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Message from the two Presidents

The Monitoring Report 2012 marks the first time the Bundesnetzagentur (Federal Network Agency) and the Bundeskartellamt (Federal Cartel Office) have presented a joint report on the development of the electricity and gas markets in Germany. This close cooperation bears witness to the fact that both authorities have assumed a leading role in monitoring activities since 2011. The 2012 data survey was carried out by the two authorities working together. This had the advantage of minimising the reporting requirements on the companies concerned. The cooperation also built upon the experiences of the Bundesnetzagentur with monitoring processes in the last few years, in which the Bundeskartellamt was already involved.

The Monitoring Report 2012 documents, analyses and evaluates developments in the electricity and gas markets. The data collected and evaluated reflect the dynamic changes on the German energy market in 2011.

The report is an impressive testament to the fact that the *Energiewende* – the turnaround in energy policy – has brought about a significant change in the energy supply structure in Germany, particularly in terms of electricity generation. The decommissioning of eight nuclear power plants in early 2011, together with strong growth in volatile generation capacities in the renewables sector (particularly in solar facilities), has led to a noticeable decrease in the capacities of the four leading network operators RWE, E.ON, Vattenfall and EnBW. Moreover, conventional generation capacities have come under economic pressure from the growth of renewables. As a result of their feed-in priority, decoupled as it is from market activity, the increase in renewable capacities is forcing back conventional generation, which is managed by the market. The report demonstrates the paradigm change in the German energy industry related to the nuclear exit and expansive growth in renewable generation capacities.

A significant challenge is to reliably balance fluctuations in intermittent generation from renewable sources in the interests of securing supply. Although the grid was under considerably more strain than in 2010, the electricity network operators were able to rise to this challenge in 2011. Apart from a slight increase in the average interruption duration on the medium and low voltage levels, quality of supply remains at a very high level. Nevertheless, the various intervention measures the network operators had to take – primarily rescheduling, redispatching and countertrading, along with reduced feed-in – and the activation of conventional cold reserve power plants indicate how critical the situation has become.

There is an urgent need for expansion of the electricity grid, particularly the transmission network. Compared to the strong increase in renewables, network expansion has only made extremely slow progress, with key projects experiencing considerable delays. On a positive note, however, it should be mentioned here that an initial draft of a national Network Development Plan based on the first scenario framework for electricity approved by the Bundesnetzagentur in 2011 has been submitted, which is to be used to develop a draft Federal Requirements Plan Act by the end of 2012.

Liquidity in the wholesale electricity markets continued to develop encouragingly in the year under review. This is an important factor for competition throughout the electricity sector, as the power exchange and bilateral wholesale trading create a broad spectrum of possibilities for downstream regional and local suppliers to procure electricity in a competitive environment. This means that consumers' options for switching supplier have also improved.

In the gas sector, importing is of key significance for supply to the German market. Border prices on the German import market – which are largely still linked to the oil price in the long-term import contracts – have increased steadily since 2010, increasing the difference from the spot market prices on the downstream market. Price negotiations between customers and gas importers and producers have already led to price reductions in long-term contracts.

Consolidation of gas market areas took place on 1 April 2011 and 1 October 2011, leaving two market areas in Germany at present. These mergers have also increased the liquidity and efficiency of the wholesale markets. Liquid wholesale markets, in particular the power exchanges, have gained real significance for pricing. The positive developments on the wholesale markets and the option of buying or selling gas on a day ahead basis or on the futures market have contributed significantly to allowing regional suppliers and municipal utilities to procure their gas via more short-term, flexible contracts, instead of on a long-term basis. The retail gas market continues to enjoy dynamic development, with the number of supplier switches increasing markedly compared to the previous year and the number of active gas suppliers in the network areas rising. Consumers' options for switching supplier have thus also improved in the gas sector.

Success in competition development, as can be seen at both wholesale and retail level in the electricity and gas sectors for example, is by no means permanently assured however. There are risks for competition and the market particularly in the electricity sector with its non-market-oriented organisation of renewables.

A high level of societal acceptance is fundamental if the *Energiewende* is to succeed. This applies to grid expansion and upgrading measures, as well as to the reconfiguration of generation structure. The Bundesnetzagentur and the Bundeskartellamt, each working in its own area of expertise in the interests of energy consumers and competition, are guiding the restructuring of energy supply in Germany with great dedication and awareness of their shared responsibility.

Jochen Homann
Bundesnetzagentur President

Andreas Mundt
Bundeskartellamt President

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Generation

In 2011, the year under review, the area of power generation was characterised by a significant decline in non-intermittent generation capacities resulting from the permanent decommissioning of eight nuclear power plants. Intermittent generation capacity, on the other hand, saw a continued increase in 2011, driven in particular by the significant rise in the number of photovoltaic systems; this increase has continued unabated into the current year. Against the background of the decommissioning of the eight nuclear power plants, substantial network calculations were undertaken in the summer of 2011 in the interest of ensuring security of supply for the winter of 2011/12.

Based on these calculations, a re-commissioning of one of the eight decommissioned nuclear power plants was not necessary. In order to safeguard security of supply in areas that are particularly at risk, such as southern Germany, conventional power plants in southern Germany and Austria were activated from cold reserve status, and resumed operations as reserve power plants. During the winter of 2011/12, there were several situations in which the responsible transmission system operators had to fall back on reserve power plants in order to maintain system stability. Due to the decommissioning of one power plant block for technical reasons, a slight reduction of non-intermittent generation capacities in southern Germany is expected for the winter of 2012/2013. This year, transmission system operators again conducted network calculations in order to determine the need for reserve power plant capacity in the interest of maintaining security of supply for the winter of 2012/13. In this context, a figure of 2,500 MW of available generation capacity was assessed as being required to maintain secure network operations. This requirement can be covered by available reserve power plants in the winter of 2012/2013.

Networks

The quality of the electricity supply, despite a slight increase in the average duration of interruptions in the medium to low voltage range, continues to be at a relatively high level. The average non-availability (System Average Interruption Duration Index - SAIDI) for final consumers in the low and medium voltage range was 15.31 minutes, putting it slightly above the figure of 14.90 minutes calculated for the year 2010. It was, however, significantly lower than the average of 17.44 minutes for the period of 2006 to 2010.

Despite the significant increase, compared to the year 2010, in the number of tense network situations, German transmission system operators in 2011 were at all times able to manage the situation using the instruments in accordance with section 13(1) of the Energy Act (EnWG) (primarily network switching, redispatch and countertrade measures) as well as in accordance with section 13(2) of the EnWG (primarily reduction of electricity feed-in).

Compared to 2010, renewable energy feed-in restrictions under section 11 of the EEG at the different network levels more than tripled, totalling 421 GWh (compared to around 127 GWh in 2010). The rapid increase in feed-in management measures to temporarily reduce the feed-in from renewable energy sources, cogeneration plants and mine gas systems is directly tied to the unabated expansion of renewable energy sources and the slow pace of network expansion projects. In 2011, the temporary reduction of feed-in capacity was necessary in particular in network areas in northern Germany with a high volume of installed wind power capacity.
A majority of the 24 network expansion projects listed in the annex to the Power Grid Expansion Act (EnLAG), according to information provided by the TSOs (status October 2012), will start operations later than expected. 15 of the 24 projects already have an expected delay of between one and five years.

The draft of the first electricity scenario framework, which the TSOs submitted to the Bundesnetzagentur on 19 July 2011, was first presented for consultation and subsequently approved by the Bundesnetzagentur. As a result, on 3 June 2012, the TSOs were able to submit to the Bundesnetzagentur the first ever joint national draft Network Development Plan, which contains all effective measures, from the standpoint of TSOs, for the demand-based optimisation, strengthening and expansion of the network.

In the year 2011, investments in and expenditures on network infrastructure by the four German TSOs totalled approx. €847m (2010: €807m). In the area of the DSOs, investments in and expenditures on network infrastructure in the year 2011 amounted to approx. €6,281m (2010: €6,401m). However, the expansion and upgrading of network infrastructure at transmission and distribution system levels will increase significantly in the years to come. In particular the expansion of renewable energies requires considerable investments in network infrastructure. Against this background, there will be a continued increase in the revenue cap, and, as a result, in network tariffs. The revenue cap, which serves as the basis for calculating the tariffs of the different network areas, increased for transmission system operators by around 16.71 percent from 2011 to 2012. The increase for distribution system operators was 8.87 percent. The average volume-weighted network tariff in the period between 1 April 2011 and 1 April 2012 increased significantly, both for household (low voltage) and business (low voltage, metered profile) customers, as well as for industrial customers (medium voltage), an increase which is due to a variety of factors.

European integration of electricity markets

In 2011, Germany was once again the hub for electricity exchange in the central European interconnected system. Compared to the year 2010, the average available transmission capacity decreased, for various reasons, across all German cross-border interconnectors, by 7.12 percent, to 21,336 MW (import and export capacity). There were changes in particular at the German-French border brought about by the decrease in the average available export capacity (by 9.2 percent) and import capacity (by 13.5 percent), as well as at the border between Germany and Denmark. Here, the average available export capacity decreased by 7.8 percent, while the import capacity decreased by 30.8 percent. On the Baltic Cable (Germany-Sweden), there was a reduction in capacity of 35 percent on the export side and 20.5 percent on the import side. Against this background, following the successful introduction of market coupling in the CWE region in fall of 2010, the rapid implementation of the flow-based method of market coupling is now planned. In April 2011, the first feasibility study on this was presented, accompanied by an updated project plan, which showed that the launch can be expected in mid 2013.

Retail

There have been further improvements in the possibilities for electricity customers to choose from a wide range of suppliers in 2011. In 2011, nearly three quarters of all network areas had more than 50 active suppliers. In 2007, that number was only at around one quarter. All total, in 2011, the year under review, there were 219,272 switches of supplier in the segment of industrial and business customers, which is nearly 32,000 more than in the year 2010. As of late 2011, only 3.1 percent of industrial and business customers were still with their default supplier. 42.8 percent of industrial and business customers have a special contact with the electricity company that is the default supplier in the respective area. 54 percent receive electricity from a supplier other than their default supplier. Among household customers, there is a continuing trend to leave their default supply contract. By now, 43.4 percent of customers have a special contract with their default supplier, while 17 percent of all household customers have a supply contract with companies other than the default supplier. Nevertheless, nearly 40 percent of all household customers remain in their default supply contracts. In 2011, a total of over 3.8m final customers switched suppliers. Compared to the year 2010, that amounts to an increase of 27 percent.

In 2012, the average total price for industrial customers increased slightly, compared to the previous year, by 0.04 ct/kWh. For business customers, there is an average increase of the total price by 0.51 ct/kWh. Compared to the year 2011, the average price for household customers in the default price plan has increased by 2.8 percent. The price increase in all consumer groups – default supply, special contract with the default supplier, and special contract with a third-party supplier – has declined slightly compared to the previous year. Default supply is still the most expensive type of supply. Household customers can achieve lower prices by switching supplier or contract. The average electricity price for all household customers (as volume-weighted average across all tariff categories) was 26.06 ct/kWh in the year 2012. Despite the price-reducing effect brought about through supplier and contract switches, that is 2.4% (+0.61 ct/kWh) above the figure for the year 2011.

Seen in a European context, a comparison of electricity prices in the European Union shows that, in the segment of household customers, prices in Germany are above average or in the top tier, depending on whether taxes and duties are taken into consideration. In a comparison of European electricity prices for industrial consumers, Germany is below the European average (not including taxes and duties), and in the upper quarter if taxes and duties are included. For 2011, the year under review, the Bundesnetzagentur for the first time conducted surveys concerning threatened interruptions of supply, interruption requests and interruptions actually carried out under section 19(2) of the Electricity Default Supply Ordinance (StromGVV) as well as the related costs. The surveyed companies reported that interruptions of service were threatened a total of approximately six million times, with an average outstanding payment of €120. In approximately 1.25m cases, electricity suppliers commissioned an interruption of service, and actual interruptions in supply were carried out approximately 312,000 times. Electricity network operators billed suppliers an average of €32 for carrying out an interruption of supply.

Market developments (BKartA)

In its assessment of the electricity sector, the BKartA has focused mainly on the wholesale and retail markets, but the generation sector is also highly relevant under competition aspects.

Generation

In analysing the wholesale and retail sectors it is particularly important to take into account the situation in the upstream generation sector. At the generation level the Bundeskartellamt defines a product market for the first-time sale of electricity (first-time sales market) which also includes imports and exports. This market also plays a key role with regard to the downstream levels of distribution, networks and final customers.

The generation market has changed with the closure of nuclear power stations and the significant expansion of capacity from renewable energy sources. The closure of nuclear power plants has reduced the generation capacities and thus the market shares of the leading power generating companies E.ON, EnBW, RWE and Vattenfall. In Germany, the four companies still account for approx. 73 percent of the competitive electricity generation capacity. As there are no bottlenecks at the cross-border interconnectors, the Bundeskartellamt considers Germany and Austria as one market: On this relevant geographic market the share of the four large suppliers in competitive generation capacity is about one tenth less.

Furthermore, conventional generation capacity has come under economic pressure due to the expansion of renewable energy sources. In view of the feed-in priority for renewables which is isolated from the market mechanism, the expansion of capacity from renewable energy sources is pushing back electricity generation which is controlled by the market mechanism. In Germany, the non-competitive capacity derived from renewable energy sources meanwhile amounts to 68 GW as compared to 105 GW of conventional power generation capacity. The enormous expansion of subsidised renewable energy sources which benefit from priority feed-in limits the market power of the four large electricity generators on the first-time sales market. In the retail sector the market shares of the four large suppliers have also decreased over the past years. Their market share in the household customers sector amounted to 45 percent in 2011. In 2008, it was still 50 percent.

Wholesale

The wholesale sector is characterised by high liquidity as illustrated by exchange trading: Trading volumes in the spot markets have increased; in the futures market last year's high volume has been maintained. The spot market recorded a total trading volume of 240 TWh, the futures market 457 TWh. Compared to the overall value achieved in 2002, the year when the two power exchanges of Frankfurt/Main and Leipzig merged, this represents an increase by a factor of 4.6.

Although exchange trading only represents a small part of the wholesale sector, it has an important signalling function for price formation, also in the off-exchange wholesale sector. In comparison to the 2010 mean value, the mean prices of the standard products increased in the spot and futures markets in 2011 by 5 to 15 percent.

The liquidity of the wholesale sector is decisive for competition as exchange trading and bilateral wholesale provide the downstream regional and local suppliers of electricity with a broad range of opportunities to purchase electricity, thus expanding their scope for pro-competitive activities.

Retail

Competition in the electricity retail sector has shown some positive development. The possibilities for final customers to switch supplier have been further improved. Competition is based on the concept that customers are free to choose between a variety of offers by different suppliers. This possibility to switch to another offer is crucially important for the development of the market. In contrast to the situation for commercial and industrial customers and households in the electricity sector, opportunities to switch supplier are still considerably restricted in the electric heating sector. In this sector, the basic suppliers still more or less have monopoly positions. Efforts to open up this market are still at an initial stage although some success has been achieved not least through antitrust proceedings.

In the year under review the final customer prices in the key customer groups of industrial customers, commercial customers and household customers, which have significantly increased in the course of the last few years, remained on average unchanged or increased relatively moderately as compared to the previous year. Specifically the price components for network fees, taxes and state duties, which are not formed under competitive conditions, have increased.

Conclusion and prospects

It is due to the liberalisation process which eliminated outdated market regulations and restrictions that the creation and stimulation of competition in the network-based energy sector, and above all in the electricity sector, has become possible at all. However, the success of market development under competitive conditions has by no means been secured on a permanent basis. The volatile renewable energy sources sector is not organised on market economy concepts and therefore poses risks to competition and the market.

Non-market mechanisms in the renewable energies sector lead to crowding out and distorting effects on the competitively organised conventional generation of electricity. Conventional power stations are being squeezed out of the market; at the same time, however, there is still a need for these capacities due to the unreliable feeding in of electricity generated from renewable energy sources. This makes further regulatory intervention in the market necessary which further restricts the functioning of the market.

Ultimately, only competitive framework conditions can secure efficient and cost-saving energy supply. Competition and supply security are not inconsistent with one another. On the contrary, competition is an efficient path leading to the desired security of supply.

Market data and market coverage

Network structure figures 2011[1]	**TSOs**	**DSOs**	**Total**
Network operators (number)	**4**	**735**	**739**
Circuit length (in km)	**34,404**	**1,869,670**	**1,904,074**
of which extra high voltage	34,314	483	34,797
of which high voltage	90	94,932	95,022
of which medium voltage		532,894	532,894
of which low voltage		1,241,361	1,241.361
Transmission route length (in km)	**17,799**		
of which extra high voltage	17,248		
of which high voltage	531		
Capacity of connected generation plants (in GW) As of: July 2012			**172.4**
of which conventional generation plants			101.2
of which facilities based on renewable energy sources			71.2
of which facilities eligible for payment under the EEG			67.5
Output (in TWh)			**551.4**
of which from conventional generation plants			436.2
of which from facilities based on renewable energy sources			115.2
of which from facilities eligible for payment under the EEG			91.2
Non fed-in output (in TWh)			**37.3**
Network losses (in TWh)	**3.3**	**18.1**	**21.4**
of which extra high voltage	2.6	0	2.6
of which high voltage (including EHV/HV)	0.7	3.4	4.1
of which medium voltage (including HV/MV)	0	6	6
of which low voltage (including MV/NV)	0	8.7	8.7
Cross-border exchange (in TWh) (realised exchange schedules)			**74**
of which imports			35.5
of which exports			38.5
Offtake volume (in TWh)	**44.8**	**461.3**	**506.1**
of which industrial and business customers	34.7	334.2	368.9
of which household customers	0	126	126
of which pumped storage	10.1	1.1	**11.2**
Final consumers (metering points)	**630**	**47,660,927**	**47,661,557**
of which industrial and business customers	496	2,894,412	2,894,908
of which household customers	134	44,766,515	44,766,649

Table 1: Network structure data of electricity network operators in Germany 2011[2]

[1] As of July 25th. 2012, a total number of 883 DSOs has been registered at BNetzA. The data of 735 DSOs, that have participated at the monitoring enquiry,has been used in the following table.
[2] The difference between the production side (generation 551.4 TWh) and the consumption side (567.8 TWh) is primarily attributable to smaller conventional generation installations that have so far not been registered.

The four German transmission system operators (TSOs) took part in the 2012 monitoring survey. As of 31 December 2011, the TSOs' overall circuit length (cables and overhead power lines) amounted to 34,314 km at extra high voltage level and 90 km at high voltage level. The total number of metering points in the network areas of the four TSOs, as of 31 December 2011, amounted to 630, not including the so-called virtual metering points as defined by the 2006 Metering Code. Of those, 496 metering points had a recording load profile measurement. The total offtake volume of the 141 (as of 31 December 2011) final consumers connected to the TSOs' networks amounted to 34.7 TWh in 2011.

As of 25 July 2012, 883 electricity distribution system operators (DSOs) are registered with the Bundesnetzagentur. Of those, 735 took part in the Bundesnetzagentur's 2012 monitoring activities. The offtake of these DSOs' final consumers totalled 460.2 TWh.

The total circuit length (cables and overhead power lines) of the DSOs taking part in the 2012 monitoring survey amounted to 1,869,670 km as of 31 December 2011. Across all network levels, a total of 47,661,557 metering points were supplied. In the network areas of electricity DSOs, the total number of metering points as of 31 December 2011 amounted to 47,660,927, not including the so-called virtual metering points as defined by the 2006 Metering Code. Of those, 334,773 metering points had a recording load profile measurement. In total, 44,766,515 metering points are considered household customers as defined in section 3 no 22 of the EnWG; of these, 35,517,935 (79.3 percent) are supplied by the respective default supplier as defined in section 36(2) of the EnWG.

In the area of electricity wholesalers and suppliers, 923 companies took part in the Bundesnetzagentur's 2012 monitoring activities. Of these, 562 companies are active only as wholesalers who do not supply final consumers, while 846 are active as suppliers. In 2011, the suppliers reported a delivery volume to final consumers totalling 455.6 TWh.

The figures in the following table represent the electricity offtake volume of final consumers in the network areas of surveyed TSOs and DSOs, as well as the delivery volume of the surveyed suppliers, for 2011. Also listed in the table is the respective percentage of the individual categories for the overall offtake and delivery volume to final consumers.

2011				
Category	**Electricity offtake volume TSOs/DSOs in TWh**	**Share of total amount in percent**	**Volumes delivered by suppliers in TWh**	**Share of total amount in percent**
≤ 10 MWh/year	125.6	25.4	128.7	28.3
> 10 MWh/year ≤2 GWh/year	132.7	26.8	105.9	23.4
> 2GWh/year	236.2	47.8	219.3	48.3
Total amount	**494.5**	**100**	**453.9**	**100**

Table 2: Total sum of offtake-volumes by final customers in different consumption categories according to TSOs and DSOs answers

Despite a relatively low number of large industrial customers, these customers account for approximately 47.8 percent of the electricity market in terms of volume. Smaller industrial and business customers make up a volume-based share of approximately 26.8 percent. Domestic customers, who make up the largest category in terms of numbers, account for a share of approximately 25.4 percent of the electricity market.

The structure outlined above still includes business areas for green electricity, as well as for heat storage electricity and heat pump electricity. In the year under review, 5,544,571 final consumers were supplied with green electricity, and 1,963,599 with heat storage and heat pump electricity. The delivery volume for green electricity amounted to 33.6 TWh, while for heat storage and heat pump electricity it was 13.2 TWh.

Shares of the major companies (dominance method)

Using the dominance method, four companies (E.ON, RWE, Vattenfall, EnBW) in Germany accounted for a volume-based share of at least five percent in the total volume supplied in 2011. After last year's reduction by nearly four percentage points, the share of the four largest suppliers in 2011 has again fallen by nearly two percent. In 2011, the four largest suppliers reported an electricity delivery volume to final consumers in Germany totalling 208.9 TWh. This corresponds to a share of approximately 42 percent of the overall electricity offtake, totalling 494.5 TWh, from general supply networks. For this purpose, the dominance method was applied to allocate delivery volumes of the dominated (consolidated) company to the dominant company (based on shareholding status at the time of reporting).

2011			
Category	Electricity offtake volumes of TSOs/DSOs in TWh	Volumes supplied by the four largest companies in TWh	Share of total amount in percent
≤ 10 MWh/year	125.6	59.5	47
> 10 MWh/year ≤2 GWh/year	132.7	36.3	27
> 2GWh/year	236.2	113.1	48
Total amount	**494.5**	**208.9**	**42**

Table 2: Shares (reference value) of the four largest companies according to customer categories (final consumers), using the dominance method, for 2011

Generation / Security of supply

Generation

Existing capacity and structure of the generation sector

With the amendment of the Energy Act (EnWG), the Bundesnetzagentur, under section 35(1) subpara 12 of the EnWG, received the mandate to carry out a monitoring survey of the existing capacity, including the commissioning or decommissioning of generating facilities, and electricity storage systems with a capacity exceeding 10 MW. Since then, the Bundesnetzagentur has published on its website (www.bundesnetzagentur.de) an overview of generation capacities, updated each month, containing the key data (including location, energy source, capacity, network connection). Besides the separate listing of installations with a capacity of 10 MW and up, renewable energy sources are documented in detail by federal state and energy source, based on data reported by transmission system operators as well as on Bundesnetzagentur data.

The published list of power plants also includes summarised information according to energy source, operational status of power plant, federal state as well as renewable energy source. Also included on the list are an overview of the new power plants with non-intermittent capacity that are currently under construction, as well as plants that operators have scheduled for permanent decommissioning in the respective timeframe.

In the area of power generation, the year 2011 was characterised by a significant decrease in non-intermittent generation capacity, resulting from the permanent decommissioning of eight nuclear power plants pursuant to the amended Atomic Energy Act. Intermittent generation capacity (solar power, wind power and hydro power), on the other hand, continued to grow, primarily as a result of a continued increase in the number of photovoltaic systems. As a result of this development, the share of renewable energy sources in the total energy generation mix increased from approximately 34 percent (as of 31 December 2010) to approx. 41 percent in July 2012.

At a current level of 30.5 GW, solar radiation energy is the energy source with the highest amount of installed capacity, followed by wind power at 29.4 GW. That puts the two renewable energy sources sun and wind well ahead of the non-renewable energy source of hard coal, which makes up the third-highest installed capacity per energy source, at 20.5 GW.

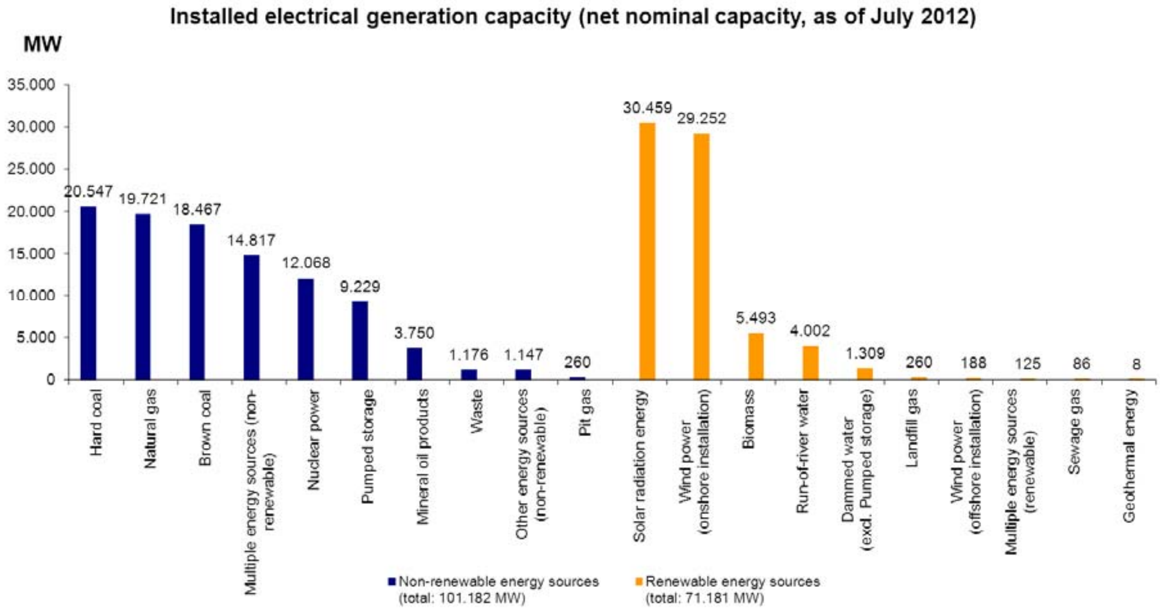

Figure 1: Installed electrical generation capacity (net nominal capacity, as of July 2012)

The total installed generation capacity connected to the German power grid, according to the Bundesnetzagentur’s list of power plants, is 172.4 GW,[3] 71.2 GW of which is accounted for by renewable energy sources. A total of 67.5 GW of generation capacity is eligible for remuneration pursuant to the Renewable Energy Sources Act (EEG).

[3] Systems smaller than 10 MW that do not receive remuneration under the EEG have so far not been registered. A respective adjustment of the 2013 monitoring survey with regard to generation capacity is planned so that aggregate figures can be incorporated into the list of power plants.

Of the total of 172.4 GW, 2.7 GW of non-intermittent generation capacity is currently in cold reserve status, and can thus become operational within a period of six months. Cold reserve capacity is located almost exclusively to the north of Frankfurt/Main and could thus not make a positive contribution to improving the tense supply situation in the southern German region.

Accounting for 35.4 GW of a total of 107.2 GW, North-Rhine Westphalia is the federal state with the majority of power plants based on non-intermittent energy sources (ie all energy sources except for the volatile renewable energy sources sun, wind and water), which are significant for ensuring security of supply. Following at a considerable distance are the federal states of Bavaria (accounting for 13.3 GW), Baden-Württemberg (11.4 GW) and Lower Saxony (10.4 GW).

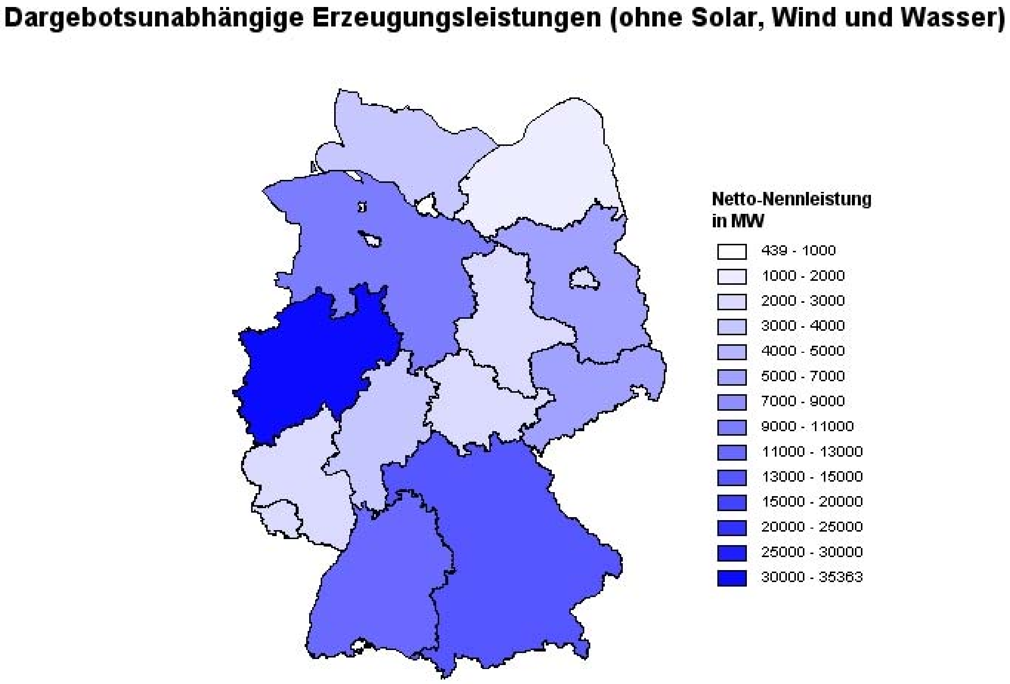

Figure 2: Non-intermittent generation capacity (without solar, wind and hydro power) by federal state (net nominal capacity in MW, as of July 2012)

A regional analysis of intermittent generation capacity (solar, wind and hydro power) identifies two major centres: Bavaria, with 11.7 GW, and Lower Saxony, with 10.2 GW, are the federal states with the highest intermittent generation capacity. As the detailed look at the energy sources solar and wind power shows, the figure for Bavaria is based primarily on solar power (9.1 GW), while that for Lower Saxony is based primarily on wind power (7.3 GW).

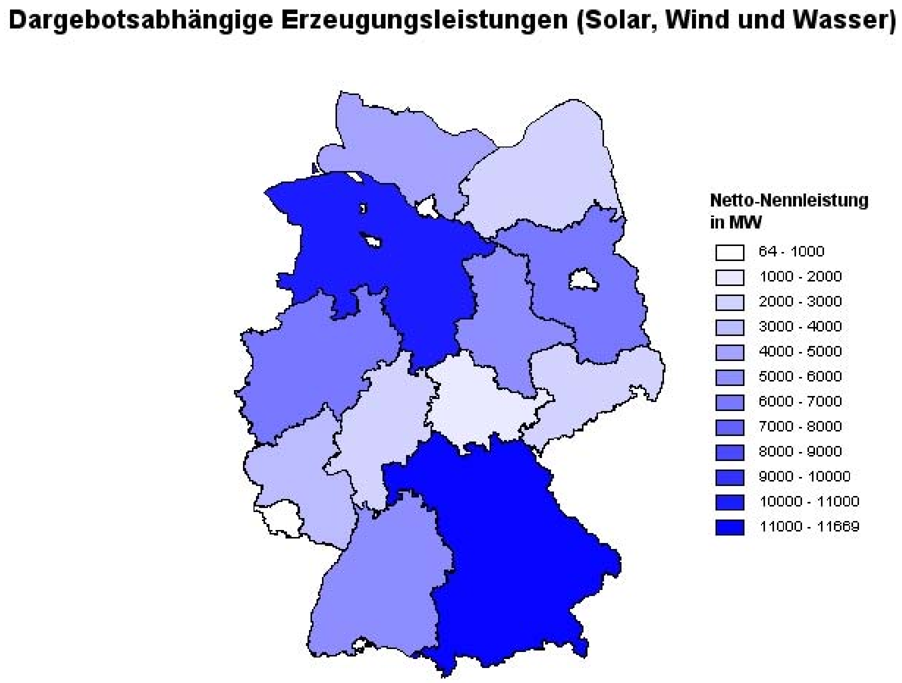

Figure 3: Intermittent generation capacity (solar, wind and hydro power) by federal state (net nominal capacity in MW, as of July 2012)

The generating capacity based on solar power, which amounts nationwide to 30.5 GW, is located primarily in the southern federal states of Bavaria (9.1 GW) and Baden-Württemberg (4.1 GW), followed by North-Rhine Westphalia, with 3.4 GW of solar power capacity.

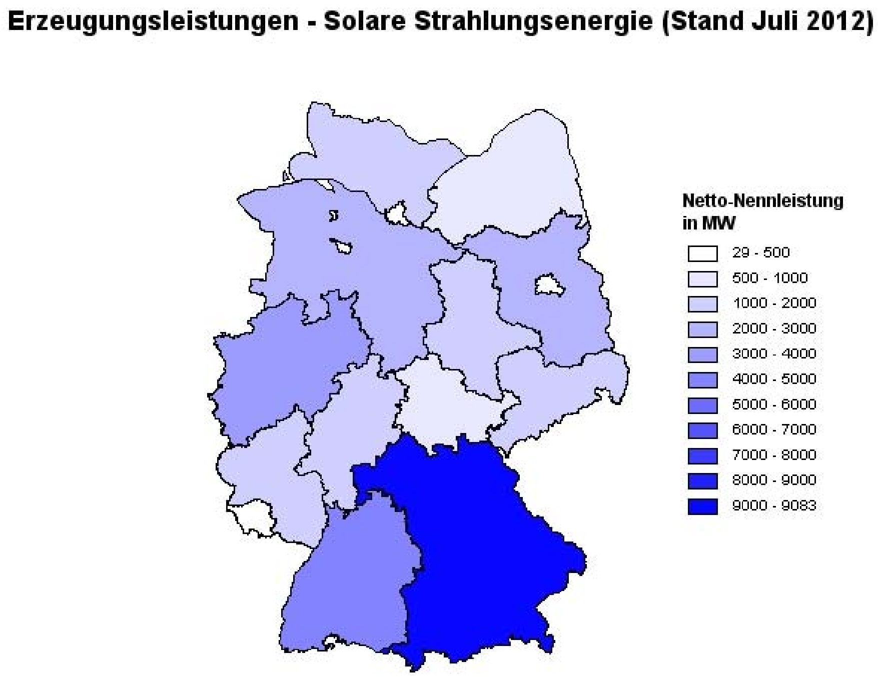

Figure 4: Generation capacity – Solar radiation energy by federal state (net nominal capacity in MW)

The installed capacity for wind power, by contrast, is located largely in the northern and eastern parts of Germany, with Lower Saxony as the federal state with the highest installed wind power capacity (7.3 GW), followed by Brandenburg (4.6 GW) and Saxony-Anhalt (3.8 GW).

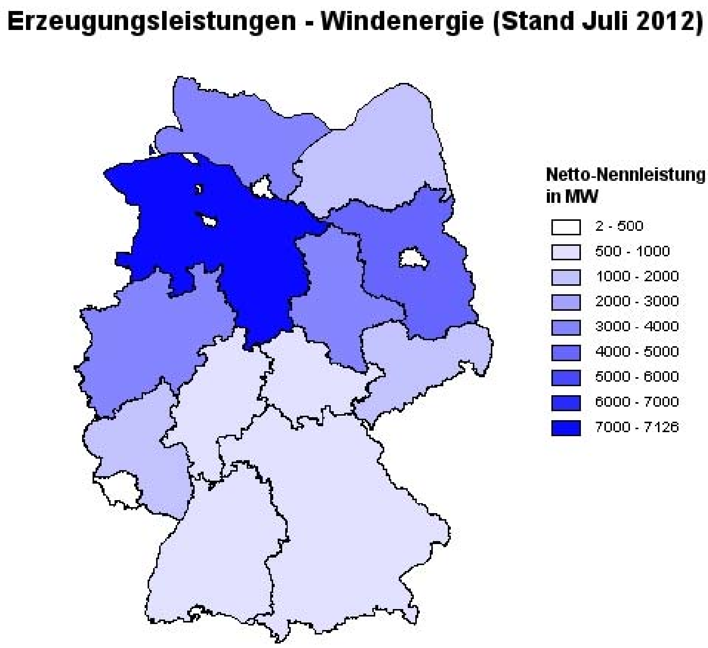

Figure 5: Generation capacity – wind power by federal state (net nominal capacity in MW, as of July 2012)

The total amount of power generated in 2011 by the installations included in the Bundesnetzagentur's power plant list was 551.4 TWh.[4] Of that amount, 115.2 TWh or 20.9% was generated by installations powered by renewable energy sources. For 91.2 TWh remuneration under the EEG was paid in 2011.

[4] Systems smaller than 10 MW that do not receive remuneration under the EEG have so far not been registered. A respective adjustment of the 2013 monitoring survey with regard to generation capacity is planned so that aggregate figures can be incorporated into the list of power plants.

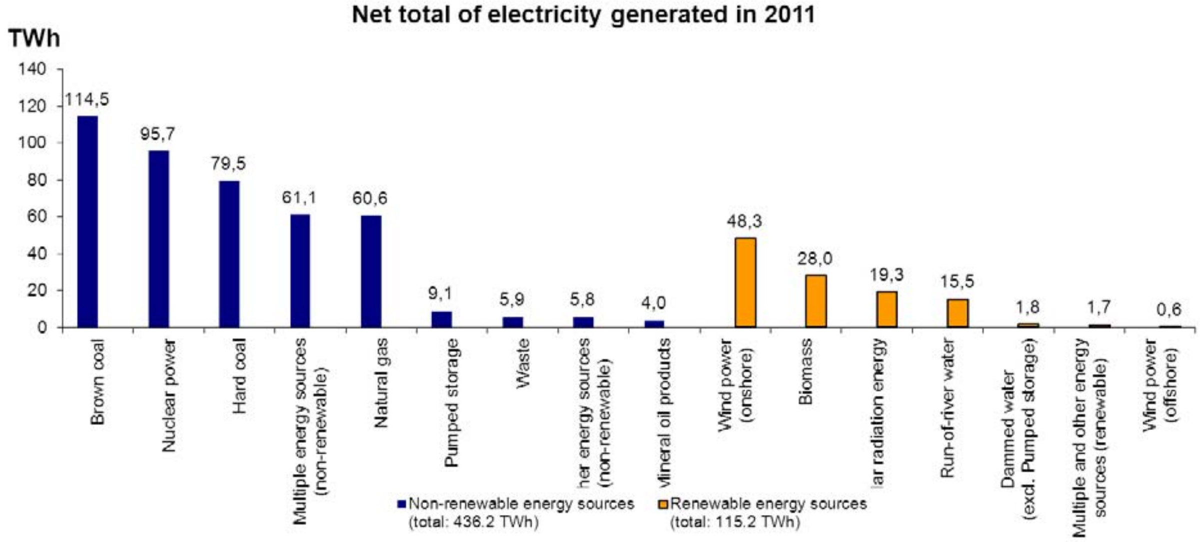

Figure 6: Net total of electricity generated in 2011

As of 31 December 2011, the electricity generating companies included in the 2012 monitoring survey accounted for a net nominal capacity of 104.0 GW in Germany that does not receive remuneration under the EEG. In terms of the recorded capacity of 104.0 GW (without EEG) in the market-based generation sector in Germany, the share of the four largest generating companies (E.ON, EnBW, RWE and Vattenfall), calculated using the dominance method, totalled approximately 73.6 percent as of 31 December 2011 (76.5 GW). Electricity feed-in which is eligible for tariff payments under the EEG is not taken into account here as it is not part of the market-based generation market.

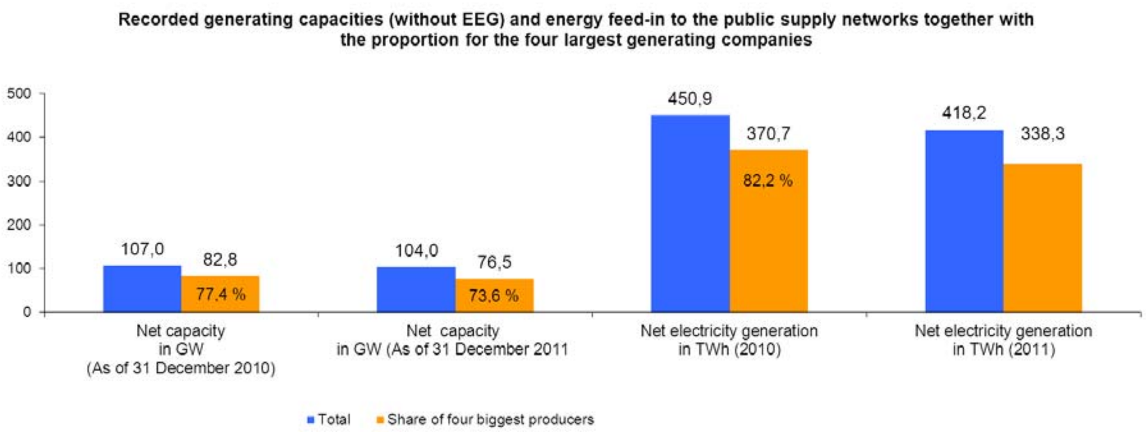

Figure 7: Recorded generation capacity (without EEG) and electricity fed into generalsupply networks, with shares of four largest generating companies in Germany

In particular as a result of the permanent decommissioning of eight nuclear power plants pursuant to the Atomic Energy Act, the net capacity of the four largest power producers in Germany dropped from 82.8 GW (31 December 2010) to 76.5 GW as of 31 December 2011.

In 2011, the volume of energy fed into general supply networks amounted to 418.2 TWh (without EEG). Here, the share of the four largest electricity producing companies in the market driven generation sector was at 338.3 TWh (80.9 percent). While the percentage of the four largest producers' capacity fell by 3.8 percent, their share in the volume of electricity fed into the grid only fell by 1.4 percentage points.

Expected growth and decline in generation capacity

Against the background of the current developments regarding the energy mix, with a steadily increasing proportion of volatile energy sources, the building of non-intermittent power plants in particular in southern Germany is of particular significance for the system security of the electricity supply.

The nationwide planning data from power plant operators show a net growth of approximately 4.0 GW to the year 2015. Compared to the 2011 monitoring survey, however, the growth figures have declined. One key reason behind this decline can be found in the power plant operators' plans for an earlier permanent decommissioning of generation installations due to insufficient profitability.

Moreover, an analysis of the power plant projects currently under construction indicates that the start of operations for 5 power plants, with a total capacity of approximately 3.5 GW, will be delayed by one year relative to the 2011 monitoring survey. A positive development, however, is the commencement of construction of approximately 0.6 GW more non-intermittent capacity than was included in the 2011 monitoring survey.

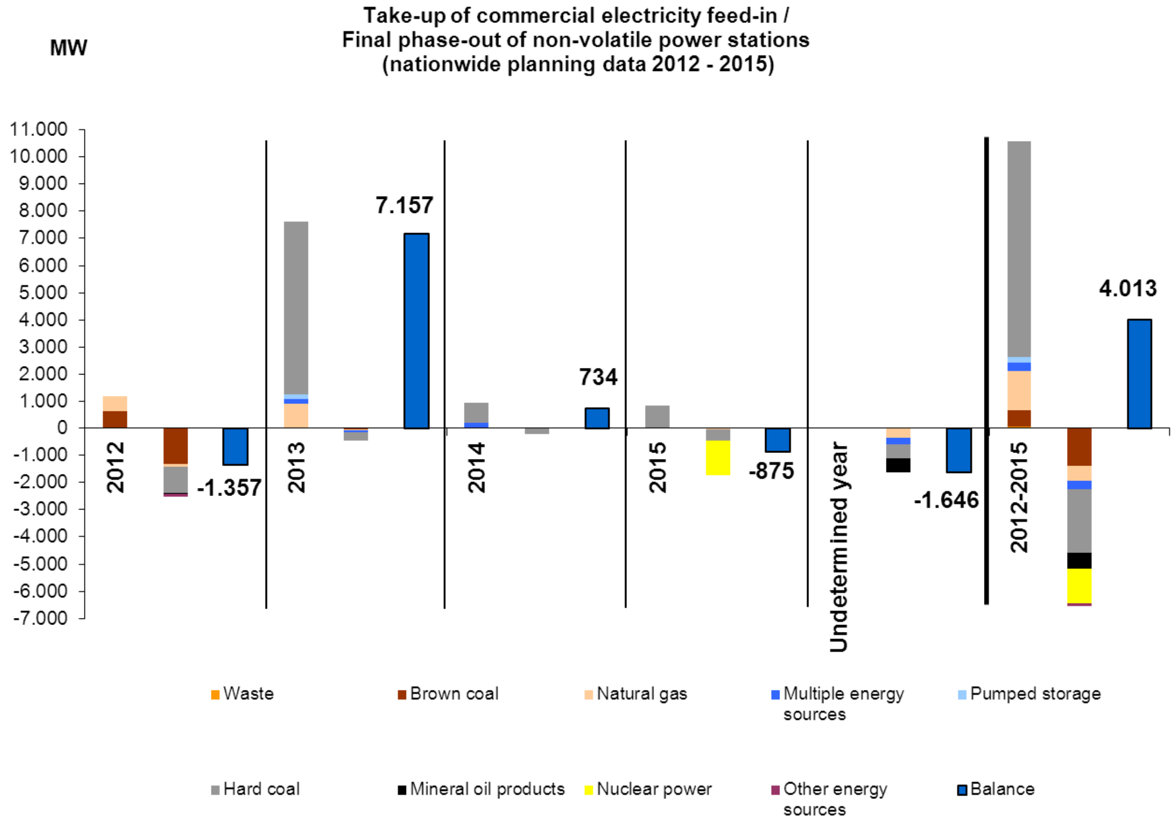

Figure 8: Commencement of commercial electricity feed-in / Permanent shut-down of non-intermittent power plants (nationwide planning data 2012 – 2015 for net nominal capacity, as of September 2012)

Net-nominal capacity in MW	In-crease	De-crease	In-crease	De-crease	In-crease	De-crease	In-crease	De-crease	In-crease	De-crease	Total
Energy source.	**2012**		**2013**		**2014**		**2015**		**Undeter-mined year**		
Waste	13	-8	26	0	0	0	0	0	0	0	31
Brown coal	640	-1,306	0	-60	0	0	0	0	0	0	-726
Natural gas	523	-125	884	-37	10	-13	8	-45	0	-353	852
Nuclear power	0	0	0	0	0	0	0	-1,275	0	0	-1,275
Mineral oil products	0	-30	0	0	0	0	0	0	0	-543	-573
Pumped storage	0	0	195	0	0	0	0	0	0	0	195
Hard coal	0	-954	6.343	-304	760	-186	843	-406	0	-494	5,602
Multiple energy sources	0	0	160	-50	169	-6	0	0	0	-256	17
Other ener-gy sources	0	-110	0	0	0	0	0	0	0	0	-110
Total	**1,176**	**-2,533**	**7,608**	**-451**	**939**	**-205**	**851**	**-1,726**	**0**	**-1,646**	**4,013**
Balance	**0**	**-1,357**	**7,157**	**0**	**734**	**0**	**0**	**-875**	**0**	**-1,646**	**4,013**

Tabelle 4: Aufnahme kommerzielle Stromeinspeisung / Endgültige Aufgabe von dargebotsunabhängigen Kraftwerken 2012 – 2015 (Bundesweite Plandaten für Netto-Nennleistungen, Stand: September 2012)

Power plant operators' planning data show an expected decline of up to 1.7 GW in the increase/decrease balance of non-intermittent generation capacity for southern Germany to the year 2015. By contrast, the 2011 monitoring survey showed an increase of 1.3 GW between 2012 and 2014 for power plants located in the region south of Frankfurt/Main. This negative development is primarily the result of plans by power plant operators for early decommissioning of generation installations due to insufficient profitability; the planned power plant closures are almost exclusively located in southern Germany.

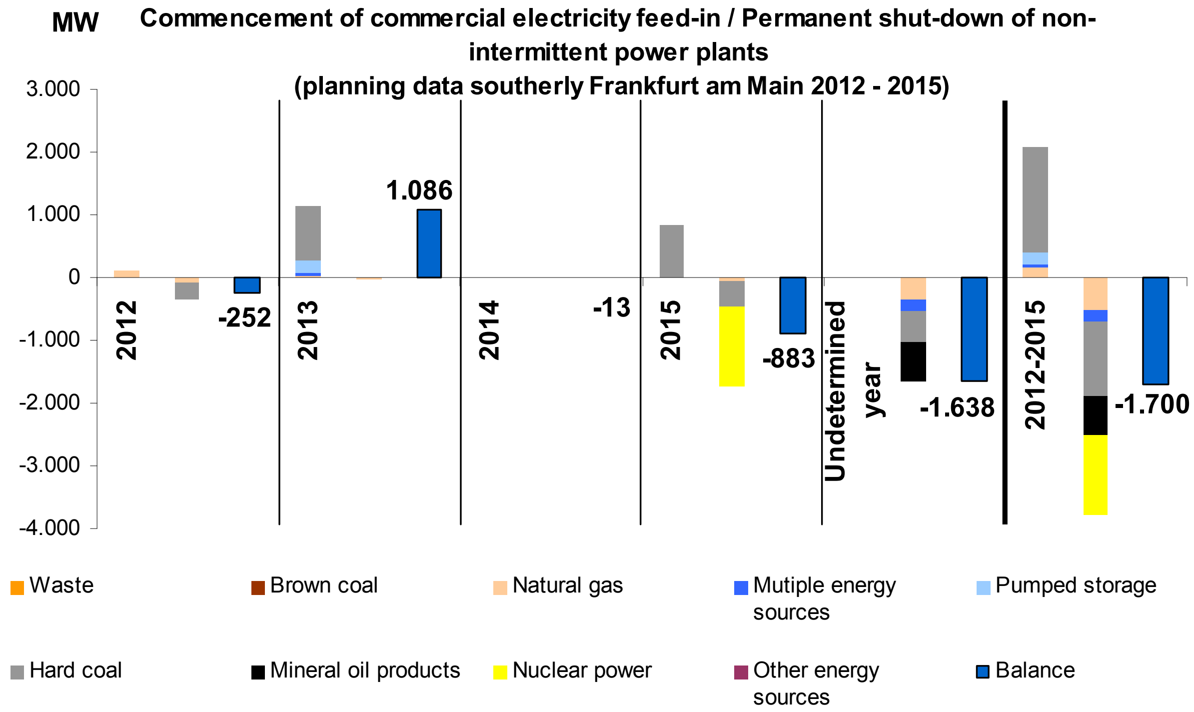

Figure 9: Commencement of commercial electricity feed-in / Permanent shut-down of non-intermittent power plants 2012 – 2015 (planning data for power plants Frankfurt/Main and southwards 2012 - 2015, net nominal capacity in MW, as of September 2012)

Net-nominal ca-pacity in MW	In-crease	De-crease	In-crease	De-crease	In-crease	De-crease	In-crease	De-crease	In-crease	De-crease	Total
Energy source	**2012**		**2013**		**2014**		**2015**		**Undeter-mined year**		
Waste	13	-8	0	0	0	0	0	0	0	0	5
Brown coal	0	0	0	0	0	0	0	0	0	0	0
Natural gas	97	-61	39	-37	0	-13	0	-45	8	-353	-365
Nuclear power	0	0	0	0	0	0	0	-1,275	0	0	-1,275
Mineral oil products	0	0	0	0	0	0	0	0	0	-629	-629
Pumped sto-rage	0	0	195	0	0	0	0	0	0	0	195
Hard coal	0	-293	842	0	0	0	843	-406	0	-476	510
Multiple energy sources	0	0	47	0	0	0	0	0	0	-188	-141
Other energy sources	0	0	0	0	0	0	0	0	0	0	0
Total	**110**	**-362**	**1,123**	**-37**	**0**	**-13**	**843**	**-1,726**	**8**	**-1,646**	**-1,700**
Balance	**0**	**-252**	**1,086**	**0**	**0**	**-13**	**0**	**-883**	**0**	**-1,638**	**-1,700**

Table 5: Commencement of commercial electricity feed-in / Permanent shut-down of non-intermittent power plants 2012 – 2015 (planning data for power plants Frankfurt/Main and southwards 2012 – 2015 for net nominal capacity in MW, as of September 2012)

Development of the generation of electricity eligible for remuneration in accordance with the EEG

Within the framework of its mandate pursuant to the Renewable Energy Sources Act (EEG), the Bundesnetzagentur collects data every year from approximately 900 distribution system operators (DSOs), the four transmission system operators (TSOs) and approximately 1200 electricity suppliers. The EEG accounting data provided by these companies for the year 2011 constituted the basis for the 2012 Monitoring Report.

At the time of the compiling of the 2012 Monitoring Report, the collection and evaluation of the 2011 data on renewables by the Bundesnetzagentur were not yet fully concluded. It was only possible to begin full data evaluation after reporting by the respective TSOs, which were required to meet the deadline of 31 July 2012. Therefore, with regard to the installed capacity of the various renewable energy sources, the figures for the accounting year 2011 have only a preliminary character. In contrast to the TSOs' 2011 figures for the annual energy feed-in from renewables and the minimum remuneration paid to system operators, submitted to the Bundesnetzagentur in the TSOs' final annual account and underlying this report, the value for the installed renewables capacity does not need to be certified. The Bundesnetzagentur must first use a complex method to calculate this information using the available individual figures.

Detailed findings of the 2010 final annual account, including in-depth representations by federal state, can be found in the Bundesnetzagentur's EEG report at: http://www.bundesnetzagentur.de/cln_1911/DE/Sachgebiete/ElektrizitaetGas/ErneuerbareEnergienGesetz/VeroeffentlichungZahlenEEG_Basepage.html?nn=135464.

As of 31 December 2011, the total installed capacity of installations eligible for remuneration under the EEG in Germany amounted to approximately 60.5 GW (31 December 2010: approximately 51.4 GW). That constitutes an increase of approximately 9.1 GW for the installed capacity of all installations eligible for remuneration under the EEG in 2011, or a relative growth rate of around 18 percent within one year.

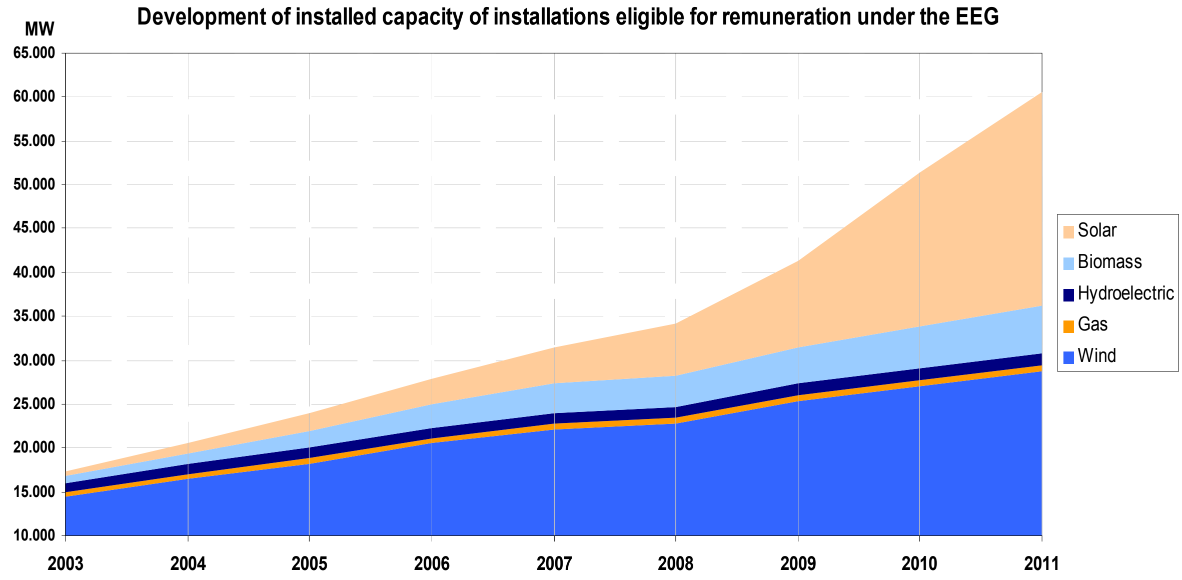

Figure 10: Development of installed capacity of installations eligible for remuneration under the EEG from 2003 to 2011

	Hydro power	Gas	Biomass	Geothermal power	Wind power	Solar energy	Total
Total in 2011	**1,384**	**606**	**5,454**	**8**	**28,807**	**24,279**	**60,538**
Total in 2010	**1,417**	**629**	**4,685**	**8**	**27,071**	**17,554**	**51,364**
Increase/decrease in comparison to 2010	**-2.3 %**	**-3.7 %**	**16.4 %**	**0.0 %**	**6.4 %**	**38.3 %**	**17.9 %**

Table 6: Installed capacity, in MW, of installations eligible for remuneration under the EEG (31 December 2011) by energy source

In 2011 there was another sharp increase in the installed capacity of solar PV installations. According to data supplied by network operators, systems with a total capacity of approximately 6.7 GW (2010: approx. 7.0 GW) were newly installed,[5] which amounts to an increase of around 38 percent for PV installations in the year 2011. The installed capacity of wind power installations increased in 2011 by approximately 1.7 GW, which amounts to a six percent rate of increase. The capacity of biomass installations increased by 0.8 GW, or an increase of

[5] Note: In conjunction with reporting of photovoltaic systems pursuant to section 17(2) para 1a EEG, the Bundesnetzagentur in the year 2011 received reports of a total solar PV capacity of approximately 7.5 GW. The deviation from the preliminary data of network operators (6.7 GW of new PV systems) thus amounts to approximately 0.8 GW. From the Bundesnetzagentur's standpoint, the reason for the discrepancy between these preliminary reports by the network operators and the figures established by the Bundesnetzagentur is primarily a sometimes significant time lag between the data submission of the DSOs to the TSOs, in particular with regard to the reporting of solar PV installations. Especially in the period just before significant cuts in support rates for photovoltaic systems come into effect, there is normally a boom in the building of new systems. Many DSOs therefore, for logistical and organisational reasons, tend to significantly delay the submission of the required report to the TSOs. This means that the data of the TSOs regarding the installed capacity of the different renewable energy sources for the previously reported year must be retroactively adjusted. Furthermore, the comparability of the network operators' data on the currently installed solar PV capacity and the Bundesnetzagentur's data from the PV reporting procedure is flawed by virtue of definition. While for the network operators' information, the key date is that of the system's start of operations, the key date for the Bundesnetzagentur's information is the date of submission of the notification. For reasons of better comparability with information from previous Monitoring Reports, the network operators' data will hereafter serve as reference point.

16.4 percent. The installed capacity of the remaining renewable energy sources was similar to that of the previous year. Electricity generated by system operators using regenerative technologies, when it is fed into the public electricity grid, receives remuneration from the DSO according to a tariff that is defined by law and differs according to energy source.

The following table Annual energy feed-in during 2011 and minimum amount paid to installation operators according to energy source shows the change relative to the year 2010.

Energy source	Total 2011		Change relative to 2010 in percent
Hydropower	GWh	2,397	-52.5
	million €	231	-45.1
Biomass	GWh	23,374	-7.0
	million €	4,476	5.6
Gas6	GWh	487	-58.0
	million €	36	-56.6
Geothermal	GWh	19	-32.1
	million €	4	-33.3
Wind power	GWh	45,611	21.2
	million €	4,250	27.2
Solar energy	GWh	19,339	65.5
	million €	7,766	52.6
Total	**GWh**	**91,227**	**13.0**
	million €	**16,763**	**27.2**

Table 7: Total energy feed-in remunerated under the EEG and minimum amount paid out to the installation operators by energy source in 2011

According to the collected data on renewables and the TSOs' certified final financial statement for renewables, which is available to the Bundesnetzagentur, the total annual energy feed-in in 2011 amounted to 91,227 GWh (2010: 80,700 GWh), and the minimum amount paid out to the installation operators totalled €16,763m (2010: €13,182m). This means that the feed-in from all EEG installations increased from 2010 to 2011 by approximately 13 percent, while the overall amount of remuneration increased by approximately 27 percent.

6 Sewage gas, landfill and pit gas

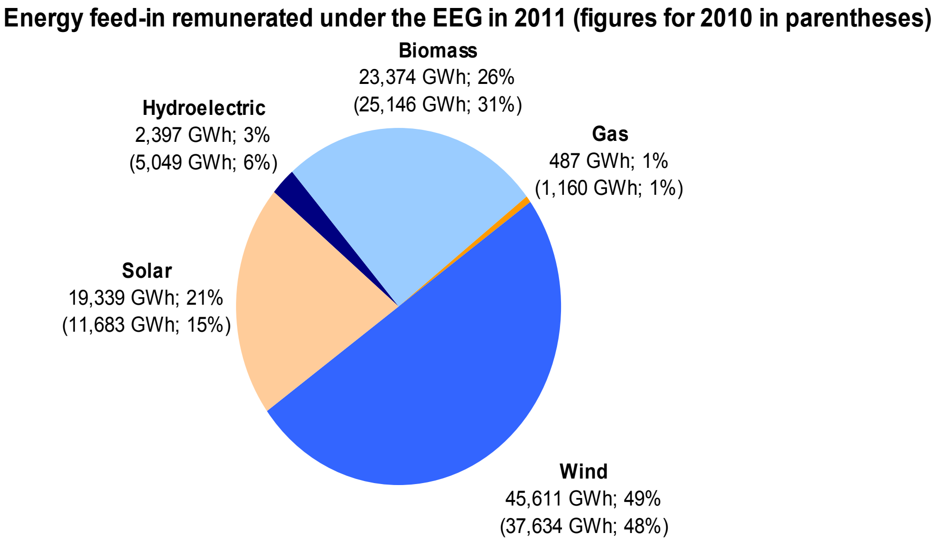

Figure 11: Total energy feed-in remunerated under the EEG in 2011 by energy source, absolute and proportional (figures for 2010 in parentheses). Due to the small amount, the category "geothermal energy" was not included.

As in previous years, the development of feed-in levels in comparison with 2010 figures differs considerably from one energy source to another. The feed-in from wind power installations in 2011 was 21 percent higher than in the low-wind year of 2010. Accordingly, there was a sharp increase in the volume of minimum remuneration that had to be paid by network operators. In addition to the approx. 45,611 GWh of energy feed-in from wind remunerated according to the EEG, approximately 3,272 GWh of wind power that was marketed directly and therefore did not receive remuneration under the EEG must also be taken into account.

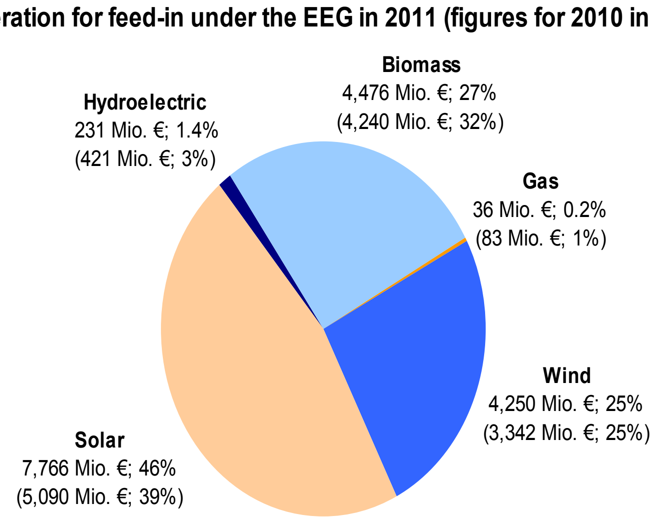

Figure 12: Remuneration for feed-in under the EEG in 2011 according to energy source, absolute and proportional (figures for 2010 in parentheses). Due to the small amount, the category "geothermal energy" was not included.

As a result of the above-described significant expansion of solar power installations in 2011, there was another sharp increase, relative to 2010, in both the annual energy feed-in, with an absolute value of 19,339 GWh (2010: 11,683 GWh) and the amount of remuneration paid, with an absolute value of €7,766m (2010: €5,090m). On the whole, however, solar power installations have only a share of approximately 21 percent of the entire volume of electricity remunerated according to the EEG in 2011. In relation to total sales to final consumers in the year 2011, that corresponds to a share of 4.2 percent, or an increase of 1.8 percentage points compared to the year 2010. With a share of 46 percent, solar power accounts for by far the largest portion of EEG remuneration payments. The remuneration payments are granted for the year in which the system goes operational and for subsequent 20 years. The amount of remuneration during this period of time remains constant. Regardless of the future development in terms of the expansion of solar power installations and the recently adopted significant cuts in the remuneration rates for solar power installations, the remuneration to be paid to the operators of those installations will, also in the years to come, remain at a very high level.

Direct selling of electricity generated from renewable energy sources

As an alternative to the system of fixed EEG remuneration, system operators also have the option of selling the electricity they generate on their own in accordance with section 17 of the EEG. Up to and including the year 2009, only few system operators had decided to pursue this option. 2010 saw a small increase in the number of operators pursuing this option. In 2011, the year under review, significantly more system operators chose the direct sales route, with the result that the volume of renewable energy sold directly increased more than sevenfold compared to 2010, to approximately 11,650 GWh (2010: 1,587 GWh). This means that in 2011, slightly more than 11 percent of the overall volume of EEG electricity was sold via direct sales. The dominant energy source in the area of direct selling in the year 2011 was biomass, making up a share of nearly 40 percent. A large share was also accounted for by wind power (approximately 28 percent) and hydropower (21 percent).

Energy source	Volume of electricity sold directly, in GWh	Share per energy source of total direct selling, in percent
Biomass	4,603	39.51
Wind power onshore	3,272	28.09
Hydro power	2,446	21.00
Landfill, sewage and pit gas	1,328	11.40
Solar energy	1	0.01
Geothermal energy	0	0
Total	**11,650**	100

Table 8: Volume of electricity sold directly in accordance with section 17 of the EEG in the year 2011

The reason for the increase can be found in the interplay between direct sales in accordance with section 17 of the EEG and the so-called green electricity privilege in accordance with section 37(1) of the EEG. System operators who choose to pursue direct selling channels mostly enter into an agreement with traders who utilise this electricity, which in principle is eligible for EEG remuneration, to fulfil the criteria of the green electricity privilege. In 2011, the appeal of the green electricity privilege was significantly boosted as a business model and became very attractive in terms of a direct selling option. Since then, the federal legislator has responded and significantly tightened the requirements for fulfilling the green electricity privilege. For the year 2012, a marked decline in this form of direct selling is thus to be expected.

Assessment of security of supply

Security of supply

On 14 March 2011, following the nuclear catastrophe in the Japanese nuclear power plant Fukushima I, the federal government passed a three-month nuclear moratorium that led to the decommissioning of the eight oldest German nuclear power plants, initially on a preliminary basis. This resulted in the elimination of nearly 5,000 MW of secured generation capacity in the southern German region alone. Against this background, the Bundesnetzagentur, together with the German transmission system operators, analysed the effects of the moratorium on the security and reliability of the German system of electricity supply. In the assumed case of a simultaneous failure of key network equipment and of a major power plant, particular problems will be posed by the potential overloading of individual transmission routes and by voltage control (avoidance of undervoltage) in the southern German region as well as in the Hamburg area. Through the amendment of the Atomic Energy Act it was decided to revoke the operating licences for the eight oldest nuclear power plants; however, the Bundesnetzagentur had until 31 August 2011 to determine whether one of the decommissioned nuclear power plants should be designated as a so-called cold reserve power plant in order to ensure security of supply. Further in-depth examinations established that, even in the event of the above-described disturbances, system security in the transmission network would still be guaranteed – with a variety of measures taken into account – and the utilisation of nuclear cold reserve capacity could be avoided. The Bundesnetzagentur, on 31 August 2011, published details of its assessments and the measures that had to be taken for winter 2011/2012 in its *Report on the impact of the nuclear power exit on the transmission networks and security of supply*.

It must be pointed out that secure operations in the transmission system were ensured by making conventional power plants available to the TSOs between October 2011 and March 2012 as so-called reserve power plants for the purpose of relieving strained power lines. Utilising the "reserve capacity" of these power plants makes it possible for the TSOs to resolve any transport congestion that may occur on individual power lines within the transmission system. By calling up these reserve power plants for redispatch measures, ie a short-term change in a power plant's dispatch schedule by the TSO, planned feed-in from power plants can be shifted within the network in order to prevent excessive load on local power line sections. However, the only installations that can be used as "reserve power plants" are those which are no longer used to produce electricity for the market, but which are available to the TSO for redispatch measures only.

The Bundesnetzagentur supervised the process of selecting suitable operators of reserve power plants and determining which and to what extent costs incurred by operators for making their power plants available can be recognised. Based on the individual contracts, a voluntary reserve power plant commitment (*FSV Reservekraftwerk*) was agreed upon, which enables costs to be recovered through the TSOs' revenue caps.

For the purpose of maintaining network stability in the southern German region, the *FSV Reservekraftwerk* was used to implement, from Germany, block 3 of the large-scale power plant Mannheim AG (200 MW) and block 2 of the power plants Mainz-Wiesbaden AG (350 MW) into the revenue caps of the responsible transmission system operators. From Austria the power plant block Theiß Kombi (450 MW) and other blocks from the power plants Theiß and Korneuburg (totalling 335 MW) from Energieversorgung Niederösterreich AG (EVN AG) were contractually guaranteed. In addition, block 2 of the power plant Neudorf-Werndorf (150 MW) was contracted from Verbund AG. For resolving voltage control problems in the Frankfurt region, the voluntary reserve power plant commitment enabled, by way of network tariffs, the refinancing of the phase shifter that began operations in February 2012. For this purpose, the generator in block A of the Biblis power plant was converted for phase-shift operations.

By way of the *FSV Reservekraftwerk*, the Bundesnetzagentur's competent ruling chamber implemented the measures outlined here and analysed in detail in the network report of 31 August 2011 into the revenue caps of the responsible transmission system operators. This also includes an ex-post cost control.

On 8 and 9 December 2011, reserve capacity was actually called up by a TSO in order to alleviate power line load. At that point in time, the nuclear power plant Gundremmingen C was not available for feed-in, which meant that the redispatch potential in southern Germany was significantly limited. Additionally, a major wind front brought about a particularly high amount of energy feed-in, amounting to more than 19,000 MW, from wind power installations, which coincided with a high network load (a mid-week winter evening). In order to eliminate the resulting power line strain on the north-south transmission route, it was necessary to utilise Austrian reserve power plants for redispatch purposes. In that situation it was possible to test the reserve power plants' effectiveness with regard to maintaining security of supply, which had previously only been calculated in theory. Additionally, the conversion of the generator in block 1 of the Biblis nuclear power plant to a rotating phase-shifter made a significant contribution to maintaining voltage.

An additional critical period for security of supply occurred between Christmas 2011 and New Year's Eve 2011/2012. During this period, the balancing groups experienced significant surplus supplies in which more electricity was produced than was consumed. In the process, the available negative system balancing energy was temporarily exhausted, so that an increase in the power-line frequency could be observed throughout the entire continental European interconnected system. This was not, however, a purely German, but rather a European incident. There was no connection to the exit from nuclear energy.

In February 2012, in the midst of a cold spell, two potentially critically situations occurred simultaneously. On the one hand, due to congestion in the gas network, not all German gas-fired power plants could be sufficiently supplied with gas; on the other hand, there was a temporary major deficit supply of balancing groups. Within hours, the deficit supply led to the complete exhaustion of system balancing energy reserves and even significantly exceeded, for a short period, the available capacity. In order to ensure security of supply, the transmission system operators were forced to rely on reserve power plants in order to supplement system balancing energy, and also had to procure additional energy on the intraday market in Germany and in neighbouring countries. In this situation, the failure of one additional large power plant would have been very difficult to compensate for. Due to the shutdown of gas-fired power plants in particular in southern Germany as well as the high network load and significant energy exports to France, Austria and Switzerland, there was a substantial strain on the network, which endangered the so-called (n-1) security within hours. The Bundesnetzagentur published an in-depth analysis of this situation in its *Report on Energy Supplies in Winter 2011/12* of 3 May 2012.

The Bundesnetzagentur is currently going forward with additional measures, as proposed in the report of 3 May 2012, for providing support for network security during the coming winter 2012/2013.

The continuing tense network situation in southern Germany, seen in particular against the background of security of supply in winter 2012/2013, underlines the need to recalculate the required reserve capacity which is made available to transmission system operators by way of designated reserve power plants. It was determined that up to 2,500 MW is needed so that under certain circumstances in which network critical events come about, network stability and the security of the electricity supply can be maintained. This requirement was calculated for a scenario in which high feed-in of wind power is assumed, occurring in combination with the typically high consumption load on a mid-week evening and the simultaneous non-availability of several power plants throughout the country due to overhauls or technical malfunctions. The availability of 2,600 MW of reserve capacity is sufficient to compensate for the calculated amount of 2,500 MW.

Duties to report supply disruptions under section 52 EnWG

Operators of energy supply networks are now required, under section 52 of the EnWG, to submit to the Bundesnetzagentur by 30 April of each year, a report detailing all interruptions of supply that took place in their networks during the previous calendar year. The report contains information regarding the point in time, duration, scope and cause of every supply interruption that lasts longer than three minutes. Furthermore, the network operator must provide information on measures to be taken in order to avoid interruptions of supply in the future.

For 2011, 864 network operators reported on approximately 206,673 interruptions of supply for 928 networks for the calculation of the System Average Interruption Duration Index (SAIDI) for final consumers. The figure of 15.31 minutes calculated for the low voltage and medium voltage range is slightly above the figure of 14.90 minutes for the year 2010 and – as the following diagram shows – significantly below the average of 17.44 minutes calculated for the period between 2006 and 2010.

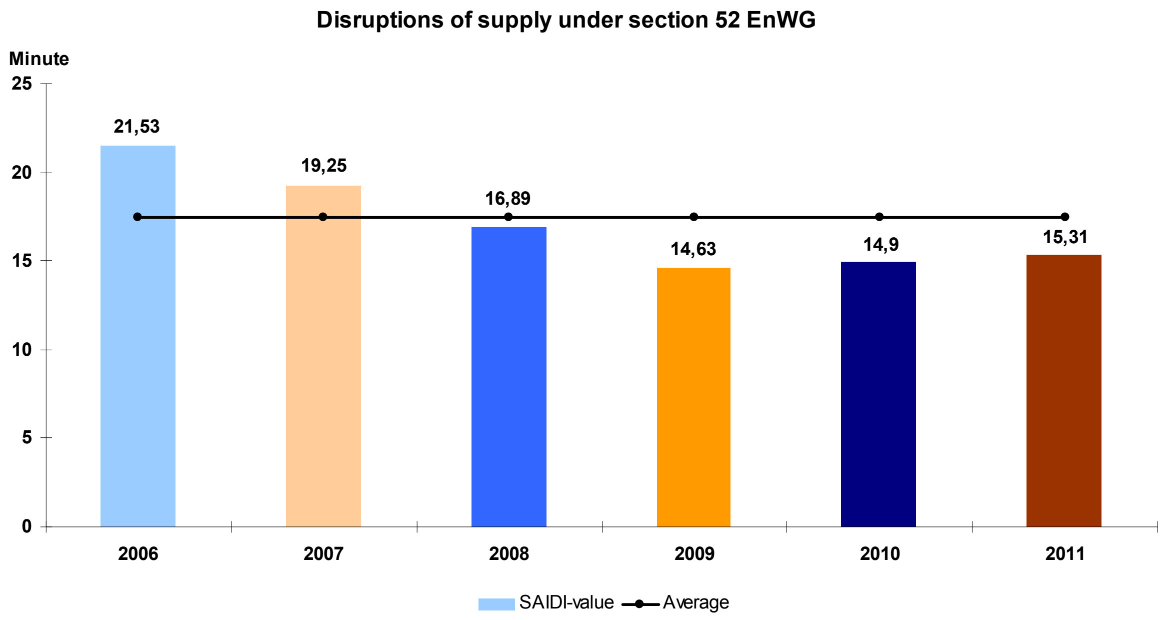

Figure 13: Disruptions of supply under section 52 EnWG (electricity)

In 2011 there was thus high quality of supply. The slight increase in the average interruption duration is only to be found in the medium voltage range, with an increase of 34.8 seconds, from 12.10 minutes to 12.68 minutes. In the low voltage range, on the other hand, the average interruption duration decreased by 10.2 seconds, from 2.80 minutes to 2.63 minutes.

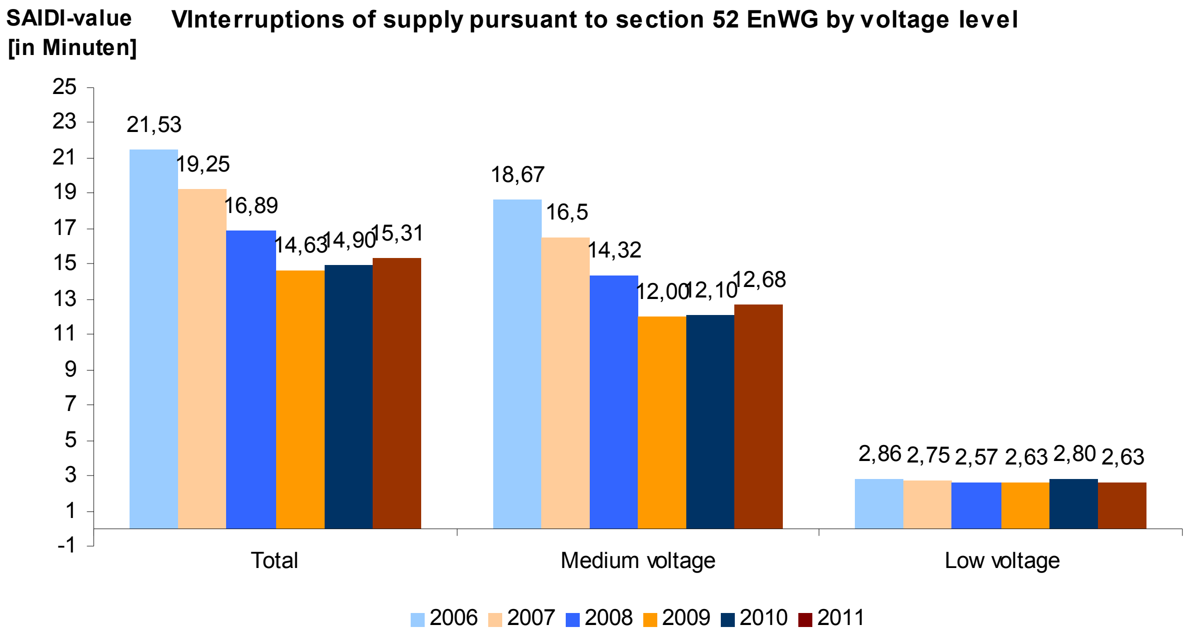

Figure 14: Disruptions of supply under section 52 EnWG by voltage level (electricity)

At both voltage levels, a significant increase in feedback disruptions can be observed. A feedback disruption occurs, according to the definition of the Bundesnetzagentur, when an interruption of supply in the respective network is caused by a disturbance in an upstream or downstream network, in a final consumer's system or by an interruption of supply from power plants. However, at both voltage levels, this increase stands in contrast to a significant decline in disturbances based on atmospheric influences, such as lightning strikes. Disruptions based on force majeure, which as so-called “exceptional events” are not considered in the calculation of SAIDI, occurred with far less frequency in 2011 compared to the year 2010.

The SAIDI takes into account neither planned interruptions nor interruptions based on force majeure, such as natural catastrophes. The calculation takes into account only unplanned interruptions that occur as a result of atmospheric influences, of the actions of third parties, of repercussions from other networks or of other disruptions in the area of the network operator.

Networks / network expansion / investments / network tariffs

Networks / network expansion / investments

Status of network expansion (EnLAG projects, offshore wind farms)

In the year 2009, the German Bundestag and Bundesrat passed the Power Grid Expansion Act (Energieleitungsausbaugesetz – EnLAG). The purpose of the legislation is to accelerate the expansion of the transmission networks. It details 24 projects that are necessary for the system of energy supply in Germany. With the EnLAG, the necessity of certain network expansion projects for the energy industry was, for the first time, set down in law.

The EnLAG constitutes the response by the federal legislator to the need for expansion of the transmission networks. In particular the increasing transport distance and the growing use of renewable energy sources accentuate the urgency of this network expansion. The 24 expansion projects detailed in the EnLAG are to be completed on a fast-track schedule. They comprise 1,834 km of transmission routes to be newly built or to be upgraded. By way of comparison, the existing extra-high voltage network comprises a total transmission route length of 17,610 km. The Bundesnetzagentur, on its website www.netzausbau.de, provides ongoing documentation of the current status of approval procedures for the individual projects. The basis of this documentation is made up of the quarterly reports of the four transmission system operators TenneT, 50Hertz, Amprion and TransnetBW detailing current progress in planning and construction.

An evaluation of TSO data (as of October 2012) shows that a large part of the planned power lines will become operational later than expected:
Of the total of 1,834 kilometres of EnLAG power lines, only 214 kilometres (nearly 12 percent) have already been completed. In the year 2012, only 35 kilometres are expected to be added.

Of the 24 projects, two are currently fully completed and operational; another two are to be finished by the end of 2012. In another four projects, at least partial segments have been completed. In two other EnLAG projects, feasibility studies are still being compiled; in the transmission system operators' draft of the 2012 network development plan, those two projects are to be dropped. The remaining 16 projects are currently in various stages of the approval procedure. 15 of the 24 projects are subject to an expected delay of between one and five years. As of yet, none of the projects with pilot sections for underground cable is under construction.

The following illustration depicts the status of individual projects and their progress, as well as the four control areas of the German transmission system. Also depicted are the existing network and the 16 federal states.

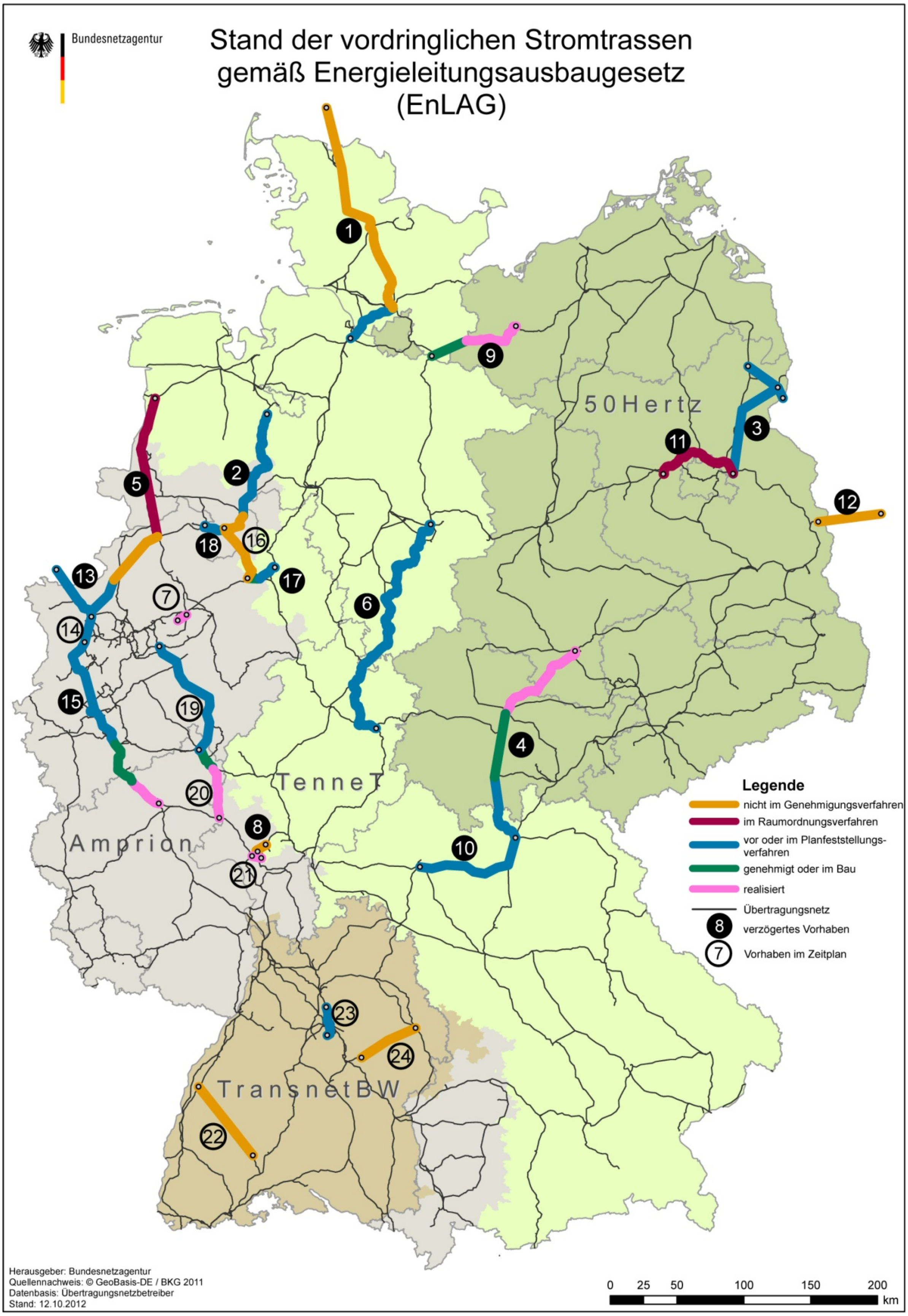

Figure 15: Status and progress of priority transmission routes pursuant to EnLAG

Legende to Figure 15	Key
nicht im Genehmigungsverfahren	No approval process
im Raumordnungsverfahren	Regional impact assessment phase
vor oder im Planfeststellungsverfahren	Plan approval process has been or will be initiated
genehmigt oder im Bau	Approved or under construction
realisiert	Completed
Übertragungsnetz	Transmission network
verzögertes Vorhaben	Project behind schedule
Vorhaben im Zeitplan	Project on schedule

Data from the second quarter of 2012 indicates additional delays, relative to the first quarter of 2012. Four planning approval applications that were meant to be submitted this year will not be submitted until the following year. TenneT expects that the commissioning of one section of the EnLAG project Redwitz-Grafenrheinfeld (no. 10) will be delayed by another year, to the year 2013. A positive development to be pointed out is the fact that planning approval for the Schleswig-Holstein section of the Hamburg/Krümmel-Schwerin EnLAG project (no. 9) was granted in April 2012. The construction of the remaining segment was begun already in May 2012. TenneT remains optimistic that the Hamburg/Krümmel-Schwerin EnLAG project (no. 9), for which construction was resumed last summer, can be completed by the end of the year and that operation of the overall project can subsequently begin. That would constitute a significant step for the securing of system stability and security of supply in the greater Hamburg region and all of northern Germany, which is absorbing the impact of the decommissioning of the nuclear power plants Krümmel and Brunsbüttel. There has also been progress in the construction of the Osterath-Weißenthurm project (no. 15) with the establishment of the 30 kilometre-long segment from Sechtem to the German border.

The third quarter report showed additional progress. While 50Hertz predicts that the completion of the EnLAG project Neuenhagen-Bertikow/Vieraden-Krajnik (no. 3) could be delayed until the year 2016, 50Hertz expects the Eisenhüttenstadt-Baczyna project (no. 12) to be completed already in 2017 – one year earlier than previously planned. However, on the Polish side, this project will likely not become operational until the year 2022.

There has also been progress in the construction of the EnLAG project Lauchstädt-Redwitz (no. 4), namely in the Vieselbach-Altenfeld section, despite ongoing legal action that is being taken against the planning approval, since no suspension of construction has been imposed in the summary proceedings.

Electricity Network Development Plan

In conjunction with the amendment of the Energy Act (EnWG) in the year 2011, a new procedure to assess needs and prioritised requirements in the energy sector was introduced in the form of the Federal Requirements Plan.

The Federal Requirements Plan, which is drawn up by the federal legislator, is based on a review of the energy industry needs that follow from the scenario frameworks and the Network Development Plan, as well as on a review of environmental impacts that follow from a strategic environmental assessment by the Bundesnetzagentur.

What all of the stages of the procedure have in common is that the Bundesnetzagentur must review and put up for public consultation the data that was submitted by the transmission system operators for the first time on 15 August 2012.

By the end of the year, the Bundesnetzagentur will present the environmental report as well as the 2012 Network Development Plan to the federal government as a draft version for a Federal Requirements Plan. Within the framework of the legislative process, the federal legislator will, with the adoption of the Federal Requirements Plan Act, establish the necessity and priority of the line projects contained in the Federal Requirements Plan in a legally binding form.

Scenario framework

Section 12a of the Energy Act requires transmission system operators to draw up one joint scenario framework per year, which forms the basis for developing the Network Development Plan.

On 19 July 2011, the transmission system operators submitted to the Bundesnetzagentur the draft of the first electricity scenario framework. The Bundesnetzagentur put this draft up for consultation until 29 August 2011, and approved it on 20 December 2011.

In parallel with the work on the first Network Development Plan, preparations have now begun for the 2013 Network Development Plan; in July 2012, transmission system operators submitted to the Bundesnetzagentur the second scenario framework, which will form the basis for the 2013 Network Development Plan. This was open for consultation until 30 August 2012.

Electricity Network Development Plan

In accordance with section 12b of the Energy Act, the transmission system operators must submit to the Bundesnetzagentur, on 3 March each year, a joint national Network Development Plan on the basis of the scenario framework; the first submission, however, was on 3

June 2012. This plan must detail all effective optimisation, reinforcement and expansion measures, which from the standpoint of the transmission system operators are required in order to ensure secure and reliable network operations over the next 10 years.

Following the approval of the scenario framework in December 2011, the transmission system operators drew up the draft of the 2012 Network Development Plan and opened it up for consultation between 30 May and 10 July 2012. After carrying out revisions based on the consultation process, the transmission system operators, on 15 August 2012, submitted to the Bundesnetzagentur the draft of the 2012 Network Development Plan.

It is the responsibility of the Bundesnetzagentur to verify the revised Network Development Plan as the basis for the Federal Requirements Plan Act. On 6 September 2012, the Bundesnetzagentur published on the Internet the revised draft of the 2012 Electricity Network Development Plan, along with supporting documents and the draft 2012 environmental report of the Bundesnetzagentur. In parallel to this, the documents were laid out for public inspection at Bundesnetzagentur headquarters in Bonn between 6 September 2012 and 17 October 2012. Relevant comments could be submitted to the Bundesnetzagentur between 6 September 2012 and 2 November 2012. Following the evaluation of the comments submitted, the drafts of the 2012 Network Development Plan and environmental report are revised and presented to the Bundestag as draft for a Federal Requirements Plan under section 12e(1).

Environmental report

Based on the Network Development Plan, the Bundesnetzagentur drafted the strategic environmental assessment for the Federal Requirements Plan. In the environmental report, as the foundation of the strategic environmental assessment, the expected significant environmental impacts resulting from the implementation of the plan are identified, described and assessed in accordance with section 14g Environmental Impact Assessment Act (UVPG).

The environmental report includes a general section on the impacts of extra high voltage power lines on resources protected under the UVPG, as well as a depiction of potential environmental impacts in the regions examined.

The strategic environmental assessment begins with the determination of the scope of the assessment. The determination of the scope of the strategic environmental assessment by the Bundesnetzagentur was preceded by extensive discussions with the relevant stakeholders – network operators and representatives of technical agencies and associations – that took place within the framework of the scoping conference on 27 February 2012.

The environmental report was made available for public consultation along with the draft of the Network Development Plan. A copy of the documents was available for inspection at the Bundesnetzagentur's headquarters in Bonn for six weeks beginning on 6 September 2012, and could be viewed on the Internet. The public has the chance to comment on the draft of the Network Development Plan and on the 2012 environmental report up to two weeks after the end of the lay-out period. The participation of government authorities is governed by section 14h of the UVPG. Once public and governmental participation is concluded, the positions and evaluations of the environmental report are reviewed and, if necessary, revised according to the respective comments (section 14k UVPG).

The Bundesnetzagentur is expected to present the results of the consultation and subsequent review process to the federal government by the end of the year for final decision-making by the federal legislator.

Preparations for federal sectoral planning

After the Bundestag has adopted the Federal Requirements Planning Act, the transmission system operators can apply for the first federal sectoral planning procedures for projects marked as having transnational or cross-border status in the Federal Requirements Plan. The federal sectoral planning procedure is a planning instrument, replacing the federal states' regional impact assessments, with which transmission route corridors for cross-border and transnational projects are established in binding form. The task of federal sectoral planning was transferred to the Bundesnetzagentur with the Grid Expansion Acceleration Act (NABEG). In order to eliminate the sometimes considerable regional planning differences between the federal states, the Bundesnetzagentur developed and published uniform nationwide standards in advance. The currently existing differences extend to both the procedures applied and the relevant standards for regional planning assessments.

To expedite the beginning of these procedures, the Bundesnetzagentur began to draw up the requirements, both in terms of form and content, for the application documents already in 2012, so that the information can be communicated to all stakeholders in due time. In this way, it is hoped that immediately following the adoption of the 2013 Federal Requirements Plan Act, the first application procedures can begin, based on standardised application materials that have been developed using systematic methods. A related methodology conference attended by representatives of federal and state agencies took place on 1 June 2012.

In order to clarify basic questions surrounding federal sectoral planning, the federal sectoral planning council was established on 21 June 2012, as provided for in section 32 of the NABEG. This council consists of representatives of the federal states and relevant federal ministries, as well as their subordinate authorities. The federal sectoral planning council facilitates the exchange of information and has an advisory function.

Outlook

In parallel with the work on the first Network Development Plan, preparations for the 2013 Network Development Plan have already begun; in July, transmission system operators submitted to the Bundesnetzagentur the second scenario framework, which will form the basis for the 2013 Network Development Plan. This scenario framework was open for consultation until 30 August 2012.

Grid connection of offshore wind farms

In 2011, no new grid connections for offshore wind farms (OWF) began operation. For OWFs in the Baltic Sea, the transmission system operator 50Hertz awarded a contract for one network connection and issued a call to tender for another. The transmission system operator TenneT, after awarding a contract for a hub connection in the North Sea for the cluster SylWin in January 2011, awarded contracts, after a call to tender, for two more OWFs in the clusters HelWin and DolWin. TenneT also awarded the contract for installation of grid connections for the OWFs Riffgat and Nordergründe. In addition, in spring 2011, TenneT issued a call to tender for the third hub connection for OWFs located in the DolWin cluster. The contract for this connection, according to specifications set out in a position paper published by the Bundesnetzagentur in October 2009 on grid connection obligations pursuant to section 17(2a) EnWG – and further defined by the annex in January 2011 – should have already been awarded by the end of 2011 and calls to tender issued for two additional hub connections for the BorWin cluster.

Instead, in November 2011, TenneT argued that there was insufficient material, personnel and financial resources for connecting additional offshore wind farms to the grid and that, under the existing conditions, they could therefore not build any new direct current connections.

The Bundesnetzagentur became very involved in the discussion process, with the result that a new legal regulation was introduced to resolve the problems of transmission system operators obligated to install grid connections. As a result of these efforts, TenneT resumed negotiations on the DolWin 3 hub connection and issued a call to tender for the two hub connections BorWin 3 and 4.

