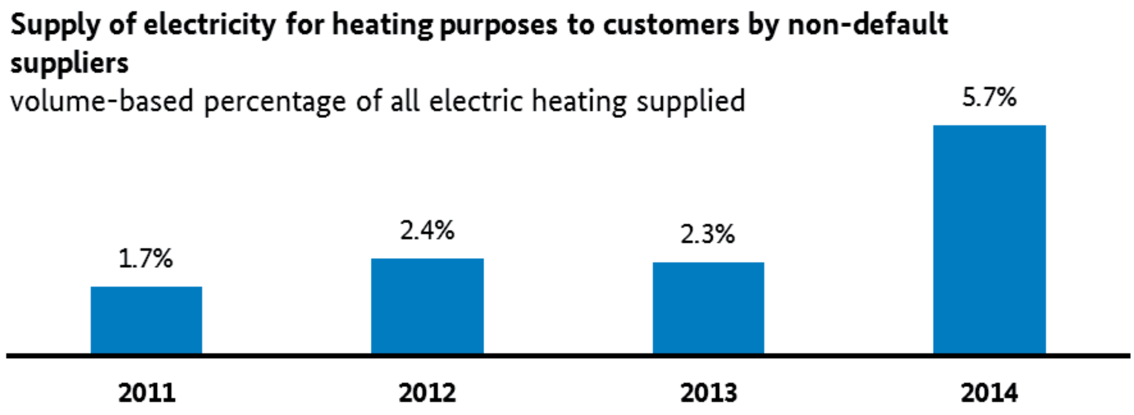

Figure 95: Share of electricity for heating purposes received from a supplier other than the local default supplier

Pursuant to the data provided by the DSOs, the number of supplier switches in the electric heating sector has risen considerably. According to this, supplier switching took place at about 43,000 electric heating meter points (prior year: just under 24,000); in 2014 these meter points accounted for about 290 GWh. This corresponds to a switching rate based on volume of 2.3% and at the meter point of 2.2%. In 2013 the switching rate by meter points was 1.5%; in 2009 it was only 0.5%.

Of the 722 DSOs that provided data on the volume of electricity for heating purposes, 418 also reported supplier switching figures. These 418 DSOs represent about 95% of the electric heating volume and meter points of all 722 DSOs (11.8 TWh and 1.9 million meter points). Of the remaining 304 DSOs, more specifically those DSOs providing data on electric heating volumes but not on switches to electric heating, the majority reported less than 150 electric heating meter points.[102]

The switching rates varied depending on the network area. With respect to the volume-based switch rate per DSO, the middle 80% of the figures, according to size, fell between 0.3% and 6.4% (analysis based on the 418 DSOs).

There was a significant increase in the number of night storage and heat pump electricity customers who switched supplier, which followed many years of hardly any customers switching. The last two years have seen an increase in transparency for end customers and in the services available to these customers from national suppliers (see 2014 Monitoring Report, page 176). Consumers can now find locally available suppliers more easily, for instance by using internet portals, looking in consumer magazines or obtaining information from consumer advice centres. Yet at the same time, the switching rates of night storage and heat pump customers are still far below the switching rates for household electricity and of non-household customers.

[102] Several DSOs also pointed out that as far as they were concerned either no data or only individual data could be analysed in the electric heating sector.

5.2 Price level

In prior years the price question related only to the night storage electricity tariff but this year the monitoring was extended to include the heat pump tariff. The price level was determined as at the key date of 1 April 2015 with the suppliers taking annual consumption of 7,500 kWh as the basis. The following analysis is based on the price data provided by 751 suppliers (prior year: 694) for night storage heating and on price data provided by 719 suppliers for heat pumps.

According to the data provided, the arithmetic mean of the total price for night storage heating with annual consumption of 7,500 kWh as at 1 April 2015 was 20.42 ct/kWh (including VAT), which roughly corresponds to the prior year's level (20.62 ct/kWh). The arithmetic mean of the total price for heat pump electricity was 21.37 ct/kWh (including VAT), which makes it a bare 1 ct/kWh higher than for night storage.

Price level of night storage heating with 7,500 kWh per year as of 1 April 2015

	Spread in the 10-90 percentile range of supplier data sorted by size (in ct/kWh)	**Average** (arithmetic) in ct/kWh	**Percentage of total price**
Price components not controlled by the supplier			
Net network charge	1.50 - 3.40	2.42	12%
Charge for billing, metering and meter operation	0.24 - 0.68	0.45	2%
Concession fee	0.11 - 0.97	0.43	2%
Surcharge under EEG	6.17	6.17	30%
Other surcharges[1]	0.45	0.45	2%
Electricity tax	2.05	2.05	10%
Value added tax	2.89 - 3.68	3.26	16%
Price component controlled by the supplier (residual amount)	3.39 - 7.19	5.19	25%
Total price (incl. VAT)	18.09 - 23.07	20.42	

[1] KWKG (0:254 ct/kWh), section 19(2) StromNEV (0.237 ct/kWh), offshore liability (-0.051 ct/kWh) and interruptible loads (0.006 ct/kWh)

Table 56: Price level for night storage heating with annual consumption of 7,500 GWh as at 1 April 2015

The residual price component controlled by the supplier, which includes the costs of procurement and supply, other costs and the margin, of 5.19 ct/kWh has remained more or less at the prior year's level for night storage heating (prior year: 5.24 ct/kWh). As at 1 April 2012 and 1 April 2013, the price component that is controlled by the supplier still averaged 5.72 ct/kWh and 5.8 ct/kWh, respectively. The price data collected for the first time as at 1 April 2015 on heat pumps was slightly higher at 5.63 kWh than the price for night storage heating. For night storage consumption the price component controlled by the supplier continued to make up only about 25% of the total price including VAT.

About 60% was accounted for by taxes, surcharges and concession fees. Compared with the year before, the sum of all fixed surcharges fell by 0.15 ct/kWh. The Federal Cartel Office considers that in general 0.11 ct/kWh should be attributed to the concession fees as night storage and heat pumps involve special contracts for heating electricity.[103] Nevertheless, during this year's data collection some suppliers gave figures of more than 0.11 ct/kWh. This could be due to issuing a single invoice if standard household electricity and electricity for heating purposes are not recorded on separate meters but might also be as a result of incorrect data entries or assessments.

The average figures collected for network charges and metering for night storage heating correspond roughly to the prior year's figures. Network charges for electric heating supply continue to be less than half the network charges for standard household electricity.

[103] See Federal Cartel Office, "*Heizstrom - Überblick und Verfahren*" (Electric heating - overview and proceedings), September 2010, pages 9-10.

Price level of heat pumps with 7,500 kWh per year as of 1 April 2015

	Spread in the 10-90 percentile range of supplier data sorted by size (in ct/kWh)	**Average** (arithmetic) in ct/kWh	**Percentage of total price**
Price components not controlled by the supplier			
Net network charge	1.50 - 4.43	2.69	13%
Charge for billing, metering and meter operation	0.25 - 0.71	0.45	2%
Concession fees	0.11 - 1.32	0.52	2%
Surcharge under EEG	6.17	6.17	29%
Other surcharges[1]	0.45	0.45	2%
Electricity tax	2.05	2.05	10%
Value added tax	3.00 - 3.88	3.41	16%
Price component controlled by the supplier (residual amount)	3.41 - 7.71	5.63	26%
Total price (incl. VAT)	18.79 - 24.28	21.37	

[1] KWKG (0:254 ct/kWh), section 19(2) StromNEV (0.237 ct/kWh), offshore liability (-0.051 ct/kWh) and interruptible loads (0.006 ct/kWh)

Table 57: Price level for heat pumps with annual consumption of 7,500 GWh as at 1 April 2015

6. Green electricity segment

Information was collected from suppliers during the 2015 monitoring on the volume of green electricity delivered to final customers. Due to an error in the data collection, no data is available on the number of customers supplied or on the volume of green electricity delivered to household customers in 2014. For this reason, the information on prices in this chapter is presented as arithmetical mean values rendering direct comparison with the volume weighted prices of previous monitoring reports infeasible. Therefore the prices as at 1 April 2015 are compared with the arithmetic mean values as at 1 April 2014.

Green electricity delivered to household customers and other final consumers

	Category	Total electricity offtake	Total green electricity supplied	Green electricity volume delivered and meter points (%)
Household customers	TWh	124.1	20.8	16.7
	Number of meter points	43,968,870	7,447,754	17.0
Other final consumers	TWh	331.9	27.5	8.3
	Number of meter points	4,125,176	673,225	16.3
Total	TWh	456.1	48.3	10.6
	Number of meter points	48,093,883	8,120,979	17.0

Table 58: Green electricity delivered to household customers and other final consumers in 2013[104]

The data, tables and diagrams in this report on volumes and meter points reflect the data status of 2013. The data will be included again in the 2016 Monitoring Report and will incorporate a review of the year 2014.

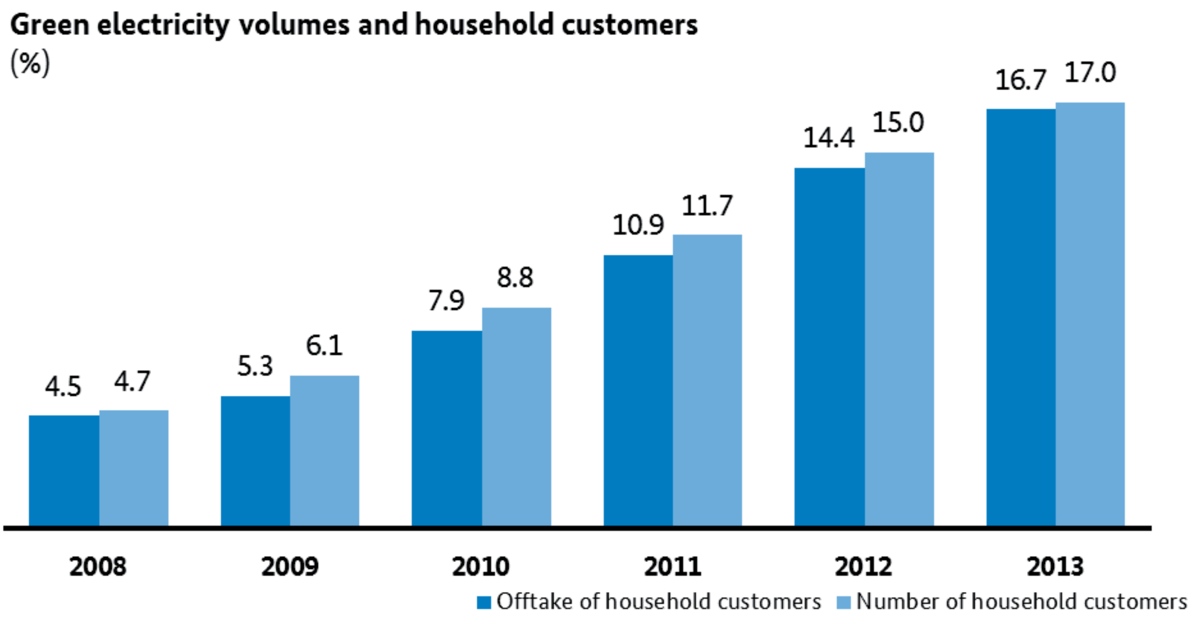

Figure 96: Green electricity volumes and household customers in 2013[105]

[104] Due to an error in the data collection, no data is available on the actual number of customers supplied or on the volume of green electricity delivered to household customers in 2014. The diagram depicts the data from 2013.

[105] Due to an error in the data collection, no data is available on the actual number of customers supplied or on the volume of green electricity delivered to household customers in 2014. The diagram shows the data from 2013.

The following analysis is based on information from 740 companies that have provided data on tariffs as part of the 2015 monitoring. The table shows the green electricity price components for a typical consumption category (household with annual consumption of 3,500 kWh, low voltage supply (0.4 kV)).

Average arithmetically determined retail price level for green electricity for household customers with annual consumption of 3,500 kWh

Household customers (green electricity) 1 April 2014	Arithmetic average in ct/kWh	Percentage of total price (%)
Net network charge	5.89	20.5
Billing charge	0.31	1.1
Metering charge	0.09	0.3
Meter operation charge	0.28	1.0
Energy procurement, supply, other costs and margin	7.45	25.9
Concession fee	1.48	5.1
Surcharge under EEG	6.17	21.5
Surcharge under KWKG	0.25	0.9
Surcharge under section 19 StromNEV	0.24	0.8
Offshore liability surcharge	-0.05	-0.2
Surcharge for interruptible loads	0.01	0.0
Electricity tax	2.05	7.1
Value added tax	4.59	16.0
Total	28.75	100

Table 59: Average arithmetically determined retail price for green electricity for household customers with annual consumption of 3,500 kWh

Based on a table of individual price components, an arithmetically determined total price was arrived at for household customers in Germany with annual consumption of 3,500 kWh of 28.75 ct/kWh. This means the price for green electricity was 0.42 ct/kWh or 1.5% less that the prior year's arithmetically determined total price (29.18 ct/kWh).[106] Thus a trend towards lower prices was also noted when purchasing green electricity, the same as it has been noted for the three different contracts models for purchasing conventional electricity.

A breakdown of the individual price components by percentage results in the following diagram.

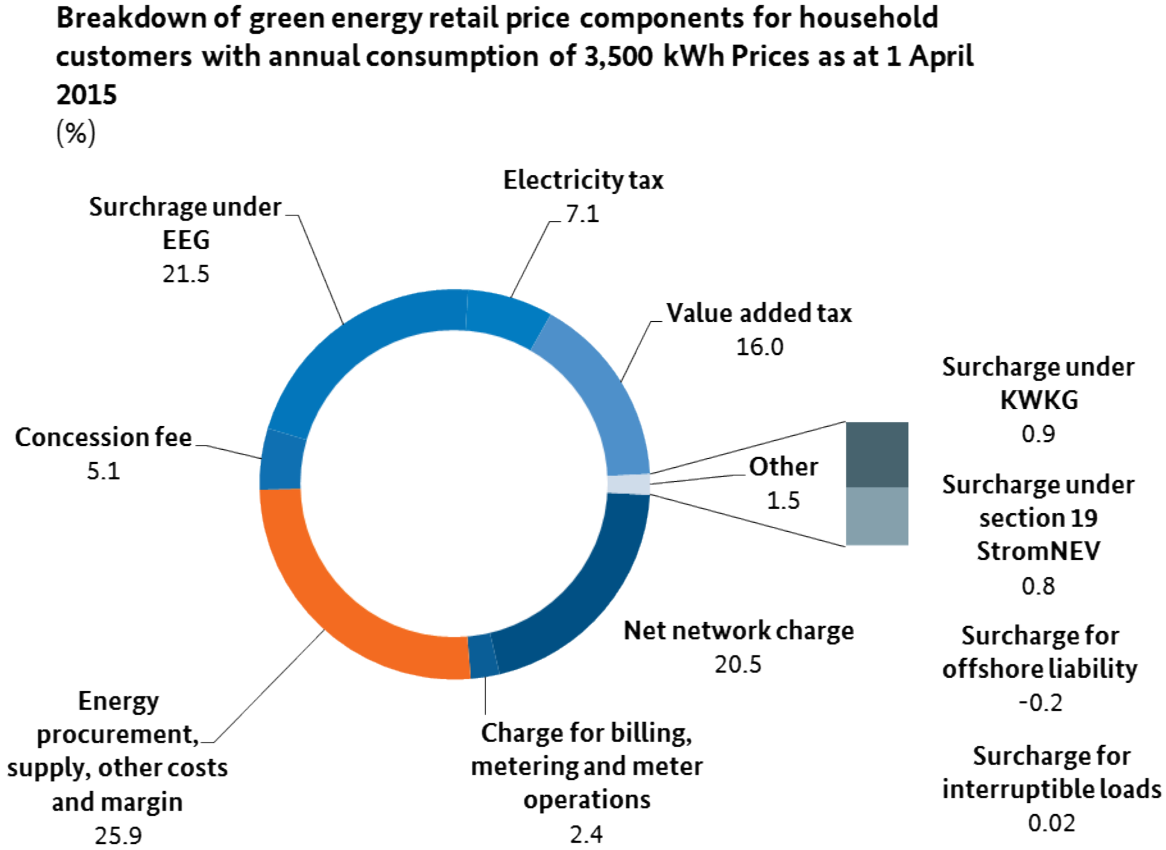

Figure 97: Breakdown of green energy retail price components for household customers with annual consumption of 3,500 kWh

[106] An ex post calculation of the arithmetic mean from 2014 due to a lack of data on volumes of green electricity in 2015.

The biggest retail price component is the item energy procurement and supply, other costs and margin accounting for about 26% of the total price. If the arithmetic means of 2014 and 2015 were taken into consideration for this price component, this would give rise to a slight decrease from 7.72 ct/kWh on 1 April 2014 to 7.45 ct/kWh on 1 April 2015. This corresponds to a reduction in the price component of 0.28 ct/kWh or nearly 4%.

As with conventional electricity, green electricity suppliers have introduced a range of special bonuses and schemes for household customers that could result in lower prices. These most frequently comprise minimum contract periods or fixed prices for a set period of time. With respect to the prior year, the number of tariffs with a minimum contract period, fixed price and one-off bonus payment has increased by more than 10%. Pre-paid tariffs or those with a deposit remained at a similar low level this year and report an increase of four and two suppliers, respectively.

Special bonuses and arrangements as of 1 April 2015

	Household customers (green electricity)	
	Number of tariffs	**Average scope**
Minimum contract term	406	10 months
Price stability	329	14 months
Advance payment	45	11 months
One-off bonus payment	117	€ 53
Deposit	4	-
Other bonuses and special arrangements	105	-

Table 60: Special bonuses and schemes for household customers (green electricity) in 2015

7. Comparison of European electricity prices

Eurostat, the statistical office of the European Union, publishes final consumer electricity prices every six months that show the average payments by household customers and non-household customers in the individual EU Member States. The figures published include for each consumer groups (i) the price including all taxes, levies and surcharges, (ii) the price without any recoverable taxes, levies and surcharges ("net price") and (iii) the price without taxes, levies and surcharges ("price excluding taxes and levies"). Furthermore, Eurostat publishes a breakdown every six months of the prices, adjusted for taxes and duties, relating to network charges and to the residual amount that is controlled by the supplier ("energy and supply"), which includes the costs of electricity procurement and supply, other costs and the margin. Eurostat does not collect the data itself but receives the data from the national data offices. Rules on the classification, analysis and presentation of the price data aim to establish a basis of comparison throughout Europe.[107] Nonetheless, the

[107] For more details see: http://ec.europa.eu/eurostat/web/energy/methodology/prices

choice of methodology to be applied by the Member States in collecting the data (see Directive 2008/91/EC, Annex Ih) is left open, as a result national differences arise. For instance the German price data is based on the 2014 prices reported by 24 industrial suppliers and 28 domestic suppliers.[108]

7.1 Non-household customers

For non-household customers Eurostat publishes price statistics for seven different consumer groups that differ according to annual consumption ("consumption bands"). As an example of these consumption bands, the annual consumption category of "between 20 GWh and 70 GWh" is presented below. The 24 GWh per year consumption level, for which specific price data is collected as part of the monitoring (see chapter I.G.4.1), falls under this consumption cateogry.

Customers with annual consumption of 20-70 GWh are mainly industrial customers. Industrial customers can deduct the national value added tax on a regular basis, so the total price has been adjusted for VAT to enable comparison of the total price across Europe. In addition to VAT, there are other taxes, levies and surcharges due in part to specific national circumstances, which can be recovered by industrial customers and which, as per VAT, have also been deducted from the gross price in accordance with the Eurostat classification. For German industrial customers, in particular, any such possible reductions are a determining factor in the individual net electricity price incurred (for more details refer to chapter I.G.4.1).

According to the Eurostat data there are considerable differences in the price of electricity for industrial customers. Cyprus reports the highest net price at 16.33 ct/kWh, whilst Sweden reports the lowest at 5.33 ct/kWh. The European averages is 9.37 ct/kWh. Of this, 2.13 ct/kWh is attributed to non-reimbursable taxes, levies and surcharges with 7.24 ct/kWh attributed to network charges and the residual amount controlled by the supplier ("energy and supply").

The price adjusted for taxes and levies in Germany of 6.27 ct/kWh is markedly below (about 1 ct/kWh) the European average. The price adjusted for taxes and levies in Great Britain of 11.76 ct/kWh is nearly double that of Germany. The figure of 6.27 ct/kWh comprises 1.68 ct/kWh network charges and 4.59 ct/kWh "energy and supply". The "energy and supply" price component is nearly exactly the same as the figure determined during the monitoring for the consumption level of 24 GWh per year as at 1 April 2014 (see 2014 Monitoring Report, page 154).

Whether German industrial customers in the 20-70 GWh per year consumption band pay a net price that is higher or lower than the European average depends crucially on the specific amount of the non-reimbursable surcharges, taxes and levies. In the relevant consumption band this amount can vary between 0.63 ct/kWh and 8.60 ct/kWh (see 2014 Monitoring Report, page 155). To state the actual net price in the relevant consumption band by means of a random data selection, numerous assumptions must be made about the use made on average of any possible reductions. In the documentation published by Eurostat, however, the pertinent assumptions for the German industrial customer price have not been listed.[109] The figure given for Germany in the 20-70 GWh per year consumption band for the average amount of non-reimbursable

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[108] See Eurostat, Electricity Prices – Price Systems 2014, S. 21 http://ec.europa.eu/eurostat/documents/38154/42201/Electricity-prices-Price-systems-2014.pdf; accessed 14 September 2015.

[109] See Eurostat, Electricity Prices – Price Systems 2014, pages 19-22.

surcharges, taxes and levies is 4.90 ct/kWh. This results in a net price for Germany of 11.17 ct/kWh, which is higher than the European average (9.37 ct/kWh). The amount of non-reimbursable taxes, levies and surcharges given for Germany (4.90 ct/kWh) is more than double the European average (2.13 ct/kWh).

Figure 98: Comparison of European electricity prices in the second six months of 2014 for non-household customers with annual consumption of between 20 GWh and 70 GWh

7.2 Household customers

Eurostat takes five different consumption bands into consideration when comparing household customer prices. The consumption amounts of German household customers can be attributed mainly to the middle category with annual consumption of between 2,500 kWh and 5,000 kWh. The 3,500 kWh per year consumption level, for which specific price data is collected as part of the monitoring (see chapter I.G.4.2), falls under this consumption band. Accordingly, a European comparison of the middle consumption band is presented below. As a rule, household customers cannot claim reimbursement of any of the surcharges, taxes and levies incurred, hence the total price including VAT is relevant for these customers.

There are big differences throughout Europe in the price of electricity for household customers. At 29.74 ct/kWh Germany reports the second highest price of the 28 EU Member States. German prices are about 45% higher than the European average (20.52 ct/kWh). Only in Denmark were household customer prices higher still than those in Germany. The figure given for Germany corresponds roughly to the average price determined during the monitoring of 29.53f ct/kWh as at 1 April 2014 (see 2014 Monitoring Report, page 170).

The high price in Germany compared with the other Member States is due to a higher proportion of surcharges, taxes and levies. On a European average, 6.55 ct/kWh are attributed to surcharges, taxes and levies, whereas these are more than twice as much in Germany at 15.34 ct/kWh. In contrast, the price of 14.40 ct/kWh adjusted for all taxes, surcharges and levies lies within the European average (EU average: 13.97 ct/kWh).

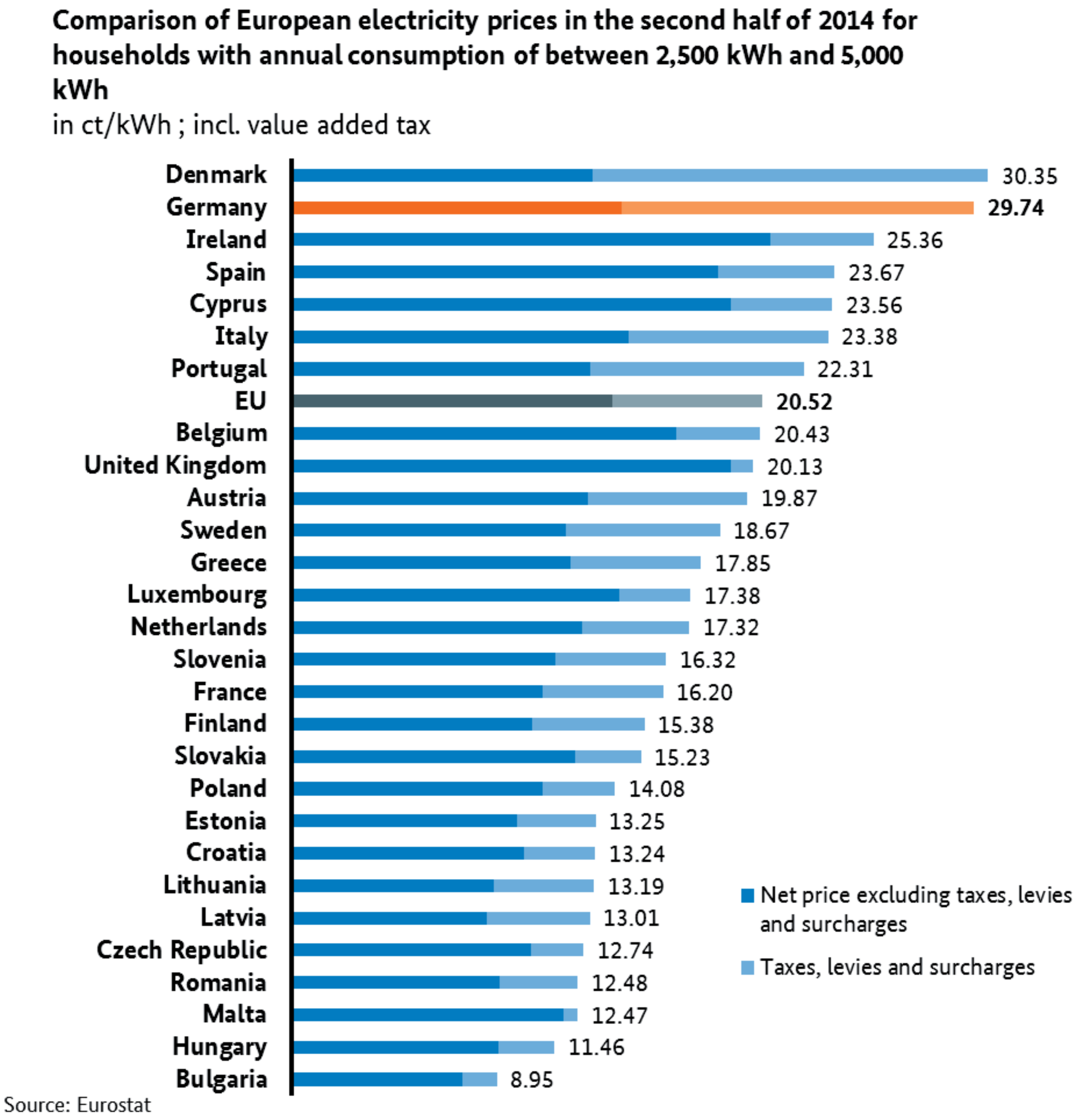

Figure 99: Comparison of European electricity prices in the second six months of 2014 for household customers with annual consumption of between 2,500 kWh and 5,000 kWh

H Metering

1. The network operator as the default meter operator and independent meter operators

The 2015 monitoring questionnaire collected 770 responses from network operators, suppliers and independent meter operators.

Following the liberalisation of metering, the companies providing metering services can be categorised as follows:

Meter operators

	2014	2013
Default DSO	680	598
Non-default DSO	34	109
of which exclusively	10	
Suppliers	40	20
of which suppliers that are also independent meter operators	4	3
Meter operators independent of DSOs and suppliers	14	22

Table 61: Meter operators

Independent meter operators also provide metering services in the network areas of some 738 distribution network operators, which leads to the following distribution breakdown irrespective of the network size.

Distribution networks by number of independent meter operators

	Number of independent meter operators					
	up to 5	up to 10	up to 20	up to 30	up to 40	more than 40
Number of networks	265	245	178	32	14	4

Table 62: Breakdown of distribution networks by number of independent meter operators

Irrespective of the network size, the average number of independent meter operators working in the distribution network is nine per distribution network area. The highest number is 92 independent meter operators.

Independent meter operators cover 203,703 meter points in the distribution networks, which equates to a share of 0.4% of the total number of meter points in these networks. The following table provides a breakdown of the meter points operated by independent meter operators in relation to all the meter points in the network area. Of particular note is the picture that arises of a very uniform distribution with only a few outliers.

Share of independent meter operators in the distribution network areas

	Percentage of meter points with independent meter operators in relation to all meter points in the network area					
	up to 1%	up to 5%	up to 10%	up to 15%	up to 20%	more than 20%
Number of networks	677	24	7	1	0	5

Table 63: Share of independent meter operators in the distribution network areas

2. Requirements under section 21b ff EnWG

The EnWG provides for the obligatory installation of intelligent metering systems if specific requirements have been met and it is technically feasible. The number of meter points that fall under section 21c EnWG requirement a) has risen by about 30,000 meter points compared with the previous year (up 8%). The number of meter points that meet requirement b) have fallen by nearly the same number (down 1%). The meter points under c) have risen compared with the prior year[110] by about 20,000 meter points, which represents an increase of approximately 14%. The following table shows the meter points that meet the requirements in each case:

[110] The number of meter points requiring smart meters under c) "Operators of new installations with an installed capacity exceeding 7 kW as regulated under the EEG or the KWKG" for the 2013 reporting year has been subsequently corrected to 147,503.

Obligatory installation of smart meters under section 21c EnWG

Requirement	Meters
a) Buildings that have been newly connected to the energy supply network or have undergone major refurbishment	385,775
b) Final customers with annual consumption of more than 6,000 kWh	4,505,664
c) Operators of new installations with installed capacity exceeding 7 kW as regulated under the EEG or KWKG	167,971

Table 64: Metering points requiring smart meters under section 21c EnWG

3. Meter technology for household customers

Meter technology employed for SLP customers

Requirement	Meters 2014	Meters 2013
a) Electro-mechanical meters (AC and DC meters following the Ferraris principle)	45,064,524	44,516,072
of which twin tariff or multiple tariff meters (Ferraris principle)	2,986,830	2,923,912
b) electronic meter (basic meter not connected to communications network)	4,219,719	3,595,451
c) electronic metering system (whose basic meter can communicate remotely but does not meet the criteria of section 21i ff EnWG)	507,349	435,281
d) Metering system corresponding to sections 21d, 21e EnWG	149,563	79,940

Table 65: Meter technology employed for standard load profile (SLP) customers

The distribution of meter technology across the household customer segment (SLP customers) is roughly the same as that of the prior year. For the most part, the majority of meters in use are still Ferraris meters, which are found at about 45 million meter points. Even the use of two-tariff and multiple-tariff meters has remained practically unchanged from the prior year's level at 3 million meter points, equating to a share of about 7%. The technical requirement for remote communication connection to allow remote meter readings has been complied with at 507,349 meter points with electronic metering systems that do not meet the criteria of section 21i ff EnWG and at 149,563 meter points where the metering systems do meet the criteria of sections 21d and 21e EnWG. In total, this involves 656,912 meter points in the SLP segment. The following diagram shows the number and breakdown of transmission technologies used for the 325,940 meter points that are read remotely:

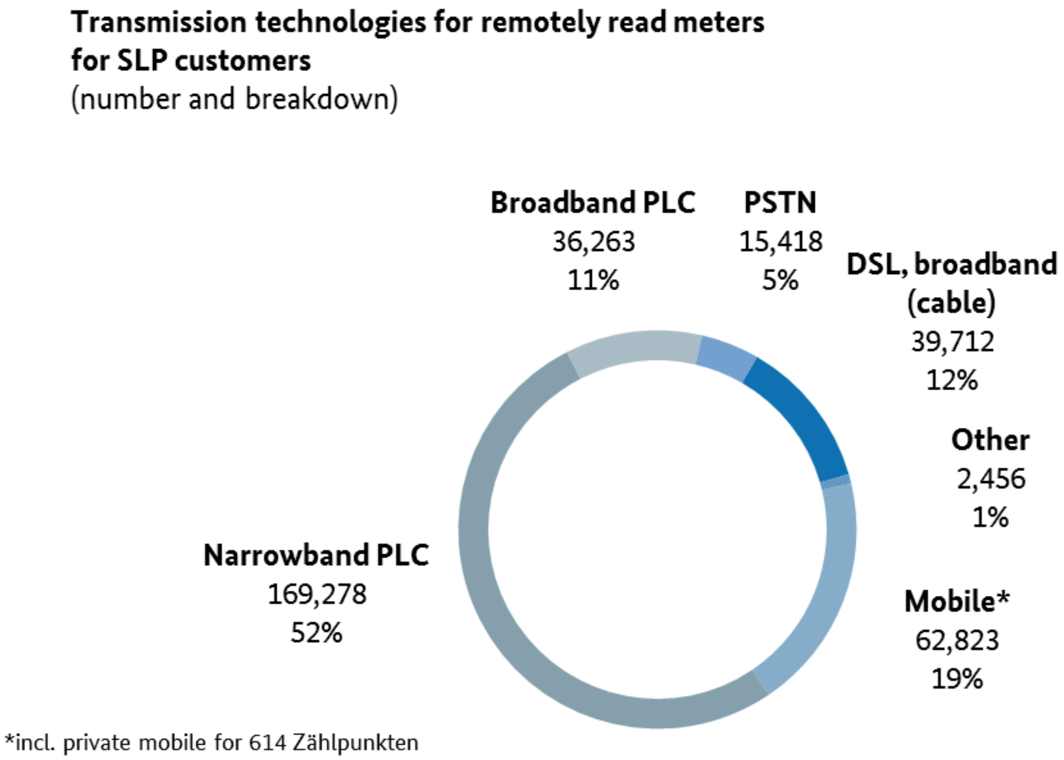

Figure 100: Transmission technologies for remotely read meters for SLP customers

The percentage of transmissions via power line communication (PLC) has grown strongest since the prior year (more than 38%). This is mainly attributable to the rise in narrowband transmission. Moreover, PLC transmission technology is being used in nearly two-thirds of all cases. Similarly, a rise has been noted in the share (29%) of connections via telephone lines (PSTN), whereas the share of other transmission technologies employed has fallen. Both DSL and broadband transmission, as well as mobile transmission (GSM, GPRS, UMTS, LTE), have fallen proportionately by between 35% and 40%.

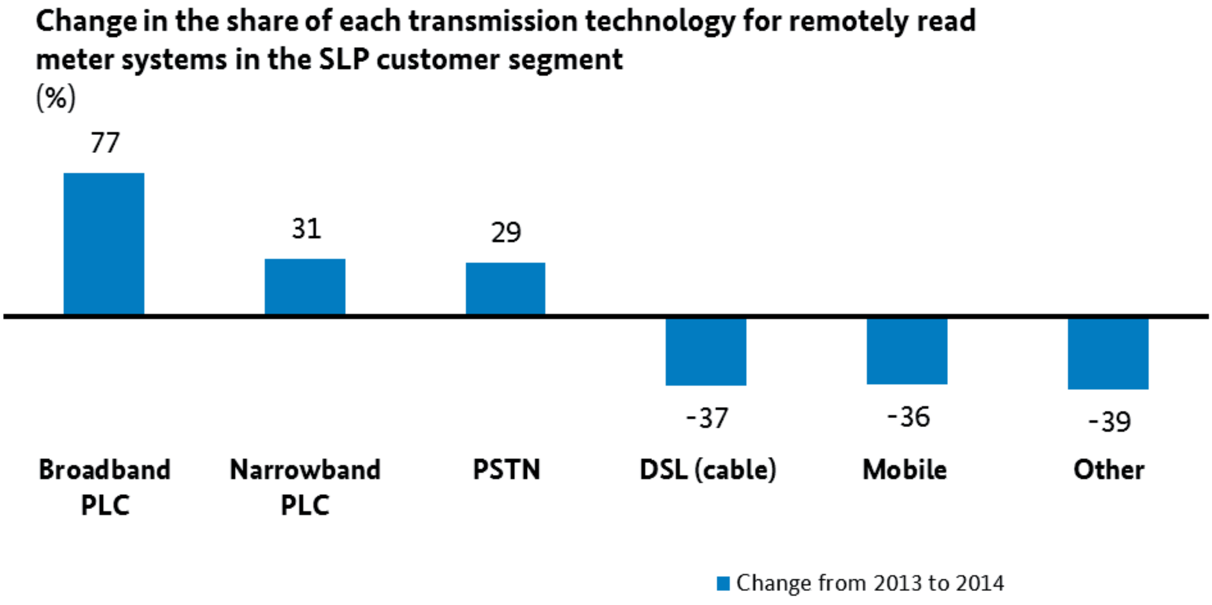

Figure 101: Change in the percentage of transmission technology used for remotely read metering systems for SLP customers compared with the prior year

This change in the SLP sector is a continuation of the changes in the prior year. While the number of metering systems that transmit via the electricity network is growing unabated, the number of meters using mobile transmission is falling.

4. Meter technology used for interval-metered customers

The number of meter points for interval-metered industrial and business customers has reached 406,423. A breakdown (see Figure 100) of the transmission technologies used to read data remotely at 397,113 meter points for interval-metered customers has been given above.

Meter technology employed for interval-metered customers

Requirement	Meters 2014
Meter installations for interval-metered customers	406,423
Metering systems complying with sections 21d and 21e EnWG	45,159
Other	21,199

Table 66: Meter technology employed for interval-metered customers

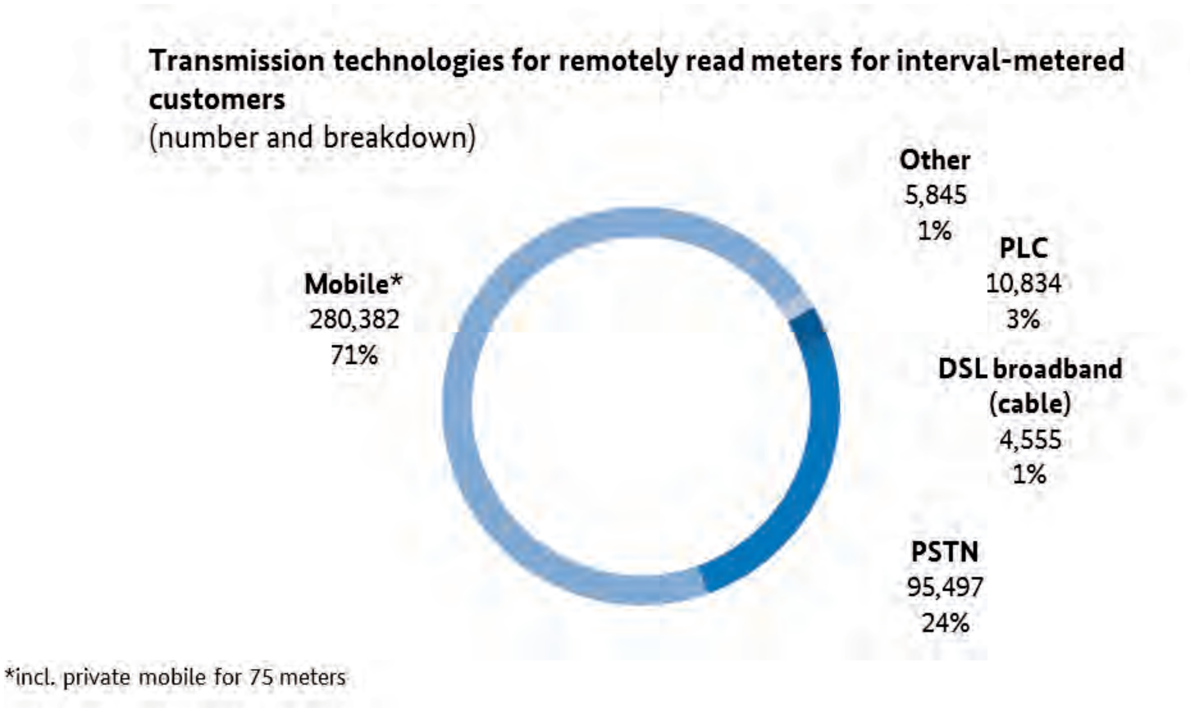

Figure 102: Transmission technologies for interval-metered customers

Changes from the prior year are only found in the single digit percentage range for all transmission technologies. Moreover, as can be seen in the diagram above, apart from mobile (GSM, GPRS, UMTS, LTE) and telephone (PSTN) transmission, the use of other transmission technologies is insignificant.

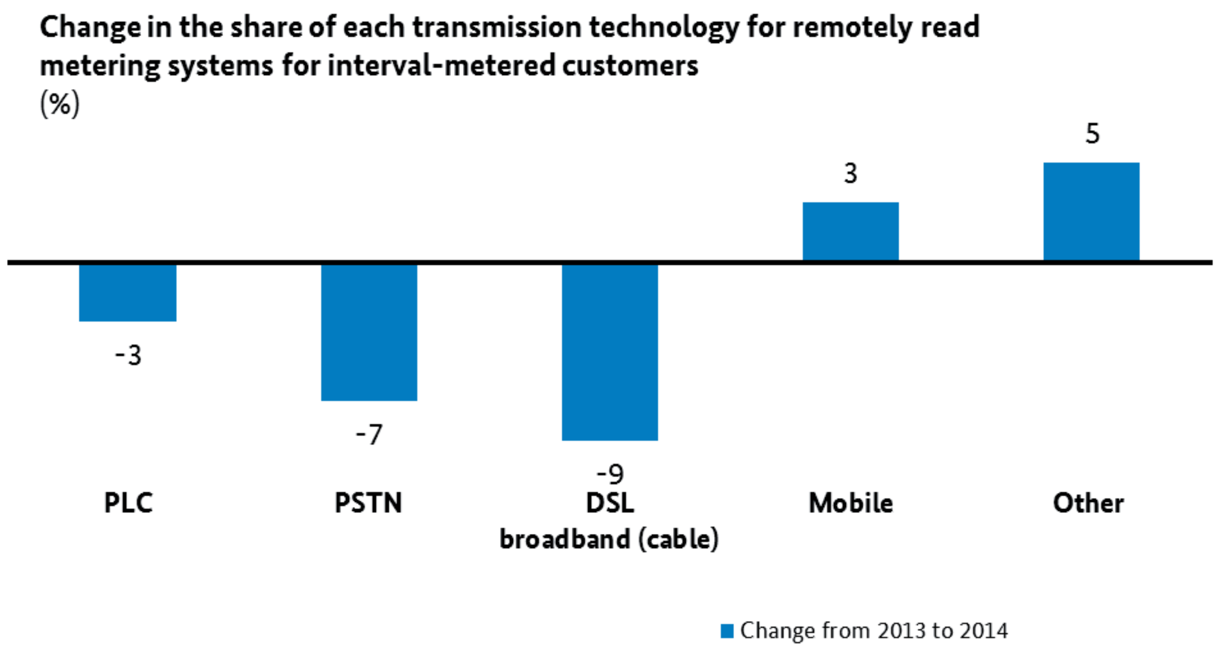

Figure 103: Change in the transmission technologies used for remotely read metering systems for interval-metered customers compared with the prior year

Other than for the SLP segment, the interval-metered segment shows the main change to be transmission via mobile communication. At the same time as telephone line transmission is falling, mobile transmission of meter data is growing at a similar rate. Nearly three-quarters of remote read meters now communicate by mobile transmission.

This difference may be explained primarily by the typical voltage level at which the meter is connected to the network. Whilst a low-voltage supply is common for SLP customers, commercial and industrial interval-metered customers are usually connected to a medium-high voltage system or higher. However, less effort is needed for low voltage data transmission than for a higher voltage level. In addition, there is little data transmission without a repeater, meaning that a dense network with many meters (that can also work as repeaters) is a pre-condition for PLC use. This is more a given for household customers in the network area rather than for industrial or commercial customers.

A second reason for the difference between SLP and interval-metered customers is the cost aspect. Data transfer via power lines incurs fewer costs by far than mobile data transmission, which means that this can create a barrier to using the latter for household customers.

5. Metering investment and expenditure

Total investment in metering has remained ready when compared with the previous year. Expenditure has risen slightly. A comparison of budget figures for 2014 from the last monitoring report with actual figures from this year's monitoring report shows a significant deviation in investment in new installations, development and expansion, which is down about 36%. For investment in maintenance and replacement the corrected figure is still down 17%. The planned expenditure, however, was practically equal to actual expenditure as here the amount only deviates by 2%.

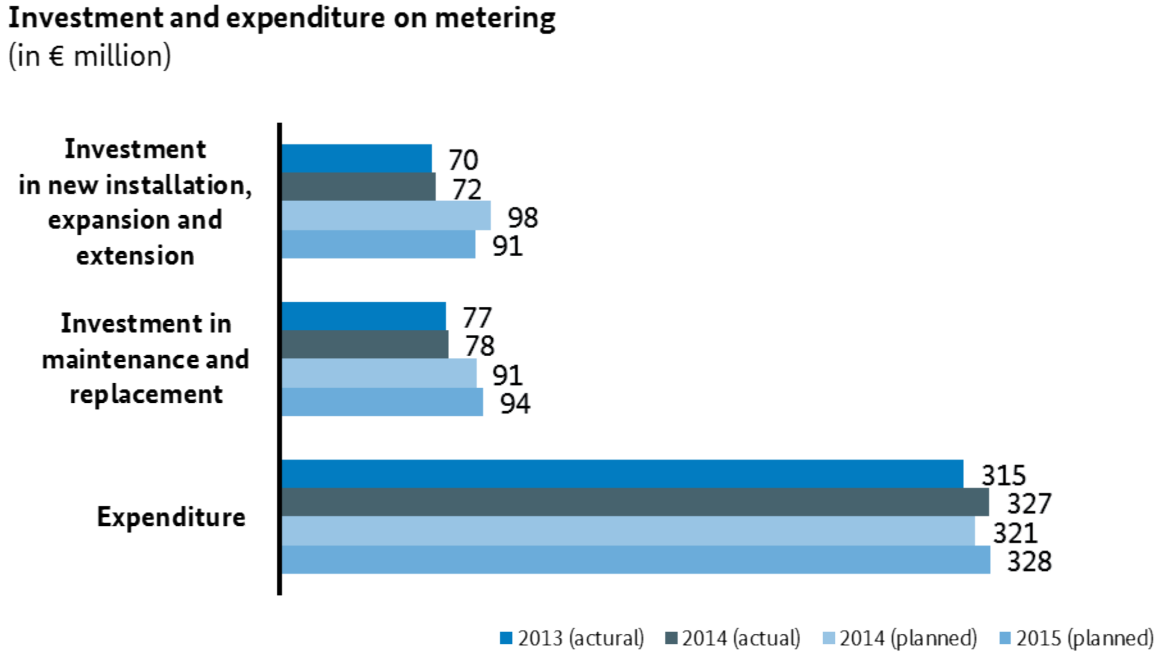

Figure 104: Investment and expenditure for metering

When compared with the DSOs' total investment volume, expenditure behaviour is revealed as the opposite of that of investment behaviour. For metering, the actual investments in 2014 are far below the figures planned for 2014, whereas the total investments planned by the DSOs for 2014 have been met comfortably. With respect to expenditure, too, there is a distinct difference between expenditure for metering and the DSOs' total expenditure. Whilst the planned and actual investments for 2014 are practically equivalent, the DSOs' total expenditure has been more than exceeded.

Also when comparing the change in the planning data there are differences both in investments and in expenditure. Whereas overall the DSOs plan a sharp rise in the investment volume and also to increase the planned expenditure when compared with 2014, the figures for metering remain relatively constant in both areas.

II Gas market

A Developments in the gas markets

1. Summary

1.1 Gas production, imports/exports and storage facilities

In 2014, the year under review, natural gas production in Germany fell by 0.59bn m³ to 9.1bn m³. This corresponds to a decline of 6.1% compared to the previous year. The steady decline in natural gas reserves and in production is chiefly due to the increasing decline of existing deposits. The reserves-to-production ratio for proven and probable natural gas reserves, calculated as the ratio of the previous year's production volume and reserves, was 8.8 years as of 1 January 2015; this represents a decrease of almost one year compared to 2013.

The volume of gas imported into Germany increased by some 16.5 TWh (0.9%) from 1,771.7 TWh (in 2013) to 1,788.2 TWh. The major sources of gas imports remain Russia / CIS States together with Norway and the Netherlands.

Gas exports have also risen: from 725.8 TWh in 2013 to 852.9 TWh in 2014 (a rise of 17.5%). The main recipients of Germany's exports were the Czech Republic, Switzerland, Austria and France. Exports to the Czech Republic have increased significantly.

On 23 October 2014, there was an explosion during construction work at the Erdgasleitung Rhein-Main (ERM - Rhine-Main natural gas pipeline) in Ludwigshafen-Oppau. The pipeline had to be temporarily taken out of service. The comparatively very long interruption duration of 35 hours quite substantially influences the SAIDI value for 2014. Excluding this accident, the SAIDI value is 1.3 minutes and is in line with the long-term average for gas supply interruptions. The SAIDI value including the accident at the ERM pipeline is 16.8 minutes; it does not, however, reflect an overall weakening of the security of supply in Germany. Thus, without taking the accident into account, the level of gas supply reliability is 99.999%. Taking the accident into account this figure is 99.996%.

The maximum usable working gas volume in underground storage totalled 25.68bn Nm³ on 31 December 2014. Of this, 13.30bn Nm³ was stored in cavern storage and 12.38bn Nm³ in pore storage facilities. There was another slight decrease in the volume of working gas available for short-term booking (up to 1 October 2015), and the capacities bookable from 2016/2017 also decreased slightly. The working gas volume available for long-term booking increased again compared to previous years.

The total level of natural gas at German storage facilities is currently low compared to previous years. According to statements made by traders, this can be mainly attributed to the present situation on the market that expects high levels of imports from Russia in the upcoming winter. The Bundesnetzagentur is confident that all market participants strive to maintain the present very high level of supply security on the gas market.

The level of concentration in the market for the operation of underground natural gas storage facilities is relatively high. This concentration - after a fall in previous years - has risen in the year under review. The cumulative market share of the three companies with the largest storage capacities was around 75% on 31 December 2014, a 7% CR3 increase compared to the previous year.

1.2 Networks

The gas network development plan (Gas NDP) 2014 was submitted to the Bundesnetzagentur by the gas transmission system operators (gas TSOs) within the specified deadline on 1 April 2014. Taking the results of the consultation into account, the Bundesnetzagentur addressed a written modification request to the TSOs on 17 November 2014. In its decision, the Bundesnetzagentur required the TSOs to take out five of the 56 proposed network expansion measures from the Gas NDP 2014. The Gas NDP 2014 was published on the website of the gas TSOs on 28 January 2015.

The gas TSOs submitted the latest applicable Gas NDP 2015 to the Bundesnetzagentur on 1 April 2015. Essentially, the measures made binding by the Bundesnetzagentur for the Gas NDP 2014 are continued in the results of the Gas NDP 2015. Additionally, a total of 37 new expansion measures are considered as necessary by 2025. A larger share of these measures (27 new measures) is made necessary by the market area conversion and the resulting higher demand for H-gas. The document was put out to public consultation by the Bundesnetzagentur from 14 April to 5 June 2015. On 1 September 2015, the Bundesnetzagentur addressed to the TSOs a request for modification of the Gas NDP 2015 which took the results of the consultation into account. Two unspecific measures concerning market area conversion from gas TSOs Open Grid Europe (OGE) and Thyssengas were not confirmed. One measure submitted by Gasunie Deutschland (GUD) was amended.

Based on the Bundesnetzagentur's calculations, the approved measures amount to 810 km in new lines and an increase of 393 MW in compressor power in the next ten years. The volume of investment that arises from the in total 84 measures is €3.3bn over the next ten years. After the modification request has been issued, the gas TSOs are obliged to implement the requested changes within three months as per section 15a(3) fifth sentence of the Energy Act (EnWG). The gas network development plan 2015 has become binding on the gas TSOs with the modification request.

The net network charge for a household customer with a standard consumption of 23,269 kWh has remained at a consistent level for several years now. On 1 April 2015 the net network charge for such a customer stood at 1.4 ct/kWh. Over the past years, the share that network charges (excluding VAT) constitute in the overall gas price for household customers (including VAT) has remained almost the same at around 20%.

The total quantity of gas provided from general supply networks in 2014 decreased by 127 TWh, or 13.7%, compared to the previous year. Especially in the first half of 2014, significantly warmer temperatures caused gas supplies to household customers, in particular, to go down by just over 20% to 224.2 TWh. The quantity of gas delivered to gas-fired power plants is still in decline. In 2014, the year-on-year decrease was just over 10 TWh or 12%.

A look at the number of meter points served by the distribution system operators (DSOs) shows that only 25 out of a total number of 714 DSOs supply more than 100,000 meter points each. These 25 DSOs accounted for 43% (276 TWh) of the total quantity of gas supplied by all DSOs.

1.3 Wholesale

Liquid wholesale markets are vital to ensure well-functioning markets along the entire value-added chain in the natural gas sector, from the procurement of natural gas all the way to supplying final customers. Liquid wholesale markets facilitate market entry and foster the competition for final consumers.

There was a further increase in the liquidity of the wholesale natural gas markets in Germany in 2014. There has been significant growth in bilateral wholesale trading. In 2014, natural gas trading transactions brokered on broker platforms with Germany as a supply area totalled 3,000 TWh. This corresponds to an increase of 15%. On-exchange gas trading volumes have even more than doubled. The Bundeskartellamt holds the view that a nationwide wholesale market has developed and no longer applies its definition of these markets by network or market area. Foreign gas producers now trade at the German virtual trading points directly, while gas transmission companies have gradually relinquished their special status in the past years.

2014, the year under review, was marked by significantly lower wholesale gas prices. The daily reference prices calculated by EEX fell by around 22% (annual average) and the average cross-border price calculated by BAFA (Federal Office for Economic Affairs and Export Control) dropped by 15%. This drop in price is generally attributed to the drop in German and European gas consumption. The changes in the BAFA cross-border price over the course of 2014 clearly show its conformity to exchange prices for natural gas and confirm that the significance of oil prices for pricing continued to decrease.

1.4 Retail

The trend of customers switching from their local default supplier to a supplier operating in more than one region has strengthened. The share of household customers supplied under a special contract with a supplier other than the local default supplier is now 18.8% after increasing by 5%. Default supply is of only minor significance for non-household customers. Around 67% of the total quantity of gas supplied to interval metered customers in 2014 was supplied on the basis of a contract with a legal entity other than the local default supplier.