The Bundesnetzagentur continues to maintain regular contact with all stakeholders, providing support in terms of questions pertaining to the grid connection of OWFs.

By the end of 2011, 22 applications for approval of investments for the construction of OWF grid connections have been submitted to the Bundesnetzagentur, with a total volume of approximately 12.4bn euros; to date, 14 applications with a volume of approximately 6bn euros have been approved.

Investments in transmission networks (including cross-border connections)

In the year 2011, investments in and expenditure on network infrastructure by the four German TSOs totalled approximately 847m euros (2010: 807m euros). This also includes investments in and expenditure on cross-border connections amounting to approximately 13m euros (2010: 5m euros). In particular because of delayed grid expansion projects, there is again a difference between the actual expenditures for network infrastructure and the planning data submitted in the previous year (planning value for 2011: approximately 910m euros). The cause of this difference is primarily to be found in the category of investments in new construction/expansion/extension, since in this category the actual value for 2011 (470m euros) is 60m euros lower than the value planned for 2011 (530m euros). However, a comparison with the previous years shows that the difference between planning value and actual value is growing smaller.

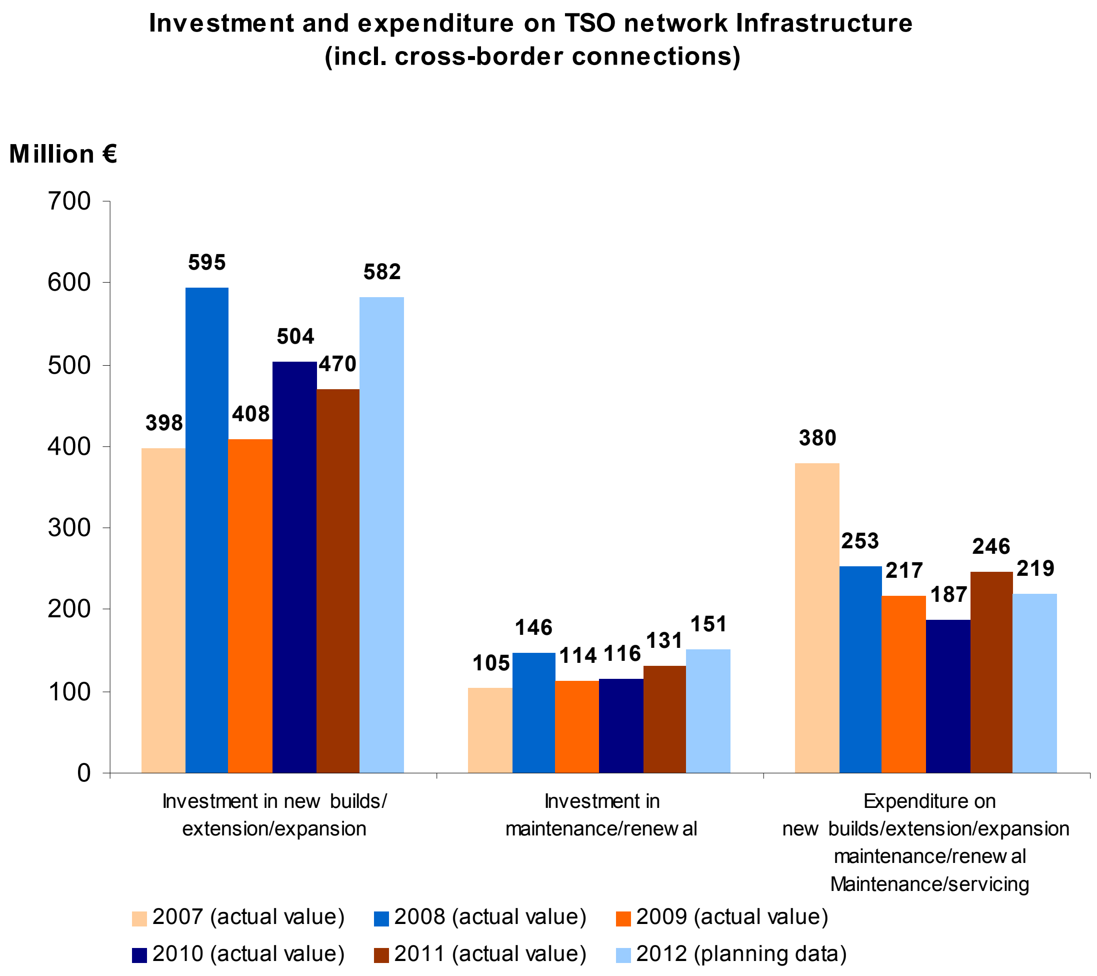

Figure 16: Investments in and expenditure on network infrastructure by TSOs since 2007 (including cross-border connections)

Investments in distribution networks

In 2011, investment in and expenditure on the 735 DSOs' network infrastructure totalled approximately 6,281m euros (2010: 6,401m euros). This figure includes investment in and expenditure on metering/control devices and communication infrastructure amounting to approximately 462m euros (2010: 432m euros). In the category of sustainment/renewal investments, in contrast to the other two categories, a downward trend could be observed for the first time. All in all, the actual level of investment by DSOs in network infrastructure, with a gap of 270m euros, was below the planning data for 2011 of 6,551m euros. However, it is significant that in the category of new build/expansion/extension investments, the actual value for 2011 (1,604m euros) was 94m euros higher than the value planned for 2011 (1,510m euros).

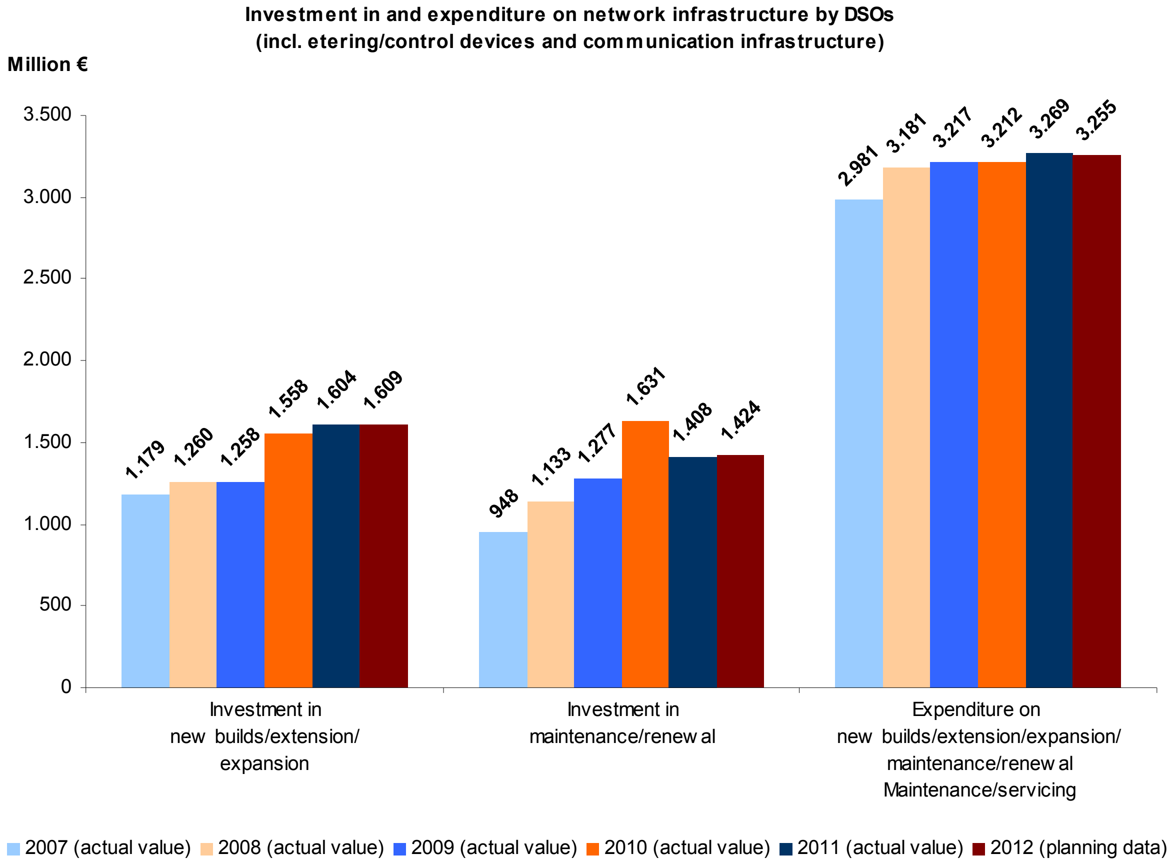

Figure 17: Investment in and expenditure on network infrastructure by DSOs (including metering/control devices and communication infrastructure)

Measures for the optimisation, reinforcement and expansion of the distribution network

The DSOs are obliged under section 11(1) EnWG and section 9(1) EEG to optimise, reinforce and expand their networks to reflect the state of the art without undue delay, in order to ensure the purchase, transmission and distribution of electricity. The strong expansion of generation installations based on renewable energies, coupled with the legal obligation to connect and purchase regardless of network capacity, represents a considerable challenge to the DSOs. Alongside conventional expansion measures, network operators are primarily responding to these challenges by increasingly structuring their networks on an intelligent basis, which allows them to adapt to changing requirements over time. The individual approach and the measures applied can vary considerably from one network operator to the other. Because of the extremely heterogeneous network situation in Germany, each DSO must find its own strategy for ensuring efficient network operations in the future energy landscape. It helps the situation that many networks must be modernised anyway. The restructuring of the networks can therefore often take place using returns of capital from existing installations (intelligent restructuring).

As of 1 April 2012, a total of 735 (1 April 2011: 686) DSOs have provided information pertaining to the measures they have taken to optimise, reinforce and expand their networks. A comparison with previous years shows that the number of DSOs has again increased.

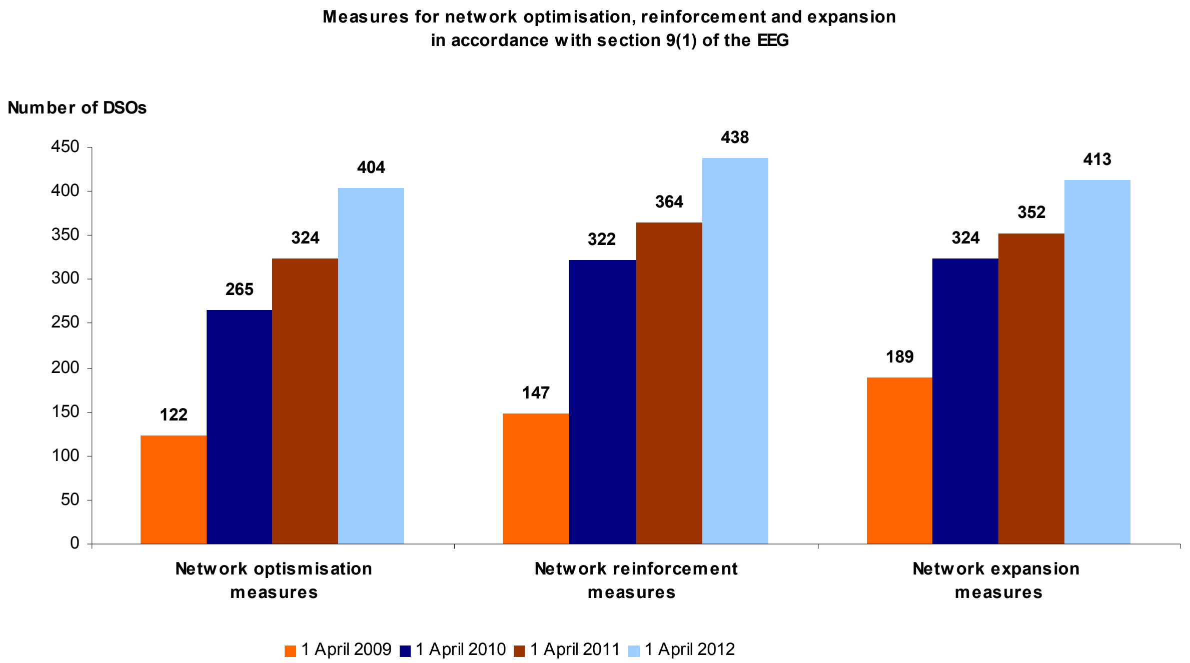

Figure 18: Measures for network optimisation, reinforcement and expansion pursuant to section 9(1) EEG

The following network optimisation and reinforcement measures are being implemented by the DSOs. Information on measures "Increase of conductor cross-sections", "Undergrounding of overhead lines" and "Changes in network topology" was requested for the first time. For these measures there are therefore no relevant reference values for 1 April 2010.

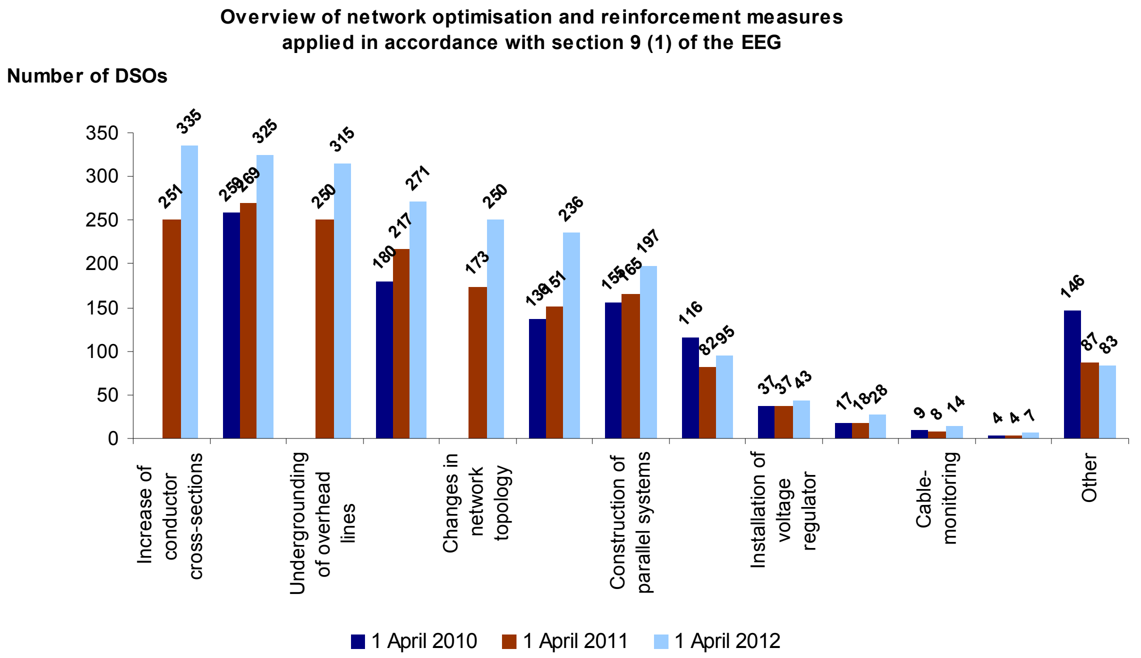

Figure 19: Overview of network optimisation and reinforcement measures applied in accordance with section 9(1) EEG.**7**

Compared to previous years, there has been an increase in all measures. The measures with the greatest increase are "Metering technology installation", "Increase of conductor cross–sections" and "Changes in network topology".

System responsibility of transmission system operators using measures in accordance with section 13(1) EnWG in the calendar years 2010 and 2011

In accordance with section 13(1) EnWG, the transmission system operators are both authorised and obliged to remedy any threat to or malfunction in the electricity supply network through the adoption of system–related and market–related measures. To the extent that electricity distribution system operators are responsible for the security and reliability of the electricity supply in their networks, DSOs are also authorised and obliged to implement such measures under section 14(1) EnWG.

Network–related measures, in particular network switching, were implemented by TSOs on nearly every day of the year. To a large extent, the market–related measures took the form of congestion management measures. Here, it is necessary to differentiate between re-dispatching and counter-trading: Re-dispatching is the preventive or corrective adaptation of effective power feed-in from generating installations or storage facilities on the part of transmission system operators in order to prevent or eliminate short–term congestion, as well as measures for voltage control. Redispatch measures can be applied either internally within control areas or across control areas. By reducing the feed-in capacity of one or more power sta-

[7] The values as of 1 April 2011 were adjusted relative to the 2011 Monitoring Report.

tions while simultaneously increasing the feed-in capacity of one or more other power stations, it is possible to keep the overall energy feed-in capacity at a constant level. Counter-trading, by contrast, is a preventive or corrective commercial transaction undertaken across control areas at the TSO's initiative in order to prevent or eliminate short–term congestion.

Calendar year 2010

During the calendar year 2010, in particular the areas listed in the following table experienced tense network situations in which transmission system operators were forced to implement measures in accordance with section 13(1) of the EnWG (redispatch and counter-trade) in order to maintain secure network (n-1) operations:

Affected network section	Number of hours
Remptendorf – Redwitz power line	790.82
Vierraden / Krajnik area	278.28
Flensburg / Hamburg area *(primarily affected: Audorf substation, Emden, Audorf-Hamburg power line)*	196.43
Helmstedt – Wolmirstedt power line	59.33
Conneforde / Sottrum area *(primarily affected: substations Conneforde, Maade, Sottrum, Unterweser, Farge)*	55.72
Kriegenbrunn area *(primarily affected: substations Kriegenbrunn, Raitersaich, Irsching)*	25.70

Table 9: Measures implemented under section 13(1) EnWG during the calendar year 2010 on the most heavily affected network sections in the German transmission system.

As in previous years, the situation on the Remptendorf (50Hertz) – Redwitz (TenneT) power line was particularly critical, with an above-average need for redispatch measures. This is followed by the area around the cross-border interconnector Vierraden / Krajnik (50Hertz), and in third position the Audorf – Hamburg (TenneT) power line.

The other redispatch measures necessary in the German transmission system amount to a total period of 181.79 hours, which is one fourth of the measures taken on the Remptendorf – Redwitz network section alone.

Calendar year 2011 (year under review)

The data from the calendar year 2011 shows that the overall number of tense network situations has increased dramatically, and that on the whole, more areas and thus more network sections were affected. The volume used for redispatch measures also increased significantly.

The Remptendorf – Redwitz power line was subject to substantial strains during the calendar year 2011 as well. A major increase continues to be seen in the area around and to the south of Kriegenbrunn. The number of hours with redispatch measures taken, however, has increased significantly on other power lines as well, as the following table shows.

Affected network section	Number of hours	Changes relative to calendar year 2010 in percent
Redwitz – Remptendorf power line	1,727.20	+ 218.4%
Kriegenbrunn area (mainly affected: substations Kriegenbrunn, Raitersaich, Irsching)	726.58	- 11%
Lehrte / Mehrum / Borken area (mainly affected: Lehrte – Mehrum power line)	575.53	+ 577%
Conneforde / Sottrum area (mainly affected: substations Conneforde, Maade, Sottrum, Unterweser, Farge)	400.82	+ 719.5%
Sottrum / Borken area (mainly affected: substations Bechterdissen, Eickum, Ovenstädt, Twistetal, Sottrum, Landesbergen)	319.11	+ 1.242%
Flensburg / Hamburg area (mainly affected: substations Audorf, Emden, Audorf-Hamburg power line)	281.29	+ 43.5%
Helmstedt – Wolmirstedt power line	271.87	+ 358%
Vierraden / Krajnik area	249.54	- 10.5%

Table 10: Measures implemented under section 13(1) EnWG during the calendar year 2011 on the most heavily affected network sections in the German transmission system

German transmission system operators also carried out additional redispatch measures that amounted to a total duration of nearly 447 hours. The following map shows the power lines and substations which required redispatch measures during the calendar year 2011, using data from the previous table according to the frequency of tense network situations.

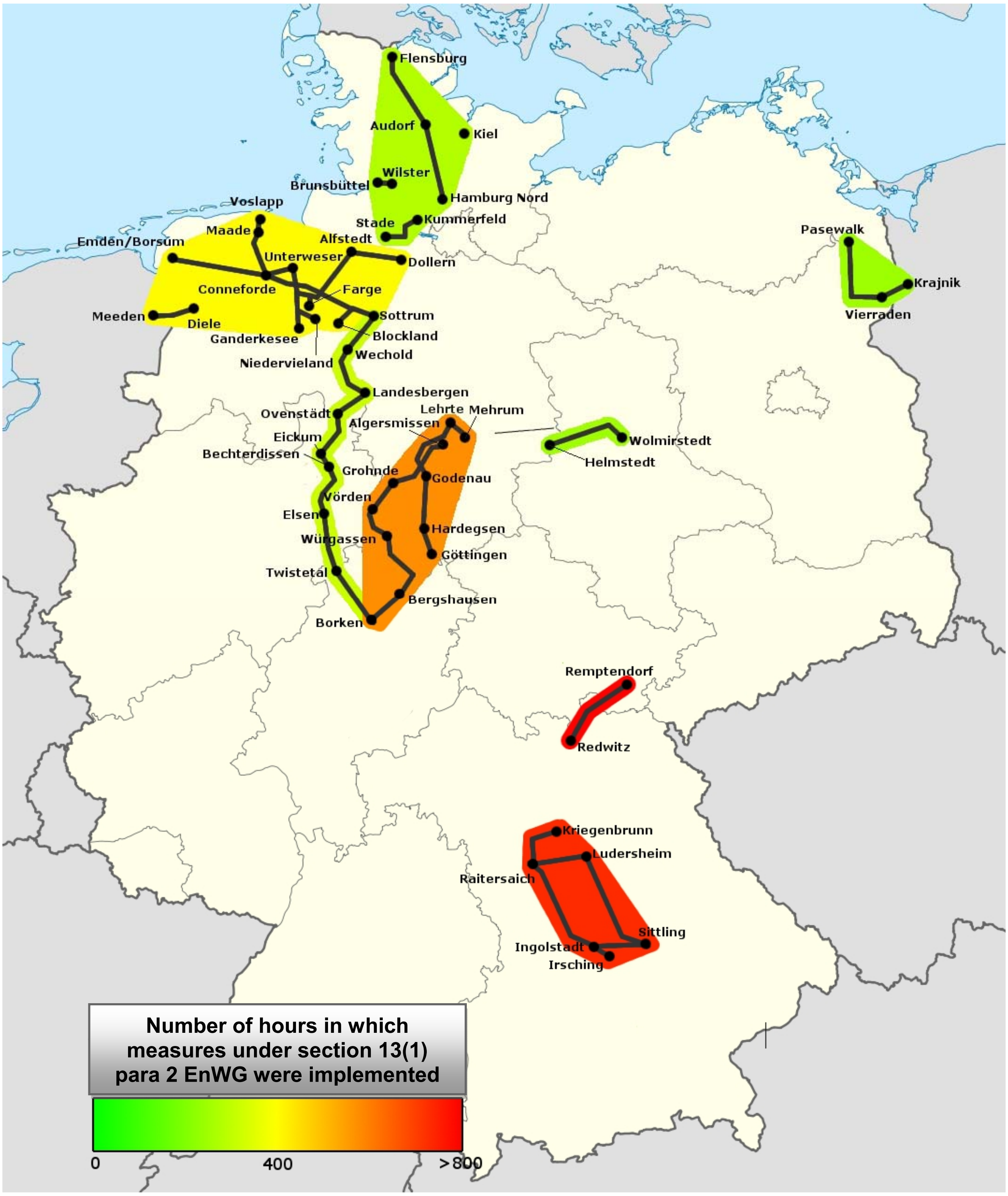

Figure 20: Depiction of network sections on which redispatch measures had to be implemented for more than 250 hours during the calendar year 2011

The illustration shows that during the calendar year 2011 (as in 2010), the network of 50Hertz Transmission was subject to considerable strain. Particularly striking is the very tense network situation of TenneT TSO. Despite the significant increase, compared to the year 2010, in the number and volume of tense network situations, German transmission system operators were at all times able to manage the situation using the existing instruments. It is expected that the situation will remain tense, in particular in the transmission systems of TenneT TSO and 50Hertz Transmission, and that intervention in the schedules of power plants is likely in the course of the next year. This underlines the urgency of rapidly implementing those EnLAG projects that are still uncompleted, in particular the completion of the line projects Lauchstädt-Redwitz (EnLAG project no. 4) as well as Hamburg/Krümmel-Schwerin (EnLAG project no. 9). The completion of those projects will likely bring about substantial relief to the situation and thus result in significantly fewer tense network situations requiring intervention on the part of transmission system operators.

System responsibility of transmission system operators using measures in accordance with section 13(2) EnWG in the calendar years 2010 and 2011

Under section 13(2) EnWG, TSOs are both authorised and obliged to adapt electricity feed-in, transit and output, or to demand that such adaptations be made (adaptation measures), if a threat to, or malfunction affecting the security or reliability of the electricity supply system cannot be eliminated in due time through system and network-related measures pursuant to section 13(1) of the EnWG. To the extent that electricity distribution system operators are responsible for the security and reliability of the electricity supply in their networks, the distribution system operators are also both authorised and obliged under section 14(1) EnWG to implement adaptation measures pursuant to section 13(2) EnWG.

In 2011, a TSO carried out or commissioned the carrying out of adaptation measures pursuant to section 13(2) EnWG for 342 hours on 45 days in his own network and/or downstream networks. Electricity feed-in was reduced by a maximum capacity of 1000 MW and a total of 44,771 MWh.

In addition, nine DSOs undertook adaptation measures pursuant to sections 14(1) and 13(2) of the EnWG for over 384 hours spread over 73 days in 2011. Electricity feed-in was reduced by a maximum capacity of 113 MW and a total of approximately 5,360 MWh.

Feed-in management under section 11 and hardship clause under section 12 EEG

Feed-in management measures describe the temporary reduction of feed-in from renewable energy sources, combined heat and power and pit gas installations. Under section 11 of the EEG, network operators are entitled to adjust electricity feed-in from such installations with a power generating capacity of over 100 kW to a lower level, notwithstanding their obligation to optimise, reinforce and expand their networks. This applies in particular if otherwise the network capacity in the respective network area would be overloaded by this electricity, and if it is simultaneously ensured that on the whole the largest possible amount of electricity from renewable energy sources, combined heat and power plants and pit gas installations has been fed in.

Under section 12 EEG the network operator responsible for the network requiring feed-in management measures (this can be either a TSO or a DSO) is obliged to pay compensation for the restricted feed-in of energy and heat. According to the 2012 monitoring survey, the following use was made of this regulation in 2011:

	Unused energy pursuant to section 11 EEG in kWh and %		Compensation payments pursuant to section 12 EEG in € and %	
Total	**420,646,809.40**	100%	**33,456,759.63**	100%
Share compensated by network operator to whose network the installations were connected	135,735,336.75	32%	11,661,804.13	35%
Share compensated by the upstream network operator whose network caused the requirement for FMM	234,961,472.65	56%	21,794,955.49	65%
of which without compensation to date	49,950,000.00	12%		

Table 11: Feed-in management measures (FMM) pursuant to sections 11 and 12 EEG in 2011

Compared to 2010, the volume of unused energy due to feed-in restrictions more than tripled, at around 421 GWh (2010: around 127 GWh). The rapid increase in unused energy is directly linked to the unabated increase in capacity based on renewable energy sources and the slow progress of grid expansion. FMMs were applied primarily to wind power plants (97.4 percent) and, to a minor degree, to biomass, photovoltaic and CHP installations. Recourse to these measures focused mainly on the network areas with a high level of installed wind capacity in northern Germany. For the most part, FMMs were called on by those network operators who were already in need of them in 2010. Relative to total feed-in from EEG installations, unused energy in 2011 amounted to a share of 0.41 percent (2010: 0.16 percent). The corresponding value as a proportion of total wind power feed-in was 0.89 percent (2010: 0.34 percent). The cause of 56 percent of FMMs resulting in unused energy and compensation payments lay in an upstream network (2010: approximately 40 percent). On the whole, the sum total of compensation payments made, corresponding to the volume of unused energy, more than tripled at around 33.5m euros (2010: approximately 10m euros); at the end of the data survey period, 12 percent of unused energy remained without compensation. A possible reason for this is that the affected installation operator may not have submitted a claim (yet), or delays to payments due to legal disputes.

Feasibility study on the linking of rail and power line infrastructures

Given the growing volume of electricity from renewable sources which needs to be transported from northern Germany to consumers in the south of the country, the Bundesnetzagentur examined whether long-distance traction current lines might be able to play a helpful role in transmitting electricity through the public power grid as part of current grid expansion planning. The expert report was drawn up by the Bundesnetzagentur, in collaboration with the Federal Ministry of Economics and Technology (BMWi) and the Federal Ministry of Transport, Building and Urban Development (BMVBS), the Federal Railway Office, Deutsche Bahn AG and representatives of the four transmission system operators. The expert report entitled "Feasibility study on the linking of rail and power line infrastructures" is published on the Bundesnetzagentur's website under http://www.bundesnetzagentur.de/GutachtenBahnstromtrassen. One of the conclusions of the expert report is that use of the routes of long-distance traction current lines is not ruled out, although the advantage in terms of the planning and approval process for the shared use of routes is not thought to be significant. The report sees a realistic possibility that in individual cases new transmission networks can be built parallel to long-distance traction current lines.

Network Tariffs

Revenue Cap Development in Incentive Regulation.

Networks; Network Tariffs (Electricity)

On 1 January 2009, the Bundesnetzagentur set revenue caps[8] for the first time as part of incentive regulation. These determine how much revenue a network operator can generate in a calendar year. In the years since, the network operators have adjusted the revenue caps themselves. On 1 January 2012, for the third time since the introduction of incentive regulation, the network operators were able to independently adjust the revenue caps and network tariffs in line with the relevant ordinances and taking into consideration the altered retail price index and the changes in the cost shares that cannot be controlled on a lasting basis.

For transmission system operators, costs which cannot be controlled on a lasting basis include the costs arising from approved investment measures in particular. For the distribution system operators, these costs include those for upstream networks along with those for the avoided network tariffs, and for DSOs taking part in standard proceedings, in addition to this there are costs for statutory works council and staff council activities and operating taxes, for example. Moreover, the revenue cap is also influenced by the reduced amount resulting from the individually calculated network operator inefficiencies. The Bundesnetzagentur examines the ad-

[8] The revenue caps regulate the income a network operator is allowed to collect in the year from network tariffs Based on this ruling, the network operator sets their tariffs and aims to achieve the permitted amount as precisely as possible. Discrepancies between the revenue cap and the actual income are balanced out in the incentive regulation account over the following years.

justments made by the network operators by comparing them with the permitted revenue, so that any unjustified adjustments can be re-credited with interest in future to the shippers via the incentive regulation account. The incentive regulation account also made an adjustment to network tariffs necessary for 24 network operators when a threshold of five percent of the permitted return was exceeded due to the difference between the permitted and achievable revenue for 2010. Alignment of network tariffs when the five percent threshold was not exceeded was possible for 15 network operators.

In 2011 the DSOs could again request an expansion factor for their expansion investments if there were lasting supply changes. In 2012, 82 approved applications for an expansion factor resulted in an increase in revenue caps. In addition, 54 expansion factors already approved in 2011 were still valid in 2012.

A significant driving factor in the increase in revenue caps are the additional costs from the TSOs investment budgets, including the change to a t-0-time delay, the consequences of the Federal Court of Justice ruling (Decision EnVR 48/10 of 28 June 2011) on the sectoral productivity factor and the absence of annuities from the transfer of excess proceeds. Changes in the expansion factors continue to play their role in the increasing revenue caps. In addition to the reduction amount, only a change to the consumer price index (CPI) and sectoral productivity factor (Pf) has a curbing effect on the revenue caps.

The adjustments mentioned led to an increase in revenue caps of around 16.71 percent between 2011 and 2012 for the TSOs. The expansion of renewable energy sources in particular requires high investments in transmission system infrastructure.

For their part, the DSOs witnessed an increase of 8.87 percent between 2011 and 2012. The tariffs for the individual network areas are calculated based on these revenue caps. Overall, household, industrial and business customers experienced an increase in network tariffs.

The expansion and restructuring of the network infrastructure on the transmission and distribution system levels will increase significantly over the next years. The necessary expansion on the TSO level already outlined in the EnLAG projects were further specified in the Network Development Plan submitted in 2012. In addition, partial restructuring and expansion is required on the DSO level, the cost effectiveness of which is still to be determined in detail. The costs of grid development are predominantly taken into consideration via the expansion factor under section 10 of the ARegV and the investment budget under section 23 of the same.

A further increase in tariffs in the long term is the result of increased implementation and further development of additional remuneration systems, eg payments for load close down, rising costs from the payment of avoided network tariffs, the rollout of smart meters and the equipping of solar modules with new inverters to avoid the so-called "50.2 hertz problem". In addition to this, increasing costs are the result of necessary restructuring and expansion of grid infrastructure related to the *energiewende*, and the construction of offshore connection lines in particular.

Changes to network tariffs and thus to electricity prices can differ significantly in the individual networks.

Network tariff development

Network tariff development

With the introduction of tariff regulation in 2005, the charges for network usage in the electricity sector could be consistently lowered until 2009. A slight increase has been observed since then. However, it is important to bear in mind that it was already ensured that specific tariffs were also limited in this period to a large extent via "special effects" such as the transfer of excess proceeds in 2010. Without these, recent years would have seen increasing specific network tariffs.

The graphic below shows the development of average, volume-weighted net network tariffs including those for billing, metering and metering operations by customer category in ct/kWh between 1 April 2006 and 1 April 2012. [9]

[9] The depictions of the network tariffs are based on the following offtakes:

- Household customers: Households with an annual consumption of 3,500 kWh/year, low voltage supply (0.4 kV)
- Business customers: Annual consumption of 50 MWh/year, annual peak load of 50 kW and annual usage time of 1,000 hours, low voltage supply (0.4 kV)
  (Where no load metering was made for business customers, the value was provided based on supply without this)
- Industrial customers: Annual consumption of 24 GW/year, annual peak load of 4,000 kW and annual usage time of 6,000 hours, medium voltage supply (10 or 20 kV)

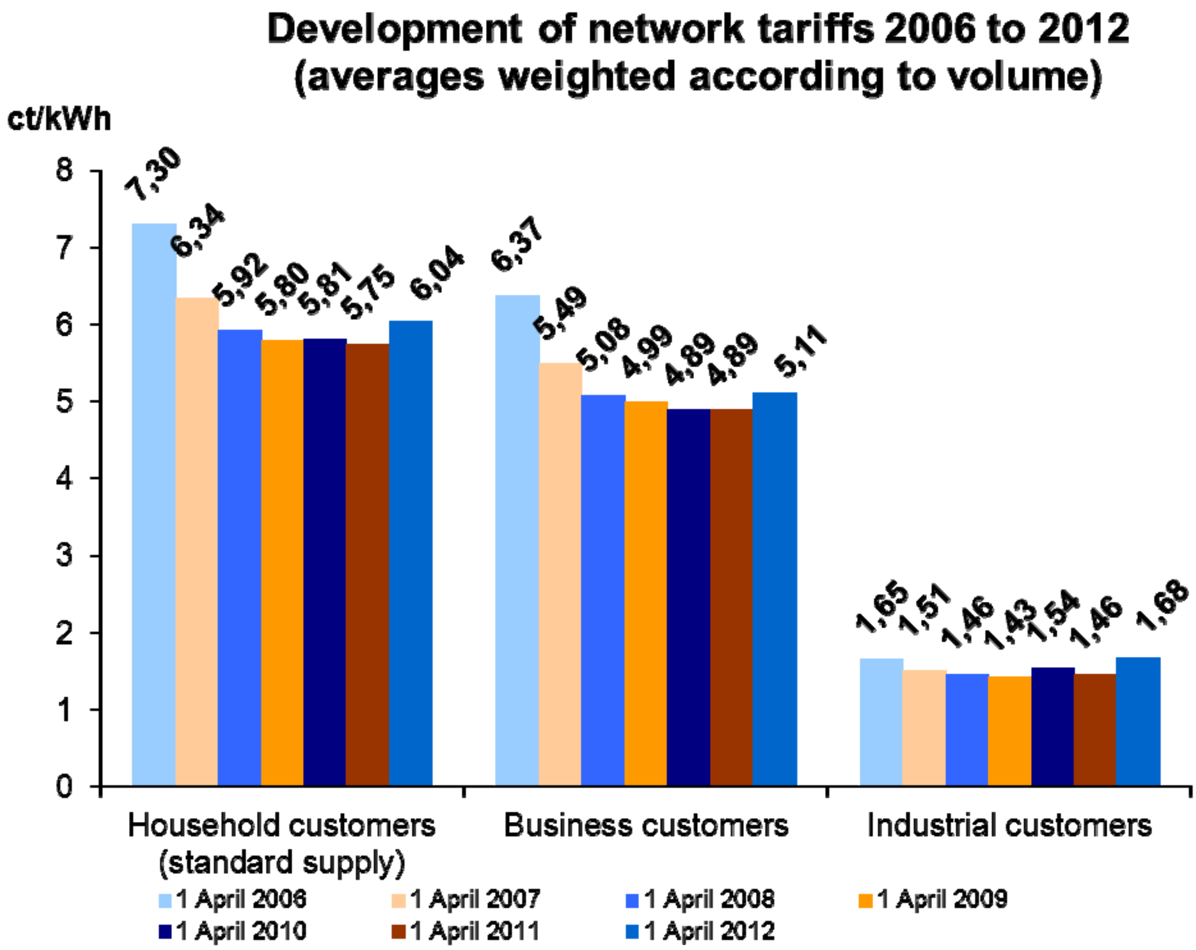

Figure 21: Development of average, volume-weighted network tariffs[10]

The average volume-weighted network tariffs initially decreased for household customers (low voltage) and business customers (low voltage, power measured) from 2006 to 1 April 2011. The network tariffs for industrial customers (medium voltage), however, rose over the entire period under review. In the period from 1 April 2011 to 1 April 2012, a clear increase in network tariffs for all customer groups was visible.

The regulation of network usage tariffs in the electricity sector was introduced in 2005 with a focus on reducing existing monopoly profits and inefficiencies in network operations. Network tariffs had stabilised in recent years following initial significant reductions in network costs and the subsequent tariffs. Considerable increases are to be expected in future.

The increase in tariffs from 2011 to 2012 can be traced back to a number of factors. Although one-off effects, such as the absence of the effects of the transfer of excess profits, had a dampening outcome on tariffs in recent years, these, together with new permanent effects related to the *energiewende* amongst other things, led to an increase in tariffs in 2012.

[10] The electricity surcharge under section 19 StromNEV is not taken unto account here, however it leads to a further increase of 0.151 ct/kWh for household and business customers, and of 0.05 ct/kWh for industrial customers.

In principle, in addition to the increase in the overall revenue cap, change in the electricity volumes upon which the tariffs are calculated is a significant factor in the development of specific network tariffs. Without an increase in these electricity volumes, the specific network tariffs would have risen even further between 2011 and 2012. The effect of a higher revenue cap was lessened by a greater offtake volume.

It must also be taken into consideration that this increase in tariffs has already been cushioned by step-by-step pooling restriction. According to calculations be the BNetzA, keeping pooling at its current size would have resulted in an even greater increase. Network operators and industrial customers who had thus far benefited from the simultaneous power summary are on the other hand now charged more precisely.

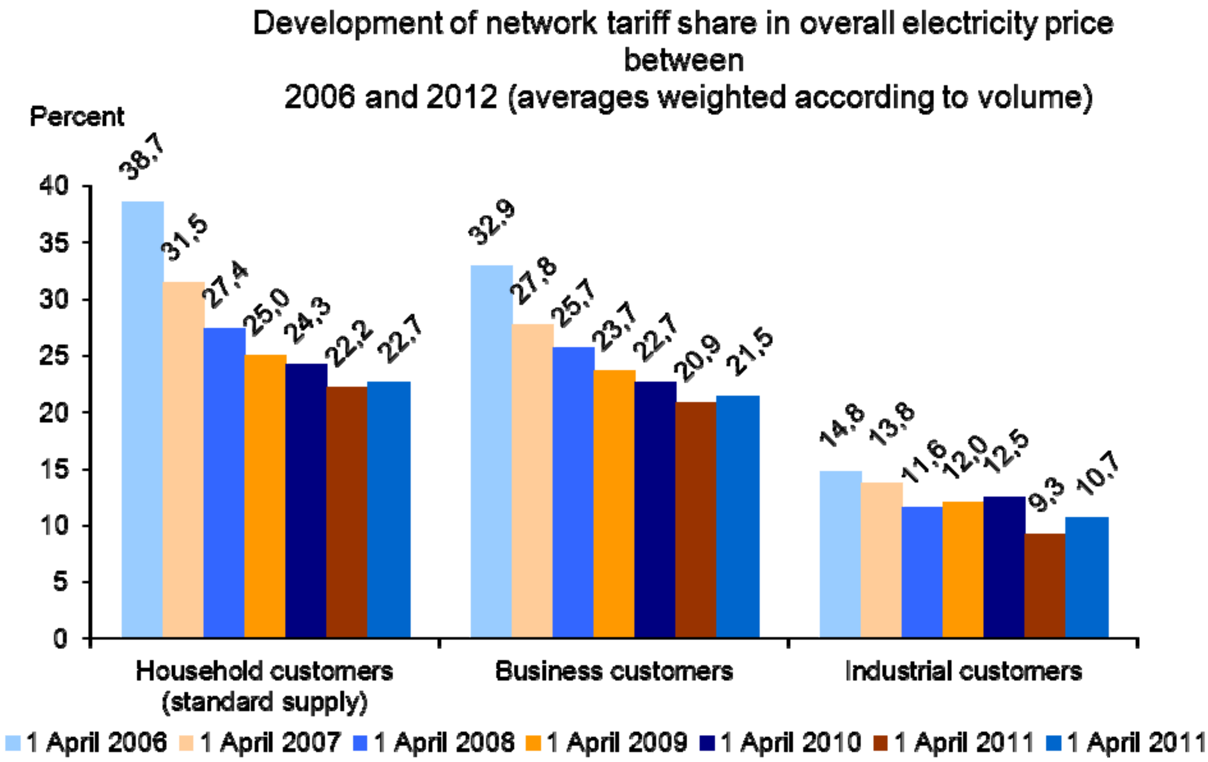

Figure 22: Development of network tariff share of total electricity price

In the entire period under review from 2006 (prior to the issuing of the first network tariff approval) until 1 April 2012, the share of network tariffs in the total electricity price for industrial, business and household customers decreased overall. The network tariff share of the total electricity price increased significantly from 2011 to 2012.

Conclusion

Overall it has emerged that in the absence of individual special effects which are not caused by the regulatory system, along with the start of the ongoing expansion in the transmission networks as a result of the *energiewende*, significant cost and thus tariff increases were triggered by the adjustment of the revenue cap for 2012. In contrast, the efficiency and cost reduction potential offered by incentive regulation only had a minor dampening effect.

The Bundesnetzagentur aims for standardised and transparent network tariff regulation which ensures target-oriented and also cost-effective development of the energy system. This can lead to increasing tariffs and thus have a corresponding effect on the electricity price. This raise must be restricted to what is necessary, however.

Electricity cost examination

In 2012, the Bundesnetzagentur calculated the starting level for determining the revenue caps in the electricity sector for the second regulatory period (2014 - 2018) through a cost examination based on company data from the 2011 business year. On 14 May 2012 the relevant Ruling Chamber set the data survey requirements for this, under which the necessary data was to be submitted by the network operators to the Bundesnetzagentur by 30 June 2012.

As one of its core tasks, the Bundesnetzagentur carries out the cost examination for 98 network operators operating 174 networks. Additionally, in accordance with an administrative agreement, the Bundesnetzagentur examines the costs of 171 further network operators on behalf of the states of Berlin, Brandenburg, Bremen, Mecklenburg-Western Pomerania, Lower Saxony, Schleswig-Holstein and Thuringia

Operators of electricity supply networks with less than 30,000 customers directly or indirectly connected to their distribution networks, were able to apply to take part in simplified proceedings until 30 June 2012. Overall, numerous network operators made use of this option, with 155 operators now taking part in simplified proceedings in the second regulatory period. These operators must submit the key documents necessary for the cost examination to the Bundesnetzagentur by 30 September 2012.

Pan-European TSO Efficiency Benchmarking

European efficiency benchmarking of the transmission system operators as per section 22 of the ARegV is to be carried out in preparation for determining the revenue caps for the second regulatory period. The aim of the benchmarking is to establish efficiency values for the German and European TSOs. In light of the fact that most national regulatory authorities regulate only one or very few TSOs, efficiency evaluation is necessary on a pan-European scale. The benchmarking aims to ensure structural comparability and will thus be carried out using established scientific methods. The DEA (Data Envelopment Analysis) benchmarking method is to be used. Special national features (such as wage levels) are to be taken into account in particular here. The Bundesnetzagentur commissioned European efficiency benchmarking in the form of a specialist report in 2012. The timescale for this project is likely to run from August 2012 until June 2013. The preparation and drafting of the specialist report is carried out by the CEER Task Force Efficiency Benchmarking, led by the Bundesnetzagentur.

Treatment of transmission loss costs in the second regulatory period.

The Bundesnetzagentur intends to determine the process for dealing with transmission loss costs in the second regulatory period. In this period, these costs are essentially to be determined as part of the volatile costs under section 11(5) of the ARegV. The main elements of "transmission loss" voluntary commitments from 2010 remain in place.

Closed distribution networks

Under section 110 of the EnWG, distribution networks are to be categorised by request as closed distribution networks under certain conditions. Certain provisions of the EnWG do not apply to these networks, in particular regarding incentive regulation and tariff approval. The regulatory authorities of the federal states, together with the Bundesnetzagentur, adopted a joint position paper on closed distribution networks on 23 February 2012, which looked at the requirements and legal consequences of section 110 of the EnWG, whilst also touching on the differentiation from customer facility and customer facility for operational self-supply as terms. Furthermore, electronic application procedures for categorisation as a closed distribution network were developed and implemented.

Start of electricity quality regulation on 1 January 2012

Under incentive regulation, network operators are required to lower their revenue. There is however a risk here that costs will be saved by avoiding necessary investments in the networks, potentially leading to a decrease in quality of supply. For this reason, the ARegV provides for the introduction of quality regulation. Operators whose network has had above-average quality levels in past years will thus have an amount added to the cap, while operators whose networks have comparatively poor quality levels will have amounts deducted (bonus / penalty system).

According to section 19(1) of the ARegV, electricity quality regulation must start in the second regulatory period at the latest. If a sufficiently robust data basis is available, however, the quality regulation should already begin at the start of or during the first regulatory period. In 2010 the Bundesnetzagentur developed a concept detailing the "electricity network reliability" quality element. This included the planned implementation of a basic variant of quality regulation for electricity network reliability on 1 January 2012.

In order to calculate the quality element, this variant uses the SAIDI (System Average Interruption Duration Index) for the low voltage level and the ASIDI (Average System Interruption Duration Index) for the medium voltage level to indicate network reliability. Interruptions of less than three minutes are disregarded. SAIDI and ASIDI, in turn, are based on the interruptions to supply notified by the operators under section 52 of the Energy Act. Reference figures are derived from the indices, with load density as a parameter to replicate structural differences between the individual networks. If a network operator's individual SAIDI/ASIDI value deviates from the calculated reference value, the operator receives a bonus or penalty on their permitted revenue cap.

It must be stressed that the reference values are not targets set by the authorities for the individual network operators regarding the level of network reliability to be achieved.

National data are to be taken into consideration in the quality regulation system. The basic variant is to be applied solely to low and medium-high voltage networks taking part in efficiency benchmarking as set out in section 12 of the ARegV. The basic variant excludes high and extra high voltage networks from the quality element, as no reliable quality regulation can be carried out in this area with the figures mentioned above.

In the first regulatory period, quality regulation was applied for 202 electricity distribution system operators with a total of 214 networks. This resulted in a bonus for 2012 and 2013 for 143 network operators, while 59 were awarded a penalty. One basic premise of the quality element calculation was revenue neutrality in the total bonus and penalty amounts among all network operators. Divergence from revenue neutrality was ultimately 220,000 euros, which was in particular due to the capping of the bonus and penalty amounts. The amounts for the individual network operators ranged from approx. -4,000,000 euros to approx. 4,000,000 euros.

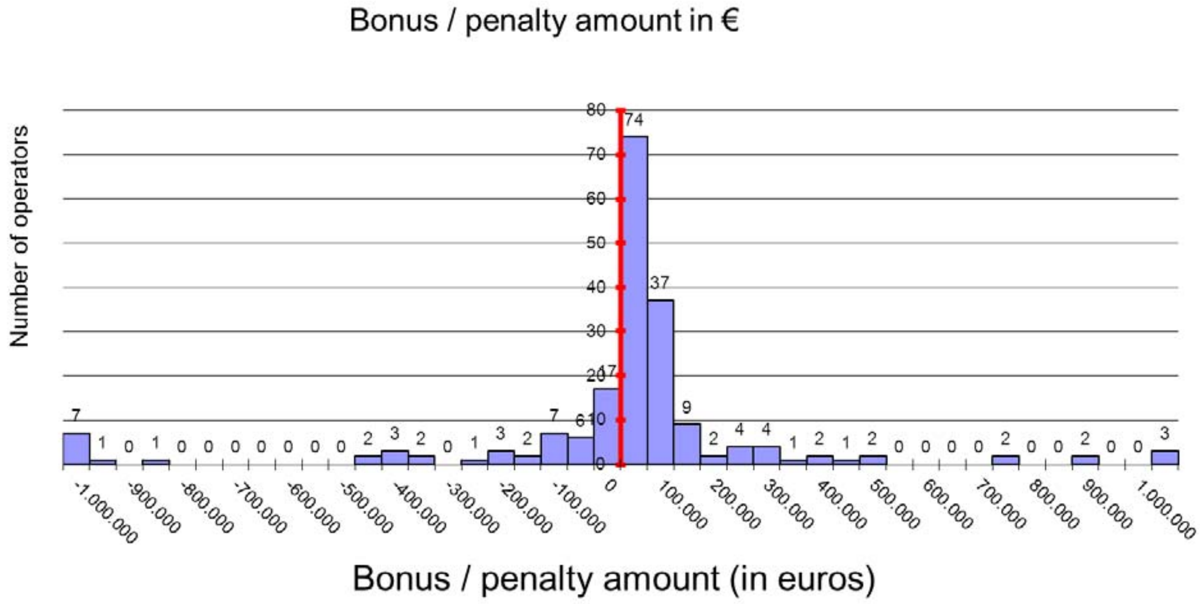

Figure 23: Bonus and penalty amounts for the individual network operators

The electricity network reliability quality elements must be redetermined for the second regulatory period.

As per sections 19 and 20 of the ARegV, bonus or penalty amounts can be applied to the revenue cap if the network operator deviates from the network reliability indicators. For this reason, the Bundesnetzagentur is investigating what a quality element for electricity or gas network performance would involve. However, as this is relatively new terrain in quality regulation, with no experience available in an international context, this indicator needs to be examined in detail prior to any application.

Preparation of electricity DSO efficiency benchmarking for the second regulatory period

The second regulatory period for electricity DSOs begins on 1 January 2014. The Bundesnetzagentur must also carry out nationwide efficiency benchmarking for these network operators (section 12(1) of the ARegV).

The structural data for the electricity DSO benchmarking in the second regulatory period are to be submitted to the Bundesnetzagentur by the DSOs by 1 September 2012. The efficiency values for the operators are to be calculated in 2013.

Cross-border trading, cross-border interconnectors

Medium available transmission capacity

The availability of transmission capacities between Member States plays an important role for the internal electricity market. Average available transmission capacity values were determined, to the extent available, by drawing on the TSOs' annual average hourly Network Transfer Capacity (NTC) values. Gaps were filled in by applying the average NTC values derived from ENTSO-E calculation formulas.[11]

The data shows that Germany continued to be the commercial hub of electricity trading in the interconnected central European system. Changes took place at the French and Danish borders in particular, as well as on the Baltic Cable (Germany-Sweden). On the Franco-German border average available export capacity fell by 9.2 percent and import capacity by 13.5 percent. Average available export capacity fell by 7.8 percent on the border between Germany and Denmark. Import capacity at the border between Germany and Denmark fell by 30.8 percent.

Export capacities through the Baltic Cable (Germany-Sweden) have fallen by 35 percent and import capacities by 20.5 percent. Average available transmission capacity across all German cross-border interconnectors has dropped from a total of 22,970 MW in 2010 by 7.12 percent to 21,336 MW (import and export capacities) in 2011.

[11] Care was taken to ensure that border values were determined using data from the same source. Only a very limited comparison can be made of individual country capacities, however, as the NTC values transmitted on an hourly basis from the TSOs may, owing to the different calculation methods applied, deviate from the average values calculated according to ENTSO-E. Details on the way NTC values are calculated by ENTSO-E or the German TSOs can be found at https://www.entsoe.eu/resources/ntc-values/ and at http://www.enbw.com/content/de/netznutzer/media/pdf/Allgemeines_Kapazit__tsberechnungsmodell.pdf.

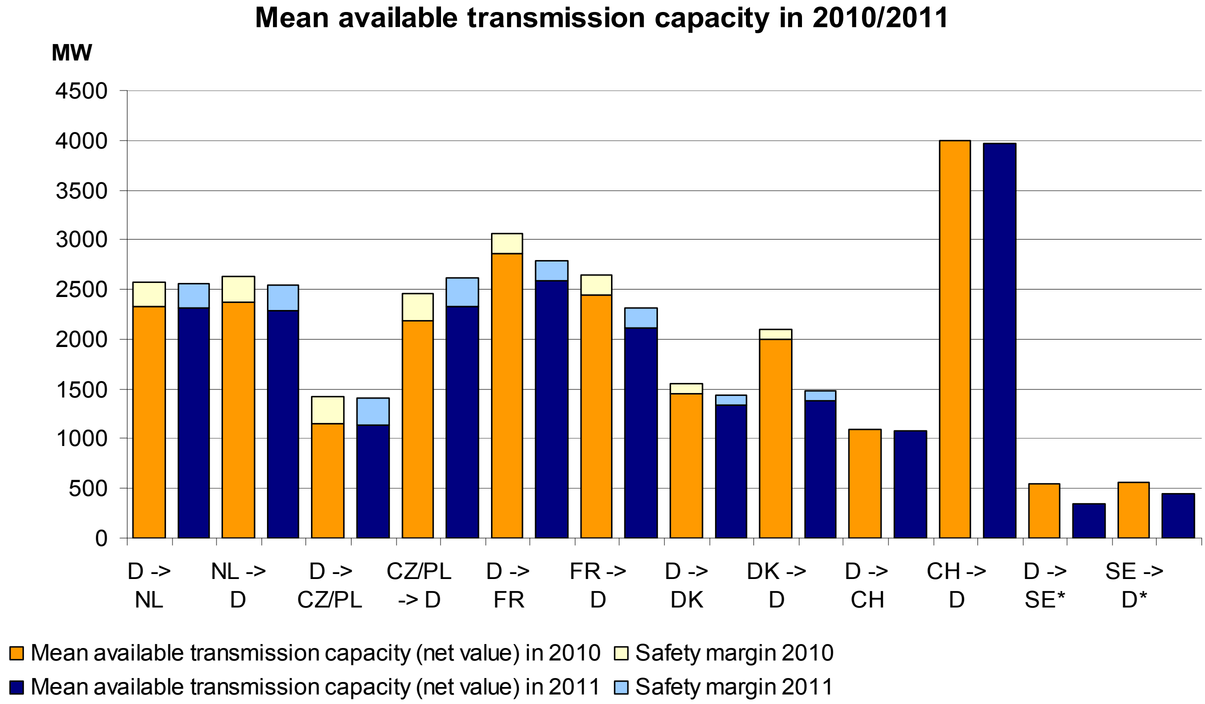

Figure 24: Medium available transmission capacity

The network calculations undertaken by German TSOs show that the growing strains to which the network has been subject since spring 2011 have made adjustments necessary to long-term capacities in particular. The "relocation" of capacities from the long term to the short term field enables TSOs to respond more flexibly to short-term changes. According to transmission system operators, other reasons for capacity adjustments on the German/Danish border included construction work involving the installation of a phase shifter transformer by the Danish transmission system operator, construction work by TenneT on the relevant network equipment and larger volumes of energy generated from renewable energy sources in Schleswig Holstein.

Cross-border load flows and implemented exchange schedules

Actually implemented exchange schedules are decisive in assessing the net balance of electricity imports and exports at each external frontier and all Germany's borders. These exchange schedules follow the rules of the market[12] and map excess generation or shortages of demand which are also reflected in the results of physical electricity transport. The following diagram shows the exchange schedules in place at Germany's frontiers in 2011.

[12] The idea is for electricity trading to take place via cross-border interconnectors from low-price to high-price countries.

Exchange schedules
(cross-border trading)

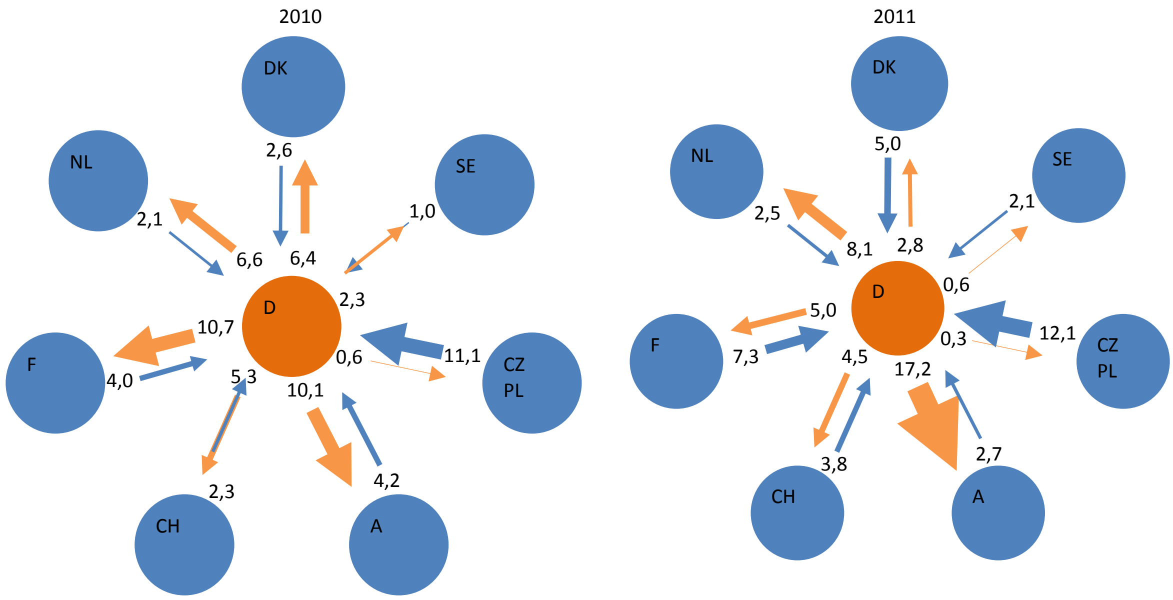

Figure 25: Exchange schedules in TWh (Cross-border electricity exchange)

Cross-border traded volumes have risen from 69.3 TWh (2010) to 74 TWh in 2011. Of this amount, 38.5 TWh was exported and 35.5 TWh imported. This means that Germany was also a net exporter in 2011, with a surplus of approximately 3 TWh. This is 11.7 TWh less than in the previous year, 2010[13].

In 2011 as well, the balance of electricity imported from the Czech Republic and Poland remained largely unchanged. Germany was also a net importer on the Franco-German border where trading volumes changed markedly between 2010 and 2011. While there was a substantial increase in imports to Germany (+ 82 percent), exports to France fell by 53 percent. This was in contrast to the considerable increase in exports to Austria (+ 70 percent). 23 percent more electricity was also exported to the Netherlands. From the German perspective, the main electricity customers in 2011, on balance, were Austria and the Netherlands.
In this context, the development of cross-border trading volumes primarily reflects shifting price differentials between Germany and its neighbours. There are many reasons for these price differences which ultimately depend on a variety of factors which influence the merit order and thus wholesale prices in each country. This means that changes in trading volumes do not simply reflect developments on the German market, but are also an expression of shifting supply and demand in neighbouring countries.

[13] This value is for all German external frontiers, with the exception of Germany's borders with Sweden and Luxembourg; no data was available for these borders.

Important factors on the demand side are the temperature and season: both of these have a direct impact on demand in the form of heating or cooling or lighting requirements. The overall economic situation can also play a role in that a weak economy often goes hand in hand with lower electricity consumption.

The supply side of the equation is also often dependent on the weather which determines how much power is produced by wind and photovoltaic systems. Finally, fuel costs are important for conventional sources of energy as the former are often determined on the world market and find their way directly into electricity wholesale prices. Effects differ markedly owing to the very different structure of the stock of power plants in each European country. In this connection it may also be important this year for the German market that, with the shutdown of nuclear power plants from March 2011, capacity suitable for covering base loads is withdrawn from the merit order.

As most of these effects overlap in time and can only be roughly measured, it is not possible to determine the specific influence on wholesale electricity prices or on cross-border trading.

The actual physical load flows shown in the following diagram deviate from the exchange schedules at each frontier.[14]

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

Physical cross-border load flows 2010/2011

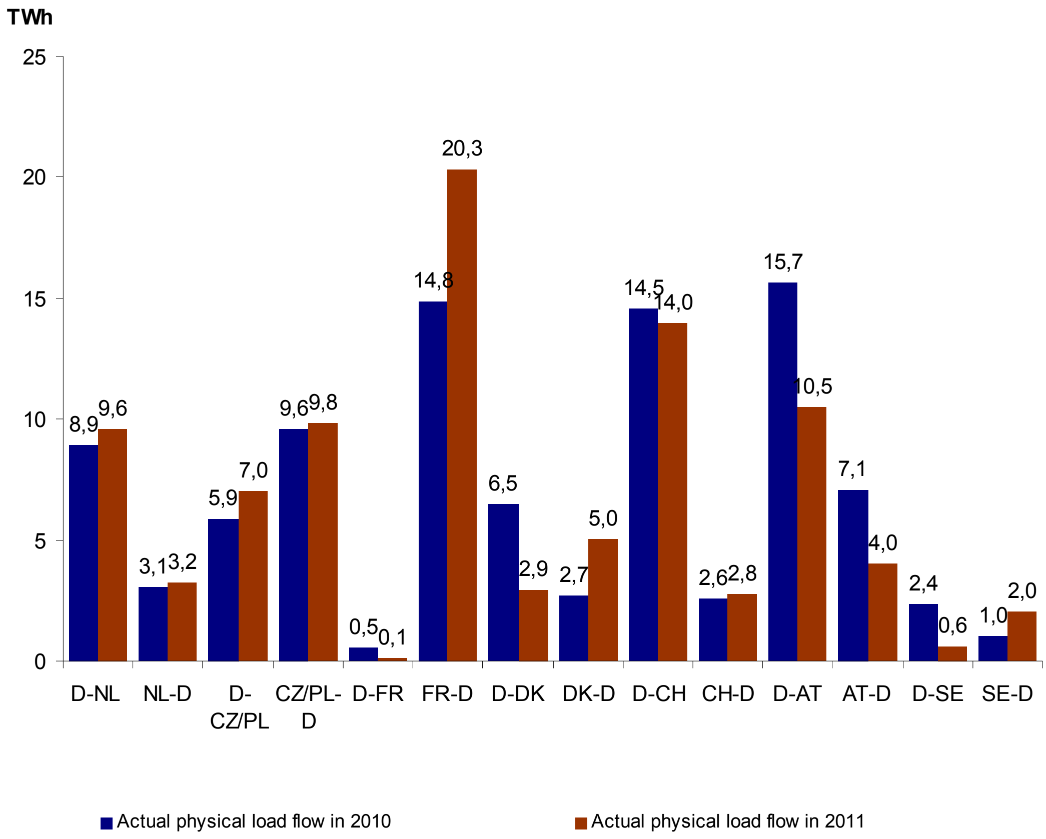

Figure 26: Physical cross-border load flows

Source: ENTSO-E - European Network of Transmission System Operators for Electricity

Revenue from compensation payments for cross-border load flows

Under Article 13(1) of Regulation (EC) No 714/2009, inter-TSO compensation (ITC) is paid for the costs incurred by TSOs as a result of hosting cross-border flows of electricity ("transits") on their networks. Since 23 September 2010, the ITC mechanism has been governed by Commission Regulation (EU) No 838/2010 on laying down guidelines relating to the inter-transmission system operator compensation mechanism and a single regulatory approach to transmission charging.

The four German TSOs received total payments in 2011 of €22.06 million (2010: €12.5 million) as compensation from the application of the ITC mechanism.

In the future, the European Agency for the Cooperation of Energy Regulators (ACER) will play an important role in the framework of the ITC mechanism and will, amongst other things, produce a proposal within two years of the commencement date of Regulation (EU) No 838/2010, for the annual compensation amount for cross-border infrastructures based on a Europe-wide evaluation of the transmission infrastructure needed to encourage cross-border flows of electricity. It will submit this proposal to the European Commission which will then stipulate the amount of compensation. This regulation also gives ACER numerous monitoring rights and imposes notification duties on ENTSO-E. At present ACER is finalising a report on the implementation of the ITC mechanism (Report on the implementation of the ITC mechanism and management of the ITF fund in 2011) in accordance with subpara 1.4 of the Annex Part A of Regulation (EU) No 838/2010.

ACER also performed extensive data surveys on anticipated long-run average incremental costs and calculations of the losses in individual ITC states (i.e. data is also obtained from non-EU countries participating in the ITC mechanism, such as Switzerland). This data survey is part of the study commissioned by ACER from Consentec (Consulting für Energiewirtschaft und -technik GmbH). The study looks at the ITC infrastructure fund and its fitness for the purpose of compensating transmission system operators whose infrastructure is used for the transmission of cross-border flows of electricity. As well as monitoring implementation, the study also aims to find out what methods of computation and which input parameters are used in each country, and to evaluate the current ITC mechanism. It does not study any further improvements to or the broadening of the ITC mechanism. A public workshop on Consentec's initial findings will take place in October.

ACER plans to submit its findings to the European Commission in March 2013.

European integration

Market coupling of European electricity wholesale markets

The coupling of the day-ahead electricity markets of north-west Europe (Germany, France, Benelux and Scandinavia) launched in November 2010 lived up to expectations throughout 2011, both operatively and in terms of market outcomes. In operative terms, market coupling is performed in two different but closely coordinated procedures: CWE Market Coupling brings together the electricity markets of Central West Europe (CWE: Germany, France, Benelux). The coupling between CWE and Scandinavia is undertaken by the Hamburg-based European Market Coupling Company (EMCC). However, this two-step system will be replaced by the second quarter of 2013 by uniform coupling which will also include the United Kingdom and the Baltic.

The objective of market coupling is the efficient use of day-ahead available transmission capacities between participating countries. The method consequently brings about an alignment of prices on national day-ahead markets.

Greater price convergence, and consequently more efficient congestion management, is clearly discernible in CWE in 2011: Before the introduction of CWE market coupling, prices were identical in Germany, France and the Benelux countries in just 0.3 percent of hours of the year. This figure rose dramatically after market coupling was launched and in 2011 was over 65 percent.[15] Prices in Germany and at least one other country are aligned in 23 percent of hours. In 2011, prices were only completely unequal in CWE in 0.4 percent of hours.

Against this background neighbouring countries, such as Switzerland, Spain and the United Kingdom, have also shown great interest in market coupling. At the European level, ACER has transferred the project management of implementing market coupling throughout Europe by 2014 to the Bundesnetzagentur. With this aim in mind, the Bundesnetzagentur has drawn up an implementation plan for ACER which details specific milestones. The Bundesnetzagentur is endeavouring to extend market coupling in north-west Europe successively to other regions and markets.

Flow-based capacity allocation

Framework Guidelines on "Capacity Allocation and Congestion Management for Electricity" drawn up by ACER define flow-based market coupling as the target model for short-term capacity management. One of the key cornerstones for this is flow-based capacity calculation. This involves taking account of the physical flows which specific commercial transactions are expected to generate as soon as capacity is calculated and then determining the transmission capacities which are subsequently available according to efficiency criteria and system security aspects. This guarantees greater system security and the improved use of transmission capacities.

Work is currently underway on two projects which are based on regional initiatives. Network operators in North West Europe (NWE) and in Central East Europe (CEE) are working on flow-based calculation methods which are tailored to meet specific regional characteristics.

The successful launch of market coupling in CWE in autumn 2010 was followed by the rapid implementation of the flow-based method. In April 2011 the project partners, electricity exchanges and transmission system operators presented the first feasibility study and, at the same time, an updated project plan. This plan envisaged a preparatory phase up to November 2011 followed by an implementation phase. The detailed project plan provides for flow-based market coupling to be introduced in CWE by mid-2013. The project was presented to the associations of market participants at a forum held in June 2011. The feasibility study was pre-

[15] These calculations assume price parity up to a neglible price difference of 5 ct/MWh.

sented in an updated form in October 2011 and foresees the project having a positive impact on the market, regardless of the precise implementation model adopted.

The original project in CEE entailed an explicit allocation of transmission capacities, based on a flow-based capacity calculation. Despite great expectations and six years of project work, TSOs were unfortunately not able to agree on the introduction of the model in autumn 2011. Following intensive discussion at the turn of the year 2011/2012 a decision was taken in the CEE region to bypass the intermediary steps and to adopt the target model (flow-based market coupling) directly in the form of explicit flow-based allocation. After introducing flow-based market coupling in CWE/ NEW, the aim now is to bring about common market coupling of the markets in CEE and NWE as soon as possible. This market coupling will be based on the flow-based calculation methods used in CWE and CEE. All the harmonisation steps for both methods which this cooperation will require are currently being developed.

One particular challenge is to launch common flow-based market coupling by the end of 2013 without this leading to delays for projects in the CWE and NWE regions.

Framework guidelines on system operation and associated network codes

In December 2011 ACER completed its work on the preparation of framework guidelines on system operation which it had begun one year earlier on behalf of the European Commission. The guidelines were made available for public consultation from July through to September. The contributions of market participants were integrated in the document. The Bundesnetzagentur is participating in the framework of ACER. The framework guidelines are intended to specify the areas referred to in Article 8(6) (a), (d), (e), and (f) of Regulation (EC) No 714/2009. These are intended to provide rules on network security and reliability, including rules for technical transmission reserve capacity for operational network security, rules for data exchange and settlement, rules for interoperability and operational procedures in an emergency.

ACER passed the framework guidelines on to the European Commission in December 2011. There after the European Network of Transmission Operators (ENTSO-E) was asked to draw up corresponding network codes to go with these framework guidelines. ENTSO-E is currently working on three planned network codes (operational security, operational planning and scheduling, load-frequency control and reserves).

Framework guidelines on capacity allocation and congestion management

With the aim of speeding up the European-wide integration of electricity markets in individual states, one of the things Regulation (EC) No 714/2009 envisages is that the regulatory authorities in ACER initially draw up framework guidelines on cross-border congestion management. ENTSO-E is asked to prepare corresponding network codes in accordance with these framework guidelines.

The regulatory authorities began their work on the framework guidelines on capacity allocation and congestion management at the end of 2009 and completed it in summer 2011. These guidelines set out the fundamental contours for the future organisation of the single market in electricity. Specifically, the guidelines detail the form which congestion management methods for long-term, day-ahead and intraday capacity allocation should take. They also stipulate the abstract method which should be used to calculate cross-border electricity transmission capacities.

Financial transmission rights are envisaged for long-term capacity allocations. A single Community-wide platform for the secondary trading of long-term transmission rights should also be provided. Day-ahead capacity trading should be settled implicitly, in other words, at the same time as commercial transactions in electricity. This implicit trading is to take place via a single price coupling algorithm. Intraday trading should also be implicitly organised. A corresponding algorithm should work according to the first-come-first-served principle. Intraday available capacities should be pooled on a single platform and linked to the exchanges' order books.

In the future, a flow-based capacity calculation procedure will be introduced which will determine cross-border transport capacities on the basis of commercial transactions and neighbouring cross-border interconnectors. At the same time, various implementation projects for the models in the framework guidelines have been started in the Regional Initiatives established for the electricity sector. These are partly based on projects which were begun in the relevant regions prior to 2010.

Against the background of the Community-wide focus of the framework guidelines, the boundaries of the respective Regional Initiatives have been increasingly overcome and interregional cooperation started. Of particular interest here is the introduction of volume-based market coupling between Central West Europe (CWE)[16] and the northern states[17].

The preparation of the network code is accompanied by a discussion of issues regarding the control, structure and the allocation of roles (governance) for day-ahead and intraday trading.

[16] Benelux, Germany and France.
[17] Denmark, Sweden, Finland and Norway.

Specifically, discussion focuses on the relationship between exchanges and transmission system operators in the context of day-ahead and intraday cross-border electricity trading and on the allocation of costs. Consideration is currently being given to whether these governance guidelines (for which the European Commission is responsible) should be included in the network code and enacted with it in the comitology procedure to put the network code on a legal footing, which is due to begin in spring 2013, or whether the governance guideline rules should be enacted in law separately. The Commission has not yet stated its conclusive position.

The issue of long-term capacity allocations will be dealt with in a separate network code as this still requires further discussion and study. The current timetable envisages the matter being handed over to ACER in September 2013.

Transparency

Market transparency also developed satisfactorily in 2011. As has been the case in recent years, the market coverage of the EEX transparency platform was improved. In autumn 2012 this was 96.21 percent. The aim is to achieve further improvements.

The European Regulators' Group for Electricity and Gas (ERGEG) proposed issuing binding guidelines for the electricity sector in 2010 with the aim of establishing comparable publication duties throughout Europe. The European Commission took up this proposal and, in 2011, initiated comitology procedures for the adoption of such guidelines. An initial draft was discussed in June 2012; it is due to be enacted in winter 2012. The Bundesnetzagentur is following this process very closely. Under the guidelines, central data on the generation, transmission and consumption of electricity will be published in a standardised form on a central platform. The guidelines will also be important in other ways as well. Under REMIT (Wholesale Energy Markets Integrity and Transparency)[18] the disclosure of inside information under these guidelines is regarded as effective under this Regulation as well (Article 4 of the Regulation).

Intraday trading

Section 5(1) of the Electricity Network Access Ordinance basically allows schedule notifications, in which balancing group managers notify transmission system operators about planned electricity supply and commercial transactions for the respective day (based on quarter-hour values), up to 2.30 p.m. on the day before. In order to enable balancing group managers to respond to short-term changes in the supply and demand situation, schedules can be modified during the day as well.

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[18] More information about REMIT is provided in the Chapter: General – Bundesnetzagentur activities.

To date, section 5(2) of the Electricity Network Access Ordinance enabled changes to be made to intraday schedules in a control area and to schedules across control areas with at least three quarters of an hour prior notice every 15 minutes of the day. Under section 5(4) of this Ordinance, it is also possible in the event of power station outages to change schedules with 15 minutes notice every quarter of an hour.

On 1 December 2010 German TSOs reduced the prior notice under subsection 2 to 15 minutes, adjusted to the rules in subsection 4. All intraday schedules can now be changed with prior notice of 15 minutes.

The following diagram shows the development of the number and volume of intraday changes in schedule in 2011.

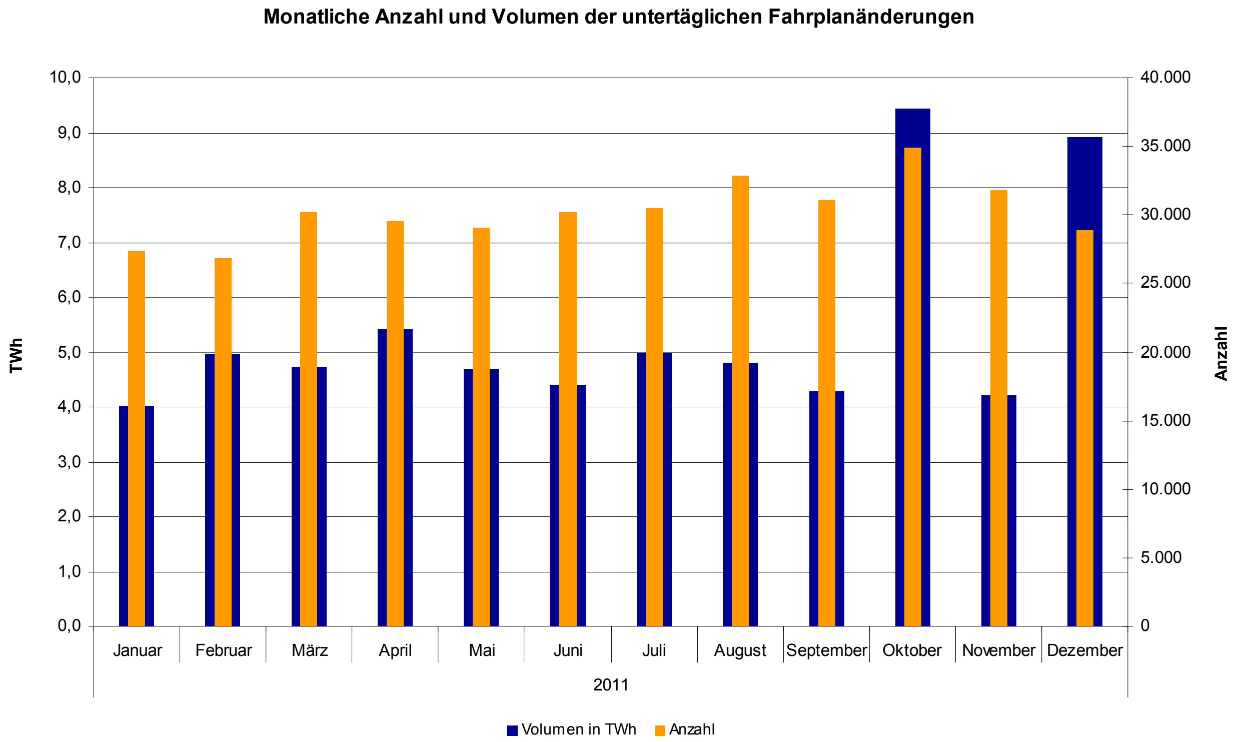

Figure 27: Monthly number and volume of intraday changes to schedules in 2011

The increase (both in number and volume) of intraday schedule changes can be partly explained by the increase in intermittent input of renewable energies which make it necessary to balance this out during the day by means of intraday trading. In the reporting year of 2011 a total number of 363,281 schedule changes (2010: 265,710) accounted for a total volume of 64.8 TWh (2010: 41.3 TWh). On average, 30,000 schedule changes were made every month[19].

[19] The highest value was in 2011 at 34,948 changes per month; the lowest was 26,870.

System support services

System support services are core tasks for the transmission system operators. They include keeping and using the three kinds of system balancing power, that is to say primary balancing power, secondary balancing power and minute reserve. Other system support services are the provision of energy to compensate for transmission losses, the provision of reactive power and black start capability, and national and cross-border redispatch and countertrading.

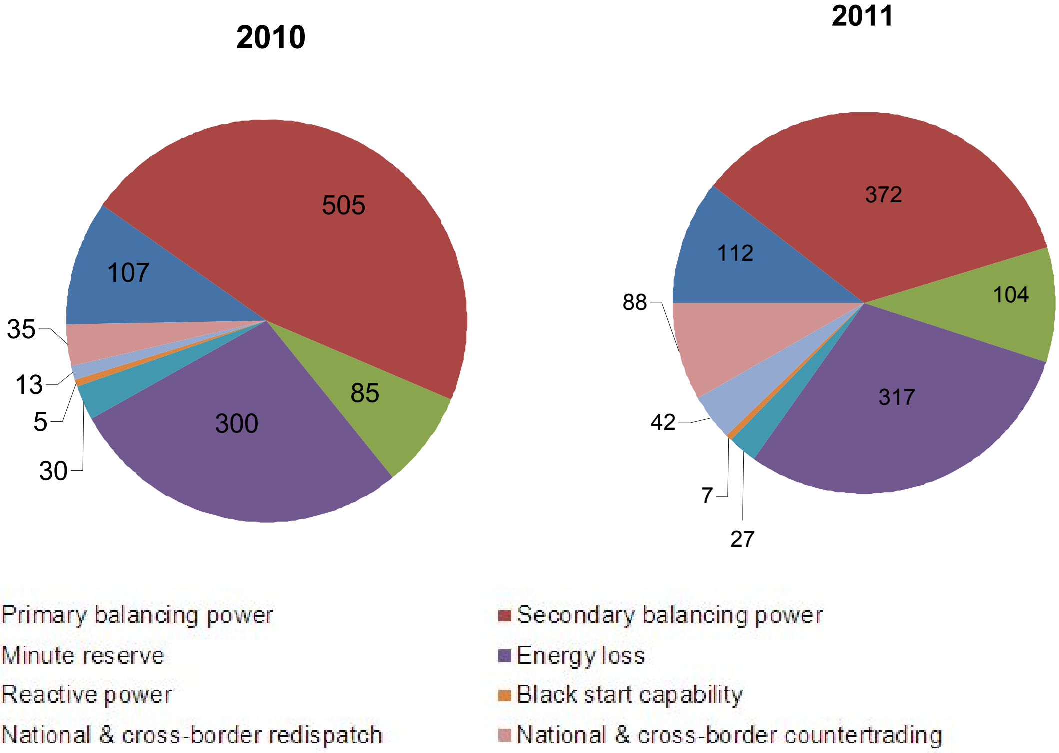

Figure 28: Total costs of TSOs' system support services in 2011 und 2010 in Euro millions

There was a slight fall in the total costs of system support services in 2011 to 1,135m Euro (2010: 1,176m Euro). Despite lower cost-reducing revenues of altogether 66m Euro (2010: 96m Euro) the total costs for system support services fell slightly to 1,069m Euro (2010: 1,080m Euro). The main part of the total costs (2011: 697m Euro) fell to keeping the reserves of balancing power, which accounted for 588m Euro.

The cost structure of the system support services was not the same in 2011 as in 2010. There was a noticeable drop (109m Euro) in the total costs for system balancing energy, most notably because of the lower costs for secondary reserve. By contrast, there was a clear increase in the redispatch costs (+29m Euro) and the countertrading costs (+ 53m Euro).

System balancing energy

A cooperation scheme for grid control, covering the control areas of all four German transmission system operators (50 Hertz, EnBW TNG, TenneT TSO, Amprion), was completed when

Amprion joined in 2010. Its modular structure prevents inefficient use of secondary and minute reserve, dimensions the reserve requirements for all four control areas together, creates a single nationwide market for secondary and minute reserve and optimises the cost of using balancing power for the whole of Germany. The imbalances in the individual control areas are netted so that only what remains has to be balanced by the use of this energy. Inefficient use is almost completely eliminated and the level of balancing power that has to be kept is reduced, as seen in the lower levels of secondary and minute reserve tendered for and actually used.

One of the aims of the determinations issued by the Bundesnetzagentur in 2011 on reducing minimum bid volumes, tendering periods and timeslices on the primary, secondary and minute reserve market is to encourage new suppliers to enter the market and to further open the system balancing energy market for other technologies, eg for interruptible consumption, for storage facilities, etc.

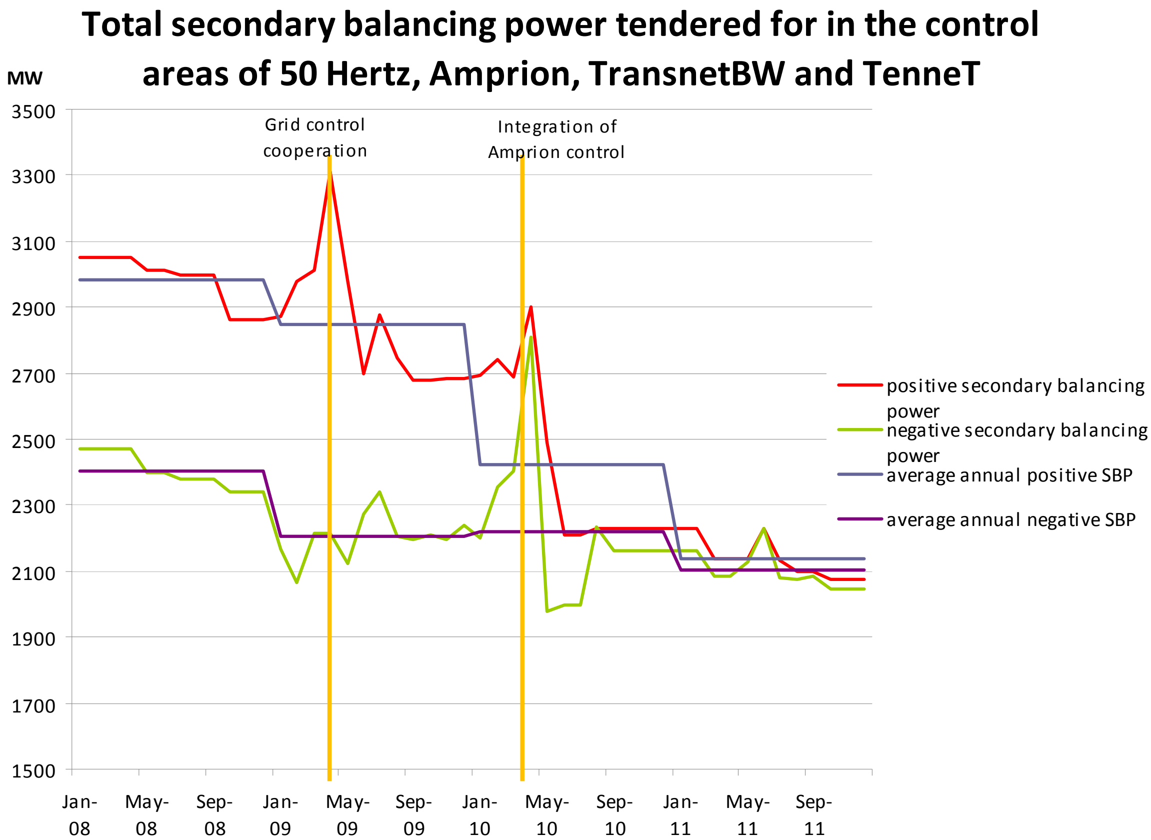

Figure 29: Total secondary balancing power tendered for in the control areas of 50 Hertz, Amprion, TransnetBW and TenneT

The above figure shows the effect of introducing grid control cooperation: there is a clear drop in the average volume of secondary balancing power tendered for in the periods between May of one year and April of the next. Compared with 2010, the average level of positive secondary balancing power tendered for fell to 2,139 MW (2010: 2,425 MW) and negative secondary balancing power to 2,102 MW (2010: 2,219 MW).

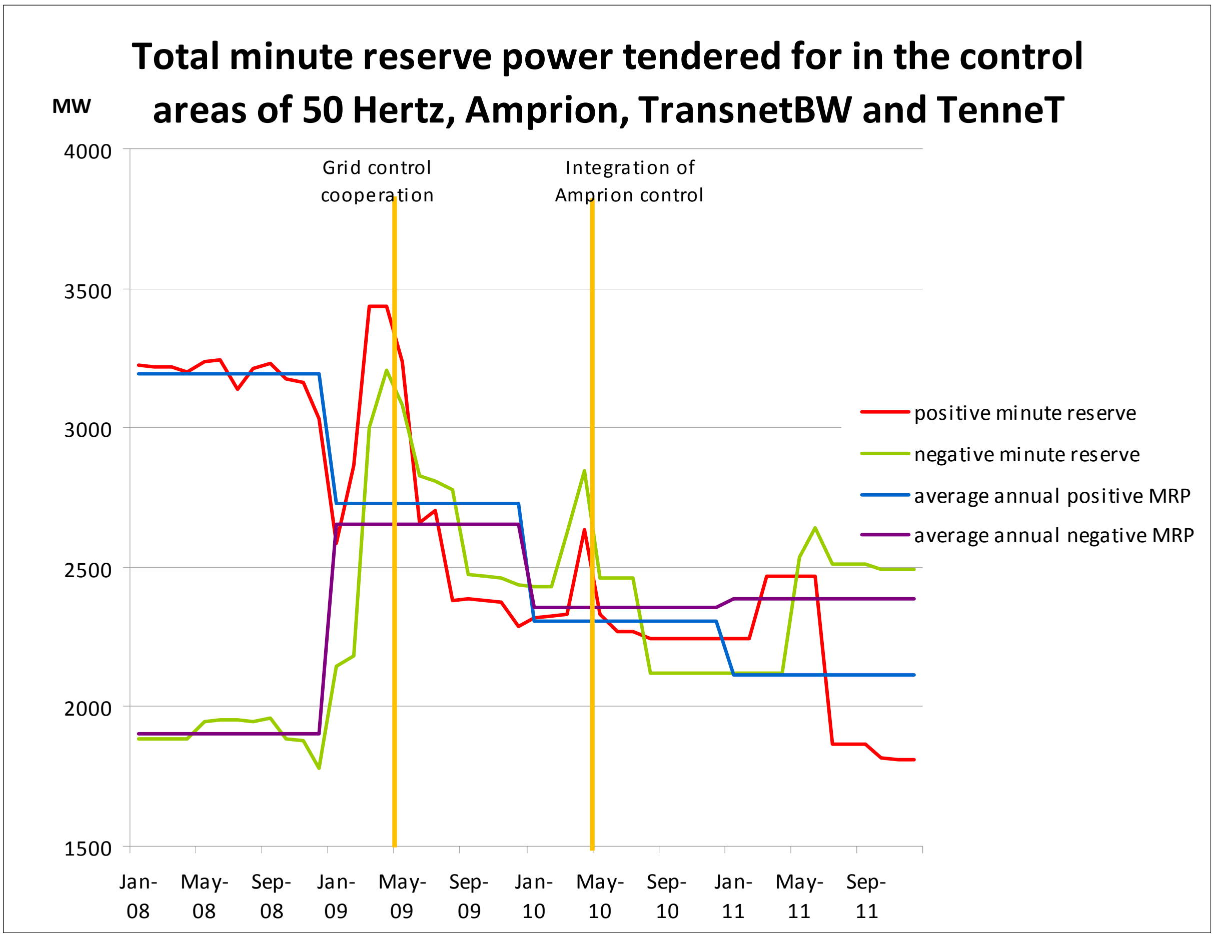

Figure 30: Total minute reserve power tendered for in the control areas of 50 Hertz, Amprion, TransnetBW andTenneT

The picture is less uniform when it comes to the provision of minute reserve. Whereas there was a continued decline here too in the average volume of positive minute reserve tendered for from 2,316 MW in 2010 to 1,812 MW in 2011, the share of negative minute reserve kept in late 2010 and early 2011 was consistently low to begin with but then rose to reach approximately the level of early 2010. To some extent, this is accounted for by the changed generating patterns and the growing number of generating installations for renewables in Germany. It is also accounted for by surpluses that often occur in the control area at the end of the year as a result of the dimensioning method used later reappearing in the dimensioning of the balancing power kept. The efficiency-increasing potential of grid control cooperation has now been exhausted in Germany. Yet the modular structure of the scheme makes it possible to extend it to neighbouring control areas in other countries, something the German transmission system operators are looking to do. The framework conditions for the system balancing energy markets in Europe still differ from one another, and so not all the modules are applicable straightaway. What can be implemented in the short term, however, is the first module, which prevents inefficient use of reserves. At the borders subject to congestion management, offsetting the use of system balancing energy is limited to the transmission capacities not used by the market. There is no booking of capacity for an exchange of system balancing energy. Nor does the planned cooperation with foreign TSOs have any effect on the level of balancing power procured jointly by the German TSOs.

The ranges of the volumes tendered for in 2011 can be seen in the table below.

	Primary**	**Secondary****		**Minute reserve****	
	pos / neg	**pos**	**neg**	**pos / neg**	**pos**
Volume tendered for [MW]	612	2073 - 2231	2044 - 2228	1812 - 2469	2118 - 2642

Table 12: Overview of the system balancing power tendered for by the TSOs in MW; Source: www.regelleistung.net

The requirements of primary balancing power were lower in 2011 than in 2010 (612 MW and 623 MW respectively).

The German TSOs and the Swiss TSO Swissgrid are seeking, in consultation with the Bundesnetzagentur and the Swiss regulatory authority, the Eidgenössische Elektrizitätskommission ElCom, to harmonise both markets for primary balancing power with a view to merger. Since 12 March 2011, the beginning of the first harmonisation stage, Swissgrid has issued calls for tender for 25 MW of Switzerland's requirements for coverage by German primary balancing reserve suppliers. There is no limit on coverage of the German requirements from Switzerland. But there are technical limits on account of the rules in the Operation Handbook of the Union for the Co-ordination of Transmission of Electricity (UCTE). Swissgrid is taking part, with this 25 MW for joint tendering, as the fifth TSO in the German tenders in line with the German regulations and is the connecting TSO for the Swiss suppliers.

Grid control cooperation and the determinations issued by the Bundesnetzagentur are contributing to greater competitive potential as a result of enlarging the market area by creating a nationwide market for secondary balancing power and for minute reserve and amending the tender specifications. Thus the number of prequalified suppliers of system balancing energy had risen to 14 for primary reserve (2010: eight), to15 for secondary reserve (2010: eleven) and to 35 for minute reserve (2010: 28) by 26 June 2012.Use of secondary balancing power

Use of secondary balancing power dipped in 2011. It should perhaps be mentioned that the diagram below includes the balance resulting from the nationwide cooperation scheme for grid control from 1 May 2010. As the figure above shows, the secondary reserve procured in 2010 and 2011 fell successively, the cooperation scheme being one of the reasons for the lower demand.

For the year 2011 the total volume of energy used was some 1,6TWh (2010: 3 TWh) for positive and 4,5 TWh (2010: 3,2 TWh) for negative secondary balancing power. A shift towards negative secondary balancing power can be observed with a slightly lower overall volume of energy. One of the reasons may be the increase in renewables generation and associated fluctuations in feed-in.

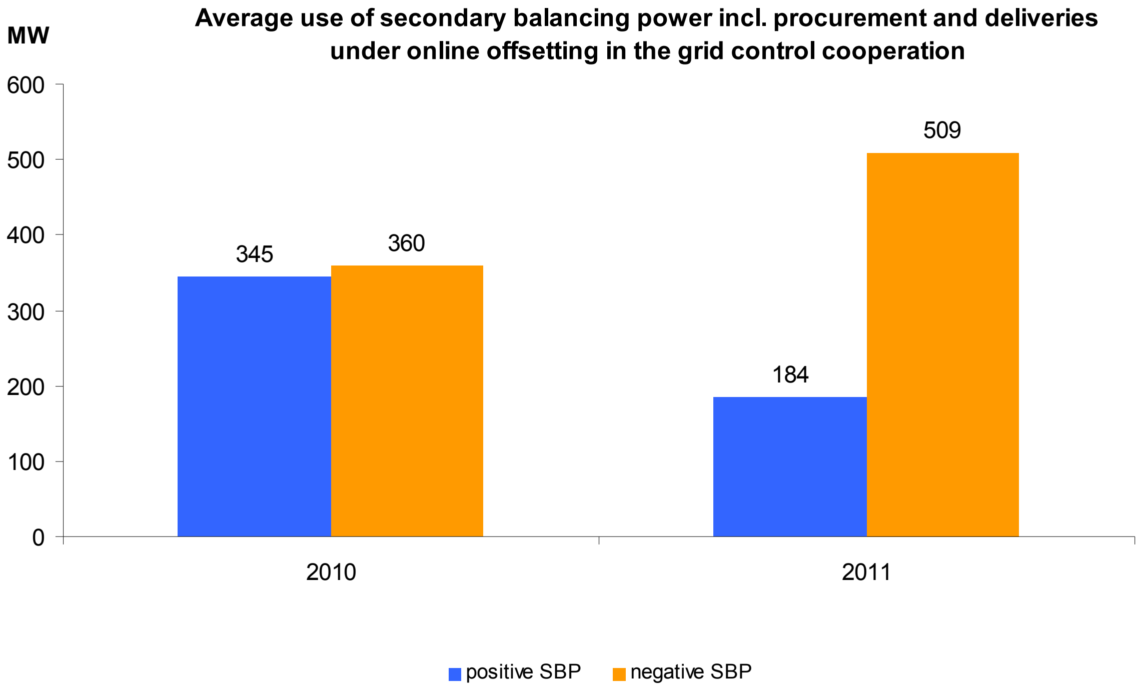

Figure 31: Average use of secondary balancing power per 15 minutes in 2010 and 2011

Use of minute reserve

With a total of 18,065 release requests, the frequency with which minute reserve was used in 2011 returned to the level of 2009, as shown in the table below. This is primarily due to the increase in the use of negative minute reserve, analagous to secondary balancing power.

Year	Release request
2004	12,737
2005	6,456
2006	3,940
2007	4,888
2008	6,014
2009	18,206
2010	16,567
2011	18,065

Table 13: Minute reserve frequency of use

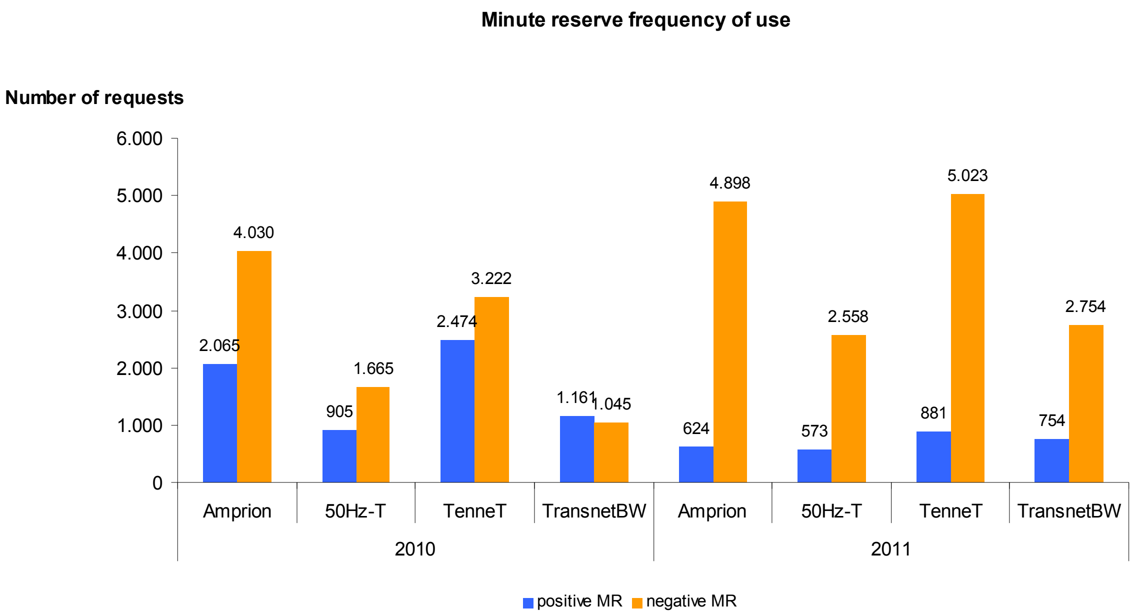

Figure 32: Minute reserve frequency of use in the four German control areas in 2010 and 2011

The average power in a release request, approx 238 MW, was lower for positive minute reserve than in 2010 (262 MW). With around 322 MW for negative minute reserve in 2011 the average volume of power requested was higher than in 2010 (318 MW).

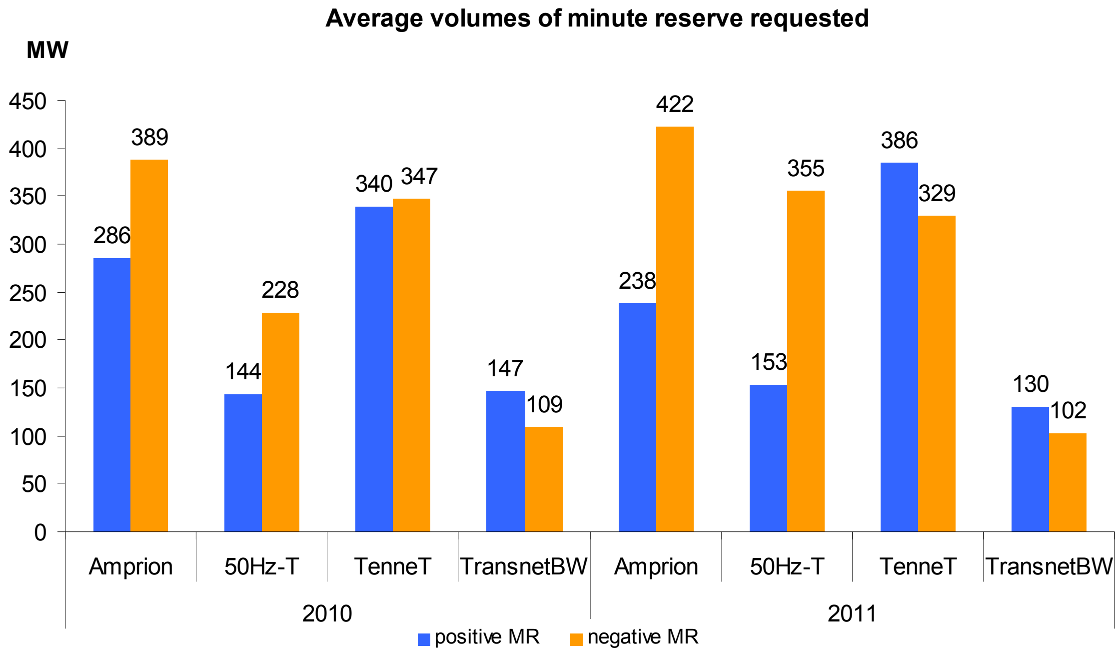

Figure 33: Average volumes of minute reserve requested by the TSOs in 2010 and 2011

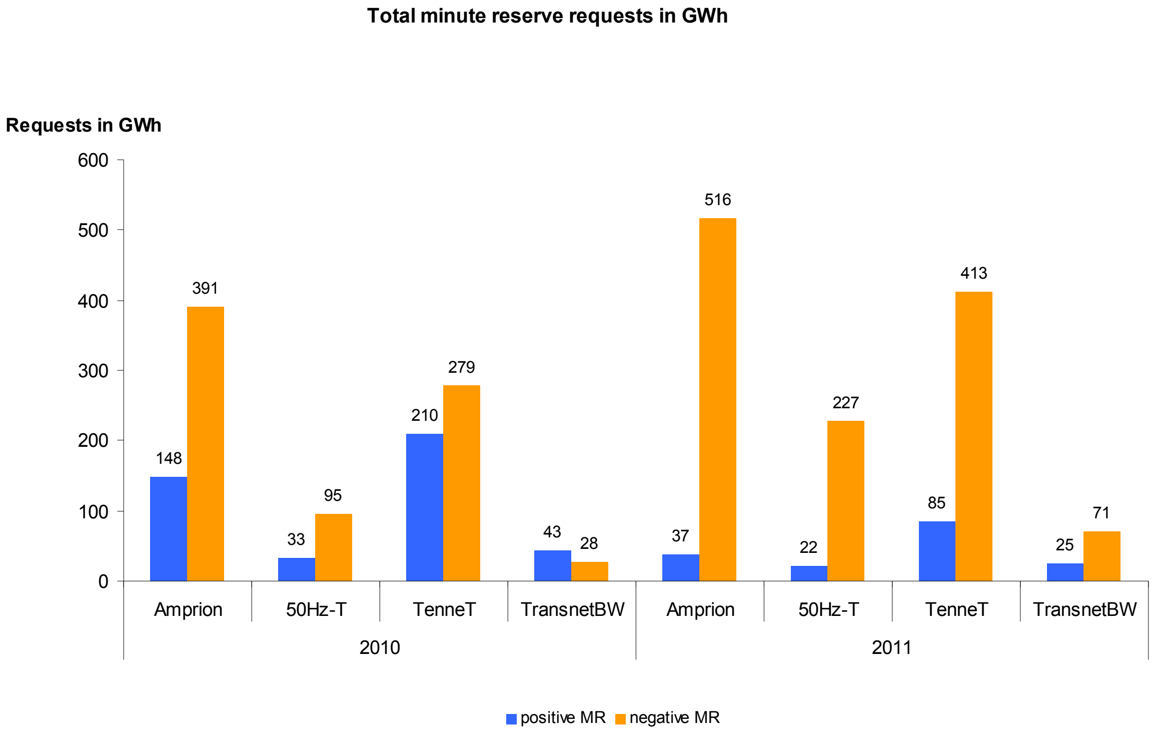

Figure 34: Energy volumes requested in 2010 and 2011 in GWh

Thus altogether, 168 GWh (2010: 433 GWh) was used in 2011 for positive minute reserve and 1,226 GWh (2010: 794 GWh) for negative minute reserve. A shift away from positive to negative minute reserve was also observed, which can possibly be accounted for by the increase in the generation of electricity from renewables and the greater fluctuations in feed-in that this brings.

The figure below shows the average use of system balancing energy for each calendar month. It also shows a period mean. A period always begins with a change in grid control cooperation (eg setting up, Amprion joining). This indicates the savings potential of the scheme in relation to the system energy.

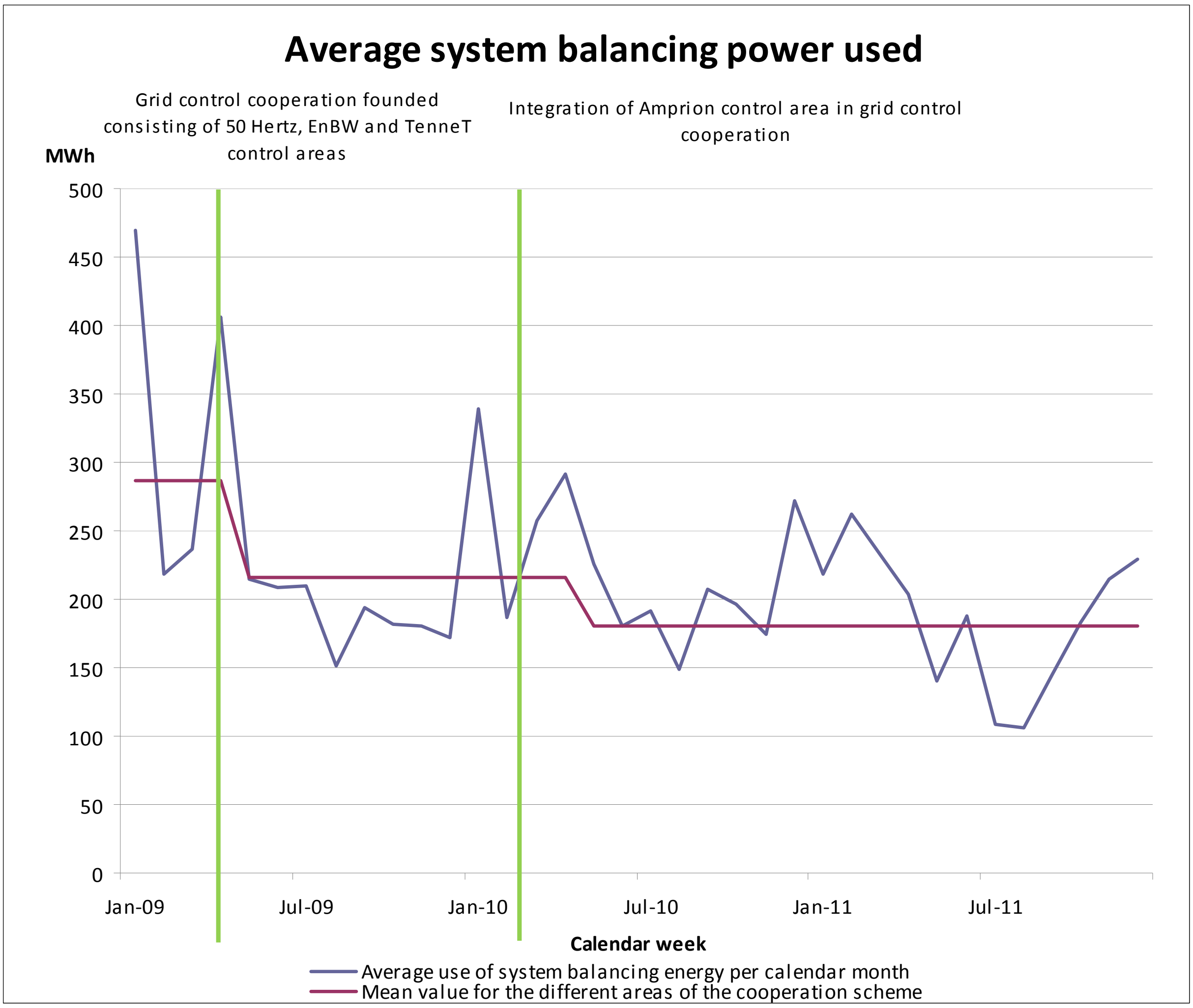

Figure 35: Average system balancing power used in MWh

Portfolio balancing energy

Unlike in 2010, the maximum prices for portfolio balancing energy fell under the cooperation scheme. One of the reasons for the lower maximum prices is the inclusion of Amprion and the resulting synergies. This effect was stronger still in 2011 since all four transmission system operators were engaged in the scheme throughout the period under review.

Year	Amprion in ct/kWh	NRV in ct/kWh
2010	**130,1.**[20]	60.09
2011	55.16	55.16

Table 14: Maximum portfolio balancing energy prices in 2010 and 2011

Under the cooperation scheme, the average 15 minute price for portfolio balancing energy in 2010, in the case of a positive control area balance (short portfolio), was approx 10.71 ct/kWh, and in the case of a negative balance (long portfolio), approx -0.06 ct/kWh. A slight year-on-year increase in the average price for portfolio balancing energy was identified in 2011. The average weighted price in 2011 with a positive control area balance was 11.86 ct/kWh, and – 0.20 ct/kWh with a negative balance (cf Figure 35).

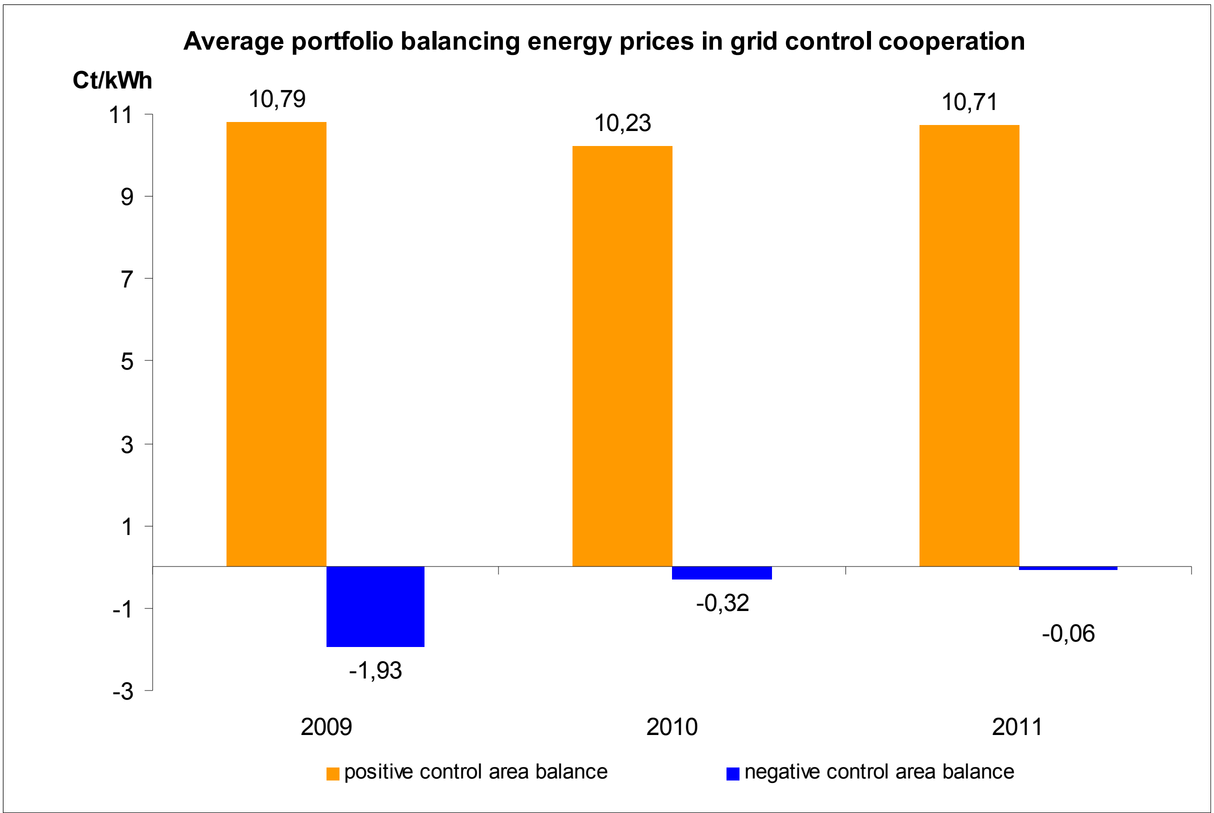

Figure 36: Average portfolio balancing energy prices

[20] Applicable until Amprion joined in May 2010

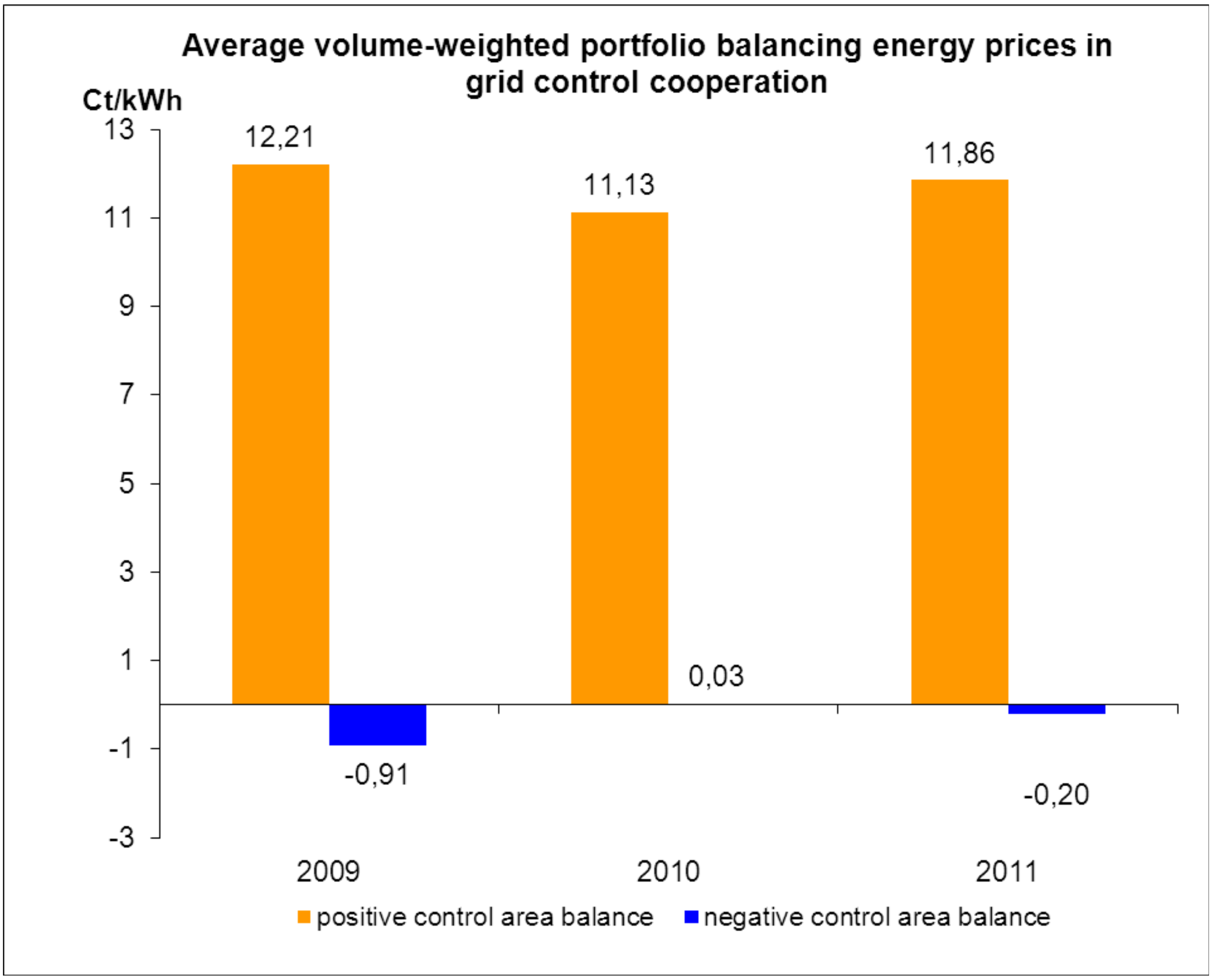

Figure 37: Average volume-weighted portfolio balancing energy prices in 2009, 2010 and 2011

The following diagram shows the frequency distribution of the prices for portfolio balancing energy in grid cooperation control. With the negative control area balance there is an accumulation of the prices around 0 €/MWh. This effect was stronger in 2011 than in 2010, which is attributable to the expansion of the grid control cooperation scheme and the greater competition. This effect can be seen even more clearly with the positive control area balance, where the prices congregate at the lower price level. Again, this is explained by the expansion of the cooperation scheme and the impact of this.

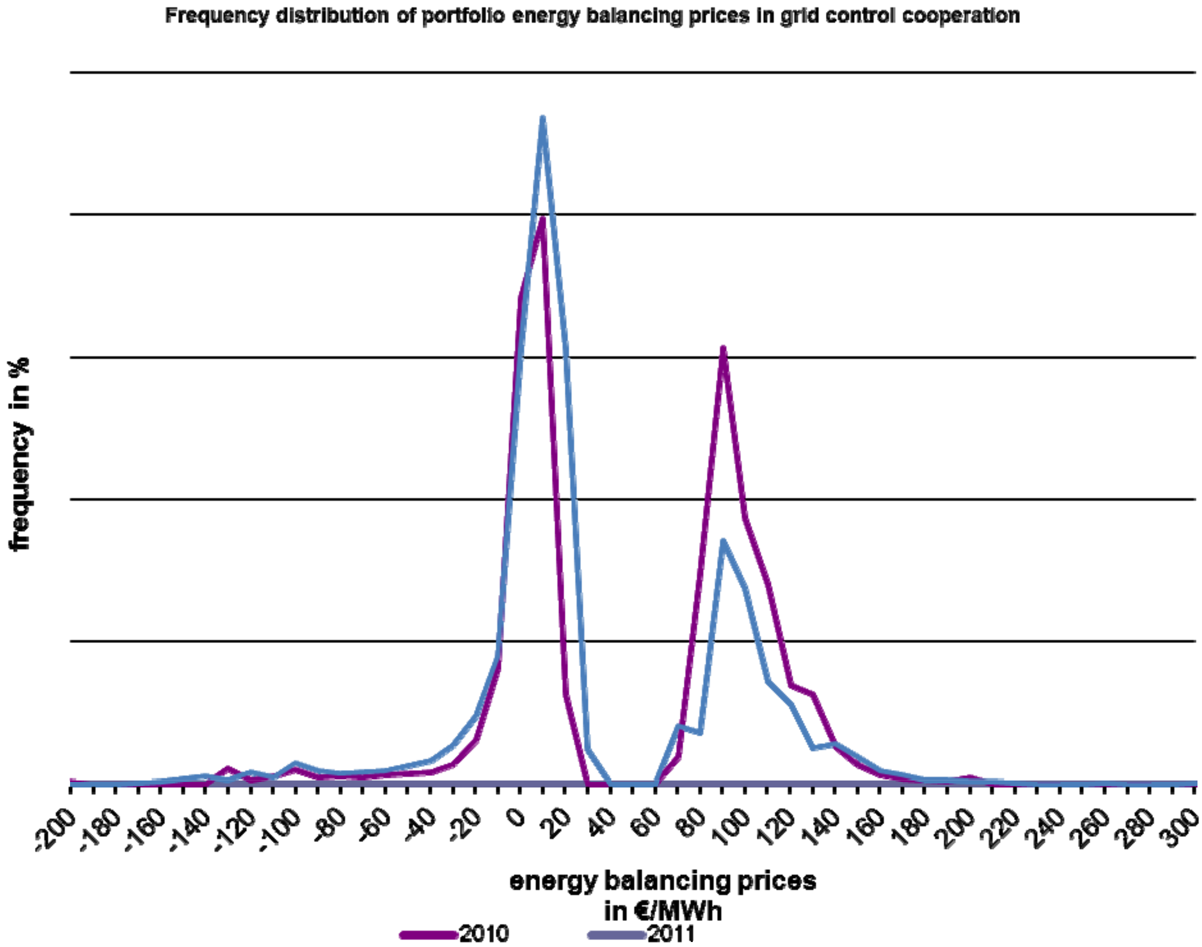

Figure 38: Frequency distribution of portfolio energy balancing prices in 2011 and 2012 in percentages

International expansion of grid control cooperation

The modular grid control scheme of cooperation among the four German transmission system operators has been fully active in all respects since mid-2010. Accordingly, it has no more potential for yet more efficient use of system balancing energy in Germany.

However, the modular structure makes a phased expansion of grid control cooperation to neighbouring foreign control areas possible. And in 2011 and 2012, the transmission system operators indeed sought to push the expansion of Module 1 (Avoidance of action leading to inefficient use of reserve power). As merely the imbalances in the control areas are offset at this stage in line with the transmission capacity remaining after the participants' trades, no changes to the national framework conditions are required. The optimisation potential can be realised relatively easily through incorporation in the system. The optimisation system is managed in TransnetBW's main control centre in Wendlingen and operated for all the participants from there.

Cooperation to avoid inefficient use of reserves is carried out with the following countries: Denmark (since October 2011), the Netherlands (since February 2012), Switzerland (since

March 2012) and the Czech Republic (since June 2012). The next step is to include Belgium; the inclusion is planned before the close of 2012.

Framework Guidelines

June 2011 saw the beginning of ACER's preparatory work on drawing up Framework Guidelines on balancing energy. In January 2012 the European Commission officially mandated ACER with drawing up these Framework Guidelines. The Bundesnetzagentur is making a major contribution to this within ACER. The Framework Guidelines will concretise the areas named in Article 8(6) (h) and (j) of Regulation (EC) No 714/2009 and set rules for trading related to technical and operational provision of network access services and system balancing, and balancing rules including network-related power reserve rules. The Framework Guidelines aim to ensure security of supply, to strengthen competition in the system balancing energy markets, to enable the inclusion of load management and renewables in the system balancing energy markets and to promote cross-border exchanges of system balancing energy. All Framework Guidelines must contribute to non-discrimination, to real competition and to the efficient working of the market. To this end the balancing energy Framework Guidelines aim to achieve, to the necessary degree, the integration, the coordination and the harmonisation of the national system balancing energy regimes.

ACER will provide the Framework Guidelines to the European Commission by September 2012. The European Network of Transmission System Operators for Electricity, ENTSO-E, is then called upon to draw up network codes in accordance with the Framework Guidelines.

Redispatch – suitable payment

The Bundesnetzagentur in 2012 set criteria for determining suitable payment for redispatch measures. Redispatch measures denote intervention by the transmission system operators in generating schedules in order to maintain system security. When congestion occurs, the strain is taken off particular lines by entering the volumes elsewhere. This involves reducing the output of the power plant in the region on one side of the place of congestion and raising output in the region on the other side. This measure reduces the flow of electricity through the network element affected by the congestion. In a redispatch measure the power plants that increase their output receive payment from the transmission system operator to cover their added costs. Power plants reducing their production must pay the transmission system operator a sum that reflects their cost savings. Suitable payment levels are fixed in a determination to this effect.

Publication Requirements

National publication requirements for distribution system operators

The Energy Act and the statutory instruments based on the Act require distribution system operators (DSOs) to publish information on third-party access, network charges and network structure, for instance. This information should be complete and its format as standardised as possible in order to enable market participants such as producers, suppliers, meter operators or even final consumers to access the information and compare the various DSOs.

In the 2012 monitoring survey, the DSOs were asked if they had met their publication requirements under the Act and the accompanying statutory instruments as of 1 April 2012. Out of a total of 735 companies (1 April 2011: 677), 614 (1 April 2011: 601) said "yes", 100 (1 April 2011: 75) said that they had only "partly" met the requirements, and 20 (1 April 2011: 1) did not respond.

The DSOs were also asked to say to what extent they implemented the publication requirements as set out in the Bundesnetzagentur's guidelines on the electricity network operators' internet publication requirements. Here, out of a total of 635 companies (1 April 2011: 672), 511 (1 April 2011: 465) said "yes", 183 (1 April 2011: 200) said "partly" and 41 (1 April 2011: 7) said "no" or did not respond.

There are no significant changes in the percentage distribution in comparison with previous years. However, there is a slight increase in the number of DSOs saying "no" or not responding compared to previous years.

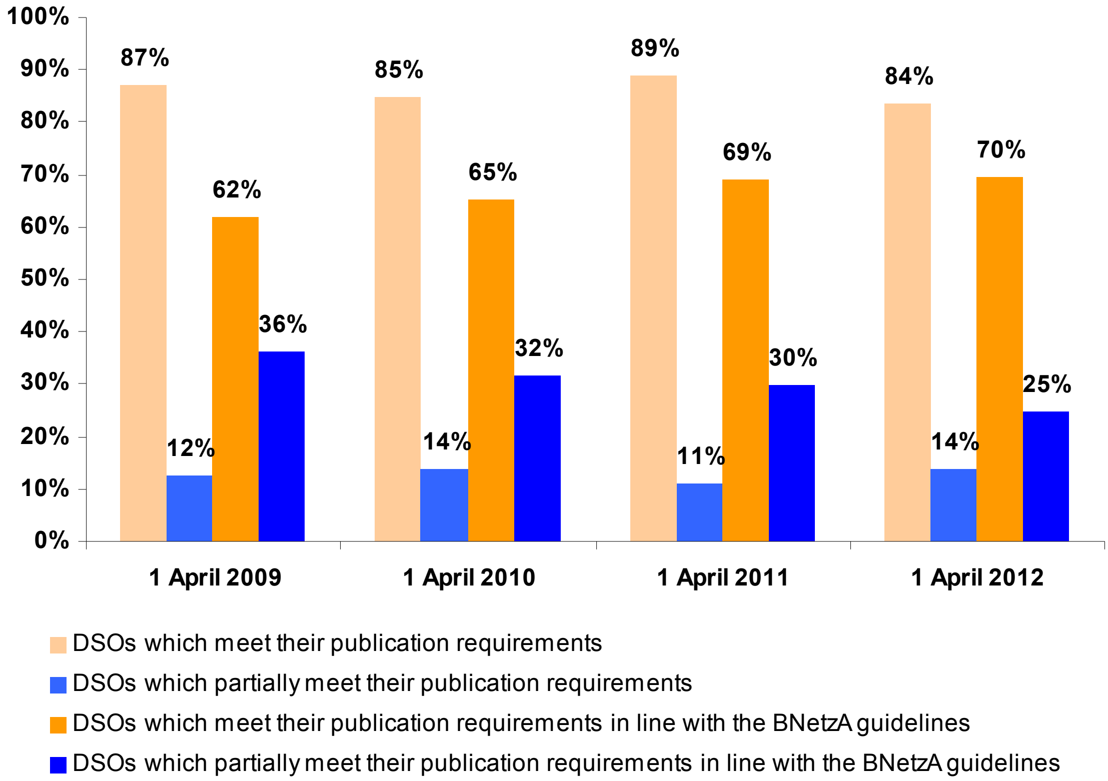

Abbildung 39: fulfilling publication requirements DSO´s (electricity)

Wholesale

General

Wholesale markets play a decisive role for competition in the electricity sector. Of particular importance are spot markets, where electricity can be bought at short notice and quantities that are no longer required can be sold at short notice, and futures markets, which allow for a medium and long-term hedging of price risks. The energy exchanges send important price signals to market participants, also in other areas of the wholesale electricity trading. One pre-condition for effective wholesale markets is sufficient liquidity, i.e. adequate quantities on the supply and demand side.

Basis of the survey

In the course of the survey, 562 companies submitted information on their wholesale activities. As in the past two years, five broker platforms were also included in the survey, as were the relevant exchanges for supplies into the four German control areas and the Austrian control area[21].

[21] In the reporting year 2011, Vorarlberg still belonged to the VKW-Netz AG control area. As of 1 January 2012, this control area has been integrated into the Austrian Power Grid (APG) control area. The year before, on 1 January 2011, the TIWAG network control area (for the Tyrol region) had also been integrated into the APG control area.

Types of wholesale electricity trading

There are two types of trading activities in the electricity wholesale sector, exchange trading and off-exchange trading. OTC clearing[22] has its own significance as an interface:

There are two forms of off-exchange wholesale electricity trading: one is bilateral trading in the strict sense (which denotes direct trade between a seller and a buyer[23], provided the latter does not buy as a final customer) and the other is bilateral trading between companies via broker platforms[24]. Under certain conditions, an off-exchange contract can be cleared at the exchange and thus subsequently be registered as an exchange transaction[25]. Exchange trading in the strict sense (i.e. bringing together supply and demand through an exchange) complements these two types of off-exchange trading.

[22] See in detail under "OTC clearing at the exchange"
[23] Seller and buyer can also be associated companies. System services are not included.
[24] Wholesale electricity trading involves various supporting or brokering services. This report will focus on trading volumes rather than on how individual services are provided.
[25] "The OTC clearing is defined as the bilateral exchange of trades concluded outside the exchange and the registration of these trades as OTC trades into the EEX trading systems by mutual consent..."; § 1 (2) OTC Clearing Conditions of the European Energy Exchange (EEX); cf. www.eex.com.

Structure of the survey

Wholesale electricity trading can take two forms: short-term trading (spot market) and long-term trading (futures market). On the spot markets, contract settlement is usually physical, on the futures markets financial.

	Futures market	**Spot market**
Over the counter (OTC) Bilateral transactions in the strict sense Bilateral transactions on specific broker platforms Place of delivery: Germany	• Settlement in the year of contract conclusion • Settlement in the year(s) after contract conclusion defined as transactions with a settlement period of at least one week	• Intra-day and day-after • Day-ahead • Other contracts defined as transactions with a settlement period of less than one week
OTC Clearing at the exchange (bilateral transactions in the strict sense and on broker platforms) Wholesaler/ broker: Place of delivery: Germany	Conditions according to specifications of the exchange in principle possible for the products in question	Conditions according to specifications of the exchange Admitted for intra-day at EPEX SPOT[26]
Exchange (EEX/EPEX SPOT; EXAA[27]) General place of delivery: Germany/Austria	• Phelix Futures • German Power Futures[28] • Options on Phelix Futures (here no differentiation according to weekly, monthly, quarterly or annual futures)	• Intra-day Place of delivery: **exclusively** Germany • Day-ahead

Table 15: Structure of survey on electricity wholesale in 2011

[26] cf. "On-exchange wholesale trading - Introduction"
[27] cf. "On-exchange wholesale trading - Introduction"
[28] Survey did not produce any data on quantities. Trading discontinued as of 23 January 2012; customer information of the European Energy Exchange AG of 20 January 2012, www.eex.com.

On-exchange wholesale trading

Introduction

In its analysis of the exchange electricity trading, this report will, as in previous years, focus on the European Energy Exchange (EEX) or European Energy Exchange AG (EEX AG), Leipzig, the EPEX SPOT SE (EPEX SPOT), Paris, and the Energy Exchange Austria (EXAA), Vienna. Uniform products for the delivery zones Germany and Austria are traded at all three exchanges[29]. The five control areas (Amprion GmbH, Tennet TSO GmbH, 50Hertz Transmission GmbH and EnBW Transportnetze for Germany, and Austrian Power Grid for Austria[30]) form one market area with uniform exchange prices for electricity trading products.

The EEX is an institution under public law; section 2 (1) BörsG (Stock Exchange Act). Operating companies within the meaning of section 5 BörsG are the EEX AG and its 80% subsidiary, EEX Power Derivatives GmbH[31]. As part of EEX AG, EEX Power Derivatives GmbH offers electricity products in the longer-term futures trading business[32]. The EPEX SPOT, which was founded in 2008/2009, is a 50/50 joint venture of EEX AG and the French Powernext SA[33]. The EPEX SPOT and the EXAA are trading platforms for spot market products.

The exchanges have become important trading venues[34]. The number of trading participants admitted to them (who are not necessarily active participants) has constantly increased in the past five years:

[29] Other market places can also be of relevance for electricity trading in Germany, such as the ELBAS intra-day trading platform of Nord Pool Spot (Lysaker, Norway).
[30] In the reporting year 2011, the VKW control area still existed in Austria; cf. footnote under "Basis of the survey".
[31] The remaining 20 per cent are held by the French Powernext SA.
[32] For the sake of simplicity, "EEX" will be used hereafter where futures trading is concerned.
[33] Comparisons with previous years will refer to "EPEX SPOT", and will not differentiate between the EEX Power Spot (previous spot market of EEX in Leipzig, Germany) and the EPEX SPOT.
[34] On account of the cooperation between the German and French exchanges in futures trading (Leipzig) and spot trading (Paris), electricity trading also includes the territories of France and - only with regard to the spot market - Switzerland. The report on wholesale trading does not cover these regions.

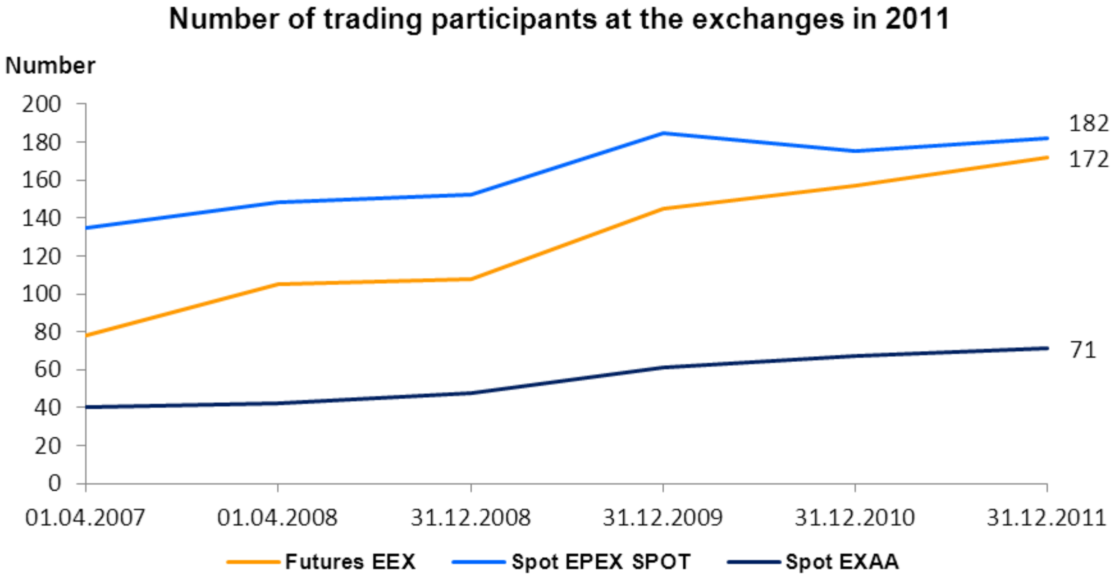

Diagram 40: Number of trading participants at the exchanges in 2011

Participants admitted to the EEX and the EPEX SPOT are categorised as follows[35]:

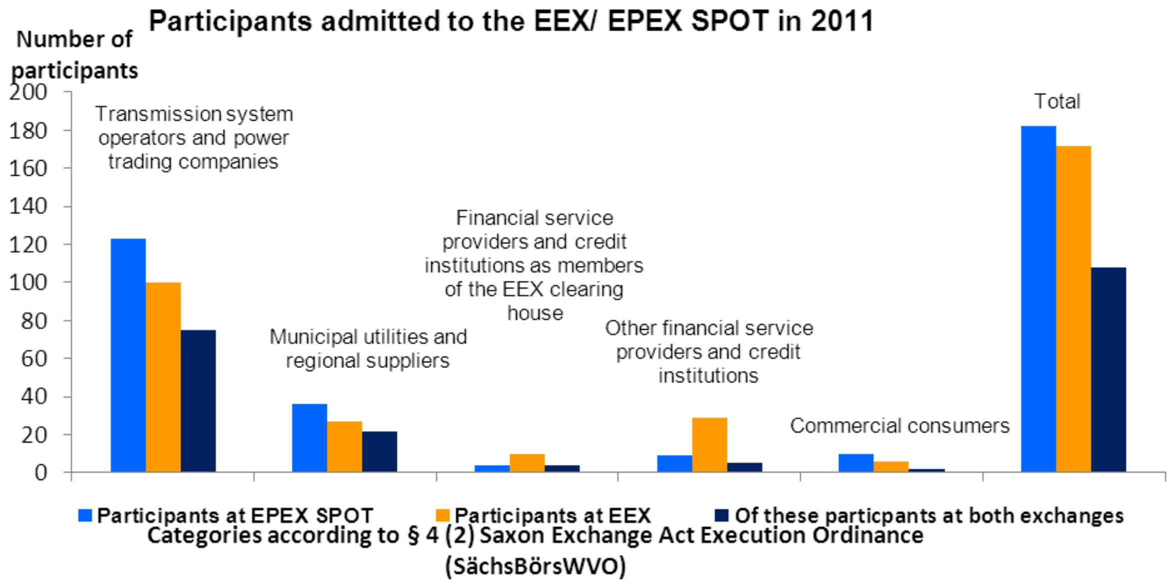

Diagram 41: Participants admitted to the EEX/ EPEX SPOT in 2011

At the spot market, transmission system operators and power trading companies, together with municipal utilities and regional suppliers, account for 87 per cent of the participants admitted to trade, at the futures market this figure amounts to 74 per cent. The category "Other financial service providers and credit institutions" is represented to a significantly greater extent at the futures market (29 participants; 17 per cent) than at the spot market (nine participants, five per cent).

[35] This categorisation is also reflected in the composition of the exchange council of the EEX. The EPEX SPOT uses the category "Producers and trading companies", there is only one category for financial service providers and credit institutions and one separate category for "Transmission system operators".

Spot markets EPEX SPOT and EXAA

Standard products traded at the EPEX SPOT are designed for two different trading processes. These are on the one hand the day-ahead auction (possible for supplies into all German control areas and the Austrian control area) and on the other the continuous intra-day market (possible for the German control areas but not for the Austrian control area). At day-ahead auctions, both individual hours and standard or user-defined blocks[36] are traded. So-called market coupling contracts (MCC) are also traded in the daily auctions; these, however, are not considered in detail in the survey on wholesale trading. Intra-day trading also consists of both, individual hours and (standard or user-defined) blocks. The EXAA offers trading of individual hours and user-defined blocks in day-ahead auctions; physical settlement is effected into the Austrian control area or into one of the German control areas.

The day-ahead market for Germany/Austria

Active participants

One possible indicator of the significance of a market place is the development of the number of its active participants. Point of reference are the annual average values for the total number of days[37] over a period of five years. Participants are considered 'active' if there is a registered bid (sale or purchase) in their name.

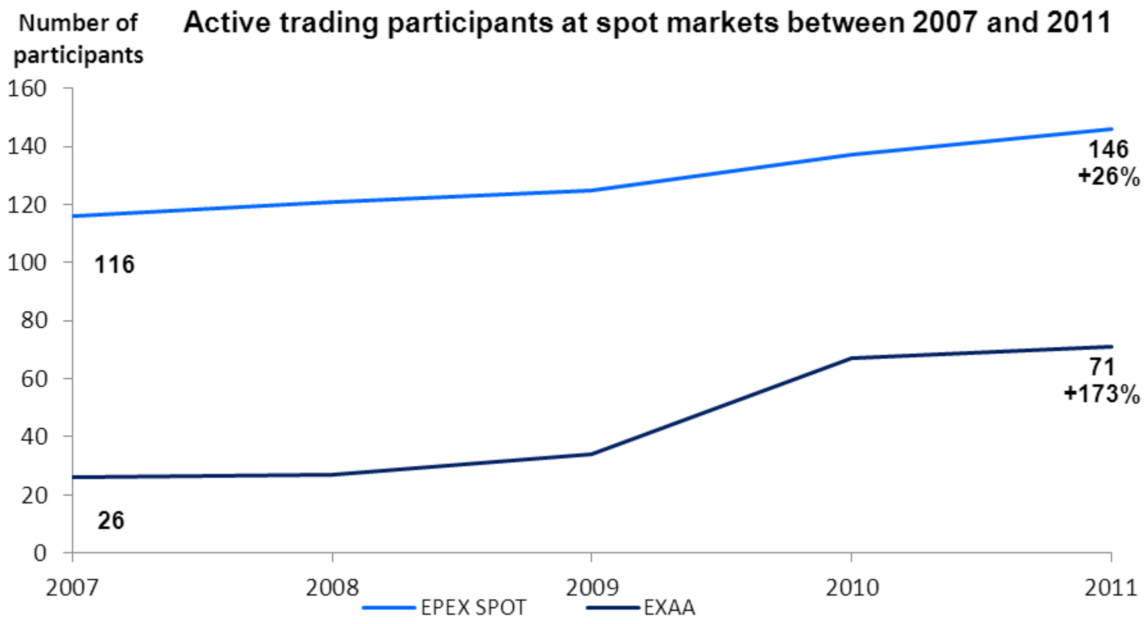

Diagram 42: Active trading participants at spot markets between 2007 and 2011

[36] Individual contracts combined in a 'block bid' can only be effected in their full quantity.
[37] Business at the EXAA is limited to five trading days/week, while the EPEX SPOT trades on all seven days. For the sake of comparability, in the case of the EXAA the survey therefore focuses on delivery days rather than trading days.

Active participation at the spot market/ day-ahead market of the EPEX SPOT has continuously increased. The corresponding increase at the EXAA was particularly strong in the years 2009 and 2010. In examining the total increase in percentage terms, it must be kept in mind that the initial value for 2007 was significantly smaller at the EXAA than at the EPEX SPOT. Today, however, the number of active participants at the EXAA[38] has increased to almost half of the number of EPEX SPOT participants.

At the EPEX SPOT, the average number of participants per trading day who have participated in the hourly auction and have made a purchase for at least one single hour rose from 101 (in 2010) to 123 (in 2011); the number of sellers, on the other hand, dropped from 118 (in 2010) to 105 (in 2011). The number of net buyers per trading day (balance in favour of "purchases") hardly changed (89 participants in 2011 compared with 88 in 2010), the number of net sellers (balance in favour of "sales") increased (from 49 in 2010 to 56 in 2011).

Trading volumes

In the reporting year, the volume of the day-ahead market at the EPEX SPOT and the EXAA has continued to increase, albeit at a lesser rate than in the previous year (relative increase between 2009 and 2010):

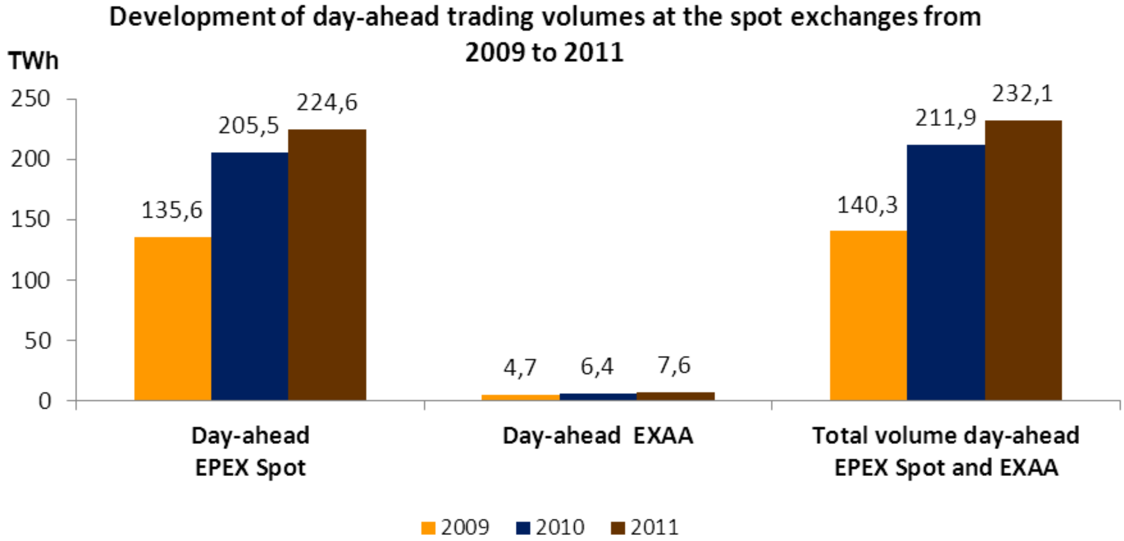

Diagram 43: Development of day-ahead trading volumes at the spot exchanges from 2009 to 2011

The total volume of electricity traded at the EPEX SPOT amounts to 224.6 TWh; at the EXAA this value amounts to only 7.6 TWh. The contract trading volume in the day-ahead market at the EXAA thus amounts to only 3.4 per cent of the respective trading volume at the EPEX SPOT.

[38] Auctions at the EXAA take place at 10:15 a.m., which is earlier than at the other exchanges; the EX-AA considers this advantageous for the OTC market which thus receives an early price reference (EXAA; information leaflet 2011).

A significant share of the electricity traded at the EPEX SPOT is traded on the basis of price-independent bids, both on the seller and the buyer side.

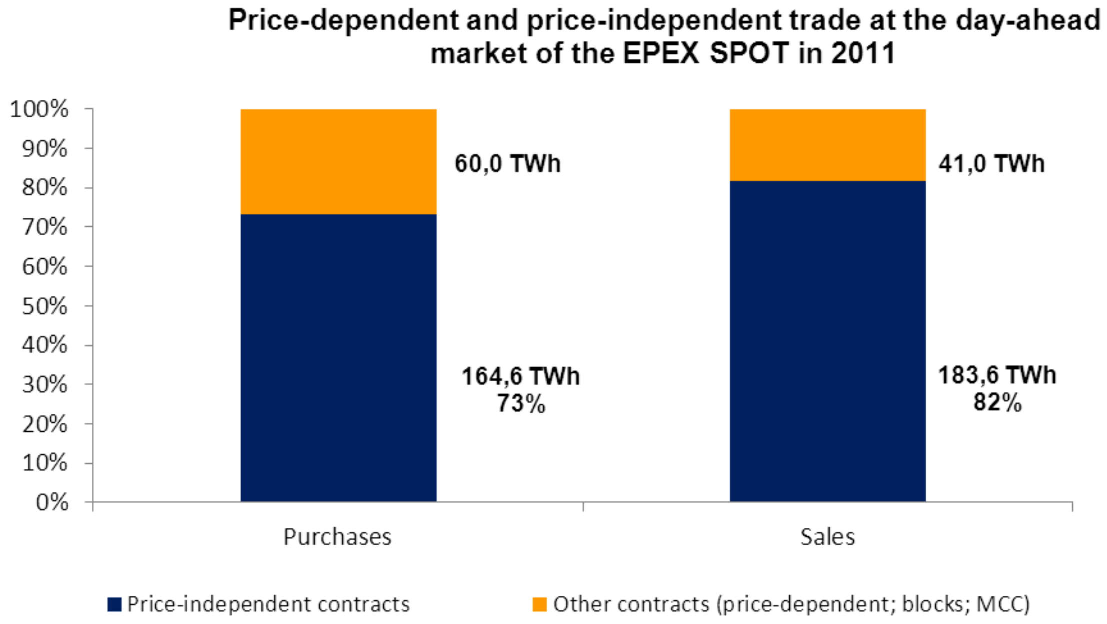

Diagram 44: Price-dependent and price-independent trade at the day-ahead market of the EPEX SPOT in 2011.

Price-independent bids are possible in the single hour auctions. Other than in the case of price-dependent bids, participants here do not decide on a fixed price/quantity combination. Price independence on the demand side signifies that buyers aim to satisfy their demand irrespective of a price limit; price independence on the sales side signifies that the quantities are to be sold irrespective of the price. While transmission system operators (TSO) only play a minor role in price-independent purchases, the electricity quantities they offer play a major role in price-independent sales. Most, but not all, price-independent sales of the TSO involve electricity regulated under the EEG (Renewable Energy Sources Act). Finally, there is the option of the physical settlement of EEX financial futures products. Settlement here also takes place via price-independent bids in spot trading. The following diagram illustrates the significance of the individual categories of price-independent trading in the year under review:

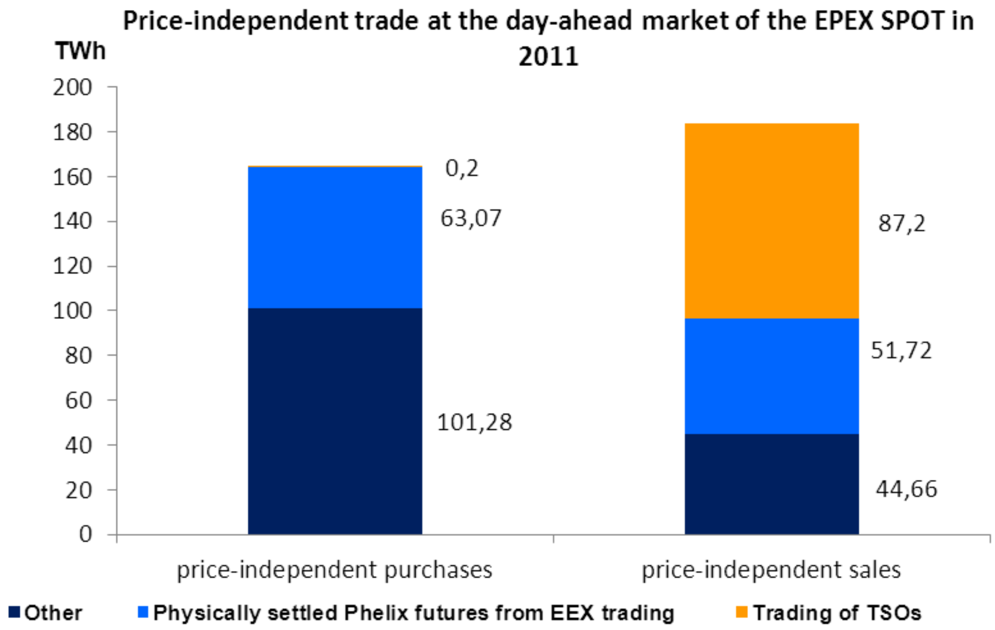

Diagram 45: Price-independent trade at the day-ahead market of the EPEX SPOT in 2011.

Breakdown of traded products in the year under review:

	Purchases		Sales	
	in TWh	in %	in TWh	in %
Price-independent bids	164.6	73.3%	183.6	81.8%
• Of which via TSOs	0.2	0.1%	87.2	47.5%
• Of which physically settled Phelix Futures	63.1	38.3%	51.7	28.2%
• Other	101.3	61.5%	44.7	24.3%
Price-dependent bids	35.6	15.9%	24.8	11.0%
Blocks	15.2	6.8%	8.4	3.8%
Import / Export (MCC)	9.2	4.1%	7.8	3.5%
Total (rounding differences)	**224.6**	**100%**	**224.6**	**100%**

Table 16: Sales and purchases at the day-ahead market of the EPEX SPOT in 2011

While the volume of physically settled Phelix Futures through price-independent purchases increased compared to the previous year, both in absolute terms (by 17.6 TWh) and in relative terms (by 38.6 per cent), the volume of price-independent sales decreased in 2011 by 4.6 TWh (8.1 per cent).

Price level

As can be expected, the arithmetic averages of prices of day-ahead products at the spot market exchanges hardly differ from one another; the arithmetic averages at the EXAA are usually slightly higher than those at the EPEX SPOT.

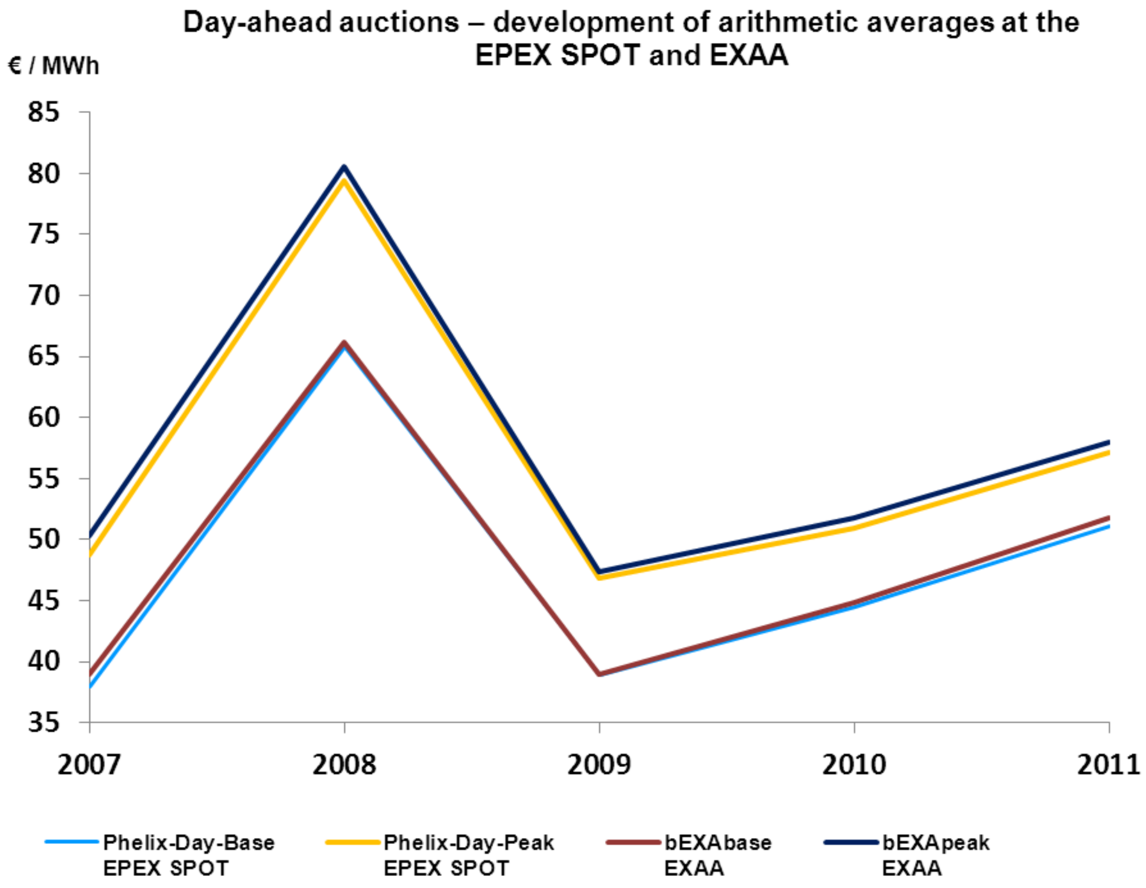

Diagram 46: Day-ahead auctions - development of arithmetic averages at the EPEX SPOT and EXAA

€ / MWh	2007	2008	2009	2010	2011
Phelix-Day-Base EPEX SPOT	37.99	65.76	38.85	44.49	51.12
Phelix-Day-Peak EPEX SPOT	48.75	79.43	46.83	50.95	57.12
bEXAbase EXAA	38.96	66.18	38.92	44.81	51.80
bEXApeak EXAA	50.34	80.52	47.36	51.82	57.94

Table 17: Day-ahead auctions - development of arithmetic averages at the EPEX SPOT and EXAA

The annual average prices for base products increased (from previous year to reference year) in the last two years by between 15 and 16 per cent; the average annual prices for peak products increased by 9 per cent between 2009 and 2010, and by 12 per cent between 2010 and 2011.

The following two diagrams depict the price spread (span between minimum value and maximum value) of the same products for the year under review and the year before. In addition to the increase in average prices, they also show how the price spreads have changed. A reduction in the span is particularly obvious in the EXAA figures, where the maximum values drop while the minimum values rise. As regards the Phelix products traded at the EPEX SPOT, both values drop; however, since the maximum value decreases to a larger extent than the minimum value, the price spread here is also lower than in the year under review. In total, prices in the spot market segment under review are on average higher, but within a tighter range with lower maximum values.

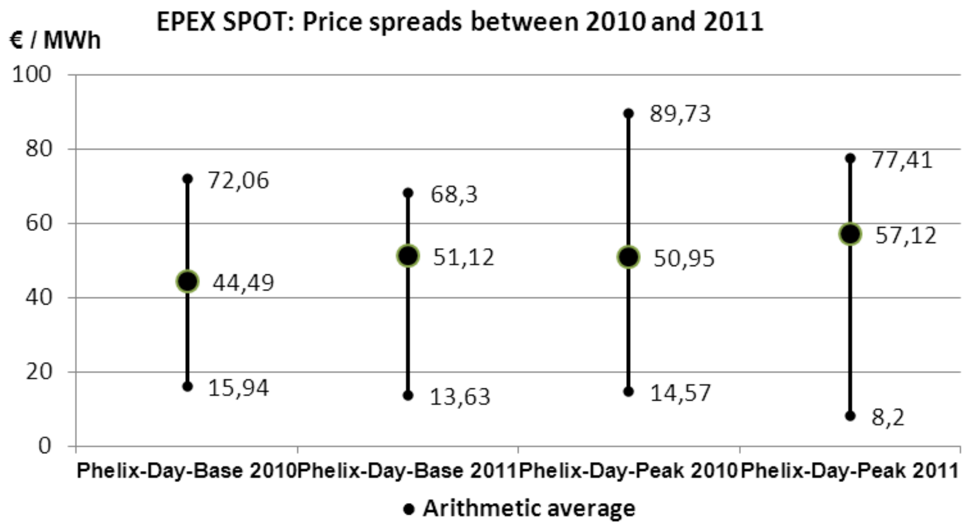

Diagram 47: EPEX SPOT: Price spreads 2010 – 2011

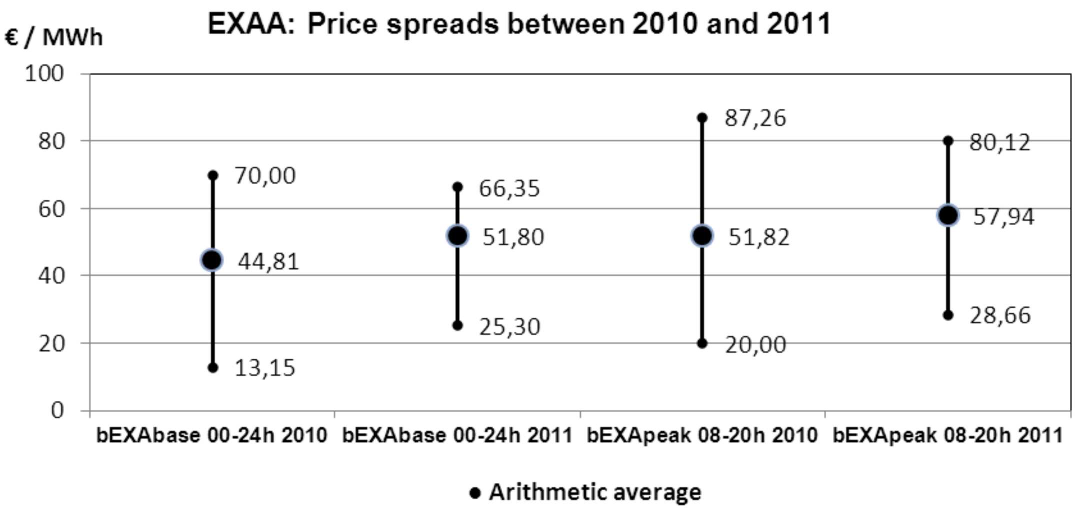

Diagram 48: EXAA: Price spreads 2010 - 2011

The intra-day market at the EPEX SPOT

Since 2006, continuous intra-day exchange trading is offered in Germany. The following diagram depicts the development of trading volumes between 2006 and 2011[39]:

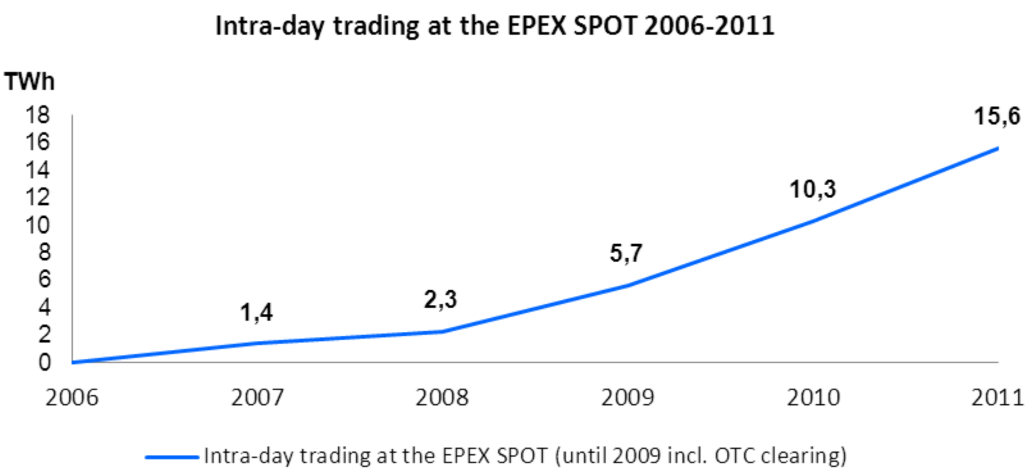

Diagram 49: Intra-day trading at the EPEX SPOT 2006-2011

This market segment is growing at a rapid pace; the last annual rate of increase (2010 - 2011) amounted to 52 per cent.

[39] As of 2010, quantities resulting from OTC clearing are not included; on OTC clearing cf. "OTC clearing at the exchange".

Futures Market EEX Power Derivatives GmbH

In Germany / Austria Phelix Futures and Phelix Options can be traded on this derivatives market. There is a whole range of products with different standardised delivery periods (futures) and exercise periods (options)

Overview of participants and volumes

The number of active participants in the future markets in 2011 averaged 43.4 (previous year: 23.3) per trading day; this figure only applies to the trade with futures, including the clearing of OTC transactions.

In the year under review, as in 2010, only Phelix Futures were traded on the German / Austrian futures market - excluding OTC clearing.

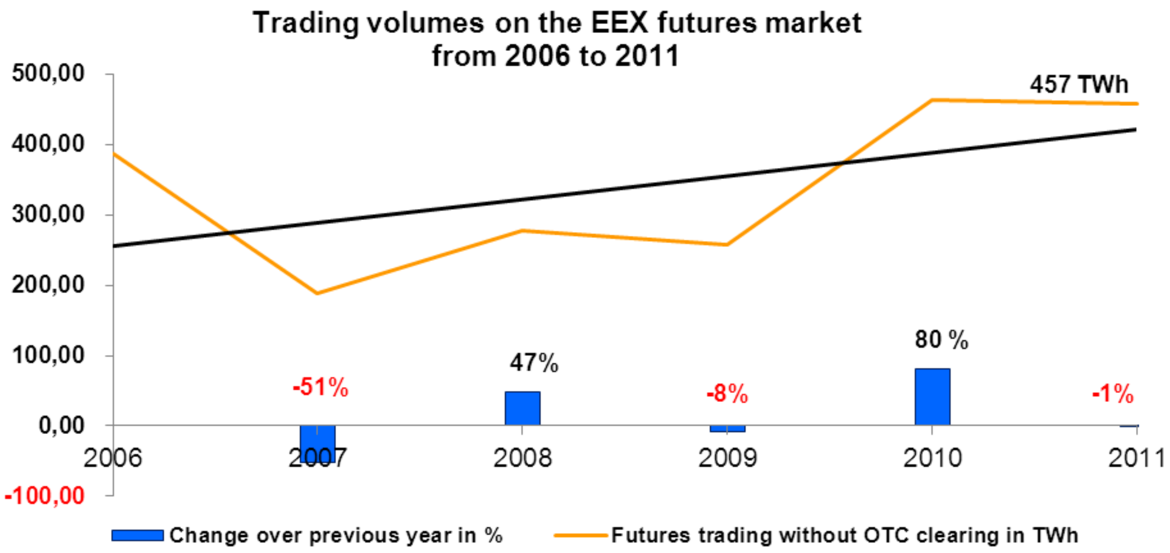

Diagram 50: Trading volumes on the EEX futures market from 2006 to 2011

There has been a clearly rising trend in trading volumes over several years, which however does not exclude intermittent falls.

Contracts are concluded for various settlement periods. Trading is mainly concentrated on the following year:

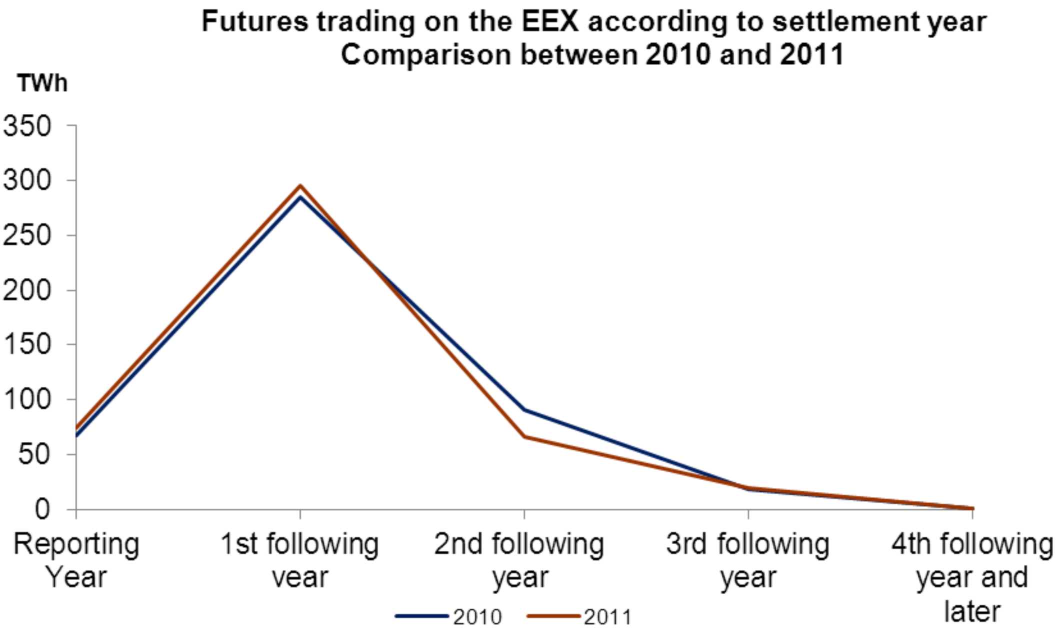

Diagram 51: Futures trading on the EEX according to settlement year – Comparison between 2010 and 2011

The comparison of trading activities in 2001 and 2010[40] in respect of the settlement period of concluded futures contracts reveals an almost equal contracting pattern in both years.

Price level

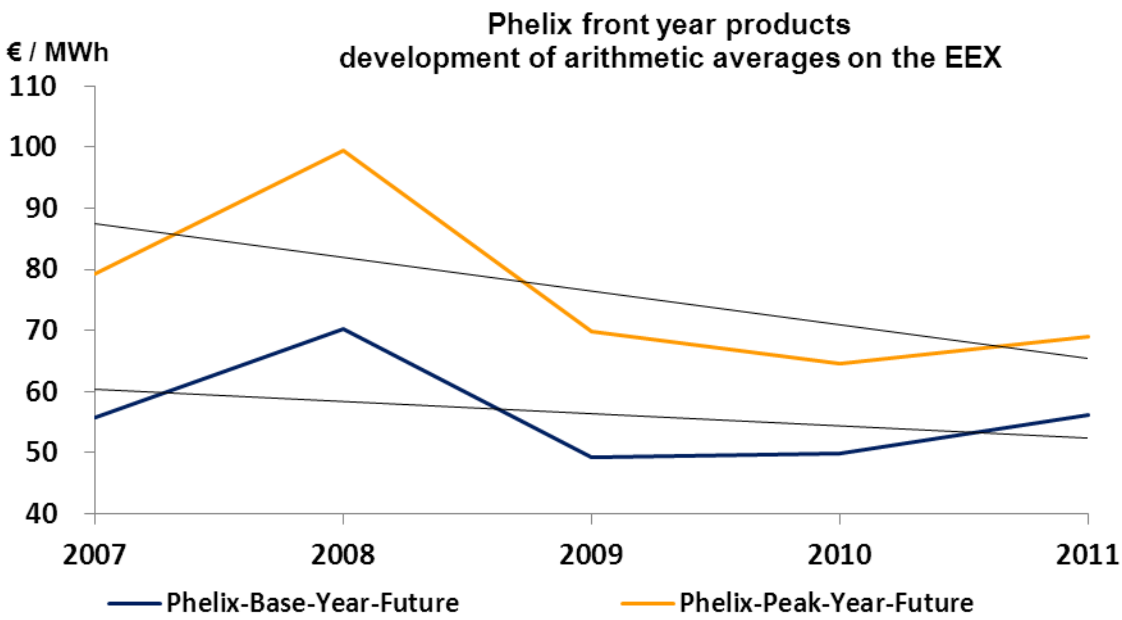

Diagram 52: Phelix front year products - development of arithmetic averages on the EEX

[40] A comparison with further previous years is not possible because of changes in the data survey.

€ / MWh	2007	2008	2009	2010	2011
Phelix-Base-Year-Future	55.83	70.33	49.20	49.90	56.08
Phelix-Base-Year-Future	79.33	99.40	69.84	64.48	69.03

Table 18: Phelix front year products - development of arithmetic averages on the EEX

The arithmetic averages for Phelix futures (Base/Peak), (based on all ascertainable prices for the front year) have generally fallen more heavily in the past 5 years in the case of peak load rather than base load. However, in the period under review, prices were found to rise over the previous year (base: by 12 percent, peak: by 7 percent).

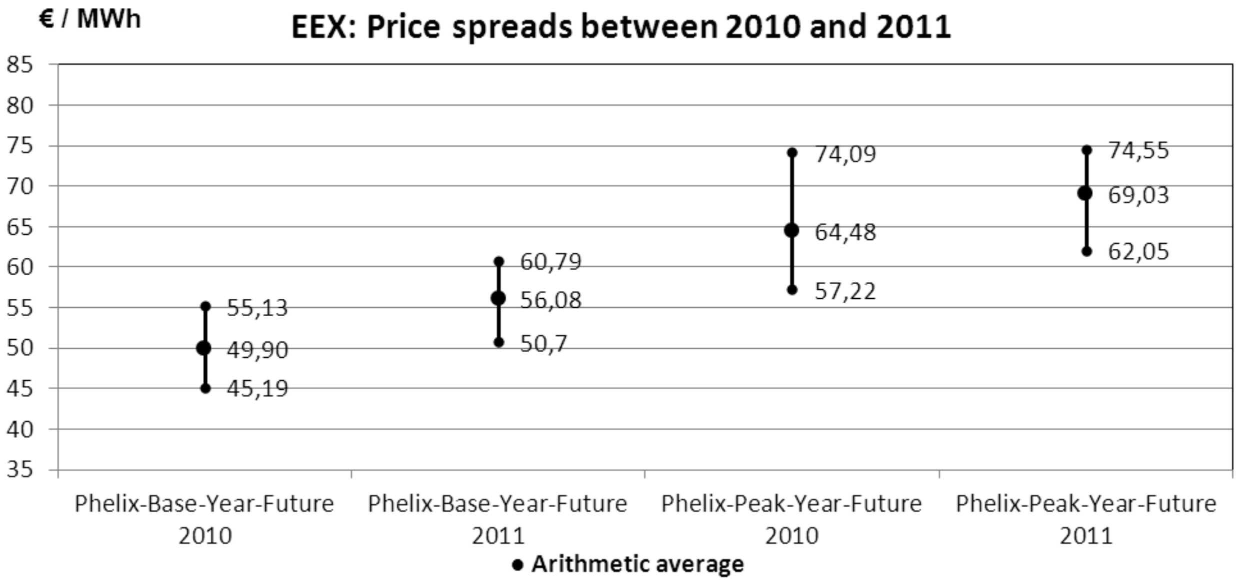

Diagram 53: EEX: Price spreads between 2010 and 2011

Compared to the previous year, the deviation (span between minimum value and maximum value) for the Phelix Peak Year Future was considerably smaller in the year under review (from € 16.87 to € 12.50.) In the Base area there was a slight increase in deviation (from € 9.94 to €10.09).

OTC clearing at the exchange

Apart from trade at the exchange, there is also the "over-the-counter" trading which does not have to take place on the exchange (OTC trading, bilateral trading, see below). OTC clearing is an interface between on-exchange transactions and off-exchange OTC trading. It allows parties to an (off-exchange) OTC contract to subsequently subject it to the rules of the exchange and thus to combine the benefits of both forms of trade.

A special feature of OTC trading is that the trading partners are known to one another; if an intermediary (e.g. a broker) is involved, the identity of the partners becomes known, at the latest on conclusion of the transaction. In terms of their private autonomy the parties have full flexibility in the formulation of their agreement. Trading on the exchange, on the other hand, is anonymous; here a standardisation of the products is necessary in order to bring together supply and demand. As the exchange itself becomes the contractual partner of the trading party, there is no counterparty risk. Apart from selecting the contractual partner, this can be reduced in bilateral trading by protective agreements but cannot be completely excluded at first. By using the clearing facility for OTC transactions, a special service provided by the exchange, this counterparty risk can be shifted to the exchange. The specific conditions are set by the exchange. EEX Power Derivatives GmbH enables clearing for all registered futures products. At the EPEX SPOT this is also possible for intra-day trading. European Commodity Clearing AG (ECC), Leipzig, is responsible for the actual clearing service.

The contract is initially concluded off-exchange as a bilateral trading transaction, in some cases with the assistance of a broker. By concluding a clearing transaction the contractual partners ensure that their contract will be treated as an exchange transaction. Consequently, OTC clearing is examined in the following from the perspective of exchange trading.

If the areas of exchange trading and OTC clearing are taken as a whole from 2006 to 2011, the total volume of trade is found to be highly stable. Whereas the volume of OTC clearing tends to fall after an initial growth phase, the volume of direct exchange trading tends to rise after after an initial decline.

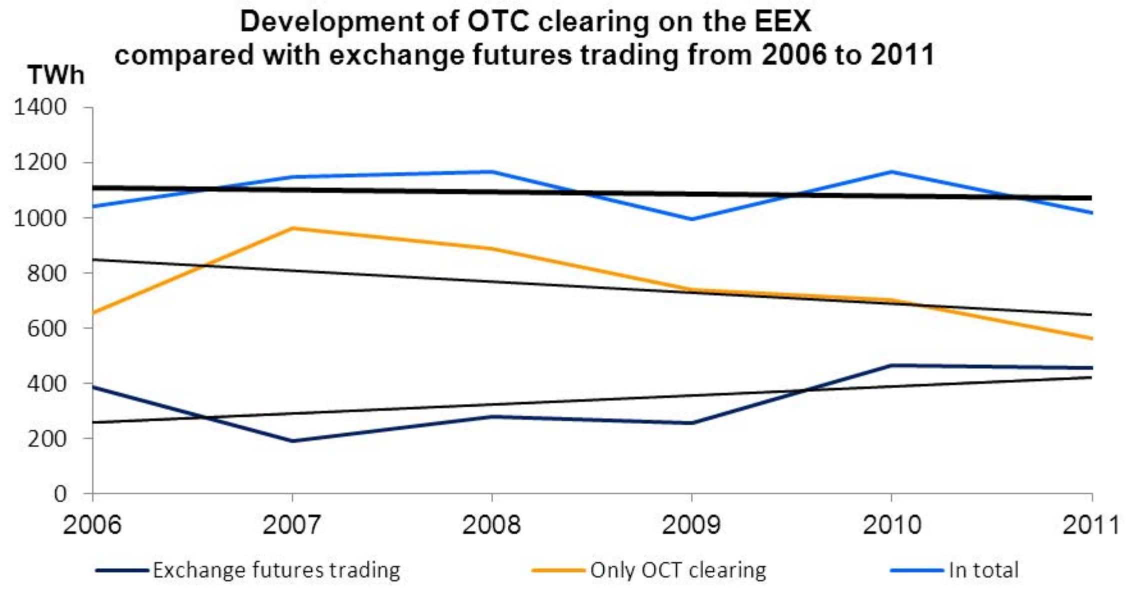

Diagram 54: Development of OTC clearing on the EEX compared with exchange futures trading in the strict sense from 2006 to 2011

As in the last two years, data of five broker platforms were collected which are all admitted to the exchange and together are of supreme relevance for the area of "wholesale electricity on broker platforms."

The following two diagrams compare the segments "exchange futures trading" in the strict sense and "OTC clearing“, whereby the latter is differentiated according to clearing via the brokers involved and other forms of OTC clearing, in 2011 and 2010. Due to the significance of brokers in the market, it can be assumed that the "other forms of OTC clearing" mainly include contracts which buyers and sellers have themselves directly registered for clearing.[41] An overall view of both diagrams shows a decline in volumes registered for clearing by brokers and a distinct rise in the volumes which the companies have registered for clearing.

[41] The exchange data collected provide information about OTC clearing as a whole. The data differentiating between the different forms of clearing are based on information provided by the five brokers surveyed, which according to information currently available, account for the major share of this business. The category "other forms of OTC clearing" differentiates from values from EEX transactions.

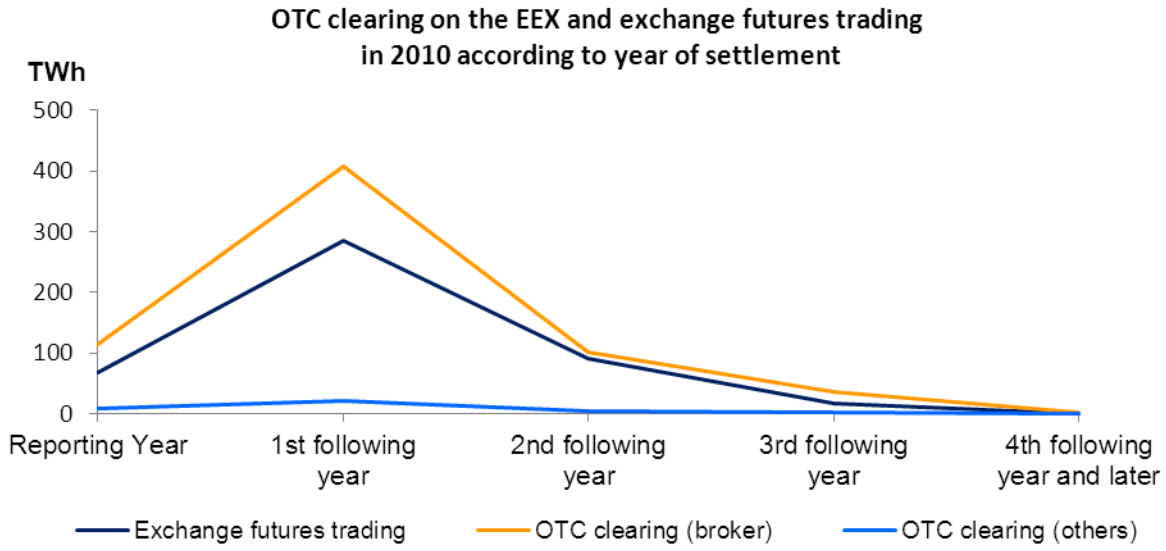

Diagram 55: OTC clearing on the EEX and exchange futures trading in the strict sense in 2010 according to year of settlement

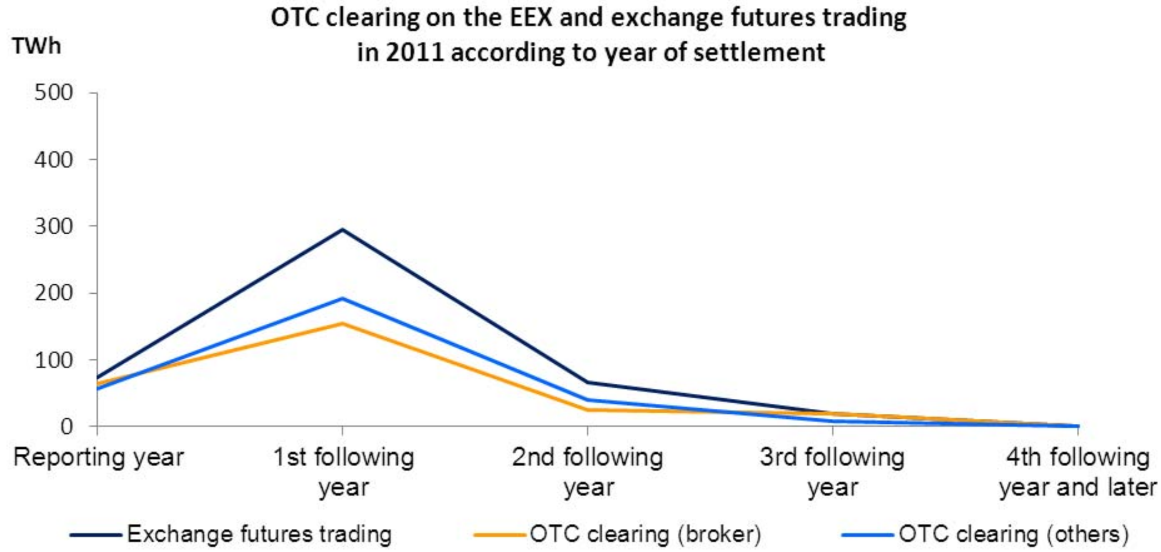

Diagram 56: OTC clearing on the EEX and exchange futures trading in the strict sense in 2011 according to year of settlement

In addition to these aspects, the graphical illustrations [42] show that also in the OTC clearing of futures transactions the emphasis is clearly on contracts with settlement in the following year.

[42] The data "only OTC Clearing Broker" are based on information provided by the five brokers surveyed, which based on current information, account for the major share of this business. The "only OTC Clearing Rest" represents the difference from EEX values. These values include a share with settlement in the Austrian control area. However, the two previous diagrams only indicate trends: the reference values for 2010 / 2011 focus on equally defined volumes.

The volume of OTC clearing on the EPEX SPOT intra-day market rose from 0.008 TWh in 2010 to 0.295 TWh in 2011.

Bilateral wholesale (including brokers)

Equally, as in exchange trading, a differentiation is necessary in bilateral trading between longer-term futures and short-term spot market transactions. The data survey differentiates between trading with (a) settlement period of at least one week and of less than a week. A separate survey was conducted for both forms of trading to find out whether contracts materialised via the broker platforms included in the survey.

A complete picture of bilateral electricity wholesale trading is not possible on the basis of the data collected as, inter alia, the information provided by the companies on transactions with specific brokers differs considerably from the comprehensive details provided by the brokers.[43]

The data collected in the survey, as presented below, are lower boundaries for the volumes. These boundaries are exceeded to an extent which cannot be quantified by the survey, although it can definitely be assumed to be significant (see above on data provided by the brokers):

[43] Deviations are to be expected, albeit only to a small extent, because the features of the survey of companies and brokers were inconsistent (the broker data include an estimated two percent average ratio of trade by commercial consumers.) The extent of deviation shows, however, that the survey of companies is not fully congruent.

Volumes recorded in the bilateral futures market 2011

(Settlement period of one week or more)

Contracts in the year under review	assumed minimum values[44] in TWh
Settlement year 2011	435.1
Settlement year 2012	1,015.2
Settlement year 2013	462.7
Settlement year 2014	210.5
Settlement year 2015 and later	58.7
Contract via broker[45] without OTC clearing	4,019.3
only contracts with OTC clearing[46] (all)	257.1
Total	**6,458.6**

Table 19: Volumes recorded in bilateral futures market 2011

Volumes recorded in bilateral short-term trading[47] 2011

(Settlement period of less than a week)

Contracts in the year under review	assumed minimum values in TWh
Intra-day[48] and day-after	18.0
Day-ahead	115.5
other contracts Settlement period < one week	30.4
Contract via broker (all)[49]	89.9
Total	**253.8**

Table 20: Volumes recorded in bilateral short-term trading 2011

[44] As a contract concluded via a broker platform constitutes a bilateral trading transaction which is concluded via the platform (in the same way as a cleared OTC transaction can only be bilateral), the volumes from the bilateral purchase and bilateral sale in the strict sense have to correspond with one another. If there is a deviation between the total purchase and sales volumes, the deficit between the smaller value and the overall value can be added to the overall transaction. The larger value is always taken as a reference.

[45] Value adjusted (see estimate footnote 42)

[46] Here again the data provided by the brokers were taken as a reference (two percent deduction). A total volume of 561 TWh in OTC futures transactions was cleared at the ECC; however, this value includes a share with settlement in the Austrian control area and trading by commercial consumers. In assessing the established minimum values, the lower value was deliberately used in this context.

[47] The assumptions made in the futures market (previous table) also apply here. As the participants in the survey were not questioned specifically about cleared intra-day contracts on the spot market, it is assumed that the volume indicated by the EPEX SPOT is included in the quantities stated by the companies and brokers surveyed.

[48] The survey showed that the companies recorded their data in some cases with different time periods (i.e. quantities were registered as intra-day contracts although according to the definition of the survey a day-ahead transaction would have been the appropriate answer). However, possible differences in categorisation do not alter the reliably established total volume from contracts with short-term settlement.

[49] Value adjusted (see estimate footnote 42)

The data collected on bilateral wholesale trading give a reliable picture of the market. This is made possible by the overall evaluation of the number and type of the participating companies and the extent of the information in view of the available control data. This is also supported by the broad congruence of the purchase and sales volumes (differentiated according to product).

Diagram 57: Bilateral wholesale trading in the strict sense in 2011 according to settlement period (recorded volumes)

As already established in the chapter on exchange trading including OTC clearing, the emphasis in bilateral futures trading is on transactions with settlement in the following year. In the spot market day-ahead trading plays the key role.

Additional Aspects

Market maker

The term market maker is used to describe a participant on the exchange who has undertaken to simultaneously publish binding purchase and sale prices (quotations). The function of the market maker raises the liquidity of the market.[50]

In the period under review the companies Vattenfall Energy Trading GmbH, RWE Supply & Trading GmbH and E.ON Energy Trading SE were generally active as market makers on the

[50] The specific (varying) conditions are regulated between the exchange and market makers in market maker agreements (quotation periods, quotation duration, minimum number of contracts, maximal spread etc.)

Phelix Futures market. All three companies[51] had already been active in this function in previous years. The share of the market makers of the Phelix Futures purchase volume fell from 29.1 percent (2010) to 27 percent (2011), their share of the sales volume fell from 33.7 percent (2010) to 31.5 percent (2011).

The market making activities mentioned do not provide any indication of the extent of further activities of the companies concerned in exchange trading (i.e. beyond their role as market makers or under the rules applicable).

The companies with the highest turnover on EPEX SPOT and EEX

The focus on the five companies with the highest turnover[52] gives an indication of the degree of concentration in the trade. The assessment of these companies takes into account specific areas of trade and is also differentiated according to purchase and sales volumes. In order to illustrate this development, the companies' share of the trade (in percent) over the last three years under review is shown in the following diagram:

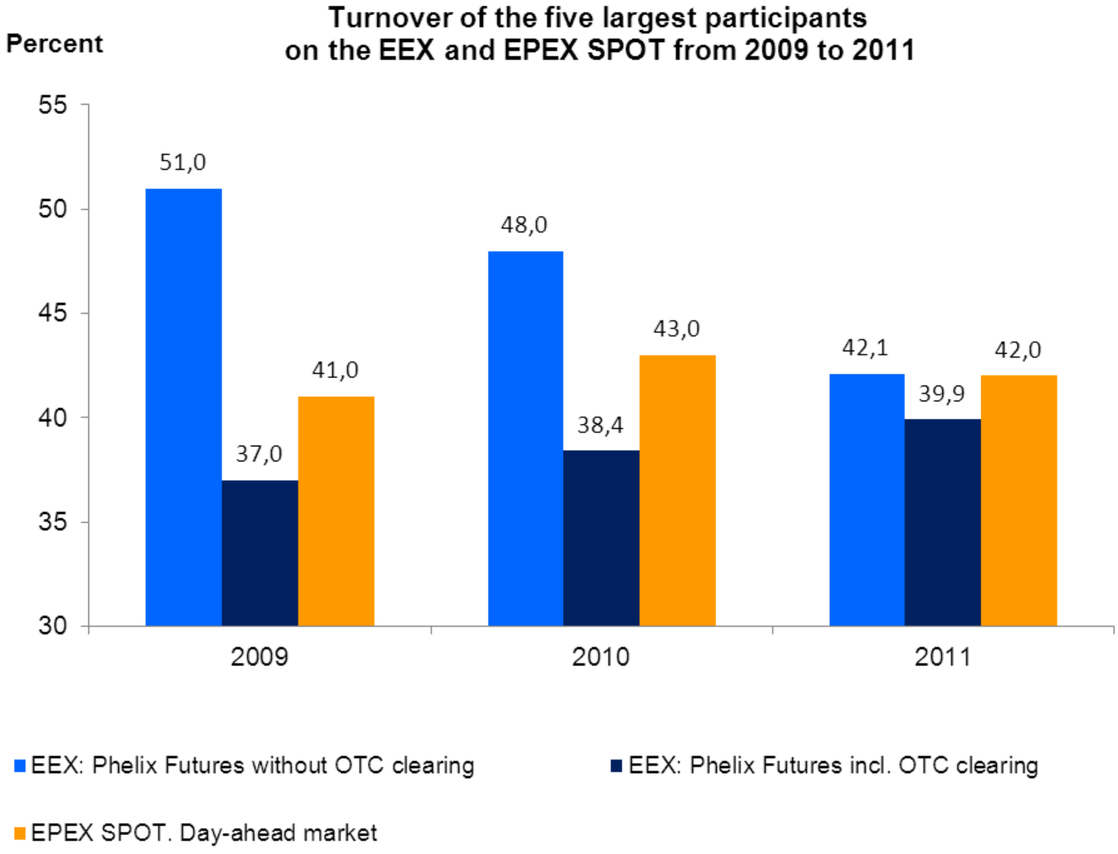

Diagram 58: Turnover of the five largest participants on the EEX and EPEX SPOT from 2009 to 2011

51 In the first half of 2010, another market maker other than those mentioned above was active on this market.

52 This does not conclusively determine whether or not the combination of the group of high-turnover companies has varied or remained constant over the years or in the areas of trade under review.

In terms of the total trading volume in each area of trading (total purchase and sales activities), there was little change in the concentration on the day-ahead market between 2009 and 2011. If volumes from cleared OTC contracts are included, the concentration on the futures market increased, whereas if these volumes are left out, it fell sharply from a high level.