The volume-based supplier switching rate for business and industrial customers in 2014 was around 12%. There was a strong rise in the switching rates among non-household customers between 2006 and 2010. Since then the switching rate has remained more or less constant. The number of household customers switching supplier when moving home increased by almost 10% in 2014. Around 1m household customers, or 8.4% of all household customers, switched their gas supplier. This corresponds to the figures for 2013.

The Bundeskartellamt believes that no single gas supplier holds a dominant position anymore on either one of the largest retail markets. The cumulative share of the three strongest suppliers in the national market for supplying interval-metered customers with gas was 32%, and was 22% in the national market for supplying special contract customers without load metering (in particular household customers). These values are clearly below the statutory thresholds for the presumption of a market-dominating position.

One indicator of a greater degree of choice for gas customers is the number of gas suppliers available per network area. In 2014, the trend towards more diversity has strengthened. That year, customers were able to choose among more than 50 gas suppliers in almost 74% of the network areas (without taking corporate groups into account). Already more than 100 gas suppliers are active in over 22% of the network areas.

Consumer prices paid by customers other than household customers fell again. This is due to a further decrease in the price component that can be influenced by the supplier (procurement and supply, other costs and the margin). At 3.5 ct/kWh (excluding VAT) on 1 April 2015, the average gas price for customers with an annual consumption of 116 GWh ("industrial customers") was at the lowest level since price surveys were introduced (on 1 April 2008).

The volume-weighted prices decreased slightly in all three contract categories, ie "standard contract with default supplier", "special contract with default supplier" and "contract with a supplier that is not the local default supplier". The volume-weighted price for household customers with a standard contract with their default supplier fell from 7.20 ct/kWh to 7.11 ct/kWh (including VAT) compared to 1 April 2014. This corresponds to a 1% price drop. The average price for customers served by a supplier other than their default supplier decreased from 6.39 ct/kWh to 6.12 ct/kWh. A look at the development of the price component for energy procurement and supply, other costs and the margin shows that a downward trend has emerged by now in all three contract categories.

A comparison with the gas prices across Europe shows that household customers and non-household customers in Germany continue to pay average prices.

The number of gas supply disconnections actually carried out on account of an unpaid bill roughly corresponds to the previous year's amount.

2. Market overview

All 17 German gas TSOs took part in the Bundesnetzagentur's 2015 monitoring survey. As the table below shows, the total length of the gas transmission network was 37,580 km on 31 December 2014. The number of final customer meter points in the transmission network was 571. The total quantity of gas supplied from the gas TSOs' network (as of 31 December 2014) was 165 TWh and thus around 24 TWh or 12.7% less than in 2013.

As of 13 July 2015, a total of 714 DSOs were registered with the Bundesnetzagentur, 670 of whom took part in the 2015 monitoring survey. As of 31 December 2014, the total length of pipelines in the gas distribution network was 481,103 km. There were 13.8m final customer meter points in the gas distribution network of the surveyed DSOs, including around 12.5m meter points of household customers as defined by section 3 para 22 EnWG. Total gas supplies from the network of these DSOs amounted to 636.3 TWh in 2014, down by 103 TWh or just under 14% compared to the previous year. Of this, 224 TWh were consumed by household customers as defined by section 3 para 22 EnWG.

Number of gas network operators in Germany

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
TSOs	5	20	18	18	18	14	17	17	17	17[1]
DSOs	734	697	686	712	712	711	739	724	714	714
of which DSOs with fewer than 100,000 connected customers	708	668	659	667	671	678	683	686	689	689

[1] In its ruling of 20 October 2015 (file ref. BK7-15-091), Ruling chamber 7 has revoked Gasunie Ostseeanbindungsleitung GmbH's (GOAL) certification as a transport network operator and its designation as a transport network operator, effective 1 January 2015, as GOAL ceased to exist after its merger forming Gasunie Germany Transport Services GmbH (GUD) and as GUD has claimed succession.

Table 67: Number of gas network operators in Germany

Network operators were asked to state the total length of their pipeline networks and the length of pipelines according to pressure range (nominal test pressure in bar). The findings were as follows:

Network structure figures 2014

	TSO	DSO	Total
Network operators (number)	17[1]	670	687
Pressure range (km)	37,580	481,103	518,683
of which ≤ 0.1 bar	0	157,287	157,287
of which > 0.1 – 1 bar	1	231,602	231,603
of which > 1 bar	37,579	92,214	129,793
Final customers (meter points)	571	13,836,686	13,837,257
of which industrial and business customers and other non-household customers	507	1,323,387	1,323,894
of which household customers	0	12,511,854	12,511,854
of which gas-fired power plants	64	1,445	1,509

[1] In its ruling of 20 October 2015 (file ref. BK7-15-091), Ruling chamber 7 has revoked Gasunie Ostseeanbindungsleitung GmbH's (GOAL) certification as a transport network operator and its designation as a transport network operator, effective 1 January 2015, as GOAL ceased to exist after its merger forming Gasunie Germany Transport Services GmbH (GUD) and as GUD has claimed succession.

Table 68: Network structure figures 2014

The majority of gas DSOs (589 operators or 89%) have networks with a short to medium length up to 1,000 km. 75 DSOs have networks with a total length exceeding 1,000 km. The following figure shows a breakdown of DSOs according to network length:

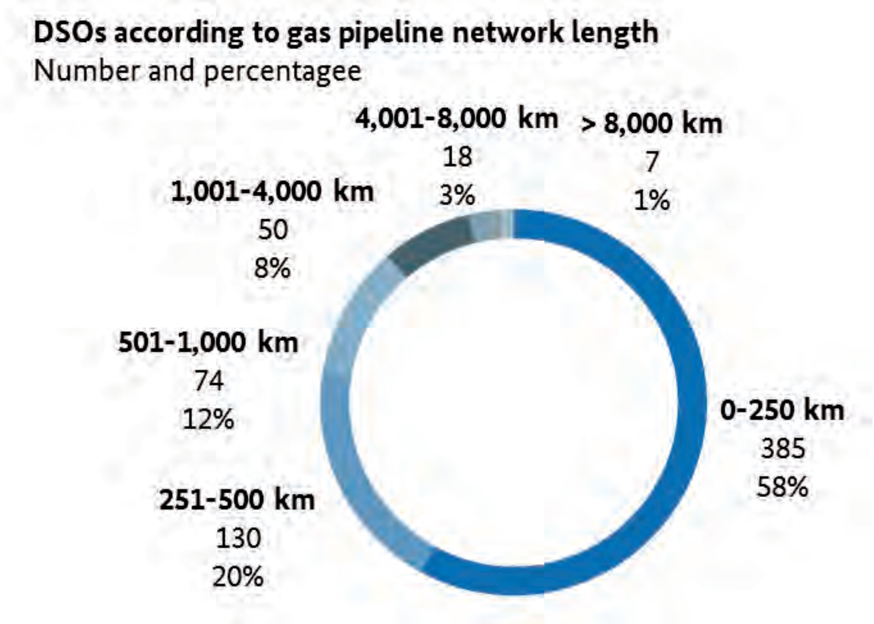

Figure 105: DSOs according to gas pipeline network length as stated in the DSO survey

The table below shows a breakdown of the quantity of gas provided to final customers in the network areas of the surveyed TSOs and DSOs in 2014.

Quantity of gas supplied in 2014 according to category of final consumer, as stated in the TSO and DSO survey

Category	Quantity supplied by TSOs and DSOs (TWh)	Share of total (%)	Quantity supplied by TSOs and DSOs (TWh)	Share of total (%)
≤ 300 MWh/Jahr	0.003	0.0%	284.0	44.6%
> 300 MWh/Jahr ≤ 10.000 MWh/Jahr	0.6	0.4%	108.1	17.0%
> 10.000 MWh/Jahr ≤ 100.000 MWh/Jahr	6.6	4.0%	82.2	12.9%
> 100.000 MWh/Jahr	126.1	76.4%	115.6	18.2%
Gas-fired power plants	31.7	19.2%	46.4	7.3%
Total	165.0	100%	636.3	100%

Table 69: Quantity of gas supplied by TSOs and DSOs broken down by category of final consumer, as stated in the TSO and DSO survey

The following consolidated overview of the total quantity of gas provided by TSOs and DSOs and the quantity that suppliers sold to final consumers shows differences between the two values. One explanation for this difference is the gas suppliers' somewhat smaller market coverage. This difference can further be explained by the fact that the largest consumers of gas (industrial customers and gas-fired power plants) are supplied in individual cases "through virtual trading points", while the monitoring survey refers to the sale of gas to final customers "at meter points".

Total quantity of gas provided in 2014 according to TSO and DSO survey and quantity sold according to supplier survey, broken down by final consumer category

	Quantity supplied by TSOs and DSOs (TWh)	Percentage	Quantity sold by suppliers (TWh)	Percentage
≤ 300 MWh/year	284.0	35.4%	277.3	39.0%
> 300 MWh/year ≤ 10,000 MWh/year	108.7	13.6%	100.3	14.1%
> 10,000 MWh/year ≤ 100,000 MWh/year	88.8	11.1%	78.7	11.1%
> 100,000 MWh/year	241.8	30.2%	202.3	28.4%
Gas-fired power plants	78.1	9.7%	52.7	7.4%
Total	801.3	100%	711.4	100%

Table 70: Total quantity of gas provided by TSOs and DSOs and quantity sold by gas suppliers, broken down by final consumer category

In 2014, the total quantity of gas provided from general supply networks decreased by 127 TWh, or 13.7%, compared to the previous year. Significantly warmer temperatures especially in the first half of 2014 caused gas consumption by household customers (as defined by section 3 para 22 EnWG) to go down by just over 20% to 224.2 TWh. The quantity of gas supplied to gas-fired power stations also decreased in 2014, dropping by just over 10 TWh or around 12% compared with the previous year.

The structure of the gas retail market remained for the most part unchanged. There is a total of 5,937 entry points to the gas distribution networks, of which 209 entry points are for emergency entry only.

A look at the number of meter points served by the DSOs shows that only 25 DSOs supply more than 100,000 meter points each. Out of a total of 13.8m meter points supplied by the DSOs in Germany, some 45% (6.3m), accounting for 43% (276 TWh) of the total gas supplies, are served by DSOs that supply more than 100,000 meter points. The majority (57%) of DSOs active in Germany supply between 1,000 and 10,000 gas customers.

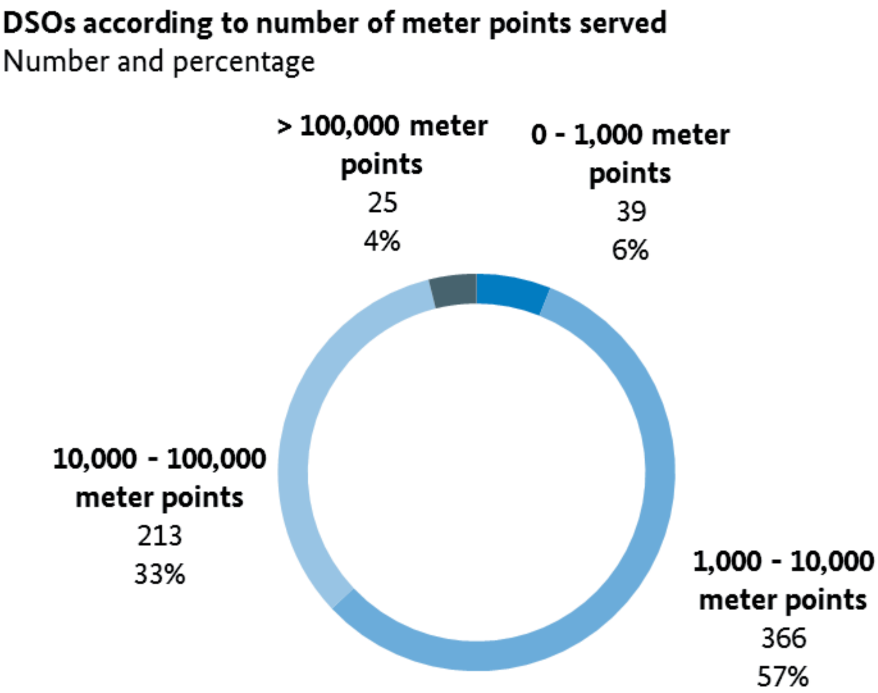

Figure 106: DSOs according to number of meter points supplied (data from the gas DSO survey)

3. Market concentration

The degree of market concentration is a good indicator of the intensity of competition. Market shares are a useful reference point for estimating market power because they represent (for the period of reference) the extent to which demand in the relevant market was actually satisfied by one company[111]. The following methods are typically used to represent the market share distribution, i.e. the market concentration: The Herfindahl-Hirschman Index or the sum of the market shares of the three, four or five competitors with the largest market shares (so-called "concentration ratios", CR3 - CR4 - CR5). The larger the market share covered by only a few competitors, the higher the market concentration.

The following text explains the CR3 values (i.e. the sum of the market shares of the three strongest suppliers) for the market for natural gas storage facilities and for the two largest natural gas retail markets. Due to the actual market structure in the sectors of natural gas storage facilities and natural gas retail, the CR3 value is more relevant here than CR4 or CR5.

3.1 Natural gas storage facilities

In its decision-making practice the Bundeskartellamt defines a relevant product market for the operation of underground gas storage facilities which include both porous rock and cavern storage facilities. In geographic terms the Bundeskartellamt has defined this market as a national market. It has also considered including the

[111] Cf. Bundeskartellamt, Guidance on substantive merger control, para. 25.

"Haidach“ and "7Fields“ storage facilities located in Austria.[112] These two storage facilities located near the Austrian-German border are connected directly or indirectly to the German gas networks. The European Commission also recently considered this alternative market definition as well as some further alternatives - and ultimately left open the exact market definition.[113] For the purposes of illustrating the concentration in the market for the operation of underground natural gas storage facilities, the Haidach and 7Fields storage facilities in Austria will be included in the following assessment. The Bundeskartellamt assesses the market shares in this market on the basis of storage capacities (maximum working gas volume).[114]

This year's survey, based on the questionnaire "Underground natural gas storage facility operators", again focussed on all storage facilities and requested among other data information on working gas volumes at the reference date 31 December 2014. The storage facility operators are a total of 24 legal persons. The attribution of companies to a group was carried out according to the dominance method (cf. the methodological notes in section I.A.3 p. 32).

The market for the operation of underground natural gas storage facilities is characterised by a relatively high level of concentration. After a decline in the previous years, the level of concentration has risen in the reporting year. On 31 December 2014, the maximum working gas volume of the German underground natural gas storage facilities connected to the German gas network (i.e. including Haidach and 7Fields) amounted to approx. 27.4 billion m^3. (previous year: 27.2 billion m^3). On 31 December 2014, the aggregate working gas volume of the three companies with the largest storage capacities amounted to approx. 20.5 billion m3, approx. 18.5 billion m3 on 31 December 2013. The CR3 value thus rose from approx. 68 % to approx. 75 %. The increase is mainly due to the increase in the number of shares held by EWE AG in VNG AG.[115] As EWE's participation in VNG now exceeds the 50 % threshold, VNG's capacities on 31 December 2014 were attributable to EWE in accordance with the dominance method. However, the market share distribution is asymmetrical.[116]

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[112] Cf. Bundeskartellamt, decision of 23 October 2014, B8-69/14 – EWE/VNG, para. 215 ff., Bundeskartellamt, decision of 31 January 2012, B8-116/11 - Gazprom/VNG para. 208 ff.

[113] Cf. COMP/M.6910 – Gazprom/Wintershall of 3 December 2013. para. 30 ff.

[114] Cf. Bundeskartellamt, decision of 23 October 2014, B8-69/14 – EWE/VNG, para. 236 ff.

[115] Cf. the capacity data in Bundeskartellamt, decision of 23 October 2014, B8-69/14 – EWE/VNG, para. 237

[116] Cf. Bundeskartellamt, decision of 31 December 2012, B8-116/11 – Gazprom/VNG, para. 209 ff.

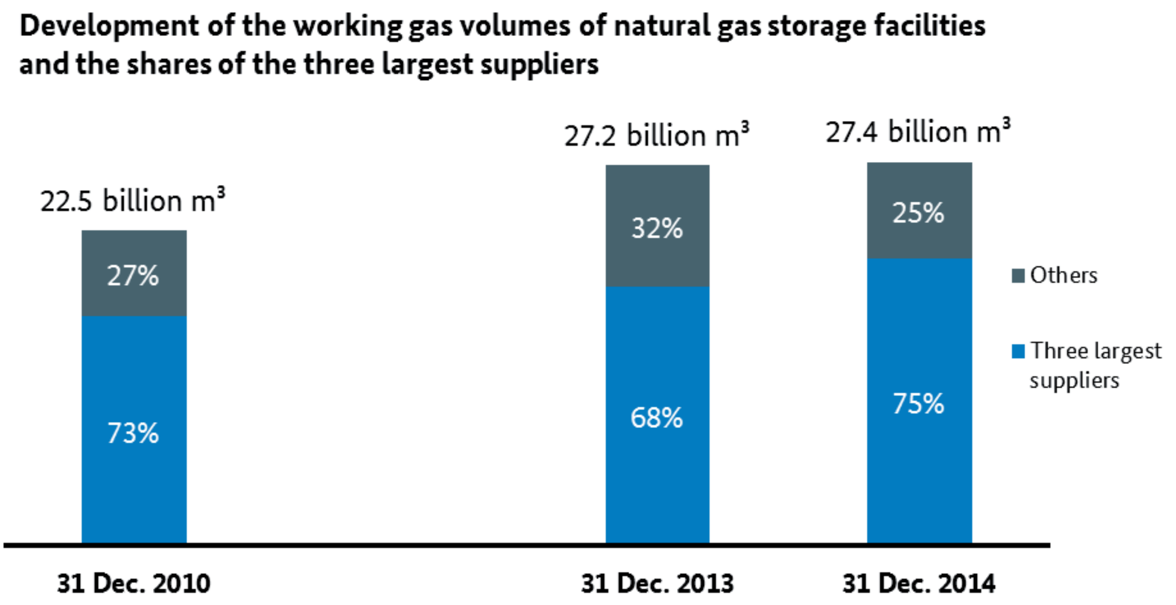

Figure 107: Development of the working gas volumes of natural gas storage facilities and the shares of the three largest suppliers

3.2 Gas retail markets

On the gas retail markets the Bundeskartellamt differentiates between customers with metered load profiles and those with standard load profiles. Metered load profile customers are customers whose electricity consumption is determined on the basis of a recording load profile measurement. These are generally industrial or large-scale commercial customers and gas power stations. Standard load profile customers are consumers with relatively low levels of consumption. These are usually household customers and smaller commercial customers. A standard load profile is assumed for the distribution of their gas consumption over specific time intervals. The Bundeskartellamt currently defines the market for the supply of gas to customers with metered load profiles and the market for the supply of gas to customers with standard load profiles on the basis of special contracts as national markets. The supply of gas to standard load profile customers in the basic supply sector is a separate product market which is still defined according to the respective network area.[117]

In the energy monitoring process the suppliers' sales are recorded as cumulative values throughout Germany at the level of the individual companies (legal persons). In the survey a differentiation is made between basic supply to standard load profile customers and supply on the basis of special contracts. The following evaluation is based on the data of approx. 800 gas suppliers (legal persons) (780 in the previous year). In 2014, these companies sold a total of approx. 321 TWh of gas to standard load profile customers in Germany (previous year: 387 TWh) and approx. 391 TWh of gas to customers with metered load profiles (previous year: 481 TWh). In accordance with the Bundeskartellamt's practice of market definition, sales to customers with metered load profiles also include sales to gas power stations. Of the total volume of sales to standard load

[117] Cf. Bundeskartellamt, decision of 23 December 2014, B8-69/14 – EWE/VNG, para. 129-214.

profile customers, special contracts accounted for 261 TWh (previous year: 310 TWh) and basic supply contracts accounted for 60 TWh (previous year: 77 TWh). The decline in sales volume is generally attributed to the relatively mild temperatures in 2014.

The attribution of sales volumes to the company groups was again carried out on the basis of the dominance method which provides sufficiently accurate results for the purposes of this report (cf. methodological notes in section I.A.3 p. 32).

In the case of customers with standard load profiles, the total cumulative sales of the three strongest companies amounted to approx. 71 TWh in 2014, 60 TWh of which were accounted for by special contracts. In the case of customers with metered load profiles, sales amounted to at least 123 TWh. In 2014, the aggregated market share of the three strongest companies (CR3) thus amounts to about 23% for standard load profile customers with special contracts (previous year: 22%), and about 32% for customers with metered load profiles (previous year: 33%). These market shares continue to be clearly below the statutory threshold for the presumption of market dominance (§18 GWB). Compared to the previous year, no change in market concentration can be found in any of the two markets. For the standard load profile sector an additional calculation was made to determine the CR3 value for the supply of gas to all standard load profile customers- throughout Germany (i.e. including basic supply customers). As in the previous year, this resulted in a CR3 value of about 22%.

With regard to the percentage shares provided it should be noted that in the sector of gas suppliers, the monitoring survey does not cover the whole market. The percentage shares are thus merely approximate to the actual values.

Share of the three strongest companies in the sale of gas to metered load profile customers and standard load profile customers in 2014

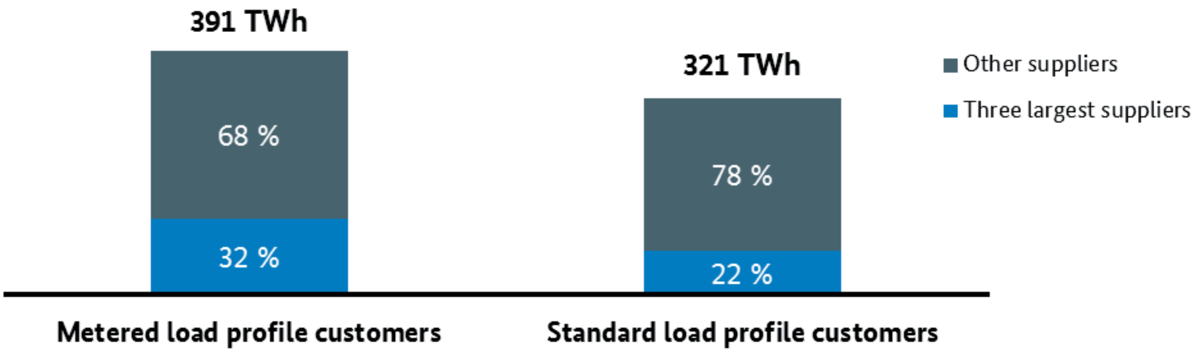

Figure 108: Share of the three strongest companies in the sale of gas to metered load profile customers and standard load profile customers in 2014

B Production, imports/exports, and supply disruptions

1. Production of natural gas in Germany and imports/exports

1.1 Production of natural gas in Germany

In 2014, the year under review, natural gas production in Germany fell by 0.59bn m^3 to 9.1bn m^3,[118] down 6.1% compared to the previous year. The steady decline in natural gas reserves and in production is chiefly due to the increasing exhaustion and dilution of existing deposits. The reserves-to-production ratio of the proven and probable natural gas reserves, that is the ratio of last year's production and reserves, is 8.8 years on 1 January 2015. This ratio does not take the natural decline in production from the deposits into account and therefore should not be seen as a forecast, but rather as a snapshot and guideline figure, (source: Oil and natural gas reserves in the Federal Republic of Germany on 1 January 2015; Lower Saxony State Authority for Mining, Energy and Geology).

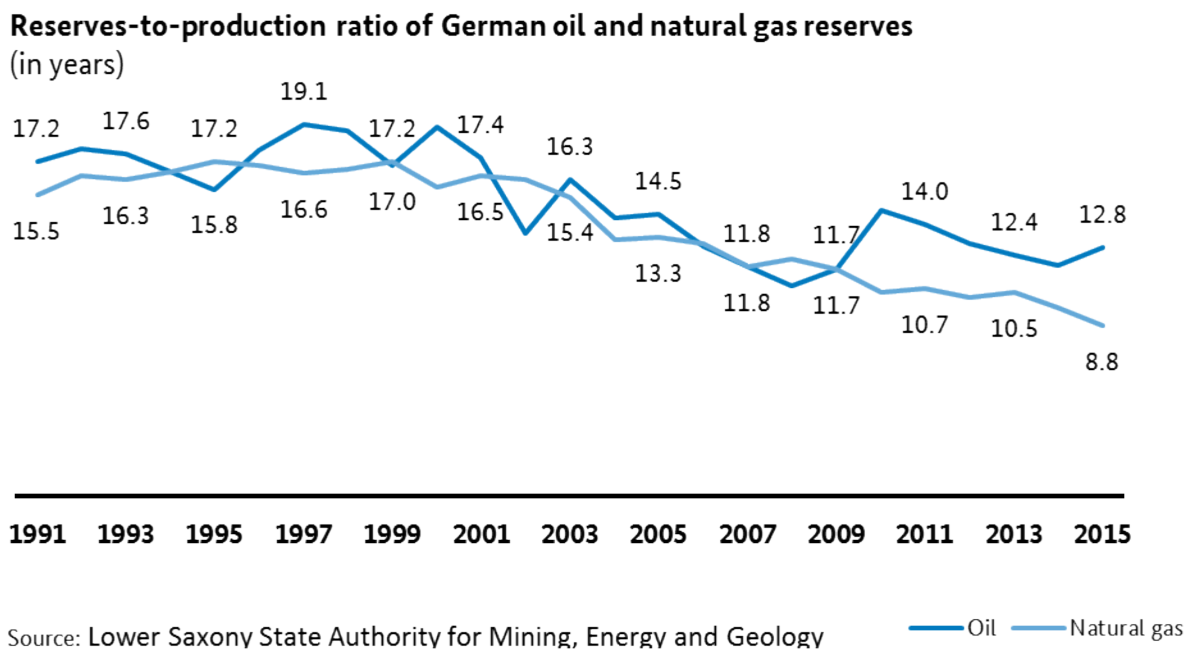

Figure 109: Reserves-to-production ratio of German oil and natural gas reserves since 1991

1.2 Imports and exports of gas

The volume of gas imported into Germany rose by some 16.5 TWh or 0.9% from 1,771.7 TWh in 2013 to 1,788.2 TWh ín 2014.

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[118] Domestic production accounts for just under 10% of the total consumption of natural gas in Germany.

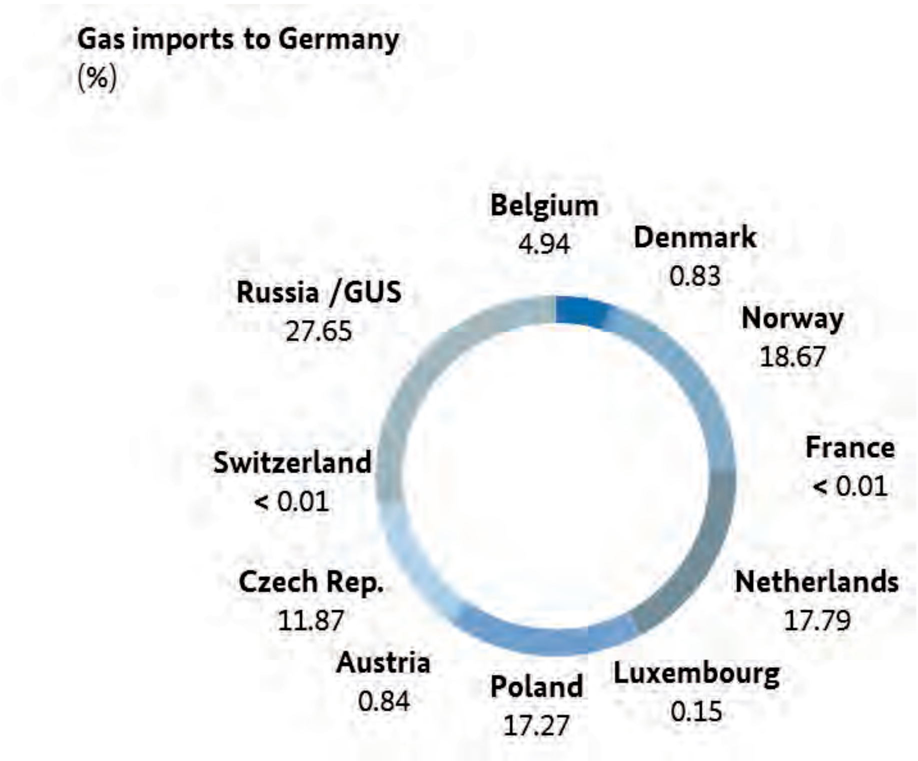

Figure 110: Countries of origin of the gas imported into Germany in 2014

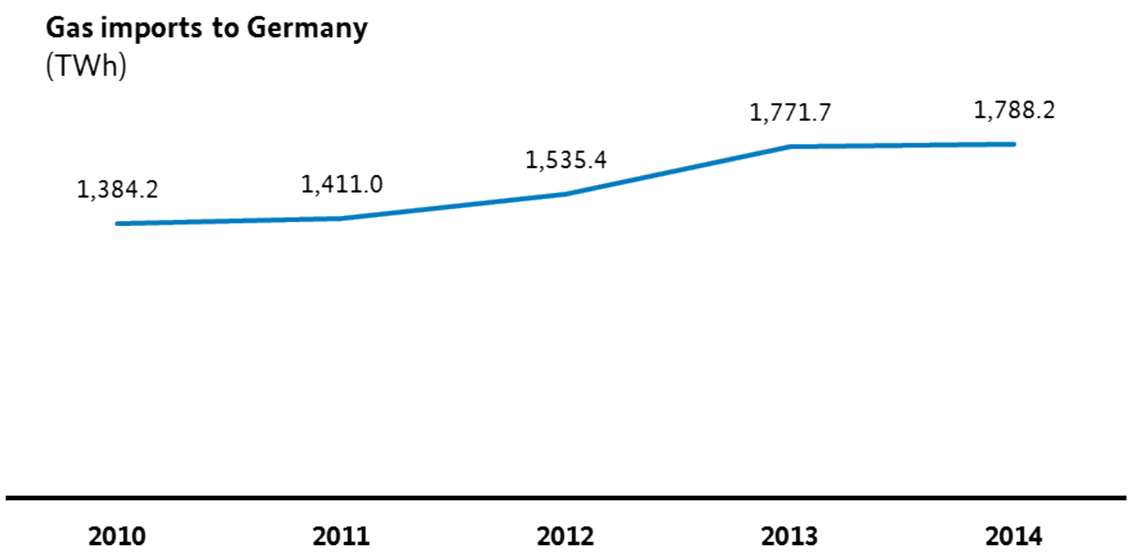

Figure 111: Gas imports

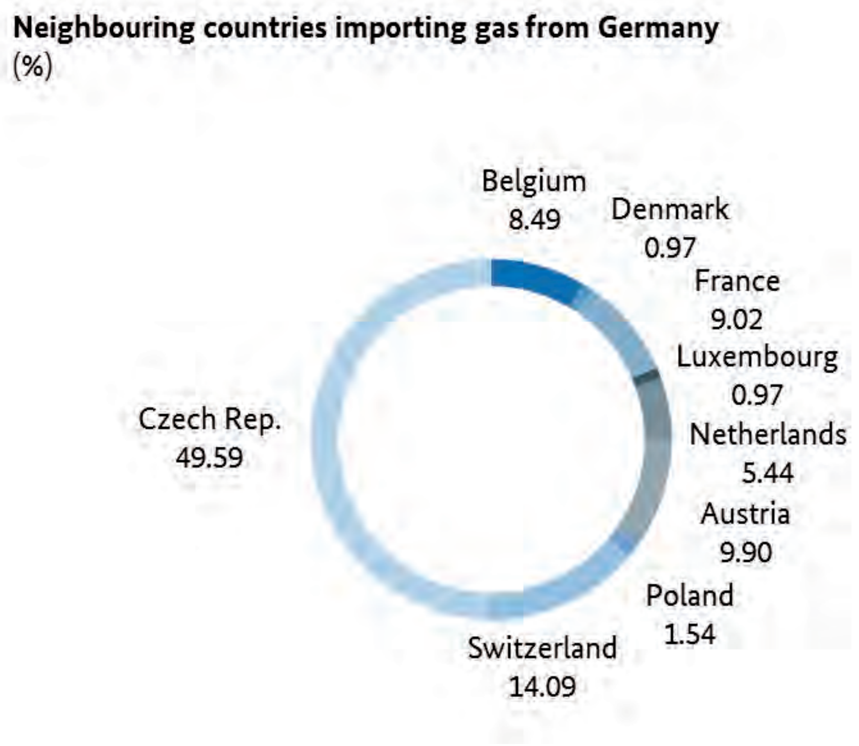

Figure 112: Neighbouring countries importing gas from Germany in 2014

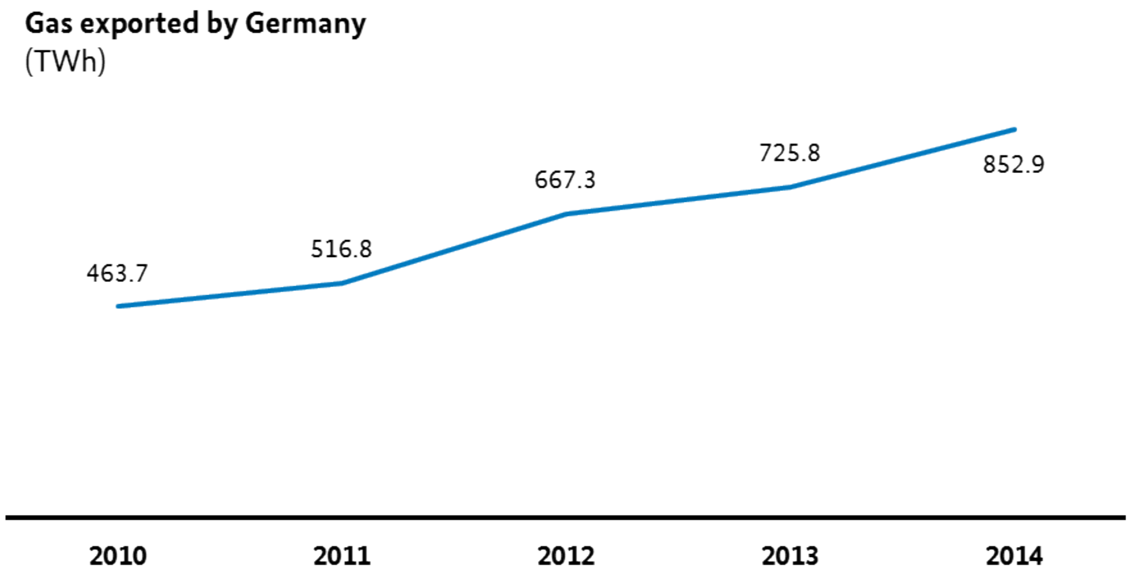

Figure 113: Gas exported by Germany

The main sources of gas imports remain the Commonwealth of Independent States (CIS) and Norway. However, the Netherlands, as an established and liquid producer and trading hub in Europe and point of arrival for LNG shipments with connections to natural gas fields in Norway and the United Kingdom, is also a significant source of imports for Germany. Improved integration of national markets and more efficient management of cross-border capacities has eased trading and provided further alternatives for gas traders.

The third full operational year of the Nord Stream pipeline under the Baltic Sea saw imports from the CIS maintained at a constant high level. Some 57% of all gas imports came from the CIS.[119]

Gas exports have also risen: from 725.8 TWh in 2013 to 852.9 TWh in 2014, corresponding to a rise of 17.5%.

Changes in gas exports

	Exports in 2013 (TWh)	Percentage of total gas exports	Exports in 2014 (TWh)	Percentage of total gas exports	Change (%)
Belgium	0.0	5.8%	0.0	8.5%	71.5%
Denmark	0.0	1.6%	0.0	1.0%	-29.9%
France	0.0	17.6%	0.0	9.0%	-39.9%
Luxembourg	0.0	1.2%	0.0	1.0%	-2.2%
Netherlands	0.0	10.3%	0.0	5.4%	-38.2%
Austria	0.0	8.0%	0.0	9.9%	45.1%
Poland	0.0	1.7%	0.0	1.5%	7.2%
Switzerland	0.0	13.6%	0.0	14.1%	21.3%
Czech Rep.	0.0	40.1%	0.0	49.6%	45.4%
Total	0.0	100%	0.0	100%	

Table 71: Changes in gas exports

An analysis of the destination of German exports essentially confirmed the trends from the previous year. There was a large increase in the volume exported to Austria, the Czech Republic and Switzerland. Expansions and upgrades in the Nordstream pipeline and OPAL made these increases in exports to the Czech Republic possible. However, for reasons related to the infrastructure involved, for the most part these exports were transit flows that flowed back to Germany through the Waidhaus cross-border interconnection point. Exports to Belgium have also increased considerably, while exports to the Netherlands and France have dropped noticeably.

2. Gas supply disruptions

The Bundesnetzagentur again conducted a comprehensive survey of all gas supply interruptions throughout the Federal Republic of Germany. Section 52 of the Energy Act (EnWG) requires gas network operators to report all interruptions in supply to the Bundesnetzagentur by 30 April of each year. The Bundesnetzagentur uses the information to calculate the system average interruption duration index (SAIDI). This indicates the

[119] Poland, the Czech Republic and Austria are included in the gas imports from Russia.

average interruption duration per final customer[120]). The SAIDI does not take into account scheduled interruptions, nor those caused by force majeure, for example by natural disasters. Only unplanned interruptions caused by third-party intervention, ripple effects from other networks or other disturbances in the network operator's area are included in the calculations. On 23 October 2014 there was an explosion during construction work at the Rhine-Main natural gas pipeline in Ludwigshafen-Oppau. The pipeline then had to be temporarily taken out of service. Supply to both industrial customers affected was restored on 24 October 2014 by diverting feed-in and switching fuels. The outage of a very large amount of capacity suffered by the large industrial customers lasted 35 hours. There were no supply disruptions experienced by standard load profile (SLP) customers.

This comparatively large capacity outage lasting 35 hours has quite a significant effect on the SAIDI figure for 2014. The SAIDI figure not including the accident is 1.3 minutes and is thus in line with the long-term average for gas supply interruptions. The SAIDI figure including the accident is 16.8 minutes. However, this does not indicate a deterioration in national security of supply. The level of gas supply reliability excluding the accident was 99.999%, and 99.996% including the accident.

The 2014 results of the comprehensive survey of supply disruptions in all existing gas networks in the Federal Republic of Germany that are registered in the Bundesnetzagentur's energy database (approximately 730) were as follows:

SAIDI results for 2014

Pressure range	Specific SAIDI	Comments
≤ 100 mbar	0.87 min/a	Household and small consumers
> 100 mbar	15.93 min/a	High-volume customers, gas-fired powerplants including accident
> 100 mbar	0.38 min/a	High-volume customers, gas-fired powerplants excluding accident
> 100 mbar	0.10 min/a	Downstream network operators
All pressure ranges	16.80 min/a	SAIDI value for all final customers including ERM accident
All pressure ranges	1.25 min/a	SAIDI value for all final customers excluding ERM accident

Table 72: SAIDI results for 2014

The SAIDI figures for gas networks in Germany have been calculated by the Bundesnetzagentur since 2006: The figures have been as follows over the years:

[120] All reported supply disruptions (with the exception of scheduled interruptions and interruptions caused by force majeure) in the pressure ranges of ≤100mbar and >100mbar are factored in with the number of final customers that experienced interruptions to determine the nationwide SAIDI figure.

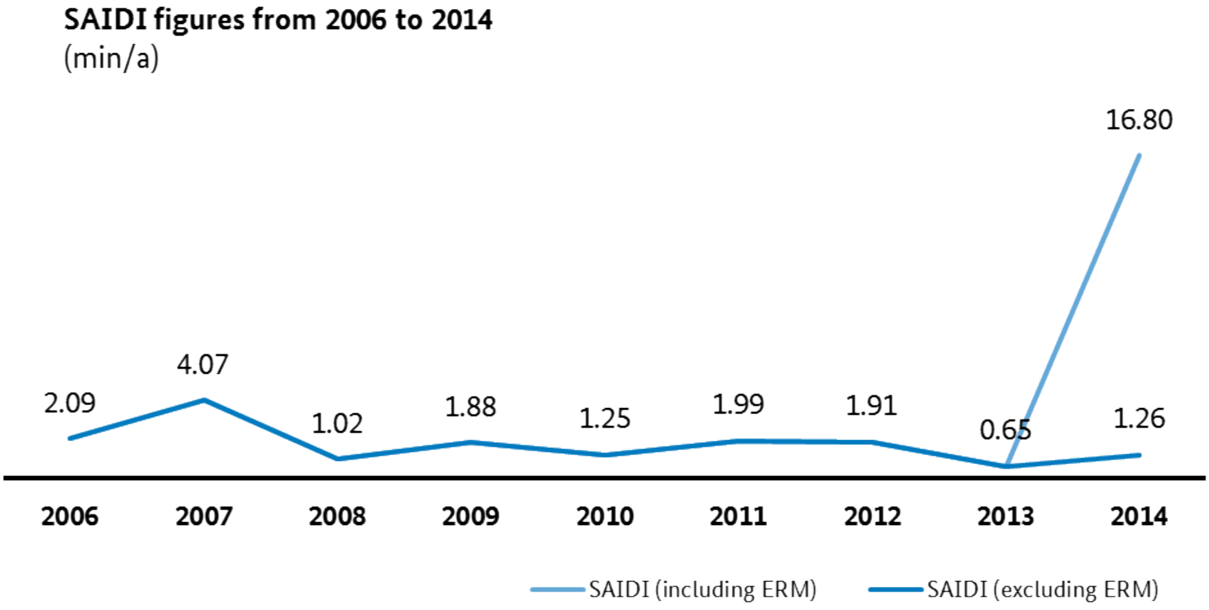

Figure 114: SAIDI figures from 2006 to 2014

C Networks

1. Networks and investments

1.1 Gas Network Development Plan

The gas network development plan includes measures for needs-oriented optimisation, reinforcement and expansion of the network, as well as for maintaining security of supply; these will be necessary in the next decades to ensure secure and reliable network operations. It is published on an annual basis as required by law. The content of the gas network development plan focuses on the one hand on expansion issues arising due to the connection of new gas power plants – there is an interconnection here with the electricity market – and gas storage facilities. On the other hand it looks at connections between the German gas transmission network and those in neighbouring European countries and at capacity needs in the downstream networks.

The gas network development plan 2014 was presented to the Bundesnetzagentur by the TSOs within the specified period on 1 April 2014. The document was then submitted for comprehensive consultation by the Bundesnetzagentur.[121] Taking the results of the consultation into account, the Bundesnetzagentur formulated a modification request addressed to the TSOs on 17 November 2014.

The necessity of the new measures contained in the gas network development plan 2014 is derived in particular from the market area conversion from low-calorific L-gas to H-gas, which has a higher calorific value, the consideration of the higher consumption in the whole H-gas network and increased capacity requirements for gas storage facilities. Another reason for individual measures is the increased need for capacity in the distribution network in southern Germany. In its decision, the Bundesnetzagentur instructed the TSOs to remove five of the 56 proposed network expansion measures from the gas network development plan 2014. The TSOs had not yet adequately documented the need for three of these measures, while two additional measures did not show the required degree of specification.

The gas network development plan 2014 became binding on the TSOs with the announcement of the modification request. The gas network development plan 2014, which was revised with respect to the modification request of the Bundesnetzagentur, has been published on the website of the TSOs on 28 January 2015.[122]

On 1 April 2015, the TSOs presented the Bundesnetzagentur with the currently valid gas network development plan 2015. For the most part, the measures included in the gas network development plan 2014 that the Bundesnetzagentur specified as binding are continued in the gas network development plan 2015. In addition to those measures, the view to 2025 contains 37 additional necessary expansion measures that result primarily from the market area conversion (27 new measures) and the associated increased need for H-gas.

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[121] The results of the consultation have been published on the website of the Bundesnetzagentur: http://www.bundesnetzagentur.de/cln_1422/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/NetzentwicklungundSmartGrid/Gas/NEP_Gas2014/Netzentwicklungsplan_Gas_2014_node.html.

[122] http://www.fnb-gas.de/de/netzentwicklungsplan/nep-2014/nep-2014.html.

This topic plays an important role in the draft gas network development plan 2015 under the aspect of security of supply. The result is a concrete proposal for the gradual conversion of the areas beyond 2025 to the year 2030.

The draft network development plan 2015 contains two different modelling variations which only differ by one measure in terms of scope and costs of expansion. This deviation is based on the consideration of unequal amounts for the capacity requirements of downstream distribution system operators.

The TSOs' network expansion proposal that was selected from these variants translates into a required line construction of 810km increased compressor capacity of 405 MW. The 86 measures translate into an investment volume of €3.5bn over the next 10 years.[123] The submitted document was made available by the Bundesnetzagentur for consultation from 14 April up to 5 June 2015. Taking the results of the consultation into account, the Bundesnetzagentur formulated a modification request for the gas network development plan 2015 and addressed it to the TSOs on 1 September 2015.[124]

For the most part, the measures proposed by the TSOs in the network development plan 2015 have been confirmed. Two unspecific measures for the market area conversion of the TSOs Open Grid Europe (OGE) and Thyssengas were not confirmed, and one measure of Gasunie Deutschland (GUD) was modified.

According to calculations by the Bundesnetzagentur, the approved measures result in a required line construction of 810km and an increased compressor capacity of 393 MW over the next 10 years. The 84 measures correspond to an investment volume of €3.3bn over the next 10 years. The total package of measures contain 204 MW of increased compressor capacity and 294km of new line construction with a value of around €1.6bn, which must be brought into conjunction with the market area conversion at transmission system level.

Following the announcement of the modification request, the TSOs must under section 15a(3) fifth sentence EnWG implement the required changes within a period of three months. The gas network development plan 2015 becomes binding on the TSOs with the announcement of the modification request.

[123] See draft of the Network development plan 2015: http://www.fnb-gas.de/de/netzentwicklungsplan/nep-2015/nep-2015.html.

[124] http://www.bundesnetzagentur.de/cln_1421/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/NetzentwicklungundSmartGrid/Gas/NEP_Gas2015/Netzentwicklungsplan_Gas_2015_node.html;jsessionid=84364AC4AE941C67546FDFF7B0A4641F

Network expansion measures Gas NDP 2014 and Gas NDP 2015

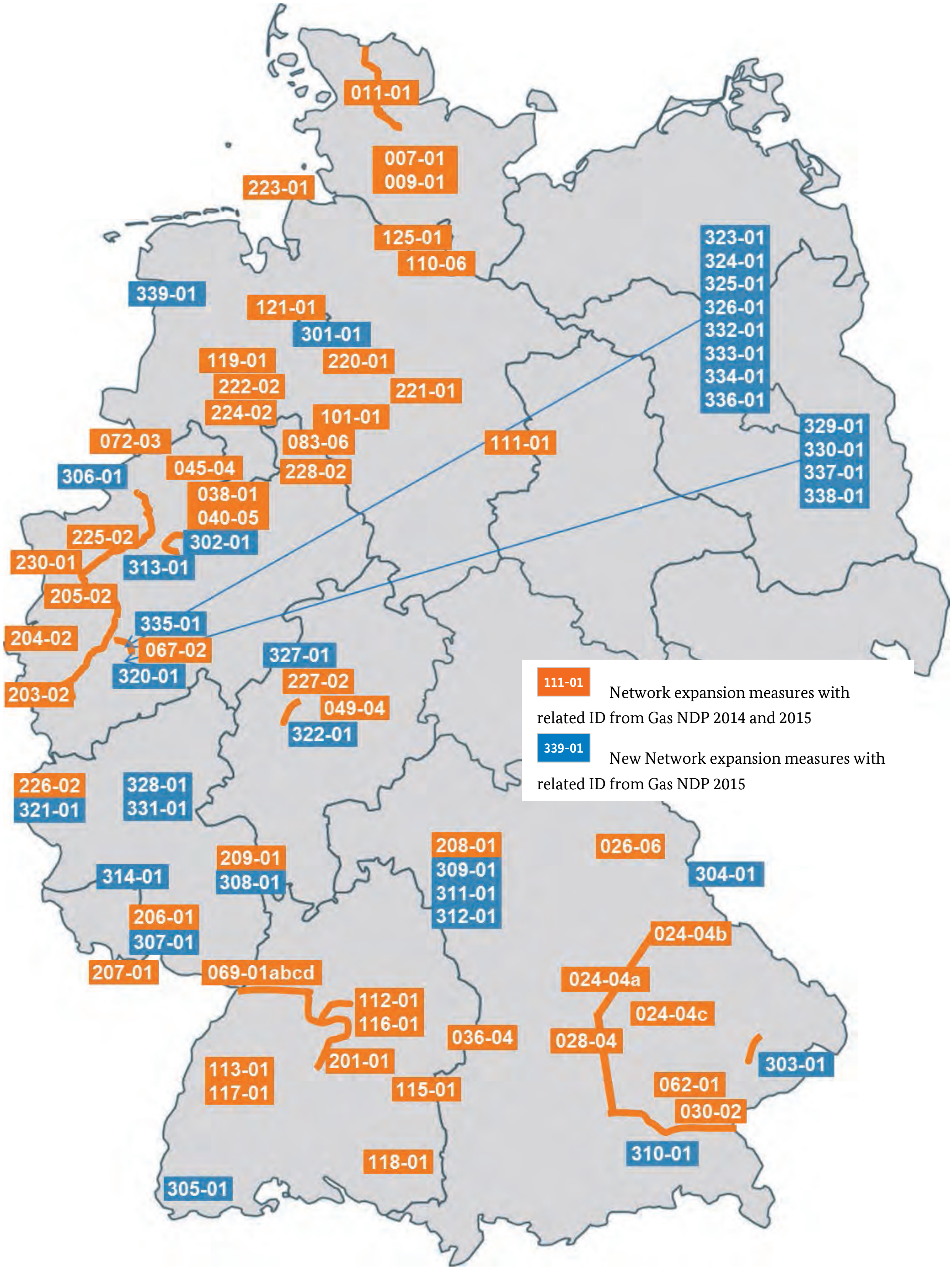

Figure 115: Graphical presentation of the results of gas NDPs 2014 and 2015

Confirmed network expansion measures Gas NDP

ID	Expansion measure	Length of pipeline km	Compressor station (VDS) capacity MW	Costs € million	Commissioning
007-01/ 009-01	VDS Quarnstedt		24	131.0	2016
011-01	Loop Fockbek-Ellund	63.5		177.0	2016
024-04a	Line Schwandorf-F.	62.0		126.0	2017
024-04b	GDRM Schwandorf			7.0	2017
024-04c	GDRM Arresting			5.0	2017
026-06	VDS Rothenstadt		45	119.0	2018
028-04	Line Forchheim-Finsing	79.0		180.0	2018
030-02	MONACO 1	86.5		197.0	2017
036-04	VDS Amerdingen/W.		33	107.0	2019
038-01	VDS Werne			26.0	2017
040-05	VDS Werne		49	147.0	2018
045-04	Line Epe-Legden	15.0		41.0	2018
049-07	VDS Herbstein		39	120.0	2018
062-01	M+R Landshut			4.5	2015
067-02	Line Voigtslach-Paffrath	23.0		48.0	2023
069-01a	Nordschwarzwaldleitung	71.0		71.0	2015
069-01c	M+R Ettlingen-Hägenich			3.0	2015
069-01d	M+R Leonberg-West			3.0	2015
072-03	VDS Ochtrup	3.0	24	83.0	2018
083-06	NOWAL 2	26.0	13	86.0	2017
101-01	Conversion Rehden			15.6	2016
110-06	Expansion NEL		50	157.0	2025
111-01	Connection Ahlten 3	0.4		1.0	2015
112-01	Crossover Pforzh.-B.	26.0		33.0	2024
113-01	Crossover Leonb.-R.	62.0		88.0	2024
115-01	VDS Scharenstetten		12	44.0	2016
116-01	M+R Pforzh.-B. region			6.0	2024
117-01	M+R Leonb.-R. region			6.0	2024

Table 73: Confirmed network expansion measures Gas NDP (007-01 - 117-01)

Confirmed network expansion measures Gas NDP

ID	Expansion measure	Length of pipeline km	Compressor station (VDS) capacity MW	Costs € million	Commissioning
119-01	M+R Achim			7.0	2018
121-01	M+R Ganderkesee			7.0	2020
125-01	Project Wedel			3.0	2016
201-01	M+R Tachenhausen			1.0	2015
203-02	VDS Zeelink		39	142.0	2020
204-02	Zeelink 1	112.0		291.0	2020
205-02	Zeelink 2	115.0		299.0	2020
206-01	GDRM Mittelbrunn			14.0	2019
207-01	GDRM Obermichelb.			6.0	2019
208-01	GDRM Rimpar			10.0	2019
209-01	GDRM Gernsheim			10.0	2019
220-01	MRU Walsrode/Fall.			2.0	2016
221-01	MRU Luttum-Wolfsburg			12.0	2020
222-02	MRU Bremen/Achim			12.0	2020
223-01	MRU Bremen-Cuxh.			1.0	2021
224-02	GDRM Nordlohne	0.3		5.0	2018
225-02	GDRM Legden	0.3		5.0	2018
226-02	GDRM Rechtenbach	0.2		5.0	2018
227-02	GDRM Marburg	2.5		9.0	2018
228-02	GDRM Hilter	0.4		6.0	2018
230-01	MRU Hüthum	1.0		1.0	2017
300-01	VDS Folmhusen			n.n.	2020
301-01	Überspeisung Embsen			2.0	2020
302-01	Line Datteln-Herne	23.0		32.0	2020
303-01	Line Deggendorf-Platt.	12.0		9.0	2017
304-01	Rev. MEGAL/Waidhaus			19.0	2018
305-01	Reversierung TENP			20.0	2020
306-01	GDRM Epe			7.0	2020
307-01	GDRM Mittelbrunn			17.0	2020

Table 74: Confirmed network expansion measures Gas NDP (119-01 - 307-01)

Confirmed network expansion measures Gas NDP

ID	Expansion measure	Length of pipeline km	Compressor station (VDS) capacity MW	Costs € million	Commissioning
308-01	GDRM Gernsheim			2.0	2020
309-01	VDS MEGAL Rimpar			1.0	2020
310-01	GDRM Reichertsheim			10.0	2020
311-01	Line Schlüchtern-Rimpar	1.0		2.0	2020
312-01	VDS MEGAL Rimpar		39	128.0	2023
313-01	VDS St. Hubert		26	96.0	2023
314-01	GDRM Leeheim			4.0	2025
320-01	MRU Bergheim 1	1.0		1.0	2020
321-01	GDRM Weidenhausen	1.0		6.0	2018
322-01	Line Weidenhausen-G.	8.5		12.0	2018
323-01	Schieberanlage Paffrath	0.2		1.0	2019
324-01	Schieberanlage Niederpl	0.1		1.0	2019
325-01	Schieberanlage Neukir.	0.1		1.0	2020
326-01	Schieberanlage Horrem	0.1		1.0	2020
327-01	GDRM Niederschelden	0.1		3.0	2020
328-01	GDRM Langenscheid	0.1		4.0	2020
329-01	GDRM Siegwiesen	0.1		4.0	2020
330-01	GDRM Elsdorf	0.1		5.0	2020
331-01	GDRM Scheidt			8.0	2020
332-01	Schieberanlage Ergste	0.1		1.0	2021
333-01	GDRM Asbeck	0.1		7.0	2021
334-01	Schieberanlage Rausch.	0.1		1.0	2021
335-01	GDRM Marienheide	12.8		18.0	2021
336-01	Schieberanlage Oberad.	0.1		1.0	2022
337-01	GDRM Porz			4.0	2022
338-01	GDRM Paffrath			2.0	2023
339-01	GDRM Wiefelstede			3.0	2023
Total	**84 measures**	**809.7**	**393**	**3,313.1**	

Table 75: Confirmed network expansion measures Gas NDP (308-01 - 339-01)

1.2 Investments in and expenditure on infrastructure by gas DSOs

Investments in and expenditure on network infrastructure by 671 DSOs amounted to approximately €2,230m in 2014 (2013: €2,014), an increase of 10.7% compared with the previous year. The DSOs' forecasted investment volume in the distribution networks of €1,107m for the year 2014 was exceeded by €48m, bringing it to a total actual investment volume of €1,155m. By contrast, actual expenditures fell short of forecasted expenditures by €168m (-13.5%), bringing that figure to €1,075m. In total, the amount of DSOs' expenditures for network infrastructure was, with a delta of €120m (-5.1%), lower than the 2014 forecast of €2,350m. For the coming year 2015, the DSOs have planned a decreasing volume of investment in new installations, expansion, extension, maintenance and renewal of approximately 6.7% and falling expenditures of approximately 7.7%. In previous years, by contrast, there has been a steady increase in investment. With the exception of the year 2010, expenditures have remained at a constant level.