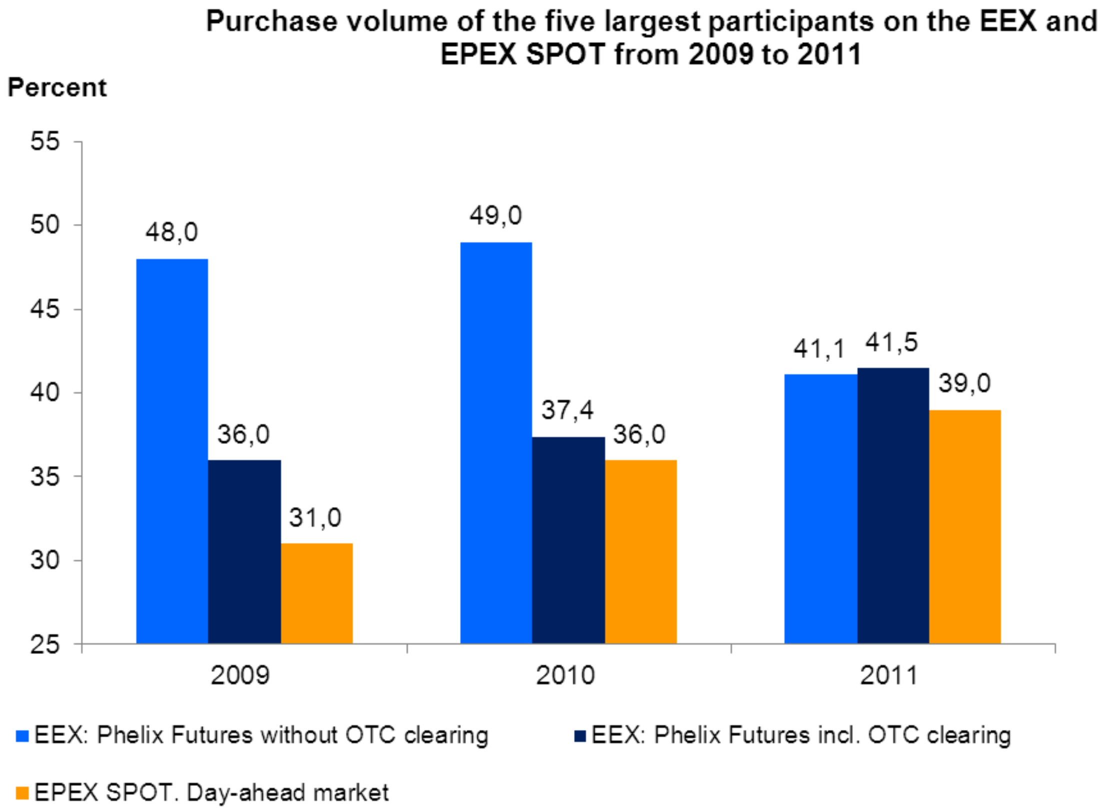

Diagram 59: Purchase volume of the five largest participants on the EEX and EPEX SPOT from 2009 to 2011

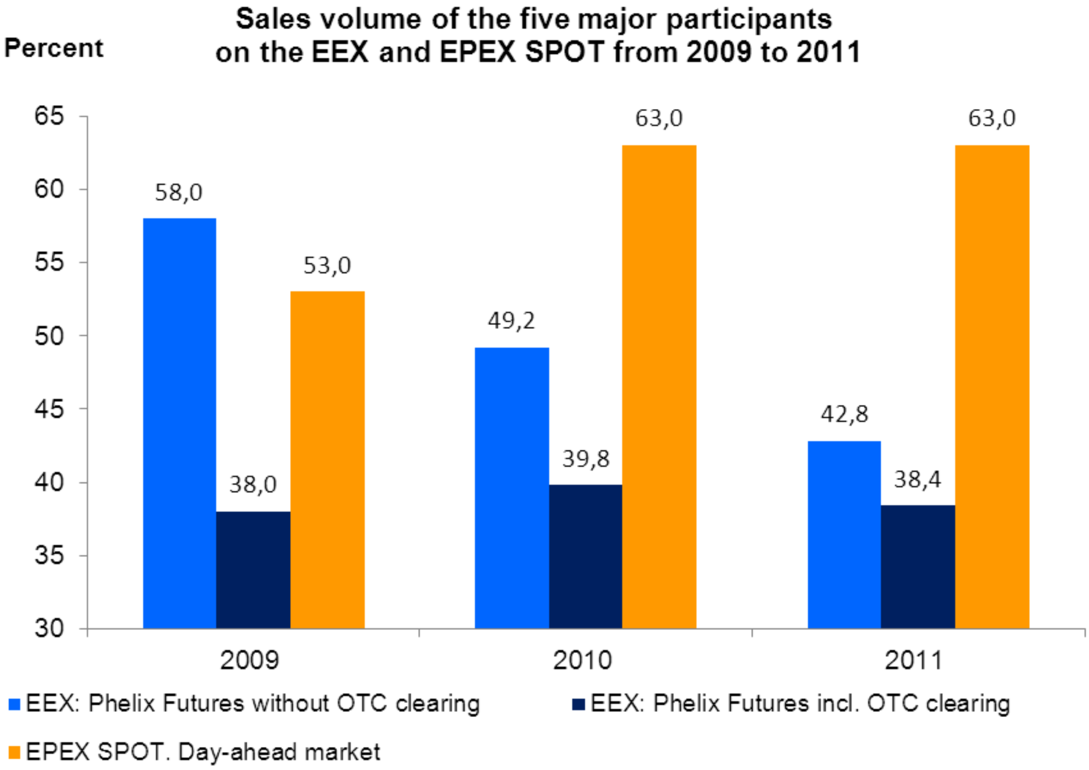

Diagram 60: Sales volume of the five major participants on the EEX and EPEX SPOT from 2009 to 2011

In the day-ahead market the share of the five high-turnover companies rose on the buyer's side from 31 percent in 2009 to 39 percent in 2011; on the seller's side they retained their previous year's share of 63 percent. The Monitoring Report 2011 stated that the reason for this high share was the sale of electricity under the EEG by the TSOs[53]. In the futures market without OTC clearing the concentration of the leading five companies is diminishing on both the buyer's and seller's side. If OTC clearing transactions are taken into consideration, the share of the five strongest sellers remains little changed, whereas there is a more distinct increase in concentration on the buyer's side.

Participants admitted to the EEX are categorised according to Section 4 (2) of the Saxon Exchange Act Execution Ordinance (cf. "On-exchange Wholesale Trading – Introduction"). The total turnover volumes (sum of purchases and sales) can be broken down among these categories as follows[54]:

[53] cf. "Spot market EPEX SPOT and EXAA"

[54] The data for the previous year is only available in the previous form of classification and can therefore not be used as a comparison.

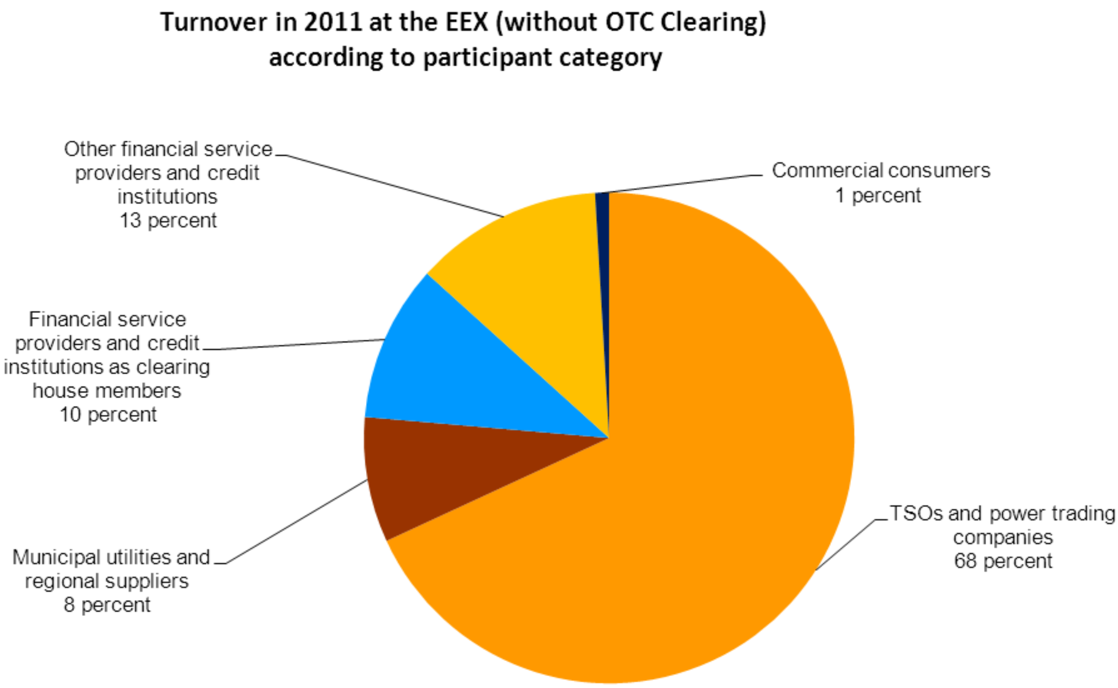

Diagram 61: Turnover in 2011 at the EEX (without OTC Clearing) according to participant category

TSOs and power trading companies as well as municipal utilities and regional suppliers together account for 76 percent of the trading volume, banks and financial service providers account for 23 percent.

High turnover companies on EXAA

An assessment of the turnover concentration of the leading five companies on the exchange can be carried out based on the day-ahead market on the EXAA. In percentage terms the shares of the five[55] strongest companies on both the buyer's and seller's side are falling; the concentration of the leading market participants is therefore diminishing. The main reason for this is the increase in trading activities of other market participants and consequently a growth in the volume of trade at the exchange. The activities of the leading companies in absolute terms have remained almost the same on the sales side and have even increased on the purchase side.

[55] Here again no indication is given whether or not there has been a change in identity of the high turnover participants (from 2010 to 2011).

Significance of high turnover companies in bilateral trade in the strict sense (without OTC Clearing)

533 companies quoted their purchase volumes in futures trading. The five leading companies in this group account for 59 percent of the total purchase volume; the ten leading companies account for 70 percent of the purchase volume.

331 companies quoted their sales volumes in futures trading. The five companies with the highest sales volumes account for 63 percent of the total volumes quoted by the sellers. The ten leading companies on the seller side together account for 78 percent.

Retail

Number of suppliers

Electricity customers are now even more able to switch between and choose from a wide range of suppliers. More than 50 suppliers were active in almost three quarters of all network areas in 2011. In 2007 this was true of just one quarter of areas. A sufficiently large number of suppliers in a market area is generally considered a necessary condition for functioning competition, although a large number does not automatically translate into a high level of competition. Many default suppliers offer tariffs in several network areas in which they have not acquired a significant number of customers. On average across the whole country a final customer is able to choose from 80 suppliers; on average household customers have the choice of 65 suppliers. The population-weighted mean[56] for suppliers per network area was 169 in 2011.

[56] This figure is derived from the weighted total of suppliers based on number of inhabitants in a network area aggregated across all network areas and set in relation to total population. Network areas with high levels of population density are considered separately in the overall figures.

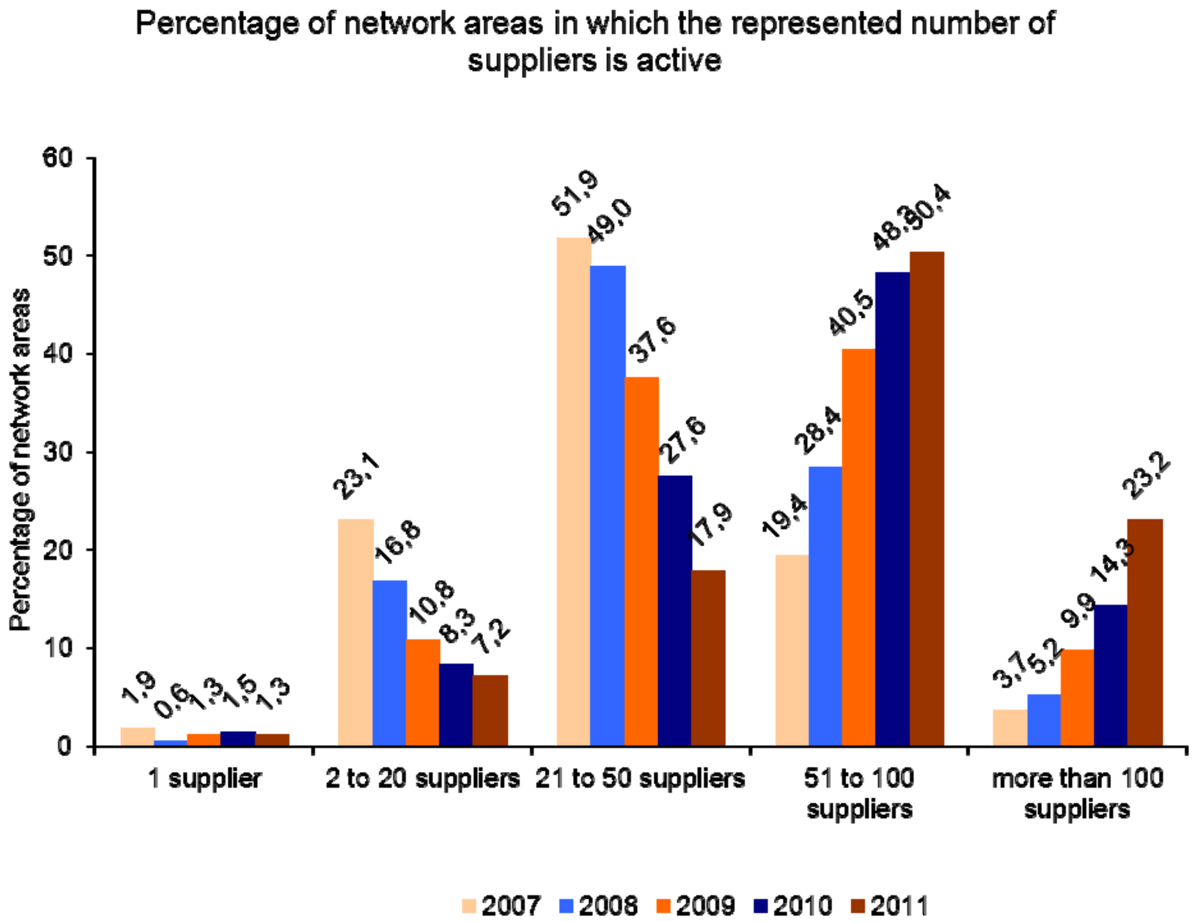

Figure 62: Percentage of network areas in which the represented number of suppliers is active

Most suppliers pursue a regional sales strategy. Around two thirds of suppliers are active in a maximum of ten network areas, one fifth in just a single network area. The percentage of suppliers who limit themselves to activities in a single network area has thus halved in five years. The number of suppliers active in more than one network area grew continuously between 2007 and 2011 as a result. The suppliers with the highest rate of growth - 8.2 percentage points - were those which operated in eleven to 50 network areas.

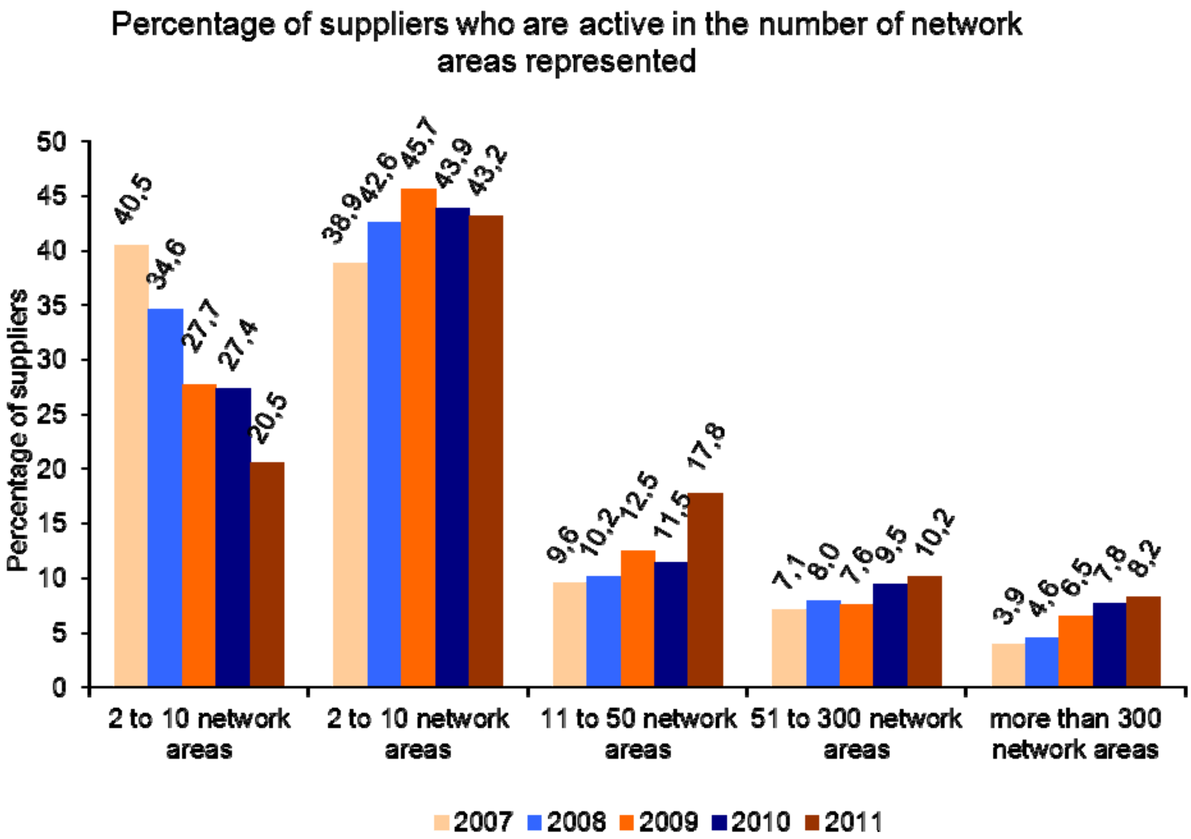

Figure 63: Percentage of suppliers who are active in the number of network areas represented

Contract structure and change of supplier

Business and industrial customers

The surveyed TSOs and DSOs stated the volume and number of changes of supplier in 2011 in their network area as an aggregated value as well as for each of the three customer categories. The resulting values are shown in the following table.

Category	2011 Change of supplier in TWh	Percentage electricity offtake Category in percent	2011 Number Change of supplier	Percentage Number of final customers in percent
≤ 10 MWh/year[57]	11.5	9.2	3,537,117	7.8
> 10 MWh/year ≤ 2 GWh/year	17.3	13.0	216,211	8.9
> 2 GWh/year	27.2	11.5	3,061	14.0
Total	**56.0**	**11.3**	**3,792,522**	**8.0**

Table 21: Change of supplier by final customers based on customer category, according to TSO and DSO survey

[57] The "≤ 10 MWh/year" category includes household customers, not business and industrial customers, and is included to provide a comprehensive overview of all groups of consumers.

The number and volume-based supplier change rates in categories with electricity offtake of over 10 MWh/year are significantly higher than the rates for final customers with less electricity offtake. The number and volume-based supplier change rate for large industrial customers is 14.0 and 11.5 percent respectively. Compared with 2010 this is equal to an increase of 1.3 percentage points. The same is true of smaller industrial and business customers who have a number and volume-based supplier change rate of 8.9 and around 13 percent respectively. During the year under review 2011 as a whole, 219,272 - or almost 32,000 more than in 2010 - industry and business customers changed supplier.

The volume-based supplier change rate for all groups of customers rose by 1.8 percentage points compared to 2010. The numerical supplier change rate was up by 1.7 percentage points. This increase is mainly due to an increase in the number of switches made by household customers, not by industrial and business customers.

In addition to change of supplier rates another factor which is relevant in terms of competition is changes in contract. The following diagram shows the structure of contracts with industry and business customers.

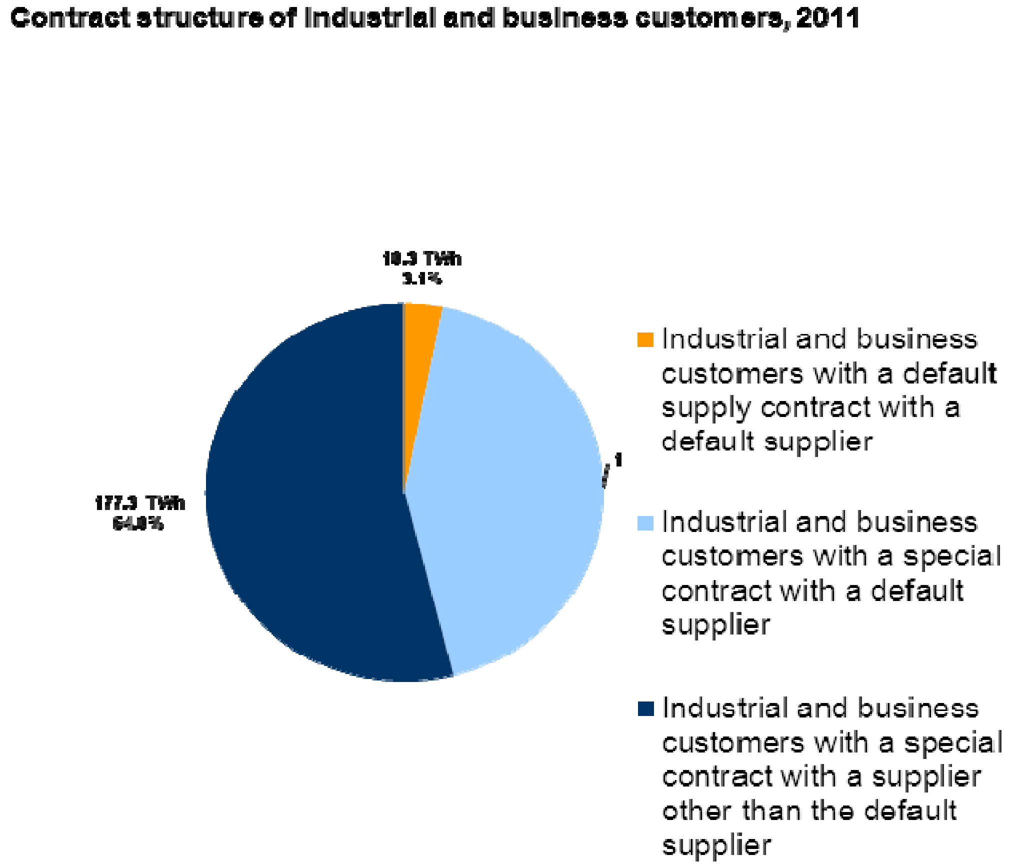

Figure 64: Deliveries to industrial and business customers, 2011

At the end of 2011 just 3.1 percent of industrial and business customers were served by their default supplier. These are almost exclusively smaller business customers; very few larger business customers or industrial customers continue to receive deliveries from default suppliers. 42.8 percent of industrial and business customers have a special contract with the electricity undertaking which is the default supplier in the area. This is a fall of three percentage points compared to 2010. 54 percent are served by suppliers other than the default supplier - an increase of 3.2 percent on the previous year (2010). More than half of all industrial and business customers buy electricity from a supplier operating on a supra-regional basis. These findings largely coincide with the survey on the category of load-metered (RLM) customers[58] which was undertaken for the first time in the year under review. According to the information provided by 758 electricity undertakings RLM customers used a total of 282.16 TWh of electricity in the year under review. RLM customers served by their default supplier accounted for

[58] Customers with an annual electricity offtake of over 100,000 kWh

a total of 4.58 TWh (1.6 percent of total supplies to RLM customers). A RLM customer receiving standard supply (default) services was - on average and over the course of a year - supplied with 163,000 kWh. Standard supply services for RLM customers were primarily provided as back up services. RLM customers with special contracts with the local default supplier were supplied a total of 112.14 TWh (39.7 percent) of electricity during the year under review, equal to an average volume of electricity of 473,000 kWh per customer. RLM customers with special contracts with electricity suppliers other than the local default supplier were supplied a total of 165.44 TWh (58.6 percent) of electricity. On average, these customers were supplied 1,313,000 kWh of electricity per year.

Household customers

Change of supplier and contract by household customers[59]

Analysis of the contractual structure for supplies to household customers shows that there is a continuing trend away from default supply contracts. The share of household customers receiving default supplies fell by 3.7 percentage points compared with the previous year. 43.4 percent of customers now have a special contract with a default supplier and 17 percent of all household customers have a special contract with a company other than the default supplier. Despite this, around 40 percent of all household customers continue to receive default supply services. This suggests that default suppliers continue to hold a strong share of regional markets.

[59] This chapter covers the entire segment of household customers. The statements made here are consequently not based on the definition of markets under anti-trust law for standard profile customers (standard supply customers, special contract customers, heat current customers).

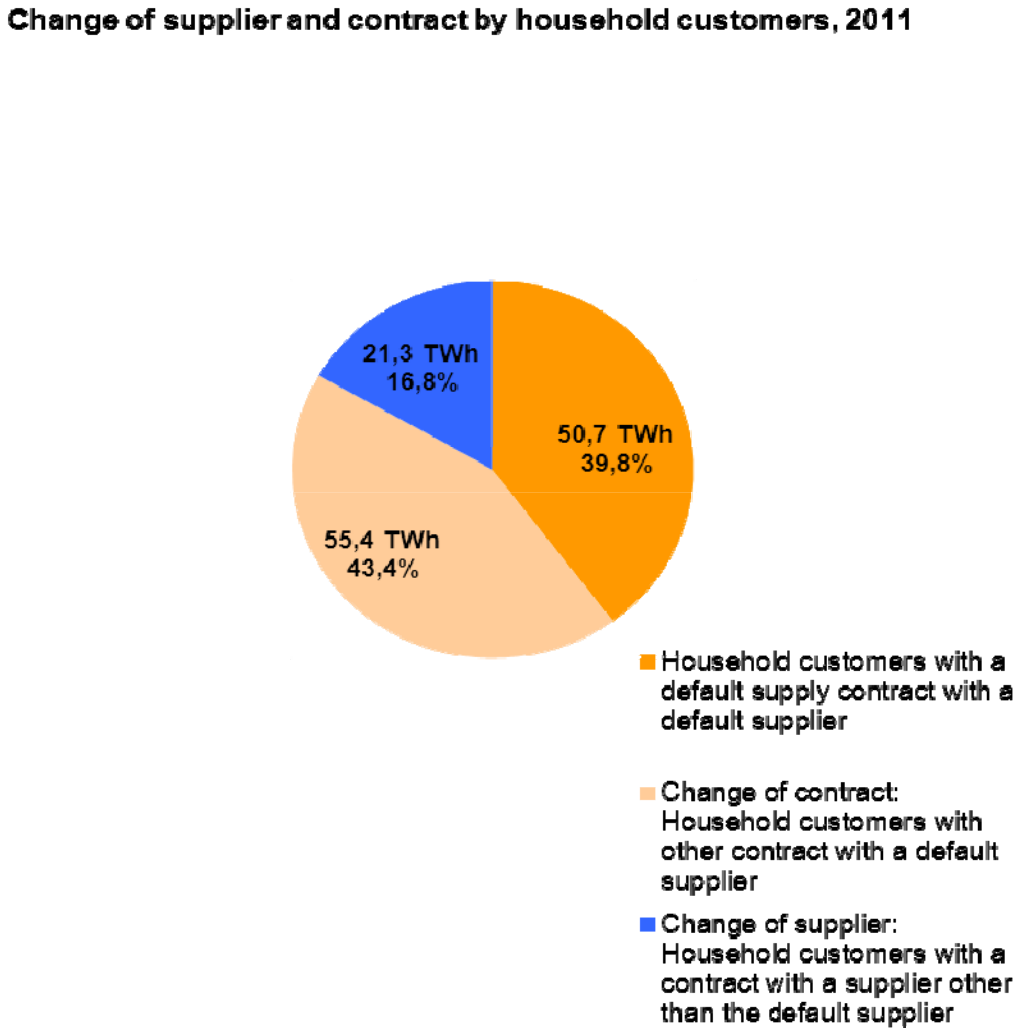

Figure 65: Change of supplier and contract by household customers, 2011

The share of the four biggest electricity undertakings within their respective default supply network area is around 45 percent and, outside of these areas, around 43 percent.

Supply to household customers	Electricity deliveries in TWh	Volumes supplied by the four biggest companies in TWh	Percentage of electricity deliveries
in their default supply network areas	105.8	47.5	45
outside their default supply network areas	21.3	9.1	43
Total	**127.1**	**56.6**	**45**

Table 22: Share of supplies to household customers provided by the four biggest electricity suppliers in 2011

Over 3.8 million final customers changed supplier in 2011. This was 27 percent more than in 2010. At the same time, however, account must be taken of the impact of the insolvency of a major supplier with around 500,000 customers.[60]

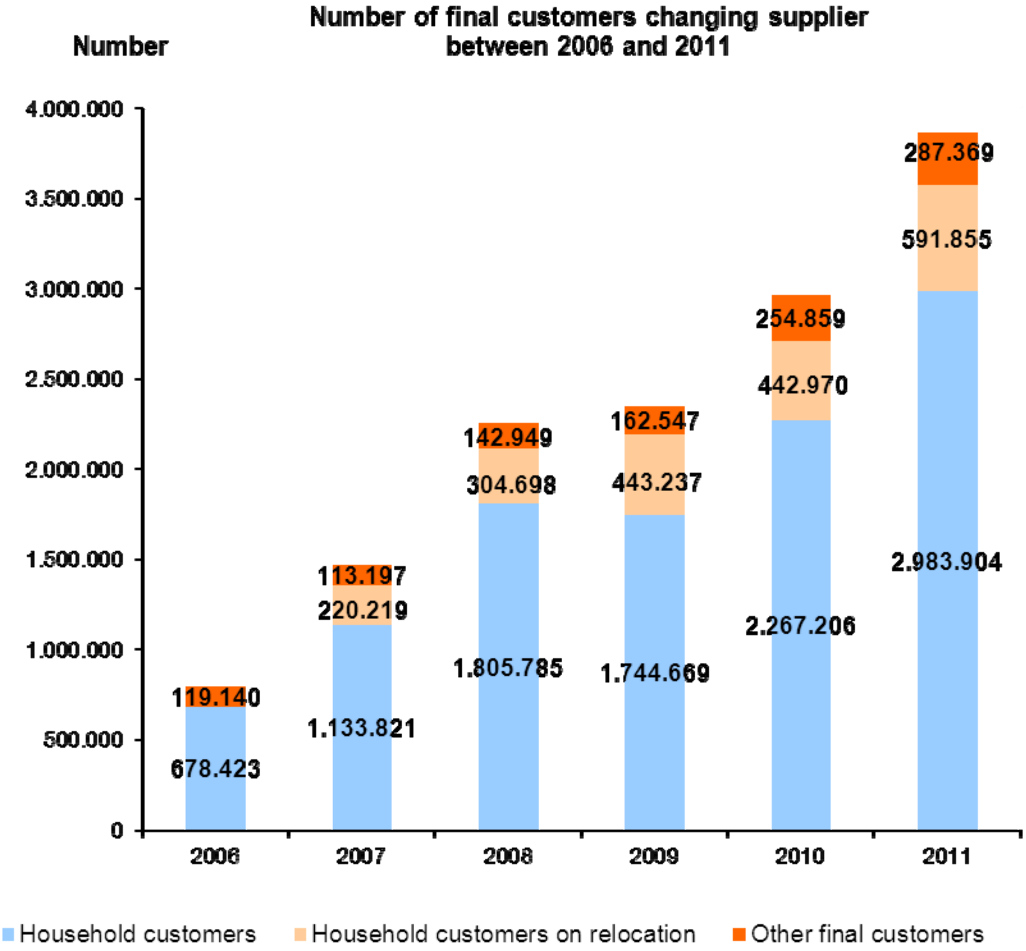

Figure 66: Number of final customers changing suppliers between 2006 and 2011

Almost three million household customers opted for a supplier other than the default supplier without moving house. Almost 600,000 customers chose a supplier other than the default supplier directly on moving into a new home. The supplier change rate is 7.8 percent as a share of all household customers and 9.2 percent of the total offtake volume.

[60] After this supplier became insolvent its customers initially reverted to receiving standard supply services. A large number of these customers will probably have switched to another supplier. For this reason it is reasonable to assume that - leaving aside the impact of the insolvency referred to - the number of supplier switches would probably be much the same as in the previous year. This conclusion is also supported by the fact that the percentage of customers being served by suppliers other than the default supplier rose by just 1.3 percentage points.

Category	2011 supplier change in TWh	Percentage of offtake volume	2011 supplier change Number	Percentage of number of house-hold cus-tomers
Household customers who opted for a supplier other than the default supplier without moving to a new home.	10.15	8.1	2,983,904	6.6
Household customers who opted for a supplier other than the default supplier directly on moving to a new home.	1.44	1.1	591,855	1.2
Total	**11.59**	**9.2**	**3,575,759**	**7.8**

Table 23: Household customers switching supplier in 2011

As business and industrial customers are in general more sensitive to prices than household customers, the supplier change rate is higher for non-household customers. The change rate for final customers who use between 10 MWh/year and two GWh/year was 8.9 percent in 2011; the change rate for customers who use over two GWh/year was 14 percent.

Category	2011 supplier change in TWh	Percentage of offtake volume in category	2011 number of changes of supplier	Percentage of number of final customers
≤ 10 MWh/year	11.5	9.2	3,537,117	7.8
> 10 MWh/year ≤ 2 GWh/year	17.3	13.0	216,211	8.9
> 2 GWh/year	27.2	11.5	3,061	14.0
Total	**56.0**	**11.3**	**3,792,522**	**8.0**

Table 24: Change of supplier by final customers according to customer categories

In line with the study of load-metered customers, information about the category of standard profile customers was collected for the first time[61] in the year under review. The following is based on information from 809 electricity undertakings. Standard profile customers were supplied with a total of 171.98 TWh of electricity in the year under review. Standard profile customers receiving standard supply services accounted for a total of 55.95 TWh (32.5 percent of total supplies to standard profile customers) or an average of 2,620 kWh per customer. Standard profile customers with special contracts with the local default supplier were supplied a total of 82.96 TWh (48.2 percent) of electricity during the year under review, equal to an average volume of electricity of 4,616 kWh per customer. Standard profile customers with special contracts with the local default supplier were supplied a total of 82.96 TWh (48.2 percent), equal

[61] Customer with standard load profile; annual electricity offtake of up to 100,000 kWh

to an average volume of 4,616 kWh per customer. Standard profile customers with special contracts with electricity suppliers other than the local default supplier were supplied a total of 33.07 TWh (19.2 percent) of electricity. On average, these customers were supplied 4,497 kWh of electricity per year.

Default supply: Disconnections, tariffs and contract terminations

Electricity – disconnection notices, tariffs and terminations

Disconnections

To date there have been no national surveys of the frequency with which household customers in particular are affected by disconnections in supply. There are huge discrepancies in the estimates produced by consumer protection groups and the industry. It was for this reason that the 2011 amendment to the Energy Act extended the Bundesnetzagentur's monitoring powers to cover 'disconnections of household customers' (section 35(1) para. 10 EnWG). Section 19(2) of the Electricity Default Supply Ordinance (StromGVV) entitles default suppliers to disconnect supplies to customers, particularly for non-payment where arrears have mounted to 100 euros or more and after a corresponding reminder has been given.

In the year under review 2011 the Bundesnetzagentur consequently performed surveys of tariffs on offer for the first time and asked network operators and suppliers about threatened disconnections, disconnection orders as well as the number of actual disconnections under section 19 (2) StromGVV and the associated costs. This provides a source of information on this issue for the first time. Some companies were not able to provide exact figures, but did disclose estimated figures. Sufficient data was made available to produce a useful overview.

Electricity network operators were asked at how many metering points they had disconnected or reconnected supplies in the calendar year 2011 at the request of a supplier. A total of 620 network operators reported 312,059 disconnections. Bearing in mind the actual number of metering points in the network areas, the responses cover less than one per cent of the metering points in Germany.

On average, electricity network operators charged suppliers 32 euros for cutting off electricity supplies, although the actual charge made varies between 0 euros and 300 euros.

At the same time, suppliers and wholesalers were asked how often in 2011 they had issued disconnection notices warning customers in arrears that they may be disconnected or had applied to the responsible network operator for supplies to be disconnected.

Companies stated that they had issued around six million disconnection notices to customers. According to the data provided by companies, disconnection notices threatening to cut a customer off are issued when the statutory requirements of section 19 StromGVV are met and when, on average, a customer is 120 euros in arrears. However, of the six million disconnection notices issued, only around 1.25 million resulted in electricity being cut off by the responsible network operator.

Number	
Disconnection notices sent by suppliers	6,075,433
Disconnections applied for by suppliers	1,255,146
Disconnections by network operators	312,059

Table 25: Disconnections/Disconnection notices

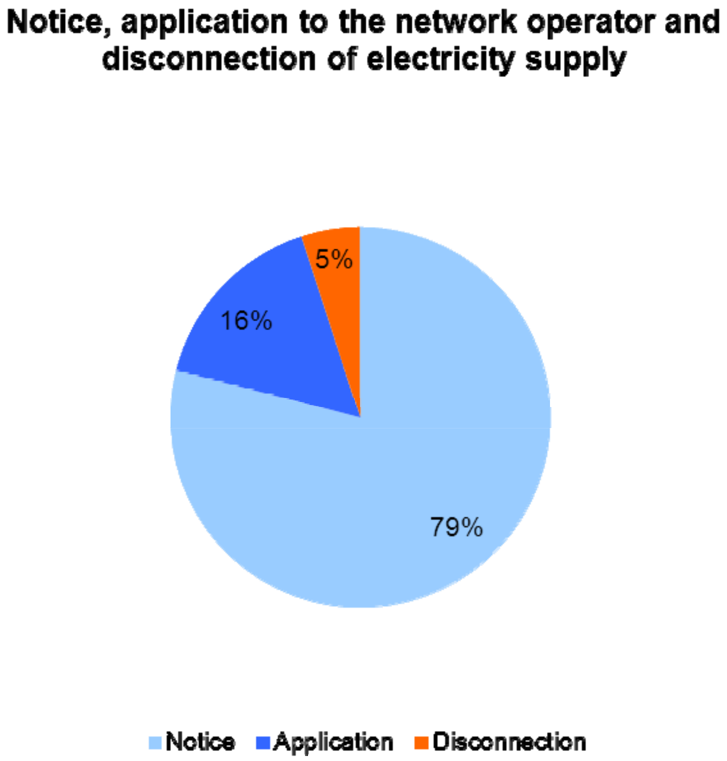

Figure 67: Notice, application to the network operator and disconnection of supply

On average, suppliers charged their customers 32 euros for cutting off supplies; actual charges varied between 0 euros and 220 euros.

Tariffs and terminations

Under section 40(5) EnWG suppliers of electricity must offer final customers load-based or time-differentiated tariffs if this is technically and economically feasible. In 2011, however, only a very small number of suppliers offered load-based tariffs. Most suppliers only offer time-differentiated tariffs; very few suppliers offer any other kind of tariff. Under section 40(3) EnWG suppliers are also required to offer final customers monthly, quarterly or half-yearly settlement. However, demand from final customers for these forms of settlement is negligible. The overwhelming majority of suppliers report no demand at all.

Despite the number of disconnection notices and applications for disconnection shown above, very few suppliers actually wish to stop doing business with their customers. In 2011 suppliers terminated contracts with around 143,000 customers. However, the overwhelming majority of these contracts appear to have been terminated by just a few, young inter-regionally operative companies, while regional providers seldom if ever terminate contracts with customers.

Price level

Business and industrial customers

Retail prices for industrial customers are based on the following purchase case:

24 GWh annual consumption

4,000 kW annual peak load and 6,000 hours annual usage time

Medium voltage supplies (10 or 20 kV) [62]

The retail price for industrial customers is composed of the following:

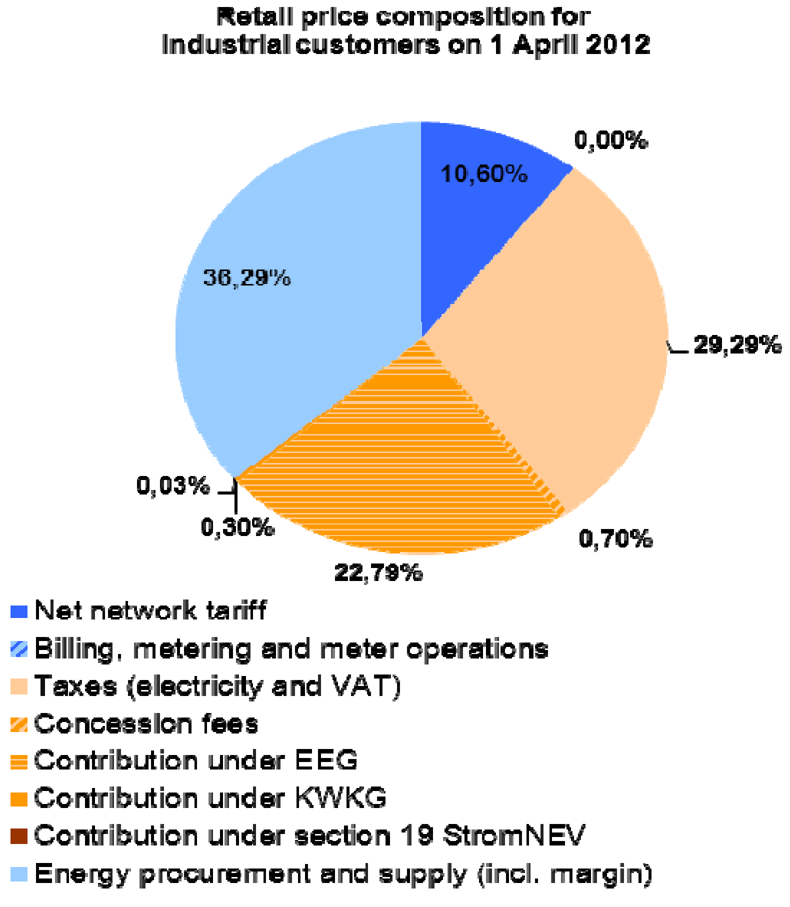

Figure 68: Electricity retail price composition for industrial customers on 1 April 2012

As the diagram shows, the net network tariffs (including billing, metering and meter operations) account for 10.6 percent of the entire electricity price for industrial customers. Taxes (electricity and value-added tax) account for 29.3 percent and fees for around 22.8 percent. In other words, over 50 percent of the price of electricity charged to industrial customers is made up of tax and fees. The "energy procurement and supply" element accounts for 36.3 percent of the total electricity price paid by industrial customers.

[62] The following additional assumptions were made for the category of industrial customers: It was assumed that the compensation scheme for large electricity-consuming enterprises and rail operators foreseen by sections 40 to 44 EEG are not applied and that electricity costs in the previous year did not exceed four percent of sales (when determining the current contribution under KWKG, cf. section 9(7) KWKG).

The suppliers reporting on the prices charged to industrial customers were asked to provide plausible estimates, based on the conditions applying on 1 April 2012, for the amount charged to their customers with a purchase structure comparable with the stated purchase case. The evaluation of information provided by 614 companies (volume-weighted average) produced the results shown in the following table[63].

Industrial customers (volume weighted) on 1 April 2012	Share of price in cents	Share of total price in percent
Net network tariff	1.67	10.6
Charge for billing	0	0.0
Charge for metering	0	0.0
Charge for meter operations	0	0.0
Concession fees	0.11	0.7
Contribution under EEG	3.59	22.8
Contribution under section 19 StromNEV	0.05	0.3
Contribution under KWKG	0.04	0.3
Taxes (electricity and VAT)	4.61	29.2
Energy procurement and supply (incl. margin)	5.71	36.2
Total price	**15.78**	**100.0**

Table 26: Average retail price level (fixed and variable price components) on 1 April 2012 for industrial customers according to survey of wholesalers and suppliers

The arithmetically determined price level for industrial customers (not shown here) is around one ct/kWh above the volume-weighted price level.

The retail prices shown for business customers are based on the following purchase case:

50 MWh annual consumption

50 kW annual peak load and 1,000 hours annual usage time

Low-voltage supply (0.4 kV) (where the load profile of business customers is not measured the value is stated on the basis of delivery without load metering.)

The retail price for business customers is composed of the following:

[63] When evaluating the volume-weighted average it was only possible to use prices for which companies had also provided information in the corresponding customer category on volumes delivered to final customers. As not all companies which have provided information about the price level also provided data on the volumes delivered to final customers in the applicable customer category, the number of companies considered in the evaluation for the volume-weighted average is lower than the number of companies for the arithmetic mean.

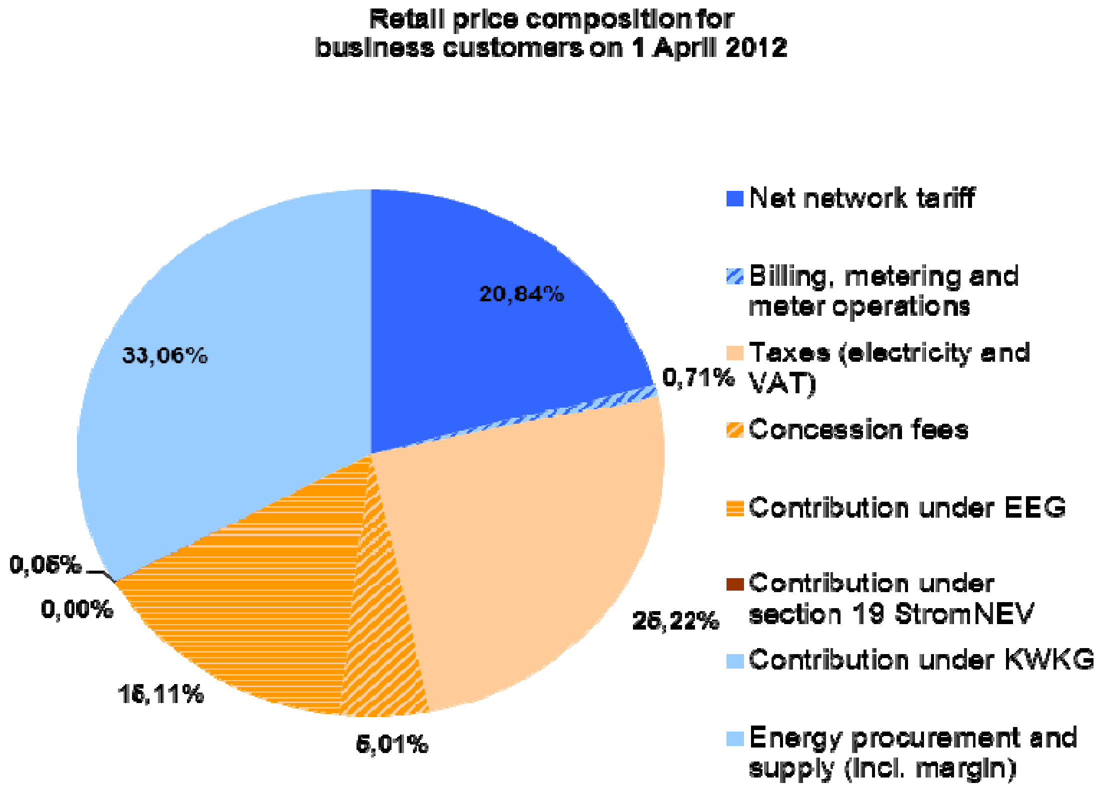

Figure 69: Electricity retail price composition for business customers on 1 April 2012

610 companies provided tariff information on the prices for business customers. This produced the results shown in the following table[64].

Business customers (volume-weighted) 1 April 2012	Share of price in cents	Share of total price in percent
Net network tariff	4.95	20.7
Charge for billing	0.07	0.3
Charge for metering	0.03	0.1
Charge for meter operations	0.07	0.3
Concession fees	1.19	5.0
Contribution under EEG	3.59	15.0
Contribution under KWKG	0	0.0
Contribution under section 19 StromNEV	0.15	0.6
Taxes (electricity and VAT)	5.99	25.1
Energy procurement and supply (incl. margin)	7.85	32.9
Total price	**23.89**	**100.00**

Table 27: Average retail price level (fixed and variable price components) on 1 April 2012 for business customers according to survey of wholesalers and suppliers

[64] When evaluating the volume-weighted average it was only possible to use prices for which companies had also provided information in the corresponding customer category on volumes purchased by final customers. As data on the volume of electricity sold to final customers in the applicable customer category is not available from all the companies which provided information about the price level, the number of companies in the evaluation for the volume-weighted average is lower than the number of companies for the arithmetic mean.

The following table shows the changes in the volume-weighted average of net network tariffs, charges for billing, metering and meter operations, taxes and other elements of price due to the state, energy procurement and supply as well as total electricity prices for business and industrial customers from 1 April 2011 to 1 April 2012 in ct/kWh. It also shows the percentage change in the relevant price components.

Development of electricity price, 1 April 2012 compared to 1 April 2011				
Volume-weighted average	**Industrial customers**		**Business customers**	
	in ct/kWh	**in percent**	**in ct/kWh**	**in percent**
Net network tariff	0.21	14.00	0.24	5.00
Charge for billing	-0.01	-100.00	0.00	0.00
Charge for metering	0.00	0.00	-0.02	-40.00
Charge for meter operations	0.00	0.00	0.01	17.00
Concession fees	0.00	0.00	-0.03	-2.00
Contribution under EEG	0.15	4.00	0.12	3.00
Contribution under KWKG	0.01	33.00	-0.03	-100.00
Contribution under section 19 StromNEV	0.05	--	0.151	--
Taxes (electricity and VAT)	0.08	2.00	0.23	4.00
Energy procurement and supply (incl. margin)	-0.45	-7.00	-0.16	-2.00
Total	**0.04**	**0.25**	**0.51**	**0.21**

Table 28: Development of the volume-weighted price level for industrial and business customers (electricity)

Compared with 2011 and in relation to the volume-weighted average of price components for industrial customers, the contributions payable under KWKG and EEG, taxes and net network tariffs have both gone up. In contrast, the energy procurement/supply and billing charge components of the price have gone down. For business customers the charges for meter operations have gone up alongside increases in taxes, contribution under EEG and network tariffs. The energy procurement/supply components of the price, as well as the contribution under KWKG, concession fees and metering fees have gone down. The total price for industrial customers rose slightly compared to 2011 by 0.04 ct/kWh. For business customers the total price went up on average by 0.51 ct/kWh.

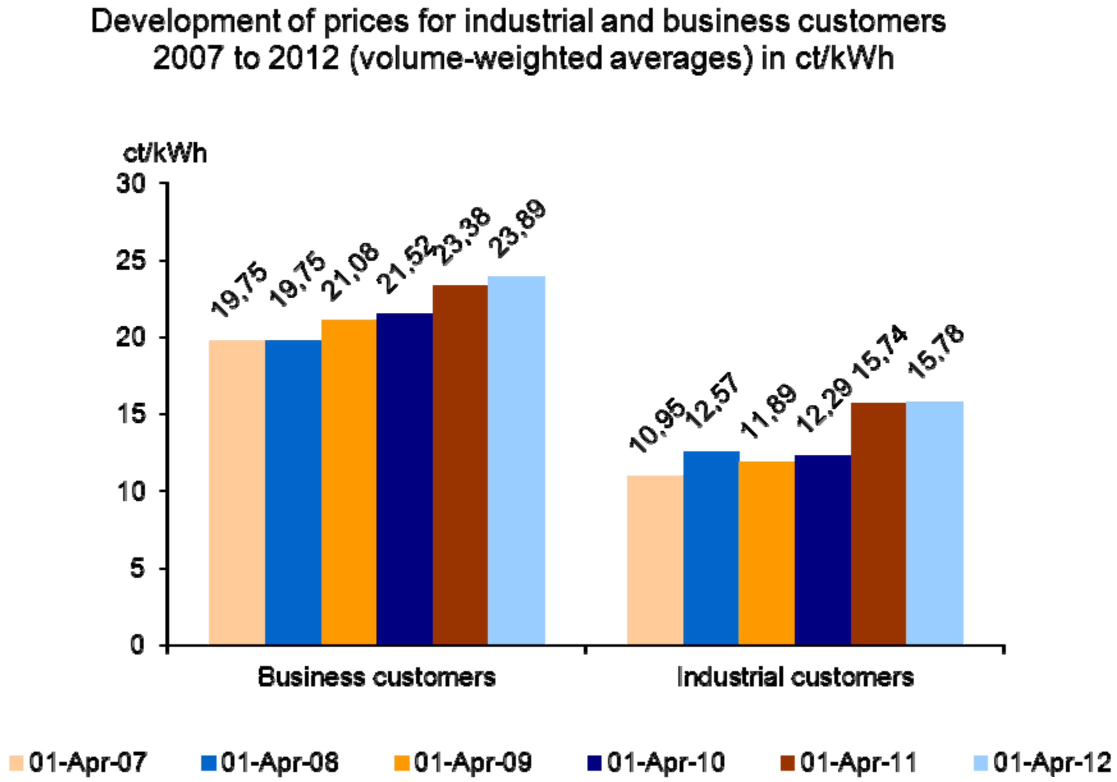

Figure 70: Development of volume-weighted prices for industrial and business customers, from 2007 to 2012

In the years 2007-2012 prices for industrial customers did not go up at a steady rate. Over the last five years electricity prices paid by industrial customers have risen in total by 4.83 ct/kWh. This corresponds to an increase of 44 percent. In the case of the electricity prices paid by industrial customers, this additional burden is predominantly due to the substantially higher fees which have been payable since 2006. Increases in fees still make up well over 50 percent of the total increase in prices between 2007 and 2012. The total price for industrial customers has gone up slightly compared with the previous year.

The electricity prices paid by business customers between 2007 and 2012 have risen by 4.14 ct/kWh or 21 percent. This is largely due to higher fees and the increase in the "energy procurement and supply" price component. Last year, the relatively large increase in charges for billing, metering and meter operations was cushioned by reductions in the procurement and supply elements of prices. The net impact of these changes was an increase in the calculated total price paid by business customers of 0.51 ct/kWh. The total price paid by business customers also remained fairly stable compared to 2011.

Household customers

Development of electricity prices for household customers

The prices paid by household customers are shown in the following as volume-weighted averages per price plan. Prices have again gone up during the year under review in the tariff categories of default supply services, change of contract and change of supplier. Compared with 2011, the price for default supply for household customers rose by 2.8 percent in 2012. At the same time the price rise was much weaker for all consumer groups – default supply, special contract with default supplier, special contract with a third supplier. Default supply continued to be the most expensive form of service. Household customers can pay lower prices if they change contract or supplier, whereby changing supplier is the more cost effective alternative. This category is 4.7 percent below the default supply price which rose by 0.6 percent compared with 2011. The development of household customer prices in each tariff category for the years 2007 to 2012 is shown in the following diagram.

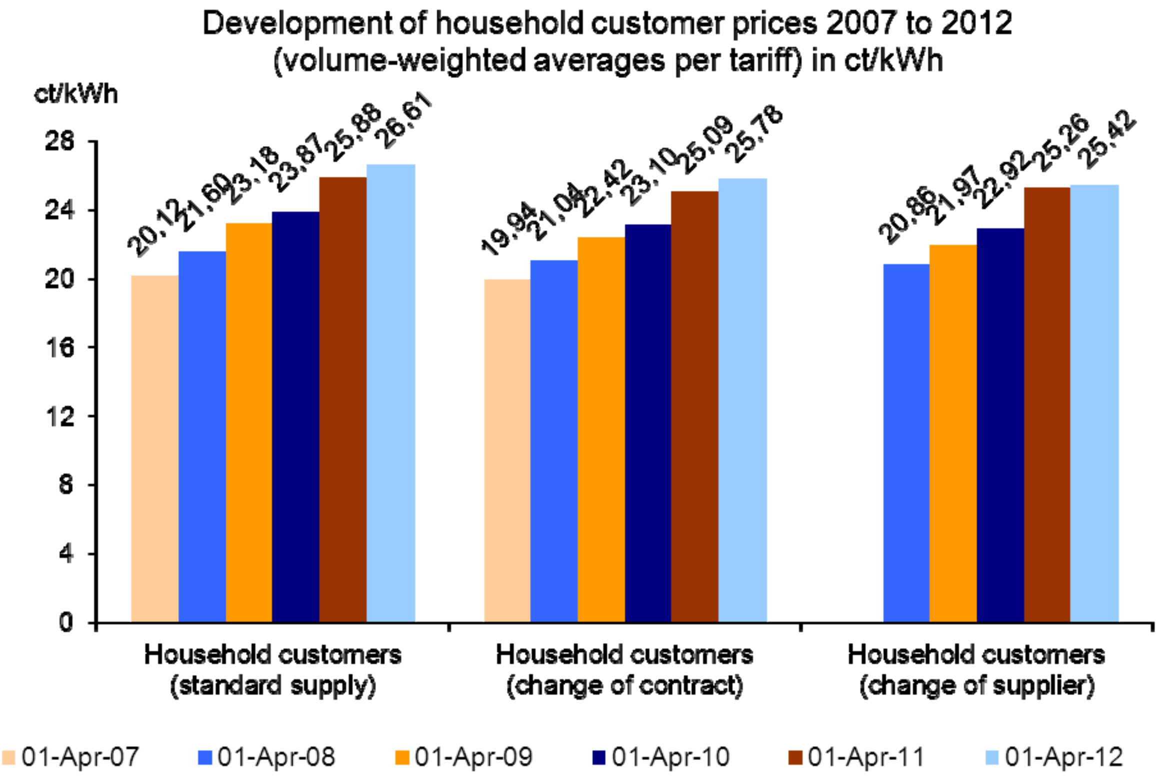

Figure 71: Development of household customer prices, 2007 to 2012

The price differences between the various household customer categories are largely due to the different proportional contribution to costs made by energy procurement and supply.[65] At 8,86 ct/kWh this price component in the default supply service is 13 percent above the average value for special contracts with an electricity utility which is not a local default supplier. The average cost of energy procurement and supply when changing to a special contract with

[65] Both cost components have been surveyed separately for the first time in this year's monitoring report.

a local default supplier is still eight percent lower than the price for standard supply services. A detailed overview of this development is provided in the following diagram.

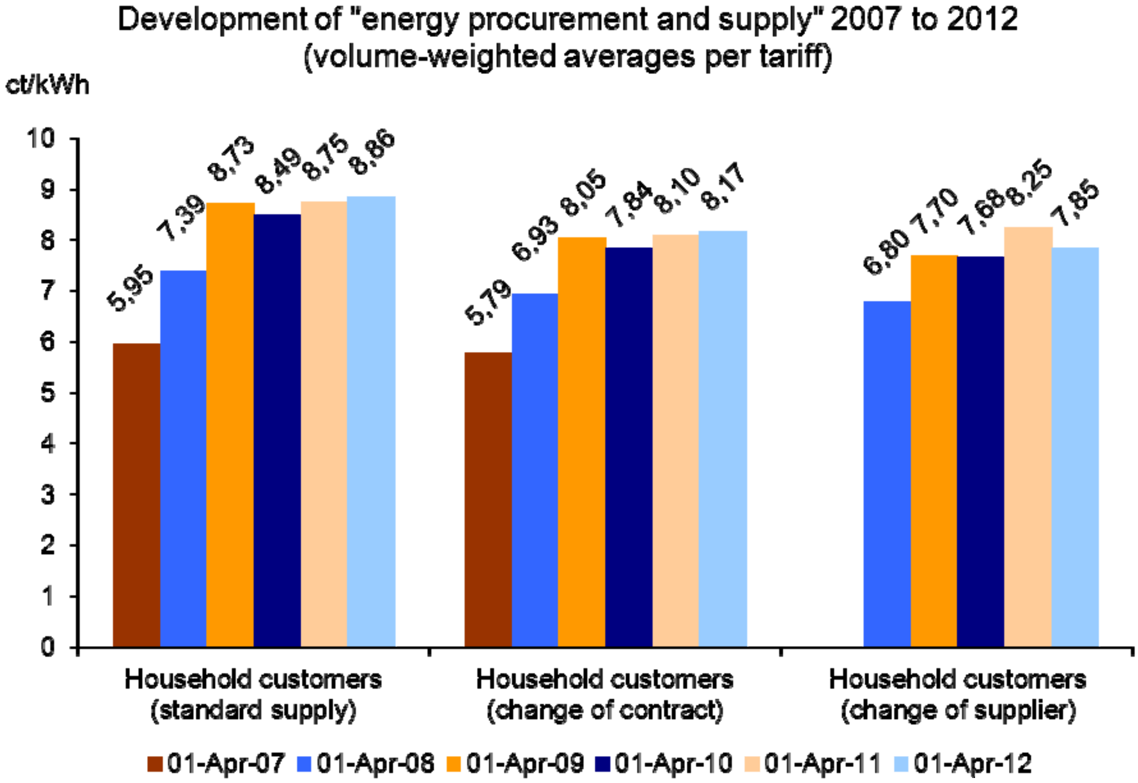

Figure 72: Development of energy procurement and supply, 2007 to 2012

In addition to the costs of procurement and supply (including margin), electricity prices are composed of network tariffs, contributions, taxes and fees. Each of the components of the price in various tariff categories for household customers are shown in the following table.

Household customers (volume-weighted) 1 April 2012 (in ct/kWh)	Default supply price plan	Non-default supply tariff (Contract change)	Non-default supply network area tariff (Supplier change)
Net network tariff	5.38		
Charge for billing	0.33		
Charge for metering	0.08		
Charge for meter operations	0.24		
Energy procurement	6.36	6.28	6.10
Supply (incl. margin)	2.50	1.89	1.75
Concession fees	1.68		
Contribution under EEG	3.59		
Contribution under KWKG	0.00		
Contribution under section 19 StromNEV	0.15		
Electricity tax	2.05		
Valued-added tax	4.25	4.10	4.06
Total price	**26.61**	**25.78**	**25.42**

Table 29: Average retail price for household customers per tariff category, 2012

In terms of household customers, the following applies for the year 2012: comparing the consumer categories of default supply, special contract with the default supplier (contract change) and special contract with another supplier (supplier change) on average the electricity price is highest for default supply, while the electricity price in the supplier change category is lowest. The average price for the contract change category lies between the two. Comparing the average values for the three categories over the period 2008 to 2012 shows that the provision of default supply is consistently the most expensive category of electricity supply for household customers. Over the monitored period, the change contract category is cheaper than default supply every year. Considered over the entire period the change supplier category is also, on average, cheaper than default supply. The relationship between the change contract and change supplier categories fluctuates to some extent. In four of the years monitored the average price in the category change supplier was – more or less clearly – below that for the category change contract, as was the case this year as well. Last year, in contrast, the change contract category was cheaper on average than the change supplier category.

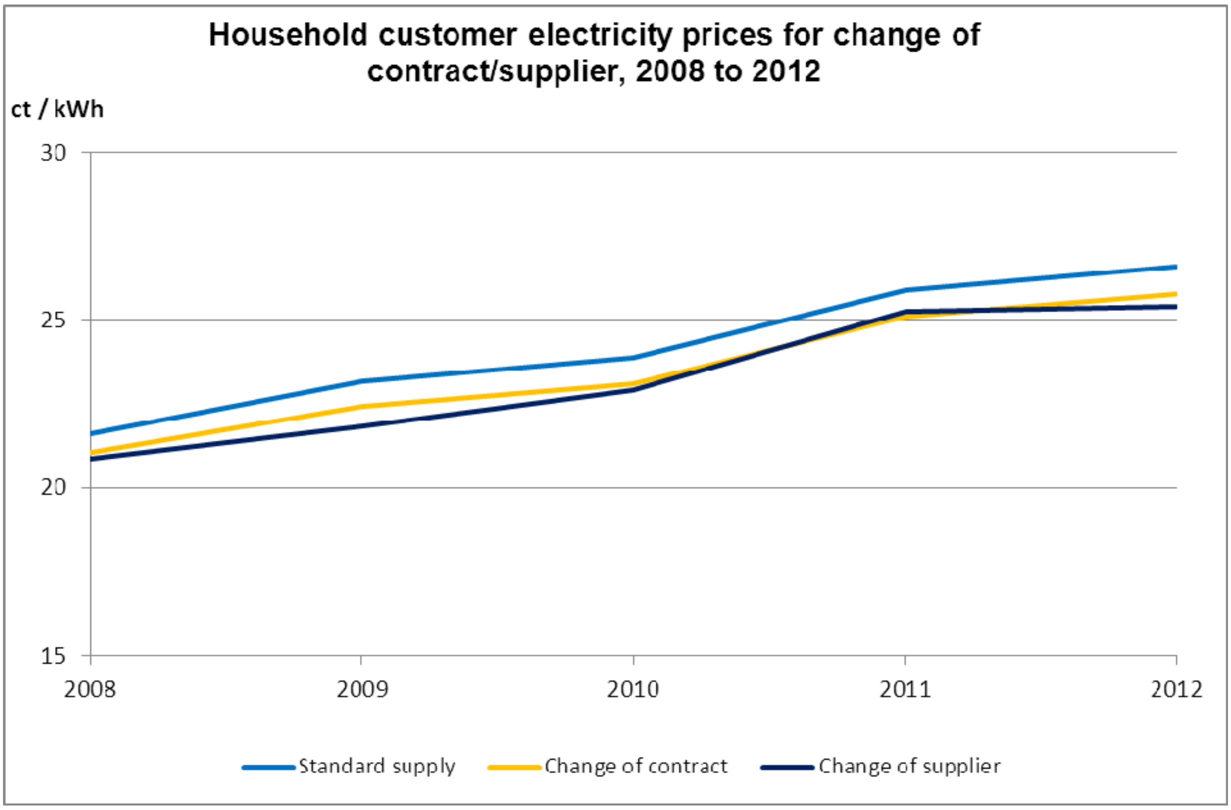

Figure 73: Household customer electricity prices for change of contract/supplier, 2008 to 2012

In addition to cheaper offers for a change of contract or supplier many energy utilities also offer contractual special conditions which make it more attractive for customers to move away from a default supply tariff.

Special bonuses and special arrangements (1 April 2012)	Household customers (Contract change)		Household customers (Supplier change)	
	Number of tariffs	Average scope	Number of tariffs	Average scope
Minimum contract term	304	10 months	302	10 months
Price stability	200	13 months	223	14 months
Advance payment	61	11 months	40	12 months
One-off bonus payment	60	€41	99	€50
Deposit	3		2	
Other bonuses and special arrangements	91		90	

Table 30: Special bonuses and arrangements for household customers in 2012

The stipulation of a minimum contract term or guaranteed price stability are often offered with average commitment periods of 10-14 months.

The average electricity price for household customers in 2012 of 26.06 ct/kWh is based on the calculation of a volume-weighted average across all tariff categories. The average electricity price in 2012 is thus 2.4 percent higher than in 2011.
In detail the price is composed of the following elements.

Household customers 1 April 2012 (in ct/kWh)	**Volume-weighted average across all tariffs**	**Share of total price in percent**
Net network tariff	5.38	20.6
Charge for billing	0.33	1.3
Charge for metering	0.08	0.3
Charge for meter operations	0.24	0.9
Energy procurement	6.28	24.1
Supply (incl. margin)	2.11	8.1
Concession fees	1.68	6.4
Contribution under EEG	3.59	13.8
Contribution under KWKG	0.00	0.0
Contribution under section 19 StromNEV	0.15	0.6
Electricity tax	2.05	7.9
Valued-added tax	4.16	16.0
Total price	**26.06**	**100.0**

Table 31: Average retail price for household customers per tariff category, 2012

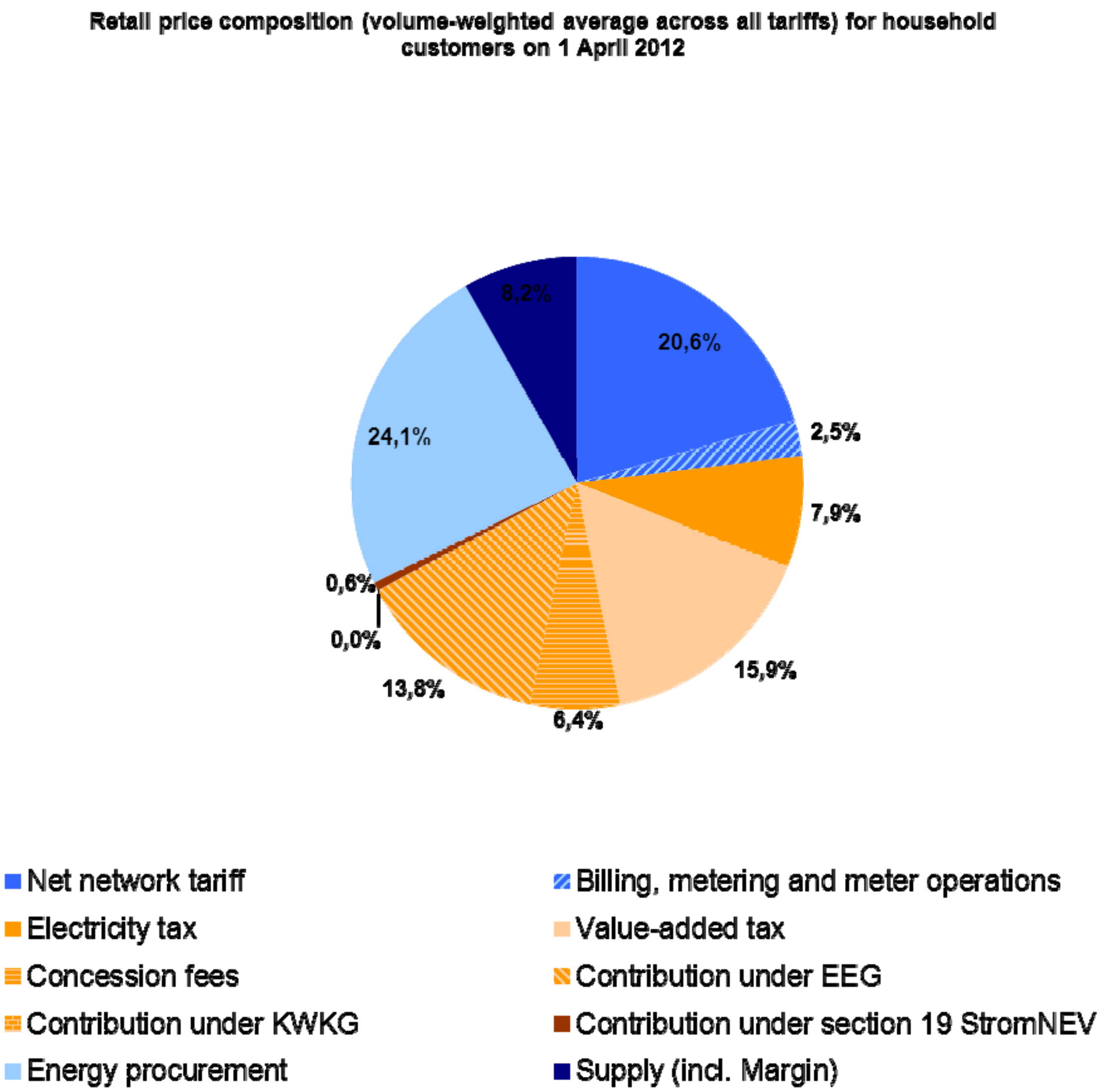

Figure 74: Electricity retail price composition for household customers on 1 April 2012

Energy procurement accounts for 24.1 percent, supply (incl. margin) 8.2 percent, taxes 23.9 percent and network tariffs (including billing, metering and meter operations) 23.1 percent.

The following table shows the development of the volume-weighted electricity price for all tariffs from 2011 to 2012. Despite the price reducing impact of completed changes of supplier and contract, the price of electricity went up by 2.4 per cent (+0.61 ct/kWh) compared with 2011. This is mainly due to higher network tariffs and higher taxes and fees. Net tariffs rose by 0.32 ct/kWh, the contribution under section 19 EnWG by 0.15 ct/kWh and taxes and the contribution under EEG by 0.10 ct/kWh each compared with the previous year. (The contribution under section 19 StromNEV was included in the network tariffs in 2011 and has been treated separately since this year.)

Change in electricity price: 1 April 2012 compared to 1 April 2011.		
Household customers (volume-weighted across all tariffs)	**in ct/kWh**	**in percent**
Net network tariff	+0.32	+6.3
Charge for billing, metering and meter operations	-0.03	-4.3
Energy procurement and supply (incl. margin)	-0.02	-0.2
Concession fees	+0.03	+1.8
Contribution under EEG	+0.10	+2.9
Contribution under KWKG	-0.04	-92.5
Contribution under section 19 StromNEV	+0.15	--
Taxes (electricity and VAT)	+0.10	+1.6
Total price	**+0.61**	**+2.4**

Table 32: Development of price level for household customers, volume-weighted across all tariffs

The development of the volume-weighted electricity price for household customers since 2006 is shown below. Following a period during which network tariffs consistently fell between 2006 and 2011, these tariffs rose in 2012 for the first time since regulation commenced. Network tariffs went up by five percent (+0.29 ct/kWh) compared with the previous year 2011. Over a 6-year period, however, network tariffs have in fact fallen on average by 17 percent.

The network tariff components of the price for billing, metering and meter operations fell by four percent compared with 2011 (0.03 ct/kWh) and by as much as 22 percent since 2009. (Network tariffs excluding contribution under section 19 StromNEV of 0.15 ct/kWh)

The share of the electricity price made up of taxes and fees has risen since 2006. Over a period of six years fees have gone up by 119 percent and taxes by 33 percent. The share of the price made up of energy procurement and supply (incl. margin) costs rose by 87 percent in the same period. The largest increase occurred between 2006 and 2009. Since 2009 the share accounted for by energy procurement and supply has remained fairly constant.

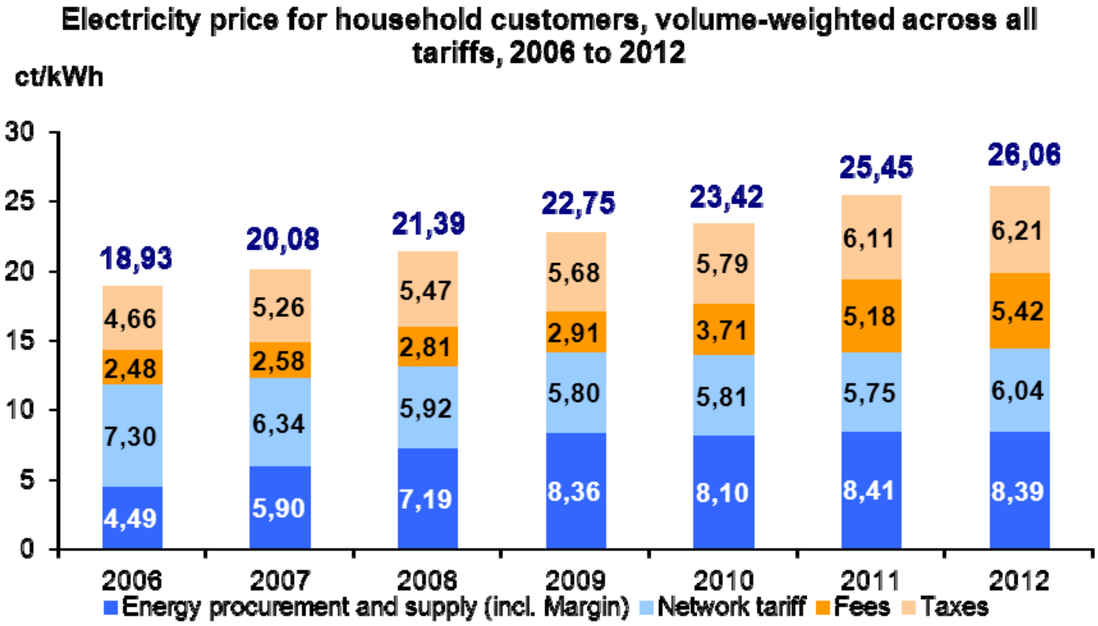

Figure 75: Electricity price for household customers, volume-weighted across all tariffs, 2006 to 2012

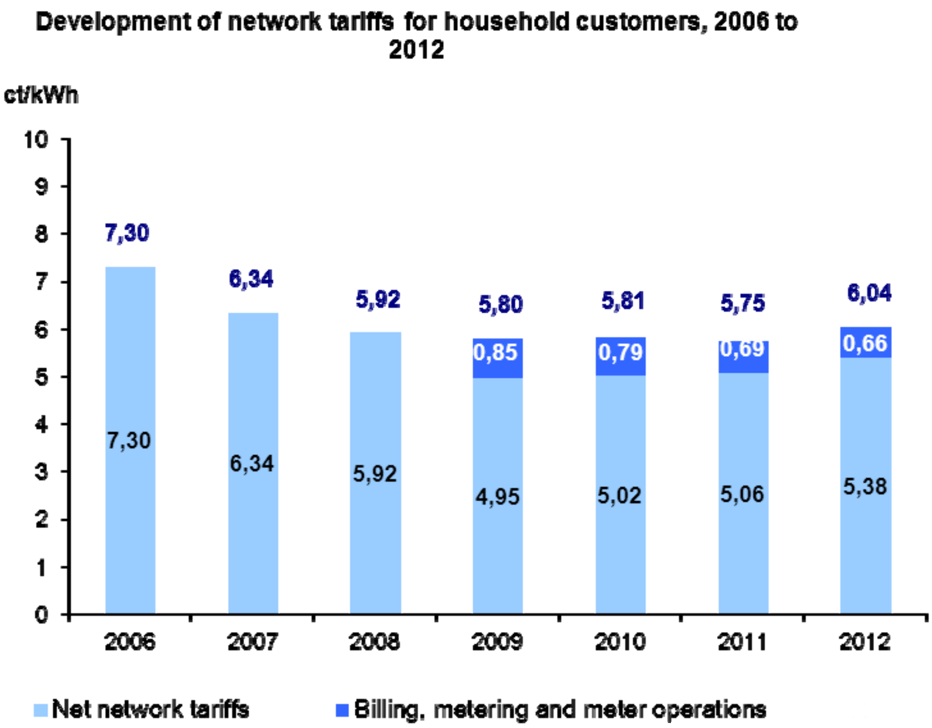

Figure 76: Development of network tariffs, including billing, metering and meter operations, 2006 to 2012[66]

In the past the costs of energy procurement were calculated indirectly and approximately from the data collected. The energy procurement and supply cost elements of the price paid by household customers have been determined separately for the first time this year. The data collected fit well with the approximately calculated data used in last year's report as shown in the diagram below. However, given the change of method direct comparisons are very difficult

[66] The price component "billing, metering and meter operations" was not recorded separately in the period 2006 to 2008 and is therefore included in the net network tariffs.

to make in this case. Supply costs, including margin, make up 25 percent and energy procurement costs 75 percent of the total price, and as such the relationship between the two price components is similar to last year.

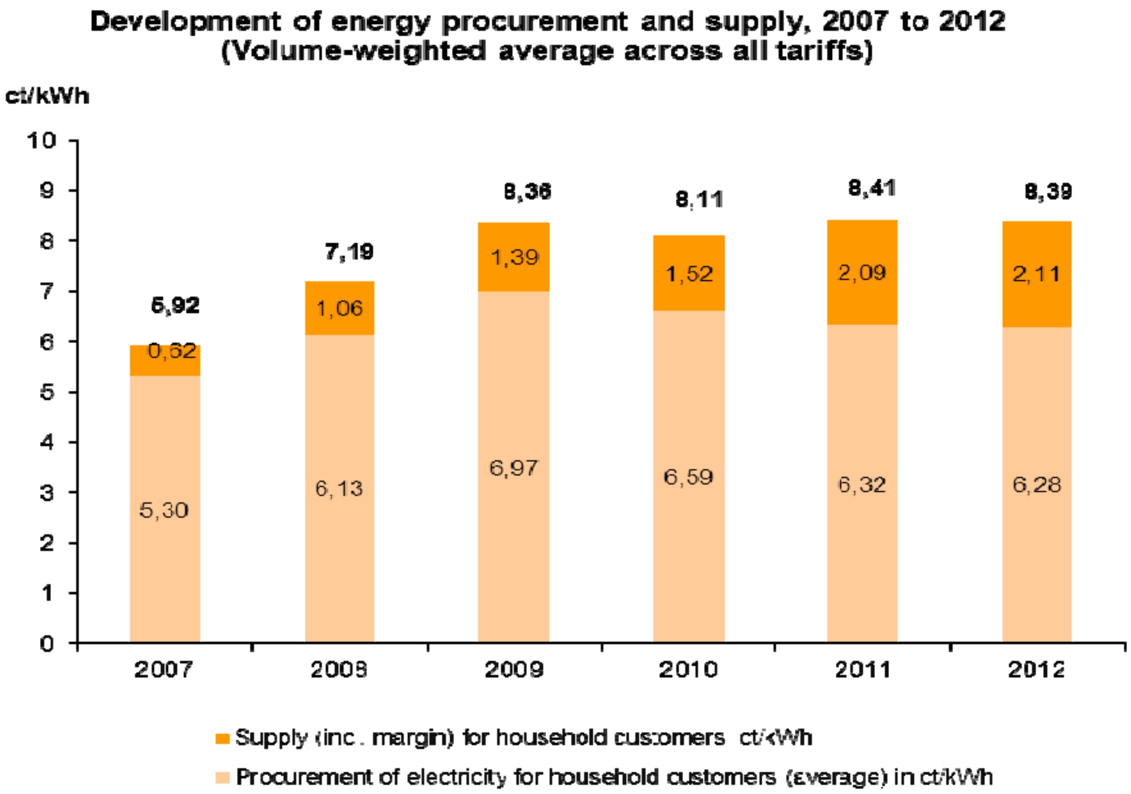

Figure 77: Development of energy procurement and supply, 2007 to 2012 [67]

The relationship between network tariffs and supply costs (including margin) has remained fairly constant compared with last year as shown by the following diagram. While the relationship (network tariffs: supply) was 73:27 last year, this year it is 74:26.

[67] Data on energy procurement for 2012 was obtained from suppliers. The data for the period 2006 to 2011 was calculated from surveyed procurement volumes and EEX prices. However, given the change of method it is very difficult to compare the data for 2012 with data for previous years.

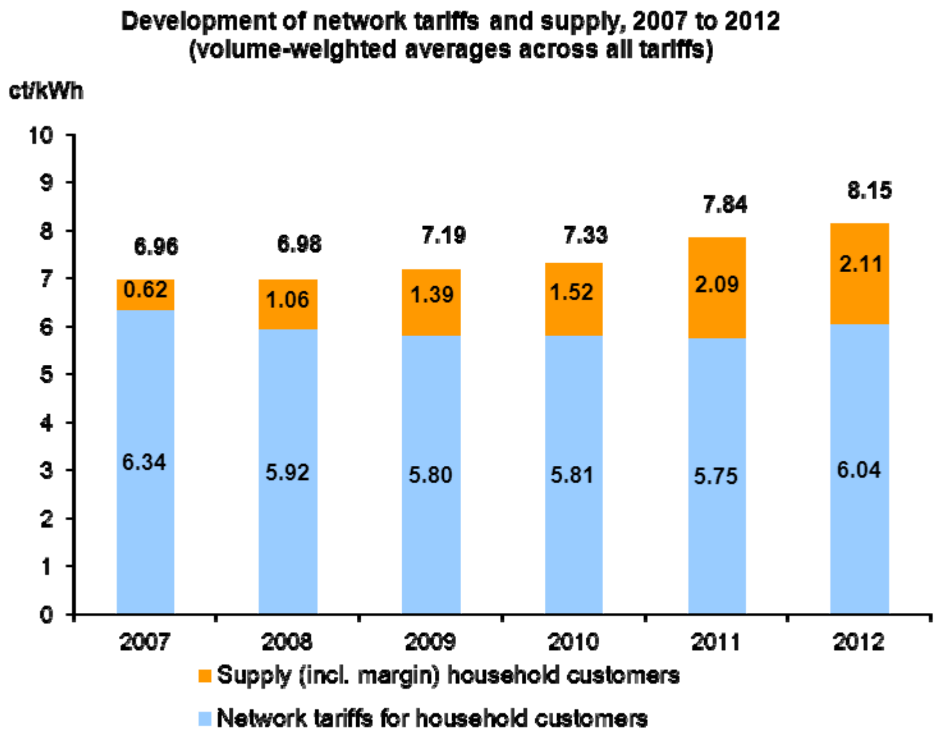

Figure 78: Development of network tariffs and supply (incl. margin), 2007 to 2012

Heat current

Surveys were undertaken on the supply of heating current (electricity for interruptible consumer equipment for room heating purposes, such as night storage heating or heat pumps) to customers in the year under review. The following is based on information from 621 electricity undertakings. 76 percent of the total volume of heating current delivered was supplied by the 30 highest-volume suppliers. In the year under review utilities supplied heating current customers with a total of 13.44 TWh of electricity in the applicable default supply areas.[68] This is roughly equal to an electricity volume of 7,373 kWh per customer.

229 companies reported that they supplied customers in areas in which they are not the default supplier. These suppliers - i.e. not the default suppliers - supplied a total volume of electricity of 0.23 TWh (1.7 percent of the total volume) to heating current customers. The supplier change rate in 2009 was 0.46 percent[69] and has more than tripled since. The number of suppliers which are not default suppliers (229 of 621, i.e. 37 percent), and the slight increase in market share, are a positive signal for the – slow – development of competition. This trend might have been strengthened by the structural assurances given by the 25 large suppliers of heating current (who cover around 70 percent of the market) to the Bundeskartellamt on the dismantling of barriers to market entry (uniform calculation method for load profiles, publication of load profiles on the Internet, publication of heating current tariffs on the Internet, uniform

[68] This is somewhat less than the heating current volume of 13.88 TWh in 2009; refer to the 2010 Monitoring Report, p. 79
[69] Monitoring Report 2010, p. 79

concession fees for supplies of heating current of 0.11 ct/kWh) [70]. The very low heating current volumes supplied by non-default suppliers do, however, show that competition is still very much at the teething stage.

Data was also collected on tariffs charged for supplies for night storage heating (household customers) which account for more than 80 percent of the heating current market. Based on the information provided by 598 default suppliers, the arithmetic mean for the corresponding price is 17.64 ct/kWh; the arithmetic mean for the component of the price accounted for by energy procurement and supply combined is 5.72 ct/kWh.

Green electricity segment

The suppliers who were surveyed for the 2012 Monitoring provided information about the volume and number of final customers who are supplied with green electricity. In 2011 a total of 33.6 TWh green electricity was supplied to 5.5 million final customers. This is equal to a share of 7.4 percent of total electricity supplies, 1.4 percentage points higher than in 2010. The percentage of total final customers has gone up by 2.1 percentage points to 11.8 percent. A detailed breakdown of the delivery of green electricity to final customers is given in the following table.

Category	Total electricity deliveries in TWh (number)	Total green electricity deliveries in TWh (number)	Percentage of deliveries or number (in brackets)
Household customers	127.4 (42,969,046)	13.9 (5,014,467)	10.9 (11.7)
Other final customers	328.2 (4,179,030)	19.7 (530,104)	6.0 (12.7)
Total	**455.6 (47,148,076)**	**33.6 (5,544,571)**	**7.4 (11.8)**

Table 33: Green electricity delivered to household customers and other final customers in 2011

10.9 percent of total electricity deliveries to household customers is green electricity. However, 11.7 percent of all household customers are in fact supplied with green electricity. This suggests that green electricity customers use relatively less electricity than other household customers. This relation is also confirmed for previous years, as the following diagram shows.

[70] Refer to Bundeskartellamt, Heizstrom – Marktüberblick und Verfahren, Bericht, September 2010, available at: http://www.bundeskartellamt.de/wDeutsch/download/pdf/Stellungnahmen/2010-09-28_Heizstrom-Bericht_verbessert101103.pdf and the decision by the Federal Cartel Office of 19 March 2012 (entega): http://www.bundeskartellamt.de/wDeutsch/download/pdf/Missbrauchsaufsicht/B10-16-09.pdf?navid=60

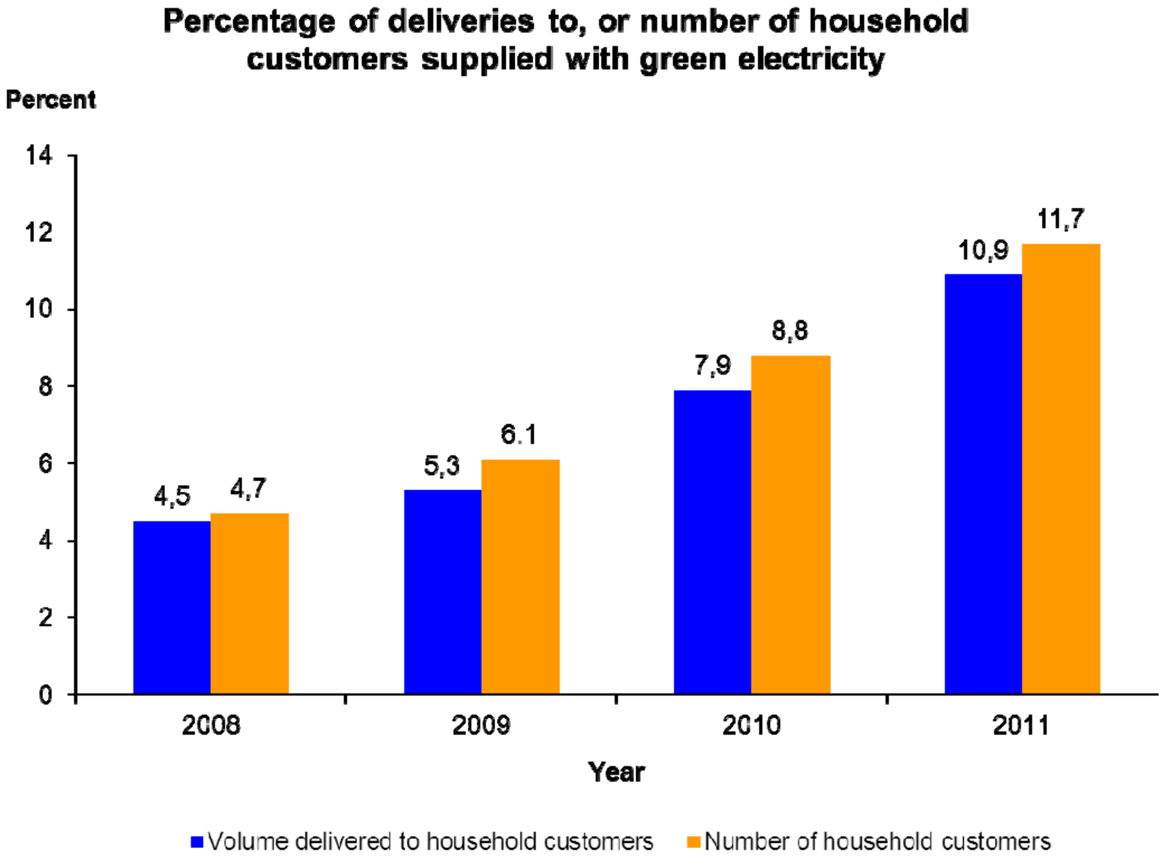

Figure 79: Percentage of deliveries to, or number of household customers supplied with green electricity

There are several label organisations in Germany which evaluate the ecological quality of green electricity according to firmly defined criteria. The following diagram provides information about the share of labelled power in the green electricity segment.

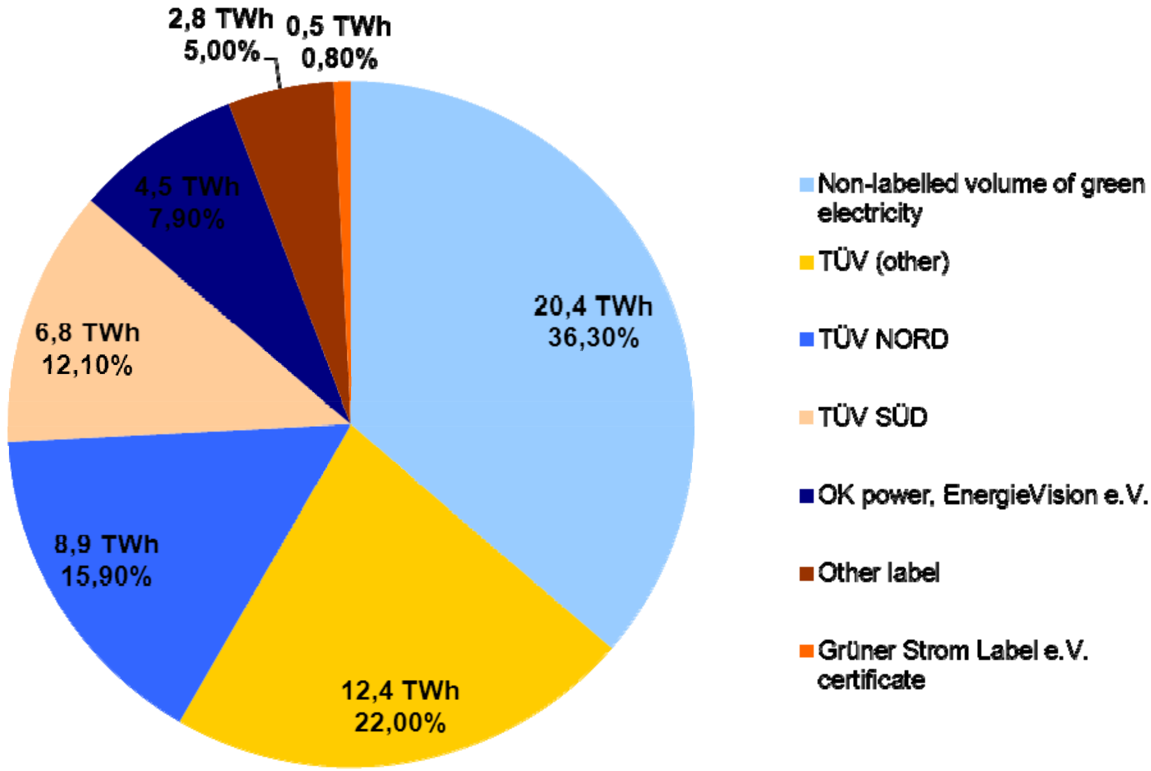

Figure 80: Share of labelled electricity in the green electricity segment in 2011

Half of the green electricity sold in Germany has been awarded a label by one of the TÜV (technical inspection body) organisations. Around 36 percent of green electricity is not labelled. Almost eight percent have been given the "OK power" label while the "Zertifikat des Grüner Strom Label e.V." (Certificate of Green Electricity Label) has a share of around one percent of the total volume. The remaining volumes are spread among various other labels.

The difference between the labelled and non-labelled volume of green electricity (56.3 TWh) and the volume supplied to final customers (33.6 TWh) can be partly explained by the fact that suppliers estimated a higher volume of sales than they were ultimately able to achieve.

The average price of a green electricity product in 2012 was 26.10 ct/kWh. That is 0.59 ct/kWh more, or 2.3 percent higher, than last year. The price of green electricity consequently rose less than the average price of total electricity (+2.4 percent). The price of green electricity products is just 0.04 ct/kWh above the average price for all household customers (26.06 ct/kWh). This means that, on average, green electricity is only a little more expensive than conventional electricity. The different components of the price paid by green electricity customers are shown in the following table.

Green electricity customers 1 April 2012	Household customers in ct/kWh	Development 2011 to 2012 in ct/kWh
Net network tariff	5.38	0.32
Charge for billing, metering and meter operations	0.66	-0.03
Energy procurement and supply (incl. margin)	8.42	0.10
Concession fees	1.68	0.03
Contribution under EEG	3.59	0.13
Contribution under KWKG	0.00	-0.04
Contribution under section 19 StromNEV	0.15	0.15
Electricity tax	2.05	0.00
Valued-added tax	4.17	-0.07
Total price	**26.10**	**0.59**[71]

Table 34: Average retail price for green electricity customers in 2012

As was also the case for supplies of conventional electricity, suppliers of green electricity offer a series of special bonuses and arrangements for household customers which have a downward impact on prices. The most frequently applied of these are the definition of a minimum contract term or guaranteed price stability.