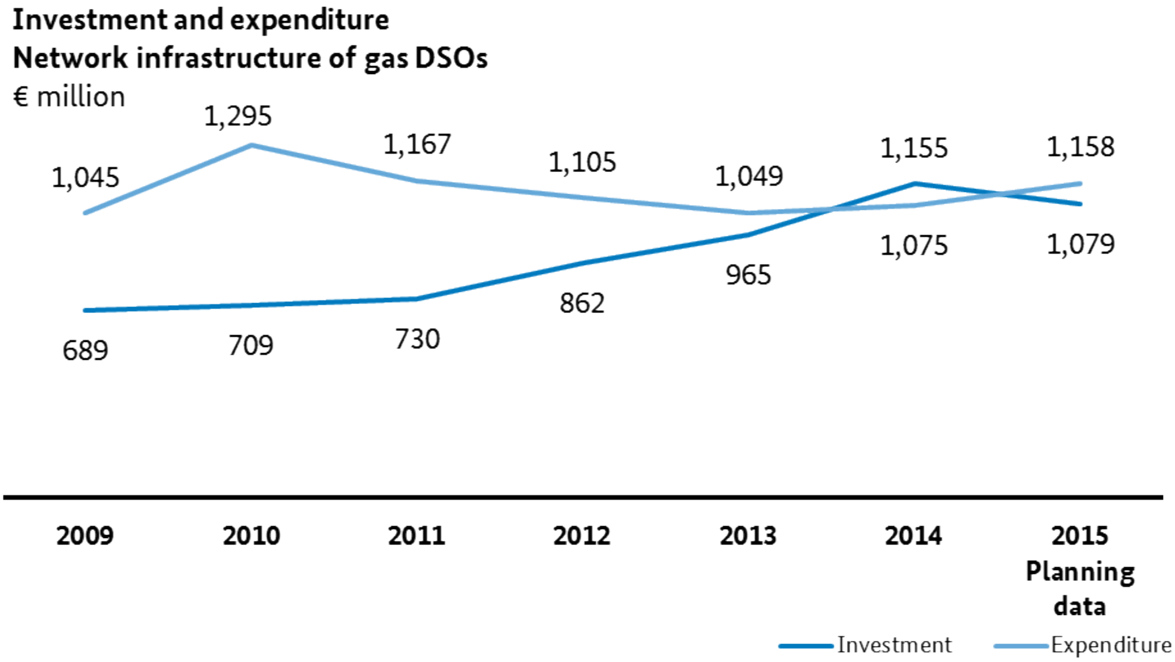

Figure 116: Investments in and expenditure on network infrastructure by gas DSOs

The level of DSO investment depends on the length of their gas pipeline network, the number of meter points served as well as other individual structure parameters, including, in particular, geographical circumstances. As a rule, DSOs tend to invest more the longer their pipeline networks are. While 122 DSOs (19%) report investments of between €0 and €100,000, only 8% of companies report investment in the highest category of over €5m per network area. The following illustration shows the share of the total investment volume for different investment categories:

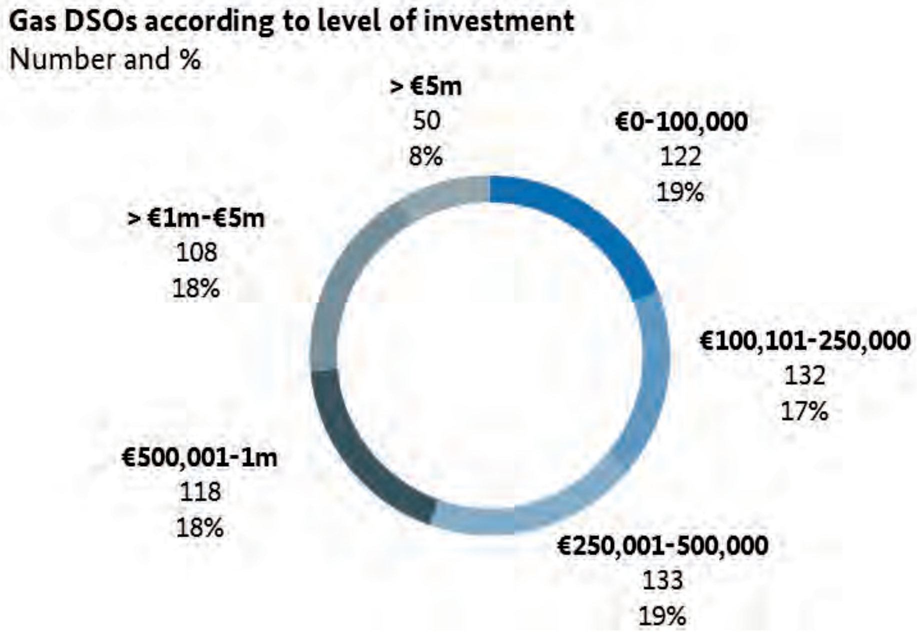

Figure 117: Gas distribution system operators according to level of investment

The percentage of DSOs' expenditures according to volume category shows a similar distribution as investments. While 152 companies report expenditures of between €0 and €100,000, there are 51 companies in the highest category, with expenditures exceeding €5m.

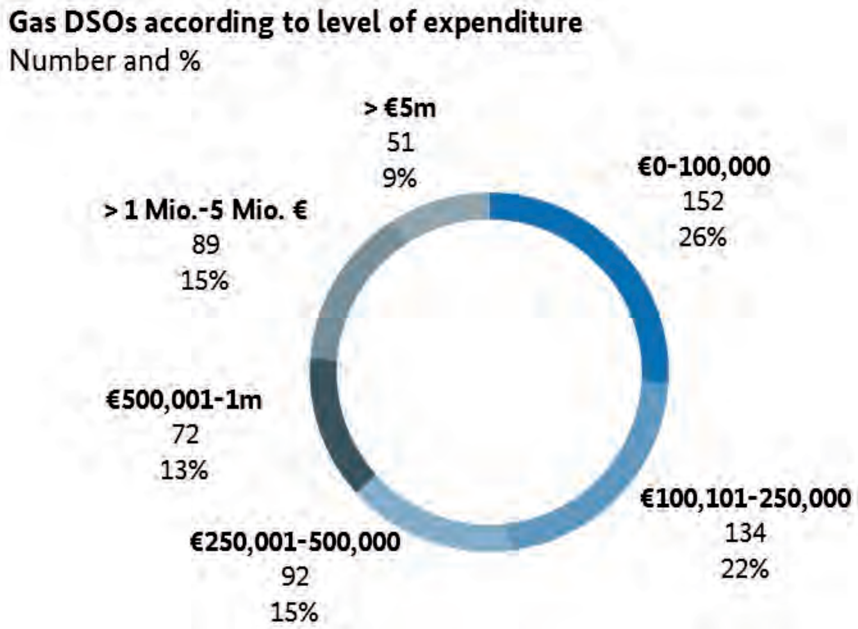

Figure 118: Gas distribution system operators according to level of expenditure

1.3 Capacity offer and marketing

As in the previous reporting year 2013, the questions asked dealt with the booking, use, availability and booking preference for transport capacity in 2014. Distinctions were again made between the various capacity products offered on the market.

Shippers were asked about their preference for the different capacity products offered by gas TSOs. They were asked to state on a scale from 1 (for very important) to 4 (unimportant) whether in addition to firm and freely allocable capacity (FZK) only interruptible capacity products should be offered. The alternative would be to retain the offer of firm capacity products with limited allocability. Following the trend of the last reporting year, there was no longer a majority (45%) of shippers who preferred the two-product variant (see gas year 2011/12: 60 to 40%, and gas year 2012/13: 49 to 51% in favour of the two-product variant). The absolute figures of shippers surveyed are shown inside the column in the diagram.

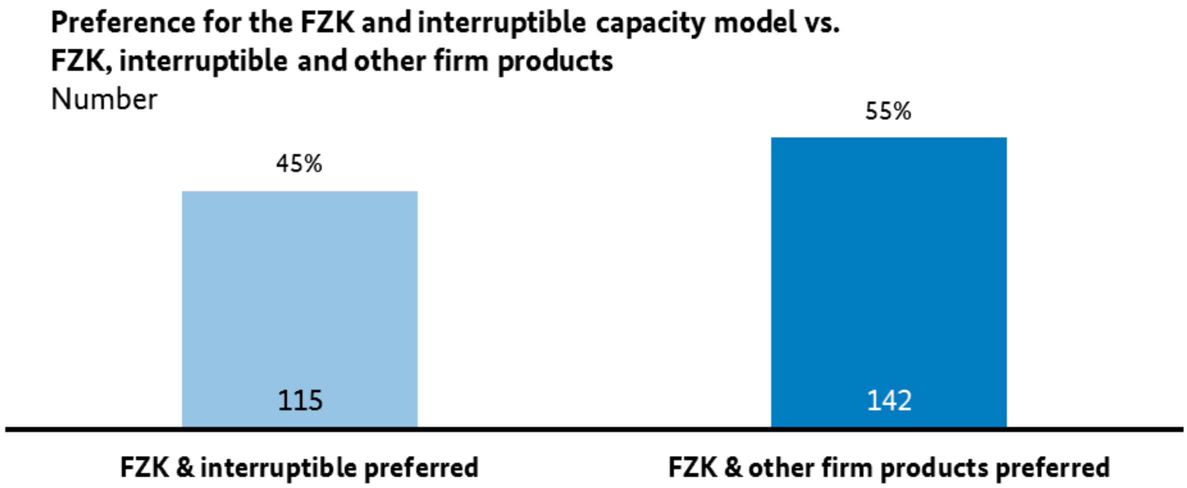

Figure 119: Preference for the FZK and interruptible capacity model vs. FZK, interruptible and other firm products

Shippers were also asked whether load flow commitments (LFZ) should be entered into so as to safeguard FZK in existing market areas or whether other capacity products should be offered instead of FZK (eg capacity with conditional firmness and allocability (bFZK) or dynamically allocable capacities (DZK)). Load flow commitments are contractual agreements between a TSO and a third party (usually a shipper or a storage user) regarding the provision or restriction, upon the request of a TSO, of a specific gas flow at an entry or exit point or zone within the network. They can be offered by third parties which have either physical entry or exit points in their portfolio and are prepared, against payment by the network operator, to adapt the original free use of their capacities, when necessary, to the TSOs' requirements.

A majority of the shippers surveyed (69%) preferred the alternative, ie the offer of other capacity products. 31% were in favour of the alternative variant of using load flow commitments.

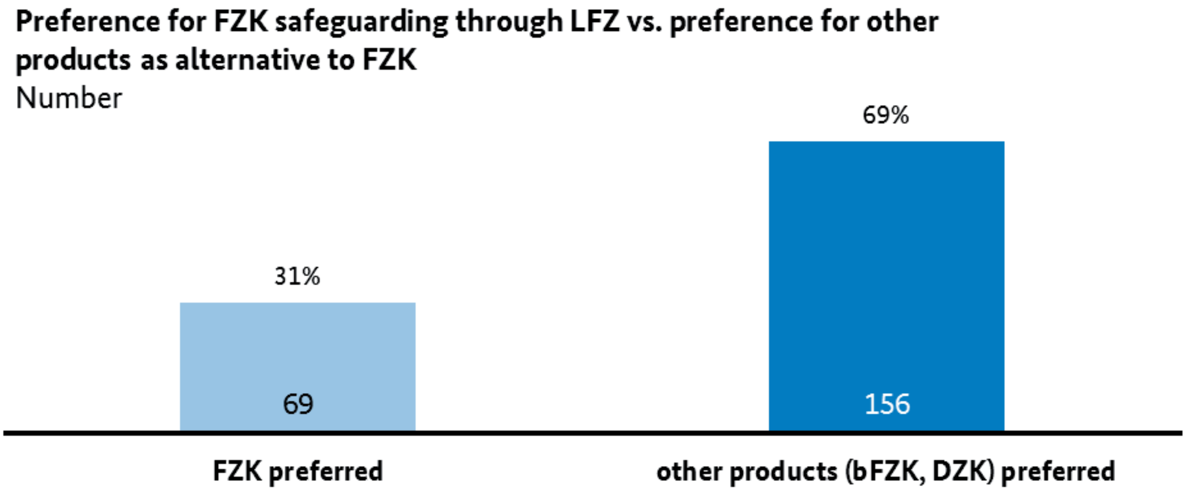

Figure 120: Preference for FZK safeguarding through load flow commitments vs. preference for other products as alternative to FZK

1.4 Available entry and exit capacities

In the 2013/14 gas year the supply of entry and exit capacities that can be firmly booked by shippers increased in both market areas NetConnect Germany and GASPOOL. These figures do not take interruptible capacity and internal orders into account, but refer instead to the median offer of firm capacity at cross-border and market area interconnection points and also at points of interconnection with storage facilities, power stations and final consumers. While the entry capacity of all TSOs increased in total by 22.8m kWh/h to 489m kWh/h, the exit capacity showed an increase of 49m kWh/h compared to the previous year, to 318.1m kWh/h.

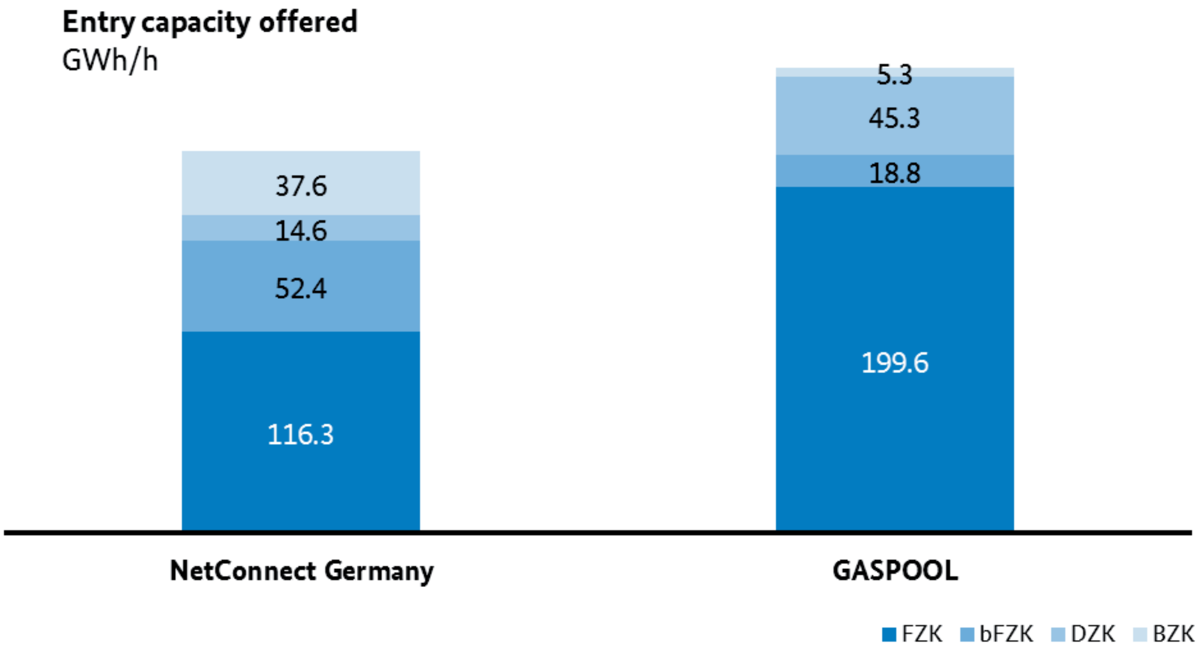

Figure 121: Entry capacity offered in the market areas of NetConnect Germany and GASPOOL

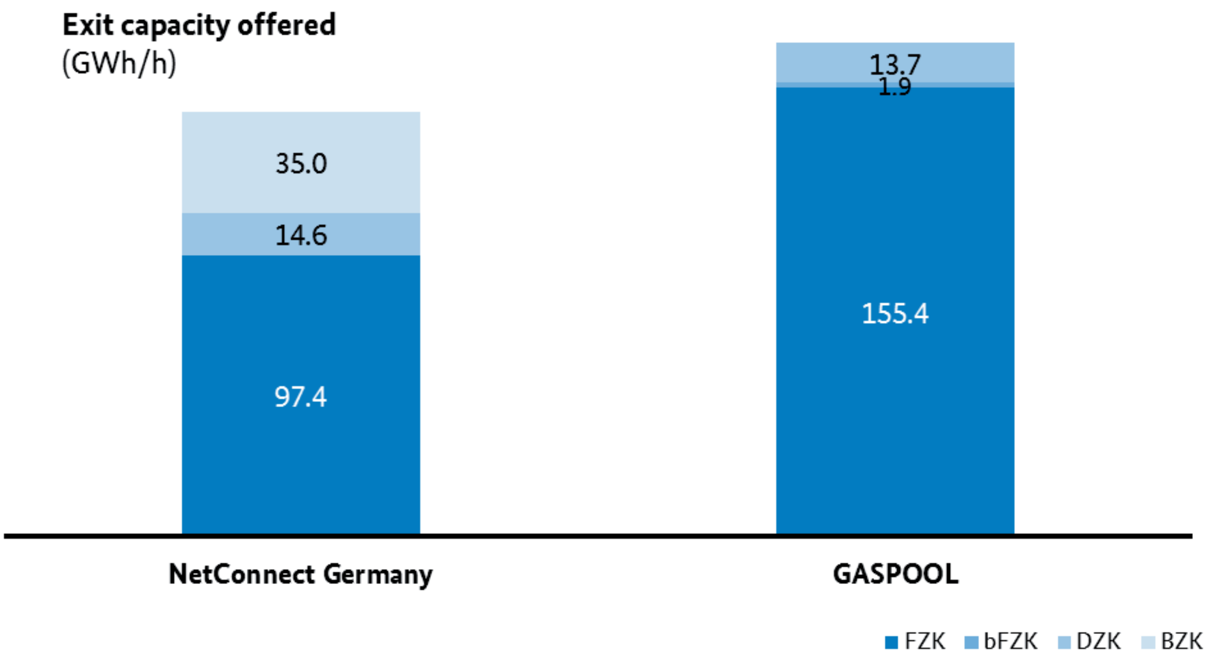

Figure 122: Exit capacity offered in the market areas of NetConnect Germany and GASPOOL

A fundamental element of the TSOs' capacity model is the firm exit capacity (internal booking) agreed with the downstream network operators. Although this reserve capacity is not booked by shippers, it still has a significant influence on the level of firm capacity offered at marketable entry and exit points.

According to section 12(6) para 3 of the cooperation agreement (KoV) VII, renominations at market area and cross-border interconnection points are subject to a restriction. The renomination is only permitted if it does not exceed 90% of the total capacity booked by shippers at the booking point and does not fall below 10% of the booked capacity. In the case of initial nominations of a minimum of 80% of booked capacity, half of the unnominated capacity is allowed for upward renomination. In the case of initial nominations of a maximum of 20% of booked capacity, half of the unnominated capacity is allowed for downward renomination. These restrictions allow TSOs to offer more capacity than is the case in a base case without a renomination restriction. In the year 2014, the offer of entry capacity through TSOs' renomination restrictions amounted to 1.443bn kWh/h in the NCG market area, which corresponds to an increase of 6% compared with the year 2013. The offer of respective exit capacity increased by 35% to 1.484bn kWh/h. In 2014 TSOs in the GASPOOL market area were able to increase the offer of entry capacities based on renomination restrictions by 45% to 1.444bn kWh/h. The exit capacities offered increased sevenfold compared to the year 2013, to 1.292bn kWh/h.

1.5 Termination of capacity contracts

During the reporting period, a total of 176 long-term capacity contracts were terminated, in particular at cross-border points. The following kinds of capacity were affected: 153x FZK, 21x interruptible and 1x DZK and BZK. The terminated contracts had a median contract term of 3 years and comprised capacity rights averaging 0.7m kWh/h. The reasons for the termination of capacity contracts are varied and may include the dissipation of further contractual congestion situations as well as the secured procurement of short-term capacity.

The changing booking situation offers the TSOs both opportunities and risks. On the one hand the fact that the capacity bookings by the shippers are tied more closely to physical transport requirements enables them to align their offer of capacity more precisely to market needs. Capacity can be shifted from points of low demand to points where it is high, provided this is hydraulically possible. On the other hand there is the challenge posed by the TSOs' liquidity planning and network charge calculation. When it is more difficult to forecast booking patterns it becomes harder to set specific charges and plan revenue flows.

1.6 Interruptible capacity

Interruptible gas capacity is, as a rule, less expensive than firm capacity. It does however involve the risk that the desired gas transport may not be possible.

10 gas wholesalers and suppliers stated that they had in fact experienced interruptions in the 2013/14 gas year. As in recent reporting years, there was a very uneven distribution of both the number and the length of the interruptions among the various wholesalers and suppliers. Apart from the average duration of interruption in hours, the diagram below shows the absolute number of interruptions experienced by the wholesalers and suppliers in the particular gas year. While the number of interruptions remained nearly constant compared with the previous year, the average interruption duration has significantly declined: 14 hours as against 28 in the year before. In total, there was a continued year-on-year overall decrease in the total length of interruption for all affected companies (gas year 2013/14: 946 h; gas year 2012/13: 1,975 h; gas year 2011/12: 6,753 h). There was a slight decrease in the absolute number of affected wholesalers and suppliers whose contracts were interrupted at least once, compared with previous years (gas year 2013/14: 10; gas year 2012/13: 11; gas year 2011/12: 14). Key elements for calculating the tariffs for interruptible capacity were defined in the Determination for Pricing Entry and Exit Capacity ("BEATE") (see chapter II.C.2).

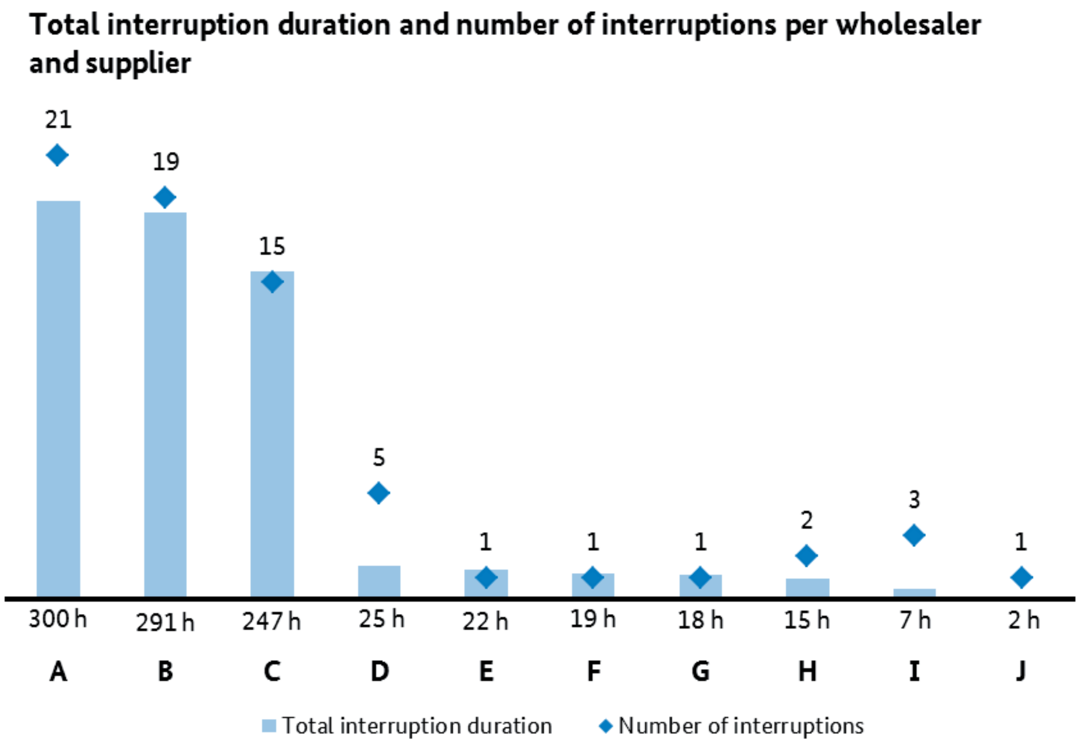

Figure 123: Number of interruptions and average interruption duration per company for the gas year 2013/14

The diagram can be elucidated by a brief explanation of a single example: The diagram lists the 10 wholesalers and suppliers who experienced at least one interruption in the period under review, specifying the respective pair of values of interruption duration and frequency. The company with the highest interruption duration (column 1) experienced a total of 21 interruptions lasting a total of 300 hours.

Similarly, network operators were surveyed on the duration of interruption and interrupted volume of both interruptible and firm capacity products in relation to the initial nomination or alternatively the last figure renominated by the shipper before the interruption was made known.

In 2014, the volume of initially nominated gas that was not transported through all entry and exit points was 6.6bn kWh. Of that amount, the interruption of interruptible capacity made up the majority (95.7%).

Through the interruption of interruptible capacity, a total of 6.3bn kWh of the nominated volume was not transported. The majority of interrupted volume (75%) is attributed to interruptions at cross-border interconnection points; of that amount, 70.7% was accounted for by one single interconnection point. The share of interruptions at storage facility connection points was 24.7%; the remainder of interruptions was attributed to inter-market-area transports.

With regard to firm capacity contracts, interruptions at cross-border interconnection points made up the overwhelming majority (99.8%) of interrupted volume; interconnection points to storage facilities made up the rest. An interruption of transport to a final consumer connection point did not lead to any restrictions of the nominated volume.

The following diagram depicts the regional distribution of interruptions. The interrupted volume and services depicted relate to the share of the nominated volume that was not transported due to an interruption issued by the TSO. In relation to the total nomination volume accepted, there were interruptions to 0.1% of the volume nominated by shippers at entry points and 0.55% at exit points. As mentioned above, however, a majority of interruptions were attributed to volume from interruptible transport contracts.

The direction of the arrow shows in which direction transmission was interrupted. In this context it is important to note that the width of each arrow grows in proportion to the share of the volume interrupted in relation to total interruptions.

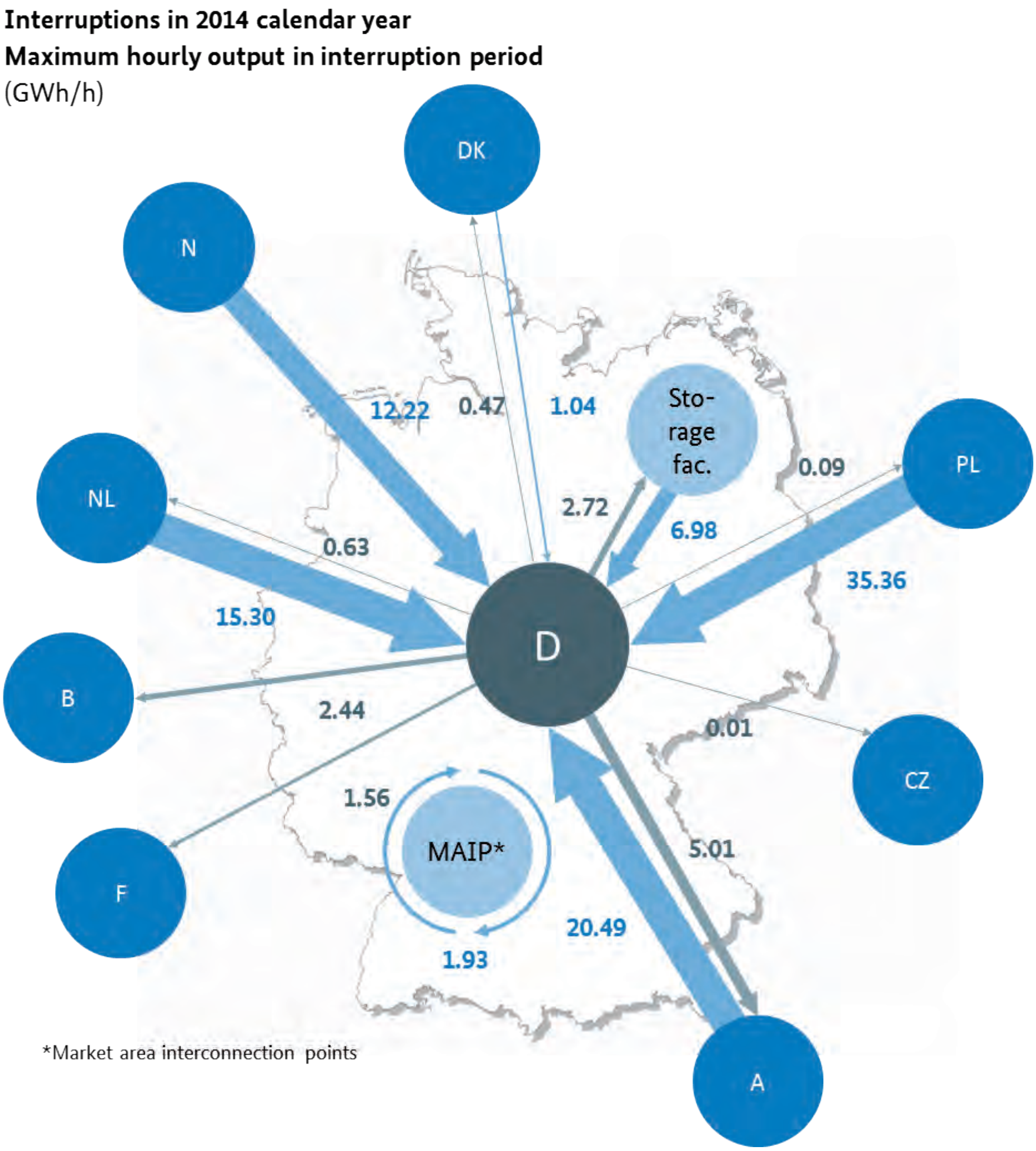

Figure 124: Maximum hourly output in interruption period by region

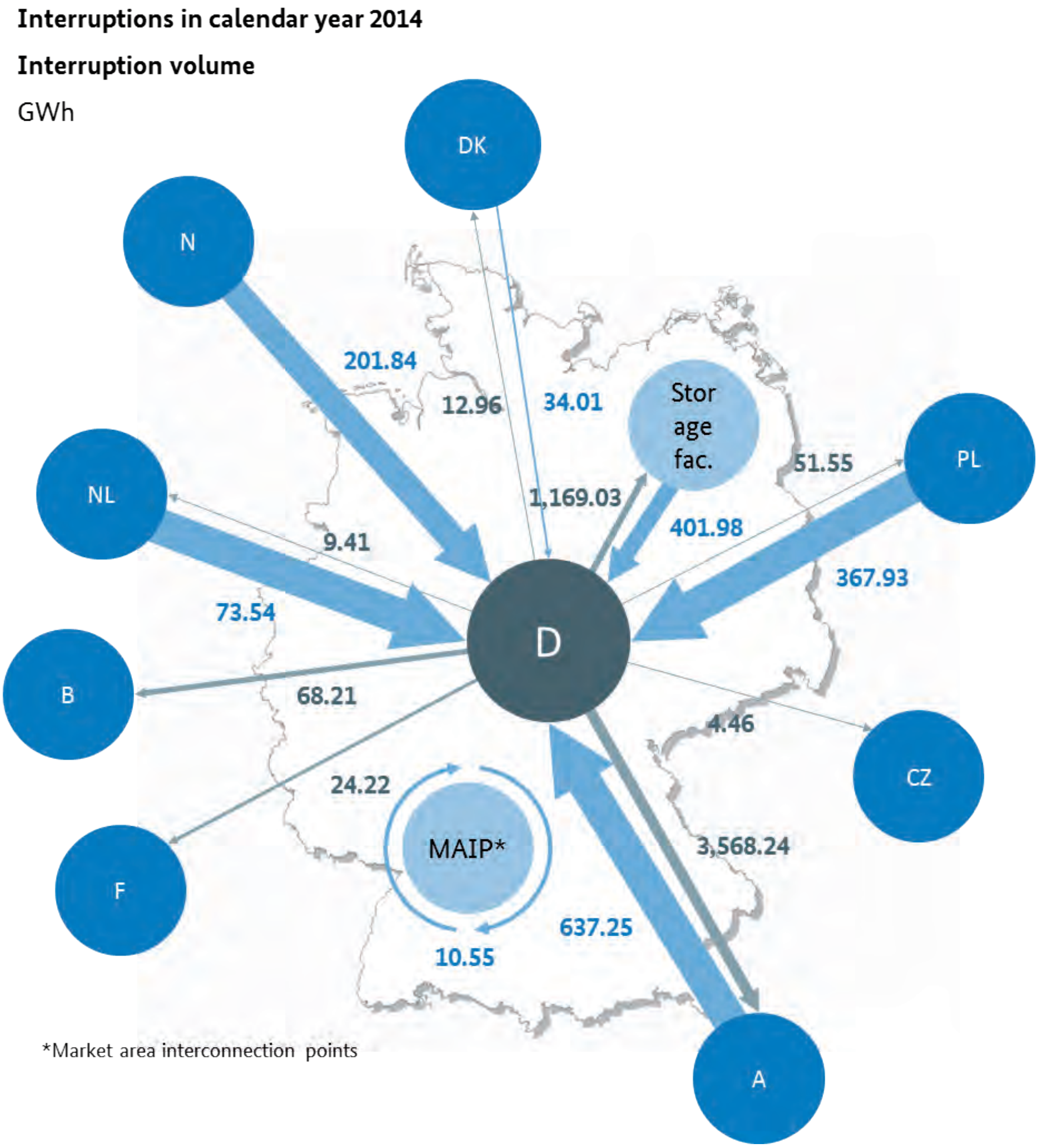

Figure 125: Interruption volume according to region

2. Network charges

2.1 Development of network charges in overall gas price between 2007 and 2015

The following figure shows the development of the average volume-weighted net gas network charges for three consumption categories in ct/kWh from 1 April 2007 to 1 April 2015. The charges include upstream network costs as well as charges for billing, metering and metering operations. The values shown are based on data provided by gas suppliers, which shows considerable spread. The data collection systems used have also been adjusted on numerous occasions over the course of time. The network charges shown are based on the following three consumption categories:

- Household customers: Households with an annual consumption of 23,269 kWh/year. This value falls within the consumption range of Eurostat customer category D3.

- Business customers: Consumers with an annual consumption of 116 MWh and without a fixed annual usage time.

- Industrial customers: Consumers with an annual consumption of 116 GWh and an annual usage time of 250 days (4,000 hours).

The network charge for household customers with a consumption volume of 23,269 kWh has remained at a similar level since 2013; as of 1 April 2015, it amounts to €1.40/kWh. As the figure after next shows, the share of network charges in the overall gas price has, at nearly 20%, remained nearly unchanged over the years.

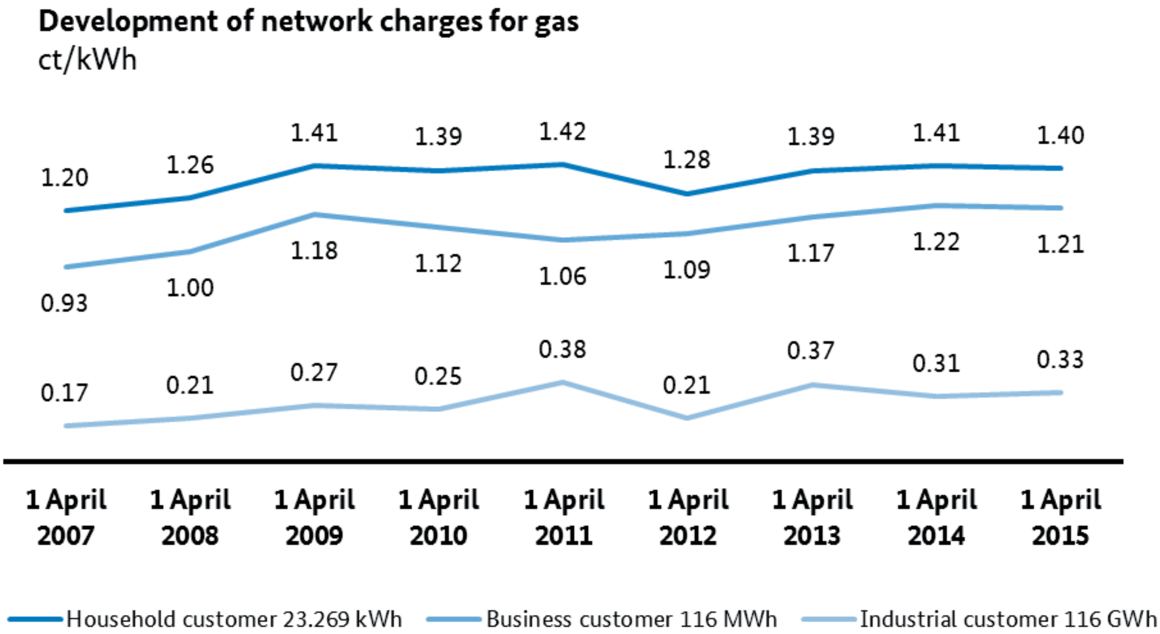

Figure 126: Development of network charges for gas based on survey of gas suppliers

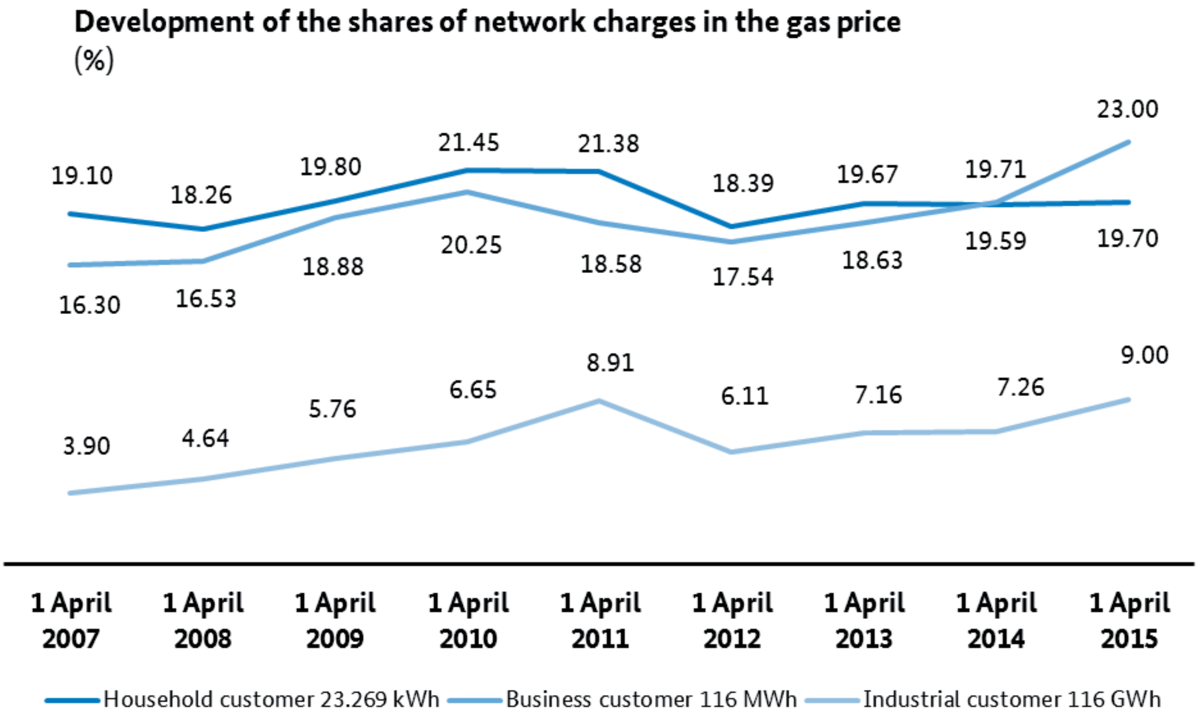

Figure 127: Development of the shares of network charges in the gas price based on survey of gas suppliers

2.2 Expansion factor as per section 10 ARegV

A lasting change in supply services allowed DSOs to apply this year again for an expansion factor for their investments in network expansion. This factor ensures that costs for these investments resulting from a lasting change in the operator's supply services during the regulatory period are also taken into account when determining the revenue cap. A lasting change in supply services is deemed to have occurred if the parameters cited in section 10(2), second sentence, of the Incentive Regulation Ordinance (ARegV) change on a permanent basis and to a significant extent. In the 2014 reporting year, 74 applications for expansion factors were made.

2.3 Incentive regulation account as per section 5 ARegV

The difference between revenue allowed under section 4 ARegV and revenue potentially generated by operators in light of the development of actual consumption volumes is entered annually in an incentive regulation account. Section 28 para 2 ARegV requires operators to submit the data needed to keep the incentive regulation account to the regulatory authority in each instance by 30 June of the following calendar year. The regulatory authorities use the data to determine the differences to be entered in the incentive regulation account. In the final year of the regulatory period, the balance of the account is established for the past calendar years in accordance with section 5(4) ARegV. The balance in the account is cleared by additions or deductions spread evenly over the following regulatory period; these carry interest as stated in section 5(2), third sentence, ARegV.

2.4 Network interconnection points under section 26(2) ARegV

In 2014, a total of 35 applications concerning network transfer, merging and splitting of networks in the gas sectors were submitted under section 26(2) ARegV. The network operators state in their applications which percentage of the revenues is to be assigned to the part of the network being transferred and which percentage to the remaining part. In many cases there is a time lag in processing the applications; concession changes in particular can bring about delays as a result of disagreements between the two network operators involved with regard to the purchase price, the tangible assets to be transferred and the revenue cap to be transferred. Before a final decision is made by the Bundesnetzagentur, the network operators must agree on the percentage of revenues that is to be transferred. The Bundesnetzagentur as well as any regulatory authorities of the federal states must in particular ensure that the total of both parts of the revenue does not exceed the revenue cap already set as a whole.

2.5 Horizontal cost allocation

Currently no prices are charged for gas transports between TSOs. Costs are thus not allocated at network interconnection points between TSOs, even though they come about there. According to the scheme of the two-contract model, the calculation of tariffs is distorted at the “margins” of the market area, which puts out imprecise price signals. This can result in disincentives within the German capacity market.

In recent years, the Bundesnetzagentur’s Ruling Chamber 9 recognised that TSOs were increasingly taking advantage of this exchange of services free of charge, thus contributing to the danger of wrong price signals contained in the network charges. As a result, a determination process was initiated in order to appropriately address the problem described. To this end, formal consultations with the market participants were held in November 2014 and in early 2015. A determination is to be issued on the topic in 2015.

2.6 Determination for pricing entry and exit capacity (“BEATE”)

In 2014, the 9th Ruling Chamber initiated proceedings for the correct calculation of network charges by defining requirements for converting annual capacity prices into capacity prices for non-annual capacity rights in accordance with section 13(2), fourth sentence, GasNEV i. c. w. section 50(1) para. 4 GasNZV, as well as for appropriate arrangements for setting network charges in accordance with section 30(2) para. 7 i. c. w. section 15(2-7) GasNEV. The aim of this determination was to establish, in addition to specifications for calculating tariffs for non-annual capacity rights, specifications for interruptible capacity as well as for entry and exit points at storage facilities. In 2014, Ruling Chamber 9 conducted several hearings with industry representatives on the contents of the planned determination. The market participants were given several opportunities to comment. In March 2015, the determination was issued which set the calculation from annual price to quarterly price at a factor of 1.1, to monthly price at a factor of 1.25 and to daily price at a factor of 1.4. The method to calculate the interruption probability as a basis for pricing interruptible capacity was also defined. In addition, a discount of 50% was set for entry and exit at gas storage facilities.

D Balancing

1. Balancing gas and imbalance gas

Balancing gas is used to ensure network stability and security of supply within the market areas and is procured by the market area managers. A distinction is to be made here between internal balancing gas that is free of charge (network buffer within the market area) and chargeable external balancing gas (procurement through exchanges and/or balancing platforms). As a rule, the share of internal balancing gas is higher, as the market area managers are obligated to use this energy first. Because in winter months there are more frequent fluctuations regarding short and long portfolios, there is an increase in the share of external balancing gas during this period.

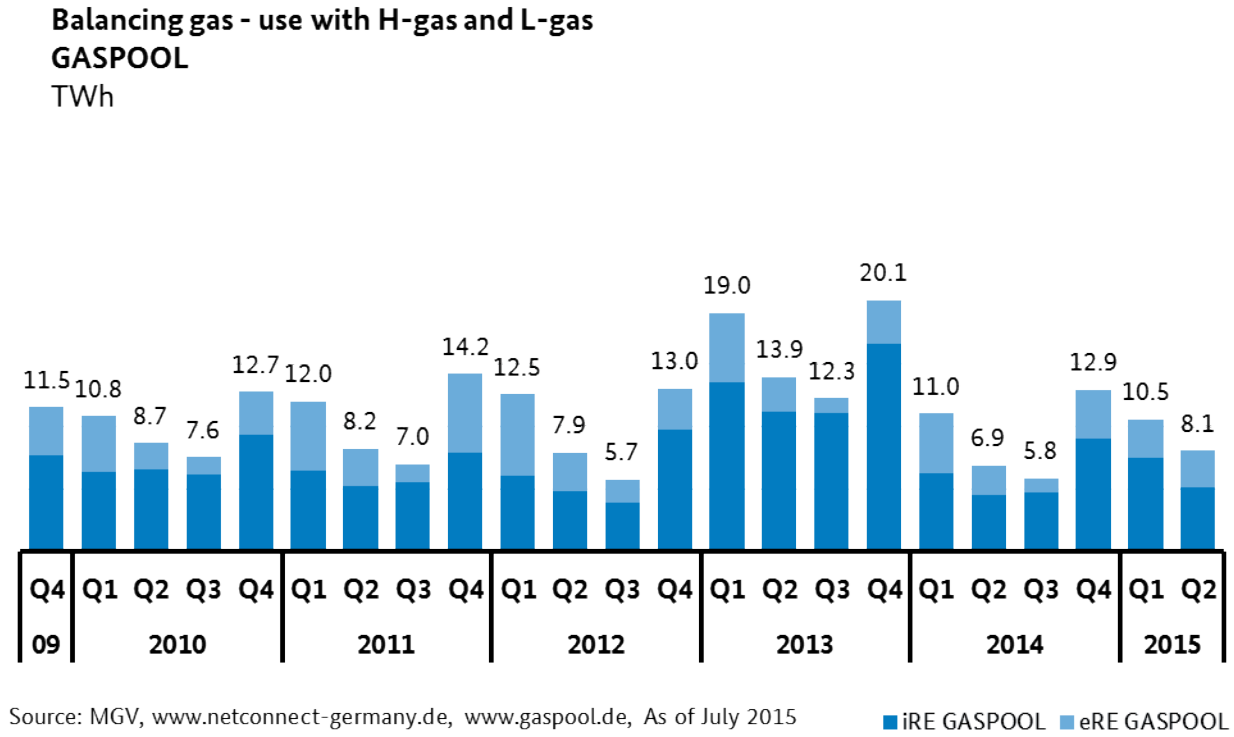

Figure 128: Balancing gas – Use with H-gas and L-gas (GASPOOL)

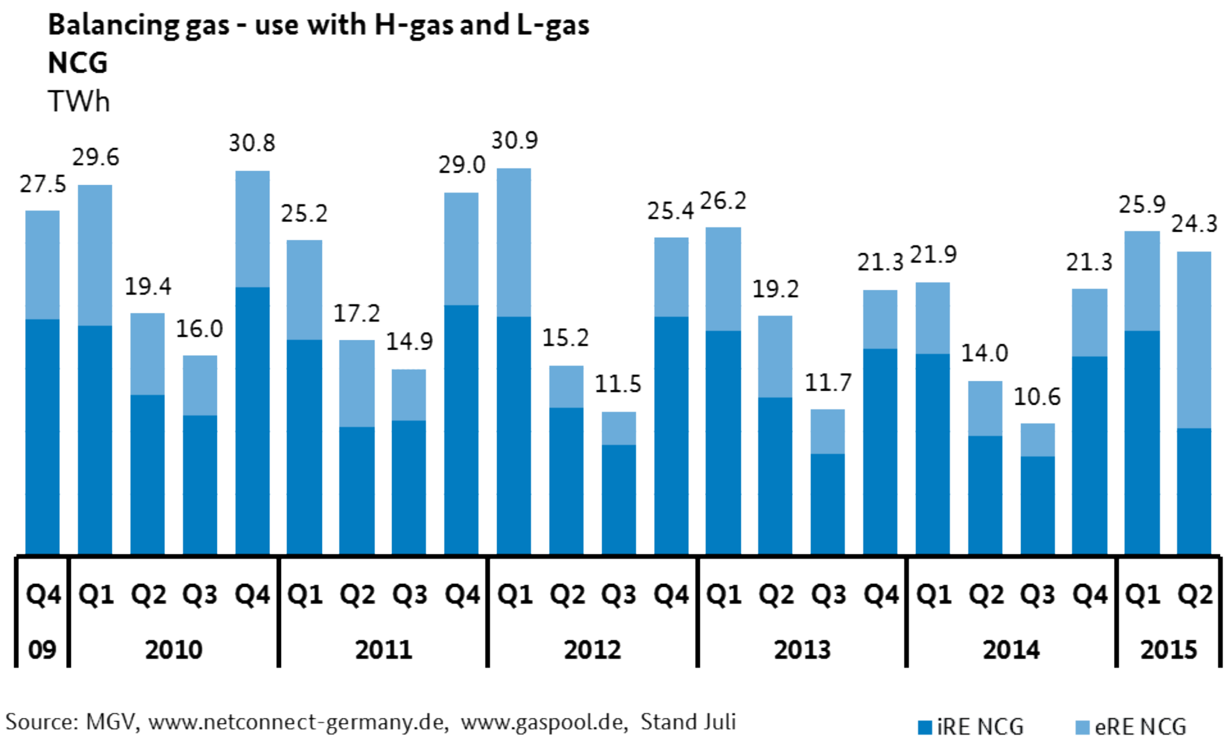

Figure 129: Balancing gas – Use with H-gas and L-gas (NCG)

The procurement of external balancing gas takes place through the exchanges (Pegas and ICE ENDEX) and balancing platforms within the market areas. In addition to this short-term procurement, in the market area NetConnect Germany (NCG) balancing gas is also procured or sold through the contracting of reserve capacity at capacity prices. The purchase price depicted for balancing gas takes into account the reserve costs per MWh and thus enables the comparison between market areas.

The term imbalance gas refers to the difference between entry and exit quantities within a balancing group at the end of the balancing period. It comes about through deviations between the amount of gas actually consumed and the forecast consumption volume. For this quantity of gas the balancing group manager is charged a positive imbalance price in the case short supply and a negative imbalance price in the case of surplus supply; this price is oriented to the prices at the various trading places. Additions and deductions serve as incentives for the balancing group manager to avoid imbalances in his balancing group.

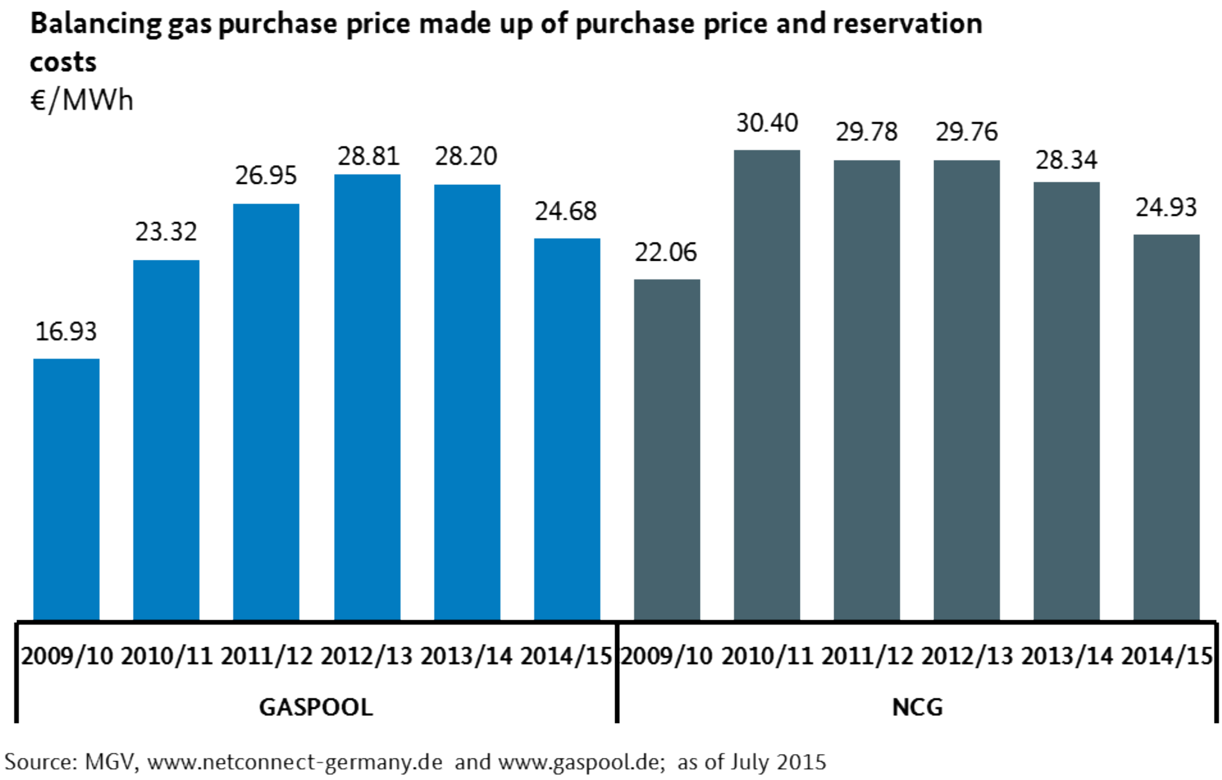

Figure 130: Balancing gas purchase price made up of purchase price and reservation costs

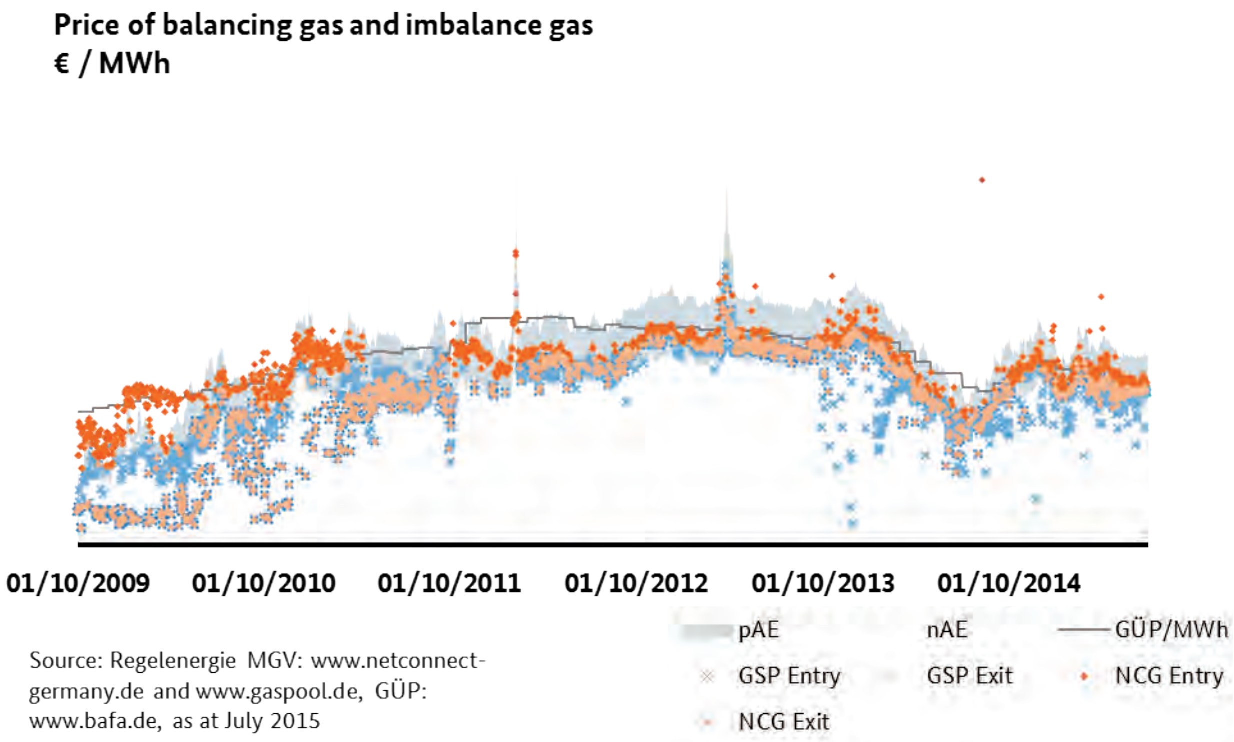

Figure 131: Price for balancing gas and imbalance gas

2. Development of the balancing neutrality charge

The costs and revenues incurred by the market area manager from the gas balancing regime must be allocated to the balancing group managers. In the process, the market area manager forecasts the future costs and revenues for his neutrality charge account. If the forecasted costs exceed forecasted revenues, the market area manager levies a balancing neutrality charge from the respective balancing group managers.

The increasing procurement of balancing gas at the exchanges and a well-functioning balancing system, among other factors, have allowed both of the market area managers to temporarily lower the balancing neutrality charges to €0/MWh for several periods.

The forecasted demand for balancing gas and the associated costs have led GASPOOL and NCG to reintroduce a neutrality charge. Due to the revision of balancing rules that became necessary under the Network Code for Balancing, as of 1 October 2015 both market area managers will calculate and levy separate neutrality charges for non-daily metered (SLP) and (intraday) interval metered (RLM) customers according to a set key. In the GASPOOL market area, the RLM neutrality charge will amount to €0/MWh and the SLP neutrality charge to €1.50/MWh. In the NCG market area, both charges will amount to €0/MWh.

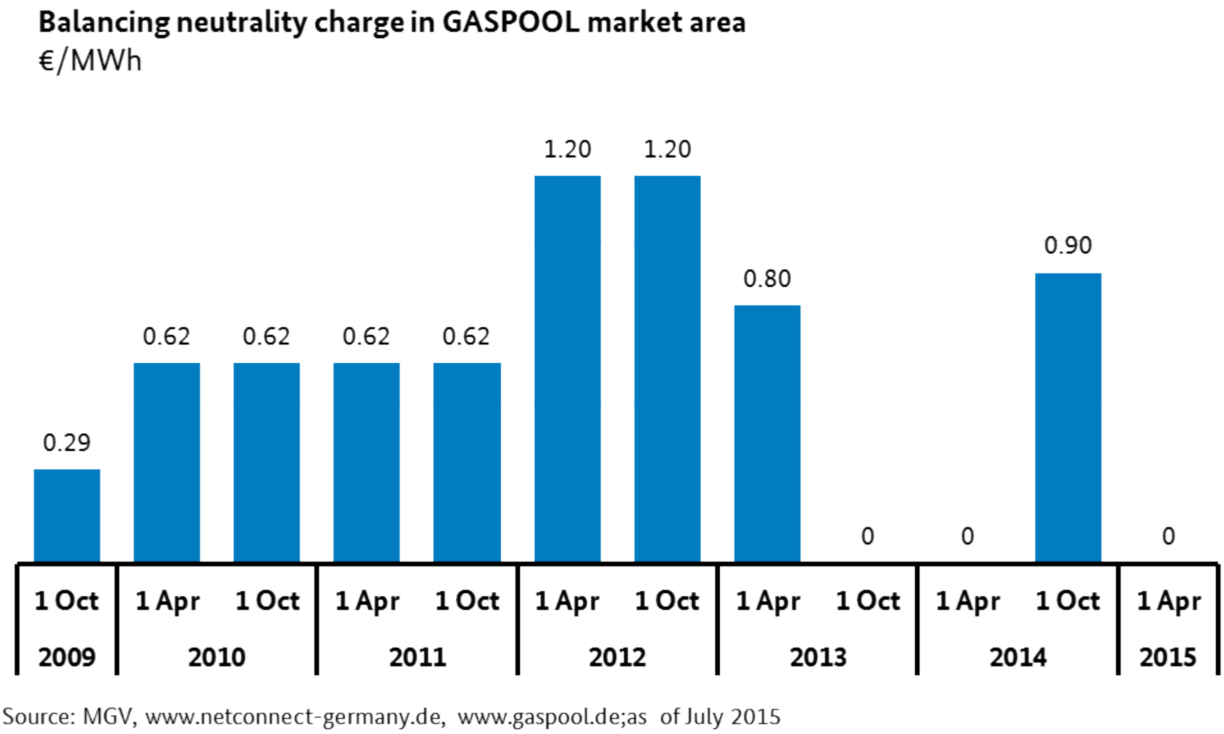

Figure 132: Balancing neutrality charge in GASPOOL market area

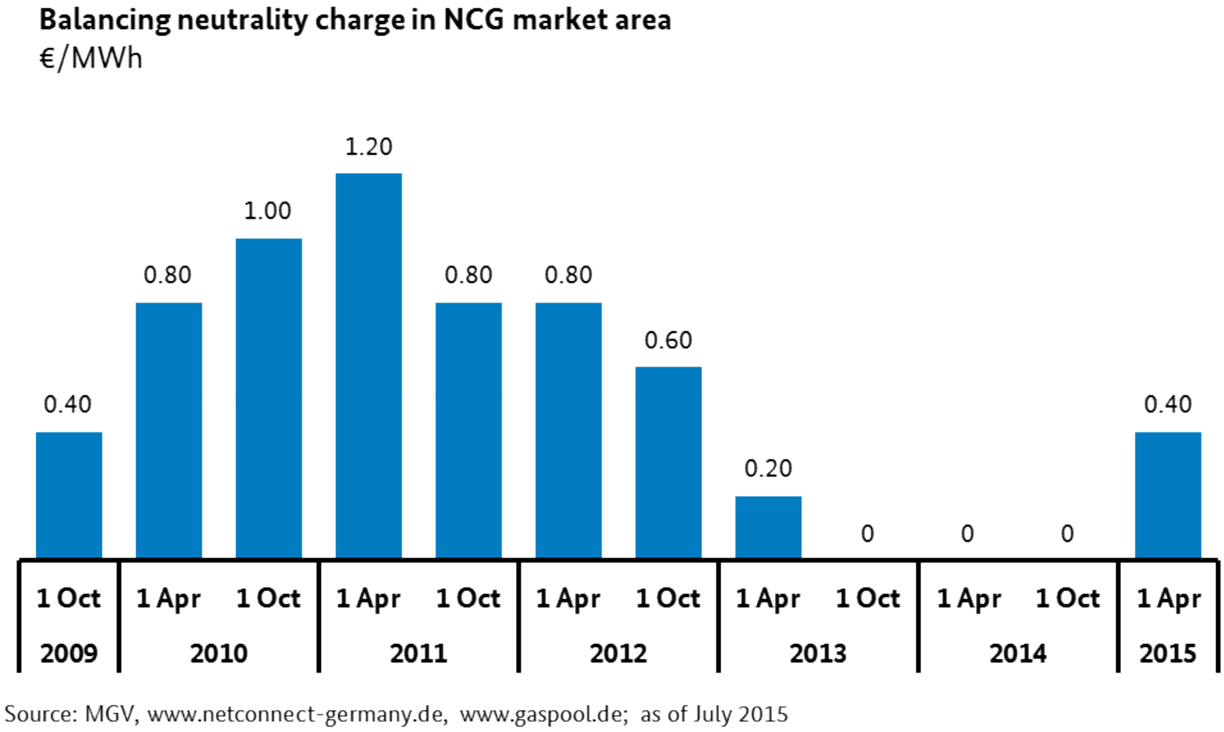

Figure 133: Balancing neutrality charge in NCG market area

3. Non-daily metered customers

The balancing system according to the basic model of balancing services and balancing rules in the gas sector (GABi Gas) categorises final consumers according to their offtake behaviour and maximum supply capacity and allocates them into different case groups. These include, on the one hand, SLP customers who are, for the most part, household and small business customers. On the other hand, there is the group of high-volume interval-metered industrial customers, which in turn is divided into high-volume customers with and without a daily flat supply (RLMmT and RLMoT). Network operators can use two types of SLP profiles: analytical profiles, which in general terms are based on the previous day's consumption at the time of estimation, and synthetic profiles, which rely on statistically calculated values. In 2014, the synthetic SLP profiles were used by 83.4% of operators; analytical profiles were used by 14.2% of operators, compared with 12.2% in 2013.

The significance of SLP profiles is evident in the fact that nearly all exit network operators (98%) used them when delivering to household or small business customers. The synthetic profiles of the Technical University of Munich (TU München), used in the versions of 2002 and 2005, dominate with a market coverage of 95.6%. This figure also remains virtually unchanged compared with the previous year (94.4%).

The TU München offers a range of different profiles which reflect the offtake behaviour of various customer groups. 48.9% of network operators stated that all available profiles were applied, compared with 48% in 2013. The responses to the follow-up question as to how many profiles were actually used indicated a slight trend toward using more profiles. In the previous years, two profiles were generally used for household customers, while on average seven profiles were used for business customers. In the year under review, the number increased to an average of 2.5 among household customers and 8 profiles among business customers.

SLP profiles, as forecasts, are naturally marked by inaccuracies. The average deviation between allocation and the actual offtake on a daily basis was 3.8%, which is lower than in 2013 (4.6%). The average maximum deviation on one day was 56.1%, which is virtually unchanged compared with the previous year's level (56.4%). These extreme fluctuations are a cause for concern as they can each result in increased balancing gas. It must be borne in mind, however, that these figures may not be representative as only 62.6% of the network operators provided relevant data regarding deviations at all, although it could be assumed that operators with a comparatively high forecast quality tended to respond. In 2013, 62.1% of network operators provided relevant data.

14.6% of operators made adjustments to the load profiles owing to the deviations, compared to 22.6% in 2013.

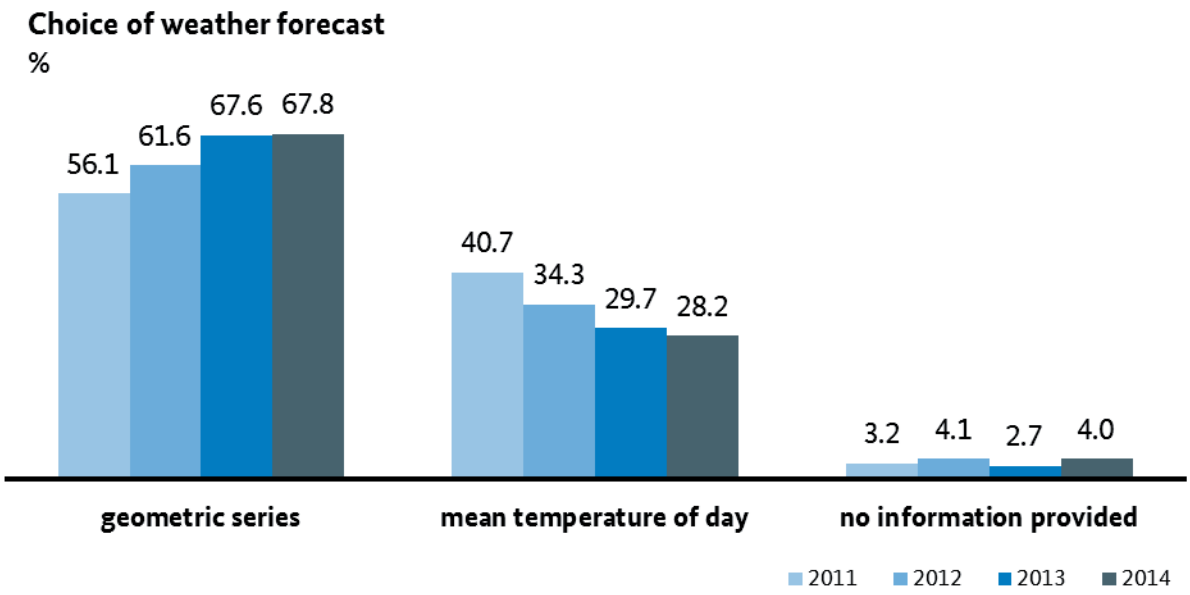

Figure 134: Choice of weather forecast

Due to the strong temperature dependence of SLP profiles, there is a continuing strong trend toward using a differentiated forecast temperature ("geometric series"). In this procedure, the actual temperatures of the days before the day of delivery are taken into account to decrease the deviation risk.

Various procedures are available to the operators for the settlement of the SLP reconciliation quantities. As can be seen in Figure 135, a trend towards fixed-date procedures was already observed in previous years.

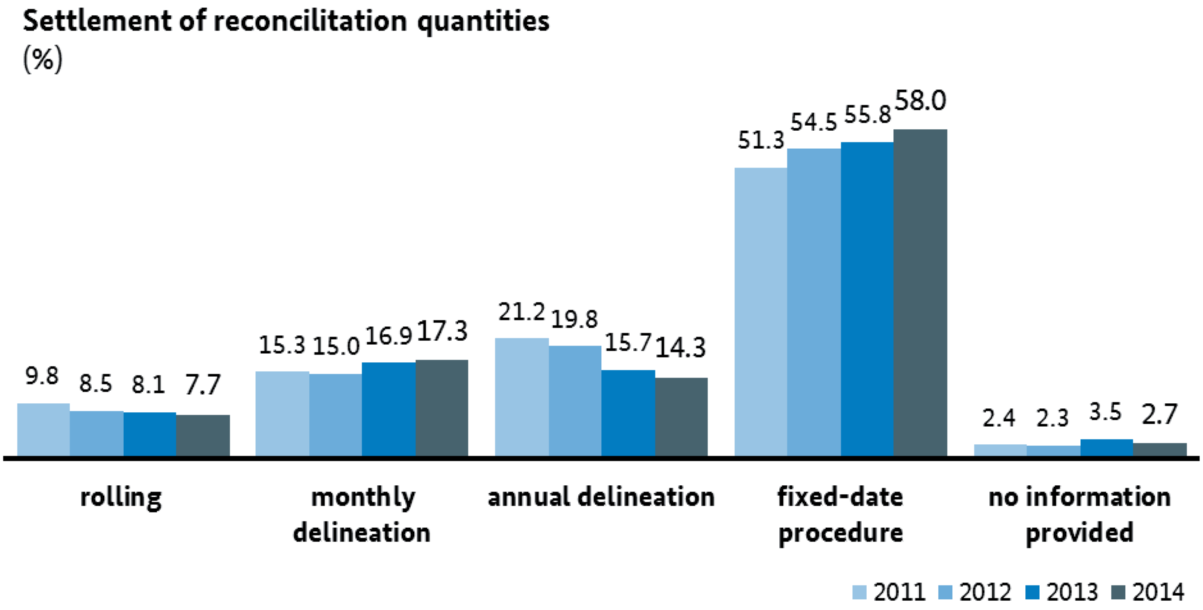

Figure 135: Procedures for the settlement of reconciliation quantities

4. Interval metering and case group switching

The balancing system according to the basic model of balancing services and balancing rules in the gas sector (GABi Gas) categorises final consumers according to their offtake behaviour and maximum supply capacity and allocates them into different groups. These include, on the one hand, standard load profile customers who are, for the most part, household and small business customers. On the other hand, there is the group of high-volume interval-metered industrial customers, which in turn is divided into high-volume customers with and without a daily flat supply (RLMmT and RLMoT). The allocation of these high-volume customer groups is principally based on the respective maximum supply (or offtake) capacity, for which a threshold of 300 MWh/h has been set. High-volume customers with a supply capacity of more than 300 MWh/h are allocated to the consumer group RLMoT and vice versa, although the balancing group manager can decide, at the request of the shipper, to switch groups, provided that the market area manager does not see the risk of an unacceptable degradation of system stability and reject the request of a planned switch. The advantage of the RLMmT group, in addition to the ex-post allocation of offtake volumes to a daily flat supply, also lies in the higher hourly balancing group deviation tolerance of 15% (compared to a 2% tolerance for the RLMoT group).

In the survey on the gas year 2013/2014, 301 balancing group managers provided information about the groups to which their interval-metered customers were allocated.

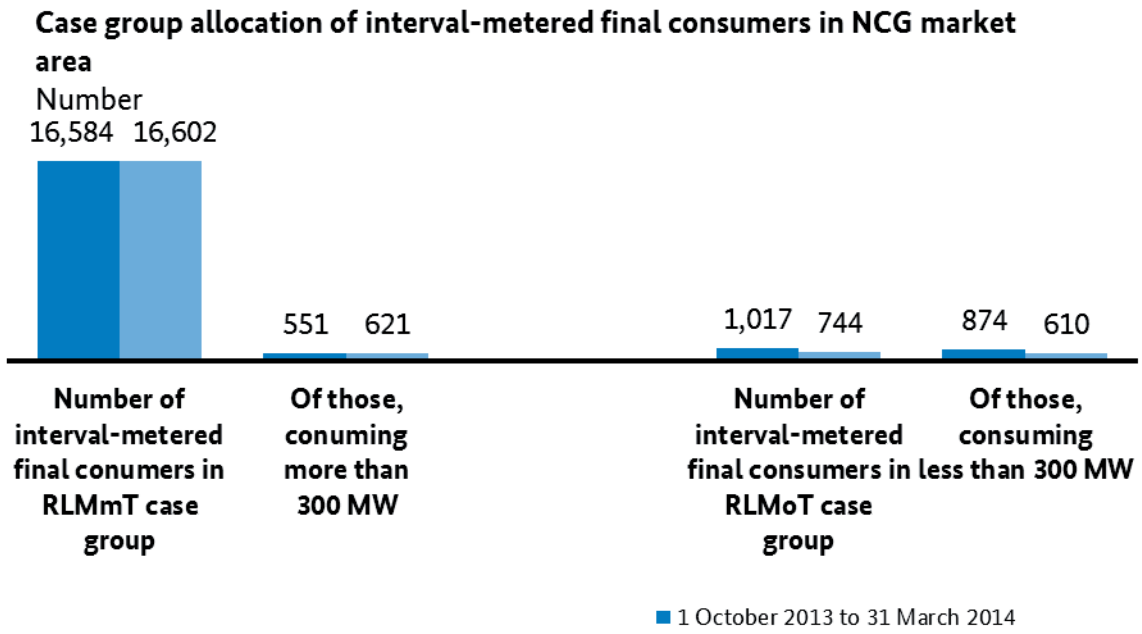

Figure 136: Case group allocation of interval-metered final consumers in the NCG market area

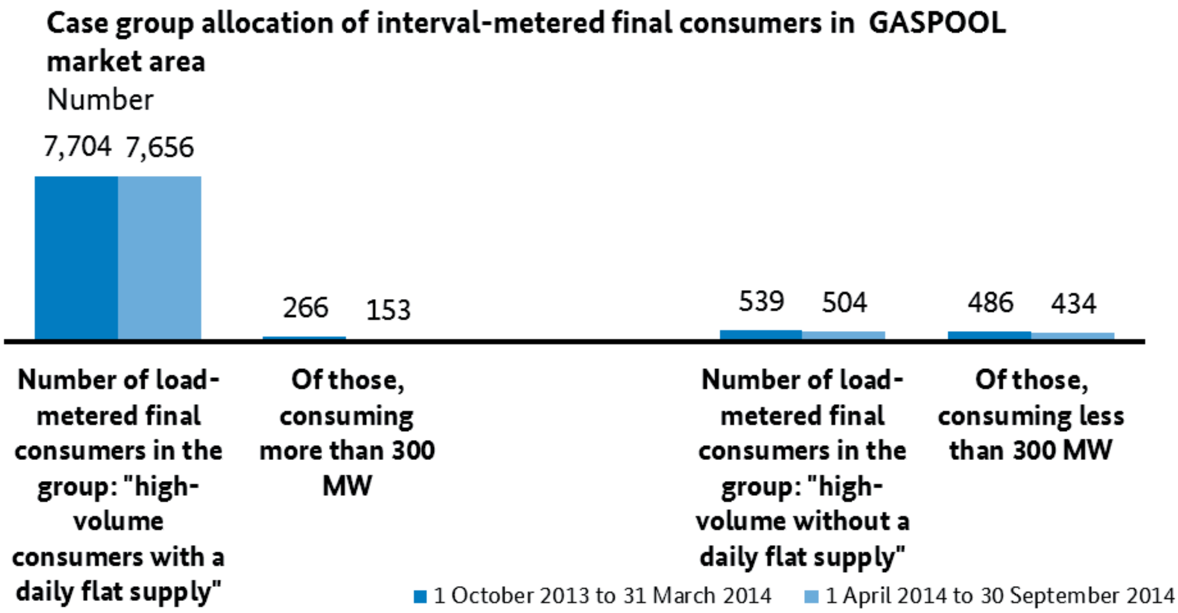

Figure 137: Case group allocation of interval-metered final consumers in the GASPOOL market area

Both diagrams show that the balancing neutrality charge, which was not applied in the period under review, constitutes a significant factor in the decision of customers in favour of the RLMmT group. It should be noted, however, that the increased charge in the GASPOOL market area in winter 2014/15 is not yet reflected in this assessment, as only data from the 2013/14 gas year has been collected. For this reason, we can expect to see an increased share of the case group RLMoT in the GASPOOL market area in the next reporting period.

In general, the balancing group manager or shipper can choose their case group independently of the maximum supply capacity, as long as the market area manager does not see an associated risk to the safe and efficient operation of the gas network. In this case, the market area manager is authorised to reject the request. In the gas year 2013/14, three out a total of 7,204 notices was rejected on technical grounds. Compared to the previous year's figures of 8,984 notices and one rejection on technical grounds, the number of switches has declined significantly, with the neutrality charge in the period under review remaining steady at €0/kWh; as a result, the reason for the high number of group switches in recent years was not given.

In accordance with the GeLi Gas business processes for change of gas supplier, shippers can receive hourly data of their RLM customers from their network operators. Balancing group managers were asked within the context of monitoring how many high-volume customers with daily flat supply this hourly data transmission was used for in order to carry out intraday adjustments to the nominations. During the period from 1 October 2013 to 31 March 2014 such an adjustment was undertaken for 1,512 customers; from 1 April 2014 to 30 September 2014 this number increased to 1,562, which corresponds to around 6% of the high-volume customers with daily flat supply served by the balancing group managers providing data.

In addition to the case groups mentioned above, there are also RLM exit points with the possibility of a substitute nomination procedure, for example in the form of an online flow control system (RLMNEV). The balancing group managers who provided data put the number of high-volume customers with substitute nomination procedures in their balancing groups at a total of 138 for the first half of the gas year and 123 for the second half.

E The wholesale market

Liquid wholesale markets are vital to ensure well-functioning markets along the entire added-value chain in the natural gas sector, from the procurement of natural gas through to supplying end customers. The more varied the possibilities for the short- and long-term procurement of gas at wholesale level are, the less companies depend on tying themselves to a single supplier in the long term. The options open to market players to select from a large number of trading partners and to hold a diversified portfolio of short- and long-term trading contracts are expanded. Liquid wholesale markets hence make it easier to enter the market, and promote competition for end customers.

The liquidity of the German natural gas wholesale markets increased once more in 2014. Major increases can be observed at bilateral wholesale level. The volume of the exchange trade in gas more than doubled. The Bundeskartellamt meanwhile assumes the existence of a nation-wide natural gas wholesale market and no longer defines it by reference to a network or market area. The foreign gas producers meanwhile trade directly on the German virtual trading points and the wholesale transmission companies have increasingly lost their special position in recent years.

The year under report 2014 featured significantly lower gas wholesale prices. The various price indices show a year-on-year decrease of between 15 percent and 22 percent. This development is generally attributed to the reduction in German and European gas consumption, due mainly to the relatively mild weather in 2014.

1. On-exchange wholesale trading

The exchange that is relevant for German natural gas trading is operated by the European Energy Exchange AG and its subsidiaries (referred to collectively below as EEX). EEX has once more taken part in this year's data collection within monitoring. The trading place of EEX includes short- and long-term trading transactions (spot market and futures market). All types of contract are equally tradable for both of the German market areas NetConnect Germany (NCG) and GASPOOL.

Natural gas trading for the current gas supply day is possible on the spot market with a lead time of three hours (within-day contract/intraday product), for one or two days in advance (day contract) and for the following weekend (weekend contract), and is possible continuously ("24/7 trading"). The minimum contract size is one MW, so that smaller volumes of natural gas can also be procured or sold at short notice. Quality-specific contracts (high calorific gas or low calorific gas) have also been available since October 2013.

The futures market serves to ensure the long-term procurement of gas, as well as to optimise portfolios, and to hedge against price and volume risks. Futures are tradable on EEX for specific months, quarters, seasons (summer/winter) and years.

PEGAS, a cooperation established between the EEX and the French Powernext SA in 2013, which aims to enhance cross-border trading, was further developed in the year under report 2014. Following antitrust clearance by authorities including the Bundeskartellamt, EEX acquired the majority of the shares in Powernext SA as of 1 January 2015, making it part of the EEX group. Meanwhile (situation as of July 2015), spot and futures market products for the gas market areas in Germany, France, the Netherlands, Belgium, Great Britain and Italy can be traded via PEGAS.

Another new development during the year under report is the introduction of a transparency platform for energy market data by EEX as of September 2014, which shows data including the daily consumption of natural gas in the GASPOOL and NCG market areas.

The entire trading volume on EEX related to the German market areas GASPOOL and NCG was roughly 212 TWh in 2014, which corresponds to an increase of roughly 122 TWh, or 136 percent, on the previous year's value of 90 TWh. Whereas the trading volumes for the GASPOOL market area increased by approximately 40 TWh, the volume for the NCG market area increased by 82 TWh.

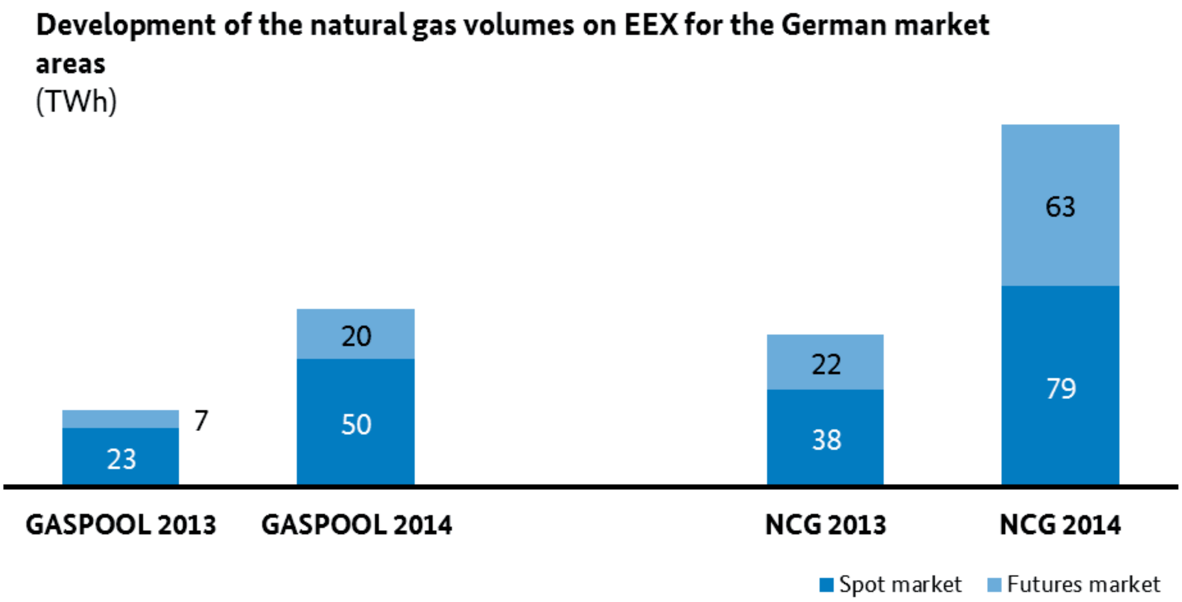

Figure 138: Development of the natural gas volumes on EEX for the German market areas

The volumes traded on the spot market once again more than doubled in 2014, amounting to approx. 129 TWh. This corresponds to five times the volume of the spot market in 2012. As in the previous years, the focus for both market areas in the spot market in 2014 was on day contracts (NCG: 47.8 TWh; GASPOOL: 34.2 TWh). The volume of futures contracts rose from 29 TWh in 2013 to 83 TWh in the year under report, corresponding to an increase of approx. 186 percent.

The number of active participants for NCG contracts per trading day on the spot market averaged over the year was roughly 35 and was approximately 26 for GASPOOL contracts. By contrast, the average number of active participants per trading day for the two market areas on the futures market was 7.7 (NCG) and

3.6 (GASPOOL). It should be taken into account when comparing these numbers that, by virtue of its term, a futures contract aims to achieve a higher volume than a spot contract does.[125]

Four market makers operated in the EEX gas futures market in 2014, ensuring liquidity and continual trade: Bayerngas, E.ON, PGNiG and RWE. The four companies' share of turnover in their function as market makers in all the gas futures contracts concluded via EEX in 2014 was approx. 12 percent on the sales side and approx. 11 percent on the purchase side. In addition to agreements with market makers, EEX has contracts with trading participants that commit themselves to strengthening liquidity to an extent that is individually agreed. These companies accounted for a total of approx. 8 percent of the total trading volume, both of purchases and sales, in 2014.

2. Bilateral wholesale trading

By far the largest share of wholesale trading in natural gas is transacted bilaterally, that is outside the exchanges ("over the counter" - OTC). Bilateral trading offers the advantage that it can be carried out flexibly, i.e. in particular without having to have recourse to a limited set of contracts. A significant role is played in OTC trading by brokerage via broker platforms.

2.1 Broker platforms

Brokers act as intermediaries between buyers and sellers, and combine information on the demand and supply of short- and long-term natural gas trading products. Taking up the services of a broker can reduce the search costs and make it easier to effect larger transactions. At the same time, as a matter of principle it makes a broader risk spread possible. Finally, brokers offer as a service to have the trading transaction which they have brokered registered for clearing on the exchange, so that the parties' trading risk is hedged.[126] The bringing together of interested parties on the supply and demand sides is formalised on electronic broker platforms, and the chance is increased that two parties will come together.

A total of eleven broker platforms took part in this year's data collection on wholesale trading. Nine of these platforms brokered natural gas trading transactions in 2014 with the supply area Germany (NCG and/or GASPOOL).

The natural gas trading transactions brokered by these nine broker platforms in 2014 with the supply area Germany account for a total volume of 2,966 TWh, 1,281 TWh of which were accounted for by contracts with fulfilment in 2014. In comparison to the values that were collected in the previous year - with a total of seven broker platforms - this corresponds to an increase of roughly 15 percent.

Short-term transactions with a fulfilment period of less than one week account for roughly 20 percent of the trading brokered by these nine broker platforms. The transactions for the ongoing year are the clear focus of natural gas trading, followed by the activities for the following year. Whilst the natural gas traded in and for 2014 (including spot trading) constituted as much as 62 percent of the total volume and as much as 32 percent

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[125] A participant is considered to be active on a trading day if at least one of its bids has been implemented.

[126] OTC clearing on EEX in natural gas has been of only relatively slight practical significance to date. In 2014, OTC clearing comprised contracts amounting to a volume of 2.5 TWh.

are traded for the following year (2015), transactions with delivery dates in 2016 and later account for a share of 6 percent. This structure roughly corresponds to the previous year's result.

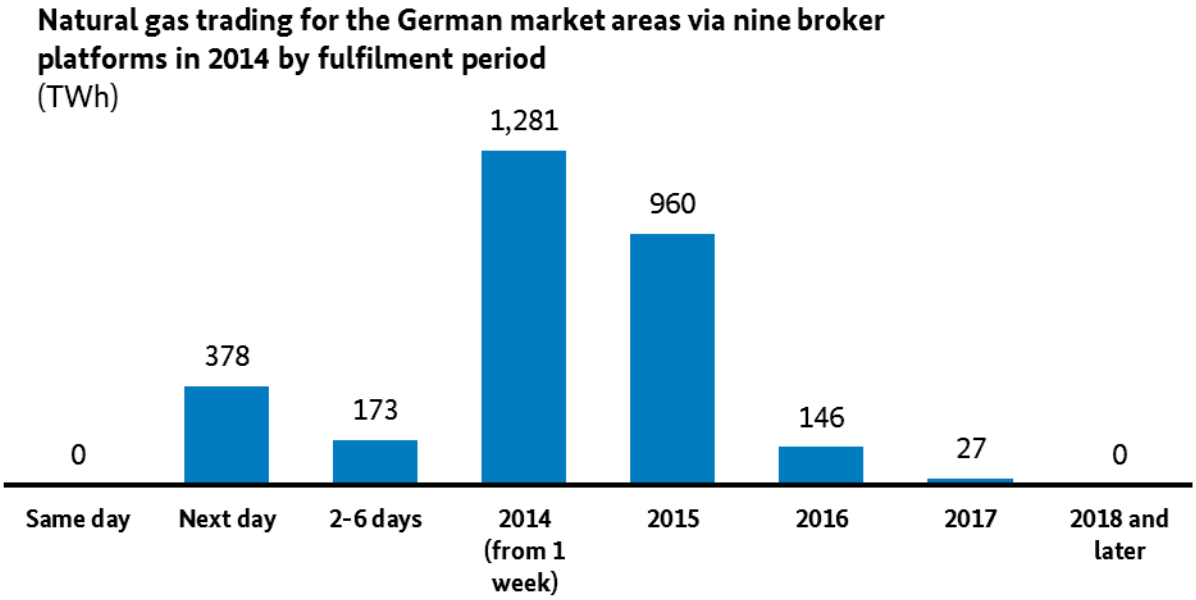

Figure 139: Natural gas trading for the German market areas via nine broker platforms in 2014 by fulfilment period

The increase in volume is confirmed by the figures published by the London Energy Brokers' Association (LEBA) on brokered natural gas trading for the market areas NCG and GASPOOL.[127] Six of the nine broker platforms which provided the information on which the above evaluation was based are members of LEBA. Also according to the figures published by LEBA, a considerable increase can be observed for 2014, as in the previous years. A total of 2,613 TWh was accounted for on the corresponding broker platforms in 2014 for the two German market areas. This corresponds to an increase of 18 percent vis-à-vis the previous year's volume of 2,212 TWh.

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[127] See http://www.leba.org.uk/pages/index.cfm?page_id=59&title=leba_data_notifications (retrieved on 10 November 2015)

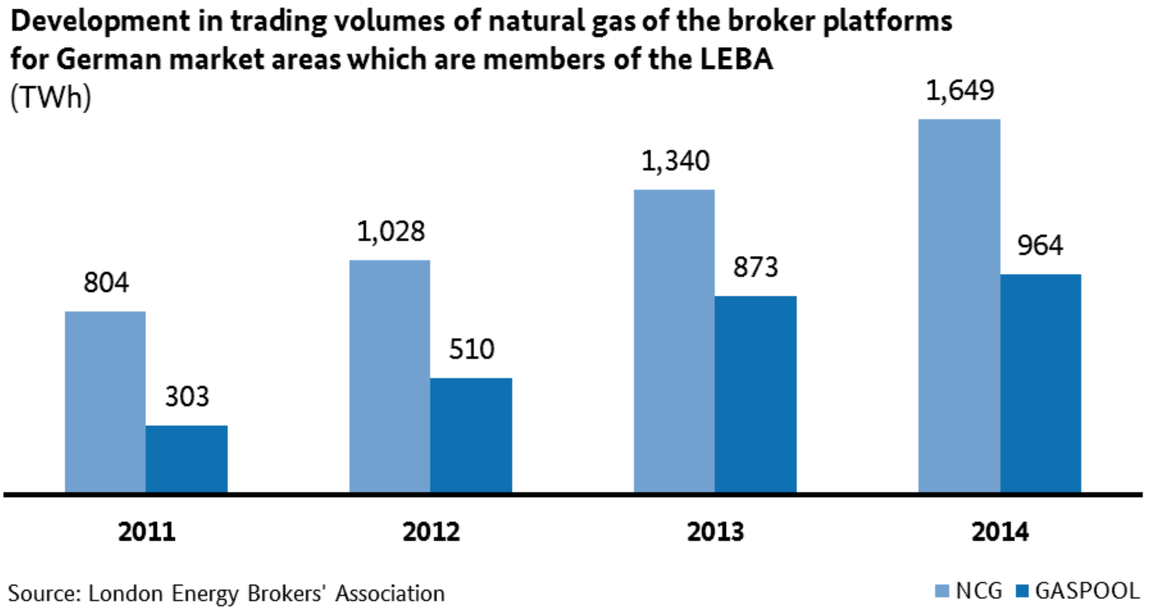

Figure 140: Development in trading volumes of natural gas of the broker platforms for German market areas which are members of the LEBA

2.2 Nomination volumes at the Virtual Trading Points

Significant indicators of the liquidity of the wholesale natural gas markets are also the nomination volumes on the two German Virtual Trading Points NetConnect Germany GmbH & Co. KG (NCG) and GASPOOL Balancing Services GmbH (GASPOOL). Via the Virtual Trading Points (VP), parties responsible for balance groups can transfer gas volumes between balance groups via nominations. Wholesale transactions with physical fulfilment are reflected in corresponding balance group transfers as a rule, so that an increase in wholesale transactions leads to a corresponding increase in the nomination values.[128]

A significant increase in the nomination volumes has been observed at the Virtual Trading Points since the consolidation of the German market areas. This trend also continued in the year under report.

The two parties responsible for market areas, namely NCG and GASPOOL, once more participated in this year's data survey on gas wholesale trading. In spite of gas consumption being approx. 14 percent lower in 2014, there was an increase in the gas volumes nominated on the two Virtual Trading Points. The increase from a total of 2,948 TWh to 3,074 TWh corresponds to growth of roughly 4 percent, without making adjustments to account for the decrease in consumption. The GASPOOL VP accounts for roughly 42 percent of the nomination volume, and the NCG VP accounts for 58 percent. Almost 90 percent of the nomination volume is account for by high calorific gas.

[128] Conversely, however, not all nomination volumes are necessarily tied to a transaction on the wholesale markets since nominations can also be in-group balance group transfers.

An increase in the nominated volumes was observed year-on-year with high calorific gas, both on NCG's VP and on GASPOOL's VP. The nomination volumes of low calorific gas also increased on GASPOOL's VP, but significantly decreased on NCG's VP (reduction by roughly one third).

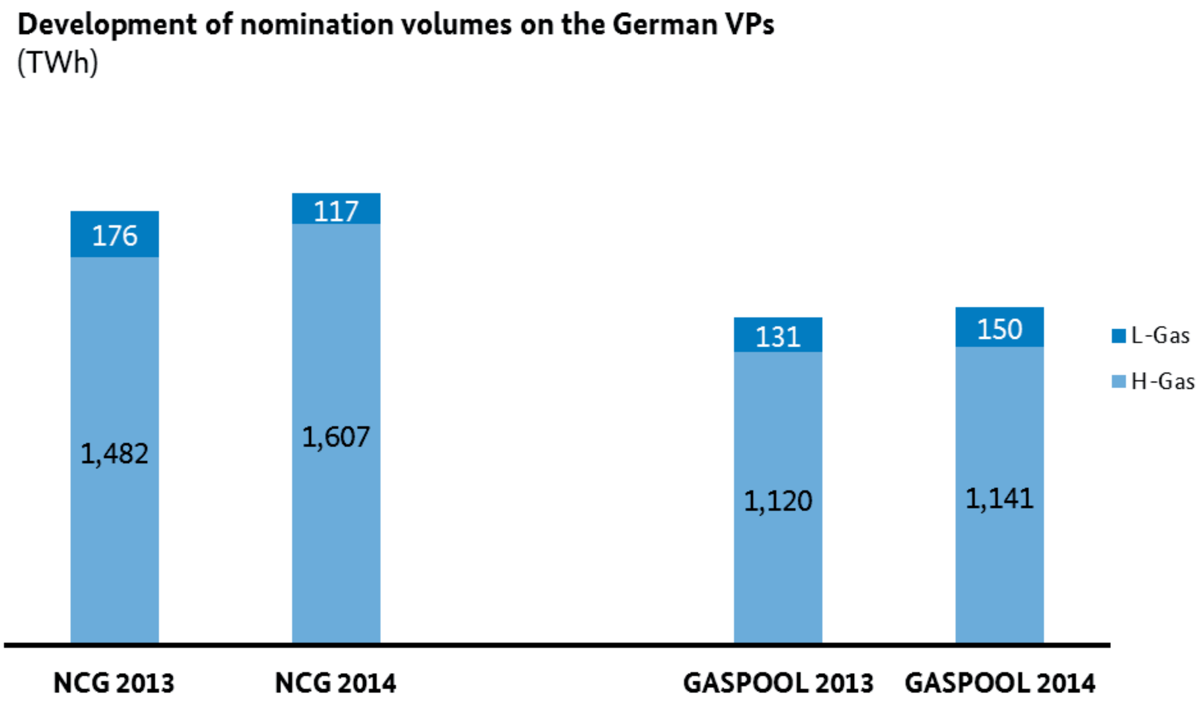

Figure 141: Development of nomination volumes on the German VPs

As in the previous years, seasonal differences are shown in the monthly nomination volumes. In the months April to July 2014, the (added) monthly nomination volume of both VPs was a maximum of 220 TWh. The lowest nomination volume was 207 TWh in June 2014; the peak value for the year was reached in December 2014, at roughly 336 TWh.

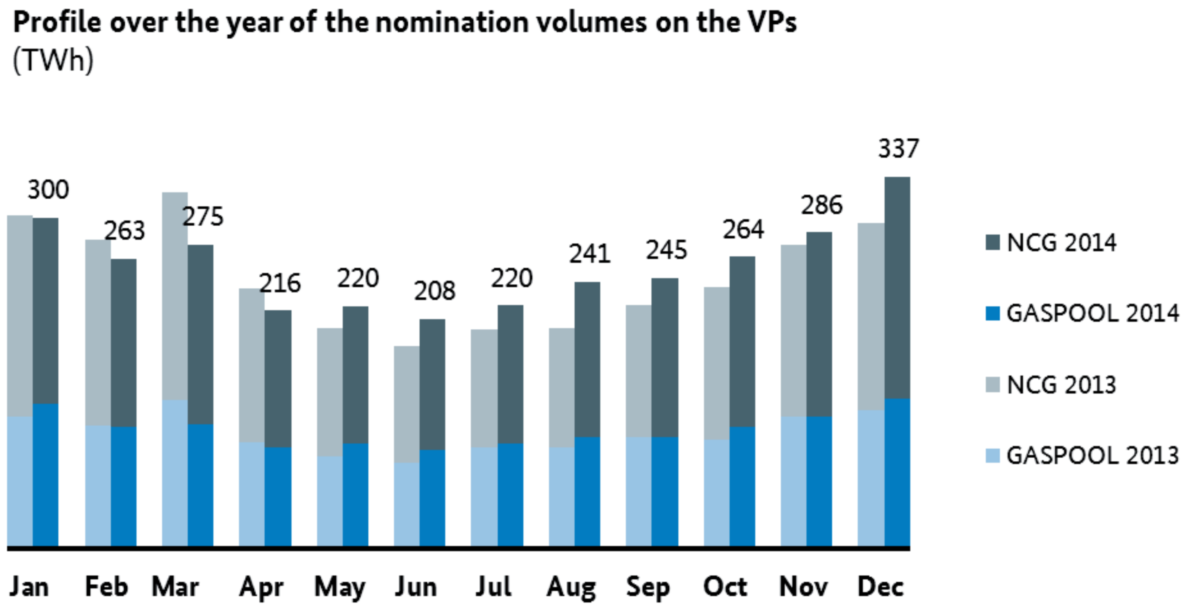

Figure 142: Profile over the year of the nomination volumes on the VPs in 2013 and 2014

The number of active trading participants, i.e. of companies which carried out at least one nomination in the respective month, increased once more in the NCG market area in 2014. The number of active trading participants for high calorific gas in the NCG market area increased from 291 to 303 (4 percent) and for low calorific gas from 145 to 159 (some 10 percent). In contrast, the number of active participants for high calorific gas in the GASPOOL market area, averaged over the year, fell year-on-year from 311 to 255 (by 18 percent) and for low calorific gas it fell from 149 to 134 (by 10 percent).

3. Wholesale prices

The daily reference prices published by EEX show the price level on the on-exchange spot market and thus the average costs of the short-term procurement of natural gas. The European Gas Index Germany (EGIX) also provides a reference price for procurement within a time frame of approximately a month. The price of natural gas procurement on the basis of long-term supply contracts, by contrast, can be read approximately in the BAFA cross-border price for natural gas.

On the on-exchange spot market, EEX calculates daily reference prices for the GASPOOL and NCG market areas by depicting the volume-weighted average of the prices over all trading transactions for gas supply days on the last day prior to physical fulfilment.[129] The daily reference prices are published by EEX at 10:00 a.m. CET on the respective supply day. They are an indicator of the price level of the spot market trading transactions.

[129] For details on the calculation method see http://cdn.eex.com/document/150893/2013-11-28_Beschreibung_Tagesreferenzpreis.pdf (retrieved on 10 November 2015).

The (unweighted) daily reference price averaged 21.21 Euro/MWh for the market area of NCG in 2014 and 21.08 Euro/MWh for GASPOOL. In the previous year, both these values were 27.16 Euro/MWh, i.e. the daily average reference prices over the year fell by some 22 percent. Over 2014, the daily reference prices fluctuated between 15.18 Euro/MWh (on 5 July) and 29.00 Euro/MWh (on 13 January).

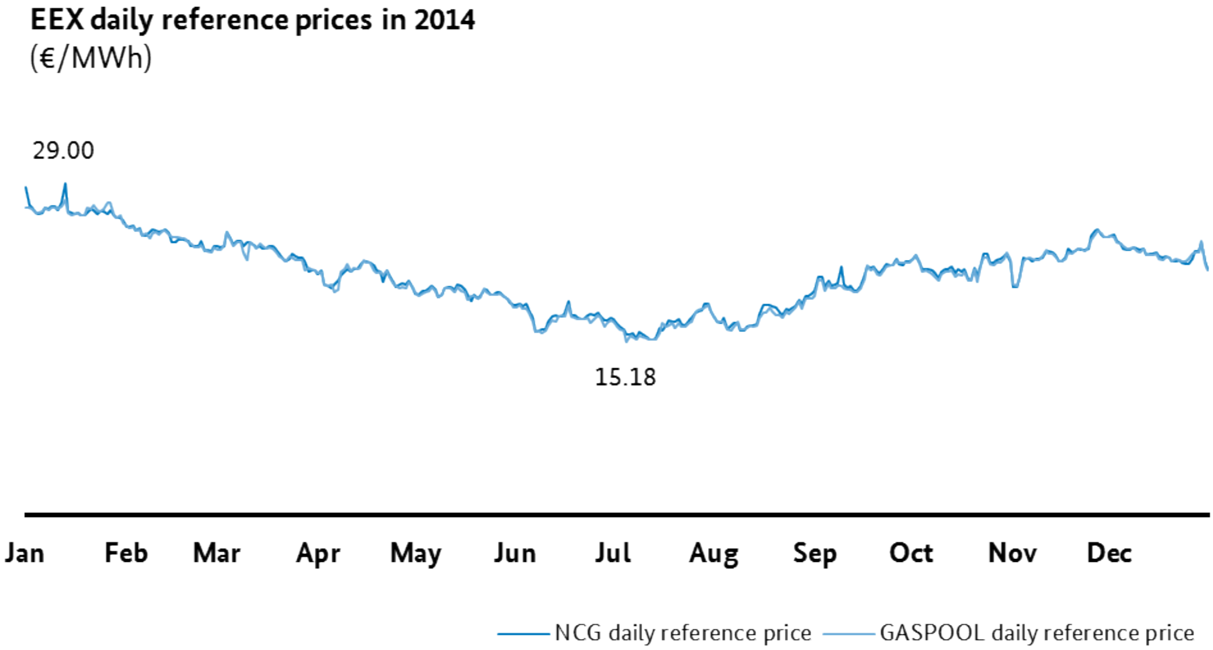

Figure 143: EEX daily reference prices in 2014

The deviations between the daily reference prices on NCG and GASPOOL in 2014 were once again very small. On 344 out of 365 days, the absolute difference was a maximum of 2 percent. Only on three days was the price difference more than 5 percent.

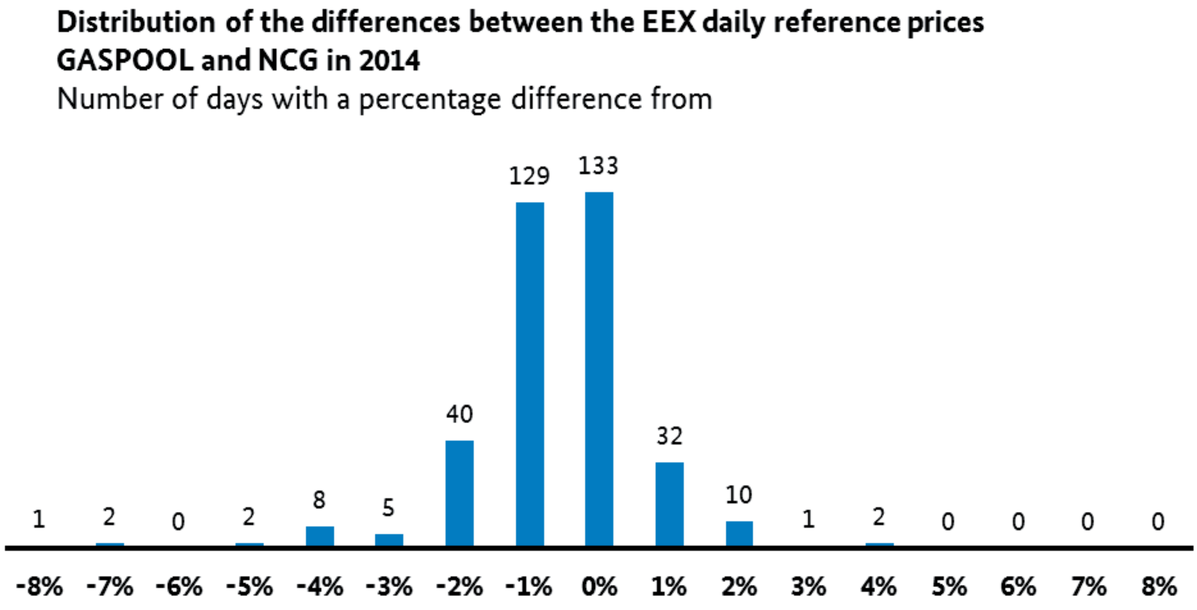

Figure 144: Distribution of the differences between the EEX daily reference prices GASPOOL and NCG in 2014

The European Gas Index Deutschland (EGIX) is a monthly reference price for the futures market. It is based on the trading transactions on the on-exchange futures market which are concluded in the respectively current front month contracts of the NCG and GASPOOL market areas.[130] In 2014, EGIX Germany was between 16.69 Euro/MWh (August) and 28.02 Euro/MWh (January). The twelve monthly values averaged 22.04 Euro/MWh, which corresponds to a fall of approx. 18 percent year-on-year (26.76 Euro/MWh).