Special bonuses and arrangements 1 April 2012	Household customers (green electricity)	
	Number of **tariffs**	**Average scope**
Minimum contract term	305	10 months
Price stability	222	13 months
Advance payment	41	12 months
One-off bonus payment	73	€48
Deposit	1	
Other bonuses and special arrangements	91	

Table 35: Special bonuses and arrangements for household customers (green electricity tariff) in 2012

[71] The total price for customers of green electricity cited in the 2011 Monitoring Report of 25.31 ct/kWh was not reported correctly. The corrected value for 2011 is 25.51 ct/kWh.

Development of network tariffs

Network tariffs went up in all customer categories in 2012. This is apparent by simply looking at the network tariffs for household customers with default supply services, business customers and industrial customers as the volume-weighted averages in the period 2006 to 2012.

The highest rise in absolute terms was 0.29 ct/kWh in the household customers segment. This is equal to growth of five percent compared with the year 2011. In percentage terms, network tariffs for industrial customers have gone up most markedly. These have risen by 15 percent or 0.22 ct/kWh in absolute terms. The network tariffs paid by business customers have also gone up by 0.22 ct/kWh or four percent on last year 2011. The precise development in previous years is shown in the following diagram.

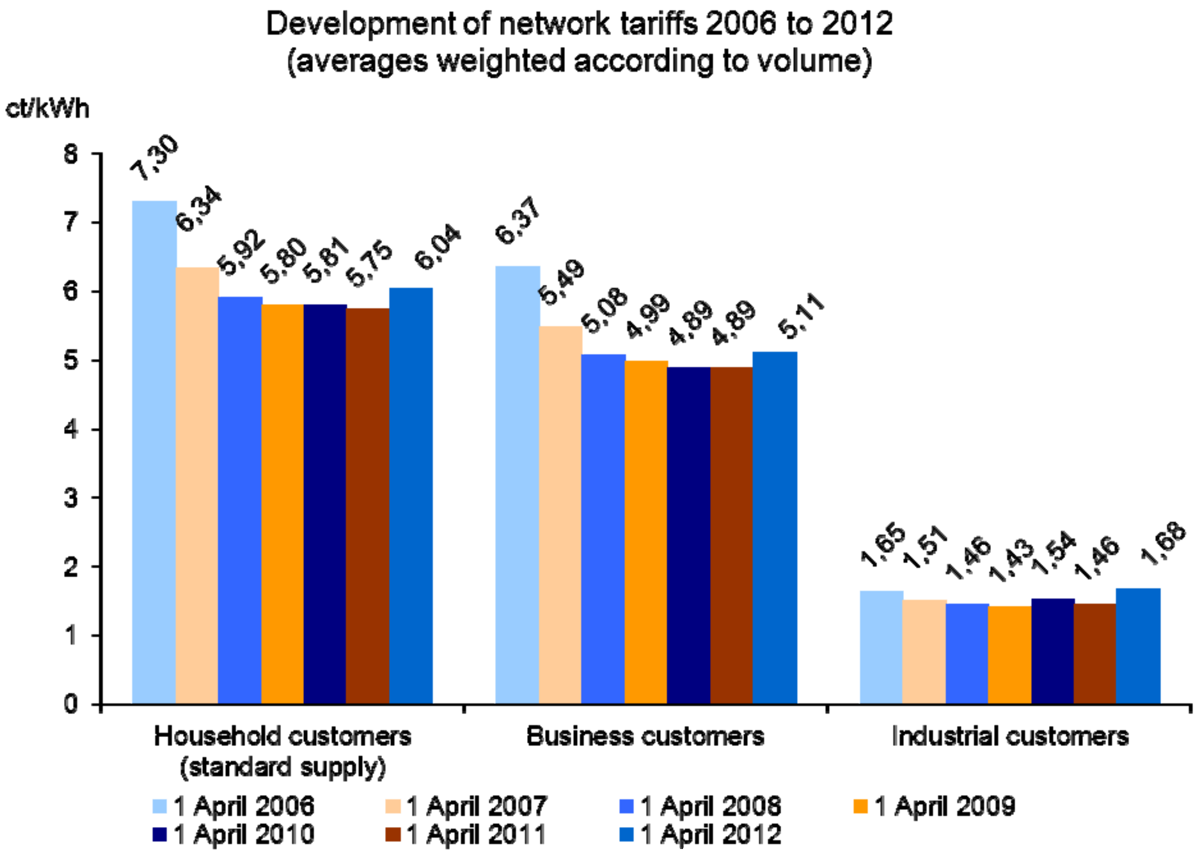

Figure 81: Development of average volume-weighted network tariffs

The rise in network tariffs also affects the share of the total electricity price which is made up of tariffs. The network tariff elements went up in all customer segments. Tariffs made up 22.7 percent of the price paid by household customers, 21.5 percent of the price paid by business customers and 10.7 percent of that paid by industrial customers. This is equal to an increase of 0.5 and 0.6 percentage points respectively for household and business customers. The largest growth of 1.4 percentage points was for industrial customers. The development of network tariffs as a share of the total electricity price is shown in the following diagram.

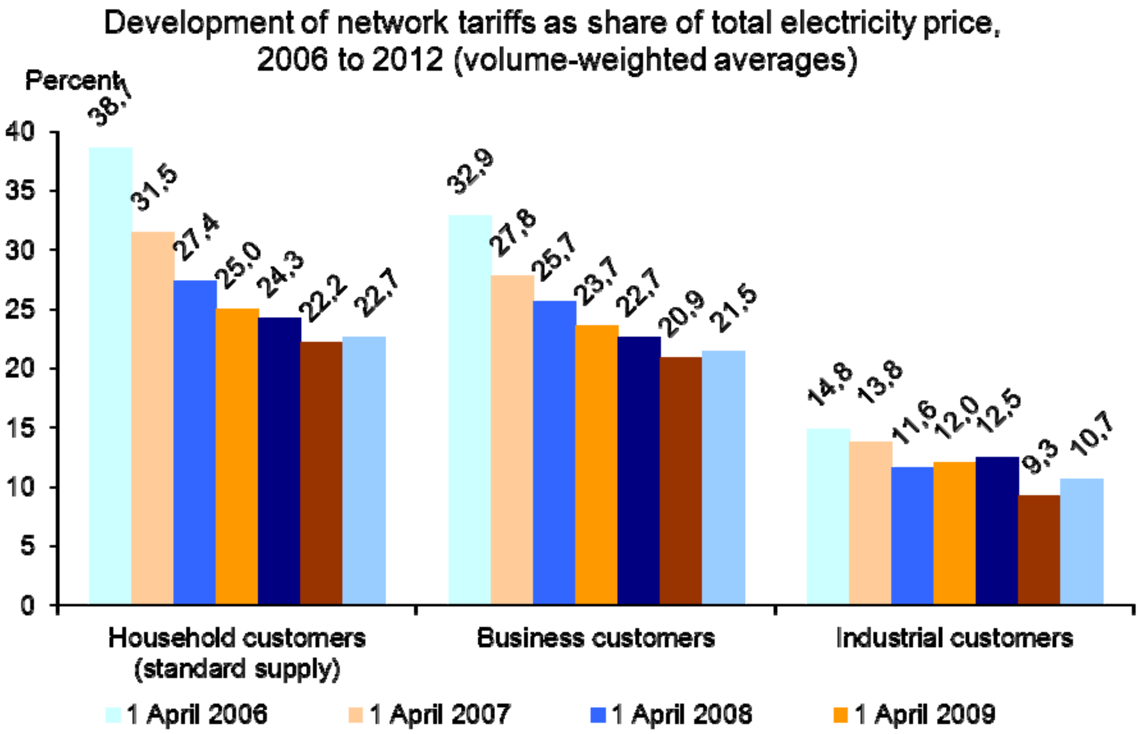

Figure 82: Development of network tariffs as a share of the total electricity price

Comparison of European electricity prices

The price of electricity - and the price paid by household customers in particular - is often a topic of public discussion. A comparison of electricity prices across the European Union shows that, when compared with prices paid across Europe as a whole, household customers in Germany pay above average prices or are in fact in the group of highest paying customers, depending on whether or not account is taken of tax and fees. The data on which such a comparison is based is taken from a Eurostat survey of national average prices for household customers in 2011.[72]

If fees and taxes are not taken into account the average price for Germany is 14.01 ct/kWh and the overall average price for Europe 12.96 ct/kWh. Thus the average price in Germany is eight percent higher. Prices for household customers are lowest in Bulgaria and highest in Cyprus. The exact values for all EU countries considered are shown in the next diagram.

[72] The survey looks at households in the group Dc which consume between 2,500 and 5,000 kWh annually. The average was calculated for the first and second half of 2011 (survey 2011S1, 2011S2), total values for EU-27, provisional ("p"). Cf.: http://epp.eurostat.ec.europa.eu/portal/page/portal/energy/data/database (Accessed: 05.10.2012),

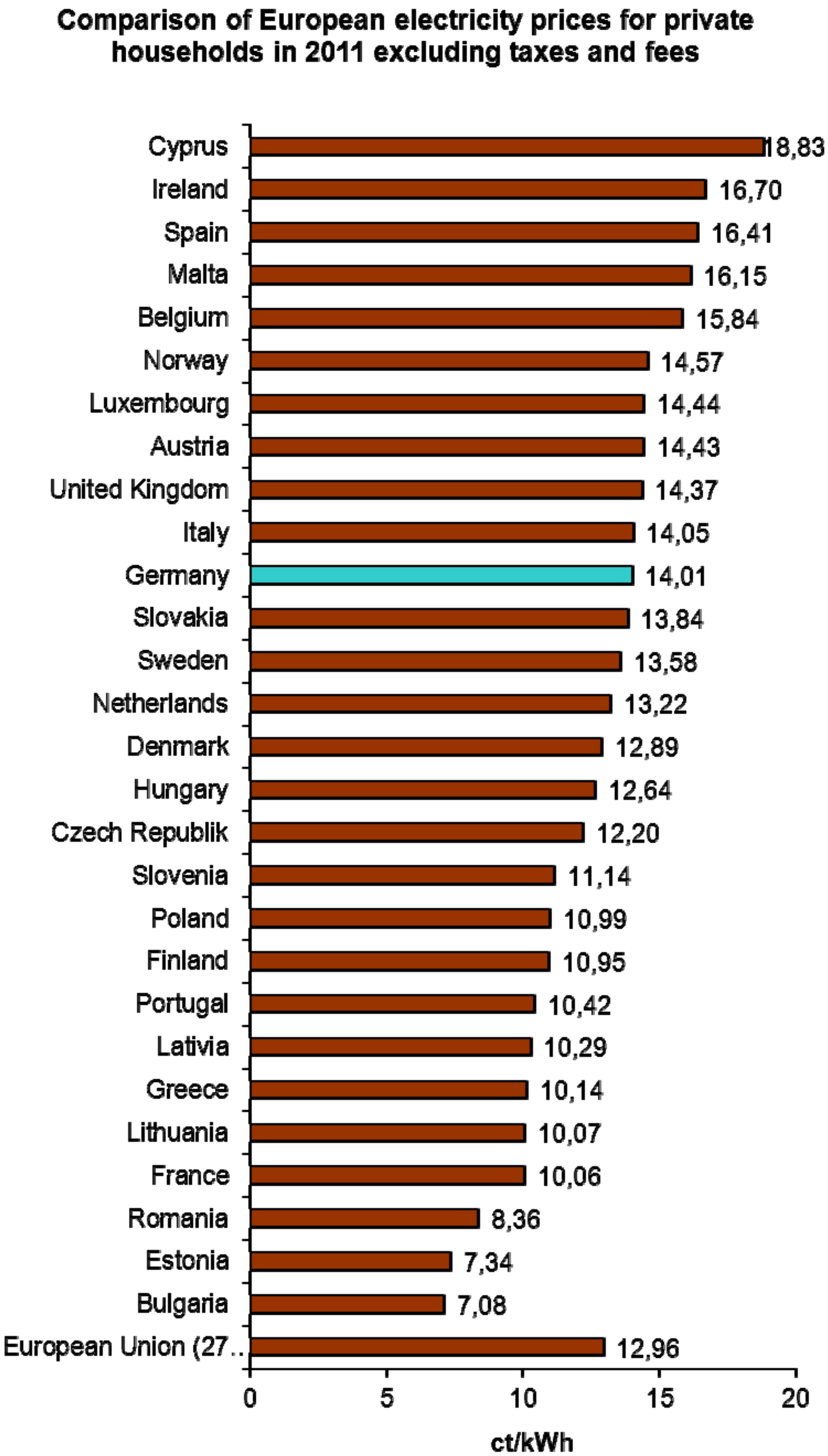

Figure 83: Comparison of European electricity prices for private households in 2011 excluding taxes and fees

The average household price for Germany, including taxes and fees, is 25.30 ct/kWh. This is the second highest price in the whole of Europe and 39 percent above the European average. The highest prices are charged in Denmark and the lowest in Bulgaria.

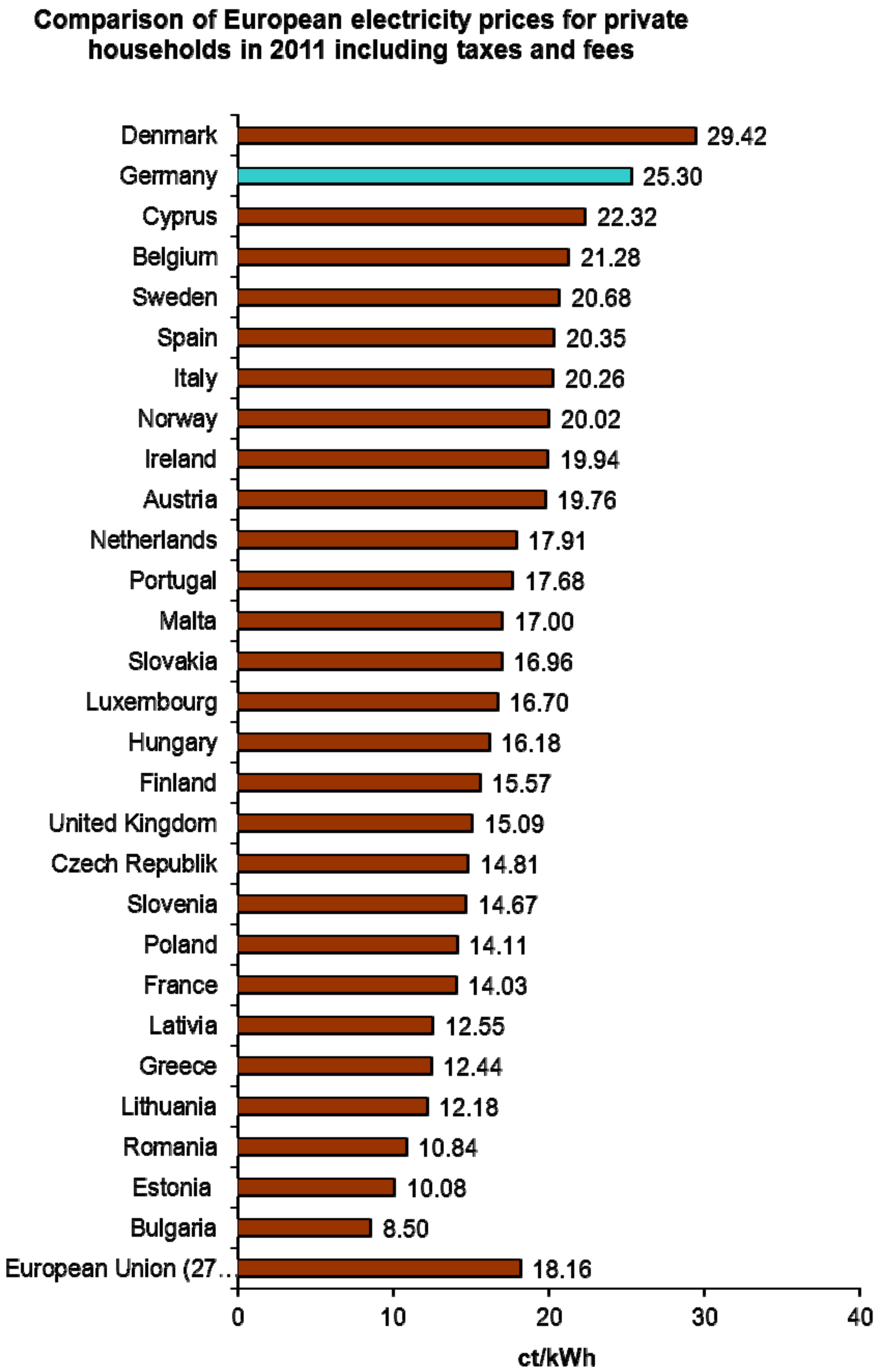

Figure 84: Comparison of European electricity prices for private households in 2011 including taxes and fees

Germany does much better in a comparison of European electricity prices (excluding tax) for industrial consumers[73]. In this customer segment, prices in Germany are 9 ct/kWh – lower than the average for Europe as a whole of 9.35 ct/kWh. The highest prices are charged in Cyprus and the lowest in Estonia. The detailed values are given in the following diagram.

[73] The survey looks at national average prices excluding taxes for medium-sized industrial consumers in the Ic group which consumed between 500 and 2.000 MWh a year, in the first and second six months of 2011 (survey 2011S1, 2011S2). Totals for EU-27, provisional ("p"). Cf.: http://epp.eurostat.ec.europa.eu/portal/page/portal/energy/data/database. (Accessed: 05.10.2012),

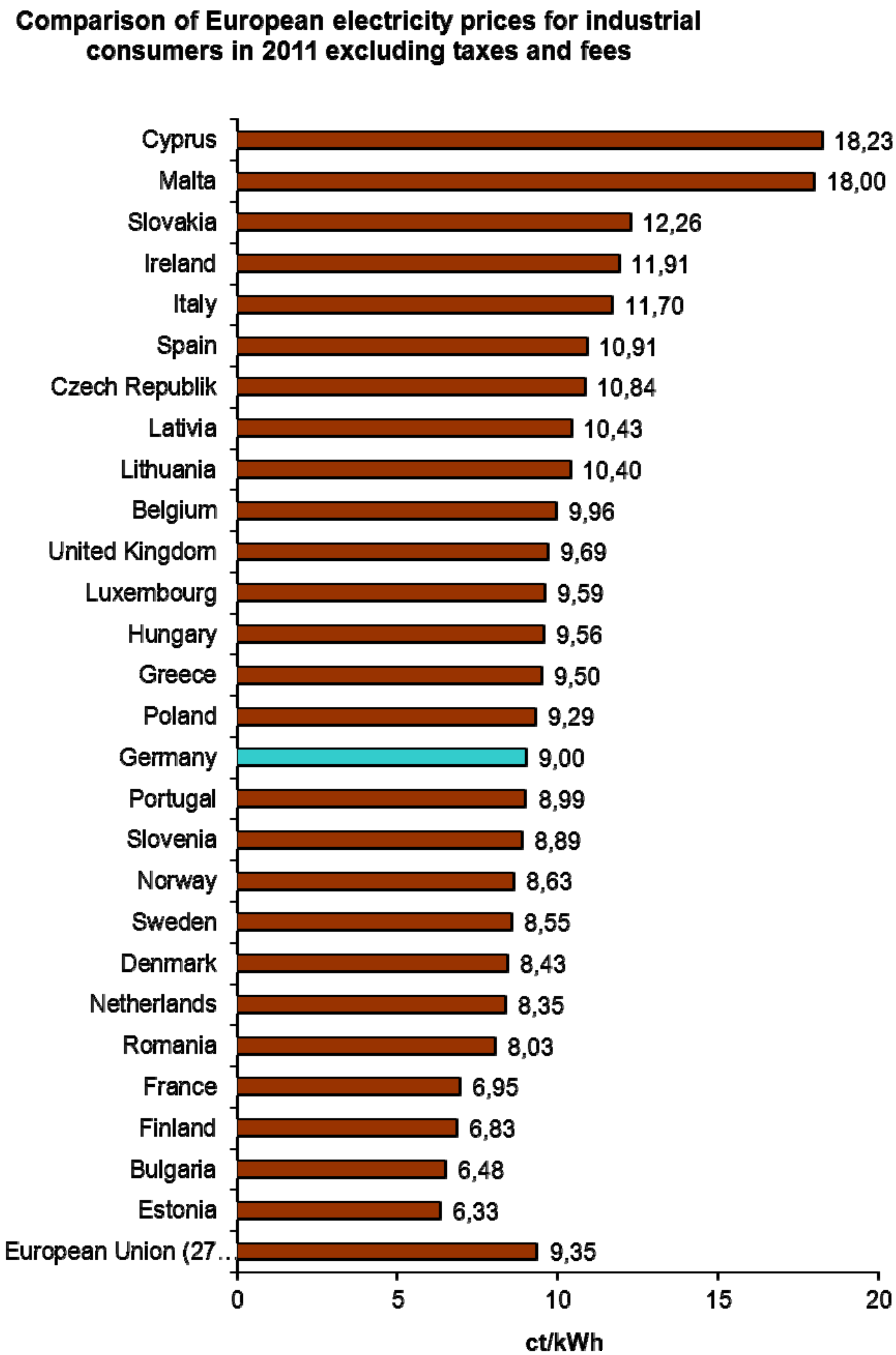

Figure 85: Comparison of European electricity prices for industrial consumers in 2011 excluding taxes and fees

If taxes and fees are included, the average price in Germany is 16.65 ct/kWh, which is 21 percent above the European average; this price places Germany in the top quarter price bracket.

Comparison of European electricity prices for industrial consumers in 2011 including taxes and fees

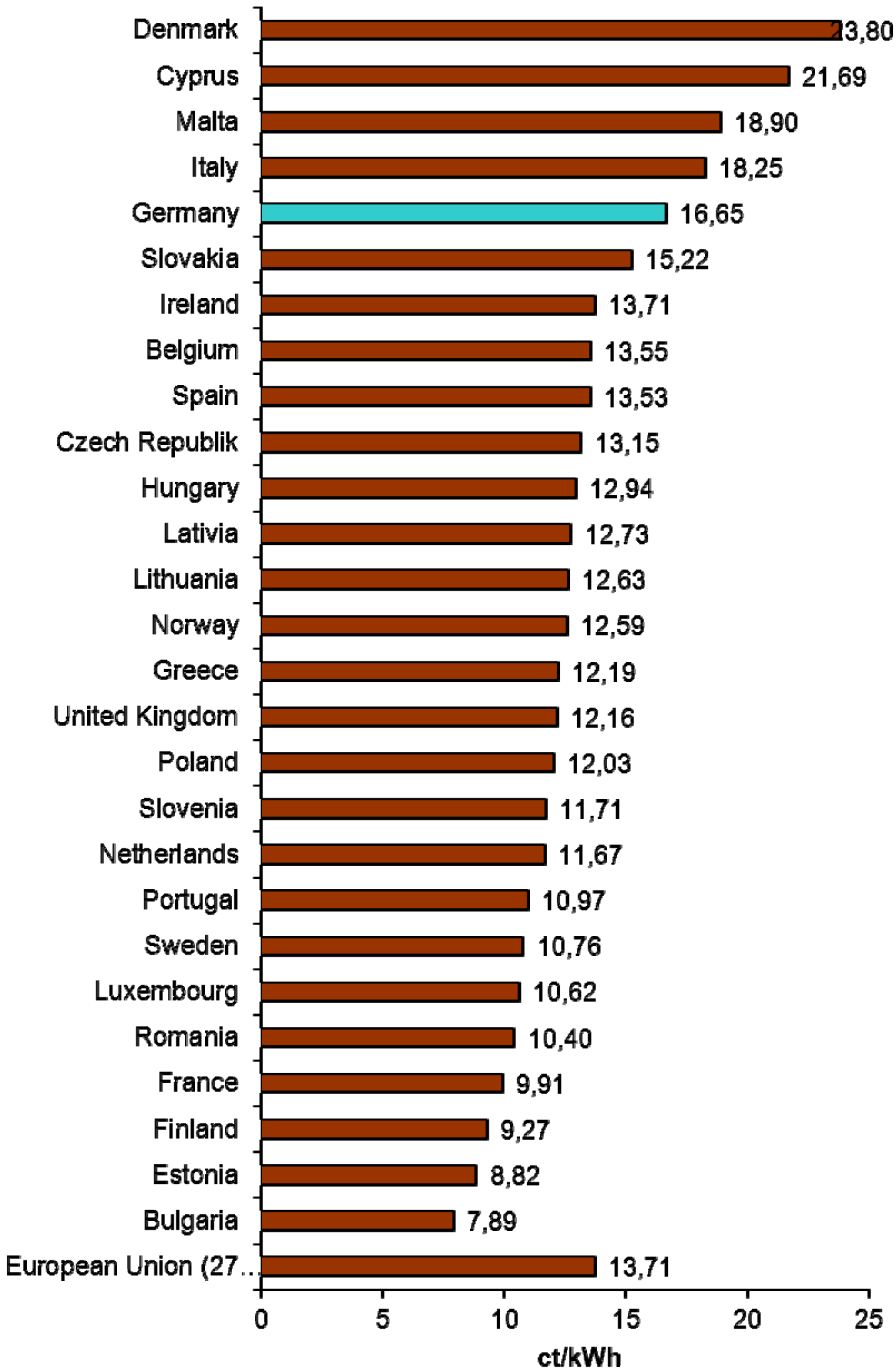

Figure 86: Comparison of European electricity prices for industrial consumers in 2011 including taxes and fees

The picture is more differentiated when prices are compared across Europe as a whole. Excluding taxes and fees Germany has one of the highest prices in the household customer segment; prices for industrial customers in Germany, in contrast, are below average. If taxes and fees are included, the final customer prices for both customer groups are among the highest in Europe.

Metering

The 2012 monitoring survey was addressed both to the network operators in their role as operating their networks as well as in their role as having "basic responsibility" for meter operation and to the independent meter operators operating freely in the market (and who may include network operators providing metering services outside their own network areas).

Furthermore, the 2012 monitoring survey differed to previous years as a result of the revision of the EnWG in mid-2011 and the consequent amendments to section 21b ff of the EnWG and the effects on metering arrangements.

Consumption metering under the EnWG

653 network operators stated that independent meter operators provided meter reading services (electricity supply from the public network in accordance with section 21b of the EnWG in its old and revised form) within their network areas, serving around 260,721 metering points in total. This is not even one percent of the estimated 44.8m domestic electricity meters.

Under the EEG and the KWKG, installation operators, third parties and network operators may all be responsible as meter operators for measuring energy feed-in from renewable energy and combined heat and power (CHP) installations. The survey revealed that here again it is primarily the network operators who provide the metering services, as the following figures show.

Feed-in metering under the EEG

Out of a total of 1,165,776 known metering points for renewable energy, around 75 percent are read by the network operator and some 25 percent by the installation operator himself or an independent meter operator.

Feed-in metering under the KWKG

97 percent of the 148,124 known metering points for CHP installations are read by the network operators.

Metering points meeting the criteria of section 21c of the revised EnWG

In view of the revised version of the EnWG, the companies were asked to state the number of metering points known to meet the new criteria for the compulsory installation of metering equipment (section 21c of the revised EnWG). Of these,

- 212,027 are in buildings which have been newly connected to the energy supply network or which have undergone major renovation;
- 838,159 are for final consumers with an annual consumption exceeding 6,000 kWh;
- 61,082 are for operators of new installations with an installed capacity exceeding 7 kW as regulated under the EEG or the KWKG; and
- 46,231 meet these criteria owing to other reasons, including in particular meters in all other buildings as specified in section 21c(1d) of the EnWG and routine meter replacements.

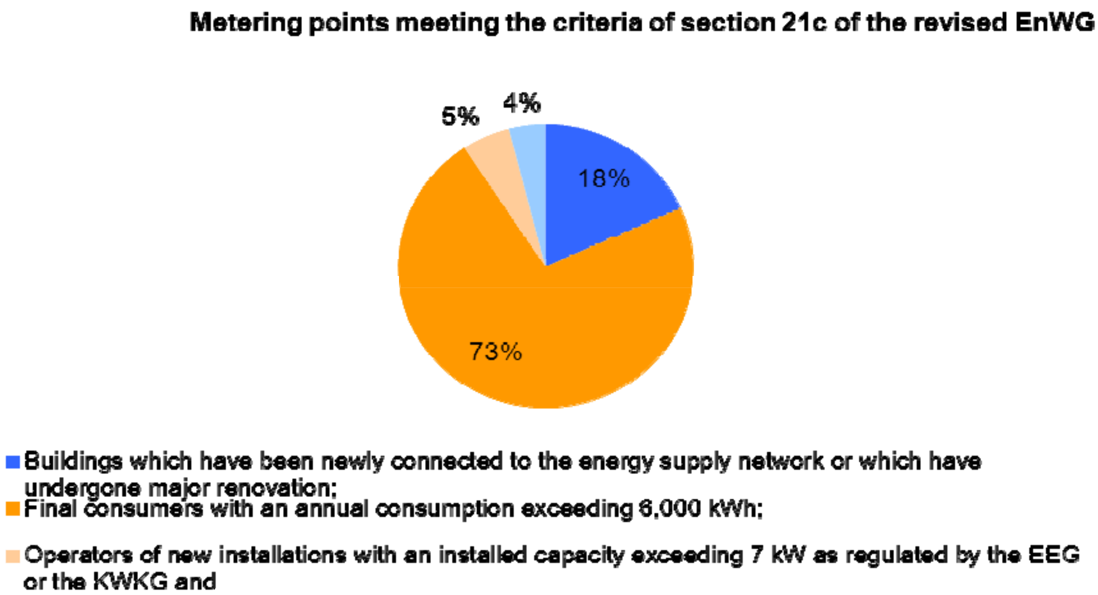

Figure 87: Metering points as per criteria under section 21c new EnWG

In all, therefore, according to the meter operators who responded, around one million metering points met the requirements set out in section 21c of the EnWG at the end of 2011. This is less than three percent of a total of some 42m domestic meters.

Meter technology used for domestic consumers (standard profile customers)

Most of the domestic meters in use are still Ferraris meters: 42,143,851 are in use (as reported by the 698 companies participating in the 2012 survey). Of these, 3,050,698 (around seven percent) are two-tariff or multiple-tariff meters. 2,089,486 (some two thirds) of the two- and multiple-tariff meters use ripple control. In addition, 2,062,083 non-remotely and 199,846 remotely read electronic meters were reported.

The following transmission technologies are used for the remote communication links for electronically read meters:

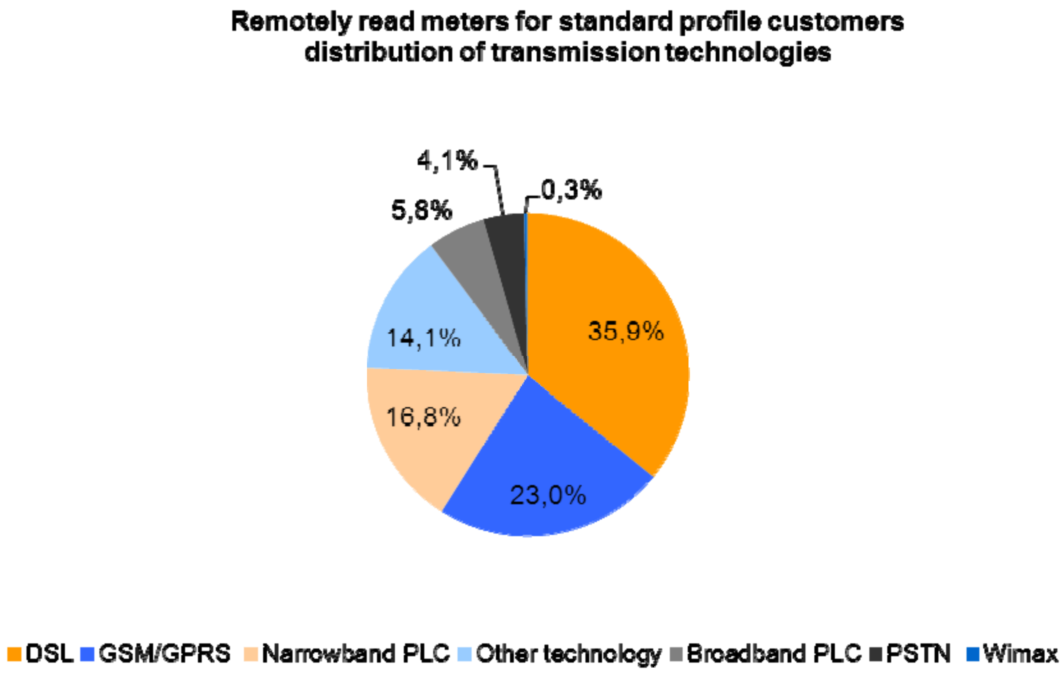

Figure 88: Distribution of transmission technologies for remotely-read meters for standard profile customers

Meter technology used for recording load-metered customers

363,167 load meters and 9,850 meters of other types are in use for recording load-metered customers. The following transmission technologies are used for the remote communication links:

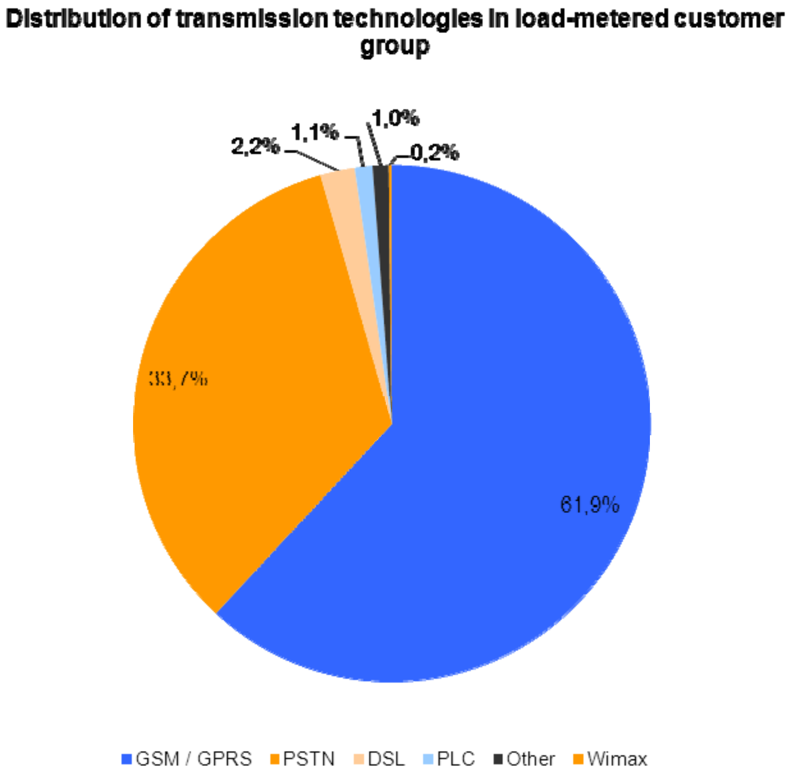

Figure 89: Distribution of transmission technologies for load-metered customers

Developments in the gas markets

Market developments (BNetzA)

Gas imports have risen slightly since 2010 to their current level of 1,411 TWh (2010: 1,384 TWh). Exports increased over the same period from 463 TWh in 2010 to 516 TWh in 2011. Production of domestic gas continued to decline, amounting in 2010 to around 11.9bn m^3 (2011: 12.63bn m^3). The reserves-to-production ratio of eleven years has remained unchanged since 2010.

On 1 April 2011 the number of market areas was reduced to one for L-gas and two for H-gas. Market areas were merged again on 1 October 2011 with the integration of the L-Gas 1 (Nowega, EWE, Gasunie) and Gaspool market areas; Germany therefore still has two market areas.

The maximum usable volume of working gas in underground storage is 22.245bn mN^3 (2010: 20.970bn mN^3). Of this, 9.250bn mN^3 is held in cavern storage facilities and 12.996bn mN^3 in pore facilities.

Developments in the gas retail market are as dynamic as ever. Around 15 percent less gas was sold to final customers than was the case in 2010. The fall in consumption by private households was particularly marked, largely due to relatively warm weather in January/February and November/December 2011. In 2011, gas network operators delivered 934.61 TWh of gas to final customers, who can now choose between 31 or more gas suppliers in over 41 percent of network areas. In over 31 percent of network areas final customers even have the choice between more than 50 gas suppliers. The dynamic development of this very healthy diversity of suppliers indicates how attractive regional and supraregional gas markets are in Germany.

Over 1.2m final customers switched their gas suppliers in 2011. Compared with the previous year, 370,000, or around 40 percent, more customers switched suppliers. This ongoing positive trend in 2011 was reflected in a relative switching rate of 11.54 percent and corresponds with the growing number of gas suppliers operating in each of the network areas referred to earlier.

On 1 April 2011 the gas price for household customers with standard, or default, supply was 6.95 ct/kWh. This is equal to an increase in the gas price of almost five percent. Network tariffs in this consumer category are 1.16 ct/kWh, equal to a share in the total gas price of approximately 17 percent. Energy procurement and supply costs, which make up 54 percent of the retail price paid by household customers, have risen in the course of a year by around twelve percent to 3.75 ct/kWh.

Market developments (BKartA)

In its assessment of competition in the gas sector, the BKartA has focused mainly on the wholesale and the retail markets. Other areas of relevance from a competition point of view are imports and production.

Imports and production

The supply of the German market with gas crucially depends on gas imports. Border prices on the German import market are largely determined by the indexing of gas prices to oil prices in long-term import contracts and have steadily risen since 2010. This has resulted in a gap between border prices and spot market prices on the downstream markets. On account of the significant price differences of up to more than 60 percent, distributors have entered into price revision negotiations with gas importers and producers. These negotiations have already resulted in lower prices in long-term supply contracts and should, with a certain delay, also have an effect on border prices.

Wholesale

This relation between spot-market prices and border prices shows how much pricing is influenced by liquid wholesale markets, in particular the gas exchange. The positive developments on the wholesale markets and the fact that it is now possible to buy or sell any quantity of gas at short term or for future delivery has induced municipal utilities and regional suppliers to change their gas supply contracts from long-term contracts to shorter and more flexible contracts.

Furthermore, the liquidity and efficiency of the wholesale markets has been further increased by the merging of market areas into two remaining areas. Trade volumes on the exchange and off-exchange have again significantly increased compared to the previous year, in both cases by up to 25 percent. Most of the trading takes place off-exchange: The volume traded on the exchange amounts to only three percent of the total volume, whereas 97 percent are traded off-exchange.

Retail

At the retail level, the volume sold to final customers has decreased by approx. 15 percent (mostly due to the mild winter of 2011). Not surprisingly, the absolute amount of gas that was purchased by final customers from new suppliers (changeover volume) has also decreased and is slightly lower than last year. The number of customers who have switched supplier, however, has significantly increased compared to last year, by approx. 40 percent. At the same time, the number of gas suppliers active in the network areas has also increased. In more than 70 percent of the network areas, final customers can now buy their natural gas from 30 or more gas suppliers. This shows that also in the gas sector it has become easier for customers to change supplier.

The average price level, however, has continued to increase (compared to last year) for all final customer groups. This is most likely due to the increasing border prices for natural gas.

Market data and market coverage

Shares of largest companies (dominance method)

The market share held by the biggest companies in each sector of the gas market – gas production, gas imports, gas exports, volume of working gas in underground storage facilities and gas distributed to final customers – in the 2011 reporting year was determined by analysing the majority shareholdings of around 730 companies which took part in the 2012 monitoring survey and by allocating the corresponding market shares to the consolidated parent undertakings using the dominance [74] method.

Calculations of the market shares of companies in nine sectors evaluated in the gas market show that a total of eight companies were among the groups of the largest three in all market categories in 2011. A closer look at the spread of companies in the groups of the largest three in all market categories reveals that one company was represented in all nine, one company in six categories, two companies in three categories and one company in two categories in the group of the largest three.

Across all market categories in 2011, a total of 13 companies were represented in the groups of the largest five. Two companies were in the group of the largest five in all nine market categories. One company was found to be in six categories and one in five categories in the group of the largest five.

The largest three and largest five companies cover a high percentage of gas imports, exports and production. The market in gas delivered to final customers is considerably less concentrated in the categories shown below.

The following table shows the market shares of the largest three and largest five companies in the evaluated sectors of the gas market as calculated using the dominance method.

[74] The dominance method allocates the volume of gas delivered by dominated (consolidated) undertakings to each of the dominant undertakings. 100 percent allocations are made. For joint ventures with a 50/50 participating interest allocation is made accordingly.

Area	Shares of the largest three in percent			Shares of the largest five in percent		
Year	2009	2010	2011	2009	2010	2011
Production	82.6	66.2	67.1	99.4	82.6	79.2
Import	60.6	56.4	55.8	74.7	72.9	69.2
Export	53.5	66.0	57.6	76.0	82.7	82.2
Storage - Working volume	69.5	56.0	58.9	84.3	72.2	72.0
Gas delivered to final customers Total	30.1	29.5	27.1	39.6	37.1	33.3
Gas delivered to final customers ≤ 300 MWh/year	25.9	26.7	23.6	31.7	31.5	29.3
Gas delivered to final customers > 300 - ≤ 100,000 MWh/year	22.8	25.5	20.5	30.4	33.3	27.6
Gas delivered to final customers > 100,000 MWh/year	51.6	46.7	43.8	66.1	57.7	54.0
Gas delivered to gas-fired power stations	41.5	39.2	38.2	59.0	50.0	40.6

Table 35: Shares of the largest three and largest five companies in each sector of the gas market, 2009- 2011

Share of natural gas produced by the largest companies

The following diagram shows the market shares of the three and five largest natural gas producing companies which, at the same time, are also importers of natural gas.

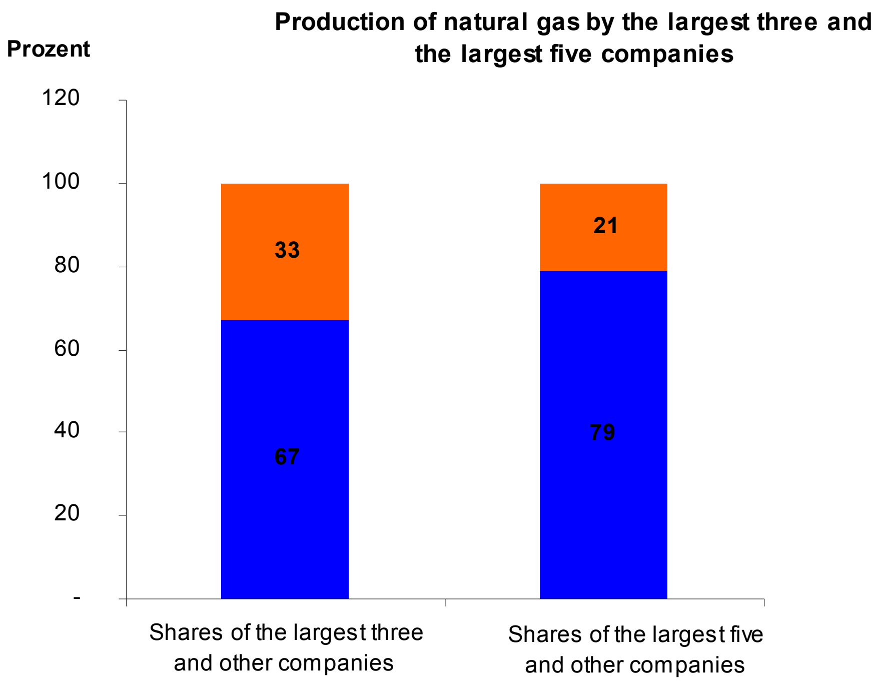

Figure 90: Shares of the largest three and largest five natural gas producing companies

Shares of natural gas imported by the largest companies

A total of 31 gas importers took part in the 2012 monitoring survey. The share of total gas imported by the largest three (largest five) companies in 2011 was 55.8 (69.2) percent.

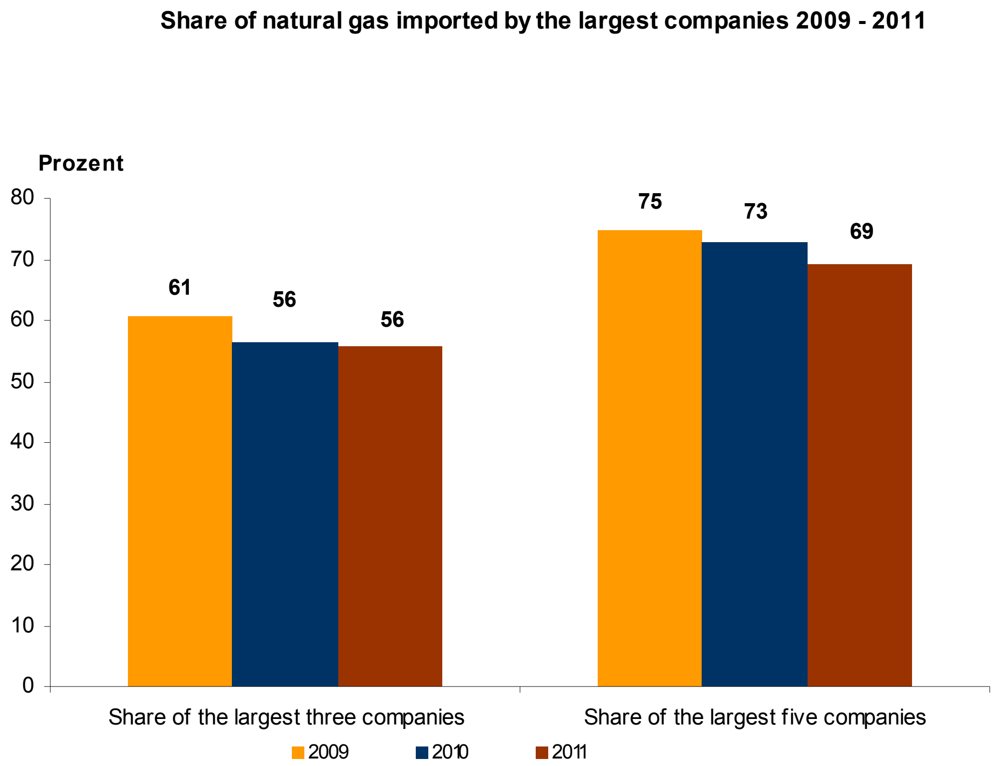

Figure 91: Share of natural gas imported by the largest companies, 2009-2011

Shares of natural gas exported by the largest companies

A total of 24 gas exporters took part in the 2012 monitoring survey. The share of total gas exported by the largest three (largest five) companies in 2011 was 67.6 (82.2) percent.

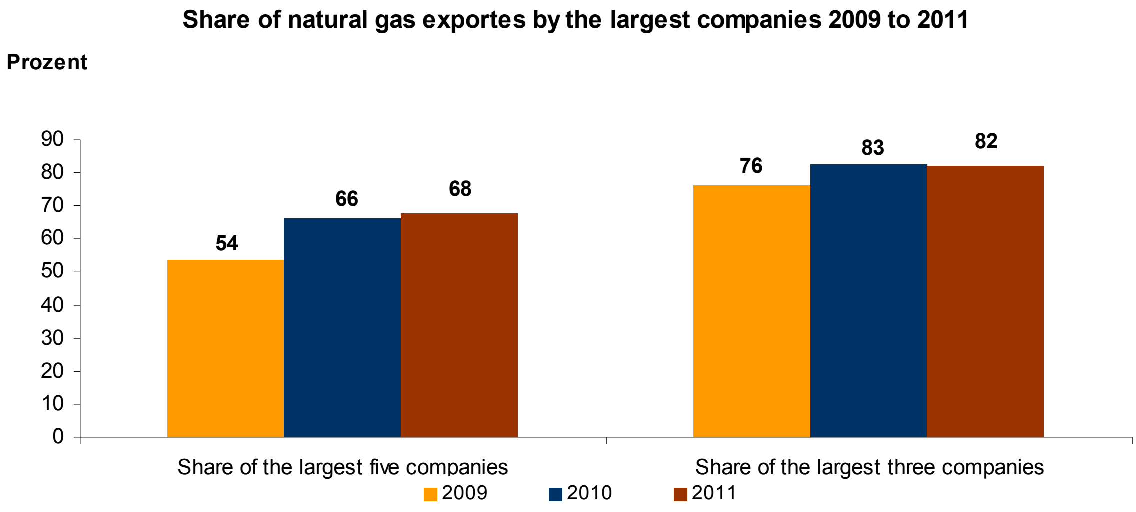

Figure 92: Share of the natural gas exports accounted for by the largest companies, 2009-2011

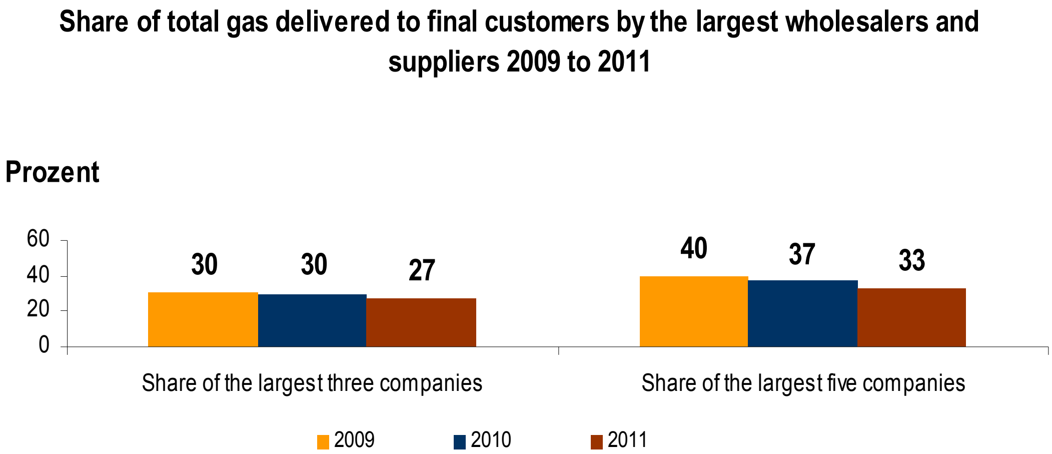

Figure 93: Shares of total gas delivered to final customers by the largest wholesalers and suppliers, 2009-2011

The shares of total gas delivered to final customers by the largest three and largest five wholesalers and suppliers have fallen continuously over the last three years.

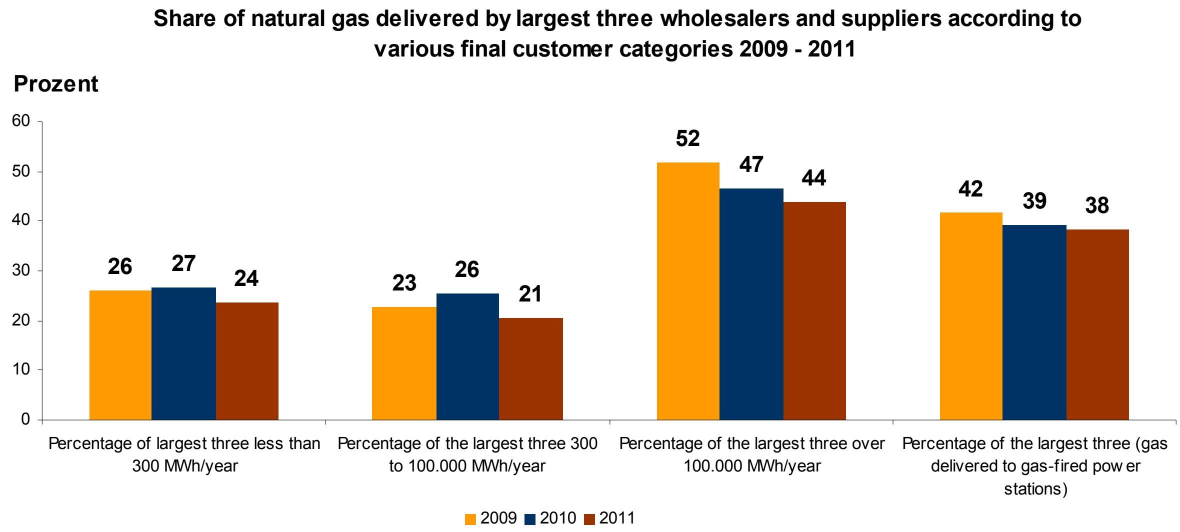

Figure 94: Share of gas delivered by the largest three wholesalers and suppliers according to various final customer categories, 2009-2011

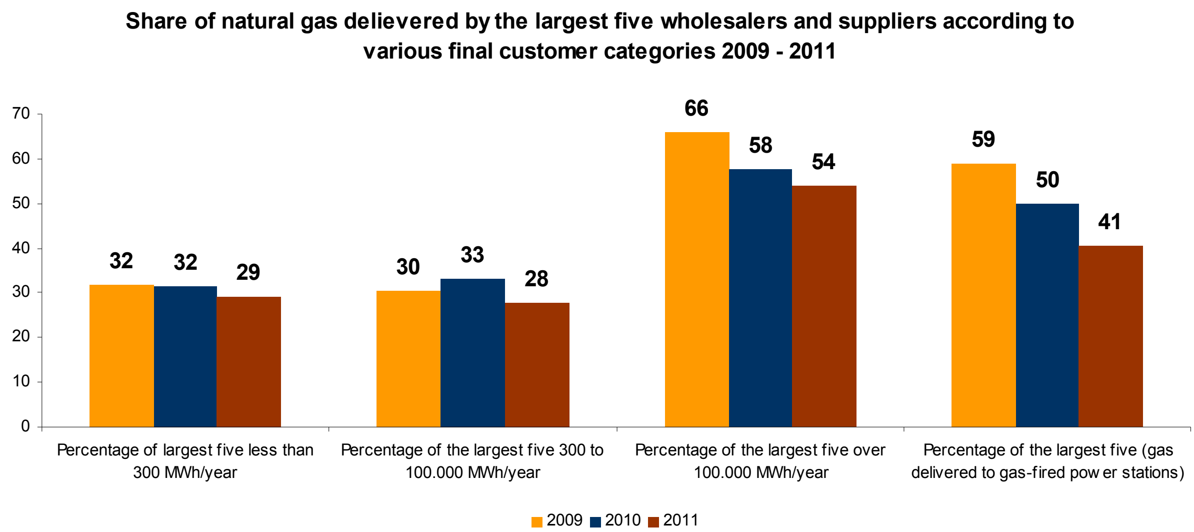

Figure 95: Share of gas delivered by the largest five wholesalers and suppliers according to various final customer categories, 2009-2011

Shares of the maximum usable working gas volume stored by the largest gas storage facility operators

In 2011, the shares allocable to each operator by applying the dominance method were calculated solely on the basis of the maximum usable volume of working gas in underground storage facilities and the operators of such storage facilities.

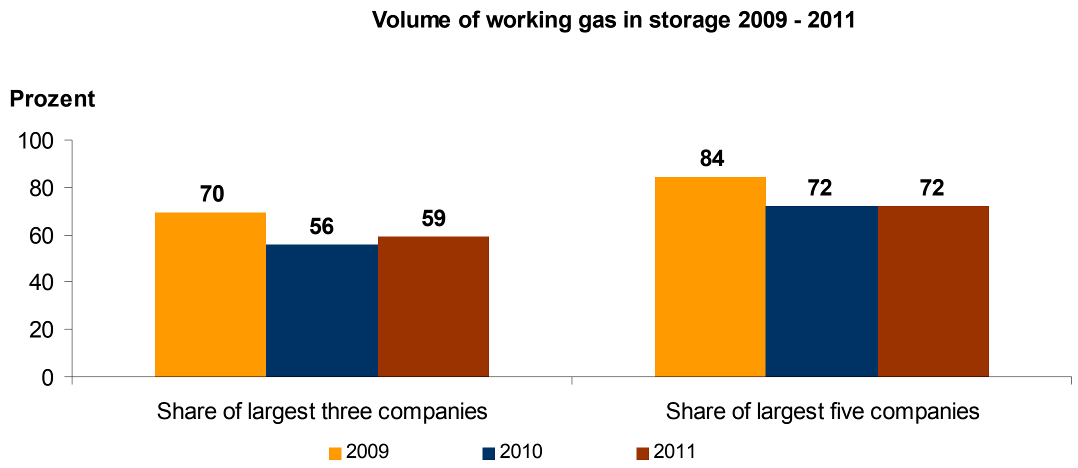

Figure 96: Share of the volume of working gas stored by the largest three and largest five companies

The survey therefore shows that a total of 19 underground storage facility operators held a usable working gas volume of 22.245bn m3 in 2011. In the same year the three (five) largest companies held over 58.9 (72) percent of the maximum usable working gas volume. The difference between these volumes and those in the reporting year 2010 arises from the opening of additional underground storage facilities.

Production of natural gas in Germany and imports / exports / security of supply

Production of natural gas in Germany and imports/exports

Production of natural gas in Germany

At approximately 11.9bn m^3 (2010: 12.65bn m^3) production of domestic natural gas in Germany is still in decline. Germany was estimated to have around 125bn m^3(2010: 136.7bn m^3) of "proven" and "probable" reserves of natural gas in 2011. Based on the volume of production in 2011, the reserves-to-production ratio of Germany's natural gas reserves has not changed since last year and is just under eleven years. (Source: Wirtschaftsverband Erdöl- und Erdgasgewinnung e. V. (WEG), 2011 Annual Report).

Development of gas imports/exports

The volume of gas imported to Germany has risen by around 27 TWh from 1,384.2 TWh (2010) to 1,411 TWh (2011). This corresponds to an increase of 1.95 percent.

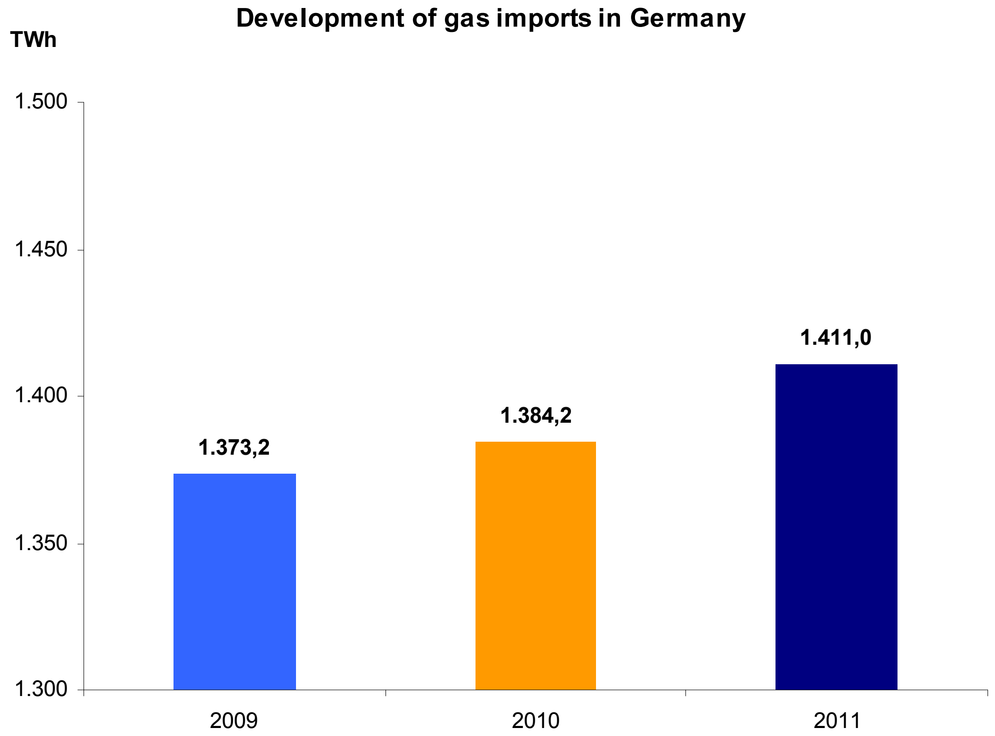

Figure 97: Development of gas imports

The most important sources of gas supplied to Germany are still Russia / CIS countries and Norway. However, the Netherlands, an established and liquid hub in Europe and point of arrival for liquefied gas with connections to natural gas fields in Norway and the United Kingdom, is also an important 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. Additional gas volumes are also imported from Belgium and Denmark in particular. This development is particularly evident in the category of "other countries of origin".

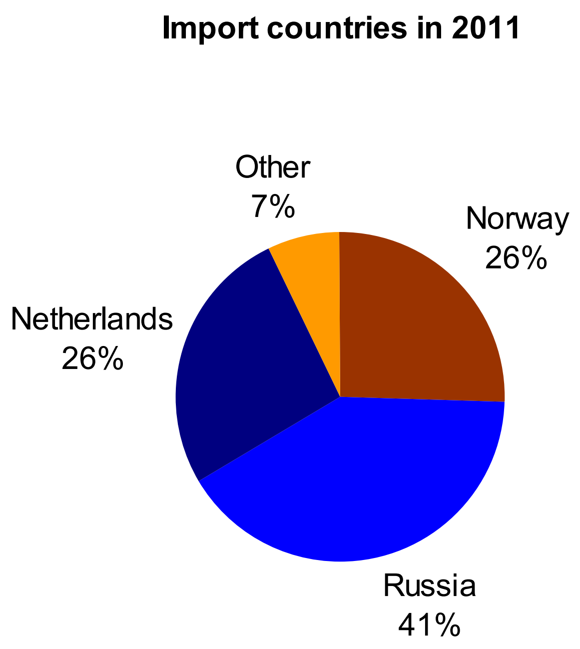

Figure 98: Countries of origin for gas volumes imported to Germany

Gas exports have also risen. While 463.7 TWh were exported in 2010, this rose to 516.8 TWh in 2011. This corresponds to an increase of 11.5 percent.

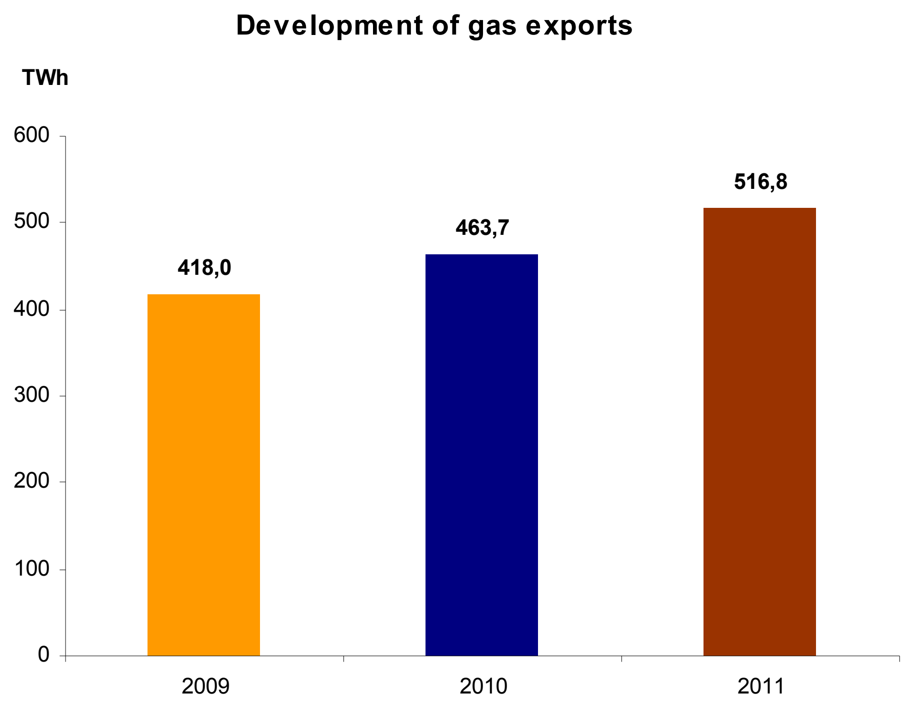

Figure 99: Development of gas exports in Germany

An analysis of countries to which gas was exported from Germany shows that considerable changes have taken place since 2010. Particularly striking is the substantial reduction in the volume of exports to the Netherlands from 28 percent in 2010 to 19 percent in 2011. In contrast, shipments of gas to the Czech Republic rose from five percent of total exports in 2010 to 21 percent in 2011. Exports to Belgium (from eleven percent in 2010 to 7 percent in 2011) and Switzerland (from 24 percent in 2010 to 19 percent in 2011) also fell. The share of export volumes in percentage terms to other countries remained fairly constant.

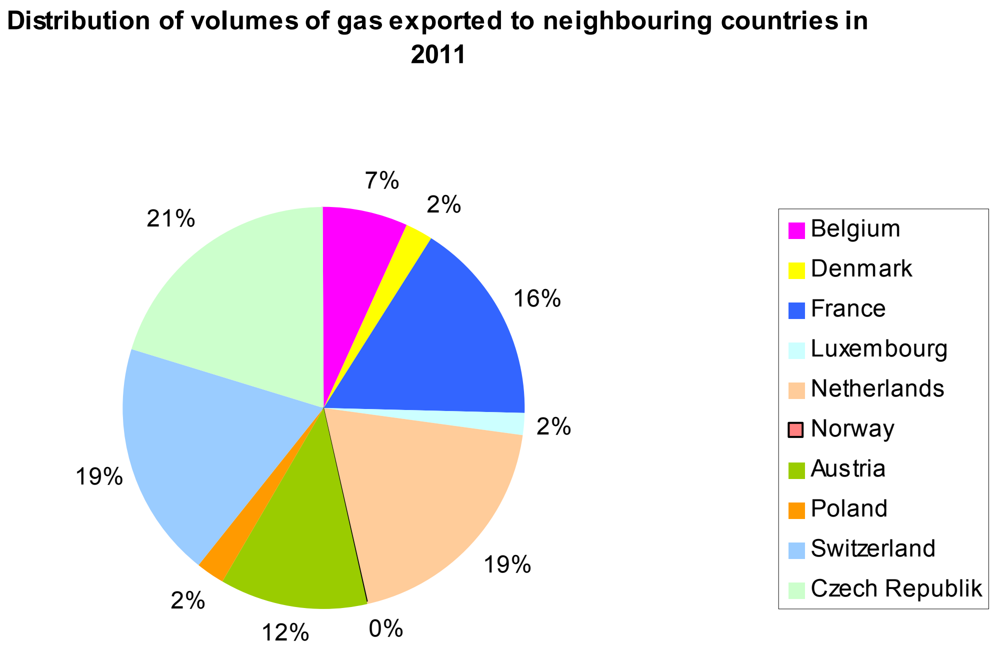

Figure 100: Distribution of volumes of gas exported to neighbouring countries

Assessment of security of supply

Market conditions and gas infrastructure in Germany

Supplies of natural gas in Germany are considered to be extremely secure and reliable. Gas transmission system operators can respond to interruptions in supply by utilising a large range of market-based instruments which are suitable for ensuring continuing supplies to protected customers and which are usually sufficient for this purpose.

Bearing in mind the relative decline in consumption of natural gas shown by recent surveys, the reduction in domestic production is not expected to lead to an increase in Germany's import requirements. In terms of secure and reliable supplies of gas, it is extremely important that the existing gas transportation infrastructure in Germany connects the German gas market with a relatively large number of gas procurement sources. In addition to "classic" pipeline gas - which is mainly imported into Germany from Norway, Russia and the Netherlands - in the medium term the German market will be able to source increasing volumes from Belgium and the Netherlands where gas arrives in the form of Liquefied Natural Gas (LNG).

Just as important is the fact that Germany's transportation infrastructure provides several standard transportation routes for transporting gas from its source to the German market. The recently inaugurated "Nord Stream" natural gas pipeline, which provides a direct link between Russia and Germany, is a good example.

Security of supply is also substantially reinforced by Germany's high natural gas storage volume (with a total of 43 underground storage facilities). Germany has the capacity to store around 22bn m³ of working gas, far more than any other country in the EU.

Infrastructure standard under Regulation (EU) No 994/2010 (Gas SOS Regulation)

Under Article 6(1) of the SOS Regulation, Member States or the Competent Authority must ensure that the necessary measures are taken so that by 3 December 2014 at the latest, in the event of a disruption of the single largest gas infrastructure, the capacity of the remaining infrastructure, determined according to the N – 1 formula in point 2 of Annex I, is able to satisfy total gas demand in the calculated area during a day of exceptionally high gas demand occurring with a statistical probability of once in 20 years.

Germany complies with the Regulation's infrastructure standard (N-1 ≥ 100 percent).

Disruption of supplies at the "Mallnow" and "Waidhaus" cross-border entry points would result in values of 180 and 179 percent. However, these values only present a comparison of input capacity and daily peak loads for the whole of Germany. The limited predictive power of this indicator becomes apparent if it is borne in mind that supply disruptions for the most part only have regional impact due to the physical characteristics of networks.

Interruptions in gas supplies in February 2012

In February 2012, the supply situation at the Waidhaus cross-border point was compounded by extremely low temperatures in Germany (especially in southern Germany) as well as the high transportation demands placed on the German gas network by transit flows to Switzerland and Italy. There was also demand for increased supplies to France at the "Medelsheim" cross-border exit point which was not, however, accompanied by higher volumes of gas entered into the MEGAL pipeline at the "Waidhaus" cross-border point. A key feature of the entry/exit system, however, is that injections and withdrawals are made independently of specific physical characteristics at any one time, ie injections and withdrawals of gas do not have to correlate with one another in "technical network" terms.

The affected gas transmission system operators were able to master supply demands in February 2012 by adopting market-based measures in transactions with downstream system operators, gas-fired power plants and industrial customers. Transmission system operators were also able to maintain system stability by adjusting gas flows with foreign network operators, in particular by maximising the north-south transportation of gas. Contracts for firm capacities did not have to be restricted. Ultimately it was possible to provide security of supply for all final customers, not just protected customers.

The situation in February 2012 showed that restricted gas flows can impact gas-fired power plants and, as a result, the stability of the power grid as well. As electricity generation depends on secure and reliable supplies of gas to specific gas power stations which are relevant for the stability of the power grid, it is essential that security of gas and electricity supplies are monitored together. Experience also shows that, in congestion situations, fast processes for coordination between electricity and gas networks are required, along with corresponding decision-making processes with clearly defined decision-making criteria. This is a task which needs to be resolved in the national emergency plan.

No structural risks which might seriously jeopardise secure and reliable supplies of natural gas in Germany have been identified. Gas transmission system operators can respond to potential supply shortages and avert crises by using a number of effective market-based and - in emergencies - non-market-based instruments (such as instructions to store or withdraw). It is important to note that at root the SoS Regulation takes a European-wide view of security of supply. If security of supply is disrupted at the local level due to unforeseeable events (such as accidents) or improper conduct by individuals, the affected companies and competent administrative authorities must identify solutions and remedial action.

Duties to report supply disruptions under section 52 of the EnWG

As in previous years the Bundesnetzagentur undertook a comprehensive survey of all disruptions in gas supplies throughout the Federal Republic of Germany. Section 52 of the EnWG requires gas network operators to report all supply disruptions to the Bundesnetzagentur by 30 April of the following year. The Bundesnetzagentur uses these reports to calculate the SAIDI (System Average Interruption Duration Index) value for all final customers. This indicator expresses the average duration of supply disruptions experienced by a customer over a period of one year. The SAIDI value does not take account of planned interruptions or disconnections which are due to force majeure, such as natural disasters. The value only reflects unplanned interruptions which are caused by third parties or other networks, or which are due to other faults subject to the influence of the network operator.

The SAIDI value (for gas) was 1.993 minutes in 2011. For each final customer, this meant an average interruption of gas supplies in 2011 of just two minutes. Gas supplies were thus very reliable in Germany in 2011 and were on a par with the multiannual mean.

The 2011 results of the comprehensive survey of supply disruptions in all gas networks in Germany registered in the Bundesnetzagentur's energy database (approximately 720) were as follows:

Survey results for 2011

Pressure range	**Specific SAIDI**	**Notes**
≤ 100mbar	1.373 min/a	Households and small consumers
> 100mbar	0.620 min/a	Major consumers
> 100mbar	0.497 min/a	Downstream network operators
Independent of pressure range	**1.993 min A**	**SAIDI value for customers**

Table 36: Survey results for 2011

The SAIDI value for German gas network operators has been calculated by the Bundesnetzagentur since 2005. These measurements are reflected in the following time series.

Year	**SAIDI value**
2006	2.090 min A
2007	4.072 min A
2008	1.020 min A
2009	1.880 min A
2010	1.254 min A
2011	1.993 min A

Tabelle 37: Zeitablauf der SAIDI-Werte

Networks / Network expansion / Investments / Network tariffs

Networks

Network data

Network operators were asked about the total length of their network, as well as its length subdivided according to pressure ranges (nominal test pressure in bar). The findings were as follows:

	Total length	Pressure range ≤ 0.1 bar	Pressure range > 0.1 - 1 bar	Pressure range > 1 bar
Distribution system operators	471,213 km	157,300 km	224,879 km	89,033 km
Transmission system operators	39,496 km	0	1 km	39,495 km

Table 38: Total network length with subdivisions according to pressure ranges

96 percent of surveyed companies have published this data in accordance with section 27(2) of the Gas Network Charges Ordinance (GasNEV); four percent have not done so or did not respond. There is a total of 6,181 entry points to all gas networks, of which 198 entry points are for emergency entry only. 76 percent of companies which responded can access upstream network operators at several interconnection points; this is not the case for 23 percent, and one percent did not respond.

Gas distribution network operators were asked whether they had placed an internal order under section 8 of the cooperation agreement KoV IV with upstream network operators in the reporting year 2011 or, alternatively, whether they had notified the required capacity in accordance with section 13 KoV IV. This was the case for 93 percent of companies which responded; six percent gave a negative response and one percent did not reply at all. Companies which responded with "yes" were also asked whether their internal orders had been reduced by the upstream network operator. This was the case for almost seven percent of the relevant companies. In almost all cases these were alternatively offered interruptible capacities for internal bookings. 14 percent of companies exceeded their internal bookings or notified capacity in the reporting year 2011, considerably fewer than in the previous year. In some cases capacity was exceeded by over 25 percent.

The number of exit points developed as follows between 2007 and 2011:

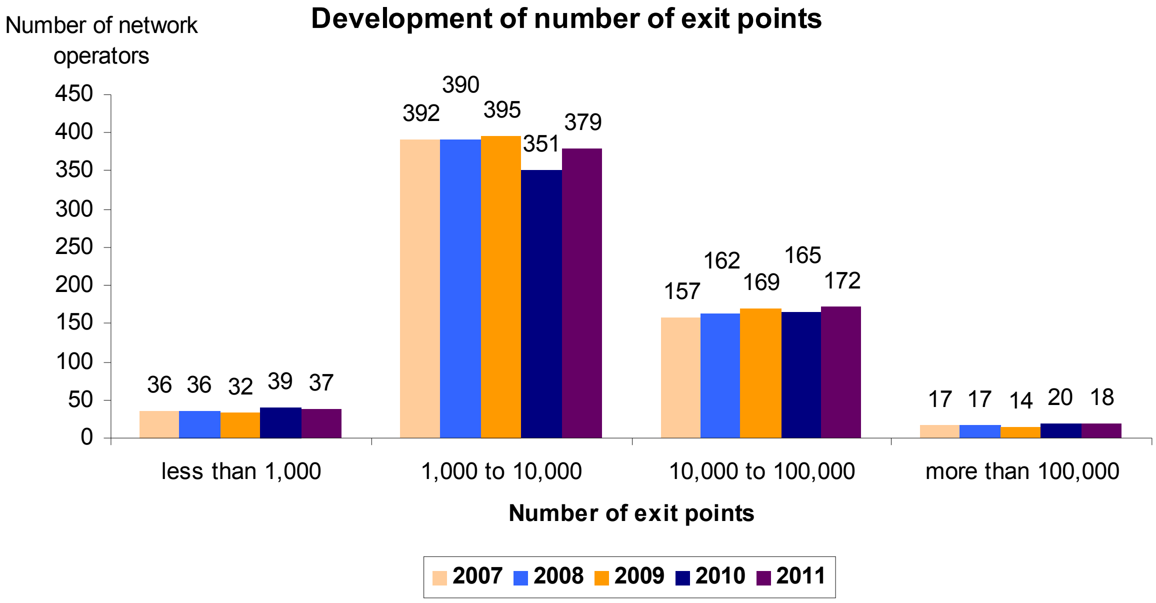

Figure 101: Development of number of exit points

Changes in the market area landscape for gas

Market areas

Section 21(1) of the Gas Network Access Ordinance (GasNZV) requires gas transmission system operators to reduce the number of market areas to a maximum of one L-gas market area and a maximum of two H-gas market areas by 1 April 2011. The gas TSOs fulfilled this requirement on time and on 1 April 2011 had integrated the former Thyssengas H-gas and Thyssengas L-gas market areas and the OGE L-gas market area with NCG's H-gas market area. As a result, there were three market areas in Germany in April 2011: the dual-quality NCG market area plus the two single-quality market areas L-Gas 1 and Gaspool.

Further concentration of market areas took place on 1 October 2011 with the consolidation of the L-Gas 1 and Gaspool market areas. This means that the natural gas market in Germany is divided into two dual-quality market areas, or balancing zones, and it is commercially feasible to supply L-gas customers with H-gas and vice-versa. The "Konni Gas" conversion system was introduced to allocate the associated additional network operator costs appropriately. The reduction to two market areas was completed well before the deadline of 1 August 2013 stipulated by section 21(1) GasNZV. The geographical location of the market areas on 1 April 2011 as well as the current market area landscape are shown on the following map.

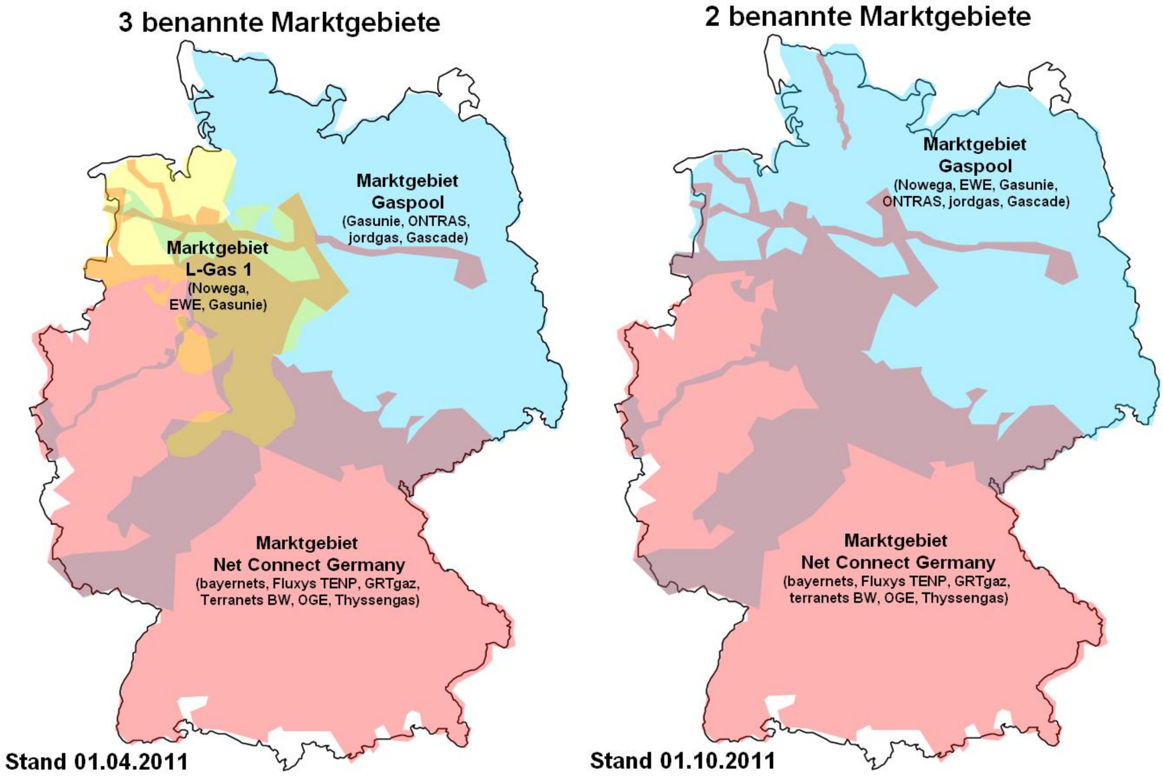

Figure 102: Market area landscape for gas on 1 April and 1 October 2011.
Three market areas as of 1 April 2011 Two market areas as of 1 October 2011

In principle the merger of market areas now means that all the exit points in one market area can be combined with all the entry points in the other market area. There are, however, points between what were previously completely separate market areas where transport flows are congested (transfer volumes). This means that the merger of market areas reduces the offer of firm and freely allocable entry-exit capacity (FZK) at the remaining booking points in the merged market area. However, the usability of the remaining capacity is significantly greater (contractually agreed range) for shippers as all exit points in the former market area A can now be supplied with a remaining firm entry capacity from the former market area B, which in the past was only possible to a limited extent or not at all.

In addition to FZK capacity, some gas TSOs also offer capacity products whose firmness and free allocability is subject to conditions (bFZK). The firmness of bFZK capacity is often dependent on the forecast temperature for the next day or the forecast flows at problematic interconnection points in the market area. Fundamentally this means that when temperatures are low, large volumes of gas flow through the network and the capacity of market area entry points is used to a greater extent, and more evenly (use of entry points to serve the needs of the network), with firm capacities as a result. When the weather is warmer and more flexible use is made of entry points owing to lower gas flows (entry primarily in the south or north), only interruptible use – depending on the ability and capacity of network operators – is available. However, this does not mean that the nominated transportation really does need to be interrupted. Interruption critically depends on the transportation capacities of gas transmission systems and the total nominations of all shippers. It is also theoretically possible with bFZK products that a local component could increase firmness by, for example, making possible the firm use - without the risk of interruption - of a southern entry point in combination with southern exit points in a defined local area, regardless of the forecast temperature of the previous day. However, capacities such as these are not as yet offered by transmission system operators.

The 2012 monitoring survey asked shippers – wholesalers and suppliers – about which possible solutions to capacity restrictions at the remaining booking points they would prefer. The available choice was between securing firm capacity levels by obtaining flow commitments or converting firm FZK – at least in part – into capacity products with conditional firmness and allocability (bFZK). As the response options are mutually exclusive, shippers were asked to assign values of 1 or 2 to one option and values of 3 or 4 to the other option, where 1 stands for "very important" and 4 for "unimportant". The results are shown by dividing shippers into three categories: shippers who had no capacity bookings in gas year 2010/11 and shippers who, in terms of total entry and exit bookings, had booked more or less than 1 million kWh/h of capacity.

Over 80 percent (in 2011 68 percent) of shippers with high capacity bookings of over 1 million kWh/h prefer to secure firm capacity by obtaining flow commitments. Shippers with bookings of less than 1 million kWh/h are distributed equally across both response options with a slight preference of 55 as opposed to 45 percent (2011: 50/50) in favour of securing firm capacity by obtaining flow commitments. The following diagram shows the results, including the number of responses.

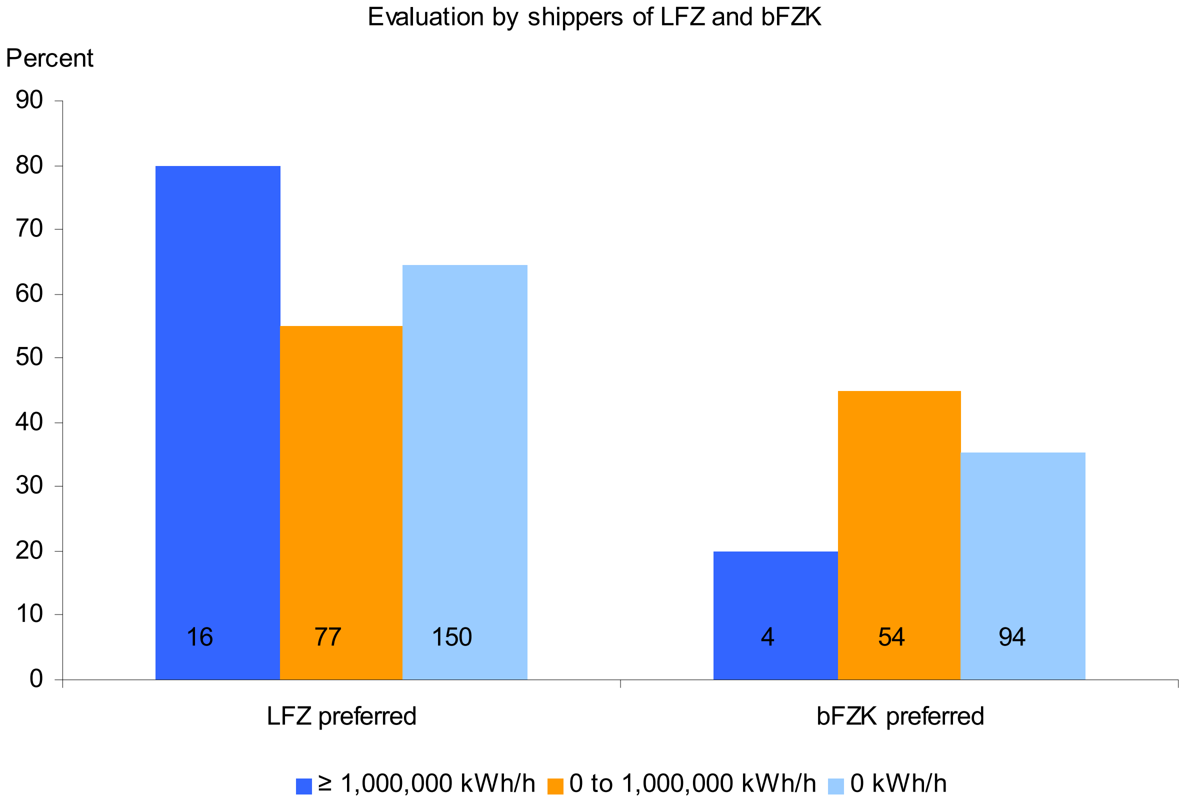

Figure 103: Evaluation by shippers of two options (LFZ or bFZK) for presenting firm capacities in large market areas

Compared with 2010 there would therefore appear to be a stronger preference for securing FZK by means of flow commitments. However, the number of shippers who answered the question in the reporting year 2011 was lower (number of responses in 2012: 244; 2011: 262); this led to a significant percentage shift among shippers in particular with bookings of over 1,000,000 kWh/h (number of responses 2012: 20; 2011: 25).

Shippers with high capacity bookings who prefer the (partial) transformation of capacity into bFZK to the purchase of flow commitments will probably already have acquired considerable experience with this capacity product – including in particular the low probability of interruptions. In addition, the remaining market areas are increasingly liquid such that procuring gas on the spot market to secure uninterrupted supplies is a genuine option. What is more, it is becoming increasingly difficult and costly to obtain flow commitments from network operators. In addition, from the shipper's point of view calling on a flow commitment is tantamount to an interruption as the shipper cannot use its actual nomination but must observe the nomination value of the flow commitment contractually agreed with the network operator. As a result, the bFZK capacity product could well become even more important in the future. However, the network operator's bFZK offer should take greater account of the local component referred to above in order to reduce the interruption scenarios even further. This would appear to be a good way of providing the large market areas in Germany with sufficient capacity offers.

Capacity offer

As in the previous reporting year, questions were raised about the booking, use, availability and booking preference for transport capacity. A more precise distinction was made for the first time between different capacity products.

Shippers were asked about their preference for different capacity products. 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 or whether, in contrast, interruptible capacity and other firm capacity products should be offered in addition to firm FZK. The results are shown by dividing shippers (wholesalers and suppliers) into three categories: shippers who had no capacity bookings in gas year 2010/11 and shippers who, in terms of total entry and exit bookings, had booked more or less than 1 million kWh/h of firm and interruptible capacity.

A slim majority of 55 percent (as against 45 percent) of shippers who had booked more than one million kWh/h in the reporting period would prefer only interruptible capacity to be offered in addition to FZK. In contrast, 55 percent of shippers with bookings of up to one million kWh/h take precisely the opposite view and favour additional firm capacity products. It is important to remember, however, that many shippers have had no practical experience to date with other firm capacity products. Compared with other types of products the share of approximately five percent is relatively low in relation to overall booked entry and exit capacity. There is no discernible clear preference either for a "two-class capacity model" or for a "multi-class capacity model". The following diagram shows the results, including the number of responses.

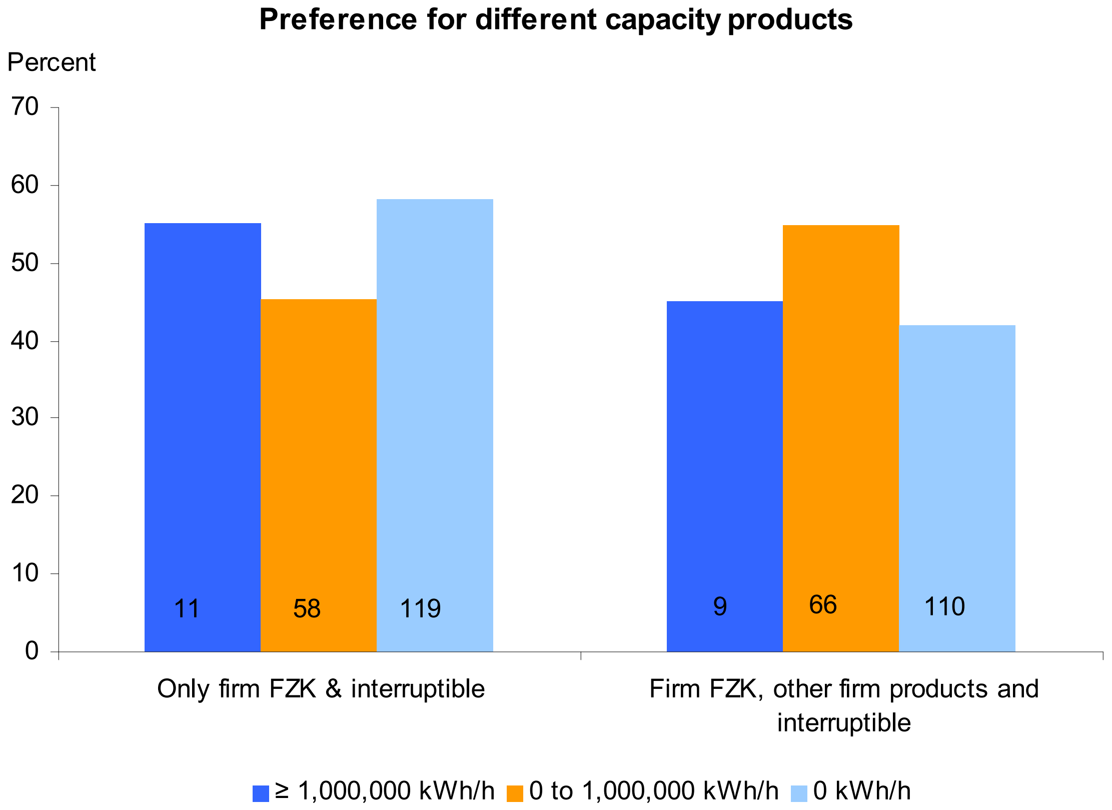

Figure 104: Preference for different capacity products: firm FZK & interruptible vs. firm FZK, other firm products and interruptible

Six shippers were affected by transformations of firm FZK capacity into other capacity products in the gas year 2010/11. A total of approximately 50.2 million kWh/h and 3.5 million kWh/h of firm FZK capacity was transformed on the entry side and exit side, respectively. One reason for the necessary switch from firm FZK capacity to other capacity products was the merger of market areas. The impact of the market merger on the capacity products offered was evaluated by asking network operators about the scale on which different capacity products were offered on 15 March 2011 (prior to the reduction from six to three market areas) and 15 October 2011 (following reduction from three to two market areas). This survey looked at the total capacity already being marketed plus the still available capacities. In contrast, as far as interruptible capacities are concerned, the survey only looked at the total capacity marketed on the relevant date as unlimited interruptible capacities are offered in some cases.

The results for both market areas on the relevant dates for entry and exit capacities are shown separately in the following diagram. In this context it is important to note that the total capacity shown for the NCG market area on 15 March already includes the values for all transmission system operators after the merger (ie incl. Thyssengas and OGE L-Gas) to ensure comparability. The information for both reporting dates therefore includes data from Open Grid Europe

L-Gas, Open Grid Europe H-Gas, Thyssengas L-Gas, Thyssengas H-Gas, terranets BW, bay-ernets, Fluxys TENP and grtGaz Deutschland.

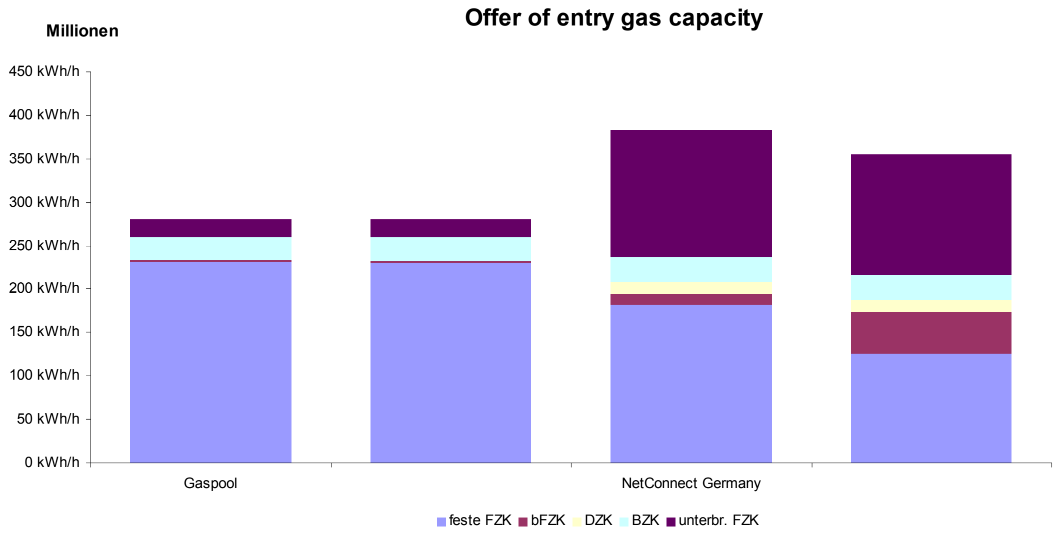

Figure 105: Change in offered entry capacity as a result of the reduction in market areas in the calendar year 2011

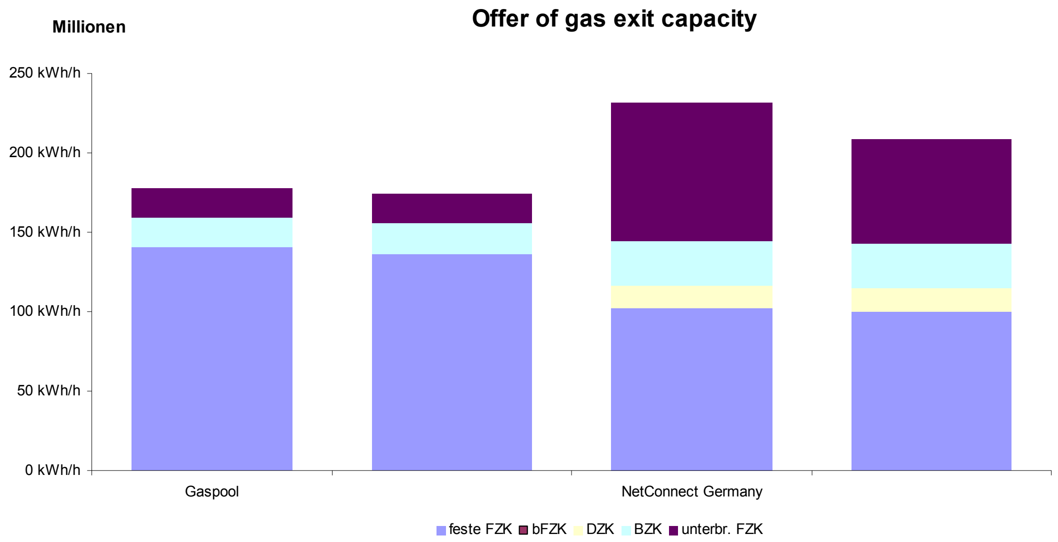

Figure 106: Change in offered exit capacity as a result of the reduction in market areas in calendar year 2011

The diagrams clearly illustrate that the merger of market areas impacted entry capacities in particular. There was a reduction in firm FZK capacity (-48 GWh/h) in the NCG market area in particular and an increase in capacity with conditional firmness and allocability (bFZK; +36 GWh/h). It is also important to note that the data on exit capacity does not encompass internal bookings but only the exit capacity which can be booked by shippers.