The price of natural gas procurement on the basis of long-term supply contracts can be read approximately in the cross-border price for natural gas. The cross-border price is calculated for each month by the Federal Office for Economic Affairs and Export Control (Bundesamt für Wirtschaft und Ausfuhrkontrolle - BAFA). In order to do this, BAFA evaluates available documents on natural gas received from Russian, Dutch, Norwegian, Danish and British gas extraction areas. The main figures indicated are the import quantities and prices agreed in import agreements.[131]

The monthly BAFA cross-border prices for natural gas ranged from 20.18 Euro/MWh to 29.84 Euro/MWh from 2012 to 2014. For 2014, the (unweighted) monthly cross-border price averaged 23.39 Euro/MWh, whereas this value in 2013 was 27.56 Euro/MWh (down 15 percent).

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[130] On the calculation of the values in detail: www.eex.com/blob/68596/836d03126059d5115fb61134fe8f9993/2014-02-06---beschreibung-egix-pdf-data.pdf (retrieved on 10 November 2015).

[131] For details, see www.bafa.de/bafa/de/energie/erdgas/publikationen/energie_erdgas_ermittlung_preis.pdf (retrieved on 10 November 2015).

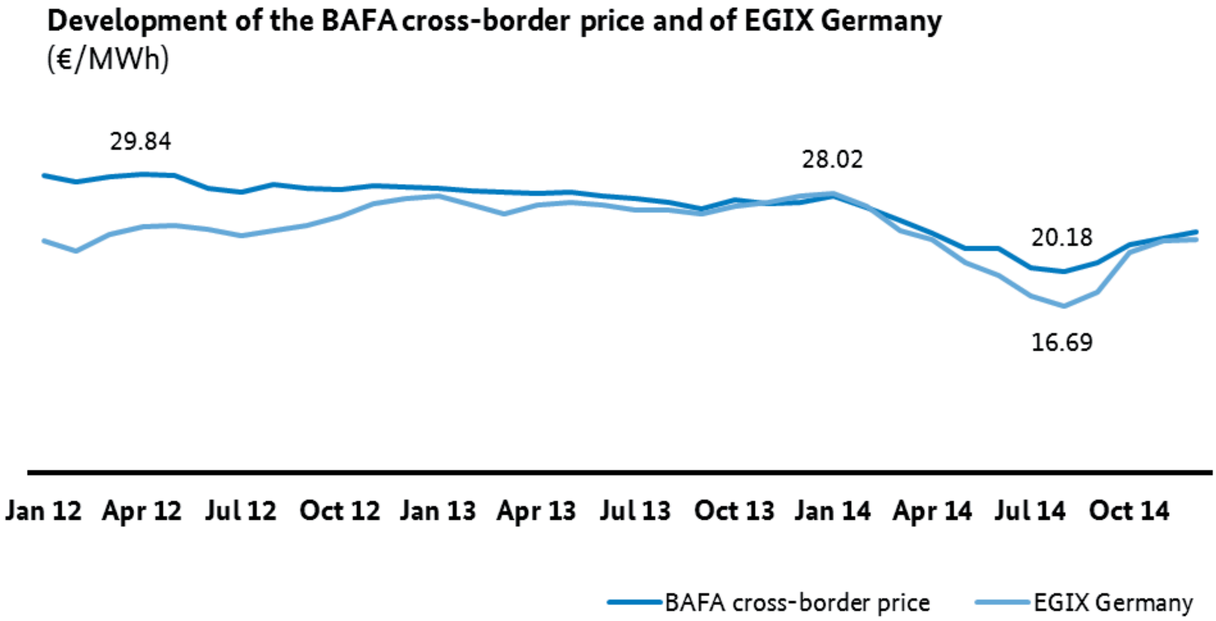

Figure 145: Development of the BAFA cross-border price and of EGIX Germany in the period 2012 to 2014

Older gas import contracts were as a rule based on a price agreement linked to the oil price. This has been the case less and less frequently in recent years in new contracts and within contract adjustments.[132] Price indices such as the EEX daily reference price or EGIX make it possible to index long-term contracts to exchange prices. The development of the cross-border price calculated by BAFA in 2014 clearly shows its orientation to natural gas exchange prices, thereby confirming the declining importance of oil-indexed prices.

[132] Cf. for example RWE AG, annual report (*Geschäftsbericht*) 2013, p. 93; E.ON SE, annual report (*Geschäftsbericht*) 2012, p. 15.

F Retail

1. Supplier structure and number of providers

A total of 854 gas suppliers took part in the 2015 monitoring survey. In the evaluation of the data provided by gas suppliers, each gas supplier is considered as an individual legal entity without taking possible company affiliations or links into account. This evaluation came to the conclusion that the majority of the gas suppliers (436 suppliers or 54%) supplied between 1,000 and 10,000 metering points. These 436 suppliers supplied 14% of all final consumer metering points.[133] The 436 suppliers delivered around 80 TWh to final customers. Based on the total reported volume of gas delivered of 711.4 TWh, this corresponds to a share of 11%. The smallest group of gas suppliers (comprising 26 companies), in which each company supplies more than 100,000 metering points, supplies 42% of the metering points with a total volume of 201.5 TWh (28%). Most gas suppliers in Germany therefore have a relatively small number of customers, whereas in absolute terms the few large gas suppliers serve the majority of metering points.

Breakdown of suppliers according to the number of meter points supplied
(excluding company affliations)

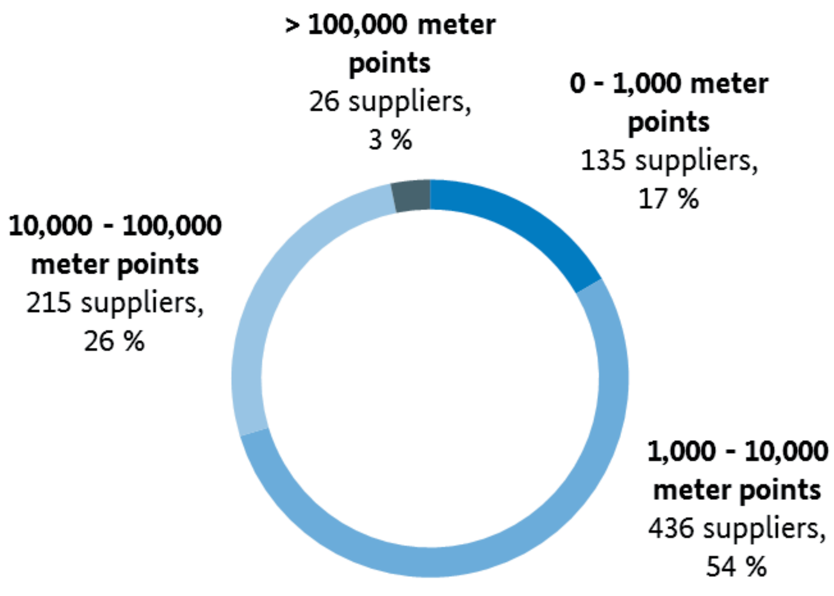

Figure 146: Breakdown of suppliers according to the number of metering points supplied (according to the survey of gas suppliers)

[133] The number of final consumer metering points reported by the gas suppliers, standing at 13,650,615, deviates slightly from the figure reported by the network operators, which stands at 13,837,257. This difference is due to the greater market coverage of gas TSOs and DSOs.

One indicator of the degree of choice for gas customers is the number of suppliers in each network area. In the 2015 survey, the gas network operators were asked to report on the number of suppliers serving at least one final consumer in their networks. This refers to the number of supplying legal entities, meaning that any company affiliations or links among the suppliers are not taken account of. Seeing as many suppliers are offering rates in many network areas in which they do not have a considerable customer base, the reported high number of suppliers does not automatically assume a high level of competitive intensity.

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 gas suppliers for all final consumers active in the various network areas since 2006. In 2014, the year under review, the trend towards more diversity has continued. In nearly 74% of the network areas there was a choice of more than 50 gas suppliers. In over 22% of the network areas customers even had a choice of more than 100 suppliers. The situation is similar when taking a particular look at household customers: In just under 60% of the network areas, household customers have a choice of 50 or more suppliers. In just over 13% of the network areas customers have a choice of more than 100 suppliers.

On average, final consumers in Germany can choose between 80 suppliers in their network area; household customers can choose between 65 suppliers (these figures do not take account of company affiliations or links).

Breakdown of network areas by number of gas suppliers operating (all final consumers (left) and household customers (right)) according to DSO survey
(%), excluding company affiliations

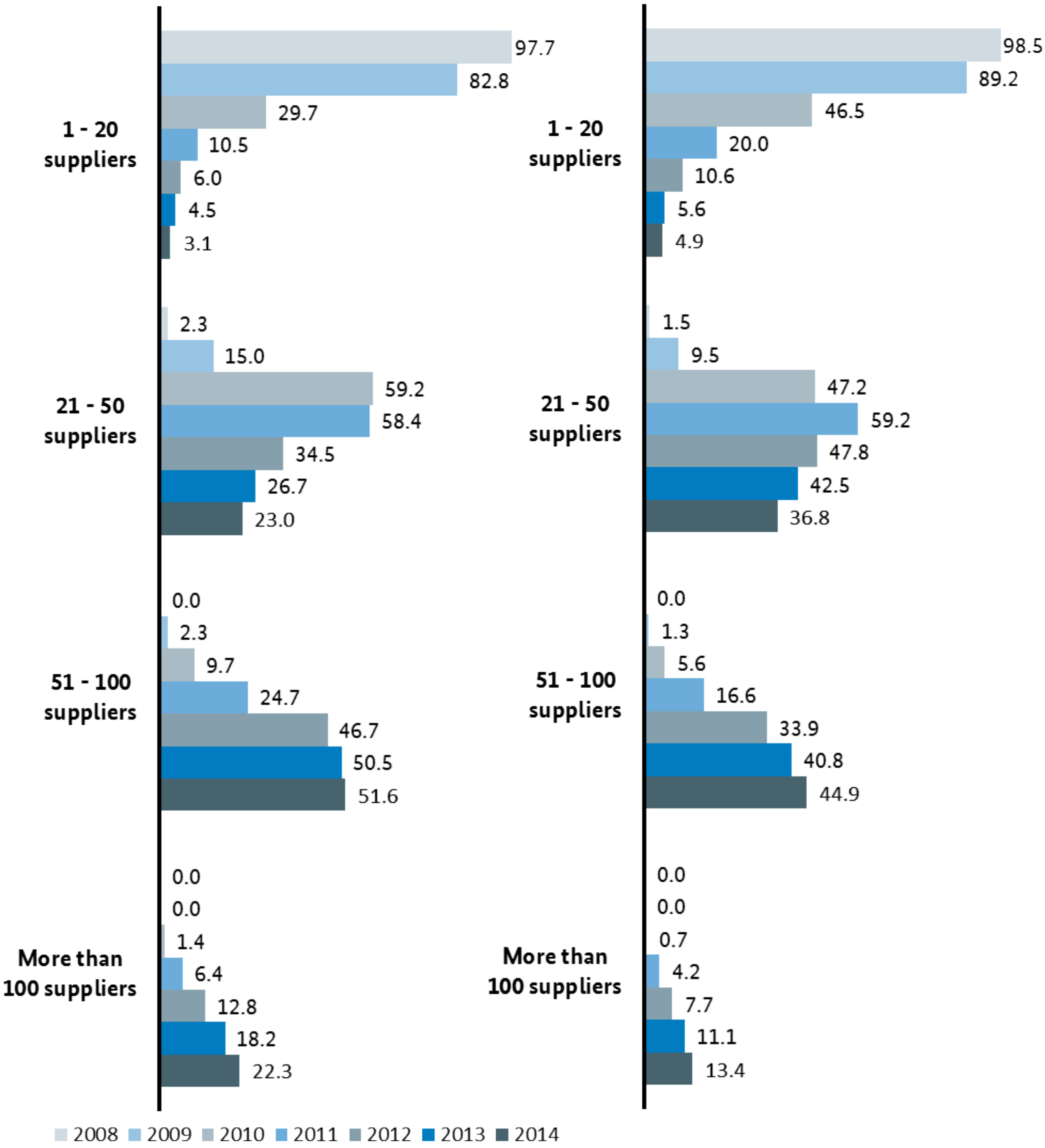

Figure 147: Breakdown of network areas by number of gas suppliers operating according to the survey of gas DSOs

Suppliers were also asked about the number of network areas in which they supply final consumers with gas. More than half of all gas suppliers surveyed (58%) supply at most 10 network areas with gas and are therefore only active regionally. 21% of the gas suppliers only operate in one single network area. 21 suppliers, that is 3%

of all suppliers, are active in more than 500 network areas and therefore virtually across all of Germany. On a national average, suppliers are active in around 53 network areas.

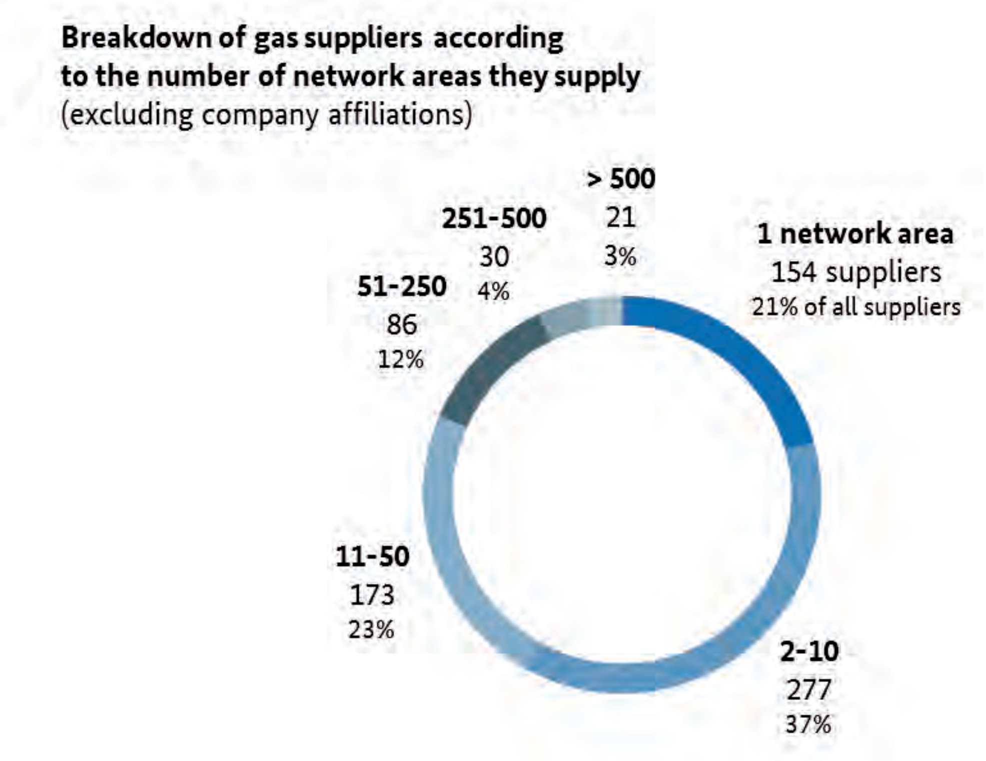

Figure 148: Number of suppliers according to number of network areas they supply
as per survey of gas suppliers

2. Contract structure and supplier switching

Switching rates and processes are important indicators of competition trends. Collecting such key figures, however, is bound up with many difficulties and, as a result, the relevant collection of data has to be limited to what best reflects the actual switching behaviour.

In the survey, data on contract structures and supplier switching is collected through questionnaires relating to each specific customer group to be completed by the TSOs, DSOs and suppliers.

Final consumers can be grouped according to their metering profile into customers with and without interval metering. For customers without interval metering, consumption over a set period of time is estimated using a standard load profile (SLP).

Final gas consumers can also be divided into household and non-household customers. Household customers are defined in the German Energy Act (EnWG) according to specific characteristics.[134] All other customers are

[134] Section 3 para 22 EnWG defines household customers as final consumers who purchase energy primarily for their own household consumption or for their own consumption for professional, agricultural or business purposes not exceeding an annual consumption of 10,000 kilowatt hours.

non-household customers, which includes customers in the industrial, commercial, service and agricultural sectors as well as public administration.

According to the questionnaire filled out by gas wholesalers and suppliers, the total quantity of gas supplied by suppliers to all final consumers in 2014 reached approximately 712 TWh. Of this, approximately 391 TWh was supplied to interval metered customers and 321 TWh to non-interval metered customers. The majority of non-interval metered customers are household customers. In 2014 around 204 TWh were supplied to household customers.

As part of the monitoring survey, data is collected on the breakdown of gas sold to various final consumer groups into the following three contract categories:

- default supply contract,
- special contract with the default supplier and
- contract with a supplier who is not the local default supplier

For the purposes of this analysis, the default supply contract category also includes fallback energy supply (section 38 EnWG) and doubtful cases.[135] A special contract with a default supplier is one with delivery outside the default supply contract. An analysis on the basis of these three categories makes it possible to draw conclusions on the extent to which the importance and role of default supply have lessened since the liberalisation of the energy market. The corresponding figures, however, should not be directly interpreted as "cumulative net switching figures since liberalisation". It must be noted that the monitoring report takes the legal entity to be the contracting party, thus a contract with a company affiliated with the default supplier falls under the category "contract with a supplier who is not the local default supplier".[136]

Additionally, data from TSOs and DSOs was collected on the level of supplier switching in different customer categories in 2014. Switching supplier is taken to mean the process where a final consumer's meter point (meter) is served by a new supplier in this context. As a rule, moving into or out of premises does not meet the definition of "supplier switching", however additional household customer data is collected on how many customers choose a supplier other than the local supplier when moving home ("change on relocation"). In this analysis, too, it must be noted that the change of supplier query refers to a change in the supplying legal entity. A network operator cannot distinguish between an internal reallocation of supply contracts to another group company and a change of supplier initiated by a customer – or only at considerable time and expense – and therefore both fall under supplier switching. The same applies to any insolvency of the former supplier or in the event the supplier terminates the contract ("involuntary supplier switch"). The actual number of customers choosing to switch supplier is therefore lower than the number of switches registered.

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[135] In addition to household customers, final consumers served by fallback supply are usually included under the default supply tariff, section 38 EnWG. For monitoring purposes, suppliers were asked to allocate cases that could not be clearly categorised to "default supply".

[136] It is also possible that further ambiguities may arise, for example if the local default supplier changes.

2.1 Non-household customers

Contract structure

The gas sold to non-household customers is mainly to interval-metered customers where the offtake is recorded at short intervals ("load profile"). Interval-metered customers are characterised by high consumption and/or energy requirements[137] and are all non-household customers such as industrial customers or gas power plants.

In 2014 around 730 gas suppliers (separate legal entities) provided information on the meter points served and quantities supplied to interval-metered customers (the previous year's figure was 690). The 730 gas suppliers include many affiliated companies, hence the number of suppliers is not equal to the actual number of competitors.

In 2014, these suppliers delivered more than 391 TWh of gas to interval-metered customers through a total of over 37,500 meter points. Over 99% of this volume was supplied under a special contract. It is unusual, but not impossible, for interval-metered customers to be supplied under default supply or fallback supply.
Around 0.3 TWh of gas was supplied to interval-metered customers under default or fallback supply. This is about 0.1% of the total volume supplied to interval-metered customers. About 33% of the total volume delivered to interval-metered customers was supplied under a special contract with the default supplier and some 67% under a contract with a legal entity other than the default supplier. This more or less corresponds to last year's distribution (34% and 66%). These figures show that default supply is of little practical significance for interval-metered gas customers.

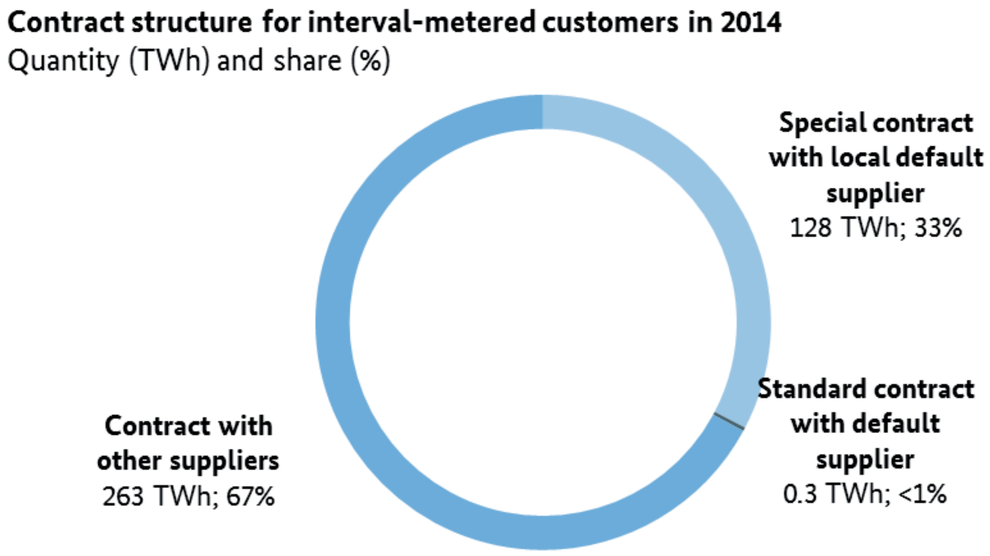

Figure 149: Contract structure for interval-metered customers in 2014

[137] In accordance with section 24 of the Gas Network Access Ordinance (GasNZV) interval metering is generally required for a maximum hourly offtake capacity above 500 KW or a maximum annual offtake above 1.5 GWh.

Supplier switch

Furthermore, data was collected in questionnaires 7 and 8 (gas TSOs and DSOs) on the level of supplier switching (as defined above) that took place in the different customer groups in 2014. Five different consumer categories were used here. The survey produced the following results:

Supplier switching in 2014 by consumer category

Final consumer category	Number of meter points with a change in 2014 in the legal person supplying gas	Percentage of all meter points for category	Quantity supplied in 2014 at meter points with a change of supplier in 2014	Percentage of total quantity supplied in category in 2014
< 0.3 GWh/year	1,135,971	8.3%	26.2 TWh	9.2%
0.3 GWh/year – 10 GWh/year	14,617	13.7%	16.2 TWh	15.0%
10 GWh/year – 100 GWh/year	662	17.8%	16.4 TWh	18.5%
> 100 GWh/year	106	15.9%	26.4 TWh	10.9%
Gas power plants	24	1.6%	2.2 TWh	2.8%

Table 76: Supplier switching in 2014 by consumer category

The four categories with a consumption of more than 0.3 GWh/year (including gas-fired power plants) consist entirely of non-household customers. The volume-based switching rate in 2014 across these four categories was 11.8%. This represents a decrease of approximately 0.9% compared to the previous year. There was a strong rise in the switching rates among industrial and business customers between 2006 and 2010. At around 12-13%, the switching rate has remained more or less constant since 2010. The survey does not analyse which percentage of industrial and business customers have switched supplier once, more than once or not at all over a period of several years.

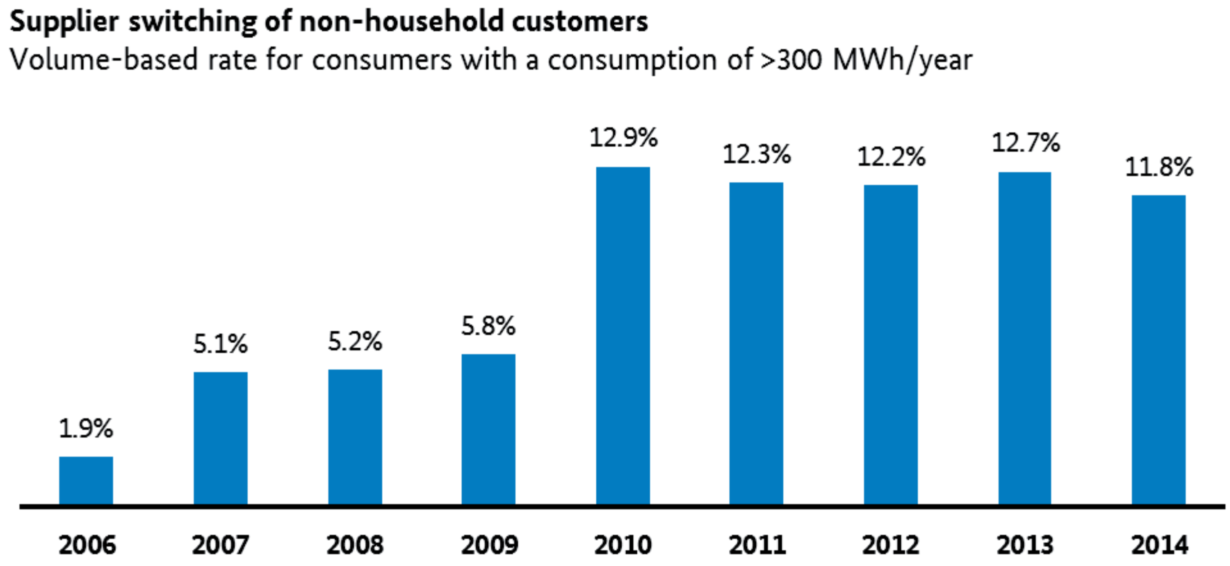

Figure 150: Supplier switching of non-household customers

2.2 Household consumers

Contract structure

A closer look at how household customers were supplied in 2014 in terms of volume shows that the majority of household customers (56.8%) are still served by their local default supplier under a special contract; the quantity of gas supplied here totals 116 TWh ((2013: 60% or 146.2 TWh). Just under one quarter of household customers (24.4%) with a default supply contract were supplied with 49.8 TWh of gas (2013: 26% or 65.1 TWh). The percentage of household customers who have a contract with a supplier other than the local default supplier increased by 5% and now amounts to 18.8% for 38.3 TWh of gas (2013: 14.2% or 34.2 TWh).

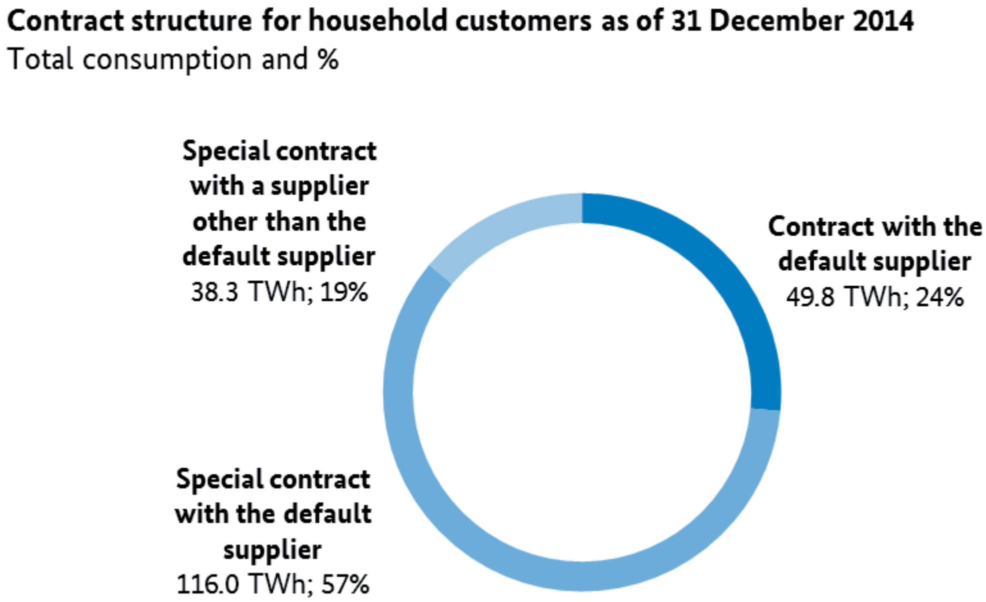

Figure 151: Contract structure for household customers according to the gas supplier data survey[138]

The following diagram shows that the trend of customers switching from local to supraregional suppliers has strengthened.

[138] Gas suppliers reported a total of 204.05 TWh gas supplied to household customers, which differs from the amount reported by the gas DSOs of 224.18 TWh. This is due to higher market coverage for network operators.

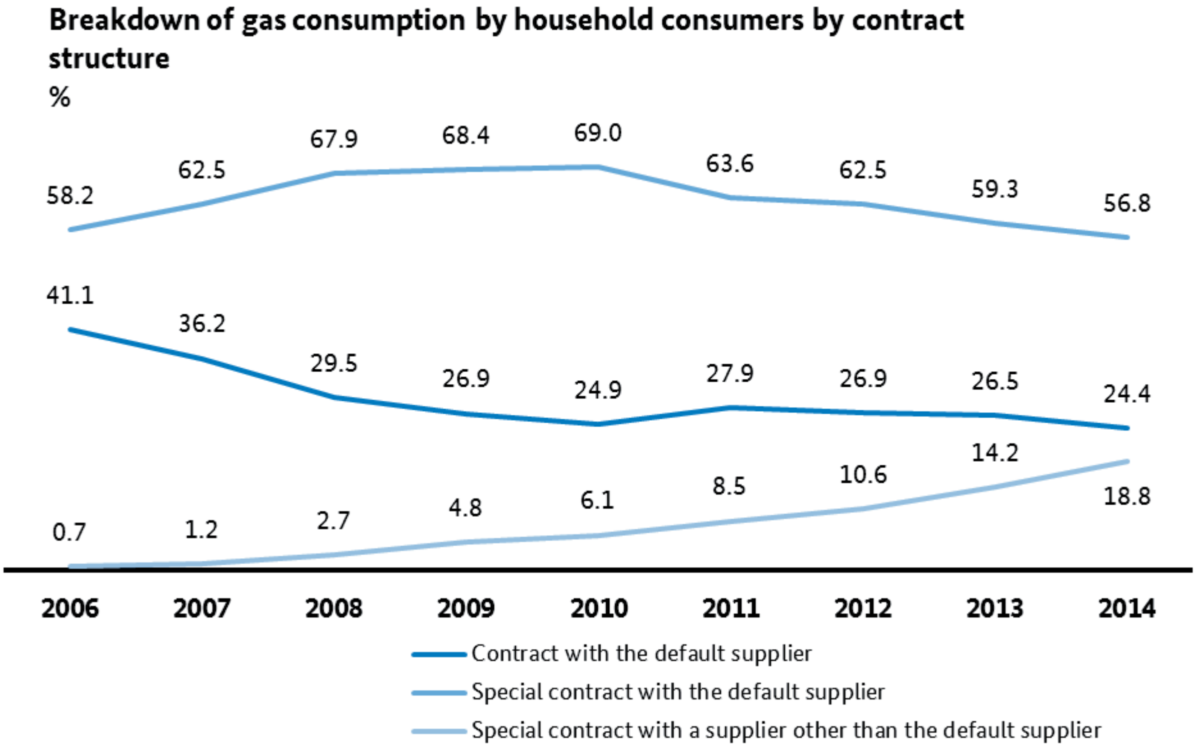

Figure 152: Breakdown of gas consumption by household consumers by contract structure according to the gas supplier survey

Some 18.7% of the total volume of 321 TWh of natural gas delivered to non-interval metered customers was provided under default supply, representing a slight decrease compared to the previous year's figure (approx 19.9%).

A standard load profile (SLP), which is a simplified method of metering, is used for customers whose consumption is not registered in defined intervals. An SLP is generally used only for those gas customers with a maximum annual offtake of 1.5 GWh and a maximum hourly offtake capacity of 500 kWh (section 24 GasNZV). SLP (non-interval metered) customers comprise primarily household customers but also non-household customers with a relatively low consumption.

790 individual companies provided information on meter points and delivery volumes for SLP customers. (2013: 760). Approximately 321 TWh of gas was delivered to 13.6m meter points. 2013: 387 TWh to 13.6m meter points). The total volume comprises about 204 TWh (64%) for household customers and some 117 TWh (36%) for non-household, non-interval metered customers. The decrease in consumption is generally attributed to the relatively mild weather conditions in 2014.

Of the total quantity of gas supplied on a non-interval metered basis, 60 TWh (19%) was supplied under standard default supply contracts, 189 TWh (59%) under special contracts with the default supplier and 71 TWh (22%) under special contracts with another legal entity.

Higher consumption non-interval metered customers are much more likely to have a special contract than those with lower consumption. The average (median) annual consumption of default supply customers was just over 14,000 kWh and 29,000 kWh with regard to customers with a special contract with their default supplier. For customers with contracts with another legal entity the corresponding figure was over 3,600 kWh.

641 of the 790 or so suppliers (individual companies) providing data on meter points and volumes for SLP customers were active as default suppliers. The majority of suppliers have a relatively small customer base: 563 default suppliers serve fewer than 30,000 meter points for SLP customers, including 420 serving fewer than 10,000 meter points.

Supplier switch

To determine the number of supplier switches by household customers, the DSOs were questioned as to the number of supplier switches, including the volume involved, at the meter points as well as the choice of supplier when moving home in their network area. Compared to the previous year, the total number of household customers switching supplier (including switches made due to relocation) has remained constant at 1.06 million (2013: 1.05m). The number of household customers that immediately chose an alternative supplier, rather than the default one, when relocating increased by 22,000. The trend of household customers taking advantage of a chance to switch supplier at their new place of residence has been strengthening since 2007. By contrast, the number of customers conventionally switching supplier while staying in the same place of residence decreased by nearly 34,000.

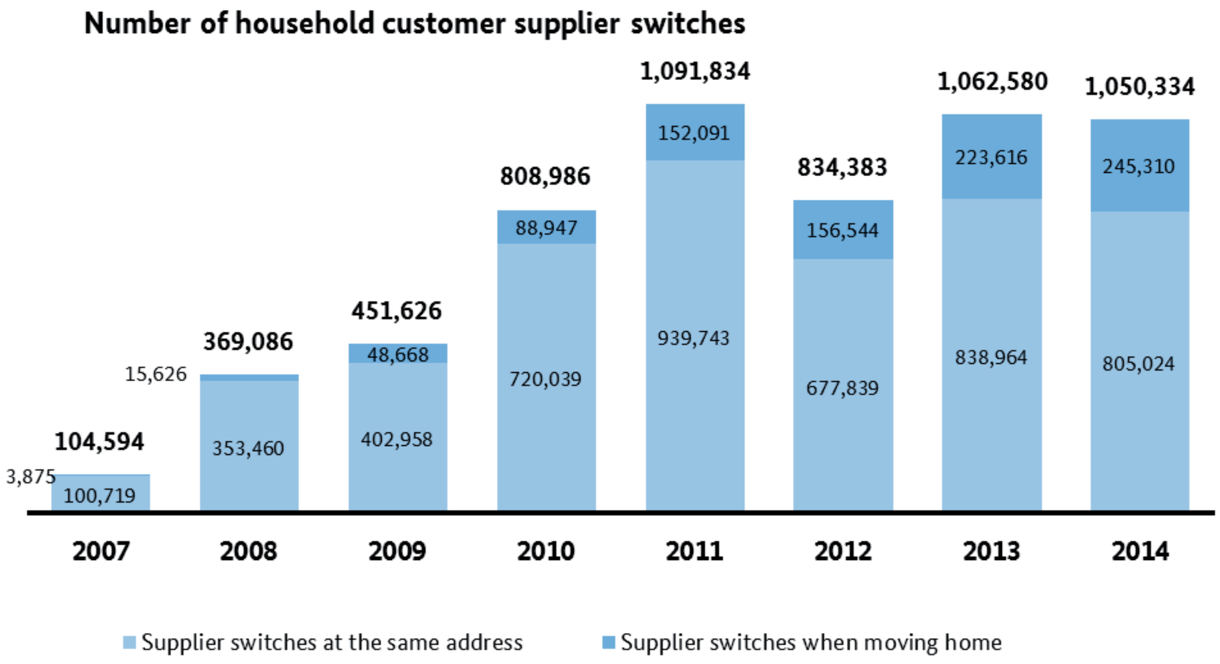

Figure 153: Household customer supplier switches as stated in the DSO survey

Based on the total of 12.5m household customers as reported by the DSOs, the switching rate for household customers was 8.4% in 2014. The following diagram highlights the sustained positive trend in the figures reflecting the number of household customers switching supplier.

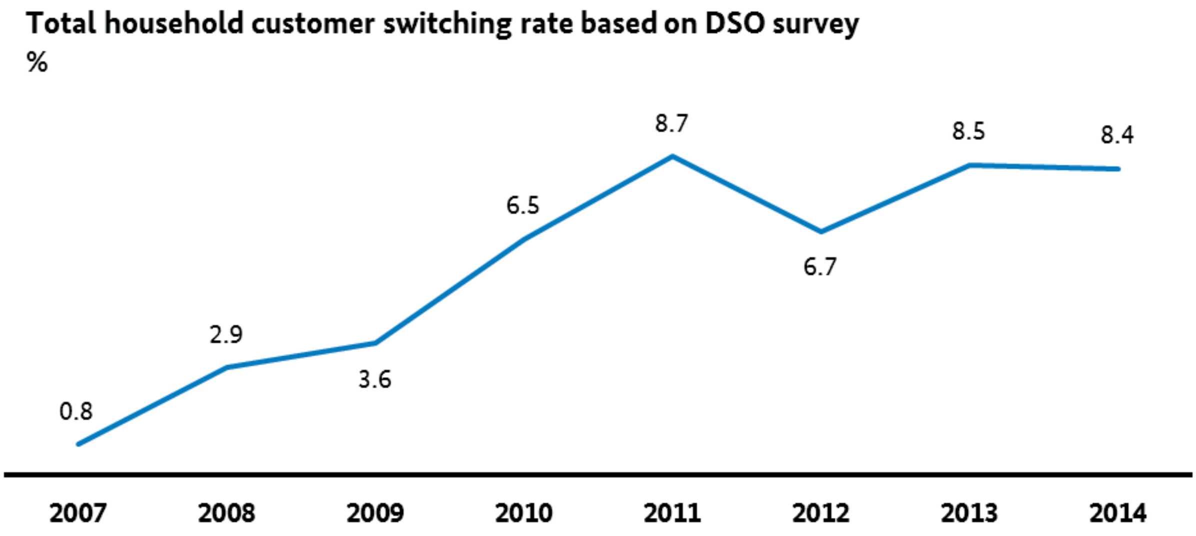

Figure 154: Total household customer switching rate based on DSO data survey

The gas DSOs were also asked to provide information on the consumption volumes recorded at the meter points of households that switched supplier. According to the figures provided, the total volume of gas supplied to household customers that switched supplier (including the total volume of gas supplied to customers changing residence) was 22.6 TWh.

Considering the clearly lower volume of 224 TWh of gas provided by network operators to household customers in 2014, the total volume-based switching rate for household customers increased slightly from 9.7% to 10.1%. The positive trend in the figures reflecting the volume-based switching rate has therefore been sustained. Noteworthy is the fact that the volume-based switching rate (at 10.1%) continues to be higher than the rate based on the number of customers that switched (at 8.4%). To some extent, this can be explained by the fact that, among private gas customers, in particular high-consumption customers make real use of the benefits of switching supplier. This is also reflected by the calculated annual consumption of an average gas customer that switched supplier, which, at around 22,000 kWh, is above the national average of approx 20,000 kWh.

The volume of gas delivered to household customers who changed supplier when moving home and chose a supplier that was not the local default supplier decreased slightly from 4.4 TWh in 2014 to 4.3 TWh in 2013. Even though the number of household customers making a switch when moving home increased by 10%, the volume of gas consumed by customers that switched decreased by just under 2%. This trend and the decrease in the total volume of gas supplied to household customers that switched is plausible against the background of the strong decrease in gas consumption by private households, which in turn was caused by warmer weather conditions and lower financial incentives that were a result of the recently stagnating gas price.

Household customer supplier switches, including switches by customers when moving home

Category	Supplier switches in 2014 (TWh)	Share of the entire amount of gas provided to final consumers (224.18 TWh)	Number of supplier switches in 2014	Household customer share of total (12,511,854)
Household customers that chose a supplier other than the default supplier without moving home	18.2	8.1%	805,024	6.4%
Household customers that chose a supplier other than the default supplier directly after moving home	4.3	1.9%	245,310	2.0%
Total	22.6	10.1%	1,050,334	8.4%

Table 77: Household customer supplier switches, including switches by customers when moving home

3. Disconnection notices, disconnections, tariffs and terminations

3.1 Disconnection of supply

In 2014, the Bundesnetzagentur for the fourth time carried out surveys of the tariffs offered and asked network operators and gas suppliers about disconnection notices and requests (to the DSOs) as well as the number of actual disconnections under section 19(2) of the Gas Default Supply Ordinance (GasGVV) and the associated costs.

Section 19(2) GasGVV entitles default suppliers to disconnect supplies to customers in particular upon failure to fulfil payment obligations and after appropriate notice has been given. The number of disconnection notices,[139] at around 1,288,000, increased by 31.5% compared to the previous year. The number of disconnection requests also increased compared to 2013. By contrast the number of actual disconnections, at 46,488, has remained more or less unchanged compared to the prior year. The number of disconnections is based on information from the DSOs, who carry out the disconnections on behalf of the suppliers. According to the information provided by the suppliers, the ratio between absolute disconnections and the number of household customers affected was 1 to 0.94 in 2014. This means that an estimated 6% of disconnections were related to repeated disconnections of the same customers. Based on the total number of meter points at the distribution system level covered by the monitoring data survey in Germany, the market coverage rate for this question was approximately 97.9%.

[139] Some of the (gas) DSOs provided one figure encompassing all disconnection notices for gas, electricity, water and heating.

Number of disconnection notices and requests for disconnection of default gas supply; disconnection on behalf of the local default supplier of gas

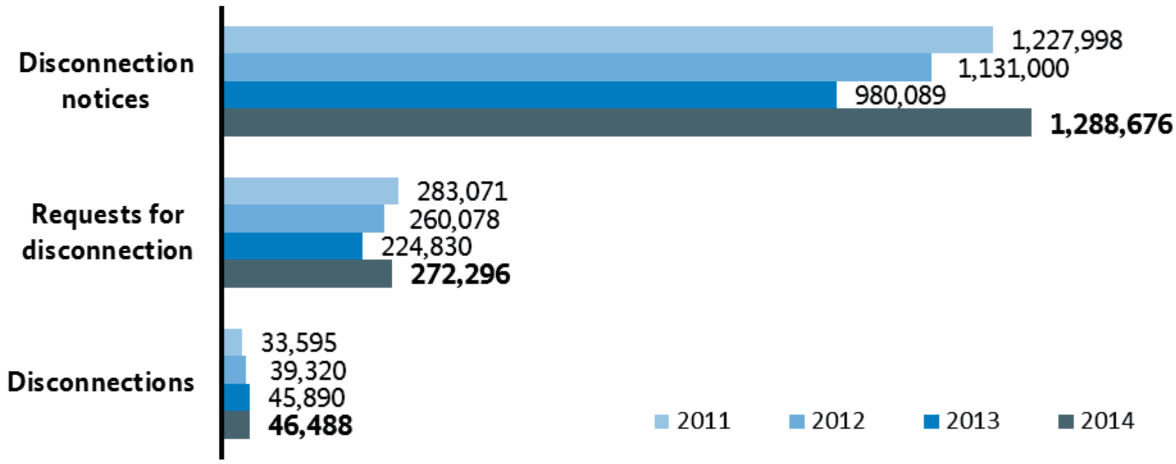

Figure 155: Disconnection notices and requests for disconnection of default gas supply[140]; disconnection on behalf of the local default supplier of gas

The Ordinance does not specify a minimum level of arrears for supply disconnection. The average level of arrears was about €114. The average charge paid by suppliers to DSOs for disconnecting customers was around €76, with the actual costs charged ranging from €12 to €205. The average charge for reconnecting customers was about €59, with the lowest charge at €10 and the highest at €203.

Suppliers charged their customers an average of around €34 per disconnection. The charges ranged from €4 to €200, excluding the DSOs' costs - which averaged €76 (see above). Customers were charged an average reconnection fee of €40, with the lowest fee at €2 and the highest at €200 for reconnection.

3.2 Cash/smart card meters

For the 2014 reporting period, information was collected for the first time during the 2015 monitoring process on prepayment systems as per section 14 GasGVV, such as cash or smart card meters. The questions directed at the distribution network operators and suppliers produced the following results:

Around 1,700 prepayment meters were set up in 2014. In total, around 500 systems were newly installed and around 500 systems were removed. This corresponds to about 0.01% of all household customer meter points in Germany.

Section 40(3) EnWG requires suppliers to offer final consumers monthly, quarterly or half yearly bills. Customer demand for these types of billing cycle for the provision of gas remained low, however.

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[140] In respect of the data for 2011 it is important to note that some of the suppliers could only provide estimates of the number of disconnection notices and requests.

Non-annual billing

	Number of requests	Number of bills	Average charge per additional bill with customer reading (range of charges in €)	Average charge per additional bill without customer reading (range of charges in €)
Non-annual billing for household customers	12,910	15,943	9.74 (0.00 - 113.91)	12.43 (0.00 - 116.60)
Monthly	796	1.026		
Quarterly	112	108		
Half yearly	880	895		

Table 78: Non-annual billing

Only few gas suppliers terminate service with their customers. In 2014, suppliers issued a total of some 38,300 termination notices to customers (a decrease of 13% compared to 2013's figure of 44,000). The average level of customer arrears here was about €125, with the highest amount reported being €1,500.

As in the past, the vast majority of contract terminations were carried out by just a few, young inter-regional companies, while regional providers rarely or never terminated service with their customers.

Usually only customers receiving default supply services will be disconnected. Termination of default supply is only possible if stringent requirements have been met, meaning that default supply obligations must not apply or conditions must have been violated repeatedly. With respect to customers with a special contract, by contrast, disconnections and disconnection notices are rare since it is easier and less expensive for the supplier to terminate the contract.

4. Price level

For monitoring purposes, suppliers that provide final customers with gas in Germany were asked about the retail prices charged by their companies on 1 April 2015 for three purchase cases. The three purchase cases are based on annual consumption of 23 MWh (for a "household customer"), 116 MWh (for a "business customer") and 116 GWh (for an "industrial customer").

Suppliers were asked to give the overall price in cents per kilowatt hour (ct/kWh) including the non-variable price components such as the service price, base price and transfer or internal price. Suppliers were also asked to provide a breakdown of the non-controllable price components including in particular network tariffs, concession fees and charges for billing, metering and meter operations. After deducting these components from the overall price, the amount remaining is the amount controlled by the supplier which comprises above all gas procurement, supply, other costs and the supplier's margin.

The suppliers were asked to provide their "average" overall prices and price components for each of the three consumption levels. Several companies drew attention to the fact that they were unable to provide average figures on account of their inter-regional activity and/or customer-specific pricing.

Companies were asked to provide data on the price components for the lowest consumption level of 23 kWh/year (household customer) for three different contract types:

- default supply contract,
- special contract with the default supplier and
- contract with a supplier who is not the local default supplier.

The findings are set out separately for each consumption level below. To better illustrate any long-term trends, a comparison is made in each case with the previous year's figures. When comparing the figures as at 1 April 2015 and 1 April 2014, it should be noted that differences in the calculated averages are lower in part than the range of error for the data collection method. Hence a statistically significant statement as to whether or not there was an increase or decrease in the price (components) in a year-on-year comparison cannot be given.

In addition, it should be noted that a different group of suppliers was asked to provide data. In the past, only suppliers active as default suppliers in at least one network area suppliers were asked. As of last year, all suppliers operating in Germany now participate in the data survey. In the case of the prices for the two higher consumption levels 116 GWh/year and 116 MWh/year, however, as of last year, only suppliers serving at least one customer with the relevant consumption were asked to provide data.

4.1 Non-household customers

116 GWh/year ("industrial customers")

Customers with annual consumption in the 116 GWh range are only interval-metered customers and, in general, these are industrial customers. The wide scope for customer-specific contracts plays a large role for this customer group. In general, suppliers do not have any specific tariff groups for consumers of 116 GWh/year but instead tailor pricing according to individual customers, which includes those receiving the full range of services as well as those whose negotiated offtake is only part of their procurement portfolio. In the case of customers with the highest consumption, there are natural crossovers between retail and wholesale trading, with retail prices often being indexed to wholesale prices. In some contract, the suppliers' customers themselves are responsible for paying the network charges to the network operator. Such contracts may go so far that in economic terms the "supplier" only provides balancing group and nomination management services to the customer.

The customer was taken to have an annual consumption of 116 GWh and an annual usage period of 250 days (4,000 hours). Only those suppliers with at least one customer with an annual consumption of between 50 GWh and 200 GWh were asked to provide data. This limits the suppliers to a small group. The following price analysis for the consumption category is based on data from 98 suppliers (prior year: 96).

The data was used to calculate the arithmetic mean of the overall price and the individual price components. The distribution of the figures for each price component was also analysed using ranges. The 10th percentile represents the lower limit and the 90th percentile the upper limit of each range, with the 80% average of the figures provided by the suppliers therefore within the range. The analysis produced the following results:

Price level of customer with annual consumption of 116 GWh as of 1 April 2016

	Spread in the 10-90 percentile range of supplier data sorted by size in ct/kWh	**Average** (arithmetical) in ct/kWh	**Percentage of total price**
Price components that cannot be controlled by the supplier			
Net network charge	0.15 - 0.57	0,32	9%
Charge for billing, metering and meter operations	0.00 – 0.01	0,01	0%
Concession fee	0,00	0.00[1]	0%
Gas tax	0,55	0,55	16%
Price components that can be controlled by the supplier (residual amount)	2.24 - 3.05	2,58	75%
Total price (without value added tax)	3.01 - 4.14	3,46	

[1] Under section 2(5) para 1 Electricity and Gas Concession Fees Ordinance (KAV), concession fees for special contract customers are only incurred for the first 5 GWh (0.03 ct/kWh). In cases of 116GWh consumption, this results in an average (rounded up) 0.00 ct/kWh.

Table 79: Price for customers with an annual consumption of 116 GWh (correct as of 01 April 2015)

On average, the network tariff, concession fees and metering charges account for less than 10% of the overall price for industrial customers (116 GWh/year). This is considerably lower than for household customers and non-household customers with low consumption. Accordingly the components that can be controlled by the supplier (gas procurement and supply, other costs and the margin) account for a much larger share of the overall price at 75%.

The average overall price (excluding VAT) of 3.46 ct/kWh is 0.13 ct/kWh or around 4% lower than last year's average price. The difference is due to a reduction in the price components that can be controlled by the supplier. The average price as of 1 April 2015 for an annual consumption of 116 GWh was therefore the lowest ever since the first data on gas prices (as of 1 April 2008) was collected for monitoring reports.

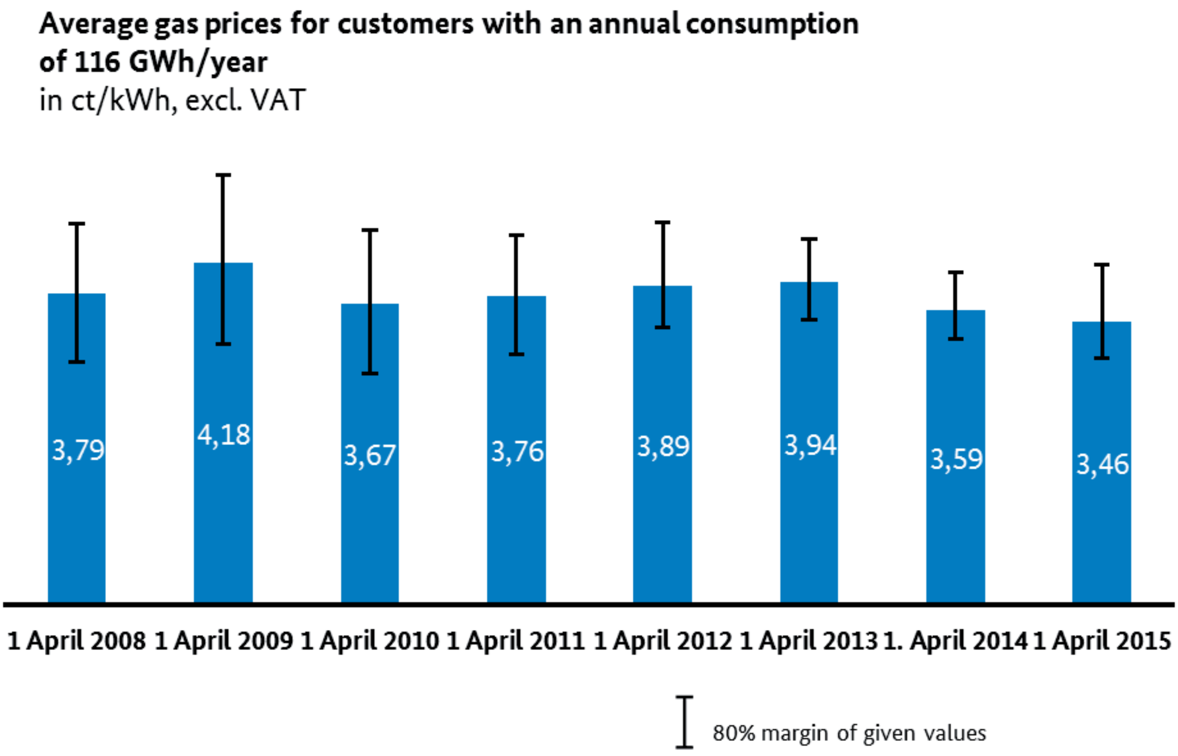

Figure 156: Average gas prices for customers with an annual consumption of 116 GWh

116 MWh/year ("commercial customers")

The non-household customer was taken to have an annual consumption of 116 MWh, which represents a business customer with a relatively low level of consumption. No specific annual usage period was indicated for this customer category. This annual consumption level is a thousandth of the industrial customer level (116 GWh) and five times higher than the household customer level (23 MWh). Given the moderate level of consumption, individual contractual arrangements play a significantly smaller role in this category than in the 116 GWh per year consumption category. Suppliers were asked to provide plausible estimates based on the terms and conditions that were applicable on 1 April 2015 for the prices billed to customers with similar consumption. Suppliers serving customers with a comparable consumption, ie an annual gas consumption of between 50 MWh and 200 MWh, were asked to provide data. Since this consumption level is well below the 1.5 GWh threshold, above which network operators are required to use interval metering, it can be assumed that a standard load profile is generally used for such customers.