Capacity offer; interruptible capacity (gas)

Bookings of interruptible capacity have risen in absolute terms compared with the year 2010. However, this is only true of bookings of exit capacity. Interruptible capacity is fundamentally more economic than firm capacity. It does, however, entail the risk that it may not be possible to transport gas as required.

The market area merger and the fact that it is consequently no longer possible to book points between what were formerly separate market areas means that the offer of firm transport capacity, in particular firm and freely allocable capacity (FZK), has been reduced at the remaining points. The outcome in both cases is that less firm capacity was booked and the relative share of interruptible bookings in relation to firm capacity bookings rose by over 35 percent during the year under review.

The following table reproduces the information provided by wholesalers and suppliers concerning interruptible capacity bookings in recent years.

	Entry		Exit	
Year	**Interruptible capacity in million kWh/h**	**Share of booked firm capacity in percent**	**Interruptible capacity in million kWh/h**	**Share of booked firm capacity in percent**
2011	127	38	76	35
2010	127	34	56	30
2009	137	21	71	23
2008	116	22	91	26
2007	44	8	59	10

Table 40: Interruptible capacity bookings in the reporting years 2007 to 2011

18 of 62 wholesalers and suppliers who have entered into contracts for interruptible capacity stated that interruptions had actually occurred in the 2010/11 gas year; one shipper was unable to specify the length of interruption and is consequently not included in the diagram below. This means that more than twice as many wholesalers and suppliers are affected than in the gas year 2010/2011 (when seven were affected). As in previous reporting years the number of interruptions and the length of such interruptions are distributed very differently among individual wholesalers and suppliers. In addition to the average interruption duration in hours (column height), the following diagram also shows the absolute number of interruptions (figures in white along the horizontal axis) for each wholesaler and supplier in the corresponding gas year. Compared with previous years, the total average interruption duration has fallen once again (gas year 2009/10: 26 hours; gas year 2010/11: 17 hours). In conclusion, while more shippers were more frequently affected by an interruption, on average such interruptions were considerably shorter than in previous years.

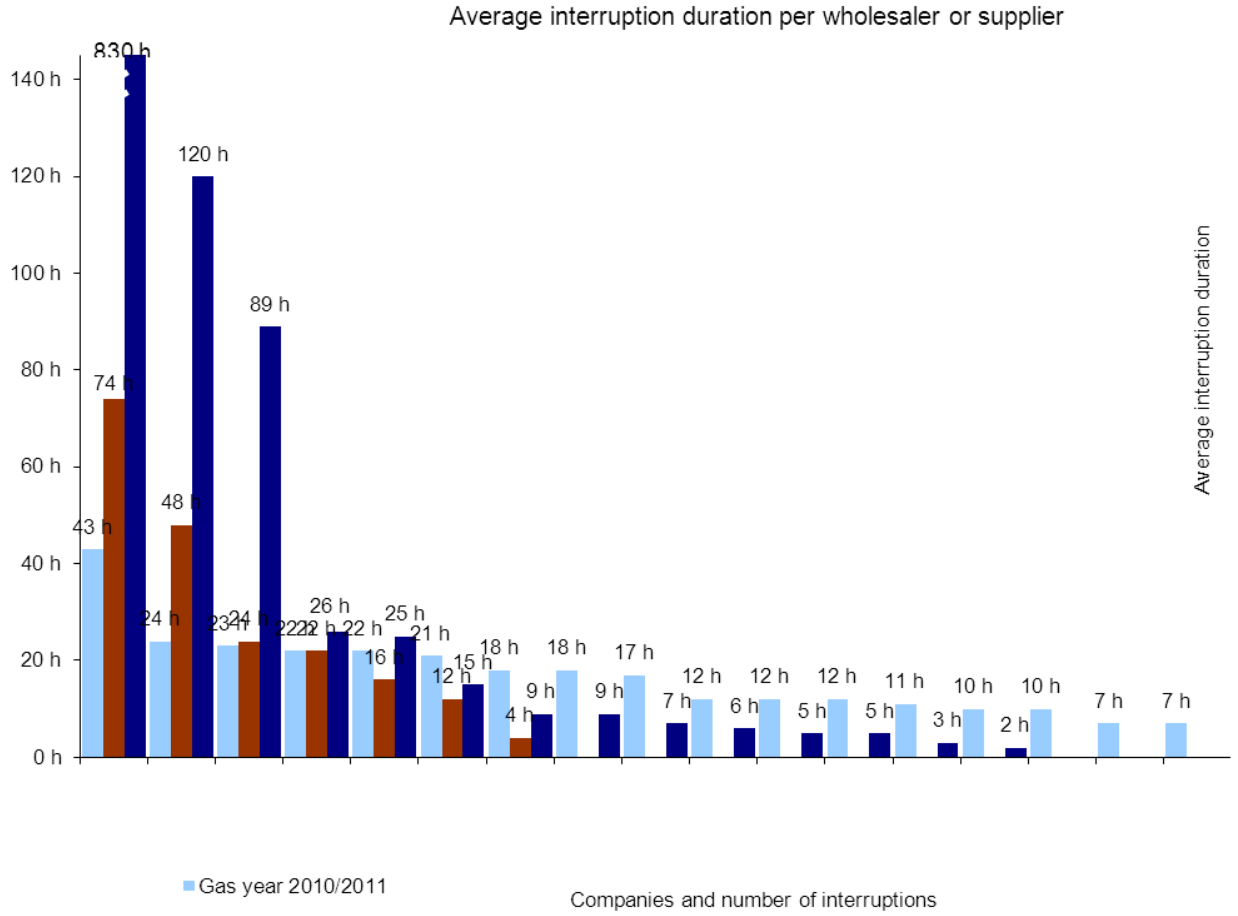

Figure 107: Number of interruptions and average interruption duration per wholesaler or supplier for gas years 2008/09, 2009/10 and 2010/11.

The diagram can be explained by a brief explanation of a single example. The company with the highest interruption duration in gas year 2010/11 (column 1) experienced a total of three interruptions lasting on average 43 hours. The total for all capacity contracts for this company adds up to an overall interruption duration of 129 hours. A second company (eg column 3) was interrupted much more frequently in the gas year 2010/11 (112 interruptions), on average however for just 23 hours in each case. As a result, the total interruption duration for this company is 2,576 hours, significantly higher than is the case for the first company. The total interruption duration for all companies concerned was slightly longer than in the previous year (gas year 2009/10: 8053 hours; gas year 2010/11: 8787 hours).

Similarly, network operators were asked about the duration of interruption and the volume of interruptible and firm capacity products in relation to the initial nomination at 14.00 hours on the previous day. In the gas year 2010/11, a volume of 3.3bn kWh of gas was transported through all entry and exit points in ways which did not meet the transport wishes of network users. In most cases interruptible capacities were interrupted. Where firm capacity products were interrupted a total of 30.5 million kWh of the initially nominated volume was not transported. Most of these interruptions concerned bFZK capacity (93 percent). In relation to the total volume transported in the gas year 2010/11 only 0.18 percent of the nominated gas volume was actually interrupted.

The following map shows the regional distribution of actual interruptions in the gas year 2010/11. 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. Capacities are shown as weighted averages in relation to total interruptions in hours and the total nominated volume across all points in the respective region. This means that where capacities are identical but the arrows wider, interruptions were more frequent, in other words took place over a longer period or several times during the gas year, in the region to which the wider arrow belongs; in weighted average terms the same capacity (level) was interrupted. The direction of the arrows shows in what direction transmission was interrupted. The red arrow – storage in northern storage facilities – shows that in this region it was mostly firm capacity products (in particular bFZK) which were interrupted. Interruptions between market areas (interruption volume ten percent; average capacity of approximately 290,000 kWh/h) and to final customers (interruption volume 0.02 percent; average capacity 143,602 kWh/h) are not illustrated.

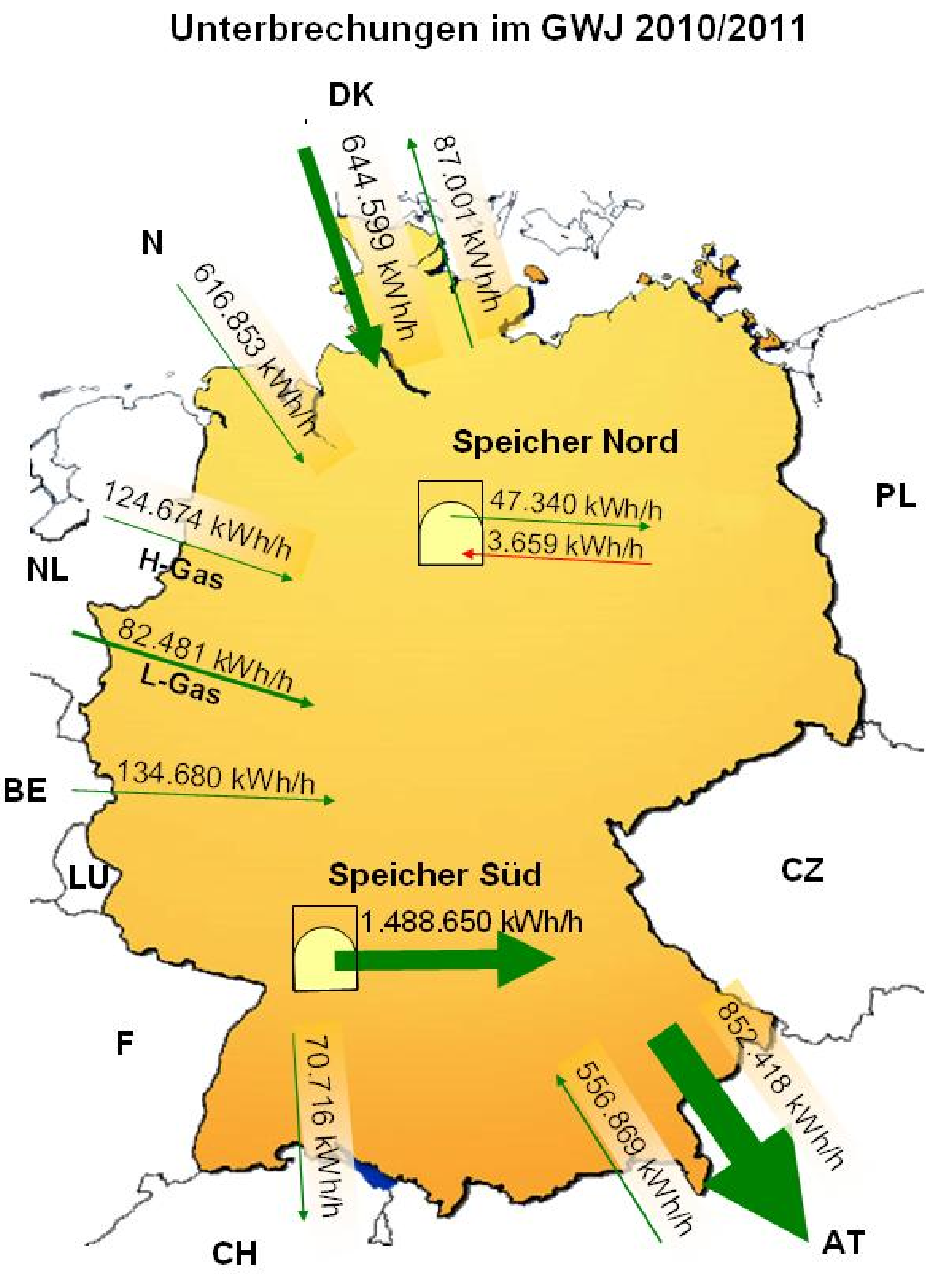

Figure 108: Regional overview of interruptions, incl. medium capacity levels

Unterbrechungen im GWJ	Interruptions in the gas year
Speicher Nord	Northernn storage facility
Speicher Süd	Southern storage facility

Network expansion and investments

Based on the findings of the 2012 monitoring survey, investments – both made and planned – in the sustainment, renewal and expansion of existing gas transmission systems are estimated and shown at the aggregated level. Transmission system operators were asked about their investments in 2011 and investment plans for the periods 2012-2014 and 2015-2017. Network operators were also asked to name specific individual projects and to quantify the sums to be invested in specific projects. Many transmission system operators did not specify their planned investments for the 2012 monitoring in the form of individual projects and the total sums can consequently not be derived from the specific projects mentioned. What is more, the figures referred to here do not anticipate the outcomes of the gas Network Development Plan. The Network Development Plan for gas continues to determine the infrastructure measures which need to be implemented in the future. The figures given in the 2012 monitoring survey therefore simply represent estimates based on transmission system operators' current vision for the period up to 2017.

Investments by gas transmission system operators

The diagram below shows the volume of investments anticipated for the entire German gas transmission system in the period up to 2017. According to the information provided by 14 transmission system operators, investments of 232 million euros were made in the year 2011. Almost 118 million euros of this were invested in the new build/expansion or extension of lines and 114 million euros in sustainment and renewal. Expenditure on servicing and maintenance totalled 398 million euros in 2009.

The responding gas TSOs quoted a figure of 1,303 million euros which they planned to invest in the new build/expansion and extension of networks from 2012 to 2014. Combined with sustainment and renewal investments of 667 million euros, investments of almost two billion euros are therefore planned. Expenditure of 1.2 billion euros on servicing and maintenance is planned for the period 2012 to 2014.

Investments in the period 2015 to 2017 will probably add up to 1.6 billion euros. This amount is divided between investments in new/expanded or extended networks worth 1.3 billion euros and investments in sustainment and renewal of 0.4 billion euros. Investments of 0.9 billion euros are planned for servicing and maintenance.

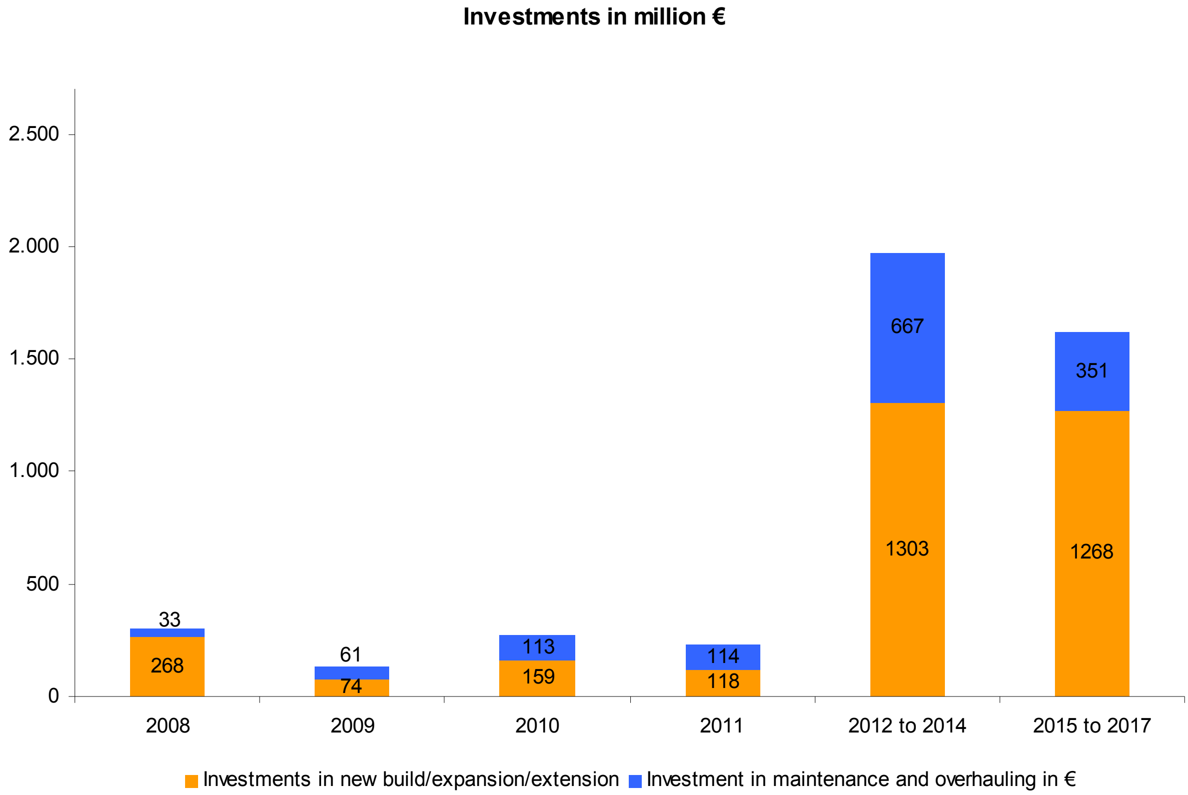

Figure 109: Investments by gas transmission system operators

Compared with 2011 there will be a substantial increase in planned investments for the period 2012 to 2014 which will subsequently remain at much the same level in the period 2015 to 2017. Larger scale single projects, such as the MONACO natural gas pipeline or the integration of the second line of the Nord Stream pipeline into the German gas infrastructure, fall within this period. A significant part of the total volume of investments is therefore earmarked for a small number of very large investment projects.

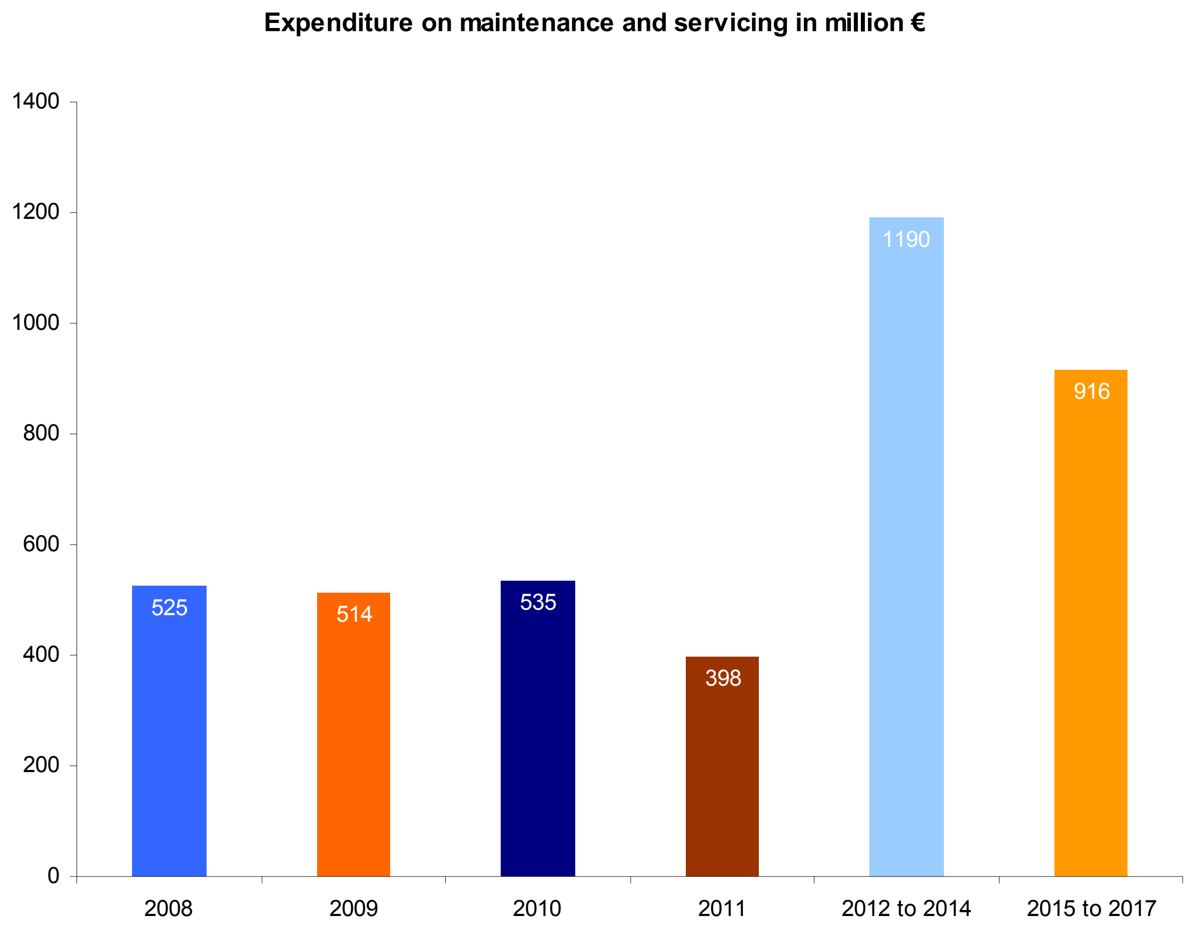

Figure 110: Expenditure by transmission system operators on servicing and maintenance

Fewer resources were spent on maintenance and servicing in 2011 than in 2010. A substantial increase of more than twice the volume for 2011 is anticipated for the years 2012 to 2014 and 2015 to 2017.

Increased technical capacity

The analysis of the available data reveals that hardly any significant additional capacity was created in 2011. Additional capacities of 30 million kWh/h through 394 single projects are planned for the period 2012 to 2014. Another 16 million kWh/h will be created by 306 single projects in the period 2015 to 2017. From the information provided by transmission system operators it is unclear where additional capacities will be created.

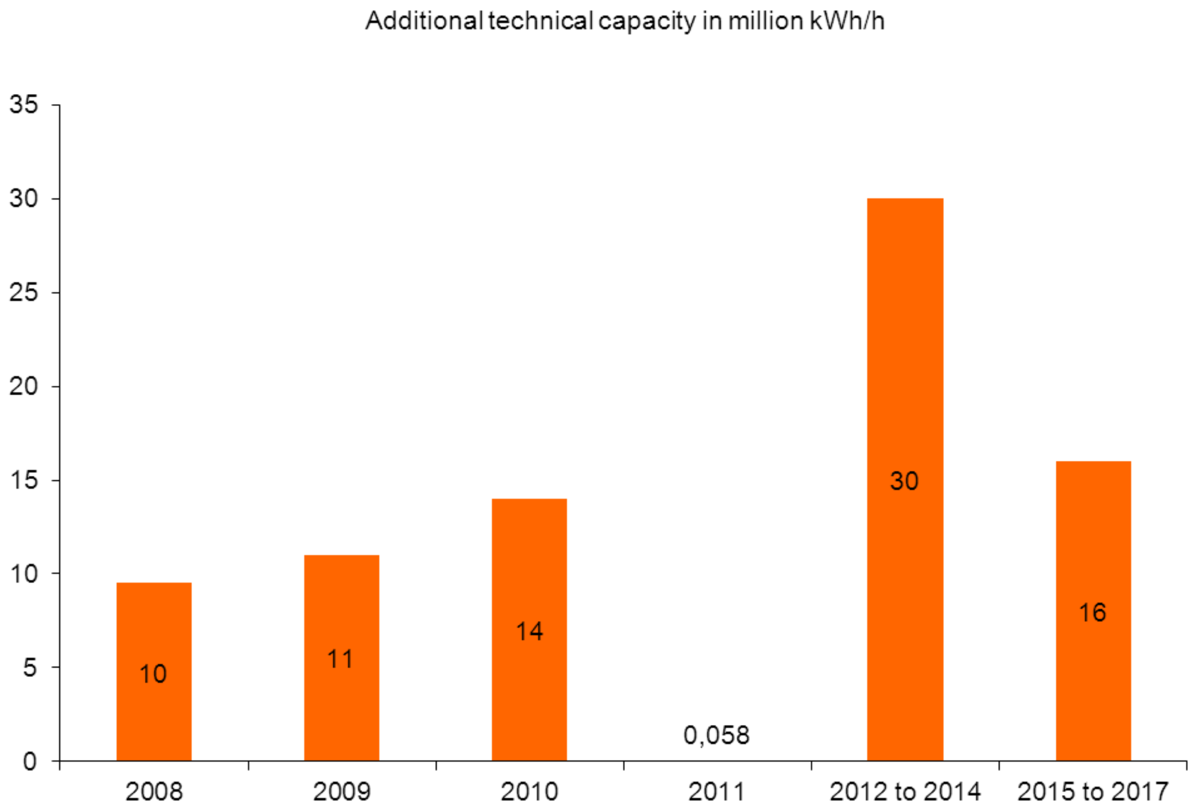

Figure 111: Additional technical capacity of transmission system operators

Distribution system operators

Investment in and expenditure on the network infrastructure of gas DSOs

Gas distribution system operators were asked to specify the total investments in and expenditure on build/extension/expansion and sustainment/renewal of the network infrastructure (excluding metering technology) for 2011 and the investments projected for 2012. The results are shown in the following diagram.

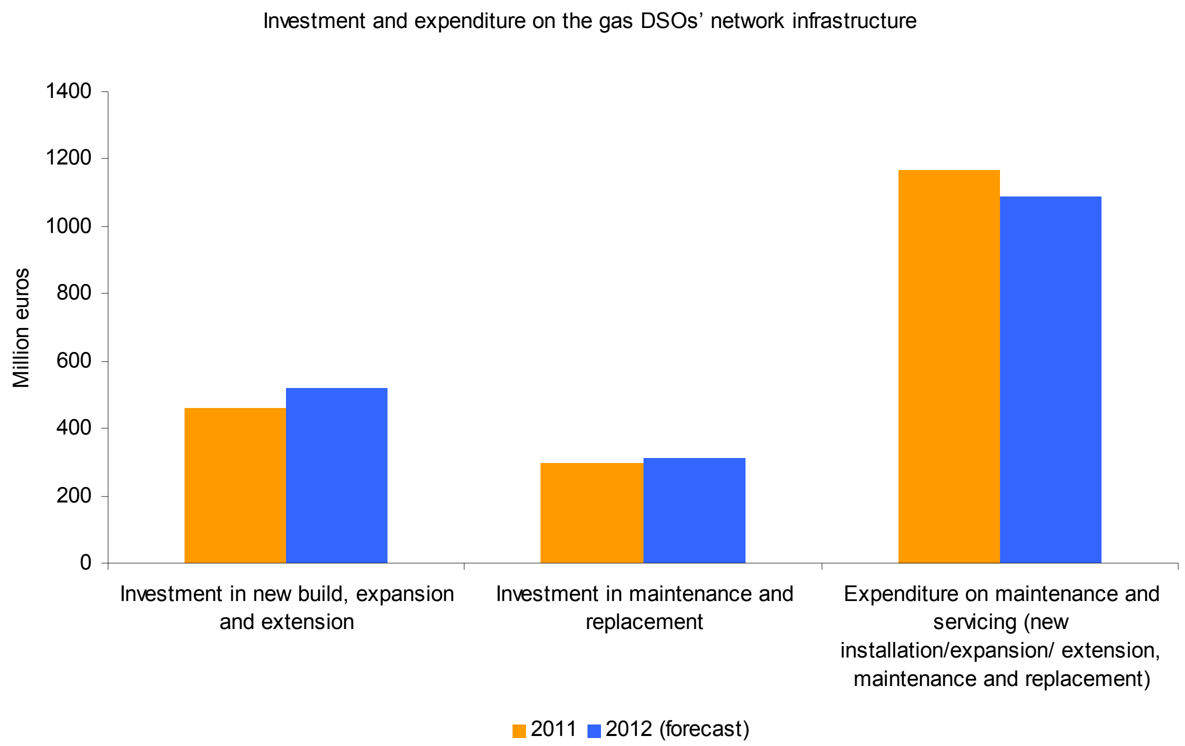

Figure 112: Investment in and expenditure on the gas DSOs' network infrastructure

In the "investments in new build/expansion/extension" category the comparison of the values for 2011 (461 million euros) with those for 2010 (388 million euros) shows that there was a significant increase in investment activities during this period. In their forecasts the companies expect this trend to continue in 2012. The forecast for 2012 shows an anticipated rising trend in the "investments in sustainment and renewal" category and a tailing off in the "maintenance/servicing" spending category.

Network tariffs

Expansion factor as per Section 10 of the ARegV

A lasting change in supply services allowed distribution system operators (DSO) to apply once again for an expansion factor for their investments in this area. This factor ensures that costs for these investments resulting from a lasting change in the operator's supply services over the course of the regulatory period are taken into consideration when determining the revenue cap. A lasting change in supply services is deemed to have occurred if the parameters cited in section 10(2) sentence 2 of the ARegV alter permanently and significantly. A total of 62 applications for expansion factors were made in 2011; in 2012 there are 74 applications.

Network interconnection points under section 26(2) of the ARegV

In 2011, a total of 26 applications for network transfer, merging and splitting in the gas sector were submitted to the Bundesnetagentur. These applications by network operators state what percentage of the revenues are to be assigned to the part of the network being transferred and what percentage to the remaining part. The Bundesnetzagentur must ensure in particular that the total of both parts of the revenue does not exceed the determined revenue cap.

Development of network tariff share of overall gas price between 2007 and 2012

The figure below charts the development of the average volume-weighted net gas network tariff's share, including upstream network costs, charges for billing, metering and metering operations, in the overall gas price as of 1 April
between 2007 and 2012. The network tariff share of the overall gas price falls for all customer categories.

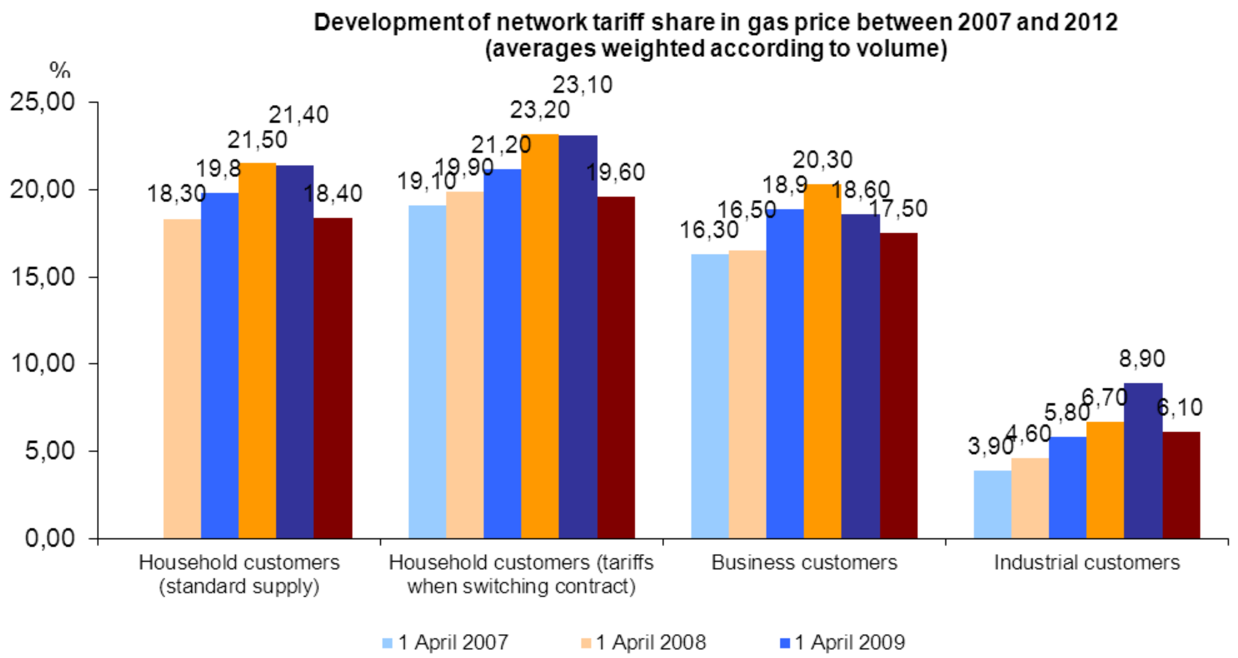

Figure 113: Development of volume-weighted network tariff share of gas price between 2007 and 2012. Price as of 1 April 2012 as per gas wholesaler and supplier survey

Cost examination as per section 6 ARegV and for efficiency benchmarking as per section 22 ARegV

The Bundesnetzagentur established the base level for determining the revenue caps for the second gas regulatory period (2013-2017) via a cost examination. In total, 243 operators of gas supply networks were obliged to submit to the Bundesnetzagentur the necessary documents for determining the base level as per section 6(1) of the ARegV for the second regulatory period (2013-2017). Of the 243 operators, 100 are taking part in standard proceedings (benchmarking), while143 are involved in simplified proceedings. The cost examination was completed in both sets of proceedings. The operators' efficiency values are now determined on this basis, before the revenue caps are set.

The difference between the data requests made for the cost examination in the second regulatory period and those in the first period in particular is that the operators were required to complete an electronic questionnaire in order to demonstrate the cost calculation based on third-party services as part of the cap setting. Furthermore, the Bundesnetzagentur focussed on the effects of the Act to Modernise Accounting Law (*Bilanzrechtsmodernisierungsgesetz* - BilMoG).

The Bundesnetzagentur additionally took into consideration the rulings of the Federal Court of Justice, in particular on the valuation of necessary equity, ie the obligation to prove the necessity of the current assets claimed by the network operator.

As soon as the cost examination was completed for the standard proceedings, those participants were then called upon to communicate which costs were to be allocated to the shares that cannot be controlled on a lasting basis within the meaning of section 11(2) of the ARegV. This "reconciliation" carried out by the operators was then ultimately checked by the Bundesnetzagentur.

In addition to the data for the cost examination, in the period under review the Bundesnetzagentur also collected data on load, structure and sales for the 2010 financial year. These data were then checked for consistency and plausibility. The network operators were informed which benchmarking parameters were used to calculate the efficeincy value.

Balancing

With the determination of 28 May 2008, the Bundesnetagentur introduced comprehensive new arrangements for the portfolio and system balancing energy regime for gas (GABi Gas). This is the basis on which daily balancing has been based in Germany since 1 October 2008. Portfolio balancing energy charges have been based since then on the reference prices of national and international trading markets. System balancing energy is bought by the market area manager centrally who controls its use in conjunction with the network operators.

Substitute nomination procedures

The transmission system operators offer substitute nomination procedures as far as this is technically feasible and economically reasonable, which is the case for nine of 14 TSOs. Customers who are supplied using this method are allocated to the load-metering with substitute nomination procedures customer group. Of a total of 546 recorded load-metered exit points connected to the transmission system, 94 (17 percent) are supplied using substitute nomination procedures. If the TSOs are looked at individually, they supply between two and 67 percent of their load-metered exit points using this method. Exits points for this customer group are supplied with feed-in from storage facilities and production facilities as a priority. In total, in the period under review the 14 TSOs had an gas offtake volume of 230,191.84 GWh received by load-metered customers. Of this total, 89,088.34 GWh came from exit points which were supplied using substitute nomination procedures. Online flow control is offered and used as a priority here, in addition to steering difference balancing at storage facilities or online rebooking at virtual trading points. The time delay between feed-in and offtake varies greatly between the various procedures and ranges from zero minutes up to 240 minutes, with three minutes being the usual case.

Once the GABi Gas balancing system has become established, a substitute nomination procedure should no longer be necessary, since every shipper will be able to obtain suitable products in the market at short notice and in line with the forecasts. The use of flexibilities solely on account of the requirements of individual customers will lead to inefficient use, these then being withdrawn from the market.

Harmonisation of European balancing regimes

On 18 October 2011, European agency ACER published a guideline on pan-European standardised balancing regimes ("Framework Guideline on Gas Balancing"). Based on this document, the European network operator association ENTSOG is currently developing a network code in line with Article 6(6) of Regulation (EC) No 715/2009. This is to be completed by November 2012 and will then be adopted by the European Commission, who, as per Articles 6(11) and 28(2) of the Regulation (EC) No 715/2009, can then introduce comitology proceedings as per Articles 5a(1) to (4) and 7 of Decision 1999/468/EC in order to give the network code a legal basis as a guideline. In this way, the network code becomes part of Regulation (EC) No 715/2009. Transmission system operators must implement the code developed by ENTSOG within twelve months of its taking effect. Exceptions allows for the timescale to be stretched to five years, before national systems are to be adapted. Step-by-step introduction of the target model is possible to some extent. The first draft of the network code has now been submitted and is undergoing public consultation by ENTSOG.

The German balancing regime already agrees with the provisions of the draft code to a large extent. Completion of the detailed final network code by ENTSOG based on the guideline is expected in November 2012, only then will an ultimate evaluation be possible.

The key content of the submitted balancing draft network code is as follows:

Arrangements for system balancing energy procurement

Network operators are to procure system balancing energy either via four standardised short-term products (VTP, local, limited term and local limited term products) from a trading platform or via longer-term contracts. A merit order list gives the short-term VTP products (eg those obtained via an exchange) priority over all others. These network code provisions correspond with the current efforts of the Bundesnetzagentur and market area managers in terms of procurement of system balancing energy and standardisation of such energy products.

Nomination arrangements

The network code provides certain criteria and provisions for the content and running of nominations and renominations at cross-border points. In principle, it should be possible to renominate up to two hours before the end of the gas day. The German arrangements conform to the content of the draft network code.

Portfolio balancing energy prices

The network code links the portfolio energy prices to the marginal costs of the respective market area managers when procuring system balancing energy. The marginal buy price is the higher of the system balancing energy price or the weighted average market price. The marginal sell price is thus the lower of these two prices. All system balancing energy transactions actually made in the respective balancing period (the gas day) are relevant, regardless of whether they are purchases or sales. A small adjustment can be made to increase or decrease the weighted average price. The Bundesnetzagentur will adapt the system for determining portfolio balancing energy prices in Germany accordingly. This approach also now suits the conditions on the German system balancing energy market.

Balancing periods and intra-day incentive mechanisms

The balancing period is the day from 6 am to 6 am. The network code makes it possible to introduce intraday incentive mechanisms if certain criteria are met. This means that the profiling fees that are part of the German balancing regime remain a possible incentive mechanism under the current draft. However, it should be anticipated that this point will continue to be discussed at a European level. It is thus not possible to further anticipate any need for change or the effects of these arrangements.

Neutrality mechanisms

The draft network code states that the network operators must be financially neutral. All costs and income from the balancing regime should be allocated to the network users. The decision regarding the method for calculating and distributing potential neutrality charges is up to the national regulatory authority, and also applies to the German balancing energy levy.

Provision of information

The draft network code contains information requirements for transmission and distribution system operators. TSOs are to provide shippers with the system status analogue to Annex 1 of the Regulation, their system balancing energy purchases and sales and the feed-in and offtake of a shipper. Distinctions are made between the basic case, variant one and variant two, although the latter does not match the German approach to allocation of day ahead forecast values for standard load profile customers in terms of the exit points not metered on a daily basis. This highly pro-competitive approach simplifies supply to household customers, and thus very effectively supports the overarching aim of stimulating competition in final customer and wholesale markets.

Under the provision of the draft network code, offtake information for industrial customers and other large-scale customers (load-metered customers) is to be supplied at least twice a day instead of only once. The time of the first delivery needs to be moved forward from 7pm to 6pm at the latest. The provisions in the draft are not yet specific enough in terms of the information requirements and their relationship to intraday incentive mechanisms, and an evaluation is thus not appropriate at this time.

System balancing energy

System balancing energy costs - Winter 2010 and 2011 balance

Market area managers NCG and Gaspool now publish comprehensive data on system balancing energy volumes implemented and the resulting costs. However, the strained situation in gas and electricity networks in February 2012 is to be considered separately. The Bundesnetzagentur analysed this "cold period" in a separate "report on energy supplies in winter 2011/2012", published on 7 May 2012 on its website[75].

75 http://www.bundesnetzagentur.de/DE/Sachgebiete/ElektrizitaetGas/StromNetzEntwicklung/Netzbericht Winter/Netzbericht_Basepage.html

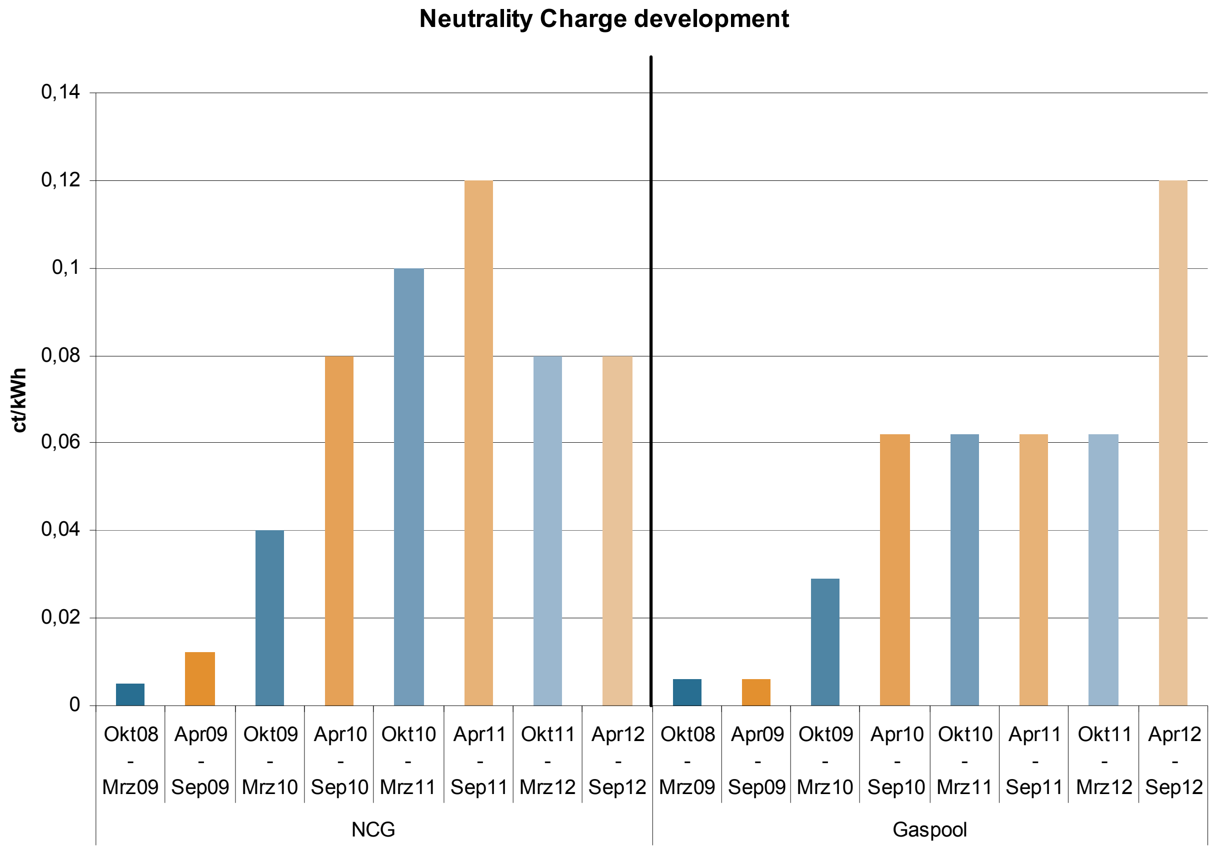

Figure 114: Development of balancing energy levy

The balancing energy levy is also increasing greatly in the Gaspool market area in light of this in particular. In the NCG market area, the levy was ultimately able to be maintained at the level of the previous period for the current period of 1 April to 30 September 2012, following increases at the end of 2010 and the beginning of 2011.

Standard load profile

Network operators can use two types of standard load profiles (SLP); analytical profiles, which in general terms are based on the previous day's consumption at the time of estimation, and synthetic profiles, which rely on statistically calculated values. Analytical profiles were used by 9.7 percent of operators in 2011. In 2010 it was 10.8 percent.

The significance of this standard load profile is evident in the fact that all exit operators (98.7 percent) use them when delivering to household or small business customers. Where synthetic profiles were used, those of the Technical University of Munich (TU München), used in the versions of 2002 and 2005, clearly dominate with market coverage of 96.5 percent. This value also remains virtually unchanged from 2010 (96.7 percent).

The TU München offers a range of different profiles which reflect the offtake behaviour of various customer groups. 47.8 percent of network operators answered yes to the question of whether all available profiles were applied. In 2010 it was 45.8 percent. Responses to the subsequent question of how many profiles were actually used indicated that, as in 2010, two profiles are generally used by household customers, while business customers continue to use six profiles on average.

It becomes increasingly clear that the quality of the load profile depends significantly on the quality of the weather forecast. As visible in the figure below, more network operators have started using a geometric range of the previous day's temperature instead of the daily average temperature. This solution is now used by 56 percent of network operators; the trend of recent years thus continues.

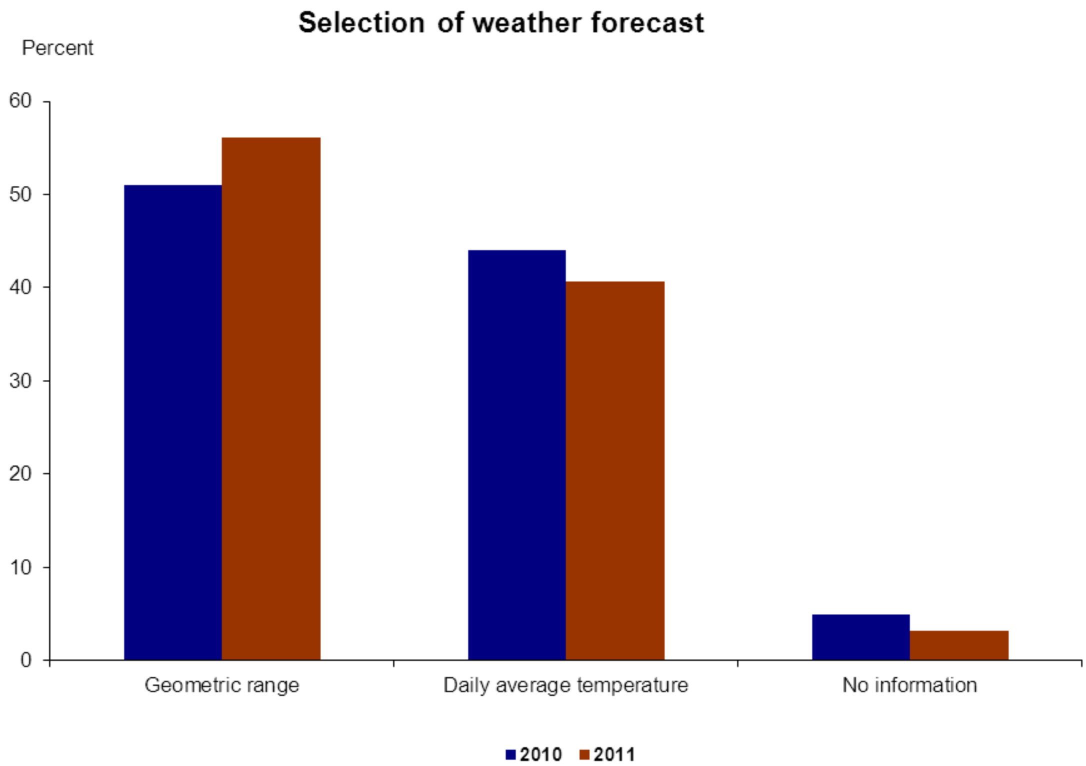

Figure 115: Selection of weather forecast

Inaccuracies are of course a feature of standard load profiles as forecasts. The average percentage deviation between allocation and actual offtake on a daily basis is 5.7 percent and is therefore around the same level as 2010 (5.5 percent). The value is slightly more meaningful than that for 2010, as 63 percent of operators provided information for the current Monitoring report (2010: 53.4 percent). The average maximum deviation on one day decreased from 61.7 percent to 44.7 percent. These maximum fluctuations only occur in isolated cases, but are cause for concern as they can each result in increased system balancing energy. It is must be borne in mind, however, that these figures may not be representative as it could be assumed that the network operators with a comparatively high forecast quality tended to respond.

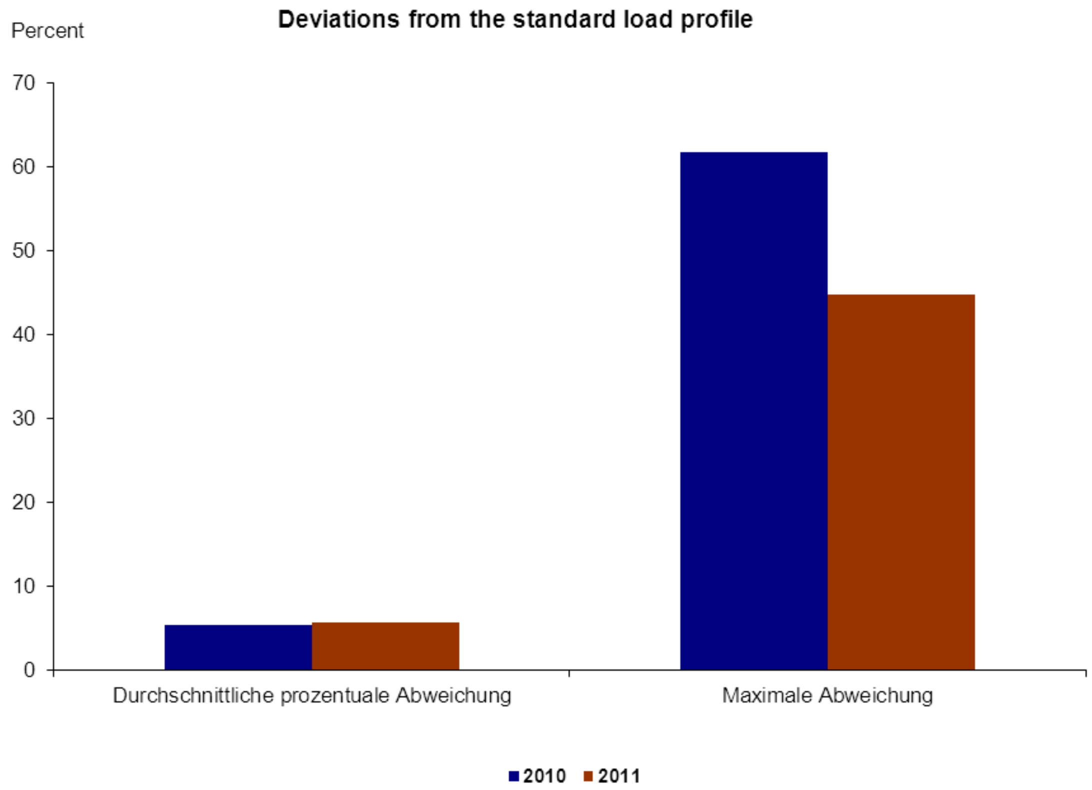

Figure 116: Deviations from standard load profile

13.3 percent of network operators made fixed adjustments to the load profile due to the deviations, which is a slight increase from 2010 (12.9 percent).

Billing for higher and lower volumes

Various procedures are available to the network operators for carrying out SLP billing for higher and lower volumes. A trend towards fixed date procedures has already been observed in recent years.

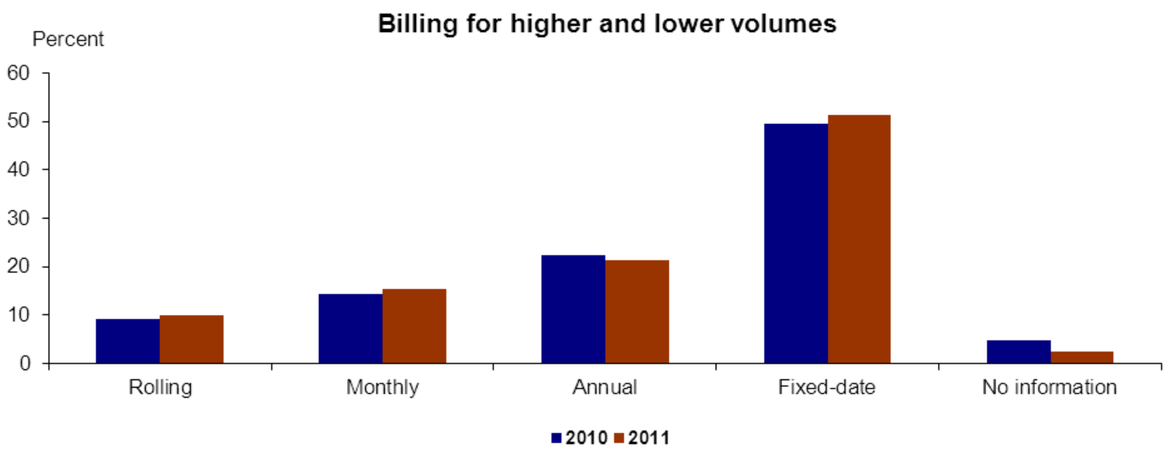

Figure 117: Billing for higher and lower volumes

On average, around 347 network operators had completed billing for SLP customers for the survey period between October 2009 and September 2011. This number was significantly lower in the 2011 Monitoring survey. Around 265 network operators had already completed billing for the gas financial year from October 2010 to September 2011. This value is therefore twice as high as in 2010 (125). The dip in the curve below is due to the different billing periods in the various procedures.

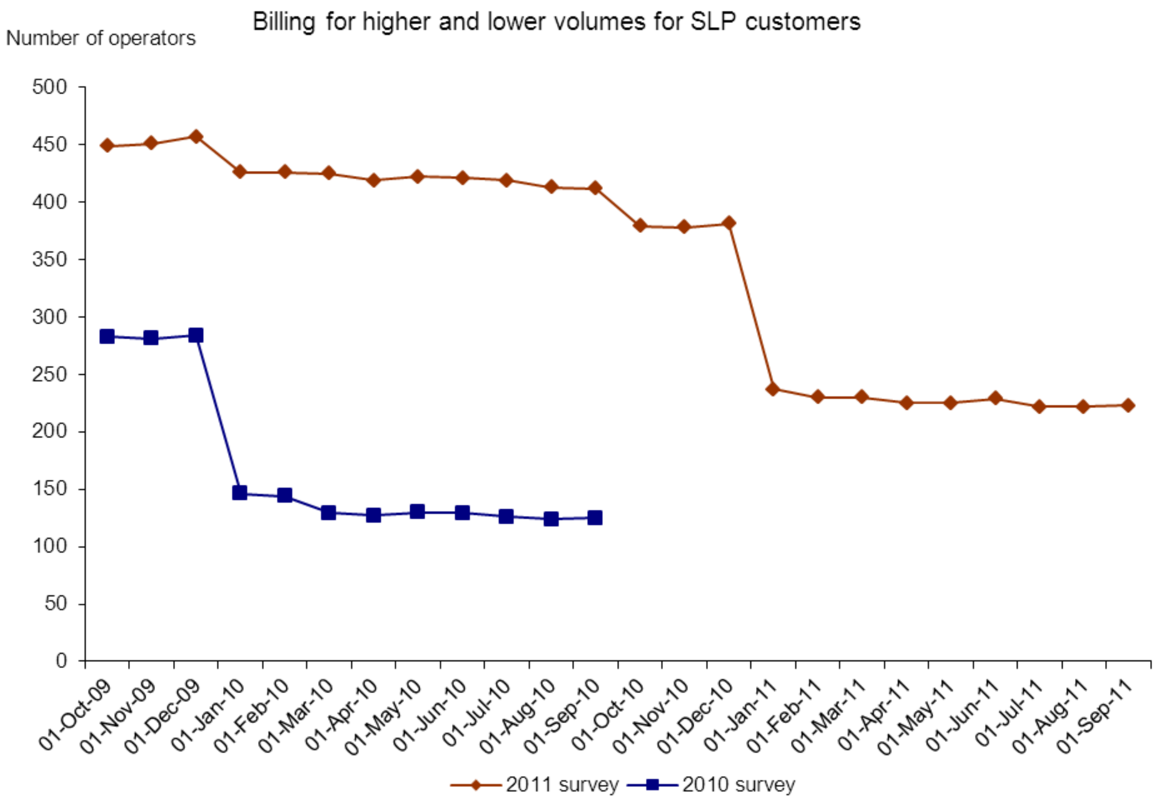

Figure 118: Billing for higher and lower volumes for SLP customers

Most operators now appear to have the initial problems associated with billing higher or lower volumes for load-metered customers under control. This is clear from the comparatively high number of operators who have already completed billing.

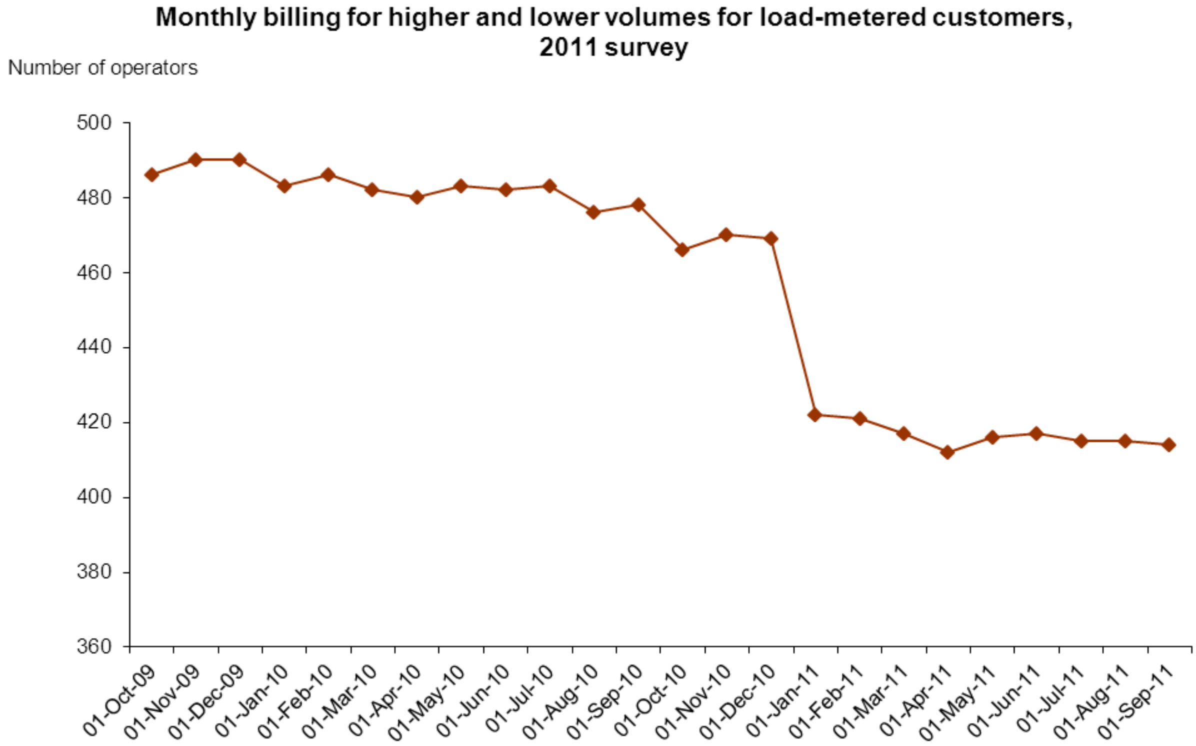

Figure 119: Monthly billing for higher and lower volumes for load-metered customers

In terms of the gas financial year from October 2010 to September 2011, for offtake volume, on average 84.1 percent of load-metered customer billing for higher or lower volumes was carried out. This figure is significantly higher than in the 2011 survey, where billing was carried out for 62 percent of the volumes.

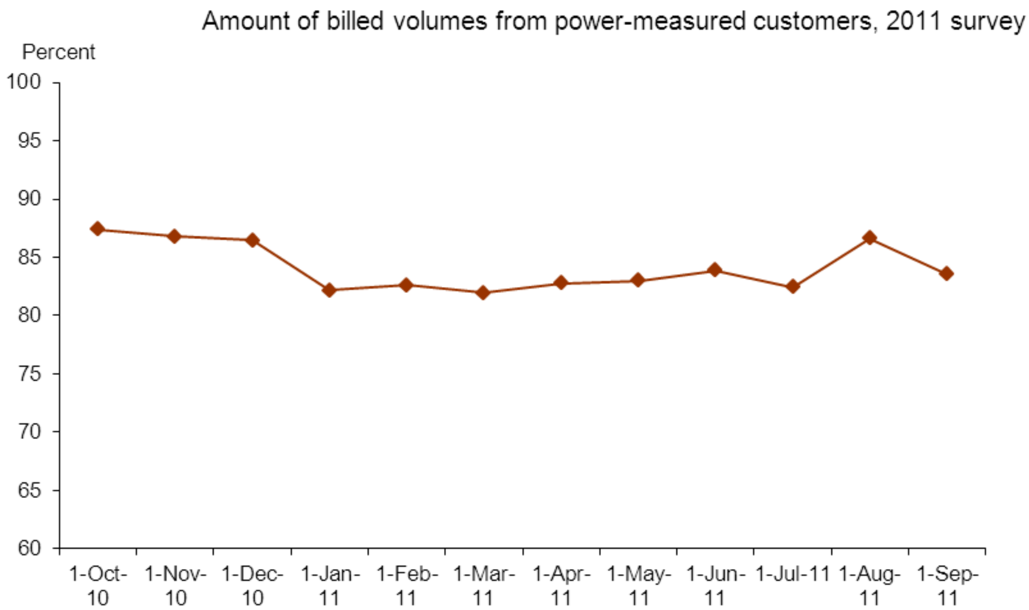

Figure 120: Amount of billed volumes from power-measured customers

Publication Requirements

Implementation of the publication requirements by gas distribution system operators

The publication of information relating to network usage by gas distribution system operators is a key requirement laid down by the legislator with the aim of creating transparency and hence undistorted competition. Section 33(3) of the Gas Network Access Ordinance provides for several publication requirements which are of particular importance especially as regards the connection of biogas facilities. The Ordinance requires that the information be published on the network operators' websites.

Specifically, the information to be published comprises the minimum information required to consider a request for connection (section 33(3) subpara 1), standardised conditions for connection (section 33(3) subpara 2) and a constantly updated, clear depiction of capacity utilisation in the network as a whole, indicating where congestion is occurring or is likely to occur (section 33(3) subpara 3).

These publication requirements have been implemented as follows:

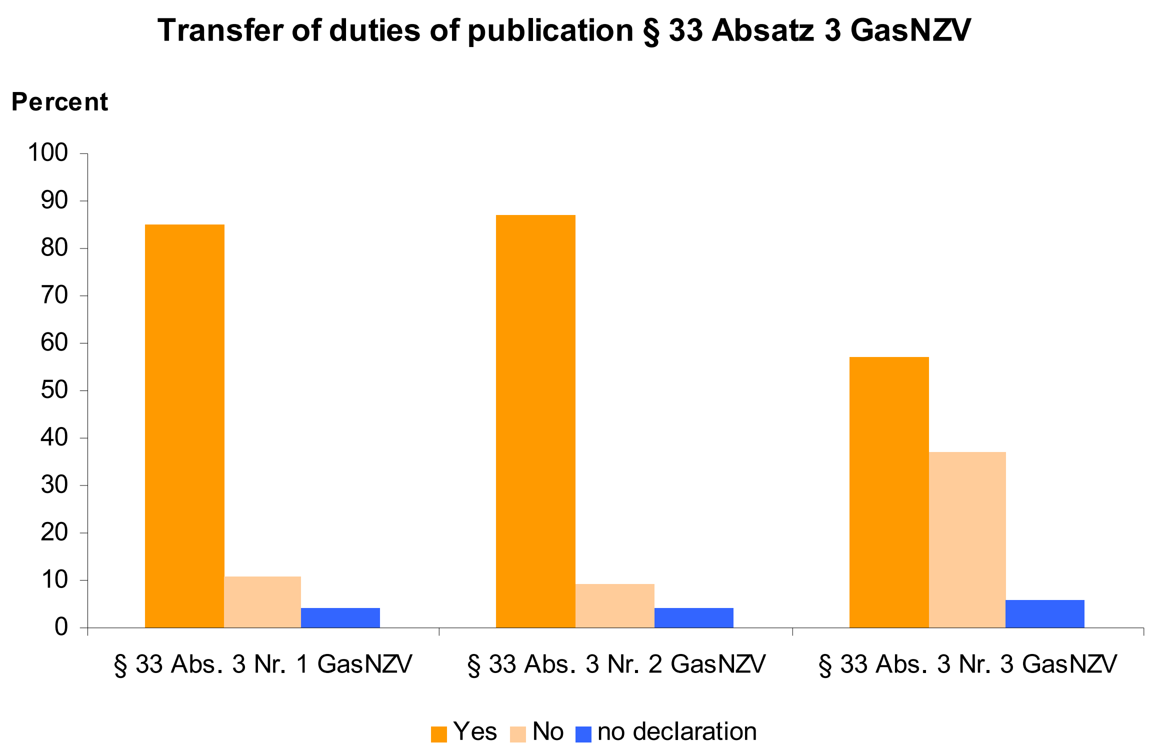

Figure 121: Transfer of duties of publication § 33 Absatz 3 GasNZV

In all three instances, the percentage of operators meeting the requirement has risen significantly compared with 2010. There has been an increase of nine percentage points in each case. 85 and 87 percent of operators now meet the requirements set out in section 33(3) subparas 1 and 2 respectively. According to the 2012 monitoring data, 46 percent of the network operators surveyed met the publication requirement under subpara 3.

Storage facilities

Access to underground storage facilities

19 companies operating and marketing a total of 39 underground natural gas storage facilities took part in the 2012 monitoring survey. The total maximum usable volume of working gas in these storage facilities is 22,245m m_N^3. Of this, 9,250m m_N^3 is accounted for by cavern and 12,996m m_N^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 (20,055m m_N^3 for H-gas compared to 2,190m m_N^3 for L-gas).

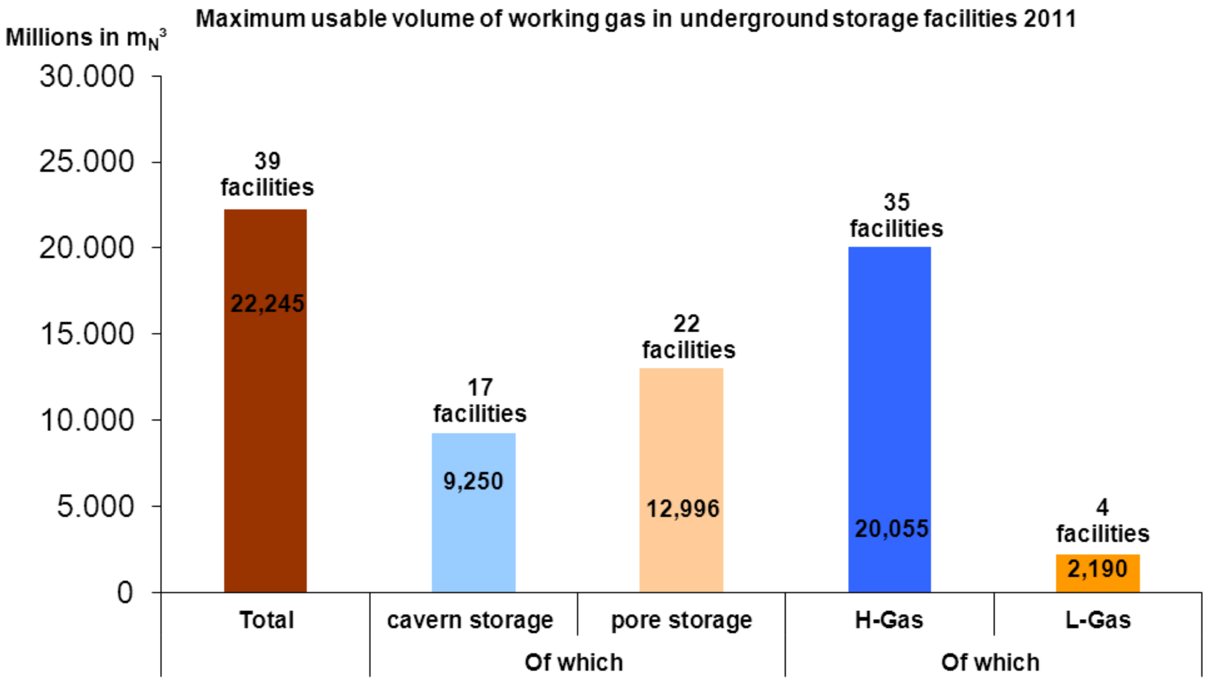

Figure 122: Maximum usable volume of working gas in underground storage facilities in 2011

Use for production operations

In 2011, the proportion of the maximum usable volume of working gas in underground natural gas storage facilities used for production operations in a storage facility was less than one percent (2010: 2.4 percent). After deducting the working gas volume used for production operations from the maximum usable working gas volume recorded, the total working gas volume accessible to third parties in 2011 was 22.09bn m_N^3 (2010: 20.48bn m_N^3), the injection capacity 10.76m m_N^3/h and the withdrawal capacity 20.68m m_N^3/h.

Use by third parties - customer trends

According to the data reported by the companies, the average number of storage customers in 2011 was five (2010: 4.6). The following chart shows the trend in the number of customers per storage facility operator since 2007:

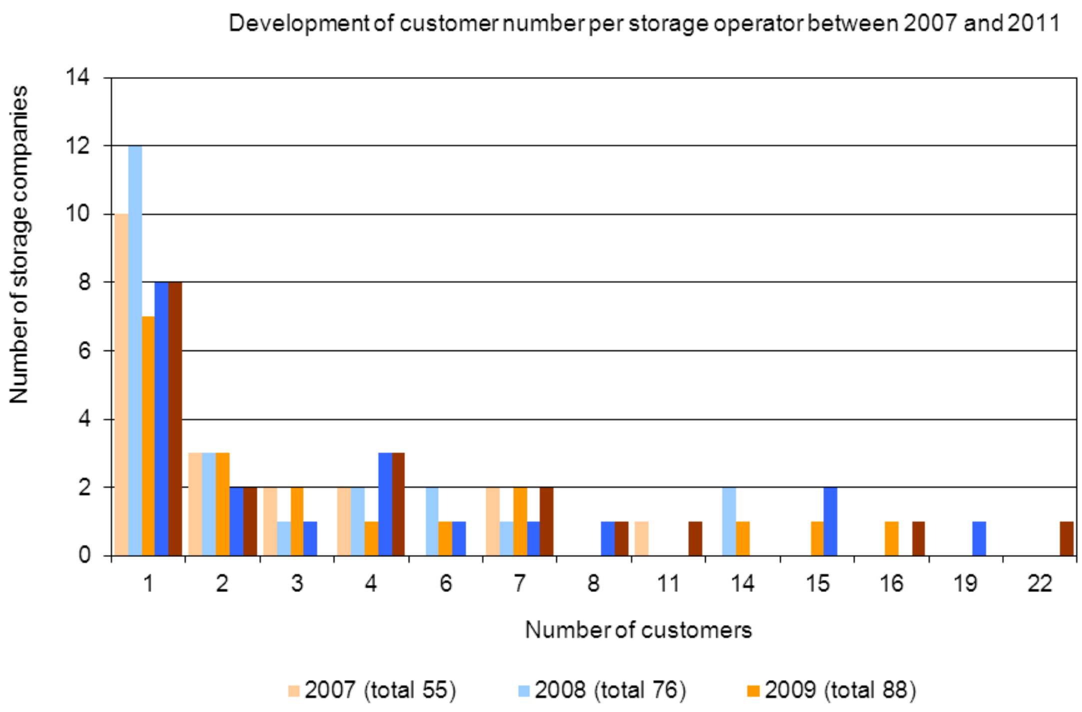

Figure 123: Development of customer number for storage operators

The number of storage customers has decreased from 97 in 2010 to 95 in 2011. The survey showed that many storage companies continue to have only one customer whilst others had up to 22 customers in 2011.

Capacity trends

The following chart shows the free capacity in underground natural gas storage as of 31 December 2011 compared to previous years from 2007 onwards.

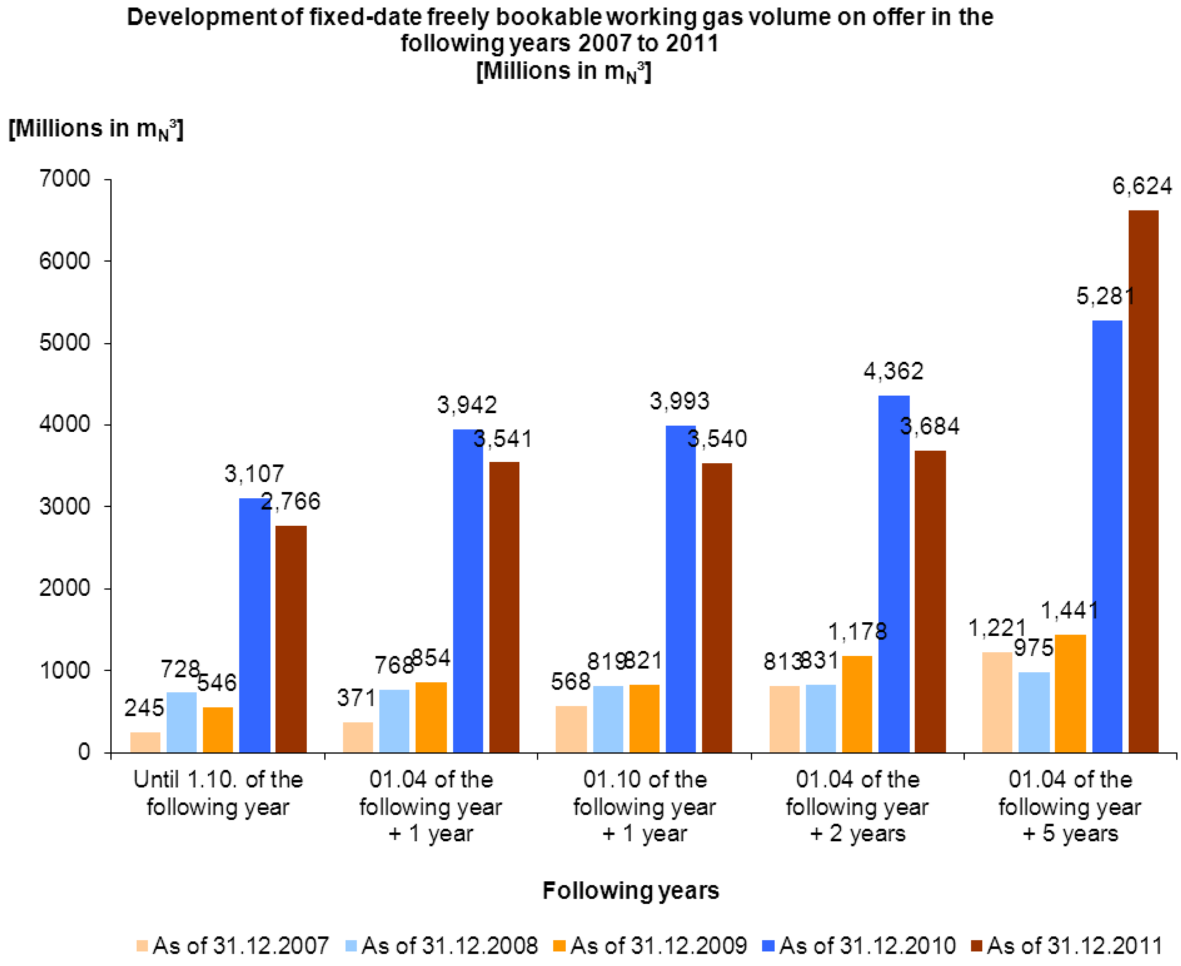

Figure 124: Development of fixed-date freely bookable working gas volume on offer in the following years 2007 to 2011

Following the large increase in the volume of freely bookable working gas in 2010, the volume of short-term available capacity fell by an average of around ten percent in 2011 whilst the volume of working gas available in the following year plus five years has again increased by 25 percent.

Wholesale

Developments on the gas markets

Efficient wholesale markets are an essential prerequisite for effective competition in the natural gas distribution markets. Liquid spot markets first of all enable the market participants to procure even large amounts of natural gas without problems on a short-term basis and provide them with alternatives to the conclusion of long-term gas supply contracts. Where sufficient gas volumes are available on a short-term basis, new distribution companies can also enter the market at any time. The ensuing increased liquidity is ultimately also to the benefit of end consumers. Liquid futures markets, where, in contrast to the spot markets, mainly financial, non-physical transactions are carried out, provide market participants with the opportunity to protect themselves against price risks and provide information regarding future market developments.

Natural gas trading generally takes place at the virtual trading points within the NetConnect Germany (NCG) and Gaspool market areas. The largest share of the natural gas trading volumes is still accounted for by the off-exchange trade (OTC trade) which either takes place bilaterally between market participants or anonymously via a broker platform. Alternatively, natural gas volumes are also traded on exchanges. Whereas the products traded anonymously on the exchanges are standardised, the participants in the OTC trade are free to design their own contracts.

Development of OTC trading

The accession of the market areas Thyssengas (H-Gas), Open Grid Europe (L-gas) and Thyssengas (L-gas) to NetConnect Germany on 1 April 2011 created the first cross-quality market areas in Germany. On 1 October 2011, the Aequamus and Gaspool market areas merged to form the new cross-quality Gaspool market area. Under Section 21 (1) of the Gas Network Access Ordinance (*GasNZV*) the transmission network operators are obliged to reduce the number of market areas in order to reduce barriers to trade and increase liquidity at the relevant virtual trading points.

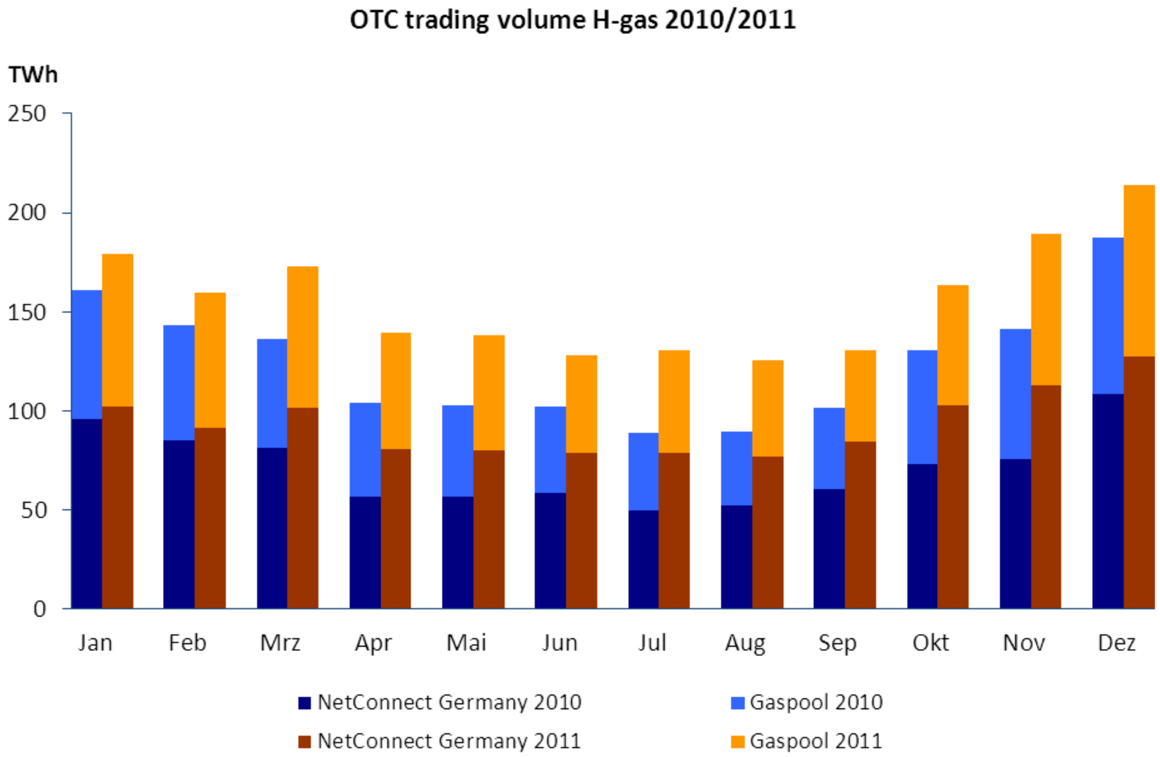

Diagram 125: H-gas trading volume in the NCG and Gaspool market areas. The trading volumes in the NCG market area up to and including March 2011 are the NCG and Thyssengas trading volumes (H-Gas).

The monthly H-gas trading volumes have increased noticeably in the Gaspool and NCG market areas as compared with the 2010 monthly trading volumes. In 2011, a total of 1872 TWh of H- gas was traded, which represents an increase of 25.6 percent over the year 2010. The market participants also made greater use of the procurement opportunities provided by the OTC trade. In 2011, 639 TWh were procured in bilateral trade transactions, i.e. 6.5 percent more H-gas than in 2010.

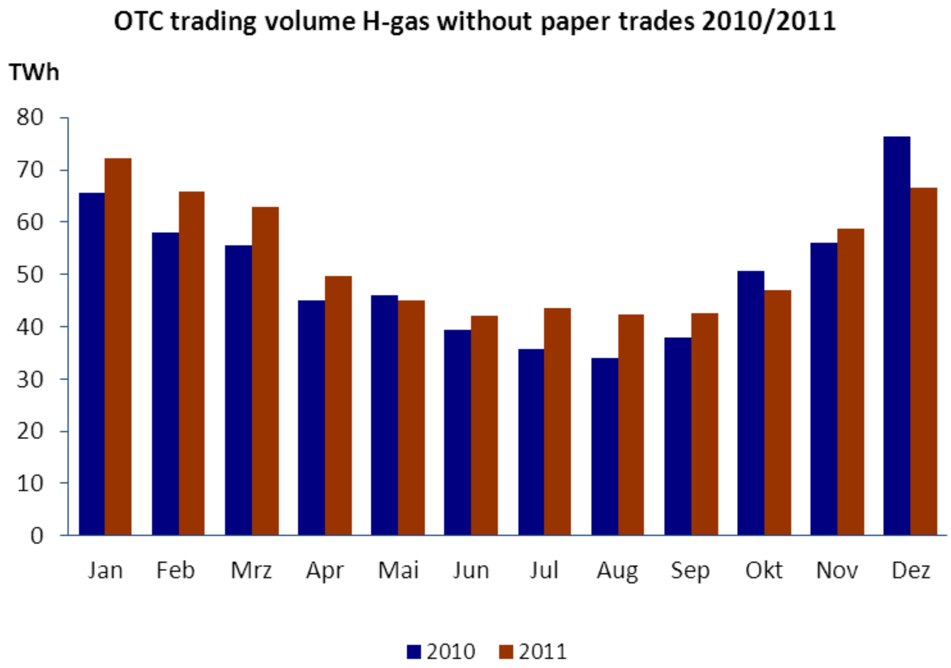

Diagram 126: H-gas trading volume without paper trades (physical settlement only)

On the other hand, OTC trading of L-gas has been stagnant. While the volume of OTC traded L-gas in the German market areas amounted to 194 TWh in 2010, an insignificantly higher volume of 196 TWh of L-gas was traded in 2011.

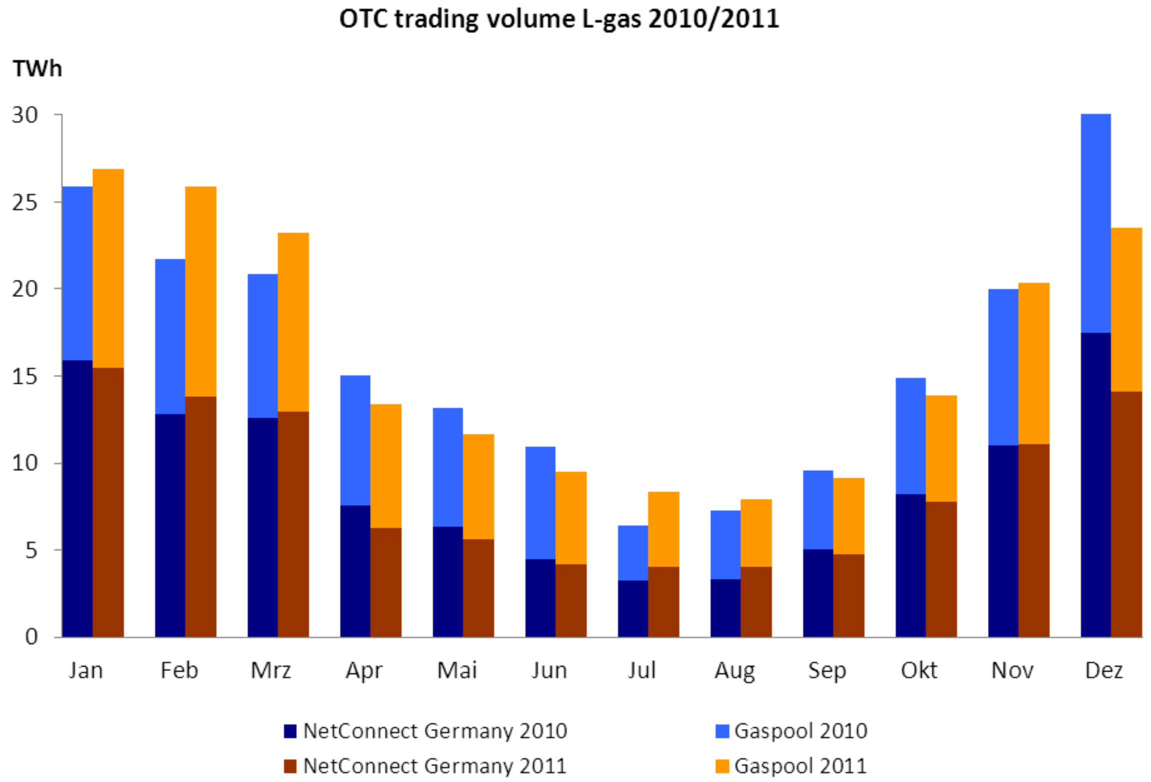

Diagram 127: L-gas trading volume in the NCG and Gaspool market areas. The trading volumes in the NCG market area up to and including March 2011 are the Open Grid Europe (L-gas) and Thyssengas (L-gas) trading volumes. The Gaspool trading volumes up to and including September 2011 correspond to the trading volumes of the Aequamus market area.

In the long term, the decline in the foreign and domestic production of L-gas will lead to a situation where natural gas can only be supplied to end consumers at high costs and where it will become economically reasonable for market areas to switch to H-gas. This trend can already be observed in the decline of L-gas volumes procured via the OTC trade. While the market participants still procured a total of 153 TWh of L-gas in 2010, the 2011 volume of L-gas procured via the OTC trade in the German market areas only amounted to 138 TWh.

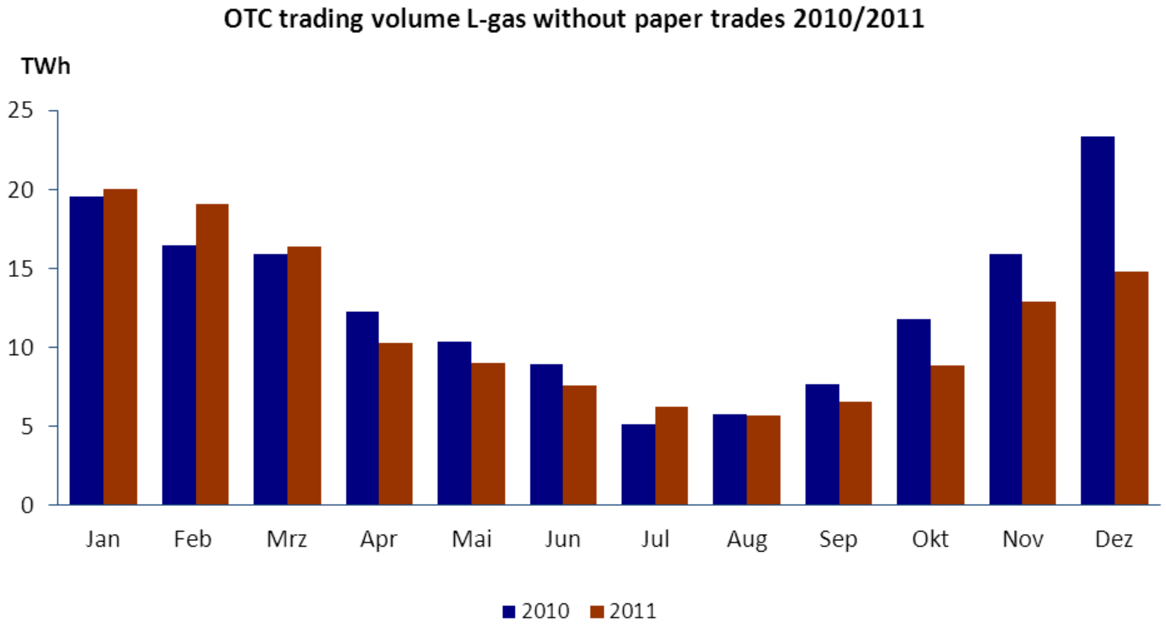

Diagram 128: L-gas trading volume without paper trades (physical settlement only)

Compared to 2010, the trading volumes for all types of natural gas at German trading platforms increased by 22.5 percent to 2066 TWh. The physical natural gas volumes procured increased by 3.2 percent to 777 TWh. Apart from the reduced number of market areas, this positive trend is probably also due to the new rules on the award of entry and exit capacities at the interconnection points between market areas and cross-border interconnection points under the Gas Network Access Ordinance (*Gas NZV*) of 3 September 2010 and the decision of the Federal Network Agency on capacity management and auction procedures in the gas sector (*KARLA Gas*) of 24 February 2011. Under Section 12 (1) of the GasNZV, transmission network operators have been obliged since 1 August 2011 to set up a joint platform for the award of entry and exit capacities. If transport customers do not use the capacities they have booked, they are obliged under Section 16 (1) of the GasNZV to offer them without delay as secondary capacities on a secondary capacity platform or to make them available to the transmission network operator which will again sell them as primary capacities. Non-nominated gas volumes are again made available to transport customers as day-ahead capacities. This has eliminated the incentives and opportunities for market participants on the distribution markets to deter potential competitors from entering the market by capacity hoarding or to hinder existing competitors. If sufficient transport capacities are available, market participants can also cover their gas requirements on a short-term basis on the wholesale market. The elimination of capacity bottlenecks thus also increases the attractiveness of the gas wholesale sector.

Another indicator of a trading platform's liquidity is the churn rate which indicates the ratio between traded and physically transferred natural gas volumes. High churn rates are an indication of high liquidity in a market. In 2010, the churn rates at the German virtual trading points for H- gas barely reached a value of three. The churn rates for L-gas were considerably lower and did not exceed a value of 1.8. The volumes traded at the NCG hub, which now covers all types of gas, therefore showed only a slight increase in comparison with the physically transferred volumes. Despite a growing number of market participants the churn rate only exceeded a value of three for a few months. At the Gaspool trading hub, which also covers all types of gas, the October 2011 churn rate fluctuated between two and three. The Belgian Zeebrugge hub, where a total of approx. 779 TWh were traded in 2011, had an annual average churn rate of 4.8[76].

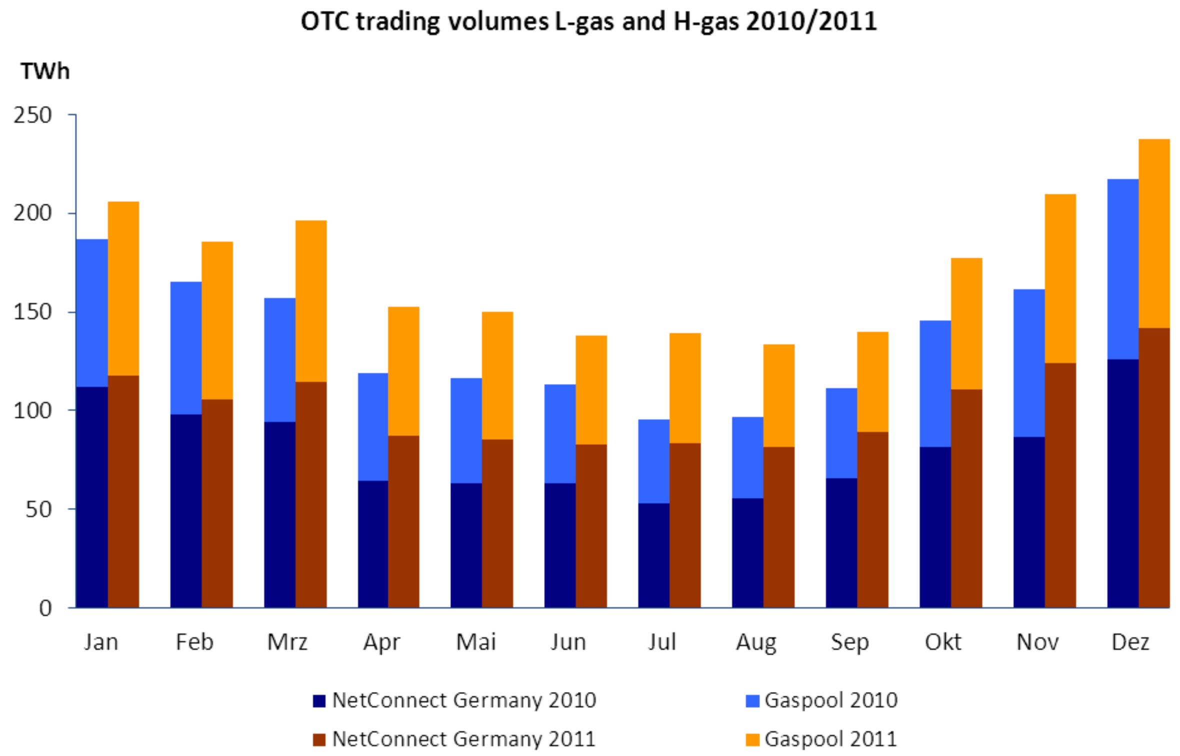

Diagram 129: L-gas and H-gas trading volumes in the NCG and Gaspool market areas. The trading volumes in the NCG market area up to and including March 2011 are the trading volumes generated by NetConnect Germany, Thyssengas (H-gas), Thyssengas (L-gas) and Open Grid Europe (L-gas). The Gaspool trading volumes up to and including September 2011 correspond to the trading volumes of the Gaspool and Aequamus market areas.

The participants in the wholesale sector also conclude parts of their OTC trading activities via broker platforms. As intermediaries between buyers and sellers, brokers bundle information on the demand and supply of natural gas spot market and products and derivatives.

The following data are based on the replies of five European brokers (2010: four) which together account for a major part of the European natural gas brokerage business.

[76] Huberator, Trading Volumes 2011, as indicated at www.huberator.com on 12 September 2012.

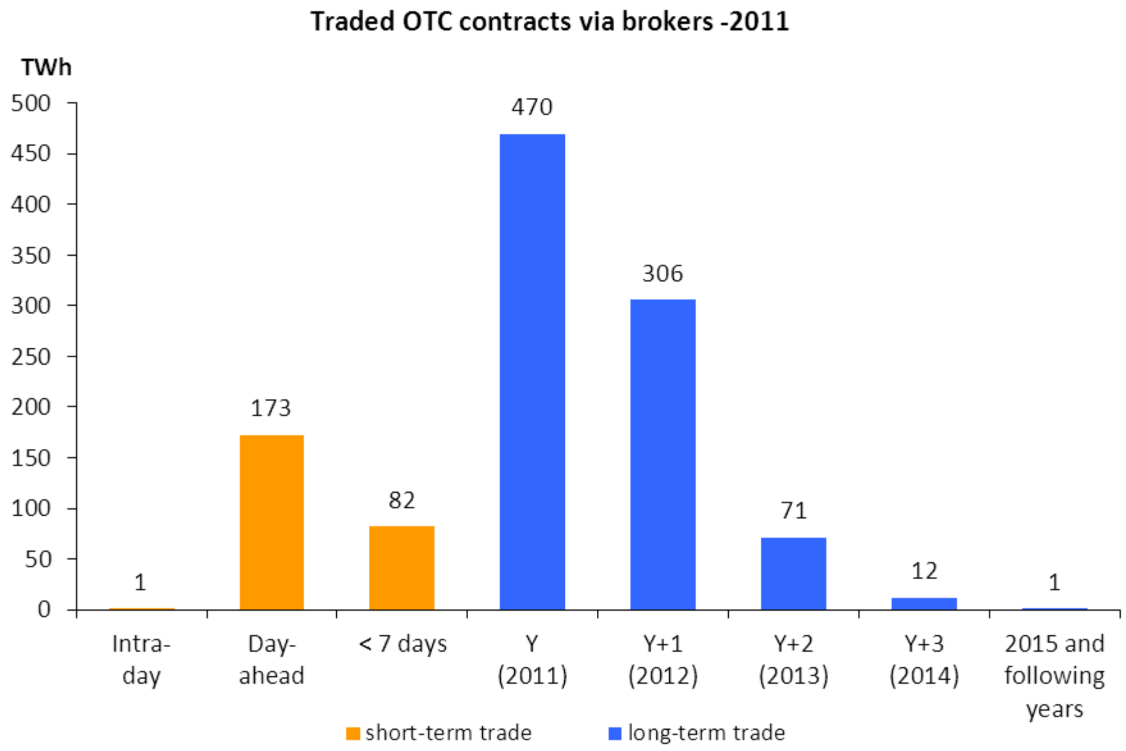

Diagram 130: Traded OTC contracts via brokers -2011

The volume of products traded via brokers in the futures market clearly exceed the trading volume in the spot market as futures contracts cover longer terms than spot market contracts and thus involve significantly larger trading volumes. Trading volumes in the futures market decrease with the increasing length of the delivery period. In 2011, the total volume of natural gas to be supplied to destinations in Germany traded via the abovementioned brokers amounted to 1114 TWh. This corresponds to approx. 54 percent of the OTC trading volume at the German virtual trading points. In 2010, the brokers who participated in the survey processed trading transactions with a total volume of 728 TWh (43 percent of the trading volume at the German virtual trading points). Due to the fact that, in preparing this report and the preceding monitoring reports, it has not been possible to survey all the brokers active in the natural gas trading business, no exact statement can be given as to the overall increase in broker trading. However, since the brokers surveyed process a significant share of the European brokerage business, it can be assumed, on the basis of the data available, that the purchase and sale of spot market products and derivatives via broker platforms is becoming increasingly attractive for market participants.

The development of exchange trading

At the Leipzig energy exchange EEX, spot market and futures contracts for natural gas can be traded anonymously. Since the launch of 24/7 trading on 30 May 2011, uninterrupted gas trading at the EEX spot market has now become possible. Spot market trading had so far only been possible between 8 am and 6 pm. On the spot market participants can trade natural gas volumes for the same day (within-day), one or two days ahead or for the following weekend. With the launch of 24/7 trading the EEX also introduced contracts with a minimum value of 1 MW (and multiples thereof) in addition to its 10 MW contracts. This enables companies to purchase or trade smaller volumes of gas at the exchange as well. At the same time the EEX extended its spot market trading to include the Dutch market area TTF (Title Transfer Facility) so that L-gas can now also be traded at the EEX. The increased attractiveness of spot market trade at the exchange is reflected by last year's trading volumes which rose by approx. ten percent to 23.1TWh.

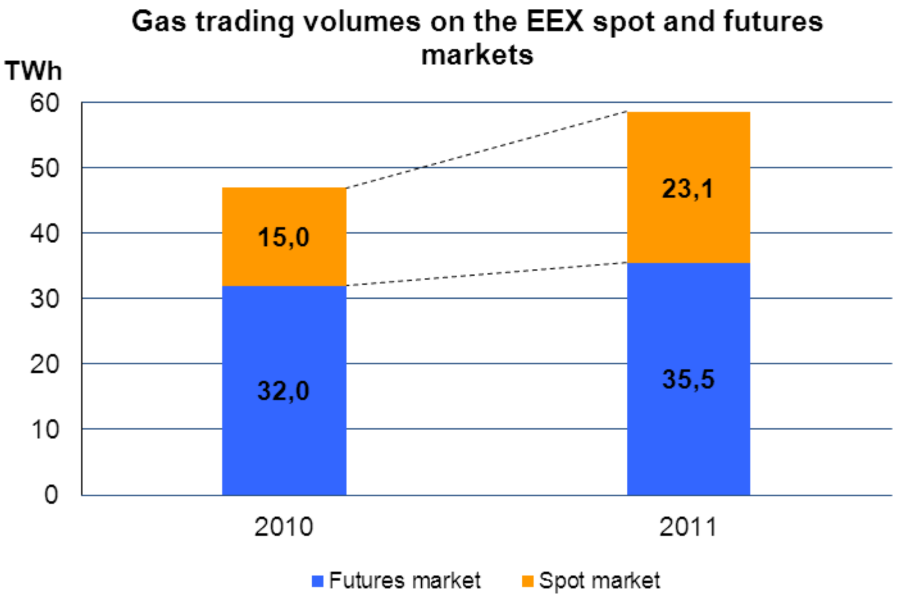

Diagram 131: Gas trading volumes on the EEX spot and futures markets from 2010 to 2011. Futures market: NCG and Gaspool. Spot market: NetConnect Germany, Gaspool and TTF. Source for spot market data: EEX[77].

The trade volumes at the EEX futures market also rose by eleven percent to 35.5 TWh. At least some of the increase could be attributable to the introduction of an incentive model which the EEX introduced in August 2011 in the futures market. Under the incentive model a bonus was to be paid out to the three most active participants in a specific month who achieved a monthly trading volume of more than one or two TWh. The incentive model ended at the end of September 2012.

The new framework conditions for trading at the futures and spot markets set up by the EEX and the development of the trading volumes at the exchange are generally to be considered a positive development. However, more than 97 percent of the natural gas volumes are still traded outside the exchange (OTC trade).

[77] EEX, press release of 12 January 2012: EEX review of 2011, available at www.eex.com.

Trading prices

On the whole, the daily reference prices for natural gas at the virtual virtual trading points Gaspool and NCG have only slightly increased during 2011. However, most of them are still higher than in 2010. They represent a volume-weighted average of the prices across all OTC transactions within one market area for 1 MW and 10 MW products for gas delivery days on the last trading day before physical settlement.

In contrast to this, the border prices [78] for natural gas, which reflect the price conditions agreed upon in the long-term supply contracts, continued to rise in the same way as in 2010. The border prices reflect the oil price trend on which the price formulae in the supply contracts are mainly based.

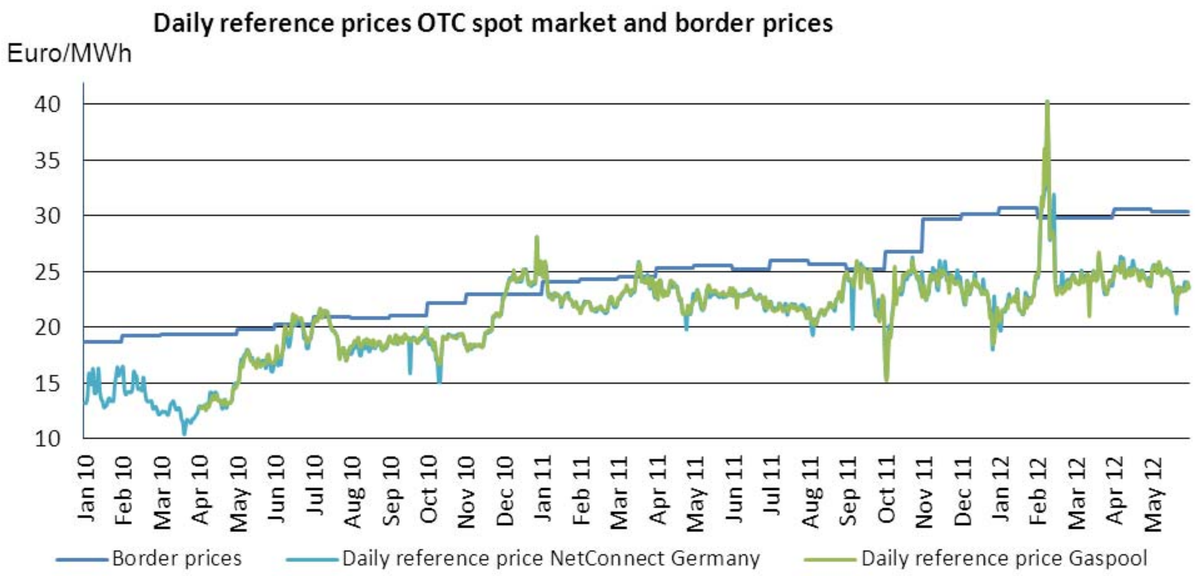

Diagram 132: Border prices and daily reference prices in the market areas. Source: NetConnect Germany, BAFA.

The difference between spot market prices and border prices has thus again increased considerably since November 2011. Whereas, in early 2011, the natural gas prices in the long-term supply contracts approximately equalled the spot market prices, companies paid up to 68 percent more in the fourth quarter of 2011 if they covered their requirements through long-term supply contracts, and not on the spot market.

The supply situation for natural gas in February 2012 had a direct impact on the daily reference prices. The low temperatures and the ensuing increase in natural gas consumption as well as the reduced amounts of gas fed into the German natural gas grids at the cross-border interconnection point Waidhaus led to an increase in the daily reference price in both market

[78] The Federal Office of Economics and Export Control (*Bundesamt für Wirtschaft und Ausfuhrkontrolle*, BAFA) calculates the statistical average of German natural gas imports by gas trading companies. The German tax on natural gas is not included.

areas from approx. 24 Euros/MWh at the end of January to 40 Euros/MWh on 8 February 2012.

Retail

Market coverage

The number of data submissions within the framework of the 2012 monitoring survey remains at a high level. In all market areas, a high level of market coverage was maintained, which in turn created a solid database for this section of the report on the gas market. The following information provides a brief overview of market coverage for gas, while certain sections include statements that go beyond the database used.

Gas transmission system operators

All 14 transmission system operators (TSOs) took part in the 2012 data survey. Market coverage in this area is thus at 100 percent.

Distribution system operators

The number of distribution system operators (DSOs) taking part in the data survey is comparable to the number of DSOs that took part in the 2011 survey. A total of 629 data reports were submitted for the 2012 survey. In addition, further surveys of the companies as well as information gathered through statistical methods was used to calculate the supply of gas to final consumers, including the supply by those companies that did not take part in the 2012 monitoring survey. Taking into account all of this information, a market coverage of over 95 percent was reached regarding the supply of gas to final consumers in Germany.

Wholesalers and suppliers

The number of data reports submitted by wholesalers and suppliers for the 2012 data survey continued to be at a high level, too. In this area, 726 data reports were submitted, which amounts to a market coverage of nearly 84 percent relative to the total volume of gas supplied to final consumers.

Importers and exporters

Within the framework of the 2012 survey, 41 gas importers and exporters submitted data reports. Here too, this amounts to a market coverage rate of nearly 100 percent.

Storage system operators

With 24 data reports submitted, market coverage in this area also remained at a high level relative to the previous year 2011; here, market coverage was at over 95 percent.

Market opening and competition

Delivery volumes of gas suppliers

The volume of gas delivered by gas suppliers to final consumers in the year 2011 amounts to 780.66 TWh. That is nearly 15 percent less than was supplied to final consumers in 2010. In particular in the area of private households, there was a pronounced decline in consumption, which is likely attributable for the most part to the relatively warm weather conditions in the periods January/February and November/December of the year 2011.

Based on the TSOs' output volume of 934.61 TWh in Germany in 2011, the calculated market coverage of the gas wholesalers and suppliers participating in the survey amounts to nearly 84 percent. As of 31 December 2011, gas suppliers in Germany delivered gas to approximately 13 million final consumers. Approximately 10.7 million final consumers belonged to the segment of household customers within the meaning of section 3 para 22 EnWG.

The following table shows the volumes delivered by gas suppliers in the years 2010 and 2011, broken down by category of consumer. As the deliveries recorded only account for nearly 84 percent of the market, the delivery volumes in the subcategories were projected to arrive at the total gas output volume of 934.61 TWh reported by German gas TSOs and DSOs. In a close analysis of gas deliveries by market area, the NCG market area accounts for a gas supply of 413.36 TWh. The market area of Gaspool accounts for a gas supply of 351.29 TWh.[79] In terms of the number of final consumers supplied, 7.49m final consumers fall under the NCG market area, while 5.24m final consumers fall under the Gaspool market area.

Category	2010		2011		
	Delivery volumes in TWh	Share of total volume in percent	Delivery volumes in TWh	Share of total volume in percent	Projected delivery volume in TWh (domestic gas consumption of 934.61 TWh equals 100%)
≤ 300 MWh/year	328.53	36.04	277.08	35.71	333.77
> 300 MWh/year ≤ 100,000 MWh/year	199.85	21.93	183.66	23.67	221.24
> 100,000 MWh/year	224.27	24.61	207.53	26.75	249.99
Gas-fired power plants	158.82	17.42	107.59	13.87	129.60
Total	**911.47**	**100**	**780.66**	**100**	**934.61**

Table 41: Gas delivery volumes to final consumers 2010 and 2011 by category of final consumer, according to

[79] The sum of gas deliveries to final consumers across market areas is smaller than the total volume of deliveries to final consumers because some gas suppliers did not break down their delivery volumes by market area. This also applies to the following number of final consumers.

Survey of gas wholesalers and suppliers[80]

Regarding the supply of final consumers with natural gas, the Bundeskartellamt principally differentiates between a market for the supply of standard load profile customers and a market for load-metered customers.

Standard load profile (SLP) customers are final consumers whose gas consumption is billed, in the absence of load metering, on the basis of a standard load profile. SLP customers were supplied a total of 321.23 TWh, while load-metered customers were supplied 437.92 TWh. The supply companies surveyed reported serving a total of 12.7m SLP customers and 65,300 load-metered customers in Germany.[81]

Output volumes of gas network operators

Gas network operators in Germany reported an output volume of 934.61 TWh in 2011. In particular for private households and small businesses, there was a significant decline in the volume of gas delivered. The analysis of output volumes in the individual market areas shows that the NCG market area accounts for 502.17 TWh, while the Gaspool market area accounts for 397.96 TWh.[82] In total, as of the relevant date of 31 December 2011, 13.42m metering points were registered by gas network operators. Approximately 11.89m metering points belonged to the segment of household customers within the meaning of section 3 para 22 EnWG. In terms of final consumers supplied, the NCG market area accounts for 7.7m metering points, while the Gaspool market area accounts for 5.47m metering points.

Category	2010		2011	
	Output volumes by gas TSOs and DSOs in TWh	Share of total volume in percent	Output volumes by gas TSOs and DSOs in TWh	Share of total volume in percent
≤ 300 MWh/year	354.52	34.94	312.44	33.45
> 300 MWh/year ≤ 100,000 MWh/year	224.59	22.14	192.99	20.66
> 100,000 MWh/year	284.97	28.09	304.85	32.64
Gas-fired power plants	150.42	14.83	123.80	13.25
Total	**1014.49**	**100**	**934.61**	**100**

Table 42: Output volumes for gas in 2010 and 2011 by category of final consumer according to survey of gas TSOs and DSOs.[83]

80 The sum of gas deliveries across individual categories is smaller than the total gas supply volume because some gas suppliers did not provide information on the individual categories.

81 The sum of gas deliveries to load-metered and SLP customers is smaller than the total volume of gas deliveries to final consumers because some gas suppliers did not break down delivery volumes by final consumer group. The same applies to the number of final consumers.

82 The sum of gas deliveries to final consumers across market areas is smaller than the total volume of gas delivered to final consumers, since some gas distribution system operators did not break down gas output volumes by market area. This also applies to the number of metering points.

83 The sum of gas deliveries across individual categories is smaller than the overall gas delivery volume because some gas network operators did not provide information on individual categories.

Category	2011		
	Number of metering points gas DSOs	Number of metering points gas TSOs	Number of metering points gas DSOs and TSOs
≤ 300 MWh/year	13,166,818	77	13,166,895
> 300 MWh/year ≤ 100,000 MWh/year	127,722	339	128,061
> 100,000 MWh/year	814	208	1,022
Gas-fired power plants	776	26	802
Total	**13,418,859**	**650**	**13,419,509**

Table 43: Number of gas metering points in 2011 by category of final consumer, according to survey of gas TSOs and DSOs.[84]

Default supply

In the data survey for the 2012 Monitoring Report, the gas suppliers were asked to submit information about the volume of gas supplied to final consumers within and outside of default supply. The following table depicts the share that default supply makes up of the total volume of gas delivered in the respective customer category. The gas supply to household customers within the meaning of section 3 para 22 EnWG amounted to 211.01 TWh in the year 2011; of that amount, 58.71 TWh were supplied within the framework of default supply.

The share of default supply relative to the overall supply volume increased slightly from 24.92 percent to 27.82 percent, since the volume of gas supplied outside of the default supply system declined more than the volume delivered within default supply during the year under review. In the category of "other final consumers", which includes all final consumers who are not household customers, the volume of gas delivered amounted to 549.18 TWh. Default supply accounted for 12.79 TWh, which translates into a default supply rate of 2.33 percent.

In the overall assessment, given a reported gas delivery volume of 760.19 TWh and a share of 71.50 TWh stemming from default supply, this results in a total default supply rate of 9.41 percent. In total, the share of default supply remained constant relative to that of previous years.

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[84] The sum of gas metering points across individual categories is smaller than the overall sum of gas metering points because some gas network operators did not provide information on individual categories.

A detailed analysis by market area produces similar results. In the NCG market area in 2011, a volume of 123.74 TWh was delivered to household customers within the meaning of section 3 para 22 EnWG (of which 27.4 percent under default supply contracts), while in the Gaspool market area, 83.67 TWh were delivered to such customers (of which 28.0 percent under default supply contracts).[85]

Natural gas suppliers delivered a total of 321.24 TWh of natural gas to SLP customers, of which 21.7 percent was accounted for by default supply. 437.92 TWh of gas was supplied to load-metered customers at a default supply rate of less than one percent.[86]

Category	Reporting Year	Delivery volume in TWh	Delivery volume default supply in TWh	Share of delivery volume in percent
Household customers	2007	199.60	72.34	36.24
	2008	236.01	69.58	29.48
	2009	228.00	61.21	26.85
	2010	273.91	68.26	24.92
	2011	**211.01**	**58.71**	**27.82**
Other final consumers	2007	638.40	20.86	3.27
	2008	669.14	17.84	2.61
	2009	615.66	16.36	2.66
	2010	602.66	13.88	2.30
	2011	**549.18**	**12.79**	**2.33**
Total	2007	838.00	93.20	11.12
	2008	905.15	87.06	9.62
	2009	843.66	77.57	9.19
	2010	876.57	82.14	9.37
	2011	**760.19**	**71.50**	**9.41**

Table 44: Delivery volumes of suppliers to customers receiving default supply services by customer category 2007-2011[87]

[85] The sum of gas deliveries to household customers across market areas is smaller than the total volume of gas deliveries to final consumers because some gas distribution network operators did not break down delivery volumes by market area.

86 The sum of gas deliveries to RLM and SLP customers is smaller than the total volume of gas deliveries to final consumers because some gas suppliers did not break down delivery volumes by final consumer group.

[87] The different value for the total gas delivery volume of 760.19 TWh is attributable to the incompleteness of information provided by gas suppliers regarding the question of supply within the framework of default supply, and should only be used in this context and in this analysis. In total a gas delivery volume of 780.66 TWh was recorded for 2011. See table "Gas delivery volumes to final consumers 2010 and 2011 by category of final consumer, according to survey of gas wholesalers and suppliers".

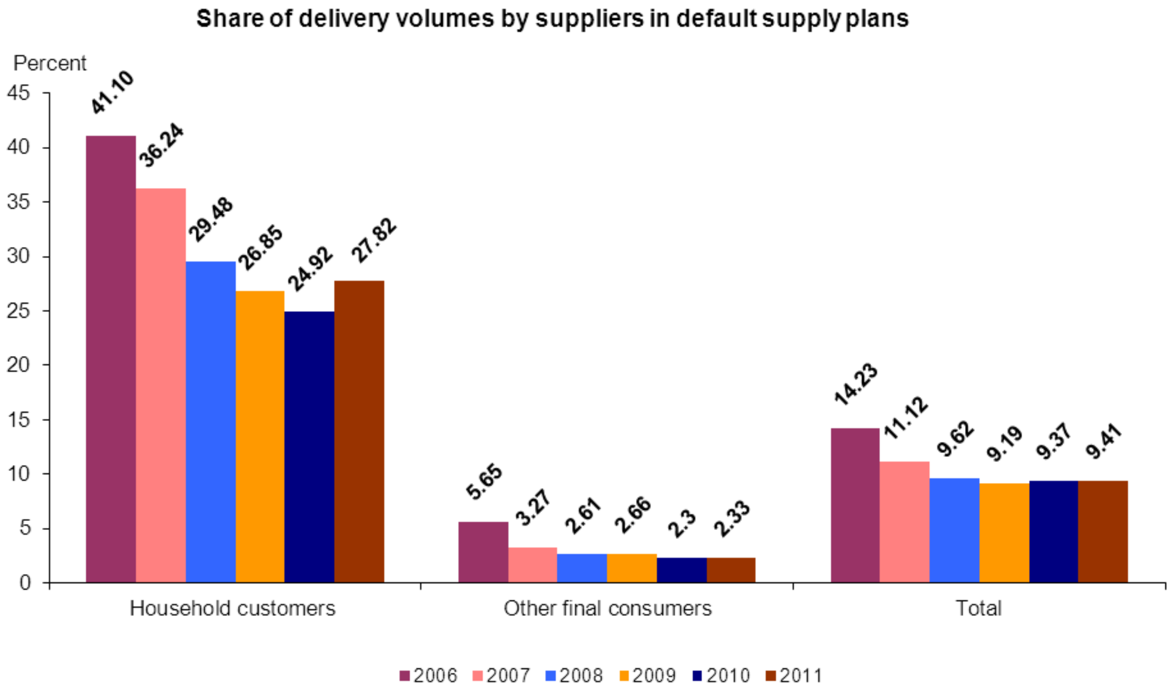

Figure 133: Share of delivery volumes by suppliers in default supply plans 2006-2011 according to customer category

Of the gas volume delivered to all final consumers, 7.72 percent was supplied to households receiving default supply services. 1.68 percent of the gas deliveries to final consumers was delivered to final consumers who are not households within the meaning of section 3 para 22 EnWG within the framework of default supply. The remaining 90.59 percent of the gas volume delivered to final consumers was delivered by natural gas suppliers outside of default supply contracts.

Supply of final consumers through default supplier in TWh

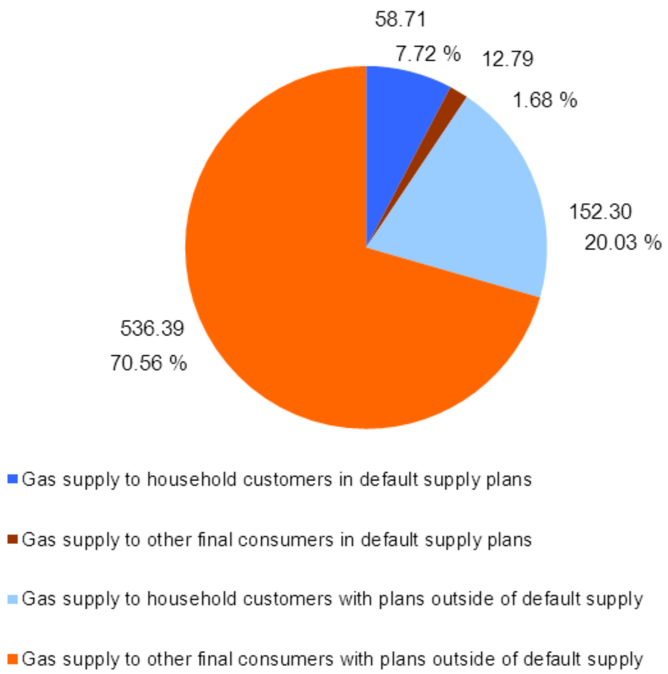

Figure 134: Supply of final consumers by default supplier in TWh in 2011 according to survey of gas wholesalers and suppliers

The following diagram illustrates the distribution in terms of numbers of final consumers supplied according to the various possibilities of gas supply. Approximately 4.1m household customers, or 31.69 percent, are supplied under default supply terms. Of that number, approximately 2.4m fall under the NCG market area and 1.7m under the Gaspool market area.

Compared to 2010, there was a decline of around nine percent across Germany in the number of household customers receiving default supply services.

Approximately 6.5m household customers receive gas under terms outside of default supply contracts, which corresponds to a rate of 50.32 percent. Approximately 3.3m household customers in the NCG market area and 2.2m household customers in the Gaspool market area received their natural gas outside the framework of default supply. Relative to 2010, this corresponds to a Germany-wide increase of approximately eight percent.

The incompleteness of company information means that this observation is not fully supportable, although it does indicate a trend, namely the shifting of approximately eight to nine percent of private households from default supply to contracts outside of default supply. Of the remaining final consumers, approximately 0.6 million receive gas under default supply terms, which corresponds to a rate of 4.69 percent. Another 1.7m final consumers, or 13.3 percent, receive gas under terms outside of default supply. A tenable comparison with data from previous years is not possible here, since the survey for the year 2011 achieved a significantly higher rate of market coverage than did the previous year's survey. As in the year 2010, however, the trend continued towards the supply of gas outside the system of default supply in all customer segments.

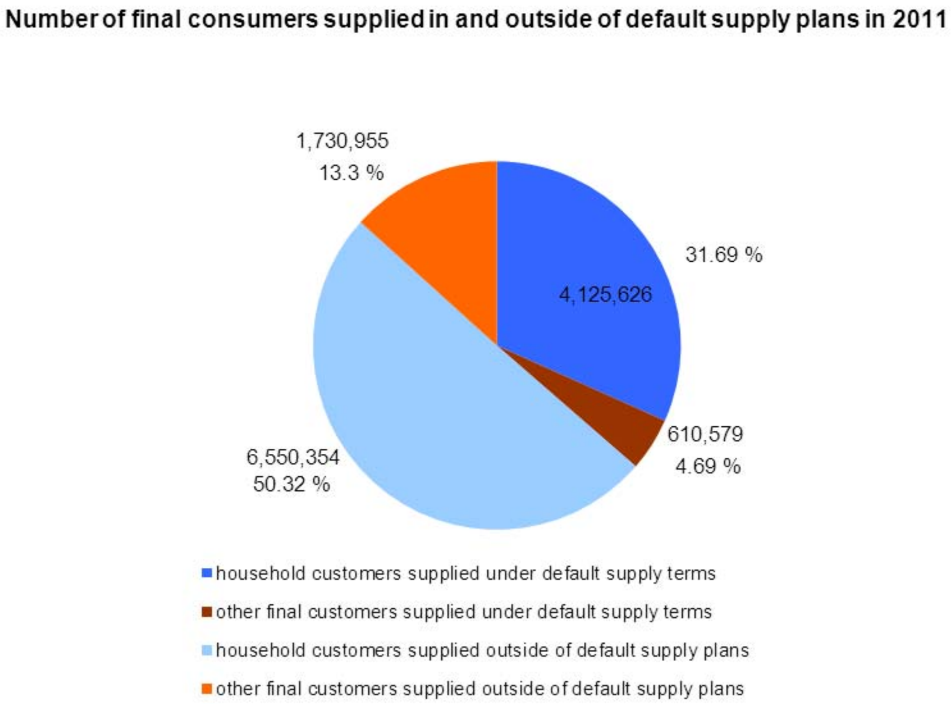

Figure 135: Number of final consumers supplied within and outside of default supply in 2011

Disconnection notices, disconnections, tariffs and contract terminations

With the amendment of the EnWG in the year 2011 (section 35(1) para 10 EnWG), the Bundesnetzagentur's monitoring powers were extended to cover, inter alia, the disconnection of supply to household customers. In 2011, the Bundesnetzagentur for the first time carried out surveys of the tariffs offered, and asked network operators and suppliers about threatened disconnections, disconnection orders 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) of the GasGVV entitles default suppliers to disconnect supplies to customers, in particular upon failure to fulfil payment obligations, after a corresponding reminder has been given. In contrast to the terms for a disconnection of the electricity supply, a minimum level of arrears of 100 euros is not required for a disconnection of the gas supply. In this area, too, there have previously been no comprehensive figures on disconnections of supply. Since this data was solicited for the first time, some companies were not able to provide precise figures, but instead submitted estimates. The reported data thus provides a usable representation.

Gas network operators were asked at how many metering points they had disconnected or reconnected supplies in the calendar year 2011 at the request of a supplier. A total of 375 network operators reported 33,595 disconnections.
Gas network operators billed suppliers an average amount of €36 for cutting off gas supplies, with actual costs charged ranging between €0 and €386.20.

At the same time, suppliers and wholesalers were asked how often in 2011 they had issued disconnection notices warning customers in arrears that they may be disconnected or had applied to the respective network operator for supplies to be disconnected. The companies reported that they had issued approximately 1.23 million disconnection notices to customers. Although the GasGVV ordinance does not stipulate a minimum level of arrears of €100 as a condition for cutting customers off, on average a disconnection notice was not issued until arrears reached €111. However, only in around 283,000 cases did disconnection notices result in gas being cut off by the respective network operator.

On average, suppliers charged their customers €44 for cutting off gas supplies, with the actual charge made ranging between €0 and €220.

	Number
Disconnection notices sent by suppliers	1,227,998
Disconnections applied for by suppliers	283,071
Disconnections by network operators	33,595

Table 45: Disconnections/Disconnection notices

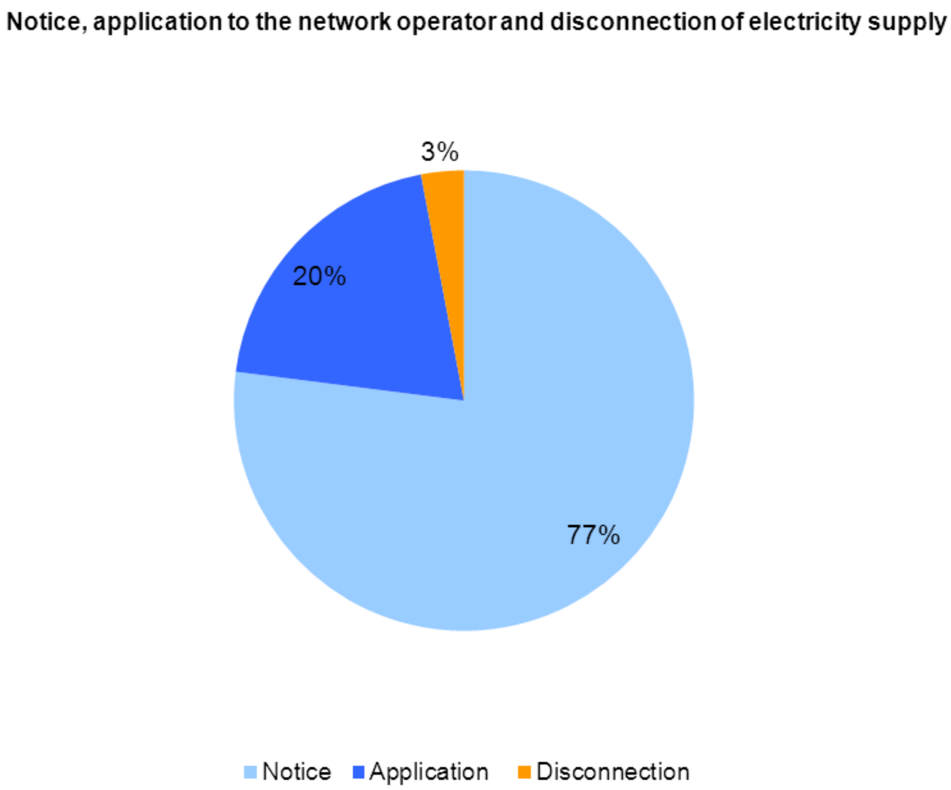

Figure 136: Disconnection notice, application to the network operator and disconnection of supply

Tariffs and terminations of contract

Under section 40(3) EnWG, suppliers are obligated to offer final consumers monthly, quarterly or semi-annual settlement. However, as is the case in the area of electricity, there is only negligible demand on the part of final consumers for such settlement options. The overwhelming majority of suppliers report no demand at all. In the gas sector, too, only few suppliers terminate service with their customers. In 2011, suppliers delivered approximately 20,000 notices of service termination to their customers. However, as in the electricity sector, the overwhelming majority of contracts appear to have been terminated by just a few, young inter-regionally operative companies, while the regional providers rarely or never terminated service with their customers.

Number of suppliers

A further indicator of well-functioning competition between gas suppliers, and thus of a greater degree of choice for gas customers, is the number of suppliers available per network area. Within the context of the 2012 monitoring survey, gas network operators were asked to report on the number of suppliers serving at least one final customer in their networks.

Since market opening and the creation of the legal basis for a well-functioning supplier switch, there has been a steady positive development in terms of the number of gas suppliers active in the various network areas. In over 70 percent of network areas already, 31 or more gas suppliers were available to final consumers. In 2010, this was true for only approximately 38% of networks. By now, in over 31 percent of networks, a final consumer can choose from over 50 gas suppliers. Only in less than one percent of network areas are there five utilities or fewer supplying gas to final consumers. In the year 2008, this level was still the norm.

A detailed analysis of gas suppliers active in the network areas shows similar results. In both market areas, well over half of the network areas have 31 or more providers supplying final consumers.

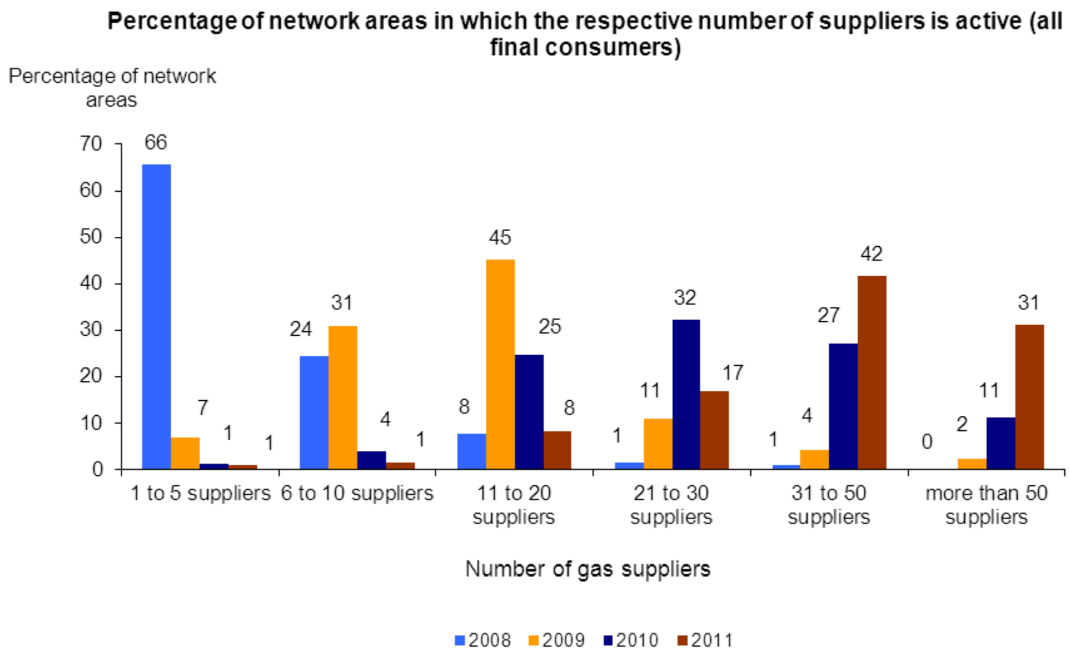

Figure 137: Percentage of network areas in which the respective number of suppliers is active (all final consumers) according to survey of DSOs 2008 - 2011

A separate examination of the customer category of household customers paints a picture that is similar to the above situation. In the majority of network areas, household customers are supplied by at least 31 different gas suppliers.

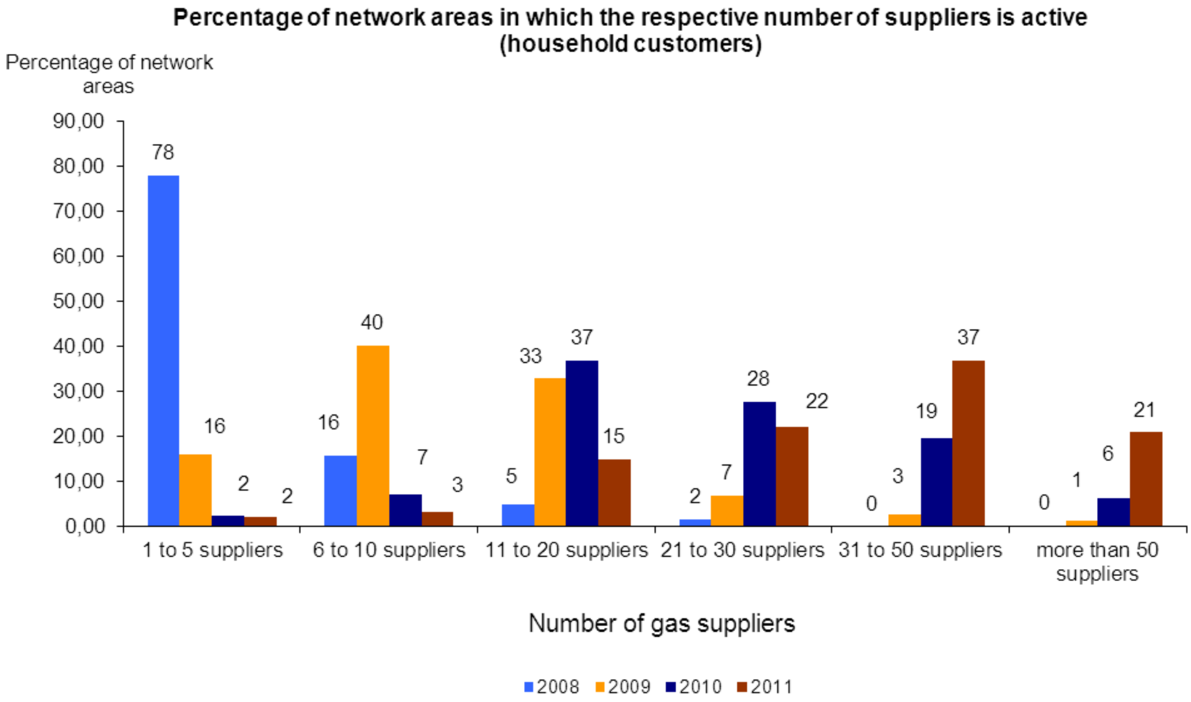

Figure 138: Percentage of network areas in which the respective number of suppliers is active (household customers) according to survey of gas DSOs 2008 – 2011

In the 2012 monitoring survey, gas suppliers were also asked to report the number of network areas in which they are active and in which they supply at least one final consumer.

Just over 33 percent of the suppliers active in Germany delivered natural gas in only one network area, while nearly two thirds of suppliers delivered gas to final consumers in two network areas or more. A positive development is the fact that more and more gas suppliers are delivering gas to customers in several network areas.

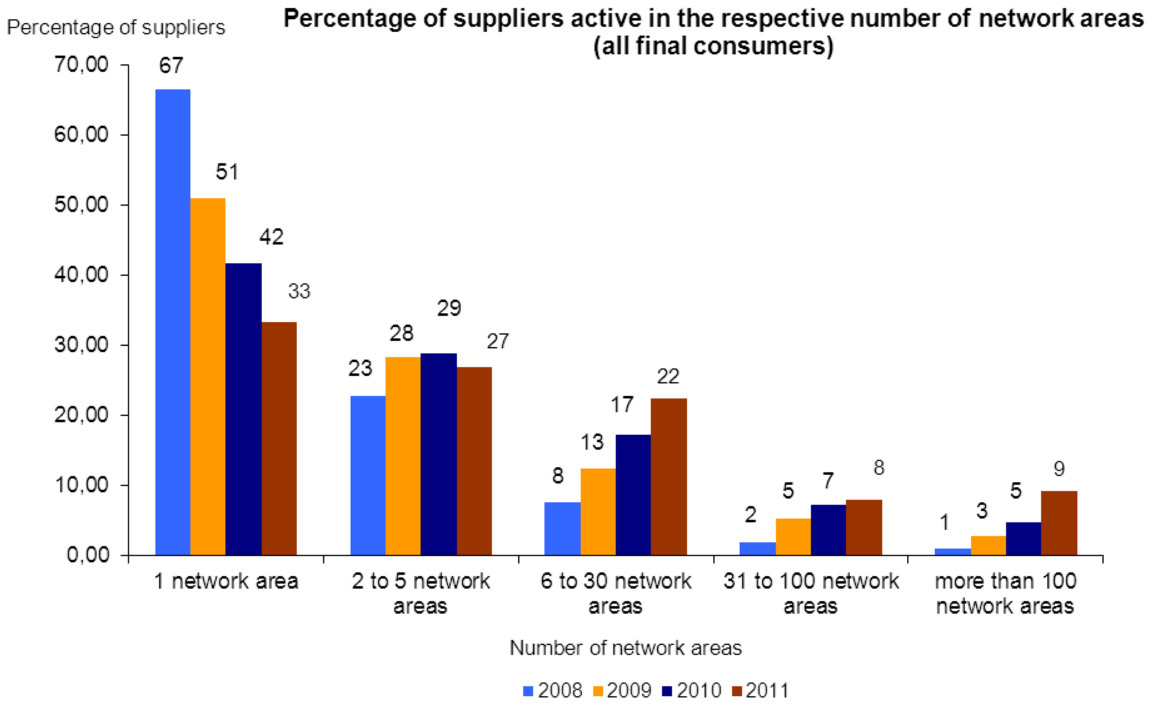

Figure 139: Percentage of gas suppliers active in the respective number of network areas (all final consumers), based on survey of gas wholesalers and suppliers 2008 - 2011

An examination of the customer category of household customers again shows a situation that is similar to the above depiction. In this customer segment as well, the gas suppliers are active in more and more network areas simultaneously.

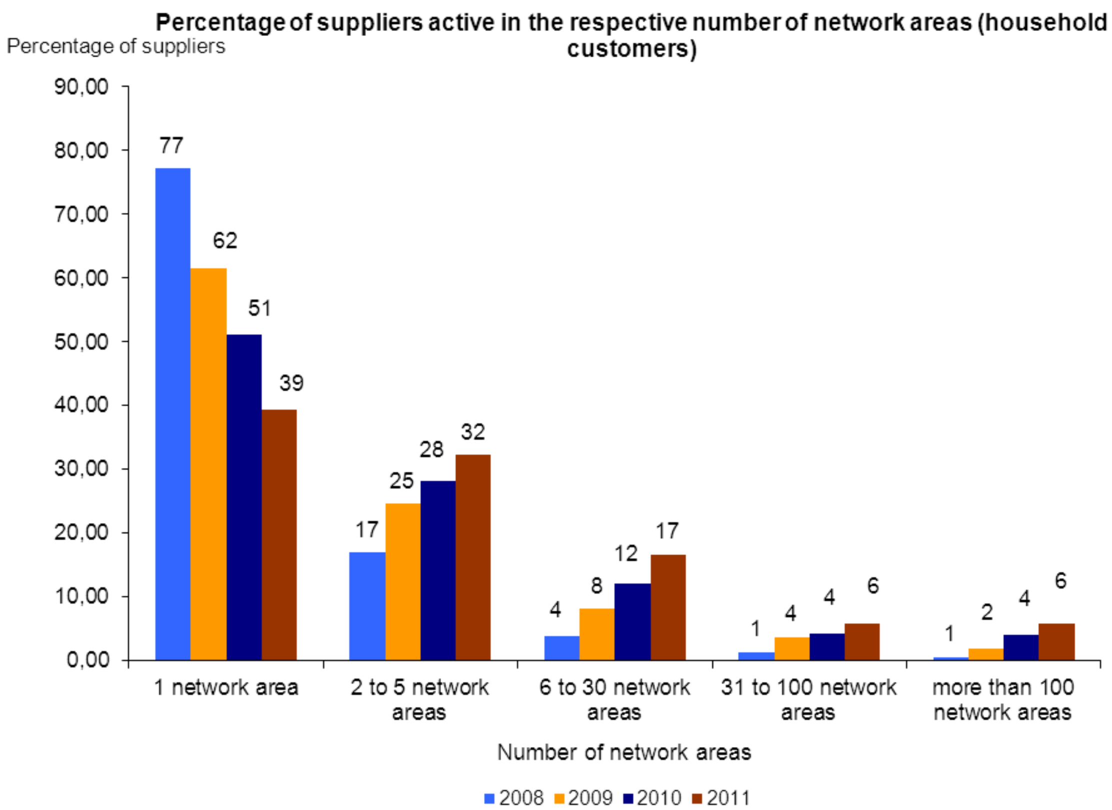

Figure 140: Percentage of gas suppliers active in the respective number of network areas (household customers), based on survey of gas wholesalers and suppliers 2008 – 2011

Contract structure and change of supplier

Final consumers can be supplied with gas in three different ways. Besides the option of default supply, the default supplier can also supply customers on special contract terms. With this supply option, the final customer stays with his current supplier but signs a new supply contract under special terms (change of contract).

Change of supplier refers to the process by which a final consumer at a metering point (eg the connection point in the building) changes his current supplier (old supplier) for a new supplier. Supplier switches resulting from customers moving into or out of a residence, or moving from one residence to another, or supply contracts transferred as a result of a concession change, are not considered to be changes of supplier in the analysis of customer categories. The number of changes of supplier is a key indicator for the development of competition in the retail sector in Germany.

According to the gas network operators surveyed for the 2012 monitoring, the supplier switching volume amounted to 107.86 TWh in 2011. Of that number, 50.5 TWh are accounted for by the NCG market area and 56.7 TWh by the Gaspool market area.[88]

Due to the significant decline in gas output volumes, the total supplier switching volume in absolute terms is slightly under the previous year's level. However, based on the reported output volume of 934.61 TWh, there is a relative supplier switching rate of 11.54 percent in 2011. This is a continuation of the positive trend in the number of supplier switches, which corresponds with the above-mentioned increase in the number of gas suppliers in the individual network areas. The greater selection of gas suppliers in the individual network areas, as described above, is leading increasing numbers of gas customers to take advantage of the option to change suppliers.

[88] The sum of supplier switching volumes across market areas is smaller than the overall supplier switching volume because some gas distribution network operators did not break down switching volumes by market area.

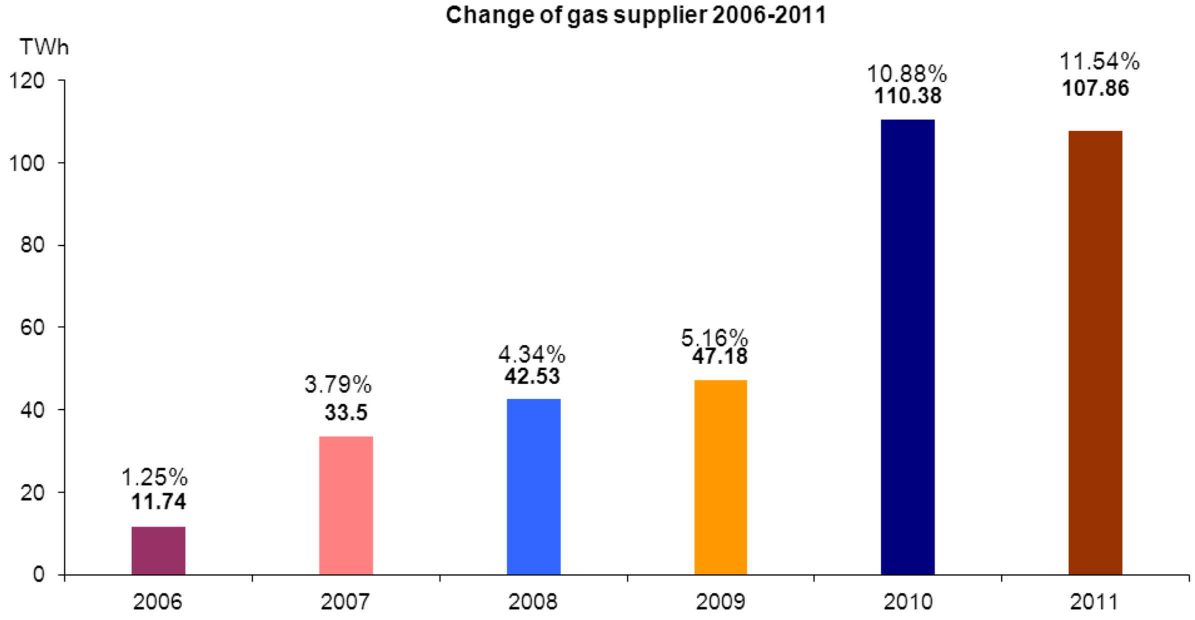

Figure 141: Development of supplier switching volumes in TWh and of the supplier switching rate (2006 - 2011) according to survey of gas TSOs and DSOs

Although in the year under review, the supplier switching volume is slightly lower than the corresponding volume in the year 2010, a look at the individual segments of final consumers shows that the trend continues to be positive. Although in the smallest category "≤ 300 MWh/year" the volume of gas output has declined substantially, the supplier switching volume in this area increased by over six TWh. Only in the category "> 100,000 MWh/year" was there a significant decline in the supplier switching volume in 2011, which also influenced the overall picture. The high fluctuations in supplier switching volumes in the category "> 100,000 MWh/year", however, are likely attributable primarily to the fact that industrial customers with a high demand for natural gas generally conclude longer term contracts with higher supply volumes and therefore do not change suppliers as often.

Category	2010 Change of supplier TSOs + DSOs in TWh	2011 Change of supplier TSOs + DSOs in TWh	Change 2010 to 2011 in TWh (+/-)
≤ 300 MWh/year	25.19	31.56	6.37
> 300 MWh/year ≤ 100,000 MWh/year	25.50	26.95	1.45
> 100,000 MWh/year	45.60	33.82	-11.78
Gas-fired power plants	14.09	15.80	1.71
Total	**110.38**	**107.86**	**-2.52**

Table 46: Total changes of supplier by final consumers in 2010 and 2011 by category of final consumers according to survey of gas TSOs and DSOs

Category	2010 Change of supplier TSOs + DSOs in TWh	Share of output volume in category in percent	2011 Change of supplier TSOs + DSOs in TWh	Share of output volume in category in percent
≤ 300 MWh/year	25.19	7.11	31.56	10.10
> 300 MWh/year ≤ 100,000 MWh/year	25.50	11.35	26.95	13.96
> 100,000 MWh/year	45.60	16	33.82	11.09
Gas-fired power plants	14.09	9.37	15.80	12.76
Total	**110.38**	**10.88**	**107.86**	**11.54**

Table 47: Share of total change of supplier by final gas consumers in 2010 and 2011 by category of final consumers in the total gas output volume according to survey of gas TSOs and DSOs

In 2011, the year under review, network operators reported a total of 1,272,648 changes of supplier which are distributed nearly equally in the NCG and Gaspool market areas. Compared to the previous year, the total number of changes of supplier thus increased by around 40 percent, or 370,450. Almost the entire increase in the number of supplier switches is accounted for by the customer category "≤ 300 MWh/year". Placed in relation to the number of 1,255,268 supplier switches, the switching volume of 31.56 TWh translates into an average switching volume of approximately 25,000 kWh per final consumer in the category of household customers and small businesses (≤ 300 MWh/year). The average switching volume is thus higher than the average consumption level of 20,000 kWh.

Altogether, the number-based supplier change rate of 9.45 percent is lower than the calculated volume-based supplier change rate of 11.54 percent.

Category	2011 Number of final consumers TSOs + DSOs	2011 Number of changes of supplier TSOs + DSOs	2011 Share of changes of supplier in the number of final consumers in percent
≤ 300 MWh/year	13,166,895	1,255,268	9.53
> 300 MWh/year ≤ 100,000 MWh/year	128,061	15,526	12.12
> 100,000 MWh/year	1,022	163	15.95
Gas-fired power plants	802	29	3.62
Total	**13,503,145**	**1,275,648**	**9.45**

Table 48: Number of final consumers and number of changes of supplier in 2011 by category of final consumers, according to survey of gas TSOs and DSOs

The positive overall picture is consolidated when household customers within the meaning of section 3 para 22 EnWG are viewed separately. Altogether, 939,743 household customers switched gas suppliers in 2011. That is nearly 220,000 household customers more than in the year 2010, which corresponds to an increase of over 20 percent. In 2011, a total of 152,091 household customers opted for a supplier other than the default supplier on moving to a new place of residence. This shows the increasing prevalence of a price-sensitive attitude among household customers who are taking the opportunity of moving house to go with a new supplier at their new place of residence.

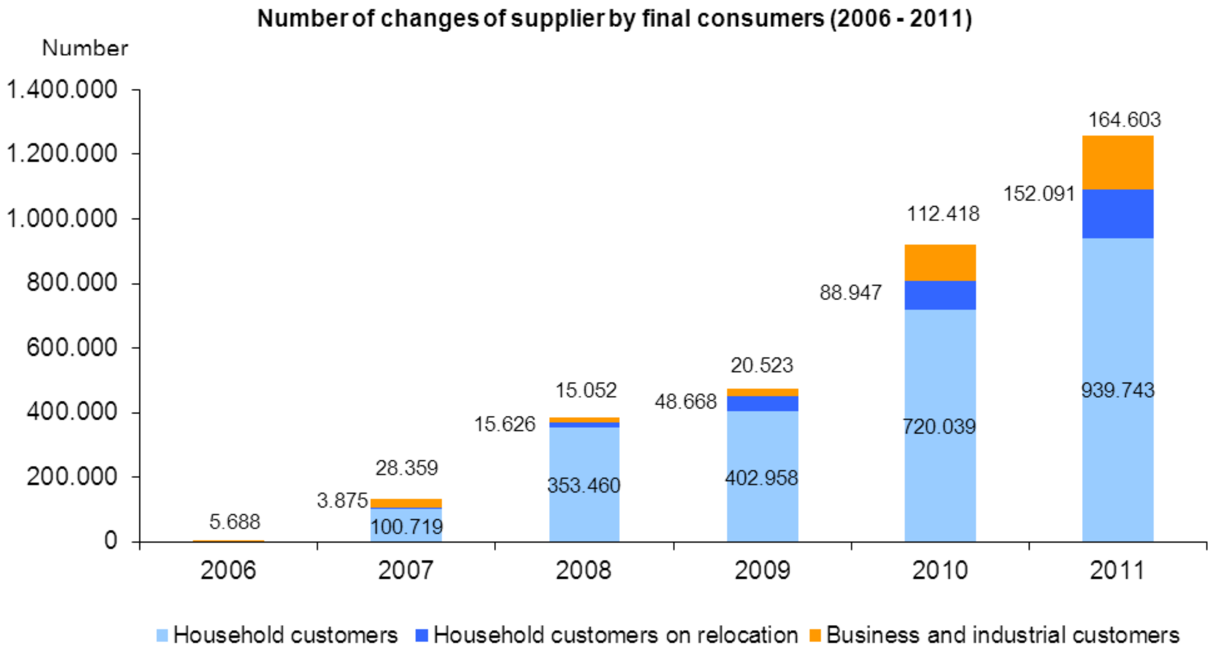

Figure 142: Number of changes of supplier by final consumers (2006 - 2011)

Looking at customer migration between the individual forms of supply and between individual groups of suppliers, it must be borne in mind that due to the fact that the Monitoring Report is not a full-scale survey, there is still a certain outstanding amount. As a result of the incompleteness of information supplied by companies, it cannot be ascertained how the missing customers are spread across the individual supplier groups. The following figure shows a differentiated view of the customers who left the area of default supply. One option is for the customer to choose a special tariff with the default supplier active in his network area (change of contract). The other option is for the customer to select a special tariff with a supplier other than the default supplier in his network area (switch of supplier).

As is evident from the following diagram, there is a sustained migration of customers away from default supply and from special contracts with the default supplier. The customer losses in these areas, however, could be offset among companies of all sizes by the acquisition of new gas customers. While in the previous year 2010 the small and medium-sized gas suppliers recorded net customer gains and the large and very large gas suppliers net customer losses, the overall picture in 2011 is significantly more homogeneous.

Gas suppliers with up to 5,000 metering points continue to show a very positive customer balance. In the mid-range, for the first time a slightly negative trend was evident, with the number of gas customers leaving higher than the number of new customers joining such companies. For the first time, large gas suppliers with more than 200,000 metering points showed a positive customer balance. In previous years, this company segment had seen the highest rate of departing gas customers. A reversal of this previous trend is an indication that the large gas suppliers are now responding to competition and offering gas customers more attractive terms.

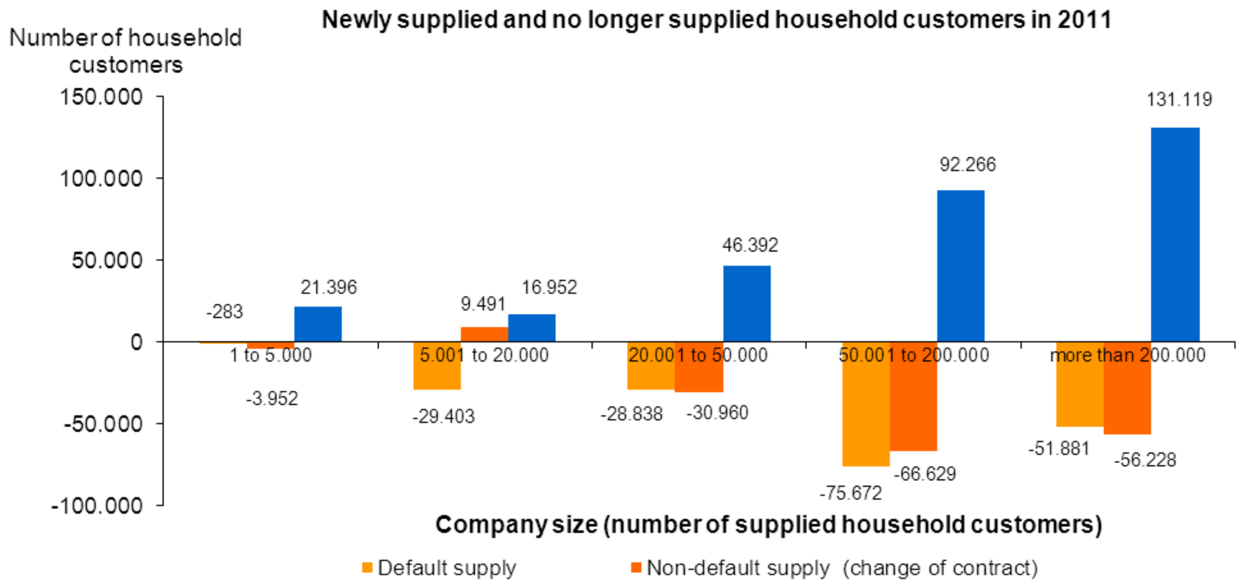

Figure 143: Newly supplied and no longer supplied household customers in 2011 – balances. It must be borne in mind here that it is not possible to counterbalance the figures for new and departing customers. The difference is based on incomplete information from the market players.

There is a sustained positive trend with regard to the structure of supply to household customers as of the relevant date of 31 December 2011. Altogether, 8.5 percent of household customers were supplied by a gas supplier other than the default supplier. Approximately 64 percent of household customers are supplied by their default supplier under a special contract. Nearly 28 percent of the gas volume delivered to household customers was delivered on the basis of default supply. Due to the substantial decline in gas consumption among household customers, this figure has increased slightly relative to the year 2010. It is also evident that many special contract customers, eg heating gas customers, are taking advantage of the possibility to switch suppliers and terminating contracts with their previous default supplier in order to sign on with a competitor.

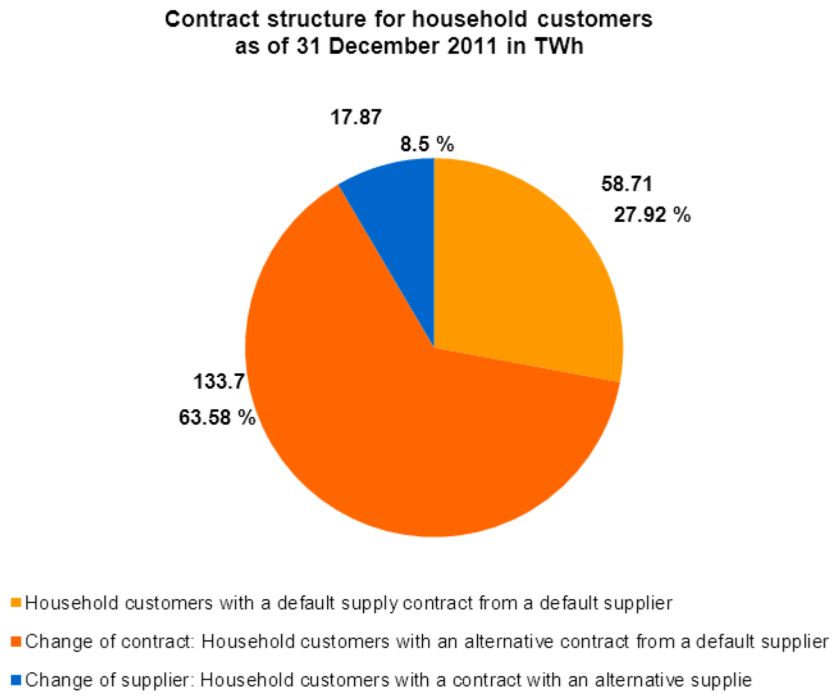

Figure 144: Contract structure for household customers according to survey of wholesalers and suppliers, as of 31 December 2011

Price level

In the 2012 monitoring survey, wholesalers and suppliers were asked to submit to the Bundesnetzagentur the average retail price level of their company in ct/kWh, as of 1 April 2012, for the customer categories listed. The overall price level had to take into account all fixed and variable price components charged to the final consumer, including kilowatt-hour price, service price (load-metered customers), base price and price for metering and billing. In addition, an estimated breakdown of the price was required into average net network tariff including upstream network costs, average charge for billing, metering and meter operations, as well as average concession fees, current gas tax and average value added tax. The average value for the price component energy procurement and supply was also requested, including the supplier's margin.

Household customers can be supplied with gas in three different ways. Besides gas supply within the framework of default supply according to default supply tariffs, two other possibilities of supply are particularly relevant in terms of competition. The supply of gas outside of the default supply structure but still in the established network area is considered supply under change of contract terms. With this supply option, the household customer stays with his current supplier, but signs a new supply contract under special terms. Supply outside of the default supply network area means that the household customer signs a supply contract with a new supplier according to special terms. This is considered supply at switch of supplier rates.

To calculate the volume-weighted average values, for each customer category the companies' sales volumes were multiplied by the respective price components, aggregated and divided by the total sales volume of the gas suppliers. In the customer category "household customers", volumes sold to household customers as reported in the survey by wholesalers and suppliers were used for the weighting. The weighting of the price components in the customer category "business customers" is based on the volumes sold to the customer category "consumption volumes between 300 MWh/year and 100,000 MWh/year", as reported by wholesalers and suppliers. The weighting of the price components in the customer category "industrial customers" is based on the volume of sales to the customer category "consumption volumes >100,000 MWh/year", as reported by wholesalers and suppliers.

For reasons of comparability with previous years, the diagrams combine the average net network tariff, including the billing charge, with the average charges for metering and meter operations as part of the same sum. The tables, however, show separate individual figures as a partial value of the average net network tariff (including charge for billing, metering and meter operations).

The evaluation of the questionnaires sent to the gas suppliers produced the following results:

Business / industrial customers

As of the relevant date of 1 April 2012, gas prices in the segment of business and industrial customers had risen again. In the segments "supply at change of contract tariffs" as well as "supply at change of supplier tariffs" there was a steady price increase, with some of the prices reaching or exceeding the highest level recorded to date, ie that of 1 April 2009. In the category "supply of business customers at change of contract tariffs", the volume-weighted gas price increased within one year from 5.71 ct/kWh to 6.26 ct/kWh. That amounts to an increase of the volume-weighted gas price by nearly ten percent. The biggest share, just over 57 percent, was accounted for by the costs for energy procurement and supply, ie by the product itself. Within one year, these costs increased by approximately 13 percent to 3.58 ct/kWh in absolute terms.

Relevant date:1 April 2012	Arithmetic average in ct/kWh	Share of total value in percent	Volume-weighted average in ct/kWh	Share of total value in percent
Average net network tariff including upstream network costs in ct/kWh	1.04	16.67	1.05	16.77
Average charge for billing in ct/kWh	0.01	0.16	0.01	0.16
Average charge for metering in ct/kWh	0.01	0.16	0.01	0.16
Average charge for metering operations in ct/kWh	0.02	0.32	0.02	0.32
Average concession fees in ct/kWh	0.06	0.96	0.04	0.64
Current gas tax in ct/kWh	0.55	8.81	0.55	8.79
Average VAT in ct/kWh	1.00	16.03	1.00	15.97
Average price component for energy procurement and supply in ct/kWh	3.55	56.89	3.58	57.19
Average total price in ct/kWh	**6.24**	**100**	**6.26**	**100**

Table 49: Average retail price level for category business customers with change of contract tariffs. Prices as of 1 April 2012, according to survey of gas wholesalers and suppliers

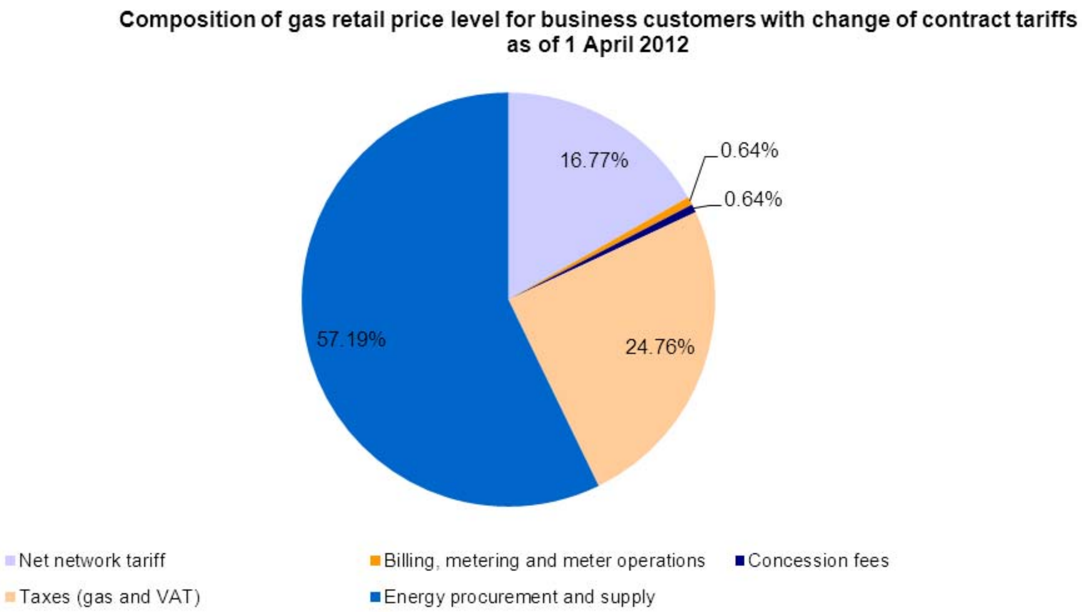

Figure 145: Composition of volume-weighted gas retail price level for business customers with change of contract tariffs. Prices as of 1 April 2012 according to survey of gas wholesalers and suppliers

For business customers supplied at change of supplier tariffs the volume-weighted gas price increased from 5.49 ct/kWh to 6.12 ct/kWh within one year. This amounts to an increase of the volume-weighted gas price by nearly twelve percent. Just over 56 percent of the volume-weighted average price was accounted for by the costs for energy procurement and supply.

Within one year, these costs increased by approximately 16 percent to 3.44 ct/kWh in absolute terms.

Relevant date: 1 April 2012	Arithmetic average in ct/kWh	Share of total value in percent	Volume-weighted average in ct/kWh	Share of total value in percent
Average net network tariff including up-stream network costs in ct/kWh	1.04	16.97	1.05	17.16
Average charge for billing in ct/kWh	0.01	0.16	0.01	0.16
Average charge for metering in ct/kWh	0.01	0.16	0.01	0.16
Average charge for meter operations in ct/kWh	0.02	0.33	0.02	0.33
Average concession fees in ct/kWh	0.06	0.98	0.04	0.65
Current gas tax in ct/kWh	0.55	8.97	0.55	8.99
Average VAT in ct/kWh	1.00	16.31	1.00	16.34
Average price component for energy pro-curement and supply in ct/kWh	3.44	56.12	3.44	56.21
Average total price in ct/kWh	**6.13**	**100**	**6.12**	**100**

Table 50: Average retail price level for the category of business customers with change of supplier tariffs. Prices as of 1 April 2012, according to survey of gas wholesalers and suppliers

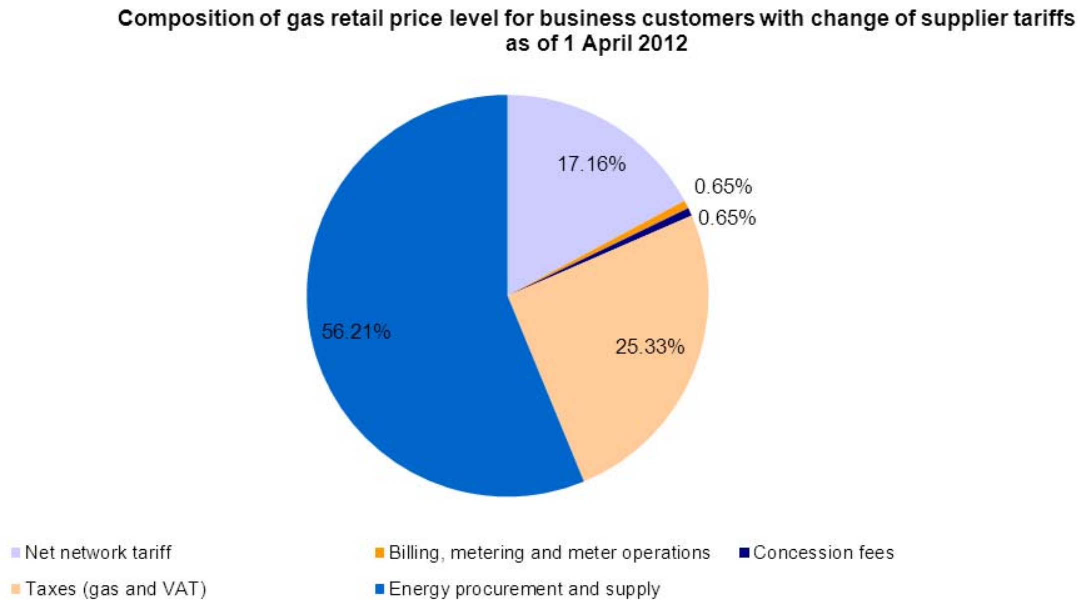

Figure 146: Composition of volume-weighted gas retail price level for business customers with change of supplier tariffs. Prices as of 1 April 2012 according to survey of gas wholesalers and suppliers

For industrial customers supplied at change of contract tariffs the volume-weighted gas price increased from 4.26 ct/kWh to 4.40 ct/kWh within one year. That amounts to an increase of the volume-weighted gas price by around four percent. Nearly 67 percent of the volume-weighted average price was accounted for by the costs for energy procurement and supply. Within one year, these costs increased by approximately ten percent to 2.94 ct/kWh in absolute terms.

Relevant date: 1 April 2012	Arithmetic average in ct/kWh	Share of total value in percent	Volume-weighted average in ct/kWh	Share of total value in percent
Average net network tariff including upstream network costs in ct/kWh	0.33	7.16	0.21	4.77
Average charge for billing in ct/kWh	0.00	0.00	0.0003	0.01
Average charge for metering in ct/kWh	0.00	0.00	0.0004	0.01
Average charge for meter operations in ct/kWh	0.00	0.00	0.0013	0.03
Current gas tax in ct/kWh	0.55	11.93	0.55	12.49
Average VAT in ct/kWh	0.74	16.05	0.70	15.90
Average price component for energy procurement and supply in ct/kWh	2.99	64.86	2.94	66.79
Average total price in ct/kWh	**4.61**	**100**	**4.40**	**100**

Table 51: Average retail price level for the category of industrial customers with change of contract tariffs. Prices as of 1 April 2012 according to survey of gas wholesalers and suppliers

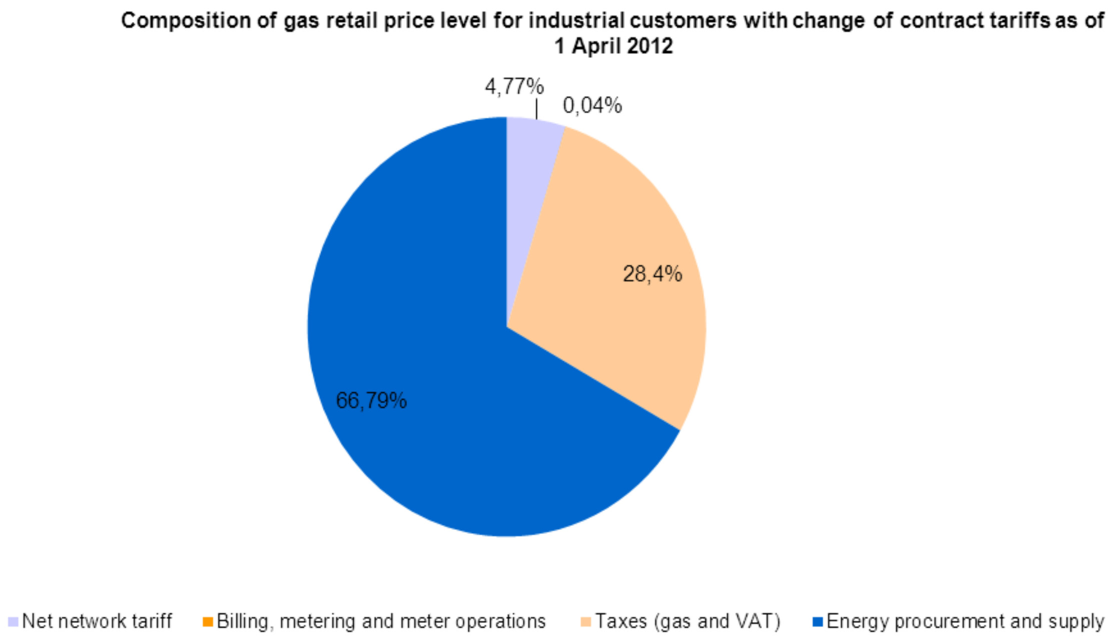

Figure 147: Composition of volume-weighted gas retail price level for industrial customers with change of contract tariffs. Prices as of 1 April 2012 according to survey of gas wholesalers and suppliers

For industrial customers supplied at change of supplier tariffs the volume-weighted gas price relative to the previous year increased from 4.19 ct/kWh to 4.49 ct/kWh. That amounts to an increase by approximately seven percent. Just over 67 percent of the volume-weighted average price was accounted for by the costs for energy procurement and supply. Within one year, these costs increased by approximately 15 percent to 3.03 ct/kWh in absolute terms.

Relevant date: 1 April 2012	Arithmetic average in ct/kWh	Share of total value in percent	Volume-weighted average in ct/kWh	Share of total value in percent
Average net network tariff including upstream network costs in ct/kWh	0.33	7.10	0.21	4.67
Average charge for billing in ct/kWh	0.00	0.00	0.0003	0.01
Average charge for metering in ct/kWh	0.00	0.00	0.0004	0.01
Average charge for meter operations in ct/kWh	0.00	0.00	0.0013	0.03
Current gas tax in ct/kWh	0.55	11.83	0.55	12.24
Average VAT in ct/kWh	0.74	15.91	0.70	15.58
Average price component for energy procurement and supply in ct/kWh	3.03	65.16	3.03	67.45
Average total price in ct/kWh	**4.65**	**100**	**4.49**	**100**

Table 52: Average retail price level for the category of industrial customers with change of supplier tariffs. Prices as of 1 April 2012, according to survey of gas wholesalers and suppliers

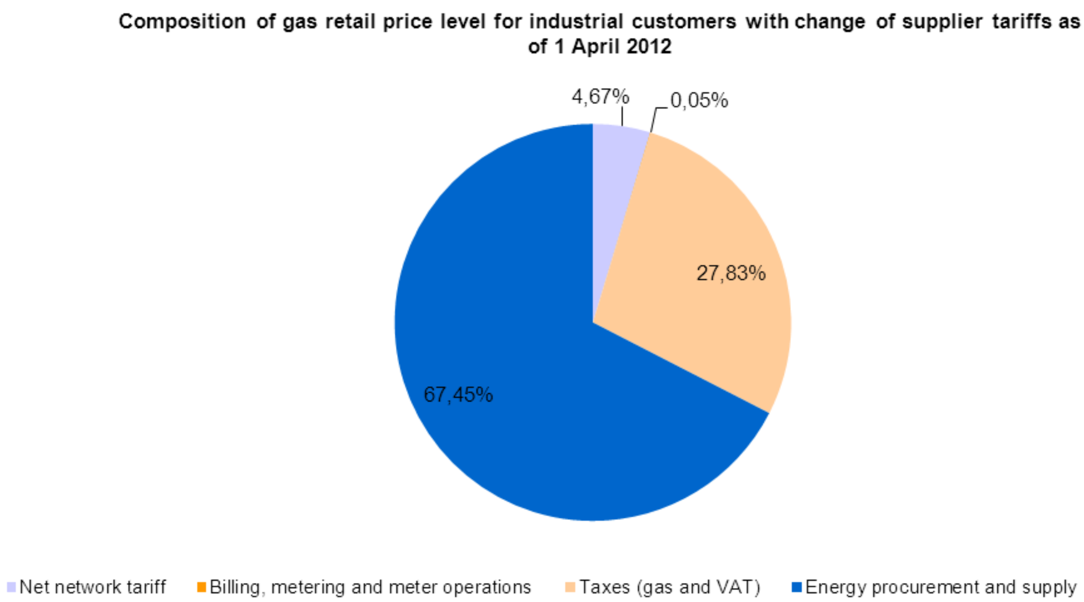

Figure 148: Composition of volume-weighted gas retail price level for industrial customers with change of supplier tariffs. Prices as of 1 April 2012 according to survey of gas wholesalers and suppliers

Looking at multiannual time series of the gas price for business and industrial customers, both supply categories show a trend towards a higher gas price. For the supply of gas according to change of contract tariffs the gas price level for industrial customers remains below the level of 1 April 2009, the highest level recorded in the surveys. In the area of supply at change of supplier tariffs the gas price on 1 April 2012 reached a new peak.

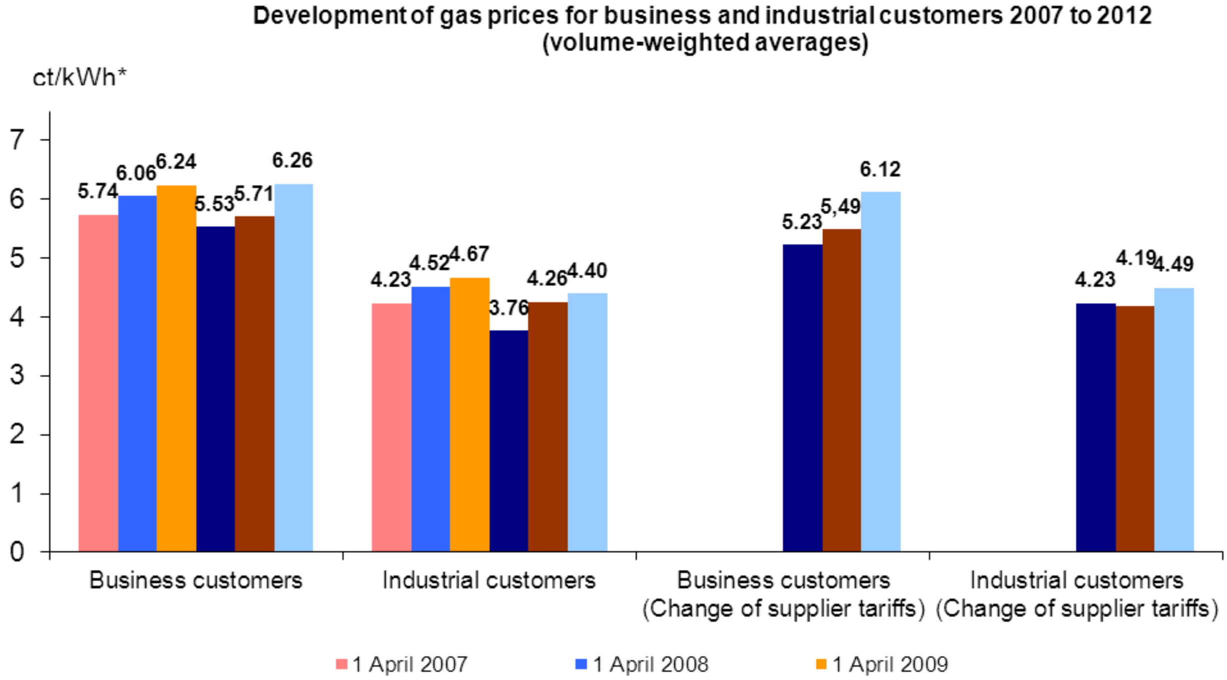

Figure 149: Development of volume-weighted gas prices for business and industrial customers 2007 – 2012. Prices as of 1 April 2012 according to survey of gas wholesalers and suppliers

Looking at multiannual time series of the price component energy procurement and supply, both supply categories for business and industrial customers show an upward trend. In particular with regard to supply according to change of supplier tariffs the costs for energy procurement and supply reached a new peak level.

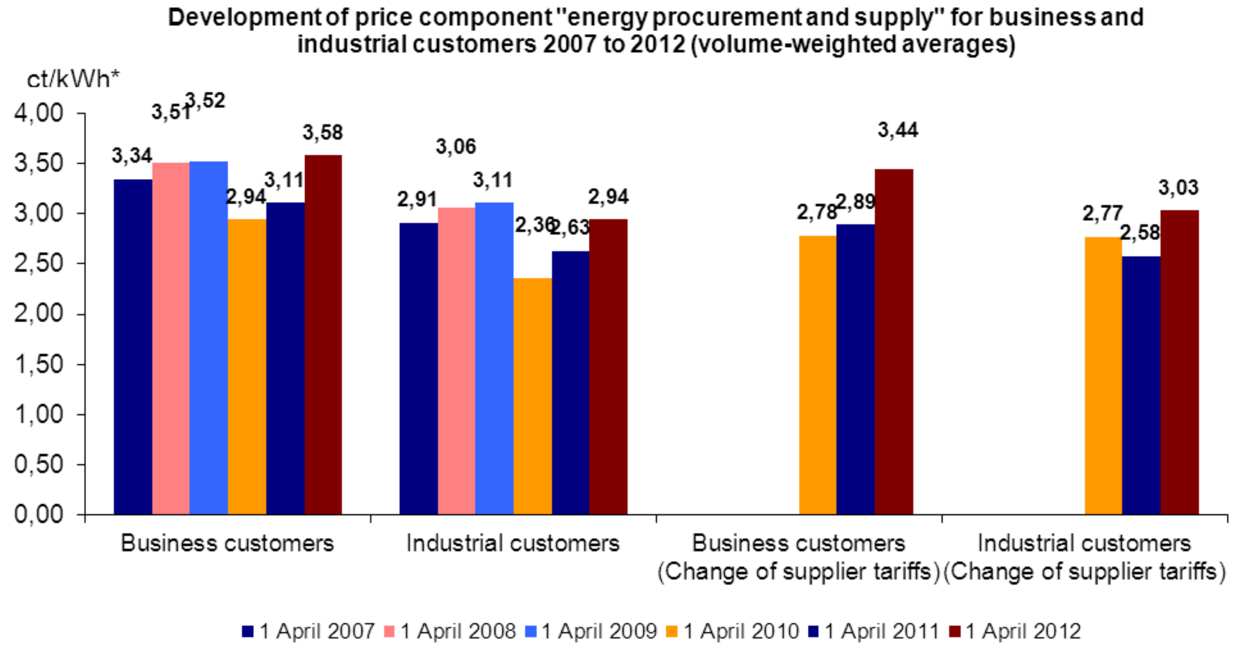

Figure 150: Development of price component "energy procurement and supply" for business and industrial customers 2007 – 2012. Prices as of 1 April 2012 according to survey of gas wholesalers and suppliers

Household customers

As of the relevant date 1 April 2012, gas prices in the household customer segment had risen once again. In all three supply segments there was a steady price increase, with some prices reaching or exceeding the highest recorded level, attained on 1 April 2009.

In the area of default supply services the volume-weighted gas price increased from 6.64 ct/kWh to 6.95 ct/kWh within one year. That amounts to an increase by nearly five percent. The costs for energy procurement and supply together make up a share of nearly 54 percent of the total price. Within one year, these costs increased by approximately twelve percent to 3.75 ct/kWh in absolute terms. Significant price reductions can be achieved by a change of contract with the current supplier or by switching an old supplier for a new one.

Relevant date: 1 April 2012	Arithmetic average in ct/kWh	Share of total value in percent	Volume-weighted average in ct/kWh	Share of total value in percent
Average net network tariff including upstream network costs in ct/kWh	1.23	17.06	1.16	16.69
Average charge for billing in ct/kWh	0.05	0.69	0.05	0.72
Average charge for metering in ct/kWh	0.02	0.28	0.02	0.29
Average charge for meter operations in ct/kWh	0.05	0.69	0.05	0.72
Average concession fees in ct/kWh	0.25	3.47	0.26	3.74
Current gas tax in ct/kWh	0.55	7.63	0.55	7.91
Average VAT in ct/kWh	1.15	15.95	1.11	15.97
Average price component for energy procurement and supply in ct/kWh	3.91	54.23	3.75	53.96
Average total price in ct/kWh	**7.21**	**100**	**6.95**	**100**

Table 53: Average retail price level for the category of household customers receiving default supply services. Prices as of 1 April 2012 according to survey of gas wholesalers and suppliers

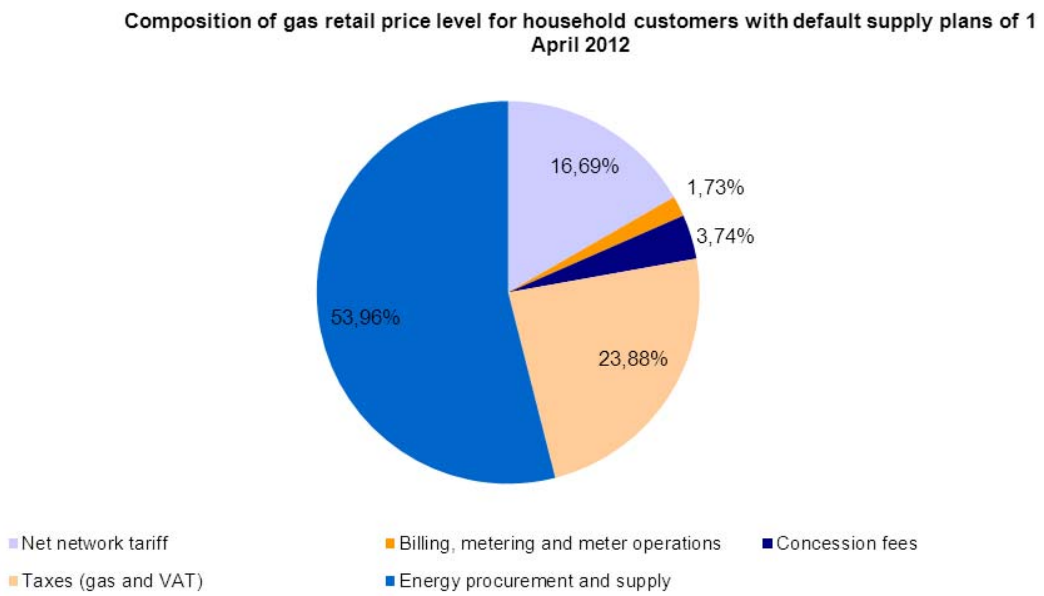

Figure 151: Composition of volume-weighted gas retail price level for household customers with default supply plans. Prices as of 1 April 2012 according to survey of gas wholesalers and suppliers

For customers receiving supply at change of contract tariffs the volume-weighted gas price increased from 6.11 ct/kWh to 6.58 ct/kWh within one year. That amounts to an increase by nearly eight percent. The gas price in this market segment thus increased to a greater degree than the gas price under default supply terms. The costs for energy procurement and supply in this customer segment increased from 3.10 ct/kWh to 3,65 ct/kWh, which amounts to an increase by nearly 18 percent.

Relevant date: 1 April 2012	Arithmetic average in ct/kWh	Share of total value in percent	Volume-weighted average in ct/kWh	Share of total value in percent
Average net network tariff including upstream network costs in ct/kWh	1.24	18.56	1.17	17.78
Average charge for billing in ct/kWh	0.05	0.75	0.05	0.76
Average charge for metering in ct/kWh	0.02	0.30	0.02	0.30
Average charge for meter operations in ct/kWh	0.05	0.75	0.05	0.76
Average concession fees in ct/kWh	0.05	0.75	0.04	0.61
Current gas tax in ct/kWh	0.55	8.23	0.55	8.36
Average VAT in ct/kWh	1.07	16.02	1.05	15.96
Average price component for energy procurement and supply in ct/kWh	3.65	54.64	3.65	55.47
Average total price in ct/kWh	**6.68**	**100**	**6.58**	**100**

Table 54: Average retail price level for the category of household customers with change of contract tariffs. Price level as of 1 April 2012 according to survey of gas wholesalers and suppliers

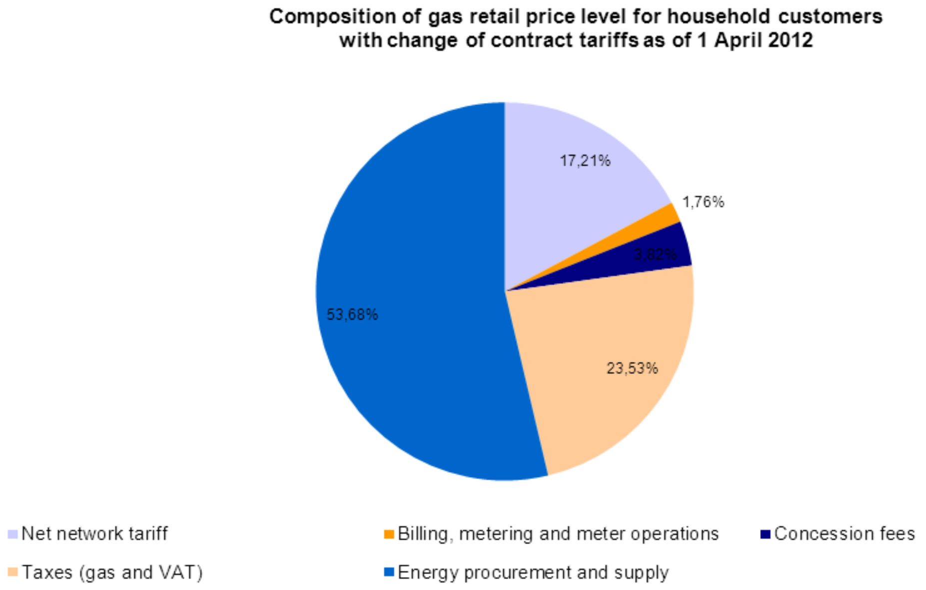

Figure 152: Composition of volume-weighted gas retail price level for household customers with change of contract tariffs. Prices as of 1 April 2012 according to survey of gas wholesalers and suppliers

For customers receiving supply at change of supplier tariffs the volume-weighted gas price increased from 6.06 ct/kWh to 6.48 ct/kWh within one year. That amounts to an increase by nearly seven percent.

In this market segment as well, the gas price increased to a greater degree than under default supply terms. The costs for energy procurement in this customer segment increased from 3.03 ct/kWh to 3.55 ct/kWh, which amounts to an increase by nearly 18 percent. On the whole it can be observed that default suppliers have not passed on the increases in energy procurement costs to customers under default supply contracts to the same degree as have suppliers delivering gas to customers at change of contract or supplier tariffs. As a result, the overall price difference between the default supply tariffs and competitive tariffs has become slightly smaller.

Relevant date: 1 April 2012	Arithmetic average in ct/kWh	Share of total value in percent	Volume-weighted average in ct/kWh	Share of total value in percent
Average net network tariff including upstream network costs in ct/kWh	1.24	18.84	1.17	18.06
Average charge for billing in ct/kWh	0.05	0.76	0.05	0.77
Average charge for metering in ct/kWh	0.02	0.30	0.02	0.31
Average charge for meter operations in ct/kWh	0.05	0.76	0.05	0.77
Average concession fees in ct/kWh	0.05	0.76	0.04	0.62
Current gas tax in ct/kWh	0.55	8.36	0.55	8.49
Average VAT in ct/kWh	1.07	16.26	1.05	16.20
Average price component for energy procurement and supply in ct/kWh	3.55	53.95	3.55	54.78
Average total price in ct/kWh	**6.58**	**100**	**6.48**	**100**

Table 55: Average retail price level for the category of household customers with change of supplier tariffs. Prices as of 1 April 2012, according to survey of gas wholesalers and suppliers

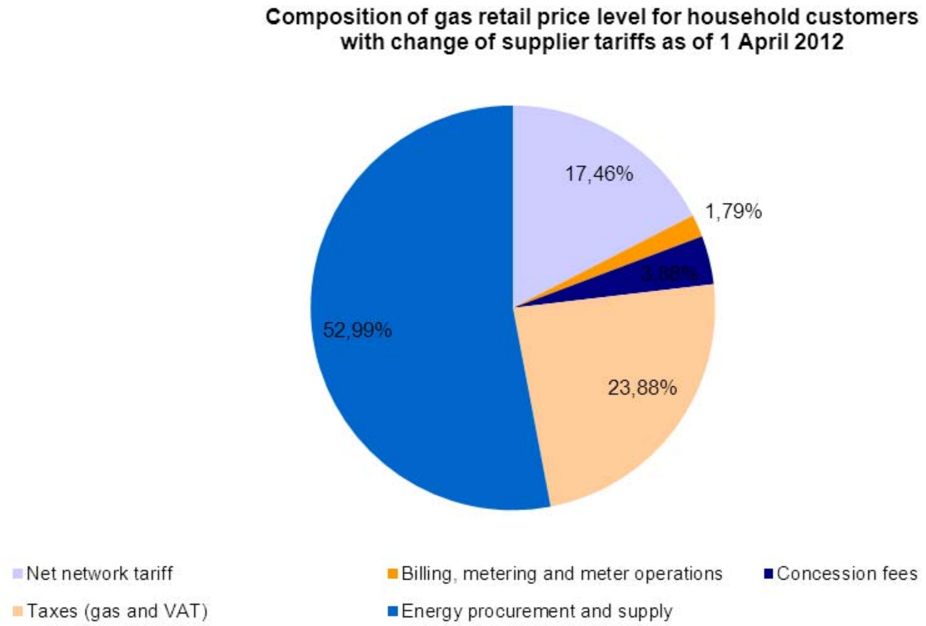

Figure 153: Composition of volume-weighted gas retail price level for household customers with change of supplier tariffs. Prices as of 1 April 2012 according to survey of gas wholesalers and suppliers

A multiannual time series of the gas price for all three supply categories shows a tendency towards a higher gas price. With regard to the supply of gas under default supply terms, the gas price level remains below the highest price level recorded to date, namely as of 1 April 2009. For supply at change of contract tariffs the highest price level from the year 2009 was nearly reached, while for supply at change of supplier tariffs a new peak level for the price of gas was even reached as of 1 April 2012.