The following price analysis for this consumption category is based on data from 630 suppliers (prior year: 582). The data was used to calculate the arithmetic mean of the overall price and the individual price components. The distribution of the figures for each price component was also analysed using ranges, with 80% of the figures provided by the suppliers within the range. The analysis produced the following results:

Price level of customer with an annual consumption of 116 MWh as of 1 April 2016

	Spread in the 10-90 percentile range of supplier data sorted by size in ct/kWh	**Average** (arithmetical) in ct/kWh	**Percentage of total price**
Price components that cannot be controlled by the supplier			
Net network charge	0.82 - 1.53	1,15	23%
Charge for billing, metering and meter operations	0.02 – 0.12	0,06	1%
Concession fee	0.03 – 0.03	0.04[1]	1%
Gas tax	0,55	0,55	11%
Price components that can be controlled by the supplier (residual amount)	2.83 - 3.82	3,29	65%
Total price (without value added tax)	4.57 - 5.66	5,09	

[1] In their reply, 43 of the 630 suppliers provided a figure for the concession fee that exceeds 0.03 ct/kWh. These are suppliers that supply lower volumes of gas. A concession fee exceeding 0.03 ct/kWh for non-household customers is also conceivable if the gas is supplied under a default supply contract (cf section 2(2) para 2b of the Electricity and Gas Concession Fees Ordinance (KAV)).

Table 80: Price for customers with an annual consumption of 116 MWh (correct as of 1 April 2015)

As was the case in the prior year, on average, non-controllable price components (network charges, gas tax and concession fee) presently account for 35% of the overall price while components that can be influenced by the supplier's company decisions account for 65%.

The average overall price (excluding VAT) of 5.09 ct/kWh is only slightly lower (by 0.11 ct/kWh) than last year's average price. The absolute level of the non-controllable price components is more or less the same as in the previous year, hence the change is due to the remaining amount.

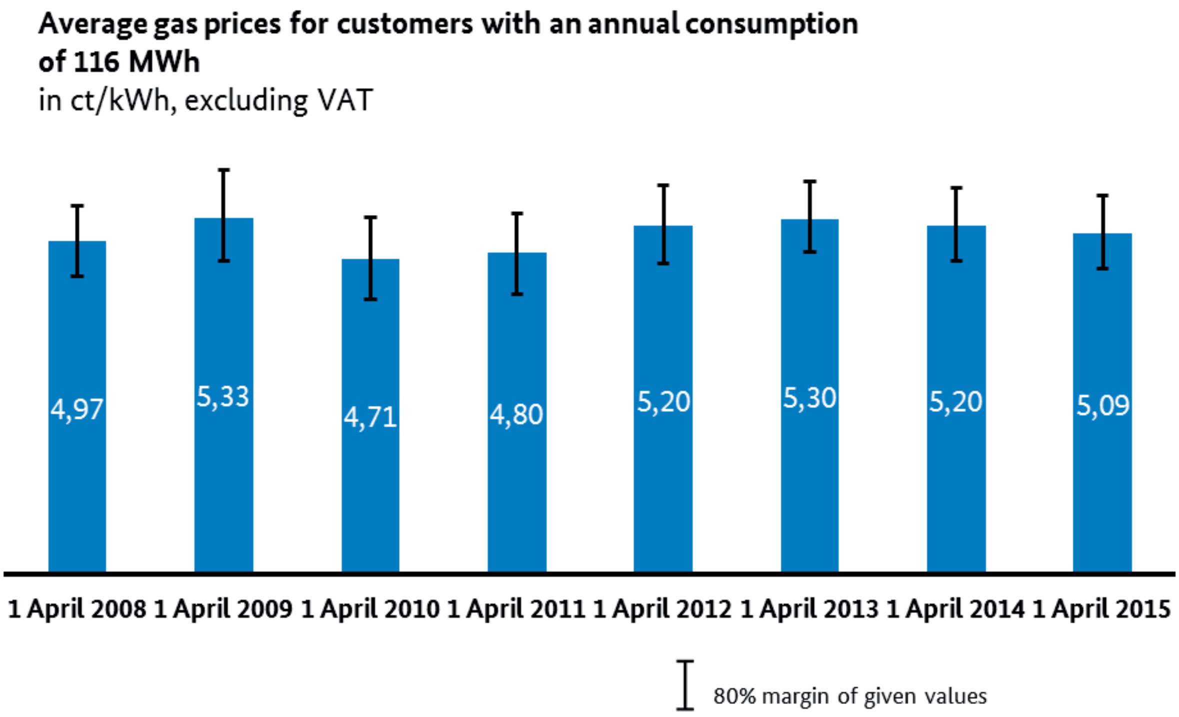

Figure 157: Changes in average gas prices for customers with an annual consumption of 116 MWh

4.2 Household consumers

As of 1 April 2015, gas prices for household customers with a consumption of 23,269 kWh decreased slightly compared to the previous year's figures. A slight decrease in gas prices was observed in all of the three contract categories being considered. This decrease was noted for both the weighted and unweighted average prices. The strongest decrease was noted in the non-default suppliers' gas price.

The volume-weighted price for customers with a standard contract with their default supplier[141] decreased by 1.3% from 7.20 ct/kWh to 7.11 ct/kWh since 1 April 2014). The average net network charge (that includes upstream network costs) went down from 1.29 ct/kWh to 1.27 ct/kWh. At around 18%, it's share of the total price remained the same as on 1 April 2014.

[141] The overall prices for household customers are shown including VAT, while a breakdown of all the individual price components is shown excluding VAT.

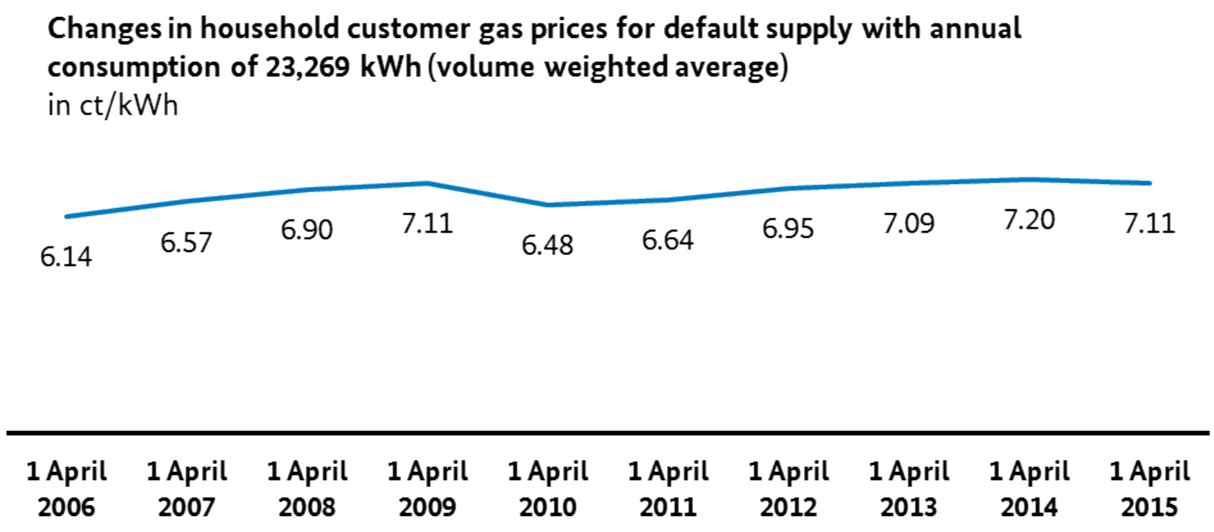

Figure 158: Changes in household customer prices for default supply with annual consumption of 23,269 kWh from 2006 until 2015 (volume weighted mean)

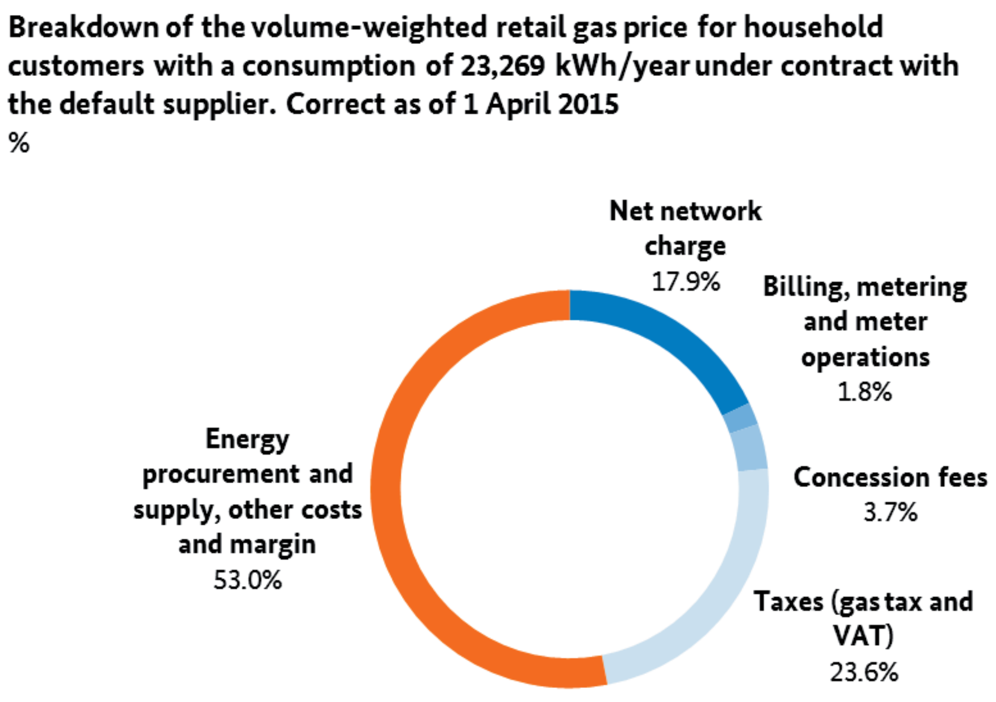

Figure 159: Composition of the volume-weighted gas retail price for default supply household customers with an annual consumption of 23,269 kWh according to the survey of gas wholesalers and suppliers
(correct as of 1 April 2015)

The volume weighted average price for customers supplied under a special contract with their default supplier fell for the first time since 1 April 2009, from 6.77 ct/kWh on 1 April 2014 to 6.68 ct/kWh on 1 April 2015. This constitutes a decrease in price of 1.3%. The price component for energy procurement and supply, other costs and the margin fell from 3.66 ct/kWh to 3.56 ct/kWh (a 2.7% decrease). The average net network charge (including upstream network costs) in this category increased very slightly from 1.31 ct/kWh to 1.32 ct/kWh and its share of the overall price increased from 19.4% (1 April 2014) to 19.8% (1 April 2015). The volume weighted mean for this contract category (6.68 ct/kWh) lies above the arithmetic mean (6.64 ct/kWh).

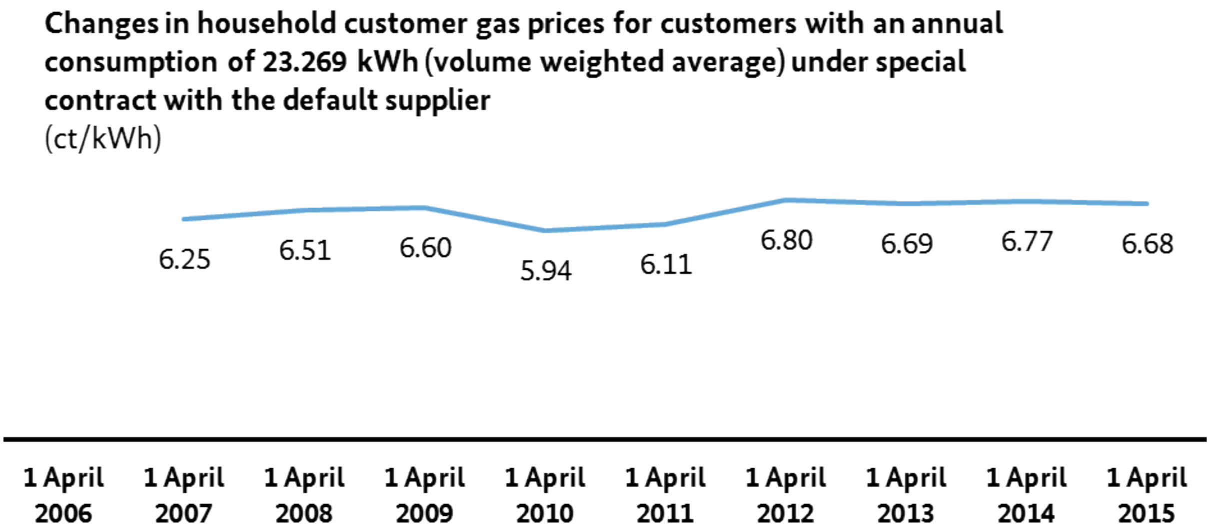

Figure 160: Changes in household customer prices for an annual consumption of 23,269 kWh under a special contract with the default supplier from 2007 until 2015 (volume weighted mean)[142]

[142] Data on the price for this consumption level was collected for the first time on 1 April 2007.

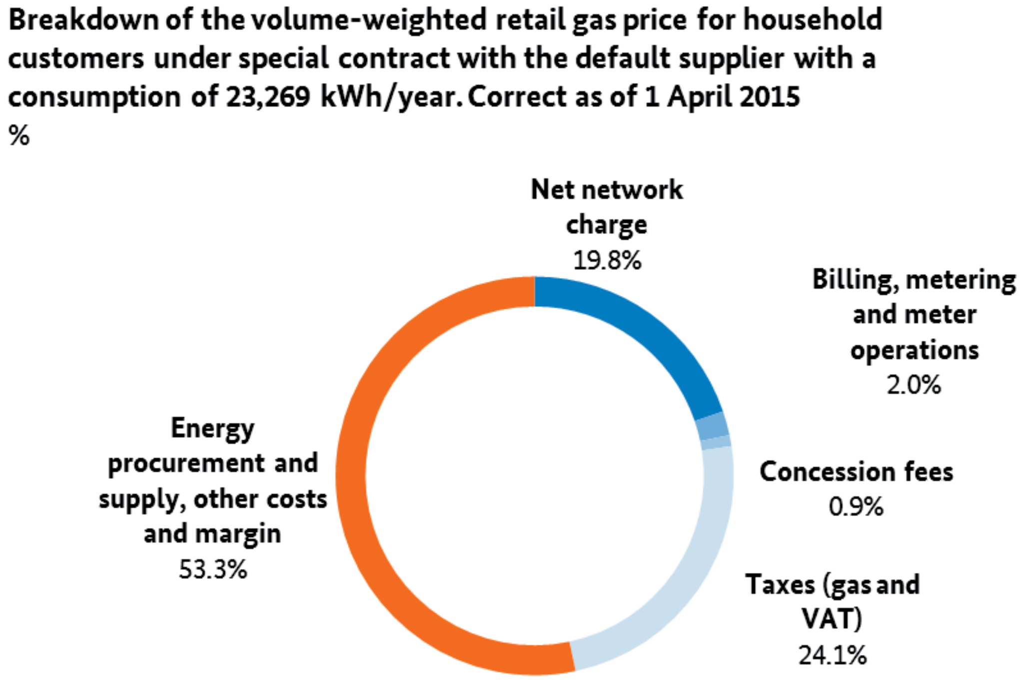

Figure 161: Composition of the gas retail price for household customers with a special default supplier contract and an annual consumption of 23,269 kWh (correct as of 1 April 2015)

The average price for customers served by a supplier other than their local default supplier decreased by over 4% from 6.39 ct/kWh to 6.12 ct/kWh. The price fell for the second time in a row in this contract category. Compared with the prior year, the share of the price component that can be controlled by the supplier ("energy procurement, supply, other costs and margin") in the overall price went down. By contrast, an increase was again recorded in the net network charge's share of the overall price – as it was on 1 April 2014.

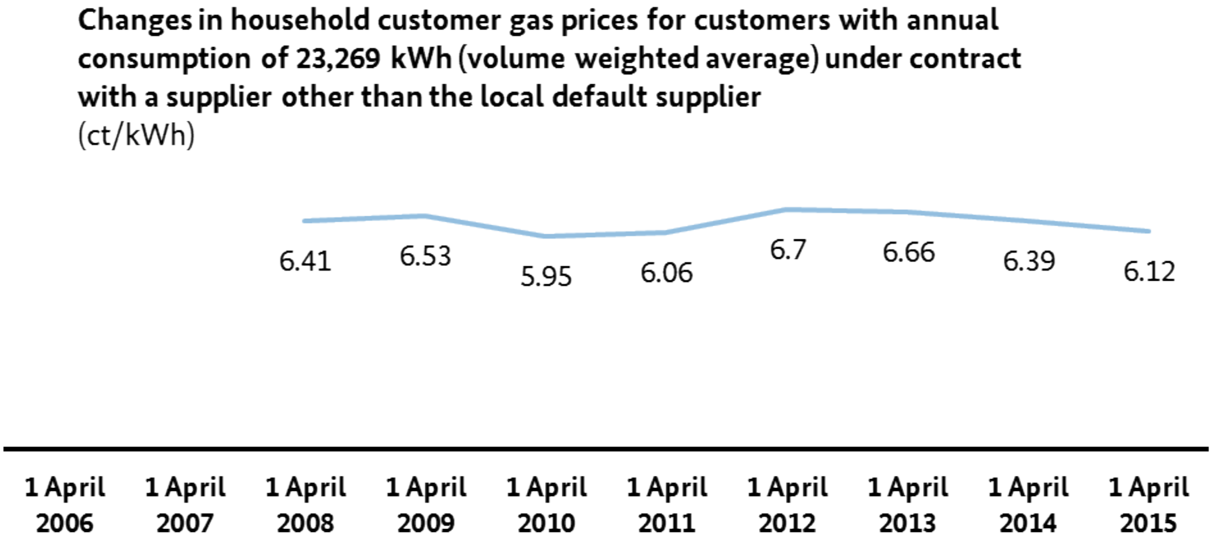

Figure 162: Changes in household customer prices for an annual consumption of 23,269 kWh under a contract with a supplier that is not the local default supplier from 2008 until 2015 (volume weighted mean)[143]

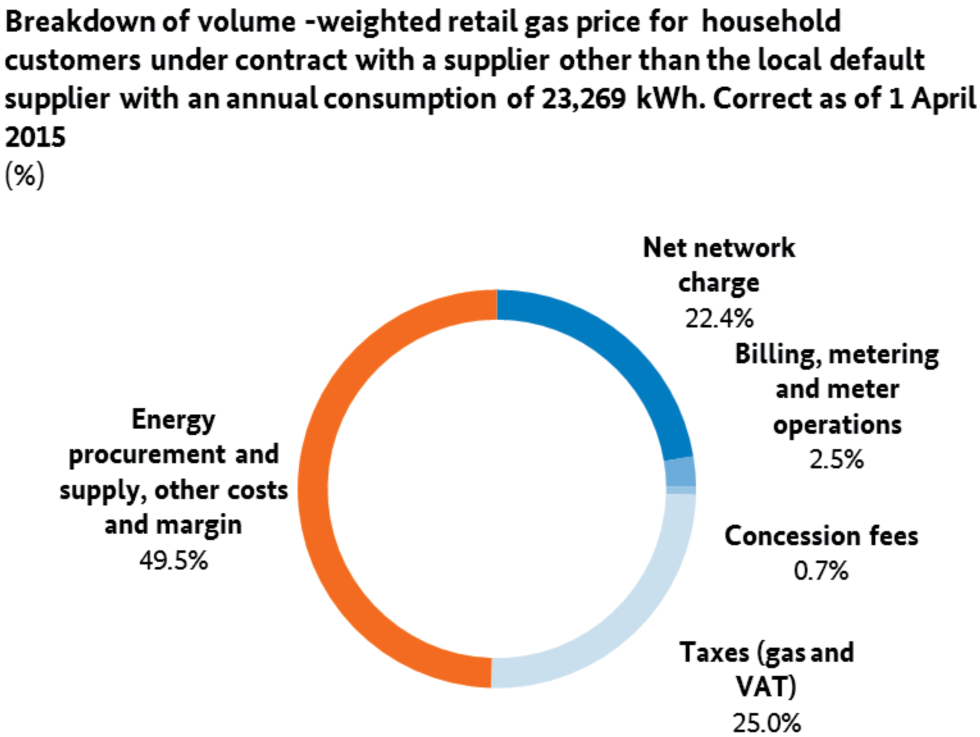

Figure 163: Composition of the gas retail price for household customers served under a contract with a supplier that is not the local default supplier as of 1 April 2015

[143] Data on the price for this consumption level was collected for the first time on 1 April 2008.

Compared to the previous year, the difference between the prices for customers with a standard contract and customers with a special contract with their local default supplier remained steady for an annual consumption of 23,269 kWh. There is therefore still an incentive for customers with this level of consumption to switch to a special contract.

Average retail price level for household customers with annual consumption of 23,269 kWh

As of 1 April 2015 (ct/kWh)	Default supply contract	Special contract with the default supplier	Contract with a supplier other than the local default supplier
Average net network charge including upstream network costs	1.27	1.32	1.37
Average charge for billing	0.05	0.06	0.06
Average charge for metering	0.02	0.02	0.02
Average charge for meter operations	0.06	0.05	0.07
Average concession fees	0.26	0.06	0.04
Current gas tax	0.55	0.55	0.55
Average VAT	1.13	1.06	0.98
Average price component for energy procurement, supply, other costs and the margin	3.77	3.56	3.03
Total	7.11	6.68	6.12

Table 81: Average retail price for household customers with an annual consumption of 23,269 kW according to contract category as of 1 April 2015

Average retail price level for household customers, according to contract category, with an annual consumption of 23,269 kWh

As of 1 April 2015	Default supply contract	Special contract with the default supplier	Contract with a supplier other than the local default supplier
Average net network tariff including upstream network costs	17.9%	19.8%	22.4%
Average charge for billing	0.7%	0.9%	1.0%
Average charge for metering	0.3%	0.3%	0.3%
Average charge for meter operations	0.8%	0.8%	1.1%
Average concession fees	3.7%	0.9%	0.7%
Current gas tax	7.7%	8.2%	9.0%
Average VAT	15.9%	15.9%	16.0%
Average price component for energy procurement, supply, other costs and the margin	53.0%	53.3%	49.5%
Total	100%	100%	100%

Table 82: Average retail price for household customers with an annual consumption of 23,269 kW according to contract category as of 1 April 2015

A reversal of the trend is apparent in the volume-weighted prices since 2008 in the "default supply customers" and "customers with a special contract with their default supplier" categories. A tendency towards falling prices has intensified for customers served under a contract with a supplier who is not the local default supplier. Since 1 April 2013 the total decrease in price for this category amounted to 8.1%.

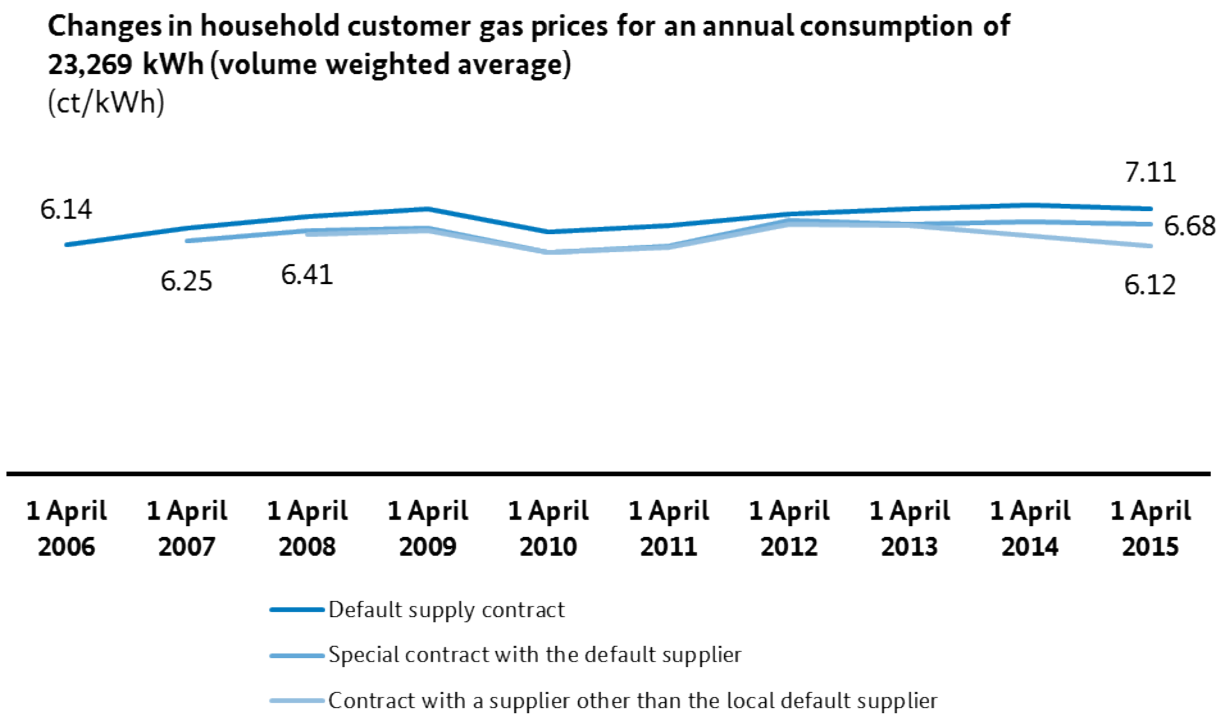

Figure 164: Volume-weighted gas prices for household customers with an annual consumption of 23,269 kWh from 2006 to 2015[144]

A look at the changes in the price component for energy procurement, supply, other costs and margin shows a downward trend in all of the three defined contract categories (cf Figure 165).

[144] Data for customers served under a "special contract with a default supplier" was collected for the first time on 1 April 2007, while data for "contracts with suppliers other than the local default supplier" was collected for the first time on 1 April 2008.

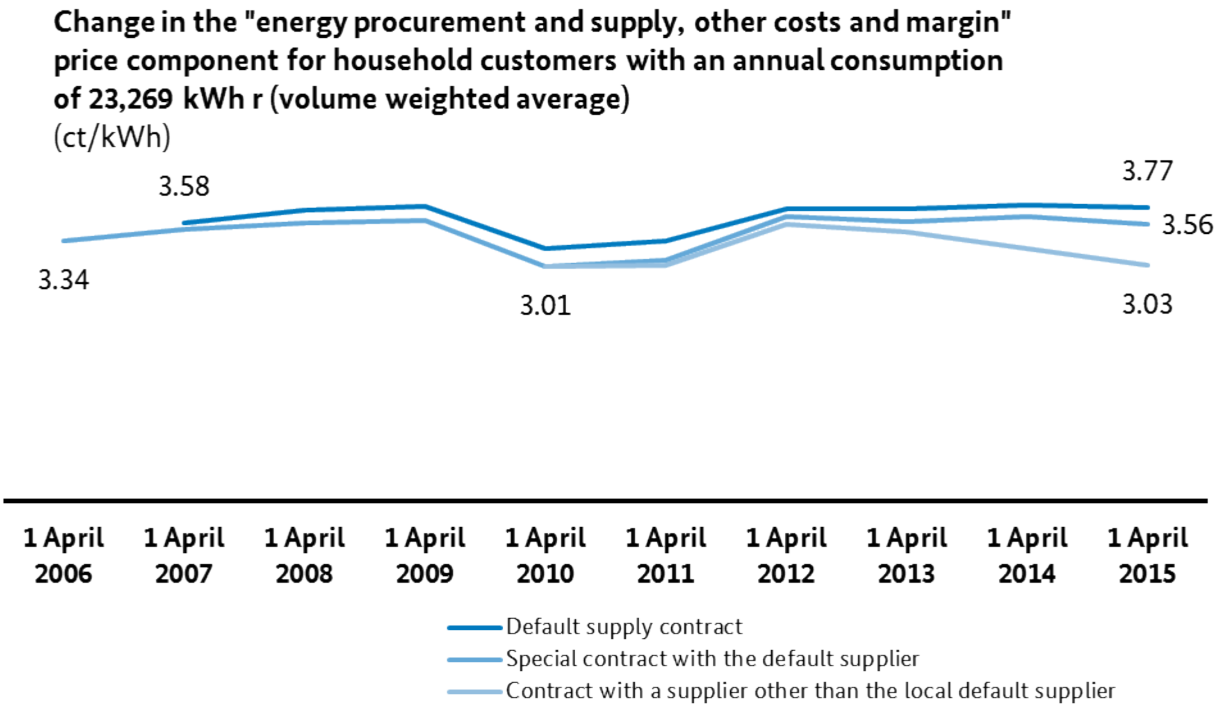

Figure 165: Price component for energy procurement and supply, other costs and the margin for household customers with an annual consumption of 23,269 kWh from 2006 to 2015

5. Comparison of European gas prices

Eurostat, the statistical office of the European Union, publishes final consumer gas prices every six months that show the average payments by household customers and non-household customers in the individual EU Member States. The figures published include for each consumer group (i) the price including all taxes and levies, (ii) the price without any recoverable taxes and levies (in particular without VAT) and (iii) the price without taxes and levies. Eurostat does not collect the data itself but receives the data from the national data offices. Rules on the classification, analysis and presentation of the price data aim to establish a basis of comparison throughout Europe.[145] Nonetheless, the choice of methodology to be applied by the Member States in collecting the data (see Directive 2008/91/EC, Annex I(h)) is left open, as a result national differences arise. For instance the German gas price data is based on the 2014 prices reported by 17 industrial suppliers and 11 domestic suppliers.[146]

5.1 Non-household customers

For non-household customers Eurostat publishes price statistics for six different consumer groups that differ according to annual consumption ("consumption bands"). As an example of these consumption bands, presented below is the annual consumption category of "between 27.8 GWh and 278 GWh" (corresponding to the range between 10,000 and 100,000 GJ). The 116 GWh per year (industrial customer) consumption level, for

[145] For more details refer to: http://ec.europa.eu/eurostat/web/energy/methodology/prices

[146] Cf Eurostat, Gas Prices – Price Systems 2014, S. 20 http://ec.europa.eu/eurostat/documents/38154/42201/Gas-prices-Price-systems-2014.pdf; accessed on 10 November 2015.

which specific price data is collected as part of the monitoring survey (see section II.F.4.1), falls under this consumption category.

Customers with this level of annual consumption are mainly industrial customers. Industrial customers can deduct the national value added tax, so the total price has been adjusted for VAT to enable comparison of the total price across Europe. In addition to VAT, there are other taxes and levies due in part to specific national circumstances, which can typically be recovered by industrial customers and which have also been deducted from the gross price in accordance with the Eurostat classification.[147] Additionally, other taxes and levies apply in most Member States which are not reimbursable (in Germany: gas tax and concession fee).

Across Europe, price differences are much smaller for industrial customers than for household customers. At 3.19 ct/kWh, the net gas price that German customers with an annual consumption of 27.8 - 278 GWh pay lies within the European mid range. The EU average is 3.12 ct/kWh. On average, non-reimbursable taxes and levies amount to 7% (0.22 ct/kWh) of the net gas price in Europe. With a share amounting to around 13% (0.41% ct/kWh), non-reimbursable taxes and levies in Germany are somewhat higher than the European average.

[147] For more on country-specific deductions, see Eurostat, Gas Prices – Price Systems 2014.

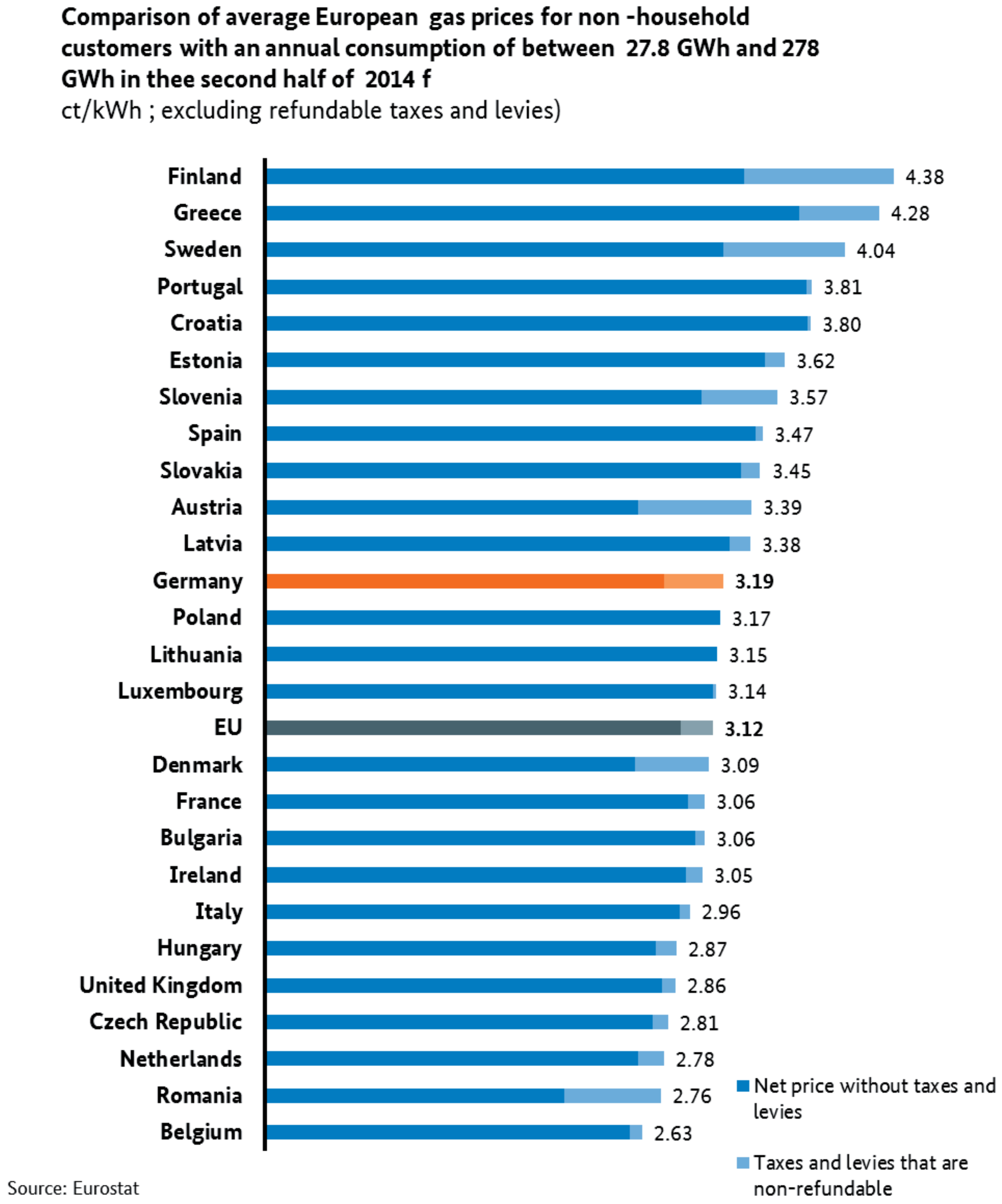

Figure 166: Comparison of European gas prices in the second six months of 2014 for non-household customers with annual consumption of between 27.8 GWh and 278 GWh

5.2 Household customers

Eurostat takes three different consumption bands into consideration when comparing household customer prices. They apply to an annual consumption of: less than 5,555 kWh, between 5,555 kWh and 55,555 kWh and exceeding 55,555 kWh. The 23,269 kWh per year consumption level, for which specific price data is collected as part of the monitoring survey (see section II.F.4.2 from page 305), is in the middle of the three consumption bands. Accordingly, a European comparison of the middle consumption band is presented below. As a rule, household customers cannot claim reimbursement of any of the taxes and levies incurred, hence the total price including VAT is relevant for these customers.

Unlike prices for industrial customers, gas prices for household customers vary strongly across Europe. In Portugal and Sweden household customers pay more than three times as much for natural gas as they do in Romania. At 6.81 ct/kWh, the gas price paid by German household customers is close to the EU average price of 7.19 ct/kWh.

The share that taxes and levies make up in the overall price also varies strongly in the EU. While taxes and levies account for around 5% of the price in the United Kingdom, they make up more than 60% of the price in Denmark. In Germany, taxes and levies account for about 25% of the overall price, which is close to the European average. 1.68 ct/kWh of the overall price in Germany is accounted for by taxes and levies. The EU average for this figure is 1.64 ct/kWh.

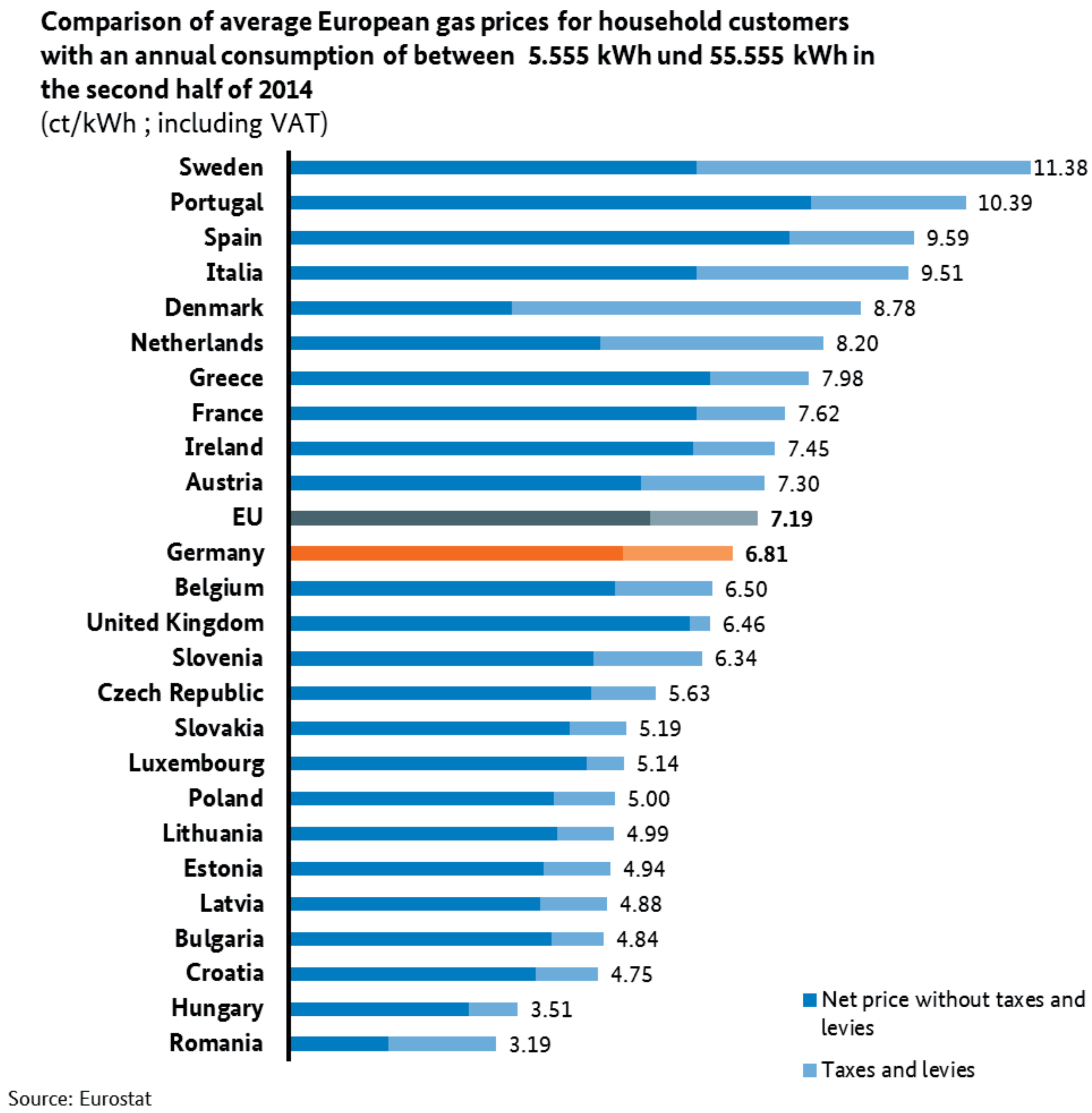

Figure 167: Comparison of European gas prices in the second six months of 2014 for household customers with annual consumption of between 5,555 kWh and 55,555 kWh

G Storage facilities

1. Access to underground storage facilities

All 24 companies operating and marketing a total of 42 underground natural gas storage facilities took part in the monitoring survey. On 31 December 2014 the total maximum usable volume of working gas in these storage facilities was 25.68bn Nm^3.[148] Of this, 13.30bn Nm^3 was accounted for by cavern storage and 12.38bn Nm^3 by pore storage facilities. Reflecting the structure of the German natural gas market, the largest part of the storage facilities, by far, is designed for the storage of H-gas (23.33bn Nm^3, compared to 2.34bn Nm^3 for L-gas).

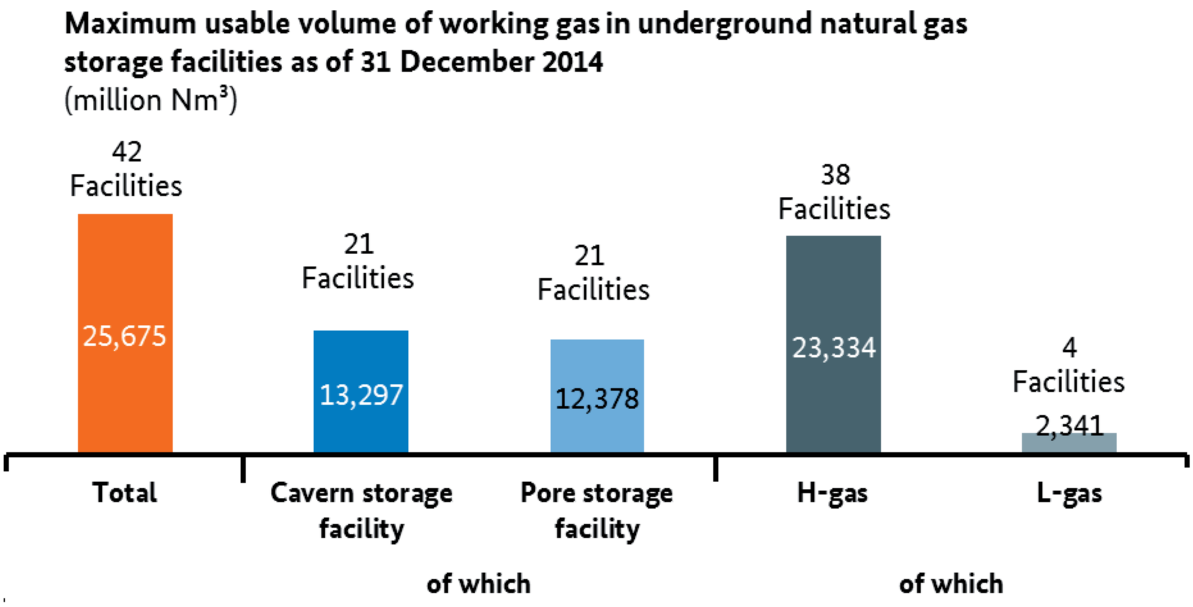

Figure 168: Maximum usable volume of working gas in underground natural gas storage facilities as of 31 December 2014

The next figure shows the changes in storage levels since 2010. Despite the sometimes strongly varying conditions under which the gas market operated (eg the cold spell in February 2012 or the longer winter in 2013), natural gas storage facilities were sufficiently filled each winter in the period monitored. The total storage level of all German storage facilities was very high at the beginning of the past winter 2014/15. This is partly attributed to the very mild winter in 2013/14, meaning that customer demand for gas was significantly lower and hardly any gas was withdrawn from the storage facilities. Because of the abundant supply of gas in the storage facilities, the short-term price of natural gas in early 2014 was so low that the withdrawal from storage and sale of gas did not make sense for storage customers. The high level of gas supply in storage

[148] Included in this value is the storage volume of the 7Fields storage facility and a part of the volume of the Haidach storage facility, both of which are located in Austria close to the German border.

facilities reflected this situation at the beginning of the injection period. Moreover, additional storage capacity came onto the market (eg Jemgum), which increased the total volume of working gas available.

The total level of natural gas at German storage facilities is currently low compared to previous years. According to statements made by traders, this can be mainly attributed to the present situation on the market that expects high levels of imports from Russia in the upcoming winter. The Bundesnetzagentur is confident that all market participants strive to maintain the present very high level of supply security on the gas market.

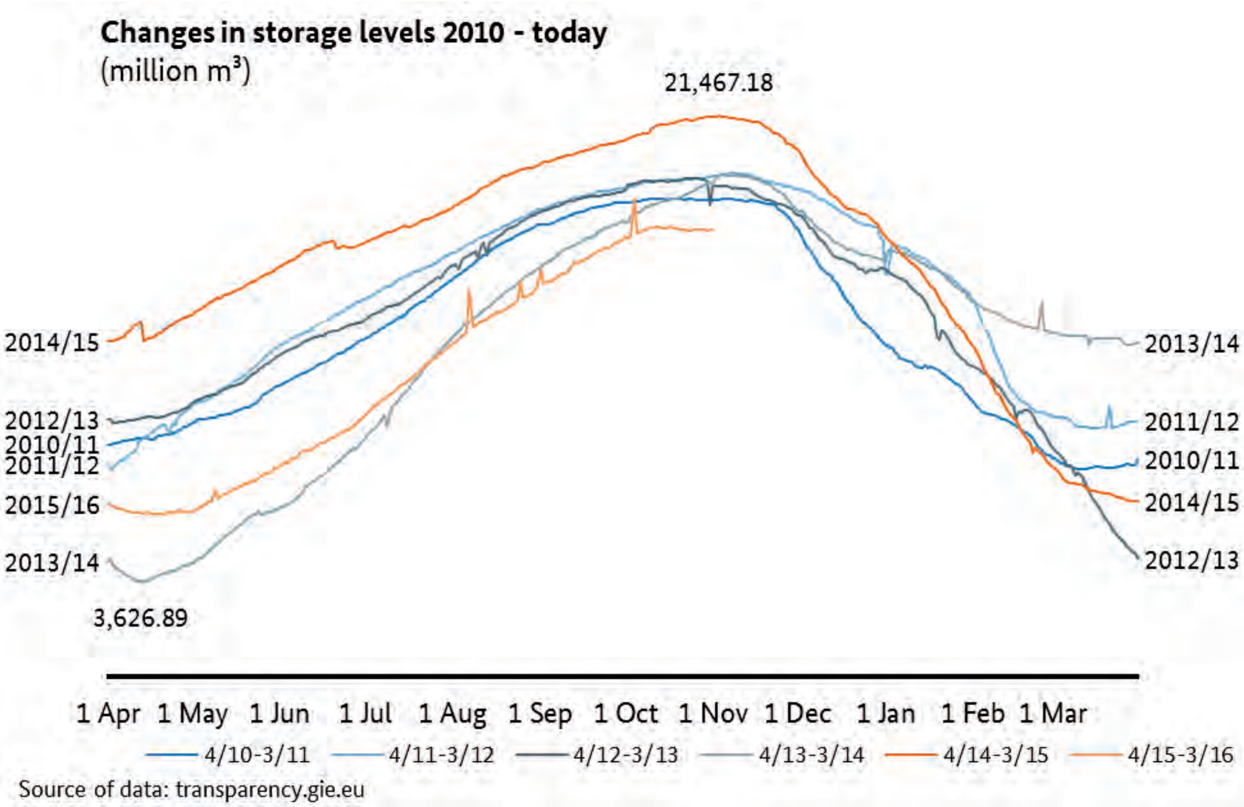

Figure 169: Changes in storage levels: 2010 - today.

2. Use of underground storage facilities for production operations

Production operations involve the use of storage facilities by companies that produce gas in Germany. In 2014, less than one percent of the maximum usable volume of working gas in underground natural gas storage facilities was used for production operations in two storage facilities. After deducting the working gas volume used for production operations, the total working gas volume accessible to third parties in 2014 was 25.43bn Nm³ (2013: 25.20bn Nm³); the accessible injection capacity and the withdrawal capacity were 12.84m Nm³/h and 25.82m Nm³/h, respectively.

3. Use of underground storage facilities – customer trends

According to the companies' data, the average number of customers of each storage facility operator in 2014 was 6.1 (2010: 4.4; 2011: 5.0; 2012: 5.4, 2013: 5.3). The following chart shows the trend in the number of customers per storage facility operator since 2010:

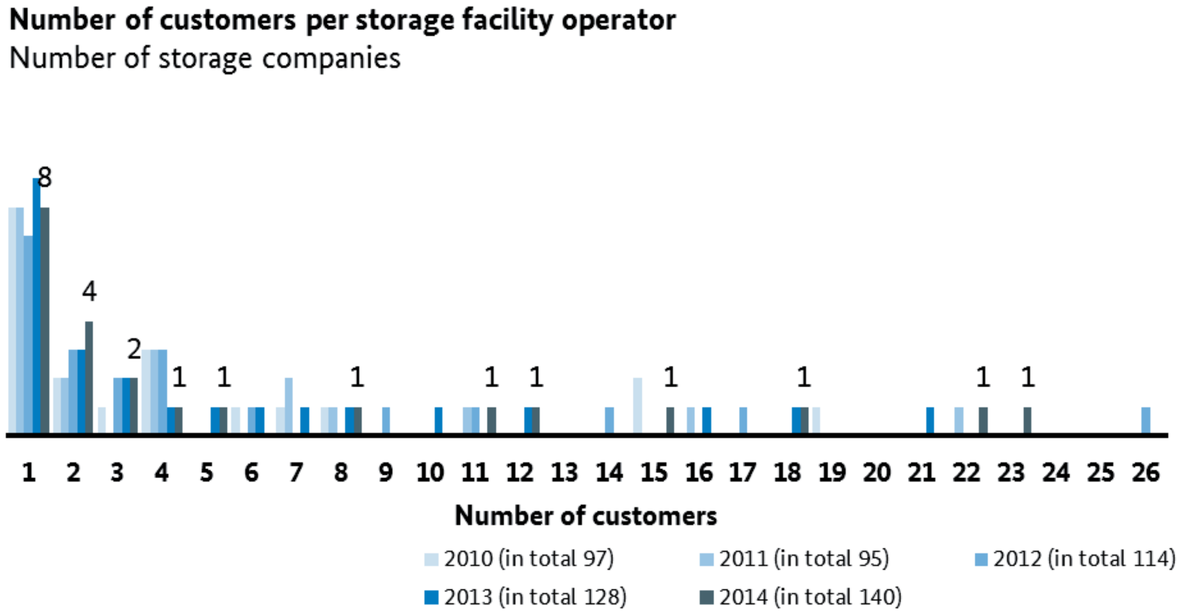

Figure 170: Number of customers per storage facility operator from 2010 to 2014

The number of storage customers increased year-on-year. The survey again showed, however, that one third of the storage companies have only one customer. In 2014, there were two storage companies with more than 20 customers for the very first time.

4. Capacity trends

The following chart shows the free working gas volumes in underground natural gas storage as of 31 December 2014 compared to the previous years.

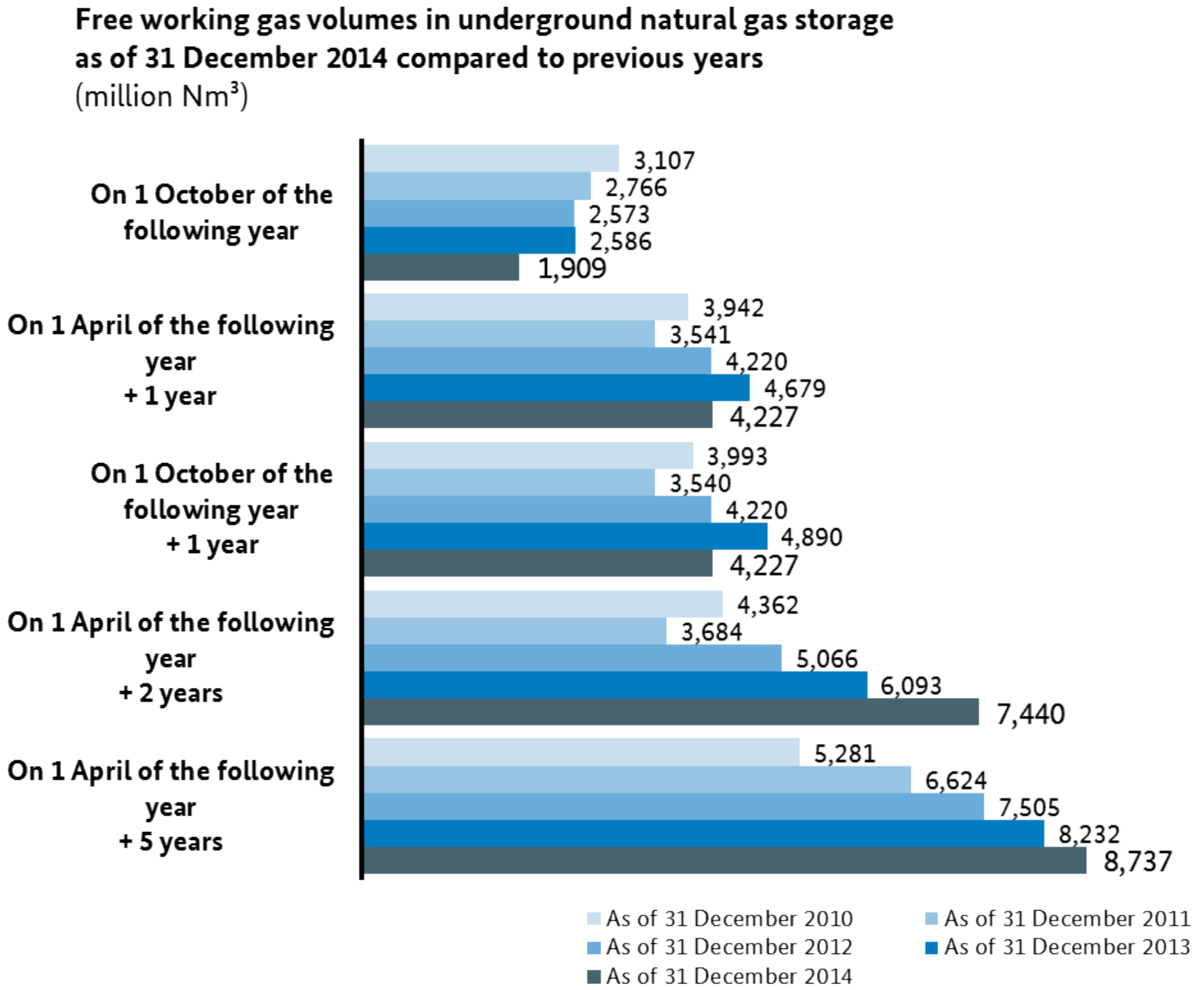

Figure 171: Volume of freely bookable working gas available on the specified date in the following periods from 2010 to 2014

There was another slight decrease in the volume of freely bookable working gas that can be booked at short notice (up to 1 October 2014), and the capacities bookable from 2016 also decreased slightly. The volume of working gas available for long-term booking increased again compared to previous years.

H Biogas monitoring

As of 31 December 2014, 185 biogas plants (including two power-to-gas systems) had injected 688m Nm³/h or 7,489m kWh of biogas into the gas supply network, an increase of 37% compared to the prior year. The market-indexed selling price for biogas in 2014 was between €0.05 per kWh and €0.08 kWh.

Key biogas injection figures

	2011	2012	2013	2014
Number of injecting systems (incl. injection of hydrogen)	77	108	144	185
Volume of biogas injected (million Nm³)	275	413	520	688
Volume of biogas injected (million kWh)	2,674	4,393	5,471	7,489
Ancillary costs passed on by gas network operators to all network users (€ million)	78	107	131	154
Ancillary costs incurred per kWh of biogas injected (ct/kWh)	2.917	2.436	2.394	2.056

Table 83: Biogas injection, key figures for 2011-2014

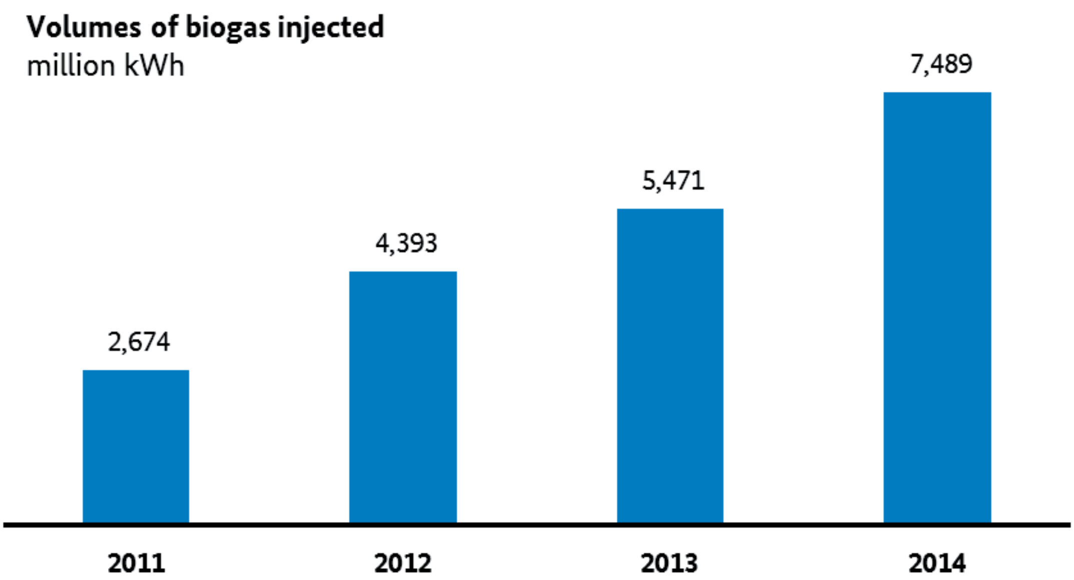

Figure 172: Volumes of biogas injected, 2011-2014

1. Ancillary costs passed on in 2014

Gas network operators can spread the costs incurred for biogas injection among all the network users via the network charges. These costs amounted to €154m in 2014. This represents an increase of 18% compared to 2013. The trend of rising ancillary costs thus also continued in 2014.

A nationwide biogas surcharge has been in force since 2014 as a result of the amendment of section 20b of the Gas Network Charges Ordinance (GasNEV) applicable as of 22 August 2013. This serves the purpose of counteracting the increasingly uneven distribution of the cost burden between the two market areas. Since 1 January 2015, the biogas surcharge has been at €0.60194 per kWh/h/a.

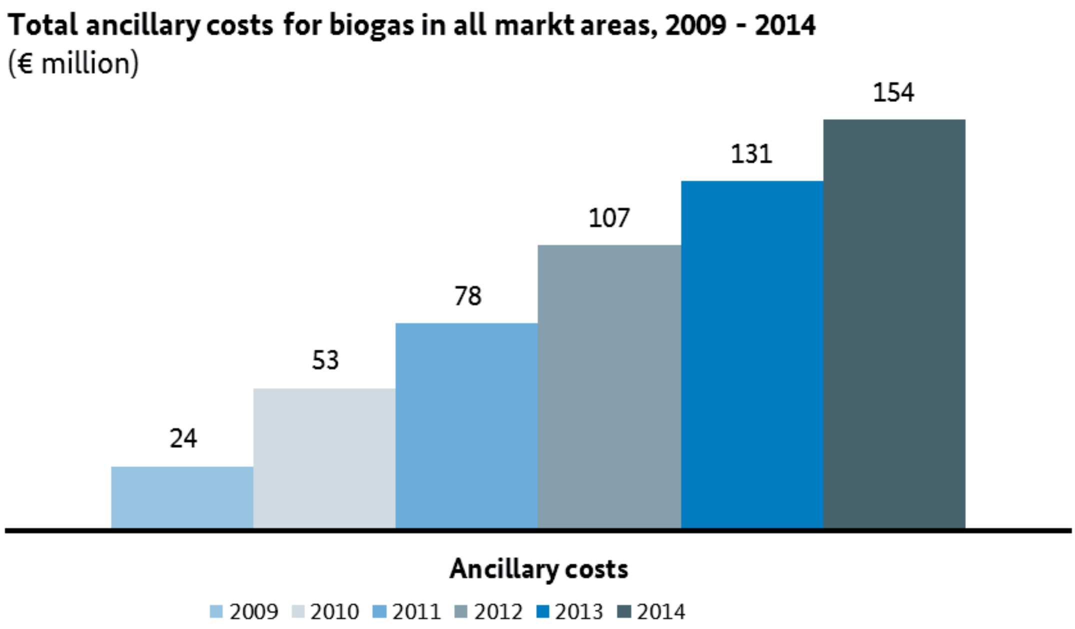

Figure 173: Total ancillary costs for biogas in all market areas, 2009-2014

2. Market areas

The number of biogas balancing groups or invoicing balancing groups remained more or less constant in 2014 compared to 2013.

Key biogas injection figures for each market area

	2013		2014	
Market areas	**NCG**	**GASPOOL**	**NCG**	**GASPOOL**
Number of biogas balancing group managers	53	53	58	57
Number of biogas balancing groups	149	131	141	138
Biogas invoicing balancing groups	82	83	81	85

Table 84: Key biogas injection figures for each market area

I Metering

1. The network operator as the default meter operator and independent meter operators

Since the full liberalisation of electricity and gas metering activities, gas customers have been free to choose a different provider than the network operator for meter operations and services. If a customer does not switch to another provider, the network operator is responsible by law for providing these services.

654 companies operating a total of almost 13.96m meters responded to the questions about gas metering.

Metering services are provided by (gas) distribution system operators who also act as meter operators, by suppliers and by independent meter operators. The following table shows in which capacity meter operators are present in the market and how their activities are to be classified with regard to meter operations and meter reading.

Meter operators

Function	2014	2013
System operator acting as meter operator within the meaning of section 21b(2) of the EnWG	648	625
System operator acting as meter operator within the meaning of section 21b(2) of the EnWG, providing (metering) services in the market	8	9
Supplier with meter operator activities	1	5
Provider of metering services to customers whom they do not supply	4	1

Table 85: Role of meter operator

The number of interval-metered supply points increased slightly from 38,070 in 2013 to 39,641 to in 2014[149]. The number of meter points fitted by the meter operator with metering equipment as defined in section 21f EnWG and capable of connection to metering systems as defined in section 21d EnWG was around 1,131,000 (2013: 919,000[150]). This amounted to 7.8% of all metering equipment installed

[149] Subsequent correction of the figure of 74,945 from the 2014 monitoring report.

[150] Subsequent correction of the figure of 871,000 from the 2014 monitoring report.

2. Meter technology used for household customers

The following table shows the types of metering equipment used by the meter operators for standard load profile (SLP) customers:

Metering equipment for SLP customers

Metering equipment used by the meter operator for SLP customers	Number of meter points according to meter size		
	G1.6 to G6	G10 to G25	G40 and upwards
Diaphragm gas meter with mechanical counter	8,799,944	285,586	36,941
Diaphragm gas meter with mechanical counter and pulse output	4,375,647	139,868	14,651
Diaphragm gas meter with electronic counter	8,896	209	852
Load meters as for load-metered customers	60	249	3,598
Other mechanical gas meters	11,037	2,380	25,055
Other mechanical gas meters	3,741	7	1,427
Total number of meters within the meaning of section 21f of the EnWG (revised)	38,084	43,779	4,157
Total number of meters that can be converted within the meaning of section 21f of the EnWG (revised)	871,077	1,631	512

Table 86: Metering equipment for SLP customers

The following figure shows the technologies used to connect metering equipment to systems as defined in section 21d EnWG.

A total of 310,699 (2013: 106,944 meters of SLP customers were connected to such systems :

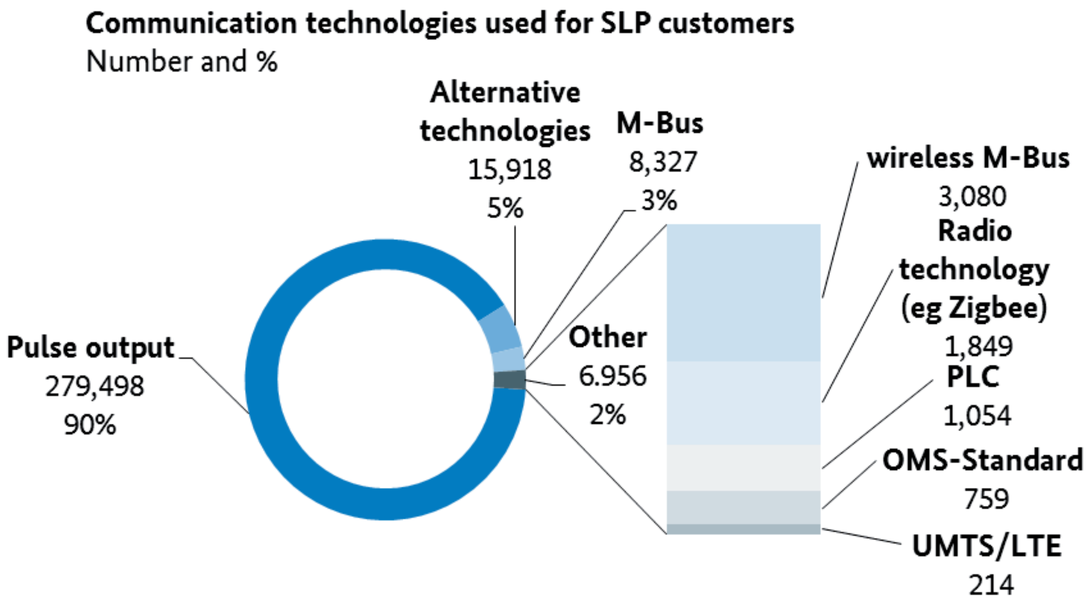

Figure 174: Communication technologies used for SLP customers

3. Meter technology used for interval-metered customers

The meter operators were also asked which type of meter they used for interval-metered customers. The following table shows the number of meter points fitted with each type of meter.

Metering equipment for load-metered customers

Function	Number of meter points
Transmitting meter with pulse output/encoder meter + recording device/data storage	18,303
Transmitting meter with pulse output/encoder meter + volume corrector	9,418
Transmitting meter with pulse output/encoder meter + volume corrector + recording device/data storage	14,407
Other	235

Table 87: Metering equipment for interval-metered customers

The following figure shows the technologies used for the remote reading of 36,516 meters of interval-metered customers in 2014 (36,516 in 2013).

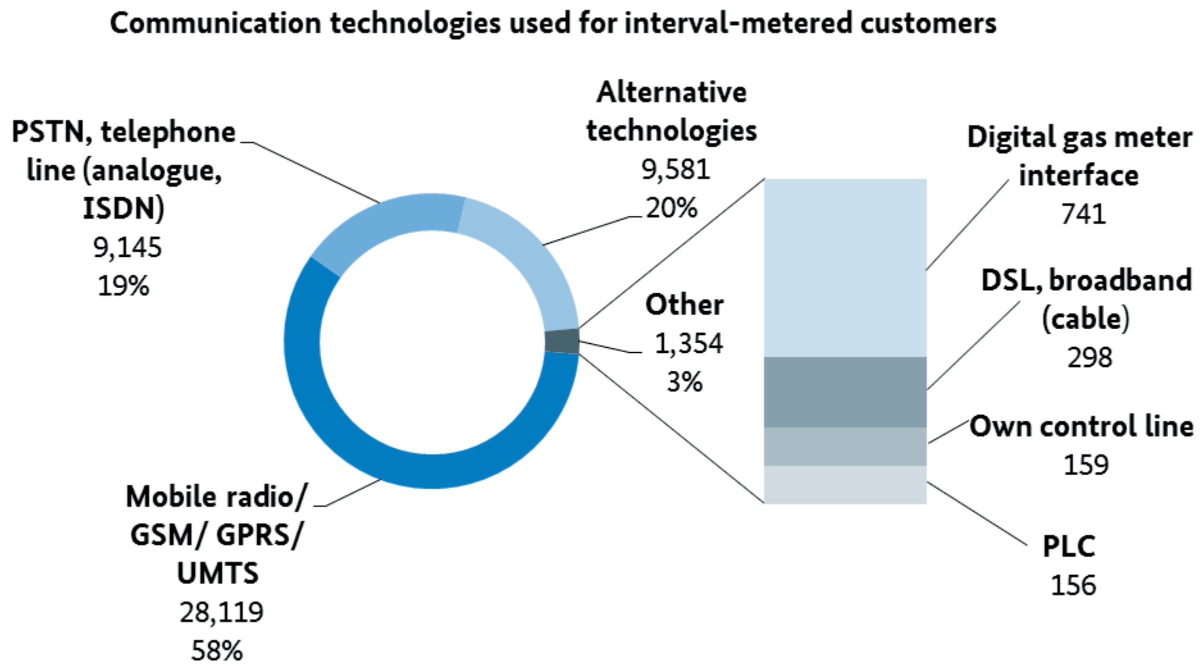

Figure 175: Communication technologies used for interval-metered customers

III General topics

A Market Transparency Unit for Wholesale Electricity and Gas Markets

The tasks of the Market Transparency Unit for Wholesale Electricity and Gas Markets are carried out jointly by the Bundesnetzagentur and the Bundeskartellamt. The Market Transparency Unit was officially set up at the Bundesnetzagentur on 12 December 2012; it was established within the Bundesnetzagentur's energy regulation department, with staff from both the Bundesnetzagentur and the Bundeskartellamt working together.

1. Joint market monitoring

Staff from both of the authorities within the Market Transparency Unit jointly monitor the wholesale energy markets pursuant to section 47b of the German Competition Act and Article 7 of the EU Regulation on wholesale energy market integrity and transparency (REMIT). This task involves collating the data collected and passed on by ACER as from 7 October 2015 together with the data to be reported under national regulations, and analysing the data for possible breaches of the law. The data is analysed from the different viewpoints of the two authorities: the Bundesnetzagentur looks for signs of breaches of REMIT and the Bundeskartellamt for breaches of national competition law. Circumstances suggesting a breach of the German Security Trading Act or Stock Exchange Act are reported to the competent authorities. In a wider context the Bundesnetzagentur and the Bundeskartellamt plan to develop joint guidelines on evaluating price spikes in the wholesale electricity markets with regard to competition law and REMIT.

In monitoring the markets, the Market Transparency Unit works closely with ACER – which monitors trading in wholesale energy products at European level – to detect and prevent trading based on inside information and market manipulation. The Bundesnetzagentur is notified for instance via ACER's Notification Platform[151] of suspected breaches of REMIT relating to the German market area or wholesale energy products traded in Germany. Here, the focus is on assessing whether inside information has been published in accordance with the REMIT provisions and whether the insider trading and market manipulation prohibitions have been infringed.

The focus of market monitoring from a competition law viewpoint is on the prohibition of abuse of a dominant position. The aim of market monitoring within the Market Transparency Unit is initially to create the appropriate conditions allowing dominant positions in the market for the first-time sale of electricity to be regularly identified. If circumstances suggest that a company may have a dominant position in this market, the Market Transparency Unit will analyse the market for possible indications of abusive practices. It will also analyse the data it collects for indications of cartel offences, and in particular prohibited cartel arrangements. Any initial suspicions are investigated further and pursued by the Bundeskartellamt.

[151] https://www.acer-remit.eu/np/home

2. Cooperation agreement

The Presidents of the Bundesnetzagentur and the Bundeskartellamt concluded the agreement on cooperation within the Market Transparency Unit in February 2015.

The agreement as provided for by section 47a of the Competition Act lays down the foundation for the two authorities to work together within the Market Transparency Unit. It covers in particular the aspects prescribed by law such as staffing, task allocation, coordinated data collection and the exchange of data and information.

Thus the Market Transparency Unit comprises staff from both authorities. The tasks are allocated on the basis of each authority's area of activity.

In identifying indications of suspected breaches of REMIT, competition law or provisions of the Security Trading Act or Stock Exchange Act, the Market Transparency Unit adopts the procedures developed by the authorities responsible for pursuing such cases. A continual exchange of information between the staff working together is ensured. Data and information are exchanged with the Bundeskartellamt as prescribed by law via an effective system providing secure and direct electronic data access complying with the data protection requirements. The cooperation agreement is available on the Market Transparency Unit's website[152].

3. Joint data basis

The Market Transparency Unit is authorised to collect the data and information it requires to fulfil its tasks (section 47b(3) of the Competition Act). A significant amount of the data it needs is to be passed on by ACER under Article 7 of REMIT. The Market Transparency Unit may also initiate proceedings to stipulate its own requirements for the data to be reported in accordance with an ordinance to be issued by the German Federal Ministry for Economic Affairs and Energy. These requirements may apply to both transaction data and fundamental data. No requirements proceedings have as yet been implemented. The Market Transparency Unit is expected to define requirements for both electricity and gas balancing energy data and for selected fundamental data relating to electricity generation plants with a capacity of less than 100 MW. The authorities, stakeholders and market participants affected are given an opportunity to state their views in good time before requirements are issued; initial exploratory talks were held in 2014 and 2015. The Market Transparency Unit is expected to make only limited use of its power to stipulate its own requirements since most of the data it requires is collected by ACER under the REMIT provisions and passed on direct to the Market Transparency Unit.

The Market Transparency Unit will collect transaction reports and fundamental data for continuous and comprehensive analysis. Together, this will result in a substantial amount of data being acquired. To perform the necessary tasks with such a large volume of data, the Market Transparency Unit is setting up a market monitoring system to collate and analyse specific market data. This system will enable the Market Transparency Unit to record the market data provided by ACER or collected under national regulations and to continuously monitor the wholesale electricity and gas markets for indications of violations.

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[152] http://www.markttransparenzstelle.de/SharedDocs_MTS/Downloads/DE/MTS/Kooperationsvereinbarung.pdf?__blob=publicationFile&v=2

Market Transparency Unit website

The Market Transparency Unit's website at http://www.markttransparenzstelle.de went live in January 2015.

The primary aim of the website is to provide participants in the wholesale electricity and gas markets with information about their registration and data reporting obligations in relation to the Market Transparency Unit, and in particular information about past and current requirements proceedings. More specifically, the Market Transparency Unit will publish lists of all the data and data categories to be reported as laid down in its requirements proceedings, together with details of the formats, transmission media and deadlines, as prescribed by law (section 47h(3) of the Competition Act). Information about market participants' registration and data reporting obligations under REMIT and about the Bundesnetzagentur's tasks and enforcement powers under REMIT is available at the Bundesnetzagentur's dedicated REMIT information portal at http://www.remit.bundesnetzagentur.de/.

The Market Transparency Unit's website provides information about its tasks in connection with monitoring the wholesale electricity and gas markets and about its work in cooperation with the supervisory enforcement authorities. The website also provides access to a range of background information, in particular legislation, additional material and answers to frequently asked questions about the Market Transparency Unit. RSS news feeds about the Market Transparency Unit's activities, reporting deadlines, requirements proceedings and legislative procedures can be subscribed to. There is also a schedule of relevant events and presentations. In addition, the law provides for the Market Transparency Unit's activity report to be published on the website.

B Selected activities of the Bundesnetzagentur

1. Obligations and prohibitions under REMIT

REMIT imposes an obligation on market participants to publish inside information, to register, to report data and also lays down a prohibition on insider trading and market manipulation. The task of ensuring compliance with REMIT has been assigned to the Bundesnetzagentur pursuant to section 56 sentence 1(4) EnWG. The Bundesnetzagentur ensures that the integrity and transparency of the wholesale energy market is safeguarded. The following topics are particularly relevant at the current time.

1.1 Registration of market participants

Since 6 March 2015 the Bundesnetzagentur has been registering market participants as required under REMIT. Enterprises that are required to report data to ACER must first of all register with their national regulatory authority. The obligation to report data to ACER has been defined in the Commission Implementing Regulation (EU) No 1348/2014, which entered into force on 7 January 2015. A distinction is made between standard contracts, which must be reported to ACER from 7 October 2015, and non-standard contracts, which must be reported to ACER from 7 April 2106. Before the data can start being reporting to ACER as of the specific date, the market participants must have registered with the Bundesnetzagentur to obtain an ACER registration code for reporting data. Registration takes place via CEREMP, the Centralised European Registry for Energy Market Participants, a registration portal set up by ACER. The Bundesnetzagentur has drawn up a registration manual that can be accessed online at the Bundesnetzagentur's website.[153] At the beginning of November 2015, 1100 market participants had registered with the Bundesnetzagentur. They have been entered in ACER's European register[154].

The Bundesnetzagentur receives numerous enquiries about registration every day from enterprises and municipal utility companies. In the first six months of 2015 alone there were more than 700 email and telephone enquiries. A separate email address[155] and telephone number[156] have been set up to deal with registration enquiries. Frequently asked questions by market participants have been put together in a list of FAQs and can be accessed at the REMIT information portal.[157]

In addition to this, the Bundesnetzagentur took part in registration workshops hosted by the energy associations as well as in numerous other events to inform market participants of their registration and reporting obligations.

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[153] http://remit.bundesnetzagentur.de/SharedDocs_MTS/Downloads/DE/REMIT/CEREMP_Handbuch.pdf?__blob=publicationFile&v=4

[154] https://www.acer-remit.eu/portal/european-register

[155] REMIT-Registrierung@bnetza.de

[156] 0228 145000

[157] www.remit.bundesnetzagentur.de

1.2 Reporting obligations of market participants

The reporting obligation placed on market participants covers transaction data and fundamental data. Records of transactions on the wholesale energy market, including the orders to trade, will only be collected by ACER. Which transactions have to be reported and how, the details that have to be included, and who is subject to the reporting obligations in this respect, can be found in the REMIT Transaction Reporting User Manual (TRUM).[158] The fundamental data to be reported includes information on the capacity and use of facilities for production and storage, the consumption or transmission of electricity and natural gas, and on the capacity and use of LNG facilities. This also includes the planned or unplanned unavailability of these facilities. Pursuant to Articles 8 and 9 of the Implementing Regulation (EU) No 1348/2014, ENTSO-E and ENTSO-G are required to forward the aforementioned fundamental data to ACER on behalf of the market participants.

To allow data reporting via a third party, a so-called "Registered Reporting Mechanism" (RRM) can register with ACER. ACER publishes a list of all registered RRMs.[159]

The entire data reporting of the market participants registered in Germany and of those third parties operating on their behalf, as well as all transactions for the supply of energy where the place of performance is Germany, will be forwarded by ACER to the Bundesnetzagentur. Added to this information is the fundamental data from Germany and the countries immediately bordering Germany. Thus in this way the Bundesnetzagentur obtains the transaction and fundamental data that relates to the German market area and multiple reporting of identical data to various offices can be avoided.

1.3 Insider trading and market manipulation

Insider trading and market manipulation are prohibited under REMIT. Depending on the individual breach of a prohibition, it may be considered an administrative offence or a criminal act. At the present time the Bundesnetzagentur does not have the data necessary to carry out its own data analysis to uncover any prohibited conduct. Consequently it is dependent upon external information. However, should any information it receives hint at suspicious activity, the Bundesnetzagentur will then request all the necessary related data and will analyse it. Up to now the Bundesnetzagentur has been in receipt of external information from other supervisory authorities, from ACER and from other European regulatory authorities.

Persons who professionally arrange transactions in wholesale energy products and who have a reasonable suspicion of insider trading or market manipulation must notify the Bundesnetzagentur of this without delay pursuant to Article 15 REMIT. As a rule, the ACER Notification Platform[160] is used for this, with ACER receiving information in English at the European level and passing this on to the national regulatory authorities concerned. At the national level the Bundesnetzagentur gives market participants the opportunity to report any breaches of REMIT directly by post or by telephone, in German, and in doing so safeguards the confidentiality of the information.

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[158] http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/Transaction Prozent20Reporting Prozent20User Prozent20Manual Prozent20 Prozent28TRUM Prozent29.pdf

[159] https://www.acer-remit.eu/portal/list-of-rrm

[160] https://www.acer-remit.eu/np/home

In 2014 the Bundesnetzagentur received five reports of possible breaches of REMIT from other authorities. Two of these cases comprised a possible breach of the prohibition on insider trading and actually fall under the jurisdiction of foreign regulatory authorities. The three remaining cases related to a possible breach of the prohibition on market manipulation. Following a thorough examination, one of these cases was not pursued further. This case involved a suspected manipulation of wholesale gas products. In 2015 the Bundesnetzagentur received information about four suspicious cases. Three of the cases related to a possible breach of the prohibition on market manipulation and the other to an apparent unintentionally erroneous transaction. One of the breach issues is a suspected illegal blocking of cross-border transmission capacity with no intention of trading electricity, which the Bundesnetzagentur is currently investigating together with the other regulatory authorities affected. The case relating to the "manifest error" was dropped following a brief investigation. The remaining possible breaches of the REMIT regulations from 2014 and 2015 are still being dealt with.

2. Bundesnetzagentur cooperation with the Agency for the Cooperation of Energy Regulators

The Agency for the Cooperation of Energy Regulators (ACER) was established in 2011 to support the authorities charged with regulatory tasks in the Member States to fulfil these at the Community level and to coordinate their efforts where necessary. From the start, the Bundesnetzagentur has played an active role in the Agency's bodies, in particular on the Board of Regulators and in working groups, in order to press ahead with sound European solutions. More than 30 members of Bundesnetzagentur staff are active in the some 20 working groups and task forces in the areas of electricity, gas, REMIT and monitoring. The Agency's REMIT working group is chaired by the Bundesnetzagentur.

With the publication of the "Energy Regulation: A Bridge to 2025" strategy paper on 23 September 2014, ACER and the independent Council of European Energy Regulators (CEER) presented recommendations to the European Parliament, the Council and the European Commission for the further development of the internal energy market up to 2025. The implementation of the Third Internal Market Package and the electricity and gas target models continue to be of highest priority for ACER and CEER. The regulators are discussing the challenges of the transition to a low-carbon energy economy based on renewable energy sources and of difficulties involved in the shift to an intelligent, flexible and responsive energy supply.

On 25 February 2015 the European Commission adopted a "Framework Startegy for a Resilient Energy Union with a Forward-Looking Climate Change Policy". The "Energy Union" as a vision and a guiding principle for the priorities of European energy policy names five closely interrelated dimensions: Energy security, solidarity and trust; a fully integrated European energy market; energy efficiency (contributing to moderation of demand); decarbonising the economy. The accompanying action plan submitted contains 15 priority action points that go far beyond the EU's (energy, environment and competition) acquis and gives notice of a series of legislative proposals. In its first practical initiative, the European Commission published a consultation on the future energy market design on 15 July 2015.

2.1 Drawing up Framework Guidelines and Network Codes

National regulatory authorities, market participants, the European Commission and the Member States have been drafting so-called network codes in a multi-stage process since 2009. These network codes serve as key European rules following the principles of the Third Energy Package. Taking the ACER framework guidelines as a basis, the European associations of gas and electricity transmission system operators (ENTSO-E for electricity and ENTSOG for gas) draw up the network codes. They will enter into force following a comitology procedure initiated by the European Commission with the participation of the Member States. The Bundesnetzagentur has contributed actively to the Agency working groups responsible for preparing the framework guidelines and the opinions on the network codes and is assisting the Federal Ministry for Economic Affairs and Energy (BMWi) in the ongoing comitology procedures.

The Guideline on Capacity Allocation and Congestion Management, which was adopted via the comitology procedure on 5 December 2014, was the first electricity network code to be adopted. After publication in the Official Journal of the European Union on 25 July 2015, the Guideline entered force on 14 August 2015 as Regulation (EU) 2015/1222.

In the gas sector, the Network Code on Interoperability and Data Exchange adopted on 1 May 2015 was already the third network code to be adopted. The INT Network Code was published in the Official Journal of the European Union on 1 May 2015 as Regulation (EU) 2015/703 establishing a network code on interoperability and data exchange rules and will be in force from 1 May 2016. The CAM Network Code was already published in October 2013 as Regulation (EU) 2013/984 and is in force since 1 November 2015. In the context of the required revisions for incremental capacity, an amendment of the CAM Network Code will take place. The Network Code on Gas Balancing of Transmission Networks was published on 26 March 2014 as Regulation (EU) 2014/312 and applies as of 1 October 2015/1 October 2016. The "ACER-ENTSOG Report on the early implementation of the Balancing Network Code (BAL NC)" was first published on 22 October 2014. This report is based on a survey of the national implementation measures for the Network Code carried out in cooperation with the national regulatory authorities.

Amendment to the Network Code on Gas Capacity Allocation (Incremental Capacity – INC)

Although the CAM NC prescribes Community rules for the uniform auctioning of existing capacity at cross-border interconnection points, it does not contain any provisions for the creation of new capacity – where necessary – at cross-border interconnection points or for incremental capacity. This is the capacity that is in demand at existing cross-border interconnection points and that exceeds the technically available capacity. Therefore there is a need to set harmonised, market-based approaches to identify demand for new capacity and incremental capacity.

ACER produced a corresponding framework guideline on 2 December 2013. ENTSOG submitted the corresponding Network Code on 26 December 2014.

This proposal was put out for public consultation by ACER from February to March 2015. Based on the comments received as part of the consultation process, the draft was revised for the purpose of streamlining procedures and making them more transparent. The revised draft was then again consulted on by the market from July to August 2015. As matters stand, the amendments to the CAM NC regarding the rules on the creation of new capacity are expected to be adopted through the comitology procedure by the end of 2015.

Guidelines to prevent congestion in the European gas transmission pipelines (Congestion Management Procedures - CMP)

The frequent occurrence of contractual congestion prevents (new) shippers from gaining access to the gas transmission system despite the physical availability of the capacity.

To remove these obstacles and complete the internal market, guidelines have been drawn up to prevent congestion in the European gas transmission pipelines, which essentially promote efficient handling of capacity and increase the amount of capacity available. Based on Decision 2012/490/EU of the European Commission of 24 August 2012 on amending Annex 1 to Regulation (EC) No 715/2009 on conditions for access to the natural gas transmission networks, these new provisions have applied to congestion management since 1 October 2013. ACER published a Monitoring Report on the implementation of the Congestion Management Procedures (CMP) Guidelines for the first time on 13 January 2015. Based on surveys among the national regulatory authorities and gas transmission system operators, as well as extensive data analyses, the effects of the newly implemented rules were assessed and recommendations for improved implementation formulated.

Network Code on Harmonised Transmission Tariff Structures for Gas (TAR NC)

Market participants in the European gas market are often subject to a large number of inconsistent tariffications that frequently do not reflect costs adequately.

At the Commission's request, ACER therefore had drawn up a framework guideline in 2013 that is intended to ensure both cost-reflective, non-discriminatory access for all market participants and competition. Moreover, the guideline aims to encourage the efficient use of the gas transmission systems and appropriate investment in them. Based on this, ENTSOG drafted a corresponding network code and submitted it to ACER on 26 December 2014. Together with the amendments to the CAM NC, the TAR NC is expected to be adopted via the comitology procedure by the end of 2015.

As work on the initial draft of network codes progresses, focus is increasingly being put on the implementation and monitoring of the new rules.

2.2 Energy infrastructure package

Regulation (EU) 2013/347 entered into force in May 2013 as a revised version of the TEN-E Regulation. In October 2013 the European Commission adopted the first Union-wide list of projects of common interest. This list totals 248 projects in the fields of electricity, gas and oil infrastructure to which the provisions of the Regulation will be applied. It contains 20 projects in the electricity sector, five in the gas sector and two in the oil sector relating directly to Germany.

The first list became legally binding on 10 January 2014 as the Commission Delegated Regulation (EU) 1391/2013. It will be continually updated every two years. Work has already started on the second PCI list. The Member States, regulatory authorities, TSOs and project developers come together in various regional groups chaired by the Commission to develop and assess proposals for projects of common interest. ACER is to actively cooperate with regional groups and make comments on the drafts of regional lists. The Bundesnetzagentur contributed actively to both the work of regional groups in the selection process and to the preparation of ACER's comments.

An application for cross-border cost allocation for an electricity interconnector between Lithuania and Poland (LitPol Link) was received by the Bundesnetzagentur in 2014. The regulatory authorities involved in the process from Lithuania, Poland, Sweden, Finland, Norway and Germany were not able to make a decision on cross-border cost allocation within the prescribed period of six months. The process has therefore been handed over to ACER. In its dispute settlement process, ACER made a non-binding decision on 16 April 2015 to involve Germany in the cost allocation.

The national regulatory authorities cooperating within the framework of ACER are, in accordance with Article 11(7) of the TEN-E Regulation, obliged to publish a set of indicators and corresponding reference values for a comparison of unit investment costs for projects that are comparable to the projects of common interest. In the future, these reference values can be used in the cost-benefit analyses carried out for the ten-year network development plans. The Bundesnetzagentur intensively contributed to the process of determining the indicators and reference values. German transmission system operators were asked to provide data on the already concluded expansion projects. This data was combined with data obtained from a further 24 European Member States and formed the statistical base for the calculation of the reference values that are accessible on the Bundesnetzagentur's website.

ACER published the relevant indicators and reference values for electricity and gas on 23 July 2015.

Since the designation of the Bundesnetzagentur as a "one-stop shop" for the approval procedure for projects of common interest on 15 November 2013, synergies with the Grid Expansion Acceleration Act and the Planning Approval Responsibilities Ordinance have been made use of and expertise combined. This should serve to further speed up the approval procedure. In this respect, the Bundesnetzagentur has fulfilled its diverse monitoring, publication and surveillance responsibilities, as set out by the TEN-E Regulation, and cooperated with other one-stop shop authorities. To fulfil its duties with regard to bolstering transparency and public participation, the Bundesnetzagentur increased the amount of information it shares, in particular on its website, and published a manual of procedures for the planning approval process applicable to PCIs on 30 May 2014.

3. Bundesnetzagentur participation in the Council of European Energy Regulators

Since 2005 the Bundesnetzagentur has been a member of the independent Council of European Energy Regulators (CEER). Since ACER was established in 2011, CEER has concentrated on issues that do not fall under the remit of ACER; these include consumer protection, regulatory aspects of retail markets, the promotion of renewable energy sources, the future of the internal market, and international cooperation. In addition, CEER supports the work of ACER in many areas. One of the CEER vice president positions is currently held by the Bundesnetzagentur. About 30 Bundesnetzagentur staff are members of 20 CEER working groups and task forces in the areas of electricity, gas, REMIT, consumer protection, benchmarking, distribution network regulation and international cooperation.

3.1 European developments in consumer protection

Through its participation in the CEER Customer and Retail Markets Working Group (CRM WG), the Bundesnetzagentur once again made a decisive contribution over the past year to the development of ground-breaking guidelines for consumer affairs.

Last year CEER drew up guidelines on how to deal with consumer-related data. According to these, the development of consumer-focused data management models in Europe should be based on five areas of activity: data privacy protection and security, transparency, accuracy, accessibility and non-discrimination. Building on this, and based on public consultation and a hearing, seven specific recommendations for the individual topic areas were drawn up to continue the development of data management pursuant to the guidelines in the third energy package.

To further the integration of the internal electricity market, following a public consultation CEER put forward recommendations on guarantees of origin for electricity. Essentially, information on guarantees of origin must be presented in a transparent manner, providing consumers with a sound basis for any decision. Given this background, an analysis was carried out focussing specifically on the consumer perspective. The recommendations aim to provide electricity customers with the appropriate, reliable and comprehensive information they need when choosing an electricity supplier.

Moreover, under the requirements of the third internal market package, ACER has to draw up a report every year on the status of the electricity and gas markets. The report is drafted jointly with CEER, although the Bundesnetzagentur also contributed once again most particularly on the issue of consumer complaints ("ACER/CEER Market Monitoring Report"). The aim of the report is to identify weaknesses on the retail markets and to organise these more efficiently in the future.

The future role of the distribution system operators on the retail markets was the focus of a public consultation held by CEER that occasioned great interest. In conclusion it was acknowledged that, given the differences in the number, size and profile of the DSOs in the Member States, no single European model would be suitable for appropriate regulation of their activities. Instead, the paper provides for a conceptual framework to distinguish (at a national level) between regulated core/monopoly activities, competitive activities, and those grey areas in need of more precise definition. The more a DSO turns its attention to other activities, the more relevant and necessary regulatory supervision, including unbundling, becomes.

3.2 The Bundesnetzagentur's international work

The Bundesnetzagentur has strengthened its relations with the International Energy Agency (IEA) within the Electricity Security Advisory Panel (ESAP) initiated by the IEA. ESAP is intended to give public and private stakeholders an opportunity for an exchange of information regarding new developments on the electricity market and to discuss proposals for improved security of supply. The Bundesnetzagentur contributed greatly to the organisation and creation of a joint workshop on network investment and regulation. The findings and conclusions of the programme of events are to be set out in a completion report at the end of 2015.

4. Investment measures and incentive-based regulation

The Ordinance concerning Incentive Regulation for the Energy Supply Networks (ARegV) offers network operators an opportunity to budget for costs for expansion and restructuring investment beyond the authorised revenue cap of network tariffs. Based on section 23 ARegV, the Bundesnetzagentur grants approval upon application for individual projects insofar as the prerequisites stated in the Ordinance have been met.

Since the amendment to section 23 ARegV in spring 2012, approval of a project is granted on the merits of the investment. Once the approval has been given, the network operator may adjust his revenue cap by the costs of capital and of operation connected to the project immediately in the year the costs are incurred. The costs budgeted are checked by the Bundesnetzagentur in an ex-post control. In August 2013 a new paragraph 7 was added to Section 23 ARegV to increase the possibilities for approval of investment measures for DSOs at the high voltage level. In the past such investments were generally covered by the expansion factor pursuant to section 10 ARegV. By making this change the issuer of the ordinance wanted to accommodate the DSOs' need for investment at the high voltage level where a greater number of transport tasks would have to be assumed because of the expansion of facilities in the renewable energy sector.

As of 31 March 2015 some 159 applications for investment projects have been submitted to the competent Ruling Chamber. Costs of acquisition and production of about €3bn are linked to these investment measures. Some 105 applications concern the electricity sector with an investment volume totalling approximately €2bn. Of these, the transmission system operators accounted for 26 applications worth about €1.4bn and the distribution system operators accounted for 79 applications worth €0.6bn. Gas network operators submitted 54 applications in total with a volume of about €1bn. Compared to 2014, the number of applications has risen slightly whereas the investment amount has fallen slightly. In 2014 there were 147 applications with a total investment volume of approximately €5bn.

5. Evaluation Report

On 21 January 2015 the Bundesnetzagentur published its report on an evaluation of incentive-based regulation. The Bundesnetzagentur presented a critical situation analysis of the present regulatory system pointing out investment behaviour in particular and put forward proposals to develop the regulatory regime.

This was the final stage in a comprehensive evaluation process that had commenced in November 2013 with an initial workshop. This was followed at regular intervals by three further workshops, each with about 300 participants. The Bundesnetzagentur commissioned a scientific study on how investment behaviour had developed since the introduction of the Incentive Regulation Ordinance; the study was based on the Bundesnetzagentur's own data and also on additional information provided by about 200 network operators. In addition, an analysis of the profitability of network investment was carried out as well as an examination of the problems that the individual procedures pose for the stakeholders. Further analysis was carried out on how comparable network operators are treated in other European countries. The industry was informed on an on-going basis of the status of the evaluation and of any interim findings, and was given the opportunity to comment.

The current incentive regulation provides network operators with incentives to operate the network efficiently by making a specific budget available to the network operators (revenue cap) for a period of five years (regulatory period) for the performance of their tasks. In addition, efficiency improvement targets are set for the network operators. These targets are determined on the basis of efficiency benchmarking between the network operators. Below the revenue cap, network operators are free to decide regarding their own business how they want to meet these efficiency targets. If they exceed the efficiency targets, they may retain the additional revenues throughout the remainder of that regulatory period. As a consequence of the *Energiewende*, a considerable need for overhaul and expansion, especially in the electricity distribution networks, will become necessary in the coming years to integrate electricity generating plants on the network side that are based on renewable energy sources.

An evaluation of incentive regulation has shown that the current incentive-based regulation has essentially proven itself. The incentive regulation has not had any negative impact on the investment activity of electricity and gas network operators. The quality of supply remains high despite the gains achieved in efficiency. These evaluation results based on past performance, however, are not sufficient on their own to provide a view of future developments within the context of the *Energiewende*.

For incentive regulation to remain viable as part of the *Energiewende*, especially in the electricity distribution system, some adjustments will have to be made to the existincg system according to an analysis of the current regulatory regime.

The Bundesnetzagentur's proposals for action can be divided on the one hand into model-independent recommendations that will lead to improvements in the current regulatory system without interfering with any of its fundamental principles. On the other hand, however, the Incentive Regulation Ordinance 2.0 (ARegV 2.0), the differentiated regulation, the true-up of capital expenditure with bonus and the adjustment of capital expenditure represent four independent proposed models that each involve stronger intervention in the regulatory system.

Of the aforementioned models, the Bundesnetzagentur favours ARegV 2.0, that is, the development of the existing regulatory system. For this to happen, the time delay between an investment and the revenue adjustment through the expansion factor, which maps expansion investment in the distribution system (equivalent to investment measures in the transmission network), will have to be abolished. This will allow the timely refinancing of investments and make investment conditions more compatible with the *Energiewende*.

In addition to this, options have been proposed that would encourage network operators to invest in intelligent solutions ("intelligence not cables"). Using intelligent solutions, an efficiency carry-over or a bonus system could leverage potential savings, which a BMWi distribution networks study has estimated at 10-20% when compared with conventional network expansion. Furthermore, the investment measure, which up to now has governed expansion in the transmission networks, is to be extended to those distribution system operators who are especially affected by the *Energiewende* so as to take appropriate account of their specific situation.

Regulatory models that provide for an annual adaptation of the cost of capital to improve the conditions for investment are rejected by the Bundesnetzagentur. Although these models address the existing time delay between investment and refinancing, they create incentives for network expansion strategies that are more capital-intensive. Hence, incentives to save costs through intelligent and innovative solutions would diminish.

The proposed model-independent possible actions have the effect of working towards improved regulatory regime negotiability. This includes recommendations on the incentive regulation account and on the action to be taken in splitting the revenue caps for split networks.

Aspects to increase efficiency will be addressed with recommendations to deal with non-controllable costs within the scope of simplified procedures and to extend efficiency benchmarking and the general sectoral productivity factor.

The introduction of an index-based investment monitoring has been proposed as a means of securing investing activities. Alongside this, it has also been recommended to increase transparency to publish the revenue caps and essential structural features of the individual network operators.

C Selected activities of the Bundeskartellamt

As regards the prohibition of anticompetitive agreements the Bundeskartellamt was able to close its proceedings concerning a contractual agreement aimed at limiting electricity generation at the Irshing 4 and 5 power plants. The focus of its control of the abuse of a dominant position lay in several proceedings concerning the award of concessions for gas and electricity networks. As regards the metering and billing of heating and water costs (submetering), the Bundeskartellamt has launched a sector inquiry to monitor developments in this area. In the discussion about the future design of the German electricity market the authority has strongly advocated maintaining competitive structures.

1. Prohibition of anti-competitive agreements

Irsching contracts

In close cooperation with the Bundesnetzagentur, the Bundeskartellamt conducted an administrative offence proceeding against the power plants E.ON Kraftwerke GmbH, Gemeinschaftskraftwerk Irsching GmbH and the electricity transmission system operator TenneT TSO GmbH on account of two agreements concluded on 26 April 2013 ("Irsching contracts"). These contracts limited electricity generation at the Irsching 4 and Irsching 5 power plants. After the Düsseldorf Higher Regional Court had confirmed the Bundeskartellamt's legal opinion on the matter, the proceeding was closed in May 2015.

The proceeding was directed against the specific arrangements for remuneration in the Irsching contracts. The contracts stipulated that the remuneration payable by TenneT for the maintenance of capacity be calculated according to the following formula:
Fee = XX million euros x (quantity fed in as a redispatch measure within the calendar year / total quantity fed in within the calendar year). Based on this formula the payments to the power plant operators increased the less the plants were used on the "regular" production markets, i.e. outside the area of redispatch measures. The design of the remuneration arrangement provided an economic incentive to limit the amount of electricity generated by the power plants (see Monitoring Report 2014, p. 293f.) even though under the contracts the power plants were obliged to continue operating "market-driven as previously". In the year before the Irshing contracts were concluded the power plants were still operating on a large scale in the normal electricity market whereas throughout 2014 they did not generate any electricity for the "regular" market at any time.

At the same time as the Bundeskartellamt's proceeding another proceeding was pending at the Düsseldorf Higher Regional Court which concerned the regulatory basis of the Irsching contracts. In the proceeding before the court several energy suppliers had objected to the Bundesnetzagentur's stipulation BK812019 which regulated payments for power plant operation requested by the system operators (TSOs).

As the significance of the proceeding reached beyond the individual Irsching case, the Bundeskartellamt made use of its right under Section 90 GWB, Art. 15 (3) Regulation 1/2003, to comment on the issue in the Higher Regional Court proceeding. In its decision of 28 April 2015 the Düsseldorf Higher Regional Court confirmed the Bundeskartellamt’s legal opinion on the matter: "In its comments the Bundeskartellamt has plausibly explained that due to the design of the contracts it had been agreed to limit electricity generation, which consequently constituted an anticompetitive agreement under Art. 101 (1) TFEU. In this way the

Bundeskartellamt has demonstrated logically and in detail how the system of remuneration in inverse proportion provides an incentive to operate a power plant in the least market-driven way possible."[161]

The decision of the Düsseldorf Higher Regional Court sufficiently confirms that the remuneration system applied in the Irsching contracts violates competition law[162] and is now final. The Bundeskartellamt sees no risk of a recurrent infringement. Under Section 134 of the German Civil Code a contract clause which violates competition law is void. By virtue of the higher regional court's decision, contracts with similar remuneration arrangements are also inadmissible for other power plants. The Bundeskartellamt's proceeding could therefore be discontinued.

Verivox's best price clauses

The Bundeskartellamt has examined data products and tariff optimisation services which the online comparison portal Verivox offers to energy suppliers. The examination was triggered by a feature of the Plusminus consumer programme of the German TV channel ARD. Verivox subsequently approached the Bundeskartellamt. At least in their present design and in view of the current market situation, these offers do not raise any competition law concerns.

Irrespective of the authority's examination, Verivox has removed all the 'best price' clauses (MFNs) agreed with energy suppliers from its contracts. Comparison websites for the supply of electricity and gas generally have a positive effect on competition as they make it easier for consumers to switch provider. 'Best price' clauses can reduce this effect if they restrict the freedom of suppliers to set their prices and impede competition between different comparison portals. Verivox has voluntarily pledged to stop using 'best price' clauses.

2. Control of abuse of dominant positions

Award of concessions for electricity and gas networks

In its decision of January 2015 the Bundeskartellamt established that the municipality of Titisee-Neustadt had acted abusively in its award of rights of way for electricity networks and ordered it to carry out a new, transparent and non-discriminatory award procedure. In the Bundeskartellamt's view the municipality had abused its dominant position by carrying out a discriminatory selection procedure, giving preference to the municipal bidder without any objective justification and applying inadmissible selection criteria. It had also violated the principle of secret competition and the prohibition to agree or grant other benefits than those admissible under the German Ordinance on Concession Fees for Electricity and Gas (KAV).

The municipality of Titisee-Neustadt had applied for a suspension of the proceedings as it believed that the legal framework for the award of concessions unconstitutionally restricted the guarantee of municipal self-government and lodged a municipal constitutional complaint with the Federal Constitutional Court. The Bundeskartellamt refused to suspend the proceedings because the Federal Court of Justice and all the higher

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[161] Cf. Düsseldorf Higher Regional Court, decision of 28 April 2015, VI-3 Kart 332/12 (V), NRWE- para. 255. available for download at http://www.justiz.nrw.de/nrwe/olgs/duesseldorf/j2015/VI_3_Kart_332_12_V_Beschluss_20150428.html

[162] For further details of the Bundeskartellamt's assessment of the case, please see Case Summary B8-78/13 (available only in German): http://www.bundeskartellamt.de/SharedDocs/Entscheidung/DE/Fallberichte/Kartellverbot/2015/B8-78-13.pdf

civil and administrative courts that have dealt with concession awards have expressly held that the guarantee of municipal self-government was not violated. Also, the Federal Constitutional Court had not accepted a constitutional complaint filed by the town of Heiligenhafen in 2013. Furthermore, constitutional complaints by municipalities against court decisions are inadmissible and an appeal against the relevant laws (Sections 19, 20 GWB, 46 Energy Industry Act, EnWG) is likely to be time-barred. For the same reasons the Bundeskartellamt decided not to suspend the immediate enforceability of its abuse proceedings.

On 15 July 2015 the Düsseldorf Higher Regional Court rejected an application by the municipality of Titisee-Neustadt to have the immediate enforceability of the authority's decision suspended. The court did not doubt the legitimacy of the Bundeskartellamt's decision and could not establish any undue hardship which its immediate enforceability might have caused. In the court's opinion the selection procedure and award decision of the municipality were illegal in many aspects (violation of sections 1, 19, 20 GWB, section 46 EnWG). Neither did the municipality's constitutional complaint induce the Higher Regional Court to alter its assessment. In particular, in accordance with the case-law of the Federal Court of Justice, it rejected the municipality's argument that Art. 28 (2) of the Basic Law had been violated. The Düsseldorf Higher Regional Court did not grant the municipality leave to appeal to the Federal Court of Justice because this had already commented extensively on the relevant issues at dispute in its rulings of 17 December 2013. The municipality appealed against the denial of leave to appeal against the Düsseldorf Higher Regional Court's decision on the continuance of the immediate enforceability of the Bundeskartellamt's decision, and filed an appeal against the violation of the right to be heard before the Federal Court of Justice. At the Federal Court of Justice's suggestion the Bundeskartellamt has declared that it would not take any measures to enforce its decision on the abusive practices until the senate of the Federal Court of Justice decides on the appeal on points of law against the decision and the appeal against the denial of leave to appeal.

Furthermore, on 4 August 2015, in a court order on the apportionment of legal costs concerning a complaint against the Bundeskartellamt 's failure to act, which had meanwhile been resolved, the Düsseldorf Higher Regional Court established that the authority's conduct regarding the summoning of third parties and file access was both legitimate and appropriate.

The proceeding against the federal state of Berlin concerning the award of rights of way for gas networks was suspended by the Bundeskartellamt after the Berlin Regional Court had established on 9 December 2014 in a parallel civil action that the federal state had abused its dominant position and the court had prohibited it from concluding a concession contract with the state undertaking Berlin Energie. In the opinion of the Berlin Regional Court the state of Berlin had in many respects violated sections 19, 20 GWB, 46 EnWG in the award procedure and its award decision. Consequently, its award decision was thus illegal under competition and energy law.

Both parties (the state of Berlin and GASAG/NBB) have appealed against the Regional Court's decision to the Berlin Higher Regional Court. The appellants GASAG and NBB are thus pursuing their main plea for the conclusion of the concession contract. In this legal dispute the Bundeskartellamt has submitted written statements (amicus curiae brief) in accordance with section 90 GWB. It has therefore suspended its own abuse control proceeding. The legal dispute pending at the Düsseldorf Higher Regional Court regarding Berlin Energie's admission to the proceeding was also suspended until the decision of the Berlin Higher Regional Court. In its decision of 20 August 2015 on the hearing of the civil appeal case the Berlin Higher Regional Court rejected the intervention of the state undertaking Berlin Energie as a third party as inadmissible.

The federal state of Berlin addressed another enquiry to the Bundeskartellamt about the Berlin award of concessions for electricity networks. This request was solely for the admissibility of a change of control clause, on which the Bundeskartellamt gave its preliminary assessment.

In May 2015 the Bundeskartellamt and the Bundesnetzagentur published a second revised edition of their joint guidelines http://www.bundeskartellamt.de/SharedDocs/Publikation/DE/Leitfaden/Leitfaden%20-%20Vergabe%20von%20Strom-%20und%20Gaskonzessionen.html?nn=3591568. Since the first publication of the guidelines in 2010 important issues and problems which arose in practice were dealt with and clarified by the amendment of the Energy Industry Act in 2011 and the case-law of the Federal Court of Justice, higher regional courts and higher administrative courts. The positions adopted by the Bundeskartellamt and the Bundesnetzagentur in the first edition of the guidelines and in their administrative practice have been confirmed to a large extent by the Federal Court of Justice. The second edition of the guidelines incorporates new developments in case-law and amendments to the law, bringing the guidelines up to date. The guidelines also address topical issues on the weighting of selection criteria, establishment of sub-criteria, the award procedure and selection decision as well as the extent of information to be provided to the municipality. In the second edition the authorities have already taken account of the Federal Court of Justice's decision of principle of 14 April 2015 in the Springe case (EnZR 11/14) which made it clear that the municipality's right to information under section 46 (2) sentence 4 EnWG also includes imputed network data.

On 17 April 2014 the EU Directive of the European Parliament and of the Council on the award of concession contracts (RL 2014/23/EU) of 26 February 2014 entered into force (Official Journal No. L 94, p. 1). The directive has to be implemented into national law within two years. For the first time it sets rules for the award of concessions for services. However, according to recital no.16 of the Directive, agreements that grant rights of way do not fall within the scope of its application in so far as they neither impose an obligation of supply nor involve any acquisition of services by a contracting authority or contracting entity to itself or to end users.