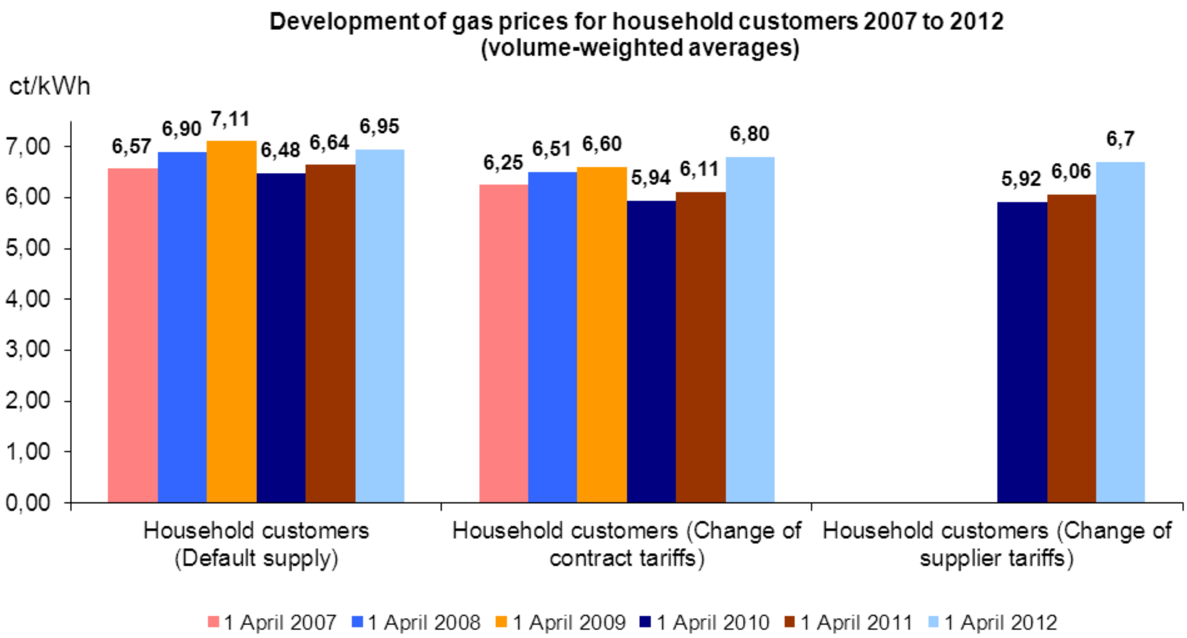

Figure 154: Development of volume-weighted gas prices for household customers 2007 – 2012. Prices as of 1 April 2012 according to survey of gas wholesalers and suppliers

Looking at multiannual time series of the price component energy procurement and supply, there is an upward trend in all three supply categories. Although in the area of default supply services, the highest price levels from the year 2009 were not quite attained, the costs for energy procurement and supply for customers who changed their contract or supplier have reached a new high point since the start of survey activities. The increase in the costs of procurement and supply is likely attributable primarily to the cross-border prices for natural gas, which have been increasing since 2010. The cross-border prices represent the import prices of natural gas and reflect the oil price trend that forms the main basis of the price formulas in natural gas import agreements (see chapter on "Wholesale gas").

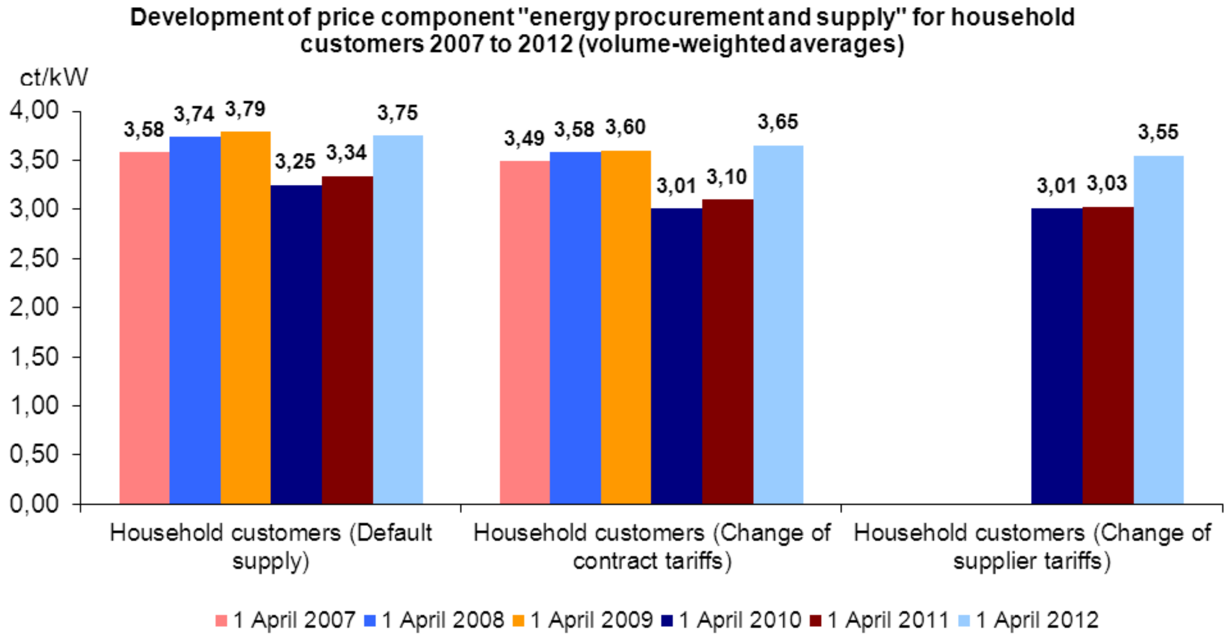

Figure 155: Development of price component "energy procurement and supply" for household customers 2007 – 2012. Prices as of 1 April 2012 according to survey of gas wholesalers and suppliers

Due to the significant increase in the price of gas in all three categories, the average household customer with a consumption of around 20,000 kWh can be faced with significant additional costs. In particular when non-default services are used, annual added costs of up to 100 euros are possible.

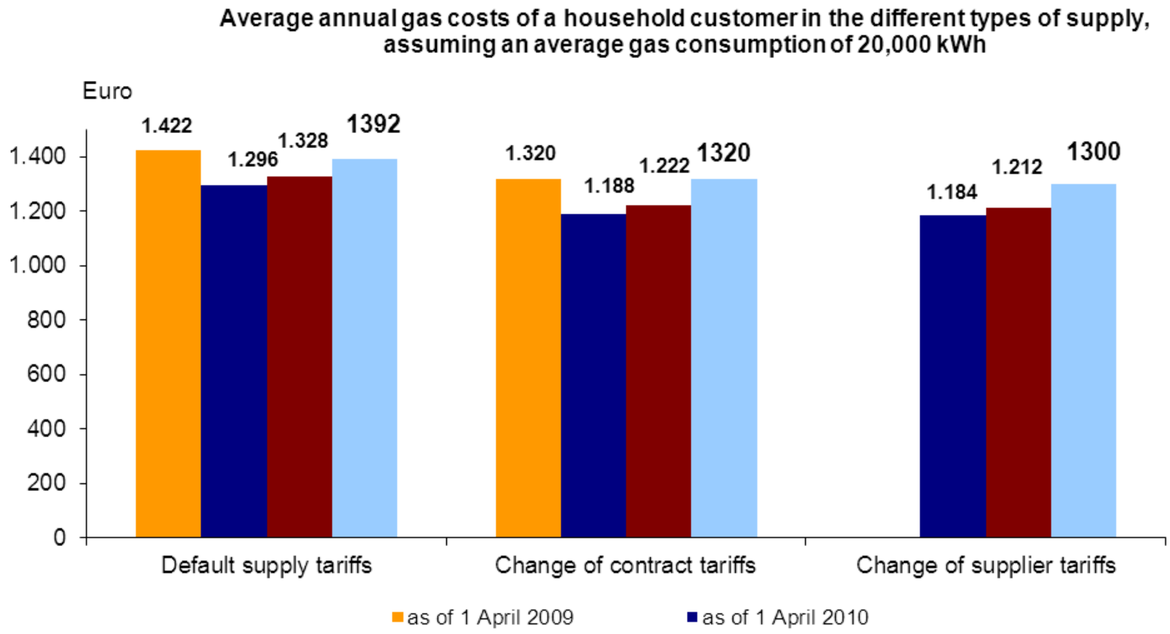

Figure 156: Average annual gas costs of a household customer in the different types of supply assuming an average gas consumption of 20,000 kWh.

Within the context of 2012 monitoring activities, the gas suppliers were asked if they offer gas customers special bonuses or other special contract arrangements. The most common type of special bonus is the one-time bonus payment that coincides with the first annual bill. In the area of gas supply under change of contract terms, nearly 13 percent of suppliers who responded to the question offered a one-time bonus payment. The amount of the bonus payment ranges from five to 180 euros, although on average a bonus payment of around 55 euros is granted. In the area of gas supply under switch of supplier terms, nearly 20 percent of suppliers who responded to the question with a "yes" or "no" answer offered a one-time bonus payment. The amount of the bonus payment ranges from five to 350 euros, although on average a bonus payment of around 75 euros is granted.

A second type of special bonus is the offering of free kWh, which are deducted from the overall consumption on the first annual bill and thus not charged. In the area of gas supply under change of contract tariffs, nearly 16 percent of suppliers who responded to the question offered free kWh. The number of kilowatt hours offered free of charge ranges from 600 kWh to 5000 kWh, although the average number of kWh not charged under such special bonus terms was approximately 1,900. In the area of gas supply at change of supplier tariffs, nearly 13 percent of suppliers who responded to the question with a "yes" or "no" answer offered free kWh. The number of kWh not charged ranges from 100 kWh to 700 kWh, although the average number of kWh not charged under such special bonus terms was approximately 320.

Another contractual special arrangement for household customers is the contractual commitment to price stability with regard to those price components that the company can influence, eg energy procurement and supply. In the area of supply at change of contract tariffs, the companies offer price stability for a duration of between one and 31 months, although on average the contractually agreed price stability period is 13 months. In the area of supply at change of supplier tariffs, the companies offer price stability for a duration of between one and 24 months, although on average the contractually agreed price stability period is twelve months.

Yet another example of a contractually fixed special arrangement is advance payment, which is frequently linked to a significant reduction in price. However, the potentially significant cost savings for the household customer also bring an unforeseeable risk, since the costs for an entire year of gas consumption usually have to be paid to the gas supplier in advance. In the area of supply at change of contract tariffs, nearly ten percent of suppliers who responded with a "yes" or "no" offer such a possibility of advance payment. Advance payment is required for a period of between three and twelve months, although the average advance payment period is twelve months. In the area of supply at change of supplier tariffs, approximately seven percent of suppliers who responded to the question offer the possibility of advance payment. Here too, advance payment is required for a period of between three and twelve months, although the average advance payment period is twelve months.

Another kind of special contractual arrangement is the agreement of a minimum contract term. This contractual provision can be found in particular among inexpensive tariffs with special bonuses. In the area of supply at change of contract tariffs, the gas suppliers require a minimum contract term of between one and 60 months, although the average minimum contract term is twelve months. In the area of supply at change of supplier tariffs, the gas suppliers require a minimum contract term of between one and 24 months, although the average minimum contract term is also twelve months.

A special provision that plays only a negligible role is the requirement of a deposit by the gas supplier. In the area of gas supply at change of contract tariffs, nearly one percent of companies require a deposit that must be paid before delivery. In the area of gas supply at change of supplier tariffs, there are no recorded cases of this special arrangement.

Comparison of European gas prices

A comparison of the gas prices in the European Union shows that, in the area of household customers, prices in Germany are close to the European average. The database comes from a study by Eurostat on national average prices for household customers.[89] Excluding taxes and fees, an average value of 4.57 ct/kWh was calculated for the year 2011; including taxes and fees, that value was 6.14 ct/kWh. The influence of taxes and fees changes the ranking in the overall comparison only to a slight degree. Prices for household customers are lowest in Romania and highest in Sweden. The exact figures for all EU countries examined can be found in the following diagrams.

[89] Prices were examined for households of the group D2 with an annual consumption of between 20 and 200 GJ, averaged for the first and second semester 2011 (Survey 2011S1, 2011S2). Cf: http://epp.eurostat.ec.europa.eu/portal/page/portal/energy/data/database (accessed: 05 Oct. 2012).

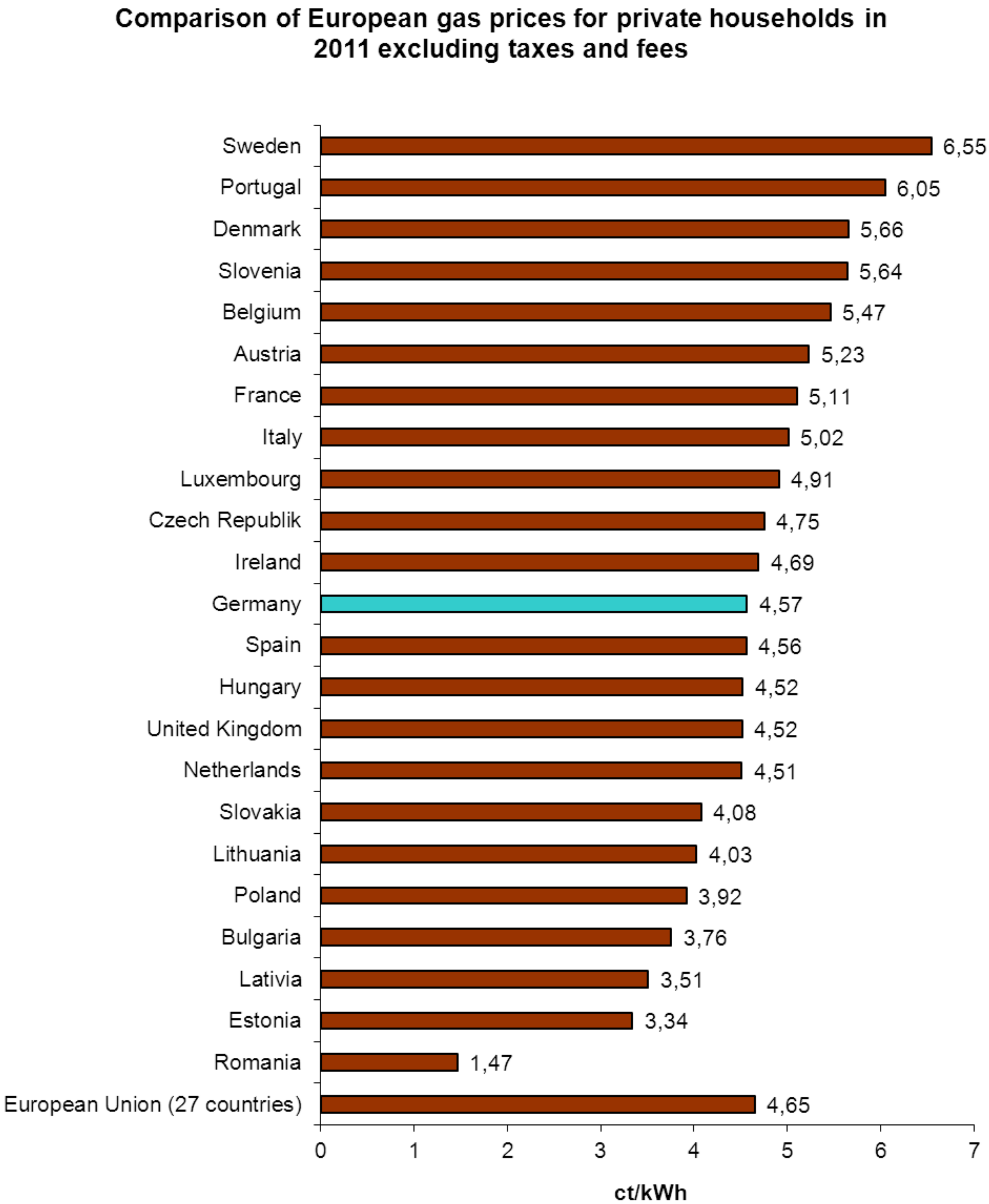

Figure 157: Comparison of European gas prices for private households in 2011 excluding taxes and fees

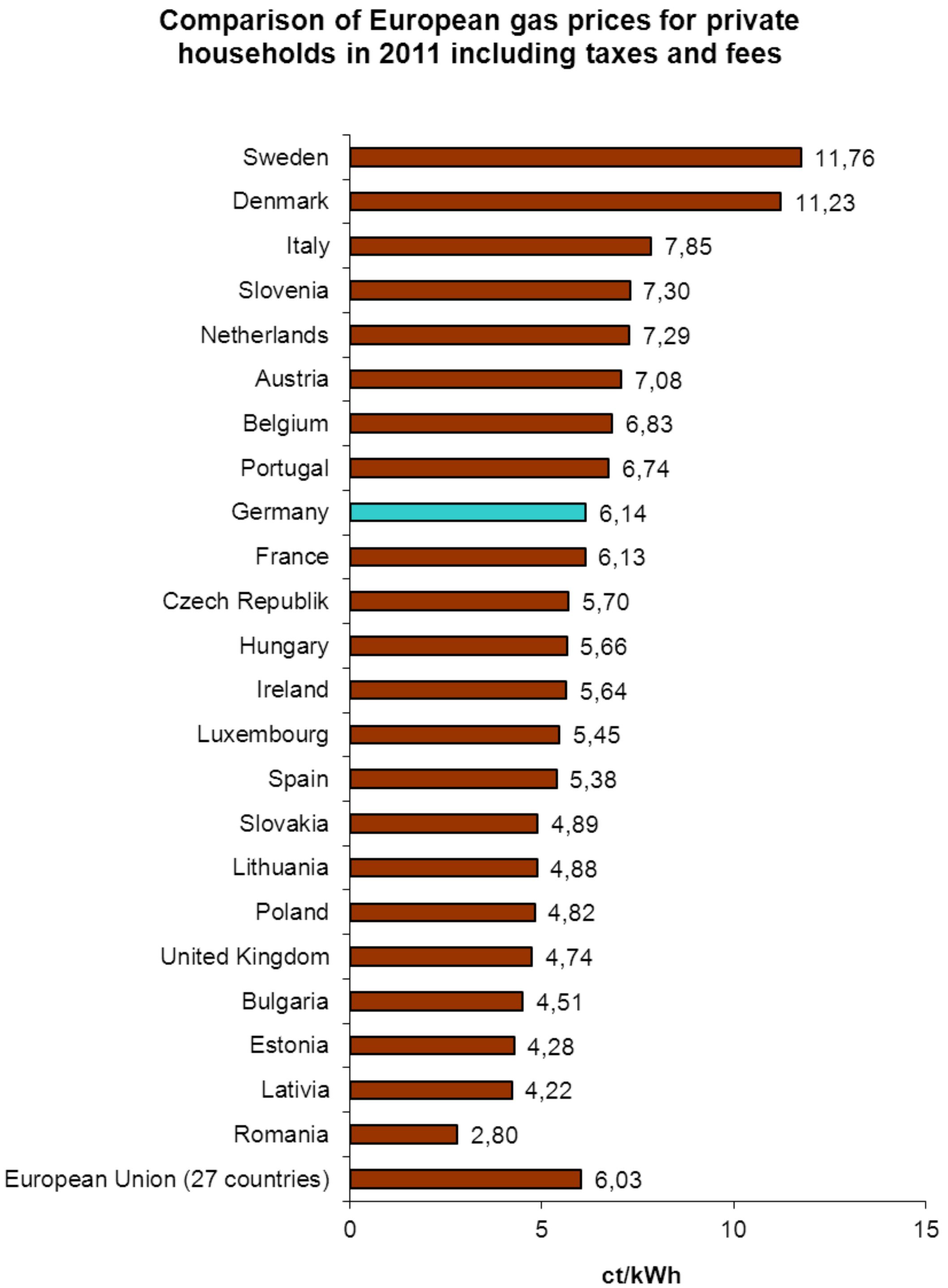

Figure 158: Comparison of European gas prices for private households in 2011 including taxes and fees

In a comparison of European gas prices for industrial consumers,[90] Germany does not do so well. In this customer segment, Germany's price of 4.37 ct/kWh excluding taxes, or 5.68 ct/kWh including taxes and fees, is significantly above the respective overall European average, putting it in the top tier. Here too, taxes and fees play only a negligible role in terms of changing the ranking in the overall European comparison. The exact figures can be found in the following diagrams.

[90] National average prices were examined for medium sized industrial consumers of the group Ic with an annual consumption of between 500 and 2,000 MWh. The figures were averaged for the first and second semesters of 2011 (Study 2011S1, 2011S2).
Cf. http://epp.eurostat.ec.europa.eu/portal/page/portal/energy/data/database (accessed: 5 Oct. 2012).

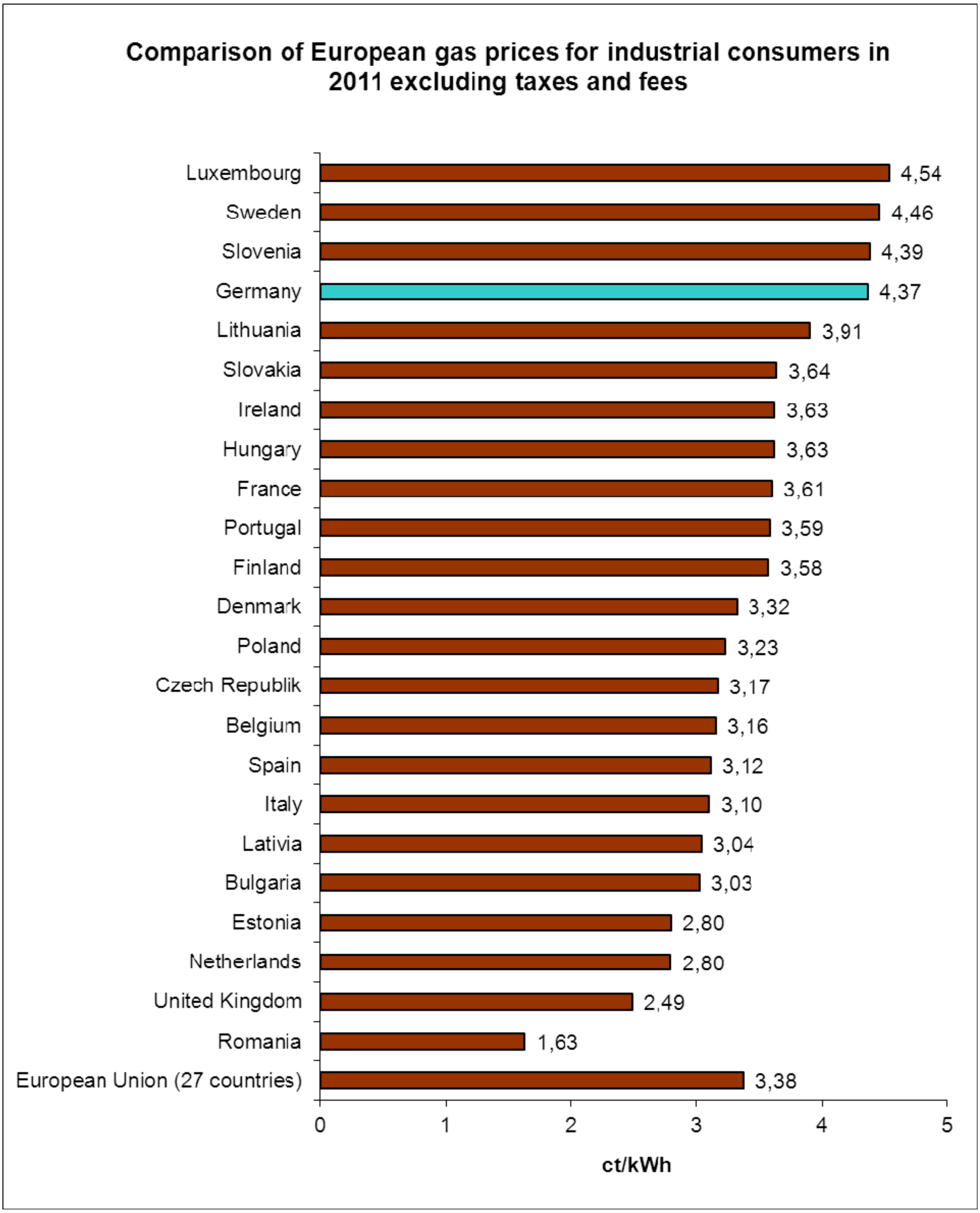

Figure 159: Comparison of European gas prices for industrial consumers in 2011 excluding taxes and fees

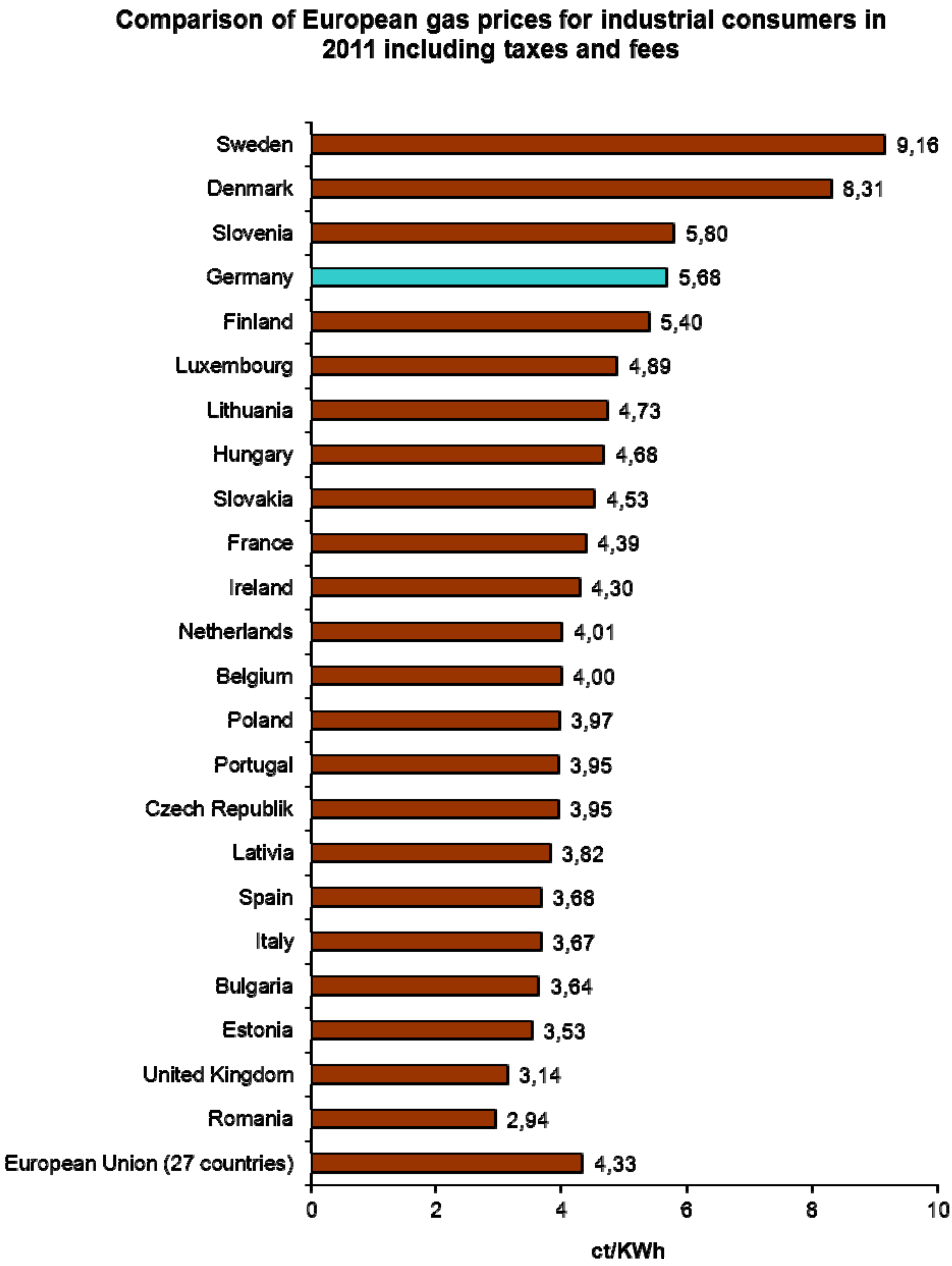

Figure 160: Comparison of European gas prices for industrial consumers in 2011 including taxes and fees

The comparison of gas prices across Europe shows a more differentiated picture. While in the household customer segment Germany is positioned in the middle of the field, it is among the top positions when it comes to industrial customers. The influence of taxes and fees on the retail prices here does not have as significant an impact as it does in the area of electricity.[91]

Metering

In the following section a distinction is made between distribution system operators acting as meter operator for their own systems and those providing (metering) services in the market. A further distinction is made between suppliers undertaking meter operator activities and independent meter operators.

The following tables show in which capacity the meter operators are present in the market and the breakdown in meter operation and meter reading activities:

Function	**Number**
System operator acting as meter operator within the meaning of section 21b(1) of the EnWG	618
System operator acting as meter operator within the meaning of section 21b(2) of the EnWG, providing (metering) services in the market	9
Supplier with meter operator activities	0
Independent meter operator	0

Table 56: Meter operator function

Activity	**Number of metering points**
Meter operation including meter reading and data transmission within the meaning of section 21b of the EnWG (revised)	12,800,000
Meter operation only (without meter reading) within the meaning of section 21b of the EnWG (unrevised)	36,000
Meter reading only (without meter operation) within the meaning of section 21b of the EnWG (unrevised)	19,000

Table 57: Breakdown of meter operation and meter reading activities

[91] Cf section on Comparison of European electricity prices

Activity	Number of metering points
Meter operation including meter reading and data transmission within the meaning of section 21b of the EnWG (revised)	12,800,000
Meter operation only (without meter reading) within the meaning of section 21b of the EnWG (unrevised)	36,000
Meter reading only (without meter operation) within the meaning of section 21b of the EnWG (unrevised)	19,000

Table 57: Breakdown of meter operation and meter reading activities

Distribution system operators (gas)

In 2011, the year under review, there was a total of around 13m metering devices, which is more or less the same as in 2010. The proportion of recording load meters increased to 0.5 percent (2010: 0.2 percent). In the reporting year 2011, the number of metering points fitted by the meter operator with metering equipment within the meaning of section 21f of the EnWG and capable of connection to metering systems as defined in section 21d of the EnWG was around 347,000.

Meter operators

The following table shows the types of metering equipment used by the meter operators for standard profile customers:

Metering equipment used by the meter operator for standard profile customers	Number of metering points according to meter size			
	G1.6 to G6	G10 to G25	G40 upwards	Ownership percentage
Diaphragm gas meter with mechanical counter	10,230,272	326,831	46,746	92
Diaphragm gas meter with mechanical counter and pulse output	2,960,157	95,451	14,321	74
Diaphragm gas meter with electronic counter	4,309	225	165	34
Load meters as for load-metered customers	260	564	4,013	66
Other mechanical gas meters	3,353	1,285	20,550	77
Other electronic gas meters	1,957	0	346	29
Total number of meters within the meaning of section 21f of the EnWG (revised)	103,856	5,630	795	37
Total number of upgradeable meters within the meaning of section 21f of the EnWG (revised)	610,484	18,120	4,286	44

Table 58: Metering equipment for standard profile customers

The following table shows the number of metering points connected via communication links to a metering system within the meaning of section 21d of the EnWG as well as the customers' contribution in percentage:

Transmission method	**Number of metering points**	**Customers' contribution (percentage)**
Pulse output	1,117,157	65
Radio technology (eg ZigBee)	785	23
PLC	241	10
M-Bus	3,555	44
Wireless M-Bus	1,331	16
OMS standard	742	11
Other (eg encoder)	3,554	24

Table 59: Communication link-up with a metering or communication system for standard profile customers

The meter operators were also asked which type of meter they used for recording load-metered customers. The following table shows the number of metering points and ownership percentage.

Function	Number of metering points	Ownership percentage
Transmitting meter with pulse output/encoder meter and recording device/data storage	14,741	87
Transmitting meter with pulse output/encoder meter and volume corrector	6,256	72
Transmitting meter with pulse output/encoder meter and volume corrector and recording device/data storage	14,794	85
Other	79	18

Table 60: Metering equipment for load-metered customers

The following table shows the various possibilities for remote communication links and the customers' contribution in percentage.

Transmission technology	Number of metering points	Customers' contribution (percentage)
PLC	276	19
PSTN, (analogue, ISDN)	10,611	77
DSL, broadband (cable)	219	23
Own control line	817	24
Mobile radio/GSM/GPRS/UMTS	25,472	85
Digital interface for gas meters	496	28
Other	87	17

Table 61: Communication links for load-metered customers

General Topics

Gas network access regulation decisions

E.ON "regi.on"

In the period under review, the relevant Ruling Chamber at the Bundesnetzagentur prohibited the "regi.on" structural model implemented in the E.ON group in its ruling of 3 February 2012 in a model case decision against E.ON Bayern AG and E.ON Energie AG on the grounds that it did not conform with unbundling requirements.

The "regi.on" concept was implemented in the E.ON group for the electricity and gas distribution network level. In this model, the regional supply companies were restructured in such a way that each of the distribution companies were hived off into subsidiaries of a parent company. With E.ON Vertrieb Deutschland GmbH (EVD), owned directly by both E.ON Energie AG as well as the individual regional network operators, an additional central distribution company was founded which took over and bundled strategic distribution functions for the regional distribution companies.

On the whole, this structure creates a commercial linking of interests between the network and distribution areas, meaning a significant influence on distribution interests. For this reason, such a model is not suitable for ensuring that the network operator has the necessary entrepreneurial freedom to orient its business solely in line with the interests of the network - as provided for in the unbundling rules under sections 6ff of the Energy Act.

In its decision of 3 February 2012, the relevant Ruling Chamber thus established that the "regi.on" structure breaches the unbundling independence provisions as laid out in section 6 sentences 1 and 2 as well as section 7a(1) and (4) of the Energy Act. E.ON Energie AG and E.ON Bayern AG were therefore obliged to surrender the holdings within a transition period of six months following the decision coming into force. Court appeal proceedings against this decision are pending.
Ultimately, the decision means that the parent company model is prohibited as a possible unbundling concept on the distribution network level.

KARLA Gas

Another issue was the determination on capacity management in the gas sector. The relevant Ruling Chamber at the Bundesnetzagentur issued a determination on 24 February 2011 which redefined and standardised key regulations for capacity management and capacity allocation. The determination and thus improved and standardised capacity management essentially apply for processing of all contracts from 1 October 2011.

The booking and use of capacity is the basis for access to transmission networks. In order to be able to transport gas on the market, shippers need to have exit and entry capacities booked from the TSOs. As part of its annual monitoring activities, the Bundesnetzagentur established that, in terms of actual use of the key points of interconnection at market area and international borders, the physical load flows at many of these points did not reflect full utilisation of the network by any means. At the same time, many points were fully booked, often for the foreseeable future. Often there were cases of contractual, rather than physical congestion, leading to market entry for new competitors being delayed in terms of processing bookings, although this would have been physically possible without any problems in many cases. The new approach to capacity management focuses on this. The central objective of the determination is to make the technically unused but booked capacities commercially viable in the event of contractual congestion and thus work towards more efficient network access. This should enable simultaneous network access for a larger number of shippers. Unused capacities which can be predicted are to be returned to the market at the latest at short notice (day-ahead) to allow other transport customers to use them. The right to renomination is restricted to a moderate degree here. The share of the booked capacity no longer available through renomination can be provided to other transport customers, who then transport the gas between two neighbouring market areas and can ultimately connect gas markets with each other. As determined, the arrangements for returning capacities and for renomination were implemented on 1 April 2012.

Furthermore, the transaction effort involved in capacity booking should be minimised. Where previously the exit capacity and corresponding entry capacity for each booking had to be obtained at the same exit or entry point in order to transport gas between market areas or countries, the determination proposes to remove this artificial sub-division and make the move to bundled bookings only. A booking will thus refer to moving gas from one market into another. The consolidation into one single bookable point also increases the liquidity of the virtual trading points, as trading activity is shifted there. At the same time, the shippers' risk of only receiving one side of the desired market border capacity is lowered and the number of auctions necessary per bookable point is halved. Obligatory bundling at interconnection points with neighbouring countries for international trade is only planned if the foreign network operator enables bundling. Initial projects for bundling capacities at cross-border interconnection points have already been implemented.

Ultimately, the determination has the aim of designing capacity booking in a market-oriented way. That is why it regulates the central pillars of primary capacity platform construction and the auction proceedings to be implemented. The platform was successfully launched under the name "TRAC-X primary" (TSO online booking platform) on 1 August 2011. Teething difficulties have now been resolved. This also applies to the day-ahead process introduced for many points on 1 April 2012.

Approval of exceptions to publication requirements on system status

Under number 3.4.5 of Annex I of the Regulation (EC) no 715/2009 of the European Parliament and of the Council on conditions for access to the natural gas transmission networks ("Transmission Network Regulation), TSOs are obliged to publish information and forecasts on the gas capacity available in the transmission network or alternatively on the aggregated imbalance position of all users. With the Bundesnetzagentur's Chamber Decision of

13 December 2011, twelve transmission system operators were permitted to be excepted from this publishing requirement until 1 April 2013. As the need for external system balancing energy in the respective market area is based to a significant extent on the information published about the volume of gas available in the transmission network and the aggregated imbalance position of all users, efforts were made in the decision-making process to balance the interests of those responsible for procuring system balancing energy in the market area, represented by the applicants, against the interests of the market participants regarding publication of system status information. The relevant Ruling Chamber came to the conclusion here that under current competitive structures on the system balancing energy market, the publication of the requested system status information could be misused by network users for their pricing of external system balancing energy. However, as improvements in competitive structures and the liquidity of the balancing energy market are expected in future and restriction of the publication requirements should then no longer be necessary, this exception rule applies only until 1 April 2013.

Approval of relevant TSO points

As per Article 18(4) of the Transmission Networks Regulation, the relevant points of a transmission networks for which information is to be made public are to be approved by the competent authority. In June 2011 the relevant Ruling Chamber issued twelve transmission system operators with approvals for their relevant points for which information is to be made public. Following the approvals, a total of 237 entry and exit points in Germany were classified as relevant points within the meaning of the Regulation. This means that detailed information, such as technical, booked and available capacity, nominations, renominations and actual load flows is to be made public. The approvals also provide additional legal clarity in terms of the validity of publication requirements, leading to a further improvement in publications and greater transparency on the gas market.

Switching supplier – Gas

In October 2011, the relevant Ruling Chambers at the Bundesnetzagentur (Electricity and Gas) issued two largely congruent determinations which amended the processes for switching electricity and gas supplier ("GeLi Gas" and "GPKE" decisions). With these determinations, the Bundesnetzagentur reacted directly to the new arrangements in section 20a(2) sentence 1 of the Energy Act, under which switching to a new energy provider is to be processed within a maximum of three weeks in future.

All forms of supplier switching take place via a uniform process as of 1 April 2012, regardless of whether a customer switches supplier at a consumption point, moves house or wishes to connect a newly-established consumption point to the network for the first time. The discontinuation of the month deadline not only shortens the switching period, but also enables switching to take place within the course of the month. In accordance with the registration submitted by the new supplier to the network operator, the final consumer can start receiving energy on any day of the month. At the same time, the new determinations also include very restrictive rejection regulations for cases in which a consumer wishes to switch despite not having given notice on their contract. On one hand, this is in order to protect competition, and on the other to protect the consumers themselves, who would otherwise be subject to claims for damages.

The arrangements for the electricity and gas sector which have been largely standardised by the Ruling Chambers at the Bundesnetzagentur thus take into account the legal requirement for consumers to be able to switch energy provider quickly and simply. They also indicate further positive development for competition. Moreover, restricting content changes to what is directly necessary in order to implement the new legal framework allows companies to initiate the required processes and IT systems swiftly.

Report on GABi Gas portfolio and system balancing energy regime and GABi Gas amending determination

On 1 April 2011, in line with section 30 of the Gas Network Access Ordinance (GasNZV), the Bundesnetzagentur submitted a report to the Federal Ministry of Economics and Technology containing an evaluation of the economic effects of the portfolio and system balancing energy regime and proposals for its further development. The report concluded that following some initial difficulties, which have since been resolved, the portfolio and system balancing regime currently in place has proved itself and met the expectations for stimulating competition. No essential action was deemed necessary in light of the existing arrangements. However, the Bundenetzagentur did see potential for development in the form of fine tuning and adjustments to individual rules, but these are ultimately minor corrections which do not call into question the framework conditions. In future, harmonisation of European balancing regulations through a standardised framework guideline will make modifications to the German portfolio and system balancing energy regime likely.

The report by the Bundesnetzagentur proposes several approaches to this. Incentives to improve data transmission quality, forecast quality and application of standard load profiles, together with timely settlement of surpluses and shortfalls by exit operators should be established with the help of monthly billing of network accounts. The standardisation of system balancing products should be promoted and transparency increased for the entire portfolio and system balancing regime.

In addition, the relevant Ruling Chamber at the Bundesnetzagentur initiated further measures regarding amendment proceedings to the GABi gas determination, which commenced in May

2011. The amendment proceedings focused in particular on legal certainty in terms of the tolerance volumes provided for in section 23(2) sentence 2 of the GasNZV (five percent of the volume supplied to the final consumer without a standard load profile and without substitute nomination proceedings). A total of 25 comments were submitted as part of a consultation, the evaluation of which concluded that the majority of market participants and associations reject the introduction of 5 percent tolerance volume for a variety of reasons. In addition to a general increase in the complexity of the balancing system, the complaints also touched in particular on the incentive effect on balancing discipline, which in the opinion of the market participants holds the risk of increasing the need for system balancing energy. Moreover, the relevant Ruling Chamber expected the 5 percent tolerance volume to have a negative effect on the introduction of the conversion charge system. Following a further consultation, the introduction of the 5 percent tolerance volume was provisionally suspended in summary proceedings. This suspension was finally confirmed in the principal proceedings which were concluded in early 2012.

The Ruling Chamber at the Bundesnetzagentur ended determination proceedings as regards further proposed amendments. This concerns the expansion of customers groups who pay the balancing energy contribution to include power measurement customer groups; the expansion of the balancing energy contribution to exit points at market area borders, international borders and storage facilities; the potential introduction of symmetrically widened portfolio balancing charges via a reduction in the factor for creating the negative charge to 0.8, along with the introduction of further publishing requirements. The partial closing of proceedings is due to the fact that the harmonisation process for European balancing rules is progressing at a rate which indicates that this process will be completed with concrete provisions before the end of the year. In addition, transparency in the portfolio and system balancing energy regime has improved considerably in the interim without the need for a determination.

Determination proceedings for levying charges for usage of the virtual trading point (VTP charges)

The Bundesnetzagentur's Ruling Chamber decision of 23 August 2011 determined the levying of charges for usage of the virtual trading point (VTP charges) These charges are not a fundamentally new instrument - until the new Gas Network Access Ordinance of 3 September 2012, a charge used to be levied at the VTP in some market areas for the transmission of gas volumes between two balancing groups. The charge was incurred when shippers used the VTP service as part of their trading activities. This service includes cost-relevant services from the market area managers affected, such as providing balancing groups and processing matching and mismatching.

Section 22(1) sentence 6 of the amended GasNZV of 3 September 2010 states that no charges can be levied for the use of the virtual trading point, subject to a determination which deviates from this by the Bundesnetzagentur as per section 50(1) no 10 of the GasNZV. Without the possibility of levying VTP charges, financing the costs of trading activities at the VTP would primarily be possible via service contracts between the market area managers and the cooperating TSOs in the market area. However, this solution would not include all VTP users carrying out costs-generating trading activities at the VTP. In particular, shippers who only make financial transactions at the VTP (so-called paper traders) would neither directly not indirectly contribute to VTP charges in this case, as they do not pay any network tariffs due to a lack of capacity booking.

In order to ensure more efficient network access while taking into consideration the aims of section 1(1) of the Energy Act, particularly with regard to causation of cost allocation, the Bundesnetzagentur made use of its determination power under section 50(1) no 10 of the GasNZV to issue a determination on the levying of VTP charges. This determination enables market area managers to levy low VTP charges. They are to set the cost-oriented VTP charge, taking into consideration the limit of 0.8 ct/MWh set by the relevant ruling chamber. The VTP charge is levied for every nominated transmission of gas volumes between two balancing groups at the VTP. It is billed to both the entry and exit balancing group managers. The charge applies for a period of twelve months from 1 October, starting on 1 October 2011.

Based on the determination, the market area managers calculated VTP charges of 0.25 ct/MWh (Gaspool) and 0.18 ct/MWh (NCG) for the period from 1 October 2011 until 30 September 2012.

Determination proceedings for the introduction of a conversion charge system for multi-quality market areas - express orders for the multi-quality NCG and Gaspool areas

One focus of activities in 2011 was the continued consolidation of the German gas market areas. Section 21(1) of the amended GasNZV requires the gas network operators to reduce the current six market areas to three by April 2011 and to two by August 2013.

A growing tendency first became apparent among the network operators to bring about the reduction not, as in the past, by joining market areas with the same gas quality, but by integrating the H-gas and the L-gas areas. In a multi-quality market area the combined H and L-gas network areas are still physically operated with different gas qualities. At the same time the shippers can combine all freely usable entry and exit capacities in the entire market area regardless of their respective quality and thus transport multi-quality gas throughout the market area (in balancing terms). In the event of multi-quality entry and exit between H-gas network areas and L-gas network areas in the market area, the physical balance in the network can be ensured either through technical measures (eg gas conversion or gas mixing) or commercial measures (eg use of system balancing energy or load flow commitments).

In order to create framework conditions for multi-quality market areas, the relevant Ruling Chamber initiated determination proceedings on 13 January 2011 on the basis of sections 29 of the EnWG, section 50(1) no 1, no 9, no 10 and section 30(2) no 8 of the Gas Network Charges Ordinance (GasNEV) As the two multi-quality market areas NCG and Gaspool had already commenced operations prior to conclusion of the determination proceedings on the conversion, the Ruling Chamber issued provisional determinations on the introduction of a conversion charge in the NCG and Gaspool market areas by means of a temporary order on 24 February 2011 and on 24 August 2011 for the respective starting dates of 1 April 2011 and 1 October 2011.

These express orders introduced the necessary basic components of the conversion charge system and thus created the key requirements for multi-quality market areas, making it possible for a conversion charge to be levied. The conversion charge aims to cover the costs incurred by moving gas flows in multi-quality market areas and to prevent improper arbitrage transactions by individual market participants. The charge is necessary, at least for the start-up phase of the multi-quality market areas, and applies for a period of six months, starting on either the 1 April or 1 October of the calender year.

The conversion charge calculated by the market area managers based on the express orders was two euros/MWh for the NCG market area between 1 April 2011 and 30 September 2011 and 1.50 euros/MWh between 1 October 2011 and 31 March 2012; for the Gaspool market area the charge was 2.20 euros/MWh.

Extensive framework conditions were determined for the conversion system as part of the principal proceedings on the matter. These thus complete the basic components of the conversion system based on the express orders and replace the latter.

Biogas feed-in

In 2011, abuse proceedings opened by the relevant Ruling Chambers at the Bundesnetzagentur were able to clarify a series of unclear and disputed issues between biogas facility operators and gas network operators regarding the GasNZV (Landwärme GmbH ./. E.ON edis AG). In detail, these looked at compliance with time limits for the examination of the connection and the submission of a connection contract by the network operator, along with the scope and binding nature of connection checks and commitments.

This means that the connection check in particular must be final and a positive result binding. In other words, the network operator cannot express any reservations regarding the connection commitment. Moreover, after commitment has been made the network operator can no longer examine any further grounds for refusal, unless they were unaware of such grounds or the connection is objectively impossible for them for technical reasons.

Preparation and execution of efficiency benchmarks for gas DSOs and TSOs for the second regulatory period

The second regulatory period for gas network operators begins on 1 January 2013. As per section 1(1) of the Incentive Regulation Ordinance (ARegV), the Bundesnetzagentur must carry out nationwide efficiency benchmarking of gas DSOs prior to the start of a regulatory period. This must also be carried out by the Bundesnetzagentur for the gas TSOs as laid out in section 22 of the ARegV. Efficiency benchmarking aims to calculate an efficiency level for the network operators involved[92]. The Bundesnetzagentur must use the methods described in annex 3 of the ARegV to calculate the efficiency levels.

It must also use a data basis for the benchmarking which takes into consideration both input and output parameters. Input parameters are the company costs established under section 14 of the ARegV. Output parameters reflect the companies' supply services under section 13 of the ARegV. The relative efficiency of the companies is calculated based on the data collected in this way. As in the first regulatory period, a web portal set up by the Bundesnetzagentur was used by the gas DSOs to communicate the structural data in 2011. These data were then examined intensively in terms of plausibility by the Bundesnetagentur, which used a variety of options to identify potential misunderstandings, data entry errors and inconsistencies before clarifying these with the network operators.

Data collection from the TSOs was carried out using prepared Excel sheets which were to be completed and sent to the Bundesnetzagentur by September 2011, before also being thoroughly checked for plausibility. The Bundesnetzagentur commissioned a consultancy firm to carry out the benchmarking. Preparations for efficiency benchmarking of gas DSOs and TSOs began at the start of 2012.

[92] As a rule, only those network operators taking part in the full ARegV proceedings are included here. Small network operators have the option before the regulatory period of selecting simplified proceedings as outlined in section 24 of the ARegV, if there are fewer than 15,000 (gas distribution network) or 30,000 (electricity distribution network) customers connected directly or indirectly to their network.

Gas Network Development Plan 2012[93]

The exact requirements for the German and European gas network infrastructure in ten years can currently only be estimated at best. Nevertheless, the development of the gas transmission network needs to be investigated today, if gas supply is to remain at its current quality level in the decade to come.

The gas network development plan, to be published on an annual basis as provided for by section 15a of the EnWG, includes measures for needs-oriented optimisation and expansion of the network which will be necessary in the next decade to ensure security of supply. The content of the plan focuses on the one hand on expansion issues arising via the connection of new gas power plants - there is particular overlap here with the electricity market - and storage, while on the other hand looking at further connections between the German transmission network with those in neighbouring European countries.

In line with section 15a(1) sentence 4 of the EnWG, TSOs drafted the 2012 plan on the basis of a scenario framework. This includes assumptions regarding the development of gas production, supply and consumption and the exchange with other countries, identifying planned investment projects in regional and community-wide network infrastructure along with the impact of potential supply interference. The draft scenario framework was submitted to the Bundesnetzagentur in August 2011 and then consulted upon by the TSOs[94].

Gas scenario framework		Scenarios on power generation from gas		
		Scenario I: Gas capacities increase strongly	**Scenario II:** Gas capacities increase moderately, assumption of TSO scenario B*	**Scenario III** Gas capacities almost constant, assumption of TSO scenario A*
Final energy demand (gas) scenarios	**Scenario I**: High demand for gas	**Scenario I: High demand scenario**		
	Scenario II: Medium demand for gas		**Scenario II: Medium demand scenario**	
	Scenario III Low demand for gas			**Scenario III Low demand scenario**

Table 62: Scenarios agreed with the electricity sector Source: Prognos (2011), simplified view.
*in terms of the scenario framework on the Electricity Network Development Plan by the transmission system operators (TSOs), 2011

[93] At the time of writing, only the draft Network Development Plan, not yet confirmed by the BNetzA, was available.
[94] Public consultation proceedings by transmission system operators, http://www.netzentwicklungsplan-gas.de/szenariorahmen/szenariorahmen.html

Following confirmation of the scenario framework by the Bundesnetzagentur on 6 February 2012 as per section 15a(2) sentence 7 of the EnWG[95] the TSOs created the Gas Network Development Plan, which was based on two of the three scenarios submitted. These were Scenario I, assuming higher gas consumption ("high gas requirement scenario", indicative view) and the moderate Scenario II ("medium gas requirement scenario", complete view).

In terms of current gas requirements a decrease of between three and 16 percent was forecast in all scenarios which reached until 2022. Above all, this development is due to the decreasing gas requirements of final consumers, particularly thanks to improved heating insulation and energy efficiency. The forecast installed gas plant capacity is based on a list compiled by the TSOs and DSOs of existing and replacement plants along with those planned or under construction. Scenario I ("high gas requirement") is a "stress scenario" for the transmission network and assumes a particularly high growth rate in gas plant generation capacities. It also assumes that the promotion of domestic natural gas will fall significantly in the next decade and will not be able to be compensated by increased biogas feed-in.

The Gas Network Development Plan, which has undergone market consultation by both the TSOs and the Bundesnetzagentur in separate proceedings[96], shows the necessary measures for needs-oriented development of the transmission network. These are based on the modelling results from Scenario II, which was considered realistic. The modelling indicated necessary construction measures totalling 200km and additional compressor capacity of 90 MW for Scenario II by 2015, which represents a required investment of €600m. By 2022, the measures indicate line construction of 730 km and compressor capacity of almost 360 MW requiring investment of €2.2bn, from today's perspective.

[95] Gas Network Development Plan Scenario Framework: Decision in administrative proceedings, 6 February 2012, http://www.bundesnetzagentur.de/cln_1931/DE/Sachgebiete/ElektrizitaetGas/GasNetzEntwicklung/GasNetzEntwicklung_node.html#doc200612bodyText2

[96] Consultation of the Gas Network Development Plan 2012 by transmission system operators as per section 15a(3) sentence 1 of the EnWG, 8 June 2012, http://www.bundesnetzagentur.de/cln_1931/DE/Sachgebiete/ElektrizitaetGas/GasNetzEntwicklung/NetzEntwicklungsPlan/NetzEntwicklungsPlan_node.html

Input parameters for network modelling:

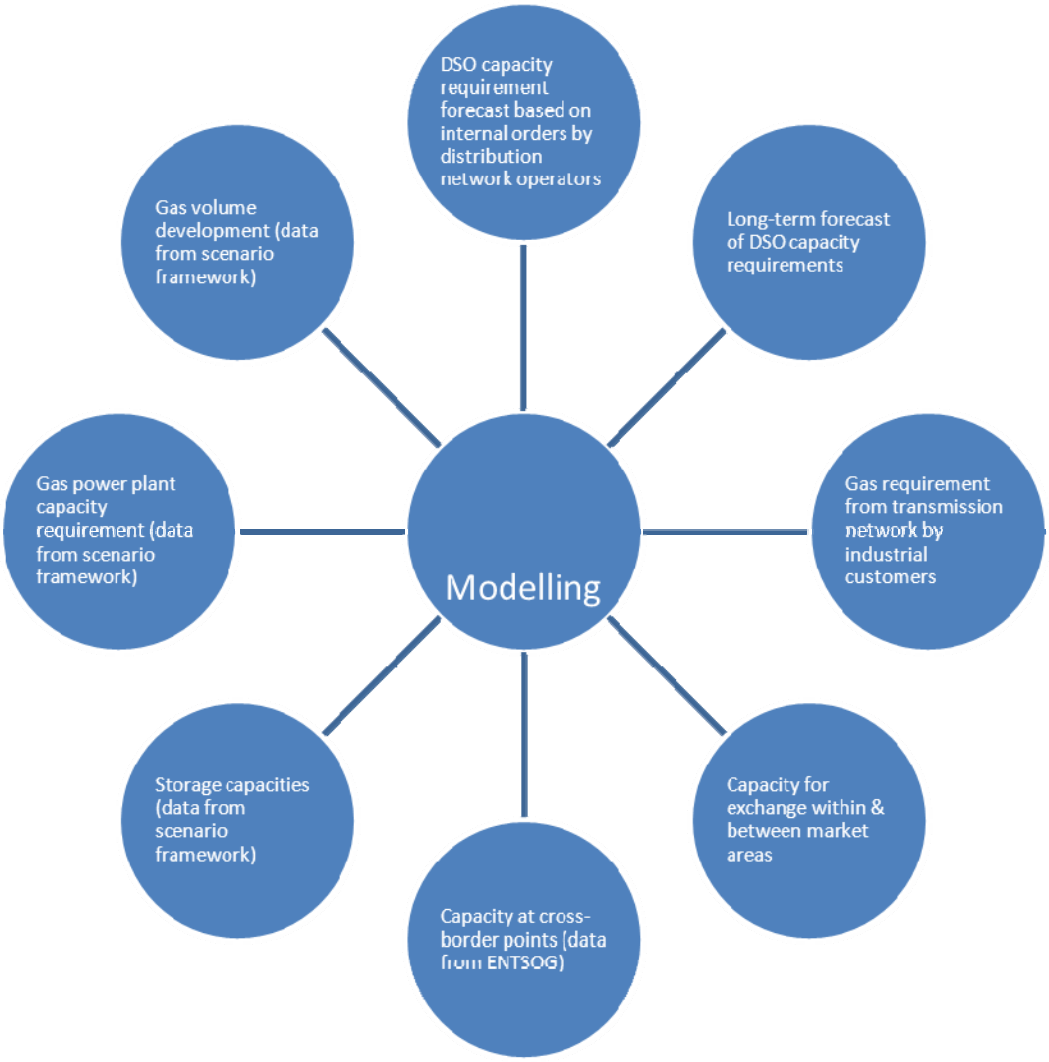

Figure 161: Input parameters for network modelling Source: Transmission system operators (2012), simplified view. DSO: Distribution network operator (downstream network operator from TSO), ENTSOG: European Network of Transmission System Operators for Gas, see www.ENTSO-G.eu.

These results were calculated on the basis of internal orders by downstream network operators and requests for plant and storage capacity, amongst other aspects. In addition to the conversion of gas requirement and volume into regional capacity requirements, the Gas Network Development Plan also includes the current expansion status for all projects connected to the transmission network. Furthermore, the plan shows connections already completed or those that are highly likely to be realised. Furthermore, it contains quantitative estimates regarding the potential of Power-to-Gas and any consequences of congestion in supply for the customers.

The Gas Network Development Plan 2012 can be found at www.netzentwicklungsplan-gas.de. On the Bundesnetzagentur's website www.bundesnetzagentur.de (Gas Network Development section), there is also a list of power plants and storage facilities, a study of capacity development, a table of grid expansion measures and an overview of all comments submitted on the draft Network Development Plan.

Activities of the Bundeskartellamt

Areas of focus of competition control

In the Bundeskartellamt's merger control practice four merger projects proved to be of particular significance. In the area of abuse control the Bundeskartellamt issued formal decisions in two cases dealing with electric heating and in three cases concerning the award of concessions for electricity and gas. It also concluded a sector inquiry into the district heating sector and published a detailed report on its findings as well as a report on its examination of concession fees payable by suppliers of gas to household customers.

Merger Control

In second phase examination proceedings the Bundeskartellamt cleared the acquisition by RWE AG of a 24 percent share in the municipal utility Stadtwerke Unna GmbH. Regardless of RWE's market position in the electricity markets, the merger project did not have any strengthening effects. The minority share in Stadtwerke Unna had already been acquired in the late 1990s by RWE's predecessor VEW. However, this participation was limited to twelve years. The plans behind the more recent project were to secure RWE's permanent participation in the municipal utility. Despite RWE's existing minority participation, Stadtwerke Unna had thus far proven to be an independent purchaser of electricity and gas. The utility had already terminated its long-term full-requirement electricity and gas contracts with RWE years before and in despite of RWE's stake had operated its own market-oriented procurement management system.

In second phase examination proceedings the Bundeskartellamt cleared Gazprom's acquisition of a minority interest in VNG, the largest gas supplier in the east of Germany. The project included plans to increase Gazprom's participation in VNG to 10.52 percent; together with the existing share of BASF subsidiary Wintershall of 15.79 percent in VNG, the Bundeskartellamt viewed this development as exerting a joint and competitively significant influence on VNG on the part of Gazprom and Wintershall. The two companies already cooperate with one another in several joint ventures, including the gas transmission company Wingas. The Bundeskartellamt based its clearance decision on a market for the development, production and sale of natural gas, which it defined as national, i.e. limited to Germany. In this market the Russian state-owned company Gazprom had a share of approximately one third, the Dutch state-owned company Gasterra and the Norwegian state-owned company Statoil each a share of around one fifth. The question whether Gazprom has a single or joint dominant position as an oligopolist together with Statoil and Gasterra on the market for the production of natural gas and its import into Germany was left open because in any case Gazprom's minority share in VNG would not strengthen its market position in a way which would be negative for competition. In addition, the standard practice of geographic market definition was changed on two downstream markets, the markets for the supply of regional distributors by long-distance transmission companies and for the supply of large industrial customers by long-distance transmission companies. The Bundeskartellamt now bases its assessments on national markets instead of regional markets which were limited to the respective supply area. According to the Bundeskartellamt's preliminary assessment, neither VNG nor Wintershall can be regarded as dominant on either of these national markets. E.ON, as a third party to the proceedings, appealed the clearance decision to the Düsseldorf Higher Regional Court but later withdrew its appeal after an agreement was reached with Gazprom in arbitration proceedings on the review of prices in long-term gas import contracts.

The Bundeskartellamt cleared the acquisition of ESW GasVertrieb by Enovos in second phase examination proceedings. Enovos was formed by a merger in 2009 between two Luxembourg electricity and gas providers and Saar Ferngas. The company is the incumbent gas supplier in Luxembourg, the federal state of Saarland and the southern part of Rhineland-Palatinate. This merger project gave the Bundeskartellamt an opportunity to revise its previous market assessment in view of the increasing competition in the gas sector. The Bundeskartellamt still maintains its practice of defining geographic markets limited to the respective network areas at the distributor level (the supply of municipal utilities and regional distributors by long-distance and regional transmission companies) and at the final customer level and has not yet switched to a nationwide definition. Enovos is still dominant on the market for the supply of downstream distributors with gas in the Saarland and southern Rhineland-Palatinate. However, the Bundeskartellamt expects competition in this market to significantly increase in the coming years. Therefore, the merger will not strengthen Enovos' market position to an extent that would harm competition.

The Bundeskartellamt cleared the sale of the E.ON subsidiary Open Grid Europe (OGE) to a consortium of investors in the second phase of merger control. OGE operates the largest gas transmission network in Germany. With its pipelines from east to west and north to south this network represents a key gas transit infrastructure within Europe. Due to ownership unbundling requirements under European law, E.ON-Ruhrgas had already hived off its network to OGE in autumn 2010. Prior to this, Macquarie, one of the investors, had already acquired Thyssengas' gas transmission network, which had previously belonged to RWE. Thyssengas operates a gas transmission network mainly in North Rhine-Westphalia and Lower Saxony, which also includes gas pipelines which are operated either jointly or in parallel with OGE. In the Bundeskartellamt's view the dominant position of OGE and Thyssengas has not been strengthened because, due to legal provisions, the calculation and setting of their network fees will continue to be the sole responsibility of the management of the two network operators without the involvement of their shareholders. Under the German Energy Industry Act, OGE and Thyssengas are defined as independent transmission operators (ITO). The ITO model ensures that independent transmission operators are in a position to decide independently on all issues concerning network operation. In separate proceedings the Bundeskartellamt is examining whether a possible cooperation between the two companies in the calculation of capacity and network fees would restrict competition.

Control of abusive practices

In one of the abuse proceedings which the Bundeskartellamt initiated against electric heating providers and later concluded in some cases subject to commitments by the companies to financially compensate their customers, the authority obliged the energy provider Entega to pay back in total approx. five million euros to its customers. The authority had found that from 2007 to 2009 the company had charged its household and small business customers abusively excessive prices. In the electric heating sector consumers still have virtually no possibility to switch provider. Following Entega's appeal against the authority's decision, the case is pending at the Düsseldorf Higher Regional Court. The proceeding against another electric heating provider, the municipal utility Städtische Werke AG in Kassel, was concluded with a commitment in accordance with § 32b GWB (German Act against Restraints of Competition) by which the utility undertook to reimburse specific customers with a significant amount and to comply with four structural commitments.

As to the abuse proceedings concerning the award of concession agreements for the supply of electricity and gas, the Bundeskartellamt has concluded three proceedings with commitment decisions under § 32b GWB (municipalities of Markkleeberg, Dinkelsbühl and Pulheim). In the Pulheim case the third parties to the proceedings have appealed the commitment decision to the Düsseldorf Higher Regional Court.

In the case involving GAG Ahrensburg, a test case for abusively excessive concession fees, the Bundeskartellamt's decision was confirmed by the Düsseldorf Higher Regional Court. In accordance with the ordinance on concession fees, the Bundeskartellamt had prohibited the practice of charging third gas suppliers the higher concession fee for the supply of gas to tariff customers instead of the lower concession fee for special contract customers.

Reports and Sector Inquiries

The Bundeskartellamt published a report on gas concessions and the effect of concession fees on the competition for end customers. Concession fees are charges payable by network operators to municipalities in return for the award of rights of way for the installation of gas and electricity lines. The network operator is entitled to pass on the concession fee to the energy providers using its network. The energy providers then pass on the concession fee to their final customers. The Bundeskartellamt's inquiry empirically proves that highly excessive concession fees which are passed on to the supply companies, and ultimately the final customers, lead to a lower number of gas household customers switching to another supplier. If the costs of competitors in supplying gas to household customers are artificially increased due to excessive concession fees, this constitutes an exploitative abuse.

The Bundeskartellamt published a final report on its inquiry into the district heating sector launched in September 2009. The inquiry reveals clear competition deficits in the district heating markets. The locally incumbent providers face practically no competition and each have a dominant position in their market. Consumers have no possibility to switch provider. There is no evidence of generally excessive price levels in the district heating sector. However, prices differ substantially in the individual network areas, in some cases by more than 100 percent. The Bundeskartellamt now plans to take a closer look at the situation in network areas earning the highest revenue in 2007 and 2008.

Competition Advocacy

Consumers have significantly benefited from competition in the energy production and distribution markets since the liberalisation of the markets, even if this is not always evident given increasing state or state-induced duties. Of particular relevance is the question whether the trend towards competition will continue in view of the turnaround in energy policy initiated in 2011 which will fundamentally alter basic conditions on the energy markets. During the reporting period the Bundeskartellamt has always emphasized that the competitive development of the energy production markets can help to make energy supply more efficient and cost-effective. Competition and supply security are by no means inconsistent with one another. A competitive development of the energy markets can help to divide the responsibility for supply security among as many stakeholders as possible. Plans to set up the market transparency unit envisaged in the energy concept of the Federal Government took on a more specific form during the reporting period. The Bundeskartellamt welcomes the plan to set up the market transparency unit which is to be jointly operated by the Bundeskartellamt and the Federal Network Agency.

Bundesnetzagentur activities

Bundesnetzagentur involvement in the Agency for the Cooperation of Energy Regulators (ACER)

The Agency for the Cooperation of Energy Regulators (ACER) officially commenced its operations in Ljubljana as the Third Energy Package took effect on 3 March 2011. Through its active involvement in the Agency's central Board of Regulators and the working groups, the Bundesnetzagentur plays a role in the fulfilment of the Agency's duties and represents the interests of German energy regulation, ensuring that the German energy market carries adequate weight on a European level.

The European Regulators' Group for Electricity and Gas (ERGEG), founded in 2003, was dissolved by the Commission in July 2011 with ACER assuming its function as the Commission's official advisory board. Within ERGEG, regulatory authorities had decided together with the European Commission that the transition period of almost two years between adoption of the Third Energy Package in 2009 and its full entry into force in 2011 should be used for preparatory work. This made it easier for the Agency to start its work promptly and allowed it to pick up various issues seamlessly.

The Energy Infrastructure Package

Since the beginning of 2011, the Commission's "Energy Infrastructure Package" initiative has been accompanied by on-going dialogue with the European energy regulators. In a series of workshops involving network operators, institutional investors and banks, regulators investigated the Commission's core assumptions on the level of investment expected by 2020, the obstacles to realising this investment, and suitable remedies. Like the European network operator associations ENTSO-E and ENTSOG, these emphasised the central problem of complex, over-long planning and approval procedures. The extent of potential refinancing of such projects through regulated network tariffs is viewed in a considerably more positive light by the regulatory authorities than by the EU Commission. Regulators therefore see only a limited potential requirement for financial support of individual projects as part of the "Connecting Europe Facility" suggested by the Commission. The role of so-called "innovative financing tools" such as project bonds is also viewed sceptically as regards the specific regulatory framework of the closely intermeshed continental electricity transmission grid. A comparative overview of investment conditions within the framework of the national rates regulation systems was created in the CEER, under the presidency of the Bundesnetzagentur.

European energy regulators are making a constructive contribution to the public discussion on the Commission's legislative proposals of October 2011 and published a position paper on "Regulatory issues in the Energy Infrastructure Package" in January 2012.

In addition, the Bundesnetzagentur has been working since February 2012 on the implementation of the draft regulation ahead of schedule in ten out of twelve priority corridors. In particular, the regional groups in the electricity sector (Northern Sea Offshore Grid, North-South Electricity Interconnections in Western Europe, North South Electricity Interconnections in Eastern Europe und Baltic Energy Market Interconnection Plan in Electricity) and gas sector (North South Gas Interconnections in Western Europe, North South Gas Interconnections in Central Eastern and South Eastern Europe, Southern Gas Corridor, Baltic Energy Market Interconnection Plan in Gas) are to be mentioned here. In these corridors, in working groups led by the EU Commission and consisting of representatives from member states, the regulatory authorities and the TSOs, potential projects of common interest (PCIs) were identified and discussed.

Comments on the joint ten-year-network development plan by ENTSO-E and ENTSOG;

ENTSO-E and ENTSOG are obliged to produce a European network development plan for electricity and gas every two years, looking ten years into the future. ACER, on the other hand, is tasked with preparing a comment on the plan within two months of receipt of the 10-year-network development plan. The objectives of non-discrimination, functional competition and market integration also need to be taken into account in doing so, and it should examine the extent to which the European plan is consistent with the respective national plan. For the electricity sector, the current plan was submitted by ENTSO-E and evaluated by ACER in July 2012.

After receiving the ENTSOG plan on 18 July 2011, ACER examined the plan in terms of consistency and the objectives described, and prepared a comment within two months with the cooperation of the respective national regulatory authorities.

Electricity

System operations framework guideline and associated network codes

ACER sent final system operations framework guidelines to the EU Commission in December 2011. The European network operator association ENTSO-E was then called upon to develop network codes accordingly within these guidelines.

Capacity allocation and congestion management framework guideline and associated network codes

In April 2011 ACER began work on a framework guideline for capacity allocation and congestion management. The completed framework guideline was sent to the European Commission on 29 June 2011. The Commission then asked ENTSO-E on 16 September 2011 to create the network code within this guideline (for capacity calculation, day-ahead and intra-day trade sections) by the deadline. The long-term capacity allocation section is looked at in a separate network code, as further discussions and studies are required in this area first.

System balancing energy framework guideline

In June 2011, ACER started preparations for a framework guideline on system balancing energy, and will submit this to the Commission in September 2012. ENTSO-E is then required to develop a network code in line with this guideline.

Further details regarding the guidelines can be found in the relevant chapters in the "European Integration" section.

Gas

Capacity allocation mechanism framework guideline and congestion management guideline.

On 3 August 2011 the first framework guideline for the gas sector was adopted by ACER. The framework guideline on Capacity Allocation Mechanisms (CAM) provides for non-discriminatory allocation of capacity products standardised across Europe by auction. The guideline lays the foundation for the development of network codes, created by the TSOs on a communal level within ENTSOG. ENTSOG transmitted the network code on 6 March 2012, upon which it was checked for compliance with the provisions in the guideline. ENTSOG are currently revising the network code based on the Agency's evaluation. The Bundesnetzagentur chairs the Capacity Working Group and is therefore closely involved in the process.

In addition to capacity allocation the European Commission published draft guidelines on Congestion Management Procedure (CMP). These are based on recommendations adopted at the time of ERGEG. The Bundesnetzagentur has also made an important contribution to the creation of a European single market in this area. The proposal was accepted by comitology following some amendments in the first quarter of 2012 and is thus a result of Decision 2012/490/EU of the EU Commission. It is to be regarded as a supplement to Annex I of Regulation (EC) No 715/2009 on conditions for access to the natural gas transmission networks. As they currently stand, both measures are compatible with the Bundesnetzagentur's national determination on capacity management and allocation, known as KARLA Gas.

Balancing framework guideline

On 18 October 2011, the balancing framework guideline, the development of which the Bundesnetzagentur played a fundamental role in, was adopted by ACER. The core points of the guideline, which include the principle of daily balancing and the procurement of system balancing energy via the short-term wholesale market, are essentially compatible with the German balancing regime as per GABi Gas. On 13 April 2012 the European TSOs in ENTSOG published a draft network code on balancing based on the framework guideline and made this available for public consultation until 12 June 2012. The contents of the final network code, which is to be submitted in November 2012, are to be nationally binding and the Bundesnetzagentur will continue to monitor its development closely. A detailled description of the key content of the submitted draft can be found in the "Balancing" section of the report.

Interoperability and data exchange framework guideline

ON 26 July 2012 ACER adopted a "Framework Guideline on Interoperability and Data Exchange Rules for European Transmission Networks". The framework guideline will then be passed on to ENTSOG, which is required to create a network code. The guideline aims to establish pan-European rules for data exchange and to promote interoperability between transmission networks. The essential provisions of the framework guideline will be developed in greater detail in the network code.

REMIT (**R**egulation on wholesale **E**nergy **M**arket **I**ntegrity and **T**ransparency)- **Implementation of Regulation 1227/2011/EU**

As part of Regulation 1227/2011 EU on the integrity and transparency of the wholesale energy market (REMIT) of 25 October 2011, both ACER and the national regulatory authorities assumed new duties which aim to prevent insider trading and market manipulation on wholesale energy markets. The current timetable aims for the entire REMIT supervisory system to be fully functional on a European and national level by the end of 2013. Achieving this will be a significant challenge for ACER, companies and NRAs over the next few years. The Bundesnetzagentur is represented in the relevant working groups and actively supports ACER in creating an effcient and effective supervisory system.

Involvement of Bundesnetzagentur in the Council of European Energy Regulators (CEER).

The Bundesnetzagentur has been a member in the independent Council of European Energy Regulators (CEER) since 2005. The CEER continues despite the establishment of ACER and is particularly dedicated to issues outwith ACER's remit. This includes, amongst other issues, consumer protection, regulatory aspects of customer markets, promotion of renewable energy sources and international cooperation. The CEER also supports the work of ACER in many respects.

European developments in consumer protection

In 2011, as part of its involvement in the CEER's Customer Retail Market Working Group (CRM WG), the Bundesnetzagentur contributed to the development of several documents relating to consumer issues. The third energy package contains consumer law provisions for the national regulators, upon the basis of which the CEER develops various guides for the consumer market. The EU Commission bases its work in consumer market design on these recommendations.

In July 2011 the CEER developed "Guidelines of Good Practice on electricity and gas retail market design, with a focus on switching and billing" for consumer protection and empowerment. In preparation for this, the CEER compiled a summary of the existing national practices in this respect.

In addition, case studies and a first draft of a recommendation on price comparison tools were prepared. A report comparing the roles and duties of the national regulatory authorities in terms of promotion of consumer rights and empowerment was also drawn up, providing an overview of national regulatory authority practices before the Third Energy Package came into force ("Benchmarking Report on the roles and responsibilities of NRA's in customer empowerment and protection as of 1st January 2011").

At the request of the EU Commission, in 2010 ERGEG developed Guidelines of Good Practice for customer complaint handling. In September 2011 the CEER prepared a "Status Review of the Implementation of the GGP on Complaint Handling, Reporting and Classification as of 1 January 2011". The review shows that most recommendations were fully or at least partially implemented in all member states. The Third Energy Package also makes firm proposals for alternative dispute resolution procedures. In this context, the CEER expressed its position regarding the 'branding' of ADR bodies.

In Germany, the provisions of the Third Energy Package were implemented in the new version of the Energy Act (EnWG) in 2011, which led to an increase and specification in the contents of electricity and gas bills and in energy supplier contracts with household consumers (cf sections 40ff of the EnWG) and to companies establishing internal complaint management systems, as well as the creation of a energy dispute resolution service (cf sections 111a ff of the EnWG).

International Strategy Group

The International Strategy Group (ISG) continued dialogues with states and partners of strategic importance and coordinates the CEER's international positions. In particular, this ultimately aimed to strengthen the role of European regulatory authorities on an international level. Special focus was placed on the development of the European external energy policy, with the group taking on an active role here. Moreover, it aimed to further develop common regulatory practices through the exchange of experience and the creation of Best Practices. Examples of this include discussions with the Russion regulator (Federal Tariff Service) and cooperation with the states in the Commission's "Eastern Partnership Platform". Furthermore, there were close bilateral exchanges with other regulator associations and bodies (African Forum for Utility Regulators (AFUR), Association of Ibero-American Regulators (ARIAE), Federal Energy Regulatory Commission (FERC), National Association of Regulatory Utility Commissioners (NARUC), Association of Mediteranean Regulatory for Electricity and Gas (MEDREG)).

Electricity

CEER report on the promotion of renewable energy sources in Europe

The "CEER Report on Renewable Energy Support in Europe", published for the first time in 2011, aimed to establish a record of data comparing support systems for renewable energy sources in 16 EU member states. In the report, the various systems were classified and the supported energy volumes and costs for the systems were compared in terms of technology. The regulatory authorities will prepare an updated version of this report which investigates the progress in market integration of renewables in particular.

As a result of a public consultation in 2011, the CEER published conclusions in June 2012 on the impact of non-harmonisation of national RES support schemes The document looks beyond the public debate on feed-in tariffs versus quota systems to highlight the long-term stability of support systems and the minimisation of investment risks in particular as success factors. In addition, the report underlines the key significance of the Third Energy Package network codes for RES grid integration.

CEER report on regulatory approaches to smart grids

The CEER paper "CEER status review of regulatory approaches to smart electricity grids" is a continuation of the ERGEG position paper on smart grids published in 2010. The investigation makes it clear once again that there is a long way to go before a consensus regarding smart grids is reached on a European level – only four out of 27 countries had a definition for smart grids at the time of the investigation.

The "Regulatory Challenges" section indicates development of smart grids is restricted by a lack of national understanding and political initiatives, non-existent standards and a certain helplessness as to how network operators can be encouraged to choose innovative solutions Nevertheless, three countries do have fixed road maps for smart grids, while these are being considered in eleven more. Cost-benefit analyses of smart grids have already been carried out in three countries and are planned in six others. A large number of countries are currently adhering to their demonstration projects, which are still to be evaluated.

CEER proposes moving forward with demonstration projects and spreading the results as widely as possible. Furthermore, work should continue on the development of indicators for measuring and comparing smart grid output in future.

Best Practice guidelines for regulatory issues surrounding smart metering

At the beginning of 2011, ERGEG published the Guidelines of Good Practice of Regulatory Aspects of Smart Metering. This publication was preceded by a one-year drafting process and built upon a survey of member states regarding the implementation status of smart metering, focussing on 2008. Through its active involvement in ERGEG/CEER's Retail Market Functioning Task Force (RMF TF), the Bundesnetzagentur made a significant contribution to the guidelines' development.

The guidelines contain 29 recommendations, divided into the electricity and gas sectors.
Within these two fields, the following areas were examined more closely:

a) Services that customers can expect from a Smart Metering system and which are linked to certain basic technical functions similar to those in Mandate M/441 (EU Commission mandate for standardisation organisations to establish uniform basic functions for electronic meters). These services are not to be equated with technical functions on the device, but instead are desirable and constructive effects and results of the overall Smart Metering system from a consumer perspective.
b) Cost-benefit analyses and rollout, along with
c) Data protection

The document presents future-oriented requirements that comply with other European provisions, which are to be taken into account both by the member states themselves as well as the industry and users when it comes to Smart Metering.

CEER recommendation for the introduction of a demand response market with smart meters

In 2011 the RMF TF, with the involvement of the Bundesnetzagentur, drafted “CEER Advice on the take-off of a demand response electricity market with smart meters“, a recommendation for the introduction of a demand response market, which should encourage consumers to become more involved in their load management.

The recommendation identified seven market roles which both individually and combined could influence the creation of a load-oriented market: customers, small-scale generators, metering operators, DSOs, suppliers, service providers and national regulators. All involved will be called upon to develop a functioning market with attractive products.

In order for households to (want to) participate in such markets, the applications and functions on offer must be simple and easy to understand. Initiative is not only required from the distribution system operators here. Dynamic network usage tariffs as a means of providing incentives for customer participation in this type of market are viewed critically, as they lead to greater complexity and less transparency for all involved.

Gas

Gas Target Model

At the 18th Madrid Gas Forum in September 2010, regulators were called upon to initiate proceedings which would culminate in a target model for the European gas market. The Commission set the ambitious target of completing the European single gas market by 2014. The regulators then commenced close dialogue with stakeholders. The Bundesnetzagentur led this project together with the Austrian and British regulatory authorities. The Gas Target Model was presented at the 21st Madrid Forum at the beginning of 2012. The model is a plea for the creation of functional wholesale markets, which it defines using a number of criteria. While the provisions in the Third Energy Package and the framework guidelines aim for the most efficient possible use of the existing gas infrastructure, the Gas Target Model attempts to take this as a starting point and offers proposals on how, as a next step, functional supply markets can be created and then linked. The aim here is to keep prices in line as far as possible. Both the concept as a whole, and the two individual steps (creation of liquid markets and connection of these) are highly compatible with the German system and embed this constructively in an overall European model.

Additions to the Best Practice Guidelines for third party access to gas storage - capacity allocation and congestion management

The expansion of the existing Guidelines of Good Practice for Storage System Operators (GGP SSO) on CAM and CMP, developed with the involvement of the Bundesnetzagentur, was adopted in mid-2011. The guideline, which is not legally binding, deals with the determination of capacity allocation to storage facitilities and advises standardised Open Subscription Periods[97]. Similarly, auctions are proposed as a market-based allocation mechanism and the possibility for "combined products", ie bundling storage products and transport capacity if there is sufficient demand on the market. In congestion management, storage facility operators are viewed as having the responsibility for establishing secondary markets. Furthermore, transparency in using interruptible products needs to be improved.

[97] Standardised booking periods.

REMIT and financial market regulation

The Financial Services Working Group (FIS WG), chaired by the Bundesnetzagentur, contributed to the CEER's input for the Commission's draft REMIT regulation. Key projects in 2011 included recommendations on the registration and licensing of energy traders (introduction of a uniform European energy trading passport) and a status report on the supervisory arrangements in European energy trading prior to the application of REMIT. In addition, in preparation for trade monitoring as outlined in REMIT, an IT pilot project was carried out, testing IT structures and analysis methods. For this reason in particular, and for their years of commitment to improving transparency in energy trading, the CEER and FIS were awarded the "Energy Transparency Award" by the Florence School of Regulation in 2011 (see below). The Market Integrity and Transparency Working Group, the successor to the FIS WG, will continue to guide the implementation of REMIT, particularly in terms of the cooperation between the national authorities. The focus here is on the European financial market regulations, the development of which the CEER plays a key role in. The aim of the CEER is that the regulatory framework is adapted to the needs of the energy market, creating a more positive effect for trade and consumers.

Energy Transparency Award 2011

The CEER is the winner of the "Energy Transparency Award 2011". The prize-winning project, the "Energy Trade Data Reporting Scheme" (ETDRS) is the result of a working group which was led by the then Vice-President of the Bundesnetzagentur, Johannes Kindler, together with the General Secretary of the Committee of European Securities Regulators (CESR), Carlo Comporti.

Work on the ETDRS began in 2007. A joint market survey carried out by the European energy and financial market regulators came to the conclusion that the European financial market legislation valid at the time did not provide sufficient protection against abuse and manipulation, as the special needs of the market are not adequately taken into account. The regulators therefore submitted a joint proposal to the Commission to issue a regulation tailored to the energy market which promoted transparency and prevented market abuse and manipulation. According to the regulators' proposal, this should be achieved through publication obligations and sanction mechanisms tailored specially to the energy market Taking up this proposal, in December 2010 the EU Commission published a draft REMIT which came into force in November 2011.

Parallel to this, the ETDRS was instigated as a pilot project in 2010 for the later implementation of REMIT. The project involved the testing of an IT infrastructure and data formats, as well as the methods for analysing trade data. It emerged that cost-effective and standardised recording of the data is possible. The experiences of the ETDRS pilot project today provide the basis for the implementation of REMIT, as they can be called upon in the collection of transparency data and the analysis thereof.

The Bundesnetzagentur's European trade supervision activity

In light of the increasing economic significance of electricity and gas trade and the steadily advancing European orientation of trade activity, the need for fundamental improvement in state supervision of European energy markets has become clear.

In order to close gaps in the supervision of energy trade, European legislators adopted the Regulation (EU) No 1227/2009 on Wholesale Energy Market Integrity and Transparency (REMIT), which came into force on 28 December 2011. The core objective of REMIT is to prevent abusive trade activities by individuals in order to protect market participants' trust in a "functioning" wholesale market.

To help achieve this objective, REMIT contains both a ban on insider trading and a ban on market manipulation in energy trading, each aimed at the market participants (REMIT Article 3 and Article 5).

Extensive data surveys and analyses are required to monitor whether these bans are infringed upon and identify potential cases of insider trading or market manipulation. ACER plays an important role here, as under REMIT it is responsible for the data survey and an initial evaluation. For the data survey, the traders and buyers are for example essentially obliged to report to ACER framework data on each individual transaction, particularly the product description, volume traded and price.

On a national level, questions of responsibility regarding the enforcement of REMIT should be clarified by the law on the creation of a market transparency body in the EnWG (Bundesnetzagentur) and GWB (Bundeskartellamt). This provides for joint market supervision by the Bundeskartellamt and the Bundesnetzagentur, where the latter is responsible for the registration of the market participants applicable under REMIT and has the power to enforce the ban on insider trading and market manipulation. In accordance with draft legislation, the market transparency body (MTB) will be housed at the Bundeskartellamt, which in cooperation with the Bundesnetagentur assumes the role of national "market monitoring body" and thus complements ACER's ongoing monitoring activities. The data and suspicious cases collected by ACER and the MTB are made available to the Bundesnetzagentur in order for a more detailed analysis of the information to be carried out. The Bundesnetzagentur can take action if any infringements against the conditions of a ban are identified. In the event of any particularly serious infringements which constitute a criminal offence, the proceedings are passed on to the public prosecutor by the Bundesnetzagetur.

In future, market participants active in Germany need to register with the Bundesnetzagentur before they are permitted to trade wholesale products. The Bundesnetzagentur transmits the information on registered companies to ACER.

Taking into account the various responsibilities, close but flexible cooperation needs to be established with the relevant players in order to ensure effective supervision. In addition to the MTB and ACER, these also include the Federal Financial Supervisory Authority, exchange regulators, trade supervisory offices and other national regulatory authorities (NRA).

Report on investment conditions in European countries

One duty involved in the management of the CEER's Efficiency Benchmarking Task Force is to further develop the internal Report on Investment Conditions in European Countries. The report analyses the different investment conditions in the electricity and gas networks in the individual European states. This report was first drafted in 2011. An update is currently being prepared for 2012 and electronically processed in a CEER database. In addition, interesting aspects (usage durations, basis of assessment and rate of return) from the previous report will be further analysed.

Investment measures/incentive regulation

The Incentive Regulation Ordinance (ARegV) offers network operators the option of including costs for investments in expansion and restructuring in the network tariffs, above the approved revenue cap Under section 23 of the ARegV the Bundesnetzagentur issues approval for individual projects upon request, as long as the requirements cited therein are met.

In 2011, 89 applications for investment measures were made to the relevant Ruling Chamber, with the overall investment volume totalling approx. 8.7bn euros. 62 applications were made relating to the electricity sector, with a volume of approx. 8.15bn euros, of which 7.6bn euros came from the four transmission system operators combined. Gas network operators submitted a total of 24 applications with a volume of approx. 0.7bn euros. The number of applications has thus decreased slightly compared to 2010. However, the investment volumes applied for in 2010 already totalled 9.1bn euros, with 5.7bn euros from the four TSOs. The total volume for the gas sector in 2010 was 2.9bn euros.

Following an amendment to Section 23 ARegV from 2010, approvals under this section no longer only cover capital costs, but also operational costs. As a result of this amendment, the Bundesnetzagentur adapted a total of 214 existing approvals to the new legal situation The Bundesnetzagentur also received determination powers (section 32(1) subpara 8a ARegV) in order to specify the statutory operating costs fixed rate of 0.8 percent of the annual procurement and manufacturing costs which can be attached to an investment measure. Different fixed rates could be determined for particular assets in this way. The relevant Ruling Chamber made use of this option in three cases and set different values for offshore assets (3.4 percent), gas compressor stations (5.2 percent) and gas pressure regulating and metering facilities (5.8 percent). These three decisions are final.

Return on equity

In accordance with the provisions of section 7(6) of the StromNEV and GasNEV, prior to the start of the second regulatory period (electricity: 2014-2018; gas: 2013-2017) the Bundesnetzagentur must issue a new determination on the rates of return on equity for electricity and gas supply networks for this period. The Bundesnetzagentur fulfilled this duty with its determination of 31 October 2011. Following a consultation, the relevant Ruling Chamber determined a permissible return on equity of 9.05 percent. Due to the particular provisions in section 8 of the StromNEV and the GasNEV, this value is calculated after trade tax but before corporation tax. Post-tax the interest rate is 7.39 percent

Compared to the rate of return of 9.29 percent for the first regulatory period, the value has decreased slightly.

Approvals as per section 19(2) of the StromNEV

As a result of reform in energy regulations dated 4 August 2011, the existing provision under section 19(2) of the StromNEV was subject to a fundamental amendment of a number of points (cf Article 7 of the Act Reforming Energy Regulations of 26 July 2011, Federal Gazette I page 1554). The amendments to section 19(2) StromNEV led to significantly more atypical network customers taking advantage of the option of concluding an individual network tariff agreement as per section 19(2) sentence 1 StromNEV and thus enjoying a lower network tariff than they previously had. Furthermore, in connection with the complete exemption of customers with particularly high electricity consumption under section 19(2) sentence 2 StromNEV, these requirements are also lowered.

These amendments to the legal foundation led to a large increase in the number of applications to the relevant Ruling Chamber. 1,286 applications were submitted for 2011 relating to the provisions of section 19(2) sentence 1 StromNEV, which led to a reduction in payment of 161m euros. 277 applications were made relating to section 19(2) sentence 2 StromNEV, which reduced the payment by approx. 209m euros in total. These amounts were passed on pro rata to customers nationwide.

Smart Grid / Smart Market

"Smart grids and smart markets - a key elements paper by the Bundesnetzagentur on aspects of the changing energy supply system" was completed in December 2011.

The paper tackled the issue of how the energy supply system needs to be changed in the course of the *energiewende*. The Bundesnetzagentur's key stipulation is a clear differentiation between smart grids and smart markets. This difference takes into account the legal philosophy of unbundling, where monopolies subject to regulation (the energy network) are to be separated from liberalised market areas.

Contrary to the understanding of the term commonly applied thus far, the Bundesnetzagentur views 'smart grids' as a specialist topic for network operators, who can enjoy increased control possibilities for their networks through the optional use of communication, metering, regulating, controlling and automating technologies and IT components. The aim is essentially to create more space in the network, in other words to increase the actual network capacities if this proves more economical than an increase in further conventional network components. It is important that the Bundesnetzagentur does not make network operation the focus of the *energiewende*, but instead that it gives network operators a functional role on the market, in which the network and the level of capacity provision and management are to be tailored to the needs of the market participants.

The future of energy supply and the associated greatly increased integration of intermittent renewable energy sources requires huge changes in the energy supply system, which can only be implemented via as many innovative business models as possible, and corresponding consumer acceptance (changes in behaviour). These will only be achieved, however, if they are organised by 'market professionals' in a liberalised environment, taking into account customers' wishes. This (competitive) element of the energy future is described by the Bundesnetzagentur as "smart markets".

The introduction of smart metering systems falls under smart markets in the view of the Bundesnetzagentur, where, through the use of variable tariffs, for example, it could make a key contribution to the integration of fluctuating renewable energy volumes, among other things. The Bundesnetzagentur does not believe that nationwide rollout of this technology is necessary for the development of energy networks into smart grids.

Unbundling

Since the Energy Act came into force in 2011, new unbundling regulations have applied to network operators since August of that year. Transmission system operators in particular were therefore faced with new structural and organisational challenges. However, the 2011 Energy Act also brought new regulations for distribution network operators to some extent, particularly regarding their separation from associated retail activities.

As a result of the new arrangements for monitoring unbundling, the data are not based on the monitoring survey carried out by the Bundesnetzagentur. To a greater extent that in previous years, the basis for the data consists of the DSOs' compliance reports which are to be submitted to the Bundesnetzagentur as per section 7a(5) of the Energy Act.

The trend which had emerged in recent years and which appears to continue is that DSOs are better equipped with staff and fulfil the network operator tasks prone to discrimination as determined by the Bundesnetzagentur in the interpretation guide. It should be said however, on a restrictive note, that this trend applies to the large network companies, with the staffing situation in the 20 smaller companies virtually unchanged since 2008. These DSOs are only obliged to submit a compliance report partially as the customers of the controlling company need to be taken into account. The DSOs have between 4,000 and 120,000 customers connected.

What's more, the trend is more evident among electricity network operators than in the gas sector, with a tendency towards larger network companies here too. Overall, the structure in that sector appears slightly more balanced that for electricity.

DSOs have on average approximately 220 permanent employees. Only nine network operators have shown that the number of employees is not even five percent of the employees working on network activity in the vertically integrated utility company. Staff interconnections in the linked companies have not yet been completely remedied, although they continue to decrease, particularly thanks to targeted proceedings by the Bundesnetzagentur.

The network companies are continually presented with the challenge of arranging their processes in such a manner that information unbundling is complied with. Examination of the compliance reports for 2011 thus focussed on network tariffs and feed-in management.

The successful work of the compliance officers in the companies also becomes clear through the examination of processes. 84 percent of compliance officers reported on the process of non-discriminatory calculation and publication of network tariffs - an increase of ten percent on the previous year. 69 percent of compliance officers reported on the examination of non-discriminatory feed-in management, which was requested for the first time in 2011. Complaints about network tariff calculation also decreased in the period under review.

Although the network companies continue to grow, the compliance officer – responsible for overseeing unbundling – is in most cases employed by the parent company and seldom directly by the network operator. In a few cases this function is also performed by an external service provider. Moreover, the compliance officer holds other additional positions in some of the companies. This can be problematic in instances where the compliance officer is very busy with additional function(s), and should be subject to closer investigation in the next compliance report.

A significant change for distribution system operators in the new Energy Act is the obligation to establish clear separation from associated retail activities. This includes all branding. 76 percent of network operators reported on work and changes in this area in the period under review. Over half the companies reported fixed communication design measures that were already planned. In light of the legal obligation of having a separate brand and communication, in place since August 2011, the Bundesnetzagentur estimates that very few DSOs have met the requirements thus far. Further implementation measures are necessary. Initial progress in this respect can be seen online, where now almost all network operators have their own site separate from their parent company.

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