Electric heating

In October 2015 the Bundeskartellamt concluded its last remaining proceeding from 2009 against ENTEGA Energie GmbH on electric heating prices after the company had undertaken in a settlement agreement under public law to reimburse its customers of night storage heating and heat pumps with 155.72 euros (incl. VAT and interest) for the period 2007 to 2009. In return the Bundeskartellamt lifted its ruling on abusive practices of 19 March 2012.

In September 2009 the Bundeskartellamt had initiated proceedings against various providers of electricity for heating purposes on account of abusive pricing. With the exception of the proceeding against ENTEGA all the other proceedings were already concluded by settlement in the autumn of 2010 (see Monitoring Report 2011, p. 85). In March 2012 the Bundeskartellamt ordered ENTEGA to make reimbursement payments to its customers (see Monitoring Report 2012, p. 268). Since then ENTEGA's appeal against this decision had been pending at the Düsseldorf Higher Regional Court. Both the outcome of the court case as well as its duration were unforeseeable. In the Bundeskartellamt's view it was therefore not in the interests of the customers affected to continue with the proceeding. The settlements also take account of the positive development of competition on the electric heating markets (see chapter I.G.5.1).

3. Sector inquiry

Submetering of Heating and Water Costs

In July 2015 the Bundeskartellamt launched a sector inquiry into the metering and billing of heating and water costs (submetering). Submetering services cover the consumption-based metering and billing of heating and water costs in buildings as well as the provision of the necessary metering equipment such as heating cost distributors or water and heat meters.

Submetering is thus to be defined as a separate product market to metering. Whereas metering covers the consumption-based billing of the supply of energy to a property, submetering covers services relating to the allocation of the energy supplied to the consumers or units at one property.

The sector inquiry is intended to give a picture of the market structure in the submetering segment. It is to clarify who the market participants are and how the market functions. In particular, it is expected to establish the legal framework conditions and the current role of billing software and remote meter-reading via a radio transmitter.

The general purpose of the inquiry is to find out whether there are competition deficits, restraints of competition or abusive practices due to the structure of the market. In a prohibition decision in 2002 it was found that a non-competitive duopoly existed between ista (then: Viterra) and Techem with a joint market share of over 50 %. The sector inquiry is expected to clarify in particular whether the non-competitive duopoly still exists between Techem and ista and whether it has been strengthened or extends to more companies. It is also intended to establish whether, in the case of market dominance, the companies are charging excessive fees. It is also to take account of the fact that the contractual partners of the submetering companies do not usually bear the costs of submetering themselves but pass these on to the tenants. The aim of the inquiry is also to establish whether there are any barriers to entry and if so, what form these take.

The inquiry can lead to the initiation of proceedings or recommendations to the legislator for further action.

As a first step the Bundeskartellamt has sent out online questionnaires to around 90 submetering companies. The criteria used for selecting the companies for the inquiry were in particular size, number of customers and shareholder structure. In a second step customers from the real estate sector were questioned.

4. Competition advocacy

In the discussion about the future design of the German electricity market the Bundeskartellamt has strongly advocated competitive structures.

In its comments on the Green Paper "An electricity market for Germany's energy transition" published by the Federal Ministry for Economic Affairs and Energy[163] the Bundeskartellamt advocated an optimised electricity market from a competitive perspective ("Electricity Market 2.0") and rejected the introduction of a capacity

[163] The Bundeskartellamts comments are available (in German only) for download at http://www.bundeskartellamt.de/SharedDocs/Publikation/DE/Stellungnahmen/Stellungnahme-Gr%C3%BCnbuch_BMWi_Strommarkt.html?nn=3591026

market. In the Bundeskartellamt's view an optimised electricity market can guarantee security of supply also in the future. There are currently no indications that the effectiveness of the market is limited and that peak load coverage is endangered. In particular, the current market situation shoes no signs of market failure. In view of existing over-capacities the profitability problems of power plants, market exits and the reluctance to invest are normal market reactions. Furthermore, a capacity market would mean a significant intervention in the competitive mechanisms of the electricity market and poses a number of risks for its competitive structure. These include the danger of regulatory failure and higher system costs. Moreover, the introduction of a national capacity market is difficult to reconcile with the completion of the European internal market.

Against this background the Bundeskartellamt welcomes the decision in favour of an electricity market 2.0 taken by the Federal Ministry for Economic Affairs and Energy in its White Paper "An electricity market for Germany's energy transition". This will be implemented with the Electricity Market Act which has already been approved by the Cabinet. The electricity market 2.0 will build on existing market mechanisms and develop them further by eliminating wrong incentives and distortions of competition. It is essential that undistorted price signals reach the market, which, for instance, adequately reflect scarcities of supply and set the right investment incentives.

In this context the fear is being expressed that the control of the abuse of a dominant position under competition law prevents price peaks in situations of scarcity. However, contrary to previous arguments, the control of the abuse of a dominant position does not lead to a general ban on companies offering capacities with a surcharge beyond their marginal costs (mark-up). The prohibition of the abuse of a dominant position applies exclusively to dominant companies. These may not use their market power to for example drive up prices artificially and to a substantial degree. If, on the other hand, price peaks occur because of actual scarcities which are not market power-related, they are not objectionable under competition law. The Bundeskartellamt therefore does not share the concerns already mentioned. Nevertheless it does support the interest of the Federal Ministry for Economic Affairs and Energy in making the control of the abuse of a dominant position in electricity generation even more transparent (Measure 2 of the White Paper). In its comments on the Green Paper the Bundeskartellamt had pointed out that it could publish guidelines on the control of abuse of a dominant position in electricity generation. This proposal has now been adopted in the White Paper. The Bundeskartellamt is also to regularly present a report in future on the market power situation in the electricity generation sector. This will enable companies to assess more easily whether they are dominant and therefore subject to the prohibition of the abuse of a dominant position. The rules applying to the report are set out in the Cabinet billof the Electricity Market Act. Accordingly the preparation of the report will form part of the monitoring tasks of the Bundeskartellamt. In the future the Bundeskartellamt will make use of the data collected by the Market Transparency Body for Electricity and Gas Wholesale Trading (Section 47c (1) no. 1 GWB). The report is to be published at least every two years upon receipt of the data.

As regards the award of rights of way, the Federal Government is planning to amend Section 46 EnWG within this legislature period. This amendment is intended to regulate the evaluation procedure in the award of new concessions (e.g. in remunicipalisation cases) for distribution networks in a transparent and legally conforming manner and increase legal certainty in network transfer. However, the Bundeskartellamt sees no need to change the law because any legal issues have meanwhile already been clarified by the Federal Court of Justice. The Bundeskartellamt takes a critical view of suggestions that in the award of rights of way greater consideration could be given to the interests of municipalities in addition to the objectives of Section 1 EnWG.

This could raise competition concerns because it would no longer be possible to ensure non-discriminatory competition on quality.

D Consumer protection and consumer service

As the central information point for energy consumers, the Bundesnetzagentur advises private energy consumers about the current legal situation, their rights as domestic customers and the dispute resolution option.

In 2014 the energy consumer service received a total of approximately 12,400 telephone and written queries and complaints, with some 7,800 about electricity, 900 about gas and around 3,800 about general issues.

The following chart shows a breakdown of all the queries and complaints received in the period under review up to 30 June 2015:

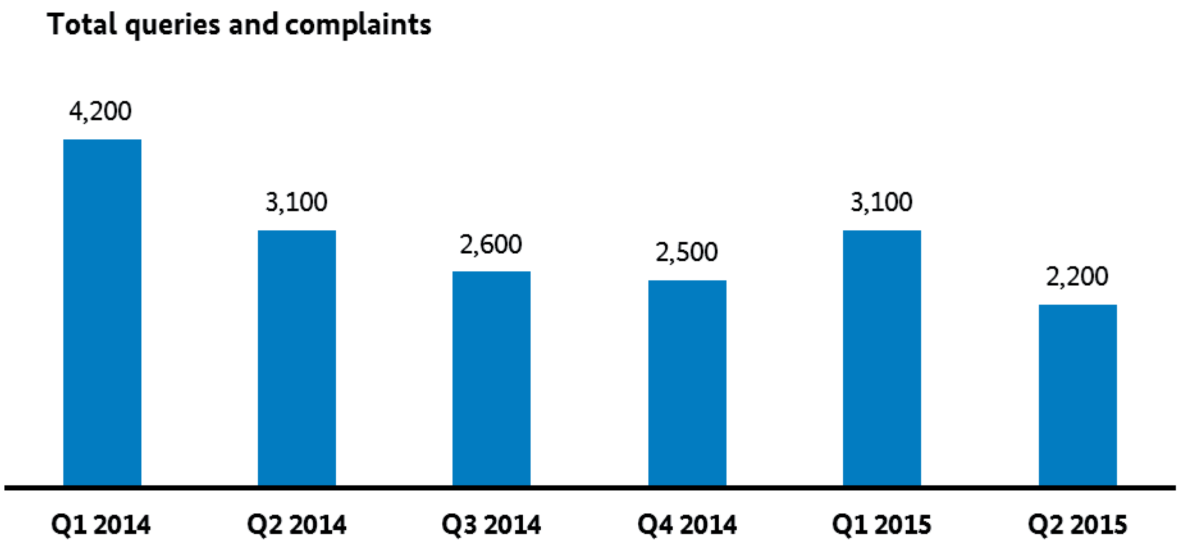

Figure 176: Total queries and complaints up to 30 June 2015

The increase in queries and complaints in the first quarter of each year is most likely due to the fact that price changes made by suppliers as of 1 January lead to an increase in the number of consumers switching suppliers and resultant problems with, for instance, the switching process and/or billing.

As in previous years, the majority of queries and complaints concerning gas and electricity were questions regarding contracts and billing and complaints about the quality of service offered by suppliers in particular.

The following charts show the issues to which the queries and complaints received in the period under review related:

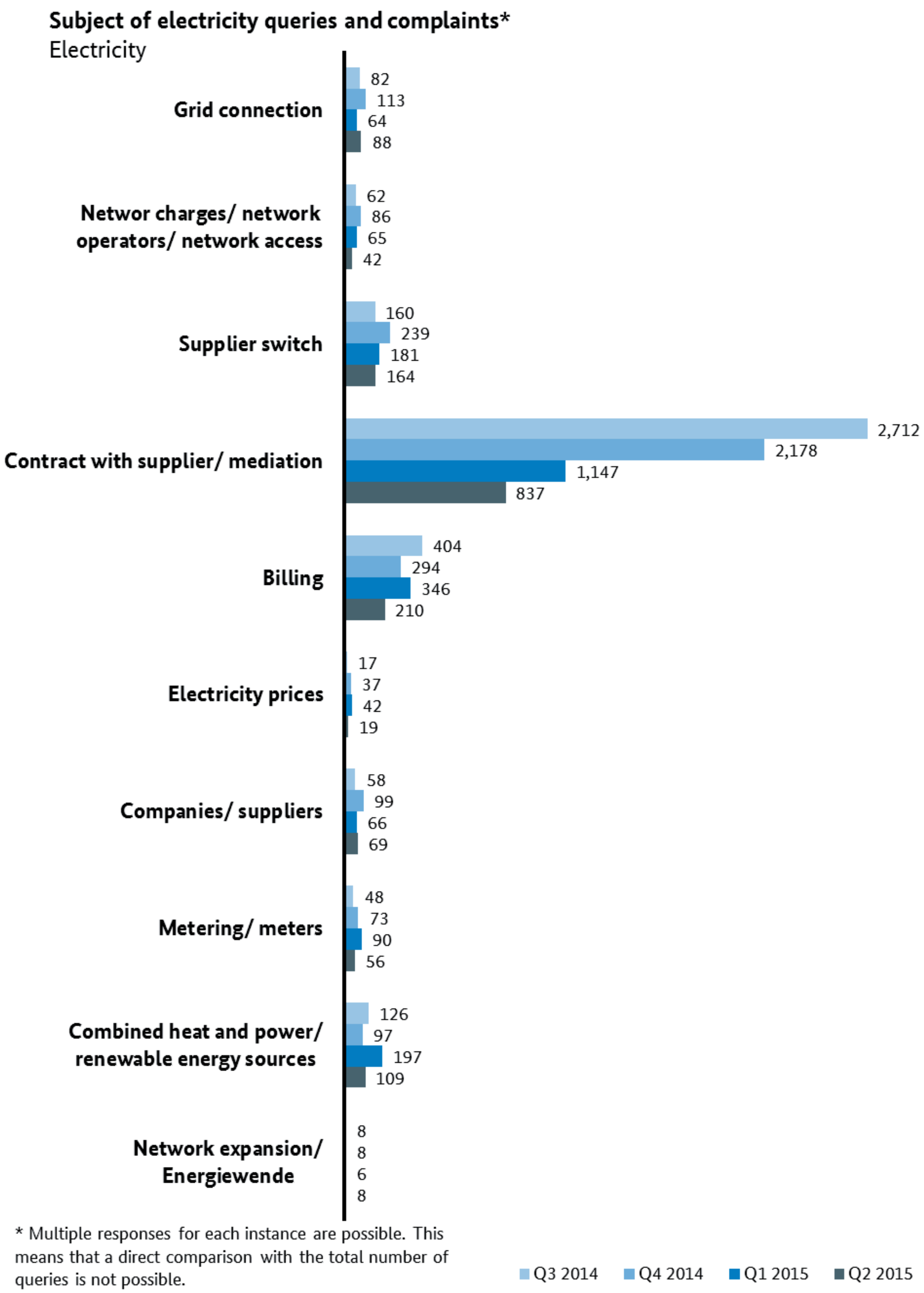

Figure 177: Subject of electricity queries and complaints

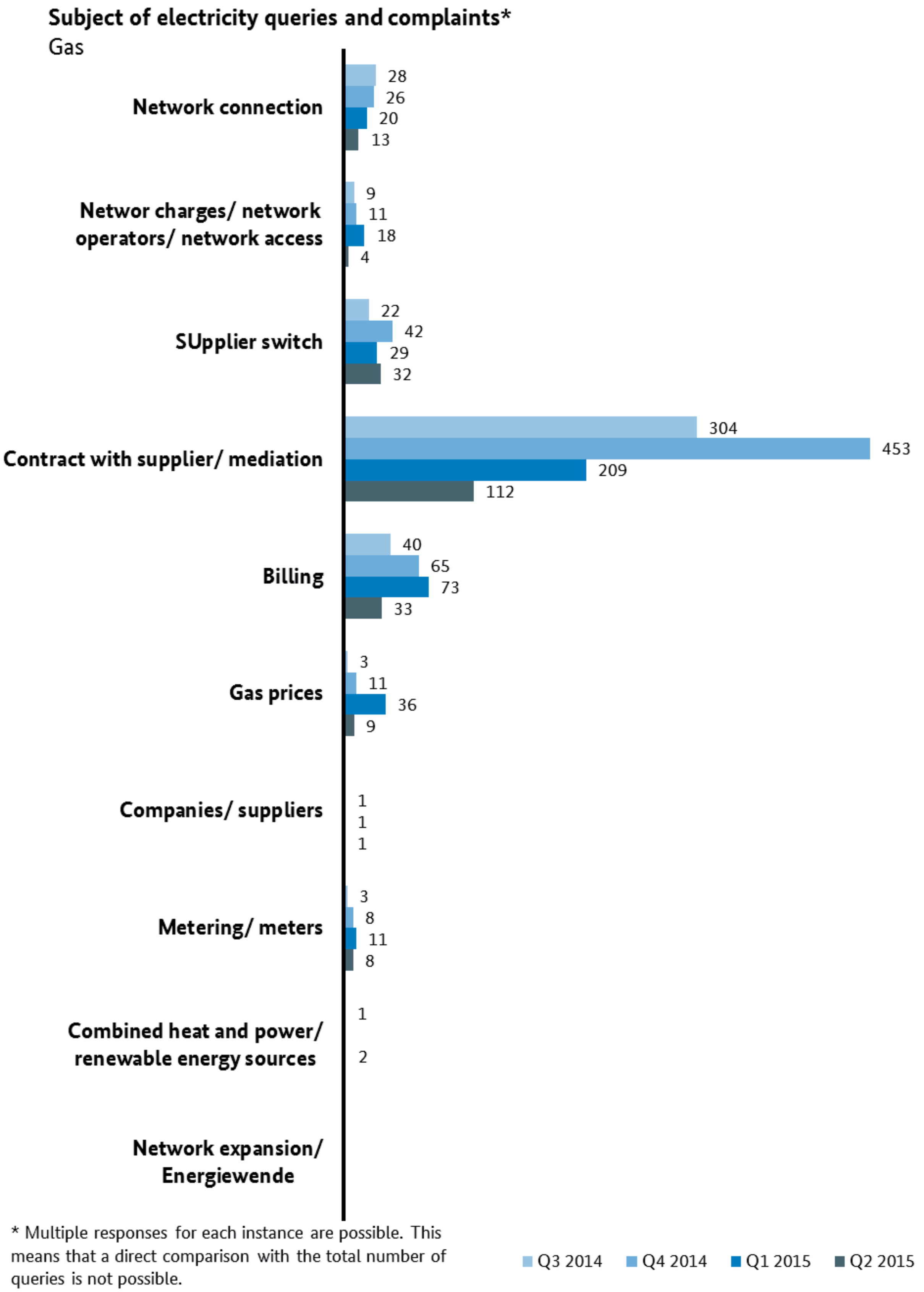

Figure 178: Subject of gas queries and complaints

The charts show that the main problem areas were contracts with suppliers and billing. The bulk of these queries and complaints concerned the same few companies. Consumers complained in particular about differences in interpreting the terms and conditions of bonus payments or contract termination, delayed or incorrect billing, and delays in receiving credit balances and bonuses.

Owing to the large number of complaints about delays in interim or final billing by immergrün-Energie GmbH, the Bundesnetzagentur initiated supervisory proceedings in November 2014 to investigate suspected breaches of the supplier obligations laid down in section 40 of the German Energy Act. The legislation requires suppliers to ensure that final consumers receive their interim bills within six weeks of the end of the particular billing period and final bills within six weeks of the expiry of their contract. Since there was a significant decrease in the number of complaints about breaches of the billing rules in 2015, however, the supervisory proceedings were discontinued in June 2015.

In November 2014 the Bundesnetzagentur also initiated supervisory proceedings against Care-Energy Energiedienstleistungs GmbH & Co. KG (BK6-14-159) and once again formally obliged the company to provide notification of its activity as a supplier as required by section 5 of the Energy Act. The company subsequently notified its activity on 3 December 2014, but the notification did not meet the statutory requirements. On the same day, the company withdrew its notification, stating that it was not active as an energy supplier.

In December 2014 the Bundesnetzagentur thus fined the company €400,000 and warned the company that it could face a further fine of €800,000 should it fail to meet its obligations. Despite the warning the company did not submit the required notification, and in March 2015 the Bundesnetzagentur imposed a second fine of €800,000 and issued a warning of a third fine of another €800,000.

The company appealed against the obligation to provide notification and against the fines imposed. In June 2015 the Higher Regional Court in Düsseldorf dismissed the appeals and ruled that the fines were legitimate and that the company was obliged to notify its supply of energy to household customers.

Private consumers with contractual or billing problems are entitled to have a complaints procedure carried out with their company instead of taking their case to court. If the company does not provide a remedy within a period of four weeks, energy consumers can then turn to the energy dispute resolution panel – *Schlichtungsstelle Energie e.V.* – for redress.

Since November 2011 the energy dispute resolution panel has been responsible for mediating between consumers with complaints about contracts or the quality of a company's service and their energy utility, meter operator or metering service provider. In 2014 the panel received 9,300 requests for redress. The panel publishes its conciliatory proposals and an annual report of its activities on its website at http://www.schlichtungsstelle-energie.de.

As a rule, the dispute resolution procedure is free of charge for the consumers. The conciliatory proposal is not binding, however, so that both consumers and companies still have the option of going to court.

Lists

List of authorship

Common parts of the text

Key findings

Summary of the electricity market (I.A.1)

Summary of the gas market (II.A.1)

Market Transparency Unit for Wholesale Electricity and Gas Markets (III.A)

(Blocks of text in these four sections respectively according to the following authorship)

Bundesnetzagentur's authorship (Notes)

I Electricity market

- A Developments in the electricity markets (in the following parts:)
  - 2. Market overview
- B Generation and security of supply
- C Networks
- D System services
- E Cross-border trading and European integration
- G Retail (in the following parts:)
  - 1. Supplier structure and number of providers
    - 2.2 Contract structure and supplier switching household customers
  - 3. Disconnection notices, disconnections, cash or smart card meters, tariffs and terminations
    - 4.2 Price level household customers
  - 6. Green electricity segment
- H Metering

II Gas market

A Developments in the gas markets (in the following parts:)

2. Market overview

B Production, imports/exports, and supply disruptions

C Networks

D Balancing

F Retail (in the following parts:)

1. Supplier structure and number of providers

2.2 Contract structure and supplier switching household customers

3. Disconnection notices, disconnections, tariffs and terminations

4.2 Price level household customers

G Storage facilities

H Biogas monitoring

I Metering

III General topics

B Selected activities of the Bundesnetzagentur

D Consumer protection and consumer service

Bundeskartellamt's authorship (Notes)

I Electricity market

A Developments in the electricity markets (in the following parts:)

3. Market concentration

F The wholesale market

G Retail (in the following parts:)

2.1 Contract structure and supplier switching non-household customers

4.1 Price level non-household customers

5. Night storage (electricity for heating)

7. Comparison of European electricity prices

II Gas market

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List of abbreviations

Term	Definition
50Hertz	
AblaV	Interruptible Loads Ordinance
ACER	Agency for the Cooperation of Energy Regulators
AGV	Working gas volume(s) (of gas storage facilities)
Amprion	Amprion GmbH
ARegV	Incentive Regulation Ordinance
ASIDI	Average System Interruption Duration Index
ATC	Availabe Transfer Capacity
AusglMechAV	Ordinance Implementing the Equalisation Scheme Ordinance
AusglMechV	Equalisation Scheme Ordinance
BAFA	Federal Office of Economics and Export Control
BDEW	German Association of Energy and Water Industries
BFZK	Capacity with conditional firmness and free allocability
BGBl.	Federal Law Gazette
BGH	Federal Court of Justice
BilMOG	Accounting Law Modernisation Act
BKV	Balancing group manager
BMWi	Federal Ministry for Economic Affairs and Energy
CACM	Capacity Allocation and Congestion Management
CAO	Coordinated Auction Office

CASC-CWE	Capacity Allocation Service Company for the Central West-European Electricity Market
CEE	Central East Europe
CEER	Council of European Energy Regulators
CEN	European Committee for Standardization
CENELEC	European Committee for Electrotechnical Standardization
CEPS	Czech transmission system operator
CSE	Central South Europe
CWE	Central West Europe
DEA	Data Envelopment Analysis
DIN	German Institute for Standardization
DSfG	Digital interface for gas meters
DSL	Digital Subscriber Line
DSO	Distribution system operator
ECC	European Commodity Clearing AG
EDIFACT	(United Nations) Electronic Data Interchange For Administration, Commerce and Transport
EEG	Renewable Energy Sources Act
EEX	European Energy Exchange AG
EICOM	Swiss Federal Electricity Commission
EMCC	European Market Coupling Company GmbH
EMM	Feed-in management measure
EnBW TNG	Energieversorgung Baden Württemberg Transportnetze AG
EnLAG	Power Grid Expansion Act

ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSO-G	European Network of Transmission System Operators for Gas
EnWG	Energy Act
EPEX SPOT	European Power Exchange
ERGEG	European Regulators Group for Electricity and Gas
ETSI	European Telecommunications Standards Institute
EU	European Union
Eurostat	Statistical Office of the European Communities
EVU	Energy utility
EXAA	Energy Exchange Austria
FBA	Flow Based Allocation
FCFS	First come first serve
FNB	Gas transmission system operator
FTP	File Transfer Protocol
FZK	Freely allocable capacity
GABi Gas	Basic model for imbalance services and balancing rules in the gas sector
GasGVV	Gas Default Supply Ordinance
GasNEV	Gas Network Charges Ordinance
GasNZV	Gas Network Access Ordinance
GeLi Gas	Business processes for change of gas supplier
GPKE	Business processes for supplying customers with electricity
GPRS	General Packet Radio Service
GSM	Global System for Mobile Communications (Groupe Spécial Mobile)

GW	Gigawatt
GWB	Competition Act
GWh	Gigawatt hour
GWJ	Gas year
HGÜ	High voltage direct current (HVDC) transmission
HöS	Extra-high voltage
HS	High voltage
HTWK	Leipzig University of Applied Sciences
ITC	Inter-TSO compensation
ITO	Independent Transport Operator
KARLA	Capacity arrangements and auctions in the gas sector
KAV	Concession Fees Ordinance
KoV IV	Cooperation agreement IV
KraftNAV	Power Plant Grid Connection Ordinance
kWh/h	Kilowatt hour per hour
KWK	Combined Heat and Power
KWKG	Combined Heat and Power Act
LNG	Liquified Natural Gas
LPG	Liquified Petroleum Gas
LV	Low Voltage
m^3/h	cubic metre per hour
MessZV	Meter Access Ordinance
MR	Minute reserve

MRL	Minute reserve power
MS	Medium voltage
MUC	Multi-Utility Controller
MüT	Interconnection points between market areas
MWh	Megawatt hour
MWh/km^2	Megawatt hour per square kilometre
NABEG	Grid Expansion Acceleration Act
nAE	Negative imbalance price
NAV	Low-Voltage Connection Ordinance
NaWaRo	Renewable resources
NBP	National Balancing Point
NCG	Net Connect Germany
NDAV	Low Pressure Connection Ordinance
NE	Northern Europe
NEL	North European natural gas pipeline
NEMO	Nominated electricity market operator
NKP	Interconnection point
Nm^3	Normalised cubic metre
Nm^3/h	Normalised cubic metre per hour
NRV	Grid control cooperation
NS	Low voltage
NTC	Net transfer capacity
OFC	Online flow control

OGE	Open Grid Europe
OLG	Higher regional court
OMS-Standard	Open Metering System
OPAL	Baltic Sea Pipeline Link
OTC	Over the counter
OWF	Offshore wind farm
pAE	Positive imbalance price
PLC	Powerline Carrier / Powerline Communication
PRL	Primary control power
PRS	General Packet Radio Service
PSA	Pressure swing adsorption
PSTN	Public switched telephone network
reBAP	Uniform portfolio balancing energy price across control areas
REMIT	Regulation on wholesale Energy Market Integrity and Transparency
RLM	Interval load metering
RLMmT	Load metering with daily flat supply
RLMoT	Load metering without a daily flat supply
RLMNEV	Load metering with substitute nomination procedures
RSI	Residual Supply Index
SAIDI	System Average Interruption Duration Index
SFA	Stochastic Frontier Analysis
SLP	Standard load profile
SRL	Secondary control power

StromGVV	Electricity Default Supply Ordinance
StromNEV	Electricity Network Charges Ordinance
StromNZV	Electricity Network Access Ordinance
StromStG	Electricity Tax Act
SysStabV	System Stability Ordinance
TenneT	TenneT TSO GmbH
TFEU	Treaty on the Functioning of the European Union
TGL	Tauern gas pipeline
tps	transpower Stromübertragungs GmbH
TransnetBW	TransnetBW
TRM	Transmission Reliability Margin
TSO	Transmission System Operator
TTC	Total transfer capacity
TTF	Title transfer facility
TU	Technical university
TWh	Terawatt per hour
ÜTS	Above-ground storage facility
UGS	Underground storage facility
UMTS	Universal Mobile Telecommunications System
VAN	Value added network
VNG	Verbundnetz Gas AG
VP	Virtual trading point
WEG	Wirtschaftsverband Erdöl- und Erdgasgewinnung e.V.

Glossary

The definitions pursuant to section 3 EnWG, section 2 StromNZV, section 2 GasNZV, section 2 StromNEV, section 2 GasNEV, section 3 EEG and section 3 KWKG apply. In addition the following definitions and the Bundesnetzagentur's guidelines on electricity network operators' internet publication obligations (Leitfaden für die Internet-Veröffentlichungspflichten der Stromnetzbetreiber) apply.

Term	Definition
Access	*Electricity* Includes all the equipment that is the property of the supplier and that is used for one customer only. *Gas* The network connection joins the general supply network with the customer's gas facilities from the supply pipeline to the internal pipes on the premises. It comprises the connecting pipe, any shut-off device outside the building, insulator, main shut-off device and any in-house pressure regulator. The provisions on connection to the network are still applicable to the pressure regulator when it is installed after the end of the network connection but located within the customer's system.
Actual energy consumption	For indicating the actual consumption of gas it would seem appropriate to state the volume at measurement conditions in m^3, instead of the number of kWh.
Affiliated undertakings within the meaning of section 15 AktG	Legally independent companies that in relation to each other are subsidiary and parent company (section 16 AktG), controlled and controlling companies (section 17 AktG), members of a group (section 18 AktG), undertakings with cross-shareholdings (section 19 AktG) or parties to a company agreement (sections 291, 292 AktG).
Annual peak load (final consumer)	Peak load, expressed in kilowatt (kW), as metered in 15 minute readings, in the course of a year.[6)]
Annual usage time (final consumer)	Annual usage time defines the regularity of the consumer’s offtake of electrical energy from the network during a year. The longer the time, the more evenly consumption is distributed over the 8,760 hours of the year (8,784 in a leap year). The time gives the number of hours the consumer needs to reach his annual consumption if he constantly uses the power corresponding to his annual peak load (annual usage time = annual consumption divided by annual peak load).[5)]
Balancing energy	Difference between entry and exit quantities established by the balancing group network operator for the market area at the end of each balancing period and settled with the balancing group managers.

Balancing group network operator	A network operator covering the whole market area or a third party enabling a balancing group to be established and with whom a balancing group contract is concluded.
Balancing services	Energy procured by the balancing group manager and used to guarantee the stability of the networks in the particular market area.
Balancing zone	Within a balancing zone all entry and exit points can be allocated to a specific balancing point. In the gas sector a balancing zone corresponds to the market area. This means that all entry and exit points in all networks or network segments that are part of the particular market area belong to a balancing group (cf section 3 para 10b EnWG).
Binding exchange schedules	Unlike physical load flows, which represent the actual cross-border flow of electricity, exchange schedules reflect the commercial cross-border exchange of electricity. Physical load flows and commercial exchange schedules do not necessarily have to match (eg due to loop flows).
Black start capability	Ability of a generating unit (power plant) to start up independently of power supplies from the electricity network. As a first step to restore supply, this is particularly important in the event of a disruption causing the network to break down. Additionally, a "stand-alone capability" is required with a steady supply voltage and capable of bearing loads without any significant voltage and frequency fluctuations.
BlmSchG	Bundes-Immissionsschutzgesetz (Federal Immission Control Act)
Cavern storage facility	Artificial hollows in salt domes created by drilling and solution mining. In comparison to pore storage facilities, these often have higher injection and withdrawal capacities and a lower cushion gas requirement, but are also smaller in volume.
Certified technical management of safety	A network operator's technical safety management that has been certified by an independent external body and is subject to regular reviews.
Change of contract	A customer's change to a new tariff with the same energy supplier.
Charge for billing	Charge for settling network use and forecasting annual consumption in accordance with section13(1) StromNZV.
Charge for metering	Charge for reading the meter, reading out and passing on the meter data to the authorised party.
Charge for meter operations	Charge for meter installation, operation and maintenance.
CHP net nominal capacity (effective electrical output)	Proportion of electrical net nominal capacity in heating nominal capacity that is directly linked to the heat extraction. The proportion of electric power relating solely to electricity generation (condensation share) has not been taken into account.[5)]

Completion / Start of operation	The time at which gas supply could begin (gas pipeline under pressure up to the shut-off valve).
Continuous capacity	Maximum capacity at which a generation, transmission or consumption facility can be operated for a sustained period without impairing its service life (operating life) or safety, provided it is operated as intended. NB Continuous capacity may be subject to seasonal variations (eg as a result of cooling water conditions).[2)]
Day-ahead capacity	Capacity for the next day
Day-ahead trade	Trading market for energy supplied the next day.
Default supplier	The gas and electricity company providing default supply in a network area as provided for by section 36(1) EnWG.
Default supply	Energy supply by the default supplier to household customers on the basis of general terms and conditions and general prices (cf section 36 EnWG).
Delivery volumes	Amounts of gas delivered by gas suppliers to final consumers.
Denial of network access	A network operator's negative reply or revised contract offer after receiving a formal request for network access.
Dominance method	Simplified group accounting method for the purposes of evaluating market concentration. It focuses solely on whether one shareholder holds at least 50% of the shares in a company. If the shares in a company are held as to more than 50% by one shareholder, the company's volume of sales is attributed to the shareholder in full. If two shareholders have a shareholding of 50% each, then the sales are split in half and attributed to each of the shareholders. If there is no shareholding of 50% or more in a company, the volume of sales of this company is not attributed to any shareholder (the company is then itself a "controlling company").
Downstream distributor	Regional and local gas distribution network operator (not an exporter)
EEG surcharge	Pursuant to the AusglMechV, as of 1 January 2010 electricity utility companies must pay an EEG surcharge to the transmission system operators for every kilowatt hour of electricity supplied to a final customer. These payments cover the difference between the transmission system operators' income and expenditure in implementing the EEG in accordance with section 3(3) and (4) AusglMechV and section 6 AusglMechAV. The TSOs are required pursuant to section 3(2) AusglMechV to determine and publish the EEG surcharge for the following calendar year by 15 October each year.
EEX / EPEX Spot	European Energy Exchange / European Power Exchange. The EEX operates marketplaces for trading electricity, natural gas, CO2 emission rights and coal. EEX

	holds a 51% equity investment in the Paris-based EPEX Spot, which operates the power spot markets for Germany, France, Austria and Switzerland (see http://www.eex.com).
Electrical power used by the plant	Electrical power a generating unit requires to operate its auxiliary and ancillary facilities (eg for water treatment, water supply to steam generators, fresh air and fuel supply, flue gas cleaning), plus the power losses of step-up transformers (generator transformers). There are two types of internally used electrical power: the electrical power required to operate a generating unit's auxiliary and ancillary facilities during operating hours and the electrical power required to operate its auxiliary and ancillary facilities outside operating hours.[2)]
Energy to cover power losses	The energy required for the compensation of technical power losses.
Entry-exit system	Gas booking system in which the shipper signs only one entry and exit contract, even if the transport is distributed among several TSOs.
Entry point	A point at which gas can be transferred to the network or subnetwork of a system operator, including transfers from storage, gas production facilities, hubs, or blending and conversion plants.
Exit point	The point at which gas can leave an operator's network for delivery to final customers, downstream networks (own and/or other) or redistributors, plus the points at which gas can be taken off for delivery to storage facilities, hubs and conditioning or conversion plants.
Expenditure on maintenance	Expenditure on any technical, administrative or management measure taken to maintain or restore working order to an asset during its life cycle so that it can perform the function required.
Explicit auction	In an explicit auction, available capacity is allocated to market participants submitting the highest bids (cf ETSO: An Overview of Current Cross-border Congestion Management Methods in Europe, May 2006).
FBA	Flow Based Allocation of capacity Starting from the planned commercial flows (trades), the capacity available for cross-border electricity trading is determined and allocated on the basis of the actual flows in the network. FBA thus makes it possible to allocate transmission capacity in line with the actual market situation as reflected by the bids.
FCFS	The first to request capacity will be served first, obtaining as much capacity as requested, as far as possible. First come first served/First committed first served.
Fractional ownership	Line sections whose capacity is shared by two or more network operators (by ownership or similar) and which can therefore be used only partially by each network

	operator.
Futures	Contractual obligation to buy (futures buyer) or deliver (futures seller) a specified amount of, for example, electricity, gas or emission rights at a fixed price in a defined future period (period of delivery). Futures contracts are settled either physically or financially.[4)]
Futures market	Market for trading futures and derivatives. It differs from the spot market in that obligation and settlement do not take place at the same time.
Green electricity tariff	An electricity tariff for which, compared with any other renewables, the supplier has proven to the final customer that the electricity is produced from renewable energy sources by way of a guarantee of origin issued by the Federal Environmental Agency (UBA).
Gross capacity	Delivered power to the generator terminals Hydro power: In turbine operation, gross capacity is measured at the generator's terminals. In a pumped storage station, net capacity is measured at the terminals of the (motor) generator if the facility is operated as a motor. Gross capacity is equal to net capacity plus the electrical power used by the plant, including power lost by the plant's transformers but not the power consumed in the process of generation and the power required for the phase shifter.[2)]
Gross electricity generation	Electrical energy produced by a generating unit, measured at the generator's terminals.[2)]
H-gas	A second-family gas with a higher amount of methane (87 to 99 volume percent) and thus a lower volume percentage of nitrogen and carbon dioxide. It has a medium calorific value of 11.5 kWh/m³ and a Wobbe index of 12.8 kWh/m³ to 15.7 kWh/m³.
Hub	An important physical node in the gas network where different pipelines, networks and other gas infrastructures come together and where gas is traded.
Implicit auction	See market coupling
Intermediate network operator	A network operator downstream from one operator, for instance a market area-wide gas transmission system operator, and usually also upstream from a distribution system operator.
Intraday trading	On the EEX, transactions involving gas and electricity contracts for supply on the same or following day (see http://www.eex.de)
Investments	Investments are considered to be gross additions to fixed assets capitalised in the year under review and the value of new fixed assets newly rented in the year under review.

	Gross additions also include leased goods capitalised by the lessee. The gross additions must be notified without deductible input VAT. The value of the internally generated assets as capitalised in the fixed asset account (production costs) is to be included. Notification is also required of assets under construction (work begun for operational purposes, as far as capitalised). If a special "assets under construction" summary account is kept, notification should be made only of the gross additions without the holdings shown in the account at the beginning of the year under review. Payments on account should be included only if the parts of assets under construction for which they were made have been settled and if they have been capitalised. Not included are the acquisition of holdings, securities etc (financial assets), the acquisition of concessions, patents, licences etc and the acquisition of entire undertakings or businesses and the acquisition of rental equipment formerly used in the undertaking, additions to fixed assets in branch offices or specialist units in other countries and financing charges for investments.[5)]
L-gas (low calorific gas)	A second-family gas with a lower amount of methane (80 to 87 volume percent) and higher volume percentages of nitrogen and carbon dioxide. It has a medium calorific value of 9.77 kWh/m^3 and a Wobbe index from 10.5 kWh/m^3 to 13.0 kWh/m^3.
Length of circuit	System length (the three phases L1+L2+L3 together) of cables at the network levels LV, MV, HV and EHV (example: If L1 = 1km, L2 = 1km and L3 = 1km, then the length of the circuit = 1km). In the case of different phase lengths, the average length in kilometres is to be determined. The number of cables used per phase is irrelevant for the length of circuit. However, cables leased by, or otherwise made available to the network operator, should be included to the extent they are operated by the network operator. Planned cables, cables under construction or let on lease, and decommissioned cables are not included. Lines in fractional ownership should be included with their full number of kilometres to determine the network length. The circuit length at the low voltage network level should include service lines but not the lines of street lighting systems. Lines of more than 36 kV that have a transport function and are subject to a high voltage tariff may be considered at the high voltage level.
Load-metered customer	Final customers with an annual electricity consumption exceeding 100,000 kWh, or with a gas consumption exceeding 1.5m kWh per year or more than 500 kWh per hour.
Load-metered final customers	Measurement of the power used by final consumers in a defined period. Load metering is used to establish a load profile showing a final customer's consumption over a defined period. A distinction is made between customers with and customers without load metering.
m:n nomination procedure	The m:n nomination procedure facilitates schedule nominations to any corresponding balancing group. For cross-border transactions it is therefore no longer necessary for the balancing groups on each side of the border to be managed by the same company (1:1 nomination). With this procedure it is now possible to nominate transactions

	between non-neighbouring countries, as may be the case in flow-based capacity allocation procedures.
Market area	*Electricity* Several points of supply (TSOs) are combined in one market area if there is no congestion between these TSOs' networks. The auction prices of hour contracts for the same hour of supply but for different points of supply (TSOs) are the same if they belong to the same market area.[4)] *Gas* A gas market area refers to a consolidation of networks at the same or downstream level in which shippers can freely allocate booked capacity, deliver gas to final consumers and provide gas to other balancing groups.
Market area network operator	The gas transmission system operator operating the top-level pipeline network in a market area. This can also be several network operators jointly covering a market area.
Market coupling	A process for efficient congestion management between different market areas involving several power exchanges. Market coupling improves the use of scarce transmission capacities by taking into account the energy prices in the coupled markets. It involves day-ahead allocation of cross-border transmission capacities and energy auctions on the power exchanges being carried out at the same time, based on the prices on the exchanges. For this reason, reference is also made here to implicit capacity auctions.
Market maker	Trading participant who, for a minimum period of time during a trading day, has both a buy and a sell quote in his order book at the same time. Market makers ensure basic liquidity.
Market splitting	Same procedure as market coupling but involving only one electricity exchange.
Master data	Company data for the successful processing of business transactions. These include contract data such as a customer's name, address and meter number.
Matching/ Mismatching	Comparing nominations in a balancing group. Entry/exit in balance = matching; imbalances = mismatching
Maximum capacity	Capacity at which a generating unit can be operated for a sustained period under normal conditions. It is limited by the weakest part of the plant, determined by measurement and converted to the levels applicable under normal conditions. In the case of a long-term change (eg changes in individual units, changes as a result of ageing) maximum capacity needs to be redetermined. It may deviate from the rated capacity by +/- Δ P. Short downtimes of individual parts of the plant do not result in reduced maximum capacity.[2)]

Maximum usable volume of working gas	The total storage volume less the cushion gas required.
Meter point	Point in the grid at which the flow of energy, or the amount of gas transported, is recorded for billing purposes.
Metering service	Metering the energy supplied in accordance with verification regulations and processing the metered data for billing purposes.
Minimum capacity	The minimum capacity of a generating unit is the minimum level of power that must be maintained in continuous operation for specific plant or operational requirements.[2)]
Natural gas reserves	Secure reserves: in known deposits based on reservoir engineering or geological findings that can be extracted with a high degree of certainty under current economic and technical conditions (90% probability). Probable reserves: a probability level of 50%.
Net capacity	The power a generating unit delivers to the supply system (transmission and distribution networks, consumers) at the high-voltage side of the transformer. It corresponds to the gross capacity less the power consumed by the unit in the process of generation, even if this is not supplied by the generating unit itself but by a different source.[2)]
Net electricity generation	A generating unit's gross electricity generation less the energy consumed in the process of generation. Unless otherwise indicated, the net electricity output relates to the reference period.[2)]
Net network tariffs	*Electricity* Electricity network tariff excluding billing, metering and meter operation charges. *Gas* Gas network tariff excluding billing, metering and meter operation charges.
Net Transfer Capacity (NTC)	Total transfer capacity less the transmission reliability margin (cf Transmission Code 2003)
Netting	Netting (by the TSOs), as far as technically possible, of the capacity requirements of power flows in opposite directions on a congested cross-border interconnection line in order to use this line to its maximum capacity (cf Art. 6(5) s.1 EC Regulation 1228/2003).
Network area	Entire area over which the network and substation levels of a network operator extend.
Network level	Areas of power supply networks in which electrical energy is transmitted or distributed at extra high, high, medium or low voltage (section 2 para 6 StromNEV)

	low voltage			≤ 1 kV
	medium voltage	> 1 kV	and	≤ 72.5 kV
	high voltage	> 72.5 kV	and	≤ 125 kV
	extra-high voltage	> 125 kV		

Network losses	The energy lost in the transmission and distribution system is the difference between the electrical energy physically delivered to the system and the energy drawn from the system within the same period.[2)]
Network number	On assignment of a registration number, network operators are automatically given the network number 1. Upon request, the Bundesnetzagentur will assign additional network numbers for additional network segments. ≤ 1 kV > 1 kV und ≤ 72,5 kV > 72,5 kV und ≤ 125 kV > 125 kV
Nomination	Shippers' duty to notify the network operator, by 2pm at the latest, of their intended use of the latter's entry and exit capacity for each hour of the following day.
Offtake load	The correct sum of all offtakes by downstream network areas (+) and reverse flows from downstream network areas (-) via transformers and lines that are directly connected with downstream network areas. This corresponds to the vertical grid load less the final consumers' offtake. Horizontal load flows and grid losses are not taken into account.
Offtake volume	The gas network operators' offtake gas quantities.
OMS standard	Selection of options chosen by the OMS Group from the European Standard 13757-x. This open metering system specification standardises communication in consumption metering.
Open season procedures	Procedures for identifying market demand for capacity in a new or expanded gas infrastructure. Data is also collected on the conclusion of binding capacity agreements. With its Guidelines for Good Practice on Open Season Procedures (GGPOS), ERGEG has drawn up guidelines for transparent and non-discriminatory open season procedures for the first time.
Operating time	Length of time during which a plant or part thereof converts or transmits energy. The operating time begins with the connection of the plant, or part thereof, to the network and ends with its disconnection. It does not include start-up and shut-down times of generation plant without any usable energy output.[2)]
OTC trading	Over-the counter or off-exchange trade.
Own consumption	Electrical energy consumed in the auxiliary and ancillary facilities of a generating unit

	(eg a power plant unit or power plant) for water treatment, water supply to steam generators, fresh air and fuel supply and flue gas cleaning, but excluding the energy consumed in the process of generation. A power plant's own consumption also includes step-up transformer (generator transformer) losses, but not, however, the power consumed by auxiliary and ancillary facilities that are not electrically operated; this is covered by the power plant's total heat consumption. A power plant's own consumption during the reference period comprises two elements: own consumption for operations during operating hours and own consumption during idle hours. The latter is not taken into account in the net calculation.[2)]
Peak load	Load profile for constant electricity supply or consumption over a period of 12 hours from 8am to 8pm every day of a delivery period.[4)]
Phelix (Physical Electricity Index)	The Phelix Day Base is the calculated average of the hourly auction prices for hours 1-24 every calendar day of the year on the EPEX Spot SE market for the market area of Germany/Austria. The Phelix Peakload Index is based on the hourly prices during peak load hours (8am to 8pm) (see http://www.eex.com).
Physical network congestion	A situation in which demand for supply exceeds the technical capacity at a given point in time.
Pore storage facility	Storage facilities where the natural gas is housed within the pores of suitable rock formations. These are often large in volume but, in comparison to cavern storage, have lower entry and exit capacity and greater cushion gas requirements.
Power plant status	*Reserve power plants:* power plants that are operated only at the TSOs' request to ensure security of supply. *Exceptional cases:* plants temporarily not in operation (eg owing to repairs following damage) or with restricted operation; *Seasonal mothballing:* power plants that are closed during the summer season and fired up again afterwards.
Pro rata	The quota allocated to a party requesting goods in short supply is determined by calculating the respective share of total demand and subsequently allocating this percentage as a share of the available supply.
Provision	The former supplier provides a customer with energy on behalf of the new supplier; the latter buys the energy from the former supplier in order to sell it to his customer. The competitor signs a provision contract with the former supplier to this effect.
Pulse output	Mechanical counter with a permanent magnet in the counter rotation. May be modified by a synchronising pulse generator (reed contact). Pulse output also includes what is known as a "cyble counter".

Rated capacity	Maximum capacity at which a plant can be operated for a sustained period under rated conditions at the time of handover. Capacity changes are only permitted in conjunction with major modifications of the rated conditions and structural alterations at the plant. Until the exact rated capacity has been determined, the value ordered in the supply contract should be indicated. If it is unclear whether the value ordered complies with the actual permit and operating conditions expected, a preliminary average rated capacity is to be determined and applied until definitive measurement results are available. The average is to be fixed in such a way that higher or lower production levels, over a normal year, will be offset (eg on account of the cooling water temperature curve). The definitive rated capacity of a power plant unit is determined when the plant has been handed over, usually when the acceptance measurement results are available. It should be noted that the rated conditions apply to an annual average, ie that seasonal changes (for example in the cooling water and air inlet temperature) and internal electrical and steam-side requirements balance out, and that exemplary conditions used in the acceptance test, eg special closed circuit switching, must be converted to normal operating conditions. The rated capacity, unlike the maximum capacity, may not be adjusted to a temporary change in capacity. The rated capacity may not be changed in the case of a reduction in capacity as a result of, or to prevent, damage, nor may it be reduced on account of ageing, deterioration or pollution. Capacity changes require: • additional investment with a view to increasing the plant's capacity, eg retrofitting to enhance efficiency; • the decommissioning or removal of parts of the plant, accepting a loss of capacity; • operation of the plant outside the design range stipulated in the supply contracts on a permanent basis, ie for the rest of its life, for external reasons, or • a restriction of capacity, imposed by statutory regulations or orders of public authorities without there being a technical fault in the plant, until the end of its operating life.[2)]
Rated thermal capacity	Maximum capacity at which a plant can be operated for a sustained period and ordered in the supply agreement. If the rated capacity cannot be established from the order documents, the average capacity that can be reached under normal conditions needs to be determined once for a new plant. Net rated thermal capacity corresponds to gross rated thermal capacity less the thermal output used for thermal processes in the plant itself.
Redispatching	Adjustment of power plant dispatch to the requirements of the network if this is congested or congestion is threatening. As trade transactions remain unaffected by such intervention, the TSOs may take the costs involved into account in their calculation of network tariffs.
Reference period	Total uninterrupted reporting period (calendar period, eg day, month, quarter, year).[2)]

Reference power	The reference power is the correct sum of all withdrawals from upstream grid areas (+) and reverse feed-in to upstream grid areas (-) via directly connected transformers and lines to upstream grid areas. Horizontal load flows and grid losses are not taken into account.
Registration number for network operators	The eight-digit registration number is assigned by the Bundesnetzagentur as a code identifying the undertaking and categorising it according to field of activity; the number for network operators begins with 1000 (electricity) or 1200 (gas) and comprises four additional digits (eg 10005678 or 12005679).
Registration number for suppliers	The eight-digit registration number is assigned by the Bundesnetzagentur as a code identifying the undertaking and categorising it according to field of activity; the number for suppliers begins with 2000 and comprises four additional digits (eg 20001234).
Rucksack principle	Subject to the conditions referred to in section 42 GasNZV, a new supplier may insist that the capacity required to supply a final consumer is transferred to him from the former supplier.
Shift factor	The shift factor cos φ is the cosine of the phase angle between the sine oscillations of voltage and current. It also represents the ratio between active and apparent power and indicates the extent to which reactive power is used. A distinction is made between capacitive and inductive reactive power. If the sinus oscillations of the current move faster than those of voltage, the reactive power is called capacitive, while in the opposite case it is called inductive.
Spot market	Market where transactions are handled immediately.
Standard cubic metre	Section 2 subpara 11 GasNZV defines a standard cubic metre as the quantity of gas which, free of water vapour and at a temperature of 0°Celsius and an absolute pressure of 1.01325 bar, corresponds to the volume of one cubic metre.
Standard load profile customer (SLP)	*Electricity:* Section 12 StromNZV defines standard load profile customers as final customers with an annual consumption up to 100,000 kWh (electricity) for whom no load profile needs to be recorded by the DSO. (Any deviation to the specific consumption limit may be determined in exceptional cases by the DSOs.) *Gas:*Section 24 GasNZV defines standard load profile customers as final customers with a maximum annual consumption of 1.5m kWh and a maximum hourly consumption of 500 kWh (gas) for whom no load profile needs to be recorded by the DSO. (Any variations above or below these specific withdrawal and offtake capacity limits may be determined by the DSOs.)
Standard supplier	The default supplier (cf section 38 EnWG).
Standard supply	Energy received by final customers from the general supply system at low voltage or

	low pressure and not allocable to a particular delivery or a particular supply contract (cf section 38 EnWG).
Storage facility operator	In this context the term refers to a storage facility operator in the commercial sense. It does not refer to the technical operator, but rather to the company which sells the storage capacities and appears as a market participant.
Supplier switch	This process describes the interaction between market partners when a customer at a metering station wishes to change supplier from the current one to a different one. In principle this does not include cases of moving home. A switch of supplier when moving home need only be recorded if the customer chooses a supplier other than the default supplier within the meaning of section 36(2) EnWG directly at the time of moving in. The transfer of supply contracts as a result of a change of supply rights is not regarded as a switch of supplier.
Transformation level	Areas in power supply networks in which electrical energy is transformed from extra high to high voltage, high to medium voltage and medium to low voltage (section 2 para 7 StromNEV). An additional transformation within one of the separate network levels (eg within the medium voltage level) is part of that network level.
Two-contract model	Procedure for handling the transport of gas within a balancing zone (market area) with two contracts with the shippers: one contract for input into the market area and one for output to final consumers in that market area or to a bookable exit point at the market area border.
Unbundled storage services	Products for which the volume of working gas, feed-in and offtake capacity are sold separately.
Usage time (final consumers)	Number of days that would be required to withdraw the annual consumption volume by taking off the maximum daily amount (usage time in days = annual consumption divided by maximum daily amount). Usage time in hours indicates the number of hours required to withdraw the annual consumption volume by taking off the maximum hourly amount (usage time in hours = annual consumption divided by maximum hourly amount) (cf Eurostat)[1)]
Underground storage facilities	These are notably pore, cavern and aquifer storage facilities.
Vertical network load	The correct sum of all transfers from the transmission network over directly connected transformers and lines to distribution networks and final customers.
Virtual point (VP) (also called virtual trading point)	The VP is used as a reference point for settlement in order to represent the gas trading and gas transport transactions within the two-contract model. When gas is injected into a market area, it is available at the VP of that market area and can be traded there as deemed necessary.

Wireless M-Bus	(wireless) meter-bus (fieldbus)
Within-day capacity	Capacity of the (current) trading day
Working gas	Gas actually available for withdrawal from a gas storage facility. The formula is: storage volume – cushion gas (volume not available for use) = working gas.

Glossary sources:

1) European Communities: Gas prices; Data 1990-2003, Luxembourg, 2003
2) VGB PowerTech e.V.: VGB Standard, Basic Terms of the Electric Utility Industry, VGB-Standard-S-002-T-01:2012-04.DE, Essen 1st Edition 2012
3) Federal Statistical Office: Subject matter series 4, series 6.1, Industry; employment, turnover, investment and cost structure of energy and water utilities, 2005, Wiesbaden, 2007
4) European Communities: Electricity prices; Data 1990-2003, Luxembourg, 2003
5) Öko-Institut e.V. (Institute for Applied Ecology): Monitoring der Kraft-Wärme-Kopplungs-Vereinbarung vom 19. Dezember 2003 für den Teilbereich Kraft-Wärme-Kopplung, (Monitoring the combined electricity/heat production agreement of 19 December 2013 for the combined electricity/heat production market area) reporting period 2010, Berlin, 2012, page 79f.

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